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October 12, 2021

Arkansas Department of Energy and Environment
Division of Environmental Quality
Office of Water Quality
Attn: Associate Director Alan York
5301 Northshore Drive
North Little Rock, AR 72118-5317

Re: Notice of Planned Participation Pursuant to 40 C.F.R. 423.19(f)
White Bluff Steam Electric Generating Facility
AFIN: 35-00110; Permit Number: AR0036331

Dear Mr. York:

On October 13, 2020, the U.S. Environmental Protection Agency ("EPA") published a final rule revising the technology-based effluent limitations guidelines and standards for the steam electric power generating point source category applicable to bottom ash transport water ("2020 Reconsideration Rule").[1] The 2020 Reconsideration Rule modified the EPA's 2015 Steam Electric Power Generating Effluent Limitations Guidelines[2] applicable to the facility owned by Entergy Arkansas, LLC located at 1100 White Bluff Road, Redfield, Arkansas 72132 in Jefferson County, Arkansas, known as the White Bluff Steam Electric Generating Station ("White Bluff").

The 2020 Reconsideration Rule prescribes certain effluent limitations guidelines ("ELGs") applicable to existing point sources and provides certain limited exceptions to the new ELGs. Facilities planning permanent cessation of coal combustion by December 31, 2028 may seek to qualify for such exemptions.

White Bluff "seeks to qualify as an electric generating unit that will achieve permanent cessation of combustion of coal by December 31, 2028" under Part 423 of Title 40 of the Code of Federal

[1] United States, Environmental Protection Agency. "Steam Electric Reconsideration Rule." 85 FR 64,650 (Oct. 13, 2020).

[2] United States, Environmental Protection Agency. "Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category." 80 FR 67,838 (Nov. 3, 2015).

Regulations and makes that election through this Notice of Planned Participation ("NOPP") pursuant to 40 C.F.R § 423.19(f).

Affirmative Statement of 40 C.F.R § 423.19(f) Requirements

- White Bluff operates two units, Units 1 and 2, which will achieve permanent cessation of coal combustion no later than December 31, 2028.
- Units 1 and 2 will achieve permanent cessation of coal combustion by December 31, 2028 through retirement.
- The retirement of Units 1 and 2 is approved by the Arkansas Department of Energy and Environment, Division of Environmental Quality ("DEQ") through (1) an Administrative Order, dated August 7, 2018[3] and (2) the 2018 Arkansas Phase II Regional Haze State Implementation Plan Revision where the Administrative Order is incorporated.[4]
- Further, the retirement of Units 1 and 2 is approved by the EPA through its approval of Regional Haze State Implementation Plan Revision for Electric Generating Units in Arkansas.[5]
- A copy of EAL's most recently filed Integrated Resource Plan ("IRP") is attached to this Notice as Attachment C.

Milestones to be met between the date of this NOPP and the permanent cessation of coal combustion at White Bluff are described in Attachment A. Should any milestones be added or modified, they will be updated in the Annual Report required to be filed by 40 C.F.R. § 423.19(f)(3). The Annual Reports will provide a narrative discussion of any completed, missed, or delayed milestones.

Please contact me if you have any questions regarding this qualification request.

Sincerely,

John Peiserich

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[3] The Administrative Order is attached to this NOPP as Attachment B.

[4] The 2018 Arkansas Phase II Regional Haze State Implementation Plan Revision is attached to this NOPP as Attachment C.

[5] United States, Environmental Protection Agency. "Approval and Promulgation of Implementation Plans; Arkansas; Approval of Regional Haze State Implementation Plan Revision for Electric Generating Units in Arkansas." 84 FR 51,033 (Sep. 27, 2019).

Attachment A

Milestones to Permanent Cessation of Coal Combustion

Date	Milestone
October 12, 2021	NOPP Filed
March 2022	File NPDES Permit Modification Application
October 13, 2022	NOPP Annual Report Deadline
October 13, 2023	NOPP Annual Report Deadline
December 31, 2023	Current NPDES Permit Compliance Date for Zero Discharge of Bottom Ash Transport Water
October 13, 2024	NOPP Annual Report Deadline
October 13, 2025	NOPP Annual Report Deadline
October 13, 2026	NOPP Annual Report Deadline
October 13, 2027	NOPP Annual Report Deadline
October 13, 2028	NOPP Annual Report Deadline
December 31, 2028	Permanent Cessation of Coal Combustion at White Bluff

Entergy

Entergy Arkansas, Inc.
425 West Capitol Avenue
P. O. Box 551
Little Rock, AR 72203-0551
Tel 501 377 3571
Fax 501 377 3599

J. David Palmer
Director, Regulatory Affairs

October 31, 2018

Ms. Mary Loos
Arkansas Public Service Commission
P. O. Box 400
1000 Center Street
Little Rock, AR 72203

Re: APSC Docket No. 07-016-U
Entergy Arkansas, Inc. 2018 Integrated Resource Plan

Dear Ms. Loos:

Consistent with Section 6 of Attachment 1 to the Arkansas Public Service Commission ("Commission") Order No. 6 – Docket No. 06-028-R Resource Planning Guidelines for Electric Utilities, Entergy Arkansas, Inc. ("EAI") submits its 2018 Integrated Resource Plan and the Stakeholder Report that was prepared in accordance with Section 4.8 of the Commission's Resource Planning Guidelines.

Should you have any questions concerning this filing, please call me at (501) 377-3571 or Jeff McGee at (501) 377-3976.

Sincerely,

/s/ J. David Palmer

DP
Attachments

c: All Parties of Record

Entergy Arkansas, Inc.
2018 Integrated Resource Plan

Entergy

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Abbreviations & Definitions	
ACE	Affordable Clean Energy
ADEQ	Arkansas Department of Environmental Quality
AECC	Arkansas Electric Cooperative Corporation
AILC	Agricultural Irrigation Load Control
AMI	Advanced Metering Infrastructure
ANO	Arkansas Nuclear One
APSC	Arkansas Public Service Commission
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals
CEO	Chief Executive Officer
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CT	Simple Cycle Combustion Turbine
DLC	Direct Load Control
DR	Demand Response
DSM	Demand-Side Management
EAI	Entergy Arkansas, Inc.
EE	Energy Efficiency
EGU	Electric Generating Unit
EIA	Energy Information Administration
ELG	Effluent Limitation Guideline Rule
EPA	Environmental Protection Agency
FIP	Federal Implementation Plan
GW, GWh	Gigawatt, Gigawatt Hour
HVAC	Heating, Ventilation and Air Conditioning
ICF	ICF International, Inc.
IRP	Integrated Resource Plan
ISES	Independence Steam Electric Station
kW, kWh	Kilowatt, Kilowatt Hour
LMR	Load Modifying Resource
MISO	Midcontinent Independent System Operator
MLG	Modified Load Growth
MTEP	MISO Transmission Expansion Plan
MW, MWh	Megawatt, Megawatt Hour
NAAQS	National Ambient Air Quality Standard
NERC	North American Electric Reliability Corporation
NO_x	Oxides of Nitrogen
OISR	Optional Interruptible Service Rider
POV	Point of View
PPA	Power Purchase Agreement
PV	Solar Photovoltaic
RICE	Reciprocating Internal Combustion Engine
RPOC	Resource Planning and Operations Committee
RTO	Regional Transmission Organization
SAE	Statistically Adjusted End-Use
SIP	State Implementation Plan
SERC	Southeastern Electric Reliability Council
SO_2	Sulfur Dioxide
SSRP	Strategic Supply Resource Plan
TOU	Time-of-Use
WB	White Bluff Steam Electric Station
UPC	Usage Per Customer
UPP	Union Power Plant
WIIN Act	Water Infrastructure Improvements for the Nation Act

EXECUTIVE SUMMARY

For more than a century, Entergy Arkansas, Inc.'s ("EAI" or the "Company") has provided safe, reliable, and affordable electricity to its customers in Arkansas. EAI continues to serve its diverse, growing customer base by proactively planning for future resource needs by the most reliable and economic means possible.

This document describes EAI's long-term Integrated Resource Plan ("IRP") for the study period 2020-2039 and is intended to provide Arkansas Public Service Commission ("APSC" or the "Commission") and stakeholders insight into the Company's long-term planning process for meeting future demand and energy needs. Similar fundamental uncertainties remain when compared to EAI's most recent IRP, which was filed with the Commission on October 31, 2015. These uncertainties include advances in renewable technologies and their associated costs, future natural gas prices, economics of existing generation, and prospective changes in environmental regulations. Based on subsequent analysis, EAI's total generating capacity is forecasted to be short of its peak customer demand plus reserve margin target in 2025, coinciding with the assumed deactivation of the Company's Lake Catherine resource, or potentially sooner given uncertainty around near-term resource assumptions. This deficit expands over time as forecasted customer demand increases and existing resources reach the end of their assumed useful lives.

As with the Company's most recent IRP, the 2018 IRP utilized a futures-based approach by which three future worlds were constructed in order to reasonably bookend a broad range of future uncertainties. These futures were supplemented with sensitivity cases, which provide insight as to how each future's portfolio of resources reacts to possible changes in key input assumptions. An economically optimal portfolio of both supply-side and demand-side resources was developed for each of the three futures and sensitivity cases. A summary of the modeled portfolios is shown in the table below.

2018 IRP Results	Future A	Future B	Future C
Total Incremental Installed Capacity:	6,660 MW	4,984 MW	7,128 MW
Natural Gas Capacity Additions:	68.4%	94.0%	67.5%
Renewable Capacity Additions:	31.6%	6.0%	32.5%

Based on the results of the IRP analysis, it is reasonable to conclude that EAI's future supply-side resource additions will likely consist of a mix of both natural gas-fired and renewable energy resources. The total amount, timing, and technology mix of new supply-side capacity additions are each uncertain. Based on this uncertainty, EAI has not established any specific targets for traditional or renewable generation additions as part of this IRP analysis.

The IRP's future resource portfolios are developed consistent with the Commission's Resource Planning Guidelines but do not represent planning decisions by EAI. Rather, the Company's specific long-term resource planning actions (e.g., capacity additions) are typically subject to review and approval by the Commission. In the same respect, the IRP's assumptions regarding the cost and availability of various supply-side resources do not reflect the actual cost for implementing those options. They are merely planning assumptions, with the actual costs to be determined at a later time, likely through a market solicitation. In addition, while the IRP seeks to address EAI's capacity needs, this approach should not be read to foreclose a future resource that may provide significant energy value to EAI's customers, and it is not EAI's intent to do so.

While no specific approvals are sought for this IRP pursuant to the Commission's Resource Planning Guidelines, the Action Plan outlined in Section IV of the IRP reflects EAI's present expectations regarding the planning actions that can be expected over the next several years based on the relevant information available at that time.

The 2018 IRP Action Plan consists of seven action items, which are summarized below:

1. Complete Build-Own-Transfer of Solar PV Capacity	As a result of EAI's 2017 Request for Proposals for Build-Own-Transfer Solar Resources, EAI has made selections and is currently working toward acquiring additional solar PV generation by 2021.
2. Supply-side Resource Additions	EAI will monitor its load and capability position and take steps to add supply side resources for both traditional and/or renewable resources as warranted. A competitive solicitation may be issued in 2019 for long-term resources.
3. Potential 2025 Capacity Need	EAI will complete an evaluation of the availability of Lake Catherine Unit 4 past the assumed deactivation date of 2025. In combination with Action Item 2 above, EAI will update the load and capability position in order to monitor the capacity need in 2025.
4. Demand-side Resource Opportunities	EAI will seek and evaluate cost-effectiveness and feasibility for potential projects/programs to gain energy efficiencies in addition to its existing Arkansas Energy Efficiency Program Portfolio.
5. Continue participation in EE	EAI will continue to offer cost-effective EE and DR programs within the Commission's Rules for Conservation and EE Programs and subsequent future Commission orders as provided through Arkansas State law.
6. Coal Environmental Compliance	EAI will continue to monitor changes in environmental law and regulations at the state and federal level and evaluate options for environmental compliance for the EAI coal units.
7. Stakeholder Engagement Process	Stakeholder engagement has been an important part of the development of this IRP. An immediate priority will be for EAI to closely review the stakeholder report and take steps to address concerns and suggestions.

I. Integrated Resource Plan Background and Context

1. Introduction

This document describes EAI's long-term IRP for the period 2020 – 2039. This is the fifth IRP filed by EAI since the APSC adopted its Resource Planning Guidelines in Order No. 6 in Docket No. 06-028-R. Similar to prior IRPs, the 2018 IRP reflects the fact that uncertainty remains an issue that must be considered in long-term resource planning, with no outcome providing absolute certainty as to the appropriate path for the utility to take. In other words, the uncertainties that dominated EAI's 2015 IRP filed with the Commission on October 31, 2015 (*e.g.,* uncertainties associated with potential environmental regulation and advances in renewable resource technology) still remain but have been expanded to include other uncertainties, such as the impact and role of more significant amounts of renewable generation in the market and changes in customer preferences, something that EAI intends to continue to research and monitor.

EAI's process for preparing this IRP considered potential future scenarios in which various resource plans could be evaluated. As with EAI's 2015 IRP, this IRP was (i) developed by EAI's Resource Planning and Operations Staff, (ii) reviewed by EAI's Resource Planning and Operations Committee ("RPOC"), and (iii) approved by EAI's current President and Chief Executive Officer ("CEO"), Laura R. Landreaux.

As indicated above, this IRP does not provide a fixed path for future EAI resource planning. Rather, EAI's specific long-term resource planning actions (e.g., capacity additions) typically are subject to review and approval by the Commission. While no specific approvals are sought for this IRP pursuant to the Commission's Resource Planning Guidelines, the Action Plan contained within this IRP reflects EAI's current expectations regarding the planning actions it will take over the next several years.

2. Resource Planning Objectives

EAI has established a set of resource planning objectives to guide its development of the IRP. These planning objectives were recommended by the RPOC and approved by EAI's former President and CEO Hugh McDonald on May 16, 2012. During the next planning cycle, EAI intends to review and update, if necessary, its planning objectives, which will remain focused on four key areas: cost, risk, reliability, and sustainability. EAI's resource planning objectives are shown in Appendix A.

3. Regulatory Context for EAI's IRP

In 2006, the Commission adopted an IRP rule requiring APSC-jurisdictional utilities to file an IRP at least every three years.[1] The rule required that utilities would immediately file their then-current resource plans. EAI met that obligation by filing the Strategic Supply Resource Plan ("SSRP") that was in place at that time. EAI's next resource plan was filed in 2009, and included the results and report of a stakeholder input process conducted for EAI's 2009 IRP, as well as more comprehensive considerations of demand-side management and load control options. For EAI's 2012 IRP, EAI modified its stakeholder process, reviewing actual study results with stakeholders rather than only reviewing high-level study assumptions and plans, as EAI did for its 2009 IRP. In addition, EAI addressed numerous questions from stakeholders, presented at open meetings or in writing to EAI, with written responses provided for all such questions.

For the 2015 IRP, EAI's stakeholder process proved to be far more interactive than prior stakeholder processes conducted by the Company, with numerous meetings and conference calls directed by the stakeholders with EAI participation and input. EAI takes this opportunity to note the extensive work by the Stakeholder Group on this IRP, which is reflected in the Stakeholder Comments that were attached to the 2015 IRP. These comments reflected the diversity of the views held by various stakeholders, which to their credit appear to have been resolved in an amicable manner.

For this IRP, EAI's Stakeholder Engagement Process began in May 2018 with distribution of a detailed slide presentation describing proposed assumptions, inputs and modeling framework. The materials, while still preliminary, were posted to EAI's IRP website[2]. Additional meeting materials, which included preliminary modeling results from all three Futures, were provided to stakeholders in advance of the in-person stakeholder meeting hosted by EAI in June 2018. The meeting was well-attended with representation from many stakeholder groups. The agenda included an update on the status of EAI's planning activities since 2015, assumptions and modeling framework for the 2018 IRP, as well as preliminary modeling results and a discussion of challenges and observations. In response, during June and July 2018 over 100 detailed questions were submitted to EAI by stakeholders, to which EAI responded via follow-up postings to the IRP website. Most of the questions received were responded to within a week of receipt. In August 2018, EAI hosted a conference call with the Stakeholder Committee to have a technical discussion of the Committee's feedback regarding EAI's IRP

[1] *See* Order No. 6 in APSC Docket 06-028-R
[2] http://www.entergy-arkansas.com/integrated_resource_planning

modeling. Finalized portfolio optimization modeling results for all Futures and Sensitivities were posted to EAI's IRP website on October 4th, 2018.

4. The 2015 IRP Action Plan

The 2015 EAI IRP Action Plan contained six action items, some of which are still in process. The current status of each action item is described below:

1. Coal Unit Environmental Compliance – EAI has resolved its regional haze compliance requirements for its White Bluff Steam Electric Station ("WB") by committing to burn low sulfur coal and to cease burning coal at WB by 2028. EAI continues to work with the Arkansas Department of Environmental Quality ("ADEQ") and other interested parties regarding long-term environmental compliance issues at the Independence Steam Electric Station ("ISES"). EAI will continue to monitor changes in environmental law and regulations at the state and federal level and evaluate options for environmental compliance for the EAI coal units.

2. Clean Power Plan – EAI is continuing to monitor changes in environmental law at the state and federal level. Since the Clean Power Plan was published in the Federal Register in October 2015, there have been various legal challenges. Recently, the Environmental Protection Agency ("EPA") has proposed to repeal the Clean Power Plan and published the proposed Affordable Clean Energy (ACE) Rule, which is intended to replace the Clean Power Plan. See *infra* Section III of this IRP for a detailed discussion of environmental regulation/compliance issues.

3. Complete Acquisition of Power Block 2 from Union Power Plant ("UPP") – EAI completed its acquisition of Power Block 2 from the UPP in March 2016, adding over 500 MW to EAI's generation fleet.

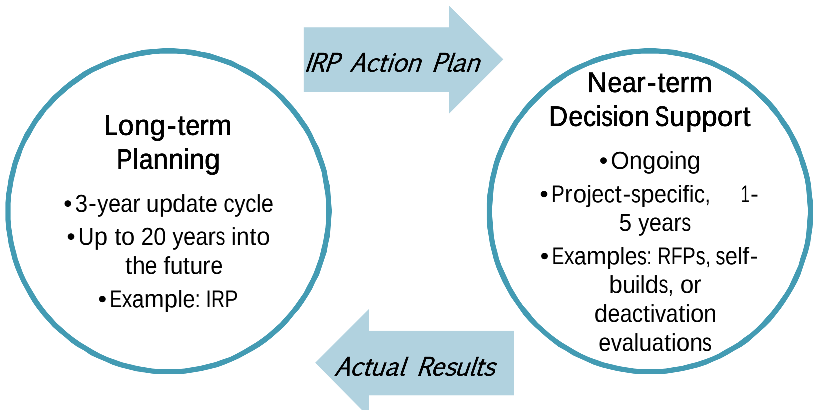
4. Continue Participation in Energy Efficiency – Since 2015, EAI has added approximately 125 MW of peak period savings as a result of expanded DSM and EE programs. A detailed discussion of EAI's participation in DSM and EE is provided *infra* in Section III.

5. Supply-side Resource Additions – In addition to the completed acquisition of Power Block 2 from Union Power Plant in item 3 above, EAI also has added two long-term Power Purchase Agreements ("PPAs") to its portfolio since the 2015 IRP. A detailed discussion of these solar PPAs is provided *infra* in Section II.

6. Stakeholder Engagement Process – EAI implemented changes in the IRP project schedule as well as the modeling based on feedback received through the Stakeholder Engagement Process in the 2015 IRP, as well as EAI's experiences and observations. A detailed discussion of this process is provided in Section V.

II. EAI Resource Planning

The IRP plays an important role in the planning of EAI's future resource portfolio by providing a comprehensive look at long-term themes and tendencies in designing and leveraging a diverse, balanced, and forward-thinking portfolio of resources to EAI planners, as well as stakeholders. While these long-term and forward-looking indicators are important guides to resource planning, the IRP fulfills a distinctly different purpose and process from near-term, specific resource decisions that typically are presented to the Commission for approval.



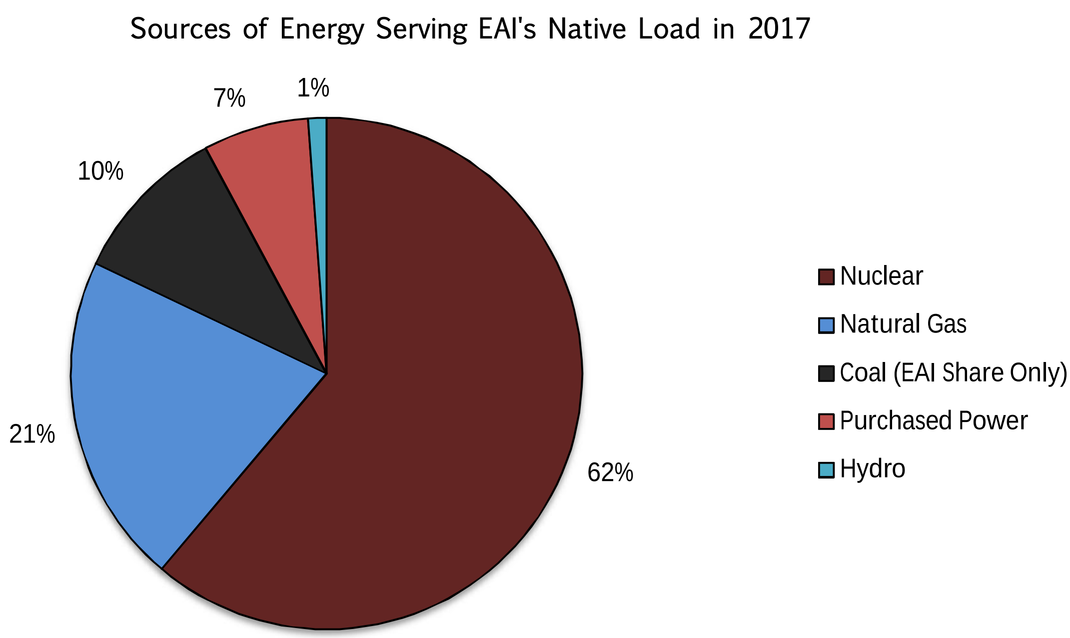
The considerations detailed in the following pages are focused on efficiently meeting all of our customers' ever-changing supply needs. EAI's IRP strategy ensures we are taking the necessary steps today to continue to enhance reliability and affordability while mitigating risks that could impact either of these factors for our customers as much as possible. This approach also provides the flexibility EAI requires to respond and adapt to a constantly shifting utility landscape.

The study period for the 2018 IRP is 2020 through 2039 and outlines the current energy landscape as well as the challenges and opportunities that lie ahead. A twenty-year study period was chosen for this IRP in order for EAI to evaluate long-term trends under a broad range of possible future outcomes. As in EAI's previous IRPs, the 2018 IRP is guided by EAI's Resource Planning Objectives, which focus on four key areas: cost, risk, reliability and sustainability. The full details of the Resource Planning Objectives are available in Appendix A.

1. Existing Resources

EAI's customer base has grown to over 709,000 residential, commercial, industrial, and governmental customers located in 63 of Arkansas' 75 counties, covering over 40,880 square miles. The Company currently controls, through ownership or through PPAs, a diverse array of generating resources totaling approximately 5,365 MW to serve these native load customers. The Company's nuclear power resources include 1,722 MW from the two-unit Arkansas Nuclear One ("ANO") plant located near Russellville and 308 MW from the Grand Gulf Nuclear Station ("Grand Gulf") near Port Gibson, Mississippi, under a long-term PPA. EAI also utilizes 1,024 MW from coal-fired generation at WB and ISES located near Redfield and Newark. EAI shares ownership of WB with the Arkansas Electric Cooperative Corporation ("AECC") and several municipal electric utilities and shares ownership of ISES with Entergy Mississippi, Inc., AECC, Entergy Power Inc., an Entergy affiliate, and several municipal electric utilities. The Company's generation fleet is rounded out with 92 MW of hydro-electric capacity along the Ouachita River Valley and 2,139 MW of natural gas-fired generation that includes 606 MW from the Hot Spring Plant, 505 MW from the Ouachita Plant and 501 MW from Power Block 2 of UPP, which are modern combined cycle gas turbines ("CCGT"). Figure 1 below shows the percentage, by fuel type, of energy sources serving EAI's native load in 2017.

FIGURE 1: FUEL MIX



In addition to these generating resources, EAI's portfolio also includes resources that provide capacity value through reducing customer load. These load modifying resources ("LMRs") contributed nearly 230 MW combined of capacity including value associated with reduced line losses and reserves. EAI also manages a portfolio of energy efficiency ("EE") programs that produce both energy savings for customers and a reduction in load served for the company. These programs have reduced the company's load behind the customer meter by an incremental 125 MW since 2015 and an aggregate 348MW since programs were introduced in 2008.

A new addition to EAI's portfolio since the 2015 IRP and a result of EAI's 2014 Request for Proposals[3], EAI has executed a long-term PPA for an 81 MW solar photovoltaic resource located near Stuttgart, Arkansas named Stuttgart Solar.[4] The Commission issued Order No. 5 in Docket No. 15-014-U on September 24, 2015, approving the PPA. The resource achieved commercial operations ahead of schedule in December 2017. EAI's PPA began with the start of the 2018/19 MISO Planning Year, which was June 1, 2018.

Additional information about EAI's existing resources is available in Appendix B.

2. Planned Resources

Since 2015 EAI has sought regulatory approval for additional renewable generation. As a result of EAI's 2016 Request for Proposals for Renewable Generation Resources, EAI has executed a long-term PPA for a planned 100 MW solar photovoltaic resource to be located near Lake Village, Arkansas, to be called Chicot Solar[5]. The Commission issued Order No. 4 in Docket No. 17-041-U on June 18, 2018, approving the PPA. The 2018 IRP assumes the resource achieves commercial operations and the PPA begins by 2020.

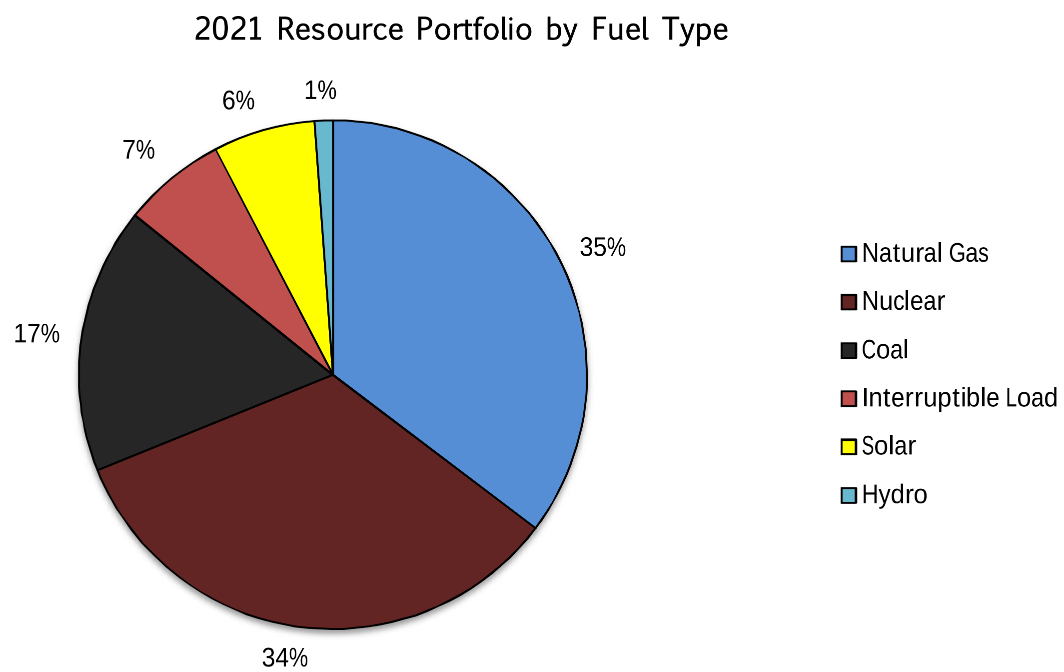
Additionally, in its 2017 Request for Proposals for Build-Own-Transfer Solar Photovoltaic Resources EAI sought up to 200 MW of solar generation to add to its resource portfolio. EAI has not yet brought this future resource before the Commission to seek approval; however, EAI expects to initiate those proceedings in the near future. These acquisitions would provide low-cost, emissions-free capacity and energy to EAI's portfolio. The 2018 IRP assumes Commission approval is received and commercial operation is achieved by 2021.

Under the assumption that the planned resources described above proceed as planned, the 2018 IRP reflects a total of approximately 5,859 MW of resources in EAI's portfolio

[3] Information on EAI Requests for Proposals can be found at: http://www.entergy-arkansas.com/rfp/energy_capacity.aspx.
[4] Docket No. 15-014-U
[5] Docket No. 17-041-U.

by 2021 on an effective capacity basis[6]. The diversity of EAI's currently planned resource portfolio in 2021 is shown in Figure 2 below.

FIGURE 2: CAPACITY MIX



3. FUTURE OF EXISTING RESOURCES

As indicated above, uncertainty is an ongoing issue that resource planners must consider in preparing long-term resource plans. In subsequent sections, EAI will review a number of factors that are assessed to guide and inform the portfolio design strategies and other issues facing EAI's planners.

Developing an IRP requires making assumptions about the future operating lives of existing generating units. Two key issues in this determination are the effective date of future environmental compliance requirements and whether the investments needed for EAI's older units to keep operating in compliance with those regulations are economical compared to alternative capacity resources. The IRP includes deactivation assumptions for existing generation in order to plan for and evaluate the best options for replacement capacity over the planning horizon. These deactivation assumptions do not constitute a definitive deactivation schedule, but are used as planning tools and help to prompt cross-functional reviews and recommendations. It is not unusual for these

[6] Effective capacity is 50% of installed capacity for solar resources, 15.6% for wind resources and 100% for conventional resources. LMRs receive peak hour capability plus reserve margin and transmission losses.

assumptions to change over time given the dynamic use and operating characteristics of generating resources.

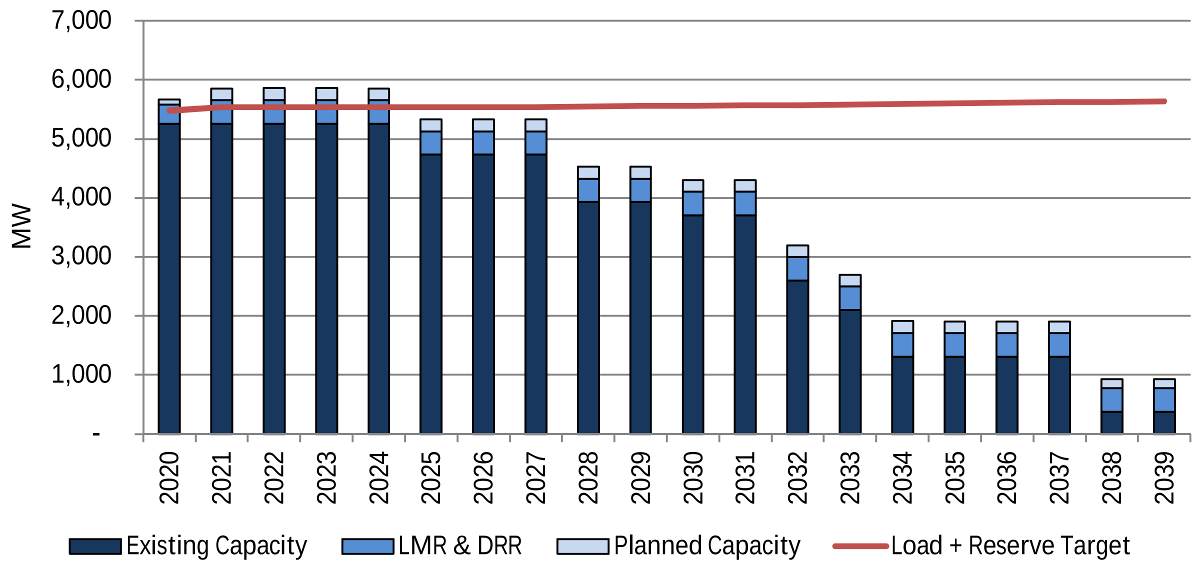
It is important to recognize that assumptions related to these uncertainties about operating lives of existing generating units do not reflect actual decisions regarding the future investment in resources or the actual dates that generating units will be removed from service. Key uncertainties related to environmental compliance, for example, include the requirements of rules still under development, the effective dates for compliance, the outcome of current litigation, congressional activity, and the possibility of extensions of the compliance deadlines. Rather, unit-specific portfolio decisions, e.g. sustainability investments, environmental compliance investment, or unit deactivations, will be made at the appropriate time and will be based on economic and technical evaluations considering such factors as projected forward costs, anticipated operating roles, and the cost of supply alternatives. These factors are dynamic, and as a result, actual decisions may differ from planning assumptions as greater certainty is gained regarding requirements of legislation, regulation and relative economics. Accordingly, EAI's resource plans seek to retain the flexibility to respond to changes in circumstances up to the time that a commitment is required to be made.

4. Resource Needs

A number of factors are considered and evaluated in order to understand and determine EAI's resource needs:

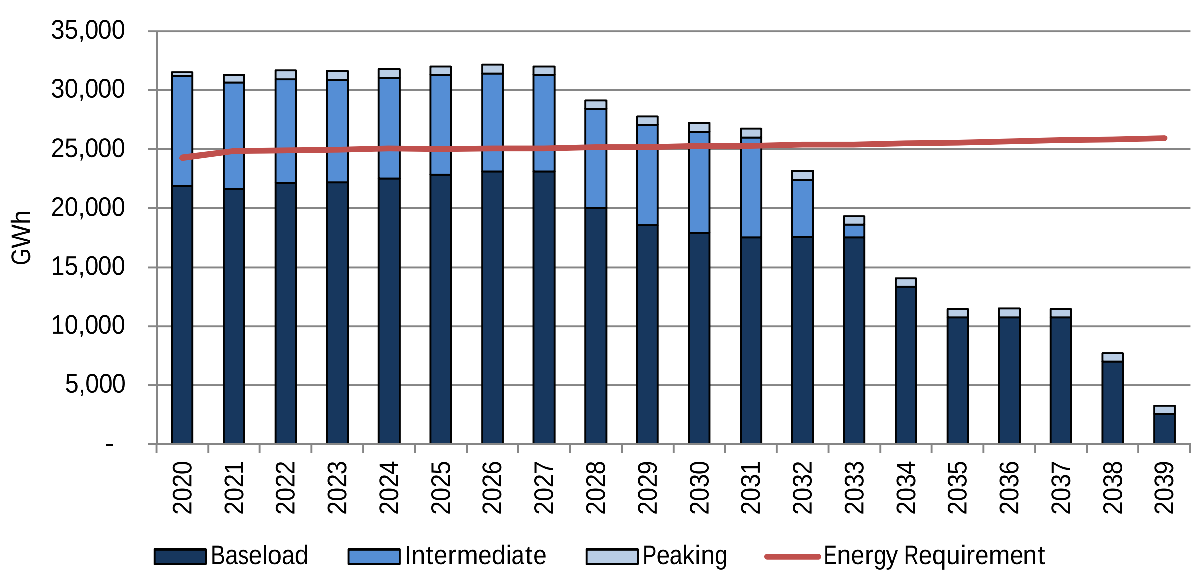
- *Long-Term Capacity Requirements* - EAI is projected to need new generating capacity over the course of the 20-year IRP planning period in order to reliably serve customers. Taking deactivation assumptions into account, short of any new additions to generation beyond the planned resources described earlier, the long-term deficit is expected to exceed 1,000 MW by 2028. This need grows to over 4,700 MW by the end of the planning horizon. Figure 3 below shows EAI's portfolio of existing resources, including both generating units and demand-side capacity, and planned resources, as described above, compared to EAI's peak load-plus-reserve-margin target. An assumption for future energy savings due to continued and expanded EE programs is included in the peak load. The total capability is short of the peak load plus reserves by as soon as 2025. The deficit expands over time as expected loads increase and older generating units reach an assumed end of useful life.

Figure 3: EAI Capacity Position



- *Energy Requirements* - In addition to capacity requirements, EAI evaluates how its existing and planned resources effectively meet its energy requirements to help inform future portfolio design. As resources deactivate and capacity requirements increase, EAI will look to balance energy producing and peaking generation to effectively and efficiently meet customer requirements.

FIGURE 4: EAI ENERGY REQUIREMENTS



- *Customer Usage* – Of course, both capacity and energy resource needs are driven by customers' consumption and preferences. Customer conservation efforts, some of which are currently driven by energy efficiency programs, have already directly affected resource needs as discussed further in Section III. The type, size and timing of future resource needs may be affected as customers gain additional resources to manage consumption, such as those that will be enhanced by Advanced Metering Infrastructure ("AMI") as well as increased accessibility to rooftop solar or battery storage technology

EAI's long-term planning process and the evaluation outlined in this IRP helps inform how EAI will meet its future capacity and energy requirements needed to continue to reliably serve its customers. EAI's planning approach is to use a diverse portfolio of energy generation resource alternatives, located in relatively close proximity to customer load with flexible attributes to help provide sufficient capacity during peak demand periods as well as adequate reserves, ensuring EAI is able to continue providing safe and reliable service at a just and reasonable cost for our customers, given the primary objective of risk mitigation.

5. Transmission Planning

The Company's transmission planning group ensures that the transmission system: (1) remains compliant with applicable North American Electric Reliability Corporation ("NERC") standards, and related Southeastern Electric Reliability Council ("SERC") and Entergy's local planning criteria, and (2) is designed to efficiently deliver energy to end-use customers at a reasonable cost. Since December 2013, EAI has been a Transmission Owning member of MISO, a Regional Transmission Organization ("RTO"). MISO was approved as the nation's first RTO in 2001 and is an independent nonprofit member-based organization that supports the delivery of wholesale electricity and operates energy and capacity markets in 15 U.S. states and the Canadian province of Manitoba. In cooperation with stakeholders, MISO manages 65,000 miles of high voltage transmission and 200,000 megawatts of power generating resources across its footprint. Since joining MISO, EAI has planned its transmission system in accordance with the MISO Tariff.

A key responsibility of MISO is the development of the annual MISO Transmission Expansion Plan ("MTEP"). EAI is an active participant in the MISO MTEP development process, which is currently in development of the MTEP 19 cycle. Participation in the MISO MTEP process is the method by which EAI's transmission plan is incorporated into the annual MTEP document. The overall planning process can be described as a combination of "Bottom–Up" projects identified in the individual MISO Transmission Owner's transmission plans which address issues more local in nature and are driven by the need to safely and reliably provide service to customers, and projects identified during MISO's "Top-Down" studies, which address issues more regional in nature and provide economic benefits or address public policy mandates or goals.

Through these MTEP related activities, EAI works with MISO, other MISO Transmission Owners, and stakeholders to promote a robust and beneficial transmission system throughout the MISO region. EAI's participation helps ensure that opportunities for system expansion that would provide benefits to EAI customers are thoroughly examined. This combination of Bottom-Up and Top-Down planning helps ensure all issues are addressed in an effective and efficient manner.

EAI's transmission strategy is centered upon meeting the evolving needs of its customers for safe and reliable energy. Each year the EAI transmission system is thoroughly studied to verify that it will continue to provide EAI customers with reliable and safe service through compliance with all applicable NERC standards as well as Entergy's local planning criteria and guidelines.

These studies identify potential system conditions where reduced reliability may occur in the future. Additional studies are then performed to develop projects and determine what, where and when system upgrades are required to address the future reliability concerns. This annual review identifies any transmission system reinforcements necessary to provide reliable and safe service in response to changing system conditions. These studies consider the effects of overall system load growth, retirements of existing generation resources, implementation of new generating resources, the adequacy of new and existing substations to meet local load, the expected power flows on the bulk electric system, and the resulting impacts on the reliability of the EAI transmission system.

These reliability studies result in projects which are presented annually to the EAI RPOC and ultimately must be approved by the EAI President and CEO. Once approved, these reliability projects are submitted to MISO for regional study, to 1) verify that the reliability need exists, 2) to verify that the proposed solutions solve the reliability need, and 3) to provide stakeholders the opportunity to discuss alternatives. Additionally, MISO performs other studies each year to consider planning issues including market efficiency projects and customer driven projects, such as those driven by generator interconnection requests and opportunities for interregional projects with neighboring planning regions.

The result of the MISO MTEP process is a compilation of transmission projects that are needed to address system reliability requirements, improve market efficiency, and/or provide specific system benefits as delineated in the MISO Tariff. The MTEP identifies solutions to meet regional transmission needs and to create value opportunities through the implementation of a comprehensive planning approach.

Each MTEP document is identified by the year in which it was completed. Appendix A of each MTEP cycle lists and briefly describes the transmission projects that have been evaluated, determined to be needed and subsequently approved by the MISO Board of Directors. Since joining MISO, EAI has submitted projects into MTEP 14, MTEP 15, MTEP 16, MTEP 17, MTEP 18, and is currently in preparation for MTEP 19. The EAI projects that were approved for inclusion in Appendix A of MISO's MTEP 17 cycle are provided in Appendix C, Table 13. Also, submitted Target Appendix A projects for MTEP 18 are located in Appendix C, Table 14, and proposed projects for Target Appendix A of MTEP 19 are located in Appendix C, Table 15. These future transmission projects and other transmission plans developed during the next three years will be important inputs to consideration of future resource needs.

Integration of Transmission and Resource Planning

The availability and location of current and future generation on the transmission system can have a significant impact on the long-term transmission plan, requirements for meeting NERC reliability standards, and efficiently delivering energy to customers at a reasonable cost. Like transmission, new generation must be planned well in advance, and due to the interrelationship of generation and transmission planning, looking far enough into the future and addressing potential generation needs is critical in meeting EAI's planning objectives of low cost, improved reliability, and reduced risk.

The continued evaluation and condition of EAI's generation fleet must be taken into account for integrated generation and transmission planning. EAI's planning assumption includes deactivation of existing generation resources during the planning horizon, which will have an impact on transmission reliability requirements without proper replacement generation.

6. Distribution Planning

EAI has put in place programs that have and will continue to maintain and improve the reliability of our distribution lines and our distribution line infrastructure, while aiming to minimize customer outages. Customers directly benefit from improvements in line maintenance, infrastructure, vegetation management, and substation reliability through reduced outages and outage duration. Customers also benefit from the reduction in costs from extending the life of distribution assets and minimizing maintenance costs with respect to those assets.

Modernization of the distribution system has several key components. One of them is the replacement of existing physical infrastructure and distribution assets to provide more reliable service to our customers. This aspect of modernization is addressed on an ongoing basis through the annual Transmission and Distribution Plan. Additionally, via the modernization of distribution system technology, EAI can gather faster and more accurate data from the distribution system than was previously possible. With this information, the Company can make quicker, more informed decisions about impacts to the system and thereby potentially reduce both the number and duration of outages, improving overall system reliability. For example, improvements to the speed and accuracy of crew deployments during customer outages would improve outage restoration times and ultimately lower costs to customers.

EAI's approach to grid modernization will continue to be a thoughtful and balanced analysis of the costs and benefits for customers, with a preference for technologies that have a track-record of delivering on their promises of benefits. The Company must be able to respond to and implement these emerging technologies in a timely manner.

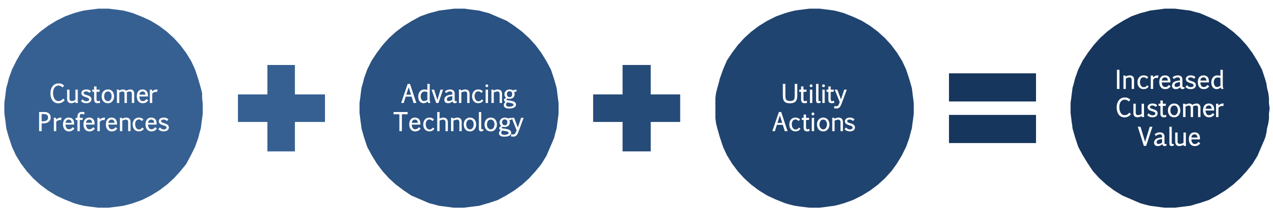
III. The 2018 Integrated Resource Plan

1. Key Inputs and Assumptions Overview

1.1 Changing Utility

Guided by the Resource Planning Objectives, EAI's resource planning process seeks to maintain a portfolio of resources that reliably meets customer power needs at a just and reasonable supply cost while minimizing risk exposure. While the landscape within the electric utility industry is changing, the Resource Planning Objectives are as important and relevant as ever, and this IRP offers early insight for opportunities to respond to this evolving environment.

Figure 5: Changes and Opportunities Within the Utility Industry



EAI recognizes the way customers consume energy is changing, so the way the company plans for, produces, and delivers the power customers rely on must continue to evolve as well. EAI strives to have a planning process that provides for the flexibility needed to better respond to this constantly-evolving environment. Below are considerations, changes, and opportunities that have comprised part of EAI's 2018 IRP development.

Customer Preferences

With advancements in technology and evolving priorities, both within and outside of the traditional utility framework, customer expectations will continue to change. The evolution and adoption of customer-centric technology and services has created a shift in customer preferences and expectations—both in terms of how the power they use is generated and the services and offerings they value from utility companies.

Today's energy customers are using energy more efficiently than ever before, due to both an increasing emphasis on social responsibility and sustainability and advances in energy efficiency standards. As specified in the Resource Planning Guidelines, EAI approaches energy efficiency with the broader goal of enhancing the generation, delivery and use of energy, recognizing that a well-designed electric system, with the proper mix of generating resources, is just as important to reducing customer costs and bills as are programs aimed at educating customers how to efficiently manage their usage.

Customers are also seeking more options in the generation and delivery of energy, including how they interact with, understand, and manage their own energy use, as well as the actual sources from which their energy is derived. Increasingly, our customers are becoming more interested in sourcing their power from cleaner, more sustainable sources of energy, including natural gas, nuclear, and renewables like solar. As reflected in EAI's AMI proceeding in Docket No. 16-060-U, EAI's deployment of AMI is in response to ever-evolving customer expectations regarding the provision of electric service and technological innovation that is changing the way energy is supplied and distributed. EAI's interest is in actively engaging its customers to obtain a better sense of those expectations and the ways in which EAI can bring offerings to the marketplace to meet those expectations.

EAI is focused on achieving a better understanding of these changing customer preferences and the IRP is one set of input information EAI can leverage to help accomplish that goal. That will allow EAI to:

- Develop a comprehensive outlook on the future utility environment so we can more effectively anticipate and plan for the future energy needs of our customers and region.
- Incorporate new, smart technologies and advanced analytics to better assess where expanding resource alternatives can be leveraged, and plan for improvements and enhancements to the electrical grid.
- Continue integrating and offering the innovative products and services our customers want and expect as is reasonable.

Advancing Technology

Technological advancements provide the energy industry increased opportunities and alternative pathways to plan for and efficiently meet customers' energy needs. From improving the reliability and efficiency of energy production and delivery of that energy to customers, to more customer facing opportunities, like storage, conservation, and AMI-enabled options, these innovations can strengthen reliability and increase affordability for the homes, businesses, industries, and communities that EAI serves. These new technologies also support the continued development and expansion of sustainability efforts while addressing EAI's long-term planning objectives, outlined in further detail below.

The deployment of advanced meters and development of smart energy grids, for example, are enabling the entire utility industry to better understand the new and changing ways in which customers are using energy. This allows energy companies to make more informed decisions and provide tailored customer solutions through enhancements to electric infrastructure and the adoption of new products and services.

Utility Actions

EAI understands that how our customers use energy is changing and these changing needs and expectations will inform the IRP process as well as EAI's approach to customer service. As a utility provider, it is incumbent upon EAI to adapt to the evolving needs of customers. The scope and nature of our business will and must change in response to the changing landscape. EAI's objective is to find, deploy, and integrate the right mix of technology, products, and services that provide solutions to serve the needs of customers while maintaining the reliability they need and expect.

To do that, EAI is evaluating and incorporating new, customer-centric technology, and designing an energy portfolio that leverages a more diverse mix of energy resources—including a greater reliance on what have recently become cost-effective renewable and clean energy sources—to adapt to the changing needs of customers. EAI, as compared to individual customers, is better positioned to efficiently integrate these new technologies and solutions into the electric grid. All the while, EAI is keeping affordability and reliability for its customers at the forefront of its planning.

Increased Customer Value

By combining an understanding of what customers want with sound and comprehensive planning, we can deliver the types of services and products our customers expect while continuing to address the traditional planning objectives of cost, reliability, and risk. Increasing the array of alternatives provides an opportunity to better meet our planning principles by providing a diverse portfolio of resources to meet long-term service requirements. A diverse portfolio mitigates customer exposure to price volatility associated with uncertainties in fuel and power purchase costs and risks that may occur through a concentration of portfolio attributes such as technology, location, large capital commitments, or supply channels. Additionally, by taking advantage of increased and evolving opportunities, EAI continues its effort of modernizing its supply portfolio.

2. Sales and Load Forecasts

As discussed in prior sections, future customer peak load and energy requirements are key determinants of resource needs. A wide range of factors affect electric load in the long-term, including:

- Levels of economic activity and growth, including the rate at which new customers come into or leave a service area;
- The potential for technological change to affect the efficiency of energy consumption;
- Potential changes in the purposes for which customers use electricity (*e.g.*, the adoption of electric vehicles);
- The potential adoption of end-use (behind-the-meter) self-generation technologies (*e.g.*, rooftop solar panels); and
- The level of energy efficiency measures adopted by customers.

Such factors may affect both the level and shape of load in the future, and, as a result, peak loads may be higher or lower than projected levels. Similarly, industrial customer load factors may vary from current projections based on the age of a customer's facility and equipment as well as the economics of the markets in which industrial customers operate. Uncertainties in load may affect both the amount and type of resources required to efficiently meet customer needs in the future.

In order to consider the potential implications of load uncertainties on long-term resource needs, three load forecast scenarios reflecting a range of outcomes were prepared for the 2018 IRP, which forecasts are described below:

- The Reference Case load forecast reflects baseline model and input assumptions, including near-term sales growth from a new industrial customer.

- The Low Case load forecast assumes weaker customer count growth, lower Residential and Commercial usage-per-customer ("UPC") attributable to stronger than forecasted gains in organic energy efficiency, and lower industrial sales volumes tied to potentially worsening economic conditions.

- The High Case load forecast assumes stronger customer count growth, higher Residential UPC attributable to weaker than forecasted gains in organic energy efficiency, and higher industrial sales tied to a strengthening economy.

Forecast Methodology

The same load forecasting process used to develop each of the three load forecast cases described above has also been used in EAI's previous IRPs. That process uses computer software from Itron to develop long-term, hour-by-hour load forecasts. The MetrixND™[7] and the MetrixLT™[8] programs are used widely in the utility industry, to the point where they may be considered an industry standard for energy forecasting, weather normalization, and hourly load and peak load forecasting.

EAI's Retail Energy Forecast ("Sales Forecast") is a primary input for developing the load forecast. Regression models are used for forecasting residential, commercial, small industrial and governmental revenue class electricity ("MWh") sales as well as customer counts on a monthly billed sales basis. EAI's largest industrial customers (the Large Industrial Segment) are forecasted individually.

Economic driver data used in the regression models, both historical and forecasted were obtained from IHS Markit, Inc. and includes customized data for the EAI service region as well as national drivers for a wide variety of variables. Statistically adjusted end-use ("SAE") data from the U.S. Energy Information Administration ("EIA"), which reflect historical electric consumption from appliances, HVAC systems, lighting, and other devices are also used in the regression models. Temperature data is the same as used in the weather normalization analyses and is used in all models except for those instances (such as for industrial class models) where no significant dependence of sales to weather can be established. Actual weather data is used for historical time periods and normal cooling and heating degree days are used for forecasted periods.

The sales forecast for the residential class is derived from separate usage per customer and customer count models, the outputs of which are multiplied together on a monthly basis to produce forecasted total sales volumes. For the other classes, the total usage is directly calculated by the models. The key drivers for the UPC and usage models are generally trends in average consumption such as decreases due to HVAC efficiency or increases due to individuals having more devices to plug-in (phones, computers, etc.) while customer count models are typically based on drivers such as population or numbers of households. Additionally, the residential UPC and commercial usage models incorporate end-use variables such as appliance efficiencies and home size to account for the impact of changing end-use characteristics over time. EAI uses a mix of SAEs and econometric data in its regression models to capture the effects of

[7] MetrixND™ by Itron is an advanced statistics program for analysis and forecasting of time series data.
[8] MetrixLT™ by Itron is a specialized tool for developing medium and long term hourly load shapes that are consistent with monthly sales and peak forecasts.

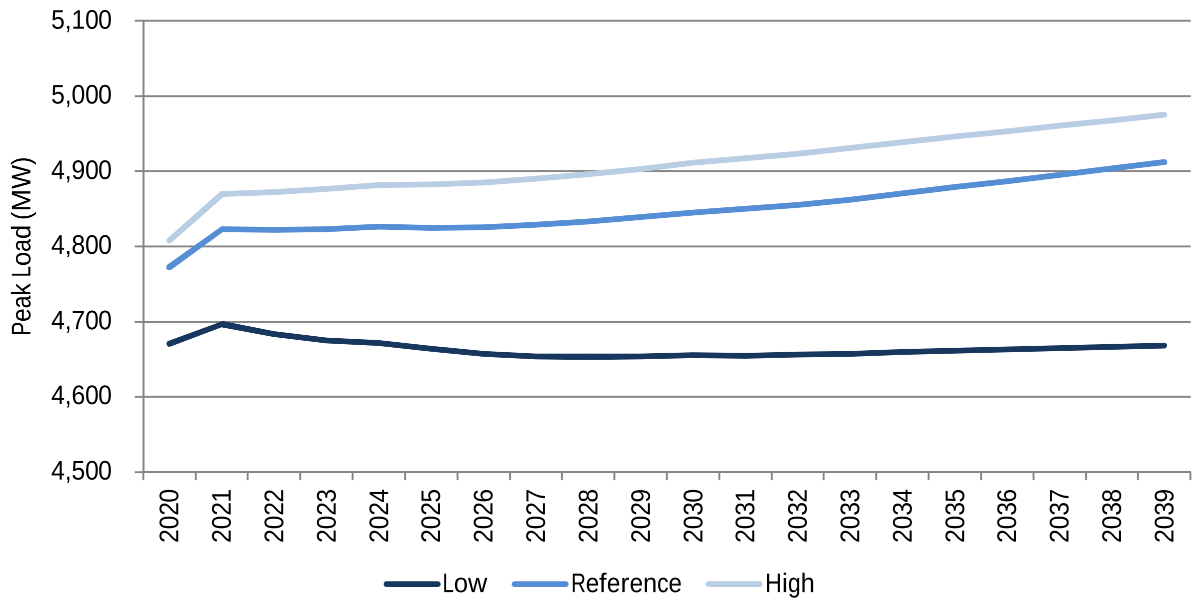
changes in end-use data as well as changes in population, household counts, and other economic drivers.

EAI has had company-sponsored EE programs since 2008 with incremental annual program-year savings that began at 20 GWh, rising to more than 260 GWh in 2017. Due to the increasing levels of these programs over that time, which covers the historical estimation period for the residential and commercial forecasts, EAI has employed a new method since the 2015 IRP to account for the effects of the historical EE programs on sales levels. This updated methodology, referred to as the add-back method or reconstituted sales method, also provides a means to calculate the future effects of continued EE programs as well as the build-up effects from prior years. Historical program EE savings were carried forward based on program measure life, with depreciation applied for future years. These aggregated EE savings were then added back to historical sales in EAI's regression models to produce a forecast trajectory as if there had never been any company-sponsored EE programs. From this point, assuming that future programs continue at current levels, the cumulative effects of historical and future EE programs were decremented from the no-EE forecast to arrive at a final sales forecast. This methodology allows for more understanding of the effects of each EE program as well as more precision on the net effect of future EE program levels.

To develop the load forecast, the monthly Sales Forecast is allocated to each hour based on historical load shapes. Twenty-year "typical weather" is used to convert historical load shapes into "typical load shapes." For example, if the actual sales for EAI's residential customers occurred during very hot weather conditions, the typical load shape would flatten the historic load shape. If the actual weather was mild, the typical load shape would raise the historic load shape. Each customer class responds differently to weather, so each has its own weather response function. MetrixND™ is used to adjust the historical load shapes by typical weather, and MetrixLT™ is used to create the hourly load forecast.

The load forecast is grossed up to account for transmission and distribution line losses. Unique distribution loss factors are applied to each revenue class after the forecast is developed. For example, EAI's residential class is grossed up by a different amount than the commercial class. The transmission line loss assumption is the value calculated by MISO for EAI's Local Resource Zone for the 2018/19 Planning Year, which is 2.5%.

FIGURE 6: EAI IRP LOAD FORECASTS



2.1 Arkansas Economic Outlook

The economic outlook for EAI's service territory, and the state of Arkansas in general, continues to show modest growth but lags behind the US in several key economic performance indicators, including Total Employment, Population, Real Average Wage, and Real Personal Income growth.

Key Performance Indicators, 2018 % Change, Y-O-Y	Employment	Population	Real Average Wage	Real Personal Income
Arkansas	0.59%	0.50%	0.33%	0.33%
United States	1.66%	0.72%	0.82%	1.86%

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As of August 2018, the compound annual growth rate for gross state product for 2014-2021 was 1.4%[9]. Payroll employment[10] across EAI's service territory diverges from sustained strong growth in the Jonesboro area, to modest growth in the Little Rock and Hot Springs areas, with a sharp decline in the Pine Bluff area. The overall economic environment in the EAI service territory is positive, which has historically suggested increased energy demand. However, increasing social and regulatory focus on energy efficiency, including the recent Commission mandate to increase EAI's DSM program savings goal to 1.2%, will temper demand. The bright spot for demand in the EAI service territory comes from a new large industrial customer that has provided a

[9] IHS Markit, Inc.
[10] Bureau of Labor Statistics, *Current Employment Statistics*, August 2018

step change in EAI's base load. In aggregate, higher energy demand from a healthy economy in the EAI service territory is offset by higher energy efficiency and solar adoption, resulting in a modest long term upward trend.

2.2 Demand-side Management

EAI considers Demand-side Management ("DSM") to be a valuable resource when implemented in a cost-effective manner compared to supply-side resources, and the 2018 IRP reflects EAI's continued commitment to DSM. In recent IRPs, EAI has included DSM resource options in four categories: customer-sponsored DSM, existing Utility-sponsored DSM, Utility-sponsored DSM Growth, and potential DSM resources. While the first three categories are discussed here, the fourth category, potential DSM resources, was enhanced in development of the 2018 IRP, which is described in detail later in this section. The potential DSM resources category represents additional investment in resources on the customer side of the meter that may be cost-effective in meeting EAI's long-term resource needs. It is not a decrement to the Sales and Load Forecast, but rather is modeled dynamically alongside supply side resource alternatives, so it is included in the section below which discusses all modeled resource options. DSM planning includes EE, demand response ("DR"), and interruptible loads. Each category is described below.

Figure 7: DSM Categories

Customer-sponsored DSM	Existing Utility-sponsored DSM	Utility-sponsored DSM Growth	Potential DSM Resources
· Improvements in energy efficiency and conservation that occur without Utility involvement. · An assumption for this type of DSM is included in the Retail Sales Forecast.	· Generally, large scale, regulator approved programs that provide incentives to go above and beyond efficiency standards. · An assumption for the impact of existing programs is included in the Retail Sales Forecast.	· Represents the annual incremental savings produced by regulator-approved programs. · An assumption for the impact of incremental programs is included in the Retail Sales Forecast.	· These programs are like existing Utility programs but require regulatory approval to implement. · These resources are modeled like a supply side resource and are not included in the retail sales forecast.

Customer-sponsored DSM

EAI's customers may elect to make EE improvements or take steps to reduce energy usage in their homes, businesses and communities without EAI's involvement. Also, new requirements for EE, such as new construction building codes and appliance or lighting efficiency standards, and new technologies, such as learning thermostats, may reduce customer's electricity usage or change energy usage patterns. This type of DSM is included in the development of the Sales Forecast described in the previous section.

Existing Utility-sponsored DSM

For several years, EAI has maintained and expanded its Arkansas Energy Efficiency Program Portfolio ("EE Portfolio"), which consists of generally large scale, regulator-approved programs that provide incentives to customers to go above and beyond current EE standards. The comprehensive EE Portfolio is reviewed and approved by the Commission and developed in an attempt to meet the Commission's utility EE targets, which are currently set at 0.9% of retail sales (excluding industrial opt-out). As part of its current three-year EE plan, EAI's approved EE targets increase to 1.0% for program year 2019. In July 2018, the Commission set new EE targets of 1.2% of retail sales for program years 2020 through 2022[11].

Impacts of the existing EE Portfolio are included in the Sales Forecast referenced earlier in this section. The MW and MWh savings achieved by existing EE programs for the 2017 Program Year can be found in EAI's Arkansas Energy Efficiency Program Portfolio Annual Report, filed May 1, 2018 in Docket No. 07-085-TF.

In addition to its EE Portfolio, which currently includes two DR programs, Agricultural Irrigation Load Control ("AILC") and Direct Load Control ("DLC"), EAI also offers the Optional Interruptible Service Rider ("OISR"). Each of these programs allows EAI to either reduce participants' usage or send a request to participants to reduce usage during an emergency situation. Although these resources reduce or shift load on the demand side of the meter, EAI treats these resources the same way as its existing supply-side capacity resources in the 2018 IRP analysis, as opposed to including as an offset a decrement to the Sales Forecast. In 2018, the interruptible loads provide 250 MW of total capacity savings. The assumption grows to 319 MW by the first year of the IRP study period (2020) based upon the expansion of a customer taking interruptible service pursuant to a Commission-approved contract.

Utility-sponsored DSM Growth

[11] Order 43 in Docket No. 13-002-U, effective July 13, 2018

Beyond the existing DSM programs, the 2018 IRP assumes that EAI continues to grow its EE Portfolio at an incremental level of 0.9% of retail sales per year, which is approximately 260 GWh of additional savings per year at the meter. Note that the Sales and Load Forecasts used in the 2018 IRP were developed prior to the Commission's approval of new EE targets for the 2020 through 2022 program years. As previously referenced, these new EE targets increased to 1.2% of retail sales.

This assumption is based on several factors. The 2018 IRP incremental Utility-sponsored EE assumption:

1. is based on the historical achievement of EE in a fuel cost environment that is at or lower than the 2018 IRP and with a greater number of Self Direct customers than assumed in the 2015 IRP;
2. is consistent with a perceived desire of state policy makers to moderate the cost of EE on the customer's utility bills; and
3. is based on the belief that the EE market that has been built up over the last 10 years will be sustainable in the foreseeable future.

Of course, there are uncertainties regarding the incremental Utility-sponsored EE assumption. Those uncertainties include:

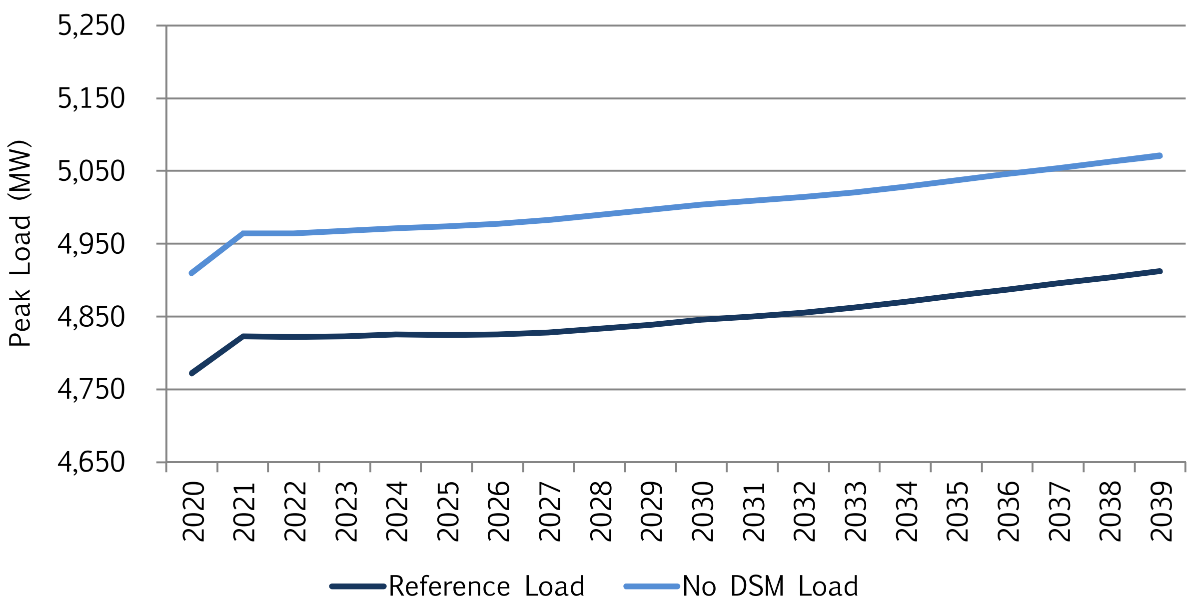
1. DSM and DR technology innovation and market adoption,
2. Future avoided cost projections could change significantly in future years, thus changing the cost-effectiveness and quantity of EE and DR programs,
3. The speed of the Arkansas market's adoption of building and technology standards,
4. Measure assumptions (e.g. variation in actual EE measure performance),
5. DSM and DR program assumptions, and
   a. Costs (e.g. program incentive and implementation cost, the market and policymakers' tolerance to DSM and DR cost impacts to customers' utility bills)
   b. Free-ridership (the portion of the program participants who would have installed the efficient equipment in the absence of the programs)
   c. Participation (e.g. variance in actual market response to EAI's programs)
6. General economic uncertainty (e.g. level of new construction, unemployment rates, etc.).

In addition, in the early stages of EAI's EE programs with the APSC, EAI noted that numerous potential projects would be dependent upon the implementation of AMI or "smart grid" technology. EAI continues to believe that AMI may provide opportunities to enhance EAI's EE Portfolio of programs or measures available to its customers. Once AMI is implemented in EAI's service area, the programs and measures that can be implemented in a cost-effective manner may increase.

The energy and peak-reducing impacts of incremental Utility-sponsored EE programs are included in the development of the Sales Forecast. The energy and peak reductions are the same amounts in each of the three IRP load forecast scenarios (Reference, Low and High Cases).

Figure 8 below shows the estimated impacts of existing EAI-sponsored and incremental EAI-sponsored EE programs to EAI's peak load forecast. The 2018 IRP only utilizes the load forecast sensitivities that include the impacts of EE.

FIGURE 8: LOAD FORECAST DSM IMPACTS



3. CAPACITY RESOURCE OPTIONS

3.1 GENERATION TECHNOLOGY ASSESSMENT

The IRP process considers a range of alternatives available to meet customer energy needs in accordance with planning objectives, including supply-side and demand-side management resource alternatives. As part of this process, a Generation Technology Assessment was prepared to identify a wide range of potential supply-side resource alternatives that merit more detailed analysis due to their potential to meet EAI's planning objectives of balancing reliability, cost, and risk. Alternatives evaluated (see Figure 9) are technologically mature and could reasonably be expected to be operational in or around the EAI service territory. Demand-side resources are discussed later in this section.

FIGURE 9: TECHNOLOGY SCREENING CURVE ILLUSTRATION

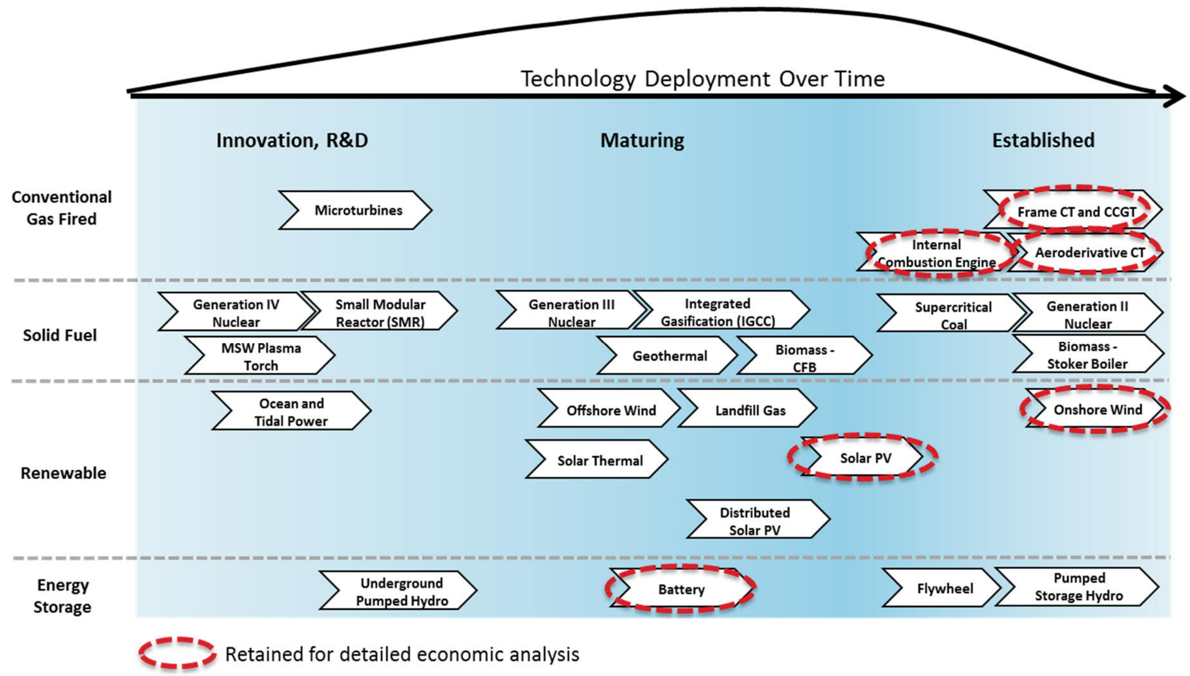


TABLE 1: 2018 IRP TECHNOLOGY CATEGORIES

Natural Gas	Simple Cycle Combustion Turbine ("CT") Combined Cycle Gas Turbines ("CCGT") Aeroderivative CT Reciprocating Internal Combustion Engine ("RICE")
Renewable	Wind Solar Photovoltaic ("PV")
Energy Storage	Battery Storage

Each of these technologies has relative advantages and disadvantages to consider when designing a resource portfolio to meet customers' energy needs. The information in Table 2 below summarizes some of these considerations.

TABLE 2: GAS-FIRED TECHNOLOGY CONSIDERATIONS

	CT	CCGT	Aeroderivative CT	RICE

Description	Frame CTs are a mature technology. Low gas prices and continual heat rate and capacity improvements have made CTs the industry's technology of choice for peaking applications. CTs can also help integrate renewables by providing quick start (~10 minutes) backup power.	Modern combined cycle facilities provide efficiencies, moderate flexibility, and improved CO_2 emissions relative to coal plants, making them suitable for a variety of supply roles (baseload, load-following, limited peaking). CCGT efficiency and flexibility is expected to continue to improve.	Aeroderivative CTs trade increased cost for greater flexibility (start time, ramp times), lower heat rates, and higher reliability relative to frame CTs.	RICEs are useful for applications requiring heavy cycling and ramping, as they incur lower O&M penalties when operated in this manner relative to other conventional peaker technologies. As renewable penetration increases, RICEs will likely see increased deployment in North American power markets due to its flexibility and efficiency.
Advantages	• Low capital and staffing costs • Existing operating expertise • Flexible, quick start capability	• Lowest heat rates • Moderate capital cost • Synergies with existing and planned fleet (e.g., parts, staff)	• Higher flexibility • Moderate heat rates • High reliability	• Low heat rates • Highest flexibility • No gas compression needed • Modular additions
Disadvantages	• Higher heat rates • Difficult to neatly match need (blocky additions) • High gas pressure requirements	• Blocky additions • High gas pressure requirements	• Moderate capital cost • High gas pressure requirements • Less experience with technology	• Moderate capital cost • High variable operating cost • Less experience with technology

In addition to the qualitative factors considered above, the table below summarizes the major inputs from the Generation Technology Assessment for gas-fired generation, which were utilized in the portfolio analyses discussed later in the report.

TABLE 3: GAS-FIRED RESOURCE ASSUMPTIONS

Technology		Summer Capacity [MW]	Capital Cost [2017$/kW]	Fixed O&M [2017$/kW-yr]	Variable O&M [2017$/MWh]	Heat Rate [Btu/kWh]	Expected Capacity Factor [%]
CCGT	1x1 501JAC	510	$1,238	$17.02	$3.14	6,400	80%
	2x1 501JAC	1020	$1,090	$11.12	$3.15	6,400	80%
	501JAC	300	$833	$2.84	$13.35	9,400	10%
Aero-derivative CT	LMS100PA	102	$1,543	$5.86	$2.90	9,397	20%
RICE	7x Wartsila 18V50SG	128	$1,642	$31.94	$7.30	8,401	30%

In the last decade, the renewable energy industry has experienced substantial growth, driven in large part by government subsidies and cost declines, technological improvements, and environmental concerns. As shown in Figure 10, solar capital cost declines are particularly evident in utility-scale solar installations within the U.S. over the past five years.[12] Among all technologically-feasible renewable energy options, solar and onshore wind resources are the most cost-effective, commercially-available alternatives to meet EAI's capacity and energy needs.

FIGURE 10: HISTORICAL UTILITY-SCALE SOLAR CAPITAL COSTS

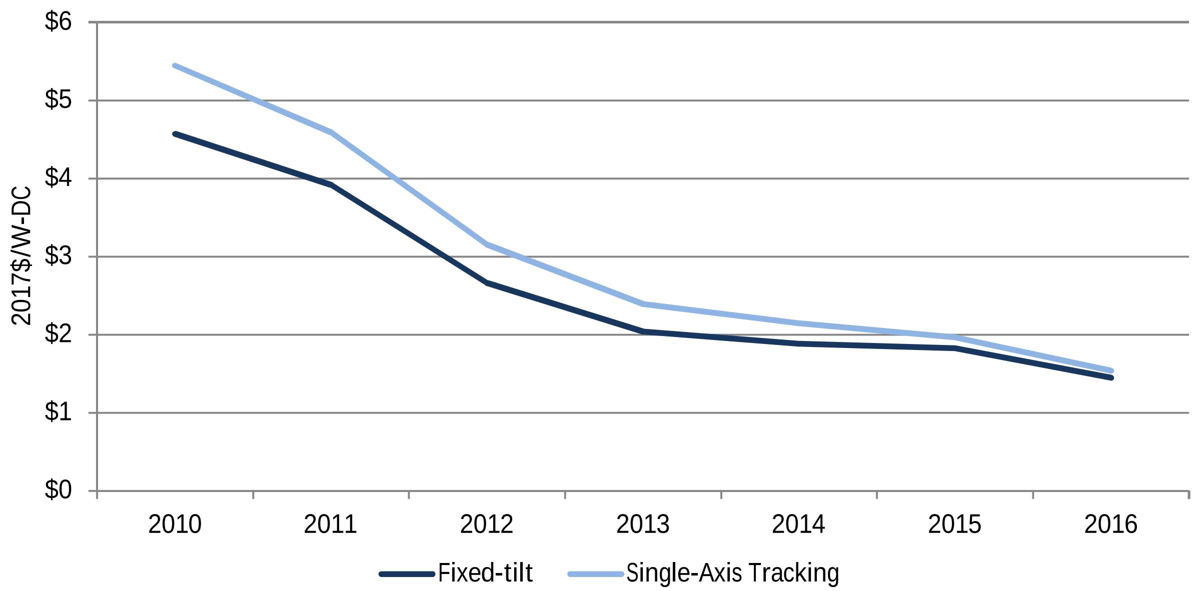


Table 4 below expands upon the relative advantages and disadvantages presented by solar and wind generation. In general, the advantages of renewable energy resources are zero emissions and zero fuel costs (which decreases overall reliance on fuel commodities), increased diversity within the resource portfolio, and decreased risk for the benefit of EAI customers. Disadvantages include increased relative land use compared with traditional alternatives, as well as relative capacity contribution due to the intermittent nature of these energy sources. The inability to effectively dispatch renewable resources to meet the changing instantaneous nature of customer usage and the renewable production curves (e.g., on-peak production versus off-peak production) also affect the value of the resources given EAI's existing generation portfolio.

TABLE 4: RENEWABLE TECHNOLOGY CONSIDERATIONS

	Solar	Wind

[12] Data adapted from NREL U.S. Solar Photovoltaic System Cost Benchmark, Q1 2017.

Description	Solar capital costs have fallen dramatically in the last decade and continue to decline as the industry matures. Solar production roughly aligns with customer load patterns, but grid flexibility and quick start backup generation are necessary to ensure reliability in the absence of large-scale, economic energy storage alternatives. The industry will continue to mature and solar energy is expected to continue to compete with gas-fired generation within the planning horizon, constrained mainly by site-specific performance and market conditions (e.g. construction cost, energy value).	The wind industry is mature relative to the solar industry. Current research focuses more on improving performance, rather than cost, through larger, taller turbines and improved control technologies (e.g. turbine alignment sensors, integrated battery storage). Wind is not likely to see extensive local deployment within the MISO South region, but could play a role in the region's energy mix if storage economics improve or significant high voltage direct current (HVDC) projects are completed.
Advantages	• Zero emissions • No fuel cost • Capital costs continue to decline • Federal investment tax credits (ITCs) • Predictable energy curve	• Zero emissions • No fuel cost • Federal production tax credits (PTCs) • Efficiency continues to increase
Disadvantages	• Capacity value relative to traditional generation • Land-intensive • Integration requirements (responsive, quick start generation is necessary to integrate large amounts of solar PV) • Site-specific performance • Lack of effective instantaneous dispatch capability	• Capacity value relative to traditional generation • Land-intensive • Integration requirements (responsive, quick start generation is necessary to integrate large amounts of wind) • Site-specific performance • Lack of effective instantaneous dispatch capability

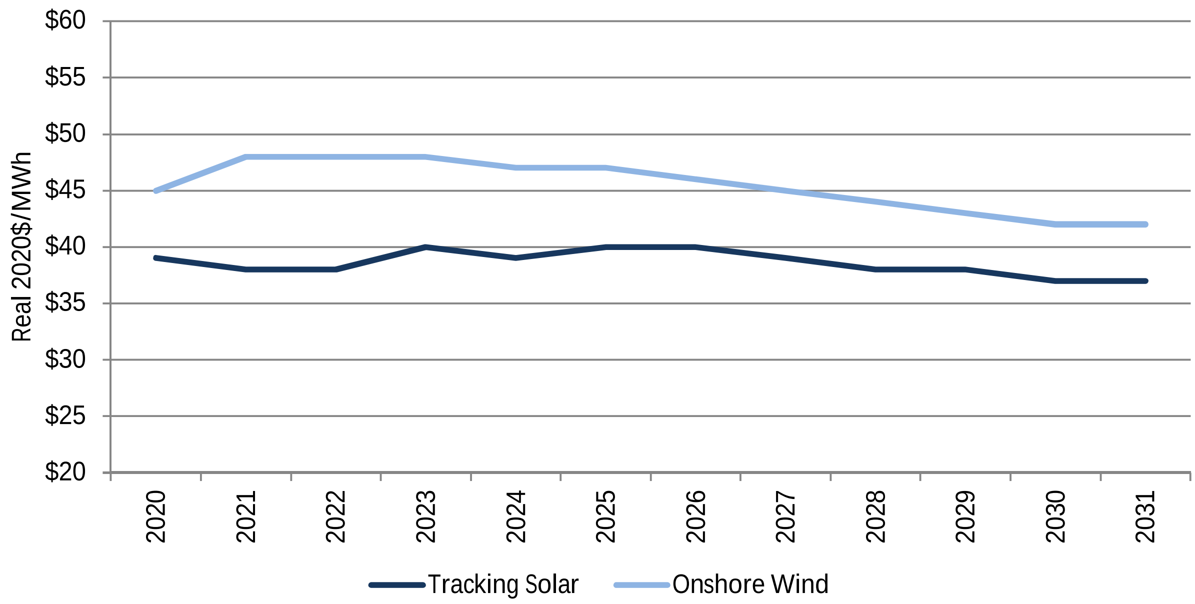
Additional unique qualities associated with renewable generation are summarized below.

TABLE 5: ADDITIONAL BENEFITS OF RENEWABLES

Additional Benefits of Renewables	
Diversity	Renewables add fuel diversity and provide a hedge within gas-centric resource portfolios as EAI's ability to rely on coal for fuel diversity becomes uncertain.
Infrastructure	Reduced infrastructure requirements (e.g., gas pipelines, water supply) increases siting flexibility.
Scalability	Deployment potentially can be scaled up or down to meet capacity needs more easily relative to conventional alternatives, although economics remain a factor.
Carbon	Renewables offer customers reduced exposure to potential CO_2 costs.
Customer Engagement	EAI's experience with renewables will help meet customer expectations with respect to green tariff offerings, community solar, deployment of distributed energy resources (DERs), and the integration of AMI.

As shown in Figure 11, the levelized real electricity costs for utility-scale renewables (wind and solar) are expected to decline over the planning horizon, although solar is expected to maintain its cost advantage over wind on a $/MWh basis.

FIGURE 11: LEVELIZED REAL COST OF ELECTRICITY FOR RENEWABLES



The table below provides a summary of operational costs and performance assumptions for solar and wind technology used within the 2018 IRP.

TABLE 6: RENEWABLE MODELING ASSUMPTIONS

	Solar	Wind
Fixed O&M (2017$/kW-yr)	$16.00	$23.46
Useful Life (yr)	30	25
Capacity Factor	26%	41%
DC:AC	1.35	N/A
Hourly Profile Modeling Software	PlantPredict	NREL SAM

3.2 ENERGY STORAGE SYSTEMS

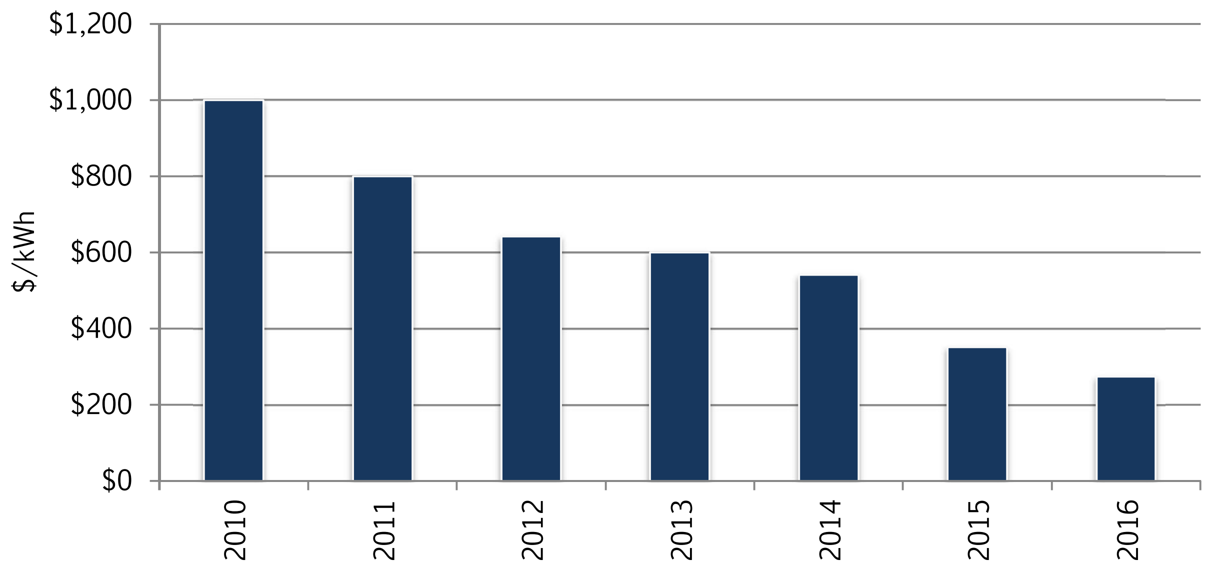
Energy storage, particularly in the case of battery-enabled storage, provides a range of attributes that differ from traditional supply-side options discussed previously, such as:

- the ability to store energy for later commitment and dispatch
- ability to discharge in milliseconds and fast ramping capability
- rapid construction (on the order of months)
- modular deployment providing potential scalability
- portability and capability to be redeployed in different areas
- small footprint (typically less than an acre), allowing for flexible siting
- low round-trip losses compared to other storage technologies (such as compressed air)

Battery storage system benefits lie in the attributes highlighted above and the ability to offer stacked values through MISO markets to benefit customers. Battery storage effectively enables an intra-day temporal shift between energy production and energy use. Energy can be absorbed and stored during off-peak/low cost hours and discharged during on-peak/high cost hours. The spread (i.e., cost difference) between the time periods creates cost savings for customers. In addition to energy market attributes, battery storage systems qualify in some markets for various ancillary service applications such as regulation, reserves, and voltage regulation, and qualify for MISO's capacity market, given sufficient discharge duration. Energy storage, when efficiently integrated into the electric grid, can provide transmission benefits by avoiding investments required due to line overloads that occur under peak conditions. In addition to these peak-shaving applications, energy storage sited in location-specific areas provide voltage support, which mitigates the effects of electrical anomalies and disturbances. Lastly, if paired together, battery storage systems have the potential to shift some solar energy production to late afternoon hours, mitigating the ramping requirement created by the decline in solar energy production. In addition to the operational benefit, this can enhance the capacity and energy value of the solar PV installation and can lower the battery storage cost through use of the investment tax credit.

Similar to what has been seen in recent years within the solar industry, it is expected that battery storage costs will decline within the planning horizon. Therefore, while limited deployment may make sense for EAI customers today, this technology will continue to evolve, and additional applications could present themselves in the future.

FIGURE 12: LITHIUM ION BATTERY COSTS



Source: Bloomberg New Energy Finance

3.3 Potential DSM Resource Assessment

As part of the development of the 2018 IRP, EAI engaged a third-party consultant, ICF International, Inc., ("ICF")[13] to quantify potential opportunities for Utility-sponsored DSM programs to be evaluated as future resource alternatives alongside the supply-side options discussed later in this Section. The potential DSM consists of three DR portfolios and two EE portfolios.

As part of their engagement with EAI, ICF developed Low, Mid, and High DR portfolios with demand savings targets of 25 MW, 50 MW, and 100 MW, respectively. These portfolios consist of a mix of five Residential and Commercial DLC programs and one Commercial Time-of-Use program ("TOU"). ICF produced hourly demand savings and accompanying annual program costs for three assumed program start dates: 2020, 2025, and 2030. The varying demand savings targets and assumed program start dates yielded nine DR portfolios for economic evaluation in the AURORA model. Note that the DR program savings targets build-up; as a result, each of the portfolios are mutually exclusive. The AURORA model cannot select more than one portfolio as a result.

ICF also developed Low and High EE portfolios based on potential savings from self-direct Industrial customers. Rather than setting specific demand savings targets, ICF modeled the portfolios based on assumptions around self-direct customer compliance with APSC EE goals. The Low and High portfolios represent 50% and 25% compliance

13 http://www.icf.com

with these EE goals, respectively. For example, in the High portfolio ICF's model assumes that self-direct customers achieve 25% of their APSC EE target on their own; the remaining 75% represents opportunity for additional demand savings. As with DR, ICF provided the same 2020, 2025, and 2030 program start dates yielding six EE portfolios for evaluation in the AURORA model. The EE program savings associated with each portfolio build-up and are therefore mutually exclusive.

As described in detail later in this section, these incremental DR and EE portfolios were included in AURORA's Capacity Expansion Tool for economic selection alongside existing supply-side resource options. Each portfolio included an assumed start date, program measure life, hourly demand profile, and annual program costs.

4. Environmental

Another key driver to changes in future resource needs is the various environmental regulations that have the potential to affect the long-term viability of EAI's existing generating units. Five key areas of regulations are discussed here: the Regional Haze Rule, Cross-State Air Pollution Rule, Coal Combustion Residuals Rule, Effluent Limitation Guideline Rule, and the Affordable Clean Energy Rule. The uncertainty associated with each area varies. For example, the Regional Haze requirements have been in place for some time and are far more developed, with greater certainty as to the compliance requirements and timing. Even so, the specifics that will be required for compliance with Regional Haze are not known fully at this time.

Regional Haze Rule

The EPA issued a final Federal Implementation Plan ("FIP") on September 27, 2016, to address the requirements of the Regional Haze Rule and visibility transport requirements for the State of Arkansas that the EPA had previously disapproved. EAI owns three facilities in Arkansas that were subject to the FIP through emission limitations that required sulfur dioxide ("SO_2") controls (scrubbers) at the White Bluff and Independence coal-fired plants and oxides of nitrogen ("NO_x") controls (Low-NO_x Burners/Separated Overfire Air) at White Bluff and Independence, and lesser NO_x controls at one natural gas-fired plant, Lake Catherine Unit 4. The final FIP required installation of the NO_x controls at White Bluff and Independence by April 27, 2018, the NO_x controls at Lake Catherine Unit 4 by October 27, 2019, and the SO_2 controls at White Bluff and Independence by October 27, 2021. On March 17, 2018, the 8th Circuit court of appeals granted Entergy's stay motion for the Arkansas Regional Haze FIP.

Following issuance of the final FIP, the ADEQ commenced an effort to develop a State Implementation Plan ("SIP") to replace the FIP while still addressing the applicable

Regional Haze program requirements for the first Regional Haze planning period. The ADEQ SIP process resulted in two separate SIPs, a Phase I SIP which addressed NO_x emissions from electric generating units ("EGUs"), and a second Phase II SIP which primarily addressed SO_2 emissions.

The Arkansas Phase I SIP was finalized by ADEQ in October 2017 and approved by the EPA on February 12, 2018. This SIP replaced the source-specific FIP NO_x limits for White Bluff, Independence, and Lake Catherine with an obligation to meet the Regional Haze program obligations for NO_x via compliance with the Cross-State Air Pollution Rule ("CSAPR") ozone-season NO_x cap-and-trade program.

The Arkansas Phase II SIP was finalized by ADEQ and transmitted to the EPA for review in August 2018. This SIP replaces the source-specific FIP SO_2 emission limitations for White Bluff and Independence with a requirement that each unit at these plants achieve SO_2 emission reductions via combustion of low-sulfur coal. In addition, the SIP requires that White Bluff cease to burn coal by December 31, 2028. The SIP also acknowledges the assumed planned retirement of Lake Catherine Unit 4 in 2025, which is consistent with EAI's 2015 and 2018 IRPs, and EAI's planning assumption that Independence will cease to use coal in 2030. EPA review of this SIP is expected to occur throughout late 2018 with final EPA action anticipated in early 2019.

Cross-State Air Pollution Rule (CSAPR)

The EPA finalized the CSAPR in 2011 under the "good neighbor" provision of the Clean Air Act to reduce transported pollution that significantly affects downwind non-attainment and maintenance problems for the 2008 ozone National Ambient Air Quality Standard ("NAAQS"). The rule was vacated and stayed December 30, 2011, but in late 2014 the stay was lifted following a Supreme Court reversal of the lower court decision. Arkansas is subject to CSAPR for ozone-season (May 1 – September 30) emissions of NO_x. Affected entities must hold one allowance for every ton of NO_X and SO_2 generated, depending on which programs their respective state is required to participate.

Phase I of CSAPR went into effect in May 2015 and Phase II went into effect in May of 2017. On September 7, 2016, the EPA issued a CSAPR update rule which revised the CSAPR program. This 2016 update rule revised the total allowance pool for Arkansas sources, including a significant reduction in available allowances beginning with the 2018 ozone season.

Coal Combustion Residuals Rule

In April 2015 the EPA published the final Coal Combustion Residuals ("CCR") rule regulating coal ash from coal-fired generating units as non-hazardous wastes under RCRA Subtitle D. The final regulations became effective on October 19, 2015 and created new compliance requirements for CCR management including modified storage, new notification and reporting practices, product disposal considerations, ongoing monitoring requirements and CCR unit closure criteria. In December 2016, the Water Infrastructure Improvements for the Nation Act ("WIIN Act") was signed into law, which authorizes EPA to enforce the CCR rule rather than leaving primary enforcement to citizen suit actions. On August 21, 2018, the D.C. Circuit Court vacated and remanded several provisions of the CCR rule that relate to inactive and unlined surface impoundments. The CCR rule allows states to seek approval from EPA for state CCR permit programs. Arkansas has not submitted a CCR permit program proposal to EPA to date.

Entergy operates CCR units at both White Bluff and Independence which are subject to the CCR rule. Entergy believes that on-site disposal options will continue to be available at its facilities, to the extent needed for CCR that cannot be transferred for beneficial reuse.

Effluent Limitation Guideline Rule

The final Effluent Limitation Guideline rule ("ELG") was issued by the EPA on November 3, 2015. This rule applies to the units at White Bluff and Independence and imposes a requirement that there be zero discharge of bottom ash transport water from the site. This requirement was originally scheduled to become effective between November 1, 2018 and December 31, 2023, with the exact date to be determined by the permitting authority (ADEQ). On September 17, 2017, the EPA finalized a revision to the ELG rule which modified the earliest possible compliance date from November 1, 2018 to November 1, 2020. In this action, the EPA also indicated intent to reconsider other aspects of the 2015 ELG rule, including the requirements for bottom ash transport water.

Clean Power Plan/Affordable Clean Energy Rule

EAI's Point of View ("POV"), which is based on Entergy's corporate POV, is that national carbon regulation for the power generation sector will occur; however, the timing, design, and outcome of any carbon control program are highly uncertain. The EPA issued the final Clean Power Plan ("CPP") on October 23, 2015. The final plan targeted emissions from electric generators utilizing three building blocks (coal plant heat rate improvements, an increase in dispatch of NGCC units, and an increase sin zero and low-emitting generation) to establish state-by-state emission rate limits, expressed in terms of lbs. CO_2/MWh.

On February 9, 2016, the US Supreme Court issued a stay of the CPP. On March 28, 2017, President Trump signed an executive order directing the EPA administrator to review the CPP. Formal review of the CPP was announced by the EPA on April 4, 2017, and a proposal to repeal the CPP was published by the EPA on October 10, 2017. On August 31, 2018, the EPA published the proposed Affordable Clean Energy ("ACE") Rule, which is intended to replace the CPP.

The proposed ACE rule would require that each state conduct an analysis of available heat rate improvements at coal-fired electric generating units. The proposal contains a list of candidate technologies to be included in this review. These technologies are: neural network/intelligent sootblowers, boiler feed pumps, air heater and duct leakage control, variable frequency drives, blade path upgrades (steam turbine), and redesign/replace economizer. In addition, EPA also proposed revisions to the NSR program to address potential barriers to implementation of heat rate improvement projects at generating units.

EAI will monitor the development of the final ACE rule. Once the rule is final, it is anticipated that the ADEQ and/or APSC will conduct a stakeholder process to guide implementation of the ACE rule in Arkansas. EAI's participation in the various regulatory processes associated with the ACE rule will, in part, focus on assuring that EAI's customers retain the value of the low-greenhouse gas emissions resources for which they are and/or have been providing cost-support.

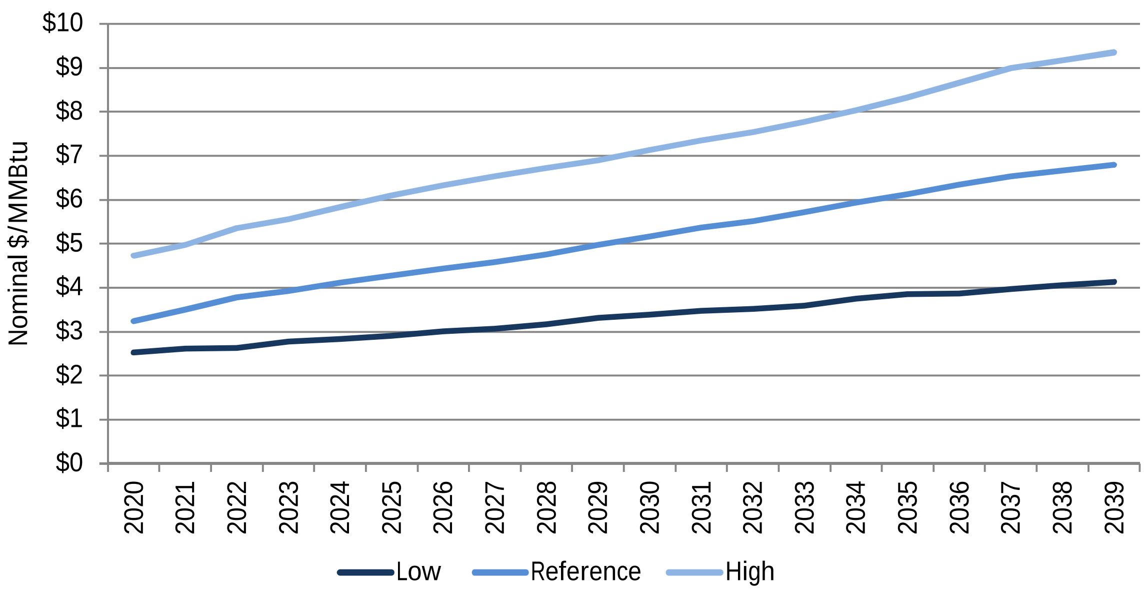
5. Fuel Price Forecasts

5.1 Natural Gas Price Forecasts

The near-term portion (year one) of the natural gas price forecast is based on NYMEX Henry Hub forward prices, which are market future prices as of January 2018. Because the NYMEX futures market becomes increasingly illiquid as the time horizon increases, NYMEX forward prices are not a reliable predictor of future prices in the long term. Due to this limitation, the long-term point of view regarding future natural gas prices utilizes a consensus average of several expert independent, third-party consultant forecasts. The long-term natural gas price forecast used in the IRP also includes cases for high and low gas prices to support analysis across a range of future scenarios. In levelized 2018 dollars per MMBtu through the IRP period (2020-2039), the reference case natural gas price forecast is $3.88, the low case is $2.59, and the high case is

$5.43. Described in more detail later in this section, each of the IRP Futures assumes the natural gas price forecast sensitivity appropriate for the future world envisioned.

FIGURE 13: NATURAL GAS PRICE FORECAST AND SENSITIVITIES



5.2 COAL PRICE FORECASTS

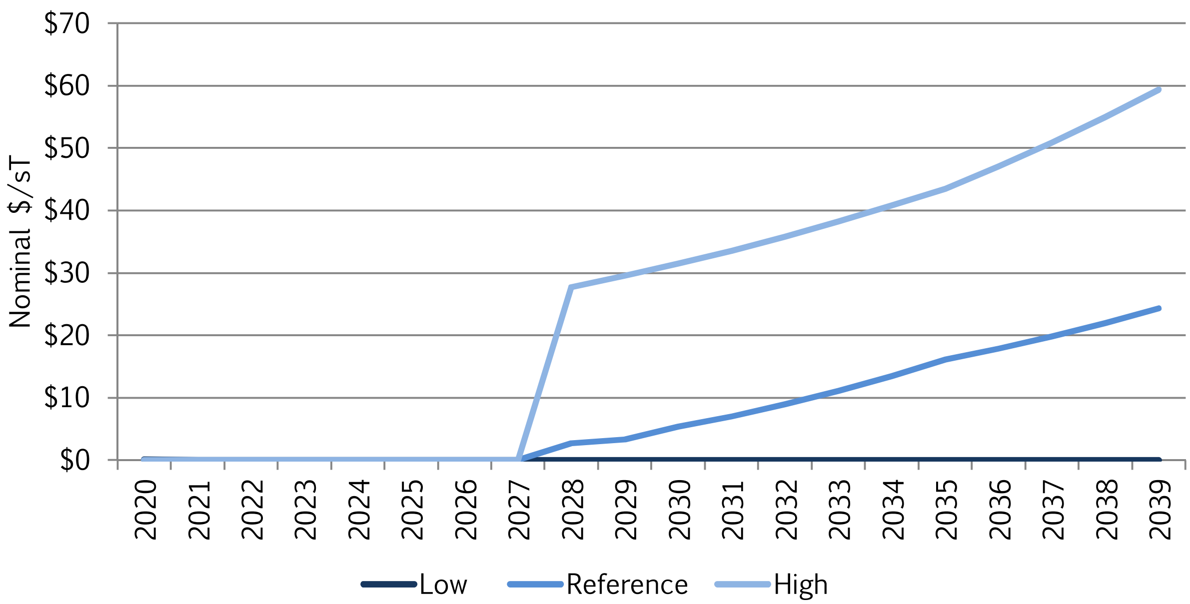
The delivered to Entergy coal price forecast is based on a weighted average price of coal commodity and coal transportation commitments under contract, as well as third-party consultant forecasts of Powder River Basin coal prices for any open coal commodity position. In addition, railcar expenses and appropriate plant specific coal handling cost adders are included. Current transportation rates are escalated by the All Inclusive Less Fuel index and current fuel surcharges are escalated by the diesel fuel price index. Current plant specific delivery component costs are escalated based on an appropriate index to forecast the future year component cost. In levelized 2018 dollars per MMBtu through the IRP period (2020-3039), the reference volume weighted delivered to EAI Coal Price is $2.30. The delivered coal price forecast for non-Entergy plants comes directly from the EVA Forecasts and prices vary by plant.

5.3 CO_2 PRICE FORECASTS

EAI's point of view is that national carbon regulation for the power generation sector will occur; however, the timing, design, and outcome of any carbon-control program remain uncertain. The scenarios forecasted and utilized in EAI's evaluations are based on the following three cases:

1. *Low Scenario* – A \$0/ton CO_2 price, representing either no program or a program that requires "inside-the-fence" measures at generating facilities, such as efficiency improvements, that do not result in tradable CO_2 prices.
2. *Reference Scenario* – A "CPP Delay" Mid Case representing a regional mass-based cap consistent with achieving the final CPP requirements, but delayed by approximately 4-6 years due to the federal administration change in 2017 and consistent with the President's executive order in March 2017; and,
3. *High Scenario* – A "National Cap and Trade" High Case assumes a national cap and trade program that begins in 2028 and targets an approximately 80 percent reduction from 2005 sector emissions by 2050.

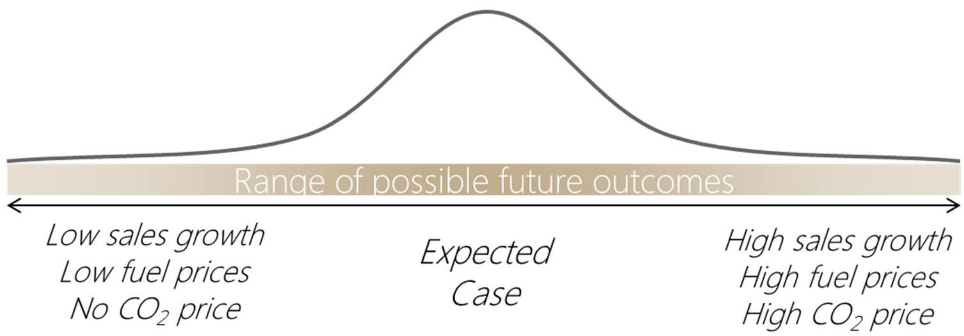
FIGURE 14: CO_2 PRICE FORECAST



6. MODELING FRAMEWORK

6.1 FUTURES-BASED APPROACH

In order to reasonably account for a broad range of uncertainty, the 2018 IRP takes a futures-based approach. In this approach, three "futures" were developed that represent different combinations of possible outcomes of many variables and reasonably bookend the range of possible outcomes. Although EAI does not expect the actual future to materialize exactly like any of the three modeled futures, the futures-based approach provides insight to supply needs and indicates the most attractive options to meet those needs under that future's particular circumstances. This approach to developing various future scenarios is consistent with Section 4.4 of the Commission's Resource Planning Guidelines, which recommends that the planning process identify multiple integrated resource portfolios, each of which meets reliability criteria. To further test the futures, a sensitivity scenario for each future was also modeled to provide insight as to how the optimized portfolios react to changes in assumptions.



Future A – Reference Case

Future A represents a future world which is most closely aligned with the expected outcome, or mid-point of the range of uncertainty, of several unknowns. In this future, natural gas prices and future CO_2 prices are assumed at the Reference Case levels. The Reference Case Peak Load Forecast is also assumed in Future A.

For EAI's existing units, CCGTs are assumed to have a 30-year useful life. The White Bluff and Independence coal units are assumed to cease using coal by 2028 and 2030, respectively.

TABLE 7: FUTURE A ASSUMPTIONS

Future A Key Assumptions (prices shown are 2018$, levelized for the period 2020-39)	
White Bluff and Independence	Assume the proposed Arkansas Phase II SIP White Bluff ceases to use coal in 2028 Independence ceases to use coal in 2030
CCGT Units	Assume 30-year useful life
Electric Sales & Load Forecasts	Reference Case
Henry Hub Natural Gas Price Forecast	$3.88/MMBtu
Coal Price Forecast	$2.30/MMBtu (volume weighted average for EAI units)
CO_2 Price Forecast	$4.15/short ton; pricing begins in 2028
Sensitivity Case	*Low Case Load Forecast* *Extend EAI CCGTs through 2039* *Independence continues using coal through 2039*

To supplement the portfolio optimization results from Future A, additional modeling was performed as a sensitivity case. For the Future A Sensitivity, the load forecast input was changed from Reference Case to the Low Case and the useful life for the CCGT units was extended through the end of the IRP evaluation period. Independence was also assumed to continue operating as a coal plant through 2039. The Future A Sensitivity was designed to reflect more aggressive underlying trends in customer usage patterns and organic energy efficiency penetration as well as acknowledge that existing generation may reliably operate beyond the technology-specific useful life assumptions used for the purposes of the IRP.

Future B – Low Supply Additions Case

Future B represents a future world in which the need and economics for new supply additions are depressed. In this future, natural gas prices, as shown in Figure 13, are assumed at Low case level. Coal prices are assumed at Reference levels given that EAI procures coal via plant-specific contracts, which reduces associated market price variability. The Low Case for CO_2 does not assume any price for carbon emissions over the entire study period. The Low Case Load Forecast is assumed in Future B, which reduces EAI's need for future supply additions.

Assumptions for EAI's existing units align with Future A; existing CCGT units were assumed at a 30-year useful life and White Bluff and Independence are assumed to cease using coal in 2028 and 2030, respectively.

TABLE 8: FUTURE B ASSUMPTIONS

Future B Key Assumptions (prices shown are 2018$, levelized for the period 2020-39)	
White Bluff and Independence	Assume the proposed Arkansas Phase II SIP White Bluff ceases to use coal in 2028 Independence ceases to use coal in 2030
CCGT Units	Assume 30-year useful life
Electric Sales & Load Forecasts	Low Case
Henry Hub Natural Gas Price Forecast	$2.59/MMBtu
Coal Price Forecast	$2.30/MMBtu (volume weighted average for EAI units)
CO_2 Price Forecast	No price for CO_2 throughout IRP study period
Sensitivity Case	*Reference Case Load Forecast* *Extend EAI CCGTs through 2039* *Independence continues using coal through 2039*

Additional portfolio optimization modeling was also completed for Future B as a sensitivity case. Complementary to the Future A Sensitivity, for the Future B Sensitivity the load forecast input was changed from Low Case to Reference Case. Also, the useful life for the CCGT units was extended through the end of the IRP evaluation period. Independence was also assumed to continue operating through 2039. The

Future B Sensitivity models a future scenario that effectively extends the current status quo, i.e. persistent low gas prices and energy growth that reflects current trends in customer usage and energy efficiency penetration.

Future C – High Supply Additions Case

Future C represents a future world in which the need and economics for new supply additions are enhanced. In this future, natural gas prices are assumed at the High Case levels. As noted in Future B, delivered coal prices are assumed at the Reference level. The High Case price for CO_2 is also assumed, which begins in 2028 as in Future A, but at a higher price. The High Case Load Forecast is assumed in Future C, which increases EAI's need for future supply additions.

Assumptions for EAI's existing units align with Futures A and B; existing CCGT units were assumed at a 30-year useful life and White Bluff and Independence are assumed to cease using coal in 2028 and 2030, respectively.

TABLE 9: FUTURE C ASSUMPTIONS

Future C Key Assumptions (prices shown are 2018$, levelized for the period 2020-39)	
White Bluff and Independence	Assume the proposed Arkansas Phase II SIP White Bluff ceases to use coal in 2028 Independence ceases to use coal in 2030
CCGT Units	Assume 30-year useful life
Electric Sales & Load Forecasts	High Case
Henry Hub Natural Gas Price Forecast	$5.43/MMBtu
Coal Price Forecast	$2.30/MMBtu (volume weighted average for EAI units)
CO_2 Price Forecast	$14.50/short ton; pricing begins in 2028
Sensitivity Case	*Modified Load Growth Load Forecast*

As with Futures A and B, a portfolio optimization sensitivity was developed for Future C to supplement the baseline portfolio results. The Future C Sensitivity explores how the portfolio of resources changes in response to higher levels of customer investment in rooftop solar or other AMI-enabled activities that reduce usage during traditional peak hours.

The load forecast input was changed from High Case to Modified Load Growth ("MLG"), which was developed specifically for Future C's Sensitivity case using modified DR load shapes produced by ICF. As in Future C, the Sensitivity case assumes high natural gas and environmental costs which yield higher energy costs versus Futures A and B. The MLG forecast envisions a future where EAI's customers are enabled by AMI technology and have a greater economic incentive to adapt their energy consumption given higher relative energy prices. One example of how the Future C Sensitivity could develop is through significant increases in customer investment in rooftop solar or other types of distributed generation.

DR load shapes were decremented from the Reference Load forecast to produce the MLG load forecast. The resulting forecast primarily shifts customer energy usage away from peak hours and into off-peak hours, when energy is less expensive. As a result, annual peak loads are -1.0% to -2.3% lower versus the Reference Load forecast.

6.2 IRP Modeling Overview

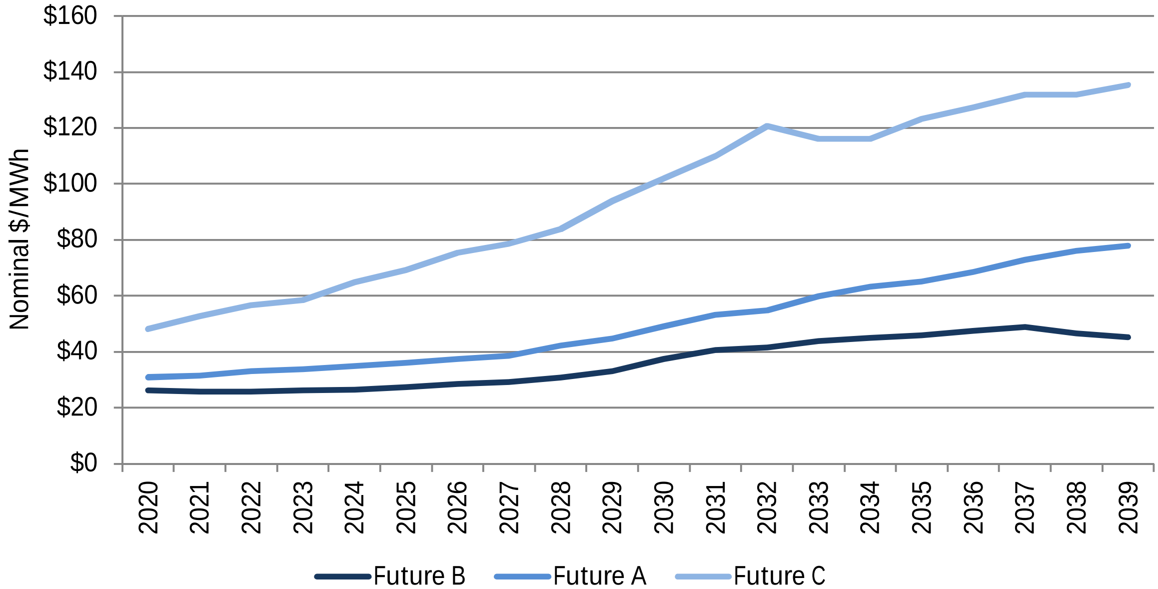
The development of the 2018 IRP relied on the AURORA[14] Energy Market Model to generate market prices (Locational Marginal prices or LMPs) for the MISO energy market and develop optimized portfolios for EAI under a range of possible futures. AURORA is a production cost and capacity expansion optimization tool that simulates energy market operations using hourly demands and individual resource operating characteristics in a chronological dispatch algorithm and uses projected market economics to determine the optimal long-term resource portfolio under varying future conditions including fuel prices, available generation technologies, available DSM program alternatives, environmental constraints, and future demand forecasts. AURORA's optimization process identifies the set of future resources that economically meets the identified requirements given the defined constraints.

6.3 Market Modeling

The first step in the IRP modeling process is to utilize AURORA to develop a projection of the MISO market energy price and operations based on the specific characteristics of each future. The energy market simulation results in hourly energy prices for each of the three futures. The projection encompasses the power market for the entire MISO footprint, excluding EAI. MISO-South (excluding EAI) projected power prices are used to assess potential portfolio strategies for EAI in each future during the capacity expansion optimization step. The scope of the markets modeled in this step is shown in Appendix D.

Figure 15: Average Annual MISO South Non-EAI LMP

[14] The AURORA Model is the primary production cost tool used to perform MISO energy market modeling and long-term variable supply cost planning for EAI. AURORA supports a variety of resource planning activities and is well suited for scenario modeling through hourly simulation of the MISO market. It is widely used by a range of organizations, including large investor-owned utilities, small publically-owned utilities, and regulators.



6.4 EAI Portfolio Optimization

Following the market modeling process, which results in LMPs for the MISO South region excluding EAI, the AURORA long-term capacity expansion logic was used to select resources to meet EAI's future capacity needs. Each of the three futures was modeled in AURORA and the capacity expansion logic was utilized to determine the timing, amount, and type of incremental capacity and incremental DSM to be added to EAI's existing portfolio to meet EAI's reliability requirements (target planning reserve margin requirements), subject to constraints, under each future. This step resulted in a 20-year resource expansion plan which is economically optimized to meet EAI's forecasted demand under each future scenario.

For the 2018 IRP, EAI sought to take into account capacity credit considerations of non-dispatchable, intermittent generation that is provided by solar and wind resources. As the amount of installed renewable resources in the generation portfolio increases, the contribution of an individual renewable resource towards meeting the planning reserve margin may decrease. This is due to solar production potentially shifting a load serving entity's net peak (demand less solar), such that every incremental unit of solar provides less value in supporting reliability needs. The concept that solar provides diminishing returns in capacity and energy value has been further explored in works by CAISO[15] and MISO[16] to great detail.

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15 https://www.nrel.gov/docs/fy16osti/65023.pdf
16 https://cdn.misoenergy.org/20180605%20RIIA%20Workshop%20Presentation213125.pdf

To account for the diminishing value of non-dispatchable, intermittent resources, EAI used functionality within the AURORA model that considers the impact of solar and wind on the peak load when selecting resources to include in the optimized portfolios. As a result, the capacity contribution of solar and wind within the optimized portfolios is dependent on the amount of incremental solar and wind added, the production profiles of these resources, and the load shape of EAI's customers. The diminishing returns of solar and wind resource additions are accounted for in the AURORA capacity expansion; for the purposes of computing a total supply cost to customers, EAI defaulted to the current MISO practice for new resources without sufficient operating history – 50% capacity credit for solar and 15.6% capacity credit for wind.

6.5 2018 EAI IRP DSM Modeling

Potential DSM Programs were evaluated as resource alternatives alongside supply side resource alternatives in the AURORA capacity expansion optimization in order to identify the most economic combination of DSM programs and supply side resources that meet EAI's customer needs subject to constraints.

Potential DSM programs were evaluated based on the characteristics and attributes described in earlier in this section. Each DSM program was modeled in AURORA based on annual program costs, hourly demand reduction profiles, program start date(s), assumed program life, and program dependencies or mutually exclusive restrictions and evaluated to identify the DSM programs that are economic (i.e. have a positive net benefit). The following potential DSM programs were modeled, totaling 15 potential alternatives:

- DR resource alternatives included three mutually exclusive DR portfolios (low, mid, high) with three discrete start year options (2020, 2025, 2030). Refer to Figure 16.
- EE resource alternatives included two mutually exclusive EE portfolios (low, high) with 3 discrete start year options (2020, 2025, 2030). Refer to Figure 17.

FIGURE 16: DR RESOURCE ALTERNATIVES

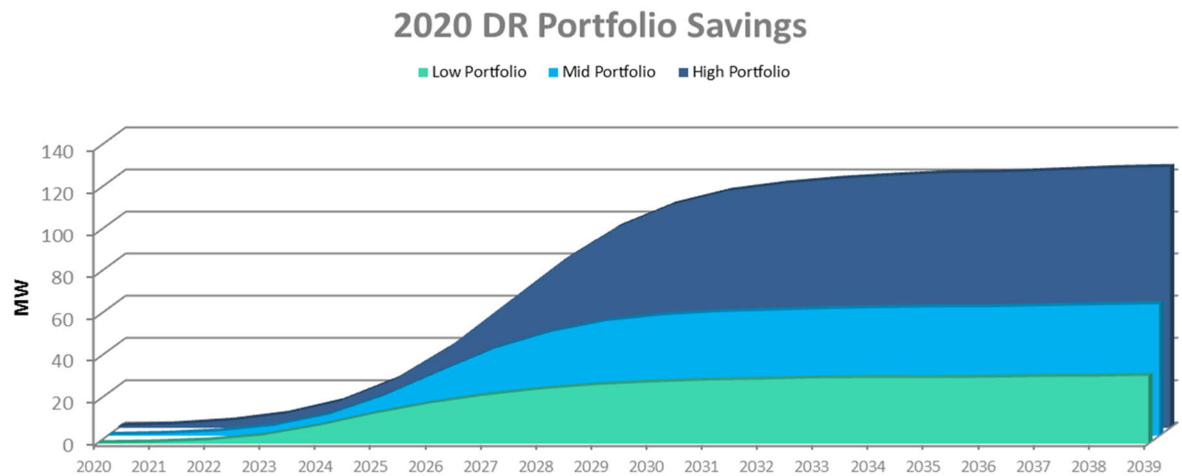
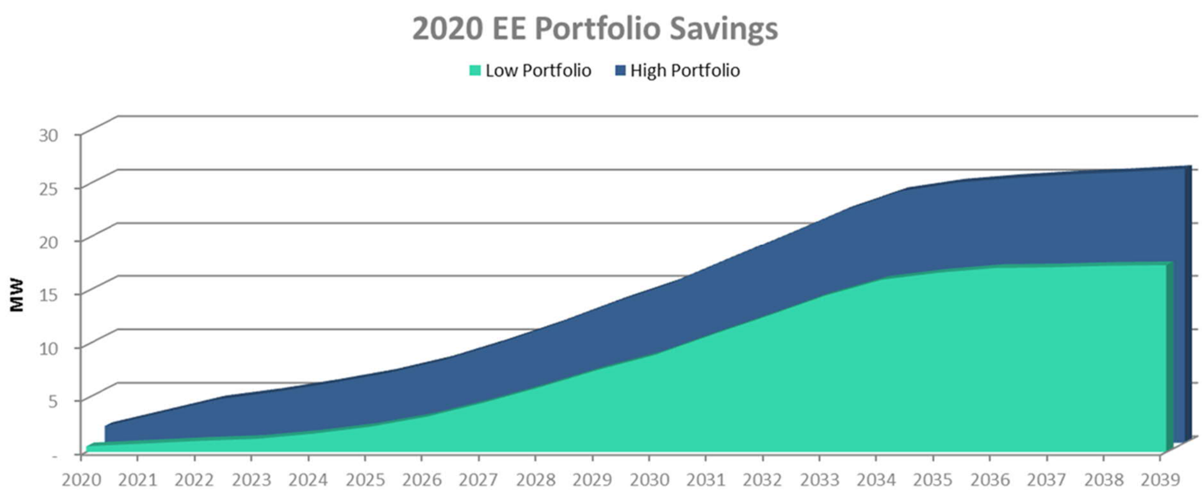


FIGURE 17: EE RESOURCE ALTERNATIVES



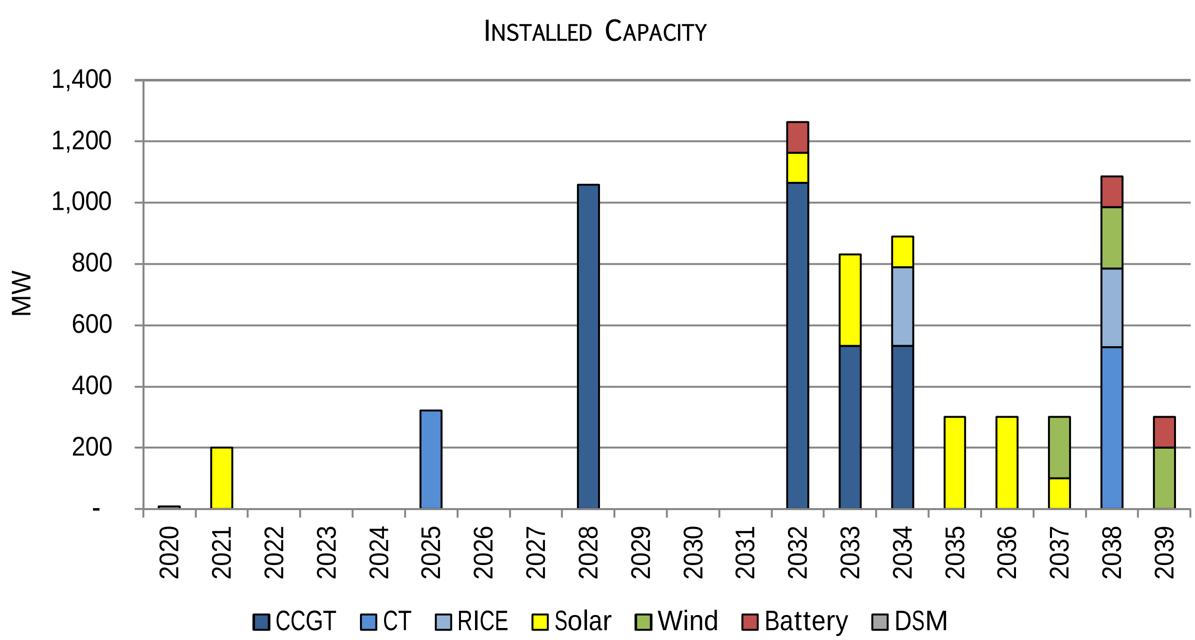
AURORA considers the cost and revenue of energy and capacity in the context of the MISO market for each supply side alternative and each DSM alternative. Selection of DSM alternatives in the model was based strictly on economics in order to avoid non-selection due to a lack of capacity need in the discrete start year options. The capacity credit of selected DSM programs is counted toward meeting EAI's capacity needs through reduction of peak load.

7. Results

7.1 Future A Results

A total of 6,660 MW of installed capacity is added to EAI's resource portfolio in Future A. On an effective capacity basis, which accounts for the intermittency of solar and wind resources, the total capacity addition is 5,545 MW (excluding DSM). The first resource added is the Low EE 2020 portfolio from the Potential DSM Resources. The first generation capacity is added in 2025 and consists of one CT unit; note that the solar capacity additions illustrated in Figure 18 below did not originate from AURORA's capacity expansion model (these resources are discussed in Section II). Overall, 68% of the modeled supply additions are natural gas resources while the remaining 32% are from renewable resources. The total relevant supply cost[17] for the Future A optimized portfolio is $9,050 million (2020-2039 present value, 2020$MM).

Figure 18: Future A Supply Additions



The portfolio mix of capacity resources over the 20-year IRP study period is shown below, followed by the fuel diversity based on energy generated for the Future A portfolio. The energy mix shown includes energy used to meet native load need and sales to the market.

[17] The total relevant supply cost consists of the sum of two components: the variable supply cost for the entire portfolio (existing, planned and incremental resources added via AURORA optimization) plus the fixed cost components of the incremental resources added via AURORA optimization and any other future fixed costs of existing resources that vary among the futures.

FIGURE 19: FUTURE A CAPACITY MIX

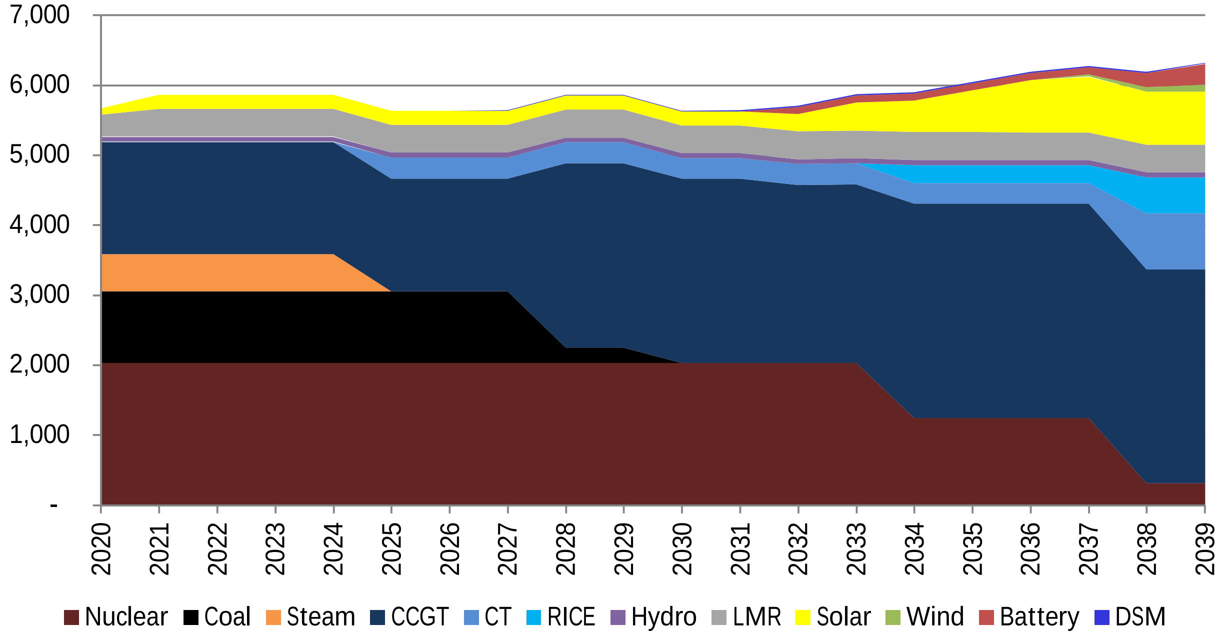
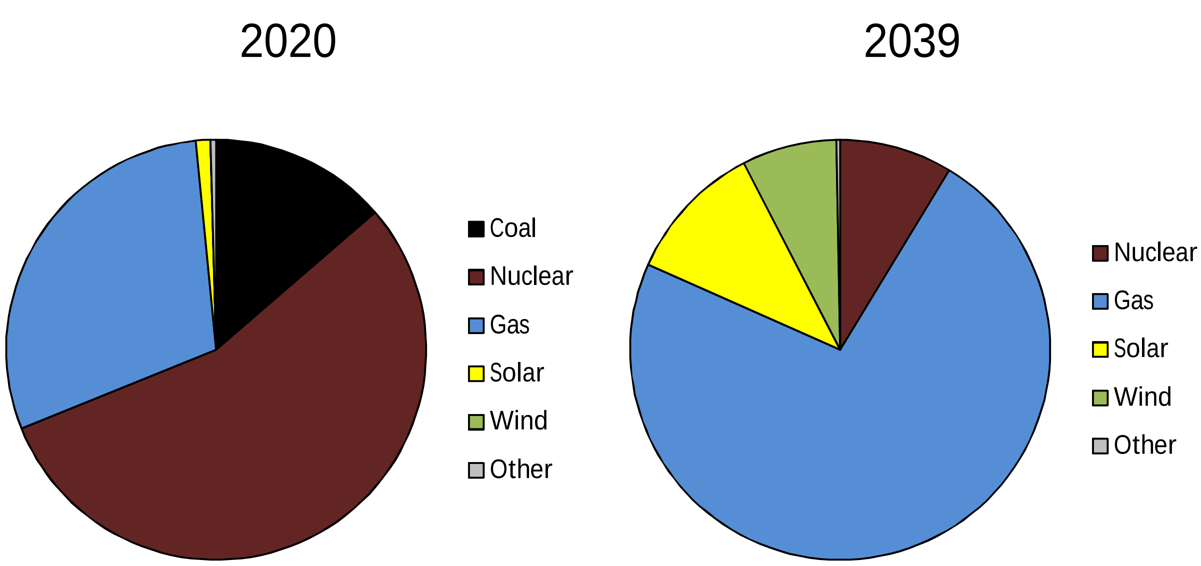


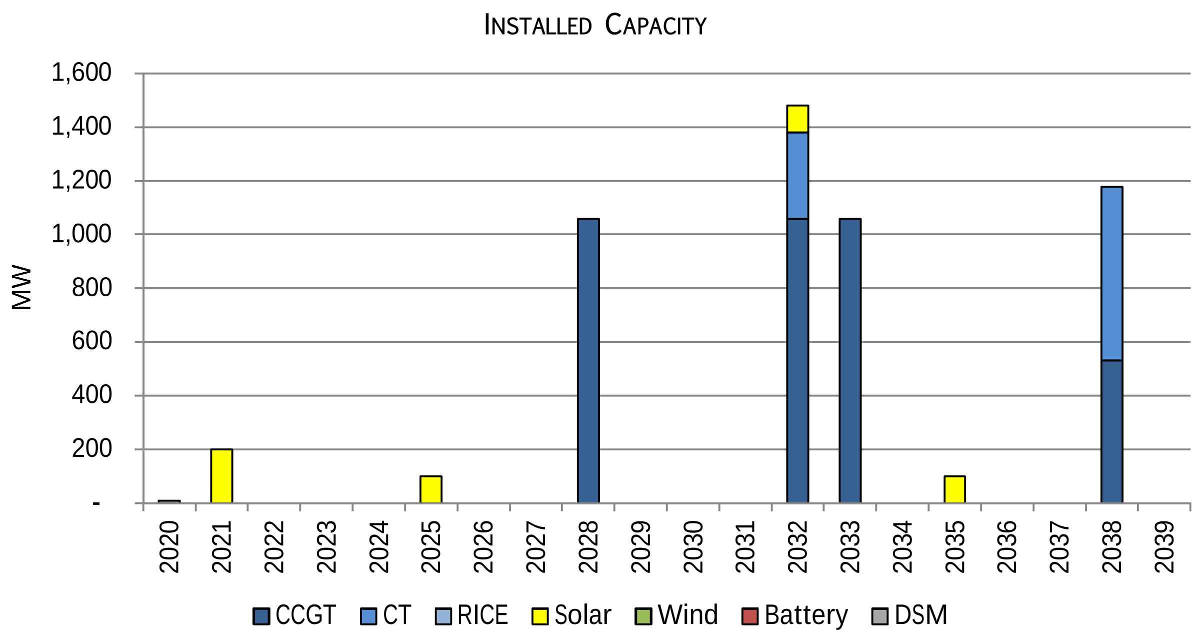
FIGURE 20: FUTURE A ENERGY MIX



7.2 Future B Results

A total of 4,984 MW of installed capacity is added to EAI's resource portfolio in Future B. On an effective capacity basis, which accounts for the intermittency of solar and wind resources, the total capacity addition is 4,825 MW (excluding DSM). The first resource added is the Low EE 2020 portfolio from the Potential DSM Resources. The first generation capacity is added in 2025 and consists of 100 MW of solar; as in Future A, note that the solar capacity additions illustrated in Figure 21 below did not originate from AURORA's capacity expansion model. Overall, 94% of the modeled supply additions are natural gas resources while the remaining 6% are from renewable resources. The total relevant supply cost for the Future B optimized portfolio is $6,673 million (2020-2039 present value, 2020$MM).

Figure 21: Future B Supply Additions



The portfolio mix of capacity resources over the 20-year IRP study period is shown below, followed by the fuel diversity based on energy generated for the Future B portfolio. The energy mix shown includes energy used to meet native load need and sales to the market.

Figure 22: Future B Capacity Mix

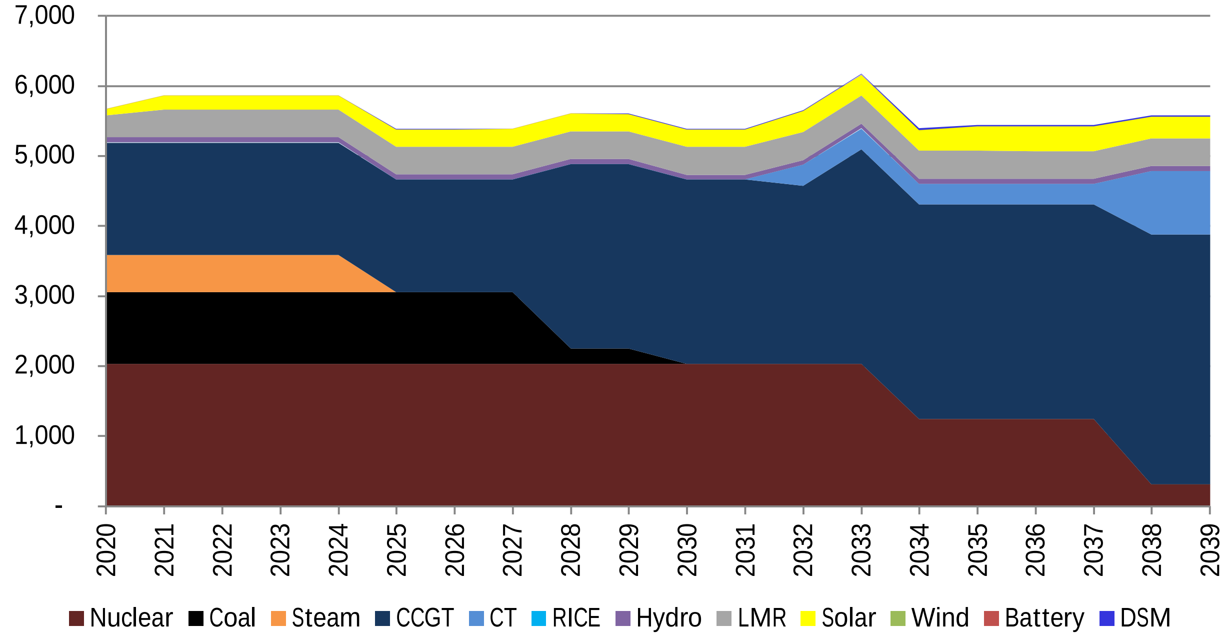
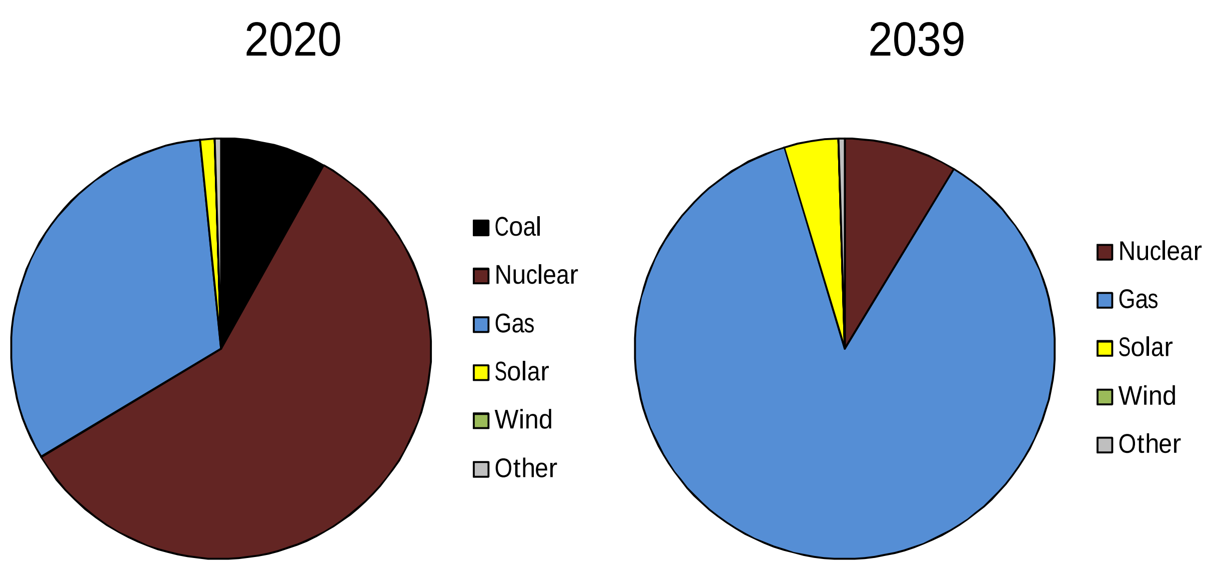


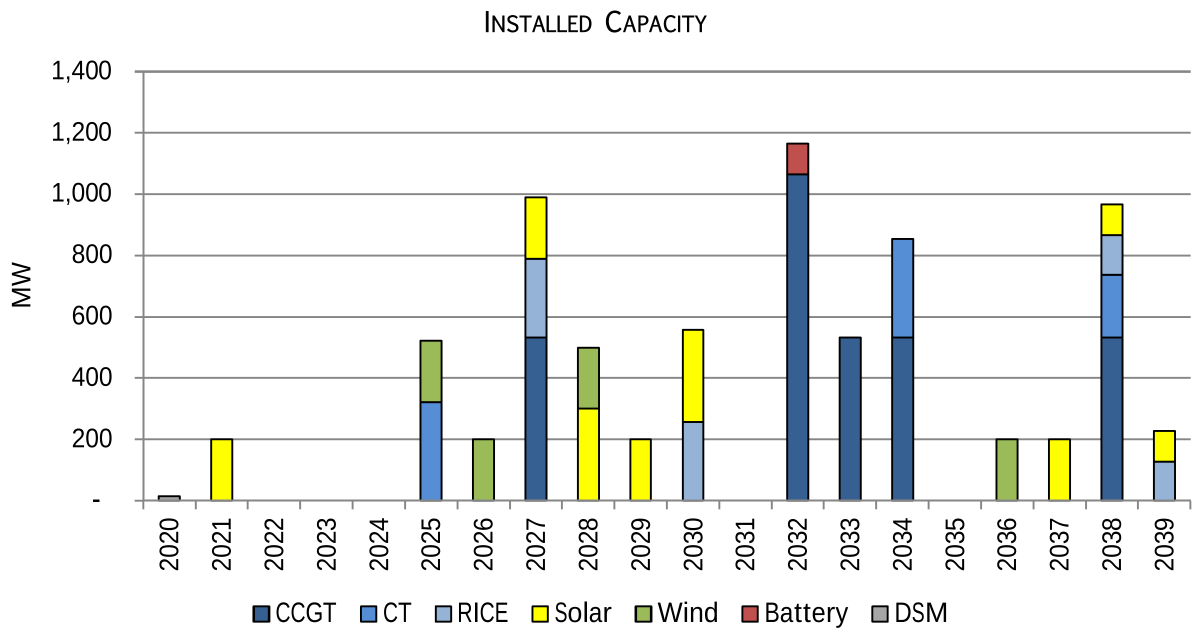
FIGURE 23: FUTURE B ENERGY MIX



7.3 FUTURE C RESULTS

A total of 7,128 MW of installed capacity is added to EAI's resource portfolio in Future C. On an effective capacity basis, which accounts for the intermittency of solar and wind resources, the total capacity addition is 5,739 MW (excluding DSM). The first resource added is the High EE 2020 portfolio from the Potential DSM Resources. The first generation capacity is added in 2025 and consists of one CT unit and 200 MW of wind; as in Futures A and B, note that the solar capacity additions illustrated in Figure 24 below did not originate from AURORA's capacity expansion model. Overall, 68% of the modeled supply additions are natural gas resources while the remaining 32% are from renewable resources. The total relevant supply cost for the Future C optimized portfolio is $10,416 million (2020-2039 present value, 2020$MM).

FIGURE 24: FUTURE C SUPPLY ADDITIONS



The portfolio mix of capacity resources over the 20-year IRP study period is shown below, followed by the fuel diversity based on energy generated for the Future C portfolio. The energy mix shown includes energy used to meet native load need and sales to the market.

FIGURE 25: FUTURE C CAPACITY MIX

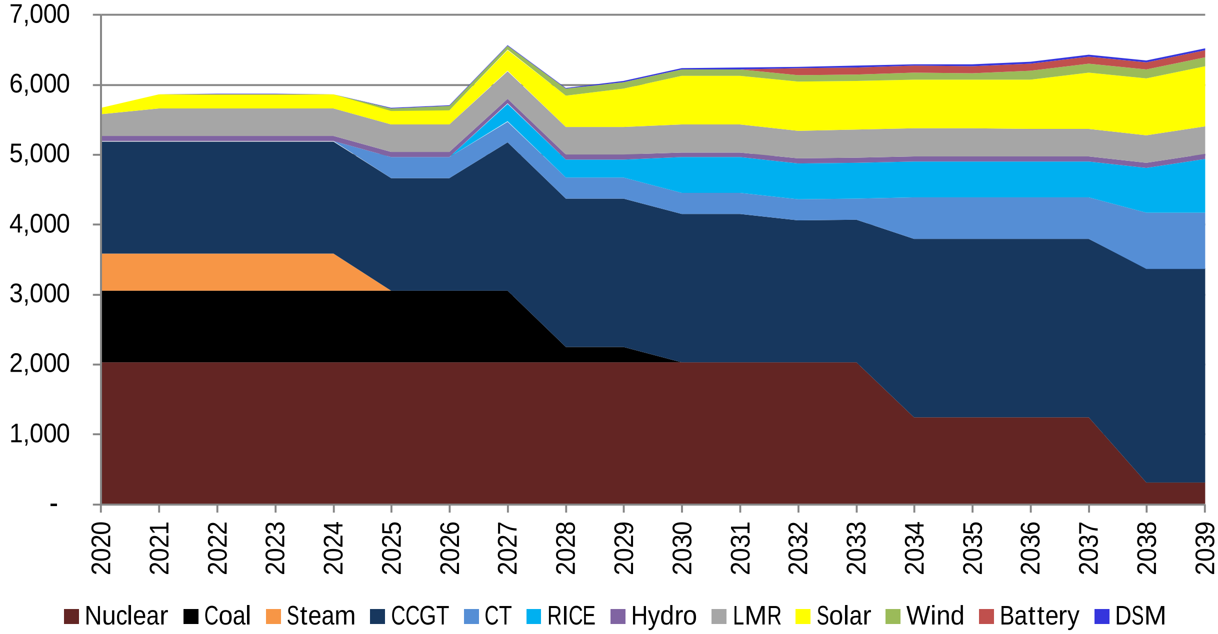
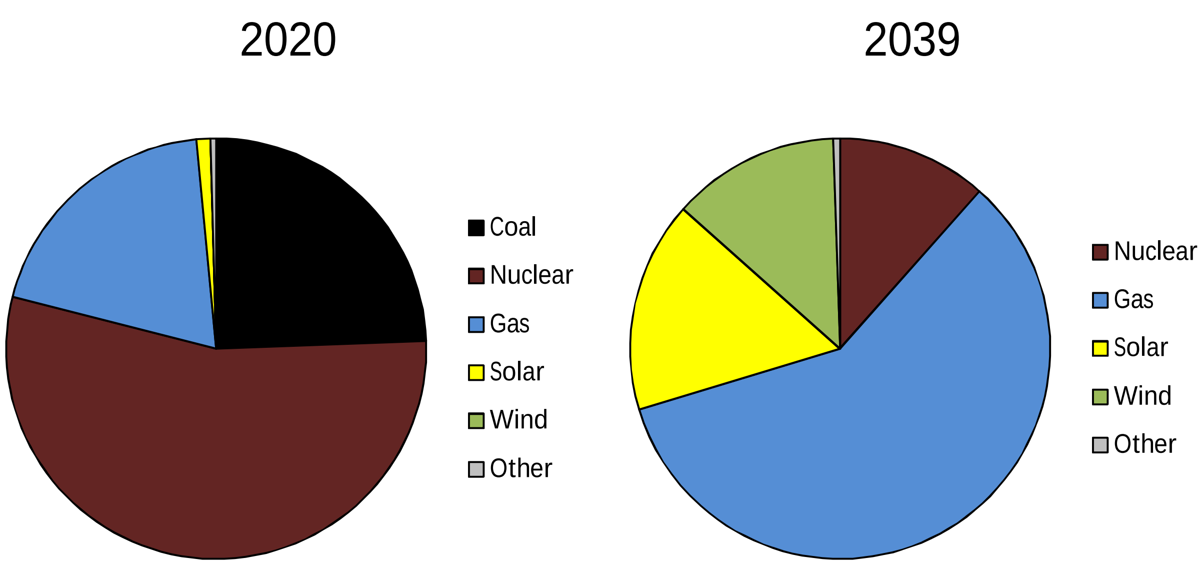


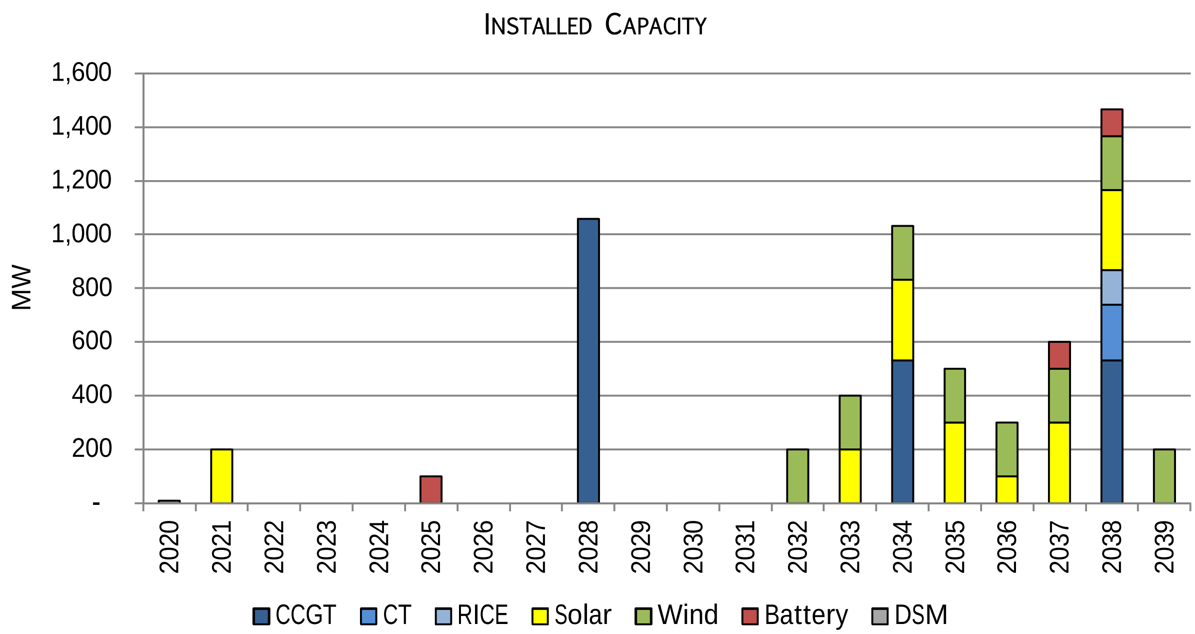
FIGURE 26: FUTURE C ENERGY MIX



7.4 Future A Sensitivity Results

A total of 5,866 MW of installed capacity is added to EAI's resource portfolio in the Future A Sensitivity. On an effective capacity basis, which accounts for the intermittency of solar and wind resources, the total capacity addition is 3,756 MW (excluding DSM). The first resource added is the Low EE 2020 portfolio from the Potential DSM Resources. The first generation capacity is added in 2025 and consists of a 100 MW battery; note that the solar capacity additions illustrated in Figure 27 below did not originate from AURORA's capacity expansion model. Overall, 42% of the modeled supply additions are natural gas resources while the remaining 58% are from renewable resources. The total relevant supply cost for the Future A Sensitivity optimized portfolio is $7,556 million (2020-2039 present value, 2020$MM).

Figure 27: Future A Sensitivity Supply Additions



The portfolio mix of capacity resources over the 20-year IRP study period is shown below, followed by the fuel diversity based on energy generated for the Future A Sensitivity portfolio. The energy mix shown includes energy used to meet native load need and sales to the market.

Figure 28: Future A Sensitivity Capacity Mix

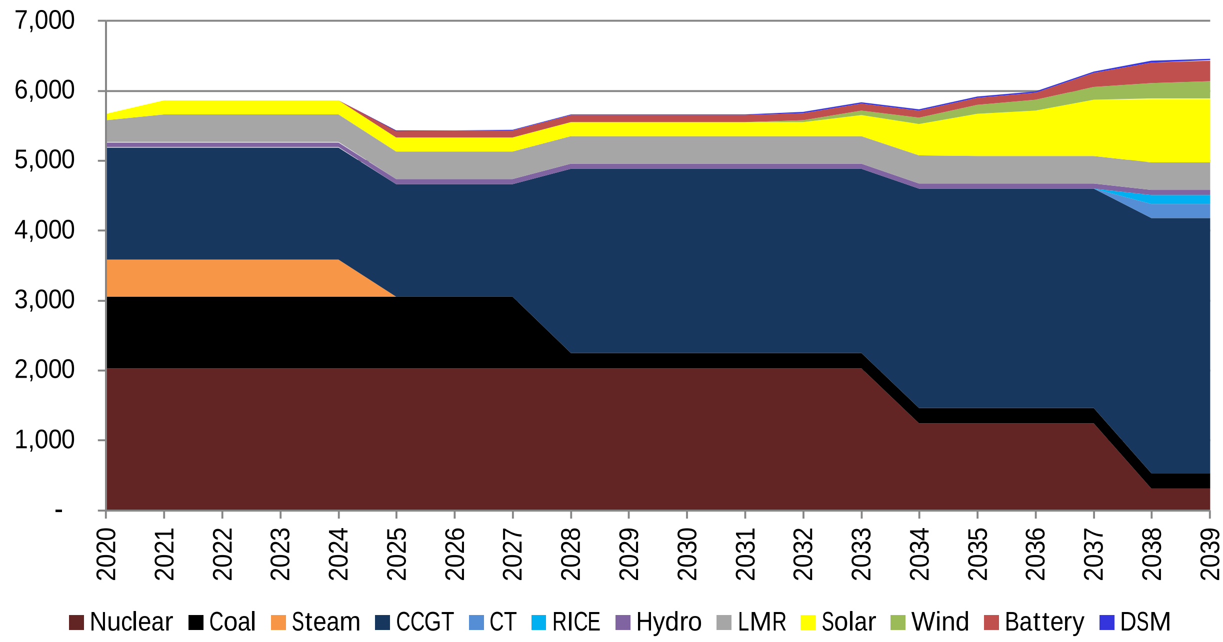
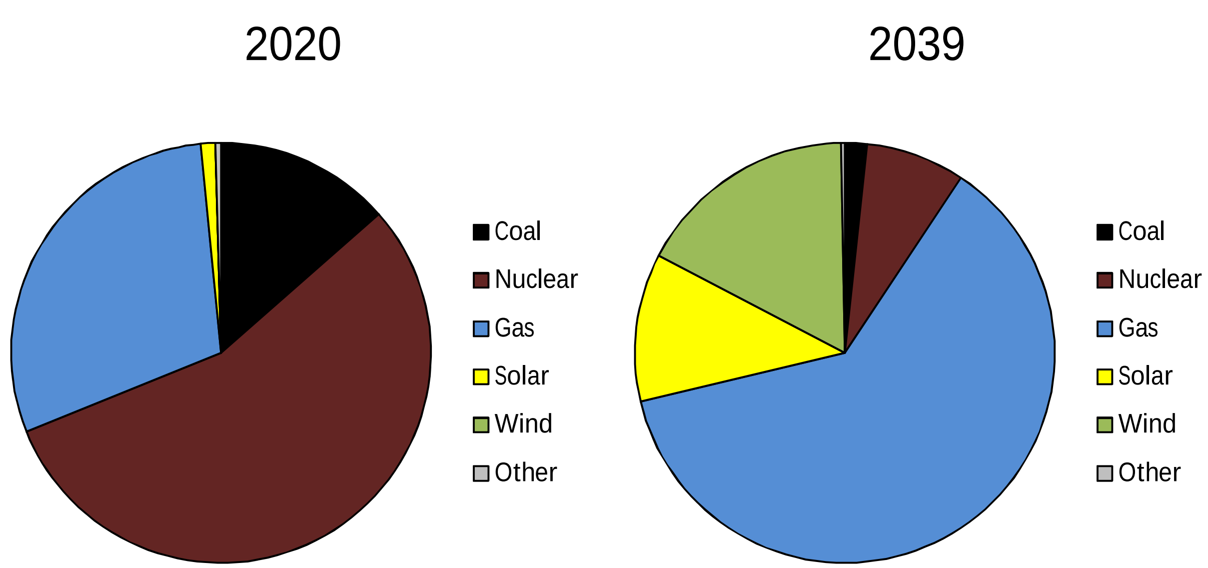


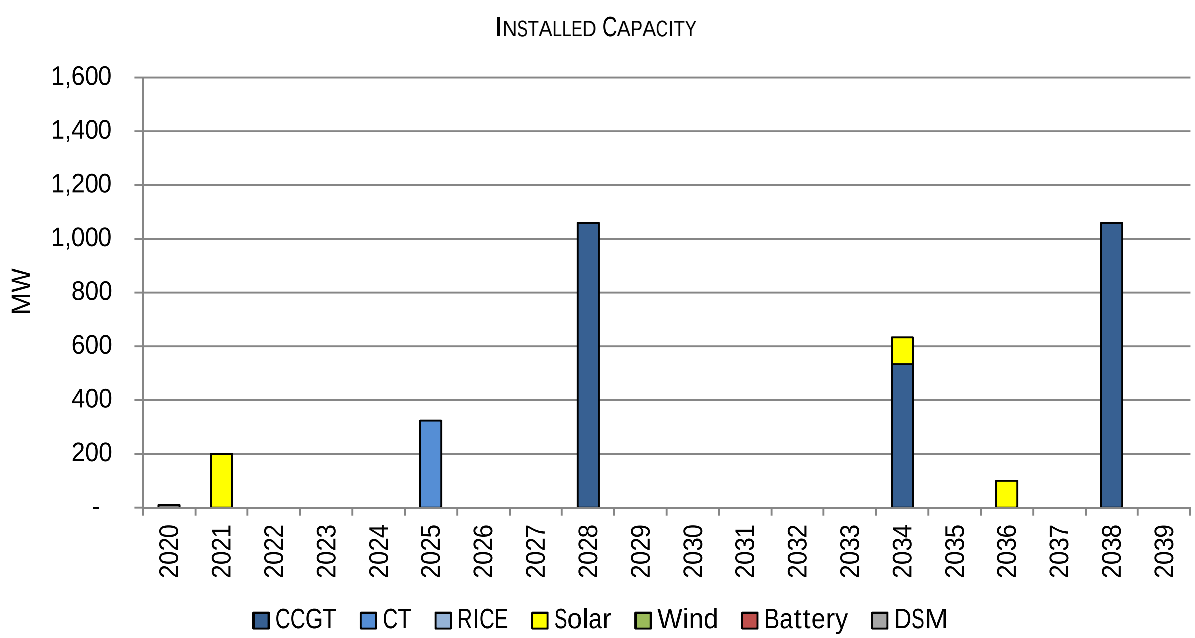
FIGURE 29: FUTURE A SENSITIVITY ENERGY MIX



7.5 Future B Sensitivity Results

A total of 3,180 MW of installed capacity is added to EAI's resource portfolio in the Future B Sensitivity. On an effective capacity basis, which accounts for the intermittency of solar and wind resources, the total capacity addition is 3,071 MW (excluding DSM). The first resource added is the Low EE 2020 portfolio from the Potential DSM Resources. The first generation capacity is added in 2025 and consists of one CT unit; note that the solar capacity additions illustrated in Figure 30 below did not originate from AURORA's capacity expansion model. Overall, 94% of the modeled supply additions are natural gas resources while the remaining 6% are from renewable resources. The total relevant supply cost for the Future B Sensitivity optimized portfolio is $7,064 million (2020-2039 present value, 2020$MM).

Figure 30: Future B Sensitivity Supply Additions



The portfolio mix of capacity resources over the 20-year IRP study period is shown below, followed by the fuel diversity based on energy generated for the Future B Sensitivity portfolio. The energy mix shown includes energy used to meet native load need and sales to the market.

FIGURE 31: FUTURE B SENSITIVITY CAPACITY MIX

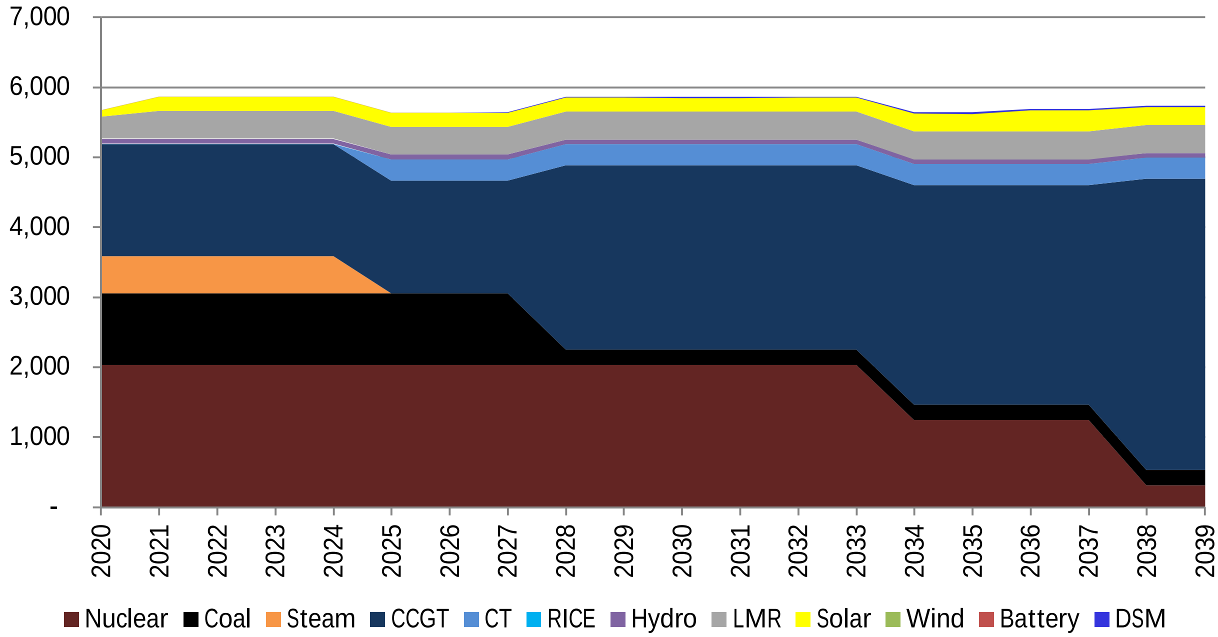
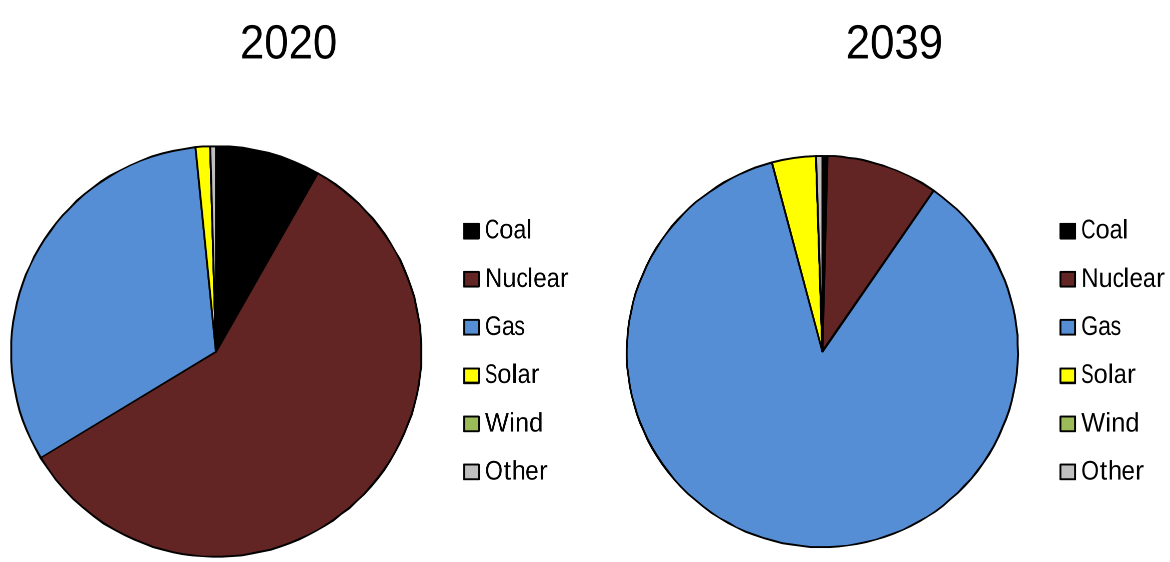


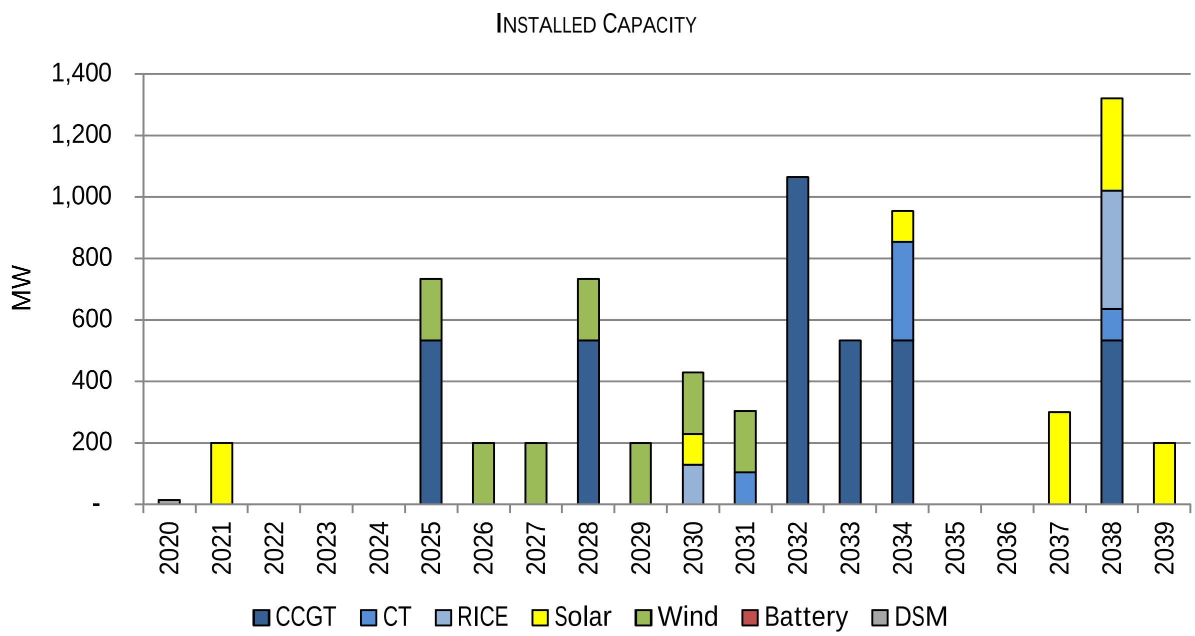
FIGURE 32: FUTURE B SENSITIVITY ENERGY MIX



7.6 Future C Sensitivity Results

A total of 7,181 MW of installed capacity is added to EAI's resource portfolio in the Future C Sensitivity. On an effective capacity basis, which accounts for the intermittency of solar and wind resources, the total capacity addition is 5,485 MW (excluding DSM). The first resource added is the High EE 2020 portfolio from the Potential DSM Resources. The first generation capacity is added in 2025 and consists of a 1x1 CCGT paired with 200 MW of wind; note that the solar capacity additions illustrated in Figure 33 below did not originate from AURORA's capacity expansion model. Overall, 66% of the modeled supply additions are natural gas resources while the remaining 34% are from renewable resources. The total relevant supply cost for the Future C Sensitivity optimized portfolio is $9,228 million (2020-2039 present value, 2020$MM).

Figure 33: Future C Sensitivity Supply Additions



The portfolio mix of capacity resources over the 20-year IRP study period is shown below, followed by the fuel diversity based on energy generated for the Future C Sensitivity portfolio. The energy mix shown includes energy used to meet native load need and sales to the market.

FIGURE 34: FUTURE C SENSITIVITY CAPACITY MIX

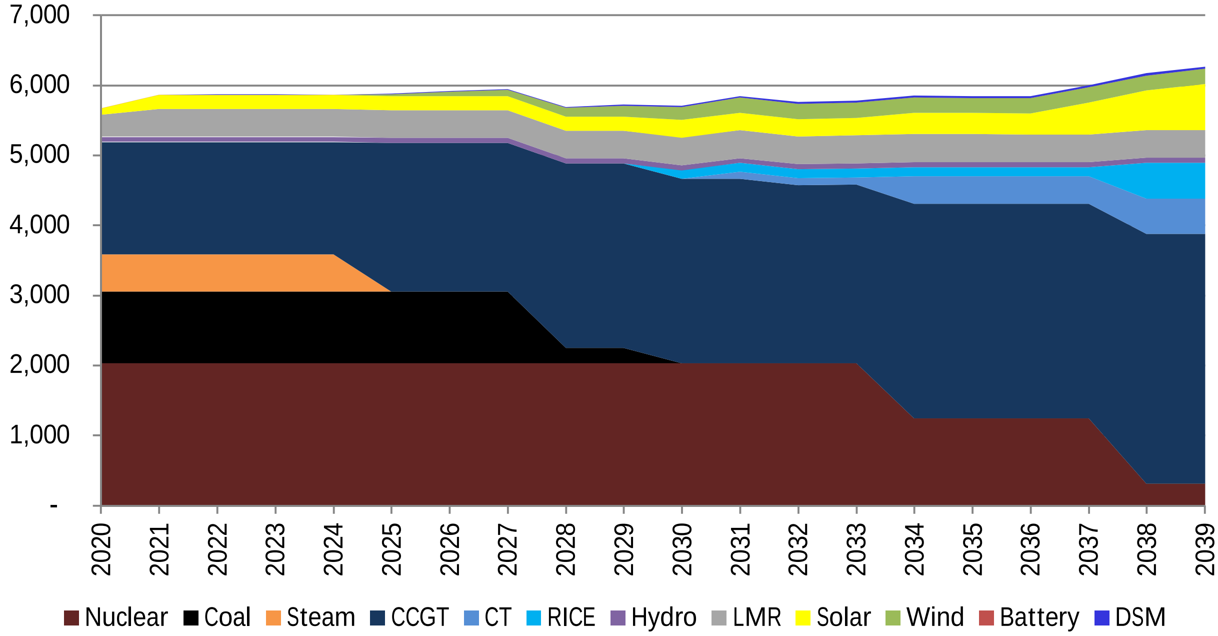
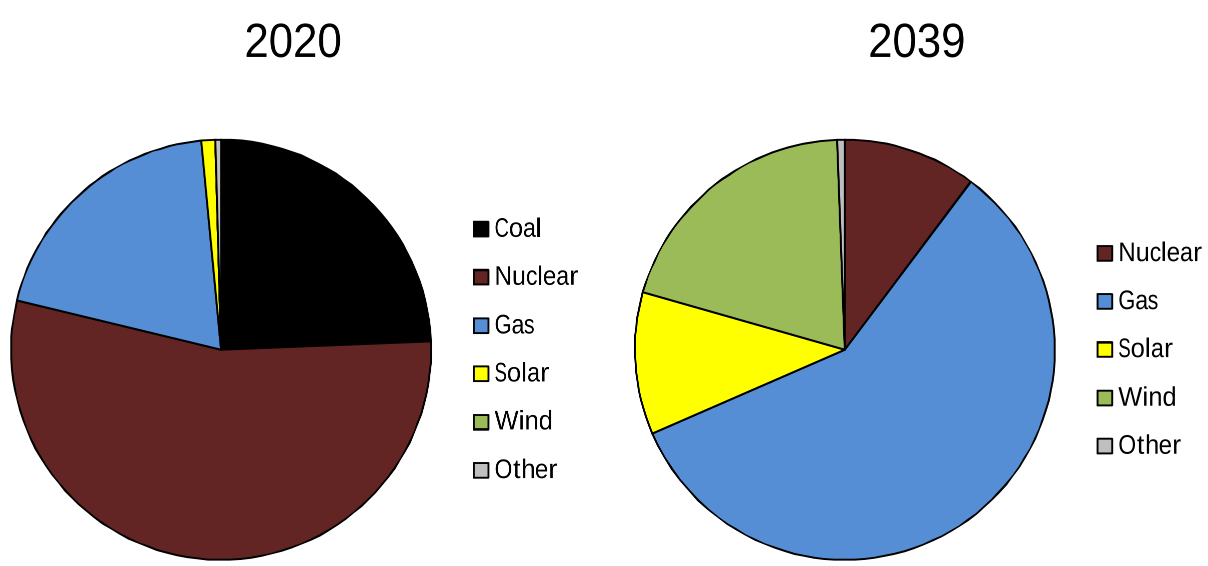


FIGURE 35: FUTURE C SENSITIVITY ENERGY MIX



IV. Action Plan

1. Findings and Conclusions

1.1 Summary of Findings

As discussed above, the AURORA Portfolio Optimization process resulted in six distinct resource portfolios, each of which are economically optimal for the respective future or sensitivity cases. When reviewing the results of those distinct resource portfolios, the many varying inputs across the futures must be taken into consideration. Because it was necessary to capture a broad range of uncertainties in the IRP Futures in order to bookend the range of possible outcomes, caution must be taken when comparing results between the futures. Nevertheless, the table below summarizes the results of the Portfolio Optimization for each future.

Table 10: Summary of Modeling Results

2020-39 Modeling Results	Future A	Future B	Future C
Total Incremental Installed Capacity:	6,660 MW	4,984 MW	7,128 MW
Natural Gas Capacity Additions:	68.4%	94.0%	67.5%
Renewable Capacity Additions:	31.6%	6.0%	32.5%
DSM Capacity Additions:	2020 Low EE	2020 Low EE	2020 High EE
Incremental Generation Capacity Additions Begin:	2025	2025	2025
Incremental Generation Capacity Type:	CT	Solar	CT + Wind

The optimal portfolio is consistent across the futures. Future C adds more capacity overall than Future A, but the fuel mix is similar. Future B has the smallest need for incremental capacity additions and assumptions that favor gas-fired resources, so the resulting portfolio mix is different from the others but is reasonable for that set of assumptions. Overall, the indication is that both renewable and gas-fired resources are cost-effective in the future. The result also affirms the current resource planning protocol of gradually adding cost-effective renewables and monitoring the resource needs as well as external market factors for the appropriate time to add other types of resources.

Renewables have become more cost-effective. As a percentage of incremental resource additions, renewables have increased across all futures since the 2015 IRP. While the increase in the ratios may appear modest, this is even more significant given that the natural gas price forecast has decreased almost 30% since the 2015 IRP. As discussed in the prior section, the 2018 IRP modeling also used functionality within the AURORA model that considers the impact of solar and wind on the peak load when selecting resources to include in the optimized portfolios.

TABLE 11: GAS TO RENEWABLES COMPARISON

Gas to Renewables Ratios	2015 IRP	2018 IRP
Low Case Ratio:	100% / 0%	94% / 6%
Reference Case Ratio:	73% / 27%	68% / 32%
High Case Ratio:	73% / 27%	68% / 32%

Generation is added in 2025 across all futures and sensitivities. The first generation resource addition in each of the three futures, as well as each of the three sensitivities, is added in 2025, though the technology type and size varies ranging from a 100 MW solar resource to 732 MW of combined CT and wind resources. Since resources are added in all futures, including Future B which assumes the Low Load Forecast, this is primarily driven by the deactivation assumption used in the 2018 IRP model for Lake Catherine Unit 4. Also, the recent actions EAI has taken by adding two solar PPAs and issuing a third RFP for solar resources over the past four years have partially mitigated the 2025 capacity need depending on how customer load requirements change over the next few years.

A CCGT is added in 2028 across all futures and most sensitivities. The next common theme across the 2018 IRP portfolios is that a CCGT resource is consistently added in 2028. The exception is Future C, which adds a CCGT resource in 2027 and a similar amount of renewable capacity in 2028. While EAI saw in its 2015 IRP and has seen in this 2018 IRP that the optimal resource portfolio of the future is likely comprised of a combination of renewables and conventional resources, the potential 2028 capacity need (created by the need to replace the coal-fired energy from White Bluff) may need to be primarily addressed by gas-fired, i.e. non-intermittent, generation that can serve the energy requirements of EAI customers.

A demand-side resource alternative is cost-effective in all scenarios. Specifically, varying levels of potential energy efficiency is selected in each portfolio. On the other hand, none of the demand response programs were selected. This result indicates that opportunity may exist for EAI to explore potential cost-effective energy efficiency investments as part of its future portfolio of resources.

2. ACTION PLAN

As was concluded in the 2015 IRP, the 2018 IRP continues to support the conclusion that EAI's future supply-side resource additions will likely consist of a mix of natural gas fired resources and renewable energy resources. Based on the work conducted as part of the 2018 IRP analysis, it is also reasonable to conclude that demand-side resources will continue to be a component of the capacity portfolio. The amount of total capacity that will be needed and exactly when that capacity will be needed are uncertain. There is even more uncertainty associated with exactly how much of each supply-side technology should be added to EAI's fleet and exactly how to identify potential demand-side resources. Because of those uncertainties, EAI will not establish specific targets for renewable generation or traditional generation as part of this IRP analysis. Rather, EAI will take deliberate steps in its Integrated Resource Planning at the appropriate time based on all the relevant information available at that time. For example, supply-side resource additions will be made based on specific project proposals.

The action items below represent a pragmatic approach to EAI's integrated planning over the coming three years. By necessity, the integrated planning process is subdivided into work streams, each with their own process and timeline.

2018 IRP Action Plan

1. Complete the Build-Own-Transfer of Solar PV	As a result of EAI's 2017 Request for Proposals for Build-Own-Transfer Solar Resources, EAI is currently working toward executing agreements for additional solar generation. Assuming required regulatory approvals are received, the acquisition of additional solar PV generation is expected to take place in 2021.
2. Supply-side Resource Additions	EAI will monitor its load and capability position and take steps to add supply side resources for both traditional and/or renewable resources as warranted. Based on current information, a competitive solicitation may be issued in 2019 for long-term resources. In addition to market solicitation, EAI will be considering developing self-build proposals for certain supply side technologies. However, the exact scope and timing of the next EAI RFP is uncertain and is dependent on many factors noted throughout this report.
3. Potential 2025 Capacity Need	EAI will complete an evaluation of the availability and economics of Lake Catherine Unit 4 past the assumed deactivation date of 2025. In combination with Action Item #2 above, EAI will update the load and capability position in order to monitor the capacity need in 2025.

4. Demand-side Resource Opportunities	EAI will seek and evaluate cost-effectiveness and feasibility for potential projects or programs to gain energy efficiencies in addition to its existing Arkansas Energy Efficiency Program Portfolio. For example, this may be achieved through EE programs with Self-Direct customers or, after implementation of AMI, through AMI-enabled programs or distributed generation resources.
5. Continue Participation in EE	EAI will continue to offer cost effective EE and DR programs within the Commission's Rules for Conservation and Energy Efficiency Programs and subsequent future Commission orders as provided through Arkansas State law, including the recently increased targets that were not available at the time of the 2018 IRP study[18]. Finally, EAI is committed to update the IRP in 2021 and will include an update to the future outlook for DSM as well.
6. Coal Environmental Compliance	The challenge utilities face with regards to environmental compliance is unprecedented in terms of the number of recent and upcoming rules which affect utilities, the compressed time frame for compliance, and the continuing ratcheting down of compliance obligations. Key uncertainties include the requirements related to Regional Haze, ambient air quality standards, coal combustion residuals regulation, effluent limitation guidelines, among others, the outcome of current litigation, congressional activity and the possibility of extensions of compliance deadlines. Another key uncertainty is the nation's long-term carbon policy. The industry needs a satisfactory resolution of both the current regulatory challenges and a long-term legislative solution on carbon. EAI will continue to monitor changes in environmental law and regulations at the state and federal level and evaluate options for environmental compliance for the EAI coal units.
7. Stakeholder Engagement Process	Stakeholder engagement has been an important part of the development of this IRP. An immediate priority will be for EAI to closely review the stakeholder report, which can be found in Appendix E of this report, and take steps to address concerns and suggestions.

[18] Order 43 in Docket No. 13-002-U, effective July 13, 2018

V. STAKEHOLDER ENGAGEMENT

Per the APSC Resource Planning Guidelines,[19] one part of the development of the IRP is to engage with all of the stakeholders in EAI's long-term planning process. Stakeholders include representatives of retail and wholesale customers, independent power suppliers, marketers, and other interested entities in EAI's service area.

For the 2018 IRP, the Stakeholder Engagement Process began in May 2018 with distribution of a detailed slide presentation describing proposed assumptions, inputs, and modeling framework. The materials, while still preliminary, were posted to EAI's IRP website[20]. Additional meeting materials, which included preliminary modeling results from all three Futures, were provided to stakeholders in advance of the in-person stakeholder meeting hosted by EAI in June 2018.

As noted, EAI hosted an in-person meeting at the MISO South building in Little Rock on June 6, 2018. During the June 6th meeting, presentations were given by several EAI representatives covering a broad range of inputs and modeling results for the IRP. The Company received questions and feedback both during and subsequent to the meeting. Additionally, the stakeholders organized into a Stakeholder Committee during the June 6th meeting.

Both during and subsequent to the June 6th meeting, over 100 detailed questions were submitted to EAI by various stakeholders, to which EAI responded via follow-up postings to the IRP website. EAI's responses were posted in four subsets in order to provide responses as quickly as possible, with most responses posted within a week of receipt. A notification was sent to stakeholders via email at the time of each posting.

At the request of the Stakeholder Committee, EAI hosted a conference call in August 2018 to have a technical discussion of the Committee's feedback regarding EAI's IRP modeling. During the call, EAI offered to provide additional modeling scenarios based on requested assumptions from the Stakeholder Committee. No additional requests from the Stakeholder Committee were presented at that time or following the conference call. Finalized portfolio optimization modeling results for all Futures and Sensitivities were posted by EAI to the IRP website on October 4, 2018. The Stakeholder Committee requested additional time to complete the Stakeholder Report, which was provided to EAI on October 24, 2018. As described in Item 7 of the 2018 IRP Action Plan, EAI will closely review the Stakeholder Report and incorporate

[19] Docket No. 06-028-R, Order No. 6, Attachment 1
[20] http://www.entergy-arkansas.com/integrated_resource_planning

feedback as EAI executes the 2018 IRP Action Plan and prepares for the next IRP cycle.

APPENDIX A – RESOURCE PLANNING OBJECTIVES

PURPOSE:

The purpose of this document is to establish resource planning objectives to guide Entergy Arkansas, Inc. (EAI) resource planning and operations staff in development of EAI's Integrated Resource Plan (IRP) and to meet the requirements of the APSC Resource Planning Guidelines for Electric Utilities.

OBJECTIVES:

In developing EAI's IRP, EAI's resource planning and operations staff should consider the following resource planning objectives:

1. Policy Objectives – The development of the IRP should reflect policy and planning objectives reviewed by the EAI RPOC and approved by EAI's President and Chief Executive Officer. Those policy and planning objectives will consider and reflect the policy objectives and other requirements provided by EAI's regulators.

2. Resource Planning – The development of the IRP will consider generation, transmission, and demand-side (e.g., demand response, energy efficiency) options.

3. Planning for Uncertainty – The development of the IRP will consider scenarios that reflect the inherent unknowns and uncertainties regarding the future operating and regulatory environments applicable to electric supply planning including the potential for changes in statutory requirements.

4. Reliability – The IRP should provide adequate resources to meet EAI's customer demands and expected contingency events in keeping with established reliability standards.

5. Baseload Production Costs – The IRP should provide baseload resources that provide stable long-term production costs and low operating costs to serve baseload energy requirements.

6. Operational Flexibility for Load Following – The IRP should provide efficient, dispatchable, load-following generation and fuel supply resources to serve the operational needs associated with electric system operations and the time-varying load shape levels

that are above the baseload supply requirement. Further the IRP should provide sufficient flexible capability to provide ancillary services such as regulation, contingency and operating reserves, ramping, and voltage support.

7. Generation Portfolio Enhancement – The IRP should provide a generation portfolio that over time will realize the efficiency and emissions benefits of technology improvements and that avoids an over-reliance on aging resources.

8. Price Stability Risk Mitigation – The IRP should consider factors contributing to price volatility and should seek to mitigate unreasonable exposure to the price volatility associated with the major uncertainties in fuel and purchased power costs.

9. Supply Diversity and Supply Risk Mitigation – The IRP should consider and seek to mitigate the risk exposure to major supply disruptions such as outages at a single generation facility or the source of fuel supply.

10. Locational Considerations - The IRP should consider the uncertainty and risks associated with dependence on remote generation and its location relative to EAI's load so as to enhance the certainty associated with the resource's ability to provide deliver power to EAI's customers.

11. Reliance on Long-Term Resources – EAI will meet reliability requirements primarily through long-term resources, both owned assets and long-term power purchase agreements. While a reasonable utilization of short-term purchased power is anticipated, the emphasis on long-term resources is to mitigate exposure to supply replacement risks and price volatility, and ensure the availability of resources sufficient to meet long-term reliability and operational needs. Over-reliance on limited-term purchased power (*i.e.*, power purchased for a one to five year term) exposes customers to risk associated with market price volatility and power availability.

12. Sustainable Development – The IRP should be developed consistent with EAI's vision to conduct its business in a manner that is environmentally, socially and economically sustainable.

APPENDIX B - EAI PORTFOLIO OF RESOURCES

Owned Generation	Total Installed Capacity (MW)	Ownership (%)	Retail Capacity (MW)	Commercial Operations Date
Arkansas Nuclear One Unit 1	834	100%	789	1974
Arkansas Nuclear One Unit 2	986	100%	933	1980
Carpenter Unit 1	31	100%	31	1932
Carpenter Unit 2	31	100%	31	1932
Hot Spring	606	100%	606	2002
Independence Unit 1	839	31.5%	221	1983
Lake Catherine Unit 4	528	100%	528	1970
Ouachita Unit 1	252	100%	252	2002
Ouachita Unit 2	253	100%	253	2002
Remmel Units 1, 2 & 3	12	100%	12	1925
Union 2	501	100%	501	2003
White Bluff Unit 1	815	57.0%	401	1980
White Bluff Unit 2	822	57.0%	402	1981

Purchased Generation	Total Installed Capacity (MW)	Retail Capacity (MW)	Commercial Operations Date
Blakely	86	11	1956
DeGray	78	10	1972
Grand Gulf	1,409	308	1985
Stuttgart Solar	81	81	2017

Notes:
- Blakely and DeGray capacity is assumed through 5/31/2019
- Grand Gulf Capacity is assumed through the IRP study horizon.
- Stuttgart Solar achieved commercial operations in December 2017; EAI's PPA began effective 6/1/2018.

Demand-side Resources	Reduction During Peak Load Hours (MW)
Demand Response	59
Interruptible Load	57

Notes:
- Estimates above are 2018 reductions.
- EAI's Demand Response includes Residential Direct Load Control and Agricultural Irrigation Load Control programs.
- Demand Response and Interruptible capacity is grossed up to account for reserve margin and line loss value in the Load & Capability analysis.

APPENDIX C - MISO MTEP SUBMISSIONS

TABLE 12: EAI PROJECTS APPROVED IN APPENDIX A OF MTEP17

Project Driver	Project Name	Current Projected ISD
Load Growth	LR Kanis: Install 3rd distribution transformer (necessitates station conversion to breaker and a half configuration)	Complete
Load Growth	Greyhawk 161 kV: New Distribution Substation	6/1/2020
Load Growth	Tarleton 230 kV: New Distribution Substation	6/1/2019
Load Growth	MacArthur 115 kV: New Distribution Substation	11/1/2019
Load Growth	Pecan Street 161 kV: New Distribution Substation	11/15/2019
Load Growth	Big Creek 115 kV: New Distribution Substation	5/1/2020
Load Growth	Russellville Industrial 161 kV: New Distribution Substation	12/1/2019
Transmission Reliability - Meeting Planning Criteria	Jacksonville North - Sylvan Hills 115 kV: Upgrade line bay bus at Sylvan Hills	12/1/2018
Transmission Reliability - Meeting Planning Criteria	El Dorado Donan 115 kV: Install 30MVAR capacitor bank	Complete
Transmission Reliability - Meeting Planning Criteria	Independence: Replace 500/161 kV Autos	12/1/2019
Transmission Reliability - Meeting Planning Criteria	West Helena: Install 115 kV breakers	12/1/2019
Transmission Reliability - Meeting Planning Criteria	Russellville East 161 kV: Install 10 Ohm Series Reactor	6/1/2020
Transmission Reliability - Meeting Planning Criteria	Happy Valley - Hot Springs 500 kV Project	6/1/2024

TABLE 13: EAI PROJECTS SUBMITTED AS TARGET APPENDIX A IN MTEP18

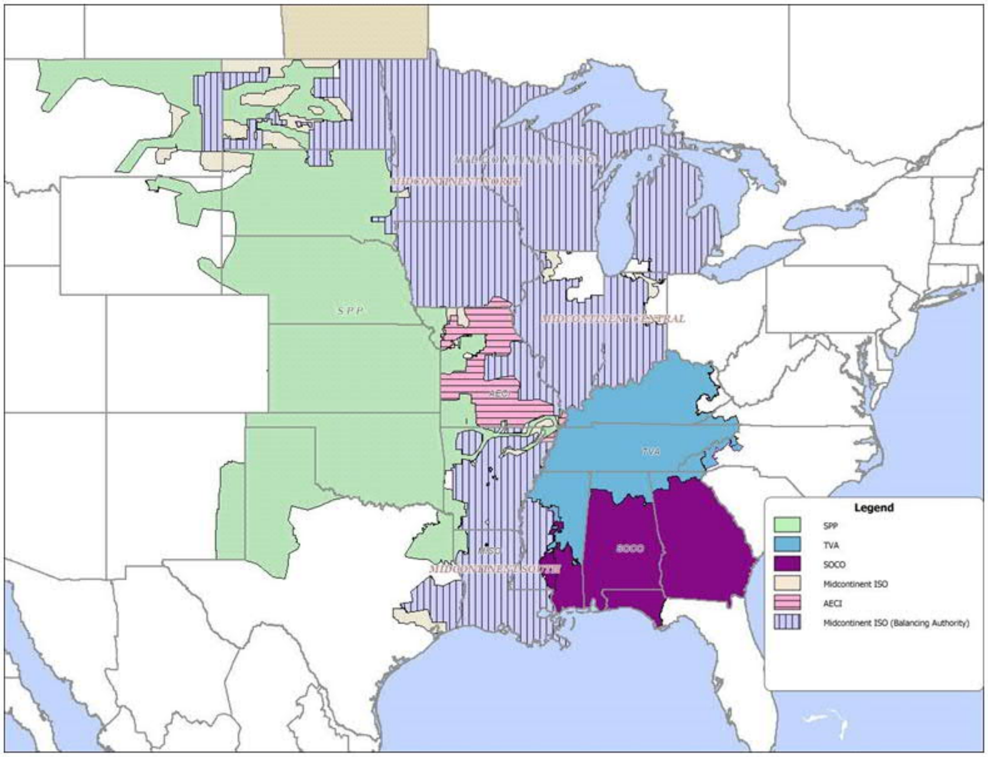
Project Driver	Project Name	Current Projected ISD
Asset Management	Moses 161 kV: New Substation	6/1/2019
Load Growth	Sierra 115 kV: New Distribution Substation	5/1/2020
Load Growth	Skunk Hollow 161 kV: New Distribution Substation	6/1/2021
Load Growth	Social Hill 115 kV: New Distribution Substation	6/1/2021
Load Growth	Palestine 161 kV: New Distribution Substation	6/1/2023
Transmission Reliability - Meeting Planning Criteria	Jacksonville North - Holland Bottom 115 kV: Upgrade line to 100 C operation	12/1/2019
Transmission Reliability - Meeting Planning Criteria	Cheetah - Hot Springs Village 115 kV: Rebuild line	12/1/2020
Transmission Reliability - Meeting Planning Criteria	Conway S. - Conway Ind. 161 kV: Rebuild line	12/1/2020
Transmission Reliability - Meeting Planning Criteria	Camden Maguire - Smackover 115 kV: Rebuild line	6/1/2021
Transmission Reliability - Meeting Planning Criteria	Paragould 161/115 kV: Install station service to enable autotransformer cooling pumps and uprate autotransformer.	12/1/2021
Transmission Reliability - Meeting Planning Criteria	Fourche - Little Rock East 115 kV: Rebuild line	6/1/2021
Transmission Reliability - Meeting Planning Criteria	Hilltop - St Joe 161 kV: Rebuild line	6/1/2023
Transmission Reliability - Meeting Planning Criteria	St Joe - Everton Road 161 kV: Rebuild line	12/1/2024
Transmission Reliability - Meeting Planning Criteria	Everton Road - Harrison East 161 kV: Rebuild line	6/1/2025
Transmission Reliability - Meeting Planning Criteria	Southland - Mt Home 161 kV: Rebuild line	12/1/2023
Transmission Reliability - Meeting Planning Criteria	Norfork - Southland 161 kV: Rebuild line	12/1/2027
Transmission Service	Mabelvale 500 kV: Switch Replacement	11/1/2018

TABLE 14: EAI PROJECTS TO BE SUBMITTED AS TARGET APPENDIX A IN MTEP19

Project Driver	Project Name	Current Projected ISD
Transmission Reliability - Meeting Planning Criteria	Hot Springs Village – Sierra 115kV Rebuild	6/1/2021
Transmission Enhanced Reliability	Little Rock Area Enhanced Reliability – Phase 1 Rebuild L.R. Gaines – L.R. 8th & Woodrow 115kV	12/1/2021
Transmission Enhanced Reliability	Little Rock Area Enhanced Reliability – Phase 2 Rebuild L.R. 8th & Woodrow – L.R. Palm Street – L.R. West 115kV	12/1/2022
Transmission Enhanced Reliability	Amity Tap 115kV Construct Breaker Station	6/1/2024
Transmission Enhanced Reliability	Batesville 161kV Install Breakers	6/1/2024

APPENDIX D – SCOPE OF AURORA MARKET MODEL

The shaded areas shown on the map are modeled in AURORA. These areas include MISO-South, the 1st tier markets adjacent to MISO-South (SPP, TVA, AECI and SOCO), and the remainder of MISO (MISO-Central and MISO-North).



APPENDIX E – STAKEHOLDER REPORT

[ATTACHMENT]

STAKEHOLDER COMMENTS REGARDING ENTERGY ARKANSAS'S 2018 INTEGRATED RESOURCE PLAN

The stakeholders that participated in the Entergy Arkansas Inc. ("EAI") Integrated Resource Plan ("IRP") thank the company for providing information and assisting the stakeholders in understanding EAI's policy and planning objectives of the IRP for the next 20 years. The stakeholders agreed at the start of the IRP process to avoid suppressing contrary opinions and comments. For the purpose of concluding its review of the 2018 IRP, the stakeholders recommend to EAI that it should consider and respond to each issue and recommendation as presented in the comments.

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I. Comment Topic: Stakeholder Process

Simon Mahan, Southern Renewable Energy Association

Other Stakeholders Joining This Comment: Advanced Energy Management Alliance, Arkansas Electric Energy Consumers, Inc., and Sierra Club.

* * *

Arkansas' Integrated Resource Planning (IRP) Guidelines provide a few explicit requirements for utility resource planning.[1] EAI has followed some of the Commission's Guidelines, while others have been left deficient, and others entirely ignored.

A. Evaluation of EAI IRP Process

The Arkansas IRP process is unique compared to processes across the southeast. For instance, individual utilities do not appear to have standard service lists, there are rarely publicly posted information about the IRP processes or timelines, and it is difficult for stakeholders to get engaged in the various IRPs without first initially contacting the utilities ahead of the initial stakeholder meeting. Stakeholders that are unable to make the first (and frequently, only) in-person meeting often have little ability to provide input and interact with Stakeholder Committees after the first meeting. Requests made of the utility at the stakeholder meeting may or may not be documented, and may or may not be responded to. For example, a number of questions at the EAI stakeholder meeting held on June 6, 2018 were not answered and EAI did not provide estimated timelines for when questions would be responded to.

While the Stakeholder Committee is empowered to create its own rules and procedures, those rules and procedures are commonly left unstated and informal due to insufficient time. Stakeholder Committees frequently lack a "point person" to pull together the Committee's

[1] http://www.apscservices.info/Rules/resource_plan_guid_for_elec_06-028-R_1-7-07.pdf

requests of a utility, and development of Committee milestones or goals also frequently do not occur.

The current Stakeholder Committee on this EAI IRP requested the company not rely on capacity-only resource planning, that renewable energy prices be lowered to reflect current market realities, and that certain power plant retirements be accelerated in various sensitivity scenarios. None of those requests were fulfilled, and it was only until mid-October when EAI provided its final set of IRP information that the Stakeholder Committee realized that the company would not be fulfilling any of these requests.

When compared to the SWEPCO Arkansas IRP process, this EAI process underscores significant deficiencies in this current EAI process, and the Arkansas IRP Guidelines broadly.

- EAI did provide slides ahead of the June 2018 stakeholder meeting; however, the company did not provide preliminary results prior to the meeting. As such, stakeholders learned of some of the modeling problems at the meeting itself and had to interpret the results in real time.
- EAI did provide a number of responses to those questions in four sets of "Follow Up" material and one "Modeling Update"; however, Stakeholders were not provided with a timeline for when information would be provided, and even if all requests would be responded to.
- A number of requests were not addressed by EAI. For example, stakeholders requested current unit heat rates and operational costs. EAI responded regarding that information in its second Follow Up, and stated the information "constitute market sensitive data."[2] However, Stakeholders were able to find such information, publicly available and provided by Entergy to its annually published Investors Guide.[3] Similarly, renewable energy capital cost assumptions were also deemed market sensitive and kept confidential.

B. SWEPCO Comparison

Several Stakeholders have also been involved with the SWEPCO IRP process in Arkansas. The SWEPCO IRP process is truly a cooperative effort between the utility and the

[2] http://entergy-arkansas.com/content/IRP/2018/Follow-Up_Materials_Set_2.pdf
[3] http://www.entergy.com/content/investor_relations/docs/2017_Investor_Guide.pdf

Stakeholder Committee; whereas the EAI IRP process has been marked with lackluster utility engagement, poor information exchange, and insufficient research. SWEPCO IRP Stakeholders have been allowed to provide two sets of questions, along with a list of model sensitivity run improvements – virtually all of which have been responded to by SWEPCO, by a clear deadline set by SWEPCO. SWEPCO staff have earnestly engaged in dialog, and even provided stakeholders a webinar to present information and allow an additional opportunity for engagement. Because SWEPCO has conducted a robust and collaborative stakeholder process, that stakeholder report is likely to be highly supportive of SWEPCO's findings and minor in content. The fact that Stakeholders can have such drastically different experiences between the EAI and SWEPCO IRPs suggests that the IRP rules themselves are deficient in providing a standard quality of engagement, and that Stakeholders are almost entirely dependent on utility staff being earnest, interested and eager to cooperate.

C. <u>IRP Guidelines Ignored</u>

While the Arkansas IRP Resource Guidelines are not prescriptive, they do suggest several deficiencies:

- APSC Guidelines Section 3 states, "Resource planning will be relevant to future resource investment decisions and approval proceedings, as well as revenue requirements and rate design." However, in several occasions at the Stakeholder Meeting, EAI staff seemed to indicate that the IRP would mostly be ignored and is not considered a driving-force for future decisions.
- It does not appear that EAI formally established the Resource Plan objectives. Per the APSC Guidelines, Section 4.1, "The utility shall clearly state and support its objectives. The objectives of the Resource Plan include, but are not limited to, low cost, adequate and reliable energy services; economic efficiency; financial integrity of the utility; comparable consideration of demand and supply resources; mitigation of risks, consideration of environmental impacts; and consistency with governmental regulations and policies."
- Per APSC Guidelines Section 4.3 "The utility should assess existing resources based on their cost effectiveness and considering the utility's planning objectives." However,

Stakeholders are unable to help provide assessment of existing resources based on their cost effectiveness without relevant information, such as heat rates and operational costs.

- EAI has not provided economic comparisons between the various futures, as required by APSC Guidelines Section 4.4, which states that, "The portfolios should be compared on the present value of the cost of each."
- Stakeholder comments specifically requested EAI evaluate power purchase agreement (PPA) options, as well as purchases in the MISO Market. Indeed, those items are required by APSC Guidelines Section 4.6 "A self-build option must be compared to market opportunities." Yet, such comparisons have not been made.

D. Stakeholder Questions and Requests Ignored

Per the APSC's Resource Planning Guidelines, "The reason for stakeholder involvement is to open up the planning process and provide an opportunity for others with an interest in the planning process to provide input as a check on the reasoning of a utility during the development of the resource plan." However, if stakeholder questions and observations are ignored, unanswered, or unresolved, stakeholder involvement in the IRP process has failed to serve as "a check". There is no recourse for stakeholders to resolve unresolved issues. Here is a synopsis of some questions and requests asked of EAI that went unresolved:

- Wind/solar prices should continue to decline over time.
- The PTC/ITC for wind and solar is not accurately reflected.
- EAI should model PPA versions for wind/solar.
- Provide megawatt values for various scenarios regarding the MISO market futures.
- Provide planned unit deactivated in the MISO market based on the 60, 55 and 50 year lifetimes.
- How are variables tied together – in a low economy, it's possible the economy is low due to high fuel prices, but there seems to be no connection between any of those variables in the narrative.
- Provide MW values of market coal/gas deactivations, and MW values of incremental market resources, including on a unit-level.
- EAI should incorporate MISO capacity purchases as a resource option.
- EAI should evaluate an expanded MISO North/South connection as a resource option.

E. EAI Devalued the IRP Process

Stakeholders raised significant concern over EAI's capacity-only planning methodology. EAI staff explained that the modeling software would only evaluate capacity solutions, meaning, until pre-determined capacity needs were inserted into the modeling parameters, no new generation resources would be procured. In fact, that explanation was borne out in all three futures in the preliminary results presented on June 6, 2018, whereby no new generation was added until 2025, when the Lake Catherine Unit 4 was pre-determined to retire in the model. Concern was raised at the stakeholder meeting by several stakeholders that capacity-only planning would eliminate low-cost energy solutions that may reduce overall operational costs, and costs to ratepayers. As a model alternative, stakeholders recommended using the Plexos suite of software tools as opposed to the AURORA modeling software. SWEPCO already uses Plexos, as does MISO, in resource planning. EAI staff strongly suggested that business decisions made by EAI are not bound by the IRP, and thus the IRP outcomes are not the only resource planning results; however, these statements which were meant as reassurances, were suggestive that EAI would simply ignore the IRP results, further weakening the value of the IRP process as well as stakeholder involvement.

Stakeholders also encouraged EAI to evaluate MISO capacity and energy purchases as opposed to only evaluating self-build options. EAI responded that the MISO capacity and energy markets were too short-term, and that the company would only look at long-term solutions. However, when Stakeholders suggested that Demand Response opportunities should be properly valued, EAI staff cited low-cost MISO capacity prices as a justification to devalue those resources. EAI staff rather flippantly also stated that the company planned to eliminate the DR program altogether because MISO capacity prices were so low.

Conclusion

Given the extensiveness of these comments along with the additional Stakeholder Committee report, the Stakeholder Committee believes that EAI has failed APSC Guidelines Section 4.8, that "[t]he utility shall make a good faith effort to properly inform and respond to the Stakeholder Committee." The APSC Guidelines provide little recourse for a deficient IRP process, only stating that Section 4.8 "If comments concerning the process and results warrant, the Commission may require the utility to re-evaluate and resubmit its Resource Plan for the current planning cycle to address concerns raised in the comments." The Stakeholder Committee encourages the APSC to exercise its option in requiring an updated IRP by EAI. The Stakeholder Committee also recommends to the APSC to open a new docket to reform the IRP rules in an effort to fix the deficiencies experienced in this IRP process.

II. Comment Topic: Modeling Deficiencies

Simon Mahan, Southern Renewable Energy Association

Other Stakeholders Joining This Comment: Advanced Energy Management Alliance, Arkansas Electric Energy Consumers, Inc. (only the section regarding MISO capacity market purchases), and Sierra Club

* * *

Entergy has developed multiple IRPs in 2018, including for Entergy Arkansas (EAI), Entergy Louisiana (ELL) and Entergy Mississippi (EMI), as well as ongoing work in the Entergy New Orleans (ENO) market. While the focus of these comments is on EAI and the IRP process in Arkansas, there are lessons to be learned from the other Entergy subsidiaries and processes. In some instances, data sets have been provided in one proceeding while blocked in others (such as renewable energy cost assumptions), methodologies have been written in narrative form or at least documented, and comparisons may provide information to fill knowledge gaps. Overall, it appears Entergy performs a fairly consistent IRP process across its entire footprint, making a comparative analysis not only more informative, but more accurate in identifying potential deficiencies in processes. The current process suffers from several modeling deficiencies, including:

- Does not optimize for low-cost energy procurement
- Does not result in retirement recommendations
- Does not model sub-hourly generation and load
- Does not incorporate MISO capacity purchases as a power resource option
- Does not use MISO-developed futures

A. <u>AURORA Modeling Deficiencies</u>

Entergy Arkansas (EAI) relies heavily on the "capacity planning" software called AURORA. Regarding modeling software and capabilities, EAI should develop a study detailing the various benefits and limitations of its current modeling software. In 2017, Puget Sound Energy (an electric utility in Washington state), conducted a brief overview of AURORA versus Plexos software, highlighting the benefits of using the Plexos software. AURORA is a capacity-centric modeling product, whereas Plexos appears to have greater flexibility in evaluating lowest cost energy resources, capacity resources and sub-hourly ancillary services. Capacity-centric planning tends to focus on generator-based solutions (retirements, new construction or general ramping capabilities). Based on analysis by Puget Sound Energy, the AURORA suite of products focuses on hourly capacity-based operations; however, Plexos can provide sub-hourly operational capabilities. Such modeling software flexibility is exceptionally important for variable energy resources (such as wind energy and solar energy) which have sub-hourly ramping capabilities, and energy storage systems, which can provide ancillary services on a sub-hourly basis. Currently, Plexos appears to be better software compared to AURORA. For comparison, both MISO and SWEPCO uses Plexos software.

At the EAI stakeholder meeting in June 2018, the IRP team noted that there are significant deficiencies in the IRP modeling software program itself and its negative implications for renewable energy resources. EAI stated, "Reference Case Future: ***the proportion of renewables as part of the future portfolio is smaller than in the 2015 IRP*** Capacity Expansion Modeling (Future 1) ***even though the technology cost assumptions are lower***. Several factors are contributing to this result, but ***the biggest impact is coming from recently added AURORA dynamic modeling enhancements***…Based on the initial evaluation of results from the 2018 IRP modeling, it appears that AURORA is seeing the capacity shortage in the afternoon/evening as demonstrated in the example on the previous slides. ***The model seems to be addressing this shortage by building gas technologies rather than renewables, even if its first preference is renewables***."[4] (emphasis added).

When deficiencies regarding the AURORA model have been presented by stakeholders, Entergy's common response has been that the utility has relied on AURORA for a number of IRPs and finds no need to change. ELL has stated, "ELL adopted AURORA for long-term energy price forecasting and production costing in 2013 and has used AURORA for several resource certifications and IRPs that were accepted by the LPSC. ELL regularly reviews the software alternatives available to meet its long-term energy price forecasting and production costing needs and currently it has determined that AURORA best meets those needs."[5] Since Entergy adopted the use of AURORA in 2013, MISO South has been developed.

[4] http://entergy-arkansas.com/content/IRP/2018/June_6_Stakeholder_Meeting_Materials.pdf
[5] http://www.entergy-louisiana.com/content/irp/2019/ELL_IRP_2019.pdf

B. Current Capacity Planning Does Not Identify Opportunities for Deactivation or Retirement

In keeping with capacity planning, without a formal *input* of a capacity need, a model will not return a result showing new capacity being built. Such inputs are frequently planned retirements or deactivations. Entergy appears to conduct retirement and deactivation studies outside of the IRP context. The Entergy IRPs rely on these previously determined retirement schedules and dates as inputs to the IRP models, and it does not appear that the IRPs have any bearing on identifying units for possible retirement or deactivation.

- EAI has stated, "The market price of energy is one of several factors that may influence a particular deactivation opportunity. Such an evaluation is part of a separate planning process, and the result of that process is an input to the IRP model."[6]
- ELL has been requested by the Louisiana PSC to effectively provide these analyses, and ELL has stated, "As a part of its robust and iterative long-term planning processes, the Company continually monitors and studies the condition of units, market conditions, and economics to evaluate whether legacy units are candidates for deactivation or retirement. Consistent with the LPSC directive from the February 21, 2018 open session, ELL will conduct a comprehensive evaluation to assess the continued operations and role of its legacy fleet."[7]
- EMI has stated, "Recently, a cross-functional evaluation team conducted assessments and analyses of the units at the Baxter Wilson facility, which consisted of a comparison over a particular time frame of the cost of continuing to maintain and reliably operate the specific units to the cost of deactivating the units and obtaining newer, reliable replacement capacity over that same time frame. … The result of that effort found that it was reasonable to adjust the Baxter Wilson unit 2 deactivation date to 2018 and to adjust the Baxter Wilson unit 1 deactivation planning assumption to an earlier-than-previously-assumed deactivation date. …In addition to the analysis of Baxter Wilson unit 2, EMI also reviewed the economics associated with required improvements to continue to operate Rex Brown 3 in a safe and reliable manner. That review concluded the costs associated with continued operation of Rex Brown 3 in addition to the near-term assumed deactivation date of 2019 for the unit, made further investment uneconomic. Based on the results of the review, EMI retired Rex Brown 3 in 2018."

Retirements and deactivations are therefore "baked in" assumptions for IRP planning purposes across the Entergy footprint. Capacity-centric planning, as performed by Entergy in its

[6] http://entergy-arkansas.com/content/IRP/2018/Follow-Up_Materials_Set_2.pdf
[7] http://www.entergy-louisiana.com/content/irp/2019/ELL_IRP_2019.pdf

IRPs, is not optimizing energy purchases nor identifying existing generation for possible retirement.

C. Capacity Planning Ignores Low-Cost Energy Resources

The preliminary results provided to stakeholders at the June 2018 meeting suggested that EAI would add no new capacity until approximately 2025, when the utility plans to retire Lake Catherine Unit 4. For comparison, ELL's capacity position shows a capacity need in roughly 2027. After the addition of a new CCGT in 2023, EMI's capacity position does not show a capacity need until the year 2030. When asked directly, "Will the AURORA model select a low cost energy resource if no capacity need exists?" EAI responded, "No; AURORA only selects/builds resources based on capacity need."[8] Stakeholders have asked as a hypothetical, if a $0/MWh energy resource were readily available would AURORA select the resource? Entergy staff have stated in several fora that the AURORA model would not select those resources without a capacity need. As a follow-up, some Entergy staff have stated that despite this deficiency in the AURORA model, that Entergy would ignore the results of the IRP to procure low-cost energy resources, if such resources were made available. As such, Entergy's current capacity-only planning methodology is ignoring potentially lower cost energy resources, such as renewable energy resources, that may reduce overall system costs.

In fact, the renewable energy capacity additions provided in Entergy's IRPs do not match with Entergy's own investor analysts' presentations and announcements. Based on IRPs from Entergy Arkansas (EAI), Entergy Louisiana (ELL) and Entergy Mississippi (EMI), and Entergy New Orleans (ENO), Entergy plans to add roughly 200-300 MW of solar power by 2025. Rod West, Entergy's Group President of Utility Operations, stated on June 21, 2018 that Entergy's

[8] http://entergy-arkansas.com/content/IRP/2018/Follow-Up_Materials_Set_3.pdf

five-year plan includes renewable energy with "~1,000 MW in various stages of development".[9] While this summary of IRPs does not include Entergy Texas (ETI), it seems infeasible that the remaining quantity of announced renewable energy would be covered solely in Texas. Effectively, due to IRP planning deficiencies, Entergy plans to ignore its IRPs.

D. MISO Capacity Market is Ignored

In all three IRPs, Entergy ignores the MISO capacity market as a potential resource. Entergy claims that the MISO capacity market is too short-term to be of any value for evaluation. For example, Louisiana Public Service Commission staff requested that ELL "include information detailing how excess capacity available through MISO and potential purchase power agreements were considered as available alternative resources in the Company's analysis." ELL's response was that, "Excess capacity available through MISO is not guaranteed long-term and partially a function of proactive planning actions of regulated utilities such as ELL. Accordingly, excess market capacity is not considered as an option for meeting long-term planning objectives such as the reserve margin. Resource alternative inputs to the model are developed from a financial perspective assuming utility ownership." EMI similarly states, "the MISO Resource Adequacy process establishes minimum requirements that must be met in the short term and are reviewed regularly as part of the resource planning process, it does not provide an appropriate basis for determining EMI's long-term resource needs." EAI similarly does not evaluate MISO capacity purchases.

While Entergy excludes MISO capacity as a potential resource in its modeling, Entergy simultaneously uses low-cost MISO capacity as a justification to de-value Demand Response (DR) programs. At the EAI meeting in June 2018, Entergy staff flippantly mentioned the utility

[9] Entergy (June 21, 2018). Utility, Reimagined. Analyst Day. [https://entergycorporation.gcs-web.com/static-files/5adf1e57-d0f1-469f-bac8-ca188b0f4d2e]

was planning on eliminating DR programs. EAI stated that, "… the continued low capacity prices in MISO South are negatively impacting the cost-effectiveness of the DR programs."[10]

Entergy's contradictory positions on evaluating MISO's capacity likely lead to model runs that incorporate more costly new generation resources, while ignoring lower cost capacity purchases and DR programs.

[10] http://entergy-arkansas.com/content/IRP/2018/Follow-Up_Materials_Set_2.pdf

		Load Growth	Coal/Gas Age Deactivations	MISO Market Conversion	Conversion Mix	CO2 Price	Gas Price
Future 1	EAI	Ref.	60 years	12%x2028	34% RE/66% Gas	Ref.	$5.01
Future 1 Future 2	ELL	Ref.	60 years	12%x2028	34% RE/66% Gas	Ref.	$4.81
	EMI	Ref.	Ref.	N/A	34% RE/66% Gas	Ref.	Ref.
	EAI	Low	55 years	31%x2028	25% RE/75% Gas	Low	$3.40
Future 2 Future 3	ELL	High	55 years	31%x2028	25% RE/75% Gas	None	$3.27
	EMI	High	"Moderate"	N/A	25% RE/75% Gas	None	Low
	EAI	High	50 years	54%x2028	50% RE/50% Gas	High	$6.78
Future 3 Future 4	ELL	Low	50 years	54%x2028	50% RE/50% Gas	High	$3.27
	EMI	Low	"Accelerated"	N/A	50% RE/50% Gas	High	Low
	EAI						
Future 4	ELL	High	55 years	31%x2028	50% RE/50% Gas	Ref.	$6.70
	EMI	High	"Moderate"	N/A	50% RE/50% Gas	Ref.	High

E. <u>Futures Development</u>

EAI, ELL and EMI use a mixture of futures development that are all nearly the same, but without clear explanation regarding interrelations. For example, in the "Reference" Futures 1, all three assume market deactivations of coal and legacy gas units after 60 years of operation, which results in 12% of the MISO market being converted to 33% renewable energy and 64% natural gas by 2028; all use a "reference" CO2 price; and, all use a reference natural gas price of around $5/mmbtu. In the Futures 2 scenarios, EAI, ELL and EMI all use roughly the same metrics; however, EAI assumes low load growth, while ELL and EMI assume high load growth. EAI also assumes a price on carbon dioxide emissions whereas ELL and EMI do not. EAI's Future 3 aligns more closely with ELL's and EMI's Future 4, due to high load growth, high CO2 pricing and high gas prices. It is unclear how, for instance, high gas prices affect individual utility load growth. Presumably higher natural gas prices would likely lead to lower load growth, or that high CO2 prices would lead to significantly more renewable energy development. Stakeholders involved in the EAI process requested a narrative explaining how resources interrelate, however no clear narrative has been provided explaining how seemingly mutually exclusive future assumptions exist together.

In both EAI and ELL IRP stakeholder processes, it has been requested by stakeholders that Entergy should rely on MISO's Futures developed through the MISO Transmission Expansion Planning (MTEP) process. MISO's TEP process is annually updated, and Energy has been heavily involved in all steps regarding the MTEP process, including futures development. Even if Entergy chooses to not adopt the MISO Futures for its own IRP planning, Entergy should develop some sort of comparison between MISO's Futures and its own Futures, to highlight areas of similarity and difference.

One note of importance, it appears that MISO's Futures have a more holistic look at the footprint, in terms of what generators are likely to be retired over the time horizon evaluated. MISO collects information from all of its members regarding actual retirement dates, and uses other methodologies to determine possible retirement dates for units where a retirement date is not yet planned or is unknown. Entergy uses a 60-year, 55-year and 50-year age methodology for retirement assumptions. ELL has noted that, "an Electric Power Research Institute (EPRI) analysis performed in 2012 projected that the average age of natural gas steam turbine retirements as of 2016 would be 52.9 years old. A 2017 study performed by the Lawrence Berkley National Laboratory (and supported by the Department of Energy) produced similar results finding that the most common age of recently retired natural gas steam turbines was between 40 and 50 years. This is consistent with the 52.4 years average life of the Entergy Operating Companies' natural gas steam turbines either deactivated or retired since 2000. Given these trends, there is risk that ELL's legacy gas units may not be economic or feasible to operate through their assumed 60 year useful life." As such, using 60-years as Entergy's "reference" case for existing legacy generation units in MISO, or even for itself, may be overly optimistic. It appears MISO has already corrected for this in its Futures.[11]

Recommendations

- EAI should provide a comparative analysis regarding various modeling programs (e.g., AURORA vs. Plexos).
- EAI should conduct long-term planning beyond solely capacity planning. Ideally, EAI would rely on energy-planning, too.
- EAI's IRP should be capable of identifying potential retirement opportunities and those recommendations should be made in this IRP.
- EAI should use MISO's Futures, or at least provide some sort of comparison of similarities and differences.
- EAI should incorporate the possibility of MISO capacity purchases and/or MISO energy purchases.
- EAI should provide futures/portfolio cost estimates, similar to what is done with EMI.

III. Comment Topic: Transmission Assumptions

Simon Mahan, Southern Renewable Energy Association

Other Stakeholders Joining This Comment: Arkansas Electric Energy Consumers, Inc. and Sierra Club

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EAI did not evaluate expanding transmission options in this IRP. With regards to transmission evaluations, it is well known that the MISO North/South interconnection is a severe limitation for power flow between the two regions. By pre-determining the MISO system constraints continue to exist in perpetuity, EAI has ignored a potentially lower-cost alternative to

[11] http://www.entergy-louisiana.com/content/irp/2019/ELL_IRP_2019.pdf

building new generation – namely, building new high capacity transmission to lower-cost resources in MISO North or to SPP. EAI stated, “For the IRP capacity expansion modeling, the import and export limits between MISO regions is an input assumption and is not varied to accommodate future resource additions. The resource additions are based on generic assumptions for EAI-sited resources but do not represent or imply a selection of any specific resource or location. Outside of the scope of the IRP, any evaluation of potential resources located in SPP would be resource-specific and handled individually. Such an evaluation would require inclusion of all the costs required to deliver the energy to MISO South.”[12]

During the January and September 2018 Maximum Generation Events, higher levels of North/South flow would have better served MISO South than calling on emergency power purchases from outside the MISO footprint. Several meetings held by both MISO and SPP suggest that when emergency prices were set in both the January and September events, that those exceptionally high emergency prices for imported power would be “uplifted” to the entire MISO footprint. Stated another way, MISO North is likely to subsidize MISO South’s Maximum Generation Events. Given that two Maximum Generation events occurred in the same year during historically non-peak periods, the likelihood of further Maximum Generation Events appears to be exceptionally high, with no clear plan to resolve these issues in the future. Currently, there appears to be few venues for MISO to evaluate transmission expansion based on these extreme events; thus, absent such analysis from MISO, MISO South utilities should conduct some minor levels of evaluating expanding transmission connections between the North and South.

[12] http://entergy-arkansas.com/content/IRP/2018/Follow-Up_Materials_Set_2.pdf

Modeling higher levels of interconnectivity between MISO North/South and SPP should not be difficult. For instance, EAI could have developed cost metrics for installing a new transmission line, and possible cost allocation scenarios, coupled with average hourly LMP from MISO North or SPP, or perhaps a flat-cost wind power purchase agreement. These metrics, when added together, would appear much like a new power station in MISO South. As such, transmission resources could serve the same or similar purposes as new-build power generation, and should have been evaluated.

Recommendation

- EAI should develop a transmission expansion plan, in addition to what MISO and SPP perform.
- EAI should evaluate the effect of potentially expanding the MISO North/South interconnection. Such an evaluation could look at an expansion of 1 GW, 5 GW, 10GW and 20 GW to create a broad set of sensitivities.

IV. Comment Topic: Renewable Energy Assumptions

Simon Mahan, Southern Renewable Energy Association

Other Stakeholders Joining This Comment: National Audubon Society and Sierra Club

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A. Renewable Energy Data Assumptions

The National Renewable Energy Lab (NREL) publishes its Annual Technology Baseline (ATB) as a resource for "realistic and timely set of input assumptions (e.g., technology cost, fuel costs), and a diverse set of potential futures (standard scenarios) to inform electric sector analysis in the United States. The products of this work, including assessments of current and projected technology cost and performance for both renewable and conventional electricity generation technologies, as well as market projections of more than a dozen scenarios produced with

NREL's Regional Energy Deployment Systems (ReEDS) model…."[13] NREL's ATB is one of the most comprehensive, and accurate, resources for various energy resource inputs. NREL's ATB is used by regional transmission organizations (RTOs) including the Midcontinent Independent System Operator (MISO)[14] and PJM.[15] NREL's ATB data should be used for model inputs and future forecasts. Given that future purchases of renewable energy resources would take several years before power production, NREL ATB data starting in 2019 or 2020 is recommended, as well as incorporating future pricing and performance levels. NREL's ATB is updated annually, usually in July or August.

1. Wind Energy

NREL's ATB evaluates wind energy resources as "techno-resource groups" (TRGs) that effectively provides a scale of various wind energy opportunities.[16] For example, TRG 1 resources are anticipated to be the lowest cost and highest performance wind energy resources, and are mostly concentrated in the Central US. A fair amount of wind energy capacity potential in the Southeast opens in TRG 5, with the entire Southeastern region opening up with TRG 7. Based on the current market, the "low" values for NREL ATB's land-based wind resources should be used, beginning in 2019 or 2020. Evaluating these three different wind energy resources provides an adequate range of wind energy resources available to the Southeast.

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[13] NREL (National Renewable Energy Laboratory). 2018. 2018 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/analysis/data_tech_baseline.html.

[14] Midcontinent Independent System Operator (March 20, 2018). "MTEP19 Futures Development Workshop." [https://cdn.misoenergy.org/20180320%20MTEP19%20Futures%20Workshop%20Presentation150635.pdf]

[15] Muhsin K. Abdur-Rahman (April 25, 2016). "PJM's Clean Power Plan Modeling Reference Model and Sensitivities," PJM. [https://www.pjm.com/-/media/committees-groups/committees/mc/20160425-webinar/20160425-item-02-clean-power-plan-reference-model-results.ashx]

[16] National Renewable Energy Lab (November 2016). Regional Energy Deployment System (ReEDS) Model Documentation: Version 2016. [https://www.nrel.gov/docs/fy17osti/67067.pdf]

Evaluating multiple types of wind energy resources, and not solely evaluating the lowest cost options (e.g., TRG 1 resources), may help identify different generation profiles that more closely align with a particular utility's demand load. Geographic diversity of renewable energy resources is anticipated to generally increase capacity value of a particular resource and reduce overall generation variability. Hourly and sub-hourly wind energy generation profiles are available from the NREL Wind Integration National Database (WIND) Toolkit for up to 122,000 different sites across the country. Data are available from NREL, here: https://www.nrel.gov/grid/wind-toolkit.html

The federal Production Tax Credit (PTC) for wind energy is expiring. The details of the PTC will be discussed later; however, for the chart below, the PTC has been converted into a rough reduction in overnight capital costs. Generally, CAPEX costs below have been reduced by $600/kW in 2019 and 2020, $500/kW in 2021, and $400/kW in 2022.

NREL ATB Wind Energy Pricing Examples With Production Tax Credit as Overnight Cost Reduction ($/kW) by Year

		2019	*2020*	*2021*	*2022*	*2023**	*2024**	*2025**
TRG1	Overnight $/kW	$730	$687	$739	$787	$1,133	$1,075	$730
	Capacity Factor	50%	50%	51%	51%	52%	52%	53%
	LCOE $/MWh	$19	$21	$22	$23	$27	$26	$24
TRG5	Overnight $/kW	$840	$803	$839	$874	$1,208	$1,142	$1,075
	Capacity Factor	44%	45%	45%	46%	47%	48%	48%
	LCOE $/MWh	$25	$26	$27	$28	$31	$29	$28
TRG7	Overnight $/kW	$1,013	$991	$1,023	$1,054	$1,384	$1,313	$1,241
	Capacity Factor	35%	36%	37%	38%	38%	39%	40%
	LCOE $/MWh	$39	$40	$39	$39	$41	$39	$36

Source: based on LBNL 2014, 2018 NREL ATB
*No PTC Value

2. Solar Energy

Costs for fixed-tilt versus single-axis tracking solar projects are estimated to be approximately similar, with minor capital cost and maintenance cost differences; however, capacity factors are anticipated to increase significantly with single-axis trackers. NREL's ATB only evaluates single-axis tracking systems, with the best performing projects achieving an estimated 27% capacity factor (NREL ATB projects located in Daggett, CA). As a proxy for fixed-tilt solar projects, it is recommended that a 20% capacity factor be used (NREL ATB projects located in Kansas City, MO). NREL's ATB converts solar DC power to AC power output for capacity factor purposes, while keeping several financial metrics in $/kWDC units.

To provide a better range of pricing and performance, it is recommended that the "Mid" overnight costs for Kansas City and Daggett utility-scale solar projects from NREL's ATB should be used, along with the 20% and 27% capacity factors, respectively, beginning in 2019.

Due to new guidance from the IRS, solar power projects that qualify for the 30% ITC in 2019, 26% ITC in 2020, or the 22% ITC in 2021 each have until the end of the year 2023 to become operational. A 10% ITC is available for projects that commence construction in or after 2022, and for projects that become operational in or after 2024. At the same time the federal ITC is slated to decline, the NREL ATB shows that solar power installed costs are anticipated to decline, almost in the exact same proportion as the ITC phase-out through 2023. Applying the ITC phase-out to the NREL ATB 2018 overnight capital costs, results in overnight costs of approximately $700/kWDC for projects that begin construction between now and 2021, which are also operational by the end of 2023. By 2024, when the bulk of the ITC has expired, solar pricing is anticipated to decline an equivalent amount, thus overall levelized cost of energy of utility-scale solar projects are anticipated to remain relatively flat from 2019-2030. For utility-scale solar projects with 20% capacity factors, and taking the ITC into account for near-term projects, overall LCOE is anticipated to remain in the mid-$30s/MWh range for the next decade. For projects with 27% capacity factors, LCOE values in the $20s/MWh are anticipated. We have worked with utility-scale solar development companies in the region who have corroborated the view that utility-scale projects in BREC region can be currently be delivered with an LCOE in the mid-$30/MWh range thanks to the ITC value and for the decade ahead with the forecasted future cost-declines following the ITC step-down to 10%.

NREL ATB Utility-Scale Solar Energy Pricing (ITC Included)

		2019	2020	2021	2022	2023	2024	2025
Mid	Overnight $/kWdc	$707	$707	$707	$707	$707	$784	$775
	Capacity Factor AC	20%	20%	20%	20%	20%	20%	20%
	LCOE $/MWhAC	$32	$32	$32	$$32	$32	$38	$38
Low	Overnight $/kWdc	$707	$707	$707	$707	$707	$784	$775
	Capacity Factor AC	27%	27%	27%	27%	27%	27%	27%
	LCOE $/MWhAC	$20	$20	$20	$20	$20	$24	$23

Source: NREL ATB 2018[17], 20-year LCOE, "Mid" is Kansas City, "Low" is Daggett

B. Market-Based Benchmarking

Many utilities have issued requests for proposals (RFPs) for renewable energy resources from around the country; however, not all utilities publicly summarize results from those solicitations. Wherever recent results from renewable RFP solicitations are made public, it is highly encouraged that those data be used as benchmarks when developing IRP data inputs.

It is highly recommended that utilities should develop a request for proposals (RFP) or request for information (RFI) in tandem with IRP development to receive the most recent market information, specific to that utility. Developing an RFP or RFI to coincide with an IRP would create a significant amount of high quality data, while potentially expediting future power purchase agreements, procurements or developments.

1. Xcel Energy Colorado All-Source Solicitation

[17] National Renewable Energy Lab (July 2018). NREL Annual Technology Baseline (ATB) 2018. [https://atb.nrel.gov/]

Xcel Energy, a Colorado electric utility, published the results of its 2017 All-Source Solicitation request for proposals in December 2017.[18] Xcel received over 400 bids representing over 100,000 MW of capacity from a wide variety of technologies; however, most bids provided wind energy or solar power resources. The median bid price or equivalent for stand-alone wind energy resources was $18.10/MWh, suggesting several projects below and above that price. Adding battery storage to wind energy resulted in median bids of $21/MWh. For stand-alone solar energy resources, the median bid was $29.50/MWh. Adding battery storage to solar energy resulted in median prices of $36/MWh. While these prices may be specific to Xcel, the fact remains that these represent real project bids and are aligned with projections by NREL's ATB, Lazard Associates and these comments.

[18] Xcel Energy (December 28, 2017). 2016 Electric Resource Plan, 2017 All Source Solicitation 30-Day Report (Public Version) CPUC Proceeding No. 16A-0396E. [https://assets.documentcloud.org/documents/4340162/Xcel-Solicitation-Report.pdf]

<u>Xcel RFP Responses by Technology 2017</u>

RFP Responses by Technology

Generation Technology	# of Bids	Bid MW	# of Projects	Project MW	Median Bid Price or Equivalent	Pricing Units
Combustion Turbine/IC Engines	30	7,141	13	2,466	$ 4.80	$/kW-mo
Combustion Turbine with Battery Storage	7	804	3	476	6.20	$/kW-mo
Gas-Fired Combined Cycles	2	451	2	451	[redacted]	$/kW-mo
Stand-alone Battery Storage	28	2,143	21	1,614	11.30	$/kW-mo
Compressed Air Energy Storage	1	317	1	317	[redacted]	$/kW-mo
Wind	96	42,278	42	17,380	$ 18.10	$/MWh
Wind and Solar	5	2,612	4	2,162	19.90	$/MWh
Wind with Battery Storage	11	5,700	8	5,097	21.00	$/MWh
Solar (PV)	152	29,710	75	13,435	29.50	$/MWh
Wind and Solar and Battery Storage	7	4,048	7	4,048	30.60	$/MWh
Solar (PV) with Battery Storage	87	16,725	59	10,813	36.00	$/MWh
IC Engine with Solar	1	5	1	5	[redacted]	$/MWh
Waste Heat	2	21	1	11		$/MWh
Biomass	1	9	1	9		$/MWh
Total	430	111,963	238	58,283		

Source: Xcel Energy 2017[19]

2. Northern Indiana Public Service Company Request for Proposals

Northern Indiana Public Service Company (NIPSCO), an electric company in the MISO system, held an integrated resource plan (IRP) meeting on July 24, 2018 to discuss renewable energy options. As part of its IRP process, NIPSCO shared results from an all source request for proposals (RFP) summary. NIPSCO received bids for wind energy, solar energy, energy storage, and amalgamations of those resources together. The company received proposals across five states, predominately via power purchase agreement (PPA), but also as asset sale or option. Resources offered as asset sale or as an option were provided at an average bid cost of $1,151.01/kW for solar energy projects, and $1,457.07/kW for wind energy projects. For PPA's, average bids for solar energy reached $35.67/MWh, and average bids for wind energy reached $26.97/MWh. Solar plus energy storage projects were offered as asset sales at $1,182.79/kW and

[19] Xcel Energy (December 28, 2017). 2016 Electric Resource Plan, 2017 All Source Solicitation 30-Day Report (Public Version) CPUC Proceeding No. 16A-0396E. [https://assets.documentcloud.org/documents/4340162/Xcel-Solicitation-Report.pdf]

also as a PPA at $5.90/kW-Mo plus $35/MWh.[20] These values provide recent market data that are relevant to states in MISO and further south.

<u>NIPSCO RFP Responses by Technology 2018</u>

	Technology	# of Bids	Bid MW (ICAP)	# of Projects	Project MW	Average Bid Price	Pricing Units	Comments
Asset Sale or Option	Combine Cycle Gas (CCGT)	7	4,846	4	3,055	$959.61	$/kW	
	Combustion Turbine (CT)	1						
	Solar	9	1,374	5	669	$1,151.01	$/kW	
	Wind	8	1,807	7	1,607	$1,457.07	$/kW	
	Solar + Storage	4	705	3	465	$1,182.79	$/kW	
	Wind + Solar + Storage	1						
	Storage	1						
Purchase Power Agreement	Combine Cycle Gas (CCGT)	8	2,715	6	2,415	$7.86	$/kW-Mo	+ fuel and variable O&M
	Solar + Storage	7	1,055	5	755	$5.90	$/kW-Mo	+ $35/MWh (Average)
	Storage	8	1,055	5	925	$11.24	$/kW-Mo	
	Solar	26	3,591	16	1,911	$35.67	$/MWh	
	Wind	6	788	4	603	$26.97	$/MWh	
	Fossil	3	1,494	2	772	N/A		Structure not amenable to price comparison
	Demand Response	1						
	Total	**90**	**20,585**	**59**	**13,247**			

Source: NIPSCO 2018.[21]

<u>Recommendations</u>

- EAI should model multiple types of wind energy resource, including resources from SPP, MISO and inside Arkansas.
- EAI should model both fixed and tracking solar energy resources.
- EAI should use NREL's ATB regarding energy pricing, performance levels and forecasts.
- EAI should incorporate the federal Production Tax Credit and Investment Tax Credit.
- EAI should benchmark its data assumptions against publicly available information.
- EAI should immediately issue an RFP for renewable energy resources.

[20] Northern Indiana Public Service Company (July 24, 2018). NIPSCO Integrated Resource Plan 2018 Update Public Advisory Meeting Three. [https://www.nipsco.com/docs/default-source/about-nipsco-docs/7-24-2018-nipsco-irp-public-advisory-presentation.pdf]

[21] Northern Indiana Public Service Company (July 24, 2018). NIPSCO Integrated Resource Plan 2018 Update Public Advisory Meeting Three. [https://www.nipsco.com/docs/default-source/about-nipsco-docs/7-24-2018-nipsco-irp-public-advisory-presentation.pdf]

- This RFP should be completed in a single year. The current RFP process EAI undertook for renewable energy resources was excessively long and likely deterred many good projects from being bid in.
- As shown by the expedited SWEPCO procurement process for the Windcatcher project, Arkansas PSC's approval process can be significantly faster to secure favorable tax credits.

V. Comment Topic: DSM and Demand Response Assumptions

Peter Dotson-Westphalen, CPower Energy Management for Advanced Energy Management Alliance

Other Stakeholders Joining This Comment: National Audubon Society and Sierra Club

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The stakeholders appreciate EAI's incorporation of feedback made in prior IRPs to incorporate Demand Response ("DR") and Demand Side Management ("DSM") into the supply-side for evaluation. However, there appears to be several shortcomings in the Aurora model, as discussed in further detail within the "Modeling Deficiencies" section of the stakeholder comments earlier in this document. Because of these modeling shortcomings, including capacity selection based upon predetermined inputs of planned retirement dates and not looking at sub-hourly time horizons, potential DSM was only selected in 2020 based upon the low case scenario in the initial modeling, none of which came from any new DR.[22] In the subsequent modeling results, the model selected only between 9 to 14 MW of additional installed capacity coming from DSM,[23] all of which are lower than the lowest DSM portfolio additions used within the initial modeling run. No further information was provided by EAI staff as to what changed from the initial modeling runs that reduced the potential DSM that was selected in the second modeling run, or how or why the DSM potential was reduced from the initial model runs.

[22] http://www.entergy-arkansas.com/content/IRP/2018/June_6_Stakeholder_Meeting_Materials.pdf
[23] http://www.entergy-arkansas.com/content/IRP/2018/Modeling_Update.pdf

The stakeholders believe EAI's cost effectiveness methodology is flawed because DR is modeled solely at the MISO capacity auction price in the short term, which has remained suppressed for some time. There was no clear delineation of when EAI transitioned to their long-term methodology of modeling DR based upon the cost of building a new peaking resource, so stakeholders cannot tell which cost-effectiveness methodology was used with each set of the potential portfolios considered, and whether they aligned with the need for additional capacity resources to be procured. At the initial stakeholder meeting on June 6, 2018, EAI presented results from the Aurora Capacity Expansion Model and stated existing DR and incremental DSM and DR is competing with all other supply-side resources.[24] However, this model does not consider comparing the cost-effectiveness of DR to existing generation resources that may be impacted by higher future operating costs due to environmental compliance regulations and market forces and may not be cost-effective in advance of their modeled retirement dates.

DR is found by many utilities to be a cost-effective resource,[25] and the model's failure to select lower cost resources when it would be in the economic interest to do so appears to be a significant flaw that is prevalent throughout EAI's IRP. Several other utilities within MISO have found DR to be a cost-effective resource within their IRPs. Consumers Energy in Michigan and NIPSCO in Indiana both found that DR was the least-cost resource when compared to any traditional supply-side generation resources within their recent modeling work. Ameren Missouri, which was found to not have a need for new capacity until 2024, took an approach that realized that the suppressed MISO capacity prices will not remain so over the longer term.

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[24] http://www.entergy-arkansas.com/content/IRP/2018/June_6_Stakeholder_Meeting_Materials.pdf

[25] Advanced Energy Management Alliance (May 2018). Demand-Response Cost Effectiveness Case Studies. http://aem-alliance.org/download/121151/

Ameren extended a rising cost curve for avoided capacity, energy, and T&D costs,[26] and decided that it could build out DR as a lower cost resource and then sell their excess generation capacity from their existing resources into the MISO capacity market. Matt Michaels, Director of Corporate Analysis for Ameren Missouri provided testimony to the value of DR and DSM, stating, "[d]emand-side resources are generally more cost-effective than supply side-resources and generate net benefits to an extent that most supply-side resources cannot."[27] The DSM resource expansion portfolios developed by ICF International, Inc. ("ICF") for EAI and included in the Aurora Capacity Expansion Model reflect low total expansion opportunity for DR based on scenarios, which consist of five Direct Load Control programs and one commercial Time-of-Use program. The incremental DR from these six new programs ranges from a low of 25 MW up to 100 MW.[28] The stakeholders think these scenarios are not comprehensive of the total DR opportunity available, especially considering EAI is forecasting significant growth in sales and peak load through 2021 which it largely attributes to industrial customers that are typically good candidates for DR. EAI noted in its presentation to stakeholders that none of these incremental DR portfolios were selected in its model runs[29] EAI has not provided any additional details on the study assumptions ICF used to develop these incremental portfolios, and stakeholders have

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26 Ameren Missouri. 2019-2024 MEEIA Plan – Appendix C - 2017 IRP Avoided Costs. [https://www.efis.psc.mo.gov/mpsc/commoncomponents/view_itemno_details.asp?caseno=EO-2018-0211&attach_id=2018020108]

27 Missouri Public Service Commission File No. EO-2018-0211. Surrebuttal Testimony of Matt Michels on Behalf of Union Electric Company d/b/a Ameren Missouri (September 17, 2018). [https://www.efis.psc.mo.gov/mpsc/commoncomponents/view_itemno_details.asp?caseno=EO-2018-0211&attach_id=2019003994]

28 http://www.entergy-arkansas.com/content/IRP/2018/June_6_Stakeholder_Meeting_Materials.pdf -

29 http://www.entergy-arkansas.com/content/IRP/2018/June_6_Stakeholder_Meeting_Materials.pdf

not had the opportunity to review the assumptions to compare to other potential studies to validate whether these assumptions allow the full DR potential to be captured.

EAI's implementation of AMI within the service territory will open up additional DSM program participation potential. EAI stated that they did not model any specific assumptions for new rate or program designs that would capitalize on AMI infrastructure. EAI instead factored in any load reductions attributed to increased AMI to the load forecast and are not assigned any costs within the IRP.[30] Stakeholders believe there is additional value through potential DSM/DR programs that can be tapped into through AMI at a low cost that should be modeled on the supply-side.

Finally, stakeholders are very concerned that EAI staff indicated that EAI may plan to discontinue its existing DR programs based solely on low capacity clearing prices in the MISO market and concluded that these programs are no longer cost effective to operate. As renewable generation penetration increases, the need for more flexible and fast-responding resources will be needed to help maintain reliability. It would be imprudent of EAI to disband their existing DR programs, getting rid of approximately 230MW of LMR resources comprised of over 24,000 EAI customers that are helping to provide capacity and reliability during emergency conditions, especially when EAI's Total Resource Cost (TRC) for their entire portfolio of EE and DSM programs have been cost effective in prior years and appear to be on track to remain cost effective at a TRC of 1.8.[31]

[30] http://www.entergy-arkansas.com/content/IRP/2018/Follow-Up_Materials_Set_3.pdf
[31] http://www.entergy-arkansas.com/content/IRP/2018/June_6_Stakeholder_Meeting_Materials.pdf

Recommendations

- EAI should seek to include T&D and avoided costs in its methodology for valuing its existing DR and DSM programs, and not solely rely on the MISO capacity value for assessing cost-effectiveness of these resources.
- EAI should model existing and potential DR and DSM against current generator operating costs, and not just against the cost of new entry of future generation.
- EAI should include Non-Wires Alternatives that can address localized needs that may reduce the need for T&D investment and increased capacity from traditional generation sources in their IRP modeling.
- EAI should model for additional potential DSM/DR program participation enabled by AMI being rolled out within their territory.
- EAI should not terminate their existing DR programs as these resources will be vital to help maintain a reliable grid today and in the future.

VI. Comment Topic: Energy Storage Assumptions

Simon Mahan, Southern Renewable Energy Association

Other Stakeholders Joining This Comment: Advanced Energy Management Alliance, National Audubon Society, and Sierra Club

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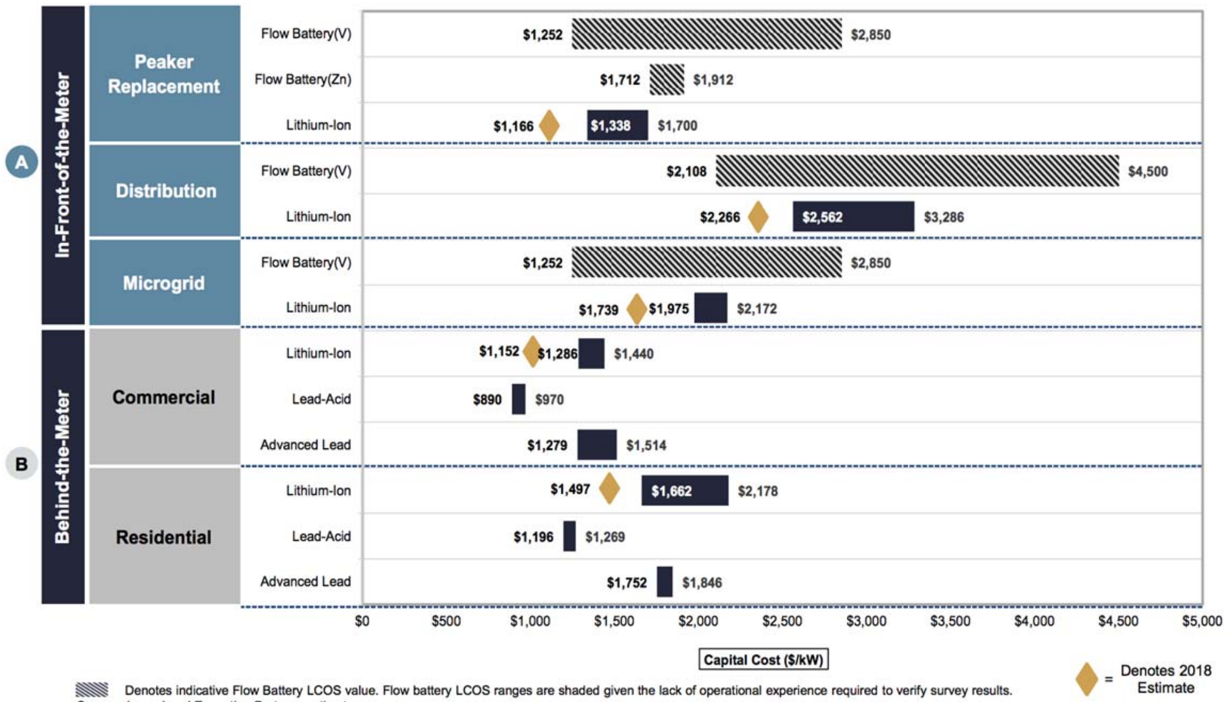
A. Energy Storage Data Assumptions

Lazard Associates' estimated capital costs for various energy storage technologies reaches as low as $1,152/kW in 2018. It is more difficult to assign a particular LCOE for energy storage solutions; not only because of the variety of technology (batteries, fly wheels, etc.) and rapidly declining prices, but because energy storage project finances are highly dependent on the type of services being provided. For example, Lazard Associates notes that, "Although energy storage developers/project owners often include Energy Arbitrage and Spinning/Non-Spinning Reserves as sources of revenue for commissioned energy storage projects, Frequency Regulation, Bill Management and Resource Adequacy are currently the predominant forms of realized sources of revenue."[32] For example, an energy storage project that predominantly provides frequency regulation may appear to be exceptionally costly, on an LCOE basis, compared to a traditional power plant; however, such a facility is providing a highly valued service that may not be accurately reflected in current integrated resource planning processes, models or specific utility markets. Energy storage is not simply a "cost adder" to renewable energy to establish better capacity value.

The design of an energy storage project can also vary based on the specific services desired; for example, a recent presentation by GTM Research showed four-hour and eight-hour energy storage resources compared to peaking power resources. The researchers found that in 82% of planned future peaker plants would be at risk from eight-hour storage projects (e.g., 100 MW/800 MWh).[33] Due to limitations in resource planning practices, LCOE or even capital costs alone will not adequately assess the full benefits of energy storage. As energy storage resources begin to be co-located with renewable energy resources, those energy storage technologies may qualify for federal incentives, such as the investment tax credit. Energy storage pricing, as with renewable energy, is anticipated to continue to considerably decline, while performance is expected to improve, especially over the near-term.

[32] Lazard Associates (November 2017). Levelized Cost of Storage Analysis, Version 3.0. [https://www.lazard.com/media/450338/lazard-levelized-cost-of-storage-version-30.pdf]
[33] Ravi Manghani (March 2018). "Will Energy Storage Replace Peaker Plants?" GTM Research. [https://d3v6gwebjc7bm7.cloudfront.net/event/15/88/96/3/rt/1/documents/resourceList1519927946005/willenergystoragereplacepeakerplantswebinarslides1519927951937.pdf]

Unsubsidized Energy Storage Capital Costs ($/kW)



Source: Lazard Associates 2017[34]

1. Energy Storage Modeling

In February 2018, the Federal Energy Regulatory Commission (FERC) issued Order Number 841 regarding energy storage. FERC stated, "In a November 2016 Notice of Proposed Rulemaking (NOPR), the Commission noted that market rules designed for traditional generation resources can create barriers to entry for emerging technologies such as electric storage resources. Today's final rule helps remove these barriers by requiring each regional grid operator to revise its tariff to establish a participation model for electric storage resources that consist of market rules that properly recognize the physical and operational characteristics of electric storage resources." FERC noted in its rule that, artificial "restriction on competition can reduce

[34] Lazard Associates (November 2017). Levelized Cost of Storage Analysis, Version 3.0. [https://www.lazard.com/media/450338/lazard-levelized-cost-of-storage-version-30.pdf]

the efficiency of the RTO/ISO markets, potentially leading an RTO/ISO to dispatch more expensive resources to meet its system needs."[35] Even though RTO/ISO compliance filings are due to FERC in early December, with tariff implementation due by December 2019, utilities should strive to follow the spirit of FERC Order Number 841 in developing multiple modelling capabilities, sensitivities and analyses around energy storage issues.[36] In keeping with the principles of FERC Order Number 841, it is recommended that multiple energy storage configurations be evaluated (e.g., 2MW/2MWh, 2MW/4MWh, 2MW/8MWh, etc.), using sub-hourly dispatch, with multiple revenue streams (e.g., capacity credit, energy, frequency/voltage control, etc.), as stand-alone projects as well as coupled with generation resources (such as renewable energy resources).

Models that use sub-hourly intervals can better quantify the value of both capacity and flexibility benefits provided by advanced energy storage. By comparing flexibility benefits to the cost of storage—thereby using a "net cost" analysis of capacity investment options—planners can more accurately compare advanced energy storage with traditional capacity resources. Analysis of models that look at system flexibility needs and risk management will be more likely to reduce costs to ratepayers, including through use of storage. In addition to providing an LCOE regarding energy storage options, it is also recommended that values also be provided in $/kW-mo or $/kW-yr terms.

Behind the meter storage capabilities should be taken into consideration as well. As

[35] Federal Energy Regulatory Commission (February 15, 2018). Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators. [Docket Nos. RM16-23-000; AD16-20-000; Order No. 841]. https://www.ferc.gov/whats-new/comm-meet/2018/021518/E-1.pdf

[36] Federal Energy Regulatory Commission (February 15, 2018). FERC issues final rule on electric storage participation in regional markets. [https://www.ferc.gov/media/news-releases/2018/2018-1/02-15-18-E-1.asp#.Wv3-1NOUv-Z]

storage costs decline and customers begin to adopt storage technologies to serve needs and may look to provide grid services as well, these resources should be accounted for within EAIs modeling process.

Recommendations

- EAI should develop a "value stack" for energy storage resources incorporating energy, capacity, frequency response, black-start capability and other attributes available via energy storage devices.
- EAI should explain how it plans to incorporate lessons learned from FERC Order 841 on energy storage in future resource planning.
- EAI should procure significant energy storage assets to better evaluate storage costs and benefits.

VII. Comment Topic: Coal

Jordan Tinsley, Arkansas Electric Energy Consumers, Inc.

Other Stakeholders Joining This Comment: Arkansas Attorney General's Office

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In its 2015 Integrated Resource Plan, EAI acknowledged that its coal-fired power plants should have a useful life of sixty years.[37] At least two of the futures evaluated in the 2015 IRP presumed the operation of EAI's existing coal-fired power plants for a sixty-year useful life.[38] Notably, however, EAI presumed (when evaluating those futures) that it would install costly environmental controls at those plants as the result of a federal implementation plan ("FIP") for the Regional Haze Rule that will likely be superseded by a less onerous state implementation plan ("SIP") that does not require the installation of those environmental controls.[39]

[37] *See, e.g.*, EAI's 2015 Integrated Resource Plan, APSC Docket No. 07-016-U, Doc. 49, p. 40.
[38] Id. at 40-42.
[39] Id.

Although EAI acknowledges (at least implicitly) that the FIP promulgated by the EPA in October 2016 will probably not survive ADEQ's issuance of a new SIP,[40] EAI has nonetheless presumed early retirements of all its coal-fired capacity in the 2018 IRP process.[41] Slide 6 of the second set of Follow-Up Materials provided to IRP stakeholders clarified that EAI presumes it will deactivate both White Bluff units by 2028; then, in 2030, it will deactivate Independence Unit 1. Slide 7 of the second set of Follow-Up Materials states that White Bluff unit 1 is 38 years old, while unit 2 is 37 years old. It also states that Independence unit 1 is 35 years old. Thus, if EAI retires White Bluff units 1 and 2 in 2028 as planned, EAI will be retiring those units approximately twelve (12) to thirteen (13) years before the expiration of their sixty-year useful lives. If EAI retires Independence unit 1 in 2030 as planned, EAI will be retiring that unit approximately thirteen (13) years before the expiration of its sixty-year useful life.

Collectively, deactivation of those coal-fired power plants will retire over one thousand (1000) megawatts of generating capacity. Of course, EAI plans to pass the cost of obtaining replacement capacity for these early retirements on to its ratepayers. As noted in the comments regarding early coal-plant deactivations AEEC included in EAI's 2015 IRP stakeholder report, EAI's plans to retire its coal plants early will significantly raise electricity rates unnecessarily.[42]

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[40] *See, e.g.*, slides 59-60 of the June 2018 Stakeholder Meeting Materials, which one can access using the following URL: http://entergy-arkansas.com/content/IRP/2018/June_6_Stakeholder_Meeting_Materials.pdf.
[41] *See* slide 12 of the June 2018 Stakeholder Meeting Materials; *see also* slide 6 of the second set of Follow-Up Materials, which one can access using the following URL: http://entergy-arkansas.com/content/IRP/2018/Follow-Up_Materials_Set_2.pdf.
[42] *See* EAI's 2015 Integrated Resource Plan, APSC Docket No. 07-016-U, Doc. 49, p. 263-269.

Further, EAI abdicates its fiduciary duties to its ratepayers under Arkansas law[43] by divesting them of approximately thirteen (13) years of cheap generating capacity without justification.

EAI and other parties attempt to justify the divestment of these assets from ratepayers by emphasizing that these facilities are rarely dispatched in the status quo.[44] The relatively low rate of dispatch for these units, however, results primarily from low natural gas prices. Should natural gas prices increase, the existence of this coal-fired capacity insulates ratepayers against an electricity price spike. Further, since natural gas prices are inherently hard to predict,[45] planning to retire these assets ten years in advance based upon uncertain gas price forecasts seems imprudent. Further, as discussed below, the increased utilization of natural gas as a fuel source for electricity generation continues to inject additional uncertainty into the natural gas market, particularly with regard to extreme cold weather events.

If EAI proceeds with these planned retirements in 2028 and 2030 respectively, it will remove coal as a fuel source from its fleet entirely. This eliminates valuable fuel diversity from the EAI system. EAI's primary resource planner strongly emphasized the value of fuel diversity when justifying the acquisition of the Stuttgart Solar facility in 2015. He stated:

> Diversity means utilizing a mix of generating technologies and fuel sources within the generation portfolio. A diverse generation portfolio *mitigates risk by helping protect customers from fluctuations in the cost and availability of the fuel*

[43] See Acme Brick Co. v. Arkansas Public Service Commission, 227 Ark. 436, 299 S.W.2d 208 (1957) and City of El Dorado v. Arkansas Public Service Commission, 362 S.W.2d 680, 235 Ark. 812 (Ark., 1962).

[44] For example, slide 7 of the second set of Follow-Up Materials states that White Bluff unit 1 has a capacity factor of sixty eight percent (68%), while the other two coal-fired units have capacity factors of approximately forty three percent (43%).

[45] In APSC Docket No. 12-008-U, a witness for the Staff named Richard Hahn stated the following: "…the uncertainty in fuel prices should be considered. This factor is *very difficult* to assess either quantitatively or qualitatively. *There is simply no way to know with any degree of certainty whether coal prices will remain lower than natural gas prices, or vice versa*. It is true that *historically natural gas prices have tended to be more volatile* than coal prices." Surrebuttal Testimony of Richard S. Hahn, APSC Docket No. 12-008-U, Doc. 145, p. 15 (emphasis added).

> *needed to produce electricity*. For example, *a diverse generation portfolio protects customers from supply disruptions associated with particular fuel sources or delivery channels because alternative fuels are available within the portfolio*. Similarly, *fluctuations in the price of particular fuels are less likely to affect total supply cost*. The effect of changes in the price of any one fuel is less significant because a diverse generation portfolio relies on a variety of fuels and resource types, the prices of which are not likely to move in perfect unison. Increases in the price of one fuel *may be offset or mitigated by other fuels that exhibit declining or stable costs*.[46]

Of course, Mr. Castleberry's argument regarding fuel diversity has as much validity in this context as it did in the context of adding some solar to EAI's diverse portfolio. Notably, the U.S. Energy Information Administration has noted that emphasizing natural gas as a fuel source for electricity generation injects additional volatility into natural gas prices because of fundamental economic realities concerning supply and demand.[47] Therefore, the coal-fired plants that EAI wants to divest from its portfolio thirteen years early actually provide ratepayers with a valuable hedge against volatile natural gas prices.

Recent extreme cold weather events have demonstrated that concerns regarding gas supply reliability are well-founded. For example, during extreme cold weather events, like the polar vortex in 2014, gas plant curtailments may result from various factors. Problems with gas transportation may also occur. NERC undertook an analysis of the polar vortex in the fall of 2014; it stated:

> Increased reliance on natural gas during the polar vortex exposed the industry to various challenges with fuel supply and delivery. This increased reliance,

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[46] Direct Testimony of Kurtis W. Castleberry, APSC Docket No. 15-014-U, Doc. 16, p. 15-16 (emphasis added).

[47] "Because there are limited short-term alternatives to natural gas as a fuel for heating and electricity generation during peak demand periods, *changes in supply or demand over a short period may result in large price changes*."
U.S. Energy Information Administration, Frequently Asked Questions, "What are the major factors affecting natural gas prices?," https://www.eia.gov/tools/faqs/faq.php?id=43&t=8 (emphasis added).

> compounded by generation outages during the extreme conditions, increased the risks to the reliable operation of the BPS [bulk power system].
>
> As the industry relies more on natural-gas-fired capacity to meet electricity needs, it is important to examine *potential risks associated with increased dependence on a single fuel type*. The extent of these concerns varies from Region to Region; however, they are most acute in areas where power generators rely on interruptible natural gas pipeline transportation.
>
> Unlike coal and fuel oil, natural gas is not typically stored on site. As a result, real-time delivery of natural gas through a network of pipelines and bulk gas storage is critical to support electric generators. Natural gas is widely used outside the power sector, and the demand from other sectors—particularly coincident end-user gas peak demand during cold winter weather—critically affects gas providers' ability to deliver interruptible transportation service in the power sector. Additionally, demand for natural gas is expected to grow in other sectors (e.g., transportation, exports, and manufacturing).[48]

Since the reliability of natural gas production, transportation, and generation in a world where natural gas serves as the primary fuel source for electricity generation remains unknown, it does not seem prudent for EAI to plan for the total elimination of coal as a fuel source in its generation mix without further development and continued testing of the natural gas infrastructure. As noted by NERC, coal plants do not suffer from some of the challenges posed by natural gas-fired plants in extreme cold weather events. Additionally, FERC has recently noted that natural gas storage inventories are at their lowest level since 2005, which could result in increased natural gas prices as soon as this winter.[49]

Additionally, although EAI and other parties have emphasized the declining cost of renewable generators as partial justification for the abandonment of the coal-fired plants, federal

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[48] North American Electric Reliability Corporation, Polar Vortex Review, September 2014, p. 17, available at the following link: https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.

[49] Federal Energy Regulatory Commission, "2018-2019 Winter Energy Market Assessment," available at the following link: https://ferc.gov/market-oversight/reports-analyses/mkt-views/2018/10-18-18-A-3-presented.pdf?csrt=66746001818521317.

tax incentives driving those declining costs begin to expire soon,[50] and the expiration of those tax incentives may reverse the trend of declining costs.[51] Therefore, EAI should not necessarily presume that it can replace over one thousand megawatts of coal-fired generation with cheap renewable plants.

In conclusion, EAI has reacted to the loosening of environmental regulations regarding its coal plants with plans to accelerate their retirements. Said reaction, which is somewhat counter-intuitive, creates concern that EAI merely hopes to retire those plants early so that it can incur capital costs (and get a return on them) by building replacement capacity. Instead of resource planning with its shareholders in mind, EAI should fulfill its fiduciary duties to its ratepayers by examining the viability of operating its coal plants for the remainder of their sixty-year useful lives.

Recommendation

- EAI should closely examine the economic viability of operating its coal-fired power plants for the remainder of their sixty-year useful lives.

VIII. Comment Topic: Energy Efficiency

Gary Moody, National Audubon Society

Other Stakeholders Joining This Comment: Advanced Energy Management Alliance, Arkansas Electric Energy Consumers, Inc., and Sierra Club

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[50] US Department of Energy, available at the following link: https://www.energy.gov/savings/renewable-electricity-production-tax-credit-ptc.

[51] *See* U.S. Energy Information Administration, "Tax credits and solar tariffs affect timing of projected renewable power plant deployment," May 15, 2018, available at the following link: https://www.eia.gov/todayinenergy/detail.php?id=36212; *see also* U.S. Department of Energy, 2017 Wind Technologies Market Report, p. xii, available at the following link: https://emp.lbl.gov/sites/default/files/2017_wind_technologies_market_report.pdf.

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A. EAI Treatment of EE in 2018 EAI IRP

The Stakeholder Group commends EAI for their leadership in EE program development and deployment. Since the adoption of comprehensive energy efficiency targets in 2011, Entergy Arkansas has been the leader among their peers in achieving efficiency savings. During the 2015, EAI IRP process, stakeholders encouraged modeling EE as a resource. Stakeholders commend EAI for working to implement that suggestion and offer the following comments as an opportunity to further improve EE treatment in the IRP process moving forward.

The 2018 draft IRP as presented to the Stakeholder group considers four types of DSM: Customer-sponsored DSM, Existing Utility-Sponsored DSM, Incremental Utility-Sponsored DSM, and Interruptible Loads/DR. The draft IRP includes assumptions for the impacts of Customer-Sponsored DSM and existing Utility-Sponsored DSM as modifiers to their Retail Sales Forecast, while Incremental Utility sponsored DSM and Interruptible Loads/DR are modeled as a supply side resource.

B. EE as a resource

The Stakeholders commend EAI for working with ICF to treat incremental Utility-sponsored EE as a supply-side resource, and allowing it to compete dynamically in the model for future utility investment against other capacity resources as recommended in the 2015 IRP Stakeholder report.

Stakeholders note that one of the two available EE portfolio options was selected by the model in all futures modeled at the earliest date available (2020). As EAI has noted that APSC approval will be needed for these additional resources, we encourage EAI to begin that process as soon as is practicable.

The Stakeholder group would also encourage EAI to continue to refine and expand their EE modeling process for future IRP processes.

C. Stakeholder Concerns

Despite the above noted improvement, the Stakeholder group does want to express one concern related to EAI's treatment of EE in the IRP draft. The estimate for Existing Utility – Sponsored DSM is likely too conservative. With little explanation EAI chose to use 1.0% of retail sales as the DSM proxy within the Sales and Load forecasts, despite significantly higher achieved savings for recent years and the subsequent APSC order increasing targets to 1.2% of annual sales. Planning on 1.0% savings despite actually achieving 1.57% savings in 2016, 1.49% for 2017, and estimated savings of 1.8% for 2018 - drastically underestimates the likely impact of EE on future load. At a minimum EAI should use 120% of the current EE Savings target as a reasonable proxy as they have indicated their planning and budgets for the next 3 year plan will be designed to achieve at least that level of cost-effective savings. Underestimating EE this substantially will lead to over estimating future capacity needs and increased costs for consumers.

IX. Comment Topic: Coal

Tony Mendoza, Sierra Club

Other Stakeholders Joining This Comment: Advanced Energy Management Alliance, National Audubon Society

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Entergy Arkansas co-owns and operates two large coal-burning power plants, the two-unit White Bluff plant near Redfield and the two-unit Independence plant near Newark. As Entergy evaluates how and when to replace these plants, Sierra Club urges the company to rely on "all-source" requests for proposals to determine the most-economical, least-polluting means of meeting customers' power needs.

A. Entergy Arkansas's coal plants are dirty.

Burning coal is the single most environmentally damaging means of producing electricity. At a time when the UN Intergovernmental Panel on Climate Change has warned in its October 2018 report that a climate crisis of inundated coastlines, intensifying droughts, food shortages, and powerful storms is approaching as soon as 2040, coal remains the most carbon-intensive means of producing electricity. White Bluff and Independence are by far the largest single sources of carbon pollution in Arkansas. In 2017, White Bluff emitted 9,143,967 tons of carbon and Independence emitted 7,989,772 tons, according to U.S. EPA data.

In addition, White Bluff and Independence are the top two sources of sulfur dioxide ("SO_2") and nitrogen oxides ("NOx") pollution in the state of Arkansas and are among the largest in the United States. The four Independence and White Bluff units are the largest in the United States that lack post-combustion controls for both NOx and SO_2. According to U.S. EPA data, White Bluff emitted 23,212 tons of SO_2 in 2017 and Independence emitted 19,486 tons that year, which made these plants the 9th and 15th largest sources of SO_2 pollution in the entire country. In 2017, White Bluff was the 7th largest source of NOx in the entire United States, emitting 11,418 tons, and Independence was the 25th largest source in the country, spewing 8,694 tons of NOx. Both NOx and SO_2 are harmful to human health.

These plants also produce vast quantities of coal combustion residuals ("CCRs") that are likely to contaminate groundwater for generations, directly on the banks of the Arkansas and White rivers. Entergy Arkansas's public reporting confirms that the CCRs at both plants are likely contaminating the groundwater.

There is therefore a moral imperative for Entergy Arkansas to cease burning coal as soon as possible. Entergy's decision to model the retirement of White Bluff in 2028 and

Independence in 2030 is a positive start in that direction.

B. The economics of Entergy Arkansas's coal plants are deteriorating.

The economics of Entergy Arkansas coal have deteriorated in recent years, as shown in their annual capacity factors. These plants simply do not operate as often as they did before 2014 as more-efficient, less-expensive generation plants dispatch more often in the MISO and SPP energy markets. The lack of any post-combustion controls for NOx and SO_2 and of closed-loop ash handling systems, at both plants is also a significant risk of increased costs at both plants.

Table 1: Annual Capacity Factors for Entergy Arkansas Coal Plants

	2014	**2015**	**2016**	**2017**
Independence	74.64%	35.21%	52.18%	51.63%
1	75.6%	37.81%	52.13%	43.19%
2	73.68%	32.61%	52.22%	60.13%
White Bluff	73.41%	43.35%	39.58%	55.59%
1	75.5%	43.04%	34.34%	67.52%
2	71.25%	43.66%	44.79%	43.75%

Moreover, based on data reported by the MISO and SPP energy markets and by Entergy Arkansas, Sierra Club calculated the approximate revenues each plant generated by producing power in recent years. These estimated revenues were compared to the actual operation costs of the power plants, based on data reported by the owners of the power plants. This comparison can show if the power plants were able to cover their costs to operate by selling electricity into the SPP and MISO markets.

Table 2: Cash Flow of White Bluff and Independence

White Bluff	**2015**	**2016**	**2017**
SPP Energy Revenues	*$37*	*$35*	*$47*
MISO Energy Revenues	*$134*	*$125*	*$177*
MISO Capacity Revenues	*$8*	*$2*	*$1*
Total Revenues	$179	$162	$225
Fuel Costs	*($167)*	*($161)*	*($226)*
Operation Costs	*($15)*	*($15)*	*($14)*
Maintenance Costs	*($26)*	*($20)*	*($25)*
Total Costs	($208)	($196)	($265)
Net Earnings (Losses)	**($29)**	**($34)**	**($40)**

Independence	2015	2016	2017
SPP Energy Revenues	*$44*	*$65*	*$68*
MISO Energy Revenues	*$109*	*$149*	*$158*
MISO Capacity Revenues	*$7*	*$1*	*$1*
Total Revenues	$160	$215	$227
Fuel Costs	*($160)*	*($198)*	*($206)*
Operation Costs	*($13)*	*($9)*	*($11)*
Maintenance Costs	*($21)*	*($19)*	*($22)*
Total Costs	($194)	($226)	($239)
Net Earnings (Losses)	**($34)**	**($11)**	**($12)**

Since the start of 2015, the White Bluff plant is estimated to have generated $119 million dollars of revenue from the SPP energy market, $447 million of revenue from the MISO energy market, and $11 million from the MISO capacity market. However, the cost to operate the coal plant has been in excess of $669 million, meaning the plant has accumulated $103 million in losses that were covered by customers. Independence has similarly been uncompetitive. It is estimated to have generated $177 million dollars of revenue from the SPP energy market, $416 million of revenue from the MISO energy market, and $9 million of revenue from the MISO Capacity market. However, the cost to operate the coal plant has been in excess of $659 million, meaning the plant has lost a cumulative $57 million.

Both SPP and MISO markets have a large excess of available power plant resources, including access to low-cost wind and solar. This market reality means that Entergy Arkansas and the owners of White Bluff and Independence have had, and will continue to have, access to lower cost energy off the market rather than operating the two coal plants.

In fact, during the last three years the cost of energy from the White Bluff and Independence plants has generally exceeded the MISO market energy price. The cost of energy from the MISO energy market was $28.91—$31.34/MWh (nominal) in the 2015—2017 period. The cost of energy from White Bluff was $32.37—$34.07/MWh (nominal) in the 2015—2017 period. The cost of energy from Independence was $29.33—$36.14/MWh (nominal) in the 2015—2017 period. Thus, on the energy side, Entergy clearly has an opportunity to save customers money by shifting away from these coal-burning plants.

C. <u>Entergy Arkansas's coal plants support economic development in Wyoming.</u>

Each year, Entergy Arkansas and the co-owners of White Bluff and Independence spend hundreds of millions of dollars on out-of-state coal, almost exclusively sourced from Wyoming. These costs are ultimately paid by electric customers in Arkansas, and provide an economic boost to the Wyoming and Montana economies, and a corresponding drain on the Arkansas economy via direct payments and the negative multiplier effect.

<u>Recommendation</u>

Sierra Club recommends that EAI issue an "all-source" requests for proposal ("RFP") modeled on the Xcel (2017) and NIPSCO (2018) RFPs to test the market for replacing the energy and/or capacity provided by White Bluff and Independence sooner than 2028 and 2030. If EAI ultimately determines that it will shut White Bluff and Independence in 2028 and 2030, then EAI should use an all-source RFP ahead of those shutdowns to test the market for the most-economical and least-polluting means of replacing these plants. Key attributes of such an RFP should include: i) requesting all solutions regardless of technology, including demand-side options and storage, such that the RFP is truly "all source;" ii) defining a minimum total need of a certain number MW for the portfolio of resources but without a cap, while also allowing smaller resources to offer their solution as a piece of the total need; and iii) seeking bids for asset purchases and purchase power agreements for new and existing resources. Sierra Club asks that EAI provide an opportunity for stakeholders to comment on a draft RFP before it issued.

X. <u>Comment Topic: Advanced Nuclear</u>

Katie Niebaum, Arkansas Advanced Energy Association

Other Stakeholders Joining This Comment: None.

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The Arkansas Advanced Energy Association (AAEA) encourages EAI to consider advanced nuclear energy in its long-term resource planning. Advanced nuclear power technologies are different in that they address many of the concerns that have limited the deployment of commercial-scale conventional nuclear power generation. Some of the benefits of advanced nuclear include:

- **Zero emissions.** Not just GHGs, but also other criteria pollutants such as NOx, SOx, PM, etc.
- **High Capacity Factor.** The U.S. nuclear fleet currently averages >92%.
- **Baseload.** Nuclear generating facilities are reliable and dispatchable.
- **Small scale.** Advanced nuclear systems are available in much smaller increments (e.g., 50-300 MW) than conventional systems.
- **Small land area.** Small physical footprints.
- **Short lead time.** Compared to conventional nuclear technologies, advanced technologies require less lead time for commercial deployment.
- **Improved waste management.** Advanced nuclear technologies can address some of the concerns associated with long-term management of spent nuclear fuel from conventional nuclear plants. In some cases, advanced nuclear systems actually use the spent fuel from conventional facilities as feedstock.

AAEA recognizes that many of the issues associated with conventional nuclear facilities have created a climate of concern and distrust regarding nuclear technology. Nonetheless, the broad range of benefits noted above warrant serious consideration of advanced nuclear energy for future power generation in Arkansas, particularly in light of EAI's plans to decommission the White Bluff, Independence, and Arkansas Nuclear One facilities. AAEA stands ready to work with EAI to evaluate and, potentially, deploy advanced nuclear power generation technologies in Arkansas during the longer-term horizon. Advanced nuclear energy could become a key component of EAI's strategy to replace baseload power while also reducing emissions.

§ 165.T08–0614 Safety Zone; Neches River, Beaumont, TX.

(a) *Location.* The following area is a safety zone: All navigable waters extending 500-feet on either side of the Kansas City Southern Railroad Bridge that crosses the Neches River in Beaumont, TX in approximate location 30° 04′54.8″N 094°05′29.4″W.

(b) *Effective period.* This section is effective from 1 a.m. on October 1, 2019, through midnight on January 31, 2020, or until missing and/or damaged fendering systems are repaired or replaced, whichever occurs first.

(c) *Regulations.* (1) No vessel may enter or remain in the safety zone except:

(i) A vessel less than 65 feet in length and not engaged in towing; or

(ii) A vessel authorized by the Captain of the Port Marine Safety Unit Port Arthur (COTP) or a designated representative.

(2) Persons and vessels desiring to enter the safety zone must request permission from the COTP or a designated representative. They may be contacted through Vessel Traffic Service (VTS) on channels 65A or 13 VHF–FM, or by telephone at (409) 719–5070.

(3) Permission to transit through the bridge will be based on weather, tide and current conditions, vessel size, horsepower, and availability of assist vessels. All persons and vessels permitted to enter this temporary safety zone shall comply with the lawful orders or directions given to them by COTP or a designated representative.

(4) Intentional or unintentional contact with any part of the bridge or associated structure, including fendering systems, support columns, spans or any other portion of the bridge, is strictly prohibited. Report any contact with the bridge or associated structures immediately to VTS Port Arthur on channels 65A, 13 or 16 VHF–FM or by telephone at (409) 719–5070.

(d) *Informational broadcasts.* The Coast Guard will inform the public through public of the effective period of this safety zone through VTS Advisories, Broadcast Notices to Mariners (BNMs), Local Notice to Mariners (LNMs), and/or Marine Safety Information Bulletins (MSIBs) as appropriate.

Dated: September 18, 2019.

Jacqueline Twomey,

Captain, U.S. Coast Guard, Captain of the Port Marine Safety Unit Port Arthur.

[FR Doc. 2019–20580 Filed 9–26–19; 8:45 am]

BILLING CODE 9110–04–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R06–OAR–2015–0189; FRL–9998–66–Region 6]

Approval and Promulgation of Implementation Plans; Arkansas; Approval of Regional Haze State Implementation Plan Revision for Electric Generating Units in Arkansas

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Pursuant to the Federal Clean Air Act (CAA or the Act), the Environmental Protection Agency (EPA) is finalizing an approval of a portion of a revision to the Arkansas State Implementation Plan (SIP) submitted by the State of Arkansas through the Arkansas Department of Environmental Quality (ADEQ) that addresses certain requirements of the CAA and the EPA's regional haze rules for the protection of visibility in mandatory Class I Federal areas (Class I areas) for the first implementation period. The EPA is taking final action to approve, among other things, the state's sulfur dioxide (SO_2) and particulate matter (PM) best available retrofit technology (BART) determinations for electric generating units (EGUs) in Arkansas and the determination that no additional SO_2 and PM controls at any Arkansas sources are necessary under reasonable progress. In conjunction with this final approval of a portion of the SIP revision, we are finalizing in a separate rulemaking, published elsewhere in this issue of the **Federal Register**, our withdrawal of the corresponding Federal implementation plan (FIP) provisions established in a prior action to address regional haze requirements for Arkansas.

DATES: This rule is effective on October 28, 2019.

ADDRESSES: The EPA has established a docket for this action under Docket No. EPA–R06–OAR–2015–0189. All documents in the dockets are listed on the *http://www.regulations.gov* website. Although listed in the index, some information is not publicly available, *e.g.,* Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at the EPA Region 6, 1201 Elm Street, Suite 500, Dallas, Texas 75270–2102.

FOR FURTHER INFORMATION CONTACT: Dayana Medina, 214–665–7241, *medina.dayana@epa.gov,* EPA Region 6, 1201 Elm Street, Suite 500, Dallas, Texas 75270–2102.

SUPPLEMENTARY INFORMATION: Throughout this document ''we,'' ''us,'' and ''our'' means the EPA.

Table of Contents

I. Background

A. The Regional Haze Program

Regional haze is visibility impairment that is produced by a multitude of sources and activities that are located across a broad geographic area and emit fine particulates ($PM_{2.5}$) (*e.g.,* sulfates, nitrates, organic carbon (OC), elemental carbon (EC), and soil dust), and their precursors (*e.g.,* SO_2, nitrogen oxides (NO_X), and in some cases, ammonia (NH_3) and volatile organic compounds (VOCs)). Fine particle precursors react in the atmosphere to form $PM_{2.5}$, which impairs visibility by scattering and absorbing light. Visibility impairment reduces the clarity, color, and visible distance that can be seen. $PM_{2.5}$ can also cause serious adverse health effects and mortality in humans; it also contributes to environmental effects such as acid deposition and eutrophication.

Data from the existing visibility monitoring network, the ''Interagency Monitoring of Protected Visual Environments'' (IMPROVE), shows that visibility impairment caused by air pollution occurs virtually all of the time at most national parks and wilderness areas. In 1999, the average visual range [1] in many Class I areas (*i.e.,* national parks and memorial parks, wilderness areas, and international parks meeting certain size criteria) in the western United States was 100–150 kilometers, or about one-half to two-thirds of the visual range that would exist under

[1] Visual range is the greatest distance, in kilometers or miles, at which a dark object can be viewed against the sky.

estimated natural conditions.[2] In most of the eastern Class I areas of the United States, the average visual range was less than 30 kilometers, or about one-fifth of the visual range that would exist under estimated natural conditions. CAA programs have reduced emissions of some haze-causing pollution, lessening some visibility impairment and resulting in partially improved average visual ranges.[3]

In Section 169A of the 1977 Amendments to the CAA, Congress created a program for protecting visibility in the nation's national parks and wilderness areas. This section of the CAA establishes as a national goal the prevention of any future, and the remedying of any existing, man-made impairment of visibility in 156 national parks and wilderness areas designated as mandatory Class I Federal areas.[4] Congress added section 169B to the CAA in 1990 to address regional haze issues, and the EPA promulgated regulations addressing regional haze in 1999. The Regional Haze Rule[5] revised the existing visibility regulations to add provisions addressing regional haze impairment and established a comprehensive visibility protection program for Class I areas. The requirements for regional haze, found at 40 CFR 51.308 and 51.309, are included in our visibility protection regulations at 40 CFR 51.300–309. The requirement to submit a regional haze SIP applies to all 50 states, the District of Columbia, and the Virgin Islands. States were required to submit the first implementation plan addressing regional haze visibility impairment no later than December 17, 2007.[6]

Section 169A of the CAA directs states to evaluate the use of retrofit controls at certain larger, often under-controlled, older stationary sources in order to address visibility impacts from these sources. Specifically, section 169A(b)(2)(A) of the CAA requires states to revise their SIPs to contain such measures as may be necessary to make reasonable progress toward the natural visibility goal, including a requirement that certain categories of existing major stationary sources[7] built between 1962 and 1977 procure, install and operate BART controls. Larger ''fossil-fuel fired steam electric plants'' are one of these source categories. Under the Regional Haze Rule, states are directed to conduct BART determinations for ''BART-eligible'' sources that may be anticipated to cause or contribute to any visibility impairment in a Class I area. The evaluation of BART for electric generating units (EGUs) that are located at fossil-fuel fired power plants having a generating capacity in excess of 750 megawatts must follow the ''Guidelines for BART Determinations Under the Regional Haze Rule'' at appendix Y to 40 CFR part 51 (hereinafter referred to as the ''BART Guidelines''). Rather than requiring source-specific BART controls, states also have the flexibility to adopt an emissions trading program or other alternative program as long as the alternative provides for greater progress towards improving visibility than BART.

B. Our Previous Actions

Arkansas submitted a SIP revision on September 9, 2008, to address the requirements of the first regional haze implementation period. On August 3, 2010, Arkansas submitted a SIP revision with mostly non-substantive revisions to Arkansas Pollution Control and Ecology Commission (APCEC) Regulation 19, Chapter 15.[8] On September 27, 2011, the State submitted supplemental information to address the regional haze requirements. We are hereafter referring to these regional haze submittals collectively as the ''2008 Arkansas Regional Haze SIP.'' On March 12, 2012, we partially approved and partially disapproved the 2008 Arkansas Regional Haze SIP.[9] On September 27, 2016, we promulgated a FIP (the Arkansas Regional Haze FIP) addressing the disapproved portions of the 2008 Arkansas Regional Haze SIP.[10] Among other things, the FIP established SO_2, NO_X, and PM emission limits under the BART requirements for nine units at six facilities: Arkansas Electric Cooperative Corporation (AECC) Bailey Plant Unit 1; AECC McClellan Plant Unit 1; the American Electric Power/Southwestern Electric Power Company (AEP/SWEPCO) Flint Creek Plant Boiler No. 1; Entergy Arkansas, Inc. (Entergy) Lake Catherine Plant Unit 4; Entergy White Bluff Plant Units 1 and 2; Entergy White Bluff Auxiliary Boiler; and the Domtar Ashdown Mill Power Boilers No. 1 and 2. The FIP also established SO_2 and NO_X emission limits under the reasonable progress requirements for Entergy Independence Units 1 and 2.

Following the issuance of the Arkansas Regional Haze FIP, the State of Arkansas and several industry parties filed petitions for reconsideration and an administrative stay of the final rule.[11] On April 14, 2017, we announced our decision to reconsider several elements of the FIP, as follows: Appropriate compliance dates for the NO_X emission limits for Flint Creek Boiler No. 1, White Bluff Units 1 and 2, and Independence Units 1 and 2; the low-load NO_X emission limits applicable to White Bluff Units 1 and 2 and Independence Units 1 and 2 during periods of operation at less than 50 percent of the units' maximum heat input rating; the SO_2 emission limits for White Bluff Units 1 and 2; and the compliance dates for the SO_2 emission limits for Independence Units 1 and 2.[12]

EPA also published a document in the **Federal Register** on April 25, 2017, administratively staying the effectiveness of the NO_X compliance dates in the FIP for the Flint Creek,

[2] 64 FR 35715 (July 1, 1999).

[3] An interactive ''story map'' depicting efforts and recent progress by EPA and states to improve visibility at national parks and wilderness areas may be visited at: *http://arcg.is/29tAbS3.*

[4] Areas designated as mandatory Class I Federal areas consist of National Parks exceeding 6,000 acres, wilderness areas and national memorial parks exceeding 5,000 acres, and all international parks that were in existence on August 7, 1977. 42 U.S.C. 7472(a). In accordance with section 169A of the CAA, EPA, in consultation with the Department of Interior, promulgated a list of 156 areas where visibility is identified as an important value. 44 FR 69122 (November 30, 1979). The extent of a mandatory Class I area includes subsequent changes in boundaries, such as park expansions. 42 U.S.C. 7472(a). Although states and tribes may designate as Class I additional areas which they consider to have visibility as an important value, the requirements of the visibility program set forth in section 169A of the CAA apply only to ''mandatory Class I Federal areas.'' Each mandatory Class I Federal area is the responsibility of a ''Federal Land Manager.'' 42 U.S.C. 7602(i). When we use the term ''Class I area'' in this action, we mean a ''mandatory Class I Federal area.''

[5] Here and elsewhere in this document, the term ''Regional Haze Rule,'' refers to the 1999 final rule (64 FR 35714), as amended in 2005 (70 FR 39156, July 6, 2005), 2006 (71 FR 60631, October 13, 2006), 2012 (77 FR 33656, June 7, 2012), and January 10, 2017 (82 FR 3078).

[6] See 40 CFR 51.308(b). EPA's regional haze regulations require subsequent updates to the regional haze SIPs. 40 CFR 51.308(g)–(i).

[7] See 42 U.S.C. 7491(g)(7) (listing the set of ''major stationary sources'' potentially subject-to-BART).

[8] The September 9, 2008 SIP submittal included APCEC Regulation 19, Chapter 15, which is the state regulation that identified the BART-eligible and subject-to-BART sources in Arkansas and established BART emission limits for subject-to-BART sources. The August 3, 2010 SIP revision did not revise Arkansas' list of BART-eligible and subject-to-BART sources or revise any of the BART requirements for affected sources. Instead, it included mostly non-substantive revisions to the state regulation.

[9] 77 FR 14604.

[10] 81 FR 66332; *see also* 81 FR 68319 (October 4, 2016) (correction).

[11] See the docket associated with this rulemaking for a copy of the petitions for reconsideration and administrative stay submitted by the State of Arkansas; Entergy Arkansas Inc., Entergy Mississippi Inc., and Entergy Power LLC (collectively ''Entergy''); AECC; and the Energy and Environmental Alliance of Arkansas (EEAA).

[12] Letter from E. Scott Pruitt, Administrator, EPA, to Nicholas Jacob Bronni and Jamie Leigh Ewing, Arkansas Attorney General's Office (April 14, 2017). A copy of this letter is included in the docket, *https://www.regulations.gov/document?D=EPA-R06-OAR-2015-0189-0240.*

White Bluff, and Independence units, as well as the compliance dates for the SO_2 emission limits for the White Bluff and Independence units for a period of 90 days.[13] On July 13, 2017, the EPA published a proposed rule to extend the NO_X compliance dates for Flint Creek Boiler No. 1, White Bluff Units 1 and 2, and Independence Units 1 and 2, by 21 months to January 27, 2020.[14] However, EPA did not take final action on the July 13, 2017 proposed rule because on July 12, 2017, Arkansas submitted a proposed SIP revision with a request for parallel processing, addressing the NO_X BART requirements for Bailey Unit 1, McClellan Unit 1, Flint Creek Boiler No. 1, Lake Catherine Unit 4, White Bluff Units 1 and 2, and White Bluff Auxiliary Boiler, as well as the reasonable progress requirements with respect to NO_X (Arkansas Regional Haze NO_X SIP revision or Arkansas Phase I SIP revision). We proposed to approve the State's proposed SIP revision in parallel with the state's SIP process. Our proposed approval of the Arkansas Regional Haze NO_X SIP revision and withdrawal of the corresponding parts of the Arkansas Regional Haze FIP was published in the **Federal Register** on September 11, 2017.[15] On October 31, 2017, we received ADEQ's final Regional Haze NO_X SIP revision addressing NO_X BART for EGUs and the reasonable progress requirements with respect to NO_X for the first implementation period. On February 12, 2018, we finalized our approval of the Arkansas Regional Haze NO_X SIP revision and our withdrawal of the corresponding parts of the FIP.[16]

On August 8, 2018, Arkansas submitted a SIP revision (Arkansas Regional Haze SO_2 and PM SIP revision or Arkansas Regional Haze Phase II SIP revision) addressing all remaining disapproved parts of the 2008 Regional Haze SIP, with the exception of the BART and associated long-term strategy requirements for the Domtar Ashdown Mill Power Boilers No. 1 and 2. The Phase II SIP revision also included a discussion on Arkansas' interstate visibility transport requirements. In a proposed rule published in the **Federal Register** on November 30, 2018, we proposed approval of a portion of the SIP revision and we also proposed to withdraw the parts of the FIP corresponding to our proposed approvals.[17] We stated in our proposed rule that we intend to propose action on the portion of the SIP revision discussing the interstate visibility transport requirements in a future proposed rulemaking. Since we proposed to withdraw certain portions of the FIP, we also proposed to redesignate the FIP by revising the numbering of certain paragraphs under 40 CFR 52.173 to reflect the removal of language applicable to EGUs and the retention of language applicable to the Domtar Ashdown Mill, the only remaining facility subject to the provisions of the FIP.

II. Summary of Final Action

This action finalizes our proposed approval of a portion of the Arkansas Regional Haze SO_2 and PM SIP revision. We are finalizing our approval of ADEQ's revised identification of the 6A Boiler at the Georgia-Pacific Crossett Mill as BART-eligible and the determination based on the additional information and technical analysis presented in the SIP revision that the Georgia-Pacific Crossett Mill 6A and 9A Boilers are not subject to BART. We are finalizing our approval of the state's BART determinations as follows: SO_2 and PM BART for the AECC Bailey Plant Unit 1; SO_2 and PM BART for the AECC McClellan Plant Unit 1; SO_2 BART for the AEP/SWEPCO Flint Creek Plant Boiler No. 1; SO_2 BART for Entergy White Bluff Units 1 and 2; SO_2, NO_X, and PM BART for the Entergy White Bluff Auxiliary Boiler; and the prohibition on burning of fuel oil at Entergy Lake Catherine Unit 4 until SO_2 and PM BART determinations for the fuel oil firing scenario are approved into the SIP by EPA. These BART requirements have been made enforceable by the state through Administrative Orders and submitted as part of the SIP revision. We are finalizing our approval of these BART Administrative Orders as part of the SIP.

We are finalizing our withdrawal of our prior approval of Arkansas' reliance on participation in the Cross-State Air Pollution Rule (CSAPR) for ozone season NO_X to satisfy the NO_X BART requirement for the White Bluff Auxiliary Boiler. The Arkansas Regional Haze NO_X SIP revision erroneously stated that the Auxiliary Boiler participates in CSAPR for ozone season NO_X and that the state was electing to rely on participation in that trading program to satisfy the Auxiliary Boiler's NO_X BART requirements, and we erroneously approved this determination in a final action published in the **Federal Register** on February 12, 2018.[18] We are finalizing our withdrawal of our approval of that determination for the Auxiliary Boiler and are replacing it with our final approval of a source-specific NO_X BART emission limit contained in the Arkansas Regional Haze SO_2 and PM SIP Revision before us. The NO_X BART requirement has been made enforceable by the state through an Administrative Order and submitted as part of the SIP revision. We are finalizing our approval of the Administrative Order that contains the NO_X BART requirement as part of the SIP.

We are also finalizing our approval of Arkansas' reasonable progress determinations for Independence Units 1 and 2 and determination that no additional controls are necessary for SO_2 or PM under the reasonable progress requirements for the first implementation period and are also agreeing with the state's calculation of revised RPGs for its Class I areas. We are finalizing our determination that, based on the state's currently approved SIP and the analyses and determinations we are approving in this final action, the state's reasonable progress obligations for the first implementation period have been satisfied. At this time, the majority of the BART requirements for the Domtar Ashdown Mill are satisfied by a FIP.[19] The SIP revision explains that, based upon the BART determinations and analysis in that FIP, nothing further is currently needed for reasonable progress at the Domtar Ashdown Mill. EPA agrees with this determination. We do note that ADEQ recently submitted a SIP revision to address the BART requirements for Domtar Power Boilers No. 1 and No. 2 that are currently satisfied by the FIP, and we intend to take action on that SIP revision addressing Domtar in a future rulemaking. At that time, we will evaluate any conclusions ADEQ draws in that SIP submittal about the adequacy of such SIP-based measures for reasonable progress. We will also evaluate any changes in the measures for the Domtar Ashdown Mill in that SIP revision relative to those currently in the FIP to determine whether the calculation of the reasonable progress goals for the first implementation period continues to be sufficient.

We are finalizing our approval of the components of the long-term strategy addressed by the Arkansas Regional

[13] 82 FR 18994.

[14] 82 FR 32284.

[15] 82 FR 42627.

[16] 83 FR 5927 and 83 FR 5915 (February 12, 2018).

[17] 83 FR 62204 (November 30, 2018).

[18] 83 FR 5927.

[19] We note that the only exception to this is the PM determination for Domtar Ashdown Mill Power Boiler No. 1 contained in the 2008 Arkansas Regional Haze SIP. That BART determination was approved in our 2012 rulemaking. 77 FR 14604, March 12, 2012.

Haze Phase II SIP revision and are finding that Arkansas' long-term strategy for reasonable progress with respect to all sources other than Domtar is approved. We are finalizing our approval of the 0.60 lb/MMBtu SO_2 emission limitations for Independence Units 1 and 2, and these measures are now integrated into the State's long-term strategy. The long-term strategy is the compilation of all control measures a state relies on to make reasonable progress towards the goal of natural visibility conditions, including emission limitations corresponding to BART determinations. Because the Arkansas Regional Haze Phase II SIP revision does not address the BART requirements for Domtar, those components of the long-term strategy will remain satisfied by the FIP unless and until EPA has received and approved a SIP revision containing the required analyses and determinations for this facility.[20]

We are also finalizing our determination that Arkansas has satisfied the requirement under 40 CFR 51.308(i) to consult and coordinate with the federal land managers (FLMs).[21] Additionally, we are finalizing our determination that Arkansas has satisfied the requirement under 40 CFR 51.308(d)(3)(i) to coordinate and consult with Missouri, which has Class I areas affected by Arkansas sources.[22]

As we discussed in our proposal, the SIP revision also includes a discussion on interstate visibility transport. We are aware that Arkansas is working on a SIP revision to address the interstate visibility transport requirements for several national ambient air quality standards (NAAQS), and we therefore deferred evaluating and proposing action on the interstate visibility transport portion of the Arkansas Regional Haze Phase II SIP revision until a future proposed rulemaking.

We are finalizing our approval of a portion of the Arkansas Regional Haze Phase II SIP revision as we have found it to meet the applicable provisions of the Act and EPA regulations and is consistent with EPA guidance. We received comments from several commenters on our proposed approval. Our responses to the substantive comments we received are summarized in Section III. We have fully considered all significant comments on our proposed action on the SIP revision submittal and have concluded that no changes to our final determinations are warranted.

We are approving a portion of the Arkansas Regional Haze Phase II SIP revision submitted by ADEQ on August 8, 2018, as we have determined that it meets the regional haze SIP requirements, including the BART requirements in § 51.308(e); the reasonable progress requirements in § 51.308(d); and the long-term strategy requirements in § 51.308(d)(3). In conjunction with this final approval, we are finalizing in a separate rulemaking, published elsewhere in this issue of the **Federal Register**, our withdrawal of FIP provisions corresponding to the portions of the SIP revision we are taking final action to approve in this rulemaking.

III. Response to Comments

The public comments received on our proposed rule are included in the publicly posted docket associated with this action at *www.regulations.gov*.[23] We reviewed all public comments that we received on the proposed action. Below, we provide a summary of substantive comments and our responses. Summaries of all comments and our full responses thereto are contained in a separate document titled the Arkansas Regional Haze Phase II SIP Revision Response to Comments, which can be found in the docket associated with this final rulemaking.

A. White Bluff SO_2 BART Requirements

Comment: EPA proposed to approve ADEQ's determination that low sulfur coal with an emission rate of 0.60 lb/MMBtu on a 30-day rolling average is SO_2 BART for White Bluff Units 1 and 2. However, the cost-effectiveness figures for dry scrubbers at White Bluff Units 1 and 2 are well within the range of what has been found to be cost effective in other regional haze actions. EPA should reverse its position, disapprove ADEQ's White Bluff SO_2 BART determination, and finalize its previous rule that SO_2 emission limits corresponding to dry scrubbers constitute SO_2 BART at White Bluff.

Response: We remind the commenter that each BART determination is dependent on the specific situation of the source and involves the consideration of a number of factors that usually vary on a case by case basis. This includes consideration of the five statutory factors required under the Regional Haze Rule at § 51.308(e)(1)(ii)(A) and CAA section 169A(g)(2). BART determinations are source specific—what is a reasonable determination for one source may not be appropriate given the facts and circumstances applicable to another source. The states also have wide discretion in the evaluation of the five statutory factors and in formulating SIPs, so long as they satisfy the applicable requirements and provide a reasoned and rational basis for their decisions.

While it is true that some SO_2 BART controls required under other regional haze actions have similar cost-effectiveness figures as those for dry scrubbers for White Bluff, we find that ADEQ satisfied the requirements of the CAA and the Regional Haze Rule by fully considering the five statutory factors in the SO_2 BART analysis for White Bluff Units 1 and 2. Taking into account the remaining useful life of White Bluff Units 1 and 2 (based on Entergy's enforceable Administrative Order to cease coal combustion by December 31, 2028), and the resulting cost-effectiveness of controls, as well as the anticipated visibility improvement of the SO_2 control options and the other BART factors, ADEQ determined that SO_2 BART for White Bluff Units 1 and 2 is an emission limit of 0.60 lb/MMBtu based on the use of low sulfur coal beginning no later than three years from the effective date of the Administrative Order (August 7, 2021) through the end of 2028.

As we explained in our proposal, ADEQ's cost analysis was based on a dry scrubber system assuming an inlet coal sulfur content of 1.2 lb/MMBtu, which is based on Entergy's current coal contract sulfur limit.[24] However, the White Bluff units have historically burned coal with a lower sulfur content. Therefore, we relied on our FIP's cost analysis for dry scrubbers for White Bluff, which was based on a scrubber system designed to burn coal having a sulfur content consistent with what the units have historically burned, and we adjusted for a 7-year as opposed to a 30-year capital cost recovery period to reflect that the units will cease coal combustion by the end of 2028.[25] Based on our revised cost estimates, dry scrubbers are estimated to cost approximately $4,376/ton for Unit 1 and $4,129/ton for Unit 2. The visibility benefit of dry scrubbers at White Bluff Units 1 and 2 is anticipated to be 0.603 dv at Caney Creek and 0.642 dv at Upper Buffalo for Unit 1 and 0.574 dv at Caney Creek and 0.632 dv at Upper Buffalo for Unit 2; Caney Creek and Upper Buffalo are the two Class I areas

[20] As noted above, ADEQ recently submitted a SIP revision to address the BART requirements for Domtar Power Boilers No. 1 and No. 2 that are currently satisfied by the FIP. We intend to evaluate that SIP revision and to take action on it in a future rulemaking.

[21] 83 FR 62234.

[22] 83 FR 62234.

[23] Docket No. EPA–R06–OAR–2015–0189.

[24] 83 FR 62222.

[25] 83 FR 62222.

where White Bluff Units 1 and 2 have the greatest modeled baseline visibility impacts.[26]

In this instance, we believe Arkansas is within its discretion to evaluate the BART factors as it has done, and we find that the state has presented a reasoned basis for its BART determination and has met all CAA and Regional Haze Rule requirements in making the BART determination for White Bluff. Considering all the above, we are finalizing our approval of ADEQ's determination that SO_2 BART for White Bluff Units 1 and 2 is an emission limit of 0.60 lb/MMBtu based on the use of low sulfur coal, with an enforceable Administrative Order requiring Entergy to cease coal combustion at White Bluff Units 1 and 2 by December 31, 2028.

Comment: EPA's proposed approval of ADEQ's determination that low sulfur coal with an emission rate of 0.60 lb/MMBtu on a 30-day rolling average is SO_2 BART for White Bluff Units 1 and 2 and rejection of dry scrubbers is arbitrary when compared to the Flint Creek SO_2 BART determination. The SO_2 BART determination for Flint Creek Boiler No. 1 was based on very similar cost-effectiveness figures for dry scrubbers, but in that case, EPA required a scrubber as BART. EPA should reverse its position and disapprove ADEQ's SO_2 BART determination for White Bluff Units 1 and 2.

Response: We disagree with the commenter that our proposed approval of ADEQ's SO_2 BART determination for White Bluff Units 1 and 2 is arbitrary when compared to our proposed approval of the Flint Creek SO_2 BART determination. In particular, the commenter contends that it is arbitrary and capricious for EPA to find that White Bluff SO_2 BART is an emission limit based on low-sulfur coal, while also finding that SO_2 BART for Flint Creek is an emission limits based on a dry scrubber. EPA did not make these findings in the context of a FIP, but rather proposed to approve ADEQ's determinations based on our finding that the State reasonably determined that SO_2 BART for White Bluff Units 1 and 2 is an emission limit of 0.60 lb/MMBtu based on the use of low sulfur coal and that SO_2 BART for Flint Creek Boiler No. 1 is an emission limit of 0.06 lb/MMBtu based on the use of a dry scrubber. The states have wide discretion in the evaluation of the five statutory factors and in formulating SIPs, so long as they satisfy the applicable requirements and provide a reasoned and rational basis for their decisions. Furthermore, BART determinations are source specific—what is a reasonable determination for one source may not be appropriate given the facts and circumstances applicable to another source. In this instance, we believe Arkansas is within its discretion to evaluate the BART factors as it has done, and we find that the state has presented a reasoned basis for its BART determinations and has met all CAA and Regional Haze Rule requirements in making the SO_2 BART determinations for White Bluff and Flint Creek.

We note that the cost-effectiveness figures for dry scrubbers for White Bluff are in fact higher than that for a Novel Integrated Deacidification (NID) system, a type of dry scrubbing technology, for Flint Creek. In our proposed rule, we estimated the cost effectiveness of dry scrubbers for White Bluff Units 1 and 2 to be $4,376/ton for Unit 1 and $4,129/ton for Unit 2. The visibility benefit of dry scrubbers at White Bluff is anticipated to be 0.603 dv at Caney Creek and 0.642 dv at Upper Buffalo for Unit 1 and 0.574 dv at Caney Creek and 0.632 dv at Upper Buffalo for Unit 2; Caney Creek and Upper Buffalo are the two Class I areas where White Bluff Units 1 and 2 have the greatest modeled baseline visibility impacts.[27] The cost-effectiveness of a NID system for Flint Creek is $3,845/ton. We consider the cost of a dry scrubber at Flint Creek to be generally cost effective when also taking into account the level of visibility benefit of the control and the other BART factors. The visibility benefit of a NID system at Flint Creek Boiler No. 1 is anticipated to be 0.615 dv at Caney Creek and 0.464 dv at Upper Buffalo, the two Class I areas where Flint Creek Boiler No. 1 has the greatest modeled baseline visibility impacts.[28] The anticipated level of visibility benefit at Caney Creek and Upper Buffalo due to dry scrubbers at White Bluff Units 1 and 2 is comparable to the anticipated visibility benefit due to NID at Flint Creek Boiler No. 1, but the cost-effectiveness figures for dry scrubbers at White Bluff are higher than that for Flint Creek, and start to go into the higher end of what has been found to be cost effective in other regional haze actions when also taking into account the level of visibility benefit of the controls and other factors.[29] Additionally, the NID system was already installed and operating at Flint Creek Boiler No. 1 at the time that ADEQ finalized and submitted the Reginal Haze SO_2 and PM SIP revision. Thus, we believe it would have been unreasonable for ADEQ to find that SO_2 BART for Flint Creek Boiler No. 1 is not a NID system when those controls are already installed and operational at the facility. In contrast, there is no planned installation of this control equipment at White Bluff Units 1 and 2, which have a shortened remaining useful life based on an enforceable Administrative Order that is part of this SIP revision. Furthermore, since Flint Creek Boiler No. 1 is currently assumed to continue operating for at least another 30 years while White Bluff Units 1 and 2 are required to cease coal combustion by the end of December 2028 based on the enforceable Administrative Order that is part of this SIP revision, we find that it is reasonable for ADEQ to have determined that SO_2 BART for Flint Creek Boiler No. 1 is an emission limit based on the use of dry scrubbers while SO_2 BART for White Bluff Units 1 and 2 is an emission limit based on the use of low sulfur coal. We are taking final action to approve the state's SO_2 BART determinations for these units.

Comment: Although EPA's estimated dry scrubber costs demonstrate that this control technology is not cost-effective for White Bluff Units 1 and 2, the costs of dry scrubbers are actually underestimated by EPA. EPA's cost assessment assumes that White Bluff will combust coal with a sulfur content of 0.68 lb/MMBtu, which was the maximum monthly emission rate from 2009–2013, and its calculation of the equipment costs reflects scrubbers sized to accommodate this sulfur content. However, EPA is incorrect to assume that the sulfur content of coal that will be combusted at the plant in the future will not exceed the maximum monthly average sulfur content from 2009–2013. EPA ignores the fact that the plant can receive coal with a sulfur content up to 1.2 lb/MMBtu pursuant to its coal contracts, and that White Bluff in fact had a maximum 3-hour average emission rate of 1.1 lb/MMBtu from 2014–2016. A dry scrubber must be designed to handle the highest sulfur content that may be combusted at the unit, as an inappropriately designed scrubber would be incapable of addressing SO_2 emissions exceeding the design limit. If the scrubber system at White Bluff were designed to treat flue gas with a SO_2 emission rate of 0.68 lb/MMBtu, the system would be inadequately sized to add sufficient reagent when sulfur levels increase beyond that level, which would result in emissions above the proposed emission rate for that period of operation. The cost analysis in the SIP

[26] See 83 FR 62221–62222.

[27] See 83 FR 62221–62222.

[28] See 83 FR 62218.

[29] 83 FR 62222.

revision appropriately reflected the installation of scrubbers designed to handle the maximum coal sulfur content at the plant. If EPA retains its cost estimate based on the installation of scrubbers that can accommodate only lower sulfur coal, then EPA must account for the fact that Entergy would need to ensure that only lower sulfur coal is purchased in the future. The resulting increase in fuel costs must be accounted for in the scrubber cost analysis. Failure to do so renders EPA's estimates inaccurate and does not allow for a proper evaluation of the costs of dry scrubbers at White Bluff.

Response: We disagree with the commenter's approach for estimating the cost-effectiveness of dry scrubbers for White Bluff Units 1 and 2. The commenter argues that a mismatch between the cost of the scrubber systems and the SO_2 emission baseline against which the cost-effectiveness will be measured can be legitimately introduced. Specifically, the commenter argues that the units could in the future burn coal containing a higher sulfur content than what has been burned in the past, emphasizing that the plant can receive coal with a sulfur content up to 1.2 lb/MMBtu pursuant to its coal contracts. Therefore, the commenter insists on costing the dry scrubbers for White Bluff Units 1 and 2 assuming the units will burn coal with a sulfur content of 1.2 lb/MMBtu, while at the same time basing the calculation of the SO_2 tons reduced in the cost-effectiveness calculations on a lower emissions level of 0.68 lb/MMBtu based on the same 2009–2013 SO_2 baseline period that the commenter objects to for purposes of costing the scrubbers.[30] This cherry-picking of emission rates has ramifications for the scrubber cost effectiveness calculation, in which the annualized cost of the controls are compared to the SO_2 tons reduced from the SO_2 baseline. A scrubber capable of treating a higher sulfur coal is more expensive. While Entergy is free to design a scrubber capable of burning a coal with a higher sulfur content (assuming all regulatory requirements are otherwise met), this expense must be balanced against the greater SO_2 removal capabilities of such a scrubber. Otherwise, the cost effectiveness calculation is unreasonably skewed. In other words, if the Entergy cost analysis on which the SIP revision relies had also based the calculation of the SO_2 tons reduced on an assumed baseline emission rate of 1.2 lb/MMBtu, this would have reflected greater tons of SO_2 removed, which would in turn result in cost estimates more cost-effective than reflected in Entergy's estimates.

Instead of relying on the SIP's cost estimates, which are based on Entergy's estimates for a dry scrubber designed to treat coal with a sulfur content of 1.2 lb/MMBtu, we presented revised cost estimates for dry scrubbers for White Bluff in our proposal. After considering our lower revised cost numbers, we still agree with ADEQ's SO_2 BART determination for White Bluff Units 1 and 2 in the SIP revision. Our revised cost estimates rely on our FIP's cost analysis, which was based on a scrubber system designed to burn coal having a sulfur content of 0.68 lb/MMBtu, which is the units' maximum monthly emission rate from 2009–2013.[31] Assuming a coal sulfur content that reflects the sulfur levels of the coal historically burned at the units is the appropriate basis for our cost estimate, consistent with the BART Guidelines:[32]

> The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period. When you project that future operating parameters (*e.g.,* limited hours of operation or capacity utilization, type of fuel, raw materials or product mix or type) will differ from past practice, and if this projection has a deciding effect in the BART determination, then you must make these parameters or assumptions into enforceable limitations. In the absence of enforceable limitations, you calculate baseline emissions based upon continuation of past practice.

Based on the BART Guidelines, the presumption is that the baseline emissions should be based on historical emissions. If future operations are expected to differ from past practices, and this impacts the BART analysis, an enforceable mechanism must be in place. The example in the above reference to the BART Guidelines anticipates that future operations will cause the baseline to be lower, resulting in a correspondingly lower denominator in the $/ton cost effectiveness calculation, thus resulting in the cost effectiveness seeming less attractive (higher) and triggering the need for an enforceable mechanism to ensure the integrity of the cost-effectiveness calculation into the future. The same principle applies to Entergy's situation, in that using a higher scrubber cost for scrubbing a higher sulfur coal, in conjunction with using an unrepresentative (lower) baseline, both act to make the $/ton cost effectiveness of the scrubber seem less attractive (higher). In this instance, we would not require an enforceable mechanism to ensure Entergy burns a higher sulfur coal, but the need to ensure the future integrity of the cost-effectiveness calculation nevertheless remains.

There are two obvious ways to ensure the cost effectiveness calculation accurately reflects the costs and emission reductions of scrubbers for White Bluff: Either (1) the higher cost of a scrubber designed to handle a higher sulfur coal must be balanced against its greater SO_2 reduction potential, or (2) the scrubber system's capability and cost must match the facility's historical emissions. We took the latter approach in estimating the cost of dry scrubbers in our proposal. However, the commenter disagrees with either approach, arguing instead that the higher scrubber cost for scrubbing a higher sulfur coal (which it claims could be representative of future emission rates) should be paired with a historical (lower) baseline.

We also note that the commenter does not appear to argue that basing the cost analysis on a scrubber system designed to burn coal having a sulfur content of 0.68 lb/MMBtu is inconsistent with its historical maximum monthly emission rate, but only suggests that in the future the White Bluff units may be burning coal containing a higher sulfur content. The commenter also points to the units' maximum 3-hour average emission rate of 1.1 lb/MMBtu from 2014–2016 in arguing that the cost analysis must reflect a dry scrubber that is designed to handle the highest sulfur content that may be combusted at the unit. However, we note that this is a maximum 3-hour average, while our cost estimates were based on a scrubber system designed to burn coal having a sulfur content of 0.68 lb/MMBtu, which is the units' maximum monthly emission rate from 2009–2013. This is significant because variations in emissions due to changes in coal quality, reagent quality, or scrubber performance are normally accommodated in permitting by specifying a sufficiently long averaging time, such as a 30-day averaging period, which is specifically designed to average out short term fluctuations. In general, averaging smooths out fluctuations in data.[33] Furthermore, the emission limit evaluated by ADEQ and Entergy in the BART analysis for scrubbers, if selected as BART, would have been on a rolling 30 boiler-

[30] See the Arkansas Regional Haze SO_2 and PM SIP Revision, p. 4–4.

[31] 83 FR 62222.

[32] 70 FR 39167.

[33] Thad Godish, *Air Quality,* Lewis Publishers, 2nd Ed., 1991, p. 216, Figure 7.1; Richard W. Boubel, Donald L. Fox, Bruce Turner, and Arthur C. Stern, *Fundamentals of Air Pollution,* Academic Press, 3rd Ed., 1994, pp. 41—43.

operating-day averaging period; therefore, the cost analysis should reflect the design of a scrubber that would meet the same averaging period. In this context, the maximum 3-hour emission rate does not hold much significance. Therefore, we do not agree with the commenter's argument that since White Bluff had a maximum 3-hour average emission rate of 1.1 lb/MMBtu, it is necessary to install a scrubber designed to treat flue gas with a SO_2 emission rate of 1.2 lb/MMBtu.

Considering the above, we disagree with the commenter that we underestimated the cost of dry scrubbers for White Bluff by basing our cost assessment on the assumption that White Bluff will combust coal with a sulfur content of 0.68 lb/MMBtu. Nevertheless, our disagreement with the commenter on the above issues does not ultimately impact our final action given that even after considering our lower cost estimates, we find that ADEQ reasonably exercised its discretion in concluding that the costs of dry scrubbers are not warranted after also taking into account the level of anticipated visibility benefit at the affected Class I areas due to these controls and the other BART factors, including consideration that an Administrative Order that is part of the SIP revision requires the White Bluff units to cease coal combustion by December 31, 2028. We are finalizing our proposed approval of ADEQ's determination that SO_2 BART for White Bluff Units 1 and 2 is an emission limit of 0.60 lb/MMBtu based on the use of low sulfur coal.

Comment: The commenter supports EPA's proposed approval of rolling 30-day average BART SO_2 emission limits of 0.60 lb/MMBtu for White Bluff Units 1 and 2 based on combustion of low sulfur coal. While EPA underestimates the costs of dry scrubbers at White Bluff, even its undervalued costs support a determination that add-on SO_2 control technology is not BART for White Bluff. EPA's cost estimates fail to include certain cost items that EPA claims are disallowed pursuant to the Control Cost Manual. These ''disallowed'' costs should be included in the cost analyses, as they reflect the actual costs of planning, installing, and operating controls. Accounting for the disallowed costs makes the control technologies even less cost-effective. However, even EPA's flawed cost estimates demonstrate that dry sorbent injection (DSI), enhanced DSI and dry scrubbers are not cost-effective for White Bluff.

Response: We appreciate the commenter's support of our proposed approval of ADEQ's determination that SO_2 BART for White Bluff Units 1 and 2 are emission limits of 0.60 lb/MMBtu based on combustion of low sulfur coal. However, we disagree with the commenter that we have underestimated the costs of dry scrubbers at White Bluff. In particular, the commenter states that EPA's cost estimates fail to include certain cost items that EPA claims are disallowed pursuant to the Control Cost Manual and that Entergy continues to believe that these ''disallowed'' costs should be included in the cost analyses. The commenter claims these disallowed costs reflect the actual costs of planning, installing, and operating controls. We disagree with the commenter that the disallowed line items should be included in the cost analyses. As we discussed in our proposal, ADEQ's evaluation of controls in the SIP revision is based on Entergy's set of cost numbers that excludes the line items disallowed under the EPA Control Cost Manual,[34] which the BART Guidelines specify should be the basis of cost estimates, where possible.[35] We stated in our proposal that we agree that Allowance for Funds Used During Construction (AFUDC) and certain other cost items are not allowed to be considered in estimating the cost-effectiveness of controls for regional haze purposes under the EPA Control Cost Manual.[36] We explained in our proposal that we, therefore, agree with ADEQ's decision to base its evaluation of controls on Entergy's set of cost numbers that did not include the disallowed line items instead of relying on the set of cost numbers that did include the disallowed line items.[37] However, as we discussed in a previous response, we ultimately presented revised cost estimates for dry scrubbers for White Bluff in our proposal instead of relying on ADEQ's cost estimates from the SIP revision because ADEQ's cost estimates were based on Entergy's estimates for a dry scrubber that was inappropriately designed to treat coal with a sulfur content of 1.2 lb/MMBtu.

As we have noted in a number of other regional haze actions, certain line items such as AFUDC, owner's costs, and escalation during construction are not valid costs under our Control Cost Manual methodology. We incorporate our responses to similar comments we have received in those actions here.[38] The exclusion of these disallowed line items in estimating the cost-effectiveness of controls for BART purposes is consistent with the ''overnight'' methodology outlined in our Control Cost Manual. We note that the Ninth and Tenth Circuits have upheld our use of the overnight cost methodology and our long-standing position in the regional haze program that certain line items such as AFUDC are not allowed under the Control Cost Manual approach of cost estimating.[39]

Despite our disagreement with the commenter on the above issues, we note that our position on these issues does not ultimately impact our final action given that even after considering the set of cost-effectiveness figures that exclude the disallowed line items, we find that ADEQ reasonably determined that the costs of DSI, enhanced DSI, and dry scrubbers are not warranted after also taking into account the level of anticipated visibility benefit at the affected Class I areas due to these controls and the other BART factors, including consideration that an Administrative Order that is part of the SIP revision requires the White Bluff units to cease coal combustion by December 31, 2028. We are therefore finalizing our proposed approval of ADEQ's determination that SO_2 BART for White Bluff Units 1 and 2 is an emission limit of 0.60 lb/MMBtu based on the use of low sulfur coal.

Comment: ADEQ's SO_2 BART determination for White Bluff Units 1 and 2 is based on a voluntary decision made by Entergy to cease coal combustion at the units by December 31, 2028. White Bluff Units 1 and 2 are co-owned by Entergy, AECC, and several Arkansas municipalities. Entergy and AECC are public utilities subject to the jurisdiction of the Arkansas Public Service Commission (APSC). Since the Administrative Order requires Entergy to comply with applicable law, EPA should acknowledge that Entergy is required to

[34] 83 FR 62220.

[35] 40 CFR part 51, appendix Y, IV.D.4.a.

[36] 83 FR 62222.

[37] 83 FR 62222.

[38] See for instance, our ''Response to Technical Comments for Sections E through H of the **Federal Register** Notice for the Oklahoma Regional Haze and Visibility Transport Federal Implementation Plan,'' Docket No. EPA–R06–OAR–2010–0190, 12/13/2011. See pages 7–10, 12–21, 33–34, 46–47, 63–64, 68, 70–71, 80, 85–86, and 88. This document can also be found in the docket for our final action on the Arkansas Regional Haze Phase II SIP Revision (Docket No. EPA–R06–OAR–2015–0189).

[39] See *Ariz. ex rel. Darwin* v. *EPA,* 815 F.3d 519 (9th Cir. 2016), page 39: ''This argument restates Petitioners' objections to EPA's reliance on the overnight costing methodology when it partially disapproved Arizona's SIP. See supra note 14. EPA's use of such a methodology in its own FIP's cost analysis is, without doubt, reasonable.'' See also *Oklahoma* v. *EPA,* 723 F.3d 1201 (July 19, 2013), *cert. denied* (U.S. May 27, 2014) where EPA disapproved certain BART determinations that did not rely on the overnight cost methodology as well as relied on certain cost items such AFUDC which are not allowed per the EPA Control Cost Manual.

seek APSC approval for the cessation of coal combustion at White Bluff prior to the end of its effective useful life.

Response: The relevant consideration for BART determinations is whether any commitment to change future operations, when such changes impact the outcome of the BART analysis, is enforceable for purposes of the SIP.[40] Under a BART analysis, the remaining useful life of a scrubber is assumed to be 30 years unless a facility has an enforceable agreement in place to shut down or cease coal combustion earlier in order for EPA or the state to rely on it in calculating the remaining useful life as part of the BART determination analysis. Here, Entergy entered into an Administrative Order with ADEQ, which is an enforceable document that ADEQ has incorporated into its SIP revision, to cease coal combustion at Units 1 and 2 at White Bluff by December 31, 2028. It was therefore appropriate for ADEQ to rely on this cease to combust coal date for White Bluff Units 1 and 2 in the calculation of the units' remaining useful life, which is used to determine the cost effectiveness of controls in the BART analysis.

To the extent the commenter is contending that the Administrative Order itself requires Entergy to obtain APSC approval in order to be able to make the changes in operations necessary to comply with the requirements of that Administrative Order (AO), we note that Provision No. 12 provides that ''Nothing contained in this AO shall relieve Entergy Arkansas of any obligations imposed by any other applicable local, state, or federal laws, nor, except as specifically provided herein, shall this AO be deemed in any way to relieve Entergy Arkansas of responsibilities contained in the permit.'' [41] EPA cannot comment on what other local or state laws are applicable including whether Entergy and some of the White Bluff co-owners are public utilities subject to the jurisdiction of the APSC. With regard to the commenter's statement that Entergy will be required to obtain approval from the APSC with respect to the provisions in the Administrative Order, we note that such matter falls under the jurisdiction of Arkansas state law and is outside of the scope of our proposal.

To the extent that the commenter is suggesting that EPA should acknowledge that approval will be required from the APSC because the lack of such approval would prevent Entergy from complying with the voluntary cessation of coal combustion, we note that Entergy has entered into an enforceable Administrative Order, which requires the cessation of coal combustion at White Bluff Units 1 and 2 by December 31, 2028. In this final action, we are approving the Administrative Order as part of the SIP, and it is now therefore federally enforceable as a source-specific requirement. If Entergy does not comply with the terms of the Administrative Order, such as not ceasing coal combustion by December 31, 2028, Entergy will be in violation of the SIP, which is a federal requirement. Under Section 113 of the CAA (42 U.S.C. 7413), which addresses, among other things, federal enforcement of SIPs, EPA has the authority to enforce the terms of the Entergy Administrative Order, such as ceasing coal combustion by December 31, 2028, that are being incorporated into Arkansas' SIP here. In addition, under Section 304 of the CAA (42 U.S.C. 7604), citizens and/or citizens groups have the authority to enforce emission limitations in orders, such as the provisions within the Entergy Administrative Order, or require EPA to do so, through the notice of the CAA citizens' suit process.

Comment: Entergy's five factor analysis for White Bluff does not take into account any electric reliability or energy supply impacts arising from Entergy's voluntary decision to prematurely close White Bluff, which ultimately will require the replacement of White Bluff's firm electric generating capacity, not only for Entergy but also for the other White Bluff co-owners. This factor should have been considered in the five-factor analysis for White Bluff.

Response: The commenter is correct that Entergy's BART analysis for White Bluff, which is part of the SIP revision, and on which ADEQ based its BART determination for White Bluff, did not identify any electric reliability or energy supply impacts arising from Entergy's voluntary decision to cease coal combustion at White Bluff. We note that the energy and nonair quality environmental impacts of compliance is one of the factors that the CAA and the Regional Haze rule require to be considered in the BART analysis.[42] However, neither Entergy in its BART analysis nor ADEQ in the SIP revision identify any adverse energy and nonair quality environmental impacts associated with Entergy's enforceable measure to cease coal combustion at White Bluff prior to the end of the effective useful life of the facility, or with any other BART control option evaluated. EPA is also not aware of any such adverse impacts, and we therefore defer to ADEQ's determination that there are no significant energy impacts to consider in the five-factor BART analysis for White Bluff.

B. Reasonable Progress

Comment: EPA's proposed approval of ADEQ's reasonable progress analysis and conclusions for the Independence facility are arbitrary, capricious, and contrary to law. Dry scrubbers at Independence are highly cost-effective when considering other regional haze actions in Arkansas and elsewhere, and thus EPA's and ADEQ's consideration of cost is arbitrary and unlawful. EPA should revise its proposed rule to find that dry scrubbers at Independence are cost-effective and should be required under reasonable progress.

Response: We disagree with the commenter that our proposed approval of ADEQ's reasonable progress analysis and conclusions for the Independence facility for the first implementation period are arbitrary, capricious, or contrary to law. We do not contest that the cost effectiveness of dry scrubbers at Independence on a dollar per ton reduced ($/ton) basis is within the range of what other states and EPA have found reasonable for reasonable progress controls. However, in this action we evaluated ADEQ's reasonable progress analysis and conclusions and determined that it was not unreasonable for the State to conclude that dry scrubbers for Independence are not necessary to make reasonable progress.

We noted in our proposal that Arkansas considered the capital costs of dry scrubbers and wet scrubbers to be high even though the costs in terms of $/ton of SO_2 emissions reduced for both dry and wet scrubbers at the Independence facility (assuming a 30-year remaining useful life) are within a range that has been found to be cost-effective in other regional haze actions.[43] However, Arkansas' reasonable progress determination was not just based on the consideration of the cost-effectiveness of controls. Arkansas' reasonable progress determination with respect to the Independence facility was appropriately based on its consideration and weighing of the costs of compliance along with the other reasonable progress factors, as

[40] *See* 40 CFR part 51, appendix Y, IV.D.4.d, k.

[41] The Administrative Order for Entergy can be found in the Arkansas Regional Haze SO_2 and PM BART SIP Revision. See Paragraph 12 of the Order and Agreement Section. *https://www.adeq.state.ar.us/air/planning/sip/pdfs/regional-haze/entergy-ao-executed-8-7-2018.pdf.*

[42] See § 51.308(e)(1)(ii)(A) and CAA section 169A(g)(2).

[43] See 83 FR 62230.

well as visibility, which the state deemed to be a relevant factor for consideration in its analysis. Arkansas discussed its concerns regarding the cost of scrubber controls,[44] noted that the evaluation of the $/dv metric demonstrated a greater difference in cost between dry FGD and low sulfur coal compared to the $/ton metric, and ultimately concluded that all the controls it evaluated would cost millions of dollars for what it considers to be little visibility benefit. We explained in our proposal that we believe that Arkansas' weighing of the four statutory factors and other factors it deemed relevant in its reasonable progress analysis for the Independence facility was reasonable and within the state's discretion.[45] Furthermore, we note that our 2007 Reasonable Progress Guidance allows for the deferral of emission reductions to later planning periods, which ADEQ cites in its SIP,[46] in deciding what amount of emissions reduction is appropriate in setting the RPGs considering that the long-term goal of no manmade impairment encompasses several planning periods.[47] We are finding here that considering all the above, including the state's concerns about the cost of controls[48] and given that the state is requiring Independence Units 1 and 2 to switch to low sulfur coal within 3 years under the long-term strategy, which is expected to reduce SO_2 emissions and result in visibility improvements at Arkansas' Class I areas, it is not unreasonable for Arkansas to weigh the factors in the way that it did and conclude that no SO_2 controls under the reasonable progress requirements are necessary for the Independence facility in the first implementation period. We are finalizing our approval of Arkansas' reasonable progress determination with respect to the Independence facility and all other Arkansas sources.

Comment: The proposed reasonable progress determination with respect to the Independence facility is arbitrary, capricious, and contrary to law because EPA's and ADEQ's reliance on the visibility ''glidepath'' is an excuse for avoiding pollution reductions and is unlawful. ADEQ unlawfully concluded that no additional controls are required at Independence largely because the state is on the ''glidepath'' toward natural visibility in distant decades. However, the glidepath is not an independently enforceable requirement and being ''on the glidepath'' does not relieve the state of conducting a reasoned analysis. EPA should revise its proposed rule to make clear that ADEQ's reliance on the ''glidepath'' as an excuse to allow unabated air pollution from the Independence facility is unlawful and unreasonable.

Response: We disagree with the commenter that ADEQ concluded that no additional controls are required at Independence because the state's Class I areas are on the glidepath. Instead, ADEQ's determination on reasonable progress with respect to the Independence facility was based on its consideration and weighing of the four reasonable progress factors, as well as consideration of potential visibility benefit of controls, which the state deemed to be a relevant factor for consideration in its analysis. We noted in our proposal that the statutory factor that appears to have been the most significant in Arkansas' reasonable progress determination with respect to the Independence facility is the cost of compliance, along with consideration of visibility benefits.[49] As such, we disagree that ADEQ's determination was based solely or primarily on the fact that the state's Class I areas are on the glidepath toward natural visibility. Regardless of any consideration Arkansas might have placed on the fact that the state's Class I areas are on the glidepath in making its reasonable progress determination, our proposed and final approval is not based on the Class I areas' position with respect to the glidepath. We explained in our proposal that considering the state's concerns about the cost of the evaluated controls[50] and given that the state is requiring Independence Units 1 and 2 to switch to low sulfur coal within 3 years under the long-term strategy, which is expected to reduce SO_2 emissions and result in visibility improvements at Arkansas' Class I areas, we found that it is not unreasonable for Arkansas to conclude that SO_2 controls under the reasonable progress requirements are not necessary for the Independence facility in the first implementation period.[51] Our proposal further stated that one of the components forming the basis of our proposed approval is ''the state's evaluation and reasonable weighing of the four statutory factors along with consideration of the visibility benefits of controls for the Independence facility.''[52] As is evident from our discussion of ''degree of improvement in visibility'' in the proposal, ADEQ considered the potential visibility benefits of controls in its analysis of controls for Independence, as opposed to visibility conditions in relation to the glidepath.[53] We did not point to the glidepath as a basis for our approval of the state's reasonable progress analysis and determination. Therefore, the commenter is incorrect in contending that EPA is relying on the visibility glidepath as a reason for not requiring pollution reductions at the Independence facility.

Comment: ADEQ cites the high capital costs of new scrubbers as a basis for declining to require them for the Independence facility. This is inappropriate because the capital costs are already assessed in the calculation of cost-effectiveness and the rejection of a control on the basis of capital costs neglects consideration of the benefits of that control, which could justify that cost.

Response: While the commenter is correct that Arkansas considered capital costs in its four-factor analysis and that its reasonable progress determination was based in part on the capital cost of controls, this was not the only factor Arkansas considered and based its decision on. Arkansas considered the cost of controls in the form of cost-effectiveness ($/ton) and capital costs, in addition to also considering the remaining reasonable progress factors

[44] As discussed in our proposal, in light of Entergy's anticipated cessation of coal combustion at the Independence facility, although it is not state- or federally-enforceable, Arkansas considered it important to take into account the capital cost of controls along with the cost-effectiveness in terms of dollars per ton of emissions reduced. In its consideration of the cost of compliance, Arkansas also took into account that these costs would be passed on to Arkansas ratepayers. See 83 FR 62230.

[45] 83 FR 62233.

[46] See pages 28–53 of Arkansas Final Regional Haze Phase II SIP. *https://www3.epa.gov/ttn/naaqs/aqmguide/collection/cp2/20070601_wehrum_reasonable_progress_goals_reghaze.pdf.*

[47] See Section 1.2 of EPA's ''Guidance for Setting Reasonable Progress Goals under the Regional Haze Program'' (June 1, 2007). *https://www3.epa.gov/ttn/naaqs/aqmguide/collection/cp2/20070601_wehrum_reasonable_progress_goals_reghaze.pdf.*

[48] EPA is revising its assessment of ADEQ's consideration of capital costs in the state's reasonable progress determination for Independence. We are clarifying that our evaluation and conclusion in this final action that Arkansas' reasonable progress determination is reasonable does not rely on Arkansas' consideration of capital costs because Arkansas' decision to consider the capital costs of scrubber controls in its analysis was based on Entergy's anticipated early cessation of coal combustion at the Independence facility, which is not state- or federally-enforceable. However, EPA continues to find that ADEQ's determination is reasonable based on the totality of the circumstances.

[49] 83 FR 62232.

[50] As explained elsewhere in this section of the notice, EPA is revising its assessment of ADEQ's consideration of capital costs in the state's reasonable progress determination for Independence. However, EPA continues to find that ADEQ's determination is reasonable based on the totality of the circumstances.

[51] 83 FR 62233.

[52] 83 FR 62233.

[53] 83 FR 62229.

and the anticipated visibility improvement of controls, as it deemed consideration of visibility to be a relevant factor in its reasonable progress analysis. Arkansas noted that the evaluation of the $/dv metric demonstrated a greater difference in cost between dry FGD and low sulfur coal compared to the $/ton metric, and ultimately concluded that the controls it evaluated would cost millions of dollars for what it considers to be little visibility benefit. Thus, Arkansas' reasonable progress determination with respect to the Independence facility was based on its consideration and weighing of the costs of compliance and the other reasonable progress factors, as well as visibility.

We do note that based on comments we received and having given the matter further consideration, we realize that Arkansas' consideration of capital costs in the four-factor analysis for the Independence facility is not appropriate because the state's decision to consider capital costs was rooted in Entergy's anticipated early cessation of coal combustion at the Independence facility, which is not state- or federally-enforceable. Considering the capital costs of controls in this context would be equivalent to inappropriately assuming a shorter remaining useful life for Independence in the cost-effectiveness calculation based on an unenforceable measure to change future operations. Therefore, we are clarifying that our evaluation and conclusion in this final action that Arkansas' reasonable progress determination is reasonable does not rely on Arkansas' consideration of capital costs. EPA's long-standing position in other regional haze actions is that consideration of certain cost metrics such as capital costs and $/dv are not appropriate bases for rejecting controls that would have otherwise been determined to be reasonable. However, given the totality of the circumstances in this case, including the SIP's requirement for Independence Units 1 and 2 to switch to low sulfur coal within 3-years under the long-term strategy, the anticipated emissions reductions due to the implementation of BART controls required by the SIP revision,[54] and the anticipated cessation of coal combustion at Independence by the end of 2030, we continue to find that Arkansas reasonably exercised its discretion in determining that no SO_2 controls are necessary under reasonable progress for the Independence facility in the first implementation period. We do note that we are merely clarifying the basis for our approval of Arkansas' reasonable progress determination, but the outcome of our evaluation and our decision to approve the state's reasonable progress determination remain unchanged from proposal.

Comment: EPA should disapprove Arkansas' method of identifying sources for further analysis under reasonable progress because Arkansas failed to appropriately evaluate area sources, in particular concentrated animal feeding operations (CAFO's). This is despite clear evidence in the record that area sources, such as CAFO's, are a significant part of the haze problem in Arkansas. CAFO's, which are a source of ammonia emissions, are likely a significant contributor to haze in Arkansas and ADEQ should have evaluated the cost-effectiveness of controlling emissions from these sources.

Response: We disagree with the commenter that Arkansas' reasonable progress analysis was inappropriate with respect to its treatment of area sources, which includes CAFO's. EPA's Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program (EPA's Reasonable Progress Guidance) provides that the reasonable progress analysis involves identification of key pollutants and source categories that contribute to visibility impairment at the Class I area.[55] The guidance provides that once the key pollutants contributing to visibility impairment at each Class I area have been identified, the sources or source categories responsible for emitting these pollutants or pollutant precursors can also be determined.[56] The reasonable progress factors are then to be applied to the key pollutants and sources or source categories contributing to visibility impairment at each affected Class I area.

The approach taken by Arkansas in its reasonable progress analysis involved an assessment of both region-wide Particulate Source Apportionment Technology (PSAT) data and PSAT data for Arkansas sources.[57] Based on this assessment, Arkansas identified sulfate (SO_4) as the key species contributing to light extinction at Caney Creek and Upper Buffalo. Arkansas further determined that the primary driver of SO_4 formation is emissions of SO_2 from point sources both region-wide and in Arkansas. As such, Arkansas decided to focus on point sources emitting at least 250 tpy of SO_2 to determine whether their emissions and proximity to Arkansas Class I areas warranted further analysis using the four statutory factors. Arkansas did assert that when all source categories within Arkansas are considered, light extinction due to Arkansas area sources is greater compared to the light extinction due to Arkansas point sources at both Caney Creek and Upper Buffalo on the 20% worst days in 2002. However, Arkansas explained that the cost of controlling many individual small area sources may be difficult to quantify. CAFO's fall under the category of small area sources and it is therefore likely that Arkansas would find it difficult to quantify the cost of controlling emissions from CAFO's. While we acknowledge the commenter's concerns regarding the visibility impact of ammonia emissions from CAFO's, we note the BART Guidelines provide that states should use their best judgment in deciding whether ammonia emissions from a source are likely to have an impact on visibility in an area, as controlling ammonia emissions in some areas may not have a significant impact on visibility.[58] The BART Guidelines further provide that given that air quality modeling may not be feasible for individual sources of ammonia, states should also exercise their judgement in assessing the degree of visibility impacts due to emissions of ammonia or ammonia compounds.[59] Since our 2007 Reasonable Progress Guidance does not itself provide recommendations on how sources of ammonia should be addressed in the reasonable progress analysis, we believe it would be reasonable for states to rely on the BART Guidelines in this instance for addressing ammonia emissions under the reasonable progress analysis. Therefore, we find that Arkansas' decision not to evaluate sources of ammonia emissions in its reasonable progress analysis to be reasonable. We find that Arkansas has provided a reasoned basis for the approach it took

[54] See ''Arkansas Regional Haze SO_2 and PM SIP Revision,'' section V.E, page 53.

[55] See EPA's ''Guidance for Setting Reasonable Progress Goals under the Regional Haze Program'' (June 1, 2007), page 3–1. The guidance document can be found at the following link: *https://www3.epa.gov/ttn/naaqs/aqmguide/collection/cp2/20070601_wehrum_reasonable_progress_goals_reghaze.pdf.*

[56] See EPA's ''Guidance for Setting Reasonable Progress Goals under the Regional Haze Program'' (June 1, 2007), page 3–1.

[57] As part of its reasonable progress analysis, ADEQ provided a discussion of the results of air quality modeling performed by the Central Regional Air Planning Association (CENRAP) in support of SIP development in the central states region. The CENRAP modeling included Particulate Source Apportionment Technology Tool (PSAT) with CAMx version 4.4, which was used to provide source apportionment by geographic regions and major source categories for pollutants that contribute to visibility impairment at each of the Class I areas in the central states region.

[58] 40 CFR part 51, appendix Y, II(A)(3).

[59] 40 CFR part 51, appendix Y, II(A)(3).

to identify sources for further consideration in the reasonable progress analysis and we find that it is reasonable for Arkansas to arrive at the decision not to further examine area sources in its reasonable progress analysis for the first implementation period. We also note that states may prioritize their planning in the manner that best suits their circumstances, so long as they demonstrate that their prioritization is reasonable given the statutory requirement to make reasonable progress. Our 2007 Reasonable Progress Guidance provides that states may wish to defer emission reductions to later planning periods, which ADEQ cites in its SIP,[60] since the long-term goal of no manmade impairment encompasses several planning periods.[61] We find that ADEQ has appropriately decided to focus on the point source category for evaluation of SO_2 emissions reductions in the reasonable progress analysis for the first planning period. In future planning periods, it may be appropriate for Arkansas to reevaluate the benefit of addressing emissions from area sources, which will likely become more important as emissions from other source categories are reduced.

Comment: Although the commenter supports EPA's proposal to approve ADEQ's reasonable progress determination, which requires no additional controls on sources in Arkansas for the first planning period, the commenter believes that a four-factor analysis was not required because controls are not necessary to ensure reasonable progress for the first planning period. The threshold issue when addressing reasonable progress is whether further actions are necessary to ensure that visibility improvement is continuing toward background levels (*i.e.,* on or below the uniform rate of progress (URP)). Since Arkansas' Class I areas are below the URP and are already meeting the RPGs Arkansas established in the SIP revision, a reasonable progress analysis was not required.

Response: While we appreciate the commenter's support of our proposed approval of Arkansas' reasonable progress determination, we disagree with the commenter that it was not necessary for Arkansas to conduct a reasonable progress analysis for the first implementation period. The Clean Air Act requires that states' SIPs contain a long-term strategy for making reasonable progress, and that in determining reasonable progress states must consider the very four-factor analysis which the commenter purports is not needed. The Regional Haze Rule implements the statutory requirements and provides that states must determine whether controls are necessary to ensure reasonable progress based on four statutory factors. The preamble to the 1999 Regional Haze Rule states that ''. . . EPA is not specifying in this final rule what specific control measures a State must implement in its initial SIP for regional haze. That determination can only be made by a State once it has conducted the necessary technical analyses of emissions, air quality, and the other factors that go into determining reasonable progress.'' [62] The Regional Haze Rule clearly states that the technical analysis of the four factors that determines what is necessary for reasonable progress occurs prior to a reasonable progress determination, including in cases where the reasonable progress determination is that no further controls are required under reasonable progress.[63]

CAA section 169A(g)(1) provides that reasonable progress is determined by consideration of (1) the costs of compliance, (2) the time necessary for compliance, (3) the energy and nonair quality environmental impacts of compliance, and (4) the remaining useful life of any existing source subject to such requirements. The Regional Haze regulations under § 51.308(d)(1)(i)(A) also require consideration of these four statutory factors when establishing the RPGs for a Class I area, along with a demonstration showing how these factors were taken into consideration in selecting the goal.

The statute and regulations are both clear that the states have the authority and obligation to evaluate the four reasonable progress factors and that the decision regarding the controls required to make reasonable progress and the subsequent establishment of the RPGs must be based on these factors identified in CAA section 169A(g)(1) and the Regional Haze regulations under § 51.308(d)(1)(i)(A). The URP framework is not based on the four statutory factors, but is instead an analytical tool created by extrapolating emission reductions from the mid-1990s through approximately 2005 into the future.[64] While § 51.308(d)(1)(i)(B) of the Regional Haze regulations requires that a state also consider the URP glidepath in establishing the RPGs, this does not mean that no further analysis or controls are required as long as a state's Class I areas are below the URP, as the commenter contends. In fact, the preamble to the 1999 Regional Haze Rule reinforces that the amount of progress that is reasonable is defined based on the statutory factors, notwithstanding the URP.[65] Clearly, a state's obligation to evaluate the four statutory factors and set RPGs based on CAA section 169A(g)(1) and § 51.308(d)(1) applies in all cases, without regard to the Class I area's position relative to the URP. There is nothing in the CAA or Regional Haze regulations that suggests that a state's obligation to ensure reasonable progress can be met by just meeting the URP.[66]

We note that our conclusion here is consistent with our final action on the 2008 Arkansas Regional Haze SIP, where we disapproved Arkansas' RPGs and found that Arkansas had not met its reasonable progress obligations precisely because the state established its RPGs without conducting an evaluation of the four statutory factors and did so based on the fact that its Class I areas were below the URP glidepath. In the preamble to our final action on the 2008 Arkansas Regional Haze SIP, we were clear that an evaluation of the four statutory factors is required regardless of the Class I area's position relative to the URP glidepath:

> [B]eing on the ''glidepath'' does not mean a state is allowed to forego an evaluation of the four statutory factors when establishing its RPGs. Based on an evaluation of the four statutory factors, states may determine that RPGs that provide for a greater rate of visibility improvement than would be achieved with the URP for the first implementation period are reasonable.[67]

Our final action on the Arkansas Regional Haze SIP was published in the **Federal Register** on March 12, 2012, and became effective on April 11, 2012. Our final action disapproving Arkansas' reasonable progress determination and RPGs and our position with regard to the URP was not challenged. We reiterate in this final action that the CAA and Regional Haze regulations require an analysis of the four reasonable progress factors regardless of a Class I area's position relative to the URP and that being below the glide path

[60] See pages 28–53 of Arkansas Final Regional Haze Phase II SIP. *https://www3.epa.gov/ttn/naaqs/aqmguide/collection/cp2/20070601_wehrum_reasonable_progress_goals_reghaze.pdf.*

[61] See Section 1.2 of EPA's ''Guidance for Setting Reasonable Progress Goals under the Regional Haze Program'' (June 1, 2007). *https://www3.epa.gov/ttn/naaqs/aqmguide/collection/cp2/20070601_wehrum_reasonable_progress_goals_reghaze.pdf.*

[62] 64 FR 35721.

[63] See 64 FR 35714 at 35721 and 35731–35735 and 35734 (July 1, 1999).

[64] See 64 FR 35731–35733.

[65] 64 FR 35732.

[66] See 77 FR 14604, at 14629.

[67] 77 FR 14629.

does not automatically mean that no controls are necessary under reasonable progress.

With regard to the commenter's argument that it was not necessary for Arkansas to conduct a four-factor analysis given that Arkansas Class I areas are already meeting the RPGs established in the SIP revision, we note first that this is a circular argument. The numeric RPGs are calculated by taking into account the visibility improvement anticipated from enforceable emission limitations and other control measures (including BART, reasonable progress, and other ''on the books'' controls). Thus, the RPGs for the first planning period represent the best estimate of the degree of visibility improvement that will result in 2018 from changes in emissions inventories, changes driven by the particular set of control measures the state has adopted in its regional haze SIP to address visibility, as well as all other enforceable measures expected to reduce emissions over the period of the SIP from 2002 to 2018.[68] To argue that a four-factor analysis is not needed because the RPGs, which are based in part on the outcome of that very four-factor analysis, are at a certain level is circular. Furthermore, the Regional Haze Rule provides that the emission limitations and control measures established under BART and under the reasonable progress determinations are what is enforceable, not the RPGs themselves.[69] EPA cannot enforce an RPG in the sense of seeking to apply penalties on a state for failing to meet the RPG or obtaining injunctive relief to require a state to achieve its RPG. However, the long-term strategy can and must contain emission limits and other control measures that apply to specific sources, and that are themselves enforceable. Meeting or being projected to meet the RPG does not automatically demonstrate that a state has satisfied its requirements under BART and reasonable progress.

Comment: The commenter supports EPA's proposal to approve ADEQ's reasonable progress determination, which requires no additional controls on sources in Arkansas for the first planning period. However, Arkansas' reasonable progress analysis ''broadly applicable'' to Arkansas sources was sufficient to satisfy the reasonable progress requirements and Arkansas surpassed the CAA requirements when it nonetheless undertook an analysis that applied the four reasonable progress factors to the Independence facility. EPA inappropriately proposed to conclude that the broad analysis was merely ''informative'' and ''not a determinative component of the state's reasonable progress analysis.'' Even if a four-factor analysis were necessary in this case, ADEQ's broad analysis was sufficient to satisfy its reasonable progress obligations, making a site-specific four-factor analysis for Independence unnecessary. ADEQ's broad approach was appropriate, as there is no requirement that a reasonable progress analysis be performed on a source-specific basis. EPA should conclude that this broad analysis was sufficient and rendered further analysis, including any source-specific four-factor analysis, unnecessary.

Response: While we appreciate the commenter's support of our proposed approval of ADEQ's reasonable progress determination, we disagree with the commenter that the broad analysis included in ADEQ's SIP revision satisfies this reasonable progress obligation and note that it is not a basis for our approval of ADEQ's reasonable progress analysis. While it may not be necessary to conduct a source-specific analysis of the four factors in all instances to satisfy the reasonable progress obligations,[70] we do not agree that the broad analysis provided in ADEQ's SIP revision complies with the applicable statutory and regulatory requirements. As discussed further below, the broad analysis of a group of sources provided by ADEQ in the SIP revision does not clearly identify any sources or controls that were evaluated in the state's weighing of the costs and other statutory factors nor did it estimate in specific numeric form the cost of controls, making it clear that the dispositive consideration in the broad analysis was visibility conditions with respect to the URP.[71] Therefore, we find that the broad analysis presented in the SIP revision does not satisfy Arkansas' reasonable progress obligations. ADEQ's broad analysis does not discuss pollutants or identify possible specific controls for these pollutants or for source categories for these pollutants. Instead, in evaluating the costs of compliance, the broad analysis discusses in a very generic manner the anticipated impact of additional costs of compliance on the health and vitality of industries within the state and on Arkansas ratepayers, without ever even identifying the potential controls or discussing actual cost estimates.

Moreover, ADEQ itself deemed the application of the four factors to the Independence facility necessary, stating in the SIP revision that ''due to the circumstances of the 2016 AR RH FIP, which applied the factors to a single facility, Independence, ADEQ has determined that application of the four factors to the specific source analyzed by EPA is also ''relevant.'' [72] The SIP revision further explains that for this reason, ''ADEQ has performed both a broader analysis using the four factors as well as a more narrow analysis specific to Independence before determining whether any controls are necessary.'' [73] ADEQ did not reach a final determination regarding reasonable progress until after evaluating large point sources individually to identify sources for potential further evaluation under the four reasonable progress factors and conducting a more narrow and focused analysis on those sources. In this case, one source was identified for further evaluation under the four reasonable progress factors, specifically, the Independence facility. Therefore, we are concluding that the state's broad analysis of a group of sources was not a determinative component of the state's reasonable progress analysis. We appreciate the thoroughness of the state's reasonable progress analysis but reiterate and clarify, as necessary, here that the broad analysis is not a component of our finding that the state has satisfied the reasonable progress requirements.[74]

Although we disagree with the commenter that the broad analysis included in ADEQ's SIP revision satisfies Arkansas' reasonable progress obligations, we are finalizing our proposed approval of ADEQ's reasonable progress determination based on the following: (1) The state's discussion of the key pollutants and source categories that contribute to visibility impairment in Arkansas' Class I areas per the CENRAP's source apportionment modeling; (2) the state's identification of a group of large SO_2 point sources in Arkansas for potential evaluation of controls under reasonable progress; (3) the state's rationale for narrowing down its list of potential sources to evaluate under the reasonable progress requirements; and (4) the state's evaluation and reasonable

[68] 64 FR 35733.

[69] 64 FR 35733.

[70] On the contrary, we discussed in our proposal that we agree that an approach that involves a broad analysis of groups of sources or source categories may be appropriate in certain cases, as provided by EPA's Reasonable Progress Guidance. 83 FR 62232.

[71] 83 FR 62232.

[72] See ''Arkansas Regional Haze SO_2 and PM SIP Revision,'' section V, page 30.

[73] See ''Arkansas Regional Haze SO_2 and PM SIP Revision,'' section V, page 30.

[74] *See* 83 FR 62233 (laying out the four components of ADEQ's reasonable progress analysis on which EPA based its proposed approval).

weighing of the four statutory factors along with consideration of the visibility benefits of controls for the Independence facility.

Comment: No additional controls can be considered for reasonable progress at sources in Arkansas since no controls could be implemented before the end of the first planning period in 2018. EPA's regulations require SIPs to consider ''the emission reduction measures needed to achieve [reasonable progress goals] for the period covered by the implementation plan.'' 40 CFR 51.308(d)(1)(i)(B). In staying the effectiveness of EPA's Regional Haze FIP for the state of Texas, the U.S. Court of Appeals for the Fifth Circuit explained that ''[t]he emissions controls included in a state implementation plan . . . must be those designed to achieve the reasonable progress goal for the period covered by the plan,'' and that the parties challenging the FIP ''persuasively argue that [EPA's requirement that power plants meet Reasonable Progress goals by installing scrubbers in 2019 and 2021] exceeds the power granted by the Regional Haze Rule.'' *Texas* v. *EPA,* 829 F.3d 405, 429 (5th Cir. 2016) (internal citations omitted). It is therefore inappropriate to require reasonable progress controls in a SIP for the first planning period when the controls cannot be installed or result in visibility benefits in that planning period.

Response: The Fifth Circuit stay decision cited by the commenter suggested that it was likely that the EPA had exceeded its statutory authority by imposing emission controls that go into effect after the end of the implementation period in the Texas Regional Haze FIP. This assessment is incorrect. First, we note that the decision, by a Fifth Circuit motions panel, did not cite to a provision of the CAA to support the proposition that the EPA exceeded its statutory authority, as the CAA contains no such constraint. Subsequent to the Fifth Circuit decision to grant a stay of the EPA's Texas FIP, EPA finalized its revisions to the Regional Haze Rule, and, in the process, clarified its long-standing interpretation of the relationship between long-term strategies and RPGs. As stated in the final rule, ''portions of the stay decision indicate a fundamental misunderstanding of aspects of the visibility program and the EPA's action on the Oklahoma and Texas regional haze SIPs.'' 82 FR 3078, 3087 (January 10, 2017). CAA section 169A(b)(2)(B) requires that SIPs include ''a long-term (ten to fifteen years) strategy for making reasonable progress toward meeting the national goal.'' In our rulemaking, we noted that ''ten to fifteen years'' was ambiguous and could either mean that the long-term strategy must be updated every ten to fifteen years or that it must be fully implemented within ten to fifteen years. To impose the latter interpretation would restrict states' or the EPA's ability to require controls that could not be fully implemented before the end of the implementation period and would incentivize states to delay the submission of a regional haze SIP since they could essentially ''run out the clock.'' Further, EPA's 2007 reasonable progress guidance specifically recognized that the time needed for full implementation of a control measure might extend beyond the end of the implementation period.[75] Additionally, EPA does not lose its authority to regulate after a deadline, even a mandatory deadline, has passed; rather, the appropriate remedy is a court order compelling the agency to fulfill the regulatory obligation. For a more in-depth discussion on this issue, please see our final rule at 82 FR 3078, 3087–3089.

Comment: Although EPA should finalize its approval of ADEQ's reasonable progress determination, EPA's analysis of the application of DSI and enhanced DSI at the Independence facility should not be part of EPA's final action. ADEQ did not assess these two control technologies in its four-factor analysis for Independence, nor was it required to. Therefore, EPA's DSI and enhanced DSI analyses are inappropriate and extraneous and should not be included in the final action, as EPA has no authority under the CAA to substitute its judgment for that of the state's. Nevertheless, the commenter does agree that DSI and enhanced DSI are not required under reasonable progress.

Response: We appreciate the commenter's support of our proposal to approve ADEQ's reasonable progress determination. While ADEQ's decision to not evaluate DSI or enhanced DSI at the Independence facility does not change the result of the state's determination and we are therefore approving that determination here, we disagree that our analysis of DSI and enhanced DSI at Independence should not be part of our final action. As we explained in our proposal, since the White Bluff and Independence facilities are sister facilities with nearly identical units and comparable levels of annual SO_2 emissions, and since both DSI and enhanced DSI were evaluated in the BART analysis for White Bluff Units 1 and 2, we find it appropriate to consider these controls in the four-factor analysis for the Independence facility as well.[76] However, neither the SIP revision nor Entergy's four factor analysis for controls on the Independence facility considered DSI or enhanced DSI as control options. Therefore, we provided this information in our proposal to demonstrate that even if ADEQ had considered DSI and enhanced DSI in its reasonable progress analysis for the Independence facility, it likely would not have changed the state's final determination on reasonable progress.[77] We note that we estimated the cost-effectiveness of DSI and enhanced DSI at the Independence facility by relying on Entergy's estimates of the capital costs and annual operation and maintenance costs of these controls for White Bluff. Thus, based on the results of our analysis of DSI and enhanced DSI, we do not consider the omission of consideration of DSI and enhanced DSI as control options for SO_2 at the Independence facility to be an impediment to approving ADEQ's reasonable progress analysis. Without the results of our analysis of DSI and enhanced DSI for the Independence facility, we would not be able to arrive at the conclusion that ADEQ's omission did not impact our ultimate conclusion regarding the state's reasonable progress analysis. Therefore, we disagree with the commenter that our analysis of DSI and enhanced DSI for the Independence facility is unnecessary in our review and approval of ADEQ's reasonable progress analysis.

Comment: The commenter agrees that Independence is not subject to BART, that no additional controls beyond use of low-sulfur coal at Independence are necessary to achieve reasonable progress and agrees with the adoption of low-sulfur coal as the long-term strategy for Independence.

Response: We appreciate the commenter's support of our proposal with respect to the Independence facility and the long-term strategy.

C. Clean Air Act Section 110(l)

Comment: EPA's proposed rule as a whole violates the Clean Air Act's ''anti-backsliding'' requirement, 42 U.S.C. 7410(*l*). Compared to the existing FIP, the State's plan would result in greater air pollution and greater visibility impairment at affected Class I areas. In the 2016 Arkansas FIP, EPA required Independence Units 1 and 2 to meet SO_2 emission limits based on the use of new

[75] See Guidance for Setting Reasonable Progress Goals under the Regional Haze Program, June 1, 2007.

[76] 83 FR 62232.

[77] 83 FR 62232.

scrubbers under the reasonable progress provisions. Now, EPA has proposed to approve a SIP revision that would replace those SO_2 emission limits with much higher limits based on the use of low-sulfur coal. In addition, whereas the existing FIP requires White Bluff Units 1 and 2 to meet SO_2 emission limits based on the use of new scrubbers, the proposed SIP revision would replace that requirement with a much higher emission limit based on the use of low sulfur coal. The SIP revision includes no reductions beyond those in the FIP that would compensate for allowing higher SO_2 emissions from both Independence and White Bluff. As a result, EPA's proposed rule would authorize significantly more SO_2 emissions and produce worse air quality than the existing FIP. Section 110(*l*) of the Clean Air Act prohibits a plan revision that would weaken the existing FIP requirements in this manner. This increase in SO_2 emissions under the SIP relative to the FIP violates the Clean Air Act's anti-backsliding provision, which prohibits plan revisions that would interfere with attainment of the NAAQS or other ''applicable requirements'' of the Act and prohibits plan revisions that would interfere with an existing requirement to make reasonable further progress.

Response: We disagree that our rulemaking violates the CAA's requirements under section 110(l). The commenter mischaracterizes CAA section 110(l)'s requirements. Section 110(l) states that, ''[t]he Administrator shall not approve a revision of a plan if the revision would interfere with an applicable requirement concerning attainment and reasonable further progress or any other applicable requirement of this chapter.'' First, the SIP revision will not interfere with the ''applicable requirements'' of the regional haze program. The CAA requires that the SIP ''contain such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal.'' The corresponding federal regulations found at 40 CFR 51.308 and appendix Y to part 51 detail the required process for determining the appropriate emission limits for the regional haze program. The State followed the prescribed process for determining the levels of control that are required for BART and reasonable progress. Our approval of the SIP revision is supported by our evaluation of the state's conclusions and our determination that the BART and reasonable progress requirements under the CAA are met. The rationale supporting that determination was presented in the notice of proposed rulemaking for this action.[78] For these reasons, our final approval of the SIP revision and concurrent withdrawal of the corresponding parts of the FIP will not interfere with the CAA requirements for BART or reasonable progress.

Second, the SIP revision will not interfere with any applicable requirement concerning attainment and reasonable further progress. EPA interprets CAA section 110(l) as applying to all NAAQS that are in effect, including those that have been promulgated but for which EPA has not yet made designations. EPA has concluded that 110(l) can be satisfied by demonstrating that substitute measures ensure that status quo air quality is preserved. However, 110(l) can also be satisfied by an air quality analysis demonstrating that any change in emissions will not interfere with any applicable requirement concerning attainment and reasonable further progress, or any other applicable CAA requirement. Noninterference with attainment of the NAAQS may be demonstrated by an air quality analysis showing that any emission changes associated with the revision will not interfere with attainment of the NAAQS. This option requires a showing that the area (as well as interstate and intrastate areas downwind) can attain the NAAQS even with the plan in its revised form. *See, e.g. Kentucky Resources Council, Inc.* v. *EPA,* 467 F.3d 986 (6th Cir. 2006).

Though the commenter is correct in noting that the higher SO_2 emission limits for White Bluff Units 1 and 2 contained in the SIP are replacing the more stringent SO_2 emission limits contained in the FIP, the commenter fails to consider that the SIP revision contains an Administrative Order making enforceable Entergy's voluntary plans to cease coal combustion at White Bluff Units 1 and 2 by December 31, 2028. Because the cessation of coal combustion will lead to emission reductions greater than the SO_2 emission reductions required for White Bluff under the FIP, the SIP revision with respect to the SO_2 limits for White Bluff will clearly not interfere with attainment and reasonable further progress in the long term (*i.e.,* after December 31, 2028).

While it is true that the FIP included more stringent SO_2 emission limits for Independence Units 1 and 2 than the SIP revision,[79] there is no evidence that withdrawal of the SO_2 limits in the FIP for White Bluff and Independence and the approval of the SO_2 emission limits in the SIP revision will interfere with attainment of the SO_2 NAAQS. At this time, and notwithstanding the fact that the FIP provisions have not gone into effect, the areas that would be potentially impacted by the increase in SO_2 emissions allowed under the SIP revision as compared to the FIP are attaining the 1-hour SO_2 NAAQS. Based on an assessment of current air quality in the areas most affected by this SIP revision, which we discuss in the paragraphs that follow, we are concluding that the near term less stringent SO_2 emissions limits in the SIP will not interfere with attainment of the NAAQS. Jefferson County, where the White Bluff facility is located, was designated by EPA as ''attainment/unclassifiable,'' for the 2010 1-hour SO_2 NAAQS in a rulemaking signed on June 30, 2016.[80] This area was able to attain the 2010 1-hour SO_2 NAAQS without the emissions limits that were promulgated in the FIP being implemented. In the same June 30, 2016 rulemaking, EPA designated Independence County, where the Independence facility is located, as ''unclassifiable'' for the 2010 1-hour SO_2 NAAQS.[81] In a subsequent rulemaking signed on March 7, 2019, EPA approved the State of Arkansas' request to redesignate Independence County from unclassifiable to attainment/unclassifiable based on a new modeling analysis provided by the State.[82] In a rulemaking signed on December 21,

[78] 83 FR 62204.

[79] Entergy plans to cease coal combustion at Independence Units 1 and 2 by December 31, 2030, which we expect would result in comparable or greater SO_2 emissions reductions than required for the Independence facility under the FIP. However, this planned cessation of coal combustion at the Independence units by the end of 2030 is not required under the SIP revision.

[80] The EPA's attainment/unclassifiable designation for Jefferson County was based on, among other things, our evaluation of the State's modeling that showed attainment, and which we concluded generally followed EPA guidance. See 81 FR 45039 (July 12, 2016).

[81] The EPA's unclassifiable designation for Independence County was based on, among other things, our evaluation of the State's air dispersion modeling analysis, as well as the additional modeling analysis submitted by environmental groups for the area surrounding the Independence Steam Electric Station. Based on our evaluation of these analyses and our consideration of all available data and information, the EPA determined that the area cannot be classified as meeting or not meeting the NAAQS based on information available at the time. See 81 FR 45039 (July 12, 2016).

[82] EPA determined that the modeling analysis submitted by the State appropriately characterized the air quality in Independence County, Arkansas, and predicted that ambient SO_2 concentrations are below the 1-hour SO_2 NAAQS. See 84 FR 8986 (March 13, 2019).

2017, EPA designated all remaining areas in Arkansas as attainment/unclassifiable.[83] On March 18, 2019, EPA finalized a rule which retained the 2010 1-hour SO_2 standard. At the time that Independence County, Jefferson County, and all other areas in Arkansas were designated or redesignated as attainment/unclassifiable under the 2010 1-hour SO_2 NAAQS in June 2016, December 2017, and March 2019, Independence Units 1 and 2 and White Bluff Units 1 and 2 were emitting SO_2 at levels not restricted by SIP or FIP limits. So the establishment of the SIP limits based on low sulfur coal will not interfere with attainment of the SO_2 NAAQS in the near term. In the long term, the cessation of coal combustion at White Bluff will result in more reductions in SO_2 emissions than the FIP and will result in further improvement in air quality.

Since sulfate is a precursor to particulate matter, there is also a need to address whether withdrawal of the FIP and approval of the SIP revision will interfere with attainment of the PM NAAQS. There is no evidence that withdrawal of the SO_2 limits in the FIP and the approval of the SO_2 emission limits in the SIP revision will interfere with attainment of the PM NAAQS. At this time, and notwithstanding the fact that the FIP provisions have not gone into effect, the areas that would be potentially impacted by the increase in SO_2 emissions are attaining the 2012 annual $PM_{2.5}$ NAAQS. In a **Federal Register** document signed on January 15, 2015, EPA designated all areas in Arkansas as unclassifiable/attainment under the 2012 annual $PM_{2.5}$ NAAQS.[84] All areas in Arkansas were able to attain the 2012 annual $PM_{2.5}$ NAAQS before the SO_2 and PM emissions limits from the FIP were promulgated.

While the FIP provisions might have produced better air quality than the provisions we are approving into the SIP, CAA section 110(l) does not require that each SIP revision include greater emissions reductions than the plan being revised or replaced. Instead, section 110(l) requires a showing that approval of the SIP revision will not interfere with attainment and reasonable further progress or any other applicable CAA provision. In this case, the relevant areas are attaining the SO_2 and PM NAAQS even though the units at White Bluff and Independence are emitting SO_2 at levels not restricted by SIP or FIP limits. Thus, by approving the State's 0.60 lb/MMBtu SO_2 emission limits for White Bluff Units 1 and 2 and Independence Units 1 and 2, the EPA is approving limits that will further reduce emissions from the levels that were already sufficient to designate the potentially impacted areas as attainment/unclassifiable for both the 1-hour SO_2 NAAQS and the 2012 annual $PM_{2.5}$ NAAQS. Thus, there is no evidence to suggest that areas will not continue to attain the NAAQS following our approval of the SIP and concurrent withdrawal of the FIP.[85] Therefore, we find that EPA approval of the 0.60 lb/MMBtu SO_2 BART emission limits for White Bluff Units 1 and 2 and the 0.60 lb/MMBtu SO_2 emission limits for Independence Units 1 and 2 under the long-term strategy will not interfere with attainment of the 2010 1-hour SO_2 NAAQS or the 2012 annual $PM_{2.5}$ NAAQS under CAA section 110(l).

Additionally, since there are no areas in Arkansas designated nonattainment under the 2010 1-hour SO_2 NAAQS or the 2012 annual $PM_{2.5}$ NAAQS, the increase in SO_2 emissions would not impact any such nonattainment areas in the state. We are also not aware of any nonattainment areas in downwind states that are likely to be impacted by these emissions.

While the comment appears to focus on SO_2 controls for the White Bluff and Independence facilities, to the extent that the commenter is contending that the SO_2 emission limits we are taking final action to approve for other facilities would also violate the CAA's requirements under section 110(l), we note that this claim is incorrect. As explained above, one way of demonstrating noninterference is by showing that the status quo air quality will be preserved. In this case, the SO_2 controls for all other sources in the Phase II SIP revision (*i.e.,* AECC Bailey Unit 1, AECC McClellan Unit 1, AEP/SWEPCO Flint Creek Plant Boiler No. 1, Entergy Lake Catherine Unit 4, and the Entergy White Bluff Auxiliary Boiler), which we are taking final action to approve, are identical to those contained in the Arkansas FIP. All the PM BART controls in the Phase II SIP revision, which we are taking final action to approve, are also identical to those contained in the Arkansas FIP.

Comment: EPA's approval of ADEQ's SIP revisions is appropriate even though the SIP revision is not based on installation of the same control technology that was used to set the limits for White Bluff and Independence in the currently stayed FIP. While EPA has interpreted the CAA's anti-backsliding provision as allowing the Agency ''to approve a SIP revision unless the agency finds it will make the air quality worse,'' that standard is inapplicable here where the existing requirements have not yet gone into effect and are the subject of administrative and judicial challenges. Specifically, the SO_2 requirements for White Bluff and Independence were judicially stayed and cannot be deemed to represent the existing limitations applicable to the units. Thus, nothing in the SIP revision ''weakens or removes any pollution controls.'' To the contrary, the SIP revision would impose emission limitations that are better than the status quo.

Response: We agree with the commenter's assertion that, in this particular case, our approval of the SIP is appropriate even though the SIP revision is not based on installation of the same control technology that was used to set the limits for White Bluff and Independence in the FIP. However, we disagree with the commenter's characterization of the requirements of CAA 110(l) and the commenter's characterization of EPA's interpretation of those requirements. Under section 110(l) of the CAA, the EPA cannot approve a plan revision if the revision would interfere with any applicable requirements concerning attainment and reasonable further progress of the NAAQS, or any other applicable requirement of the Act. Section 110(l) applies to all requirements of the CAA and to all areas of the country regardless of their attainment status. To evaluate whether a plan revision would interfere with any requirements, air pollutants

[83] The EPA's designations for remaining areas in the state were based on an assessment and characterization of air quality through ambient air quality data, air dispersion modeling, other evidence and supporting information, or a combination of the above. See 83 FR 1098 (January 9, 2018).

[84] 80 FR 2206.

[85] We also note that for any area where modeling of actual SO_2 emissions served as the basis for designating such area as attainment of the 2010 1-hour SO_2 NAAQS, the SO_2 Data Requirements Rule under 40 CFR 51.1205 requires the submission of an annual report that documents the annual SO_2 emissions of each applicable source in each such area and provides an assessment of the cause of any emissions increase from the previous year. That report must also include a recommendation regarding whether additional modeling is needed to characterize air quality in any area to determine whether the area continues to meet the 2010 1-hour SO_2 NAAQS. Since modeling of actual SO_2 emissions served as the basis for EPA's designation of Jefferson County, where the White Bluff facility is located, and redesignation of Independence County, where the Independence facility is located, this annual reporting requirement applies to ADEQ. The data and other information provided by ADEQ in this annual report will help EPA assess whether actual annual SO_2 emissions from White Bluff, Independence, and other sources in Arkansas have increased to such an extent that there is uncertainty as to whether the areas where these sources are located continue to meet the 2010 1-hour SO_2 NAAQS. At this time, no reports have been submitted by ADEQ that indicate that revised modeling of SO_2 emissions from sources in Jefferson and Independence Counties is warranted.

whose emissions and/or ambient concentrations may change as a result of the revision must be identified. Noninterference with attainment of the NAAQS may be demonstrated by an air quality analysis showing that any emission changes associated with the revision will not interfere with attainment of the NAAQS. This option requires a showing that the area (as well as interstate and intrastate areas downwind) can attain the NAAQS even with the plan in its revised form. Noninterference may also be demonstrated by showing that the status quo air quality is preserved by the use of substitute measures to compensate for any emissions increases associated with the revision. *See Kentucky Resources Council* v. *EPA,* 467 F.3d 986 (6th Cir. 2006). A revision that maintains the status quo would not interfere with attainment of the NAAQS. *See Wildearth Guardians* v. *EPA,* 759 F.3d 1064 (9th Cir. 2014). In general, the level of rigor needed for any 110(l) demonstration will vary depending on the nature of the revision, its potential impact on air quality and the air quality in the affected area.

D. Modeling

Comment: We received comments arguing that the CALPUFF model is unreliable and should not be used in making BART determinations. A commenter stated that although CALPUFF may have had some limited utility in the BART screening process, it should not be used in making an SO_2 BART determination for White Bluff due to its purported limitations in accuracy and precision given the distances to Class I areas and the atmospheric conditions involved, as well as limited chemistry mechanism and blanket background ammonia values. One commenter presumed that CAMx modeling for White Bluff would likely show negligible visibility improvements from each of the SO_2 controls evaluated and contended that SO_2 BART is therefore the use of low sulfur coal even without Entergy's voluntary decision to cease coal combustion at White Bluff. Commenters also argued that CALPUFF is no longer an EPA preferred model, and that EPA should instead rely on the Comprehensive Air Quality Model with Extensions (CAMx), which the commenter claims is more reliable in characterizing visibility impairment.

Response: As we discuss in the Response to Comments (RTC) Document associated wih this rulemaking [86] and the RTC Document associated with the Arkansas Regional Haze FIP,[87] the use of CALPUFF in the context of the Regional Haze rule provides results that can be used to evaluate the level of visibility benefits anticipated for each level of control and is one of several factors considered in the overall BART determination. In the rulemaking for the BART Guidelines, we responded to comments concerning the limitations and appropriateness of using CALPUFF, and we further addressed similar comments in the RTC document associated with the Arkansas Regional Haze FIP. We stated in the BART Guidelines that the visibility results from CALPUFF could be used as one of the five factors in a BART evaluation and the impacts could be utilized because CALPUFF was the best modeling method available to calculate potential impacts for a BART evaluation.[88] The regulatory status of CALPUFF was changed in the recent revisions to the Guideline on Air Quality Models (GAQM) [89] as far as the classification of CALPUFF as a preferred model for transport of pollutants for primary impacts, not impacts based on chemistry. The GAQM changes indicated that the change in model preferred status had no impact on the use of CALPUFF to determine the applicability of BART or the BART determination itself.[90] CALPUFF is an appropriate tool for BART evaluations and remains the recommended model for BART.

The commenter contends that CALPUFF may have had some limited utility in the BART screening process (*i.e.,* making ''subject-to-BART'' determinations), but that its use for making a BART determination for White Bluff is not appropriate. We disagree with this contention. The BART Guidelines provide that states should establish a threshold that should be no higher than 0.5 deciviews for determining whether sources contribute to visibility and are therefore subject to BART [91] and recommend the use of CALPUFF [92] to predict the visibility impacts from a single source at a Class I area to compare against this threshold as well as to help inform the BART determination.[93] The CALPUFF modeling ADEQ relied on in its SO_2 BART determination for White Bluff is consistent with the BART Guidelines and Appendix W. Nearly every BART determination made since the promulgation of the Regional Haze Rule and the BART Guidelines has utilized the CALPUFF modeling method in analyzing impacts. Absent any additional information that would justify not using the CALPUFF model in this particular case, it is appropriate for the state to rely on CALPUFF modeling as it has done to support the White Bluff BART determination, consistent with the modeling for nearly every other BART determination EPA has reviewed and acted upon. EPA also concluded from the evaluation of the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Report case studies that the CALPUFF dispersion model performs in a reasonable manner and has no apparent bias toward over or under prediction, so long as the transport distance is limited to less than 300 km.[94] [95] We note that since the BART Guidelines were finalized in 2005

[86] See ''Arkansas Regional Haze Phase II SIP Revision Response to Comments,'' which can be found in the docket associated with this final rulemaking.

[87] See ''Response to Comments for the **Federal Register** Notice for the State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan,'' dated 8/31/2016. See Docket ID. EPA–R06–OAR–2015–0189, Document ID. AR020.0187.

[88] 70 FR 39123, 39124. ''We understand the concerns of commenters that the chemistry modules of the CALPUFF model are less advanced than some of the more recent atmospheric chemistry simulations. To date, no other modeling applications with updated chemistry have been approved by EPA to estimate single source pollutant concentrations from long range transport.'' and in discussion of using other models with more advanced chemistry it continues, ''A discussion of the use of alternative models is given in the Guideline on Air Quality in appendix W, section 3.2.''

[89] 82 FR 5182, 5196 (Jan. 17, 2017).

[90] 82 FR 5182, 5196 (Jan. 17, 2017). ''As detailed in the preamble of the proposed rule, it is important to note that the EPA's final action to remove CALPUFF as a preferred appendix A model in this Guideline does not affect its use under the FLM's guidance regarding AQRV assessments (FLAG 2010) nor any previous use of this model as part of regulatory modeling applications required under the CAA. Similarly, this final action does not affect the EPA's recommendation [See 70 FR 39104, 39122–23 (July 6, 2005)] that states use CALPUFF to determine the applicability and level of best available retrofit technology in regional haze implementation plans.''

[91] 40 CFR 51 Appendix Y, III(A)(1): ''As a general matter, any threshold that you use for determining whether a source ''contributes'' to visibility impairment should not be higher than 0.5 deciviews.''

[92] 40 CFR 51 Appendix Y, III(A)(3): ''CALPUFF is the best regulatory modeling application currently available for predicting a single source's contribution to visibility impairment''.

[93] 70 FR 39123: ''. . . we *also* recommend that the States use CALPUFF as a screening application in estimating the degree of visibility improvement that may reasonably be expected from controlling a single source in order to inform the BART determination.''

[94] Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long-Range Transport Impacts. Publication No. EPA–454/R–98–019. Office of Air Quality Planning & Standards, Research Triangle Park, NC. 1998.

[95] See also 68 FR 18458, 2003 Revisions to Appendix W, Guideline on Air Quality Models.

there has been more modeling with CALPUFF for BART and PSD primary impact purposes and the general community has utilized CALPUFF in the 300–450 km range many times. EPA has indicated historically that use of CALPUFF was generally acceptable at 300 km and for larger emissions sources with elevated stacks EPA and FLM representatives have also allowed or supported the use of CALPUFF results beyond 400 km in some cases.[96] EPA and FLM representatives have weighed the additional potential uncertainties with the magnitude of the modeled impacts in comparison to screening/impact thresholds on a case-by-case basis in approving the use of CALPUFF results at these extended ranges. Furthermore, we note that White Bluff is located within 200 km of Caney Creek and Upper Buffalo. Therefore, we find that ADEQ appropriately considered CALPUFF modeling for White Bluff in the SIP revision. We invite the reader to examine our detailed responses to comments arguing against the use of CALPUFF modeling in making BART determinations in the RTC Document associated wih this rulemaking[97] as well as the RTC Document associated with the Arkansas Regional Haze FIP.[98] We find that Arkansas' reliance on CALPUFF modeling in the SIP revision is reasonable and appropriate since it meets the requirements of the CAA and the Regional Haze Rule and is consistent with the BART Guidelines and Appendix W. Therefore, we find no reason to disapprove the SIP's reliance on CALPUFF modeling.

With regard to the comment that CAMx modeling would show that visibility improvements from each of the SO_2 controls evaluated are negligible and that SO_2 BART should therefore be the use of low sulfur coal even without Entergy's voluntary decision to cease coal combustion at White Bluff, we emphasize that the issue of what would constitute BART in the absence of Entergy's enforceable measure to cease burning coal in 2028 is not before the agency in this action. We also note that the CALPUFF results are not an apples to apples comparison to the CAMx model results referred to by the commenter due to differences in metrics, models and model inputs.[99] We discuss this issue and our assessment of CAMx modeling in detail in the RTC Document associated with this rulemaking.[100] In sum, the visibility modeling provided in the SIP revision demonstrates that scrubber controls are anticipated to result in significant visibility benefits.

E. Legal

Comment: EPA cannot approve Arkansas's SIP submission because ADEQ failed to comply with Arkansas's statutory legislative review process for rulemaking by not submitting the Regional Haze SIP for legislative review; the SIP is therefore invalid and unenforceable until ADEQ complies with the law.

Response: It is EPA's position that Arkansas' SIP revision has met applicable requirements for an enforceable SIP, including enforceable emission limitations and other control measures, means, or techniques as well as schedules and timetables for compliance as required under section 110(a)(2)(A). The SIP also includes a program to provide for enforcement of the measures described above, as required by section 110(a)(2)(C). Furthermore, the ADEQ has shown the SIP meets Section 110(a)(2)(F)(i) through (iii) (monitoring and recordkeeping for sources) and section 110(a)(2)(K) (modeling). Section 169A(b)(2) requires a regional haze SIP to contain such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress, including a long-term strategy and certain defined major stationary sources to meet BART. ADEQ's SIP revision included Administrative Orders entered between ADEQ and the companies that own the facilities that are required to comply with emission limits and schedules in compliance with the BART and long-term strategy requirements. Based upon all of the above, it is appropriate for EPA to approve Arkansas SIP revision in accordance with section 110(k)(3).

As part of the state's notice and comment period for the SIP, ADEQ received a comment that ADEQ lacked the authority to implement the SIP revision under state law since the SIP (including the Administrative Orders) did not undergo legislative review. The comment further alleged that EPA cannot approve the SIP until the Arkansas legislature has reviewed the SIP revision. ADEQ responded that the SIP did not need to undergo legislative review per Arkansas state law because, among other things, it does not fit within the state's statutory definition of a ''rule'', rather state law defines SIPs as a plan, the statutory construction of provisions pertaining to plans, and in particular SIPs, exhibits an intent on the part of the Arkansas legislature to create a separate and distinct set of requirements for SIPs, and the SIP is issued by the Director and such action is subject to an appeals process differently from that of a rule. Furthermore, ADEQ has the authority under state law to enter into Administrative Orders to include as part of its SIP revision. These all establish that legislative review is not required for this SIP revision, thereby the state's SIP process met the state's statutory requirements and when the Director issued the SIP, it became an enforceable document under state law. See Response 33 of Arkansas' ''Responsive Summary for State Implementation Plan Revision: Revisions to Arkansas SIP: Regional Haze SIP Revision for 2008–2018 Planning Period.''[101] This is a matter of Arkansas interpreting its state law. EPA finds it is a reasonable interpretation and defers to ADEQ's interpretation regarding the resulting requirements for the process for state rulemaking for enforceable SIP revisions.

Based on ADEQ's response to comments explaining the state authority to issue an enforceable SIP revision without the need to undergo state legislative review, we find it reasonable

[96] For example, South Dakota used CALPUFF for Big Stone's BART determination, including its impact on multiple Class I areas further than 400 km away, including Isle Royale, which is more than 600 km away. See 76 FR 76656. Nebraska relied on CALPUFF modeling to evaluate whether numerous power plants were subject to BART where the ''Class I areas [were] located at distances of 300 to 600 kilometers or more from'' the sources. See Best Available Retrofit Technology Dispersion Modeling Protocol for Selected Nebraska Utilities, p. 3. EPA Docket ID No. EPA–R07–OAR–2012–0158–0008. Texas relied on CALPUFF to screen BART-eligible non-EGU sources at distances of 400 to 614 km for some sources. See 79 FR 74818 (Dec. 16, 2014), 81 FR 296 (Jan. 5, 2016).

[97] See ''Arkansas Regional Haze Phase II SIP Revision Response to Comments,'' which can be found in the docket associated with this final rulemaking.

[98] See ''Response to Comments for the **Federal Register** Notice for the State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan,'' dated 8/31/2016. See Docket ID. EPA–R06–OAR–2015–0189, Document ID. AR020.0187.

[99] Some of the major differences are: (1) CALPUFF modeling used maximum 24-hour emission rates, while the CAMx modeling used annual average emission rates; (2) CALPUFF focuses on the day with the 98th percentile highest visibility impact from the source being evaluated, whereas the CAMx modeling analysis was focused on the average visibility impacts across the 20% worst days regardless of whether the impacts from a specific facility are large or small; and (3) CAMx models all sources of emissions in the modeling domain, which includes all of the continental U.S., whereas CALPUFF only models the impact of emissions from one facility without explicit chemical interaction with other sources' emissions.

[100] See ''Arkansas Regional Haze Phase II SIP Revision Response to Comments,'' which can be found in the docket associated with this final rulemaking.

[101] *https://www.adeq.state.ar.us/air/planning/sip/pdfs/regional-haze/public-notice-and-comments-aggregated.pdf*.

for the state to conclude that ADEQ followed state law in developing and finalizing its SIP revision. Thus, the state's SIP revision is enforceable as a matter of state law and ADEQ has met the requirements of section 110(a)(2)(A), 110(a)(2)(C), and 110(a)(2)(E) since its SIP includes ''necessary assurances'' that the state agency responsible for implementing the SIP has adequate ''authority'' under state law ''to carry out such implementation plan'' and ''responsibility for ensuring adequate implementation'' of the plan. It also includes ''enforceable limitations and other control measures'' as necessary to meet ''the applicable requirements of the CAA and includes ''a program for enforcement'' of the required emission limitations and control measures. Thus, it is appropriate for EPA to finalize approval of ADEQ's plan since it meets all applicable requirements of the Clean Air Act. We believe it is reasonable to rely on ADEQ's explanation and interpretation. Moreover, an Administrative Law Judge and the APCEC have also upheld the state's interpretation of the state law with regards to the issuance of SIPs not being a ''rule'' including SIPs containing administrative orders and there being no statutory requirement for them to undergo state legislative review. However, we also acknowledge that an appeal process of the state rulemaking procedures for the SIP revision is still ongoing. When a rulemaking is being challenged, the EPA relies on the current legal interpretation of state law. If circumstances change where Arkansas is no longer found to have followed the state process for issuing the SIP and the Administrative Orders and needs to undergo another round of state rulemaking because the SIP revision is unenforceable, section 110(k)(5) of the CAA allows for EPA to call for plan revisions and sets out timetables for a SIP or FIP revision. This is commonly known as a ''SIP call.''

Comment: In its attempt to avoid Arkansas' statutory legislative-review requirement, ADEQ has repeatedly represented to an Arkansas tribunal that the SIP itself is not actually enforceable. Thus, according to ADEQ, the SIP itself is not enforceable under state law, but only enforceable through separate Administrative Orders. Because ADEQ admits that the SIP revision is not, by itself, enforceable, the SIP is not approvable under the Clean Air Act. 42 U.S.C. 7410(a)(2)(A). EPA cannot approve the SIP revision unless ADEQ corrects the state law deficiencies or provides the necessary assurances that the state plan is, in fact, an enforceable implementation plan.

Response: While we agree with the commenter's statement that a state must demonstrate that it has the necessary legal authority under state law to adopt and implement an enforceable SIP, we disagree with the commenter's assertion that Arkansas has failed to demonstrate that it has such authority. According to appendix V to 40 CFR part 51, states are required to submit evidence that they have this authority at the time they submit a SIP revision. Arkansas submitted such evidence. See AR020.0267–003 State Legal Authority to Adopt and Implement SIP. The requirements that need to be met in order for a state to adopt and implement provisions intended to meet CAA requirements vary from state to state and are governed by state law. The requirements that govern SIP submissions for Arkansas are found in Ark. Code Ann. 8–4–317, and, as explained by the State, there is no legislative review required for a SIP. See pg. 5 of Ex. A. This position does not make the SIP unenforceable. The Director issues the decision and an appeal is processed as a permit appeal. ADEQ is not arguing that the SIP is not an enforceable decision; rather, it is arguing issuance of the SIP does not fall within the state statutory definition of a ''rule'' requiring legislative review. As explained above, the State has already provided evidence that EPA deemed adequate to meet the requirements in Appendix V. We are aware that the commenter requested an adjudicatory hearing at the state level, as is appropriate, and the administrative law judge ruled in the State's favor. If it is eventually found by a judge or hearing officer during the appropriate state judicial or administrative process that the Commenter is correct in their assertion that the State did not submit an enforceable SIP to EPA, EPA can issue a SIP call under CAA 110(k)(5) to require the State to correct this deficiency.

In addition, the commenter states that ADEQ's position is that the SIP revision as a package is not enforceable, only the individual, component Administrative Orders. According to the commenter, since the SIP package as a whole is not enforceable, it does not meet the requirements of CAA section 110(a)(2). We reject that the ADEQ's position is that the SIP package as a whole is not enforceable, as discussed previously. As explained above, an Administrative Law Judge and the Commission have determined that the issuance of the SIP revision by the Director did not need legislative review in order for the SIP to be adopted and implemented as a matter of state law, thereby making it enforceable.

F. General

Comment: Although public utility plant owners and operators will be responsible initially for installing the pollution controls or taking other actions required under the Arkansas Regional Haze SO_2 and PM SIP Revision, under Arkansas law, such owners and operators are permitted to directly pass through and recover the costs and expenses of installing, operating, and maintaining pollution controls from electric utility customers and ratepayers through electricity rates and tariffs filed with the APSC. In addition, utility plant owners and operators are permitted to recover from electric utility customers and ratepayers the cost of replacement power or capacity needed to replace the premature retirement of electric generating units, or the costs of switching fuel at such facilities. These ratepayers, some of which are providers of goods and services, would be harmed financially if any of these plants were to curtail or modify operations or prematurely close pursuant to the Arkansas Regional Haze SO_2 and PM SIP Revision.

Response: We appreciate the commenter's concerns. We note that the SIP revision submitted by ADEQ did not contain an analysis of the impact the requirement of these controls would have on electricity ratepayers. Neither has the commenter provided such an analysis. There are many factors that could serve to increase or decrease electric rates and absent such an analysis, it is not possible to say what overall effect the SIP's requirements will have on electric rates. ADEQ, in its drafting of the SIP revision, ensured that the requirements of the CAA and the Regional Haze Rule were met, including cost considerations for BART determinations for each of the affected facilities. While we assure the commenter that we are very sensitive to the ramifications of our actions in the regional haze program, we note that we are approving a majority of the Arkansas Regional Haze SO_2 and PM SIP Revision as it meets the requirements of the CAA and the Regional Haze Rule. Our proposal and our final action associated with this document explain the rationale for our approval. We cannot disapprove a SIP revision and/or substitute our judgment for that of the state when we find that the SIP revision meets all requirements of the CAA and applicable federal regulations.

Comment: Various commenters expressed support for one or more portions of our proposal, including our proposed approval of ADEQ's SO_2 BART determination for White Bluff Units 1 and 2; SO_2 BART determination for Flint Creek No. 1 Boiler; SO_2, NO_X, and PM BART determinations for the White Bluff Auxiliary Boiler; and ADEQ's reasonable progress determination.

Response: We appreciate support of our proposed approval of ADEQ's SIP revision. After careful consideration of all the comments we received, we are finalizing our approval of the majority of the SIP revision without changes from proposal. We identify the portions of the SIP revision we are approving elsewhere in this final action.

IV. Final Action

We are approving a portion of the Arkansas SIP revision submitted on August 8, 2018, as meeting the regional haze requirements for the first implementation period. This action includes the finding that the submittal meets the applicable regional haze requirements as set forth in sections 169A and 169B of the CAA and 40 CFR 51.300–308. The EPA is approving the SIP revision submittal as meeting the following regional haze requirements for the first implementation period: The core requirements for regional haze SIPs found in 40 CFR 51.308(d), including the reasonable progress requirements as well as the long-term strategy requirements with respect to all sources other than the Domtar Ashdown Mill; the SO_2, PM, and particular NO_X BART requirements for regional haze visibility impairment with respect to emissions of visibility impairing pollutants from EGUs in 40 CFR 51.308(e); the requirement for coordination with state and FLMs in 40 CFR 51.308(i); and the requirement for coordination and consultation with states with Class I areas affected by Arkansas sources in 40 CFR 51.308(d)(3)(i).

Specifically, the EPA is finalizing approval of the following revisions to the Arkansas Regional Haze SIP submitted to EPA on August 8, 2018: The SO_2 and PM BART requirements for the AECC Bailey Plant Unit 1; the SO_2 and PM BART requirements for the AECC McClellan Plant Unit 1; the SO_2 BART requirements for Flint Creek Plant Boiler No. 1; the SO_2 BART requirements for the White Bluff Plant Units 1 and 2; the SO_2, NO_X, and PM BART requirements for the White Bluff Auxiliary Boiler; and the prohibition on burning of fuel oil at Lake Catherine Unit 4 until SO_2 and PM BART determinations for the fuel oil firing scenario are approved into the SIP by EPA. We are also finalizing our approval of the compliance dates and reporting and recordkeeping requirements associated with these BART determinations. These BART requirements have been made enforceable by the state through Administrative Orders that have been adopted and incorporated in the SIP revision. We are finalizing our approval of these BART Administrative Orders as part of the SIP. The BART requirements and associated Administrative Orders are listed under Table 1 below. We are finalizing our withdrawal of our February 12, 2018,[102] approval of Arkansas' reliance on participation in the CSAPR ozone season NO_X trading program to satisfy the NO_X BART requirement for the White Bluff Auxiliary Boiler given that Arkansas erroneously identified the Auxiliary Boiler as participating in CSAPR for ozone season NO_X. We are taking final action to replace our prior approval of Arkansas' determination for the White Bluff Auxiliary Boiler with our final approval of the source-specific NO_X BART emission limit contained in the Arkansas Regional Haze Phase II SIP revision. The NO_X BART requirement has been made enforceable by the state through an Administrative Order that has been adopted and incorporated in the SIP revision. We are finalizing our approval of the Administrative Order that contains the NO_X BART requirement as part of the SIP. The NO_X BART requirement and associated Administrative Order is listed under Table 1 below. We are finalizing our approval of ADEQ's revised identification of the 6A Boiler at the Georgia-Pacific Crossett Mill as BART-eligible and the determination based on additional information and technical analysis presented in the SIP revision that the Georgia-Pacific Crossett Mill 6A and 9A Boilers are not subject to BART.

We are also finalizing our determination that the reasonable progress requirements under § 51.308(d)(1) have been fully addressed for the first implementation period. The Arkansas Regional Haze Phase I SIP revision, which we approved on February 12, 2018,[103] addressed the reasonable progress requirements with respect to NO_X emissions and the SIP revision before us addresses the reasonable progress requirements with respect to SO_2 and PM emissions. Specifically, we are finalizing our approval of the state's focused reasonable progress analysis and the reasonable progress determination that no additional SO_2 controls at Independence Units 1 and 2 or any other Arkansas sources are necessary under reasonable progress for the first implementation period. We are also in agreement with the state's calculation of revised RPGs for Arkansas' Class I areas. We are basing our final approval of the reasonable progress provisions and agreement with the state's calculation of the revised RPGs on the following: The state's discussion of the key pollutants and source categories that contribute to visibility impairment in Arkansas' Class I areas per the CENRAP's source apportionment modeling; the state's identification of a group of large SO_2 point sources in Arkansas for potential evaluation of controls under reasonable progress; the state's rationale for narrowing down its list of potential sources to evaluate under the reasonable progress requirements; and the state's evaluation and reasonable weighing of the four statutory factors along with consideration of the visibility benefits of controls for the Independence facility.

The Arkansas Regional Haze Phase II SIP revision does not address BART and associated long-term strategy requirements for the Domtar Ashdown Mill Power Boilers No. 1 and 2, and the FIP's BART emission limits for the facility continue to remain in place at this time. However, ADEQ recently submitted a SIP revision to address the regional haze requirements for Domtar Power Boilers No. 1 and No. 2, and we will evaluate any conclusions ADEQ has drawn in that submission with respect to the need to conduct a reasonable progress analysis for Domtar. As long as the BART requirements for Domtar continue to be addressed by the measures in the FIP, however, we propose to agree with ADEQ's conclusion that nothing further is needed to satisfy the reasonable progress requirements for the first implementation period. With respect to the RPGs for Arkansas' Class I areas, we will assess the SIP revision ADEQ recently submitted addressing Domtar to determine if changes are needed based on any differences between the SIP-based measures and the measures currently contained in the FIP. We intend to take action on the SIP revision addressing Domtar in a future rulemaking.

We are finalizing our approval of the components of the long-term strategy under § 51.308(d)(3) addressed by the Arkansas Regional Haze Phase II SIP revision, including the BART measures contained in the SIP revision and the SO_2 emission limit of 0.60 lb/MMBtu under the long-term strategy provisions

[102] 83 FR 5927.

[103] 83 FR 5927.

for Independence Units 1 and 2 based on the use of low sulfur coal. We are also finalizing our approval of the compliance date and reporting and recordkeeping requirements associated with the SO_2 emission limit for the Independence facility under the long term strategy provisions. These requirements for Independence Units 1 and 2 have been made enforceable by the state through an Administrative Order that has been adopted and incorporated in the SIP revision. We are finalizing our approval of this BART Administrative Order as part of the SIP. The SO_2 emission limit and associated Administrative Order for the Independence facility are listed under Table 2 below. We are making a final determination that Arkansas' long-term strategy is approved with respect to sources other than the Domtar Ashdown Mill. We are also finalizing our determination that Arkansas has appropriately provided an opportunity for consultation to the FLMs and to Missouri on the SIP revision, as required under § 51.308(d)(3)(i) and (i)(2).

The BART emission limits we are approving as source-specific requirements that are part of the SIP are presented in Table 1; the SO_2 emission limits under the long-term strategy and associated Administrative Order we are approving for the Independence facility are presented in Table 2; and Arkansas' revised 2018 RPGs are presented in Table 3.

TABLE 1—SIP REVISION BART EMISSION LIMITS AND ADMINISTRATIVE ORDERS EPA IS APPROVING IN THIS FINAL ACTION

Subject-to-BART source	SIP revision SO_2 BART emission limits	SIP revision PM BART emission limits	SIP revision NO_X BART emission limits	Administrative order
AECC Bailey Unit 1	0.5% limit on sulfur content of fuel combusted *.	0.5% limit on sulfur content of fuel combusted *.	Already SIP-approved	Administrative Order LIS No. 18–071.
AECC McClellan Unit 1	0.5% limit on sulfur content of fuel combusted *.	0.5% limit on sulfur content of fuel combusted *.	Already SIP-approved	Administrative Order LIS No. 18–071.
AEP Flint Creek Boiler No. 1.	0.06 lb/MMBtu *	Already SIP-approved	Already SIP-approved	Administrative Order LIS No. 18–072.
Entergy Lake Catherine Unit 4 (fuel oil firing scenario)	Unit is allowed to burn only natural gas *.	Unit is allowed to burn only natural gas *.	Already SIP-approved	Administrative Order LIS No. 18–073.
Entergy White Bluff Unit 1.	0.60 lb/MMBtu (Interim emission limit with a 3-year compliance date and cessation of coal combustion by end of 2028).	Already SIP-approved	Already SIP-approved	Administrative Order LIS No. 18–073.
Entergy White Bluff Unit 2.	0.60 lb/MMBtu (Interim emission limit with a 3-year compliance date and cessation of coal combustion by end of 2028).	Already SIP-approved	Already SIP-approved	Administrative Order LIS No. 18–073.
Entergy White Bluff Auxiliary Boiler.	105.2 lb/hr *	4.5 lb/hr *	32.2 lb/hr *	Administrative Order LIS No. 18–073.

* This BART emission limit required by the SIP revision is the same as what was required under the Arkansas Regional Haze FIP.

TABLE 2—SIP REVISION EMISSION LIMITS UNDER REASONABLE PROGRESS AND ADMINISTRATIVE ORDERS PROPOSED FOR APPROVAL

Source	SIP revision SO_2 emission limits (lb/MMBtu)	Administrative order
Entergy Independence Unit 1	0.60	Administrative Order LIS No. 18–073.
Entergy Independence Unit 2	0.60	Administrative Order LIS No. 18–073.

TABLE 3—ARKANSAS' REVISED 2018 RPGS

Class I area	2018 RPG 20% worst days (dv)
Caney Creek	22.47
Upper Buffalo	22.51

Concurrent with our final approval of the Arkansas Regional Haze Phase II SIP revision, we are finalizing in a separate rulemaking our final action to withdraw those portions of the Arkansas Regional Haze FIP at 40 CFR 52.173 that impose SO_2 and PM BART emission limits for Bailey Unit 1; SO_2 and PM BART emission limits for McClellan Unit 1; the SO_2 BART emission limit for Flint Creek Boiler No. 1; the SO_2 BART emission limits for White Bluff Units 1 and 2; the SO_2 and PM BART emission limits for the White Bluff Auxiliary Boiler; the prohibition on burning fuel oil at Lake Catherine Unit 4; and the SO_2 emission limits for Independence Units 1 and 2 under the reasonable progress provisions.[104]

[104] Our final action withdrawing part of the Arkansas Regional Haze FIP is published elsewhere in this issue of the **Federal Register**.

We find that an approval of the SIP revision meets the Clean Air Act's 110(1) provisions. Approval of the Arkansas Regional Haze SO_2 and PM SIP revision will not interfere with continued attainment of all the NAAQS within the state of Arkansas, nor will it interfere with any other applicable requirements of the CAA.

V. Incorporation by Reference

In this final action, we are including regulatory text that includes incorporation by reference. In accordance with the requirements of 1 CFR 51.5, we are incorporating by reference revisions to the Arkansas source-specific requirements as described in the Final Action section above. We have made, and will continue to make, these documents generally available electronically through *www.regulations.gov* and in hard copy at the EPA Region 6 office (please contact the person listed in **FOR FURTHER INFORMATION CONTACT** for more information). Therefore, these materials have been approved by EPA for inclusion in the SIP, have been incorporated by reference by EPA into that plan, are fully federally enforceable under sections 110 and 113 of the CAA as of the effective date of the final rulemaking of EPA's approval, and will be incorporated in the next update to the SIP compilation.

VI. Statutory and Executive Order Reviews

Under the Clean Air Act, the Administrator is required to approve a SIP submission that complies with the provisions of the Act and applicable Federal regulations. 42 U.S.C. 7410(k)(3); 40 CFR 52.02(a). Thus, in reviewing SIP submissions, the EPA's role is to approve state choices, provided that they meet the criteria of the Clean Air Act. Accordingly, this action merely approves state law as meeting Federal requirements and does not impose additional requirements beyond those imposed by state law. For that reason, this action:

- Is not a ''significant regulatory action'' subject to review by the Office of Management and Budget under Executive Orders 12866 (58 FR 51735, October 4, 1993) and 13563 (76 FR 3821, January 21, 2011);
- Is not an Executive Order 13771 (82 FR 9339, February 2, 2017) regulatory action because SIP approvals are exempted under Executive Order 12866;
- Does not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*);
- Is certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*);
- Does not contain any unfunded mandate or significantly or uniquely affect small governments, described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4);
- Does not have Federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999);
- Is not an economically significant regulatory action based on health or safety risks subject to Executive Order 13045 (62 FR 19885, April 23, 1997);
- Is not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001);
- Is not subject to requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) because application of those requirements would be inconsistent with the CAA; and
- Does not provide EPA with the discretionary authority to address, as appropriate, disproportionate human health or environmental effects, using practicable and legally permissible methods, under Executive Order 12898 (59 FR 7629, February 16, 1994).

In addition, the SIP is not approved to apply on any Indian reservation land or in any other area where EPA or an Indian tribe has demonstrated that a tribe has jurisdiction. In those areas of Indian country, the rule does not have tribal implications and will not impose substantial direct costs on tribal governments or preempt tribal law as specified by Executive Order 13175 (65 FR 67249, November 9, 2000).

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this action and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

Under section 307(b)(1) of the Clean Air Act, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by November 26, 2019. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this action for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements. (See section 307(b)(2).)

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Best available retrofit technology, Incorporation by reference, Intergovernmental relations, Ozone, Particulate Matter, Regional haze, Reporting and recordkeeping requirements, Sulfur Dioxide, Visibility.

Dated: August 28, 2019.

Kenley McQueen,

Regional Administrator, Region 6.

Title 40, chapter I, of the Code of Federal Regulations is amended as follows:

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

■ 1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart E—Arkansas

■ 2. In § 52.170:

■ a. The table in paragraph (d), entitled ''EPA-Approved Arkansas Source-Specific Requirements'' is revised; and

■ b. The third table in paragraph (e), entitled ''EPA-Approved Non-Regulatory Provisions and Quasi-Regulatory Measures in the Arkansas SIP,'' is amended by adding and entry for ''Arkansas Regional Haze Phase II SIP Revision'' at the end of the table.

The revision and addition read as follows:

§ 52.170 Identification of plan.

* * * * *

(d) * * *

EPA-APPROVED ARKANSAS SOURCE-SPECIFIC REQUIREMENTS

Name of source	Permit or Order No.	State approval/ effective date	EPA approval date	Comments
Arkansas Electric Cooperative Corporation Carl E. Bailey Generating Station.	Administrative Order LIS No. 18–071.	8/7/2018	9/27/2019 [[Insert **Federal Register** citation of the final rule].	Unit 1.
Arkansas Electric Cooperative Corporation John L. McClellan Generating Station.	Administrative Order LIS No. 18–071.	8/7/2018	9/27/2019 [[Insert **Federal Register** citation of the final rule].	Unit 1.
Southwestern Electric Power Company Flint Creek Power Plant.	Administrative Order LIS No.. 18–072	8/7/2018	9/27/2019 [[Insert **Federal Register** citation of the final rule].	Unit 1.
Entergy Arkansas, Inc. Lake Catherine Plant.	Administrative Order LIS No. 18–073.	8/7/2018	9/27/2019 [[Insert **Federal Register** citation of the final rule].	Unit 4.
Entergy Arkansas, Inc. White Bluff Plant.	Administrative Order LIS No. 18–073.	8/7/2018	9/27/2019 [[Insert **Federal Register** citation of the final rule].	Units 1, 2, and Auxiliary Boiler.
Entergy Arkansas, Inc. Independence Plant.	Administrative Order LIS No. 18–073.	8/7/2018	[[Insert Date of publication of the final rule in the **Federal Register**] [[Insert **Federal Register** citation of the final rule].	Units 1 and 2.

(e) * * *

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EPA-APPROVED NON-REGULATORY PROVISIONS AND QUASI-REGULATORY MEASURES IN THE ARKANSAS SIP

Name of SIP provision	Applicable geographic or nonattainment area	State submittal/ effective date	EPA approval date	Explanation
*	*	*	* *	* *
Arkansas Regional Haze Phase II SIP Revision.	Statewide	August 8, 2018	9/27/2019 [[Insert **Federal Register** citation of the final rule].	Regional Haze SIP revision addressing SO_2 and PM BART requirements for Arkansas EGUs, NO_X BART requirement for the White Bluff Auxiliary Boiler, reasonable progress requirements for SO_2 and PM for the first implementation period, and the long-term strategy requirements. We are approving a portion of this SIP revision. There are two aspects of this SIP revision we are not taking action on at this time: (1) The interstate visibility transport requirements under section 110(a)(2)(D)(i)(II); and (2) the long-term strategy is approved with respect to sources other than the Domtar Ashdown Mill.

■ 3. In § 52.173, add paragraph (g) to read as follows:

§ 52.173 Visibility protection.

* * * * *

(g) *Regional Haze Phase II SIP Revision.* A portion of the Regional Haze Phase II SIP Revision submitted on August 8, 2018, is approved as follows:

(1) Identification of the 6A Boiler at the Georgia-Pacific Crossett Mill as BART-eligible and the determination based on the additional information and technical analysis presented in the SIP revision that the Georgia-Pacific Crossett Mill 6A and 9A Boilers are not subject to BART. (2) SO_2 and PM BART for the AECC Bailey Plant Unit 1; SO_2 and PM BART for the AECC McClellan Plant Unit 1; SO_2 BART for the AEP/SWEPCO Flint Creek Plant Boiler No. 1; SO_2 BART for Entergy White Bluff Units 1 and 2; SO_2, NO_X, and PM BART for the Entergy White Bluff Auxiliary Boiler; and the prohibition on burning of fuel oil at Entergy Lake Catherine Unit 4 until SO_2 and PM BART determinations for the fuel oil firing scenario are approved into the SIP by EPA.

(3) The focused reasonable progress analysis and the reasonable progress determination that no additional SO_2 and PM controls are necessary under the reasonable progress requirements for the first implementation period.

(4) The long-term strategy is approved with respect to sources other than the Domtar Ashdown Mill. This includes the BART emission limits contained in the SIP revision and the SO_2 emission limit of 0.60 lb/MMBtu under the long-term strategy provisions for Independence Units 1 and 2 based on the use of low sulfur coal.

(5) Consultation and coordination in the development of the SIP revision with the FLMs and with other states with Class I areas affected by emissions from Arkansas sources.

[FR Doc. 2019–19497 Filed 9–26–19; 8:45 am]

BILLING CODE 6560–50–P

BART FIVE FACTOR ANALYSIS

ARKANSAS ELECTRIC COOPERATIVE CORPORATION

BAILEY AND MCCLELLAN GENERATING STATIONS

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March 2014
Version 4

Electric Cooperatives of Arkansas
We Are Arkansas

Trinity Consultants

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1. EXECUTIVE SUMMARY

This report documents the determination of the Best Available Retrofit Technology (BART) as proposed by Arkansas Electric Cooperative Corporation (AECC) for the Unit 1 Boiler at the Bailey Generating Station and the Unit 1 Boiler at the McClellan Generating Station. Bailey Unit 1 is a wall-fired boiler with a maximum heat input of 1,350 million British thermal units per hour (MMBtu/hr) that burns natural gas and No. 6 fuel oil. McClellan Unit 1 is a wall-fired boiler with a maximum heat input of 1,436 MMBtu/hr that burns natural gas and No. 6 fuel oil. The ability to burn fuel oil at both Bailey and McClellan is important – even if the fuel oil is more expensive to burn than natural gas. During natural gas curtailments, natural gas infrastructure maintenance, and other emergencies, AECC relies on the fuel oil stored at the plants to maintain electrical reliability.

Arkansas Department of Environmental Quality (ADEQ) has determined based on results of previous air dispersion modeling that cumulative emissions of nitrogen oxides (NO_x), sulfur dioxide (SO_2), and particulate matter with a mass mean diameter smaller than ten microns (PM_{10}) from Bailey Unit 1 and McClellan Unit 1 each cause or contribute greater than 0.5 delta deciviews (Δdv) to visibility impairment in four Class I Areas: Caney Creek Wilderness (CACR), Upper Buffalo Wilderness (UPBU), Hercules Glades Wilderness (HERC), and Mingo Wilderness (MING). Since both Bailey Unit 1 and McClellan Unit 1 meet the three criteria that make a source BART-eligible, the fact that Bailey Unit 1 and McClellan Unit 1contribute to visibility impairment in a Class I area greater than 0.5 Δdv means that the boilers are subject to BART.

A summary of the existing visibility impairment attributable to each boiler based on the default natural conditions is provided in Table 1-1. Note that the visibility impairment summarized in Table 1-1 is based on recent modeling conducted by Trinity Consultants (Trinity) using emissions data based on a combination of stack testing, Continuous Emission Monitoring System (CEMS) data and AP-42 emission factors as further described in Section 4 of this report. AECC recognizes that the recent modeling shows impacts for Bailey Unit 1 that are less than 0.5Δdv, the threshold that ADEQ used to classify a source as subject to BART. Nevertheless, AECC is continuing with the BART analysis.

TABLE 1-1. EXISTING VISIBILITY IMPAIRMENT ATTRIBUTABLE TO BAILEY UNIT 1 AND MCCLELLAN UNIT 1 (2001-2003)

	CACR		UPBU		HERC		MING	
Unit / Fuel Scenario	**98th % Δdv**	**Days > 0.5 Δdv**	**98th % Δdv**	**Days > 0.5 Δdv**	**98th % Δdv**	**Days > 0.5 Δdv**	**98th % Δdv**	**Days > 0.5 Δdv**
Bailey, Unit 1 – Natural Gas	0.083	0	0.072	0	0.073	0	0.102	0
Bailey, Unit 1 – Fuel Oil	0.330	8	0.348	7	0.368	6	0.379	12
McClellan, Unit 1 – Natural Gas	0.125	3	0.052	0	0.040	0	0.058	0
McClellan, Unit 1 – Fuel Oil	0.622	24	0.266	5	0.231	2	0.228	2

Trinity used the EPA's BART guidelines in 40 CFR Part 51[1] to determine BART for Bailey Unit 1 and McClellan Unit 1. Specifically, Trinity conducted a five-step analysis to determine BART for SO_2, NO_x, and PM_{10} that included the following:

1. Identifying all available retrofit control technologies;
2. Eliminating technically infeasible control technologies;
3. Evaluating the control effectiveness of remaining control technologies;
4. Evaluating impacts and document the results;
5. Evaluating visibility impacts.

Based on the five-step analysis, the following were determined to be BART:

- SO_2 – AECC has determined that BART for both Bailey Unit 1 and McClellan Unit 1 is using fuels with 0.5% sulfur or less (including natural gas).
- NO_x – AECC has determined that the requirements of the Cross State Air Pollution Rule (CSAPR) satisfy BART for NO_X from Bailey Unit 1and McClellan Unit 1.[2]
- PM_{10} –AECC has determined that no controls constitute BART. Neither a fuel change beyond that proposed for SO_2 nor add-on controls are cost effective or result in an improvement to the visibility impairment attributable to the AECC boilers of greater than 0.011 Δdv, an insignificant improvement, as documented in Section 7.

[1] The BART guidelines were published as amendments to the EPA's RHR in 40 CFR Part 51, Section 308 on July 6, 2005.

[2] This determination was originally submitted on July 24, 2012. In response to CSAPR being vacated on August 21, 2012, AECC submitted a five-factor analysis for NOx to ADEQ in September 2012 as an addendum to this analysis.

2. INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to pristine conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to pristine conditions in 156 specific areas across the United States known as Class I areas. The CAA defines Class I areas as certain national parks (larger than 6,000 acres), wilderness areas (larger than 5,000 acres), national memorial parks (larger than 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the Best Available Retrofit Technology (BART) rule, which included guidance for making source-specific BART determinations. The BART rule defines BART-eligible sources as sources that meet the following criteria:

(1) Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant,
(2) Began operation between August 7, 1962 and August 7, 1977, and
(3) Are included as one of the 26 listed source categories in the guidance.

A BART-eligible source is subject to BART if the source is "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." EPA has determined that a source is reasonably anticipated to cause or contribute to visibility impairment if the 98th percentile visibility impacts from the source are greater than 0.5 delta deciviews (Δdv) when compared against a natural background.[3] Air quality modeling is the tool that is used to determine a source's visibility impacts.

Once it is determined that a source is subject to BART, a BART determination must address air pollution control measures for the source. The visibility regulations define BART as follows:

> *"…an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by…[a BART-eligible source]. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the cost of compliance, the energy and non air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonable be anticipated to result from the use of such technology.*

Specifically, the BART rule states that a BART determination should address the following five statutory factors:

[3] Note this is a change from the ADEQ protocol with the 2006 CENRAP data, as the original analysis for Arkansas reviewed the "High First High" impacts rather than the 98th percentile impacts

1. Existing controls
2. Cost of controls
3. Energy and non-air quality environmental impacts
4. Remaining useful life of the source
5. Degree of visibility improvement as a result of controls

Further, the BART rule indicates that the five basic steps in a BART analysis can be summarized as follows:

1. Identify all available retrofit control technologies;
2. Eliminate technically infeasible control technologies;
3. Evaluate the control effectiveness of remaining control technologies;
4. Evaluate impacts and document the results;
5. Evaluate visibility impacts

A BART determination should be made for each visibility affecting pollutant (VAP) by following the five steps listed above for each VAP.

Bailey Unit 1 and McClellan Unit 1 meet the three BART-eligibility criteria described above. Further, the existing visibility impairment attributable to each Bailey Unit 1 and McClellan Unit 1 is greater than 0.5 dv in at least one Class I area. Thus, both Bailey Unit 1 and McClellan Unit 1 are subject to BART. The details of the Bailey Unit 1 and McClellan Unit 1 existing/baseline emissions and the contribution of the emissions to visibility impairment can be found in Section 4. The VAPs emitted by Bailey Unit 1 and McClellan Unit 1 include NO_x, SO_2, and PM_{10} of various forms (filterable coarse particulate matter [PM_c], filterable fine particle matter [PM_f], elemental carbon [EC], inorganic condensable particulate matter [IOR CPM] as sulfates [SO_4], and organic condensable particulate matter [OR CPM] also referred to as secondary organic aerosols [SOA]). The BART determinations for SO_2, NO_x, and PM_{10} can be found in Sections 5, 6, and 7, respectively.

On June 7, 2012 EPA published a final rule allowing states participating in the Cross-State Air Pollution Rule (CSAPR) trading program to use CSAPR to satisfy BART. Thus, AECC is proposing to satisfy BART for NO_x by complying with CSAPR at Bailey Unit 1 and McClellan Unit 1.[4]

[4] This proposal was originally submitted on July 24, 2012. In response to CSAPR being vacated on August 21, 2012, AECC submitted a five-factor analysis for NOx to ADEQ in September 2012 as an addendum to this analysis.

3. Modeling Methodologies and Procedures

This section summarizes the dispersion modeling methodologies and procedures applied in this BART analysis. All dispersion modeling has been conducted using the CALPUFF modeling system, consisting of the CALPUFF dispersion model, the CALMET meteorological data processor, and the CALPOST post-processing program.

CALPUFF is a multi-layer, multi-species, non-steady-state puff dispersion model, which can simulate the effects of time and space varying meteorological conditions on pollutant transport, transformation, and removal. CALPUFF uses three-dimensional meteorological fields developed by the CALMET model. In addition to meteorological data, several other input files are used by the CALPUFF model to specify source and receptor parameters. The selection and control of CALPUFF options are determined by user-specific inputs contained in the control file. This file contains all of the necessary information to define a model run (e.g., starting date, run length, grid specifications, technical options, output options). CALPOST processes concentration, deposition, and visibility impacts based on pollutant specific concentrations predicted by CALPUFF.

3.1 CALMET and CALPUFF

The CALPUFF data and parameters are based on the 2005 BART modeling guidelines prepared for the Central States Regional Air Planning Association (CENRAP). The CALMET data and parameters are based on the modeling protocol included in Appendix B. Note that the protocol included in Appendix B summarizes modeling methods and procedures that were followed to predict visibility impairment for several BART-eligible sources located in Oklahoma as part of the BART analyses for these sources. In addition, several sources in Texas used the CALMET data that was generated in accordance with the protocol in their BART analyses.

3.2 CALPOST

The CALPOST visibility processing completed for this BART analysis is based on the October 2010 guidance from the Federal Land Managers Air Quality Related Values Workgroup (FLAG). The 2010 FLAG guidance, which was issued in draft form on July 8, 2008 and published as final guidance in December 2010, makes technical revisions to the previous guidance issued in December 2000.

Visibility impairment is quantified using the light extinction coefficient (b_{ext}), which is expressed in terms of the haze index expressed in deciviews (dv). The haze index (*HI*) is calculated as follows:

$$HI(\text{dv}) = 10\ln\left(\frac{b_{ext}}{10}\right)$$

The impact of a source is determined by comparing the *HI* attributable to a source relative to estimated natural background conditions. The change in the haze index, in deciviews, also referred to as “delta dv,” or Δdv, based on the source and background light extinction is based on the following equation:

$$\Delta \mathrm{dv} = 10 * \ln\left[\frac{\mathrm{b}_{\text{ext, background}} + \mathrm{b}_{\text{ext, source}}}{\mathrm{b}_{\text{ext, background}}}\right]$$

The Interagency Monitoring of Protected Visual Environments (IMPROVE) workgroup adopted an equation for predicting light extinction as part of the 2010 FLAG guidance (often referred to as the new IMPROVE equation). The new IMPROVE equation is as follows:

$$b_{ext} = \begin{array}{l} 2.2 f_S(RH)[\mathrm{NH_4(SO_4)_2}]_{\text{Small}} + 4.8 f_L(RH)[\mathrm{NH_4(SO_4)_2}]_{\text{Large}} + \\ 2.4 f_S(RH)[\mathrm{NH_4NO_3}]_{\text{Small}} + 5.1 f_L(RH)[\mathrm{NH_4NO_3}]_{\text{Large}} + \\ 2.8[\mathrm{OC}]_{\text{Small}} + 6.1[\mathrm{OC}]_{\text{Large}} + 10[\mathrm{EC}] + 1[\mathrm{PMF}] + 0.6[\mathrm{PMC}] + \\ 1.4 f_{SS}(RH)[\text{Sea Salt}] + b_{\text{Site-specific Rayleigh Scattering}} + 0.33[\mathrm{NO_2}] \end{array}$$

Visibility impairment predictions for Bailey Unit 1 and McClellan Unit 1 relied upon in this BART analysis used the equation shown above. The use of this equation is referred to as “Method 8” in the CALPOST control file. The use of Method 8 requires that one of five different “modes” be selected. The modes specify the approach for addressing the growth of hygroscopic particles due to moisture in the atmosphere. “Mode 5” has been used in this BART analysis. Mode 5 addresses moisture in the atmosphere in a similar way as to “Method 6”, where “Method 6” is specified as the preferred approach for use with the old IMPROVE equation in the CENRAP BART modeling protocol.

CALPOST Method 8, Mode 5 requires the following:

- ▲ Annual average concentrations reflecting natural background for various particles and for sea salt
- ▲ Monthly RH factors for large and small ammonium sulfates and nitrates and for sea salts
- ▲ Rayleigh scattering parameter corrected for site-specific elevation

Tables 3-1 to Table 3-4 below show the values for the data described above that were input to CALPOST for use with Method 8, Mode 5. The values were obtained from the 2010 FLAG guidance.

TABLE 3-1. ANNUAL AVERAGE BACKGROUND CONCENTRATION

Class I Area	**$(NH_4)_2SO_4$**	**NH_4NO_3**	**OM**	**EC**	**Soil**	**CM**	**Sea Salt**	**Rayleigh (Mm^{-1})**
CACR	0.23	0.1	1.8	0.02	0.5	3	0.03	11
UPBU	0.23	0.1	1.8	0.02	0.5	3	0.03	11
HERC	0.23	0.1	1.8	0.02	0.5	3	0.02	11
MING	0.23	0.1	1.83	0.02	0.51	3.05	0.04	12

TABLE 3-2. F_L(RH) LARGE RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CACR	2.77	2.53	2.37	2.43	2.68	2.71	2.59	2.6	2.71	2.69	2.67	2.79
UPBU	2.71	2.48	2.31	2.33	2.61	2.64	2.57	2.59	2.71	2.58	2.59	2.72
HERC	2.7	2.48	2.3	2.3	2.57	2.59	2.56	2.6	2.69	2.54	2.57	2.72
MING	2.73	2.52	2.34	2.28	2.53	2.6	2.64	2.67	2.71	2.56	2.56	2.73

TABLE 3-3. F_S(RH) SMALL RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CACR	3.85	3.44	3.14	3.24	3.66	3.71	3.49	3.51	3.73	3.72	3.68	3.88
UPBU	3.73	3.33	3.03	3.07	3.54	3.57	3.43	3.5	3.71	3.51	3.52	3.74
HERC	3.7	3.33	3.01	3.01	3.47	3.48	3.41	3.51	3.67	3.43	3.46	3.73
MING	3.74	3.38	3.07	2.97	3.39	3.52	3.57	3.64	3.72	3.47	3.43	3.74

TABLE 3-4. F_{SS}(RH) SEA SALT RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CACR	3.9	3.52	3.31	3.41	3.83	3.88	3.69	3.68	3.82	3.76	3.77	3.93
UPBU	3.85	3.47	3.23	3.27	3.72	3.78	3.69	3.7	3.84	3.64	3.67	3.86
HERC	3.86	3.51	3.23	3.22	3.66	3.72	3.69	3.73	3.81	3.57	3.65	3.88
MING	3.92	3.58	3.3	3.19	3.58	3.72	3.8	3.82	3.85	3.61	3.66	3.9

This section summarizes the existing (i.e. baseline) visibility impairment attributable to Bailey Unit 1 and McClellan Unit 1 based on air quality modeling conducted by Trinity.

4.1 NO_X, SO_2, AND PM_{10} BASELINE EMISSION RATES

Table 4-1 summarizes the emission rates that were modeled for SO_2, NO_x, and PM_{10}, including the speciated PM_{10} emissions. The SO_2 and NO_x emission rates are the highest actual 24-hour emission rates based on 2001-2003 continuous emissions monitoring system (CEMS) data – broken out to distinguish SO_2 and NO_x from burning No. 6 fuel oil and natural gas individually.

The PM_{10} emission rates for natural gas combustion are based on the emission factor for total PM_{10} in Table 1.4-2 of AP-42, which is 7.6 lbs/MMscf, and the maximum heat inputs for the units. The emission rates for the PM_{10} species shown in Table 4-1 reflect the breakdown of the filterable and condensable PM_{10} determined from AP-42 Table 1.4-2 *Combustion of Natural Gas.* All filterable PM was assumed to be elemental carbon, as this is the assumption that the NPS uses for filterable PM_{10} from natural gas fired combustion turbines. All of the condensable PM was assumed to be SOA, except for a small fraction of the condensable PM that was estimated to be SO_4. One-third of the estimated SO_2 emissions were separated and adjusted for differences in molecular weight to represent SO_4 emissions. This double counts some of the fuel sulfur based emissions as SO_2 but also as SO_4. Since pipeline natural gas contains very little sulfur, both the SO_2 and SO_4 emission rates are very low.

The PM_{10} rates for fuel oil combustion are based on stack testing of both filterable and condensable PM_{10} conducted on Unit 1 at the McClellan plant on May 29, 2013. The total PM_{10} emission rate determined during the testing was 59.4 lb/hr. Thus, a total PM_{10} emission rate of 59.4 lb/hr was modeled for McCllellan. Stack testing was not conducted at Bailey in 2013, however, the total PM_{10} emission rate for Unit 1 at Bailey was scaled by the ratio of the heat input for Bailey vs McClellan (1436/1350) to get a total PM_{10} emission rate of 55.8 lb/hr. The emission rates for the PM_{10} species shown in Table 4-1 reflect the breakdown of the PM_{10} determined from the National Park Service (NPS) "speciation spreadsheet" for *Uncontrolled Utility Residual Oil Boilers.*[5] More specifically, the NPS workbook shows the following baseline distributions for the PM species from No. 6 fuel oil at Bailey and McClellan, respectively:

- ▲ Coarse PM (PM_C) = 24.5%, 23.9%
- ▲ Fine soil (modeled as PM_F) = 61.0%, 64.3%
- ▲ Fine elemental carbon (modeled as EC) = 4.9 %, 4.8%
- ▲ Organic condensable PM (modeled as SOA) = 1.4%, 1.8%
- ▲ Inorganic condensable PM (modeled as SO_4) = 8.2%, 10.0%

[5] The NPS Workbook, "Uncontrolled Utility Residual Oil Boiler.xls" updated 03/2006, was obtained from the NPS website: http://www.nature.nps.gov/air/Permits/ect/index.cfm. The following parameters were input into the workbook for speciation determination for Bailey: #6 oil with a sulfur content of 1.81%, and a heat input of 1,350 MMBtu/hr and for McClellan: #6 oil with a sulfur content of 1.38%, and a heat input of 1,436 MMBtu/hr.

TABLE 4-1. BASELINE MAXIMUM 24-HOUR SO_2, NO_X, AND PM_{10} EMISSION RATES (AS HOURLY EQUIVALENTS)

Unit / Fuel Scenario	SO_2[6] (lb/hr)	NO_x[7] (lb/hr)	Total PM_{10} (lb/hr)	SO_4 (lb/hr)	PM_c (lb/hr)	PM_f (lb/hr)	SOA (lb/hr)	EC (lb/hr)
Bailey, Unit 1 – Natural Gas	0.5	443.8	10.2	0.3	0.0	0.0	7.4	2.6
Bailey, Unit 1 – Fuel Oil	2,375.8	408.8	55.8	4.6	13.7	34.1	0.8	2.7
McClellan, Unit 1 – Natural Gas	0.6	423.9	10.9	0.3	0.0	0.0	7.9	2.7
McClellan, Unit 1 – Fuel Oil	2,747.5	579.8	59.4	5.9	14.2	35.4	1.0	2.8

4.2 BASELINE VISIBILITY IMPAIRMENT

Trinity conducted modeling to determine the visibility impairment attributable to Bailey Unit 1 and McClellan Unit 1 in four Class I Areas: Caney Creek Wilderness (CACR), Upper Buffalo Wilderness (UPBU), Hercules Glades Wilderness (HERC), and Mingo Wilderness (MING) using the CALPUFF dispersion model.

Table 4-2 through Table 4-5 provide a summary of the modeled visibility impairment attributable to Bailey Unit 1 and McClellan Unit 1 at CACR, UPBU, HERC, and MING based on the emission rates shown in Table 4-1. Note that all of the CALMET, CALPUFF, and CALPOST modeling files are included as part of the electronic files submitted with this document.

[6] Hourly rates were derived from EPA's Clean Air Market Database (CAMD) daily rates of 12 lb/day and 14 lb/day from natural gas at Bailey and McClellan, respectively, and 57,018 lb/day and 65,940 lb/day from No. 6 fuel oil at Bailey and McClellan, respectively.

[7] Hourly rates were derived from EPA's Clean Air Market Database (CAMD) daily rates of 10,650 lb/day and 10,174 lb/day from natural gas at Bailey and McClellan, respectively, and 9,812 lb/day and 13,914 lb/day from No. 6 fuel oil at Bailey and McClellan, respectively.

TABLE 4-2. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO BAILEY, UNIT 1 (2001-2003) – NATURAL GAS

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Day with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek Wilderness							
2001	0.137	0.083	0	0.28	96.36	3.35	0.00
2002	0.219	0.075	0	0.31	95.93	3.22	0.54
2003	0.147	0.067	0	0.40	91.98	5.51	2.10
Upper Buffalo Wilderness							
2001	0.089	0.04	0	0.23	95.01	3.05	1.72
2002	0.160	0.031	0	0.30	86.44	5.48	7.77
2003	0.170	0.072	0	0.29	95.02	3.43	1.26
Hercules Glades Wilderness							
2001	0.238	0.056	0	0.23	96.39	3.08	0.31
2002	0.067	0.039	0	0.88	87.67	10.78	0.67
2003	0.175	0.073	0	0.22	92.76	3.67	3.35
Mingo Wilderness							
2001	0.154	0.070	0	0.29	90.58	5.41	3.72
2002	0.443	0.084	0	0.43	83.07	7.92	8.58
2003	0.201	0.102	0	0.45	83.34	8.10	8.11

TABLE 4-3. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO BAILEY, UNIT 1 (2001-2003) – FUEL OIL

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Day with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek Wilderness							
2001	0.684	0.307	2	75.66	22.47	1.44	0.44
2002	0.745	0.330	3	87.19	12.11	0.57	0.14
2003	0.970	0.327	3	98.80	0.81	0.40	0
Upper Buffalo Wilderness							
2001	0.578	0.282	3	94.29	4.99	0.73	0.00
2002	0.668	0.305	1	73.65	21.28	3.43	1.64
2003	0.696	0.348	3	90.73	8.42	0.83	0.02
Hercules Glades Wilderness							
2001	0.687	0.327	3	98.40	1.07	0.52	0
2002	0.635	0.249	2	80.38	18.62	0.87	0.12
2003	0.648	0.368	1	82.74	14.39	2.08	0.79
Mingo Wilderness							
2001	0.524	0.355	1	89.57	8.35	1.67	0.41
2002	1.592	0.379	7	93.95	4.68	1.26	0.11
2003	0.689	0.300	4	66.17	29.13	2.83	1.87

TABLE 4-4. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO MCCLELLAN, UNIT 1 (2001-2003), NATURAL GAS

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Day with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek Wilderness							
2001	0.670	0.116	1	0.31	93.69	4.43	1.57
2002	0.175	0.092	0	0.55	82.94	8.35	8.15
2003	0.538	0.125	2	0.39	87.09	6.63	5.89
Upper Buffalo Wilderness							
2001	0.096	0.048	0	0.38	92.78	5.43	1.41
2002	0.258	0.031	0	0.32	94.54	4.04	1.10
2003	0.112	0.052	0	0.34	91.78	4.82	3.05
Hercules Glades Wilderness							
2001	0.064	0.034	0	0.29	93.50	4.42	1.79
2002	0.082	0.022	0	0.74	88.76	10.09	0.41
2003	0.092	0.04	0	0.74	86.01	10.18	3.07
Mingo Wilderness							
2001	0.091	0.032	0	0.30	92.13	3.91	3.67
2002	0.132	0.058	0	0.33	91.96	5.13	2.58
2003	0.107	0.034	0	0.37	90.42	5.85	3.35

TABLE 4-5. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO MCCLELLAN, UNIT 1 (2001-2003), FUEL OIL

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Day with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek Wilderness							
2001	1.685	0.622	10	89.86	9.62	0.53	0.00
2002	1.021	0.389	4	86.29	11.26	1.72	0.74
2003	3.007	0.616	9	82.89	15.76	0.36	0.62
Upper Buffalo Wilderness							
2001	0.604	0.258	2	84.02	14.98	0.99	0.01
2002	1.323	0.184	1	77.31	20.96	1.43	0.30
2003	0.599	0.266	2	98.47	0.95	0.58	0.00
Hercules Glades Wilderness							
2001	0.512	0.231	1	78.67	20.16	1.17	0.01
2002	0.463	0.168	0	59.28	37.65	2.31	0.75
2003	0.662	0.211	1	76.18	20.22	2.51	1.08
Mingo Wilderness							
2001	0.417	0.228	0	80.90	17.89	1.20	0.01
2002	0.547	0.213	2	59.42	36.88	2.32	1.38
2003	0.471	0.203	0	87.39	11.23	1.29	0.09

5.1 IDENTIFICATION OF AVAILABLE RETROFIT SO_2 CONTROL TECHNOLOGIES – FUEL OIL COMBUSTION

Bailey Unit 1 and McClellan Unit 1 currently combust No. 6 fuel oil and natural gas. Because the SO_2 emissions profile from natural gas is so small, no additional controls will be considered for combustion of natural gas. This section concerns controlling SO_2 emissions from the combustion of No. 6 fuel oil.

Sulfur oxides, SO_x, are generated during fuel oil combustion from the oxidation of sulfur contained in the fuel. SO_x emissions are almost entirely dependent on the sulfur content of the fuel and are not affected by boiler size or burner design. SO_x emission from conventional combustion systems are predominantly in the form of SO_2. Since SO_2 is the predominant sulfur compound emitted from the AECC boilers, the BART analysis is specific to emissions of SO_2.

Step 1 of the top-down control review is to identify available retrofit control options for SO_2. The available SO_2 retrofit control technologies for the AECC boilers are summarized in Table 5-2. The retrofit controls include both add-on controls that eliminate SO_2 after it is formed and switching to lower sulfur fuels which reduces the formation of SO_2.

TABLE 5-2. AVAILABLE SO_2 CONTROL TECHNOLOGIES FOR BAILEY UNIT 1 AND MCCLELLAN UNIT 1

SO_2 Control Technologies
Dry Sorbent Injection
Spray Dryer Absorber (SDA) i.e., Semi-Dry Scrubber
Wet Scrubber
Circulating Dry Scrubber (CDS)
Fuel Switching

5.2 ELIMINATE TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES

Step 2 of the BART determination is to eliminate technically infeasible SO_2 control technologies that were identified in Step 1.

5.2.1 DRY SORBENT INJECTION, SPRAY DRYER ABSORPTION (SDA), WET SCRUBBER, CIRCULATING DRY SCRUBBER (CDS)

These technologies are collectively known as flue gas desulfurization (FGD) systems. FGD applications have not been used historically for SO_2 control on oil-fired units in the U.S. electric industry. As there are no known FGD applications for oil-fired units, the performance of FGDs on oil-fired units is unknown. EPA took this into account when evaluating the presumptive SO_2 emission rate for oil-fired units and determined that the presumptive emission rate should be based on the sulfur content of the fuel oil, rather than on FGD rates.[8] Since there are no applications of FGD on oil-fired units in the U.S., FGDs are considered technically infeasible for the control of SO_2 from Bailey Unit 1 and McClellan Unit 1 and are not considered further for BART.

5.2.2 FUEL SWITCHING

The AECC boilers currently burn some residual fuel oil. The most recent fuel oil shipment for Bailey was in December of 2006, and the most recent fuel oil shipment for McClellan was in April of 2009. The fuel oil that has been stored at Bailey since 2006 has an average sulfur content of 1.81 percent by weight, and the fuel oil that has been stored at McClellan since 2009 has an average sulfur content of 1.38 percent by weight.

Switching to a fuel with lower sulfur content should reduce SO_2 emissions in proportion to the reduction in the sulfur content of the fuel, assuming similar heat contents of the fuels. Fuels with lower sulfur content include lower sulfur No. 6 fuel oil, No. 2 fuel oil, or natural gas.

5.3 RANK OF TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis is to rank the technically feasible options according to effectiveness. Fuel switching is the only technically feasible control option. SO_2 emissions from fuel combustion are generally proportional to the sulfur content of the fuel. For example, combusting diesel oil (0.05 percent sulfur) should result in approximately a 96-97 percent reduction in SO_2 emissions from the AECC boilers as compared to the combustion of the current No. 6 fuel oil (1.81 and 1.38 percent sulfur for Bailey and McClellan, respectively).

Table 5-3 provides a ranking of the control levels for switching fuels in the AECC boilers.

TABLE 5-3. CONTROL EFFECTIVENESS OF TECHNICALLY FEASIBLE SO_2 CONTROL TECHNOLOGIES

Fuel Switching to:	Estimated Control Efficiency (Bailey, McClellan)
1% sulfur No. 6 fuel oil	45%, 28%
0.5% sulfur No. 6 fuel oil	72%, 64%
0.05% sulfur diesel	97%, 96%
Natural gas	99.9%, 99.9%

5.4 EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS

Step four of the BART analysis procedure is the impact analysis. The BART determination guidelines list the four factors to be considered in the impact analysis:

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[8] *Summary of Comments and Responses on the 2004 and 2001 Proposed Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations* EPA Docket Number OAR-2002-0076.

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

5.4.1 COST OF COMPLIANCE

Control Costs

The cost of the fuel switching that was used in the cost effectiveness calculations was determined by calculating the annual cost of the current No. 6 fuel oil and determining the increased cost of switching to the various lower sulfur fuels. Switching fuel to diesel will require changes to the burners and the fuel system. However, for this analysis, capital expenses were not included.

As AECC currently burns both No. 6 fuel oil and natural gas at Bailey and McClellan, the costs for these fuels were based on historical pricing, as an average dollar per MMBtu from 2000 to 2011. The supplier of the existing fuels (i.e., No. 6 fuel oil and natural gas) provided cost estimates for lower sulfur No. 6 fuel oils and diesel in phone calls with AECC staff.

Annual Tons Reduced

The annual tons reduced used in the cost effectiveness calculations were determined by subtracting the estimated controlled annual emission rates from the baseline annual emission rates.

The baseline and controlled annual emission rates were estimated by conducting a mass balance on the sulfur in the various fuels.

The sulfur content used for baseline was 1.81% for Bailey Unit 1 and 1.38% for McClellan Unit 1. Table 5-4 below summarizes the annual average sulfur content of the No. 6 fuel oil historically used at Bailey and McClellan. The most recent fuel oil shipment for Bailey was in December of 2006, and the most recent fuel oil shipment for McClellan was in April of 2009. The fuel oil that has been stored at Bailey since 2006 has an average sulfur content of 1.81 percent by weight, and the fuel oil that has been stored at McClellan since 2009 has an average sulfur content of 1.38 percent by weight.

TABLE 5-7. AVERAGE SULFUR CONTENT OF FUEL STORED AT BAILEY AND MCCLELLAN

	Bailey	McClellan
2000	1.59	1.84
2001	1.30	1.70
2002	1.69	2.21
2003	1.89	1.67
2004	1.07	1.60
2005	1.45	1.94
2006	1.33	2.08
2007	1.81	2.06
2008	1.81	2.18
2009	1.81	1.38
2010	1.81	1.38
2011	1.81	1.38
2001 - 2003 average	1.63	1.86
2009 - 2011 average	1.81	1.38

In the EPA's 2005 Regional Haze Rule BART Guidelines, EPA described baseline emissions as follows:

"The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source… In the absence of enforceable limitations, you calculate baseline emissions based upon continuation of past practice."

Since EPA states that baseline emissions should be based on anticipated annual emissions and a continuation of past practice, AECC used the sulfur content of the fuel oil currently stored at Bailey and McClellan to estimate baseline emissions for Bailey Unit 1 and McClellan Unit 1.

The No. 2 fuel oil emission rate, for example, was determined by first using the No. 2 fuel oil heat content to determine the quantity of No. 2 fuel that would be used per year:

Average annual heat input from 2007-2011 / No. 2 oil heat content

The tons per year of sulfur that is available to form sulfur compounds (i.e. SO_2 and SO_4) was calculated:

No. 2 fuel use per year * No. 2 oil density * Sulfur content in No. 2 fuel

The mass of sulfur in the form of SO_4 was estimated and subtracted from the total sulfur to determine the quantity of sulfur that could form SO_2. The SO_2 emission rate was estimated by multiplying the sulfur available to form SO_2 by the ratio of the molecular weight for

SO_2 vs. sulfur. The mass of sulfur in the form of SO_4 was estimated by reducing the baseline SO_4 emission rate in proportion to the percent reduction in fuel sulfur and then multiplying the SO_4 rate by the ratio of the molecular weight of sulfur vs. SO_4.

Tables 5-4 through and 5-8 provide a summary of the mass balance data and calculations for the future annual SO_2 emission rates.

TABLE 5-4. SUMMARY OF FUTURE ANNUAL SO_2 EMISSIONS ASSOCIATED WITH CURRENT NO. 6 FUEL OIL

Parameter	Bailey	McClellan
No. 6 Oil Heat Content (MMBtu/Mgal)	155	155
Fuel Use (gal/yr)	252,855	1,882,146
No. 6 Oil Density (lb/gal)	8.26	8.26
Average Sulfur in No. 6 Oil (%)	1.81	1.38
Average Sulfur in No. 6 Oil (tpy)	18.90	107.27
SO4 (lb/hr)	4.55	5.92
SO4 (tpy)	2.31	15.35
SO4 as Sulfur in Fuel [Assume 1 mol S for each mol SO4] (tpy)	0.39	2.56
% S as SO4	2.04	2.39
Sulfur Available for SO2 Formation [backing out Sulfur for SO4]	18.52	104.71
% S as SO2	97.96	97.61
SO2 (tpy)	37.03	209.43

TABLE 5-5. SUMMARY OF FUTURE ANNUAL SO_2 EMISSIONS ASSOCIATED WITH 1% SULFUR NO. 6 FUEL OIL

Parameter	Bailey	McClellan
No. 6 Oil Heat Content (MMBtu/Mgal)	155	155
Fuel Use (gal/yr)	252,855	1,882,146
No. 6 Oil Density (lb/gal)	8.26	8.26
Sulfur in No. 6 Oil (%)	1	1
Sulfur in No. 6 Oil (tpy)	10.44	77.73
SO4 (lb/hr)	1.26	2.14
SO4 (tpy)	0.64	5.56
SO4 as Sulfur in Fuel [Assume 1 mol S for each mol SO4] (tpy)	0.11	0.93
% S as SO4	1.02	1.19
Sulfur Available for SO2 Formation [backing out Sulfur for SO4]	10.34	76.81
% S as SO2	98.98	98.81
SO2 (tpy)	20.67	153.61

TABLE 5-6. SUMMARY OF FUTURE ANNUAL SO_2 EMISSIONS ASSOCIATED WITH 0.5% SULFUR NO. 6 FUEL OIL

Parameter	Bailey	McClellan
No. 6 Oil Heat Content (MMBtu/Mgal)	155	155
Fuel Use (gal/yr)	252,855	1,882,146
No. 6 Oil Density (lb/gal)	8.26	8.26
Sulfur in No. 6 Oil (%)	0.5	0.5
Sulfur in No. 6 Oil (tpy)	5.22	38.87
SO4 (lb/hr)	1.26	2.14
SO4 (tpy)	0.64	5.56
SO4 as Sulfur in Fuel [Assume 1 mol S for each mol SO4] (tpy)	0.11	0.93
% S as SO4	2.04	2.39
Sulfur Available for SO2 Formation [backing out Sulfur for SO4]	5.12	37.94
% S as SO2	97.96	97.61
SO2 (tpy)	10.23	75.88

TABLE 5-7. SUMMARY OF FUTURE ANNUAL SO_2 EMISSIONS ASSOCIATED WITH DIESEL

Parameter	Bailey	McClellan
No. 2 Oil Heat Content (MMBtu/Mgal)	136.15	136.15
Fuel Use (gal/yr)	287,863	2,142,730
No. 2 Oil Density (lb/gal)	7.0	7.0
Sulfur in No. 2 Oil (%)	0.05	0.05
Sulfur in No. 2 Oil (tpy)	0.50	3.75
SO4 (lb/hr)	0.13	0.21
SO4 (tpy)	0.06	0.56
SO4 as Sulfur in Fuel [Assume 1 mol S for each mol SO4] (tpy)	0.01	0.09
% S as SO4	2.11	2.47
Sulfur Available for SO2 Formation [backing out Sulfur for SO4]	0.49	3.66
% S as SO2	0.98	0.98
SO2 (tpy)	0.99	7.31

TABLE 5-8. SUMMARY OF FUTURE ANNUAL SO_2 EMISSIONS ASSOCIATED WITH NATURAL GAS

Parameter	Bailey	McClellan
Natural Gas Heat Content (MMBtu/Mscf)	1,011.00	1,011.00
Fuel Use (scf/yr)	38,766	288,558
Natural Gas Density (lb/scf)	0.5825	0.5798
Sulfur in N.G (%)	0.0437	0.0435
Sulfur in N.G. (tpy)	0.00	0.04
% S as SO4	1.22%	1.33%
Sulfur Available for SO2 Formation [backing out Sulfur for SO4]	0.00	0.04
% S as SO2	98.78%	98.67%
SO2 (tpy)	0.01	0.07

Cost Effectiveness

Table 5-9 presents a summary of the cost effectiveness of switching from the current No. 6 fuel oil to the lower sulfur fuels. The cost effectiveness was determined by dividing the annual cost increase of fuel switching by the annual tons of SO_2 reduced. Tables 5-9 and 5-10 indicate that the cost of switching to lower sulfur No. 6 fuel oil is over 1,000/ton of SO_2 reduced for Bailey Unit 1 and over $2,000/ton for McClellan Unit 1; switching to diesel is greater than $7,000/ton for Bailey Unit 1 and over $10,000/ton for McClellan Unit 1, and switching to natural gas would save AECC money.[9] Because fuel is a traded commodity, the price for fuel can vary greatly dependent upon factors such as supply, demand, as well as environmental and regulatory influences. The estimates provided by current fuel suppliers for lower sulfur fuel oils, while higher than the estimates provided in 2001-2003, are representative of today's market available at Bailey and McClellan.[10]

AECC believes for fuel switching analyses, it may not be prudent to compare pricing between natural gas and fuel oil due to the fuel price variability. It is important to note that with fuel price variability the cost effectiveness values summarized above will vary from year to year. For instance, over the past ten years, there were periods of time when fuel oil was less expensive than natural gas. During those times, the cost effectiveness numbers would yield different results – with the natural gas cost effectiveness numbers being greater than the fuel oil cost effectiveness numbers.

This is demonstrated in Figure 5-1, below, which is a historical graph of costs of natural gas and fuel oil from years 2003 through 2012. In four out of the last ten years, natural gas prices have been higher than fuel oil prices.

[9] Although AECC would save money under this scenario, the option to burn fuel oil must be maintained for electricity reliability purposes in case natural gas is not available (such as during a natural gas curtailment).

[10] Current vendor estimates (not quotes) for fuel oil with varying levels of sulfur include: 0.5% sulfur - $18/MMBtu, 1.0% - $16.90/MMBtu, $1.5% - $16.50/MMBtu, 2.0% $16.00/MMbtu

FIGURE 5-1. SUMMARY OF FUTURE ANNUAL SO_2 EMISSIONS ASSOCIATED WITH NATURAL GAS

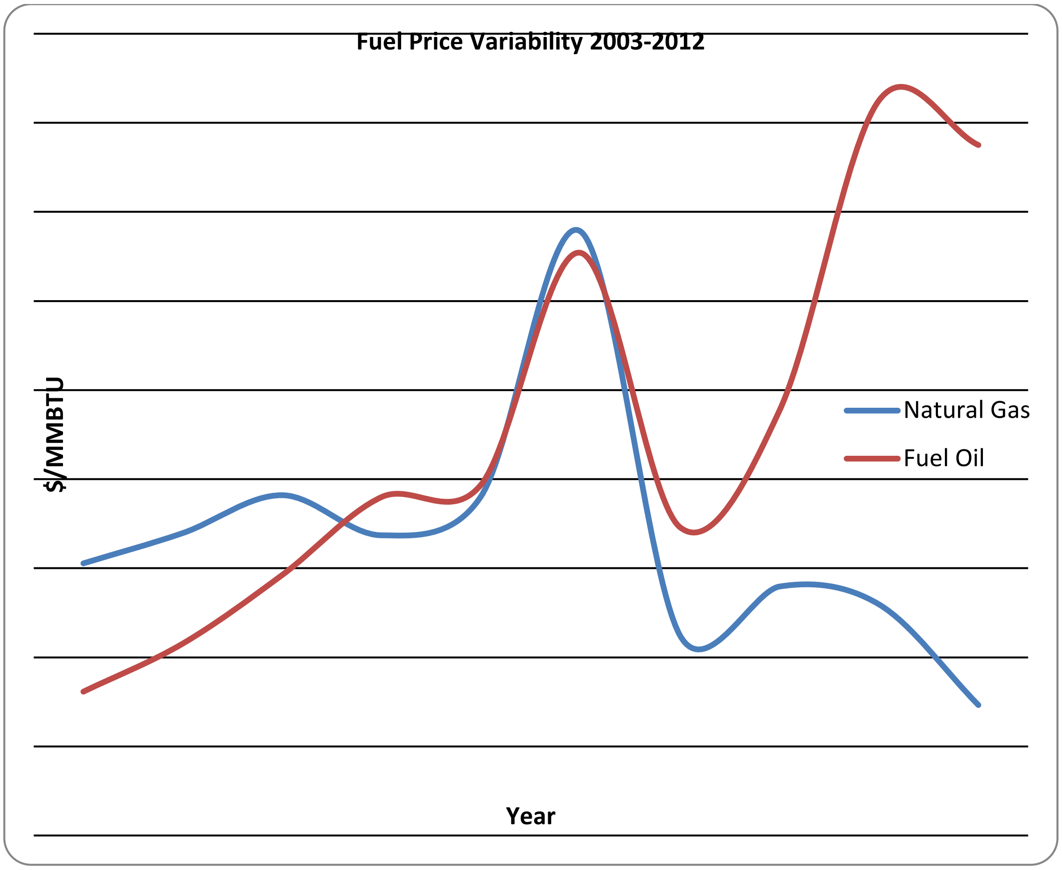

TABLE 5-9. SUMMARY OF COST EFFECTIVENESS FOR FUEL SWITCHING FOR CURRENT NO. 6 FUEL OIL AT BAILEY UNIT 1

	Average Sulfur Content[A]	Baseline SO_2 Emission Rate[B]	Controlled SO_2 Emission Rate[G]	SO_2 Reduced	Baseline PM10 Emission Rate[B]	Controlled PM10 Emission Rate[F]	PM10 Reduced	Annual Heat Input	Fuel Heating Value (HHV)[C]	Annual Fuel Usage	Fuel Cost	Differential Cost of Fuel Switching	SO_2 Cost Effectiveness[E]	PM10 Cost Effectiveness[E]
	(%)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(MMBtu/yr)	(MMBtu/Mgal) or (MMBtu/Mscf)	(Mgal/yr)	($/MMBtu)	($/yr)	($/ton)	($/ton)
Base Case[A]	1.81	37.03	-	-	25.63	-	-	39,193	155.00	252.86	16.00	-	-	-
No. 6 - 1%	1.00	-	20.67	16.36	-	8.80	16.83	39,193	155.00	252.86	16.50	$ 19,596	1,198	1,165
No. 6 - 0.5%	0.50	-	10.23	26.80	-	2.75	22.88	39,193	155.00	252.86	17.75	$ 68,587	2,559	2,998
Diesel[A]	0.05	-	0.99	36.05	-	0.13	25.50	39,193	136.15	287.86	20.95	$ 194,003	5,382	7,608
Natural Gas	-	-	0.01	37.02	-	0.26	25.37	39,193	1,011.00	38.77	6.19	$ (384,550)	-10,387	-15,158

TABLE 5-10. SUMMARY OF COST EFFECTIVENESS FOR FUEL SWITCHING FOR CURRENT NO. 6 FUEL OIL AT MCCLELLAN UNIT 1

	Average Sulfur Content[A]	Baseline SO_2 Emission Rate[B]	Controlled SO_2 Emission Rate	SO_2 Reduced	Baseline PM10 Emission Rate[B]	Controlled PM10 Emission Rate[F]	PM10 Reduced	Annual Heat Input	Fuel Heating Value (HHV)[C]	Annual Fuel Usage	Fuel Cost	Differential Cost of Fuel Switching	SO_2 Cost Effectiveness	PM10 Cost Effectiveness
	(%)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(MMBtu/yr)	(MMBtu/Mgal) or (MMBtu/Mscf)	(Mgal/yr)	($/MMBtu)	($/yr)	($/ton)	($/ton)
Base Case	1.38	209.43	-	-	136.08	-	-	291,733	155.00	1882.15	16.00	-	-	-
No. 6 - 1%	1.00	-	153.61	55.81	-	76.70	59.38	291,733	155.00	1882.15	16.50	145,866	2,613	2,457
No. 6 - 0.5%	0.50	-	75.88	133.55	-	23.94	112.14	291,733	155.00	1882.15	17.75	510,532	3,823	4,553
Diesel[A]	0.05	-	7.31	202.11	-	1.10	134.98	291,733	136.15	2142.73	20.95	1,444,077	7,145	10,698
Natural Gas	0.04	-	0.07	209.35	-	1.36	134.72	291,733	1,011.00	288.56	5.97	-2,926,874	-13,980	-21,726

[A] Sulfur content of base case No. 6 fuel oil based on average of fuel burned in 2009- 2011. Sulfur content of diesel based on average sulfur in diesel burned at AECC Fitzhugh plant during the same timeframe since diesel is not burned at Bailey or McClellan.

[B] The baseline SO2 emission rates were calcauted using the average fuel usage from 2007 to 2011, the average heat content of the No. 6 fuel oil during that same time, and the average sulfur content of the fuel during that time. The baseline PM10 emission rates are the sum of the filterable PM species as predicted by the NPS workbook (based on total PM10 rates input to the workbook).

[C] Higher heating value of residual oil based on data from supplier. Higher heating value of diesel is the average from Fitzhugh plant. Higher heating value of natural gas from 6.23.11 Bailey gas analysis and 7.12.11 gas analysis.

[F] Reductions in PM Species are based on default NPS profile.

5.4.2 ENERGY IMPACTS AND NON-AIR QUALITY IMPACTS

There are no energy or non-air quality impacts associated with fuel switching to 1% sulfur No. 6 fuel oil, 0.5% sulfur No. 6 fuel oil, or diesel. Switching to natural gas may have an impact during periods of natural gas curtailments. However, temporary permitted use of fuel oil would provide for electric grid reliability. The ability to burn fuel oil at both Bailey and McClellan is important – even if fuel oil is more expensive and difficult to burn than natural gas. During natural gas curtailments, natural gas infrastructure maintenance, and other emergencies, AECC relies on the fuel oil stored at the plants to maintain electrical reliability.

5.4.3 REMAINING USEFUL LIFE

The remaining useful lives of Bailey Unit 1 and McClellan Unit 1 do not impact the annualized capital costs since it is assumed that fuel switching will not require any significant capital costs, and thus for the purpose of this analysis there is nothing to capitalize that would require a review of the life of the equipment.

5.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE SO_2 CONTROLS

A final impact analysis was conducted to assess the visibility improvement associated with switching fuels. Tables 5-11 and 5-12 summarize the lb/hr emission rates that were modeled to reflect fuel switching as a control at Bailey and McClellan, respectively. The SO_2 emission rate in lb/MMBtu associated with the combustion of a particular fuel was calculated by scaling the existing rolling 30-day average emission rate from 2001 to 2003 by the ratio of the sulfur content of the new fuel and the current maximum annual average sulfur content from 2009 to 2011.

The controlled 30-day lb/MMBtu was converted to lb/hr by multiplying by the boiler design heat input. The calculation of the SO_2 emission rate for the one percent sulfur fuel oil for Bailey Unit 1 is provided for an example:

$$1.592 lb/MMBtu * \frac{(1.81\% - 1\%) Sulfur}{1.81\% Sulfur} = 0.880 \text{ lb/MMBtu}$$

$$0.880 lb/MMBtu * 1{,}350 MMBtu/hr = 1{,}187.62 \text{ lb/hr}$$

The SO_4 emission rate was determined assuming the reduction in SO_4 is proportional to the reduction in SO_2 from the baseline case to the controlled case. Once the SO4 emission rate was determined, this rate was assumed to be IOR CPM and the emission rate was divided by the percentage of the total PM that NPS workbook indicates is IOR CPM to get the total PM rate. The total PM rate was then entered into the NPS workbook to get the emission rates for all of the PM species. The NO_x emission rate was modeled at the baseline rate.

TABLE 5-11. SUMMARY OF EMISSION RATES MODELED TO REFLECT FUEL SWITCHING FOR SO_2 CONTROL AT BAILEY UNIT 1

Bailey Unit 1	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_x (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
1% sulfur fuel oil No. 6	1,187.6	2.5	408.8	4.7	11.7	0.4	0.9	20.3
0.5% sulfur fuel oil No. 6	593.8	1.3	408.8	1.5	3.7	0.2	0.3	6.9
Diesel	59.4	0.1	408.8	0.1	0.2	0.0	0.0	0.4
Natural gas	0.5	0.3	443.8	0.0	0.0	7.4	2.6	10.3

TABLE 5-12. SUMMARY OF EMISSION RATES MODELED TO REFLECT FUEL SWITCHING FOR SO_2 CONTROL AT MCCLELLAN UNIT 1

McClellan Unit 1	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_x (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
1% sulfur fuel oil No. 6	2,317.1	4.3	579.8	8.0	19.9	0.8	1.6	34.6
0.5% sulfur fuel oil No. 6	1,158.5	2.1	579.8	2.5	6.2	0.4	0.5	11.7
Diesel	115.9	0.2	579.8	0.1	0.3	0.0	0.0	0.7
Natural gas	0.6	0.3	423.9	0.0	0.0	7.9	2.7	10.9

Visibility improvement was evaluated by comparing the visibility impairment from the baseline scenario to the impairment for a control scenario. The baseline rate used to establish the baseline visibility impairment reflects a peak 24-hour emission rate. Thus, it would make sense that the emission rates used in control scenarios would represent the peak emission rates associated with the controls. That being said, control effectiveness is typically not evaluated on a 24-hour basis. Typically, control effectiveness for EGUs for NO_X/SO_X is based on a longer term performance, with 30-day being standard. While using rolling 30-day average emissions rates gives a lower emission rate than using peak rates, this methodology of comparing the peak to average is consistent with other accepted BART methodologies.

Comparisons of the existing visibility impacts and the visibility impacts based on fuel switching, including the maximum modeled visibility impact, 98th percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv, for each Class I area are provided in Tables 5-13 and 5-14. The visibility improvement associated with fuel switching was calculated as the difference between the existing visibility impairment and the visibility impairment for the various fuels as measured by the 98th percentile modeled visibility impact.

TABLE 5-13. SUMMARY OF MODELED IMPACTS FROM SO_2 CONTROL VISIBILITY IMPACT ANALYSIS FOR BAILEY UNIT 1 (2001-2003)

	Caney Creek Wilderness				**Upper Buffalo Wilderness**				**Hercules Glades Wilderness**				**Mingo NWR**			
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*
Baseline Emission Rate – (fuel oil)	0.970	0.330	8	-	0.696	0.348	7	-	0.687	0.368	6	-	1.592	0.379	12	-
1% sulfur fuel oil No. 6	0.544	0.193	1	41.52%	0.377	0.194	0	44.25%	0.408	0.206	0	44.02%	1.008	0.206	2	45.65%
0.5% sulfur fuel oil No. 6	0.333	0.142	0	56.97%	0.227	0.127	0	63.51%	0.279	0.135	0	63.32%	0.706	0.170	1	55.15%
Diesel	0.208	0.084	0	74.55%	0.156	0.069	0	80.17%	0.215	0.069	0	81.25%	0.429	0.095	0	74.93%
Natural gas	0.219	0.083	0	74.85%	0.170	0.072	0	79.31%	0.238	0.073	0	80.16%	0.443	0.102	0	73.09%

*Improvement is based on the 98th percentile impact (Δdv) for the control scenario compared to the 98th percentile impact (Δdv) baseline impact (Δdv).

†The visibility improvement shown in the table has been calculated from 98th percentile baseline and controlled impacts that include more decimal places than what is shown in the table. Due to rounding of the baseline and controlled 98th percentile impacts shown in the table, the visibility improvement calculated from the baseline and controlled 98th percentile impacts shown in the table may be slightly different than the visibility improvement reflected in the table.

TABLE 5-14. SUMMARY OF MODELED IMPACTS FROM SO_2 CONTROL VISIBILITY IMPACT ANALYSIS FOR MCCLELLAN UNIT 1 (2001-2003)

	Caney Creek Wilderness				Upper Buffalo Wilderness				Hercules Glades Wilderness				Mingo NWR			
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*
Baseline Emission Rate	3.015	0.622	24	-	1.323	0.266	5	-	0.662	0.231	2	-	0.547	0.228	2	-
1% sulfur fuel oil No. 6	2.671	0.537	18	13.67%	1.170	0.231	4	13.16%	0.562	0.202	1	12.55%	0.478	0.193	0	15.35%
0.5% sulfur fuel oil No. 6	1.722	0.322	8	48.23%	0.761	0.146	1	45.11%	0.294	0.115	0	50.22%	0.324	0.136	0	40.35%
Diesel	0.909	0.174	4	72.03%	0.382	0.073	0	72.56%	0.136	0.062	0	73.16%	0.190	0.080	0	64.91%
Natural gas	0.670	0.125	3	79.90%	0.258	0.052	0	80.45%	0.092	0.040	0	82.68%	0.132	0.058	0	74.56%

*Improvement is based on the 98th percentile impact (Δdv) for the control scenario compared to the 98th percentile impact (Δdv) baseline impact (Δdv)
†The visibility improvement shown in the table has been calculated from 98th percentile baseline and controlled impacts that include more decimal places than what is shown in the table. Due to rounding of the baseline and controlled 98th percentile impacts shown in the table, the visibility improvement calculated from the baseline and controlled 98th percentile impacts shown in the table may be slightly different than the visibility improvement reflected in the table.

As shown in Table 5-13, based on visibility predictions from the CALPUFF modeling system, fuel switching at Bailey Unit 1 will result in up to a 45.65, 63.51, 81.25 or 80.16 percent improvement (depending on the Class I area) to the existing visibility impairment attributable to this unit for fuel switching to 1% sulfur fuel oil, 0.5% sulfur fuel oil, diesel and natural gas, respectively. Please note that despite the varying levels of percent visibility improvement, the number of days of visibility impairment >Δ0.5 dv is 0 in many of the control cases. For example, at Hercules Glades Wilderness there are 0 days of visibility impairment greater than >Δ0.5 dv for the 1% sulfur fuel oil and also for the natural gas control although the visibility improvement varies from 44.02% to 81.25%.

As shown in Table 5-14, based on visibility predictions from the CALPUFF modeling system, fuel switching at McClellan Unit 1 will result in up to a 15.35, 50.22, 73.16, or 82.68 percent improvement (depending on the Class I area) to the existing visibility impairment attributable to this unit for fuel switching to 1% sulfur fuel oil, 0.5% sulfur fuel oil, diesel and natural gas, respectively.

5.6 PROPOSED BART FOR SO_2

AECC has determined that BART for Bailey Unit 1 and McClellan Unit 1 is fuel switching to using fuels with 0.5% sulfur or less (including natural gas). As mentioned in the Section 5.5 of this report, fuel with a sulfur content of 0.5% or less will have visibility improvements in Class I areas of up to 63.51% for Bailey and 50.22% for McClellan.

When the BART limits become effective, Bailey and McClellan would burn the existing supply of No. 6 fuel oil as the normal course of business dictates and in accordance with any operating restrictions enforced by ADEQ. Future fuel purchases will be fuels of 0.5% sulfur content or less.

While EPA might have some hesitation comparing the visibility impairment from the baseline scenario on a peak 24-hour basis to visibility impairment due to control effectiveness on a 30-day rolling average basis, the increased visibility improvement did not have a significant bearing on AECC selecting to burn 0.5% sulfur fuel oil going forward. Because burning fuel oil is necessary in addition to using natural gas from a grid reliability perspective, AECC had to select a lower sulfur fuel oil than currently received fuel oil. And because the cost/ton of the 0.5% sulfur is lower than for 1% sulfur, 0.5% sulfur is the appropriate option.

6. NO_X BART EVALUATION

On June 7, 2012 EPA published a final rule allowing states participating in the Cross-State Air Pollution Rule (CSAPR) trading program to use CSAPR to satisfy BART. Arkansas is one of the states with units subject to CSAPR that will participate in a NO_x trading program during the ozone season. EPA commented that "NO_x control in the five ozone season-only states is achieved predominantly by combustion controls."[11] Due to the nature of combustion controls, plants typically keep combustion controls in place and running year-round, even if emission limitations are seasonal. Although Arkansas is an ozone season-only state, units with combustion controls would run anytime the unit is in operation.

An email dated June 28, 2012 from ADEQ stated, "ADEQ agrees CSAPR is better than BART and the subject-to-BART sources do not need to include NOx in their five-factor analysis."[12] Therefore, AECC is not including NOx analyses in the Bailey and McClellan five-factor analyses.

On July 6, 2012 EPA published a final rule of the Nebraska Regional Haze Federal Implementation Plan (FIP).[13] Nebraska is subject to CSAPR for annual SO_2 and NO_x. The FIP reviewed the Nebraska suggest BART for NO_x, but ultimately stated that because CSAPR satisfies BART, CSAPR controls will equate with BART in the state.[14]

AECC is proposing to satisfy BART for NO_x by complying with CSAPR at Bailey Unit 1 and McClellan Unit 1.[15]

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[11] "Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available Retrofit Technology (BART) Determination, Limited SIP Disapprovals, and Federal Implementation Plans." CFR Vol. 77, No. 110. Thursday, June 7, 2012, Rules and Regulations. Page 33651.

[12] Email from Mary Pettyjohn of ADEQ to subject-to-BART unit operators dated June 28, 2012.

[13] "Approval, Disapproval and Promulgation of Implementation Plans; State of Nebraska; Regional Haze State Implementation Plan; Federal Implementation Plan for Best Available Retrofit Technology Determination." CFR Vol. 77, No. 130. Friday, July 6, 2012. Page 40150.

[14] Ibid, 40151.

[15] This proposal was originally submitted on July 24, 2012. In response to CSAPR being vacated on August 21, 2012, AECC submitted a five-factor analysis for NOx to ADEQ in September 2012 as an addendum to this analysis.

7.1 IDENTIFICATION OF AVAILABLE RETROFIT PM_{10} CONTROL TECHNOLOGIES

PM_{10} emissions are either "filterable" or "condensable". Filterable PM_{10} is generally considered to be particles less than or equal to 10 microns in diameter that are trapped by a filter during testing of exhaust gas. Condensable PM is material that is emitted in the vapor state but that condenses in the atmosphere to form particles. Filterable PM_{10} emissions from fuel oil combustion depend predominantly on the grade of fuel oil fired. Combustion of lighter distillate oils results in significantly lower PM_{10} formation than does combustion of heavier residual oils. Among residual oils, firing of No. 4 or No. 5 oil usually produces less PM_{10} than does the firing of heavier residual oil. This is due to the higher ash and sulfur contents of residual oil compared to lighter oils.

Step 1 of the BART determination is the identification of all available retrofit PM_{10} control technologies. The available retrofit PM_{10} control technologies are summarized in Table 6-2 for Bailey Unit 1 and McClellan Unit 1.

TABLE 7-1. AVAILABLE PM CONTROL TECHNOLOGIES FOR BAILEY UNIT 1 AND MCCLELLAN UNIT 1

PM_{10} Control Technologies
Dry Electrostatic Precipitator (ESP)
Wet Electrostatic Precipitator (ESP)
Fabric Filter
Wet Scrubber
Cyclone
Fuel Switching

7.2 ELIMINATE TECHNICALLY INFEASIBLE PM CONTROL TECHNOLOGIES

Step 2 of the BART determination is to eliminate technically infeasible PM control technologies that were identified in Step 1.

7.2.1 DRY ELECTROSTATIC PRECIPITATORS (ESP)

A dry ESP operates by first placing a charge on the particles through a series of electrodes, and then capturing the charged particles on collection plates. Particles from oil-fired boilers tend to be sticky and small. Because of these properties and a general lack of existence in practice, a dry ESP is not a good technological match for either Bailey Unit 1 or McClellan Unit 1.

7.2.2 WET ELECTROSTATIC PRECIPITATORS (ESP)

A wet ESP operates similarly to a dry ESP but is a better technological match for oil-fired boilers because it is not sensitive to small and sticky particulates. A wet ESP utilizes water to collect and remove the particles, and will produce a waste-water product. Flue gas leaving wet ESPs will be saturated and may result in a visual steam plume exiting the stack. The estimated PM control efficiency is up to 90% for a wet ESP.[16] Wet ESP is a technically feasible option for control of PM_{10} for Bailey Unit 1 and McClellan Unit 1.

7.2.3 MECHANICAL COLLECTORS (CYCLONES)

Mechanical collectors, or cyclones, control particulates generated during soot blowing, during upset conditions, or when a heavy oil is fired. For these situations, high-efficiency cyclonic collectors can achieve up to 85% control of particulate.[17] This control is designed for the larger PM size fractions, and thus, when firing residual oil, the control will not be as effective at controlling the smaller particles that are the primary source of visibility impairment. Further, when a clean oil is combusted, cyclonic collectors are not nearly so effective because of the high percentage of small particles (less than 3 micrometers in diameter) emitted.

7.2.4 FABRIC FILTER

Fabric filters work by filtering the PM in flue gas through filter bags. The collected particles are periodically removed from the bag through a pulse jet or reverse flow mechanism. Due to the sticky nature of particles from oil-fired boilers and the associated hazard from flammability of their use, fabric filters are not used to control PM from boilers firing residual oil. Thus, fabric filters are not technically feasible for Bailey Unit 1 and McClellan Unit 1.

7.2.5 WET SCRUBBER

Wet scrubbers remove PM from flue gas by contacting it with a scrubbing liquid using one of several approaches: spraying the gas stream with the liquid, forcing the gas stream through a pool of liquid, or by some other contact method. PM in the gas stream is captured in the scrubbing liquid. The PM-laden scrubbing liquid is separated from the gas stream, and the resultant scrubbing liquid is treated prior to discharge or reuse in the plant. Problems associated with scrubbers include corrosion issues, high power requirements, and water-disposal challenges. However, the use of wet scrubbers for Bailey Unit 1 and McClellan Unit 1 is considered a technically feasible option. The estimated PM_{10} removal efficiency for a wet scrubber is 50-60%.[18]

While wet scrubbers are considered technically feasible, it is worth noting the wet scrubbers are not very efficient at controlling submicron size particles. When drops of water are suspended in a stream of air containing particles, such as they are in wet scrubbers, the air must go around the drops to pass through the scrubber. This creates streamlines of higher velocity air near each drop. For particles to be captured, they must push through these streamlines to the surface of the drop. Particles that are smaller than 1 micron are hardest to control because they follow the streamlines and avoid contact with

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[16] Ibid.

[17] AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.3.4.1

[18] AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.3.4.1

the drop. As particle size decreases, more energy is needed to force contact with the drops. This makes conventional scrubbers ineffective for particles smaller than a few microns.[19] While the majority of the PM emissions for Bailey Unit 1 and McClellan Unit 1 are not less than a few microns, particles of this size have the highest ability to impair visibility; thus, a wet scrubber may not be effective at controlling the particles that have the greatest ability to impair visibility.

7.2.6 FUEL SWITCHING

Residual oil has inherent ash that contributes to the emissions of filterable PM. Lower grades of fuel oil have less ash and ultimately lower filterable PM emissions. Filterable PM emissions could be reduced by switching to a lower grade fuel oil or natural gas. Section 5 discussed the option of fuel switching with respect to reducing SO_2 emissions.

Distillate fuel oil has only trace amounts of ash.[20] It is estimated that filterable PM_{10} emissions would be reduced in proportion to the reduction in ash content. Based on the reduction in ash content, reductions of filterable PM_{10} would be expected to be greater than 99%. Reductions in filterable PM_{10} in No. 6 fuel oil are directly related to the sulfur content of the fuel, as seen in AP-42, 1.3-1. The percent reduction in filterable PM_{10} from fuel switching to natural gas is estimated from the reduced ash content in natural gas (trace amount) as compared to current No. 6 fuel, 0.035% ash content, for 99% control efficiency.

7.3 RANK OF TECHNICALLY FEASIBLE PM_{10} CONTROL OPTIONS BY EFFECTIVENESS

Step 3 of the top-down control review is to rank the technically feasible options according to effectiveness. Table 7-3 provides a ranking of the control levels for the controls listed in the previous section.

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[19] http://www.tri-mer.com/q&a/comparing-electrostatic-precipitator.htm

[20] *Combustion-Fossil Power Systems*, J.G. Singer published by Combustion Engineer, Inc.[21]AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.3.4.1, 9.19(S)+3.22. For Bailey, the average sulfur content of fuel delivered in 2009-2011 was 1.81%, and the average fuel usage was 252,855 gal. For McClellan these values were 1.38% sulfur and 1,882,146 gal. Bailey: $(9.19*(1.81)+3.22)*(252{,}855*10^3/200) = 2.51$ tpy. McClellan: $(9.19*(1.38)+3.22)*(1{,}882{,}146*10^3/200) = 14.97$ tpy

TABLE 7-3. CONTROL EFFECTIVENESS OF TECHNICALLY FEASIBLE PM CONTROL TECHNOLOGIES

Control Technology	Control Efficiency[21] (%)
Fuel Switching	≤99%
Wet ESP	≤90
Cyclone	85%
Wet Scrubber	55%

7.4 EVALUATION OF IMPACTS FOR FEASIBLE PM_{10} CONTROLS

Step four for the BART analysis procedure is the impact analysis. The BART determination guidelines list the four factors to be considered in the impact analysis:

- ▲ Cost of compliance
- ▲ Energy impacts
- ▲ Non-air quality impacts; and
- ▲ The remaining useful life of the source

7.4.1 COST OF COMPLIANCE

The capital costs, operating costs, and cost effectiveness of wet ESPs, cyclones and wet scrubbers have been estimated for Bailey Unit 1 and McClellan Unit 1. The cost effectiveness of fuel switching to 1% sulfur fuel oil, 0.5% sulfur fuel oil, diesel and natural gas has also been estimated.

Control Costs

The capital and operating costs of the wet ESP and wet scrubber were prepared by AECC using Electric Power Research Institute's (EPRI) IECCOST Software, and cyclone estimates were derived from EPA estimates. The capital costs were annualized over a 15-year period and then added to the annual operating costs to obtain the total annualized costs. The details of the capital and operating cost estimates are provided in Appendix B of this report.

Annual Tons Reduced

The annual tons reduced that were used in the cost effectiveness calculations were determined by subtracting the estimated controlled annual emission rates from the baseline annual emission rates, as calculated from AP-42: 1.3-1. The controlled annual emission rates were estimated by reducing the existing annual emission rate by the control percentages shown in Table 7-3.

[21] AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.3.4.1, 9.19(S)+3.22. For Bailey, the average sulfur content of fuel delivered in 2009-2011 was 1.81%, and the average fuel usage was 252,855 gal. For McClellan these values were 1.38% sulfur and 1,882,146 gal. Bailey: $(9.19*(1.81)+3.22)*(252,855*10^3/200) = 2.51$ tpy. McClellan: $(9.19*(1.38)+3.22)*(1,882,146*10^3/200) = 14.97$ tpy

Cost Effectiveness

The cost effectiveness was determined by dividing the annualized cost by the annual tons reduced. The costs effectiveness analysis is summarized in Tables 7-4 and 7-5.

Table 7-4 indicates that the cost effectiveness of switching to natural gas is over $5,000/ton for each boiler. Further, Tables 7-4 and 7-5 indicate that the cost effectiveness for all other controls is excessively expensive at $300,217/ton for fuel switching to diesel at McClellan Unit 1 to $36,326,871/ton for a wet scrubber at Bailey Unit 1.

7.4.1.1 ENERGY IMPACTS AND NON-AIR QUALITY IMPACTS

There are no energy or non-air quality impacts associated with fuel switching, but there are impacts associated with wet ESPs and wet scrubbers. ESPs by design apply energy to the particles they are collecting. This energy usage can be significant, especially if the wet ESP is designed to control submicron size particles where more energy is applied to collect more of the particles. Wet scrubbers also require a substantial amount of energy to force exhaust gases through the scrubber.

Both wet ESPs and wet scrubber generate wastewater streams that must either be treated on-site or sent to a waste water treatment plant. Further, the wastewater treatment process will generate a filter cake that would likely require land-filling.

7.4.1.2 REMAINING USEFUL LIFE

The remaining useful lives of Bailey Unit 1 and McClellan Unit 1 do not impact the annualized capital costs of the wet ESP, wet scrubber, or cyclone because the useful life of the boilers is anticipated to be at least as long as the capital cost recovery period, which is 15 years. Further, the remaining useful lives of Bailey Unit 1 and McClellan Unit 1 do not impact the annualized fuel cost, since it is assumed that fuel switching will not require any capital costs, and thus there is nothing to capitalize that would require a review of the life of the equipment.

TABLE 7-4. SUMMARY OF COST EFFECTIVENESS FOR BAILEY UNIT 1 PM_{10} CONTROLS

	Baseline Emission Rate	Control Efficiency	Annual Heat Input[A]	Controlled Emission Rate	PM_{10} Reduced	Capital Cost	Total Annual Cost	Cost Effectiveness
	(tpy)	%	(MMBtu/yr)	(tpy)	(ton/yr)	($)	($/yr)	($/ton)
Wet ESP	25.63	90.00	39,193	2.56	23.06	105,141,431	22,638,340	981,583
Wet Scrubber	25.63	55.00	39,193	11.53	14.09	140,957,713	50,150,862	3,558,286
Cyclone	25.63	85.00	39,193	3.84	21.78	989,479	1,188,630	54,570
No. 6 Fuel Oil - 1%	25.63	-	39,193	8.80	16.83	-	463,185	27,528
No 6. Fuel Oil - 0.5%	25.63	-	39,193	2.75	22.88	-	512,175	22,386
Diesel	25.63	-	39,193	0.13	25.50	-	637,592	25,004
Natural Gas	25.63	-	39,193	0.26	25.37	-	59,038	2,327

[A] Annual Heat Input derived for 2007-2011 average fuel usage times the heat content of No. 6 fuel oil

TABLE 7-5. SUMMARY OF COST EFFECTIVENESS FOR MCCLELLAN UNIT 1 PM_{10} CONTROLS

	Baseline Emission Rate	Control Efficiency	Annual Heat Input[A]	Controlled Emission Rate	PM_{10} Reduced	Capital Cost	Total Annual Cost	Cost Effectiveness
	(tpy)	%	(MMBtu/yr)	(tpy)	(ton/yr)	($)	($/yr)	($/ton)
Wet ESP	136.08	90.00	291,733	13.61	122.47	151,509,333	32,605,907	266,237
Wet Scrubber	136.08	55.00	291,733	61.23	74.84	146,303,011	52,056,542	695,549
Cyclone	136.08	85.00	291,733	20.41	115.67	1,432,971	1,721,384	14,882
No. 6 Fuel Oil - 1%	136.08	-	291,733	76.70	59.38	-	3,149,652	53,044
No 6. Fuel Oil - 0.5%	136.08	-	291,733	23.94	112.14	-	3,514,317	31,338
Diesel	136.08	-	291,733	1.10	134.98	-	4,447,862	32,952
Natural Gas	136.08	-	291,733	1.36	134.72	-	76,911	571

[A] Annual Heat Input derived for 2007-2011 average fuel usage times the heat content of No. 6 fuel oil

7.5 Evaluation of Visibility Impact of Feasible PM_{10} Controls

A final impact analysis was conducted to assess the visibility improvement associated with wet ESPs, wet scrubbers, and cyclones. Note that fuel switching has impacts on both SO_2 and PM, as shown in Section 5 of this report. Section 4 of this report documented the existing visibility impairment attributable to Bailey Unit 1 and McClellan Unit 1.

In order to assess the visibility improvement associated with wet ESPs, scrubbers, and cyclones the maximum short-term PM_{10} emission rates associated with these controls were modeled using CALPUFF. The maximum short-term PM_{10} emission rates associated with wet ESPs, scrubbers, and cyclones were calculated by reducing the uncontrolled yearly PM_{10} emission rates, in Table 7-4, by the control percentages shown in Table 7-3. Tables 7-5 through 7-7 summarize the emission rates that were modeled to reflect the wet ESPs, wet scrubbers, and cyclones, respectively. The emission rates for the pollutants shown in Tables 7-5 through 7-7 for NO_X and SO_2 that are not PM are the same as in the baseline modeling.

TABLE 7-5. SUMMARY OF EMISSION RATES MODELED TO REFLECT WET ESP FOR PM_{10} CONTROL

Unit	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
Bailey Unit 1	2,375.8	0.4	408.8	1.2	3.0	0.1	0.2	4.9
McClellan Unit 1	2,747.5	0.5	579.8	1.2	2.9	0.1	0.2	4.8

TABLE 7-6. SUMMARY OF EMISSION RATES MODELED TO REFLECT WET SCRUBBER FOR PM_{10} CONTROL

Unit	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
Bailey Unit 1	2,375.8	1.8	408.8	5.5	13.6	0.3	1.1	22.2
McClellan Unit 1	2,747.5	2.2	579.8	5.2	12.9	0.4	1.0	21.7

TABLE 7-7. SUMMARY OF EMISSION RATES MODELED TO REFLECT CYCLONE FOR PM_{10} CONTROL

Unit	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
Bailey Unit 1	2,375.8	4.0	408.8	1.8	4.5	0.7	0.4	7.4
McClellan Unit 1	2,747.5	4.8	579.8	1.7	4.3	0.8	0.3	7.2

Comparisons of the existing visibility impacts and the visibility impacts for PM-specific controls, excluding fuels switching which are included in Section 5, including the maximum modeled visibility impact, 98^{th} percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv, for each Class I area are provided in Tables 7-8 and 7-9. The visibility improvement associated with PM controls was calculated as the difference between the existing visibility impairment and the visibility impairment for the control as measured by the 98th percentile modeled visibility impact.

TABLE 7-8. SUMMARY OF MODELED IMPACTS FROM PM_{10} CONTROL VISIBILITY IMPACT ANALYSIS FOR BAILEY UNIT 1 (2001-2003)

	Caney Creek Wilderness				**Upper Buffalo Wilderness**				**Hercules Glades Wilderness**				**Mingo NWR**			
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*
Baseline Emission Rate	0.969	0.330	8	-	0.695	0.347	7	-	0.686	0.367	6	-	1.589	0.378	12	-
Wet ESP	0.961	0.327	8	0.91%	0.687	0.343	6	1.15%	0.677	0.356	5	3.00%	1.572	0.371	12	1.85%
Wet Scrubber	0.964	0.328	8	0.61%	0.690	0.345	6	0.58%	0.681	0.360	5	1.91%	1.579	0.374	12	1.06%
Cyclone	0.965	0.328	8	0.61%	0.691	0.345	7	0.58%	0.682	0.361	5	1.63%	1.580	0.374	12	1.06%

*Improvement is based on the 98th percentile impact (Δdv) for the control scenario compared to the 98th percentile impact (Δdv) baseline impact (Δdv)

†The visibility improvement shown in the table has been calculated from 98th percentile baseline and controlled impacts that include more decimal places than what is shown in the table. Due to rounding of the baseline and controlled 98th percentile impacts shown in the table, the visibility improvement calculated from the baseline and controlled 98th percentile impacts shown in the table may be slightly different than the visibility improvement reflected in the table.

TABLE 7-9. SUMMARY OF MODELED IMPACTS FROM PM_{10} CONTROL VISIBILITY IMPACT ANALYSIS FOR MCCLELLAN UNIT 1 (2001-2003)

	Caney Creek Wilderness				Upper Buffalo Wilderness				Hercules Glades Wilderness				Mingo NWR			
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*
Baseline Emission Rate	3.007	0.621	22	-	1.319	0.266	5	-	0.660	0.230	2	-	0.546	0.227	2	-
Wet ESP	2.977	0.617	21	0.64%	1.305	0.263	5	1.13%	0.656	0.227	2	1.30%	0.540	0.223	2	1.76%
Wet Scrubber	2.989	0.619	21	0.32%	1.311	0.264	5	0.75%	0.657	0.228	2	0.87%	0.542	0.224	2	1.32%
Cyclone	2.993	0.619	21	0.32%	1.313	0.265	5	0.38%	0.658	0.229	2	0.43%	0.543	0.225	2	0.88%

*Improvement is based on the 98th percentile impact (Δdv) for the control scenario compared to the 98th percentile impact (Δdv) baseline impact (Δdv)

†The visibility improvement shown in the table has been calculated from 98th percentile baseline and controlled impacts that include more decimal places than what is shown in the table. Due to rounding of the baseline and controlled 98th percentile impacts shown in the table, the visibility improvement calculated from the baseline and controlled 98th percentile impacts shown in the table may be slightly different than the visibility improvement reflected in the table.

As shown in Table 7-8, the operation of wet ESPs results in an estimated 0.003 to 0.004 Δdv improvement (0.64 to 1.76 percent) of the 98th percentile visibility impairment attributable to Bailey Unit 1 at the applicable Class I areas. Further, as shown in Table 7-8, the operation of wet scrubbers results in an estimated 0.002 to 0.003 Δdv improvement (0.32 to 1.32 percent) of the 98th percentile visibility impairment attributable to Bailey Unit 1, and the operation of cyclones results in an estimated 0.001 to 0.002 Δdv improvement (0.32 to 0.88 percent) of the 98th percentile visibility impairment attributable to Bailey Unit 1.

As shown in Table 7-9, the operation of wet ESPs results in an estimated 0.003 to 0.011 Δdv improvement (0.91 to 3.00 percent) of the 98th percentile visibility impairment attributable to McClellan Unit 1 at the applicable Class I areas. Further, as shown in Table 7-9, the operation of wet scrubbers results in an estimated 0.002 to 0.007 Δdv improvement (0.58 to 1.91 percent) of the 98th percentile visibility impairment attributable to McClellan Unit 1, and the operation of cyclones results in an estimated 0.002 to 0.006 Δdv improvement (0.58 to 1.63 percent) of the 98th percentile visibility impairment attributable to McClellan Unit 1.

7.6 PROPOSED BART FOR PM_{10}

The cost effectiveness of all the PM controls evaluated for both the boilers is greater than $5,000/ton, and for most controls is <u>much greater than</u> $5,000/ton. Based on the low PM_{10} emission from the boilers (less than 15 tpy for either Bailey Unit 1 or McClellan Unit 1) and the related low improvement to the visibility impairment attributable to the boilers based on the application of the controls (only up to 0.011 Δdv), none of the controls are determined to satisfy BART. Thus, there are no fuel changes or add-on controls proposed as BART for PM_{10} for Bailey Unit 1 or McClellan Unit 1.[22]

[22] However, AECC is proposing fuel switching to 0.5% sulfur fuel oil as BART for SO_2.

APPENDIX A

PM_{10} CONTROL COST CALCULATIONS

Capital Costs		Total Direct Capital	
Technology Wet ESP		Bailey	McClellan
Average High Exhaust Flow Rate (ACFM)[1]		342,529	493,587
Electricity Cost ($Cost_{elect}$, $/kwh)[2]		$0.05	$0.05
Water Cost ($Cost_{water}$, $/gal)[3]		$0.00362	$0.00362
Annual Operating Time (hrs, θ')		8,760	8,760
ESP efficiency (from white paper)		90%	90%
ESP Plate Area (ft^2)[4]	ESCA = $-\ln(p)/w_e \times 5.080 \times Q$	12,760	18,387
Purchased Equipment Cost (Based on 90% Control Efficiency, 2nd Quarter 1987 dollars) - Table 3.14	$33.9/acfm	$11,611,748	$16,732,588
Basic Equipment Costs -Table 3.12	0.45 × Equipment Cost	$5,225,287	$7,529,665
Direct Costs - Table 3.16			
Purchased equipment costs			
ESP + auxiliary equipment (A)	As estimated, A	$16,837,035	$24,262,253
Instrumentation	0.10 A	$1,683,704	$2,426,225
Sales taxes	0.03 A	$505,111	$727,868
Freight	0.05 A	$841,852	$1,213,113
Purchased Equipment cost, PEC	B = 1.18 A	$19,867,701	$28,629,458
Direct Installation Costs Table 3.16			
Foundation & supports	0.04 B	$794,708	$1,145,178
Handling & erection	0.50 B	$9,933,851	$14,314,729
Electrical	0.08 B	$1,589,416	$2,290,357
Piping	0.01 B	$198,677	$286,295
Insulation for ductwork	0.02B	$397,354	$572,589
Painting	0.02B	$397,354	$572,589
Direct Installation Costs	**0.67 B**	**$13,311,360**	**$19,181,737**
Indirect Costs (installation) Table 3.16			
Engineering	0.20B	$3,973,540	$5,725,892
Construction & field expenses	0.20B	$3,973,540	$5,725,892
Contractor fees	0.10B	$1,986,770	$2,862,946
Start-up	0.01B	$198,677	$286,295
Performance test	0.01B	$198,677	$286,295
Model study	0.02B	$397,354	$572,589
Contingencies	0.03B	$596,031	$858,884
Total Indirect Costs, IC	**0.57B**	**$11,324,590**	**$16,318,791**
Cost Index[5]			
a. 2011	585		
b. 1987 Second Quarter (June)	321.9		
Capital recovery factor (CRF)	CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life a. Equipment CRF, 15-yr life, 7% interest	0.11	0.11
TOTAL CAPITAL INVESTMENT (2012$)	**(DC + IC) * (Retrofit factor of 1.4)*(CI_{2012}/CI_{1987}) (Retrofit factor based on average provided for ESP on Page 3-41). No specific factor provided for scrubber, so factor for ESP was relied on.**	**$105,141,431**	**$151,509,333**

Annual Costs			
Direct Annual Costs - Table 2.9			
Operating Labor			
Operator	3hr/shift*2shifts/day*360 days/yr * $12/hr (Assumed operator hrs/day consistent with example on Page 2-57, will adjust pay for 2012 dollars)	$25,920	$25,920
Supervisor	15% of operator	$3,888	$3,888
Maintenance			
Labor	For ESP plate area < 50,000 ft^2 = $4125	$4,125	$4,125
Material	= 0.01 × B	$198,677	$286,295
Utilities			
Fan[6]	$= 0.000181 \times Q \times \Delta P \times \theta' \times Cost_{elect}$	$121,655	$175,305
ESP operating power[7]	$= 1.94 \times 10^{-3} \times A \times \theta'$	$216,847	$312,478
Pump[8]	$= 0.746 \times Q_l \times Z \times S_g \times \theta' / 3{,}960\eta \times$ Costelect	$11,776	$16,970
Water Use (gal/yr)	5 gpm/1000 acfm × air flow × minutes operated per year	900,167,392	1,297,145,760
Water Cost	= Water use × water cost	$3,258,606	$4,695,668
Wastewater treatment	$3.25/1000 gal × Annual water use (based on EPA Manual, 2012 dollars)	$2,925,544	$4,215,724
Total Direct Annual Cost		**$6,767,038**	**$9,736,371**
Indirect Costs, IC			
Administrative charges	2% of Total Capital Investment	$2,102,829	$3,030,187
Property tax	1% of Total Capital Investment	$1,051,414	$1,515,093
Insurance	1% of Total Capital Investment	$1,051,414	$1,515,093
Overhead	60% of total labor and material costs	$121,681	$174,252
Annualized Capital Cost	Capital Recovery Factor * Total Capital Investment	$11,543,964	$16,634,910
Total Indirect Annual Costs		**$15,871,302**	**$22,869,535**
TOTAL ANNUAL COST		**$22,638,340**	**$32,605,907**

Cost estimates made using the EPA Air Pollution Control Cost Manual (APCCM), 6th Edition (January 2002). Section 6, Chapter 3 - Electrostatic Precipitators

Notes:

[1] From RATA data, see 'Exhaust Flowrates' tab for source of system flowrate

[2] Electricity cost form Arkansas Industrial Energy Clearinghouse, http://www.arkansasiec.org/newsmanager/templates/?a=71&z=1

[3] Water cost estimate from Bentonville, AK commercial rate of $0.00362/gal, http://www.bentonvillear.com/utbc_rates.html

[4] For ESP Plate Area:
p = 1 - (Eff/100)
w_e = effective migration velocity (m/s), assume w_e = 31.4 cm/s for Bituminous coal fly ash for a design efficiency of 95% from Table 3.3 (no listings for 90% efficiency or fuel oil)
Q = system flow rate (kacfm)

[5] From Chemical Engineering Plant Cost Index (CEPCI)

[6] For fan power cost:
Q = system flow rate (acfm)
ΔP = system pressure drop (in. H_2O)

Assuming ΔP = 0.38 in. H2O for inlet diffuser plate, inlet and outlet transitions, baffles and plates from Table 3.11, assume ductwork contributres 4.1 in. H_2O (based on EPA Manual). Total pressure drop is 4.48 in. H_2O
θ' = annual operating time (h/yr)

[7] For ESP power cost
A = ESP plate area (ft^2)
θ' = annual operating time (h/yr)

[8] For pump power cost:

Q_l = water flow rate (gal/min)

Z = Fluid head (ft), assume maximum fluid heat is 50 ft

S_g = specific gravity of water being pumped compared to water at 70 °F and 29.92 in. Hg, assume 1

θ' = annual operating time (h/yr)

η = pump motor efficiency (fractional), assume efficiency of 60%

Capital Costs		Total Direct Capital	
Technology WFGD		Bailey	McClellan
Installed Capital Cost (TCI)[1]		$140,957,713	$146,303,011
Annual Costs			
	Equation	Bailey	McClellan
Annualized Fixed O&M		$6,952,216	$7,184,611
Annualized Fixed Charges		$27,120,264	$28,148,699
Annualized Fixed O&M + Fixed Charges		$34,072,480	$35,333,310
Annualized Variable O&M		$601,983	$659,948
Capital Recovery Factor (CRF)	CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life a. Equipment CRF, 15-yr life, 7% interest	0.11	0.11
Annualized Installed Capital Cost	= TCI × CRF	$15,476,399	$16,063,284
Total Annual Costs ($/yr)		$50,150,862	$52,056,542

Notes:

Cost estimates were prepared by AECC using Electric Power Research Institute (EPRI) IECCOST Software.

[1] Includes equipment and installation costs

Capital Costs			
Technology Cyclone		Bailey	McClellan
Average High Exhaust Flow Rate[1] (DSCFM)		234,781	340,011
Cost Index[2] a. 2011 b. 2002	 585 395.6		
Capital Cost[3]	\$2.85/scfm [4]	\$989,479	\$1,432,971
O&M Cost (annual)	\$4.6/scfm [4]	\$1,079,991	\$1,564,051
Capital recovery factor (CRF)	CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life a. Equipment CRF, 15-yr life, 7% interest	0.11	0.11
Annualized Installed Capital Cost	= TCI × CRF	\$108,639	\$157,333
Total Annual Costs (\$/yr)		\$1,188,630	\$1,721,384

Notes:

[1] Average WSCFM flow rate determined from 2011 RATA

[2] From Chemical Engineering Plant Cost Index (CEPCI)

[3] Capital cost adjusted to 2011 cost index using CEPCI cost index

[4] Capital and O&M costs are averaged from the cost ranges given in the EPA Cyclones Air Pollution Control Technology Fact Sheet, document # EPA-452/F-03-005. These costs are expressed in 2002 dollars. Costing was performed for one cyclone. The EPA Cyclone fact sheet states that these costs are based on air flow rates up to 106,000 scfm. Both Bailey and McClellan have air flow rates above this guideline, so it may be necessary to treat the air flow with two cyclones operating in parallel (as stated by the fact sheet)

APPENDIX B

MODELING PROTOCOL

CALMET DATA PROCESSING PROTOCOL ▲ BART DETERMINATION
OKLAHOMA GAS & ELECTRIC

MUSKOGEE GENERATING STATION
SEMINOLE GENERATING STATION
SOONER GENERATING STATION

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Project 083701.0004

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1. INTRODUCTION

Oklahoma Gas & Electric (OG&E) owns and operates three electric generating stations near Muskogee, Oklahoma (Muskogee Generating Station), Seminole, Oklahoma (Seminole Generating Station), and Stillwater, Oklahoma (Sooner Generating Station). These generating stations are considered eligible to be regulated under the U.S. Environmental Protection Agency's (EPA) Best Available Retrofit Technology (BART) provisions of the Regional Haze Rule. This protocol describes the proposed methodology for conducting the CALMET data processing for the refined CALPUFF BART modeling analysis for OG&E's Muskogee, Seminole, and Sooner Generating Stations. A detailed CALPUFF BART modeling protocol will be submitted in the near future and will include a discussion of the CALPUFF parameters as well as the post processing methodologies to be used in the refined modeling analysis for each station.

1.1 BEST AVAILABLE RETROFIT TECHNOLOGY RULE BACKGROUND

On July 1, 1999, the U.S. Environmental EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to improve visibility in 156 specific areas across with United States, known as Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence on August 7, 1977.

On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the BART rule, which included guidance for making source-specific Best Available Retrofit Technology (BART) determinations. The BART rule defines BART-eligible sources as sources that meet the following criteria:

(1) Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant,
(2) Began operation between August 7, 1962 and August 7, 1977, and
(3) Are listed as one of the 26 listed source categories in the guidance.

A BART-eligible source is not automatically subject to BART. Rather, BART-eligible sources are subject-to-BART if the sources are "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." EPA has determined that sources are reasonably anticipated to cause or contribute to visibility impairment if the visibility impacts from a source are greater than 0.5 deciviews (dv) when compared against a natural background.

Air quality modeling is the tool that is used to determine a source's visibility impacts. States have the authority to exempt certain BART-eligible sources from installing BART controls if the results of the dispersion modeling demonstrate that the source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I area. Further, states also have the authority to define the modeling procedures for conducting modeling related to making BART determinations.

1.2 OBJECTIVE

The objective of this document is to provide a protocol summarizing the modeling methods and procedures that will be followed to conduct the CALMET data processing necessary to complete a refined CALPUFF modeling analysis for the OG&E generating stations discussed above. The modeling methods and procedures contained in this protocol and the CALPUFF protocol yet to be submitted will be used to determine appropriate controls for OG&E's BART-eligible sources that can reasonably be anticipated to reduce the sources' effects on or contribution to visibility impairment in the surrounding Class I areas. It is OG&E's intent to determine a combination of emissions controls that will reduce the impact of each generating station to a degree that the 98^{th} percentile of the visibility impact predicted by the model due to all the BART eligible sources at each station collectively is below EPA's recommended visibility contribution threshold of 0.5 Δdv.

1.3 LOCATION OF SOURCES AND RELEVANT CLASS I AREAS

The sources listed in Table 1-1 are the sources that have been identified by OG&E as sources that meet the three criteria for BART-eligible sources.

TABLE 1-1. BART-ELIGIBLE SOURCES

EPN	Description
	Muskogee Sources
Unit 4	5,480 MMBtu/hr Coal Fired Boiler
Unit 5	5,480 MMBtu/hr Coal Fired Boiler
	Seminole Sources
SM1	5,480 MMBtu/hr Natural Gas Fired Boiler
SM2	5,480 MMBtu/hr Natural Gas Fired Boiler
SM3	5,496 MMBtu/hr Natural Gas Fired Boiler
	Sooner Sources
Unit 1	5,116 MMBtu/hr Coal Fired Boiler
Unit 2	5,116 MMBtu/hr Coal Fired Boiler

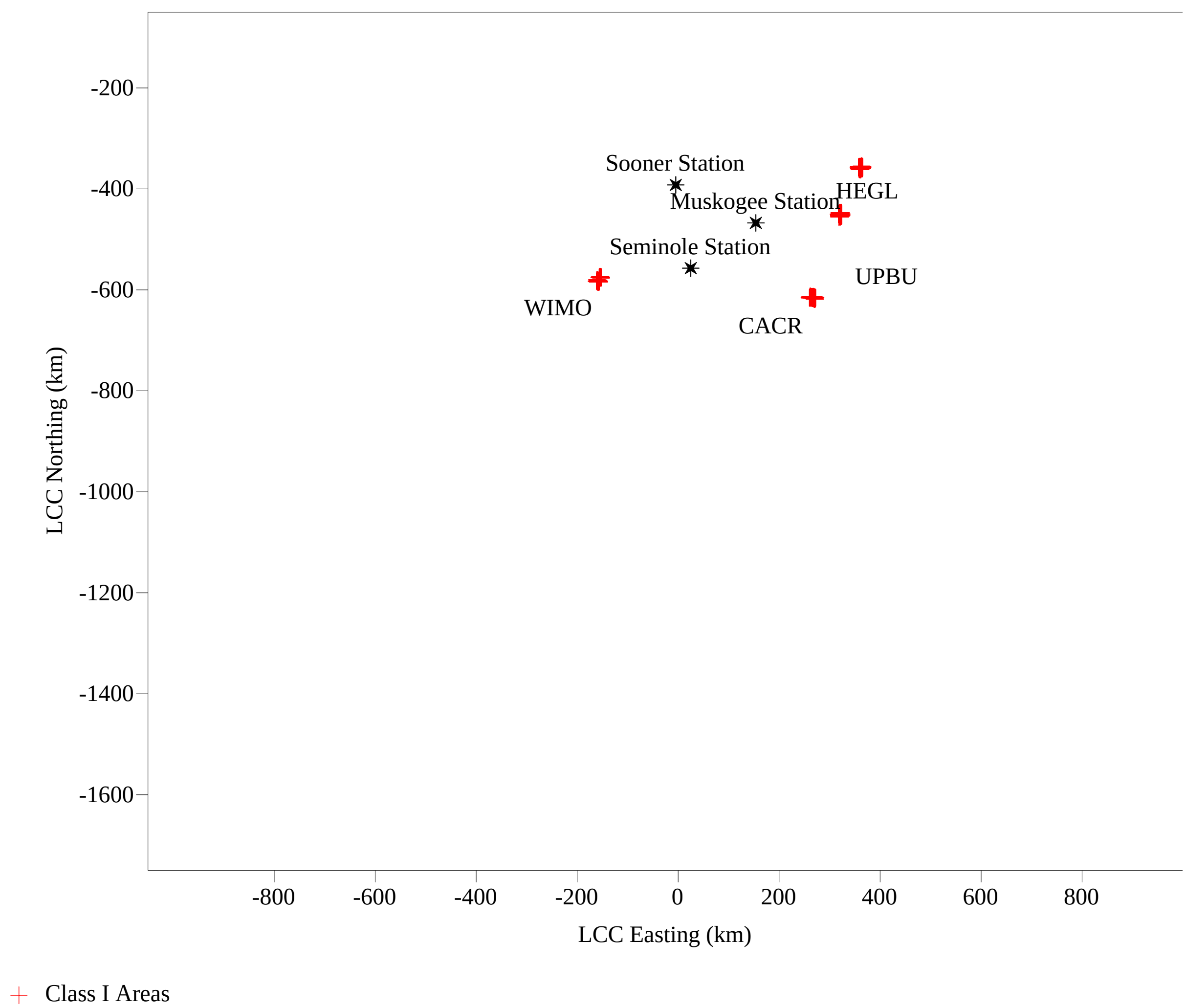
As required in CENRAP's BART Modeling Guidelines, Class I areas within 300 km of each station will be included in each analysis. The following table summarizes the distances of the four closest Class I areas to each station. As seen from this summary, some Class I areas are more than 300 km from the certain stations. However, in order to demonstrate that each station will not have an adverse effect on the visibility at any of the four nearest Class I areas, OG&E has opted to include those Class I areas more than 300 km away in this analysis. Note that the distances listed in the table below are the distances between the stations and the closest border of the Class I areas.

TABLE 1-2. DISTANCE FROM STATION TO SURROUNDING CLASS I AREAS

	CACR	HEGL	UPBU	WIMO
Muskogee	180	230	164	324
Seminole	242	386	310	178
Sooner	345	363	327	234

A plot of the Class I areas with respect to the each station is provided in Figure 1-1.

FIGURE 1-1. PLOT OF SOURCES AND NEAREST CLASS I AREAS



2. CALPUFF MODEL SYSTEM

The main components of the CALPUFF modeling system are CALMET, CALPUFF, and CALPOST. CALMET is the meteorological model that generates hourly three-dimensional meteorological fields such as wind and temperature. CALPUFF simulates the non-steady state transport, dispersion, and chemical transformation of air pollutants emitted from a source in "puffs". CALPUFF calculates hourly concentrations of visibility affecting pollutants at each specified receptor in a modeling domain. CALPOST is the post-processor for CALPUFF that computes visibility impacts from a source based on the visibility affecting pollutant concentrations that were output by CALPUFF.

2.1 MODEL VERSIONS

The versions of the CALPUFF modeling system programs that are proposed for conducting OG&E's BART modeling are listed in Table 2-1. A detailed refined CALPUFF BART modeling protocol will be submitted in the near future.

TABLE 2-1. CALPUFF MODELING SYSTEM VERSIONS

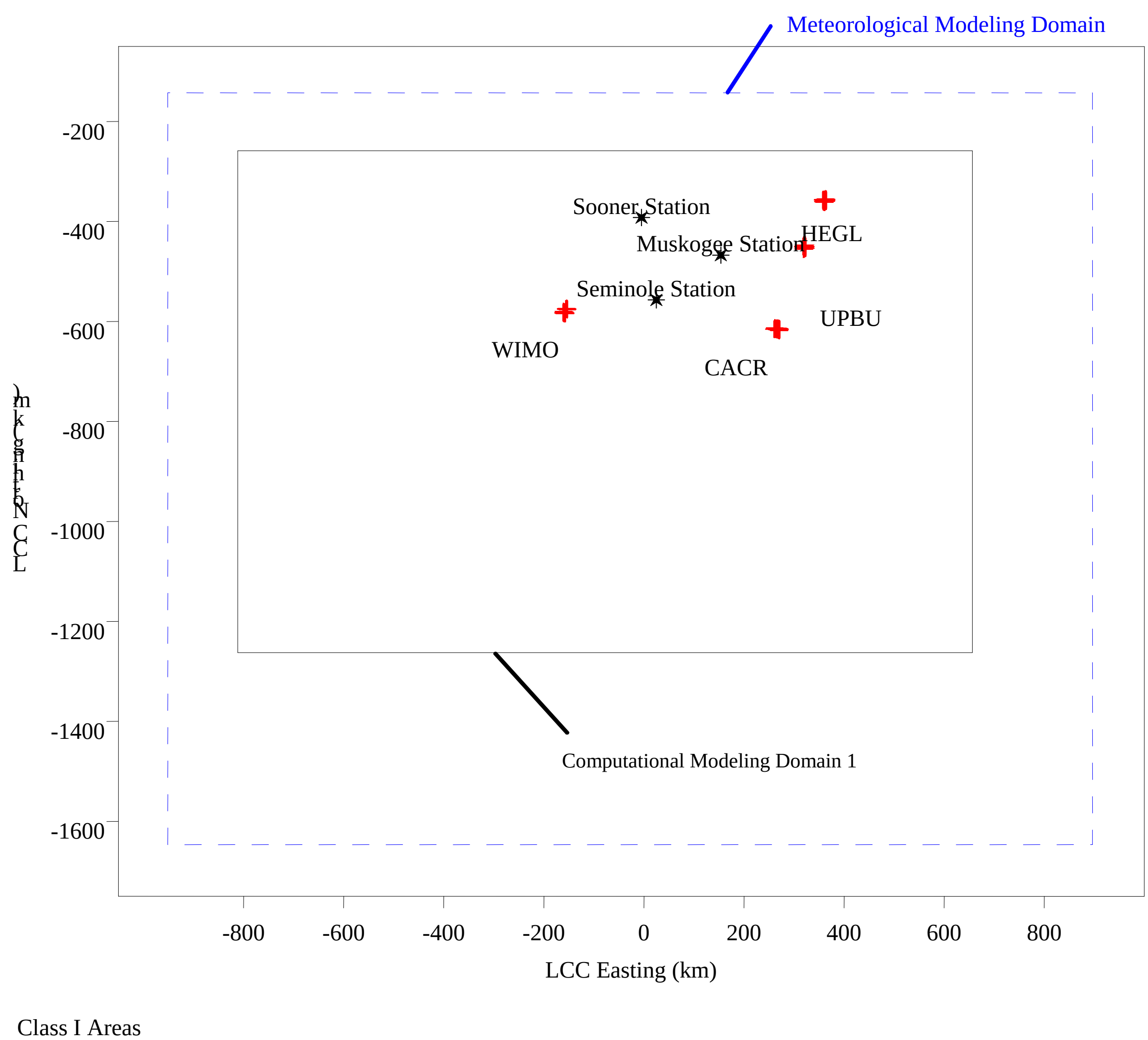
Processor	Version	Level
TERREL	3.3	030402
CTGCOMP	2.21	030402
CTGPROC	2.63	050128
MAKEGEO	2.2	030402
CALMET	5.53a	040716
CALPUFF	5.8	070623
POSTUTIL	1.3	030402
CALPOST	5.51	030709

2.2 MODELING DOMAIN

The CALPUFF modeling system utilizes three modeling grids: the meteorological grid, the computational grid, and the sampling grid. The meteorological grid is the system of grid points at which meteorological fields are developed with CALMET. The computational grid determines the computational area for a CALPUFF run. Puffs are advected and tracked only while within the computational grid. The meteorological grid is defined so that it covers the areas of concern and gives enough marginal buffer area for puff transport and dispersion. A plot of the proposed meteorological modeling domain with respect to the Class I areas being modeled is also provided in

Figure 2-1. The computational domain will be set to extend at least 50 km in all directions beyond the Muskogee, Seminole, and Sooner Generating Stations and the Class I areas of interest. Note that the map projection for the modeling domain will be Lambert Conformal Conic (LCC) and the datum will be the World Geodetic System 84 (WGS-84). The reference point for the modeling domain is Latitude 40ºN, Longitude 97ºW. The southwest corner will be set to -951.547 km LCC, -1646.637 km LCC corresponding to Latitude 24.813 ºN and Longitude 87.778ºW. The meteorological grid spacing will be 4 km, resulting in 462 grid points in the X direction and 376 grid points in the Y direction.

FIGURE 2-1. REFINED METEOROLOGICAL MODELING DOMAIN



3. CALMET

The EPA Approved Version of the CALMET meteorological processor will be used to generate the meteorological data for CALPUFF. CALMET is the meteorological processor that compiles meteorological data from raw observations of surface and upper air conditions, precipitation measurements, mesoscale model output, and geophysical parameters into a single hourly, gridded data set for input into CALPUFF. CALMET will be used to assimilate data for 2001- 2003 using National Weather Service (NWS) surface station observations, upper air station observations, precipitation station observations, buoy station observations (for overwater areas), and mesoscale model output to develop the meteorological field.

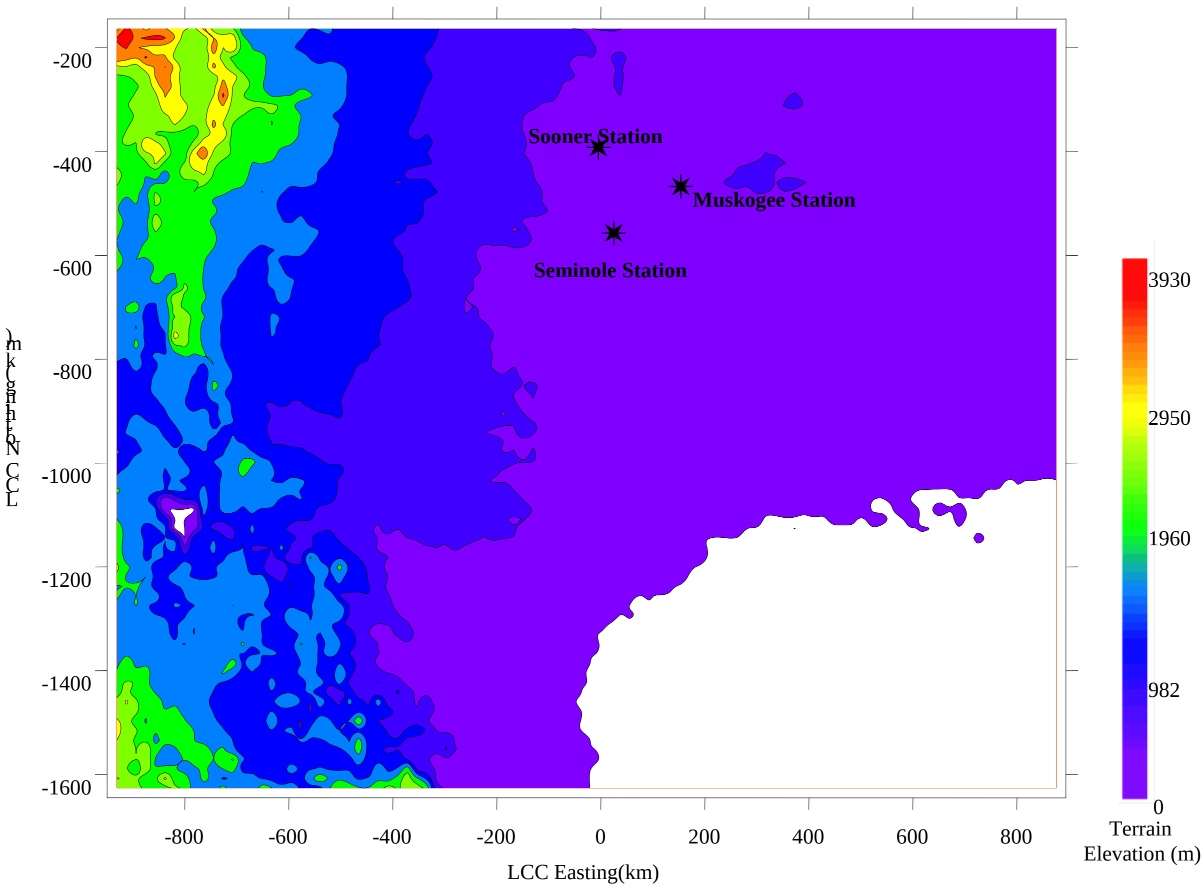
3.1 GEOPHYSICAL DATA

CALMET requires geophysical data to characterize the terrain and land use parameters that potentially affect dispersion. Terrain features affect flows and create turbulence in the atmosphere and are potentially subjected to higher concentrations of elevated puffs. Different land uses exhibit variable characteristics such as surface roughness, albedo, Bowen ratio, and leaf-area index that also effect turbulence and dispersion.

3.1.1 TERRAIN DATA

Terrain data will be obtained from the United States Geological Survey (USGS) in 1-degree (1:250,000 scale or approximately 90 meter resolution) digital format. The USGS terrain data will then be processed by the TERREL program to generate grid-cell elevation averages across the modeling domain. A plot of the land elevations based on the USGS data for the modeling domain is provided in Figure 3-1.

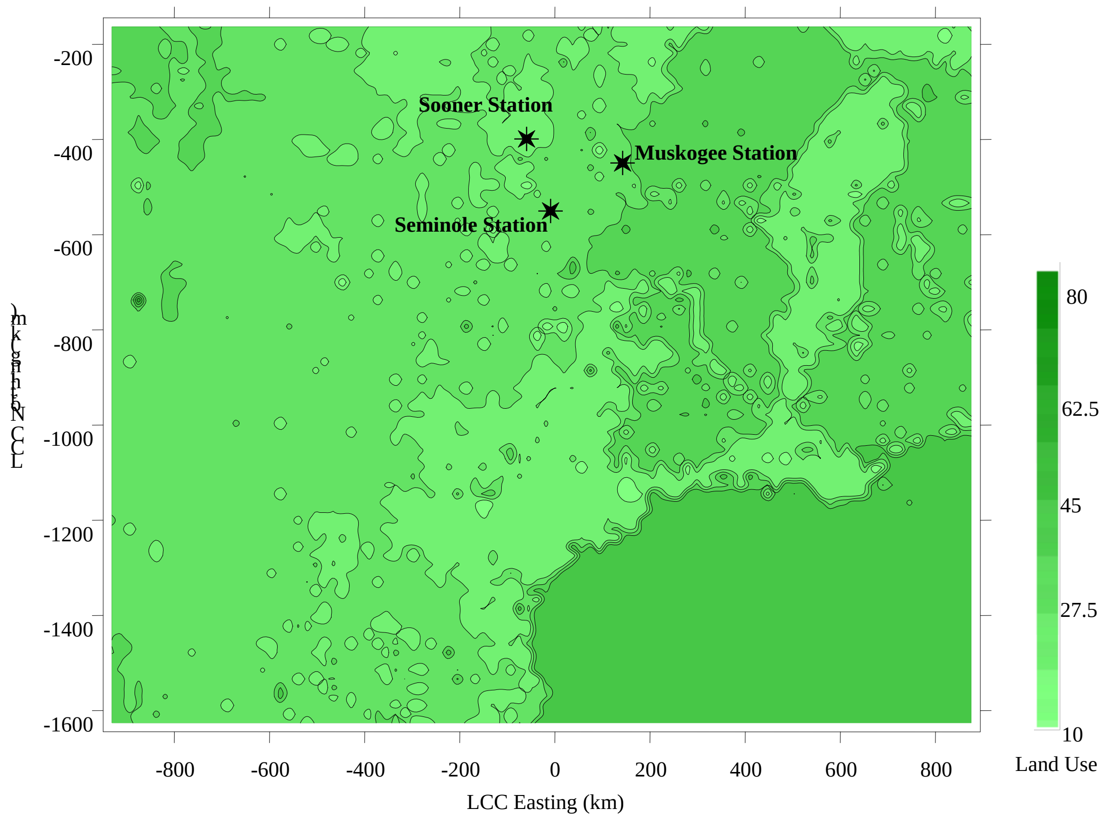
FIGURE 3-1. PLOT OF LAND ELEVATION USING USGS TERRAIN DATA



3.1.2 LAND USE DATA

The land use land cover (LULC) data from the USGS North American land cover characteristics data base in the Lambert Azimuthal equal area map projection will be used in order to determine the land use within the modeling domain. The LULC data will be processed by the CTGPROC program which will generate land use for each grid cell across the modeling domain. A plot of the land use based on the USGS data for the modeling domain is provided in Figure 3-2.

FIGURE 3-2. PLOT OF LAND USE USING USGS LULC DATA



3.1.3 COMPILING TERRAIN AND LAND USE DATA

The terrain data files output by the TERELL program and the LULC files output by the CTGPROC program will be uploaded into the MAKEGEO program to create a geophysical data file that will be input into CALMET.

3.2 METEOROLOGICAL DATA

CALMET will be used to assimilate data for 2001, 2002, and 2003 using mesoscale model output and National Weather Service (NWS) surface station observations, upper air station observations, precipitation station observations, and National Oceanic and Atmosphere Administrations (NOAA) buoy station observations to develop the meteorological field.

3.2.1 MESOSCALE MODEL METEOROLOGICAL DATA

Hourly mesoscale data will also be used as the initial guess field in developing the CALMET meteorological data. It is OG&E's intent to use the following 5th generation mesoscale model meteorological data sets (or MM5 data) in the analysis:

- 2001 MM5 data at 12 km resolution generated by the U.S. EPA
- 2002 MM5 data at 36 km resolution generated by the Iowa DNR

- 2003 MM5 data set at 36 km resolution generated by the Midwest RPO

The specific MM5 data that will be used are subsets of the data listed above. As the contractor to CENRAP for developing the meteorological data sets for the BART modeling, Alpine Geophysics extracted three subsets of MM5 data for each year from 2001 to 2003 from the data sets listed above using the CALMM5 extraction program. The three subsets covered the northern, central, and southern portions of CENRAP. TXI is proposing to use the southern set of the extracted MM5 data.

The 2001 southern subset of the extracted MM5 data includes 30 files that are broken into 10 to 11 day increments (3 files per month). The 2002 and 2003 southern subsets of extracted MM5 data include 12 files each of which are broken into 30 to 31 day increment files (1 file per month). Note that the 2001 to 2003 MM5 data extracted by Alpine Geophysics will not be able to be used directly in the modeling analysis. To run the Alpine Geophysics extracted MM data in the EPA approved CALMET program, each of the MM5 files will need to be adjusted by appending an additional six (6) hours, at a minimum, to the end of each file to account for the shift in time zones from the Greenwich Mean Time (GMT) prepared Alpine Geophysics data to Time Zone 6 for this analysis. No change to the data will occur.

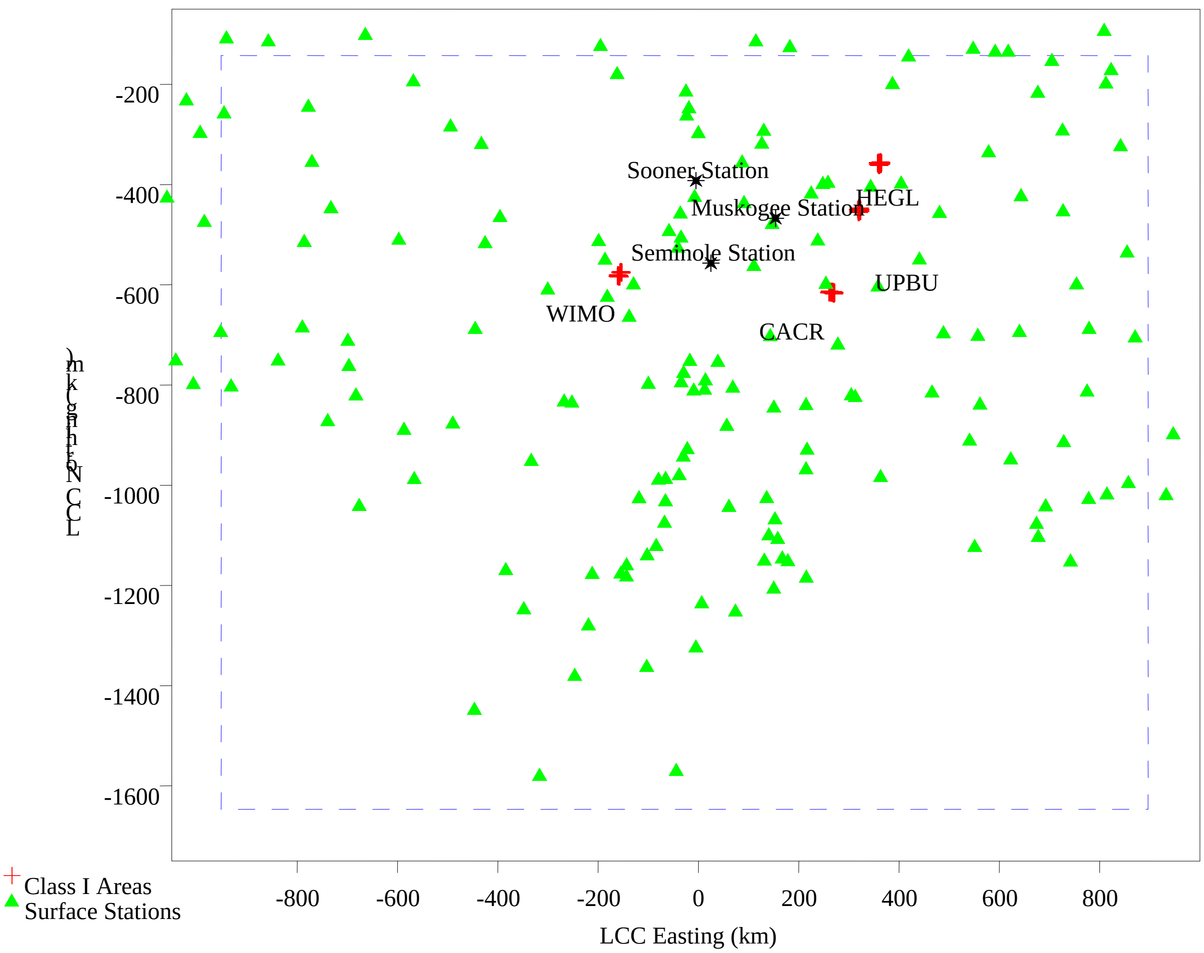
The time periods covered by the data in each of the MM5 files extracted by Alpine Geophysics include a specific number of calendar days, where the data starts at Hour 0 in GMT for the first calendar day and ends at Hour 23 in GMT on the last calendar day. In order to run CALMET in the local standard time (LST), which is necessary since the surface meteorological observations are recorded in LST, there must be hours of MM5 data referenced in a CALMET run that match the LST observation hours. Since the LST hours in Central Standard Time (CST) are 6 hours behind GMT, it is necessary to adjust the data in each MM5 file so that the time periods covered in the files match CST.

Based on the above discussion, the Alpine Geophysics MM5 data will not be used directly. Instead the data files will be modified to add 8 additional hours of data to the end of each file from the beginning of the subsequent file. CALMET will then be run using the appended MM5 data to generate a contiguous set of CALMET output files. The converted MM5 data files occupy approximately 1.2 terabytes (TB) of hard drive space.

3.2.2 SURFACE METEOROLOGICAL DATA

Parameters affecting turbulent dispersion that are observed hourly at surface stations include wind speed and direction, temperature, cloud cover and ceiling, relative humidity, and precipitation type. It is OG&E's intent to use the surface stations listed in Table A-1 of Appendix A. The locations of the surface stations with respect to the modeling domain are shown in Figure 3-3. The stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA's SMERGE program.

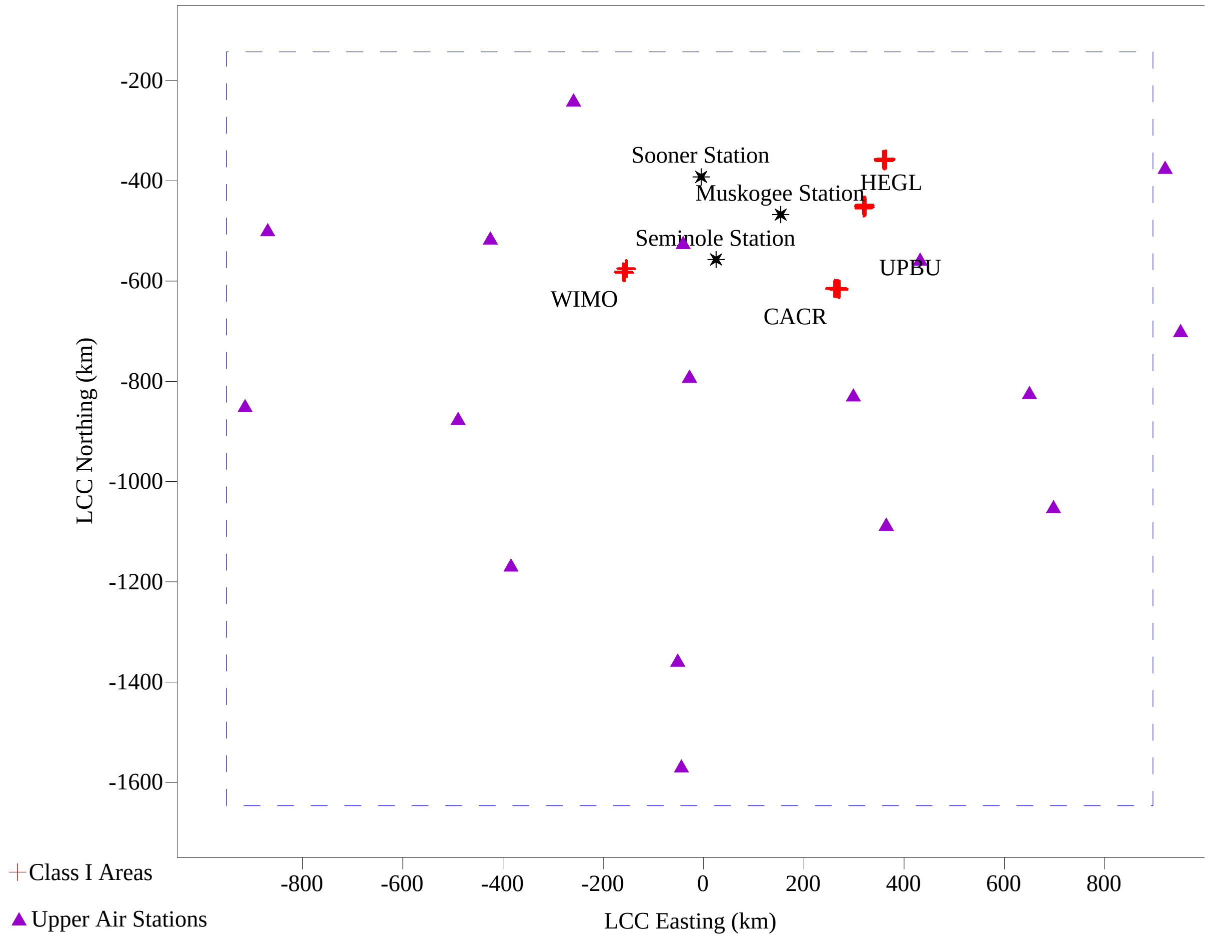
FIGURE 3-3. PLOT OF SURFACE STATION LOCATIONS



3.2.3 UPPER AIR METEOROLOGICAL DATA

Observations of meteorological conditions in the upper atmosphere provide a profile of turbulence from the surface through the depth of the boundary layer in which dispersion occurs. Upper air data are collected by balloons launched simultaneously across the observation network at 0000 Greenwich Mean Time (GMT) (6 o'clock PM in Oklahoma) and 1200 GMT (6 o'clock AM in Oklahoma). Sensors observe pressure, wind speed and direction, and temperature (among other parameters) as the balloon rises through the atmosphere. The upper air observation network is less dense than surface observation points since upper air conditions vary less and are generally not as affected by local effects (e.g., terrain or water bodies). The upper air stations that are proposed for this analysis are listed in Table A-2 of Appendix A. The locations of the upper air stations with respect to the modeling domain are shown in Figure 3-4. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA's READ62 program.

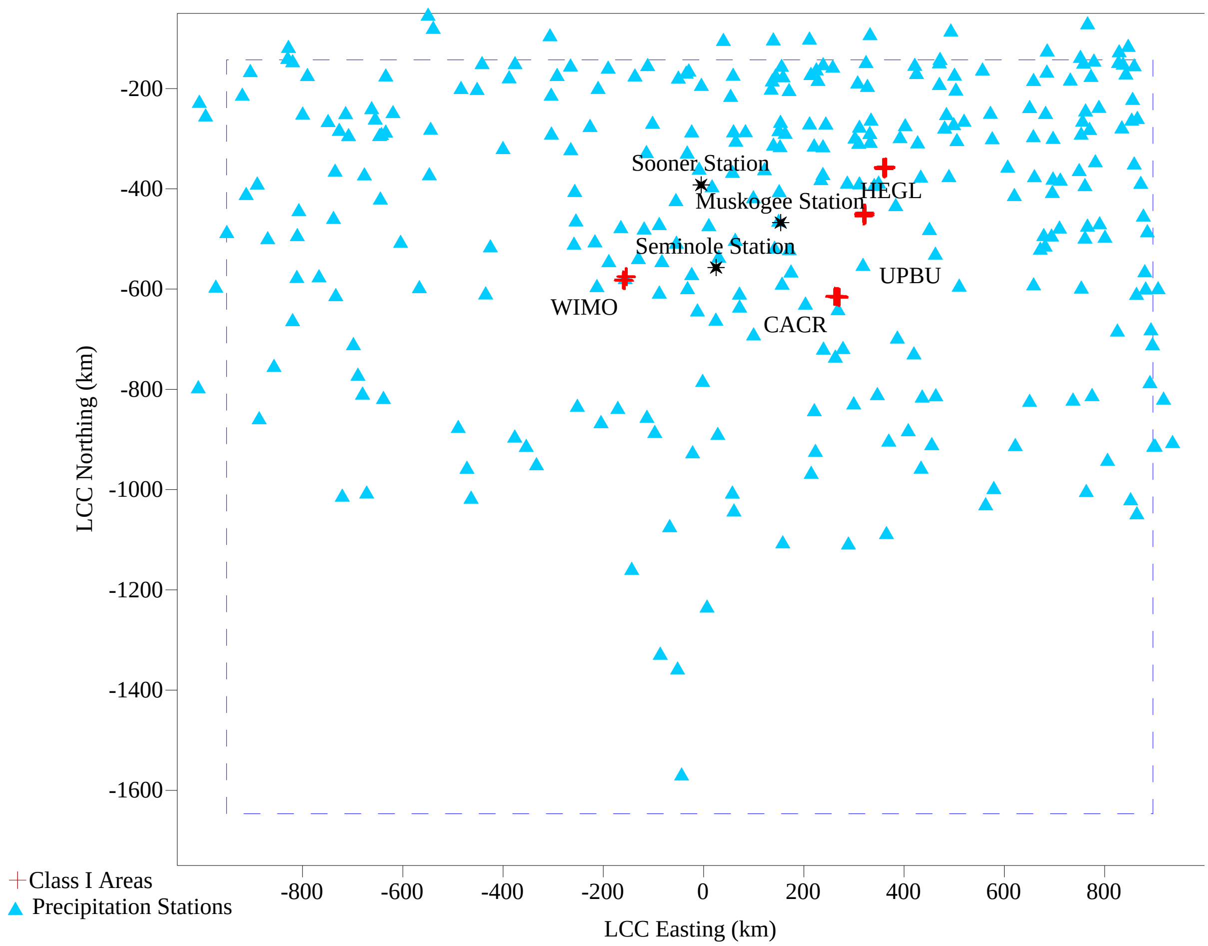
FIGURE 3-4. PLOT OF UPPER AIR STATIONS LOCATIONS



3.2.4 PRECIPITATION METEOROLOGICAL DATA

The effects of chemical transformation and deposition processes on ambient pollutant concentrations will be considered in this analysis. Therefore, it is necessary to include observations of precipitation in the CALMET analysis. The precipitation stations that are proposed for this analysis are listed in Table A-3 of Appendix A. The locations of the precipitation stations with respect to the modeling domain are shown in Figure 3-5. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA's PMERGE program.

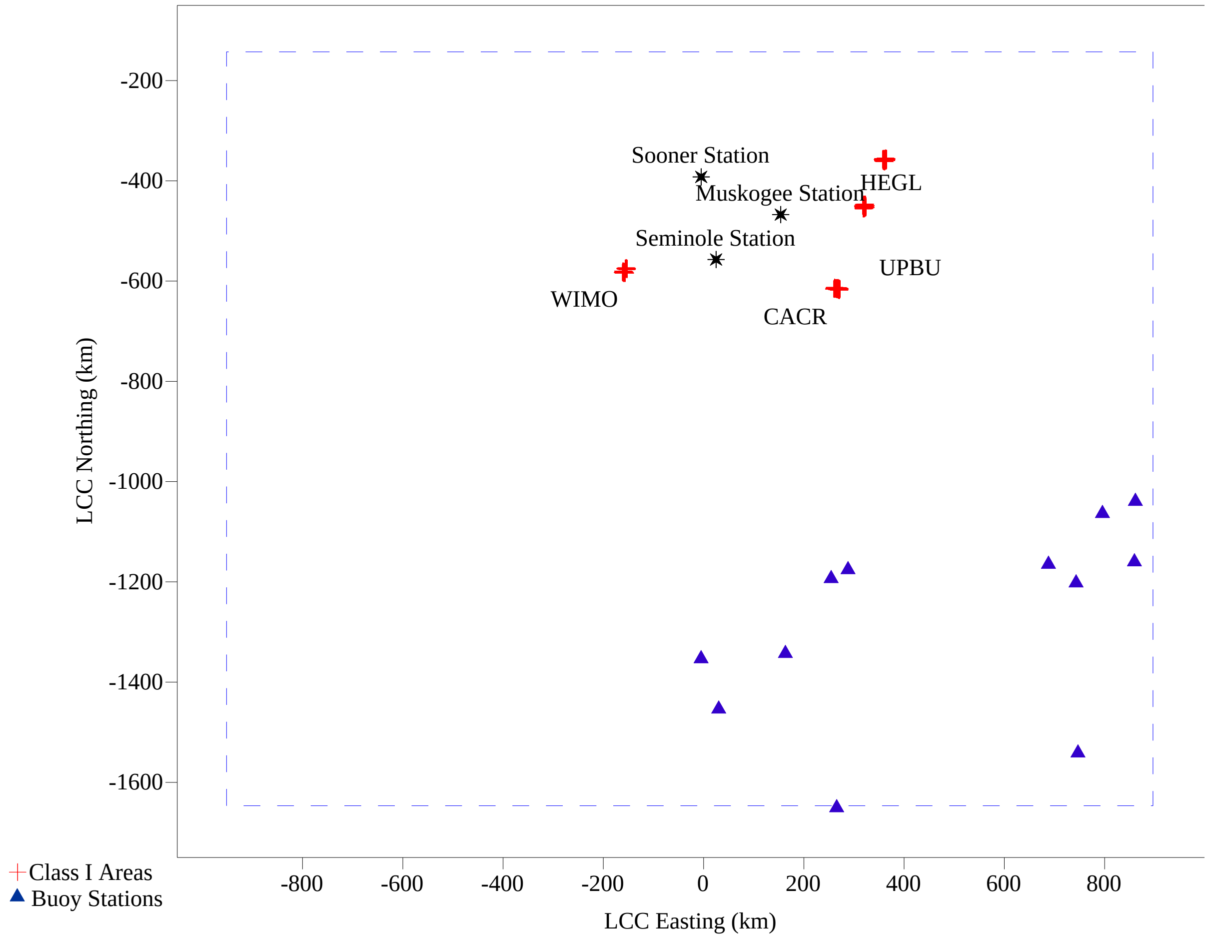
FIGURE 3-5. PLOT OF PRECIPITATION METEOROLOGICAL STATIONS



3.2.5 BUOY METEOROLOGICAL DATA

The effects of land/sea breeze on ambient pollutant concentrations will be considered in this analysis. Therefore, it is necessary to include observations of buoy stations in the CALMET analysis. The buoy stations that are proposed for this analysis are listed in Table A-4 of Appendix A. The locations of the buoy stations with respect to the modeling domain are shown in Figure 3-6. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain along the coastline. Data from the stations will be prepared by filling missing hour records with the CALMET missing parameter value (9999). No adjustments to the data will occur.

FIGURE 3-6. PLOT OF BUOY METEOROLOGICAL STATIONS



3.3 CALMET CONTROL PARAMETERS

Appendix B provides a sample CALMET input file used in OG&E's modeling analysis. A few details of the CALMET model setup for sensitive parameters are also discussed below.

3.3.1 VERTICAL METEOROLOGICAL PROFILE

The height of the top vertical layer will be set to 3,500 meters. This height corresponds to the top sounding pressure level for which upper air observation data will be relied upon. The vertical dimension of the domain will be divided into 12 layers with the maximum elevations for each layer shown in Table 3-1. The vertical dimensions are weighted towards the surface to resolve the mixing layer while using a somewhat coarser resolution for the layers aloft.

TABLE 3-1. VERTICAL LAYERS OF THE CALMET METEOROLOGICAL DOMAIN

Layer	Elevation (m)
1	20
2	40
3	60
4	80
5	100
6	150
7	200
8	250
9	500
10	1000
11	2000
12	3500

CALMET allows for a bias value to be applied to each of the vertical layers. The bias settings for each vertical layer determine the relative weight given to the vertically extrapolated surface and upper air wind and temperature observations. The initial guess fields are computed with an inverse distance weighting ($1/r^2$) of the surface and upper air data. The initial guess fields may be modified by a layer dependent bias factor. Values for the bias factor may range from -1 to +1. A bias of -1 eliminates upper-air observations in the $1/r^2$ interpolations used to initialize the vertical wind fields. Conversely, a bias of +1 eliminates the surface observations in the interpolations for this layer. Normally, bias is set to zero (0) for each vertical layer, such that the upper air and surface observations are given equal weight in the $1/r^2$ interpolations. The biases for each layer of the proposed modeling domain will be set to zero.

CALMET allows for vertical extrapolation of surface wind observations to layers aloft to be skipped if the surface station is close to the upper air station. Alternatively, CALMET allows data from all surface stations to be extrapolated. The CALMET parameter that controls this setting is IEXTRP. Setting IEXTRP to a value less than zero (0) means that layer 1 data from upper air soundings is ignored in any vertical extrapolations. IEXTRP will be set to -4 for this analysis (i.e., the similarity theory is used to extrapolate the surface winds into the layers aloft, which provides more information on observed local effects to the upper layers).

3.3.2 INFLUENCES OF OBSERVATIONS

Step 1 wind fields will be based on an initial guess using MM5 data and refined to reflect terrain affects. Step 2 wind fields will adjust the Step 1 wind field by incorporating the influence of local observations. An inverse distance method is used to determine the influence of observations to the Step 1 wind field. RMAX1 and RMAX2 define the radius of influence for data from surface stations to land in the surface layer and data from upper air stations to land in the layers aloft. In general, RMAX1 and RMAX2 are used to exclude observations from being inappropriately included in the development of the Step 2

wind field if the distance from an observation station to a grid point exceeds the maximum radius of influence.

If the distance from an observation station to a grid point is less than the value set for RMAX, the observation data will be used in the development of the Step 2 wind field. R1 represents the distance from a surface observation station at which the surface observation and the Step 1 wind field are weighted equally. R2 represents the comparable distance for winds aloft. R1 and R2 are used to weight the observation data with respect to the MM5 data that was used to generate the Step 1 wind field. Large values for R1 and R2 give more weight to the observations, where as small values give more weight to the MM5 data.

In this BART modeling analysis, RMAX 1 will be set to 20 km, and R1 will be set to 10 km. This will limit the influence of the surface observation data from all surface stations to 20 km from each station, and will equally weight the MM5 and observation data at 10 km. RMAX2 will be set to 50 km, and R2 will be set to 25 km. This will limit the influence of the upper air observation data from all surface stations to 50 km from each station, and will equally weight the MM5 and observation data at 25 km. These settings of radius of influence will allow for adequate weighting of the MM5 data and the observation data across the modeling domain due to the vast domain to be modeled. RAMX 3 will be set to 500 km.

TABLE A-1. LIST OF SURFACE METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	KDYS	69019	-267.672	-834.095	96.9968	39.9925
2	KNPA	72222	932.565	-1020.909	97.0110	39.9908
3	KBFM	72223	857.471	-996.829	97.0101	39.9910
4	KGZH	72227	946.767	-899.515	97.0112	39.9919
5	KTCL	72228	870.843	-706.104	97.0103	39.9936
6	KNEW	53917	674.172	-1078.342	97.0080	39.9903
7	KNBG	12958	677.719	-1104.227	97.0080	39.9900
8	BVE	12884	741.996	-1153.463	97.0088	39.9896
9	KPTN	72232	550.88	-1124.295	97.0065	39.9898
10	KMEI	13865	774.911	-814.225	97.0092	39.9926
11	KPIB	72234	728.416	-915.165	97.0086	39.9917
12	KGLH	72235	557.072	-703.097	97.0066	39.9936
13	KHEZ	11111	540.777	-912.22	97.0064	39.9918
14	KMCB	11112	622.755	-949.618	97.0074	39.9914
15	KGWO	11113	640.102	-695.286	97.0076	39.9937
16	KASD	72236	692.381	-1043.261	97.0082	39.9906
17	KPOE	72239	363.294	-984.839	97.0043	39.9911
18	KBAZ	72241	-102.133	-1140.886	96.9988	39.9897
19	KGLS	72242	215.108	-1185.604	97.0025	39.9893
20	KDWH	11114	140.413	-1101.174	97.0017	39.9900
21	KIAH	12960	158.266	-1108.37	97.0019	39.9900
22	KHOU	72243	167.147	-1147.402	97.0020	39.9896
23	KEFD	12906	178.551	-1152.782	97.0021	39.9896
24	KCXO	72244	152.739	-1069.309	97.0018	39.9903
25	KCLL	11115	60.898	-1044.381	97.0007	39.9906
26	KLFK	93987	214.643	-969.355	97.0025	39.9912
27	KUTS	11116	136.056	-1026.773	97.0016	39.9907
28	KTYR	11117	150.451	-846.207	97.0018	39.9924
29	KCRS	72246	56.655	-882.642	97.0007	39.9920
30	KGGG	72247	214.572	-841.163	97.0025	39.9924
31	KGKY	11118	-9.365	-812.25	96.9999	39.9927
32	KDTN	72248	304.827	-821.713	97.0036	39.9926
33	KBAD	11119	312.743	-825.101	97.0037	39.9925
34	KMLU	11120	465.834	-816.211	97.0055	39.9926
35	KTVR	11121	561.446	-840.225	97.0066	39.9924
36	KTRL	11122	68.599	-806.417	97.0008	39.9927
37	KOCH	72249	216.81	-930.252	97.0026	39.9916
38	KBRO	12919	-44.167	-1571.387	96.9995	39.9858

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
39	KALI	72251	-103.012	-1363.74	96.9988	39.9877
40	KLRD	12920	-246.548	-1381.603	96.9971	39.9875
41	KSSF	72252	-143.386	-1183.35	96.9983	39.9893
42	KRKP	11123	-4.965	-1324.914	96.9999	39.9880
43	KCOT	11124	-219.097	-1280.964	96.9974	39.9884
44	KLBX	11125	150.245	-1207.466	97.0018	39.9891
45	KSAT	12921	-143.024	-1160.935	96.9983	39.9895
46	KHDO	12962	-211.702	-1178.172	96.9975	39.9894
47	KSKF	72253	-154.625	-1177.555	96.9982	39.9894
48	KHYI	11126	-84.156	-1122.487	96.9990	39.9899
49	KTKI	72254	38.788	-754.791	97.0005	39.9932
50	KBMQ	11127	-118.39	-1027.031	96.9986	39.9907
51	KATT	11128	-67.587	-1075.97	96.9992	39.9903
52	KSGR	11129	131.478	-1151.702	97.0016	39.9896
53	KGTU	11130	-65.624	-1033.173	96.9992	39.9907
54	KVCT	12912	6.587	-1236.788	97.0001	39.9888
55	KPSX	72255	73.878	-1253.33	97.0009	39.9887
56	KACT	13959	-22.12	-929.156	96.9997	39.9916
57	KPWG	72256	-30.147	-944.073	96.9996	39.9915
58	KILE	72257	-65.288	-988.507	96.9992	39.9911
59	KGRK	11131	-79.643	-990.173	96.9991	39.9911
60	KTPL	11132	-38.203	-981.19	96.9996	39.9911
61	KPRX	13960	143.317	-703.663	97.0017	39.9936
62	KDTO	72258	-17.018	-752.974	96.9998	39.9932
63	KAFW	11133	-29.564	-777.061	96.9997	39.9930
64	KFTW	72259	-34.302	-795.502	96.9996	39.9928
65	KMWL	11134	-99.769	-798.767	96.9988	39.9928
66	KRBD	11135	12.453	-810.467	97.0002	39.9927
67	KDRT	11136	-384.069	-1170.59	96.9955	39.9894
68	KFST	22010	-566.418	-988.838	96.9933	39.9911
69	KGDP	72261	-739.127	-873.302	96.9913	39.9921
70	KSJT	72262	-333.338	-952.54	96.9961	39.9914
71	KMRF	23034	-676.265	-1042.616	96.9920	39.9906
72	KMAF	72264	-489.668	-878.107	96.9942	39.9921
73	KINK	23023	-586.882	-890.654	96.9931	39.9920
74	KABI	72265	-252.044	-836.353	96.9970	39.9924
75	KLBB	13962	-445.006	-689.313	96.9948	39.9938
76	KATS	11137	-696.818	-763.258	96.9918	39.9931
77	KCQC	11138	-785.757	-515.724	96.9907	39.9953
78	KROW	23009	-698.822	-712.898	96.9918	39.9936
79	KSRR	72268	-789.593	-686.226	96.9907	39.9938
80	KCNM	11139	-682.79	-822.109	96.9919	39.9926
81	KALM	36870	-838.056	-752.338	96.9901	39.9932
82	KLRU	72269	-931.527	-804.112	96.9890	39.9927
83	KTCS	72271	-952.353	-695.469	96.9888	39.9937

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
84	KSVC	93063	-1042.03	-752.033	96.9877	39.9932
85	KDMN	72272	-1006.77	-799.231	96.9881	39.9928
86	KMSL	72323	854.846	-536.687	97.0101	39.9952
87	KPOF	72330	578.62	-336.733	97.0068	39.9970
88	KGTR	11140	779.065	-689.108	97.0092	39.9938
89	KTUP	93862	753.875	-600.337	97.0089	39.9946
90	KMKL	72334	727.051	-454.383	97.0086	39.9959
91	KLRF	72340	440.654	-550.661	97.0052	39.9950
92	KHKA	11141	643.365	-424.419	97.0076	39.9962
93	KHOT	72341	358.094	-604.603	97.0042	39.9945
94	KTXK	11142	278.022	-720.623	97.0033	39.9935
95	KLLQ	72342	488.655	-698.008	97.0058	39.9937
96	KMWT	72343	254.18	-599.224	97.0030	39.9946
97	KFSM	13964	237.97	-512.87	97.0028	39.9954
98	KSLG	72344	224.881	-419.064	97.0027	39.9962
99	KVBT	11143	248.074	-399.892	97.0029	39.9964
100	KHRO	11144	343.525	-405.601	97.0041	39.9963
101	KFLP	11145	404.239	-399.142	97.0048	39.9964
102	KBVX	11146	480.712	-457.853	97.0057	39.9959
103	KROG	11147	258.44	-397.685	97.0031	39.9964
104	KSPS	13966	-138.053	-664.886	96.9984	39.9940
105	KHBR	72352	-186.121	-551.123	96.9978	39.9950
106	KCSM	11148	-198.844	-513.911	96.9977	39.9954
107	KFDR	11149	-181.653	-625.205	96.9979	39.9944
108	KGOK	72353	-35.905	-458.97	96.9996	39.9959
109	KTIK	72354	-34.581	-506.938	96.9996	39.9954
110	KPWA	11150	-58.596	-493.951	96.9993	39.9955
111	KSWO	11151	-7.42	-425.828	96.9999	39.9962
112	KMKO	72355	146.972	-479.879	97.0017	39.9957
113	KRVS	72356	91.059	-438.276	97.0011	39.9960
114	KBVO	11152	87.136	-357.069	97.0010	39.9968
115	KMLC	11153	110.647	-563.566	97.0013	39.9949
116	KOUN	72357	-40.731	-527.298	96.9995	39.9952
117	KLAW	11154	-129.405	-600.222	96.9985	39.9946
118	KCDS	72360	-300.297	-610.668	96.9965	39.9945
119	KGNT	72362	-985.117	-475.563	96.9884	39.9957
120	KGUP	11155	-1059.48	-427.151	96.9875	39.9961
121	KAMA	23047	-425.319	-518.171	96.9950	39.9953
122	KBGD	72363	-395.603	-466.083	96.9953	39.9958
123	KFMN	72365	-993.449	-297.944	96.9883	39.9973
124	KSKX	72366	-770.464	-355.855	96.9909	39.9968
125	KTCC	23048	-597.271	-511.241	96.9930	39.9954
126	KLVS	23054	-732.565	-448.329	96.9914	39.9960
127	KEHR	72423	812.573	-199.695	97.0096	39.9982
128	KEVV	93817	822.929	-172.715	97.0097	39.9984

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
129	KMVN	72433	704.666	-154.54	97.0083	39.9986
130	KMDH	11156	676.745	-218.041	97.0080	39.9980
131	KBLV	11157	617.659	-136.018	97.0073	39.9988
132	KSUS	3966	547.898	-130.122	97.0065	39.9988
133	KPAH	3816	725.985	-293.319	97.0086	39.9974
134	KJEF	72445	419.01	-145.496	97.0050	39.9987
135	KAIZ	11158	387.096	-200.609	97.0046	39.9982
136	KIXD	72447	182.322	-126.913	97.0022	39.9989
137	KWLD	72450	0	-298.57	97.0000	39.9973
138	KAAO	11159	-18.976	-248.773	96.9998	39.9978
139	KIAB	11160	-23.392	-263.471	96.9997	39.9976
140	KEWK	11161	-24.645	-215.58	96.9997	39.9981
141	KGBD	72451	-161.892	-180.781	96.9981	39.9984
142	KHYS	11162	-195.191	-124.723	96.9977	39.9989
143	KCFV	11163	126.442	-319.698	97.0015	39.9971
144	KFOE	72456	114.618	-115.26	97.0014	39.9990
145	KEHA	72460	-432.761	-320.089	96.9949	39.9971
146	KALS	72462	-777.592	-245.892	96.9908	39.9978
147	KDRO	11164	-945.713	-259.163	96.9888	39.9977
148	KLHX	72463	-568.426	-195.178	96.9933	39.9982
149	KSPD	2128	-494.076	-285.176	96.9942	39.9974
150	KCOS	93037	-664.022	-102.596	96.9922	39.9991
151	KGUC	72467	-857.452	-115.301	96.9899	39.9990
152	KMTJ	93013	-940.981	-109.358	96.9889	39.9990
153	KCEZ	72476	-1020.87	-233.14	96.9880	39.9979
154	KCPS	72531	591.652	-136.14	97.0070	39.9988
155	KLWV	72534	808.939	-94.46	97.0096	39.9992
156	KPPF	74543	130.433	-293.855	97.0015	39.9973
157	KHOP	74671	841.751	-324.569	97.0099	39.9971
158	KBIX	74768	778.252	-1028.514	97.0092	39.9907
159	KPQL	11165	814.599	-1019.583	97.0096	39.9908
160	MMPG	76243	-348.007	-1248.779	96.9959	39.9887
161	MMMV	76342	-446.576	-1449.334	96.9947	39.9869
162	MMMY	76394	-316.664	-1581.176	96.9963	39.9857

TABLE A-2. LIST OF UPPER AIR METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	KABQ	23050	-869.46	-501.713	96.9897	39.9955
2	KAMA	23047	-425.319	-518.171	96.9950	39.9953
3	KBMX	53823	951.609	-702.935	97.0112	39.9936
4	KBNA	13897	920.739	-377.164	97.0109	39.9966
5	KBRO	12919	-44.167	-1571.39	96.9995	39.9858
6	KCRP	12924	-51.535	-1360.35	96.9994	39.9877
7	KDDC	13985	-259.352	-242.681	96.9969	39.9978
8	KDRT	22010	-384.069	-1170.59	96.9955	39.9894
9	KEPZ	3020	-914.558	-852.552	96.9892	39.9923
10	KFWD	3990	-28.034	-793.745	96.9997	39.9928
11	KJAN	3940	650.105	-826.452	97.0077	39.9925
12	KLCH	3937	364.461	-1089.15	97.0043	39.9902
13	KLZK	3952	432.063	-560.441	97.0051	39.9949
14	KMAF	23023	-489.668	-878.107	96.9942	39.9921
15	KOUN	3948	-40.731	-527.298	96.9995	39.9952
16	KSHV	13957	298.869	-831.166	97.0035	39.9925
17	KSIL	53813	698.079	-1054.03	97.0082	39.9905

TABLE A-3. LIST OF PRECIPITATION METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	ADDI	10063	906.825	-601.428	97.0107	39.9946
2	ALBE	10140	917.606	-821.64	97.0108	39.9926
3	BERR	10748	892.454	-683.388	97.0105	39.9938
4	HALE	13620	881.928	-601.878	97.0104	39.9946
5	HAMT	13645	863.663	-612.725	97.0102	39.9945
6	JACK	14193	898.014	-915.623	97.0106	39.9917
7	MBLE	15478	851.953	-1022.41	97.0101	39.9908
8	MUSC	15749	880.113	-567.484	97.0104	39.9949
9	PETE	16370	935.558	-908.259	97.0110	39.9918
10	THOM	18178	900.858	-915.326	97.0106	39.9917
11	TUSC	18385	895.631	-713.223	97.0106	39.9936
12	VERN	18517	825.585	-685.773	97.0098	39.9938
13	BEEB	30530	462.394	-532.485	97.0055	39.9952
14	BRIG	30900	318.015	-554.857	97.0038	39.9950
15	CALI	31140	419.619	-731.44	97.0050	39.9934
16	CAMD	31152	386.546	-699.659	97.0046	39.9937
17	DIER	32020	268.114	-643.184	97.0032	39.9942
18	EURE	32356	286.738	-390.862	97.0034	39.9965
19	GILB	32794	383.362	-435.625	97.0045	39.9961
20	GREE	32978	450.594	-483.201	97.0053	39.9956
21	STUT	36920	509.943	-596.328	97.0060	39.9946
22	TEXA	37048	278.022	-720.623	97.0033	39.9935
23	ALAM	50130	-749.044	-267.856	96.9912	39.9976
24	ARAP	50304	-441.903	-152.324	96.9948	39.9986
25	COCH	51713	-819.794	-148.582	96.9903	39.9987
26	CRES	51959	-828.107	-119.911	96.9902	39.9989
27	GRAN	53477	-451.781	-203.82	96.9947	39.9982
28	GUNN	53662	-829.573	-141.995	96.9902	39.9987
29	HUGO	54172	-539.364	-81.948	96.9936	39.9993
30	JOHN	54388	-483.95	-201.915	96.9943	39.9982
31	KIM	54538	-544.501	-283.337	96.9936	39.9974
32	MESA	55531	-993.391	-256.696	96.9883	39.9977
33	ORDW	56136	-549.552	-55.741	96.9935	39.9995
34	OURA	56203	-904.197	-168.246	96.9893	39.9985
35	PLEA	56591	-1005.94	-229.472	96.9881	39.9979
36	PUEB	56740	-633.961	-176.872	96.9925	39.9984
37	TYE	57320	-662.095	-242.254	96.9922	39.9978
38	SAGU	57337	-790.269	-176.061	96.9907	39.9984

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
39	SANL	57428	-726.777	-285.47	96.9914	39.9974
40	SHEP	57572	-714.046	-252.189	96.9916	39.9977
41	TELL	58204	-920.205	-215.382	96.9891	39.9981
42	TERC	58220	-708.229	-296.023	96.9916	39.9973
43	TRIN	58429	-642.489	-293.805	96.9924	39.9973
44	TRLK	58436	-646.185	-295.727	96.9924	39.9973
45	WALS	58781	-654.989	-262.821	96.9923	39.9976
46	WHIT	58997	-619.615	-250.12	96.9927	39.9977
47	ASHL	110281	684.787	-169.285	97.0081	39.9985
48	CAIR	111166	697.177	-301.436	97.0082	39.9973
49	CARM	111302	772.938	-177.782	97.0091	39.9984
50	CISN	111664	758.146	-151.446	97.0090	39.9986
51	FLOR	113109	751.801	-139.837	97.0089	39.9987
52	HARR	113879	762.044	-246.62	97.0090	39.9978
53	KASK	114629	650.464	-239.886	97.0077	39.9978
54	LAWR	114957	829.038	-128.708	97.0098	39.9988
55	MTCA	115888	827.797	-149.966	97.0098	39.9986
56	MURP	115983	682.261	-251.649	97.0081	39.9977
57	NEWT	116159	766.098	-72.902	97.0090	39.9993
58	REND	117187	731.633	-185.058	97.0086	39.9983
59	SMIT	118020	770.027	-283.638	97.0091	39.9974
60	SPAR	118147	658.275	-185.973	97.0078	39.9983
61	VAND	118781	685.449	-127.048	97.0081	39.9989
62	WEST	119193	778.655	-147.215	97.0092	39.9987
63	EVAN	122738	842.476	-172.871	97.0100	39.9984
64	NEWB	126151	855.854	-223.713	97.0101	39.9980
65	PRIN	127125	836.901	-153.449	97.0099	39.9986
66	STEN	128442	859.099	-156.613	97.0101	39.9986
67	JTML	128967	788.703	-239.572	97.0093	39.9978
68	ARLI	140326	-101.734	-271.373	96.9988	39.9976
69	BAZI	140620	-210.423	-201.758	96.9975	39.9982
70	BEAU	140637	59.762	-288.39	97.0007	39.9974
71	BONN	140957	211.236	-103.29	97.0025	39.9991
72	CALD	141233	-32.689	-330.586	96.9996	39.9970
73	CASS	141351	54.006	-217.645	97.0006	39.9980
74	CENT	141404	170.503	-206.038	97.0020	39.9981
75	CHAN	141427	150.257	-286.094	97.0018	39.9974
76	CLIN	141612	155.623	-157.682	97.0018	39.9986
77	COLL	141730	-265.465	-156.95	96.9969	39.9986
78	COLU	141740	220.541	-316.555	97.0026	39.9971

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
79	CONC	141867	58.918	-175.589	97.0007	39.9984
80	DODG	142164	-226.497	-277.655	96.9973	39.9975
81	ELKH	142432	-400.112	-321.784	96.9953	39.9971
82	ENGL	142560	-264.927	-324.066	96.9969	39.9971
83	ERIE	142582	162.669	-291.383	97.0019	39.9974
84	FALL	142686	83.491	-288.177	97.0010	39.9974
85	GALA	142938	-136.931	-176.83	96.9984	39.9984
86	GARD	142980	-304.059	-215.308	96.9964	39.9981
87	GREN	143248	64.308	-307.161	97.0008	39.9972
88	HAYS	143527	-190.307	-161.342	96.9978	39.9985
89	HEAL	143554	-292.133	-175.921	96.9966	39.9984
90	HILL	143686	214.018	-174.006	97.0025	39.9984
91	INDE	143954	139.335	-315.058	97.0016	39.9972
92	IOLA	143984	153.451	-269.438	97.0018	39.9976
93	JOHR	144104	134.784	-203.41	97.0016	39.9982
94	KANO	144178	-50.289	-181.177	96.9994	39.9984
95	KIOW	144341	-113.967	-329.843	96.9987	39.9970
96	MARI	145039	-4.343	-195.712	97.0000	39.9982
97	MELV	145210	137.104	-186.781	97.0016	39.9983
98	MILF	145306	39.504	-106.05	97.0005	39.9990
99	MOUD	145536	152.624	-318.136	97.0018	39.9971
100	OAKL	145888	-306.378	-96.814	96.9964	39.9991
101	OTTA	146128	158.639	-178.635	97.0019	39.9984
102	POMO	146498	143.864	-176.707	97.0017	39.9984
103	SALI	147160	-29.426	-166.908	96.9997	39.9985
104	SMOL	147551	-34.639	-171.31	96.9996	39.9985
105	STAN	147756	225.026	-164.85	97.0027	39.9985
106	SUBL	147922	-303.514	-292.808	96.9964	39.9974
107	TOPE	148167	139.116	-104.91	97.0016	39.9991
108	TRIB	148235	-387.855	-180.643	96.9954	39.9984
109	UNIO	148293	211.43	-272.537	97.0025	39.9975
110	WALL	148535	-376.076	-152.432	96.9956	39.9986
111	WICH	148830	-23.729	-288.579	96.9997	39.9974
112	WILS	148946	-111.502	-156.22	96.9987	39.9986
113	BENT	150611	781.608	-348.109	97.0092	39.9969
114	CALH	151227	865.268	-261.635	97.0102	39.9976
115	CLTN	151631	749.287	-365.634	97.0088	39.9967
116	HERN	153798	859.01	-352.458	97.0101	39.9968
117	MADI	155067	854.116	-265.064	97.0101	39.9976
118	PADU	156110	753.185	-293.024	97.0089	39.9974

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
119	PCTN	156580	834.464	-280.496	97.0099	39.9975
120	ALEX	160103	433.824	-959.253	97.0051	39.9913
121	BATN	160549	562.794	-1032.4	97.0066	39.9907
122	CALH	161411	436.113	-817.451	97.0052	39.9926
123	CLNT	161899	578.969	-999.986	97.0068	39.9910
124	JENA	164696	455.225	-912.366	97.0054	39.9918
125	LACM	165078	364.784	-1089.92	97.0043	39.9901
126	MIND	166244	346.708	-812.651	97.0041	39.9927
127	MONR	166314	463.225	-814.905	97.0055	39.9926
128	NATC	166582	369.451	-905.316	97.0044	39.9918
129	SHRE	168440	299.526	-831.143	97.0035	39.9925
130	WINN	169803	408.309	-884.596	97.0048	39.9920
131	BROK	221094	621.827	-914.236	97.0073	39.9917
132	CONE	221900	737.007	-823.513	97.0087	39.9926
133	JAKS	224472	650.361	-826.097	97.0077	39.9925
134	LEAK	224966	805.886	-943.78	97.0095	39.9915
135	MERI	225776	774.942	-814.558	97.0092	39.9926
136	SARD	227815	658.33	-593.661	97.0078	39.9946
137	SAUC	227840	763.399	-1005.93	97.0090	39.9909
138	TUPE	229003	753.571	-600.03	97.0089	39.9946
139	ADVA	230022	657.892	-298.102	97.0078	39.9973
140	ALEY	230088	505.348	-305.864	97.0060	39.9972
141	BOLI	230789	331.651	-291.689	97.0039	39.9974
142	CASV	231383	310.855	-392.187	97.0037	39.9965
143	CLER	231674	575.868	-302.209	97.0068	39.9973
144	CLTT	231711	307.465	-190.83	97.0036	39.9983
145	COLU	231791	421.287	-155.672	97.0050	39.9986
146	DREX	232331	228.23	-185.776	97.0027	39.9983
147	ELM	232568	257.758	-159.419	97.0030	39.9986
148	FULT	233079	470.408	-150.668	97.0056	39.9986
149	HOME	233999	619.93	-415.469	97.0073	39.9962
150	JEFF	234271	424.774	-172.095	97.0050	39.9984
151	JOPL	234315	238.245	-318.262	97.0028	39.9971
152	LEBA	234825	402.239	-276.263	97.0048	39.9975
153	LICK	234919	480.849	-280.775	97.0057	39.9975
154	LOCK	235027	302.048	-300.612	97.0036	39.9973
155	MALD	235207	659.982	-377.876	97.0078	39.9966
156	MARS	235298	332.062	-94.655	97.0039	39.9991
157	MAFD	235307	391.968	-300.033	97.0046	39.9973
158	MCES	235415	471.737	-143.942	97.0056	39.9987

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
159	MILL	235594	309.516	-311.398	97.0037	39.9972
160	MTGV	235834	426.937	-310.43	97.0050	39.9972
161	NVAD	235987	243.915	-272.715	97.0029	39.9975
162	OZRK	236460	349.133	-390.626	97.0041	39.9965
163	PDTD	236777	334.055	-265.018	97.0039	39.9976
164	POTO	236826	572.215	-251.455	97.0068	39.9977
165	ROLL	237263	484.503	-253.958	97.0057	39.9977
166	ROSE	237300	500.59	-175.393	97.0059	39.9984
167	SALE	237506	498.94	-274.122	97.0059	39.9975
168	SENE	237656	233.959	-383.703	97.0028	39.9965
169	SPRC	237967	238.112	-373.616	97.0028	39.9966
170	SPVL	237976	332.385	-309.374	97.0039	39.9972
171	STEE	238043	503.354	-205.135	97.0059	39.9981
172	STOK	238082	310.911	-279.239	97.0037	39.9975
173	SWSP	238223	324.053	-150.325	97.0038	39.9986
174	TRKD	238252	340.418	-395.428	97.0040	39.9964
175	TRUM	238466	326.883	-197.796	97.0039	39.9982
176	UNIT	238524	238.567	-154.494	97.0028	39.9986
177	VIBU	238609	519.633	-267.258	97.0061	39.9976
178	VIEN	238620	470.383	-193.872	97.0056	39.9983
179	WAPP	238700	606.68	-358.746	97.0072	39.9968
180	WASG	238746	556.425	-164.993	97.0066	39.9985
181	WEST	238880	489.373	-377.809	97.0058	39.9966
182	ALBU	290234	-869.46	-501.713	96.9897	39.9955
183	ARTE	290600	-689.529	-773.897	96.9919	39.9930
184	AUGU	290640	-973.07	-598.391	96.9885	39.9946
185	CARL	291469	-680.335	-811.474	96.9920	39.9927
186	CARR	291515	-819.836	-665.132	96.9903	39.9940
187	CLAY	291887	-547.124	-374.102	96.9935	39.9966
188	CLOV	291939	-566.973	-599.296	96.9933	39.9946
189	CUBA	292241	-890.304	-392.495	96.9895	39.9965
190	CUBE	292250	-951.142	-489.293	96.9888	39.9956
191	DEMI	292436	-1007.99	-799.087	96.9881	39.9928
192	DURA	292665	-767.148	-577.618	96.9909	39.9948
193	EANT	292700	-735.089	-366.94	96.9913	39.9967
194	LAVG	294862	-738.245	-461.163	96.9913	39.9958
195	PROG	297094	-811.39	-578.971	96.9904	39.9948
196	RAMO	297254	-733.737	-615.175	96.9913	39.9944
197	ROSW	297610	-698.544	-712.921	96.9918	39.9936
198	ROY	297638	-644.735	-422.422	96.9924	39.9962

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
199	SANT	298085	-807.375	-445.708	96.9905	39.9960
200	SPRI	298501	-676.681	-374.272	96.9920	39.9966
201	STAY	298518	-810.491	-495.501	96.9904	39.9955
202	TNMN	299031	-912.488	-413.425	96.9892	39.9963
203	TUCU	299156	-604.359	-508.834	96.9929	39.9954
204	WAST	299569	-638.605	-820.288	96.9925	39.9926
205	WISD	299686	-856.967	-756.366	96.9899	39.9932
206	AIRS	340179	-212.731	-597.062	96.9975	39.9946
207	ARDM	340292	-12.242	-645.633	96.9999	39.9942
208	BENG	340670	174.368	-568.011	97.0021	39.9949
209	CANE	341437	71.857	-637.935	97.0009	39.9942
210	CHRT	341544	203.233	-632.067	97.0024	39.9943
211	CHAN	341684	10.494	-475.655	97.0001	39.9957
212	CHIK	341750	-83.175	-547.26	96.9990	39.9951
213	CCTY	342334	-165	-479.536	96.9981	39.9957
214	DUNC	342654	-88.38	-610.04	96.9990	39.9945
215	ELKC	342849	-216.769	-507.879	96.9974	39.9954
216	FORT	343281	-129.964	-541.113	96.9985	39.9951
217	GEAR	343497	-118.53	-482.187	96.9986	39.9956
218	HENN	344052	-31.964	-601.206	96.9996	39.9946
219	HOBA	344202	-189.062	-547.36	96.9978	39.9951
220	KING	344865	24.538	-664.103	97.0003	39.9940
221	LKEU	344975	141.702	-520.6	97.0017	39.9953
222	LEHI	345108	71.634	-612.05	97.0009	39.9945
223	MACI	345463	-254.63	-466.154	96.9970	39.9958
224	MALL	345589	-55.127	-425.644	96.9994	39.9962
225	MAYF	345648	-258.49	-512.583	96.9970	39.9954
226	MUSK	346130	149.764	-466.905	97.0018	39.9958
227	NOWA	346485	121.551	-364.038	97.0014	39.9967
228	OKAR	346620	-88.424	-473.338	96.9990	39.9957
229	OKEM	346638	63.188	-504.958	97.0008	39.9954
230	OKLA	346661	-54.198	-510.562	96.9994	39.9954
231	PAOL	346859	-23.665	-573.142	96.9997	39.9948
232	PAWH	346935	57.704	-369.174	97.0007	39.9967
233	PAWN	346944	16.927	-398.139	97.0002	39.9964
234	PONC	347196	-8.871	-363.068	96.9999	39.9967
235	PRYO	347309	150.763	-407.824	97.0018	39.9963
236	SHAT	348101	-256.963	-407.368	96.9970	39.9963
237	STIG	348497	171.02	-523.736	97.0020	39.9953
238	TULS	348992	99.361	-419.873	97.0012	39.9962

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
239	TUSK	349023	156.629	-592.395	97.0019	39.9946
240	WMWR	349629	-156.42	-581.308	96.9982	39.9947
241	WOLF	349748	30.212	-538.388	97.0004	39.9951
242	BOLI	400876	760.886	-500.256	97.0090	39.9955
243	BROW	401150	710.048	-480.346	97.0084	39.9957
244	CETR	401587	877.35	-456.294	97.0104	39.9959
245	DICS	402489	872.14	-391.132	97.0103	39.9965
246	DYER	402680	695.792	-409.316	97.0082	39.9963
247	GRNF	403697	760.795	-395.69	97.0090	39.9964
248	JSNN	404561	765.932	-476.414	97.0090	39.9957
249	LWER	405089	885.291	-487.757	97.0105	39.9956
250	LEXI	405210	790.003	-471.897	97.0093	39.9957
251	MASO	405720	694.163	-496.166	97.0082	39.9955
252	MEMP	405954	671.8	-522.492	97.0079	39.9953
253	MWFO	405956	681.292	-516.15	97.0080	39.9953
254	MUNF	406358	678.65	-495.241	97.0080	39.9955
255	SAMB	408065	697.077	-382.536	97.0082	39.9965
256	SAVA	408108	800.788	-498.682	97.0095	39.9955
257	UNCY	409219	711.595	-384.605	97.0084	39.9965
258	ABIL	410016	-251.753	-836.027	96.9970	39.9924
259	AMAR	410211	-425.302	-517.839	96.9950	39.9953
260	AUST	410428	-67.587	-1075.97	96.9992	39.9903
261	BRWN	411136	-43.861	-1571.39	96.9995	39.9858
262	COST	411889	60.611	-1044.72	97.0007	39.9906
263	COCR	412015	-51.832	-1360.01	96.9994	39.9877
264	CROS	412131	-204.599	-868.469	96.9976	39.9922
265	DFWT	412242	-1.867	-786.341	97.0000	39.9929
266	EAST	412715	-171.024	-840.253	96.9980	39.9924
267	ELPA	412797	-886.583	-860.763	96.9895	39.9922
268	HICO	414137	-97.323	-888.181	96.9989	39.9920
269	HUST	414300	157.976	-1108.38	97.0019	39.9900
270	KRES	414880	-434.746	-611.717	96.9949	39.9945
271	LKCK	414975	99.734	-693.521	97.0012	39.9937
272	LNGV	415348	220.962	-844.674	97.0026	39.9924
273	LUFK	415424	214.652	-969.69	97.0025	39.9912
274	MATH	415661	-86.438	-1330.47	96.9990	39.9880
275	MIDR	415890	-489.385	-878.123	96.9942	39.9921
276	MTLK	416104	-672.024	-1008.98	96.9921	39.9909
277	NACO	416177	223.065	-925.966	97.0026	39.9916
278	NAVA	416210	28.358	-892.028	97.0003	39.9919

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
279	NEWB	416270	239.111	-721.818	97.0028	39.9935
280	BPAT	417174	288.962	-1110.65	97.0034	39.9900
281	RANK	417431	-472.048	-959.488	96.9944	39.9913
282	SAAG	417943	-333.338	-952.54	96.9961	39.9914
283	SAAT	417945	-143.322	-1161.27	96.9983	39.9895
284	SHEF	418252	-463.759	-1019.19	96.9945	39.9908
285	STEP	418623	-112.988	-857.918	96.9987	39.9922
286	STER	418630	-376.683	-897.195	96.9956	39.9919
287	VALE	419270	-720.749	-1015.17	96.9915	39.9908
288	VICT	419364	6.882	-1236.45	97.0001	39.9888
289	WACO	419419	-21.834	-928.823	96.9997	39.9916
290	WATR	419499	-353.767	-916.015	96.9958	39.9917
291	WHEE	419665	57.489	-1008.99	97.0007	39.9909
292	WPDM	419916	262.792	-737.786	97.0031	39.9933
293	DORA	232302	433.256	-378.797	97.0051	39.9966
294	DIXN	112353	756.057	-267.193	97.0089	39.9976
295	DAUP	12172	864.408	-1050.41	97.0102	39.9905
296	FREV	123104	847.031	-117.884	97.0100	39.9989
297	WARR	18673	890.447	-788.703	97.0105	39.9929
298	MDTN	235562	493.264	-87.222	97.0058	39.9992

TABLE A-4. LIST OF OVER WATER METEOROLOGICAL STATIONS

Number	Station ID	Input file Name	LCC East (km)	LCC North (km)	Long	Lat
1	42001	42001	746.874	-1541.35	89.67	25.9
2	42002	42002	265.486	-1650.616	94.42	25.19
3	42007	42007	795.674	-1063.667	88.77	30.09
4	42019	42019	163.178	-1342.917	95.36	27.91
5	42020	42020	30.212	-1453.738	96.7	26.94
6	42035	42035	254.465	-1193.539	94.41	29.25
7	42040	42040	859.497	-1160.066	88.21	29.18
8	BURL1	42045	743.116	-1202.117	89.43	28.9
9	DPIA1	42046	861.385	-1039.466	88.07	30.25
10	GDIL1	42047	687.984	-1164.910	89.96	29.27
11	PTAT2	42048	-4.980	-1353.398	97.05	27.83
12	SRST2	42049	288.163	-1175.682	94.05	29.67

ADEQ

ARKANSAS
Department of Environmental Quality

May 23, 2012

James Cutbirth
Superintendent -Environmental Services
Georgia-Pacific LLC - Crossett Paper Operations
P.O. Box 3333
Crossett, AR 71635-3333

Re: Notice of Administrative Amendment
AFIN: 02-00013, Permit #0597-AOP-R14

Dear Mr. Cutbirth:

Enclosed is Permit 0597-AOP-R14 completed in accordance with the provisions of Section 19.407 of Regulation No. 19, *Regulations of the Arkansas Plan of Implementation for Air Pollution Control*.

This revised permit is being issued because the original permit had the incorrect permit number 0579-AOP-R14. The correct permit number is 0597-AOP-R14.

Please place the revised permit in your files.

Sincerely,

Mike Bates

Mike Bates
Chief, Air Division

TWP
Enclosure

ADEQ
OPERATING
AIR PERMIT

Pursuant to the Regulations of the Arkansas Operating Air Permit Program, Regulation 26:

Permit No. : 0597-AOP-R14

IS ISSUED TO:

Georgia-Pacific LLC - Crossett Paper Operations
100 Mill Supply Road
Crossett, AR 71635
Ashley County
AFIN: 02-00013

THIS PERMIT AUTHORIZES THE ABOVE REFERENCED PERMITTEE TO INSTALL, OPERATE, AND MAINTAIN THE EQUIPMENT AND EMISSION UNITS DESCRIBED IN THE PERMIT APPLICATION AND ON THE FOLLOWING PAGES. THIS PERMIT IS VALID BETWEEN:

August 4, 2011 AND August 3, 2016

THE PERMITTEE IS SUBJECT TO ALL LIMITS AND CONDITIONS CONTAINED HEREIN.

Signed:

Mike Bates
Chief, Air Division

May 23, 2012
Date

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List of Acronyms and Abbreviations

A.C.A.	Arkansas Code Annotated
AFIN	ADEQ Facility Identification Number
CFR	Code of Federal Regulations
CO	Carbon Monoxide
HAP	Hazardous Air Pollutant
lb/hr	Pound Per Hour
MVAC	Motor Vehicle Air Conditioner
No.	Number
NO_x	Nitrogen Oxide
PM	Particulate Matter
PM_{10}	Particulate Matter Smaller Than Ten Microns
SNAP	Significant New Alternatives Program (SNAP)
SO_2	Sulfur Dioxide
SSM	Startup, Shutdown, and Malfunction Plan
Tpy	Tons Per Year
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compound

SECTION I: FACILITY INFORMATION

PERMITTEE:	Georgia-Pacific LLC - Crossett Paper Operations
AFIN:	02-00013
PERMIT NUMBER:	0597-AOP-R14
FACILITY ADDRESS:	100 Mill Supply Road Crossett, AR 71635
MAILING ADDRESS:	P.O. Box 3333 Crossett, AR 71635-3333
COUNTY:	Ashley County
CONTACT NAME:	James Cutbirth
CONTACT POSITION:	Superintendent -Environmental Services
TELEPHONE NUMBER:	870-567-8144
REVIEWING ENGINEER:	Ambrosia Brown
UTM North South (Y):	Zone 15: 3667408.69 m
UTM East West (X):	Zone 15: 596029.30 m

SECTION II: INTRODUCTION

Summary of Permit Activity

The Georgia-Pacific LLC - Paper Operations facility operates a kraft paper mill at 100 Paper Mill Road, Crossett, Arkansas 71635. This facility produces a variety of paper products on eight paper machines and two paper extruding machines. The paper machines include two fine paper machines, one board paper machine, and five tissue machines. This permitting action was requested in order to reduce the maximum hourly emission rate of sulfur dioxide for its 9A Boiler (SN-22). This emission reduction is achieved through limiting use of specification grade oil as a fuel. Actual emission rates shall decrease as a result of this limit, however permitted PM_{10} emissions shall increase because new emission factors and safety factors that were used in emission calculations. The increase to permitted emissions is 95.7 tpy PM/PM_{10}. The decreases to permitted emissions are 877 tpy SO_2, 0.1 tpy VOC, and 96.1 tpy NO_X.

Process Description

Chips are received at the Mill by truck and rail. Upon unloading, the chips are pneumatically blown to the distribution tower and are then dropped onto the chip piles. Round logs are also received at the facility. After storage, the logs are transported to the debarking drums for bark removal. The debarked logs are fed to the chipper and the produced chips are then conveyed to the chip piles. The chips from the chip piles are screened prior to entering the chip silos. Rejected chips from the screening are burned in the Mill's combination boiler. The removed bark is pneumatically sent to bark piles for storage and eventual use in the Mill's boilers.
The chips from the silos are conveyed to the Mill's thirteen batch digesters. The function of the digesters is to cook the chips using white liquor, black liquor, and the steam from the boilers. In the digestion process, these products are combined and cooked at a set pressure and temperature until the quality pulp is obtained. At the end of each "cook", the blow valves at the bottom of the digesters are opened, with the resulting pressure forcing the pulp mass through a blow line into one of the two blow tanks.

The blow tanks are at atmospheric pressure and the contents of the digesters enter the blow tanks tangentially at the top. When the chips hit the lower pressure in the tank, the liquor and water flash, blowing the chips apart to produce the pulp fibers. The vapors from the blow tanks are sent to the blow heat condensing system, where non condensable gases (NCGs) are removed. The steam vapors are condensed in the accumulator. The accumulator water is sent to the stripper and returned to the washers as cleaned condensate. Knots (e.g. undercooked wood chips, irregularly shaped or overly thick pieces of wood, etc.) are removed with the use of vibrating knotters/screens.

The pulp is washed to remove spent cooking chemicals. The Mill has two horizontal washers. In the washers, the wash water and pulp move in counter current directions. The washed pulp is passed through screening and cleaning stages which remove debris from the stock. After screening, the pulp passes through the decker system, which thickens the pulp for storage in high density storage chests.

The unbleached Kraft pulp is taken from the high density storage chests for further processing in the bleach plant. The bleaching process removes the remaining lignin and Kraft color from the unbleached pulp. Bleaching is performed in several stages using chlorine dioxide, caustic soda, oxygen, and hydrogen peroxide.

Recovery describes the set of operations that recovers the spent cooking chemicals for reuse in the digesters. The recovery process utilizes a multi-effect evaporator to concentrate weak black liquor. The concentrated black liquor is burned in the Mill's recovery furnace. The spent chemicals leave the recovery furnace from the bottom in a molten form and enter the smelt dissolving tanks. The causticizing operation reacts molten inorganic salts from the smelt dissolving tanks with weak wash water to form green liquor. This green liquor is then treated with slaked lime to form white liquor. The white liquor is then ready for use as the main cooking liquor in the digesters.

The facility, in order to accommodate production levels, may export black liquor to another mill with excess recovery capacity in exchange for white or green liquor. The 'liquor-swapping' is considered routine and normal for the industry, and equipment needed for the exchange has been present since the facility has been built.

Paper products are currently manufactured on eight paper machines and two paper extruding machines. The paper machines include two fine paper machines, one board paper machine, and five tissue machines. Each machine has its own stock preparation, head box, wire section, press section, dryer sections, coater section, calendar stacks, reel, and drum winder. The two fine paper machines produce a variety of products including but not limited to bond, envelope, tablet, and copier paper.

Tissue and towel converting includes the operations involved with converting large parent rolls of tissue/towel from the machines into finished product. This includes rewinding onto smaller sized rolls, folding, printing, cutting, packaging, and shipping.

The two extruding machines receive board from the board paper machine and from outside board customers and apply a polymer coating. Rolls of board are loaded onto an unwind stand before passing through a calendar stack, where they are subjected to burners which flame seal the board. An extruded poly sheet is then pressed together with the board.

Regulations

The following table contains the regulations applicable to this permit.

Source (SN)	Regulation
Arkansas Air Pollution Code (Regulation 18) effective June 18, 2010	
Regulations of the Arkansas Plan of Implementation for Air Pollution Control (Regulation 19) effective July 18, 2009	
Regulations of Arkansas Air Permit Operating Program (Regulation 26) effective June 18, 2010	
SN-03	NSPS Subpart D
SN-25	NSPS Subpart BB NESHAP Subpart MM
SN-26	NSPS Subpart BB NESHAP Subpart MM
SN-27A & 27B	NSPS Subpart BB NESHAP Subpart MM
SN-30	NESHAP Part S
SN-33 and SN-34	NSPS Subpart BB
SN-40	NSPS Subpart Kb
SN-59	NSPS Subpart BB
SN-71, SN-72, SN-80, SN-111, SN-112, and SN-113	NESHAP JJJJ
SN-115, 116, 117, 118, 119, 120, and 121	NESHAP ZZZZ
SN-118 and SN-119	NSPS IIII

Emission Summary

The following table is a summary of emissions from the facility. This table, in itself, is not an enforceable condition of the permit.

EMISSION SUMMARY				
Source #	Description	Pollutant	Emission Rates	
			lb/hr	tpy
Total Allowable Emissions		PM	335.7	1,403.5
		PM_{10}	325.5	1,372.6
		SO_2	1,237.6	1,037.4
		VOC	743.9	3,209.3
		CO	2,649.5	11,484.5
		NO_X	1,331.3	5,522.4
		Pb	0.21	0.53
		TRS	32.3	130.7
HAPs		Acetaldehyde*	7.80	32.49
		Acetophenone*	0.44	1.66
		Acrolein*	0.56	1.70
		Arsenic	0.13	0.25
		Benzene*	1.05	3.19
		Beryllium	0.06	0.06
		Biphenyl*	3.71	16.18
		Cadmium	0.13	0.13
		Carbon Disulfide*	0.32	1.33
		Carbon Tetrachloride*	0.15	0.39
		Carbonyl Sulfide*	0.14	0.50
		Chloroform*	9.87	42.70
		Chromium, Hex	0.04	0.08
		Cobalt	0.14	0.18
		Cresol*	2.34	8.86
		Cumene*	0.48	1.95
		2,4-Dinitrotoluene*	0.02	0.02
		Ethylene Dibromide*	0.03	0.11
		Ethylene Dichloride*	0.11	0.32
		Formaldehyde*	5.56	20.05
		Hexane*	4.95	21.15
		Hexachlorobenzene*	0.04	0.10

EMISSION SUMMARY				
Source #	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Hexachloroethane*	0.21	0.90
		Hexachloropentadiene*	0.16	0.66
		Hydrogen chloride	12.30	48.36
		Manganese	0.19	0.49
		Mercury	0.13	0.13
		Methanol*	57.85	243.74
		Methylene Chloride	1.22	4.92
		Naphthalene*	1.01	3.42
		Nickel	0.16	0.34
		Phenol*	1.93	8.03
		Phosphorus	0.32	1.23
		Propionaldehyde*	0.43	1.60
		Propylene dichloride*	0.06	0.27
		POM*	0.65	2.41
		SAM**	3.6	10.4
		Selenium	0.06	0.08
		Styrene*	0.52	1.52
		Tetrachloroethylene	0.75	2.73
		1,2,4-Trichlorobenzene*	0.60	2.11
		Toluene*	0.58	1.33
		Vinyl Chloride*	0.04	0.15
		Xylene*	0.97	3.09
Air Contaminants **		Acetone**	10.2	35.0
		Ammonia**	14.0	53.0
		Ozone	2.3	9.5
		Sulfuric Acid (SAM)**	38.5	83.4
03	10A Boiler	PM	100.1	438.5
		PM_{10}	100.1	438.5
		SO_2	21.0	92.0
		VOC	17.1	74.6
		CO	600.6	2,630.7
		NO_X	500.5	2,192.2
		Pb	0.06	0.26
		Acetaldehyde*	0.28	1.22
		Acetophenone*	0.01	0.01
		Acetone**	0.3	1.1
		Acrolein*	0.10	0.42
		Arsenic	0.01	0.02
		Benzene*	0.33	1.43
		Beryllium	0.01	0.01

EMISSION SUMMARY				
Source #	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Cadmium	0.01	0.01
		Carbon Disulfide*	0.16	0.69
		Carbon Tetrachloride*	0.01	0.01
		Chloroform*	0.05	0.20
		Chromium, Hex	0.01	0.04
		Cobalt	0.01	0.01
		Cumene*	0.03	0.10
		2,4-Dinitrotoluene*	0.01	0.01
		Ethylene Dichloride*	0.04	0.16
		Formaldehyde*	0.86	3.74
		Hexane*	1.57	6.84
		Hexachlorobenzene	0.01	0.01
		Hydrogen chloride*	0.19	0.79
		Manganese	0.05	0.22
		Mercury	0.01	0.01
		Methanol*	1.04	4.53
		Methylene Chloride	0.43	1.85
		Naphthalene*	0.13	0.53
		Nickel	0.01	0.03
		Phenol*	0.02	0.05
		Phosphorus	0.12	0.53
		Propionaldehyde*	0.08	0.33
		Propylene dichloride*	0.04	0.18
		POM*	0.30	1.30
		Selenium	0.01	0.02
		Styrene*	0.04	0.17
		Tetrachloroethylene	0.07	0.28
		Toluene*	0.04	0.15
		Vinyl Chloride*	0.03	0.10
		Xylene*	0.03	0.12
18	5A Boiler	PM	2.1	8.8
		PM_{10}	2.1	8.8
		SO_2	0.2	0.7
		VOC	1.5	6.4
		CO	22.2	97.2
		NO_X	74.0	323.8
		Pb	0.01	0.01
		Arsenic	0.01	0.01
		Benzene*	0.01	0.01
		Cadmium	0.01	0.01

EMISSION SUMMARY				
Source #	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Cobalt	0.01	0.01
		Formaldehyde*	0.02	0.09
		Hexane*	0.48	2.09
		Manganese	0.01	0.01
		Mercury	0.01	0.01
		Naphthalene*	0.01	0.01
		Nickel	0.01	0.01
		POM*	0.01	0.01
		Toluene*	0.01	0.01
19	6A Boiler	PM	3.3	14.3
		PM_{10}	3.3	14.3
		SO_2	0.3	1.2
		VOC	2.4	10.4
		CO	36.0	157.7
		NO_X	120.0	525.4
		Pb	0.01	0.01
		Arsenic	0.01	0.01
		Benzene*	0.01	0.01
		Cadmium	0.01	0.01
		Cobalt	0.01	0.01
		Formaldehyde*	0.04	0.15
		Hexane*	0.78	3.38
		Manganese	0.01	0.01
		Mercury	0.01	0.01
		Naphthalene*	0.01	0.01
		Nickel	0.01	0.01
		POM*	0.01	0.01
		Toluene*	0.01	0.01
22	9A Boiler	PM	77.4	339.0
		PM_{10}	77.4	339.0
		SO_2	199.8	484.6
		VOC	11.3	49.5
		CO	366.8	1,606.7
		NO_X	196.0	858.6
		Pb	0.03	0.14
		Acetaldehyde*	0.13	0.57
		Acetophenone*	0.01	0.01
		Acetone**	0.2	0.5
		Acrolein*	0.04	0.19
		Arsenic	0.01	0.03

EMISSION SUMMARY				
Source #	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Benzene*	0.15	0.68
		Beryllium	0.01	0.01
		Cadmium	0.01	0.01
		Carbon Disulfide*	0.07	0.32
		Carbon Tetrachloride*	0.01	0.01
		Chloroform*	0.02	0.09
		Chromium, Hex	0.01	0.02
		Cobalt	0.02	0.06
		Cumene*	0.01	0.05
		2,4-Dinitrotoluene*	0.01	0.01
		Ethylene Dichloride*	0.02	0.07
		Formaldehyde*	0.47	2.06
		Hexane*	1.56	6.81
		Hexachlorobenzene*	0.01	0.01
		Hydrogen Chloride	0.13	0.57
		Manganese	0.03	0.13
		Mercury	0.01	0.01
		Methanol*	0.49	2.15
		Methylene Chloride	0.20	0.87
		Naphthalene*	0.06	0.26
		Nickel	0.04	0.17
		Phenol*	0.01	0.03
		Phosphorus	0.08	0.33
		Propionaldehyde*	0.04	0.15
		Propylene Dichloride*	0.02	0.09
		POM*	0.14	0.63
		SAM**	3.6	10.4
		Selenium	0.01	0.02
		Styrene*	0.02	0.08
		Tetrachloroethylene	0.03	0.13
		Toluene*	0.02	0.11
		Vinyl Chloride*	0.01	0.05
		Xylene*	0.01	0.02
25	No. 4 Lime Kiln	PM	28.3	123.8
		PM_{10}	28.3	123.8
		SO_2	10.9	41.2
		VOC	1.5	5.6
		CO	5.8	21.9
		NO_X	53.5	203.6
		Pb	0.01	0.02

EMISSION SUMMARY				
Source #	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		TRS	2.2	9.6
		Acetaldehyde*	0.18	0.67
		Acetone**	0.1	0.1
		Acrolein*	0.01	0.01
		Arsenic	0.01	0.01
		Benzene*	0.02	0.04
		Beryllium	0.01	0.01
		Cadmium	0.01	0.01
		Carbon Disulfide*	0.01	0.04
		Chloroform*	0.01	0.01
		Chromium Hex	0.01	0.01
		Cobalt	0.01	0.01
		Formaldehyde*	0.18	0.67
		Hexane*	0.01	0.01
		Hydrogen Chloride	0.01	0.03
		Manganese	0.01	0.04
		Mercury	0.01	0.01
		Methanol*	0.38	1.45
		Methylene Chloride	0.01	0.01
		Naphthalene*	0.42	1.57
		Nickel	0.01	0.02
		Phenol*	0.01	0.04
		Phosphorous	0.06	0.21
		POM*	0.01	0.02
		SAM**	0.7	2.6
		Selenium	0.01	0.01
		Styrene*	0.01	0.01
		Tetrachloroethylene	0.01	0.04
		Toluene*	0.01	0.01
		1,2,4-Trichlorobenzene*	0.01	0.02
		Xylene*	0.01	0.03
26	8R Recovery Furnace	PM	60.0	262.8
		PM_{10}	60.0	262.8
		SO_2	989.1	371.0
		VOC	25.9	98.6
		CO	1,420.0	6,219.6
		NO_X	276.0	1,208.6
		Pb	0.01	0.01
		TRS	11.2	48.8
		Acetaldehyde*	0.08	0.28

EMISSION SUMMARY				
Source #	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Acetone**	2.3	8.6
		Arsenic	0.01	0.01
		Benzene*	0.12	0.43
		Beryllium	0.01	0.01
		Cadmium	0.01	0.01
		Chloroform*	0.01	0.02
		Chromium, Hex	0.01	0.01
		Cobalt	0.01	0.01
		Formaldehyde*	1.35	5.13
		Hexane*	0.05	0.17
		Hydrogen Chloride	9.49	36.14
		Manganese	0.01	0.04
		Methanol*	7.59	28.91
		Mercury	0.01	0.01
		Methylene Chloride	0.09	0.32
		Naphthalene*	0.05	0.18
		Nickel	0.01	0.03
		Phosphorous	0.04	0.14
		POM*	0.02	0.06
		Selenium	0.01	0.01
		Styrene*	0.10	0.37
		SAM**	7.3	27.6
		Tetrachloroethylene	0.09	0.32
		Toluene*	0.01	0.03
		1,2,4-Trichlorobenzene*	0.14	0.51
		Xylene*	0.09	0.34
27A	Smelt Dissolving Tank (East)	PM	14.4	54.8
		PM_{10}	14.4	54.8
		SO_2	0.5	1.7
		VOC	1.5	5.5
		CO	0.7	2.7
		NOx	1.8	6.6
		Pb	0.01	0.01
		TRS	2.4	9.1
		Acetaldehyde*	0.08	0.30
		Acetone**	0.2	0.5
		Acrolein*	0.01	0.01
		Arsenic	0.01	0.01
		Benzene*	0.01	0.01
		Beryllium	0.01	0.01

EMISSION SUMMARY				
Source #	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Cadmium	0.01	0.01
		Carbon Disulfide*	0.01	0.01
		Chloroform*	0.01	0.01
		Cobalt	0.01	0.01
		Cumene*	0.01	0.01
		Formaldehyde*	0.31	1.15
		Hexachlorocyclopentadiene*	0.01	0.04
		Hexane*	0.01	0.01
		Manganese	0.01	0.01
		Mercury	0.01	0.01
		Methanol*	0.95	3.62
		Methylene Chloride	0.01	0.01
		Naphthalene*	0.05	0.17
		Nickel	0.01	0.01
		Phosphorous	0.01	0.01
		POM*	0.04	0.15
		Selenium	0.01	0.01
		Styrene*	0.02	0.04
		Tetrachloroethylene	0.01	0.01
		Toluene*	0.01	0.01
		1,2,4-Trichlorbenzene*	0.01	0.01
		Xylene*	0.01	0.01
27B	Smelt Dissolving Tank (West)	PM	14.4	54.8
		PM_{10}	14.4	54.8
		SO_2	0.5	1.7
		VOC	1.5	5.5
		CO	0.7	2.7
		NOx	1.8	6.6
		Pb	0.01	0.01
		TRS	2.4	9.1
		Acetaldehyde*	0.08	0.30
		Acetone**	0.2	0.5
		Acrolein*	0.01	0.01
		Arsenic	0.01	0.01
		Benzene*	0.01	0.01
		Beryllium	0.01	0.01
		Cadmium	0.01	0.01
		Carbon Disulfide*	0.01	0.01
		Chloroform*	0.01	0.01
		Cobalt	0.01	0.01

EMISSION SUMMARY				
Source #	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Cumene*	0.01	0.01
		Formaldehyde*	0.31	1.15
		Hexachlorocyclopentadiene*	0.01	0.04
		Hexane*	0.01	0.01
		Manganese	0.01	0.01
		Mercury	0.01	0.01
		Methanol*	0.95	3.62
		Methylene Chloride	0.01	0.01
		Naphthalene*	0.05	0.17
		Nickel	0.01	0.01
		Phosphorous	0.01	0.01
		POM*	0.04	0.15
		Selenium	0.01	0.01
		Styrene*	0.02	0.04
		Tetrachloroethylene	0.01	0.01
		Toluene*	0.01	0.01
		1,2,4-Trichlorbenzene*	0.01	0.01
		Xylene*	0.01	0.01
30	Bleach Plant	VOC	21.4	93.7
		CO	136.1	596.1
		Acetaldehyde*	0.23	0.99
		Acetone**	0.5	2.0
		Acrolein*	0.01	0.01
		Benzene*	0.01	0.01
		Carbon Tetrachloride*	0.01	0.01
		Chloroform*	7.64	33.44
		Cresol*	0.06	0.25
		Cumene*	0.01	0.01
		Ethylene Dibromide*	0.03	0.11
		Ethylene Dichloride*	0.01	0.01
		Formaldehyde*	0.05	0.21
		Hexachlorocyclopentadiene*	0.16	0.66
		Hexachloroethane*	0.21	0.90
		Hydrogen Chloride	2.48	10.83
		Hexane*	0.01	0.01
		Methanol*	12.90	56.51
		Methylene Chloride	0.01	0.03
		Propionaldehyde*	0.06	0.25
		Phenol*	0.04	0.14
		Styrene*	0.02	0.09

EMISSION SUMMARY				
Source #	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Tetrachloroethylene	0.01	0.05
		Toluene*	0.01	0.01
		1,2,4-Trichlorbenzene*	0.01	0.03
		Xylene*	0.01	0.01
33	Line 1 Washer	VOC	7.5	28.4
		TRS	2.1	7.9
		Acetaldehyde*	0.10	0.35
		Acetone**	0.3	0.8
		Acetophenone*	0.21	0.79
		Acrolein*	0.01	0.02
		Benzene*	0.01	0.02
		Carbon Tetrachloride*	0.03	0.09
		Carbonyl Sulfide*	0.07	0.25
		Chloroform*	0.01	0.01
		Cresol*	0.34	1.29
		Ethylene Dichloride*	0.01	0.03
		Formaldehyde*	0.01	0.01
		Hexane*	0.01	0.03
		Methanol*	4.66	17.69
		Methylene Chloride	0.01	0.01
		Phenol*	0.37	1.40
		Styrene*	0.01	0.04
		Tetrachloroethylene	0.04	0.15
		Toluene*	0.02	0.05
		1,2,4-Trichlorobenzene*	0.02	0.08
		Xylene*	0.01	0.02
34	Line 2 Washer	VOC	7.5	28.4
		TRS	2.1	7.9
		Acetaldehyde*	0.10	0.35
		Acetone**	0.3	0.8
		Acetophenone*	0.21	0.79
		Acrolein*	0.01	0.02
		Benzene*	0.01	0.02
		Carbon Tetrachloride*	0.03	0.09
		Carbonyl Sulfide*	0.07	0.25
		Chloroform*	0.01	0.01
		Cresol*	0.34	1.29
		Ethylene Dichloride*	0.01	0.03
		Formaldehyde*	0.01	0.01
		Hexane*	0.01	0.03

EMISSION SUMMARY				
Source #	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Methanol*	4.66	17.69
		Methylene Chloride	0.01	0.01
		Phenol*	0.37	1.40
		Styrene*	0.01	0.04
		Tetrachloroethylene	0.04	0.15
		Toluene*	0.02	0.05
		1,2,4-Trichlorobenzene*	0.02	0.08
		Xylene*	0.01	0.02
35F	Aeration Stabilization Basin	VOC	17.3	75.5
		Acetaldehyde*	0.14	0.61
		Acrolein*	0.01	0.04
		Benzene*	0.02	0.07
		Biphenyl*	0.01	0.02
		Carbon Disulfide*	0.05	0.21
		Chloroform*	0.61	2.66
		Cresol*	0.01	0.01
		Cumene*	0.41	1.77
		Formaldehyde*	0.04	0.18
		Methanol*	15.24	66.74
		Naphthalene*	0.09	0.36
		Phenol*	0.01	0.01
		Propionaldehyde*	0.01	0.04
		Styrene*	0.08	0.34
		Toluene*	0.03	0.11
		Xylene*	0.37	1.59
40	Methanol Storage Tank	VOC	0.3	1.0
		Methanol*	0.22	1.0
46	Tissue Machine No. 4 Burners	PM	0.2	0.8
		PM_{10}	0.2	0.8
		SO_2	0.1	0.1
		VOC	0.2	0.6
		CO	2.1	8.9
		NO_x	2.4	10.6
		Pb	0.01	0.01
		Arsenic	0.01	0.01
		Benzene*	0.01	0.01
		Cadmium	0.01	0.01
		Cobalt	0.01	0.01
		Formaldehyde*	0.01	0.01
		Hexane*	0.05	0.19

EMISSION SUMMARY				
Source #	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Manganese	0.01	0.01
		Mercury	0.01	0.01
		Naphthalene*	0.01	0.01
		Nickel	0.01	0.01
		Toluene*	0.01	0.01
47	Tissue Machine No. 5 Burners	PM	0.4	1.6
		PM_{10}	0.4	1.6
		SO_2	0.1	0.1
		VOC	1.2	5.2
		CO	4.5	19.8
		NO_x	2.0	8.4
		Pb	0.01	0.01
		Arsenic	0.01	0.01
		Benzene*	0.01	0.01
		Cadmium	0.01	0.01
		Cobalt	0.01	0.01
		Formaldehyde*	0.01	0.01
		Hexane*	0.05	0.20
		Manganese	0.01	0.01
		Mercury	0.01	0.01
		Naphthalene*	0.01	0.01
		Nickel	0.01	0.01
		Toluene*	0.01	0.01
48	Tissue Machine No. 6 Burners	PM	0.4	1.7
		PM_{10}	0.4	1.7
		SO_2	0.1	0.2
		VOC	0.3	1.4
		CO	4.5	19.8
		NO_x	2.0	8.4
		Pb	0.01	0.01
		Arsenic	0.01	0.01
		Benzene*	0.01	0.01
		Cadmium	0.01	0.01
		Cobalt	0.01	0.01
		Formaldehyde*	0.01	0.02
		Hexane*	0.09	0.39
		Manganese	0.01	0.01
		Mercury	0.01	0.01
		Naphthalene*	0.01	0.01
		Nickel	0.01	0.01

EMISSION SUMMARY				
Source #	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Toluene*	0.01	0.01
49	Tissue Machine No. 7 Burners	PM	0.4	1.7
		PM_{10}	0.4	1.7
		SO_2	0.1	0.2
		VOC	0.3	1.2
		CO	4.2	18.2
		NO_x	2.5	10.8
		Pb	0.01	0.01
		Arsenic	0.01	0.01
		Benzene*	0.01	0.01
		Cadmium	0.01	0.01
		Cobalt	0.01	0.01
		Formaldehyde*	0.01	0.02
		Hexane*	0.09	0.39
		Manganese	0.01	0.01
		Mercury	0.01	0.01
		Naphthalene*	0.01	0.01
		Nickel	0.01	0.01
		Toluene*	0.01	0.01
50	Tissue Machine No. 7 Dust System	PM	0.5	2.1
		PM_{10}	0.5	2.1
51	Tissue Machine No. 6 Rewinder	PM	0.5	1.9
		PM_{10}	0.5	1.9
52	Tissue Machine No. 6 Dust System	PM	0.5	1.9
		PM_{10}	0.5	1.9
54	Tissue Machine No. 5 Dust System	PM	0.3	1.1
		PM_{10}	0.3	1.1
55F	Slaker Vent #1	PM	0.4	1.4
		PM_{10}	0.4	1.4
		VOC	1.7	6.4
		TRS	0.8	2.8
		Acetaldehyde*	0.11	0.41
		Acetone**	0.2	0.5
		Acrolein*	0.01	0.01
		Ammonia**	7.0	26.5
		Benzene*	0.01	0.01
		Methanol*	0.86	3.26
		Styrene*	0.01	0.01

EMISSION SUMMARY				
Source #	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Tetrachloroethylene Toluene* 1,2,4-Trichlorobenzene* Xylene*	0.01 0.01 0.01 0.01	0.01 0.02 0.01 0.01
56F	Slaker Vent #2	PM PM_{10} VOC TRS Acetaldehyde* Acetone** Acrolein* Ammonia** Benzene* Methanol* Styrene* Tetrachloroethylene Toluene* 1,2,4-Trichlorobenzene* Xylene*	0.4 0.4 1.7 0.8 0.11 0.2 0.01 7.0 0.01 0.86 0.01 0.01 0.01 0.01 0.01	1.4 1.4 6.4 2.8 0.41 0.5 0.01 26.5 0.01 3.26 0.01 0.01 0.02 0.01 0.01
57F	Woodyard Debarking Drum and Associated Woodyard Chip Handling System	PM PM_{10} VOC	0.1 0.1 410.9	0.2 0.1 1,799.4
58F	Woodyard Chip Storage Piles & Chippers	PM PM_{10} VOC	2.5 1.3 2.1	10.8 5.4 8.8
59	Batch Digesters (13)	VOC TRS Acetaldehyde* Acetone** Acrolein* Benzene* Carbon Tetrachloride* Chloroform* Ethylene Dichloride* Formaldehyde* Hexane* Methanol*	5.3 0.9 0.12 0.2 0.01 0.01 0.02 0.12 0.01 0.01 0.01 2.11	23.1 3.9 0.52 0.8 0.01 0.01 0.05 0.52 0.01 0.01 0.03 9.21

EMISSION SUMMARY				
Source #	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Styrene*	0.02	0.07
		Tetrachloroethylene	0.01	0.01
		Toluene*	0.02	0.06
		Xylene*	0.01	0.02
60	Line 1 Decker	Routed to the Incinerator (SN-83)		
61	Line 2 Decker	VOC	4.5	16.9
		TRS	2.1	7.7
		Acetaldehyde*	0.33	1.23
		Acetone**	0.5	1.8
		Acrolein*	0.01	0.02
		Benzene*	0.01	0.01
		Carbon Tetrachloride*	0.02	0.07
		Chloroform*	0.13	0.49
		Cresol*	1.56	5.90
		Formaldehyde*	0.09	0.33
		Methanol*	2.02	7.65
		Propionaldehyde*	0.10	0.35
		Styrene*	0.02	0.06
		Tetrachloroethylene	0.04	0.15
		Toluene*	0.01	0.02
		1,2,4-Trichlorobenzene*	0.11	0.40
		Xylene*	0.02	0.05
62	Fine Paper Machine No. 1	VOC	18.6	81.3
		Acetaldehyde*	1.20	5.23
		Acetone**	0.8	3.6
		Acrolein*	0.05	0.20
		Formaldehyde*	0.24	1.05
		Methanol*	1.20	5.23
		Methylene Chloride	0.10	0.41
		Tetrachloroethylene	0.09	0.37
		1,2,4-Trichlorobenezene*	0.05	0.22
		Xylene*	0.03	0.11
63	Fine Paper Machine No. 2	VOC	11.3	49.3
		Acetaldehyde*	1.20	5.23
		Acetone**	0.8	3.6
		Acrolein*	0.05	0.20
		Formaldehyde*	0.24	1.05
		Methanol*	1.20	5.23
		Methylene Chloride	0.10	0.41

EMISSION SUMMARY				
Source #	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Tetrachloroethylene 1,2,4-Trichlorobenezene* Xylene*	0.09 0.05 0.03	0.37 0.22 0.11
64	Board Paper Machine No. 3	VOC Acetaldehyde* Acetone** Acrolein* Formaldehyde* Methanol* Methylene Chloride Tetrachloroethylene 1,2,4-Trichlorobenzene* Xylene*	17.0 1.95 1.3 0.08 0.39 1.95 0.15 0.14 0.09 0.04	74.5 8.51 5.7 0.32 1.69 8.51 0.66 0.59 0.36 0.18
65	Board Paper Machine No. 3 Burners	PM PM_{10} SO_2 VOC CO NO_x Pb Arsenic Benzene* Cadmium Cobalt Formaldehyde* Hexane* Manganese Mercury Naphthalene* Nickel Toluene*	0.2 0.2 0.1 0.1 1.3 1.5 0.01 0.01 0.01 0.01 0.01 0.01 0.03 0.01 0.01 0.01 0.01 0.01	0.5 0.5 0.1 0.4 5.5 6.5 0.01 0.01 0.01 0.01 0.01 0.01 0.12 0.01 0.01 0.01 0.01 0.01
66	Tissue Machine No. 4	PM PM_{10} VOC Acetaldehyde* Biphenyl* Chloroform* Formaldehyde* Methanol* Methylene Chloride	0.5 0.5 13.0 0.11 0.81 0.03 0.01 0.05 0.01	2.0 2.0 74.5 0.47 3.54 0.10 0.01 0.19 0.04

EMISSION SUMMARY				
Source #	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Phenol* Propionaldehyde* Toluene*	0.18 0.01 0.03	0.76 0.01 0.10
67	Tissue Machine No. 4 Dust System	PM PM_{10}	0.3 0.3	1.1 1.1
68	Tissue Machine No. 5	PM PM_{10} VOC Acetaldehyde* Biphenyl* Chloroform* Formaldehyde* Methanol* Methylene Chloride Phenol* Propionaldehyde* Toluene*	0.3 0.3 13.0 0.07 0.46 0.02 0.01 0.03 0.01 0.10 0.01 0.02	1.1 1.1 57.0 0.27 1.99 0.06 0.01 0.11 0.03 0.43 0.01 0.06
69	Tissue Machine No. 6	PM PM_{10} VOC Acetaldehyde* Biphenyl* Chloroform* Formaldehyde* Methanol* Methylene Chloride Phenol* Propionaldehyde* Toluene*	0.7 0.7 26.7 0.17 1.26 0.04 0.01 0.07 0.02 0.27 0.01 0.04	3.1 3.1 116.6 0.74 5.52 0.15 0.01 0.29 0.08 1.19 0.01 0.15
70	Tissue Machine No. 7	PM PM_{10} VOC Acetaldehyde* Biphenyl* Chloroform* Formaldehyde* Methanol* Methylene Chloride Phenol* Propionaldehyde*	0.7 0.7 17.7 0.16 1.17 0.04 0.01 0.07 0.02 0.25 0.01	2.9 2.9 77.4 0.68 5.11 0.14 0.01 0.27 0.06 1.10 0.01

EMISSION SUMMARY				
Source #	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Toluene*	0.04	0.14
71	No. 8 Extruder Electrostatic Treaters (A&B)	PM PM_{10} Ozone	0.4 0.4 0.8	1.5 1.5 3.2
72	No. 9 Extruder Electrostatic Treater	PM PM_{10} Ozone	0.6 0.6 1.5	2.5 2.5 6.3
75	Pulp Storage Chests	VOC TRS Acetaldehyde* Benzene* Chloroform* Hexane* Methanol* Phenol* Styrene* Tetrachloroethylene Toluene* Xylene*	43.2 3.8 0.05 0.01 0.10 0.01 0.22 0.18 0.01 0.01 0.01 0.01	189.3 16.6 0.21 0.01 0.44 0.01 0.95 0.75 0.02 0.01 0.01 0.01
76F	Black Liquor Storage Basin No. 1	VOC Acetaldehyde* Acetone** Methanol*	4.4 0.20 0.2 4.02	19.3 0.87 0.7 17.61
78F	Road Emissions	PM PM_{10}	12.0 3.0	39.0 9.7

EMISSION SUMMARY				
Source #	Description	Pollutant	Emission Rates	
			lb/hr	tpy
79	Tissue Machine No. 8 Burners	PM	0.9	3.6
		PM_{10}	0.9	3.6
		SO_2	0.1	0.2
		VOC	1.0	4.3
		CO	5.7	25.0
		NO_x	4.6	20.0
		Pb	0.01	0.01
		Arsenic	0.01	0.01
		Benzene*	0.01	0.01
		Cadmium	0.01	0.01
		Cobalt	0.01	0.01
		Formaldehyde*	0.01	0.02
		Hexane*	0.11	0.48
		Manganese	0.01	0.01
		Mercury	0.01	0.01
		Naphthalene*	0.01	0.01
		Nickel	0.01	0.01
		Toluene*	0.01	0.01
80	Tissue Machine No. 8	PM	0.8	3.2
		PM_{10}	0.8	3.2
		VOC	13.6	59.6
		Acetaldehyde*	0.36	1.54
		Acetone**	0.2	0.8
		Acrolein*	0.03	0.10
		Benzene*	0.01	0.02
		Carbon Disulfide*	0.01	0.05
		Chloroform*	0.01	0.01
		Formaldehyde*	0.06	0.25
		Hexane*	0.01	0.02
		Methanol*	0.45	1.91
		Methylene Chloride	0.03	0.11
		Naphthalene*	0.01	0.03
		Phenol*	0.10	0.44
		Propionaldehyde*	0.10	0.44
		Styrene*	0.01	0.02
		Tetrachloroethylene	0.01	0.04
		Toluene*	0.01	0.01
		1,2,4 Trichlorobenzene*	0.03	0.11
		Xylene*	0.04	0.14

EMISSION SUMMARY				
Source #	Description	Pollutant	Emission Rates	
			lb/hr	tpy
81	Tissue Machine No. 8 Dust System	PM PM_{10}	1.8 1.8	7.7 7.7
82F	Landfill Operations	PM PM_{10}	2.6 1.2	0.5 0.3
83	Incinerator	PM PM_{10} SO_2 VOC CO NOx SAM** TRS Acetaldehyde* Acetone** Benzene* Carbon Tetrachloride* Formaldehyde* Hexane* Methanol* Styrene* 1,2,4-Trichlorobenzene* Xylene*	2.7 2.7 9.1 1.0 6.0 23.0 1.0 0.9 0.03 0.1 0.04 0.01 0.03 0.01 0.81 0.01 0.01 0.02	11.9 11.9 39.9 3.6 26.3 100.8 4.3 3.8 0.11 0.2 0.14 0.04 0.09 0.03 3.06 0.01 0.02 0.05
93	Repulper C	VOC Chloroform*	1.0 0.99	4.4 4.32
94	Green Liquor Clarifier A	VOC TRS Acetaldehyde* Acetone** Benzene* Methanol* Styrene* Toluene* Xylene*	2.2 0.1 0.01 0.1 0.01 2.06 0.01 0.01 0.01	8.0 0.1 0.01 0.1 0.01 7.83 0.01 0.01 0.02
96	Salt Cake Mix Tank	VOC TRS Acetaldehyde* Acetone** Acrolein* Benzene* Formaldehyde*	0.7 0.1 0.03 0.1 0.01 0.01 0.01	2.4 0.2 0.12 0.2 0.01 0.01 0.01

EMISSION SUMMARY				
Source #	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Hexane*	0.01	0.01
		Methanol*	0.51	1.91
		Styrene*	0.01	0.01
		Tetrachloroethylene	0.01	0.01
		Toluene*	0.01	0.01
		1,2,4-Trichlorobenzene*	0.01	0.01
		Xylene*	0.01	0.01
97	Storage Tanks	VOC	4.4	19.0
		TRS	2.5	11.0
		Acetaldehyde*	0.01	0.02
		Acrolein*	0.01	0.01
		Benzene*	0.01	0.01
		Carbon Tetrachloride*	0.01	0.02
		Ethylene Dichloride*	0.01	0.01
		Hexane*	0.01	0.01
		Methanol*	0.48	2.11
		Styrene*	0.01	0.01
		Tetrachloroethylene	0.01	0.01
		Toluene*	0.01	0.01
		1,2,4-Trichlorobenzene*	0.01	0.01
		Xylene*	0.01	0.03
98	"A" Side Causticizers	VOC	0.4	1.3
		TRS	0.4	1.2
		Acetaldehyde*	0.02	0.07
		Acetone**	0.1	0.1
		Benzene*	0.01	0.01
		Methanol*	0.01	0.01
		Styrene*	0.01	0.01
		Xylene*	0.01	0.01
99	"B" Side Causticizers	VOC	0.4	1.3
		TRS	0.4	1.2
		Acetaldehyde*	0.02	0.07
		Acetone**	0.1	0.1
		Benzene*	0.01	0.01
		Methanol*	0.01	0.01
		Styrene*	0.01	0.01
		Xylene*	0.01	0.01
100	White Liquor Storage Tanks (4 total)	VOC	0.2	0.6
		TRS	0.3	1.0
		Acetone**	0.1	0.2

EMISSION SUMMARY				
Source #	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Methanol*	0.01	0.02
101	10A Boiler Bark Transfer System	PM PM_{10}	0.1 0.1	0.3 0.2
102	9A Boiler Bark Transfer System	PM PM_{10}	0.1 0.1	0.2 0.1
103	Green Liquor Clarifier B	VOC TRS Acetaldehyde* Acetone** Benzene* Methanol* Styrene* Toluene* Xylene*	0.2 0.1 0.01 0.1 0.01 0.18 0.01 0.01 0.01	0.8 0.1 0.01 0.1 0.01 0.66 0.01 0.01 0.02
105	White Liquor Clarifier	VOC Acetone** Benzene* Formaldehyde* Methanol* Styrene* Xylene*	0.2 0.1 0.01 0.07 0.05 0.01 0.01	0.7 0.1 0.01 0.27 0.19 0.01 0.01
106	Mud Washer A	VOC TRS Acetone** Benzene* Formaldehyde* Methanol* Styrene* Xylene*	1.4 0.1 0.1 0.01 0.04 0.03 0.01 0.01	5.2 0.2 0.1 0.01 0.14 0.10 0.01 0.01
107	Mud Washer B	VOC TRS Acetone** Benzene* Formaldehyde* Methanol* Styrene* Xylene*	1.4 0.1 0.1 0.01 0.04 0.03 0.01 0.01	5.2 0.2 0.1 0.01 0.14 0.10 0.01 0.01
108	Pre-Coats Filter	VOC TRS	0.1 0.1	0.2 0.1

EMISSION SUMMARY				
Source #	Description	Pollutant	Emission Rates lb/hr	Emission Rates tpy
		Acetaldehyde* Acetone** Benzene* Chloroform Methanol* Tetrachloroethylene Toluene* Xylene*	0.01 0.1 0.01 0.01 0.04 0.01 0.01 0.01	0.01 0.1 0.01 0.01 0.14 0.01 0.01 0.01
109	Green Liquor Stabilization Tank	VOC TRS Acetaldehyde* Acetone** Cresol* Methanol* Phenol*	0.6 0.1 0.04 0.2 0.03 0.37 0.02	2.4 0.2 0.14 0.6 0.12 1.63 0.09
110	White Liquor Splitter Box	VOC Acetone** Benzene* Formaldehyde* Methanol* Styrene*	0.2 0.1 0.01 0.07 0.05 0.01	0.7 0.1 0.01 0.27 0.19 0.01
111	Converting Line No. 1	VOC	1.8	7.8
112	Converting Line No. 2	VOC		
113	Converting Line No. 3	VOC		
114	Temporary Debarking and Chipping equipment	PM PM_{10} SO_2 VOC CO NO_x Acetaldehyde* Acrolein* Benzene* Formaldehyde* POM* Toluene*	3.6 2.5 1.1 2.5 20.8 16.8 0.01 0.01 0.01 0.01 0.01 0.01	3.9 2.6 1.1 2.6 22.5 18.1 0.01 0.01 0.01 0.01 0.01 0.01

EMISSION SUMMARY				
Source #	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Xylene*	0.01	0.01
115	Caterpillar Model No. 3406 Firewater Pump	PM PM_{10} SO_2 VOC CO NO_x Acetaldehyde* Acrolein* Benzene* Formaldehyde* Naphthalene* POM* Toluene* Xylene*	1.0 1.0 0.9 1.1 2.9 13.1 0.01 0.01 0.01 0.01 0.01 0.01 0.01 0.01	0.3 0.3 0.3 0.3 0.8 3.3 0.01 0.01 0.01 0.01 0.01 0.01 0.01 0.01
115-ct	No. 8 TM Vac. Pump Cooling Tower	PM PM_{10}	0.1 0.1	0.1 0.1
116	Caterpillar Model No. 3406 Firewater Pump	PM PM_{10} SO_2 VOC CO NO_x Acetaldehyde* Acrolein* Benzene* Formaldehyde* Naphthalene* POM* Toluene* Xylene*	1.0 1.0 0.9 1.1 2.9 13.1 0.01 0.01 0.01 0.01 0.01 0.01 0.01 0.01	0.3 0.3 0.3 0.3 0.8 3.3 0.01 0.01 0.01 0.01 0.01 0.01 0.01 0.01
116-ct	No. 8 TM Chiller Cooling Tower	PM PM_{10}	0.1 0.1	0.1 0.1
117	Caterpillar Model No. 3406 Firewater Pump	PM PM_{10} SO_2 VOC CO	1.0 1.0 0.9 1.1 2.9	0.3 0.3 0.3 0.3 0.8

EMISSION SUMMARY				
Source #	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		NO_x Acetaldehyde* Acrolein* Benzene* Formaldehyde* Naphthalene* POM* Toluene* Xylene*	13.1 0.01 0.01 0.01 0.01 0.01 0.01 0.01 0.01	3.3 0.01 0.01 0.01 0.01 0.01 0.01 0.01 0.01
117-ct	Conv. Building HVAC Cooling Tower	PM PM_{10}	0.1 0.1	0.2 0.2
118	John Deere JU6H-UF58 Firewater Pump	PM PM_{10} SO_2 VOC CO NO_x Acetaldehyde* Acrolein* Benzene* Formaldehyde* Naphthalene* POM* Toluene* Xylene*	0.2 0.2 0.3 0.1 0.3 1.8 0.01 0.01 0.01 0.01 0.01 0.01 0.01 0.01	0.1 0.1 0.1 0.1 0.1 0.5 0.01 0.01 0.01 0.01 0.01 0.01 0.01 0.01
119	John Deere JU6H-UF58 Firewater Pump	PM PM_{10} SO_2 VOC CO NO_x Acetaldehyde* Acrolein* Benzene* Formaldehyde* Naphthalene* POM* Toluene* Xylene*	0.2 0.2 0.3 0.1 0.3 1.8 0.01 0.01 0.01 0.01 0.01 0.01 0.01 0.01	0.1 0.1 0.1 0.1 0.1 0.5 0.01 0.01 0.01 0.01 0.01 0.01 0.01 0.01

EMISSION SUMMARY				
Source #	Description	Pollutant	Emission Rates	
			lb/hr	tpy
120	Cummins Series 382 Backup Generator	PM	0.2	0.1
		PM_{10}	0.2	0.1
		SO_2	0.2	0.1
		VOC	0.3	0.1
		CO	0.6	0.2
		NO_x	2.8	0.7
		Acetaldehyde*	0.01	0.01
		Acrolein*	0.01	0.01
		Benzene*	0.01	0.01
		Formaldehyde*	0.01	0.01
		Naphthalene*	0.01	0.01
		POM*	0.01	0.01
		Toluene*	0.01	0.01
		Xylene*	0.01	0.01
121	Caterpillar 3116 Backup Lime Kiln Rotation	PM	0.6	0.2
		PM_{10}	0.6	0.2
		SO_2	0.5	0.2
		VOC	0.6	0.2
		CO	1.6	0.4
		NO_x	7.2	1.8
		Acetaldehyde*	0.01	0.01
		Acrolein*	0.01	0.01
		Benzene*	0.01	0.01
		Formaldehyde*	0.01	0.01
		Naphthalene*	0.01	0.01
		POM*	0.01	0.01
		Toluene*	0.01	0.01
		Xylene*	0.01	0.01

*HAPs included in the VOC totals. Other HAPs are not included in any other totals unless specifically stated.
**Air Contaminants such as ammonia, acetone, and certain halogenated solvents are not VOCs or HAPs.

SECTION III: PERMIT HISTORY

The first paper machine at Georgia-Pacific Crossett Paper Operations was constructed in 1937. On March 27, 1970, Georgia-Pacific was issued its first permit, Permit #16-A. On August 30, 1971 Georgia-Pacific was issued its second permit, Permit #68-A.

Permit #133-A, issued on December 15, 1972, allowed the installation of an extrusion and a laminating machine.

Permit #137-A was also issued on December 15, 1972. It permitted the installation of a fume scrubber on the digester feed system to control emissions from the digester and the installation of a cyclone and baghouse to control emissions from the sanding operations.

Permit #144-A, issued on March 28, 1973, allowed the installation of the 9A power boiler. Permit #149-A was also issued on March 28, 1973. It permitted the installation of an odor control system to collect, hold and distribute gases which are normally vented from the pulp mill digesters. The gases are burned in the lime kiln.

Permit #140-A was issued on July 23, 1976. This permit dealt with equipment maintenance problems such as the repair of boilers and the replacement of control devices. This permit allowed Georgia-Pacific to operate an additional boiler to provide steam while the existing boilers are taken out of service for repairs.

Permit #411-A, issued to Georgia-Pacific on May 27, 1977, permitted the installation of a venturi scrubber for the control of lime dust emissions from the lime slaker and lime handling system at the mill.

Permit #597-A, issued to Georgia-Pacific on March 6, 1980, permitted the installation of new equipment in the pulping and power utility areas. In the pulping area the 8R Recovery Furnace, the No. 4 Lime Kiln, a set of evaporators, new digesters and new washers were installed. In the power utility area two wood fire boilers each equipped with a multiclone and a venturi scrubber were installed.

Permit #597-AR-1 was issued on July 23, 1982. It was modified by Permit #597-AR-2, issued on November 1, 1984. Permit #597-AR-2 superseded all previously issued air permits. Permit #597-AR-2 allowed Georgia-Pacific to convert a recovery furnace to a power boiler, the 10A Boiler. This was a major modification of a major stationary source and therefore was subject to PSD review. Only NO_X and CO became subject to the PSD requirements because of reductions in all the other pollutants. Modeling predicted that the ambient air concentrations due to the increase in NO_X and CO emission would be less than the de minimis levels. Therefore, preconstruction ambient air monitoring was not required.

Permit #597-AR-3 was issued to Georgia-Pacific on August 18, 1988. Emission limits for the 10A Boiler, 8R Recovery Furnace and the No. 4 Lime Kiln were revised as the result of testing. Permit #597-AR-4 was issued on July 11, 1989. Expansions at the bleach plant were permitted.

Permit #597-AR-5 was issued to Georgia-Pacific on March 18, 1993. This permit included sources at the mill that were not previously permitted. It allowed Georgia-Pacific to burn Tire Derived Fuel (TDF), other scrap rubber products and Refuse Derived Fuel (RDF) in the 10A and 9A Boilers. In addition, a new hardwood brownstock washer system was installed to replace the existing drum washers installed in 1968.

Georgia-Pacific was issued a Prevention of Significant Deterioration (PSD) permit, Permit #1449-A, on May 18, 1993. Stack testing of the 8R Recovery Furnace showed that the current permitted emission rate for NO_X was not attainable. The allowable emission rate of NO_X from the 8R Recovery Furnace was increased by 402.1 tons per year, thus triggering PSD review. Permit #597-AOP-R0, issued on February 28, 1997, was the first operating air permit issued to Georgia-Pacific Corporation Crossett Paper Operations under Regulation #26. This permit incorporated sources that were not previously permitted. Some allowable emission rates were modified from the previous permit to reflect new emission factors, new test data and/or alternate fuel. This permit also incorporated the Prevention of Significant Deterioration (PSD) permit application submitted in relation to the installation of the new No. 8 Tissue Machine.

Permit #597-AOP-R1, issued on June 29, 1999, was the second Title V operating permit issued to Georgia-Pacific Corporation --Crossett Paper Operations under Regulation #26. The changes in this permit were solely related to air pollutant emission rates and did not affect the Mill's production limits established in the original Title V permit. One purpose of this modification was to address the requirements of a CAO regarding carbon monoxide emissions from the Bleach Plant Scrubber (SN-30). Due to a lack of industry or regulatory information suggesting otherwise, carbon monoxide emissions from the bleach plant were not included in Permit #597-AOP-R0. Specific Condition #73 of that permit required Georgia-Pacific to test for carbon monoxide emissions from SN-30. The required stack testing was performed on September 24, 1997. Emission rates were derived from the stack tests and were added to the permit.
On February 15, 1999, revised versions of Regulations #18 and #19 became effective. All regulatory citations in the permit were changed in 597-AOP-R1 to reflect the new regulations. Compliance demonstrations for all opacity limits have been added to the permit. Opacity demonstrations include, but are not limited to, daily or weekly observations and monitoring of control equipment operating parameters. The compliance demonstrations for all emission limits have been specifically identified in the permit. Applicable provisions of NSPS and NESHAP Subparts have been written into the permit.

The second purpose of this modification was to address the addition of pollution control equipment to comply with the requirements of 40 CFR Part 63 Subpart S -- National Emission Standards for Hazardous Air Pollutants from the Pulp and Paper Industry (NESHAP Subpart S or Cluster Rule). This modification qualified as a Pollution Control Project (PCP), and thus the new point source (an Incinerator, SN-83) was exempt from PSD.

Section 19.8 of Regulation #19 provides that the Lime Kiln at GP Crossett should have a TRS emission limit of 8 ppm. Because a source limited to 5 ppm was routed to the Lime Kiln, the lime kiln was assigned a 5 ppm limit. 597-AOP-R1 stipulated that once the HVLC system was outed to collect the emissions from the 5 ppm source, the emission rate for the Lime Kiln could be raised back to 8 ppm. This change has been completed.

597-AOP-R2 was finalized on December 14, 1999. A typographical error was made in a previous permit application which listed the minimum scrubbing liquid flow rate to the #4 tissue machine scrubber (SN-67) as 300 gpm. The actual minimum scrubber flow rate was 70 gpm. Note that the #4 and #5 tissue machine scrubbers are similar and that the #5 tissue machine minimum scrubbing flow rate was also 70 gpm. There was no emission increase associated with this minor modification.

On March 29, 1999, EPA Region 6 issued GP Crossett Paper Operations a NOV addressing the failure to install a continuous opacity monitor for SN-03, the 10A boiler. The current permit will be revised, in a timely manner, to assure compliance with any new applicable requirements resulting from the resolution of this issue.

597-AOP-R3 was finalized on December 14, 2001. This modification, which required PSD review, allowed the Crossett Mill to add the No. 9 Machine to produce tissue and towel. The No. 9 Machine was projected to have a production capacity of 250 Machine Dried Tons of paper (MDT) per day. The installation included the machine itself along with associated stock preparation and converting equipment. The proposed modification exceeded the PSD significant rate thresholds for PM_{10}, VOC, CO, and NOx.

597-AOP-R4 was finalized on November 12, 2003. The Georgia-Pacific Crossett - Paper Operations facility renewed their Title V permit and included CAM requirements for SN-03, SN-22, SN-50, SN-81, and SN-83. Also included with the renewal permit were four modifications, two of which were minor.

The first modification was to rebuild a Repulper (SN-93) damaged by a fire. The second minor modification involved the installation of an additional electrostatic treater and associated burner to the No. 8 Extruder, SN-71.

Previous to this modification, particulate emissions for the incinerator were underestimated. The assumed stack gas temperature and moisture content were also assumed incorrectly. In addition, the scrubber removal efficiency for particulate was actually 93% instead of 95% as stated in the application. Air Permit 597-AOP-R4 corrected these values.

Carbon monoxide emissions from the bleach plant, resulting from the converting of bleaching operations to elemental chlorine free (ECF) bleaching, were also previously underestimated. The new permit acknowledged that the source required a permitted increase of 242.6 tons of CO per year. Limited data was available at the time of the modification to illustrate any potential increase in CO emissions and none was assumed. The bleach plant conversion was part of a modification which included a PCP (Pollution Control Project) involving an incinerator (SN-83). Both of these changes allowed the facility to comply with Cluster Rule requirements.

597-AOP-R5 was finalized on November 12, 2003. The permit was modified to include applicable requirements of NESHAP Subpart MM - National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Sulfite, and Stand-Alone Semichemical Pulp Mills. Affected sources include Smelt Dissolving Tank (East and West, SN-27A and B), the No. 4 Lime Kiln (SN-25), and the 8R Recovery Furnace (SN-26). The permitted particulate emissions at the lime kiln were reduced to comply with the standards of the subpart. The current controls at SN-25, as indicated by stack test data, were sufficient to comply with the more stringent PM emission limit. The permitted particulate emission rate at SN-25 was decreased by 20.5 tons per year. Permitted limits, at the time, were sufficient to meet the established standards set forth in the subpart for the recovery furnace and smelt dissolving tanks.

597-AOP-R6 was finalized on May 31, 2005. The facility modified their permit in order to allow for the relaxation of the O_2 limits for the 10A Boiler (SN-03) during periods of startup, shutdown, and malfunction. There is no actual or permitted emission increase as a result of this modification.

Furthermore, two activities were added to the Insignificant Activity list. First, the baghouse for the Perini Towel Rewinder and Spectrum Towel Printer has been included as an A-13 activity. The Spectrum Towel Printer, which uses inks of low weight percent VOC and no HAPs, were also added as an A-13 activity.

597-AOP-R7 was finalized on December 5, 2005. An allowance to the permit was added for the continued operation of the No. 4 Tissue Machine (SN-66) during the repair of its dust control equipment (SN-67). This allowance has been granted to the facility's other paper machines since the renewal permit.

597-AOP-R8 was finalized May 12, 2006. This revision allowed the facility to modify nine of their Digesters (SN-59) by replacing the six-inch blow valves with eight-inch valves. The modification resulted in an increase in hardwood pulp production of approximately 50 tons per day. The facility is also requested the ability to receive 1.5% sulfur fuel oil while still keeping a 1.0% sulfur average on a 30-day basis. This change affected SN-19, SN-22, SN-25, and SN-26. The facility is also recalculated both criteria and non-criteria pollutants from many of their permitted sources. This recalculation has resulted in a significant drop in annual permitted rates for most criteria pollutants. Several small, existing sources were added to the permit, which were overlooked in the initial and renewal permits: A and B Side Causticizers (SN-98 and 99), White Liquor Storage Tanks (SN-100), and the 9A and 10A Boiler Bark Transfer systems (SN-101 and SN-102). The facility has also requested to remove the No. 9 Paper Machine sources, SN-84 through SN-92 from the permit. The machine was never installed.

597-AOP-R9 was finalized on April 2, 2007. This revision was to incorporate the provisions of the Health-Based Compliance Alternatives for Manganese for Total Selected Metals (TSM), contained within Appendix A to 40 CFR 63, Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters.

597-AOP-R10 was finalized on April 2, 2007. This PSD revision was submitted for replacement of the economizer section of the 8R Recovery Furnace; installation of steam boxes on Machines 6, 7 and 8; upgrades and changes in the causticizing area; and modifications to the pine and hardwood screen rooms.

597-AOP-R11 was finalized on November 1, 2007. This modification was for the replacement of the No. 6 Tissue Machine Burners (SN-48). The facility replaced the existing Hauck burners with Maxon burners rated at 20.5 MMBTU/hr each. With this revision, the PM/PM_{10} and VOC BACT limits for the No. 6 Tissue Machine decreased. SO_2, CO, NO_x factors and associated BACT limits remained unchanged. In addition to this modification, the Health Based Compliance conditions for the Boiler MACT (NESHAP DDDDD) were removed since that subpart has been vacated.

597-AOP-R12 was finalized on May 5, 2008. This modification was to revise CAM parameters for the 10A (SN-03) and 9A (SN-22) Boilers. The facility, in future testing events, must operate the scrubbers at these sources at the minimum CAM parameters. The facility has also applied for a minor modification to allow for an alternative operating scenario for maintenance on the scrubbers associated with the 10A (SN-03) and 9A (SN-22) Boilers. This condition is similar to the conditions established for monitoring of scrubber parameters on the dust collection systems for the Tissue Machines.

SECTION IV: SPECIFIC CONDITIONS

SN-03
10A Boiler

Source Description

The 10A Boiler is capable of firing woodwaste, refuse derived fuel (RDF), agriculture derived fuel (ADF), tire derived fuel (TDF) and natural gas. A woodwaste storage pile is associated with the 10A Boiler. Woodwaste consists of bark, wood scraps, wax coated paper, wax coated cardboard, wax coated sawdust, creosote treated railroad crossties and paper pellets (waste paper and wax paper). The majority of the woodwaste for the boiler is delivered by truck and occasionally by rail. It is then transferred by conveyors to either the 9A or the 10A woodwaste storage pile.

RDF and ADF are directly added to the chip piles. RDF consists of pelletized paper, lawn clippings and similar materials. TDF and other scrap rubber products are stored in segregated piles near the woodwaste piles. TDF is loaded several times a day by a front end loader into feeder bins in the vicinity. These solid fuels are then fed onto a conveyor system and delivered to the boilers. ADF consists of, but is not limited to, corn cobs, shucks, and vegetable starch.

The 7R Recovery Boiler was originally constructed in 1968. In 1984 it was converted to the 10A Boiler. The 10A Boiler (SN-03) is a 1001 million Btu per hour combination fuel boiler used to generate steam. This boiler is equipped with a wet venturi scrubber.

The 10A Boiler can operate under three different operating scenarios. The boiler can fire up to 1001 million Btu per hour of which only 669 million Btu per hour can be from natural gas. The first fuel firing scenario consists of the 10A Boiler burning just natural gas. The second fuel firing scenario consists of the 10A Boiler burning a combination of fuels none of which is natural gas. The third fuel firing scenario consists of the 10A Boiler burning a combination of fuels of which the contribution of natural gas cannot exceed 669 million Btu per hour.

The 10A boiler is subject to NSPS Subpart D- *Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced after August 17, 1971*. Monitoring of NO_X is not required since the results of a performance test showed emissions of less than 70% of the applicable standard (40 CFR 60.45 (b)(3)). Monitoring of SO_2 is not required under 40 CFR 60.45(b)(1). The CO and NO_X emissions from this boiler are regulated under PSD.

Specific Conditions

1. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #14 through #18. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr	ton/yr
SO_2	21.0	92.0
VOC	17.1	74.6
Pb	0.06	0.26

2. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #9 and #14 through #18. [§19.304, §19.501 et seq. and §19.901 of Regulation #19, 40 CFR Part 52 Subpart E, and 40 CFR §60.44]

Pollutant	lb/hr	ton/yr
Scenario #1: Natural gas only (669 MMBtu/hr)		
NO_X	133.8	586.1
	0.2 lb/MMBtu	
Scenario #3: Natural gas and any combination of woodwaste, sludge, TDF, RDF & ADF (1001 MMBtu/hr)		
NO_X	300.3	1,315.4
	0.3 lb/MMBtu	

3. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #9 and #14 through #18. [§19.501 et seq. and §19.901 of Regulation #19, and 40 CFR Part 52 Subpart E]

Pollutant	lb/hr	ton/yr
Scenario #1: Natural gas only (669 MMBtu/hr)		
CO	133.8	586.1
	0.2 lb/MMBtu	
Scenario #2: Any combination of woodwaste, sludge, TDF, RDF & ADF (1001 MMBtu/hr)		
NO_X	500.5	2,192.2
	0.5 lb/MMBtu	
CO	600.6	2,630.7
	0.6 lb/MMBtu	
Scenario #3: Natural gas and any combination of woodwaste, sludge, TDF, RDF & ADF (1001 MMBtu/hr)		
CO	600.6	2,630.7
	0.6 lb/MMBtu	

4. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #9, #14 through #18, and #21. [§19.304 and §19.501 et seq. of Regulation #19, 40 CFR Part 52 Subpart E, and 40 CFR §60.42]

Pollutant	lb/hr	ton/yr
Scenario #1: Natural gas only (669 MMBtu/hr)		
PM PM_{10}	66.9	293.1
	0.1 lb/MMBtu	
Scenario #2: Any combination of woodwaste, sludge, TDF, RDF & ADF (1001 MMBtu/hr) Scenario #3: Natural gas and any combination of woodwaste, sludge, TDF, RDF & ADF (1001 MMBtu/hr)		
PM PM_{10}	100.1	438.5
	0.1 lb/MMBtu	

5. The 10A Boiler shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #14 through #18. [§18.801 of Regulation #18 and A.C.A. §8-4 203 as referenced by §8-4 304 and §8-4 311]

Pollutant	lb/hr	tpy
Acetaldehyde	0.28	1.22
Acetophenone	0.01	0.01
Acetone	0.3	1.1
Acrolein	0.10	0.42
Arsenic	0.01	0.02
Benzene	0.33	1.43
Beryllium	0.01	0.01
Cadmium	0.01	0.01
Carbon Disulfide	0.16	0.69
Carbon Tetrachloride	0.01	0.01
Chloroform	0.05	0.20
Chromium, Hex	0.01	0.04

Pollutant	lb/hr	tpy
Cobalt	0.01	0.01
Cumene	0.03	0.10
2,4-Dinitrotoluene	0.01	0.01
Ethylene Dichloride	0.04	0.16
Formaldehyde	0.86	3.74
Hexane	1.57	6.84
Hexachlorobenzene	0.01	0.01
Hydrogen Chloride	0.19	0.79
Manganese	0.05	0.22
Mercury	0.01	0.01
Methanol	1.04	4.53
Methylene Chloride	0.43	1.85
Naphthalene	0.13	0.53
Nickel	0.01	0.03
Phenol	0.02	0.05
Phosphorus	0.12	0.53
Propionaldehyde	0.08	0.33
Propylene Dichloride	0.04	0.18
POM	0.30	1.30
Selenium	0.01	0.02
Styrene	0.04	0.17
Tetrachloroethylene	0.07	0.28
Toluene	0.04	0.15
Vinyl Chloride	0.03	0.10
Xylene	0.03	0.12

Opacity

6. When operating under any scenario, the permittee shall not cause to be discharged to the atmosphere from the 10A Boiler gases which exhibit opacity greater than 20% except for one six-minute period per hour of not more than 27% opacity. [§19.304 of Regulation #19 and 40 CFR §60.42(a)(2)]

   When operating under Scenario #1, the permittee shall not cause to be discharged to the atmosphere from the 10A Boiler gases which exhibit opacity greater than 5%. [§18.501 of Regulation #18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

7. The permittee shall conduct weekly observations of the opacity at SN-03. Observations shall be conducted by personnel familiar with the permittee's visible emissions and certified in the EPA Reference Method 9. If visible emissions in excess of the permitted opacity are detected, the permittee shall take immediate action to identify the cause of the visible emissions, implement all necessary corrective action, and reassess the visible emissions after corrective action is taken. The permittee shall maintain records related to all Method 9 Readings, to be updated on a weekly basis. The records shall contain the date and time of each observation/reading, the cause of any observed exceedance of opacity limits, corrective action taken, and results of the reassessment, and the name of the person conducting the observation/reading. The records shall be kept on site and made available to Department personnel upon request. [§19.705 of Regulation 19, Alternative Monitoring exemption of NSPS D, and 40 CFR Part 52, Subpart E]

8. The permittee may, in the event of maintenance on the 10A Boiler (SN-03) scrubber system, continue to operate the boiler without the scrubber for a period of time not to exceed 24 hours. During these events, natural gas will replace all other permitted fuels in the boiler. Woodwaste or any other permitted fuel, with the exception of natural gas, fed to the boiler will be stopped at least one hour before the scrubber is taken offline. If the event lasts longer than 6 hours, a Method 9 opacity reading is required as soon as possible during daylight hours. A log of these maintenance events will be kept which includes date, starting and ending times of event, reason for maintenance, and results of any opacity checks. The permittee shall notify the Department of the event once the scrubber is operational. [§19.703 of Regulation #19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304and §8-4-311]

NSPS D

9. The 10A Boiler (SN-03) is subject to and shall comply with all applicable provisions of 40 CFR Part 60 Subpart D- *Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971*, because it burns natural gas, was constructed after August 17, 1971, and is greater than 250 million Btu per hour.

a. The permittee shall not cause to be discharged into the atmosphere gases which contain particulate matter in excess of 0.10 lb per million Btu derived from gaseous fossil fuel of fossil fuel and wood residue. [§19.304 of Regulation #19 and 40 CFR §60.42(a)(1)]

b. Compliance with the sulfur dioxide standard shall be based on the total heat input from all fossil fuels burned, including gaseous fuels. [§19.304 of Regulation #19 and 40 CFR §60.43(c)]

c. The permittee shall not cause to be discharged into the atmosphere gases which contain nitrogen oxides, expressed as NO_2, in excess of 0.20 lb per million Btu derived from gaseous fossil fuel. [§19.304 of Regulation #19 and 40 CFR §60.44(a)(1)]

d. The permittee shall not cause to be discharged into the atmosphere gases which contain nitrogen oxides, expressed as NO_2, in excess of 0.30 lb per million Btu derived from gaseous fossil fuel and wood residue. [§19.304 of Regulation #19 and 40 CFR §60.44(a)(2)]

e. The permittee shall install, calibrate, maintain, and operate continuous monitoring systems for measuring opacity and either oxygen or carbon dioxide. In an Alternative Monitoring exemption granted by the EPA in 1999, the facility is not required to install a continuous monitoring system for opacity provided the facility conducts periodic testing, scrubber parameter monitoring, and weekly opacity observations. This exemption is included in Appendix F. [§19.304 of Regulation #19 and 40 CFR §60.45(a)]

f. The permittee shall submit excess emission and monitoring system performance reports to the Department for every calendar quarter to the address specified in General Provision 7. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter. Each excess emission and MSP report shall include the information required in 40 CFR §60.7(c). [§19.304 of Regulation #19 and 40 CFR §60.45(g)]

g. The permittee shall use as reference methods and procedures the test methods in Appendix A of this part or other methods and procedures as specified in this section, except as provided in 40 CFR §60.8(b) in conducting the performance tests required in 40 CFR §60.8. [§19.304 of Regulation #19 and 40 CFR §60.46(a)]

CEM Requirements

10. The permittee shall operate the Continuous Emission Monitor (CEM) for CO using O_2 monitoring on the 10A Boiler in accordance with the Department Continuous Emission Monitoring Systems Conditions (Appendix A) and the applicable Performance Standards

of 40 CFR Part 60 Appendix B. [§19.703 of Regulation #19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

11. The permittee shall properly maintain and operate the following existing continuous monitoring instrumentation: O_2, pressure drop across the scrubber and the liquid flow rate of the scrubber at the 10A Boiler (SN-03). [§19.703 and §19.901 Regulation #19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

12. All continuous monitoring data for O_2 may, at the discretion of the Department, be used to determine violations of NO_X or CO emissions limits. Continuous monitoring data shall be used to demonstrate compliance with the three different fuel firing scenarios of the 10A Boiler. [§19.703 of Regulation #19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

13. Compliance with the NO_X and CO limits for the 10A Boiler shall be demonstrated by monitoring flue gas O_2 and maintaining the hourly average percent O_2 within the following limits when the steam flow is greater than 100,000 pounds per hour (at actual stack gas moisture contents) and fuel is being fired :

    a. Full load on natural gas and any combination of woodwaste, sludge, RDF, TDF and ADF: not less than 2.0% nor more than 7.5% O_2

    b. Reduced load (100,000 to 400,000 pounds per hour steam) on natural gas and any combination of woodwaste, sludge, RDF, TDF and ADF: not less than 2.2% not more than 8.0% O_2

    c. Full load on gas only: not less than 1.5% nor more than 6.0% O_2

    d. Reduced load (100,000 to 400,000 pounds per hour steam) on gas only: not less than 1.5% nor more than 4.5% O_2

    [§19.703 and §19.901 of Regulation #19, and 40 CFR Part 52 Subpart E]

    The above limits for gas shall not apply when firing gas only for periods of two consecutive hours or less due to an unscheduled outage of woodwaste feed, instead, the above limits for natural gas and any combination of woodwaste, sludge, RDF, TDF and ADF shall apply. Records shall be kept of each unscheduled outage. An operation outside of these average limits shall constitute noncompliance with this Specific Condition and shall be reported quarterly along with excess emissions. The permittee shall maintain records of all flue gas O_2 for the 10A Boiler, including those readings which are to be excluded from the hourly average due to steam flow and fuel firing requirements. The permittee shall make these records available to Department personnel upon request.

Fuel Requirements

14. The permittee may use as fuel in the 10A Boiler, TDF, ADF, RDF, woodwaste, sludge, and natural gas. RDF is defined as pelletized paper, lawn clippings, or similar materials. Creosote treated railroad crossties shall not constitute more than 22.5% of the fuel requirement of the 10A Boiler. [§19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

15. The permittee shall not burn in excess of 669 thousand standard cubic feet (scf) of natural gas per hour and 5860.5 million scf of natural gas per twelve consecutive months in the 10A Boiler (SN-03). [§19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

16. The permittee shall not burn in excess of 100 pounds of TDF per minute in the 10A Boiler (SN-03). [§19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

17. The permittee shall not burn in excess of 250 tons of RDF per day in the 10A Boiler. [§19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304and §8-4-311, and 40 CFR §70.6]

18. The permittee shall not burn in excess of 62.5 BDT sludge per hour in the 10A Boiler. [§19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304and §8-4-311, and 40 CFR §70.6]

19. The permittee shall maintain records which demonstrate compliance with Specific Conditions #14, #15, #16, #17, and #18. The permittee shall maintain records of the types and quantities of fuels being used in the 10A Boiler. These records, in combination with the most recent stack tests, shall be sufficient to demonstrate compliance with the three fuel firing scenarios of the 10A Boiler. The records shall be updated on a monthly basis. These records shall be kept on site, provided to Department personnel upon request and may be used by the Department for enforcement purposes. A twelve month total and each month's individual fuel usage data shall be submitted to the Department in accordance with General Provision #7. [§19.705 of Regulation #19 and 40 CFR Part 52 Subpart E]

20. Prior to combustion of the mill's wastewater treatment sludge in the 10A Boiler, the permittee shall submit a notification to the Department concerning the applicability of 40 CFR 61 Subpart E - National Emission Standard for Mercury, and if applicable, submit a permit modification to incorporate the requirements of this subpart into the current Title V Air Permit. [§19.702 of Regulation #19 and 40 CFR Part 52 Subpart E]

CAM

21. The 10A Boiler (SN-03) is subject to and shall comply with all applicable provisions §19.304 of Regulation 19, 40 CFR Part 52 Subpart E, and Part §64.6 for Compliance Assurance Monitoring. Post control of particulate emissions from SN-03 is above major source levels.

    a. The permittee shall maintain a scrubber liquid flow rate of at least gallons 2,572 per minute. [40 CFR Part §64.6(c)(1)]

    b. The permittee shall maintain a gas pressure drop of at least 6.48 inches of water. [40 CFR Part §64.6(c)(1)]

    c. The permittee shall monitor and maintain records at least every 15 minutes of the parameters in Specific Condition #21 (A) and (B). Compliance shall be based upon a 3-hr average. Records shall be kept onsite and made available to the Department upon request. [40 CFR Part §64.6(c)(3)]

    d. The permittee shall maintain the scrubber in good working condition at all times so that pollutant removal is maintained. [40 CFR Part §64.6(c)(1)]

22. The 10A Boiler (SN-03) is subject to and shall comply with all applicable provisions §19.304 of Regulation 19, 40 CFR Part 52 Subpart E, and Part §64.9 for Compliance Assurance Monitoring. The following information pertaining to exceedances or excursions from permitted values shall be submitted in semi-annual reports in accordance with General Provision #7 as outlined in 40 CFR §70.6.

    a. The permittee shall maintain records for SN-03 that summarizes the number, duration, and cause of excursions or exceedances of emission limits as well as corrective action taken. [40 CFR §64.9(a)(2)(i) and §64.9(b)]

    b. The permittee shall maintain records for SN-03 that summarizes the number, duration, and cause of monitoring equipment downtime incidents, other than routine downtime for calibration checks. [40 CFR §64.9(a)(2)(ii) and §64.9(b)]

    c. The permittee shall maintain a quality improvement plan (QIP) threshold for each indicator of no more than nine excursions or 5% of the daily averages in a six-month period. [40 CFR §64.9(a)(2)(iii) and §64.9(b)]

    d. The permittee shall develop and implement a new QIP if the threshold is exceeded during any six-month period. [40 CFR §64.9(a)(2)(iii) and §64.9(b)]

    e. The permittee shall maintain records for SN-03 that describes the actions taken to implement the QIP. Upon completion of the QIP, documentation shall be maintained to confirm that the plan was completed and reduced the likelihood of similar excursions or exceedances. [40 CFR §64.9(a)(2)(iii) and §64.9(b)]

Testing Requirements

23. The permittee shall annually test particulate matter emissions from the 10A Boiler (SN-03) using EPA Reference Method 5 with inclusion of back half sampling train particulate. The permittee shall test at the minimum scrubber parameters of Specific Condition 21. Results from the Method 5 test shall be compared to the NSPS limit of 0.1 lb/MMBTU for compliance purposes. The testing shall be conducted using a representative fuel mixture. The proportions of each permitted fuel in the representative fuel mixture shall be based upon the month during which the fuel that generates the highest particulate matter emissions was used in greatest proportion. During the test the permittee shall operate the boiler within 10 percent of the rated throughput capacity. If 90 percent of the rated throughout capacity cannot be achieved, the permittee shall be limited to 10 percent over the actual tested throughput. The permittee shall reference this limitation in any compliance reports submitted to the Department. [§19.702 of Regulation #19, Alternative Monitoring exemption of NSPS D, and 40 CFR Part 52 Subpart E]

24. The permittee shall test sulfur dioxide emissions from the 10A Boiler (SN-03) every five years. Testing shall be performed in accordance with Plantwide Condition #3 and EPA Reference Method 6. The testing shall be conducted using the maximum TDF firing rate. During the test the permittee shall operate the boiler within 10 percent of the rated throughput capacity. If 90 percent of the rated throughput capacity cannot be achieved, the permittee shall be limited to 10 percent above the actual tested throughput. The permittee shall reference this limitation in any compliance reports submitted to the Department. [§19.702 of Regulation #19 and 40 CFR Part 52 Subpart E]

SN-18
5A Boiler

Source Description

The 5A Boiler (SN-18) is a 220 million Btu per hour boiler. The boiler is only permitted to burn natural gas. The 5A Boiler was manufactured in 1953 and has never been modified. Therefore it is not subject to NSPS regulations.

Specific Conditions

25. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition #28. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr	tpy
PM_{10}	2.1	8.8
SO_2	0.2	0.7
VOC	1.5	6.4
CO	22.2	97.2
NO_x	74.0	323.8
Pb	0.01	0.01

26. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition #28. [Regulation No.§18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Pollutant	lb/hr	tpy
PM	2.1	8.8
Arsenic	0.01	0.01
Benzene	0.01	0.01
Cadmium	0.01	0.01
Cobalt	0.01	0.01
Formaldehyde	0.02	0.09

Pollutant	lb/hr	tpy
Hexane	0.48	2.09
Manganese	0.01	0.01
Mercury	0.01	0.01
Naphthalene	0.01	0.01
Nickel	0.01	0.01
POM	0.01	0.01
Toluene	0.01	0.01

Opacity

27. The permittee shall not cause to be discharged to the atmosphere from the 5A Boiler gases which exhibit opacity greater than 5%. Compliance with this opacity limit shall be the use of natural gas only. [§18.501 of Regulation #18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Fuel Requirements

28. Natural gas may only be used as fuel in the 5A Boiler. [§18.1004 of Regulation #18, §19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

SN-19
6A Boiler

Source Description

The 6A Boiler (SN-19) is a 357 million Btu per hour boiler. The 6A Boiler was manufactured in 1962 and has never been modified. Therefore it is not subject to NSPS regulations. The 6A Boiler can use natural gas as fuel.

Specific Conditions

29. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition #32. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr	tpy
PM_{10}	3.3	14.3
SO_2	0.3	1.2
VOC	2.4	10.4
CO	36.0	157.7
NO_x	120.0	525.4
Pb	0.01	0.01

30. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition #32. [Regulation No. §18.801and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Pollutant	lb/hr	tpy
PM	3.3	14.3
Arsenic	0.01	0.01
Benzene	0.01	0.01
Cadmium	0.01	0.01
Cobalt	0.01	0.01
Formaldehyde	0.04	0.15

Pollutant	lb/hr	tpy
Hexane	0.78	3.38
Manganese	0.01	0.01
Mercury	0.01	0.01
Naphthalene	0.01	0.01
Nickel	0.01	0.01
POM	0.01	0.01
Toluene	0.01	0.01

Opacity

31. The permittee shall not cause to be discharged to the atmosphere from the 6A Boiler gases which exhibit opacity greater than 5%. Compliance with this opacity limit shall be the use of natural gas only. [§18.501 of Regulation #18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Fuel Requirements

32. Natural gas may only be used as fuel in the 6A Boiler. [§18.1004 of Regulation #18, §19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

SN-22
9A Boiler

Source Description

The 9A Boiler is a 720 million Btu per hour combination fuel boiler used to generate steam. The source is equipped with a wet venturi scrubber. The boiler may serve as backup combustion unit during times when the incinerator (SN-83) is offline.

The 9A Boiler is capable of firing tire derived fuel (TDF), agriculture derived fuel (ADF), refuse derived fuel (RDF), non-condensable gases (NCGs), woodwaste, specification grade oil, natural gas and sludge. A woodwaste storage pile is associated with the 9A Boiler. Woodwaste consists of bark, wood scraps, wax coated paper, wax coated cardboard, wax coated sawdust, creosote treated railroad crossties and paper pellets (waste paper and wax paper). Bark from the debarker in the Woodyard is pneumatically transferred to the 9A pile. A cyclone is located at the end of the pneumatic transfer line to control particulate matter emissions. The majority of the woodwaste is delivered by truck and occasionally by rail. It is then transferred by conveyors to either the 9A or the 10A woodwaste storage pile.

RDF, ADF and sludge are directly added to the chip piles. RDF consists of pelletized paper, lawn clippings and similar materials. TDF and other scrap rubber products are stored in segregated piles near the woodwaste piles. TDF is loaded several times a day by a front end loader into feeder bins in the vicinity. These solid fuels are then fed onto a conveyor system and delivered to the boilers. ADF consists of, but is not limited to, corn cobs, shucks, and vegetable starch.

Specification grade oil consists of new oil, used oil, used oil absorbent material and pitch from the production of tall oil. Used oil absorbent material shall include used oil filter paper, used rags, sorbant booms, etc. that meet the specification grade oil criteria (40 CFR 279.11).

Specific Conditions

33. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #43, #47, #48, #49, #50, and #53. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr	tpy
PM_{10}	77.4	339.0
SO_2	199.8	484.6
VOC	11.3	49.5
CO	366.8	1,606.7

Pollutant	lb/hr	tpy
NO_x	196.0	858.6
Pb	0.03	0.14

34. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #43, #47, #48, #49, #50, and #53. [Regulation No. §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Pollutant	lb/hr	tpy
PM	77.4	339.0
Acetaldehyde	0.13	0.57
Acetophenone	0.01	0.01
Acetone	0.2	0.5
Acrolein	0.04	0.19
Arsenic	0.01	0.03
Benzene	0.15	0.68
Beryllium	0.01	0.01
Cadmium	0.01	0.01
Carbon Disulfide	0.07	0.32
Carbon Tetrachloride	0.01	0.01
Chloroform	0.02	0.09
Chromium, Hex	0.01	0.02
Cobalt	0.02	0.06
Cumene	0.01	0.05
2,4-Dinitrotoluene	0.01	0.01
Ethylene Dichloride	0.02	0.07
Formaldehyde	0.47	2.06
Hexane	1.56	6.81
Hexachlorobenzene	0.01	0.01

Pollutant	lb/hr	tpy
Hydrogen Chloride	0.13	0.57
Manganese	0.03	0.13
Mercury	0.01	0.01
Methanol	0.49	2.15
Methylene Chloride	0.20	0.87
Naphthalene	0.06	0.26
Nickel	0.18	0.75
Phenol	0.01	0.03
Phosphorus	0.08	0.33
Propionaldehyde	0.04	0.15
Propylene Dichloride	0.02	0.09
POM	0.14	0.63
SAM	3.6	10.4
Selenium	0.01	0.02
Styrene	0.02	0.08
Tetrachloroethylene	0.03	0.13
Toluene	0.02	0.11
Vinyl Chloride	0.01	0.05
Xylene	0.01	0.02

Opacity

35. For all fuel scenarios except natural gas only, the permittee shall not cause to be discharged to the atmosphere from the 9A Boiler, gases which exhibit opacity greater than 20%. Emissions not exceeding 60% opacity will be allowed for six (6) minutes in any consecutive 60-minute period and no more three (3) times during any 24-hour period. [§19.503 of Regulation #19 and 40 CFR Part 52 Subpart E]

When operating using natural gas only, the permittee shall not cause to be discharged to the atmosphere from the 9A Boiler gases which exhibit opacity greater than 5%. Compliance with this limit shall be use of natural gas only. [§18.501 of Regulation #18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

36. For all fuel scenarios except natural gas only, the permittee shall conduct daily observations of the opacity at SN-22. Observations shall be conducted by personnel familiar with the permittee's visible emissions. If visible emissions in excess of the permitted opacity are detected, then a Method 9 reading is required. The permittee shall then take immediate action to identify the cause of the visible emissions, implement all necessary corrective action, and reassess the visible emissions after corrective action is taken. The permittee shall maintain records related to all observations/readings, to be updated on a daily basis. The records shall contain the date and time of each observation/reading, the cause of any observed exceedance of opacity limits, corrective action taken, and results of the reassessment, and the name of the person conducting the observation/reading. The records shall be kept on site and made available to Department personnel upon request. [§19.705 of Regulation 19 and 40 CFR Part 52, Subpart E]

37. SN-22, as a wood fired boiler, shall meet all visible emissions of this chapter except that visible emissions may exceed the permitted opacity for up to 45 minutes once in any consecutive 8 hour period, three times in any consecutive 24 hour period for soot blowing, grate cleaning, ash raking, and refiring necessary for proper operation of these units. This practice is to be scheduled for the same specific time each day and shall be recorded. The Department shall be notified in advance and in writing of the schedule or any changes. The process of soot blowing, grate cleaning, ash raking, and refiring or any part thereof is considered one activity and the time limit on this activity is 45 minutes. [§18.501(A)(4) of Regulation #18 and A.C.A. §8-4-203 as referenced by §8-4-304and §8-4-311]

38. The permittee may, in the event of maintenance on the 9A Boiler (SN-22) scrubber system, continue to operate the boiler without the scrubber for a period of time not to exceed 24 hours. During these events, natural gas will replace all other fuels in the boiler. Woodwaste or any other permitted fuel, with the exception of natural gas, fed to the boiler will be stopped at least one hour before the scrubber is taken offline. If the event lasts longer than 6 hours, a Method 9 opacity reading is required as soon as possible during daylight hours. A log of these maintenance events will be kept which includes date, starting and ending times of event, reason for maintenance, and results of any opacity checks. The permittee shall notify the Department of the event once the scrubber is operational. [§19.703 of Regulation #19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

CEM Requirements

39. The Continuous Emission Monitor (CEM) for CO using O_2 monitoring on the 9A Boiler shall be operated in accordance with the Department Continuous Emission Monitoring Systems Conditions (Appendix A) and the applicable Performance Standards of 40 CFR Part 60 Appendix B. [§19.703 of Regulation #19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304and §8-4-311]

40. The permittee shall properly maintain and operate the following existing continuous monitoring instrumentation: O_2, pressure drop across the scrubber and liquid supply flow at the 9A Boiler. [§19.703 of Regulation #19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304and §8-4-311]

41. Continuous monitoring data from the continuous monitoring instrumentation listed in Specific Condition #40 may, at the discretion of the Department, be used to determine violations of the emissions limits or conditions of this permit. [§19.703 of Regulation #19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

42. Compliance with the CO limit for the 9A Boiler shall be demonstrated by monitoring flue gas O_2 and maintaining the O_2 setpoint at not less than 2.0% O_2 (dry basis). Any operation outside this hourly average limit shall constitute noncompliance with this Specific Condition. The permittee shall maintain records of flue gas O_2 for the 9A Boiler and shall make them available to Department personnel upon request. These limits do not apply during startup and shutdown of the 9A Boiler. Startup and shutdown shall be defined as when the steam flow is less than 100,000 pounds per hour. [§19.703 of Regulation #19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

CAM

43. The 9A Boiler (SN-22) is subject to and shall comply with all applicable provisions §19.304 of Regulation 19, 40 CFR Part 52 Subpart E, and Part §64.6 for Compliance Assurance Monitoring. Post control of particulate emissions from SN-22 is above major source levels.

    a. The permittee shall maintain a scrubber liquid flow rate of at least 2,772 gallons per minute. [40 CFR Part §64.6(c)(1)]

    b. The permittee shall maintain a gas pressure drop of at least 9.16 inches of water. [40 CFR Part §64.6(c)(1)]

    c. The permittee shall monitor and maintain records at least every 15 minutes of the parameters in Specific Condition #43 (A) and (B). Compliance shall be based upon a 3-hr average. Records shall be kept onsite and made available to the Department upon request. [40 CFR Part §64.6(c)(3)]

    d. The permittee shall maintain the scrubber in good working condition at all times so that pollutant removal is maintained. [40 CFR Part §64.6(c)(1)]

44. The 9A Boiler (SN-22) is subject to and shall comply with all applicable provisions §19.304 of Regulation 19, 40 CFR Part 52 Subpart E, and Part §64.9 for Compliance Assurance Monitoring. The following information pertaining to exceedances or

excursions from permitted values shall be submitted in semi-annual reports in accordance with General Provision 7 as outlined in 40 CFR §70.6.

a. The permittee shall maintain records for SN-22 that summarizes the number, duration, and cause of excursions or exceedances of emission limits as well as corrective action taken. [40 CFR §64.9(a)(2)(i) and §64.9(b)]

b. The permittee shall maintain records for SN-22 that summarizes the number, duration, and cause of monitoring equipment downtime incidents, other than routine downtime for calibration checks. [40 CFR §64.9(a)(2)(ii) and §64.9(b)]

c. The permittee shall maintain a quality improvement plan (QIP) threshold for each indicator of no more than nine excursions or 5% of the daily averages in a six-month period. [40 CFR §64.9(a)(2)(iii) and §64.9(b)]

d. The permittee shall develop and implement a new QIP if the threshold is exceeded during any six-month period. [40 CFR §64.9(a)(2)(iii) and §64.9(b)]

e. The permittee shall maintain records for SN-22 that describes the actions taken to implement the QIP. Upon completion of the QIP, documentation shall be maintained to confirm that the plan was completed and reduced the likelihood of similar excursions or exceedances. [40 CFR §64.9(a)(2)(iii) and §64.9(b)]

Fuel Requirements

45. The permittee may use the 9A Boiler as an alternate incinerator for NCGs and SOGs only during periods when the Incinerator (SN-83) or its associated control equipment is inoperative or undergoing maintenance. [§19.304 of Regulation #19 and 40 CFR §63.443(d)(4)]

46. Specification grade oils, natural gas, woodwaste, TDF, ADF, RDF and wastewater sludge may be used as fuel in the 9A Boiler. RDF is defined as pelletized paper, lawn clippings or other similar materials. Creosote treated railroad crossties shall not constitute more than 25% of the fuel requirement of the 9A Boiler. [§18.1004 of Regulation #18, §19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

47. The permittee shall not burn in excess of 35 pounds per minute of TDF in the 9A Boiler. [§18.1004 of Regulation #18, §19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

48. The permittee shall not burn in excess of 250 tons of RDF per day in the 9A Boiler. [§18.1004 of Regulation #18, §19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304and §8-4-311, and 40 CFR §70.6]

49. The permittee shall not burn in excess of 45 BDT sludge per hour in the 9A Boiler. [§19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304and §8-4-311, and 40 CFR §70.6]

50. The permittee shall not burn in excess of 200 tons of used oil absorbent material per month in the 9A Boiler. The used oil absorbent material shall meet the specification grade oil criteria found in 40 CFR §279.11. [§18.1004 of Regulation #18, §19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304and §8-4-311, and 40 CFR §70.6]

51. The permittee shall maintain records which demonstrate compliance with Specific Conditions #46, #47, #48, #49, and #50. The records shall be updated on a monthly basis. These records shall be kept on site, provided to Department personnel upon request and may be used by the Department for enforcement purposes. A twelve month total and each individual month's data shall be submitted in accordance with General Provision #7. [§18.1004 of Regulation #18, §19.705 of Regulation #19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304and §8-4-311]

52. The permittee shall not burn in excess of 353.3 gallons per hour of fuel oil in the 9A Boiler. The permittee shall maintain records demonstrating the amount of fuel oil burned on a monthly basis. If there is any fuel oil burned during a given month, the amount of oil burned on an hourly basis shall also be required for that month. These records shall be kept on site, provided to Department personnel upon request and may be used by the Department for enforcement purposes. A twelve month total and each individual month's data shall be submitted in accordance with General Provision #7. [§18.1004 of Regulation #18, §19.705 of Regulation #19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304and §8-4-311]

53. The sulfur content of the specification grade oils shall not exceed 1.5% by weight and 1.0% on a 30-day average. [§19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

54. Sulfur dioxide emission shall be determined through a mass balance based on incoming materials, worst-case firing of specification grade oil based on the limits in Condition #53, and periods where the source is used as an alternate incinerator. This mass balance shall be submitted to the Department in accordance with General Provision #7. [§19.703 of Regulation #19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

55. Prior to combustion of the mill's wastewater treatment sludge in the 9A Boiler, the permittee shall submit a notification to the Department concerning the applicability of 40 CFR 61 Subpart E - National Emission Standard for Mercury, and if applicable, submit a permit modification to incorporate the requirements of this subpart into the current Title V Air Permit. [§19.702 of Regulation #19 and 40 CFR Part 52 Subpart E]

Testing Requirements

56. The permittee shall test particulate emissions from the 9A Boiler (SN-22) within 60 days of issuance of Permit #0597-AOP-R14, and annually thereafter until the facility conducts two successive annual tests. If both these annual tests are successful, then the facility may perform stack testing once every 5 years. If at any time the facility fails one of the 5-year tests, then the facility must conduct two successive annual tests. The test will not be considered successful if particulate emissions exceed 0.103 lb/MM Btu for maximum wood waste firing or if measured emissions exceeds the permitted limits. The test shall be performed using EPA Reference Method 5 with inclusion of back half sampling train particulate. The permittee shall test at the minimum scrubber parameters of Specific Condition 43. The permittee shall submit an application to correct emission rates, if corrections are necessary. During the test the permittee shall operate the boiler within 10 percent of the rated throughput capacity. If 90 percent of the rated throughout capacity cannot be achieved, the permittee shall be limited to 10 percent above the actual tested throughput. The permittee shall reference this limitation in any compliance reports submitted to the Department. [§18.1002 of Regulation #18, §19.702 of Regulation #19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

57. The permittee shall test nitrogen oxides emissions from the 9A Boiler (SN-22) every five years. Testing shall be performed in accordance with Plantwide Condition #3 and EPA Reference Method 7E as found in 40 CFR Part 60 Appendix A. The testing shall be done using a representative fuel mixture. The proportions of each permitted fuel in the representative fuel mixture shall be based upon the month during which the fuel that generates the highest nitrogen oxides emissions was used in greatest proportion. During the test the permittee shall operate the boiler within 10 percent of the rated throughput capacity. If 90 percent of the rated throughout capacity cannot be achieved, the permittee shall be limited to 10 percent above the actual tested throughput. The permittee shall reference this limitation in any compliance reports submitted to the Department. [§19.702 of Regulation #19 and 40 CFR Part 52 Subpart E]

58. The permittee shall test sulfur dioxide emissions from the 9A Boiler (SN-22) within 60 days of issuance of Permit #0597-AOP-R14, and annually thereafter until the facility conducts two successive annual tests. If both these annual tests are successful, then the facility may perform stack testing once every 5 years. If at any time the facility fails one of the 5-year tests, then the facility must conduct two successive annual tests. The test will not be considered successful if sulfur dioxide emissions exceed 1.03 lb /MMBtu or if measured emissions exceeds the permitted limits. Testing shall be performed in accordance with Plantwide Condition #3 and EPA Reference Method 6. The permittee shall test at the minimum scrubber parameters of Specific Condition 43. The testing shall be conducted using the maximum TDF and fuel oil firing rates. If maximum TDF and fuel oil firing rates cannot be achieved, the permittee shall be limited to the maximum tested firing rate. During the test the permittee shall operate the boiler within 10 percent of the rated throughput capacity. If 90 percent of the rated throughout capacity cannot be

achieved, the permittee shall be limited to 10 percent above the actual tested throughput. The permittee shall reference this limitation in any compliance reports submitted to the Department. [§19.702 of Regulation #19 and 40 CFR Part 52 Subpart E]

SN-57F, 58F, 101, and 102
Woodyard

Source Description

Activities in the Woodyard include unloading incoming chips and wood, wood transferring, debarking (SN-57F), chipping (SN-58F), chip storage (SN-58F) and chip screening. Emissions are controlled by the use of water sprays.

Chips are delivered either by trucks or rail cars. The truck shipments are unloaded at an inclining truck dump. The rail car shipments are emptied by rolling the rail car over. From these two delivery points the chips are conveyed to the distribution tower and are then dropped into the chip piles. Water is added to the pneumatic transfer system to control dust.

In addition to chips, Georgia-Pacific also receives round logs. After storage, the logs are transported to the debarking drum for bark removal. The removed bark is pneumatically sent to the bark piles for storage and eventual use in the 9A and 10A Boilers of the Utilities Operations. The debarked logs are fed to the chipper. The chips that are produced are conveyed to the distribution tower and deposited onto the chip piles.

Chips from the chip piles are screened prior to entering the chip silo. Rejected chips from the screening process are sent to the combination boilers for use in steam production.
Bark either purchased or from the Woodyard is transferred by enclosed conveyors to the 9A and 10A Boilers' associated fuel storage piles. Emissions for these sources are calculated using drop transfer points.

As a part of the R10 modification, some existing pine screen and hardwood screen room equipment were replaced with new more efficient equipment. The changes are to improve chip thickness and quality by removing a larger quantity of fines and contaminants from the wood chips prior to the pulp mill. BACT for SN-58F is the use of a totally enclosed building for the new pine and hardwood screen room equipment.

Specific Conditions

59. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions 62 and 64. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	ton/yr
57F	Woodyard Debarking Drum and Associated Woodyard Chip Handling System	PM_{10} VOC	0.1 410.9	0.1 1,799.4

SN	Description	Pollutant	lb/hr	ton/yr
101	10A Boiler Bark Transfer System	PM_{10}	0.1	0.2
102	9A Boiler Bark Transfer System	PM_{10}	0.1	0.1

60. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions 62 and 64. [Regulation No. 19 §19.501 et seq., 19.901, and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	ton/yr
58F	Woodyard Chip Storage Piles & Chippers	PM/PM_{10}	1.1	4.5

61. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions 62 and 64. [Regulation No. §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	ton/yr
57F	Woodyard Debarking Drum and Associated Woodyard Chip Handling System	PM	0.1	0.2
101	10A Boiler Bark Transfer System	PM	0.1	0.3
102	9A Boiler Bark Transfer System	PM	0.1	0.2

Throughput Requirements

62. The permittee shall not process in excess of 8,400 tons of wet wood as received in the Woodyard per day, 30 day rolling average. [§18.1004 of Regulation #18, §19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

63. The permittee shall maintain records which demonstrate compliance with the limit in Specific Condition #62. The records shall be updated on a monthly basis. These records shall be kept on site, provided to Department personnel upon request and may be used by the Department for enforcement purposes. A twelve month total and each individual month's data shall be submitted in accordance with General Provision #7. [§18.1004 of

Regulation #18, §19.705 of Regulation #19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Dust Suppression

64. The permittee shall use water sprays in the discharge from the conveyance system in the Woodyard area to reduce particulate matter emissions except during periods when rain provides equivalent dust suppression, or when inclement weather creates a safety hazard to operators. [§19.303 of Regulation #19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN-59
Batch Digesters

Source Description

Chips from the Woodyard are sent to the pulp mill where they are converted to pulp using the chemical Kraft process. The chip conveying system regulates the flow of chips from the silos in the Woodyard to one of the thirteen batch digesters (SN-59). The function of the digesters is to cook chips using white liquor, black liquor and steam from the boilers. In the digestion process these products are combined and cooked at a set pressure and temperature until a quality pulp is obtained. At the end of each cook the blow valve at the bottom of the digester is opened. The pressure in the digester forces the pulp mass through a blow line into the blow tanks.

The mill has two large cylindrical blow tanks. All remaining process equipment in the Pulp Mill is divided into two parallel but separate lines. The blow tanks are at atmospheric pressure. When the chips hit the lower pressure in the tank, the liquor and water flash, blowing apart the chips to produce the pulp fibers. The fibers and the spent cooking liquor fall to the bottom of the blow tank.

The vapors from the blow tanks exit through a vapor line at the top of each blow tank. The vapors from each tank are combined and sent to the blow heat condensing system. Flow to the condensing system is maintained in the absence of blow downs by steam supplements. There is a series of condensers that remove condensable gases (primarily turpentine) from the blow gas. The steam vapors are condensed in the accumulator tank and used as hot water for the washers. Gases that do not condense are sent to the Incinerator (primary) or the Lime Kiln (backup) for thermal destruction.

The operation of the digesters during the cooking time is subject to NSPS Subpart BB. However, during the time that chips are loaded into the digesters (the digester caps are opened allowing any displaced fugitive emissions to be emitted to the atmosphere), the Subpart BB rules are not applicable since only residual quantities of TRS gases remain in the digester after this activity is completed.

In 597-AOP-R8, the facility underwent PSD review in order to modify nine of their Digesters (SN-59), replacing the six-inch blow valves with eight-inch valves. All six hardwood pulp digesters were modified, along with one “swing” pulp digester (used for either hardwood or softwood) and two softwood pulp digesters. BACT for VOC was determined to be combustion of the digester gases in an incinerator, SN-83. Emissions here are fugitives from the opening of the digesters to load chips.

Specific Conditions

65. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with

Specific Condition #69. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr	tpy
VOC	5.3	23.1

66. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition #69. [§19.304 and §19.501 et seq. of Regulation #19, 40 CFR Part 52 Subpart E]

Pollutant	lb/hr	ton/yr
TRS	0.9	3.9

67. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition #69. [Regulation No. §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Pollutant	lb/hr	tpy
Acetaldehyde	0.12	0.52
Acetone	0.2	0.8
Acrolein	0.01	0.01
Benzene	0.01	0.01
Carbon Tetrachloride	0.02	0.05
Chloroform	0.12	0.52
Ethylene Dichloride	0.01	0.01
Formaldehyde	0.01	0.01
Hexane	0.01	0.03
Methanol	2.11	9.21
Styrene	0.02	0.07
Tetrachloroethylene	0.01	0.01
Toluene	0.02	0.06

Pollutant	lb/hr	tpy
Xylene	0.01	0.02

NSPS BB

68. The Batch Digesters (SN-59) are subject to and shall comply with all applicable provisions of §19.304 of Regulation 19 and 40 CFR Part 60 BB - *Standards of Performance for Kraft Pulp and Paper Mills.* The Incinerator (SN-83) satisfies the requirements under §60.283(a)(1)(iii). A copy of Subpart BB is provided in Appendix C.

   a. The permittee shall not cause to be discharged into the atmosphere from the digester system any gases which contain TRS in excess of 5 ppm by volume on a dry basis, corrected to 10 percent oxygen, unless the conditions of 40 CFR §60.283(a)(1)(i)-(vi) are met. [§19.304 of Regulation 19 and 40 CFR §60.283(a)(1)]

   b. The permittee shall install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the concentration of TRS emissions on a dry basis and the percent of oxygen by volume on a dry basis in the gases discharged into the atmosphere from the digester system, except where the provisions of 40 CFR §60.283(a)(1)(iii) or (iv) apply. This system shall be located downstream of the control device and the span shall be set at a TRS concentration of 30 ppm for the TRS continuous monitoring system and at 25 percent oxygen for the continuous oxygen monitoring system. [§19.304 of Regulation 19 and 40 CFR §60.284(a)(2)]

   c. The permittee shall calculate and record on a daily basis 12-hour average TRS concentrations for the two consecutive periods of each operating day. Each 12-hour average shall be determined as the arithmetic mean of the appropriate 12 contiguous 1-hour average total reduced sulfur concentrations provided by each continuous monitoring system installed under paragraph (a)(2) of this section. [§19.304 of Regulation 19 and 40 CFR §284(c)(1)]

   d. For the purpose of reports required under 40 CFR §60.7(c), the permittee shall report semiannually periods of excess emissions where 60.284(c)(3)(i) and (ii) apply. The applicant must also report the nature and cause of the excess emissions in accordance with 40 CFR §60.7(c)(2). Excess emission reports shall be submitted to the address in General Provision 7. [§19.304 of Regulation 19 and 40 CFR§60.284(d)]

   e. The permittee shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures in this section, except as provided in 40 CFR §60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section. [§19.304 of Regulation 19 and 40 CFR §60.285(a]

Recordkeeping

69. The permittee shall not process in excess of 8,757 tons of wood chips per day, 30 day rolling average. [§19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70]

70. The permittee shall maintain records which demonstrate compliance with the limits specified in Specific Condition #69. The records shall be updated on a monthly basis. These records shall be kept on site, provided to Department personnel upon request and may be used by the Department for enforcement purposes. A rolling twelve month total and each individual month's data shall be submitted in accordance with General Provision #7. [§19.705 of Regulation #19 and 40 CFR Part 52 Subpart E]

SN-33, 34, 60 and 61
Pulp Mill Operations

Source Description

When the pulp and black liquor exit the blow tank, the pulp goes through several processing steps before it is stored in the unbleached high density storage chest. First, knots are removed prior to washing. The knots are recovered and used as woodwaste fuel. Second, the pulp is washed to separate the pulp from the spent cooking chemicals and the black liquor. There are two horizontal washers. The emissions from the associated black liquor storage tank and Line 1 Decker (SN-60) are routed to the Incinerator (SN-83) with the 9A Boiler (SN-22) operating as a backup control device. Next, the pulp passes through the decker system. The decker system (SN-60 and 61) thickens the pulp for storage in the high density storage chests. Although the operations at the pulp mill are in parallel, the two lines are run separately.

Specific Conditions

71. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #78. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	ton/yr
33	Line 1 Washer	VOC	7.5	28.4
		TRS	2.1	7.9
34	Line 2 Washer	VOC	7.5	28.4
		TRS	2.1	7.9
60	Line 1 Decker	Routed to the Incinerator (SN-83)		
61	Line 2 Decker	VOC	4.5	16.9
		TRS	2.1	7.7

72. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition #78. [Regulation No. §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	ton/yr
33	Line 1 Washer	Acetaldehyde	0.10	0.35
		Acetone	0.3	0.8
		Acetophenone	0.21	0.79
		Acrolein	0.01	0.02
		Benzene	0.01	0.02
		Carbon Tetrachloride	0.03	0.09

SN	Description	Pollutant	lb/hr	ton/yr
		Carbonyl Sulfide	0.07	0.25
		Chloroform	0.01	0.01
		Cresol	0.34	1.29
		Ethylene Dichloride	0.01	0.03
		Formaldehyde	0.01	0.01
		Hexane	0.01	0.03
		Methanol	4.66	17.69
		Methylene Chloride	0.01	0.01
		Phenol	0.37	1.40
		Styrene	0.01	0.04
		Tetrachloroethylene	0.04	0.15
		Toluene	0.02	0.05
		1,2,4-Trichlorobenzene	0.02	0.08
		Xylene	0.01	0.02
34	Line 2 Washer	Acetaldehyde	0.10	0.35
		Acetone	0.3	0.8
		Acetophenone	0.21	0.79
		Acrolein	0.01	0.02
		Benzene	0.01	0.02
		Carbon Tetrachloride	0.03	0.09
		Carbonyl Sulfide	0.07	0.25
		Chloroform	0.01	0.01
		Cresol	0.34	1.29
		Ethylene Dichloride	0.01	0.03
		Formaldehyde	0.01	0.01
		Hexane	0.01	0.03
		Methanol	4.66	17.69
		Methylene Chloride	0.01	0.01
		Phenol	0.37	1.40
		Styrene	0.01	0.04
		Tetrachloroethylene	0.04	0.15
		Toluene	0.02	0.05
		1,2,4-Trichlorobenzene	0.02	0.08
		Xylene	0.01	0.02
61	Line 2 Decker	Acetaldehyde	0.33	1.23
		Acetone	0.5	1.8
		Acrolein	0.01	0.02
		Benzene	0.01	0.01
		Carbon Tetrachloride	0.02	0.07
		Chloroform	0.13	0.49
		Cresol	1.56	5.90

SN	Description	Pollutant	lb/hr	ton/yr
		Formaldehyde	0.09	0.33
		Methanol	2.02	7.65
		Propionaldehyde	0.10	0.35
		Styrene	0.02	0.06
		Tetrachloroethylene	0.04	0.15
		Toluene	0.01	0.02
		1,2,4-Trichlorobenzene	0.11	0.40
		Xylene	0.02	0.05

NSPS BB

73. The Line 1 Washer (SN-33) and the Line 2 Washer (SN-34) are subject to and shall comply with all applicable provisions of §19.304 of Regulation 19 and 40 CFR Part 60 Subpart BB - *Standards of Performance for Kraft Pulp and Paper Mills*. The Incinerator (SN-83) satisfies the requirements under §60.283(a)(1)(iii). A copy of Subpart BB is provided in Appendix C.

   a. The permittee shall not cause to be discharged into the atmosphere from SN-33 and SN-34 any gases which contain TRS in excess of 5 ppm by volume on a dry basis, corrected to 10 percent oxygen, unless the conditions of 40 CFR §60.283(a)(1)(i)-(vi) are met. [§19.304 of Regulation #19 and 40 CFR §60.283(a)(1)]

   b. The permittee shall install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the concentration of TRS emissions on a dry basis and the percent of oxygen by volume on a dry basis in the gases discharged into the atmosphere from SN-33 and SN-34, except where the provisions of 40 CFR §60.283(a)(1)(iii) or (iv) apply. This system shall be located downstream of the control device and the span shall be set at a TRS concentration of 30 ppm for the TRS continuous monitoring system and at 25 percent oxygen for the continuous oxygen monitoring system. [§19.304 of Regulation #19 and 40 CFR §60.284(a)(2)]

   c. The permittee shall calculate and record on a daily basis 12-hour average TRS concentrations for the two consecutive periods of each operating day. Each 12-hour average shall be determined as the arithmetic mean of the appropriate 12 contiguous 1-hour average total reduced sulfur concentrations provided by each continuous monitoring system installed under paragraph (a)(2) of this section. [§19.304 of Regulation #19 and 40 CFR §60.284(c)(1), except where the provisions of 40 CFR §60.283(a)(1)(iv) or (a)(4) apply]

   d. For the purpose of reports required under 40 CFR §60.7(c), the permittee shall report semiannually periods of excess emissions where 60.284(c)(3)(i) and (ii) apply. The applicant must also report the nature and cause of the excess emissions in accordance with 40 CFR §60.7(c)(2). Excess emission reports shall be submitted to the address in General Provision 7. [§19.304 of Regulation #19 and 40 CFR §60.284(d)]

e. In conducting the performance tests required in 40 CFR §60.8, the permittee shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures in this section, except as provided in 40 CFR §60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section. [§19.304 of Regulation #19 and 40 CFR §60.285(a)]

NESHAP S

74. The Line 1 Washer (SN-33) and the Line 2 Washer (SN-34) shall comply with applicable provisions of §19.304 of Regulation 19 and 40 CFR Part 63 Subpart S - *National Emission Standards for Hazardous Air Pollutants from the Pulp and Paper Industry.* A copy of Subpart S is provided in Appendix E.

a. The permittee shall visually inspect each closed-vent system every 30 days. The visual inspection shall include inspection of ductwork, piping, enclosures, and connections to covers for visible evidence of defects. [40 CFR §63.453(k)(2)]

b. The permittee shall demonstrate no detectable leaks as specified in §63.450(c) measured initially and annually by the procedures specified in §63.457(d). [40 CFR §63.453(k)(3)]

c. The permittee shall operate the closed-vent system with no detectable leaks as indicated by an instrument reading of less than 500 parts per million by volume (ppm) above background as specified by §63.457(d). [40 CFR §63.450(c)]

d. The permittee shall perform corrective action, in the event of visible leak detection or instrument reading of 500 ppm above background, according to §63.453(k)(6)(i) and (ii). [40 CFR §63.457(k)(6)]

As part of an alternative monitoring requirement approved by the EPA, a copy of which is located in Appendix I, the permittee shall comply with the following:

e. In lieu of monthly visual monitoring, the permittee shall conduct monthly Method 21 monitoring of leaks found around the feed and exit roll seals and along the side gaskets of the washers. [40 CFR §63.453(d)(4)]

SN-30
Bleach Plant

Source Description

The unbleached Kraft pulp is taken from the high density storage chest for further processing in the bleach plant. The bleaching process removes lignin and Kraft color from the unbleached pulp.

Bleaching is performed in several stages using chlorine/chlorine dioxide, caustic soda, oxygen, acid, hydrogen peroxide, and other non-chlorine bleaching aids. Chlorine dioxide is generated using sodium chlorate, methanol and sulfuric acid. The chlorine dioxide gas that is produced is absorbed in chilled water and sent to storage for further use in the bleaching operations.
The bleach plant uses a scrubber (SN-30) to control chlorine/chlorine dioxide emissions. All equipment in the bleach plant is either pressurized or is kept under negative pressure and connected to the scrubbing system. The Bleach Plant scrubber is a packed tower with mist eliminators. In order to satisfy Cluster Rule requirements, Crossett Paper Operations has phased out Cl_2 and hypochlorite usage by the Cluster Rule compliance date of deadline of April 16, 2001.

As part of permit revision 597-AOP-R4, the Bleach Plant was required to undergo BACT for CO. Due to the phasing out of hypochlorite and limited available data concerning the resulting carbon monoxide emissions, the facility was required to modify the permit. The increase was above the PSD significance threshold for CO. BACT was determined to be no controls.

Specific Conditions

75. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition #78. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr	tpy
VOC	21.4	93.7

76. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition #78. [§19.501 et seq. and §19.901 of Regulation #19, and 40 CFR Part 52 Subpart E]

Pollutant	lb/hr	ton/yr
CO	136.1	596.1

77. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition #78. [Regulation No. §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Pollutant	lb/hr	tpy
Acetaldehyde	0.23	0.99
Acetone	0.5	2.0
Acrolein	0.01	0.01
Benzene	0.01	0.01
Carbon Tetrachloride	0.01	0.01
Chloroform	7.64	33.44
Cresol	0.06	0.25
Cumene	0.01	0.01
Ethylene Dibromide	0.03	0.11
Ethylene Dichloride	0.01	0.01
Formaldehyde	0.05	0.21
Hexachlorocyclopentadiene	0.16	0.66
Hexachloroethane	0.21	0.90
Hydrogen Chloride	2.48	10.83
Hexane	0.01	0.01
Methanol	12.90	56.51
Methylene Chloride	0.01	0.03
Propionaldehyde	0.06	0.25
Phenol	0.04	0.14
Styrene	0.02	0.09
Tetrachloroethylene	0.01	0.05
Toluene	0.01	0.01
1,2,4-Trichlorbenzene	0.01	0.03
Xylene	0.01	0.01

Throughput Requirements

78. The permittee shall not produce in excess of 2,150 air dried tons of bleached pulp per day, 30 day rolling average. [§19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

79. The permittee shall maintain records which demonstrate compliance with the limits listed in Specific Condition #78. The records shall be updated on a monthly basis. These records shall be kept on site, provided to Department personnel upon request and may be used by the Department for enforcement purposes. A twelve month total and each individual month's data shall be submitted in accordance with General Provision #7. [§19.705 of Regulation #19 and 40 CFR Part 52 Subpart E]

Testing Requirements

80. The permittee shall test for carbon monoxide emissions from the Bleach Plant Scrubber (SN-30) every five years. Testing shall be performed in accordance with Plantwide Condition #3 and EPA Reference Method 10 as found in 40 CFR Appendix A. During the test the permittee shall operate the plant within 10 percent of the rated throughput capacity. If 90 percent of the rated throughout capacity cannot be achieved, the permittee shall be limited to 10 percent above the actual tested throughput. The permittee shall reference this limitation in any compliance reports submitted to the Department. [§19.702 and §19.901 of Regulation #19 and 40 CFR Part 52 Subpart E]

NESHAP S

81. The Bleach Plant is subject to and shall comply with applicable provisions of §19.304 of Regulation 19 and 40 CFR Part 63 Subpart S - *National Emission Standards for Hazardous Air Pollutants from the Pulp and Paper Industry.* A copy of Subpart S is provided in Appendix E.

    a. The equipment at each bleaching stage, of the bleaching systems listed in paragraph (a) of 40 CFR §63.445, where chlorinated compounds are introduced shall be enclosed and vented into a closed-vent system and routed to a control device that meets the requirements specified in paragraph (c) of 40 CFR §63.445. The enclosures and closed-vent system shall meet the requirements specified in 40 CFR §63.450. [40 CFR §63.445(b)]

    b. The control device used to reduce chlorinated HAP emission (not including chloroform) from the equipment specified in paragraph (b) of 40 CFR §63.445, the permittee shall comply with the emissions limitations required for bleaching systems by one of the following methods 1) achieving a 99% reduction efficiency across the scrubber or 2) achieving <10 ppm HAPs or 0.002 lbs/ODTP, measured as chlorine. [40 CFR §63.445(c)(3)]

c. The owner or operator of each bleaching system subject to paragraph (a)(2) of 40 CFR §63.445 shall comply with paragraph (d)(1) or (d)(2) of 40 CFR §63.445 to reduce chloroform air emissions to the atmosphere, except where the owner or operator of each bleaching system complying with extended compliance under 40 CFR §63.440(d)(3)(ii) shall comply with paragraph (d)(1) of 40 CFR §63.445. [40 CFR §63.445(d)]

d. The permittee shall use no hypochlorite or elemental chlorine for bleaching in the bleaching system or line. [40 CFR §63.445(d)(2)]

82. The Bleach Plant scrubber shall be kept in good working condition at all times and shall meet the following conditions as part of an alternative monitoring requirement approved by the EPA on July 26, 2001. A copy of this letter is included in Appendix G. [40 CFR §63.453(m)]

a. Perform a successful initial performance test to determine an acceptable range of electrical current (amps) within which the fan needs to be operated. The fan amp range is 30-70 amps.

b. Continuously record and monitor the fan motor amperage loading to ensure proper rotational fan speed and pressure drop for the bleach plant scrubber fan.

c. Conduct monthly visual inspections under the Leak Detection and Repair plan provisions for the scrubber fan and associated process.

d. Conduct annual negative pressure checks to ensure that the bleach plant scrubber fan induces the desired negative pressure across the system.

e. Conduct periodic preventative maintenance of the bleach plant scrubber fan to ensure safe and proper operation of the system.

f. Respond immediately to any signs or indications of visible emissions from the scrubber stack, washer hoods, or towers at the bleach plant.

g. Replacement of fan blades or fan motor will require a demonstration by the facility that gas flow rate to the scrubber has not increased or a performance test to ensure that the scrubber meets the emission limitations.

SN-26 and SN-96
8R Recovery Furnace and Salt Cake Mix Tank

Source Description

Recovery is the set of operations that recover spent cooking chemicals for reuse in the digesters. The recovery process uses a multi-effect evaporator to concentrate weak black liquor. Concentrated black liquor is burned in the 8R Recovery Furnace (SN-26) to recover spent chemicals, the inorganic chemicals that are necessary for pulp making. Auxiliary fuels, such as oil, may be used by the furnace for startup or to augment liquor combustion. Exhaust gases from the recovery furnace are treated in an electrostatic wet bottom precipitator. The spent chemicals leave the recovery furnace in a molten form and enter the smelt dissolving tanks.

Evaporation and concentration operations remove water from the black liquor in order to facilitate combustion in the recovery furnace. The solids in the liquor are generated from the digester and washing filtrates. The evaporators convert the weak black liquor to strong (heavy) black liquor.

There are six effects in the evaporator train at the mill, each effect operating at a different pressure. Plant steam flows countercurrent to the black liquor through the evaporators. Combined condensate from the evaporator is used in washing and recausticizing. A Low Energy Environmental Pre-evaporator and Stripper (LEEPS) system added to the evaporator system treats the foul (or strip) condensates produced in the evaporation process. The LEEPS system also treats foul condensates generated from the pulping process. The clean water produced is re-used for pulp washing. The stripped condensate (methanol) is routed to the incinerator as a liquid for destruction. The stripper overhead gases (SOGs) are routed to the incinerator for destruction, or as a backup, to the No. 4 Lime Kiln or the 9A Boiler.

Black liquor of varying concentration is stored in above ground storage tanks. There are two large weak black liquor tanks and one weak black liquor storage basin (approximately 4 acres, SN-76F). In addition, there are two strong black liquor tanks and two concentrated strong black liquor holding tanks. There are also seven multiple service tanks that may store black liquor. There are also additional, smaller black liquor storage tanks.

The concentrated black liquor is burned in the 8R Recovery Furnace with the heat being used to produce steam and electricity. Flue gas from the furnace is sent through an economizer followed by an electrostatic precipitator (ESP). The ESP is used to control particulate matter emissions. Salt cake from the ESP is sent to the Salt Cake Mix Tank (SN-96).

The 8R Recovery Furnace was installed in 1981. It is subject to regulation under NSPS Subpart BB and NESHAP Subpart MM. As a result of the R10 modification, this source has undergone PSD review for PM/PM_{10}, SO_2, VOC, CO, and NO_x. BACT is defined as the use of an ESP, boiler design, and combustion control.

Specific Conditions

83. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #93 and #94. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	ton/yr
26	8R Recovery Furnace	Pb	0.01	0.01
96	Salt Cake Mix Tank	VOC TRS	0.7 0.1	2.4 0.2

84. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #94, #95, #96, and #99. [§19.501 et seq. and §19.901 of Regulation #19, and 40 CFR Part 52 Subpart E]

SN	Pollutant	lb/hr	ton/yr
26	Startup – Specification Oil Only		
	SO_2	989.1	371.0
	Normal Operation – BLS with Supplemental Specification Oil Firing		
	SO_2	84.7	371.0
		0.589 lb/ton BLS	

85. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #93 and #94. [§19.501 et seq. and §19.901 of Regulation #19, and 40 CFR Part 52 Subpart E]

SN	Pollutant	lb/hr	ton/yr
26	NO_x	276.0	1,208.6
		110 ppmdv @ 8% O_2	

86. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #93 and #94. [§19.501 et seq., §19.901 of Regulation #19, and 40 CFR Part 52 Subpart E]

SN	Pollutant	lb/hr	ton/yr
26	CO	1,420.0	6,219.6
		930 ppmdv @ 8% O_2	

87. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #93 and #94. [§19.304, §19.501 et seq., §19.901 of Regulation #19, 40 CFR Part 52 Subpart E]

SN	Pollutant	lb/hr	ton/yr
26	PM/PM_{10}	60.0	262.8
		0.02 gr/dscf @ 8% O_2	

88. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #93 and #94. [§19.501 et seq., §19.901 of Regulation #19, and 40 CFR Part 52 Subpart E]

SN	Pollutant	lb/hr	ton/yr
26	VOC	25.9	98.6
		0.18 lb/ton of BLS	

89. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #93 and #94. [§19.304, §19.501 et seq., and §19.801 of Regulation #19; 40 CFR Part 52 Subpart E; and 40 CFR §60.283]

SN	Pollutant	lb/hr	ton/yr
26	TRS	11.2	48.8
		5 ppm @ 8% O_2, 12-hr average	

90. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #93. [§19.501 et seq. and §19.901 of Regulation #19, and 40 CFR Part 52 Subpart E]

SN	Pollutant	lb/hr	ton/yr
26	Sulfuric Acid Mist (SAM)	7.3	27.6
		0.0504 lb/ton of BLS	

91. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with

Specific Conditions #94, #95, #96, and #99. [Regulation No. §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	ton/yr
26	8R Recovery Furnace	Acetaldehyde	0.08	0.28
		Acetone	2.3	8.6
		Arsenic	0.01	0.01
		Benzene	0.12	0.43
		Beryllium	0.01	0.01
		Cadmium	0.01	0.01
		Chloroform	0.01	0.02
		Chromium, Hex	0.01	0.01
		Cobalt	0.01	0.01
		Formaldehyde	1.35	5.13
		Hexane	0.05	0.17
		Hydrogen Chloride	9.49	36.14
		Manganese	0.01	0.04
		Methanol	7.59	28.91
		Mercury	0.01	0.01
		Methylene Chloride	0.09	0.32
		Naphthalene	0.05	0.18
		Nickel	0.01	0.03
		Phosphorous	0.04	0.14
		POM	0.02	0.06
		Selenium	0.01	0.01
		Styrene	0.10	0.37
		Tetrachloroethylene	0.09	0.32
		Toluene	0.01	0.03
		1,2,4-Trichlorobenzene	0.14	0.51
		Xylene	0.09	0.34
96	Salt Cake Mix Tank	Acetaldehyde	0.03	0.12
		Acetone	0.1	0.2
		Acrolein	0.01	0.01
		Benzene	0.01	0.01
		Formaldehyde	0.01	0.01
		Hexane	0.01	0.01
		Methanol	0.51	1.91
		Styrene	0.01	0.01
		Tetrachloroethylene	0.01	0.01
		Toluene	0.01	0.01
		1,2,4-Trichlorobenzene	0.01	0.01
		Xylene	0.01	0.01

Opacity

92. The permittee shall not cause to be discharged to the atmosphere from the 8R Recovery Furnace gases which exhibit opacity greater than 20%. Compliance shall be demonstrated by the use of the Recovery Furnace's continuous opacity monitor. [§19.503 of Regulation #19 and 40 CFR Part 52 Subpart E]

NSPS BB

93. The 8R Recovery Furnace (SN-26) is subject to and shall comply with all applicable provisions of §19.304 of Regulation 19, 40 CFR Part 60 Subpart BB - *Standards of Performance for Kraft Pulp and Paper Mills*, and 40 CFR Part 63 Subpart MM - *National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Sulfite, and Stand-Alone Semichemical Pulp Mills*. A copy of Subpart BB is provided in Appendix C. The Incinerator (SN-83) satisfies the requirements under §60.283(a)(1)(iii). A copy of Subpart MM is provided in Appendix H.

   a. The permittee shall not cause to be discharged into the atmosphere from the recovery furnace gases which contain particulate matter in excess of 0.044 gr/dscf corrected to 8 percent oxygen. [§19.304 of Regulation #19 and 40 CFR §60.282(a)(1)(i) and 40 CFR §63.862(a)(i)(A)]

   b. The permittee shall not cause to be discharged into the atmosphere from the recovery furnace gases which exhibit 35 percent opacity or greater. [§19.304 of Regulation #19 and 40 CFR §60.282(a)(1)(ii)]

   c. The permittee shall not cause to be discharged into the atmosphere from the recovery furnace gases which contain TRS in excess of 5 ppm by volume on a dry basis, corrected to 8 percent oxygen. [§19.304 of Regulation #19 and 40 CFR §60.283(a)(2)]

   d. The permittee shall install, calibrate, maintain, and operate continuous monitoring systems (CEMs) to monitor and record the concentration of TRS emissions on a dry basis and the percent of oxygen by volume on a dry basis in the gases discharged into the atmosphere from the recovery furnace, except where the provisions of §60.283(a)(1) (iii) or (iv) apply. This system shall be located downstream of the control device and the span shall be set at a TRS concentration of 50 ppm for the TRS continuous monitoring system and at 25 percent oxygen for the continuous oxygen monitoring system. [§19.304 of Regulation #19 and 40 CFR §60.284(a)(2)]

   e. The permittee shall calculate and record on a daily basis 12-hour average TRS concentrations for the two consecutive periods of each operating day. Each 12-

hour average shall be determined as the arithmetic mean of the appropriate 12 contiguous 1-hour average total reduced sulfur concentrations provided by each continuous monitoring system installed under paragraph (a)(2) of this section. [§19.304 of Regulation #19 and 40 CFR §60.284(c)(1)]

f. The permittee shall calculate and record on a daily basis 12-hour average oxygen concentrations for the two consecutive periods of each operating day for the recovery furnace. These 12-hour averages shall correspond to the 12-hour average TRS concentrations under paragraph (c)(1) of this section and shall be determined as an arithmetic mean of the appropriate 12 contiguous 1-hour average oxygen concentrations provided by each continuous monitoring system installed under paragraph (a)(2) of this section. [§19.304 of Regulation #19 and 40 CFR §60.284(c)(2)]

g. For the purpose of reports required under 40 CFR §60.7(c), the permittee shall report semiannually periods of excess emissions where 60.284(c)(3)(i) and (ii) apply. The applicant must also report the nature and cause of the excess emissions in accordance with 40 CFR §60.7(c)(2). Excess emission reports shall be submitted to the address in General Provision 7. [§19.304 of Regulation #19 and 40 CFR §60.284(d)]

h. The permittee shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures in this section, except as provided in 40 CFR §60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section. [§19.304 of Regulation #19 and 40 CFR §60.285(a)]

i. The permittee is limited to a particulate concentration of no more than 0.044 gr/scf at 8% O_2. [§19.304 of Regulation #19 and 40 CFR §60.282, and 40 CFR §63.862(a)(i)(A)

Fuel Requirements

94. The permittee shall not fire in excess of 1.095 million tons of black liquor solids to the recovery furnace per twelve consecutive months. [§19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

95. The permittee shall not fire in excess of 5,256,000 gallons of glycerin to the recovery furnace per twelve consecutive months. [§19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8 4-311, and 40 CFR §70.6]

96. The permittee may fire up to 1.0 gal/min ultra-low sulfur diesel to the recovery furnace. [§19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8 4-311, and 40 CFR §70.6]

97. Specification grade oil, ultra-low sulfur diesel, and glycerin may be used as fuel in the 8R Recovery Furnace (SN-26) during startup and to supplement BLS firing during periods deemed necessary by operations. [§19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

98. The permittee shall maintain records of fuel usage which demonstrate compliance with Specific Conditions #94, #95, #96, and #97. These records shall be updated monthly, kept on site, provided to Department personnel upon request and may be used by the Department for enforcement purposes. A twelve month total and each month's individual data shall be submitted to the Department in accordance with General Provision #7. [§19.705 of Regulation #19 and 40 CFR Part 52 Subpart E]

99. The sulfur content of the specification grade oil shall not exceed 1.5% by weight and 1.0% on a 30-day average. [§19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

100. Sulfur dioxide emissions shall be determined through a mass balance based on incoming materials and worst-case firing of specification grade oil based on the limits in Condition #99. This mass balance shall be submitted to the Department in accordance with General Provision #7. [§19.703 of Regulation #19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Testing Requirements

101. The permittee shall perform testing of particulate matter emissions from the 8R Recovery Furnace (SN-26) every five years. Testing shall be performed in accordance with Plantwide Condition #3 and using EPA Reference Method 5 with inclusion of back half sampling train particulate. Results from the Method 5 test shall be compared to the NSPS limit 0.044 gr/scf at 8% O_2 for compliance purposes. During the test the permittee shall operate the source within 10 percent of the rated throughput capacity. If 90 percent of the rated throughout capacity cannot be achieved, the permittee shall be limited to 10 percent above the actual tested throughput. The permittee shall reference this limitation in any compliance reports submitted to the Department. [§19.702 of Regulation #19 and 40 CFR Part 52 Subpart E]

102. The permittee shall perform testing of the following emissions from the 8R Recovery Furnace (SN-26) every five years to verify compliance with the BACT emission limits. During the test the permittee shall operate the source within 10 percent of the rated throughput capacity. If 90 percent of the rated throughout capacity cannot be achieved, the permittee shall be limited to 10 percent above the actual tested throughput. The permittee shall reference this limitation in any compliance reports submitted to the Department. [§19.702 and §19.901 of Regulation #19, and 40 CFR Part 52 Subpart E]

Pollutant	Reference Method (or other pre-approved)
SO_2	6C
VOC	25A
NOx	7E
CO	10
SAM	8

CEMS Requirements

103. The permittee shall continue to operate and maintain opacity, TRS and O_2 continuous emission monitors at the 8R Recovery Furnace (SN-26). [§19.304 and §19.703 of Regulation #19, 40 CFR Part 52 Subpart E, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §60.284]

104. The continuous emission monitors for TRS and O_2 at the 8R Recovery Furnace shall be operated in accordance with the Department Continuous Emission Monitoring Systems Conditions (Appendix A) and the applicable Performance Standards of 40 CFR Part 60 Appendix B. [§19.703 of Regulation #19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

105. All continuous monitoring data may, at the discretion of the Department, be used to determine violations of the emissions limits or conditions of this permit. [§19.703 of Regulation #19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

106. The TRS concentration of gases leaving the 8R Recovery Furnace (SN-26) shall not exceed 5 ppm, measured as H_2S on a dry basis and on a 12 hour average, corrected to 8% volume oxygen. The permittee shall continue to operate and maintain CEMs which record the TRS concentration of gases leaving the 8R Recovery Furnace (SN-26). The TRS monitors shall be operated in accordance with the requirements of 40 CFR §60.284 (date of installation notwithstanding) and the Department Continuous Emission Monitoring Systems Conditions (Appendix A). [§19.304 and §19.801 of Regulation #19, 40 CFR §60.283, and 40 CFR §60.284]

SN-27A and 27B
Smelt Dissolving Tanks

Source Description

The combusted black liquor generates molten salts that are drained from the bottom of the 8R Recovery Furnace into one of two smelt dissolving tanks (SN-27A and SN-27B) on either side of the 8R Recovery Furnace. The smelt dissolving tanks cool the molten salts in large water tanks. Each smelt dissolving tank has an independent stack that is routed through a wet scrubber. The smelt dissolving tanks are subject to NSPS Subpart BB - *National Emission Standards for Hazardous Air Pollutants from the Pulp and Paper Industry* and NESHAP Subpart MM - *National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Sulfite, and Stand-Alone Semichemical Pulp Mills.*

Specific Conditions

107. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition #94. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	ton/yr
27A	Smelt Dissolving Tank (East)	SO_2	0.5	1.7
		VOC	1.5	5.5
		CO	0.7	2.7
		NO_x	1.8	6.6
		Pb	0.01	0.01
27B	Smelt Dissolving Tank (West)	SO_2	0.5	1.7
		VOC	1.5	5.5
		CO	0.7	2.7
		NO_x	1.8	6.6
		Pb	0.01	0.01

108. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition #94, #114, and #116. [§19.304 and §19.501 et seq. of Regulation #19, and 40 CFR Part 52 Subpart E, and 40 CFR §63.862(a)(i)(B)]

SN	Description	Pollutant	lb/hr	ton/yr
27A	Smelt Dissolving Tank (East)	PM PM_{10}	14.4	54.8
			0.2 lb PM/PM_{10} per ton of black liquor solids (TBLS)	
27B	Smelt Dissolving Tank (West)	PM PM_{10}	14.4	54.8
			0.2 lb PM/PM_{10} per ton of black liquor solids (TBLS)	

109. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition #94, #116, and #118. [§19.304, §19.501 et seq., and §19.801 of Regulation #19; 40 CFR Part 52 Subpart E, 40 CFR §60.283]

SN	Description	Pollutant	lb/hr	ton/yr
27A	Smelt Dissolving Tank (East)	TRS	2.4	9.1
			0.016 g TRS per kg of black liquor solids 0.033 lb/TBLS) as H_2S	
27B	Smelt Dissolving Tank (West)	TRS	2.4	9.1
			0.016 g TRS per ton of black liquor solids (0.033 lb/TBLS) as H_2S	

110. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition #94. [Regulation No.§18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	ton/yr
27A	Smelt Dissolving Tank (East)	Acetaldehyde	0.08	0.30
		Acetone	0.2	0.5
		Acrolein	0.01	0.01
		Arsenic	0.01	0.01
		Benzene	0.01	0.01
		Beryllium	0.01	0.01
		Cadmium	0.01	0.01
		Carbon Disulfide	0.01	0.01
		Chloroform	0.01	0.01

SN	Description	Pollutant	lb/hr	ton/yr
		Cobalt	0.01	0.01
		Cumene	0.01	0.01
		Formaldehyde	0.31	1.15
		Hexachlorocyclopentadiene	0.01	0.04
		Hexane	0.01	0.01
		Manganese	0.01	0.01
		Mercury	0.01	0.01
		Methanol	0.95	3.62
		Methylene Chloride	0.01	0.01
		Naphthalene	0.05	0.17
		Nickel	0.01	0.01
		Phosphorous	0.01	0.01
		POM	0.04	0.15
		Selenium	0.01	0.01
		Styrene	0.02	0.04
		Tetrachloroethylene	0.01	0.01
		Toluene	0.01	0.01
		1,2,4-Trichlorbenzene	0.01	0.01
		Xylene	0.01	0.01
27B	Smelt Dissolving Tank (East)	Acetaldehyde	0.08	0.30
		Acetone	0.2	0.5
		Acrolein	0.01	0.01
		Arsenic	0.01	0.01
		Benzene	0.01	0.01
		Beryllium	0.01	0.01
		Cadmium	0.01	0.01
		Carbon Disulfide	0.01	0.01
		Chloroform	0.01	0.01
		Cobalt	0.01	0.01
		Cumene	0.01	0.01
		Formaldehyde	0.31	1.15
		Hexachlorocyclopentadiene	0.01	0.04
		Hexane	0.01	0.01
		Manganese	0.01	0.01
		Mercury	0.01	0.01
		Methanol	0.95	3.62
		Methylene Chloride	0.01	0.01
		Naphthalene	0.05	0.17
		Nickel	0.01	0.01
		Phosphorous	0.01	0.01
		POM	0.04	0.15

SN	Description	Pollutant	lb/hr	ton/yr
		Selenium	0.01	0.01
		Styrene	0.02	0.04
		Tetrachloroethylene	0.01	0.01
		Toluene	0.01	0.01
		1,2,4-Trichlorbenzene	0.01	0.01
		Xylene	0.01	0.01

Opacity

111. The permittee shall not cause to be discharged from the Smelt Dissolving Tanks (SN-27A and 27B) gases which exhibit opacity greater than 20%. [§19.503 of Regulation #19 and 40 CFR Part 52 Subpart E]

112. The permittee shall conduct weekly observations of the opacity at SN-27A and B. Observations shall be conducted by personnel familiar with the permittee's visible emissions. If visible emissions in excess of the permitted opacity are detected, then a Method 9 reading is required. The permittee shall then take immediate action to identify the cause of the visible emissions, implement all necessary corrective action, and reassess the visible emissions after corrective action is taken. The permittee shall maintain records related to all observations/readings, to be updated on a weekly basis. The records shall contain the date and time of each observation/reading, the cause of any observed exceedance of opacity limits, corrective action taken, and results of the reassessment, and the name of the person conducting the observation/reading. The records shall be kept on site and made available to Department personnel upon request. [§19.705 of Regulation 19 and 40 CFR Part 52, Subpart E]

Scrubber Monitoring Requirements

113. The permittee shall continue to operate and maintain a monitoring device for the continuous measurement of the differential pressure drop across the scrubber. [§19.304 and §19.703 of Regulation #19, 40 CFR Part 52 Subpart E, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §60.284]

114. The scrubbers shall be kept in good working condition at all times and shall meet the conditions shown in the following table. The scrubber liquid flow rate and the gas pressure drop across the units shall be measured hourly and compliance shall be based upon the daily average of these measurements. The results shall be kept on site and be available to the Department personnel upon request. Future compliance tests may be used to establish the daily average pressure drop and flow rate values that are contained in the permit. [§19.303 of Regulation #19 and A.C.A §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Control Equipment	Parameter	Units	Operation Limits (minimum)
27A	scrubber	liquid flow rate	gal/min	135
		gas pressure drop across unit	inches, H_2O	5
27B	scrubber	liquid flow rate	gal/min	135
		gas pressure drop across unit	inches, H_2O	5

115. The permittee shall abide by the following alternative scenario only during emergency maintenance for scrubbers for the Smelt Dissolving Tanks (SN-27A and 27B). [§19.303 of Regulation #19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

a. Black liquor solids feed to the 8R Boiler (SN-26) shall be reduced to 3.91 MM lb/day.

b. Uncontrolled emissions shall be quantified and recorded.

c. Repair time must not extend beyond a 6 hour period.

d. Down time of the equipment will be monitored and submitted to the Department in accordance with General Provision 8.

NSPS BB and NESHAP S

116. The Smelt Dissolving Tanks (SN-27A and 27B) are subject to and shall comply with all applicable provisions of §19.304 of Regulation 19, 40 CFR Part 60 Subpart BB - *Standards of Performance for Kraft Pulp and Paper Mills* and 40 CFR Part 63 Subpart MM - *National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Sulfite, and Stand-Alone Semichemical Pulp Mills.* A copy of Subpart BB is provided in Appendix C. The Incinerator (SN-83) satisfies the requirements under §60.283(a)(1)(iii). A copy of Subpart MM is provided in Appendix H.

a. The permittee shall not cause to be discharged into the atmosphere from the smelt dissolving tanks any gases which contain particulate matter in excess of 0.2 lb/ton black liquor solids (dry weight). [§19.304 of Regulation 19, 40 CFR §60.282(a)(2) and 40 CFR §63.862(a)(i)(B)]

b. The permittee shall not cause to be discharged into the atmosphere from the smelt dissolving tanks any gases which contain TRS in excess of 0.033 lb/ton black liquor solids as H_2S. [§19.304 of Regulation 19 and 40 CFR §60.283(a)(4)]

c. The permittee shall install, calibrate, maintain, and operate continuous monitoring devices for the smelt dissolving tanks because they use a scrubber emission control device. [§19.304 of Regulation 19 and 40 CFR §60.284(b)(2)]

d. For the purpose of reports required under 40 CFR §60.7(c), the permittee shall report semiannually periods of excess emissions where 60.284(c)(3)(i) and (ii) apply. The applicant must also report the nature and cause of the excess emissions in accordance with 40 CFR §60.7(c)(2). Excess emission reports shall be submitted to the address in General Provision 7. [§19.304 of Regulation 19 and 40 CFR §60.284(d)]

e. The permittee shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures in this section, except as provided in 40 CFR §60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section. [§19.304 of Regulation 19 and 40 CFR §60.285(a)]

Testing Requirements

117. The permittee shall test particulate matter emissions from the Smelt Dissolving Tanks (SN-27A and 27B) every 5 years. Testing shall be performed in accordance with Plantwide Condition #3 and EPA Reference Method 5 with inclusion of back half sampling train particulate. Results from the Method 5 test shall be compared to the NSPS limit of 0.2 lb PM/PM_{10} per ton of black liquor solids (TBLS) for compliance purposes. During the test the permittee shall operate the sources within 10 percent of the rated throughput capacity. If 90 percent of the rated throughout capacity cannot be achieved, the permittee shall be limited to 10 percent above the actual tested throughput. The permittee shall reference this limitation in any compliance reports submitted to the Department. [§19.702 of Regulation #19 and 40 CFR Part 52 Subpart E]

118. The TRS concentration of gases leaving the Smelt Dissolving Tanks (SN-27A and 27B) shall not exceed 0.0168 g TRS per kg of black liquor solids. The permittee shall conduct annual compliance testing of TRS emissions from the Smelt Dissolving Tanks (SN-27A and 27B). Data reduction shall be performed as set forth in 40 CFR §60.8. Testing shall be performed in accordance with Plantwide Condition #3 and EPA Reference Method 16 or 16A. During the test the permittee shall operate the source within 10 percent of the rated throughput capacity. If 90 percent of the rated throughout capacity cannot be achieved, the permittee shall be limited to 10 percent above the actual tested throughput. The permittee shall reference this limitation in any compliance reports submitted to the Department. [§19.702 and §19.801 et seq of Regulation #19, and 40 CFR Part 52 Subpart E]

SN-25
Lime Kiln

Source Description

The lime kiln heats calcium carbonate (lime mud) to form calcium oxide (lime product). Fuels used in the lime kiln include specification grade oil and natural gas. Emissions from the lime kiln are controlled by a wet scrubber. Non-condensable gases (NCGs) from processes are routed to the lime kiln for thermal destruction. The lime kiln is subject to NSPS Subpart BB and NESHAP Subpart MM. The kiln is also subject to CAM requirements due to SO_2 emissions. The maximum firing rate of the lime kiln is 128 million Btu per hour. NCGs from several pulp mill sources are collected and routed to the lime kiln for combustion. The evaporator vents, digester vents and blow tank condensers are all part of the NCG system at the Crossett Paper Operations.

Reburnt lime product from the lime kiln is conveyed to a lime bin where it is fed into the slaker. The lime handling and storage system includes elevators, conveyors and lime bins. Conveyors transport lime from the storage silos to the slakers. Fresh lime is added to the system from delivery trucks by pneumatic conveyance to the two lime silos.

Specific Conditions

119. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #127, #128, #130 and #131. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr	ton/yr
SO_2	10.9	41.2
VOC	1.5	5.6
CO	5.8	21.9
NO_x	53.5	203.6
Pb	0.01	0.02

120. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition #127, #128, and #131. [§19.304 and §19.501 et seq. of Regulation #19, 40 CFR Part 52 Subpart E, and 40 CFR §63.862(a)(i)(C)]

Pollutant	lb/hr	ton/yr
PM	28.3	123.8
PM_{10}	0.064 gr/dscf corrected to 10% O_2	

121. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #127, #128, and #131. [§19.304, §19.501 et seq., §19.801 of Regulation #19; CFR Part 52 Subpart E; and 40 CFR §60.283]

Pollutant	lb/hr	ton/yr
TRS	2.2	9.6
	8 ppm measured as H_2S on a dry basis, on a 12-hour average, corrected to 10% O_2	

122. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition #128. [Regulation No. §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Pollutant	lb/hr	ton/yr
Acetaldehyde	0.18	0.67
Acetone	0.1	0.1
Acrolein	0.01	0.01
Arsenic	0.01	0.01
Benzene	0.02	0.04
Beryllium	0.01	0.01
Cadmium	0.01	0.01
Carbon Disulfide	0.01	0.04
Chloroform	0.01	0.01
Chromium Hex	0.01	0.01
Cobalt	0.01	0.01
Formaldehyde	0.18	0.67
Hexane	0.01	0.01
Hydrogen Chloride	0.01	0.03
Manganese	0.01	0.04
Mercury	0.01	0.01
Methanol	0.38	1.45
Methylene Chloride	0.01	0.01
Naphthalene	0.42	1.57
Nickel	0.01	0.02
Phenol	0.01	0.04
Phosphorous	0.06	0.21
POM	0.01	0.02
SAM	0.7	2.6
Selenium	0.01	0.01

Pollutant	lb/hr	ton/yr
Styrene	0.01	0.01
Tetrachloroethylene	0.01	0.04
Toluene	0.01	0.01
1,2,4-Trichlorobenzene	0.01	0.02
Xylene	0.01	0.03

Opacity

123. The permittee shall not cause to be discharged to the atmosphere gases which exhibit opacity greater than 20%. [§19.503 of Regulation #19 and 40 CFR Part 52 Subpart E]

124. The permittee shall conduct daily observations of the opacity at SN-25. Observations shall be conducted by personnel familiar with the permittee's visible emissions. If visible emissions in excess of the permitted opacity are detected, then a Method 9 reading is required. The permittee shall then take immediate action to identify the cause of the visible emissions, implement all necessary corrective action, and reassess the visible emissions after corrective action is taken. The permittee shall maintain records related to all observations/readings, to be updated on a daily basis. The records shall contain the date and time of each observation/reading, the cause of any observed exceedance of opacity limits, corrective action taken, and results of the reassessment, and the name of the person conducting the observation/reading. The records shall be kept on site and made available to Department personnel upon request. [§19.705 of Regulation 19 and 40 CFR Part 52, Subpart E]

CAM

125. The Lime Kiln (SN-25) is subject to and shall comply with all applicable provisions §19.304 of Regulation 19, 40 CFR Part 52 Subpart E, and Part §64.6 for Compliance Assurance Monitoring. Post control of particulate emissions from SN-25 is above major source levels.

    a. The permittee shall maintain caustic liquid flow rate in the scrubber of at least 500 gallons per minute. [40 CFR Part §64.6(c)(1)]

    b. The permittee shall maintain a gas pressure drop of at least 25 inches of water. [40 CFR Part §64.6(c)(1)]

    c. The permittee shall monitor and maintain records every 15 minutes of the parameters in Specific Conditions #125 (A) and (B). Compliance shall be based upon a 3-hr average. Records shall be kept onsite and made available to the Department upon request. [40 CFR Part §64.6(c)(3)]

d. The permittee shall maintain the scrubber in good working condition at all times so that pollutant removal is maintained. [40 CFR Part §64.6(c)(1)]

126. The Lime Kiln (SN-25) is subject to and shall comply with all applicable provisions §19.304 of Regulation 19, 40 CFR Part 52 Subpart E, and Part §64.9 for Compliance Assurance Monitoring. The following information pertaining to exceedances or excursions from permitted values shall be submitted in semi-annual reports in accordance with General Provision 7 as outlined in 40 CFR §70.6.

a. The permittee shall maintain records for SN-25 that summarizes the number, duration, and cause of excursions or exceedances of emission limits as well as corrective action taken. [40 CFR §64.9(a)(2)(i) and §64.9(b)]

b. The permittee shall maintain records for SN-25 that summarizes the number, duration, and cause of monitoring equipment downtime incidents, other than routine downtime for calibration checks. [40 CFR §64.9(a)(2)(ii) and §64.9(b)]

c. The permittee shall maintain a quality improvement plan (QIP) threshold for each indicator of no more than nine excursions or 5% of the daily averages in a six-month period. [40 CFR §64.9(a)(2)(iii) and §64.9(b)]

d. The permittee shall develop and implement a new QIP if the threshold is exceeded during any six-month period. [40 CFR §64.9(a)(2)(iii) and §64.9(b)]

e. The permittee shall maintain records for SN-25 that describes the actions taken to implement the QIP. Upon completion of the QIP, documentation shall be maintained to confirm that the plan was completed and reduced the likelihood of similar excursions or exceedances. [40 CFR §64.9(a)(2)(iii) and §64.9(b)]

NSPS BB and NESHAP MM

127. The No. 4 Lime Kiln (SN-25) is subject to and shall comply with all applicable provisions of §19.304 of Regulation 19, 40 CFR Part 60 Subpart BB - *Standards of Performance for Kraft Pulp and Paper Mills* and 40 CFR Part 63 Subpart MM - *National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Sulfite, and Stand-Alone Semichemical Pulp Mills.* A copy of Subpart BB is provided in Appendix C. The Incinerator (SN-83) satisfies the requirements under §60.283(a)(1)(iii). A copy of Subpart MM is provided in Appendix H.

a. The permittee shall not cause to be discharged into the atmosphere from the lime kiln any gases which contain particulate matter in excess of 0.064 gr/dscf corrected to 10 percent oxygen, when gaseous fossil fuel is burned. [40 CFR §63.862(a)(i)(C)]

b. The permittee shall not cause to be discharged into the atmosphere from the lime kiln gases which contain TRS in excess of 8 ppm by volume on a dry basis, corrected to 10 percent oxygen. [§19.304 of Regulation 19 and 40 CFR §60.283(a)(5)]

c. The permittee shall install, calibrate, maintain, and operate continuous monitoring systems to monitor and record the concentration of TRS emissions on a dry basis and the percent of oxygen by volume on a dry basis in the gases discharged into the atmosphere from the lime kiln. This system shall be located downstream of the control device and the span shall be set at a TRS concentration of 30 ppm for the TRS continuous monitoring system and at 20 percent oxygen for the continuous oxygen monitoring system. [§19.304 of Regulation 19 and 40 CFR §60.284(a)(2)]

d. The permittee shall install, calibrate, maintain, and operate continuous monitoring devices (CEMs) for the lime kiln because it uses a scrubber emission control device. [§19.304 of Regulation 19 and 40 CFR §60.284(b)(2)]

e. The permittee shall calculate and record on a daily basis 12-hour average TRS concentrations for the two consecutive periods of each operating day. Each 12-hour average shall be determined as the arithmetic mean of the appropriate 12 contiguous 1-hour average total reduced sulfur concentrations provided by each continuous monitoring system installed under paragraph (a)(2) of this section. [§19.304 of Regulation 19 and 40 CFR §60.284(c)(1)]

f. The permittee shall calculate and record on a daily basis 12-hour average oxygen concentrations for the two consecutive periods of each operating day for the lime kiln. These 12-hour averages shall correspond to the 12-hour average TRS concentrations under paragraph (c)(1) of this section and shall be determined as an arithmetic mean of the appropriate 12 contiguous 1-hour average oxygen concentrations provided by each continuous monitoring system installed under paragraph (a)(2) of this section. [§19.304 of Regulation 19 and 40 CFR §60.284(c)(2)]

g. For the purpose of reports required under 40 CFR §60.7(c), the permittee shall report semiannually periods of excess emissions where 60.284(c)(3)(i) and (ii) apply. The applicant must also report the nature and cause of the excess emissions in accordance with 40 CFR §60.7(c)(2). Excess emission reports shall be submitted to the address in General Provision 7. [§19.304 of Regulation 19 and 40 CFR §60.284(d)]

h. The permittee shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures in this section, except as provided in 40 CFR §60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section. [§19.304 of Regulation 19 and 40 CFR §60.285(a)]

Production Limits

128. Calcium oxide production at this source is limited to 632.4 tons/day, maximum, and 550 tons/day on an annual average. [§19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

129. The permittee shall maintain a record daily calcium oxide production. These records shall be kept on site, provided to Department personnel upon request and may be used by the Department for enforcement purposes. A twelve month total and each individual month's data shall be submitted in accordance with General Provision #7. [§19.705 of Regulation #19 and 40 CFR Part 52 Subpart E]

Fuel Requirements

130. Either natural gas, specification oil, or a combination of natural gas and specification oil may be used as fuel in the No. 4 Lime Kiln. [§19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

131. The sulfur content of the specification grade oil shall not exceed 1.5% by weight and 1.0% on a 30-day average. [§19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

Testing Requirements

132. The permittee shall test particulate matter emissions from the No. 4 Lime Kiln (SN-25) every five years. The permittee shall test at the minimum scrubber parameters of Specific Condition 125. Testing shall be performed in accordance with Plantwide Condition #3 and EPA Reference Method 5 with inclusion of back half sampling train particulate. Results from the Method 5 test shall be compared to the NSPS limit 0.064 gr/dscf corrected to 10% O_2 for compliance purposes. During the test the permittee shall operate the source within 10 percent of the rated throughput capacity. If 90 percent of the rated throughout capacity cannot be achieved, the permittee shall be limited to 10 percent above the actual tested throughput. The permittee shall reference this limitation in any compliance reports submitted to the Department. [§19.702 of Regulation #19 and 40 CFR Part 52 Subpart E]

133. The permittee shall test sulfur dioxide emissions from the No. 4 Lime Kiln (SN-25) every five years. Testing shall be performed in accordance with Plantwide Condition #3 and EPA Reference Method 6C. The permittee shall test at the minimum scrubber parameters of Specific Condition 125. During the test the permittee shall operate the source within 10 percent of the rated throughput capacity. If 90 percent of the rated throughout capacity cannot be achieved, the permittee shall be limited to 10 percent above the actual

tested throughput. The permittee shall reference this limitation in any compliance reports submitted to the Department. [§19.702 of Regulation #19 and 40 CFR Part 52 Subpart E]

CEM Requirements

134. The permittee shall continue to operate and maintain for the No. 4 Lime Kiln a continuous monitoring system to monitor and record TRS concentration on a dry basis, percent of O_2 by volume on a dry basis, pressure drop across the scrubber and liquid supply pressure. [§19.304 and §19.703 of Regulation #19, 40 CFR Part 52 Subpart E, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §60.284]

135. The continuous emission monitors at the No. 4 Lime Kiln shall be operated in accordance with the Department Continuous Emission Monitoring Systems Conditions (Appendix A) and the applicable Performance Standards of 40 CFR Part 60 Appendix B. [§19.703 of Regulation #19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

136. All continuous monitoring data may, at the discretion of the Department, be used to determine violations of the emissions limits or conditions of this permit. [§19.703 of Regulation #19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

137. The TRS concentration of gases leaving the No. 4 Lime Kiln (SN-25) shall not exceed 8 ppm, measured as H_2S on a dry basis and on a 12 hour average, corrected to 10% volume oxygen. The permittee shall continue to operate and maintain CEMs which record the TRS concentration of gases leaving the No. 4 Lime Kiln (SN-25). The TRS monitors shall be operated in accordance with the requirements of 40 CFR §60.284 (date of installation notwithstanding) and the Department Continuous Emission Monitoring Systems Conditions (Appendix A). [§19.304, §19.501 et seq., and §19.801 et seq of Regulation #19; 40 CFR §60.283; and 40 CFR §60.284]

SN-55F, 56F, SN-94, SN-98, SN-99, SN-100
SN-103, SN-105, SN-106, SN-107, SN-108, SN-109, and SN-110

Slaker Vents, Green Liquor Clarifier A, "A" and "B" Side Causticizers, White Liquor Storage Tanks, Green Liquor Clarifier A, White Liquor Clarifier, Mud Washers A and B, Pre-Coats Filter, Green Liquor Stabilization Tank, and White Liquor Splitter Box

Source Description

Causticizing vents contributions are also included with the slaker emission estimates. The causticizing operation reacts molten inorganic salts from the smelt dissolving tanks with weak wash to form green liquor. Undissolved particles in the green liquor are allowed to settle out in the Green Liquor Clarifiers A or B (SN-94 and SN-103).

The mixing of green liquor with lime to form slurry is termed slaking. The slaking process is designed to combine green liquor and burnt lime (CaO). This mixing, which involves an exothermic chemical reaction, takes place in one of two Slakers. The emissions are exhausted through two adjacent Slaker Vents, SN-55 and SN-56. After being mixed with lime in the slakers the green liquor goes through a series of causticizing tanks. These causticizers provide the residence time necessary for the lime to react with the green liquor and form white liquor. White liquor is used as the main cooking liquor in the digester. The white liquor is allowed to settle in the White Liquor Clarifier (SN-105).

The facility also has four white liquor storage tanks (SN-100) of approximately 1 million (3) and 5 million (1) gallons.

As a result of the R10 modification, SN-103, SN-105, SN-106, SN-107, SN-108, SN-109, and SN-110 underwent PSD review for VOC. BACT is defined as no controls.

Specific Conditions

138. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition is demonstrated by compliance with Specific Condition #69. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	ton/yr
55F	Lime Slaker Vent #1	PM_{10}	0.4	1.4
		VOC	0.7	2.5
		TRS	0.8	2.8
56F	Lime Slaker Vent #2	PM_{10}	0.4	1.4
		VOC	0.7	2.5
		TRS	0.8	2.8
94	Green Liquor Clarifier A	VOC	1.1	4.0
		TRS	0.1	0.1

SN	Description	Pollutant	lb/hr	ton/yr
98	"A" Side Causticizers	VOC	0.1	0.1
		TRS	0.4	1.2
99	"B" Side Causticizers	VOC	0.1	0.1
		TRS	0.4	1.2
100	White Liquor Storage Tanks (4 total)	VOC	0.2	0.6
		TRS	0.3	1.0
103	Green Liquor Clarifier B	TRS	0.1	0.1
106	Mud Washer A	TRS	0.1	0.2
107	Mud Washer B	TRS	0.1	0.2
108	Pre-Coats Filter	TRS	0.1	0.1
109	Green Liquor Stabilization Tank	TRS	0.1	0.2

139. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition is demonstrated by compliance with Specific Condition #69. [Regulation No. 19 §19.501 et seq., §19.901, and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	ton/yr
103	Green Liquor Clarifier B	VOC	0.2	0.8
105	White Liquor Clarifier	VOC	0.2	0.7
106	Mud Washer A	VOC	1.4	5.2
107	Mud Washer B	VOC	1.4	5.2
108	Pre-Coats Filter	VOC	0.1	0.2
109	Green Liquor Stabilization Tank	VOC	0.6	2.4
110	White Liquor Splitter Box	VOC	0.2	0.7

140. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition is demonstrated by compliance with Specific Condition #69. [Regulation No.§18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	ton/yr
55F	Lime Slaker Vent #1	Acetaldehyde	0.11	0.41
		Acetone	0.2	0.5
		Acrolein	0.01	0.01

SN	Description	Pollutant	lb/hr	ton/yr
		Ammonia	7.0	26.5
		Benzene	0.01	0.01
		Methanol	0.09	0.33
		Styrene	0.01	0.01
		Tetrachloroethylene	0.01	0.01
		Toluene	0.01	0.02
		1,2,4-Trichlorobenzene	0.01	0.01
		Xylene	0.01	0.01
56F	Lime Slaker Vent #2	Acetaldehyde	0.11	0.41
		Acetone	0.2	0.5
		Acrolein	0.01	0.01
		Ammonia	7.0	26.5
		Benzene	0.01	0.01
		Methanol	0.09	0.33
		Styrene	0.01	0.01
		Tetrachloroethylene	0.01	0.01
		Toluene	0.01	0.02
		1,2,4-Trichlorobenzene	0.01	0.01
		Xylene	0.01	0.01
94	Green Liquor Clarifier	Acetaldehyde	0.01	0.01
		Acetone	0.1	0.1
		Benzene	0.01	0.01
		Methanol	0.21	0.79
		Styrene	0.01	0.01
		Toluene	0.01	0.01
		Xylene	0.01	0.02
98	"A" Side Causticizers	Acetaldehyde	0.02	0.07
		Acetone	0.1	0.1
		Benzene	0.01	0.01
		Methanol	0.01	0.01
		Styrene	0.01	0.01
		Xylene	0.01	0.01
99	"B" Side Causticizers	Acetaldehyde	0.02	0.07
		Acetone	0.1	0.1
		Benzene	0.01	0.01
		Methanol	0.01	0.01
		Styrene	0.01	0.01
		Xylene	0.01	0.01
100	White Liquor Storage Tanks	Acetone	0.1	0.2
		Methanol	0.01	0.02
103	Green Liquor	Acetaldehyde*	0.01	0.01

SN	Description	Pollutant	lb/hr	ton/yr
	Clarifier B	Acetone	0.1	0.1
		Benzene*	0.01	0.01
		Methanol*	0.18	0.66
		Styrene*	0.01	0.01
		Toluene*	0.01	0.01
		Xylene*	0.01	0.02
105	White Liquor Clarifier	Acetone	0.1	0.1
		Benzene	0.01	0.01
		Formaldehyde	0.07	0.27
		Methanol	0.05	0.19
		Styrene	0.01	0.01
		Xylene	0.01	0.01
106	Mud Washer A	Acetone	0.1	0.1
		Benzene	0.01	0.01
		Formaldehyde	0.04	0.14
		Methanol	0.03	0.10
		Styrene	0.01	0.01
		Xylene	0.01	0.01
107	Mud Washer B	Acetone	0.1	0.1
		Benzene	0.01	0.01
		Formaldehyde	0.04	0.14
		Methanol	0.03	0.10
		Styrene	0.01	0.01
		Xylene	0.01	0.01
108	Pre-Coats Filter	Acetaldehyde	0.01	0.01
		Acetone	0.1	0.1
		Benzene	0.01	0.01
		Chloroform	0.01	0.01
		Methanol	0.04	0.14
		Tetrachloroethylene	0.01	0.01
		Toluene	0.01	0.01
		Xylene	0.01	0.01
109	Green Liquor Stabilization Tank	Acetaldehyde	0.04	0.14
		Acetone	0.2	0.6
		Chloroform	0.01	0.01
		Cresol	0.03	0.12
		Methanol	0.37	1.63
		Phenol	0.02	0.09
110	White Liquor Splitter Box	Acetone	0.1	0.1
		Benzene	0.01	0.01
		Formaldehyde	0.07	0.27

SN	Description	Pollutant	lb/hr	ton/yr
		Methanol	0.05	0.19
		Styrene	0.01	0.01
		Xylene	0.01	0.01

*Actual, unrounded emissions of all HAP are less than the total VOCs

SN-62 and 63
No. 1 and 2 Fine Paper Machines

Source Description

Communication paper is made on the two fine paper machines (No. 1 and 2 Fine Paper Machines). Each machine includes its own stock preparation, head box, wire section, press section, dryer sections, coater section, calendar stacks, reel and drum winder. The fine paper machines produce a variety of products, including but not limited to, bond paper, envelope, tablet and copier paper. Emissions from Fine Paper Machine No. 1 (SN-62) occur primarily from the fourdrinier vacuum pump exhausts, press section vents, dryer exhaust and coating section. Fine Paper Machine No. 2 (SN-63) is nearly identical to Fine Paper Machine No. 1.

Specific Conditions

141. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition #143. [Regulation No. 19 §19.501 et seq., §19.901, and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	ton/yr
62	Fine Paper Machine No. 1	VOC	18.6	81.3
			0.89 lb/ADTFP*	
63	Fine Paper Machine No. 2	VOC	11.3	49.3
			0.54 lb/ADTFP*	

*Air Dried Tons of Finished Paper

142. The permittee estimates the emission rates set forth in the following table will not be exceeded. The pollutant emission rates are effectively limited by Specific Condition #143. [Regulation No. §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	ton/yr
62	Fine Paper Machine No. 1	Acetaldehyde	1.20	5.23
		Acetone	0.8	4.0
		Acrolein	0.05	0.20
		Formaldehyde	0.24	1.05
		Methanol	1.20	5.23
		Methylene Chloride	0.10	0.41
		Tetrachloroethylene	0.09	0.37
		1,2,4-Trichlorobenezene	0.05	0.22
		Xylene	0.03	0.11

SN	Description	Pollutant	lb/hr	ton/yr
62	Fine Paper Machine No. 2	Acetaldehyde	1.20	5.23
		Acetone	0.8	4.0
		Acrolein	0.05	0.20
		Formaldehyde	0.24	1.05
		Methanol	1.20	5.23
		Methylene Chloride	0.10	0.41
		Tetrachloroethylene	0.09	0.37
		1,2,4-Trichlorobenezene	0.05	0.22
		Xylene	0.03	0.11

Production Limits

143. The permittee shall not produce in excess of 1050 machine dried tons of paper per day from the Fine Paper Machines No. 1 and No. 2 combined, 30 day rolling average. A conversion factor of 1.05 MDT/ ADTFP is used to account for fiber loss. [§19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

144. The permittee shall maintain records which demonstrate compliance with the paper production limits, VOC annual emission limits in tpy, and VOC BACT limits in lb/MDT listed in Specific Conditions #141 and #143. The records shall be updated on a monthly basis. These records shall be kept on site, provided to Department personnel upon request and may be used by the Department for enforcement purposes. A twelve month rolling total and each individual month's data shall be submitted in accordance with General Provision #7. [§19.705 of Regulation #19 and 40 CFR Part 52 Subpart E]

SN-64 and 65
Board Machine No. 3 and Burners

Source Description

The Board Machine No. 3 produces bleached board using the wet end, dry end and broke systems. The board is used primarily as cup stock and liner board for boxes. Emissions from Board Machine No. 3 occur primarily from the vacuum pump exhausts, press section vents, dryer exhausts, coating section and combustion sources in the coating section. Emissions from the wet end, dry end and coating operations of Board Machine No. 3 are bubbled together (SN-64). There are sixteen gas burners (SN-65) with a total heating value of 12.3 million Btu per hour located on the board machine following the coating operations.

Specific Conditions

145. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #149 and #150. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	ton/yr
65	Board Machine No. 3 Burners	PM_{10}	0.2	0.5
		SO_2	0.1	0.1
		VOC	0.1	0.4
		CO	1.3	5.5
		NO_x	1.5	6.5
		Pb	0.01	0.01

146. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #151. [Regulation No. 19 §19.501 et seq., §19.901, and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	ton/yr
64	Board Machine No. 3	VOC	10.6	46.4
			0.31 lb/ADTFP Annual Average	

*Air Dried Tons of Finished Paper

147. The permittee estimates the emission rates set forth in the following table will not be exceeded. The pollutant emission rates are effectively limited by Specific Conditions

#149 and #150. [Regulation No. §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	ton/yr
64	Board Machine No. 3	Acetaldehyde	1.95	8.51
		Acetone	1.3	5.7
		Acrolein	0.08	0.32
		Formaldehyde	0.39	1.69
		Methanol	1.95	8.51
		Methylene Chloride	0.15	0.66
		Tetrachloroethylene	0.14	0.59
		1,2,4-Trichlorobenzene	0.09	0.36
		Xylene	0.04	0.18
65	Board Machine No. 3 Burners	PM	0.2	0.5
		Arsenic	0.01	0.01
		Benzene	0.01	0.01
		Cadmium	0.01	0.01
		Cobalt	0.01	0.01
		Formaldehyde	0.01	0.01
		Hexane	0.03	0.12
		Manganese	0.01	0.01
		Mercury	0.01	0.01
		Naphthalene	0.01	0.01
		Nickel	0.01	0.01
		Toluene	0.01	0.01

Opacity

148. The permittee shall not cause to be discharged to the atmosphere from the Board Machine No. 3 Burners (SN-65) gases which exhibit opacity greater than 5%. Compliance with this opacity limit shall be the use of natural gas only. [§18.501 of Regulation #18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-11]

149. Natural gas shall be the only fuel used for the Board Machine No. 3 Burners (SN-65). [§18.1004 of Regulation #18, §19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

Production Limits

150. The permittee shall not produce in excess of 850 machine dried tons of paper per day, 30 day rolling average, from the Board Machine No. 3. A conversion factor of 1.05 MDT/ ADTFP is used to account for fiber loss. [§18.1004 of Regulation #18, §19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

151. The permittee shall maintain records which demonstrate compliance with the paper production limits, VOC annual emissions in tpy, and VOC BACT limits listed in Specific Conditions #146 and #150. The records shall be updated on a monthly basis. These records shall be kept on site, provided to Department personnel upon request and may be used by the Department for enforcement purposes. A twelve month rolling otal and each individual month's data shall be submitted in accordance with General Provision #7. [§18.1004 of Regulation #18, §19.705 of Regulation #19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Tissue Machines No. 4 through No. 8

Source Description

There are currently five tissue machines (Tissue Machines No. 4 through No. 8) at the Georgia-Pacific Crossett Paper Mill which manufacture tissue for conversion into bathroom tissue, towel, facial tissues, and napkins. In addition, the Mill also has an additional three machines that produce communications papers and bleached paperboard.

Pulp is supplied to the five tissue machines in varying proportions depending upon the desired product. The tissue papermaking process involves stock preparation, wet end - fourdrinier, press sections mix tanks and blend tanks, dry end - dryer sections with air hoods, reel and winder, and broke system finishing operations. Pulp stock is made into paper by forming a sheet on a continuously moving wire screen (the fourdrinier); removing water by gravity, vacuum and pressing, and drying with heated rolls. The water removed from the stock is called white water. The white water is collected for reuse in stock preparation or sewered as wastewater. Scrubbers control particulate from the reel sections of the No. 4 through No. 8 Tissue machines as well as the Rewinder of the No. 6 Tissue Machine.

Tissue converting includes the operations involved in converting large parent rolls of tissue from the tissue machines into finished products. This includes rewinding into smaller sized rolls, folding, printing, cutting, packaging and shipping.

Dust in the tissue converting area is controlled using filters with the exhaust air being recycled back into the building. Trim from the converting operations is sent to the repulpers by pneumatic systems. A cyclone removes the trim from the air stream prior to discharging the air through the roof. Minimal amounts of VOCs may be emitted from the glue that is used to seal boxes, the lubricants used on the machines and the dye used for printing patterns on the material.

SN-46, 66, and 67
Tissue Machine No. 4

Source Description

Emissions from the wet end and dry end of Tissue Machine No. 4 (SN-66) have been bubbled together. The Tissue Machine No. 4 Burners (SN-46) have a total heating rate of 20 million Btu per hour. Tissue Machine No. 4 Dust System (SN-67) uses a 20,000 cfm scrubber to control particulate matter emissions.

Specific Conditions

152. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #159 and #160. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	ton/yr
46	Tissue Machine No. 4 Burners	PM_{10}	0.2	0.8
		SO_2	0.1	0.1
		VOC	0.2	0.6
		CO	2.1	8.9
		NO_x	2.4	10.6
		Pb	0.01	0.01
67	Tissue Machine No. 4 Dust System	PM_{10}	0.3	1.1

153. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #160 and #161. [Regulation No. 19 §19.501 et seq., §19.901, and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	ton/yr
66	Tissue Machine No. 4	PM_{10}	0.5	2.0
			0.0646 lb/ ADTFP*	
		VOC	17.0	74.5
			2.47 lb/ADTFP* Annual Average	

*Air Dried Tons of Finished Paper

154. The permittee estimates the emission rates set forth in the following table will not be exceeded. The pollutant emission rates are effectively limited by Specific Conditions

#159 and #160. [Regulation No.§18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	ton/yr
46	Tissue Machine No. 4 Burners	Arsenic	0.01	0.01
		Benzene	0.01	0.01
		Cadmium	0.01	0.01
		Cobalt	0.01	0.01
		Formaldehyde	0.01	0.01
		Hexane	0.05	0.19
		Manganese	0.01	0.01
		Mercury	0.01	0.01
		Naphthalene	0.01	0.01
		Nickel	0.01	0.01
		Toluene	0.01	0.01
66	Tissue Machine No. 4	Acetaldehyde	0.11	0.47
		Biphenyl	0.81	3.54
		Chloroform	0.03	0.10
		Formaldehyde	0.01	0.01
		Methanol	0.05	0.19
		Methylene Chloride	0.01	0.04
		Phenol	0.18	0.76
		Propionaldehyde	0.01	0.01
		Toluene	0.03	0.10
67	Tissue Machine No. 4 Dust System	PM	0.3	1.1

Opacity

155. The permittee shall not cause to be discharged to the atmosphere from SN-46 and SN-67 gases which exhibit opacity greater than 5%. Compliance with this opacity limit shall be the use of natural gas only for SN-46. §18.501 of Regulation #18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

156. The permittee shall conduct weekly observations of the opacity at SN-67. Observations shall be conducted by personnel familiar with the permittee's visible emissions. If visible emissions in excess of the permitted opacity are detected, then a Method 9 reading is required. The permittee shall then take immediate action to identify the cause of the visible emissions, implement all necessary corrective action, and reassess the visible emissions after corrective action is taken. The permittee shall maintain records related to all observations/readings, to be updated on a weekly basis. The records shall contain the date and time of each observation/reading, the cause of any observed exceedance of opacity limits, corrective action taken, and results of the reassessment, and the name of

the person conducting the observation/reading. The records shall be kept on site and made available to Department personnel upon request. [§19.705 of Regulation 19 and 40 CFR Part 52, Subpart E]

157. The permittee shall not cause to be discharged to the atmosphere from SN-66 gases which exhibit any visible emissions exceeding 6 minutes during a 60-minute period. The permittee shall check for the presence of visible emissions from each corner of the building housing SN-66 once during each calendar week. This test will not be an EPA Method 9 test, only a yes/no check for visible emissions, and does not require that the observer be a certified visible emission reader. If visible emissions are detected for more than 6 minutes per hour, then the permittee shall determine the source of the visible emissions. Once the source is identified, the permittee shall immediately take action to identify the cause of the visible emissions, implement corrective action, and document that visible emissions did not appear following the corrective action. The permittee shall maintain log records which contain the following items in order to demonstrate compliance with this specific condition. These records shall be updated weekly, kept on site, and made available to Department personnel upon request. [§19.503 and §19.901 et seq of Regulation #19, and 40 CFR Part 52 Subpart E]

a. The date and time of the observation

b. If visible emissions were detected

c. If visible emissions were detected, the source number causing the visible emissions, the cause of the visible emissions, the corrective action taken, and whether any visible emissions appeared after the corrective action was taken.

d. The name of the person conducting the observation.

158. The permittee may, in the event of emergency maintenance on SN-67 (Tissue No. 4 Dust System), shut down the dust collection system and contain the tissue dust within the building during the continued operation of the paper machine. Good housekeeping practices shall be used to control tissue dust and prevent visible emissions to the atmosphere. In the event that repairs on a scrubber extend beyond 12 hours, then a 6 minute observation for visible emissions shall be conducted once per 12 hour shift. The observation shall be a yes/no check and shall be conducted at the outside corners of the affected Tissue Machine building. If visible tissue dust emissions are detected for more than 6 minutes per hour, then corrective action shall be taken to reduce emissions and document that visible emissions do not appear after corrective action is taken. [§19.303 of Regulation #19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Fuel Requirements

159. Natural gas shall be the only fuel used for Tissue Machine No. 4 Burners (SN-46). [§18.1004 of Regulation #18, §19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

Production Limits

160. The permittee shall not produce in excess of 173 machine dried tons of paper per day, 30 day rolling average, from the Tissue Machine No. 4. A conversion factor of 1.05 MDT/ ADTFP is used to account for fiber loss. [§18.1004 of Regulation #18, §19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

161. The permittee shall maintain records which demonstrate compliance with the paper production limits, VOC annual emission, and VOC BACT limits listed in Specific Conditions #153 and #160. The records shall be updated on a monthly basis. These records shall be kept on site, provided to Department personnel upon request and may be used by the Department for enforcement purposes. A twelve month rolling total and each individual month's data shall be submitted in accordance with General Provision #7. [§18.1004 of Regulation #18, §19.705 of Regulation #19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Scrubber Monitoring

162. The scrubber shall be kept in good working condition at all times and shall meet the conditions shown in the following table. The scrubber liquid flow rate shall be measured daily. The results shall be kept on site and be available to Department personnel upon request. [§18.1104 of Regulation #18, §19.303 of Regulation #19, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4 311]

SN	Control Equipment	Parameter	Units	Minimum Operating Limits
67	scrubber	liquid flow rate	gal/min	70

SN-47, 54, and 68
Tissue Machine No. 5

Source Description

Emissions from the wet end and dry end of Tissue Machine No. 5 (SN-68) have been bubbled together. The Tissue Machine No. 5 Burners (SN-47) are rated at 21 million Btu per hour. The burners are low NO_X burners. The Tissue Machine No. 5 Dust System (SN-54) uses a 20,000 cfm scrubber to control particulate matter emissions. The No. 5 Tissue Machine Burners (SN-47) underwent a BACT review in Air Permit 597-AOP-R0. Clean fuel, good combustion practice, and low NO_x burners were chosen as BACT at the time.

Specific Conditions

163. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition #170 and #171. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	ton/yr
47	Tissue Machine No. 5 Burners	Pb	0.01	0.01
54	Tissue Machine No. 5 Dust System	PM_{10}	0.3	1.1

164. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #170, #171. [§19.501 et seq. and §19.901 of Regulation #19, and 40 CFR Part 52 Subpart E]

SN	Description	Pollutant	lb/hr	ton/yr
47	Tissue Machine No. 5 Burners	PM	0.4	1.5
		PM_{10}	0.0164 lb/MMBtu	
		SO_2	0.1	0.1
			0.0007 lb/MMBtu	
		VOC	1.2	5.2
			0.0564 lb/MMBtu	
		CO	4.5	19.7
			0.2142 lb/MMBtu	
		NO_X	2.0	8.4

SN	Description	Pollutant	lb/hr	ton/yr
			0.0913 lb/MMBtu	
68	Tissue Machine No. 5	PM PM_{10}	0.3	1.1
			0.0646 lb/ ADTFP*	
		VOC	13.0	57.0
			3.37 lb/ ADTFP* Annual Average	

*Air Dried Tons of Finished Paper

165. The permittee estimates the emission rates set forth in the following table will not be exceeded. The pollutant emission rates are effectively limited by Specific Conditions #170 and #171. [Regulation No.§18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	ton/yr
47	Tissue Machine No. 5 Burners	Arsenic	0.01	0.01
		Benzene	0.01	0.01
		Cadmium	0.01	0.01
		Cobalt	0.01	0.01
		Formaldehyde	0.01	0.01
		Hexane	0.05	0.20
		Manganese	0.01	0.01
		Mercury	0.01	0.01
		Naphthalene	0.01	0.01
		Nickel	0.01	0.01
		Toluene	0.01	0.01
54	Tissue Machine No. 5 Dust System	PM	0.3	1.1
68	Tissue Machine No. 5	Acetaldehyde	0.07	0.27
		Biphenyl	0.46	1.99
		Chloroform	0.02	0.06
		Formaldehyde	0.01	0.01
		Methanol	0.03	0.11
		Methylene Chloride	0.01	0.03
		Phenol	0.10	0.43
		Propionaldehyde	0.01	0.01
		Toluene	0.02	0.06

Opacity

166. The permittee shall not cause to be discharged to the atmosphere from SN-47 and SN-54 gases which exhibit opacity greater than 5%. Compliance with this opacity limit shall be the use of natural gas only at SN-47. [§18.501 of Regulation #18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

167. The permittee shall conduct weekly observations of the opacity at SN-54. Observations shall be conducted by personnel familiar with the permittee's visible emissions. If visible emissions in excess of the permitted opacity are detected, then a Method 9 reading is required. The permittee shall then take immediate action to identify the cause of the visible emissions, implement all necessary corrective action, and reassess the visible emissions after corrective action is taken. The permittee shall maintain records related to all observations/readings, to be updated on a weekly basis. The records shall contain the date and time of each observation/reading, the cause of any observed exceedance of opacity limits, corrective action taken, and results of the reassessment, and the name of the person conducting the observation/reading. The records shall be kept on site and made available to Department personnel upon request. [§19.705 of Regulation 19 and 40 CFR Part 52, Subpart E]

168. The permittee shall not cause to be discharged to the atmosphere from SN-68 gases which exhibit any visible emissions exceeding 6 minutes during a 60-minute period. The permittee shall check for the presence of visible emissions from each corner of the building housing SN-68 once during each calendar week. This test will not be an EPA Method 9 test, only a yes/no check for visible emissions, and does not require that the observer be a certified visible emission reader. If visible emissions are detected for more than 6 minutes per hour, then the permittee shall determine the source of the visible emissions. Once the source is identified, the permittee shall immediately take action to identify the cause of the visible emissions, implement corrective action, and document that visible emissions did not appear following the corrective action. The permittee shall maintain log records which contain the following items in order to demonstrate compliance with this specific condition. These records shall be updated weekly, kept on site, and made available to Department personnel upon request. [§19.503 and §19.901 et seq of Regulation #19, and 40 CFR Part 52 Subpart E]

a. The date and time of the observation

b. If visible emissions were detected

c. If visible emissions were detected, the source number causing the visible emissions, the cause of the visible emissions, the corrective action taken, and whether any visible emissions appeared after the corrective action was taken.

d. The name of the person conducting the observation.

169. The permittee may, in the event of emergency maintenance on SN-54, shut down the dust collection system and contain the tissue dust within the building during the continued operation of the paper machine. Good housekeeping practices shall be used to control tissue dust and prevent visible emissions to the atmosphere. In the event that repairs on a scrubber extend beyond 12 hours, then a 6 minute observation for visible emissions shall be conducted once per 12 hour shift. The observation shall be a yes/no check and shall be conducted at the outside corners of the affected Tissue Machine building. If visible tissue dust emissions are detected for more than 6 minutes per hour, then corrective action shall be taken to reduce emissions and document that visible emissions do not appear after corrective action is taken. [§19.303 of Regulation #19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Fuel Requirements

170. Natural gas shall be the only fuel used for the Tissue Machine No. 5 Burners (SN-47). [§19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

Production Limits

171. The permittee shall not produce in excess of 97 machine dried tons of paper per day, 30 day rolling average, from the Tissue Machine No. 5. A conversion factor of 1.05 MDT/ADTFP is used to account for fiber loss. [§18.1004 of Regulation #18, §19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

172. The permittee shall maintain records which demonstrate compliance with the paper production limits, paper machine VOC annual emission, and paper machine VOC BACT limits listed in Specific Conditions #168 and #171. The records shall be updated on a monthly basis. These records shall be kept on site, provided to Department personnel upon request and may be used by the Department for enforcement purposes. A twelve month rolling total and each individual month's data shall be submitted in accordance with General Provision #7. [§18.1004 of Regulation #18, §19.705 of Regulation #19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Scrubber Monitoring

173. The scrubber shall be kept in good working condition at all times and shall meet the conditions shown in the following table. The scrubber liquid flow rate and the gas pressure drop across the unit shall be measured daily. The results shall be kept on site and be available to the Department personnel upon request. [§18.1104 of Regulation #18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Control Equipment	Parameter	Units	Minimum Operating Limits
54	scrubber	liquid flow rate	gal/min	70
		gas pressure drop across unit	inches, H_20	8

Testing Requirements

174. The permittee shall test SN-47 for CO and NO_X to verify compliance with the BACT emission limits specified in Specific Condition #168 every five years. Testing shall be performed in accordance with Plantwide Condition #3. Testing for CO and NO_X shall also be performed in accordance with EPA Reference Methods 10 and 7E respectively. During the test the permittee shall operate the source within 10 percent of the rated throughput capacity. If 90 percent of the rated throughout capacity cannot be achieved, the permittee shall be limited to 10 percent above the actual tested throughput. The permittee shall reference this limitation in any compliance reports submitted to the Department. [§19.702 and §19.901 et seq of Regulation #19, and 40 CFR Part 52 Subpart E]

SN-48, 51, 52, and 69
Tissue Machine No. 6

Source Description

Emissions from the wet end and dry end of Tissue Machine No. 6 (SN-69) have been bubbled together. The Tissue Machine No. 6 Burners (SN-48) are rated at 41.0 million Btu per hour. The burners are low NO_X burners. Tissue Machine No. 6 Dust System (SN-52) uses a 47,000 cfm scrubber to control particulate matter emissions. A 47,000 cfm scrubber is used to control particulate emissions from the Rewinder (SN-51) near Tissue Machine No. 6. The No. 6 Tissue Machine Burners (SN-48) underwent a BACT review in Air Permit 597-AOP-R0. Clean fuel, good combustion practice, and low NO_x burners were chosen as BACT at the time.

The R11 modification was for the replacement of the No. 6 Tissue Machine Burners (SN-48). The facility replaced the existing Hauck burners with Maxon burners rated at 20.5 MMBTU/hr each. BACT limits for particulate and VOC decreased. The source will continue to meet the CO, NO_x, and SO_2 limits.

Specific Conditions

175. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #183 and #190. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	ton/yr
48	Tissue Machine No. 6 Burners (41 MMBtu/hr)	Pb	0.01	0.01
51	Tissue Machine No. 6 Rewinder	PM_{10}	0.5	1.9
52	Tissue Machine No. 6 Dust System	PM_{10}	0.5	1.9

176. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #189. [§19.501 et seq. and §19.901 of Regulation #19, and 40 CFR Part 52 Subpart E]

SN	Description	Pollutant	lb/hr	ton/yr
48	Tissue Machine No. 6 Burners (41 MMBtu/hr)	PM PM_{10}	0.4	1.8
			0.00912 lb/MMBtu	
		SO_2	0.1	0.2
			0.0007 lb/MMBtu	
		VOC	0.3	1.4
			0.0066 lb/MMBtu	
		CO	4.7	20.6
			0.1139 lb/MMBtu	
		NO_X	3.8	16.7
			0.0913 lb/MMBtu	
69	Tissue Machine No. 6	PM_{10} PM	0.7	3.1
			0.0646 lb/ ADTFP*	
		VOC	26.7	116.6
			2.48 lb/ ADTFP*	

*Air Dried Tons of Finished Paper

177. The permittee estimates the emission rates set forth in the following table will not be exceeded. The pollutant emission rates are effectively limited by Specific Conditions #188 and #190. [Regulation No.§18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	ton/yr
48	Tissue Machine No. 6 Burners	Arsenic	0.01	0.01
		Benzene	0.01	0.01
		Cadmium	0.01	0.01
		Cobalt	0.01	0.01
		Formaldehyde	0.01	0.02
		Hexane	0.09	0.39
		Manganese	0.01	0.01
		Mercury	0.01	0.01
		Naphthalene	0.01	0.01
		Nickel	0.01	0.01
		Toluene	0.01	0.01
51	Tissue Machine No. 6 Rewinder	PM	0.5	1.9

SN	Description	Pollutant	lb/hr	ton/yr
52	Tissue Machine No. 6 Dust System	PM	0.5	1.9
69	Tissue Machine No. 6	Acetaldehyde	0.17	0.74
		Biphenyl	1.26	5.52
		Chloroform	0.04	0.15
		Formaldehyde	0.01	0.01
		Methanol	0.07	0.29
		Methylene Chloride	0.02	0.08
		Phenol	0.27	1.19
		Propionaldehyde	0.01	0.01
		Toluene	0.04	0.15

Opacity

178. The permittee shall not cause to be discharged to the atmosphere from SN-48, SN-51, and SN-52 gases which exhibit opacity greater than 5%. Compliance with this opacity limit shall be the use of natural gas only at SN-48. [§18.501 of Regulation #18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

179. The permittee shall conduct weekly observations of the opacity at SN-51 and 52. Observations shall be conducted by personnel familiar with the permittee's visible emissions. If visible emissions in excess of the permitted opacity are detected, then a Method 9 reading is required. The permittee shall then take immediate action to identify the cause of the visible emissions, implement all necessary corrective action, and reassess the visible emissions after corrective action is taken. The permittee shall maintain records related to all observations/readings, to be updated on a weekly basis. The records shall contain the date and time of each observation/reading, the cause of any observed exceedance of opacity limits, corrective action taken, and results of the reassessment, and the name of the person conducting the observation/reading. The records shall be kept on site and made available to Department personnel upon request. [§19.705 of Regulation 19 and 40 CFR Part 52, Subpart E]

180. The permittee shall not cause to be discharged to the atmosphere from SN-69 gases which exhibit any visible emissions exceeding 6 minutes during a 60-minute period. The permittee shall check for the presence of visible emissions from each corner of the building housing SN-69 once during each calendar week. This test will not be an EPA Method 9 test, only a yes/no check for visible emissions, and does not require that the observer be a certified visible emission reader. If visible emissions are detected for more than 6 minutes per hour, then the permittee shall determine the source of the visible emissions. Once the source is identified, the permittee shall immediately take action to identify the cause of the visible emissions, implement corrective action, and document that visible emissions did not appear following the corrective action. The permittee shall

maintain log records which contain the following items in order to demonstrate compliance with this specific condition. These records shall be updated weekly, kept on site, and made available to Department personnel upon request. [§19.503 and §19.901 et seq of Regulation #19, and 40 CFR Part 52 Subpart E]

a. The date and time of the observation.

b. If visible emissions were detected.

c. If visible emissions were detected, the source number causing the visible emissions, the cause of the visible emissions, the corrective action taken, and whether any visible emissions appeared after the corrective action was taken.

d. The name of the person conducting the observation.

Scrubber Monitoring

181. The permittee shall keep the scrubber on SN-52 in good working condition at all times and shall meet the conditions shown in the following table. The scrubber liquid flow rate and the gas pressure drop across the unit shall be measured daily. The results shall be kept on site and be available to the Department personnel upon request. [§18.1104 of Regulation #18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Control Equipment	Parameter	Units	Minimum Operating Limits
52	scrubber	liquid flow rate	gal/min	300
		gas pressure drop across unit	inches, H_20	8

182. The permittee may, in the event of emergency maintenance on SN-52, shut down the dust collection system and contain the tissue dust within the building during the continued operation of the paper machine. Good housekeeping practices shall be used to control tissue dust and prevent visible emissions to the atmosphere. In the event that repairs on a scrubber extend beyond 12 hours, then a 6 minute observation for visible emissions shall be conducted once per 12 hour shift. The observation shall be a yes/no check and shall be conducted at the outside corners of the affected Tissue Machine building. If visible tissue dust emissions are detected for more than 6 minutes per hour, then corrective action shall be taken to reduce emissions and document that visible emissions do not appear after corrective action is taken. [§19.303 of Regulation #19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Fuel Requirements

183. Natural gas shall be the only fuel used for the Tissue Machine No. 6 Burners (SN-48). [§19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

Production Limits

184. The permittee shall not produce in excess of 270 machine dried tons of paper per day, 30 day rolling average, from the Tissue Machine No. 6. A conversion factor of 1.05 MDT/ ADTFP is used to account for fiber loss. [§18.1004 of Regulation #18, §19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, and 40 CFR §70.6]

185. The permittee shall maintain records which demonstrate compliance with the paper production limits, the paper machine VOC annual emissions, and the paper machine VOC BACT limits Specific Condition #176 and #184. The records shall be updated on a monthly basis. These records shall be kept on site, provided to Department personnel upon request and may be used by the Department for enforcement purposes. A twelve month rolling total and each individual month's data shall be submitted in accordance with General Provision #7. [§18.1004 of Regulation #18, §19.705 of Regulation #19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Testing Requirements

186. The permittee shall test SN-48 for CO and NO_X to verify compliance with the BACT emission limits specified in Specific Condition #180 every five years thereafter. Testing shall be performed in accordance with Plantwide Condition #3. Testing for CO and NO_X shall also be performed in accordance with EPA Reference Methods 10 and 7E respectively. During the test the permittee shall operate the source within 10 percent of the rated throughput capacity. If 90 percent of the rated throughout capacity cannot be achieved, the permittee shall be limited to 10 percent above the actual tested throughput. The permittee shall reference this limitation in any compliance reports submitted to the Department. [§19.702 and §19.901 of Regulation #19, and 40 CFR Part 52 Subpart E]

SN-49, 50, and 70
Tissue Machine No. 7

Emissions from the wet end and dry end of Tissue Machine No. 7 (SN-70) have been bubbled together. The Tissue Machine No. 7 Burners (SN-49) combust natural gas at a total heating rate of 41 million Btu per hour. The burners are low NO_X burners. Tissue Machine No. 7 Dust System (SN-50) uses a 44,000 cfm scrubber to control particulate matter emissions.

187. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #197 and #198. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	ton/yr
49	Tissue Machine No. 7 Burners	PM_{10}	0.4	1.7
		SO_2	0.1	0.2
		VOC	0.3	1.2
		CO	4.2	18.2
		NO_x	2.5	10.8
		Pb	0.01	0.01
50	Tissue Machine No. 7 Dust System	PM_{10}	0.5	2.1

188. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition #198. [§19.501 et seq. and §19.901 of Regulation #19, and 40 CFR Part 52 Subpart E]

<table>
<tr><th>SN</th><th>Description</th><th>Pollutant</th><th>lb/hr</th><th>ton/yr</th></tr>
<tr><td rowspan="4">70</td><td rowspan="4">Tissue Machine No. 7</td><td rowspan="2">PM_{10}
PM</td><td>0.7</td><td>2.9</td></tr>
<tr><td colspan="2">0.0646 lb/ ADTFP*</td></tr>
<tr><td rowspan="2">VOC</td><td>17.7</td><td>77.4</td></tr>
<tr><td colspan="2">1.78 lb/ ADTFP*
Annual Average</td></tr>
</table>

*Air Dried Tons of Finished Paper

189. The permittee estimates the emission rates set forth in the following table will not be exceeded. The pollutant emission rates are effectively limited by Specific Conditions #197 and #198. [Regulation No.§18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	ton/yr
49	Tissue Machine No. 7 Burners	PM	0.4	1.7
		Arsenic	0.01	0.01
		Benzene	0.01	0.01
		Cadmium	0.01	0.01
		Cobalt	0.01	0.01
		Formaldehyde	0.01	0.02
		Hexane	0.09	0.39
		Manganese	0.01	0.01
		Mercury	0.01	0.01
		Naphthalene	0.01	0.01
		Nickel	0.01	0.01
		Toluene	0.01	0.01
50	Tissue Machine No. 7 Dust System	PM	0.5	2.1
70	Tissue Machine No. 7	Acetaldehyde	0.16	0.68
		Biphenyl	1.17	5.11
		Chloroform	0.04	0.14
		Formaldehyde	0.01	0.01
		Methanol	0.07	0.27
		Methylene Chloride	0.02	0.06
		Phenol	0.25	1.10
		Propionaldehyde	0.01	0.01
		Toluene	0.04	0.14

Opacity

190. The permittee shall not cause to be discharged to the atmosphere from SN-49 and SN-50 gases which exhibit opacity greater than 5%. Compliance with this opacity limit shall be the use of natural gas only at SN-49. [§18.501 of Regulation #18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

191. The permittee shall conduct weekly observations of the opacity at SN-50. Observations shall be conducted by personnel familiar with the permittee's visible emissions. If visible emissions in excess of the permitted opacity are detected, then a Method 9 reading is required. The permittee shall then take immediate action to identify the cause of the visible emissions, implement all necessary corrective action, and reassess the visible emissions after corrective action is taken. The permittee shall maintain records related to all observations/readings, to be updated on a weekly basis. The records shall contain the date and time of each observation/reading, the cause of any observed exceedance of opacity limits, corrective action taken, and results of the reassessment, and the name of the person conducting the observation/reading. The records shall be kept on site and

made available to Department personnel upon request. [§19.705 of Regulation 19 and 40 CFR Part 52, Subpart E]

192. The permittee shall not cause to be discharged to the atmosphere from SN-70 gases which exhibit any visible emissions exceeding 6 minutes during a 60-minute period. The permittee shall check for the presence of visible emissions from each corner of the building housing SN-70 once during each calendar week. This test will not be an EPA Method 9 test, only a yes/no check for visible emissions, and does not require that the observer be a certified visible emission reader. If visible emissions are detected for more than 6 minutes per hour, then the permittee shall determine the source of the visible emissions. Once the source is identified, the permittee shall immediately take action to identify the cause of the visible emissions, implement corrective action, and document that visible emissions did not appear following the corrective action. The permittee shall maintain log records which contain the following items in order to demonstrate compliance with this specific condition. These records shall be updated weekly, kept on site, and made available to Department personnel upon request. [§19.503 and §19.901 et seq of Regulation #19, and 40 CFR Part 52 Subpart E]

a. The date and time of the observation.

b. If visible emissions were detected.

c. If visible emissions were detected, the source number causing the visible emissions, the cause of the visible emissions, the corrective action taken, and whether any visible emissions appeared after the corrective action was taken.

d. The name of the person conducting the observation.

193. The permittee may, in the event of emergency maintenance on SN-50, shut down the dust collection system and contain the tissue dust within the building during the continued operation of the paper machine. Good housekeeping practices shall be used to control tissue dust and prevent visible emissions to the atmosphere. In the event that repairs on a scrubber extend beyond 12 hours, then a 6 minute observation for visible emissions shall be conducted once per 12 hour shift. The observation shall be a yes/no check and shall be conducted at the outside corners of the affected Tissue Machine building. If visible tissue dust emissions are detected for more than 6 minutes per hour, then corrective action shall be taken to reduce emissions and document that visible emissions do not appear after corrective action is taken. [§19.303 of Regulation #19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Fuel Requirements

194. Natural gas shall be the only fuel used for Tissue Machine No. 7 Burners (SN-49). [§18.1004 of Regulation #18, §19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

Production Limits

195. The permittee shall not produce in excess of 250 machine dried tons of paper per day, 30 day rolling average, from the Tissue Machine No. 7. A conversion factor of 1.05 MDT/ADTFP is used to account for fiber loss. [§18.1004 of Regulation #18, §19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

196. The permittee shall maintain records which demonstrate compliance with the paper production limits, the VOC annual emissions, and the VOC BACT limits Specific Condition #188 and #195. The records shall be updated on a monthly basis. These records shall be kept on site, provided to Department personnel upon request and may be used by the Department for enforcement purposes. A twelve month rolling total and each individual month's data shall be submitted in accordance with General Provision #7. [§18.1004 of Regulation #18, §19.705 of Regulation #19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

CAM

197. The Tissue Machine No. 7 Dust System (SN-50) is subject to and shall comply with all applicable provisions of §19.304 of Regulation 19, 40 CFR Part 52 Subpart E, and Part §64.6 for Compliance Assurance Monitoring. Post control of particulate emissions from SN-50 is below major source levels.

    a. The permittee shall maintain a scrubber liquid flow rate of at least 300 gallons per minute. [40 CFR Part §64.6(c)(1)]

    b. The permittee shall monitor and maintain daily records to demonstrate compliance with Specific Condition #197 (A). Records shall be kept onsite and made available to the Department upon request. [40 CFR Part §64.6(c)(3)]

    c. The permittee shall maintain the scrubber in good working condition at all times so that pollutant removal is maintained. [40 CFR Part §64.6(c)(1)]

198. The Tissue Machine No. 7 Dust System (SN-50) is subject to and shall comply with all applicable provisions §19.304 of Regulation 19, 40 CFR Part 52 Subpart E, and Part §64.6 for Compliance Assurance Monitoring. The following information pertaining to exceedances or excursions from permitted values shall be submitted in semi-annual reports in accordance with General Provision #7 as outlined in 40 CFR §70.6.

    a. The permittee shall maintain records for SN-50 that summarizes the number, duration, and cause of excursions or exceedances of emission limits as well as corrective action taken. [40 CFR §64.9(a)(2)(i) and §64.9(b)]

b. The permittee shall maintain records for SN-50 that summarizes the number, duration, and cause of monitoring equipment downtime incidents, other than routine downtime for calibration checks. [40 CFR §64.9(a)(2)(ii) and §64.9(b)]

c. The permittee shall maintain a quality improvement plan (QIP) threshold for each indicator of no more than nine excursions or 5% of the daily averages in a six-month period. [40 CFR §64.9(a)(2)(iii) and §64.9(b)]

d. The permittee shall develop and implement a new QIP if the threshold is exceeded during any six-month period. [40 CFR §64.9(a)(2)(iii) and §64.9(b)]

e. The permittee shall maintain records for SN-50 that describes the actions taken to implement the QIP. Upon completion of the QIP, documentation shall be maintained to confirm that the plan was completed and reduced the likelihood of similar excursions or exceedances. [40 CFR §64.9(a)(2)(iii) and §64.9(b)]

SN-79, 80, and 81
Tissue Machine No. 8

Source Description

The Tissue Machine No. 8 Burners (SN-79) combusts natural gas at a total heating rate of 50 million Btu per hour. The burners are low NO_X burners. Tissue Machine No. 8 Dust System (SN-81) is equipped with a 58,000 cfm wet venturi scrubber dust system to control particulate matter emissions.

The No. 8 Tissue Machine (SN-80) and associate equipment was subjected to a BACT review in Air Permit 597-AOP-R0. Clean fuel, good combustion practice, and low NO_x burners were chosen as BACT for the burners. For particulate control on the dust system, a wet scrubber was determined as BACT.

The proposed project, which is expected to improve production efficiency and allow for an increase in the paper machine design capacity. There will not be any changes made to the existing Yankee Dryer section of the tissue machine or the Yankee Dryer burners as part of this project. The changes will include replacement of the paper machine press section on the existing tissue machine to allow for more energy efficient drying and replacement of the dry end dust collection equipment on the existing tissue machine, including a new wet venturi scrubber rated at 58,000 dry standard cubic feet per minute (dscfm). This new dust collection equipment will replace the existing wet venturi scrubber (SN-81, rated at 55,000 dscfm) and will be used to reduce particulate matter emissions from the dry end of the paper machine and wind-up reel.

Specific Conditions

199. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition #206. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	ton/yr
79	Tissue Machine No. 8 Burners	Pb	0.01	0.01

200. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #206, #207, and #208. [§19.501 et seq. and §19.901 of Regulation #19, and 40 CFR Part 52 Subpart E]

SN	Description	Pollutant	lb/hr	ton/yr
79		PM/ PM_{10}	0.9	3.6
			0.0164 lb/MMBtu	

SN	Description	Pollutant	lb/hr	ton/yr
	Tissue Machine No. 8 Burners (50 MMBtu/hr)	SO_2	0.1	0.2
			0.0007 lb/MMBtu	
		VOC	1.0	4.2
			0.0192 lb/MMBtu	
		CO	5.7	24.9
			0.1139 lb/MMBtu	
		NO_X	4.6	20.0
			0.0913 lb/MMBtu	
80	Tissue Machine No. 8	PM/ PM_{10}	0.8	3.2
			0.0646 lb/ ADTFP*	
		VOC	13.6	59.6
			1.29 lb/MDT Annual Average	
81	Tissue Machine No. 8 Dust System	PM/ PM_{10}	1.8	7.7
			0.0035 gr/dscf	

201. The permittee estimates the emission rates set forth in the following table will not be exceeded. The pollutant emission rates are effectively limited by Specific Condition #206 and #207. [Regulation No.§18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	ton/yr
79	Tissue Machine No. 8 Burners	Arsenic	0.01	0.01
		Benzene	0.01	0.01
		Cadmium	0.01	0.01
		Cobalt	0.01	0.01
		Formaldehyde	0.01	0.02
		Hexane	0.11	0.48
		Manganese	0.01	0.01
		Mercury	0.01	0.01
		Naphthalene	0.01	0.01
		Nickel	0.01	0.01
		Toluene	0.01	0.01
80	Tissue Machine No. 8	Acetaldehyde	0.36	1.54
		Acetone	0.2	0.8
		Acrolein	0.03	0.10
		Benzene	0.01	0.02
		Carbon Disulfide	0.01	0.05
		Chloroform	0.01	0.01
		Formaldehyde	0.06	0.25
		Hexane	0.01	0.02

SN	Description	Pollutant	lb/hr	ton/yr
		Methanol	0.45	1.91
		Methylene Chloride	0.03	0.11
		Naphthalene	0.01	0.03
		Phenol	0.10	0.44
		Propionaldehyde	0.10	0.44
		Styrene	0.01	0.02
		Tetrachloroethylene	0.01	0.04
		Toluene	0.01	0.01
		1,2,4 Trichlorobenzene	0.03	0.11
		Xylene	0.04	0.14

Opacity

202. The permittee shall not cause to be discharged to the atmosphere from SN-79 and SN-81 gases which exhibit opacity greater than 5%. Compliance with this opacity limit shall be the use of natural gas only at SN-79. [§19.503 and §19.901 of Regulation #19, and 40 CFR Part 52 Subpart E]

203. The permittee shall conduct weekly observations of the opacity at SN-81. Observations shall be conducted by personnel familiar with the permittee's visible emissions. If visible emissions excess of the permitted opacity are detected, then a Method 9 reading is required. The permittee shall then take immediate action to identify the cause of the visible emissions, implement all necessary corrective action, and reassess the visible emissions after corrective action is taken. The permittee shall maintain records related to all observations/readings, to be updated on a weekly basis. The records shall contain the date and time of each observation/reading, the cause of any observed exceedance of opacity limits, corrective action taken, and results of the reassessment, and the name of the person conducting the observation/reading. The records shall be kept on site and made available to Department personnel upon request. [§19.705 of Regulation 19 and 40 CFR Part 52, Subpart E]

204. The permittee shall not cause to be discharged to the atmosphere from SN-80 gases which exhibit any visible emissions exceeding 6 minutes during a 60-minute period. The permittee shall check for the presence of visible emissions from each corner of the building housing SN-80 once during each calendar week. This test will not be an EPA Method 9 test, only a yes/no check for visible emissions, and does not require that the observer be a certified visible emission reader. If visible emissions are detected for more than 6 minutes per hour, then the permittee shall determine the source of the visible emissions. Once the source is identified, the permittee shall immediately take action to identify the cause of the visible emissions, implement corrective action, and document that visible emissions did not appear following the corrective action. The permittee shall maintain log records which contain the following items in order to demonstrate compliance with this specific condition. These records shall be updated weekly, kept on

site, and made available to Department personnel upon request. [§19.503 and §19.901 et seq of Regulation #19, and 40 CFR Part 52 Subpart E]

a. The date and time of the observation

b. If visible emissions were detected

c. If visible emissions were detected, the source number causing the visible emissions, the cause of the visible emissions, the corrective action taken, and whether any visible emissions appeared after the corrective action was taken.

d. The name of the person conducting the observation.

205. The permittee may, in the event of emergency maintenance on SN-81, shut down the dust collection system and contain the tissue dust within the building during the continued operation of the paper machine. Good housekeeping practices shall be used to control tissue dust and prevent visible emissions to the atmosphere. In the event that repairs on a scrubber extend beyond 12 hours, then a 6 minute observation for visible emissions shall be conducted once per 12 hour shift. The observation shall be a yes/no check and shall be conducted at the outside corners of the affected Tissue Machine building. If visible tissue dust emissions are detected for more than 6 minutes per hour, then corrective action shall be taken to reduce emissions and document that visible emissions do not appear after corrective action is taken. [§19.303 of Regulation #19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Fuel Requirements

206. Natural gas shall be the only fuel used for Tissue Machine No. 8 Burners (SN-79). [§19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

Production Limits

207. The permittee shall not produce in excess the machine dried tons of paper per day, 30 day rolling average, from the Tissue Machine No. 8 as represented in the January 2011 confidential application submitted Department. [18.1004 of Regulation #18, §19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

208. The permittee shall maintain records which demonstrate compliance with the paper production limits, the paper machine VOC annual emissions, and the paper machine VOC BACT limits listed in Specific Conditions #200 and #207. The records shall be updated on a monthly basis. These records shall be kept on site, provided to Department personnel upon request and may be used by the Department for enforcement purposes. For VOC annual emissions and the paper machine VOC BACT limit, a twelve month

rolling total and each individual month's data shall be submitted in accordance with General Provision #7. [§18.1004 of Regulation #18, §19.705 of Regulation #19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

CAM

209. The Tissue Machine No. 8 Dust System (SN-81) is subject to and shall comply with all applicable provisions of §19.304 of Regulation 19, 40 CFR Part 52 Subpart E, and Part §64.6 for Compliance Assurance Monitoring. Post control of particulate emissions from SN-81 is below major source levels.

   a. The permittee shall maintain a scrubber liquid pressure of at least 8 inches of water. [40 CFR Part §64.6(c)(1)]
   b. The permittee shall monitor and maintain daily records to demonstrate compliance with Specific Condition #209(A). Records shall be kept onsite and made available to the Department upon request. [40 CFR Part §64.6(c)(3)]

   c. The permittee shall maintain the scrubber in good working condition at all times so that pollutant removal is maintained. [40 CFR Part §64.6(c)(1)]

210. The Tissue Machine No. 8 Dust System (SN-81) is subject to and shall comply with all applicable provisions of §19.304 of Regulation 19, 40 CFR Part 52 Subpart E, and Part §64.6 for Compliance Assurance Monitoring. The following information pertaining to exceedances or excursions from permitted values shall be submitted in semi-annual reports in accordance with General Provision 7 as outlined in 40 CFR §70.6.

   a. The permittee shall maintain records for SN-81 that summarizes the number, duration, and cause of excursions or exceedances of emission limits as well as corrective action taken. [40 CFR §64.9(a)(2)(i) and §64.9(b)]

   b. The permittee shall maintain records for SN-81 that summarizes the number, duration, and cause of monitoring equipment downtime incidents, other than routine downtime for calibration checks. [40 CFR §64.9(a)(2)(ii) and §64.9(b)]

   c. The permittee shall maintain a quality improvement plan (QIP) threshold for each indicator of no more than nine excursions or 5% of the daily averages in a six-month period. [40 CFR §64.9(a)(2)(iii) and §64.9(b)]

   d. The permittee shall develop and implement a new QIP if the threshold is exceeded during any six-month period. [40 CFR §64.9(a)(2)(iii) and §64.9(b)]

   e. The permittee shall maintain records for SN-81 that describes the actions taken to implement the QIP. Upon completion of the QIP, documentation shall be maintained to confirm that the plan was completed and reduced the likelihood of similar excursions or exceedances. [40 CFR §64.9(a)(2)(iii) and §64.9(b)]

Testing Requirements

211. The permittee shall test SN-79 for CO and NO_X to verify compliance with the BACT emission limits specified in Specific Condition #200 every five years. Testing for CO and NO_X shall be performed in accordance with Plantwide Condition #3 and EPA Reference Methods 10 and 7E respectively. During the test the permittee shall operate the source within 10 percent of the rated throughput capacity. If 90 percent of the rated throughout capacity cannot be achieved, the permittee shall be limited to 10 percent above the actual tested throughput. The permittee shall reference this limitation in any compliance reports submitted to the Department. [§19.702 and §19.901 et seq of Regulation #19, and 40 CFR Part 52 Subpart E]

212. The permittee shall test SN-81 for PM/PM_{10} to verify compliance with the BACT emission limit specified in Specific Conditions #200 every five years. Testing shall be performed in accordance with Plantwide Condition #3 and EPA Reference Method 5 with inclusion of back half sampling train particulate. The permittee shall test at the minimum scrubber parameters of Specific Condition 209. During the test the permittee shall operate the source within 10 percent of the rated throughput capacity. If 90 percent of the rated throughout capacity cannot be achieved, the permittee shall be limited to 10 percent above the actual tested throughput. The permittee shall reference this limitation in any compliance reports submitted to the Department. [§19.702 and §19.901 et seq of Regulation #19, and 40 CFR Part 52 Subpart E]

SN-71 and 72
No. 8 and No. 9 Extruder Machines

Source Description

The extrusion plant includes the No. 8 and No. 9 extruder machines which polycoat board. The extrusion plant receives board from the board machine and outside board customers and applies a polymer coating. Rolls of board are loaded onto an unwind stand. The board passes through a calender stack and is subjected to a burner which flame seals the board. An extruded poly sheet is then pressed together with the board. The combined product is then passed through an electrostatic treater (SN-71 for No. 8 Extruder and SN-72 for No. 9 Extruder) which enhances the surface quality of the product. Each extruder has two electrostatic treaters which emit ozone. Both extrusion lines also include rewinding facilities which can be used to cut the extruded product to size and rewind the material so poly can be applied to the opposite side. The extrusion plant also performs shredding, trim chopping and spool cutting. Particulate matter emissions from these activities are controlled by cyclones.

Specific Conditions

213. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #217. [§19.501 et seq. and §19.901 et seq of Regulation #19, and 40 CFR Part 52 Subpart E]

SN	Description	Pollutant	lb/hr	ton/yr
71	No. 8 Extruder Electrostatic Treaters (A&B)	PM_{10}	0.4	1.5
72	No. 9 Extruder Electrostatic Treater	PM_{10}	0.6	2.5

214. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition #217. [Regulation No.§18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	ton/yr
71	No. 8 Extruder Electrostatic Treaters (A&B)	PM Ozone	0.4 0.8	1.5 3.2
72	No. 9 Extruder Electrostatic Treater	PM Ozone	0.6 1.5	2.5 6.3

Opacity

215. The permittee shall not cause to be discharged to the atmosphere from SN-71 and SN-72 gases which exhibit opacity greater than 10%. [§19.503 and §19.901 of Regulation #19, and 40 CFR Part 52 Subpart E]

216. The permittee shall conduct weekly observations of the opacity at SN-71and SN-72. Observations shall be conducted by personnel familiar with the permittee's visible emissions. If visible emissions excess of the permitted opacity are detected, then a Method 9 reading is required. The permittee shall then take immediate action to identify the cause of the visible emissions, implement all necessary corrective action, and reassess the visible emissions after corrective action is taken. The permittee shall maintain records related to all observations/readings, to be updated on a weekly basis. The records shall contain the date and time of each observation/reading, the cause of any observed exceedance of opacity limits, corrective action taken, and results of the reassessment, and the name of the person conducting the observation/reading. The records shall be kept on site and made available to Department personnel upon request. [§19.705 of Regulation 19 and 40 CFR Part 52, Subpart E]

Production Limits

217. The permittee shall not produce in excess of 750 machine dried tons of coated paper per day, 30 day rolling average, from the No. 8 and No. 9 Extruder Machines combined. [§18.1004 of Regulation #19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

218. The permittee shall maintain records which demonstrate compliance with the limits listed in Specific Condition #217. The records shall be updated on a monthly basis. These records shall be kept on site, provided to Department personnel upon request and may be used by the Department for enforcement purposes. A twelve month total and each individual month's data shall be submitted in accordance with General Provision #7. [§18.1004 of Regulation #18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN-35
Aeration Stabilization Basin

Source Description

Wastewater is treated by the Crossett Paper Operations treatment plant. The wastewater is gathered in two open sewers, a bleach plant/utilities sewer and a process sewer. Wastewater Treatment System nutrients are added to the bleach plant/utilities sewer to enhance biological activity. After primary clarification, the process sewer and the bleach plant/utilities sewer combine and flow into one of two settling basins. The effluent travels through a surge basin and is combined with the City of Crossett's treated effluent as it enters a 265 acre extended aeration stabilization basin (ASB, SN-35F). The effluent from the ASB is sent to a holding basin called Mossy Lake, which has a surface area that varies from 200 to 600 acres. Treated effluent is discharged from Mossy Lake to the Ouachita River via Coffee Creek.

Air emissions result from the biological wastewater treatment processes. The air emissions are a factor of such things as the flow to the secondary treatment, the volume of the aeration stabilization basin, the temperature of the aeration stabilization basin and the surface area of the aeration stabilization basin. Also included in the estimation, are contributions from the wastewater clarifier, settling ponds, and sludge dewatering. These potential emissions were not accounted for in the initial permit.

Specific Conditions

219. The permittee shall not exceed the emission rates set forth in the following table. The emissions from this source are limited by the production levels of the mill. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr	ton/yr
VOC	17.3	75.5

220. The permittee shall not exceed the emission rates set forth in the following table. The emissions from this source are limited by the production levels of the mill. [Regulation No. §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Pollutant	lb/hr	ton/yr
Acetaldehyde	0.14	0.61
Acrolein	0.01	0.04
Benzene	0.02	0.07
Biphenyl	0.01	0.02
Carbon Disulfide	0.05	0.21
Chloroform	0.61	2.66
Cresol	0.01	0.01

Pollutant	lb/hr	ton/yr
Cumene	0.41	1.77
Formaldehyde	0.04	0.18
Methanol	15.24	66.74
Naphthalene	0.09	0.36
Phenol	0.01	0.01
Propionaldehyde	0.01	0.04
Styrene	0.08	0.34
Toluene	0.03	0.11
Xylene	0.37	1.59

SN-40, 75, 76F, 78F, 82F, and 97
Tanks and Miscellaneous Activities

Source Description

There are nine large pulp storage tanks located at Crossett Paper Operations (SN-75). An open storage basin (SN-76F) at the facility stores black liquor. The front black liquor storage basin at the facility was closed in 1996.

Fugitive emissions from unpaved roads (SN-78F) are generated by vehicle traffic. Unpaved roads are located in the utilities area, Woodyard, laydown area, contractors' area and around the wastewater treatment system.

The Methanol Tank (SN-40) is subject to regulation under NSPS Subpart Kb. The emissions are due to the working and standing losses from the tank.

There are two landfills at Crossett Paper Operations, the East Landfill and the North Landfill. The East Landfill is permitted to operate as a Class IV Landfill and accepts only woodwaste and concrete debris. The North Landfill is an industrial landfill which accepts general waste from the mill. No municipal waste is disposed in either landfill. The only significant source of emissions expected from these landfills is VOC emissions from the North Landfill. The North Landfill was permitted by the Department and began operation on September 1, 1998. The North Landfill is located approximately two miles north of the mill. The West Landfill ceased operation on September 1, 1998.

Specific Conditions

221. The permittee shall not exceed the emission rates set forth in the following table. Compliance with the pollutant emission rates associated with the Methanol Tank is demonstrated by compliance with Specific Condition #224. The emissions from the other sources are limited by the production levels of the mill. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	ton/yr
40	Methanol Storage Tank	VOC	0.3	1.0
75	Pulp Storage Chests	VOC	43.2	189.3
		TRS	3.8	16.6
97	Storage Tanks	VOC	4.4	19.0
		TRS	2.5	11.0
76F	Black Liquor Storage Basin No. 1	VOC	4.4	19.3
78F	Road Emissions	PM_{10}	3.0	9.7
82F	Landfill Operations	PM_{10}	0.1	0.1

222. The permittee estimates the emission rates set forth in the following table will not be exceeded. The pollutant emission rates associated with the Methanol Tank are effectively limited by Specific Condition #224. The emissions from the other sources are limited by the production levels of the mill. [Regulation No.§18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	ton/yr
40	Methanol Storage Tank	Methanol	0.22	1.0
97	Storage Tanks	Acetaldehyde	0.01	0.02
		Acrolein	0.01	0.01
		Benzene	0.01	0.01
		Carbon Tetrachloride	0.01	0.02
		Ethylene Dichloride	0.01	0.01
		Hexane	0.01	0.01
		Methanol	0.48	2.11
		Styrene	0.01	0.01
		Tetrachloroethylene	0.01	0.01
		Toluene	0.01	0.01
		1,2,4-Trichlorobenzene	0.01	0.01
		Xylene	0.01	0.03
75	Pulp Storage Chests	Acetaldehyde	0.05	0.21
		Benzene	0.01	0.01
		Chloroform	0.10	0.44
		Hexane	0.01	0.01
		Methanol	0.22	0.95
		Phenol	0.18	0.75
		Styrene	0.01	0.02
		Tetrachloroethylene	0.01	0.02
		Toluene	0.01	0.01
		Xylene	0.01	0.01
76F	Black Liquor Storage Basin No. 1	Acetaldehyde	0.20	0.87
		Acetone	0.2	0.7
		Methanol	4.02	17.61
78F	Road Emissions	PM	12.0	39.0
82F	Landfill Operations	PM	0.2	0.1

NSPS Kb

223. The Methanol Tank is subject to and shall comply with all applicable provisions of 40 CFR Part 60 Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels. A copy of Subpart Kb is provided in Appendix D.

Applicable provisions include, but are not limited to, maintaining records showing the dimension of the storage vessel, and an analysis showing the design capacity of the storage vessel. [§19.304 of Regulation #19 and 40 CFR 60.116b (a) and (b)]

Throughput Limits

224. Throughput of methanol at SN-40 shall not exceed 40,000 barrels per twelve consecutive months. [§19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

225. The permittee shall maintain records which demonstrate compliance with the limits listed in Specific Condition #224. These records shall be updated on a monthly basis. These records shall be kept on site, provided to Department personnel upon request and may be used by the Department for enforcement purposes. A twelve month total and each individual month's data shall be submitted in accordance with General Provision #7. [§19.705 of Regulation #19 and 40 CFR Part 52 Subpart E]

Dust Suppression

226. Dust suppression activities should be conducted in a manner and at a rate of application that will not cause runoff from the area being applied. Best Management Practices (40 CFR §122.44(k)) should be used around streams and waterbodies to prevent the dust suppression agent from entering Waters of the State. Except for potable water, no agent shall be applied within 100 feet of wetlands, lakes, ponds, springs, streams, or sinkholes. Failure to meet this condition may require the permittee to obtain a National Pollutant Discharge Elimination System (NPDES) permit in accordance with 40 CFR §122.1(b). [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN-93
Repulpers A, B, and C

Source Description

Three repulpers are used to reprocess broke as well as pulp that is purchased and produced in-house. These are identified as Repulpers A, B, and C. Each repulper is identical. The repulpers operate without any hoods or fans. A sodium hypochlorite pulping aid is required to break down the broke; however not the pulp. The sodium hypochlorite is added subsurface to the repulpers. All VOC emissions are non-stack in nature. The broke that is repulped is stored in the existing broke stock chests. As part of the permit renewal, the repulpers were added as permitted sources. A minor modification allowed the reconstruction of Repulper A.

Specific Conditions

227. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition #229. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr	ton/yr
VOC	1.0	4.4

228. The permittee estimates the emission rates set forth in the following table will not be exceeded. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition #229. [Regulation No.§18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Pollutant	lb/hr	ton/yr
Chloroform	0.99	4.32

Throughput Limits

229. The permittee shall not process in excess of 270 tons per day of broke, 30-day rolling average , total combined, at all repulpers at SN-93. This limit does not apply to purchased pulp or pulp produced in-house for purposes of recycle. [§18.1004 of Regulation #18, §19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

230. The permittee shall maintain records of the amount of broke that is processed in Repulpers A, B and C which demonstrate compliance with the limits listed in Specific Condition #229. These records shall be updated on a monthly basis. These records shall be kept on site, provided to Department personnel upon request and may be used by the

Department for enforcement purposes. A twelve month total and each individual month's data shall be submitted in accordance with General Provision #7. [§19.705 of Regulation #19 and 40 CFR Part 52 Subpart E]

SN-83
Incinerator and Scrubber

Source Description

Gas streams from the LVHC Collection System, the HVLC Collection System, and SOGs from the LEEPS System are fed into the Incinerator via a common burner. The HVLC system is diluted with combustion air before being fed to the combustion chamber. The Incinerator consists of a horizontal combustion chamber followed by a vertical SO_2 caustic packed-tower scrubber which, in turn, is followed by several mist eliminators.

Minimum incineration temperature in the primary combustion zone is required for efficient oxidation. For this Kraft mill application, combustion requirements dictate a minimum temperature of 1,600°F with a 0.75 second retention time (*see* 40 CFR §63.443(d)(3)). Since the Incinerator combusts NCGs from both LVHC and HVLC Collection Systems, it has to meet a 96% uptime requirement. Crossett Paper Operations complies by using the Incinerator as the primary combustion device with the 9A Boiler (SN-22) as a backup combustion device for the LVHC NCGs and SOGs only. The HVLC gases, which by definition have lower concentrations of NCGs, are vented to the atmosphere when the Incinerator is down. In the event that downtime occurs, excess emissions will be reported as required by 40 CFR §63.455.

Under normal operation, the fuel flow is controlled by the operating temperature in the Incinerator. The fuel requirements will vary with the amount of waste gases introduced into the collection system. Maximum fuel consumption will be required to bring the system up to temperature, but the consumption will be greatly reduced during normal incineration of the NCGs and SOGs. The NCGs have some heat content which reduces fuel consumption once normal incineration begins.

The Incinerator system consists of a refractory lined Incinerator, a waste heat boiler, a cooler section, an SO_2 scrubber, a sulfuric acid removal system, and a discharge stack. The waste heat boiler is located between the Incinerator outlet and the scrubber inlet. This boiler is a fire-tube type boiler with three passes. The boiler does not combust fuels; rather it scavenges the waste heat from the Incinerator to produce steam.

The gases exiting the Incinerator are in excess of 1,600°F. In order to scrub the SO_2 from these gases, the temperature is lowered. The gases pass through a waste heat boiler. The boiler is followed by a vertical SO_2 scrubber that continues to lower the temperature as it removes most of the sulfur gases from the combustion exhaust.

The adsorption tower is followed by a sulfuric acid removal system that uses a caustic solution. A recirculation loop is used to minimize caustic use. The makeup caustic is controlled by scrubber pH to maintain scrubbing effectiveness and efficiency.

The primary fuels for the Incinerator are methanol recovered from the foul condensates via the steam stripper and the LVHC gases. Natural gas is used as a backup fuel. For a given pollutant, the combustion of methanol produces the highest emission rates. The Incinerator is equipped with low-NO_x burners to control NO_x emissions and a scrubber to control PM/PM_{10} and SO_2 emissions.

In 597-AOP-R8, the facility underwent PSD review in order to modify nine of their Digesters (SN-59), replacing the six-inch blow valves with eight-inch valves. All six hardwood pulp digesters were modified, along with one "swing" pulp digester (used for either hardwood or softwood) and two softwood pulp digesters. BACT for VOC was determined to be combustion of the digester gases in an incinerator, SN-83.

Specific Conditions

231. The permittee shall not exceed the emission rates set forth in the following table for the Incinerator (SN-83). Emissions are based on maximum capacity. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr	ton/yr
PM_{10}	2.7	11.9
SO_2	9.1	39.9
CO	6.0	26.3
NO_x	23.0	100.8
TRS	0.9	3.8

232. The permittee shall not exceed the emission rates set forth in the following table for the Incinerator (SN-83). Emissions are based on maximum capacity. [Regulation No. 19 §19.501 et seq., §19.901, and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr	ton/yr
VOC	0.8	3.5

233. The permittee shall not exceed the emission rates set forth in the following table for the Incinerator (SN-83). Emissions are based on maximum capacity. [Regulation No.§18.801 effective and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Pollutant	lb/hr	ton/yr
PM	2.7	11.9
SAM	13.7	4.3
Acetaldehyde	0.03	0.11
Acetone	0.1	0.2
Benzene	0.04	0.14
Carbon Tetrachloride	0.01	0.04
Formaldehyde	0.03	0.09

Pollutant	lb/hr	ton/yr
Hexane	0.01	0.03
Methanol	0.81	3.06
Styrene	0.01	0.01
1,2,4-Trichlorobenzene	0.01	0.02
Xylene	0.02	0.05

Opacity

234. The permittee shall not cause to be discharged to the atmosphere from the Incinerator gases which exhibit opacity greater than 20%. [§19.503 of Regulation #19 and 40 C.F.R. Part 52 Subpart E]

235. The permittee shall conduct weekly observations of the opacity at SN-83. Observations shall be conducted by personnel familiar with the permittee's visible. If visible emissions excess of the permitted opacity are detected, then a Method 9 reading is required. The permittee shall then take immediate action to identify the cause of the visible emissions, implement all necessary corrective action, and reassess the visible emissions after corrective action is taken. The permittee shall maintain records related to all observations/readings, to be updated on a weekly basis. The records shall contain the date and time of each observation/reading, the cause of any observed exceedance of opacity limits, corrective action taken, and results of the reassessment, and the name of the person conducting the observation/reading. The records shall be kept on site and made available to Department personnel upon request. [§19.705 of Regulation 19 and 40 CFR Part 52, Subpart E]

Fuel Requirements

236. Natural gas may be used as a backup fuel for the Incinerator. [§19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

237. The permittee shall maintain records which demonstrate compliance with Specific Condition #236. These records shall be updated on a monthly basis and shall include periods of usage of natural gas, (not quantities) of fuel used. These records shall be kept on site, provided to Department personnel upon request and may be used by the Department for enforcement purposes. A twelve month total and each individual month's data shall be submitted in accordance with General Provision #7. [§19.705 of Regulation #19 and 40 CFR Part 52 Subpart E]

CAM

238. Incinerator (SN-83) is subject to and shall comply with all applicable provisions §19.304 of Regulation 19, 40 CFR Part 52 Subpart E, and Part §64.6 for Compliance Assurance Monitoring. Post control of sulfur dioxide emissions from SN-83 are below major source levels.

a. The permittee shall maintain a scrubber liquid flow rate of at least 768 gallons per minute. [40 CFR Part §64.6(c)(1)]

b. The permittee shall maintain a pH of at least 7.6 in the scrubber liquid. [40 CFR Part §64.6(c)(1)]

c. The permittee shall monitor and maintain daily records to demonstrate compliance with Specific Condition #238 (A) and (B). Records shall be kept onsite and made available to the Department upon request. [40 CFR Part §64.6(c)(3)]

d. The permittee shall maintain the caustic scrubber in good working condition at all times so that pollutant removal is maintained. [40 CFR Part §64.6(c)(1)]

239. The Incinerator (SN-83) is subject to and shall comply with all applicable provisions §19.304 of Regulation 19, 40 CFR Part 52 Subpart E, and Part §64.9 for Compliance Assurance Monitoring. The following information pertaining to exceedances or excursions from permitted values shall be submitted in semi-annual reports in accordance with General Provision 7 as outlined in 40 CFR §70.6.

a. The permittee shall maintain records for SN-83 that summarizes the number, duration, and cause of excursions or exceedances of emission limits as well as corrective action taken. [40 CFR §64.9(a)(2)(i) and §64.9(b)]

b. The permittee shall maintain records for SN-83 that summarizes the number, duration, and cause of monitoring equipment downtime incidents, other than routine downtime for calibration checks. [40 CFR §64.9(a)(2)(ii) and §64.9(b)]

c. The permittee shall maintain a quality improvement plan (QIP) threshold for each indicator of no more than nine excursions or 5% of the total daily averages in a six-month period.

d. The permittee shall develop and implement a new QIP if the threshold is exceeded during any six-month period. [40 CFR §64.9(a)(2)(iii) and §64.9(b)]

e. The permittee shall maintain records for SN-83 that describes the actions taken to implement the QIP. Upon completion of the QIP, documentation shall be maintained to confirm that the plan was completed and reduced the likelihood of similar excursions or exceedances. [40 CFR §64.9(a)(2)(iii) and §64.9(b)]

Testing Requirements

240. The permittee shall test volatile organic compound emissions from the Incinerator every five years to confirm the BACT limit for this source. Testing shall be performed in accordance with Plantwide Condition #3 and EPA Reference Method 25A. During the test the permittee shall operate the source within 10 percent of the rated throughput capacity. If 90 percent of the rated throughout capacity cannot be achieved, the permittee shall be limited to 10 percent above the actual tested throughput. The permittee shall reference this limitation in any compliance reports submitted to the Department. [§19.702 and §19.901 of Regulation #19 and 40 CFR Part 52 Subpart E]

241. The permittee shall test sulfur dioxide emissions from the Incinerator every five years. Testing shall be performed in accordance with Plantwide Condition #3 and EPA Reference Method 6C. The permittee shall test at the minimum scrubber parameters of Specific Condition 238. During the test the permittee shall operate the source within 10 percent of the rated throughput capacity. If 90 percent of the rated throughout capacity cannot be achieved, the permittee shall be limited to 10 percent above the actual tested throughput. The permittee shall reference this limitation in any compliance reports submitted to the Department. [§19.702 of Regulation #19 and 40 CFR Part 52 Subpart E]

242. The permittee shall test carbon monoxide emissions from the Incinerator every five years. Testing shall be performed in accordance with Plantwide Condition #3 and EPA Reference Method 10. During the test the permittee shall operate the source within 10 percent of the rated throughput capacity. If 90 percent of the rated throughout capacity cannot be achieved, the permittee shall be limited to 10 percent above the actual tested throughput. The permittee shall reference this limitation in any compliance reports submitted to the Department. [§19.702 of Regulation #19 and 40 CFR Part 52 Subpart E]

243. The permittee shall test nitrogen oxides emissions from the Incinerator every five years. Testing shall be performed in accordance with Plantwide Condition #3 and EPA Reference Method 7E. During the test the permittee shall operate the source within 10 percent of the rated throughput capacity. If 90 percent of the rated throughout capacity cannot be achieved, the permittee shall be limited to 10 percent above the actual tested throughput. The permittee shall reference this limitation in any compliance reports submitted to the Department. [§19.702 of Regulation #19 and 40 CFR Part 52 Subpart E]

NSPS BB and NESHAP S

244. The Incinerator (SN-83) is subject to and shall comply with applicable provisions of §19.804 of Regulation #19, NSPS Subpart BB, and NESHAP Subpart S. Section 19.804 of Regulation #19 and NSPS Subpart BB both require incineration of NCGs at a minimum temperature of 1200°F for at least 0.5 seconds. NESHAP Subpart S requires

incineration at a minimum temperature of 1600°F for at least 0.75 seconds. [§19.804 of Regulation #19, NSPS Subpart BB, and NESHAP Subpart S]

245. The permittee shall maintain records which demonstrate compliance with Specific Condition #244. These records shall be kept on site, provided to Department personnel upon request and may be used by the Department for enforcement purposes. [§19.705 of Regulation #19 and 40 CFR Part 52 Subpart E]

246. The pulping system (which is comprised of all pulping process equipment beginning with the digester system, up to and including the last piece of pulp conditioning equipment prior to the bleaching system) is subject to and shall comply with applicable provisions of 40 CFR Part 63 Subpart S -*National Emission Standards for Hazardous Air Pollutants from the Pulp and Paper Industry.* A copy of Subpart S is provided in Appendix E.

Standards for the Kraft pulping systems.

a. The permittee shall control the total HAP emissions from the equipment systems listed in 40 CFR §63.443(a), as specified in paragraphs (c) and (d) of 40 CFR §63.443. [40 CFR §63.443(a)]

b. The equipment systems listed in paragraphs (a) and (b) of 40 CFR §63.443 shall be enclosed and vented into a closed-vent system and routed to a control device that meets the requirements specified in paragraph (d) of 40 CFR §63.443. The enclosure and closed-vent system shall meet the requirements specified in 40 CFR §63.450. [40 CFR §63.443(c)]

c. The control device used to reduce total HAP emissions from each equipment system listed in paragraphs (a) and (b) of 40 CFR §63.443 shall reduce total HAP emissions using a thermal oxidizer designed and operated at a minimum temperature of 871oC (1600oF) and a minimum residence time of 0.75 seconds. [40 CFR §63.443(d)(3)]

d. Periods of excess emissions reported under 40 CFR §63.455 shall not be a violation of 40 CFR §63.443 (c) and (d) provided that the time of excess emissions (excluding periods of startup, shutdown, or malfunction) divided by the total process operating time in a semi-annual period does not exceed the following levels: (1) one percent for control devices used to reduce the total HAP emissions from the LVHC system; and (2) four percent for control devices used to reduce the total HAP emissions from the HVLC system; and (3) four percent for control devices used to reduce the total HAP emissions from both the LVHC and HVLC systems. [40 CFR §63.443(e)]

Standards for Kraft pulping process condensates.

e. The pulping process condensates from the equipment systems listed in 40 CFR §63.446(b) shall be treated to meet the requirements specified in paragraphs (c), (d), and (e) of 40 CFR §63.446. [40 CFR §63.446(b)]

f. One of the combinations of HAP-containing pulping process condensates listed in 40 CFR §63.446(c) which is generated, produced, or associated with the equipment systems listed in paragraph (b) of 40 CFR §63.446 shall be subject to the requirements of paragraph (d) and (e) of 40 CFR §63.446. [40 CFR §63.446(c)]

g. The pulping process condensates from the equipment systems listed in paragraph (b) of 40 CFR §63.446 shall be conveyed in a closed collection system that is designed and operated to meet the requirements specified in paragraphs (d)(1) and (d)(2) of 40 CFR §63.446. [40 CFR §63.446(d)]

h. Each pulping process condensate from the equipment systems listed in paragraph (b) of 40 CFR §63.446 shall be treated according to the following option: at mills that perform bleaching, treat the pulping process condensates to remove 5.1 kilograms or more of total HAP per megagram (10.2 pounds per ton) of ODP (bleached), or achieve a total HAP concentration of 330 parts per million or less by weight at the outlet of the control device. [40 CFR §63.446(e)(5)]

i. Each HAP removed from a pulping process condensate stream during treatment and handling under paragraph (d) or (e) of 40 CFR §63.446 shall be controlled as specified in 40 CFR '43.443(c) and (d). [40 CFR §63.446(f)]

j. The permittee shall evaluate all new or modified pulping process condensates or changes in the annual bleached or non-bleached ODP used to comply with paragraph (i) of 40 CFR §63.446, to determine if they meet the applicable requirements of 40 CFR §63.446. [40 CFR §63.446(h)]

k. For the purposes of meeting the requirements in paragraphs (c)(2), (e)(4), or (e)(5) of 40 CFR §63.446 at mills producing both bleached and unbleached pulp products, the permittee may meet a prorated mass standard that is calculated by prorating the applicable mass standards (kilograms of total HAP per megagram of ODP) for bleached and unbleached specified in paragraphs (c)(2), (e)(4), or (e)(5) of 40 CFR §63.446 by the ratio of annual megagrams of bleached and unbleached ODP. [40 CFR §63.446(i)]

Monitoring Requirements

l. The Incinerator shall meet the monitoring requirements set forth in 40 CFR §63.453(b). [40 CFR §63.453(b)]

m. The Steam Stripper shall meet the monitoring requirements set forth in 40 CFR §63.453(g). [40 CFR §63.453(g)]

n. The Closed Vent System shall meet the monitoring requirements set forth in 40 CFR §63.453(k). [40 CFR §63.453(k)]

Recordkeeping and Reporting Requirements

o. The permittee shall prepare and maintain a site-specific inspection plan for the closed vent LVHC, HVLC, and SOG collection systems. [40 CFR §63.454(b)]

p. Excess emissions shall be reported as required by 40 CFR §63.455. [40 CFR §63.455]

247. The permittee may allow emissions from the incinerator and associated scrubber to be released to the atmosphere bypassing the associated candle filter sulfuric acid mist eliminator. Bypass shall only be allowed during periods of emergency maintenance to the sulfuric acid mist eliminator system. Bypass emissions shall also be counted toward annual limits. [A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN-111, 112, 113, 114
Converting Lines No. 1, 2, and 3
and Trim System

Source Description

This section is being installed due to the changes at the No. 8 Paper Machine. The converting lines prepare the paper for the consumer by uses of inks, glues, and cleaners. This equipment will be enclosed in a building with a drum filtering system rated at 50,000 dscfm for each line. The drum filtering system will be designed to recirculate 100% of the exhaust air back into the building. This drum filtering system is used to eliminate any potential particulate emissions from the trim line in addition to the converting lines. The drum filtering systems will be designed to recirculate 100 percent of the exhaust air back into the building.

Specific Conditions

248. The permittee shall not exceed the totals set forth in the following table for combined emissions from Converting Lines (SN-111, 112, and 113). Compliance with the VOC emission rates shall be demonstrated by Specific Condition #250. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Pollutant	lb/hr	ton/yr
111 112 113	VOC	1.8	7.8

Throughput Limits

249. The permittee shall maintain MSDS or other records which indicate the VOC content of all inks, glues and cleaners in use in converting lines SN-111, 112, and 113. MSDS sheets should be updated annually. These records shall be maintained on-site and shall be made available to Department personnel upon request. [§19.705 of Regulation 19 and 40 CFR Part 52 Subpart E and/or §18.1004 of Regulation 18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

250. The permittee shall maintain monthly records which demonstrate the amount of VOC emitted from the converting lines SN-111, 112, and 113. These records shall be maintained in a spreadsheet, database, or other well-organized format. These records shall indicate the amount of each ink, glue, or cleaner used. It shall include the corresponding VOC content of each material, and the total amount of VOC emissions from usage. Each individual month's data and a 12-month rolling total shall be maintained on-site, shall be made available to Department personnel upon request, and

shall be submitted in accordance with General Provision #7. [§19.705 of Regulation 19 and 40 CFR Part 52 Subpart E]

SN-115-ct, 116-ct, and 117-ct
Cooling Towers

Source Description

Cooling towers shall be installed for servicing the HVAC system (117-ct), No.8 Tissue Machine vacuum pump (115-ct), and No.8 Tissue Machine building HVAC system(116-ct). The total circulation flow rate for the three cooling towers shall be 12,500 gallons per minute (gpm).

Specific Conditions

251. The permittee shall not exceed the emission rates set forth in the following table for the Cooling Towers SN-115-ct, 116-ct, and 117-ct. Compliance with the PM_{10} emission rates shall be demonstrated by Specific Condition #254. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Pollutant	lb/hr	ton/yr
115-ct	PM_{10}	0.1	0.1
116-ct	PM_{10}	0.1	0.1
117-ct	PM_{10}	0.1	0.2

252. The permittee estimates the emission rates set forth in the following table for the Cooling Towers (SN115-ct, 116-ct, and 117-ct) will not be exceeded. Compliance with the PM emissions shall be demonstrated by Specific Condition #254. [Regulation No.§18.801 effective and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Pollutant	lb/hr	ton/yr
115-ct	PM	0.1	0.1
116-ct	PM	0.1	0.1
117-ct	PM	0.1	0.2

253. Visible emissions may not exceed the limits specified in the following table.

SN	Limit	Regulatory Citation
115-ct, 116-ct, & 117-ct	20%	[§19.503 and 40 CFR Part 52, Subpart E]

254. The total dissolved solids shall not exceed 750 mg/l at SN-115-ct, 116-ct, and 117-ct. [§19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

255. The permittee shall monitor and maintain monthly records which demonstrate compliance with the limits set in Specific Condition #254. Records shall be updated by the 15th day following the end of the month to which the records pertain. These records shall be kept on site and made available to Department personnel upon request. [§19.705 and 40 CFR Part 52, Subpart E]

SN-114, 115, SN-116, SN-117, SN-118, SN-119, SN-120, and SN-121
Temporary Chipping and Debarking Equipment
and
Emergency Generators

Source Description

The facility has seven emergency engines on site which use diesel fuel. SN-115, SN-116, and SN-117 Firewater Pumps are Caterpillar Model 3406 engines of model year 2002 (SN-115) and 2004 (SN-116, 117) of 420 hp each. These engines are subject to NSPS ZZZZ requirements but not NSPS IIII. SN-118 and SN-119 are John Deere JU6H-UF58 engines are model year 2007 and are 138 hp. These engines are subject to both ZZZZ and IIII NSPS requirements. The facility also has a backup generator for two leachate pumps

Specific Conditions

256. The permittee shall not exceed the emission rates set forth in the following table. Compliance shall be demonstrated by compliance with Specific Condition #260. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	ton/yr
114	Temporary Debarking and Chipping equipment	PM_{10}	2.5	2.6
		SO_2	1.1	1.1
		VOC	2.5	2.6
		CO	20.8	22.5
		NO_X	16.8	18.1
115	Caterpillar Model No. 3406 Firewater Pump	PM_{10}	1.0	0.3
		SO_2	0.9	0.3
		VOC	1.1	0.3
		CO	2.9	0.8
		NO_x	13.1	3.3
116	Caterpillar Model No. 3406 Firewater Pump	PM_{10}	1.0	0.3
		SO_2	0.9	0.3
		VOC	1.1	0.3
		CO	2.9	0.8
		NO_x	13.1	3.3
117	Caterpillar Model No. 3406 Firewater Pump	PM_{10}	1.0	0.3
		SO_2	0.9	0.3
		VOC	1.1	0.3
		CO	2.9	0.8
		NO_x	13.1	3.3
118	John Deere JU6H-UF58	PM_{10}	0.2	0.1
		SO_2	0.3	0.1

SN	Description	Pollutant	lb/hr	ton/yr
	Firewater Pump	VOC	0.1	0.1
		CO	0.3	0.1
		NO_x	1.8	0.5
119	John Deere JU6H-UF58 Firewater Pump	PM_{10}	0.2	0.1
		SO_2	0.3	0.1
		VOC	0.1	0.1
		CO	0.3	0.1
		NO_x	1.8	0.5
120	Cummins Series 382 Backup Generator	PM_{10}	0.2	0.1
		SO_2	0.2	0.1
		VOC	0.3	0.1
		CO	0.6	0.2
		NO_x	2.8	0.7
121	Caterpillar 3116 Backup Lime Kiln Rotation	PM_{10}	0.6	0.2
		SO_2	0.5	0.2
		VOC	0.6	0.2
		CO	1.6	0.4
		NO_x	7.2	1.8

257. The permittee shall not exceed the emission rates set forth in the following table. Compliance shall be demonstrated by compliance with Specific Condition #260. [Regulation No.§18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	ton/yr
114	Temporary Debarking and Chipping equipment	PM	3.6	3.9
		Acetaldehyde	0.01	0.01
		Acrolein	0.01	0.01
		Benzene	0.01	0.01
		Formaldehyde	0.01	0.01
		POM	0.01	0.01
		Naphthalene	0.01	0.01
		Toluene	0.01	0.01
		Xylene	0.01	0.01
115	Caterpillar Model No. 3406 Firewater Pump	PM	1.0	0.3
		Acetaldehyde	0.01	0.01
		Acrolein	0.01	0.01
		Benzene	0.01	0.01
		Formaldehyde	0.01	0.01
		Naphthalene	0.01	0.01
		POM	0.01	0.01
		Toluene	0.01	0.01

SN	Description	Pollutant	lb/hr	ton/yr
		Xylene	0.01	0.01
116	Caterpillar Model No. 3406 Firewater Pump	PM	1.0	0.3
		Acetaldehyde	0.01	0.01
		Acrolein	0.01	0.01
		Benzene	0.01	0.01
		Formaldehyde	0.01	0.01
		Naphthalene	0.01	0.01
		POM	0.01	0.01
		Toluene	0.01	0.01
		Xylene	0.01	0.01
117	Caterpillar Model No. 3406 Firewater Pump	PM	1.0	0.3
		Acetaldehyde	0.01	0.01
		Acrolein	0.01	0.01
		Benzene	0.01	0.01
		Formaldehyde	0.01	0.01
		Naphthalene	0.01	0.01
		POM	0.01	0.01
		Toluene	0.01	0.01
		Xylene	0.01	0.01
118	John Deere JU6H-UF58 Firewater Pump	PM	0.2	0.1
		Acetaldehyde	0.01	0.01
		Acrolein	0.01	0.01
		Benzene	0.01	0.01
		Formaldehyde	0.01	0.01
		Naphthalene	0.01	0.01
		POM	0.01	0.01
		Toluene	0.01	0.01
		Xylene	0.01	0.01
119	John Deere JU6H-UF58 Firewater Pump	PM	0.2	0.1
		Acetaldehyde	0.01	0.01
		Acrolein	0.01	0.01
		Benzene	0.01	0.01
		Formaldehyde	0.01	0.01
		Naphthalene	0.01	0.01
		POM	0.01	0.01
		Toluene	0.01	0.01
		Xylene	0.01	0.01
120	Cummins Series 382 Backup Generator	PM	0.2	0.1
		Acetaldehyde	0.01	0.01
		Acrolein	0.01	0.01
		Benzene	0.01	0.01

SN	Description	Pollutant	lb/hr	ton/yr
		Formaldehyde	0.01	0.01
		Naphthalene	0.01	0.01
		POM	0.01	0.01
		Toluene	0.01	0.01
		Xylene	0.01	0.01
121	Caterpillar 3116 Backup Lime Kiln Rotation	PM	0.6	0.2
		Acetaldehyde	0.01	0.01
		Acrolein	0.01	0.01
		Benzene	0.01	0.01
		Formaldehyde	0.01	0.01
		Naphthalene	0.01	0.01
		POM	0.01	0.01
		Toluene	0.01	0.01
		Xylene	0.01	0.01

Opacity

258. The permittee shall not cause to be discharged to the atmosphere from the Emergency Generators, SN-115 through SN-121, and the Temporary Chipper and Debarker, SN-114, gases which exhibit opacity greater than 20%. [§19.503 of Regulation #19 and 40 CFR Part 52 Subpart E]

259. The permittee shall conduct daily observations when use exceeds 24-hours per event. Observations shall be conducted by personnel familiar with the permittee's visible emissions. If visible emissions excess of the permitted opacity are detected, then a Method 9 reading is required. The permittee shall then take immediate action to identify the cause of the visible emissions, implement all necessary corrective action, and reassess the visible emissions after corrective action is taken. The permittee shall maintain records related to all observations/readings, to be updated on a weekly basis. The records shall contain the date and time of each observation/reading, the cause of any observed exceedance of opacity limits, corrective action taken, and results of the reassessment, and the name of the person conducting the observation/reading. The records shall be kept on site and made available to Department personnel upon request. [§19.705 of Regulation 19 and 40 CFR Part 52, Subpart E]

Fuel Requirements

260. The permittee is limited to 500 hours of operation for each source, SN-115 through SN-121. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

261. Diesel fuel shall be the only fuel used for the Emergency Generators, SN-115 through SN-121. [§19.705 of Regulation #19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

Limits at Temporary Debarker and Chipper

262. The permittee shall not operate either the debarker or the chipper engine in excess of 2,160 hours. The generator shall have a non-resettable hour meter in order to verify compliance with this limit. The permittee shall maintain monthly and 12-month total records in order to demonstrate compliance with the limit and which may be used by the Department for enforcement purposes. These records shall be updated no later than the fifteenth day of the month following the month which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. [Regulation 18, §18.1004 and Regulation 19, §19.705 et seq. and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

263. The permittee shall remove the debarker/chipper engines after 12 months at the location or the maximum hours allowed in Specific Condition #262, whichever occurs first. The permittee shall maintain records of equipment placement and removal in order to demonstrate compliance with these limits. These records shall include the dates the engines are moved and the correlating hour meter readings. These records shall be kept on site and shall be made available to Department personnel upon request. [40 CFR 1068.30(2)(iii) and §19.304 of Regulation #19]

264. The permittee shall operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. Records of required maintenance shall be kept on site and shall be made available to Department personnel upon request. [Regulation 18, §18.1004 and Regulation 19, §19.705 et seq. and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

NSPS IIII

265. SN-118 and SN-119, as CI ICE, certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006, are subject to the requirements of Subpart IIII—*Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*. [40 CFR §60.4200]

266. As owners or operations of SN-118 and SN-119, engines with a displacement of less than 30 liters per cylinder, the permittee must comply with the emission standards in Table 4 to this subpart, for all pollutants. [40 CFR §60.4205(c)]

Size	Year	$NMHC + NO_X$ g/HP-hr	CO g/HP-hr	PM g/HP-hr
$100 \leq HP < 175$	2009 and earlier	7.8	3.7	0.6

267. Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §60.4205 according to the manufacturer's written instructions or procedures developed by the owner or operator that

are approved by the engine manufacturer, over the entire life of the engine. [40 CFR §60.4206]

268. Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for non-road diesel fuel. [40 CFR §60.4207(b)]

269. Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart may petition the Administrator for approval to use remaining non-compliant fuel that does not meet the fuel requirements of paragraphs (a) and (b) of this section beyond the dates required for the purpose of using up existing fuel inventories. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator. [40 CFR §60.4207(c)]

270. The permittee must install a non-resettable hour meter at SN-118 and SN-119. [40 CFR §60.4209(a)]

271. The permittee must operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. In addition, owners and operators may only change those settings that are permitted by the manufacturer. The permittee must also meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you. [40 CFR §60.4211(a)]

272. The permittee, as an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section. [40 CFR §60.4211(b)]

   a. Purchasing an engine certified according to 40 CFR part 89 or 40 CFR part 94, as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications.

   b. Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

   c. Keeping records of engine manufacturer data indicating compliance with the standards.

   d. Keeping records of control device vendor data indicating compliance with the standards.

e. Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in §60.4212, as applicable.

273. Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. Anyone may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. For owners and operators of emergency engines meeting standards under §60.4205 but not §60.4204, any operation other than emergency operation, and maintenance and testing as permitted in this section, is prohibited. [40 CFR §60.4211(e)]

274. The permittee must conduct performance tests according to paragraphs (a) through (d) of this section. [40 CFR §60.4212]

a. The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F.

b. Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

c. Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \qquad \text{(Eq. 1)}$$

Where:

STD = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in §60.4213 of this subpart, as appropriate.

d. Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in §60.4204(a), §60.4205(a), or §60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in §60.4204(a), §60.4205(a), or §60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) may follow the testing procedures specified in §60.4213, as appropriate.

275. If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. [40 CFR §60.4214(b)]

NESHAP ZZZZ

276. The Emergency Generators, SN-115 through SN-121, are subject to the requirements of NESHAP ZZZZ- *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.*

a. SN-118 and SN-119 are new (commenced construction on or after June 12, 2006) compression ignition (CI) stationary RICEs with a site rating of less than or equal to 500 brake HP and located at a major source of HAP emissions. [40 CFR §63.6590(a)(2)(ii)]

b. SN-115, SN-116, SN-117, SN-120, and SN-121 are existing (commenced construction before June 12, 2006) compression ignition (CI) stationary RICEs with a site rating of less than or equal to 500 brake HP located at a major source of HAP. [40 CFR §63.6590(a)(1)(ii)]

277. SN-118 and SN-119, as new compression ignition stationary RICE with a site rating of less than or equal to 500 HP, must meet the requirements of NESHAP ZZZZ by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines. No further requirements apply for such engines under this subpart. [40 CFR §63.6590(c)]

278. SN-115, SN-116, SN-117, SN-120, and SN-121 must comply with the applicable requirements in Table 2c. [40 CFR §63.6602 and Table 2c]

a. Change oil and filter every 500 hours of operation or annually, whichever comes first.

b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first.

c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

d. Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement in Table 2c of this subpart.

e. Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

279. The permittee must be in compliance with the operating limitations in this subpart that apply to you at all times. [40 CFR §63.6605(a)]

280. The permittee must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [40 CFR §63.6605(b)]

281. The permittee must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. [40 CFR §63.6625(e)]

282. The permittee must install a non-resettable hour meter at SN-115, SN-116, SN-117, SN-120, and SN-121, if one has not already been installed. [40 CFR §63.6625 (f)]

283. The permittee has the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of

the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine. [40 CFR §63.6625(h)(i)]

284. The permittee must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1)(i) through (iii) of this section. Any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1)(i) through (iii) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1)(i) through (iii) of this section, the engine will not be considered an emergency engine under this subpart and will need to meet all requirements for non-emergency engines. [40 CFR §63.6640(f)]

a. There is no time limit on the use of emergency stationary RICE in emergency situations. [40 CFR §63.6640(f)(i)]

b. You may operate your emergency stationary RICE for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency RICE beyond 100 hours per year. [40 CFR §63.6640(f)(ii)]

c. You may operate your emergency stationary RICE up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity; except that owners and operators may operate the emergency engine for a maximum of 15 hours per year as part of a demand response program if the regional transmission organization or equivalent balancing authority and transmission operator has determined there are emergency conditions that could lead to a potential electrical blackout, such as unusually low frequency, equipment overload, capacity or energy deficiency, or unacceptable voltage level. The engine may not be operated for more than 30 minutes prior to the time when the emergency condition is expected to occur, and the engine operation must be terminated immediately after the facility is notified that the emergency condition is no longer imminent. The 15 hours per year of demand response operation are counted as part of the 50 hours of operation per year provided for non-emergency situations. The supply of emergency power to another entity or entities pursuant to financial arrangement is not limited by this paragraph (f)(1)(iii), as long as the power provided by the financial arrangement is limited to emergency power. [40 CFR §63.6640(f)(iii)]

285. As existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards, the permittee is exempt from submitting the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h). [40 CFR §63.6645(a)(5)]

286. The permittee must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE. [40 CFR §63.6655(e)]

287. The permittee must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engines are used for demand response operation, the owner or operator must keep records of the notification of the emergency situation, and the time the engine was operated as part of demand response. [40 CFR §63.6655(f)]

288. The permittee must be in a form suitable and readily available for expeditious review according to §63.10(b)(1). [40 CFR §63.6660(a)]

289. The permittee must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. [40 CFR §63.6660(b)]

290. The permittee must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). [40 CFR §63.6660(c)]

SECTION V: COMPLIANCE PLAN AND SCHEDULE

Georgia-Pacific LLC - Crossett Paper Operations will continue to operate in compliance with those identified regulatory provisions. The facility will examine and analyze future regulations that may apply and determine their applicability with any necessary action taken on a timely basis.

SECTION VI: PLANTWIDE CONDITIONS

1. The permittee shall notify the Director in writing within thirty (30) days after commencing construction, completing construction, first placing the equipment and/or facility in operation, and reaching the equipment and/or facility target production rate. [Regulation 19 §19.704, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

2. If the permittee fails to start construction within eighteen months or suspends construction for eighteen months or more, the Director may cancel all or part of this permit. [Regulation 19 §19.410(B) and 40 CFR Part 52, Subpart E]

3. The permittee must test any equipment scheduled for testing, unless otherwise stated in the Specific Conditions of this permit or by any federally regulated requirements, within the following time frames: (1) new equipment or newly modified equipment within sixty (60) days of achieving the maximum production rate, but no later than 180 days after initial start up of the permitted source or (2) operating equipment according to the time frames set forth by the Department or within 180 days of permit issuance if no date is specified. The permittee must notify the Department of the scheduled date of compliance testing at least fifteen (15) business days in advance of such test. The permittee shall submit the compliance test results to the Department within thirty (30) calendar days after completing the testing. [Regulation 19 §19.702 and/or Regulation 18 §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

4. The permittee must provide:

   a. Sampling ports adequate for applicable test methods;
   b. Safe sampling platforms;
   c. Safe access to sampling platforms; and
   d. Utilities for sampling and testing equipment.

   [Regulation 19 §19.702 and/or Regulation 18 §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

5. The permittee must operate the equipment, control apparatus and emission monitoring equipment within the design limitations. The permittee shall maintain the equipment in good condition at all times. [Regulation 19 §19.303 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

6. This permit subsumes and incorporates all previously issued air permits for this facility. [Regulation 26 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Chemical Accident Prevention Provisions

7. The permittee shall comply with all applicable provisions of 40 CFR §68.1 through §68.220. [40 CFR Part §68]

Oil Tank Requirement for SN-22, SN-25, and SN-26

8. The permittee shall monitor and record on a daily basis the fuel oil storage tank level which will be used to calculate the as fired sulfur content on a 30-day rolling average. The recorded 30-day rolling average value shall not exceed 1.0% by weight. This record shall be updated on a monthly basis. This report shall be submitted to the Department in accordance with General Provision #7 [§19.705 of Regulation #19 and 40 CFR Part 52 Subpart E]

9. The sulfur content of the fuel oil shall be verified by testing or vendors' guarantees. The permittee shall maintain a record of each fuel shipment and the associated sulfur content. This record shall be updated with each shipment, kept on site, shall be made available to Department personnel upon request and may be used by the Department for enforcement purposes. This report shall be submitted to the Department in accordance with General Provision #7. [§19.705 of Regulation #19 and 40 CFR Part 52 Subpart E]

Requirements for a Passing NAAQS Demonstration

10. In accordance with the air dispersion modeling analyses report submitted for the Crossett Complex on March 29, 2011, the permittee shall assure that the following changes to the Plywood/Studmill are completed before starting up any new and/or modified air emitting equipment associated with the Diamond Project. Upon completion of the changes, Georgia-Pacific's Crossett Paper Operations will submit a written report to the Department certifying that all of the changes described in sections a- c below, or as alternatively agreed pursuant to section d below, have been completed:

    a. Install a powered ventilation system over each board press and discharge the press exhaust through a stack. Each stack will have a height of 40 feet or greater, and a stack diameter of 4.5 feet or less.

    b. Pave sections of unpaved log truck roads at the Plywood/Studmill facility to mitigate fugitive dust emissions. The sections of log truck roads to be paved are identified in the March 29, 2011 modeling analyses report.

    c. The following wood residual material handling cyclones shall be retrofitted with baghouses to reduce PM_{10} emissions. The permittee shall maintain documentation that each baghouse achieves an outlet PM_{10} grain loading of 0.005 grain/dscf or less:

        i. C9, Wood Residuals Collection System (Plant #2)
        ii. C11, Wood Residuals Collection System (Plant #1)
        iii. C12, Wood Residuals Collection System (Plant #1)

d. Georgia-Pacific Plywood/Studmill may elect to conduct additional air dispersion modeling which demonstrates compliance with the National Ambient Air Quality Standards (NAAQS) modeled in the March 29, 2011 report. Such additional modeling may consider any combination of the above listed changes, or any other facility configuration (including other changes not listed above) that achieves a modeling resolution showing compliance with the pertinent NAAQS. Any such additional modeling, along with supporting documentation, shall be submitted to the Department prior to the planned commencement of any of the Plywood/Studmill changes. If such additional modeling demonstrates that any of the facility changes listed in #s 1-3 above are no longer necessary for NAAQS compliance demonstration purposes, and written concurrence is obtained from the Department, then the permittee shall only be required to complete the facility changes, if any, relied upon in the updated modeling analysis.

e. Prior to starting up any new and/or modified air emitting equipment associated with the Diamond Project, the Paper Operations shall submit written certification to the Department that the Plywood/Studmill has completed all such required changes (i.e., those listed in #s 1-3 above or as relied upon in any revised complex-wide air dispersion modeling analyses reviewed and approved by the Department). [§19.705 of Regulation #19 and 40 CFR Part 52 Subpart E]

11. In accordance with the air dispersion modeling analyses report submitted for the Crossett Complex on March 29, 2011, the permittee shall assure that the following changes to the Paper facility are completed before starting up any new and/or modified air emitting equipment associated with the Diamond Project of Air Permit 597-AOP-R13:

Source	Stack Change
SN-115	Modify to Vertical Stack
SN-116	
SN-117	
SN-118	
SN-119	
SN-120	
SN-121	

Upon completion of the changes, Georgia-Pacific's Crossett Paper Operations will submit a written report to the Department certifying that all of the changes described below have been completed. [§19.705 of Regulation #19 and 40 CFR Part 52 Subpart E]

12. The following requirements shall apply to any new Diamond project source or any existing source affected by the Diamond project changes as submitted to the Department in the January 11, 2011 application.

a. Except as otherwise provided in paragraph (r)(6)(vi)(b) of this section, the provisions of this paragraph (r)(6) apply with respect to any regulated NSR pollutant emitted from projects at existing emissions units at a major stationary source (other than projects at a source with a PAL) in circumstances where there is a reasonable possibility, within the meaning of paragraph (r)(6)(vi) of this section, that a project that is not a part of a major modification may result in a significant emissions increase of such pollutant, and the owner or operator elects to use the method specified in paragraphs (b)(41)(ii)(a) through (c) of this section for calculating projected actual emissions.

i. Before beginning actual construction of the project, the owner or operator shall document and maintain a record of the following information:

ii. A description of the project;

iii. Identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project; and

iv. A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded under paragraph (b)(41)(ii)(c) of this section and an explanation for why such amount was excluded, and any netting calculations, if applicable.

b. The owner or operator shall monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any emissions unit identified in paragraph (r)(6)(i)(b) of this section; and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5 years following resumption of regular operations after the change, or for a period of 10 years following resumption of regular operations after the change if the project increases the design capacity or potential to emit that regulated NSR pollutant at such emissions unit.

c. If the unit is an existing unit other than an electric utility steam generating unit, the owner or operator shall submit a report to the Administrator if the annual emissions, in tons per year, from the project identified in paragraph (r)(6)(i) of this section, exceed the baseline actual emissions (as documented and maintained pursuant to paragraph (r)(6)(i)(c) of this section), by a significant amount (as defined in paragraph (b)(23) of this section) for that regulated NSR pollutant, and if such emissions differ from the preconstruction projection as documented and maintained pursuant to paragraph (r)(6)(i)(c) of this section. Such report shall be submitted to the Administrator within 60 days after the end of such year. The report shall contain the following:

i. The name, address and telephone number of the major stationary source;

ii. The annual emissions as calculated pursuant to paragraph (r)(6)(iii) of this section; and

iii. Any other information that the owner or operator wishes to include in the report (e.g., an explanation as to why the emissions differ from the preconstruction projection).

d. A "reasonable possibility" under paragraph (r)(6) of this section occurs when the owner or operator calculates the project to result in either:

i. A projected actual emissions increase of at least 50 percent of the amount that is a "significant emissions increase," as defined under paragraph (b)(40) of this section (without reference to the amount that is a significant net emissions increase), for the regulated NSR pollutant; or

ii. A projected actual emissions increase that, added to the amount of emissions excluded under paragraph (b)(41)(ii)(c) of this section, sums to at least 50 percent of the amount that is a "significant emissions increase," as defined under paragraph (b)(40) of this section (without reference to the amount that is a significant net emissions increase), for the regulated NSR pollutant. For a project for which a reasonable possibility occurs only within the meaning of paragraph (r)(6)(vi)(b) of this section, and not also within the meaning of paragraph (r)(6)(vi)(a) of this section, then provisions (r)(6)(ii) through (v) do not apply to the project.

e. The owner or operator of the source shall make the information required to be documented and maintained pursuant to paragraph (r)(6) of this section available for review upon a request for inspection by the Administrator or the general public pursuant to the requirements contained in §70.4(b)(3)(viii) of this chapter.

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13. The permittee must limit organic HAP emissions at SN-71, 72, and 80 to the level specified in paragraph (b)(1), (2), or (3) of this section. [40 CFR Part §63.3320(b)(i-iii)]

a. **New Sources**

i. No more than 2 percent of the organic HAP applied for each month (98 percent reduction) [40 CFR §63.3320(b)(1)]

ii. No more than 1.6 percent of the mass of coating materials applied for each month [40 CFR §63.3320(b)(2)]

iii. No more than 8 percent of the coating solids applied for each month [40 CFR §63.3320(b)(3)]

b. **Existing Sources**

i. No more than 5 percent of the organic HAP applied for each month (95 percent reduction) [40 CFR §63.3320(b)(1)]

ii. No more than 4 percent of the mass of coating materials applied for each month [40 CFR §63.3320(b)(2)]

iii. No more than 20 percent of the mass of coating solids applied for each month [40 CFR §63.3320(b)(3)]

14. A new affected source subject to the provisions of this subpart, your compliance date is immediately upon start-up of the new affected source or by December 4, 2002, whichever is later. You must complete any performance test required in §63.3360 within the time limits specified in §63.7(a)(2). [40 CFR Part §63.3330(a)]

15. An existing affected source subject to the provisions of this subpart, you must comply by the compliance date. The compliance date for existing affected sources in this subpart is December 5, 2005. You must complete any performance test required in §63.3360 within the time limits specified in §63.7(a)(2). [40 CFR Part §63.3330(b)]

16. **Organic HAP content**. If you determine compliance with the emission standards in §63.3320 by means other than determining the overall organic HAP control efficiency of a control device, you must determine the organic HAP mass fraction of each coating material "as-purchased" by following one of the procedures in paragraphs (c)(1) through (3) of this section, and determine the organic HAP mass fraction of each coating material "as-applied" by following the procedures in paragraph (c)(4) of this section. If the organic HAP content values are not determined using the procedures in paragraphs (c)(1) through (3) of this section, the owner or operator must submit an alternative test method for determining their values for approval by the Administrator in accordance with §63.7(f). The recovery efficiency of the test method must be determined for all of the target organic HAP and a correction factor, if necessary, must be determined and applied.

a. **Method 311.** You may test the coating material in accordance with Method 311 of appendix A of this part. The Method 311 determination may be performed by the manufacturer of the coating material and the results provided to the owner or operator. The organic HAP content must be calculated according to the criteria and procedures in paragraphs (c)(1)(i) through (iii) of this section. [40 CFR §63.3360(c)(1)]

i. Include each organic HAP determined to be present at greater than or equal to 0.1 mass percent for Occupational Safety and Health Administration (OSHA)-defined carcinogens as specified in 29 CFR 1910.1200(d)(4) and greater than or equal to 1.0 mass percent for other organic HAP compounds. [40 CFR §63.3360(c)(1)(i)]

ii. Express the mass fraction of each organic HAP you include according to paragraph (c)(1)(i) of this section as a value truncated to four places after the decimal point (for example, 0.3791). [40 CFR §63.3360(c)(1)(ii)]

iii. Calculate the total mass fraction of organic HAP in the tested material by summing the counted individual organic HAP mass fractions and truncating the result to three places after the decimal point (for example, 0.763). [40 CFR §63.3360(c)(1)(iii)]

b. **Method 24.** For coatings, determine the volatile organic content as mass fraction of non-aqueous volatile matter and use it as a substitute for organic HAP using Method 24 of 40 CFR part 60, appendix A. The Method 24 determination may be performed by the manufacturer of the coating and the results provided to you. [40 CFR §63.3360(c)(2)]

c. **Formulation data.** You may use formulation data to determine the organic HAP mass fraction of a coating material. Formulation data may be provided to the owner or operator by the manufacturer of the material. In the event of an inconsistency between Method 311 (appendix A of 40 CFR part 63) test data and a facility's formulation data, and the Method 311 test value is higher, the Method 311 data will govern. Formulation data may be used provided that the information represents all organic HAP present at a level equal to or greater than 0.1 percent for OSHA-defined carcinogens as specified in 29 CFR 1910.1200(d)(4) and equal to or greater than 1.0 percent for other organic HAP compounds in any raw material used. [40 CFR §63.3360(c)(3)]

d. **As-applied organic HAP mass fraction.** If the as-purchased coating material is applied to the web without any solvent or other material added, then the as-applied organic HAP mass fraction is equal to the as-purchased organic HAP mass fraction. Otherwise, the as-applied organic HAP mass fraction must be calculated using Equation 1a of §63.3370. [40 CFR §63.3360(c)(4)]

17. **Volatile organic and coating solids content.** If you determine compliance with the emission standards in §63.3320 by means other than determining the overall organic HAP control efficiency of a control device and you choose to use the volatile organic content as a surrogate for the organic HAP content of coatings, you must determine the as-purchased volatile organic content and coating solids content of each coating material applied by following the procedures in paragraph (d)(1) or (2) of this section, and the as-

applied volatile organic content and coating solids content of each coating material by following the procedures in paragraph (d)(3) of this section.

a. **Method 24**. You may determine the volatile organic and coating solids mass fraction of each coating applied using Method 24 (40 CFR part 60, appendix A.) The Method 24 determination may be performed by the manufacturer of the material and the results provided to you. If these values cannot be determined using Method 24, you must submit an alternative technique for determining their values for approval by the Administrator. [40 CFR §63.3360(d)(1)]

b. **Formulation data**. You may determine the volatile organic content and coating solids content of a coating material based on formulation data and may rely on volatile organic content data provided by the manufacturer of the material. In the event of any inconsistency between the formulation data and the results of Method 24 of 40 CFR part 60, appendix A, and the Method 24 results are higher, the results of Method 24 will govern. [40 CFR §63.3360(d)(2)]

c. **As-applied volatile organic content and coating solids content**. If the as-purchased coating material is applied to the web without any solvent or other material added, then the as-applied volatile organic content is equal to the as-purchased volatile content and the as-applied coating solids content is equal to the as-purchased coating solids content. Otherwise, the as-applied volatile organic content must be calculated using Equation 1b of §63.3370 and the as-applied coating solids content must be calculated using Equation 2 of §63.3370. [40 CFR §63.3360(d)(3)]

18. **Volatile matter retained in the coated web or otherwise not emitted to the atmosphere.** The permittee may choose to take into account the mass of volatile matter retained in the coated web after curing or drying or otherwise not emitted to the atmosphere when determining compliance with the emission standards in §63.3320. If you choose this option, you must develop a testing protocol to determine the mass of volatile matter retained in the coated web or otherwise not emitted to the atmosphere and submit this protocol to the Administrator for approval. You must submit this protocol with your site-specific test plan under §63.7(f). If you intend to take into account the mass of volatile matter retained in the coated web after curing or drying or otherwise not emitted to the atmosphere and demonstrate compliance according to §63.3370(c)(3), (c)(4), (c)(5), or (d), then the test protocol you submit must determine the mass of organic HAP retained in the coated web or otherwise not emitted to the atmosphere. Otherwise, compliance must be shown using the volatile organic matter content as a surrogate for the HAP content of the coatings. [40 CFR Part §63.3360(g)]

19. The permittee must demonstrate compliance with this subpart by following the procedures in §63.3370.

a. **As-purchased "compliant" coating materials**

i. If you comply by using coating materials that individually meet the emission standards in §63.3320(b)(2) or (3), you must demonstrate that each coating material applied during the month at an existing affected source contains no more than 0.04 mass fraction organic HAP or 0.2 kg organic HAP per kg coating solids, and that each coating material applied during the month at a new affected source contains no more than 0.016 mass fraction organic HAP or 0.08 kg organic HAP per kg coating solids on an as-purchased basis as determined in accordance with §63.3360(c). [40 CFR Part §63.3370(b)(1)]

ii. You are in compliance with emission standards in §63.3320(b)(2) and (3) if each coating material applied at an existing affected source is applied as-purchased and contains no more than 0.04 kg organic HAP per kg coating material or 0.2 kg organic HAP per kg coating solids, and each coating material applied at a new affected source is applied as-purchased and contains no more than 0.016 kg organic HAP per kg coating material or 0.08 kg organic HAP per kg coating solids. [40 CFR Part §63.3370(b)(2)]

b. **Use of "as-applied" compliant coating materials**

i. Each coating material as-applied meets the mass fraction of coating material standard (§63.3320(b)(2)). You must demonstrate that each coating material applied at an existing affected source during the month contains no more than 0.04 kg organic HAP per kg coating material applied, and each coating material applied at a new affected source contains no more than 0.016 kg organic HAP per kg coating material applied as determined in accordance with paragraphs (c)(1)(i) and (ii) of this section. You must calculate the as-applied organic HAP content of as-purchased coating materials which are reduced, thinned, or diluted prior to application. [40 CFR Part §63.3370(c)(1)(i) and (ii)]

1. Determine the organic HAP content or volatile organic content of each coating material applied on an as-purchased basis in accordance with §63.3360(c).

2. Calculate the as-applied organic HAP content of each coating material using Equation 1a or 1b of this section

ii. Each coating material as-applied meets the mass fraction of coating solids standard (§63.3320(b)(3)). You must demonstrate that each coating material applied at an existing affected source contains no more than 0.20 kg of organic HAP per kg of coating solids applied and each coating material applied at a new affected source contains no more than 0.08 kg of organic HAP per kg of coating solids applied. You must demonstrate compliance in accordance with paragraphs (c)(2)(i) and (ii) of this section. [40 CFR Part §63.3370(c)(2)(i) and (ii)]

1. Determine the as-applied coating solids content of each coating material following the procedure in §63.3360(d). You must calculate the as-applied coating solids content of coating materials which are reduced, thinned, or diluted prior to application, using Equation 2 of this section

2. Calculate the as-applied organic HAP to coating solids ratio using Equation 3 of this section.

iii. Monthly average organic HAP content of all coating materials as-applied is less than the mass percent limit (§63.3320(b)(2)). Demonstrate that the monthly average as-applied organic HAP content of all coating materials applied at an existing affected source is less than 0.04 kg organic HAP per kg of coating material applied, and all coating materials applied at a new affected source are less than 0.016 kg organic HAP per kg of coating material applied, as determined by Equation 4 of this section. [40 CFR Part §63.3370(c)(3)]

iv. Monthly average organic HAP content of all coating materials as-applied is less than the mass percent limit (§63.3320(b)(2)). Demonstrate that the monthly average as-applied organic HAP content of all coating materials applied at an existing affected source is less than 0.04 kg organic HAP per kg of coating material applied, and all coating materials applied at a new affected source are less than 0.016 kg organic HAP per kg of coating material applied, as determined by Equation 4 of this section. [40 CFR Part §63.3370(c)(4)]

v. The affected source is in compliance with emission standards in §63.3320(b)(2) or (3) if: [40 CFR Part §63.3370(c)(5)(i) and (ii)]

1. The organic HAP content of each coating material as-applied at an existing affected source is no more than 0.04 kg organic HAP per kg coating material or 0.2 kg organic HAP per kg coating solids, and the organic HAP content of each coating material as-applied at a new affected source contains no more than 0.016 kg organic HAP per kg coating material or 0.08 kg organic HAP per kg coating solids; or

2. The monthly average organic HAP content of all as-applied coating materials at an existing affected source are no more than 0.04 kg organic HAP per kg coating material or 0.2 kg organic

HAP per kg coating solids, and the monthly average organic HAP content of all as-applied coating materials at a new affected source is no more than 0.016 kg organic HAP per kg coating material or 0.08 kg organic HAP per kg coating solids.

c. **Tracking total monthly organic HAP applied.** Demonstrate that the total monthly organic HAP applied as determined by Equation 6 of this section is less than the calculated equivalent allowable organic HAP as determined by Equation 13a or b in paragraph (l) of this section. [40 CFR Part §63.3370(d)]

20. The permittee must submit an initial notification as required by §63.9(b). [40 CFR Part §63.3400(b)(1-4)]

a. Initial notification for existing affected sources must be submitted no later than 1 year before the compliance date specified in §63.3330(a).

b. Initial notification for new and reconstructed affected sources must be submitted as required by §63.9(b).

c. For the purpose of this subpart, a title V or part 70 permit application may be used in lieu of the initial notification required under §63.9(b), provided the same information is contained in the permit application as required by §63.9(b) and the State to which the permit application has been submitted has an approved operating permit program under part 70 of this chapter and has received delegation of authority from the EPA to implement and enforce this subpart.

d. If you are using a permit application in lieu of an initial notification in accordance with paragraph (b)(3) of this section, the permit application must be submitted by the same due date specified for the initial notification.

21. The permittee must submit a semiannual compliance report according to paragraphs (c)(1) and (2) of this section.

a. Compliance report dates. [40 CFR Part §63.3400(c)(1)(i-v)]

i. The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.3330 and ending on June 30 or December 31, whichever date is the first date following the end of the calendar half immediately following the compliance date that is specified for your affected source in §63.3330.

ii. The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the calendar half immediately following the compliance date that is specified for your affected source in §63.3330.

iii. Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

iv. Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

v. For each affected source that is subject to permitting regulations pursuant to 40 CFR part 70 or 40 CFR part 71, and the permitting authority has established dates for submitting semiannual reports pursuant to §70.6(a)(3)(iii)(A) or §71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (c)(1)(i) through (iv) of this section.

b. The compliance report must contain the information in paragraphs (c)(2)(i) through (vi) of this section: [40 CFR Part §63.3400(c)(2)(i-v)]

i. Company name and address.

ii. Statement by a responsible official with that official's name, title, and signature certifying the accuracy of the content of the report.

iii. Date of report and beginning and ending dates of the reporting period.

iv. If there are no deviations from any emission limitations (emission limit or operating limit) that apply to you, a statement that there were no deviations from the emission limitations during the reporting period, and that no CMS was inoperative, inactive, malfunctioning, out-of-control, repaired, or adjusted.

v. For each deviation from an emission limitation (emission limit or operating limit) that applies to you and that occurs at an affected source where you are not using a CEMS to comply with the emission limitations in this subpart, the compliance report must contain the information in paragraphs (c)(2)(i) through (iii) of this section, and:

1. The total operating time of each affected source during the reporting period.

2. Information on the number, duration, and cause of deviations (including unknown cause), if applicable, and the corrective action taken.

3. Information on the number, duration, and cause for CPMS downtime incidents, if applicable, other than downtime associated with zero and span and other calibration checks.

22. The permittee must submit a Notification of Compliance Status as specified in §63.9(h). [40 CFR Part §63.3400(e)]

23. Each owner or operator of an affected source subject to this subpart must maintain the records specified in paragraphs (a)(1) and (2) of this section on a monthly basis in accordance with the requirements of §63.10(b)(1).. Records specified in §63.10(b)(2) of all measurements needed to demonstrate compliance with this standard, including: [40 CFR Part §63.3401(a)(1)(i-vi)]

  a. Organic HAP content data for the purpose of demonstrating compliance in accordance with the requirements of §63.3360(c);
  b. Volatile matter and coating solids content data for the purpose of demonstrating compliance in accordance with the requirements of §63.3360(d);

  c. Material usage, organic HAP usage, volatile matter usage, and coating solids usage and compliance demonstrations using these data in accordance with the requirements of §63.3370(b), (c), and (d).

Title VI Provisions

24. The permittee must comply with the standards for labeling of products using ozone-depleting substances. [40 CFR Part 82, Subpart E]

  a. All containers containing a class I or class II substance stored or transported, all products containing a class I substance, and all products directly manufactured with a class I substance must bear the required warning statement if it is being introduced to interstate commerce pursuant to §82.106.

  b. The placement of the required warning statement must comply with the requirements pursuant to §82.108.

  c. The form of the label bearing the required warning must comply with the requirements pursuant to §82.110.

  d. No person may modify, remove, or interfere with the required warning statement except as described in §82.112.

25. The permittee must comply with the standards for recycling and emissions reduction, except as provided for MVACs in Subpart B. [40 CFR Part 82, Subpart F]

a. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to §82.156.

b. Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to §82.158.

c. Persons performing maintenance, service repair, or disposal of appliances must be certified by an approved technician certification program pursuant to §82.161.

d. Persons disposing of small appliances, MVACs, and MVAC like appliances must comply with record keeping requirements pursuant to §82.166. ("MVAC like appliance" as defined at §82.152)

e. Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to §82.156.

f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to §82.166.

26. If the permittee manufactures, transforms, destroys, imports, or exports a class I or class II substance, the permittee is subject to all requirements as specified in 40 CFR Part 82, Subpart A, Production and Consumption Controls.

27. If the permittee performs a service on motor (fleet) vehicles when this service involves ozone depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all the applicable requirements as specified in 40 CFR part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners.

28. The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC 22 refrigerant.

29. The permittee can switch from any ozone depleting substance to any alternative listed in the Significant New Alternatives Program (SNAP) promulgated pursuant to 40 CFR Part 82, Subpart G.

SECTION VII: INSIGNIFICANT ACTIVITIES

The following sources are insignificant activities. Any activity that has a state or federal applicable requirement shall be considered a significant activity even if this activity meets the criteria of §26.304 of Regulation 26 or listed in the table below. Insignificant activity determinations rely upon the information submitted by the permittee in an application dated 5/15/2008.

Description	Category
9A Cyclone	A-13
Trim Paper Cyclone	A-13
Perini Towel Rewinder and Spectrum Towel Printer Baghouse	A-13
Spectrum Towel Printer, utilizing 0.21 wt% VOC, no HAP inks	A-13
Filling Starch Silos	A-13
Diesel Fuel Tank	A-3
Turpentine Tank	A-3
No. 8 Extruder Burner, 1.55 and 0.85 MMBTU/hr	A-1
No. 9 Extruder Burners, 1.0 MMBTU/hr (total)	A-1
Gasoline Tank	A-13
No. 6 Fuel Oil Tank 1	A-13
No. 6 Fuel Oil Tank 2	A-13

SECTION VIII: GENERAL PROVISIONS

1. Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.) as the sole origin of and authority for the terms or conditions are not required under the Clean Air Act or any of its applicable requirements, and are not federally enforceable under the Clean Air Act. Arkansas Pollution Control & Ecology Commission Regulation 18 was adopted pursuant to the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.). Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.) as the origin of and authority for the terms or conditions are enforceable under this Arkansas statute. [40 CFR 70.6(b)(2)]

2. This permit shall be valid for a period of five (5) years beginning on the date this permit becomes effective and ending five (5) years later. [40 CFR 70.6(a)(2) and Regulation 26 §26.701(B)]

3. The permittee must submit a complete application for permit renewal at least six (6) months before permit expiration. Permit expiration terminates the permittee's right to operate unless the permittee submitted a complete renewal application at least six (6) months before permit expiration. If the permittee submits a complete application, the existing permit will remain in effect until the Department takes final action on the renewal application. The Department will not necessarily notify the permittee when the permit renewal application is due. [Regulation 26 §26.406]

4. Where an applicable requirement of the Clean Air Act, as amended, 42 U.S.C. 7401, et seq. (Act) is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, the permit incorporates both provisions into the permit, and the Director or the Administrator can enforce both provisions. [40 CFR 70.6(a)(1)(ii) and Regulation 26 §26.701(A)(2)]

5. The permittee must maintain the following records of monitoring information as required by this permit.

   a. The date, place as defined in this permit, and time of sampling or measurements;
   b. The date(s) analyses performed;
   c. The company or entity performing the analyses;
   d. The analytical techniques or methods used;
   e. The results of such analyses; and
   f. The operating conditions existing at the time of sampling or measurement.

   [40 CFR 70.6(a)(3)(ii)(A) and Regulation 26 §26.701(C)(2)]

6. The permittee must retain the records of all required monitoring data and support information for at least five (5) years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. [40 CFR 70.6(a)(3)(ii)(B) and Regulation 26 §26.701(C)(2)(b)]

7. The permittee must submit reports of all required monitoring every six (6) months. If permit establishes no other reporting period, the reporting period shall end on the last day of the anniversary month of the initial Title V permit. The report is due within thirty (30) days of the end of the reporting period. Although the reports are due every six months, each report shall contain a full year of data. The report must clearly identify all instances of deviations from permit requirements. A responsible official as defined in Regulation No. 26, §26.2 must certify all required reports. The permittee will send the reports to the address below:

   Arkansas Department of Environmental Quality
   Air Division
   ATTN: Compliance Inspector Supervisor
   5301 Northshore Drive
   North Little Rock, AR 72118-5317

   [40 CFR 70.6(a)(3)(iii)(A) and Regulation 26 §26.701(C)(3)(a)]

8. The permittee shall report to the Department all deviations from permit requirements, including those attributable to upset conditions as defined in the permit.

   a. For all upset conditions (as defined in Regulation19, § 19.601), the permittee will make an initial report to the Department by the next business day after the discovery of the occurrence. The initial report may be made by telephone and shall include:

      i. The facility name and location;
      ii. The process unit or emission source deviating from the permit limit;
      iii. The permit limit, including the identification of pollutants, from which deviation occurs;
      iv. The date and time the deviation started;
      v. The duration of the deviation;
      vi. The average emissions during the deviation;
      vii. The probable cause of such deviations;
      viii. Any corrective actions or preventive measures taken or being taken to prevent such deviations in the future; and
      ix. The name of the person submitting the report.

The permittee shall make a full report in writing to the Department within five (5) business days of discovery of the occurrence. The report must include, in addition to the information required by the initial report, a schedule of actions taken or planned to eliminate future occurrences and/or to minimize the amount the permit's limits were exceeded and to reduce the length of time the limits were exceeded. The permittee may submit a full report in writing (by facsimile, overnight courier, or other means) by the next business day after discovery of the occurrence, and the report will serve as both the initial report and full report.

b. For all deviations, the permittee shall report such events in semi-annual reporting and annual certifications required in this permit. This includes all upset conditions reported in 8a above. The semi-annual report must include all the information as required by the initial and full reports required in 8a.

[Regulation 19 §19.601 and §19.602, Regulation 26 §26.701(C)(3)(b), and 40 CFR 70.6(a)(3)(iii)(B)]

9. If any provision of the permit or the application thereof to any person or circumstance is held invalid, such invalidity will not affect other provisions or applications hereof which can be given effect without the invalid provision or application, and to this end, provisions of this Regulation are declared to be separable and severable. [40 CFR 70.6(a)(5), Regulation 26 §26.701(E), and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

10. The permittee must comply with all conditions of this Part 70 permit. Any permit noncompliance with applicable requirements as defined in Regulation 26 constitutes a violation of the Clean Air Act, as amended, 42 U.S.C. §7401, et seq. and is grounds for enforcement action; for permit termination, revocation and reissuance, for permit modification; or for denial of a permit renewal application. [40 CFR 70.6(a)(6)(i) and Regulation 26 §26.701(F)(1)]

11. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the conditions of this permit. [40 CFR 70.6(a)(6)(ii) and Regulation 26 §26.701(F)(2)]

12. The Department may modify, revoke, reopen and reissue the permit or terminate the permit for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. [40 CFR 70.6(a)(6)(iii) and Regulation 26 §26.701(F)(3)]

13. This permit does not convey any property rights of any sort, or any exclusive privilege. [40 CFR 70.6(a)(6)(iv) and Regulation 26 §26.701(F)(4)]

14. The permittee must furnish to the Director, within the time specified by the Director, any information that the Director may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee must also furnish to the Director copies of records required by the permit. For information the permittee claims confidentiality, the Department may require the permittee to furnish such records directly to the Director along with a claim of confidentiality. [40 CFR 70.6(a)(6)(v) and Regulation 26 §26.701(F)(5)]

15. The permittee must pay all permit fees in accordance with the procedures established in Regulation 9. [40 CFR 70.6(a)(7) and Regulation 26 §26.701(G)]

16. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes provided for elsewhere in this permit. [40 CFR 70.6(a)(8) and Regulation 26 §26.701(H)]

17. If the permit allows different operating scenarios, the permittee shall, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility a record of the operational scenario. [40 CFR 70.6(a)(9)(i) and Regulation 26 §26.701(I)(1)]

18. The Administrator and citizens may enforce under the Act all terms and conditions in this permit, including any provisions designed to limit a source's potential to emit, unless the Department specifically designates terms and conditions of the permit as being federally unenforceable under the Act or under any of its applicable requirements. [40 CFR 70.6(b) and Regulation 26 §26.702(A) and (B)]

19. Any document (including reports) required by this permit must contain a certification by a responsible official as defined in Regulation 26, §26.2. [40 CFR 70.6(c)(1) and Regulation 26 §26.703(A)]

20. The permittee must allow an authorized representative of the Department, upon presentation of credentials, to perform the following: [40 CFR 70.6(c)(2) and Regulation 26 §26.703(B)]

    a. Enter upon the permittee's premises where the permitted source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;
    b. Have access to and copy, at reasonable times, any records required under the conditions of this permit;
    c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and

d. As authorized by the Act, sample or monitor at reasonable times substances or parameters for assuring compliance with this permit or applicable requirements.

21. The permittee shall submit a compliance certification with the terms and conditions contained in the permit, including emission limitations, standards, or work practices. The permittee must submit the compliance certification annually within 30 days following the last day of the anniversary month of the initial Title V permit. The permittee must also submit the compliance certification to the Administrator as well as to the Department. All compliance certifications required by this permit must include the following: [40 CFR 70.6(c)(5) and Regulation 26 §26.703(E)(3)]

a. The identification of each term or condition of the permit that is the basis of the certification;
b. The compliance status;
c. Whether compliance was continuous or intermittent;
d. The method(s) used for determining the compliance status of the source, currently and over the reporting period established by the monitoring requirements of this permit; and
e. Such other facts as the Department may require elsewhere in this permit or by §114(a)(3) and §504(b) of the Act.

22. Nothing in this permit will alter or affect the following: [Regulation 26 §26.704(C)]

a. The provisions of Section 303 of the Act (emergency orders), including the authority of the Administrator under that section;
b. The liability of the permittee for any violation of applicable requirements prior to or at the time of permit issuance;
c. The applicable requirements of the acid rain program, consistent with §408(a) of the Act; or
d. The ability of EPA to obtain information from a source pursuant to §114 of the Act.

23. This permit authorizes only those pollutant emitting activities addressed in this permit. [A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

24. The permittee may request in writing and at least 15 days in advance of the deadline, an extension to any testing, compliance or other dates in this permit. No such extensions are authorized until the permittee receives written Department approval. The Department may grant such a request, at its discretion in the following circumstances:

a. Such an extension does not violate a federal requirement;
b. The permittee demonstrates the need for the extension; and
c. The permittee documents that all reasonable measures have been taken to meet the current deadline and documents reasons it cannot be met.

[Regulation 18 §18.314(A), Regulation 19 §19.416(A), Regulation 26 §26.1013(A), A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

25. The permittee may request in writing and at least 30 days in advance, temporary emissions and/or testing that would otherwise exceed an emission rate, throughput requirement, or other limit in this permit. No such activities are authorized until the permittee receives written Department approval. Any such emissions shall be included in the facility's total emissions and reported as such. The Department may grant such a request, at its discretion under the following conditions:

    a. Such a request does not violate a federal requirement;
    b. Such a request is temporary in nature;
    c. Such a request will not result in a condition of air pollution;
    d. The request contains such information necessary for the Department to evaluate the request, including but not limited to, quantification of such emissions and the date/time such emission will occur;
    e. Such a request will result in increased emissions less than five tons of any individual criteria pollutant, one ton of any single HAP and 2.5 tons of total HAPs; and
    f. The permittee maintains records of the dates and results of such temporary emissions/testing.

    [Regulation 18 §18.314(B), Regulation 19 §19.416(B), Regulation 26 §26.1013(B), A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

26. The permittee may request in writing and at least 30 days in advance, an alternative to the specified monitoring in this permit. No such alternatives are authorized until the permittee receives written Department approval. The Department may grant such a request, at its discretion under the following conditions:

    a. The request does not violate a federal requirement;
    b. The request provides an equivalent or greater degree of actual monitoring to the current requirements; and
    c. Any such request, if approved, is incorporated in the next permit modification application by the permittee.

    [Regulation 18 §18.314(C), Regulation 19 §19.416(C), Regulation 26 §26.1013(C), A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

APPENDIX A - CONTINUOUS EMISSION MONITORING SYSTEMS

Arkansas Department of Environmental Quality

CONTINUOUS EMISSION MONITORING SYSTEMS CONDITIONS

Revised August 2004

PREAMBLE

These conditions are intended to outline the requirements for facilities required to operate Continuous Emission Monitoring Systems/Continuous Opacity Monitoring Systems (CEMS/COMS). Generally there are three types of sources required to operate CEMS/COMS:

1. CEMS/COMS required by 40 CFR Part 60 or 63,
2. CEMS required by 40 CFR Part 75,
3. CEMS/COMS required by ADEQ permit for reasons other that Part 60, 63 or 75.

These CEMS/COMS conditions are not intended to supercede Part 60, 63 or 75 requirements.

- Only CEMS/COMS in the third category (those required by ADEQ permit for reasons other than Part 60, 63, or 75) shall comply with SECTION II, MONITORING REQUIREMENTS and SECTION IV, QUALITY ASSURANCE/QUALITY CONTROL.

- All CEMS/COMS shall comply with Section III, NOTIFICATION AND RECORDKEEPING.

SECTION I

DEFINITIONS

Continuous Emission Monitoring System (CEMS) - The total equipment required for the determination of a gas concentration and/or emission rate so as to include sampling, analysis and recording of emission data.

Continuous Opacity Monitoring System (COMS) - The total equipment required for the determination of opacity as to include sampling, analysis and recording of emission data.

Calibration Drift (CD) - The difference in the CEMS output reading from the established reference value after a stated period of operation during which no unscheduled maintenance, repair, or adjustments took place.

Back-up CEMS (Secondary CEMS) - A CEMS with the ability to sample, analyze and record stack pollutant to determine gas concentration and/or emission rate. This CEMS is to serve as a back-up to the primary CEMS to minimize monitor downtime.

Excess Emissions - Any period in which the emissions exceed the permit limits.

Monitor Downtime - Any period during which the CEMS/COMS is unable to sample, analyze and record a minimum of four evenly spaced data points over an hour, except during one daily zero-span check during which two data points per hour are sufficient.

Out-of-Control Period - Begins with the time corresponding to the completion of the fifth, consecutive, daily CD check with a CD in excess of two times the allowable limit, or the time corresponding to the completion of the daily CD check preceding the daily CD check that results in a CD in excess of four times the allowable limit and the time corresponding to the completion of the sampling for the RATA, RAA, or CGA which exceeds the limits outlined in Section IV. Out-of-Control Period ends with the time corresponding to the completion of the CD check following corrective action with the results being within the allowable CD limit or the completion of the sampling of the subsequent successful RATA, RAA, or CGA.

Primary CEMS - The main reporting CEMS with the ability to sample, analyze, and record stack pollutant to determine gas concentration and/or emission rate.

Relative Accuracy (RA) - The absolute mean difference between the gas concentration or emission rate determined by the CEMS and the value determined by the reference method plus the 2.5 percent error confidence coefficient of a series of tests divided by the mean of the reference method tests of the applicable emission limit.

Span Value – The upper limit of a gas concentration measurement range.

SECTION II

MONITORING REQUIREMENTS

A. For new sources, the installation date for the CEMS/COMS shall be no later than thirty (30) days from the date of start-up of the source.

B. For existing sources, the installation date for the CEMS/COMS shall be no later than sixty (60) days from the issuance of the permit unless the permit requires a specific date.

C. Within sixty (60) days of installation of a CEMS/COMS, a performance specification test (PST) must be completed. PST's are defined in 40 CFR, Part 60, Appendix B, PS 1-9. The Department may accept alternate PST's for pollutants not covered by Appendix B on a case-by-case basis. Alternate PST's shall be approved, in writing, by the ADEQ CEM Coordinator prior to testing.

D. Each CEMS/COMS shall have, as a minimum, a daily zero-span check. The zero-span shall be adjusted whenever the 24-hour zero or 24-hour span drift exceeds two times the limits in the applicable performance specification in 40 CFR, Part 60, Appendix B. Before any adjustments are made to either the zero or span drifts measured at the 24-hour interval the excess zero and span drifts measured must be quantified and recorded.

E. All CEMS/COMS shall be in continuous operation and shall meet minimum frequency of operation requirements of 95% up-time for each quarter for each pollutant measured. Percent of monitor down-time is calculated by dividing the total minutes the monitor is not in operation by the total time in the calendar quarter and multiplying by one hundred. Failure to maintain operation time shall constitute a violation of the CEMS conditions.

F. Percent of excess emissions are calculated by dividing the total minutes of excess emissions by the total time the source operated and multiplying by one hundred. Failure to maintain compliance may constitute a violation of the CEMS conditions.

G. All CEMS measuring emissions shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive fifteen minute period unless more cycles are required by the permit. For each CEMS, one-hour averages shall be computed from four or more data points equally spaced over each one hour period unless more data points are required by the permit.

H. All COMS shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

I. When the pollutant from a single affected facility is released through more than one point, a CEMS/COMS shall be installed on each point unless installation of fewer systems is approved, in writing, by the ADEQ CEM Coordinator. When more than one CEM/COM is used to monitor emissions from one affected facility the owner or operator shall report the results as required from each CEMS/COMS.

SECTION III

NOTIFICATION AND RECORD KEEPING

A. When requested to do so by an owner or operator, the ADEQ CEM Coordinator will review plans for installation or modification for the purpose of providing technical advice to the owner or operator.

B. Each facility which operates a CEMS/COMS shall notify the ADEQ CEM Coordinator of the date for which the demonstration of the CEMS/COMS performance will commence (i.e. PST, RATA, RAA, CGA). Notification shall be received in writing no less than 15 days prior to testing. Performance test results shall be submitted to the Department within thirty days after completion of testing.

C. Each facility which operates a CEMS/COMS shall maintain records of the occurrence and duration of start up/shut down, cleaning/soot blowing, process problems, fuel problems, or other malfunction in the operation of the affected facility which causes excess emissions. This includes any malfunction of the air pollution control equipment or any period during which a continuous monitoring device/system is inoperative.

D. Except for Part 75 CEMs, each facility required to install a CEMS/COMS shall submit an excess emission and monitoring system performance report to the Department (Attention: Air Division, CEM Coordinator) at least quarterly, unless more frequent submittals are warranted to assess the compliance status of the facility. Quarterly reports shall be postmarked no later than the 30th day of the month following the end of each calendar quarter. Part 75 CEMs shall submit this information semi-annually and as part of Title V six (6) month reporting requirement if the facility is a Title V facility.

E. All excess emissions shall be reported in terms of the applicable standard. Each report shall be submitted on ADEQ Quarterly Excess Emission Report Forms. Alternate forms may be used with prior written approval from the Department.

F. Each facility which operates a CEMS/COMS must maintain on site a file of CEMS/COMS data including all raw data, corrected and adjusted, repair logs, calibration checks, adjustments, and test audits. This file must be retained for a period of at least five years, and is required to be maintained in such a condition that it can easily be audited by an inspector.

G. Except for Part 75 CEMs, quarterly reports shall be used by the Department to determine compliance with the permit. For Part 75 CEMs, the semi-annual report shall be used.

SECTION IV

QUALITY ASSURANCE/QUALITY CONTROL

A. For each CEMS/COMS a Quality Assurance/Quality Control (QA/QC) plan shall be submitted to the Department (Attn.: Air Division, CEM Coordinator). CEMS quality assurance procedures are defined in 40 CFR, Part 60, Appendix F. This plan shall be submitted within 180 days of the CEMS/COMS installation. A QA/QC plan shall consist of procedure and practices which assures acceptable level of monitor data accuracy, precision, representativeness, and availability.

B. The submitted QA/QC plan for each CEMS/COMS shall not be considered as accepted until the facility receives a written notification of acceptance from the Department.

C. Facilities responsible for one, or more, CEMS/COMS used for compliance monitoring shall meet these minimum requirements and are encouraged to develop and implement a more extensive QA/QC program, or to continue such programs where they already exist. Each QA/QC program must include written procedures which should describe in detail, complete, step-by-step procedures and operations for each of the following activities:

1. Calibration of CEMS/COMS
    a. Daily calibrations (including the approximate time(s) that the daily zero and span drifts will be checked and the time required to perform these checks and return to stable operation)
2. Calibration drift determination and adjustment of CEMS/COMS
    a. Out-of-control period determination
    b. Steps of corrective action
3. Preventive maintenance of CEMS/COMS
    a. CEMS/COMS information
        1) Manufacture
        2) Model number
        3) Serial number
    b. Scheduled activities (check list)
    c. Spare part inventory
4. Data recording, calculations, and reporting
5. Accuracy audit procedures including sampling and analysis methods
6. Program of corrective action for malfunctioning CEMS/COMS

D. A Relative Accuracy Test Audit (RATA), shall be conducted at least once every four calendar quarters. A Relative Accuracy Audit (RAA), or a Cylinder Gas Audit (CGA), may be conducted in the other three quarters but in no more than three quarters in succession. The RATA should be conducted in accordance with the applicable test procedure in 40 CFR Part 60 Appendix A and calculated in accordance with the applicable performance specification in 40 CFR Part 60 Appendix B. CGA's and RAA's should be conducted and the data calculated in accordance with the procedures outlined on 40 CFR Part 60 Appendix F.

If alternative testing procedures or methods of calculation are to be used in the RATA, RAA or CGA audits prior authorization must be obtained from the ADEQ CEM Coordinator.

E. Criteria for excessive audit inaccuracy.

RATA

All Pollutants except Carbon Monoxide	> 20% Relative Accuracy
Carbon Monoxide	> 10% Relative Accuracy
All Pollutants except Carbon Monoxide	> 10% of the Applicable Standard
Carbon Monoxide	> 5% of the Applicable Standard
Diluent (O_2 & CO_2)	> 1.0 % O2 or CO2
Flow	> 20% Relative Accuracy

CGA

Pollutant	> 15% of average audit value or 5 ppm difference
Diluent (O_2 & CO_2)	> 15% of average audit value or 5 ppm difference

RAA

Pollutant	> 15% of the three run average or > 7.5 % of the applicable standard
Diluent (O_2 & CO_2)	> 15% of the three run average or > 7.5 % of the applicable standard

F. If either the zero or span drift results exceed two times the applicable drift specification in 40 CFR, Part 60, Appendix B for five consecutive, daily periods, the CEMS is out-of-control. If either the zero or span drift results exceed four times the applicable drift specification in Appendix B during a calibration drift check, the CEMS is out-of-control. If the CEMS exceeds the audit inaccuracies listed above, the CEMS is out-of-control. If a CEMS is out-of-control, the data from that out-of-control period is not counted towards meeting the minimum data availability as required and described in the applicable subpart. The end of the out-of-control period is the time corresponding to the completion of the successful daily zero or span drift or completion of the successful CGA, RAA or RATA.

G. A back-up monitor may be placed on an emission source to minimize monitor downtime. This back-up CEMS is subject to the same QA/QC procedure and practices as the primary CEMS. The back-up CEMS shall be certified by a PST. Daily zero-span checks must be performed and recorded in accordance with standard practices. When the primary CEMS goes down, the back-up CEMS may then be engaged to sample, analyze and record the emission source pollutant until repairs are made and the primary unit is placed back in service. Records must be maintained on site when the back-up CEMS is placed in service, these records shall include at a minimum the reason the primary CEMS is out of service, the date and time the primary CEMS was out of service and the date and time the primary CEMS was placed back in service.

APPENDIX B - NSPS D

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Title 40: Protection of Environment
PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators

Source: 72 FR 32717, June 13, 2007, unless otherwise noted.

§ 60.40 Applicability and designation of affected facility.

(a) The affected facilities to which the provisions of this subpart apply are:

(1) Each fossil-fuel-fired steam generating unit of more than 73 megawatts (MW) heat input rate (250 million British thermal units per hour (MMBtu/hr)).

(2) Each fossil-fuel and wood-residue-fired steam generating unit capable of firing fossil fuel at a heat input rate of more than 73 MW (250 MMBtu/hr).

(b) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels as defined in this subpart, shall not bring that unit under the applicability of this subpart.

(c) Except as provided in paragraph (d) of this section, any facility under paragraph (a) of this section that commenced construction or modification after August 17, 1971, is subject to the requirements of this subpart.

(d) The requirements of §§60.44 (a)(4), (a)(5), (b) and (d), and 60.45(f)(4)(vi) are applicable to lignite-fired steam generating units that commenced construction or modification after December 22, 1976.

(e) Any facility subject to either subpart Da or KKKK of this part is not subject to this subpart.

[72 FR 32717, June 13, 2007, as amended at 77 FR 9447, Feb. 16, 2012]

§ 60.41 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, and in subpart A of this part.

Boiler operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam-generating unit. It is not necessary for fuel to be combusted the entire 24-hour period.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM D388 (incorporated by reference, see §60.17).

Coal refuse means waste-products of coal mining, cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials for the purpose of creating useful heat.

Fossil fuel and wood residue-fired steam generating unit means a furnace or boiler used in the process of burning fossil fuel and wood residue for the purpose of producing steam by heat transfer.

Fossil-fuel-fired steam generating unit means a furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer.

Natural gas means a fluid mixture of hydrocarbons (e.g., methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. In addition, *natural gas* contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Wood residue means bark, sawdust, slabs, chips, shavings, mill trim, and other wood products derived from wood processing and forest management operations.

[72 FR 32717, June 13, 2007, as amended at 77 FR 9447, Feb. 16, 2012]

§ 60.42 Standard for particulate matter (PM).

(a) Except as provided under paragraphs (b), (c), (d), and (e) of this section, on and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that:

(1) Contain PM in excess of 43 nanograms per joule (ng/J) heat input (0.10 lb/MMBtu) derived from fossil fuel or fossil fuel and wood residue.

(2) Exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity.

(b)(1) On or after December 28, 1979, no owner or operator shall cause to be discharged into the atmosphere from the Southwestern Public Service Company's Harrington Station #1, in Amarillo, TX, any gases which exhibit greater than 35 percent opacity, except that a maximum or 42 percent opacity shall be permitted for not more than 6 minutes in any hour.

(2) Interstate Power Company shall not cause to be discharged into the atmosphere from its Lansing Station Unit No. 4 in Lansing, IA, any gases which exhibit greater than 32 percent opacity, except that a maximum of 39 percent opacity shall be permitted for not more than six minutes in any hour.

(c) As an alternate to meeting the requirements of paragraph (a) of this section, an owner or operator that elects to install, calibrate, maintain, and operate a continuous emissions monitoring systems (CEMS) for measuring PM emissions can petition the Administrator (in writing) to comply with §60.42Da (a) of subpart Da of this part. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in §60.42Da(a) of subpart Da of this part.

(d) An owner or operator of an affected facility that combusts only natural gas is exempt from the PM and opacity standards specified in paragraph (a) of this section.

(e) An owner or operator of an affected facility that combusts only gaseous or liquid fossil fuel (excluding residual oil) with potential SO_2emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO_2or PM is exempt from the PM standards specified in paragraph (a) of this section.

[60 FR 65415, Dec. 19, 1995, as amended at 76 FR 3522, Jan. 20, 2011; 74 FR 5077, Jan. 28, 2009; 77 FR 9447, Feb. 16, 2012]

§ 60.43 Standard for sulfur dioxide (SO_2).

(a) Except as provided under paragraph (d) of this section, on and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain SO_2in excess of:

(1) 340 ng/J heat input (0.80 lb/MMBtu) derived from liquid fossil fuel or liquid fossil fuel and wood residue.

(2) 520 ng/J heat input (1.2 lb/MMBtu) derived from solid fossil fuel or solid fossil fuel and wood residue, except as provided in paragraph (e) of this section.

(b) Except as provided under paragraph (d) of this section, when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

$$PS_{SO_2} = \frac{y(340) + z(520)}{(y+z)}$$

Where:

$PS_{SO}2$= Prorated standard for $S_{O2}$when burning different fuels simultaneously, in ng/J heat input derived from all fossil fuels or from all fossil fuels and wood residue fired;

y = Percentage of total heat input derived from liquid fossil fuel; and

z = Percentage of total heat input derived from solid fossil fuel.

(c) Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.

(d) As an alternate to meeting the requirements of paragraphs (a) and (b) of this section, an owner or operator can petition the Administrator (in writing) to comply with §60.43Da(i)(3) of subpart Da of this part or comply with §60.42b(k)(4) of subpart Db of this part, as applicable to the affected source. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in §60.43Da(i)(3) of subpart Da of this part or §60.42b(k)(4) of subpart Db of this part, as applicable to the affected source.

(e) Units 1 and 2 (as defined in appendix G of this part) at the Newton Power Station owned or operated by the Central Illinois Public Service Company will be in compliance with paragraph (a)(2) of this section if Unit 1 and Unit 2 individually comply with paragraph (a)(2) of this section or if the combined emission rate from Units 1 and 2 does not exceed 470 ng/J (1.1 lb/MMBtu) combined heat input to Units 1 and 2.

[60 FR 65415, Dec. 19, 1995, as amended at 74 FR 5077, Jan. 28, 2009]

§ 60.44 Standard for nitrogen oxides (NOX).

(a) Except as provided under paragraph (e) of this section, on and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain NO_X, expressed as NO_2in excess of:

(1) 86 ng/J heat input (0.20 lb/MMBtu) derived from gaseous fossil fuel.

(2) 129 ng/J heat input (0.30 lb/MMBtu) derived from liquid fossil fuel, liquid fossil fuel and wood residue,

or gaseous fossil fuel and wood residue.

(3) 300 ng/J heat input (0.70 lb/MMBtu) derived from solid fossil fuel or solid fossil fuel and wood residue (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse).

(4) 260 ng/J heat input (0.60 lb MMBtu) derived from lignite or lignite and wood residue (except as provided under paragraph (a)(5) of this section).

(5) 340 ng/J heat input (0.80 lb MMBtu) derived from lignite which is mined in North Dakota, South Dakota, or Montana and which is burned in a cyclone-fired unit.

(b) Except as provided under paragraphs (c), (d), and (e) of this section, when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NO_x} = \frac{w(260) + x(86) + y(130) + z(300)}{(w + x + y + z)}$$

Where:

PS_{NOX}= Prorated standard for $NO_X$when burning different fuels simultaneously, in ng/J heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired;

w = Percentage of total heat input derived from lignite;

x = Percentage of total heat input derived from gaseous fossil fuel;

y = Percentage of total heat input derived from liquid fossil fuel; and

z = Percentage of total heat input derived from solid fossil fuel (except lignite).

(c) When a fossil fuel containing at least 25 percent, by weight, of coal refuse is burned in combination with gaseous, liquid, or other solid fossil fuel or wood residue, the standard for NO_Xdoes not apply.

(d) Except as provided under paragraph (e) of this section, cyclone-fired units which burn fuels containing at least 25 percent of lignite that is mined in North Dakota, South Dakota, or Montana remain subject to paragraph (a)(5) of this section regardless of the types of fuel combusted in combination with that lignite.

(e) As an alternate to meeting the requirements of paragraphs (a), (b), and (d) of this section, an owner or operator can petition the Administrator (in writing) to comply with §60.44Da(e)(3) of subpart Da of this part. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in §60.44Da(e)(3) of subpart Da of this part.

§ 60.45 Emissions and fuel monitoring.

(a) Each owner or operator of an affected facility subject to the applicable emissions standard shall install, calibrate, maintain, and operate continuous opacity monitoring system (COMS) for measuring opacity and a continuous emissions monitoring system (CEMS) for measuring SO_2emissions, NO_Xemissions, and either oxygen (O_2) or carbon dioxide (CO_2) except as provided in paragraph (b) of this section.

(b) Certain of the CEMS and COMS requirements under paragraph (a) of this section do not apply to owners or operators under the following conditions:

(1) For a fossil-fuel-fired steam generator that combusts only gaseous or liquid fossil fuel (excluding residual oil) with potential SO_2emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use

post-combustion technology to reduce emissions of SO_2 or PM, COMS for measuring the opacity of emissions and CEMS for measuring SO_2 emissions are not required if the owner or operator monitors SO_2 emissions by fuel sampling and analysis or fuel receipts.

(2) For a fossil-fuel-fired steam generator that does not use a flue gas desulfurization device, a CEMS for measuring SO_2 emissions is not required if the owner or operator monitors SO_2 emissions by fuel sampling and analysis.

(3) Notwithstanding §60.13(b), installation of a CEMS for NO_X may be delayed until after the initial performance tests under §60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of NO_X are less than 70 percent of the applicable standards in §60.44, a CEMS for measuring NO_X emissions is not required. If the initial performance test results show that NO_X emissions are greater than 70 percent of the applicable standard, the owner or operator shall install a CEMS for NO_X within one year after the date of the initial performance tests under §60.8 and comply with all other applicable monitoring requirements under this part.

(4) If an owner or operator is not required to and elects not to install any CEMS for either SO_2 or NO_X, a CEMS for measuring either O_2 or CO_2 is not required.

(5) For affected facilities using a PM CEMS, a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in §60.48Da of this part, or an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section §60.48Da of this part a COMS is not required.

(6) A COMS for measuring the opacity of emissions is not required for an affected facility that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected source are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis. Owners and operators of affected sources electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (b)(6)(i) through (iv) of this section.

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (b)(6)(i)(A) through (D) of this section.

(A) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in §60.58b(i)(3) of subpart Eb of this part.

(B) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(C) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in §60.13(h)(2).

(D) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(ii) You must calculate the 1-hour average CO emissions levels for each boiler operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each boiler operating day.

(iii) You must evaluate the preceding 24-hour average CO emission level each boiler operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(iv) You must record the CO measurements and calculations performed according to paragraph (b)(6) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(7) An owner or operator of an affected facility subject to an opacity standard under §60.42 that elects to not use a COMS because the affected facility burns only fuels as specified under paragraph (b)(1) of this section, monitors PM emissions as specified under paragraph (b)(5) of this section, or monitors CO emissions as specified under paragraph (b)(6) of this section, shall conduct a performance test using Method 9 of appendix A–4 of this part and the procedures in §60.11 to demonstrate compliance with the applicable limit in §60.42 by April 29, 2011 or within 45 days after stopping use of an existing COMS, whichever is later, and shall comply with either paragraph (b)(7)(i), (b)(7)(ii), or (b)(7)(iii) of this section. The observation period for Method 9 of appendix A–4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation. The permitting authority may exempt owners or operators of affected facilities burning only natural gas from the opacity monitoring requirements.

(i) Except as provided in paragraph (b)(7)(ii) or (b)(7)(iii) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A–4 of this part performance tests using the procedures in paragraph (b)(7) of this section according to the applicable schedule in paragraphs (b)(7)(i)(A) through (b)(7)(i)(D) of this section, as determined by the most recent Method 9 of appendix A–4 of this part performance test results.

(A) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(B) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(C) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

(D) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(ii) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 of this part performance test, elect to perform subsequent monitoring using Method 22 of appendix A–7 of this part according to the procedures specified in paragraphs (b)(7)(ii)(A) and (B) of this section.

(A) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A–7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i e* , 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (i.e., 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (i.e., 90 seconds) or conduct a new Method 9 of appendix A–4 of this part performance test using the procedures in paragraph (b)(7) of this section within 45 calendar days according to the requirements in §60.46(b)(3).

(B) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(iii) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (b)(7)(ii) of this section. For reference purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(8) A COMS for measuring the opacity of emissions is not required for an affected facility at which the owner or operator installs, calibrates, operates, and maintains a particulate matter continuous parametric monitoring system (PM CPMS) according to the requirements specified in subpart UUUUU of part 63.

(c) For performance evaluations under §60.13(c) and calibration checks under §60.13(d), the following procedures shall be used:

(1) Methods 6, 7, and 3B of appendix A of this part, as applicable, shall be used for the performance evaluations of $SO_2$and NO_Xcontinuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B of appendix A of this part are given in §60.46(d).

(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of appendix B to this part.

(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent. For a continuous monitoring system measuring sulfur oxides or $NO_X$the span value shall be determined using one of the following procedures:

(i) Except as provided under paragraph (c)(3)(ii) of this section, $SO_2$and NO_Xspan values shall be determined as follows:

Fossil fuel	n parts per million	
	Span value for SO_2	Span value for NO_X
Gas	([1])	500.
Liquid	1,000	500.
Solid	1,500	1,000.
Combinations	1,000y + 1,500z	500 (x + y) + 1,000z.

[1]Not applicable.

Where:

x = Fraction of total heat input derived from gaseous fossil fuel;

y = Fraction of total heat input derived from liquid fossil fuel; and

z = Fraction of total heat input derived from solid fossil fuel.

(ii) As an alternative to meeting the requirements of paragraph (c)(3)(i) of this section, the owner or operator of an affected facility may elect to use the $SO_2$and NO_Xspan values determined according to sections 2.1.1 and 2.1.2 in appendix A to part 75 of this chapter.

(4) All span values computed under paragraph (c)(3)(i) of this section for burning combinations of fossil

fuels shall be rounded to the nearest 500 ppm. Span values that are computed under paragraph (c)(3)(ii) of this section shall be rounded off according to the applicable procedures in section 2 of appendix A to part 75 of this chapter.

(5) For a fossil-fuel-fired steam generator that simultaneously burns fossil fuel and nonfossil fuel, the span value of all CEMS shall be subject to the Administrator's approval.

(d) [Reserved]

(e) For any CEMS installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/MMBtu):

(1) When a CEMS for measuring O_2 is selected, the measurement of the pollutant concentration and O_2 concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$$E = CF\left(\frac{20.9}{(20.9 - \%O_2)}\right)$$

Where E, C, F, and $\%O_2$ are determined under paragraph (f) of this section.

(2) When a CEMS for measuring CO_2 is selected, the measurement of the pollutant concentration and CO_2 concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$$E = CF_c\left(\frac{100}{\%CO_2}\right)$$

Where E, C, F_c and $\%CO_2$ are determined under paragraph (f) of this section.

(f) The values used in the equations under paragraphs (e)(1) and (2) of this section are derived as follows:

(1) E = pollutant emissions, ng/J (lb/MMBtu).

(2) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^4 M ng/dscm per ppm (2.59×10^{-9} M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for SO_2 and 46.01 for NO_X.

(3) $\%O_2$, $\%CO_2$ = O_2 or CO_2 volume (expressed as percent), determined with equipment specified under paragraph (a) of this section.

(4) F, F_c = a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of CO_2 generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:

(i) For anthracite coal as classified according to ASTM D388 (incorporated by reference, see §60.17), F = $2,723 \times 10^{-17}$ dscm/J (10,140 dscf/MMBtu) and F_c = 0.532×10^{-17} scm CO_2/J (1,980 scf CO_2/MMBtu).

(ii) For subbituminous and bituminous coal as classified according to ASTM D388 (incorporated by reference, see §60.17), F = 2.637×10^{-7} dscm/J (9,820 dscf/MMBtu) and F_c = 0.486×10^{-7} scm CO_2/J (1,810 scf CO_2/MMBtu).

(iii) For liquid fossil fuels including crude, residual, and distillate oils, F = 2.476 × 10^{-7}dscm/J (9,220 dscf/MMBtu) and F_c= 0.384 × 10^{-7}scm CO_2/J (1,430 scf CO_2/MMBtu).

(iv) For gaseous fossil fuels, F = 2.347 × 10^{-7}dscm/J (8,740 dscf/MMBtu). For natural gas, propane, and butane fuels, F_c= 0.279 × 10^{-7}scm CO_2/J (1,040 scf CO_2/MMBtu) for natural gas, 0.322 × 10^{-7}scm CO_2/J (1,200 scf CO_2/MMBtu) for propane, and 0.338 × 10^{-7}scm CO_2/J (1,260 scf CO_2/MMBtu) for butane.

(v) For bark F = 2.589 × 10^{-7}dscm/J (9,640 dscf/MMBtu) and F_c= 0.500 × 10^{-7}scm CO_2/J (1,840 scf CO_2/MMBtu). For wood residue other than bark F = 2.492 × 10^{-7}dscm/J (9,280 dscf/MMBtu) and F_c= 0.494 × 10^{-7}scm CO_2/J (1,860 scf CO_2/MMBtu).

(vi) For lignite coal as classified according to ASTM D388 (incorporated by reference, see §60.17), F = 2.659 × 10^{-7}dscm/J (9,900 dscf/MMBtu) and F_c= 0.516 × 10^{-7}scm CO_2/J (1,920 scf CO_2/MMBtu).

(5) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/MMBtu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or Fc factor (scm CO_2/J, or scf CO_2/MMBtu) on either basis in lieu of the F or $F_c$factors specified in paragraph (f)(4) of this section:

$$F = 10^{-6}\frac{[227.2\,(\%H) + 95.5\,(\%C) + 35.6\,(\%S) + 8.7\,(\%N) - 28.7\,(\%O)]}{GCV}$$

$$F_c = \frac{2.0 \times 10^{-5} (\%C)}{GCV\ (SI\ units)}$$

$$F = 10^{-6}\frac{[3.64\,(\%H) + 1.53\,(\%C) + 0.57\,(\%S) + 0.14\,(\%N) - 0.46\,(\%O)]}{GCV\ (English\ units)}$$

$$F_c = \frac{20.0\,(\%C)}{GCV\ (SI\ units)}$$

$$F_c = \frac{321 \times 10^3\,(\%C)}{GCV\ (English\ units)}$$

(i) %H, %C, %S, %N, and %O are content by weight of hydrogen, carbon, sulfur, nitrogen, and O_2 (expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM D3178 or D3176 (solid fuels), or computed from results using ASTM D1137, D1945, or D1946 (gaseous fuels) as applicable. (These five methods are incorporated by reference, see §60.17.)

(ii) GVC is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015 or D5865 for solid fuels and D1826 for gaseous fuels as applicable. (These three methods are incorporated by reference, see §60.17.)

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or Fc value shall be subject to the Administrator's approval.

(6) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or Fc factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \quad \text{or} \quad F_c = \sum_{i=1}^{n} X_i (F_c)_i$$

Where:

X_i= Fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.);

$F_i$or $(F_c)_i$= Applicable F or $F_c$factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section; and

n = Number of fuels being burned in combination.

(g) Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in §60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:

(1) *pa ity* . Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.

(i) For sources subject to the opacity standard of §60.42(b)(1), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 35 percent opacity, except that one six-minute average per hour of up to 42 percent opacity need not be reported.

(ii) For sources subject to the opacity standard of §60.42(b)(2), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 32 percent opacity, except that one six-minute average per hour of up to 39 percent opacity need not be reported.

(2) *ulfur dio ide* Excess emissions for affected facilities are defined as:

(i) For affected facilities electing not to comply with §60.43(d), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2as measured by a CEMS exceed the applicable standard in §60.43; or

(ii) For affected facilities electing to comply with §60.43(d), any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of SO_2as measured by a CEMS exceed the applicable standard in §60.43. Facilities complying with the 30-day SO_2standard shall use the most current associated SO_2compliance and monitoring requirements in §§60.48Da and 60.49Da of subpart Da of this part or §§60.45b and 60.47b of subpart Db of this part, as applicable.

(3) *Nitrogen o ides* Excess emissions for affected facilities using a CEMS for measuring $NO_X$are defined as:

(i) For affected facilities electing not to comply with §60.44(e), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in §60.44; or

(ii) For affected facilities electing to comply with §60.44(e), any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of NO_Xas measured by a CEMS exceed the applicable standard in §60.44. Facilities complying with the 30-day NO_Xstandard shall use the most current associated NO_Xcompliance and monitoring requirements in §§60.48Da and 60.49Da of subpart Da of this part.

(4) *arti ulate matter* Excess emissions for affected facilities using a CEMS for measuring PM are defined as any boiler operating day period during which the average emissions (arithmetic average of all

operating one-hour periods) exceed the applicable standards in §60.42. Affected facilities using PM CEMS must follow the most current applicable compliance and monitoring provisions in §§60.48Da and 60.49Da of subpart Da of this part.

(h) The owner or operator of an affected facility subject to the opacity limits in §60.42 that elects to monitor emissions according to the requirements in §60.45(b)(7) shall maintain records according to the requirements specified in paragraphs (h)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (h)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (h)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator.

[60 FR 65415, Dec. 19, 1995, as amended at 74 FR 5077, Jan. 28, 2009; 76 FR 3522, Jan. 20, 2011; 77 FR 9447, Feb. 16, 2012]

§ 60.46 Test met ods and procedures.

(a) In conducting the performance tests required in §60.8, and subsequent performance tests as requested by the EPA Administrator, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in paragraph (d) of this section.

(b) The owner or operator shall determine compliance with the PM, SO_2, and NO_Xstandards in §§60.42, 60.43, and 60.44 as follows:

(1) The emission rate (E) of PM, SO_2, or NO_Xshall be computed for each run using the following equation:

$$E = CF_d\left(\frac{20.9}{(20.9 - \%O_2)}\right)$$

Where:

E = Emission rate of pollutant, ng/J (1b/million Btu);

C = Concentration of pollutant, ng/dscm (1b/dscf);

$\%O_2$= O_2concentration, percent dry basis; and

F_d= Factor as determined from Method 19 of appendix A of this part.

(2) Method 5 of appendix A of this part shall be used to determine the PM concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems and Method 5B of appendix A of this part shall be used to determine the PM concentration (C) after FGD systems.

(i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train shall be set to provide an average gas temperature of 160±14 °C (320±25 °F).

(ii) The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O_2concentration ($\%O_2$). The O_2sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the O_2concentration for the run shall be the arithmetic mean of the sample O_2concentrations at all traverse points.

(iii) If the particulate run has more than 12 traverse points, the O_2traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 O_2traverse points.

(3) Method 9 of appendix A of this part and the procedures in §60.11 shall be used to determine opacity.

(4) Method 6 of appendix A of this part shall be used to determine the SO_2concentration.

(i) The sampling site shall be the same as that selected for the particulate sample. The sampling location in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). The sampling time and sample volume for each sample run shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Two samples shall be taken during a 1-hour period, with each sample taken within a 30-minute interval.

(ii) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O_2concentration ($\%O_2$). The O_2sample shall be taken simultaneously with, and at the same point as, the SO_2sample. The SO_2emission rate shall be computed for each pair of $SO_2$and O_2samples. The SO_2emission rate (E) for each run shall be the arithmetic mean of the results of the two pairs of samples.

(5) Method 7 of appendix A of this part shall be used to determine the NO_Xconcentration.

(i) The sampling site and location shall be the same as for the SO_2sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals.

(ii) For each NO_Xsample, the emission rate correction factor, grab sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O_2concentration ($\%O_2$). The sample shall be taken simultaneously with, and at the same point as, the NO_Xsample.

(iii) The NO_Xemission rate shall be computed for each pair of $NO_X$and O_2samples. The NO_Xemission rate (E) for each run shall be the arithmetic mean of the results of the four pairs of samples.

(c) When combinations of fossil fuels or fossil fuel and wood residue are fired, the owner or operator (in order to compute the prorated standard as shown in §§60.43(b) and 60.44(b)) shall determine the percentage (w, x, y, or z) of the total heat input derived from each type of fuel as follows:

(1) The heat input rate of each fuel shall be determined by multiplying the gross calorific value of each fuel fired by the rate of each fuel burned.

(2) ASTM Methods D2015, or D5865 (solid fuels), D240 (liquid fuels), or D1826 (gaseous fuels) (all of these methods are incorporated by reference, see §60.17) shall be used to determine the gross calorific values of the fuels. The method used to determine the calorific value of wood residue must be approved by the Administrator.

(3) Suitable methods shall be used to determine the rate of each fuel burned during each test period, and a material balance over the steam generating system shall be used to confirm the rate.

(d) The owner or operator may use the following as alternatives to the reference methods and procedures in this section or in other sections as specified:

(1) The emission rate (E) of PM, $SO_2$and NO_Xmay be determined by using the Fc factor, provided that the following procedure is used:

(i) The emission rate (E) shall be computed using the following equation:

$$E = CF_c \left(\frac{100}{\%CO_2} \right)$$

Where:

E = Emission rate of pollutant, ng/J (lb/MMBtu);

C = Concentration of pollutant, ng/dscm (lb/dscf);

$\%CO_2$= CO_2concentration, percent dry basis; and

F_c= Factor as determined in appropriate sections of Method 19 of appendix A of this part.

(ii) If and only if the average Fc factor in Method 19 of appendix A of this part is used to calculate E and either E is from 0.97 to 1.00 of the emission standard or the relative accuracy of a continuous emission monitoring system is from 17 to 20 percent, then three runs of Method 3B of appendix A of this part shall be used to determine the $O_2$and CO_2concentration according to the procedures in paragraph (b)(2)(ii), (4)(ii), or (5)(ii) of this section. Then if F_o(average of three runs), as calculated from the equation in Method 3B of appendix A of this part, is more than ±3 percent than the average $F_o$value, as determined from the average values of $F_d$and $F_c$in Method 19 of appendix A of this part, *i e* , F_{oa}= 0.209 (F_{da}/F_{ca}), then the following procedure shall be followed:

(A) When $F_o$is less than 0.97 F_{oa}, then E shall be increased by that proportion under 0.97 F_{oa}, *e g* , if $F_o$is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the emission standard.

(B) When $F_o$is less than 0.97 $F_{oa}$and when the average difference (d) between the continuous monitor minus the reference methods is negative, then E shall be increased by that proportion under 0.97 F_{oa}, *e g* , if $F_o$is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(C) When $F_o$is greater than 1.03 $F_{oa}$and when the average difference d is positive, then E shall be decreased by that proportion over 1.03 F_{oa}, *e g* , if $F_o$is 1.05 F_{oa}, E shall be decreased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(2) For Method 5 or 5B of appendix A–3 of this part, Method 17 of appendix A–6 of this part may be used at facilities with or without wet FGD systems if the stack gas temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of sections 8.1 and 11.1 of

Method 5B of appendix A–3 of this part may be used with Method 17 of appendix A–6 of this part only if it is used after wet FGD systems. Method 17 of appendix A–6 of this part shall not be used after wet FGD systems if the effluent gas is saturated or laden with water droplets.

(3) Particulate matter and SO_2 may be determined simultaneously with the Method 5 of appendix A of this part train provided that the following changes are made:

(i) The filter and impinger apparatus in sections 2.1.5 and 2.1.6 of Method 8 of appendix A of this part is used in place of the condenser (section 2.1.7) of Method 5 of appendix A of this part.

(ii) All applicable procedures in Method 8 of appendix A of this part for the determination of SO_2 (including moisture) are used:

(4) For Method 6 of appendix A of this part, Method 6C of appendix A of this part may be used. Method 6A of appendix A of this part may also be used whenever Methods 6 and 3B of appendix A of this part data are specified to determine the SO_2 emission rate, under the conditions in paragraph (d)(1) of this section.

(5) For Method 7 of appendix A of this part, Method 7A, 7C, 7D, or 7E of appendix A of this part may be used. If Method 7C, 7D, or 7E of appendix A of this part is used, the sampling time for each run shall be at least 1 hour and the integrated sampling approach shall be used to determine the O_2 concentration (% O_2) for the emission rate correction factor.

(6) For Method 3 of appendix A of this part, Method 3A or 3B of appendix A of this part may be used.

(7) For Method 3B of appendix A of this part, Method 3A of appendix A of this part may be used.

[60 FR 65415, Dec. 19, 1995, as amended at 74 FR 5078, Jan. 28, 2009]

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APPENDIX C - NSPS BB

Electronic Code of Federal Regulations
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e-CFR Data is current as of May 17, 2012

Title 40: Protection of Environment
PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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Subpart BB—Standards of Performance for Kraft Pulp Mills

§ 60.280 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities in kraft pulp mills: Digester system, brown stock washer system, multiple-effect evaporator system, recovery furnace, smelt dissolving tank, lime kiln, and condensate stripper system. In pulp mills where kraft pulping is combined with neutral sulfite semichemical pulping, the provisions of this subpart are applicable when any portion of the material charged to an affected facility is produced by the kraft pulping operation.

(b) Except as noted in §60.283(a)(1)(iv), any facility under paragraph (a) of this section that commences construction or modification after September 24, 1976, is subject to the requirements of this subpart.

[51 FR 18544, May 20, 1986]

§ 60.281 Definitions.

As used in this subpart, all terms not defined herein shall have the same meaning given them in the Act and in subpart A.

(a) *Kraft pulp mill* means any stationary source which produces pulp from wood by cooking (digesting) wood chips in a water solution of sodium hydroxide and sodium sulfide (white liquor) at high temperature and pressure. Regeneration of the cooking chemicals through a recovery process is also considered part of the kraft pulp mill.

(b) *Neutral sulfite semichemical pulping operation* means any operation in which pulp is produced from wood by cooking (digesting) wood chips in a solution of sodium sulfite and sodium bicarbonate, followed by mechanical defibrating (grinding).

(c) *Total reduced sulfur (TRS)* means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide, that are released during the kraft pulping operation and measured by Method 16.

(d) *Digester system* means each continuous digester or each batch digester used for the cooking of wood in white liquor, and associated flash tank(s), blow tank(s), chip steamer(s), and condenser(s).

(e) *Brown stock washer system* means brown stock washers and associated knotters, vacuum pumps, and filtrate tanks used to wash the pulp following the digester system. Diffusion washers are excluded from this definition.

(f) *Multiple-effect evaporator system* means the multiple-effect evaporators and associated condenser(s) and hotwell(s) used to concentrate the spent cooking liquid that is separated from the pulp (black liquor).

(g) *Black liquor oxidation system* means the vessels used to oxidize, with air or oxygen, the black liquor, and associated storage tank(s).

(h) *Recovery furnace* means either a straight kraft recovery furnace or a cross recovery furnace, and includes the direct-contact evaporator for a direct-contact furnace.

(i) *Straight kraft recovery furnace* means a furnace used to recover chemicals consisting primarily of sodium and sulfur compounds by burning black liquor which on a quarterly basis contains 7 weight percent or less of the total pulp solids from the neutral sulfite semichemical process or has green liquor sulfidity of 28 percent or less.

(j) *Cross recovery furnace* means a furnace used to recover chemicals consisting primarily of sodium and sulfur compounds by burning black liquor which on a quarterly basis contains more than 7 weight percent of the total pulp solids from the neutral sulfite semichemical process and has a green liquor sulfidity of more than 28 percent.

(k) *Black liquor solids* means the dry weight of the solids which enter the recovery furnace in the black liquor.

(l) *Green liquor sulfidity* means the sulfidity of the liquor which leaves the smelt dissolving tank.

(m) *Smelt dissolving tank* means a vessel used for dissolving the smelt collected from the recovery furnace.

(n) *Lime kiln* means a unit used to calcine lime mud, which consists primarily of calcium carbonate, into quicklime, which is calcium oxide.

(o) *Condensate stripper system* means a column, and associated condensers, used to strip, with air or steam, TRS compounds from condensate streams from various processes within a kraft pulp mill.

[43 FR 7572, Feb. 23, 1978, as amended at 51 FR 18544, May 20, 1986; 65 FR 61758, Oct. 17, 2000]

§ 60.282 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere:

(1) From any recovery furnace any gases which:

(i) Contain particulate matter in excess of 0.10 g/dscm (0.044 gr/dscf) corrected to 8 percent oxygen.

(ii) Exhibit 35 percent opacity or greater.

(2) From any smelt dissolving tank any gases which contain particulate matter in excess of 0.1 g/kg black liquor solids (dry weight)[0.2 lb/ton black liquor solids (dry weight)].

(3) From any lime kiln any gases which contain particulate matter in excess of:

(i) 0.15 g/dscm (0.066 gr/dscf) corrected to 10 percent oxygen, when gaseous fossil fuel is burned.

(ii) 0.30 g/dscm (0.13 gr/dscf) corrected to 10 percent oxygen, when liquid fossil fuel is burned.

[43 FR 7572, Feb. 23, 1978, as amended at 65 FR 61758, Oct. 17, 2000]

§ 60.283 Standard for total reduced sulfur (TRS).

(a) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere:

(1) From any digester system, brown stock washer system, multiple-effect evaporator system, or condensate stripper system any gases which contain TRS in excess of 5 ppm by volume on a dry basis, corrected to 10 percent oxygen, unless the following conditions are met:

(i) The gases are combusted in a lime kiln subject to the provisions of paragraph (a)(5) of this section; or

(ii) The gases are combusted in a recovery furnace subject to the provisions of paragraphs (a)(2) or (a)(3) of this section; or

(iii) The gases are combusted with other waste gases in an incinerator or other device, or combusted in a lime kiln or recovery furnace not subject to the provisions of this subpart, and are subjected to a minimum temperature of 650 °C (1200 °F) for at least 0.5 second; or

(iv) It has been demonstrated to the Administrator's satisfaction by the owner or operator that incinerating the exhaust gases from a new, modified, or reconstructed brown stock washer system is technologically or economically unfeasible. Any exempt system will become subject to the provisions of this subpart if the facility is changed so that the gases can be incinerated.

(v) The gases from the digester system, brown stock washer system, or condensate stripper system are controlled by a means other than combustion. In this case, this system shall not discharge any gases to the atmosphere which contain TRS in excess of 5 ppm by volume on a dry basis, uncorrected for oxygen content.

(vi) The uncontrolled exhaust gases from a new, modified, or reconstructed digester system contain TRS less than 0.005 g/kg air dried pulp (ADP) (0.01 lb/ton ADP).

(2) From any straight kraft recovery furnace any gases which contain TRS in excess of 5 ppm by volume on a dry basis, corrected to 8 percent oxygen.

(3) From any cross recovery furnace any gases which contain TRS in excess of 25 ppm by volume on a dry basis, corrected to 8 percent oxygen.

(4) From any smelt dissolving tank any gases which contain TRS in excess of 0.016 g/kg black liquor solids as H_2S (0.033 lb/ton black liquor solids as H_2S).

(5) From any lime kiln any gases which contain TRS in excess of 8 ppm by volume on a dry basis, corrected to 10 percent oxygen.

[43 FR 7572, Feb. 23, 1978, as amended at 50 FR 6317, Feb. 14, 1985; 51 FR 18544, May 20, 1986; 65 FR 61758, Oct. 17, 2000]

§ 60.284 Monitoring of emissions and operations.

(a) Any owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate the following continuous monitoring systems:

(1) A continuous monitoring system to monitor and record the opacity of the gases discharged into the atmosphere from any recovery furnace. The span of this system shall be set at 70 percent opacity.

(2) Continuous monitoring systems to monitor and record the concentration of TRS emissions on a dry basis and the percent of oxygen by volume on a dry basis in the gases discharged into the atmosphere from any lime kiln, recovery furnace, digester system, brown stock washer system, multiple-effect evaporator system, or condensate stripper system, except where the provisions of §60.283(a)(1) (iii) or (iv) apply. These systems shall be located downstream of the control device(s) and the spans of these continuous monitoring system(s) shall be set:

(i) At a TRS concentration of 30 ppm for the TRS continuous monitoring system, except that for any cross recovery furnace the span shall be set at 50 ppm.

(ii) At 25 percent oxygen for the continuous oxygen monitoring system.

(b) Any owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate the following continuous monitoring devices:

(1) For any incinerator, a monitoring device which measures and records the combustion temperature at the point of incineration of effluent gases which are emitted from any digester system, brown stock washer system, multiple-effect evaporator system, black liquor oxidation system, or condensate stripper system where the provisions of §60.283(a)(1)(iii) apply. The monitoring device is to be certified by the manufacturer to be accurate within ±1 percent of the temperature being measured.

(2) For any lime kiln or smelt dissolving tank using a scrubber emission control device:

(i) A monitoring device for the continuous measurement of the pressure loss of the gas stream through the control equipment. The monitoring device is to be certified by the manufacturer to be accurate to within a gage pressure of ±500 pascals (ca. ±2 inches water gage pressure).

(ii) A monitoring device for the continuous measurement of the scrubbing liquid supply pressure to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±15 percent of design scrubbing liquid supply pressure. The pressure sensor or tap is to be located close to the scrubber liquid discharge point. The Administrator may be consulted for approval of alternative locations.

(c) Any owner or operator subject to the provisions of this subpart shall, except where the provisions of §60.283(a)(1)(iii) or (iv) apply, perform the following:

(1) Calculate and record on a daily basis 12-hour average TRS concentrations for the two consecutive periods of each operating day. Each 12-hour average shall be determined as the arithmetic mean of the appropriate 12 contiguous 1-hour average total reduced sulfur concentrations provided by each continuous monitoring system installed under paragraph (a)(2) of this section.

(2) Calculate and record on a daily basis 12-hour average oxygen concentrations for the two consecutive periods of each operating day for the recovery furnace and lime kiln. These 12-hour averages shall correspond to the 12-hour average TRS concentrations under paragraph (c)(1) of this section and shall be determined as an arithmetic mean of the appropriate 12 contiguous 1-hour average oxygen concentrations provided by each continuous monitoring system installed under paragraph (a)(2) of this section.

(3) Using the following equation, correct all 12-hour average TRS concentrations to 10 volume percent oxygen, except that all 12-hour average TRS concentrations from a recovery furnace shall be corrected to 8 volume percent oxygen instead of 10 percent, and all 12-hour average TRS concentrations from a facility to which the provisions of §60.283(a)(1)(v) apply shall not be corrected for oxygen content:

$$C_{corr} = C_{meas} \times (21 - X / 21 - Y)$$

where:

C_{corr}=the concentration corrected for oxygen.

C_{meas}=the concentration uncorrected for oxygen.

X =the volumetric oxygen concentration in percentage to be corrected to (8 percent for recovery furnaces and 10 percent for lime kilns, incinerators, or other devices).

Y =the measured 12-hour average volumetric oxygen concentration.

(4) Record once per shift measurements obtained from the continuous monitoring devices installed under paragraph (b)(2) of this section.

(d) For the purpose of reports required under §60.7(c), any owner or operator subject to the provisions of this subpart shall report semiannually periods of excess emissions as follows:

(1) For emissions from any recovery furnace periods of excess emissions are:

(i) All 12-hour averages of TRS concentrations above 5 ppm by volume for straight kraft recovery furnaces and above 25 ppm by volume for cross recovery furnaces.

(ii) All 6-minute average opacities that exceed 35 percent.

(2) For emissions from any lime kiln, periods of excess emissions are all 12-hour average TRS concentration above 8 ppm by volume.

(3) For emissions from any digester system, brown stock washer system, multiple-effect evaporator system, or condensate stripper system periods of excess emissions are:

(i) All 12-hour average TRS concentrations above 5 ppm by volume unless the provisions of §60.283(a)(1) (i), (ii), or (iv) apply; or

(ii) All periods in excess of 5 minutes and their duration during which the combustion temperature at the point of incineration is less than 650 °C (1200 °F), where the provisions of §60.283(a)(1)(iii) apply.

(e) The Administrator will not consider periods of excess emissions reported under paragraph (d) of this section to be indicative of a violation of §60.11(d) provided that:

(1) The percent of the total number of possible contiguous periods of excess emissions in a quarter (excluding periods of startup, shutdown, or malfunction and periods when the facility is not operating) during which excess emissions occur does not exceed:

(i) One percent for TRS emissions from recovery furnaces.

(ii) Six percent for average opacities from recovery furnaces.

(2) The Administrator determines that the affected facility, including air pollution control equipment, is maintained and operated in a manner which is consistent with good air pollution control practice for minimizing emissions during periods of excess emissions.

(f) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems required under this section. All continuous monitoring systems shall be operated in accordance with the applicable procedures under Performance Specifications 1, 3, and 5 of appendix B of this part.

[43 FR 7572, Feb. 23, 1978, as amended at 51 FR 18545, May 20, 1986; 65 FR 61759, Oct. 17, 2000; 71 FR 55127, Sept. 21, 2006]

§ 60.285 Test methods and procedures.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures in this section, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section.

(b) The owner or operator shall determine compliance with the particulate matter standards in §60.282 (a) (1) and (3) as follows:

(1) Method 5 shall be used to determine the particulate matter concentration. The sampling time and sample volume for each run shall be at least 60 minutes and 0.90 dscm (31.8 dscf). Water shall be used as the cleanup solvent instead of acetone in the sample recovery procedure. The particulate concentration shall be corrected to the appropriate oxygen concentration according to §60.284(c)(3).

(2) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B shall be used to determine the oxygen concentration. The gas sample shall be taken at the same time and at the same traverse points as the particulate sample.

(3) Method 9 and the procedures in §60.11 shall be used to determine opacity.

(c) The owner or operator shall determine compliance with the particular matter standard in §60.282(a)

(2) as follows:

(1) The emission rate (E) of particulate matter shall be computed for each run using the following equation:

$E=c_sQ_{sd}/BLS$

where:

E=emission rate of particulate matter, g/kg (lb/ton) of BLS.

c_s= Concentration of particulate matter, g/dscm (lb/dscf).

Q_{sd}=volumetric flow rate of effluent gas, dscm/hr (dscf/hr).

BLS=black liquor solids (dry weight) feed rate, kg/hr (ton/hr).

(2) Method 5 shall be used to determine the particulate matter concentration (c_s) and the volumetric flow rate (Q_{sd}) of the effluent gas. The sampling time and sample volume shall be at least 60 minutes and 0.90 dscm (31.8 dscf). Water shall be used instead of acetone in the sample recovery.

(3) Process data shall be used to determine the black liquor solids (BLS) feed rate on a dry weight basis.

(d) The owner or operator shall determine compliance with the TRS standards in §60.283, except §60.283(a)(1)(vi) and (4), as follows:

(1) Method 16 shall be used to determine the TRS concentration. The TRS concentration shall be corrected to the appropriate oxygen concentration using the procedure in §60.284(c)(3). The sampling time shall be at least 3 hours, but no longer than 6 hours.

(2) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B shall be used to determine the oxygen concentration. The sample shall be taken over the same time period as the TRS samples.

(3) When determining whether a furnace is a straight kraft recovery furnace or a cross recovery furnace, TAPPI Method T.624 (incorporated by reference—see §60.17) shall be used to determine sodium sulfide, sodium hydroxide, and sodium carbonate. These determinations shall be made 3 times daily from the green liquor, and the daily average values shall be converted to sodium oxide (Na_20) and substituted into the following equation to determine the green liquor sulfidity:

$$GLS = 100\ C_{Na_2S}/\left(C_{Na_2S}C_{NaOH}C_{Na_2CO_3}\right)$$

Where:

GLS=green liquor sulfidity, percent.

C_{Na2S}=concentration of Na_2S as Na_2O, mg/liter (gr/gal).

C_{NaOH}=concentration of NaOH as Na_2O, mg/liter (gr/gal).

C_{Na2CO3}=concentration of Na_2CO_3as Na_2O, mg/liter (gr/gal).

(e) The owner or operator shall determine compliance with the TRS standards in §60.283(a)(1)(vi) and (4) as follows:

(1) The emission rate (E) of TRS shall be computed for each run using the following equation:

$E=C_{TRS}F\,Q_{sd}/P$

where:

E=emission rate of TRS, g/kg (lb/ton) of BLS or ADP.

C_{TRS}=average combined concentration of TRS, ppm.

F = conversion factor, 0.001417 g H_2S/m^3 -ppm (8.846×10^{-8}lb H_2S/ft^3 -ppm).

Q_{sd}=volumetric flow rate of stack gas, dscm/hr (dscf/hr).

P=black liquor solids feed or pulp production rate, kg/hr (ton/hr).

(2) Method 16 shall be used to determine the TRS concentration (C_{TRS}).

(3) Method 2 shall be used to determine the volumetric flow rate (Q_{sd}) of the effluent gas.

(4) Process data shall be used to determine the black liquor feed rate or the pulp production rate (P).

(f) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 5, Method 17 may be used if a constant value of 0.009 g/dscm (0.004 gr/dscf) is added to the results of Method 17 and the stack temperature is no greater than 204 °C (400 °F).

(2) In place of Method 16, Method 16A or 16B may be used.

[54 FR 6673, Feb. 14, 1989; 54 FR 21344, May 17, 1989, as amended at 55 FR 5212, Feb. 14, 1990; 65 FR 61759, Oct. 17, 2000]

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APPENDIX D - NSPS Kb

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Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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Subpart Kb—Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

Source: 52 FR 11429, Apr. 8, 1987, unless otherwise noted.

§ 60.110b Applicability and designation of affected facility.

(a) Except as provided in paragraph (b) of this section, the affected facility to which this subpart applies is each storage vessel with a capacity greater than or equal to 75 cubic meters (m^3) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984.

(b) This subpart does not apply to storage vessels with a capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa.

(c) [Reserved]

(d) This subpart does not apply to the following:

(1) Vessels at coke oven by-product plants.

(2) Pressure vessels designed to operate in excess of 204.9 kPa and without emissions to the atmosphere.

(3) Vessels permanently attached to mobile vehicles such as trucks, railcars, barges, or ships.

(4) Vessels with a design capacity less than or equal to 1,589.874 m^3 used for petroleum or condensate stored, processed, or treated prior to custody transfer.

(5) Vessels located at bulk gasoline plants.

(6) Storage vessels located at gasoline service stations.

(7) Vessels used to store beverage alcohol.

(8) Vessels subject to subpart GGGG of 40 CFR part 63.

(e) *Alternative means of compliance* —(1) *Option to comply with part 65.* Owners or operators may choose to comply with 40 CFR part 65, subpart C, to satisfy the requirements of §§60.112b through 60.117b for storage vessels that are subject to this subpart that meet the specifications in paragraphs (e)(1)(i) and (ii) of this section. When choosing to comply with 40 CFR part 65, subpart C, the monitoring requirements of §60.116b(c), (e), (f)(1), and (g) still apply. Other provisions applying to owners or operators who choose to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(i) A storage vessel with a design capacity greater than or equal to 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa; or

(ii) A storage vessel with a design capacity greater than 75 m^3 but less than 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa.

(2) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart C, must also comply with §§60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for those storage vessels. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(2) do not apply to owners or operators of storage vessels complying with 40 CFR part 65, subpart C, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part 65, subpart C, must comply with 40 CFR part 65, subpart A.

(3) *Internal floating roof report.* If an owner or operator installs an internal floating roof and, at initial startup, chooses to comply with 40 CFR part 65, subpart C, a report shall be furnished to the Administrator stating that the control equipment meets the specifications of 40 CFR 65.43. This report shall be an attachment to the notification required by 40 CFR 65.5(b).

(4) *External floating roof report.* If an owner or operator installs an external floating roof and, at initial startup, chooses to comply with 40 CFR part 65, subpart C, a report shall be furnished to the Administrator stating that the control equipment meets the specifications of 40 CFR 65.44. This report shall be an attachment to the notification required by 40 CFR 65.5(b).

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989; 65 FR 78275, Dec. 14, 2000; 68 FR 59332, Oct. 15, 2003]

§ 60.111b Definitions.

Terms used in this subpart are defined in the Act, in subpart A of this part, or in this subpart as follows:

Bulk gasoline plant means any gasoline distribution facility that has a gasoline throughput less than or equal to 75,700 liters per day. Gasoline throughput shall be the maximum calculated design throughput as may be limited by compliance with an enforceable condition under Federal requirement or Federal, State or local law, and discoverable by the Administrator and any other person.

Condensate means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature or pressure, or both, and remains liquid at standard conditions.

Custody transfer means the transfer of produced petroleum and/or condensate, after processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities to pipelines or any other forms of transportation.

Fill means the introduction of VOL into a storage vessel but not necessarily to complete capacity.

Gasoline service station means any site where gasoline is dispensed to motor vehicle fuel tanks from stationary storage tanks.

Maximum true vapor pressure means the equilibrium partial pressure exerted by the volatile organic compounds (as defined in 40 CFR 51.100) in the stored VOL at the temperature equal to the highest calendar-month average of the VOL storage temperature for VOL's stored above or below the ambient temperature or at the local maximum monthly average temperature as reported by the National Weather Service for VOL's stored at the ambient temperature, as determined:

(1) In accordance with methods described in American Petroleum institute Bulletin 2517, Evaporation Loss From External Floating Roof Tanks, (incorporated by reference—see §60.17); or

(2) As obtained from standard reference texts; or

(3) As determined by ASTM D2879–83, 96, or 97 (incorporated by reference—see §60.17);

(4) Any other method approved by the Administrator.

Petroleum means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

Petroleum liquids means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery.

Process tank means a tank that is used within a process (including a solvent or raw material recovery process) to collect material discharged from a feedstock storage vessel or equipment within the process before the material is transferred to other equipment within the process, to a product or by-product storage vessel, or to a vessel used to store recovered solvent or raw material. In many process tanks, unit operations such as reactions and blending are conducted. Other process tanks, such as surge control vessels and bottoms receivers, however, may not involve unit operations.

Reid vapor pressure means the absolute vapor pressure of volatile crude oil and volatile nonviscous petroleum liquids except liquified petroleum gases, as determined by ASTM D323–82 or 94 (incorporated by reference—see §60.17).

Storage vessel means each tank, reservoir, or container used for the storage of volatile organic liquids but does not include:

(1) Frames, housing, auxiliary supports, or other components that are not directly involved in the containment of liquids or vapors;

(2) Subsurface caverns or porous rock reservoirs; or

(3) Process tanks.

Volatile organic liquid (VOL) means any organic liquid which can emit volatile organic compounds (as defined in 40 CFR 51.100) into the atmosphere.

Waste means any liquid resulting from industrial, commercial, mining or agricultural operations, or from community activities that is discarded or is being accumulated, stored, or physically, chemically, or biologically treated prior to being discarded or recycled.

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989; 65 FR 61756, Oct. 17, 2000; 68 FR 59333, Oct. 15, 2003]

§ 60.112b Standard for volatile organic compounds (VOC).

(a) The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa, shall equip each storage vessel with one of the following:

(1) A fixed roof in combination with an internal floating roof meeting the following specifications:

(i) The internal floating roof shall rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.

(ii) Each internal floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof:

(A) A foam- or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal). A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the storage vessel and the floating roof continuously around the circumference of the tank.

(B) Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be vapor-mounted, but both must be continuous.

(C) A mechanical shoe seal. A mechanical shoe seal is a metal sheet held vertically against the wall of the storage vessel by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

(iii) Each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents is to provide a projection below the liquid surface.

(iv) Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains is to be equipped with a cover or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use.

(v) Automatic bleeder vents shall be equipped with a gasket and are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(vi) Rim space vents shall be equipped with a gasket and are to be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting.

(vii) Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The sample well shall have a slit fabric cover that covers at least 90 percent of the opening.

(viii) Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover.

(ix) Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.

(2) An external floating roof. An external floating roof means a pontoon-type or double-deck type cover that rests on the liquid surface in a vessel with no fixed roof. Each external floating roof must meet the following specifications:

(i) Each external floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge. The closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal, and the upper seal is referred to as the secondary seal.

(A) The primary seal shall be either a mechanical shoe seal or a liquid-mounted seal. Except as provided in §60.113b(b)(4), the seal shall completely cover the annular space between the edge of the floating roof and tank wall.

(B) The secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion except as allowed in §60.113b(b)(4).

(ii) Except for automatic bleeder vents and rim space vents, each opening in a noncontact external floating roof shall provide a projection below the liquid surface. Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is to be equipped with a gasketed cover, seal, or lid that is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting. Automatic bleeder vents and rim space vents are to be gasketed. Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

(iii) The roof shall be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill until the roof is lifted off leg supports and when the tank is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.

(3) A closed vent system and control device meeting the following specifications:

(i) The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, subpart VV, §60.485 (b).

(ii) The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (§60.18) of the General Provisions.

(4) A system equivalent to those described in paragraphs (a)(1), (a)(2), or (a)(3) of this section as provided in §60.114b of this subpart.

(b) The owner or operator of each storage vessel with a design capacity greater than or equal to 75 m^3 which contains a VOL that, as stored, has a maximum true vapor pressure greater than or equal to 76.6 kPa shall equip each storage vessel with one of the following:

(1) A closed vent system and control device as specified in §60.112b(a)(3).

(2) A system equivalent to that described in paragraph (b)(1) as provided in §60.114b of this subpart.

(c) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.* This paragraph applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site").

(1) For any storage vessel that otherwise would be subject to the control technology requirements of paragraphs (a) or (b) of this section, the site shall have the option of either complying directly with the requirements of this subpart, or reducing the site-wide total criteria pollutant emissions cap (total emissions cap) in accordance with the procedures set forth in a permit issued pursuant to 40 CFR 52.2454. If the site chooses the option of reducing the total emissions cap in accordance with the procedures set forth in such permit, the requirements of such permit shall apply in lieu of the otherwise applicable requirements of this subpart for such storage vessel.

(2) For any storage vessel at the site not subject to the requirements of 40 CFR 60.112b (a) or (b), the requirements of 40 CFR 60.116b (b) and (c) and the General Provisions (subpart A of this part) shall not apply.

[52 FR 11429, Apr. 8, 1987, as amended at 62 FR 52641, Oct. 8, 1997]

§ 60.113b Testing and procedures.

The owner or operator of each storage vessel as specified in §60.112b(a) shall meet the requirements of paragraph (a), (b), or (c) of this section. The applicable paragraph for a particular storage vessel depends on the control equipment installed to meet the requirements of §60.112b.

(a) After installing the control equipment required to meet §60.112b(a)(1) (permanently affixed roof and internal floating roof), each owner or operator shall:

(1) Visually inspect the internal floating roof, the primary seal, and the secondary seal (if one is in service), prior to filling the storage vessel with VOL. If there are holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric or defects in the internal floating roof, or both, the owner or operator shall repair the items before filling the storage vessel.

(2) For Vessels equipped with a liquid-mounted or mechanical shoe primary seal, visually inspect the internal floating roof and the primary seal or the secondary seal (if one is in service) through manholes and roof hatches on the fixed roof at least once every 12 months after initial fill. If the internal floating roof is not resting on the surface of the VOL inside the storage vessel, or there is liquid accumulated on

the roof, or the seal is detached, or there are holes or tears in the seal fabric, the owner or operator shall repair the items or empty and remove the storage vessel from service within 45 days. If a failure that is detected during inspections required in this paragraph cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in §60.115b(a)(3). Such a request for an extension must document that alternate storage capacity is unavailable and specify a schedule of actions the company will take that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(3) For vessels equipped with a double-seal system as specified in §60.112b(a)(1)(ii)(B):

(i) Visually inspect the vessel as specified in paragraph (a)(4) of this section at least every 5 years; or

(ii) Visually inspect the vessel as specified in paragraph (a)(2) of this section.

(4) Visually inspect the internal floating roof, the primary seal, the secondary seal (if one is in service), gaskets, slotted membranes and sleeve seals (if any) each time the storage vessel is emptied and degassed. If the internal floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, or the gaskets no longer close off the liquid surfaces from the atmosphere, or the slotted membrane has more than 10 percent open area, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before refilling the storage vessel with VOL. In no event shall inspections conducted in accordance with this provision occur at intervals greater than 10 years in the case of vessels conducting the annual visual inspection as specified in paragraphs (a)(2) and (a)(3)(ii) of this section and at intervals no greater than 5 years in the case of vessels specified in paragraph (a)(3)(i) of this section.

(5) Notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel for which an inspection is required by paragraphs (a)(1) and (a)(4) of this section to afford the Administrator the opportunity to have an observer present. If the inspection required by paragraph (a)(4) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance or refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

(b) After installing the control equipment required to meet §60.112b(a)(2) (external floating roof), the owner or operator shall:

(1) Determine the gap areas and maximum gap widths, between the primary seal and the wall of the storage vessel and between the secondary seal and the wall of the storage vessel according to the following frequency.

(i) Measurements of gaps between the tank wall and the primary seal (seal gaps) shall be performed during the hydrostatic testing of the vessel or within 60 days of the initial fill with VOL and at least once every 5 years thereafter.

(ii) Measurements of gaps between the tank wall and the secondary seal shall be performed within 60 days of the initial fill with VOL and at least once per year thereafter.

(iii) If any source ceases to store VOL for a period of 1 year or more, subsequent introduction of VOL into the vessel shall be considered an initial fill for the purposes of paragraphs (b)(1)(i) and (b)(1)(ii) of this section.

(2) Determine gap widths and areas in the primary and secondary seals individually by the following procedures:

(i) Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.

(ii) Measure seal gaps around the entire circumference of the tank in each place where a 0.32-cm diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the storage vessel and measure the circumferential distance of each such location.

(iii) The total surface area of each gap described in paragraph (b)(2)(ii) of this section shall be determined by using probes of various widths to measure accurately the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.

(3) Add the gap surface area of each gap location for the primary seal and the secondary seal individually and divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the respective standards in paragraph (b)(4) of this section.

(4) Make necessary repairs or empty the storage vessel within 45 days of identification in any inspection for seals not meeting the requirements listed in (b)(4) (i) and (ii) of this section:

(i) The accumulated area of gaps between the tank wall and the mechanical shoe or liquid-mounted primary seal shall not exceed 212 Cm^2 per meter of tank diameter, and the width of any portion of any gap shall not exceed 3.81 cm.

(A) One end of the mechanical shoe is to extend into the stored liquid, and the other end is to extend a minimum vertical distance of 61 cm above the stored liquid surface.

(B) There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

(ii) The secondary seal is to meet the following requirements:

(A) The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in paragraph (b)(2)(iii) of this section.

(B) The accumulated area of gaps between the tank wall and the secondary seal shall not exceed 21.2 cm^2 per meter of tank diameter, and the width of any portion of any gap shall not exceed 1.27 cm.

(C) There are to be no holes, tears, or other openings in the seal or seal fabric.

(iii) If a failure that is detected during inspections required in paragraph (b)(1) of §60.113b(b) cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in §60.115b(b)(4). Such extension request must include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(5) Notify the Administrator 30 days in advance of any gap measurements required by paragraph (b)(1) of this section to afford the Administrator the opportunity to have an observer present.

(6) Visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed.

(i) If the external floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before filling or refilling the storage vessel with VOL.

(ii) For all the inspections required by paragraph (b)(6) of this section, the owner or operator shall notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel to afford the Administrator the opportunity to inspect the storage vessel prior to refilling. If the inspection required by paragraph (b)(6) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance of refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

(c) The owner or operator of each source that is equipped with a closed vent system and control device as required in §60.112b (a)(3) or (b)(2) (other than a flare) is exempt from §60.8 of the General Provisions and shall meet the following requirements.

(1) Submit for approval by the Administrator as an attachment to the notification required by §60.7(a)(1)

or, if the facility is exempt from §60.7(a)(1), as an attachment to the notification required by §60.7(a)(2), an operating plan containing the information listed below.

(i) Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions. This documentation is to include a description of the gas stream which enters the control device, including flow and VOC content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If the control device or the closed vent capture system receives vapors, gases, or liquids other than fuels from sources that are not designated sources under this subpart, the efficiency demonstration is to include consideration of all vapors, gases, and liquids received by the closed vent capture system and control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C is used to meet the 95 percent requirement, documentation that those conditions will exist is sufficient to meet the requirements of this paragraph.

(ii) A description of the parameter or parameters to be monitored to ensure that the control device will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

(2) Operate the closed vent system and control device and monitor the parameters of the closed vent system and control device in accordance with the operating plan submitted to the Administrator in accordance with paragraph (c)(1) of this section, unless the plan was modified by the Administrator during the review process. In this case, the modified plan applies.

(d) The owner or operator of each source that is equipped with a closed vent system and a flare to meet the requirements in §60.112b (a)(3) or (b)(2) shall meet the requirements as specified in the general control device requirements, §60.18 (e) and (f).

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989]

§ 60.114b Alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in emissions at least equivalent to the reduction in emissions achieved by any requirement in §60.112b, the Administrator will publish in the Federal Register a notice permitting the use of the alternative means for purposes of compliance with that requirement.

(b) Any notice under paragraph (a) of this section will be published only after notice and an opportunity for a hearing.

(c) Any person seeking permission under this section shall submit to the Administrator a written application including:

(1) An actual emissions test that uses a full-sized or scale-model storage vessel that accurately collects and measures all VOC emissions from a given control device and that accurately simulates wind and accounts for other emission variables such as temperature and barometric pressure.

(2) An engineering evaluation that the Administrator determines is an accurate method of determining equivalence.

(d) The Administrator may condition the permission on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as specified in §60.112b.

§ 60.11 b Reporting and record eeping requirements.

The owner or operator of each storage vessel as specified in §60.112b(a) shall keep records and furnish reports as required by paragraphs (a), (b), or (c) of this section depending upon the control equipment installed to meet the requirements of §60.112b. The owner or operator shall keep copies of all reports and records required by this section, except for the record required by (c)(1), for at least 2 years. The record required by (c)(1) will be kept for the life of the control equipment.

(a) After installing control equipment in accordance with §60.112b(a)(1) (fixed roof and internal floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of §60.112b(a)(1) and §60.113b(a)(1). This report shall be an attachment to the notification required by §60.7(a)(3).

(2) Keep a record of each inspection performed as required by §60.113b (a)(1), (a)(2), (a)(3), and (a)(4). Each record shall identify the storage vessel on which the inspection was performed and shall contain the date the vessel was inspected and the observed condition of each component of the control equipment (seals, internal floating roof, and fittings).

(3) If any of the conditions described in §60.113b(a)(2) are detected during the annual visual inspection required by §60.113b(a)(2), a report shall be furnished to the Administrator within 30 days of the inspection. Each report shall identify the storage vessel, the nature of the defects, and the date the storage vessel was emptied or the nature of and date the repair was made.

(4) After each inspection required by §60.113b(a)(3) that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other control equipment defects listed in §60.113b(a)(3)(ii), a report shall be furnished to the Administrator within 30 days of the inspection. The report shall identify the storage vessel and the reason it did not meet the specifications of §61.112b(a)(1) or §60.113b(a)(3) and list each repair made.

(b) After installing control equipment in accordance with §61.112b(a)(2) (external floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of §60.112b(a)(2) and §60.113b(b)(2), (b)(3), and (b)(4). This report shall be an attachment to the notification required by §60.7(a)(3).

(2) Within 60 days of performing the seal gap measurements required by §60.113b(b)(1), furnish the Administrator with a report that contains:

(i) The date of measurement.

(ii) The raw data obtained in the measurement.

(iii) The calculations described in §60.113b (b)(2) and (b)(3).

(3) Keep a record of each gap measurement performed as required by §60.113b(b). Each record shall identify the storage vessel in which the measurement was performed and shall contain:

(i) The date of measurement.

(ii) The raw data obtained in the measurement.

(iii) The calculations described in §60.113b (b)(2) and (b)(3).

(4) After each seal gap measurement that detects gaps exceeding the limitations specified by §60.113b (b)(4), submit a report to the Administrator within 30 days of the inspection. The report will identify the vessel and contain the information specified in paragraph (b)(2) of this section and the date the vessel was emptied or the repairs made and date of repair.

(c) After installing control equipment in accordance with §60.112b (a)(3) or (b)(1) (closed vent system and control device other than a flare), the owner or operator shall keep the following records.

(1) A copy of the operating plan.

(2) A record of the measured values of the parameters monitored in accordance with §60.113b(c)(2).

(d) After installing a closed vent system and flare to comply with §60.112b, the owner or operator shall meet the following requirements.

(1) A report containing the measurements required by §60.18(f) (1), (2), (3), (4), (5), and (6) shall be furnished to the Administrator as required by §60.8 of the General Provisions. This report shall be

submitted within 6 months of the initial start-up date.

(2) Records shall be kept of all periods of operation during which the flare pilot flame is absent.

(3) Semiannual reports of all periods recorded under §60.115b(d)(2) in which the pilot flame was absent shall be furnished to the Administrator.

§ 60.116b Monitoring of operations.

(a) The owner or operator shall keep copies of all records required by this section, except for the record required by paragraph (b) of this section, for at least 2 years. The record required by paragraph (b) of this section will be kept for the life of the source.

(b) The owner or operator of each storage vessel as specified in §60.110b(a) shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.

(c) Except as provided in paragraphs (f) and (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure greater than or equal to 3.5 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure greater than or equal to 15.0 kPa shall maintain a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period.

(d) Except as provided in paragraph (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure that is normally less than 5.2 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure that is normally less than 27.6 kPa shall notify the Administrator within 30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor vapor pressure values for each volume range.

(e) Available data on the storage temperature may be used to determine the maximum true vapor pressure as determined below.

(1) For vessels operated above or below ambient temperatures, the maximum true vapor pressure is calculated based upon the highest expected calendar-month average of the storage temperature. For vessels operated at ambient temperatures, the maximum true vapor pressure is calculated based upon the maximum local monthly average ambient temperature as reported by the National Weather Service.

(2) For crude oil or refined petroleum products the vapor pressure may be obtained by the following:

(i) Available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference—see §60.17), unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(ii) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa or with physical properties that preclude determination by the recommended method is to be determined from available data and recorded if the estimated maximum true vapor pressure is greater than 3.5 kPa.

(3) For other liquids, the vapor pressure:

(i) May be obtained from standard reference texts, or

(ii) Determined by ASTM D2879–83, 96, or 97 (incorporated by reference—see §60.17); or

(iii) Measured by an appropriate method approved by the Administrator; or

(iv) Calculated by an appropriate method approved by the Administrator.

(f) The owner or operator of each vessel storing a waste mixture of indeterminate or variable composition shall be subject to the following requirements.

(1) Prior to the initial filling of the vessel, the highest maximum true vapor pressure for the range of anticipated liquid compositions to be stored will be determined using the methods described in paragraph (e) of this section.

(2) For vessels in which the vapor pressure of the anticipated liquid composition is above the cutoff for monitoring but below the cutoff for controls as defined in §60.112b(a), an initial physical test of the vapor pressure is required; and a physical test at least once every 6 months thereafter is required as determined by the following methods:

(i) ASTM D2879–83, 96, or 97 (incorporated by reference—see §60.17); or

(ii) ASTM D323–82 or 94 (incorporated by reference—see §60.17); or

(iii) As measured by an appropriate method as approved by the Administrator.

(g) The owner or operator of each vessel equipped with a closed vent system and control device meeting the specification of §60.112b or with emissions reductions equipment as specified in 40 CFR 65.42(b)(4), (b)(5), (b)(6), or (c) is exempt from the requirements of paragraphs (c) and (d) of this section.

[52 FR 11429, Apr. 8, 1987, as amended at 65 FR 61756, Oct. 17, 2000; 65 FR 78276, Dec. 14, 2000; 68 FR 59333, Oct. 15, 2003]

§ 60.117b Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities which will not be delegated to States: §§60.111b(f)(4), 60.114b, 60.116b(e)(3)(iii), 60.116b(e)(3)(iv), and 60.116b(f)(2)(iii).

[52 FR 11429, Apr. 8, 1987, as amended at 52 FR 22780, June 16, 1987]

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APPENDIX E - NESHAP S

Electronic Code of Federal Regulations
e-CFR ™

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Title 40: Protection of Environment

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

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Subpart S—National Emission Standards for Hazardous Air Pollutants from the Pulp and Paper Industry

Source: 63 FR 18617, Apr. 15, 1998, unless otherwise noted.

§ 63.440 Applicability.

(a) The provisions of this subpart apply to the owner or operator of processes that produce pulp, paper, or paperboard; that are located at a plant site that is a major source as defined in §63.2 of subpart A of this part; and that use the following processes and materials:

(1) Kraft, soda, sulfite, or semi-chemical pulping processes using wood; or

(2) Mechanical pulping processes using wood; or

(3) Any process using secondary or non-wood fibers.

(b) The affected source to which the existing sourceprovisions of this subpart apply is as follows:

(1) For the processes specified in paragraph (a)(1) of this section, the affected source is the total of all HAP emission points in the pulping and bleaching systems; or

(2) For the processes specified in paragraphs (a)(2) or (a)(3) of this section, the affected source is the total of all HAP emission points in the bleaching system.

(c) The new source provisions of this subpart apply to the total of all HAP emission points at new or existing sources as follows:

(1) Each affected source defined in paragraph (b)(1) of this section that commences construction or reconstruction after December 17, 1993;

(2) Each pulping system or bleaching system for the processes specified in paragraph (a)(1) of this section that commences construction or reconstruction after December 17, 1993;

(3) Each additional pulping or bleaching line at the processes specified in paragraph (a)(1) of this section, that commences construction after December 17, 1993;

(4) Each affected source defined in paragraph (b)(2) of this section that commences construction or reconstruction after March 8, 1996; or

(5) Each additional bleaching line at the processes specified in paragraphs (a)(2) or (a)(3) of this section,

that commences construction after March 8, 1996.

(d) Each existing source shall achieve compliance no later than April 16, 2001, except as provided in paragraphs (d)(1) through (d)(3) of this section.

(1) Each kraft pulping system shall achieve compliance with the pulping system provisions of §63.443 for the equipment listed in §63.443(a)(1)(ii) through (a)(1)(v) as expeditiously as practicable, but in no event later than April 17, 2006 and the owners and operators shall establish dates, update dates, and report the dates for the milestones specified in §63.455(b).

(2) Each dissolving-grade bleaching system at either kraft or sulfite pulping mills shall achieve compliance with the bleach plant provisions of §63.445 of this subpart as expeditiously as practicable, but in no event later than 3 years after the promulgation of the revised effluent limitation guidelines and standards under 40 CFR 430.14 through 430.17 and 40 CFR 430.44 through 430.47.

(3) Each bleaching system complying with the Voluntary Advanced Technology Incentives Program for Effluent Limitation Guidelines in 40 CFR 430.24, shall comply with the requirements specified in either paragraph (d)(3)(i) or (d)(3)(ii) of this section for the effluent limitation guidelines and standards in 40 CFR 430.24.

(i) Comply with the bleach plant provisions of §63.445 of this subpart as expeditiously as practicable, but in no event later than April 16, 2001.

(ii) Comply with paragraphs (d)(3)(ii)(A), (d)(3)(ii)(B), and (d)(3)(ii)(C) of this section.

(A) The owner or operator of a bleaching system shall comply with the bleach plant provisions of §63.445 of this subpart as expeditiously as practicable, but in no event later than April 15, 2004.

(B) The owner or operator of a bleaching system shall comply with the requirements specified in either paragraph (d)(3)(ii)(B)(*1*) or (d)(3)(ii)(B)(*2*) of this section.

(*1*) Not increase the application rate of chlorine or hypochlorite in kilograms (kg) of bleaching agent per megagram of ODP, in the bleaching system above the average daily rates used over the three months prior to June 15, 1998 until the requirements of paragraph (d)(3)(ii)(A) of this section are met and record application rates as specified in §63.454(c).

(*2*) Comply with enforceable effluent limitations guidelines for 2,3,7,8-tetrachloro-dibenzo-p-dioxin and adsorbable organic halides at least as stringent as the baseline BAT levels set out in 40 CFR 430.24(a)(1) as expeditiously as possible, but in no event later than April 16, 2001.

(C) Owners and operators shall establish dates, update dates, and report the dates for the milestones specified in §63.455(b).

(e) Each new source, specified as the total of all HAP emission points for the sources specified in paragraph (c) of this section, shall achieve compliance upon start-up or June 15, 1998, whichever is later, as provided in §63.6(b) of subpart A of this part.

(f) Each owner or operator of an affected source with affected process equipment shared by more than one type of pulping process, shall comply with the applicable requirement in this subpart that achieves the maximum degree of reduction in HAP emissions.

(g) Each owner or operator of an affected source specified in paragraphs (a) through (c) of this section must comply with the requirements of subpart A—General Provisions of this part, as indicated in table 1 to this subpart.

[63 FR 18617, Apr. 15, 1998, as amended at 63 FR 71389, Dec. 28, 1998]

§ 63.441 Definitions.

All terms used in this subpart shall have the meaning given them in the CAA, in subpart A of this part, and in this section as follows:

Acid condensate storage tank means any storage tank containing cooking acid following the sulfur dioxide gas fortification process.

Black liquor means spent cooking liquor that has been separated from the pulp produced by the kraft, soda, or semi-chemical pulping process.

Bleaching means brightening of pulp by the addition of oxidizing chemicals or reducing chemicals.

Bleaching line means a group of bleaching stages arranged in series such that bleaching of the pulp progresses as the pulp moves from one stage to the next.

Bleaching stage means all process equipment associated with a discrete step of chemical application and removal in the bleaching process including chemical and steam mixers, bleaching towers, washers, seal (filtrate) tanks, vacuum pumps, and any other equipment serving the same function as those previously listed.

Bleaching system means all process equipment after high-density pulp storage prior to the first application of oxidizing chemicals or reducing chemicals following the pulping system, up to and including the final bleaching stage.

Boiler means any enclosed combustion device that extracts useful energy in the form of steam. A boiler is not considered a thermal oxidizer.

Chip steamer means a vessel used for the purpose of preheating or pretreating wood chips prior to the digester, using flash steam from the digester or live steam.

Closed-vent system means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and, if necessary, flow-inducing devices that transport gas or vapor from an emission point to a control device.

Combustion device means an individual unit of equipment, including but not limited to, a thermal oxidizer, lime kiln, recovery furnace, process heater, or boiler, used for the thermal oxidation of organic hazardous air pollutant vapors.

Decker system means all equipment used to thicken the pulp slurry or reduce its liquid content after the pulp washing system and prior to high-density pulp storage. The decker system includes decker vents, filtrate tanks, associated vacuum pumps, and any other equipment serving the same function as those previously listed.

Digester system means each continuous digester or each batch digester used for the chemical treatment of wood or non-wood fibers. The digester system equipment includes associated flash tank(s), blow tank(s), chip steamer(s) not using fresh steam, blow heat recovery accumulator(s), relief gas condenser(s), prehydrolysis unit(s) preceding the pulp washing system, and any other equipment serving the same function as those previously listed. The digester system includes any of the liquid streams or condensates associated with batch or continuous digester relief, blow, or flash steam processes.

Emission point means any part of a stationary source that emits hazardous air pollutants regulated under this subpart, including emissions from individual process vents, stacks, open pieces of process equipment, equipment leaks, wastewater and condensate collection and treatment system units, and those emissions that could reasonably be conveyed through a stack, chimney, or duct where such emissions first reach the environment.

Evaporator system means all equipment associated with increasing the solids content and/or concentrating spent cooking liquor from the pulp washing system including pre-evaporators, multi-effect evaporators, concentrators, and vacuum systems, as well as associated condensers, hotwells, and condensate streams, and any other equipment serving the same function as those previously listed.

Flow indicator means any device that indicates gas or liquid flow in an enclosed system.

HAP means a hazardous air pollutant as defined in §63.2 of subpart A of this part.

High volume, low concentration or HVLC collection system means the gas collection and transport system used to convey gases from the HVLC system to a control device.

High volume, low concentration or HVLC system means the collection of equipment including the pulp washing, knotter, screen, decker, and oxygen delignification systems, weak liquor storage tanks, and any other equipment serving the same function as those previously listed.

Knotter system means equipment where knots, oversized material, or pieces of uncooked wood are removed from the pulp slurry after the digester system and prior to the pulp washing system. The knotter system equipment includes the knotter, knot drainer tanks, ancillary tanks, and any other equipment serving the same function as those previously listed.

Kraft pulping means a chemical pulping process that uses a mixture of sodium hydroxide and sodium sulfide as the cooking liquor.

Lime kiln means an enclosed combustion device used to calcine lime mud, which consists primarily of calcium carbonate, into calcium oxide.

Low volume, high concentration or LVHC collection system means the gas collection and transport system used to convey gases from the LVHC system to a control device.

Low volume, high concentration or LVHC system means the collection of equipment including the digester, turpentine recovery, evaporator, steam stripper systems, and any other equipment serving the same function as those previously listed.

Mechanical pulping means a pulping process that only uses mechanical and thermo-mechanical processes to reduce wood to a fibrous mass. The mechanical pulping processes include, but are not limited to, stone groundwood, pressurized groundwood, refiner mechanical, thermal refiner mechanical, thermo-mechanical, and tandem thermo-mechanical.

Non-wood pulping means the production of pulp from fiber sources other than trees. The non-wood fiber sources include, but are not limited to, bagasse, cereal straw, cotton, flax straw, hemp, jute, kenaf, and leaf fibers.

Oven-dried pulp or ODP means a pulp sample at zero percent moisture content by weight. Pulp samples for applicability or compliance determinations for both the pulping and bleaching systems shall be unbleached pulp. For purposes of complying with mass emission limits in this subpart, megagram of ODP shall be measured to represent the amount of pulp entering and processed by the equipment system under the specified mass limit. For equipment that does not process pulp, megagram of ODP shall be measured to represent the amount of pulp that was processed to produce the gas and liquid streams.

Oxygen delignification system means the equipment that uses oxygen to remove lignin from pulp after high-density stock storage and prior to the bleaching system. The oxygen delignification system equipment includes the blow tank, washers, filtrate tanks, any interstage pulp storage tanks, and any other equipment serving the same function as those previously listed.

Primary fuel means the fuel that provides the principal heat input to the combustion device. To be considered primary, the fuel must be able to sustain operation of the combustion device without the addition of other fuels.

Process wastewater treatment system means a collection of equipment, a process, or specific technique that removes or destroys the HAPs in a process wastewater stream. Examples include, but are not limited to, a steam stripping unit, wastewater thermal oxidizer, or biological treatment unit.

Pulp washing system means all equipment used to wash pulp and separate spent cooking chemicals following the digester system and prior to the bleaching system, oxygen delignification system, or paper machine system (at unbleached mills). The pulp washing system equipment includes vacuum drum washers, diffusion washers, rotary pressure washers, horizontal belt filters, intermediate stock chests, and their associated vacuum pumps, filtrate tanks, foam breakers or tanks, and any other equipment serving the same function as those previously listed. The pulp washing system does not include deckers, screens, knotters, stock chests, or pulp storage tanks following the last stage of pulp washing.

Pulping line means a group of equipment arranged in series such that the wood chips are digested and the resulting pulp progresses through a sequence of steps that may include knotting, refining, washing, thickening, blending, storing, oxygen delignification, and any other equipment serving the same function as those previously listed.

Pulping process condensates means any HAP-containing liquid that results from contact of water with organic compounds in the pulping process. Examples of process condensates include digester system condensates, turpentine recovery system condensates, evaporator system condensates, LVHC system condensates, HVLC system condensates, and any other condensates from equipment serving the same function as those previously listed. Liquid streams that are intended for byproduct recovery are not considered process condensate streams.

Pulping system means all process equipment, beginning with the digester system, and up to and including the last piece of pulp conditioning equipment prior to the bleaching system, including treatment with ozone, oxygen, or peroxide before the first application of a chemical bleaching agent intended to brighten pulp. The pulping system includes pulping process condensates and can include multiple pulping lines.

Recovery furnace means an enclosed combustion device where concentrated spent liquor is burned to recover sodium and sulfur, produce steam, and dispose of unwanted dissolved wood components in the liquor.

Screen system means equipment in which oversized particles are removed from the pulp slurry prior to the bleaching or papermaking system washed stock storage.

Secondary fiber pulping means a pulping process that converts a fibrous material, that has previously undergone a manufacturing process, into pulp stock through the addition of water and mechanical energy. The mill then uses that pulp as the raw material in another manufactured product. These mills may also utilize chemical, heat, and mechanical processes to remove ink particles from the fiber stock.

Semi-chemical pulping means a pulping process that combines both chemical and mechanical pulping processes. The semi-chemical pulping process produces intermediate yields ranging from 55 to 90 percent.

Soda pulping means a chemical pulping process that uses sodium hydroxide as the active chemical in the cooking liquor.

Spent liquor means process liquid generated from the separation of cooking liquor from pulp by the pulp washing system containing dissolved organic wood materials and residual cooking compounds.

Steam stripper system means a column (including associated stripper feed tanks, condensers, or heat exchangers) used to remove compounds from wastewater or condensates using steam. The steam stripper system also contains all equipment associated with a methanol rectification process including rectifiers, condensers, decanters, storage tanks, and any other equipment serving the same function as those previously listed.

Strong liquor storage tanks means all storage tanks containing liquor that has been concentrated in preparation for combustion or oxidation in the recovery process.

Sulfite pulping means a chemical pulping process that uses a mixture of sulfurous acid and bisulfite ion as the cooking liquor.

Temperature monitoring device means a piece of equipment used to monitor temperature and having an accuracy of ±1.0 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 degrees Celsius ((°deg;C), whichever is greater.

Thermal oxidizer means an enclosed device that destroys organic compounds by thermal oxidation.

Turpentine recovery system means all equipment associated with recovering turpentine from digester system gases including condensers, decanters, storage tanks, and any other equipment serving the same function as those previously listed. The turpentine recovery system includes any liquid streams associated with the turpentine recovery process such as turpentine decanter underflow. Liquid streams that are intended for byproduct recovery are not considered turpentine recovery system condensate streams.

eak liquor storage tank means any storage tank except washer filtrate tanks containing spent liquor recovered from the pulping process and prior to the evaporator system.

[63 FR 18617, Apr. 15, 1998, as amended at 64 FR 17563, Apr. 12, 1999]

§ 63.442 Reserved

§ 63.443 Standards for the pulpin system at raft, soda, and semi-chemical processes.

(a) The owner or operator of each pulping system using the kraft process subject to the requirements of this subpart shall control the total HAP emissions from the following equipment systems, as specified in paragraphs (c) and (d) of this section.

(1) At existing affected sources, the total HAP emissions from the following equipment systems shall be controlled:

(i) Each LVHC system;

(ii) Each knotter or screen system with total HAP mass emission rates greater than or equal to the rates specified in paragraphs (a)(1)(ii)(A) or (a)(1)(ii)(B) of this section or the combined rate specified in paragraph (a)(1)(ii)(C) of this section.

(A) Each knotter system with emissions of 0.05 kilograms or more of total HAP per megagram of ODP (0.1 pounds per ton).

(B) Each screen system with emissions of 0.10 kilograms or more of total HAP per megagram of ODP (0.2 pounds per ton).

(C) Each knotter and screen system with emissions of 0.15 kilograms or more of total HAP per megagram of ODP (0.3 pounds per ton).

(iii) Each pulp washing system;

(iv) Each decker system that:

(A) Uses any process water other than fresh water or paper machine white water; or

(B) Uses any process water with a total HAP concentration greater than 400 parts per million by weight; and

(v) Each oxygen delignification system.

(2) At new affected sources, the total HAP emissions from the equipment systems listed in paragraphs (a)(1)(i), (a)(1)(iii), and (a)(1)(v) of this section and the following equipment systems shall be controlled:

(i) Each knotter system;

(ii) Each screen system;

(iii) Each decker system; and

(iv) Each weak liquor storage tank.

(b) The owner or operator of each pulping system using a semi-chemical or soda process subject to the requirements of this subpart shall control the total HAP emissions from the following equipment systems as specified in paragraphs (c) and (d) of this section.

(1) At each existing affected source, the total HAP emissions from each LVHC system shall be controlled.

(2) At each new affected source, the total HAP emissions from each LVHC system and each pulp washing system shall be controlled.

(c) Equipment systems listed in paragraphs (a) and (b) of this section shall be enclosed and vented into a closed-vent system and routed to a control device that meets the requirements specified in paragraph (d) of this section. The enclosures and closed-vent system shall meet the requirements specified in §63.450.

(d) The control device used to reduce total HAP emissions from each equipment system listed in paragraphs (a) and (b) of this section shall:

(1) Reduce total HAP emissions by 98 percent or more by weight; or

(2) Reduce the total HAP concentration at the outlet of the thermal oxidizer to 20 parts per million or less by volume, corrected to 10 percent oxygen on a dry basis; or

(3) Reduce total HAP emissions using a thermal oxidizer designed and operated at a minimum temperature of 871 °C (1600 °F) and a minimum residence time of 0.75 seconds; or

(4) Reduce total HAP emissions using one of the following:

(i) A boiler, lime kiln, or recovery furnace by introducing the HAP emission stream with the primary fuel or into the flame zone; or

(ii) A boiler or recovery furnace with a heat input capacity greater than or equal to 44 megawatts (150 million British thermal units per hour) by introducing the HAP emission stream with the combustion air.

(e) Periods of excess emissions reported under §63.455 shall not be a violation of §63.443 (c) and (d) provided that the time of excess emissions (excluding periods of startup, shutdown, or malfunction) divided by the total process operating time in a semi-annual reporting period does not exceed the following levels:

(1) One percent for control devices used to reduce the total HAP emissions from the LVHC system; and

(2) Four percent for control devices used to reduce the total HAP emissions from the HVLC system; and

(3) Four percent for control devices used to reduce the total HAP emissions from both the LVHC and HVLC systems.

[63 FR 18617, Apr. 15, 1998, as amended at 64 FR 17563, Apr. 12, 1999; 66 FR 80762, Dec. 22, 2000]

§ 63.444 Standards for the pulpin system at sulfite processes.

(a) The owner or operator of each sulfite process subject to the requirements of this subpart shall control the total HAP emissions from the following equipment systems as specified in paragraphs (b) and (c) of this section.

(1) At existing sulfite affected sources, the total HAP emissions from the following equipment systems shall be controlled:

(i) Each digester system vent;

(ii) Each evaporator system vent; and

(iii) Each pulp washing system.

(2) At new affected sources, the total HAP emissions from the equipment systems listed in paragraph (a)(1) of this section and the following equipment shall be controlled:

(i) Each weak liquor storage tank;

(ii) Each strong liquor storage tank; and

(iii) Each acid condensate storage tank.

(b) Equipment listed in paragraph (a) of this section shall be enclosed and vented into a closed-vent system and routed to a control device that meets the requirements specified in paragraph (c) of this section. The enclosures and closed-vent system shall meet the requirements specified in §63.450. Emissions from equipment listed in paragraph (a) of this section that is not necessary to be reduced to meet paragraph (c) of this section is not required to be routed to a control device.

(c) The total HAP emissions from both the equipment systems listed in paragraph (a) of this section and the vents, wastewater, and condensate streams from the control device used to reduce HAP emissions, shall be controlled as follows.

(1) Each calcium-based or sodium-based sulfite pulping process shall:

(i) Emit no more than 0.44 kilograms of total HAP or methanol per megagram (0.89 pounds per ton) of ODP; or

(ii) Remove 92 percent or more by weight of the total HAP or methanol.

(2) Each magnesium-based or ammonium-based sulfite pulping process shall:

(i) Emit no more than 1.1 kilograms of total HAP or methanol per megagram (2.2 pounds per ton) of ODP; or

(ii) Remove 87 percent or more by weight of the total HAP or methanol.

§ 63.44 Standards for the bleachin system.

(a) Each bleaching system that does not use any chlorine or chlorinated compounds for bleaching is exempt from the requirements of this section. Owners or operators of the following bleaching systems shall meet all the provisions of this section:

(1) Bleaching systems that use chlorine;

(2) Bleaching systems bleaching pulp from kraft, sulfite, or soda pulping processes that use any chlorinated compounds; or

(3) Bleaching systems bleaching pulp from mechanical pulping processes using wood or from any process using secondary or non-wood fibers, that use chlorine dioxide.

(b) The equipment at each bleaching stage, of the bleaching systems listed in paragraph (a) of this section, where chlorinated compounds are introduced shall be enclosed and vented into a closed-vent system and routed to a control device that meets the requirements specified in paragraph (c) of this section. The enclosures and closed-vent system shall meet the requirements specified in §63.450. If process modifications are used to achieve compliance with the emission limits specified in paragraphs (c)(2) or (c)(3), enclosures and closed-vent systems are not required, unless appropriate.

(c) The control device used to reduce chlorinated HAP emissions (not including chloroform) from the equipment specified in paragraph (b) of this section shall:

(1) Reduce the total chlorinated HAP mass in the vent stream entering the control device by 99 percent or more by weight;

(2) Achieve a treatment device outlet concentration of 10 parts per million or less by volume of total chlorinated HAP; or

(3) Achieve a treatment device outlet mass emission rate of 0.001 kg of total chlorinated HAP mass per megagram (0.002 pounds per ton) of ODP.

(d) The owner or operator of each bleaching system subject to paragraph (a)(2) of this section shall comply with paragraph (d)(1) or (d)(2) of this section to reduce chloroform air emissions to the atmosphere, except the owner or operator of each bleaching system complying with extended compliance under §63.440(d)(3)(ii) shall comply with paragraph (d)(1) of this section.

(1) Comply with the following applicable effluent limitation guidelines and standards specified in 40 CFR part 430:

(i) Dissolving-grade kraft bleaching systems and lines, 40 CFR 430.14 through 430.17;

(ii) Paper-grade kraft and soda bleaching systems and lines, 40 CFR 430.24(a)(1) and (e), and 40 CFR 430.26 (a) and (c);

(iii) Dissolving-grade sulfite bleaching systems and lines, 40 CFR 430.44 through 430.47; or

(iv) Paper-grade sulfite bleaching systems and lines, 40 CFR 430.54(a) and (c), and 430.56(a) and (c).

(2) Use no hypochlorite or chlorine for bleaching in the bleaching system or line.

[63 FR 18617, Apr. 15, 1998, as amended at 64 FR 17563, Apr. 12, 1999]

§ 63.446 Standards for raft pulpin process condensates.

(a) The requirements of this section apply to owners or operators of kraft processes subject to the requirements of this subpart.

(b) The pulping process condensates from the following equipment systems shall be treated to meet the requirements specified in paragraphs (c), (d), and (e) of this section:

(1) Each digester system;

(2) Each turpentine recovery system;

(3) Each evaporator system condensate from:

(i) The vapors from each stage where weak liquor is introduced (feed stages); and

(ii) Each evaporator vacuum system for each stage where weak liquor is introduced (feed stages).

(4) Each HVLC collection system; and

(5) Each LVHC collection system.

(c) One of the following combinations of HAP-containing pulping process condensates generated, produced, or associated with the equipment systems listed in paragraph (b) of this section shall be subject to the requirements of paragraphs (d) and (e) of this section:

(1) All pulping process condensates from the equipment systems specified in paragraphs (b)(1) through (b)(5) of this section.

(2) The combined pulping process condensates from the equipment systems specified in paragraphs (b)(4) and (b)(5) of this section, plus pulping process condensate stream(s) that in total contain at least 65 percent of the total HAP mass from the pulping process condensates from equipment systems listed in paragraphs (b)(1) through (b)(3) of this section.

(3) The pulping process condensates from equipment systems listed in paragraphs (b)(1) through (b)(5) of this section that in total contain a total HAP mass of 3.6 kilograms or more of total HAP per megagram (7.2 pounds per ton) of ODP for mills that do not perform bleaching or 5.5 kilograms or more of total HAP per megagram (11.1 pounds per ton) of ODP for mills that perform bleaching.

(d) The pulping process condensates from the equipment systems listed in paragraph (b) of this section shall be conveyed in a closed collection system that is designed and operated to meet the requirements specified in paragraphs (d)(1) and (d)(2) of this section.

(1) Each closed collection system shall meet the individual drain system requirements specified in §§63.960, 63.961, and 63.962 of subpart RR of this part, except for closed vent systems and control devices shall be designed and operated in accordance with §§63.443(d) and 63.450, instead of in accordance with §63.693 as specified in §63.962 (a)(3)(ii), (b)(3)(ii)(A), and (b)(5)(iii); and

(2) If a condensate tank is used in the closed collection system, the tank shall meet the following requirements:

(i) The fixed roof and all openings (e.g., access hatches, sampling ports, gauge wells) shall be designed and operated with no detectable leaks as indicated by an instrument reading of less than 500 parts per million above background, and vented into a closed-vent system that meets the requirements in §63.450 and routed to a control device that meets the requirements in §63.443(d); and

(ii) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that the tank contains pulping process condensates or any HAP removed from a pulping process condensate stream except when it is necessary to use the opening for sampling, removal, or for equipment inspection, maintenance, or repair.

(e) Each pulping process condensate from the equipment systems listed in paragraph (b) of this section shall be treated according to one of the following options:

(1) Recycle the pulping process condensate to an equipment system specified in §63.443(a) meeting the requirements specified in §63.443(c) and (d); or

(2) Discharge the pulping process condensate below the liquid surface of a biological treatment system and treat the pulping process condensates to meet the requirements specified in paragraph (e)(3), (4), or (5) of this section, and total HAP shall be measured as specified in §63.457(g); or

(3) Treat the pulping process condensates to reduce or destroy the total HAPs by at least 92 percent or more by weight; or

(4) At mills that do not perform bleaching, treat the pulping process condensates to remove 3.3 kilograms or more of total HAP per megagram (6.6 pounds per ton) of ODP, or achieve a total HAP concentration of 210 parts per million or less by weight at the outlet of the control device; or

(5) At mills that perform bleaching, treat the pulping process condensates to remove 5.1 kilograms or more of total HAP per megagram (10.2 pounds per ton) of ODP, or achieve a total HAP concentration of 330 parts per million or less by weight at the outlet of the control device.

(f) Each HAP removed from a pulping process condensate stream during treatment and handling under paragraphs (d) or (e) of this section, except for those treated according to paragraph (e)(2) of this section, shall be controlled as specified in §63.443(c) and (d).

(g) For each control device (e.g. steam stripper system or other equipment serving the same function) used to treat pulping process condensates to comply with the requirements specified in paragraphs (e)(3) through (e)(5) of this section, periods of excess emissions reported under §63.455 shall not be a violation of paragraphs (d), (e)(3) through (e)(5), and (f) of this section provided that the time of excess emissions (including periods of startup, shutdown, or malfunction) divided by the total process operating time in a semi-annual reporting period does not exceed 10 percent. The 10 percent excess emissions allowance does not apply to treatment of pulping process condensates according to paragraph (e)(2) of this section (e.g. the biological wastewater treatment system used to treat multiple (primarily non-condensate) wastewater streams to comply with the Clean Water Act).

(h) Each owner or operator of a new or existing affected source subject to the requirements of this section shall evaluate all new or modified pulping process condensates or changes in the annual bleached or non-bleached ODP used to comply with paragraph (i) of this section, to determine if they meet the applicable requirements of this section.

(i) For the purposes of meeting the requirements in paragraph (c)(2) or (3) or paragraph (e)(4) or (5) of this section at mills producing both bleached and unbleached pulp products, owners and operators may meet a prorated mass standard that is calculated by prorating the applicable mass standards (kilograms of total HAP per megagram of ODP) for bleached and unbleached mills specified in paragraph (c)(2) or (3) or paragraph (e)(4) or (5) of this section by the ratio of annual megagrams of bleached and unbleached ODP.

[63 FR 18617, Apr. 15, 1998; 63 FR 42239, Aug. 7, 1998, as amended at 63 FR 49459, Sept. 16, 1998; 64 FR 17563, Apr. 12, 1999; 65 FR 80762, Dec. 22, 2000]

§ 63.447 Clean condensate alternative.

As an alternative to the requirements specified in §63.443(a)(1)(ii) through (a)(1)(v) for the control of HAP emissions from pulping systems using the kraft process, an owner or operator must demonstrate to the satisfaction of the Administrator, by meeting all the requirements below, that the total HAP emissions reductions achieved by this clean condensate alternative technology are equal to or greater than the total HAP emission reductions that would have been achieved by compliance with §63.443(a)(1)(ii) through (a)(1)(v).

(a) For the purposes of this section only the following additional definitions apply.

(1) *Clean condensate alternative affected source* means the total of all HAP emission points in the pulping, bleaching, causticizing, and papermaking systems (exclusive of HAP emissions attributable to additives to paper machines and HAP emission points in the LVHC system).

(2) *Causticizing system* means all equipment associated with converting sodium carbonate into active sodium hydroxide. The equipment includes smelt dissolving tanks, lime mud washers and storage tanks, white and mud liquor clarifiers and storage tanks, slakers, slaker grit washers, lime kilns, green liquor clarifiers and storage tanks, and dreg washers ending with the white liquor storage tanks prior to the digester system, and any other equipment serving the same function as those previously listed.

(3) *Papermaking system* means all equipment used to convert pulp into paper, paperboard, or market pulp, including the stock storage and preparation systems, the paper or paperboard machines, and the paper machine white water system, broke recovery systems, and the systems involved in calendering, drying, on-machine coating, slitting, winding, and cutting.

(b) Each owner or operator shall install and operate a clean condensate alternative technology with a continuous monitoring system to reduce total HAP emissions by treating and reducing HAP concentrations in the pulping process water used within the clean condensate alternative affected source.

(c) Each owner or operator shall calculate HAP emissions on a kilogram per megagram of ODP basis and measure HAP emissions according to the appropriate procedures contained in §63.457.

(d) Each owner or operator shall determine the baseline HAP emissions for each equipment system and the total of all equipment systems in the clean condensate alternative affected source based on the following:

(1) Process and air pollution control equipment installed and operating on December 17, 1993, and

(2) Compliance with the following requirements that affect the level of HAP emissions from the clean condensate alternative affected source:

(i) The pulping process condensates requirements in §63.446;

(ii) The applicable effluent limitation guidelines and standards in 40 CFR part 430, subparts A, B, D, and E; and

(iii) All other applicable requirements of local, State, or Federal agencies or statutes.

(e) Each owner or operator shall determine the following HAP emission reductions from the baseline HAP emissions determined in paragraph (d) of this section for each equipment system and the total of all equipment systems in the clean condensate alternative affected source:

(1) The HAP emission reduction occurring by complying with the requirements of §63.443(a)(1)(ii)

through (a)(1)(v); and

(2) The HAP emissions reduction occurring by complying with the clean condensate alternative technology.

(f) For the purposes of all requirements in this section, each owner or operator may use as an alternative, individual equipment systems (instead of total of all equipment systems) within the clean condensate alternative affected source to determine emissions and reductions to demonstrate equal or greater than the reductions that would have been achieved by compliance with §63.443(a)(1)(ii) through (a)(1)(v).

(g) The initial and updates to the control strategy report specified in §63.455(b) shall include to the extent possible the following information:

(1) A detailed description of:

(i) The equipment systems and emission points that comprise the clean condensate alternative affected source;

(ii) The air pollution control technologies that would be used to meet the requirements of §63.443(a)(1)(ii) through (a)(1)(v); and

(iii) The clean condensate alternative technology to be used.

(2) Estimates and basis for the estimates of total HAP emissions and emission reductions to fulfill the requirements of paragraphs (d), (e), and (f) of this section.

(h) Each owner or operator shall report to the Administrator by the applicable compliance date specified in §63.440(d) or (e) the rationale, calculations, test procedures, and data documentation used to demonstrate compliance with all the requirements of this section.

[63 FR 18617, Apr. 15, 1998; 63 FR 42239, Aug. 7, 1998, as amended at 64 FR 17563, Apr. 12, 1999]

§§ 63.44 -63.44 Reserved

§ 63.4 0 Standards for enclosures and closed-vent systems.

(a) Each enclosure and closed-vent system specified in §§63.443(c), 63.444(b), and 63.445(b) for capturing and transporting vent streams that contain HAP shall meet the requirements specified in paragraphs (b) through (d) of this section.

(b) Each enclosure shall maintain negative pressure at each enclosure or hood opening as demonstrated by the procedures specified in §63.457(e). Each enclosure or hood opening closed during the initial performance test specified in §63.457(a) shall be maintained in the same closed and sealed position as during the performance test at all times except when necessary to use the opening for sampling, inspection, maintenance, or repairs.

(c) Each component of the closed-vent system used to comply with §§63.443(c), 63.444(b), and 63.445(b) that is operated at positive pressure and located prior to a control device shall be designed for and operated with no detectable leaks as indicated by an instrument reading of less than 500 parts per million by volume above background, as measured by the procedures specified in §63.457(d).

(d) Each bypass line in the closed-vent system that could divert vent streams containing HAP to the atmosphere without meeting the emission limitations in §§63.443, 63.444, or 63.445 shall comply with either of the following requirements:

(1) On each bypass line, the owner or operator shall install, calibrate, maintain, and operate according to the manufacturer's specifications a flow indicator that is capable of taking periodic readings as frequently as specified in §63.454(e). The flow indicator shall be installed in the bypass line in such a way as to indicate flow in the bypass line; or

(2) For bypass line valves that are not computer controlled, the owner or operator shall maintain the

bypass line valve in the closed position with a car seal or a seal placed on the valve or closure mechanism in such a way that valve or closure mechanism cannot be opened without breaking the seal.

[63 FR 18617, Apr. 15, 1998, as amended at 64 FR 17563, Apr. 12, 1999; 68 FR 37348, June 23, 2003]

§§ 63.4 1-63.4 2 Reserved

§ 63.4 3 Monitorin re uirements.

(a) Each owner or operator subject to the standards specified in §§63.443(c) and (d), 63.444(b) and (c), 63.445(b) and (c), 63.446(c), (d), and (e), 63.447(b) or §63.450(d), shall install, calibrate, certify, operate, and maintain according to the manufacturer's specifications, a continuous monitoring system (CMS, as defined in §63.2 of this part) as specified in paragraphs (b) through (m) of this section, except as allowed in paragraph (m) of this section. The CMS shall include a continuous recorder.

(b) A CMS shall be operated to measure the temperature in the firebox or in the ductwork immediately downstream of the firebox and before any substantial heat exchange occurs for each thermal oxidizer used to comply with the requirements of §63.443(d)(1) through (d)(3). Owners and operators complying with the HAP concentration requirements in §63.443(d)(2) may install a CMS to monitor the thermal oxidizer outlet total HAP or methanol concentration, as an alternative to monitoring thermal oxidizer operating temperature.

(c) A CMS shall be operated to measure the following parameters for each gas scrubber used to comply with the bleaching system requirements of §63.445(c) or the sulfite pulping system requirements of §63.444(c).

(1) The pH or the oxidation/reduction potential of the gas scrubber effluent;

(2) The gas scrubber vent gas inlet flow rate; and

(3) The gas scrubber liquid influent flow rate.

(d) As an option to the requirements specified in paragraph (c) of this section, a CMS shall be operated to measure the chlorine outlet concentration of each gas scrubber used to comply with the bleaching system outlet concentration requirement specified in §63.445(c)(2).

(e) The owner or operator of a bleaching system complying with 40 CFR 430.24, shall monitor the chlorine and hypochlorite application rates, in kg of bleaching agent per megagram of ODP, of the bleaching system during the extended compliance period specified in §63.440(d)(3).

(f) A CMS shall be operated to measure the gas scrubber parameters specified in paragraphs (c)(1) through (c)(3) of this section or those site specific parameters determined according to the procedures specified in paragraph (n) of this section to comply with the sulfite pulping system requirements specified in §63.444(c).

(g) A CMS shall be operated to measure the following parameters for each steam stripper used to comply with the treatment requirements in §63.446(e) (3), (4), or (5):

(1) The process wastewater feed rate;

(2) The steam feed rate; and

(3) The process wastewater column feed temperature.

(h) As an option to the requirements specified in paragraph (g) of this section, a CMS shall be operated to measure the methanol outlet concentration to comply with the steam stripper outlet concentration requirement specified in §63.446 (e)(4) or (e)(5).

(i) A CMS shall be operated to measure the appropriate parameters determined according to the procedures specified in paragraph (n) of this section to comply with the condensate applicability requirements specified in §63.446(c).

(j) Each owner or operator using an open biological treatment system to comply with §63.446(e)(2) shall perform the daily monitoring procedures specified in either paragraph (j)(1) or (2) of this section and shall conduct a performance test each quarter using the procedures specified in paragraph (j)(3) of this section.

(1) Comply with the monitoring and sampling requirements specified in paragraphs (j)(1)(i) and (ii) of this section.

(i) On a daily basis, monitor the following parameters for each open biological treatment unit:

(A) Composite daily sample of outlet soluble BOD_5concentration to monitor for maximum daily and maximum monthly average;

(B) Mixed liquor volatile suspended solids;

(C) Horsepower of aerator unit(s);

(D) Inlet liquid flow; and

(E) Liquid temperature.

(ii) If the Inlet and Outlet Concentration Measurement Procedure (Procedure 3) in appendix C of this part is used to determine the fraction of HAP compounds degraded in the biological treatment system as specified in §63.457(l), conduct the sampling and archival requirements specified in paragraphs (j)(1)(ii)(A) and (B) of this section.

(A) Obtain daily inlet and outlet liquid grab samples from each biological treatment unit to have HAP data available to perform quarterly performance tests specified in paragraph (j)(3) of this section and the compliance tests specified in paragraph (p) of this section.

(B) Store the samples as specified in §63.457(n) until after the results of the soluble BOD_5test required in paragraph (j)(1)(i)(A) of this section are obtained. The storage requirement is needed since the soluble BOD_5test requires 5 days or more to obtain results. If the results of the soluble BOD_5test are outside of the range established during the initial performance test, then the archive sample shall be used to perform the mass removal or percent reduction determinations.

(2) As an alternative to the monitoring requirements of paragraph (j)(1) of this section, conduct daily monitoring of the site-specific parameters established according to the procedures specified in paragraph (n) of this section.

(3) Conduct a performance test as specified in §63.457(l) within 45 days after the beginning of each quarter and meet the applicable emission limit in §63.446(e)(2).

(i) The performance test conducted in the first quarter (annually) shall be performed for total HAP as specified in §63.457(g) and meet the percent reduction or mass removal emission limit specified in §63.446(e)(2).

(ii) The remaining quarterly performance tests shall be performed as specified in paragraph (j)(3)(i) of this section except owners or operators may use the applicable methanol procedure in §63.457(l)(1) or (2) and the value of r determined during the first quarter test instead of measuring the additional HAP to determine a new value of r.

(k) Each enclosure and closed-vent system used to comply with §63.450(a) shall comply with the requirements specified in paragraphs (k)(1) through (k)(6) of this section.

(1) For each enclosure opening, a visual inspection of the closure mechanism specified in §63.450(b) shall be performed at least once every 30 days to ensure the opening is maintained in the closed position and sealed.

(2) Each closed-vent system required by §63.450(a) shall be visually inspected every 30 days and at other times as requested by the Administrator. The visual inspection shall include inspection of ductwork, piping, enclosures, and connections to covers for visible evidence of defects.

(3) For positive pressure closed-vent systems or portions of closed-vent systems, demonstrate no detectable leaks as specified in §63.450(c) measured initially and annually by the procedures in §63.457 (d).

(4) Demonstrate initially and annually that each enclosure opening is maintained at negative pressure as specified in §63.457(e).

(5) The valve or closure mechanism specified in §63.450(d)(2) shall be inspected at least once every 30 days to ensure that the valve is maintained in the closed position and the emission point gas stream is not diverted through the bypass line.

(6) If an inspection required by paragraphs (k)(1) through (k)(5) of this section identifies visible defects in ductwork, piping, enclosures or connections to covers required by §63.450, or if an instrument reading of 500 parts per million by volume or greater above background is measured, or if enclosure openings are not maintained at negative pressure, then the following corrective actions shall be taken as soon as practicable.

(i) A first effort to repair or correct the closed-vent system shall be made as soon as practicable but no later than 5 calendar days after the problem is identified.

(ii) The repair or corrective action shall be completed no later than 15 calendar days after the problem is identified. Delay of repair or corrective action is allowed if the repair or corrective action is technically infeasible without a process unit shutdown or if the owner or operator determines that the emissions resulting from immediate repair would be greater than the emissions likely to result from delay of repair. Repair of such equipment shall be completed by the end of the next process unit shutdown.

(l) Each pulping process condensate closed collection system used to comply with §63.446(d) shall comply with the requirements specified in paragraphs (l)(1) through (l)(3) of this section.

(1) Each pulping process condensate closed collection system shall be visually inspected every 30 days and shall comply with the inspection and monitoring requirements specified in §63.964 of subpart RR of this part, except:

(i) Owners or operators shall comply with the recordkeeping requirements of §63.454 instead of the requirements specified in §63.964(a)(1)(vi) and (b)(3) of subpart RR of this part.

(ii) Owners or operators shall comply with the inspection and monitoring requirements for closed-vent systems and control devices specified in paragraphs (a) and (k) of this section instead of the requirements specified in §63.964(a)(2) of subpart RR of this part.

(2) Each condensate tank used in the closed collection system shall be operated with no detectable leaks as specified in §63.446(d)(2)(i) measured initially and annually by the procedures specified in §63.457(d).

(3) If an inspection required by this section identifies visible defects in the closed collection system, or if an instrument reading of 500 parts per million or greater above background is measured, then corrective actions specified in §63.964(b) of subpart RR of this part shall be taken.

(m) Each owner or operator using a control device, technique or an alternative parameter other than those specified in paragraphs (b) through (l) of this section shall install a CMS and establish appropriate operating parameters to be monitored that demonstrate, to the Administrator's satisfaction, continuous compliance with the applicable control requirements.

(n) To establish or reestablish the value for each operating parameter required to be monitored under paragraphs (b) through (j), (l), and (m) of this section or to establish appropriate parameters for paragraphs (f), (i), (j)(2), and (m) of this section, each owner or operator shall use the following procedures:

(1) During the initial performance test required in §63.457(a) or any subsequent performance test, continuously record the operating parameter;

(2) Determinations shall be based on the control performance and parameter data monitored during the performance test, supplemented if necessary by engineering assessments and the manufacturer's

recommendations;

(3) The owner or operator shall provide for the Administrator's approval the rationale for selecting the monitoring parameters necessary to comply with paragraphs (f), (i), and (m) of this section; and

(4) Provide for the Administrator's approval the rationale for the selected operating parameter value, and monitoring frequency, and averaging time. Include all data and calculations used to develop the value and a description of why the value, monitoring frequency, and averaging time demonstrate continuous compliance with the applicable emission standard.

(o) Each owner or operator of a control device subject to the monitoring provisions of this section shall operate the control device in a manner consistent with the minimum or maximum (as appropriate) operating parameter value or procedure required to be monitored under paragraphs (a) through (n) of this section and established under this subpart. Except as provided in paragraph (p) of this section, §63.443(e), or §63.446(g), operation of the control device below minimum operating parameter values or above maximum operating parameter values established under this subpart or failure to perform procedures required by this subpart shall constitute a violation of the applicable emission standard of this subpart and be reported as a period of excess emissions.

(p) The procedures of this paragraph apply to each owner or operator of an open biological treatment system complying with paragraph (j) of this section whenever a monitoring parameter excursion occurs, and the owner or operator chooses to conduct a performance test to demonstrate compliance with the applicable emission limit. A monitoring parameter excursion occurs whenever the monitoring parameters specified in paragraphs (j)(1)(i)(A) through (C) of this section or any of the monitoring parameters specified in paragraph (j)(2) of this section are below minimum operating parameter values or above maximum operating parameter values established in paragraph (n) of this section.

(1) As soon as practical after the beginning of the monitoring parameter excursion, the following requirements shall be met:

(i) Before the steps in paragraph (p)(1)(ii) or (iii) of this section are performed, all sampling and measurements necessary to meet the requirements in paragraph (p)(2) of this section shall be conducted.

(ii) Steps shall be taken to repair or adjust the operation of the process to end the parameter excursion period.

(iii) Steps shall be taken to minimize total HAP emissions to the atmosphere during the parameter excursion period.

(2) A parameter excursion is not a violation of the applicable emission standard if the results of the performance test conducted using the procedures in this paragraph demonstrate compliance with the applicable emission limit in §63.446(e)(2).

(i) Conduct a performance test as specified in §63.457 using the monitoring data specified in paragraph (j)(1) or (2) of this section that coincides with the time of the parameter excursion. No maintenance or changes shall be made to the open biological treatment system after the beginning of a parameter excursion that would influence the results of the performance test.

(ii) If the results of the performance test specified in paragraph (p)(2)(i) of this section demonstrate compliance with the applicable emission limit in §63.446(e)(2), then the parameter excursion is not a violation of the applicable emission limit.

(iii) If the results of the performance test specified in paragraph (p)(2)(i) of this section do not demonstrate compliance with the applicable emission limit in §63.446(e)(2) because the total HAP mass entering the open biological treatment system is below the level needed to demonstrate compliance with the applicable emission limit in §63.446(e)(2), then the owner or operator shall perform the following comparisons:

(A) If the value of f_{bio}(MeOH) determined during the performance test specified in paragraph (p)(2)(i) of this section is within the range of values established during the initial and subsequent performance tests approved by the Administrator, then the parameter excursion is not a violation of the applicable standard.

(B) If the value of f_{bio}(MeOH) determined during the performance test specified in paragraph (p)(2)(i) of this section is not within the range of values established during the initial and subsequent performance tests approved by the Administrator, then the parameter excursion is a violation of the applicable standard.

(iv) The results of the performance test specified in paragraph (p)(2)(i) of this section shall be recorded as specified in §63.454(f).

(3) If an owner or operator determines that performing the required procedures under paragraph (p)(2) of this section for a nonthoroughly mixed open biological system would expose a worker to dangerous, hazardous, or otherwise unsafe conditions, all of the following procedures shall be performed:

(i) Calculate the mass removal or percent reduction value using the procedures specified in §63.457(l) except the value for f_{bio}(MeOH) shall be determined using the procedures in appendix E to this part.

(ii) Repeat the procedures in paragraph (p)(3)(i) of this section for every day until the unsafe conditions have passed.

(iii) A parameter excursion is a violation of the standard if the percent reduction or mass removal determined in paragraph (p)(3)(i) of this section is less than the percent reduction or mass removal standards specified in §63.446(e)(2), as appropriate, unless the value of f_{bio}(MeOH) determined using the procedures in appendix E of this section, as specified in paragraph (p)(3)(i), is within the range of f_{bio} (MeOH) values established during the initial and subsequent performance tests previously approved by the Administrator.

(iv) The determination that there is a condition that exposes a worker to dangerous, hazardous, or otherwise unsafe conditions shall be documented according to requirements in §63.454(e) and reporting in §63.455(f).

(v) The requirements of paragraphs (p)(1) and (2) of this section shall be performed and met as soon as practical but no later than 24 hours after the conditions have passed that exposed a worker to dangerous, hazardous, or otherwise unsafe conditions.

[63 FR 18617, Apr. 15, 1998, as amended at 64 FR 17563, Apr. 12, 1999; 65 FR 80762, Dec. 22, 2000]

§ 63.4 4 Record eepin re uirements.

(a) The owner or operator of each affected source subject to the requirements of this subpart shall comply with the recordkeeping requirements of §63.10, as shown in table 1 of this subpart, and the requirements specified in paragraphs (b) through (f) of this section for the monitoring parameters specified in §63.453.

(b) For each applicable enclosure opening, closed-vent system, and closed collection system, the owner or operator shall prepare and maintain a site-specific inspection plan including a drawing or schematic of the components of applicable affected equipment and shall record the following information for each inspection:

(1) Date of inspection;

(2) The equipment type and identification;

(3) Results of negative pressure tests for enclosures;

(4) Results of leak detection tests;

(5) The nature of the defect or leak and the method of detection (i.e., visual inspection or instrument detection);

(6) The date the defect or leak was detected and the date of each attempt to repair the defect or leak;

(7) Repair methods applied in each attempt to repair the defect or leak;

(8) The reason for the delay if the defect or leak is not repaired within 15 days after discovery;

(9) The expected date of successful repair of the defect or leak if the repair is not completed within 15 days;

(10) The date of successful repair of the defect or leak;

(11) The position and duration of opening of bypass line valves and the condition of any valve seals; and

(12) The duration of the use of bypass valves on computer controlled valves.

(c) The owner or operator of a bleaching system complying with §63.440(d)(3)(ii)(B) shall record the daily average chlorine and hypochlorite application rates, in kg of bleaching agent per megagram of ODP, of the bleaching system until the requirements specified in §63.440(d)(3)(ii)(A) are met.

(d) The owner or operator shall record the CMS parameters specified in §63.453 and meet the requirements specified in paragraph (a) of this section for any new affected process equipment or pulping process condensate stream that becomes subject to the standards in this subpart due to a process change or modification.

(e) The owner or operator shall set the flow indicator on each bypass line specified in §63.450(d)(1) to provide a record of the presence of gas stream flow in the bypass line at least once every 15 minutes.

(f) The owner or operator of an open biological treatment system complying with §63.453(p) shall prepare a written record specifying the results of the performance test specified in §63.453(p)(2).

[63 FR 18617, Apr. 15, 1998, as amended at 65 FR 80763, Dec. 22, 2000; 68 FR 37348, June 23, 2003]

§ 63.4 Reportin re uirements.

(a) Each owner or operator of a source subject to this subpart shall comply with the reporting requirements of subpart A of this part as specified in table 1 and all the following requirements in this section. The initial notification report specified under §63.9(b)(2) of subpart A of this part shall be submitted by April 15, 1999.

(b) Each owner or operator of a kraft pulping system specified in §63.440(d)(1) or a bleaching system specified in §63.440(d)(3)(ii) shall submit, with the initial notification report specified under §63.9(b)(2) of subpart A of this part and paragraph (a) of this section and update every two years thereafter, a non-binding control strategy report containing, at a minimum, the information specified in paragraphs (b)(1) through (b)(3) of this section in addition to the information required in §63.9(b)(2) of subpart A of this part.

(1) A description of the emission controls or process modifications selected for compliance with the control requirements in this standard.

(2) A compliance schedule, including the dates by which each step toward compliance will be reached for each emission point or sets of emission points. At a minimum, the list of dates shall include:

(i) The date by which the major study(s) for determining the compliance strategy will be completed;

(ii) The date by which contracts for emission controls or process modifications will be awarded, or the date by which orders will be issued for the purchase of major components to accomplish emission controls or process changes;

(iii) The date by which on-site construction, installation of emission control equipment, or a process change is to be initiated;

(iv) The date by which on-site construction, installation of emissions control equipment, or a process change is to be completed;

(v) The date by which final compliance is to be achieved;

(vi) For compliance with paragraph §63.440(d)(3)(ii), the tentative dates by which compliance with effluent limitation guidelines and standards intermediate pollutant load effluent reductions and as available, all the dates for the best available technology's milestones reported in the National Pollutant Discharge Elimination System authorized under section 402 of the Clean Water Act and for the best professional milestones in the Voluntary Advanced Technology Incentives Program under 40 CFR 430.24 (b)(2); and

(vii) The date by which the final compliance tests will be performed.

(3) Until compliance is achieved, revisions or updates shall be made to the control strategy report required by paragraph (b) of this section indicating the progress made towards completing the installation of the emission controls or process modifications during the 2-year period.

(c) The owner or operator of each bleaching system complying with §63.440(d)(3)(ii)(B) shall certify in the report specified under §63.10(e)(3) of subpart A of this part that the daily application rates of chlorine and hypochlorite for that bleaching system have not increased as specified in §63.440(d)(3)(ii)(B) until the requirements of §63.440(d)(3)(ii)(A) are met.

(d) The owner or operator shall meet the requirements specified in paragraph (a) of this section upon startup of any new affected process equipment or pulping process condensate stream that becomes subject to the standards of this subpart due to a process change or modification.

(e) If the owner or operator uses the results of the performance test required in §63.453(p)(2) to revise the approved values or ranges of the monitoring parameters specified in §63.453(j)(1) or (2), the owner or operator shall submit an initial notification of the subsequent performance test to the Administrator as soon as practicable, but no later than 15 days, before the performance test required in §63.453(p)(2) is scheduled to be conducted. The owner or operator shall notify the Administrator as soon as practicable, but no later than 24 hours, before the performance test is scheduled to be conducted to confirm the exact date and time of the performance test.

(f) To comply with the open biological treatment system monitoring provisions of §63.453(p)(3), the owner or operator shall notify the Administrator as soon as practicable of the onset of the dangerous, hazardous, or otherwise unsafe conditions that did not allow a compliance determination to be conducted using the sampling and test procedures in §63.457(l). The notification shall occur no later than 24 hours after the onset of the dangerous, hazardous, or otherwise unsafe conditions and shall include the specific reason(s) that the sampling and test procedures in §63.457(l) could not be performed.

[63 FR 18617, Apr. 15, 1998, as amended at 65 FR 80763, Dec. 22, 2000]

§ 63.4 6 Reserved

§ 63.4 7 Test methods and procedures.

(a) *nitial performance test* An initial performance test is required for all emission sources subject to the limitations in §§63.443, 63.444, 63.445, 63.446, and 63.447, except those controlled by a combustion device that is designed and operated as specified in §63.443(d)(3) or (d)(4).

(b) *Vent sampling port locations and gas stream properties* For purposes of selecting vent sampling port locations and determining vent gas stream properties, required in §§63.443, 63.444, 63.445, and 63.447, each owner or operator shall comply with the applicable procedures in paragraphs (b)(1) through (b)(6) of this section.

(1) Method 1 or 1A of part 60, appendix A, as appropriate, shall be used for selection of the sampling site as follows:

(i) To sample for vent gas concentrations and volumetric flow rates, the sampling site shall be located prior to dilution of the vent gas stream and prior to release to the atmosphere;

(ii) For determining compliance with percent reduction requirements, sampling sites shall be located prior to the inlet of the control device and at the outlet of the control device; measurements shall be performed simultaneously at the two sampling sites; and

(iii) For determining compliance with concentration limits or mass emission rate limits, the sampling site shall be located at the outlet of the control device.

(2) No traverse site selection method is needed for vents smaller than 0.10 meter (4.0 inches) in diameter.

(3) The vent gas volumetric flow rate shall be determined using Method 2, 2A, 2C, or 2D of part 60, appendix A, as appropriate.

(4) The moisture content of the vent gas shall be measured using Method 4 of part 60, appendix A.

(5) To determine vent gas concentrations, the owner or operator shall conduct a minimum of three test runs that are representative of normal conditions and average the resulting pollutant concentrations using the following procedures.

(i) Method 308 in Aappendix A of this part shall be used to determine the methanol concentration.

(ii) Except for the modifications specified in paragraphs (b)(5)(ii)(A) through (b)(5)(ii)(K) of this section, Method 26A of part 60, appendix A shall be used to determine chlorine concentration in the vent stream.

(A) *Probe sampling line* A separate probe is not required. The sampling line shall be an appropriate length of 0.64 cm (0.25 in) OD Teflon®tubing. The sample inlet end of the sampling line shall be inserted into the stack in such a way as to not entrain liquid condensation from the vent gases. The other end shall be connected to the impingers. The length of the tubing may vary from one sampling site to another, but shall be as short as possible in each situation. If sampling is conducted in sunlight, opaque tubing shall be used. Alternatively, if transparent tubing is used, it shall be covered with opaque tape.

(B) *mpinger train* Three 30 milliliter (ml) capacity midget impingers shall be connected in series to the sampling line. The impingers shall have regular tapered stems. Silica gel shall be placed in the third impinger as a desiccant. All impinger train connectors shall be glass and/or Teflon®.

(C) *Critical orifice* The critical orifice shall have a flow rate of 200 to 250 ml/min and shall be followed by a vacuum pump capable of providing a vacuum of 640 millimeters of mercury (mm Hg). A 45 millimeter diameter in-line Teflon 0.8 micrometer filter shall follow the impingers to protect the critical orifice and vacuum pump.

(D) The following are necessary for the analysis apparatus:

(*1*) Wash bottle filled with deionized water;

(*2*) 25 or 50 ml graduated burette and stand;

( ) Magnetic stirring apparatus and stir bar;

( ) Calibrated pH Meter;

( ) 150–250 ml beaker or flask; and

( ) A 5 ml pipette.

(E) The procedures listed in paragraphs (b)(5)(ii)(E)(*1*) through (b)(5)(ii)(E)( ) of this section shall be used to prepare the reagents.

(*1*) To prepare the 1 molarity (M) potassium dihydrogen phosphate solution, dissolve 13.61 grams (g) of potassium dihydrogen phosphate in water and dilute to 100 ml.

(*2*) To prepare the 1 M sodium hydroxide solution (NaOH), dissolve 4.0 g of sodium hydroxide in water and dilute to 100 ml.

( ) To prepare the buffered 2 percent potassium iodide solution, dissolve 20 g of potassium iodide in 900 ml water. Add 50 ml of the 1 M potassium dihydrogen phosphate solution and 30 ml of the 1 M sodium hydroxide solution. While stirring solution, measure the pH of solution electrometrically and add the 1 M sodium hydroxide solution to bring pH to between 6.95 and 7.05.

( ) To prepare the 0.1 normality (N) sodium thiosulfate solution, dissolve 25 g of sodium thiosulfate, pentahydrate, in 800 ml of freshly boiled and cooled distilled water in a 1-liter volumetric flask. Dilute to volume. To prepare the 0.01 N sodium thiosulfate solution, add 10.0 ml standardized 0.1 N sodium thiosulfate solution to a 100 ml volumetric flask, and dilute to volume with water.

( ) To standardize the 0.1 N sodium thiosulfate solution, dissolve 3.249 g of anhydrous potassium bi-iodate, primary standard quality, or 3.567 g potassium iodate dried at 103 =/−2 degrees Centigrade for 1 hour, in distilled water and dilute to 1000 ml to yield a 0.1000 N solution. Store in a glass-stoppered bottle. To 80 ml distilled water, add, with constant stirring, 1 ml concentrated sulfuric acid, 10.00 ml 0.1000 N anhydrous potassium bi-iodate, and 1 g potassium iodide. Titrate immediately with 0.1 n sodium thiosulfate titrant until the yellow color of the liberated iodine is almost discharged. Add 1 ml starch indicator solution and continue titrating until the blue color disappears. The normality of the sodium thiosulfate solution is inversely proportional to the ml of sodium thiosulfate solution consumed:

$$\begin{matrix}\text{Normality of}\\ \textit{SodiumThiosulfate}\end{matrix} = \frac{1}{\text{ml Sodium Thiosulfate Consumed}}$$

( ) To prepare the starch indicator solution, add a small amount of cold water to 5 g starch and grind in a mortar to obtain a thin paste. Pour paste into 1 L of boiling distilled water, stir, and let settle overnight. Use clear supernate for starch indicator solution.

( ) To prepare the 10 percent sulfuric acid solution, add 10 ml of concentrated sulfuric acid to 80 ml water in a 100 ml volumetric flask. Dilute to volume.

(F) The procedures specified in paragraphs (b)(5)(ii)(F)(*1*) through (b)(5)(ii)(F)( ) of this section shall be used to perform the sampling.

(*1*) *Preparation of collection train* Measure 20 ml buffered potassium iodide solution into each of the first two impingers and connect probe, impingers, filter, critical orifice, and pump. The sampling line and the impingers shall be shielded from sunlight.

(*2*) *Leak and flow check procedure* Plug sampling line inlet tip and turn on pump. If a flow of bubbles is visible in either of the liquid impingers, tighten fittings and adjust connections and impingers. A leakage rate not in excess of 2 percent of the sampling rate is acceptable. Carefully remove the plug from the end of the probe. Check the flow rate at the probe inlet with a bubble tube flow meter. The flow should be comparable or slightly less than the flow rate of the critical orifice with the impingers off-line. Record the flow and turn off the pump.

( ) *Sample collection* Insert the sampling line into the stack and secure it with the tip slightly lower than the port height. Start the pump, recording the time. End the sampling after 60 minutes, or after yellow color is observed in the second in-line impinger. Record time and remove the tubing from the vent. Recheck flow rate at sampling line inlet and turn off pump. If the flow rate has changed significantly, redo sampling with fresh capture solution. A slight variation (less than 5 percent) in flow may be averaged. With the inlet end of the line elevated above the impingers, add about 5 ml water into the inlet tip to rinse the line into the first impinger.

( ) *Sample analysis* Fill the burette with 0.01 N sodium thiosulfate solution to the zero mark. Combine the contents of the impingers in the beaker or flask. Stir the solution and titrate with thiosulfate until the solution is colorless. Record the volume of the first endpoint (TN, ml). Add 5 ml of the 10 percent sulfuric acid solution, and continue the titration until the contents of the flask are again colorless. Record the total volume of titrant required to go through the first and to the second endpoint (TA, ml). If the volume of neutral titer is less than 0.5 ml, repeat the testing for a longer period of time. It is important that sufficient lighting be present to clearly see the endpoints, which are determined when the solution turns from pale yellow to colorless. A lighted stirring plate and a white background are useful for this purpose.

( ) *nterferences* Known interfering agents of this method are sulfur dioxide and hydrogen peroxide. Sulfur dioxide, which is used to reduce oxidant residuals in some bleaching systems, reduces formed iodine to iodide in the capture solution. It is therefore a negative interference for chlorine, and in some cases could result in erroneous negative chlorine concentrations. Any agent capable of reducing iodine to iodide could interfere in this manner. A chromium trioxide impregnated filter will capture sulfur dioxide and pass chlorine and chlorine dioxide. Hydrogen peroxide, which is commonly used as a bleaching agent in modern bleaching systems, reacts with iodide to form iodine and thus can cause a positive interference in the chlorine measurement. Due to the chemistry involved, the precision of the chlorine analysis will decrease as the ratio of chlorine dioxide to chlorine increases. Slightly negative calculated concentrations of chlorine may occur when sampling a vent gas with high concentrations of chlorine dioxide and very low concentrations of chlorine.

(G) The following calculation shall be performed to determine the corrected sampling flow rate:

$$S_C = S_U\left(\frac{BP-PW}{760}\right)\left(\frac{293}{273+t}\right)$$

Where:

S_C=Corrected (dry standard) sampling flow rate, liters per minute;

S_U=Uncorrected sampling flow rate, L/min;

BP=Barometric pressure at time of sampling;

PW=Saturated partial pressure of water vapor, mm Hg at temperature; and

t=Ambient temperature, °C.

(H) The following calculation shall be performed to determine the moles of chlorine in the sample:

$$Cl_2 Moles = 1/8000\,(5T_N - T_A)\times N_{Thio}$$

Where:

T_N=Volume neutral titer, ml;

T_A=Volume acid titer (total), ml; and

N_{Thio}=Normality of sodium thiosulfate titrant.

(I) The following calculation shall be performed to determine the concentration of chlorine in the sample:

$$Cl_2\,ppmv = \frac{3005(5T_N - T_A)\times N_{Thio}}{S_C \times t_S}$$

Where:

S_C=Corrected (dry standard) sampling flow rate, liters per minute;

t_S=Time sampled, minutes;

T_N=Volume neutral titer, ml;

T_A=Volume acid titer (total), ml; and

N_{Thio}=Normality of sodium thiosulfate titrant.

(J) The following calculation shall be performed to determine the moles of chlorine dioxide in the sample:

$$ClO_2\ Moles = 1/4000(T_A - T_N) \times N_{Thio}$$

Where:

T_A=Volume acid titer (total), ml;

T_N=Volume neutral titer, ml; and

N_{Thio}=Normality of sodium thiosulfate titrant.

(K) The following calculation shall be performed to determine the concentration of chlorine dioxide in the sample:

$$ClO_2\ ppmv = \frac{6010(T_A - T_N) \times N_{Thio}}{S_C \times t_S}$$

Where:

S_C=Corrected (dry standard) sampling flow rate, liters per minute;

t_S=Time sampled, minutes;

T_A=Volume acid titer (total), ml;

T_N=Volume neutral titer, ml; and

N_{Thio}=Normality of sodium thiosulfate titrant.

(iii) Any other method that measures the total HAP or methanol concentration that has been demonstrated to the Administrator's satisfaction.

(6) The minimum sampling time for each of the three test runs shall be 1 hour in which either an integrated sample or four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately equal intervals in time, such as 15 minute intervals during the test run.

(c) *Liquid sampling locations and properties* For purposes of selecting liquid sampling locations and for determining properties of liquid streams such as wastewaters, process waters, and condensates required in §§63.444, 63.446, and 63.447, the owner or operator shall comply with the following procedures:

(1) Samples shall be collected using the sampling procedures of the test method listed in paragraph (c)(3) of this section selected to determine liquid stream HAP concentrations;

(i) Where feasible, samples shall be taken from an enclosed pipe prior to the liquid stream being exposed to the atmosphere; and

(ii) When sampling from an enclosed pipe is not feasible, samples shall be collected in a manner to minimize exposure of the sample to the atmosphere and loss of HAP compounds prior to sampling.

(2) The volumetric flow rate of the entering and exiting liquid streams shall be determined using the inlet

and outlet flow meters or other methods demonstrated to the Administrator's satisfaction. The volumetric flow rate measurements to determine actual mass removal shall be taken at the same time as the concentration measurements.

(3) The owner or operator shall conduct a minimum of three test runs that are representative of normal conditions and average the resulting pollutant concentrations. The minimum sampling time for each test run shall be 1 hour and the grab or composite samples shall be taken at approximately equally spaced intervals over the 1-hour test run period. The owner or operator shall use one of the following procedures to determine total HAP or methanol concentration:

(i) Method 305 in Appendix A of this part, adjusted using the following equation:

$$\bar{C} = \sum_{i=1}^{n} C_i / fm_i$$

Where:

C=Pollutant concentration for the liquid stream, parts per million by weight.

C_i=Measured concentration of pollutant i in the liquid stream sample determined using Method 305, parts per million by weight.

fm_i=Pollutant-specific constant that adjusts concentration measured by Method 305 to actual liquid concentration; the fm for methanol is 0.85. Additional pollutant fm values can be found in table 34, subpart G of this part.

n=Number of individual pollutants, i, summed to calculate total HAP.

(ii) For determining methanol concentrations, NCASI Method DI/MEOH–94.02, Methanol in Process Liquids by GC/FID, August 1998, Methods Manual, NCASI, Research Triangle Park, NC. This test method is incorporated by reference in §63.14(f) of subpart A of this part.

(iii) Any other method that measures total HAP concentration that has been demonstrated to the Administrator's satisfaction.

(4) To determine soluble BOD_5in the effluent stream from an open biological treatment unit used to comply with §§63.446(e)(2) and 63.453(j), the owner or operator shall use Method 405.1 of part 136 of this chapter with the following modifications:

(i) Filter the sample through the filter paper, into an Erlenmeyer flask by applying a vacuum to the flask sidearm. Minimize the time for which vacuum is applied to prevent stripping of volatile organics from the sample. Replace filter paper as often as needed in order to maintain filter times of less than approximately 30 seconds per filter paper. No rinsing of sample container or filter bowl into the Erlenmeyer flask is allowed.

(ii) Perform Method 405.1 on the filtrate obtained in paragraph (c)(4) of this section. Dilution water shall be seeded with 1 milliliter of final effluent per liter of dilution water. Dilution ratios may require adjustment to reflect the lower oxygen demand of the filtered sample in comparison to the total BOD_5. Three BOD bottles and different dilutions shall be used for each sample.

(5) If the test method used to determine HAP concentration indicates that a specific HAP is not detectable, the value determined as the minimum measurement level (MML) of the selected test method for the specific HAP shall be used in the compliance demonstration calculations. To determine the MML for a specific HAP using one of the test methods specified in paragraph (c)(3) of this section, one of the procedures specified in paragraphs (c)(5)(i) and (ii) of this section shall be performed. The MML for a particular HAP must be determined only if the HAP is not detected in the normal working range of the method.

(i) To determine the MML for a specific HAP, the following procedures shall be performed each time the method is set up. Set up is defined as the first time the analytical apparatus is placed in operation, after any shut down of 6 months or more, or any time a major component of the analytical apparatus is replaced.

(A) Select a concentration value for the specific HAP in question to represent the MML. The value of the MML selected shall not be below the calibration standard of the selected test method.

(B) Measure the concentration of the specific HAP in a minimum of three replicate samples using the selected test method. All replicate samples shall be run through the entire analytical procedure. The samples must contain the specific HAP at the selected MML concentration and should be representative of the liquid streams to be analyzed in the compliance demonstration. Spiking of the liquid samples with a known concentration of the target HAP may be necessary to ensure that the HAP concentration in the three replicate samples is at the selected MML. The concentration of the HAP in the spiked sample must be within 50 percent of the proposed MML for the demonstration to be valid. As an alternative to spiking, a field sample above the MML may be diluted to produce a HAP concentration at the MML. To be a valid demonstration, the diluted sample must have a HAP concentration within 20 percent of the proposed MML, and the field sample must not be diluted by more than a factor of five.

(C) Calculate the relative standard deviation (RSD) and the upper confidence limit at the 95 percent confidence level using the measured HAP concentrations determined in paragraph (c)(5)(i)(B) of this section. If the upper confidence limit of the RSD is less than 30 percent, then the selected MML is acceptable. If the upper confidence limit of the RSD is greater than or equal to 30 percent, then the selected MML is too low, and the procedures specified in paragraphs (c)(5)(i)(A) through (C) of this section must be repeated.

(ii) Provide for the Administrator's approval the selected value of the MML for a specific HAP and the rationale for selecting the MML including all data and calculations used to determine the MML. The approved MML must be used in all applicable compliance demonstration calculations.

(6) When using the MML determined using the procedures in paragraph (c)(5)(ii) of this section or when using the MML determined using the procedures in paragraph (c)(5)(i), except during set up, the analytical laboratory conducting the analysis must perform and meet the following quality assurance procedures each time a set of samples is analyzed to determine compliance.

(i) Using the selected test method, analyze in triplicate the concentration of the specific HAP in a representative sample. The sample must contain the specific HAP at a concentration that is within a factor of two of the MML. If there are no samples in the set being analyzed that contain the specific HAP at an appropriate concentration, then a sample below the MML may be spiked to produce the appropriate concentration, or a sample at a higher level may be diluted. After spiking, the sample must contain the specific HAP within 50 percent of the MML. If dilution is used instead, the diluted sample must contain the specific HAP within 20 percent of the MML and must not be diluted by more than a factor of five.

(ii) Calculate the RSD using the measured HAP concentrations determined in paragraph (c)(6)(i) of this section. If the RSD is less than 20 percent, then the laboratory is performing acceptably.

(d) *Detectable leak procedures* To measure detectable leaks for closed-vent systems as specified in §63.450 or for pulping process wastewater collection systems as specified in §63.446(d)(2)(i), the owner or operator shall comply with the following:

(1) Method 21, of part 60, appendix A; and

(2) The instrument specified in Method 21 shall be calibrated before use according to the procedures specified in Method 21 on each day that leak checks are performed. The following calibration gases shall be used:

(i) Zero air (less than 10 parts per million by volume of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration of approximately, but less than, 10,000 parts per million by volume methane or n-hexane.

(e) *Negative pressure procedures* To demonstrate negative pressure at process equipment enclosure openings as specified in §63.450(b), the owner or operator shall use one of the following procedures:

(1) An anemometer to demonstrate flow into the enclosure opening;

(2) Measure the static pressure across the opening;

(3) Smoke tubes to demonstrate flow into the enclosure opening; or

(4) Any other industrial ventilation test method demonstrated to the Administrator's satisfaction.

(f) *HAP concentration measurements* For purposes of complying with the requirements in §§63.443, 63.444, and 63.447, the owner or operator shall measure the total HAP concentration as one of the following:

(1) As the sum of all individual HAPs; or

(2) As methanol.

(g) *Condensate HAP concentration measurement* For purposes of complying with the kraft pulping condensate requirements in §63.446, the owner or operator shall measure the total HAP concentration as methanol. For biological treatment systems complying with §63.446(e)(2), the owner or operator shall measure total HAP as acetaldehyde, methanol, methyl ethyl ketone, and propionaldehyde and follow the procedures in §63.457(l)(1) or (2).

(h) *Bleaching HAP concentration measurement* For purposes of complying with the bleaching system requirements in §63.445, the owner or operator shall measure the total HAP concentration as the sum of all individual chlorinated HAPs or as chlorine.

(i) *Vent gas stream calculations* To demonstrate compliance with the mass emission rate, mass emission rate per megagram of ODP, and percent reduction requirements for vent gas streams specified in §§63.443, 63.444, 63.445, and 63.447, the owner or operator shall use the following:

(1) The total HAP mass emission rate shall be calculated using the following equation:

$$E = K_2 \left[\sum_{j-1}^{n} C_j M_j \right] Q_s$$

Where:

E=Mass emission rate of total HAP from the sampled vent, kilograms per hour.

K_2=Constant, 2.494×10^{-6}(parts per million by volume)$^{-1}$(gram-mole per standard cubic meter) (kilogram/gram) (minutes/hour), where standard temperature for (gram-mole per standard cubic meter) is 20 °C.

C_j=Concentration on a dry basis of pollutant j in parts per million by volume as measured by the test methods specified in paragraph (b) of this section.

M_j=Molecular weight of pollutant j, gram/gram-mole.

Q_s=Vent gas stream flow rate (dry standard cubic meter per minute) at a temperature of 20 °C as indicated in paragraph (b) of this section.

n=Number of individual pollutants, i, summed to calculate total HAP.

(2) The total HAP mass emission rate per megagram of ODP shall be calculated using the following equation:

$$F = \frac{E}{P}$$

Where:

F=Mass emission rate of total HAP from the sampled vent, in kilograms per megagram of ODP.

E=Mass emission rate of total HAP from the sampled vent, in kilograms per hour determined as specified in paragraph (i)(1) of this section.

P=The production rate of pulp during the sampling period, in megagrams of ODP per hour.

(3) The total HAP percent reduction shall be calculated using the following equation:

$$R = \frac{E_i - E_O}{E_i}(100)$$

Where:

R=Efficiency of control device, percent.

Ei=Inlet mass emission rate of total HAP from the sampled vent, in kilograms of pollutant per hour, determined as specified in paragraph (i)(1) of this section.

E_o=Outlet mass emission rate of total HAP from the sampled vent, in kilograms of pollutant per hour, determined as specified in paragraph (i)(1) of this section.

(j) *Liquid stream calculations* To demonstrate compliance with the mass flow rate, mass per megagram of ODP, and percent reduction requirements for liquid streams specified in §63.446, the owner or operator shall use the following:

(1) The mass flow rates of total HAP or methanol entering and exiting the treatment process shall be calculated using the following equations:

$$E_b = \frac{K}{n \times 10^6}\left(\sum_{i=1}^{n} V_{bi} C_{bi}\right)$$

$$E_a = \frac{K}{n \times 10^6}\left(\sum_{i=1}^{n} V_{ai} C_{ai}\right)$$

Where:

E_b=Mass flow rate of total HAP or methanol in the liquid stream entering the treatment process, kilograms per hour.

E_a=Mass flow rate of total HAP or methanol in the liquid exiting the treatment process, kilograms per hour.

K=Density of the liquid stream, kilograms per cubic meter.

V_{bi}=Volumetric flow rate of liquid stream entering the treatment process during each run i, cubic meters per hour, determined as specified in paragraph (c) of this section.

V_{ai}=Volumetric flow rate of liquid stream exiting the treatment process during each run i, cubic meters per hour, determined as specified in paragraph (c) of this section.

C_{bi}=Concentration of total HAP or methanol in the stream entering the treatment process during each run i, parts per million by weight, determined as specified in paragraph (c) of this section.

C_{ai}=Concentration of total HAP or methanol in the stream exiting the treatment process during each run i, parts per million by weight, determined as specified in paragraph (c) of this section.

n=Number of runs.

(2) The mass of total HAP or methanol per megagram ODP shall be calculated using the following equation:

$$F = \frac{E_a}{P}$$

Where:

F=Mass loading of total HAP or methanol in the sample, in kilograms per megagram of ODP.

E_a=Mass flow rate of total HAP or methanol in the wastewater stream in kilograms per hour as determined using the procedures in paragraph (j)(1) of this section.

P=The production rate of pulp during the sampling period in megagrams of ODP per hour.

(3) The percent reduction of total HAP across the applicable treatment process shall be calculated using the following equation:

$$R = \frac{E_b - E_a}{E_b} \times 100$$

Where:

R=Control efficiency of the treatment process, percent.

E_b=Mass flow rate of total HAP in the stream entering the treatment process, kilograms per hour, as determined in paragraph (j)(1) of this section.

E_a=Mass flow rate of total HAP in the stream exiting the treatment process, kilograms per hour, as determined in paragraph (j)(1) of this section.

(4) Compounds that meet the requirements specified in paragraphs (j)(4)(i) or (4)(ii) of this section are not required to be included in the mass flow rate, mass per megagram of ODP, or the mass percent reduction determinations.

(i) Compounds with concentrations at the point of determination that are below 1 part per million by weight; or

(ii) Compounds with concentrations at the point of determination that are below the lower detection limit where the lower detection limit is greater than 1 part per million by weight.

(k) *Oxygen concentration correction procedures* To demonstrate compliance with the total HAP concentration limit of 20 ppmv in §63.443(d)(2), the concentration measured using the methods specified in paragraph (b)(5) of this section shall be corrected to 10 percent oxygen using the following procedures:

(1) The emission rate correction factor and excess air integrated sampling and analysis procedures of

Methods 3A or 3B of part 60, appendix A shall be used to determine the oxygen concentration. The samples shall be taken at the same time that the HAP samples are taken.

(2) The concentration corrected to 10 percent oxygen shall be computed using the following equation:

$$C_c = C_m \left(\frac{10.9}{20.9 - \%O_{2d}} \right)$$

Where:

C_c=Concentration of total HAP corrected to 10 percent oxygen, dry basis, parts per million by volume.

C_m=Concentration of total HAP dry basis, parts per million by volume, as specified in paragraph (b) of this section.

$\%0_{2d}$=Concentration of oxygen, dry basis, percent by volume.

(l) *Biological treatment system percent reduction and mass removal calculations* To demonstrate compliance with the condensate treatment standards specified in §63.446(e)(2) and the monitoring requirements specified in §63.453(j)(3) using a biological treatment system, the owner or operator shall use one of the procedures specified in paragraphs (1)(1) and (2) of this section. Owners or operators using a nonthoroughly mixed open biological treatment system shall also comply with paragraph (1)(3) of this section.

(1) *Percent reduction methanol procedure* For the purposes of complying with the condensate treatment requirements specified in §63.446(e)(2) and (3), the methanol percent reduction shall be calculated using the following equations:

$$R = \frac{f_{bio}(\mathrm{MeOH})}{(1 + 1.087(r))} * 100$$

$$r = \frac{F_{(nonmethanol)}}{F_{(methanol)}}$$

Where:

R = Percent destruction.

f_{bio}(MeOH) = The fraction of methanol removed in the biological treatment system. The site-specific biorate constants shall be determined using the appropriate procedures specified in appendix C of this part.

r = Ratio of the sum of acetaldehyde, methyl ethyl ketone, and propionaldehyde mass to methanol mass.

F(nonmethanol)= The sum of acetaldehyde, methyl ethyl ketone, and propionaldehyde mass flow rates (kg/Mg ODP) entering the biological treatment system determined using the procedures in paragraph (j)(2) of this section.

F(methanol)= The mass flow rate (kg/Mg ODP) of methanol entering the system determined using the procedures in paragraph (j)(2) of this section.

(2) *Mass removal methanol procedure* For the purposes of complying with the condensate treatment requirements specified in §63.446(e)(2) and (4), or §63.446(e)(2) and (5), the methanol mass removal

shall be calculated using the following equation:

$$F = F_b * \left(f_{bio} \left(MeOH \right) / \left(1 + 1.087 \left(r \right) \right) \right)$$

Where:

F = Methanol mass removal (kg/Mg ODP).

F_b= Inlet mass flow rate of methanol (kg/Mg ODP) determined using the procedures in paragraph (j)(2) of this section.

f_{bio}(MeOH) = The fraction of methanol removed in the biological treatment system. The site-specific biorate constants shall be determined using the appropriate procedures specified in appendix C of this part.

r = Ratio of the sum of acetaldehyde, methyl ethyl ketone, and propionaldehyde mass to methanol mass determined using the procedures in paragraph (1) of this section.

(3) The owner or operator of a nonthoroughly mixed open biological treatment system using the monitoring requirements specified in §63.453(p)(3) shall follow the procedures specified in section III.B.1 of appendix E of this part to determine the borate constant, Ks, and characterize the open biological treatment system during the initial and any subsequent performance tests.

(m) *Condensate segregation procedures* The following procedures shall be used to demonstrate compliance with the condensate segregation requirements specified in §63.446(c).

(1) To demonstrate compliance with the percent mass requirements specified in §63.446(c)(2), the procedures specified in paragraphs (m)(1)(i) through (iii) of this section shall be performed.

(i) Determine the total HAP mass of all condensates from each equipment system listed in §63.446 (b)(1) through (b)(3) using the procedures specified in paragraphs (c) and (j) of this section.

(ii) Multiply the total HAP mass determined in paragraph (m)(1)(i) of this section by 0.65 to determine the target HAP mass for the high-HAP fraction condensate stream or streams.

(iii) Compliance with the segregation requirements specified in §63.446(c)(2) is demonstrated if the condensate stream or streams from each equipment system listed in §63.446(b)(1) through (3) being treated as specified in §63.446(e) contain at least as much total HAP mass as the target total HAP mass determined in paragraph (m)(1)(ii) of this section.

(2) To demonstrate compliance with the percent mass requirements specified in §63.446(c)(3), the procedures specified in paragraphs (m)(2)(i) through (ii) of this section shall be performed.

(i) Determine the total HAP mass contained in the high-HAP fraction condensates from each equipment system listed in §63.446(b)(1) through (b)(3) and the total condensates streams from the equipment systems listed in §63.446(b)(4) and (b)(5), using the procedures specified in paragraphs (c) and (j) of this section.

(ii) Compliance with the segregation requirements specified in §63.446(c)(3) is demonstrated if the total HAP mass determined in paragraph (m)(2)(i) of this section is equal to or greater than the appropriate mass requirements specified in §63.446(c)(3).

(n) *Open biological treatment system monitoring sampling storage* The inlet and outlet grab samples required to be collected in §63.453(j)(1)(ii) shall be stored at 4 °C (40 °F) to minimize the biodegradation of the organic compounds in the samples.

[63 FR 18617, Apr. 15, 1998, as amended at 64 FR 17564, Apr. 12, 1999; 65 FR 80763, Dec. 22, 2000; 66 FR 24269, May 14, 2001]

§ 63.4 Implementation and enforcement.

(a) This subpart can be implemented and enforced by the U.S. EPA, or a delegated authority such as the applicable State, local, or Tribal agency. If the U.S. EPA Administrator has delegated authority to a State, local, or Tribal agency, then that agency, in addition to the U.S. EPA, has the authority to implement and enforce this subpart. Contact the applicable U.S. EPA Regional Office to find out if this subpart is delegated to a State, local, or Tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or Tribal agency under subpart E of this part, the authorities contained in paragraph (c) of this section are retained by the Administrator of U.S. EPA and cannot be transferred to the State, local, or Tribal agency.

(c) The authorities that cannot be delegated to State, local, or Tribal agencies are as specified in paragraphs (c)(1) through (4) of this section.

(1) Approval of alternatives to the requirements in §§63.440, 63.443 through 63.447 and 63.450. Where these standards reference another subpart, the cited provisions will be delegated according to the delegation provisions of the referenced subpart.

(2) Approval of alternatives to using §§63.457(b)(5)(iii), 63.457(c)(3)(ii) through (iii), and 63.257(c)(5)(ii), and any major alternatives to test methods under §63.7(e)(2)(ii) and (f), as defined in §63.90, and as required in this subpart.

(3) Approval of alternatives using §64.453(m) and any major alternatives to monitoring under §63.8(f), as defined in §63.90, and as required in this subpart.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f), as defined in §63.90, and as required in this subpart.

[68 FR 37348, June 23, 2003]

§ 63.4 Alternative standards.

(a) *Flint River Mill* The owner or operator of the pulping system using the kraft process at the manufacturing facility, commonly called Weyerhaeuser Company Flint River Operations, at Old Stagecoach Road, Oglethorpe, Georgia, (hereafter the Site) shall comply with all provisions of this subpart, except as specified in paragraphs (a)(1) through (a)(5) of this section.

(1) The owner or operator of the pulping system is not required to control total HAP emissions from equipment systems specified in paragraphs (a)(1)(i) and (a)(1)(ii) if the owner or operator complies with paragraphs (a)(2) through (a)(5) of this section.

(i) The brownstock diffusion washer vent and first stage brownstock diffusion washer filtrate tank vent in the pulp washing system specified in §63.443(a)(1)(iii).

(ii) The oxygen delignification system specified in §63.443(a)(1)(v).

(2) The owner or operator of the pulping system shall control total HAP emissions from equipment systems listed in paragraphs (a)(2)(i) through (a)(2)(ix) of this section as specified in §63.443(c) and (d) of this subpart no later than April 16, 2002.

(i) The weak liquor storage tank;

(ii) The boilout tank;

(iii) The utility tank;

(iv) The fifty percent solids black liquor storage tank;

(v) The south sixty-seven percent solids black liquor storage tank;

(vi) The north sixty-seven percent solids black liquor storage tank;

(vii) The precipitator make down tanks numbers one, two and three;

(viii) The salt cake mix tank; and

(ix) The NaSH storage tank.

(3) The owner and operator of the pulping system shall operate the Isothermal Cooking system at the site while pulp is being produced in the continuous digester at any time after April 16, 2002.

(i) The owner or operator shall monitor the following parameters to demonstrate that isothermal cooking is in operation:

(A) Continuous digester dilution factor; and

(B) The difference between the continuous digester vapor zone temperature and the continuous digester extraction header temperature.

(ii) The isothermal cooking system shall be in operation when the continuous digester dilution factor and the temperature difference between the continuous digester vapor zone temperature and the continuous digester extraction header temperature are maintained as set forth in Table 2:

Table 2 to Subpart S—Isothermal Coo in System perational alues

Parameter	Instrument number	imit	nits
Digester Dilution Factor	K1DILFAC	>0.0	None
Difference in Digester Vapor Zone Temperature and Digester	03TI0311	<10	Degrees F.
Extraction Header Temperature	03TI0329		

(iii) The owner or operator shall certify annually the operational status of the isothermal cooking system.

(4) [Reserved]

(5) *Definitions* All descriptions and references to equipment and emission unit ID numbers refer to equipment at the Site. All terms used in this paragraph shall have the meaning given them in this part and this paragraph. For the purposes of this paragraph only the following additional definitions apply:

Boilout tank means the tank that provides tank storage capacity for recovery of black liquor spills and evaporator water washes for return to the evaporators (emission unit ID No. U606);

Brownstock diffusion washer means the equipment used to wash pulp from the surge chests to further reduce lignin carryover in the pulp;

Continuous digester means the digester system used to chemically and thermally remove the lignin binding the wood chips to produce individual pulp fibers (emission unit ID No. P300);

Fifty percent solids black liquor storage tank means the tank used to store intermediate black liquor prior to final evaporation in the 1A, 1B, and 1C Concentrators (emission unit ID No. U605);

First stage brownstock diffusion washer means the equipment that receives and stores filtrate from the first stage of washing for return to the pressure diffusion washer;

sothermal cooking system means the 1995–1996 modernization of brownstock pulping process including conversion of the Kamyr continuous vapor phase digester to an extended delignification unit and changes in the knotting, screening, and oxygen stage systems:

NaSH storage tank means the tank used to store sodium hydrosulfite solution prior to use as make-up to the liquor system

North sixty-seven percent solids black liquor storage tank means one of two tanks used to store black liquor prior to burning in the Recovery Boiler for chemical recovery (emission unit ID No. U501);

Precipitator make down tank numbers one, two and three mean tanks used to mix collected particulate from electrostatic precipitator chamber number one with 67% black liquor for recycle to chemical recovery in the Recovery Boiler (emission unit ID Nos. U504, U505 and U506);

Salt cake mix tank means the tank used to mix collected particulate from economizer hoppers with black liquor for recycle to chemical recovery in the Recovery Boiler (emission unit ID No. U503);

South sixty-seven percent solids black liquor storage tank means one of two tanks used to store black liquor prior to burning in the Recovery Boiler for chemical recovery (emission unit ID No. U502);

tility tank means the tank used to store fifty percent liquor and, during black liquor tank inspections and repairs, to serve as a backup liquor storage tank (emission unit ID No. U611);

eak gas system means high volume, low concentration or HVLC system as defined in §63.441; and

eak liquor storage tank means the tank that provide surge capacity for weak black liquor from digesting prior to feed to multiple effect evaporators (emission unit ID No. U610).

(b) *Tomahawk isconsin Mill* —(1) *Applicability* (i) The provisions of this paragraph (b) apply to the owner or operator of the stand-alone semi-chemical pulp and paper mill located at N9090 County Road E in Tomahawk, Wisconsin, referred to as the Tomahawk Mill.

(ii) The owner or operator is not required to comply with the provisions of this paragraph (b) if the owner and operator chooses to comply with the otherwise applicable sections of this subpart and provides the EPA with notice.

(iii) If the owner or operator chooses to comply with the provisions of this paragraph (b) the owner or operator shall comply with all applicable provisions of this part, including this subpart, except the following:

(A) Section 63.443(b);

(B) Section 63.443(c); and

(C) Section 63.443(d).

(2) *Collection and routing of HAP emissions* (i) The owner or operator shall collect the total HAP emissions from each LVHC system.

(ii) Each LVHC system shall be enclosed and the HAP emissions shall be vented into a closed-vent system. The enclosures and closed-vent system shall meet requirements specified in paragraph (b)(6) of this section.

(iii) The HAP emissions shall be routed as follows:

(A) The HAP emissions collected in the closed-vent system from the digester system shall be routed through the primary indirect contact condenser, secondary indirect contact condenser, and evaporator indirect contact condenser; and

(B) The HAP emissions collected in the closed-vent system from the evaporator system and foul condensate standpipe shall be routed through the evaporator indirect contact condenser.

(3) *Collection and routing of pulping process condensates* (i) The owner or operator shall collect the pulping process condensates from the following equipment systems:

(A) Primary indirect contact condenser;

(B) Secondary indirect contact condenser; and

(C) Evaporator indirect contact condenser.

(ii) The collected pulping process condensates shall be conveyed in a closed collection system that is designed and operated to meet the requirements specified in paragraph (b)(7) of this section.

(iii) The collected pulping process condensates shall be routed in the closed collection system to the wastewater treatment plant anaerobic basins for biodegradation.

(iv) The pulping process condensates shall be discharged into the wastewater treatment plant anaerobic basins below the liquid surface of the wastewater treatment plant anaerobic basins.

(4) *HAP destruction efficiency requirements of the wastewater treatment plant* (i) The owner or operator shall achieve a destruction efficiency of at least one pound of HAPs per ton of ODP by biodegradation in the wastewater treatment plant.

(ii) The following calculation shall be performed to determine the HAP destruction efficiency by biodegradation in the wastewater treatment plant:

$$HAP_d = \frac{\left[\left(RME_{fr} \times RME_c\right) + \left(PPC_{fr} \times PPC_c\right) - \left(ABD_{fr} \times ABD_c\right)\right] \times 8.34}{ODP_r}$$

Where:

HAP_d= HAP destruction efficiency of wastewater treatment plant (pounds of HAPs per ton of ODP);

RME_{fr}= flow rate of raw mill effluent (millions of gallons per day);

RME_c= HAP concentration of raw mill effluent (milligrams per liter);

PPC_{fr}= flow rate of pulping process condensates (millions of gallons per day);

PPC_c= HAP concentration of pulping process condensates (milligrams per liter);

ABD_{fr}= flow rate of anaerobic basin discharge (millions of gallons per day);

ABD_c= HAP concentration of anaerobic basin discharge (milligrams per liter); and

ODP_r= rate of production of oven dried pulp (tons per day).

(5) *Monitoring requirements and parameter ranges* (i) The owner or operator shall install, calibrate, operate, and maintain according to the manufacturer's specifications a continuous monitoring system (CMS, as defined in §63.2), using a continuous recorder, to monitor the following parameters:

(A) Evaporator indirect contact condenser vent temperature;

(B) Pulping process condensates flow rate;

(C) Wastewater treatment plant effluent flow rate; and

(D) Production rate of ODP.

(ii) The owner or operator shall additionally monitor, on a daily basis, in each of the four anaerobic basins, the ratio of volatile acid to alkalinity (VA/A ratio). The owner or operator shall use the test methods identified for determining acidity and alkalinity as specified in 40 CFR 136.3, Table 1B.

(iii) The temperature of the evaporator indirect contact condenser vent shall be maintained at or below 140 °F on a continuous basis.

(iv) The VA/A ratio in each of the four anaerobic basins shall be maintained at or below 0.5 on a continuous basis.

(A) The owner or operator shall measure the methanol concentration of the outfall of any basin (using NCASI Method DI/MEOH 94.03) when the VA/A ratio of that basin exceeds the following:

(*1*) 0.38, or

(*2*) The highest VA/A ratio at which the outfall of any basin has previously measured non-detect for methanol (using NCASI Method DI/MEOH 94.03).

(B) If the outfall of that basin measures detect for methanol, the owner or operator shall verify compliance with the emission standard specified in paragraph (b)(4) of this section by conducting a performance test pursuant to the requirements specified in paragraph (b)(8) of this section.

(v) The owner or operator may seek to establish or reestablish the parameter ranges, and/or the parameters required to be monitored as provided in paragraphs (b)(5)(i) through (v) of this section, by following the provisions of §63.453(n)(1) through (4).

(6) *Standards and monitoring requirements for each enclosure and closed-vent system* (i) The owner or operator shall comply with the design and operational requirements specified in paragraphs (b)(6)(ii) through (iv) of this section, and the monitoring requirements of paragraphs (b)(6)(v) through (x) of this section for each enclosure and closed-vent system used for collecting and routing of HAP emissions as specified in paragraph (b)(2) of this section.

(ii) Each enclosure shall be maintained at negative pressure at each enclosure or hood opening as demonstrated by the procedures specified in §63.457(e). Each enclosure or hood opening closed during the initial performance test shall be maintained in the same closed and sealed position as during the performance test at all times except when necessary to use the opening for sampling, inspection, maintenance, or repairs.

(iii) Each component of the closed-vent system that is operated at positive pressure shall be designed for and operated with no detectable leaks as indicated by an instrument reading of less than 500 parts per million by volume above background, as measured by the procedures specified in §63.457(d).

(iv) Each bypass line in the closed-vent system that could divert vent streams containing HAPs to the atmosphere without meeting the routing requirements specified in paragraph (b)(2) of this section shall comply with either of the following requirements:

(A) On each bypass line, the owner or operator shall install, calibrate, maintain, and operate according to the manufacturer's specifications a flow indicator that provides a record of the presence of gas stream flow in the bypass line at least once every 15 minutes. The flow indicator shall be installed in the bypass line in such a way as to indicate flow in the bypass line; or

(B) For bypass line valves that are not computer controlled, the owner or operator shall maintain the bypass line valve in the closed position with a car seal or seal placed on the valve or closure mechanism in such a way that the valve or closure mechanism cannot be opened without breaking the seal.

(v) For each enclosure opening, the owner or operator shall perform, at least once every 30 days, a visual inspection of the closure mechanism specified in paragraph (b)(6)(ii) of this section to ensure the opening is maintained in the closed position and sealed.

(vi) For each closed-vent system required by paragraph (b)(2) of this section, the owner or operator shall perform a visual inspection every 30 days and at other times as requested by the Administrator. The visual inspection shall include inspection of ductwork, piping, enclosures, and connections to covers for visible evidence of defects.

(vii) For positive pressure closed-vent systems, or portions of closed-vent systems, the owner or operator shall demonstrate no detectable leaks as specified in paragraph (b)(6)(iii) of this section, measured initially and annually by the procedures in §63.457(d).

(viii) For each enclosure that is maintained at negative pressure, the owner or operator shall demonstrate initially and annually that it is maintained at negative pressure as specified in §63.457(e).

(ix) For each valve or closure mechanism as specified in paragraph (b)(6)(iv)(B) of this section, the owner or operator shall perform an inspection at least once every 30 days to ensure that the valve is maintained in the closed position and the emissions point gas stream is not diverted through the bypass line.

(x) If an inspection required by paragraph (b)(6) of this section identifies visible defects in ductwork, piping, enclosures, or connections to covers required by paragraph (b)(6) of this section, or if an instrument reading of 500 parts per million by volume or greater above background is measured, or if the enclosure openings are not maintained at negative pressure, then the following corrective actions shall be taken as soon as follows:

(A) A first effort to repair or correct the closed-vent system shall be made as soon as practicable but no later than 5 calendar days after the problem is identified.

(B) The repair or corrective action shall be completed no later than 15 calendar days after the problem is identified.

(7) *Standards and monitoring requirements for the pulping process condensates closed collection system* (i) The owner or operator shall comply with the design and operational requirements specified in paragraphs (b)(7)(ii) through (iii) of this section, and monitoring requirements of paragraph (b)(7)(iv) for the equipment systems in paragraph (b)(3) of this section used to route the pulping process condensates in a closed collection system.

(ii) Each closed collection system shall meet the individual drain system requirements specified in §§63.960, 63.961, and 63.962, except that the closed vent systems shall be designed and operated in accordance with paragraph (b)(6) of this section, instead of in accordance with §63.693 as specified in §63.692(a)(3)(ii), (b)(3)(ii)(A), and (b)(3)(ii)(B)(5)(iii); and

(iii) If a condensate tank is used in the closed collection system, the tank shall meet the following requirements:

(A) The fixed roof and all openings (e.g., access hatches, sampling ports, gauge wells) shall be designed and operated with no detectable leaks as indicated by an instrument reading of less than 500 parts per million above background, and vented into a closed-vent system that meets the requirements of paragraph (b)(6) of this section and routed in accordance with paragraph (b)(2) of this section; and

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that the tank contains pulping process condensates or any HAPs removed from a pulping process condensate stream except when it is necessary to use the opening for sampling, removal, or for equipment inspection, maintenance, or repair.

(iv) For each pulping process condensate closed collection system used to comply with paragraph (b)(3) of this section, the owner or operator shall perform a visual inspection every 30 days and shall comply with the inspection and monitoring requirements specified in §63.964 except for the closed-vent system and control device inspection and monitoring requirements specified in §63.964(a)(2).

(8) *uarterly performance testing* (i) The owner or operator shall, within 45 days after the beginning of each quarter, conduct a performance test.

(ii) The owner or operator shall use NCASI Method DI/HAPS–99.01 to collect a grab sample and determine the HAP concentration of the Raw Mill Effluent, Pulping Process Condensates, and Anaerobic Basin Discharge for the quarterly performance test conducted during the first quarter each year.

(iii) For each of the remaining three quarters, the owner or operator may use NCASI Method DI/MEOH 94.03 as a surrogate to collect and determine the HAP concentration of the Raw Mill Effluent, Pulping Process Condensates, and Anaerobic Basin Discharge.

(iv) The sample used to determine the HAP or Methanol concentration in the Raw Mill Effluent, Pulping Process Condensates, or Anaerobic Basin Discharge shall be a composite of four grab samples taken evenly spaced over an eight hour time period.

(v) The Raw Mill Effluent grab samples shall be taken from the raw mill effluent composite sampler.

(vi) The Pulping Process Condensates grab samples shall be taken from a line tap on the closed condensate collection system prior to discharge into the wastewater treatment plant.

(vii) The Anaerobic Basic Discharge grab samples shall be taken subsequent to the confluence of the four anaerobic basin discharges.

(viii) The flow rate of the Raw Mill Effluent, Pulping Process Condensates, and Anaerobic Basin Discharge, and the production rate of ODP shall be averaged over eight hours.

(ix) The data collected as specified in paragraphs (b)(5) and (b)(8) of this section shall be used to determine the HAP destruction efficiency of the wastewater treatment plant as specified in paragraph (b)(4)(ii) of this section.

(x) The HAP destruction efficiency shall be at least as great as that specified by paragraph (b)(4)(i) of this section.

(9) *Recordkeeping requirements* (i) The owner or operator shall comply with the recordkeeping requirements as specified in Table 1 of subpart S of part 63 as it pertains to §63.10.

(ii) The owner or operator shall comply with the recordkeeping requirements as specified in §63.454(b).

(iii) The owner or operator shall comply with the recordkeeping requirements as specified in §63.453(d).

(10) *Reporting requirements* (i) Each owner or operator shall comply with the reporting requirements as specified in Table 1 of §63.10.

(ii) Each owner or operator shall comply with the reporting requirements as specified in §63.455(d).

(11) *Violations* (i) Failure to comply with any applicable provision of this part shall constitute a violation.

(ii) Periods of excess emissions shall not constitute a violation provided the time of excess emissions (excluding periods of startup, shutdown, or malfunction) divided by the total process operating time in a semi-annual reporting period does not exceed one percent. All periods of excess emission (including periods of startup, shutdown, and malfunction) shall be reported, and shall include:

(A) Failure to monitor a parameter, or maintain a parameter within minimum or maximum (as appropriate) ranges as specified in paragraph (b)(5), (b)(6), or (b)(7) of this section; and

(B) Failure to meet the HAP destruction efficiency standard specified in paragraph (b)(4) of this section.

(iii) Notwithstanding paragraph (b)(11)(ii) of this section, any excess emissions that present an imminent threat to public health or the environment, or may cause serious harm to public health or the environment, shall constitute a violation.

[66 FR 34124, June 27, 2001, as amended at 66 FR 52538, Oct. 16, 2001; 69 FR 19740, Apr. 13, 2004]

Table 1 to Subpart S of Part 63— eneral Provisions Applicability to Subpart S[a]

Reference	Applies to Subpart S	Comment
63.1(a)(1)–(3)	Yes	
63.1(a)(4)	Yes	Subpart S (this table) specifies applicability of

		each paragraph in subpart A to subpart S.
63.1(a)(5)	No	Section reserved.
63.1(a)(6)–(8)	Yes	
63.1(a)(9)	No	Section reserved.
63.1(a)(10)	No	Subpart S and other cross-referenced subparts specify calendar or operating day.
63.1(a)(11)–(14)	Yes	
63.1(b)(1)	No	Subpart S specifies its own applicability.
63.1(b)(2)–(3)	Yes	
63.1(c)(1)–(2)	Yes	
63.1(c)(3)	No	Section reserved.
63.1(c)(4)–(5)	Yes	
63.1(d)	No	Section reserved.
63.1(e)	Yes	
63.2	Yes	
63.3	Yes	
63.4(a)(1)	Yes	
63.4(a)(3)		
63.4(a)(4)	No	Section reserved.
63.4(a)(5)	Yes	
63.4(b)	Yes	
63.4(c)	Yes	
63.5(a)	Yes	
63.5(b)(1)	Yes	
63.5(b)(2)	No	Section reserved.
63.5(b)(3)	Yes	
63.5(b)(4)–(6)	Yes	
63.5(c)	No	Section reserved.
63.5(d)	Yes	
63.5(e)	Yes	
63.5(f)	Yes	
63.6(a)	Yes	
63.6(b)	No	Subpart S specifies compliance dates for sources subject to subpart S.
63.6(c)	No	Subpart S specifies compliance dates for sources subject to subpart S.
63.6(d)	No	Section reserved.
63.6(e)	Yes	

63.6(f)	Yes	
63.6(g)	Yes	
63.6(h)	No	Pertains to continuous opacity monitors that are not part of this standard.
63.6(i)	Yes	
63.6(j)	Yes	
63.7	Yes	
63.8(a)(1)	Yes	
63.8(a)(2)	Yes	
63.8(a)(3)	No	Section reserved.
63.8(a)(4)	Yes	
63.8(b)(1)	Yes	
63.8(b)(2)	No	Subpart S specifies locations to conduct monitoring.
63.8(b)(3)	Yes	
63.8(c)(1)	Yes	
63.8(c)(2)	Yes	
63.8(c)(3)	Yes	
63.8(c)(4)	No	Subpart S allows site specific determination of monitoring frequency in §63.453(n)(4).
63.8(c)(5)	No	Pertains to continuous opacity monitors that are not part of this standard.
63.8(c)(6)	Yes	
63.8(c)(7)	Yes	
63.8(c)(8)	Yes	
63.8(d)	Yes	
63.8(e)	Yes	
63.8(f)(1)–(5)	Yes	
63.8(f)(6)	No	Subpart S does not specify relative accuracy test for CEMs.
63.8(g)	Yes	
63.9(a)	Yes	
63.9(b)	Yes	Initial notifications must be submitted within one year after the source becomes subject to the relevant standard.
63.9(c)	Yes	
63.9(d)	No	Special compliance requirements are only applicable to kraft mills.
63.9(e)	Yes	
63.9(f)	No	Pertains to continuous opacity monitors that are not part of this standard.
63.9(g)(1)	Yes	
63.9(g)(2)	No	Pertains to continuous opacity monitors that are

		not part of this standard.
63.9(g)(3)	No	Subpart S does not specify relative accuracy tests, therefore no notification is required for an alternative.
63.9(h)	Yes	
63.9(i)	Yes	
63.9(j)	Yes	
63.10(a)	Yes	
63.10(b)	Yes	
63.10(c)	Yes	
63.10(d)(1)	Yes	
63.10(d)(2)	Yes	
63.10(d)(3)	No	Pertains to continuous opacity monitors that are not part of this standard.
63.10(d)(4)	Yes	
63.10(d)(5)	Yes	
63.10(e)(1)	Yes	
63.10(e)(2)(i)	Yes	
63.10(e)(2)(ii)	No	Pertains to continuous opacity monitors that are not part of this standard.
63.10(e)(3)	Yes	
63.10(e)(4)	No	Pertains to continuous opacity monitors that are not part of this standard.
63.10(f)	Yes	
63.11–63.15	Yes	

[a]Wherever subpart A specifies “postmark” dates, submittals may be sent by methods other than the U.S. Mail (e.g., by fax or courier). Submittals shall be sent by the specified dates, but a postmark is not required.

[63 FR 18617, Apr. 15, 1998, as amended at 64 FR 17564, Apr. 12, 1999]

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APPENDIX F - 10A BOILER ALTERNATIVE MONITORING EXEMPTION

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 6
1445 ROSS AVENUE, SUITE 1200
DALLAS, TX 75202-2733

JUL 30 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

RECEIVED
AUG 04 1999

Mr. Keith Michaels
Chief, Air Division
Arkansas Department of Environmental Quality
8001 National Drive
P.O. Box 8913
Little Rock, AR 72219-8913

Re. Georgia-Pacific Crossett Paper Operations 10A Boiler--Request for Alternative Monitoring

Dear Mr. Michaels:

On July 9, 1999, we received your letter of July 1, 1999, which supported and transmitted Georgia-Pacific's (GP) June 21, 1999, request for alternative monitoring of their 10A boiler that is subject to NSPS Subpart D. GP has noted that new Permit 597-AOP-R1 reflects an appropriate [illegible]s of monitoring opacity. The purpose of this letter is to approve GP's request given the [illegible]wing:

The 10A boiler is required to have continuous monitoring systems (CMS) for measuring various emitted pollutants, including the opacity of emissions, pursuant to 40 C.F.R. 60.45. It is GP's request that given the fact that a venturi scrubber is the control equipment for this boiler and that liquid water interference from the scrubber renders the CMS inaccurate, that parametric monitoring of the scrubber along with weekly visual observation of the boiler's emissions using EPA Reference Method 9 be accepted in lieu of a CMS. This alternative may be accepted by EPA via the general provisions of NSPS Subpart A, at 40 C.F.R. 60.13(i).

Enclosed with GP's letter of June 21, 1991, were relevant sections of permit 597-AOP-R1. After review of these sections, there were questions regarding the annual particulate tests for the boiler and the relationship between the tests and the parametric monitoring of the scrubber. Accordingly, on July 16, 1999, Rich Raybourne of my staff spoke with GP's Scott Bailey and received clarification on this issue which included a fax of the entire 10A Boiler section of 597-AOP-R1. After review of the entire 10A Boiler section and the conversation with Mr. Bailey, the questions were resolved. By this letter we approve GP's request via the provisions of NSPS Subpart A, at 40 C.F.R. 60.13(i).

If you should have any questions regarding this letter, please contact Rich Raybourne, Senior Enforcement Officer of my staff, at 214-665-7260. Legal inquiries should be directed to Jan Gerro, Enforcement Counsel, Legal Branch at 214-665-2121.

Sincerely yours,

John R. Hepola

John R. Hepola
Chief
Air, Toxics and Inspection Coordination Branch

cc: Scott Bailey, GP
Drew Hodges, Esq. GP
Gordon Alphonso, Esq. GP
Tom Hudson, ADEQ
Melissa Blumenthal, ADEQ

APPENDIX G - BLEACH PLANT ALTERNATIVE MONITORING EXEMPTION

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 6
1445 ROSS AVENUE, SUITE 1200
DALLAS, TX 75202-2733

FEB 1 1 2004

Charles E. Hodges
Senior Vice President
Manufacturing Southern Region
Georgia-Pacific
Crossett Paper Operations
P.O. Box 3333
Crossett, Arkansas 71635

RE: Alternative Monitoring Request for Pulp Washing System (Chemiwashers) located at Georgia-Pacific Corporation's Crossett Paper Operations

Dear Mr. Hodges:

This is in response to your letter dated August 18, 2003, regarding a 40 CFR 63 Subpart S request for the use of alternative monitoring for the pulp washing systems subject to § 63.443(a)(1)(iii). The Georgia-Pacific (G-P) Crossett Paper Operations Mill, located in Crossett, Arkansas, is subject to the Maximum Achievable Control Technology (MACT) standards regulations for the pulp and paper industry, promulgated at 40 CFR Part 63, Subpart S.

One requirement of Subpart S is to control hazardous air pollutant (HAP) emissions from pulp washing systems (40 CFR 63.443(a)(1)(iii)). In your letter, you describe the pulp washing system used at the Crossett Mill, which consists of two Chemiwashers. These Chemiwashers are flat, belt-type washers rather than conventional drum washers. The washers pull a vacuum on the wire (or belt), pulling the wash water, black liquor, and air through the pulp. The air is separated in the washer and recycled back into the enclosing hood over the wire. The manufacturer designed the Chemiwashers as closed systems, and therefore, collection and incineration of emissions from these units are not required under Subpart S since there are no discreet emission points. However, you point out in your letter that even though the washing system is essentially closed, there are, however, minor fugitive leaks of steam around the feed and exit roll seals and along the side gaskets.

Subpart S does require monitoring of the closed vent collection system for visual defects at least every 30 days (40 CFR 63.453(k)(2)) and instrumental monitoring for "detectable leaks" using Method 21 annually (40 CFR 63.453(k)(3)). 40 CFR 63.453(k) further requires that "visual defects" (in ductwork, piping, etc.) and detectable leaks (i.e., those greater than 500 parts per million (ppm) as measured by Method 21) be repaired within a specific timeframe.

According to your letter, G-P Crossett conducted preliminary testing of the minor fugitive leaks found around the feed and exit roll seals and along the side gaskets of the Chemiwashers using EPA Method 21 and had found that all were well under 500 ppm. Based upon these tests, you believe that the closed Chemiwasher systems at the Crossett facility do meet the 500 ppm limit, and have no "detectable leaks", even though there are minor visible emissions.

Therefore, G-P Crossett is requesting an alternative monitoring parameter for the closed vent system visual inspections by proposing to conduct monthly testing of the Chemiwashers using EPA Method 21. in lieu of the requirement to demonstrate monthly that there are no visual defects. Any leaks greater than 500 ppm that are detected during these monthly tests will be repaired as outlined in 40 CFR 63.453(k)(6).

Based upon the information supplied in your letter dated August 18, 2003, EPA Region 6 approves your request to conduct monthly Method 21 monitoring, in lieu of monthly visual monitoring, of the fugitive leaks found around the feed and exit roll seals and along the side gaskets of the Chemiwashers. However, you are still required to satisfy all of the other applicable monitoring and recordkeeping requirements of Subpart S.

If you have any questions regarding this alternative monitoring parameter approval, please feel free to contact Ms. Michelle Kelly, of my staff, at (214) 665-7580.

Sincerely yours,

William K. Honker, P.E.
Chief
Air/Toxics and Inspection
Coordination Branch

cc: Tom Hudson, ADEQ
Anna Hubbard, ADEQ
Tom Rheaume, ADEQ

APPENDIX H - NESHAP MM

Electronic Code of Federal Regulations
e-CFR ™

e-CFR Data is current as of May 17, 2012

Title 40: Protection of Environment

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES (CONTINUED)

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Subpart MM—National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills

Source: 66 FR 3193, Jan. 12, 2001, unless otherwise noted.

§ 63.860 Applicability and designation of affected source.

(a) The requirements of this subpart apply to the owner or operator of each kraft, soda, sulfite, or stand-alone semichemical pulp mill that is a major source of hazardous air pollutants (HAP) emissions as defined in §63.2.

(b) *Affected sources.* The requirements of this subpart apply to each new or existing affected source listed in paragraphs (b)(1) through (7) of this section:

(1) Each existing chemical recovery system (as defined in §63.861) located at a kraft or soda pulp mill.

(2) Each new nondirect contact evaporator (NDCE) recovery furnace and associated smelt dissolving tank(s) located at a kraft or soda pulp mill.

(3) Each new direct contact evaporator (DCE) recovery furnace system (as defined in §63.861) and associated smelt dissolving tank(s) located at a kraft or soda pulp mill.

(4) Each new lime kiln located at a kraft or soda pulp mill.

(5) Each new or existing sulfite combustion unit located at a sulfite pulp mill, except such existing units at Weyerhaeuser Paper Company's Cosmopolis, Washington facility (Emission Unit no. AP–10).

(6) Each new or existing semichemical combustion unit located at a stand-alone semichemical pulp mill.

(7) The requirements of the alternative standard in §63.862(d) apply to the hog fuel dryer at Weyerhaeuser Paper Company's Cosmopolis, Washington facility (Emission Unit no. HD–14).

(c) The requirements of the General Provisions in subpart A of this part that apply to the owner or operator subject to the requirements of this subpart are identified in Table 1 to this subpart.

[66 FR 3193, Jan. 12, 2001, as amended at 68 FR 7713, Feb. 18, 2003]

§ 63.861 Definitions.

All terms used in this subpart are defined in the Clean Air Act, in subpart A of this part, or in this section. For the purposes of this subpart, if the same term is defined in subpart A or any other subpart of this part and in this section, it must have the meaning given in this section.

Bag leak detection system means an instrument that is capable of monitoring PM loadings in the exhaust of a fabric filter in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on triboelectric, light scattering, light transmittance, or other principle to monitor relative PM loadings.

Black liquor means spent cooking liquor that has been separated from the pulp produced by the kraft, soda, or semichemical pulping process.

Black liquor gasification means the thermochemical conversion of black liquor into a combustible gaseous product.

Black liquor oxidation (BLO) system means the vessels used to oxidize the black liquor, with air or oxygen, and the associated storage tank(s).

Black liquor solids (BLS) means the dry weight of the solids in the black liquor that enters the recovery furnace or semichemical combustion unit.

Black liquor solids firing rate means the rate at which black liquor solids are fed to the recovery furnace or the semichemical combustion unit.

Chemical recovery combustion source means any source in the chemical recovery area of a kraft, soda, sulfite or stand-alone semichemical pulp mill that is an NDCE recovery furnace, a DCE recovery furnace system, a smelt dissolving tank, a lime kiln, a sulfite combustion unit, or a semichemical combustion unit.

Chemical recovery system means all existing DCE and NDCE recovery furnaces, smelt dissolving tanks, and lime kilns at a kraft or soda pulp mill. Each existing recovery furnace, smelt dissolving tank, or lime kiln is considered a process unit within a chemical recovery system.

Direct contact evaporator (DCE) recovery furnace means a kraft or soda recovery furnace equipped with a direct contact evaporator that concentrates strong black liquor by direct contact between the hot recovery furnace exhaust gases and the strong black liquor.

Direct contact evaporator (DCE) recovery furnace system means a direct contact evaporator recovery furnace and any black liquor oxidation system, if present, at the pulp mill.

Dry electrostatic precipitator (ESP) system means an electrostatic precipitator with a dry bottom (*i.e.,* no black liquor, water, or other fluid is used in the ESP bottom) and a dry particulate matter return system (*i.e.,* no black liquor, water, or other fluid is used to transport the collected PM to the mix tank).

Fabric filter means an air pollution control device used to capture PM by filtering a gas stream through filter media; also known as a baghouse.

Hazardous air pollutants (HAP) metals means the sum of all emissions of antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, mercury, nickel, and selenium as measured by EPA Method 29 (40 CFR part 60, appendix A) and with all nondetect data treated as one-half of the method detection limit.

Hog fuel dryer means the equipment that combusts fine particles of wood waste (hog fuel) in a fluidized bed and directs the heated exhaust stream to a rotary dryer containing wet hog fuel to be dried prior to combustion in the hog fuel boiler at Weyerhaeuser Paper Company's Cosmopolis, Washington facility. The hog fuel dryer at Weyerhaeuser Paper Company's Cosmopolis, Washington facility is Emission Unit no. HD–14.

Kraft pulp mill means any stationary source that produces pulp from wood by cooking (digesting) wood chips in a solution of sodium hydroxide and sodium sulfide. The recovery process used to regenerate cooking chemicals is also considered part of the kraft pulp mill.

Kraft recovery furnace means a recovery furnace that is used to burn black liquor produced by the kraft pulping process, as well as any recovery furnace that burns black liquor produced from both the kraft and semichemical pulping processes, and includes the direct contact evaporator, if applicable. Includes black liquor gasification.

Lime kiln means the combustion unit (*e.g.,* rotary lime kiln or fluidized-bed calciner) used at a kraft or soda pulp mill to calcine lime mud, which consists primarily of calcium carbonate, into quicklime, which is calcium oxide (CaO).

Lime production rate means the rate at which dry lime, measured as CaO, is produced in the lime kiln.

Method detection limit means the minimum concentration of an analyte that can be determined with 99 percent confidence that the true value is greater than zero.

Modification means, for the purposes of §63.862(a)(1)(ii)(E)(*1*), any physical change (excluding any routine part replacement or maintenance) or operational change (excluding any operational change that occurs during a start-up, shutdown, or malfunction) that is made to the air pollution control device that could result in an increase in PM emissions.

Nondetect data means, for the purposes of this subpart, any value that is below the method detection limit.

Nondirect contact evaporator (NDCE) recovery furnace means a kraft or soda recovery furnace that burns black liquor that has been concentrated by indirect contact with steam.

Particulate matter (PM) means total particulate matter as measured by EPA Method 5, EPA Method 17 (§63.865(b)(1)), or EPA Method 29 (40 CFR part 60, appendix A).

Process unit means an existing DCE or NDCE recovery furnace, smelt dissolving tank, or lime kiln in a chemical recovery system at a kraft or soda mill.

Recovery furnace means an enclosed combustion device where concentrated black liquor produced by the kraft or soda pulping process is burned to recover pulping chemicals and produce steam. Includes black liquor gasification.

Regenerative thermal oxidizer (RTO) means a thermal oxidizer that transfers heat from the exhaust gas stream to the inlet gas stream by passing the exhaust stream through a bed of ceramic stoneware or other heat-absorbing medium before releasing it to the atmosphere, then reversing the gas flow so the inlet gas stream passes through the heated bed, raising the temperature of the inlet stream close to or at its ignition temperature.

Semichemical combustion unit means any equipment used to combust or pyrolyze black liquor at stand-alone semichemical pulp mills for the purpose of chemical recovery. Includes black liquor gasification.

Similar process units means all existing DCE and NDCE recovery furnaces, smelt dissolving tanks, or lime kilns at a kraft or soda pulp mill.

Smelt dissolving tanks (SDT) means vessels used for dissolving the smelt collected from a kraft or soda recovery furnace.

Soda pulp mill means any stationary source that produces pulp from wood by cooking (digesting) wood chips in a sodium hydroxide solution. The recovery process used to regenerate cooking chemicals is also considered part of the soda pulp mill.

Soda recovery furnace means a recovery furnace used to burn black liquor produced by the soda pulping process and includes the direct contact evaporator, if applicable. Includes black liquor gasification.

Stand-alone semichemical pulp mill means any stationary source that produces pulp from wood by partially digesting wood chips in a chemical solution followed by mechanical defibrating (grinding), and has an onsite chemical recovery process that is not integrated with a kraft pulp mill.

Startup means, for the chemical recovery system employing black liquor gasification at Georgia-Pacific's facility in Big Island, Virginia only, the end of the gasification system commissioning phase. Commissioning is that period of time in which each part of the new gasification system will be checked and operated on its own to make sure it is installed and functions properly. Commissioning will conclude with the successful completion of the gasification technology supplier's performance warranty demonstration, which proves the technology and equipment are performing to warranted levels and the system is ready to be placed in active service. For all other affected sources under this subpart, startup has the meaning given in §63.2.

Sulfite combustion unit means a combustion device, such as a recovery furnace or fluidized-bed reactor, where spent liquor from the sulfite pulping process (i.e., red liquor) is burned to recover pulping chemicals.

Sulfite pulp mill means any stationary source that produces pulp from wood by cooking (digesting) wood chips in a solution of sulfurous acid and bisulfite ions. The recovery process used to regenerate cooking chemicals is also considered part of the sulfite pulp mill.

Total hydrocarbons (THC) means the sum of organic compounds measured as carbon using EPA Method 25A (40 CFR part 60, appendix A).

[66 FR 3193, Jan. 12, 2001, as amended at 66 FR 16408, Mar. 26, 2001; 68 FR 7713, Feb. 18, 2003]

§ 63.862 Standards.

(a) *Standards for HAP metals: existing sources.* (1) Each owner or operator of an existing kraft or soda pulp mill must comply with the requirements of either paragraph (a)(1)(i) or (ii) of this section.

(i) Each owner or operator of a kraft or soda pulp mill must comply with the PM emissions limits in paragraphs (a)(1)(i)(A) through (C) of this section.

(A) The owner or operator of each existing kraft or soda recovery furnace must ensure that the concentration of PM in the exhaust gases discharged to the atmosphere is less than or equal to 0.10 gram per dry standard cubic meter (g/dscm) (0.044 grain per dry standard cubic foot (gr/dscf)) corrected to 8 percent oxygen.

(B) The owner or operator of each existing kraft or soda smelt dissolving tank must ensure that the concentration of PM in the exhaust gases discharged to the atmosphere is less than or equal to 0.10 kilogram per megagram (kg/Mg) (0.20 pound per ton (lb/ton)) of black liquor solids fired.

(C) The owner or operator of each existing kraft or soda lime kiln must ensure that the concentration of PM in the exhaust gases discharged to the atmosphere is less than or equal to 0.15 g/dscm (0.064 gr/dscf) corrected to 10 percent oxygen.

(ii) As an alternative to meeting the requirements of §63.862(a)(1)(i), each owner or operator of a kraft or soda pulp mill may establish PM emissions limits for each existing kraft or soda recovery furnace, smelt dissolving tank, and lime kiln that operates 6,300 hours per year or more by:

(A) Establishing an overall PM emission limit for each existing process unit in the chemical recovery system at the kraft or soda pulp mill using the methods in §63.865(a)(1) and (2).

(B) The emissions limits for each kraft recovery furnace, smelt dissolving tank, and lime kiln that are used to establish the overall PM limit in paragraph (a)(1)(ii)(A) of this section must not be less stringent than the emissions limitations required by §60.282 of part 60 of this chapter for any kraft recovery furnace, smelt dissolving tank, or lime kiln that is subject to the requirements of §60.282.

(C) Each owner or operator of an existing kraft or soda recovery furnace, smelt dissolving tank, or lime kiln must ensure that the PM emissions discharged to the atmosphere from each of these sources are less than or equal to the applicable PM emissions limits, established using the methods in §63.865(a)(1), that are used to establish the overall PM emissions limits in paragraph (a)(1)(ii)(A) of this section.

(D) Each owner or operator of an existing kraft or soda recovery furnace, smelt dissolving tank, or lime kiln must reestablish the emissions limits determined in paragraph (a)(1)(ii)(A) of this section if either of the actions in paragraphs (a)(1)(ii)(D)(*1*) and (*2*) of this section are taken:

(*1*) The air pollution control system for any existing kraft or soda recovery furnace, smelt dissolving tank, or lime kiln for which an emission limit was established in paragraph (a)(1)(ii)(A) of this section is modified (as defined in §63.861) or replaced; or

(2) Any kraft or soda recovery furnace, smelt dissolving tank, or lime kiln for which an emission limit was established in paragraph (a)(1)(ii)(A) of this section is shut down for more than 60 consecutive days.

(iii) Each owner or operator of an existing kraft or soda recovery furnace, smelt dissolving tank, or lime kiln that operates less than 6,300 hours per year must comply with the applicable PM emissions limits for that process unit provided in paragraph (a)(1)(i) of this section.

(2) Except as specified in paragraph (d) of this section, the owner or operator of each existing sulfite combustion unit must ensure that the concentration of PM in the exhaust gases discharged to the atmosphere is less than or equal to 0.092 g/dscm (0.040 gr/dscf) corrected to 8 percent oxygen.

(b) *Standards for HAP metals: new sources.* (1) The owner or operator of any new kraft or soda recovery furnace must ensure that the concentration of PM in the exhaust gases discharged to the atmosphere is less than or equal to 0.034 g/dscm (0.015 gr/dscf) corrected to 8 percent oxygen.

(2) The owner or operator of any new kraft or soda smelt dissolving tank must ensure that the concentration of PM in the exhaust gases discharged to the atmosphere is less than or equal to 0.06 kg/Mg (0.12 lb/ton) of black liquor solids fired.

(3) The owner or operator of any new kraft or soda lime kiln must ensure that the concentration of PM in the exhaust gases discharged to the atmosphere is less than or equal to 0.023 g/dscm (0.010 gr/dscf) corrected to 10 percent oxygen.

(4) The owner or operator of any new sulfite combustion unit must ensure that the concentration of PM in the exhaust gases discharged to the atmosphere is less than or equal to 0.046 g/dscm (O.020 gr/dscf) corrected to 8 percent oxygen.

(c) *Standards for gaseous organic HAP.* (1) The owner or operator of any new recovery furnace at a kraft or soda pulp mill must ensure that the concentration or gaseous organic HAP, as meauared by methanol, discharged to the atmosphere is no greater than 0.012 kg/Mg (0.025 lb/ton) of black liquor solids fired.

(2) The owner or operator of each existing or new semichemical combustion unit must ensure that:

(i) The concentration of gaseous organic HAP, as measured by total hydrocarbons reported as carbon, discharged to the atmosphere is less than or equal to 1.49 kg/Mg (2.97 lb/ton) of black liquor solids fired; or

(ii) The gaseous organic HAP emissions, as measured by total hydrocarbons reported as carbon, are reduced by at least 90 percent prior to discharge of the gases to the atmosphere.

(d) *Alternative standard.* As an alternative to meeting the requirements of paragraph (a)(2) of this section, the owner or operator of the existing hog fuel dryer at Weyerhaeuser Paper Company's Cosmopolis, Washington facility (Emission Unit no. HD–14) must ensure that the mass of PM in the exhaust gases discharged to the atmosphere from the hog fuel dryer is less than or equal to 4.535 kilograms per hour (kg/hr) (10.0 pounds per hour (lb/hr)).

[66 FR 3193, Jan. 12, 2001, as amended at 68 FR 7713, Feb. 18, 2003; 68 FR 67954, Dec. 5, 2003]

§ 63.863 Compliance dates.

(a) The owner or operator of an existing affected source or process unit must comply with the requirements in this subpart no later than March 13, 2004.

(b) The owner or operator of a new affected source that has an initial startup date after March 13, 2001 must comply with the requirements in this subpart immediately upon startup of the affected source, except as specified in §63.6(b).

(c) The two existing semichemical combustion units at Georgia-Pacific Corporation's Big Island, VA facility must comply with the requirements of this subpart no later than March 13, 2004, except as provided in paragraphs (c)(1) and (c)(2) of this section.

(1) If Georgia-Pacific Corporation constructs a new black liquor gasification system at Big Island, VA, determines that its attempt to start up the new system has been a failure and, therefore, must construct another type of chemical recovery unit to replace the two existing semichemical combustion units at Big Island, then the two existing semichemical combustion units must comply with the requirements of this subpart by the earliest of the following dates: three years after Georgia-Pacific declares the gasification system a failure, upon startup of the new replacement unit(s), or March 1, 2008.

(2) After March 13, 2004 and if Georgia-Pacific Corporation constructs and successfully starts up a new black liquor gasification system, the provisions of this subpart will not apply to the two existing semichemical combustion units at Georgia-Pacific's facility in Big Island, VA for up to 1500 hours, while Georgia-Pacific conducts trials of the new gasification system on black liquor from a Kraft pulp mill.

[66 FR 3193, Jan. 12, 2001, as amended at 66 FR 16408, Mar. 26, 2001; 66 FR 37593, July 19, 2001; 68 FR 46108, Aug. 5, 2003]

§ 63.864 Monitoring re uirements.

(a)–(c) [Reserved]

(d) *Continuous opacity monitoring system (COMS).* The owner or operator of each affected kraft or soda recovery furnace or lime kiln equipped with an ESP must install, calibrate, maintain, and operate a COMS according to the provisions in §§63.6(h) and 63.8 and paragraphs (d)(1) through (4) of this section.

(1)–(2) [Reserved]

(3) As specified in §63.8(c)(4)(i), each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(4) The COMS data must be reduced as specified in §63.8(g)(2).

(e) *Continuous parameter monitoring system (CPMS).* For each CPMS required in this section, the owner or operator of each affected source or process unit must meet the requirements in paragraphs (e)(1) through (14) of this section.

(1)–(9) [Reserved]

(10) The owner or operator of each affected kraft or soda recovery furnace, kraft or soda lime kiln, sulfite combustion unit, or kraft or soda smelt dissolving tank equipped with a wet scrubber must install, calibrate, maintain, and operate a CPMS that can be used to determine and record the pressure drop across the scrubber and the scrubbing liquid flow rate at least once every successive 15-minute period using the procedures in §63.8(c), as well as the procedures in paragraphs (e)(10)(i) and (ii) of this section:

(i) The monitoring device used for the continuous measurement of the pressure drop of the gas stream across the scrubber must be certified by the manufacturer to be accurate to within a gage pressure of ±500 pascals (±2 inches of water gage pressure); and

(ii) The monitoring device used for continuous measurement of the scrubbing liquid flow rate must be certified by the manufacturer to be accurate within ±5 percent of the design scrubbing liquid flow rate.

(11) The owner or operator of each affected semichemical combustion unit equipped with an RTO must install, calibrate, maintain, and operate a CPMS that can be used to determine and record the operating temperature of the RTO at least once every successive 15-minute period using the procedures in §63.8(c). The monitor must compute and record the operating temperature at the point of incineration of effluent gases that are emitted using a temperature monitor accurate to within ±1 percent of the temperature being measured.

(12) The owner or operator of the affected hog fuel dryer at Weyerhaeuser Paper Company's Cosmopolis, Washington facility (Emission Unit no. HD–14) must meet the requirements in paragraphs

(e)(12)(i) through (xi) of this section for each bag leak detection system.

(i) The owner or operator must install, calibrate, maintain, and operate each triboelectric bag leak detection system according to the "Fabric Filter Bag Leak Detection Guidance," (EPA–454/R–98–015, September 1997). This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality Planning and Standards; Emissions, Monitoring and Analysis Division; Emission Measurement Center, MD-D205-02, Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network under Emission Measurement Center Continuous Emission Monitoring. The owner or operator must install, calibrate, maintain, and operate other types of bag leak detection systems in a manner consistent with the manufacturer's written specifications and recommendations.

(ii) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 10 milligrams per actual cubic meter (0.0044 grains per actual cubic foot) or less.

(iii) The bag leak detection system sensor must provide an output of relative PM loadings.

(iv) The bag leak detection system must be equipped with a device to continuously record the output signal from the sensor.

(v) The bag leak detection system must be equipped with an audible alarm system that will sound automatically when an increase in relative PM emissions over a preset level is detected. The alarm must be located where it is easily heard by plant operating personnel.

(vi) For positive pressure fabric filter systems, a bag leak detector must be installed in each baghouse compartment or cell.

(vii) For negative pressure or induced air fabric filters, the bag leak detector must be installed downstream of the fabric filter.

(viii) Where multiple detectors are required, the system's instrumentation and alarm may be shared among detectors.

(ix) The baseline output must be established by adjusting the range and the averaging period of the device and establishing the alarm set points and the alarm delay time according to section 5.0 of the "Fabric Filter Bag Leak Detection Guidance."

(x) Following initial adjustment of the system, the sensitivity or range, averaging period, alarm set points, or alarm delay time may not be adjusted except as detailed in the site-specific monitoring plan. In no case may the sensitivity be increased by more than 100 percent or decreased more than 50 percent over a 365-day period unless such adjustment follows a complete fabric filter inspection which demonstrates that the fabric filter is in good operating condition. Record each adjustment.

(xi) The owner or operator must record the results of each inspection, calibration, and validation check.

(13) The owner or operator of each affected source or process unit that uses an ESP, wet scrubber, RTO, or fabric filter may monitor alternative control device operating parameters subject to prior written approval by the Administrator.

(14) The owner or operator of each affected source or process unit that uses an air pollution control system other than an ESP, wet scrubber, RTO, or fabric filter must provide to the Administrator an alternative monitoring request that includes the site-specific monitoring plan described in paragraph (a) of this section, a description of the control device, test results verifying the performance of the control device, the appropriate operating parameters that will be monitored, and the frequency of measuring and recording to establish continuous compliance with the standards. The alternative monitoring request is subject to the Administrator's approval. The owner or operator of the affected source or process unit must install, calibrate, operate, and maintain the monitor(s) in accordance with the alternative monitoring request approved by the Administrator. The owner or operator must include in the information submitted to the Administrator proposed performance specifications and quality assurance procedures for the monitors. The Administrator may request further information and will approve acceptable test methods and procedures. The owner or operator must monitor the parameters as approved by the Administrator using the methods and procedures in the alternative monitoring request.

(f) [Reserved]

(g) The owner or operator of each affected source or process unit complying with the gaseous organic HAP standard of §63.862(c)(1) through the use of an NDCE recovery furnace equipped with a dry ESP system is not required to conduct any continuous monitoring to demonstrate compliance with the gaseous organic HAP standard.

(h)–(i) [Reserved]

(j) *Determination of operating ranges.* (1) During the initial performance test required in §63.865, the owner or operator of any affected source or process unit must establish operating ranges for the monitoring parameters in paragraphs (e)(10) through (14) of this section, as appropriate; or

(2) The owner or operator may base operating ranges on values recorded during previous performance tests or conduct additional performance tests for the specific purpose of establishing operating ranges, provided that test data used to establish the operating ranges are or have been obtained using the test methods required in this subpart. The owner or operator of the affected source or process unit must certify that all control techniques and processes have not been modified subsequent to the testing upon which the data used to establish the operating parameter ranges were obtained.

(3) The owner or operator of an affected source or process unit may establish expanded or replacement operating ranges for the monitoring parameter values listed in paragraphs (e)(10) through (14) of this section and established in paragraph (j)(1) or (2) of this section during subsequent performance tests using the test methods in §63.865.

(4) The owner or operator of the affected source or process unit must continuously monitor each parameter and determine the arithmetic average value of each parameter during each performance test. Multiple performance tests may be conducted to establish a range of parameter values.

(5)–(6) [Reserved]

(k) *On-going compliance provisions.* (1) Following the compliance date, owners or operators of all affected sources or process units are required to implement corrective action if the monitoring exceedances in paragraphs (k)(1)(i) through (vi) of this section occur:

(i) For a new or existing kraft or soda recovery furnace or lime kiln equipped with an ESP, when the average of ten consecutive 6-minute averages result in a measurement greater than 20 percent opacity;

(ii) For a new or existing kraft or soda recovery furnace, kraft or soda smelt dissolving tank, kraft or soda lime kiln, or sulfite combustion unit equipped with a wet scrubber, when any 3-hour average parameter value is outside the range of values established in paragraph (j) of this section.

(iii) For a new or existing semichemical combustion unit equipped with an RTO, when any 1-hour average temperature falls below the temperature established in paragraph (j) of this section;

(iv) For the hog fuel dryer at Weyerhaeuser Paper Company's Cosmopolis, Washington facility (Emission Unit no. HD–14), when the bag leak detection system alarm sounds.

(v) For an affected source or process unit equipped with an ESP, wet scrubber, RTO, or fabric filter and monitoring alternative operating parameters established in paragraph (e)(13) of this section, when any 3-hour average value is outside the range of parameter values established in paragraph (j) of this section; and

(vi) For an affected source or process unit equipped with an alternative air pollution control system and monitoring operating parameters approved by the Administrator as established in paragraph (e)(14) of this section, when any 3-hour average value is outside the range of parameter values established in paragraph (j) of this section.

(2) Following the compliance date, owners or operators of all affected sources or process units are in violation of the standards of §63.862 if the monitoring exceedances in paragraphs (k)(2)(i) through (vii) of this section occur:

(i) For an existing kraft or soda recovery furnace equipped with an ESP, when opacity is greater than 35 percent for 6 percent or more of the operating time within any quarterly period;

(ii) For a new kraft or soda recovery furnace or a new or existing lime kiln equipped with an ESP, when opacity is greater than 20 percent for 6 percent or more of the operating time within any quarterly period;

(iii) For a new or existing kraft or soda recovery furnace, kraft or soda smelt dissolving tank, kraft or soda lime kiln, or sulfite combustion unit equipped with a wet scrubber, when six or more 3-hour average parameter values within any 6-month reporting period are outside the range of values established in paragraph (j) of this section;

(iv) For a new or existing semichemical combustion unit equipped with an RTO, when any 3-hour average temperature falls below the temperature established in paragraph (j) of this section;

(v) For the hog fuel dryer at Weyerhaeuser Paper Company's Cosmopolis, Washington facility (Emission Unit no. HD-14), when corrective action is not initiated within 1 hour of a bag leak detection system alarm and the alarm is engaged for more than 5 percent of the total operating time in a 6-month block reporting period. In calculating the operating time fraction, if inspection of the fabric filter demonstrates that no corrective action is required, no alarm time is counted; if corrective action is required, each alarm is counted as a minimum of 1 hour; if corrective action is not initiated within 1 hour, the alarm time is counted as the actual amount of time taken to initiate corrective action.

(vi) For an affected source or process unit equipped with an ESP, wet scrubber, RTO, or fabric filter and monitoring alternative operating parameters established in paragraph (e)(13) of this section, when six or more 3-hour average values within any 6-month reporting period are outside the range of parameter values established in paragraph (j) of this section; and

(vii) For an affected source or process unit equipped with an alternative air pollution control system and monitoring operating parameters approved by the Administrator as established in paragraph (e)(14) of this section, when six or more 3-hour average values within any 6-month reporting period are outside the range of parameter values established in paragraph (j) of this section.

(3) For purposes of determining the number of nonopacity monitoring exceedances, no more than one exceedance will be attributed in any given 24-hour period.

[68 FR 7713, Feb. 18, 2003, as amended at 68 FR 42605, July 18, 2003; 68 FR 67955, Dec. 5, 2003; 71 FR 20458, Apr. 20, 2006]

§ 63.86 Performance test re uirements and test methods.

The owner or operator of each affected source or process unit subject to the requirements of this subpart is required to conduct an initial performance test using the test methods and procedures listed in §63.7 and paragraph (b) of this section, except as provided in paragraph (c)(1) of this section.

(a) The owner or operator of a process unit seeking to comply with a PM emission limit under §63.862(a)(1)(ii)(A) must use the procedures in paragraphs (a)(1) and (2) of this section:

(1) Determine the overall PM emission limit for the chemical recovery system at the mill using Equation 1 of this section as follows:

$$EL_{PM} = \frac{\left[(C_{ref,RF})(Q_{RFtot}) + (C_{ref,LK})(Q_{LKtot}) \right](F1)}{(BLS_{tot})} + ER1_{ref,SDT} \qquad \text{(Eq. 1)}$$

Where:

EL_{PM}= overall PM emission limit for all existing process units in the chemical recovery system at the kraft or soda pulp mill, kg/Mg (lb/ton) of black liquor solids fired.

$C_{ref, RF}$= reference concentration of 0.10 g/dscm (0.044 gr/dscf) corrected to 8 percent oxygen for existing kraft or soda recovery furnaces.

Q_{RFtot}= sum of the average volumetric gas flow rates measured during the performance test and corrected to 8 percent oxygen for all existing recovery furnaces in the chemical recovery system at the kraft or soda pulp mill, dry standard cubic meters per minute (dscm/min) (dry standard cubic feet per minute (dscf/min)).

$C_{ref,LK}$= reference concentration of 0.15 g/dscm (0.064 gr/dscf) corrected to 10 percent oxygen for existing kraft or soda lime kilns.

Q_{LKtot}= sum of the average volumetric gas flow rates measured during the performance test and corrected to 10 percent oxygen for all existing lime kilns in the chemical recovery system at the kraft or soda pulp mill, dscm/min (dscf/min).

F1 = conversion factor, 1.44 minutes·kilogram/day·gram (min·kg/d·g) (0.206 minutes·pound/day·grain (min·b/d·gr)).

BLS_{tot}= sum of the average black liquor solids firing rates of all existing recovery furnaces in the chemical recovery system at the kraft or soda pulp mill measured during the performance test, megagrams per day (Mg/d) (tons per day (ton/d)) of black liquor solids fired.

$ER1_{ref,\ SDT}$= reference emission rate of 0.10 kg/Mg (0.20 lb/ton) of black liquor solids fired for existing kraft or soda smelt dissolving tanks.

(2) Establish an emission limit for each kraft or soda recovery furnace, smelt dissolving tank, and lime kiln; and, using these emissions limits, determine the overall PM emission rate for the chemical recovery system at the mill using the procedures in paragraphs (a)(2)(i) through (v) of this section, such that the overall PM emission rate calculated in paragraph (a)(2)(v) of this section is less than or equal to the overall PM emission limit determined in paragraph (a)(1) of this section, as appropriate.

(i) The PM emission rate from each affected recovery furnace must be determined using Equation 2 of this section as follows:

$$ER_{RF} = (F1)(C_{EL,RF})(Q_{RF})/(BLS) \qquad (Eq.\ 2)$$

Where:

ER_{RF}=emission rate from each recovery furnace, kg/Mg (lb/ton) of black liquor solids.

F1=conversion factor, 1.44 min·kg/d·g (0.206 min·/d·gr).

$C_{EL,\ RF}$=PM emission limit proposed by owner or operator for the recovery furnace, g/dscm (gr/dscf) corrected to 8 percent oxygen.

Q_{RF}=average volumetric gas flow rate from the recovery furnace measured during the performance test and corrected to 8 percent oxygen, dscm/min (dscf/min).

BLS=average black liquor solids firing rate of the recovery furnace measured during the performance test, Mg/d (ton/d) of black liquor solids.

(ii) The PM emission rate from each affected smelt dissolving tank must be determined using Equation 3 of this section as follows:

$$ER_{SDT} = (F1)(C_{EL,SDT})(Q_{SDT})/(BLS) \qquad (Eq.\ 3)$$

Where:

ER_{SDT}=emission rate from each SDT, kg/Mg (lb/ton) of black liquor solids fired.

F1=conversion factor, 1.44 min·kg/d•g (0.206 min·lb/d·gr).

$C_{EL, SDT}$=PM emission limit proposed by owner or operator for the smelt dissolving tank, g/dscm (gr/dscf).

Q_{SDT}=average volumetric gas flow rate from the smelt dissolving tank measured during the performance test, dscm/min (dscf/min).

BLS=average black liquor solids firing rate of the associated recovery furnace measured during the performance test, Mg/d (ton/d) of black liquorsolids fired. If more than one SDT is used to dissolve the smelt from a given recovery furnace, then the black liquor solids firing rate of the furnace must be proportioned according to the size of the SDT.

(iii) The PM emission rate from each affected lime kiln must be determined using Equation 4 of this section as follows:

$$ER_{LK} = (F1)(C_{EL,LK})(Q_{LK})(CaO_{tot}/BLS_{tot})/(CaO_{LK}) \qquad (Eq. 4)$$

Where:

ER_{LK}=emission rate from each lime kiln, kg/Mg (lb/ton) of black liquor solids.

F1=conversion factor, 1.44 min·kg/d·g (0.206 min·lb/d·gr).

$C_{EL,LK}$=PM emission limit proposed by owner or operator for the lime kiln, g/dscm (gr/dscf) corrected to 10 percent oxygen.

Q_{LK}=average volumetric gas flow rate from the lime kiln measured during the performance test and corrected to 10 percent oxygen, dscm/min (dscf/min).

CaO_{LK}=lime production rate of the lime kiln, measured as CaO during the performance test, Mg/d (ton/d) of CaO.

CaO_{tot}=sum of the average lime production rates for all existing lime kilns in the chemical recovery system at the mill measured as CaO during the performance test, Mg/d (ton/d).

BLS_{tot}=sum of the average black liquor solids firing rates of all recovery furnaces in the chemical recovery system at the mill measured during the performance test, Mg/d (ton/d) of black liquor solids.

(iv) If more than one similar process unit is operated in the chemical recovery system at the kraft or soda pulp mill, Equation 5 of this section must be used to calculate the overall PM emission rate from all similar process units in the chemical recovery system at the mill and must be used in determining the overall PM emission rate for the chemical recovery system at the mill:

$$ER_{PUtot} = ER_{PU1}\left(PR_{PU1}/PR_{tot}\right) + \ldots + \left(ER_{PUi}\right)\left(PR_{PUi}/PR_{tot}\right) \qquad (Eq. 5)$$

Where:

ER_{PUtot}=overall PM emission rate from all similar process units, kg/Mg (lb/ton) of black liquor solids fired.

ER_{PU1}=PM emission rate from process unit No. 1, kg/Mg (lb/ton) of black liquor solids fired, calculated using Equation 2, 3, or 4 in paragraphs (a)(2)(i) through (iii) of this section.

PR_{PU1}=black liquor solids firing rate in Mg/d (ton/d) for process unit No. 1, if process unit is a recovery furnace or SDT. The CaO production rate in Mg/d (ton/d) for process unit No. 1, if process unit is a lime kiln.

PR_{tot}=total black liquor solids firing rate in Mg/d (ton/d) for all recovery furnaces in the chemical recovery system at the kraft or soda pulp mill if the similar process units are recovery furnaces or SDT, or the total CaO production rate in Mg/d (ton/d) for all lime kilns in the chemical recovery system at the mill if the similar process units are lime kilns.

ER_{PUi}=PM emission rate from process unit No. i, kg/Mg (lb/ton) of black liquor solids fired.

PR_{PUi}=black liquor solids firing rate in Mg/d (ton/d) for process unit No. i, if process unit is a recovery furnace or SDT. The CaO production rate in Mg/d (ton/d) for process unit No. i, if process unit is a lime kiln.

i=number of similar process units located in the chemical recovery system at the kraft or soda pulp mill.

(v) The overall PM emission rate for the chemical recovery system at the mill must be determined using Equation 6 of this section as follows:

$$ER_{tot} = ER_{RFtot} + ER_{SDTtot} + ER_{LKtot} \qquad (Eq.\ 6)$$

Where:

ER_{tot}=overall PM emission rate for the chemical recovery system at the mill, kg/Mg (lb/ton) of black liquor solids fired.

ER_{RFtot}=PM emission rate from all kraft or soda recovery furnaces, calculated using Equation 2 or 5 in paragraphs (a)(2)(i) and (iv) of this section, where applicable, kg/Mg (lb/ton) of black liquor solids fired.

ER_{SDTtot}=PM emission rate from all smelt dissolving tanks, calculated using Equation 3 or 5 in paragraphs (a)(2)(ii) and (iv) of this section, where applicable, kg/Mg (lb/ton) of black liquor solids fired.

ER_{LKtot}=PM emission rate from all lime kilns, calculated using Equation 4 or 5 in paragraphs (a)(2)(iii) and (iv) of this section, where applicable, kg/Mg (lb/ton) of black liquor solids fired.

(vi) After the Administrator has approved the PM emissions limits for each kraft or soda recovery furnace, smelt dissolving tank, and lime kiln, the owner or operator complying with an overall PM emission limit established in §63.862(a)(1)(ii) must demonstrate compliance with the HAP metals standard by demonstrating compliance with the approved PM emissions limits for each affected kraft or soda recovery furnace, smelt dissolving tank, and lime kiln, using the test methods and procedures in paragraph (b) of this section.

(b) The owner or operator seeking to determine compliance with §63.862(a), (b), or (d) must use the procedures in paragraphs (b)(1) through (6) of this section.

(1) For purposes of determining the concentration or mass of PM emitted from each kraft or soda recovery furnace, sulfite combustion unit, smelt dissolving tank, lime kiln, or the hog fuel dryer at Weyerhaeuser Paper Company's Cosmopolis, Washington facility (Emission Unit no. HD–14), Method 5 or 29 in appendix A of 40 CFR part 60 must be used, except that Method 17 in appendix A of 40 CFR part 60 may be used in lieu of Method 5 or Method 29 if a constant value of 0.009 g/dscm (0.004 gr/dscf)

is added to the results of Method 17, and the stack temperature is no greater than 205 °C (400 °F). For Methods 5, 29, and 17, the sampling time and sample volume for each run must be at least 60 minutes and 0.90 dscm (31.8 dscf), and water must be used as the cleanup solvent instead of acetone in the sample recovery procedure.

(2) For sources complying with §63.862(a) or (b), the PM concentration must be corrected to the appropriate oxygen concentration using Equation 7 of this section as follows:

$$C_{corr} = C_{meas} \times \frac{(21-X)}{(21-Y)} \qquad \text{(Eq. 7)}$$

Where:

C_{corr}= The measured concentration corrected for oxygen, g/dscm (gr/dscf);

C_{meas}= The measured concentration uncorrected for oxygen, g/dscm (gr/dscf);

X = The corrected volumetric oxygen concentration (8 percent for kraft or soda recovery furnaces and sulfite combustion units and 10 percent for kraft or soda lime kilns); and

Y = The measured average volumetric oxygen concentration.

(3) Method 3A or 3B in appendix A of 40 CFR part 60 must be used to determine the oxygen concentration. The voluntary consensus standard ANSI/ASME PTC 19.10–1981—Part 10 (incorporated by reference—see §63.14) may be used as an alternative to using Method 3B. The gas sample must be taken at the same time and at the same traverse points as the particulate sample.

(4) For purposes of complying with of §63.862(a)(1)(ii)(A), the volumetric gas flow rate must be corrected to the appropriate oxygen concentration using Equation 8 of this section as follows:

Q_{corr}=Qmeas×(21−Y)/(21−X) (Eq. 8)

Where:

Q_{corr}=the measured volumetric gas flow rate corrected for oxygen, dscm/min (dscf/min).

Q_{meas}=the measured volumetric gas flow rate uncorrected for oxygen, dscm/min (dscf/min).

Y=the measured average volumetric oxygen concentration.

X=the corrected volumetric oxygen concentration (8 percent for kraft or soda recovery furnaces and 10 percent for kraft or soda lime kilns).

(5)(i) For purposes of selecting sampling port location and number of traverse points, Method 1 or 1A in appendix A of 40 CFR part 60 must be used;

(ii) For purposes of determining stack gas velocity and volumetric flow rate, Method 2, 2A, 2C, 2D, 2F, or 2G in appendix A of 40 CFR part 60 must be used;

(iii) For purposes of conducting gas analysis, Method 3, 3A, or 3B in appendix A of 40 CFR part 60 must be used. The voluntary consensus standard ANSI/ASME PTC 19.10–1981—Part 10 (incorporated by reference—see §63.14) may be used as an alternative to using Method 3B; and

(iv) For purposes of determining moisture content of stack gas, Method 4 in appendix A of 40 CFR part 60 must be used.

(6) Process data measured during the performance test must be used to determine the black liquor

solids firing rate on a dry basis and the CaO production rate.

(c) The owner or operator of each affected source or process unit complying with the gaseous organic HAP standard in §63.862(c)(1) must demonstrate compliance according to the provisions in paragraphs (c)(1) and (2) of this section.

(1) The owner or operator complying through the use of an NDCE recovery furnace equipped with a dry ESP system is not required to conduct any performance testing to demonstrate compliance with the gaseous organic HAP standard.

(2) The owner or operator complying without using an NDCE recovery furnace equipped with a dry ESP system must use Method 308 in appendix A of this part, as well as the methods listed in paragraphs (b)(5)(i) through (iv) of this section. The sampling time and sample volume for each Method 308 run must be at least 60 minutes and 0.014 dscm (0.50 dscf), respectively.

(i) The emission rate from any new NDCE recovery furnace must be determined using Equation 9 of this section as follows:

$$ER_{NDCE} = \frac{(MR_{meas})}{BLS} \qquad \text{(Eq. 9)}$$

Where:

ER_{NDCE}= Methanol emission rate from the NDCE recovery furnace, kg/Mg (lb/ton) of black liquor solids fired;

MR_{meas}= Measured methanol mass emission rate from the NDCE recovery furnace, kg/hr (lb/hr); and

BLS = Average black liquor solids firing rate of the NDCE recovery furnace, megagrams per hour (Mg/hr) (tons per hour (ton/hr)) determined using process data measured during the performance test.

(ii) The emission rate from any new DCE recovery furnace system must be determined using Equation 10 of this section as follows:

$$ER_{DCE} = \left[\frac{(MR_{meas,RF})}{BLS_{RF}}\right] + \left[\frac{MR_{meas,BLO}}{BLS_{BLO}}\right] \qquad \text{(Eq. 10)}$$

Where:

ER_{DCE}= Methanol emission rate from each DCE recovery furnace system, kg/Mg (lb/ton) of black liquor solids fired;

$MR_{meas,RF}$= Average measured methanol mass emission rate from each DCE recovery furnace, kg/hr (lb/hr);

$MR_{meas,BLO}$= Average measured methanol mass emission rate from the black liquor oxidation system, kg/hr (lb/hr);

BLS_{RF}= Average black liquor solids firing rate for each DCE recovery furnace, Mg/hr (ton/hr) determined using process data measured during the performance test; and

BLS_{BLO}= The average mass rate of black liquor solids treated in the black liquor oxidation system, Mg/hr (ton/hr) determined using process data measured during the performance test.

(d) The owner or operator seeking to determine compliance with the gaseous organic HAP standards in §63.862(c)(2) for semichemical combustion units must use Method 25A in appendix A of 40 CFR part 60, as well as the methods listed in paragraphs (b)(5)(i) through (iv) of this section. The sampling time for each Method 25A run must be at least 60 minutes. The calibration gas for each Method 25A run must be propane.

(1) The emission rate from any new or existing semichemical combustion unit must be determined using Equation 11 of this section as follows:

$$ER_{SCCU} = \frac{(THC_{meas})}{BLS} \qquad \text{(Eq. 11)}$$

Where:

ER_{SCCU}= THC emission rate reported as carbon from each semichemical combustion unit, kg/Mg (lb/ton) of black liquor solids fired;

THC_{meas}= Measured THC mass emission rate reported as carbon, kg/hr (lb/hr); and

BLS = Average black liquor solids firing rate, Mg/hr (ton/hr); determined using process data measured during the performance test.

(2) If the owner or operator of the semichemical combustion unit has selected the percentage reduction standards for THC, under §63.862(c)(2)(ii), the percentage reduction in THC emissions is computed using Equation 12 of this section as follows, provided that Ei and Eo are measured simultaneously:

$$(\% R_{THC}) = \left(\frac{E_i - E_o}{E_i}\right) \times 100 \qquad (Eq.\ 12)$$

Where:

$\%R_{THC}$= percentage reduction of total hydrocarbons emissions achieved.

E_i= measured THC mass emission rate at the THC control device inlet, kg/hr (lb/hr).

E_o= measured THC mass emission rate at the THC control device outlet, kg/hr (lb/hr).

[66 FR 3193, Jan. 12, 2001, as amended at 66 FR 37593, July 19, 2001; 68 FR 7716, Feb. 18, 2003; 68 FR 67955, Dec. 5, 2003]

§ 63.866 Record eeping re uirements.

(a) *Startup, shutdown, and malfunction plan.* The owner or operator must develop a written plan as described in §63.6(e)(3) that contains specific procedures for operating the source and maintaining the source during periods of startup, shutdown, and malfunction, and a program of corrective action for malfunctioning process and control systems used to comply with the standards. In addition to the information required in §63.6(e), the plan must include the requirements in paragraphs (a)(1) and (2) of this section.

(1) Procedures for responding to any process parameter level that is inconsistent with the level(s) established under §63.864(j), including the procedures in paragraphs (a)(1)(i) and (ii) of this section:

(i) Procedures to determine and record the cause of an operating parameter exceedance and the time the exceedance began and ended; and

(ii) Corrective actions to be taken in the event of an operating parameter exceedance, including procedures for recording the actions taken to correct the exceedance.

(2) The startup, shutdown, and malfunction plan also must include the schedules listed in paragraphs (a)(2)(i) and (ii) of this section:

(i) A maintenance schedule for each control technique that is consistent with, but not limited to, the manufacturer's instructions and recommendations for routine and long-term maintenance; and

(ii) An inspection schedule for each continuous monitoring system required under §63.864 to ensure, at least once in each 24-hour period, that each continuous monitoring system is properly functioning.

(b) The owner or operator of an affected source or process unit must maintain records of any occurrence when corrective action is required under §63.864(k)(1), and when a violation is noted under §63.864(k)(2).

(c) In addition to the general records required by §63.10(b)(2), the owner or operator must maintain records of the information in paragraphs (c)(1) through (7) of this section:

(1) Records of black liquor solids firing rates in units of Mg/d or ton/d for all recovery furnaces and semichemical combustion units;

(2) Records of CaO production rates in units of Mg/d or ton/d for all lime kilns;

(3) Records of parameter monitoring data required under §63.864, including any period when the operating parameter levels were inconsistent with the levels established during the initial performance test, with a brief explanation of the cause of the deviation, the time the deviation occurred, the time corrective action was initiated and completed, and the corrective action taken;

(4) Records and documentation of supporting calculations for compliance determinations made under §§63.865(a) through (d);

(5) Records of monitoring parameter ranges established for each affected source or process unit;

(6) Records certifying that an NDCE recovery furnace equipped with a dry ESP system is used to comply with the gaseous organic HAP standard in §63.862(c)(1).

(7) For the bag leak detection system on the hog fuel dryer fabric filter at Weyerhaeuser Paper Company's Cosmopolis, Washington facility (Emission Unit no. HD–14), records of each alarm, the time of the alarm, the time corrective action was initiated and completed, and a brief description of the cause of the alarm and the corrective action taken.

(d) For operation under §63.863(c)(2), Georgia-Pacific Corporation must keep a record of the hours of operation of the two existing semichemical combustion units at their Big Island, VA facility.

[66 FR 3193, Jan. 12, 2001, as amended at 66 FR 16408, Mar. 26, 2001; 68 FR 7718, Feb. 18, 2003; 69 FR 25323, May 6, 2004; 71 FR 20458, Apr. 20, 2006]

§ 63.867 Reporting re uirements.

(a) *Notifications.* (1) The owner or operator of any affected source or process unit must submit the applicable notifications from subpart A of this part, as specified in Table 1 of this subpart.

(2) Notifications specific to Georgia-Pacific Corporation's affected sources in Big Island, Virginia.

(i) For a compliance extension under §63.863(c)(1), submit a notice that provides the date of Georgia-Pacific's determination that the black liquor gasification system is not successful and the reasons why the technology is not successful. The notice must be submitted within 15 days of Georgia-Pacific's determination, but not later than March 16, 2005.

(ii) For operation under §63.863(c)(2), submit a notice providing: a statement that Georgia-Pacific Corporation intends to run the Kraft black liquor trials, the anticipated period in which the trials will take place, and a statement explaining why the trials could not be conducted prior to March 1, 2005. The notice must be submitted at least 30 days prior to the start of the Kraft liquor trials.

(3) In addition to the requirements in subpart A of this part, the owner or operator of the hog fuel dryer at Weyerhaeuser Paper Company's Cosmopolis, Washington, facility (Emission Unit no. HD–14) must include analysis and supporting documentation demonstrating conformance with EPA guidance and specifications for bag leak detection systems in §63.864(e)(12) in the Notification of Compliance Status.

(b) *Additional reporting requirements for HAP metals standards.* (1) Any owner or operator of a group of process units in a chemical recovery system at a mill complying with the PM emissions limits in §63.862 (a)(1)(ii) must submit the PM emissions limits determined in §63.865(a) for each affected kraft or soda recovery furnace, smelt dissolving tank, and lime kiln to the Administrator for approval. The emissions limits must be submitted as part of the notification of compliance status required under subpart A of this part.

(2) Any owner or operator of a group of process units in a chemical recovery system at a mill complying with the PM emissions limits in §63.862(a)(1)(ii) must submit the calculations and supporting documentation used in §63.865(a)(1) and (2) to the Administrator as part of the notification of compliance status required under subpart A of this part.

(3) After the Administrator has approved the emissions limits for any process unit, the owner or operator of a process unit must notify the Administrator before any of the actions in paragraphs (b)(3)(i) through (iv) of this section are taken:

(i) The air pollution control system for any process unit is modified or replaced;

(ii) Any kraft or soda recovery furnace, smelt dissolving tank, or lime kiln in a chemical recovery system at a kraft or soda pulp mill complying with the PM emissions limits in §63.862(a)(1)(ii) is shut down for more than 60 consecutive days;

(iii) A continuous monitoring parameter or the value or range of values of a continuous monitoring parameter for any process unit is changed; or

(iv) The black liquor solids firing rate for any kraft or soda recovery furnace during any 24-hour averaging period is increased by more than 10 percent above the level measured during the most recent performance test.

(4) An owner or operator of a group of process units in a chemical recovery system at a mill complying with the PM emissions limits in §63.862(a)(1)(ii) and seeking to perform the actions in paragraph (b)(3)(i) or (ii) of this section must recalculate the overall PM emissions limit for the group of process units and resubmit the documentation required in paragraph (b)(2) of this section to the Administrator. All modified PM emissions limits are subject to approval by the Administrator.

(c) *Excess emissions report.* The owner or operator must report quarterly if measured parameters meet any of the conditions specified in paragraph (k)(1) or (2) of §63.864. This report must contain the information specified in §63.10(c) of this part as well as the number and duration of occurrences when the source met or exceeded the conditions in §63.864(k)(1), and the number and duration of occurrences when the source met or exceeded the conditions in §63.864(k)(2). Reporting excess emissions below the violation thresholds of §63.864(k) does not constitute a violation of the applicable standard.

(1) When no exceedances of parameters have occurred, the owner or operator must submit a semiannual report stating that no excess emissions occurred during the reporting period.

(2) The owner or operator of an affected source or process unit subject to the requirements of this subpart and subpart S of this part may combine excess emissions and/or summary reports for the mill.

[66 FR 3193, Jan. 12, 2001 as amended at 66 FR 16408, Mar. 26, 2001; 68 FR 7718, Feb. 18, 2003; 68 FR 42605, July 18, 2003; 68 FR 46108, Aug. 5, 2003; 69 FR 25323, May 6, 2004]

§ 63.868 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 112(d) of the Clean Air Act, the authorities contained in paragraph (b) of this section must be retained by the Administrator and not transferred to a State.

(b) The authorities which will not be delegated to States are listed in paragraphs (b)(1) through (4) of this section:

(1) Approval of alternatives to standards in §63.862 under §63.6(g).

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(3) Approval of major alternatives to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

Table 1 to Subpart MM of Part 63— eneral Provisions Applicability to Subpart MM

eneral provisions reference	Summary of re uirements	Applies to subpart MM	E planation
63.1(a)(1)	General applicability of the General Provisions	Yes	Additional terms defined in §63.861; when overlap between subparts A and MM of this part, subpart MM takes precedence.
63.1(a)(2)–(14)	General applicability of the General Provisions	Yes	
63.1(b)(1)	Initial applicability determination.	No.	Subpart MM specifies the applicability in §63.860.
63.1(b)(2)	Title V operating permit—see 40 CFR part 70	Yes	All major affected sources are required to obtain a title V permit.
63.1(b)(3)	Record of the applicability determination	No	All affected sources are subject to subpart MM according to the applicability definition of subpart MM.
63.1(c)(1)	Applicability of subpart A of this part after a relevant standard has been set	Yes	Subpart MM clarifies the applicability of each paragraph of subpart A of this part to sources subject to subpart MM.
63.1(c)(2)	Title V permit requirement	Yes	All major affected

			sources are required to obtain a title V permit. There are no area sources in the pulp and paper mill source category.
63.1(c)(3)	[Reserved]	NA.	
63.1(c)(4)	Requirements for existing source that obtains an extension of compliance	Yes	
63.1(c)(5)	Notification requirements for an area source that increases HAP emissions to major source levels	Yes	
63.1(d)	[Reserved]	NA	
63.1(e)	Applicability of permit program before a relevant standard has been set	Yes	
63.2	Definitions	Yes	Additional terms defined in §63.861; when overlap between subparts A and MM of this part occurs, subpart MM takes precedence.
63.3	Units and abbreviations	Yes	
63.4	Prohibited activities and circumvention	Yes	
63.5(a)	Construction and reconstruction—applicability	Yes	
63.5(b)(1)	Upon construction, relevant standards for new sources	Yes	
63.5(b)(2)	[Reserved]	NA	
63.5(b)(3)	New construction/reconstruction	Yes	
63.5(b)(4)	Construction/reconstruction notification	Yes	
63.5(b)(5)	Construction/reconstruction compliance	Yes	
63.5(b)(6)	Equipment addition or process change	Yes	
63.5(c)	[Reserved]	NA	
63.5(d)	Application for approval of construction/reconstruction	Yes	
63.5(e)	Construction/reconstruction approval	Yes	

63.5(f)	Construction/reconstruction approval based on prior State preconstruction review	Yes	
63.6(a)(1)	Compliance with standards and maintenance requirements—applicability	Yes	
63.6(a)(2)	Requirements for area source that increases emissions to become major	Yes	
63.6(b)	Compliance dates for new and reconstructed sources	Yes	
63.6(c)	Compliance dates for existing sources	Yes, except for sources granted extensions under 63.863(c)	Subpart MM specifically stipulates the compliance schedule for existing sources.
63.6(d)	[Reserved]	NA	
63.6(e)	Operation and maintenance requirements	Yes	
63.6(f)	Compliance with nonopacity emissions standards	Yes	
63.6(g)	Compliance with alternative nonopacity emissions standards	Yes	
63.6(h)	Compliance with opacity and visible emissions (VE) standards	Yes	Subpart MM does not contain any opacity or VE standards; however, §63.864 specifies opacity monitoring requirements.
63.6(i)	Extension of compliance with emission standards	Yes, except for sources granted extensions under 63.863(c)	
63.6(j)	Exemption from compliance with emissions standards	Yes	
63.7(a)(1)	Performance testing requirements—applicability	Yes	§63.865(c)(1) specifies the only exemption from performance testing allowed under subpart MM.
63.7(a)(2)	Performance test dates	Yes	

63.7(a)(3)	Performance test requests by Administrator under CAA section 114	Yes	
63.7(b)(1)	Notification of performance test	Yes	
63.7(b)(2)	Notification of delay in conducting a scheduled performance test	Yes	
63.7(c)	Quality assurance program	Yes	
63.7(d)	Performance testing facilities	Yes	
63.7(e)	Conduct of performance tests	Yes	
63.7(f)	Use of an alternative test method	Yes	
63.7(g)	Data analysis, recordkeeping, and reporting	Yes	
63.7(h)	Waiver of performance tests	Yes	§63.865(c)(1) specifies the only exemption from performance testing allowed under subpart MM.
63.8(a)	Monitoring requirements—applicability	Yes	See §63.864.
63.8(b)	Conduct of monitoring	Yes	See §63.864.
63.8(c)	Operation and maintenance of CMS	Yes	See §63.864.
63.8(d)	Quality control program	Yes	See §63.864.
63.8(e)(1)	Performance evaluation of CMS	Yes	
63.8(e)(2)	Notification of performance evaluation	Yes	
63.8(e)(3)	Submission of site-specific performance evaluation test plan	Yes	
63.8(e)(4)	Conduct of performance evaluation and performance evaluation dates	Yes	
63.8(e)(5)	Reporting performance evaluation results	Yes	
63.8(f)	Use of an alternative monitoring method	Yes	
63.8(g)	Reduction of monitoring data	Yes	
63.9(a)	Notification requirements—applicability and general information	Yes	
63.9(b)	Initial notifications	Yes	
63.9(c)	Request for extension of	Yes	

	compliance		
63.9(d)	Notification that source subject to special compliance requirements	Yes	
63.9(e)	Notification of performance test	Yes	
63.9(f)	Notification of opacity and VE observations	Yes	Subpart MM does not contain any opacity or VE standards; however, §63.864 specifies opacity monitoring requirements.
63.9(g)(1)	Additional notification requirements for sources with CMS	Yes	
63.9(g)(2)	Notification of compliance with opacity emissions standard	Yes	Subpart MM does not contain any opacity or VE emissions standards; however, §63.864 specifies opacity monitoring requirements.
63.9(g)(3)	Notification that criterion to continue use of alternative to relative accuracy testing has been exceeded	Yes	
63.9(h)	Notification of compliance status	Yes	
63.9(i)	Adjustment to time periods or postmark deadlines for submittal and review of required communications	Yes	
63.9(j)	Change in information already provided	Yes	
63.10(a)	Recordkeeping requirements—applicability and general information	Yes	See §63.866.
63.10(b)(1)	Records retention	Yes	
63.10(b)(2)	Information and documentation to support notifications and demonstrate compliance	Yes	
63.10(b)(3)	Records retention for sources not subject to relevant standard	Yes	Applicability requirements are given in §63.860.

63.10(c)	Additional recordkeeping requirements for sources with CMS.	Yes	
63.10(d)(1)	General reporting requirements	Yes	
63.10(d)(2)	Reporting results of performance tests	Yes	
63.10(d)(3)	Reporting results of opacity or VE observations	Yes	Subpart MM does not include any opacity or VE standards; however, §63.864 specifies opacity monitoring requirements.
63.10(d)(4)	Progress reports	Yes	
63.10(d)(5)	Periodic and immediate startup, shutdown, and malfunction reports	Yes	
63.10(e)	Additional reporting requirements for sources with CMS	Yes	
63.10(f)	Waiver of recordkeeping and reporting requirements	Yes	
63.11	Control device requirements for flares	No	The use of flares to meet the standards in subpart MM is not anticipated.
63.12	State authority and delegations	Yes	
63.13	Addresses of State air pollution control agencies and EPA Regional Offices	Yes	
63.14	Incorporations by reference	Yes	
63.15	Availability of information and confidentiality	Yes	

[66 FR 3193, Jan. 12, 2001, as amended at 66 FR 16408, Mar. 26, 2001]

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APPENDIX I- LINE WASHER ALTERNATIVE MONITORING EXEMPTION

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 6
1445 ROSS AVENUE, SUITE 1200
DALLAS, TX 75202-2733

P.P.

02.00013.

DEC 1 0 2003

Charles E. Hodges
Senior Vice President
Manufacturing Southern Region
Georgia Pacific
Crossett Paper Operations
P.O. Box 3333
Crossett, Arkansas 71635

RECD DEC 15 2003

Dear Mr. Hodges:

This is in response to your letter dated August 18, 2003, regarding a 40 C.F.R. 63 Subpart S request for the use of alternative monitoring and inspection procedures for the closed vent systems subject to § 63.453(k)(2).

40 C.F.R. § 63.453(k) and 40 C.F.R. § 63.453(l) specify that monitoring occur every 30 days or at least once every 30 days. You are requesting approval to have monitoring established on a calendar month, due to the fact that you utilize the same third-party contractor for the 30-day visual inspections at the Crossett Paper and for inspections at the Crossett Chemical plant, and it would be easier to schedule both facilities in the same time frame.

We will allow Georgia Pacific Crossett Paper to conduct monitoring and inspections for the closed vent systems subject to § 63.453(k)(2), based upon the information contained in your letter, once during each calendar month, with at least 21 days elapsed time between inspection.

If you have any questions regarding this determination response, please contact me at (214) 665-7220 or Michelle Kelly, of my staff, at (214) 665-7580.

Sincerely yours,

WK Honker

William K. Honker, P.E.
Chief
Air/Toxic and Inspection
Coordination Branch

cc: Tom Hudson, ADEQ
Tom Rheaume, ADEQ

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 6
1445 ROSS AVENUE, SUITE 1200
DALLAS, TX 75202-2733

JUL 2 4 2001

Mr. Eric Reynolds
Environmental Engineer
Georgia-Pacific Corporation
Ashdown Operations
285 Highway 71 South
Ashdown, AR 71822

Dear Mr. Reynolds:

This is in response to your letter of March 7, 2001, requesting the approval of an alternative monitoring protocol, as required under Section 63.453(m) through (o), pursuant to the Pulp & Paper MACT standard, 40 C.F.R.63, Subpart S. Specifically, Georgia-Pacific Ashdown Operations is seeking approval to replace the required use of the §63.453(c)(2) "gas scrubber vent gas inlet flow rate" continuous monitoring system (CMS) with a system to continuously monitor amperage on the induced draft fans used to convey HAPs to the bleach plant scrubber.

Per 40 CFR 63.453(m), a source or an operator may choose to adopt an alternative monitoring parameter to comply with the standards established in Subpart S, provided that a ontinuous Monitoring System is in place and the source or operator establishes appropriate operating parameters to be monitored in such a way that it will demonstrate continuous compliance with the applicable control requirements to the satisfaction of the Administrator. However, per CFR 63.458(b)(2), the authority for determination and use of an alternative monitoring parameter can not be transferred (delegated) to a State.

Based on the discussion of the alternative monitoring parameter issue in the Environmental Protection Agency's (EPA's) O&A Document for the Pulp & Paper MACT (Volume 1, Page 8-10), Region 6 agrees that adequate rationale for using an alternative parameter (as required in §63.453(n)), has been demonstrated. Therefore, Region 6 concurs with Georgia-Pacific's request to substitute fan motor amperage as an alternative monitoring parameter to §63.453(c)(2), and accordingly approves this specific request.

In order to ensure compliance with Subpart S, we request that you perform the following:

a) conduct annual negative pressure checks to ensure that the bleach plant scrubber fan induces the desired negative pressure across the system;

b) conduct monthly visual inspections under the Leak Detection and Repair plan provisions for the scrubber fan and associated process;

c) conduct periodic preventive maintenance of the bleach plant scrubber fan to ensure safe and proper operation of the system;

d) respond immediately to any signs or indications of visible emissions from the scrubber stack, washer hoods, or towers at the bleach plant;

e) continuously record/monitor the fan motor amperage loading to ensure proper rotational fan speed and pressure drop for the bleach plant scrubber fan; and,

f) perform a successful initial performance test to determine an acceptable range of electrical current (amps) within which the fan needs to be operated.

Furthermore, in case of future replacement of the fan blades or fan motor, you must demonstrate that gas flow to the scrubber has not increased as a result of changes to the fan or conduct another performance test to ensure that the gas scrubber meets the emission limitations of the air permit.

Please be advised that this alternative monitoring determination shall by no means relieve you from complying with the applicable Record keeping and Reporting requirements established in 40 CFR 63.454 and 63.355 of Subpart S.

We also recommend that you share a copy of this alternative monitoring parameter determination letter with the appropriate State or local Title V permitting authority for any pending or future air permitting activities relevant to your mill. Consequently, the permitting authority would be able to craft air permit conditions tailored specifically for your bleach plant operations.

If you have any questions regarding this response, please contact Michelle Kelly, of my staff, at (214) 665-7580.

Sincerely yours,

John R. Hepola

John R. Hepola
Chief
Air/Toxic & Inspection
Coordination Branch

cc: Lyndon Poole, ADEQ
Tom Hudson, ADEQ
Tom Rheaume, ADEQ

APPENDIX J - NESHAP JJJJ

Electronic Code of Federal Regulations
e-CFR ™

e-CFR Data is current as of May 17, 2012

Title 40: Protection of Environment
PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES (CONTINUED)

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Subpart JJJJ—National Emission Standards for Hazardous Air Pollutants: Paper and Other Web Coating

Source: 67 FR 72341, Dec. 4, 2002, unless otherwise noted.

What This Subpart Covers

§ 63.3280 What is in this subpart?

This subpart describes the actions you must take to reduce emissions of organic hazardous air pollutants (HAP) from paper and other web coating operations. This subpart establishes emission standards for web coating lines and specifies what you must do to comply if you own or operate a facility with web coating lines that is a major source of HAP. Certain requirements apply to all who are subject to this subpart; others depend on the means you use to comply with an emission standard.

§ 63.3290 Does this subpart apply to me?

The provisions of this subpart apply to each new and existing facility that is a major source of HAP, as defined in §63.2, at which web coating lines are operated.

§ 63.3300 Which of my emission sources are affected by this subpart?

The affected source subject to this subpart is the collection of all web coating lines at your facility. This includes web coating lines engaged in the coating of metal webs that are used in flexible packaging, and web coating lines engaged in the coating of fabric substrates for use in pressure sensitive tape and abrasive materials. Web coating lines specified in paragraphs (a) through (g) of this section are not part of the affected source of this subpart.

(a) Any web coating line that is stand-alone equipment under subpart KK of this part (National Emission Standards for the Printing and Publishing Industry) which the owner or operator includes in the affected source under subpart KK.

(b) Any web coating line that is a product and packaging rotogravure or wide-web flexographic press under subpart KK of this part (national emission standards for the printing and publishing industry) which is included in the affected source under subpart KK.

(c) Web coating in lithography, screenprinting, letterpress, and narrow-web flexographic printing processes.

(d) Any web coating line subject to subpart EE of this part (national emission standards for magnetic tape manufacturing operations).

(e) Any web coating line that will be subject to the national emission standards for hazardous air pollutants (NESHAP) for surface coating of metal coil currently under development.

(f) Any web coating line that will be subject to the NESHAP for the printing, coating, and dyeing of fabric and other textiles currently under development. This would include any web coating line that coats both a paper or other web substrate and a fabric or other textile substrate, except for a fabric substrate used for pressure sensitive tape and abrasive materials.

(g) Any web coating line that is defined as research or laboratory equipment in §63.3310.

[67 FR 72341, Dec. 4, 2002, as amended at 71 FR 29805, May 24, 2006]

§ 63.3310 What definitions are used in this subpart?

All terms used in this subpart that are not defined in this section have the meaning given to them in the Clean Air Act (CAA) and in subpart A of this part.

Always-controlled work station means a work station associated with a dryer from which the exhaust is delivered to a control device with no provision for the dryer exhaust to bypass the control device unless there is an interlock to interrupt and prevent continued coating during a bypass. Sampling lines for analyzers, relief valves needed for safety purposes, and periodic cycling of exhaust dampers to ensure safe operation are not considered bypass lines.

Applied means, for the purposes of this subpart, the amount of organic HAP, coating material, or coating solids (as appropriate for the emission standards in §63.3320(b)) used by the affected source during the compliance period.

As-applied means the condition of a coating at the time of application to a substrate, including any added solvent.

As-purchased means the condition of a coating as delivered to the user.

Capture efficiency means the fraction of all organic HAP emissions generated by a process that is delivered to a control device, expressed as a percentage.

Capture system means a hood, enclosed room, or other means of collecting organic HAP emissions into a closed-vent system that exhausts to a control device.

Car-seal means a seal that is placed on a device that is used to change the position of a valve or damper (*e.g.,* from open to closed) in such a way that the position of the valve or damper cannot be changed without breaking the seal.

Coating material(s) means all inks, varnishes, adhesives, primers, solvents, reducers, and other coating materials applied to a substrate via a web coating line. Materials used to form a substrate are not considered coating materials.

Control device means a device such as a solvent recovery device or oxidizer which reduces the organic HAP in an exhaust gas by recovery or by destruction.

Control device efficiency means the ratio of organic HAP emissions recovered or destroyed by a control device to the total organic HAP emissions that are introduced into the control device, expressed as a percentage.

Day means a 24-consecutive-hour period.

Deviation means any instance in which an affected source, subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limitation (including any operating limit) or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this

subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation (including any operating limit) or work practice standard in this subpart during start-up, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Existing affected source means any affected source the construction or reconstruction of which is commenced on or before September 13, 2000, and has not undergone reconstruction as defined in §63.2.

Fabric means any woven, knitted, plaited, braided, felted, or non-woven material made of filaments, fibers, or yarns including thread. This term includes material made of fiberglass, natural fibers, synthetic fibers, or composite materials.

Facility means all contiguous or adjoining property that is under common ownership or control, including properties that are separated only by a road or other public right-of-way.

Flexible packaging means any package or part of a package the shape of which can be readily changed. Flexible packaging includes, but is not limited to, bags, pouches, labels, liners and wraps utilizing paper, plastic, film, aluminum foil, metalized or coated paper or film, or any combination of these materials.

Formulation data means data on the organic HAP mass fraction, volatile matter mass fraction, or coating solids mass fraction of a material that is generated by the manufacturer or means other than a test method specified in this subpart or an approved alternative method.

HAP means hazardous air pollutants.

HAP applied means the organic HAP content of all coating materials applied to a substrate by a web coating line at an affected source.

Intermittently-controlled work station means a work station associated with a dryer with provisions for the dryer exhaust to be delivered to or diverted from a control device through a bypass line, depending on the position of a valve or damper. Sampling lines for analyzers, relief valves needed for safety purposes, and periodic cycling of exhaust dampers to ensure safe operation are not considered bypass lines.

Metal coil means a continuous metal strip that is at least 0.15 millimeter (0.006 inch) thick which is packaged in a roll or coil prior to coating. After coating, it may or may not be rewound into a roll or coil. Metal coil does not include metal webs that are coated for use in flexible packaging.

Month means a calendar month or a pre-specified period of 28 days to 35 days to allow for flexibility in recordkeeping when data are based on a business accounting period.

Never-controlled work station means a work station that is not equipped with provisions by which any emissions, including those in the exhaust from any associated dryer, may be delivered to a control device.

New affected source means any affected source the construction or reconstruction of which is commenced after September 13, 2000.

Overall organic HAP control efficiency means the total efficiency of a capture and control system.

Pressure sensitive tape means a flexible backing material with a pressure-sensitive adhesive coating on one or both sides of the backing. Examples include, but are not limited to, duct/duct insulation tape and medical tape.

Research or laboratory equipment means any equipment for which the primary purpose is to conduct research and development into new processes and products where such equipment is operated under the close supervision of technically trained personnel and is not engaged in the manufacture of products for commercial sale in commerce except in a *de minimis* manner.

Rewind or cutting station means a unit from which substrate is collected at the outlet of a web coating line.

Uncontrolled coating line means a coating line consisting of only never-controlled work stations.

Unwind or feed station means a unit from which substrate is fed to a web coating line.

Web means a continuous substrate (*e.g.,* paper, film, foil) which is flexible enough to be wound or unwound as rolls.

Web coating line means any number of work stations, of which one or more applies a continuous layer of coating material across the entire width or any portion of the width of a web substrate, and any associated curing/drying equipment between an unwind or feed station and a rewind or cutting station.

Work station means a unit on a web coating line where coating material is deposited onto a web substrate.

Emission Standards and Compliance Dates

§ 63.3320 What emission standards must I meet?

(a) If you own or operate any affected source that is subject to the requirements of this subpart, you must comply with these requirements on and after the compliance dates as specified in §63.3330.

(b) You must limit organic HAP emissions to the level specified in paragraph (b)(1), (2), (3), or (4) of this section.

(1) No more than 5 percent of the organic HAP applied for each month (95 percent reduction) at existing affected sources, and no more than 2 percent of the organic HAP applied for each month (98 percent reduction) at new affected sources; or

(2) No more than 4 percent of the mass of coating materials applied for each month at existing affected sources, and no more than 1.6 percent of the mass of coating materials applied for each month at new affected sources; or

(3) No more than 20 percent of the mass of coating solids applied for each month at existing affected sources, and no more than 8 percent of the coating solids applied for each month at new affected sources.

(4) If you use an oxidizer to control organic HAP emissions, operate the oxidizer such that an outlet organic HAP concentration of no greater than 20 parts per million by volume (ppmv) by compound on a dry basis is achieved and the efficiency of the capture system is 100 percent.

(c) You must demonstrate compliance with this subpart by following the procedures in §63.3370.

§ 63.3321 What operating limits must I meet?

(a) For any web coating line or group of web coating lines for which you use add-on control devices, unless you use a solvent recovery system and conduct a liquid-liquid material balance, you must meet the operating limits specified in Table 1 to this subpart or according to paragraph (b) of this section. These operating limits apply to emission capture systems and control devices, and you must establish the operating limits during the performance test according to the requirements in §63.3360(e)(3). You must meet the operating limits at all times after you establish them.

(b) If you use an add-on control device other than those listed in Table 1 to this subpart or wish to monitor an alternative parameter and comply with a different operating limit, you must apply to the Administrator for approval of alternative monitoring under §63.8(f).

§ 63.3330 When must I comply?

(a) If you own or operate an existing affected source subject to the provisions of this subpart, you must comply by the compliance date. The compliance date for existing affected sources in this subpart is December 5, 2005. You must complete any performance test required in §63.3360 within the time limits specified in §63.7(a)(2).

(b) If you own or operate a new affected source subject to the provisions of this subpart, your compliance date is immediately upon start-up of the new affected source or by December 4, 2002, whichever is later. You must complete any performance test required in §63.3360 within the time limits specified in §63.7(a)(2).

(c) If you own or operate a reconstructed affected source subject to the provisions of this subpart, your compliance date is immediately upon startup of the affected source or by December 4, 2002, whichever is later. Existing affected sources which have undergone reconstruction as defined in §63.2 are subject to the requirements for new affected sources. The costs associated with the purchase and installation of air pollution control equipment are not considered in determining whether the existing affected source has been reconstructed. Additionally, the costs of retrofitting and replacing of equipment that is installed specifically to comply with this subpart are not considered reconstruction costs. You must complete any performance test required in §63.3360 within the time limits specified in §63.7(a)(2).

General Requirements for Compliance With the Emission Standards and for Monitoring and Performance Tests

§ 63.3340 What general requirements must I meet to comply with the standards?

Table 2 to this subpart specifies the provisions of subpart A of this part that apply if you are subject to this subpart, such as startup, shutdown, and malfunction plans (SSMP) in §63.6(e)(3) for affected sources using a control device to comply with the emission standards.

§ 63.3350 If I use a control device to comply with the emission standards, what monitoring must I do?

(a) A summary of monitoring you must do follows:

If you operate a web coating line, and have the following:	Then you must:
(1) Intermittently-controlled work stations	Record parameters related to possible exhaust flow bypass of control device and to coating use (§63.3350(c)).
(2) Solvent recovery unit	Operate continuous emission monitoring system and perform quarterly audits or determine volatile matter recovered and conduct a liquid-liquid material balance (§63.3350(d)).
(3) Control Device	Operate continuous parameter monitoring system (§63.3350(e)).
(4) Capture system	Monitor capture system operating parameter (§63.3350(f)).

(b) Following the date on which the initial performance test of a control device is completed to demonstrate continuing compliance with the standards, you must monitor and inspect each capture system and each control device used to comply with §63.3320. You must install and operate the monitoring equipment as specified in paragraphs (c) and (f) of this section.

(c) *Bypass and coating use monitoring.* If you own or operate web coating lines with intermittently-controlled work stations, you must monitor bypasses of the control device and the mass of each coating material applied at the work station during any such bypass. If using a control device for complying with the requirements of this subpart, you must demonstrate that any coating material applied on a never-controlled work station or an intermittently-controlled work station operated in bypass mode is allowed in your compliance demonstration according to §63.3370(n) and (o). The bypass monitoring must be conducted using at least one of the procedures in paragraphs (c)(1) through (4) of this section for each work station and associated dryer.

(1) *Flow control position indicator.* Install, calibrate, maintain, and operate according to the

manufacturer's specifications a flow control position indicator that provides a record indicating whether the exhaust stream from the dryer was directed to the control device or was diverted from the control device. The time and flow control position must be recorded at least once per hour as well as every time the flow direction is changed. A flow control position indicator must be installed at the entrance to any bypass line that could divert the exhaust stream away from the control device to the atmosphere.

(2) *Car-seal or lock-and-key valve closures.* Secure any bypass line valve in the closed position with a car-seal or a lock-and-key type configuration. A visual inspection of the seal or closure mechanism must be performed at least once every month to ensure that the valve or damper is maintained in the closed position, and the exhaust stream is not diverted through the bypass line.

(3) *alve closure continuous monitoring.* Ensure that any bypass line valve or damper is in the closed position through continuous monitoring of valve position when the emission source is in operation and is using a control device for compliance with the requirements of this subpart. The monitoring system must be inspected at least once every month to verify that the monitor will indicate valve position.

(4) *Automatic shutdown system.* Use an automatic shutdown system in which the web coating line is stopped when flow is diverted away from the control device to any bypass line when the control device is in operation. The automatic system must be inspected at least once every month to verify that it will detect diversions of flow and would shut down operations in the event of such a diversion.

(d) *olvent recovery unit.* If you own or operate a solvent recovery unit to comply with §63.3320, you must meet the requirements in either paragraph (d)(1) or (2) of this section depending on how control efficiency is determined.

(1) *Continuous emission monitoring system (CEM).* If you are demonstrating compliance with the emission standards in §63.3320 through continuous emission monitoring of a control device, you must install, calibrate, operate, and maintain the CEMS according to paragraphs (d)(1)(i) through (iii) of this section.

(i) Measure the total organic volatile matter mass flow rate at both the control device inlet and the outlet such that the reduction efficiency can be determined. Each continuous emission monitor must comply with performance specification 6, 8, or 9 of 40 CFR part 60, appendix B, as appropriate.

(ii) You must follow the quality assurance procedures in procedure 1, appendix F of 40 CFR part 60. In conducting the quarterly audits of the monitors as required by procedure 1, appendix F, you must use compounds representative of the gaseous emission stream being controlled.

(iii) You must have valid data from at least 90 percent of the hours during which the process is operated.

(2) *iquid-liquid material balance.* If you are demonstrating compliance with the emission standards in §63.3320 through liquid-liquid material balance, you must install, calibrate, maintain, and operate according to the manufacturer's specifications a device that indicates the cumulative amount of volatile matter recovered by the solvent recovery device on a monthly basis. The device must be certified by the manufacturer to be accurate to within ±2.0 percent by mass.

(e) *Continuous parameter monitoring system (CPM).* If you are using a control device to comply with the emission standards in §63.3320, you must install, operate, and maintain each CPMS specified in paragraphs (e)(9) and (10) and (f) of this section according to the requirements in paragraphs (e)(1) through (8) of this section. You must install, operate, and maintain each CPMS specified in paragraph (c) of this section according to paragraphs (e)(5) through (7) of this section.

(1) Each CPMS must complete a minimum of one cycle of operation for each successive 15-minute period. You must have a minimum of four equally spaced successive cycles of CPMS operation to have a valid hour of data.

(2) You must have valid data from at least 90 percent of the hours during which the process operated.

(3) You must determine the hourly average of all recorded readings according to paragraphs (e)(3)(i) and (ii) of this section.

(i) To calculate a valid hourly value, you must have at least three of four equally spaced data values from that hour from a continuous monitoring system (CMS) that is not out-of-control.

(ii) Provided all of the readings recorded in accordance with paragraph (e)(3) of this section clearly demonstrate continuous compliance with the standard that applies to you, then you are not required to determine the hourly average of all recorded readings.

(4) You must determine the rolling 3-hour average of all recorded readings for each operating period. To calculate the average for each 3-hour averaging period, you must have at least two of three of the hourly averages for that period using only average values that are based on valid data (*i.e.,* not from out-of-control periods).

(5) You must record the results of each inspection, calibration, and validation check of the CPMS.

(6) At all times, you must maintain the monitoring system in proper working order including, but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.

(7) Except for monitoring malfunctions, associated repairs, or required quality assurance or control activities (including calibration checks or required zero and span adjustments), you must conduct all monitoring at all times that the unit is operating. Data recorded during monitoring malfunctions, associated repairs, out-of-control periods, or required quality assurance or control activities shall not be used for purposes of calculating the emissions concentrations and percent reductions specified in §63.3370. You must use all the valid data collected during all other periods in assessing compliance of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(8) Any averaging period for which you do not have valid monitoring data and such data are required constitutes a deviation, and you must notify the Administrator in accordance with §63.3400(c).

(9) *Oxidi er.* If you are using an oxidizer to comply with the emission standards, you must comply with paragraphs (e)(9)(i) through (iii) of this section.

(i) Install, calibrate, maintain, and operate temperature monitoring equipment according to the manufacturer's specifications. The calibration of the chart recorder, data logger, or temperature indicator must be verified every 3 months or the chart recorder, data logger, or temperature indicator must be replaced. You must replace the equipment whether you choose not to perform the calibration or the equipment cannot be calibrated properly.

(ii) For an oxidizer other than a catalytic oxidizer, install, calibrate, operate, and maintain a temperature monitoring device equipped with a continuous recorder. The device must have an accuracy of ±1 percent of the temperature being monitored in degrees Celsius, or ±1 °Celsius, whichever is greater. The thermocouple or temperature sensor must be installed in the combustion chamber at a location in the combustion zone.

(iii) For a catalytic oxidizer, install, calibrate, operate, and maintain a temperature monitoring device equipped with a continuous recorder. The device must be capable of monitoring temperature with an accuracy of ±1 percent of the temperature being monitored in degrees Celsius or ±1 degree Celsius, whichever is greater. The thermocouple or temperature sensor must be installed in the vent stream at the nearest feasible point to the inlet and outlet of the catalyst bed. Calculate the temperature rise across the catalyst.

(10) *Other types of control devices.* If you use a control device other than an oxidizer or wish to monitor an alternative parameter and comply with a different operating limit, you must apply to the Administrator for approval of an alternative monitoring method under §63.8(f).

(f) *Capture system monitoring.* If you are complying with the emission standards in §63.3320 through the use of a capture system and control device for one or more web coating lines, you must develop a site-specific monitoring plan containing the information specified in paragraphs (f)(1) and (2) of this section for these capture systems. You must monitor the capture system in accordance with paragraph (f)(3) of this section. You must make the monitoring plan available for inspection by the permitting authority upon request.

(1) The monitoring plan must:

(i) Identify the operating parameter to be monitored to ensure that the capture efficiency determined during the initial compliance test is maintained; and

(ii) Explain why this parameter is appropriate for demonstrating ongoing compliance; and

(iii) Identify the specific monitoring procedures.

(2) The monitoring plan must specify the operating parameter value or range of values that demonstrate compliance with the emission standards in §63.3320. The specified operating parameter value or range of values must represent the conditions present when the capture system is being properly operated and maintained.

(3) You must conduct all capture system monitoring in accordance with the plan.

(4) Any deviation from the operating parameter value or range of values which are monitored according to the plan will be considered a deviation from the operating limit.

(5) You must review and update the capture system monitoring plan at least annually.

§ 63.3360 What performance tests must I conduct?

(a) The performance test methods you must conduct are as follows:

If you control organic HAP on any individual web coating line or any group of web coating lines by:	ou must:
(1) Limiting organic HAP or volatile matter content of coatings	Determine the organic HAP or volatile matter and coating solids content of coating materials according to procedures in §63.3360(c) and (d). If applicable, determine the mass of volatile matter retained in the coated web or otherwise not emitted to the atmosphere according to §63.3360(g).
(2) Using a capture and control system	Conduct a performance test for each capture and control system to determine: the destruction or removal efficiency of each control device other than solvent recovery according to §63.3360(e), and the capture efficiency of each capture system according to §63.3360(f). If applicable, determine the mass of volatile matter retained in the coated web or otherwise not emitted to the atmosphere according to §63.3360 (g).

(b) If you are using a control device to comply with the emission standards in §63.3320, you are not required to conduct a performance test to demonstrate compliance if one or more of the criteria in paragraphs (b)(1) through (3) of this section are met.

(1) The control device is equipped with continuous emission monitors for determining inlet and outlet total organic volatile matter concentration and capture efficiency has been determined in accordance with the requirements of this subpart such that an overall organic HAP control efficiency can be calculated, and the continuous emission monitors are used to demonstrate continuous compliance in accordance with §63.3350; or

(2) You have met the requirements of §63.7(h) (for waiver of performance testing; or

(3) The control device is a solvent recovery system and you comply by means of a monthly liquid-liquid material balance.

(c) *Organic HAP content.* If you determine compliance with the emission standards in §63.3320 by means other than determining the overall organic HAP control efficiency of a control device, you must determine the organic HAP mass fraction of each coating material "as-purchased" by following one of the procedures in paragraphs (c)(1) through (3) of this section, and determine the organic HAP mass fraction of each coating material "as-applied" by following the procedures in paragraph (c)(4) of this section. If the organic HAP content values are not determined using the procedures in paragraphs (c)(1) through (3) of this section, the owner or operator must submit an alternative test method for determining their values for approval by the Administrator in accordance with §63.7(f). The recovery efficiency of the test method must be determined for all of the target organic HAP and a correction factor, if necessary, must be determined and applied.

(1) *Method* . You may test the coating material in accordance with Method 311 of appendix A of this part. The Method 311 determination may be performed by the manufacturer of the coating material and the results provided to the owner or operator. The organic HAP content must be calculated according to the criteria and procedures in paragraphs (c)(1)(i) through (iii) of this section.

(i) Include each organic HAP determined to be present at greater than or equal to 0.1 mass percent for Occupational Safety and Health Administration (OSHA)-defined carcinogens as specified in 29 CFR 1910.1200(d)(4) and greater than or equal to 1.0 mass percent for other organic HAP compounds.

(ii) Express the mass fraction of each organic HAP you include according to paragraph (c)(1)(i) of this section as a value truncated to four places after the decimal point (for example, 0.3791).

(iii) Calculate the total mass fraction of organic HAP in the tested material by summing the counted individual organic HAP mass fractions and truncating the result to three places after the decimal point (for example, 0.763).

(2) *Method* . For coatings, determine the volatile organic content as mass fraction of nonaqueous volatile matter and use it as a substitute for organic HAP using Method 24 of 40 CFR part 60, appendix A. The Method 24 determination may be performed by the manufacturer of the coating and the results provided to you.

(3) *Formulation data.* You may use formulation data to determine the organic HAP mass fraction of a coating material. Formulation data may be provided to the owner or operator by the manufacturer of the material. In the event of an inconsistency between Method 311 (appendix A of 40 CFR part 63) test data and a facility's formulation data, and the Method 311 test value is higher, the Method 311 data will govern. Formulation data may be used provided that the information represents all organic HAP present at a level equal to or greater than 0.1 percent for OSHA-defined carcinogens as specified in 29 CFR 1910.1200(d)(4) and equal to or greater than 1.0 percent for other organic HAP compounds in any raw material used.

(4) *As-applied organic HAP mass fraction.* If the as-purchased coating material is applied to the web without any solvent or other material added, then the as-applied organic HAP mass fraction is equal to the as-purchased organic HAP mass fraction. Otherwise, the as-applied organic HAP mass fraction must be calculated using Equation 1a of §63.3370.

(d) *olatile organic and coating solids content.* If you determine compliance with the emission standards in §63.3320 by means other than determining the overall organic HAP control efficiency of a control device and you choose to use the volatile organic content as a surrogate for the organic HAP content of coatings, you must determine the as-purchased volatile organic content and coating solids content of each coating material applied by following the procedures in paragraph (d)(1) or (2) of this section, and the as-applied volatile organic content and coating solids content of each coating material by following the procedures in paragraph (d)(3) of this section.

(1) *Method* . You may determine the volatile organic and coating solids mass fraction of each coating applied using Method 24 (40 CFR part 60, appendix A.) The Method 24 determination may be performed by the manufacturer of the material and the results provided to you. If these values cannot be determined using Method 24, you must submit an alternative technique for determining their values for approval by the Administrator.

(2) *Formulation data.* You may determine the volatile organic content and coating solids content of a coating material based on formulation data and may rely on volatile organic content data provided by the manufacturer of the material. In the event of any inconsistency between the formulation data and the results of Method 24 of 40 CFR part 60, appendix A, and the Method 24 results are higher, the results of Method 24 will govern.

(3) *As-applied volatile organic content and coating solids content.* If the as-purchased coating material is applied to the web without any solvent or other material added, then the as-applied volatile organic content is equal to the as-purchased volatile content and the as-applied coating solids content is equal to the as-purchased coating solids content. Otherwise, the as-applied volatile organic content must be calculated using Equation 1b of §63.3370 and the as-applied coating solids content must be calculated using Equation 2 of §63.3370.

(e) *Control device efficiency.* If you are using an add-on control device other than solvent recovery, such as an oxidizer, to comply with the emission standards in §63.3320, you must conduct a performance test to establish the destruction or removal efficiency of the control device according to the methods and procedures in paragraphs (e)(1) and (2) of this section. During the performance test, you must establish the operating limits required by §63.3321 according to paragraph (e)(3) of this section.

(1) An initial performance test to establish the destruction or removal efficiency of the control device must be conducted such that control device inlet and outlet testing is conducted simultaneously, and the data are reduced in accordance with the test methods and procedures in paragraphs (e)(1)(i) through (ix) of this section. You must conduct three test runs as specified in §63.7(e)(3), and each test run must last at least 1 hour.

(i) Method 1 or 1A of 40 CFR part 60, appendix A, must be used for sample and velocity traverses to determine sampling locations.

(ii) Method 2, 2A, 2C, 2D, 2F, or 2G of 40 CFR part 60, appendix A, must be used to determine gas volumetric flow rate.

(iii) Method 3, 3A, or 3B of 40 CFR part 60, appendix A, must be used for gas analysis to determine dry molecular weight. You may also use as an alternative to Method 3B the manual method for measuring the oxygen, carbon dioxide, and carbon monoxide content of exhaust gas in ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus]," (incorporated by reference, see §63.14).

(iv) Method 4 of 40 CFR part 60, appendix A, must be used to determine stack gas moisture.

(v) The gas volumetric flow rate, dry molecular weight, and stack gas moisture must be determined during each test run specified in paragraph (f)(1)(vii) of this section.

(vi) Method 25 or 25A of 40 CFR part 60, appendix A, must be used to determine total gaseous non-methane organic matter concentration. Use the same test method for both the inlet and outlet measurements which must be conducted simultaneously. You must submit notice of the intended test method to the Administrator for approval along with notification of the performance test required under §63.7(b). You must use Method 25A if any of the conditions described in paragraphs (e)(1)(vi)(A) through (D) of this section apply to the control device.

(A) The control device is not an oxidizer.

(B) The control device is an oxidizer but an exhaust gas volatile organic matter concentration of 50 ppmv or less is required to comply with the emission standards in §63.3320; or

(C) The control device is an oxidizer but the volatile organic matter concentration at the inlet to the control system and the required level of control are such that they result in exhaust gas volatile organic matter concentrations of 50 ppmv or less; or

(D) The control device is an oxidizer but because of the high efficiency of the control device the anticipated volatile organic matter concentration at the control device exhaust is 50 ppmv or less, regardless of inlet concentration.

(vii) Except as provided in §63.7(e)(3), each performance test must consist of three separate runs with each run conducted for at least 1 hour under the conditions that exist when the affected source is operating under normal operating conditions. For the purpose of determining volatile organic compound concentrations and mass flow rates, the average of the results of all the runs will apply.

(viii) Volatile organic matter mass flow rates must be determined for each run specified in paragraph (e)(1)(vii) of this section using Equation 1 of this section:

$$M_f = Q_{sd} C_c [12][0.0416][10^{-6}] \quad \text{Eq. 1}$$

Where:

M_f= Total organic volatile matter mass flow rate, kilograms (kg)/hour (h).

Q_{sd}= Volumetric flow rate of gases entering or exiting the control device, as determined according to §63.3360(e)(1)(ii), dry standard cubic meters (dscm)/h.

C_c= Concentration of organic compounds as carbon, ppmv.

12.0 = Molecular weight of carbon.

0.0416 = Conversion factor for molar volume, kg-moles per cubic meter (mol/m^3) (@ 293 Kelvin (K) and 760 millimeters of mercury (mmHg)).

(ix) For each run, emission control device destruction or removal efficiency must be determined using Equation 2 of this section:

$$E = \frac{M_{fi} - M_{fo}}{M_{fi}} \times 100 \quad \text{Eq. 2}$$

Where:

E = Organic volatile matter control efficiency of the control device, percent.

M_{fi}= Organic volatile matter mass flow rate at the inlet to the control device, kg/h.

M_{fo}= Organic volatile matter mass flow rate at the outlet of the control device, kg/h.

(x) The control device destruction or removal efficiency is determined as the average of the efficiencies determined in the test runs and calculated in Equation 2 of this section.

(2) You must record such process information as may be necessary to determine the conditions in existence at the time of the performance test. Operations during periods of startup, shutdown, and malfunction will not constitute representative conditions for the purpose of a performance test.

(3) *Operating limits.* If you are using one or more add-on control device other than a solvent recovery system for which you conduct a liquid-liquid material balance to comply with the emission standards in §63.3320, you must establish the applicable operating limits required by §63.3321. These operating limits apply to each add-on emission control device, and you must establish the operating limits during the performance test required by paragraph (e) of this section according to the requirements in paragraphs (e)(3)(i) and (ii) of this section.

(i) *hermal oxidi er.* If your add-on control device is a thermal oxidizer, establish the operating limits according to paragraphs (e)(3)(i)(A) and (B) of this section.

(A) During the performance test, you must monitor and record the combustion temperature at least once every 15 minutes during each of the three test runs. You must monitor the temperature in the firebox of the thermal oxidizer or immediately downstream of the firebox before any substantial heat exchange occurs.

(B) Use the data collected during the performance test to calculate and record the average combustion temperature maintained during the performance test. This average combustion temperature is the minimum operating limit for your thermal oxidizer.

(ii) *Catalytic oxidi er.* If your add-on control device is a catalytic oxidizer, establish the operating limits according to paragraphs (e)(3)(ii)(A) and (B) or paragraphs (e)(3)(ii)(C) and (D) of this section.

(A) During the performance test, you must monitor and record the temperature just before the catalyst bed and the temperature difference across the catalyst bed at least once every 15 minutes during each of the three test runs.

(B) Use the data collected during the performance test to calculate and record the average temperature just before the catalyst bed and the average temperature difference across the catalyst bed maintained during the performance test. These are the minimum operating limits for your catalytic oxidizer.

(C) As an alternative to monitoring the temperature difference across the catalyst bed, you may monitor the temperature at the inlet to the catalyst bed and implement a site-specific inspection and maintenance plan for your catalytic oxidizer as specified in paragraph (e)(3)(ii)(D) of this section. During the performance test, you must monitor and record the temperature just before the catalyst bed at least once every 15 minutes during each of the three test runs. Use the data collected during the performance test to calculate and record the average temperature just before the catalyst bed during the performance test. This is the minimum operating limit for your catalytic oxidizer.

(D) You must develop and implement an inspection and maintenance plan for your catalytic oxidizer(s) for which you elect to monitor according to paragraph (e)(3)(ii)(C) of this section. The plan must address, at a minimum, the elements specified in paragraphs (e)(3)(ii)(D)( ) through ( ) of this section.

( ) Annual sampling and analysis of the catalyst activity (*i.e.,* conversion efficiency) following the manufacturer's or catalyst supplier's recommended procedures,

( ) Monthly inspection of the oxidizer system including the burner assembly and fuel supply lines for problems, and

( ) Annual internal and monthly external visual inspection of the catalyst bed to check for channeling, abrasion, and settling. If problems are found, you must take corrective action consistent with the manufacturer's recommendations and conduct a new performance test to determine destruction efficiency in accordance with this section.

(f) *Capture efficiency.* If you demonstrate compliance by meeting the requirements of §63.3370(e), (f), (g), (h), (i)(2), (k), (n)(2) or (3), or (p), you must determine capture efficiency using the procedures in paragraph (f)(1), (2), or (3) of this section, as applicable.

(1) You may assume your capture efficiency equals 100 percent if your capture system is a permanent total enclosure (PTE). You must confirm that your capture system is a PTE by demonstrating that it meets the requirements of section 6 of EPA Method 204 of 40 CFR part 51, appendix M, and that all exhaust gases from the enclosure are delivered to a control device.

(2) You may determine capture efficiency according to the protocols for testing with temporary total enclosures that are specified in Methods 204 and 204A through F of 40 CFR part 51, appendix M. You may exclude never-controlled work stations from such capture efficiency determinations.

(3) You may use any capture efficiency protocol and test methods that satisfy the criteria of either the Data Quality Objective or the Lower Confidence Limit approach as described in appendix A of subpart KK of this part. You may exclude never-controlled work stations from such capture efficiency determinations.

(g) *olatile matter retained in the coated web or otherwise not emitted to the atmosphere.* You may choose to take into account the mass of volatile matter retained in the coated web after curing or drying or otherwise not emitted to the atmosphere when determining compliance with the emission standards in §63.3320. If you choose this option, you must develop a testing protocol to determine the mass of volatile matter retained in the coated web or otherwise not emitted to the atmosphere and submit this protocol to the Administrator for approval. You must submit this protocol with your site-specific test plan under §63.7(f). If you intend to take into account the mass of volatile matter retained in the coated web after curing or drying or otherwise not emitted to the atmosphere and demonstrate compliance according to §63.3370(c)(3), (c)(4), (c)(5), or (d), then the test protocol you submit must determine the mass of organic HAP retained in the coated web or otherwise not emitted to the atmosphere. Otherwise, compliance must be shown using the volatile organic matter content as a surrogate for the HAP content of the coatings.

(h) *Control devices in series.* If you use multiple control devices in series to comply with the emission standards in §63.3320, the performance test must include, at a minimum, the inlet to the first control device in the series, the outlet of the last control device in the series, and all intermediate streams (*e.g.,* gaseous exhaust to the atmosphere or a liquid stream from a recovery device) that are not subsequently treated by any of the control devices in the series.

Requirements for Showing Compliance

§ 63.3370 How do I demonstrate compliance with the emission standards?

(a) A summary of how you must demonstrate compliance follows:

If you choose to demonstrate compliance by:	Then you must demonstrate that:	To accomplish this:
(1) Use of "as-purchased" compliant coating materials	(i) Each coating material used at an existing affected source does not exceed 0.04 kg organic HAP per kg coating material, and each coating material used at a new affected source does not exceed 0.016 kg organic HAP per kg coating material as-purchased; or	Follow the procedures set out in §63.3370(b).
	(ii) Each coating material used at an existing affected source does not exceed 0.2 kg organic HAP per kg coating solids, and each coating material used at a new affected source does not exceed 0.08 kg organic HAP per kg coating solids as-purchased	Follow the procedures set out in §63.3370(b).
(2) Use of "as-applied" compliant coating materials	(i) Each coating material used at an existing affected source does not exceed 0.04 kg organic HAP per kg coating material, and each coating material used at a new affected source does not exceed 0.016 kg organic HAP per kg coating material as-applied; or	Follow the procedures set out in §63.3370(c)(1). Use either Equation 1a or b of §63.3370 to determine compliance with §63.3320(b)(2) in accordance with §63.3370(c)(5)(i).
	(ii) Each coating material used at an existing affected source does not exceed 0.2 kg organic HAP per kg coating solids, and each coating material used at a	Follow the procedures set out in §63.3370(c)(2). Use Equations 2 and 3 of §63.3370 to determine compliance with §63.3320(b)(3) in accordance with

	new affected source does not exceed 0.08 kg organic HAP per kg coating solids as-applied; or	§63.3370(c)(5)(i).
	(iii) Monthly average of all coating materials used at an existing affected source does not exceed 0.04 kg organic HAP per kg coating material, and monthly average of all coating materials used at a new affected source does not exceed 0.016 kg organic HAP per kg coating material as-applied on a monthly average basis; or	Follow the procedures set out in §63.3370(c)(3). Use Equation 4 of §63.3370 to determine compliance with §63.3320(b)(2) in accordance with §63.3370(c)(5)(ii).
	(iv) Monthly average of all coating materials used at an existing affected source does not exceed 0.2 kg organic HAP per kg coating solids, and monthly average of all coating materials used at a new affected source does not exceed 0.08 kg organic HAP per kg coating solids as-applied on a monthly average basis	Follow the procedures set out in §63.3370(c)(4). Use Equation 5 of §63.3370 to determine compliance with §63.3320(b)(3) in accordance with §63.3370(c)(5)(ii).
(3) Tracking total monthly organic HAP applied	Total monthly organic HAP applied does not exceed the calculated limit based on emission limitations	Follow the procedures set out in §63.3370(d). Show that total monthly HAP applied (Equation 6 of §63.3370) is less than the calculated equivalent allowable organic HAP (Equation 13a or b of §63.3370).
(4) Use of a capture system and control device	(i) Overall organic HAP control efficiency is equal to 95 percent at an existing affected source and 98 percent at a new affected source on a monthly basis; or oxidizer outlet organic HAP concentration is no greater than 20 ppmv by compound and capture efficiency is 100 percent; or operating parameters are continuously monitored; or	Follow the procedures set out in §63.3370(e) to determine compliance with §63.3320(b)(1) according to §63.3370(i) if using a solvent recovery device, or §63.3370(j) if using a control device and CPMS, or §63.3370(k) if using an oxidizer.
	(ii) Overall organic HAP	Follow the procedures set out

	emission rate does not exceed 0.2 kg organic HAP per kg coating solids for an existing affected source or 0.08 kg organic HAP per kg coating solids for a new affected source on a monthly average as-applied basis;	in §63.3370(f) to determine compliance with §63.3320(b)(3) according to §63.3370(i) if using a solvent recovery device, or §63.3370(k) if using an oxidizer.
	(iii) Overall organic HAP emission rate does not exceed 0.04 kg organic HAP per kg coating material for an existing affected source or 0.016 kg organic HAP per kg coating material for a new affected source on a monthly average as-applied basis; or	Follow the procedures set out in §63.3370(g) to determine compliance with §63.3320(b)(2) according to §63.3370(i) if using a solvent recovery device, or §63.3370(k) if using an oxidizer.
	(iv) Overall organic HAP emission rate does not exceed the calculated limit based on emission limitations	Follow the procedures set out in §63.3370(h). Show that the monthly organic HAP emission rate is less than the calculated equivalent allowable organic HAP emission rate (Equation 13a or b of §63.3370). Calculate the monthly organic HAP emission rate according to §63.3370(i) if using a solvent recovery device, or §63.3370(k) if using an oxidizer.
(5) Use of multiple capture and/or control devices	(i) Overall organic HAP control efficiency is equal to 95 percent at an existing affected source and 98 percent at a new affected source on a monthly basis; or	Follow the procedures set out in §63.3370(e) to determine compliance with §63.3320(b)(1) according to §63.3370(e)(1) or (2).
	(ii) Average equivalent organic HAP emission rate does not exceed 0.2 kg organic HAP per kg coating solids for an existing affected source or 0.08 kg organic HAP per kg coating solids for a new affected source on a monthly average as-applied basis; or	Follow the procedures set out in §63.3370(f) to determine compliance with §63.3320(b)(3) according to §63.3370(n).
	(iii) Average equivalent organic HAP emission rate does not exceed 0.04 kg organic HAP per kg coating	Follow the procedures set out in §63.3370(g) to determine compliance with §63.3320(b)(2) according to §63.3370(n).

	material for an existing affected source or 0.016 kg organic HAP per kg coating material for a new affected source on a monthly average as-applied basis; or	
	(iv) Average equivalent organic HAP emission rate does not exceed the calculated limit based on emission limitations	Follow the procedures set out in §63.3370(h). Show that the monthly organic HAP emission rate is less than the calculated equivalent allowable organic HAP emission rate (Equation 13a or b of §63.3370) according to §63.3370(n).
(6) Use of a combination of compliant coatings and control devices	(i) Average equivalent organic HAP emission rate does not exceed 0.2 kg organic HAP per kg coating solids for an existing affected source or 0.08 kg organic HAP per kg coating solids for a new affected source on a monthly average as-applied basis; or	Follow the procedures set out in §63.3370(f) to determine compliance with §63.3320(b)(3) according to §63.3370(n).
	(ii) Average equivalent organic HAP emission rate does not exceed 0.04 kg organic HAP per kg coating material for an existing affected source or 0.016 kg organic HAP per kg coating material for a new affected source on a monthly average as-applied basis; or	Follow the procedures set out in §63.3370(g) to determine compliance with §63.3320(b)(2) according to §63.3370(n).
	(iii) Average equivalent organic HAP emission rate does not exceed the calculated limit based on emission limitations	Follow the procedures set out in §63.3370(h). Show that the monthly organic HAP emission rate is less than the calculated equivalent allowable organic HAP emission rate (Equation 13a or b of §63.3370) according to §63.3370(n).

(b) *As-purchased compliant coating materials.* (1) If you comply by using coating materials that individually meet the emission standards in §63.3320(b)(2) or (3), you must demonstrate that each coating material applied during the month at an existing affected source contains no more than 0.04 mass fraction organic HAP or 0.2 kg organic HAP per kg coating solids, and that each coating material applied during the month at a new affected source contains no more than 0.016 mass fraction organic HAP or 0.08 kg organic HAP per kg coating solids on an as-purchased basis as determined in accordance with §63.3360(c).

(2) You are in compliance with emission standards in §63.3320(b)(2) and (3) if each coating material applied at an existing affected source is applied as-purchased and contains no more than 0.04 kg organic HAP per kg coating material or 0.2 kg organic HAP per kg coating solids, and each coating material applied at a new affected source is applied as-purchased and contains no more than 0.016 kg organic HAP per kg coating material or 0.08 kg organic HAP per kg coating solids.

(c) *As-applied compliant coating materials.* If you comply by using coating materials that meet the emission standards in §63.3320(b)(2) or (3) as-applied, you must demonstrate compliance by following one of the procedures in paragraphs (c)(1) through (4) of this section. Compliance is determined in accordance with paragraph (c)(5) of this section.

(1) *Each coating material as-applied meets the mass fraction of coating material standard (. (b) ( )).* You must demonstrate that each coating material applied at an existing affected source during the month contains no more than 0.04 kg organic HAP per kg coating material applied, and each coating material applied at a new affected source contains no more than 0.016 kg organic HAP per kg coating material applied as determined in accordance with paragraphs (c)(1)(i) and (ii) of this section. You must calculate the as-applied organic HAP content of as-purchased coating materials which are reduced, thinned, or diluted prior to application.

(i) Determine the organic HAP content or volatile organic content of each coating material applied on an as-purchased basis in accordance with §63.3360(c).

(ii) Calculate the as-applied organic HAP content of each coating material using Equation 1a of this section:

$$C_{ahi} = \frac{\left(C_{hi}M_i + \sum_{j=1}^{q} C_{hij}M_{ij} \right)}{M_i + \sum_{j=1}^{q} M_{ij}} \qquad \text{Eq. 1a}$$

Where:

C_{ahi}= Monthly average, as-applied, organic HAP content of coating material, i, expressed as a mass fraction, kg/kg.

C_{hi}= Organic HAP content of coating material, i, as-purchased, expressed as a mass fraction, kg/kg.

M_i= Mass of as-purchased coating material, i, applied in a month, kg.

q = number of different materials added to the coating material.

C_{hij}= Organic HAP content of material, j, added to as-purchased coating material, i, expressed as a mass fraction, kg/kg.

M_{ij}= Mass of material, j, added to as-purchased coating material, i, in a month, kg.

M_i= Mass of as-purchased coating material, i, applied in a month, kg.

or calculate the as-applied volatile organic content of each coating material using Equation 1b of this section:

$$C_{avi} = \frac{\left(C_{vi}M_i + \sum_{j=1}^{q} C_{vij}M_{ij}\right)}{M_i + \sum_{j=1}^{q} M_{ij}} \qquad \text{Eq. 1b}$$

Where:

C_{avi}= Monthly average, as-applied, volatile organic content of coating material, i, expressed as a mass fraction, kg/kg.

C_{vi}= Volatile organic content of coating material, i, expressed as a mass fraction, kg/kg.

M_i= Mass of as-purchased coating material, i, applied in a month, kg.

q = Number of different materials added to the coating material.

C_{vij}= Volatile organic content of material, j, added to as-purchased coating material, i, expressed as a mass fraction, kg/kg.

M_{ij}= Mass of material, j, added to as-purchased coating material, i, in a month, kg.

(2) *Each coating material as-applied meets the mass fraction of coating solids standard (. (b) ( )).* You must demonstrate that each coating material applied at an existing affected source contains no more than 0.20 kg of organic HAP per kg of coating solids applied and each coating material applied at a new affected source contains no more than 0.08 kg of organic HAP per kg of coating solids applied. You must demonstrate compliance in accordance with paragraphs (c)(2)(i) and (ii) of this section.

(i) Determine the as-applied coating solids content of each coating material following the procedure in §63.3360(d). You must calculate the as-applied coating solids content of coating materials which are reduced, thinned, or diluted prior to application, using Equation 2 of this section:

$$C_{asi} = \frac{\left(C_{si}M_i + \sum_{j=1}^{q} C_{sij}M_{ij}\right)}{M_i + \sum_{j=1}^{q} M_{ij}} \qquad \text{Eq. 2}$$

Where:

C_{si}= Coating solids content of coating material, i, expressed as a mass fraction, kg/kg.

M_i= Mass of as-purchased coating material, i, applied in a month, kg.

q = Number of different materials added to the coating material.

C_{sij}= Coating solids content of material, j, added to as-purchased coating material, i, expressed as a mass-fraction, kg/kg.

M_{ij}= Mass of material, j, added to as-purchased coating material, i, in a month, kg.

(ii) Calculate the as-applied organic HAP to coating solids ratio using Equation 3 of this section:

$$H_{si} = \frac{C_{ahi}}{C_{asi}} \qquad \text{Eq. 3}$$

Where:

H_{si}= As-applied, organic HAP to coating solids ratio of coating material, i.

C_{ahi}= Monthly average, as-applied, organic HAP content of coating material, i, expressed as a mass fraction, kg/kg.

C_{asi}= Monthly average, as-applied, coating solids content of coating material, i, expressed as a mass fraction, kg/kg.

(3) *Monthly average organic HAP content of all coating materials as-applied is less than the mass percent limit (. (b)( )).* Demonstrate that the monthly average as-applied organic HAP content of all coating materials applied at an existing affected source is less than 0.04 kg organic HAP per kg of coating material applied, and all coating materials applied at a new affected source are less than 0.016 kg organic HAP per kg of coating material applied, as determined by Equation 4 of this section:

$$H_L = \frac{\sum_{i=1}^{p} C_{hi} M_i + \sum_{j=1}^{q} C_{hij} M_{ij} - M_{vret}}{\sum_{i=1}^{p} M_i + \sum_{j=1}^{q} M_{ij}} \qquad \text{Eq. 4}$$

Where:

H_L= Monthly average, as-applied, organic HAP content of all coating materials applied, expressed as kg organic HAP per kg of coating material applied, kg/kg.

p = Number of different coating materials applied in a month.

C_{hi}= Organic HAP content of coating material, i, as-purchased, expressed as a mass fraction, kg/kg.

M_i= Mass of as-purchased coating material, i, applied in a month, kg.

q = Number of different materials added to the coating material.

C_{hij}= Organic HAP content of material, j, added to as-purchased coating material, i, expressed as a mass fraction, kg/kg.

M_{ij}= Mass of material, j, added to as-purchased coating material, i, in a month, kg.

M_{vret}= Mass of volatile matter retained in the coated web after curing or drying, or otherwise not emitted to the atmosphere, kg. The value of this term will be zero in all cases except where you choose to take into account the volatile matter retained in the coated web or otherwise not emitted to the atmosphere for the compliance demonstration procedures in §63.3370.

(4) *Monthly average organic HAP content of all coating materials as-applied is less than the mass fraction of coating solids limit (. (b)( )).* Demonstrate that the monthly average as-applied organic HAP content on the basis of coating solids applied of all coating materials applied at an existing affected source is less than 0.20 kg organic HAP per kg coating solids applied, and all coating materials applied at a new affected source are less than 0.08 kg organic HAP per kg coating solids applied, as

determined by Equation 5 of this section:

$$H_s = \frac{\sum_{i=1}^{p} C_{hi}M_i + \sum_{j=1}^{q} C_{hij}M_{ij} - M_{vret}}{\sum_{i=1}^{p} C_{si}M_i + \sum_{j=1}^{q} C_{sij}M_{ij}} \qquad \text{Eq. 5}$$

Where:

H_s= Monthly average, as-applied, organic HAP to coating solids ratio, kg organic HAP/kg coating solids applied.

p = Number of different coating materials applied in a month.

C_{hi}= Organic HAP content of coating material, i, as-purchased, expressed as a mass fraction, kg/kg.

M_i= Mass of as-purchased coating material, i, applied in a month, kg.

q = Number of different materials added to the coating material.

C_{hij}= Organic HAP content of material, j, added to as-purchased coating material, i, expressed as a mass fraction, kg/kg.

M_{ij}= Mass of material, j, added to as-purchased coating material, i, in a month, kg.

M_{vret}= Mass of volatile matter retained in the coated web after curing or drying, or otherwise not emitted to the atmosphere, kg. The value of this term will be zero in all cases except where you choose to take into account the volatile matter retained in the coated web or otherwise not emitted to the atmosphere for the compliance demonstration procedures in §63.3370.

C_{si}= Coating solids content of coating material, i, expressed as a mass fraction, kg/kg.

C_{sij}= Coating solids content of material, j, added to as-purchased coating material, i, expressed as a mass-fraction, kg/kg.

(5) The affected source is in compliance with emission standards in §63.3320(b)(2) or (3) if:

(i) The organic HAP content of each coating material as-applied at an existing affected source is no more than 0.04 kg organic HAP per kg coating material or 0.2 kg organic HAP per kg coating solids, and the organic HAP content of each coating material as-applied at a new affected source contains no more than 0.016 kg organic HAP per kg coating material or 0.08 kg organic HAP per kg coating solids; or

(ii) The monthly average organic HAP content of all as-applied coating materials at an existing affected source are no more than 0.04 kg organic HAP per kg coating material or 0.2 kg organic HAP per kg coating solids, and the monthly average organic HAP content of all as-applied coating materials at a new affected source is no more than 0.016 kg organic HAP per kg coating material or 0.08 kg organic HAP per kg coating solids.

(d) *Monthly allowable organic HAP applied.* Demonstrate that the total monthly organic HAP applied as determined by Equation 6 of this section is less than the calculated equivalent allowable organic HAP as determined by Equation 13a or b in paragraph (l) of this section:

$$H_m = \sum_{i=1}^{p} C_{hi}M_i + \sum_{j=1}^{q} C_{hij}M_{ij} - M_{vret} \qquad \text{Eq. 6}$$

Where:

H_m= Total monthly organic HAP applied, kg.

p = Number of different coating materials applied in a month.

C_{hi}= Organic HAP content of coating material, i, as-purchased, expressed as a mass fraction, kg/kg.

M_i= Mass of as-purchased coating material, i, applied in a month, kg.

q = Number of different materials added to the coating material.

C_{hij}= Organic HAP content of material, j, added to as-purchased coating material, i, expressed as a mass fraction, kg/kg.

M_{ij}= Mass of material, j, added to as-purchased coating material, i, in a month, kg.

M_{vret}= Mass of volatile matter retained in the coated web after curing or drying, or otherwise not emitted to the atmosphere, kg. The value of this term will be zero in all cases except where you choose to take into account the volatile matter retained in the coated web or otherwise not emitted to the atmosphere for the compliance demonstration procedures in §63.3370.

(e) *Capture and control to reduce emissions to no more than allowable limit (. (b)( )).* Operate a capture system and control device and demonstrate an overall organic HAP control efficiency of at least 95 percent at an existing affected source and at least 98 percent at a new affected source for each month, or operate a capture system and oxidizer so that an outlet organic HAP concentration of no greater than 20 ppmv by compound on a dry basis is achieved as long as the capture efficiency is 100 percent as detailed in §63.3320(b)(4). Unless one of the cases described in paragraph (e)(1), (2), or (3) of this section applies to the affected source, you must either demonstrate compliance in accordance with the procedure in paragraph (i) of this section when emissions from the affected source are controlled by a solvent recovery device, or the procedure in paragraph (k) of this section when emissions are controlled by an oxidizer or demonstrate compliance for a web coating line by operating each capture system and each control device and continuous parameter monitoring according to the procedures in paragraph (j) of this section.

(1) If the affected source has only always-controlled work stations and operates more than one capture system or more than one control device, you must demonstrate compliance in accordance with the provisions of either paragraph (n) or (p) of this section.

(2) If the affected source operates one or more never-controlled work stations or one or more intermittently-controlled work stations, you must demonstrate compliance in accordance with the provisions of paragraph (n) of this section.

(3) An alternative method of demonstrating compliance with §63.3320(b)(1) is the installation of a PTE around the web coating line that achieves 100 percent capture efficiency and ventilation of all organic HAP emissions from the total enclosure to an oxidizer with an outlet organic HAP concentration of no greater than 20 ppmv by compound on a dry basis. If this method is selected, you must demonstrate compliance by following the procedures in paragraphs (e)(3)(i) and (ii) of this section. Compliance is determined according to paragraph (e)(3)(iii) of this section.

(i) Demonstrate that a total enclosure is installed. An enclosure that meets the requirements in §63.3360 (f)(1) will be considered a total enclosure.

(ii) Determine the organic HAP concentration at the outlet of your total enclosure using the procedures in paragraph (e)(3)(ii)(A) or (B) of this section.

(A) Determine the control device efficiency using Equation 2 of §63.3360 and the applicable test methods and procedures specified in §63.3360(e).

(B) Use a CEMS to determine the organic HAP emission rate according to paragraphs (i)(2)(i) through (x) of this section.

(iii) You are in compliance if the installation of a total enclosure is demonstrated and the organic HAP concentration at the outlet of the incinerator is demonstrated to be no greater than 20 ppmv by compound on a dry basis.

(f) *Capture and control to achieve mass fraction of coating solids applied limit (. (b)( )).* Operate a capture system and control device and limit the organic HAP emission rate from an existing affected source to no more than 0.20 kg organic HAP emitted per kg coating solids applied, and from a new affected source to no more than 0.08 kg organic HAP emitted per kg coating solids applied as determined on a monthly average as-applied basis. If the affected source operates more than one capture system, more than one control device, one or more never-controlled work stations, or one or more intermittently-controlled work stations, then you must demonstrate compliance in accordance with the provisions of paragraph (n) of this section. Otherwise, you must demonstrate compliance following the procedure in paragraph (i) of this section when emissions from the affected source are controlled by a solvent recovery device or the procedure in paragraph (k) of this section when emissions are controlled by an oxidizer.

(g) *Capture and control to achieve mass fraction limit (. (b)( )).* Operate a capture system and control device and limit the organic HAP emission rate to no more than 0.04 kg organic HAP emitted per kg coating material applied at an existing affected source, and no more than 0.016 kg organic HAP emitted per kg coating material applied at a new affected source as determined on a monthly average as-applied basis. If the affected source operates more than one capture system, more than one control device, one or more never-controlled work stations, or one or more intermittently-controlled work stations, then you must demonstrate compliance in accordance with the provisions of paragraph (n) of this section. Otherwise, you must demonstrate compliance following the procedure in paragraph (i) of this section when emissions from the affected source are controlled by a solvent recovery device or the procedure in paragraph (k) of this section when emissions are controlled by an oxidizer.

(h) *Capture and control to achieve allowable emission rate.* Operate a capture system and control device and limit the monthly organic HAP emissions to less than the allowable emissions as calculated in accordance with paragraph (l) of this section. If the affected source operates more than one capture system, more than one control device, one or more never-controlled work stations, or one or more intermittently-controlled work stations, then you must demonstrate compliance in accordance with the provisions of paragraph (n) of this section. Otherwise, the owner or operator must demonstrate compliance following the procedure in paragraph (i) of this section when emissions from the affected source are controlled by a solvent recovery device or the procedure in paragraph (k) of this section when emissions are controlled by an oxidizer.

(i) *olvent recovery device compliance demonstration.* If you use a solvent recovery device to control emissions, you must show compliance by following the procedures in either paragraph (i)(1) or (2) of this section:

(1) *iquid-liquid material balance.* Perform a monthly liquid-liquid material balance as specified in paragraphs (i)(1)(i) through (v) of this section and use the applicable equations in paragraphs (i)(1)(vi) through (ix) of this section to convert the data to units of the selected compliance option in paragraphs (e) through (h) of this section. Compliance is determined in accordance with paragraph (i)(1)(x) of this section.

(i) Determine the mass of each coating material applied on the web coating line or group of web coating lines controlled by a common solvent recovery device during the month.

(ii) If demonstrating compliance on the basis of organic HAP emission rate based on coating solids applied, organic HAP emission rate based on coating material applied, or emission of less than the calculated allowable organic HAP, determine the organic HAP content of each coating material as-applied during the month following the procedure in §63.3360(c).

(iii) Determine the volatile organic content of each coating material as-applied during the month following the procedure in §63.3360(d).

(iv) If demonstrating compliance on the basis of organic HAP emission rate based on coating solids applied or emission of less than the calculated allowable organic HAP, determine the coating solids content of each coating material applied during the month following the procedure in §63.3360(d).

(v) Determine and monitor the amount of volatile organic matter recovered for the month according to the procedures in §63.3350(d).

(vi) *Recovery efficiency.* Calculate the volatile organic matter collection and recovery efficiency using Equation 7 of this section:

$$R_v = \frac{M_{vr} + M_{vret}}{\sum_{i=1}^{p} C_{vi} M_i + \sum_{i=1}^{q} C_{vij} M_{ij}} \times 100 \quad \text{Eq. 7}$$

Where:

R_v= Organic volatile matter collection and recovery efficiency, percent.

M_{vr}= Mass of volatile matter recovered in a month, kg.

M_{vret}= Mass of volatile matter retained in the coated web after curing or drying, or otherwise not emitted to the atmosphere, kg. The value of this term will be zero in all cases except where you choose to take into account the volatile matter retained in the coated web or otherwise not emitted to the atmosphere for the compliance demonstration procedures in §63.3370.

p = Number of different coating materials applied in a month.

C_{vi}= Volatile organic content of coating material, i, expressed as a mass fraction, kg/kg.

M_i= Mass of as-purchased coating material, i, applied in a month, kg.

q = Number of different materials added to the coating material.

C_{vij}= Volatile organic content of material, j, added to as-purchased coating material, i, expressed as a mass fraction, kg/kg.

M_{ij}= Mass of material, j, added to as-purchased coating material, i, in a month, kg.

(vii) *Organic HAP emitted.* Calculate the organic HAP emitted during the month using Equation 8 of this section:

$$H_e = \left[1 - \frac{R_v}{100}\right]\left[\sum_{i=1}^{p} C_{hi} M_i + \sum_{j=1}^{q} C_{hij} M_{ij} - M_{vret}\right] \quad \text{Eq. 8}$$

Where:

H_e= Total monthly organic HAP emitted, kg.

R_v= Organic volatile matter collection and recovery efficiency, percent.

p = Number of different coating materials applied in a month.

C_{hi}= Organic HAP content of coating material, i, as-purchased, expressed as a mass fraction, kg/kg.

M_i= Mass of as-purchased coating material, i, applied in a month, kg.

q = Number of different materials added to the coating material.

C_{hij}= Organic HAP content of material, j, added to as-purchased coating material, i, expressed as a mass fraction, kg/kg.

M_{ij}= Mass of material, j, added to as-purchased coating material, i, in a month, kg.

M_{vret}= Mass of volatile matter retained in the coated web after curing or drying, or otherwise not emitted to the atmosphere, kg. The value of this term will be zero in all cases except where you choose to take into account the volatile matter retained in the coated web or otherwise not emitted to the atmosphere for the compliance demonstration procedures in §63.3370.

(viii) *Organic HAP emission rate based on coating solids applied.* Calculate the organic HAP emission rate based on coating solids applied using Equation 9 of this section:

$$L = \frac{H_e}{\sum_{i=1}^{p} C_{si}M_i + \sum_{j=1}^{q} C_{sij}M_{ij}} \qquad \text{Eq. 9}$$

Where:

L = Mass organic HAP emitted per mass of coating solids applied, kg/kg.

H_e= Total monthly organic HAP emitted, kg.

p = Number of different coating materials applied in a month.

C_{si}= Coating solids content of coating material, i, expressed as a mass fraction, kg/kg.

M_i= Mass of as-purchased coating material, i, applied in a month, kg.

q = Number of different materials added to the coating material.

C_{sij}= Coating solids content of material, j, added to as-purchased coating material, i, expressed as a mass-fraction, kg/kg.

M_{ij}= Mass of material, j, added to as-purchased coating material, i, in a month, kg.

(ix) *Organic HAP emission rate based on coating materials applied.* Calculate the organic HAP emission rate based on coating material applied using Equation 10 of this section:

$$S = \frac{H_e}{\sum_{i=1}^{p} M_i + \sum_{j=1}^{q} M_{ij}} \qquad \text{Eq. 10}$$

Where:

S = Mass organic HAP emitted per mass of material applied, kg/kg.

H_e= Total monthly organic HAP emitted, kg.

p = Number of different coating materials applied in a month.

M_i= Mass of as-purchased coating material, i, applied in a month, kg.

q = Number of different materials added to the coating material.

M_{ij}= Mass of material, j, added to as-purchased coating material, i, in a month, kg.

(x) You are in compliance with the emission standards in §63.3320(b) if:

(A) The volatile organic matter collection and recovery efficiency is 95 percent or greater at an existing affected source and 98 percent or greater at a new affected source; or

(B) The organic HAP emission rate based on coating solids applied is no more than 0.20 kg organic HAP per kg coating solids applied at an existing affected source and no more than 0.08 kg organic HAP per kg coating solids applied at a new affected source; or

(C) The organic HAP emission rate based on coating material applied is no more than 0.04 kg organic HAP per kg coating material applied at an existing affected source and no more than 0.016 kg organic HAP per kg coating material applied at a new affected source; or

(D) The organic HAP emitted during the month is less than the calculated allowable organic HAP as determined using paragraph (l) of this section.

(2) *Continuous emission monitoring of capture system and control device performance.* Demonstrate initial compliance through a performance test on capture efficiency and continuing compliance through continuous emission monitors and continuous monitoring of capture system operating parameters following the procedures in paragraphs (i)(2)(i) through (vii) of this section. Use the applicable equations specified in paragraphs (i)(2)(viii) through (x) of this section to convert the monitoring and other data into units of the selected compliance option in paragraphs (e) through (h) of this section. Compliance is determined in accordance with paragraph (i)(2)(xi) of this section.

(i) *Control device efficiency.* Continuously monitor the gas stream entering and exiting the control device to determine the total organic volatile matter mass flow rate (*e.g.,* by determining the concentration of the vent gas in grams per cubic meter and the volumetric flow rate in cubic meters per second such that the total organic volatile matter mass flow rate in grams per second can be calculated) such that the control device efficiency of the control device can be calculated for each month using Equation 2 of §63.3360.

(ii) *Capture efficiency monitoring.* Whenever a web coating line is operated, continuously monitor the operating parameters established in accordance with §63.3350(f) to ensure capture efficiency.

(iii) Determine the percent capture efficiency in accordance with §63.3360(f).

(iv) *Control efficiency.* Calculate the overall organic HAP control efficiency achieved for each month using Equation 11 of this section:

$$R = \frac{(E)(CE)}{100} \qquad \text{Eq. 11}$$

Where:

R = Overall organic HAP control efficiency, percent.

E = Organic volatile matter control efficiency of the control device, percent.

CE = Organic volatile matter capture efficiency of the capture system, percent.

(v) If demonstrating compliance on the basis of organic HAP emission rate based on coating solids applied, organic HAP emission rate based on coating materials applied, or emission of less than the calculated allowable organic HAP, determine the mass of each coating material applied on the web coating line or group of web coating lines controlled by a common control device during the month.

(vi) If demonstrating compliance on the basis of organic HAP emission rate based on coating solids applied, organic HAP emission rate based on coating material applied, or emission of less than the calculated allowable organic HAP, determine the organic HAP content of each coating material as-applied during the month following the procedure in §63.3360(c).

(vii) If demonstrating compliance on the basis of organic HAP emission rate based on coating solids applied or emission of less than the calculated allowable organic HAP, determine the coating solids content of each coating material as-applied during the month following the procedure in §63.3360(d).

(viii) *Organic HAP emitted.* Calculate the organic HAP emitted during the month for each month using Equation 12 of this section:

$$H_e = (1-R)\left(\sum_{i-1}^{p} C_{ahi}M_i\right) - M_{vret} \quad \text{Eq. 12}$$

Where:

H_e= Total monthly organic HAP emitted, kg.

R = Overall organic HAP control efficiency, percent.

p = Number of different coating materials applied in a month.

C_{ahi}= Monthly average, as-applied, organic HAP content of coating material, i, expressed as a mass fraction, kg/kg.

M_i= Mass of as-purchased coating material, i, applied in a month, kg.

M_{vret}= Mass of volatile matter retained in the coated web after curing or drying, or otherwise not emitted to the atmosphere, kg. The value of this term will be zero in all cases except where you choose to take into account the volatile matter retained in the coated web or otherwise not emitted to the atmosphere for the compliance demonstration procedures in this section.

(ix) *Organic HAP emission rate based on coating solids applied.* Calculate the organic HAP emission rate based on coating solids applied using Equation 9 of this section.

(x) *Organic HAP emission rate based on coating materials applied.* Calculate the organic HAP emission rate based on coating material applied using Equation 10 of this section.

(xi) *Compare actual performance to the performance required by compliance option.* The affected source is in compliance with the emission standards in §63.3320(b) for each month if the capture system is operated such that the average capture system operating parameter is greater than or less than (as appropriate) the operating parameter value established in accordance with §63.3350(f); and

(A) The organic volatile matter collection and recovery efficiency is 95 percent or greater at an existing affected source and 98 percent or greater at a new affected source; or

(B) The organic HAP emission rate based on coating solids applied is no more than 0.20 kg organic HAP per kg coating solids applied at an existing affected source and no more than 0.08 kg organic HAP per kg coating solids applied at a new affected source; or

(C) The organic HAP emission rate based on coating material applied is no more than 0.04 kg organic HAP per kg coating material applied at an existing affected source and no more than 0.016 kg organic HAP per kg coating material applied at a new affected source; or

(D) The organic HAP emitted during the month is less than the calculated allowable organic HAP as determined using paragraph (l) of this section.

(j) *Capture and control system compliance demonstration procedures using a CPM* . If you use an add-on control device, you must demonstrate initial compliance for each capture system and each control device through performance tests and demonstrate continuing compliance through continuous monitoring of capture system and control device operating parameters as specified in paragraphs (j)(1) through (3) of this section. Compliance is determined in accordance with paragraph (j)(4) of this section.

(1) Determine the control device destruction or removal efficiency using the applicable test methods and procedures in §63.3360(e).

(2) Determine the emission capture efficiency in accordance with §63.3360(f).

(3) Whenever a web coating line is operated, continuously monitor the operating parameters established according to §63.3350(e) and (f).

(4) You are in compliance with the emission standards in §63.3320(b) if the control device is operated such that the average operating parameter value is greater than or less than (as appropriate) the operating parameter value established in accordance with §63.3360(e) for each 3-hour period, and the capture system operating parameter is operated at an average value greater than or less than (as appropriate) the operating parameter value established in accordance with §63.3350(f); and

(i) The overall organic HAP control efficiency is 95 percent or greater at an existing affected source and 98 percent or greater at a new affected source; or

(ii) The organic HAP emission rate based on coating solids applied is no more than 0.20 kg organic HAP per kg coating solids applied at an existing affected source and no more than 0.08 kg organic HAP per kg coating solids applied at a new affected source; or

(iii) The organic HAP emission rate based on coating material applied is no more than 0.04 kg organic HAP per kg coating material applied at an existing affected source and no more than 0.016 kg organic HAP per kg coating material applied at a new affected source; or

(iv) The organic HAP emitted during the month is less than the calculated allowable organic HAP as determined using paragraph (l) of this section.

(k) *Oxidi er compliance demonstration procedures.* If you use an oxidizer to control emissions, you must show compliance by following the procedures in paragraph (k)(1) of this section. Use the applicable equations specified in paragraph (k)(2) of this section to convert the monitoring and other data into units of the selected compliance option in paragraph (e) through (h) of this section. Compliance is determined in accordance with paragraph (k)(3) of this section.

(1) Demonstrate initial compliance through performance tests of capture efficiency and control device efficiency and continuing compliance through continuous monitoring of capture system and control device operating parameters as specified in paragraphs (k)(1)(i) through (vi) of this section:

(i) Determine the oxidizer destruction efficiency using the procedure in §63.3360(e).

(ii) Determine the capture system capture efficiency in accordance with §63.3360(f).

(iii) *Capture and control efficiency monitoring.* Whenever a web coating line is operated, continuously monitor the operating parameters established in accordance with §63.3350(e) and (f) to ensure capture and control efficiency.

(iv) If demonstrating compliance on the basis of organic HAP emission rate based on coating solids applied, organic HAP emission rate based on coating materials applied, or emission of less than the calculated allowable organic HAP, determine the mass of each coating material applied on the web coating line or group of web coating lines controlled by a common oxidizer during the month.

(v) If demonstrating compliance on the basis of organic HAP emission rate based on coating solids applied, organic HAP emission rate based on coating material applied, or emission of less than the calculated allowable organic HAP, determine the organic HAP content of each coating material as-applied during the month following the procedure in §63.3360(c).

(vi) If demonstrating compliance on the basis of organic HAP emission rate based on coating solids applied or emission of less than the calculated allowable organic HAP, determine the coating solids content of each coating material applied during the month following the procedure in §63.3360(d).

(2) Convert the information obtained under paragraph (p)(1) of this section into the units of the selected compliance option using the calculation procedures specified in paragraphs (k)(2)(i) through (iv) of this section.

(i) *Control efficiency.* Calculate the overall organic HAP control efficiency achieved using Equation 11 of this section.

(ii) *Organic HAP emitted.* Calculate the organic HAP emitted during the month using Equation 12 of this section.

(iii) *Organic HAP emission rate based on coating solids applied.* Calculate the organic HAP emission rate based on coating solids applied for each month using Equation 9 of this section.

(iv) *Organic HAP based on coating materials applied.* Calculate the organic HAP emission rate based on coating material applied using Equation 10 of this section.

(3) You are in compliance with the emission standards in §63.3320(b) if the oxidizer is operated such that the average operating parameter value is greater than the operating parameter value established in accordance with §63.3360(e) for each 3-hour period, and the capture system operating parameter is operated at an average value greater than or less than (as appropriate) the operating parameter value established in accordance with §63.3350(f); and

(i) The overall organic HAP control efficiency is 95 percent or greater at an existing affected source and 98 percent or greater at a new affected source; or

(ii) The organic HAP emission rate based on coating solids applied is no more than 0.20 kg organic HAP per kg coating solids applied at an existing affected source and no more than 0.08 kg organic HAP per kg coating solids applied at a new affected source; or

(iii) The organic HAP emission rate based on coating material applied is no more than 0.04 kg organic HAP per kg coating material applied at an existing affected source and no more than 0.016 kg organic HAP per kg coating material applied at a new affected source; or

(iv) The organic HAP emitted during the month is less than the calculated allowable organic HAP as determined using paragraph (l) of this section.

(l) *Monthly allowable organic HAP emissions.* This paragraph provides the procedures and calculations for determining monthly allowable organic HAP emissions for use in demonstrating compliance in accordance with paragraph (d), (h), (i)(1)(x)(D), (i)(2)(xi)(D), or (k)(3)(iv) of this section. You will need to determine the amount of coating material applied at greater than or equal to 20 mass percent coating solids and the amount of coating material applied at less than 20 mass percent coating solids. The allowable organic HAP limit is then calculated based on coating material applied at greater than or equal to 20 mass percent coating solids complying with 0.2 kg organic HAP per kg coating solids at an existing affected source or 0.08 kg organic HAP per kg coating solids at a new affected source, and coating material applied at less than 20 mass percent coating solids complying with 4 mass percent organic HAP at an existing affected source and 1.6 mass-percent organic HAP at a new affected source as follows:

(1) Determine the as-purchased mass of each coating material applied each month.

(2) Determine the as-purchased coating solids content of each coating material applied each month in accordance with §63.3360(d)(1).

(3) Determine the as-purchased mass fraction of each coating material which was applied at 20 mass percent or greater coating solids content on an as-applied basis.

(4) Determine the total mass of each solvent, diluent, thinner, or reducer added to coating materials which were applied at less than 20 mass percent coating solids content on an as-applied basis each month.

(5) Calculate the monthly allowable organic HAP emissions using Equation 13a of this section for an existing affected source:

$$H_a = 0.20\left[\sum_{i=1}^{p} M_i G_i C_{si}\right] + 0.04\left[\sum_{i=1}^{p} M_i(1-G_i) + \sum_{j=1}^{q} M_{L_j}\right] \quad \text{Eq. 13a}$$

Where:

H_a= Monthly allowable organic HAP emissions, kg.

p = Number of different coating materials applied in a month.

M_i= mass of as-purchased coating material, i, applied in a month, kg.

G_i= Mass fraction of each coating material, i, which was applied at 20 mass percent or greater coating solids content, on an as-applied basis, kg/kg.

C_{si}= Coating solids content of coating material, i, expressed as a mass fraction, kg/kg.

q = Number of different materials added to the coating material.

M_{Lj}= Mass of non-coating-solids-containing coating material, j, added to coating-solids-containing coating materials which were applied at less than 20 mass percent coating solids content, on an as-applied basis, in a month, kg.

or Equation 13b of this section for a new affected source:

$$H_a = 0.08\left[\sum_{i=1}^{p} M_i G_i C_{si}\right] + 0.016\left[\sum_{i=1}^{p} M_i(1-G_i) + \sum_{j=1}^{q} M_{L_j}\right] \quad \text{Eq. 13b}$$

Where:

H_a= Monthly allowable organic HAP emissions, kg.

p = Number of different coating materials applied in a month.

M_i= Mass of as-purchased coating material, i, applied in a month, kg.

G_i= Mass fraction of each coating material, i, which was applied at 20 mass percent or greater coating solids content, on an as-applied basis, kg/kg.

C_{si}= Coating solids content of coating material, i, expressed as a mass fraction, kg/kg.

q = Number of different materials added to the coating material.

M_{Lj}= Mass of non-coating-solids-containing coating material, j, added to coating-solids-containing coating materials which were applied at less than 20 mass percent coating solids content, on an as-applied basis, in a month, kg.

(m) [Reserved]

(n) *Combinations of capture and control.* If you operate more than one capture system, more than one control device, one or more never-controlled work stations, or one or more intermittently-controlled work stations, you must calculate organic HAP emissions according to the procedures in paragraphs (n)(1) through (4) of this section, and use the calculation procedures specified in paragraph (n)(5) of this section to convert the monitoring and other data into units of the selected control option in paragraphs (e) through (h) of this section. Use the procedures specified in paragraph (n)(6) of this section to demonstrate compliance.

(1) *olvent recovery system using liquid-liquid material balance compliance demonstration.* If you choose to comply by means of a liquid-liquid material balance for each solvent recovery system used to control one or more web coating lines, you must determine the organic HAP emissions for those web coating lines controlled by that solvent recovery system either:

(i) In accordance with paragraphs (i)(1)(i) through (iii) and (v) through (vii) of this section, if the web coating lines controlled by that solvent recovery system have only always-controlled work stations; or

(ii) In accordance with paragraphs (i)(1)(ii), (iii), (v), and (vi) and (o) of this section, if the web coating lines controlled by that solvent recovery system have one or more never-controlled or intermittently-controlled work stations.

(2) *olvent recovery system using performance test compliance demonstration and CEM* . To demonstrate compliance through an initial test of capture efficiency, continuous monitoring of a capture system operating parameter, and a CEMS on each solvent recovery system used to control one or more web coating lines, you must:

(i) For each capture system delivering emissions to that solvent recovery system, monitor the operating parameter established in accordance with §63.3350(f) to ensure capture system efficiency; and

(ii) Determine the organic HAP emissions for those web coating lines served by each capture system delivering emissions to that solvent recovery system either:

(A) In accordance with paragraphs (i)(2)(i) through (iii), (v), (vi), and (viii) of this section, if the web coating lines served by that capture and control system have only always-controlled work stations; or

(B) In accordance with paragraphs (i)(2)(i) through (iii), (vi), and (o) of this section, if the web coating lines served by that capture and control system have one or more never-controlled or intermittently-controlled work stations.

(3) *Oxidi er.* To demonstrate compliance through performance tests of capture efficiency and control device efficiency, continuous monitoring of capture system, and CPMS for control device operating parameters for each oxidizer used to control emissions from one or more web coating lines, you must:

(i) Monitor the operating parameter in accordance with §63.3350(e) to ensure control device efficiency; and

(ii) For each capture system delivering emissions to that oxidizer, monitor the operating parameter established in accordance with §63.3350(f) to ensure capture efficiency; and

(iii) Determine the organic HAP emissions for those web coating lines served by each capture system delivering emissions to that oxidizer either:

(A) In accordance with paragraphs (k)(1)(i) through (vi) of this section, if the web coating lines served by that capture and control system have only always-controlled work stations; or

(B) In accordance with paragraphs (k)(1)(i) through (iii), (v), and (o) of this section, if the web coating lines served by that capture and control system have one or more never-controlled or intermittently-controlled work stations.

(4) *Uncontrolled coating lines.* If you own or operate one or more uncontrolled web coating lines, you must determine the organic HAP applied on those web coating lines using Equation 6 of this section. The organic HAP emitted from an uncontrolled web coating line is equal to the organic HAP applied on that web coating line.

(5) Convert the information obtained under paragraphs (n)(1) through (4) of this section into the units of the selected compliance option using the calculation procedures specified in paragraphs (n)(5)(i) through (iv) of this section.

(i) *Organic HAP emitted.* Calculate the organic HAP emissions for the affected source for the month by summing all organic HAP emissions calculated according to paragraphs (n)(1), (2)(ii), (3)(iii), and (4) of this section.

(ii) *Coating solids applied.* If demonstrating compliance on the basis of organic HAP emission rate based on coating solids applied or emission of less than the calculated allowable organic HAP, the owner or operator must determine the coating solids content of each coating material applied during the month following the procedure in §63.3360(d).

(iii) *Organic HAP emission rate based on coating solids applied.* Calculate the organic HAP emission rate based on coating solids applied for each month using Equation 9 of this section.

(iv) *Organic HAP based on materials applied.* Calculate the organic HAP emission rate based on material applied using Equation 10 of this section.

(6) *Compliance.* The affected source is in compliance with the emission standards in §63.3320(b) for the month if all operating parameters required to be monitored under paragraphs (n)(1) through (3) of this section were maintained at the values established under §§63.3350 and 63.3360; and

(i) The total mass of organic HAP emitted by the affected source based on coating solids applied is no more than 0.20 kg organic HAP per kg coating solids applied at an existing affected source and no more than 0.08 kg organic HAP per kg coating solids applied at a new affected source; or

(ii) The total mass of organic HAP emitted by the affected source based on material applied is no more than 0.04 kg organic HAP per kg material applied at an existing affected source and no more than 0.016 kg organic HAP per kg material applied at a new affected source; or

(iii) The total mass of organic HAP emitted by the affected source during the month is less than the calculated allowable organic HAP as determined using paragraph (l) of this section; or

(iv) The total mass of organic HAP emitted by the affected source was not more than 5 percent of the total mass of organic HAP applied for the month at an existing affected source and no more than 2 percent of the total mass of organic HAP applied for the month at a new affected source. The total mass of organic HAP applied by the affected source in the month must be determined using Equation 6 of this section.

(o) *Intermittently-controlled and never-controlled work stations.* If you have been expressly referenced to this paragraph by paragraphs (n)(1)(ii), (n)(2)(ii)(B), or (n)(3)(iii)(B) of this section for calculation procedures to determine organic HAP emissions for your intermittently-controlled and never-controlled work stations, you must:

(1) Determine the sum of the mass of all coating materials as-applied on intermittently-controlled work stations operating in bypass mode and the mass of all coating materials as-applied on never-controlled work stations during the month.

(2) Determine the sum of the mass of all coating materials as-applied on intermittently-controlled work stations operating in a controlled mode and the mass of all coating materials applied on always-controlled work stations during the month.

(3) *iquid-liquid material balance compliance demonstration.* For each web coating line or group of web

coating lines for which you use the provisions of paragraph (n)(1)(ii) of this section, you must calculate the organic HAP emitted during the month using Equation 14 of this section:

$$H_e = \left[\sum_{i=1}^{p} M_{Ci} C_{ahi}\right]\left[1 - \frac{R_v}{100}\right] + \left[\sum_{i=1}^{p} M_{Bi} C_{ahi}\right] - M_{vret} \qquad \text{Eq. 14}$$

Where:

H_e= Total monthly organic HAP emitted, kg.

p = Number of different coating materials applied in a month.

M_{ci}= Sum of the mass of coating material, i, as-applied on intermittently-controlled work stations operating in controlled mode and the mass of coating material, i, as-applied on always-controlled work stations, in a month, kg.

C_{ahi}= Monthly average, as-applied, organic HAP content of coating material, i, expressed as a mass fraction, kg/kg.

R_v= Organic volatile matter collection and recovery efficiency, percent.

M_{Bi}= Sum of the mass of coating material, i, as-applied on intermittently-controlled work stations operating in bypass mode and the mass of coating material, i, as-applied on never-controlled work stations, in a month, kg.

C_{ahi}= Monthly average, as-applied, organic HAP content of coating material, i, expressed as a mass fraction, kg/kg.

M_{vret}= Mass of volatile matter retained in the coated web after curing or drying, or otherwise not emitted to the atmosphere, kg. The value of this term will be zero in all cases except where you choose to take into account the volatile matter retained in the coated web or otherwise not emitted to the atmosphere for the compliance demonstration procedures in this section.

(4) *Performance test to determine capture efficiency and control device efficiency.* For each web coating line or group of web coating lines for which you use the provisions of paragraph (n)(2)(ii)(B) or (n)(3)(iii)(B) of this section, you must calculate the organic HAP emitted during the month using Equation 15 of this section:

$$H_e = \left[\sum_{i=1}^{p} M_{Ci} C_{ahi}\right]\left[1 - \frac{R}{100}\right] + \left[\sum_{i=1}^{p} M_{Bi} C_{ahi}\right] - M_{vret} \qquad \text{Eq. 15}$$

Where:

H_e= Total monthly organic HAP emitted, kg.

p = Number of different coating materials applied in a month.

M_{ci}= Sum of the mass of coating material, i, as-applied on intermittently-controlled work stations operating in controlled mode and the mass of coating material, i, as-applied on always-controlled work stations, in a month, kg.

C_{ahi}= Monthly average, as-applied, organic HAP content of coating material, i, expressed as a mass fraction, kg/kg.

R = Overall organic HAP control efficiency, percent.

M_{Bi}= Sum of the mass of coating material, i, as-applied on intermittently-controlled work stations operating in bypass mode and the mass of coating material, i, as-applied on never-controlled work stations, in a month, kg.

C_{ahi}= Monthly average, as-applied, organic HAP content of coating material, i, expressed as a mass fraction, kg/kg.

M_{vret}= Mass of volatile matter retained in the coated web after curing or drying, or otherwise not emitted to the atmosphere, kg. The value of this term will be zero in all cases except where you choose to take into account the volatile matter retained in the coated web or otherwise not emitted to the atmosphere for the compliance demonstration procedures in this section.

(p) *Always-controlled work stations with more than one capture and control system.* If you operate more than one capture system or more than one control device and only have always-controlled work stations, then you are in compliance with the emission standards in §63.3320(b)(1) for the month if for each web coating line or group of web coating lines controlled by a common control device:

(1) The volatile matter collection and recovery efficiency as determined by paragraphs (i)(1)(i), (iii), (v), and (vi) of this section is at least 95 percent at an existing affected source and at least 98 percent at a new affected source; or

(2) The overall organic HAP control efficiency as determined by paragraphs (i)(2)(i) through (iv) of this section for each web coating line or group of web coating lines served by that control device and a common capture system is at least 95 percent at an existing affected source and at least 98 percent at a new affected source; or

(3) The overall organic HAP control efficiency as determined by paragraphs (k)(1)(i) through (iii) and (k)(2)(i) of this section for each web coating line or group of web coating lines served by that control device and a common capture system is at least 95 percent at an existing affected source and at least 98 percent at a new affected source.

Notifications, Reports, and Records

§ 63.3400 What notifications and reports must I submit?

(a) Each owner or operator of an affected source subject to this subpart must submit the reports specified in paragraphs (b) through (g) of this section to the Administrator:

(b) You must submit an initial notification as required by §63.9(b).

(1) Initial notification for existing affected sources must be submitted no later than 1 year before the compliance date specified in §63.3330(a).

(2) Initial notification for new and reconstructed affected sources must be submitted as required by §63.9(b).

(3) For the purpose of this subpart, a title V or part 70 permit application may be used in lieu of the initial notification required under §63.9(b), provided the same information is contained in the permit application as required by §63.9(b) and the State to which the permit application has been submitted has an approved operating permit program under part 70 of this chapter and has received delegation of authority from the EPA to implement and enforce this subpart.

(4) If you are using a permit application in lieu of an initial notification in accordance with paragraph (b)(3) of this section, the permit application must be submitted by the same due date specified for the initial notification.

(c) You must submit a semiannual compliance report according to paragraphs (c)(1) and (2) of this section.

(1) Compliance report dates.

(i) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.3330 and ending on June 30 or December 31, whichever date is the first date following the end of the calendar half immediately following the compliance date that is specified for your affected source in §63.3330.

(ii) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the calendar half immediately following the compliance date that is specified for your affected source in §63.3330.

(iii) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(iv) Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(v) For each affected source that is subject to permitting regulations pursuant to 40 CFR part 70 or 40 CFR part 71, and the permitting authority has established dates for submitting semiannual reports pursuant to §70.6(a)(3)(iii)(A) or §71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (c)(1)(i) through (iv) of this section.

(2) The compliance report must contain the information in paragraphs (c)(2)(i) through (vi) of this section:

(i) Company name and address.

(ii) Statement by a responsible official with that official's name, title, and signature certifying the accuracy of the content of the report.

(iii) Date of report and beginning and ending dates of the reporting period.

(iv) If there are no deviations from any emission limitations (emission limit or operating limit) that apply to you, a statement that there were no deviations from the emission limitations during the reporting period, and that no CMS was inoperative, inactive, malfunctioning, out-of-control, repaired, or adjusted.

(v) For each deviation from an emission limitation (emission limit or operating limit) that applies to you and that occurs at an affected source where you are not using a CEMS to comply with the emission limitations in this subpart, the compliance report must contain the information in paragraphs (c)(2)(i) through (iii) of this section, and:

(A) The total operating time of each affected source during the reporting period.

(B) Information on the number, duration, and cause of deviations (including unknown cause), if applicable, and the corrective action taken.

(C) Information on the number, duration, and cause for CPMS downtime incidents, if applicable, other than downtime associated with zero and span and other calibration checks.

(vi) For each deviation from an emission limit occurring at an affected source where you are using a CEMS to comply with the emission limit in this subpart, you must include the information in paragraphs (c)(2)(i) through (iii) and (vi)(A) through (J) of this section.

(A) The date and time that each malfunction started and stopped.

(B) The date and time that each CEMS and CPMS, if applicable, was inoperative except for zero (low-level) and high-level checks.

(C) The date and time that each CEMS and CPMS, if applicable, was out-of-control, including the information in §63.8(c)(8).

(D) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(E) A summary of the total duration (in hours) of each deviation during the reporting period and the total duration of each deviation as a percent of the total source operating time during that reporting period.

(F) A breakdown of the total duration of the deviations during the reporting period into those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.

(G) A summary of the total duration (in hours) of CEMS and CPMS downtime during the reporting period and the total duration of CEMS and CPMS downtime as a percent of the total source operating time during that reporting period.

(H) A breakdown of the total duration of CEMS and CPMS downtime during the reporting period into periods that are due to monitoring equipment malfunctions, nonmonitoring equipment malfunctions, quality assurance/quality control calibrations, other known causes, and other unknown causes.

(I) The date of the latest CEMS and CPMS certification or audit.

(J) A description of any changes in CEMS, CPMS, or controls since the last reporting period.

(d) You must submit a Notification of Performance Tests as specified in §§63.7 and 63.9(e) if you are complying with the emission standard using a control device and you are required to conduct a performance test of the control device. This notification and the site-specific test plan required under §63.7(c)(2) must identify the operating parameters to be monitored to ensure that the capture efficiency of the capture system and the control efficiency of the control device determined during the performance test are maintained. Unless EPA objects to the parameter or requests changes, you may consider the parameter approved.

(e) You must submit a Notification of Compliance Status as specified in §63.9(h).

(f) You must submit performance test reports as specified in §63.10(d)(2) if you are using a control device to comply with the emission standard and you have not obtained a waiver from the performance test requirement or you are not exempted from this requirement by §63.3360(b). The performance test reports must be submitted as part of the notification of compliance status required in §63.3400(e).

(g) You must submit startup, shutdown, and malfunction reports as specified in §63.10(d)(5), except that the provisions in subpart A of this part pertaining to startups, shutdowns, and malfunctions do not apply unless a control device is used to comply with this subpart.

(1) If actions taken by an owner or operator during a startup, shutdown, or malfunction of an affected source (including actions taken to correct a malfunction) are not consistent with the procedures specified in the affected source's SSMP required by §63.6(e)(3), the owner or operator must state such information in the report. The startup, shutdown, or malfunction report must consist of a letter containing the name, title, and signature of the responsible official who is certifying its accuracy and must be submitted to the Administrator.

(2) Separate startup, shutdown, and malfunction reports are not required if the information is included in the report specified in paragraph (c)(2)(vi) of this section.

§ 63.3410 What records must I eep?

(a) Each owner or operator of an affected source subject to this subpart must maintain the records specified in paragraphs (a)(1) and (2) of this section on a monthly basis in accordance with the requirements of §63.10(b)(1):

(1) Records specified in §63.10(b)(2) of all measurements needed to demonstrate compliance with this standard, including:

(i) Continuous emission monitor data in accordance with the requirements of §63.3350(d);

(ii) Control device and capture system operating parameter data in accordance with the requirements of §63.3350(c), (e), and (f);

(iii) Organic HAP content data for the purpose of demonstrating compliance in accordance with the requirements of §63.3360(c);

(iv) Volatile matter and coating solids content data for the purpose of demonstrating compliance in accordance with the requirements of §63.3360(d);

(v) Overall control efficiency determination using capture efficiency and control device destruction or removal efficiency test results in accordance with the requirements of §63.3360(e) and (f); and

(vi) Material usage, organic HAP usage, volatile matter usage, and coating solids usage and compliance demonstrations using these data in accordance with the requirements of §63.3370(b), (c), and (d).

(2) Records specified in §63.10(c) for each CMS operated by the owner or operator in accordance with the requirements of §63.3350(b).

(b) Each owner or operator of an affected source subject to this subpart must maintain records of all liquid-liquid material balances performed in accordance with the requirements of §63.3370. The records must be maintained in accordance with the requirements of §63.10(b).

Delegation of Authority

§ 63.3420 What authorities may be delegated to the States?

(a) In delegating implementation and enforcement authority to a State under 40 CFR part 63, subpart E, the authorities contained in paragraph (b) of this section must be retained by the Administrator and not transferred to a State.

(b) Authority which will not be delegated to States: §63.3360(c), approval of alternate test method for organic HAP content determination; §63.3360(d), approval of alternate test method for volatile matter determination.

Table 1 to Subpart JJJJ of Part 63—Operating imits if sing Add-On Control Devices and Capture System

If you are required to comply with operating limits by §63.3321, you must comply with the applicable operating limits in the following table:

For the following device:	ou must meet the following operating limit:	And you must demonstrate continuous compliance with operating limits by:
1. Thermal oxidizer	a. The average combustion temperature in any 3-hour period must not fall below the combustion temperature limit established according to §63.3360(e)(3)(i)	i. Collecting the combustion temperature data according to §63.3350(e)(9); ii. Reducing the data to 3-hour block averages; and iii. Maintain the 3-hour average combustion temperature at or above the temperature limit.

2. Catalytic oxidizer	a. The average temperature at the inlet to the catalyst bed in any 3-hour period must not fall below the combustion temperature limit established according to §63.3360(e)(3)(ii)	i. Collecting the catalyst bed inlet temperature data according to §63.3350(e)(9); ii. Reducing the data to 3-hour block averages; and iii. Maintain the 3-hour average catalyst bed inlet temperature at or above the temperature limit.
	b. The temperature rise across the catalyst bed must not fall below the limit established according to §63.3360(e)(3)(ii)	i. Collecting the catalyst bed inlet and outlet temperature data according to §63.3350(e)(9); ii. Reducing the data to 3-hour block averages; and iii. Maintain the 3-hour average temperature rise across the catalyst bed at or above the limit.
3. Emission capture system	Submit monitoring plan to the Administrator that identifies operating parameters to be monitored according to §63.3350(f)	Conduct monitoring according to the plan (§63.3350(f)(3)).

Table 2 to Subpart JJJJ of Part 63—Applicability of 40 CFR Part 63 General Provisions to Subpart JJJJ

You must comply with the applicable General Provisions requirements according to the following table:

General provisions reference	Applicable to subpart JJJJ	E planation
§63.1(a)(1)–(4)	Yes.	
§63.1(a)(5)	No	Reserved.
§63.1(a)(6)–(8)	Yes.	
§63.1(a)(9)	No	Reserved.
§63.1(a)(10)–(14)	Yes.	
§63.1(b)(1)	No	Subpart JJJJ specifies applicability.
§63.1(b)(2)–(3)	Yes.	
§63.1(c)(1)	Yes.	
§63.1(c)(2)	No	Area sources are not subject to emission standards of subpart JJJJ.
§63.1(c)(3)	No	Reserved.
§63.1(c)(4)	Yes.	
§63.1(c)(5)	Yes.	

§63.1(d)	No	Reserved.
§63.1(e)	Yes.	
§63.1(e)(4)	No.	
§63.2	Yes	Additional definitions in subpart JJJJ.
§63.3(a)–(c)	Yes.	
§63.4(a)(1)–(3)	Yes.	
§63.4(a)(4)	No	Reserved.
§63.4(a)(5)	Yes.	
§63.4(b)–(c)	Yes.	
§63.5(a)(1)–(2)	Yes.	
§63.5(b)(1)	Yes.	
§63.5(b)(2)	No	Reserved.
§63.5(b)(3)–(6)	Yes.	
§63.5(c)	No	Reserved.
§63.5(d)	Yes.	
§63.5(e)	Yes.	
§63.5(f)	Yes.	
§63.6(a)	Yes	Applies only when capture and control system is used to comply with the standard.
§63.6(b)(1)–(5)	No	
§63.6(b)(6)	No	Reserved.
§63.6(b)(7)	Yes.	
§63.6(c)(1)–(2)	Yes.	
§63.6(c)(3)–(4)	No	Reserved.
§63.6(c)(5)	Yes.	
§63.6(d)	No	Reserved.
§63.6(e)	Yes	Provisions pertaining to SSMP, and CMS do not apply unless an add-on control system is used to comply with the emission limitations.
§63.6(f)	Yes.	
§63.6(g)	Yes.	
§63.6(h)	No	Subpart JJJJ does not require continuous opacity monitoring systems (COMS).
§63.6(i)(1)–(14)	Yes.	
§63.6(i)(15)	No	Reserved.
§63.6(i)(16)	Yes.	
§63.6(j)	Yes.	
§63.7	Yes.	
§63.8(a)(1)–(2)	Yes.	
§63.8(a)(3)	No	Reserved.
§63.8(a)(4)	No.	
§63.8(b)	Yes.	

§63.8(c)(1)–(3)	Yes	§63.8(c)(1)(i) & (ii) only apply if you use capture and control systems and are required to have a start-up, shutdown, and malfunction plan.
§63.8(c)(4)	Yes.	
§63.8(c)(5)	No	Subpart JJJJ does not require COMS.
§63.8(c)(6)–(c)(8)	Yes	Provisions for COMS are not applicable.
§63.8(d)–(f)	Yes	§63.8(f)(6) only applies if you use CEMS.
§63.8(g)	Yes	Only applies if you use CEMS.
§63.9(a)	Yes.	
§63.9(b)(1)	Yes.	
§63.9(b)(2)	Yes	Except §63.3400(b)(1) requires submittal of initial notification for existing affected sources no later than 1 year before compliance date.
§63.9(b)(3)–(5)	Yes.	
§63.9(c)–(e)	Yes.	
§63.9(f)	No	Subpart JJJJ does not require opacity and visible emissions observations.
§63.9(g)	Yes	Provisions for COMS are not applicable.
§63.9(h)(1)–(3)	Yes.	
§63.9(h)(4)	No	Reserved.
§63.9(h)(5)–(6)	Yes.	
§63.9(i)	Yes.	
§63.9(j)	Yes.	
§63.10(a)	Yes.	
§63.10(b)(1)–(3)	Yes	§63.10(b)(2)(i) through (v) only apply if you use a capture and control system.
§63.10(c)(1)	Yes.	
§63.10(c)(2)–(4)	No	Reserved.
§63.10(c)(5)–(8)	Yes.	
§63.10(c)(9)	No	Reserved.
§63.10(c)(10)–(15)	Yes.	
§63.10(d)(1)–(2)	Yes.	
§63.10(d)(3)	No	Subpart JJJJ does not require opacity and visible emissions observations.
§63.10(d)(4)–(5)	Yes.	
§63.10(e)(1)–(2)	Yes	Provisions for COMS are not applicable.
§63.10(e)(3)–(4)	No.	

§63.10(f)	Yes.	
§63.11	No.	
§63.12	Yes.	
§63.13	Yes.	
§63.14	Yes	Subpart JJJJ includes provisions for alternative ASME test methods that are incorporated by reference.
§63.15	Yes.	

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APPENDIX K – NSPS IIII

Electronic Code of Federal Regulations
e-CFR ™

e-CFR Data is current as of May 17, 2012

Title 40: Protection of Environment
PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Source: 71 FR 39172, July 11, 2006, unless otherwise noted.

What This Subpart Covers

§ 60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) and other persons as specified in paragraphs (a)(1) through (4) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines;

(ii) The model year listed in Table 3 to this subpart or later model year, for fire pump engines.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are:

(i) Manufactured after April 1, 2006, and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(3) Owners and operators of any stationary CI ICE that are modified or reconstructed after July 11, 2005 and any person that modifies or reconstructs any stationary CI ICE after July 11, 2005.

(4) The provisions of §60.4208 of this subpart are applicable to all owners and operators of stationary CI ICE that commence construction after July 11, 2005.

(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR part 89, subpart J and 40 CFR part 94, subpart J, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

(e) Owners and operators of facilities with CI ICE that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011]

Emission Standards for Manufacturers

§ 60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same model year and maximum engine power.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(c) Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.

(d) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2007 model year through 2012 non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(3) Their 2013 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(e) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards and other requirements for new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.110, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later non-emergency stationary CI ICE with a displacement of greater

than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(f) Notwithstanding the requirements in paragraphs (a) through (c) of this section, stationary non-emergency CI ICE identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 1 to 40 CFR 1042.1 identifies 40 CFR part 1042 as being applicable, 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

(1) Areas of Alaska not accessible by the Federal Aid Highway System (FAHS); and

(2) Marine offshore installations.

(g) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (e) of this section that are applicable to the model year, maximum engine power, and displacement of the reconstructed stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011]

§ 60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants for model year 2007 engines, and

(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.

(2) For engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

(c) [Reserved]

(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.

(e) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE that are not fire pump engines to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2007 model year through 2012 emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder;

(3) Their 2013 model year emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder; and

(4) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(f) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE to the certification emission standards and other requirements applicable to Tier 3 new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power less than 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(g) Notwithstanding the requirements in paragraphs (a) through (d) of this section, stationary emergency CI internal combustion engines identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 2 to 40 CFR 1042.101 identifies Tier 3 standards as being applicable, the requirements applicable to Tier 3 engines in 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

(1) Areas of Alaska not accessible by the FAHS; and

(2) Marine offshore installations.

(h) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (f) of this section that are applicable to the model year, maximum engine power and displacement of the reconstructed emergency stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011]

§ 60.4203 How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?

Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§60.4201 and 60.4202 during the certified emissions life of the engines.

[76 FR 37968, June 28, 2011]

Emission Standards for Owners and Operators

§ 60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in §60.4201 for their 2007 model year and later stationary CI ICE, as applicable.

(c) Owners and operators of non-emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the following requirements:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 grams per kilowatt-hour (g/KW-hr) (12.7 grams per horsepower-hr (g/HP-hr)) when maximum engine speed is less than 130 revolutions per minute (rpm);

(ii) $45 \cdot n^{-0.2}$g/KW-hr ($34 \cdot n^{-0.2}$g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012 and before January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$g/KW-hr ($33 \cdot n^{-0.23}$g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) For engines installed on or after January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 3.4 g/KW-hr (2.5 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $9.0 \cdot n^{-0.20}$g/KW-hr ($6.7 \cdot n^{-0.20}$g/HP-hr) where n (maximum engine speed) is 130 or more but less than 2,000 rpm; and

(iii) 2.0 g/KW-hr (1.5 g/HP-hr) where maximum engine speed is greater than or equal to 2,000 rpm.

(4) Reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

(d) Owners and operators of non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the not-to-exceed (NTE) standards as indicated in §60.4212.

(e) Owners and operators of any modified or reconstructed non-emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed non-emergency stationary CI ICE that are specified in paragraphs (a) through (d) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011]

§ 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in Table 1 to this subpart. Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) Owners and operators of emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in this section.

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/kW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

(e) Owners and operators of emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the NTE standards as indicated in §60.4212.

(f) Owners and operators of any modified or reconstructed emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed CI ICE that are specified in paragraphs (a) through (e) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§ 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 over the entire life of the engine.

[76 FR 37969, June 28, 2011]

Fuel Re uirements for Owners and Operators

§ 60.4207 What fuel re uirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must purchase diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.

(c) [Reserved]

(d) Beginning June 1, 2012, owners and operators of stationary CI ICE subject to this subpart with a displacement of greater than or equal to 30 liters per cylinder are no longer subject to the requirements of paragraph (a) of this section, and must use fuel that meets a maximum per-gallon sulfur content of 1,000 parts per million (ppm).

(e) Stationary CI ICE that have a national security exemption under §60.4200(d) are also exempt from the fuel requirements in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

Other Re uirements for Owners and Operators

§ 60.420 What is the deadline for importing or installing stationary CI ICE produced in previous model years?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.

(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.

(d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.

(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.

(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.

(g) After December 31, 2018, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power greater than or equal to 600 KW (804 HP) and less than 2,000 KW (2,680 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that do not meet the applicable requirements for 2017 model year non-emergency engines.

(h) In addition to the requirements specified in §§60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (g) of this section after the dates specified in paragraphs (a) through (g) of this section.

(i) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§ 60.420 What are the monitoring re uirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in §60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine.

(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

Compliance Re uirements

§ 60.4210 What are my compliance re uirements if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in §60.4201(a) through (c) and §60.4202(a), (b) and (d) using the certification procedures required in 40 CFR part 89, subpart B, or 40 CFR part 1039, subpart C, as applicable, and must test their engines as specified in those parts. For the purposes of this subpart, engines certified to the standards in table 1 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89. For the purposes of this subpart, engines certified to the standards in table 4 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.

(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in §60.4201(d) and (e) and §60.4202(e) and (f) using the certification procedures required in 40 CFR part 94, subpart C, or 40 CFR part 1042, subpart C, as applicable, and must test their engines as specified in 40 CFR part 94 or 1042, as applicable.

(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 1039.125, 1039.130, and 1039.135, and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 89, 40 CFR part 94 or 40 CFR part 1042 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.

(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.

(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:

(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do not have to meet the labeling requirements in 40 CFR 1039.20.

(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.

(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.

(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.

(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate.

(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate, but the words "stationary" must be included instead of "nonroad" or "marine" on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.

(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.

(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under 40 CFR parts 89, 94, 1039 or 1042 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts.

(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words "and stationary" after the word "nonroad" or "marine," as appropriate, to the label.

(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in §60.4202 but does not meet all the emission standards for non-emergency engines in §60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as "Fire Pump Applications Only".

(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of §§60.4201 or 60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.

(i) The replacement engine provisions of 40 CFR 89.1003(b)(7), 40 CFR 94.1103(b)(3), 40 CFR 94.1103 (b)(4) and 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§ 60.4211 What are my compliance re uirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

(2) Change only those emission-related settings that are permitted by the manufacturer; and

(3) Meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in §§60.4204(a) or 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified according to 40 CFR part 89 or 40 CFR part 94, as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in §60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.

(d) If you are an owner or operator and must comply with the emission standards specified in §60.4204 (c) or §60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in §60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must

include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and NO_X and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit NO_X and PM emissions;

(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in §60.4213.

(e) If you are an owner or operator of a modified or reconstructed stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(e) or §60.4205(f), you must demonstrate compliance according to one of the methods specified in paragraphs (e)(1) or (2) of this section.

(1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in §60.4204(e) or §60.4205(f), as applicable.

(2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in §60.4212 or §60.4213, as appropriate. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

(f) Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. Emergency stationary ICE may operate up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply non-emergency power as part of a financial arrangement with another entity. For owners and operators of emergency engines, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as permitted in this section, is prohibited.

(g) If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

(1) If you are an owner or operator of a stationary CI internal combustion engine with maximum engine power less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, if you do not install and configure the engine and control device according to the manufacturer's emission-related written instructions, or you change the emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of such action.

(2) If you are an owner or operator of a stationary CI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted

maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.

(3) If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37970, June 28, 2011]

Testing Re uirements for Owners and Operators

§ 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (e) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR part 1042, subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \qquad (\text{Eq. } 1)$$

Where:

STD = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in §60.4213 of this subpart, as appropriate.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in §60.4204(a), §60.4205(a), or §60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in §60.4204(a), §60.4205(a), or §60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) may follow the testing procedures specified in §60.4213, as appropriate.

(e) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1042 must not exceed the NTE standards for the same model year and maximum engine power as required in 40 CFR 1042.101(c).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

§ 60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or e ual to 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (f) of this section.

(a) Each performance test must be conducted according to the requirements in §60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §60.8(c).

(c) You must conduct three separate test runs for each performance test required in this section, as specified in §60.8(f). Each test run must last at least 1 hour.

(d) To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.

(1) You must use Equation 2 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 2)}$$

Where:

C_i= concentration of NO_X or PM at the control device inlet,

C_o= concentration of NO_X or PM at the control device outlet, and

R = percent reduction of NO_X or PM emissions.

(2) You must normalize the NO_X or PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen (O_2) using Equation 3 of this section, or an equivalent percent carbon dioxide (CO_2) using the procedures described in paragraph (d)(3) of this section.

$$C_{adj} = C_d \frac{5.9}{20.9 - \%\, O_2} \qquad \text{(Eq. 3)}$$

Where:

C_{adj}= Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d= Measured concentration of NO_X or PM, uncorrected.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

$\%O_2$= Measured O_2 concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent O_2 and CO_2 concentration is measured in lieu of O_2 concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209 F_d}{F_c} \quad \text{(Eq. 4)}$$

Where:

F_o= Fuel factor based on the ratio of O_2 volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is O_2, percent/100.

F_d= Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

F_c= Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \quad \text{(Eq. 5)}$$

Where:

X_{CO2}= CO_2 correction factor, percent.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the NO_X and PM gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \quad \text{(Eq. 6)}$$

Where:

C_{adj}= Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d= Measured concentration of NO_X or PM, uncorrected.

$\%CO_2$= Measured CO_2 concentration, dry basis, percent.

(e) To determine compliance with the NO_X mass per unit output emission limitation, convert the concentration of NO_X in the engine exhaust using Equation 7 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \quad \text{(Eq. 7)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_d= Measured NO_X concentration in ppm.

1.912×10^{-3}= Conversion constant for ppm NO_X to grams per standard cubic meter at 25 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Brake work of the engine, in KW-hour.

(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

$$ER = \frac{C_{adj} \times Q \times T}{\text{KW-hour}} \quad \text{(Eq. 8)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_{adj}= Calculated PM concentration in grams per standard cubic meter.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Energy output of the engine, in KW.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

otification, Reports, and Records for Owners and Operators

§ 60.4214 What are my notification, reporting, and record eeping re uirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in §60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section.

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

Special Re uirements

§ 60.4215 What re uirements must I meet for engines used in uam, American Samoa, or the Commonwealth of the orthern Mariana Islands?

(a) Stationary CI ICE with a displacement of less than 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §§60.4202 and 60.4205.

(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in §60.4207.

(c) Stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the following emission standards:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than

2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

§ 60.4216 What re uirements must I meet for engines used in Alas a?

(a) Prior to December 1, 2010, owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder located in areas of Alaska not accessible by the FAHS should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

(b) Except as indicated in paragraph (c) of this section, manufacturers, owners and operators of stationary CI ICE with a displacement of less than 10 liters per cylinder located in areas of Alaska not accessible by the FAHS may meet the requirements of this subpart by manufacturing and installing engines meeting the requirements of 40 CFR parts 94 or 1042, as appropriate, rather than the otherwise applicable requirements of 40 CFR parts 89 and 1039, as indicated in sections §§60.4201(f) and 60.4202(g) of this subpart.

(c) Manufacturers, owners and operators of stationary CI ICE that are located in areas of Alaska not accessible by the FAHS may choose to meet the applicable emission standards for emergency engines in §60.4202 and §60.4205, and not those for non-emergency engines in §60.4201 and §60.4204, except that for 2014 model year and later non-emergency CI ICE, the owner or operator of any such engine that was not certified as meeting Tier 4 PM standards, must meet the applicable requirements for PM in §60.4201 and §60.4204 or install a PM emission control device that achieves PM emission reductions of 85 percent, or 60 percent for engines with a displacement of greater than or equal to 30 liters per cylinder, compared to engine-out emissions.

(d) The provisions of §60.4207 do not apply to owners and operators of pre-2014 model year stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS.

(e) The provisions of §60.4208(a) do not apply to owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS until after December 31, 2009.

(f) The provisions of this section and §60.4207 do not prevent owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS from using fuels mixed with used lubricating oil, in volumes of up to 1.75 percent of the total fuel. The sulfur content of the used lubricating oil must be less than 200 parts per million. The used lubricating oil must meet the on-specification levels and properties for used oil in 40 CFR 279.11.

[76 FR 37971, June 28, 2011]

§ 60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

Owners and operators of stationary CI ICE that do not use diesel fuel may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in §60.4204 or §60.4205 using such fuels and that use of such fuel is appropriate and reasonably necessary, considering cost, energy, technical feasibility, human health and environmental, and other factors, for the operation of the engine.

[76 FR 37972, June 28, 2011]

eneral Provisions

§ 60.421 What parts of the eneral Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

Definitions

§ 60.421 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the CAA and in subpart A of this part.

Certified emissions life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for certified emissions life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101 (g). The values for certified emissions life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 94.9(a).

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Date of manufacture means one of the following things:

(1) For freshly manufactured engines and modified engines, date of manufacture means the date the engine is originally produced.

(2) For reconstructed engines, date of manufacture means the date the engine was originally produced, except as specified in paragraph (3) of this definition.

(3) Reconstructed engines are assigned a new date of manufacture if the fixed capital cost of the new and refurbished components exceeds 75 percent of the fixed capital cost of a comparable entirely new facility. An engine that is produced from a previously used engine block does not retain the date of manufacture of the engine in which the engine block was previously used if the engine is produced using all new components except for the engine block. In these cases, the date of manufacture is the date of reconstruction or the date the new engine is produced.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Diesel particulate filter means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.

Emergency stationary internal combustion engine means any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc. Stationary CI ICE used to supply power to an electric grid or that supply power as part of a financial arrangement with another entity are not considered to be emergency engines.

Engine manufacturer means the manufacturer of the engine. See the definition of "manufacturer" in this section.

Fire pump engine means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.

Freshly manufactured engine means an engine that has not been placed into service. An engine becomes freshly manufactured when it is originally produced.

Installed means the engine is placed and secured at the location where it is intended to be operated.

Manufacturer has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1039.801.

Model year means the calendar year in which an engine is manufactured (see "date of manufacture"), except as follows:

(1) Model year means the annual new model production period of the engine manufacturer in which an engine is manufactured (see "date of manufacture"), if the annual new model production period is different than the calendar year and includes January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year.

(2) For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was manufactured (see "date of manufacture").

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Reciprocating internal combustion engine means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle, aircraft, or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Subpart means 40 CFR part 60, subpart IIII.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011]

Table 1 to Subpart IIII of Part 60—Emission Standards for Stationary Pre-2007 Model ear Engines With a Displacement of 10 iters per Cylinder and 2007 2010 Model ear Engines 2,237 W 3,000 HP and With a Displacement of 10 iters per Cylinder

[As stated in §§60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]

Ma imum engine power	Emission standards for stationary pre-2007 model year engines with a displacement of 10 liters per cylinder and 2007 2010 model year engines 2,237 W 3,000 HP and with a displacement of 10 liters per cylinder in g W-hr g HP-hr				
	MHC O	HC	O	CO	PM
KW<8 (HP<11)	10.5 (7.8)			8.0 (6.0)	1.0 (0.75)
8≤KW<19 (11≤HP<25)	9.5 (7.1)			6.6 (4.9)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	9.5 (7.1)			5.5 (4.1)	0.80 (0.60)
37≤KW<56 (50≤HP<75)			9.2 (6.9)		
56≤KW<75 (75≤HP<100)			9.2 (6.9)		
75≤KW<130 (100≤HP<175)			9.2 (6.9)		
130≤KW<225 (175≤HP<300)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
225≤KW<450 (300≤HP<600)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

Table 2 to Subpart IIII of Part 60—Emission Standards for 200 Model ear and ater Emergency Stationary CI ICE 37 W 50 HP With a Displacement of 10 iters per Cylinder

[As stated in §60.4202(a)(1), you must comply with the following emission standards]

Engine power	Emission standards for 200 model year and later emergency stationary CI ICE 37 W 50 HP with a displacement of 10 liters per cylinder in g W-hr g HP-hr			
	Model year s	O MHC	CO	PM
KW<8 (HP<11)	2008+	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2008+	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)

19≤KW<37 (25≤HP<50)	2008+	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)

Table 3 to Subpart IIII of Part 60—Certification Re uirements for Stationary Fire Pump Engines

Table 3 to Subpart IIII of Part 60—Certification Re uirements for Stationary Fire Pump Engines

As stated in §60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:

Engine power	Starting model year engine manufacturers must certify new stationary fire pump engines according to §60.4202 d [1]
KW<75 (HP<100)	2011
75≤KW<130 (100≤HP<175)	2010
130≤KW≤560 (175≤HP≤750)	2009
KW>560 (HP>750)	2008

[1]Manufacturers of fire pump stationary CI ICE with a maximum engine power greater than or equal to 37 kW (50 HP) and less than 450 KW (600 HP) and a rated speed of greater than 2,650 revolutions per minute (rpm) are not required to certify such engines until three model years following the model year indicated in this Table 3 for engines in the applicable engine power category.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011]

Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

[As stated in §§60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Ma imum engine power	Model year s	MHC O	CO	PM
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
	2011+	7.5 (5.6)		0.40 (0.30)
8≤KW<19 (11≤HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
	2011+	7.5 (5.6)		0.40 (0.30)

19≤KW<37 (25≤HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
	2011+	7.5 (5.6)		0.30 (0.22)
37≤KW<56 (50≤HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+[1]	4.7 (3.5)		0.40 (0.30)
56≤KW<75 (75≤HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+[1]	4.7 (3.5)		0.40 (0.30)
75≤KW<130 (100≤HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2010+[2]	4.0 (3.0)		0.30 (0.22)
130≤KW<225 (175≤HP<300)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[3]	4.0 (3.0)		0.20 (0.15)
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[3]	4.0 (3.0)		0.20 (0.15)
450≤KW≤560 (600≤HP≤750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+	4.0 (3.0)		0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2008+	6.4 (4.8)		0.20 (0.15)

[1]For model years 2011–2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.

[2]For model years 2010–2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.

[3]In model years 2009–2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

Table 5 to Subpart IIII of Part 60— abeling and Record eeping Re uirements for ew Stationary Emergency Engines

[You must comply with the labeling requirements in §60.4210(f) and the recordkeeping requirements in §60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]

Engine power	Starting model year
19≤KW<56 (25≤HP<75)	2013
56≤KW<130 (75≤HP<175)	2012
KW≥130 (HP≥175)	2011

Table 6 to Subpart IIII of Part 60—Optional 3-Mode Test Cycle for Stationary Fire Pump Engines

[As stated in §60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]

Mode o.	Engine speed[1]	Tor ue percent [2]	Weighting factors
1	Rated	100	0.30
2	Rated	75	0.50
3	Rated	50	0.20

[1]Engine speed: ±2 percent of point.

[2]Torque: NFPA certified nameplate HP for 100 percent point. All points should be ±2 percent of engine percent load value.

Table 7 to Subpart IIII of Part 60—Re uirements for Performance Tests for Stationary CI ICE With a Displacement of 30 iters per Cylinder

[As stated in §60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of ≥30 liters per cylinder:]

For each	Complying with the re uirement to	ou must	sing	According to the following re uirements
1. Stationary CI internal combustion engine with a displacement of ≥30 liters per cylinder	a. Reduce NO_X emissions by 90 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_X concentration.
		iii. If necessary, measure	(3) Method 4 of 40 CFR	(c) Measurements to determine

		moisture content at the inlet and outlet of the control device; and,	part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	moisture content must be made at the same time as the measurements for NO_X concentration.
		iv. Measure NO_X at the inlet and outlet of the control device	(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	b. Limit the concentration of NO_X in the stationary CI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location; and,	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2 concentration must be made at the same time as the measurement for NO_X concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust	(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A,	(c) Measurements to determine moisture content must be made at the same time as the measurement for NO_X concentration.

		at the sampling port location; and,	or ASTM D 6348–03 (incorporated by reference, see §60.17)	
		iv. Measure NO_X at the exhaust of the stationary internal combustion engine	(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	c. Reduce PM emissions by 60 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(3) Method 4 of 40 CFR part 60, appendix A	(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the inlet and outlet of the control device	(4) Method 5 of 40 CFR part 60, appendix A	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	d. Limit the concentration	i. Select the sampling port	(1) Method 1 or 1A of 40	(a) If using a control device, the

	of PM in the stationary CI internal combustion engine exhaust	location and the number of traverse points;	CFR part 60, appendix A	sampling site must be located at the outlet of the control device.
		ii. Determine the O_2concentration of the stationary internal combustion engine exhaust at the sampling port location; and	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(3) Method 4 of 40 CFR part 60, appendix A	(c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the exhaust of the stationary internal combustion engine	(4) Method 5 of 40 CFR part 60, appendix A	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

Table to Subpart IIII of Part 60—Applicability of eneral Provisions to Subpart IIII

[As stated in §60.4218, you must comply with the following applicable General Provisions:]

eneral Provisions citation	Subject of citation	Applies to subpart	E planation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4219.

§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4214(a).
§60.8	Performance tests	Yes	Except that §60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart IIII.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	Yes	Except that §60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§60.14	Modification	Yes	
§60.15	Reconstruction	Yes	
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

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APPENDIX L – NESHAP ZZZZ

Electronic Code of Federal Regulations
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e-CFR Data is current as of May 17, 2012

Title 40: Protection of Environment

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES (CONTINUED)

Browse Next

Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Source: 69 FR 33506, June 15, 2004, unless otherwise noted.

What This Subpart Covers

§ 63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

[73 FR 3603, Jan. 18, 2008]

§ 63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3603, Jan. 18, 2008]

§ 63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) *Existing stationary RICE.*

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) *New stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) *Reconstructed stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(b) *Stationary RICE subject to limited requirements.* (1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of §63.6645(f)

and the requirements of §§63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(vi) Existing residential emergency stationary RICE located at an area source of HAP emissions;

(vii) Existing commercial emergency stationary RICE located at an area source of HAP emissions; or

(viii) Existing institutional emergency stationary RICE located at an area source of HAP emissions.

(c) *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;

(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9674, Mar. 3, 2010; 75 FR 37733, June 30, 2010; 75 FR 51588, Aug. 20, 2010]

§ 63.6595 When do I have to comply with this subpart?

(a) *Affected sources.* (1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than October 19, 2013.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) *Area sources that become major sources.* If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in §63.6645 and in 40 CFR part 63, subpart A.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

Emission and Operating Limitations

§ 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010]

§ 63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

§ 63.6602 What emission limitations must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

[75 FR 51589, Aug. 20, 2010]

§ 63.6603 What emission limitations and operating limitations must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 1b and Table 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE greater than 300 HP located at area sources in areas of Alaska not accessible by the Federal Aid Highway System (FAHS) you do not have to meet the numerical CO emission limitations specified in Table 2d to this subpart. Existing stationary non-emergency CI RICE greater than 300 HP located at area sources in areas of Alaska not accessible by the FAHS must meet the management practices that are shown for stationary non-emergency CI RICE less than or equal to 300 HP in Table 2d to this subpart.

[75 FR 9675, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011]

§ 63.6604 What fuel requirements must I meet if I own or operate an existing stationary CI RICE?

If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel. Existing non-emergency CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, or at area sources in areas of Alaska not accessible by the FAHS are exempt from the requirements of this section.

[75 FR 51589, Aug. 20, 2010]

eneral Compliance Requirements

§ 63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations and operating limitations in this subpart that apply to you at all times.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[75 FR 9675, Mar. 3, 2010]

Testing and Initial Compliance Requirements

§ 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]

§ 63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

[75 FR 9676, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

§ 63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again.

(c) [Reserved]

(d) You must conduct three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour.

(e)(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 1)}$$

Where:

C_i = concentration of CO or formaldehyde at the control device inlet,

C_o = concentration of CO or formaldehyde at the control device outlet, and

R = percent reduction of CO or formaldehyde emissions.

(2) You must normalize the carbon monoxide (CO) or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2 concentration is measured in lieu of oxygen concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, section 5.2, and the following equation:

$$F_o = \frac{0.209\, F_d}{F_c} \qquad \text{(Eq. 2)}$$

Where:

F_o= Fuel factor based on the ratio of oxygen volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d= Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

F_c= Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent oxygen, as follows:

$$X_{co_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 3)}$$

Where:

X_{co2}= CO_2 correction factor, percent.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the NO_X and SO_2 gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{co_2}}{\%CO_2} \qquad \text{(Eq. 4)}$$

Where:

$\%CO_2$= Measured CO_2 concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (*e.g.* operator adjustment, automatic controller adjustment, etc.) or unintentionally (*e.g.* wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9676, Mar. 3, 2010]

§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either oxygen or CO_2 at both the inlet and the outlet of the control device according to the requirements in paragraphs (a)(1) through (4) of this section.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in §63.8 and according to the applicable performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in §63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in §63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO_2concentration.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (5) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in §63.8(d). As specified in §63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (*e.g.* thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in §63.8(c)(1) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in §63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also §63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

(6) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start landfill or digester gas stationary RICE located at an area source of HAP emissions;

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (g)(2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska not accessible by the FAHS do not have to meet the requirements of paragraph (g) of this section.

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates, and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011]

§ 63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?

(a) You must demonstrate initial compliance with each emission and operating limitation that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.6645.

Continuous Compliance Requirements

§ 63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

[69 FR 33506, June 15, 2004, as amended at 76 FR 12867, Mar. 9, 2011]

§ 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?

(a) You must demonstrate continuous compliance with each emission limitation and operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in §63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) [Reserved]

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) *Requirements for emergency stationary RICE.* (1) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that was installed on or after June 12, 2006, or an existing emergency stationary RICE located at an area source of HAP emissions, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1)(i) through (iii) of this section. Any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1)(i) through (iii) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1)(i) through (iii) of this section, the engine will not be considered an emergency engine under this subpart and will need to meet all requirements for non-emergency engines.

(i) There is no time limit on the use of emergency stationary RICE in emergency situations.

(ii) You may operate your emergency stationary RICE for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency RICE beyond 100 hours per year.

(iii) You may operate your emergency stationary RICE up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity; except that owners and operators may operate the emergency engine for a maximum of 15 hours per year as part of a demand response program if the regional transmission organization or equivalent balancing authority and transmission operator has determined there are emergency conditions that could lead to a potential electrical blackout, such as unusually low frequency, equipment overload, capacity or energy deficiency, or unacceptable voltage level. The engine may not be operated for more than 30 minutes prior to the time when the emergency condition is expected to occur, and the engine operation must be terminated immediately after the facility is notified that the emergency condition is no longer imminent. The 15 hours per year of demand response operation are counted as part of the 50 hours of operation per year provided for non-emergency situations. The supply of emergency power to another entity or entities pursuant to financial arrangement is not limited by this paragraph (f)(1)(iii), as long as the power provided by the financial arrangement is limited to emergency power.

(2) If you own or operate an emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that was installed prior to June 12, 2006, you must operate the engine according to the conditions described in paragraphs (f)(2)(i) through (iii) of this section. If you do not operate the engine according to the requirements in paragraphs (f)(2)(i) through (iii) of this section, the engine will not be considered an emergency engine under this subpart and will need to meet all requirements for non-emergency engines.

(i) There is no time limit on the use of emergency stationary RICE in emergency situations.

(ii) You may operate your emergency stationary RICE for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by the manufacturer, the vendor, or the insurance company associated with the engine. Required testing of such units should be minimized, but there is no time limit on the use of emergency stationary RICE in emergency situations and for routine testing and maintenance.

(iii) You may operate your emergency stationary RICE for an additional 50 hours per year in non-emergency situations. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010]

Notifications, Reports, and Records

§ 63.6645 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

(b) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004.

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(d) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an Initial Notification not later than July 16, 2008.

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008 and you are required to submit an initial notification, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with §63.6590(b), your notification should include the information in §63.9 (b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in §63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to §63.10(d)(2).

[73 FR 3606, Jan. 18, 2008, as amended at 75 FR 9677, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010]

§ 63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10 (a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in §63.6595.

(3) For semiannual Compliance reports, each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) For semiannual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in §63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with §63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out-of-control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9677, Mar. 3, 2010]

§ 63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in §63.10(b)(2)(xiv).

(2) Records of the occurrence and duration of each malfunction of operation (*i.e.* process equipment) or the air pollution control and monitoring equipment.

(3) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

(1) Records described in §63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.* superseded) versions of the performance evaluation plan as required in §63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in §63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) or (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engines are used for demand response operation, the owner or operator must keep records of the notification of the emergency situation, and the time the engine was operated as part of demand response.

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010]

§ 63.6660 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1).

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010]

Other Requirements and Information

§ 63.6665 What parts of the eneral Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

[75 FR 9678, Mar. 3, 2010]

§ 63.6670 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in §63.6600 under §63.6(g).

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(3) Approval of major alternatives to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in §63.6610(b).

§ 63.6675 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

Area source means any stationary source of HAP that is not a major source as defined in part 63.

Associated equi ment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.

lac start engine means an engine whose only purpose is to start up a combustion turbine.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.* as amended by Public Law 101–549, 104 Stat. 2399).

Commercial emergency stationary RICE means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

Com ression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Custody transfer means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

e iation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.

(4) Fails to satisfy the general duty to minimize emissions established by §63.6(e)(1)(i).

iesel engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

iesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (*e.g.* biodiesel) that is suitable for use in compression ignition engines.

igester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO_2.

ual fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, *etc.* Stationary RICE used for peak shaving are not considered emergency stationary RICE. Stationary RICE used to supply power to an electric grid or that supply non-emergency power as part of a financial arrangement with another entity are not considered to be emergency engines, except as permitted under §63.6640(f). All emergency stationary RICE must comply with the requirements specified in §63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in §63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

Engine startu means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.

Four stro e engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

aseous fuel means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

asoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

lycol dehydration unit means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes "rich" glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The "lean" glycol is then recycled.

a ardous air ollutants AP means any air pollutants listed in or pursuant to section 112(b) of the CAA.

Institutional emergency stationary RICE means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.

IS standard day conditions means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

andfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO_2.

ean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

imited use stationary RICE means any stationary RICE that operates less than 100 hours per year.

iquefied etroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

iquid fuel means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

Major Source as used in this subpart, shall have the same meaning as in §63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in §63.1271 of subpart HHH of this part, shall not be

aggregated.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Non selecti e catalytic reduction NSCR means an add-on catalytic nitrogen oxides (NO_X) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO_X, CO, and volatile organic compounds (VOC) into CO_2, nitrogen, and water.

il and gas roduction facility as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.* remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

xidation catalyst means an add-on catalytic control device that controls CO and VOC by oxidation.

Pea ing unit or engine means any standby engine intended for use during periods of high demand that are not emergencies.

Percent load means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in §63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to §63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to §63.1270(a)(2).

Production field facility means those oil and gas production facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

Pro ane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

Residential emergency stationary RICE means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.

Res onsible official means responsible official as defined in 40 CFR 70.2.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NO_X(such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Site rated P means the maximum manufacturer's design capacity at engine site conditions.

S ar ignition means relating to either: A gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary reci rocating internal combustion engine RICE means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

Stationary RICE test cell stand means an engine test cell/stand, as defined in subpart PPPPP of this part, that tests stationary RICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Storage essel with the otential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Sub art means 40 CFR part 63, subpart ZZZZ.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

wo stro e engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3607, Jan. 18, 2008; 75 FR 9679, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 76 FR 12867, Mar. 9, 2011]

Table 1ato Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE 500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	ou must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 4SRB stationary	a. Reduce formaldehyde emissions by 76 percent or more.	Minimize the engine's time spent at idle and minimize the

RICE	If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or	engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
	b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9679, Mar. 3, 2010, as amended at 75 FR 51592, Aug. 20, 2010]

Table 1bto Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed Spark Ignition 4SRB Stationary RICE 500 HP Located at a Major Source of HAP Emissions and Existing Spark Ignition 4SRB Stationary RICE 500 HP Located at an Area Source of HAP Emissions

As stated in §§63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions and existing 4SRB stationary RICE >500 HP located at an area source of HAP emissions that operate more than 24 hours per calendar year:

For each . . .	ou must meet the following operating limitation . . .
1. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O2 and using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd or less at 15 percent O2 and using NSCR.	a. Maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and b. Maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.
2. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and	Comply with any operating limitations approved by the Administrator.

not using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O2 and not using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd or less at 15 percent O2 and not using NSCR.	

[76 FR 12867, Mar. 9, 2011]

Table 2ato Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE 500 HP and New and Reconstructed 4SLB Stationary RICE 250 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

For each . . .	ou must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 2SLB stationary RICE	a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O_2. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O_2until June 15, 2007	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
2. 4SLB stationary RICE	a. Reduce CO emissions by 93 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O_2	
3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or	
	b. Limit concentration of	

	formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O_2	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9680, Mar. 3, 2010]

Table 2bto Subpart ZZZZ of Part 63— Operating Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE 500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE 250 HP Located at a Major Source of HAP Emissions, Existing Compression Ignition Stationary RICE 500 HP, and Existing 4SLB Stationary RICE 500 HP Located at an Area Source of HAP Emissions

As stated in §§63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and compression ignition stationary RICE located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; existing compression ignition stationary RICE >500 HP; and existing 4SLB stationary RICE >500 HP located at an area source of HAP emissions that operate more than 24 hours per calendar year:

For each . . .	ou must meet the following operating limitation . . .
1. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions and using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst; or 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
2. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions and not using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; or 4SLB stationary RICE and CI stationary RICE complying with the	Comply with any operating limitations approved by the Administrator.

requirement to limit the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(g) for a different temperature range.

[75 FR 51593, Aug. 20, 2010, as amended at 76 FR 12867, Mar. 9, 2011]

Table 2cto Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE 500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions:

For each . . .	ou must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]
2. Non-Emergency, non-black start stationary CI RICE <100 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;[2]	
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first;	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
3. Non-Emergency,	Limit concentration of	

non-black start CI stationary RICE 100≤HP≤300 HP	CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O_2	
4. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
5. Non-Emergency, non-black start stationary CI RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
6. Emergency stationary SI RICE and black start stationary SI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2]	
	b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first;	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
7. Non-Emergency, non-black start stationary SI RICE <100 HP that are not 2SLB stationary RICE	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[2]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first;	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever	

	comes first, and replace as necessary.[3]	
8. Non-Emergency, non-black start 2SLB stationary SI RICE <100 HP	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[2]	
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first;	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
9. Non-emergency, non-black start 2SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O_2	
10. Non-emergency, non-black start 4SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O_2	
11. Non-emergency, non-black start 4SRB stationary RICE 100≤HP≤500	Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O_2	
12. Non-emergency, non-black start landfill or digester gas-fired stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O_2	

[1]If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.

[2]Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement in Table 2c of this subpart.

[3]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 51593, Aug. 20, 2010]

Table 2dto Subpart ZZZZ of Part 63— Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

As stated in §§63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

For each . . .	ou must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI stationary RICE ≤300 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;[1]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
3. Non-Emergency, non-black	a. Limit	

start CI stationary RICE >500 HP	concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
4. Emergency stationary CI RICE and black start stationary CI RICE.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]	
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE >500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE >500 HP that operate 24 hours or less per calendar year.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1] b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
6. Non-emergency, non-black start 2SLB stationary RICE	a. Change oil and filter every 4,320 hours of operation	

	or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.	
7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
8. Non-emergency, non-black start 4SLB stationary RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 93 percent or more.	
9. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation	

	or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
10. Non-emergency, non-black start 4SRB stationary RICE >500 HP	a. Limit concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd at 15 percent O_2; or	
	b. Reduce formaldehyde emissions by 76 percent or more.	
11. Non-emergency, non-black start landfill or digester gas-fired stationary RICE	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	

[1]Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement in Table 2d of this subpart.

[2]If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.

[75 FR 51595, Aug. 20, 2010]

Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests

As stated in §§63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

For each . . .	Complying with the requirement to . . .	ou must . . .
1. New or reconstructed 2SLB stationary RICE with a brake horsepower >500 located at major sources; new or reconstructed 4SLB stationary RICE with a brake horsepower ≥250 located at major sources; and new or reconstructed CI stationary RICE with a brake horsepower >500 located at major sources	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semiannually.[1]
2. 4SRB stationary RICE with a brake horsepower ≥5,000 located at major sources	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually.[1]
3. Stationary RICE with a brake horsepower >500 located at major sources and new or reconstructed 4SLB stationary RICE with a brake horsepower 250≤HP≤500 located at major sources	Limit the concentration of formaldehyde in the stationary RICE exhaust	Conduct subsequent performance tests semiannually.[1]
4. Existing non-emergency, non-black start CI stationary RICE with a brake horsepower >500 that are not limited use stationary RICE; existing non-emergency, non-black start 4SLB and 4SRB stationary RICE located at an area source of HAP emissions with a brake horsepower >500 that are operated more than 24 hours per calendar year that are not limited use stationary RICE	Limit or reduce CO or formaldehyde emissions	Conduct subsequent performance tests every 8,760 hrs. or 3 years, whichever comes first.

5. Existing non-emergency, non-black start CI stationary RICE with a brake horsepower >500 that are limited use stationary RICE; existing non-emergency, non-black start 4SLB and 4SRB stationary RICE located at an area source of HAP emissions with a brake horsepower >500 that are operated more than 24 hours per calendar year and are limited use stationary RICE	Limit or reduce CO or formaldehyde emissions	Conduct subsequent performance tests every 8,760 hrs. or 5 years, whichever comes first.

[1]After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[75 FR 51596, Aug. 20, 2010]

Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

As stated in §§63.6610, 63.6611, 63.6612, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

For each . . .	Complying with the requirement to . . .	ou must . . .	sing . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE	a. Reduce CO emissions	i. Measure the O_2 at the inlet and outlet of the control device; and	(1) Portable CO and O_2 analyzer	(a) Using ASTM D6522–00 (2005)[a] (incorporated by reference, see §63.14). Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.
		ii. Measure the CO at the inlet and the outlet of the control device	(1) Portable CO and O_2 analyzer	(a) Using ASTM D6522–00 (2005)[ab] (incorporated by reference, see §63.14) or Method 10 of 40 CFR appendix A. The CO

				concentration must be at 15 percent O_2, dry basis.
2. 4SRB stationary RICE	a. Reduce formaldehyde emissions	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A §63.7(d)(1)(i)	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00m (2005)	(a) Measurements to determine O_2concentration must be made at the same time as the measurements for formaldehyde concentration.
		iii. Measure moisture content at the inlet and outlet of the control device; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentration.
		iv. Measure formaldehyde at the inlet and the outlet of the control device	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03,[c]provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
3. Stationary RICE	a. Limit the concentration of formaldehyde	i. Select the sampling port location and the number of	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) If using a control device, the sampling site must be located

	or CO in the stationary RICE exhaust	traverse points; and	§63.7(d)(1)(i)	at the outlet of the control device.
		ii. Determine the O_2concentration of the stationary RICE exhaust at the sampling port location; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00 (2005)	(a) Measurements to determine O_2concentration must be made at the same time and location as the measurements for formaldehyde concentration.
		iii. Measure moisture content of the stationary RICE exhaust at the sampling port location; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentration.
		iv. Measure formaldehyde at the exhaust of the stationary RICE; or	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03,[c]provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. Measure CO at the exhaust of the stationary RICE	(1) Method 10 of 40 CFR part 60, appendix A, ASTM Method D6522–00 (2005),[a]Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–	(a) CO Concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour longer runs.

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[a]You may also use Methods 3A and 10 as options to ASTM–D6522–00 (2005). You may obtain a copy of ASTM–D6522–00 (2005) from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106. ASTM–D6522–00 (2005) may be used to test both CI and SI stationary RICE.

[b]You may also use Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03.

[c]You may obtain a copy of ASTM–D6348–03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[75 FR 51597, Aug. 20, 2010]

Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations and Operating Limitations

As stated in §§63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

For each . . .	Complying with the requirement to . . .	ou have demonstrated initial compliance if. . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet

calendar year		temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce CO emissions and not using oxidation catalyst	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
4. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Limit the concentration of CO, and not using oxidation catalyst	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either

major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year		O_2 or CO_2 at both the inlet and outlet of the oxidation catalyst according to the requirements in §63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and iii. The average reduction of CO calculated using §63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
6. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Limit the concentration of CO, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at the outlet of the oxidation catalyst according to the requirements in §63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average concentration of CO calculated using §63.6620 is less than or equal to the CO emission limitation. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.

7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce formaldehyde emissions and using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce formaldehyde emissions and not using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
9. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Limit the concentration of formaldehyde and not using NSCR	i. The average formaldehyde concentration determined from the initial performance test is less than or equal to the formaldehyde emission limitation; and

		ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
11. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating

		parameters (if any) during the initial performance test.
12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Reduce CO or formaldehyde emissions	i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.
13. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.

[76 FR 12867, Mar. 9, 2011]

Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, Operating Limitations, Work Practices, and Management Practices

As stated in §63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

For each . . .	Complying with the requirement to . . .	ou must demonstrate continuous compliance by . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved;[a]and ii. Collecting the catalyst inlet temperature data according to §63.6625 (b); and iii. Reducing these data to 4-hour rolling

		averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved;[a]and ii. Collecting the approved operating parameter (if any) data according to §63.6625 (b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP,	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS	i. Collecting the monitoring data according to §63.6625 (a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to §63.6620; and

existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year		ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.
4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. Collecting the catalyst inlet temperature data according to §63.6625 (b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. Collecting the approved operating parameter (if any) data according to §63.6625 (b); and ii. Reducing these data

		to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP	a. Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved.[a]
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250 ≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit;[a]and ii. Collecting the catalyst inlet temperature data according to §63.6625 (b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the

		performance test.
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250 ≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit;[a]and ii. Collecting the approved operating parameter (if any) data according to §63.6625 (b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency landfill or digester gas stationary SI RICE located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

calendar year		
10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE, and existing 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year and are not limited use stationary RICE	a. Reduce CO or formaldehyde emissions, or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and using oxidation catalyst or NSCR	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625 (b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE, and existing 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year and are not limited use stationary RICE	a. Reduce CO or formaldehyde emissions, or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and not	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or

	using oxidation catalyst or NSCR	formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625 (b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
12. Existing limited use CI stationary RICE >500 HP and existing limited use 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year	a. Reduce CO or formaldehyde emissions or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and using an oxidation catalyst or NSCR	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625 (b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the

		catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
13. Existing limited use CI stationary RICE >500 HP and existing limited use 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year	a. Reduce CO or formaldehyde emissions or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and not using an oxidation catalyst or NSCR	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625 (b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

[a]After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[76 FR 12870, Mar. 9, 2011]

Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports

As stated in §63.6650, you must comply with the following requirements for reports:

For each ...	ou must submit a ...	The report must contain ...	ou must submit the report ...
1. Existing non-emergency, non-black start stationary RICE 100≤HP≤500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >300 HP located at an area source of HAP; existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP and operated more than 24 hours per calendar year; new or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	Compliance report	a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in §63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), the information in §63.6650(e); or c. If you had a malfunction during the reporting period, the information in §63.6650(c)(4)	

		i. Semiannually according to the requirements in §63.6650(b)(1)–(5) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in §63.6650(b)(6)–(9) for engines that are limited use stationary RICE subject to numerical emission limitations. i. Semiannually according to the requirements in §63.6650(b). i. Semiannually according to the requirements in §63.6650(b).
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and i. Annually, according to the requirements in §63.6650.
		b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and i. See item 2.a.i.
		c. Any problems or errors suspected with the meters.

		i. See item 2.a.i.	

[75 FR 51603, Aug. 20, 2010]

Table 8 to Subpart ZZZZ of Part 63—Applicability of eneral Provisions to Subpart ZZZZ.

As stated in §63.6665, you must comply with the following applicable general provisions.

eneral provisions citation	Subject of citation	Applies to subpart	Explanation
§63.1	General applicability of the General Provisions	Yes.	
§63.2	Definitions	Yes	Additional terms defined in §63.6675.
§63.3	Units and abbreviations	Yes.	
§63.4	Prohibited activities and circumvention	Yes.	
§63.5	Construction and reconstruction	Yes.	
§63.6(a)	Applicability	Yes.	
§63.6(b)(1)–(4)	Compliance dates for new and reconstructed sources	Yes.	
§63.6(b)(5)	Notification	Yes.	
§63.6(b)(6)	[Reserved]		
§63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources	Yes.	
§63.6(c)(1)–(2)	Compliance dates for existing sources	Yes.	
§63.6(c)(3)–(4)	[Reserved]		
§63.6(c)(5)	Compliance dates for existing area sources that become major sources	Yes.	
§63.6(d)	[Reserved]		
§63.6(e)	Operation and maintenance	No.	
§63.6(f)(1)	Applicability of standards	No.	
§63.6(f)(2)	Methods for determining compliance	Yes.	
§63.6(f)(3)	Finding of compliance	Yes.	
§63.6(g)(1)–(3)	Use of alternate standard	Yes.	
§63.6(h)	Opacity and visible	No	Subpart ZZZZ does

	emission standards		not contain opacity or visible emission standards.
§63.6(i)	Compliance extension procedures and criteria	Yes.	
§63.6(j)	Presidential compliance exemption	Yes.	
§63.7(a)(1)–(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at §§63.6610, 63.6611, and 63.6612.
§63.7(a)(3)	CAA section 114 authority	Yes.	
§63.7(b)(1)	Notification of performance test	Yes	Except that §63.7(b)(1) only applies as specified in §63.6645.
§63.7(b)(2)	Notification of rescheduling	Yes	Except that §63.7(b)(2) only applies as specified in §63.6645.
§63.7(c)	Quality assurance/test plan	Yes	Except that §63.7(c) only applies as specified in §63.6645.
§63.7(d)	Testing facilities	Yes.	
§63.7(e)(1)	Conditions for conducting performance tests	No.	Subpart ZZZZ specifies conditions for conducting performance tests at §63.6620.
§63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart ZZZZ specifies test methods at §63.6620.
§63.7(e)(3)	Test run duration	Yes.	
§63.7(e)(4)	Administrator may require other testing under section 114 of the CAA	Yes.	
§63.7(f)	Alternative test method provisions	Yes.	
§63.7(g)	Performance test data analysis, recordkeeping, and reporting	Yes.	
§63.7(h)	Waiver of tests	Yes.	
§63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart ZZZZ contains specific requirements for monitoring at §63.6625.
§63.8(a)(2)	Performance specifications	Yes.	
§63.8(a)(3)	[Reserved]		

§63.8(a)(4)	Monitoring for control devices	No.	
§63.8(b)(1)	Monitoring	Yes.	
§63.8(b)(2)–(3)	Multiple effluents and multiple monitoring systems	Yes.	
§63.8(c)(1)	Monitoring system operation and maintenance	Yes.	
§63.8(c)(1)(i)	Routine and predictable SSM	Yes.	
§63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan	Yes.	
§63.8(c)(1)(iii)	Compliance with operation and maintenance requirements	Yes.	
§63.8(c)(2)–(3)	Monitoring system installation	Yes.	
§63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§63.8(c)(6)–(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.
§63.8(d)	CMS quality control	Yes.	
§63.8(e)	CMS performance evaluation	Yes	Except for §63.8(e)(5)(ii), which applies to COMS.
		Except that §63.8(e) only applies as specified in §63.6645.	
§63.8(f)(1)–(5)	Alternative monitoring method	Yes	Except that §63.8(f)(4) only applies as specified in §63.6645.
§63.8(f)(6)	Alternative to relative accuracy test	Yes	Except that §63.8(f)(6) only applies as specified in §63.6645.
§63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are

			specified at §§63.6635 and 63.6640.
§63.9(a)	Applicability and State delegation of notification requirements	Yes.	
§63.9(b)(1)–(5)	Initial notifications	Yes	Except that §63.9(b)(3) is reserved.
		Except that §63.9(b) only applies as specified in §63.6645.	
§63.9(c)	Request for compliance extension	Yes	Except that §63.9(c) only applies as specified in §63.6645.
§63.9(d)	Notification of special compliance requirements for new sources	Yes	Except that §63.9(d) only applies as specified in §63.6645.
§63.9(e)	Notification of performance test	Yes	Except that §63.9(e) only applies as specified in §63.6645.
§63.9(f)	Notification of visible emission (VE)/opacity test	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(1)	Notification of performance evaluation	Yes	Except that §63.9(g) only applies as specified in §63.6645.
§63.9(g)(2)	Notification of use of COMS data	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded	Yes	If alternative is in use.
		Except that §63.9(g) only applies as specified in §63.6645.	
§63.9(h)(1)–(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. §63.9(h)(4) is reserved.
			Except that §63.9(h) only applies as

			specified in §63.6645.
§63.9(i)	Adjustment of submittal deadlines	Yes.	
§63.9(j)	Change in previous information	Yes.	
§63.10(a)	Administrative provisions for recordkeeping/reporting	Yes.	
§63.10(b)(1)	Record retention	Yes.	
§63.10(b)(2)(i)–(v)	Records related to SSM	No.	
§63.10(b)(2)(vi)–(xi)	Records	Yes.	
§63.10(b)(2)(xii)	Record when under waiver	Yes.	
§63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	For CO standard if using RATA alternative.
§63.10(b)(2)(xiv)	Records of supporting documentation	Yes.	
§63.10(b)(3)	Records of applicability determination	Yes.	
§63.10(c)	Additional records for sources using CEMS	Yes	Except that §63.10(c)(2)–(4) and (9) are reserved.
§63.10(d)(1)	General reporting requirements	Yes.	
§63.10(d)(2)	Report of performance test results	Yes.	
§63.10(d)(3)	Reporting opacity or VE observations	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.10(d)(4)	Progress reports	Yes.	
§63.10(d)(5)	Startup, shutdown, and malfunction reports	No.	
§63.10(e)(1) and (2)(i)	Additional CMS Reports	Yes.	
§63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§63.10(e)(3)	Excess emission and parameter exceedances reports	Yes.	Except that §63.10(e)(3)(i) (C) is reserved.
§63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§63.10(f)	Waiver for recordkeeping/reporting	Yes.	
§63.11	Flares	No.	

§63.12	State authority and delegations	Yes.	
§63.13	Addresses	Yes.	
§63.14	Incorporation by reference	Yes.	
§63.15	Availability of information	Yes.	

[75 FR 9688, Mar. 3, 2010]

Browse Next

Georgia-Pacific LLC
Consumer Products

Crossett Paper Operations
100 Mill Supply Road
P.O. Box 3333
Crossett, AR 71635
(870) 567-8000
(870) 364-9076 (fax)
www.gp.com

April 1, 2013

Ms. Mary Pettyjohn, Epidemiologist
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118

Re: Georgia-Pacific LLC Crossett Paper Operations
Best Available Retrofit Technology-Request for Exemption from Five Factor Analysis
AFIN: 02-00013 Title V Permit No. 0597-AOP-R14

Dear Ms. Pettyjohn:

This letter is being submitted pursuant to a teleconference call on March 20, 2013, between a number of people from the Arkansas Department of Environmental Quality, the Region 6 Office of the U.S Environmental Protection Agency, Jim Cutbirth of Georgia Pacific Crossett Paper Operations, and Wayne Galler from Georgia-Pacific's Air Permitting Group in Atlanta, GA. The persons on the teleconference call are listed below:

Arkansas DEQ (ADEQ)

Mary Pettyjohn-Epidemiologist
Stuart Spencer-Attorney Specialist
Derek Brown-Permitting Engineer

Region 6 Office of US EPA

Guy Donaldson-Chief of Air Planning Section
Dayana Medina-Lead Arkansas Regional Haze Coordinator, Air Planning Section
Joe Kordzi-Overall Region 6 Haze Coordinator, Air Planning Section
Michael Feldman, Ph.D.-Regional Haze Modeler, Air Planning Section

Georgia-Pacific (GP)

Jim Cutbirth-Superintendent, Environmental Services, Crossett Paper Operations
Wayne Galler, Director, Air Permitting, Corporate Environmental Affairs Department, Atlanta, GA

The conference call was in response to ADEQ's recent request for additional information[1] to support our

[1] See attached e-mails from Dayan Medina of EPA Region 6, dated Feb. 12 and March 4, 2013

position that the Nos. 6A (SN-19) and 9A (SN-22) Boilers at the Crossett Paper Operations should be "screened out" of the BART requirements. The authority to exempt a source from a "five-factor" analysis, is conditioned on a source's ability to meet the state's criteria conforming to Section III of 40 CFR Part 51 Appendix Y and showing through dispersion modeling.

GP submitted the required dispersion modeling to ADEQ for these two boilers in December 2011[2]. The CALPUFF modeling for the three pollutants of concern (sulfur dioxide-SO_2, nitrogen oxides-NO_x, and particulate matter with an aerodynamic particle size less than 10 microns in diameter-PM_{10}), showed that the total impact from both boilers on five different Class I Areas were all below the 0.5 deciview (dv) screening threshold, with the highest impact value of 0.36 dv shown to occur at the Caney Creek AR National Wilderness Area. A copy of the results of the 2011 CALPUFF modeling analysis was submitted to Mary Pettyjohn on May 18, 2012 and is also attached to this letter.

Wayne Galler explained that the May 18, 2012 CALPUFF modeling submitted to ADEQ was the second time that GP had conducted this work, with the first CALPUFF modeling submitted to the ADEQ in 2007. As part of the Title V Renewal application we prepared in 2008, we used a more conservative NO_x emission factor for natural gas combustion in 6A Boiler. Thus, we prepared a second submittal with CALPUFF modeling to reflect the higher NO_x emission rate from the 6A Boiler to reflect the use of a higher emission factor for natural gas combustion and to also run the CALPUFF model using a lower SO_2 emission rate from the 9A Boiler.

Since the 6A Boiler was originally constructed in approximately 1962, well before the issuance of the New Source Performance Standard (NSPS) at 40 CFR 60 Subpart D, GP should have used a NO_x emission factor of 280 lbs/MM ft^3 natural gas burned for boilers with a heat input rating greater than 250 MM Btu/hr to calculate the NO_x emission rate (see Table 1.4-1 of AP-42). However, GP inadvertently used an emission factor of 100 lbs/MM ft^3 natural gas burned, which is applicable for large natural gas-fired boilers that use flue gas recirculation to reduce NO_x emissions.[3] The 6A Boiler does not have a flue gas recirculation system in place to reduce NO_x emissions.

Mr. Galler then pointed out that the 9A Boiler primarily burns bark and natural gas, but is also permitted to burn tire-derived fuel (TDF) and on-specification grade fuel oil. The 9A Boiler is permitted to burn a number of additional fuels that were not specifically discussed during the call, but include non-condensable gases (NCGs) from the pulp mill operations, agricultural derived fuel (ADF), refuse-derived fuel (RDF), wastewater treatment sludge, paper pellets, used oil absorbent material, and creosote treated railroad ties. The TDF contains sulfur in quantities of approximately 1.0% (wt.). The NCGs contain less than 0.1% (wt.) sulfur content. ADF and the other fuels other than TDF, on-specification oil, and used oil absorbent material, contain negligible quantities of sulfur.

GP determined that the SO_2 emission rate from the 9A Boiler would need to be lower than the existing Title V Permit limit of 502.5 lbs/hr to satisfy the exemption criteria using a screening approach and a revised baseline NO_x emission rate. After reviewing the operation of the 9A Boiler and the fuels burned, and conducting stack testing for SO_2 emissions when TDF and fuel oil were being fired in combination with bark, GP determined that it could operate the 9A Boiler at a lower SO_2 emission rate by reducing the quantity of on-specification grade fuel oil burned in the unit. In addition, the inherent

[2] Section 169A(c) of the Clean Air Act allows sources to be screened out of the BART five-factor analysis requirements if the source will not emit any air pollutant which may reasonably be anticipated to cause or contribute to a significant impairment of visibility in any mandatory Class I Federal area.

[3] The Crossett Mill decided to voluntarily remove on-specification fuel oil as an allowable fuel to be burned in the 6A Boiler as part of Revision R-13 to its Title V Permit.

nature of burning bark in combination with other sulfur-bearing fuels, such as TDF and non-condensable gases (NCGs) from the pulp mill, plus the use of a slightly caustic solution in the wet venturi scrubber, results in the removal of a significant portion of SO_2 emissions generated inside of the boiler. GP requested the ADEQ to reduce the permitted quantity of on-specification grade fuel oil fired in the 9A Boiler from 249.0 MM Btu/hr to 40.9 MM Btu/hr. GP made this request as part of Revision R-13 to its Title V Permit, which was issued by ADEQ on August 4, 2011.

Guy Donaldson of the Region 6 Office pointed out that GP needs to provide EPA and ADEQ detailed information to verify that the actual SO_2 emissions, as well as PM_{10} and NO_x emissions, from the two boilers during the three baseline years of 2001, 2002, and 2003, were below the Title V permit limits for each boiler and the values used in the CALPUFF modeling. Guy also stated that GP needed to explain how the maximum 24-hour emission rate values for the baseline years were calculated. Wayne Galler explained to the group of people on the conference call that the maximum 24-hour average emission rates for the baseline years were based on either stack test results (for PM_{10} emissions only for the 9A Boiler), or published EPA emission factors from AP-42, multiplied by the maximum 24-hour fuel usage for the other pollutants for both boilers.

An Excel spreadsheet that summarizes the 24-hour maximum emission rates for each of the three pollutants used as part of the Class I modeling for both the 6A and 9A Boilers is attached as Table 1. Table 1 also contains a summary of most recent Title V permit limits for SO_2, PM_{10}, and NO_x emissions for each of the boilers[4] which can be compared to the CALPUFF modeled emission rates. Table 1 also contains individual worksheet for each of the three baseline years which list of the daily fuel firing rates for each boiler and the calculated SO_2, PM_{10}, and NO_x emission rates for each day of the year. The details of how the emission rates were calculated for each of the baseline years are more fully explained in Attachment 1 to this letter.

Wayne Galler briefly explained that the daily average emission rates for the three pollutants of concern during the baseline years were all below their respective Title V Permit limits, as shown in Table 1 and summarized below, with the baseline SO_2 emission rates for the 9A Boiler much lower than the Title V Permit limits.

[4] The most recent Title V Permit (R-14) for the Crossett Paper Operations was issued on May 23, 2012.

6A Boiler	SO_2	NO_x	PM_{10}
Maximum Baseline Emissions (lbs/hr)	0.2	90.7	2.5
Modeled Emission Rate (lbs/hr)	0.3	120.0	3.3
Title V Permit Limit (lbs/hr)	0.3	120.0	3.3

9A Boiler	SO_2	NO_x	PM_{10}
Maximum Baseline Emissions (lbs/hr)	17.9	174.1	72.0
Modeled Emission Rate (lbs/hr)	200.0	218.0	75.8
Title V Permit Limit (lbs/hr)	199.8	196.0	77.4

A question was raised from EPA during the call as to why the SO_2 Title V Permit limit for the 9A Boiler was so much higher than the maximum baseline emission rate (TV Permit limit of 199.8 lbs/hr vs. maximum baseline emission rate of 17.8 lbs/hr). Jim Cutbirth explained that the main reason for the large difference between the Title V SO_2 Permit limit and the maximum baseline SO_2 emission rate for the 9A Boiler is due to the Mill's need to preserve a higher SO_2 emission rate for those times when on-specification fuel oil is burned with other fuels in the 9A Boiler. If oil is burned in the 9A Boiler, the hourly SO_2 emission rate will be higher than the maximum baseline emission rate as on-specification fuel oil and TDF were not burned anytime during the three baseline years (2001 through 2003). Some quantity of used oil absorbent material may have been burned with bark and natural gas during the baseline years, but not in amounts sufficient to affect the hourly SO_2 emissions[5].

GP understands that once all of this information is provided to both the ADEQ and to EPA's Region 6 Office, and there has been sufficient time for both agencies to review the data, a decision regarding our request to be formally "screened out" of the BART five-factor requirement will be made by Region 6 and ADEQ. If you have any further requests for information, or if you have any questions that require further explanation of the data being submitted, please do not hesitate to contact me at your earliest convenience at 870-567-8144.

Sincerely,

James W. Cutbirth

James W. Cutbirth, Superintendent, Environmental Services

JWC/wjg

Enclosures

[5] The Mill's Title V Permit (R-14) restricts the amount of oil absorbent material that can be burned in the 9A Boiler to 200 tons per month (see Condition No. 50)

ATTACHMENT 1

EXPLANATION OF 24-HR POLLUTANT BASELINE EMISSION CALCULATIONS FOR BART CALPUFF MODELING 2001-2002-2003

Calculation of Pollutant Emission Rates Emissions for 6A Boiler:

The pollutant emission rate calculations for each baseline year were conducted by taking the daily fuel usage of natural gas fired in the boiler and multiplied by the following emission factors taken from Table 1.4-1 of AP-42 and converting the factors so they are in the same units of measure as the Mill's fuel usage recordkeeping system:

Pollutant	AP-42 Emission Factor lb/MM ft^3	Emission Factor (converted units of gas usage at Mill) lb/M ft^3
PM_{10}	7.6	0.0076
SO_2	0.6	0.0006
NO_x	280	0.28

Example calculation:

Jan 1, 2001 Gas usage for 24-hour period = 459 M ft^3

Daily gas usage values were taken from the Mill's Utility Department electronic recording and recordkeeping system (see "2001 TOTAL FUELS TO BOILERS" tab on attached spreadsheet)

PM_{10} (lbs/hr) = 459 M ft^3/24 hr x 0.0076 lbs/M ft^3 = 0.145 lbs PM_{10}/hr

SO_2 (lbs/hr) = 459 ft^3/24 hr x 0.0006 lbs/M ft^3 = 0.0115 lbs SO_2/hr

NO_x (lbs/hr) = 459 ft^3/24 hr x 0.28 lbs/M ft^3 = 5.355 lbs SO_2/hr

After calculating the hourly pollutant emission rate for each day of the year, the maximum daily emission rate was determined using the "max" function of Excel. For each of the baseline years, the maximum daily emission rates were as follows:

2001 Baseline Year
PM_{10} (May 12) = 2.46 ~ 2.5 lbs/hr
SO_2 (May 12) = 0.19 ~ 0.2 lbs/hr
NO_x (May 12) = 90.67 ~ 90.7 lbs/hr

A similar process for 2002 and 2003 was used to determine the maximum hourly emission rates which are summarized below:

2002 Baseline Year

PM_{10} (March 22 = 1.8 lbs/hr

SO_2 (March 22) = 0.14 ~ 0.1 lbs/hr
NO_x (March 22) = 66.3 lbs/hr

2003 Baseline Year

PM_{10} (December 2) = 1.6 lbs/hr
SO_2 (December 2) = 0.13 ~ 0.1 lbs/hr
NO_x (December 2) = 58.8 lbs/hr

Calculation of Pollutant Emission Rates Emissions for 9A Boiler:

The only fuels burned in the 9A Boiler during the baseline years were natural gas and bark. No TDF or on-specification grade fuel oil was burned, or any other permitted fuels during the period of 2001 through 2003.

The emission rate calculations for SO_2 and NO^x for each baseline year were conducted by taking the daily fuel usage of natural gas and bark fired in the boiler and multiplied by the following emission factors taken from Table 1.6-2 of AP-42 and converting the factors so they are in the same units of measure as the Mill's fuel usage recordkeeping system:

Pollutant	Natural Gas Emission Factors lb/M ft^3	Bark Emission Factors lb/ton
PM_{10}	0.0076	0.594
SO_2	0.0006	0.225
NO_x	0.28	1.98

To convert from the Mill's recordkeeping for bark usage in tons per day to MM Btu/day, the tons of bark fired was multiplied by the average heat content for bark of 4,500 Btu/lb:

1 tons of bark = 2,000 lbs
Btu/ton of bark = 2,000 lbs x 4,500 Btu/lb = 9,000,000

Therefore, there are 9.0 MM Btu/ton of bark fired

Calculations for bark emission factors:

PM_{10} 0.066 lb/MM Btu (from Table 1.6-1 AP-42 for boiler with wet scrubber for PM control – assume PM_{10} = PM filterable)
0.066 lb/MM Btu x 9 MM Btu/ton bark = 0.594 lb/ton bark

SO_2 0.025 lb/MM Btu (from Table 1.6-2 AP-42 for wood-fired boiler)
0.025 lb/MM Btu x 9 MM Btu/ton bark = 0.225 lb/ton bark

NO_x 0.22 lb/MM Btu (from Table 1.6-2 AP-42 for wood-fired boiler)
0.22 lb/MM Btu x 9 MM Btu/ton bark = 1.98 lb/ton bark

Daily gas and bark usage values were taken from the Mill's Utility Department electronic recording and recordkeeping system

Jan 1, 2001 Bark usage for 24-hour period = 814 tons

PM_{10} (lbs/hr) = 814 tons/24 hours x 0.594 lb/ton bark = 20.15 lbs/hr

SO_2 (lbs/hr) = (814 tons/24 hr x 0.225 lbs/ton bark) = 7.63 lbs/hr

NO_x (lbs/hr) = (814 tons/24 hr x 1.98 lbs/ton bark) = 67.15 lbs/hr

Jan 1, 2001 Gas usage for 24-hour period = 2,513 M ft^3

PM_{10} (lbs/hr) = 2,513 M ft^3/24 hr x 0.0076 lbs/M ft^3 = 0.8 lbs PM_{10}/hr

SO_2 (lbs/hr) = 2,513 ft^3/24 hr x 0.0006 lbs/M ft^3 = 0.063 lbs SO_2/hr

NO_x (lbs/hr) = 2,513 ft^3/24 hr x 0.19 lbs/M ft^3 = 19.9 lbs SO_2/hr

Total PM_{10} = 20.15 + 0.8 = 20.95 lbs/hr
Total SO_2 = 7.63 + 0.063 = 7.69 lbs/hr
Total NO_x = 67.15 + 19.9 = 87.0 lbs/hr

(The NO_x emission factor for 9A is 190 lb/MM ft^3 gas from Table 1.4-1 of AP-42 for boilers constructed after 1971 (9A was constructed in 1975) and this emission factor converts to 0.19 lbs/M ft^3 for the units of measure that the Mill's recordkeeping is based on.

For PM_{10} emission calculations, the results from stack testing conducted by the Mill when the 9A Boiler was firing bark and gas was used, as these results were higher than the values calculated using AP-42 emission factors:

Total PM_{10} emission from spreadsheet calculations:

2001: 43.4 lbs/hr
2002: 42.2 lbs/hr
2003: 48.4 lbs/hr

Total PM_{10} emission from stack testing:

2001: 71.99 lbs/hr
2002: 61.0 lbs/hr
2003: 54.3 lbs/hr

Therefore, for the baseline years, we used the stack test results for the PM_{10} emission rates.

The spreadsheet contains several additional worksheets that were used in some of the emission calculations:

6A EFs and 9A EFs-these two worksheets were taken from the Title V application emission calculations and used for the BART emission factor calculations for consistency.

Medina, Dayana

From: Pettyjohn, Mary <PETTYJOHN@adeq.state.ar.us>
Sent: Thursday, March 07, 2013 11:05 AM
To: Galler, Wayne J.
Subject: FW: Region 6 feedback on Georgia Pacific- 6A and 9A boilers

Hi Wayne,

Nice talking with you today.

This is the response from EPA on the 6A boiler. To be BART-eligible a unit has to be in operation between 07 Aug 1962 and 07 Aug 1977. If you can locate documentation showing the 6A boiler was in operation prior to 07 Aug 1962, then this unit would not be BART-eligible.

Another email will follow.

Have a great day,
Mary

From: Medina, Dayana [mailto:Medina.Dayana@epa.gov]
Sent: Monday, March 04, 2013 3:46 PM
To: Pettyjohn, Mary
Cc: Feldman, Michael; Donaldson, Guy
Subject: Region 6 feedback on Georgia Pacific- 6A and 9A boilers

Hi Mary,

One of the action items from our call with you last Thursday was for Region 6 to send an email with feedback concerning the 6A and 9A boilers at the Georgia-Pacific Crossett Mill.

In our action on the Arkansas RH SIP, we disapproved the finding that the 6A Boiler at the Georgia-Pacific Crossett Mill was not BART-eligible. Assuming no new information surfaces regarding boiler 6A, then we continue to believe that the 6A and 9A boilers are BART-eligible and visibility modeling should be performed to determine whether the *combined* visibility impacts from the BART-eligible units at the facility are greater than the 0.5 dv threshold, therefore making the units subject-to-BART. As we previously discussed, we believe the best approach is for Georgia Pacific to use data on production rates, fuel usage, heat capacity, etc., to provide some kind of technical support that would demonstrate that the maximum 24-hr emissions during the 2001-2003 baseline period from the 9A boiler are less than or equal to the new permit limit used in the modeling. We do not believe that relying on the maximum permit allowable without documentation of the baseline period emissions is a good option. Maximum 24-hr emissions from the baseline period from the 6A boiler should be estimated based on available data and also included in the modeling. Should revised modeling demonstrate that the visibility impacts from the source fall below the 0.5 dv threshold at all impacted Class I areas, this would support a determination that the source (6A and 9A boilers) was never subject to BART and no five factor BART analysis is necessary.

Please let me know if you have any questions regarding this issue.

Thank you,

Dayana Medina
U.S. Environmental Protection Agency, Region 6
Multimedia Planning and Permitting Division

Air Planning Section (6PD-L)
214-665-7241
medina.dayana@epa.gov

Medina, Dayana

From:	Pettyjohn, Mary <PETTYJOHN@adeq.state.ar.us>
Sent:	Thursday, March 07, 2013 11:07 AM
To:	Galler, Wayne J.
Subject:	FW: Georgia Pacific

Wayne,

Here is the comment on the 9A boiler.

Mary

From: Medina.Dayana@epamail.epa.gov [mailto:Medina.Dayana@epamail.epa.gov]
Sent: Wednesday, February 06, 2013 1:32 PM
To: Pettyjohn, Mary
Cc: Donaldson.Guy@epamail.epa.gov; Feldman.Michael@epamail.epa.gov
Subject: Re: Georgia Pacific

Hi Mary,

When we discussed this issue with you and others from ADEQ in July, we communicated to you that Georgia Pacific wouldn't have to do a BART analysis for the 9A Boiler, but that they would have to use data on production rates, fuel usage, heat capacity, etc., to provide some kind of technical support that would demonstrate that the 2001-2003 baseline emissions from the source are similar to the emissions expected to result from the new permit limit. The purpose of this would be to help support the claim that the boiler was never subject to BART.

Please let me know if you have any other questions about this.

Thank you,

Dayana Medina
U.S. Environmental Protection Agency, Region 6
Multimedia Planning and Permitting Division
Air Planning Section (6PD-L)
1445 Ross Avenue
Dallas, TX 75202
214-665-7241
medina.dayana@epa.gov

From: "Pettyjohn, Mary" <PETTYJOHN@adeq.state.ar.us>
To: Dayana Medina/R6/USEPA/US@EPA
Cc: Guy Donaldson/R6/USEPA/US@EPA
Date: 02/06/2013 11:43 AM
Subject: Georgia Pacific

Good morning, Dayana

I am writing to request confirmation on EPA's decision that Georgia Pacific's 9A boiler can be exempt from doing a BART analysis. This decision was based on 9A boiler's new SO2 permit limit.

Thank you,
Maru

Mary Pettyjohn
Epidemiologist
Arkansas Department of Environmental Quality
Air Division
5301 Northshore Drive
North Little Rock, AR 72118-5317
Phone: 501-682-0070
Email: pettyjohn@adeq.state.ar.us

[attachment "winmail.dat" deleted by Dayana Medina/R6/USEPA/US]

Table 1. Summary of 2001-2003 Actual Emissions, R-14 Permit Allowables and CALPUFF M

	Daily Average lbs/hr Actual Emissions				
	2001	2002	2003	3-year Max.	Title V Permit Limit lbs/hr (R-14)
				6A Boiler	
Max PM_{10}	2.5	1.8	1.6	2.5	3.3
Max SO_2	0.2	0.1	0.1	0.2	0.3
Max NO_x (a)	90.7	66.3	58.8	90.7	120.0
				9A Boiler	
Max PM_{10} (b)	72.0	61.0	54.3	72.0	77.4
Max SO_2 (c)	16.3	15.8	17.9	17.9	199.8
Max NO_x	171.4	174.1	190.1	190.1	196.0

(a) NO_x emissions in the 2009 CALPUFF modeling for the 6A Boiler were originally based on the use of an incorr
This error was discovered and the correct emission factor of 280 lbs NO_x/MM ft^3 was used and the CALPUFF

(b) The greater of the annual PM stack test results (average of three, 1-hr runs) and the calculated daily emission
For all three baseline years, the stack test results were used as the highest hourly and therefore the daily ma:

(c) During 2001-2003, no on-specification fuel oil or tire-derived fuel was burned in the 9A Boiler. The Title V Per

(d) CALPUFF model for particulate matter conservatively treats all modeled particulate mass using a mean diame

2001

GEORGIA-PACIFIC CORPORATION
SOUTHERN PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

Daily Meter Readings/Production Trends

	6A Boiler					*	9A Boiler			*			
	Gas Mcf	Oil Bbls				*	Gas Mcf	TDF Tons	Bark Tons	*			
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO_2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOx EF	2.80E-01	NA	PM	SO_2	NOx		1.90E-01	1.98E+00	1.98E+00		PM	SO_2	NOx
31-Dec	3,649	0	1.16	0.09	42.57	*	2,831	0.0	1,284	*	32.68	12.11	128
01-Jan	459	0	0.145	0.0115	5.355	*	2,513	0.0	814	*	20.94	7.69	87.0
02-Jan	4,285	0	1.36	0.11	49.99	*	1,732	0.0	1,380	*	34.71	12.98	128
03-Jan	963	0	0.30	0.02	11.24	*	1,267	0.0	1,275	*	31.95	11.98	115
04-Jan	2,496	0	0.79	0.06	29.12	*	1,570	0.0	1,073	*	27.06	10.10	101
05-Jan	4,196	0	1.33	0.10	48.95	*	960	0.0	918	*	23.02	8.63	83
06-Jan	4,121	0	1.30	0.10	48.08	*	719	0.0	1,278	*	31.85	12.00	111
07-Jan	997	0	0.32	0.02	11.63	*	443	0.0	1,203	*	29.92	11.29	103
08-Jan	3,381	0	1.07	0.08	39.45	*	373	0.0	1,341	*	33.32	12.58	114
09-Jan	3,508	0	1.11	0.09	40.93	*	155	0.0	1,261	*	31.26	11.83	105
10-Jan	3,444	0	1.09	0.09	40.18	*	1,100	0.0	800	*	20.15	7.53	75
11-Jan	4,808	0	1.52	0.12	56.09	*	1,052	0.0	1,455	*	36.35	13.67	128
12-Jan	4,743	0	1.50	0.12	55.34	*	2,096	0.0	1,524	*	38.39	14.34	142
13-Jan	3,480	0	1.10	0.09	40.60	*	155	0.0	1,382	*	34.24	12.96	115
14-Jan	3,229	0	1.02	0.08	37.67	*	102	0.0	1,354	*	33.55	12.70	113
15-Jan	4,555	0	1.44	0.11	53.14	*	716	0.0	573	*	14.41	5.39	53
16-Jan	5,633	0	1.78	0.14	65.72	*	2,678	0.0	649	*	16.90	6.15	75
17-Jan	5,971	0	1.89	0.15	69.66	*	4,375	0.0	1,005	*	26.27	9.53	118
18-Jan	6,319	0	2.00	0.16	73.72	*	8,199	0.0	1,047	*	28.52	10.02	151
19-Jan	6,561	0	2.08	0.16	76.55	*	8,984	0.0	1,207	*	32.71	11.54	171

2001

GEORGIA-PACIFIC CORPORATION
SOUTHERN PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

Daily Meter Readings/Production Trends

	6A Boiler					*	9A Boiler			*			
	Gas Mcf	Oil Bbls				*	Gas Mcf	TDF Tons	Bark Tons	*			
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO_2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOx EF	2.80E-01	NA	PM	SO_2	NOx		1.90E-01	1.98E+00	1.98E+00		PM	SO_2	NOx
20-Jan	4,839	0	1.53	0.12	56.46	*	5,172	0.0	962	*	25.44	9.14	120
21-Jan	4,296	0	1.36	0.11	50.12	*	3,440	0.0	1,391	*	35.52	13.13	142
22-Jan	3,603	0	1.14	0.09	42.04	*	697	0.0	1,367	*	34.04	12.83	118
23-Jan	5,073	0	1.61	0.13	59.19	*	943	0.0	652	*	16.44	6.14	61
24-Jan	4,849	0	1.54	0.12	56.57	*	764	0.0	844	*	21.12	7.93	76
25-Jan	5,607	0	1.78	0.14	65.42	*	589	0.0	522	*	13.11	4.91	48
26-Jan	5,169	0	1.64	0.13	60.31	*	0	0.0	0	*	0.00	0.00	0
27-Jan	5,407	0	1.71	0.14	63.08	*	0	0.0	0	*	0.00	0.00	0
28-Jan	5,695	0	1.80	0.14	66.44	*	0	0.0	0	*	0.00	0.00	0
29-Jan	6,235	0	1.97	0.16	72.74	*	0	0.0	0	*	0.00	0.00	0
30-Jan	3,787	0	1.20	0.09	44.18	*	704	0.0	658	*	16.51	6.19	60
31-Jan	1,741	0	0.55	0.04	20.31	*	586	0.0	1,161	*	28.92	10.90	100
01-Feb	4,449	0	1.41	0.11	51.91	*	1,318	0.0	636	*	16.15	5.99	63
02-Feb	6,092	0	1.93	0.15	71.07	*	0	0.0	0	*	0.00	0.00	0
03-Feb	4,964	0	1.57	0.12	57.91	*	523	0.0	782	*	19.52	7.35	69
04-Feb	3,271	0	1.04	0.08	38.16	*	125	0.0	1,569	*	38.88	14.71	130
05-Feb	3,019	0	0.96	0.08	35.22	*	254	0.0	1,520	*	37.69	14.25	127
06-Feb	2,764	0	0.88	0.07	32.25	*	719	0.0	1,373	*	34.21	12.89	119
07-Feb	2,370	0	0.75	0.06	27.65	*	143	0.0	1,252	*	31.04	11.74	104
08-Feb	2,370	0	0.75	0.06	27.65	*	470	0.0	1,249	*	31.05	11.72	107
09-Feb	2,513	0	0.80	0.06	29.32	*	447	0.0	1,362	*	33.86	12.78	116

GEORGIA-PACIFIC CORPORATION
SOUTHERN PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

Daily Meter Readings/Production Trends

	6A Boiler					*	9A Boiler			*			
	Gas Mcf	Oil Bbls				*	Gas Mcf	TDF Tons	Bark Tons	*			
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO_2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOx EF	2.80E-01	NA	PM	SO_2	NOx		1.90E-01	1.98E+00	1.98E+00		PM	SO_2	NOx
10-Feb	3,341	0	1.06	0.08	38.98	*	240	0.0	1,386	*	34.38	13.00	116
11-Feb	4,477	0	1.42	0.11	52.23	*	225	0.0	1,454	*	36.06	13.64	122
12-Feb	5,275	0	1.67	0.13	61.54	*	843	0.0	1,356	*	33.82	12.73	119
13-Feb	3,984	0	1.26	0.10	46.48	*	394	0.0	1,369	*	34.02	12.85	116
14-Feb	2,357	0	0.75	0.06	27.50	*	652	0.0	1,477	*	36.77	13.87	127
15-Feb	75	0	0.02	0.00	0.88	*	836	0.0	1,374	*	34.27	12.90	120
16-Feb	0	0	0.00	0.00	0.00	*	1,639	0.0	1,376	*	34.57	12.94	126
17-Feb	0	0	0.00	0.00	0.00	*	2,165	0.0	1,387	*	35.02	13.06	132
18-Feb	0	0	0.00	0.00	0.00	*	962	0.0	1,365	*	34.08	12.82	120
19-Feb	0	0	0.00	0.00	0.00	*	1,717	0.0	1,431	*	35.96	13.46	132
20-Feb	0	0	0.00	0.00	0.00	*	319	0.0	1,514	*	37.58	14.21	127
21-Feb	0	0	0.00	0.00	0.00	*	135	0.0	1,402	*	34.75	13.15	117
22-Feb	0	0	0.00	0.00	0.00	*	183	0.0	1,374	*	34.06	12.88	115
23-Feb	0	0	0.00	0.00	0.00	*	131	0.0	1,351	*	33.47	12.67	112
24-Feb	0	0	0.00	0.00	0.00	*	937	0.0	1,253	*	31.31	11.77	111
25-Feb	0	0	0.00	0.00	0.00	*	498	0.0	1,245	*	30.96	11.68	107
26-Feb	0	0	0.00	0.00	0.00	*	377	0.0	1,209	*	30.04	11.34	103
27-Feb	0	0	0.00	0.00	0.00	*	2,945	0.0	1,347	*	34.28	12.71	134
28-Feb	1,657	0	0.52	0.04	19.33	*	3,150	0.0	1,394	*	35.51	13.15	140
01-Mar	4,889	0	1.55	0.12	57.04	*	3,769	0.0	1,312	*	33.66	12.39	138
02-Mar	5,781	0	1.83	0.14	67.45	*	4,750	0.0	1,284	*	33.28	12.16	144

GEORGIA-PACIFIC CORPORATION
SOUTHERN PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R M I L L U T I L I T Y R E P O R T

Daily Meter Readings/Production Trends

	6A Boiler					*	9A Boiler			*			
	Gas Mcf	Oil Bbls				*	Gas Mcf	TDF Tons	Bark Tons	*			
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO_2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOx EF	2.80E-01	NA	PM	SO_2	NOx		1.90E-01	1.98E+00	1.98E+00		PM	SO_2	NOx
03-Mar	5,632	0	1.78	0.14	65.71	*	4,705	0.0	1,273	*	33.00	12.05	142
04-Mar	5,371	0	1.70	0.13	62.66	*	5,247	0.0	1,401	*	36.34	13.27	157
05-Mar	5,367	0	1.70	0.13	62.62	*	4,147	0.0	1,484	*	38.05	14.02	155
06-Mar	5,304	0	1.68	0.13	61.88	*	4,741	0.0	1,568	*	40.32	14.82	167
07-Mar	5,187	0	1.64	0.13	60.52	*	5,229	0.0	1,110	*	29.12	10.53	133
08-Mar	4,470	0	1.42	0.11	52.15	*	3,255	0.0	1,458	*	37.11	13.75	146
09-Mar	5,305	0	1.68	0.13	61.89	*	4,596	0.0	1,531	*	39.35	14.47	163
10-Mar	6,032	0	1.91	0.15	70.37	*	3,852	0.0	1,554	*	39.67	14.66	159
11-Mar	5,909	0	1.87	0.15	68.94	*	4,255	0.0	1,480	*	37.97	13.98	156
12-Mar	5,940	0	1.88	0.15	69.30	*	4,593	0.0	1,564	*	40.16	14.78	165
13-Mar	5,475	0	1.73	0.14	63.88	*	4,533	0.0	1,611	*	41.31	15.22	169
14-Mar	4,124	0	1.31	0.10	48.11	*	2,996	0.0	1,379	*	35.07	13.00	137
15-Mar	4,293	0	1.36	0.11	50.09	*	3,779	0.0	1,362	*	34.92	12.87	142
16-Mar	965	0	0.31	0.02	11.26	*	3,775	0.0	1,078	*	27.88	10.20	119
17-Mar	0	0	0.00	0.00	0.00	*	464	0.0	1,493	*	37.09	14.01	127
18-Mar	0	0	0.00	0.00	0.00	*	1,017	0.0	1,418	*	35.42	13.32	125
19-Mar	467	0	0.15	0.01	5.45	*	785	0.0	1,470	*	36.63	13.80	127
20-Mar	1,036	0	0.33	0.03	12.09	*	402	0.0	1,167	*	29.01	10.95	99
21-Mar	0	0	0.00	0.00	0.00	*	380	0.0	1,342	*	33.33	12.59	114
22-Mar	0	0	0.00	0.00	0.00	*	340	0.0	1,455	*	36.13	13.65	123
23-Mar	0	0	0.00	0.00	0.00	*	342	0.0	1,288	*	31.98	12.08	109

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GEORGIA-PACIFIC CORPORATION
SOUTHERN PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

Daily Meter Readings/Production Trends

	6A Boiler Gas Mcf	6A Boiler Oil Bbls	PM	SO_2	NOx	*	9A Boiler Gas Mcf	TDF Tons	Bark Tons	*	PM	SO_2	NOx
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO_2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOx EF	2.80E-01	NA					1.90E-01	1.98E+00	1.98E+00				
24-Mar	2,143	0	0.68	0.05	25.00	*	3,602	0.0	926	*	24.05	8.77	105
25-Mar	5,249	0	1.66	0.13	61.24	*	5,623	0.0	319	*	9.68	3.13	71
26-Mar	5,432	0	1.72	0.14	63.37	*	0	0.0	0	*	0.00	0.00	0
27-Mar	5,791	0	1.83	0.14	67.56	*	0	0.0	0	*	0.00	0.00	0
28-Mar	5,556	0	1.76	0.14	64.82	*	0	0.0	0	*	0.00	0.00	0
29-Mar	4,473	0	1.42	0.11	52.19	*	0	0.0	0	*	0.00	0.00	0
30-Mar	3,929	0	1.24	0.10	45.84	*	0	0.0	0	*	0.00	0.00	0
31-Mar	3,093	0	0.98	0.08	36.09	*	0	0.0	0	*	0.00	0.00	0
01-Apr	5,185	0	1.64	0.13	60.49	*	0	0.0	0	*	0.00	0.00	0
02-Apr	5,375	0	1.70	0.13	62.71	*	0	0.0	0	*	0.00	0.00	0
03-Apr	4,365	0	1.38	0.11	50.93	*	0	0.0	0	*	0.00	0.00	0
04-Apr	3,192	0	1.01	0.08	37.24	*	0	0.0	0	*	0.00	0.00	0
05-Apr	4,124	0	1.31	0.10	48.11	*	0	0.0	0	*	0.00	0.00	0
06-Apr	4,425	0	1.40	0.11	51.63	*	0	0.0	0	*	0.00	0.00	0
07-Apr	4,535	0	1.44	0.11	52.91	*	0	0.0	0	*	0.00	0.00	0
08-Apr	4,935	0	1.56	0.12	57.58	*	0	0.0	0	*	0.00	0.00	0
09-Apr	5,416	0	1.72	0.14	63.19	*	0	0.0	0	*	0.00	0.00	0
10-Apr	5,179	0	1.64	0.13	60.42	*	0	0.0	0	*	0.00	0.00	0
11-Apr	2,244	0	0.71	0.06	26.18	*	0	0.0	0	*	0.00	0.00	0
12-Apr	4,363	0	1.38	0.11	50.90	*	0	0.0	0	*	0.00	0.00	0
13-Apr	4,033	0	1.28	0.10	47.05	*	0	0.0	0	*	0.00	0.00	0

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GEORGIA-PACIFIC CORPORATION
SOUTHERN PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

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Daily Meter Readings/Production Trends

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	6A Boiler					*	9A Boiler			*			
	Gas Mcf	Oil Bbls				*	Gas Mcf	TDF Tons	Bark Tons	*			
PM_{10} EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO_2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOx EF	2.80E-01	NA	PM	SO_2	NOx		1.90E-01	1.98E+00	1.98E+00		PM	SO_2	NOx
14-Apr	5,067	0	1.60	0.13	59.12	*	233	0.0	0	*	0.07	0.01	2
15-Apr	2,572	0	0.81	0.06	30.01	*	5,681	0.0	373	*	11.02	3.64	76
16-Apr	3,633	0	1.15	0.09	42.39	*	1,957	0.0	969	*	24.61	9.13	95
17-Apr	3,341	0	1.06	0.08	38.98	*	611	0.0	1,268	*	31.58	11.91	109
18-Apr	4,088	0	1.29	0.10	47.69	*	2,025	0.0	1,047	*	26.55	9.87	102
19-Apr	2,657	0	0.84	0.07	31.00	*	565	0.0	1,021	*	25.45	9.59	89
20-Apr	328	0	0.10	0.01	3.83	*	207	0.0	1,447	*	35.88	13.57	121
21-Apr	0	0	0.00	0.00	0.00	*	240	0.0	1,244	*	30.87	11.67	105
22-Apr	0	0	0.00	0.00	0.00	*	412	0.0	1,209	*	30.05	11.34	103
23-Apr	0	0	0.00	0.00	0.00	*	290	0.0	1,093	*	27.14	10.25	92
24-Apr	0	0	0.00	0.00	0.00	*	969	0.0	1,347	*	33.65	12.65	119
25-Apr	0	0	0.00	0.00	0.00	*	196	0.0	1,204	*	29.87	11.30	101
26-Apr	0	0	0.00	0.00	0.00	*	211	0.0	1,161	*	28.81	10.89	97
27-Apr	0	0	0.00	0.00	0.00	*	459	0.0	1,083	*	26.94	10.16	93
28-Apr	0	0	0.00	0.00	0.00	*	302	0.0	1,077	*	26.76	10.11	91
29-Apr	0	0	0.00	0.00	0.00	*	225	0.0	1,084	*	26.90	10.17	91
30-Apr	0	0	0.00	0.00	0.00	*	1,952	0.0	968	*	24.58	9.13	95
01-May	0	0	0.00	0.00	0.00	*	219	0.0	1,478	*	36.66	13.86	124
02-May	0	0	0.00	0.00	0.00	*	205	0.0	1,496	*	37.10	14.03	125
03-May	0	0	0.00	0.00	0.00	*	201	0.0	1,504	*	37.29	14.10	126
04-May	0	0	0.00	0.00	0.00	*	203	0.0	1,519	*	37.66	14.24	127

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GEORGIA-PACIFIC CORPORATION
SOUTHERN PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

Daily Meter Readings/Production Trends

	6A Boiler Gas Mcf	6A Boiler Oil Bbls	Calculated lbs/hr PM	Calculated lbs/hr SO_2	Calculated lbs/hr NOx	*	9A Boiler Gas Mcf	9A Boiler TDF Tons	9A Boiler Bark Tons	*	Calculated lbs/hr PM	Calculated lbs/hr SO_2	Calculated lbs/hr NOx
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO_2 EF	6.00E-04	NA					6.00E-04	3.08E+01	2.25E-01				
NOx EF	2.80E-01	NA					1.90E-01	1.98E+00	1.98E+00				
05-May	0	0	0.00	0.00	0.00	*	209	0.0	1,358	*	33.68	12.74	114
06-May	0	0	0.00	0.00	0.00	*	207	0.0	1,346	*	33.38	12.62	113
07-May	0	0	0.00	0.00	0.00	*	287	0.0	1,214	*	30.13	11.39	102
08-May	0	0	0.00	0.00	0.00	*	201	0.0	1,428	*	35.40	13.39	119
09-May	0	0	0.00	0.00	0.00	*	207	0.0	1,509	*	37.41	14.15	126
10-May	0	0	0.00	0.00	0.00	*	546	0.0	1,484	*	36.90	13.92	127
11-May	4,067	0	1.29	0.10	47.45	*	465	0.0	1,157	*	28.77	10.85	99
12-May	7,772	0	**2.46**	**0.19**	**90.67**	*	1,982	0.0	1,729	*	43.42	16.26	158
13-May	3,763	0	1.19	0.09	43.90	*	219	0.0	1,553	*	38.50	14.56	130
14-May	0	0	0.00	0.00	0.00	*	367	0.0	118	*	3.04	1.12	13
15-May	0	0	0.00	0.00	0.00	*	119	0.0	0	*	0.04	0.00	1
16-May	0	0	0.00	0.00	0.00	*	1,034	0.0	81	*	2.33	0.79	15
17-May	0	0	0.00	0.00	0.00	*	1,058	0.0	1,290	*	32.26	12.12	115
18-May	2,764	0	0.88	0.07	32.25	*	537	0.0	1,631	*	40.55	15.31	139
19-May	3,947	0	1.25	0.10	46.05	*	972	0.0	1,581	*	39.44	14.85	138
20-May	2,400	0	0.76	0.06	28.00	*	2,498	0.0	920	*	23.57	8.69	96
21-May	2,710	0	0.86	0.07	31.62	*	836	0.0	1,310	*	32.67	12.30	115
22-May	573	0	0.18	0.01	6.69	*	244	0.0	1,263	*	31.34	11.85	106
23-May	0	0	0.00	0.00	0.00	*	494	0.0	1,336	*	33.23	12.54	114
24-May	0	0	0.00	0.00	0.00	*	207	0.0	1,113	*	27.60	10.44	93
25-May	0	0	0.00	0.00	0.00	*	335	0.0	1,352	*	33.58	12.69	114

GEORGIA-PACIFIC CORPORATION
SOUTHERN PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

Daily Meter Readings/Production Trends

	6A Boiler Gas Mcf	6A Boiler Oil Bbls	Calculated lbs/hr PM	Calculated lbs/hr SO_2	Calculated lbs/hr NOx	*	9A Boiler Gas Mcf	9A Boiler TDF Tons	9A Boiler Bark Tons	*	Calculated lbs/hr PM	Calculated lbs/hr SO_2	Calculated lbs/hr NOx
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO_2 EF	6.00E-04	NA					6.00E-04	3.08E+01	2.25E-01				
NOx EF	2.80E-01	NA					1.90E-01	1.98E+00	1.98E+00				
26-May	0	0	0.00	0.00	0.00	*	359	0.0	1,111	*	27.62	10.43	95
27-May	0	0	0.00	0.00	0.00	*	209	0.0	1,131	*	28.05	10.61	95
28-May	2,187	0	0.69	0.05	25.52	*	586	0.0	440	*	11.06	4.13	41
29-May	3,199	0	1.01	0.08	37.32	*	0	0.0	0	*	0.00	0.00	0
30-May	2,658	0	0.84	0.07	31.01	*	0	0.0	0	*	0.00	0.00	0
31-May	3,459	0	1.10	0.09	40.36	*	465	0.0	190	*	4.85	1.79	19
01-Jun	225	0	0.07	0.01	2.63	*	339	0.0	1,398	*	34.72	13.12	118
02-Jun	0	0	0.00	0.00	0.00	*	1,021	0.0	1,356	*	33.89	12.74	120
03-Jun	0	0	0.00	0.00	0.00	*	440	0.0	1,302	*	32.37	12.22	111
04-Jun	0	0	0.00	0.00	0.00	*	987	0.0	1,168	*	29.22	10.98	104
05-Jun	3,303	0	1.05	0.08	38.54	*	784	0.0	147	*	3.88	1.39	18
06-Jun	0	0	0.00	0.00	0.00	*	198	0.0	1,087	*	26.97	10.20	91
07-Jun	0	0	0.00	0.00	0.00	*	203	0.0	1,067	*	26.46	10.00	90
08-Jun	0	0	0.00	0.00	0.00	*	206	0.0	1,300	*	32.24	12.19	109
09-Jun	0	0	0.00	0.00	0.00	*	213	0.0	1,287	*	31.91	12.07	108
10-Jun	0	0	0.00	0.00	0.00	*	214	0.0	1,236	*	30.65	11.59	104
11-Jun	0	0	0.00	0.00	0.00	*	223	0.0	1,229	*	30.49	11.53	103
12-Jun	0	0	0.00	0.00	0.00	*	217	0.0	1,115	*	27.67	10.46	94
13-Jun	0	0	0.00	0.00	0.00	*	359	0.0	860	*	21.41	8.08	74
14-Jun	0	0	0.00	0.00	0.00	*	394	0.0	902	*	22.46	8.47	78
15-Jun	0	0	0.00	0.00	0.00	*	222	0.0	1,035	*	25.67	9.70	87

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GEORGIA-PACIFIC CORPORATION
SOUTHERN PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

Daily Meter Readings/Production Trends

	6A Boiler					*	9A Boiler			*			
	Gas Mcf	Oil Bbls				*	Gas Mcf	TDF Tons	Bark Tons	*			
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO_2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOx EF	2.80E-01	NA	PM	SO_2	NOx		1.90E-01	1.98E+00	1.98E+00		PM	SO_2	NOx
16-Jun	0	0	0.00	0.00	0.00	*	272	0.0	1,168	*	28.99	10.96	99
17-Jun	0	0	0.00	0.00	0.00	*	395	0.0	1,094	*	27.20	10.26	93
18-Jun	0	0	0.00	0.00	0.00	*	214	0.0	1,077	*	26.73	10.10	91
19-Jun	0	0	0.00	0.00	0.00	*	211	0.0	1,050	*	26.06	9.85	88
20-Jun	0	0	0.00	0.00	0.00	*	215	0.0	1,024	*	25.41	9.60	86
21-Jun	0	0	0.00	0.00	0.00	*	1,081	0.0	1,162	*	29.11	10.92	104
22-Jun	0	0	0.00	0.00	0.00	*	214	0.0	1,304	*	32.34	12.23	109
23-Jun	0	0	0.00	0.00	0.00	*	220	0.0	1,227	*	30.43	11.50	103
24-Jun	0	0	0.00	0.00	0.00	*	270	0.0	1,067	*	26.48	10.01	90
25-Jun	0	0	0.00	0.00	0.00	*	212	0.0	1,083	*	26.87	10.16	91
26-Jun	0	0	0.00	0.00	0.00	*	280	0.0	1,080	*	26.82	10.13	91
27-Jun	0	0	0.00	0.00	0.00	*	316	0.0	1,148	*	28.52	10.77	97
28-Jun	0	0	0.00	0.00	0.00	*	377	0.0	1,209	*	30.03	11.34	103
29-Jun	0	0	0.00	0.00	0.00	*	204	0.0	1,335	*	33.12	12.52	112
30-Jun	0	0	0.00	0.00	0.00	*	225	0.0	1,195	*	29.64	11.21	100
01-Jul	0	0	0.00	0.00	0.00	*	225	0.0	1,120	*	27.80	10.51	94
02-Jul	0	0	0.00	0.00	0.00	*	232	0.0	1,014	*	25.17	9.51	85
03-Jul	0	0	0.00	0.00	0.00	*	229	0.0	978	*	24.29	9.18	83
04-Jul	635	0	0.20	0.02	7.41	*	639	0.0	1,034	*	25.79	9.71	90
05-Jul	1,589	0	0.50	0.04	18.54	*	1,503	0.0	1,360	*	34.13	12.78	124
06-Jul	939	0	0.30	0.02	10.96	*	2,649	0.0	508	*	13.42	4.83	63

GEORGIA-PACIFIC CORPORATION
SOUTHERN PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

Daily Meter Readings/Production Trends

	6A Boiler					*	9A Boiler			*			
	Gas Mcf	Oil Bbls				*	Gas Mcf	TDF Tons	Bark Tons	*			
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO_2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOx EF	2.80E-01	NA	PM	SO_2	NOx		1.90E-01	1.98E+00	1.98E+00		PM	SO_2	NOx
07-Jul	3,493	0	1.11	0.09	40.75	*	457	0.0	0	*	0.14	0.01	4
08-Jul	69	0	0.02	0.00	0.81	*	1,417	0.0	1,123	*	28.24	10.56	104
09-Jul	3,573	0	1.13	0.09	41.69	*	4,367	0.0	1,659	*	42.44	15.66	171
10-Jul	4,026	0	1.27	0.10	46.97	*	5,021	0.0	1,268	*	32.97	12.01	144
11-Jul	921	0	0.29	0.02	10.75	*	2,586	0.0	1,529	*	38.66	14.40	147
12-Jul	0	0	0.00	0.00	0.00	*	228	0.0	1,196	*	29.67	11.22	100
13-Jul	0	0	0.00	0.00	0.00	*	206	0.0	1,309	*	32.45	12.27	110
14-Jul	0	0	0.00	0.00	0.00	*	370	0.0	1,460	*	36.26	13.70	123
15-Jul	0	0	0.00	0.00	0.00	*	257	0.0	1,048	*	26.01	9.83	88
16-Jul	0	0	0.00	0.00	0.00	*	217	0.0	1,190	*	29.52	11.16	100
17-Jul	0	0	0.00	0.00	0.00	*	293	0.0	1,367	*	33.93	12.83	115
18-Jul	0	0	0.00	0.00	0.00	*	680	0.0	1,069	*	26.67	10.04	94
19-Jul	0	0	0.00	0.00	0.00	*	1,058	0.0	1,282	*	32.07	12.05	114
20-Jul	0	0	0.00	0.00	0.00	*	252	0.0	1,284	*	31.86	12.05	108
21-Jul	0	0	0.00	0.00	0.00	*	1,515	0.0	1,062	*	26.76	9.99	100
22-Jul	0	0	0.00	0.00	0.00	*	1,248	0.0	1,213	*	30.42	11.41	110
23-Jul	1,391	0	0.44	0.03	16.23	*	585	0.0	1,508	*	37.50	14.15	129
24-Jul	1,229	0	0.39	0.03	14.34	*	247	0.0	1,309	*	32.48	12.28	110
25-Jul	0	0	0.00	0.00	0.00	*	223	0.0	1,447	*	35.88	13.57	121
26-Jul	0	0	0.00	0.00	0.00	*	997	0.0	1,160	*	29.03	10.90	104
27-Jul	0	0	0.00	0.00	0.00	*	789	0.0	1,213	*	30.28	11.40	106

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GEORGIA-PACIFIC CORPORATION
SOUTHERN PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

Daily Meter Readings/Production Trends

	6A Boiler Gas Mcf	6A Boiler Oil Bbls	6A Calculated lbs/hr PM	6A Calculated lbs/hr SO_2	6A Calculated lbs/hr NOx	*	9A Boiler Gas Mcf	9A Boiler TDF Tons	9A Boiler Bark Tons	*	9A Calculated lbs/hr PM	9A Calculated lbs/hr SO_2	9A Calculated lbs/hr NOx
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO_2 EF	6.00E-04	NA					6.00E-04	3.08E+01	2.25E-01				
NOx EF	2.80E-01	NA					1.90E-01	1.98E+00	1.98E+00				
28-Jul	0	0	0.00	0.00	0.00	*	230	0.0	922	*	22.88	8.65	78
29-Jul	0	0	0.00	0.00	0.00	*	230	0.0	902	*	22.39	8.46	76
30-Jul	0	0	0.00	0.00	0.00	*	360	0.0	1,403	*	34.84	13.16	119
31-Jul	0	0	0.00	0.00	0.00	*	294	0.0	1,166	*	28.95	10.94	99
01-Aug	0	0	0.00	0.00	0.00	*	230	0.0	1,397	*	34.65	13.10	117
02-Aug	796	0	0.25	0.02	9.29	*	1,776	0.0	1,474	*	37.05	13.86	136
03-Aug	0	0	0.00	0.00	0.00	*	342	0.0	1,292	*	32.09	12.12	109
04-Aug	4,704	0	1.49	0.12	54.88	*	1,231	0.0	1,550	*	38.76	14.57	138
05-Aug	1,546	0	0.49	0.04	18.04	*	1,172	0.0	1,352	*	33.84	12.71	121
06-Aug	0	0	0.00	0.00	0.00	*	215	0.0	1,186	*	29.42	11.13	100
07-Aug	0	0	0.00	0.00	0.00	*	237	0.0	980	*	24.32	9.19	83
08-Aug	0	0	0.00	0.00	0.00	*	351	0.0	880	*	21.90	8.26	75
09-Aug	0	0	0.00	0.00	0.00	*	230	0.0	1,232	*	30.55	11.55	103
10-Aug	0	0	0.00	0.00	0.00	*	508	0.0	1,034	*	25.76	9.71	89
11-Aug	0	0	0.00	0.00	0.00	*	299	0.0	1,146	*	28.46	10.75	97
12-Aug	0	0	0.00	0.00	0.00	*	215	0.0	1,144	*	28.37	10.73	96
13-Aug	0	0	0.00	0.00	0.00	*	218	0.0	1,169	*	29.00	10.96	98
14-Aug	0	0	0.00	0.00	0.00	*	250	0.0	1,229	*	30.49	11.53	103
15-Aug	0	0	0.00	0.00	0.00	*	308	0.0	1,123	*	27.89	10.53	95
16-Aug	0	0	0.00	0.00	0.00	*	255	0.0	1,286	*	31.91	12.06	108
17-Aug	3,174	0	1.01	0.08	37.03	*	245	0.0	179	*	4.50	1.68	17

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GEORGIA-PACIFIC CORPORATION
SOUTHERN PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

Daily Meter Readings/Production Trends

	6A Boiler					*	9A Boiler			*			
	Gas Mcf	Oil Bbls				*	Gas Mcf	TDF Tons	Bark Tons	*			
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO_2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOx EF	2.80E-01	NA	PM	SO_2	NOx		1.90E-01	1.98E+00	1.98E+00		PM	SO_2	NOx
18-Aug	4,612	0	1.46	0.12	53.81	*	0	0.0	0	*	0.00	0.00	0
19-Aug	4,731	0	1.50	0.12	55.20	*	0	0.0	0	*	0.00	0.00	0
20-Aug	4,700	0	1.49	0.12	54.83	*	0	0.0	0	*	0.00	0.00	0
21-Aug	4,592	0	1.45	0.11	53.57	*	0	0.0	0	*	0.00	0.00	0
22-Aug	5,178	0	1.64	0.13	60.41	*	1,226	0.0	60	*	1.87	0.59	15
23-Aug	182	0	0.06	0.00	2.12	*	4,276	0.0	590	*	15.95	5.64	83
24-Aug	0	0	0.00	0.00	0.00	*	4,305	0.0	713	*	19.00	6.79	93
25-Aug	0	0	0.00	0.00	0.00	*	1,000	0.0	985	*	24.69	9.26	89
26-Aug	0	0	0.00	0.00	0.00	*	294	0.0	925	*	23.00	8.68	79
27-Aug	0	0	0.00	0.00	0.00	*	235	0.0	1,137	*	28.21	10.66	96
28-Aug	0	0	0.00	0.00	0.00	*	156	0.0	1,103	*	27.35	10.35	92
29-Aug	0	0	0.00	0.00	0.00	*	225	0.0	1,256	*	31.15	11.78	105
30-Aug	0	0	0.00	0.00	0.00	*	206	0.0	1,047	*	25.98	9.82	88
31-Aug	0	0	0.00	0.00	0.00	*	140	0.0	1,187	*	29.43	11.13	99
01-Sep	0	0	0.00	0.00	0.00	*	223	0.0	1,216	*	30.17	11.41	102
02-Sep	0	0	0.00	0.00	0.00	*	341	0.0	1,470	*	36.49	13.79	124
03-Sep	0	0	0.00	0.00	0.00	*	229	0.0	1,380	*	34.22	12.94	116
04-Sep	0	0	0.00	0.00	0.00	*	229	0.0	1,263	*	31.32	11.84	106
05-Sep	0	0	0.00	0.00	0.00	*	232	0.0	1,055	*	26.19	9.90	89
06-Sep	0	0	0.00	0.00	0.00	*	234	0.0	987	*	24.51	9.26	83
07-Sep	0	0	0.00	0.00	0.00	*	223	0.0	1,011	*	25.08	9.48	85

GEORGIA-PACIFIC CORPORATION
SOUTHERN PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

Daily Meter Readings/Production Trends

	6A Boiler					*	9A Boiler			*			
	Gas Mcf	Oil Bbls				*	Gas Mcf	TDF Tons	Bark Tons	*			
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO_2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOx EF	2.80E-01	NA	PM	SO_2	NOx		1.90E-01	1.98E+00	1.98E+00		PM	SO_2	NOx
08-Sep	0	0	0.00	0.00	0.00	*	229	0.0	1,239	*	30.74	11.62	104
09-Sep	0	0	0.00	0.00	0.00	*	832	0.0	1,308	*	32.63	12.28	114
10-Sep	0	0	0.00	0.00	0.00	*	211	0.0	1,072	*	26.61	10.06	90
11-Sep	0	0	0.00	0.00	0.00	*	655	0.0	1,268	*	31.60	11.91	110
12-Sep	0	0	0.00	0.00	0.00	*	1,165	0.0	1,056	*	26.49	9.92	96
13-Sep	1,201	0	0.38	0.03	14.01	*	2,638	0.0	1,090	*	27.80	10.28	111
14-Sep	0	0	0.00	0.00	0.00	*	727	0.0	949	*	23.73	8.92	84
15-Sep	0	0	0.00	0.00	0.00	*	814	0.0	962	*	24.08	9.04	86
16-Sep	0	0	0.00	0.00	0.00	*	1,202	0.0	842	*	21.23	7.93	79
17-Sep	0	0	0.00	0.00	0.00	*	1,084	0.0	897	*	22.53	8.43	83
18-Sep	0	0	0.00	0.00	0.00	*	1,243	0.0	976	*	24.54	9.18	90
19-Sep	0	0	0.00	0.00	0.00	*	636	0.0	878	*	21.92	8.24	77
20-Sep	0	0	0.00	0.00	0.00	*	1,173	0.0	1,172	*	29.37	11.01	106
21-Sep	0	0	0.00	0.00	0.00	*	1,554	0.0	881	*	22.31	8.30	85
22-Sep	0	0	0.00	0.00	0.00	*	1,201	0.0	895	*	22.52	8.42	83
23-Sep	0	0	0.00	0.00	0.00	*	586	0.0	937	*	23.37	8.80	82
24-Sep	0	0	0.00	0.00	0.00	*	2,200	0.0	1,283	*	32.45	12.08	123
25-Sep	0	0	0.00	0.00	0.00	*	1,232	0.0	1,123	*	28.18	10.56	102
26-Sep	0	0	0.00	0.00	0.00	*	1,207	0.0	902	*	22.70	8.48	84
27-Sep	0	0	0.00	0.00	0.00	*	626	0.0	488	*	12.29	4.60	45
28-Sep	0	0	0.00	0.00	0.00	*	697	0.0	675	*	16.92	6.34	61

GEORGIA-PACIFIC CORPORATION
SOUTHERN PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

Daily Meter Readings/Production Trends

	6A Boiler					*	9A Boiler			*			
	Gas Mcf	Oil Bbls				*	Gas Mcf	TDF Tons	Bark Tons	*			
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO_2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOx EF	2.80E-01	NA	PM	SO_2	NOx		1.90E-01	1.98E+00	1.98E+00		PM	SO_2	NOx
29-Sep	0	0	0.00	0.00	0.00	*	792	0.0	883	*	22.10	8.30	79
30-Sep	0	0	0.00	0.00	0.00	*	1,203	0.0	909	*	22.88	8.55	85
01-Oct	0	0	0.00	0.00	0.00	*	1,460	0.0	909	*	22.97	8.56	87
02-Oct	0	0	0.00	0.00	0.00	*	439	0.0	624	*	15.58	5.86	55
03-Oct	0	0	0.00	0.00	0.00	*	439	0.0	822	*	20.49	7.72	71
04-Oct	0	0	0.00	0.00	0.00	*	465	0.0	915	*	22.80	8.59	79
05-Oct	0	0	0.00	0.00	0.00	*	209	0.0	899	*	22.32	8.43	76
06-Oct	0	0	0.00	0.00	0.00	*	1,833	0.0	860	*	21.87	8.11	85
07-Oct	0	0	0.00	0.00	0.00	*	7,819	0.0	391	*	12.15	3.86	94
08-Oct	1,608	0	0.51	0.04	18.76	*	4,341	0.0	230	*	7.06	2.26	53
09-Oct	3,089	0	0.98	0.08	36.04	*	0	0.0	0	*	0.00	0.00	0
10-Oct	3,059	0	0.97	0.08	35.69	*	0	0.0	0	*	0.00	0.00	0
11-Oct	3,307	0	1.05	0.08	38.58	*	0	0.0	0	*	0.00	0.00	0
12-Oct	3,307	0	1.05	0.08	38.58	*	0	0.0	0	*	0.00	0.00	0
13-Oct	3,307	0	1.05	0.08	38.58	*	0	0.0	0	*	0.00	0.00	0
14-Oct	3,307	0	1.05	0.08	38.58	*	0	0.0	0	*	0.00	0.00	0
15-Oct	4,046	0	1.28	0.10	47.20	*	0	0.0	0	*	0.00	0.00	0
16-Oct	4,545	0	1.44	0.11	53.03	*	0	0.0	0	*	0.00	0.00	0
17-Oct	4,144	0	1.31	0.10	48.35	*	0	0.0	0	*	0.00	0.00	0
18-Oct	4,694	0	1.49	0.12	54.76	*	0	0.0	0	*	0.00	0.00	0
19-Oct	4,557	0	1.44	0.11	53.17	*	0	0.0	0	*	0.00	0.00	0

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GEORGIA-PACIFIC CORPORATION
SOUTHERN PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

Daily Meter Readings/Production Trends

	6A Boiler					*	9A Boiler			*			
	Gas Mcf	Oil Bbls				*	Gas Mcf	TDF Tons	Bark Tons	*			
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO_2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOx EF	2.80E-01	NA	PM	SO_2	NOx		1.90E-01	1.98E+00	1.98E+00		PM	SO_2	NOx
20-Oct	3,459	0	1.10	0.09	40.36	*	0	0.0	0	*	0.00	0.00	0
21-Oct	3,203	0	1.01	0.08	37.37	*	0	0.0	0	*	0.00	0.00	0
22-Oct	5,023	0	1.59	0.13	58.60	*	0	0.0	0	*	0.00	0.00	0
23-Oct	4,811	0	1.52	0.12	56.13	*	0	0.0	0	*	0.00	0.00	0
24-Oct	4,257	0	1.35	0.11	49.67	*	0	0.0	0	*	0.00	0.00	0
25-Oct	316	0	0.10	0.01	3.69	*	1,284	0.0	1,001	*	25.17	9.41	93
26-Oct	226	0	0.07	0.01	2.64	*	401	0.0	1,156	*	28.73	10.84	99
27-Oct	0	0	0.00	0.00	0.00	*	251	0.0	1,268	*	31.47	11.90	107
28-Oct	0	0	0.00	0.00	0.00	*	199	0.0	1,357	*	33.66	12.73	114
29-Oct	0	0	0.00	0.00	0.00	*	485	0.0	1,349	*	33.54	12.66	115
30-Oct	0	0	0.00	0.00	0.00	*	278	0.0	1,063	*	26.40	9.97	90
31-Oct	0	0	0.00	0.00	0.00	*	199	0.0	1,080	*	26.80	10.13	91
01-Nov	0	0	0.00	0.00	0.00	*	208	0.0	869	*	21.56	8.15	73
02-Nov	0	0	0.00	0.00	0.00	*	485	0.0	99	*	2.59	0.94	12
03-Nov	0	0	0.00	0.00	0.00	*	682	0.0	871	*	21.76	8.18	77
04-Nov	0	0	0.00	0.00	0.00	*	204	0.0	797	*	19.78	7.47	67
05-Nov	0	0	0.00	0.00	0.00	*	204	0.0	908	*	22.54	8.52	77
06-Nov	0	0	0.00	0.00	0.00	*	302	0.0	893	*	22.20	8.38	76
07-Nov	0	0	0.00	0.00	0.00	*	422	0.0	933	*	23.24	8.76	80
08-Nov	34	0	0.01	0.00	0.40	*	1,319	0.0	1,073	*	26.98	10.09	99
09-Nov	0	0	0.00	0.00	0.00	*	507	0.0	1,240	*	30.85	11.64	106

GEORGIA-PACIFIC CORPORATION
SOUTHERN PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

Daily Meter Readings/Production Trends

	6A Boiler					*	9A Boiler			*			
	Gas Mcf	Oil Bbls				*	Gas Mcf	TDF Tons	Bark Tons	*			
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO_2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOx EF	2.80E-01	NA	PM	SO_2	NOx		1.90E-01	1.98E+00	1.98E+00		PM	SO_2	NOx
10-Nov	0	0	0.00	0.00	0.00	*	637	0.0	1,186	*	29.56	11.14	103
11-Nov	1,289	0	0.41	0.03	15.04	*	733	0.0	1,365	*	34.03	12.82	118
12-Nov	1,795	0	0.57	0.04	20.94	*	365	0.0	1,038	*	25.80	9.74	89
13-Nov	345	0	0.11	0.01	4.03	*	482	0.0	1,212	*	30.16	11.38	104
14-Nov	0	0	0.00	0.00	0.00	*	218	0.0	1,137	*	28.20	10.66	96
15-Nov	0	0	0.00	0.00	0.00	*	212	0.0	1,140	*	28.27	10.69	96
16-Nov	0	0	0.00	0.00	0.00	*	207	0.0	1,065	*	26.41	9.99	89
17-Nov	0	0	0.00	0.00	0.00	*	242	0.0	1,174	*	29.12	11.01	99
18-Nov	0	0	0.00	0.00	0.00	*	216	0.0	1,056	*	26.21	9.91	89
19-Nov	0	0	0.00	0.00	0.00	*	554	0.0	1,162	*	28.93	10.91	100
20-Nov	0	0	0.00	0.00	0.00	*	264	0.0	1,362	*	33.80	12.78	114
21-Nov	0	0	0.00	0.00	0.00	*	1,237	0.0	1,367	*	34.22	12.85	123
22-Nov	0	0	0.00	0.00	0.00	*	1,241	0.0	959	*	24.12	9.02	89
23-Nov	0	0	0.00	0.00	0.00	*	1,113	0.0	973	*	24.43	9.15	89
24-Nov	0	0	0.00	0.00	0.00	*	901	0.0	917	*	22.98	8.62	83
25-Nov	0	0	0.00	0.00	0.00	*	632	0.0	923	*	23.05	8.67	81
26-Nov	0	0	0.00	0.00	0.00	*	2,252	0.0	995	*	25.34	9.38	100
27-Nov	0	0	0.00	0.00	0.00	*	1,001	0.0	1,033	*	25.87	9.71	93
28-Nov	0	0	0.00	0.00	0.00	*	3,577	0.0	915	*	23.77	8.66	104
29-Nov	582	0	0.18	0.01	6.79	*	10,093	0.0	532	*	16.37	5.24	124
30-Nov	2,989	0	0.95	0.07	34.87	*	2,188	0.0	651	*	16.80	6.15	71

GEORGIA-PACIFIC CORPORATION
SOUTHERN PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

Daily Meter Readings/Production Trends

	6A Boiler					*	9A Boiler			*			
	Gas Mcf	Oil Bbls				*	Gas Mcf	TDF Tons	Bark Tons	*			
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO_2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOx EF	2.80E-01	NA	PM	SO_2	NOx		1.90E-01	1.98E+00	1.98E+00		PM	SO_2	NOx
01-Dec	0	0	0.00	0.00	0.00	*	768	0.0	1,321	*	32.93	12.40	115
02-Dec	0	0	0.00	0.00	0.00	*	252	0.0	1,157	*	28.71	10.85	97
03-Dec	0	0	0.00	0.00	0.00	*	715	0.0	1,347	*	33.57	12.65	117
04-Dec	0	0	0.00	0.00	0.00	*	505	0.0	1,290	*	32.10	12.11	110
05-Dec	0	0	0.00	0.00	0.00	*	379	0.0	1,009	*	25.10	9.47	86
06-Dec	0	0	0.00	0.00	0.00	*	314	0.0	1,326	*	32.91	12.44	112
07-Dec	0	0	0.00	0.00	0.00	*	309	0.0	1,187	*	29.46	11.13	100
08-Dec	0	0	0.00	0.00	0.00	*	345	0.0	1,269	*	31.51	11.90	107
09-Dec	0	0	0.00	0.00	0.00	*	346	0.0	1,340	*	33.28	12.57	113
10-Dec	0	0	0.00	0.00	0.00	*	397	0.0	1,364	*	33.88	12.80	116
11-Dec	0	0	0.00	0.00	0.00	*	1,240	0.0	1,381	*	34.56	12.97	124
12-Dec	0	0	0.00	0.00	0.00	*	549	0.0	1,269	*	31.58	11.91	109
13-Dec	0	0	0.00	0.00	0.00	*	1,966	0.0	1,239	*	31.29	11.67	118
14-Dec	0	0	0.00	0.00	0.00	*	1,468	0.0	1,273	*	31.97	11.97	117
15-Dec	2,730	0	0.86	0.07	31.85	*	3,706	0.0	1,383	*	35.41	13.06	143
16-Dec	1,298	0	0.41	0.03	15.14	*	1,234	0.0	1,261	*	31.61	11.86	114
17-Dec	0	0	0.00	0.00	0.00	*	3,184	0.0	1,322	*	33.72	12.47	134
18-Dec	0	0	0.00	0.00	0.00	*	1,367	0.0	1,318	*	33.05	12.39	120
19-Dec	0	0	0.00	0.00	0.00	*	941	0.0	1,281	*	32.00	12.03	113
20-Dec	3,321	0	1.05	0.08	38.75	*	3,108	0.0	1,556	*	39.49	14.66	153
21-Dec	2,703	0	0.86	0.07	31.54	*	2,088	0.0	1,611	*	40.54	15.16	149

GEORGIA-PACIFIC CORPORATION
SOUTHERN PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

Daily Meter Readings/Production Trends

	6A Boiler					*	9A Boiler			*			
	Gas Mcf	Oil Bbls				*	Gas Mcf	TDF Tons	Bark Tons	*			
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO_2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOx EF	2.80E-01	NA	PM	SO_2	NOx		1.90E-01	1.98E+00	1.98E+00		PM	SO_2	NOx
22-Dec	0	0	0.00	0.00	0.00	*	2,404	0.0	1,526	*	38.52	14.36	145
23-Dec	0	0	0.00	0.00	0.00	*	1,509	0.0	1,499	*	37.57	14.09	136
24-Dec	0	0	0.00	0.00	0.00	*	957	0.0	1,323	*	33.05	12.43	117
25-Dec	0	0	0.00	0.00	0.00	*	186	0.0	1,023	*	25.39	9.60	86
26-Dec	0	0	0.00	0.00	0.00	*	236	0.0	1,128	*	27.99	10.58	95
27-Dec	54	0	0.02	0.00	0.63	*	2,248	0.0	1,234	*	31.25	11.62	120
28-Dec	4,321	0	1.37	0.11	50.41	*	2,640	0.0	1,477	*	37.40	13.92	143
29-Dec	2,718	0	0.86	0.07	31.71	*	946	0.0	1,447	*	36.10	13.58	127

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R M I L L U T I L I T Y R E P O R T

DATE	Gas Mcf	Oil Bbls	Calculated lbs/hr PM	Calculated lbs/hr SO_2	Calculated lbs/hr NOx	*	Gas Mcf	TDF Tons	Bark Tons	*	Calculated lbs/hr PM	Calculated lbs/hr SO_2	Calculated lbs/hr NOx
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64	5.94E-01				
SO_2 EF	6.00E-04	NA					6.00E-04	30.80	2.25E-01				
NOx EF	2.80E-01	NA					1.90E-01	1.98	1.98E+00				
30-Dec	751	0	0.24	0.02	8.76	*	1,307	0.0	1,248	*	31.30	11.73	113
31-Dec	0	0	0.00	0.00	0.00	*	342	0.0	1,412	*	35.05	13.25	119
01-Jan	0	0	0.00	0.00	0.00	*	418	0.0	1,443	*	35.85	13.54	122
02-Jan	0	0	0.00	0.00	0.00	*	1,438	0.0	1,418	*	35.54	13.33	128
03-Jan	0	0	0.00	0.00	0.00	*	1,545	0.0	1,548	*	38.81	14.55	140
04-Jan	0	0	0.00	0.00	0.00	*	1,198	0.0	1,457	*	36.45	13.69	130
05-Jan	0	0	0.00	0.00	0.00	*	1,274	0.0	1,517	*	37.96	14.26	135
06-Jan	0	0	0.00	0.00	0.00	*	1,521	0.0	1,544	*	38.70	14.51	139
07-Jan	1,561	0	0.49	0.04	18.21	*	1,409	0.0	1,499	*	37.55	14.09	135
08-Jan	2,067	0	0.65	0.05	24.12	*	431	0.0	1,535	*	38.13	14.40	130
09-Jan	0	0	0.00	0.00	0.00	*	388	0.0	1,338	*	33.23	12.55	113
10-Jan	0	0	0.00	0.00	0.00	*	284	0.0	1,199	*	29.75	11.24	101
11-Jan	0	0	0.00	0.00	0.00	*	212	0.0	1,136	*	28.18	10.66	95
12-Jan	0	0	0.00	0.00	0.00	*	370	0.0	1,458	*	36.21	13.68	123
13-Jan	0	0	0.00	0.00	0.00	*	1,584	0.0	1,667	*	41.77	15.67	150
14-Jan	0	0	0.00	0.00	0.00	*	240	0.0	1,392	*	34.53	13.06	117
15-Jan	0	0	0.00	0.00	0.00	*	265	0.0	1,567	*	38.87	14.70	131
16-Jan	0	0	0.00	0.00	0.00	*	499	0.0	1,317	*	32.76	12.36	113
17-Jan	0	0	0.00	0.00	0.00	*	583	0.0	1,528	*	38.00	14.34	131
18-Jan	0	0	0.00	0.00	0.00	*	1,222	0.0	1,610	*	40.23	15.12	142
19-Jan	3,975	0	1.26	0.10	46.38	*	2,364	0.0	261	*	7.20	2.50	40
20-Jan	5,156	0	1.63	0.13	60.15	*	423	0.0	6	*	0.27	0.06	4
21-Jan	1,157	0	0.37	0.03	13.50	*	845	0.0	1,401	*	34.94	13.15	122
22-Jan	1,501	0	0.48	0.04	17.51	*	2,990	0.0	983	*	25.28	9.29	105
23-Jan	0	0	0.00	0.00	0.00	*	253	0.0	969	*	24.05	9.09	82
24-Jan	0	0	0.00	0.00	0.00	*	1,207	0.0	1,200	*	30.08	11.28	109
25-Jan	0	0	0.00	0.00	0.00	*	1,702	0.0	1,525	*	38.29	14.34	139

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R M I L L U T I L I T Y R E P O R T

DATE	Gas	Oil				*	Gas	TDF	Bark	*			
	Mcf	Bbls				*	Mcf	Tons	Tons	*			
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64	5.94E-01				
SO_2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	30.80	2.25E-01		Calculated lbs/hr		
NOx EF	2.80E-01	NA	PM	SO_2	NOx		1.90E-01	1.98	1.98E+00		PM	SO_2	NOx
26-Jan	0	0	0.00	0.00	0.00	*	582	0.0	1,539	*	38.28	14.45	132
27-Jan	211	0	0.07	0.01	2.46	*	287	0.0	1,378	*	34.20	12.93	116
28-Jan	2,609	0	0.83	0.07	30.44	*	485	0.0	1,255	*	31.21	11.78	107
29-Jan	0	0	0.00	0.00	0.00	*	446	0.0	1,179	*	29.32	11.07	101
30-Jan	0	0	0.00	0.00	0.00	*	230	0.0	1,216	*	30.18	11.41	102
31-Jan	0	0	0.00	0.00	0.00	*	1,152	0.0	1,422	*	35.57	13.36	126
01-Feb	1,782	0	0.56	0.04	20.79	*	2,650	0.0	1,652	*	41.74	15.56	157
02-Feb	0	0	0.00	0.00	0.00	*	1,133	0.0	1,639	*	40.93	15.39	144
03-Feb	0	0	0.00	0.00	0.00	*	1,594	0.0	1,549	*	38.84	14.56	140
04-Feb	0	0	0.00	0.00	0.00	*	955	0.0	1,435	*	35.81	13.47	126
05-Feb	0	0	0.00	0.00	0.00	*	1,515	0.0	1,363	*	34.21	12.81	124
06-Feb	2,576	0	0.82	0.06	30.05	*	2,371	0.0	1,524	*	38.46	14.34	144
07-Feb	2,419	0	0.77	0.06	28.22	*	2,035	0.0	1,438	*	36.24	13.54	135
08-Feb	0	0	0.00	0.00	0.00	*	2,694	0.0	1,326	*	33.67	12.50	131
09-Feb	0	0	0.00	0.00	0.00	*	771	0.0	1,546	*	38.52	14.52	134
10-Feb	0	0	0.00	0.00	0.00	*	705	0.0	1,604	*	39.93	15.06	138
11-Feb	0	0	0.00	0.00	0.00	*	4,523	0.0	1,308	*	33.81	12.38	144
12-Feb	0	0	0.00	0.00	0.00	*	1,107	0.0	1,247	*	31.22	11.72	112
13-Feb	881	0	0.28	0.02	10.28	*	2,189	0.0	1,187	*	30.07	11.18	115
14-Feb	787	0	0.25	0.02	9.18	*	1,165	0.0	1,352	*	33.84	12.71	121
15-Feb	0	0	0.00	0.00	0.00	*	925	0.0	1,475	*	36.81	13.86	129
16-Feb	0	0	0.00	0.00	0.00	*	1,369	0.0	1,425	*	35.71	13.40	128
17-Feb	0	0	0.00	0.00	0.00	*	1,962	0.0	1,559	*	39.20	14.66	144
18-Feb	0	0	0.00	0.00	0.00	*	2,158	0.0	1,473	*	37.15	13.87	139
19-Feb	0	0	0.00	0.00	0.00	*	2,497	0.0	1,451	*	36.70	13.66	139
20-Feb	0	0	0.00	0.00	0.00	*	1,265	0.0	1,183	*	29.69	11.13	108
21-Feb	0	0	0.00	0.00	0.00	*	4,102	0.0	1,370	*	35.20	12.94	145
22-Feb	0	0	0.00	0.00	0.00	*	2,520	0.0	1,603	*	40.47	15.09	152

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GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

DATE	Gas Mcf	Oil Bbls				*	Gas Mcf	TDF Tons	Bark Tons	*			
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64	5.94E-01				
SO_2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	30.80	2.25E-01		Calculated lbs/hr		
NOx EF	2.80E-01	NA	PM	SO_2	NOx		1.90E-01	1.98	1.98E+00		PM	SO_2	NOx
23-Feb	0	0	0.00	0.00	0.00	*	2,286	0.0	1,641	*	41.33	15.44	153
24-Feb	0	0	0.00	0.00	0.00	*	2,763	0.0	1,616	*	40.86	15.22	155
25-Feb	0	0	0.00	0.00	0.00	*	2,437	0.0	1,456	*	36.82	13.71	139
26-Feb	706	0	0.22	0.02	8.24	*	4,184	0.0	1,544	*	39.54	14.58	161
27-Feb	2,579	0	0.82	0.06	30.09	*	3,615	0.0	1,167	*	30.04	11.03	125
28-Feb	1,182	0	0.37	0.03	13.79	*	2,077	0.0	1,037	*	26.32	9.77	102
01-Mar	802	0	0.25	0.02	9.36	*	2,308	0.0	1,323	*	33.48	12.46	127
02-Mar	0	0	0.00	0.00	0.00	*	3,671	0.0	1,273	*	32.67	12.03	134
03-Mar	0	0	0.00	0.00	0.00	*	3,241	0.0	1,551	*	39.41	14.62	154
04-Mar	0	0	0.00	0.00	0.00	*	2,219	0.0	1,596	*	40.21	15.02	149
05-Mar	59	0	0.02	0.00	0.69	*	3,540	0.0	1,559	*	39.71	14.71	157
06-Mar	3,619	0	1.15	0.09	42.22	*	2,602	0.0	737	*	19.06	6.97	81
07-Mar	839	0	0.27	0.02	9.79	*	1,378	0.0	1,363	*	34.17	12.81	123
08-Mar	111	0	0.04	0.00	1.30	*	2,425	0.0	1,024	*	26.10	9.66	104
09-Mar	171	0	0.05	0.00	2.00	*	3,027	0.0	1,148	*	29.37	10.84	119
10-Mar	4,300	0	1.36	0.11	50.17	*	2,715	0.0	196	*	5.71	1.91	38
11-Mar	3,887	0	1.23	0.10	45.35	*	0	0.0	0	*	0.00	0.00	0
12-Mar	3,862	0	1.22	0.10	45.06	*	0	0.0	0	*	0.00	0.00	0
13-Mar	3,711	0	1.18	0.09	43.30	*	0	0.0	0	*	0.00	0.00	0
14-Mar	4,109	0	1.30	0.10	47.94	*	0	0.0	0	*	0.00	0.00	0
15-Mar	3,736	0	1.18	0.09	43.59	*	0	0.0	0	*	0.00	0.00	0
16-Mar	3,560	0	1.13	0.09	41.53	*	0	0.0	0	*	0.00	0.00	0
17-Mar	3,956	0	1.25	0.10	46.15	*	0	0.0	0	*	0.00	0.00	0
18-Mar	3,302	0	1.05	0.08	38.52	*	0	0.0	0	*	0.00	0.00	0
19-Mar	3,574	0	1.13	0.09	41.70	*	0	0.0	0	*	0.00	0.00	0
20-Mar	3,956	0	1.25	0.10	46.15	*	0	0.0	0	*	0.00	0.00	0
21-Mar	4,091	0	1.30	0.10	47.73	*	0	0.0	0	*	0.00	0.00	0
22-Mar	5,685	0	**1.80**	**0.14**	**66.33**	*	0	0.0	0	*	0.00	0.00	0

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

DATE	Gas	Oil				*	Gas	TDF	Bark	*			
	Mcf	Bbls				*	Mcf	Tons	Tons	*			
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64	5.94E-01				
SO_2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	30.80	2.25E-01		Calculated lbs/hr		
NOx EF	2.80E-01	NA	PM	SO_2	NOx		1.90E-01	1.98	1.98E+00		PM	SO_2	NOx
23-Mar	4,755	0	1.51	0.12	55.48	*	0	0.0	0	*	0.00	0.00	0
24-Mar	4,017	0	1.27	0.10	46.87	*	0	0.0	0	*	0.00	0.00	0
25-Mar	3,367	0	1.07	0.08	39.28	*	0	0.0	0	*	0.00	0.00	0
26-Mar	3,583	0	1.13	0.09	41.80	*	0	0.0	0	*	0.00	0.00	0
27-Mar	4,151	0	1.31	0.10	48.43	*	3,112	0.0	323	*	8.97	3.10	51
28-Mar	3,872	0	1.23	0.10	45.17	*	4,658	0.0	1,313	*	33.97	12.42	145
29-Mar	4,198	0	1.33	0.10	48.98	*	1,246	0.0	1,549	*	38.72	14.55	138
30-Mar	4,347	0	1.38	0.11	50.72	*	2,263	0.0	1,676	*	42.19	15.77	156
31-Mar	3,979	0	1.26	0.10	46.42	*	4,980	0.0	1,564	*	40.30	14.79	168
01-Apr	3,499	0	1.11	0.09	40.82	*	3,442	0.0	1,180	*	30.30	11.15	125
02-Apr	1,259	0	0.40	0.03	14.69	*	2,958	0.0	930	*	23.94	8.79	100
03-Apr	4,125	0	1.31	0.10	48.13	*	4,093	0.0	952	*	24.85	9.02	111
04-Apr	4,295	0	1.36	0.11	50.11	*	2,948	0.0	1,060	*	27.18	10.02	111
05-Apr	1,955	0	0.62	0.05	22.81	*	2,904	0.0	1,554	*	39.38	14.64	151
06-Apr	656	0	0.21	0.02	7.65	*	2,233	0.0	1,573	*	39.64	14.80	147
07-Apr	0	0	0.00	0.00	0.00	*	2,523	0.0	1,195	*	30.37	11.26	119
08-Apr	0	0	0.00	0.00	0.00	*	2,838	0.0	1,164	*	29.70	10.98	118
09-Apr	0	0	0.00	0.00	0.00	*	254	0.0	1,157	*	28.71	10.85	97
10-Apr	0	0	0.00	0.00	0.00	*	1,220	0.0	1,177	*	29.51	11.06	107
11-Apr	0	0	0.00	0.00	0.00	*	678	0.0	1,273	*	31.72	11.95	110
12-Apr	0	0	0.00	0.00	0.00	*	202	0.0	1,278	*	31.71	11.99	107
13-Apr	0	0	0.00	0.00	0.00	*	161	0.0	1,025	*	25.43	9.62	86
14-Apr	0	0	0.00	0.00	0.00	*	230	0.0	1,062	*	26.36	9.96	89
15-Apr	0	0	0.00	0.00	0.00	*	161	0.0	1,085	*	26.90	10.17	91
16-Apr	0	0	0.00	0.00	0.00	*	226	0.0	1,273	*	31.58	11.94	107
17-Apr	0	0	0.00	0.00	0.00	*	1,268	0.0	1,207	*	30.27	11.34	110
18-Apr	0	0	0.00	0.00	0.00	*	610	0.0	1,297	*	32.29	12.17	112
19-Apr	0	0	0.00	0.00	0.00	*	274	0.0	1,298	*	32.21	12.18	109

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P A P E R   M I L L   U T I L I T Y   R E P O R T

DATE	Gas Mcf	Oil Bbls				*	Gas Mcf	TDF Tons	Bark Tons	*			
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64	5.94E-01				
SO_2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	30.80	2.25E-01		Calculated lbs/hr		
NOx EF	2.80E-01	NA	PM	SO_2	NOx		1.90E-01	1.98	1.98E+00		PM	SO_2	NOx
20-Apr	0	0	0.00	0.00	0.00	*	247	0.0	1,194	*	29.63	11.20	100
21-Apr	0	0	0.00	0.00	0.00	*	280	0.0	1,226	*	30.42	11.50	103
22-Apr	0	0	0.00	0.00	0.00	*	354	0.0	1,082	*	26.89	10.15	92
23-Apr	0	0	0.00	0.00	0.00	*	127	0.0	1,182	*	29.29	11.08	98
24-Apr	0	0	0.00	0.00	0.00	*	200	0.0	1,203	*	29.84	11.28	101
25-Apr	0	0	0.00	0.00	0.00	*	221	0.0	1,047	*	25.99	9.82	88
26-Apr	0	0	0.00	0.00	0.00	*	280	0.0	1,263	*	31.35	11.85	106
27-Apr	0	0	0.00	0.00	0.00	*	155	0.0	1,137	*	28.18	10.66	95
28-Apr	0	0	0.00	0.00	0.00	*	182	0.0	1,183	*	29.34	11.10	99
29-Apr	0	0	0.00	0.00	0.00	*	305	0.0	1,359	*	33.74	12.75	115
30-Apr	0	0	0.00	0.00	0.00	*	560	0.0	1,178	*	29.33	11.06	102
01-May	0	0	0.00	0.00	0.00	*	372	0.0	1,176	*	29.21	11.03	100
02-May	0	0	0.00	0.00	0.00	*	1,344	0.0	1,234	*	30.97	11.60	112
03-May	0	0	0.00	0.00	0.00	*	759	0.0	1,176	*	29.34	11.04	103
04-May	0	0	0.00	0.00	0.00	*	974	0.0	1,285	*	32.11	12.07	114
05-May	0	0	0.00	0.00	0.00	*	400	0.0	1,031	*	25.64	9.67	88
06-May	0	0	0.00	0.00	0.00	*	404	0.0	1,189	*	29.55	11.15	101
07-May	0	0	0.00	0.00	0.00	*	667	0.0	1,286	*	32.04	12.07	111
08-May	1,604	0	0.51	0.04	18.71	*	1,406	0.0	1,411	*	35.36	13.26	128
09-May	2,466	0	0.78	0.06	28.77	*	324	0.0	1,061	*	26.36	9.96	90
10-May	4,876	0	1.54	0.12	56.89	*	3,640	0.0	1,486	*	37.93	14.02	151
11-May	4,297	0	1.36	0.11	50.13	*	1,809	0.0	1,393	*	35.05	13.10	129
12-May	2,006	0	0.64	0.05	23.40	*	965	0.0	1,161	*	29.05	10.91	103
13-May	3,268	0	1.03	0.08	38.13	*	1,823	0.0	1,263	*	31.83	11.88	119
14-May	2,348	0	0.74	0.06	27.39	*	1,986	0.0	1,267	*	31.99	11.93	120
15-May	2,821	0	0.89	0.07	32.91	*	1,234	0.0	1,258	*	31.53	11.83	114
16-May	3,342	0	1.06	0.08	38.99	*	3,360	0.0	1,545	*	39.31	14.57	154
17-May	3,631	0	1.15	0.09	42.36	*	4,340	0.0	1,521	*	39.03	14.37	160

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P A P E R M I L L U T I L I T Y R E P O R T

DATE	Gas Mcf	Oil Bbls				*	Gas Mcf	TDF Tons	Bark Tons	*			
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64	5.94E-01				
SO_2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	30.80	2.25E-01		Calculated lbs/hr		
NOx EF	2.80E-01	NA	PM	SO_2	NOx		1.90E-01	1.98	1.98E+00		PM	SO_2	NOx
18-May	0	0	0.00	0.00	0.00	*	112	0.0	1,019	*	25.25	9.55	85
19-May	6	0	0.00	0.00	0.07	*	1,078	0.0	1,130	*	28.32	10.62	102
20-May	0	0	0.00	0.00	0.00	*	259	0.0	1,113	*	27.63	10.44	94
21-May	4,524	0	1.43	0.11	52.78	*	5,147	0.0	1,616	*	41.62	15.28	174
22-May	3,977	0	1.26	0.10	46.40	*	3,309	0.0	1,562	*	39.71	14.73	155
23-May	3,582	0	1.13	0.09	41.79	*	1,728	0.0	1,562	*	39.21	14.69	143
24-May	1,395	0	0.44	0.03	16.28	*	534	0.0	583	*	14.60	5.48	52
25-May	0	0	0.00	0.00	0.00	*	178	0.0	1,026	*	25.45	9.62	86
26-May	0	0	0.00	0.00	0.00	*	570	0.0	904	*	22.55	8.49	79
27-May	0	0	0.00	0.00	0.00	*	163	0.0	895	*	22.21	8.40	75
28-May	7	0	0.00	0.00	0.08	*	623	0.0	729	*	18.25	6.85	65
29-May	1,088	0	0.34	0.03	12.69	*	370	0.0	978	*	24.33	9.18	84
30-May	4,205	0	1.33	0.11	49.06	*	1,852	0.0	1,253	*	31.61	11.80	118
31-May	4,803	0	1.52	0.12	56.04	*	6,643	0.0	1,442	*	37.79	13.68	172
01-Jun	4,009	0	1.27	0.10	46.77	*	4,592	0.0	1,337	*	34.54	12.65	147
02-Jun	462	0	0.15	0.01	5.39	*	443	0.0	805	*	20.06	7.56	70
03-Jun	3,392	0	1.07	0.08	39.57	*	2,285	0.0	1,334	*	33.74	12.56	128
04-Jun	769	0	0.24	0.02	8.97	*	222	0.0	1,157	*	28.71	10.85	97
05-Jun	0	0	0.00	0.00	0.00	*	292	0.0	1,098	*	27.27	10.30	93
06-Jun	0	0	0.00	0.00	0.00	*	469	0.0	1,246	*	30.98	11.69	106
07-Jun	1,414	0	0.45	0.04	16.50	*	537	0.0	1,425	*	35.43	13.37	122
08-Jun	0	0	0.00	0.00	0.00	*	726	0.0	1,277	*	31.85	11.99	111
09-Jun	0	0	0.00	0.00	0.00	*	348	0.0	1,098	*	27.28	10.30	93
10-Jun	0	0	0.00	0.00	0.00	*	648	0.0	1,001	*	24.97	9.40	88
11-Jun	0	0	0.00	0.00	0.00	*	2,102	0.0	1,008	*	25.62	9.51	100
12-Jun	0	0	0.00	0.00	0.00	*	188	0.0	900	*	22.33	8.44	76
13-Jun	0	0	0.00	0.00	0.00	*	161	0.0	1,182	*	29.31	11.09	99
14-Jun	1,805	0	0.57	0.05	21.06	*	408	0.0	1,541	*	38.27	14.46	130

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P A P E R   M I L L   U T I L I T Y   R E P O R T

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DATE	Gas	Oil				*	Gas	TDF	Bark	*			
	Mcf	Bbls				*	Mcf	Tons	Tons	*			
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64	5.94E-01				
SO_2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	30.80	2.25E-01		Calculated lbs/hr		
NOx EF	2.80E-01	NA	PM	SO_2	NOx		1.90E-01	1.98	1.98E+00		PM	SO_2	NOx
15-Jun	3,902	0	1.24	0.10	45.52	*	1,945	0.0	1,311	*	33.07	12.34	124
16-Jun	0	0	0.00	0.00	0.00	*	159	0.0	1,232	*	30.54	11.55	103
17-Jun	1,394	0	0.44	0.03	16.26	*	3,148	0.0	996	*	25.66	9.42	107
18-Jun	159	0	0.05	0.00	1.86	*	574	0.0	927	*	23.12	8.70	81
19-Jun	0	0	0.00	0.00	0.00	*	151	0.0	1,060	*	26.27	9.94	89
20-Jun	0	0	0.00	0.00	0.00	*	167	0.0	914	*	22.67	8.57	77
21-Jun	0	0	0.00	0.00	0.00	*	370	0.0	1,028	*	25.56	9.65	88
22-Jun	0	0	0.00	0.00	0.00	*	175	0.0	1,284	*	31.84	12.04	107
23-Jun	0	0	0.00	0.00	0.00	*	192	0.0	980	*	24.32	9.19	82
24-Jun	0	0	0.00	0.00	0.00	*	154	0.0	1,062	*	26.34	9.96	89
25-Jun	0	0	0.00	0.00	0.00	*	189	0.0	960	*	23.81	9.00	81
26-Jun	0	0	0.00	0.00	0.00	*	186	0.0	881	*	21.87	8.27	74
27-Jun	0	0	0.00	0.00	0.00	*	158	0.0	891	*	22.10	8.36	75
28-Jun	0	0	0.00	0.00	0.00	*	1,708	0.0	773	*	19.66	7.29	77
29-Jun	0	0	0.00	0.00	0.00	*	1,525	0.0	907	*	22.92	8.54	87
30-Jun	0	0	0.00	0.00	0.00	*	1,819	0.0	977	*	24.75	9.20	95
01-Jul	0	0	0.00	0.00	0.00	*	2,177	0.0	1,020	*	25.94	9.62	101
02-Jul	42	0	0.01	0.00	0.49	*	1,817	0.0	947	*	24.01	8.92	92
03-Jul	0	0	0.00	0.00	0.00	*	2,055	0.0	1,170	*	29.60	11.02	113
04-Jul	0	0	0.00	0.00	0.00	*	1,487	0.0	978	*	24.67	9.20	92
05-Jul	0	0	0.00	0.00	0.00	*	2,088	0.0	971	*	24.68	9.15	97
06-Jul	0	0	0.00	0.00	0.00	*	2,314	0.0	1,056	*	26.88	9.96	105
07-Jul	0	0	0.00	0.00	0.00	*	1,982	0.0	1,065	*	27.00	10.04	104
08-Jul	0	0	0.00	0.00	0.00	*	686	0.0	857	*	21.42	8.05	76
09-Jul	0	0	0.00	0.00	0.00	*	1,327	0.0	883	*	22.28	8.31	83
10-Jul	0	0	0.00	0.00	0.00	*	402	0.0	894	*	22.26	8.39	77
11-Jul	0	0	0.00	0.00	0.00	*	1,250	0.0	864	*	21.77	8.13	81
12-Jul	0	0	0.00	0.00	0.00	*	1,288	0.0	853	*	21.52	8.03	81

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P A P E R M I L L U T I L I T Y R E P O R T

DATE	Gas Mcf	Oil Bbls	PM	SO_2	NOx	*	Gas Mcf	TDF Tons	Bark Tons	*	PM	SO_2	NOx
			Calculated lbs/hr								Calculated lbs/hr		
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64	5.94E-01				
SO_2 EF	6.00E-04	NA					6.00E-04	30.80	2.25E-01				
NOx EF	2.80E-01	NA					1.90E-01	1.98	1.98E+00				
13-Jul	0	0	0.00	0.00	0.00	*	570	0.0	792	*	19.77	7.44	70
14-Jul	0	0	0.00	0.00	0.00	*	657	0.0	844	*	21.10	7.93	75
15-Jul	0	0	0.00	0.00	0.00	*	1,398	0.0	919	*	23.19	8.65	87
16-Jul	0	0	0.00	0.00	0.00	*	771	0.0	808	*	20.25	7.60	73
17-Jul	0	0	0.00	0.00	0.00	*	2,318	0.0	1,052	*	26.77	9.92	105
18-Jul	0	0	0.00	0.00	0.00	*	371	0.0	824	*	20.52	7.74	71
19-Jul	1,921	0	0.61	0.05	22.41	*	273	0.0	263	*	6.59	2.47	24
20-Jul	2,401	0	0.76	0.06	28.01	*	0	0.0	0	*	0.00	0.00	0
21-Jul	2,191	0	0.69	0.05	25.56	*	1,332	0.0	82	*	2.44	0.80	17
22-Jul	0	0	0.00	0.00	0.00	*	751	0.0	888	*	22.22	8.35	79
23-Jul	0	0	0.00	0.00	0.00	*	1,108	0.0	848	*	21.33	7.97	79
24-Jul	0	0	0.00	0.00	0.00	*	806	0.0	836	*	20.95	7.86	75
25-Jul	0	0	0.00	0.00	0.00	*	307	0.0	808	*	20.10	7.58	69
26-Jul	0	0	0.00	0.00	0.00	*	509	0.0	859	*	21.43	8.07	75
27-Jul	0	0	0.00	0.00	0.00	*	1,290	0.0	787	*	19.88	7.41	75
28-Jul	0	0	0.00	0.00	0.00	*	1,283	0.0	810	*	20.47	7.63	77
29-Jul	0	0	0.00	0.00	0.00	*	661	0.0	820	*	20.51	7.71	73
30-Jul	98	0	0.03	0.00	1.14	*	220	0.0	866	*	21.49	8.12	73
31-Jul	3,281	0	1.04	0.08	38.28	*	1,562	0.0	1,376	*	34.55	12.94	126
01-Aug	3,281	0	1.04	0.08	38.28	*	1,562	0.0	1,376	*	34.55	12.94	126
02-Aug	4,609	0	1.46	0.12	53.77	*	4,770	0.0	570	*	15.63	5.47	85
03-Aug	4,539	0	1.44	0.11	52.96	*	3,883	0.0	1,158	*	29.90	10.96	126
04-Aug	837	0	0.27	0.02	9.77	*	1,225	0.0	689	*	17.45	6.49	67
05-Aug	243	0	0.08	0.01	2.84	*	4,030	0.0	473	*	12.98	4.53	71
06-Aug	0	0	0.00	0.00	0.00	*	993	0.0	987	*	24.75	9.28	89
07-Aug	0	0	0.00	0.00	0.00	*	543	0.0	872	*	21.74	8.18	76
08-Aug	0	0	0.00	0.00	0.00	*	2,851	0.0	1,020	*	26.14	9.63	107
09-Aug	0	0	0.00	0.00	0.00	*	734	0.0	1,028	*	25.68	9.66	91

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

DATE	Gas Mcf	Oil Bbls	PM	SO_2	NOx	*	Gas Mcf	TDF Tons	Bark Tons	*	PM	SO_2	NOx
			Calculated lbs/hr								Calculated lbs/hr		
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64	5.94E-01				
SO_2 EF	6.00E-04	NA					6.00E-04	30.80	2.25E-01				
NOx EF	2.80E-01	NA					1.90E-01	1.98	1.98E+00				
10-Aug	0	0	0.00	0.00	0.00	*	387	0.0	1,063	*	26.43	9.97	91
11-Aug	0	0	0.00	0.00	0.00	*	345	0.0	1,049	*	26.06	9.84	89
12-Aug	0	0	0.00	0.00	0.00	*	278	0.0	1,050	*	26.07	9.85	89
13-Aug	0	0	0.00	0.00	0.00	*	733	0.0	950	*	23.75	8.93	84
14-Aug	106	0	0.03	0.00	1.24	*	568	0.0	466	*	11.72	4.39	43
15-Aug	245	0	0.08	0.01	2.86	*	623	0.0	1,072	*	26.74	10.07	93
16-Aug	25	0	0.01	0.00	0.29	*	602	0.0	1,089	*	27.13	10.22	95
17-Aug	0	0	0.00	0.00	0.00	*	329	0.0	1,137	*	28.23	10.66	96
18-Aug	0	0	0.00	0.00	0.00	*	503	0.0	964	*	24.02	9.05	84
19-Aug	0	0	0.00	0.00	0.00	*	585	0.0	925	*	23.07	8.68	81
20-Aug	0	0	0.00	0.00	0.00	*	820	0.0	1,004	*	25.11	9.43	89
21-Aug	0	0	0.00	0.00	0.00	*	443	0.0	1,092	*	27.18	10.25	94
22-Aug	0	0	0.00	0.00	0.00	*	642	0.0	957	*	23.89	8.99	84
23-Aug	0	0	0.00	0.00	0.00	*	414	0.0	982	*	24.45	9.22	84
24-Aug	0	0	0.00	0.00	0.00	*	649	0.0	1,094	*	27.27	10.27	95
25-Aug	0	0	0.00	0.00	0.00	*	857	0.0	1,098	*	27.44	10.31	97
26-Aug	0	0	0.00	0.00	0.00	*	783	0.0	1,080	*	26.98	10.15	95
27-Aug	0	0	0.00	0.00	0.00	*	766	0.0	991	*	24.77	9.31	88
28-Aug	0	0	0.00	0.00	0.00	*	388	0.0	1,048	*	26.05	9.83	90
29-Aug	0	0	0.00	0.00	0.00	*	586	0.0	977	*	24.36	9.17	85
30-Aug	0	0	0.00	0.00	0.00	*	824	0.0	1,077	*	26.93	10.12	95
31-Aug	0	0	0.00	0.00	0.00	*	1,296	0.0	1,166	*	29.26	10.96	106
01-Sep	0	0	0.00	0.00	0.00	*	550	0.0	978	*	24.37	9.18	85
02-Sep	0	0	0.00	0.00	0.00	*	941	0.0	1,178	*	29.45	11.07	105
03-Sep	0	0	0.00	0.00	0.00	*	1,577	0.0	1,114	*	28.08	10.49	104
04-Sep	0	0	0.00	0.00	0.00	*	6,112	0.0	745	*	20.37	7.13	110
05-Sep	0	0	0.00	0.00	0.00	*	381	0.0	1,020	*	25.35	9.57	87
06-Sep	0	0	0.00	0.00	0.00	*	358	0.0	1,085	*	26.96	10.18	92

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R M I L L U T I L I T Y R E P O R T

DATE	Gas Mcf	Oil Bbls				*	Gas Mcf	TDF Tons	Bark Tons	*			
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64	5.94E-01				
SO_2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	30.80	2.25E-01		Calculated lbs/hr		
NOx EF	2.80E-01	NA	PM	SO_2	NOx		1.90E-01	1.98	1.98E+00		PM	SO_2	NOx
07-Sep	0	0	0.00	0.00	0.00	*	400	0.0	1,196	*	29.74	11.23	102
08-Sep	0	0	0.00	0.00	0.00	*	603	0.0	1,203	*	29.97	11.29	104
09-Sep	405	0	0.13	0.01	4.73	*	621	0.0	1,141	*	28.44	10.71	99
10-Sep	2,043	0	0.65	0.05	23.84	*	1,148	0.0	1,110	*	27.84	10.44	101
11-Sep	0	0	0.00	0.00	0.00	*	1,717	0.0	417	*	10.87	3.95	48
12-Sep	0	0	0.00	0.00	0.00	*	617	0.0	1,015	*	25.32	9.53	89
13-Sep	0	0	0.00	0.00	0.00	*	407	0.0	915	*	22.77	8.59	79
14-Sep	0	0	0.00	0.00	0.00	*	420	0.0	992	*	24.69	9.31	85
15-Sep	0	0	0.00	0.00	0.00	*	672	0.0	895	*	22.37	8.41	79
16-Sep	0	0	0.00	0.00	0.00	*	871	0.0	800	*	20.07	7.52	73
17-Sep	0	0	0.00	0.00	0.00	*	384	0.0	1,030	*	25.61	9.66	88
18-Sep	0	0	0.00	0.00	0.00	*	549	0.0	997	*	24.85	9.36	87
19-Sep	176	0	0.06	0.00	2.05	*	644	0.0	1,074	*	26.79	10.09	94
20-Sep	1,805	0	0.57	0.05	21.06	*	1,125	0.0	957	*	24.04	9.00	88
21-Sep	3,133	0	0.99	0.08	36.55	*	291	0.0	0	*	0.09	0.01	2
22-Sep	2,446	0	0.77	0.06	28.54	*	606	0.0	113	*	3.00	1.08	14
23-Sep	0	0	0.00	0.00	0.00	*	571	0.0	1,062	*	26.47	9.97	92
24-Sep	0	0	0.00	0.00	0.00	*	344	0.0	1,072	*	26.63	10.05	91
25-Sep	0	0	0.00	0.00	0.00	*	1,154	0.0	1,103	*	27.66	10.37	100
26-Sep	0	0	0.00	0.00	0.00	*	1,304	0.0	1,219	*	30.58	11.46	111
27-Sep	0	0	0.00	0.00	0.00	*	788	0.0	1,041	*	26.00	9.77	92
28-Sep	0	0	0.00	0.00	0.00	*	902	0.0	1,008	*	25.23	9.47	90
29-Sep	0	0	0.00	0.00	0.00	*	550	0.0	884	*	22.06	8.30	77
30-Sep	0	0	0.00	0.00	0.00	*	440	0.0	1,039	*	25.85	9.75	89
01-Oct	0	0	0.00	0.00	0.00	*	633	0.0	1,000	*	24.94	9.39	87
02-Oct	2,102	0	0.67	0.05	24.52	*	565	0.0	335	*	8.47	3.15	32
03-Oct	1,848	0	0.59	0.05	21.56	*	704	0.0	381	*	9.65	3.59	37
04-Oct	0	0	0.00	0.00	0.00	*	631	0.0	799	*	19.97	7.51	71

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GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

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DATE	Gas Mcf	Oil Bbls				*	Gas Mcf	TDF Tons	Bark Tons	*			
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64	5.94E-01				
SO_2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	30.80	2.25E-01		Calculated lbs/hr		
NOx EF	2.80E-01	NA	PM	SO_2	NOx		1.90E-01	1.98	1.98E+00		PM	SO_2	NOx
05-Oct	0	0	0.00	0.00	0.00	*	708	0.0	793	*	19.86	7.46	71
06-Oct	0	0	0.00	0.00	0.00	*	566	0.0	800	*	19.98	7.51	70
07-Oct	0	0	0.00	0.00	0.00	*	749	0.0	757	*	18.98	7.12	68
08-Oct	0	0	0.00	0.00	0.00	*	393	0.0	764	*	19.03	7.17	66
09-Oct	0	0	0.00	0.00	0.00	*	392	0.0	903	*	22.48	8.48	78
10-Oct	0	0	0.00	0.00	0.00	*	1,504	0.0	1,172	*	29.49	11.03	109
11-Oct	0	0	0.00	0.00	0.00	*	1,085	0.0	931	*	23.38	8.75	85
12-Oct	0	0	0.00	0.00	0.00	*	396	0.0	877	*	21.84	8.24	76
13-Oct	0	0	0.00	0.00	0.00	*	363	0.0	850	*	21.16	7.98	73
14-Oct	0	0	0.00	0.00	0.00	*	651	0.0	939	*	23.45	8.82	83
15-Oct	0	0	0.00	0.00	0.00	*	1,243	0.0	1,064	*	26.74	10.01	98
16-Oct	0	0	0.00	0.00	0.00	*	2,552	0.0	42	*	1.86	0.46	24
17-Oct	0	0	0.00	0.00	0.00	*	708	0.0	1,337	*	33.31	12.55	116
18-Oct	0	0	0.00	0.00	0.00	*	586	0.0	920	*	22.95	8.64	81
19-Oct	0	0	0.00	0.00	0.00	*	971	0.0	929	*	23.30	8.74	84
20-Oct	0	0	0.00	0.00	0.00	*	507	0.0	1,072	*	26.70	10.07	92
21-Oct	0	0	0.00	0.00	0.00	*	1,229	0.0	1,145	*	28.73	10.76	104
22-Oct	0	0	0.00	0.00	0.00	*	1,246	0.0	1,150	*	28.86	10.81	105
23-Oct	0	0	0.00	0.00	0.00	*	910	0.0	1,050	*	26.28	9.87	94
24-Oct	0	0	0.00	0.00	0.00	*	1,707	0.0	1,006	*	25.43	9.47	96
25-Oct	0	0	0.00	0.00	0.00	*	1,085	0.0	1,286	*	32.17	12.08	115
26-Oct	0	0	0.00	0.00	0.00	*	589	0.0	1,127	*	28.08	10.58	98
27-Oct	0	0	0.00	0.00	0.00	*	422	0.0	1,045	*	26.01	9.81	90
28-Oct	0	0	0.00	0.00	0.00	*	529	0.0	1,065	*	26.52	10.00	92
29-Oct	2,168	0	0.69	0.05	25.29	*	2,784	0.0	1,230	*	31.33	11.60	124
30-Oct	0	0	0.00	0.00	0.00	*	1,507	0.0	1,245	*	31.30	11.71	115
31-Oct	0	0	0.00	0.00	0.00	*	1,212	0.0	1,429	*	35.76	13.43	128
01-Nov	0	0	0.00	0.00	0.00	*	2,102	0.0	1,323	*	33.40	12.45	126

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GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

DATE	Gas	Oil				*	Gas	TDF	Bark	*			
	Mcf	Bbls				*	Mcf	Tons	Tons	*			
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64	5.94E-01				
SO_2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	30.80	2.25E-01		Calculated lbs/hr		
NOx EF	2.80E-01	NA	PM	SO_2	NOx		1.90E-01	1.98	1.98E+00		PM	SO_2	NOx
02-Nov	0	0	0.00	0.00	0.00	*	1,438	0.0	1,311	*	32.90	12.33	120
03-Nov	0	0	0.00	0.00	0.00	*	762	0.0	1,266	*	31.56	11.88	110
04-Nov	299	0	0.09	0.01	3.49	*	1,484	0.0	1,297	*	32.56	12.19	119
05-Nov	869	0	0.28	0.02	10.14	*	1,004	0.0	1,166	*	29.18	10.96	104
06-Nov	5,058	0	1.60	0.13	59.01	*	4,505	0.0	1,262	*	32.66	11.94	140
07-Nov	672	0	0.21	0.02	7.84	*	2,704	0.0	1,138	*	29.01	10.73	115
08-Nov	0	0	0.00	0.00	0.00	*	1,036	0.0	1,218	*	30.48	11.45	109
09-Nov	0	0	0.00	0.00	0.00	*	547	0.0	1,033	*	25.75	9.70	90
10-Nov	0	0	0.00	0.00	0.00	*	555	0.0	1,197	*	29.79	11.23	103
11-Nov	0	0	0.00	0.00	0.00	*	1,789	0.0	1,137	*	28.72	10.71	108
12-Nov	922	0	0.29	0.02	10.76	*	1,651	0.0	1,312	*	33.00	12.34	121
13-Nov	1,611	0	0.51	0.04	18.80	*	1,057	0.0	1,111	*	27.83	10.44	100
14-Nov	934	0	0.30	0.02	10.90	*	2,828	0.0	662	*	17.28	6.28	77
15-Nov	0	0	0.00	0.00	0.00	*	1,344	0.0	1,131	*	28.41	10.63	104
16-Nov	0	0	0.00	0.00	0.00	*	1,837	0.0	1,345	*	33.88	12.66	126
17-Nov	0	0	0.00	0.00	0.00	*	1,371	0.0	1,349	*	33.81	12.68	122
18-Nov	0	0	0.00	0.00	0.00	*	1,371	0.0	1,304	*	32.70	12.26	118
19-Nov	0	0	0.00	0.00	0.00	*	1,371	0.0	1,299	*	32.59	12.21	118
20-Nov	0	0	0.00	0.00	0.00	*	688	0.0	1,233	*	30.73	11.57	107
21-Nov	0	0	0.00	0.00	0.00	*	2,219	0.0	1,049	*	26.67	9.89	104
22-Nov	0	0	0.00	0.00	0.00	*	3,331	0.0	1,182	*	30.32	11.17	124
23-Nov	0	0	0.00	0.00	0.00	*	3,989	0.0	1,361	*	34.95	12.86	144
24-Nov	0	0	0.00	0.00	0.00	*	2,045	0.0	1,247	*	31.52	11.74	119
25-Nov	0	0	0.00	0.00	0.00	*	2,316	0.0	1,240	*	31.42	11.68	121
26-Nov	130	0	0.04	0.00	1.52	*	3,724	0.0	1,149	*	29.61	10.86	124
27-Nov	473	0	0.15	0.01	5.52	*	2,628	0.0	1,196	*	30.43	11.28	119
28-Nov	0	0	0.00	0.00	0.00	*	3,763	0.0	1,167	*	30.07	11.03	126
29-Nov	0	0	0.00	0.00	0.00	*	3,274	0.0	1,100	*	28.26	10.39	117

2002

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R M I L L U T I L I T Y R E P O R T

DATE	Gas Mcf	Oil Bbls				*	Gas Mcf	TDF Tons	Bark Tons	*			
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64	5.94E-01				
SO_2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	30.80	2.25E-01		Calculated lbs/hr		
NOx EF	2.80E-01	NA	PM	SO_2	NOx		1.90E-01	1.98	1.98E+00		PM	SO_2	NOx
30-Nov	0	0	0.00	0.00	0.00	*	1,915	0.0	1,170	*	29.56	11.02	112
01-Dec	0	0	0.00	0.00	0.00	*	1,535	0.0	1,172	*	29.50	11.03	109
02-Dec	0	0	0.00	0.00	0.00	*	1,728	0.0	1,239	*	31.21	11.66	116
03-Dec	479	0	0.15	0.01	5.59	*	3,085	0.0	1,220	*	31.17	11.51	125
04-Dec	3,133	0	0.99	0.08	36.55	*	2,712	0.0	1,112	*	28.38	10.49	113
05-Dec	3,353	0	1.06	0.08	39.12	*	2,124	0.0	1,076	*	27.30	10.14	106
06-Dec	0	0	0.00	0.00	0.00	*	1,553	0.0	1,064	*	26.84	10.02	100
07-Dec	0	0	0.00	0.00	0.00	*	1,680	0.0	968	*	24.49	9.12	93
08-Dec	0	0	0.00	0.00	0.00	*	2,255	0.0	1,155	*	29.29	10.88	113
09-Dec	0	0	0.00	0.00	0.00	*	1,600	0.0	1,141	*	28.74	10.73	107
10-Dec	0	0	0.00	0.00	0.00	*	1,203	0.0	1,189	*	29.82	11.18	108
11-Dec	1,528	0	0.48	0.04	17.83	*	912	0.0	589	*	14.87	5.54	56
12-Dec	3,704	0	1.17	0.09	43.21	*	1,346	0.0	309	*	8.07	2.93	36
13-Dec	0	0	0.00	0.00	0.00	*	2,659	0.0	1,042	*	26.63	9.84	107
14-Dec	0	0	0.00	0.00	0.00	*	2,640	0.0	1,245	*	31.65	11.74	124
15-Dec	0	0	0.00	0.00	0.00	*	1,895	0.0	1,242	*	31.34	11.69	117
16-Dec	0	0	0.00	0.00	0.00	*	1,603	0.0	1,235	*	31.07	11.62	115
17-Dec	500	0	0.16	0.01	5.83	*	2,441	0.0	1,290	*	32.71	12.16	126
18-Dec	3,329	0	1.05	0.08	38.84	*	1,456	0.0	1,241	*	31.17	11.67	114
19-Dec	395	0	0.13	0.01	4.61	*	1,781	0.0	1,241	*	31.28	11.68	117
20-Dec	0	0	0.00	0.00	0.00	*	1,053	0.0	1,172	*	29.33	11.01	105
21-Dec	0	0	0.00	0.00	0.00	*	1,742	0.0	1,166	*	29.42	10.98	110
22-Dec	0	0	0.00	0.00	0.00	*	856	0.0	1,116	*	27.89	10.48	99
23-Dec	0	0	0.00	0.00	0.00	*	2,280	0.0	1,180	*	29.92	11.12	115
24-Dec	0	0	0.00	0.00	0.00	*	4,378	0.0	1,229	*	31.80	11.63	136
25-Dec	0	0	0.00	0.00	0.00	*	3,615	0.0	1,222	*	31.38	11.54	129
26-Dec	0	0	0.00	0.00	0.00	*	2,127	0.0	1,346	*	33.98	12.67	128
27-Dec	0	0	0.00	0.00	0.00	*	2,017	0.0	1,310	*	33.06	12.33	124

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

DATE	Gas Mcf	Oil Bbls				*	Gas Mcf	TDF Tons	Bark Tons	*			
PM_{10}EF	7.60E-03	NA					7.60E-03	5.64	5.94E-01				
SO_2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	30.80	2.25E-01		Calculated lbs/hr		
NOx EF	2.80E-01	NA	PM	SO_2	NOx		1.90E-01	1.98	1.98E+00		PM	SO_2	NOx
28-Dec	0	0	0.00	0.00	0.00	*	1,431	0.0	1,351	*	33.88	12.70	123
			Calculated lbs/hr								Calculated lbs/hr		
			PM_{10}	SO_2	NOx						PM_{10}	SO_2	NOx

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

DATE	Gas Mcf	Oil Bbls	PM10	SO2	NOx	*	Gas Mcf	Rubber Tons	Bark Tons	*	PM10	SO2	NOx
PM10EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOX EF	2.80E-01	NA	PM_{10}	SO_2	NOx		1.90E-01	1.98E+00	1.98E+00		PM_{10}	SO_2	NOx
29-Dec	0	0	0.00	0.00	0.00	*	1,547	0.0	1,297	*	32.59	12.20	119
30-Dec	0	0	0.00	0.00	0.00	*	1,322	0.0	1,029	*	25.88	9.68	95
31-Dec	0	0	0.00	0.00	0.00	*	2,966	0.0	1,083	*	27.73	10.22	113
01-Jan	0	0	0.00	0.00	0.00	*	2,918	0.0	1,105	*	28.28	10.43	114
02-Jan	482	0	0.15	0.01	5.62	*	3,109	0.0	1,277	*	32.58	12.05	130
03-Jan	1,524	0	0.48	0.04	17.78	*	2,839	0.0	1,277	*	32.51	12.05	128
04-Jan	0	0	0.00	0.00	0.00	*	2,288	0.0	1,262	*	31.96	11.89	122
05-Jan	0	0	0.00	0.00	0.00	*	935	0.0	1,060	*	26.52	9.96	95
06-Jan	0	0	0.00	0.00	0.00	*	2,577	0.0	1,221	*	31.04	11.51	121
07-Jan	0	0	0.00	0.00	0.00	*	2,704	0.0	1,197	*	30.48	11.29	120
08-Jan	3,341	0	1.06	0.08	38.98	*	3,540	0.0	1,346	*	34.44	12.71	139
09-Jan	4,591	0	1.45	0.11	53.56	*	3,467	0.0	1,141	*	29.35	10.79	122
10-Jan	4,149	0	1.31	0.10	48.41	*	4,164	0.0	1,181	*	30.56	11.18	130
11-Jan	121	0	0.04	0.00	1.41	*	2,655	0.0	1,253	*	31.85	11.81	124
12-Jan	0	0	0.00	0.00	0.00	*	1,626	0.0	1,132	*	28.53	10.65	106
13-Jan	0	0	0.00	0.00	0.00	*	1,572	0.0	1,324	*	33.26	12.45	122
14-Jan	0	0	0.00	0.00	0.00	*	1,737	0.0	1,030	*	26.05	9.70	99
15-Jan	142	0	0.04	0.00	1.66	*	5,022	0.0	949	*	25.08	9.02	118
16-Jan	1,034	0	0.33	0.03	12.06	*	3,122	0.0	1,342	*	34.19	12.66	135
17-Jan	4,046	0	1.28	0.10	47.20	*	3,586	0.0	1,366	*	34.94	12.89	141
18-Jan	2,079	0	0.66	0.05	24.26	*	2,845	0.0	1,325	*	33.68	12.49	132
19-Jan	0	0	0.00	0.00	0.00	*	3,907	0.0	1,250	*	32.17	11.82	134
20-Jan	0	0	0.00	0.00	0.00	*	2,496	0.0	1,116	*	28.42	10.53	112
21-Jan	0	0	0.00	0.00	0.00	*	1,948	0.0	1,205	*	30.45	11.35	115
22-Jan	311	0	0.10	0.01	3.63	*	1,341	0.0	1,111	*	27.92	10.45	102
23-Jan	967	0	0.31	0.02	11.28	*	3,268	0.0	997	*	25.72	9.43	108
24-Jan	2,879	0	0.91	0.07	33.59	*	4,163	0.0	1,902	*	48.39	17.93	190
25-Jan	3,928	0	1.24	0.10	45.83	*	1,732	0.0	1,531	*	38.43	14.39	140
26-Jan	4,082	0	1.29	0.10	47.62	*	1,479	0.0	1,310	*	32.88	12.32	120
27-Jan	2,440	0	0.77	0.06	28.47	*	891	0.0	1,439	*	35.91	13.52	126
28-Jan	1,087	0	0.34	0.03	12.68	*	1,647	0.0	1,306	*	32.84	12.28	121

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

DATE	Gas Mcf	Oil Bbls	Calculated lbs/hr PM_{10}	Calculated lbs/hr SO_2	Calculated lbs/hr NOx	*	Gas Mcf	Rubber Tons	Bark Tons	*	Calculated lbs/hr PM_{10}	Calculated lbs/hr SO_2	Calculated lbs/hr NOx
PM10EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO2 EF	6.00E-04	NA					6.00E-04	3.08E+01	2.25E-01				
NOX EF	2.80E-01	NA					1.90E-01	1.98E+00	1.98E+00				
29-Jan	0	0	0.00	0.00	0.00	*	965	0.0	1,878	*	46.78	17.63	163
30-Jan	0	0	0.00	0.00	0.00	*	1,844	0.0	1,666	*	41.83	15.67	152
31-Jan	0	0	0.00	0.00	0.00	*	2,706	0.0	1,440	*	36.51	13.57	140
01-Feb	0	0	0.00	0.00	0.00	*	1,413	0.0	1,369	*	34.32	12.87	124
02-Feb	0	0	0.00	0.00	0.00	*	1,099	0.0	1,228	*	30.75	11.54	110
03-Feb	0	0	0.00	0.00	0.00	*	1,884	0.0	1,317	*	33.20	12.40	124
04-Feb	0	0	0.00	0.00	0.00	*	1,024	0.0	1,325	*	33.13	12.45	117
05-Feb	0	0	0.00	0.00	0.00	*	1,255	0.0	1,074	*	26.98	10.10	99
06-Feb	318	0	0.10	0.01	3.71	*	2,603	0.0	1,452	*	36.76	13.68	140
07-Feb	957	0	0.30	0.02	11.17	*	3,622	0.0	1,447	*	36.96	13.65	148
08-Feb	0	0	0.00	0.00	0.00	*	3,326	0.0	1,437	*	36.63	13.56	145
09-Feb	0	0	0.00	0.00	0.00	*	3,582	0.0	1,493	*	38.09	14.09	152
10-Feb	0	0	0.00	0.00	0.00	*	2,406	0.0	1,448	*	36.61	13.64	139
11-Feb	0	0	0.00	0.00	0.00	*	2,940	0.0	1,304	*	33.20	12.30	131
12-Feb	0	0	0.00	0.00	0.00	*	1,601	0.0	1,053	*	26.57	9.91	100
13-Feb	0	0	0.00	0.00	0.00	*	2,743	0.0	1,123	*	28.66	10.60	114
14-Feb	0	0	0.00	0.00	0.00	*	1,802	0.0	1,005	*	25.44	9.47	97
15-Feb	0	0	0.00	0.00	0.00	*	1,673	0.0	1,279	*	32.18	12.03	119
16-Feb	0	0	0.00	0.00	0.00	*	1,987	0.0	1,307	*	32.98	12.30	124
17-Feb	0	0	0.00	0.00	0.00	*	2,608	0.0	1,312	*	33.30	12.37	129
18-Feb	74	0	0.02	0.00	0.86	*	2,198	0.0	1,094	*	27.77	10.31	108
19-Feb	485	0	0.15	0.01	5.66	*	1,702	0.0	1,014	*	25.65	9.55	97
20-Feb	0	0	0.00	0.00	0.00	*	2,250	0.0	1,396	*	35.26	13.14	133
21-Feb	0	0	0.00	0.00	0.00	*	2,768	0.0	1,299	*	33.02	12.24	129
22-Feb	0	0	0.00	0.00	0.00	*	3,326	0.0	1,347	*	34.40	12.71	137
23-Feb	0	0	0.00	0.00	0.00	*	2,376	0.0	1,399	*	35.38	13.18	134
24-Feb	2,295	0	0.73	0.06	26.78	*	2,135	0.0	511	*	13.32	4.84	59
25-Feb	4,188	0	1.33	0.10	48.86	*	0	0.0	0	*	0.00	0.00	0
26-Feb	3,547	0	1.12	0.09	41.38	*	0	0.0	0	*	0.00	0.00	0
27-Feb	3,054	0	0.97	0.08	35.63	*	2,541	0.0	225	*	6.38	2.17	39
28-Feb	0	0	0.00	0.00	0.00	*	3,788	0.0	1,221	*	31.42	11.54	131

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R M I L L U T I L I T Y R E P O R T

DATE	Gas Mcf	Oil Bbls	PM10	SO2	NOx	*	Gas Mcf	Rubber Tons	Bark Tons	*	PM10	SO2	NOx
			Calculated lbs/hr								Calculated lbs/hr		
PM10EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO2 EF	6.00E-04	NA					6.00E-04	3.08E+01	2.25E-01				
NOX EF	2.80E-01	NA					1.90E-01	1.98E+00	1.98E+00				
01-Mar	0	0	0.00	0.00	0.00	*	4,735	0.0	1,138	*	29.66	10.78	131
02-Mar	0	0	0.00	0.00	0.00	*	2,613	0.0	1,161	*	29.57	10.95	116
03-Mar	0	0	0.00	0.00	0.00	*	1,958	0.0	1,272	*	32.11	11.98	120
04-Mar	0	0	0.00	0.00	0.00	*	1,738	0.0	1,241	*	31.26	11.68	116
05-Mar	0	0	0.00	0.00	0.00	*	1,116	0.0	988	*	24.80	9.29	90
06-Mar	0	0	0.00	0.00	0.00	*	1,391	0.0	1,180	*	29.65	11.10	108
07-Mar	0	0	0.00	0.00	0.00	*	3,144	0.0	1,139	*	29.20	10.76	119
08-Mar	0	0	0.00	0.00	0.00	*	1,626	0.0	1,224	*	30.80	11.51	114
09-Mar	0	0	0.00	0.00	0.00	*	858	0.0	1,008	*	25.22	9.47	90
10-Mar	0	0	0.00	0.00	0.00	*	639	0.0	1,148	*	28.61	10.78	100
11-Mar	555	0	0.18	0.01	6.48	*	652	0.0	1,298	*	32.33	12.18	112
12-Mar	0	0	0.00	0.00	0.00	*	510	0.0	1,024	*	25.50	9.61	88
13-Mar	0	0	0.00	0.00	0.00	*	33	0.0	981	*	24.28	9.20	81
14-Mar	0	0	0.00	0.00	0.00	*	1,141	0.0	1,033	*	25.94	9.72	94
15-Mar	0	0	0.00	0.00	0.00	*	1,342	0.0	1,125	*	28.28	10.58	103
16-Mar	0	0	0.00	0.00	0.00	*	793	0.0	1,206	*	30.09	11.32	106
17-Mar	0	0	0.00	0.00	0.00	*	360	0.0	908	*	22.59	8.52	78
18-Mar	0	0	0.00	0.00	0.00	*	1,190	0.0	1,098	*	27.54	10.32	100
19-Mar	0	0	0.00	0.00	0.00	*	372	0.0	912	*	22.69	8.56	78
20-Mar	0	0	0.00	0.00	0.00	*	733	0.0	1,179	*	29.42	11.08	103
21-Mar	0	0	0.00	0.00	0.00	*	552	0.0	1,127	*	28.07	10.58	97
22-Mar	0	0	0.00	0.00	0.00	*	790	0.0	1,215	*	30.33	11.41	107
23-Mar	0	0	0.00	0.00	0.00	*	358	0.0	1,214	*	30.17	11.39	103
24-Mar	0	0	0.00	0.00	0.00	*	291	0.0	930	*	23.11	8.73	79
25-Mar	1,474	0	0.47	0.04	17.20	*	1,312	0.0	1,046	*	26.29	9.83	97
26-Mar	4,587	0	1.45	0.11	53.52	*	1,635	0.0	1,368	*	34.37	12.86	126
27-Mar	3,844	0	1.22	0.10	44.85	*	1,068	0.0	1,414	*	35.33	13.28	125
28-Mar	2,298	0	0.73	0.06	26.81	*	1,173	0.0	1,385	*	34.64	13.01	124
29-Mar	0	0	0.00	0.00	0.00	*	749	0.0	1,099	*	27.44	10.32	97
30-Mar	0	0	0.00	0.00	0.00	*	522	0.0	962	*	23.97	9.03	83
31-Mar	0	0	0.00	0.00	0.00	*	1,478	0.0	1,309	*	32.87	12.31	120

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

DATE	Gas Mcf	Oil Bbls	PM_{10}	SO_2	NOx	*	Gas Mcf	Rubber Tons	Bark Tons	*	PM_{10}	SO_2	NOx
PM10EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOX EF	2.80E-01	NA					1.90E-01	1.98E+00	1.98E+00				
01-Apr	97	0	0.03	0.00	1.13	*	494	0.0	967	*	24.08	9.07	84
02-Apr	105	0	0.03	0.00	1.23	*	504	0.0	1,019	*	25.37	9.56	88
03-Apr	0	0	0.00	0.00	0.00	*	694	0.0	1,025	*	25.60	9.63	90
04-Apr	0	0	0.00	0.00	0.00	*	878	0.0	1,032	*	25.83	9.70	92
05-Apr	0	0	0.00	0.00	0.00	*	360	0.0	1,165	*	28.95	10.93	99
06-Apr	0	0	0.00	0.00	0.00	*	857	0.0	954	*	23.88	8.96	85
07-Apr	3,302	0	1.05	0.08	38.52	*	1,508	0.0	1,185	*	29.82	11.15	110
08-Apr	2,811	0	0.89	0.07	32.80	*	1,783	0.0	1,283	*	32.33	12.08	120
09-Apr	0	0	0.00	0.00	0.00	*	954	0.0	1,277	*	31.90	11.99	113
10-Apr	0	0	0.00	0.00	0.00	*	1,546	0.0	1,377	*	34.57	12.95	126
11-Apr	0	0	0.00	0.00	0.00	*	988	0.0	1,199	*	30.00	11.27	107
12-Apr	0	0	0.00	0.00	0.00	*	581	0.0	1,101	*	27.45	10.34	95
13-Apr	0	0	0.00	0.00	0.00	*	792	0.0	916	*	22.91	8.60	82
14-Apr	0	0	0.00	0.00	0.00	*	592	0.0	1,004	*	25.04	9.43	88
15-Apr	0	0	0.00	0.00	0.00	*	660	0.0	910	*	22.73	8.55	80
16-Apr	0	0	0.00	0.00	0.00	*	587	0.0	860	*	21.48	8.08	76
17-Apr	0	0	0.00	0.00	0.00	*	337	0.0	842	*	20.95	7.90	72
18-Apr	0	0	0.00	0.00	0.00	*	686	0.0	843	*	21.07	7.92	75
19-Apr	0	0	0.00	0.00	0.00	*	377	0.0	984	*	24.48	9.24	84
20-Apr	0	0	0.00	0.00	0.00	*	381	0.0	702	*	17.50	6.59	61
21-Apr	0	0	0.00	0.00	0.00	*	256	0.0	838	*	20.83	7.87	71
22-Apr	0	0	0.00	0.00	0.00	*	492	0.0	905	*	22.56	8.50	79
23-Apr	0	0	0.00	0.00	0.00	*	2,713	0.0	789	*	20.39	7.46	87
24-Apr	0	0	0.00	0.00	0.00	*	827	0.0	1,215	*	30.33	11.41	107
25-Apr	0	0	0.00	0.00	0.00	*	914	0.0	1,189	*	29.71	11.17	105
26-Apr	0	0	0.00	0.00	0.00	*	929	0.0	1,353	*	33.78	12.71	119
27-Apr	0	0	0.00	0.00	0.00	*	496	0.0	1,166	*	29.02	10.95	100
28-Apr	0	0	0.00	0.00	0.00	*	543	0.0	1,089	*	27.12	10.22	94
29-Apr	0	0	0.00	0.00	0.00	*	463	0.0	1,028	*	25.58	9.65	88
30-Apr	0	0	0.00	0.00	0.00	*	481	0.0	967	*	24.09	9.08	84
01-May	0	0	0.00	0.00	0.00	*	240	0.0	1,017	*	25.26	9.54	86

GEORGIA-PACIFIC CORPORATION
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CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

DATE	Gas Mcf	Oil Bbls	Calculated lbs/hr PM10	SO2	NOx	*	Gas Mcf	Rubber Tons	Bark Tons	*	Calculated lbs/hr PM10	SO2	NOx
PM10EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO2 EF	6.00E-04	NA					6.00E-04	3.08E+01	2.25E-01				
NOX EF	2.80E-01	NA	PM_{10}	SO_2	NOx		1.90E-01	1.98E+00	1.98E+00		PM_{10}	SO_2	NOx
02-May	0	0	0.00	0.00	0.00	*	345	0.0	986	*	24.50	9.25	84
03-May	0	0	0.00	0.00	0.00	*	433	0.0	985	*	24.53	9.25	85
04-May	4,144	0	1.31	0.10	48.35	*	1,778	0.0	1,313	*	33.06	12.35	122
05-May	2,286	0	0.72	0.06	26.67	*	1,072	0.0	1,217	*	30.45	11.43	109
06-May	1,749	0	0.55	0.04	20.41	*	785	0.0	1,157	*	28.87	10.86	102
07-May	2,871	0	0.91	0.07	33.50	*	1,431	0.0	1,126	*	28.32	10.59	104
08-May	1,640	0	0.52	0.04	19.13	*	1,129	0.0	1,108	*	27.77	10.41	100
09-May	2,314	0	0.73	0.06	27.00	*	1,200	0.0	1,181	*	29.62	11.10	107
10-May	4,117	0	1.30	0.10	48.03	*	1,924	0.0	1,278	*	32.23	12.02	121
11-May	3,985	0	1.26	0.10	46.49	*	751	0.0	1,305	*	32.53	12.25	114
12-May	3,255	0	1.03	0.08	37.98	*	1,355	0.0	1,388	*	34.79	13.05	125
13-May	819	0	0.26	0.02	9.56	*	686	0.0	868	*	21.69	8.15	77
14-May	0	0	0.00	0.00	0.00	*	685	0.0	911	*	22.76	8.56	81
15-May	0	0	0.00	0.00	0.00	*	495	0.0	857	*	21.37	8.05	75
16-May	0	0	0.00	0.00	0.00	*	903	0.0	961	*	24.06	9.03	86
17-May	0	0	0.00	0.00	0.00	*	643	0.0	944	*	23.56	8.86	83
18-May	0	0	0.00	0.00	0.00	*	628	0.0	922	*	23.03	8.66	81
19-May	2,985	0	0.95	0.07	34.83	*	1,888	0.0	1,082	*	27.37	10.19	104
20-May	3,430	0	1.09	0.09	40.02	*	3,296	0.0	1,327	*	33.88	12.52	136
21-May	0	0	0.00	0.00	0.00	*	1,731	0.0	968	*	24.50	9.12	94
22-May	0	0	0.00	0.00	0.00	*	456	0.0	1,114	*	27.72	10.46	96
23-May	0	0	0.00	0.00	0.00	*	342	0.0	1,027	*	25.53	9.64	87
24-May	0	0	0.00	0.00	0.00	*	690	0.0	874	*	21.85	8.21	78
25-May	0	0	0.00	0.00	0.00	*	723	0.0	780	*	19.53	7.33	70
26-May	0	0	0.00	0.00	0.00	*	816	0.0	1,721	*	42.85	16.15	148
27-May	0	0	0.00	0.00	0.00	*	1,284	0.0	774	*	19.55	7.28	74
28-May	1,450	0	0.46	0.04	16.92	*	1,221	0.0	1,082	*	27.16	10.17	99
29-May	3,087	0	0.98	0.08	36.02	*	2,421	0.0	1,094	*	27.84	10.32	109
30-May	0	0	0.00	0.00	0.00	*	1,604	0.0	835	*	21.17	7.87	82
31-May	0	0	0.00	0.00	0.00	*	1,725	0.0	970	*	24.54	9.13	94
01-Jun	0	0	0.00	0.00	0.00	*	981	0.0	829	*	20.84	7.80	76

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R M I L L U T I L I T Y R E P O R T

DATE	Gas Mcf	Oil Bbls	Calculated lbs/hr PM$_{10}$	SO$_2$	NOx	*	Gas Mcf	Rubber Tons	Bark Tons	*	Calculated lbs/hr PM$_{10}$	SO$_2$	NOx
PM10EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO2 EF	6.00E-04	NA					6.00E-04	3.08E+01	2.25E-01				
NOX EF	2.80E-01	NA					1.90E-01	1.98E+00	1.98E+00				
02-Jun	0	0	0.00	0.00	0.00	*	836	0.0	837	*	20.97	7.86	76
03-Jun	0	0	0.00	0.00	0.00	*	548	0.0	718	*	17.94	6.74	64
04-Jun	0	0	0.00	0.00	0.00	*	544	0.0	727	*	18.17	6.83	64
05-Jun	0	0	0.00	0.00	0.00	*	323	0.0	699	*	17.39	6.56	60
06-Jun	0	0	0.00	0.00	0.00	*	326	0.0	740	*	18.42	6.95	64
07-Jun	0	0	0.00	0.00	0.00	*	378	0.0	779	*	19.41	7.32	67
08-Jun	0	0	0.00	0.00	0.00	*	567	0.0	665	*	16.64	6.25	59
09-Jun	0	0	0.00	0.00	0.00	*	374	0.0	671	*	16.72	6.30	58
10-Jun	0	0	0.00	0.00	0.00	*	516	0.0	711	*	17.76	6.68	63
11-Jun	0	0	0.00	0.00	0.00	*	483	0.0	832	*	20.73	7.81	72
12-Jun	0	0	0.00	0.00	0.00	*	4,423	0.0	507	*	13.96	4.87	77
13-Jun	0	0	0.00	0.00	0.00	*	2,550	0.0	607	*	15.83	5.75	70
14-Jun	0	0	0.00	0.00	0.00	*	334	0.0	770	*	19.16	7.22	66
15-Jun	0	0	0.00	0.00	0.00	*	327	0.0	860	*	21.39	8.07	74
16-Jun	0	0	0.00	0.00	0.00	*	319	0.0	722	*	17.97	6.78	62
17-Jun	0	0	0.00	0.00	0.00	*	475	0.0	864	*	21.53	8.11	75
18-Jun	0	0	0.00	0.00	0.00	*	324	0.0	714	*	17.78	6.71	62
19-Jun	0	0	0.00	0.00	0.00	*	745	0.0	811	*	20.31	7.62	73
20-Jun	0	0	0.00	0.00	0.00	*	618	0.0	939	*	23.43	8.82	82
21-Jun	0	0	0.00	0.00	0.00	*	349	0.0	855	*	21.27	8.03	73
22-Jun	0	0	0.00	0.00	0.00	*	1,121	0.0	834	*	21.00	7.85	78
23-Jun	0	0	0.00	0.00	0.00	*	397	0.0	958	*	23.85	8.99	82
24-Jun	0	0	0.00	0.00	0.00	*	835	0.0	973	*	24.35	9.14	87
25-Jun	612	0	0.19	0.02	7.14	*	2,930	0.0	642	*	16.82	6.09	76
26-Jun	0	0	0.00	0.00	0.00	*	851	0.0	726	*	18.24	6.83	67
27-Jun	0	0	0.00	0.00	0.00	*	324	0.0	793	*	19.74	7.44	68
28-Jun	0	0	0.00	0.00	0.00	*	313	0.0	711	*	17.69	6.67	61
29-Jun	0	0	0.00	0.00	0.00	*	375	0.0	712	*	17.73	6.68	62
30-Jun	0	0	0.00	0.00	0.00	*	516	0.0	862	*	21.50	8.10	75
01-Jul	0	0	0.00	0.00	0.00	*	321	0.0	668	*	16.63	6.27	58
02-Jul	0	0	0.00	0.00	0.00	*	326	0.0	724	*	18.03	6.80	62

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P A P E R M I L L U T I L I T Y R E P O R T

DATE	Gas Mcf	Oil Bbls				*	Gas Mcf	Rubber Tons	Bark Tons	*			
PM10EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOX EF	2.80E-01	NA	PM_{10}	SO_2	NOx		1.90E-01	1.98E+00	1.98E+00		PM_{10}	SO_2	NOx
	-------	-------				*	-------	-------	-------	*			
03-Jul	0	0	0.00	0.00	0.00	*	497	0.0	720	*	17.98	6.76	63
04-Jul	0	0	0.00	0.00	0.00	*	929	0.0	1,006	*	25.19	9.45	90
05-Jul	0	0	0.00	0.00	0.00	*	1,082	0.0	1,226	*	30.69	11.52	110
06-Jul	0	0	0.00	0.00	0.00	*	977	0.0	807	*	20.28	7.59	74
07-Jul	25	0	0.01	0.00	0.29	*	2,056	0.0	821	*	20.97	7.75	84
08-Jul	0	0	0.00	0.00	0.00	*	824	0.0	556	*	14.02	5.23	52
09-Jul	1,124	0	0.36	0.03	13.11	*	1,729	0.0	940	*	23.80	8.85	91
10-Jul	0	0	0.00	0.00	0.00	*	358	0.0	746	*	18.57	7.00	64
11-Jul	0	0	0.00	0.00	0.00	*	365	0.0	679	*	16.92	6.37	59
12-Jul	0	0	0.00	0.00	0.00	*	338	0.0	781	*	19.45	7.33	67
13-Jul	0	0	0.00	0.00	0.00	*	355	0.0	644	*	16.04	6.04	56
14-Jul	0	0	0.00	0.00	0.00	*	314	0.0	717	*	17.84	6.73	62
15-Jul	0	0	0.00	0.00	0.00	*	1,711	0.0	769	*	19.57	7.25	77
16-Jul	0	0	0.00	0.00	0.00	*	374	0.0	654	*	16.30	6.14	57
17-Jul	0	0	0.00	0.00	0.00	*	507	0.0	780	*	19.46	7.32	68
18-Jul	0	0	0.00	0.00	0.00	*	634	0.0	912	*	22.77	8.56	80
19-Jul	0	0	0.00	0.00	0.00	*	730	0.0	1,219	*	30.39	11.44	106
20-Jul	0	0	0.00	0.00	0.00	*	324	0.0	740	*	18.43	6.95	64
21-Jul	0	0	0.00	0.00	0.00	*	868	0.0	833	*	20.90	7.83	76
22-Jul	0	0	0.00	0.00	0.00	*	362	0.0	679	*	16.91	6.37	59
23-Jul	0	0	0.00	0.00	0.00	*	430	0.0	771	*	19.21	7.24	67
24-Jul	0	0	0.00	0.00	0.00	*	381	0.0	671	*	16.72	6.30	58
25-Jul	0	0	0.00	0.00	0.00	*	358	0.0	737	*	18.36	6.92	64
26-Jul	0	0	0.00	0.00	0.00	*	394	0.0	798	*	19.87	7.49	69
27-Jul	0	0	0.00	0.00	0.00	*	400	0.0	680	*	16.95	6.38	59
28-Jul	1,511	0	0.48	0.04	17.63	*	1,055	0.0	908	*	22.81	8.54	83
29-Jul	4,001	0	1.27	0.10	46.68	*	1,309	0.0	970	*	24.42	9.12	90
30-Jul	591	0	0.19	0.01	6.90	*	430	0.0	693	*	17.28	6.50	61
31-Jul	0	0	0.00	0.00	0.00	*	448	0.0	678	*	16.93	6.37	60
01-Aug	0	0	0.00	0.00	0.00	*	370	0.0	800	*	19.92	7.51	69
02-Aug	0	0	0.00	0.00	0.00	*	421	0.0	662	*	16.51	6.21	58

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PULP & PAPER DIVISION
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P A P E R M I L L U T I L I T Y R E P O R T

DATE	Gas Mcf	Oil Bbls	Calculated lbs/hr PM_{10}	SO_2	NOx	*	Gas Mcf	Rubber Tons	Bark Tons	*	Calculated lbs/hr PM_{10}	SO_2	NOx
PM10EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO2 EF	6.00E-04	NA					6.00E-04	3.08E+01	2.25E-01				
NOX EF	2.80E-01	NA					1.90E-01	1.98E+00	1.98E+00				
03-Aug	0	0	0.00	0.00	0.00	*	1,118	0.0	963	*	24.19	9.06	88
04-Aug	0	0	0.00	0.00	0.00	*	716	0.0	879	*	21.99	8.26	78
05-Aug	0	0	0.00	0.00	0.00	*	423	0.0	735	*	18.33	6.90	64
06-Aug	0	0	0.00	0.00	0.00	*	1,310	0.0	871	*	21.98	8.20	82
07-Aug	0	0	0.00	0.00	0.00	*	1,158	0.0	798	*	20.11	7.51	75
08-Aug	0	0	0.00	0.00	0.00	*	394	0.0	762	*	18.99	7.15	66
09-Aug	0	0	0.00	0.00	0.00	*	376	0.0	714	*	17.80	6.71	62
10-Aug	0	0	0.00	0.00	0.00	*	371	0.0	713	*	17.77	6.70	62
11-Aug	0	0	0.00	0.00	0.00	*	602	0.0	759	*	18.97	7.13	67
12-Aug	0	0	0.00	0.00	0.00	*	480	0.0	773	*	19.27	7.25	68
13-Aug	0	0	0.00	0.00	0.00	*	1,364	0.0	1,076	*	27.06	10.12	100
14-Aug	338	0	0.11	0.01	3.94	*	806	0.0	730	*	18.31	6.86	67
15-Aug	2,468	0	0.78	0.06	28.79	*	384	0.0	202	*	5.13	1.91	20
16-Aug	3,464	0	1.10	0.09	40.41	*	0	0.0	0	*	0.00	0.00	0
17-Aug	2,934	0	0.93	0.07	34.23	*	542	0.0	116	*	3.04	1.10	14
18-Aug	0	0	0.00	0.00	0.00	*	1,887	0.0	937	*	23.79	8.83	92
19-Aug	0	0	0.00	0.00	0.00	*	595	0.0	766	*	19.14	7.19	68
20-Aug	0	0	0.00	0.00	0.00	*	1,443	0.0	811	*	20.53	7.64	78
21-Aug	0	0	0.00	0.00	0.00	*	1,167	0.0	1,061	*	26.62	9.97	97
22-Aug	0	0	0.00	0.00	0.00	*	1,060	0.0	861	*	21.64	8.09	79
23-Aug	0	0	0.00	0.00	0.00	*	657	0.0	675	*	16.91	6.34	61
24-Aug	0	0	0.00	0.00	0.00	*	674	0.0	772	*	19.32	7.25	69
25-Aug	0	0	0.00	0.00	0.00	*	3,057	0.0	1,081	*	27.72	10.21	113
26-Aug	1,035	0	0.33	0.03	12.08	*	1,851	0.0	1,189	*	30.01	11.19	113
27-Aug	3,819	0	1.21	0.10	44.56	*	2,318	0.0	1,275	*	32.29	12.01	124
28-Aug	1,792	0	0.57	0.04	20.91	*	2,870	0.0	693	*	18.07	6.57	80
29-Aug	874	0	0.28	0.02	10.20	*	861	0.0	605	*	15.25	5.69	57
30-Aug	0	0	0.00	0.00	0.00	*	423	0.0	823	*	20.50	7.73	71
31-Aug	0	0	0.00	0.00	0.00	*	341	0.0	795	*	19.78	7.46	68
01-Sep	433	0	0.14	0.01	5.05	*	1,960	0.0	961	*	24.40	9.06	95
02-Sep	238	0	0.08	0.01	2.78	*	548	0.0	955	*	23.80	8.96	83

GEORGIA-PACIFIC CORPORATION
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CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

DATE	Gas Mcf	Oil Bbls	PM10	SO2	NOx	*	Gas Mcf	Rubber Tons	Bark Tons	*	PM10	SO2	NOx
PM10EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOX EF	2.80E-01	NA	PM_{10}	SO_2	NOx		1.90E-01	1.98E+00	1.98E+00		PM_{10}	SO_2	NOx
03-Sep	142	0	0.04	0.00	1.66	*	1,735	0.0	995	*	25.18	9.37	96
04-Sep	55	0	0.02	0.00	0.64	*	395	0.0	878	*	21.85	8.24	76
05-Sep	1,606	0	0.51	0.04	18.74	*	552	0.0	410	*	10.32	3.86	38
06-Sep	2,787	0	0.88	0.07	32.52	*	76	0.0	0	*	0.02	0.00	1
07-Sep	191	0	0.06	0.00	2.23	*	693	0.0	674	*	16.91	6.34	61
08-Sep	0	0	0.00	0.00	0.00	*	374	0.0	703	*	17.52	6.60	61
09-Sep	0	0	0.00	0.00	0.00	*	305	0.0	649	*	16.16	6.09	56
10-Sep	0	0	0.00	0.00	0.00	*	529	0.0	695	*	17.37	6.53	62
11-Sep	0	0	0.00	0.00	0.00	*	295	0.0	601	*	14.97	5.64	52
12-Sep	0	0	0.00	0.00	0.00	*	304	0.0	755	*	18.77	7.08	65
13-Sep	0	0	0.00	0.00	0.00	*	1,218	0.0	961	*	24.18	9.04	89
14-Sep	0	0	0.00	0.00	0.00	*	806	0.0	1,027	*	25.67	9.65	91
15-Sep	0	0	0.00	0.00	0.00	*	302	0.0	713	*	17.74	6.69	61
16-Sep	0	0	0.00	0.00	0.00	*	293	0.0	704	*	17.51	6.61	60
17-Sep	0	0	0.00	0.00	0.00	*	443	0.0	883	*	22.00	8.29	76
18-Sep	0	0	0.00	0.00	0.00	*	577	0.0	948	*	23.66	8.91	83
19-Sep	0	0	0.00	0.00	0.00	*	2,859	0.0	629	*	16.47	5.97	75
20-Sep	0	0	0.00	0.00	0.00	*	294	0.0	602	*	14.99	5.65	52
21-Sep	0	0	0.00	0.00	0.00	*	977	0.0	924	*	23.18	8.69	84
22-Sep	0	0	0.00	0.00	0.00	*	427	0.0	883	*	22.00	8.29	76
23-Sep	0	0	0.00	0.00	0.00	*	399	0.0	728	*	18.15	6.84	63
24-Sep	0	0	0.00	0.00	0.00	*	291	0.0	593	*	14.77	5.57	51
25-Sep	0	0	0.00	0.00	0.00	*	331	0.0	703	*	17.51	6.60	61
26-Sep	0	0	0.00	0.00	0.00	*	557	0.0	909	*	22.68	8.54	79
27-Sep	0	0	0.00	0.00	0.00	*	551	0.0	917	*	22.87	8.61	80
28-Sep	0	0	0.00	0.00	0.00	*	1,747	0.0	627	*	16.06	5.92	66
29-Sep	0	0	0.00	0.00	0.00	*	6,631	0.0	481	*	14.00	4.67	92
30-Sep	0	0	0.00	0.00	0.00	*	1,855	0.0	838	*	21.33	7.90	84
01-Oct	167	0	0.05	0.00	1.95	*	853	0.0	836	*	20.97	7.86	76
02-Oct	0	0	0.00	0.00	0.00	*	553	0.0	885	*	22.08	8.31	77
03-Oct	205	0	0.06	0.01	2.39	*	514	0.0	927	*	23.12	8.71	81

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P A P E R   M I L L   U T I L I T Y   R E P O R T

DATE	Gas Mcf	Oil Bbls	PM10	SO2	NOx	*	Gas Mcf	Rubber Tons	Bark Tons	*	PM10	SO2	NOx
PM10EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO2 EF	6.00E-04	NA	Calculated lbs/hr				6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOX EF	2.80E-01	NA	PM_{10}	SO_2	NOx		1.90E-01	1.98E+00	1.98E+00		PM_{10}	SO_2	NOx
04-Oct	4,544	0	1.44	0.11	53.01	*	1,228	0.0	694	*	17.55	6.53	67
05-Oct	3,917	0	1.24	0.10	45.70	*	2,674	0.0	782	*	20.21	7.40	86
06-Oct	3,816	0	1.21	0.10	44.52	*	1,017	0.0	1,535	*	38.32	14.42	135
07-Oct	4,114	0	1.30	0.10	48.00	*	2,083	0.0	1,477	*	37.22	13.90	138
08-Oct	4,171	0	1.32	0.10	48.66	*	2,391	0.0	1,423	*	35.97	13.40	136
09-Oct	4,798	0	1.52	0.12	55.98	*	2,366	0.0	1,368	*	34.60	12.88	132
10-Oct	2,806	0	0.89	0.07	32.74	*	1,666	0.0	921	*	23.33	8.68	89
11-Oct	1,253	0	0.40	0.03	14.62	*	1,147	0.0	834	*	21.00	7.84	78
12-Oct	0	0	0.00	0.00	0.00	*	901	0.0	997	*	24.95	9.37	89
13-Oct	0	0	0.00	0.00	0.00	*	657	0.0	931	*	23.24	8.74	82
14-Oct	0	0	0.00	0.00	0.00	*	372	0.0	817	*	20.34	7.67	70
15-Oct	0	0	0.00	0.00	0.00	*	657	0.0	981	*	24.50	9.22	86
16-Oct	0	0	0.00	0.00	0.00	*	572	0.0	885	*	22.08	8.31	78
17-Oct	0	0	0.00	0.00	0.00	*	995	0.0	934	*	23.43	8.78	85
18-Oct	0	0	0.00	0.00	0.00	*	424	0.0	983	*	24.46	9.23	84
19-Oct	0	0	0.00	0.00	0.00	*	344	0.0	904	*	22.48	8.48	77
20-Oct	0	0	0.00	0.00	0.00	*	1,081	0.0	965	*	24.24	9.08	88
21-Oct	726	0	0.23	0.02	8.47	*	585	0.0	797	*	19.91	7.49	70
22-Oct	2,024	0	0.64	0.05	23.61	*	704	0.0	960	*	23.99	9.02	85
23-Oct	169	0	0.05	0.00	1.97	*	813	0.0	956	*	23.92	8.98	85
24-Oct	0	0	0.00	0.00	0.00	*	1,147	0.0	1,128	*	28.29	10.61	102
25-Oct	0	0	0.00	0.00	0.00	*	1,147	0.0	1,128	*	28.28	10.60	102
26-Oct	0	0	0.00	0.00	0.00	*	1,276	0.0	1,236	*	31.00	11.62	112
27-Oct	0	0	0.00	0.00	0.00	*	984	0.0	1,168	*	29.21	10.97	104
28-Oct	0	0	0.00	0.00	0.00	*	1,348	0.0	891	*	22.47	8.38	84
29-Oct	0	0	0.00	0.00	0.00	*	607	0.0	973	*	24.28	9.14	85
30-Oct	0	0	0.00	0.00	0.00	*	1,702	0.0	1,079	*	27.25	10.16	103
31-Oct	0	0	0.00	0.00	0.00	*	520	0.0	1,067	*	26.57	10.01	92
01-Nov	0	0	0.00	0.00	0.00	*	468	0.0	1,054	*	26.25	9.90	91
02-Nov	0	0	0.00	0.00	0.00	*	549	0.0	1,006	*	25.06	9.44	87
03-Nov	0	0	0.00	0.00	0.00	*	387	0.0	981	*	24.39	9.20	84

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R M I L L U T I L I T Y R E P O R T

DATE	Gas Mcf	Oil Bbls	Calculated lbs/hr			*	Gas Mcf	Rubber Tons	Bark Tons	*	Calculated lbs/hr		
PM10EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO2 EF	6.00E-04	NA					6.00E-04	3.08E+01	2.25E-01				
NOX EF	2.80E-01	NA	PM_{10}	SO_2	NOx		1.90E-01	1.98E+00	1.98E+00		PM_{10}	SO_2	NOx
04-Nov	0	0	0.00	0.00	0.00	*	609	0.0	847	*	21.17	7.96	75
05-Nov	0	0	0.00	0.00	0.00	*	648	0.0	766	*	19.16	7.20	68
06-Nov	0	0	0.00	0.00	0.00	*	635	0.0	913	*	22.80	8.58	80
07-Nov	0	0	0.00	0.00	0.00	*	1,274	0.0	1,110	*	27.89	10.44	102
08-Nov	0	0	0.00	0.00	0.00	*	980	0.0	1,122	*	28.08	10.54	100
09-Nov	0	0	0.00	0.00	0.00	*	1,132	0.0	1,116	*	27.99	10.49	101
10-Nov	0	0	0.00	0.00	0.00	*	662	0.0	993	*	24.80	9.33	87
11-Nov	0	0	0.00	0.00	0.00	*	687	0.0	914	*	22.85	8.59	81
12-Nov	0	0	0.00	0.00	0.00	*	925	0.0	868	*	21.78	8.16	79
13-Nov	451	0	0.14	0.01	5.26	*	635	0.0	891	*	22.25	8.37	79
14-Nov	3,636	0	1.15	0.09	42.42	*	708	0.0	1,072	*	26.75	10.07	94
15-Nov	3,434	0	1.09	0.09	40.06	*	335	0.0	1,023	*	25.43	9.60	87
16-Nov	3,326	0	1.05	0.08	38.80	*	324	0.0	979	*	24.33	9.18	83
17-Nov	3,395	0	1.08	0.08	39.61	*	849	0.0	945	*	23.65	8.88	85
18-Nov	3,833	0	1.21	0.10	44.72	*	1,700	0.0	992	*	25.09	9.34	95
19-Nov	3,367	0	1.07	0.08	39.28	*	1,657	0.0	974	*	24.64	9.17	93
20-Nov	3,524	0	1.12	0.09	41.11	*	923	0.0	943	*	23.63	8.86	85
21-Nov	3,901	0	1.24	0.10	45.51	*	1,384	0.0	1,097	*	27.60	10.32	101
22-Nov	3,756	0	1.19	0.09	43.82	*	833	0.0	1,075	*	26.88	10.10	95
23-Nov	3,848	0	1.22	0.10	44.89	*	2,933	0.0	1,062	*	27.21	10.03	111
24-Nov	4,152	0	1.31	0.10	48.44	*	6,064	0.0	1,192	*	31.43	11.33	146
25-Nov	4,818	0	1.53	0.12	56.21	*	8,918	0.0	1,449	*	38.68	13.80	190
26-Nov	4,124	0	1.31	0.10	48.11	*	583	0.0	1,020	*	25.44	9.58	89
27-Nov	3,479	0	1.10	0.09	40.59	*	1,656	0.0	1,289	*	32.42	12.12	119
28-Nov	4,173	0	1.32	0.10	48.69	*	1,990	0.0	1,335	*	33.68	12.57	126
29-Nov	3,724	0	1.18	0.09	43.45	*	1,528	0.0	1,262	*	31.72	11.87	116
30-Nov	3,724	0	1.18	0.09	43.45	*	1,529	0.0	1,262	*	31.72	11.87	116
01-Dec	4,409	0	1.40	0.11	51.44	*	1,733	0.0	1,263	*	31.82	11.89	118
02-Dec	5,039	0	**1.60**	**0.13**	**58.79**	*	3,506	0.0	1,342	*	34.34	12.67	139
03-Dec	4,590	0	1.45	0.11	53.55	*	2,541	0.0	1,251	*	31.77	11.79	123
04-Dec	3,347	0	1.06	0.08	39.05	*	745	0.0	1,095	*	27.33	10.28	96

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R M I L L U T I L I T Y R E P O R T

DATE	Gas Mcf	Oil Bbls		Calculated lbs/hr		*	Gas Mcf	Rubber Tons	Bark Tons	*		Calculated lbs/hr	
PM10EF	7.60E-03	NA					7.60E-03	5.64E+00	5.94E-01				
SO2 EF	6.00E-04	NA					6.00E-04	3.08E+01	2.25E-01				
NOX EF	2.80E-01	NA	PM_{10}	SO_2	NOx		1.90E-01	1.98E+00	1.98E+00		PM_{10}	SO_2	NOx
05-Dec	4,421	0	1.40	0.11	51.58	*	1,889	0.0	1,233	*	31.11	11.61	117
06-Dec	894	0	0.28	0.02	10.43	*	1,416	0.0	1,188	*	29.85	11.17	109
07-Dec	1,295	0	0.41	0.03	15.11	*	1,325	0.0	1,235	*	30.99	11.61	112
08-Dec	1,264	0	0.40	0.03	14.75	*	820	0.0	954	*	23.87	8.96	85
09-Dec	4,445	0	1.41	0.11	51.86	*	2,609	0.0	1,285	*	32.64	12.12	127
10-Dec	2,685	0	0.85	0.07	31.33	*	1,367	0.0	1,142	*	28.70	10.74	105
11-Dec	2,910	0	0.92	0.07	33.95	*	1,724	0.0	1,073	*	27.11	10.11	102
12-Dec	2,101	0	0.67	0.05	24.51	*	733	0.0	999	*	24.97	9.39	88
13-Dec	0	0	0.00	0.00	0.00	*	2,291	0.0	1,066	*	27.10	10.05	106
14-Dec	0	0	0.00	0.00	0.00	*	3,094	0.0	1,177	*	30.11	11.11	122
15-Dec	245	0	0.08	0.01	2.86	*	2,052	0.0	1,201	*	30.38	11.31	115
16-Dec	1,733	0	0.55	0.04	20.22	*	2,875	0.0	1,238	*	31.55	11.68	125
17-Dec	548	0	0.17	0.01	6.39	*	1,051	0.0	1,198	*	29.99	11.26	107
18-Dec	0	0	0.00	0.00	0.00	*	2,345	0.0	1,193	*	30.28	11.25	117
19-Dec	0	0	0.00	0.00	0.00	*	2,118	0.0	1,141	*	28.91	10.75	111
20-Dec	0	0	0.00	0.00	0.00	*	1,474	0.0	1,083	*	27.26	10.19	101
21-Dec	0	0	0.00	0.00	0.00	*	1,493	0.0	1,102	*	27.75	10.37	103
22-Dec	0	0	0.00	0.00	0.00	*	1,518	0.0	1,096	*	27.61	10.32	102
23-Dec	0	0	0.00	0.00	0.00	*	709	0.0	970	*	24.23	9.11	86
24-Dec	0	0	0.00	0.00	0.00	*	712	0.0	1,098	*	27.39	10.31	96
25-Dec	0	0	0.00	0.00	0.00	*	1,336	0.0	1,174	*	29.48	11.04	107
26-Dec	0	0	0.00	0.00	0.00	*	1,073	0.0	1,187	*	29.71	11.15	106
27-Dec	0	0	0.00	0.00	0.00	*	1,572	0.0	1,132	*	28.51	10.65	106
28-Dec	0	0	0.00	0.00	0.00	*	865	0.0	1,072	*	26.81	10.07	95
29-Dec	1,922	0	0.61	0.05	22.42	*	1,364	0.0	313	*	8.18	2.97	37
30-Dec	3,741	0	1.18	0.09	43.65	*	915	0.0	50	*	1.53	0.49	11
31-Dec	1,380	0	0.44	0.03	16.10	*	522	0.0	587	*	14.71	5.52	53
01-Jan	0	0	0.00	0.00	0.00	*	359	0.0	926	*	23.02	8.69	79
02-Jan	0	0	0.00	0.00	0.00	*	739	0.0	931	*	23.29	8.75	83
03-Jan	0	0	0.00	0.00	0.00	*	410	0.0	772	*	19.23	7.25	67
	5,039	0					472,484	0	367,133				

Emission Factors and Throughputs:
Emission factors and throughputs have been researched and are summarized in the following tables.

NOTE: GP requested the ADEQ to eliminate the use of on-specification fuel oil for this boiler as
As a result, the 6A Boiler is no longer allowed to fire any fuel oil

Table 6A-1

Summary of Criteria Pollutant Emission Factors for the 6A Boiler (SN-19) (lb/MMBtu)												
Fuel	**PM_{10}**	**Note**	**SO_2**	**Note**	**VOC**	**Note**	**CO**	**Note**	**NO_X**	**Note**	**Pb**	**Note**
Natural Gas	7.6E-03	A	6.0E-04	A	5.5E-03	A	8.4E-02	B	0.28	B	5.0E-07	A
Specification Oil (Short-term)	0.11	C	1.51	C	1.8E-03	D	3.2E-02	C	0.30	C	9.7E-06	E
Specification Oil (Long-term)	0.08	C	1.01	C	1.8E-03	D	3.2E-02	C	0.30	C	9.7E-06	E

A. Emission factor obtained from AP-42 Section 1.4, Table 1.4-2, given in terms of lb/MMscf and converted to lb/MMBtu.
B. Emission factor obtained from AP-42 Section 1.4, Table 1.4-1 for uncontrolled post-NSPS large wall-fired boilers, given terms of lb/MMscf and converted to lb/MMBtu.
C. Emission factor obtained from AP-42 Section 1.3, Table 1.3-1, boilers >100 MMBtu/hr firing No. 6 fuel oil, converted from lb/mgal to lb/MMBtu.
AP-42 PM_{10} emission factor (lb/mgal) = 9.19 * Suflur Content (% by weight) + 3.22
AP-42 SO_2 emission factor (lb/mgal) = 157 * Suflur Content (% by weight)

Short-term maximum sulfur conter	1.5	%
Long-term average sulfur content	1.0	%

D. Emission factor obtained from AP-42 Section 1.3, Table 1.3-3 for industrial boilers firing No. 6 fuel oil, converted from lb/mgal to lb/MMBtu.
E. Emission factor obtained from AP-42 Section 1.3, Table 1.3-11 for industrial boilers firing No. 6 fuel oil, converted from lb/mgal to lb/MMBtu.

Table 6A-2

Maximum Fuel Firing Rates and Heating Values for the 6A Boiler (SN-19)				
Fuel	**Maximum Rate (MMBtu/hr)**	**Note**	**Heating Value**	**Note**
Natural Gas	357.0	A	1,000 Btu/scf	B
Specification Oil	280.8	C	156 MMBtu/mgal	D

A. Maximum rating of the unit.
B. Heating value obtained from AP-42 Section 1.4, Page 1.4-1.
C. Based on a permit limit of 1,800 gallons per hour.
D. Mill-specific data.

Emission Factors and Throughputs:
Emission factors and throughputs have been researched and are summarized in the following tables.

Table 9A-1

Summary of Criteria Pollutant Emission Factors for the 9A Boiler (SN-22) (lb/MMBtu)												
Fuel	**PM_{10}**	**Note**	**SO_2**	**Note**	**VOC**	**Note**	**CO**	**Note**	**NO_X**	**Note**	**Pb**	**Note**
Woodwaste	0.066	A	0.025	B	0.017	C	0.6	B	0.22	B	4.8E-05	D
Natural Gas	7.6E-03	E	6.0E-04	E	5.5E-03	E	8.4E-02	F	0.190	F	5.0E-07	E
Specification Oil (Short-term)	0.11	G	1.51	G	0.002	H	3.2E-02	G	0.30	G	9.7E-06	I
Specification Oil (Long-term)	0.08	G	1.01	G	0.002	H	3.2E-02	G	0.30	G	9.7E-06	I
TDF	0.188	J	1.03	K	-	L	-	L	-	L	-	L
ADF	0.066	M	0.025	M	0.017	M	0.6	M	0.22	M	4.8E-05	M
RDF	0.15	N	0.25	N	-	O	2.0	N	0.2	N	2.0E-03	P
Sludge	-	Q	-	Q	-	Q	-	Q	-	Q	-	Q
NCGs	-	-	**(lb/ADTP)** 0.76	R	-	-	-	-	-	-	-	-

A. Woodwaste PM/PM_{10} emission factor obtained from AP-42 Section 1.6, Table 1.6-1 for boilers with a wet scrubber control device.
B. Emission factor obtained from AP-42 Section 1.6, Table 1.6-2, for "bark/bark and wet wood/wet wood-fired boiler".
C. Emission factor obtained from AP-42 Section 1.6, Table 1.6-3.
D. Emission factor obtained from AP-42 Section 1.6, Table 1.6-4.
E. Emission factor obtained from AP-42 Section 1.4, Table 1.4-2, given in terms of lb/MMscf and converted to lb/MMBtu.
F. Emission factor obtained from AP-42 Section 1.4, Table 1.4-1 for uncontrolled post-NSPS large wall-fired boilers, given in terms of lb/MMscf and converted to lb/MMBtu.
G. Emission factor obtained from AP-42 Section 1.3, Table 1.3-1, boilers >100 MMBtu/hr firing No. 6 fuel oil, converted from lb/mgal to lb/MMBtu.

AP-42 PM_{10} emission factor (lb/mgal) = 9.19 * Suflur Content (% by weight) + 3.22
AP-42 SO_2 emission factor (lb/mgal) = 157 * Suflur Content (% by weight)

Short-term maximum sulfur content 1.5 %
Long-term maximum sulfur content 1.0 %

H. Emission factor obtained from AP-42 Section 1.3, Table 1.3-3 for industrial boilers firing No. 6 fuel oil, converted from lb/mgal to lb/MMBtu.
I. Emission factor obtained from AP-42 Section 1.3, Table 1.3-11 for industrial boilers firing No. 6 fuel oil, converted from lb/mgal to lb/MMBtu. of lb/mgal and converted to lb/MMBtu.
J. Emission factor obtained from NCASI Technical Bulletin No. 906: Alternative Fuels Used In The Forest Products Industry: Their Composition and Impact On Emissions (September 2005), Table 3.8, Boiler L (venturi scrubber) Run 2 where fuel compostion was 93% wood and 7% TDF.
K. SO_2 emission factor is based on % sulfur in the TDF. For calculation of potential emissions, the average % sulfur given in NCASI Technical Bulletin No. 906: Alternative Fuels Used In The Forest Products Industry: Their Composition And Impact On Emissions (September 2005) of 1.8% is used to determine the SO_2 potential emission factor. The Crossett facility conducted a TDF composition analysis in November 2006 and found that the % sulfur was 1.1%. As stated in Section 3.3, Page 14 of NCASI TB No. 906, it is conservatively assumed that 30% of the sulfur in TDF is absorbed by the woodwaste as these fuels are co-fired. SO_2 emission factor calculation details are as follows:

SO_2 Emission Factor (lb/MMBtu) = 1.8 lb S/100 lb TDF * 2 lb SO_2/lb S * ton TDF/30 MMBtu * (2,000 lb/ton) * (1 - 30% S absorbed)

Where:	% Sulfur in TDF =	1.1%	November 2006 TDF composition analysis
	lb SO_2/lb S =	2	Stoichiometric analysis
	Sulfur absorbed in wood =	30%	NCASI Technical Bulletin No. 906, Page 14.

L. Per NCASI Technical Bulletin No. 906, Pages 13-14, VOC, CO, NO_X and trace metals (other than zinc) emissions are generally expected to be lowered or unchanged by burning TDF in a wood-fired boiler. Therefore, no emission factor is chosen for these pollutants.
M. Emission factors for ADF are assumed equal to woodwaste emission factors.
N. Emission factor from AP-42 Section 2.1, Refuse Combustion (Oct 1996), Table 2.1-12. The factors given in AP-42 are uncontrolled; therefore, a control efficiency of 90% is assumed for PM_{10}.
O. No emission factor for VOC is given in AP-42 Section 2.1, Refuse Combustion; only total organic matter is presented.
P. Emission factor from AP-42 Section 2.1, Refuse Combustion, Table 2.1-8. The factors given in AP-42 are uncontrolled; therefore, a control efficiency of 90% is assumed for Pb.
Q. Per NCASI Technical Bulletin No. 906, Section 8.1, burning of WWTP residuals (sludge) is not expected to lead to an increase in any criteria or related pollutant including metals. While sulfur in the sludge could result in higher SO_2 emissions, when sludge is co-fired with woodwaste (as is done at the Crossett Mill), the sulfur removal capability of the woodwaste reduces the SO_2 emitted such that it is not discernible.
R. The 9A Boiler is permitted as an alternate incinerator for NCGs and SOGs during periods when the incinerator or its associated control equipment is inoperative. NCASI Technical Bulletin No. 849 (August 2002), Table 9 gives mean sulfur contents of 0.34 lb/ADTP for hardwood and 0.46 lb/ADTP for softwood. The normal pulp mix is 66% hardwood and 34% softwood, resulting in an emission factor of:
SO_2 emission factor = [0.34 lb/ADTP * 66% + 0.46 lb/ADTP * 34%] * 2 lb SO_2/lb S = 0.76 lb SO_2/ADTP

Table 9A-2

Maximum Fuel Firing Rates and Heating Values for the 9A Boiler (SN-22)				
Fuel	Maximum Rate (MMBtu/hr)	Note	Heating Value	Note
Woodwaste	475.2	A	9 MMBtu/ton	B
Natural Gas	720.0	C	1,000 Btu/scf	D
Specification Oil	249.0	A	156 MMBtu/mgal	E
TDF	31.5	F	30 MMBtu/ton	G
ADF	475.2	H	9 MMBtu/ton	H
RDF	104.2	I	10 MMBtu/ton	J
Sludge	405.0	K	9 MMBtu/BDT	-

A. Based on information provided in the August 21, 1980 letter submitted by GP to EPA.
B. Heating value obtained from AP-42 Section 1.6, Page 1.6-1, given as 4,500 Btu/lb and converted to MMBtu/ton.
C. Maximum boiler rating.
D. Heating value obtained from AP-42 Section 1.4, Page 1.4-1.
E. Mill-specific data.
F. Based on permit limit of 35 lb/min. Maximum Rate (MMBtu/hr) = 35 lb/min * 30 MMBtu/ton * (60 min/hr) * (ton/2,000 lb)
G. Heating value obtained from NCASI Technical Bulleting No. 906: Alternative Fuels Used In The Forest Products Industry: Their Composition and Impact On Emissions (September 2005), Page 2, given as 15,000 Btu/lb and converted to MMBtu/ton.
H. Data for ADF is assumed to be equal to woodwaste.
I. Based on permit limit of 250 tons/day. Maximum Rate (MMBtu/hr) = 250 tons/day * 10 MMBtu/ton * (day/24 hr)
J. A heating value of 5,000 Btu/lb is assumed for RDF.
K. Based on permit limit of 45 BDT/hr. Maximum Rate (MMBtu/hr) = 45 BDT/hr * 9 MMBtu/BDT

Medina, Dayana

From:	Cutbirth, James W. <James.Cutbirth@GAPAC.com>
Sent:	Monday, April 01, 2013 11:58 AM
To:	'PETTYJOHN@adeq.state.ar.us'
Cc:	'Davis, Anthony (DavisA@adeq.state.ar.us)'; 'mac@adeq.state.ar.us'; 'spencer@adeq.state.ar.us'; Medina, Dayana; Donaldson, Guy; Nann, Barbara; Feldman, Michael; Kordzi, Joe
Subject:	Georgia-Pacific Responses to ADEQ and EPA Region 6 BART Questions for Crossett Paper Operations, Crossett AR
Attachments:	BART Response to ADEQ and EPA Region 6 04-01-2013.pdf; FW: Region 6 feedback on Georgia Pacific-6A and 9A boilers; FW: Georgia Pacific; Table 1-Baseline 2001 2002 2003 BART Analyses 3-27-2013.xls; BART Five Factor Analysis Response 05-18-2012.pdf

Mary and all other personnel at ADEQ and EPA Region 6:

Please find enclosed Georgia-Pacific's written responses to the questions and issues related to BART compliance for the Crossett Paper Operations facility in Crossett AR that were discussed during our teleconference call on March 20, 2013. Enclosed with this submittal are the following attachments:

- Letter from Georgia-Pacific to Mary Pettyjohn at ADEQ, dated April 1, 2013, transmitting written responses related to BART compliance for the Crossett Paper Operations
- E-mail correspondence between Dayana Medina and Mary Pettyjohn, dated February 06, 2013 for Boiler 9A
- E-mail correspondence between Dayana Medina and Mary Pettyjohn, dated March 4, 2013 for Boiler 6A
- Table 1-Baseline Years (2001-2002-2003) BART Emission Calculations and Explanation fo How 24-hour Maximum Emission Rates Were Determined for BART Analyses
- Correspondence Letter between Georgia-Pacific and ADEQ, dated May 18, 2012, with results of CALPUFF Modeling for 6A Boiler and 9A Boiler

Sincerely,

Jim Cutbirth

Jim Cutbirth
Environmental Manager
Georgia Pacific LLC
Crossett Consumer Products Mill
(870)567-8144

Georgia-Pacific

Georgia-Pacific LLC
Consumer Products

Crossett Paper Operations
100 Mill Supply Rd.
P.O. Box 3333
Crossett, AR 71635
(870) 567-8000
(870) 364-9076 fax
www.gp.com

CERTIFIED MAIL 7011-1150-0000-8947-6853
Return Receipt Requested

May 18, 2012

Ms. Mary Pettyjohn
Arkansas Department of Environmental Quality
Epidemiologist
5301 Northshore Drive
North Little Rock, AR 72118

Re: Georgia-Pacific LLC Crossett Paper Operations
Best Available Retrofit Technology Five Factor Analysis
AFIN: 02-00013 Title V Permit No. 0597-AOP-R14

Dear Ms. Pettyjohn:

Georgia-Pacific LLC Crossett Paper Operations (GP) received Mike Bates' letter of May 14, 2012 requesting submittal of a five factor analysis for GP Boilers 6A and 9A located at the mill. Based on the letter and the attached April 26, 2012 letter from EPA, we understand that there are questions regarding the BART eligibility of these two boilers. With this letter we would like to summarize the background of this issue and explain why GP believes submitting a five-factor analysis is not appropriate in this case.

As we discussed in our meeting on October 26, 2011 the Mill has prepared additional CALPUFF modeling to demonstrate that our Title V permitted emission rates do not cause or contribute to an impact above the screening threshold of 0.5 deciviews (dv) in regional Class I Areas. In our 2006 CALPUFF analyses, we modeled highest actual daily rates instead of the Title V permit allowable emission rates. As submitted in December, we re-analyzed our BART-eligible sources using our current Title V Permit limits and reducing our maximum hourly emission rate of sulfur dioxide (SO_2) for the 9A Boiler (SN-22) from 502.5 pounds per hour to 200.0 pounds per hour. This limit is now enforceable in Permit #0579-AOP-R14. Section 169A(c) of the Clean Air Act allows sources to be screened out of further requirements including a five-factor analysis. Specifically:

> *(c) Exemptions*
> *(1) The Administrator may, by rule, after notice and opportunity for public hearing, exempt any major stationary source from the requirement of subsection (b)(2)(A) of this section, upon his determination that such source does not or will not, by itself or in combination with other sources, emit any air pollutant which may reasonably be anticipated to cause or contribute to a significant impairment of visibility in any mandatory class I Federal area.*
> *(2) Paragraph (1) of this subsection shall not be applicable to any fossil-fuel fired powerplant with total design capacity of 750 megawatts or more, unless the owner or operator of any such plant demonstrates to the satisfaction of the Administrator that such powerplant is located at such distance from all areas listed by the Administrator under subsection (a)(2) of this section that such powerplant does not or will not, by itself or in combination with other sources,*

emit any air pollutant which may reasonably be anticipated to cause or contribute to significant impairment of visibility in any such area.
(3) An exemption under this subsection shall be effective only upon concurrence by the appropriate Federal land manager or managers with the Administrator's determination under this subsection.

GP believes the 2011 analysis and the current air permit which enforces those limits is sufficient to demonstrate no cause or contribution to an impairment of visibility by BART-eligible source at our Crossett operations. Thus, the state is afforded by 169A(c)(1) to not require analyses under 169A Section or Appendix Y to 40 CFR Part 51, Section V.E.2:

> *As we discuss in detail in these guidelines, the regional haze rule codifies and clarifies the BART provisions in the CAA. The rule requires that States identify and list "BART-eligible sources," that is, that States identify and list those sources that fall within the 26 source categories, were put in place during the 15-year window of time from 1962 to 1977, and have potential emissions greater than 250 tons per year. Once the State has identified the BART-eligible sources, the next step is to identify those BART-eligible sources that may "emit any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility." Under the rule, a source which fits this description is "subject to BART."*

If the visibility impairment modeling protocol and techniques require an updated demonstration for EPA and ADEQ's review, we believe that is the next step to affirm our request for screening out of a Five-factor analysis using the most up-to-date methodology. EPA's disapproval of ADEQ's regional haze SIP does not affect the definition of a subject-to-BART source nor our ability to demonstrate that the allowable emissions from these sources do not cause impairment sufficient to require a five-factor analysis.

To follow-up on this letter, we will contact you in the near future to further discuss and clarify the appropriate steps forward to properly address the BART eligibility of Boilers 6A and 9A. If you have any questions regarding this matter, please do not hesitate to contact me at (870) 567-8144.

Sincerely,

James W. Cutbirth

James W. Cutbirth
Superintendent, Environmental Services

JWC/wjg

Enclosure:
Previously submitted BART Golder Modeling Analysis Summary
Page 54 of current Title V Permit depicting lower SO2 emission rate of 9A Boiler.

SN-22
9A Boiler

Source Description

The 9A Boiler is a 720 million Btu per hour combination fuel boiler used to generate steam. The source is equipped with a wet venturi scrubber. The boiler may serve as backup combustion unit during times when the incinerator (SN-83) is offline.

The 9A Boiler is capable of firing tire derived fuel (TDF), agriculture derived fuel (ADF), refuse derived fuel (RDF), non-condensable gases (NCGs), woodwaste, specification grade oil, natural gas and sludge. A woodwaste storage pile is associated with the 9A Boiler. Woodwaste consists of bark, wood scraps, wax coated paper, wax coated cardboard, wax coated sawdust, creosote treated railroad crossties and paper pellets (waste paper and wax paper). Bark from the debarker in the Woodyard is pneumatically transferred to the 9A pile. A cyclone is located at the end of the pneumatic transfer line to control particulate matter emissions. The majority of the woodwaste is delivered by truck and occasionally by rail. It is then transferred by conveyors to either the 9A or the 10A woodwaste storage pile.

RDF, ADF and sludge are directly added to the chip piles. RDF consists of pelletized paper, lawn clippings and similar materials. TDF and other scrap rubber products are stored in segregated piles near the woodwaste piles. TDF is loaded several times a day by a front end loader into feeder bins in the vicinity. These solid fuels are then fed onto a conveyor system and delivered to the boilers. ADF consists of, but is not limited to, corn cobs, shucks, and vegetable starch.

Specification grade oil consists of new oil, used oil, used oil absorbent material and pitch from the production of tall oil. Used oil absorbent material shall include used oil filter paper, used rags, sorbant booms, etc. that meet the specification grade oil criteria (40 CFR 279.11).

Specific Conditions

33. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #43, #47, #48, #49, #50, and #53. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr	tpy
PM_{10}	77.4	339.0
SO_2	199.8	484.6
VOC	11.3	49.5
CO	366.8	1,606.7

Golder Associates

December 14, 2011

113-87721
Via Electronic Delivery

James Cutbirth
Georgia-Pacific Consumer Products LLC
Superintendent – Environmental Services
100 Mill Supply Road
Crossett, AR 71635

RE: BART AIR MODELING ANALYSIS FOR THE CROSSETT (AR) MILL

Dear Mr. Cutbirth:

At the request of Georgia-Pacific, LLC (GP), Golder Associates, Inc. (Golder) performed an air modeling analysis to revise the Best Available Retrofit Technology (BART) Application for the Crossett Mill (Mill). The original application was provided to the Arkansas Department of Environmental Quality (ADEQ) in 2006 and used the California Puff modeling system to address the maximum 24-hour visibility impairment due to the Mill's BART-eligible sources. The analysis followed the procedures as outlined in the BART Modeling Protocol (ADEQ, June, 2006) to determine if the Mill could qualify for an exemption under the BART regulations. The following paragraphs summarize the modeling inputs and results.

Source and Emission Data

Emission and source parameter data for the BART modeling analysis were provided by GP. The 6A and 9A Boilers are the only BART-eligible sources at the Mill and the emissions for these sources were provided for sulfur dioxide, nitrogen oxides and particulate matter with diameters less than or equal to 10 microns. These emissions represent the maximum 24-hour emissions allowed by air permit except for sulfur dioxide emissions for SN-22 which were lowered to 200 lbs/hr to match emission rate in GP's December 2011 application for a permit modification.

Meteorological Data

The modeling analysis used three years of gridded 3-dimensional wind field meteorological data developed by the Central Regional Air Planning Association (CENRAP) for the years 2001 to 2003.

Receptor Locations

In accordance with the Air Protocol, predictions of visibility impairment were made at the following Prevention of Significant Deterioration (PSD) Class I areas that are located within 300-km of Arkansas:

- Caney Creek (AR, 235 km) Wilderness Area (WA)
- Upper Buffalo (AR, 325 km) WA
- Hercules-Glade (MO, 398 km) WA
- Mingo (MO, 448 km) WA, and
- Sipsey (AL, 442 km) WA

Golder Associates Inc.
6026 NW 1st Place
Gainesville, FL 32607 USA
Tel: (352) 336-5600 Fax: (352) 336-6603 www.golder.com

Receptors for each PSD Class I area were obtained from the National Park Service. All source and receptor locations were based in the Lambert Conformal Coordinate (LCC) system for input to CALPUFF.

Modeling Results

The air modeling results are summarized in Table 1. The maximum predicted 24-hour visibility impairment of 0.359 deciview (dv) was predicted at the Caney Creek WA in 2002. This impact is less than the BART exemption criteria of 0.5 dv.

The air modeling files used to perform the analysis are included with this submittal and include the CALPUFF, POSTUTIL and CALPOST input and list files for years 2001 to 2003, the hourly ozone files for each year, and the executable files.

If you have any questions regarding this analysis please contact me at (352) 336-5600. Thank you.

Sincerely,

GOLDER ASSOCIATES INC.

Steven R. Marks, CCM
Associate, Project Manager

Robert C. McCann, Jr.
Principal

Enclosures

TABLE 1

Maximum Predicted 24-Hour Visibility Impairment (dV) From BART Eligible Sources

PSD Class I Area Area	Highest Deciview for Year 2001	 2002	 2003
Caney Creek (AR) NWA	0.16	0.359	0.296
Upper Buffalo (AR) NWA	0.099	0.074	0.099
Hercules-Glade (MO) NWA	0.08	0.288	0.125
Mingo (MO) NWA	0.123	0.093	0.168
Sipsey (AL) NWA	0.171	0.184	0.119
BART Exemption Criterion	0.5	0.5	0.5

NWA = National Wilderness Area

Notes: All emitted PM emissions assumed as PMF per AR BART protocol

Medina, Dayana

From: Medina, Dayana
Sent: Friday, April 12, 2013 3:59 PM
To: pettyjohn@adeq.state.ar.us
Cc: Donaldson, Guy; Feldman, Michael
Subject: Region 6 response on Georgia-Pacific Crossett Mill

Hi Mary,

We appreciate the opportunity to review the April 1, 2013, letter sent to ADEQ by James Cutbirth from the Georgia-Pacific Crossett Mill. We have reviewed the additional information provided and believe that the technical analysis presented in the letter and the spreadsheets and other attachments included in Mr. Cutbirth's April 1, 2013 email, demonstrate that the actual SO_2, PM, and NOx emissions from the 6A and 9A boilers during the 2001-2003 baseline period are below the emission rates modeled by Georgia Pacific in its 2011 BART screening CALPUFF modeling. We believe that Georgia-Pacific's analysis, which compares the modeled emission rates with estimates of 2001-2003 maximum 24-hour emission rates that were calculated based on daily fuel usage and EPA's AP-42 emission factors, and other newly provided information allow for a more accurate assessment of whether or not the 6A and 9A boilers are subject to BART. Based on this newly provided information, we believe the 6A and 9A boilers are not subject to BART and therefore it is not necessary for Georgia-Pacific to submit a BART five factor analysis. Please inform Region 6 whether ADEQ concurs with our assessment or if you would like to discuss this matter further. If ADEQ concurs with Region 6, please ensure that when you submit the Arkansas Regional Haze SIP revision, the SIP submittal includes the BART screening CALPUFF modeling files for the Georgia-Pacific Crossett Mill, as well as a copy of Mr. Cutbirth's April 1, 2013, letter and the spreadsheets and other attachments provided in Mr. Cutbirth's April 1, 2013 email.

Thank you,

Dayana Medina
U.S. Environmental Protection Agency, Region 6
Multimedia Planning and Permitting Division
Air Planning Section (6PD-L)
214-665-7241
medina.dayana@epa.gov

Medina, Dayana

From: Galler, Wayne J. <WJGALLER@GAPAC.com>
Sent: Wednesday, March 20, 2013 8:52 AM
To: Medina, Dayana
Cc: Cutbirth, James W.
Subject: Files for BART call Review
Attachments: SN19 6A Boiler Natural Gas 2001 2002 2003-WJG Revision 03-12-2013.xls; BART Five Factor Analysis Response 05-18-2012.pdf

Can you send these files and my notes below out to everyone on the call list, except for Jim Cutbirth and myself for our call shortly? Thanks.

I wanted to share a couple of documents in advance of our conference call. The PDF file is a copy of a letter sent to Mary Pettyjohn at ADEQ, dated May 18, 2012. This memo explains that the two boilers at the Crossett Mill, 6A and 9A, are both BART eligible units, and as a result, GP conducted CALPUFF modeling for the combined maximum daily emissions of PM10, SO2, and NO2 from these units. The results of the modeling indicate that there is no impact above the screening level of 0.5 deciviews in any of the regional Class I areas near the Crossett Mill. The highest impact was 0.36 deciviews at the Caney Creek National Wilderness Area in Arkansas. As explained in the memo, the two boilers are exempt from the BART five factor analysis requirements. The emission rates modeled for the analysis are all less than the Title V Permit limits contained in the latest revision issue dot the Mill in May 2012.

The attached spreadsheet summarizes the values subjected to the CALPUFF modeling for each boiler versus the maximum pollutant emissions rates and compares these data to the R14 Title V permit limits.

DRAFT Subject to Review

Table 1. Summary of 2001-2003 Actual Emissions, R14 Permit Allowables and CALPUFF Model Emission Rates

	Daily Average lb/hr Actual Emissions						
	2001	2002	2003	3-year Max	R14 Limit	CALPUFF(c)	Model <Permit?
	6A Boiler						
Max SO2	0.2	0.1	0.1	0.2	0.3	2.4	No
Max NOx @ 280 lb/MMscf	90.7	66.3	58.8	90.7	120.0	32.4	Yes
Max PM_{10}	2.5	1.8	1.6	2.5	3.3	2.6	Yes
	9A Boiler						
Max SO2 (b)	16.3	15.8	17.9	17.9	199.8	306.7	Yes
Max NOx	171.4	154.6	174.1	174.1	196.0	244.4	No
Max PM_{10} (a)	72.0	61.0	54.3	72.0	77.4	90.0	No

(a) The greater of annual PM test values for 3 1-hr runs average and calculated daily emission rate using emission factors.
For all three baseline years, the stack test results were used as the highest hourly and therefore the daily maximum emisison rates

(b) During 2001-2003, no oil or TDF was fired in 9A Boiler. Permit limit allows both fuels to be burned.

(c) CALPUFF model for particulate matter conservatively treats all modeled particulate mass using a mean diameter of less than 1um.

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CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

Daily Meter Readings/Production Trends

	6A Boiler							*	9A Boiler					*			
	S/B MLbs	Steam MLbs	Gas Mcf	Oil Bbls	Calculated lbs/hr PM	SO2	Nox	*	S/B MLbs	Steam MLbs	Gas Mcf	Rubber Tons	Bark Tons	*	Calculated lbs/hr PM	SO2	Nox
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA							6.00E-04	3.08E+01	2.25E-01				
NOX EF			2.80E-01	NA							1.90E-01	1.98E+00	1.98E+00				
31-Dec	0	2,737	3,649	0	1.16	0.09	42.57	*	327	8,455	2,831	0.0	1,284	*	32.68	12.11	128
01-Jan	0	344	459	0	0.15	0.01	5.36	*	431	5,449	2,513	0.0	814	*	20.94	7.69	87
02-Jan	0	3,214	4,285	0	1.36	0.11	49.99	*	503	8,356	1,732	0.0	1,380	*	34.71	12.98	128
03-Jan	0	722	963	0	0.30	0.02	11.24	*	416	7,617	1,267	0.0	1,275	*	31.95	11.98	115
04-Jan	0	1,872	2,496	0	0.79	0.06	29.12	*	376	6,611	1,570	0.0	1,073	*	27.06	10.10	101
05-Jan	0	3,147	4,196	0	1.33	0.10	48.95	*	369	5,436	960	0.0	918	*	23.02	8.63	83
06-Jan	0	3,091	4,121	0	1.30	0.10	48.08	*	374	7,435	719	0.0	1,278	*	31.85	12.00	111
07-Jan	0	748	997	0	0.32	0.02	11.63	*	391	6,860	443	0.0	1,203	*	29.92	11.29	103
08-Jan	0	2,536	3,381	0	1.07	0.08	39.45	*	368	7,661	373	0.0	1,341	*	33.32	12.58	114
09-Jan	0	2,631	3,508	0	1.11	0.09	40.93	*	389	7,073	155	0.0	1,261	*	31.26	11.83	105
10-Jan	0	2,583	3,444	0	1.09	0.09	40.18	*	373	4,805	1,100	0.0	800	*	20.15	7.53	75
11-Jan	0	3,606	4,808	0	1.52	0.12	56.09	*	384	8,614	1,052	0.0	1,455	*	36.35	13.67	128
12-Jan	0	3,557	4,743	0	1.50	0.12	55.34	*	382	9,483	2,096	0.0	1,524	*	38.39	14.34	142
13-Jan	0	2,610	3,480	0	1.10	0.09	40.60	*	376	7,792	155	0.0	1,382	*	34.24	12.96	115
14-Jan	0	2,422	3,229	0	1.02	0.08	37.67	*	370	7,614	102	0.0	1,354	*	33.55	12.70	113
15-Jan	0	3,416	4,555	0	1.44	0.11	53.14	*	330	3,346	716	0.0	573	*	14.41	5.39	53
16-Jan	0	4,225	5,633	0	1.78	0.14	65.72	*	348	4,641	2,678	0.0	649	*	16.90	6.15	75
17-Jan	0	4,478	5,971	0	1.89	0.15	69.66	*	377	10,478	4,375	0.0	1,005	*	26.27	9.53	118
18-Jan	0	4,739	6,319	0	2.00	0.16	73.72	*	378	12,416	8,199	0.0	1,047	*	28.52	10.02	151
19-Jan	0	4,921	6,561	0	2.08	0.16	76.55	*	346	13,728	8,984	0.0	1,207	*	32.71	11.54	171
20-Jan	0	3,629	4,839	0	1.53	0.12	56.46	*	445	10,506	5,172	0.0	962	*	25.44	9.14	120
21-Jan	0	3,222	4,296	0	1.36	0.11	50.12	*	408	9,552	3,440	0.0	1,391	*	35.52	13.13	142
22-Jan	0	2,702	3,603	0	1.14	0.09	42.04	*	391	7,929	697	0.0	1,367	*	34.04	12.83	118
23-Jan	0	3,805	5,073	0	1.61	0.13	59.19	*	363	3,877	943	0.0	652	*	16.44	6.14	61
24-Jan	0	3,637	4,849	0	1.54	0.12	56.57	*	369	4,915	764	0.0	844	*	21.12	7.93	76
25-Jan	0	4,205	5,607	0	1.78	0.14	65.42	*	361	2,961	589	0.0	522	*	13.11	4.91	48
26-Jan	0	3,877	5,169	0	1.64	0.13	60.31	*	0	0	0	0.0	0	*	0.00	0.00	0
27-Jan	0	4,055	5,407	0	1.71	0.14	63.08	*	0	0	0	0.0	0	*	0.00	0.00	0
28-Jan	0	4,271	5,695	0	1.80	0.14	66.44	*	0	0	0	0.0	0	*	0.00	0.00	0
29-Jan	0	4,676	6,235	0	1.97	0.16	72.74	*	0	0	0	0.0	0	*	0.00	0.00	0
30-Jan	0	2,840	3,787	0	1.20	0.09	44.18	*	350	3,820	704	0.0	658	*	16.51	6.19	60

2001

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P A P E R   M I L L   U T I L I T Y   R E P O R T

Daily Meter Readings/Production Trends

	6A Boiler							*	9A Boiler					*			
	S/B MLbs	Steam MLbs	Gas Mcf	Oil Bbls				*	S/B MLbs	Steam MLbs	Gas Mcf	Rubber Tons	Bark Tons	*			
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA	Calculated lbs/hr						6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOX EF			2.80E-01	NA	PM	SO2	Nox				1.90E-01	1.98E+00	1.98E+00		PM	SO2	Nox
31-Jan	0	1,306	1,741	0	0.55	0.04	20.31	*	393	6,673	586	0.0	1,161	*	28.92	10.90	100
01-Feb	0	3,337	4,449	0	1.41	0.11	51.91	*	364	3,947	1,318	0.0	636	*	16.15	5.99	63
02-Feb	0	4,569	6,092	0	1.93	0.15	71.07	*	0	0	0	0.0	0	*	0.00	0.00	0
03-Feb	0	3,723	4,964	0	1.57	0.12	57.91	*	363	4,454	523	0.0	782	*	19.52	7.35	69
04-Feb	0	2,453	3,271	0	1.04	0.08	38.16	*	388	8,867	125	0.0	1,569	*	38.88	14.71	130
05-Feb	0	2,264	3,019	0	0.96	0.08	35.22	*	390	8,632	254	0.0	1,520	*	37.69	14.25	127
06-Feb	0	2,073	2,764	0	0.88	0.07	32.25	*	375	7,992	719	0.0	1,373	*	34.21	12.89	119
07-Feb	0	1,781	2,370	0	0.75	0.06	27.65	*	376	7,029	143	0.0	1,252	*	31.04	11.74	104
08-Feb	0	1,781	2,370	0	0.75	0.06	27.65	*	378	7,150	470	0.0	1,249	*	31.05	11.72	107
09-Feb	0	1,885	2,513	0	0.80	0.06	29.32	*	438	7,746	447	0.0	1,362	*	33.86	12.78	116
10-Feb	0	2,506	3,341	0	1.06	0.08	38.98	*	419	7,813	240	0.0	1,386	*	34.38	13.00	116
11-Feb	0	3,358	4,477	0	1.42	0.11	52.23	*	354	8,271	225	0.0	1,454	*	36.06	13.64	122
12-Feb	0	3,956	5,275	0	1.67	0.13	61.54	*	340	7,982	843	0.0	1,356	*	33.82	12.73	119
13-Feb	0	2,988	3,984	0	1.26	0.10	46.48	*	320	7,882	394	0.0	1,369	*	34.02	12.85	116
14-Feb	0	1,692	2,357	0	0.75	0.06	27.50	*	284	8,665	652	0.0	1,477	*	36.77	13.87	127
15-Feb	0	42	75	0	0.02	0.00	0.88	*	333	8,093	836	0.0	1,374	*	34.27	12.90	120
16-Feb	0	0	0	0	0.00	0.00	0.00	*	358	8,433	1,639	0.0	1,376	*	34.57	12.94	126
17-Feb	0	0	0	0	0.00	0.00	0.00	*	378	8,713	2,165	0.0	1,387	*	35.02	13.06	132
18-Feb	0	0	0	0	0.00	0.00	0.00	*	353	8,073	962	0.0	1,365	*	34.08	12.82	120
19-Feb	0	0	0	0	0.00	0.00	0.00	*	316	8,832	1,717	0.0	1,431	*	35.96	13.46	132
20-Feb	0	0	0	0	0.00	0.00	0.00	*	278	8,741	319	0.0	1,514	*	37.58	14.21	127
21-Feb	0	0	0	0	0.00	0.00	0.00	*	331	7,949	135	0.0	1,402	*	34.75	13.15	117
22-Feb	0	0	0	0	0.00	0.00	0.00	*	347	7,788	183	0.0	1,374	*	34.06	12.88	115
23-Feb	0	0	0	0	0.00	0.00	0.00	*	336	7,640	131	0.0	1,351	*	33.47	12.67	112
24-Feb	0	0	0	0	0.00	0.00	0.00	*	309	7,452	937	0.0	1,253	*	31.31	11.77	111
25-Feb	0	0	0	0	0.00	0.00	0.00	*	320	7,197	498	0.0	1,245	*	30.96	11.68	107
26-Feb	0	0	0	0	0.00	0.00	0.00	*	349	6,905	377	0.0	1,209	*	30.04	11.34	103
27-Feb	0	0	0	0	0.00	0.00	0.00	*	349	8,854	2,945	0.0	1,347	*	34.28	12.71	134
28-Feb	0	1,243	1,657	0	0.52	0.04	19.33	*	354	9,215	3,150	0.0	1,394	*	35.51	13.15	140
01-Mar	0	3,667	4,889	0	1.55	0.12	57.04	*	328	9,031	3,769	0.0	1,312	*	33.66	12.39	138
02-Mar	0	4,336	5,781	0	1.83	0.14	67.45	*	349	9,282	4,750	0.0	1,284	*	33.28	12.16	144
03-Mar	0	4,224	5,632	0	1.78	0.14	65.71	*	356	9,192	4,705	0.0	1,273	*	33.00	12.05	142

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CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

Daily Meter Readings/Production Trends

	6A Boiler S/B MLbs	6A Boiler Steam MLbs	6A Boiler Gas Mcf	6A Boiler Oil Bbls	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox	*	9A Boiler S/B MLbs	9A Boiler Steam MLbs	9A Boiler Gas Mcf	9A Boiler Rubber Tons	9A Boiler Bark Tons	*	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA							6.00E-04	3.08E+01	2.25E-01				
NOX EF			2.80E-01	NA							1.90E-01	1.98E+00	1.98E+00				
04-Mar	0	4,028	5,371	0	1.70	0.13	62.66	*	347	10,190	5,247	0.0	1,401	*	36.34	13.27	157
05-Mar	0	4,025	5,367	0	1.70	0.13	62.62	*	349	10,189	4,147	0.0	1,484	*	38.05	14.02	155
06-Mar	0	3,978	5,304	0	1.68	0.13	61.88	*	344	10,949	4,741	0.0	1,568	*	40.32	14.82	167
07-Mar	0	3,890	5,187	0	1.64	0.13	60.52	*	332	8,489	5,229	0.0	1,110	*	29.12	10.53	133
08-Mar	0	3,352	4,470	0	1.42	0.11	52.15	*	344	9,644	3,255	0.0	1,458	*	37.11	13.75	146
09-Mar	0	3,979	5,305	0	1.68	0.13	61.89	*	355	10,657	4,596	0.0	1,531	*	39.35	14.47	163
10-Mar	0	4,524	6,032	0	1.91	0.15	70.37	*	333	10,481	3,852	0.0	1,554	*	39.67	14.66	159
11-Mar	0	4,432	5,909	0	1.87	0.15	68.94	*	331	10,228	4,255	0.0	1,480	*	37.97	13.98	156
12-Mar	0	4,455	5,940	0	1.88	0.15	69.30	*	311	10,891	4,593	0.0	1,564	*	40.16	14.78	165
13-Mar	0	4,106	5,475	0	1.73	0.14	63.88	*	315	10,581	4,533	0.0	1,611	*	41.31	15.22	169
14-Mar	0	3,093	4,124	0	1.31	0.10	48.11	*	336	8,649	2,996	0.0	1,379	*	35.07	13.00	137
15-Mar	0	3,220	4,293	0	1.36	0.11	50.09	*	333	9,573	3,779	0.0	1,362	*	34.92	12.87	142
16-Mar	0	724	965	0	0.31	0.02	11.26	*	331	7,662	3,775	0.0	1,078	*	27.88	10.20	119
17-Mar	0	0	0	0	0.00	0.00	0.00	*	355	8,601	464	0.0	1,493	*	37.09	14.01	127
18-Mar	0	0	0	0	0.00	0.00	0.00	*	365	8,400	1,017	0.0	1,418	*	35.42	13.32	125
19-Mar	0	350	467	0	0.15	0.01	5.45	*	352	8,614	785	0.0	1,470	*	36.63	13.80	127
20-Mar	0	777	1,036	0	0.33	0.03	12.09	*	318	6,701	402	0.0	1,167	*	29.01	10.95	99
21-Mar	0	0	0	0	0.00	0.00	0.00	*	330	7,704	380	0.0	1,342	*	33.33	12.59	114
22-Mar	0	0	0	0	0.00	0.00	0.00	*	311	8,372	340	0.0	1,455	*	36.13	13.65	123
23-Mar	0	0	0	0	0.00	0.00	0.00	*	300	7,401	342	0.0	1,288	*	31.98	12.08	109
24-Mar	0	1,607	2,143	0	0.68	0.05	25.00	*	329	6,692	3,602	0.0	926	*	24.05	8.77	105
25-Mar	0	3,937	5,249	0	1.66	0.13	61.24	*	316	4,046	5,623	0.0	319	*	9.68	3.13	71
26-Mar	0	4,074	5,432	0	1.72	0.14	63.37	*	0	0	0	0.0	0	*	0.00	0.00	0
27-Mar	0	4,343	5,791	0	1.83	0.14	67.56	*	0	0	0	0.0	0	*	0.00	0.00	0
28-Mar	0	4,167	5,556	0	1.76	0.14	64.82	*	0	0	0	0.0	0	*	0.00	0.00	0
29-Mar	0	3,355	4,473	0	1.42	0.11	52.19	*	0	0	0	0.0	0	*	0.00	0.00	0
30-Mar	0	2,947	3,929	0	1.24	0.10	45.84	*	0	0	0	0.0	0	*	0.00	0.00	0
31-Mar	0	2,320	3,093	0	0.98	0.08	36.09	*	0	0	0	0.0	0	*	0.00	0.00	0
01-Apr	0	3,889	5,185	0	1.64	0.13	60.49	*	0	0	0	0.0	0	*	0.00	0.00	0
02-Apr	0	4,031	5,375	0	1.70	0.13	62.71	*	0	0	0	0.0	0	*	0.00	0.00	0
03-Apr	0	3,274	4,365	0	1.38	0.11	50.93	*	0	0	0	0.0	0	*	0.00	0.00	0
04-Apr	0	2,394	3,192	0	1.01	0.08	37.24	*	0	0	0	0.0	0	*	0.00	0.00	0

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Daily Meter Readings/Production Trends

	6A Boiler S/B MLbs	6A Steam MLbs	6A Gas Mcf	6A Oil Bbls	6A Calculated lbs/hr PM	6A SO2	6A Nox	*	9A Boiler S/B MLbs	9A Steam MLbs	9A Gas Mcf	9A Rubber Tons	9A Bark Tons	*	9A Calculated lbs/hr PM	9A SO2	9A Nox
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA							6.00E-04	3.08E+01	2.25E-01				
NOX EF			2.80E-01	NA							1.90E-01	1.98E+00	1.98E+00				
05-Apr	0	3,093	4,124	0	1.31	0.10	48.11	*	0	0	0	0.0	0	*	0.00	0.00	0
06-Apr	0	3,319	4,425	0	1.40	0.11	51.63	*	0	0	0	0.0	0	*	0.00	0.00	0
07-Apr	0	3,401	4,535	0	1.44	0.11	52.91	*	0	0	0	0.0	0	*	0.00	0.00	0
08-Apr	0	3,701	4,935	0	1.56	0.12	57.58	*	0	0	0	0.0	0	*	0.00	0.00	0
09-Apr	0	4,062	5,416	0	1.72	0.14	63.19	*	0	0	0	0.0	0	*	0.00	0.00	0
10-Apr	0	3,884	5,179	0	1.64	0.13	60.42	*	0	0	0	0.0	0	*	0.00	0.00	0
11-Apr	0	1,683	2,244	0	0.71	0.06	26.18	*	0	0	0	0.0	0	*	0.00	0.00	0
12-Apr	0	3,272	4,363	0	1.38	0.11	50.90	*	0	0	0	0.0	0	*	0.00	0.00	0
13-Apr	0	3,025	4,033	0	1.28	0.10	47.05	*	0	0	0	0.0	0	*	0.00	0.00	0
14-Apr	0	3,800	5,067	0	1.60	0.13	59.12	*	0	0	233	0.0	0	*	0.07	0.01	2
15-Apr	0	1,929	2,572	0	0.81	0.06	30.01	*	202	4,498	5,681	0.0	373	*	11.02	3.64	76
16-Apr	0	2,725	3,633	0	1.15	0.09	42.39	*	288	6,260	1,957	0.0	969	*	24.61	9.13	95
17-Apr	0	2,506	3,341	0	1.06	0.08	38.98	*	302	7,404	611	0.0	1,268	*	31.58	11.91	109
18-Apr	0	3,066	4,088	0	1.29	0.10	47.69	*	262	6,772	2,025	0.0	1,047	*	26.55	9.87	102
19-Apr	0	1,993	2,657	0	0.84	0.07	31.00	*	199	6,037	565	0.0	1,021	*	25.45	9.59	89
20-Apr	0	246	328	0	0.10	0.01	3.83	*	165	8,411	207	0.0	1,447	*	35.88	13.57	121
21-Apr	0	0	0	0	0.00	0.00	0.00	*	162	7,239	240	0.0	1,244	*	30.87	11.67	105
22-Apr	0	0	0	0	0.00	0.00	0.00	*	178	7,092	412	0.0	1,209	*	30.05	11.34	103
23-Apr	0	0	0	0	0.00	0.00	0.00	*	241	6,294	290	0.0	1,093	*	27.14	10.25	92
24-Apr	0	0	0	0	0.00	0.00	0.00	*	304	8,023	969	0.0	1,347	*	33.65	12.65	119
25-Apr	0	0	0	0	0.00	0.00	0.00	*	256	6,891	196	0.0	1,204	*	29.87	11.30	101
26-Apr	0	0	0	0	0.00	0.00	0.00	*	221	6,724	211	0.0	1,161	*	28.81	10.89	97
27-Apr	0	0	0	0	0.00	0.00	0.00	*	210	6,340	459	0.0	1,083	*	26.94	10.16	93
28-Apr	0	0	0	0	0.00	0.00	0.00	*	180	6,269	302	0.0	1,077	*	26.76	10.11	91
29-Apr	0	0	0	0	0.00	0.00	0.00	*	183	6,272	225	0.0	1,084	*	26.90	10.17	91
30-Apr	0	0	0	0	0.00	0.00	0.00	*	177	6,364	1,952	0.0	968	*	24.58	9.13	95
01-May	0	0	0	0	0.00	0.00	0.00	*	187	8,576	219	0.0	1,478	*	36.66	13.86	124
02-May	0	0	0	0	0.00	0.00	0.00	*	176	8,687	205	0.0	1,496	*	37.10	14.03	125
03-May	0	0	0	0	0.00	0.00	0.00	*	158	8,748	201	0.0	1,504	*	37.29	14.10	126
04-May	0	0	0	0	0.00	0.00	0.00	*	153	8,841	203	0.0	1,519	*	37.66	14.24	127
05-May	0	0	0	0	0.00	0.00	0.00	*	160	7,894	209	0.0	1,358	*	33.68	12.74	114
06-May	0	0	0	0	0.00	0.00	0.00	*	183	7,799	207	0.0	1,346	*	33.38	12.62	113

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Daily Meter Readings/Production Trends

	6A Boiler							*	9A Boiler					*			
	S/B MLbs	Steam MLbs	Gas Mcf	Oil Bbls				*	S/B MLbs	Steam MLbs	Gas Mcf	Rubber Tons	Bark Tons	*			
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA	Calculated lbs/hr						6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOX EF			2.80E-01	NA	PM	SO2	Nox				1.90E-01	1.98E+00	1.98E+00		PM	SO2	Nox
07-May	0	0	0	0	0.00	0.00	0.00	*	201	7,041	287	0.0	1,214	*	30.13	11.39	102
08-May	0	0	0	0	0.00	0.00	0.00	*	175	8,283	201	0.0	1,428	*	35.40	13.39	119
09-May	0	0	0	0	0.00	0.00	0.00	*	139	8,767	207	0.0	1,509	*	37.41	14.15	126
10-May	0	0	0	0	0.00	0.00	0.00	*	156	8,784	546	0.0	1,484	*	36.90	13.92	127
11-May	0	3,050	4,067	0	1.29	0.10	47.45	*	183	6,803	465	0.0	1,157	*	28.77	10.85	99
12-May	0	5,829	7,772	0	2.46	0.19	90.67	*	247	10,766	1,982	0.0	1,729	*	43.42	16.26	158
13-May	0	2,822	3,763	0	1.19	0.09	43.90	*	231	8,968	219	0.0	1,553	*	38.50	14.56	130
14-May	0	0	0	0	0.00	0.00	0.00	*	31	824	367	0.0	118	*	3.04	1.12	13
15-May	0	0	0	0	0.00	0.00	0.00	*	0	20	119	0.0	0	*	0.04	0.00	1
16-May	0	0	0	0	0.00	0.00	0.00	*	26	907	1,034	0.0	81	*	2.33	0.79	15
17-May	0	0	0	0	0.00	0.00	0.00	*	166	7,864	1,058	0.0	1,290	*	32.26	12.12	115
18-May	0	2,073	2,764	0	0.88	0.07	32.25	*	151	9,651	537	0.0	1,631	*	40.55	15.31	139
19-May	0	2,960	3,947	0	1.25	0.10	46.05	*	164	9,536	972	0.0	1,581	*	39.44	14.85	138
20-May	0	1,800	2,400	0	0.76	0.06	28.00	*	79	6,422	2,498	0.0	920	*	23.57	8.69	96
21-May	0	2,033	2,710	0	0.86	0.07	31.62	*	247	7,800	836	0.0	1,310	*	32.67	12.30	115
22-May	0	430	573	0	0.18	0.01	6.69	*	239	7,274	244	0.0	1,263	*	31.34	11.85	106
23-May	0	0	0	0	0.00	0.00	0.00	*	198	7,855	494	0.0	1,336	*	33.23	12.54	114
24-May	0	0	0	0	0.00	0.00	0.00	*	231	6,383	207	0.0	1,113	*	27.60	10.44	93
25-May	0	0	0	0	0.00	0.00	0.00	*	235	7,842	335	0.0	1,352	*	33.58	12.69	114
26-May	0	0	0	0	0.00	0.00	0.00	*	177	6,497	359	0.0	1,111	*	27.62	10.43	95
27-May	0	0	0	0	0.00	0.00	0.00	*	186	6,535	209	0.0	1,131	*	28.05	10.61	95
28-May	0	1,640	2,187	0	0.69	0.05	25.52	*	40	2,796	586	0.0	440	*	11.06	4.13	41
29-May	0	2,399	3,199	0	1.01	0.08	37.32	*	0	0	0	0.0	0	*	0.00	0.00	0
30-May	0	1,993	2,658	0	0.84	0.07	31.01	*	0	0	0	0.0	0	*	0.00	0.00	0
31-May	0	2,594	3,459	0	1.10	0.09	40.36	*	27	1,293	465	0.0	190	*	4.85	1.79	19
01-Jun	0	169	225	0	0.07	0.01	2.63	*	98	8,250	339	0.0	1,398	*	34.72	13.12	118
02-Jun	0	0	0	0	0.00	0.00	0.00	*	139	8,263	1,021	0.0	1,356	*	33.89	12.74	120
03-Jun	0	0	0	0	0.00	0.00	0.00	*	113	7,716	440	0.0	1,302	*	32.37	12.22	111
04-Jun	0	0	0	0	0.00	0.00	0.00	*	159	7,126	987	0.0	1,168	*	29.22	10.98	104
05-Jun	0	2,477	3,303	0	1.05	0.08	38.54	*	49	1,158	784	0.0	147	*	3.88	1.39	18
06-Jun	0	0	0	0	0.00	0.00	0.00	*	164	6,298	198	0.0	1,087	*	26.97	10.20	91
07-Jun	0	0	0	0	0.00	0.00	0.00	*	182	6,161	203	0.0	1,067	*	26.46	10.00	90

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Daily Meter Readings/Production Trends

	6A Boiler							*	9A Boiler					*			
	S/B MLbs	Steam MLbs	Gas Mcf	Oil Bbls				*	S/B MLbs	Steam MLbs	Gas Mcf	Rubber Tons	Bark Tons	*			
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA	Calculated lbs/hr						6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOX EF			2.80E-01	NA	PM	SO2	Nox				1.90E-01	1.98E+00	1.98E+00		PM	SO2	Nox
08-Jun	0	0	0	0	0.00	0.00	0.00	*	172	7,541	206	0.0	1,300	*	32.24	12.19	109
09-Jun	0	0	0	0	0.00	0.00	0.00	*	170	7,467	213	0.0	1,287	*	31.91	12.07	108
10-Jun	0	0	0	0	0.00	0.00	0.00	*	179	7,159	214	0.0	1,236	*	30.65	11.59	104
11-Jun	0	0	0	0	0.00	0.00	0.00	*	155	7,148	223	0.0	1,229	*	30.49	11.53	103
12-Jun	0	0	0	0	0.00	0.00	0.00	*	144	6,491	217	0.0	1,115	*	27.67	10.46	94
13-Jun	0	0	0	0	0.00	0.00	0.00	*	141	5,062	359	0.0	860	*	21.41	8.08	74
14-Jun	0	0	0	0	0.00	0.00	0.00	*	232	2,532	394	0.0	902	*	22.46	8.47	78
15-Jun	0	0	0	0	0.00	0.00	0.00	*	196	5,967	222	0.0	1,035	*	25.67	9.70	87
16-Jun	0	0	0	0	0.00	0.00	0.00	*	202	6,765	272	0.0	1,168	*	28.99	10.96	99
17-Jun	0	0	0	0	0.00	0.00	0.00	*	175	6,412	395	0.0	1,094	*	27.20	10.26	93
18-Jun	0	0	0	0	0.00	0.00	0.00	*	169	6,240	214	0.0	1,077	*	26.73	10.10	91
19-Jun	0	0	0	0	0.00	0.00	0.00	*	233	6,018	211	0.0	1,050	*	26.06	9.85	88
20-Jun	0	0	0	0	0.00	0.00	0.00	*	150	5,947	215	0.0	1,024	*	25.41	9.60	86
21-Jun	0	0	0	0	0.00	0.00	0.00	*	154	7,139	1,081	0.0	1,162	*	29.11	10.92	104
22-Jun	0	0	0	0	0.00	0.00	0.00	*	184	7,556	214	0.0	1,304	*	32.34	12.23	109
23-Jun	0	0	0	0	0.00	0.00	0.00	*	153	7,135	220	0.0	1,227	*	30.43	11.50	103
24-Jun	0	0	0	0	0.00	0.00	0.00	*	166	6,206	270	0.0	1,067	*	26.48	10.01	90
25-Jun	0	0	0	0	0.00	0.00	0.00	*	191	6,251	212	0.0	1,083	*	26.87	10.16	91
26-Jun	0	0	0	0	0.00	0.00	0.00	*	146	6,309	280	0.0	1,080	*	26.82	10.13	91
27-Jun	0	0	0	0	0.00	0.00	0.00	*	210	6,661	316	0.0	1,148	*	28.52	10.77	97
28-Jun	0	0	0	0	0.00	0.00	0.00	*	153	7,099	377	0.0	1,209	*	30.03	11.34	103
29-Jun	0	0	0	0	0.00	0.00	0.00	*	156	7,763	204	0.0	1,335	*	33.12	12.52	112
30-Jun	0	0	0	0	0.00	0.00	0.00	*	141	6,962	225	0.0	1,195	*	29.64	11.21	100
01-Jul	0	0	0	0	0.00	0.00	0.00	*	145	6,523	225	0.0	1,120	*	27.80	10.51	94
02-Jul	0	0	0	0	0.00	0.00	0.00	*	146	5,901	232	0.0	1,014	*	25.17	9.51	85
03-Jul	0	0	0	0	0.00	0.00	0.00	*	127	5,710	229	0.0	978	*	24.29	9.18	83
04-Jul	0	443	635	0	0.20	0.02	7.41	*	106	6,237	639	0.0	1,034	*	25.79	9.71	90
05-Jul	0	1,369	1,589	0	0.50	0.04	18.54	*	139	8,497	1,503	0.0	1,360	*	34.13	12.78	124
06-Jul	0	860	939	0	0.30	0.02	10.96	*	51	4,101	2,649	0.0	508	*	13.42	4.83	63
07-Jul	0	3,338	3,493	0	1.11	0.09	40.75	*	2	153	457	0.0	0	*	0.14	0.01	4
08-Jul	0	48	69	0	0.02	0.00	0.81	*	134	7,077	1,417	0.0	1,123	*	28.24	10.56	104
09-Jul	0	3,340	3,573	0	1.13	0.09	41.69	*	125	11,534	4,367	0.0	1,659	*	42.44	15.66	171

GEORGIA-PACIFIC CORPORATION
SOUTHERN PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

Daily Meter Readings/Production Trends

	6A Boiler							*	9A Boiler					*			
	S/B MLbs	Steam MLbs	Gas Mcf	Oil Bbls				*	S/B MLbs	Steam MLbs	Gas Mcf	Rubber Tons	Bark Tons	*			
PM10EF			7.60E-03	NA	Calculated lbs/hr						7.60E-03	5.64E+00	5.94E-01		Calculated lbs/hr		
SO2 EF			6.00E-04	NA							6.00E-04	3.08E+01	2.25E-01				
NOX EF			2.80E-01	NA	PM	SO2	Nox				1.90E-01	1.98E+00	1.98E+00		PM	SO2	Nox
10-Jul	0	3,778	4,026	0	1.27	0.10	46.97	*	112	9,544	5,021	0.0	1,268	*	32.97	12.01	144
11-Jul	0	262	921	0	0.29	0.02	10.75	*	138	9,970	2,586	0.0	1,529	*	38.66	14.40	147
12-Jul	0	0	0	0	0.00	0.00	0.00	*	153	6,958	228	0.0	1,196	*	29.67	11.22	100
13-Jul	0	0	0	0	0.00	0.00	0.00	*	216	7,547	206	0.0	1,309	*	32.45	12.27	110
14-Jul	0	0	0	0	0.00	0.00	0.00	*	169	8,556	370	0.0	1,460	*	36.26	13.70	123
15-Jul	0	0	0	0	0.00	0.00	0.00	*	141	6,115	257	0.0	1,048	*	26.01	9.83	88
16-Jul	0	0	0	0	0.00	0.00	0.00	*	155	6,917	217	0.0	1,190	*	29.52	11.16	100
17-Jul	0	0	0	0	0.00	0.00	0.00	*	144	8,001	293	0.0	1,367	*	33.93	12.83	115
18-Jul	0	0	0	0	0.00	0.00	0.00	*	192	6,376	680	0.0	1,069	*	26.67	10.04	94
19-Jul	0	0	0	0	0.00	0.00	0.00	*	122	7,858	1,058	0.0	1,282	*	32.07	12.05	114
20-Jul	0	0	0	0	0.00	0.00	0.00	*	141	7,499	252	0.0	1,284	*	31.86	12.05	108
21-Jul	0	0	0	0	0.00	0.00	0.00	*	139	6,757	1,515	0.0	1,062	*	26.76	9.99	100
22-Jul	0	0	0	0	0.00	0.00	0.00	*	126	7,091	1,248	0.0	1,213	*	30.42	11.41	110
23-Jul	0	856	1,391	0	0.44	0.03	16.23	*	138	8,960	585	0.0	1,508	*	37.50	14.15	129
24-Jul	0	1,029	1,229	0	0.39	0.03	14.34	*	150	7,634	247	0.0	1,309	*	32.48	12.28	110
25-Jul	0	0	0	0	0.00	0.00	0.00	*	146	8,435	223	0.0	1,447	*	35.88	13.57	121
26-Jul	0	0	0	0	0.00	0.00	0.00	*	152	7,090	997	0.0	1,160	*	29.03	10.90	104
27-Jul	0	0	0	0	0.00	0.00	0.00	*	127	7,336	789	0.0	1,213	*	30.28	11.40	106
28-Jul	0	0	0	0	0.00	0.00	0.00	*	124	5,381	230	0.0	922	*	22.88	8.65	78
29-Jul	0	0	0	0	0.00	0.00	0.00	*	124	5,265	230	0.0	902	*	22.39	8.46	76
30-Jul	0	0	0	0	0.00	0.00	0.00	*	121	8,263	360	0.0	1,403	*	34.84	13.16	119
31-Jul	0	0	0	0	0.00	0.00	0.00	*	108	6,858	294	0.0	1,166	*	28.95	10.94	99
01-Aug	0	0	0	0	0.00	0.00	0.00	*	162	8,321	230	0.0	1,397	*	34.65	13.10	117
02-Aug	0	607	796	0	0.25	0.02	9.29	*	143	9,488	1,776	0.0	1,474	*	37.05	13.86	136
03-Aug	0	0	0	0	0.00	0.00	0.00	*	128	7,776	342	0.0	1,292	*	32.09	12.12	109
04-Aug	0	3,528	4,704	0	1.49	0.12	54.88	*	155	9,692	1,231	0.0	1,550	*	38.76	14.57	138
05-Aug	0	1,369	1,546	0	0.49	0.04	18.04	*	141	8,491	1,172	0.0	1,352	*	33.84	12.71	121
06-Aug	0	0	0	0	0.00	0.00	0.00	*	190	7,022	215	0.0	1,186	*	29.42	11.13	100
07-Aug	0	0	0	0	0.00	0.00	0.00	*	129	5,854	237	0.0	980	*	24.32	9.19	83
08-Aug	0	0	0	0	0.00	0.00	0.00	*	128	5,309	351	0.0	880	*	21.90	8.26	75
09-Aug	0	0	0	0	0.00	0.00	0.00	*	171	7,320	230	0.0	1,232	*	30.55	11.55	103
10-Aug	0	0	0	0	0.00	0.00	0.00	*	135	6,295	508	0.0	1,034	*	25.76	9.71	89

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SOUTHERN PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

Daily Meter Readings/Production Trends

	6A Boiler S/B MLbs	6A Steam MLbs	6A Gas Mcf	6A Oil Bbls	6A Calculated lbs/hr PM	6A SO2	6A Nox	*	9A Boiler S/B MLbs	9A Steam MLbs	9A Gas Mcf	9A Rubber Tons	9A Bark Tons	*	9A Calculated lbs/hr PM	9A SO2	9A Nox
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA							6.00E-04	3.08E+01	2.25E-01				
NOX EF			2.80E-01	NA							1.90E-01	1.98E+00	1.98E+00				
11-Aug	0	0	0	0	0.00	0.00	0.00	*	136	6,874	299	0.0	1,146	*	28.46	10.75	97
12-Aug	0	0	0	0	0.00	0.00	0.00	*	132	6,825	215	0.0	1,144	*	28.37	10.73	96
13-Aug	0	0	0	0	0.00	0.00	0.00	*	140	6,969	218	0.0	1,169	*	29.00	10.96	98
14-Aug	0	0	0	0	0.00	0.00	0.00	*	155	7,328	250	0.0	1,229	*	30.49	11.53	103
15-Aug	0	0	0	0	0.00	0.00	0.00	*	175	6,698	308	0.0	1,123	*	27.89	10.53	95
16-Aug	0	0	0	0	0.00	0.00	0.00	*	132	7,698	255	0.0	1,286	*	31.91	12.06	108
17-Aug	0	2,776	3,174	0	1.01	0.08	37.03	*	13	1,168	245	0.0	179	*	4.50	1.68	17
18-Aug	0	3,459	4,612	0	1.46	0.12	53.81	*	0	0	0	0.0	0	*	0.00	0.00	0
19-Aug	0	3,548	4,731	0	1.50	0.12	55.20	*	0	0	0	0.0	0	*	0.00	0.00	0
20-Aug	0	3,600	4,700	0	1.49	0.12	54.83	*	0	0	0	0.0	0	*	0.00	0.00	0
21-Aug	0	3,444	4,592	0	1.45	0.11	53.57	*	0	0	0	0.0	0	*	0.00	0.00	0
22-Aug	0	3,884	5,178	0	1.64	0.13	60.41	*	49	877	1,226	0.0	60	*	1.87	0.59	15
23-Aug	0	150	182	0	0.06	0.00	2.12	*	148	5,284	4,276	0.0	590	*	15.95	5.64	83
24-Aug	0	0	0	0	0.00	0.00	0.00	*	127	6,055	4,305	0.0	713	*	19.00	6.79	93
25-Aug	0	0	0	0	0.00	0.00	0.00	*	130	6,222	1,000	0.0	985	*	24.69	9.26	89
26-Aug	0	0	0	0	0.00	0.00	0.00	*	123	5,560	294	0.0	925	*	23.00	8.68	79
27-Aug	0	0	0	0	0.00	0.00	0.00	*	153	6,772	235	0.0	1,137	*	28.21	10.66	96
28-Aug	0	0	0	0	0.00	0.00	0.00	*	149	6,539	156	0.0	1,103	*	27.35	10.35	92
29-Aug	0	0	0	0	0.00	0.00	0.00	*	163	7,470	225	0.0	1,256	*	31.15	11.78	105
30-Aug	0	0	0	0	0.00	0.00	0.00	*	159	6,215	206	0.0	1,047	*	25.98	9.82	88
31-Aug	0	0	0	0	0.00	0.00	0.00	*	140	7,084	140	0.0	1,187	*	29.43	11.13	99
01-Sep	0	0	0	0	0.00	0.00	0.00	*	144	7,252	223	0.0	1,216	*	30.17	11.41	102
02-Sep	0	0	0	0	0.00	0.00	0.00	*	118	8,853	341	0.0	1,470	*	36.49	13.79	124
03-Sep	0	0	0	0	0.00	0.00	0.00	*	133	8,247	229	0.0	1,380	*	34.22	12.94	116
04-Sep	0	0	0	0	0.00	0.00	0.00	*	133	7,544	229	0.0	1,263	*	31.32	11.84	106
05-Sep	0	0	0	0	0.00	0.00	0.00	*	72	6,362	232	0.0	1,055	*	26.19	9.90	89
06-Sep	0	0	0	0	0.00	0.00	0.00	*	156	5,871	234	0.0	987	*	24.51	9.26	83
07-Sep	0	0	0	0	0.00	0.00	0.00	*	135	6,027	223	0.0	1,011	*	25.08	9.48	85
08-Sep	0	0	0	0	0.00	0.00	0.00	*	136	7,399	229	0.0	1,239	*	30.74	11.62	104
09-Sep	0	0	0	0	0.00	0.00	0.00	*	197	8,017	832	0.0	1,308	*	32.63	12.28	114
10-Sep	0	0	0	0	0.00	0.00	0.00	*	160	6,368	211	0.0	1,072	*	26.61	10.06	90
11-Sep	0	0	0	0	0.00	0.00	0.00	*	202	7,699	655	0.0	1,268	*	31.60	11.91	110

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SOUTHERN PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

Daily Meter Readings/Production Trends

	6A Boiler							*	9A Boiler					*			
	S/B MLbs	Steam MLbs	Gas Mcf	Oil Bbls	Calculated lbs/hr			*	S/B MLbs	Steam MLbs	Gas Mcf	Rubber Tons	Bark Tons	*	Calculated lbs/hr		
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA							6.00E-04	3.08E+01	2.25E-01				
NOX EF			2.80E-01	NA	PM	SO2	Nox				1.90E-01	1.98E+00	1.98E+00		PM	SO2	Nox
12-Sep	0	0	0	0	0.00	0.00	0.00	*	200	6,649	1,165	0.0	1,056	*	26.49	9.92	96
13-Sep	0	649	1,201	0	0.38	0.03	14.01	*	79	7,627	2,638	0.0	1,090	*	27.80	10.28	111
14-Sep	0	0	0	0	0.00	0.00	0.00	*	174	5,844	727	0.0	949	*	23.73	8.92	84
15-Sep	0	0	0	0	0.00	0.00	0.00	*	180	5,955	814	0.0	962	*	24.08	9.04	86
16-Sep	0	0	0	0	0.00	0.00	0.00	*	158	5,428	1,202	0.0	842	*	21.23	7.93	79
17-Sep	0	0	0	0	0.00	0.00	0.00	*	203	5,656	1,084	0.0	897	*	22.53	8.43	83
18-Sep	0	0	0	0	0.00	0.00	0.00	*	128	6,277	1,243	0.0	976	*	24.54	9.18	90
19-Sep	0	0	0	0	0.00	0.00	0.00	*	139	5,408	636	0.0	878	*	21.92	8.24	77
20-Sep	0	0	0	0	0.00	0.00	0.00	*	142	7,408	1,173	0.0	1,172	*	29.37	11.01	106
21-Sep	0	0	0	0	0.00	0.00	0.00	*	158	5,819	1,554	0.0	881	*	22.31	8.30	85
22-Sep	0	0	0	0	0.00	0.00	0.00	*	137	5,763	1,201	0.0	895	*	22.52	8.42	83
23-Sep	0	0	0	0	0.00	0.00	0.00	*	155	5,724	586	0.0	937	*	23.37	8.80	82
24-Sep	0	0	0	0	0.00	0.00	0.00	*	268	8,403	2,200	0.0	1,283	*	32.45	12.08	123
25-Sep	0	0	0	0	0.00	0.00	0.00	*	275	7,007	1,232	0.0	1,123	*	28.18	10.56	102
26-Sep	0	0	0	0	0.00	0.00	0.00	*	201	5,744	1,207	0.0	902	*	22.70	8.48	84
27-Sep	0	0	0	0	0.00	0.00	0.00	*	149	3,059	626	0.0	488	*	12.29	4.60	45
28-Sep	0	0	0	0	0.00	0.00	0.00	*	224	4,133	697	0.0	675	*	16.92	6.34	61
29-Sep	0	0	0	0	0.00	0.00	0.00	*	280	5,367	792	0.0	883	*	22.10	8.30	79
30-Sep	0	0	0	0	0.00	0.00	0.00	*	254	5,732	1,203	0.0	909	*	22.88	8.55	85
01-Oct	0	0	0	0	0.00	0.00	0.00	*	211	5,891	1,460	0.0	909	*	22.97	8.56	87
02-Oct	0	0	0	0	0.00	0.00	0.00	*	107	3,830	439	0.0	624	*	15.58	5.86	55
03-Oct	0	0	0	0	0.00	0.00	0.00	*	107	5,019	439	0.0	822	*	20.49	7.72	71
04-Oct	0	0	0	0	0.00	0.00	0.00	*	125	5,572	465	0.0	915	*	22.80	8.59	79
05-Oct	0	0	0	0	0.00	0.00	0.00	*	297	5,190	209	0.0	899	*	22.32	8.43	76
06-Oct	0	0	0	0	0.00	0.00	0.00	*	255	5,717	1,833	0.0	860	*	21.87	8.11	85
07-Oct	0	0	0	0	0.00	0.00	0.00	*	194	5,614	7,819	0.0	391	*	12.15	3.86	94
08-Oct	0	1,378	1,608	0	0.51	0.04	18.76	*	57	3,244	4,341	0.0	230	*	7.06	2.26	53
09-Oct	0	2,745	3,089	0	0.98	0.08	36.04	*	0	0	0	0.0	0	*	0.00	0.00	0
10-Oct	0	2,792	3,059	0	0.97	0.08	35.69	*	0	0	0	0.0	0	*	0.00	0.00	0
11-Oct	0	3,000	3,307	0	1.05	0.08	38.58	*	0	0	0	0.0	0	*	0.00	0.00	0
12-Oct	0	3,000	3,307	0	1.05	0.08	38.58	*	0	0	0	0.0	0	*	0.00	0.00	0
13-Oct	0	3,000	3,307	0	1.05	0.08	38.58	*	0	0	0	0.0	0	*	0.00	0.00	0

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P A P E R   M I L L   U T I L I T Y   R E P O R T

Daily Meter Readings/Production Trends

	6A Boiler S/B MLbs	6A Steam MLbs	6A Gas Mcf	6A Oil Bbls	6A Calculated lbs/hr PM	6A SO2	6A Nox	*	9A Boiler S/B MLbs	9A Steam MLbs	9A Gas Mcf	9A Rubber Tons	9A Bark Tons	*	9A Calculated lbs/hr PM	9A SO2	9A Nox
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA							6.00E-04	3.08E+01	2.25E-01				
NOX EF			2.80E-01	NA							1.90E-01	1.98E+00	1.98E+00				
14-Oct	0	3,000	3,307	0	1.05	0.08	38.58	*	0	0	0	0.0	0	*	0.00	0.00	0
15-Oct	0	3,751	4,046	0	1.28	0.10	47.20	*	0	0	0	0.0	0	*	0.00	0.00	0
16-Oct	0	4,230	4,545	0	1.44	0.11	53.03	*	0	0	0	0.0	0	*	0.00	0.00	0
17-Oct	0	3,900	4,144	0	1.31	0.10	48.35	*	0	0	0	0.0	0	*	0.00	0.00	0
18-Oct	0	4,415	4,694	0	1.49	0.12	54.76	*	0	0	0	0.0	0	*	0.00	0.00	0
19-Oct	0	4,365	4,557	0	1.44	0.11	53.17	*	0	0	0	0.0	0	*	0.00	0.00	0
20-Oct	0	3,348	3,459	0	1.10	0.09	40.36	*	0	0	0	0.0	0	*	0.00	0.00	0
21-Oct	0	3,026	3,203	0	1.01	0.08	37.37	*	0	0	0	0.0	0	*	0.00	0.00	0
22-Oct	0	4,605	5,023	0	1.59	0.13	58.60	*	0	0	0	0.0	0	*	0.00	0.00	0
23-Oct	0	4,481	4,811	0	1.52	0.12	56.13	*	0	0	0	0.0	0	*	0.00	0.00	0
24-Oct	0	3,995	4,257	0	1.35	0.11	49.67	*	0	0	0	0.0	0	*	0.00	0.00	0
25-Oct	0	171	316	0	0.10	0.01	3.69	*	260	6,313	1,284	0.0	1,001	*	25.17	9.41	93
26-Oct	0	170	226	0	0.07	0.01	2.64	*	276	6,835	401	0.0	1,156	*	28.73	10.84	99
27-Oct	0	0	0	0	0.00	0.00	0.00	*	312	7,408	251	0.0	1,268	*	31.47	11.90	107
28-Oct	0	0	0	0	0.00	0.00	0.00	*	262	7,970	199	0.0	1,357	*	33.66	12.73	114
29-Oct	0	0	0	0	0.00	0.00	0.00	*	212	8,096	485	0.0	1,349	*	33.54	12.66	115
30-Oct	0	0	0	0	0.00	0.00	0.00	*	200	6,302	278	0.0	1,063	*	26.40	9.97	90
31-Oct	0	0	0	0	0.00	0.00	0.00	*	195	6,375	199	0.0	1,080	*	26.80	10.13	91
01-Nov	0	0	0	0	0.00	0.00	0.00	*	156	5,148	208	0.0	869	*	21.56	8.15	73
02-Nov	0	0	0	0	0.00	0.00	0.00	*	44	762	485	0.0	99	*	2.59	0.94	12
03-Nov	0	0	0	0	0.00	0.00	0.00	*	235	5,290	682	0.0	871	*	21.76	8.18	77
04-Nov	0	0	0	0	0.00	0.00	0.00	*	268	4,602	204	0.0	797	*	19.78	7.47	67
05-Nov	0	0	0	0	0.00	0.00	0.00	*	232	5,308	204	0.0	908	*	22.54	8.52	77
06-Nov	0	0	0	0	0.00	0.00	0.00	*	189	5,304	302	0.0	893	*	22.20	8.38	76
07-Nov	0	0	0	0	0.00	0.00	0.00	*	174	5,986	422	0.0	933	*	23.24	8.76	80
08-Nov	0	0	34	0	0.01	0.00	0.40	*	189	7,877	1,319	0.0	1,073	*	26.98	10.09	99
09-Nov	0	0	0	0	0.00	0.00	0.00	*	261	7,403	507	0.0	1,240	*	30.85	11.64	106
10-Nov	0	0	0	0	0.00	0.00	0.00	*	175	7,224	637	0.0	1,186	*	29.56	11.14	103
11-Nov	0	613	1,289	0	0.41	0.03	15.04	*	247	8,270	733	0.0	1,365	*	34.03	12.82	118
12-Nov	0	1,856	1,795	0	0.57	0.04	20.94	*	226	9,187	365	0.0	1,038	*	25.80	9.74	89
13-Nov	0	452	345	0	0.11	0.01	4.03	*	178	8,693	482	0.0	1,212	*	30.16	11.38	104
14-Nov	0	0	0	0	0.00	0.00	0.00	*	123	6,794	218	0.0	1,137	*	28.20	10.66	96

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GEORGIA-PACIFIC CORPORATION
SOUTHERN PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

Daily Meter Readings/Production Trends

	6A Boiler S/B MLbs	6A Boiler Steam MLbs	6A Boiler Gas Mcf	6A Boiler Oil Bbls	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox	*	9A Boiler S/B MLbs	9A Boiler Steam MLbs	9A Boiler Gas Mcf	9A Boiler Rubber Tons	9A Boiler Bark Tons	*	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA							6.00E-04	3.08E+01	2.25E-01				
NOX EF			2.80E-01	NA							1.90E-01	1.98E+00	1.98E+00				
15-Nov	0	0	0	0	0.00	0.00	0.00	*	125	6,807	212	0.0	1,140	*	28.27	10.69	96
16-Nov	0	0	0	0	0.00	0.00	0.00	*	125	6,354	207	0.0	1,065	*	26.41	9.99	89
17-Nov	0	0	0	0	0.00	0.00	0.00	*	109	7,040	242	0.0	1,174	*	29.12	11.01	99
18-Nov	0	0	0	0	0.00	0.00	0.00	*	120	6,314	216	0.0	1,056	*	26.21	9.91	89
19-Nov	0	0	0	0	0.00	0.00	0.00	*	113	7,104	554	0.0	1,162	*	28.93	10.91	100
20-Nov	0	0	0	0	0.00	0.00	0.00	*	127	8,164	264	0.0	1,362	*	33.80	12.78	114
21-Nov	0	0	0	0	0.00	0.00	0.00	*	70	8,224	1,237	0.0	1,367	*	34.22	12.85	123
22-Nov	0	0	0	0	0.00	0.00	0.00	*	111	8,713	1,241	0.0	959	*	24.12	9.02	89
23-Nov	0	0	0	0	0.00	0.00	0.00	*	122	9,131	1,113	0.0	973	*	24.43	9.15	89
24-Nov	0	0	0	0	0.00	0.00	0.00	*	110	8,717	901	0.0	917	*	22.98	8.62	83
25-Nov	0	0	0	0	0.00	0.00	0.00	*	118	8,619	632	0.0	923	*	23.05	8.67	81
26-Nov	0	0	0	0	0.00	0.00	0.00	*	123	9,642	2,252	0.0	995	*	25.34	9.38	100
27-Nov	0	0	0	0	0.00	0.00	0.00	*	124	6,515	1,001	0.0	1,033	*	25.87	9.71	93
28-Nov	0	0	0	0	0.00	0.00	0.00	*	109	6,962	3,577	0.0	915	*	23.77	8.66	104
29-Nov	0	425	582	0	0.18	0.01	6.79	*	49	7,615	10,093	0.0	532	*	16.37	5.24	124
30-Nov	0	2,485	2,989	0	0.95	0.07	34.87	*	77	4,796	2,188	0.0	651	*	16.80	6.15	71
01-Dec	0	0	0	0	0.00	0.00	0.00	*	75	8,189	768	0.0	1,321	*	32.93	12.40	115
02-Dec	0	0	0	0	0.00	0.00	0.00	*	84	6,968	252	0.0	1,157	*	28.71	10.85	97
03-Dec	0	0	0	0	0.00	0.00	0.00	*	106	8,295	715	0.0	1,347	*	33.57	12.65	117
04-Dec	0	0	0	0	0.00	0.00	0.00	*	102	7,864	505	0.0	1,290	*	32.10	12.11	110
05-Dec	0	0	0	0	0.00	0.00	0.00	*	108	6,116	379	0.0	1,009	*	25.10	9.47	86
06-Dec	0	0	0	0	0.00	0.00	0.00	*	97	7,996	314	0.0	1,326	*	32.91	12.44	112
07-Dec	0	0	0	0	0.00	0.00	0.00	*	98	7,158	309	0.0	1,187	*	29.46	11.13	100
08-Dec	0	0	0	0	0.00	0.00	0.00	*	106	7,660	345	0.0	1,269	*	31.51	11.90	107
09-Dec	0	0	0	0	0.00	0.00	0.00	*	97	8,098	346	0.0	1,340	*	33.28	12.57	113
10-Dec	0	0	0	0	0.00	0.00	0.00	*	102	8,257	397	0.0	1,364	*	33.88	12.80	116
11-Dec	0	0	0	0	0.00	0.00	0.00	*	98	8,735	1,240	0.0	1,381	*	34.56	12.97	124
12-Dec	0	0	0	0	0.00	0.00	0.00	*	113	7,743	549	0.0	1,269	*	31.58	11.91	109
13-Dec	0	0	0	0	0.00	0.00	0.00	*	104	8,202	1,966	0.0	1,239	*	31.29	11.67	118
14-Dec	0	0	0	0	0.00	0.00	0.00	*	120	8,168	1,468	0.0	1,273	*	31.97	11.97	117
15-Dec	0	2,398	2,730	0	0.86	0.07	31.85	*	138	9,803	3,706	0.0	1,383	*	35.41	13.06	143
16-Dec	0	899	1,298	0	0.41	0.03	15.14	*	127	7,987	1,234	0.0	1,261	*	31.61	11.86	114

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GEORGIA-PACIFIC CORPORATION
SOUTHERN PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

Daily Meter Readings/Production Trends

	6A Boiler S/B MLbs	6A Boiler Steam MLbs	6A Boiler Gas Mcf	6A Boiler Oil Bbls	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox	*	9A Boiler S/B MLbs	9A Boiler Steam MLbs	9A Boiler Gas Mcf	9A Boiler Rubber Tons	9A Boiler Bark Tons	*	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA							6.00E-04	3.08E+01	2.25E-01				
NOX EF			2.80E-01	NA							1.90E-01	1.98E+00	1.98E+00				
17-Dec	0	0	0	0	0.00	0.00	0.00	*	135	9,204	3,184	0.0	1,322	*	33.72	12.47	134
18-Dec	0	0	0	0	0.00	0.00	0.00	*	135	8,377	1,367	0.0	1,318	*	33.05	12.39	120
19-Dec	0	0	0	0	0.00	0.00	0.00	*	125	7,977	941	0.0	1,281	*	32.00	12.03	113
20-Dec	0	2,977	3,321	0	1.05	0.08	38.75	*	137	10,575	3,108	0.0	1,556	*	39.49	14.66	153
21-Dec	0	2,466	2,703	0	0.86	0.07	31.54	*	127	10,465	2,088	0.0	1,611	*	40.54	15.16	149
22-Dec	0	0	0	0	0.00	0.00	0.00	*	133	10,086	2,404	0.0	1,526	*	38.52	14.36	145
23-Dec	0	0	0	0	0.00	0.00	0.00	*	129	9,531	1,509	0.0	1,499	*	37.57	14.09	136
24-Dec	0	0	0	0	0.00	0.00	0.00	*	143	8,220	957	0.0	1,323	*	33.05	12.43	117
25-Dec	0	0	0	0	0.00	0.00	0.00	*	141	6,082	186	0.0	1,023	*	25.39	9.60	86
26-Dec	0	0	0	0	0.00	0.00	0.00	*	135	6,736	236	0.0	1,128	*	27.99	10.58	95
27-Dec	0	0	54	0	0.02	0.00	0.63	*	121	8,277	2,248	0.0	1,234	*	31.25	11.62	120
28-Dec	0	3,241	4,321	0	1.37	0.11	50.41	*	131	9,902	2,640	0.0	1,477	*	37.40	13.92	143
29-Dec	0	2,591	2,718	0	0.86	0.07	31.71	*	105	8,993	946	0.0	1,447	*	36.10	13.58	127
			7772		2.46	0	91								43	16	171

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

PAPER MILL UTILITY REPORT

	6A Boiler							*	9A Boiler					*			
DATE	S/B MLbs	Steam MLbs	Gas Mcf	Oil Bbls				*	S/B MLbs	Steam MLbs	Gas Mcf	Rubber Tons	Bark Tons	*			
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA	Calculated lbs/hr						6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOX EF			2.80E-01	NA	PM	SO2	Nox				9.91E-02	1.98E+00	1.98E+00		PM	SO2	Nox
30-Dec	0	734	751	0	0.24	0.02	8.76	*	109	7,957	1,307	0.0	1,248	*	31.30	11.73	108
31-Dec	0	0	0	0	0.00	0.00	0.00	*	87	8,536	342	0.0	1,412	*	35.05	13.25	118
01-Jan	0	0	0	0	0.00	0.00	0.00	*	111	8,733	418	0.0	1,443	*	35.85	13.54	121
02-Jan	0	0	0	0	0.00	0.00	0.00	*	111	9,032	1,438	0.0	1,418	*	35.54	13.33	123
03-Jan	0	0	0	0	0.00	0.00	0.00	*	111	9,862	1,545	0.0	1,548	*	38.81	14.55	134
04-Jan	0	0	0	0	0.00	0.00	0.00	*	134	9,140	1,198	0.0	1,457	*	36.45	13.69	125
05-Jan	0	0	0	0	0.00	0.00	0.00	*	156	9,512	1,274	0.0	1,517	*	37.96	14.26	130
06-Jan	0	0	0	0	0.00	0.00	0.00	*	151	9,787	1,521	0.0	1,544	*	38.70	14.51	134
07-Jan	0	1,323	1,561	0	0.49	0.04	18.21	*	159	9,459	1,409	0.0	1,499	*	37.55	14.09	129
08-Jan	0	1,878	2,067	0	0.65	0.05	24.12	*	129	9,273	431	0.0	1,535	*	38.13	14.40	128
09-Jan	0	0	0	0	0.00	0.00	0.00	*	125	8,072	388	0.0	1,338	*	33.23	12.55	112
10-Jan	0	0	0	0	0.00	0.00	0.00	*	110	7,207	284	0.0	1,199	*	29.75	11.24	100
11-Jan	0	0	0	0	0.00	0.00	0.00	*	127	6,783	212	0.0	1,136	*	28.18	10.66	95
12-Jan	0	0	0	0	0.00	0.00	0.00	*	129	8,784	370	0.0	1,458	*	36.21	13.68	122
13-Jan	0	0	0	0	0.00	0.00	0.00	*	128	10,578	1,584	0.0	1,667	*	41.77	15.67	144
14-Jan	0	0	0	0	0.00	0.00	0.00	*	129	8,329	240	0.0	1,392	*	34.53	13.06	116
15-Jan	0	0	0	0	0.00	0.00	0.00	*	140	9,381	265	0.0	1,567	*	38.87	14.70	130
16-Jan	0	0	0	0	0.00	0.00	0.00	*	133	7,991	499	0.0	1,317	*	32.76	12.36	111
17-Jan	0	0	0	0	0.00	0.00	0.00	*	162	9,263	583	0.0	1,528	*	38.00	14.34	128
18-Jan	0	0	0	0	0.00	0.00	0.00	*	135	10,066	1,222	0.0	1,610	*	40.23	15.12	138
19-Jan	0	3,569	3,975	0	1.26	0.10	46.38	*	47	2,564	2,364	0.0	261	*	7.20	2.50	31
20-Jan	0	4,739	5,156	0	1.63	0.13	60.15	*	0	221	423	0.0	6	*	0.27	0.06	2
21-Jan	0	770	1,157	0	0.37	0.03	13.50	*	124	8,655	845	0.0	1,401	*	34.94	13.15	119
22-Jan	0	1,528	1,501	0	0.48	0.04	17.51	*	115	7,108	2,990	0.0	983	*	25.28	9.29	93
23-Jan	0	0	0	0	0.00	0.00	0.00	*	120	5,803	253	0.0	969	*	24.05	9.09	81
24-Jan	0	0	0	0	0.00	0.00	0.00	*	157	7,576	1,207	0.0	1,200	*	30.08	11.28	104
25-Jan	0	0	0	0	0.00	0.00	0.00	*	111	9,795	1,702	0.0	1,525	*	38.29	14.34	133
26-Jan	0	0	0	0	0.00	0.00	0.00	*	106	9,388	582	0.0	1,539	*	38.28	14.45	129
27-Jan	0	32	211	0	0.07	0.01	2.46	*	106	8,291	287	0.0	1,378	*	34.20	12.93	115
28-Jan	0	2,490	2,609	0	0.83	0.07	30.44	*	153	7,591	485	0.0	1,255	*	31.21	11.78	106
29-Jan	0	0	0	0	0.00	0.00	0.00	*	130	7,142	446	0.0	1,179	*	29.32	11.07	99
30-Jan	0	0	0	0	0.00	0.00	0.00	*	142	7,258	230	0.0	1,216	*	30.18	11.41	101
31-Jan	0	0	0	0	0.00	0.00	0.00	*	131	8,914	1,152	0.0	1,422	*	35.57	13.36	122
01-Feb	0	1,529	1,782	0	0.56	0.04	20.79	*	151	10,937	2,650	0.0	1,652	*	41.74	15.56	147
02-Feb	0	0	0	0	0.00	0.00	0.00	*	127	10,209	1,133	0.0	1,639	*	40.93	15.39	140
03-Feb	0	0	0	0	0.00	0.00	0.00	*	115	9,884	1,594	0.0	1,549	*	38.84	14.56	134

2002

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R M I L L U T I L I T Y R E P O R T

DATE	6A Boiler S/B MLbs	6A Boiler Steam MLbs	6A Boiler Gas Mcf	6A Boiler Oil Bbls	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox	*	9A Boiler S/B MLbs	9A Boiler Steam MLbs	9A Boiler Gas Mcf	9A Boiler Rubber Tons	9A Boiler Bark Tons	*	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA							6.00E-04	3.08E+01	2.25E-01				
NOX EF			2.80E-01	NA							9.91E-02	1.98E+00	1.98E+00				
04-Feb	0	0	0	0	0.00	0.00	0.00	*	145	8,885	955	0.0	1,435	*	35.81	13.47	122
05-Feb	0	0	0	0	0.00	0.00	0.00	*	147	8,700	1,515	0.0	1,363	*	34.21	12.81	119
06-Feb	0	2,438	2,576	0	0.82	0.06	30.05	*	151	10,041	2,371	0.0	1,524	*	38.46	14.34	135
07-Feb	0	2,426	2,419	0	0.77	0.06	28.22	*	121	9,410	2,035	0.0	1,438	*	36.24	13.54	127
08-Feb	0	0	0	0	0.00	0.00	0.00	*	125	9,023	2,694	0.0	1,326	*	33.67	12.50	121
09-Feb	0	0	0	0	0.00	0.00	0.00	*	106	9,514	771	0.0	1,546	*	38.52	14.52	131
10-Feb	0	0	0	0	0.00	0.00	0.00	*	134	9,804	705	0.0	1,604	*	39.93	15.06	135
11-Feb	0	0	0	0	0.00	0.00	0.00	*	101	9,752	4,523	0.0	1,308	*	33.81	12.38	127
12-Feb	0	0	0	0	0.00	0.00	0.00	*	96	7,877	1,107	0.0	1,247	*	31.22	11.72	107
13-Feb	0	784	881	0	0.28	0.02	10.28	*	110	7,980	2,189	0.0	1,187	*	30.07	11.18	107
14-Feb	0	640	787	0	0.25	0.02	9.18	*	99	8,531	1,165	0.0	1,352	*	33.84	12.71	116
15-Feb	0	0	0	0	0.00	0.00	0.00	*	139	9,123	925	0.0	1,475	*	36.81	13.86	126
16-Feb	0	0	0	0	0.00	0.00	0.00	*	113	9,045	1,369	0.0	1,425	*	35.71	13.40	123
17-Feb	0	0	0	0	0.00	0.00	0.00	*	127	10,094	1,962	0.0	1,559	*	39.20	14.66	137
18-Feb	0	0	0	0	0.00	0.00	0.00	*	118	9,677	2,158	0.0	1,473	*	37.15	13.87	130
19-Feb	0	0	0	0	0.00	0.00	0.00	*	115	9,695	2,497	0.0	1,451	*	36.70	13.66	130
20-Feb	0	0	0	0	0.00	0.00	0.00	*	154	7,506	1,265	0.0	1,183	*	29.69	11.13	103
21-Feb	0	0	0	0	0.00	0.00	0.00	*	87	9,948	4,102	0.0	1,370	*	35.20	12.94	130
22-Feb	0	0	0	0	0.00	0.00	0.00	*	128	10,605	2,520	0.0	1,603	*	40.47	15.09	143
23-Feb	0	0	0	0	0.00	0.00	0.00	*	117	10,739	2,286	0.0	1,641	*	41.33	15.44	145
24-Feb	0	0	0	0	0.00	0.00	0.00	*	128	10,789	2,763	0.0	1,616	*	40.86	15.22	145
25-Feb	0	0	0	0	0.00	0.00	0.00	*	165	9,652	2,437	0.0	1,456	*	36.82	13.71	130
26-Feb	0	601	706	0	0.22	0.02	8.24	*	262	10,855	4,184	0.0	1,544	*	39.54	14.58	145
27-Feb	0	2,360	2,579	0	0.82	0.06	30.09	*	133	8,472	3,615	0.0	1,167	*	30.04	11.03	111
28-Feb	0	930	1,182	0	0.37	0.03	13.79	*	102	7,040	2,077	0.0	1,037	*	26.32	9.77	94
01-Mar	0	728	802	0	0.25	0.02	9.36	*	133	8,829	2,308	0.0	1,323	*	33.48	12.46	119
02-Mar	0	0	0	0	0.00	0.00	0.00	*	225	9,039	3,671	0.0	1,273	*	32.67	12.03	120
03-Mar	0	0	0	0	0.00	0.00	0.00	*	280	10,460	3,241	0.0	1,551	*	39.41	14.62	141
04-Mar	0	0	0	0	0.00	0.00	0.00	*	207	10,353	2,219	0.0	1,596	*	40.21	15.02	141
05-Mar	0	0	59	0	0.02	0.00	0.69	*	214	10,709	3,540	0.0	1,559	*	39.71	14.71	143
06-Mar	0	3,312	3,619	0	1.15	0.09	42.22	*	160	5,413	2,602	0.0	737	*	19.06	6.97	72
07-Mar	0	717	839	0	0.27	0.02	9.79	*	159	8,629	1,378	0.0	1,363	*	34.17	12.81	118
08-Mar	0	0	111	0	0.04	0.00	1.30	*	201	7,015	2,425	0.0	1,024	*	26.10	9.66	94
09-Mar	0	0	171	0	0.05	0.00	2.00	*	199	8,028	3,027	0.0	1,148	*	29.37	10.84	107
10-Mar	0	4,101	4,300	0	1.36	0.11	50.17	*	64	2,315	2,715	0.0	196	*	5.71	1.91	27
11-Mar	0	3,954	3,887	0	1.23	0.10	45.35	*	0	0	0	0.0	0	*	0.00	0.00	0
12-Mar	0	3,714	3,862	0	1.22	0.10	45.06	*	0	0	0	0.0	0	*	0.00	0.00	0

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

	6A Boiler							*	9A Boiler					*			
DATE	S/B MLbs	Steam MLbs	Gas Mcf	Oil Bbls				*	S/B MLbs	Steam MLbs	Gas Mcf	Rubber Tons	Bark Tons	*			
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA	Calculated lbs/hr						6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOX EF			2.80E-01	NA	PM	SO2	Nox				9.91E-02	1.98E+00	1.98E+00		PM	SO2	Nox
13-Mar	0	3,542	3,711	0	1.18	0.09	43.30	*	0	0	0	0.0	0	*	0.00	0.00	0
14-Mar	0	3,882	4,109	0	1.30	0.10	47.94	*	0	0	0	0.0	0	*	0.00	0.00	0
15-Mar	0	3,631	3,736	0	1.18	0.09	43.59	*	0	0	0	0.0	0	*	0.00	0.00	0
16-Mar	0	3,540	3,560	0	1.13	0.09	41.53	*	0	0	0	0.0	0	*	0.00	0.00	0
17-Mar	0	3,729	3,956	0	1.25	0.10	46.15	*	0	0	0	0.0	0	*	0.00	0.00	0
18-Mar	0	3,358	3,302	0	1.05	0.08	38.52	*	0	0	0	0.0	0	*	0.00	0.00	0
19-Mar	0	3,540	3,574	0	1.13	0.09	41.70	*	0	0	0	0.0	0	*	0.00	0.00	0
20-Mar	0	3,815	3,956	0	1.25	0.10	46.15	*	0	0	0	0.0	0	*	0.00	0.00	0
21-Mar	0	3,937	4,091	0	1.30	0.10	47.73	*	0	0	0	0.0	0	*	0.00	0.00	0
22-Mar	0	4,264	5,685	0	1.80	0.14	66.33	*	0	0	0	0.0	0	*	0.00	0.00	0
23-Mar	0	4,439	4,755	0	1.51	0.12	55.48	*	0	0	0	0.0	0	*	0.00	0.00	0
24-Mar	0	3,883	4,017	0	1.27	0.10	46.87	*	0	0	0	0.0	0	*	0.00	0.00	0
25-Mar	0	3,155	3,367	0	1.07	0.08	39.28	*	0	0	0	0.0	0	*	0.00	0.00	0
26-Mar	0	3,369	3,583	0	1.13	0.09	41.80	*	0	0	0	0.0	0	*	0.00	0.00	0
27-Mar	0	3,778	4,151	0	1.31	0.10	48.43	*	3	3,965	3,112	0.0	323	*	8.97	3.10	39
28-Mar	0	3,557	3,872	0	1.23	0.10	45.17	*	73	9,381	4,658	0.0	1,313	*	33.97	12.42	128
29-Mar	0	3,765	4,198	0	1.33	0.10	48.98	*	81	9,301	1,246	0.0	1,549	*	38.72	14.55	133
30-Mar	0	3,918	4,347	0	1.38	0.11	50.72	*	179	10,267	2,263	0.0	1,676	*	42.19	15.77	148
31-Mar	0	3,612	3,979	0	1.26	0.10	46.42	*	192	10,746	4,980	0.0	1,564	*	40.30	14.79	150
01-Apr	0	3,165	3,499	0	1.11	0.09	40.82	*	103	10,438	3,442	0.0	1,180	*	30.30	11.15	112
02-Apr	0	1,069	1,259	0	0.40	0.03	14.69	*	107	9,804	2,958	0.0	930	*	23.94	8.79	89
03-Apr	0	3,733	4,125	0	1.31	0.10	48.13	*	275	10,272	4,093	0.0	952	*	24.85	9.02	95
04-Apr	0	3,935	4,295	0	1.36	0.11	50.11	*	263	10,449	2,948	0.0	1,060	*	27.18	10.02	100
05-Apr	0	1,429	1,955	0	0.62	0.05	22.81	*	266	10,343	2,904	0.0	1,554	*	39.38	14.64	140
06-Apr	0	497	656	0	0.21	0.02	7.65	*	152	10,274	2,233	0.0	1,573	*	39.64	14.80	139
07-Apr	0	0	0	0	0.00	0.00	0.00	*	79	8,206	2,523	0.0	1,195	*	30.37	11.26	109
08-Apr	0	0	0	0	0.00	0.00	0.00	*	89	8,150	2,838	0.0	1,164	*	29.70	10.98	108
09-Apr	0	0	0	0	0.00	0.00	0.00	*	203	6,849	254	0.0	1,157	*	28.71	10.85	96
10-Apr	0	0	0	0	0.00	0.00	0.00	*	152	7,448	1,220	0.0	1,177	*	29.51	11.06	102
11-Apr	0	0	0	0	0.00	0.00	0.00	*	100	7,837	678	0.0	1,273	*	31.72	11.95	108
12-Apr	0	0	0	0	0.00	0.00	0.00	*	99	7,661	202	0.0	1,278	*	31.71	11.99	106
13-Apr	0	0	0	0	0.00	0.00	0.00	*	112	6,111	161	0.0	1,025	*	25.43	9.62	85
14-Apr	0	0	0	0	0.00	0.00	0.00	*	88	6,387	230	0.0	1,062	*	26.36	9.96	89
15-Apr	0	0	0	0	0.00	0.00	0.00	*	75	6,504	161	0.0	1,085	*	26.90	10.17	90
16-Apr	0	0	0	0	0.00	0.00	0.00	*	109	7,629	226	0.0	1,273	*	31.58	11.94	106
17-Apr	0	0	0	0	0.00	0.00	0.00	*	140	7,662	1,268	0.0	1,207	*	30.27	11.34	105
18-Apr	0	0	0	0	0.00	0.00	0.00	*	106	7,946	610	0.0	1,297	*	32.29	12.17	110

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R M I L L U T I L I T Y R E P O R T

	6A Boiler							*	9A Boiler					*			
DATE	S/B MLbs	Steam MLbs	Gas Mcf	Oil Bbls				*	S/B MLbs	Steam MLbs	Gas Mcf	Rubber Tons	Bark Tons	*			
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA	Calculated lbs/hr						6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOX EF			2.80E-01	NA	PM	SO2	Nox				9.91E-02	1.98E+00	1.98E+00		PM	SO2	Nox
19-Apr	0	0	0	0	0.00	0.00	0.00	*	138	7,771	274	0.0	1,298	*	32.21	12.18	108
20-Apr	0	0	0	0	0.00	0.00	0.00	*	128	7,146	247	0.0	1,194	*	29.63	11.20	100
21-Apr	0	0	0	0	0.00	0.00	0.00	*	141	7,336	280	0.0	1,226	*	30.42	11.50	102
22-Apr	0	0	0	0	0.00	0.00	0.00	*	111	6,538	354	0.0	1,082	*	26.89	10.15	91
23-Apr	0	0	0	0	0.00	0.00	0.00	*	155	6,991	127	0.0	1,182	*	29.29	11.08	98
24-Apr	0	0	0	0	0.00	0.00	0.00	*	154	7,153	200	0.0	1,203	*	29.84	11.28	100
25-Apr	0	0	0	0	0.00	0.00	0.00	*	197	6,184	221	0.0	1,047	*	25.99	9.82	87
26-Apr	0	0	0	0	0.00	0.00	0.00	*	205	7,497	280	0.0	1,263	*	31.35	11.85	105
27-Apr	0	0	0	0	0.00	0.00	0.00	*	147	6,742	155	0.0	1,137	*	28.18	10.66	94
28-Apr	0	0	0	0	0.00	0.00	0.00	*	129	7,050	182	0.0	1,183	*	29.34	11.10	98
29-Apr	0	0	0	0	0.00	0.00	0.00	*	153	8,138	305	0.0	1,359	*	33.74	12.75	113
30-Apr	0	0	0	0	0.00	0.00	0.00	*	124	7,191	560	0.0	1,178	*	29.33	11.06	99
01-May	0	0	0	0	0.00	0.00	0.00	*	153	7,065	372	0.0	1,176	*	29.21	11.03	99
02-May	0	0	0	0	0.00	0.00	0.00	*	203	7,797	1,344	0.0	1,234	*	30.97	11.60	107
03-May	0	0	0	0	0.00	0.00	0.00	*	215	7,175	759	0.0	1,176	*	29.34	11.04	100
04-May	0	0	0	0	0.00	0.00	0.00	*	186	7,954	974	0.0	1,285	*	32.11	12.07	110
05-May	0	0	0	0	0.00	0.00	0.00	*	126	6,236	400	0.0	1,031	*	25.64	9.67	87
06-May	0	0	0	0	0.00	0.00	0.00	*	127	7,184	404	0.0	1,189	*	29.55	11.15	100
07-May	0	0	0	0	0.00	0.00	0.00	*	77	7,935	667	0.0	1,286	*	32.04	12.07	109
08-May	0	1,356	1,604	0	0.51	0.04	18.71	*	114	8,973	1,406	0.0	1,411	*	35.36	13.26	122
09-May	0	2,013	2,466	0	0.78	0.06	28.77	*	46	6,464	324	0.0	1,061	*	26.36	9.96	89
10-May	0	4,425	4,876	0	1.54	0.12	56.89	*	139	10,389	3,640	0.0	1,486	*	37.93	14.02	138
11-May	0	3,943	4,297	0	1.36	0.11	50.13	*	127	9,032	1,809	0.0	1,393	*	35.05	13.10	122
12-May	0	1,666	2,006	0	0.64	0.05	23.40	*	154	7,242	965	0.0	1,161	*	29.05	10.91	100
13-May	0	2,467	3,268	0	1.03	0.08	38.13	*	170	8,213	1,823	0.0	1,263	*	31.83	11.88	112
14-May	0	1,593	2,348	0	0.74	0.06	27.39	*	149	8,332	1,986	0.0	1,267	*	31.99	11.93	113
15-May	0	2,231	2,821	0	0.89	0.07	32.91	*	139	7,957	1,234	0.0	1,258	*	31.53	11.83	109
16-May	0	2,875	3,342	0	1.06	0.08	38.99	*	127	10,632	3,360	0.0	1,545	*	39.31	14.57	141
17-May	0	3,283	3,631	0	1.15	0.09	42.36	*	166	10,884	4,340	0.0	1,521	*	39.03	14.37	143
18-May	0	0	0	0	0.00	0.00	0.00	*	235	5,926	112	0.0	1,019	*	25.25	9.55	84
19-May	0	0	6	0	0.00	0.00	0.07	*	183	7,077	1,078	0.0	1,130	*	28.32	10.62	98
20-May	0	0	0	0	0.00	0.00	0.00	*	120	6,673	259	0.0	1,113	*	27.63	10.44	93
21-May	0	4,028	4,524	0	1.43	0.11	52.78	*	49	11,925	5,147	0.0	1,616	*	41.62	15.28	155
22-May	0	3,651	3,977	0	1.26	0.10	46.40	*	129	10,708	3,309	0.0	1,562	*	39.71	14.73	143
23-May	0	3,328	3,582	0	1.13	0.09	41.79	*	63	4,975	1,728	0.0	1,562	*	39.21	14.69	136
24-May	0	1,273	1,395	0	0.44	0.03	16.28	*	71	3,664	534	0.0	583	*	14.60	5.48	50
25-May	0	0	0	0	0.00	0.00	0.00	*	131	6,103	178	0.0	1,026	*	25.45	9.62	85

2002

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

PAPER MILL UTILITY REPORT

	6A Boiler								9A Boiler								
DATE	S/B MLbs	Steam MLbs	Gas Mcf	Oil Bbls				*	S/B MLbs	Steam MLbs	Gas Mcf	Rubber Tons	Bark Tons	*			
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA	Calculated lbs/hr						6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOX EF			2.80E-01	NA	PM	SO2	Nox				9.91E-02	1.98E+00	1.98E+00		PM	SO2	Nox
26-May	0	0	0	0	0.00	0.00	0.00	*	153	5,522	570	0.0	904	*	22.55	8.49	77
27-May	0	0	0	0	0.00	0.00	0.00	*	130	5,314	163	0.0	895	*	22.21	8.40	75
28-May	0	0	7	0	0.00	0.00	0.08	*	151	4,501	623	0.0	729	*	18.25	6.85	63
29-May	0	969	1,088	0	0.34	0.03	12.69	*	164	5,870	370	0.0	978	*	24.33	9.18	82
30-May	0	3,925	4,205	0	1.33	0.11	49.06	*	134	8,207	1,852	0.0	1,253	*	31.61	11.80	111
31-May	0	4,450	4,803	0	1.52	0.12	56.04	*	126	11,466	6,643	0.0	1,442	*	37.79	13.68	146
01-Jun	0	3,677	4,009	0	1.27	0.10	46.77	*	132	9,923	4,592	0.0	1,337	*	34.54	12.65	129
02-Jun	0	85	462	0	0.15	0.01	5.39	*	117	4,909	443	0.0	805	*	20.06	7.56	68
03-Jun	0	3,110	3,392	0	1.07	0.08	39.57	*	131	8,884	2,285	0.0	1,334	*	33.74	12.56	119
04-Jun	0	676	769	0	0.24	0.02	8.97	*	122	6,919	222	0.0	1,157	*	28.71	10.85	96
05-Jun	0	0	0	0	0.00	0.00	0.00	*	140	6,579	292	0.0	1,098	*	27.27	10.30	92
06-Jun	0	0	0	0	0.00	0.00	0.00	*	131	7,552	469	0.0	1,246	*	30.98	11.69	105
07-Jun	0	1,232	1,414	0	0.45	0.04	16.50	*	128	8,658	537	0.0	1,425	*	35.43	13.37	120
08-Jun	0	0	0	0	0.00	0.00	0.00	*	141	7,712	726	0.0	1,277	*	31.85	11.99	108
09-Jun	0	0	0	0	0.00	0.00	0.00	*	171	6,569	348	0.0	1,098	*	27.28	10.30	92
10-Jun	0	0	0	0	0.00	0.00	0.00	*	157	6,133	648	0.0	1,001	*	24.97	9.40	85
11-Jun	0	0	0	0	0.00	0.00	0.00	*	105	6,876	2,102	0.0	1,008	*	25.62	9.51	92
12-Jun	0	0	0	0	0.00	0.00	0.00	*	111	5,371	188	0.0	900	*	22.33	8.44	75
13-Jun	0	0	0	0	0.00	0.00	0.00	*	125	7,040	161	0.0	1,182	*	29.31	11.09	98
14-Jun	0	1,650	1,805	0	0.57	0.05	21.06	*	129	9,298	408	0.0	1,541	*	38.27	14.46	129
15-Jun	0	3,633	3,902	0	1.24	0.10	45.52	*	128	8,601	1,945	0.0	1,311	*	33.07	12.34	116
16-Jun	0	0	0	0	0.00	0.00	0.00	*	152	7,309	159	0.0	1,232	*	30.54	11.55	102
17-Jun	0	1,195	1,394	0	0.44	0.03	16.26	*	64	7,308	3,148	0.0	996	*	25.66	9.42	95
18-Jun	0	153	159	0	0.05	0.00	1.86	*	148	5,666	574	0.0	927	*	23.12	8.70	79
19-Jun	0	0	0	0	0.00	0.00	0.00	*	140	6,284	151	0.0	1,060	*	26.27	9.94	88
20-Jun	0	0	0	0	0.00	0.00	0.00	*	145	5,412	167	0.0	914	*	22.67	8.57	76
21-Jun	0	0	0	0	0.00	0.00	0.00	*	125	6,206	370	0.0	1,028	*	25.56	9.65	86
22-Jun	0	0	0	0	0.00	0.00	0.00	*	125	7,657	175	0.0	1,284	*	31.84	12.04	107
23-Jun	0	0	0	0	0.00	0.00	0.00	*	140	5,826	192	0.0	980	*	24.32	9.19	82
24-Jun	0	0	0	0	0.00	0.00	0.00	*	128	6,315	154	0.0	1,062	*	26.34	9.96	88
25-Jun	0	0	0	0	0.00	0.00	0.00	*	154	5,687	189	0.0	960	*	23.81	9.00	80
26-Jun	0	0	0	0	0.00	0.00	0.00	*	155	5,214	186	0.0	881	*	21.87	8.27	73
27-Jun	0	0	0	0	0.00	0.00	0.00	*	201	5,214	158	0.0	891	*	22.10	8.36	74
28-Jun	0	0	0	0	0.00	0.00	0.00	*	157	5,235	1,708	0.0	773	*	19.66	7.29	71
29-Jun	0	0	0	0	0.00	0.00	0.00	*	138	5,977	1,525	0.0	907	*	22.92	8.54	81
30-Jun	0	0	0	0	0.00	0.00	0.00	*	141	6,526	1,819	0.0	977	*	24.75	9.20	88
01-Jul	0	0	0	0	0.00	0.00	0.00	*	123	6,962	2,177	0.0	1,020	*	25.94	9.62	93

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R M I L L U T I L I T Y R E P O R T

	6A Boiler								9A Boiler								
DATE	S/B MLbs	Steam MLbs	Gas Mcf	Oil Bbls				*	S/B MLbs	Steam MLbs	Gas Mcf	Rubber Tons	Bark Tons	*			
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA	Calculated lbs/hr						6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOX EF			2.80E-01	NA	PM	SO2	Nox				9.91E-02	1.98E+00	1.98E+00		PM	SO2	Nox
02-Jul	0	0	42	0	0.01	0.00	0.49	*	140	6,345	1,817	0.0	947	*	24.01	8.92	86
03-Jul	0	0	0	0	0.00	0.00	0.00	*	127	7,802	2,055	0.0	1,170	*	29.60	11.02	105
04-Jul	0	0	0	0	0.00	0.00	0.00	*	198	6,327	1,487	0.0	978	*	24.67	9.20	87
05-Jul	0	0	0	0	0.00	0.00	0.00	*	159	6,589	2,088	0.0	971	*	24.68	9.15	89
06-Jul	0	0	0	0	0.00	0.00	0.00	*	121	7,242	2,314	0.0	1,056	*	26.88	9.96	97
07-Jul	0	0	0	0	0.00	0.00	0.00	*	151	7,119	1,982	0.0	1,065	*	27.00	10.04	96
08-Jul	0	0	0	0	0.00	0.00	0.00	*	135	5,308	686	0.0	857	*	21.42	8.05	73
09-Jul	0	0	0	0	0.00	0.00	0.00	*	81	5,806	1,327	0.0	883	*	22.28	8.31	78
10-Jul	0	0	0	0	0.00	0.00	0.00	*	164	5,379	402	0.0	894	*	22.26	8.39	75
11-Jul	0	0	0	0	0.00	0.00	0.00	*	156	5,579	1,250	0.0	864	*	21.77	8.13	76
12-Jul	0	0	0	0	0.00	0.00	0.00	*	157	5,532	1,288	0.0	853	*	21.52	8.03	76
13-Jul	0	0	0	0	0.00	0.00	0.00	*	157	4,845	570	0.0	792	*	19.77	7.44	68
14-Jul	0	0	0	0	0.00	0.00	0.00	*	127	5,228	657	0.0	844	*	21.10	7.93	72
15-Jul	0	0	0	0	0.00	0.00	0.00	*	141	5,993	1,398	0.0	919	*	23.19	8.65	82
16-Jul	0	0	0	0	0.00	0.00	0.00	*	112	5,080	771	0.0	808	*	20.25	7.60	70
17-Jul	0	0	0	0	0.00	0.00	0.00	*	114	7,224	2,318	0.0	1,052	*	26.77	9.92	96
18-Jul	0	0	0	0	0.00	0.00	0.00	*	141	4,970	371	0.0	824	*	20.52	7.74	70
19-Jul	0	1,793	1,921	0	0.61	0.05	22.41	*	42	1,655	273	0.0	263	*	6.59	2.47	23
20-Jul	0	2,273	2,401	0	0.76	0.06	28.01	*	0	0	0	0.0	0	*	0.00	0.00	0
21-Jul	0	1,978	2,191	0	0.69	0.05	25.56	*	27	1,052	1,332	0.0	82	*	2.44	0.80	12
22-Jul	0	0	0	0	0.00	0.00	0.00	*	149	5,513	751	0.0	888	*	22.22	8.35	76
23-Jul	0	0	0	0	0.00	0.00	0.00	*	112	5,464	1,108	0.0	848	*	21.33	7.97	75
24-Jul	0	0	0	0	0.00	0.00	0.00	*	117	5,257	806	0.0	836	*	20.95	7.86	72
25-Jul	0	0	0	0	0.00	0.00	0.00	*	139	4,845	307	0.0	808	*	20.10	7.58	68
26-Jul	0	0	0	0	0.00	0.00	0.00	*	123	5,258	509	0.0	859	*	21.43	8.07	73
27-Jul	0	0	0	0	0.00	0.00	0.00	*	123	5,169	1,290	0.0	787	*	19.88	7.41	70
28-Jul	0	0	0	0	0.00	0.00	0.00	*	173	5,258	1,283	0.0	810	*	20.47	7.63	72
29-Jul	0	0	0	0	0.00	0.00	0.00	*	134	5,081	661	0.0	820	*	20.51	7.71	70
30-Jul	0	0	98	0	0.03	0.00	1.14	*	139	5,152	220	0.0	866	*	21.49	8.12	72
31-Jul	0	3,368	3,281	0	1.04	0.08	38.28	*	124	8,825	1,562	0.0	1,376	*	34.55	12.94	120
01-Aug	0	3,991	3,281	0	1.04	0.08	38.28	*	124	8,824	1,562	0.0	1,376	*	34.55	12.94	120
02-Aug	0	4,579	4,609	0	1.46	0.12	53.77	*	77	5,458	4,770	0.0	570	*	15.63	5.47	67
03-Aug	0	4,476	4,539	0	1.44	0.11	52.96	*	143	8,526	3,883	0.0	1,158	*	29.90	10.96	112
04-Aug	0	374	837	0	0.27	0.02	9.77	*	182	4,496	1,225	0.0	689	*	17.45	6.49	62
05-Aug	0	0	243	0	0.08	0.01	2.84	*	125	4,496	4,030	0.0	473	*	12.98	4.53	56
06-Aug	0	0	0	0	0.00	0.00	0.00	*	101	6,262	993	0.0	987	*	24.75	9.28	86
07-Aug	0	0	0	0	0.00	0.00	0.00	*	119	5,351	543	0.0	872	*	21.74	8.18	74

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R M I L L U T I L I T Y R E P O R T

DATE	6A Boiler S/B MLbs	6A Boiler Steam MLbs	6A Boiler Gas Mcf	6A Boiler Oil Bbls	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox	*	9A Boiler S/B MLbs	9A Boiler Steam MLbs	9A Boiler Gas Mcf	9A Boiler Rubber Tons	9A Boiler Bark Tons	*	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA							6.00E-04	3.08E+01	2.25E-01				
NOX EF			2.80E-01	NA							9.91E-02	1.98E+00	1.98E+00				
08-Aug	0	0	0	0	0.00	0.00	0.00	*	72	7,308	2,851	0.0	1,020	*	26.14	9.63	96
09-Aug	0	0	0	0	0.00	0.00	0.00	*	131	6,363	734	0.0	1,028	*	25.68	9.66	88
10-Aug	0	0	0	0	0.00	0.00	0.00	*	124	6,424	387	0.0	1,063	*	26.43	9.97	89
11-Aug	0	0	0	0	0.00	0.00	0.00	*	126	6,318	345	0.0	1,049	*	26.06	9.84	88
12-Aug	0	0	0	0	0.00	0.00	0.00	*	132	6,290	278	0.0	1,050	*	26.07	9.85	88
13-Aug	0	0	0	0	0.00	0.00	0.00	*	156	5,870	733	0.0	950	*	23.75	8.93	81
14-Aug	0	0	106	0	0.03	0.00	1.24	*	82	2,967	568	0.0	466	*	11.72	4.39	41
15-Aug	0	0	245	0	0.08	0.01	2.86	*	109	6,601	623	0.0	1,072	*	26.74	10.07	91
16-Aug	0	0	25	0	0.01	0.00	0.29	*	125	6,673	602	0.0	1,089	*	27.13	10.22	92
17-Aug	0	0	0	0	0.00	0.00	0.00	*	123	6,842	329	0.0	1,137	*	28.23	10.66	95
18-Aug	0	0	0	0	0.00	0.00	0.00	*	123	5,885	503	0.0	964	*	24.02	9.05	82
19-Aug	0	0	0	0	0.00	0.00	0.00	*	140	5,667	585	0.0	925	*	23.07	8.68	79
20-Aug	0	0	0	0	0.00	0.00	0.00	*	137	6,250	820	0.0	1,004	*	25.11	9.43	86
21-Aug	0	0	0	0	0.00	0.00	0.00	*	123	6,628	443	0.0	1,092	*	27.18	10.25	92
22-Aug	0	0	0	0	0.00	0.00	0.00	*	154	5,873	642	0.0	957	*	23.89	8.99	82
23-Aug	0	0	0	0	0.00	0.00	0.00	*	122	5,956	414	0.0	982	*	24.45	9.22	83
24-Aug	0	0	0	0	0.00	0.00	0.00	*	152	6,697	649	0.0	1,094	*	27.27	10.27	93
25-Aug	0	0	0	0	0.00	0.00	0.00	*	127	6,840	857	0.0	1,098	*	27.44	10.31	94
26-Aug	0	0	0	0	0.00	0.00	0.00	*	127	6,700	783	0.0	1,080	*	26.98	10.15	92
27-Aug	0	0	0	0	0.00	0.00	0.00	*	128	6,157	766	0.0	991	*	24.77	9.31	85
28-Aug	0	0	0	0	0.00	0.00	0.00	*	129	6,329	388	0.0	1,048	*	26.05	9.83	88
29-Aug	0	0	0	0	0.00	0.00	0.00	*	142	5,977	586	0.0	977	*	24.36	9.17	83
30-Aug	0	0	0	0	0.00	0.00	0.00	*	130	6,699	824	0.0	1,077	*	26.93	10.12	92
31-Aug	0	0	0	0	0.00	0.00	0.00	*	135	7,433	1,296	0.0	1,166	*	29.26	10.96	102
01-Sep	0	0	0	0	0.00	0.00	0.00	*	110	6,000	550	0.0	978	*	24.37	9.18	83
02-Sep	0	0	0	0	0.00	0.00	0.00	*	106	7,378	941	0.0	1,178	*	29.45	11.07	101
03-Sep	0	0	0	0	0.00	0.00	0.00	*	102	8,589	1,577	0.0	1,114	*	28.08	10.49	98
04-Sep	0	0	0	0	0.00	0.00	0.00	*	64	7,171	6,112	0.0	745	*	20.37	7.13	87
05-Sep	0	0	0	0	0.00	0.00	0.00	*	299	5,987	381	0.0	1,020	*	25.35	9.57	86
06-Sep	0	0	0	0	0.00	0.00	0.00	*	103	6,563	358	0.0	1,085	*	26.96	10.18	91
07-Sep	0	0	0	0	0.00	0.00	0.00	*	97	7,259	400	0.0	1,196	*	29.74	11.23	100
08-Sep	0	0	0	0	0.00	0.00	0.00	*	97	7,389	603	0.0	1,203	*	29.97	11.29	102
09-Sep	0	254	405	0	0.13	0.01	4.73	*	39	7,083	621	0.0	1,141	*	28.44	10.71	97
10-Sep	0	2,023	2,043	0	0.65	0.05	23.84	*	87	7,083	1,148	0.0	1,110	*	27.84	10.44	96
11-Sep	0	0	0	0	0.00	0.00	0.00	*	117	3,146	1,717	0.0	417	*	10.87	3.95	42
12-Sep	0	0	0	0	0.00	0.00	0.00	*	108	6,255	617	0.0	1,015	*	25.32	9.53	86
13-Sep	0	0	0	0	0.00	0.00	0.00	*	119	5,550	407	0.0	915	*	22.77	8.59	77

2002

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

PAPER MILL UTILITY REPORT

DATE	6A Boiler S/B MLbs	6A Steam MLbs	6A Gas Mcf	6A Oil Bbls	6A Calculated lbs/hr PM	6A SO2	6A Nox	*	9A Boiler S/B MLbs	9A Steam MLbs	9A Gas Mcf	9A Rubber Tons	9A Bark Tons	*	9A Calculated lbs/hr PM	9A SO2	9A Nox
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA							6.00E-04	3.08E+01	2.25E-01				
NOX EF			2.80E-01	NA							9.91E-02	1.98E+00	1.98E+00				
14-Sep	0	0	0	0	0.00	0.00	0.00	*	103	6,035	420	0.0	992	*	24.69	9.31	84
15-Sep	0	0	0	0	0.00	0.00	0.00	*	121	5,548	672	0.0	895	*	22.37	8.41	77
16-Sep	0	0	0	0	0.00	0.00	0.00	*	115	5,069	871	0.0	800	*	20.07	7.52	70
17-Sep	0	0	0	0	0.00	0.00	0.00	*	106	6,242	384	0.0	1,030	*	25.61	9.66	87
18-Sep	0	0	0	0	0.00	0.00	0.00	*	102	6,124	549	0.0	997	*	24.85	9.36	85
19-Sep	0	0	176	0	0.06	0.00	2.05	*	118	6,613	644	0.0	1,074	*	26.79	10.09	91
20-Sep	0	1,787	1,805	0	0.57	0.05	21.06	*	52	6,187	1,125	0.0	957	*	24.04	9.00	84
21-Sep	0	3,565	3,133	0	0.99	0.08	36.55	*	0	0	291	0.0	0	*	0.09	0.01	1
22-Sep	0	2,875	2,446	0	0.77	0.06	28.54	*	26	923	606	0.0	113	*	3.00	1.08	12
23-Sep	0	0	0	0	0.00	0.00	0.00	*	151	6,475	571	0.0	1,062	*	26.47	9.97	90
24-Sep	0	0	0	0	0.00	0.00	0.00	*	119	6,463	344	0.0	1,072	*	26.63	10.05	90
25-Sep	0	0	0	0	0.00	0.00	0.00	*	128	7,000	1,154	0.0	1,103	*	27.66	10.37	96
26-Sep	0	0	0	0	0.00	0.00	0.00	*	135	7,755	1,304	0.0	1,219	*	30.58	11.46	106
27-Sep	0	0	0	0	0.00	0.00	0.00	*	121	6,471	788	0.0	1,041	*	26.00	9.77	89
28-Sep	0	0	0	0	0.00	0.00	0.00	*	112	6,335	902	0.0	1,008	*	25.23	9.47	87
29-Sep	0	0	0	0	0.00	0.00	0.00	*	109	5,440	550	0.0	884	*	22.06	8.30	75
30-Sep	0	0	0	0	0.00	0.00	0.00	*	117	6,311	440	0.0	1,039	*	25.85	9.75	88
01-Oct	0	0	0	0	0.00	0.00	0.00	*	105	6,173	633	0.0	1,000	*	24.94	9.39	85
02-Oct	0	2,445	2,102	0	0.67	0.05	24.52	*	51	2,209	565	0.0	335	*	8.47	3.15	30
03-Oct	0	2,411	1,848	0	0.59	0.05	21.56	*	57	2,540	704	0.0	381	*	9.65	3.59	34
04-Oct	0	0	0	0	0.00	0.00	0.00	*	119	4,954	631	0.0	799	*	19.97	7.51	69
05-Oct	0	0	0	0	0.00	0.00	0.00	*	115	4,959	708	0.0	793	*	19.86	7.46	68
06-Oct	0	0	0	0	0.00	0.00	0.00	*	143	4,907	566	0.0	800	*	19.98	7.51	68
07-Oct	0	0	0	0	0.00	0.00	0.00	*	141	4,734	749	0.0	757	*	18.98	7.12	66
08-Oct	0	0	0	0	0.00	0.00	0.00	*	256	4,502	393	0.0	764	*	19.03	7.17	65
09-Oct	0	0	0	0	0.00	0.00	0.00	*	55	5,539	392	0.0	903	*	22.48	8.48	76
10-Oct	0	0	0	0	0.00	0.00	0.00	*	89	7,610	1,504	0.0	1,172	*	29.49	11.03	103
11-Oct	0	0	0	0	0.00	0.00	0.00	*	63	6,001	1,085	0.0	931	*	23.38	8.75	81
12-Oct	0	0	0	0	0.00	0.00	0.00	*	51	5,389	396	0.0	877	*	21.84	8.24	74
13-Oct	0	0	0	0	0.00	0.00	0.00	*	162	5,101	363	0.0	850	*	21.16	7.98	72
14-Oct	0	0	0	0	0.00	0.00	0.00	*	159	5,765	651	0.0	939	*	23.45	8.82	80
15-Oct	0	0	0	0	0.00	0.00	0.00	*	131	6,806	1,243	0.0	1,064	*	26.74	10.01	93
16-Oct	0	0	0	0	0.00	0.00	0.00	*	57	1,328	2,552	0.0	42	*	1.86	0.46	14
17-Oct	0	0	0	0	0.00	0.00	0.00	*	64	6,148	708	0.0	1,337	*	33.31	12.55	113
18-Oct	0	0	0	0	0.00	0.00	0.00	*	51	5,726	586	0.0	920	*	22.95	8.64	78
19-Oct	0	0	0	0	0.00	0.00	0.00	*	60	5,945	971	0.0	929	*	23.30	8.74	81
20-Oct	0	0	0	0	0.00	0.00	0.00	*	123	6,536	507	0.0	1,072	*	26.70	10.07	91

2002

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R M I L L U T I L I T Y R E P O R T

DATE	6A Boiler S/B MLbs	6A Boiler Steam MLbs	6A Boiler Gas Mcf	6A Boiler Oil Bbls	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox	*	9A Boiler S/B MLbs	9A Boiler Steam MLbs	9A Boiler Gas Mcf	9A Boiler Rubber Tons	9A Boiler Bark Tons	*	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA							6.00E-04	3.08E+01	2.25E-01				
NOX EF			2.80E-01	NA							9.91E-02	1.98E+00	1.98E+00				
21-Oct	0	0	0	0	0.00	0.00	0.00	*	63	7,351	1,229	0.0	1,145	*	28.73	10.76	100
22-Oct	0	0	0	0	0.00	0.00	0.00	*	40	7,412	1,246	0.0	1,150	*	28.86	10.81	100
23-Oct	0	0	0	0	0.00	0.00	0.00	*	182	6,522	910	0.0	1,050	*	26.28	9.87	90
24-Oct	0	0	0	0	0.00	0.00	0.00	*	158	6,631	1,707	0.0	1,006	*	25.43	9.47	90
25-Oct	0	0	0	0	0.00	0.00	0.00	*	154	8,041	1,085	0.0	1,286	*	32.17	12.08	111
26-Oct	0	0	0	0	0.00	0.00	0.00	*	94	6,929	589	0.0	1,127	*	28.08	10.58	95
27-Oct	0	0	0	0	0.00	0.00	0.00	*	78	6,381	422	0.0	1,045	*	26.01	9.81	88
28-Oct	0	0	0	0	0.00	0.00	0.00	*	70	6,553	529	0.0	1,065	*	26.52	10.00	90
29-Oct	0	2,016	2,168	0	0.69	0.05	25.29	*	78	8,537	2,784	0.0	1,230	*	31.33	11.60	113
30-Oct	0	0	0	0	0.00	0.00	0.00	*	90	8,049	1,507	0.0	1,245	*	31.30	11.71	109
31-Oct	0	0	0	0	0.00	0.00	0.00	*	75	9,038	1,212	0.0	1,429	*	35.76	13.43	123
01-Nov	0	0	0	0	0.00	0.00	0.00	*	80	8,787	2,102	0.0	1,323	*	33.40	12.45	118
02-Nov	0	0	0	0	0.00	0.00	0.00	*	78	8,424	1,438	0.0	1,311	*	32.90	12.33	114
03-Nov	0	0	0	0	0.00	0.00	0.00	*	80	7,851	762	0.0	1,266	*	31.56	11.88	108
04-Nov	0	0	299	0	0.09	0.01	3.49	*	64	8,373	1,484	0.0	1,297	*	32.56	12.19	113
05-Nov	0	517	869	0	0.28	0.02	10.14	*	100	7,342	1,004	0.0	1,166	*	29.18	10.96	100
06-Nov	0	4,862	5,058	0	1.60	0.13	59.01	*	78	9,488	4,505	0.0	1,262	*	32.66	11.94	123
07-Nov	0	634	672	0	0.21	0.02	7.84	*	79	7,944	2,704	0.0	1,138	*	29.01	10.73	105
08-Nov	0	0	0	0	0.00	0.00	0.00	*	77	7,692	1,036	0.0	1,218	*	30.48	11.45	105
09-Nov	0	0	0	0	0.00	0.00	0.00	*	77	6,366	547	0.0	1,033	*	25.75	9.70	88
10-Nov	0	0	0	0	0.00	0.00	0.00	*	76	7,349	555	0.0	1,197	*	29.79	11.23	101
11-Nov	0	0	0	0	0.00	0.00	0.00	*	72	7,545	1,789	0.0	1,137	*	28.72	10.71	101
12-Nov	0	694	922	0	0.29	0.02	10.76	*	73	8,532	1,651	0.0	1,312	*	33.00	12.34	115
13-Nov	0	1,500	1,611	0	0.51	0.04	18.80	*	79	7,054	1,057	0.0	1,111	*	27.83	10.44	96
14-Nov	0	591	934	0	0.30	0.02	10.90	*	83	5,141	2,828	0.0	662	*	17.28	6.28	66
15-Nov	0	0	0	0	0.00	0.00	0.00	*	96	7,284	1,344	0.0	1,131	*	28.41	10.63	99
16-Nov	0	0	0	0	0.00	0.00	0.00	*	77	8,809	1,837	0.0	1,345	*	33.88	12.66	119
17-Nov	0	0	0	0	0.00	0.00	0.00	*	75	8,624	1,371	0.0	1,349	*	33.81	12.68	117
18-Nov	0	0	0	0	0.00	0.00	0.00	*	75	8,355	1,371	0.0	1,304	*	32.70	12.26	113
19-Nov	0	0	0	0	0.00	0.00	0.00	*	75	8,327	1,371	0.0	1,299	*	32.59	12.21	113
20-Nov	0	0	0	0	0.00	0.00	0.00	*	187	7,514	688	0.0	1,233	*	30.73	11.57	105
21-Nov	0	0	0	0	0.00	0.00	0.00	*	79	7,199	2,219	0.0	1,049	*	26.67	9.89	96
22-Nov	0	0	0	0	0.00	0.00	0.00	*	79	8,490	3,331	0.0	1,182	*	30.32	11.17	111
23-Nov	0	0	0	0	0.00	0.00	0.00	*	66	9,867	3,989	0.0	1,361	*	34.95	12.86	129
24-Nov	0	0	0	0	0.00	0.00	0.00	*	77	8,312	2,045	0.0	1,247	*	31.52	11.74	111
25-Nov	0	0	0	0	0.00	0.00	0.00	*	81	8,384	2,316	0.0	1,240	*	31.42	11.68	112
26-Nov	0	40	130	0	0.04	0.00	1.52	*	81	8,461	3,724	0.0	1,149	*	29.61	10.86	110

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R M I L L U T I L I T Y R E P O R T

DATE	6A Boiler S/B MLbs	6A Boiler Steam MLbs	6A Boiler Gas Mcf	6A Boiler Oil Bbls	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox	*	9A Boiler S/B MLbs	9A Boiler Steam MLbs	9A Boiler Gas Mcf	9A Boiler Rubber Tons	9A Boiler Bark Tons	*	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA							6.00E-04	3.08E+01	2.25E-01				
NOX EF			2.80E-01	NA							9.91E-02	1.98E+00	1.98E+00				
27-Nov	0	478	473	0	0.15	0.01	5.52	*	71	8,267	2,628	0.0	1,196	*	30.43	11.28	110
28-Nov	0	0	0	0	0.00	0.00	0.00	*	80	8,587	3,763	0.0	1,167	*	30.07	11.03	112
29-Nov	0	0	0	0	0.00	0.00	0.00	*	79	7,971	3,274	0.0	1,100	*	28.26	10.39	104
30-Nov	0	0	0	0	0.00	0.00	0.00	*	80	7,787	1,915	0.0	1,170	*	29.56	11.02	104
01-Dec	0	0	0	0	0.00	0.00	0.00	*	82	7,631	1,535	0.0	1,172	*	29.50	11.03	103
02-Dec	0	0	0	0	0.00	0.00	0.00	*	94	8,104	1,728	0.0	1,239	*	31.21	11.66	109
03-Dec	0	371	479	0	0.15	0.01	5.59	*	83	8,603	3,085	0.0	1,220	*	31.17	11.51	113
04-Dec	0	3,084	3,133	0	0.99	0.08	36.55	*	127	7,746	2,712	0.0	1,112	*	28.38	10.49	103
05-Dec	0	3,322	3,353	0	1.06	0.08	39.12	*	131	7,264	2,124	0.0	1,076	*	27.30	10.14	98
06-Dec	0	0	0	0	0.00	0.00	0.00	*	81	6,993	1,553	0.0	1,064	*	26.84	10.02	94
07-Dec	0	0	0	0	0.00	0.00	0.00	*	79	6,474	1,680	0.0	968	*	24.49	9.12	87
08-Dec	0	0	0	0	0.00	0.00	0.00	*	109	7,818	2,255	0.0	1,155	*	29.29	10.88	105
09-Dec	0	0	0	0	0.00	0.00	0.00	*	82	7,471	1,600	0.0	1,141	*	28.74	10.73	101
10-Dec	0	0	0	0	0.00	0.00	0.00	*	82	7,587	1,203	0.0	1,189	*	29.82	11.18	103
11-Dec	0	1,328	1,528	0	0.48	0.04	17.83	*	24	3,914	912	0.0	589	*	14.87	5.54	52
12-Dec	0	3,656	3,704	0	1.17	0.09	43.21	*	53	2,396	1,346	0.0	309	*	8.07	2.93	31
13-Dec	0	0	0	0	0.00	0.00	0.00	*	82	7,348	2,659	0.0	1,042	*	26.63	9.84	97
14-Dec	0	0	0	0	0.00	0.00	0.00	*	68	8,571	2,640	0.0	1,245	*	31.65	11.74	114
15-Dec	0	0	0	0	0.00	0.00	0.00	*	75	8,216	1,895	0.0	1,242	*	31.34	11.69	110
16-Dec	0	0	0	0	0.00	0.00	0.00	*	78	8,040	1,603	0.0	1,235	*	31.07	11.62	108
17-Dec	0	0	500	0	0.16	0.01	5.83	*	79	8,744	2,441	0.0	1,290	*	32.71	12.16	117
18-Dec	0	3,344	3,329	0	1.05	0.08	38.84	*	79	8,011	1,456	0.0	1,241	*	31.17	11.67	108
19-Dec	0	0	395	0	0.13	0.01	4.61	*	80	8,156	1,781	0.0	1,241	*	31.28	11.68	110
20-Dec	0	0	0	0	0.00	0.00	0.00	*	80	7,416	1,053	0.0	1,172	*	29.33	11.01	101
21-Dec	0	0	0	0	0.00	0.00	0.00	*	106	7,663	1,742	0.0	1,166	*	29.42	10.98	103
22-Dec	0	0	0	0	0.00	0.00	0.00	*	83	6,692	856	0.0	1,116	*	27.89	10.48	96
23-Dec	0	0	0	0	0.00	0.00	0.00	*	102	7,987	2,280	0.0	1,180	*	29.92	11.12	107
24-Dec	0	0	0	0	0.00	0.00	0.00	*	121	9,191	4,378	0.0	1,229	*	31.80	11.63	119
25-Dec	0	0	0	0	0.00	0.00	0.00	*	100	8,830	3,615	0.0	1,222	*	31.38	11.54	116
26-Dec	0	0	0	0	0.00	0.00	0.00	*	75	8,941	2,127	0.0	1,346	*	33.98	12.67	120
27-Dec	0	0	0	0	0.00	0.00	0.00	*	95	8,657	2,017	0.0	1,310	*	33.06	12.33	116
28-Dec	0	0	0	0	0.00	0.00	0.00	*	142	8,595	1,431	0.0	1,351	*	33.88	12.70	117
			5685		1.80	0	66								42	16	155

2003

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

PAPER MILL UTILITY REPORT

DATE	6A Boiler S/B MLbs	6A Boiler Steam MLbs	6A Boiler Gas Mcf	6A Boiler Oil Bbls	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox	*	9A Boiler S/B MLbs	9A Boiler Steam MLbs	9A Boiler Gas Mcf	9A Boiler Rubber Tons	9A Boiler Bark Tons	*	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA							6.00E-04	3.08E+01	2.25E-01				
NOX EF			2.80E-01	NA							9.91E-02	1.98E+00	1.98E+00				
29-Dec	0	0	0	0	0.00	0.00	0.00	*	95	8,371	1,547	0.0	1,297	*	32.59	12.20	113
30-Dec	0	0	0	0	0.00	0.00	0.00	*	100	6,657	1,322	0.0	1,029	*	25.88	9.68	90
31-Dec	0	0	0	0	0.00	0.00	0.00	*	148	7,661	2,966	0.0	1,083	*	27.73	10.22	102
01-Jan	0	0	0	0	0.00	0.00	0.00	*	105	7,818	2,918	0.0	1,105	*	28.28	10.43	103
02-Jan	0	346	482	0	0.15	0.01	5.62	*	122	8,915	3,109	0.0	1,277	*	32.58	12.05	118
03-Jan	0	1,554	1,524	0	0.48	0.04	17.78	*	108	8,813	2,839	0.0	1,277	*	32.51	12.05	117
04-Jan	0	0	0	0	0.00	0.00	0.00	*	76	8,509	2,288	0.0	1,262	*	31.96	11.89	114
05-Jan	0	0	0	0	0.00	0.00	0.00	*	76	6,696	935	0.0	1,060	*	26.52	9.96	91
06-Jan	0	0	0	0	0.00	0.00	0.00	*	104	8,365	2,577	0.0	1,221	*	31.04	11.51	111
07-Jan	0	0	0	0	0.00	0.00	0.00	*	110	8,268	2,704	0.0	1,197	*	30.48	11.29	110
08-Jan	0	3,029	3,341	0	1.06	0.08	38.98	*	79	9,566	3,540	0.0	1,346	*	34.44	12.71	126
09-Jan	0	4,235	4,591	0	1.45	0.11	53.56	*	59	8,325	3,467	0.0	1,141	*	29.35	10.79	108
10-Jan	0	3,942	4,149	0	1.31	0.10	48.41	*	123	8,809	4,164	0.0	1,181	*	30.56	11.18	115
11-Jan	0	100	121	0	0.04	0.00	1.41	*	104	8,588	2,655	0.0	1,253	*	31.85	11.81	114
12-Jan	0	0	0	0	0.00	0.00	0.00	*	120	6,643	1,626	0.0	1,132	*	28.53	10.65	100
13-Jan	0	0	0	0	0.00	0.00	0.00	*	99	8,540	1,572	0.0	1,324	*	33.26	12.45	116
14-Jan	0	0	0	0	0.00	0.00	0.00	*	117	6,833	1,737	0.0	1,030	*	26.05	9.70	92
15-Jan	0	0	142	0	0.04	0.00	1.66	*	91	7,827	5,022	0.0	949	*	25.08	9.02	99
16-Jan	0	891	1,034	0	0.33	0.03	12.06	*	190	9,242	3,122	0.0	1,342	*	34.19	12.66	124
17-Jan	0	4,105	4,046	0	1.28	0.10	47.20	*	146	9,636	3,586	0.0	1,366	*	34.94	12.89	127
18-Jan	0	2,772	2,079	0	0.66	0.05	24.26	*	94	9,113	2,845	0.0	1,325	*	33.68	12.49	121
19-Jan	0	0	0	0	0.00	0.00	0.00	*	89	9,141	3,907	0.0	1,250	*	32.17	11.82	119
20-Jan	0	0	0	0	0.00	0.00	0.00	*	53	7,750	2,496	0.0	1,116	*	28.42	10.53	102
21-Jan	0	0	0	0	0.00	0.00	0.00	*	150	7,944	1,948	0.0	1,205	*	30.45	11.35	107
22-Jan	0	0	311	0	0.10	0.01	3.63	*	221	7,039	1,341	0.0	1,111	*	27.92	10.45	97
23-Jan	0	607	967	0	0.31	0.02	11.28	*	508	6,923	3,268	0.0	997	*	25.72	9.43	96
24-Jan	0	2,549	2,879	0	0.91	0.07	33.59	*	292	12,962	4,163	0.0	1,902	*	48.39	17.93	174
25-Jan	0	4,328	3,928	0	1.24	0.10	45.83	*	52	9,899	1,732	0.0	1,531	*	38.43	14.39	133
26-Jan	0	3,956	4,082	0	1.29	0.10	47.62	*	121	8,392	1,479	0.0	1,310	*	32.88	12.32	114
27-Jan	0	1,974	2,440	0	0.77	0.06	28.47	*	111	8,920	891	0.0	1,439	*	35.91	13.52	122
28-Jan	0	1,005	1,087	0	0.34	0.03	12.68	*	24	8,541	1,647	0.0	1,306	*	32.84	12.28	115
29-Jan	0	0	0	0	0.00	0.00	0.00	*	206	11,489	965	0.0	1,878	*	46.78	17.63	159
30-Jan	0	0	0	0	0.00	0.00	0.00	*	287	10,528	1,844	0.0	1,666	*	41.83	15.67	145
31-Jan	0	0	0	0	0.00	0.00	0.00	*	178	9,663	2,706	0.0	1,440	*	36.51	13.57	130

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R M I L L U T I L I T Y R E P O R T

DATE	6A Boiler S/B MLbs	6A Boiler Steam MLbs	6A Boiler Gas Mcf	6A Boiler Oil Bbls	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox	*	9A Boiler S/B MLbs	9A Boiler Steam MLbs	9A Boiler Gas Mcf	9A Boiler Rubber Tons	9A Boiler Bark Tons	*	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA							6.00E-04	3.08E+01	2.25E-01				
NOX EF			2.80E-01	NA							9.91E-02	1.98E+00	1.98E+00				
01-Feb	0	0	0	0	0.00	0.00	0.00	*	130	8,707	1,413	0.0	1,369	*	34.32	12.87	119
02-Feb	0	0	0	0	0.00	0.00	0.00	*	135	7,722	1,099	0.0	1,228	*	30.75	11.54	106
03-Feb	0	0	0	0	0.00	0.00	0.00	*	201	8,537	1,884	0.0	1,317	*	33.20	12.40	116
04-Feb	0	0	0	0	0.00	0.00	0.00	*	282	8,124	1,024	0.0	1,325	*	33.13	12.45	114
05-Feb	0	0	0	0	0.00	0.00	0.00	*	298	6,701	1,255	0.0	1,074	*	26.98	10.10	94
06-Feb	0	232	318	0	0.10	0.01	3.71	*	303	9,562	2,603	0.0	1,452	*	36.76	13.68	131
07-Feb	0	863	957	0	0.30	0.02	11.17	*	306	9,979	3,622	0.0	1,447	*	36.96	13.65	134
08-Feb	0	0	0	0	0.00	0.00	0.00	*	304	9,793	3,326	0.0	1,437	*	36.63	13.56	132
09-Feb	0	0	0	0	0.00	0.00	0.00	*	288	10,258	3,582	0.0	1,493	*	38.09	14.09	138
10-Feb	0	0	0	0	0.00	0.00	0.00	*	254	9,088	2,406	0.0	1,448	*	36.61	13.64	129
11-Feb	0	0	0	0	0.00	0.00	0.00	*	162	8,963	2,940	0.0	1,304	*	33.20	12.30	120
12-Feb	0	0	0	0	0.00	0.00	0.00	*	231	6,795	1,601	0.0	1,053	*	26.57	9.91	93
13-Feb	0	0	0	0	0.00	0.00	0.00	*	227	7,725	2,743	0.0	1,123	*	28.66	10.60	104
14-Feb	0	0	0	0	0.00	0.00	0.00	*	56	6,771	1,802	0.0	1,005	*	25.44	9.47	90
15-Feb	0	0	0	0	0.00	0.00	0.00	*	144	8,270	1,673	0.0	1,279	*	32.18	12.03	112
16-Feb	0	0	0	0	0.00	0.00	0.00	*	323	8,400	1,987	0.0	1,307	*	32.98	12.30	116
17-Feb	0	0	0	0	0.00	0.00	0.00	*	243	8,785	2,608	0.0	1,312	*	33.30	12.37	119
18-Feb	0	0	74	0	0.02	0.00	0.86	*	241	7,295	2,198	0.0	1,094	*	27.77	10.31	99
19-Feb	0	200	485	0	0.15	0.01	5.66	*	201	6,639	1,702	0.0	1,014	*	25.65	9.55	91
20-Feb	0	0	0	0	0.00	0.00	0.00	*	292	9,079	2,250	0.0	1,396	*	35.26	13.14	124
21-Feb	0	0	0	0	0.00	0.00	0.00	*	250	8,767	2,768	0.0	1,299	*	33.02	12.24	119
22-Feb	0	0	0	0	0.00	0.00	0.00	*	282	9,275	3,326	0.0	1,347	*	34.40	12.71	125
23-Feb	0	0	0	0	0.00	0.00	0.00	*	269	9,178	2,376	0.0	1,399	*	35.38	13.18	125
24-Feb	0	1,997	2,295	0	0.73	0.06	26.78	*	143	3,867	2,135	0.0	511	*	13.32	4.84	51
25-Feb	0	3,802	4,188	0	1.33	0.10	48.86	*	0	0	0	0.0	0	*	0.00	0.00	0
26-Feb	0	3,261	3,547	0	1.12	0.09	41.38	*	0	0	0	0.0	0	*	0.00	0.00	0
27-Feb	0	2,660	3,054	0	0.97	0.08	35.63	*	88	2,388	2,541	0.0	225	*	6.38	2.17	29
28-Feb	0	0	0	0	0.00	0.00	0.00	*	296	8,707	3,788	0.0	1,221	*	31.42	11.54	116
01-Mar	0	0	0	0	0.00	0.00	0.00	*	299	8,624	4,735	0.0	1,138	*	29.66	10.78	113
02-Mar	0	0	0	0	0.00	0.00	0.00	*	321	7,804	2,613	0.0	1,161	*	29.57	10.95	107
03-Mar	0	0	0	0	0.00	0.00	0.00	*	293	8,208	1,958	0.0	1,272	*	32.11	11.98	113
04-Mar	0	0	0	0	0.00	0.00	0.00	*	220	7,995	1,738	0.0	1,241	*	31.26	11.68	110
05-Mar	0	0	0	0	0.00	0.00	0.00	*	296	6,124	1,116	0.0	988	*	24.80	9.29	86
06-Mar	0	0	0	0	0.00	0.00	0.00	*	314	7,384	1,391	0.0	1,180	*	29.65	11.10	103

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R M I L L U T I L I T Y R E P O R T

DATE	6A Boiler S/B MLbs	6A Boiler Steam MLbs	6A Boiler Gas Mcf	6A Boiler Oil Bbls	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox	*	9A Boiler S/B MLbs	9A Boiler Steam MLbs	9A Boiler Gas Mcf	9A Boiler Rubber Tons	9A Boiler Bark Tons	*	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA							6.00E-04	3.08E+01	2.25E-01				
NOX EF			2.80E-01	NA							9.91E-02	1.98E+00	1.98E+00				
07-Mar	0	0	0	0	0.00	0.00	0.00	*	276	7,953	3,144	0.0	1,139	*	29.20	10.76	107
08-Mar	0	0	0	0	0.00	0.00	0.00	*	238	7,825	1,626	0.0	1,224	*	30.80	11.51	108
09-Mar	0	0	0	0	0.00	0.00	0.00	*	317	6,110	858	0.0	1,008	*	25.22	9.47	87
10-Mar	0	0	0	0	0.00	0.00	0.00	*	315	6,855	639	0.0	1,148	*	28.61	10.78	97
11-Mar	0	0	555	0	0.18	0.01	6.48	*	244	7,831	652	0.0	1,298	*	32.33	12.18	110
12-Mar	0	0	0	0	0.00	0.00	0.00	*	211	6,157	510	0.0	1,024	*	25.50	9.61	87
13-Mar	0	0	0	0	0.00	0.00	0.00	*	250	5,649	33	0.0	981	*	24.28	9.20	81
14-Mar	0	0	0	0	0.00	0.00	0.00	*	302	6,403	1,141	0.0	1,033	*	25.94	9.72	90
15-Mar	0	0	0	0	0.00	0.00	0.00	*	271	7,075	1,342	0.0	1,125	*	28.28	10.58	98
16-Mar	0	0	0	0	0.00	0.00	0.00	*	228	7,357	793	0.0	1,206	*	30.09	11.32	103
17-Mar	0	0	0	0	0.00	0.00	0.00	*	273	5,336	360	0.0	908	*	22.59	8.52	76
18-Mar	0	0	0	0	0.00	0.00	0.00	*	255	6,858	1,190	0.0	1,098	*	27.54	10.32	95
19-Mar	0	0	0	0	0.00	0.00	0.00	*	241	5,395	372	0.0	912	*	22.69	8.56	77
20-Mar	0	0	0	0	0.00	0.00	0.00	*	243	7,158	733	0.0	1,179	*	29.42	11.08	100
21-Mar	0	0	0	0	0.00	0.00	0.00	*	315	6,692	552	0.0	1,127	*	28.07	10.58	95
22-Mar	0	0	0	0	0.00	0.00	0.00	*	252	7,390	790	0.0	1,215	*	30.33	11.41	104
23-Mar	0	0	0	0	0.00	0.00	0.00	*	227	7,217	358	0.0	1,214	*	30.17	11.39	102
24-Mar	0	0	0	0	0.00	0.00	0.00	*	258	5,452	291	0.0	930	*	23.11	8.73	78
25-Mar	0	1,103	1,474	0	0.47	0.04	17.20	*	215	6,639	1,312	0.0	1,046	*	26.29	9.83	92
26-Mar	0	3,886	4,587	0	1.45	0.11	53.52	*	267	8,664	1,635	0.0	1,368	*	34.37	12.86	120
27-Mar	0	3,250	3,844	0	1.22	0.10	44.85	*	226	8,731	1,068	0.0	1,414	*	35.33	13.28	121
28-Mar	0	1,798	2,298	0	0.73	0.06	26.81	*	278	8,550	1,173	0.0	1,385	*	34.64	13.01	119
29-Mar	0	0	0	0	0.00	0.00	0.00	*	316	6,610	749	0.0	1,099	*	27.44	10.32	94
30-Mar	0	0	0	0	0.00	0.00	0.00	*	314	5,689	522	0.0	962	*	23.97	9.03	81
31-Mar	0	0	0	0	0.00	0.00	0.00	*	254	8,255	1,478	0.0	1,309	*	32.87	12.31	114
01-Apr	0	0	97	0	0.03	0.00	1.13	*	304	5,714	494	0.0	967	*	24.08	9.07	82
02-Apr	0	0	105	0	0.03	0.00	1.23	*	158	6,178	504	0.0	1,019	*	25.37	9.56	86
03-Apr	0	0	0	0	0.00	0.00	0.00	*	101	6,358	694	0.0	1,025	*	25.60	9.63	87
04-Apr	0	0	0	0	0.00	0.00	0.00	*	116	6,467	878	0.0	1,032	*	25.83	9.70	89
05-Apr	0	0	0	0	0.00	0.00	0.00	*	191	6,958	360	0.0	1,165	*	28.95	10.93	98
06-Apr	0	0	0	0	0.00	0.00	0.00	*	221	5,882	857	0.0	954	*	23.88	8.96	82
07-Apr	0	2,751	3,302	0	1.05	0.08	38.52	*	210	7,670	1,508	0.0	1,185	*	29.82	11.15	104
08-Apr	0	2,422	2,811	0	0.89	0.07	32.80	*	285	8,204	1,783	0.0	1,283	*	32.33	12.08	113
09-Apr	0	0	0	0	0.00	0.00	0.00	*	260	7,823	954	0.0	1,277	*	31.90	11.99	109

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PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R M I L L U T I L I T Y R E P O R T

	6A Boiler							*	9A Boiler					*			
DATE	S/B MLbs	Steam MLbs	Gas Mcf	Oil Bbls				*	S/B MLbs	Steam MLbs	Gas Mcf	Rubber Tons	Bark Tons	*			
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA	Calculated lbs/hr						6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOX EF			2.80E-01	NA	PM	SO2	Nox				9.91E-02	1.98E+00	1.98E+00		PM	SO2	Nox
10-Apr	0	0	0	0	0.00	0.00	0.00	*	258	8,689	1,546	0.0	1,377	*	34.57	12.95	120
11-Apr	0	0	0	0	0.00	0.00	0.00	*	143	7,491	988	0.0	1,199	*	30.00	11.27	103
12-Apr	0	0	0	0	0.00	0.00	0.00	*	112	6,754	581	0.0	1,101	*	27.45	10.34	93
13-Apr	0	0	0	0	0.00	0.00	0.00	*	119	5,726	792	0.0	916	*	22.91	8.60	79
14-Apr	0	0	0	0	0.00	0.00	0.00	*	90	6,198	592	0.0	1,004	*	25.04	9.43	85
15-Apr	0	0	0	0	0.00	0.00	0.00	*	116	5,635	660	0.0	910	*	22.73	8.55	78
16-Apr	0	0	0	0	0.00	0.00	0.00	*	74	5,348	587	0.0	860	*	21.48	8.08	73
17-Apr	0	0	0	0	0.00	0.00	0.00	*	167	5,036	337	0.0	842	*	20.95	7.90	71
18-Apr	0	0	0	0	0.00	0.00	0.00	*	99	5,261	686	0.0	843	*	21.07	7.92	72
19-Apr	0	0	0	0	0.00	0.00	0.00	*	93	5,979	377	0.0	984	*	24.48	9.24	83
20-Apr	0	0	0	0	0.00	0.00	0.00	*	175	4,208	381	0.0	702	*	17.50	6.59	60
21-Apr	0	0	0	0	0.00	0.00	0.00	*	185	4,959	256	0.0	838	*	20.83	7.87	70
22-Apr	0	0	0	0	0.00	0.00	0.00	*	202	5,448	492	0.0	905	*	22.56	8.50	77
23-Apr	0	0	0	0	0.00	0.00	0.00	*	128	5,807	2,713	0.0	789	*	20.39	7.46	76
24-Apr	0	0	0	0	0.00	0.00	0.00	*	77	7,579	827	0.0	1,215	*	30.33	11.41	104
25-Apr	0	0	0	0	0.00	0.00	0.00	*	220	7,316	914	0.0	1,189	*	29.71	11.17	102
26-Apr	0	0	0	0	0.00	0.00	0.00	*	225	7,365	929	0.0	1,353	*	33.78	12.71	115
27-Apr	0	0	0	0	0.00	0.00	0.00	*	92	7,122	496	0.0	1,166	*	29.02	10.95	98
28-Apr	0	0	0	0	0.00	0.00	0.00	*	91	6,683	543	0.0	1,089	*	27.12	10.22	92
29-Apr	0	0	0	0	0.00	0.00	0.00	*	90	6,281	463	0.0	1,028	*	25.58	9.65	87
30-Apr	0	0	0	0	0.00	0.00	0.00	*	74	5,942	481	0.0	967	*	24.09	9.08	82
01-May	0	0	0	0	0.00	0.00	0.00	*	4	6,207	240	0.0	1,017	*	25.26	9.54	85
02-May	0	0	0	0	0.00	0.00	0.00	*	22	6,044	345	0.0	986	*	24.50	9.25	83
03-May	0	0	0	0	0.00	0.00	0.00	*	165	5,939	433	0.0	985	*	24.53	9.25	83
04-May	0	3,450	4,144	0	1.31	0.10	48.35	*	88	8,578	1,778	0.0	1,313	*	33.06	12.35	116
05-May	0	1,825	2,286	0	0.72	0.06	26.67	*	142	7,633	1,072	0.0	1,217	*	30.45	11.43	105
06-May	0	1,080	1,749	0	0.55	0.04	20.41	*	106	7,181	785	0.0	1,157	*	28.87	10.86	99
07-May	0	2,243	2,871	0	0.91	0.07	33.50	*	99	7,291	1,431	0.0	1,126	*	28.32	10.59	99
08-May	0	815	1,640	0	0.52	0.04	19.13	*	53	7,092	1,129	0.0	1,108	*	27.77	10.41	96
09-May	0	1,380	2,314	0	0.73	0.06	27.00	*	99	7,520	1,200	0.0	1,181	*	29.62	11.10	102
10-May	0	3,499	4,117	0	1.30	0.10	48.03	*	89	8,428	1,924	0.0	1,278	*	32.23	12.02	113
11-May	0	3,358	3,985	0	1.26	0.10	46.49	*	168	7,992	751	0.0	1,305	*	32.53	12.25	111
12-May	0	2,629	3,255	0	1.03	0.08	37.98	*	209	8,720	1,355	0.0	1,388	*	34.79	13.05	120
13-May	0	0	819	0	0.26	0.02	9.56	*	119	5,390	686	0.0	868	*	21.69	8.15	74

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P A P E R M I L L U T I L I T Y R E P O R T

DATE	6A Boiler S/B MLbs	6A Boiler Steam MLbs	6A Boiler Gas Mcf	6A Boiler Oil Bbls	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox	*	9A Boiler S/B MLbs	9A Boiler Steam MLbs	9A Boiler Gas Mcf	9A Boiler Rubber Tons	9A Boiler Bark Tons	*	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA							6.00E-04	3.08E+01	2.25E-01				
NOX EF			2.80E-01	NA							9.91E-02	1.98E+00	1.98E+00				
14-May	0	0	0	0	0.00	0.00	0.00	*	153	5,616	685	0.0	911	*	22.76	8.56	78
15-May	0	0	0	0	0.00	0.00	0.00	*	98	5,263	495	0.0	857	*	21.37	8.05	73
16-May	0	0	0	0	0.00	0.00	0.00	*	106	6,058	903	0.0	961	*	24.06	9.03	83
17-May	0	0	0	0	0.00	0.00	0.00	*	105	5,843	643	0.0	944	*	23.56	8.86	81
18-May	0	0	0	0	0.00	0.00	0.00	*	134	5,679	628	0.0	922	*	23.03	8.66	79
19-May	0	2,338	2,985	0	0.95	0.07	34.83	*	81	7,245	1,888	0.0	1,082	*	27.37	10.19	97
20-May	0	2,577	3,430	0	1.09	0.09	40.02	*	187	9,232	3,296	0.0	1,327	*	33.88	12.52	123
21-May	0	0	0	0	0.00	0.00	0.00	*	245	6,328	1,731	0.0	968	*	24.50	9.12	87
22-May	0	0	0	0	0.00	0.00	0.00	*	203	6,684	456	0.0	1,114	*	27.72	10.46	94
23-May	0	0	0	0	0.00	0.00	0.00	*	149	6,165	342	0.0	1,027	*	25.53	9.64	86
24-May	0	0	0	0	0.00	0.00	0.00	*	93	5,456	690	0.0	874	*	21.85	8.21	75
25-May	0	0	0	0	0.00	0.00	0.00	*	112	4,886	723	0.0	780	*	19.53	7.33	67
26-May	0	0	0	0	0.00	0.00	0.00	*	207	5,027	816	0.0	1,721	*	42.85	16.15	145
27-May	0	0	0	0	0.00	0.00	0.00	*	145	5,065	1,284	0.0	774	*	19.55	7.28	69
28-May	0	1,050	1,450	0	0.46	0.04	16.92	*	94	6,937	1,221	0.0	1,082	*	27.16	10.17	94
29-May	0	2,388	3,087	0	0.98	0.08	36.02	*	97	7,539	2,421	0.0	1,094	*	27.84	10.32	100
30-May	0	0	0	0	0.00	0.00	0.00	*	83	5,636	1,604	0.0	835	*	21.17	7.87	75
31-May	0	0	0	0	0.00	0.00	0.00	*	150	6,431	1,725	0.0	970	*	24.54	9.13	87
01-Jun	0	0	0	0	0.00	0.00	0.00	*	113	5,297	981	0.0	829	*	20.84	7.80	72
02-Jun	0	0	0	0	0.00	0.00	0.00	*	109	5,281	836	0.0	837	*	20.97	7.86	72
03-Jun	0	0	0	0	0.00	0.00	0.00	*	115	4,434	548	0.0	718	*	17.94	6.74	61
04-Jun	0	0	0	0	0.00	0.00	0.00	*	131	4,472	544	0.0	727	*	18.17	6.83	62
05-Jun	0	0	0	0	0.00	0.00	0.00	*	151	4,183	323	0.0	699	*	17.39	6.56	59
06-Jun	0	0	0	0	0.00	0.00	0.00	*	157	4,427	326	0.0	740	*	18.42	6.95	62
07-Jun	0	0	0	0	0.00	0.00	0.00	*	129	4,714	378	0.0	779	*	19.41	7.32	66
08-Jun	0	0	0	0	0.00	0.00	0.00	*	142	4,099	567	0.0	665	*	16.64	6.25	57
09-Jun	0	0	0	0	0.00	0.00	0.00	*	109	4,082	374	0.0	671	*	16.72	6.30	57
10-Jun	0	0	0	0	0.00	0.00	0.00	*	125	4,370	516	0.0	711	*	17.76	6.68	61
11-Jun	0	0	0	0	0.00	0.00	0.00	*	95	5,108	483	0.0	832	*	20.73	7.81	71
12-Jun	0	0	0	0	0.00	0.00	0.00	*	90	4,913	4,423	0.0	507	*	13.96	4.87	60
13-Jun	0	0	0	0	0.00	0.00	0.00	*	0	4,771	2,550	0.0	607	*	15.83	5.75	61
14-Jun	0	0	0	0	0.00	0.00	0.00	*	108	4,658	334	0.0	770	*	19.16	7.22	65
15-Jun	0	0	0	0	0.00	0.00	0.00	*	108	5,196	327	0.0	860	*	21.39	8.07	72
16-Jun	0	0	0	0	0.00	0.00	0.00	*	75	4,399	319	0.0	722	*	17.97	6.78	61

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P A P E R M I L L U T I L I T Y R E P O R T

DATE	6A Boiler S/B MLbs	6A Boiler Steam MLbs	6A Boiler Gas Mcf	6A Boiler Oil Bbls	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox	*	9A Boiler S/B MLbs	9A Boiler Steam MLbs	9A Boiler Gas Mcf	9A Boiler Rubber Tons	9A Boiler Bark Tons	*	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA							6.00E-04	3.08E+01	2.25E-01				
NOX EF			2.80E-01	NA							9.91E-02	1.98E+00	1.98E+00				
17-Jun	0	0	0	0	0.00	0.00	0.00	*	96	5,297	475	0.0	864	*	21.53	8.11	73
18-Jun	0	0	0	0	0.00	0.00	0.00	*	92	4,338	324	0.0	714	*	17.78	6.71	60
19-Jun	0	0	0	0	0.00	0.00	0.00	*	100	5,097	745	0.0	811	*	20.31	7.62	70
20-Jun	0	0	0	0	0.00	0.00	0.00	*	84	5,822	618	0.0	939	*	23.43	8.82	80
21-Jun	0	0	0	0	0.00	0.00	0.00	*	87	5,198	349	0.0	855	*	21.27	8.03	72
22-Jun	0	0	0	0	0.00	0.00	0.00	*	90	5,412	1,121	0.0	834	*	21.00	7.85	73
23-Jun	0	0	0	0	0.00	0.00	0.00	*	77	5,849	397	0.0	958	*	23.85	8.99	81
24-Jun	0	0	0	0	0.00	0.00	0.00	*	86	6,123	835	0.0	973	*	24.35	9.14	84
25-Jun	0	857	612	0	0.19	0.02	7.14	*	83	5,067	2,930	0.0	642	*	16.82	6.09	65
26-Jun	0	0	0	0	0.00	0.00	0.00	*	101	4,633	851	0.0	726	*	18.24	6.83	63
27-Jun	0	0	0	0	0.00	0.00	0.00	*	136	4,767	324	0.0	793	*	19.74	7.44	67
28-Jun	0	0	0	0	0.00	0.00	0.00	*	106	4,298	313	0.0	711	*	17.69	6.67	60
29-Jun	0	0	0	0	0.00	0.00	0.00	*	93	4,343	375	0.0	712	*	17.73	6.68	60
30-Jun	0	0	0	0	0.00	0.00	0.00	*	151	5,251	516	0.0	862	*	21.50	8.10	73
01-Jul	0	0	0	0	0.00	0.00	0.00	*	145	4,005	321	0.0	668	*	16.63	6.27	56
02-Jul	0	0	0	0	0.00	0.00	0.00	*	75	4,415	326	0.0	724	*	18.03	6.80	61
03-Jul	0	0	0	0	0.00	0.00	0.00	*	143	4,398	497	0.0	720	*	17.98	6.76	61
04-Jul	0	0	0	0	0.00	0.00	0.00	*	87	6,359	929	0.0	1,006	*	25.19	9.45	87
05-Jul	0	0	0	0	0.00	0.00	0.00	*	91	7,746	1,082	0.0	1,226	*	30.69	11.52	106
06-Jul	0	0	0	0	0.00	0.00	0.00	*	82	5,192	977	0.0	807	*	20.28	7.59	71
07-Jul	0	0	25	0	0.01	0.00	0.29	*	102	5,735	2,056	0.0	821	*	20.97	7.75	76
08-Jul	0	0	0	0	0.00	0.00	0.00	*	37	3,663	824	0.0	556	*	14.02	5.23	49
09-Jul	0	735	1,124	0	0.36	0.03	13.11	*	99	6,304	1,729	0.0	940	*	23.80	8.85	85
10-Jul	0	0	0	0	0.00	0.00	0.00	*	76	4,557	358	0.0	746	*	18.57	7.00	63
11-Jul	0	0	0	0	0.00	0.00	0.00	*	109	4,126	365	0.0	679	*	16.92	6.37	58
12-Jul	0	0	0	0	0.00	0.00	0.00	*	90	4,748	338	0.0	781	*	19.45	7.33	66
13-Jul	0	0	0	0	0.00	0.00	0.00	*	160	3,859	355	0.0	644	*	16.04	6.04	55
14-Jul	0	0	0	0	0.00	0.00	0.00	*	72	4,367	314	0.0	717	*	17.84	6.73	60
15-Jul	0	0	0	0	0.00	0.00	0.00	*	60	5,310	1,711	0.0	769	*	19.57	7.25	70
16-Jul	0	0	0	0	0.00	0.00	0.00	*	101	3,988	374	0.0	654	*	16.30	6.14	55
17-Jul	0	0	0	0	0.00	0.00	0.00	*	90	4,813	507	0.0	780	*	19.46	7.32	66
18-Jul	0	0	0	0	0.00	0.00	0.00	*	108	5,643	634	0.0	912	*	22.77	8.56	78
19-Jul	0	0	0	0	0.00	0.00	0.00	*	81	5,191	730	0.0	1,219	*	30.39	11.44	104
20-Jul	0	0	0	0	0.00	0.00	0.00	*	82	4,504	324	0.0	740	*	18.43	6.95	62

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

PAPER MILL UTILITY REPORT

DATE	6A Boiler S/B MLbs	6A Boiler Steam MLbs	6A Boiler Gas Mcf	6A Boiler Oil Bbls	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox	*	9A Boiler S/B MLbs	9A Boiler Steam MLbs	9A Boiler Gas Mcf	9A Boiler Rubber Tons	9A Boiler Bark Tons	*	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA							6.00E-04	3.08E+01	2.25E-01				
NOX EF			2.80E-01	NA							9.91E-02	1.98E+00	1.98E+00				
21-Jul	0	0	0	0	0.00	0.00	0.00	*	125	5,259	868	0.0	833	*	20.90	7.83	72
22-Jul	0	0	0	0	0.00	0.00	0.00	*	127	4,105	362	0.0	679	*	16.91	6.37	57
23-Jul	0	0	0	0	0.00	0.00	0.00	*	94	4,720	430	0.0	771	*	19.21	7.24	65
24-Jul	0	0	0	0	0.00	0.00	0.00	*	114	4,079	381	0.0	671	*	16.72	6.30	57
25-Jul	0	0	0	0	0.00	0.00	0.00	*	109	4,474	358	0.0	737	*	18.36	6.92	62
26-Jul	0	0	0	0	0.00	0.00	0.00	*	95	4,866	394	0.0	798	*	19.87	7.49	67
27-Jul	0	0	0	0	0.00	0.00	0.00	*	99	4,156	400	0.0	680	*	16.95	6.38	58
28-Jul	0	1,181	1,511	0	0.48	0.04	17.63	*	91	5,824	1,055	0.0	908	*	22.81	8.54	79
29-Jul	0	3,307	4,001	0	1.27	0.10	46.68	*	83	7,762	1,309	0.0	970	*	24.42	9.12	85
30-Jul	0	468	591	0	0.19	0.01	6.90	*	77	4,269	430	0.0	693	*	17.28	6.50	59
31-Jul	0	0	0	0	0.00	0.00	0.00	*	89	4,179	448	0.0	678	*	16.93	6.37	58
01-Aug	0	0	0	0	0.00	0.00	0.00	*	81	4,883	370	0.0	800	*	19.92	7.51	68
02-Aug	0	0	0	0	0.00	0.00	0.00	*	81	4,075	421	0.0	662	*	16.51	6.21	56
03-Aug	0	0	0	0	0.00	0.00	0.00	*	107	6,167	1,118	0.0	963	*	24.19	9.06	84
04-Aug	0	0	0	0	0.00	0.00	0.00	*	89	5,503	716	0.0	879	*	21.99	8.26	75
05-Aug	0	0	0	0	0.00	0.00	0.00	*	90	4,508	423	0.0	735	*	18.33	6.90	62
06-Aug	0	0	0	0	0.00	0.00	0.00	*	108	5,701	1,310	0.0	871	*	21.98	8.20	77
07-Aug	0	0	0	0	0.00	0.00	0.00	*	81	5,217	1,158	0.0	798	*	20.11	7.51	71
08-Aug	0	0	0	0	0.00	0.00	0.00	*	103	4,644	394	0.0	762	*	18.99	7.15	64
09-Aug	0	0	0	0	0.00	0.00	0.00	*	73	4,379	376	0.0	714	*	17.80	6.71	60
10-Aug	0	0	0	0	0.00	0.00	0.00	*	90	4,354	371	0.0	713	*	17.77	6.70	60
11-Aug	0	0	0	0	0.00	0.00	0.00	*	110	4,709	602	0.0	759	*	18.97	7.13	65
12-Aug	0	0	0	0	0.00	0.00	0.00	*	106	4,742	480	0.0	773	*	19.27	7.25	66
13-Aug	0	0	0	0	0.00	0.00	0.00	*	102	6,957	1,364	0.0	1,076	*	27.06	10.12	94
14-Aug	0	170	338	0	0.11	0.01	3.94	*	92	4,643	806	0.0	730	*	18.31	6.86	64
15-Aug	0	2,600	2,468	0	0.78	0.06	28.79	*	25	1,359	384	0.0	202	*	5.13	1.91	18
16-Aug	0	2,944	3,464	0	1.10	0.09	40.41	*	0	0	0	0.0	0	*	0.00	0.00	0
17-Aug	0	2,352	2,934	0	0.93	0.07	34.23	*	14	922	542	0.0	116	*	3.04	1.10	12
18-Aug	0	0	0	0	0.00	0.00	0.00	*	44	6,414	1,887	0.0	937	*	23.79	8.83	85
19-Aug	0	0	0	0	0.00	0.00	0.00	*	138	4,720	595	0.0	766	*	19.14	7.19	66
20-Aug	0	0	0	0	0.00	0.00	0.00	*	69	5,437	1,443	0.0	811	*	20.53	7.64	73
21-Aug	0	0	0	0	0.00	0.00	0.00	*	74	6,806	1,167	0.0	1,061	*	26.62	9.97	92
22-Aug	0	0	0	0	0.00	0.00	0.00	*	83	5,550	1,060	0.0	861	*	21.64	8.09	75
23-Aug	0	0	0	0	0.00	0.00	0.00	*	75	4,265	657	0.0	675	*	16.91	6.34	58

2003

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R   M I L L   U T I L I T Y   R E P O R T

DATE	6A Boiler S/B MLbs	6A Boiler Steam MLbs	6A Boiler Gas Mcf	6A Boiler Oil Bbls	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox	*	9A Boiler S/B MLbs	9A Boiler Steam MLbs	9A Boiler Gas Mcf	9A Boiler Rubber Tons	9A Boiler Bark Tons	*	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA							6.00E-04	3.08E+01	2.25E-01				
NOX EF			2.80E-01	NA							9.91E-02	1.98E+00	1.98E+00				
24-Aug	0	0	0	0	0.00	0.00	0.00	*	74	4,856	674	0.0	772	*	19.32	7.25	66
25-Aug	0	0	0	0	0.00	0.00	0.00	*	73	7,767	3,057	0.0	1,081	*	27.72	10.21	102
26-Aug	0	385	1,035	0	0.33	0.03	12.08	*	74	7,878	1,851	0.0	1,189	*	30.01	11.19	106
27-Aug	0	3,151	3,819	0	1.21	0.10	44.56	*	60	8,617	2,318	0.0	1,275	*	32.29	12.01	115
28-Aug	0	1,387	1,792	0	0.57	0.04	20.91	*	62	5,368	2,870	0.0	693	*	18.07	6.57	69
29-Aug	0	634	874	0	0.28	0.02	10.20	*	59	3,953	861	0.0	605	*	15.25	5.69	53
30-Aug	0	0	0	0	0.00	0.00	0.00	*	75	5,051	423	0.0	823	*	20.50	7.73	70
31-Aug	0	0	0	0	0.00	0.00	0.00	*	76	4,845	341	0.0	795	*	19.78	7.46	67
01-Sep	0	42	433	0	0.14	0.01	5.05	*	54	6,579	1,960	0.0	961	*	24.40	9.06	87
02-Sep	0	0	238	0	0.08	0.01	2.78	*	73	5,897	548	0.0	955	*	23.80	8.96	81
03-Sep	0	0	142	0	0.04	0.00	1.66	*	75	6,665	1,735	0.0	995	*	25.18	9.37	89
04-Sep	0	0	55	0	0.02	0.00	0.64	*	103	5,338	395	0.0	878	*	21.85	8.24	74
05-Sep	0	1,026	1,606	0	0.51	0.04	18.74	*	66	2,639	552	0.0	410	*	10.32	3.86	36
06-Sep	0	3,354	2,787	0	0.88	0.07	32.52	*	0	0	76	0.0	0	*	0.02	0.00	0
07-Sep	0	151	191	0	0.06	0.00	2.23	*	97	4,256	693	0.0	674	*	16.91	6.34	58
08-Sep	0	0	0	0	0.00	0.00	0.00	*	77	4,308	374	0.0	703	*	17.52	6.60	60
09-Sep	0	0	0	0	0.00	0.00	0.00	*	75	3,955	305	0.0	649	*	16.16	6.09	55
10-Sep	0	0	0	0	0.00	0.00	0.00	*	75	4,379	529	0.0	695	*	17.37	6.53	60
11-Sep	0	0	0	0	0.00	0.00	0.00	*	71	3,667	295	0.0	601	*	14.97	5.64	51
12-Sep	0	0	0	0	0.00	0.00	0.00	*	96	4,566	304	0.0	755	*	18.77	7.08	64
13-Sep	0	0	0	0	0.00	0.00	0.00	*	71	6,237	1,218	0.0	961	*	24.18	9.04	84
14-Sep	0	0	0	0	0.00	0.00	0.00	*	122	6,395	806	0.0	1,027	*	25.67	9.65	88
15-Sep	0	0	0	0	0.00	0.00	0.00	*	80	4,331	302	0.0	713	*	17.74	6.69	60
16-Sep	0	0	0	0	0.00	0.00	0.00	*	64	4,289	293	0.0	704	*	17.51	6.61	59
17-Sep	0	0	0	0	0.00	0.00	0.00	*	62	5,434	443	0.0	883	*	22.00	8.29	75
18-Sep	0	0	0	0	0.00	0.00	0.00	*	50	5,896	577	0.0	948	*	23.66	8.91	81
19-Sep	0	0	0	0	0.00	0.00	0.00	*	133	4,906	2,859	0.0	629	*	16.47	5.97	64
20-Sep	0	0	0	0	0.00	0.00	0.00	*	122	3,619	294	0.0	602	*	14.99	5.65	51
21-Sep	0	0	0	0	0.00	0.00	0.00	*	139	5,839	977	0.0	924	*	23.18	8.69	80
22-Sep	0	0	0	0	0.00	0.00	0.00	*	137	5,352	427	0.0	883	*	22.00	8.29	75
23-Sep	0	0	0	0	0.00	0.00	0.00	*	119	4,427	399	0.0	728	*	18.15	6.84	62
24-Sep	0	0	0	0	0.00	0.00	0.00	*	187	3,500	291	0.0	593	*	14.77	5.57	50
25-Sep	0	0	0	0	0.00	0.00	0.00	*	92	4,274	331	0.0	703	*	17.51	6.60	59
26-Sep	0	0	0	0	0.00	0.00	0.00	*	57	5,646	557	0.0	909	*	22.68	8.54	77

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R M I L L U T I L I T Y R E P O R T

DATE	6A Boiler S/B MLbs	6A Boiler Steam MLbs	6A Boiler Gas Mcf	6A Boiler Oil Bbls	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox	*	9A Boiler S/B MLbs	9A Boiler Steam MLbs	9A Boiler Gas Mcf	9A Boiler Rubber Tons	9A Boiler Bark Tons	*	Calculated lbs/hr PM	Calculated lbs/hr SO2	Calculated lbs/hr Nox
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA							6.00E-04	3.08E+01	2.25E-01				
NOX EF			2.80E-01	NA							9.91E-02	1.98E+00	1.98E+00				
27-Sep	0	0	0	0	0.00	0.00	0.00	*	105	5,642	551	0.0	917	*	22.87	8.61	78
28-Sep	0	0	0	0	0.00	0.00	0.00	*	226	4,307	1,747	0.0	627	*	16.06	5.92	59
29-Sep	0	0	0	0	0.00	0.00	0.00	*	232	5,589	6,631	0.0	481	*	14.00	4.67	67
30-Sep	0	0	0	0	0.00	0.00	0.00	*	149	5,701	1,855	0.0	838	*	21.33	7.90	77
01-Oct	0	0	167	0	0.05	0.00	1.95	*	243	5,152	853	0.0	836	*	20.97	7.86	73
02-Oct	0	0	0	0	0.00	0.00	0.00	*	201	5,353	553	0.0	885	*	22.08	8.31	75
03-Oct	0	0	205	0	0.06	0.01	2.39	*	71	5,721	514	0.0	927	*	23.12	8.71	79
04-Oct	0	3,652	4,544	0	1.44	0.11	53.01	*	88	7,896	1,228	0.0	694	*	17.55	6.53	62
05-Oct	0	3,198	3,917	0	1.24	0.10	45.70	*	103	8,798	2,674	0.0	782	*	20.21	7.40	76
06-Oct	0	3,230	3,816	0	1.21	0.10	44.52	*	88	8,090	1,017	0.0	1,535	*	38.32	14.42	131
07-Oct	0	3,463	4,114	0	1.30	0.10	48.00	*	92	7,441	2,083	0.0	1,477	*	37.22	13.90	130
08-Oct	0	3,513	4,171	0	1.32	0.10	48.66	*	88	7,387	2,391	0.0	1,423	*	35.97	13.40	127
09-Oct	0	3,964	4,798	0	1.52	0.12	55.98	*	102	7,157	2,366	0.0	1,368	*	34.60	12.88	123
10-Oct	0	2,089	2,806	0	0.89	0.07	32.74	*	110	6,923	1,666	0.0	921	*	23.33	8.68	83
11-Oct	0	834	1,253	0	0.40	0.03	14.62	*	100	5,410	1,147	0.0	834	*	21.00	7.84	74
12-Oct	0	0	0	0	0.00	0.00	0.00	*	132	6,247	901	0.0	997	*	24.95	9.37	86
13-Oct	0	0	0	0	0.00	0.00	0.00	*	93	5,781	657	0.0	931	*	23.24	8.74	79
14-Oct	0	0	0	0	0.00	0.00	0.00	*	181	4,886	372	0.0	817	*	20.34	7.67	69
15-Oct	0	0	0	0	0.00	0.00	0.00	*	132	6,047	657	0.0	981	*	24.50	9.22	84
16-Oct	0	0	0	0	0.00	0.00	0.00	*	103	5,458	572	0.0	885	*	22.08	8.31	75
17-Oct	0	0	0	0	0.00	0.00	0.00	*	226	5,819	995	0.0	934	*	23.43	8.78	81
18-Oct	0	0	0	0	0.00	0.00	0.00	*	194	5,892	424	0.0	983	*	24.46	9.23	83
19-Oct	0	0	0	0	0.00	0.00	0.00	*	88	5,487	344	0.0	904	*	22.48	8.48	76
20-Oct	0	0	0	0	0.00	0.00	0.00	*	103	6,168	1,081	0.0	965	*	24.24	9.08	84
21-Oct	0	418	726	0	0.23	0.02	8.47	*	78	4,963	585	0.0	797	*	19.91	7.49	68
22-Oct	0	1,446	2,024	0	0.64	0.05	23.61	*	119	5,954	704	0.0	960	*	23.99	9.02	82
23-Oct	0	0	169	0	0.05	0.00	1.97	*	98	5,999	813	0.0	956	*	23.92	8.98	82
24-Oct	0	0	0	0	0.00	0.00	0.00	*	90	7,187	1,147	0.0	1,128	*	28.29	10.61	98
25-Oct	0	0	0	0	0.00	0.00	0.00	*	91	7,184	1,147	0.0	1,128	*	28.28	10.60	98
26-Oct	0	0	0	0	0.00	0.00	0.00	*	266	7,715	1,276	0.0	1,236	*	31.00	11.62	107
27-Oct	0	0	0	0	0.00	0.00	0.00	*	188	7,254	984	0.0	1,168	*	29.21	10.97	100
28-Oct	0	0	0	0	0.00	0.00	0.00	*	121	5,819	1,348	0.0	891	*	22.47	8.38	79
29-Oct	0	0	0	0	0.00	0.00	0.00	*	86	6,022	607	0.0	973	*	24.28	9.14	83
30-Oct	0	0	0	0	0.00	0.00	0.00	*	128	7,102	1,702	0.0	1,079	*	27.25	10.16	96

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

PAPER MILL UTILITY REPORT

	6A Boiler							*	9A Boiler					*			
DATE	S/B MLbs	Steam MLbs	Gas Mcf	Oil Bbls				*	S/B MLbs	Steam MLbs	Gas Mcf	Rubber Tons	Bark Tons	*			
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA	Calculated lbs/hr						6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOX EF			2.80E-01	NA	PM	SO2	Nox				9.91E-02	1.98E+00	1.98E+00		PM	SO2	Nox
31-Oct	0	0	0	0	0.00	0.00	0.00	*	119	6,512	520	0.0	1,067	*	26.57	10.01	90
01-Nov	0	0	0	0	0.00	0.00	0.00	*	105	6,429	468	0.0	1,054	*	26.25	9.90	89
02-Nov	0	0	0	0	0.00	0.00	0.00	*	102	6,175	549	0.0	1,006	*	25.06	9.44	85
03-Nov	0	0	0	0	0.00	0.00	0.00	*	109	5,946	387	0.0	981	*	24.39	9.20	82
04-Nov	0	0	0	0	0.00	0.00	0.00	*	164	5,190	609	0.0	847	*	21.17	7.96	72
05-Nov	0	0	0	0	0.00	0.00	0.00	*	155	4,727	648	0.0	766	*	19.16	7.20	66
06-Nov	0	0	0	0	0.00	0.00	0.00	*	294	5,541	635	0.0	913	*	22.80	8.58	78
07-Nov	0	0	0	0	0.00	0.00	0.00	*	288	6,939	1,274	0.0	1,110	*	27.89	10.44	97
08-Nov	0	0	0	0	0.00	0.00	0.00	*	295	6,871	980	0.0	1,122	*	28.08	10.54	97
09-Nov	0	0	0	0	0.00	0.00	0.00	*	293	6,906	1,132	0.0	1,116	*	27.99	10.49	97
10-Nov	0	0	0	0	0.00	0.00	0.00	*	208	6,046	662	0.0	993	*	24.80	9.33	85
11-Nov	0	0	0	0	0.00	0.00	0.00	*	113	5,677	687	0.0	914	*	22.85	8.59	78
12-Nov	0	0	0	0	0.00	0.00	0.00	*	142	5,476	925	0.0	868	*	21.78	8.16	75
13-Nov	0	273	451	0	0.14	0.01	5.26	*	284	5,342	635	0.0	891	*	22.25	8.37	76
14-Nov	0	3,105	3,636	0	1.15	0.09	42.42	*	230	6,515	708	0.0	1,072	*	26.75	10.07	91
15-Nov	0	2,874	3,434	0	1.09	0.09	40.06	*	105	6,182	335	0.0	1,023	*	25.43	9.60	86
16-Nov	0	2,794	3,326	0	1.05	0.08	38.80	*	107	5,909	324	0.0	979	*	24.33	9.18	82
17-Nov	0	2,821	3,395	0	1.08	0.08	39.61	*	198	5,847	849	0.0	945	*	23.65	8.88	81
18-Nov	0	3,167	3,833	0	1.21	0.10	44.72	*	237	6,467	1,700	0.0	992	*	25.09	9.34	89
19-Nov	0	2,803	3,367	0	1.07	0.08	39.28	*	289	6,290	1,657	0.0	974	*	24.64	9.17	87
20-Nov	0	2,849	3,524	0	1.12	0.09	41.11	*	280	5,787	923	0.0	943	*	23.63	8.86	82
21-Nov	0	3,295	3,901	0	1.24	0.10	45.51	*	251	6,946	1,384	0.0	1,097	*	27.60	10.32	96
22-Nov	0	3,116	3,756	0	1.19	0.09	43.82	*	254	6,567	833	0.0	1,075	*	26.88	10.10	92
23-Nov	0	3,157	3,848	0	1.22	0.10	44.89	*	286	7,383	2,933	0.0	1,062	*	27.21	10.03	100
24-Nov	0	3,325	4,152	0	1.31	0.10	48.44	*	301	9,539	6,064	0.0	1,192	*	31.43	11.33	123
25-Nov	0	3,944	4,818	0	1.53	0.12	56.21	*	295	12,346	8,918	0.0	1,449	*	38.68	13.80	156
26-Nov	0	3,250	4,124	0	1.31	0.10	48.11	*	255	6,126	583	0.0	1,020	*	25.44	9.58	87
27-Nov	0	2,365	3,479	0	1.10	0.09	40.59	*	294	8,171	1,656	0.0	1,289	*	32.42	12.12	113
28-Nov	0	3,272	4,173	0	1.32	0.10	48.69	*	290	8,604	1,990	0.0	1,335	*	33.68	12.57	118
29-Nov	0	2,738	3,724	0	1.18	0.09	43.45	*	272	7,977	1,528	0.0	1,262	*	31.72	11.87	110
30-Nov	0	3,000	3,724	0	1.18	0.09	43.45	*	273	7,977	1,529	0.0	1,262	*	31.72	11.87	110
01-Dec	0	3,265	4,409	0	1.40	0.11	51.44	*	298	8,050	1,733	0.0	1,263	*	31.82	11.89	111
02-Dec	0	4,181	5,039	0	1.60	0.13	58.79	*	280	9,327	3,506	0.0	1,342	*	34.34	12.67	125
03-Dec	0	3,802	4,590	0	1.45	0.11	53.55	*	222	8,411	2,541	0.0	1,251	*	31.77	11.79	114

GEORGIA-PACIFIC CORPORATION
PULP & PAPER DIVISION
CROSSETT PAPER OPERATIONS

P A P E R M I L L U T I L I T Y R E P O R T

	6A Boiler								9A Boiler								
DATE	S/B MLbs	Steam MLbs	Gas Mcf	Oil Bbls				*	S/B MLbs	Steam MLbs	Gas Mcf	Rubber Tons	Bark Tons	*			
PM10EF			7.60E-03	NA							7.60E-03	5.64E+00	5.94E-01				
SO2 EF			6.00E-04	NA	Calculated lbs/hr						6.00E-04	3.08E+01	2.25E-01		Calculated lbs/hr		
NOX EF			2.80E-01	NA	PM	SO2	Nox				9.91E-02	1.98E+00	1.98E+00		PM	SO2	Nox
04-Dec	0	2,635	3,347	0	1.06	0.08	39.05	*	250	6,648	745	0.0	1,095	*	27.33	10.28	93
05-Dec	0	3,710	4,421	0	1.40	0.11	51.58	*	308	7,926	1,889	0.0	1,233	*	31.11	11.61	110
06-Dec	0	671	894	0	0.28	0.02	10.43	*	279	7,476	1,416	0.0	1,188	*	29.85	11.17	104
07-Dec	0	936	1,295	0	0.41	0.03	15.11	*	279	7,719	1,325	0.0	1,235	*	30.99	11.61	107
08-Dec	0	727	1,264	0	0.40	0.03	14.75	*	250	5,837	820	0.0	954	*	23.87	8.96	82
09-Dec	0	3,713	4,445	0	1.41	0.11	51.86	*	247	8,621	2,609	0.0	1,285	*	32.64	12.12	117
10-Dec	0	2,018	2,685	0	0.85	0.07	31.33	*	263	7,195	1,367	0.0	1,142	*	28.70	10.74	100
11-Dec	0	2,272	2,910	0	0.92	0.07	33.95	*	302	6,901	1,724	0.0	1,073	*	27.11	10.11	96
12-Dec	0	1,635	2,101	0	0.67	0.05	24.51	*	302	6,019	733	0.0	999	*	24.97	9.39	85
13-Dec	0	0	0	0	0.00	0.00	0.00	*	294	7,115	2,291	0.0	1,066	*	27.10	10.05	97
14-Dec	0	0	0	0	0.00	0.00	0.00	*	292	8,141	3,094	0.0	1,177	*	30.11	11.11	110
15-Dec	0	0	245	0	0.08	0.01	2.86	*	268	7,847	2,052	0.0	1,201	*	30.38	11.31	108
16-Dec	0	1,198	1,733	0	0.55	0.04	20.22	*	303	8,397	2,875	0.0	1,238	*	31.55	11.68	114
17-Dec	0	429	548	0	0.17	0.01	6.39	*	305	7,349	1,051	0.0	1,198	*	29.99	11.26	103
18-Dec	0	0	0	0	0.00	0.00	0.00	*	322	7,876	2,345	0.0	1,193	*	30.28	11.25	108
19-Dec	0	0	0	0	0.00	0.00	0.00	*	310	7,473	2,118	0.0	1,141	*	28.91	10.75	103
20-Dec	0	0	0	0	0.00	0.00	0.00	*	312	6,836	1,474	0.0	1,083	*	27.26	10.19	95
21-Dec	0	0	0	0	0.00	0.00	0.00	*	274	6,999	1,493	0.0	1,102	*	27.75	10.37	97
22-Dec	0	0	0	0	0.00	0.00	0.00	*	261	6,989	1,518	0.0	1,096	*	27.61	10.32	97
23-Dec	0	0	0	0	0.00	0.00	0.00	*	304	5,830	709	0.0	970	*	24.23	9.11	83
24-Dec	0	0	0	0	0.00	0.00	0.00	*	322	6,579	712	0.0	1,098	*	27.39	10.31	93
25-Dec	0	0	0	0	0.00	0.00	0.00	*	318	7,317	1,336	0.0	1,174	*	29.48	11.04	102
26-Dec	0	0	0	0	0.00	0.00	0.00	*	316	7,279	1,073	0.0	1,187	*	29.71	11.15	102
27-Dec	0	0	0	0	0.00	0.00	0.00	*	297	7,191	1,572	0.0	1,132	*	28.51	10.65	100
28-Dec	0	0	0	0	0.00	0.00	0.00	*	277	6,540	865	0.0	1,072	*	26.81	10.07	92
29-Dec	0	1,523	1,922	0	0.61	0.05	22.42	*	172	2,310	1,364	0.0	313	*	8.18	2.97	31
30-Dec	0	2,971	3,741	0	1.18	0.09	43.65	*	43	664	915	0.0	50	*	1.53	0.49	8
31-Dec	0	1,075	1,380	0	0.44	0.03	16.10	*	100	3,656	522	0.0	587	*	14.71	5.52	51
01-Jan	0	0	0	0	0.00	0.00	0.00	*	85	5,628	359	0.0	926	*	23.02	8.69	78
02-Jan	0	0	0	0	0.00	0.00	0.00	*	89	5,827	739	0.0	931	*	23.29	8.75	80
03-Jan	0	0	0	0	0.00	0.00	0.00	*	89	4,723	410	0.0	772	*	19.23	7.25	65
	0	4,328.00	5,039.00	0	1.60	0.13	58.79		58,170	2,344,793	472,484	0	367,133		48.39	17.93	174.09

Maximum Daily Gas Usage for 6A Boiler

Month	2001		2002		2003	
	High Day	Gas Usage	High Day	Gas Usage	High Day	Gas Usage
January	19	4921	20	5156	9	4591
February	2	4569	27	2579	24	4188
March	10	6032	22	5685	26	4587
April	9	5415	5	4295	7	3302
May	12	7772	10	4876	4	4144
June	5	3303	31	4803	25	612
July	10	4026	31	3281	29	4001
August	22	5178	2	4609	27	3819
September	13	1201	21	3133	6	2787
October	22	5023	29	2168	9	4798
November	30	2989	6	5058	25	4818
December	28	4321	12	3704	2	5039

	2001	2002	2003
Maximum Gas Usage Per Day	7772 MCF	5685 MCF	5039 MCF

Emissions			
PM	2.4611333	1.80025	1.5956833
SO2	0.1943	0.142125	0.125975
NOX	32.383333	23.6875	20.995833
NOX (low NOX)	16.191667	11.84375	10.497917

Sample Calculation

7772 MCF	1 MMCF	7.6 lb PM	1 day
day	1000 MCF	MMCF	24 hr

AP-42 Factors

PM	7.6	
SO2	0.6	
NOX	100	
NOX	50	for Low NOX burners

Emission Calculations:

Emissions from the 6A Boiler are directly tied to the amount and combination of fuels combusted in the boiler. Fo pollutant, the two fuels used can be sorted in terms of their potential to generate the highest emissions. Therefor each pollutant, a hierarchy of the available fuels is established starting with the fuel with the highest emission fact As natural gas can be fired at the maximum rating of the boiler, if the natural gas emission factor is greater than th specification oil factor, only emissions associated with natural gas use are needed. If, however, the specification emission factor is greater, emissions will be calculated using the maximum firing rate of specification oil and emiss associated with the remaining capacity of the boiler (357 MMBtu/hr - 280.8 MMBtu/hr) will be calculated using nat gas emission factors.

PM/PM_{10}

PM/PM_{10} emissions from the 6A Boiler are not limited by any NSPS or other standard. As such, potential emissio have been calculated by applying the calculation hierarchy previously described and including a safety factor.

Fuel Heirarchy	Emission Factor (lb/MMBtu)	Maximum Firing Rate (MMBtu/hr)	Safety Factor	Emission Rates[A] (lb/hr)	(tpy)
Specification Oil (Short-term)	0.11	280.8	1.2	36.7	-
Specification Oil (Long-term)	0.08	280.8	1.2	-	117.4
Natural Gas	7.6E-03	76.2	1.2	0.7	3.0
			Total Emissions =	**37.4**	**120.4**

A. Emission Rates (lb/hr) = Emission Factor (lb/MMBtu) * Maximum Firing Rate (MMBtu/hr) * Safety Factor
Emission Rates (tpy) = Emission Rate (lb/hr) * (8,760 hr/yr) * (ton/2,000 lb)

SO_2

SO_2 emissions from the 6A Boiler are not limited by any NSPS or other standard. As such, potential emissions ha been calculated by applying the calculation hierarchy previously described. A safety factor is not included in calcu potential emissions of SO_2.

Fuel Hierarchy	Emission Factor (lb/MMBtu)	Maximum Firing Rate (MMBtu/hr)	Emission Rates[A] (lb/hr)	(tpy)
Specification Oil (Short-term)	1.51	280.8	423.9	-
Specification Oil (Long-term)	1.01	280.8	-	1,237.8
Natural Gas	6.0E-04	76.2	4.6E-02	0.2
		Total Emissions =	**423.9**	**1,238.0**

A. Emission Rates (lb/hr) = Emission Factor (lb/MMBtu) * Maximum Firing Rate (MMBtu/hr)
Emission Rates (tpy) = Emission Rate (lb/hr) * (8,760 hr/yr) * (ton/2,000 lb)

VOC

VOC emissions from the 6A Boiler are not limited by any NSPS or other standard. As such, potential emissions have been calculated by applying the calculation hierarchy previously described and including a safety factor.

Fuel Hierarchy	Emission Factor (lb/MMBtu)	Maximum Firing Rate (MMBtu/hr)	Safety Factor	Emission Rates[A] (lb/hr)	(tpy)
Natural Gas	5.5E-03	357.0	1.2	2.4	10.5
			Total Emissions =	**2.4**	**10.5**

A. Emission Rates (lb/hr) = Emission Factor (lb/MMBtu) * Maximum Firing Rate (MMBtu/hr) * Safety Factor
Emission Rates (tpy) = Emission Rate (lb/hr) * (8,760 hr/yr) * (ton/2,000 lb)

CO

CO emissions from the 6A Boiler are not limited by any NSPS or other standard. As such, potential emissions have been calculated by applying the calculation hierarchy previously described and including a safety factor.

Fuel Hierarchy	Emission Factor (lb/MMBtu)	Maximum Firing Rate (MMBtu/hr)	Safety Factor	Emission Rates[A] (lb/hr)	(tpy)
Natural Gas	8.4E-02	357.0	1.2	36.0	157.7
			Total Emissions =	**36.0**	**157.7**

A. Emission Rates (lb/hr) = Emission Factor (lb/MMBtu) * Maximum Firing Rate (MMBtu/hr) * Safety Factor
Emission Rates (tpy) = Emission Rate (lb/hr) * (8,760 hr/yr) * (ton/2,000 lb)

NO_X

NO_X emissions from the 6A Boiler are not limited by any NSPS or other standard. As such, potential emissions have been calculated by applying the calculation hierarchy previously described and including a safety factor.

Fuel Hierarchy	Emission Factor (lb/MMBtu)	Maximum Firing Rate (MMBtu/hr)	Safety Factor	Emission Rates[A] (lb/hr)	(tpy)
Specification Oil	0.30	0.0	1.2	0.0	0.0
Natural Gas	0.28	357.0	1.0	100.0	438.0
			Total Emissions =	**100.0**	**438.0**

A. Emission Rates (lb/hr) = Emission Factor (lb/MMBtu) * Maximum Firing Rate (MMBtu/hr) * Safety Factor
Emission Rates (tpy) = Emission Rate (lb/hr) * (8,760 hr/yr) * (ton/2,000 lb)

Pb

Lead emissions are not limited by any NSPS or other standard; therefore, potential emissions are estimated using the calculation hierarchy previously described.

Fuel Hierarchy	Emission Factor (lb/MMBtu)	Maximum Firing Rate (MMBtu/hr)	Safety Factor	Emission Rates[A] (lb/hr)	(tpy)
Specification Oil	9.7E-06	280.8	1.2	3.3E-03	1.4E-02
Natural Gas	5.0E-07	76.2	1.2	4.6E-05	2.0E-04
			Total Emissions =	**3.3E-03**	**1.4E-02**

A. Emission Rates (lb/hr) = Emission Factor (lb/MMBtu) * Maximum Firing Rate (MMBtu/hr) * Safety Factor
Emission Rates (tpy) = Emission Rate (lb/hr) * (8,760 hr/yr) * (ton/2,000 lb)

9A (SN-22) Stack Test Results			
lbs/hr	2008	2009	2010
SO2 (11/2/2006)	96.32	96.32	96.32
NOx	149.36	105.73	136.49
PM	61.11	78.07	61.92
	11/18/2008	12/4/2009	12/17/2010

9A Operating Time	min/quarter	1	2	3	4	Total (Hrs)
	2008	130680	127695	116160	129840	8406.25
	2009	127879.8	129294	113478	131904	8375.93
	2010	129504	128034	131700	122484	8528.7

9A (SN-22)			
TPY	2008	2009	2010
SO2	404.85	403.38	410.74
NOx	627.78	442.79	582.04
PM	256.85	326.95	264.05

	lb PM/hr	MMBtu/hr	lb/MMBtu
Run 1	68.21	588.78	0.11585
Run 2	57.32	613.65	0.093408
Run 3	57.45	574.36	0.100024

	lb NOx/hr	MMBtu/hr	lb/MMBtu
Run 1	45.47	475.15	0.095696
Run 2	45.66	475.07	0.096112
Run 3	45.35	429.54	0.105578

Emission Factors and Throughputs:
Emission factors and throughputs have been researched and are summarized in the following tables.

Table 6A-1

Summary of Criteria Pollutant Emission Factors for the 6A Boiler (SN-19) (lb/MMBtu)												
Fuel	**PM_{10}**	**Note**	**SO_2**	**Note**	**VOC**	**Note**	**CO**	**Note**	**NO_X**	**Note**	**Pb**	**Note**
Natural Gas	7.6E-03	A	6.0E-04	A	5.5E-03	A	8.4E-02	B	0.28	B	5.0E-07	A
Specification Oil (Short-term)	0.11	C	1.51	C	1.8E-03	D	3.2E-02	C	0.30	C	9.7E-06	E
Specification Oil (Long-term)	0.08	C	1.01	C	1.8E-03	D	3.2E-02	C	0.30	C	9.7E-06	E

A. Emission factor obtained from AP-42 Section 1.4, Table 1.4-2, given in terms of lb/MMscf and converted to lb/MMBtu.
B. Emission factor obtained from AP-42 Section 1.4, Table 1.4-1 for uncontrolled post-NSPS large wall-fired boilers, given terms of lb/MMscf and converted to lb/MMBtu.
C. Emission factor obtained from AP-42 Section 1.3, Table 1.3-1, boilers >100 MMBtu/hr firing No. 6 fuel oil, converted from lb/mgal to lb/MMBtu.
AP-42 PM_{10} emission factor (lb/mgal) = 9.19 * Suflur Content (% by weight) + 3.22
AP-42 SO_2 emission factor (lb/mgal) = 157 * Suflur Content (% by weight)

Short-term maximum sulfur conter	1.5	%
Long-term average sulfur content	1.0	%

D. Emission factor obtained from AP-42 Section 1.3, Table 1.3-3 for industrial boilers firing No. 6 fuel oil, converted from lb/mgal to lb/MMBtu.
E. Emission factor obtained from AP-42 Section 1.3, Table 1.3-11 for industrial boilers firing No. 6 fuel oil, converted from lb/mgal to lb/MMBtu.

Table 6A-2

Maximum Fuel Firing Rates and Heating Values for the 6A Boiler (SN-19)				
Fuel	**Maximum Rate (MMBtu/hr)**	**Note**	**Heating Value**	**Note**
Natural Gas	357.0	A	1,000 Btu/scf	B
Specification Oil	280.8	C	156 MMBtu/mgal	D

A. Maximum rating of the unit.
B. Heating value obtained from AP-42 Section 1.4, Page 1.4-1.
C. Based on a permit limit of 1,800 gallons per hour.
D. Mill-specific data.

Emission Factors and Throughputs:
Emission factors and throughputs have been researched and are summarized in the following tables.

Table 9A-1

Summary of Criteria Pollutant Emission Factors for the 9A Boiler (SN-22) (lb/MMBtu)

Fuel	PM_{10}	Note	SO_2	Note	VOC	Note	CO	Note	NO_X	Note	Pb	Note
Woodwaste	0.066	A	0.025	B	0.017	C	0.6	B	0.22	B	4.8E-05	D
Natural Gas	7.6E-03	E	6.0E-04	E	5.5E-03	E	8.4E-02	F	0.19	F	5.0E-07	E
Specification Oil (Short-term)	0.11	G	1.51	G	0.002	H	3.2E-02	G	0.30	G	9.7E-06	I
Specification Oil (Long-term)	0.08	G	1.01	G	0.002	H	3.2E-02	G	0.30	G	9.7E-06	I
TDF	0.188	J	1.03	K	-	L	-	L	-	L	-	L
ADF	0.066	M	0.025	M	0.017	M	0.6	M	0.22	M	4.8E-05	M
RDF	0.15	N	0.25	N	-	O	2.0	N	0.2	N	2.0E-03	P
Sludge	-	Q	-	Q	-	Q	-	Q	-	Q	-	Q
NCGs	-	-	**(lb/ADTP)** 0.76	R	-	-	-	-	-	-	-	-

A. Woodwaste PM/PM_{10} emission factor obtained from AP-42 Section 1.6, Table 1.6-1 for boilers with a wet scrubber control device.
B. Emission factor obtained from AP-42 Section 1.6, Table 1.6-2, for "bark/bark and wet wood/wet wood-fired boiler".
C. Emission factor obtained from AP-42 Section 1.6, Table 1.6-3.
D. Emission factor obtained from AP-42 Section 1.6, Table 1.6-4.
E. Emission factor obtained from AP-42 Section 1.4, Table 1.4-2, given in terms of lb/MMscf and converted to lb/MMBtu.
F. Emission factor obtained from AP-42 Section 1.4, Table 1.4-1 for uncontrolled post-NSPS large wall-fired boilers, given in terms of lb/MMscf and converted to lb/MMBtu.
G. Emission factor obtained from AP-42 Section 1.3, Table 1.3-1, boilers >100 MMBtu/hr firing No. 6 fuel oil, converted from lb/mgal to lb/MMBtu.
AP-42 PM_{10} emission factor (lb/mgal) = 9.19 * Suflur Content (% by weight) + 3.22
AP-42 SO_2 emission factor (lb/mgal) = 157 * Suflur Content (% by weight)

Short-term maximum sulfur content	1.5	%
Long-term maximum sulfur content	1.0	%

H. Emission factor obtained from AP-42 Section 1.3, Table 1.3-3 for industrial boilers firing No. 6 fuel oil, converted from lb/mgal to lb/MMBtu
I. Emission factor obtained from AP-42 Section 1.3, Table 1.3-11 for industrial boilers firing No. 6 fuel oil, converted from lb/mgal to lb/MMBt of lb/mgal and converted to lb/MMBtu.
J. Emission factor obtained from NCASI Technical Bulletin No. 906: Alternative Fuels Used In The Forest Products Industry: Their Composition and Impact On Emissions (September 2005), Table 3.8, Boiler L (venturi scrubber) Run 2 where fuel compostion was 93% wood and 7% TDF.
K. SO_2 emission factor is based on % sulfur in the TDF. For calculation of potential emissions, the average % sulfur given in NCASI Technic Bulletin No. 906: Alternative Fuels Used In The Forest Products Industry: Their Composition And Impact On Emissions (September 2005) of 1.8% is used to determine the SO_2 potential emission factor. The Crossett facility conducted a TDF composition analysis in November 2006 and found that the % sulfur was 1.1%. As stated in Section 3.3, Page 14 of NCASI TB No. 906, it is conservatively assumed that 30% of the sulfur in TDF is absorbed by the woodwaste as these fuels are co-fired. SO_2 emission factor calculation details are as follows:
SO_2 Emission Factor (lb/MMBtu) = 1.8 lb S/100 lb TDF * 2 lb SO_2/lb S * ton TDF/30 MMBtu * (2,000 lb/ton) * (1 - 30% S absorbed)

Where:			
	% Sulfur in TDF =	1.1%	November 2006 TDF composition analysis
	lb SO_2/lb S =	2	Stoichiometric analysis
	Sulfur absorbed in wood =	30%	NCASI Technical Bulletin No. 906, Page 14.

L. Per NCASI Technical Bulletin No. 906, Pages 13-14, VOC, CO, NO_X and trace metals (other than zinc) emissions are generally expected to be lowered or unchanged by burning TDF in a wood-fired boiler. Therefore, no emission factor is chosen for these pollutants.
M. Emission factors for ADF are assumed equal to woodwaste emission factors.
N. Emission factor from AP-42 Section 2.1, Refuse Combustion (Oct 1996), Table 2.1-12. The factors given in AP-42 are uncontrolled; therefore, a control efficiency of 90% is assumed for PM_{10}.
O. No emission factor for VOC is given in AP-42 Section 2.1, Refuse Combustion; only total organic matter is presented.
P. Emission factor from AP-42 Section 2.1, Refuse Combustion, Table 2.1-8. The factors given in AP-42 are uncontrolled; therefore, a control efficiency of 90% is assumed for Pb.
Q. Per NCASI Technical Bulletin No. 906, Section 8.1, burning of WWTP residuals (sludge) is not expected to lead to an increase in any crit or related pollutant including metals. While sulfur in the sludge could result in higher SO_2 emissions, when sludge is co-fired with woodwa (as is done at the Crossett Mill), the sulfur removal capability of the woodwaste reduces the SO_2 emitted such that it is not discernible.
R. The 9A Boiler is permitted as an alternate incinerator for NCGs and SOGs during periods when the incinerator or its associated control equipment is inoperative. NCASI Technical Bulletin No. 849 (August 2002), Table 9 gives mean sulfur contents of 0.34 lb/ADTP for hardw and 0.46 lb/ADTP for softwood. The normal pulp mix is 66% hardwood and 34% softwood, resulting in an emission factor of:
SO_2 emission factor = [0.34 lb/ADTP * 66% + 0.46 lb/ADTP * 34%] * 2 lb SO_2/lb S = 0.76 lb SO_2/ADTP

Table 9A-2

Maximum Fuel Firing Rates and Heating Values for the 9A Boiler (SN-22)				
Fuel	**Maximum Rate (MMBtu/hr)**	**Note**	**Heating Value**	**Note**
Woodwaste	475.2	A	9 MMBtu/ton	B
Natural Gas	720.0	C	1,000 Btu/scf	D
Specification Oil	249.0	A	156 MMBtu/mgal	E
TDF	31.5	F	30 MMBtu/ton	G
ADF	475.2	H	9 MMBtu/ton	H
RDF	104.2	I	10 MMBtu/ton	J
Sludge	405.0	K	9 MMBtu/BDT	-

A. Based on information provided in the August 21, 1980 letter submitted by GP to EPA.
B. Heating value obtained from AP-42 Section 1.6, Page 1.6-1, given as 4,500 Btu/lb and converted to MMBtu/ton.
C. Maximum boiler rating.
D. Heating value obtained from AP-42 Section 1.4, Page 1.4-1.
E. Mill-specific data.
F. Based on permit limit of 35 lb/min. Maximum Rate (MMBtu/hr) = 35 lb/min * 30 MMBtu/ton * (60 min/hr) * (ton/2,000 lb)
G. Heating value obtained from NCASI Technical Bulleting No. 906: Alternative Fuels Used In The Forest Products Industry: Their Composition and Impact On Emissions (September 2005), Page 2, given as 15,000 Btu/lb and converted to MMBtu/ton.
H. Data for ADF is assumed to be equal to woodwaste.
I. Based on permit limit of 250 tons/day. Maximum Rate (MMBtu/hr) = 250 tons/day * 10 MMBtu/ton * (day/24 hr)
J. A heating value of 5,000 Btu/lb is assumed for RDF.
K. Based on permit limit of 45 BDT/hr. Maximum Rate (MMBtu/hr) = 45 BDT/hr * 9 MMBtu/BDT

Georgia-Pacific

Georgia-Pacific LLC
Consumer Products

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CERTIFIED MAIL 7011-1150-0000-8947-6853
Return Receipt Requested

May 18, 2012

Ms. Mary Pettyjohn
Arkansas Department of Environmental Quality
Epidemiologist
5301 Northshore Drive
North Little Rock, AR 72118

Re: Georgia-Pacific LLC Crossett Paper Operations
Best Available Retrofit Technology Five Factor Analysis
AFIN: 02-00013 Title V Permit No. 0597-AOP-R14

Dear Ms. Pettyjohn:

Georgia-Pacific LLC Crossett Paper Operations (GP) received Mike Bates' letter of May 14, 2012 requesting submittal of a five factor analysis for GP Boilers 6A and 9A located at the mill. Based on the letter and the attached April 26, 2012 letter from EPA, we understand that there are questions regarding the BART eligibility of these two boilers. With this letter we would like to summarize the background of this issue and explain why GP believes submitting a five-factor analysis is not appropriate in this case.

As we discussed in our meeting on October 26, 2011 the Mill has prepared additional CALPUFF modeling to demonstrate that our Title V permitted emission rates do not cause or contribute to an impact above the screening threshold of 0.5 deciviews (dv) in regional Class I Areas. In our 2006 CALPUFF analyses, we modeled highest actual daily rates instead of the Title V permit allowable emission rates. As submitted in December, we re-analyzed our BART-eligible sources using our current Title V Permit limits and reducing our maximum hourly emission rate of sulfur dioxide (SO_2) for the 9A Boiler (SN-22) from 502.5 pounds per hour to 200.0 pounds per hour. This limit is now enforceable in Permit #0579-AOP-R14. Section 169A(c) of the Clean Air Act allows sources to be screened out of further requirements including a five-factor analysis. Specifically:

> *(c) Exemptions*
> *(1) The Administrator may, by rule, after notice and opportunity for public hearing, exempt any major stationary source from the requirement of subsection (b)(2)(A) of this section, upon his determination that such source does not or will not, by itself or in combination with other sources, emit any air pollutant which may reasonably be anticipated to cause or contribute to a significant impairment of visibility in any mandatory class I Federal area.*
> *(2) Paragraph (1) of this subsection shall not be applicable to any fossil-fuel fired powerplant with total design capacity of 750 megawatts or more, unless the owner or operator of any such plant demonstrates to the satisfaction of the Administrator that such powerplant is located at such distance from all areas listed by the Administrator under subsection (a)(2) of this section that such powerplant does not or will not, by itself or in combination with other sources,*

> *emit any air pollutant which may reasonably be anticipated to cause or contribute to significant impairment of visibility in any such area.*
> *(3) An exemption under this subsection shall be effective only upon concurrence by the appropriate Federal land manager or managers with the Administrator's determination under this subsection.*

GP believes the 2011 analysis and the current air permit which enforces those limits is sufficient to demonstrate no cause or contribution to an impairment of visibility by BART-eligible source at our Crossett operations. Thus, the state is afforded by 169A(c)(1) to not require analyses under 169A Section or Appendix Y to 40 CFR Part 51, Section V.E.2:

> *As we discuss in detail in these guidelines, the regional haze rule codifies and clarifies the BART provisions in the CAA. The rule requires that States identify and list "BART-eligible sources," that is, that States identify and list those sources that fall within the 26 source categories, were put in place during the 15-year window of time from 1962 to 1977, and have potential emissions greater than 250 tons per year. Once the State has identified the BART-eligible sources, the next step is to identify those BART-eligible sources that may "emit any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility." Under the rule, a source which fits this description is "subject to BART."*

If the visibility impairment modeling protocol and techniques require an updated demonstration for EPA and ADEQ's review, we believe that is the next step to affirm our request for screening out of a Five-factor analysis using the most up-to-date methodology. EPA's disapproval of ADEQ's regional haze SIP does not affect the definition of a subject-to-BART source nor our ability to demonstrate that the allowable emissions from these sources do not cause impairment sufficient to require a five-factor analysis.

To follow-up on this letter, we will contact you in the near future to further discuss and clarify the appropriate steps forward to properly address the BART eligibility of Boilers 6A and 9A. If you have any questions regarding this matter, please do not hesitate to contact me at (870) 567-8144.

Sincerely,

James W. Cutbirth

James W. Cutbirth
Superintendent, Environmental Services

JWC/wjg

Enclosure:
Previously submitted BART Golder Modeling Analysis Summary
Page 54 of current Title V Permit depicting lower SO2 emission rate of 9A Boiler.

SN-22
9A Boiler

Source Description

The 9A Boiler is a 720 million Btu per hour combination fuel boiler used to generate steam. The source is equipped with a wet venturi scrubber. The boiler may serve as backup combustion unit during times when the incinerator (SN-83) is offline.

The 9A Boiler is capable of firing tire derived fuel (TDF), agriculture derived fuel (ADF), refuse derived fuel (RDF), non-condensable gases (NCGs), woodwaste, specification grade oil, natural gas and sludge. A woodwaste storage pile is associated with the 9A Boiler. Woodwaste consists of bark, wood scraps, wax coated paper, wax coated cardboard, wax coated sawdust, creosote treated railroad crossties and paper pellets (waste paper and wax paper). Bark from the debarker in the Woodyard is pneumatically transferred to the 9A pile. A cyclone is located at the end of the pneumatic transfer line to control particulate matter emissions. The majority of the woodwaste is delivered by truck and occasionally by rail. It is then transferred by conveyors to either the 9A or the 10A woodwaste storage pile.

RDF, ADF and sludge are directly added to the chip piles. RDF consists of pelletized paper, lawn clippings and similar materials. TDF and other scrap rubber products are stored in segregated piles near the woodwaste piles. TDF is loaded several times a day by a front end loader into feeder bins in the vicinity. These solid fuels are then fed onto a conveyor system and delivered to the boilers. ADF consists of, but is not limited to, corn cobs, shucks, and vegetable starch.

Specification grade oil consists of new oil, used oil, used oil absorbent material and pitch from the production of tall oil. Used oil absorbent material shall include used oil filter paper, used rags, sorbant booms, etc. that meet the specification grade oil criteria (40 CFR 279.11).

Specific Conditions

33. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions #43, #47, #48, #49, #50, and #53. [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

Pollutant	lb/hr	tpy
PM_{10}	77.4	339.0
SO_2	199.8	484.6
VOC	11.3	49.5
CO	366.8	1,606.7

Golder Associates

December 14, 2011

113-87721

Via Electronic Delivery

James Cutbirth
Georgia-Pacific Consumer Products LLC
Superintendent – Environmental Services
100 Mill Supply Road
Crossett, AR 71635

RE: BART AIR MODELING ANALYSIS FOR THE CROSSETT (AR) MILL

Dear Mr. Cutbirth:

At the request of Georgia-Pacific, LLC (GP), Golder Associates, Inc. (Golder) performed an air modeling analysis to revise the Best Available Retrofit Technology (BART) Application for the Crossett Mill (Mill). The original application was provided to the Arkansas Department of Environmental Quality (ADEQ) in 2006 and used the California Puff modeling system to address the maximum 24-hour visibility impairment due to the Mill's BART-eligible sources. The analysis followed the procedures as outlined in the BART Modeling Protocol (ADEQ, June, 2006) to determine if the Mill could qualify for an exemption under the BART regulations. The following paragraphs summarize the modeling inputs and results.

<u>Source and Emission Data</u>

Emission and source parameter data for the BART modeling analysis were provided by GP. The 6A and 9A Boilers are the only BART-eligible sources at the Mill and the emissions for these sources were provided for sulfur dioxide, nitrogen oxides and particulate matter with diameters less than or equal to 10 microns. These emissions represent the maximum 24-hour emissions allowed by air permit except for sulfur dioxide emissions for SN-22 which were lowered to 200 lbs/hr to match emission rate in GP's December 2011 application for a permit modification.

<u>Meteorological Data</u>

The modeling analysis used three years of gridded 3-dimensional wind field meteorological data developed by the Central Regional Air Planning Association (CENRAP) for the years 2001 to 2003.

<u>Receptor Locations</u>

In accordance with the Air Protocol, predictions of visibility impairment were made at the following Prevention of Significant Deterioration (PSD) Class I areas that are located within 300-km of Arkansas:

- Caney Creek (AR, 235 km) Wilderness Area (WA)
- Upper Buffalo (AR, 325 km) WA
- Hercules-Glade (MO, 398 km) WA
- Mingo (MO, 448 km) WA, and
- Sipsey (AL, 442 km) WA

Receptors for each PSD Class I area were obtained from the National Park Service. All source and receptor locations were based in the Lambert Conformal Coordinate (LCC) system for input to CALPUFF.

Modeling Results

The air modeling results are summarized in Table 1. The maximum predicted 24-hour visibility impairment of 0.359 deciview (dv) was predicted at the Caney Creek WA in 2002. This impact is less than the BART exemption criteria of 0.5 dv.

The air modeling files used to perform the analysis are included with this submittal and include the CALPUFF, POSTUTIL and CALPOST input and list files for years 2001 to 2003, the hourly ozone files for each year, and the executable files.

If you have any questions regarding this analysis please contact me at (352) 336-5600. Thank you.

Sincerely,

GOLDER ASSOCIATES INC.

Steven R. Marks
Steven R. Marks, CCM
Associate, Project Manager

Robert C. McCann
Robert C. McCann, Jr.
Principal

Enclosures

TABLE 1
Maximum Predicted 24-Hour Visibility Impairment (dV) From BART Eligible Sources

PSD Class I Area Area	Highest Deciview for Year 2001	 2002	 2003
Caney Creek (AR) NWA	0.16	0.359	0.296
Upper Buffalo (AR) NWA	0.099	0.074	0.099
Hercules-Glade (MO) NWA	0.08	0.288	0.125
Mingo (MO) NWA	0.123	0.093	0.168
Sipsey (AL) NWA	0.171	0.184	0.119
BART Exemption Criterion	0.5	0.5	0.5

NWA = National Wilderness Area
Notes: All emitted PM emissions assumed as PMF per AR BART protocol

Entergy

Arkansas Environmental Support
425 West Capitol Avenue
A-TCBY-22D
Little Rock, AR 72203
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G. Tracy Johnson, Manager
Arkansas Environmental Support

AR-12-078

October 14, 2013

Mr. Mike Bates
Chief, Air Division
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118

RE: Entergy Arkansas, Inc. – White Bluff Plant
Revised BART Five-Factor Analysis
Permit No. 0263-AOP-R7, AFIN 35-00110

Dear Mr. Bates:

Please find attached a revised and updated Best Available Retrofit Technology (BART) Five-Factor Analysis (FFA) for the Entergy Arkansas, Inc – White Bluff Plant. This updated FFA was completed in order to incorporate revisions made to the analysis in response to questions received from EPA Region 6 staff regarding the revised FFA which was submitted on June 10, 2013.

In addition to the revised FFA document, we have enclosed a question and answer document in which we directly respond to each specific issue raised in EPA's comments.

We appreciate ADEQ's consideration of this analysis and additional supporting information. Should you or your staff have any questions regarding this submittal, please contact me at (501) 377-4033 or David Triplett at (501) 377-4030.

Sincerely,

G. Tracy Johnson

G. Tracy Johnson
Manager, Arkansas Environmental Support

GTJ/dct

CC: Mary Pettyjohn, ADEQ (via email)

Entergy Response to 8/21/2013 EPA Region 6 comments on the White Bluff BART FFA

Entergy has reviewed the comments provided by EPA Region 6 on August 21, 2013, and appreciates the opportunity to provide the below response. To simplify the format of this response, we have included each of EPA's comments, followed by our response. Submitted concurrently herewith is a revised Five-Factor Analysis (FFA) incorporating several revisions as discussed below.

NOx BART

- **EPA Comment 1** - The 2012 S&L NOx Study identifies neural net system upgrades as a potential NOx control. However, this control option is not evaluated by Entergy in the BART analysis for Units 1 and 2. While it appears that the added visibility benefit of LNB/SOFA + SNCR compared to LNB/SOFA is too small to justify the added cost of installing SNCR, we believe the added cost of LNB/SOFA + Neural Net System Upgrades compared to LNB/SOFA would likely be small and may provide some visibility benefit. ADEQ should ensure that if a NOx emission limit more stringent than 0.15 lb/MMBtu could be expected from LNB/SOFA + Neural Net System Upgrades, this should be evaluated as a separate control option in the BART analysis.

  Entergy Response – Entergy does not believe that operation of neural network system upgrades in conjunction with LNB/SOFA would result in a NOx emission limit more stringent than the 0.15 lb/MMBtu proposed in the FFA. The information[1] presented in the S&L NOx study regarding neural network system upgrades was an estimate of the level of NOx reductions which could potentially be achieved through implementation of neural network system upgrades for the White Bluff units as currently configured (without LNB/SOFA). As no vendor guarantees were available for the NOx performance of such neural network system upgrades, and the level of NOx emission reduction estimated by S&L from the operation of neural network system upgrades alone (10%) was significantly less than the potential NOx emission reductions achievable by other evaluated control technologies, no consideration was given to this option in the FFA.

  Since receiving this question from EPA, Entergy has conducted additional discussions with S&L regarding the potential for neural network system upgrades to be operated in conjunction with LNB/SOFA to achieve additional levels of NOx control beyond that expected from LNB/SOFA alone. S&L provided the following statement on this subject.

  > The Neural Network (NN) is a computer program that evaluates controllable parameters affecting the NOx emission rate from the boiler and learns over a long period of operation (years) how to minimize the NOx emission rate. The suppliers of NN do not

[1] Percent NOx emission reduction and expected NOx emission rates

offer a guarantee on NOx emission rate or percent reduction. The primary benefit is to maintain over time the guaranteed NOx emission rate performance resulting from LNB/SOFA. There are NN installations that have achieved small improvements in NOx emission rate over a long period of time but as previously stated, the NN suppliers aren't offering guarantees and the NN may take many years to realize the performance improvement. While this combination of technologies may be desirable in the long run, we don't recommend it as a separate NOx control option to be evaluated in the BART analysis.

Based on the lack of a NOx emission reduction guarantee, Entergy does not believe that the combination of NN system upgrades with LNB/SOFA should be evaluated as a separate, distinct control option within the FFA.

Cost Analysis for SO_2 and NO_x Controls

- **EPA Comment 2** - We are not providing an exhaustive line-by-line review of costs for SO2 and NOx controls because we do not anticipate that further revisions to the cost numbers would change the ultimate BART determinations. However, we wish to make clear that EPA disagrees that the Control Cost Manual (CCM) allows for AFUDC to be included in the BART cost evaluation. AFUDC is the cost of capital that is incurred to finance the project during the construction period. While AFUDC is a valid cost under the all-in cost estimating methodology, it is not a valid cost under the CCM methodology. The Regional Haze Rule states the CCM should be followed where possible, and the CCM uses overnight costing methodology. The overnight cost method is the cost of a construction project if no interest is incurred during construction, as if the project is completed overnight. Thus, AFUDC is never valid under the CCM overnight cost approach. ADEQ should ensure that the cost estimates for all SO2 and NOx controls are revised to exclude AFUDC in order to reflect an accurate estimate of cost-effectiveness of controls.

Entergy Response – Entergy continues to believe that the overnight costing methodology advocated by EPA represents an overly simplistic view of the true costs associated with a significant pollution control project such as those evaluated by Entergy in this FFA. AFUDC represents the interest expense on the investment in the technology that is incurred during construction, before the equipment is placed in service. For major control technology installations, such as scrubbers or SCR, the interest expense incurred during the 30 - 46 months of construction can reach $30 million to $60 million for a large unit. AFUDC simply includes the interest as part of the capital cost, which is standard accounting and rate-making treatment of such costs.

Entergy does not agree that the CCM requires the company to exclude AFUDC from control technology costs. Nonetheless, although Entergy is not waiving its ability to include AFUDC in future control cost analyses, to expedite ADEQ's consideration of the FFA for White Bluff, we have revised the FFA document to remove AFUDC from the costs of each evaluated pollution control technology as requested by EPA staff. While this change lowers the overall capital costs presented within the latest FFA, the BART determinations for each affected pollutant (SO_2 and NO_x) remain unchanged.

Auxiliary Boiler (SN-05)

- **EPA Comment 3** - The calculations provided indicate that average sulfur content over the 2009-2011 period and the average heat content over this same period were utilized to estimate the modeled emission rate. The use of average values based on a three year average of annual values is inconsistent with estimating the maximum 24-hr emission rate from the baseline period. Please provide additional information on the variability of sulfur content and heat content in order to estimate the range of the maximum impact.

Entergy Response – Entergy reviewed the monthly fuel oil sampling data for the facility along with daily records of aux. boiler hours of operation for 2009-2011. Over the 2009-2011 period, the heat content of the fuel oil ranged from 134,318 btu/gal to 142,422 btu/gal, and the sulfur content ranged from 0.004% to 0.056%[2]. By combining each month's fuel sampling result for heat and oil sulfur content with the maximum daily hours of operation for the aux. boiler for the month, it is possible to produce a refined estimate of the maximum daily (24-hour) average SO_2 emission rate from this unit.

Based on this data, the maximum 24-hour average SO_2 emission rate occurred on May 10, 2009. The monthly fuel analysis for May 2009 indicates a heat content of 135,438 btu/gal (135.438 MMBtu/Mgal) and a sulfur content of 0.0441% by weight. Based on the emission factor presented in AP-42 Table 1.3-1 for distillate fuel-fired boilers of >100 MMBtu/hr (142S lb/Mgal), the SO_2 emission factor for May 2009 is calculated as 0.0462 lb/MMBtu. At the maximum 24-hour average heat input rate for May 2009 of 121.23 MMBtu/hr[3], the maximum 24-hour average SO_2 emission rate for the 2009-2011 period is calculated as 5.61 lb/hr.

This refined estimate of the maximum baseline 24-hour SO_2 emission rate for the aux. boiler is less than the rate (5.8 lb/hr) which was utilized to estimate the baseline visibility impairment

[2] Entergy notes that the sulfur content of the No. 2 fuel oil used at White Bluff has trended downward over time, with the annual average sulfur content for 2011 being 0.013% and the average for 2012 being 0.0042%. Due to the increasing restrictions on the sulfur content of commercially available No. 2 fuel oil, it is unlikely that the sulfur content in future years will return to past levels.

[3] This rate was calculated based on the maximum daily hours of operation in May of 2009 (15.9 hours on May 10) and the maximum heat input capacity of the aux. boiler (183 MMBtu/hr). This calculation assumes that the aux. boiler was operating at the maximum rated capacity at all times that it was online on this date. This assumption results in an over-estimate of the actual average heat input for this date.

attributable to this unit. As such, the analysis presented within the FFA is conservative and no refinement to the modeled SO_2 emission rate for the aux. boiler is necessary.

- **EPA Comment 4** - The rationale for determining that no additional controls are required for this unit differs in the revised BART report and the response to Region 6 comments you provided (comment 16). Please revise the BART report to be consistent with your response to our comments, as the response provides an appropriate justification for no additional controls at the auxiliary boiler.

Entergy Response – The BART FFA report has been revised to include the rationale for determining that no additional controls are required for the auxiliary boiler which was presented in the June 2013 response to comments document.

REVISED BART FIVE FACTOR ANALYSIS

WHITE BLUFF STEAM ELECTRIC STATION

REDFIELD, ARKANSAS (AFIN 35-00110)

Prepared By:

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Trinity Project No. 123701.0053

October 2013

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1. EXECUTIVE SUMMARY

This report is a revision to “BART Five Factor Analysis” submitted to ADEQ on February 21, 2013, and revised and resubmitted on June 10, 2013. This report is submitted to provide a comprehensive document that encompasses the determination of the Best Available Retrofit Technology (BART) for Entergy Arkansas, Inc.’s (Entergy’s) BART-affected electric generating units (EGUs) at the White Bluff including changes made in response to EPA’s comments and suggestions on the previous submittal, which were received by Entergy on March 6 and August 21, 2013. This analysis updates and replaces the previous June 2013 FFA. The BART determination for each pollutant has not changed.

Entergy operates three BART-affected EGUs at White Bluff: two coal-fired primary boilers (SN-01 and SN-02) and one fuel oil-fired auxiliary boiler (SN-05). The coal-fired boilers are identical tangentially-fired boilers with a maximum net power rating of 850 MW each and a nominal heat input capacity of 8,950 million British thermal units per hour (MMBtu/hr) each. The boilers burn sub-bituminous or bituminous coal[1] as the primary fuel and No. 2 fuel oil or biofuel as a start-up fuel. SN-01 and SN-02 are currently equipped with electrostatic precipitators (ESPs).

The Auxiliary Boiler, SN-05, is a 183 MMBtu/hr auxiliary boiler burning No. 2 fuel oil or biodiesel as its only fuel types. The purpose of the Auxiliary Boiler is to provide steam for the start-up of the two primary boilers, SN-01 and SN-02. There is no emissions control equipment connected to the Auxiliary Boiler. Typically, the Auxiliary Boiler is only used in the rare instance when both of the main boilers are not operating.

Based on modeling performed for this analysis, cumulative emissions of nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter with a mass mean diameter smaller than ten microns (PM_{10}) from SN-01, SN-02, and SN-05 are predicted to cause or contribute greater than 0.5 delta deciviews (Δdv) of visibility impairment in four (4) Class I Areas: Caney Creek Wilderness (CACR), Upper Buffalo Wilderness (UPBU), Hercules Glades Wilderness (HERC), and Mingo Wilderness (MING)[2, 3]. A summary of the modeled visibility impairment attributable to SN-01, SN-02, and SN-05 based on default natural conditions is provided in Table 1-1. The visibility impairment summarized in Table 1-1 is based on modeling conducted by Trinity Consultants (Trinity) using emissions data based on a combination of continuous emissions monitoring system (CEMS) data as reported to EPA’s Clean Air Markets Database (CAMD), stack testing, and annual emissions inventory information as further described in Section 4 of this report.

[1] SN-01 and SN-02 primarily burn sub-bituminous coal, but are permitted to burn bituminous or sub-bituminous coal. Only sub-bituminous coals were burned during the 2001-2003 and 2009-2011 baseline periods evaluated in this analysis.

[2] SN-05 does not cause visibility impairment greater than 0.5 Δdv in any Class I area but has been reviewed as part of the BART five factor analysis for the site because total impairment from the combined units is greater than 0.5 Δdv in at least one Class I area. *See* Table 4-4.

[3] Sipsey Wilderness was included in the Arkansas Department of Environmental Quality's (ADEQ’s) original BART analyses, but is not included in this analysis because the EPA-requested change in meteorological data (to a refined, or "NO OBS = 0", dataset; *see* Section 3 and Appendix B) excludes Sipsey from the modeling domain.

TABLE 1-1. MODELED EXISTING VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-01, SN-02 AND SN-05

Source	CACR		UPBU		HERC		MING	
	98^{th} % Δdv	Days > 0.5 Δdv	98^{th} % Δdv	Days > 0.5 Δdv	98^{th} % Δdv	Days > 0.5 Δdv	98^{th} % Δdv	Days > 0.5 Δdv
SN-05	0.010	0	0.005	0	0.004	0	0.008	0
SN-01	1.628	106	1.140	77	1.041	61	0.887	56
SN-02	1.695	112	1.185	80	1.060	65	0.903	57

Trinity used the EPA's BART guidelines in 40 CFR Part 51[4] and other recent EPA guidance[5] to determine BART for the boilers. Trinity conducted a five-step analysis to determine BART for SO_2 and NO_x that included the following:

1. Identifying all available retrofit control technologies;
2. Eliminating technically infeasible control technologies;
3. Evaluating the control effectiveness of remaining control technologies;
4. Evaluating impacts and documenting the results; and
5. Evaluating visibility impacts.

The BART analysis concluded that the installation of a semi-dry FGD system constitutes BART for SO_2 for both SN-01 and SN-02. The proposed BART emission rate for SO_2 is 0.06 lb/MMBtu on a rolling 30-day average. Since baseline visibility modeling showed that there is no opportunity for visibility improvement attributable to SN-05, because not a single day greater than 0.5 Δdv is associated with SN-05, it is not possible to install control equipment to improve visibility. Therefore, *no controls* is the SO_2 BART determination for SN-05.

The BART analysis concludes that for NO_X, the achievement of an emission rate of 0.15 lb/MMBtu through the installation and use of low NO_X burners and separated overfire air (LNB/SOFA) represents BART for SN-01 and SN-02.[6] Based on the same logic outlined above for SO_2, NO_x controls are not appropriate or required for SN-05.

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[4] The BART guidelines were published as amendments to the EPA's Regional Haze Rule (RHR) in 40 CFR Part 51, Section 308 on July 6, 2005.

[5] April 26, 2012, letter from Mr. Guy Donaldson, EPA Region VI, to Mr. Anthony Davis, ADEQ.

[6] EPA recently issued a final rule allowing states that are subject to the Cross-State Air Pollution Rule (CSAPR) trading program for seasonal NO_X to rely on the reductions achieved through that trading program to satisfy the regional haze program requirements for units subject to BART. "Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available Technology (BART) Determinations, Limited SIP Disapprovals and Federal Implementation Plans," 77 Fed. Reg. 33651 (June 7, 2012). On August 21, 2012, the D.C. Circuit in a 2-1 decision vacated CSAPR (*EME Homer City Generation v. EPA*, --F. 3d --, No. 11-1302 (D.C. Cir. 2012)), and the Clean Air Interstate Rule (CAIR) remains in effect until a replacement rule, if any, is promulgated. If CSAPR ultimately is upheld and implemented in Arkansas, Entergy may rely on CSAPR to satisfy its NOx regional haze obligations at SN-01 and SN-02. Alternatively, if CSAPR is vacated and CAIR remains in place, Entergy may rely on CAIR to satisfy its NOx obligations under BART as EPA has previously determined that the CAIR season NOx trading program provides greater visibility improvement than BART.

EPA approved a BART determination for PM_{10} at SN-01 and SN-02 in its March 12, 2012, final rule based on the existing ESPs, and established a BART emission rate of 0.1 lb/MMBtu for each boiler.[7]

[7] "Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze. Final Rule," 77 Fed. Reg. 14604 (March 12, 2012).

2. INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to pristine conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to pristine conditions in 156 specific areas across the United States known as Class I areas. The CAA defines Class I areas as certain national parks (larger than 6,000 acres), wilderness areas (larger than 5,000 acres), national memorial parks (larger than 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the Best Available Retrofit Technology (BART) rule, which included guidance for making source-specific BART determinations.[8] The BART rule defines BART-eligible sources as sources that meet the following criteria:

1. Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant;
2. Began operation between August 7, 1962 and August 7, 1977; and
3. Are included as one of the 26 listed source categories in the guidance.

A BART-eligible source is subject to BART if the source is "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." EPA has determined that a source is reasonably anticipated to cause or contribute to visibility impairment if the 98th percentile visibility impacts from the source are modeled to be greater than 0.5 delta deciviews (Δdv) when compared against a natural background.[9] Air quality modeling is the tool that is used to determine a source's visibility impacts.

Once it is determined that a source is subject to BART, a BART determination must address air pollution control measures for the source. The visibility regulations define BART as follows:

> *…an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by…[a BART-eligible source]. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the cost of compliance, the energy and non air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.*

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[8] The BART guidelines were published as amendments to the EPA's RHR in 40 CFR Part 51, Section 308.

[9] The original modeling for Arkansas sources relied on screening met data and, as such, reviewed the maximum impact rather than the 98th percentile impact. Use of the 98th percentile impact based on the use of refined met data (such as that used in the modeling conducted as part of this BART analysis) is consistent with both the EPA's 2005 BART rule and the 2005 Central Regional Air Planning Association (CENRAP) BART modeling guidelines.

Specifically, the BART rule states that a BART determination should address the following five statutory factors:

1. Existing controls;
2. Cost of controls;
3. Energy and non-air quality environmental impacts;
4. Remaining useful life of the source; and
5. Degree of visibility improvement as a result of controls.

Further, the BART rule indicates that the five basic steps in a BART analysis can be summarized as follows:

1. Identify all available retrofit control technologies;
2. Eliminate technically infeasible control technologies;
3. Evaluate the control effectiveness of remaining control technologies;
4. Evaluate impacts and document the results; and
5. Evaluate visibility impacts.

A BART determination should be made for each visibility-affecting pollutant (VAP) by following the five steps listed above for each VAP.

SN-01 and SN-02 meet the three BART-eligibility criteria described above, and the existing visibility impairment attributable to each boiler is greater than 0.5 Δdv in at least one Class I area. Thus, SN-01 and SN-02 are subject to BART. SN-05 does not cause visibility impairment greater than 0.5 Δdv in any Class I area[10] but has been reviewed as part of the BART five factor analysis for the site because total impairment from the combined units is greater than 0.5 Δdv in at least one Class I area. Details of the existing/baseline emissions and the contribution of the emissions to visibility impairment can be found in Section 4. The VAPs emitted by the boilers include NO_X, SO_2, and PM_{10} of various forms (filterable coarse particulate matter [PM_c], filterable fine particulate matter [PM_f], elemental carbon [EC], inorganic condensable particulate matter [IOR CPM] as sulfates [SO_4], and organic condensable particulate matter [OR CPM] also referred to as secondary organic aerosols [SOA]). The BART determinations for SO_2, NO_X, and PM_{10} can be found in Sections 5, 6, and 7, respectively.

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10 *See* Table 4-4.

3. MODELING METHODOLOGIES AND PROCEDURES

This section summarizes the dispersion modeling methodologies and procedures applied in this BART analysis. All dispersion modeling has been conducted using the CALPUFF modeling system, consisting of the CALPUFF dispersion model, the CALMET meteorological data processor, and the CALPOST post-processing program. These methodologies and procedures are consistent with the ADEQ modeling protocol submitted to EPA in June 2012.

CALPUFF is a multi-layer, multi-species, non-steady-state puff dispersion model, which can simulate the effects of time and space varying meteorological conditions on pollutant transport, transformation, and removal. CALPUFF uses three-dimensional meteorological fields developed by the CALMET model. In addition to meteorological data, several other input files are used by the CALPUFF model to specify source and receptor parameters. The selection and control of CALPUFF options are determined by user-specific inputs contained in the control file. This file contains all of the necessary information to define a model run (e.g., starting date, run length, grid specifications, technical options, output options). CALPOST processes concentration, deposition, and visibility impacts based on pollutant specific concentrations predicted by CALPUFF.

3.1 CALMET AND CALPUFF

The CALPUFF data and parameters are based on the 2005 BART modeling guidelines prepared for CENRAP. The CALMET data and parameters are based on the modeling protocol included in Appendix B. Note that the protocol included in Appendix B summarizes modeling methods and procedures that were followed to predict visibility impairment as part of the BART analyses for several BART-eligible sources located in Oklahoma, the first of which was Oklahoma Gas & Electric in 2007. The CALMET dataset developed per this protocol has been used – and approved by EPA – numerous times since its development.

3.2 CALPOST

The CALPOST visibility processing completed for this BART analysis is based on the October 2010 guidance from the Federal Land Managers Air Quality Related Values Workgroup (FLAG).[11]

Visibility impairment is quantified using the light extinction coefficient (b_{ext}), which is expressed in terms of the haze index expressed in deciviews (dv). The haze index (*HI*) is calculated as follows:

$$HI(\text{dv}) = 10 \ln\left(\frac{b_{ext}}{10}\right)$$

The impact of a source is determined by comparing the *HI* attributable to a source relative to estimated natural background conditions. The change in the haze index, in deciviews, also referred to

[11] The 2010 FLAG guidance, which was issued in draft form on July 8, 2008, and published as final guidance in December 2010, makes technical revisions to the previous guidance issued in December 2000.

as “delta dv,” or Δdv, based on the source and background light extinction is based on the following equation:

$$\Delta \mathrm{dv} = 10 * \ln\left[\frac{\mathrm{b}_{\text{ext, background}} + \mathrm{b}_{\text{ext, source}}}{\mathrm{b}_{\text{ext, background}}}\right]$$

The Interagency Monitoring of Protected Visual Environments (IMPROVE) workgroup adopted an equation for predicting light extinction as part of the 2010 FLAG guidance (often referred to as the new IMPROVE equation). The new IMPROVE equation is as follows:

$$b_{ext} = \begin{array}{l} 2.2 f_S(RH)[\mathrm{NH_4(SO_4)_2}]_{\text{Small}} + 4.8 f_L(RH)[\mathrm{NH_4(SO_4)_2}]_{\text{Large}} + \\ 2.4 f_S(RH)[\mathrm{NH_4NO_3}]_{\text{Small}} + 5.1 f_L(RH)[\mathrm{NH_4NO_3}]_{\text{Large}} + \\ 2.8[\mathrm{OC}]_{\text{Small}} + 6.1[\mathrm{OC}]_{\text{Large}} + 10[\mathrm{EC}] + 1[\mathrm{PMF}] + 0.6[\mathrm{PMC}] + \\ 1.4 f_{SS}(RH)[\text{Sea Salt}] + b_{\text{Site-specific Rayleigh Scattering}} + 0.33[\mathrm{NO_2}] \end{array}$$

Visibility impairment predictions relied upon in this BART analysis used the equation shown above. The use of this equation is referred to as “Method 8” in the CALPOST control file. The use of Method 8 requires that one of five different “modes” be selected. The modes specify the approach for addressing the growth of hygroscopic particles due to moisture in the atmosphere. “Mode 5” has been used in this BART analysis. Mode 5 addresses moisture in the atmosphere in a similar way as to “Method 6”, where “Method 6” is specified as the preferred approach for use with the old IMPROVE equation in the CENRAP BART modeling protocol.

CALPOST Method 8, Mode 5 requires the following:

- Annual average concentrations reflecting natural background for various particles and for sea salt
- Monthly Relative Humidity (RH) adjustment factors for large and small ammonium sulfates and nitrates and for sea salts
- Rayleigh scattering parameter corrected for site-specific elevation

Tables 3-1 to Table 3-4 below show the values for the data described above that were input to CALPOST for use with Method 8, Mode 5. The values were obtained from the 2010 FLAG guidance.

TABLE 3-1. ANNUAL AVERAGE BACKGROUND CONCENTRATION

Class I Area	$(NH_4)_2SO_4$ (μg/m^3)	NH_4NO_3 (μg/m^3)	OM (μg/m^3)	EC (μg/m^3)	Soil (μg/m^3)	CM (μg/m^3)	Sea Salt (μg/m^3)	Rayleigh (Mm^{-1})
CACR	0.23	0.1	1.8	0.02	0.5	3	0.03	11
UPBU	0.23	0.1	1.8	0.02	0.5	3	0.03	11
HERC	0.23	0.1	1.8	0.02	0.5	3	0.02	11
MING	0.23	0.1	1.83	0.02	0.51	3.05	0.04	12

TABLE 3-2. F_L(RH) LARGE RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CACR	2.77	2.53	2.37	2.43	2.68	2.71	2.59	2.6	2.71	2.69	2.67	2.79
UPBU	2.71	2.48	2.31	2.33	2.61	2.64	2.57	2.59	2.71	2.58	2.59	2.72
HERC	2.7	2.48	2.3	2.3	2.57	2.59	2.56	2.6	2.69	2.54	2.57	2.72
MING	2.73	2.52	2.34	2.28	2.53	2.6	2.64	2.67	2.71	2.56	2.56	2.73

TABLE 3-3. F_S(RH) SMALL RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CACR	3.85	3.44	3.14	3.24	3.66	3.71	3.49	3.51	3.73	3.72	3.68	3.88
UPBU	3.73	3.33	3.03	3.07	3.54	3.57	3.43	3.5	3.71	3.51	3.52	3.74
HERC	3.7	3.33	3.01	3.01	3.47	3.48	3.41	3.51	3.67	3.43	3.46	3.73
MING	3.74	3.38	3.07	2.97	3.39	3.52	3.57	3.64	3.72	3.47	3.43	3.74

TABLE 3-4. F_{SS}(RH) SEA SALT RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CACR	3.9	3.52	3.31	3.41	3.83	3.88	3.69	3.68	3.82	3.76	3.77	3.93
UPBU	3.85	3.47	3.23	3.27	3.72	3.78	3.69	3.7	3.84	3.64	3.67	3.86
HERC	3.86	3.51	3.23	3.22	3.66	3.72	3.69	3.73	3.81	3.57	3.65	3.88
MING	3.92	3.58	3.3	3.19	3.58	3.72	3.8	3.82	3.85	3.61	3.66	3.9

4. EXISTING EMISSIONS AND VISIBILITY IMPAIRMENT

This section summarizes the existing (i.e., baseline) visibility based on air quality modeling conducted by Trinity.

4.1 NO_X, SO_2, AND PM_{10} BASELINE EMISSION RATES

Table 4-1 summarizes the emission rates that were modeled for SO_2, NO_X, and PM_{10}, including the speciated PM_{10} emissions. The SO_2 and NO_X emission rates are the highest actual 24-hour emission rates based on CAMD data from 2001-2003 for SO_2 and from 2009-2011 for NO_X[12]. The 2001-2003 period was not used for NO_X because that period no longer represents actual operation of the boilers. In 2006, Entergy completed the addition of a neural net system and also conducted extensive boiler tuning. These projects substantially reduced NO_X emissions. Accordingly, there is a real difference in operations/emissions between the original baseline period (2001-2003) and current operations such that the 2001-2003 time period is not representative of current (and thus future, post-BART) operations. The BART regulation, at 40 CFR Part 51, Appendix Y, Section IV.D.4.c, speaks to this issue:

> *The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period. When you project that future operating parameters (e.g., limited hours of operation or capacity utilization, type of fuel, raw materials or product mix or type) will differ from past practice, and if this projection has a deciding effect in the BART determination, then you must make these parameters or assumptions into enforceable limitations. In the absence of enforceable limitations, you calculate baseline emissions based upon continuation of past practice.*

Using the emission rates from 2001-2003 for NO_X would over-state the emissions reductions from the proposed BART control technology. Moreover, using the 2001-2003 NO_X emission rates would exaggerate the projected visibility improvement in the Class I areas. Thus, updating the NO_X emission rates to represent current, normal operation better comports with the regulations. Entergy submitted a determination request to ADEQ on August 23, 2012, to use the 2009-2011 NO_X emission rates based on CEMS data. ADEQ and EPA determined that using the 2009-2011 NO_X emission rates is consistent with the BART guidance[13].

The PM_{10} emission rates are based on emission factors from AP-42 for PM_{10} filterable and PM condensable with a 99.5% control efficiency for ESP applied to the PM_{10} filterable in conjunction with the average coal heat value and average coal % ash from 2009-2011. The emission rates for the PM_{10} species reflect the breakdown of the PM_{10} determined from the National Park Service (NPS)

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12 *See* Appendix D.

13 *See* Email, dated September 10, 2012, from Guy Donaldson (EPA, Region VI) to Mary Pettyjohn (ADEQ).

"speciation spreadsheet" for *Dry Bottom Boiler Burning Pulverized Coal using only ESP*.[14] More specifically, the NPS workbook shows the following baseline distribution for the PM species:

- ▲ Coarse PM (PM_C) = 33.6%
- ▲ Fine soil (modeled as PM_F) = 25.9%
- ▲ Fine elemental carbon (modeled as EC) = 1.0 %
- ▲ Organic condensable PM (modeled as SOA) = 7.9%
- ▲ Inorganic condensable PM (modeled as SO_4) = 31.6%

TABLE 4-1. BASELINE MAXIMUM 24-HOUR SO_2, NO_X, AND PM_{10} EMISSION RATES (AS HOURLY EQUIVALENTS)

Source	SO_2[15] (lb/hr)	NO_X[16] (lb/hr)	Total PM_{10} (lb/hr)	SO_4 (lb/hr)	PM_c (lb/hr)	PM_f (lb/hr)	SOA (lb/hr)	EC (lb/hr)
SN-05	5.8	31.7	2.8	0.9	0.5	1.2	0.2	0.1
SN-01	7,763.5	3,001.4	118.6	36.8	40.4	31.1	9.2	1.2
SN-02	7,825.1	3,527.4	118.6	36.8	40.4	31.1	9.2	1.2

4.2 BASELINE VISIBILITY IMPAIRMENT

Trinity conducted modeling to estimate the current visibility impairment attributable to SN-01, SN-02, and SN-05 in four Class I Areas: Caney Creek Wilderness (CACR), Upper Buffalo Wilderness (UPBU), Hercules Glades Wilderness (HERC), and Mingo Wilderness (MING) using the CALPUFF dispersion model.[17] Table 4-2, Table 4-3, and Table 4-4 provide a summary of the modeled visibility impairment attributable to SN-01, SN-02, and SN-05 respectively, based on the emission rates shown in Table 4-1. These tables show the maximum impairment in Δdv, the 98th percentile impacts in Δdv, and the number of days with impacts greater than 0.5 Δdv as well as the breakdown by pollutant species for the 98th percentile impact.

As BART is determined on a unit-by-unit basis, this baseline modeling is presented to show how the BART proposed controls will cause improvement, at least on a relative basis.

All of the CALMET, CALPUFF, and CALPOST modeling files used to generate these results are included as part of the electronic files submitted with this document.

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[14] The NPS Workbook, "PC Dry Bottom ESP Example.xls" updated 03/2006, was obtained from the NPS website: http://www.nature.nps.gov/air/Permits/ect/index.cfm. The following parameters were input into the workbook for speciation determination: total PM_{10} emission rate of 118.6 lb/hr, heat value of 8,950 Btu/lb, sulfur content of 0.27% and, ash content of 4.87%.

[15] The SO_2 hourly rates were derived from EPA's CAMD data for 2001 - 2003. The 2001-2003 max daily rates were 183,324 lb/day and 187,802 lb/day for SN-01 and SN-02, respectively. *See* Appendix D.

[16] The NO_X hourly rates were derived from EPA's CAMD data for 2009-2011. The 2001-2003 max daily rates were 72,034 lb/day and 84,658 lb/day for SN-01 and SN-02, respectively. *See* Appendix D.

[17] Due to an EPA-requested change in meteorological data which excluded Sipsey Class 1 Area from the modeling domain, Sipsey was not included in this analysis. *See* footnote 1, above.

TABLE 4-2. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-01 BY POLLUTANT

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Day with Δdv ≥ 0.5	98th Percentile Δdv SO_4	98th Percentile Δdv NO_3	98th Percentile Δdv PM_{10}	98th Percentile Δdv NO_2
Caney Creek Wilderness							
2001	2.956	1.628	41	1.287	0.336	0.003	0.002
2002	2.111	1.386	30	0.662	0.659	0.011	0.054
2003	4.194	1.130	35	0.722	0.385	0.003	0.020
Upper Buffalo Wilderness							
2001	2.339	1.128	34	0.835	0.290	0.003	0.000
2002	1.544	0.818	18	0.680	0.133	0.003	0.002
2003	1.900	1.140	25	1.117	0.021	0.003	0.000
Hercules Glades Wilderness							
2001	1.737	1.041	28	0.961	0.078	0.002	0.000
2002	1.288	0.617	13	0.487	0.128	0.001	0.000
2003	2.230	0.786	20	0.699	0.085	0.002	0.000
Mingo Wilderness							
2001	1.569	0.887	18	0.828	0.053	0.003	0.002
2002	1.012	0.750	24	0.427	0.319	0.002	0.002
2003	1.114	0.702	14	0.448	0.245	0.003	0.007

Table 4-2 demonstrates that the 98th percentile impacts from SO_4 are always greater than the 98th percentile impacts from NO_3. Therefore, SO_4, and by default SO_2, is clearly the dominating pollutant of concern from SN-01.

TABLE 4-3. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-02 BY POLLUTANT

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Day with $\Delta dv \geq$ 0.5	98th Percentile Δdv SO_4	98th Percentile Δdv NO_3	98th Percentile Δdv PM_{10}	98th Percentile Δdv NO_2
Caney Creek Wilderness							
2001	3.199	1.695	41	1.292	0.398	0.003	0.002
2002	2.270	1.481	33	0.964	0.465	0.011	0.041
2003	4.437	1.169	38	0.595	0.555	0.004	0.015
Upper Buffalo Wilderness							
2001	2.385	1.185	35	0.840	0.343	0.003	0.000
2002	1.618	0.846	20	0.685	0.156	0.003	0.003
2003	1.998	1.176	25	0.958	0.215	0.003	0.000
Hercules Glades Wilderness							
2001	1.838	1.060	30	0.966	0.092	0.002	0.000
2002	1.340	0.643	14	0.490	0.151	0.001	0.001
2003	2.263	0.806	21	0.703	0.101	0.002	0.000
Mingo Wilderness							
2001	1.701	0.903	18	0.834	0.063	0.003	0.003
2002	1.031	0.805	25	0.674	0.129	0.002	0.000
2003	1.150	0.750	14	0.452	0.288	0.003	0.008

Table 4-3 demonstrates that the 98th percentile impacts from SO_4 are always greater than the 98th percentile impacts from NO_3. Therefore, as with SN-01, SO_4, and by default SO_2, is clearly the dominating pollutant of concern from SN-02.

TABLE 4-4. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-05 BY POLLUTANT

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Day with Δdv ≥ 0.5	98th Percentile Δdv SO_4	98th Percentile Δdv NO_3	98th Percentile Δdv PM_{10}	98th Percentile Δdv NO_2
Caney Creek Wilderness							
2001	0.028	0.008	0	0.001	0.007	0.000	0.000
2002	0.02	0.005	0	0.001	0.004	0.000	0.000
2003	0.036	0.01	0	0.002	0.008	0.000	0.000
Upper Buffalo Wilderness							
2001	0.014	0.004	0	0.001	0.003	0.000	0.000
2002	0.009	0.004	0	0.003	0.000	0.000	0.000
2003	0.013	0.005	0	0.001	0.004	0.000	0.000
Hercules Glades Wilderness							
2001	0.007	0.004	0	0.001	0.003	0.000	0.000
2002	0.006	0.003	0	0.001	0.002	0.000	0.000
2003	0.008	0.004	0	0.002	0.001	0.000	0.000
Mingo Wilderness							
2001	0.009	0.003	0	0.000	0.003	0.000	0.000
2002	0.019	0.008	0	0.001	0.007	0.000	0.000
2003	0.015	0.003	0	0.001	0.002	0.000	0.000

Table 4-4 demonstrates that the 98th percentile impacts from the combined pollutants are well below the 0.5 Δdv threshold to be considered a contributor to visibility impairment.

5.1 IDENTIFICATION OF AVAILABLE RETROFIT SO_2 CONTROL TECHNOLOGIES FOR SN-01 AND SN-02

Sulfur oxides, SO_X, are generated during coal combustion from the oxidation of sulfur contained in the fuel. SO_X emissions are almost entirely dependent on the sulfur content of the fuel and are generally not affected by boiler size or burner design. SO_X emissions from conventional combustion systems are predominantly in the form of SO_2. Since SO_2 is the predominant sulfur compound emitted from SN-01 and SN-02, the BART analysis is specific to emissions of SO_2. Reductions in emissions of SO_2 will reduce visibility impairment by reducing sulfate (SO_4) formation.

Step 1 of the top-down control review is to identify available retrofit control options for SO_2. The available SO_2 retrofit control technologies for SN-01 and SN-02 are summarized in Table 5-1. The retrofit controls examined are limited to add-on controls that eliminate SO_2 after it is formed, as SN-01 and SN-02 currently use a low sulfur fuel and thus would not achieve significant additional reductions through alternative fuel supplies comparable to the most efficient add-on controls. The available SO_2 control technologies are Dry Sorbent Injection (DSI), semi-dry scrubbing, and wet scrubbing.

TABLE 5-1. AVAILABLE SO_2 CONTROL TECHNOLOGIES FOR SN-01 AND SN-02

SO_2 Control Technologies
Dry Sorbent Injection
Semi-Dry Scrubbing
Wet Scrubbing

5.2 ELIMINATE TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES FOR SN-01 AND SN-02

Step 2 of the BART determination is to eliminate technically infeasible SO_2 control technologies that were identified in Step 1.

5.2.1 DRY SORBENT INJECTION

Dry sorbent injection involves the injection of a sorbent into the exhaust gas stream where SO_2 reacts with and becomes entrained in the sorbent. The stream is then passed through a particulate control device to remove the sorbent and entrained SO_2. The process was developed as a lower cost Flue Gas Desulfurization (FGD) option because the mixing of the SO_2 and sorbent occurs directly in the exhaust gas stream instead of in a separate tower. Depending on the residence time, gas stream temperature, and limitations of the particulate control device, sorbent injection control efficiency can range between 40 and 60 percent.[18] This control is a technically feasible option for the control of SO_2 from SN-01 and SN-02.

5.2.2 SEMI-DRY SCRUBBER

There are various designs of semi-dry scrubbing; or fuel gas desulfurization (FGD); systems, including the Spray Dryer Absorber (SDA) and Circulating Dry Scrubber (CDS) designs. In the SDA design, a fine mist of lime slurry is sprayed into an absorption tower where the SO_2 is absorbed by the slurry droplets. The absorption of the SO_2 leads to the formation of calcium sulfite and calcium sulfate within the droplets. The liquid-to-gas ratio is such that the heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the tower. This leads to the formation of a dry powder which is carried out with the gas and collected with a fabric filter.

In the CDS process, the flue gas is introduced into the bottom of a reactor vessel at high velocity through a venturi nozzle; the exhaust is mixed with water, hydrated lime, recycled flyash and CDS reaction products. The intensive gas-solid mixing that occurs in the reactor promotes the reaction of sulfur oxides in the flue gas with the dry lime particles. The mixture of reaction products (calcium sulfite/sulfate), unreacted lime, and fly ash is carried out with the exhaust and collected in an ESP or fabric filter. A large portion of the collected particles is recycled to the reactor to sustain the bed and improve lime utilization.

Semi-dry scrubbing control efficiencies range from 60 to 95 percent,[19] and is a technically feasible option for the control of SO_2 from SN-01 and SN-02.

5.2.3 WET SCRUBBER

Wet scrubbing involves scrubbing the exhaust gas stream with slurry comprised of lime or limestone in suspension. The process takes place in a wet scrubbing tower located downstream of a PM control device such as a fabric filter or an electrostatic precipitator (ESP) to prevent the plugging of spray nozzles and other problems caused by the presence of particulates in the scrubber. Similar to the chemistry illustrated above for spray dryer absorption, the SO_2 in the gas stream reacts with the lime or limestone slurry to form calcium sulfite and calcium sulfate. Wet lime scrubbing is generally capable of achieving 80-95 percent control.[20] Higher control efficiencies may be achieved in certain applications. This control is a technically feasible option for the control of SO_2 from SN-01 and SN-02.

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[18] "Assessment of Control Technology Options for BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities" Northeast States for Coordinated Air Use Management (NESCAUM), March 2005.

[19] EPA Basic Concepts in Environmental Sciences, Module 6: Air Pollutants and Control Techniques http://www.epa.gov/eogapti1/module6/sulfur/control/control.htm

[20] *Id.*

EPA has recently suggested the control from wet scrubbing can achieve emissions reductions of up to 97%. Engineering evaluations conducted on Unit 1 and 2 by Sargent & Lundy (S&L) suggest that a control efficiency of up to 97% may be achievable through the application of wet scrubbing for higher-sulfur coals. However, as no vendor guarantee for greater than 95% control from wet scrubbing was available, Entergy cannot confidently rely on this level of control specific to SN-01 and SN-02. Moreover, Entergy has not received any assurances from vendors or its engineering consultant, S&L, of achieving such a level on a consistent, 30-day average basis.

5.3 RANK OF TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS BY EFFECTIVENESS FOR SN-01 AND SN-02

The third step in the BART analysis is to rank the technically feasible options according to their effectiveness in reducing the VAP. Table 5-2 provides a ranking of the control levels for the controls listed in the previous section.

TABLE 5-2. CONTROL EFFECTIVENESS OF TECHNICALLY FEASIBLE SO_2 CONTROL TECHNOLOGIES

Control Technology	Estimated Control Efficiency
Wet Scrubber	80-95%[21]
Semi-Dry Scrubber	60-95%
Dry Sorbent Injection	40-60%

5.4 EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS FOR SN-01 AND SN-02

The fourth step in the BART analysis is the impact analysis where the impacts for those control options deemed feasible in Step 2 are evaluated. This analysis is typically conducted to demonstrate that a control technology that is more effective than another technology does not constitute BART. The BART determination guidelines list the four factors to be considered in the impact analysis:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

Wet and dry scrubbing are the most effective technologies at reducing SO_2. As shown in Table 5-2, both technologies can achieve 95 percent reduction in SO_2.

[21] Estimated efficiency for wet FGD for low-sulfur coals typically combusted at White Bluff. Higher efficiencies are achievable for wet FGD when burning higher-sulfur coal, but may not be achievable for the low-sulfur coal typically combusted at SN-01 and SN-02.

Site-specific specifications from S&L indicate that semi-dry scrubbing can achieve an outlet rate of 0.06 lb/MMBtu on a 30-day rolling average basis. Entergy believes that semi-dry scrubbing represents a superior technology in comparison to wet scrubbing, thus the majority of research for this analysis has been focused on this control option. Information from S&L also indicate that wet scrubbing may be able to achieve an outlet rate of 0.04 lb/MMBtu on a 30-day rolling average basis.[22] These emission levels represent reductions of 95% for semi-dry scrubbing and 97% for wet scrubbing when applied to the facility's current maximum allowable SO_2 emission rate of 1.2 lb/MMBtu. Notwithstanding a lack of vendor assurances, for the purposes of this analysis, wet scrubbing has been evaluated at an outlet SO_2 emission rate of 0.04 lb/MMBtu.

5.4.1 COST OF COMPLIANCE

Control Costs

The capital costs were annualized over a 30-year period and then added to the annual operating costs to obtain the total annualized costs. The details of the cost effectiveness calculations are provided in Appendix A of this report.

The capital and direct operating and maintenance (O&M) costs of a semi-dry scrubber used in the cost effectiveness calculations were based on vendor estimates. The indirect operating costs such as property tax and insurance are based on calculation methods published in the sixth edition of the EPA's Air Pollution Cost Control Manual for wet acid gas absorber systems. The capital and O&M costs of a wet scrubber used in the cost effectiveness calculations are based on vendor estimates for a system estimated to achieve 97% control for an inlet SO_2 rate of 2.0 lb/MMBtu (0.06 lb/MMBtu) and calculation methods published in the sixth edition of the EPA's Air Pollution Cost Control Manual. The costs for a system capable of achieving equivalent control with an inlet SO2 rate of 1.2 lb/MMBtu or 0.04 lb/MMBtuwould be approximately 5 to 6 percent higher. The capital cost associated with a wet scrubber system is considerably higher than for a semi-dry scrubber system.

It should be noted that the capital costs presented for the SO_2 control options do not include any Allowance for Funds Used During Construction (AFUDC). AFUDC represents the interest expense incurred on the investment in a large capital project, such as a scrubber installation, which can take several years to complete. While interest expenses will certainly be incurred on a such a project, and AFUDC is typically considered as part of the capital cost of such a project for standard accounting and rate-making purposes, EPA Region 6 has expressed concern with the inclusion of this expense. In order to facilitate timely review of this revised FFA, Entergy, without waiver, has omitted this cost from the capital costs presented within this FFA.

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[22] The cost estimate from S&L for a wet FGD system represents a system estimated to achieve 97% control for an inlet SO_2 rate of 2.0 lb/MMBtu (0.06 lb/MMBtu) S&L has indicated the cost for a system capable of achieving 97% control for an inlet SO_2 rate of 1.2 lb/MMBtu (0.04 lb/MMBtu) would be 5 to 6 percent higher. Entergy has not received any guarantee that an outlet SO_2 emission rate of 0.04 lb/MMBtu is consistently achievable for SN-01 or SN-02.

Annual Tons Reduced

The annual tons reduced that were used in the cost effectiveness calculations were determined by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. The baseline annual emission rate was the average rate from 2001-2003, as reported by Entergy in their air emission inventories. The controlled annual emission rates were based on the lb/MMBtu levels believed to be achievable for the control technologies multiplied by the future annual heat input. The future annual heat input is based on the average hourly heat input from CAMD for 2001 to 2003 multiplied by the average annual operating hours from 2001-2003 for each boiler.

Cost Effectiveness

The cost effectiveness in dollars per ton of SO_2 reduced was determined by dividing the annualized cost of control by the annual tons reduced. Table 5-3 indicates that the cost effectiveness of semi-dry scrubber at an SO_2 rate of 0.06 lb/MMBtu is approximately \$2,913 per ton of SO_2 removed for SN-01 and \$3,355 per ton of SO_2 removed for SN-02. The incremental costs for wet scrubbing at 0.04 lb/MMBtu over semi-dry scrubbing at 0.06 lb/MMBtu are \$26,701/ton for SN-01 and \$27,218/ton for SN-02. As documented in Section 5.5 below, the additional cost of wet FGD is not justified in light of the negligible improvement in visibility impacts associated with this control technology.

TABLE 5-3. SUMMARY OF COST EFFECTIVENESS FOR SN-01 AND SN-02 SO_2 CONTROLS

	Baseline Emission Rate	Controlled Emission Level	Annual Heat Input[1]	Controlled Emission Rate	SO_2 Reduced	Capital Cost	Annual Capital Cost	Annual Direct O&M	Annual Indirect O&M	Total Annual Cost	Cost Effectiveness	Incremental Cost Compared to Semi-Dry Scrubbing	Incremental Visibility Improvement[2]
	(tpy)	(lb/MMBtu)	(MMBtu/yr)	(tpy)	(tpy)	($)	($/yr)	($/yr)	($/yr)	($/yr)	($/ton)	($/ton)	(dv)
SN-01 -Semi-Dry Scrubbing	19,550	0.06	55,269,197	1,658	17,892	335,133,908	27,007,236	8,837,861	16,282,987	52,128,084	2,913	-	0.813
SN-02 - Semi-Dry Scrubbing	17,167	0.06	54,138,841	1,624	15,543	335,133,908	27,007,236	8,859,823	16,282,987	52,150,047	3,355	-	0.767
SN-01 -Wet Scrubbing	19,550	0.04	55,269,197	1,105	18,445	389,496,052	31,388,086	15,946,729	19,550,719	66,885,535	3,626	26,701	0.021
SN-02 - Wet Scrubbing	17,167	0.04	54,138,841	1,083	16,084	389,496,052	31,388,086	15,946,729	19,550,719	66,885,535	4,158	27,218	0.021

1. The future annual heat input was estimated by multiplying the average hourly heat input from CAMD for 2009-2011 for each boiler by the average number of operating hours for each boiler from 2009-2011.

2. The incremental visibility improvement for semi-dry scrubbing is the maximum visibility improvement in the 98th percentile impact compared to baseline (See Tables 5-5 and 5-6). The incremental visibility improvement for wet scrubbing is the difference between the maximum improvement due to wet scrubbing less the maximum visibility improvement from dry scrubbing (See Tables 5-5 and 5-6).

5.4.2 ENERGY IMPACTS AND NON-AIR QUALITY IMPACTS

As illustrated in Table 5-3 and in Section 5.5 below, wet scrubbing is expected to achieve approximately the same level of visibility improvement as the proposed dry scrubbing technology. However, the negative non-air quality environmental impacts are greater with wet scrubbing systems. Such impacts include a potential increase in particulate and sulfuric acid (H_2SO_4) mist emissions. In addition, wet scrubbers require increased water use and generate large volumes of wastewater and solid waste/sludge that must be managed and/or treated. This places additional burdens on the wastewater treatment and solid waste management capabilities. Moreover, if wet scrubbing produces calcium sulfite sludge, the sludge will be water-laden, and it must be stabilized for landfilling. Wet scrubbing systems require increased power requirements and increased reagent usage over dry scrubbers. Thus, from an overall environmental perspective, dry scrubbing is superior to wet scrubbing.

5.4.3 REMAINING USEFUL LIFE

The remaining useful life of SN-01 and SN-02 does not impact the annualized capital costs for either semi-dry scrubbing or wet scrubbing because the useful life of the units is anticipated to be at least as long as the capital cost recovery period, which is 30 years based on the recovery period documented for wet scrubbers for acid gas in the EPA's Control Cost Manual.

5.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE SO_2 CONTROLS FOR SN-01 AND SN-02

A final impact analysis was conducted to assess the visibility improvement achieved by comparing the impacts associated with the baseline emission rates to the impacts associated with the controlled emission rates. Section 4 of this report documents the existing visibility impairment attributable to SN-01 and SN-02. In order to assess the visibility improvement associated with semi-dry and wet scrubbing, the controlled emission rates associated with each control technology were modeled using CALPUFF. The SO_2 emission rates associated with wet and semi-dry scrubbers were calculated as follows:

$$P * HI = 537.00 \text{ lb/hr}$$

Where:
P for wet scrubber = 0.04 lb/MMBtu
P for semi-dry scrubber = 0.06 lb/MMBtu
HI (hourly heat input) = 8,950 MMBtu/hr

Table 5-4 summarizes the lb/hr emission rates that were modeled to reflect the addition of wet and semi-dry scrubbers on SN-01 and SN-02. One important thing to note is the ammonium sulfate emission rate indicated for wet scrubbers is higher than the ammonium sulfate emission rate indicated for semi-dry scrubbers. For all PM species other than ammonium sulfate, the NPS speciation spreadsheets were relied upon to determine emission rates for PM species. For ammonium sulfate, the approach described below was used. The NO_X emission rates were modeled at the baseline rates.

Sulfur in the fuel reacts with oxygen during the combustion process to form SO_2. Some of the SO_2 is further oxidized to SO_3, which is a precursor to sulfuric acid (H_2SO_4). Sulfuric acid can react with ammonia to cause primary emissions of ammonium sulfate. According to both FGD suppliers and the EPA, wet scrubbers have less affinity for SO_3 and typically capture between 25-50% of the SO_3.[23] Since SO_3 can lead to the formation of H_2SO_4, which leads to the formation of ammonium sulfates, the higher level of SO_3 control for semi-dry scrubbers will result in lower H_2SO_4 emissions and thus lower ammonium sulfate emissions. The ammonium sulfate emission rates for semi-dry scrubbers shown in Table 5-4 were determined assuming the reduction in ammonium sulfate (SO_4) is proportional to the reduction in SO_2 from the baseline case to the controlled case (95%). The ammonium sulfate emission rates for wet scrubbers shown in Table 5-4 were determined assuming a 50% reduction in SO_4 from the baseline case to the controlled case.

TABLE 5-4. SUMMARY OF EMISSION RATES MODELED TO REFLECT SO_2 CONTROLS

Source	SO_2 (lb/hr)	SO_4[1] (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
SN-01 – Semi-Dry Scrubbing	537.0	2.7	3,001.4	1.0	1.0	0.7	0.0	5.4
SN-02 – Semi-Dry Scrubbing	537.0	2.8	3,527.4	1.0	1.0	0.7	0.0	5.6
SN-01 – Wet Scrubbing	358.0	18.4	3,001.4	6.7	6.5	4.6	0.2	36.4
SN-02 – Wet Scrubbing	358.0	18.4	3,527.4	6.7	6.5	4.6	0.2	36.4

[1] SO_4 as it is displayed in this table represents ammonium sulfate.

Comparisons of the existing visibility impacts and the visibility impacts based on wet and semi-dry scrubbing, including the maximum modeled visibility impact, 98th percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv, for each Class I area are provided in Table 5-5 and Table 5-6.

[23] In addition, according to the EPA Technical Support Document for the Rules to Reduce Interstate Transport of Fine Particulate Matter and Ozone, "More than 90 percent of SO_3/H_2SO_4 is removed in a dry FGD, while up to about 50 percent removal occurs in a wet FGD system." http://www.epa.gov/cair/pdfs/0053-2263.pdf

TABLE 5-5 SUMMARY OF MODELED IMPACTS FROM SO_2 CONTROL VISIBILITY IMPACT ANALYSIS FOR SN-01 (2001-2003)

	Caney Creek Wilderness			Upper Buffalo Wilderness			Hercules Glades Wilderness			Mingo NWR		
	Maximum Impact (Δdv)	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**
Existing Emission Rate	4.194	1.628	106	2.339	1.140	77	2.230	1.041	61	1.569	0.887	56
Semi-Dry Scrubber	1.961	0.815	27	0.763	0.378	6	0.698	0.358	5	0.841	0.267	2
Post Control Improvement†	*2.233*	*0.813*	*79*	*1.576*	*0.762*	*71*	*1.532*	*0.683*	*56*	*0.728*	*0.620*	*54*
Wet Scrubber	1.941	0.794	26	0.774	0.350	6	0.687	0.360	3	0.838	0.271	1
Incremental Improvement over Semi-Dry Scrubber†	*0.020*	*0.021*	*1*	*-0.011*	*0.028*	*0*	*0.011*	*-0.002*	*2*	*0.003*	*-0.004*	*1*

†The visibility improvement shown in the table has been calculated from values that include more decimal places than what is shown in the table. Due to rounding, the visibility improvement calculated from the baseline and controlled 98th percentile impacts shown in the table may be slightly different than the visibility improvement reflected in the table.

TABLE 5-6. SUMMARY OF MODELED IMPACTS FROM SO_2 CONTROL VISIBILITY IMPACT ANALYSIS FOR SN-02 (2001-2003)

	Caney Creek Wilderness			**Upper Buffalo Wilderness**			**Hercules Glades Wilderness**			**Mingo NWR**		
	Maximum Impact (Δdv)	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**
Existing Emission Rate	4.437	1.695	112	2.385	1.185	80	2.263	1.060	65	1.701	0.903	57
Semi-Dry Scrubber	2.245	0.941	35	0.888	0.418	11	0.803	0.415	6	0.977	0.310	3
Post Control Improvement†	*2.192*	*0.754*	*77*	*1.497*	*0.767*	*69*	*1.460*	*0.645*	*59*	*0.724*	*0.593*	*54*
Wet Scrubber	2.226	0.920	35	0.899	0.405	10	0.792	0.416	6	0.974	0.315	3
Post Control Improvement over Semi-Dry Scrubber†	*0.019*	*0.021*	*0*	*-0.011*	*0.013*	*1*	*0.011*	*-0.001*	*0*	*0.003*	*-0.005*	*0*

†The visibility improvement shown in the table has been calculated from values that include more decimal places than what is shown in the table. Due to rounding, the visibility improvement calculated from the baseline and controlled 98th percentile impacts shown in the table may be slightly different than the visibility improvement reflected in the table.

As shown in Table 5-5 and Table 5-6, based on visibility predictions from the CALPUFF modeling system, the operation of a semi-dry scrubber achieving 0.06 lb/MMBtu will result in up to a 0.813 Δdv improvement (depending on the Class I area) to the existing 98th percentile day of visibility impairment attributable to SN-01 and up to 0.767 Δdv improvement for SN-02. By comparison, wet scrubbing achieving 0.04 lb/MMBtu only adds up to an additional 0.028 Δdv improvement for SN-01 and up to 0.021 Δdv improvement for SN-02.

For convenience, Tables 5-7 and 5-8 provide a condensed summary of the predicted improvements to visibility impairment alongside the estimated control costs. While the application of wet scrubbing may be able to achieve a nominally lower outlet SO_2 emission rate, there is essentially no incremental visibility benefit of going from semi-dry scrubbing to wet scrubbing. Further, in some cases, CALPUFF predicts worse visibility impairment for wet scrubbing as opposed to semi-dry scrubbing. This is likely due to the higher SO_4 emissions associated with wet vs dry scrubbing. Overall, the very small differences in predicted visibility impacts likely fall within the relative accuracy level of CALPUFF's modeling results. Given that wet scrubbing requires a significantly higher capital investment and is more expensive from an incremental cost effectiveness standpoint than semi-dry scrubbing, it cannot be justified as BART at SN-01 and SN-02. The adverse non-air environmental impacts from wet scrubbing also make it a less desirable control technology.

TABLE 5-7. INCREMENTAL COST EFFECTIVENESS FOR SN-01 WITH CLASS I AREA IMPROVEMENT

Unit ID	Control Description	SO_2 Emissions (lb/MMBtu)	Control Eff. From Baseline (%)	Emission Reduction from Baseline (tons/yr)	Installed Cost ($)	Total Annual Control Cost ($)	Pollution Control Cost ($/ton)	Incremental Cost Compared to Semi-dry Scrubbing ($/ton)	Class I Area	Baseline 98th Percentile Δdv	Controlled 98th Percentile Δdv	Improvement in 98th Percentile Δdv	Incremental Improvement in 98th Percentile Δdv Compared to Semi-dry Scrubbing	Baseline # Days > 0.5 Δdv	Controlled # Days > 0.5 Δdv	Improvement in Controlled # Days > 0.5 Δdv Compared to Semi-dry Scrubbing
SN-01	Semi-dry Scrubbing	0.06	93%	17,892.26	335,133,908	52,128,084	2,913	-	Caney Creek	1.628	0.815	0.813	-	106	27	-
									Hercules-Glades	1.041	0.358	0.683	-	61	5	-
									Mingo	0.887	0.267	0.620	-	56	2	-
									Upper Buffalo	1.140	0.378	0.762	-	77	6	-
SN-01	Wet Scrubbing	0.04	95%	18,444.95	389,496,052	66,885,535	3,626	26,701	Caney Creek	1.628	0.794	0.834	0.021	106	26	1
									Hercules-Glades	1.041	0.360	0.681	-0.002	61	3	2
									Mingo	0.887	0.271	0.616	-0.004	56	1	1
									Upper Buffalo	1.140	0.350	0.790	0.028	77	6	0

TABLE 5-8. INCREMENTAL COST EFFECTIVENESS FOR SN-02 WITH CLASS I AREA IMPROVEMENT

Unit ID	Control Description	SO_2 Emissions (lb/MMBtu)	Control Eff. From Baseline (%)	Emission Reduction from Baseline (tons/yr)	Installed Cost ($)	Total Annual Control Cost ($)	Pollution Control Cost ($/ton)	Incremental Cost Compared to Semi-dry Scrubbing ($/ton)	Class I Area	Baseline 98th Percentile Δdv	Controlled 98th Percentile Δdv	Improvement in 98th Percentile Δdv	Incremental Improvement in 98th Percentile Δdv Compared to Semi-dry Scrubbing	Baseline # Days > 0.5 Δdv	Controlled # Days > 0.5 Δdv	Incremental Improvement in Controlled # Days > 0.5 Δdv Compared to Semi-dry Scrubbing
SN-02	Semi-dry Scrubbing	0.06	92%	15,542.83	335,133,908	52,150,047	3,355	-	Caney Creek	1.695	0.941	0.754	-	112	35	-
									Hercules-Glades	1.060	0.415	0.645	-	65	6	-
									Mingo	0.903	0.310	0.593	-	57	3	-
									Upper Buffalo	1.185	0.418	0.767	-	80	11	-
SN-02	Wet Scrubbing	0.04	95%	16,084.22	389,496,052	66,885,535	4,158	27,218	Caney Creek	1.695	0.920	0.775	0.021	112	35	0
									Hercules-Glades	1.060	0.416	0.644	-0.001	65	6	0
									Mingo	0.903	0.315	0.588	-0.005	57	3	0
									Upper Buffalo	1.185	0.405	0.780	0.013	80	10	1

5.6 PROPOSED BART FOR SO_2 FOR SN-01 AND SN-02

Entergy is proposing that the SO_2 BART emission level for SN-01 and SN-02 be 0.06 lb/MMBtu based on the installation and operation of a semi-dry scrubber or whatever technology may become available to achieve that level of control. EPA has previously agreed that "this [SDA] technology is BART for these two units."[24] Entergy is proposing to meet this limit on a 30-day rolling average basis. This emission level provides for a very small compliance margin considering the variability of the coal content for the White Bluff units; therefore, the proposed 30-day averaging period and compliance demonstration method is critical. Compliance will be demonstrated using data from the existing CEMS.

5.6.1 COMPARATIVE SO_2 BART DETERMINATIONS

EPA has agreed with similar and even less stringent SO_2 BART determinations in other states. For example, in Oklahoma,[25] EPA agreed with the BART determination of 0.06 lb/MMBtu achieved through use of dry scrubbers for similar boilers, based on the minimal visibility improvement associated with wet vs dry scrubbing.. In Nebraska[26] at GGS, BART for SO_2 was also determined to be 0.06 lb/MMBtu achieved through the use of dry scrubbers. These similar units provide a good comparison of emission levels achievable through similar control technology.

Other BART determinations have resulted in higher emission limitations. For example, in Alabama,[27] a smaller EGU was allowed an emission limitation of 0.47 lb/MMBtu through use of flue solvent injection or comparable technologies. In Arizona,[28] SO_2 BART was determined to be in the range of 0.08 – 0.15 lb/MMBtu from existing wet scrubbers. An EGU in Colorado[29] has a proposed BART emission rate of 0.13 lb/MMBtu through use of dry scrubbing. A lower emission rate of 0.09 lb/MMBtu was evaluated and determined not reasonable due to the minimal visibility improvement projected as compared to the higher costs of scrubbing to meet the lower rate.

In other determinations, such as Illinois,[30] the control technology was not stated in the BART determination but the SO_2 rate determined to be BART was in the range of 0.11 – 0.23 lb/MMBtu, dependent upon boiler type and averaging considerations. SO_2 BART in Kansas[31] was achieved through "scrubbing" with an emission limitation of 0.10 lb/MMBtu for one boiler and through wet scrubbing with an emission limitation of 0.15 lb/MMBtu for another. An EGU in Montana[32] similar to Entergy's SN-01 and SN-02 has a BART emission rate of 0.08 lb/MMBtu.

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24 November 25, 2009, letter from Mr. Jeff Robinson, EPA, to Mr. Tom Rheaume, ADEQ.

25 77 Fed. Reg. 16168 (March 22, 2011).

26 77 Fed. Reg. 40150 (July 6, 2012).

27 77 Fed. Reg. 11937 (February 28, 2012).

28 77 Fed. Reg. 42834 (July 20, 2012).

29 77 Fed. Reg. 18052 (March 26, 2012).

30 77 Fed. Reg. 3966 (January 26, 2012).

31 77 Fed. Reg. 52604 (August 23, 2011).

32 77 Fed. Reg. 23988 (April 20, 2012).

5.7 SO_2 BART FOR SN-05

The maximum visibility impairment predicted by the CALPUFF modeling system for SN-05 is only 0.036 Δdv[33]. This is an extremely low level of impairment, so low that it is likely falls within the level of accuracy that can be attributed to CALPUFF. In addition, this modeling assumes that the auxiliary boiler operates at the maximum daily emission rate 365 days per year. Since the existing visibility impairment predicted by CALPUFF is extremely low, to the point of practically being nonexistent, the impairment cannot be considered significant such as to require controls. Said another way, the impairment is so low that any improvement from reductions would be less than negligible. Therefore, no controls will be considered BART for SN-05. This conclusion is consistent with EPA's determinations for similar boilers in other states, such as the auxiliary boiler at the Basin Electric Power Cooperative's Leland Olds Station located in North Dakota or the auxiliary boiler at the Golden Valley Electric Association's Healy Power plant in Fairbanks, Alaska.

[33] *See* Table 4-4

6.1 IDENTIFICATION OF AVAILABLE RETROFIT NO_X CONTROL TECHNOLOGIES FOR SN-01 AND SN-02

Nitrogen oxides, NO_X, are produced during fuel combustion when nitrogen contained in both the fuel and the combustion air is exposed to high temperatures. The origin of the nitrogen (i.e. fuel vs. combustion air) has led to the use of the terms "thermal" NO_X and "fuel" NO_X when describing NO_X emissions. Thermal NO_X emissions are produced when elemental nitrogen in the combustion air is exposed to a high temperature zone and oxidized. Fuel NO_X emissions are created during the rapid oxidation of nitrogen compounds contained in the fuel.

Nitrogen oxide (NO) is typically the predominant form of NO_X from fossil fuel combustion. Nitrogen dioxide (NO_2) makes up the remainder of the NO_X. The formation of NO_X compounds in utility boilers is sensitive to the method of firing. In tangentially-fired boilers, such as SN-01 and SN-02, a single rotating flame is created in the center of the furnace, rather than the discrete flames produced by burners in the wall-fired boilers. Tangentially fired boilers typically have lower uncontrolled NO_X emissions than wall-fired boilers. Therefore, baseline NO_X emission rates can vary significantly from plant to plant due to method of firing as well as several other factors.

Step 1 of the BART determination is the identification of all available retrofit NO_X control technologies. The available retrofit NO_X control technologies are summarized in Table 6-1 for SN-01 and SN-02.

NO_X emissions controls, as listed in Table 6-1, can be categorized as combustion or post-combustion controls. Combustion controls, including flue gas recirculation (FGR), overfire air (OFA) or separated OFA (SOFA), and Low NO_X Burners (LNB), reduce the peak flame temperature and excess air in the furnace which minimizes NO_X formation. Post-combustion controls, such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR), convert NO_X in the flue gas to molecular nitrogen and water.

TABLE 6-1. AVAILABLE NO_X CONTROL TECHNOLOGIES FOR SN-01 AND SN-02

NO_X Control Technologies	
Combustion Controls	Flue Gas Recirculation (FGR) Separated Overfire Air (SOFA) Low NO_X Burners (LNB)
Post-Combustion Controls	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR)

6.2 ELIMINATE TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES

Step 2 of the BART determination is to eliminate technically infeasible NO_X control technologies that were identified in Step 1. Control ranges were developed using a combination of literature control ranges and efficiencies. Because many controlled emissions rates from literature values were higher than the baseline NO_X rate at SN-01 and SN-02, vendor estimates were also used to assist in developing the expected emission rates from the known relationships between the control options.

6.2.1 COMBUSTION CONTROLS

6.2.1.1 FLUE GAS RECIRCULATION (FGR)

FGR uses flue gas as an inert material to reduce flame temperatures. In a typical flue gas recirculation system, flue gas is collected from the combustion chamber or stack and returned to the burner via a duct and blower. The addition of flue gas reduces the oxygen content of the "combustion air" (air + flue gas) in the burner. The lower oxygen level in the combustion zone reduces flame temperatures, which in turn reduces thermal NO_X formation. However, vendor-specific review of the White Bluff boilers has concluded that NO_X reduction efficiency data for coal-fired units with FGR are limited. The amount of NO_X reduction achievable with FGR depends primarily on the fuel nitrogen content and amount of FGR used. Generally, FGR is more effective when used with low nitrogen content fuels such as natural gas and propane, since FGR is more effective in controlling thermal NO_X rather than fuel NO_X. Industry experience with FGR on coal-fired units for steam temperature control has shown very high maintenance on the gas recirculation fans due to erosion and corrosion. Many of the units with FGR for steam temperature control have removed the recirculation fans from service. The NO_X control achievable on tangentially fired units like White Bluff – Units 1&2 with LNB+OFA has been comparable to that of FGR at lower capital and O&M cost. Currently, FGR technology is not offered by OEMs for coal-fired units. For these reasons, FGR is not a feasible technology for the White Bluff coal-fired units.

6.2.1.2 OVERFIRE AIR (OFA) / SEPARATED OVERFIRE AIR (SOFA)

OFA diverts a portion of the total combustion air from the burners and injects it through separate air ports above the top level of burners. Staging of the combustion air creates an initial fuel-rich combustion zone with a lower peak flame temperature. This reduces the formation of thermal NO_X by lowering combustion temperature and limiting the availability of oxygen in the combustion zone where NO_X is most likely to be formed.

SOFA refers to a system wherein the OFA is injected in a separate wind box mounted above the main wind box in order to achieve greater separation from the combustion zone resulting in more effective NO_X suppression. SOFA as a single NO_X control technique results in estimated NO_X emissions for coal fired boilers of approximately 10%,[34] or 0.28-0.32 lb/MMBtu from SN-01 and SN-02. This control is a technically feasible option for the control of NO_X from SN-01 and SN-02.

[34] *Id.*

6.2.1.3 LOW NO_X BURNERS (LNB)

LNB technology utilizes advanced burner design to reduce NO_X formation through the restriction of oxygen, lowering of flame temperature, and/or reduced residence time. NO_X creation rates typically peak at oxygen levels of five to seven percent.[35] LNB is a staged combustion process that is designed to split fuel combustion into two zones. In the primary zone, NO_X formation is limited by one of two methods. Under staged fuel-rich conditions, low oxygen levels limit flame temperatures resulting in less NO_X formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel-lean conditions, excess air will reduce flame temperature to reduce NO_X formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NO_X formation.

When combined with SOFA, the estimated NO_X emission rate is 0.15 lb/MMBtu.[36] LNB systems with SOFA are technically feasible for the control of NO_X from SN-01 and SN-02.

6.2.2 POST COMBUSTION CONTROLS

6.2.2.1 SELECTIVE CATALYTIC REDUCTION (SCR)

SCR refers to the process in which NO_X is reduced by ammonia over a heterogeneous catalyst in the presence of oxygen. The process is termed selective because the ammonia preferentially reacts with NO_X rather than oxygen, although the oxygen enhances the reaction and is a necessary component of the process. The overall reactions are:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

The SCR process requires a reactor, a catalyst, and an ammonia storage and injection system. The effectiveness of an SCR system is dependent on a variety of factors, including the inlet NO_X concentration, the exhaust temperature, the ammonia injection rate, and the type of catalyst. When combined with LNB and OFA, the estimated NO_X emission rate is 0.055 lb/MMBtu.[37] This control is a technically feasible option for the control of NO_X from SN-01 and SN-02.

6.2.2.2 SELECTIVE NON-CATALYTIC REDUCTION (SNCR)

In SNCR systems, a reagent is injected into the flue gas in the furnace within an appropriate temperature window. The NO_X and reagent (ammonia or urea)

[35] http://www.energysolutionscenter.org/boilerburner/Workshop/RCTCombustion.htm.

[36] 2012 S&L NOx Study.

[37] *Id.*, this rate includes consideration of normal fluctuations which may occur over a 30-day compliance period.

react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. The SNCR reagent storage and handling systems are similar to those for SCR systems. However, both ammonia and urea SNCR processes require three to four times as much reagent as SCR systems to achieve similar NO_X reductions. When combined with LNB/OFA, the estimated NO_X emission rate is 0.13 lb/MMBtu.[38] This control is a technically feasible option for the control of NO_X from SN-01 and SN-02.

[38] *Id.*

6.3 RANK OF TECHNICALLY FEASIBLE NO_X CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis is to rank the technically feasible options according to effectiveness. Table 6-2 provides a ranking of the control levels for the controls listed in the previous section.

TABLE 6-2. CONTROL EFFECTIVENESS OF TECHNICALLY FEASIBLE NO_X CONTROL TECHNOLOGIES

Control Technology	Estimated Controlled Level for SN-01 and SN-02 (lb/MMBtu)
SOFA	0.28-0.32
LNB/SOFA	0.15
LNB/SOFA + SNCR	0.13
LNB/SOFA + SCR	0.055

Current NO_X emissions are approximately 0.31 lb/MMBtu from SN-01 and approximately 0.36 lb/MMBtu from SN-02. Based on evaluations by S&L, it is believed that combustion controls such as LNB in combination with SOFA will achieve a NO_X level of 0.15 lb/MMBtu for SN-01 and SN-02.[39] Further, it is believed that the addition of SCR to LNB/SOFA will achieve a NO_X level of approximately 0.055 lb/MMBtu at each unit and LNB/SOFA + SNCR will achieve a level of 0.13 lb/MMBtu at each unit.

6.4 EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS

Step four for the BART analysis is the impact analysis. The BART determination guidelines list four factors to be considered in the impact analysis:

- ▲ Cost of compliance;
- ▲ Energy impacts;
- ▲ Non-air quality impacts; and
- ▲ The remaining useful life of the source.

6.4.1 COST OF COMPLIANCE

The capital costs, operating costs, and cost effectiveness of LNB/SOFA, LNB/SOFA + SNCR and LNB/SOFA + SCR were estimated for the cost analysis.

[39] EPA established presumptive SO_2 and NO_X controls for coal-fired EGUs in the BART rule. For dry bottom tangentially-fired EGUs, the presumptive NO_X limit is 0.15 lb/MMBtu. (Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART Determinations; Final Rule.") 77 FR 39134 (July 6, 2005).

Control Costs

Control costs were calculated using vendor capital and operating cost estimates specific to the units. The capital costs were annualized over a 30-year period and then added to the annual operating costs to obtain the total annualized costs.

The details of the capital and operating cost estimates are provided in Appendix A of this report.

It should be noted that the capital costs presented for the various NO_x control options do not include any Allowance for Funds Used During Construction (AFUDC). AFUDC represents the interest expense incurred on the investment in a large capital project, such as a NOx controls installation, during the construction phase, which can take many months to several years to complete. While interest expenses will certainly be incurred on a such a project, and AFUDC is typically considered as part of the capital cost of such a project for standard accounting and rate-making purposes, EPA Region 6 has expressed concern with the inclusion of this expense. In order to facilitate review of this revised FFA, Entergy, without waiver, has omitted this cost from the capital costs presented within this FFA.

Annual Tons Reduced

The annual tons reduced that were used in the cost effectiveness calculations were determined by subtracting the estimated controlled annual emission rate from the baseline annual emission rate.

The baseline annual emission rates were the average rates from 2009-2011, as reported by Entergy in their air emission inventories. The controlled annual emission rate is based on the lb/MMBtu level believed to be achievable from the control technology multiplied by the future annual input to the boiler in MMBtu/yr. The future annual heat input is based on the average hourly heat input from CAMD for 2001 to 2003 multiplied by the average annual operating hours from 2001to 2003 for each boiler. This was the same approach that was used to estimate future annual heat input in the review of SO_2 controls

Cost Effectiveness

The cost effectiveness in dollars per ton of NO_X reduced was determined by dividing the annualized cost of control by the annual tons reduced. An incremental cost analysis was also performed to show the incremental increase in costs between LNB/SOFA + SCR and an LNB/SOFA system, as well as between LNB/SOFA + SNCR and LNB/SOFA. The costs effectiveness analysis is summarized in Table 6-3.

In the BART guidelines, EPA calculated that for all types of boilers other than cyclone boilers, combustion control technology is generally more cost-effective than post-combustion controls. EPA estimates that approximately 75 percent of the BART units (non-cyclone) could meet the presumptive NO_X limits at a cost of $100 to $1,000 per ton of

NO_X removed based on the use of combustion control technology.[40] For the units that could not meet the presumptive limits using combustion control technology, EPA estimates that almost all of these sources could meet the presumptive limits using advanced combustion controls. The EPA estimates that the costs of such controls are usually less than $1,500 per ton of NO_X removed.[41]

Table 6-3 indicates that the cost effectiveness of LNB/SOFA is approximately $375 per ton of NO_X removed. Installing LNB/SOFA would reduce NO_X emissions by more than 50%. By contrast, the incremental cost effectiveness of adding SNCR to LNB/SOFA is approximately $10,000/ton per unit. Similarly, the incremental cost of adding SCR to LNB/SOFA is approximately $7,250-$8,000/ton per unit.

Table 6-3 also demonstrates the improvement in the maximum of the 98th percentile visibility impairment results due to each control technology. As Table 6-3 clearly shows, LNB/SOFA + SNCR offers very little visibility improvement over LNB/SOFA alone (~0.03 dv). The addition of SCR incrementally improves visibility over LNB/SOFA by only approximately 0.1 dv at an annual cost of well over $20,000,000 per unit. Such a large cost cannot be justified by the negligible visibility improvement provided by SCR.

40 *Id.* at 39134-39135.
41 *Id.*

TABLE 6-3. SUMMARY OF COST EFFECTIVENESS FOR SN-01 AND SN-02 NO_X CONTROLS

	Baseline Emission Rate	Controlled Emission Level	Annual Heat Input[1]	Controlled Emission Rate	NOx Reduced	Capital Cost	Annual Capital Cost	Annual Fixed O&M	Annualized Variable O&M	Total Annual Cost	Cost Effectiveness	Incremental Cost Compared to LNB/SOFA	Incremental Visbility Improvement[2]
	(tpy)	(lb/MMBtu)	(MMBtu/yr)	(tpy)	(ton/yr)	($)	($/yr)	($/yr)	($/yr)	($/yr)	($/ton)	($/ton)	(dv)
SN-01 LNB/SOFA	7,249.23	0.15	55,269,197	4145.19	3104.04	10,461,206	843,031	142,000	177,887	1,162,918	375	-	0.176
SN-01 LNB/SOFA/SNCR	7,249.23	0.13	55,269,197	3592.50	3656.73	21,371,325	1,722,238	311,000	4,538,000	6,571,238	1,797	9,785	0.024
SN-01 LNB/SOFA/SCR	7,249.23	0.055	55,269,197	1519.90	5729.33	230,329,138	18,561,397	608,000	2,836,000	22,005,397	3,841	7,939	0.093
	(tpy)	(lb/MMBtu)	(MMBtu/yr)	(tpy)	(ton/yr)	($)	($/yr)	($/yr)	($/yr)	($/yr)	($/ton)	($/ton)	(dv)
SN-02 LNB/SOFA	8,185.33	0.15	54,138,841	4060.41	4124.91	14,488,206	1,167,552	142,000	170,838	1,480,391	359	-	0.225
SN-02 LNB/SOFA/SNCR	8,185.33	0.13	54,138,841	3519.02	4666.30	25,398,325	2,046,760	311,000	4,542,000	6,899,760	1,479	10,010	0.033
SN-02 LNB/SOFA/SCR	8,185.33	0.055	54,138,841	1488.82	6696.51	206,747,898	16,661,070	608,000	2,858,000	20,127,070	3,006	7,251	0.102

1. The future annual heat input was estimated by multiplying the average hourly heat input from CAMD for 2009-2011 for each boiler by the average number of operating hours for each boiler from 2009-2011.

2. The incremental visibility improvement for LNB/SOFA is the maximum visibility improvement in the 98th percentile impact compared to baseline (See Tables 6-5 and 6-6). The incremental visibility improvement for LNB/SOFA/SNCR and LNB/SOFA/SCR is the difference between the maximum improvement due to LNB/SOFA/SNCR or LNB/SOFA/SCR in the four Class I areas considered in the analysis less the maximum visibility improvement in the four Class I areas from LNB/SOFA (See Tables 6-5 and 6-6).

6.4.2 ENERGY IMPACTS & NON-AIR IMPACTS

As noted in Table 6-3 and in Section 6.5 below, SCR and SNCR systems are capable of achieving additional NO_X mass emission reductions in comparison to combustion controls such as LNB/SOFA. However, both SCR and SNCR systems create additional energy and/or non-air environmental impacts. SCR and SNCR systems require electricity to operate the ancillary equipment. The need for electricity to help power some of the ancillary equipment creates a demand for energy that currently does not exist.

SCR and SNCR can potentially cause significant environmental impacts. The primary avenue is related to the storage of ammonia. The storage of aqueous ammonia above 10,000 lbs is regulated by a risk management program (RMP), since the accidental release of ammonia has the potential to cause serious injury and death to persons in the vicinity of the release. Additionally, SCR and SNCR will likely also cause the release of unreacted ammonia to the atmosphere. This is referred to as ammonia slip. Ammonia slip from SCR and SNCR systems occurs either from ammonia injection at temperatures too low for effective reaction with NO_X, leading to an excess of unreacted ammonia, or from over-injection of reagent leading to uneven distribution; which also leads to an excess of unreacted ammonia. Ammonia released from SCR and SNCR systems will react with sulfates and nitrates in the atmosphere to form ammonium sulfate and ammonium nitrate. Together, ammonium sulfate and ammonium nitrate are the predominant sources of regional haze.

Another environmental impact associated with SCR is the disposal of catalyst waste. To maintain NO_X-removal effectiveness, the catalyst in an SCR system must periodically be cleaned, regenerated, or replaced. Cleaning and regeneration are preferred, but eventually the catalyst reaches the end of its useful life and must be replaced. Ideally the exhausted catalyst can be recycled for reuse, however, if the condition of the spent catalyst does not warrant recycling or a market is unavailable, the old catalyst must be disposed of. Current regulatory interpretations indicate spent SCR catalysts are exempted from hazardous waste regulation via 40 CFR § 261.4(b)(4) (Bevill Exemption) as flue gas emission control wastes. However, ongoing efforts by EPA to increase regulatory oversight of coal combustion residuals could alter that exemption, and create the potential that spent SCR catalysts would be characterized as hazardous wastes, hence increasing the cost of disposal. Regardless of the regulatory treatment of the waste, the disposal creates additional potential financial and environmental impacts associated with an SCR system.

6.4.3 REMAINING USEFUL LIFE

The remaining useful life of SN-01 and SN-02 are sufficiently long such that it does not affect the BART analysis.

6.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE NO_X CONTROLS

A final impact analysis was conducted to assess the visibility improvement for existing emission rates when compared to the emission rates associated with LNB/SOFA, LNB/SOFA + SNCR and LNB/SOFA + SCR. Section 4 of this report documented the existing visibility impairment attributable to SN-01 and SN-02. In order to assess the visibility improvement associated with LNB/SOFA, SCR and SNCR systems, the NO_X emission rates associated with the control systems were modeled using CALPUFF. The controlled emission level associated with LNB/SOFA system is 0.15 lb/MMBtu; the controlled emission level associated with SOFA + SNCR is 0.13 lb/MMBtu; and the controlled emission level associated with LNB/SOFA + SCR systems is 0.055 lb/MMBtu for each unit. These levels were multiplied by the maximum heat input to derive the hourly emission rates used in the modeling.

Table 6-4 summarizes the NO_X emission rates that were modeled to reflect the LNB/SOFA, LNB/SOFA + SNCR, and LNB/SOFA + SCR. The emission rates for the other pollutants shown in Tables 6-4 are the same as in the baseline modeling.

TABLE 6-4. SUMMARY OF EMISSION RATES MODELED TO REFLECT NO_X CONTROLS

	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
SN-01 – LNB/SOFA	7,763.5	36.8	1342.5	40.4	31.1	9.2	1.2	118.6
SN-02 – LNB/SOFA	7,825.1	36.8	1342.5	40.4	31.1	9.2	1.2	118.6
SN-01 - LNB/SOFA + SNCR	7,763.5	36.8	1163.5	40.4	31.1	9.2	1.2	118.6
SN-02 - LNB/SOFA + SNCR	7,825.1	36.8	1163.5	40.4	31.1	9.2	1.2	118.6
SN-01 – LNB/SOFA + SCR	7,763.5	36.8	492.3	40.4	31.1	9.2	1.2	118.6
SN-02 - LNB/SOFA + SCR	7,825.1	36.8	492.3	40.4	31.1	9.2	1.2	118.6

Tables 6-5 and 6-6 provide a comparison of the existing visibility impairment and the visibility impairment associated with the addition of NO_X controls on SN-01 and SN-02, respectively, in all affected Class I areas, including the maximum modeled visibility impact, the 98^{th} percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv.

TABLE 6-5. SUMMARY OF VISIBILITY IMPROVEMENT ASSOCIATED WITH NO_X CONTROL SYSTEMS ON SN-01 (2001-2003)

	Caney Creek Wilderness			Upper Buffalo Wilderness			Hercules Glades Wilderness			Mingo NWR		
	Maximum Impact (Δdv)	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**
Existing Emission Rate	4.194	1.628	106	2.339	1.140	77	2.230	1.041	61	1.569	0.887	56
LNB/OFA	3.465	1.462	89	2.243	1.039	62	2.175	0.865	48	1.168	0.849	45
Post Control Improvement	*0.729*	*0.166*	*17*	*0.096*	*0.101*	*15*	*0.055*	*0.176*	*13*	*0.401*	*0.038*	*11*
LNB/OFA + SNCR	3.386	1.428	86	2.233	1.029	62	2.170	0.844	47	1.146	0.842	44
Incremental Improvement Over LNB/SOFA	*0.079*	*0.034*	*3*	*0.010*	*0.01*	*0*	*0.005*	*0.021*	*1*	*0.022*	*0.007*	*1*
LNB/OFA + SCR	3.089	1.359	73	2.196	0.991	59	2.148	0.832	45	1.132	0.817	38
Incremental Improvement Over LNB/OFA	*0.376*	*0.103*	*16*	*0.047*	*0.048*	*3*	*0.027*	*0.033*	*3*	*0.036*	*0.032*	*7*

†The visibility improvement shown in the table has been calculated from values that include more decimal places than what is shown in the table. Due to rounding, the visibility improvement calculated from the baseline and controlled 98th percentile impacts shown in the table may be slightly different than the visibility improvement reflected in the table.

TABLE 6-6. SUMMARY OF VISIBILITY IMPROVEMENT ASSOCIATED WITH NO_X CONTROL SYSTEMS ON SN-02 (2001-2003)

\	Caney Creek Wilderness			Upper Buffalo Wilderness			Hercules Glades Wilderness			Mingo NWR		
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv
Existing Emission Rate	4.437	1.695	112	2.385	1.185	80	2.263	1.060	65	1.701	0.903	57
LNB/SOFA	3.483	1.47	91	2.258	1.046	62	2.191	0.870	48	1.174	0.856	45
Post Control Improvement	*0.954*	*0.225*	*21*	*0.127*	*0.139*	*18*	*0.072*	*0.190*	*17*	*0.527*	*0.047*	*12*
LNB/SOFA + SNCR	3.404	1.437	87	2.248	1.035	62	2.185	0.849	47	1.152	0.849	45
Incremental Improvement Over LNB/SOFA	*0.079*	*0.033*	*4*	*0.010*	*0.011*	*0*	*0.006*	*0.021*	*1*	*0.022*	*0.007*	*0*
LNB/SOFA + SCR	3.107	1.368	75	2.211	0.997	59	2.164	0.838	45	1.138	0.823	39
Incremental Improvement Over LNB/SOFA	*0.376*	*0.102*	*16*	*0.047*	*0.049*	*3*	*0.027*	*0.032*	*3*	*0.036*	*0.033*	*6*

†The visibility improvement shown in the table has been calculated from values that include more decimal places than what is shown in the table. Due to rounding, the visibility improvement calculated from the baseline and controlled 98th percentile impacts shown in the table may be slightly different than the visibility improvement reflected in the table.

In light of the very small incremental visibility benefit and the high marginal cost, SNCR cannot be considered BART for either SN-01 or SN-02. As shown in Table 6-5 and Table 6-6, based on visibility predictions from the CALPUFF modeling system, the operation of a LNB/SOFA will result in up to a 0.176 Δdv improvement (depending on the Class I area) to the existing visibility impairment attributable to SN-01 and up to 0.225 Δdv improvement for SN-02. There is essentially zero visibility improvement due to including SNCR, with a modeled change of approximately 0.03 Δdv for both units. The addition of SCR would produce a modeled improvement of only 0.103 Δdv for Unit 1 and 0.102 Δdv for Unit 2 over LNB/SOFA alone.

Tables 6-7 and 6-8 provide a condensed summary of these predicted improvements alongside the estimated control costs. The incremental benefit of going from LNB/SOFA to either LNB/SOFA + SCNR or LNB/SOFA + SCR is clearly not justified. The control technologies are very expensive in terms of initial capital investment and are prohibitively more expensive from an incremental cost effectiveness standpoint than LNB/SOFA alone.

TABLE 6-7. INCREMENTAL COST EFFECTIVENESS FOR SN-01 WITH CLASS I AREA IMPROVEMENT

Unit ID	Control Description	NOx Emissions (lb/MMBtu)	Control Eff. From Baseline (%)	Emission Reduction from Baseline (tons/yr)	Installed Cost ($)	Total Annual Control Cost ($)	Pollution Control Cost ($/ton)	Incremental Cost Compared to LNB/SOFA ($/ton)	Class I Area	Baseline 98th Percentile Δdv	Controlled 98th Percentile Δdv	Improvement in 98th Percentile Δdv	Incremental Improvement in 98th Percentile Δdv Compared to LNB/SOFA	Baseline # Days > 0.5 Δdv	Controlled # Days > 0.5 Δdv	Incremental Improvement in Controlled # Days > 0.5 Δdv Compared to LNB/SOFA
SN-01	LNB/SOFA	0.15	51%	3,104.04	10,461,206	1,162,918	375	-	Caney Creek	1.628	1.462	0.166	-	106	89	-
									Hercules-Glades	1.041	0.865	0.176	-	61	48	-
									Mingo	0.887	0.849	0.038	-	56	45	-
									Upper Buffalo	1.140	1.039	0.101	-	77	62	-
SN-01	LNB/SOFA + SNCR	0.13	58%	3,656.73	21,371,325	6,571,238	1,797	9,785	Caney Creek	1.628	1.428	0.200	0.034	106	86	3
									Hercules-Glades	1.041	0.844	0.197	0.021	61	47	1
									Mingo	0.887	0.842	0.045	0.007	56	44	1
									Upper Buffalo	1.140	1.029	0.111	0.010	77	62	0
SN-01	LNB/SOFA + SCR	0.055	82%	5,729.33	230,329,138	22,005,397	3,841	7,939	Caney Creek	1.628	1.359	0.269	0.103	106	73	16
									Hercules-Glades	1.041	0.832	0.209	0.033	61	45	3
									Mingo	0.887	0.817	0.070	0.032	56	38	7
									Upper Buffalo	1.140	0.991	0.149	0.048	77	59	3

TABLE 6-8. INCREMENTAL COST EFFECTIVENESS FOR SN-02 WITH CLASS I AREA IMPROVEMENT

Unit ID	Control Description	NOx Emissions (lb/MMBtu)	Control Eff. From Baseline (%)	Emission Reduction from Baseline (tons/yr)	Installed Cost ($)	Total Annual Control Cost ($)	Pollution Control Cost ($/ton)	Incremental Cost Compared to LNB/SOFA ($/ton)	Class I Area	Baseline 98th Percentile Δdv	Controlled 98th Percentile Δdv	Improvement in 98th Percentile Δdv	Incremental Improvement in 98th Percentile Δdv Compared to LNB/SOFA	Baseline # Days > 0.5 Δdv	Controlled # Days > 0.5 Δdv	Incremental Improvement in Controlled # Days > 0.5 Δdv Compared to LNB/SOFA
SN-02	LNB/SOFA	0.15	58%	4,124.91	14,488,206	1,480,391	359	-	Caney Creek	1.695	1.470	0.225	-	112	91	-
									Hercules-Glades	1.060	0.870	0.190	-	65	48	-
									Mingo	0.903	0.856	0.047	-	57	45	-
									Upper Buffalo	1.185	1.046	0.139	-	80	62	-
SN-02	LNB/SOFA + SNCR	0.13	63%	4,666.30	206,747,898	6,899,760	1,479	10,010	Caney Creek	1.695	1.437	0.258	0.033	112	87	4
									Hercules-Glades	1.060	0.849	0.211	0.021	65	47	1
									Mingo	0.903	0.849	0.054	0.007	57	45	0
									Upper Buffalo	1.185	1.035	0.150	0.011	80	62	0
SN-02	LNB/SOFA + SCR	0.055	85%	6,696.51	206,747,898	20,127,070	3,006	7,251	Caney Creek	1.695	1.368	0.327	0.102	112	75	16
									Hercules-Glades	1.060	0.838	0.222	0.032	65	45	3
									Mingo	0.903	0.823	0.080	0.033	57	39	6
									Upper Buffalo	1.185	0.997	0.188	0.049	80	59	3

6.6 PROPOSED BART FOR NO_X FOR SN-01 AND SN-02

If CSAPR ultimately is upheld and implemented in Arkansas, Entergy may rely on CSAPR to satisfy its NO_X regional haze obligations at SN-01 and SN-02. Alternatively, if CSAPR is vacated and CAIR remains in place, Entergy may rely on CAIR to satisfy its NO_X obligations under BART as EPA has previously determined that the CAIR season NO_X trading program provides greater visibility improvement than BART.

With full consideration of all five factors outlined by EPA for BART determinations, Entergy proposes a BART emission level of 0.15 lb/MMBtu on a 30-day rolling average basis, achievable through use of LNB/SOFA at SN-01 and SN-02. Compliance will be demonstrated using data from the existing CEMS. This determination is consistent with the BART determinations approved by EPA in Oklahoma, including the determinations for OG&E Seminole Units 1, 2, and 3 that combustion controls achieving 30-day rolling average NO_X levels of 0.203 lb/MMBtu, 0.212 lb/MMBtu, and 0.164 lb/MMBtu, respectively, constitute BART and the determination for OG&E Sooner Units 1 and 2, OG&E Muskogee Unit 4, and AEP/PSO Northeastern Units 3 and 4 that combustion controls achieving a 30-day rolling average NO_X level of 0.15 lb/MMBtu constitute BART.[42]

6.7 PROPOSED BART FOR NO_X FOR SN-05

The maximum visibility impairment predicted by the CALPUFF modeling system for SN-05 is only 0.036 Δdv[43]. This is an extremely low level of impairment, so low that it is likely falls within the level of accuracy that can be attributed to CALPUFF. In addition, this modeling assumes that the auxiliary boiler operates at the maximum daily emission rate 365 days per year. Since the existing visibility impairment predicted by CALPUFF is extremely low, to the point of practically being nonexistent, the impairment cannot be considered significant such as to require controls. Said another way, the impairment is so low that any improvement from reductions would be less than negligible. Therefore, *no controls* is the NO_X BART determination for SN-05. This conclusion is consistent with EPA's determinations in other states with similar auxiliary boilers.

[42] 77 Fed. Reg. 16168 (March 22, 2011).

[43] *See* Table 4-4

7. PM_{10} BART EVALUATION

EPA's Approval and Promulgation of Implementation Plans, published March 12, 2012, determined that the currently installed ESP is BART for PM_{10} for SN-01 and SN-02.

> The federally enforceable operating air permit states the PM emissions from the two units are controlled with ESPs and requires that the two units comply with a PM emission standard of 0.10 lb/MMBtu. Since we have found that the visibility impact of the source due to PM emissions alone is so minimal such that the installation of any additional PM controls on the units would likely achieve very low emissions reductions, have minimal visibility benefits, and not be cost-effective, we are proposing to approve ADEQ's determination that PM BART for both the bituminous and subbituminous coal firing scenarios is the existing PM emission limit for Units 1 and 2.[44]

As such, no further PM_{10} analysis has been conducted.

Section 4 of this report summarized the baseline visibility impairment attributable to SN-01, SN-02 and SN-05. Table 4-4 demonstrates that SN-05 does not contribute to a single day of visibility impairment greater than 0.5 Δdv. Therefore, no controls will be considered BART for SN-05. This conclusion is consistent with EPA's determinations in other states with similar auxiliary boilers.

[44] "Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze. Final Rule," 77 FR 14658 (March 12, 2012).

APPENDIX A

SO_2 AND NO_X CONTROL COST CALCULATIONS

Semi-Dry Scrubber Capital and O&M Cost Estimate			
Operational Data		**Unit 1**	**Unit 2**
Maximum HI (MMBtu/hr)		8950	8950
Annual Operating Hours, 2009-2011		7361	7401
Capital Costs[1]		**Unit 1**	**Unit 2**
Total Contractor Costs (2012 Dollars)		$174,854,437	$174,854,437
Total Contractor Costs (2010 Dollars):		$156,974,274	$156,974,274
FGD Equipment (2010 Dollars)		$57,649,982	$57,649,982
FGD Materials (2010 Dollars)		$14,840,928	$14,840,928
FGD Contractor Labor (2010 Dollars)		$63,607,654	$63,607,654
FGD Contractor Contingency (2010 Dollars)		$20,875,711	$20,875,711
Total Balance of Plant (BOP) Direct Costs (2012 Dollars)		$118,537,729	$118,537,729
Balance of Plant (BOP) Equipment (2012 Dollars)		$24,816,321	$24,816,321
BOP Materials (2012 Dollars)		$26,464,135	$26,464,135
BOP Labor (2012 Dollars)		$67,257,273	$67,257,273
Balance of Plant (BOP) Indirect Costs (2012 Dollars)		$8,733,104	$8,733,104
Misc Contractor Labor (2012 Dollars)		$4,583,719	$4,583,719
Misc Contractor Labor (2010 Dollars)[2]		$4,115,000	$4,115,000
Entergy Internal Costs (2012 Dollars)		$20,076,644	$20,076,644
Entergy Internal Costs (2010 Dollars)[3]		$18,023,659	$18,023,659
Capital suspense (2010 Dollars)		$7,494,603	$7,494,603
Capital suspense (2012 Dollars)		$8,348,276	$8,348,276
CEPCI 2008		530.7	530.7
CEPCI 2010		533	533
CEPCI 2012 (January)		593.6	593.6
Total Capital Investment		$335,133,908	$335,133,908
Capital Recovery Factor (CRF)[4]		0.08	0.08
Annual Costs[5]			
CEPCI 2008		530.7	530.7
Direct Annual Costs (2012 Dollars)		$8,837,861	$8,859,823
Direct Annual Costs (2008 Dollars)		$7,901,369	$7,921,004
Operating Labor and Materials (2008 Dollars)		$4,287,845	$4,287,845
Water, Waste & Bag Replacement Costs $/MWh (2008 Dollars)		0.29	0.29
Lime Costs $/MWh (2008 Dollars)		0.75	0.75
Water, Waste, Bag Replacement and Lime Costs $/MWh (2008 Dollars)		1.04	1.04
Anticipated Yearly MWh[6]		3,474,543	3,493,423
Water, Waste, Bag Replacement and Lime Costs (2008 Dollars)		3,613,525	3,633,160
Indirect Annual Costs (IC) (2012 Dollars):		$43,290,224	$43,290,224
Overhead (2008 Dollars)	60% of total labor and materials costs	$2,572,707	$2,572,707
Overhead (2012 Dollars)		$2,877,631	$2,877,631
Administrative charges (2012 Dollars)	2% of TCI	$6,702,678	$6,702,678
Property Tax (2012 Dollars)	1% of TCI	$3,351,339	$3,351,339
Insurance (2012 Dollars)	1% of TCI	$3,351,339	$3,351,339
Capital recovery (2012 Dollars)	CRF* TCI	$27,007,236	$27,007,236
Total Annual Costs		$52,128,084	$52,150,047

1: The capital costs are based on contractor estimates provided by Sargent & Lundy (S&L) to Entergy in 2010 and other estimates compiled by Entergy in 2008. Both the 2010 cost from S&L and the 2008 cost estimated by Entergy were scaled to reflect 2012 dollars.

2: Misc contract labor includes permitting and regulatory support.

3: Entergy internal costs include labor, travel, and loader costs.

4: CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life
Equipment CRF, 30-yr life, 7% interest

5: The O&M cost estimates are based on the Sargent & Lundy economic model from May 2008. The cost estimates were scaled to reflect 2012 dollars.

6: Anticipated yearly MWh = (944 MW/2 * anticipated annual operating hours) - 13 MWh, where 944 MW is anticipated EIA share for both boilers and 13 MWh is the estimated parsitic load loss estimate due to operation of the control from both boilers.

Wet Scrubber Capital and O&M Cost Estimate[1]			
Operational Data		**Unit 1**	**Unit 2**
Maximum HI (MMBtu/hr)		8950	8950
Annual Operating Hours, 2001-2003		7361	7401
Capital Costs		**Unit 1**	**Unit 2**
Total Equipment Costs (EC) (2012 Dollars)[2]		$150,037,000	$150,037,000
Purchased Equipment Cost (PEC)	PEC = 1.18 * EC	$177,043,660	$177,043,660
Total Capital Investment (TCI)		$389,496,052	$389,496,052
Capital Recovery Factor (CRF)(2012 Dollars)[3]		0.08	0.08
Annual Costs			
Direct Annual Costs (DC)[4] (2011 Dollars)		$15,734,500	$15,734,500
CECPI 2011		585.7	585.7
CECPI 2012 (January)		593.6	593.6
Direct Annual Costs (DC) (2012 Dollars)		$15,946,729	$15,946,729
Indirect Annual Costs (IC) (2012 Dollars)		$50,938,806	$50,938,806
Overhead (2011 Dollars)	60% of fixed labor and material costs from 2011 S&L conceptual costs	$2,987,400	$2,987,400
Overhead (2012 Dollars)		$3,027,694	$3,027,694
Administrative charges (2012 Dollars)	2% of TCI	$8,733,104	$8,733,104
Property Tax (2012 Dollars)	1% of TCI	$3,894,961	$3,894,961
Insurance (2012 Dollars)	1% of TCI	$3,894,961	$3,894,961
Capital recovery	CRF* TCI	$31,388,086	$31,388,086
Total Annual Costs		$66,885,535	$66,885,535

1: The costing method is modeled after the cost method summarized in Section 5.2 of the EPA Control Cost Manual (Post-Combustion Controls, Chapter 1 - Wet Scrubbers for Acid Gas, Table 1.3). Costs for capital suspense have been accounted for and added to the TCI calculated using the Cost Control Manual.

2: The total equipment cost is the sum of the equipment and material costs from the November 30, 2012 Sargent & Lundy conceptual cost estimate.

3: CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life
Equipment CRF, 30-yr life, 7% interest

4: The direct costs include the fixed O&M from the S&L 2011 conceptual costs (operating labor, operating materials, and maintenance materials) plus variable O&M from the S&L 2011 conceptual costs (aux power, bags, cages, lime, limestone, and water)

LNB-SOFA Capital and O&M Cost Estimate		
Operational Data	**Unit 1**	**Unit 2**
Maximum HI (MMBtu/hr)	8950	8950
Annual Operating Hours, 2001-2003	7361	7401
Capital Costs	**Unit 1**	**Unit 2**
Installed Capital Cost[1]	10,461,206	14,488,206
Capital Recovery Factor (CRF)[2]	0.08	0.08
Annual Costs	**Unit 1**	**Unit 2**
Fixed O&M Costs[3]	142,000	142,000
Variable O&M Costs[4]	177,887	170,838
Annualized Capital Cost	843,031	1,167,552
Total Annual Costs	1,162,918	1,480,391

1: The installed capital cost estimates for LNB/OFA are based on the installed capital cost estimates for each unit as provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study (Unit 1 = $7,804,000 and Unit 2 = $11,831,000) plus additional cost not accounted for in the S&L cost estimate, including cost for permitting and legal/regulatory support (estimated by Entergy to be $112,500 for each unit), cost for Entergy employee labor and loaders (estimated by Entergy to be $1,589,033 for each unit), and cost for capital suspense (estimated by Entergy to be $955,673 for each unit) .

2: CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life
Equipment CRF, 30-yr actual service life, 7% interest

3: The fixed O&M cost estimates were provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study

4: The variable O&M costs are based on the Eastern Research Group report "Analysis of Combustion Controls for Reducing NOx Emissions from Coal-fired EGUs in the WRAP Region" September 6, 2005. Section 4.3.1 and Appendix D.

Variable O&M = (0.027 mills/kW-hr/1000) x (1 kW-hr/10,000 Btu) x H x C x 10^6 Btu/mmBtu

Where:
H = Annual operating hours
C = Boiler design capacity (mmBtu/hr)
Note: The variable rate used for variable O&M costs was 0.027 mills/kW-hr. This is the rate listed in Appendix D

LNB-SOFA + SNCR Capital and O&M Cost Estimate

Operational Data	Unit 1	Unit 2
Maximum HI (MMBtu/hr)	8950	8950
Annual Operating Hours, 2001-2003	7361	7401
Capital Costs	**Unit 1**	**Unit 2**
Installed Capital Cost [1]	21,371,325	25,398,325
Capital Recovery Factor (CRF)[2]	0.08	0.08
Annual Costs	**Unit 1**	**Unit 2**
Fixed O&M Costs[3]	311,000	311,000
Variable O&M Costs[4]	4,538,000	4,542,000
Annualized Capital Cost	1,722,238	2,046,760
Total Annual Costs	6,571,238	6,899,760

1: The installed capital cost estimates for LNB/OFA + SNCR are based on the installed capital cost estimates for each unit as provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study (Unit 1 = $16,290,000 and Unit 2 = $20,317,000) plus additional cost not accounted for in the S&L cost estimate, including cost for permitting and legal/regulatory support (estimated by Entergy to be $112,500 for each unit), cost for Entergy employee labor and loaders (estimated by Entergy to be $3,223,396 for each unit), and cost for capital suspense (estimated by Entergy to be $1,745,429 for each unit) .

2: CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life

Equipment CRF, 30-yr actual service life, 7% interest

3: The fixed O&M cost estimates are based on the cost estimates provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study.

4: The variable O&M cost estimates are based on the cost estimates provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study. Adding LNB/OFA to SNCR makes the variable O&M costs less than that of SNCR alone due to a lower NOx concentration and resulting less reagent usage.

LNB-SOFA + SCR Capital and O&M Cost Estimate

Operational Data	**Unit 1**	**Unit 2**
Maximum HI (MMBtu/hr)	8950	8950
Annual Operating Hours, 2001-2003	7361	7401
Capital Costs[1]	**Unit 1**	**Unit 2**
Installed Capital Cost	230,329,138	206,747,898
Capital Recovery Factor (CRF)[2]	0.08	0.08
Annual Costs[3]	**Unit 1**	**Unit 2**
Fixed O&M Costs	608,000	608,000
Variable O&M Costs	2,836,000	2,858,000
Annualized Capital Cost	18,561,397	16,661,070
Total Annual Costs	22,005,397	20,127,070

1: The installed capital cost estimates for LNB/OFA + SCR are based on the installed capital cost estimates for each unit as provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study (Unit 1 = $202,601,000 and Unit 2 = $178,240,000) plus additional cost not accounted for in the S&L cost estimate, including cost for permitting and legal/regulatory support (estimated by Entergy to be $450,000 for each unit), cost for Entergy employee labor and loaders (estimated by Entergy to be $6,725,610 for each unit), and cost for capital suspense (estimated by Entergy to be $20,552,528 for Unit 1 and $21,332,288 for Unit 2) .

2: CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life

Equipment CRF, 30-yr actual service life, 7% interest

3: The fixed O&M cost estimates are based on the cost estimates provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study.

4: The variable O&M cost estimates are based on the cost estimates provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study. Adding LNB/OFA to SCR makes the variable O&M costs less than that of SCR alone due to a lower NOx concentration and resulting less reagent usage.

APPENDIX B

BASELINE VISIBILITY IMPAIRMENT BY POLLUTANT

The following tables are a continuation of the information presented in Tables 4-2 through 4-4. Tables B-1 through B-3 shows the delta deciview by pollutant in a percentage format.

TABLE B-1. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-01 BY POLLUTANT

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Day with $\Delta dv \geq 0.5$	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek Wilderness							
2001	2.956	1.628	41	79.06	20.65	0.16	0.12
2002	2.111	1.386	30	47.73	47.56	0.82	3.90
2003	4.194	1.13	35	63.88	34.05	0.30	1.76
Upper Buffalo Wilderness							
2001	2.339	1.128	34	74.05	25.72	0.23	0.00
2002	1.544	0.818	18	83.19	16.22	0.34	0.26
2003	1.900	1.140	25	97.99	1.80	0.22	0.00
Hercules Glades Wilderness							
2001	1.737	1.041	28	92.29	7.51	0.21	0.00
2002	1.288	0.617	13	78.93	20.76	0.23	0.08
2003	2.230	0.786	20	88.91	10.87	0.21	0.00
Mingo Wilderness							
2001	1.569	0.887	18	93.36	6.03	0.33	0.28
2002	1.012	0.750	24	56.89	42.59	0.25	0.28
2003	1.114	0.702	14	63.85	34.84	0.38	0.94

TABLE B-2. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-02 BY POLLUTANT

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Day with $\Delta dv \geq 0.5$	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek Wilderness							
2001	3.199	1.695	41	76.22	23.49	0.16	0.14
2002	2.270	1.481	33	65.10	31.38	0.73	2.80
2003	4.437	1.169	38	50.94	47.45	0.31	1.31
Upper Buffalo Wilderness							
2001	2.385	1.185	35	70.85	28.92	0.23	0.00
2002	1.618	0.846	20	80.92	18.47	0.31	0.30
2003	1.998	1.176	25	81.45	18.30	0.24	0.00
Hercules Glades Wilderness							
2001	1.838	1.060	30	91.12	8.68	0.20	0.00
2002	1.340	0.643	14	76.19	23.50	0.21	0.09
2003	2.263	0.806	21	87.28	12.51	0.21	0.00
Mingo Wilderness							
2001	1.701	0.903	18	92.36	6.99	0.31	0.33
2002	1.031	0.805	25	83.70	16.04	0.22	0.03
2003	1.150	0.750	14	60.22	38.39	0.35	1.04

TABLE B-3. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-05 BY POLLUTANT

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Day with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek Wilderness							
2001	0.028	0.008	0	12.12	82.96	1.17	2.01
2002	0.020	0.005	0	13.56	82.08	0.17	3.94
2003	0.036	0.010	0	15.90	76.81	1.12	4.55
Upper Buffalo Wilderness							
2001	0.014	0.004	0	18.99	77.59	1.36	0.12
2002	0.009	0.004	0	22.05	75.33	1.01	0.12
2003	0.013	0.005	0	17.05	74.39	1.76	4.31
Hercules Glades Wilderness							
2001	0.007	0.004	0	15.47	80.65	0.89	1.68
2002	0.006	0.003	0	30.17	65.62	1.50	0.49
2003	0.008	0.004	0	60.26	33.74	2.40	0.03
Mingo Wilderness							
2001	0.009	0.003	0	12.83	84.94	0.89	0.06
2002	0.019	0.008	0	11.22	84.34	1.02	1.91
2003	0.015	0.003	0	21.56	77.36	0.43	0.05

APPENDIX C

CALMET MODELING PROTOCOL

As stated in Section 3.1, the meteorological data used in the analyses presented in this report was originally developed in 2007 and was first used in a BART determination for Oklahoma Gas & Electric. Because the development of a set of CALMET/CALPUFF meteorological data is so intensive, this same dataset has been used numerous times since 2007 for various other BART projects in EPA Region 6. The protocol that accompanied the original development has followed the dataset in each case and is doing so here again.

CALMET DATA PROCESSING PROTOCOL ▲ BART DETERMINATION
OKLAHOMA GAS & ELECTRIC

MUSKOGEE GENERATING STATION
SEMINOLE GENERATING STATION
SOONER GENERATING STATION

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1. INTRODUCTION

Oklahoma Gas & Electric (OG&E) owns and operates three electric generating stations near Muskogee, Oklahoma (Muskogee Generating Station), Seminole, Oklahoma (Seminole Generating Station), and Stillwater, Oklahoma (Sooner Generating Station). These generating stations are considered eligible to be regulated under the U.S. Environmental Protection Agency's (EPA) Best Available Retrofit Technology (BART) provisions of the Regional Haze Rule. This protocol describes the proposed methodology for conducting the CALMET data processing for the refined CALPUFF BART modeling analysis for OG&E's Muskogee, Seminole, and Sooner Generating Stations. A detailed CALPUFF BART modeling protocol will be submitted in the near future and will include a discussion of the CALPUFF parameters as well as the post processing methodologies to be used in the refined modeling analysis for each station.

1.1 BEST AVAILABLE RETROFIT TECHNOLOGY RULE BACKGROUND

On July 1, 1999, the U.S. Environmental EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to improve visibility in 156 specific areas across with United States, known as Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence on August 7, 1977.

On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the BART rule, which included guidance for making source-specific Best Available Retrofit Technology (BART) determinations. The BART rule defines BART-eligible sources as sources that meet the following criteria:

(1) Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant,
(2) Began operation between August 7, 1962 and August 7, 1977, and
(3) Are listed as one of the 26 listed source categories in the guidance.

A BART-eligible source is not automatically subject to BART. Rather, BART-eligible sources are subject-to-BART if the sources are "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." EPA has determined that sources are reasonably anticipated to cause or contribute to visibility impairment if the visibility impacts from a source are greater than 0.5 deciviews (dv) when compared against a natural background.

Air quality modeling is the tool that is used to determine a source's visibility impacts. States have the authority to exempt certain BART-eligible sources from installing BART controls if the results of the dispersion modeling demonstrate that the source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I area. Further, states also have the authority to define the modeling procedures for conducting modeling related to making BART determinations.

1.2 OBJECTIVE

The objective of this document is to provide a protocol summarizing the modeling methods and procedures that will be followed to conduct the CALMET data processing necessary to complete a refined CALPUFF modeling analysis for the OG&E generating stations discussed above. The modeling methods and procedures contained in this protocol and the CALPUFF protocol yet to be submitted will be used to determine appropriate controls for OG&E's BART-eligible sources that can reasonably be anticipated to reduce the sources' effects on or contribution to visibility impairment in the surrounding Class I areas. It is OG&E's intent to determine a combination of emissions controls that will reduce the impact of each generating station to a degree that the 98th percentile of the visibility impact predicted by the model due to all the BART eligible sources at each station collectively is below EPA's recommended visibility contribution threshold of 0.5 Δdv.

1.3 LOCATION OF SOURCES AND RELEVANT CLASS I AREAS

The sources listed in Table 1-1 are the sources that have been identified by OG&E as sources that meet the three criteria for BART-eligible sources.

TABLE 1-1. BART-ELIGIBLE SOURCES

EPN	Description
	Muskogee Sources
Unit 4	5,480 MMBtu/hr Coal Fired Boiler
Unit 5	5,480 MMBtu/hr Coal Fired Boiler
	Seminole Sources
SM1	5,480 MMBtu/hr Natural Gas Fired Boiler
SM2	5,480 MMBtu/hr Natural Gas Fired Boiler
SM3	5,496 MMBtu/hr Natural Gas Fired Boiler
	Sooner Sources
Unit 1	5,116 MMBtu/hr Coal Fired Boiler
Unit 2	5,116 MMBtu/hr Coal Fired Boiler

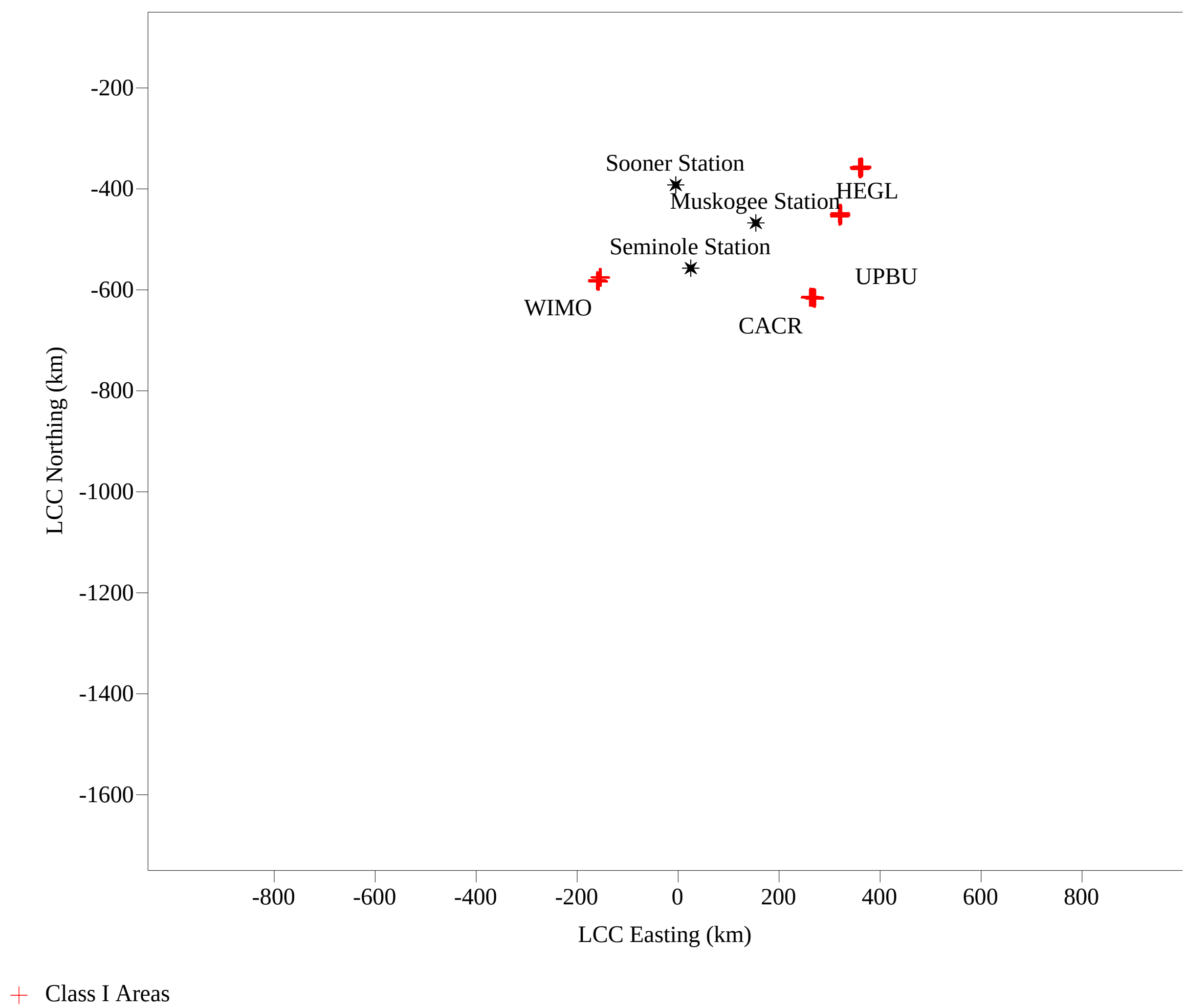
As required in CENRAP's BART Modeling Guidelines, Class I areas within 300 km of each station will be included in each analysis. The following table summarizes the distances of the four closest Class I areas to each station. As seen from this summary, some Class I areas are more than 300 km from the certain stations. However, in order to demonstrate that each station will not have an adverse effect on the visibility at any of the four nearest Class I areas, OG&E has opted to include those Class I areas more than 300 km away in this analysis. Note that the distances listed in the table below are the distances between the stations and the closest border of the Class I areas.

TABLE 1-2. DISTANCE FROM STATION TO SURROUNDING CLASS I AREAS

	CACR	HEGL	UPBU	WIMO
Muskogee	180	230	164	324
Seminole	242	386	310	178
Sooner	345	363	327	234

A plot of the Class I areas with respect to the each station is provided in Figure 1-1.

FIGURE 1-1. PLOT OF SOURCES AND NEAREST CLASS I AREAS



2. CALPUFF MODEL SYSTEM

The main components of the CALPUFF modeling system are CALMET, CALPUFF, and CALPOST. CALMET is the meteorological model that generates hourly three-dimensional meteorological fields such as wind and temperature. CALPUFF simulates the non-steady state transport, dispersion, and chemical transformation of air pollutants emitted from a source in “puffs”. CALPUFF calculates hourly concentrations of visibility affecting pollutants at each specified receptor in a modeling domain. CALPOST is the post-processor for CALPUFF that computes visibility impacts from a source based on the visibility affecting pollutant concentrations that were output by CALPUFF.

2.1 MODEL VERSIONS

The versions of the CALPUFF modeling system programs that are proposed for conducting OG&E’s BART modeling are listed in Table 2-1. A detailed refined CALPUFF BART modeling protocol will be submitted in the near future.

TABLE 2-1. CALPUFF MODELING SYSTEM VERSIONS

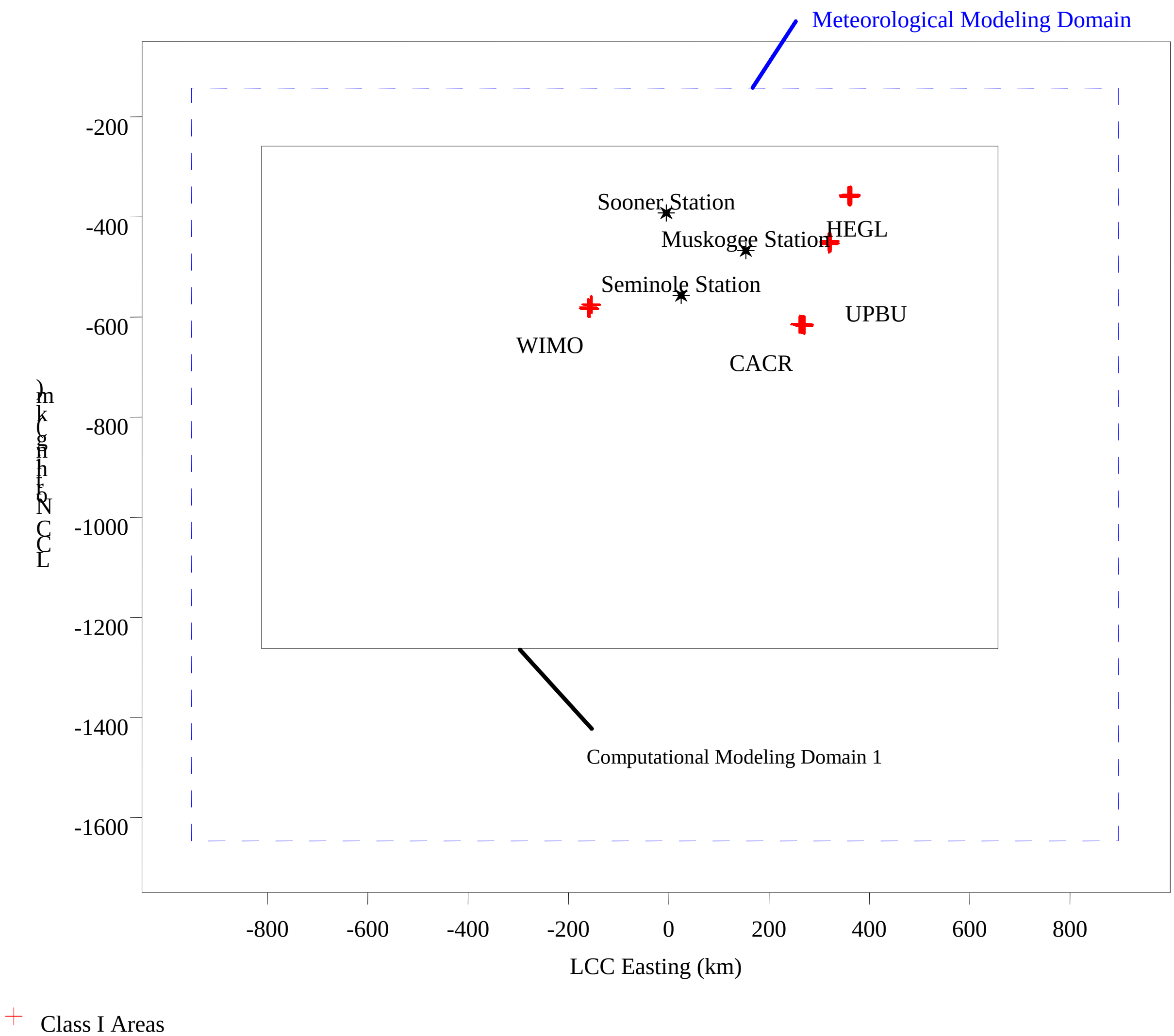
Processor	Version	Level
TERREL	3.3	030402
CTGCOMP	2.21	030402
CTGPROC	2.63	050128
MAKEGEO	2.2	030402
CALMET	5.53a	040716
CALPUFF	5.8	070623
POSTUTIL	1.3	030402
CALPOST	5.51	030709

2.2 MODELING DOMAIN

The CALPUFF modeling system utilizes three modeling grids: the meteorological grid, the computational grid, and the sampling grid. The meteorological grid is the system of grid points at which meteorological fields are developed with CALMET. The computational grid determines the computational area for a CALPUFF run. Puffs are advected and tracked only while within the computational grid. The meteorological grid is defined so that it covers the areas of concern and gives enough marginal buffer area for puff transport and dispersion. A plot of the proposed meteorological modeling domain with respect to the Class I areas being modeled is also provided in

Figure 2-1. The computational domain will be set to extend at least 50 km in all directions beyond the Muskogee, Seminole, and Sooner Generating Stations and the Class I areas of interest. Note that the map projection for the modeling domain will be Lambert Conformal Conic (LCC) and the datum will be the World Geodetic System 84 (WGS-84). The reference point for the modeling domain is Latitude 40ºN, Longitude 97ºW. The southwest corner will be set to -951.547 km LCC, -1646.637 km LCC corresponding to Latitude 24.813 ºN and Longitude 87.778ºW. The meteorological grid spacing will be 4 km, resulting in 462 grid points in the X direction and 376 grid points in the Y direction.

FIGURE 2-1. REFINED METEOROLOGICAL MODELING DOMAIN



3. CALMET

The EPA Approved Version of the CALMET meteorological processor will be used to generate the meteorological data for CALPUFF. CALMET is the meteorological processor that compiles meteorological data from raw observations of surface and upper air conditions, precipitation measurements, mesoscale model output, and geophysical parameters into a single hourly, gridded data set for input into CALPUFF. CALMET will be used to assimilate data for 2001- 2003 using National Weather Service (NWS) surface station observations, upper air station observations, precipitation station observations, buoy station observations (for overwater areas), and mesoscale model output to develop the meteorological field.

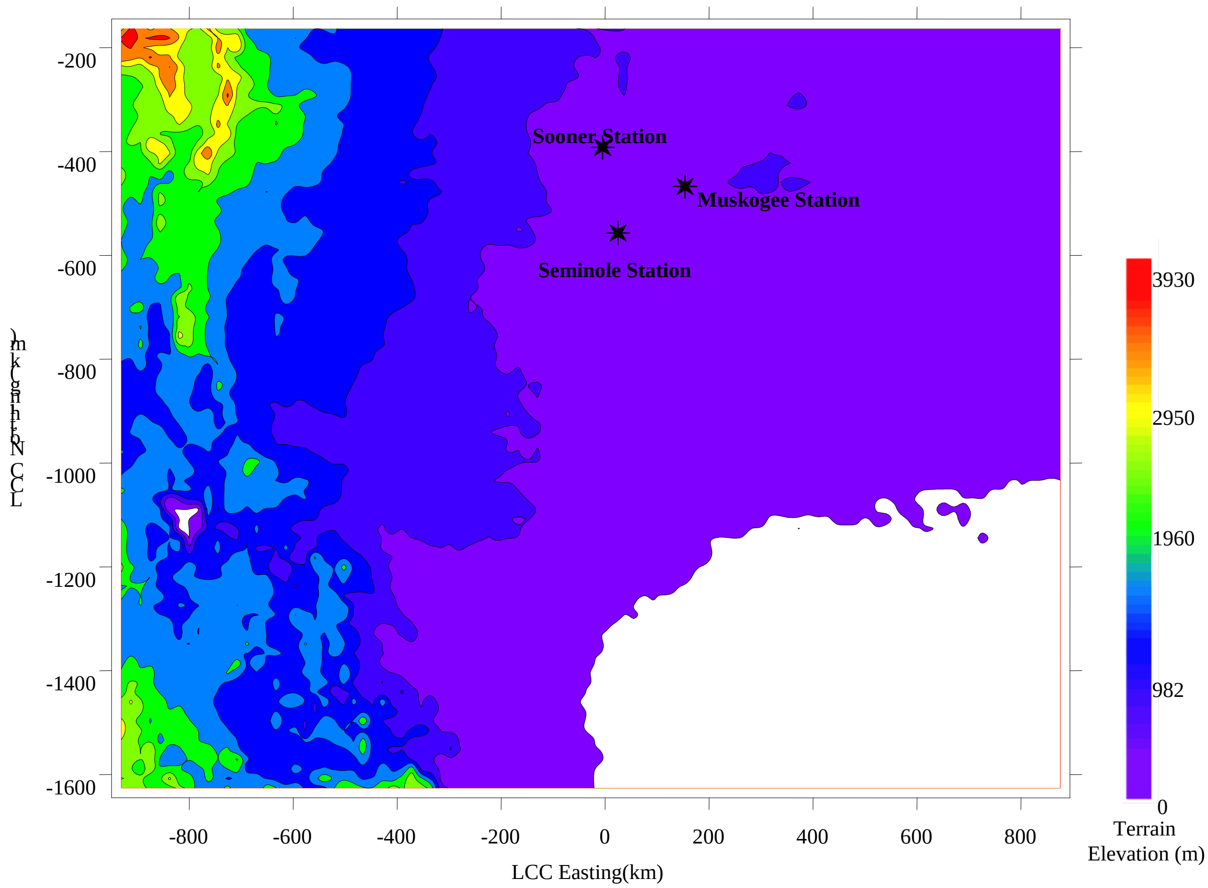
3.1 GEOPHYSICAL DATA

CALMET requires geophysical data to characterize the terrain and land use parameters that potentially affect dispersion. Terrain features affect flows and create turbulence in the atmosphere and are potentially subjected to higher concentrations of elevated puffs. Different land uses exhibit variable characteristics such as surface roughness, albedo, Bowen ratio, and leaf-area index that also effect turbulence and dispersion.

3.1.1 TERRAIN DATA

Terrain data will be obtained from the United States Geological Survey (USGS) in 1-degree (1:250,000 scale or approximately 90 meter resolution) digital format. The USGS terrain data will then be processed by the TERREL program to generate grid-cell elevation averages across the modeling domain. A plot of the land elevations based on the USGS data for the modeling domain is provided in Figure 3-1.

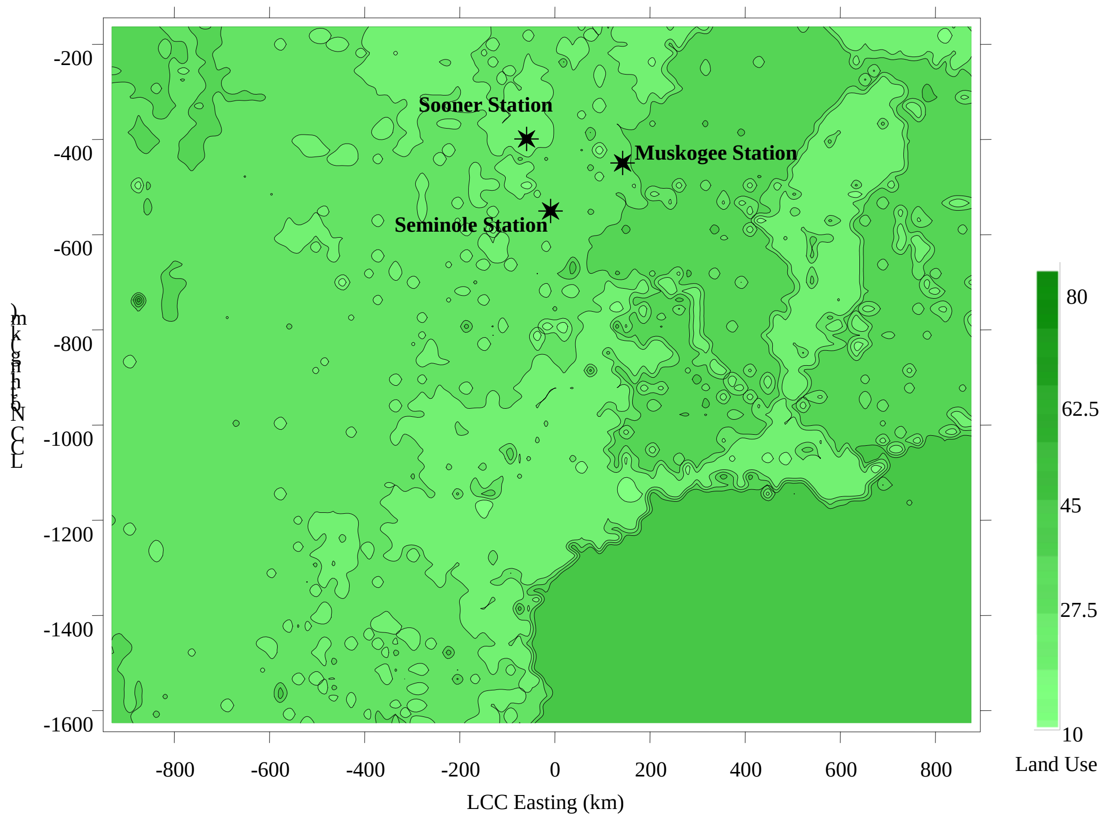
FIGURE 3-1. PLOT OF LAND ELEVATION USING USGS TERRAIN DATA



3.1.2 LAND USE DATA

The land use land cover (LULC) data from the USGS North American land cover characteristics data base in the Lambert Azimuthal equal area map projection will be used in order to determine the land use within the modeling domain. The LULC data will be processed by the CTGPROC program which will generate land use for each grid cell across the modeling domain. A plot of the land use based on the USGS data for the modeling domain is provided in Figure 3-2.

FIGURE 3-2. PLOT OF LAND USE USING USGS LULC DATA



3.1.3 COMPILING TERRAIN AND LAND USE DATA

The terrain data files output by the TERELL program and the LULC files output by the CTGPROC program will be uploaded into the MAKEGEO program to create a geophysical data file that will be input into CALMET.

3.2 METEOROLOGICAL DATA

CALMET will be used to assimilate data for 2001, 2002, and 2003 using mesoscale model output and National Weather Service (NWS) surface station observations, upper air station observations, precipitation station observations, and National Oceanic and Atmosphere Administrations (NOAA) buoy station observations to develop the meteorological field.

3.2.1 MESOSCALE MODEL METEOROLOGICAL DATA

Hourly mesoscale data will also be used as the initial guess field in developing the CALMET meteorological data. It is OG&E's intent to use the following 5th generation mesoscale model meteorological data sets (or MM5 data) in the analysis:

- 2001 MM5 data at 12 km resolution generated by the U.S. EPA
- 2002 MM5 data at 36 km resolution generated by the Iowa DNR

- 2003 MM5 data set at 36 km resolution generated by the Midwest RPO

The specific MM5 data that will be used are subsets of the data listed above. As the contractor to CENRAP for developing the meteorological data sets for the BART modeling, Alpine Geophysics extracted three subsets of MM5 data for each year from 2001 to 2003 from the data sets listed above using the CALMM5 extraction program. The three subsets covered the northern, central, and southern portions of CENRAP. TXI is proposing to use the southern set of the extracted MM5 data.

The 2001 southern subset of the extracted MM5 data includes 30 files that are broken into 10 to 11 day increments (3 files per month). The 2002 and 2003 southern subsets of extracted MM5 data include 12 files each of which are broken into 30 to 31 day increment files (1 file per month). Note that the 2001 to 2003 MM5 data extracted by Alpine Geophysics will not be able to be used directly in the modeling analysis. To run the Alpine Geophysics extracted MM data in the EPA approved CALMET program, each of the MM5 files will need to be adjusted by appending an additional six (6) hours, at a minimum, to the end of each file to account for the shift in time zones from the Greenwich Mean Time (GMT) prepared Alpine Geophysics data to Time Zone 6 for this analysis. No change to the data will occur.

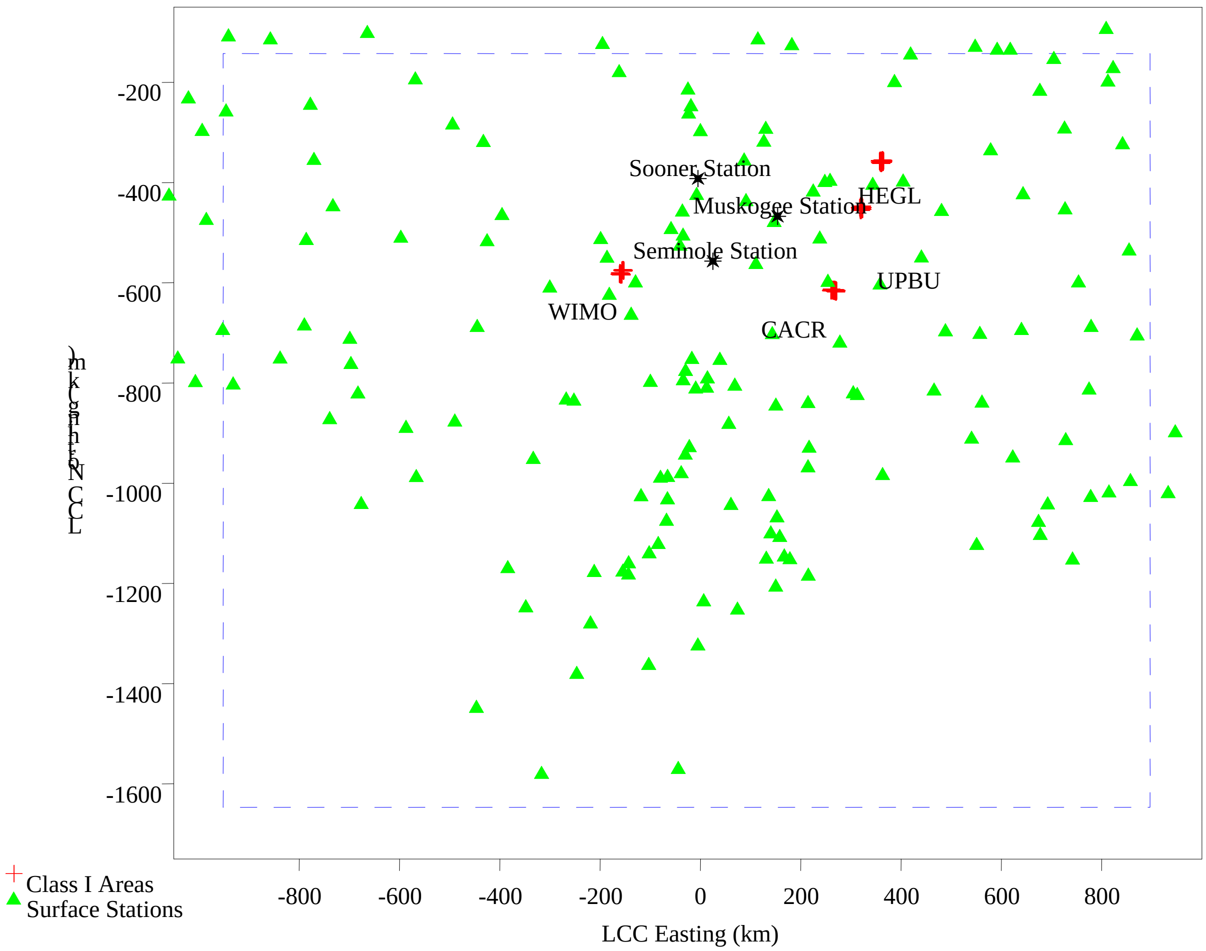
The time periods covered by the data in each of the MM5 files extracted by Alpine Geophysics include a specific number of calendar days, where the data starts at Hour 0 in GMT for the first calendar day and ends at Hour 23 in GMT on the last calendar day. In order to run CALMET in the local standard time (LST), which is necessary since the surface meteorological observations are recorded in LST, there must be hours of MM5 data referenced in a CALMET run that match the LST observation hours. Since the LST hours in Central Standard Time (CST) are 6 hours behind GMT, it is necessary to adjust the data in each MM5 file so that the time periods covered in the files match CST.

Based on the above discussion, the Alpine Geophysics MM5 data will not be used directly. Instead the data files will be modified to add 8 additional hours of data to the end of each file from the beginning of the subsequent file. CALMET will then be run using the appended MM5 data to generate a contiguous set of CALMET output files. The converted MM5 data files occupy approximately 1.2 terabytes (TB) of hard drive space.

3.2.2 SURFACE METEOROLOGICAL DATA

Parameters affecting turbulent dispersion that are observed hourly at surface stations include wind speed and direction, temperature, cloud cover and ceiling, relative humidity, and precipitation type. It is OG&E's intent to use the surface stations listed in Table A-1 of Appendix A. The locations of the surface stations with respect to the modeling domain are shown in Figure 3-3. The stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA's SMERGE program.

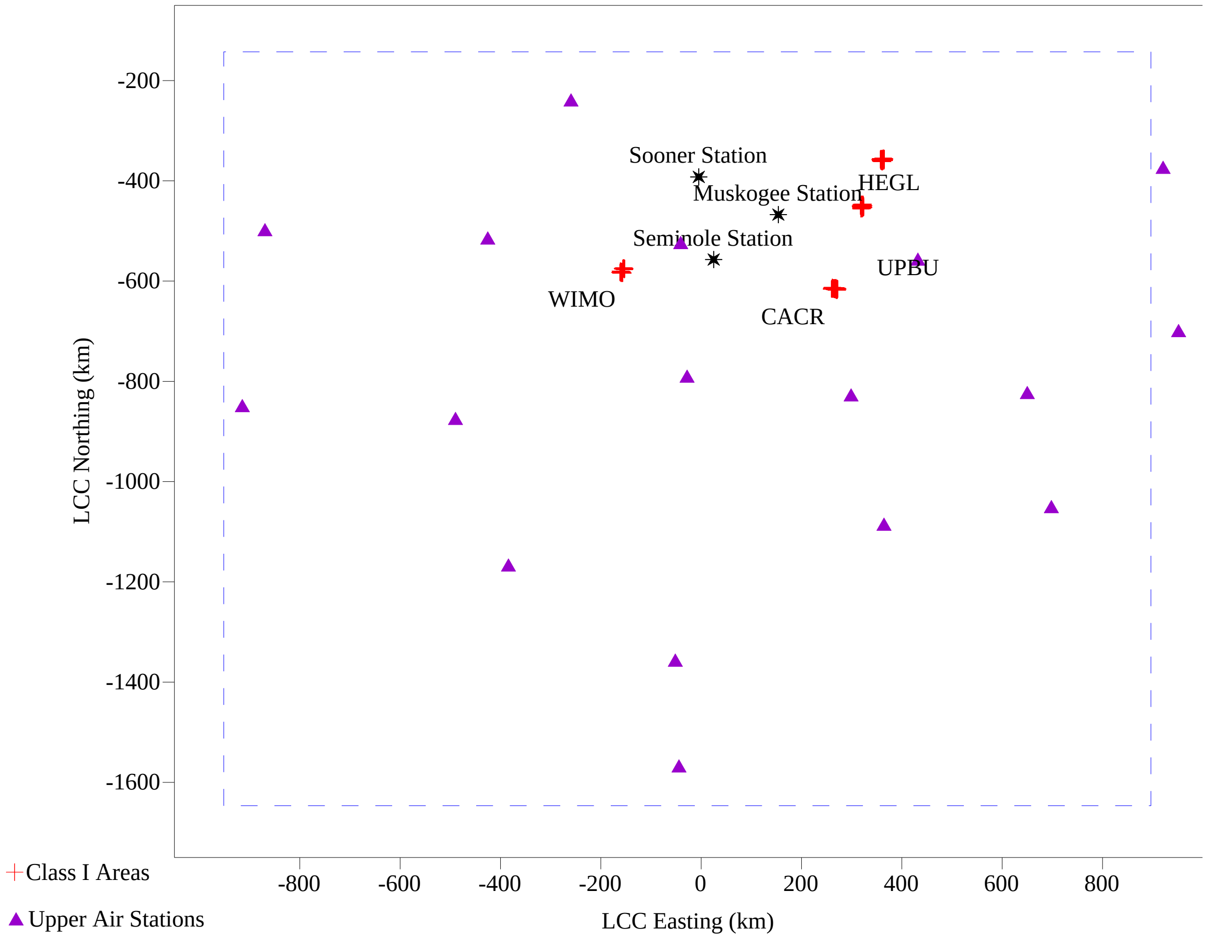
FIGURE 3-3. PLOT OF SURFACE STATION LOCATIONS



3.2.3 UPPER AIR METEOROLOGICAL DATA

Observations of meteorological conditions in the upper atmosphere provide a profile of turbulence from the surface through the depth of the boundary layer in which dispersion occurs. Upper air data are collected by balloons launched simultaneously across the observation network at 0000 Greenwich Mean Time (GMT) (6 o'clock PM in Oklahoma) and 1200 GMT (6 o'clock AM in Oklahoma). Sensors observe pressure, wind speed and direction, and temperature (among other parameters) as the balloon rises through the atmosphere. The upper air observation network is less dense than surface observation points since upper air conditions vary less and are generally not as affected by local effects (e.g., terrain or water bodies). The upper air stations that are proposed for this analysis are listed in Table A-2 of Appendix A. The locations of the upper air stations with respect to the modeling domain are shown in Figure 3-4. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA's READ62 program.

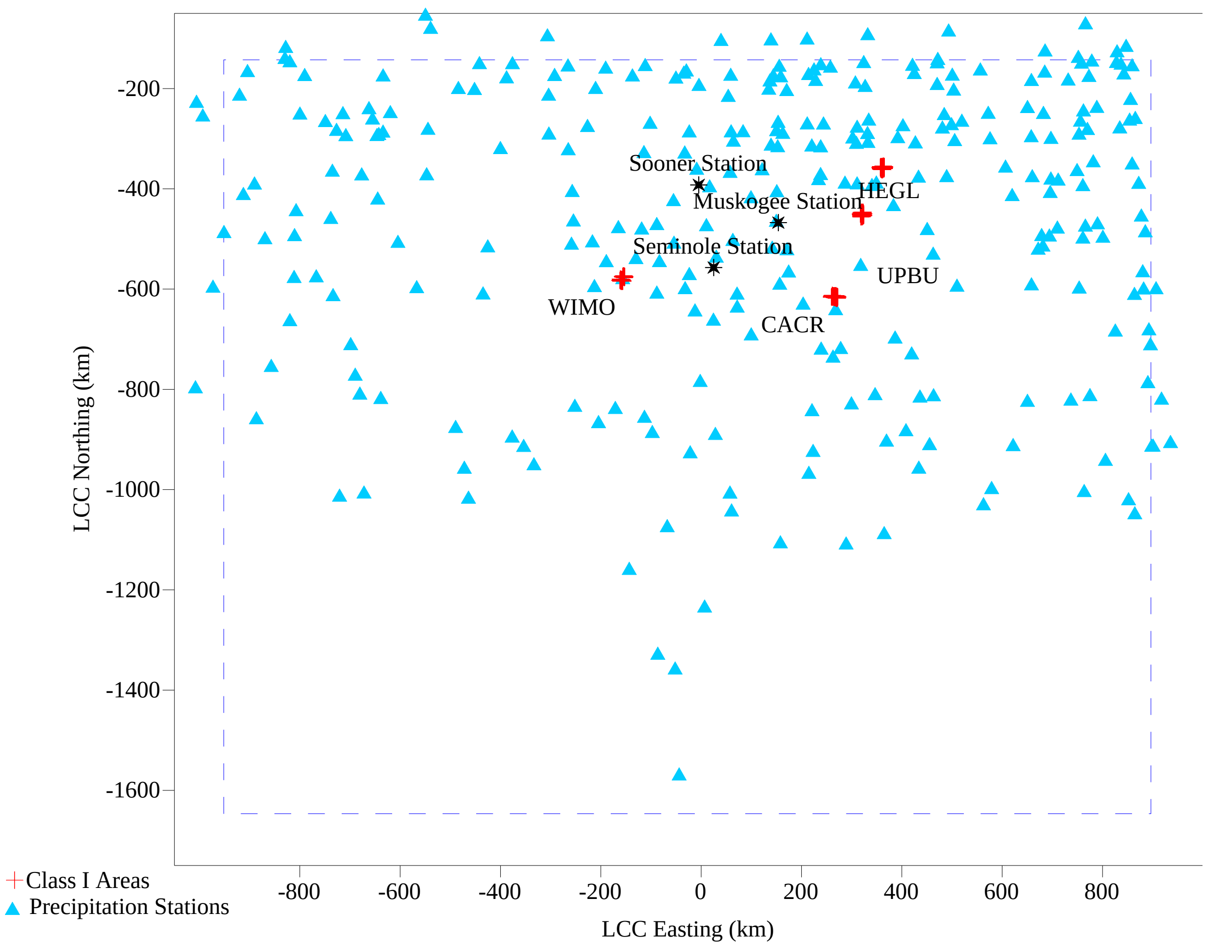
FIGURE 3-4. PLOT OF UPPER AIR STATIONS LOCATIONS



3.2.4 PRECIPITATION METEOROLOGICAL DATA

The effects of chemical transformation and deposition processes on ambient pollutant concentrations will be considered in this analysis. Therefore, it is necessary to include observations of precipitation in the CALMET analysis. The precipitation stations that are proposed for this analysis are listed in Table A-3 of Appendix A. The locations of the precipitation stations with respect to the modeling domain are shown in Figure 3-5. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA's PMERGE program.

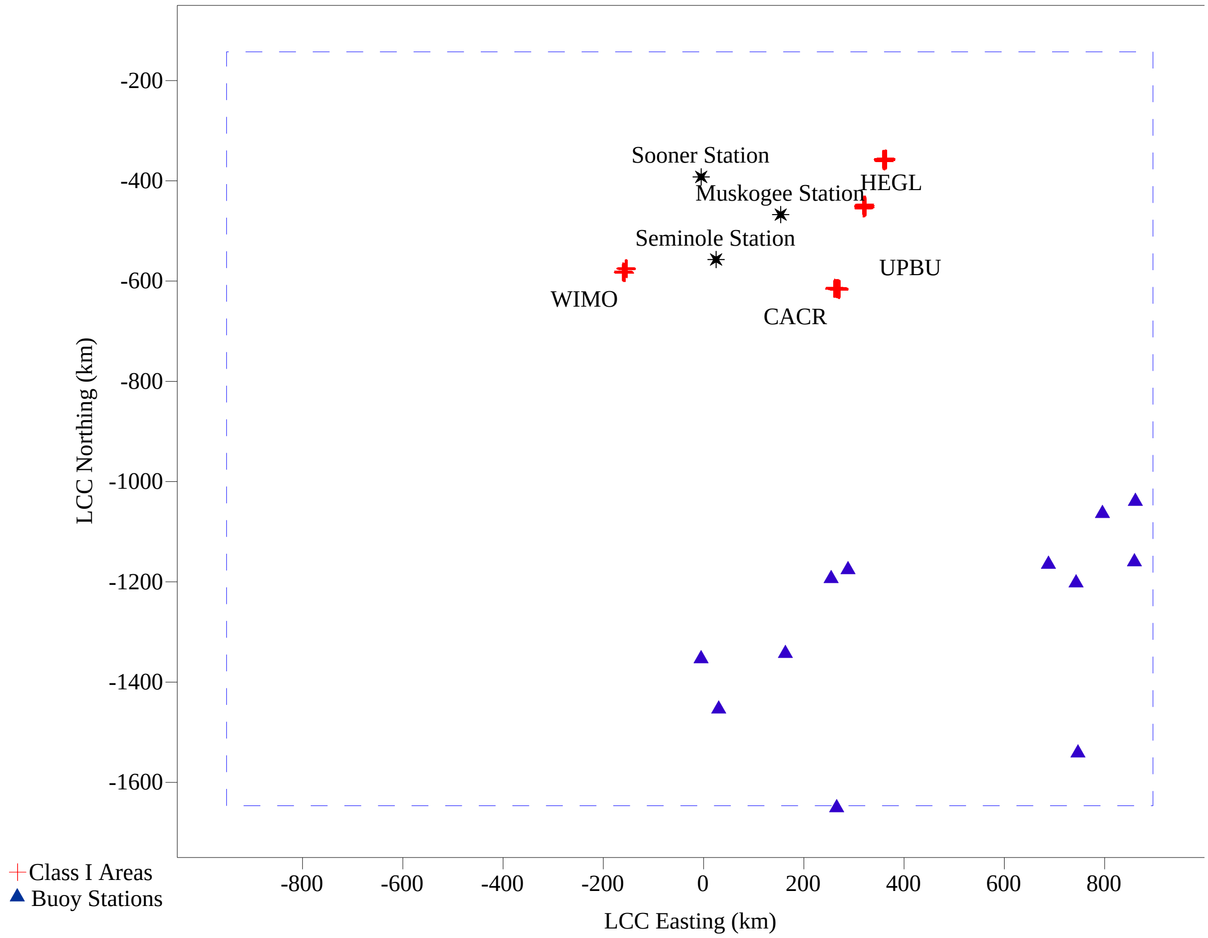
FIGURE 3-5. PLOT OF PRECIPITATION METEOROLOGICAL STATIONS



3.2.5 BUOY METEOROLOGICAL DATA

The effects of land/sea breeze on ambient pollutant concentrations will be considered in this analysis. Therefore, it is necessary to include observations of buoy stations in the CALMET analysis. The buoy stations that are proposed for this analysis are listed in Table A-4 of Appendix A. The locations of the buoy stations with respect to the modeling domain are shown in Figure 3-6. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain along the coastline. Data from the stations will be prepared by filling missing hour records with the CALMET missing parameter value (9999). No adjustments to the data will occur.

FIGURE 3-6. PLOT OF BUOY METEOROLOGICAL STATIONS



3.3 CALMET CONTROL PARAMETERS

Appendix B provides a sample CALMET input file used in OG&E's modeling analysis. A few details of the CALMET model setup for sensitive parameters are also discussed below.

3.3.1 VERTICAL METEOROLOGICAL PROFILE

The height of the top vertical layer will be set to 3,500 meters. This height corresponds to the top sounding pressure level for which upper air observation data will be relied upon. The vertical dimension of the domain will be divided into 12 layers with the maximum elevations for each layer shown in Table 3-1. The vertical dimensions are weighted towards the surface to resolve the mixing layer while using a somewhat coarser resolution for the layers aloft.

TABLE 3-1. VERTICAL LAYERS OF THE CALMET METEOROLOGICAL DOMAIN

Layer	Elevation (m)
1	20
2	40
3	60
4	80
5	100
6	150
7	200
8	250
9	500
10	1000
11	2000
12	3500

CALMET allows for a bias value to be applied to each of the vertical layers. The bias settings for each vertical layer determine the relative weight given to the vertically extrapolated surface and upper air wind and temperature observations. The initial guess fields are computed with an inverse distance weighting ($1/r^2$) of the surface and upper air data. The initial guess fields may be modified by a layer dependent bias factor. Values for the bias factor may range from -1 to +1. A bias of -1 eliminates upper-air observations in the $1/r^2$ interpolations used to initialize the vertical wind fields. Conversely, a bias of +1 eliminates the surface observations in the interpolations for this layer. Normally, bias is set to zero (0) for each vertical layer, such that the upper air and surface observations are given equal weight in the $1/r^2$ interpolations. The biases for each layer of the proposed modeling domain will be set to zero.

CALMET allows for vertical extrapolation of surface wind observations to layers aloft to be skipped if the surface station is close to the upper air station. Alternatively, CALMET allows data from all surface stations to be extrapolated. The CALMET parameter that controls this setting is IEXTRP. Setting IEXTRP to a value less than zero (0) means that layer 1 data from upper air soundings is ignored in any vertical extrapolations. IEXTRP will be set to -4 for this analysis (i.e., the similarity theory is used to extrapolate the surface winds into the layers aloft, which provides more information on observed local effects to the upper layers).

3.3.2 INFLUENCES OF OBSERVATIONS

Step 1 wind fields will be based on an initial guess using MM5 data and refined to reflect terrain affects. Step 2 wind fields will adjust the Step 1 wind field by incorporating the influence of local observations. An inverse distance method is used to determine the influence of observations to the Step 1 wind field. RMAX1 and RMAX2 define the radius of influence for data from surface stations to land in the surface layer and data from upper air stations to land in the layers aloft. In general, RMAX1 and RMAX2 are used to exclude observations from being inappropriately included in the development of the Step 2

wind field if the distance from an observation station to a grid point exceeds the maximum radius of influence.

If the distance from an observation station to a grid point is less than the value set for RMAX, the observation data will be used in the development of the Step 2 wind field. R1 represents the distance from a surface observation station at which the surface observation and the Step 1 wind field are weighted equally. R2 represents the comparable distance for winds aloft. R1 and R2 are used to weight the observation data with respect to the MM5 data that was used to generate the Step 1 wind field. Large values for R1 and R2 give more weight to the observations, where as small values give more weight to the MM5 data.

In this BART modeling analysis, RMAX 1 will be set to 20 km, and R1 will be set to 10 km. This will limit the influence of the surface observation data from all surface stations to 20 km from each station, and will equally weight the MM5 and observation data at 10 km. RMAX2 will be set to 50 km, and R2 will be set to 25 km. This will limit the influence of the upper air observation data from all surface stations to 50 km from each station, and will equally weight the MM5 and observation data at 25 km. These settings of radius of influence will allow for adequate weighting of the MM5 data and the observation data across the modeling domain due to the vast domain to be modeled. RAMX 3 will be set to 500 km.

TABLE A-1. LIST OF SURFACE METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	KDYS	69019	-267.672	-834.095	96.9968	39.9925
2	KNPA	72222	932.565	-1020.909	97.0110	39.9908
3	KBFM	72223	857.471	-996.829	97.0101	39.9910
4	KGZH	72227	946.767	-899.515	97.0112	39.9919
5	KTCL	72228	870.843	-706.104	97.0103	39.9936
6	KNEW	53917	674.172	-1078.342	97.0080	39.9903
7	KNBG	12958	677.719	-1104.227	97.0080	39.9900
8	BVE	12884	741.996	-1153.463	97.0088	39.9896
9	KPTN	72232	550.88	-1124.295	97.0065	39.9898
10	KMEI	13865	774.911	-814.225	97.0092	39.9926
11	KPIB	72234	728.416	-915.165	97.0086	39.9917
12	KGLH	72235	557.072	-703.097	97.0066	39.9936
13	KHEZ	11111	540.777	-912.22	97.0064	39.9918
14	KMCB	11112	622.755	-949.618	97.0074	39.9914
15	KGWO	11113	640.102	-695.286	97.0076	39.9937
16	KASD	72236	692.381	-1043.261	97.0082	39.9906
17	KPOE	72239	363.294	-984.839	97.0043	39.9911
18	KBAZ	72241	-102.133	-1140.886	96.9988	39.9897
19	KGLS	72242	215.108	-1185.604	97.0025	39.9893
20	KDWH	11114	140.413	-1101.174	97.0017	39.9900
21	KIAH	12960	158.266	-1108.37	97.0019	39.9900
22	KHOU	72243	167.147	-1147.402	97.0020	39.9896
23	KEFD	12906	178.551	-1152.782	97.0021	39.9896
24	KCXO	72244	152.739	-1069.309	97.0018	39.9903
25	KCLL	11115	60.898	-1044.381	97.0007	39.9906
26	KLFK	93987	214.643	-969.355	97.0025	39.9912
27	KUTS	11116	136.056	-1026.773	97.0016	39.9907
28	KTYR	11117	150.451	-846.207	97.0018	39.9924
29	KCRS	72246	56.655	-882.642	97.0007	39.9920
30	KGGG	72247	214.572	-841.163	97.0025	39.9924
31	KGKY	11118	-9.365	-812.25	96.9999	39.9927
32	KDTN	72248	304.827	-821.713	97.0036	39.9926
33	KBAD	11119	312.743	-825.101	97.0037	39.9925
34	KMLU	11120	465.834	-816.211	97.0055	39.9926
35	KTVR	11121	561.446	-840.225	97.0066	39.9924
36	KTRL	11122	68.599	-806.417	97.0008	39.9927
37	KOCH	72249	216.81	-930.252	97.0026	39.9916
38	KBRO	12919	-44.167	-1571.387	96.9995	39.9858

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
39	KALI	72251	-103.012	-1363.74	96.9988	39.9877
40	KLRD	12920	-246.548	-1381.603	96.9971	39.9875
41	KSSF	72252	-143.386	-1183.35	96.9983	39.9893
42	KRKP	11123	-4.965	-1324.914	96.9999	39.9880
43	KCOT	11124	-219.097	-1280.964	96.9974	39.9884
44	KLBX	11125	150.245	-1207.466	97.0018	39.9891
45	KSAT	12921	-143.024	-1160.935	96.9983	39.9895
46	KHDO	12962	-211.702	-1178.172	96.9975	39.9894
47	KSKF	72253	-154.625	-1177.555	96.9982	39.9894
48	KHYI	11126	-84.156	-1122.487	96.9990	39.9899
49	KTKI	72254	38.788	-754.791	97.0005	39.9932
50	KBMQ	11127	-118.39	-1027.031	96.9986	39.9907
51	KATT	11128	-67.587	-1075.97	96.9992	39.9903
52	KSGR	11129	131.478	-1151.702	97.0016	39.9896
53	KGTU	11130	-65.624	-1033.173	96.9992	39.9907
54	KVCT	12912	6.587	-1236.788	97.0001	39.9888
55	KPSX	72255	73.878	-1253.33	97.0009	39.9887
56	KACT	13959	-22.12	-929.156	96.9997	39.9916
57	KPWG	72256	-30.147	-944.073	96.9996	39.9915
58	KILE	72257	-65.288	-988.507	96.9992	39.9911
59	KGRK	11131	-79.643	-990.173	96.9991	39.9911
60	KTPL	11132	-38.203	-981.19	96.9996	39.9911
61	KPRX	13960	143.317	-703.663	97.0017	39.9936
62	KDTO	72258	-17.018	-752.974	96.9998	39.9932
63	KAFW	11133	-29.564	-777.061	96.9997	39.9930
64	KFTW	72259	-34.302	-795.502	96.9996	39.9928
65	KMWL	11134	-99.769	-798.767	96.9988	39.9928
66	KRBD	11135	12.453	-810.467	97.0002	39.9927
67	KDRT	11136	-384.069	-1170.59	96.9955	39.9894
68	KFST	22010	-566.418	-988.838	96.9933	39.9911
69	KGDP	72261	-739.127	-873.302	96.9913	39.9921
70	KSJT	72262	-333.338	-952.54	96.9961	39.9914
71	KMRF	23034	-676.265	-1042.616	96.9920	39.9906
72	KMAF	72264	-489.668	-878.107	96.9942	39.9921
73	KINK	23023	-586.882	-890.654	96.9931	39.9920
74	KABI	72265	-252.044	-836.353	96.9970	39.9924
75	KLBB	13962	-445.006	-689.313	96.9948	39.9938
76	KATS	11137	-696.818	-763.258	96.9918	39.9931
77	KCQC	11138	-785.757	-515.724	96.9907	39.9953
78	KROW	23009	-698.822	-712.898	96.9918	39.9936
79	KSRR	72268	-789.593	-686.226	96.9907	39.9938
80	KCNM	11139	-682.79	-822.109	96.9919	39.9926
81	KALM	36870	-838.056	-752.338	96.9901	39.9932
82	KLRU	72269	-931.527	-804.112	96.9890	39.9927
83	KTCS	72271	-952.353	-695.469	96.9888	39.9937

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
84	KSVC	93063	-1042.03	-752.033	96.9877	39.9932
85	KDMN	72272	-1006.77	-799.231	96.9881	39.9928
86	KMSL	72323	854.846	-536.687	97.0101	39.9952
87	KPOF	72330	578.62	-336.733	97.0068	39.9970
88	KGTR	11140	779.065	-689.108	97.0092	39.9938
89	KTUP	93862	753.875	-600.337	97.0089	39.9946
90	KMKL	72334	727.051	-454.383	97.0086	39.9959
91	KLRF	72340	440.654	-550.661	97.0052	39.9950
92	KHKA	11141	643.365	-424.419	97.0076	39.9962
93	KHOT	72341	358.094	-604.603	97.0042	39.9945
94	KTXK	11142	278.022	-720.623	97.0033	39.9935
95	KLLQ	72342	488.655	-698.008	97.0058	39.9937
96	KMWT	72343	254.18	-599.224	97.0030	39.9946
97	KFSM	13964	237.97	-512.87	97.0028	39.9954
98	KSLG	72344	224.881	-419.064	97.0027	39.9962
99	KVBT	11143	248.074	-399.892	97.0029	39.9964
100	KHRO	11144	343.525	-405.601	97.0041	39.9963
101	KFLP	11145	404.239	-399.142	97.0048	39.9964
102	KBVX	11146	480.712	-457.853	97.0057	39.9959
103	KROG	11147	258.44	-397.685	97.0031	39.9964
104	KSPS	13966	-138.053	-664.886	96.9984	39.9940
105	KHBR	72352	-186.121	-551.123	96.9978	39.9950
106	KCSM	11148	-198.844	-513.911	96.9977	39.9954
107	KFDR	11149	-181.653	-625.205	96.9979	39.9944
108	KGOK	72353	-35.905	-458.97	96.9996	39.9959
109	KTIK	72354	-34.581	-506.938	96.9996	39.9954
110	KPWA	11150	-58.596	-493.951	96.9993	39.9955
111	KSWO	11151	-7.42	-425.828	96.9999	39.9962
112	KMKO	72355	146.972	-479.879	97.0017	39.9957
113	KRVS	72356	91.059	-438.276	97.0011	39.9960
114	KBVO	11152	87.136	-357.069	97.0010	39.9968
115	KMLC	11153	110.647	-563.566	97.0013	39.9949
116	KOUN	72357	-40.731	-527.298	96.9995	39.9952
117	KLAW	11154	-129.405	-600.222	96.9985	39.9946
118	KCDS	72360	-300.297	-610.668	96.9965	39.9945
119	KGNT	72362	-985.117	-475.563	96.9884	39.9957
120	KGUP	11155	-1059.48	-427.151	96.9875	39.9961
121	KAMA	23047	-425.319	-518.171	96.9950	39.9953
122	KBGD	72363	-395.603	-466.083	96.9953	39.9958
123	KFMN	72365	-993.449	-297.944	96.9883	39.9973
124	KSKX	72366	-770.464	-355.855	96.9909	39.9968
125	KTCC	23048	-597.271	-511.241	96.9930	39.9954
126	KLVS	23054	-732.565	-448.329	96.9914	39.9960
127	KEHR	72423	812.573	-199.695	97.0096	39.9982
128	KEVV	93817	822.929	-172.715	97.0097	39.9984

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
129	KMVN	72433	704.666	-154.54	97.0083	39.9986
130	KMDH	11156	676.745	-218.041	97.0080	39.9980
131	KBLV	11157	617.659	-136.018	97.0073	39.9988
132	KSUS	3966	547.898	-130.122	97.0065	39.9988
133	KPAH	3816	725.985	-293.319	97.0086	39.9974
134	KJEF	72445	419.01	-145.496	97.0050	39.9987
135	KAIZ	11158	387.096	-200.609	97.0046	39.9982
136	KIXD	72447	182.322	-126.913	97.0022	39.9989
137	KWLD	72450	0	-298.57	97.0000	39.9973
138	KAAO	11159	-18.976	-248.773	96.9998	39.9978
139	KIAB	11160	-23.392	-263.471	96.9997	39.9976
140	KEWK	11161	-24.645	-215.58	96.9997	39.9981
141	KGBD	72451	-161.892	-180.781	96.9981	39.9984
142	KHYS	11162	-195.191	-124.723	96.9977	39.9989
143	KCFV	11163	126.442	-319.698	97.0015	39.9971
144	KFOE	72456	114.618	-115.26	97.0014	39.9990
145	KEHA	72460	-432.761	-320.089	96.9949	39.9971
146	KALS	72462	-777.592	-245.892	96.9908	39.9978
147	KDRO	11164	-945.713	-259.163	96.9888	39.9977
148	KLHX	72463	-568.426	-195.178	96.9933	39.9982
149	KSPD	2128	-494.076	-285.176	96.9942	39.9974
150	KCOS	93037	-664.022	-102.596	96.9922	39.9991
151	KGUC	72467	-857.452	-115.301	96.9899	39.9990
152	KMTJ	93013	-940.981	-109.358	96.9889	39.9990
153	KCEZ	72476	-1020.87	-233.14	96.9880	39.9979
154	KCPS	72531	591.652	-136.14	97.0070	39.9988
155	KLWV	72534	808.939	-94.46	97.0096	39.9992
156	KPPF	74543	130.433	-293.855	97.0015	39.9973
157	KHOP	74671	841.751	-324.569	97.0099	39.9971
158	KBIX	74768	778.252	-1028.514	97.0092	39.9907
159	KPQL	11165	814.599	-1019.583	97.0096	39.9908
160	MMPG	76243	-348.007	-1248.779	96.9959	39.9887
161	MMMV	76342	-446.576	-1449.334	96.9947	39.9869
162	MMMY	76394	-316.664	-1581.176	96.9963	39.9857

TABLE A-2. LIST OF UPPER AIR METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	KABQ	23050	-869.46	-501.713	96.9897	39.9955
2	KAMA	23047	-425.319	-518.171	96.9950	39.9953
3	KBMX	53823	951.609	-702.935	97.0112	39.9936
4	KBNA	13897	920.739	-377.164	97.0109	39.9966
5	KBRO	12919	-44.167	-1571.39	96.9995	39.9858
6	KCRP	12924	-51.535	-1360.35	96.9994	39.9877
7	KDDC	13985	-259.352	-242.681	96.9969	39.9978
8	KDRT	22010	-384.069	-1170.59	96.9955	39.9894
9	KEPZ	3020	-914.558	-852.552	96.9892	39.9923
10	KFWD	3990	-28.034	-793.745	96.9997	39.9928
11	KJAN	3940	650.105	-826.452	97.0077	39.9925
12	KLCH	3937	364.461	-1089.15	97.0043	39.9902
13	KLZK	3952	432.063	-560.441	97.0051	39.9949
14	KMAF	23023	-489.668	-878.107	96.9942	39.9921
15	KOUN	3948	-40.731	-527.298	96.9995	39.9952
16	KSHV	13957	298.869	-831.166	97.0035	39.9925
17	KSIL	53813	698.079	-1054.03	97.0082	39.9905

TABLE A-3. LIST OF PRECIPITATION METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	ADDI	10063	906.825	-601.428	97.0107	39.9946
2	ALBE	10140	917.606	-821.64	97.0108	39.9926
3	BERR	10748	892.454	-683.388	97.0105	39.9938
4	HALE	13620	881.928	-601.878	97.0104	39.9946
5	HAMT	13645	863.663	-612.725	97.0102	39.9945
6	JACK	14193	898.014	-915.623	97.0106	39.9917
7	MBLE	15478	851.953	-1022.41	97.0101	39.9908
8	MUSC	15749	880.113	-567.484	97.0104	39.9949
9	PETE	16370	935.558	-908.259	97.0110	39.9918
10	THOM	18178	900.858	-915.326	97.0106	39.9917
11	TUSC	18385	895.631	-713.223	97.0106	39.9936
12	VERN	18517	825.585	-685.773	97.0098	39.9938
13	BEEB	30530	462.394	-532.485	97.0055	39.9952
14	BRIG	30900	318.015	-554.857	97.0038	39.9950
15	CALI	31140	419.619	-731.44	97.0050	39.9934
16	CAMD	31152	386.546	-699.659	97.0046	39.9937
17	DIER	32020	268.114	-643.184	97.0032	39.9942
18	EURE	32356	286.738	-390.862	97.0034	39.9965
19	GILB	32794	383.362	-435.625	97.0045	39.9961
20	GREE	32978	450.594	-483.201	97.0053	39.9956
21	STUT	36920	509.943	-596.328	97.0060	39.9946
22	TEXA	37048	278.022	-720.623	97.0033	39.9935
23	ALAM	50130	-749.044	-267.856	96.9912	39.9976
24	ARAP	50304	-441.903	-152.324	96.9948	39.9986
25	COCH	51713	-819.794	-148.582	96.9903	39.9987
26	CRES	51959	-828.107	-119.911	96.9902	39.9989
27	GRAN	53477	-451.781	-203.82	96.9947	39.9982
28	GUNN	53662	-829.573	-141.995	96.9902	39.9987
29	HUGO	54172	-539.364	-81.948	96.9936	39.9993
30	JOHN	54388	-483.95	-201.915	96.9943	39.9982
31	KIM	54538	-544.501	-283.337	96.9936	39.9974
32	MESA	55531	-993.391	-256.696	96.9883	39.9977
33	ORDW	56136	-549.552	-55.741	96.9935	39.9995
34	OURA	56203	-904.197	-168.246	96.9893	39.9985
35	PLEA	56591	-1005.94	-229.472	96.9881	39.9979
36	PUEB	56740	-633.961	-176.872	96.9925	39.9984
37	TYE	57320	-662.095	-242.254	96.9922	39.9978
38	SAGU	57337	-790.269	-176.061	96.9907	39.9984

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
39	SANL	57428	-726.777	-285.47	96.9914	39.9974
40	SHEP	57572	-714.046	-252.189	96.9916	39.9977
41	TELL	58204	-920.205	-215.382	96.9891	39.9981
42	TERC	58220	-708.229	-296.023	96.9916	39.9973
43	TRIN	58429	-642.489	-293.805	96.9924	39.9973
44	TRLK	58436	-646.185	-295.727	96.9924	39.9973
45	WALS	58781	-654.989	-262.821	96.9923	39.9976
46	WHIT	58997	-619.615	-250.12	96.9927	39.9977
47	ASHL	110281	684.787	-169.285	97.0081	39.9985
48	CAIR	111166	697.177	-301.436	97.0082	39.9973
49	CARM	111302	772.938	-177.782	97.0091	39.9984
50	CISN	111664	758.146	-151.446	97.0090	39.9986
51	FLOR	113109	751.801	-139.837	97.0089	39.9987
52	HARR	113879	762.044	-246.62	97.0090	39.9978
53	KASK	114629	650.464	-239.886	97.0077	39.9978
54	LAWR	114957	829.038	-128.708	97.0098	39.9988
55	MTCA	115888	827.797	-149.966	97.0098	39.9986
56	MURP	115983	682.261	-251.649	97.0081	39.9977
57	NEWT	116159	766.098	-72.902	97.0090	39.9993
58	REND	117187	731.633	-185.058	97.0086	39.9983
59	SMIT	118020	770.027	-283.638	97.0091	39.9974
60	SPAR	118147	658.275	-185.973	97.0078	39.9983
61	VAND	118781	685.449	-127.048	97.0081	39.9989
62	WEST	119193	778.655	-147.215	97.0092	39.9987
63	EVAN	122738	842.476	-172.871	97.0100	39.9984
64	NEWB	126151	855.854	-223.713	97.0101	39.9980
65	PRIN	127125	836.901	-153.449	97.0099	39.9986
66	STEN	128442	859.099	-156.613	97.0101	39.9986
67	JTML	128967	788.703	-239.572	97.0093	39.9978
68	ARLI	140326	-101.734	-271.373	96.9988	39.9976
69	BAZI	140620	-210.423	-201.758	96.9975	39.9982
70	BEAU	140637	59.762	-288.39	97.0007	39.9974
71	BONN	140957	211.236	-103.29	97.0025	39.9991
72	CALD	141233	-32.689	-330.586	96.9996	39.9970
73	CASS	141351	54.006	-217.645	97.0006	39.9980
74	CENT	141404	170.503	-206.038	97.0020	39.9981
75	CHAN	141427	150.257	-286.094	97.0018	39.9974
76	CLIN	141612	155.623	-157.682	97.0018	39.9986
77	COLL	141730	-265.465	-156.95	96.9969	39.9986
78	COLU	141740	220.541	-316.555	97.0026	39.9971

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
79	CONC	141867	58.918	-175.589	97.0007	39.9984
80	DODG	142164	-226.497	-277.655	96.9973	39.9975
81	ELKH	142432	-400.112	-321.784	96.9953	39.9971
82	ENGL	142560	-264.927	-324.066	96.9969	39.9971
83	ERIE	142582	162.669	-291.383	97.0019	39.9974
84	FALL	142686	83.491	-288.177	97.0010	39.9974
85	GALA	142938	-136.931	-176.83	96.9984	39.9984
86	GARD	142980	-304.059	-215.308	96.9964	39.9981
87	GREN	143248	64.308	-307.161	97.0008	39.9972
88	HAYS	143527	-190.307	-161.342	96.9978	39.9985
89	HEAL	143554	-292.133	-175.921	96.9966	39.9984
90	HILL	143686	214.018	-174.006	97.0025	39.9984
91	INDE	143954	139.335	-315.058	97.0016	39.9972
92	IOLA	143984	153.451	-269.438	97.0018	39.9976
93	JOHR	144104	134.784	-203.41	97.0016	39.9982
94	KANO	144178	-50.289	-181.177	96.9994	39.9984
95	KIOW	144341	-113.967	-329.843	96.9987	39.9970
96	MARI	145039	-4.343	-195.712	97.0000	39.9982
97	MELV	145210	137.104	-186.781	97.0016	39.9983
98	MILF	145306	39.504	-106.05	97.0005	39.9990
99	MOUD	145536	152.624	-318.136	97.0018	39.9971
100	OAKL	145888	-306.378	-96.814	96.9964	39.9991
101	OTTA	146128	158.639	-178.635	97.0019	39.9984
102	POMO	146498	143.864	-176.707	97.0017	39.9984
103	SALI	147160	-29.426	-166.908	96.9997	39.9985
104	SMOL	147551	-34.639	-171.31	96.9996	39.9985
105	STAN	147756	225.026	-164.85	97.0027	39.9985
106	SUBL	147922	-303.514	-292.808	96.9964	39.9974
107	TOPE	148167	139.116	-104.91	97.0016	39.9991
108	TRIB	148235	-387.855	-180.643	96.9954	39.9984
109	UNIO	148293	211.43	-272.537	97.0025	39.9975
110	WALL	148535	-376.076	-152.432	96.9956	39.9986
111	WICH	148830	-23.729	-288.579	96.9997	39.9974
112	WILS	148946	-111.502	-156.22	96.9987	39.9986
113	BENT	150611	781.608	-348.109	97.0092	39.9969
114	CALH	151227	865.268	-261.635	97.0102	39.9976
115	CLTN	151631	749.287	-365.634	97.0088	39.9967
116	HERN	153798	859.01	-352.458	97.0101	39.9968
117	MADI	155067	854.116	-265.064	97.0101	39.9976
118	PADU	156110	753.185	-293.024	97.0089	39.9974

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
119	PCTN	156580	834.464	-280.496	97.0099	39.9975
120	ALEX	160103	433.824	-959.253	97.0051	39.9913
121	BATN	160549	562.794	-1032.4	97.0066	39.9907
122	CALH	161411	436.113	-817.451	97.0052	39.9926
123	CLNT	161899	578.969	-999.986	97.0068	39.9910
124	JENA	164696	455.225	-912.366	97.0054	39.9918
125	LACM	165078	364.784	-1089.92	97.0043	39.9901
126	MIND	166244	346.708	-812.651	97.0041	39.9927
127	MONR	166314	463.225	-814.905	97.0055	39.9926
128	NATC	166582	369.451	-905.316	97.0044	39.9918
129	SHRE	168440	299.526	-831.143	97.0035	39.9925
130	WINN	169803	408.309	-884.596	97.0048	39.9920
131	BROK	221094	621.827	-914.236	97.0073	39.9917
132	CONE	221900	737.007	-823.513	97.0087	39.9926
133	JAKS	224472	650.361	-826.097	97.0077	39.9925
134	LEAK	224966	805.886	-943.78	97.0095	39.9915
135	MERI	225776	774.942	-814.558	97.0092	39.9926
136	SARD	227815	658.33	-593.661	97.0078	39.9946
137	SAUC	227840	763.399	-1005.93	97.0090	39.9909
138	TUPE	229003	753.571	-600.03	97.0089	39.9946
139	ADVA	230022	657.892	-298.102	97.0078	39.9973
140	ALEY	230088	505.348	-305.864	97.0060	39.9972
141	BOLI	230789	331.651	-291.689	97.0039	39.9974
142	CASV	231383	310.855	-392.187	97.0037	39.9965
143	CLER	231674	575.868	-302.209	97.0068	39.9973
144	CLTT	231711	307.465	-190.83	97.0036	39.9983
145	COLU	231791	421.287	-155.672	97.0050	39.9986
146	DREX	232331	228.23	-185.776	97.0027	39.9983
147	ELM	232568	257.758	-159.419	97.0030	39.9986
148	FULT	233079	470.408	-150.668	97.0056	39.9986
149	HOME	233999	619.93	-415.469	97.0073	39.9962
150	JEFF	234271	424.774	-172.095	97.0050	39.9984
151	JOPL	234315	238.245	-318.262	97.0028	39.9971
152	LEBA	234825	402.239	-276.263	97.0048	39.9975
153	LICK	234919	480.849	-280.775	97.0057	39.9975
154	LOCK	235027	302.048	-300.612	97.0036	39.9973
155	MALD	235207	659.982	-377.876	97.0078	39.9966
156	MARS	235298	332.062	-94.655	97.0039	39.9991
157	MAFD	235307	391.968	-300.033	97.0046	39.9973
158	MCES	235415	471.737	-143.942	97.0056	39.9987

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
159	MILL	235594	309.516	-311.398	97.0037	39.9972
160	MTGV	235834	426.937	-310.43	97.0050	39.9972
161	NVAD	235987	243.915	-272.715	97.0029	39.9975
162	OZRK	236460	349.133	-390.626	97.0041	39.9965
163	PDTD	236777	334.055	-265.018	97.0039	39.9976
164	POTO	236826	572.215	-251.455	97.0068	39.9977
165	ROLL	237263	484.503	-253.958	97.0057	39.9977
166	ROSE	237300	500.59	-175.393	97.0059	39.9984
167	SALE	237506	498.94	-274.122	97.0059	39.9975
168	SENE	237656	233.959	-383.703	97.0028	39.9965
169	SPRC	237967	238.112	-373.616	97.0028	39.9966
170	SPVL	237976	332.385	-309.374	97.0039	39.9972
171	STEE	238043	503.354	-205.135	97.0059	39.9981
172	STOK	238082	310.911	-279.239	97.0037	39.9975
173	SWSP	238223	324.053	-150.325	97.0038	39.9986
174	TRKD	238252	340.418	-395.428	97.0040	39.9964
175	TRUM	238466	326.883	-197.796	97.0039	39.9982
176	UNIT	238524	238.567	-154.494	97.0028	39.9986
177	VIBU	238609	519.633	-267.258	97.0061	39.9976
178	VIEN	238620	470.383	-193.872	97.0056	39.9983
179	WAPP	238700	606.68	-358.746	97.0072	39.9968
180	WASG	238746	556.425	-164.993	97.0066	39.9985
181	WEST	238880	489.373	-377.809	97.0058	39.9966
182	ALBU	290234	-869.46	-501.713	96.9897	39.9955
183	ARTE	290600	-689.529	-773.897	96.9919	39.9930
184	AUGU	290640	-973.07	-598.391	96.9885	39.9946
185	CARL	291469	-680.335	-811.474	96.9920	39.9927
186	CARR	291515	-819.836	-665.132	96.9903	39.9940
187	CLAY	291887	-547.124	-374.102	96.9935	39.9966
188	CLOV	291939	-566.973	-599.296	96.9933	39.9946
189	CUBA	292241	-890.304	-392.495	96.9895	39.9965
190	CUBE	292250	-951.142	-489.293	96.9888	39.9956
191	DEMI	292436	-1007.99	-799.087	96.9881	39.9928
192	DURA	292665	-767.148	-577.618	96.9909	39.9948
193	EANT	292700	-735.089	-366.94	96.9913	39.9967
194	LAVG	294862	-738.245	-461.163	96.9913	39.9958
195	PROG	297094	-811.39	-578.971	96.9904	39.9948
196	RAMO	297254	-733.737	-615.175	96.9913	39.9944
197	ROSW	297610	-698.544	-712.921	96.9918	39.9936
198	ROY	297638	-644.735	-422.422	96.9924	39.9962

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
199	SANT	298085	-807.375	-445.708	96.9905	39.9960
200	SPRI	298501	-676.681	-374.272	96.9920	39.9966
201	STAY	298518	-810.491	-495.501	96.9904	39.9955
202	TNMN	299031	-912.488	-413.425	96.9892	39.9963
203	TUCU	299156	-604.359	-508.834	96.9929	39.9954
204	WAST	299569	-638.605	-820.288	96.9925	39.9926
205	WISD	299686	-856.967	-756.366	96.9899	39.9932
206	AIRS	340179	-212.731	-597.062	96.9975	39.9946
207	ARDM	340292	-12.242	-645.633	96.9999	39.9942
208	BENG	340670	174.368	-568.011	97.0021	39.9949
209	CANE	341437	71.857	-637.935	97.0009	39.9942
210	CHRT	341544	203.233	-632.067	97.0024	39.9943
211	CHAN	341684	10.494	-475.655	97.0001	39.9957
212	CHIK	341750	-83.175	-547.26	96.9990	39.9951
213	CCTY	342334	-165	-479.536	96.9981	39.9957
214	DUNC	342654	-88.38	-610.04	96.9990	39.9945
215	ELKC	342849	-216.769	-507.879	96.9974	39.9954
216	FORT	343281	-129.964	-541.113	96.9985	39.9951
217	GEAR	343497	-118.53	-482.187	96.9986	39.9956
218	HENN	344052	-31.964	-601.206	96.9996	39.9946
219	HOBA	344202	-189.062	-547.36	96.9978	39.9951
220	KING	344865	24.538	-664.103	97.0003	39.9940
221	LKEU	344975	141.702	-520.6	97.0017	39.9953
222	LEHI	345108	71.634	-612.05	97.0009	39.9945
223	MACI	345463	-254.63	-466.154	96.9970	39.9958
224	MALL	345589	-55.127	-425.644	96.9994	39.9962
225	MAYF	345648	-258.49	-512.583	96.9970	39.9954
226	MUSK	346130	149.764	-466.905	97.0018	39.9958
227	NOWA	346485	121.551	-364.038	97.0014	39.9967
228	OKAR	346620	-88.424	-473.338	96.9990	39.9957
229	OKEM	346638	63.188	-504.958	97.0008	39.9954
230	OKLA	346661	-54.198	-510.562	96.9994	39.9954
231	PAOL	346859	-23.665	-573.142	96.9997	39.9948
232	PAWH	346935	57.704	-369.174	97.0007	39.9967
233	PAWN	346944	16.927	-398.139	97.0002	39.9964
234	PONC	347196	-8.871	-363.068	96.9999	39.9967
235	PRYO	347309	150.763	-407.824	97.0018	39.9963
236	SHAT	348101	-256.963	-407.368	96.9970	39.9963
237	STIG	348497	171.02	-523.736	97.0020	39.9953
238	TULS	348992	99.361	-419.873	97.0012	39.9962

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
239	TUSK	349023	156.629	-592.395	97.0019	39.9946
240	WMWR	349629	-156.42	-581.308	96.9982	39.9947
241	WOLF	349748	30.212	-538.388	97.0004	39.9951
242	BOLI	400876	760.886	-500.256	97.0090	39.9955
243	BROW	401150	710.048	-480.346	97.0084	39.9957
244	CETR	401587	877.35	-456.294	97.0104	39.9959
245	DICS	402489	872.14	-391.132	97.0103	39.9965
246	DYER	402680	695.792	-409.316	97.0082	39.9963
247	GRNF	403697	760.795	-395.69	97.0090	39.9964
248	JSNN	404561	765.932	-476.414	97.0090	39.9957
249	LWER	405089	885.291	-487.757	97.0105	39.9956
250	LEXI	405210	790.003	-471.897	97.0093	39.9957
251	MASO	405720	694.163	-496.166	97.0082	39.9955
252	MEMP	405954	671.8	-522.492	97.0079	39.9953
253	MWFO	405956	681.292	-516.15	97.0080	39.9953
254	MUNF	406358	678.65	-495.241	97.0080	39.9955
255	SAMB	408065	697.077	-382.536	97.0082	39.9965
256	SAVA	408108	800.788	-498.682	97.0095	39.9955
257	UNCY	409219	711.595	-384.605	97.0084	39.9965
258	ABIL	410016	-251.753	-836.027	96.9970	39.9924
259	AMAR	410211	-425.302	-517.839	96.9950	39.9953
260	AUST	410428	-67.587	-1075.97	96.9992	39.9903
261	BRWN	411136	-43.861	-1571.39	96.9995	39.9858
262	COST	411889	60.611	-1044.72	97.0007	39.9906
263	COCR	412015	-51.832	-1360.01	96.9994	39.9877
264	CROS	412131	-204.599	-868.469	96.9976	39.9922
265	DFWT	412242	-1.867	-786.341	97.0000	39.9929
266	EAST	412715	-171.024	-840.253	96.9980	39.9924
267	ELPA	412797	-886.583	-860.763	96.9895	39.9922
268	HICO	414137	-97.323	-888.181	96.9989	39.9920
269	HUST	414300	157.976	-1108.38	97.0019	39.9900
270	KRES	414880	-434.746	-611.717	96.9949	39.9945
271	LKCK	414975	99.734	-693.521	97.0012	39.9937
272	LNGV	415348	220.962	-844.674	97.0026	39.9924
273	LUFK	415424	214.652	-969.69	97.0025	39.9912
274	MATH	415661	-86.438	-1330.47	96.9990	39.9880
275	MIDR	415890	-489.385	-878.123	96.9942	39.9921
276	MTLK	416104	-672.024	-1008.98	96.9921	39.9909
277	NACO	416177	223.065	-925.966	97.0026	39.9916
278	NAVA	416210	28.358	-892.028	97.0003	39.9919

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
279	NEWB	416270	239.111	-721.818	97.0028	39.9935
280	BPAT	417174	288.962	-1110.65	97.0034	39.9900
281	RANK	417431	-472.048	-959.488	96.9944	39.9913
282	SAAG	417943	-333.338	-952.54	96.9961	39.9914
283	SAAT	417945	-143.322	-1161.27	96.9983	39.9895
284	SHEF	418252	-463.759	-1019.19	96.9945	39.9908
285	STEP	418623	-112.988	-857.918	96.9987	39.9922
286	STER	418630	-376.683	-897.195	96.9956	39.9919
287	VALE	419270	-720.749	-1015.17	96.9915	39.9908
288	VICT	419364	6.882	-1236.45	97.0001	39.9888
289	WACO	419419	-21.834	-928.823	96.9997	39.9916
290	WATR	419499	-353.767	-916.015	96.9958	39.9917
291	WHEE	419665	57.489	-1008.99	97.0007	39.9909
292	WPDM	419916	262.792	-737.786	97.0031	39.9933
293	DORA	232302	433.256	-378.797	97.0051	39.9966
294	DIXN	112353	756.057	-267.193	97.0089	39.9976
295	DAUP	12172	864.408	-1050.41	97.0102	39.9905
296	FREV	123104	847.031	-117.884	97.0100	39.9989
297	WARR	18673	890.447	-788.703	97.0105	39.9929
298	MDTN	235562	493.264	-87.222	97.0058	39.9992

TABLE A-4. LIST OF OVER WATER METEOROLOGICAL STATIONS

Number	Station ID	Input file Name	LCC East (km)	LCC North (km)	Long	Lat
1	42001	42001	746.874	-1541.35	89.67	25.9
2	42002	42002	265.486	-1650.616	94.42	25.19
3	42007	42007	795.674	-1063.667	88.77	30.09
4	42019	42019	163.178	-1342.917	95.36	27.91
5	42020	42020	30.212	-1453.738	96.7	26.94
6	42035	42035	254.465	-1193.539	94.41	29.25
7	42040	42040	859.497	-1160.066	88.21	29.18
8	BURL1	42045	743.116	-1202.117	89.43	28.9
9	DPIA1	42046	861.385	-1039.466	88.07	30.25
10	GDIL1	42047	687.984	-1164.910	89.96	29.27
11	PTAT2	42048	-4.980	-1353.398	97.05	27.83
12	SRST2	42049	288.163	-1175.682	94.05	29.67

APPENDIX D

CEMS DATA FROM CAMD FOR 2001 TO 2003 AND 2009 TO 2011

Unit ID	Date	SO2 (tons)	Heat Input (MMBtu)
1	1/5/2001	1.427	26,054
1	1/6/2001	42.883	149,330
1	1/7/2001	68.245	194,455
1	1/8/2001	63.914	182,770
1	1/9/2001	67.859	204,772
1	1/10/2001	65.955	190,485
1	1/11/2001	70.031	202,920
1	1/12/2001	56.743	187,273
1	1/13/2001	64.013	207,805
1	1/14/2001	48.542	144,623
1	1/15/2001	67.075	192,264
1	1/16/2001	57.886	185,487
1	1/17/2001	68.777	198,849
1	1/18/2001	62.858	188,091
1	1/19/2001	58.119	185,976
1	1/20/2001	66.6	191,109
1	1/21/2001	69.856	206,742
1	1/22/2001	65.144	190,490
1	1/23/2001	64.994	194,193
1	1/24/2001	56.804	182,694
1	1/25/2001	63.27	202,127
1	1/26/2001	55.296	171,617
1	4/3/2001	0.547	6,873
1	4/4/2001	1.055	8,573
1	4/5/2001	1.546	10,088
1	4/6/2001	8.967	38,007
1	4/7/2001	6.478	26,784
1	4/9/2001	5.976	26,103
1	4/10/2001	24.207	93,161
1	4/11/2001	55.76	174,874
1	4/12/2001	59.522	173,490
1	4/13/2001	54.427	165,840
1	4/14/2001	58.422	171,216
1	4/15/2001	24.188	72,680
1	4/16/2001	2.533	10,525
1	4/17/2001	56.651	164,701
1	4/18/2001	64.409	164,695
1	4/19/2001	61.953	160,949
1	4/20/2001	63.59	173,481
1	4/21/2001	31.694	94,929
1	4/22/2001	59.626	164,679
1	4/23/2001	43.525	120,867
1	4/24/2001	9.105	28,862
1	4/25/2001	62.678	180,855
1	4/26/2001	49.349	140,127

1	4/27/2001	62.261	187,109
1	4/28/2001	62.59	179,852
1	4/29/2001	52.9	155,338
1	4/30/2001	69.128	180,489
1	5/1/2001	49.114	136,478
1	5/2/2001	63.29	182,498
1	5/3/2001	62.078	184,546
1	5/4/2001	63.607	185,637
1	5/5/2001	60.206	174,287
1	5/6/2001	55.887	164,969
1	5/7/2001	66.414	181,665
1	5/8/2001	66.104	187,835
1	5/9/2001	61.648	183,461
1	5/10/2001	61.171	181,272
1	5/11/2001	57.942	172,097
1	5/12/2001	5.656	17,561
1	5/13/2001	0.609	3,950
1	5/14/2001	55.397	159,810
1	5/15/2001	64.475	183,212
1	5/16/2001	63.77	181,857
1	5/17/2001	59.676	176,776
1	5/18/2001	61.378	176,568
1	5/19/2001	64.114	180,838
1	5/20/2001	59.087	170,626
1	5/21/2001	50.906	148,628
1	5/22/2001	52.519	154,556
1	5/23/2001	58.172	170,287
1	5/24/2001	61.455	179,175
1	5/25/2001	58.992	169,017
1	5/26/2001	60.789	175,004
1	5/27/2001	58.749	172,696
1	5/28/2001	64.869	174,922
1	5/29/2001	60.546	180,550
1	5/30/2001	59.685	173,119
1	5/31/2001	55.194	161,952
1	6/1/2001	56.076	161,968
1	6/2/2001	62.356	179,767
1	6/3/2001	62.691	187,445
1	6/4/2001	69.826	195,288
1	6/5/2001	65.276	187,650
1	6/6/2001	62.966	184,410
1	6/7/2001	62.048	178,041
1	6/8/2001	70.887	192,530
1	6/9/2001	59.876	178,409
1	6/10/2001	58.98	177,831
1	6/11/2001	61.296	185,722
1	6/12/2001	68.818	196,712

1	6/13/2001	72.77	206,791
1	6/14/2001	82.035	228,623
1	6/15/2001	72.149	202,380
1	6/16/2001	69.886	199,793
1	6/17/2001	71.396	201,210
1	6/18/2001	75.678	217,184
1	6/19/2001	69.793	203,565
1	6/20/2001	70.83	204,866
1	6/21/2001	69.739	203,174
1	6/22/2001	69.941	208,054
1	6/23/2001	67.056	193,075
1	6/24/2001	66.104	193,681
1	6/25/2001	62.686	186,522
1	6/26/2001	68.046	197,197
1	6/27/2001	59.758	173,545
1	6/28/2001	69.789	201,036
1	6/29/2001	71.015	199,606
1	6/30/2001	67.63	196,607
1	7/1/2001	64.938	190,313
1	7/2/2001	67.968	201,234
1	7/3/2001	74.092	198,062
1	7/4/2001	68.436	197,642
1	7/5/2001	67.987	196,138
1	7/6/2001	65.934	200,553
1	7/7/2001	67.562	194,432
1	7/8/2001	61.583	219,889
1	7/9/2001	59.883	204,470
1	7/10/2001	83.794	215,984
1	7/11/2001	67.369	194,599
1	7/12/2001	64.477	189,174
1	7/13/2001	7.831	34,051
1	7/14/2001	68.11	194,471
1	7/15/2001	69.282	181,728
1	7/16/2001	70.182	195,428
1	7/17/2001	56.916	200,084
1	7/18/2001	67.033	211,803
1	7/19/2001	67.091	201,315
1	7/20/2001	79.587	213,335
1	7/21/2001	67.74	202,185
1	7/22/2001	70.121	207,400
1	7/23/2001	58.683	178,725
1	7/24/2001	57.098	206,917
1	7/25/2001	52.214	177,632
1	7/26/2001	70.82	217,541
1	7/27/2001	68.711	199,604
1	7/28/2001	69.585	206,823
1	7/29/2001	49.378	192,050

1	7/30/2001	54.797	208,774
1	7/31/2001	69.394	201,992
1	8/1/2001	63.745	189,763
1	8/2/2001	71.075	218,726
1	8/3/2001	69.396	200,818
1	8/4/2001	64.49	197,670
1	8/5/2001	64.868	191,622
1	8/6/2001	63.636	212,620
1	8/7/2001	57.665	191,653
1	8/8/2001	64.678	213,642
1	8/9/2001	47.023	193,280
1	8/10/2001	58.4	208,250
1	8/11/2001	48.012	184,435
1	8/12/2001	60.14	189,596
1	8/13/2001	57.645	181,656
1	8/14/2001	58.304	186,898
1	8/15/2001	58.225	180,890
1	8/16/2001	71.981	214,532
1	8/17/2001	64.94	198,444
1	8/18/2001	67.218	203,643
1	8/19/2001	67.619	192,562
1	8/20/2001	65.533	194,140
1	8/21/2001	62.648	196,979
1	8/22/2001	68.512	199,137
1	8/23/2001	70.948	209,984
1	8/24/2001	63.321	194,695
1	8/25/2001	59.971	192,155
1	8/26/2001	62.562	189,841
1	8/27/2001	67.055	195,409
1	8/28/2001	63.287	190,177
1	8/29/2001	69.2	199,246
1	8/30/2001	61.391	189,474
1	8/31/2001	65.847	203,921
1	9/1/2001	60.489	185,501
1	9/2/2001	57.116	170,413
1	9/3/2001	55.47	188,460
1	9/4/2001	52.537	205,793
1	9/5/2001	69.889	198,384
1	9/6/2001	68.654	207,117
1	9/7/2001	62.387	187,751
1	9/8/2001	69.789	198,880
1	9/9/2001	58.532	171,631
1	9/10/2001	51.286	186,885
1	9/11/2001	58.135	183,969
1	9/12/2001	64.083	193,770
1	9/13/2001	66.92	207,704
1	9/14/2001	65.662	199,431

1	9/15/2001	47.991	149,423
1	9/16/2001	61.057	173,907
1	9/17/2001	64.579	196,262
1	9/18/2001	66.304	197,588
1	9/19/2001	42.479	135,150
1	9/20/2001	59.628	188,047
1	9/21/2001	55.154	191,343
1	9/22/2001	59.266	203,172
1	9/23/2001	52.687	178,601
1	9/24/2001	61.1	191,425
1	9/25/2001	58.935	173,197
1	9/26/2001	58.448	172,509
1	9/27/2001	64.197	190,973
1	9/28/2001	59.903	183,833
1	9/29/2001	52.612	164,330
1	9/30/2001	47.5	151,261
1	10/1/2001	55.079	172,521
1	10/2/2001	48.89	185,647
1	10/3/2001	55.909	193,065
1	10/4/2001	61.833	206,607
1	10/8/2001	36.186	112,976
1	10/9/2001	72.988	220,068
1	10/10/2001	66.767	206,153
1	10/11/2001	66.98	219,629
1	10/12/2001	59.135	188,092
1	10/13/2001	62.573	194,097
1	10/14/2001	51.93	161,238
1	10/15/2001	61.904	193,931
1	10/16/2001	62.534	190,118
1	10/17/2001	62.392	191,378
1	10/18/2001	55.951	175,127
1	10/19/2001	43.663	140,910
1	10/21/2001	0.262	8,330
1	10/22/2001	35.667	126,447
1	10/23/2001	25.149	78,862
1	10/24/2001	12.77	50,607
1	10/25/2001	66.722	207,816
1	10/26/2001	62.93	193,711
1	10/27/2001	59.814	193,744
1	10/28/2001	67.952	212,723
1	10/29/2001	62.573	196,544
1	10/30/2001	68.954	213,301
1	10/31/2001	61.194	189,622
1	11/1/2001	63.85	199,791
1	11/2/2001	62.444	192,209
1	11/3/2001	67.009	174,125
1	11/4/2001	54.729	170,634

1	11/5/2001	63.401	199,959
1	11/6/2001	66.746	205,470
1	11/7/2001	49.409	157,872
1	11/8/2001	69.802	213,781
1	11/9/2001	64.883	203,484
1	11/10/2001	73.337	218,963
1	11/11/2001	61.848	187,807
1	11/12/2001	65.828	204,133
1	11/13/2001	63.046	189,526
1	11/14/2001	22.495	92,696
1	11/15/2001	36.48	111,862
1	11/16/2001	36.041	114,142
1	11/17/2001	35.271	115,121
1	11/18/2001	32.37	105,190
1	11/21/2001	0.361	9,218
1	11/22/2001	28.09	104,413
1	11/23/2001	45.663	142,873
1	11/24/2001	48.864	149,650
1	11/25/2001	47.17	157,334
1	11/26/2001	60.874	188,092
1	11/27/2001	66.46	203,520
1	11/28/2001	63.65	198,498
1	11/29/2001	71.885	218,758
1	11/30/2001	66.244	185,155
1	12/1/2001	64.506	193,567
1	12/2/2001	45.619	139,533
1	12/3/2001	59.412	195,898
1	12/4/2001	67.238	203,423
1	12/5/2001	65.347	196,961
1	12/6/2001	66.744	199,382
1	12/7/2001	65.415	190,727
1	12/8/2001	58.997	188,729
1	12/9/2001	57.892	180,602
1	12/10/2001	71.695	204,009
1	12/11/2001	71.263	198,053
1	12/12/2001	65.161	194,984
1	12/13/2001	64.638	191,787
1	12/14/2001	62.025	189,609
1	12/15/2001	55.166	191,899
1	12/16/2001	60.591	193,126
1	12/17/2001	58.482	185,205
1	12/18/2001	64.737	197,302
1	12/19/2001	61.156	186,406
1	12/20/2001	68.073	202,192
1	12/21/2001	57.529	181,524
1	12/22/2001	58.981	185,305
1	12/23/2001	51.357	174,111

1	12/24/2001	59.022	184,946
1	12/25/2001	50.786	161,430
1	12/26/2001	66.38	205,423
1	12/27/2001	64.214	194,709
1	12/28/2001	64.287	192,369
1	12/29/2001	61.542	192,964
1	12/30/2001	65.491	212,269
1	12/31/2001	47.421	191,796
1	1/1/2002	63.679	210,165
1	1/2/2002	63.43	201,368
1	1/3/2002	67.6	206,525
1	1/4/2002	65.712	198,917
1	1/5/2002	61.49	190,678
1	1/6/2002	64.831	200,976
1	1/7/2002	62.917	197,310
1	1/8/2002	54.84	171,604
1	1/9/2002	53.326	171,734
1	1/10/2002	63.441	195,374
1	1/11/2002	62.568	188,959
1	1/12/2002	68.436	202,097
1	1/13/2002	63.656	186,189
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1	5/26/2002	65.7	186,889
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1	5/29/2002	66.227	185,455
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1	6/28/2003	67.706	208,435
1	6/29/2003	67.217	187,558
1	6/30/2003	65.28	203,057
1	7/1/2003	65.351	190,432
1	7/2/2003	69.546	199,595
1	7/3/2003	64.51	190,141
1	7/4/2003	69.444	199,252
1	7/5/2003	63.391	186,550
1	7/6/2003	68.122	194,179
1	7/7/2003	64.627	194,081
1	7/8/2003	70.035	216,937
1	7/9/2003	67.854	192,724
1	7/10/2003	75.468	212,229
1	7/11/2003	40.227	119,467
1	7/12/2003	43.857	177,807
1	7/13/2003	64.739	190,585
1	7/14/2003	75.933	214,321
1	7/15/2003	65.332	189,958
1	7/16/2003	79.905	210,593
1	7/17/2003	66.713	185,541
1	7/18/2003	74.769	200,491
1	7/19/2003	63.41	179,781
1	7/20/2003	64.059	187,000
1	7/21/2003	64.143	182,203
1	7/22/2003	69.373	208,488

1	7/23/2003	61.926	187,284
1	7/24/2003	65.816	188,519
1	7/25/2003	68.838	192,488
1	7/26/2003	75.838	208,652
1	7/27/2003	81.805	189,342
1	7/28/2003	77.288	202,758
1	7/29/2003	64.397	181,305
1	7/30/2003	74.549	207,311
1	7/31/2003	60.462	178,377
1	8/1/2003	79.776	207,621
1	8/2/2003	74.712	190,328
1	8/3/2003	73.136	185,354
1	8/4/2003	69.243	182,655
1	8/5/2003	74.251	202,146
1	8/6/2003	68.204	180,048
1	8/7/2003	81.741	211,571
1	8/8/2003	75.561	180,633
1	8/9/2003	86.654	208,892
1	8/10/2003	72.31	183,393
1	8/11/2003	74.953	181,523
1	8/12/2003	69.09	171,808
1	8/13/2003	86.837	203,211
1	8/14/2003	73.976	186,090
1	8/15/2003	73.209	203,578
1	8/16/2003	67.895	181,561
1	8/17/2003	93.162	196,475
1	8/18/2003	72.154	174,771
1	8/19/2003	74.077	193,269
1	8/20/2003	73.109	175,428
1	8/21/2003	77.381	201,428
1	8/22/2003	70.2	182,433
1	8/23/2003	91.532	202,832
1	8/24/2003	65.128	177,111
1	8/25/2003	73.702	201,739
1	8/26/2003	84.332	190,904
1	8/27/2003	79.137	210,683
1	8/28/2003	78.61	181,626
1	8/29/2003	86.346	205,609
1	8/30/2003	68.113	169,092
1	8/31/2003	60.59	164,527
1	9/1/2003	80.553	183,088
1	9/2/2003	66.713	192,087
1	9/3/2003	84.924	200,176
1	9/4/2003	82.67	203,396
1	9/5/2003	64.663	170,245
1	9/6/2003	71.003	180,289
1	9/7/2003	68.442	188,070

1	9/8/2003	72.396	200,412
1	9/9/2003	52.094	186,675
1	9/10/2003	51.619	204,556
1	9/11/2003	60.897	188,556
1	9/12/2003	77.23	215,322
1	9/13/2003	70.109	191,303
1	9/14/2003	67.612	198,122
1	9/15/2003	50.225	144,245
1	9/16/2003	61.598	186,390
1	9/17/2003	47.096	176,742
1	9/18/2003	73.404	201,265
1	9/19/2003	78.07	183,382
1	9/20/2003	67.711	190,857
1	9/21/2003	50.187	147,848
1	9/22/2003	72.89	209,098
1	9/23/2003	63.921	188,354
1	9/24/2003	72.307	209,389
1	9/25/2003	68.655	189,550
1	9/26/2003	74.139	217,294
1	9/27/2003	62.645	192,418
1	9/28/2003	65.072	196,056
1	9/29/2003	51.733	150,167
1	9/30/2003	75.945	179,170
1	10/1/2003	75.132	191,347
1	10/2/2003	77.766	193,514
1	10/3/2003	70.78	180,580
1	10/4/2003	77.717	197,639
1	10/5/2003	63.532	169,279
1	10/6/2003	74.317	196,516
1	10/7/2003	69.527	176,009
1	10/8/2003	46.857	187,470
1	10/9/2003	59.214	164,025
1	10/10/2003	76.928	183,433
1	10/11/2003	61.462	167,840
1	10/12/2003	67.021	157,181
1	10/13/2003	58.332	149,366
1	10/14/2003	54.619	152,338
1	10/15/2003	67.231	162,497
1	10/16/2003	51.32	139,546
1	10/17/2003	25.108	97,924
1	10/18/2003	31.745	97,235
1	10/19/2003	28.424	115,530
1	10/20/2003	71.574	172,790
1	10/21/2003	58.697	161,902
1	10/22/2003	51.816	140,425
1	10/23/2003	45.927	130,821
1	10/24/2003	62.545	161,974

1	10/25/2003	39.379	114,413
1	10/26/2003	44.288	142,423
1	10/27/2003	70.436	193,057
1	10/28/2003	89.193	215,641
1	10/29/2003	73.661	193,136
1	10/30/2003	74.113	208,511
1	10/31/2003	79.092	190,986
1	11/1/2003	83.82	210,706
1	11/2/2003	76.881	193,170
1	11/3/2003	88.042	215,517
1	11/4/2003	73.123	188,981
1	11/5/2003	83.25	215,410
1	11/6/2003	68.31	193,683
1	11/7/2003	78.174	205,225
1	11/8/2003	68.221	184,594
1	11/9/2003	76.211	207,142
1	11/10/2003	74.678	182,625
1	11/11/2003	62.183	147,918
1	11/12/2003	40.936	112,803
1	11/13/2003	59.962	147,031
1	11/14/2003	69.853	179,370
1	11/15/2003	58.64	199,238
1	11/16/2003	65.906	217,826
1	11/17/2003	66.262	198,597
1	11/18/2003	67.264	209,841
1	11/19/2003	66.151	196,649
1	11/20/2003	1.077	3,432
1	11/23/2003	25.616	89,769
1	11/24/2003	83.178	210,402
1	11/25/2003	47.086	130,602
1	11/26/2003	71.232	211,313
1	11/27/2003	70.576	186,143
1	11/28/2003	81.882	205,139
1	11/29/2003	57.244	183,532
1	11/30/2003	59.679	201,943
1	12/1/2003	58.438	186,624
1	12/2/2003	70.331	210,820
1	12/3/2003	28.762	118,238
1	12/7/2003	6.674	27,268
1	12/8/2003	67.963	191,589
1	12/9/2003	58.688	192,922
1	12/10/2003	71.468	201,157
1	12/11/2003	68.585	188,687
1	12/12/2003	65.425	196,780
1	12/13/2003	67.233	188,328
1	12/14/2003	79.576	195,868
1	12/15/2003	58.623	162,122

1	12/16/2003	60.004	170,922
1	12/17/2003	75.008	205,815
1	12/18/2003	73.319	179,105
1	12/19/2003	78.713	207,009
1	12/20/2003	42.448	140,551
1	12/21/2003	42.35	150,557
1	12/22/2003	69.795	203,348
1	12/23/2003	47.569	192,196
1	12/24/2003	45.567	177,562
1	12/25/2003	53.871	201,360
1	12/26/2003	49.882	194,279
1	12/27/2003	42.371	205,291
1	12/28/2003	38.072	181,144
1	12/29/2003	44.555	203,197
1	12/30/2003	38.917	189,748
1	12/31/2003	40.608	202,584
	Max (tpd) -->	**93.162**	
	Max (lb/hr) -->	**7763.5**	

Note: Dates with no operation/emissions not shown

Unit ID	Date	SO2 (tons)	Heat Input (MMBtu)
2	1/10/2001	0.754	33,637
2	1/11/2001	48.572	155,023
2	1/12/2001	69.767	223,001
2	1/13/2001	63.279	199,585
2	1/14/2001	70.944	196,874
2	1/15/2001	70.445	196,066
2	1/16/2001	71.084	214,936
2	1/17/2001	73.798	206,033
2	1/18/2001	80.818	228,270
2	1/19/2001	65.111	199,193
2	1/20/2001	82.298	228,161
2	1/21/2001	67.036	191,946
2	1/22/2001	82.267	231,789
2	1/23/2001	69.272	202,867
2	1/24/2001	67.477	203,133
2	1/25/2001	65.347	208,993
2	1/26/2001	72.167	221,736
2	1/27/2001	62.866	198,308
2	1/28/2001	64.123	208,264
2	1/29/2001	57.277	185,626
2	1/30/2001	71.366	213,747
2	1/31/2001	64.4	192,322
2	2/1/2001	74.805	220,513
2	2/2/2001	65.668	199,773
2	2/3/2001	76.063	219,848
2	2/4/2001	66.935	184,402
2	2/5/2001	73.809	217,446
2	2/6/2001	60.475	165,070
2	2/7/2001	59.292	172,471
2	2/8/2001	58.984	185,584
2	2/9/2001	51.92	154,356
2	2/10/2001	77.024	216,492
2	2/11/2001	59.475	187,862
2	2/12/2001	67.554	213,302
2	2/13/2001	59.31	183,263
2	2/14/2001	73.915	216,849
2	2/15/2001	56.155	185,480
2	2/16/2001	60.275	200,034
2	2/17/2001	60.896	185,447
2	2/18/2001	68.563	210,910
2	2/19/2001	63.536	192,921
2	2/20/2001	67.91	198,402
2	2/21/2001	65.391	193,429
2	2/22/2001	75.288	224,203
2	2/23/2001	66.278	200,474

2	2/24/2001	58.537	179,453
2	2/25/2001	59.957	181,189
2	2/26/2001	67.115	195,041
2	2/27/2001	60.745	174,238
2	2/28/2001	65.639	197,401
2	3/1/2001	62.668	184,455
2	3/2/2001	68.041	191,218
2	3/3/2001	57.07	171,070
2	3/4/2001	54.392	173,991
2	3/5/2001	65.951	197,817
2	3/6/2001	58.349	193,610
2	3/7/2001	78.118	223,725
2	3/8/2001	66.484	208,325
2	3/9/2001	69.273	191,776
2	3/10/2001	71.556	207,104
2	3/11/2001	56.766	160,681
2	3/12/2001	65.797	189,519
2	3/13/2001	63.754	186,465
2	3/14/2001	66.415	190,865
2	3/15/2001	63.324	185,756
2	3/16/2001	63.264	199,374
2	3/17/2001	60.518	184,595
2	3/18/2001	60.969	197,853
2	3/19/2001	66.76	197,346
2	3/20/2001	72.834	214,610
2	3/21/2001	61.998	188,273
2	3/22/2001	67.614	199,344
2	3/23/2001	60.426	186,547
2	3/24/2001	64.326	199,333
2	3/25/2001	53.746	174,018
2	3/26/2001	64.952	205,578
2	3/27/2001	64.971	193,287
2	3/28/2001	62.664	200,393
2	3/29/2001	59.724	185,695
2	3/30/2001	58.081	178,069
2	3/31/2001	68.646	191,096
2	4/1/2001	65.108	187,792
2	4/2/2001	57.317	202,604
2	4/3/2001	61.401	187,272
2	4/4/2001	58.343	194,899
2	4/5/2001	62.93	184,590
2	4/6/2001	59.78	191,757
2	4/7/2001	56.841	184,682
2	4/8/2001	69.676	190,946
2	4/9/2001	70.81	185,970
2	4/10/2001	54.723	197,849
2	4/11/2001	54.058	166,491

2	5/2/2001	4.915	25,051
2	5/3/2001	51.471	164,389
2	5/4/2001	70.899	214,110
2	5/5/2001	71.413	211,101
2	5/6/2001	63.354	193,817
2	5/7/2001	73.029	205,431
2	5/8/2001	68.396	200,902
2	5/9/2001	70.645	217,872
2	5/10/2001	67.923	208,187
2	5/11/2001	71.207	215,447
2	5/12/2001	62.622	180,366
2	5/13/2001	58.775	182,784
2	5/14/2001	68.965	197,405
2	5/15/2001	74.064	215,433
2	5/16/2001	66.586	197,138
2	5/17/2001	71.711	217,359
2	5/18/2001	70.055	206,643
2	5/19/2001	77.958	226,785
2	5/20/2001	68.772	204,157
2	5/21/2001	76.383	227,471
2	5/22/2001	58.712	177,827
2	5/23/2001	65.708	196,638
2	5/24/2001	63.432	189,095
2	5/25/2001	70.807	206,448
2	5/26/2001	65.271	193,677
2	5/27/2001	64.151	192,107
2	5/28/2001	52.023	150,016
2	5/29/2001	67.867	204,749
2	5/30/2001	67.63	199,560
2	5/31/2001	55.825	168,511
2	6/1/2001	62.407	184,927
2	6/2/2001	66.765	198,276
2	6/3/2001	67.295	208,569
2	6/4/2001	72.126	208,934
2	6/5/2001	73.841	217,607
2	6/6/2001	67.472	203,457
2	6/7/2001	69.52	206,278
2	6/8/2001	72.702	200,918
2	6/9/2001	71.159	210,583
2	6/10/2001	61.293	186,716
2	6/11/2001	65.811	203,227
2	6/12/2001	73.256	216,533
2	6/13/2001	76.688	225,531
2	6/14/2001	73.748	213,698
2	6/15/2001	73.415	210,730
2	6/16/2001	66.115	195,508
2	6/17/2001	69.267	201,585

2	6/18/2001	69.607	203,752
2	6/19/2001	70.868	205,665
2	6/20/2001	69.426	200,905
2	6/21/2001	74.099	214,438
2	6/22/2001	65.397	195,042
2	6/23/2001	71.333	204,508
2	6/24/2001	62.279	184,534
2	6/25/2001	69.734	206,170
2	6/26/2001	66.976	190,843
2	6/27/2001	66.883	201,570
2	6/28/2001	66.285	203,199
2	6/29/2001	72.059	202,362
2	6/30/2001	65.79	190,828
2	7/1/2001	63.437	186,111
2	7/2/2001	65.055	192,992
2	7/3/2001	77.963	205,510
2	7/4/2001	68.741	197,931
2	7/5/2001	68.553	197,585
2	7/6/2001	65.11	198,174
2	7/7/2001	74.56	213,383
2	7/8/2001	57.577	200,508
2	7/9/2001	62.687	223,282
2	7/10/2001	80.286	204,301
2	7/11/2001	80.159	221,400
2	7/12/2001	67.158	198,449
2	7/13/2001	80.201	221,335
2	7/14/2001	64.879	186,691
2	7/15/2001	68.191	179,878
2	7/16/2001	64.455	184,835
2	7/17/2001	47.578	174,526
2	7/18/2001	59.551	194,020
2	7/19/2001	70.542	213,198
2	7/20/2001	78.579	212,660
2	7/21/2001	71.753	217,047
2	7/22/2001	67.675	202,953
2	7/23/2001	68.944	210,570
2	7/24/2001	55.819	209,676
2	7/25/2001	62.294	230,575
2	7/26/2001	65.226	205,030
2	7/27/2001	68.019	202,340
2	7/28/2001	26.181	74,905
2	7/31/2001	15.582	46,223
2	8/1/2001	72.198	213,617
2	8/2/2001	68.602	216,562
2	8/3/2001	75.064	222,019
2	8/4/2001	65.508	206,369
2	8/5/2001	75.123	223,639

2	8/6/2001	60.963	209,754
2	8/7/2001	66.684	227,861
2	8/8/2001	68.328	233,054
2	8/9/2001	53.607	225,908
2	8/10/2001	56.111	212,219
2	8/11/2001	57.198	219,172
2	8/12/2001	62.849	207,576
2	8/13/2001	65.699	210,656
2	8/14/2001	61.753	203,483
2	8/15/2001	62.701	199,017
2	8/16/2001	68.982	213,177
2	8/17/2001	72.722	228,291
2	8/18/2001	66.308	208,089
2	8/19/2001	71.842	211,722
2	8/20/2001	66.222	203,776
2	8/21/2001	41.063	134,558
2	8/22/2001	73.13	219,632
2	8/23/2001	75.166	230,730
2	8/24/2001	69.238	218,750
2	8/25/2001	60.076	199,470
2	8/26/2001	65.824	205,122
2	8/27/2001	67.93	205,057
2	8/28/2001	66.653	207,979
2	8/29/2001	69.296	207,352
2	8/30/2001	71.494	227,618
2	8/31/2001	66.864	214,649
2	9/1/2001	71.312	223,891
2	9/2/2001	54.945	171,070
2	9/3/2001	58.511	203,589
2	9/4/2001	53.648	217,219
2	9/5/2001	77.724	229,361
2	9/6/2001	68.612	213,826
2	9/7/2001	76.503	226,878
2	9/8/2001	71.728	201,547
2	9/9/2001	66.574	193,595
2	9/10/2001	57.558	207,255
2	9/11/2001	72.633	230,033
2	9/12/2001	66.838	201,660
2	9/13/2001	73.934	227,204
2	9/14/2001	66.582	202,911
2	9/15/2001	59.653	186,297
2	9/16/2001	62.589	180,933
2	9/17/2001	66.522	204,906
2	9/18/2001	68.244	205,911
2	9/19/2001	74.626	226,638
2	9/20/2001	62.004	196,958
2	9/21/2001	56.879	205,070

2	9/22/2001	58.812	199,954
2	9/23/2001	58.074	198,779
2	9/24/2001	63.074	198,244
2	9/25/2001	62.399	184,066
2	9/26/2001	63.043	186,581
2	9/27/2001	66.482	200,156
2	9/28/2001	63.309	196,213
2	9/29/2001	62.67	194,975
2	9/30/2001	52.489	167,163
2	10/1/2001	64.268	201,430
2	10/2/2001	54.281	205,445
2	10/3/2001	62.915	218,269
2	10/4/2001	61.427	207,816
2	10/5/2001	69.979	226,059
2	10/6/2001	52.653	224,064
2	10/7/2001	62.748	204,980
2	10/8/2001	67.948	216,413
2	10/9/2001	69.421	215,028
2	10/10/2001	73.355	229,679
2	10/11/2001	62.266	208,230
2	10/12/2001	65.488	212,243
2	10/13/2001	58.759	186,099
2	10/14/2001	52.159	164,770
2	10/15/2001	62.781	199,326
2	10/16/2001	70.195	216,177
2	10/17/2001	64.077	202,867
2	10/18/2001	63.541	201,395
2	10/19/2001	57.453	184,769
2	10/20/2001	62.825	197,439
2	10/21/2001	66.511	204,790
2	10/22/2001	66.245	208,530
2	10/23/2001	67.053	216,718
2	10/24/2001	64.778	205,617
2	10/25/2001	58.75	192,113
2	10/26/2001	54.903	177,526
2	11/17/2001	1.436	32,899
2	11/18/2001	35.186	123,443
2	11/19/2001	49.752	170,295
2	11/20/2001	62.651	200,500
2	11/21/2001	55.149	181,063
2	11/22/2001	36.993	125,983
2	11/23/2001	38.869	125,294
2	11/24/2001	45.988	144,401
2	11/25/2001	43.804	151,134
2	11/26/2001	54.635	176,780
2	11/27/2001	62.528	200,430
2	11/28/2001	70.364	229,371

2	11/29/2001	66.22	213,787
2	11/30/2001	57.485	170,671
2	12/1/2001	63.727	197,244
2	12/2/2001	42.317	133,471
2	12/3/2001	59.164	200,205
2	12/4/2001	64.828	204,270
2	12/5/2001	68.503	212,388
2	12/6/2001	62.011	193,322
2	12/7/2001	75.636	222,251
2	12/8/2001	55.142	197,931
2	12/9/2001	57.054	188,726
2	12/10/2001	67.225	201,196
2	12/11/2001	74.844	226,565
2	12/12/2001	66.64	207,128
2	12/13/2001	67.535	207,164
2	12/14/2001	66.079	209,182
2	12/15/2001	66.339	235,036
2	12/16/2001	58.733	194,882
2	12/17/2001	64.843	211,213
2	12/18/2001	61.79	194,774
2	12/19/2001	64.132	202,373
2	12/20/2001	61.942	193,031
2	12/21/2001	68.826	222,563
2	12/22/2001	58.313	189,778
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2	12/24/2001	58.919	192,729
2	12/25/2001	52.663	176,095
2	12/26/2001	61.802	201,052
2	12/27/2001	71.321	223,889
2	12/28/2001	61.129	193,331
2	12/29/2001	69.055	224,118
2	12/30/2001	65.647	219,707
2	12/31/2001	52.399	227,640
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2	1/3/2002	75.864	245,312
2	1/4/2002	70.449	221,367
2	1/5/2002	73.951	237,679
2	1/6/2002	63.773	208,778
2	1/7/2002	67.44	226,227
2	1/8/2002	46.998	159,482
2	1/9/2002	62.622	212,629
2	1/10/2002	61.763	204,240
2	1/11/2002	62.735	204,685
2	1/12/2002	58.128	189,070
2	1/13/2002	63.343	205,872
2	1/14/2002	39.41	120,321

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2	1/20/2002	56.205	195,467
2	1/21/2002	72.29	230,019
2	1/22/2002	57.036	186,395
2	1/23/2002	61.568	197,176
2	1/24/2002	55.53	184,772
2	1/25/2002	58.035	191,601
2	1/26/2002	51.602	174,901
2	1/27/2002	52.553	178,355
2	1/28/2002	50.679	152,352
2	1/29/2002	60.533	187,478
2	1/30/2002	58.67	193,409
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2	2/3/2002	54.381	171,970
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2	2/5/2002	67.477	205,471
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2	2/8/2002	62.479	199,087
2	2/9/2002	55.252	182,193
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2	2/13/2002	62.493	200,276
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2	2/17/2002	50.575	171,532
2	2/18/2002	59.098	204,245
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2	2/24/2002	52.372	189,719
2	2/25/2002	65.295	201,438
2	2/26/2002	56.154	208,396
2	2/27/2002	72.037	236,746
2	2/28/2002	64.238	208,195
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2	3/13/2002	56.569	190,646
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2	4/7/2002	67.165	203,299
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2	4/22/2002	72.421	225,344
2	4/23/2002	68.627	202,654
2	4/24/2002	69.78	213,992
2	4/25/2002	63.821	199,226
2	4/26/2002	66.662	207,529
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2	4/29/2002	69.386	198,134
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2	7/21/2002	38.988	118,885
2	7/22/2002	40.61	125,594
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2	7/24/2002	40.241	123,002
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2	7/30/2002	42.387	132,270
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2	8/4/2002	42.95	133,154
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2	8/8/2002	43.569	128,427
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2	8/13/2002	45.872	130,659
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2	8/16/2002	40.682	131,262
2	8/17/2002	42.923	125,941
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2	8/21/2002	42.211	132,139
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2	8/23/2002	38.883	123,059
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2	9/14/2002	43.498	133,266
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2	9/16/2002	38.665	127,547
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2	9/28/2002	43.877	122,563
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2	10/8/2002	52.868	131,411
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2	12/22/2002	39.851	114,174
2	12/23/2002	46.372	130,222
2	12/24/2002	42.257	121,970
2	12/25/2002	43.695	124,949
2	12/26/2002	45.922	131,297
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2	12/28/2002	41.979	125,825
2	12/29/2002	41.407	130,355
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2	1/7/2003	43.265	129,584
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2	1/16/2003	35.639	124,641
2	1/17/2003	40.614	126,291
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2	1/25/2003	39.378	127,484
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2	2/5/2003	51.338	123,725
2	2/6/2003	41.152	131,622
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2	2/8/2003	43.205	130,678
2	2/9/2003	36.771	121,808
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2	2/11/2003	35.582	123,701
2	2/12/2003	47.622	134,658
2	2/13/2003	38.8	124,207
2	2/14/2003	44.771	131,396
2	2/15/2003	46.803	134,435
2	2/16/2003	45.905	132,770
2	2/17/2003	41.288	133,121
2	2/18/2003	45.265	131,622
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2	2/22/2003	24.402	77,292
2	2/23/2003	29.682	90,028
2	2/24/2003	40.007	131,088
2	2/25/2003	38.767	126,340
2	2/26/2003	36.996	121,711
2	2/27/2003	35.323	129,456
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2	4/26/2003	1.182	11,608
2	4/27/2003	1.331	10,900
2	4/28/2003	27.687	97,392
2	4/29/2003	23.224	72,650
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2	5/14/2003	70.563	200,534
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2	5/18/2003	19.448	115,299
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2	5/21/2003	25.872	89,078
2	5/22/2003	36.635	120,936
2	5/23/2003	48.567	147,872
2	5/24/2003	52.07	156,613
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2	5/28/2003	65.86	179,119
2	5/29/2003	55.553	174,322
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2	6/3/2003	68.958	210,743
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2	6/7/2003	65.11	197,511
2	6/8/2003	62.324	181,844
2	6/9/2003	63.884	191,746
2	6/10/2003	63.19	201,659
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2	6/17/2003	62.629	196,250
2	6/18/2003	64.786	189,691
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2	6/21/2003	63.918	197,410
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2	6/25/2003	72.313	226,759
2	6/26/2003	66.525	197,524
2	6/27/2003	68.121	197,548
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2	6/30/2003	52.714	170,043
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2	7/3/2003	73.932	215,785
2	7/4/2003	60.631	178,823
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2	7/6/2003	61.564	178,612
2	7/7/2003	74.013	223,042
2	7/8/2003	67.694	208,792
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2	7/11/2003	66.898	195,582
2	7/12/2003	59.027	207,695
2	7/13/2003	75.38	218,117
2	7/14/2003	69.033	203,421
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2	7/16/2003	74.257	203,521
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2	7/25/2003	73.576	210,531
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2	8/2/2003	80.742	214,317
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2	8/6/2003	73.18	207,756
2	8/7/2003	69.856	190,980
2	8/8/2003	77.228	187,873
2	8/9/2003	72.809	191,248
2	8/10/2003	75.267	200,240
2	8/11/2003	60.618	154,754
2	8/12/2003	63.981	167,678
2	8/13/2003	74.526	186,716
2	8/14/2003	82.677	219,956
2	8/15/2003	69.953	198,724
2	8/16/2003	78.945	219,751
2	8/17/2003	84.556	185,941
2	8/18/2003	87.543	217,540
2	8/19/2003	74.519	199,463
2	8/20/2003	88.865	221,338
2	8/21/2003	70.209	187,889
2	8/22/2003	81.354	217,865
2	8/23/2003	77.177	179,597
2	8/24/2003	62.13	172,445
2	8/25/2003	68.592	194,288
2	8/26/2003	87.919	203,448
2	8/27/2003	80.932	216,513
2	8/28/2003	82.687	197,918
2	8/29/2003	82.208	202,540
2	8/30/2003	83.364	211,336
2	8/31/2003	65.314	183,922
2	9/1/2003	93.901	216,245
2	9/2/2003	67.103	195,437
2	9/3/2003	87.882	211,604
2	9/4/2003	73.831	185,708
2	9/5/2003	62.172	169,129
2	9/6/2003	69.933	172,549
2	9/7/2003	71.082	186,768
2	9/8/2003	67.777	194,007
2	9/9/2003	59.869	208,235
2	9/10/2003	47.297	191,134
2	9/11/2003	70.439	214,754
2	9/12/2003	68.502	194,246
2	9/13/2003	77.372	212,995
2	9/14/2003	62.285	185,112
2	9/15/2003	62.138	181,443

2	9/16/2003	54.365	159,836
2	9/17/2003	44.087	170,662
2	9/18/2003	64.266	179,510
2	9/19/2003	84.561	198,395
2	9/20/2003	61.237	175,201
2	9/21/2003	45.248	135,969
2	9/22/2003	64.048	184,563
2	9/23/2003	72.375	210,158
2	9/24/2003	67.512	190,162
2	9/25/2003	82.877	216,409
2	9/26/2003	66.416	195,764
2	9/27/2003	71.255	214,105
2	9/28/2003	48.564	144,440
2	10/1/2003	0.739	5,350
2	10/2/2003	33.504	91,269
2	10/3/2003	69.337	173,240
2	10/4/2003	70.961	181,775
2	10/5/2003	78.203	208,329
2	10/6/2003	75.187	201,250
2	10/7/2003	89.169	220,542
2	10/8/2003	49.203	193,751
2	10/9/2003	67.662	186,810
2	10/10/2003	79.918	191,964
2	10/11/2003	77.311	208,470
2	10/12/2003	55.02	133,243
2	10/13/2003	57.783	146,579
2	10/14/2003	57.2	158,381
2	10/15/2003	70.099	163,846
2	10/16/2003	39.172	119,677
2	10/17/2003	22.491	110,018
2	10/18/2003	28.818	111,833
2	10/19/2003	26.99	97,703
2	10/20/2003	47.314	136,379
2	10/21/2003	58.792	171,856
2	10/22/2003	44.082	123,176
2	10/23/2003	38.065	108,419
2	10/24/2003	46.912	121,940
2	10/25/2003	40.834	121,636
2	10/26/2003	41.361	134,381
2	10/27/2003	77.893	217,120
2	10/28/2003	81.213	189,818
2	10/29/2003	88.045	219,499
2	10/30/2003	69.841	189,813
2	10/31/2003	88.683	217,110
2	11/1/2003	73.396	187,086
2	11/2/2003	83.102	204,959
2	11/3/2003	78.948	190,234

2	11/4/2003	82.853	207,766
2	11/5/2003	80.004	205,747
2	11/6/2003	72.8	209,571
2	11/7/2003	68.317	179,234
2	11/8/2003	78.886	216,308
2	11/9/2003	66.667	184,689
2	11/10/2003	78.976	195,905
2	11/11/2003	52.075	130,022
2	11/12/2003	41.692	117,091
2	11/13/2003	11.611	36,258
2	11/17/2003	0.17	2,225
2	11/18/2003	38.966	117,867
2	11/19/2003	65.18	198,434
2	11/20/2003	71.803	194,782
2	11/21/2003	83.116	211,544
2	11/22/2003	70.553	193,300
2	11/23/2003	74.376	201,621
2	11/24/2003	77.352	199,592
2	11/25/2003	80.788	215,593
2	11/26/2003	63.023	192,250
2	11/27/2003	63.937	183,110
2	11/28/2003	68.873	184,297
2	11/29/2003	66.042	216,610
2	11/30/2003	46.244	167,797
2	12/1/2003	57.318	183,858
2	12/2/2003	63.35	181,812
2	12/3/2003	56.658	195,654
2	12/4/2003	65.813	180,092
2	12/5/2003	58.821	198,595
2	12/6/2003	54.429	201,880
2	12/7/2003	87.118	207,001
2	12/8/2003	61.162	166,563
2	12/9/2003	65.51	208,456
2	12/10/2003	73.371	197,599
2	12/11/2003	81.449	210,498
2	12/12/2003	60.767	176,633
2	12/13/2003	75.382	202,675
2	12/14/2003	68.046	166,486
2	12/15/2003	76.107	200,848
2	12/16/2003	59.007	163,400
2	12/17/2003	74.676	202,708
2	12/18/2003	80.577	193,320
2	12/19/2003	71.731	183,867
2	12/20/2003	71.602	216,101
2	12/21/2003	57.933	178,546
2	12/22/2003	56.158	161,064
2	12/23/2003	47.942	181,785

2	12/24/2003	56.125	196,775
2	12/25/2003	51.062	177,009
2	12/26/2003	54.125	196,221
2	12/27/2003	40.469	186,754
2	12/28/2003	41.98	191,214
2	12/29/2003	40.674	182,939
2	12/30/2003	44.935	209,032
2	12/31/2003	42.973	185,415
	Max (tpd) -->	**93.901**	
	Max (lb/hr) -->	**7825.1**	

Note: Dates with no operation/emissions not shown

Unit ID	Date	Avg. NOx Rate (lb/MMBtu)	NOx (tons)	Heat Input (MMBtu)
1	1/1/2009	0.2417	22.557	185,974
1	1/2/2009	0.229	21.102	183,955
1	1/3/2009	0.2418	21.9	178,066
1	1/4/2009	0.3366	29.789	180,075
1	1/5/2009	0.3364	31.511	187,206
1	1/6/2009	0.3416	32.861	192,024
1	1/7/2009	0.3303	31.933	193,023
1	1/8/2009	0.3044	29.676	194,965
1	1/9/2009	0.2255	20.636	182,247
1	1/10/2009	0.2662	18.387	144,944
1	1/11/2009	0.2362	20.178	172,039
1	1/12/2009	0.2348	22.039	186,247
1	1/13/2009	0.2088	16.731	158,242
1	1/14/2009	0.172	11.413	132,759
1	1/15/2009	0.1951	12.023	120,430
1	1/16/2009	0.2145	13.936	129,923
1	1/17/2009	0.1877	1.053	8,769
1	1/19/2009	0.0508	0.224	6,180
1	1/20/2009	0.2751	22.771	172,042
1	1/21/2009	0.2678	27.201	203,889
1	1/22/2009	0.2832	28.739	202,984
1	1/23/2009	0.2964	29.004	195,578
1	1/24/2009	0.2543	22.006	181,460
1	1/25/2009	0.2193	21.944	199,901
1	1/26/2009	0.2823	27.765	196,432
1	1/27/2009	0.2893	23.969	166,298
1	1/28/2009	0.2787	21.49	156,515
1	1/29/2009	0.2604	22.952	175,543
1	1/30/2009	0.2155	16.605	153,462
1	1/31/2009	0.2364	14.627	124,976
1	2/1/2009	0.252	20.969	166,864
1	2/2/2009	0.2503	19.149	155,816
1	2/3/2009	0.2304	21.501	187,220
1	2/4/2009	0.2326	21.196	182,571
1	2/5/2009	0.2295	18.233	156,315
1	2/6/2009	0.2191	21.27	194,417
1	2/7/2009	0.2425	22.265	187,834
1	2/8/2009	0.2223	22.37	201,308
1	2/9/2009	0.2375	23.27	195,674
1	2/10/2009	0.2649	24.645	185,718
1	2/11/2009	0.2936	26.569	180,885
1	2/12/2009	0.2832	27.88	197,109
1	2/13/2009	0.2948	29.084	197,610
1	2/14/2009	0.2948	23.967	165,802
1	2/15/2009	0.2688	25.925	193,017

1	2/16/2009	0.2419	22.894	189,774
1	2/17/2009	0.2365	22.752	193,112
1	2/18/2009	0.2326	20.909	179,771
1	2/19/2009	0.2327	16.466	129,297
1	2/20/2009	0.2777	24.159	173,092
1	2/21/2009	0.3317	28.161	172,865
1	2/22/2009	0.2971	26.247	177,509
1	2/23/2009	0.2568	24.565	191,481
1	2/24/2009	0.2597	24.822	190,964
1	2/25/2009	0.2659	23.68	178,208
1	2/26/2009	0.2962	26.941	181,698
1	2/27/2009	0.2946	25.36	175,220
1	2/28/2009	0.2531	21.377	170,065
1	3/1/2009	0.2629	25.952	197,521
1	3/2/2009	0.2688	26.674	198,445
1	3/3/2009	0.2677	26.519	198,236
1	3/4/2009	0.2792	26.801	190,996
1	3/5/2009	0.2172	20.312	186,838
1	3/6/2009	0.2316	23.537	202,821
1	3/7/2009	0.2378	18.594	157,394
1	3/8/2009	0.2346	21.958	187,077
1	3/9/2009	0.2279	20.968	181,867
1	3/10/2009	0.2394	23.077	190,866
1	3/11/2009	0.2459	24.583	200,550
1	3/12/2009	0.2488	22.693	182,849
1	3/13/2009	0.226	22.412	198,704
1	3/14/2009	0.2755	25.641	188,369
1	3/15/2009	0.242	23.083	191,574
1	3/16/2009	0.2407	23.256	193,804
1	3/17/2009	0.2453	23.086	189,229
1	3/18/2009	0.2315	23.342	201,601
1	3/19/2009	0.2322	22.393	192,481
1	3/20/2009	0.2223	21.275	190,261
1	3/21/2009	0.2848	25.606	182,647
1	3/22/2009	0.2231	20.163	180,672
1	3/23/2009	0.2219	20.184	182,865
1	3/24/2009	0.227	20.394	179,816
1	3/25/2009	0.2252	17.466	155,017
1	3/26/2009	0.3166	22.005	139,523
1	3/27/2009	0.2665	20.626	159,139
1	3/28/2009	0.2748	22.249	163,292
1	3/29/2009	0.2876	24.313	169,540
1	3/30/2009	0.2566	18.694	147,977
1	3/31/2009	0.2418	20.157	170,786
1	4/1/2009	0.2425	20.385	169,170
1	4/2/2009	0.2625	23.178	175,663
1	4/3/2009	0.2749	7.911	59,243

1	5/28/2009	0.0287	0.083	6,885
1	5/29/2009	0.0786	1.378	19,230
1	5/30/2009	0.2526	10.539	85,244
1	5/31/2009	0.0899	1.982	20,766
1	6/1/2009	0.26	15.038	122,900
1	6/3/2009	0.1327	7.661	62,957
1	6/4/2009	0.2477	16.053	138,038
1	6/5/2009	0.199	14.148	144,774
1	6/6/2009	0.2236	16.432	157,342
1	6/7/2009	0.2445	21.247	168,616
1	6/8/2009	0.2495	21.429	171,595
1	6/9/2009	0.2165	18.829	176,195
1	6/10/2009	0.2166	19.84	182,888
1	6/11/2009	0.2525	19.041	152,239
1	6/12/2009	0.2261	15.507	129,907
1	6/13/2009	0.229	16.4	148,419
1	6/14/2009	0.2191	15.878	147,645
1	6/15/2009	0.2167	19.406	175,677
1	6/16/2009	0.2202	18.626	167,794
1	6/17/2009	0.2194	20.474	186,024
1	6/18/2009	0.224	19.253	172,835
1	6/19/2009	0.227	20.813	184,848
1	6/20/2009	0.2731	24.007	177,114
1	6/21/2009	0.2538	24.095	191,110
1	6/22/2009	0.2253	21.912	194,107
1	6/23/2009	0.2313	22.821	197,316
1	6/24/2009	0.2539	24.536	192,962
1	6/25/2009	0.27	25.93	192,250
1	6/26/2009	0.2407	22.151	183,922
1	6/27/2009	0.2341	23.052	196,801
1	6/28/2009	0.2227	18.801	169,557
1	6/29/2009	0.214	16.968	157,727
1	6/30/2009	0.2357	16.931	140,820
1	7/1/2009	0.2701	21.895	161,488
1	7/2/2009	0.2266	19.26	169,047
1	7/3/2009	0.2322	21.273	183,230
1	7/4/2009	0.2604	19.154	152,742
1	7/5/2009	0.2276	17.629	153,938
1	7/6/2009	0.2195	18.51	168,092
1	7/7/2009	0.2192	20.064	182,222
1	7/8/2009	0.2178	19.794	180,994
1	7/9/2009	0.2311	21.53	185,874
1	7/10/2009	0.2643	23.126	180,863
1	7/11/2009	0.231	21.777	187,959
1	7/12/2009	0.2395	22.676	188,909
1	7/13/2009	0.2328	22.305	191,569
1	7/14/2009	0.2259	19.839	174,964

1	7/15/2009	0.2104	18.974	178,437
1	7/16/2009	0.279	24.991	178,594
1	7/17/2009	0.268	22.174	163,644
1	7/18/2009	0.3062	21.149	139,841
1	7/19/2009	0.2583	15.447	131,234
1	7/20/2009	0.2221	17.685	157,902
1	7/21/2009	0.2088	17.162	162,416
1	7/22/2009	0.2248	18.977	168,446
1	7/23/2009	0.2218	21.006	189,176
1	7/24/2009	0.2592	22.812	174,486
1	7/25/2009	0.2445	19.792	172,882
1	7/26/2009	0.2194	19.74	178,570
1	7/27/2009	0.2739	25.05	184,085
1	7/28/2009	0.2653	23.752	178,477
1	7/29/2009	0.259	22.421	173,100
1	7/30/2009	0.2096	14.423	137,320
1	8/1/2009	0.1339	5.494	51,274
1	8/2/2009	0.2293	20.221	176,461
1	8/3/2009	0.218	21.863	200,576
1	8/4/2009	0.2283	22.657	198,572
1	8/5/2009	0.2138	20.259	189,372
1	8/6/2009	0.217	19.174	176,305
1	8/7/2009	0.2181	20.147	184,761
1	8/8/2009	0.2771	24.472	177,359
1	8/9/2009	0.2812	27.31	193,766
1	8/10/2009	0.2857	28.233	197,731
1	8/11/2009	0.2744	26.897	196,156
1	8/12/2009	0.2698	24.817	182,817
1	8/13/2009	0.269	24.551	181,456
1	8/14/2009	0.2743	26.741	195,153
1	8/15/2009	0.2836	24.237	174,577
1	8/16/2009	0.2333	22.542	193,038
1	8/17/2009	0.272	26.42	194,019
1	8/18/2009	0.2321	21.397	184,088
1	8/19/2009	0.2271	20.926	183,818
1	8/20/2009	0.236	20.698	175,508
1	8/21/2009	0.2556	21.222	164,035
1	8/22/2009	0.2527	20.179	166,278
1	8/23/2009	0.288	22.807	161,085
1	8/24/2009	0.2919	24.46	167,101
1	8/25/2009	0.2717	23.916	175,933
1	8/26/2009	0.2889	25.766	177,843
1	8/27/2009	0.2782	25.141	180,206
1	8/28/2009	0.2753	26.642	193,609
1	8/29/2009	0.2828	23.682	169,967
1	8/30/2009	0.2709	22.767	171,656
1	8/31/2009	0.2385	20.603	172,786

1	9/1/2009	0.2895	23.532	165,149
1	9/2/2009	0.2393	20.326	171,089
1	9/3/2009	0.2754	25.441	182,556
1	9/4/2009	0.2936	28.943	197,227
1	9/5/2009	0.2339	19.971	172,357
1	9/6/2009	0.2321	20.473	176,563
1	9/7/2009	0.2785	23.08	166,814
1	9/8/2009	0.2849	26.244	182,516
1	9/9/2009	0.2972	29.066	195,567
1	9/10/2009	0.3008	29.164	193,968
1	9/11/2009	0.2925	27.837	190,060
1	9/12/2009	0.309	25.17	164,710
1	9/13/2009	0.2767	22.257	159,705
1	9/14/2009	0.2844	26.049	182,422
1	9/15/2009	0.2845	27.594	193,972
1	9/16/2009	0.2789	26.122	187,725
1	9/17/2009	0.2723	26.244	192,695
1	9/18/2009	0.2669	25.69	192,762
1	9/19/2009	0.2603	21.785	172,989
1	9/20/2009	0.2673	24.945	185,873
1	9/21/2009	0.2783	27.284	196,072
1	9/22/2009	0.2793	24.525	174,692
1	9/23/2009	0.2764	25.169	181,883
1	9/24/2009	0.2818	23.014	163,024
1	9/25/2009	0.254	22.424	176,232
1	9/26/2009	0.3217	25.439	164,445
1	9/27/2009	0.2624	22.396	171,350
1	9/28/2009	0.244	21.716	178,652
1	9/29/2009	0.2477	20.784	169,790
1	9/30/2009	0.2524	20.863	169,604
1	10/1/2009	0.2411	22.513	186,683
1	10/2/2009	0.2325	20.856	179,414
1	10/3/2009	0.1313	0.598	6,060
1	10/7/2009	0.0181	0.035	3,276
1	10/8/2009	0.103	2.601	27,845
1	10/9/2009	0.2059	18.142	175,119
1	10/10/2009	0.2194	20.806	190,259
1	10/11/2009	0.2098	19.8	188,683
1	10/12/2009	0.2499	24.099	192,840
1	10/13/2009	0.2572	24.66	191,558
1	10/14/2009	0.217	19.215	177,612
1	10/15/2009	0.2197	20.66	188,342
1	10/16/2009	0.2181	16.934	146,061
1	10/17/2009	0.2859	26.442	184,801
1	10/18/2009	0.2393	18.891	157,944
1	10/19/2009	0.2471	22.67	183,876
1	10/20/2009	0.2434	23.219	190,813

1	10/21/2009	0.2457	22.037	178,846
1	10/22/2009	0.2437	23.546	193,233
1	10/23/2009	0.2342	21.505	183,381
1	10/24/2009	0.2778	21.986	164,660
1	10/25/2009	0.261	23.63	180,733
1	10/26/2009	0.282	25.897	181,600
1	10/27/2009	0.2388	22.245	186,229
1	10/28/2009	0.2646	23.03	173,453
1	10/29/2009	0.2612	25.197	192,993
1	10/30/2009	0.2969	25.771	173,152
1	10/31/2009	0.275	20.524	155,484
1	11/1/2009	0.24	20.422	170,338
1	11/2/2009	0.2407	21.915	181,037
1	11/3/2009	0.2439	23.658	193,988
1	11/4/2009	0.2441	24.191	198,227
1	11/5/2009	0.2408	23.14	192,201
1	11/6/2009	0.239	23.424	195,972
1	11/7/2009	0.3008	26.77	179,558
1	11/8/2009	0.2839	27.824	196,035
1	11/9/2009	0.2309	22.044	191,074
1	11/10/2009	0.2232	21.629	193,791
1	11/11/2009	0.2322	21.276	183,505
1	11/12/2009	0.2323	21.877	188,405
1	11/13/2009	0.2235	21.093	188,761
1	11/14/2009	0.2407	19.833	169,629
1	11/15/2009	0.2398	21.074	178,440
1	11/16/2009	0.2416	22.088	182,498
1	11/17/2009	0.2444	22.727	185,298
1	11/18/2009	0.2675	25.5	190,795
1	11/19/2009	0.2644	24.905	187,826
1	11/20/2009	0.2558	25.076	196,091
1	11/21/2009	0.2614	25.879	198,002
1	11/22/2009	0.2866	25.585	180,892
1	11/23/2009	0.2669	25.978	194,669
1	11/24/2009	0.2643	25.777	195,036
1	11/25/2009	0.2674	26.216	196,066
1	11/26/2009	0.2421	22.007	181,702
1	11/27/2009	0.2024	19.373	191,302
1	11/28/2009	0.2262	19.388	176,586
1	11/29/2009	0.2126	21.011	197,657
1	11/30/2009	0.2246	21.342	191,357
1	12/1/2009	0.235	22.887	194,779
1	12/2/2009	0.2278	21.908	192,199
1	12/3/2009	0.2326	23.514	202,177
1	12/4/2009	0.2377	23.785	200,205
1	12/5/2009	0.2578	21.824	175,921
1	12/6/2009	0.2358	22.975	194,875

1	12/7/2009	0.2438	22.599	185,385
1	12/8/2009	0.2312	22.272	192,772
1	12/9/2009	0.2334	22.255	191,311
1	12/10/2009	0.2236	22.199	198,546
1	12/11/2009	0.2138	20.299	190,078
1	12/12/2009	0.2895	23.82	168,420
1	12/13/2009	0.2328	18.793	164,736
1	12/14/2009	0.217	20.137	184,394
1	12/15/2009	0.2241	21.809	194,862
1	12/16/2009	0.2255	21.731	192,781
1	12/17/2009	0.2121	20.822	196,522
1	12/18/2009	0.224	20.335	181,966
1	12/19/2009	0.2375	20.414	175,193
1	12/20/2009	0.2233	21.12	189,243
1	12/21/2009	0.2246	21.168	188,467
1	12/22/2009	0.2485	23.497	188,998
1	12/23/2009	0.2691	26.104	194,235
1	12/24/2009	0.2794	14.639	114,166
1	12/25/2009	0.0621	0.925	15,502
1	12/26/2009	0.2232	20.471	182,723
1	12/27/2009	0.2245	21.517	191,879
1	12/28/2009	0.217	20.65	190,240
1	12/29/2009	0.2149	21.123	196,616
1	12/30/2009	0.2244	21.379	190,648
1	12/31/2009	0.2446	22.456	183,231
1	1/1/2010	0.2255	21.167	187,682
1	1/2/2010	0.2472	21.08	175,457
1	1/3/2010	0.2242	21.432	191,270
1	1/4/2010	0.2109	20.432	193,792
1	1/5/2010	0.2211	21.426	193,808
1	1/6/2010	0.2386	18.882	165,099
1	1/7/2010	0.221	19.644	176,462
1	1/8/2010	0.2114	17.623	163,427
1	1/9/2010	0.2193	20.508	187,241
1	1/10/2010	0.2208	20.749	187,960
1	1/11/2010	0.2365	22.163	187,485
1	1/12/2010	0.2453	23.306	189,615
1	1/13/2010	0.297	28.967	194,558
1	1/14/2010	0.2842	27.53	193,543
1	1/15/2010	0.2856	28.326	198,336
1	1/16/2010	0.2991	25.997	177,113
1	1/17/2010	0.2743	25.113	182,520
1	1/18/2010	0.279	24.438	174,657
1	1/19/2010	0.2733	24.846	181,325
1	1/20/2010	0.2664	23.481	175,532
1	1/21/2010	0.274	24.503	177,916
1	1/22/2010	0.2829	26.412	186,815

1	1/23/2010	0.243	19.837	165,166
1	1/24/2010	0.2338	20.511	175,806
1	1/25/2010	0.2278	22.615	198,554
1	1/26/2010	0.2249	22.198	197,377
1	1/27/2010	0.2165	19.971	184,713
1	1/28/2010	0.2849	27.012	189,575
1	1/29/2010	0.2828	25.113	176,670
1	1/30/2010	0.2876	22.229	154,818
1	1/31/2010	0.2515	22.09	148,725
1	2/1/2010	0.2703	25.648	176,129
1	2/2/2010	0.2992	27.251	182,544
1	2/3/2010	0.275	27.686	201,338
1	2/4/2010	0.2721	27.138	199,542
1	2/5/2010	0.2478	23.519	190,047
1	2/6/2010	0.2328	20.58	182,706
1	2/7/2010	0.224	20.72	187,002
1	2/8/2010	0.2207	21.21	192,460
1	2/9/2010	0.2625	22.6	170,525
1	2/10/2010	0.2496	24.191	193,793
1	2/11/2010	0.2535	24.713	195,079
1	2/12/2010	0.2606	25.127	192,890
1	2/13/2010	0.2875	24.965	175,028
1	2/14/2010	0.2655	25.665	193,162
1	2/15/2010	0.2664	26.05	195,651
1	2/16/2010	0.2698	26.075	193,291
1	2/17/2010	0.2835	27.085	191,050
1	2/18/2010	0.2786	25.657	184,026
1	2/19/2010	0.2704	24.66	184,949
1	2/20/2010	0.105	0.977	10,224
1	3/21/2010	0.0201	0.083	7,244
1	3/22/2010	0.1987	7.368	66,506
1	3/23/2010	0.1843	16.561	181,217
1	3/24/2010	0.1821	18.207	199,792
1	3/25/2010	0.194	18.609	193,014
1	3/26/2010	0.2142	21.415	199,711
1	3/27/2010	0.1965	17.51	184,033
1	3/28/2010	0.1796	17.291	193,052
1	3/29/2010	0.1676	16.833	200,835
1	3/30/2010	0.1735	16.877	195,738
1	3/31/2010	0.1718	17.426	202,869
1	4/1/2010	0.1728	16.812	195,291
1	4/2/2010	0.1737	16.811	194,109
1	4/3/2010	0.1388	4.837	42,477
1	4/4/2010	0.1594	11.931	134,220
1	4/5/2010	0.1843	18.174	197,060
1	4/6/2010	0.1902	19.021	199,982
1	4/7/2010	0.1808	17.778	196,771

1	4/8/2010	0.1835	17.509	191,422
1	4/9/2010	0.1862	17.693	190,318
1	4/10/2010	0.228	19.36	174,659
1	4/11/2010	0.2044	19.104	188,655
1	4/12/2010	0.19	18.486	195,273
1	4/13/2010	0.2028	18.624	187,867
1	4/14/2010	0.2214	22.472	202,716
1	4/15/2010	0.2516	24.652	196,234
1	4/16/2010	0.2648	25.092	189,530
1	4/17/2010	0.2157	17.869	171,836
1	4/18/2010	0.2518	22.823	180,405
1	4/19/2010	0.259	23.98	185,074
1	4/20/2010	0.2578	24.199	187,740
1	4/21/2010	0.2654	25.315	190,730
1	4/22/2010	0.2631	25.777	195,921
1	4/23/2010	0.2647	25.062	189,340
1	4/24/2010	0.2699	21.67	162,829
1	4/25/2010	0.2553	23.076	180,663
1	4/26/2010	0.2689	25.284	187,997
1	4/27/2010	0.2529	24.266	192,112
1	4/28/2010	0.2435	24.092	197,625
1	4/29/2010	0.2153	20.848	193,827
1	4/30/2010	0.2161	21.827	202,101
1	5/1/2010	0.2627	23.583	181,531
1	5/2/2010	0.2089	21.664	207,393
1	5/3/2010	0.25	25.62	205,100
1	5/4/2010	0.2575	25.729	199,527
1	5/5/2010	0.2416	23.278	191,991
1	5/6/2010	0.2315	23.214	200,811
1	5/7/2010	0.2694	27.233	202,258
1	5/8/2010	0.2733	25.744	190,707
1	5/9/2010	0.2963	27.154	184,815
1	5/10/2010	0.2247	22.817	203,258
1	5/11/2010	0.2684	26.112	199,306
1	5/12/2010	0.2552	26.633	208,659
1	5/13/2010	0.2555	25.429	199,001
1	5/14/2010	0.2523	26.851	212,840
1	5/15/2010	0.25	23.115	188,487
1	5/16/2010	0.2388	24.284	203,473
1	5/17/2010	0.2402	24.465	203,525
1	5/18/2010	0.2502	25.344	202,638
1	5/19/2010	0.2603	26.042	199,883
1	5/20/2010	0.2413	24.035	199,037
1	5/21/2010	0.2449	24.816	202,660
1	5/22/2010	0.2607	23.546	184,935
1	5/23/2010	0.2441	26.169	214,435
1	5/24/2010	0.2526	26.032	205,992

1	5/25/2010	0.2518	25.772	204,656
1	5/26/2010	0.2464	24.331	196,980
1	5/27/2010	0.2496	25.909	207,626
1	5/28/2010	0.2353	22.017	185,447
1	5/29/2010	0.2644	23.718	180,639
1	5/30/2010	0.2595	23.648	182,486
1	5/31/2010	0.2593	25.021	191,134
1	6/1/2010	0.2641	27.579	207,957
1	6/2/2010	0.2546	27.177	213,484
1	6/3/2010	0.2455	23.534	189,871
1	6/6/2010	0.1503	11.423	95,868
1	6/7/2010	0.2485	25.341	203,099
1	6/8/2010	0.2484	26.455	212,998
1	6/9/2010	0.2488	25.949	208,623
1	6/10/2010	0.275	29.23	212,646
1	6/11/2010	0.2842	29.996	210,952
1	6/12/2010	0.2451	23.58	192,764
1	6/13/2010	0.2509	26.557	211,620
1	6/14/2010	0.24	25.088	209,081
1	6/15/2010	0.2763	28.133	203,272
1	6/16/2010	0.275	28.614	208,149
1	6/17/2010	0.266	27.845	209,373
1	6/18/2010	0.2703	28.041	207,522
1	6/19/2010	0.2934	27.652	189,156
1	6/20/2010	0.2922	30.563	209,187
1	6/21/2010	0.2885	30.561	211,832
1	6/22/2010	0.2844	28.471	199,716
1	6/23/2010	0.2758	27.324	197,144
1	6/24/2010	0.27	28.11	208,190
1	6/25/2010	0.2548	26.307	206,529
1	6/26/2010	0.2746	25.234	186,579
1	6/27/2010	0.259	26.651	205,554
1	6/28/2010	0.2641	27.109	205,362
1	6/29/2010	0.2663	27.287	205,077
1	6/30/2010	0.2635	27.147	206,030
1	7/1/2010	0.2596	26.917	207,354
1	7/2/2010	0.2391	24.64	206,221
1	7/3/2010	0.2528	22.579	183,539
1	7/4/2010	0.2474	25.063	202,228
1	7/5/2010	0.2432	24.872	204,498
1	7/6/2010	0.282	28.964	205,475
1	7/7/2010	0.2782	28.761	206,738
1	7/8/2010	0.279	29.277	209,878
1	7/9/2010	0.2808	29.026	206,709
1	7/10/2010	0.3021	28.47	188,958
1	7/11/2010	0.2915	29.614	203,030
1	7/12/2010	0.2835	28.878	203,711

1	7/13/2010	0.255	23.689	183,736
1	7/14/2010	0.2803	28.11	200,418
1	7/15/2010	0.2795	28.962	207,259
1	7/16/2010	0.2609	25.521	195,534
1	7/17/2010	0.28	25.098	180,246
1	7/18/2010	0.2653	25.887	194,004
1	7/19/2010	0.2645	26.17	197,810
1	7/20/2010	0.2578	24.882	192,669
1	7/21/2010	0.2676	26.094	194,914
1	7/22/2010	0.2393	22.75	188,229
1	7/23/2010	0.2103	20.808	197,760
1	7/24/2010	0.2269	18.969	175,143
1	7/25/2010	0.2214	21.322	194,389
1	7/26/2010	0.2356	24.52	207,912
1	7/27/2010	0.2179	20.532	187,760
1	7/28/2010	0.2498	22.324	176,755
1	7/29/2010	0.256	25.736	200,983
1	7/30/2010	0.2568	25.573	198,910
1	7/31/2010	0.311	29.639	191,293
1	8/1/2010	0.2794	28.948	207,134
1	8/2/2010	0.2789	28.839	206,544
1	8/3/2010	0.2832	30.087	212,590
1	8/4/2010	0.2669	28.321	212,274
1	8/5/2010	0.2843	28.321	199,293
1	8/6/2010	0.3009	30.435	201,985
1	8/7/2010	0.2324	21.7	188,963
1	8/8/2010	0.2139	21.677	203,123
1	8/9/2010	0.2075	18.951	182,041
1	8/10/2010	0.2226	22.429	201,886
1	8/11/2010	0.2355	19.065	162,431
1	8/12/2010	0.2611	25.678	195,833
1	8/13/2010	0.2678	23.715	180,693
1	8/14/2010	0.2618	20.084	155,737
1	8/15/2010	0.2574	23.858	182,175
1	8/16/2010	0.2257	17.033	148,284
1	8/17/2010	0.2456	22.964	186,131
1	8/18/2010	0.222	18.659	167,918
1	8/19/2010	0.2218	21.829	196,812
1	8/20/2010	0.2172	20.633	189,236
1	8/21/2010	0.2232	20.823	190,519
1	8/22/2010	0.2424	25.208	207,480
1	8/23/2010	0.2075	20.834	200,692
1	8/24/2010	0.2227	22.663	203,579
1	8/25/2010	0.2298	22.997	199,797
1	8/26/2010	0.2856	29.761	208,340
1	8/27/2010	0.2811	29.603	210,589
1	8/28/2010	0.2958	28.791	196,519

1	8/29/2010	0.2801	28.725	205,089
1	8/30/2010	0.2704	28.33	209,586
1	8/31/2010	0.2646	27.699	209,384
1	9/1/2010	0.2722	28.265	207,699
1	9/2/2010	0.2639	27.717	210,090
1	9/3/2010	0.2751	28.493	207,171
1	9/4/2010	0.229	20.452	181,873
1	9/5/2010	0.2362	18.821	166,586
1	9/6/2010	0.2136	19.503	180,968
1	9/7/2010	0.2181	22.5	206,398
1	9/8/2010	0.219	22.125	202,297
1	9/9/2010	0.2172	21.891	201,643
1	9/10/2010	0.2271	23.876	210,145
1	9/11/2010	0.2981	29.211	194,520
1	9/12/2010	0.3042	30.691	201,350
1	9/13/2010	0.2831	27.855	196,057
1	9/14/2010	0.2443	23.41	192,607
1	9/15/2010	0.2952	28.846	193,737
1	9/16/2010	0.2925	30.161	206,219
1	9/17/2010	0.2794	28.594	204,671
1	9/18/2010	0.2954	27.328	189,977
1	9/19/2010	0.2806	27.332	194,854
1	9/20/2010	0.2732	27.685	202,718
1	9/21/2010	0.2832	29.207	206,223
1	9/22/2010	0.2922	30.047	205,699
1	9/23/2010	0.2785	28.874	207,392
1	9/24/2010	0.2737	28.257	206,512
1	9/25/2010	0.294	27.525	188,132
1	9/26/2010	0.2893	27.046	186,762
1	9/27/2010	0.25	22.598	183,103
1	9/28/2010	0.2439	23.748	195,172
1	9/29/2010	0.2505	22.465	185,011
1	9/30/2010	0.2404	21.511	183,748
1	10/1/2010	0.2294	23.508	205,060
1	10/2/2010	0.2288	21.437	188,776
1	10/3/2010	0.2259	21.641	192,327
1	10/4/2010	0.2856	27.984	195,610
1	10/5/2010	0.2834	29.092	205,354
1	10/6/2010	0.2862	28.692	200,593
1	10/7/2010	0.2824	28.298	200,537
1	10/8/2010	0.2802	29.073	207,529
1	10/9/2010	0.292	27.867	190,877
1	10/10/2010	0.2769	28.683	207,054
1	10/11/2010	0.2459	24.448	199,999
1	10/12/2010	0.2136	20.95	195,506
1	10/13/2010	0.2154	21.868	202,773
1	10/14/2010	0.2196	21.985	200,529

1	10/15/2010	0.2204	21.505	195,926
1	10/16/2010	0.2917	27.461	188,175
1	10/17/2010	0.2618	23.545	183,396
1	10/18/2010	0.2446	25.17	205,989
1	10/19/2010	0.2188	20.826	191,391
1	10/20/2010	0.224	22.764	203,360
1	10/21/2010	0.2309	23.088	201,067
1	10/22/2010	0.2318	23.651	204,159
1	10/23/2010	0.235	21.697	186,421
1	10/24/2010	0.24	23.459	196,188
1	10/25/2010	0.2665	22.188	169,915
1	10/26/2010	0.2359	19.292	165,852
1	10/27/2010	0.2318	20.855	180,684
1	10/28/2010	0.2406	22.741	189,539
1	10/29/2010	0.2455	23.099	188,395
1	10/30/2010	0.2967	27.207	185,547
1	10/31/2010	0.2561	21.88	175,138
1	11/1/2010	0.2347	22.033	189,015
1	11/2/2010	0.277	26.873	194,078
1	11/3/2010	0.285	28.206	198,065
1	11/4/2010	0.3434	20.56	124,880
1	11/5/2010	0.241	21.14	172,918
1	11/6/2010	0.2381	21.488	184,218
1	11/7/2010	0.2274	20.738	183,946
1	11/8/2010	0.2383	23.397	196,588
1	11/9/2010	0.2398	22.365	187,077
1	11/10/2010	0.2361	21.876	186,398
1	11/11/2010	0.2535	19.769	154,191
1	11/12/2010	0.2768	27.724	200,178
1	11/13/2010	0.2898	24.397	171,689
1	11/14/2010	0.2768	26.116	188,681
1	11/15/2010	0.2703	25.702	189,586
1	11/16/2010	0.2877	21.164	149,409
1	11/17/2010	0.1694	5.503	55,507
1	11/18/2010	0.2278	20.195	177,298
1	11/19/2010	0.2353	21.078	180,626
1	11/20/2010	0.2288	20.684	183,259
1	11/21/2010	0.2258	21.767	193,751
1	11/22/2010	0.2905	27.242	188,178
1	11/23/2010	0.3445	13.456	80,656
1	11/24/2010	0.2676	8.61	65,010
1	11/25/2010	0.2434	18.831	157,963
1	11/26/2010	0.2239	19.222	170,019
1	11/27/2010	0.2383	21.741	183,949
1	11/28/2010	0.2398	20.67	173,911
1	11/29/2010	0.2239	21.048	187,884
1	11/30/2010	0.2323	22.708	194,543

1	12/1/2010	0.2416	24.592	203,637
1	12/2/2010	0.2433	22.339	184,162
1	12/3/2010	0.2371	24.03	202,866
1	12/4/2010	0.2331	23.785	204,109
1	12/5/2010	0.2478	22.067	184,403
1	12/6/2010	0.2543	26.265	206,875
1	12/7/2010	0.2663	25.039	187,245
1	12/8/2010	0.293	28.38	194,102
1	12/9/2010	0.2817	26.434	183,511
1	12/10/2010	0.2875	27.647	191,913
1	12/11/2010	0.256	22.286	177,015
1	12/12/2010	0.2492	24.616	197,914
1	12/13/2010	0.2475	24.822	200,824
1	12/14/2010	0.2296	19.921	171,815
1	12/15/2010	0.285	27.567	193,842
1	12/16/2010	0.2455	20.802	170,358
1	12/17/2010	0.2324	21.843	190,273
1	12/18/2010	0.2613	21.366	170,576
1	12/19/2010	0.2424	22.605	186,984
1	12/20/2010	0.2312	22.482	194,653
1	12/21/2010	0.23	21.245	185,043
1	12/22/2010	0.2856	25.944	181,207
1	12/23/2010	0.2844	27.014	190,152
1	12/24/2010	0.2795	24.808	177,347
1	12/25/2010	0.2407	19.198	164,425
1	12/26/2010	0.2235	21.217	190,308
1	12/27/2010	0.2313	20.666	179,642
1	12/28/2010	0.2375	21.652	182,546
1	12/29/2010	0.2645	25.449	190,736
1	12/30/2010	0.277	23.855	171,533
1	12/31/2010	0.3026	26.151	173,570
1	1/1/2011	0.2744	21.536	156,218
1	1/2/2011	0.2672	23.105	172,336
1	1/3/2011	0.2753	27	196,242
1	1/4/2011	0.2806	26.048	185,438
1	1/5/2011	0.2575	23.648	183,496
1	1/6/2011	0.2365	22.322	189,487
1	1/7/2011	0.2353	22.8	194,000
1	1/8/2011	0.2947	27.576	186,016
1	1/9/2011	0.3177	31.251	196,676
1	1/10/2011	0.3198	31.702	198,103
1	1/11/2011	0.3328	30.367	182,314
1	1/12/2011	0.3181	32.243	203,185
1	1/13/2011	0.2867	27.99	194,900
1	1/14/2011	0.2786	24.58	173,679
1	1/15/2011	0.327	30.171	187,100
1	1/16/2011	0.3086	30.303	196,273

1	1/17/2011	0.256	26.117	204,260
1	1/18/2011	0.2441	23.742	194,861
1	1/19/2011	0.2426	25.2	207,769
1	1/20/2011	0.2318	24.361	210,154
1	1/21/2011	0.2457	25.702	209,251
1	1/22/2011	0.2451	20.654	171,748
1	1/23/2011	0.2604	24.549	188,781
1	1/24/2011	0.227	21.365	189,609
1	1/25/2011	0.2405	24.748	205,811
1	1/26/2011	0.2602	25.822	198,511
1	1/27/2011	0.2867	25.786	179,872
1	1/28/2011	0.2598	26.364	202,981
1	1/29/2011	0.2598	22.796	176,057
1	1/30/2011	0.2678	24.491	184,992
1	1/31/2011	0.2594	25.458	196,838
1	2/1/2011	0.248	24.14	194,921
1	2/2/2011	0.256	24.036	186,626
1	2/3/2011	0.2923	6.742	50,057
1	2/7/2011	0.0326	0.119	6,602
1	2/8/2011	0.258	14.579	114,382
1	2/9/2011	0.2642	23.684	178,339
1	2/10/2011	0.2757	23.783	172,219
1	2/11/2011	0.2694	25.17	187,353
1	2/12/2011	0.2474	20.674	169,900
1	2/13/2011	0.262	22.12	171,222
1	2/14/2011	0.2597	20.397	158,752
1	2/15/2011	0.2999	22.772	152,588
1	2/16/2011	0.3121	18.583	119,114
1	2/17/2011	0.2927	16.883	117,158
1	2/18/2011	0.2941	19.895	140,530
1	2/19/2011	0.2715	23.768	176,567
1	2/20/2011	0.2998	29.001	191,782
1	2/21/2011	0.3223	29.897	187,466
1	2/22/2011	0.3201	31.697	197,027
1	2/23/2011	0.3143	32.46	206,620
1	2/24/2011	0.3074	31.299	203,713
1	2/25/2011	0.289	28.713	201,221
1	2/26/2011	0.366	0.42	2,297
1	3/11/2011	0.0187	0.06	6,279
1	3/12/2011	0.1579	10.754	90,201
1	3/13/2011	0.2883	29.341	203,713
1	3/14/2011	0.2793	29.347	210,151
1	3/15/2011	0.2819	29.423	208,766
1	3/16/2011	0.2881	29.67	205,998
1	3/17/2011	0.2551	25.673	201,221
1	3/18/2011	0.2693	27.686	205,444
1	3/19/2011	0.2478	24.946	202,814

1	3/20/2011	0.2425	25.152	207,659
1	3/21/2011	0.2491	25.753	206,897
1	3/22/2011	0.2512	25.491	202,952
1	3/23/2011	0.3294	32.169	197,040
1	3/24/2011	0.3284	28.585	171,004
1	3/25/2011	0.3242	33.688	207,489
1	3/26/2011	0.3377	35.203	208,540
1	3/27/2011	0.3066	28.918	191,333
1	3/28/2011	0.2696	25.198	186,586
1	3/29/2011	0.2587	23.697	184,101
1	3/30/2011	0.2491	24.75	199,260
1	3/31/2011	0.2541	24.441	192,974
1	4/1/2011	0.2089	18.767	156,848
1	4/2/2011	0.3048	26.807	177,289
1	4/3/2011	0.3077	30.696	198,991
1	4/4/2011	0.2943	28.607	191,457
1	4/5/2011	0.2855	25.756	177,800
1	4/6/2011	0.251	25.47	203,163
1	4/7/2011	0.2511	25.93	206,684
1	4/8/2011	0.2607	27.166	209,541
1	4/9/2011	0.2617	27.56	210,651
1	4/10/2011	0.3235	30.564	193,483
1	4/11/2011	0.3025	24.518	162,199
1	4/12/2011	0.3081	18.537	120,044
1	4/13/2011	0.3173	26.756	169,180
1	4/14/2011	0.2785	29.024	208,382
1	4/15/2011	0.3225	21.052	135,124
1	4/16/2011	0.3033	23.975	159,188
1	4/17/2011	0.3225	21.95	140,316
1	4/18/2011	0.2923	28.136	193,723
1	4/19/2011	0.2926	27.145	187,623
1	4/20/2011	0.2662	26.325	199,464
1	4/21/2011	0.3068	25.387	166,261
1	4/22/2011	0.3052	27.694	180,982
1	4/23/2011	0.1818	13.913	96,641
1	4/24/2011	0.2565	21.49	146,069
1	4/25/2011	0.3061	25.211	167,085
1	4/26/2011	0.2926	28.505	194,483
1	4/27/2011	0.3103	29.212	187,361
1	4/28/2011	0.3153	33.476	212,167
1	4/29/2011	0.3142	32	202,245
1	4/30/2011	0.3348	31.344	193,614
1	5/1/2011	0.3035	31.286	205,693
1	5/2/2011	0.3157	29.217	188,517
1	5/3/2011	0.2953	30.087	203,771
1	5/4/2011	0.2882	30.358	210,564
1	5/5/2011	0.3253	33.008	203,050

1	5/6/2011	0.3303	32.479	197,656
1	5/7/2011	0.335	31.433	190,510
1	5/8/2011	0.3232	32.219	197,485
1	5/9/2011	0.3485	33.531	190,878
1	5/10/2011	0.3502	36.017	205,098
1	5/11/2011	0.3198	30.162	187,118
1	5/12/2011	0.3328	34.496	206,860
1	5/13/2011	0.3	25.255	166,465
1	5/14/2011	0.2685	22.316	166,620
1	5/15/2011	0.2583	20.237	156,706
1	5/16/2011	0.2401	23.336	195,978
1	5/17/2011	0.245	20.526	167,790
1	5/18/2011	0.3041	29.025	188,581
1	5/19/2011	0.3013	28.953	192,586
1	5/20/2011	0.2849	24.003	174,209
1	5/21/2011	0.3387	19.749	119,185
1	5/22/2011	0.3179	26.546	167,128
1	5/23/2011	0.2817	19.462	138,655
1	5/24/2011	0.2652	12.27	94,238
1	5/25/2011	0.3277	14.403	88,399
1	5/26/2011	0.3134	11.742	75,516
1	5/27/2011	0.2824	18.587	132,303
1	5/28/2011	0.2844	17.518	128,124
1	5/29/2011	0.2762	21.743	158,702
1	5/30/2011	0.2673	25.753	194,432
1	5/31/2011	0.2588	27.233	212,989
1	6/1/2011	0.2501	25.855	209,164
1	6/2/2011	0.2549	26.463	207,806
1	6/3/2011	0.304	33.777	222,247
1	6/4/2011	0.2468	23.901	201,577
1	6/5/2011	0.2215	23.022	194,071
1	6/6/2011	0.2938	17.844	123,104
1	6/7/2011	0.2529	22.972	180,960
1	6/8/2011	0.289	28.385	192,998
1	6/9/2011	0.2639	26.331	198,818
1	6/10/2011	0.2426	22.745	185,207
1	6/11/2011	0.2614	21.274	165,344
1	6/12/2011	0.285	21.684	162,833
1	6/13/2011	0.2448	23.68	192,365
1	6/14/2011	0.2439	24.562	200,470
1	6/15/2011	0.2418	26.31	217,535
1	6/16/2011	0.3014	29.69	196,018
1	6/17/2011	0.3077	31.325	202,696
1	6/18/2011	0.2494	21.733	176,490
1	6/19/2011	0.2443	19.919	162,985
1	6/20/2011	0.2401	17.898	148,992
1	6/21/2011	0.2552	26.63	208,883

1	6/22/2011	0.3066	30.557	198,190
1	6/23/2011	0.2923	27.879	190,172
1	6/24/2011	0.2943	28.55	193,016
1	6/25/2011	0.2772	25.397	190,278
1	6/26/2011	0.2567	26.21	206,105
1	6/27/2011	0.2488	27.561	221,597
1	6/28/2011	0.2837	27.863	194,319
1	6/29/2011	0.2798	26.347	187,317
1	6/30/2011	0.2873	30.244	210,121
1	7/1/2011	0.2909	30.598	210,254
1	7/2/2011	0.2971	32.532	218,892
1	7/3/2011	0.2991	27.738	188,972
1	7/4/2011	0.2654	22.959	174,073
1	7/5/2011	0.2439	23.389	190,364
1	7/6/2011	0.2513	26.535	211,123
1	7/7/2011	0.2504	26.951	215,346
1	7/8/2011	0.2533	27.767	219,197
1	7/9/2011	0.239	24.282	205,122
1	7/10/2011	0.2417	26.837	222,145
1	7/11/2011	0.2405	26.62	221,393
1	7/12/2011	0.2691	28.291	209,935
1	7/13/2011	0.2866	31.379	218,780
1	7/14/2011	0.2852	30.975	217,155
1	7/15/2011	0.2978	32.598	218,739
1	7/16/2011	0.303	30.545	202,319
1	7/17/2011	0.2943	31.621	214,289
1	7/18/2011	0.2935	32.197	219,095
1	7/19/2011	0.2508	26.214	209,355
1	7/20/2011	0.2438	26.822	220,143
1	7/21/2011	0.2373	26.004	219,243
1	7/22/2011	0.2316	25.712	221,899
1	7/23/2011	0.2612	26.251	207,145
1	7/24/2011	0.2442	26.09	214,034
1	7/25/2011	0.2436	25.395	208,556
1	7/26/2011	0.2933	31.12	210,499
1	7/27/2011	0.3134	10.128	66,037
1	7/29/2011	0.089	2.118	20,420
1	7/30/2011	0.2457	19.261	158,945
1	7/31/2011	0.2636	25.89	198,165
1	8/1/2011	0.2543	27.118	215,177
1	8/2/2011	0.2931	30.617	209,369
1	8/3/2011	0.2884	30.395	210,149
1	8/4/2011	0.3111	34.653	222,817
1	8/5/2011	0.3055	33.391	218,715
1	8/6/2011	0.2476	24.84	204,489
1	8/7/2011	0.2378	25.849	217,528
1	8/8/2011	0.24	26.288	219,150

1	8/9/2011	0.2348	25.06	213,851
1	8/10/2011	0.2389	25.277	212,023
1	8/11/2011	0.2506	24.41	196,750
1	8/12/2011	0.2346	24.911	213,060
1	8/13/2011	0.2855	27.835	194,252
1	8/14/2011	0.2836	29.626	207,997
1	8/15/2011	0.2905	28.901	196,583
1	8/16/2011	0.2593	26.475	205,376
1	8/17/2011	0.242	26.494	218,994
1	8/18/2011	0.2462	26.264	213,453
1	8/19/2011	0.246	26.58	216,304
1	8/20/2011	0.3125	31.158	202,466
1	8/21/2011	0.2984	31.718	212,613
1	8/22/2011	0.3041	32.923	216,539
1	8/23/2011	0.3016	32.883	218,035
1	8/24/2011	0.3044	29.698	194,978
1	8/25/2011	0.297	30.825	207,837
1	8/26/2011	0.2936	29.115	198,020
1	8/27/2011	0.3214	30.116	190,500
1	8/28/2011	0.2824	27.764	198,603
1	8/29/2011	0.2455	25.407	207,435
1	8/30/2011	0.3029	31.871	210,147
1	8/31/2011	0.3024	33.783	223,442
1	9/1/2011	0.2995	28.429	188,503
1	9/2/2011	0.275	27.589	198,660
1	9/3/2011	0.2956	29.259	200,164
1	9/4/2011	0.294	30.918	210,336
1	9/5/2011	0.335	28.566	171,987
1	9/6/2011	0.3073	22.283	157,653
1	9/7/2011	0.2566	22.851	181,872
1	9/8/2011	0.2522	23.43	187,528
1	9/9/2011	0.2672	24.381	186,087
1	9/10/2011	0.2612	24.521	192,639
1	9/11/2011	0.2345	24.68	211,851
1	9/12/2011	0.2929	15.006	102,976
1	9/13/2011	0.3017	11.17	75,172
1	9/15/2011	0.0121	0.031	3,566
1	9/16/2011	0.2529	22.791	169,360
1	9/17/2011	0.2808	29.152	208,051
1	9/18/2011	0.2764	28.756	207,730
1	9/19/2011	0.2666	28.215	211,593
1	9/20/2011	0.269	28.224	209,369
1	9/21/2011	0.2565	27.649	215,740
1	9/22/2011	0.2566	27.998	218,256
1	9/23/2011	0.265	26.895	203,117
1	9/24/2011	0.2555	23.691	185,965
1	9/25/2011	0.2568	25.174	195,549

1	9/26/2011	0.2658	26.646	200,705
1	9/27/2011	0.2838	29.077	204,780
1	9/28/2011	0.2901	30.027	207,673
1	9/29/2011	0.3062	27.442	179,335
1	9/30/2011	0.2993	24.304	165,646
1	10/1/2011	0.3272	28.377	172,370
1	10/2/2011	0.332	27.139	167,584
1	10/3/2011	0.299	27.784	185,830
1	10/4/2011	0.2973	26.108	185,301
1	10/5/2011	0.2848	28.83	202,563
1	10/6/2011	0.2912	29.672	203,710
1	10/7/2011	0.2583	20.305	158,190
1	12/1/2011	0.0344	0.276	12,257
1	12/2/2011	0.1488	2.584	19,245
1	12/3/2011	0.2449	7.913	67,100
1	12/4/2011	0.0213	0.064	5,278
1	12/5/2011	0.2395	3.643	27,954
1	12/6/2011	0.1552	11.391	97,526
1	12/7/2011	0.1832	6.469	54,040
1	12/8/2011	0.0355	0.24	12,053
1	12/9/2011	0.1425	4.276	35,345
1	12/10/2011	0.2094	18.036	166,221
1	12/11/2011	0.2645	26.706	201,593
1	12/12/2011	0.3437	27.04	159,061
1	12/13/2011	0.3433	21.816	130,345
1	12/14/2011	0.3019	21.065	140,785
1	12/15/2011	0.2904	22.341	156,132
1	12/16/2011	0.2785	25.628	184,586
1	12/17/2011	0.3318	25.227	154,770
1	12/18/2011	0.2967	26.504	178,319
1	12/19/2011	0.3098	25.612	164,932
1	12/20/2011	0.2955	26.485	178,182
1	12/21/2011	0.2774	23.53	176,338
1	12/22/2011	0.2623	19.466	151,302
1	12/23/2011	0.2683	20.937	163,070
1	12/24/2011	0.2581	18.565	145,510
1	12/25/2011	0.2963	17.234	117,109
1	12/26/2011	0.2589	19.485	156,074
1	12/27/2011	0.2525	18.381	147,026
1	12/28/2011	0.2361	18.315	157,262
1	12/29/2011	0.267	19.695	146,980
1	12/30/2011	0.2305	17.172	148,630
1	12/31/2011	0.2204	15.742	146,090
		Max (tpd) -->	**36.017**	
		Max (lb/hr) -->	**3001.4**	

Note: Dates with no operation/emissions not shown

Unit ID	Date	Avg. NOx Rate (lb/MMBtu)	NOx (tons)	Heat Input (MMBtu)
2	1/1/2009	0.0261	0.091	5,640
2	1/2/2009	0.2909	18.42	127,323
2	1/3/2009	0.2318	13.585	119,933
2	1/8/2009	0.0775	1.118	12,624
2	1/9/2009	0.2739	23.517	171,068
2	1/10/2009	0.2507	20.168	162,382
2	1/11/2009	0.2739	22.223	163,644
2	1/12/2009	0.2975	29.043	193,510
2	1/13/2009	0.2893	26.767	181,728
2	1/14/2009	0.3188	32.754	205,116
2	1/15/2009	0.31	28.395	180,371
2	1/16/2009	0.3048	27.868	176,283
2	1/17/2009	0.2602	25.026	191,525
2	1/18/2009	0.2593	23.665	180,663
2	1/19/2009	0.3101	30.405	194,800
2	1/20/2009	0.3551	35.611	201,033
2	1/21/2009	0.3343	34.302	205,302
2	1/22/2009	0.3221	32.896	204,164
2	1/23/2009	0.3216	31.966	198,290
2	1/24/2009	0.2958	27.507	183,605
2	1/25/2009	0.3155	28.282	178,578
2	1/26/2009	0.2993	28.875	192,705
2	1/27/2009	0.3009	25.29	166,495
2	1/28/2009	0.2567	21.379	167,368
2	1/29/2009	0.2704	22.598	164,099
2	1/30/2009	0.2523	18.045	142,425
2	1/31/2009	0.2298	15.086	129,124
2	2/1/2009	0.2836	22.647	158,168
2	2/2/2009	0.3019	25.355	166,649
2	2/3/2009	0.2946	28.553	193,402
2	2/4/2009	0.2917	27.911	191,143
2	2/5/2009	0.278	24.888	178,569
2	2/6/2009	0.2869	24.119	169,541
2	3/10/2009	0.0153	0.055	5,142
2	3/11/2009	0.0995	2.116	27,663
2	3/12/2009	0.2269	11.877	105,805
2	3/13/2009	0.224	12.707	116,628
2	3/14/2009	0.278	24.624	174,313
2	3/15/2009	0.2862	28.461	198,920
2	3/16/2009	0.2786	23.489	162,301
2	3/17/2009	0.2813	28.246	200,711
2	3/18/2009	0.2543	24.712	192,237
2	3/19/2009	0.2388	22.403	186,664
2	3/20/2009	0.2793	26.931	192,324
2	3/21/2009	0.2939	28.949	196,639

2	3/22/2009	0.3368	25.926	160,754
2	3/23/2009	0.2891	27.445	185,615
2	3/24/2009	0.28	26.217	183,347
2	3/25/2009	0.2845	26.316	183,498
2	3/26/2009	0.2292	17.558	154,379
2	3/27/2009	0.2301	19.644	169,547
2	3/28/2009	0.2328	20.618	174,851
2	3/29/2009	0.2912	22.947	161,137
2	3/30/2009	0.2319	18.375	157,407
2	3/31/2009	0.2632	21.662	165,761
2	4/1/2009	0.2305	19.969	173,539
2	4/2/2009	0.2834	26.598	185,888
2	4/3/2009	0.2948	25.478	178,791
2	4/4/2009	0.2834	26.519	187,224
2	4/5/2009	0.2995	22.771	158,096
2	4/6/2009	0.2886	24.795	170,003
2	4/7/2009	0.2774	22.94	165,933
2	4/8/2009	0.2798	27.927	199,584
2	4/9/2009	0.2935	28.35	192,328
2	4/10/2009	0.2943	29.188	197,666
2	4/11/2009	0.2406	21.521	178,271
2	4/12/2009	0.2444	20.202	170,894
2	4/13/2009	0.2386	23.46	196,569
2	4/14/2009	0.235	21.614	183,468
2	4/15/2009	0.2654	25.425	189,209
2	4/16/2009	0.2962	29.264	197,585
2	4/17/2009	0.3001	29.528	196,034
2	4/18/2009	0.2917	26.649	181,591
2	4/19/2009	0.2607	20.281	163,877
2	4/20/2009	0.2765	20.982	151,331
2	4/21/2009	0.2872	18.688	134,224
2	4/22/2009	0.2946	19.749	140,507
2	4/23/2009	0.2872	20.909	147,977
2	4/24/2009	0.2655	21.91	165,115
2	4/25/2009	0.2919	26.843	185,377
2	4/26/2009	0.3163	26.158	174,199
2	4/27/2009	0.2764	27.239	196,737
2	4/28/2009	0.2998	26.418	179,218
2	4/29/2009	0.2612	25.324	193,188
2	4/30/2009	0.2669	24.279	182,477
2	5/1/2009	0.2713	26.87	197,305
2	5/2/2009	0.2759	25.246	182,506
2	5/3/2009	0.3023	24.906	169,518
2	5/4/2009	0.2453	24.406	199,418
2	5/5/2009	0.2289	22.984	200,712
2	5/6/2009	0.2312	24.118	208,634
2	5/7/2009	0.2237	21.628	192,131

2	5/8/2009	0.2238	20.322	184,264
2	5/10/2009	0.0475	0.316	6,652
2	5/13/2009	0.0345	0.095	5,089
2	5/14/2009	0.2212	15.754	144,287
2	5/15/2009	0.2099	19.947	188,515
2	5/16/2009	0.2342	22.483	192,186
2	5/17/2009	0.2663	17.789	143,453
2	5/18/2009	0.3109	16.009	119,022
2	5/19/2009	0.3356	23.757	148,024
2	5/20/2009	0.3431	27.769	172,398
2	5/21/2009	0.2713	25.308	187,292
2	5/22/2009	0.271	25.287	186,142
2	5/23/2009	0.2786	24.6	177,111
2	5/24/2009	0.2987	22.044	149,976
2	5/25/2009	0.3122	28.598	182,290
2	5/26/2009	0.2694	25.161	187,188
2	5/27/2009	0.2783	27.584	198,031
2	5/28/2009	0.2693	25.369	188,054
2	5/29/2009	0.2698	26.267	194,221
2	5/30/2009	0.2825	23.995	174,613
2	5/31/2009	0.3342	28.272	172,557
2	6/1/2009	0.266	23.483	178,127
2	6/2/2009	0.2611	25.715	196,721
2	6/3/2009	0.2533	22.715	179,806
2	6/4/2009	0.271	20.851	158,037
2	6/5/2009	0.2674	22.602	171,796
2	6/6/2009	0.2957	22.743	162,591
2	6/7/2009	0.2636	21.407	170,189
2	6/8/2009	0.2481	22.267	181,947
2	6/9/2009	0.2329	22.017	189,044
2	6/10/2009	0.2265	21.733	191,665
2	6/11/2009	0.2374	18.931	162,381
2	6/12/2009	0.2573	19.877	155,848
2	6/13/2009	0.2581	21.896	170,331
2	6/14/2009	0.2747	19.471	147,429
2	6/15/2009	0.2846	26.277	182,258
2	6/16/2009	0.2907	25.986	178,046
2	6/17/2009	0.3072	29.88	194,039
2	6/18/2009	0.2996	28.044	186,931
2	6/21/2009	0.1197	4.959	46,582
2	6/22/2009	0.2236	22.416	200,395
2	6/23/2009	0.2248	22.535	200,333
2	6/24/2009	0.2741	27.504	199,998
2	6/25/2009	0.3138	31.309	199,188
2	6/26/2009	0.2556	23.784	184,452
2	6/27/2009	0.2583	24.851	162,343
2	6/28/2009	0.2903	28.691	197,646

2	6/29/2009	0.263	22.635	171,126
2	6/30/2009	0.2483	19.334	151,681
2	7/1/2009	0.2656	23.073	169,900
2	7/2/2009	0.2575	23.22	177,500
2	7/3/2009	0.2675	22.222	166,394
2	7/4/2009	0.273	24.728	179,753
2	7/5/2009	0.2543	20.745	159,592
2	7/6/2009	0.2562	23.265	178,252
2	7/7/2009	0.2721	26.092	190,572
2	7/8/2009	0.3048	29.026	189,384
2	7/9/2009	0.3118	30.494	195,328
2	7/10/2009	0.3191	32.415	202,918
2	7/11/2009	0.3213	30.604	188,437
2	7/12/2009	0.3187	28.733	176,910
2	7/13/2009	0.3282	32.729	199,236
2	7/14/2009	0.2708	25.07	184,893
2	7/15/2009	0.2813	26.429	186,932
2	7/16/2009	0.2845	27.408	191,498
2	7/17/2009	0.2359	19.018	162,426
2	7/18/2009	0.2425	20.145	164,577
2	7/19/2009	0.2653	19.508	155,821
2	7/20/2009	0.236	21.72	184,119
2	7/21/2009	0.22	20.124	183,440
2	7/22/2009	0.274	24.392	173,242
2	7/23/2009	0.3088	30.97	200,132
2	7/24/2009	0.286	26.564	184,917
2	7/25/2009	0.2697	24.839	184,894
2	7/26/2009	0.2895	19.872	142,800
2	7/27/2009	0.2409	19.605	163,263
2	7/28/2009	0.246	20.557	164,855
2	7/29/2009	0.2853	23.79	166,403
2	7/30/2009	0.291	24.573	167,059
2	7/31/2009	0.3055	31.279	204,690
2	8/1/2009	0.2828	25.528	179,649
2	8/2/2009	0.2508	19.842	161,155
2	8/3/2009	0.245	24.245	198,288
2	8/4/2009	0.2352	23.658	201,238
2	8/5/2009	0.2216	20.975	188,904
2	8/6/2009	0.2191	20.001	182,055
2	8/7/2009	0.2285	22.092	192,540
2	8/8/2009	0.2277	23.152	203,064
2	8/9/2009	0.2445	22.201	182,293
2	8/10/2009	0.2472	25.346	204,973
2	8/11/2009	0.2256	22.964	203,497
2	8/12/2009	0.2961	29.01	192,204
2	8/13/2009	0.2277	21.492	188,631
2	8/14/2009	0.2335	23.534	201,382

2	8/15/2009	0.2299	21.944	191,080
2	8/16/2009	0.2366	20.663	179,765
2	8/17/2009	0.2187	21.87	200,005
2	8/18/2009	0.2978	28.635	191,809
2	8/19/2009	0.2924	27.803	189,161
2	8/20/2009	0.2888	26.9	185,739
2	8/21/2009	0.2437	21.693	178,823
2	8/22/2009	0.2332	21.642	186,341
2	8/23/2009	0.2612	19.258	159,475
2	8/24/2009	0.2303	20.179	176,997
2	8/25/2009	0.3071	28.576	186,272
2	8/26/2009	0.2597	24.244	186,079
2	8/27/2009	0.3139	30.067	190,691
2	8/28/2009	0.3126	31.529	201,669
2	8/29/2009	0.3215	31.495	195,088
2	8/30/2009	0.3267	27.579	169,222
2	8/31/2009	0.3178	29.264	183,648
2	9/1/2009	0.3099	27.268	175,096
2	9/2/2009	0.3059	28.038	181,422
2	9/3/2009	0.3375	32.789	193,031
2	9/4/2009	0.3618	36.842	203,599
2	9/5/2009	0.3384	33.023	194,479
2	9/6/2009	0.3513	29.848	169,190
2	9/7/2009	0.3366	29.943	172,742
2	9/8/2009	0.3393	32.53	188,604
2	9/9/2009	0.3634	36.179	198,949
2	9/10/2009	0.3643	36.752	201,548
2	9/11/2009	0.3347	32.879	196,345
2	9/12/2009	0.3207	30.37	188,358
2	9/13/2009	0.3158	25.212	157,901
2	9/14/2009	0.3433	32.589	189,217
2	9/15/2009	0.3474	35.384	203,659
2	9/16/2009	0.3135	30.582	195,154
2	9/17/2009	0.278	28.479	205,009
2	9/18/2009	0.2556	26.107	204,203
2	9/19/2009	0.2477	24.919	200,940
2	9/20/2009	0.24	20.354	179,055
2	9/21/2009	0.2965	29.334	197,473
2	9/22/2009	0.2865	24.363	169,762
2	9/23/2009	0.3193	31.254	194,834
2	9/24/2009	0.2957	29.356	198,015
2	9/25/2009	0.3429	32.891	190,096
2	9/26/2009	0.2707	24.502	181,353
2	9/27/2009	0.3319	29.016	173,398
2	9/28/2009	0.3338	31.934	190,619
2	9/29/2009	0.3264	30.063	181,892
2	9/30/2009	0.3341	31.157	185,729

2	10/1/2009	0.337	33.527	198,295
2	10/2/2009	0.3071	29.155	189,928
2	10/3/2009	0.3392	34.386	202,442
2	10/4/2009	0.3227	28.311	174,891
2	10/5/2009	0.3143	30.416	192,620
2	10/6/2009	0.2634	26.18	198,787
2	10/7/2009	0.2722	27.582	202,631
2	10/8/2009	0.2904	30.102	207,317
2	10/9/2009	0.3225	32.316	200,214
2	10/10/2009	0.3102	31.064	200,417
2	10/11/2009	0.2866	25.449	179,828
2	10/12/2009	0.3364	34.524	205,186
2	10/13/2009	0.3295	33.467	202,938
2	10/14/2009	0.2984	28.168	188,546
2	10/15/2009	0.3007	30.132	200,178
2	10/16/2009	0.2585	24.37	189,105
2	10/17/2009	0.2405	23.248	193,325
2	10/18/2009	0.2327	19.852	172,447
2	10/19/2009	0.2583	21.54	176,853
2	10/20/2009	0.3089	30.936	200,414
2	10/21/2009	0.331	31.573	189,942
2	10/22/2009	0.3215	32.427	201,492
2	10/23/2009	0.3254	31.777	195,004
2	10/24/2009	0.3237	30.929	190,847
2	10/25/2009	0.3014	24.939	173,417
2	10/26/2009	0.2904	28.241	193,625
2	10/27/2009	0.2895	27.138	187,182
2	10/28/2009	0.2762	25.385	183,112
2	10/29/2009	0.3016	24.228	149,851
2	10/30/2009	0.276	24.937	179,381
2	10/31/2009	0.3163	29.015	183,175
2	11/1/2009	0.3	24.027	160,652
2	11/2/2009	0.2995	28.419	189,147
2	11/3/2009	0.2779	26.764	191,721
2	11/4/2009	0.3273	32.177	196,367
2	11/5/2009	0.3008	28.209	187,854
2	11/6/2009	0.2773	26.957	194,014
2	11/7/2009	0.239	24.316	203,639
2	11/8/2009	0.2415	20.624	179,056
2	11/9/2009	0.2334	22.196	191,275
2	11/10/2009	0.274	25.86	188,887
2	11/11/2009	0.2899	25.937	177,459
2	11/12/2009	0.2822	26.204	185,163
2	11/13/2009	0.3457	33.076	191,030
2	11/14/2009	0.308	26.008	167,792
2	11/15/2009	0.2969	22.156	154,028
2	11/16/2009	0.303	28.564	186,117

2	11/17/2009	0.2463	21.708	176,444
2	11/18/2009	0.2287	20.859	182,735
2	11/19/2009	0.257	23.372	182,126
2	11/20/2009	0.3081	29.036	188,264
2	11/21/2009	0.3112	31.302	200,799
2	11/22/2009	0.2751	24.259	182,490
2	11/23/2009	0.2678	25.736	190,654
2	11/24/2009	0.283	23.623	176,602
2	11/25/2009	0.2725	27.097	198,807
2	11/26/2009	0.2737	25.751	186,850
2	11/27/2009	0.2691	24.821	182,788
2	11/28/2009	0.2781	27.448	197,275
2	11/29/2009	0.2995	26.176	176,650
2	11/30/2009	0.2893	27.559	188,729
2	12/1/2009	0.263	25.754	195,438
2	12/2/2009	0.2288	22.158	193,764
2	12/3/2009	0.2292	22.967	200,612
2	12/4/2009	0.2789	28.516	204,516
2	12/5/2009	0.3279	33.185	202,289
2	12/6/2009	0.3362	30.336	181,762
2	12/7/2009	0.2911	23.975	163,918
2	12/8/2009	0.3119	13.806	89,495
2	12/12/2009	0.1133	2.242	17,812
2	12/13/2009	0.3005	9.515	64,247
2	12/15/2009	0.0715	0.495	7,631
2	12/16/2009	0.3058	13.259	87,248
2	12/17/2009	0.2774	24.817	179,647
2	12/18/2009	0.2795	23.795	170,154
2	12/19/2009	0.2925	26.9	183,803
2	12/20/2009	0.3163	26.804	169,918
2	12/21/2009	0.3035	27.058	176,287
2	12/22/2009	0.3173	29.349	183,895
2	12/23/2009	0.3085	28.641	184,277
2	12/24/2009	0.3026	23.362	151,431
2	12/25/2009	0.2614	20.029	138,839
2	12/26/2009	0.2884	26.201	181,269
2	12/27/2009	0.3037	25.434	172,918
2	12/28/2009	0.2686	25.538	190,783
2	12/29/2009	0.2632	24.618	187,058
2	12/30/2009	0.2595	24.177	185,973
2	12/31/2009	0.2488	20.416	164,415
2	1/1/2010	0.2521	21.984	175,045
2	1/2/2010	0.2541	25.184	198,140
2	1/3/2010	0.2991	26.232	177,269
2	1/4/2010	0.3008	29.406	195,488
2	1/5/2010	0.3034	29.976	197,637
2	1/6/2010	0.2983	23.951	161,388

2	1/7/2010	0.2696	23.191	171,608
2	1/8/2010	0.267	27.171	203,605
2	1/9/2010	0.259	24.768	190,624
2	1/10/2010	0.28	23.223	174,232
2	1/11/2010	0.2847	26.609	186,798
2	1/12/2010	0.2849	12.514	87,786
2	1/13/2010	0.0186	0.024	2,204
2	1/14/2010	0.2851	23.986	147,505
2	1/15/2010	0.3113	31.803	204,470
2	1/16/2010	0.2878	28.004	194,510
2	1/17/2010	0.3285	26.02	158,205
2	1/18/2010	0.3239	28.176	173,134
2	1/19/2010	0.3114	27.115	171,179
2	1/20/2010	0.2508	20.844	166,137
2	1/21/2010	0.2464	21.427	175,286
2	1/22/2010	0.2232	19.947	179,534
2	1/23/2010	0.2739	23.923	172,387
2	1/24/2010	0.2533	19.566	159,630
2	1/25/2010	0.23	21.699	188,704
2	1/26/2010	0.2524	24.197	190,859
2	1/27/2010	0.2611	22.576	171,951
2	1/28/2010	0.3136	26.415	167,979
2	1/29/2010	0.274	23.494	171,604
2	1/30/2010	0.2962	26.224	177,073
2	1/31/2010	0.2905	22.917	157,574
2	2/1/2010	0.3446	29.991	172,425
2	2/2/2010	0.3399	27.803	162,876
2	2/3/2010	0.3475	32.646	187,540
2	2/4/2010	0.366	34.608	189,024
2	2/5/2010	0.3118	26.923	172,586
2	2/6/2010	0.3215	31.463	195,644
2	2/7/2010	0.2856	23.847	171,558
2	2/8/2010	0.2714	26.051	191,688
2	2/9/2010	0.2904	22.913	161,523
2	2/10/2010	0.274	25.86	188,792
2	2/11/2010	0.3164	29.867	187,058
2	2/12/2010	0.3386	32.637	192,683
2	2/13/2010	0.3157	29.228	184,452
2	2/14/2010	0.3246	27.164	168,702
2	2/15/2010	0.3329	33.142	199,022
2	2/16/2010	0.3281	30.89	187,869
2	2/17/2010	0.3458	32.105	184,900
2	2/18/2010	0.3348	30.135	178,528
2	2/19/2010	0.2944	26.965	181,186
2	2/20/2010	0.2753	26.523	192,646
2	2/21/2010	0.2781	22.728	167,967
2	2/22/2010	0.3088	26.762	171,561

2	2/23/2010	0.2846	25.187	176,544
2	2/24/2010	0.2874	25.997	180,771
2	2/25/2010	0.2931	26.44	180,272
2	2/26/2010	0.2967	27.438	184,193
2	2/27/2010	0.289	27.136	187,376
2	2/28/2010	0.3167	25.16	164,061
2	3/1/2010	0.299	22.904	157,411
2	3/2/2010	0.314	30.757	195,772
2	3/3/2010	0.3001	26.325	174,761
2	3/4/2010	0.368	32.709	176,014
2	3/5/2010	0.375	34.798	184,149
2	3/6/2010	0.3696	34.14	183,305
2	3/7/2010	0.3727	34.272	182,926
2	3/8/2010	0.3644	35.184	192,521
2	3/9/2010	0.3495	33.952	193,746
2	3/10/2010	0.3603	36.566	202,397
2	3/11/2010	0.3514	34.602	196,089
2	3/12/2010	0.3642	34.605	189,238
2	3/13/2010	0.3768	35.512	187,053
2	3/14/2010	0.3635	31.076	171,359
2	3/15/2010	0.3218	29.648	183,534
2	3/16/2010	0.3101	28.696	184,617
2	3/17/2010	0.3079	29.313	190,207
2	3/18/2010	0.3283	32.476	197,363
2	3/19/2010	0.3117	30.682	196,351
2	3/20/2010	0.302	26.599	176,023
2	3/21/2010	0.3317	29.287	179,193
2	3/22/2010	0.3054	28.434	185,702
2	3/23/2010	0.2925	24.976	170,091
2	3/24/2010	0.3304	32.319	193,083
2	3/25/2010	0.3379	32.485	189,060
2	3/26/2010	0.3578	35.405	197,427
2	3/27/2010	0.373	37.857	203,107
2	3/28/2010	0.3594	31.488	175,683
2	3/29/2010	0.3452	33.909	196,164
2	3/30/2010	0.3747	36.331	193,829
2	3/31/2010	0.335	32.242	191,293
2	4/1/2010	0.3479	33.54	191,858
2	4/2/2010	0.3054	25.083	164,350
2	4/21/2010	0.0104	0.009	1,248
2	4/22/2010	0.1424	5.172	47,139
2	4/23/2010	0.2579	23.589	182,271
2	4/24/2010	0.2622	23.872	182,387
2	4/25/2010	0.3231	23.56	154,666
2	4/26/2010	0.306	29.095	190,300
2	4/27/2010	0.3617	33.912	187,710
2	4/28/2010	0.3753	34.644	183,603

2	4/29/2010	0.3645	32.248	176,285
2	4/30/2010	0.3723	36.861	197,950
2	5/1/2010	0.367	37.547	204,578
2	5/2/2010	0.3828	35.725	187,772
2	5/3/2010	0.3332	33.052	198,238
2	5/4/2010	0.3265	30.152	183,692
2	5/5/2010	0.2584	22.273	172,845
2	5/6/2010	0.2874	26.371	183,523
2	5/7/2010	0.3903	40.035	205,043
2	5/8/2010	0.4003	39.405	198,799
2	5/9/2010	0.4328	35.521	170,135
2	5/10/2010	0.3978	39.861	200,328
2	5/11/2010	0.3931	40.6	206,565
2	5/12/2010	0.388	40.227	207,331
2	5/13/2010	0.4002	41.74	208,549
2	5/14/2010	0.4039	42.329	209,606
2	5/15/2010	0.4003	41.404	206,779
2	5/16/2010	0.3858	34.968	181,387
2	5/17/2010	0.359	35.109	194,245
2	5/18/2010	0.3375	32.519	191,826
2	5/19/2010	0.3555	32.992	184,593
2	5/20/2010	0.3539	23.745	141,069
2	5/21/2010	0.266	24.74	185,979
2	5/22/2010	0.2758	24.289	177,848
2	5/23/2010	0.3413	30.208	175,857
2	5/24/2010	0.3102	28.437	182,297
2	5/25/2010	0.3129	28.355	181,153
2	5/26/2010	0.309	26.721	173,220
2	5/27/2010	0.307	29.872	193,938
2	5/28/2010	0.2945	25.802	172,520
2	5/29/2010	0.2803	24.142	174,728
2	5/30/2010	0.3133	24.148	162,494
2	5/31/2010	0.3765	34.825	186,096
2	6/1/2010	0.3768	37.764	199,921
2	6/2/2010	0.373	38.857	208,101
2	6/3/2010	0.3377	33.463	197,657
2	6/4/2010	0.3548	37.292	210,092
2	6/5/2010	0.3643	37.882	207,525
2	6/6/2010	0.3784	36.735	190,765
2	6/7/2010	0.3485	33.179	186,705
2	6/8/2010	0.392	40.222	205,035
2	6/9/2010	0.3822	38.475	200,887
2	6/10/2010	0.3068	30.981	200,751
2	6/11/2010	0.2801	28.255	201,667
2	6/12/2010	0.2662	26.587	199,525
2	6/13/2010	0.2632	23.522	178,654
2	6/14/2010	0.3279	31.576	192,221

2	6/15/2010	0.4133	41.545	200,266
2	6/16/2010	0.4036	41.298	204,473
2	6/17/2010	0.3988	40.592	203,371
2	6/18/2010	0.3715	37.442	201,230
2	6/19/2010	0.3702	37.421	201,635
2	6/20/2010	0.3685	34.684	181,864
2	6/21/2010	0.3697	38.138	206,264
2	6/22/2010	0.3138	29.065	182,869
2	6/23/2010	0.3401	32.751	191,169
2	6/24/2010	0.354	35.952	203,054
2	6/25/2010	0.362	36.045	198,253
2	6/26/2010	0.3605	35.497	195,790
2	6/27/2010	0.358	31.223	173,774
2	6/28/2010	0.3546	35.884	202,169
2	6/29/2010	0.346	33.691	193,606
2	6/30/2010	0.3413	33.914	197,055
2	7/1/2010	0.3533	36.572	206,953
2	7/2/2010	0.3557	36.588	205,608
2	7/3/2010	0.3384	32.9	192,412
2	7/4/2010	0.3551	14.261	80,752
2	7/6/2010	0.1452	5.573	49,282
2	7/7/2010	0.2467	17.715	140,569
2	7/10/2010	0.108	3.371	35,086
2	7/11/2010	0.235	22.931	194,447
2	7/12/2010	0.2325	22.063	188,786
2	7/13/2010	0.2195	19.448	175,188
2	7/14/2010	0.2428	23.049	188,608
2	7/15/2010	0.3083	30.652	198,278
2	7/16/2010	0.326	30.626	187,183
2	7/17/2010	0.3212	29.628	182,888
2	7/18/2010	0.3038	25.898	168,068
2	7/19/2010	0.2688	25.087	186,290
2	7/20/2010	0.279	25.228	179,195
2	7/21/2010	0.2851	26.858	187,148
2	7/22/2010	0.2703	25.008	182,559
2	7/23/2010	0.2768	26.549	190,507
2	7/24/2010	0.2814	26.978	189,979
2	7/25/2010	0.3176	27.256	170,903
2	7/26/2010	0.3116	31.933	204,884
2	7/27/2010	0.2922	26.244	177,889
2	7/28/2010	0.3106	26.435	168,005
2	7/29/2010	0.3374	32.237	190,341
2	7/30/2010	0.3345	32.409	192,843
2	7/31/2010	0.3568	35.895	200,721
2	8/1/2010	0.3287	30	181,805
2	8/2/2010	0.3021	27.242	165,631
2	8/3/2010	0.0843	3.155	34,642

2	8/4/2010	0.2788	23.472	165,844
2	8/5/2010	0.288	24.484	169,998
2	8/6/2010	0.3184	30.386	188,776
2	8/7/2010	0.3336	33.039	197,750
2	8/8/2010	0.3155	29.241	181,162
2	8/9/2010	0.2735	24.581	173,678
2	8/10/2010	0.2764	26.072	187,917
2	8/11/2010	0.292	21.984	148,836
2	8/12/2010	0.2346	21.782	184,976
2	8/13/2010	0.2312	21.354	183,762
2	8/14/2010	0.2738	25.002	180,481
2	8/15/2010	0.3087	28.549	181,951
2	8/16/2010	0.268	23.016	166,550
2	8/17/2010	0.2336	19.862	168,430
2	8/18/2010	0.2405	20.847	170,012
2	8/19/2010	0.2278	21.202	184,826
2	8/20/2010	0.2172	19.364	177,073
2	8/21/2010	0.2313	20.219	175,695
2	8/22/2010	0.3024	22.011	151,000
2	8/23/2010	0.3017	23.994	162,738
2	8/24/2010	0.3201	29.647	183,312
2	8/25/2010	0.3027	29.621	194,079
2	8/26/2010	0.2993	13.546	93,683
2	8/28/2010	0.0992	1.178	9,671
2	8/29/2010	0.2742	25.988	187,043
2	8/30/2010	0.3024	31.544	208,567
2	8/31/2010	0.2914	29.6	202,961
2	9/1/2010	0.3032	31.274	206,243
2	9/2/2010	0.2655	26.697	200,547
2	9/3/2010	0.2697	25.059	186,800
2	9/4/2010	0.2585	22.862	176,069
2	9/5/2010	0.331	26.176	157,180
2	9/6/2010	0.312	28.411	175,000
2	9/7/2010	0.3131	31.378	200,025
2	9/8/2010	0.3125	30.693	195,640
2	9/9/2010	0.3145	30.443	192,209
2	9/10/2010	0.3163	31.898	201,819
2	9/11/2010	0.2995	31.21	208,424
2	9/12/2010	0.2738	24.756	180,088
2	9/13/2010	0.2593	23.663	180,788
2	9/14/2010	0.2643	24.632	183,553
2	9/15/2010	0.2785	26.015	184,117
2	9/16/2010	0.2548	24.886	194,499
2	9/17/2010	0.2407	23.854	197,457
2	9/18/2010	0.2501	24.501	195,124
2	9/19/2010	0.2547	20.716	165,500
2	9/20/2010	0.28	26.703	189,739

2	9/21/2010	0.3073	30.549	197,237
2	9/22/2010	0.3044	31.192	204,795
2	9/23/2010	0.2878	29.327	203,673
2	9/24/2010	0.2917	29.842	204,519
2	9/25/2010	0.3368	34.531	205,023
2	9/26/2010	0.3225	25.374	157,556
2	9/27/2010	0.343	30.288	174,395
2	9/28/2010	0.3529	33.819	189,660
2	9/29/2010	0.337	31.985	188,700
2	9/30/2010	0.3067	29.497	190,706
2	10/1/2010	0.3061	26.78	173,646
2	12/1/2010	0.045	0.104	4,636
2	12/2/2010	0.0236	0.135	9,467
2	12/3/2010	0.0877	1.465	18,170
2	12/4/2010	0.104	2.504	23,515
2	12/5/2010	0.2113	6.47	69,803
2	12/6/2010	0.0967	2.243	20,772
2	12/7/2010	0.2328	19.758	169,934
2	12/8/2010	0.2653	22.339	170,105
2	12/9/2010	0.2912	26.479	182,383
2	12/10/2010	0.3654	33.078	180,526
2	12/11/2010	0.3696	32.651	175,081
2	12/12/2010	0.3963	34.441	175,418
2	12/13/2010	0.399	37.477	187,689
2	12/14/2010	0.3696	35.364	191,113
2	12/15/2010	0.336	30.552	177,027
2	12/16/2010	0.3313	29.197	173,761
2	12/17/2010	0.2907	26.929	186,977
2	12/18/2010	0.2787	24.665	179,379
2	12/19/2010	0.3178	26.705	168,255
2	12/20/2010	0.349	33.694	192,951
2	12/21/2010	0.3601	32.432	178,474
2	12/22/2010	0.3515	30.947	175,259
2	12/23/2010	0.351	32.509	184,333
2	12/24/2010	0.2968	22.214	134,210
2	12/25/2010	0.3695	28.806	155,197
2	12/26/2010	0.3838	31.738	167,463
2	12/27/2010	0.3962	33.913	172,104
2	12/28/2010	0.3877	32.717	169,848
2	12/29/2010	0.374	32.493	175,121
2	12/30/2010	0.3763	17.001	92,260
2	1/1/2011	0.1571	10.258	72,888
2	1/2/2011	0.3065	24.754	159,372
2	1/3/2011	0.3377	31.976	188,868
2	1/4/2011	0.3243	29	178,447
2	1/5/2011	0.3359	31.322	186,552
2	1/6/2011	0.3528	32.887	186,140

2	1/7/2011	0.3586	33.09	184,333
2	1/8/2011	0.3365	31.695	188,497
2	1/9/2011	0.3695	32.573	178,845
2	1/10/2011	0.3815	37.065	194,270
2	1/11/2011	0.322	27.342	169,244
2	1/12/2011	0.2904	26.611	182,779
2	1/13/2011	0.329	28.225	171,284
2	1/14/2011	0.3639	29.033	157,835
2	1/15/2011	0.3727	34.019	182,470
2	1/16/2011	0.3495	29.224	167,817
2	1/17/2011	0.3616	35.227	194,763
2	1/18/2011	0.3418	31.47	183,364
2	1/19/2011	0.3505	34.12	194,647
2	1/20/2011	0.362	35.962	198,712
2	1/21/2011	0.409	38.632	188,608
2	1/22/2011	0.3447	29.003	166,832
2	1/23/2011	0.2647	20.198	156,556
2	1/24/2011	0.3425	31.143	178,516
2	1/25/2011	0.3683	35.628	193,152
2	1/26/2011	0.3587	34.163	189,917
2	1/27/2011	0.327	28.503	172,541
2	1/28/2011	0.3474	33.637	193,289
2	1/29/2011	0.2487	21.766	175,190
2	1/30/2011	0.2694	21.502	162,375
2	1/31/2011	0.2805	26.358	187,686
2	2/1/2011	0.2641	25.027	189,268
2	2/2/2011	0.2776	24.727	179,526
2	2/3/2011	0.2923	28.113	191,589
2	2/4/2011	0.3581	36.424	203,281
2	2/5/2011	0.3545	32.365	181,344
2	2/6/2011	0.3216	26.366	162,975
2	2/7/2011	0.3342	32.138	191,591
2	2/8/2011	0.3262	29.09	176,917
2	2/9/2011	0.329	27.564	167,571
2	2/10/2011	0.3225	25.494	157,562
2	2/11/2011	0.3317	29.545	176,463
2	2/12/2011	0.3191	27.466	169,020
2	2/13/2011	0.2287	16.557	134,415
2	2/14/2011	0.2986	22.494	148,370
2	2/15/2011	0.2849	19.686	139,767
2	2/16/2011	0.2948	15.505	106,012
2	2/17/2011	0.2732	14.729	111,337
2	2/18/2011	0.2881	19.392	135,793
2	2/19/2011	0.331	26.26	162,383
2	2/20/2011	0.3196	28.728	179,729
2	2/21/2011	0.3105	29.272	185,021
2	2/22/2011	0.3304	29.663	177,386

2	2/23/2011	0.3506	35.712	203,253
2	2/24/2011	0.3146	31.055	194,571
2	2/25/2011	0.2811	28.443	202,408
2	2/26/2011	0.2765	28.378	205,295
2	2/27/2011	0.2891	27.658	189,608
2	2/28/2011	0.3297	34.86	211,352
2	3/1/2011	0.3283	33.836	206,093
2	3/2/2011	0.331	34.265	206,423
2	3/3/2011	0.3394	35.523	209,307
2	3/4/2011	0.3215	30.34	188,099
2	3/5/2011	0.3319	29.637	178,607
2	3/6/2011	0.3313	27.632	169,866
2	3/7/2011	0.3144	32.563	206,953
2	3/8/2011	0.3067	32.381	211,010
2	3/9/2011	0.3152	31.182	197,610
2	3/10/2011	0.3255	30.724	188,717
2	3/11/2011	0.3295	34.078	206,650
2	3/12/2011	0.3235	34.456	213,036
2	3/13/2011	0.3058	24.608	162,616
2	3/14/2011	0.3025	30.474	199,841
2	3/15/2011	0.2844	26.545	185,436
2	3/16/2011	0.2795	25.471	181,160
2	3/17/2011	0.2815	22.485	158,614
2	3/18/2011	0.292	28.045	192,123
2	3/19/2011	0.3094	32.343	208,308
2	3/20/2011	0.3246	30.831	189,882
2	3/21/2011	0.3083	30.126	194,306
2	3/22/2011	0.3078	28.047	181,559
2	3/23/2011	0.3182	31.24	196,293
2	3/24/2011	0.3351	32.411	192,495
2	3/25/2011	0.3134	25.287	161,512
2	4/22/2011	0.0154	0.032	3,347
2	4/23/2011	0.0797	0.905	10,938
2	4/24/2011	0.2057	6.768	47,080
2	4/25/2011	0.4353	14.765	67,630
2	4/26/2011	0.4074	17.319	90,046
2	4/27/2011	0.3159	26.349	167,264
2	4/28/2011	0.3023	29.551	195,195
2	4/29/2011	0.2912	27.205	187,004
2	4/30/2011	0.2893	27.584	190,167
2	5/1/2011	0.2915	27.14	191,320
2	5/2/2011	0.3033	26.229	174,501
2	5/3/2011	0.2965	28.338	190,403
2	5/4/2011	0.2855	27.677	193,587
2	5/5/2011	0.3054	25.994	175,667
2	5/6/2011	0.3395	20.327	131,417
2	5/7/2011	0.2989	26.32	176,429

2	5/8/2011	0.2846	26.157	181,568
2	5/9/2011	0.2891	24.19	166,892
2	5/10/2011	0.297	27.609	184,996
2	5/11/2011	0.2976	24.67	165,855
2	5/12/2011	0.3067	30.139	195,742
2	5/13/2011	0.2613	18.901	143,927
2	5/14/2011	0.276	21.857	158,210
2	5/15/2011	0.2631	18.014	139,159
2	5/16/2011	0.2928	27.122	183,308
2	5/17/2011	0.2739	22.106	158,795
2	5/18/2011	0.2705	23.72	174,718
2	5/19/2011	0.2911	26.385	179,383
2	5/20/2011	0.2539	20.339	159,868
2	5/21/2011	0.2578	12.945	101,852
2	5/22/2011	0.2976	21.231	144,917
2	5/23/2011	0.2485	14.69	118,399
2	5/24/2011	0.3088	12.364	80,878
2	5/25/2011	0.2932	11.129	76,148
2	5/26/2011	0.3034	10.596	69,987
2	5/27/2011	0.2583	14.89	120,281
2	5/28/2011	0.32	16.437	111,238
2	5/29/2011	0.2447	15.595	130,302
2	5/30/2011	0.2413	20.953	170,818
2	5/31/2011	0.2467	24.483	196,530
2	6/1/2011	0.2744	27.395	196,527
2	6/2/2011	0.2744	26.665	192,143
2	6/3/2011	0.2734	28.35	206,952
2	6/4/2011	0.2702	27.107	199,470
2	6/5/2011	0.2429	14.817	122,241
2	6/6/2011	0.2496	13.002	107,680
2	6/7/2011	0.2536	21.797	167,955
2	6/8/2011	0.268	25.231	184,359
2	6/9/2011	0.2729	26.915	194,932
2	6/10/2011	0.3011	29.11	190,674
2	6/11/2011	0.2943	27.653	184,465
2	6/12/2011	0.2657	19.515	156,987
2	6/13/2011	0.2168	19.877	183,027
2	6/14/2011	0.2618	24.78	185,435
2	6/15/2011	0.2891	29.903	206,659
2	6/16/2011	0.2811	27.153	191,163
2	6/17/2011	0.2731	25.534	185,428
2	6/18/2011	0.2508	22.435	175,735
2	6/19/2011	0.2364	15.654	134,013
2	6/20/2011	0.2294	14.844	130,187
2	6/21/2011	0.2589	25.915	199,965
2	6/22/2011	0.2662	24.749	183,686
2	6/23/2011	0.261	22.766	173,460

2	6/24/2011	0.2989	27.056	177,380
2	6/25/2011	0.3237	30.516	185,524
2	6/26/2011	0.3334	30.913	182,575
2	6/27/2011	0.3429	35.861	208,930
2	6/28/2011	0.294	25.958	174,332
2	6/29/2011	0.2607	22.085	171,964
2	6/30/2011	0.2809	27.622	195,290
2	7/1/2011	0.288	28.731	198,248
2	7/2/2011	0.1999	9.025	61,606
2	7/3/2011	0.2851	28.029	195,550
2	7/4/2011	0.268	21.373	157,070
2	7/5/2011	0.288	25.499	176,014
2	7/6/2011	0.235	23.654	200,501
2	7/7/2011	0.3074	31.39	203,619
2	7/8/2011	0.3149	31.906	200,271
2	7/9/2011	0.3007	27.847	178,256
2	7/10/2011	0.3209	27.654	169,295
2	7/11/2011	0.3645	31.83	178,807
2	7/12/2011	0.2723	24.976	181,806
2	7/13/2011	0.3083	31.829	205,909
2	7/14/2011	0.2963	30.862	208,357
2	7/15/2011	0.3132	32.633	207,754
2	7/16/2011	0.3098	32.203	207,288
2	7/17/2011	0.301	28.777	190,890
2	7/18/2011	0.3318	34.52	207,540
2	7/19/2011	0.3313	33.476	198,487
2	7/20/2011	0.3009	30.804	204,046
2	7/21/2011	0.3122	31.825	202,267
2	7/22/2011	0.3216	33.074	205,062
2	7/23/2011	0.2972	30.875	207,394
2	7/24/2011	0.3365	31.384	186,061
2	7/25/2011	0.3251	31.846	193,676
2	7/26/2011	0.3286	32.634	196,129
2	7/27/2011	0.3365	34.355	201,593
2	7/28/2011	0.3529	37.867	214,033
2	7/29/2011	0.2943	26.439	174,026
2	7/30/2011	0.3167	29.456	178,259
2	7/31/2011	0.3233	30.134	183,246
2	8/1/2011	0.3192	32.162	199,254
2	8/2/2011	0.2609	25.231	192,635
2	8/3/2011	0.2618	25.831	194,914
2	8/4/2011	0.2329	24.194	207,737
2	8/5/2011	0.2261	23.17	204,342
2	8/6/2011	0.2253	23.26	206,213
2	8/7/2011	0.2264	21.331	188,936
2	8/8/2011	0.2853	29.578	206,554
2	8/9/2011	0.2811	28.673	202,776

2	8/10/2011	0.2896	29.131	199,345
2	8/11/2011	0.252	22.855	179,447
2	8/12/2011	0.2611	26.332	200,232
2	8/13/2011	0.2598	25.658	197,416
2	8/14/2011	0.2565	22.782	178,243
2	8/15/2011	0.2477	22.743	183,781
2	8/16/2011	0.2086	19.929	190,837
2	8/17/2011	0.2208	23.255	210,147
2	8/18/2011	0.2521	25.62	202,877
2	8/19/2011	0.2647	27.012	204,403
2	8/20/2011	0.2563	26.25	204,545
2	8/21/2011	0.2664	24.956	186,682
2	8/22/2011	0.2675	27.336	203,535
2	8/23/2011	0.2676	27.43	203,865
2	8/24/2011	0.2668	23.601	178,100
2	8/25/2011	0.2871	28.338	196,837
2	8/26/2011	0.2703	24.915	185,898
2	8/27/2011	0.2457	23.195	189,383
2	8/28/2011	0.2696	22.77	176,413
2	8/29/2011	0.2583	25.34	196,451
2	8/30/2011	0.2771	27.346	197,920
2	8/31/2011	0.2656	28.467	214,333
2	9/1/2011	0.2654	23.516	175,562
2	9/2/2011	0.2482	23.565	187,428
2	9/3/2011	0.2916	30.884	211,687
2	9/4/2011	0.2594	24.55	189,483
2	9/5/2011	0.2502	20.05	161,186
2	9/6/2011	0.2585	20.204	155,925
2	9/7/2011	0.2793	23.578	172,454
2	9/8/2011	0.2599	23.223	178,486
2	9/9/2011	0.2633	22.618	175,494
2	9/10/2011	0.2599	24.196	186,193
2	9/11/2011	0.2642	24.619	187,124
2	9/12/2011	0.247	22.818	184,261
2	9/13/2011	0.246	21.46	174,038
2	9/14/2011	0.2328	19.757	169,212
2	9/15/2011	0.2435	23.005	188,691
2	9/16/2011	0.2602	24.435	186,465
2	9/17/2011	0.2682	26.451	196,960
2	9/18/2011	0.3064	28.174	184,043
2	9/19/2011	0.2624	7.302	55,153
2	9/22/2011	0.134	5.352	44,509
2	9/23/2011	0.3209	31.305	192,018
2	9/24/2011	0.304	28.682	184,634
2	9/25/2011	0.3203	28.745	174,812
2	9/26/2011	0.3344	32.405	192,834
2	9/27/2011	0.3165	31.052	194,835

2	9/28/2011	0.3546	35.064	196,437
2	9/29/2011	0.3133	26.285	165,518
2	9/30/2011	0.3222	25.44	156,812
2	10/1/2011	0.318	26.529	163,164
2	10/2/2011	0.3493	26.624	153,355
2	10/3/2011	0.3246	28.623	174,058
2	10/4/2011	0.3429	29.855	177,266
2	10/5/2011	0.3263	31.736	193,368
2	10/6/2011	0.3228	31.616	194,987
2	10/7/2011	0.295	28.243	190,849
2	10/8/2011	0.3057	31.318	204,446
2	10/9/2011	0.3088	27.552	176,986
2	10/10/2011	0.329	32.957	199,629
2	10/11/2011	0.273	27.712	203,250
2	10/12/2011	0.2425	23.365	191,902
2	10/13/2011	0.2402	23.74	197,459
2	10/14/2011	0.2455	23.187	189,663
2	10/15/2011	0.3059	24.14	155,345
2	10/16/2011	0.2848	25.31	173,345
2	10/17/2011	0.2955	28.576	189,933
2	10/18/2011	0.2881	27.075	186,994
2	10/19/2011	0.2738	24.63	181,250
2	10/20/2011	0.2779	24.269	173,114
2	10/21/2011	0.2913	26.878	182,907
2	10/22/2011	0.3466	36.089	208,037
2	10/23/2011	0.2785	26.041	184,885
2	10/24/2011	0.2721	27.894	204,883
2	10/25/2011	0.2856	28.708	199,779
2	10/26/2011	0.2744	26.353	188,847
2	10/27/2011	0.2793	27.005	191,413
2	10/28/2011	0.2963	30.04	202,311
2	10/29/2011	0.2928	28.162	191,651
2	10/30/2011	0.2954	25.071	167,684
2	10/31/2011	0.3375	31.984	188,030
2	11/1/2011	0.3317	32.563	193,330
2	11/2/2011	0.3139	32.454	206,908
2	11/3/2011	0.2676	23.265	172,204
2	11/4/2011	0.2889	25.527	176,428
2	11/5/2011	0.289	24.936	172,793
2	11/6/2011	0.2969	25.477	171,359
2	11/7/2011	0.262	19.485	129,072
2	11/9/2011	0.1507	6.801	50,118
2	11/10/2011	0.2725	21.016	153,874
2	11/11/2011	0.2444	20.408	165,110
2	11/12/2011	0.3042	26.637	175,346
2	11/13/2011	0.3302	30.458	185,707
2	11/14/2011	0.2984	25.694	170,338

2	11/15/2011	0.2926	20.775	141,914
2	11/16/2011	0.3269	21.819	136,238
2	11/17/2011	0.3152	28.964	184,844
2	11/18/2011	0.3428	33.473	195,154
2	11/19/2011	0.3236	32.434	200,738
2	11/20/2011	0.3436	33.209	192,162
2	11/21/2011	0.3228	32.172	196,138
2	11/22/2011	0.3177	28.567	178,506
2	11/23/2011	0.3145	28.129	176,366
2	11/24/2011	0.3302	21.202	130,692
2	11/25/2011	0.2779	21.25	151,984
2	11/26/2011	0.2963	26.207	173,827
2	11/27/2011	0.3308	27.062	162,932
2	11/28/2011	0.3039	27.534	178,807
2	11/29/2011	0.2962	25.953	175,906
2	11/30/2011	0.3092	24.526	159,232
2	12/1/2011	0.3134	26.167	168,733
2	12/2/2011	0.2819	25.736	181,519
2	12/3/2011	0.3392	24.974	149,365
2	12/4/2011	0.2985	26.271	178,248
2	12/5/2011	0.2946	28.484	193,406
2	12/6/2011	0.289	25.317	179,603
2	12/7/2011	0.2953	21.698	149,209
2	12/8/2011	0.3079	19.546	132,742
2	12/9/2011	0.3015	21.19	147,856
2	12/10/2011	0.2896	26.812	186,436
2	12/11/2011	0.302	27.771	185,936
2	12/12/2011	0.285	23.779	166,663
2	12/13/2011	0.2806	18.117	129,960
2	12/14/2011	0.2838	19.14	134,316
2	12/15/2011	0.2949	23.489	157,149
2	12/16/2011	0.3114	29.531	190,167
2	12/17/2011	0.3121	25.9	165,930
2	12/18/2011	0.327	27.776	168,922
2	12/19/2011	0.3095	25.127	161,665
2	12/20/2011	0.2754	22.849	163,201
2	12/21/2011	0.3067	25.873	164,714
2	12/22/2011	0.3334	27.904	166,210
2	12/23/2011	0.3517	30.803	174,912
2	12/24/2011	0.3165	24.891	158,405
2	12/25/2011	0.3011	17.471	117,238
2	12/26/2011	0.305	25.869	168,332
2	12/27/2011	0.306	25.925	167,343
2	12/28/2011	0.3137	27.543	172,303
2	12/29/2011	0.2716	21.473	158,248
2	12/30/2011	0.2563	18.977	147,671
2	12/31/2011	0.2609	19.478	148,056

Max (tpd) -->	**42.329**
Max (lb/hr) -->	**3527.416667**

Note: Dates with no operation/emissions not shown

APPENDIX E

S&L NOX CONTROL TECHNOLOGY STUDY

Prepared for
Gill Elrod Ragon Owen & Sherman, P.A.

NOx Control Technology Cost and Performance Study

Entergy Services, Inc.
White Bluff & Lake Catherine

SL-011439
Final Report
Rev. 4

May 16, 2013
Project No.: 13027-001

Prepared by

Sargent & Lundy LLC

55 East Monroe Street
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White Bluff & Lake Catherine
NOx Control Technology Cost and Performance Study

ISSUE SUMMARY AND APPROVAL PAGE

This is to certify that this report has been prepared, reviewed and approved in accordance with Sargent & Lundy's Standard Operating Procedure SOP-0405, which is based on ANSI/ISO/ASSQC Q9001 Quality Management Systems.

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ENTERGY SERVICES, INC.

WHITE BLUFF AND LAKE CATHERINE

NO_X CONTROL TECHNOLOGY COST AND PERFORMANCE STUDY

CERTIFICATION PAGE

Sargent & Lundy, L.L.C. is registered in the State of Arkansas to practice engineering.
The registration number is 620.

I certify that this study was prepared by me or under my supervision and that I am a registered professional engineer under the laws of the State of Arkansas.

Certified By: Sean C. McHone Date: 5/16/2013

Seal:

STATE OF ARKANSAS LICENSED PROFESSIONAL ENGINEER No. 15308 SEAN C. MCHONE

S. C. McHone 5/16/2013

Issue:	Date:	Certified By:	Pages Certified:

1. INTRODUCTION

1.1. OBJECTIVE

The intent of this study is to provide Gill Elrod Ragon Owen & Sherman, P.A. with a technology evaluation and cost estimates for available methods of NOx control at two Entergy stations including: White Bluff – Units 1 & 2, the White Bluff Auxiliary Boiler, and Lake Catherine – Unit 4. The information developed in this study will be used to create a BART analysis, for compliance with Arkansas DEQ regulations.

1.2. UNIT DESCRIPTIONS

1.2.1. White Bluff - Units 1 & 2

White Bluff - Units 1 & 2 are Alstom-designed, tangentially-fired, pulverized-coal fueled units, rated at 815 MWnet and 844 MWnet respectively. Powder River Basin coal is the primary fuel source for Units 1 & 2. Currently, the units have no NOx controls installed.

1.2.2. White Bluff Auxiliary Boiler

The White Bluff Auxiliary boiler is a small industrial boiler capable of producing 140,000 lb/hr of steam, used for startup of the White Bluff coal units. The auxiliary boiler combusts No. 2 Diesel Oil, and does not have any existing NOx controls.

1.2.3. Lake Catherine - Unit 4

Lake Catherine - Unit 4 is an Alstom-designed, tangentially-fired, natural gas fueled unit, capable of generating 558 MWnet. The unit was originally designed as a dual-fuel unit, able to use natural gas or No. 2 Fuel Oil as fuel. This evaluation will be for natural gas firing only. If No. 2 Fuel Oil is to be combusted in the future, a separate BART analysis will be submitted. The unit currently has no NOx controls.

1.3. ESTIMATE METHODOLOGY

1.3.1. Capital Cost Estimates

S&L's capital cost estimates for retrofit NOx control technologies for White Bluff Units 1&2, White Bluff Auxiliary Boiler and Lake Catherine – Unit 4 encompass the equipment, material, labor, and all other required direct costs. The underlying assumption is that the project will be implemented on a multiple-contracting basis. The capital cost estimates provided herein are "total plant cost," and include the following:

- Equipment and material
- Installation labor
- Indirect field costs and BOP engineering
- Contingency (percentage varies with project size)
- Erection contractor profit (at 10% of material and labor)
- General and administration (at 5% of material and labor)
- Freight on material (at 5% of material)
- Freight on equipment (included with equipment costs)
- Sales/use tax (not included)
- Startup and commissioning (at 1% of construction cost)
- Spare parts (included with equipment costs)
- Consumables (0.5% of material and labor)

Owner's engineering and other Owner's costs were not included. Engineering, Procurement & Project Services and Contingency varied depending on the size of the project. License fees and royalties are not expected for the proposed control strategies. The Basis of Estimate and capital costs are summarized in Appendix A.

Capital cost estimates were calculated in one of three ways. In some cases, vendors were contacted to provide budgetary estimates for equipment and labor. These vendor's costs were used to create Total Installed Cost Estimates. In situations where Sargent & Lundy had performed cost estimates for these units previously, the existing cost estimates were updated to reflect current equipment, labor, and currency values. Remaining cost estimates were developed from similar projects that Sargent & Lundy has completed and adjusted for unit size.

1.3.2. Operating and Maintenance Cost Estimates

Operating and Maintenance Costs for White Bluff - Units 1 & 2 and Lake Catherine – Unit 4 were developed from similar projects Sargent & Lundy has completed. Costs were applied to the units on a $/kW basis, and assuming a 10% capacity factor for Lake Catherine – Unit 4, and 76% for White Bluff—Units 1 & 2. Operating and Maintenance Costs include the following costs:

- Fixed Operating and Maintenance
- Variable Operating and Maintenance
- Fuel Impact Costs

For the White Bluff Auxiliary boiler, costs were developed using Office of Air Quality Planning and Standards (OAQPS) calculations, assuming a 10% capacity factor.

1.4. DESIGN TARGET vs. COMPLIANCE NO_X EMISSION RATES

NOx control systems retrofit onto existing coal or gas-fired boilers are typically designed to achieve varying levels of NOx removal efficiencies from 10%-94%, depending on the control technologies selected. Controlled NOx emissions fluctuate during normal boiler operation in response to a number of design/operating parameters including, but not necessarily limited to: inlet NOx concentrations, boiler load, load changes, particulate matter loading, flue gas temperatures, flue gas velocities and mixing, catalyst volume and surface area, NH_3:NOx stoichiometric ratio, catalyst age and activity, and the quantity of ammonia slip deemed to be acceptable.

The “design target” NOx emission rate is the rate that a NOx control technology vendor would be willing to guarantee. Based on engineering judgment, and taking into consideration emissions data from existing coal- and gas-fired sources, a compliance margin above the design target is recommended for high removal efficiency/low emission rate technologies (such as SCR) to establish an enforceable permit limit based on long-term (e.g., annual average) emissions. Additional compliance margin would be required to establish enforceable permit limits based on shorter-term averaging times. For example, S&L recommends a compliance margin of 0.02 to 0.03 lb/MMBtu for coal units and 0.01 to 0.02 lb/MMBtu for gas units above the design target emission rate for permit limits based on a 30-day rolling average for control strategies including SCR. The NOx control technology emission rates for strategies including SCR in this report have been adjusted to include margin for compliance. The permit level NOx emission rates for SCR are higher by 0.02 to 0.03 lb/MMBtu for coal units and 0.01 to 0.02 lb/MMBtu for gas units.

2. WHITE BLUFF - UNITS 1 & 2

2.1. FUEL SWITCHING OPTIONS

2.1.1. Natural Gas

For White Bluff Units 1 & 2, fuel switching is not a feasible option. Typically, units could be switched from coal to natural gas or propane for NOx reductions. The nearest natural gas pipeline to the White Bluff facility is approximately 20 miles away. Construction of a pipeline is currently estimated at $2M per mile resulting in a cost of $40M to bring natural gas to the site, not including the additional upgrades the boiler would require to burn natural gas instead of coal.

2.1.2. Propane

White Bluff – Units 1 & 2 are each over 800 MWnet. Units of this size require more heat input than can practically be achieved with a propane delivery and storage system. Since a propane pipeline is not available, fuel switching to propane is not a feasible option.

2.2. COMBUSTION CONTROLS

2.2.1. Low NOx Burners and Over-Fire Air

Low NOx burners (LNB) limit NOx formation by controlling both the stoichiometric and temperature profiles of the combustion flame in each burner flame envelope. Control is achieved with design features that regulate the aerodynamic distribution and mixing of the fuel and air, yielding reduced oxygen (O_2) in the primary combustion zone, reduced flame temperature, and reduced residence time at peak combustion temperatures. The combination of these techniques produces lower NOx emissions during the combustion process.

OFA involves injecting combustion air downstream of the fuel-rich primary combustion zone by using over-fire air or side-fired air ports. The fuel-rich mixture that is fed to the burners reduces the flame temperature and oxygen concentration thus reducing the formation of thermal NOx. Generally, OFA is more effective when used with low nitrogen content fuels such as natural gas and propane, since OFA is more effective in controlling thermal NOx rather than fuel NOx.

LNB + OFA is a technically feasible retrofit solution for White Bluff - Units 1 & 2. The combination of LNB + OFA is capable of achieving a NOx emission rate of 0.15 lb/MMBtu. From Unit 1's baseline emissions of 0.33 lb/MMBtu, this is approximately 54.5% NOx removal efficiency. A removal efficiency of 61.5% can be expected for Unit 2, with a baseline NOx of 0.39 lb/MMBtu.

2.2.2. Flue Gas Recirculation (FGR)

NOx reduction efficiency data for coal-fired units with FGR are limited. The amount of NOx reduction achievable with FGR depends primarily on the fuel nitrogen content and amount of FGR used. Generally, FGR is more effective when used with low nitrogen content fuels such as natural gas and propane, since FGR is more effective in controlling thermal NOx rather than fuel NOx. Industry experience with FGR on coal-fired units for steam temperature control has shown very high maintenance on the gas recirculation fans due to erosion and corrosion. Many of the units with FGR for steam temperature control have removed the recirculation fans from service. The NOx control achievable on tangentially fired units like White Bluff – Units 1&2 with LNB+OFA has been comparable to that of FGR at lower capital and O&M cost. Currently, FGR technology is not offered by OEMs for coal-fired units. For these reasons, FGR is not a feasible technology for the White Bluff coal-fired units.

2.2.3. Neural Network

Neural Network (NN) systems are on-line enhancements to digital control systems (DCS) and plant information systems that improve boiler performance parameters such as heat rate, NOx emissions, and CO levels. The Neural Network model is based on historical data and parametric test data. The software applies an optimizing procedure to identify the best set points for the boiler, which are implemented without operator intervention (closed loop), or, at the plant's discretion, conveyed to the plant operators for implementation (open loop).

A Neural Network system is a technically feasible retrofit option for the White Bluff units. A NN is already installed for monitoring and controlling heat rate at White Bluff – Units 1&2. The reprogrammed

NN would be optimized first for minimizing NOx emissions and second for heat rate. It is possible that heat rate may increase as a result. Based on information available from vendors, it is expected that Neural Network technology on a coal-fired boiler can maintain the guaranteed performance of low NOx burners and potentially can achieve approximately 10% NOx reduction over a period of years, resulting in NOx emission rates of 0.30 lb/MMBtu, at max load for Unit 1, and of 0.35 lb/MMBtu for Unit 2. The cost for modifying the existing NNs at White Bluff is estimated to be approximately $250,000 per unit.

2.3. POST COMBUSTION CONTROLS

2.3.1. Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) involves the direct injection of ammonia (NH_3) or urea ($(CO(NH_2)_2)$) into the furnace at high flue gas temperatures (approximately 1600 ºF – 2000 ºF). The ammonia or urea reacts with NOx in the flue gas to produce N_2 and water as shown in the following equations:

$$(CO(NH_2)_2) + 2NO + \tfrac{1}{2}O_2 \rightarrow 2H_2O + CO_2 + 2N_2$$

$$2NH_3 + 2NO + \tfrac{1}{2}O_2 \rightarrow 2N_2 + 3H_2O$$

Flue gas temperature at the point of reactant injection can greatly affect NOx removal efficiencies and the quantity of NH_3 or urea that will pass through the furnace unreacted (referred to as NH_3 slip). In general, SNCR reactions are effective at a temperature range of 1600 ºF – 2000 ºF. At temperatures below the desired operating range, the NOx reduction reactions diminish and unreacted NH_3 emissions increase. Above the desired temperature range, NH_3 is oxidized to NOx resulting in low NOx reduction efficiencies.

Mixing of the reactant and flue gas within the reaction zone is also an important factor to SNCR performance. In large boilers, the physical distance over which reagent must be dispersed increases, and the surface area/volume ratio of the convective pass decreases. Both of these factors make it difficult to achieve good mixing of reagent and flue gas, delivery of reagent in the proper temperature window, and sufficient residence time of the reactant and flue gas in that temperature window.

The temperatures and residence times required for an SNCR system make it a feasible option for NOx reduction for White Bluff - Units 1 & 2. Based on vendor input, a unit with no additional controls and a baseline NOx of 0.33 lb/MMBtu could see a 26.5% NOx reduction, for an outlet rate of 0.24 lb/MMBtu on Unit 1. For Unit 2, with a baseline NOx of 0.39 lb/MMBtu could see a 26.5% reduction to an outlet rate of 0.29 lb/MMBtu.

SNCR systems can also be installed in conjunction with LNB + OFA controls. On these coupled systems, the starting NOx of approximately 0.15 lb/MMBtu can be reduced to 0.13 lb/MMBtu, for a total reduction (LNB + OFA + SNCR) of around 61% for Unit 1 and 67% for Unit 2. In addition to the SNCR equipment, the process requires additional demineralized water at a rate of 170 gpm. An additional water treatment system capable of providing the required flows is included in the capital cost. The cost of the SNCR equipment for the combination technology would be approximately 10% lower based on the lower starting NOx rate with LNB/OFA.

2.3.2. Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) involves injecting ammonia into boiler flue gas in the presence of a catalyst to reduce NOx to N_2 and water. The overall SCR reactions are:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$8NH_3 + 4NO_2 + 2O_2 \rightarrow 6N_2 + 12H_2O$$

The optimal temperature range depends on the type of catalyst used, but is typically between 560 °F and 800 °F to maximize NOx reduction efficiency and minimize ammonium sulfate formation. Below this range, ammonium sulfate is formed resulting in catalyst deactivation. Above the optimum temperature, the catalyst will sinter and thus deactivate rapidly. Another factor affecting SCR performance is the condition of the catalyst material. As the catalyst degrades over time or is damaged, NOx removal decreases which is typically compensated by increased ammonia slip.

SCR has been installed on many large coal-fired and some gas-fired boilers and is considered a feasible technology. Because of the expense of the reagent, SCR systems are usually installed on units with existing LNB + OFA systems, or the upgrades are done simultaneously. At White Bluff, an SCR+LNB/OFA system is capable of removing approximately 90% of NOx emissions on a continuous long-term basis. With a starting NOx of 0.33 lb/MMBtu (Unit 1) to 0.39 lb/MMBtu (Unit 2), an SCR can be expected to achieve permitted emissions compliance at 0.055 lb/MMBtu.

2.4. CAPITAL COSTS

Capital costs for the technically feasible control options for the White Bluff coal units are listed in Table 2.1. The cost of SCR on White Bluff – Unit 1 is higher than for White Bluff – Unit 2 because the ductwork arrangement is different and there is more total ductwork, support steel, and foundations for Unit 1.

Table 2.1: Expected NOx Emissions and Capital Costs, White Bluff Units 1 & 2

Technology	**Controlled NOx (lb/MMBTU)**		**Unit 1 Total Installed Capital Cost (2012$)**	**Unit 2 Total Installed Capital Cost (2012$)**
	Unit 1	Unit 2		
Baseline	0.33	0.39	NA	NA
LNB + OFA	0.15	0.15	7,804,000[1]	11,831,000
Neural Network	0.30	0.35	250,000[2]	250,000[2]
SNCR	0.24	0.29	9,372,000	9,372,000
SNCR (+ LNB/OFA)	0.13	0.13	16,290,000[1]	20,317,000
SCR (+ LNB/OFA)	0.055	0.055	202,601,000	178,240,000

1. LNB/OFA material already purchased for Unit 1. The total cost to Entergy would be the same for Unit 1 as shown for Unit 2.
2. The cost for modifying the existing neural networks on Units 1 & 2.

2.5. OPERATING AND MAINTENANCE COSTS

Annual Operating and Maintenance costs for each of the feasible technologies for White Bluff Units 1 & 2 are shown in Table 2.2. Costs were calculated assuming full load operation, and a capacity factor (C.F.) of 76%.

Table 2.2: Operating and Maintenance Costs, White Bluff – Units 1 & 2 (Based on a C.F. of 76%)

	Unit 1			**Unit 2**		
Technology	**Variable O&M[1] Costs (2012$)**	**Fixed O&M Costs (2012$)**	**Total O&M Costs (2012$)**	**Variable O&M[1] Costs (2012$)**	**Fixed O&M Costs (2012$)**	**Total O&M Costs (2012$)**
LNB + OFA	--	142,000	142,000	--	142,000	142,000
Neural Network	--	50,000	50,000	--	50,000	50,000
SNCR	5,658,000	169,000	5,827,000	6,671,000	169,000	6,840,000
SNCR (+ LNB/OFA)	4,538,000	311,000	4,849,000	4,542,000	311,000	4,853,000
SCR (+ LNB/OFA)	2,836,000	608,000	3,444,000	2,858,000	608,000	3,466,000

Note 1: Variable O&M includes fuel cost impacts.

Note 2: The current costs of ammonia and urea are highly volatile and may exceed the values used in this report.

3. WHITE BLUFF AUXILIARY BOILER

3.1. FUEL SWITCHING

The White Bluff auxiliary boiler is a B&W, single burner boiler, firing No. 2 diesel oil, rated at 140,000 lb/hr of steam. Fuel switching to natural gas or propane is not practical because the nearest natural gas pipeline is 20 miles from the site. The costs to convert the White Bluff aux boiler to either natural gas or propane would not be justified based on the low capacity factor.

3.2. COMBUSTION CONTROLS

3.2.1. Low NOx Burners + Over-Fire Air

For an auxiliary boiler such as the one at White Bluff, NOx reduction can be achieved with a combination of technologies. LNB + OFA for aux boilers achieve NOx reduction under the same principles as a coal boiler. By modifying temperatures and fuel-rich areas, less NOx is generated. LNB + OFA are feasible technologies for auxiliary boilers, and vendor data indicates that the White Bluff Aux Boiler could achieve 35% reduction with LNB + OFA, for a final emission of 0.11 lb/MMBtu. The baseline NOx emissions from the White Bluff aux boiler are calculated using US EPA's AP-42 emissions factors.

3.2.2. Flue Gas Recirculation

NOx reduction efficiency data for oil-fired units with FGR are limited. The amount of NOx reduction achievable with FGR depends primarily on the fuel nitrogen content and amount of FGR used. Generally, FGR is more effective when used with low nitrogen content fuels such as natural gas and propane, since FGR is more effective in controlling thermal NOx rather than fuel NOx. FGR is a feasible technology for the White Bluff auxiliary boiler. With a recirculation of 15% of the flue gas, the unit could expect to see 13% NOx removal, for an outlet of 0.149 lb/MMBtu.

3.2.3. Low NOx Burners + Over-fire Air + Flue Gas Recirculation

These three technologies are often installed simultaneously for greater NOx reduction. A vendor has proposed that for the White Bluff aux boiler, a combination of LNB + OFA + FGR will reduce the NOx from 0.171 lb/MMBtu to 0.100 lb/MMBtu when burning No. 2 Fuel Oil. This reduction of 42% will come from a new LNB and OFA system and the recirculation of 15% of the flue gas flow.

3.2.4. Neural Network

The White Bluff Auxiliary Boiler is not a candidate for a neural network (NN) because there are few controllable variables to be optimized. The aux boiler also uses a relatively new PLC control system.

3.3. POST COMBUSTION CONTROLS

3.3.1. Selective Non-Catalytic Reduction

SNCR control has proven to be difficult to apply to industrial boilers because of the temperature and mixing requirements, especially industrial boilers that modulate or cycle frequently. In order to effectively reduce NOx emissions, the reactant (ammonia or urea) must be injected into the flue gas within a specific flue gas temperature window, and must remain within that temperature window for a sufficient residence time. In industrial boilers that cycle frequently, the location of the specific exhaust gas temperature window is constantly changing. Thus, SNCR has not been effective on industrial boilers that have high turndown capabilities and modulate or cycle frequently. Based on the temperature and residence time requirements associated with effective NOx reduction, the planned use of the auxiliary boiler, and the limited availability of SNCR control systems for industrial boilers, it has been determined that SNCR is not technically feasible for the White Bluff auxiliary boiler.

3.3.2. Selective Catalytic Reduction

SCR for NOx control on auxiliary boilers is not common, because of their cycling operation, and the use of fuel oil. SCRs have critical operating temperature ranges, which are difficult to achieve and maintain in short periods of time. Because of the sulfur content of diesel oil, the SCR catalyst can become poisoned, resulting in a lower NOx removal efficiency. With this lower efficiency and high cost, an SCR is not considered a feasible technology.

3.4. CAPITAL COST ESTIMATES

Capital costs for the technically feasible control options for the White Bluff Auxiliary Boiler are listed in Table 3.1.

Table 3.1: Expected NOx Emissions and Capital Costs, White Bluff Units 1 & 2

Technology	Controlled NOx	Total Installed Capital Cost (2012$)
Baseline	0.171	--
LNB	0.111	255,000
OFA	0.137	231,000
FGR	0.149	366,000
LNB + OFA + FGR	0.100	852,000

3.5. OPERATING AND MAINTENANCE COST ESTIMATES

Annual Operating and Maintenance costs for each of the feasible technologies for White Bluff Units 1 & 2 are shown in Table 3.2. Costs were calculated assuming full load operation and a capacity factor (C.F.) of 10%.

Table 3.2: White Bluff Auxiliary Boiler Operating and Maintenance Costs (Based on a C.F. of 10%)

Technology	Variable O&M Costs (2012$)	Fixed O&M Costs (2012$)	Total O&M Costs (2012$)
LNB	4,000	4,000	8,000
OFA	5,000	4,000	9,000
FGR	0	7,000	7,000
LNB + OFA + FGR	9,000	15,000	24,000

4. LAKE CATHERINE - UNIT 4

4.1. FUEL SWITCHING

Lake Catherine - Unit 4 already combusts natural gas, which has the lowest NOx formation of potential fuels. Because fuel switching would not result in a lower NOx emission rate, it is not a feasible option for NOx control.

4.2. COMBUSTION CONTROLS

4.2.1. Burners-Out-Of-Service

Burners-Out-Of-Service (BOOS) allows operators to stop fuel flow to certain burners in the boiler (typically the top level of burners), while air flow is maintained. By removing fuel from the top row of burners, the combustion air becomes over-fire air and the production of thermal NOx is reduced. While the reduction of NOx can be significant, the tradeoff is a reduced generating capacity, if no further modifications to the firing system are made. BOOS is a feasible technology for Lake Catherine - Unit 4. Testing of BOOS at Lake Catherine by Entropy Technology & Environmental Consultants, Inc. (ETEC) with the top levels of burners out resulted in a maximum load of 405 MW, a 28% reduction in capacity, and NOx levels of 0.12 lb/MMBtu, a reduction of 55% from the baseline while using the existing burners.

Recovery of the lost unit capacity is possible by increasing the fuel fired in the three levels of burners that remain in service. The burners remaining in service would have to increase fuel throughput by 25%. The natural gas piping to each burner may also have to be increased in size for the higher fuel flow rates. ETEC, Inc. has experience with several units similar in design to Lake Catherine – Unit 4 that have been able to achieve full capacity by increasing the original “high” burner header pressure (BHP) to increase fuel flow to the burners (See Appendix D). The increase in BHP from 42 to 50 psig at Lake Catherine – Unit 4 would increase fuel flow by 25% and the burners would be operated “fuel rich”, lowering NOx formation. Using this approach would reduce NOx emissions at a small capital cost. The costs for BOOS with recovery of full unit capacity were based on vendor cost information for a previous project adjusted on a $/kW basis to Lake Catherine – Unit 4 and escalated to 2012. The cost provided does not include any modifications to the boiler. A boiler OEM or consultant would need to evaluate the existing fuel piping, superheat and reheat attemperation sprays, tube metal temperatures and burner tilt positions for the new operating conditions. The expected NOx reduction would range from 40% at low load to 50% at full load and NOx levels of 0.24 lb/MMBtu.

4.2.2. Low NOx Burners + Over-Fire Air

Low NOx Burners and Over-Fire Air for a gas-fired unit function similarly to coal-fired boilers, as discussed for White Bluff - Units 1 & 2. By controlling the temperature and stoichiometric profiles, the NOx produced as a result of thermal processes is reduced.

LNB + OFA are commonly installed on gas-fired units of this size, and are a feasible retrofit technology for Lake Catherine - Unit 4. With the installation of LNB + OFA, Lake Catherine could expect a 60% reduction in NOx, from 0.4825 lb/MMBtu to 0.19 lb/MMBtu.

4.2.3. Flue Gas Recirculation

Flue Gas Recirculation (FGR) reduces NOx by recirculating flue gas to the furnace. This recirculated gas has lower oxygen content than ambient air usually used for combustion. Lower oxygen and lower flame temperatures reduces thermal NOx formation. FGR can be installed on a unit in two ways. Traditional FGR installations require a new recirculation fan. Induced FGR, or IFGR, installs ductwork from the air preheater outlet to the suction of the existing forced draft fan. IFGR does not require a separate fan, but due to FD fan capacity restrictions, IFGR is not available at higher loads, because the forced draft fans were not designed for the higher air and gas flow rate.

FGR is technically feasible on Lake Catherine - Unit 4 and can result in reductions of 60%. For Unit 4, this would be equivalent to NOx emissions of 0.19 lb/MMBtu.

4.2.4. Water Injection

Water injection operates on similar principles to LNB + OFA and FGR. By injecting water into the furnace, the temperature of the flue gas is reduced, thereby reducing the amount of thermal NOx formed.

Water injection is a feasible technology for Lake Catherine - Unit 4, and can reduce NOx emissions by 9% at full load. Water injection is typically used as a trimming technology at high load. On Unit 4, the emissions would be lowered from the baseline of 0.4825 lb/MMBtu to 0.44 lb/MMBtu.

4.2.5. Neural Network

Lake Catherine – Unit 4 could also install a neural network (NN) but for the low capacity factor and current lack of NOx CEMS, a NN would not be practical. Several of the other technologies would provide greater NOx reductions.

4.3. POST COMBUSTION CONTROLS

4.3.1. Selective Non-Catalytic Reduction

Selective Non-Catalytic Reduction for gas-fired units operates under the same principles as SNCR for coal-fired units, with a few design changes. One of the keys of SNCR design is adequate chemical distribution at the right temperature for the reaction. Lake Catherine - Unit 4 has horizontal superheat platens, which requires multiple-nozzle lances to distribute the urea; the gas pattern does not provide adequate distribution. The reaction and temperature requirements are the same for gas-fired boilers as they are for coal-fired units.

SNCR has been installed on boilers such as Lake Catherine 4 and is considered a feasible technology, although the residence time in the desired temperature zone is lower for a gas-fired unit and the temperature window moves as unit load changes. The unit could expect to see reductions in NOx from the baseline of 0.4825 lb/MMBtu to 0.29 lb/MMBtu, or approximately 40% reduction at full load. In addition to the SNCR equipment, the process requires additional demineralized water at a rate of 85 gpm. An additional water treatment system capable of providing the required flows is included in the capital cost.

SNCR can be combined with LNB/OFA to achieve a combined NOx removal efficiency of 70% for an outlet emission of approximately 0.14 lb/MMBtu,

4.3.2. Selective Catalytic Reduction

Selective Catalytic Reduction units are similar for gas and coal-fired units. Ammonia or urea reagent reacts with NOx to form nitrogen and water, in the presence of a catalyst. Because gas boilers do not have particulate control or sulfur dioxide control, they typically have a shorter distance from the economizer outlet to the stack, which may result in long ductwork runs to and from the SCR.

SCR is a feasible technology for Lake Catherine - Unit 4. Combined with a LNB + OFA installation, which is typical of SCR installations, the unit could achieve a combined NOx removal efficiency of 94%, for a permitted outlet NOx of 0.03 lb/MMBtu at full load. This includes a margin for compliance as discussed in Section 1.4. Without the LNB + OFA installed, the SCR can also be designed to achieve 90% removal efficiency for an outlet emission of approximately 0.05 lb/MMBtu.

4.4. CAPITAL COST ESTIMATES

Capital costs for the technically feasible control options for Lake Catherine - Unit 4 are listed in Table 4.1.

Table 4.1: Expected NOx Emissions and Capital Costs, Lake Catherine Unit 4

Technology	Controlled NOx (lb/MMBtu)	Total Installed Capital Cost (2012$)
Baseline	0.4825[(1)]	--
BOOS (at full capacity)	0.24	893,000
LNB / OFA	0.19	8,762,000
IFGR (below 500 MW)	0.39	2,166,000
FGR	0.19	11,489,000
Water Injection	0.44	2,177,000
SNCR	0.29	15,507,000
SNCR (+ LNB/OFA)	0.14	24,269,000
SCR	0.05	59,587,000
SCR (+ LNB/OFA)	0.03	68,349,000

Note 1: The baseline NOx rate is the maximum daily emission rate from the 2001-2003 baseline period.

4.5. OPERATING AND MAINTENANCE COST ESTIMATES

Annual Operating and Maintenance costs for each of the feasible technologies for Lake Catherine - Unit 4 are shown in Table 4.2. Costs were calculated assuming full load operation, and a capacity factor (C.F. of 10%).

Table 4.2: Annual Operating and Maintenance Costs, Lake Catherine Unit 4 (Based on C.F. of 10%)

Technology	Variable O&M[1,2] Costs (2012$)	Fixed O&M Costs (2012$)	Total O&M Costs (2012$)
BOOS	--	21,000	21,000
LNB + OFA	--	210,000	210,000
IFGR	--	52,000	52,000
FGR	142,000	207,000	349,000
Water Injection	486,000	52,000	538,000
SNCR	1,640,000	279,000	1,919,000
SNCR (+ LNB/OFA)	462,000	489,000	951,000
SCR	254,000	358,000	612,000
SCR (+ LNB/OFA)	268,000	568,000	836,000

Note 1: Variable O&M includes fuel cost impacts.

Note 2: The current costs of ammonia and urea are highly volatile and may exceed the values used in this report.

APPENDIX A: CAPITAL COST ESTIMATE

1. BASIS OF ESTIMATES

2. CONCEPTUAL COST ESTIMATE SUMMARY SHEETS

Basis of Estimate

Estimates:
31813A – Lake Catherine, Unit 4 - Low NOx Burners and Over Fired Air
31814A – Lake Catherine, Unit 4 - SCR
31815A – Lake Catherine, Unit 4 - SNCR
31816A – White Bluff, Unit 1 - Low NOx Burners and Over Fired Air
31817A – White Bluff, Unit 1 – SCR
31818A – White Bluff, Unit 2 – SCR
31819A – White Bluff, Units 1 and 2 – SNCR
31820A – White Bluff, Auxiliary Boiler – Low NOx Burners, Over Fired Air, and Flue Gas Recirculation
31832A – White Bluff, Unit 2 - Low NOx Burners and Over Fired Air

General Information

Project Type – Compliance study for Lake Catherine Unit 4 and White Bluff Station Units 1&2.
Type of estimates – Conceptual Cost Estimate for the SCR Case and Order of Magnitude Cost Estimates for all other cases.
Project location – White Bluff: Close to Pine Bluff, Arkansas; Lake Catherine: Close to Mahern, AR
MW rating: White Bluff Unit 1: 815 MW, Unit 2: 844 MW; Lake Catherine Unit 4: 558 MW
Unique site issues – Existing Site.
Contracting strategy – Multiple Lump Sum.

The major components of the capital cost consist of equipment, field materials and supplies, direct labor, indirect field labor, and indirect construction costs. The capital cost was determined through the process of estimating the cost of equipment, components and bulk quantity.

The cost estimates are based largely on Sargent & Lundy LLC experience on similar projects. Detailed engineering has not been performed to firm up the project details, and specific site characteristics have not been fully analyzed. We have attempted to assign allowances where necessary to cover issues that are likely to arise but are not clearly quantified at this time.

Estimate Development

The cost estimates for the Low NOx Burners/Over Fired Air cases were based on a previous estimate prepared in 2011. Equipment costs were escalated to current pricing level. Also, material and labor have been updated to 2012 pricing.
Cost estimates for the SNCR technology (two cases) were based on budgetary quotes received from engineering and on previous estimates.
The cost estimates for the White Bluff SCR was mainly based on similar size and scope cost estimates from other projects and structural takeoffs from engineering. All equipment common to both Units was divided evenly between the two estimates.
The cost estimate for Lake Catherine SCR was adjusted from another cost estimate for a gas fired power station. White Bluff's auxiliary boiler cost estimate for Low NOx Burners/Over Fired Air/Flue Gas Recirculation was also adjusted from a similar project.

Pricing and Quantities

The data used to develop these estimates is based on using material and equipment types and sizes typically used in a power plant.
Equipment and material costs were estimated on the basis of S&L in house data, vendor catalogs, industry publications and other related projects. In most cases, the costs for bulk materials and equipment were derived from recent vendor or manufacturer's quote for similar items on other projects. Where actual or specific information regarding equipment specifications was available, that information was used to size and quantify material and equipment requirements. Where information was not furnished or was not adequate, requirements were assumed and estimated based on information available from project estimates of similar type and size.

Quantities contained herein are intended to be reasonable and representative of projects of this type. All quantity data was developed internally by S&L. Quantities were developed based on project experience of a plant of comparable size and then adjusted based on actual size and capacity differences and also taking into consideration the specific site layout based on the general arrangement drawing. While project specifics will certainly have an impact on these quantities, we feel they are appropriate for a study at this level.

Labor Wage Rates

Labor Profile – Union

Labor wage rate selected for the estimate - 2012 Union rates for Pine Bluff, Arkansas. Base craft rates are as published in RS Means Labor Rates for the Construction Industry, 2012 Edition. The craft rates are then incorporated into work crews appropriate for the activities by adding allowances for small tools, construction equipment, insurance, and site overheads to arrive at crew rates detailed in the cost estimate. A 1.15 regional labor productivity multiplier is included based on the Compass International Global Construction Yearbook.

Labor Work Schedule and Incentives - Assumed 5x10 work week for regular work and 7x10 work week for outage work. 10% of the work is assumed to be outage related.

Project Direct & Construction Indirect Costs

The estimate is constructed in such a manner where most of the direct construction costs are determined directly and several direct construction cost accounts are determined indirectly by taking a percentage of the directly determined costs and are identified as "Variable Accounts". These percentages are based on our experience with similar type and size projects. Sales tax is specific to location. Listed below are the variable accounts.

- Cost of overtime – 5-10's Hour Days and Outage Work at a 7-10 Schedule
- Subsistence (per diem) – not included
- Consumables – 0.5% of material and labor
- Freight on Equipment - included with equipment cost
- Freight on Material @ 5% of material
- Spare Parts – included with equipment costs
- Contractors G&A Expense @ 10%
- Contractors Profit @ 5%

Project Indirect Costs

Included are the following:

- Engineering, Procurement & Project Services varied depending on the size of the project estimated.
    - 31813A @ 19% of construction cost
    - 31814A @ 8% of construction cost
    - 31815A @ 8% of construction cost
    - 31816A @ 16% of construction cost
    - 31817A @ 6% of construction cost
    - 31818A @ 6% of construction cost
    - 31819A @ 8% of construction cost
    - 31820A @ 12% of construction cost
    - 31832A @ 16% of construction cost
- Construction Management varied depending on the size of the project estimated.
    - 31813A @ 6% of construction cost
    - 31814A @ 3% of construction cost
    - 31815A @ 2% of construction cost
    - 31816A @ 6% of construction cost
    - 31817A @ 2% of construction cost

  - 31818A @ 2% of construction cost
  - 31819A @ 2% of construction cost
  - 31820A @ 0% of construction cost
  - 31832A @ 6% of construction cost
- Craft start-up and commission support @ 1% of construction cost
- General Owner's Costs, including Owners Engineering & Bond Fees – not included
- EPC Fee – not included

These percentages are based on our experience with similar type and size projects.

Escalation

Not included.

Contingency

The contingency rates vary for each project based on the project's size. The rates are based on past history of similar projects. This rate relates to pricing and quantity variation in the specific scope estimated. The contingency does not cover new scope outside of what has been estimated, only the variation in the defined scope. This is a composite rate and already takes into account the plus and minuses of expected actual costs. The rate does not represent the high range of all costs, nor is it expected that the project will experience all actual costs be realized at the maximum value of their range of variation.

Exclusions

There are items that have been specifically excluded from the estimate. In order to establish the overall project costs, the following items must also be accounted for. This list is for information only and is not intended to be all inclusive.

- Permitting costs
- Rock excavation
- Remediation of soil for hazardous materials
- Power outage cost during construction

Assumptions

- No rock excavation, no dewatering
- Assumed that asbestos removal or lead paint abatement will not be required.
- No obstruction for the ammonia pipe routing. 6" clearing & grubbing of existing terrain is included, no tree removal.
- Directional boring underneath the existing railroad tracks is included, but with no major interferences or obstructions.
- Electrical equipment and wiring installation is based on non-hazardous location.
- Adjustments for plant unit size were made based on good engineering practice. Actual design and quantities may be significantly different than the quantities shown in the estimates.

Estimate Totals

Description	Amount	Totals	
Labor	331,677		
Material	125,263		
Subcontract	2,850,000		
Equipment			
Other	2,000,000		
	5,306,940	5,306,940	USD
91-1 Scaffolding	46,000		
91-2 OT Working 5-10 Hour Days	41,000		
91-3 OT Working 7-10 Hr Days			
91-4 Per Diem			
91-5 Consumables	2,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	6,000		
91-9 Freight on Process Equip.	100,000		
91-10 Sales Tax			
91-11 Contractor's G&A Expense	65,000		
91-12 Contractor's Profit	32,000		
	292,000	5,598,940	USD
93-1 EP&P Services	1,064,000		
93-2 CM Support	168,000		
93-3 Start-Up/Commissioning	56,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	1,288,000	6,886,940	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	50,000		
94-4 Contingency on Labor	145,000		
94-5 Contingency on Sub.	713,000		
94-6 Contingency on Equipment	525,000		
94-7 Contingency on Indirect	386,000		
	1,819,000	8,705,940	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		8,705,940	USD
98 - Interest During Constr			
		8,705,940	USD
Total		8,705,940	USD

Estimate Totals

Description	Amount	Totals	
Labor	19,780,000		
Material	15,815,652		
Subcontract	2,590,000		
Equipment			
Other	8,290,000		
	46,475,652	46,475,652	USD
91-1 Scaffolding			
91-2 OT Working 5-10 Hour Days			
91-3 OT Working 7-10 Hr Days			
91-4 Per Diem			
91-5 Consumables			
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material			
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense			
91-12 Contractor's Profit			
		46,475,652	USD
93-1 EP&P Services	3,718,100		
93-2 CM Support	1,394,300		
93-3 Start-Up/Commissioning	464,800		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	5,577,200	52,052,852	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	2,372,400		
94-4 Contingency on Labor	2,967,000		
94-5 Contingency on Sub.	388,500		
94-6 Contingency on Equipment	1,243,500		
94-7 Contingency on Indirect	836,600		
	7,808,000	59,860,852	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		59,860,852	USD
98 - Interest During Constr			
		59,860,852	USD
Total		59,860,852	USD

Estimate Totals

Description	Amount	Totals	
Labor	2,629,958		
Material	1,083,165		
Subcontract	80,600		
Equipment			
Other	6,193,056		
	9,986,779	9,986,779	USD
91-1 Scaffolding	445,600		
91-2 OT Working 5-10 Hour Days	311,700		
91-3 OT Working 7-10 Hr Days	99,200		
91-4 Per Diem			
91-5 Consumables	18,600		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	54,200		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	458,800		
91-12 Contractor's Profit	229,500		
	1,617,600	11,604,379	USD
93-1 EP&P Services	928,400		
93-2 CM Support	232,100		
93-3 Start-Up/Commissioning	116,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	1,276,500	12,880,879	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	390,000		
94-4 Contingency on Labor	1,209,300		
94-5 Contingency on Sub.	24,200		
94-6 Contingency on Equipment	619,300		
94-7 Contingency on Indirect	383,000		
	2,625,800	15,506,679	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		15,506,679	USD
98 - Interest During Constr			
		15,506,679	USD
Total		15,506,679	USD

Estimate Totals

Description	Amount	Totals	
Labor	653,648		
Material	306,347		
Subcontract	3,700,000		
Equipment			
Other			
	4,659,995	4,659,995	USD
91-1 Scaffolding	48,000		
91-2 OT Working 5-10 Hour Days	77,000		
91-3 OT Working 7-10 Hr Days	24,000		
91-4 Per Diem			
91-5 Consumables	5,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	15,000		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	112,000		
91-12 Contractor's Profit	55,000		
	336,000	4,995,995	USD
93-1 EP&P Services	799,000		
93-2 CM Support	300,000		
93-3 Start-Up/Commissioning	50,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	1,149,000	6,144,995	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	110,000		
94-4 Contingency on Labor	279,000		
94-5 Contingency on Sub.	925,000		
94-6 Contingency on Equipment			
94-7 Contingency on Indirect	345,000		
	1,659,000	7,803,995	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		7,803,995	USD
98 - Interest During Constr			
		7,803,995	USD
Total		7,803,995	USD

Estimate Totals

Description	Amount	Totals	
Labor	2,255,791		
Material	1,089,242		
Subcontract	68,100		
Equipment			
Other	1,948,100		
	5,361,233	5,361,233	USD
91-1 Scaffolding	368,000		
91-2 OT Working 5-10 Hour Days	267,300		
91-3 OT Working 7-10 Hr Days	85,100		
91-4 Per Diem			
91-5 Consumables	16,700		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	54,500		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	408,200		
91-12 Contractor's Profit	204,100		
	1,403,900	6,765,133	USD
93-1 EP&P Services	541,200		
93-2 CM Support	135,300		
93-3 Start-Up/Commissioning	67,700		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	744,200	7,509,333	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	392,100		
94-4 Contingency on Labor	1,032,500		
94-5 Contingency on Sub.	20,400		
94-6 Contingency on Equipment	194,800		
94-7 Contingency on Indirect	223,300		
	1,863,100	9,372,433	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		9,372,433	USD
98 - Interest During Constr			
		9,372,433	USD
Total		9,372,433	USD

Estimate Totals

Description	Amount	Totals	
Labor	56,778,212		
Material	34,013,262		
Subcontract	8,156,000		
Equipment			
Other	21,324,260		
	120,271,734	120,271,734	USD
91-1 Scaffolding	2,270,000		
91-2 OT Working 5-10 Hour Days	6,730,000		
91-3 OT Working 7-10 Hr Days	2,142,000		
91-4 Per Diem			
91-5 Consumables	454,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	1,701,000		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	10,238,000		
91-12 Contractor's Profit	5,120,000		
	28,655,000	148,926,734	USD
93-1 EP&P Services	8,936,000		
93-2 CM Support	2,979,000		
93-3 Start-Up/Commissioning	1,489,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	13,404,000	162,330,734	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	8,163,000		
94-4 Contingency on Labor	15,726,000		
94-5 Contingency on Sub.	1,631,000		
94-6 Contingency on Equipment	4,265,000		
94-7 Contingency on Indirect	2,681,000		
	32,466,000	194,796,734	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		194,796,734	USD
98 - Interest During Constr			
		194,796,734	USD
Total		194,796,734	USD

Estimate Totals

Description	Amount	Totals	
Labor	653,648		
Material	306,347		
Subcontract	3,700,000		
Equipment			
Other	2,600,000		
	7,259,995	7,259,995	USD
91-1 Scaffolding	48,000		
91-2 OT Working 5-10 Hour Days	77,000		
91-3 OT Working 7-10 Hr Days	24,000		
91-4 Per Diem			
91-5 Consumables	5,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	15,000		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	112,000		
91-12 Contractor's Profit	55,000		
	336,000	7,595,995	USD
93-1 EP&P Services	1,215,000		
93-2 CM Support	456,000		
93-3 Start-Up/Commissioning	76,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	1,747,000	9,342,995	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	110,000		
94-4 Contingency on Labor	279,000		
94-5 Contingency on Sub.	925,000		
94-6 Contingency on Equipment	650,000		
94-7 Contingency on Indirect	524,000		
	2,488,000	11,830,995	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		11,830,995	USD
98 - Interest During Constr			
		11,830,995	USD
Total		11,830,995	USD

Estimate Totals

Description	Amount	Totals	
Labor	2,255,791		
Material	1,089,242		
Subcontract	68,100		
Equipment			
Other	1,948,100		
	5,361,233	5,361,233	USD
91-1 Scaffolding	368,000		
91-2 OT Working 5-10 Hour Days	267,300		
91-3 OT Working 7-10 Hr Days	85,100		
91-4 Per Diem			
91-5 Consumables	16,700		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	54,500		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	408,200		
91-12 Contractor's Profit	204,100		
	1,403,900	6,765,133	USD
93-1 EP&P Services	541,200		
93-2 CM Support	135,300		
93-3 Start-Up/Commissioning	67,700		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	744,200	7,509,333	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	392,100		
94-4 Contingency on Labor	1,032,500		
94-5 Contingency on Sub.	20,400		
94-6 Contingency on Equipment	194,800		
94-7 Contingency on Indirect	223,300		
	1,863,100	9,372,433	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		9,372,433	USD
98 - Interest During Constr			
		9,372,433	USD
Total		9,372,433	USD

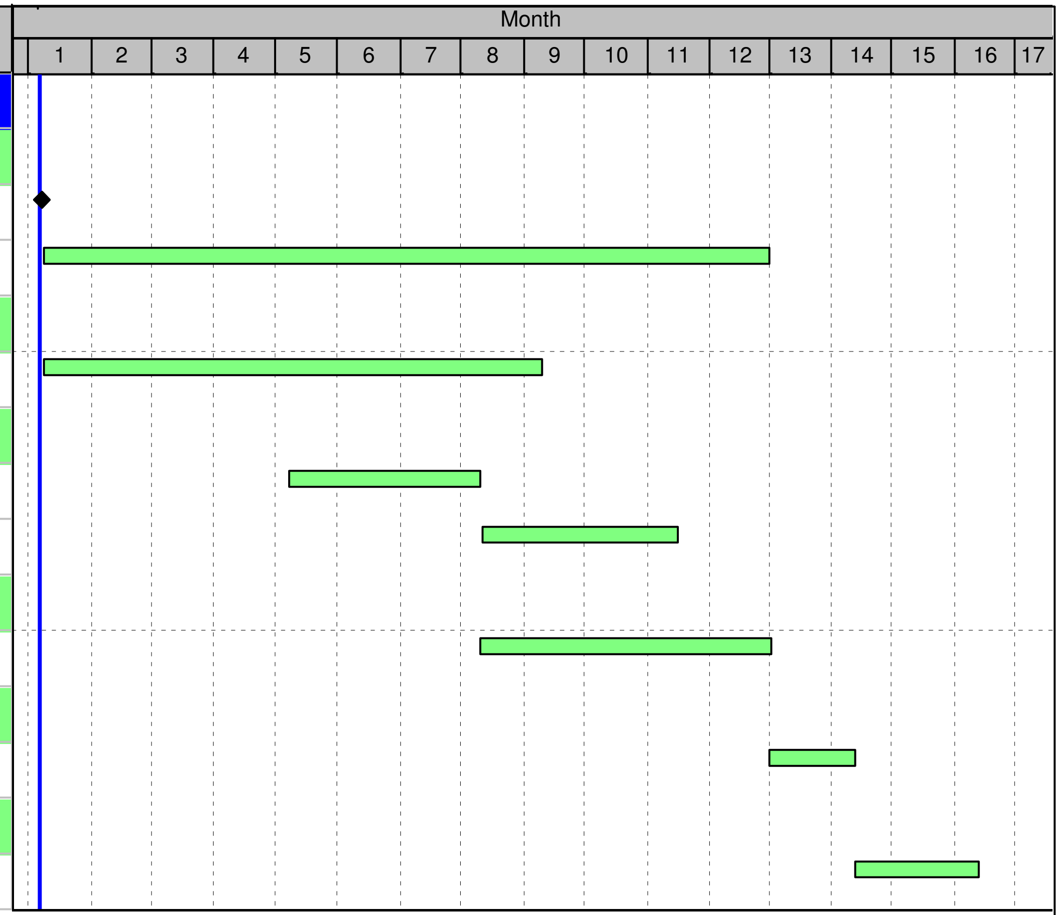
Estimate Totals

Description	Amount	Totals	
Labor	48,597,255		
Material	26,751,692		
Subcontract	6,577,640		
Equipment			
Other	21,324,260		
	103,250,847	103,250,847	USD
91-1 Scaffolding	1,884,000		
91-2 OT Working 5-10 Hour Days	5,759,000		
91-3 OT Working 7-10 Hr Days	1,834,000		
91-4 Per Diem			
91-5 Consumables	377,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	1,338,000		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	8,520,000		
91-12 Contractor's Profit	4,261,000		
	23,973,000	127,223,847	USD
93-1 EP&P Services	7,633,000		
93-2 CM Support	2,544,000		
93-3 Start-Up/Commissioning	1,272,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	11,449,000	138,672,847	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	6,421,000		
94-4 Contingency on Labor	13,444,000		
94-5 Contingency on Sub.	1,316,000		
94-6 Contingency on Equipment	4,265,000		
94-7 Contingency on Indirect	2,290,000		
	27,736,000	166,408,847	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		166,408,847	USD
98 - Interest During Constr			
		166,408,847	USD
Total		166,408,847	USD

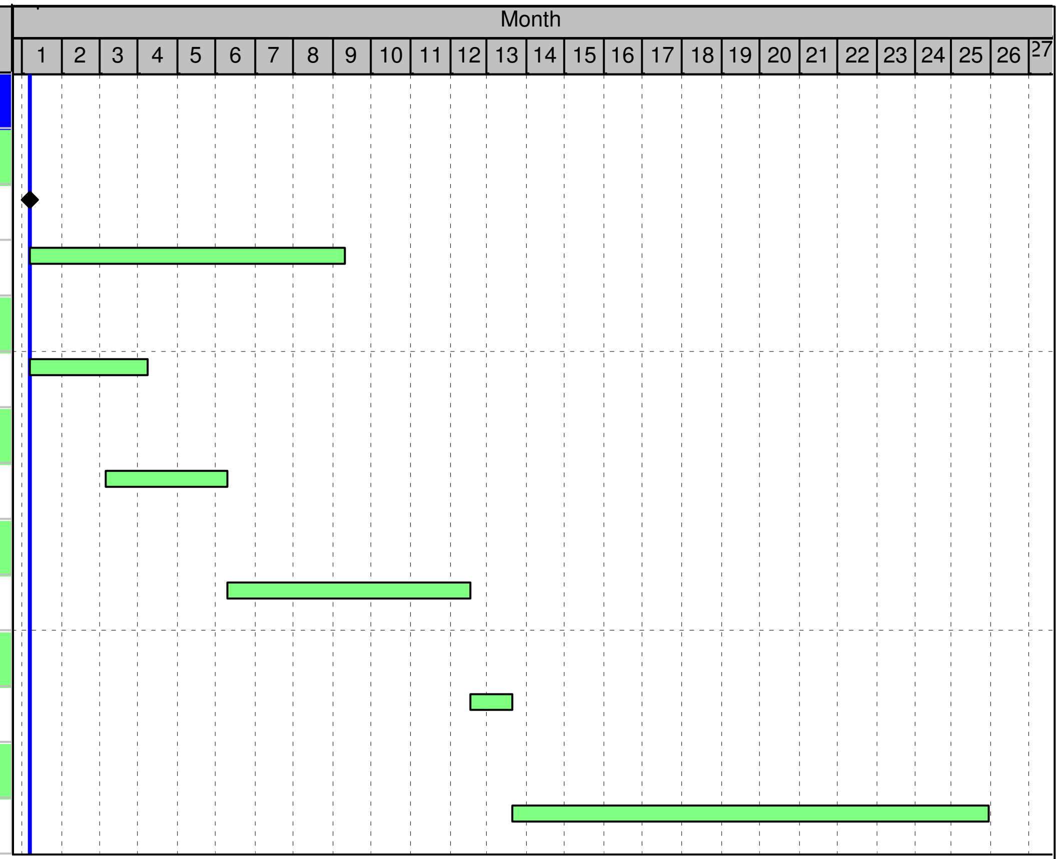
APPENDIX B

1. ESTIMATED PROJECT SCHEDULES

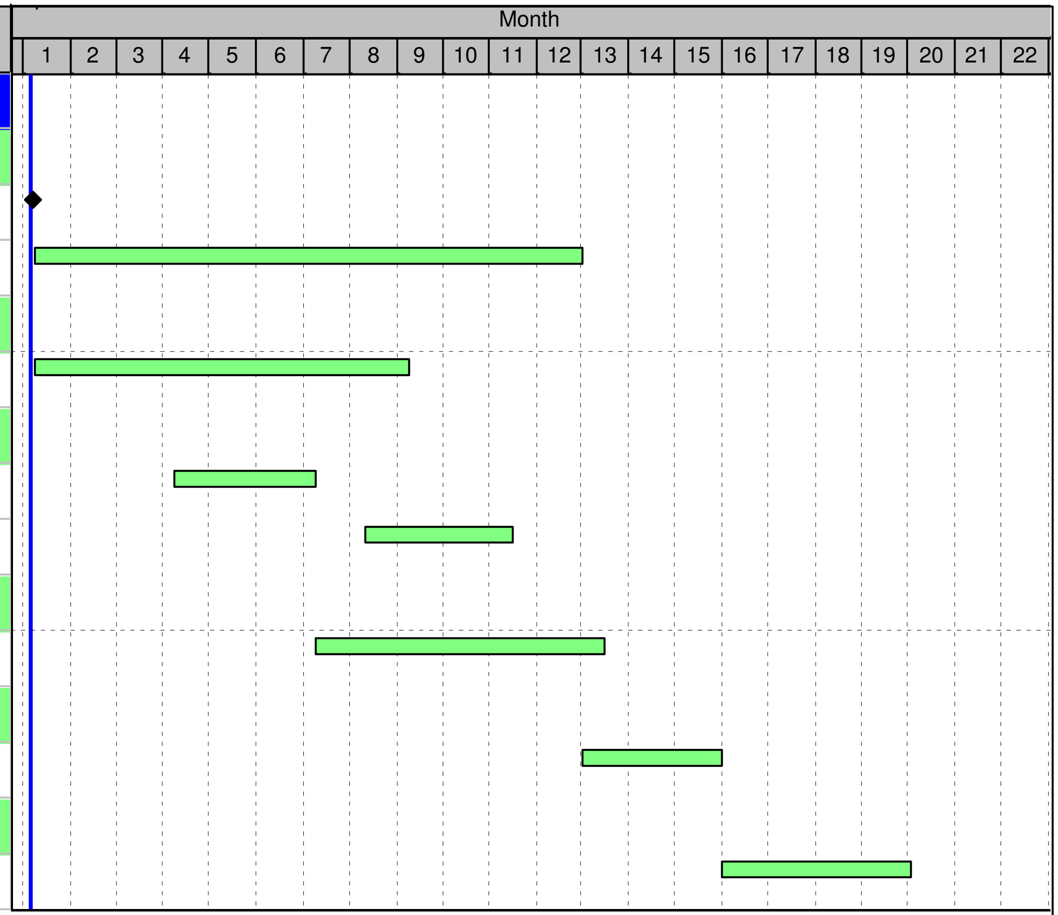
Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Aux Boiler (LNB/OFA/F...	15m
	Permitting	12m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	12m
	Engineering	8m
A1020	Engineering	8m
	Procurement of Major Equipment	6m
A1030	LNB/OFA Spec - Prep/Bid/Eval/Award	3m
A1070	GWC Spec - Prep/Bid/Eval/Award	3m
	Vendor Engineering/Fab/Delivery	5m
A1040	LNB/OFA Vendor Engineering/Fabrication/Delivery	5m
	Installation	1m
A1050	Installation	1m
	Commissioning & Start-Up	2m
A1060	Commissioning & Start-Up	2m



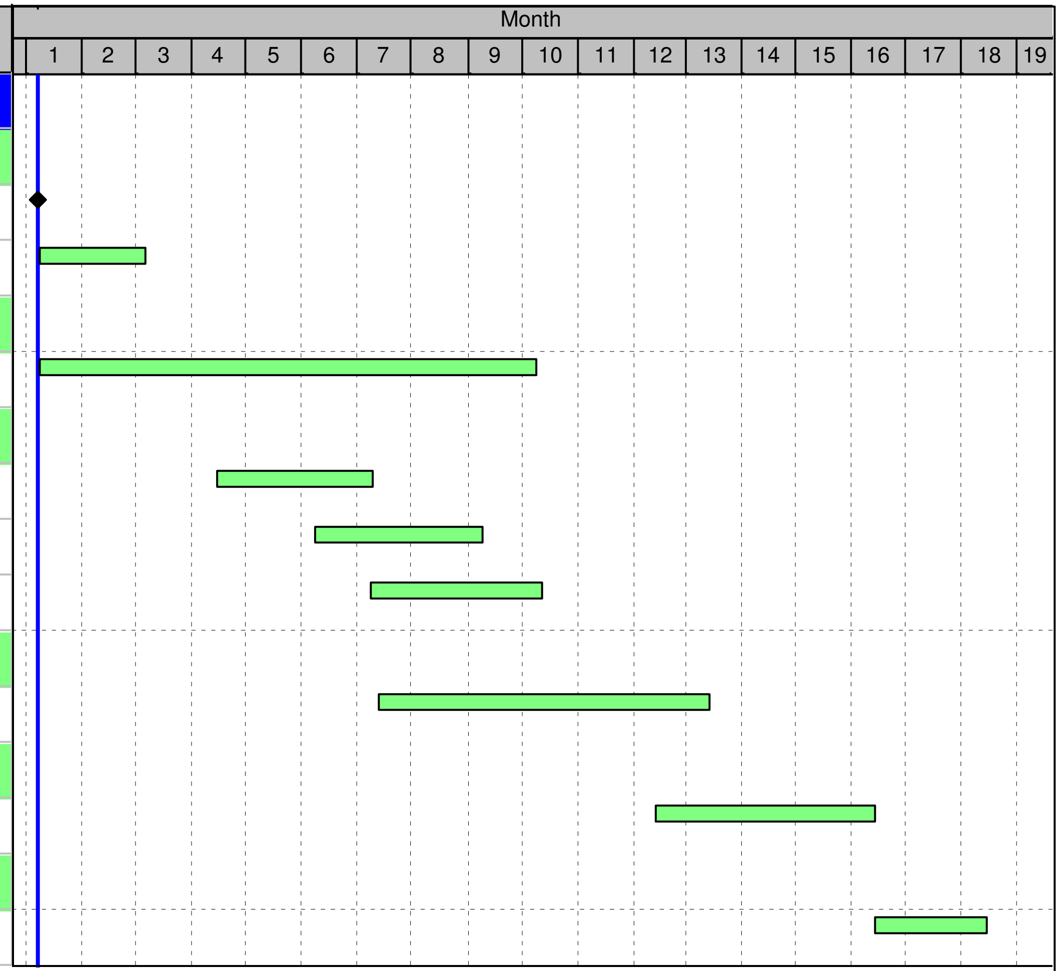
Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Neural Network	24m
	Permitting	8m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	8m
	Engineering	3m
A1020	Engineering	3m
	Procurement of Major Equipment	3m
A1030	Neural Network Spec - Prep/Bid/Eval/Award	3m
	Vendor Engineering/Fab/Delivery	6m
A1040	NN Vendor Engineering/Fabrication/Delivery	6m
	Installation	1m
A1050	Installation	1m
	Commissioning & Start-Up	12m
A1060	Commissioning & Start-Up	12m



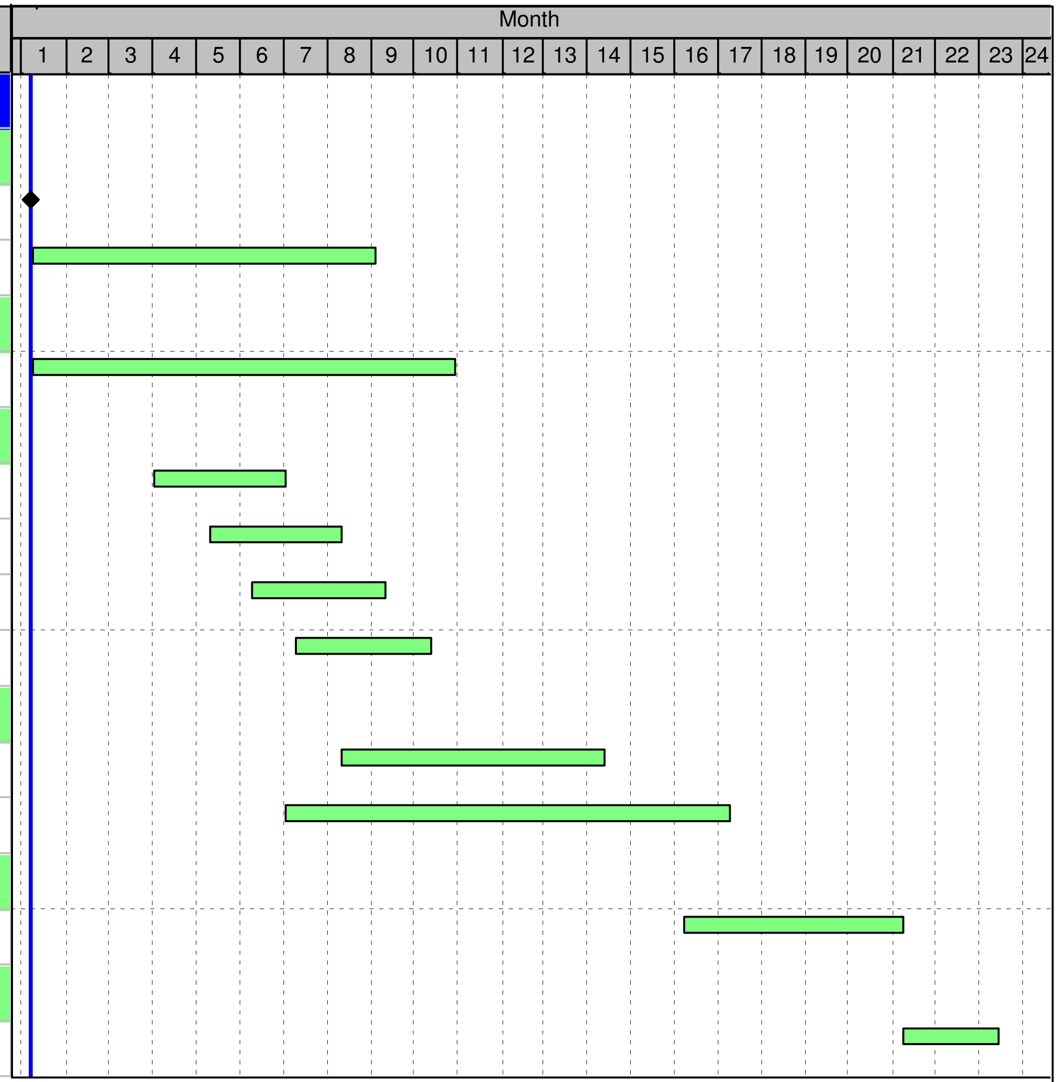
Activity ID	Activity Name	Org Dur (months)
Entergy - NOx Strategy Study - Low NOx Burners/Over ...		19m
Permitting		12m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	12m
Engineering		8m
A1020	Engineering	8m
Procurement of Major Equipment		7m
A1030	LNB/OFA Spec - Prep/Bid/Eval/Award	3m
A1070	GWC Spec - Prep/Bid/Eval/Award	3m
Vendor Engineering/Fab/Delivery		6m
A1040	LNB/OFA Vendor Engineering/Fabrication/Delivery	6m
Installation		3m
A1050	Installation	3m
Commissioning & Start-Up		4m
A1060	Commissioning & Start-Up	4m



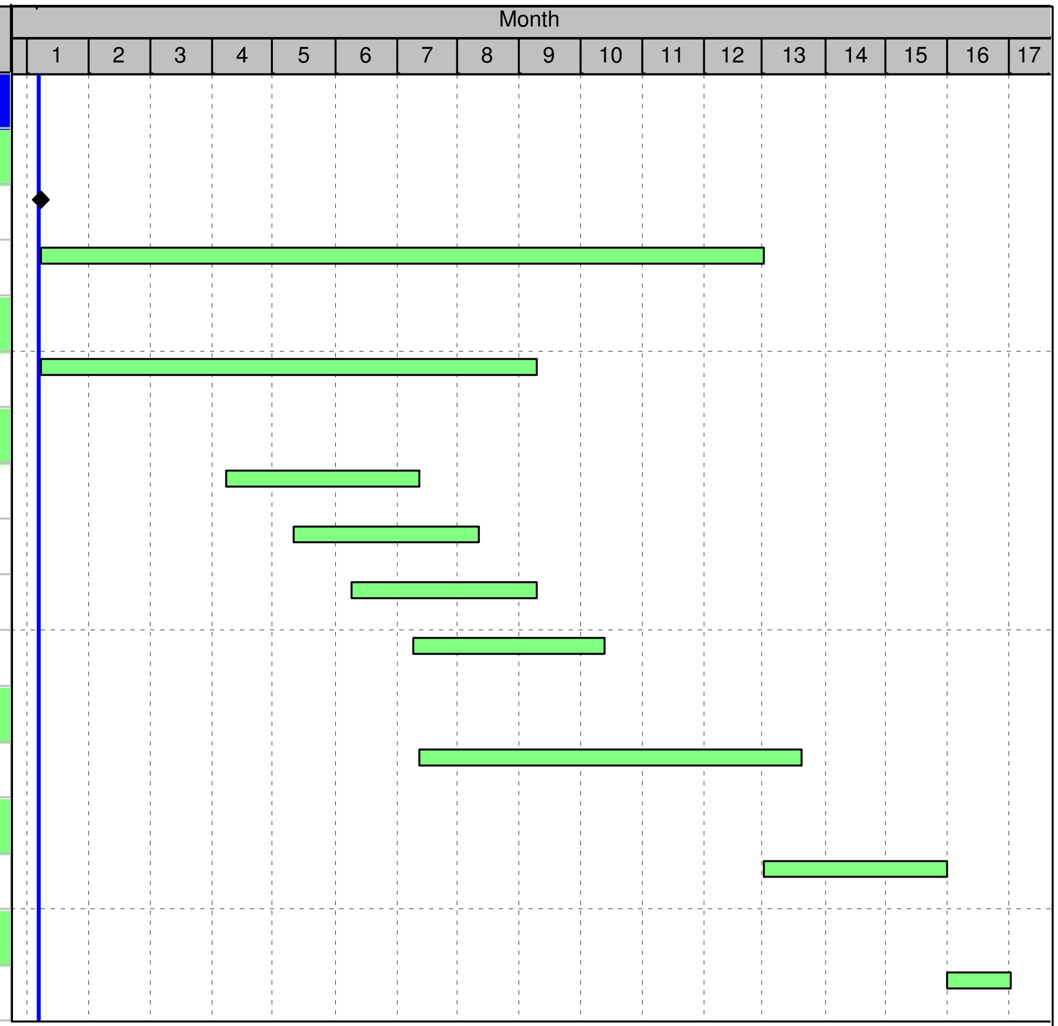
.	Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Induced Flue Gas Recir...		17m
	Permitting		2m
	A1000	Project Authorization	0m
	A1010	Air Permit - Prepare/Review/Approve	2m
	Engineering		9m
	A1020	BOP Engineering	9m
	Procurement of Major Equipment		6m
	A1140	FGR Duct Procurement Spec - Prep/Bid/Eval/Award	3m
	A1030	Mech Install Spec - Prep/Bid/Eval/Award	3m
	A1120	Elec Install Spec - Prep/Bid/Eval/Award	3m
	Vendor Engineering/Fab/Delivery		6m
	A1040	FGR Duct Vendor Engineering/Fabrication/Delivery	6m
	Installation		4m
	A1050	Installation	4m
	Commissioning & Start-Up		2m
	A1060	Commissioning & Start-Up	2m



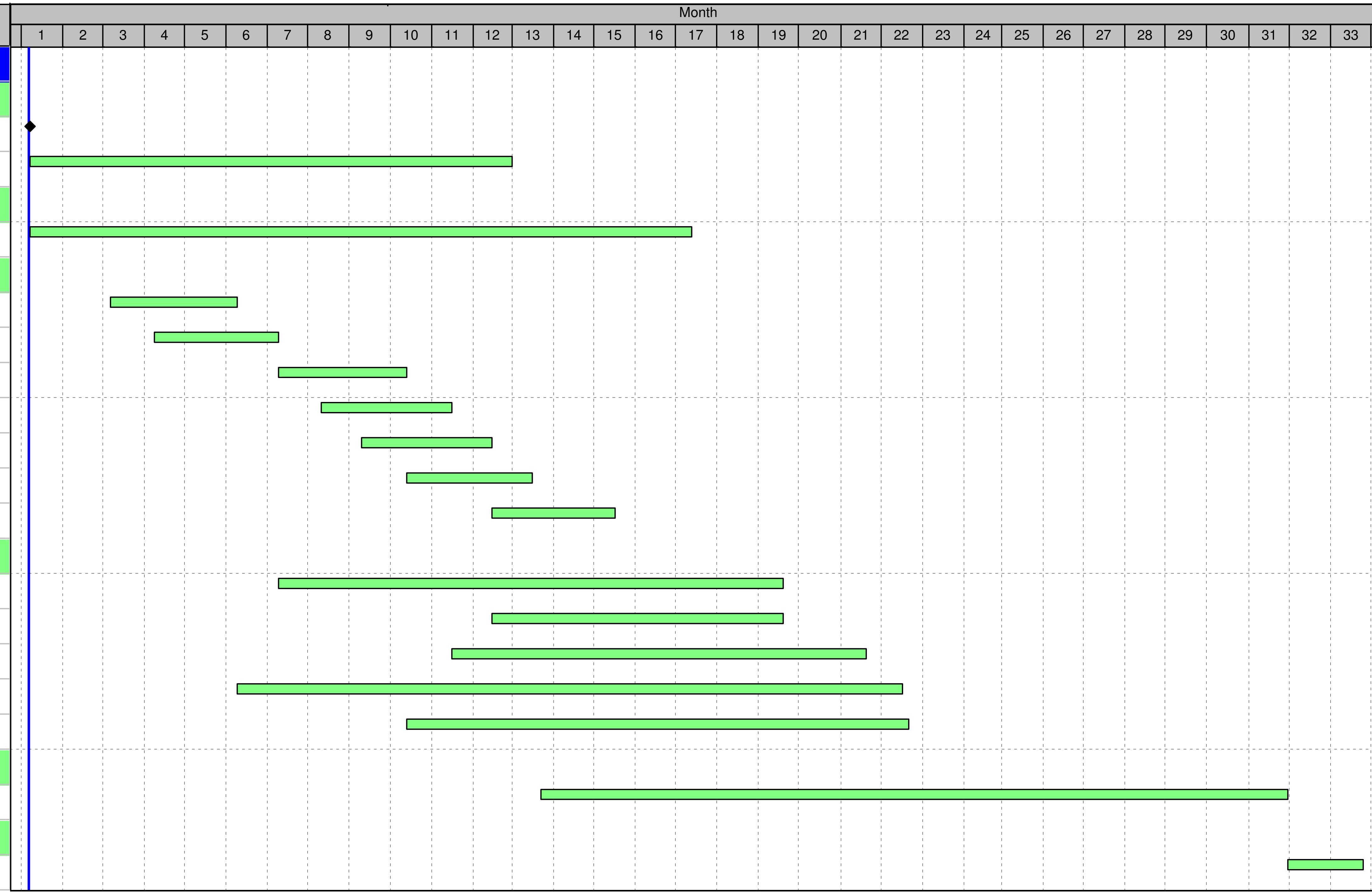
Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Flue Gas Recirculation ...	22m
	Permitting	8m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	8m
	Engineering	10m
A1020	BOP Engineering	10m
	Procurement of Major Equipment	6m
A1150	FGR Fan Procurement Spec - Prep/Bid/Eval/Award	3m
A1140	FGR Duct Procurement Spec - Prep/Bid/Eval/Award	3m
A1030	Mech Install Spec - Prep/Bid/Eval/Award	3m
A1120	Elec Install Spec - Prep/Bid/Eval/Award	3m
	Vendor Engineering/Fab/Delivery	10m
A1040	FGR Duct Vendor Engineering/Fabrication/Delivery	6m
A1160	FGR Fan Vendor Engineering/Fabrication/Delivery	10m
	Installation	5m
A1050	Installation	5m
	Commissioning & Start-Up	2m
A1060	Commissioning & Start-Up	2m



Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Selective Non-Catalytic ...	16m
	Permitting	12m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	12m
	Engineering	8m
A1020	BOP Engineering	8m
	Procurement of Major Equipment	6m
A1030	SNCR Spec - Prep/Bid/Eval/Award	3m
A1070	Civil/Structural Installation Spec - Prep/Bid/Eval/Award	3m
A1080	Mech Installation Spec - Prep/Bid/Eval/Award	3m
A1090	Elec/I&C Installation Spec - Prep/Bid/Eval/Award	3m
	Vendor Engineering/Fab/Delivery	6m
A1040	SNCR Vendor Engineering/Fabrication/Delivery	6m
	Installation	3m
A1050	Installation	3m
	Commissioning & Start-Up	1m
A1060	Commissioning & Start-Up	1m



Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Selective Catalytic Red...	32m
	Permitting	12m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	12m
	Engineering	16m
A1020	BOP Engineering	16m
	Procurement of Major Equipment	12m
A1140	Ammonia Injection System Procurement Spec - Prep/Bid/Eval/Award	3m
A1150	Catalyst Procurement Spec - Prep/Bid/Eval/Award	3m
A1170	Fan Spec - Prep/Bid/Eval/Award	3m
A1190	Ductwork Spec - Prep/Bid/Eval/Award	3m
A1130	Structural Steel Spec - Prep/Bid/Eval/Award	3m
A1030	Mech Install Spec - Prep/Bid/Eval/Award	3m
A1120	Elec Install Spec - Prep/Bid/Eval/Award	3m
	Vendor Engineering/Fab/Delivery	16m
A1160	Catalyst Vendor Engineering/Fabrication/Delivery	12m
A1210	Structural Steel Vendor Engineering/Fabrication/Delivery	7m
A1200	Ductwork Vendor Engineering/Fabrication/Delivery	10m
A1040	Ammonia Injection System Vendor Engineering/Fabrication/Delivery	16m
A1180	Fan Vendor Engineering/Fabrication/Delivery	12m
	Installation	18m
A1050	Installation	18m
	Commissioning & Start-Up	2m
A1060	Commissioning & Start-Up	2m



APPENDIX C

1. OPERATING AND MAINTENANCE COST ESTIMATES

NO_X Compliance Costs

Unit Name White Bluff 1

Unit Data		Reagent Costs	
Size (Gross kW)	815,000	Aq.Ammonia $/t	$700
Average NOx Emission Rate (lb/MMBtu at full load)	**0.33**	An.Ammonia $/t	$400
Nominal Max. Boiler Heat Input (mmBtu/hr)	8,950.0	Urea $/t	$350
Avg. Heat Rate (Btu/kwh)	10,981.6	N/F-T Urea $/t	$618
Aux. Power (kw)	-	Coal Cost, $/Mbtu	2.650
Est. Capacity Factor (%)	76.00		
Boiler Type	T/F	Water Cost, $/1000 gal (3)	2
Boiler Eff. (%)	84	Electricity, $/MWh	41.50
Estimated NOx, tons/day Max	**26.936**		
Emission Limit, tons	-		
NOx Sales/Buy rate, $/ton	-		
Fuel -	PRB		
Seasonal Days	153		
Basis	0		
Analysis - Enter "0" for Annual and 1 for Seasonal			
CF For Variable O&M	76.00		

Technology	Estimated Reduction from Baseline	Emission Rate After Control	Tons of NOx Emission, Seasonal/Annual	Tons of NOx Removed, season/annual	Estimated Capital Cost		Operating & Maintenance Cost Fixed O&M	Variable O&M, season or yr	Fuel Impact, season or yr
	%	(lb/mmBtu)	tons	tons	$/kW	$/unit	$/yr	$/@CF	$/@CF
LNB + OFA (Note 5)	54.5	0.15	4,469	5,363	9.6	$7,804,000	$142,000	$0	$0
Neural Net	10.0	0.30	8,848	983	0.3	$250,000	$50,000	$0	$0
Full SNCR	26.5	0.24	7,229	2,602	11.5	$9,372,000	$169,000	$5,377,000	$281,000
LNB+OFA+Full SNCR	61.4	0.13	3,799	6,033	20.0	$16,290,000	$311,000	$4,154,000	$384,000
LNB+OFA+Full SCR	83.3	0.055	1,639	8,193	248.6	$202,601,000	$608,000	$2,836,000	$0

(1) Aux. Power cost is calculated based on variation in capacity factor
(2) Assumed water cost of $2/1000 gallons.
(3) Assumed that 15% urea will be used for SNCR technology.
(4) Assumed that initial catalyst life is 12,000 hours
(5) LNB/OFA material already purchased for Unit 1. The total cost to Entergy would be the same for Unit 1 as shown for Unit 2.
(6) For SCR technology, the variable O&M costs are based on operating at NOx outlet emissions marginally below the compliance emission rate.

Unit Name White Bluff 2

Unit Data		Reagent Costs	
Size (Gross kW)	844,000	Aq.Ammonia $/t	$700
Average NOx Emission Rate (lb/MMBtu at full load)	**0.39**	An.Ammonia $/t	$400
Nominal Max. Boiler Heat Input (mmBtu/hr)	8,950.0	Urea $/t	$350
Avg. Heat Rate (Btu/kwh)	10,604.3	N/F-T Urea $/t	$618
Aux. Power (kw)	-	Coal Cost, $/Mbtu	2.650
Est. Capacity Factor (%)	76.00		
Boiler Type	T/F	Water Cost, $/1000 gal (3)	2
Boiler Eff. (%)	84	Electricity, $/MWh	41.50
Estimated NOx, tons/day Max	**31.833**		
Emission Limit, tons	-		
NOx Sales/Buy rate, $/ton	-		
Fuel -	PRB		
Seasonal Days	153		
Basis	0		
Analysis - Enter "0" for Annual and 1 for Seasonal			
CF For Variable O&M	76.00		

Technology	Estimated Reduction from Baseline	Emission Rate After Control	Tons of NOx Emission, Seasonal/Annual	Tons of NOx Removed, season/annual	Estimated Capital Cost		Operating & Maintenance Cost Fixed O&M	Variable O&M, season or yr	Fuel Impact, season or yr
	%	(lb/mmBtu)	tons	tons	$/kW	$/unit	$/yr	$/@CF	$/@CF
LNB + OFA	61.5	0.15	4,469	7,150	14.0	$11,831,000	$142,000	$0	$0
Neural Net	10.0	0.35	10,457	1,162	0.3	$250,000	$50,000	$0	$0
Full SNCR	26.5	0.29	8,544	3,076	11.1	$9,372,000	$169,000	$6,338,000	$333,000
LNB+OFA+Full SNCR	67.3	0.13	3,799	7,821	24.1	$20,317,000	$311,000	$4,158,000	$384,000
LNB+OFA+Full SCR	85.9	0.055	1,639	9,981	211.2	$178,240,000	$608,000	$2,858,000	$0

(1) Aux. Power cost is calculated based on variation in capacity factor
(2) Assumed water cost of $2/1000 gallons.
(3) Assumed that 15% urea will be used for SNCR technology.
(4) Assumed that initial catalyst life is 12,000 hours
(5) For SCR technology, the variable O&M costs are based on operating at NOx outlet emissions marginally below the compliance emission rate.

NO_X Compliance Costs

Unit name Lake Catherine Unit 4

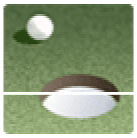
Unit Data		Reagent Costs	
Size (Gross kW)	558,000	Aq.Ammonia $/t	$700
Average NOx Emission Rate (lb/MMBtu)	0.4825	An.Ammonia $/t	$400
Nominal Max. Boiler Heat Input (mmBtu/hr)	5,850.0	Urea $/t	$350
Avg. Heat Rate (Btu/kwh)	10,483.9	N/F-T Urea $/t	$618
Aux. Power (kw)	-	Gas Cost, $/MBtu	4.900
Est. Capacity Factor (%)	10.00	Water Cost, $/1000 gal (3)	2
Boiler Type	T/F	Electricity, $/MWh	41.50
Boiler Eff. (%)	82		
Estimated NOx, tons/day Max	3.387		
Emission Limit, tons	-		
NOx Sales/Buy rate, $/ton	2500.0		
Fuel	Gas		
Seasonal Days	153		
Basis	0		
Analysis - Enter "0" for Annual and 1 for Seasonal			
CF For Variable O&M	10.00		

Technology	Estimated Reduction from Baseline	Emission Rate After Control	Tons of NOx Emission, Seasonal/Annual	Tons of NOx Removed, season/annual	Estimated Capital Cost		Operating & Maintenance Cost: Fixed O&M	Variable O&M, season or yr	Fuel Impact, season or yr
	%	(lb/mmBtu)	tons	tons	$/kW	$/unit	$/yr	$/@CF	$/@CF
Baseline	0	0.4825							
BOOS (at 558 MW)	50.0	0.24	618	618	1.6	$893,000	$21,000	$0	$0
LNB + OFA	60.0	0.19	495	742	15.7	$8,762,000	$210,000	$0	$0
SCR	90.0	0.05	124	1,113	106.8	$59,587,000	$358,000	$254,000	$0
SNCR	40.0	0.29	742	495	27.8	$15,507,000	$279,000	$1,542,000	$98,000
Water Injection	9.1	0.44	1,124	113	3.9	$2,177,000	$52,000	$18,000	$468,000
IFGR (below 500 MW)	19.0	0.39	1,001	235	3.9	$2,166,000	$52,000	$0	$0
FGR	60.0	0.19	495	742	20.6	$11,489,000	$207,000	$142,000	$0
LNB/OFA + SNCR	70.0	0.14	371	865	43.5	$24,269,000	$489,000	$393,000	$69,000
LNB/OFA + SCR	94.0	0.03	74	1,162	122.5	$68,349,000	$568,000	$268,000	$0

(1) Aux. Power cost is calculated based on variation in capacity factor
(2) Assumed water cost of $2/1000 gallons.
(3) Assumed that 15% urea will be used for SNCR technology.
(4) Assumed that initial catalyst life is 40,000 hours.
(5) Water Injection is used only for trimming at high load. Approximately 66% of Hours are affected.
(6) For SCR technology, the variable O&M costs are based on operating at NOx outlet emissions marginally below the compliance emission rate.

APPENDIX D

1. BOOS AT FULL UNIT LOAD



To: DAVID H PARK/Sargentlundy@Sargentlundy,
Cc:
Bcc:
Subject: Fw: BOOS for NOx Control
From: STEVE M KATZBERGER/Sargentlundy - Thursday 03/28/2013 03:32 PM

From: Stephen Wood [mailto:swood@etecinc.net]
Sent: Monday, March 25, 2013 2:20 PM
To: HANTZ, JOSEPH
Subject: BOOS for NOx Control

Joe,

The attached PDF file contains background information on utilizing burners out of service for NOx control, as well as, predicted Lake Catherine Unit 4 burner header pressures and NOx emissions, utilizing the top burner elevation out of service (4BOOS). If you have any questions, please let me know.

Regards,

Steve Wood
Principal Officer
Entropy Technology & Environmental Consultants, Inc. (ETEC Inc.)
12337 Jones Rd. Suite 414
Houston, TX 77070
Ph: 281-807-7007
Cell: 713-253-8230
Fax: 281-807-1414
Website: www.etecinc.net

 BOOS for NOx Control.pdf

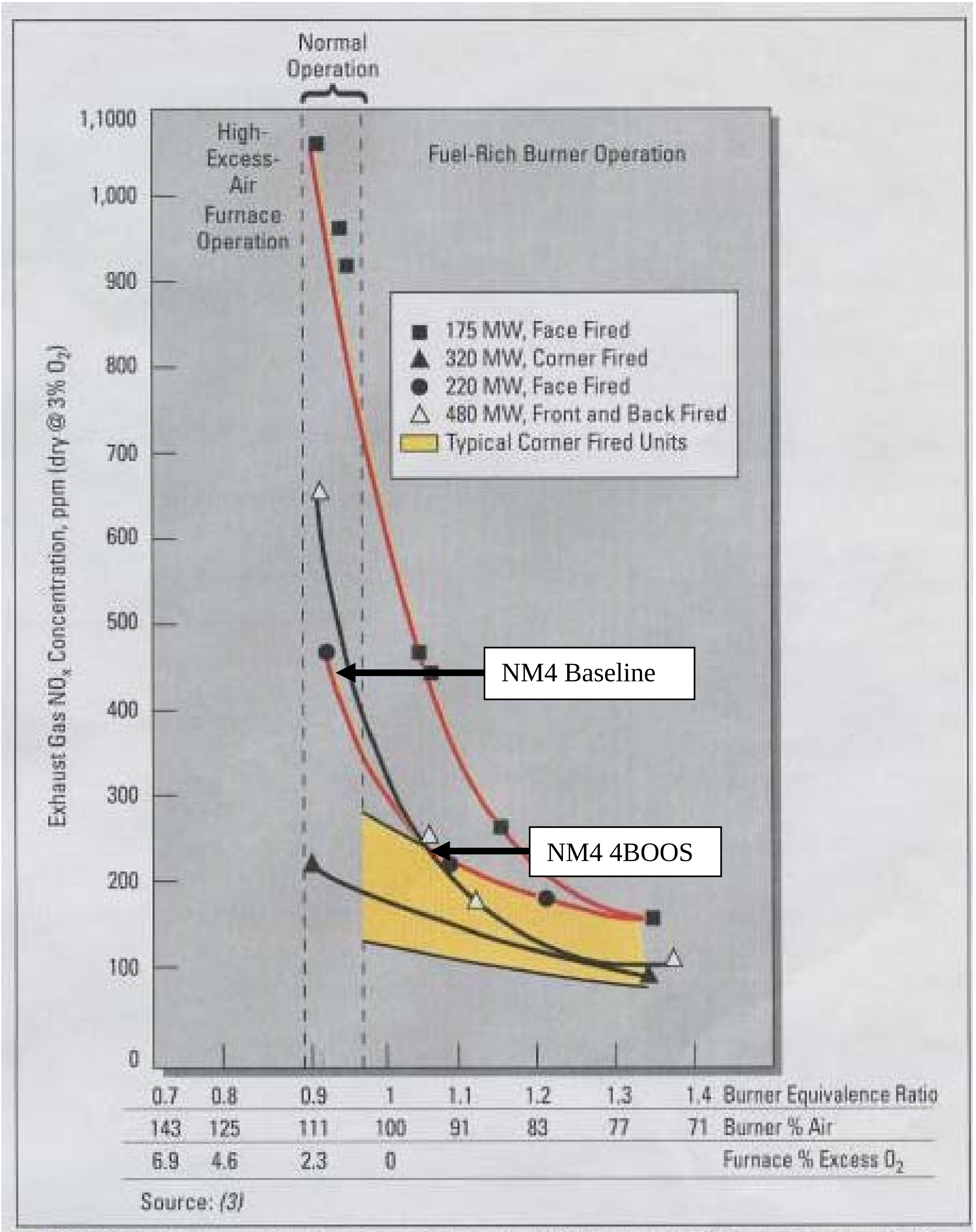
Combustion Modification (BOOS) for NOx Control

Implementation of Burner Out Of Service (BOOS) operation is a practical and cost-effective means for achieving staged combustion (i.e., modifying burner stoichoimetry to reduce NOx emissions formation) on an existing gas/oil fired electric utility boiler. Utilizing BOOS operation for NOx control is well documented in the literature, e.g., EPA 456/F-99-006R "Nitrogen Oxides (NOx), Why And How They Are Controlled", November 1999, and EPRI TR-108181 "Retrofit NOx Control Guidelines for Gas- and Oil-Fired Boilers, Version 2.0", June 1997, among numerous others.

The technique of BOOS operation involves terminating the fuel flow to selected burners on the top elevation while leaving the air registers open. The remaining burners operate fuel-rich, thereby limiting oxygen availability, lowering peak flame temperatures, and reducing NOx formation. The un-reacted products combine with the air from the above terminated-fuel burners to complete burnout before exiting the furnace. I have personally been involved with implementing BOOS operation on virtually every gas fired electric utility boiler design across the country since the mid 1970's. In almost every case, the original "high" burner header pressure (BHP) set point had to be increased to accommodate BOOS operation. No adverse operational or maintenance problems corresponding to BOOS implementation have been reported.

BOOS operation can be a very effective NOx reduction technology, depending on the degree of staging, as shown for Ninemile Unit 4 (750 mw CE Tangential Fired) in Figure 1. The corresponding BOOS pattern is shown in Figure 2. The BHP corresponding to 4BOOS operation on Lake Catherine Unit 4 is shown in Figure 3. The "High" BHP set point would need to be increased from 42 to 50 psig. The predicted NOx emissions corresponding to 4BOOS operation are presented in Figure 4.

Figure 1- Stoichiometry Modification (BOOS) NOx Reduction



■ *Figure 2. Burners-out-of-service can be an effective combustion staging technique.*

Figure 2- Ninemile Units 4 and 5 BOOS Pattern (Top Elevation Out of Service & Air Registers Open)

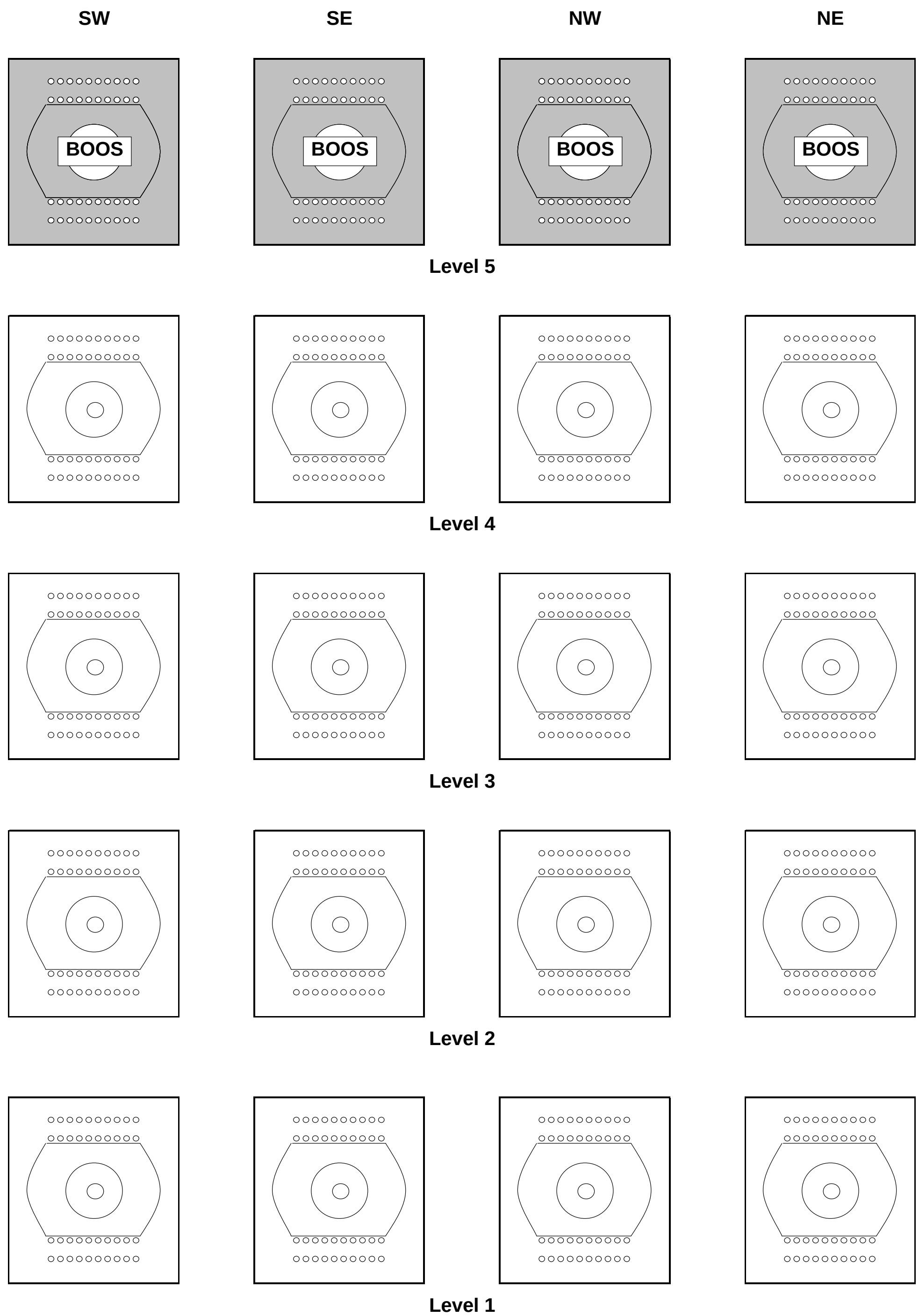


Figure 3- Lake Catherine Unit 4 Burner Header Pressure

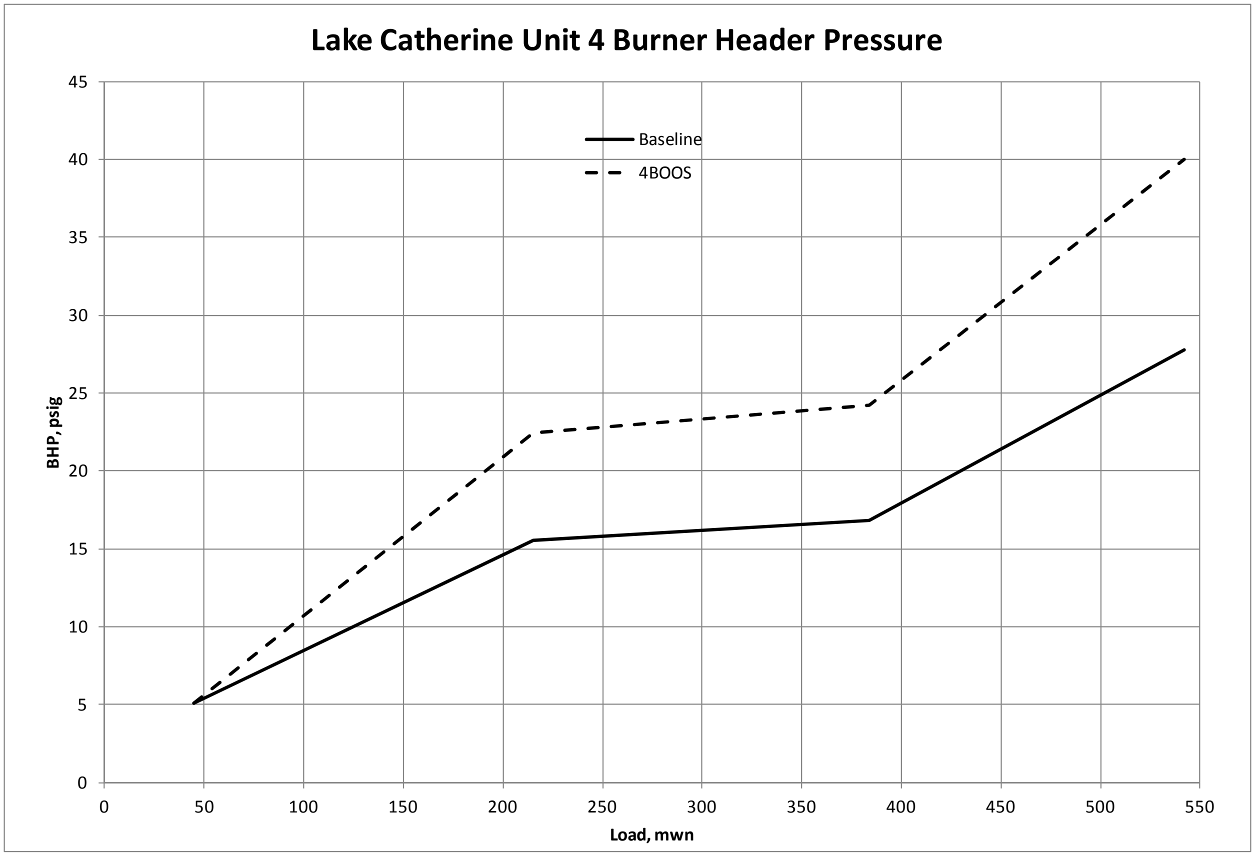
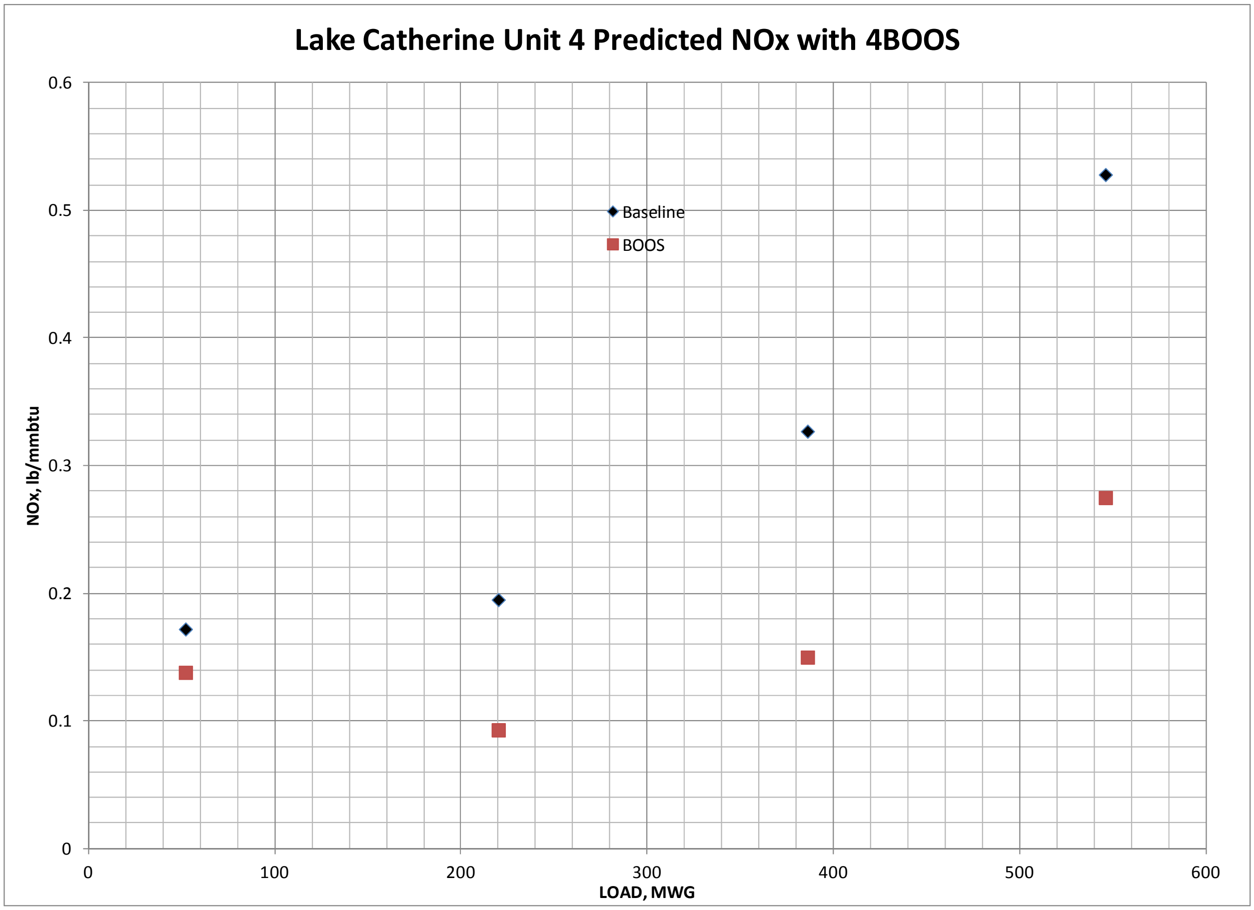


Figure 4- Lake Catherine Unit 4 NOx Emissions Prediction



April 5, 2017

Kelly McQueen, Assistant General Counsel
Entergy Arkansas, Inc.
425 W Capitol Avenue
P.O. Box 551
Little Rock, Arkansas 72201

Dear Kelly McQueen:

The Arkansas Department of Environmental Quality (ADEQ) is in the process of developing a state implementation plan (SIP) revision to address disapproved provisions in the 2008 Arkansas Regional Haze SIP (2008 AR RH SIP) and replace the federal implementation plan (FIP) promulgated by EPA on September 27, 2016. As part of this process, ADEQ requests that Entergy Arkansas, Inc. (EAI) provide supplemental information to inform ADEQ's best available retrofit technology (BART) determination for sulfur dioxide (SO_2) at White Bluff units 1 and 2.

In the "State of Arkansas Regional Haze and Interstate Visibility Transport Federal Implementation Plan" (AR RH FIP), EPA determined that BART for White Bluff was dry flue gas desulfurization (Dry FGD) technology based on the thirty year expected useful life of the Dry FGD equipment; however, EPA did not appropriately take into account the remaining useful life of the White Bluff units themselves. White Bluff unit 1 began operating in 1980 and unit 2 began operating in 1981. Given the age of the units and expected market trends for coal compared to other fuels and technologies used to generate electricity, it is not reasonable to assume that White Bluff will still be powered by coal in 2051 (thirty years after the compliance date in the AR RH FIP and 70 years after beginning operation) and to base cost-effectiveness calculations on such an assumption.

EAI has provided several analyses in support of comments on EPA's AR RH FIP with various assumptions about dates by which Entergy could commit to cease coal-fired operations at White Bluff units and what interim controls would be necessary to satisfy BART requirements under 40 CFR 51 Appendix Y. ADEQ requests that EAI confirm whether such analyses that are already on the record are still accurate. Specifically, please confirm whether the cost-effectiveness values for Dry FGD of approximately $10,400–11,800 per ton under the assumption of four to five years of remaining useful life is still accurate. Additionally, please confirm whether the cost-effectiveness values for Dry FGD of approximately $7,500 to $8,500 per ton under the assumption of six to seven years of remaining useful life is still accurate. Please provide a cost-effectiveness estimate for meeting a 0.6 lb/MMBtu on a 30-day rolling average limit for SO_2

based on the use of low-sulfur coal compared to White Bluff's currently permitted emission limit of 1.2 lb/MMBtu proposed in comments dated August 7, 2015 to EPA on the AR RH FIP.

In addition to verifying cost-effectiveness values already on the record, ADEQ requests that EAI also provide additional supplemental information for consideration. Specifically, please provide an analysis of the expected cost-effectiveness values for Dry FGD with compliance based on the following scenarios: seven to eight years remaining useful life, fifteen years remaining useful life (EPA's assumption for financing control equipment in the IPM model), and nineteen years remaining useful life (sixty years from the start of operations at White Bluff).

We request that EAI provide this supplemental information by 4:30 p.m. on April 21, 2017. Thank you for your prompt response to this request for supplemental information.

Sincerely,

Stuart Spencer
Associate Director, Office of Air Quality

Arkansas Environmental Support
425 West Capitol Avenue
A-TCBY-22D
Little Rock, AR 72203
Tel 501-377-4033
Fax 281-297-6128
G. Tracy Johnson, Manager
Arkansas Environmental Support

AR-17-039

April 21, 2017

Stuart Spencer
Associate Director
Office of Air Quality
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118-5317

Re: Response to Information Request
Entergy Arkansas, Inc. – White Bluff Plant
AFIN: 35-00110 Permit No.: 0263-AOP-R10

Dear Mr. Spencer:

On behalf of Entergy Arkansas, Inc. (EAI), Entergy Services, Inc. (ESI) has reviewed your letter of April 5, 2017, regarding costs associated with potential SO_2 emissions control options at the White Bluff Plant. As requested, ESI provides the following responses to the questions posed by ADEQ in this letter. For convenience, these responses have been numbered in the order they appear in the April 5 letter.

Please note that, for all costs associated with dry flue gas desulfurization (dry FGD) controls, two separate cost ranges are provided. The first is the full capital cost estimate prepared by Sargent and Lundy (S&L) for Entergy, based on S&L's extensive experience estimating costs for similar projects at similar electric generating facilities. While ESI believes the full S&L capital cost estimate to be the most accurate representation of costs that would be borne by EAI and its ratepayers, the U.S. EPA has previously disallowed consideration of several components of this cost estimate, including escalation, interest during construction (IDC), and owner's costs. Recognizing this, ESI is also providing a second, partial, cost range that eliminates escalation, IDC, and owner's costs, even though the removal of such costs severely underestimates the actual amount EAI would incur to install SO_2 emissions controls at White Bluff. All capital costs are from S&L estimate 33787B issued November 18, 2016.[1] O&M costs are the same for both scenarios and are from S&L report SL-012831 issued July 14, 2015. All costs are in 2015 dollars.

1. **Please confirm whether the cost-effectiveness values for Dry FGD of approximately $10,400 – 11,800 per ton under the assumption of four to five years of remaining useful life is still accurate.**

   For a four- to five-year remaining useful life (RUL), the cost-effectiveness range in dollars per ton of SO_2 emissions reduced is approximately $9,100-$11,000 based on the full costs and $6,900 to $8,200 based on the partial costs.

2. **Please confirm whether the cost effectiveness values for dry FGD of approximately $7,500 to $8,500 per ton under the assumption of six-to-seven years of remaining useful life is still accurate.**

   For a six- to seven-year RUL, the cost-effectiveness range in dollars per ton of SO_2 emissions reduced is approximately $7,100-$8,000 based on the full costs and $5,400-$6,100 based on the partial costs.[2]

[1] S&L revised its prior cost estimates, as explained in EAI's Petition for Reconsideration of the final FIP. *See* EAI Petition for Reconsideration, at 8 n. 31 (Nov. 23, 2016). These revised cost estimates have been used to respond to the Department's questions.
[2] EAI Petition for Reconsideration, at 8.

3. **Please provide a cost-effectiveness estimate for meeting a 0.6 lb/MMBtu on a 30-day rolling average limit for SO_2 based on the use of low-sulfur coal compared to White Bluff's currently permitted emission limit of 1.2 lb/MMBtu proposed in comments dated August 7, 2015 on the AR RH FIP.**

   To meet an emission limit of 0.6 lb/MMBtu, EAI would purchase coal with a sulfur content lower than 0.6 lb/MMBtu to provide an adequate margin for compliance. Based on coal market information available to Entergy's fuel supply group, the cost premium for coal purchased to meet a SO_2 limit of 0.6 lb/MMBtu is expected to be approximately 50 cents per ton of coal purchased. Based on this cost premium, a typical low-sulfur coal heat content of 8,800 btu/lb (as supplied), and the annual heat input value utilized in the S&L dry FGD cost estimate (55,829,551 MMBtu/year), the annual cost premium associated with the use of low-sulfur coal at one White Bluff unit is estimated to be approximately $1,600,000.[3]

4. **Please provide an analysis of the expected cost-effectiveness values for dry FGD with compliance based on the following scenarios:**

   a. **Seven to eight years of remaining useful life,**

      For a seven- to eight-year RUL, the cost-effectiveness range in dollars per ton of SO_2 emissions reduced is approximately $6,500-$7,200 based on the full costs and $5,000-$5,500 based on the partial costs.

   b. **Fifteen years remaining useful life (EPA's assumption for financing control equipment in the IPM model), and;**

      For a 15-year RUL, the cost-effectiveness in dollars per ton of SO_2 emissions reduced is approximately $4,500 based on the full costs and $3,500 based on the partial costs.

   c. **Nineteen years of remaining useful life (sixty years from the start of operations at White Bluff).**

      For a 19-year RUL, the cost-effectiveness in dollars per ton of SO_2 emissions reduced is approximately $4,050 based on the full costs and $3,175 based on the partial costs. It should be noted that the White Bluff units first began commercial operation on August 21, 1980 (Unit 1) and July 23, 1981 (Unit 2). Assuming that compliance with a SIP limit for a dry FGD system would be required in 2022, a 19-year RUL would end in 2041.

We appreciate the Department's consideration of this information. Should you or your staff have any further questions or require any additional information, please feel free to contact me at (501) 377-5760, Tracy Johnson at (501) 377-4033, or David Triplett at (501) 377-4030.

Sincerely,

Kelly McQueen

Associate General Counsel

KMM/dct

[3] EAI cannot estimate the cost-effectiveness of meeting a SO_2 limit of 0.6 lb/MMBtu based on the use of low sulfur coal given that the actual sulfur content of low sulfur coal varies, making it difficult to estimate the tons of SO_2 that would be reduced, particularly in comparison to the historical emissions. Furthermore, to estimate a predicted annual average SO_2 emission rate based on operation with low sulfur coal could under-estimate the cost effectiveness of this option.

Entergy Services, Inc.
425 West Capitol Avenue
P. O. Box 551
Little Rock, AR 72203-0551
Tel. 501-377-5760
Fax 501-377-5814
kmcque1@entergy.com

Kelly McQueen
Assistant General Counsel

August 18, 2017

Stuart Spencer
Associate Director
Office of Air Quality
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118-5317

Re: Updated BART Five-Factor Analysis for SO_2 at Entergy White Bluff Units 1 and 2

Dear Mr. Spencer:

Entergy Arkansas, Inc. (Entergy) respectfully submits the following Updated Best Available Retrofit Technology (BART) Five-Factor Analysis (FFA) for sulfur dioxide (SO_2) for Units 1 and 2 at the White Bluff Steam Electric Station (Updated FFA). The submittal is an update to the original FFA submitted on February 21, 2013, with revisions on June 10 and October 15, 2013. Confidential Business Information has been redacted. A hard copy of the Updated FFA which includes the redacted information will be submitted to the Department concurrently, in accordance with Regulation No. 18.1402.

The Updated FFA updates the emissions baseline period used for modeling White Bluff's baseline visibility impairment and estimate the cost-effectiveness of the SO_2 controls evaluated, incorporates new information regarding the remaining useful life (RUL) of the units, assesses a new control scenario representing combustion of only low-sulfur coal (LSC), incorporates additional information related to control options involving Dry Sorbent Injection (DSI), updates the modeling to reflect the newest methodologies for speciating particulate matter emissions into its constituents, and amends the SO_2 BART conclusion in light of the new information. The Updated FFA concludes that combustion of LSC constitutes BART for White Bluff Units 1 and 2 in light of the updated RUL. The proposed BART emission rate for SO_2 for each unit is 0.6 pounds per MMBtu (lb/MMBtu) on a rolling 30-day average. Entergy urges ADEQ to incorporate this analysis into its anticipated revisions to the SO_2 provisions in the Regional Haze State Implementation Plan (SIP) for the first planning period.

The Updated FFA addresses only SO_2 BART, and does not address BART for nitrogen oxides (NOx). Last month, ADEQ released a draft Regional Haze SIP Revision for the first planning period that concludes compliance with the updated Cross-State Air Pollution Rule constitutes BART for NOx. Entergy submitted comments in support of this conclusion on August 14, 2017. Nonetheless, Entergy would be amenable to accepting a specific emission limit for NOx at White Bluff Units 1 and 2, based on the installation of low NOx burners and separated overfire air (LNB/SOFA), but is still in the process of tuning the LNB/SOFA recently installed at White Bluff Unit 2.

We are happy to answer any questions you may have about the Updated FFA.

Sincerely,

Kelly M. McQueen
Assistant General Counsel –
Environmental (Lead)
Entergy Services, Inc.

Attachment:

Updated Five Factor Analysis

Entergy Services, Inc., on behalf of Entergy Arkansas, Inc.
White Bluff Steam Electric Station
Redfield, Arkansas (AFIN 35-00110)

Updated BART Five-Factor Analysis for SO_2 for Units 1 and 2

Submitted to:

Arkansas Department of Environmental Quality (ADEQ)
Office of Air Quality
5301 Northshore Drive
North Little Rock, AR 72118-5317

Prepared by:

TRINITY CONSULTANTS
5801 E. 41st St., Suite 450
Tulsa, OK 74135
(918) 622-7111

August 18, 2017

Trinity Project 173702.0014

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1 EXECUTIVE SUMMARY

This report provides an update to the Best Available Retrofit Technology (BART) Five Factor Analysis for sulfur dioxide (SO_2) for Unit 1 (SN-01) and Unit 2 (SN-02) at Entergy Arkansas, Inc.'s (EAI's) White Bluff Steam Electric Station (White Bluff) as well as revising the SO_2 BART conclusion. EAI submitted the original BART Five Factor Analysis to the Arkansas Department of Environmental Quality (ADEQ) on February 21, 2013, with revisions on June 10, 2013 and October 15, 2013.

- Unit 1 (SN-01) is a primary boiler with a maximum net power rating of 850 megawatts (MW) and a nominal heat input capacity of 8,950 million British thermal units per hour (MMBtu/hr). The boiler burns sub-bituminous or bituminous coal[1] as the primary fuel and No. 2 fuel oil or biofuel as a start-up fuel, and it is currently equipped with an electrostatic precipitator (ESP) for particulate matter (PM) control.
- Unit 2 (SN-02) is identical in design to Unit 1. It is a primary boiler with a maximum net power rating of 850 MW and a nominal heat input capacity of 8,950 MMBtu/hr. The boiler burns sub-bituminous or bituminous coal[2] as the primary fuel and No. 2 fuel oil or biofuel as a start-up fuel, and it is currently equipped with an ESP for PM control.

Specific updates incorporated in this version of the report are outlined below.

1.1 REPORT UPDATES

This report includes the following updates to the previous SO_2 Five Factor Analysis for White Bluff Units 1 and 2:

1. Updating the baseline period to 2009-2013.

[redacted]

3. Incorporating a new control scenario representing combustion of only low-sulfur coal (LSC).

4. Incorporating additional information (i.e., cost information and modeling results) related to control options involving Dry Sorbent Injection (DSI).

5. Updating all modeling to reflect the newest methodologies for dividing ("speciating") particulate matter (PM or PM_{10})[3] emissions into its constituents.

6. Updating the SO_2 BART conclusion in consideration of the new information and updates listed above.

[1] The coal-fired units at White Bluff primarily burn sub-bituminous coal, but are permitted to burn bituminous or sub-bituminous coal. Only sub-bituminous coals were burned during the baseline periods evaluated in this analysis.

[2] Ibid.

[3] All PM represented in this report is assumed to have a mass mean diameter smaller than ten microns.

1.2 SUMMARY OF UPDATED BART FIVE FACTOR ANALYSIS

Trinity conducted the below five-step analysis based on EPA's BART Guidelines[4] in 40 CFR Part 51 and other EPA guidance[5] to evaluate SO_2 BART for Units 1 and 2:

1. Identifying all available retrofit control technologies;
2. Eliminating technically infeasible control technologies;
3. Evaluating the control effectiveness of remaining control technologies;
4. Evaluating impacts and documenting the results; and
5. Evaluating visibility impacts.

The updated BART Five Factor Analysis concludes that combustion of LSC constitutes BART for Unit 1 and Unit 2 in light of the updated RUL. The proposed BART emission rate for SO_2 is 0.6 pounds per MMBtu (lb/MMBtu) on a rolling 30-day average.

[4] The BART guidelines were published as amendments to EPA's Regional Haze Rule (RHR) at 40 CFR 51.308 on July 6, 2005.

[5] April 26, 2012, letter from Mr. Guy Donaldson, EPA Region VI, to Mr. Anthony Davis, ADEQ.

2 INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to pristine conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to pristine conditions in 156 specific areas across the United States known as Class I areas. The CAA defines Class I areas as certain national parks (larger than 6,000 acres), wilderness areas (larger than 5,000 acres), national memorial parks (larger than 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the Best Available Retrofit Technology (BART) rule, which included guidance for making source-specific BART determinations. The BART rule defines BART-eligible sources as sources that meet the following criteria:

(1) Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant,
(2) Began operation between August 7, 1962, and August 7, 1977, and
(3) Are included as one of the 26 listed source categories in the guidance.

A BART-eligible source is subject to BART if the source is "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." For the purpose of determining which sources are subject to BART, a 1.0 Δdv change or more from an individual source is considered to "cause" visibility impairment, and a change of 0.5 Δdv is considered to "contribute" to impairment, which therefore establishes 0.5 Δdv as a numerical screening threshold for subject-to-BART determinations.[6] According to the BART guidelines, the CALPUFF modeling system (CALPUFF) or any other appropriate dispersion model can be used to predict the visibility impacts.[7] The model-predicted visibility impact, specifically when using CALPUFF the 98th percentile impact measured against natural background (and not the maximum impact), is compared to the 0.5 Δdv threshold to determine if the source is anticipated to cause or contribute to the visibility impairment.[8]

Once it is determined that a source is subject to BART, a BART determination must address air pollution control measures for the source. The visibility regulations define BART as follows:

> *…an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by…[a BART-eligible source]. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the cost of compliance, the energy and non-air quality*

---

[6] "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule," 70 Fed. Reg. 39,116-18 (July 6, 2005).

[7] Trinity and EAI assert that CALPUFF is not the most appropriate model for estimating visibility impacts. Due to its numerous inherent limitations (e.g., limited chemistry mechanism, distance limitations, blanket background ammonia values, etc.), CALPUFF does not yield reliable results. Furthermore, CALPUFF is no longer an EPA-preferred model, which further indicates CALPUFF's unreliability. More advanced models like the Comprehensive Air Quality Model with Extensions (CAMx)—if processed appropriately—can yield more reliable characterizations of visibility impairment. Nevertheless (without waiver), CALPUFF modeling will continue to be presented in this report for consistency with past submittals.

[8] Id. at 39,163.

environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

The BART Guidelines state that a BART determination should address the following five statutory factors:

1. Existing controls;
2. Cost of controls;
3. Energy and non-air quality environmental impacts;
4. Remaining useful life of the source; and
5. Degree of visibility improvement as a result of controls.

Further, the BART Guidelines indicate that the five basic steps in a BART analysis can be summarized as follows:

1. Identify all available retrofit control technologies;
2. Eliminate technically infeasible control technologies;
3. Evaluate the control effectiveness of remaining control technologies;
4. Evaluate impacts and document the results; and
5. Evaluate visibility impacts.

As described in the above-referenced, previous submittals, the boilers at White Bluff meet the three BART-eligibility criteria, and the existing visibility impairment is modeled at greater than 0.5 Δdv in at least one Class I area. Thus, the White Bluff units are subject to BART.

3 EXISTING EMISSIONS AND BASELINE VISIBILITY IMPAIRMENT

Five Factor Analyses require the determination of unit-specific baseline visibility impairment values to which any post-control scenarios can be compared. The unit-specific baseline modeling analyses are built upon, but are distinguished from, the baseline (a.k.a., "screening") modeling for the collection of BART eligible units at each source that is completed to determine if a BART eligible source is subject to BART. EAI is not updating the subject-to-BART determination at this time.

This section summarizes the baseline visibility impairment attributable to each of White Bluff's units based on CALPUFF air quality modeling conducted by Trinity.[9] Trinity conducted the modeling using the same protocol, methodologies, and inputs (except where specifically updated as described in this report) as presented in the October 15, 2013 submittal. The protocol and details method descriptions are not included with this report because nothing has changed and the CALMET dataset developed per the protocol has been used – and approved by EPA – numerous times since its development.

While this report updates the BART Five Factor Analysis for SO_2 emissions specifically, BART modeling must consider emissions of all visibility-affecting pollutants (VAP), including SO_2, oxides of nitrogen (NO_X), and speciated particulate matter, including filterable coarse particulate matter (PMc), filterable fine particulate matter (PMf), elemental carbon (EC), inorganic condensable particulate matter (IOR CPM) as sulfates (SO_4), and organic condensable particulate matter (OR CPM), also referred to as secondary organic aerosols (SOA).

3.1 BASELINE EMISSION RATES

The updated modeled NO_X and SO_2 emission rates for Unit 1 and Unit 2 are the highest actual 24-hour emission rates based on Clean Air Markets Database (CAMD) data from 2009-2013.[10] The updated modeled PM_{10} emission rates for Unit 1 and Unit 2 are based on emission factors from AP-42 for filterable PM_{10} and condensable PM (with a 99.5 percent control efficiency for ESP applied to the PM_{10} filterable fraction) used in conjunction with the average 2009-2013 coal heating value and ash content (as a percentage of mass).[11] Emission rates for specific PM_{10} species were calculated using the monitored filterable PM rate and the National Park Service (NPS) "speciation spreadsheet" for *Dry Bottom Boiler Burning Pulverized Coal using only ESP*[12] except for SO_4, which was calculated using an Electric Power Research Institute (EPRI) methodology that considers the SO_2 to SO_4 conversion rate and SO_4 reduction factors for various downstream equipment.[13] Table 3-1 summarizes the emission rates that were modeled for SO_2, NO_X, and PM_{10}, including the speciated PM_{10} emissions.

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[9] See footnote 7, above.

[10] The use of this baseline is a conservative approach. EAI would be justified in using a more recent baseline with lower emissions that would result in higher cost effectiveness values.

[11] AP-42, Chapter 1 External Combustion Sources, Section 1.1 Bituminous and Subbituminous Coal Combustion, Table 1.1-5, page 1.1-24 (September 1998).

[12] The baseline speciation is based on the NPS Workbook for a Dry Bottom Boiler burning Pulverized Coal using an ESP. Based on average 2009-2013 values, the following input values were used: heating value of 8,587 Btu/lb, 0.27% sulfur, 4.96% ash, 8,950 MMBtu/hr heat input, and a baseline total PM_{10} emission rate of 119.2 lb/hr at both White Bluff Unit 1 and Unit 2. NPS: http://www.nature.nps.gov/air/Permits/ect/index.cfm.

[13] Electric Power Research Institute (EPRI) Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: EPRI, Technical Update, Palo Alto, CA: March 2012. 1023790.

Table 3-1. Baseline Maximum 24-hour Emission Rates (As Hourly Equivalents)

Unit	SO_2 (lb/hr)	NO_X (lb/hr)	Total PM_{10} (lb/hr)	SO_4 (lb/hr)	PM_c (lb/hr)	PM_f (lb/hr)	SOA (lb/hr)	EC (lb/hr)
SN-01	6,771.9	3,355.4	119.2	5.1	40.4	31.1	9.3	1.2
SN-02	6,622.3	3,590.5	119.2	5.0	40.4	31.1	9.3	1.2

3.2 BASELINE VISIBILITY IMPAIRMENT

Trinity conducted modeling to estimate the current visibility impairment attributable to Unit 1 and Unit 2 in four Class I Areas: Caney Creek Wilderness (CACR), Upper Buffalo Wilderness (UPBU), Hercules Glades Wilderness (HERC), and Mingo Wilderness (MING) using the CALPUFF dispersion model.[14] Table 3-2 provides a summary of the modeled visibility impairment attributable to Unit 1 and Unit 2 based on the emission rates shown in Table 3-1. This table shows the 98th percentile impacts in Δdv and the number of days with impacts greater than 0.5 Δdv.

Table 3-2. Baseline Visibility Impairment

Unit	Year [A]	CACR		UPBU		HERC		MING	
		98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5
SN-01	2001	1.505	38	1.051	30	0.925	24	0.802	16
	2002	1.306	29	0.742	15	0.567	10	0.708	21
	2003	1.053	32	1.033	24	0.704	15	0.666	14
SN-02	2001	1.533	39	1.059	30	0.912	25	0.819	15
	2002	1.322	29	0.739	16	0.568	11	0.719	20
	2003	1.059	32	1.03	25	0.72	16	0.678	14

[A] Meteorological data year modeled.

[14] Due to an EPA-requested change in meteorological data (to a refined, or "NO OBS = 0", dataset), which excluded the Sipsey Class 1 Area from the modeling domain, Sipsey was not included in this analysis. See also footnote 7 above.

4.1 IDENTIFICATION OF AVAILABLE RETROFIT SO_2 CONTROL TECHNOLOGIES FOR UNIT 1 AND UNIT 2

The boilers burn primarily coal. Sulfur oxides, SO_X, are generated during coal combustion from the oxidation of sulfur contained in the fuel. SO_X emissions are almost entirely dependent on the sulfur content of the fuel and are generally not affected by boiler size or burner design. SO_X emissions from conventional combustion systems are predominantly in the form of SO_2. Since SO_2 is the predominant sulfur compound emitted from Unit 1 and Unit 2, the BART analysis is specific to emissions of SO_2. Reductions in emissions of SO_2 are expected to reduce visibility impairment by reducing sulfate (SO_4) formation.

Step 1 of the top-down control review is to identify available retrofit control options for SO_2. The available SO_2 retrofit control technologies for Unit 1 and Unit 2 are summarized in Table 4-1.

Table 4-1. Available SO_2 Control Technologies for Unit 1 and Unit 2

SO_2 Control Technologies
Fuel Switching – Low-Sulfur Coal (LSC)
Dry Sorbent Injection (DSI)
Dry / Semi-Dry Flue Gas Desulfurization (DFGD), e.g., Spray Dryer Absorber (SDA)
Wet Scrubbing, i.e., Wet Flue Gas Desulfurization (WFGD)

4.2 ELIMINATE TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES FOR UNIT 1 AND UNIT 2

Step 2 of the BART determination is to eliminate technically infeasible SO_2 control technologies that were identified in Step 1.

4.2.1 Fuel Switching - Low-Sulfur Coal

With an achievable emission level of 0.6 lb/MMBtu, switching to LSC can reduce SO_2 emissions by approximately 8.75 percent compared to baseline levels.[15]

4.2.2 Dry Sorbent Injection

DSI involves the injection of a sorbent (e.g., Trona) into the exhaust gas stream where acid gases such as hydrogen chloride (HCl) and SO_2 react with and become entrained in the sorbent. The stream then passes through a particulate control device to remove the sorbent along with the entrained SO_2. The process was developed as a lower cost FGD option because the mixing of the SO_2 and sorbent occurs directly in the exhaust gas stream rather than in a separate vessel. Sorbent injection control efficiency depends on residence time, gas stream temperature, and limitations of the particulate control device.

[15] Calculated based on a comparison of the maximum 30 boiler operating day SO_2 emission rate during the baseline period to the proposed limit for low-sulfur coal of 0.6 lb/MMBtu.

DSI is a technically feasible yet seldom used technology for moderate to high removal of SO_2 from coal-fired power plants, with limited full-scale installations for SO_2 control. A significant amount of testing of DSI for SO_2 control has been performed in recent years. This testing has shown that a wide range of performance is achievable (up to 80 or 90 percent SO_2 reduction in some cases). However, this testing has also shown that there are many factors that can impact the performance of these reagents, including particle size (milling), residence time, temperature, and the particulate collection equipment. The primary lesson learned through this testing is that each unit is unique, with various factors that can impact the achievable performance or required reagent feed rate. Different performance has even been seen on sister units. Therefore, it is critical to perform a demonstration or Proof of Concept test at each facility.

A demonstration has not to-date been performed on the White Bluff units to show the achievable SO_2 control and associated reagent feed rates. The cost reports developed by S&L, included in Appendix A, show predicted performance and required reagent rates based on Sargent & Lundy's (S&L's) extensive experience with DSI testing and previous work with the White Bluff units. Two DSI technologies are considered for White Bluff: "DSI", which would utilize the existing ESP, and "enhanced DSI", which would include installation of a fabric filter or baghouse. Enhanced DSI should achieve greater SO_2 reductions because the installation of a fabric filter increases residence time and improves collection efficiency to allow more sorbent to be injected. The S&L reports present predicted performance levels (SO_2 emission rates) for DSI and enhanced DSI of 0.35 lb/MMBtu and 0.15 lb/MMBtu, respectively. Because the actual performance and required reagent rates may vary from the predicted values due to unforeseen site-specific conditions, it is possible that the capital and annual costs represented in the S&L reports, and in Section 4.4.2 of this report, could also vary. If a significantly higher injection rate were actually required to achieve the same performance level (SO_2 emission rate) then the capital and annual costs, and corresponding cost-effectiveness of the DSI technologies, could dramatically increase.

Furthermore, DSI has yet to be demonstrated on similarly sized units to those at White Bluff. An important consideration for DSI technology is the design throughput of the system, beyond just the size and achievable performance (SO_2 emission rate). The largest DSI system installed and operating has a design feed rate of 12 tons/hour, while most of the installed systems inject approximately five to six tons/hour. The predicted injection rate for the White Bluff enhanced DSI case is approximately 15 tons/hour. The greater the injection rates, the more issues associated with supply and delivery logistics that arise. At 15 tons/hour (per unit) White Bluff would consume one railcar (100-ton capacity) of Trona every 3.3 hours if both units are operating at full load.

Prior to moving forward with DSI technology as a compliance strategy, a demonstration test would need to be performed to confirm the feasibility, achievable performance and balance of plant impacts (brown plume formation, ash handling modifications, landfill/leachate considerations and impact to mercury control). The balance of plant impacts have been addressed as part of the S&L cost reports based on typical assumptions, but would also be impacted should the design injection rate vary. Any compliance strategy which were to rely on DSI technology would need to be contingent on successful completion of a demonstration test.

4.2.3 Dry / Semi-Dry Flue Gas Desulfurization

Of the various designs for dry or semi-dry FGD systems, the most popular is the Spray Dryer Absorber (SDA) design. In the SDA design, a fine mist of lime slurry is sprayed into an absorption tower where the SO_2 is absorbed by the slurry droplets. The absorption of the SO_2 leads to the formation of calcium sulfite and calcium sulfate within the droplets. The heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the tower, resulting in the formation of a dry powder that is carried out with the gas and collected with a fabric filter.

SDA systems can achieve control efficiencies ranging from 60 to 95 percent.[16] SDA is a technically feasible option for control of SO_2 from Unit 1 and Unit 2. Based on a site-specific study completed by S&L, SDA could technically achieve an SO_2 emission rate of 0.06 lb/MMBtu at Unit 1 and Unit 2.

4.2.4 Wet Flue Gas Desulfurization

While WFGD is technically feasible, it is not expected to achieve significant reductions beyond DFGD/SDA and was eliminated in the previous analyses and in EPA's final regulations (SIP approval and FIP). Accordingly, WFGD is not considered further in this analysis.

4.3 RANK OF TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS BY EFFECTIVENESS FOR UNIT 1 AND UNIT 2

The third step in the BART analysis is to rank the technically feasible options according to their effectiveness in reducing SO_2.
Table 4-2Table 4-2 provides a ranking of the control levels for the controls listed in the previous section.

Table 4-2. Control Effectiveness of Technically Feasible SO_2 Control Technologies

Control Technology	Achievable Emission Rate (lb/MMBtu) [A]
Semi-Dry Scrubber (SDA)	0.06
Enhanced DSI	0.15
DSI	0.35
Low Sulfur Coal	0.6

4.4 EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS FOR UNIT 1 AND UNIT 2

The fourth step in the BART analysis is the impact analysis, which evaluates the impacts for the control options deemed feasible in Step 2. This analysis typically is conducted to demonstrate that the most effective control technology does not necessarily constitute BART. The BART guidelines list the four factors to be considered in the impact analysis:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The RUL of the source

Because the RUL of the source directly affects the cost of compliance, RUL is considered first.

[16] EPA Basic Concepts in Environmental Sciences, Module 6: Air Pollutants and Control Techniques http://www.epa.gov/eogapti1/module6/sulfur/control/control.htm

4.4.1 Remaining Useful Life

[redacted]

4.4.2 Cost of Compliance

The capital costs and annual operating and maintenance costs for the considered control options, except for the LSC option, were developed by S&L and are included in Appendix A. The annual cost increase due to burning only LSC is based on a cost premium of $0.50 per ton, which was the premium provided to EAI's fuel purchasing department by its coal suppliers. For the S&L-developed costs, two sets of values are presented. The first, in Table 4-3, is the actual cost estimated for each unit and control option. The second, in Table 4-4Table 4-4, is the estimated cost after excluding cost items that EPA has historically claimed should not be accounted for in BART cost effectiveness calculations. An example of an excluded cost is Allowance for Funds Used During Construction (AFUDC). AFUDC represents the interest expense incurred on the investment in a large capital project, such as a FGD installation, which can take several years to complete (≥ 5 years). Although interest expenses will certainly be incurred on such a project, and AFUDC is typically considered as part of the capital cost of such a project for standard accounting and rate-making purposes, EPA Region 6 has expressed concern with the inclusion of AFUDC and certain other costs. EAI disagrees and believes that determining the cost effectiveness of the control options must realistically reflect the actual cost of compliance. *See* EAI's comments on the proposed FIP.[17] Nonetheless, for completeness, this analysis shows a range of cost effectiveness both including AFUDC and other costs and excluding those costs.

[redacted]

Trinity determined the values for annual tons of SO_2 reduced by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. The baseline annual emission rate was based on the average rate for the 2009-2013 baseline period.[19] The controlled annual emission rates were based on the lb/MMBtu levels listed in Table 4-2 multiplied by the future annual heat input, which was based on the average actual heat input from CAMD for the 2009-2013 baseline period. For the LSC scenario, "controlled" annual emission rates were based on an 8.75 percent decrease compared to baseline annual emission rates, which is estimated by comparing the maximum 30-boiler operating day rolling average to the controlled emission rate of 0.6 lb/MMBtu.

The cost effectiveness in dollars per ton of SO_2 reduced was determined by dividing the annualized cost of control by the annual tons reduced. Table 4-3 presents a summary of the cost effectiveness for each control

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[17] Entergy Arkansas Inc. "Comments On the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas" (EPA Docket ID No. EPA-R06-OAR-2015-0189), August 7, 2015, pp. 10-11.

[18] October 27, 2021 per 81 Fed. Reg. Vol. 81, p. 66416. However, given that actual installation would take at least five years, SDA likely could not be installed until 2023 or later.

[19] As noted above, this is a conservative baseline, and EAI would have been justified in using a more recent baseline with lower emissions that would have resulted in generally higher cost effectiveness values.

option. The cost of switching to low sulfur coal is [redacted]. [redacted]. It's noted (without waiver) that the cost effectiveness of add-on controls even when excluding certain costs for which EPA has expressed concern (e.g., AFUDC), but that will be incurred as explained above, [redacted][20]

Table 4-3. Summary of SO_2 Controls Cost Effectiveness for Unit 1 and Unit 2 Based on Actual Costs

Unit & Control Option	Baseline Emission Rate (tpy)	Controlled Emission Rate (tpy)	Capital Cost ($MM)	Annualized Capital Cost ($MM/yr)	Annual O&M Cost ($MM/yr)	Average Cost Effective-ness ($/ton)	Incremental Cost Effective-ness v. LSC ($/ton)
SN-01 – LSC	15,939	14,544	0	0	1.60	1,150	
SN-02 – LSC	16,034	14,631	0	0	1.61	1,148	
SN-01 – DSI	15,939	9,770	[redacted]	[redacted]	[redacted]	[redacted]	8,900
SN-02 – DSI	16,034	9,807	[redacted]	[redacted]	[redacted]	[redacted]	8,807
SN-01 – Enhanced DSI	15,939	4,187	[redacted]	[redacted]	[redacted]	[redacted]	8,209
SN-02 – Enhanced DSI	16,034	4,203	[redacted]	[redacted]	[redacted]	[redacted]	8,153
SN-01 – SDA	15,939	1,675	[redacted]	[redacted]	[redacted]	[redacted]	7,771
SN-02 – SDA	16,034	1,681	[redacted]	[redacted]	[redacted]	[redacted]	7,722

Table 4-4. Summary of SO_2 Controls Cost Effectiveness for Unit 1 and Unit 2 Based on Costs Adjusted for EPA-Exclusions for Illustration Purposes

Unit & Control Option	Baseline Emission Rate (tpy)	Controlled Emission Rate (tpy)	Capital Cost ($MM)	Annualized Capital Cost ($MM/yr)	Annual O&M Cost ($MM/yr)	Average Cost Effective-ness ($/ton)	Incremental Cost Effective-ness v. LSC ($/ton)
SN-01 – LSC	15,939	14,544	0	0	1.60	1,150	
SN-02 – LSC	16,034	14,631	0	0	1.61	1,148	
SN-01 – DSI	15,939	9,770	[redacted]	[redacted]	[redacted]	[redacted]	7,764
SN-02 – DSI	16,034	9,807	[redacted]	[redacted]	[redacted]	[redacted]	7,683
SN-01 – Enhanced DSI	15,939	4,187	[redacted]	[redacted]	[redacted]	[redacted]	7,137
SN-02 – Enhanced DSI	16,034	4,203	[redacted]	[redacted]	[redacted]	[redacted]	7,088
SN-01 – SDA	15,939	1,675	[redacted]	[redacted]	[redacted]	[redacted]	5,883
SN-02 – SDA	16,034	1,681	[redacted]	[redacted]	[redacted]	[redacted]	5,846

[20] Issues raised on appeal of the federal plan include EPA's use of undervalued cost of controls. However, without waiver of any claims or arguments, EPA's estimates also support the conclusion that SDA is not cost effective. Using EPA's estimates of capital cost [redacted] and emissions reductions (14,363 tpy for Unit 1 and 15,221 tpy for Unit 2), [redacted]

4.4.3 Energy Impacts and Non-Air Quality Impacts

There are numerous energy impacts and adverse non-air quality environmental impacts associated with the add-on controls under consideration. Some examples related to the use of DSI include (a) the need for substantial storage and transportation – both delivery via rail and conveyance on site – of Trona, (b) the forced abandonment of the beneficial re-use of fly ash, and (c) potential negative impacts on the PM control device.[21] These impacts are more fully addressed for all the considered control options in the S&L reports included in Appendix A.

4.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE SO_2 CONTROLS FOR UNIT 1 AND UNIT 2

Trinity conducted an impact analysis to assess the visibility improvement achieved. The impact analysis compared the impacts associated with the baseline emission rates to the impacts associated with the maximum emission rates representative of each control option.

Table 4-5 summarizes the lb/hr emission rates that were modeled to reflect each control option. The NO_X and total PM_{10} emission rates were modeled at the revised 2009-2013 baseline rates. The applicable NPS speciation spreadsheets were relied upon to determine emission rates for PM species.[22,23,24] SO_4 emission rates were independently calculated using an EPRI methodology that considers the SO_2 to SO_4 conversion rate and SO_4 reduction factors for various downstream equipment.[25]

[21] Sargent & Lundy, *Entergy Arkansas, Inc. White Bluff DSI Cost Estimate Basis Document*, SL-014000 Final, Rev. 0, August 3, 2017, pp. 6-10. *See* Appendix A of this report.

[22] Low sulfur coal PM speciation is based on the NPS Workbook for a Dry Bottom Boiler burning Pulverized Coal using an ESP. The following values were input: heating value of 8,587 Btu/lb, 0.27% sulfur, 4.96% ash, 8,950 MMBtu/hr heat input, and a baseline total PM_{10} emission rate of 119.2 lb/hr at White Bluff Unit 1 and Unit 2. NPS: http://www.nature.nps.gov/air/Permits/ect/index.cfm.

[23] DSI and Enhanced DSI PM speciations are based on the NPS workbooks for a Dry Bottom Boiler burning Pulverized Coal using an FGD system with an ESP or Fabric Filter. The following values were input: heating value of 8,587 Btu/lb, 0.27% sulfur, 4.96% ash, 8,950 MMBtu/hr heat input, and a baseline total PM_{10} emission rate of 119.2 lb/hr at White Bluff Unit 1 and Unit 2. NPS: Ibid.

[24] DFGD speciation is based on the NPS workbook for a Dry Bottom Boiler burning Pulverized Coal using an FGD system with a Fabric Filter. The following values were input: heating value of 8,587 Btu/lb, 0.27% sulfur, 4.96% ash, 8,950 MMBtu/hr, and a baseline total PM_{10} emission rate of 119.2 lb/hr at White Bluff Unit 1 and Unit 2. NPS: Ibid.

[25] Electric Power Research Institute (EPRI) Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: EPRI, Technical Update, Palo Alto, CA: March 2012. 1023790.

Table 4-5. Emission Rates Modeled to Reflect SO_2 Controls for Unit 1 and Unit 2

Unit & Control Option	SO_2 (lb/hr)	SO_4 [A] (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	EC (lb/hr)	SOA (lb/hr)	Total PM_{10} (lb/hr)
SN-01 – LSC	5,370.0	4.0	3,355.4	40.4	31.1	1.2	9.3	119.2
SN-02 – LSC	5,370.0	4.0	3,590.5	40.4	31.1	1.2	9.3	119.2
SN-01 – DSI	3,132.5	0.5	3,355.4	29.0	22.4	0.9	13.4	119.2
SN-02 – DSI	3,132.5	0.5	3,590.5	29.0	22.4	0.9	13.4	119.2
SN-01 – Enhanced DSI	1,342.5	0.02	3,355.4	13.4	12.9	0.5	18.5	119.2
SN-02 – Enhanced DSI	1,342.5	0.02	3,590.5	13.4	12.9	0.5	18.5	119.2
SN-01 – SDA	537.0	0.01	3,355.4	13.4	12.9	0.5	18.5	119.2
SN-02 – SDA	537.0	0.01	3,590.5	13.4	12.9	0.5	18.5	119.2

[A] SO_4 as it is displayed in this table represents ammonium sulfate.

Comparisons of the existing/baseline visibility impacts and the post-control visibility impacts are provided in Table 4-6 and Table 4-7.

Table 4-6. Summary of CALPUFF-Modeled Visibility Impacts from SO_2 Controls for Unit 1 (Across All Modeled Years, 2001-2003)

Scenario	CACR		UBPU		HERC		MING	
	98% Impact (Δdv)	# Days > 0.5 Δdv	98% Impact (Δdv)	# Days > 0.5 Δdv	98% Impact (Δdv)	# Days > 0.5 Δdv	98% Impact (Δdv)	# Days > 0.5 Δdv
Baseline	1.505	99	1.051	69	0.925	49	0.802	51
LSC	1.376	89	0.908	54	0.758	34	0.687	40
Improvement over baseline	*0.129*	*10*	*0.143*	*15*	*0.167*	*15*	*0.115*	*11*
DSI	1.197	64	0.676	30	0.584	19	0.469	17
Improvement over baseline	*0.308*	*35*	*0.375*	*39*	*0.341*	*30*	*0.333*	*34*
Improvement over LSC	*0.179*	*25*	*0.232*	*24*	*0.174*	*15*	*0.218*	*23*
Enhanced DSI	1.013	41	0.496	14	0.458	11	0.366	6
Improvement over baseline	*0.492*	*58*	*0.555*	*55*	*0.467*	*38*	*0.436*	*45*
Improvement over LSC	*0.363*	*48*	*0.412*	*40*	*0.300*	*23*	*0.321*	*34*
Improvement over DSI	*0.184*	*23*	*0.180*	*16*	*0.126*	*8*	*0.103*	*11*
SDA	0.902	35	0.409	7	0.400	6	0.298	2
Improvement over baseline	*0.603*	*64*	*0.642*	*62*	*0.525*	*43*	*0.504*	*49*
Improvement over LSC	*0.474*	*54*	*0.499*	*47*	*0.358*	*28*	*0.389*	*38*
Improvement over DSI	*0.295*	*29*	*0.267*	*23*	*0.184*	*13*	*0.171*	*15*
Improvement over Enhanced DSI	*0.111*	*6*	*0.087*	*7*	*0.058*	*5*	*0.068*	*4*

Table 4-7. Summary of CALPUFF-Modeled Visibility Impacts from SO_2 Controls for Unit 2 (Across All Modeled Years, 2001-2003)

	CACR		UBPU		HERC		MING	
Scenario	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**
Baseline	1.533	100	1.059	71	0.912	52	0.819	49
LSC	1.436	89	0.932	55	0.775	35	0.697	41
Improvement over baseline	*0.097*	*11*	*0.127*	*16*	*0.137*	*17*	*0.122*	*8*
DSI	1.259	66	0.700	31	0.609	19	0.486	18
Improvement over baseline	*0.274*	*34*	*0.359*	*40*	*0.303*	*33*	*0.333*	*31*
Improvement over LSC	*0.177*	*23*	*0.232*	*24*	*0.166*	*16*	*0.211*	*23*
Enhanced DSI	1.073	42	0.528	17	0.483	12	0.384	7
Improvement over baseline	*0.460*	*58*	*0.531*	*54*	*0.429*	*40*	*0.435*	*42*
Improvement over LSC	*0.363*	*47*	*0.404*	*38*	*0.292*	*23*	*0.313*	*34*
Improvement over DSI	*0.186*	*24*	*0.172*	*14*	*0.126*	*7*	*0.102*	*11*
SDA	0.959	37	0.427	12	0.426	8	0.318	3
Improvement over baseline	*0.574*	*63*	*0.632*	*59*	*0.486*	*44*	*0.501*	*46*
Improvement over LSC	*0.477*	*52*	*0.505*	*43*	*0.349*	*27*	*0.379*	*38*
Improvement over DSI	*0.300*	*29*	*0.273*	*19*	*0.183*	*11*	*0.168*	*15*
Improvement over Enhanced DSI	*0.114*	*5*	*0.101*	*5*	*0.057*	*4*	*0.066*	*4*

4.6 BART FOR SO_2 FOR UNIT 1 AND UNIT 2

Based on the costs of the control options listed above, BART for Unit 1 and Unit 2, when considering the updated RUL, would be an emission level of 0.6 lb/MMBtu based on the use of low-sulfur coal.

APPENDIX A. CONTROL COST INFORMATION

SO_2 CONTROL COST INFORMATION – LAST UPDATED AUGUST 2017

Table B-8. Baseline Visibility Impairment Attributable to Unit 1 by Pollutant

Year	Maximum (Δdv)	98^{th} Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98^{th} Percentile % SO_4	98^{th} Percentile % NO_3	98^{th} Percentile % PM_{10}	98^{th} Percentile % NO_2
Caney Creek							
2001	2.912	1.505	38	74.33	25.34	0.17	0.15
2002	2.048	1.306	29	61.53	34.59	0.83	3.04
2003	4.020	1.053	32	47.92	50.35	0.35	1.39
Upper Buffalo							
2001	2.089	1.051	30	68.58	31.17	0.26	0.00
2002	1.438	0.742	15	79.11	20.19	0.37	0.32
2003	1.773	1.033	24	79.79	19.92	0.28	0.00
Hercules Glades							
2001	1.643	0.925	24	90.21	9.56	0.23	0.00
2002	1.184	0.567	10	74.20	25.45	0.25	0.10
2003	1.977	0.704	15	86.02	13.73	0.25	0.00
Mingo							
2001	1.538	0.802	16	51.46	48.03	0.39	0.12
2002	0.898	0.708	21	54.87	44.82	0.31	0.01
2003	1.003	0.666	14	57.31	41.18	0.41	1.11

Table B-9. Baseline Visibility Impairment Attributable to Unit 2 by Pollutant

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Days with $\Delta dv \geq 0.5$	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek							
2001	2.994	1.533	39	36.23	60.75	0.74	2.28
2002	2.098	1.322	29	59.43	36.53	0.82	3.22
2003	4.084	1.059	32	96.37	3.38	0.24	0.01
Upper Buffalo							
2001	2.066	1.059	30	66.54	33.21	0.26	0.00
2002	1.447	0.739	16	77.57	21.71	0.37	0.35
2003	1.791	1.030	25	78.24	21.46	0.28	0.00
Hercules Glades							
2001	1.665	0.912	25	89.39	10.38	0.23	0.00
2002	1.185	0.568	11	72.38	27.26	0.25	0.11
2003	1.947	0.720	16	40.35	58.44	0.40	0.82
Mingo							
2001	1.580	0.819	15	81.62	17.93	0.33	0.12
2002	0.886	0.719	20	58.93	40.66	0.19	0.22
2003	0.999	0.678	14	55.08	43.36	0.40	1.17

APPENDIX C. REFINED PM SPECIATION CALCULATIONS

ENTERGY ARKANSAS, INC.

WHITE BLUFF DRY FGD

COST ESTIMATE AND TECHNICAL BASIS

SL-012831
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Project 13027-002

Prepared by

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CONTENTS

EXECUTIVE SUMMARY

The purpose of this study is to estimate the total capital investment and operating and maintenance (O&M) costs associated with installing dry flue gas desulfurization (FGD) technology on White Bluff Units 1&2 using an Engineer, Procure, Construct (EPC) contracting strategy. A preliminary conceptual design was developed for implementation of dry FGD technology at the White Bluff station to serve as the technical basis of the capital and O&M estimates.

The capital cost estimate includes the following components which comprise the total cost the Owner will incur to install dry FGD technology at White Bluff:

- FGD Island Cost supplied by a Dry FGD System Supplier including the main process equipment
- Balance of Plant Cost including auxiliary equipment and systems, foundations and buildings, site work, demolition and relocation
- Other Direct and Construction Indirect Costs including labor premiums, freight, contractor's G&A and profit
- Indirect Costs including engineering, startup spare parts, technical field advisors, and the additional fee associated with an EPC contracting strategy
- Escalation and Interest During Construction associated with the project duration for implementation of a large air quality control technology
- Owner's Costs including internal labor, insurance, and initial lime reagent fill
- Third Party Services including construction management oversight, start-up and commissioning oversight, Owner's Engineer services, and performance testing
- Project Contingency to cover unknown and undefined scope associated with the project which would result in additional cost to the Owner

The total capital investment to install dry FGD on White Bluff Units 1 and 2 was estimated to be $991,489,000. The project definition and accuracy of the individual components included in this estimate result in an overall accuracy of ±20-25%. In addition, the O&M costs were estimated to be approximately $8,132,000 per year per unit and include the cost of lime (reagent), byproduct disposal, auxiliary power, water, replacement bags and cages, maintenance costs, and operating labor.

1. PURPOSE

The purpose of this study is to estimate the total capital investment and operating and maintenance costs associated with installing dry flue gas desulfurization (FGD) technology on White Bluff Units 1&2. This report documents the conceptual design and technical basis for the dry FGD cost estimate.

2. APPROACH

2.1 TECHNOLOGY SELECTION

Sargent & Lundy (S&L) previously performed an evaluation of wet and dry FGD technology for Entergy's White Bluff Station. The evaluation included development of a preliminary conceptual design for both wet and dry FGD systems at the White Bluff station. The preliminary designs were used as the basis of an evaluation which compared the overall economics of each system, including capital and operating costs. The study concluded that a dry FGD system had an economic advantage over wet FGD when the design coal sulfur is below 3 lb SO_2/MMBtu. Based on the current market and potential future regulations, dry FGD technology would have an economic advantage over wet FGD for SO_2 reduction at the White Bluff station.

2.2 CONTRACTING APPROACH

Many utilities elect to utilize a one contract engineer-procure-construct (EPC) approach for major retrofit projects, such as large FGD projects. The EPC approach allows the Owner to contract with one entity which then manages the overall project. The EPC Contractor procures the material, equipment and services needed to complete the project and the EPC Contractor takes full responsibility for the equipment and work supplied by each of its subcontractors.

With this approach the Owner takes on less risk in the overall management and coordination of the project. However, shifting this risk to the EPC Contractor increases the total price for the EPC contract; "Whilst there are… numerous advantages to using an EPC contract, there are some disadvantages. These include the fact that it can result in a higher contract price than alternative contractual structures. This higher price is a result of a number of factors not least of which is the allocation of almost all the construction risk to the contractor."[1] The additional cost due to an EPC contracting approach is represented in our cost estimate as an EPC Risk Fee.

The Owner's control over design details of the system is limited, using this contracting strategy, to the requirements specified in the contract. This results in an additional upfront effort for the Owner and the Owner's Engineer to thoroughly define the project in the specification. Whatever is not defined will be excluded from the EPC Contractor's scope resulting in potential change orders. The Owner and Owner's Engineer are also responsible for reviewing the EPC Contractor's submitted design drawings and schedules to ensure what has been agreed upon in the final contract is included.

2.3 CAPITAL COST DEVELOPMENT

The capital cost estimate is based on project-specific information, including:

- A preliminary conceptual design developed for implementation of dry FGD technology at the White Bluff station.
- An engineer-procure-construct (EPC) contracting strategy.
- A Dry FGD System Supplier, subcontracted by the EPC Contractor, providing the main process equipment as a complete FGD Island.
- The FGD Island equipment and installation cost is based on a budgetary proposal received from Alstom in September 2013. The budgetary proposal is based on installing SDA technology on both of the White Bluff units.

The capital cost estimate includes the following components which comprise the total price of the EPC Contract to complete the work:

- Equipment and material
- Installation labor
- Demolition and Relocation work
- Indirect field costs and BOP engineering
- Freight on Materials
- General and Administration
- Erection contractor profit

[1] "EPC Contracts in the Power Sector", prepared by DLA Piper, 2011, page 6. See: https://www.dlapiper.com/

- Engineering, Procurement and Project Services
- Spare parts
- EPC Fee
- Escalation

The equipment design basis is summarized in Section 3 of this report and the scope of the estimate is summarized in Section 4. The project definition and accuracy of the individual components included in this estimate result in an overall accuracy of ±20-25%. The costs provided in this report are in 2015 dollars.

In order to estimate the *total plant* capital cost for installation of FGD at White Bluff, the following costs which would be incurred outside of the scope of the EPC contract were included:

- Owner's Costs
- Third Party Services – Construction Management Oversight
- Third Party Services – Startup and Commissioning Oversight
- Third Party Services – Owner's Engineer
- Third Party Services – Performance Testing
- Project Contingency
- Interest During Construction or Allowance for Funds Used During Construction

The cash flow provided in Attachment 2 is based on a monthly progress payment schedule developed using the preliminary execution schedule included in Attachment 3. Specific details regarding the milestones making up the payment schedule are listed in Attachment 4. Below is a summary of those activities that represent major or large payment milestones based on a project start date of January 2015.

Month	Date	Milestone
1	February 2017	Award EPC Contract Execution
5	June 2017	EPC Contractor Procures Major Equipment
7	August 2017	EPC Contractor Procures Major Equipment
10	November 2017	Flue Gas Ductwork Procurement Initiated by EPC Contractor
13	February 2018	SDA and Fabric Filter Design Drawings
15	April 2018	Award Fabric Filter Bags and Cages Flue Gas Ductwork Start of Fabrication

Month	Date	Milestone
17	June 2018	Physical Flow Model Completed
19	August 2018	Mobilize On-Site
20-38	September 2018 to March 2020	Construction Activities
41	June 2020	Unit 1 Substantial Completion
45	October 2020	Unit 2 Substantial Completion
		Demobilization Complete
46	November 2020	Unit 1 Final Acceptance
47	December 2020	Unit 2 Final Acceptance

Each monthly cash outlay in the cash flow is broken down by category (labor, equipment and materials, and indirect costs).

3. DRY FGD CONCEPTUAL DESIGN AND SYSTEM COMPONENTS

A conceptual design for the implementation of Dry FGD at the White Bluff station was developed by Sargent & Lundy LLC (S&L) as a precursor to the development of the cost estimate. A general arrangement drawing showing the conceptual design is included in Attachment 7. The dry FGD conceptual design was developed for each of the following subsystems:

3.1 DRY FGD ISLAND

3.1.1 Reagent Preparation System

Lime will be supplied to the lime day bins from the long-term storage silo located in the Reagent Handling Area and supplied by the EPC Contractor. The lime day bins, located in the Reagent Preparation Area and provided by the Dry FGD System Supplier, will each have a storage capacity to supply the plant with lime reagent for 24 hours when firing 1.2 lb SO_2/mmBtu coal.

Lime from the day bin will be gravity-fed through feeders to a lime slaker, where the lime will be slaked (mixed with low pressure service water and converted from calcium oxide to calcium hydroxide slurry). The plant will have a total of two lime slaking trains (2 x 100%), each sized to process enough lime slurry to supply the entire plant. Each lime slaker will discharge to a lime slurry transfer tank, which is equipped with two lime slurry transfer pumps which will feed into the lime slurry storage tanks. The common lime slurry storage tanks will each be sized for 12 hours of storage for the entire plant when burning a 1.2 lb SO_2/mmBtu coal. The lime day bin, slaking trains, and lime slurry tanks are sized to provide the necessary reagent slurry to both units simultaneously. The lime slurry tanks are built with cross-ties such that either slurry tank can feed either the Unit 1 or Unit 2 FGD systems.

A total of four lime slurry feed pumps (two per unit), each sized for 100% flow to one unit, will pump the lime slurry from the storage tanks to the SDAs through one of 2 x 100% piping loops, and return unused slurry back to the lime slurry storage tank. The closed-loop reagent supply line requires a flow velocity between 4-10 fps to avoid any solids buildup in the piping. Because of this, the pumping requirement is higher than the actual SDA requirement and must be sufficiently greater than the slurry flow that is pumped into the absorbers to allow the returning flow to remain above 4 fps.

3.1.2 Absorbers

Three absorbers, each treating 33⅓% of the flue gas are provided for each unit. Depending on the supplier and the type of atomizer normally used, there may be one rotary atomizer per absorber with a shared spare (B&W), three rotary atomizers per absorber with one or more shared spares (Alstom, basis of the estimate), or multiple dual-fluid atomizers with 15% shared spares (Siemens). The cost estimate includes contingency to capture the possibility of any of these designs.

3.1.3 Baghouse

Each SDA will be paired with a pulse-jet baghouse with a gross air-to-cloth ratio of approximately 3.2-3.4 ft/min. The filter bags in each baghouse are cleaned by pulses of compressed air. The air compressors will be 4 x 33% for the station and are included in the scope of the baghouse supplier.

3.1.4 Byproduct Recycle System

The reaction byproducts from the absorbers will be collected in the baghouses and a portion of the collected material will be recycled. The baghouse hoppers will be emptied through air lock feeders and pneumatically conveyed to two recycle day bins located in the Byproduct Recycle Area and supplied by the Dry FGD System Supplier, which are common for both units. The air-lock feeders are installed without a spare. One recycle day bin is located in the recycle train for each unit. The common byproduct recycle day bins (one per unit) provide 8-hours of storage when burning 1.2 lb SO_2/mmBtu coal.

Each byproduct recycle day bin is equipped with two recycle slurry preparation systems. The byproduct in each recycle day bin is gravimetrically conveyed to one of two systems where the byproduct is slurried with water (cooling tower blowdown). The byproduct recycle slurry is stored in one of four plant wide recycle slurry tanks, two per unit (combined 4-hour storage capacity).

Two recycle water make-up tanks are located in the recycle area with a capacity of 250,000 gallons (to be supplied by the EPC Contractor). The recycled by-product slurry will be combined with fresh lime slurry for feed to the SDA atomizers. Recycle feed slurry pumps (4 x 100%, two installed per unit) will be used to transfer the recycle slurry from the recycle slurry tanks to the atomizers. In addition, all recycle feed lines are provided in a loop configuration as with the reagent system, with a complete redundant loop to allow unhindered operation due to any pluggage of pumps or feed piping.

3.2 REAGENT HANDLING SYSTEM

As part of the conceptual design, several lime delivery methods were evaluated and it was determined that rail delivery provided the best alternative for White Bluff based on ease of implementation, overall plant interface, and lowest evaluated cost (in terms of required capital investment and delivered cost of lime). Therefore, the basis of the estimate is delivery of lime via hopper-bottom railcars with truck unloading as a backup. In order to accommodate rail delivery to the site, a new rail spur will be constructed from the existing track bordering the west side of the plant. Lime trains will enter and exit the station from this spur. A trackmobile car positioner will position railcars, two at a time, in the enclosed delivery shed for unloading. The cost estimate includes the capital cost associated with railcar unloading, including the new rail spur and the renovation of the existing rail spur to handle lime delivery. A vacuum pneumatic system will unload the railcars into either of the two (2) lime storage silos. The lime storage silos will be sized for supply of reagent for 14 days of storage at full load when firing 1.2 lb SO2/mmBtu coal. Lime from the long-term storage silos will be pneumatically transferred to two lime day bins located in the Reagent Preparation Area and supplied by the Dry FGD System Supplier.

3.3 BYPRODUCT HANDLING SYSTEM

Excess FGD byproduct from the recycle system will be pneumatically conveyed to either of the two common long- term FGD byproduct storage silos. The two long-term FGD byproduct storage silos are each sized to handle the byproduct for a total of 7 days of storage when firing the 1.2 lb SO_2/mmBtu coal. The byproduct will be mixed with a small amount of fly ash and water to form a final product which contains approximately 65% FGD byproduct, 5% fly ash, and 30% water. In order to achieve this mixture, a common fly ash blending bin (7-day storage) will be located near the new byproduct silos. The feed rate of fly ash discharged from the blending bin is controlled to maintain the ratio of byproduct to fly ash. A pneumatic airslide conveyor will discharge fly ash directly into an unloading conditioner, simultaneously mixing fly ash with the proper ratios of water and FGD byproduct (discharged from the silo). The wetted byproduct/fly ash mixture is then loading into dump trucks, which will deposit the FGD byproduct in a final storage location in the landfill. A bulldozer will maintain the landfill pile. The capital cost for the silos, conveying system and byproduct/fly ash blending system is included in the cost estimate. As part of the conceptual design, the existing landfill was evaluated and was determined to have sufficient capacity to accommodate the addition of FGD byproduct. Therefore no costs were included in the capital estimate for the (existing) landfill. In addition, it was assumed that the existing haul trucks would be used to transport the FGD byproduct.

3.4 FLUE GAS HANDLING SYSTEM

The flue gas from the existing ID fans will be ducted to the absorbers. The gases from the absorbers will be ducted to the baghouses to collect the reaction by-products and residual fly ash. Two axial booster fans (2 x 50% for each unit) will be located downstream of the absorbers and baghouse; the booster ID fans can be provided by the Dry FGD System Supplier or the EPC Contractor. Due to the dry condition of the scrubbed flue gas, the existing stack and liners will be used for the retrofit case.

The existing chimney and carbon steel liners were evaluated as part of the conceptual design and were deemed to be suitable for a dry FGD application. In addition, the top 50 feet of the existing chimney liners are constructed of 316 stainless steel so an acid resistant coating on the liner is not required. However, downwash may result in acid attack and discoloration on the outer concrete shell of the chimney; it was determined that an acid resistant coating to the top 100 feet of the concrete shell is recommended; therefore, the cost estimate includes the coating of the top 100 feet of the chimney's outer concrete shell.

3.5 ELECTRICAL BOP SYSTEM

The existing auxiliary power system was evaluated as part of the conceptual design for the White Bluff dry FGD system. In order to feed the new dry FGD and other BOP equipment, significant modifications and additions to the existing power system are required. These include installation of new auxiliary transformers, medium- and low-voltage switchgear buses, motor control centers (MCCs) and upgrades to the isolated phase tap-off buses.

3.6 I&C BOP SYSTEM

As part of the conceptual design, the existing control system was evaluated to determine the required modifications necessary to implement dry FGD technology at the White Bluff station. The dry FGD system will be controlled using a new Foxboro I/A system which will integrate with the existing power block Foxboro I/A system. The control processors, I/O cabinets, and other system components will be located in the new electrical equipment building (EEB) for each unit. Two HMIs will be installed in the new EEB for each unit to provide any local controls for the lime preparation and byproduct recycle systems provided by the Dry FGD System Supplier. The baghouse will be controlled through the Allen-Bradley ControlLogix PLC and the ID booster fans will be controlled through the existing Foxboro I/A system controller(s), which are used to control boiler air and furnace pressure.

4. CAPITAL AND O&M COST ESTIMATE TECHNICAL BASIS

The following summarizes the design inputs used as the basis for the White Bluff dry FGD Systems:

- Design SO_2 inlet concentration of 1.2 lb SO_2/MMBtu for equipment design, based on the current coal contract sulfur limit.
- SO_2 inlet concentration of 0.57 lb SO_2/MMBtu for annual operating costs, based on the annual heat input weighted average emission from 2009 through 2013.
- Design SO_2 outlet concentration of 0.06 lb SO_2/MMBtu.
- Annual capacity factor of 72.1% (annual average capacity factor for White Bluff Units 1 and 2 based on historical heat input from 2009 through 2013).
- Compliance deadline of December 2020, based on a project start date of January 2015.

4.1 EPC CONTRACT PRICE

The Dry FGD System Supplier will provide all of the equipment within the FGD Island. The FGD Island will include the Reagent Preparation Equipment, Absorber Area Equipment, Baghouse Area Equipment and the Byproduct Recycle Equipment. The booster ID fans could be provided by either the Dry FGD System Supplier or the EPC Contractor; the basis of this estimate is supply of the booster fans by the Dry FGD System Supplier. The EPC Contractor will provide the remaining BOP scope in order to provide a complete and operable FGD system. In addition, the EPC Contractor will install/construct the entire system including the equipment provided by the DFGD supplier.

The scope of work for the cost estimate is broken out by area below:

1. <u>Dry FGD Island</u>
   a. Reagent Preparation System, common to both units:
      - Two lime day bins, 24-hours storage each
      - Two detention lime slakers at 100% capacity, each with a grit screen, gravimetric feeder
      - Two lime slurry transfer tanks
      - Four slurry transfer centrifugal pumps
      - Two lime slurry storage tanks
      - Four slurry feed centrifugal pumps

- Cost estimate based on budgetary proposal from Alstom; the budgetary proposal is based on a design sulfur of 2.0 lb/MMBtu, cost adjustments were included in the estimate for a lower design sulfur of 1.2 lb/MMBtu. These cost adjustments were developed by estimating the differential equipment cost for the reagent preparation and waste handling equipment. The impacted equipment is identified in Section 4.5 which discusses the sulfur design basis sensitivity.

b. Absorber Area, per unit
   - Three absorber vessels per unit, with access doors
   - Rotary atomizers, two spare atomizers included
   - Vessel material carbon steel, ¼ in. – ⅝ in. carbon steel
   - Heating and ventilation
   - Vacuum piping
   - SDA Superstructure
   - Cost estimate based on budgetary proposal from Alstom

c. Baghouse Area, per unit
   - New baghouse, including pulse jet cleaning system and all appurtenances
   - Cost estimate based on budgetary proposal from Alstom

d. Byproduct Recycle System, per unit (located remotely in common location for both units)
   - One recycle silo with bin vent filter per unit, 8-hour total capacity
   - Two recycle mix tanks per unit
   - Two recycle slurry tanks per unit, with two recycle slurry centrifugal pumps per unit
   - Agitators for each tank
   - Baghouse ash handling system common to both units
   - Rotary air-lock valves from baghouse hopper outlets to pressure pneumatic conveying system (60-degree typical)
   - Pneumatic pressure blowers (8 x 33⅓ %)
   - Cost estimate based on budgetary proposal from Alstom

e. ID Booster Fans, per unit
   - Two approximately 5,200 hp axial booster fans per unit sized to overcome pressure drop associated with FGD and baghouse
   - Includes motors - no spare motor included
   - Cost estimate based on budgetary proposal from Alstom
   - Dampers from ID fan to booster fans (cost estimated separately, not included in Alstom budgetary proposal)

f. Interconnecting Ductwork, per unit
   - ID fan outlet to absorber inlet ductwork and supports; carbon steel, ¼ in, design velocity, 3,600 fpm
   - Absorber outlet to baghouse inlet ductwork and supports; carbon steel, ¼ in, design velocity, 3,600 fpm
   - Baghouse outlet to new booster fans and fan outlet to the stack inlet ductwork and supports; carbon steel, ¼ in, design velocity, 3,600 fpm

2. FGD Island Foundations and Enclosures
   a. Absorber tower foundations including caissons
   b. Baghouse area foundations including 18" auger cast piles 60' long
   c. Booster fan area foundations
   d. 6" insulation with lagging for Absorbers and Baghouses (cost estimated separately, not included in Alstom budgetary proposal)
   e. Penthouse enclosure for Absorbers located in FGD Island (cost estimated separately, not included in Alstom budgetary proposal)
   f. Two elevators (one for each unit) to provide maintenance access to Absorber and Baghouse Areas
   g. Enclosure around hoppers for Baghouses located in FGD Island (cost estimated separately, not included in Alstom budgetary proposal)
   h. Lime preparation building for Reagent Preparation Area in FGD Island, 50' x 50' x 50', including substructure and superstructure (cost estimated separately, not included in Alstom budgetary proposal)
   i. Byproduct recycle building for Byproduct Recycle Area in FGD Island, 60' x 60' x 60', including substructure and superstructure (cost estimated separately, not included in Alstom budgetary proposal)

3. Reagent Storage and Handling, common to both units:
   a. Lime rail car unloader:
      - Lime delivery via 25-car unit train
      - System consists of mobile receiving pan and associated vacuum pneumatic equipment to unload railcar through railcar bottom hoppers
      - Enclosed railcar unloading building
      - One vacuum pneumatic system operating to unload a car
      - Pneumatic vacuum exhausters (2 x 100%)
      - Filter separator with vacuum-to-pressure transfer hopper and valves
      - One lot of pneumatic conveying piping located on an above-grade sleeper pipe rack

- Cost estimate based on vendor quote from United Conveyor Corporation (UCC) for a similar unit

b. Lime storage silos:
- Two silos, 14-days storage and capable of storing a train load of lime, 2,400-tons storage total, including substructure and superstructure
- 32' diameter and 95' height to top
- 1,200-tons storage, each
- Continuous level detection systems
- Bin vent filters
- Live bottom hopper outlets
- Rotary airlock assemblies
- Lime transfer systems:
  - Pressure pneumatic conveying system from lime storage silos to lime day bins
  - Pneumatic pressure blowers (3 x 100%)
  - One lot of pneumatic conveying piping located on an elevated pipe rack

c. Concrete foundations including caissons for all material silos

d. Concrete foundations for pneumatic conveying blowers and exhausters

4. Byproduct Handling System, common to both units

a. Two FGD by-product storage silos (7-day capacity each, common to both units) with bin vent filter, fluidizing system, and two unloading conditioners (one operating, one spare per silo)

b. One common fly ash blending, 7-day storage bin with bin vent filter, fluidizing system, and four pneumatic airslide conveyors

c. Water pumps and associated piping for unloading conditioners (pin mixers) at both silos

d. Compressed air system for air operated valves

e. Storage silo substructure and superstructure

f. Continuous level detection system

g. One lot pneumatic conveying piping located on an above grade pipe rack

h. Two truck scales and substructure

i. Existing road improvements for truck haulage to existing landfill

j. Cost estimate based on budgetary proposal from UCC for similar project

k. Concrete foundations including caissons for all material silos

l. Concrete foundations for pneumatic conveying blowers and exhausters

5. Flue Gas Handling BOP, per unit
   a. ID fan outlet to absorber inlet ductwork insulation; 6” with lagging6” insulation with lagging
   b. Absorber outlet to baghouse inlet ductwork insulation; 6” with lagging
   c. Baghouse outlet to new booster fans and fan outlet to the stack inlet ductwork insulation; 6” with lagging
   d. Concrete foundations for all flue gas ductwork
   e. Epoxy trowel coating on top 100 feet of outside of chimney shell

6. Civil BOP
   a. Roadwork
   b. Site grading
   c. Soil removal earthwork
   d. Excavation, backfill, and compaction for all foundations
   e. Storm sewer work
   f. Two-cell pond for wastewater storage of process water/slurry
   g. Laydown Area
      - Development of a new laydown area, approximately 10 acres, including site preparation, fencing, and temporary power. It was assumed that this area would be located on existing plant property, and does not required land to be purchased.
   h. Highway Intersection Upgrade to provide sufficient plant access for construction period
      - New Bypass Lane on Westside of Highway 365
      - New Southbound Left Turn Lane on Highway 365
      - New Northbound Merge Lane on Highway 365
      - New Northbound Right Turn Lane on Highway 365
      - Extension and upgrade of existing Contractor Haul Road (Highway 46 Spur) to Highway 365
      - Widening of the existing Main Plant Road from the Contractor Haul Road (Highway 46 Spur) to Main Guard House
      - Track crossing signal system at Haul Road (Highway 46 Spur) track crossing
   i. New warehouse building 200’ x 75’ x 15’, including substructure and superstructure.

7. Mechanical BOP System
   a. Interconnecting piping, above-ground and buried
   b. Valves for interconnecting piping, above-ground and buried
   c. Lime slaking water storage tank, 115,000-gallon capacity

d. Slaker water 3” in-line heaters, 475 kW each

e. Recycle make-up water tanks, 2 x 250,000-gallon capacity

f. Pipe Racks, common to both units
- Between lime railcar unloading enclosure and lime silos
- Between lime silos and lime day bins
- From baghouse hoppers to recycle silos and FGD by-product silo
- From lime slurry storage tanks to absorber
- From recycle slurry storage tank to absorber
- Concrete foundations including caissons for all pipe racks
- Shallow concrete foundations for other miscellaneous structures

g. BOP Pumps
- Three by-product recycle water forwarding pumps to recycle slurry, 1000 gpm @ 150’ TDH
- Four reagent prep/recycle sump pumps, 120 gpm @ 150’ TDH
- Two lime silo and unloading area sump pumps, 120 gpm @ 150’ TDH
- Two by-product ash silo area sump pumps, 120 gpm @ 150’ TDH
- Two by-product recycle make-up water tank supply pumps, 2600 gpm @ 200’ TDH
- Two lime slaking water pumps, 750 gpm @ 100’ TDH
- One new Low Pressure Service Water (LPSW) pump, 20,000 gpm @ 100’ TDH, including new intake structure, piping and valves
- Two leachate pumps, 50 hp

h. Instrument Air System, common to both units
- Air compressors; 2 x 100%, 250 scfm each @ 100 psig
- IA dryers w/filters; 2 x 100%, 250 net scfm each
- Air receivers; 2 x 100%
- Instrument air piping to every silo or day bin, bin vent and reagent preparation/recycle area
- Heat-traced piping

i. Service Air System, common to both units
- Air compressors; 2 x 100%
- Air receivers; 2 x 100%

j. Field painting
- Multiple coat system used for exposed ductwork only
- Inorganic zinc primer and polyurethane system used for steel

- Allowance for underground piping shop coatings built into piping cost

8. Demolition and Relocation
   a. Hazardous material accumulation building
   b. Ash handling maintenance building
   c. Drainage ditch
   d. Pipe trench
   e. Fabrication shop
   f. Existing contractor electrical hook up
   g. Existing drainage ditches, rerouted with new concrete trenches
   h. Relocation of ACI injection location from the air heater inlet to upstream of the DFGD
   i. Rail Yard Extension, common to both units
      - Extend rail spur to north to allow lime train to be unloaded and cars to be stored on site, designed for 136 lb rail to be consistent with existing coal spurs
   j. Fire Protection System Modifications
      - Deluge system has been included for the new transformers
      - Allowances have been included for fire protection in all of the new buildings; including piping and post indicator valves
      - The new fire protection systems will tie-in to the existing system on-site. It was assumed that the current capacity of the plant fire protections system is sufficient to accommodate the new systems; an evaluation of the current system capacity was not performed.

9. Electrical BOP System
   a. One 115-kV, 1200A isolation disconnect switch
   b. One startup transformer
   c. Two unit auxiliary transformers (UAT)
   d. Three medium-voltage (6.9-kV) switchgear buses (outdoor walk-in type)
   e. Two medium-voltage (6.9-kV) double ended switchgear per unit (total of two)
   f. Two 480-V double ended switchgear buses per unit (total of four)
   g. Six 480-V motor control centers per unit (total of twelve)
   h. Four 6.9-kV/480-V step-down transformers per unit (total of eight)
   i. Two isolated phase UAT tap bus extensions

j. Non-segregated phase bus

k. Medium-voltage cable

l. Low voltage, control and instrumentation cable, as necessary

m. Two electrical equipment buildings

10. <u>Instrumentation and Controls BOP System</u>

a. Controls System based on an estimated number of I/O points:

- Approximately 1,000 I/O points are required for each unit's DFGD system (including reagent preparation), for a total of 2,000 I/O points the cost of which is included in Alstom budgetary proposal pricing.
- Approximately 2,000 I/O points for the common areas at the station, located outside of the DFGD Island.

b. CEMS, per unit

- Existing CEMS analyzers for both units will be recalibrated and recertified; if the existing CEMS analyzers cannot be recalibrated for lower SO_2 emission, new CEMS analyzers will be installed.

11. <u>Labor Costs</u>

Installation/labor costs were included in the base estimate under the direct costs. Manhours are estimated for each item in the base estimate and are based on the type of work and typical estimates for similar work. The labor costs are based on the labor wage rates and labor crews developed by S&L.

a. Labor Wage Rates

Crew labor rates were developed using prevailing craft rates, fringe benefits and state specific worker's compensation rates as published in the 2015 edition of R.S. Means Labor Rates for Pine Bluff, Arkansas area. Costs were added to cover FICA, workers compensation, all applicable taxes, small tools, incidentals, construction equipment, and contractor's overhead. A 1.15 geographic labor productivity multiplier is included based on the Compass International Construction Yearbook for Arkansas. The crew rates do not include an allowance for weather related delays.

b. Labor crews

Construction/erection labor cost is based on the use of applicable construction crews typically required for projects of this type. The construction crew costs were specifically developed for utility industry and are proprietary to S&L. The prevailing craft rates are incorporated into work crews appropriate for the activities, and include costs for small tools, construction equipment, insurance, and site overheads.

12. Other Direct and Construction Indirect Costs

In addition to the base labor costs, other construction indirect costs for the project were broken out in the estimate as well as other contractor direct costs. The following items were included as other direct and construction indirect costs.

a. Scaffolding and Consumables
b. Premiums and per diems ($10 per hour)
c. Overtime is included based on five 10-hour shifts per week work schedule
d. Freight on construction materials
e. Contractor's General & Administration Fees (included at 10% of total direct and construction indirect costs)
f. Contractor's Profit (included at 5% of total direct and construction indirect costs)

13. EPC Indirect Costs

The final contribution to the overall EPC project price are the EPC Contractor's indirect costs; these include the EPC engineering services, startup spare parts and initial fills, technical field advisors, and the EPC risk fee.

a. EPC Engineering Services

The EPC engineering services was estimated based on recent projects with similar scopes and schedules. The total cost of the EPC engineering services was estimated to be $23,000,000 without escalation.

b. Startup Spare Parts and Initial Fills

An allowance has been included for initial fills for equipment, including first fills for lubrication of any motorized equipment. The initial fill of pebble lime was not included in the EPC Contractor's scope, as this is considered to be an operating cost rather than a capital expense. The initial fill of pebble lime is included in the Owner's costs.

c. Technical Field Advisors (Vendors)

Allowances were included for equipment supplier's technical field advisory services based on an estimated 300 man-days. The estimate includes technical field advisors for the FGD system supplier (including FGD system subcontractors) and the DCS supplier.

d. EPC Risk Fee

An EPC approach provides an alternative which is expected to reduce risk for Entergy by placing the responsibility for the project on a single entity, the EPC Contractor. The EPC Risk Fee is a premium included by the contractor which accounts for the additional coordination and management of the project as well as the additional risk assumed by the contractor (See Section 2.2 for a discussion on the contracting strategy and the EPC Risk Fee). Based on S&L's experience with recent EPC projects, an EPC Risk Fee was included at 10% of the total EPC project costs.

14. Escalation

    Escalation was included in the estimate based on the preliminary execution schedule at an escalation rate of 2.15% on equipment and materials and 3.35% on labor and indirects. These escalation rates were developed by S&L based on recent pricing and in-house escalation projections.

    For commodities and equipment related to power plant construction, S&L tracks over 200 U.S. indices from major industrial sources such as BLS, Chemical Engineering, Handy Whitman, and Engineering News Records. S&L reviews the various indices in order to develop an overall average and then evaluates the change in the indices over the last three years and the last five years. Based on this analysis, an annual rate of 2.15%/year escalation is projected for commodities and equipment for the time frame for the project.

    S&L uses RS Means as the basis for estimating labor craft rates. In order to project the escalation rate for the estimate, S&L reviewed five major craft labor types typically used in the power plant industry over the last five years using the average cost of craft labor. Based on this information, S&L projected an annual rate of 3.35%/year escalation on labor and indirects.

15. Sales Tax

    Sales Tax is included in the estimate, and was applied at a rate of 8.125% on all material costs.

4.2 OVERALL PROJECT COSTS FOR CAPITAL ESTIMATE

Outside of the EPC Contractor's total cost, Entergy will incur other costs associated with the project, such as Owner's costs, services procured from third parties (including Owner's engineer, construction management support, startup and commissioning support and performance testing), and other project related costs. The following summarizes the additional project costs to Entergy associated with installing dry FGD at the White Bluff Station:

1. Owner's Costs (by Entergy)

   Owner's Costs are direct costs that the Owner incurs over the life of the project. Entergy estimated the cost for the following items which would be real costs Entergy would incur based on the scope and schedule of this project:

   a. Internal Labor – For all major projects, Entergy assigns internal resources to manage the project from initiation through development, contracting, installation, and commissioning. Internal labor includes personnel from several departments including Capital Project Management & Technology, Engineering, Fossil Operations, Legal, Environmental Services, Supply Chain, Risk Management, Finance, Regulatory, and the Operating Company. The internal labor is estimated based on a proposed staffing plan, developed from the project scope and preliminary schedule using average wage rates. Costs are based on the following anticipated staffing levels:

      - Project Development (through EPC Award) – 25 months, equivalent of 10 people

- Project Execution (beginning at EPC Award) – 53 months, equivalent of 22 people

b. Internal Indirects – Indirect costs incurred by Entergy include a payroll allocation, materials and supplies allocation, a depreciation allocation, and capital suspense allocation. The payroll allocation includes payroll overhead costs for items such as employee benefits. The materials and supplies allocation is used to distribute the overhead costs of managing storerooms that are used to procure, track, and issue material and supplies. The depreciation allocation distributes depreciation and amortization expenses for the new assets. Capital suspense is a distribution of overhead costs associated with administrators, engineers, and supervisors and includes function specific rates and A&G (Corporate Accounting) rates.

c. Travel Expenses –Travel expenses are included to support the oversight of the project, including travel for site-visits, monthly status meetings, critical design reviews, etc. Travel expenses are estimated based on projects with similar schedules and scope.

d. Legal Services – Legal services are contracted from external law firms. These services include contract and regulatory compliance support. Entergy estimated the cost of the legal services based on recent EPC projects.

e. Builders Risk Insurance - Builder’s Risk Insurance is included in the estimate and covers the materials, equipment, and labor associated with a large scale construction project in case of physical loss or damage. The estimated is based on estimated project value and schedules.

f. Initial Fills - Entergy will procure a supply contract for pebble lime to the station. Under this contract, Entergy will arrange to provide the initial fill of pebble lime to the station for startup, commissioning, and performance testing. A 120 day supply of pebble lime for both units has been included in the estimate based on the reagent pricing identified in Section 4.3.

2. Third Party Services – Construction Management Oversight

The construction management support was estimated based on the proposed staffing plan shown below, developed from the overall project scope and the preliminary schedule. It was assumed that Entergy will not have the internal support personnel required to perform this task, and therefore it will be outsourced. The cost of labor is based on present day cost, without escalation. Travel and living expenses are based on the current per diem rate for the White Bluff area of $129/day. Costs are based on the following anticipated staffing levels:

a. Home Office Support – 15 months, 1 person

b. On-Site Construction Manager – 35 months, 1 person

c. On-Site Construction Admin/Project Controls Engineer – 35 months, 1 person

d. Construction Field Engineers – 31.5 months, 2 people

The total cost of the Construction Management Support was estimated to be $4,969,000 without escalation.

3. Third Party Services – Startup and Commissioning Oversight

   The startup and commissioning support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform this task, and therefore it will be outsourced. Costs are based on the following anticipated staffing levels:

   a. Commissioning Support Specialists – 8 months, 2 people

   The total cost of the startup and commissioning support was estimated to be $550,000 without escalation.

4. Third Party Services – Owner's Engineer

   The Owner's Engineer cost includes scope as summarized below and was estimated based on the preliminary project schedule, including assumptions on manpower requirements, as well as a comparison cost to other projects with similar scope.

   The cost of labor is based on present day cost, without escalation. Costs are based on the following scope for the Owner's Engineer work:

   a. Conceptual Study Support
   b. EPC Specification Supporting Documents
   c. Project Schedule Development
   d. EPC Specification Development
   e. EPC Bid Evaluation and Contract Conformance
   f. General Project Support
      - Monthly Project Status Meetings
      - Weekly Teleconferences
      - Overall Coordination
      - Project Administration
      - Site Visits and Travel
   g. Permitting (Construction Permits and Modification to Title V and Solid Waste Permits)
   h. Design Review of Drawing Submittals
   i. Technical support during design, fabrication, construction, commissioning, and testing
   j. Equipment vendor QA/QC audits

   The total cost of the Owner's Engineer was estimated to be $6,750,000 without escalation.

5. Third Party Services – Performance testing

   The cost for performance testing was developed as a factored estimate using costs from projects of similar scope. This cost includes the testing, performed by a third-party contractor hired by the Owner, and also includes the cost for S&L's assistance in the following tasks:

a. Development of the test protocol

b. Procuring the services of the testing contractor

c. Overseeing the performance test campaign

d. Evaluating the results of the testing with respect to guarantee compliance

The estimate for the third party testing contractor is based on the assumption that the contractor would be onsite for up to 3 days for each unit.

The total cost of the Performance Testing was estimated to be $275,000 without escalation.

6. Project Contingency

Project contingency is included in the estimate to cover the uncertainty associated with the project costs, and was developed utilizing Entergy's procedure for developing a project's contingency. The process includes developing three components of contingency:

a. Risk Contingency: This category of contingency is developed with the use of a Risk Register that is used to identify risks that may impact the project. Each risk in the Risk Register is analyzed to determine the probability of the risk and the impacts of the risk to the project.

b. Estimate Uncertainty: This category of contingency uses the estimate accuracy classifications to develop an appropriate level of contingency. Entergy has adopted expected accuracy ranges for estimates with upper and lower boundaries for each class of costs estimate. These ranges recognize the uncertainty that exists in the technical engineering and project management deliverables that define scope.

c. Unknown/Emergent Risks: This category of contingency is used to account for any issues that arise during the project that are not contained within the risk register or to cover any costs associated with unanticipated changes in project scope.

A cost qualitative risk assessment (QRA) was performed using Palisade Corporation's @RISK software. QRAs are used to validate the reasonableness of cost estimates, provide confidence for cost projections, and help establish a reasonable level of contingency based on risk-weighted estimates and project risk profiles. The QRA identifies various confidence levels that the contingency amount is sufficient for the project. For this estimate's cost QRA, an 80% confidence level was selected which means the project is 80% likely to be completed at or below the calculated value. The 80% confidence level results in a contingency value of 15% of the total project cost before escalation and IDC. This level of contingency is within Entergy's guidelines for target contingency range for this class of estimate. The contingency estimate is included in Attachment 8.

7. Escalation on Owner's Costs

Escalation was included in the estimate at an escalation rate 3.35% on the Owner's costs. This escalation rate is based on the rate developed by S&L for labor and indirects above.

8. Interest During Construction

Interest during construction (IDC) accounts for the time value of money associated with the distribution of construction cash flows over the construction period. IDC was applied to the total EPC project costs including contingency. The IDC was calculated based on the milestone payment schedule included in Attachment 4 and a typical interest rate of 7.0% per year which was assumed based on a low interest market environment.

4.3 VARIABLE OPERATING AND MAINTENANCE COSTS

The following unit costs were used to develop the variable Operating and Maintenance (O&M) costs. All of these values, with the exception of the reagent costs, were provided by Entergy and are consistent with typical industry values. The reagent costs are based on recent supplier quotes received for White Bluff.

Table 4-1: Unit Pricing for Utilities (Provided by Entergy)

Unit Cost	Units	Value
Pebble Lime	$/ton	$130.0
High Quality Water	$/1000 gal	$2.00
Low Quality Water	$/1000 gal	$0.53
Byproduct Disposal	$/ton	$7.50
Aux Power Cost[1]	$/MWh	$43.35

Note 1: Entergy provided auxiliary power costs for the first year of operation.

Table 4-2 below summarizes the consumption rates estimated as well as the first year variable O&M costs for the Dry FGD system.

Table 4-2: Variable O&M Rates and First Year Costs, per Unit

	Units	Value
Dry FGD System Parameters		
Reagent Consumption	lb/hr	5,900
Byproduct Waste Production	lb/hr	13,000
Aux Power Consumption	kW	11,000
High Quality Water Consumption	gpm	65
Low Quality Water Consumption	gpm	775
First Year[1] Variable O&M Costs (@CF[2])		
Reagent Cost	$/year	$2,422,000
Byproduct Waste Disposal Cost	$/year	$308,000
Aux Power Cost	$/year	$3,012,000
Water Cost	$/year	$205,000
Bag and Cage Replacement Cost	$/year	$372,000
Total First Year Variable O&M Cost	**$/year**	**$6,319,000**

Note 1: First year costs are provided in $2015.

Note 2: The first year costs are calculated using an annual capacity factor of 72.1%.

4.4 FIXED OPERATING AND MAINTENANCE COSTS

The fixed O&M costs for the systems consist of operating personnel as well as maintenance costs (including material and labor). Based on the conceptual design for the dry FGD system, the estimated staffing additions are 28 personnel for two systems on adjacent units.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (maintenance and labor) were estimated to be approximately 1.3% of the project capital. This is a lower value than typical because items such as track work and civil work are high capital cost items with little to no maintenance.

Table 4-3 below summarizes the first year fixed O&M costs for the design and typical cases.

Table 4-3: First Year Fixed O&M Costs for Dry FGD, per Unit

First Year[1] Fixed O&M Costs	Units	Value
Operating Labor[2]	$/year	$1,660,000
Maintenance Material	$/year	$975,000
Maintenance Labor	$/year	$650,000
Total First Year Fixed O&M Cost	**$/year**	**$3,285,000**

Note 1: First year costs are provided in $2015.

Note 2: Operating labor costs are based on a labor rate of $56.95, which was provided by Entergy.

Note 3: Installation of systems on both units would require 28 operators total. For accounting purposes, this is considered 14 operators per unit.

4.5 SULFUR DESIGN BASIS SENSITIVITY

The average sulfur content of coal received at the White Bluff station is 0.57 lb SO_2/MMBtu; however, the White Bluff station has the ability to receive coal with sulfur content up to 1.2 lb SO_2/MMBtu. In order to provide a system which is capable of meeting the design SO_2 emission rate on a continuous basis through the range of coals delivered to site, the FGD equipment must be designed for the maximum coal sulfur which could be burned in the units.

S&L evaluated the incremental cost impact of designing the FGD system for an inlet sulfur of 1.2 lb SO_2/MMBtu versus a lower inlet sulfur of 0.57 lb SO_2/MMBtu. It is important to note that the majority of the components within the FGD Island are designed to accommodate the maximum volumetric flue gas flowrate from the unit. The size and cost of these components, primarily the absorber vessels, baghouses, and ID fans, remains the same regardless of the inlet design sulfur. In addition, the majority of the BOP scope items which have been included in the capital cost estimate would remain constant regardless of the inlet design sulfur.

The primary equipment which is impacted by the design inlet sulfur would be the reagent handling, reagent preparation, and the waste handling systems. The inlet sulfur has a direct impact on the quantity of SO_2 which is being removed in the FGD system, and therefore a direct impact on the required lime (reagent) consumption rate as well as the quantity of byproduct produced. The following areas and associated equipment are impacted by adjusting the design inlet sulfur:

a. Reagent Storage and Handling System:
   - Two long-term storage silos

b. Reagent Preparation System (FGD Island):
   - Two lime day bins
   - Two detention lime slakers
   - Two lime slurry storage tanks

c. By-product Handling System:
   - Two FGD by-product storage silos

The quantity of byproduct which is recycled through the system to achieve the required performance will remain relatively constant regardless of inlet design sulfur and is therefore not impacted. In addition, the lime slurry and byproduct recycle are continuously circulated in a loop to the units and back to the storage tanks; therefore, a variation in the design sulfur would not significantly impact the sizing of the recycle storage equipment, pumps or piping systems.

The cost differential was determined by vendor quotes who were requested to provide equipment costs for design capacities at each of the design sulfur levels; this is the same approach used to adjust the Alstom budgetary proposal from a design sulfur of 2.0 lb/MMBtu to 1.2 lb/MMBtu for the cost estimate. The following table summarizes the cost differential for the equipment identified above that is impacted by the sulfur design basis:

Equipment	**Design Capacity @ 1.2 lb/MMBtu**	**Design Capacity @ 0.57 lb/MMBtu**	**Cost Reduction for 1.2 to 0.57 lb/MMBtu[1]**
Two long-term storage silos	2,200 tons each	1,000 tons each	- $4,717,000
Two lime day bins	650 tons each	300 tons each	- $321,000
Two detention lime slakers	13 tons/hour each	6 tons/hour each	- $134,000
Two lime slurry storage tanks	2,000 tons each	1,000 tons each	- $472,000

Two FGD by-product storage silos	3,000 tons each	1,200 tons each	- $3,391,000
One lime slaking water storage tank	175,000 gallons	100,000 gallons	-$34,000
		TOTAL Differential	**- $9,069,000**

Note 1: Cost Reduction shows the reduction in direct installed capital cost including reductions associated with BOP, i.e. reduced foundation sizes.

The reduction in the total direct installed costs associated with reducing the design sulfur level from 1.2 lb SO_2/MMBtu to 0.57 lb SO_2/MMBtu is approximately $9M.

5. SUMMARY

The cost estimate for the White Bluff Units 1&2 Dry FGD systems is based on the addition of two SDA FGD systems for SO_2 removal. The attached capital estimate for the White Bluff Dry FGD system is based on this technical basis.

6. ATTACHMENTS

1. White Bluff DFGD Project Units 1 and 2 Conceptual Capital Cost Estimate, Sargent & Lundy Estimate No. 33387A
2. White Bluff DFGD Project Units 1 and 2 Conceptual Cost Estimate Cash Flow, Sargent & Lundy Estimate No. 33387A
3. White Bluff DFGD Project Units 1 and 2 Level 1 Preliminary Execution Schedule
4. Monthly Progress Payment Schedule for White Bluff DFGD Project
5. S&L Estimating Documentation: Indirects and Construction Equipment included in Crew Rates
6. S&L Estimating Documentation: Escalation Projections
7. White Bluff DFGD Project Units 1 and 2 Conceptual General Arrangement Drawing
8. Entergy Basis of Contingency

ATTACHMENT 1

Conceptual Capital Cost Estimate

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Estimator	A. KOCI
Labor rate table	15ARPBL
Project No.	13027-002
Client	ENTERGY ARKANSAS
Station Name	WHITE BLUFF
Unit	1 & 2
Estimate Date	12/18/2015
Reviewed By	BA
Approved By	MNO
Estimate No.	33387B
Cost index	ARPBL

Estimate Totals

Description	Amount	Totals	Hours
Direct Costs:			
Labor	83,083,008		1,085,764
Material	50,642,339		
Subcontract	313,285,100		
Process Equipment	23,037,000		
	470,047,447	**470,047,447**	
Other Direct & Construction Indirect Costs:			
91-1 Scaffolding	5,816,000		
91-2 Cost Due To OT 5-10's	11,616,000		
91-4 Per Diem	10,858,000		
91-5 Consumables	831,553		
91-6 Freight on Material	2,532,000		
91-8 Sales Tax	7,821,000		
91-9 Contractors G&A	16,696,000		
91-10 Contractors Profit	8,348,000		
	64,518,553	**534,566,000**	
Indirect Costs:			
93-1 Engineering Services	23,000,000		
93-4 SU/S Parts/ Initial Fills	300,000		
93-5 Technical Field Advisors	600,000		
93-8 EPC Fee	55,847,000		
	79,747,000	**614,313,000**	
Escalation:			
96-1 Escalation on Material	6,012,000		
96-2 Escalation on Labor	18,769,000		
96-3 Escalation on Subcontract	37,429,000		
96-4 Escalation on Process Eq	2,115,000		
96-5 Escalation on Indirects	11,600,000		
	75,925,000	**690,238,000**	
Total EPC Cost		***690,238,000***	
Owner's Costs:			
99-1 Owner's Costs	58,546,000		
	58,546,000	**748,784,000**	
Third Party Services:			
100 CM Oversight	4,969,000		
102 Start-up Oversight	550,000		
103 Owner's Engineer	6,750,000		
104 Performance Testing	275,000		
	12,544,000	**761,328,000**	
Project Contingency :			
110 Project Contingency	102,810,000		
	102,810,000	**864,138,000**	
Escalation Addition:			
120 Escalation on Lines 99-110	2,273,000		
	2,273,000	**866,411,000**	
Interest During Construction:			
130 Interest During Constr.	125,078,000		
	125,078,000	**991,489,000**	
Total		***991,489,000***	

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Area	Description	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Total Cost
10	FGD ISLAND	297,904,000	(1,649,000)		-7,814	(680,533)	295,574,467
101	FGD ISLAND FOUNDATIONS AND ENCLOSURES			14,838,628	254,893	18,939,033	33,777,661
102	REAGENT HANDLING SYSTEM	6,000,000	2,046,000	3,162,954	59,192	4,646,650	15,855,604
105	BYPRODUCT HANDLING SYSTEM	7,713,100	6,872,000	1,089,675	107,800	7,935,771	23,610,546
111	FLUE GAS SYSTEM			3,267,828	113,961	7,898,036	11,165,864
121	CIVIL BOP	570,000		8,073,474	106,878	11,535,049	20,178,523
151	MECHANICAL BOP	998,000	1,969,000	6,882,913	115,659	9,189,021	19,038,934
190	DEMOLITION / RELOCATION	100,000		1,578,182	33,735	2,546,302	4,224,484
201	ELECTRICAL BOP SYSTEM		12,299,000	10,665,684	290,576	20,231,688	43,196,372
211	INSTRUMENTATION AND CONTROLS BOP SYSTEM		1,500,000	1,083,000	10,884	841,993	3,424,993
	TOTAL DIRECT	313,285,100	23,037,000	50,642,339	1,085,764	83,083,008	470,047,447

Note: Negative costs included in the cost estimate are due to adjustments to the FGD Budgetary Proposal which was based on a design sulfur of 2.0 lb/MMBTU.
Cost adjustments are included to adjust the design sulfur basis to 1.2 lb/MMBTU.

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
10			**FGD ISLAND**									
	23.00.00		**STEEL**									
		23.13.75	**SILO**									
			SILO - LIME DAY BINS 650 TONS - EQUIPMENT ONLY	CREDIT FOR REDUCTION FROM 1200 TONS	-2.00 LS		(273,000)			73.12 /MH		(273,000)
			SILO - LIME DAY BINS 650 TONS - LABOR ONLY	CREDIT FOR REDUCTION FROM 1200 TONS	-2.00 LS				-690	73.12 /MH	(50,428)	(50,428)
			SILO				**(273,000)**		**-690**		**(50,428)**	**(323,428)**
			STEEL				**(273,000)**		**-690**		**(50,428)**	**(323,428)**
	31.00.00		**MECHANICAL EQUIPMENT**									
		31.45.00	**FGD EQUIPMENT**									
			DRY FGD -UNITS 1 & 2 FGD ISLAND - EQUIPMENT	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	152,030,000		-		97.28 /MH		152,030,000
			DRY FGD -UNITS 1 & 2 FGD ISLAND - INSTALLATION COST	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	145,874,000		-		97.28 /MH		145,874,000
			DRY FGD - INLUDES ABSORBERS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES BAGHOUSES	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES REGEANT PREP EQUIPMENT FROM DAY SILOS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES BYPRODUCT RECYCLE PREPARATION EQUIPMENT	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES ID BOOSTER FANS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES PROCESS INSTRUMENTATION AND DCS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES INTERCONNECTING WIRING, PIPING ETC... WITHIN FGD ISLAND	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES DUCTWORK FROM INLET FLANGE TO OUTLET BOOSTER FAN FLANGE	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			FLOW MODEL	INCLUDED WITH ALSTOM PROPOSAL	1.00 LT	-		-		/MH		
			REAGENT PREPARATION - LIME SLURRY FEED TANKS - EQUIPMENT ONLY	REDUCTION IN SIZE TO 2000 TON FROM 3900 TONS BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 LT	-	(1,300,000)	-		90.81 /MH		(1,300,000)
			REAGENT PREPARATION - LIME SLURRY FEED TANKS - LABOR	REDUCTION IN SIZE TO 2000 TON FROM 3900 TONS BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 LT	-		-	-6,370	90.81 /MH	(578,470)	(578,470)
			FGD EQUIPMENT			**297,904,000**	**(1,300,000)**		**-6,370**		**(578,470)**	**296,025,530**
			MECHANICAL EQUIPMENT			**297,904,000**	**(1,300,000)**		**-6,370**		**(578,470)**	**296,025,530**
	33.00.00		**MATERIAL HANDLING EQUIPMENT**									
		33.14.00	**MATERIAL HANDLING EQUIPMENT**									
			MATERIAL HANDLING SYSTEM - LIME SLAKING TRAIN - REDUCTION FROM 25 TPH TO 13 TPH - EQUIPMENT ONLY	CREDIT BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 EA	-	(76,000)	-		68.48 /MH		(76,000)
			MATERIAL HANDLING SYSTEM - LIME SLAKING TRAIN - REDUCTION FROM 25 TPH TO 13 TPH - LABOR ONLY	CREDIT BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 EA	-		-	-754	68.48 /MH	(51,635)	(51,635)
			MATERIAL HANDLING EQUIPMENT				**(76,000)**		**-754**		**(51,635)**	**(127,635)**
			MATERIAL HANDLING EQUIPMENT				**(76,000)**		**-754**		**(51,635)**	**(127,635)**
			10 FGD ISLAND			**297,904,000**	**(1,649,000)**		**-7,814**		**(680,533)**	**295,574,467**
101			**FGD ISLAND FOUNDATIONS AND ENCLOSURES**									
	21.00.00		**CIVIL WORK**									
		21.53.00	**PILING**									
			PILE - 18" AUGER CAST X 60' LONG	UNIT 1 BAGHOUSE FDN	252.00 EA	-	-	480,816	6,662	108.46 /MH	722,568	1,203,384
			PILE - 18" AUGER CAST X 60' LONG	UNIT 2 BAGHOUSE FDN	252.00 EA	-	-	480,816	6,662	108.46 /MH	722,568	1,203,384
			PILING					**961,632**	**13,324**		**1,445,136**	**2,406,768**
		21.54.00	**CAISSON**									
			2.5 FT DIA X 30 FT DEEP CAISSON	ABSORBER TOWERS FOUNDATIONS	180.00 EA	-	-	334,260	4,552	108.46 /MH	493,680	827,940
			2.5 FT DIA X 30 FT DEEP CAISSON	ABSORBER TOWERS FOUNDATIONS	180.00 EA	-	-	334,260	4,552	108.46 /MH	493,680	827,940
			2.5 FT DIA X 30 FT DEEP CAISSON	REAGENT PREP ENCLOSURE 50'X50' SUBSTRUCTURE	50.00 EA	-	-	92,850	1,264	108.46 /MH	137,133	229,983
			2.5 FT DIA X 30 FT DEEP CAISSON	BYPRODUCTS RECYCLE EQUIPMENT BLDG 60' X 60' SUBSTRUCTURE	72.00 EA	-	-	133,704	1,821	108.46 /MH	197,472	331,176
			2.5 FT DIA X 30 FT DEEP CAISSON	UNIT 1 BOOSTER FAN FOUNDATION	40.00 EA	-	-	74,280	1,011	108.46 /MH	109,707	183,987
			2.5 FT DIA X 30 FT DEEP CAISSON	UNIT 2 BOOSTER FAN FOUNDATION	40.00 EA	-	-	74,280	1,011	108.46 /MH	109,707	183,987
			CAISSON					**1,043,634**	**14,211**		**1,541,379**	**2,585,013**

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			CIVIL WORK					**2,005,266**	**27,536**		**2,986,515**	**4,991,781**
	22.00.00		**CONCRETE**									
		22.13.00	**CONCRETE**									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	REAGENT PREP ENCLOSURE 50'X50' SUBSTRUCTURE	300.00 CY	-	-	69,000	2,414	59.71 /MH	144,128	213,128
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	BYPRODUCTS RECYCLE EQUIPMENT BLDG 60' X 60' SUBSTRUCTURE	432.00 CY	-	-	99,360	3,476	59.71 /MH	207,544	306,904
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	UNIT 1 BOOSTER FAN FOUNDATION	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	UNIT 2 BOOSTER FAN FOUNDATION	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			CONCRETE FOUNDATIONS - COMPOSITE RATE	ABSORBER TOWER FOUNDATION	1,300.00 CY	-	-	299,000	10,460	59.71 /MH	624,553	923,553
			CONCRETE FOUNDATIONS - COMPOSITE RATE	ABSORBER TOWERS FOUNDATIONS	1,300.00 CY	-	-	299,000	10,460	59.71 /MH	624,553	923,553
			CONCRETE FOUNDATIONS - COMPOSITE RATE	LIME SLURRY FEED TANKS	400.00 CY	-	-	92,000	3,218	59.71 /MH	192,170	284,170
			CONCRETE FOUNDATIONS - COMPOSITE RATE	UNIT 1 BAGHOUSE FDN 3 FDNS 83'X63'X3'	1,743.00 CY	-	-	400,890	14,024	59.71 /MH	837,381	1,238,271
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' UNIT 1 BAGHOUSE AREA, COMPRESSOR BLDG	6.00 CY	-	-	1,380	48	59.71 /MH	2,883	4,263
			CONCRETE FOUNDATIONS - COMPOSITE RATE	UNIT 2 BAGHOUSE FDN 3 FDNS 83'X63'X3'	1,743.00 CY	-	-	400,890	14,024	59.71 /MH	837,381	1,238,271
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' UNIT 2 BAGHOUSE AREA, TRUCK SCALE HOUSE	6.00 CY	-	-	1,380	48	59.71 /MH	2,883	4,263
			CONCRETE					**1,938,900**	**67,828**		**4,049,985**	**5,988,885**
			CONCRETE					**1,938,900**	**67,828**		**4,049,985**	**5,988,885**
	23.00.00		**STEEL**									
		23.17.00	**GALLERY**									
			GALVANIZED GRATING, 1 1/4" DEEP x 3/16" BEARING BAR WITH HOLD DOWN CLIPS	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	4,000.00 SF	-	-	60,000	460	66.07 /MH	30,377	90,377
			GALVANIZED GRATING, 1 1/4" DEEP x 3/16" BEARING BAR WITH HOLD DOWN CLIPS	BYPRODUCTS RECYCLE EQUIPMENT BLDG	5,760.00 SF	-	-	86,400	662	66.07 /MH	43,743	130,143
			3" HEAVY DUTY GRATING	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	200.00 SF	-	-	11,200	39	66.07 /MH	2,582	13,782
			DOUBLE PIPE HANDRAIL WITH POSTS AND GUARD PLATES, PAINTED	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	3,000.00 LF	-	-	159,000	621	66.07 /MH	41,009	200,009
			DOUBLE PIPE HANDRAIL WITH POSTS AND GUARD PLATES, PAINTED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	4,320.00 LF	-	-	228,960	894	66.07 /MH	59,053	288,013
			SELF CLOSING SWING GATE - USER DEFINED	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	40.00 EA	-	-	11,200	184	66.07 /MH	12,151	23,351
			SELF CLOSING SWING GATE - USER DEFINED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	58.00 EA	-	-	16,240	267	66.07 /MH	17,619	33,859
			LADDER	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	800.00 LF	-	-	40,000	368	66.07 /MH	24,302	64,302
			LADDER	BYPRODUCTS RECYCLE EQUIPMENT BLDG	1,100.00 LF	-	-	55,000	506	66.07 /MH	33,415	88,415
			STAIR SYSTEM	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	2,400.00 SF	-	-	218,400	3,172	66.07 /MH	209,601	428,001
			STAIR SYSTEM	BYPRODUCTS RECYCLE EQUIPMENT BLDG	3,500.00 SF	-	-	318,500	4,626	66.07 /MH	305,669	624,169
			GALLERY					**1,204,900**	**11,798**		**779,520**	**1,984,420**
		23.25.00	**ROLLED SHAPE**									
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, TWO COAT PAINT	REAGENT PREP ENCLOSURE 50'X50' GALLERY SUPPORT	200.00 TN	-	-	716,000	5,057	92.62 /MH	468,423	1,184,423
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, TWO COAT PAINT	BYPRODUCTS RECYCLE EQUIPMENT BLDG	288.00 TN	-	-	1,031,040	7,283	92.62 /MH	674,529	1,705,569
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, GALVANIZED	U1 BAGHOUSE SKIRTS STEEL GIRTS	36.00 TN	-	-	138,240	910	92.62 /MH	84,316	222,556
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, GALVANIZED	U2 BAGHOUSE SKIRTS STEEL GIRTS	36.00 TN	-	-	138,240	910	92.62 /MH	84,316	222,556
			BUILDING MIX, TWO COAT PAINTED		50.00 TN	-	-	128,000	920	92.62 /MH	85,168	213,168
			BUILDING MIX, TWO COAT PAINTED		50.00 TN	-	-	128,000	920	92.62 /MH	85,168	213,168
			BUILDING MIX, TWO COAT PAINTED	REAGENT PREP ENCLOSURE SUPERSTRUCTURE	500.00 TN	-	-	1,280,000	9,195	92.62 /MH	851,678	2,131,678
			BUILDING MIX, TWO COAT PAINTED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	720.00 TN	-	-	1,843,200	13,241	92.62 /MH	1,226,417	3,069,617
			ROLLED SHAPE					**5,402,720**	**38,437**		**3,560,015**	**8,962,735**
			STEEL					**6,607,620**	**50,235**		**4,339,534**	**10,947,154**
	24.00.00		**ARCHITECTURAL**									
		24.17.00	**ELEVATOR**									
			PASSENGER, TRACTION, 4 STOPS, 3500LB, 350 FT/MIN	SCHINDLER ELEVATOR BUDGET	1.00 LS	-	-	159,350	943	106.04 /MH	99,946	259,296
			PASSENGER, TRACTION, 4 STOPS, 3500LB, 350 FT/MIN	SCHINDLER ELEVATOR BUDGET	1.00 LS	-	-	159,350	943	106.04 /MH	99,946	259,296

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			ELEVATOR					**318,700**	**1,885**		**199,892**	**518,592**
		24.35.00	**PRE-ENGINEERED BUILDING**									
			PRE-ENGINEERED BUILDING	8' X 10' UNIT 1 BAGHOUSE AREA, COMPRESSOR BLDG	1.00 LT	-	-	20,000	115	92.62 /MH	10,646	30,646
			PRE-ENGINEERED BUILDING	8' X 10' UNIT 2 BAGHOUSE AREA, TRUCK SCALE HOUSE	1.00 LT	-	-	10,000	115	92.62 /MH	10,646	20,646
			PRE-ENGINEERED BUILDING					**30,000**	**230**		**21,292**	**51,292**
		24.37.00	**ROOFING**									
			METAL, INSULATED, 2 IN GALVANIZED, PAINTED, 22 GA	U1 SDA TOP ENCLOSURE ROOF	3,318.00 SF	-	-	54,946	339	35.02 /MH	11,887	66,833
			METAL, INSULATED, 2 IN GALVANIZED, PAINTED, 22 GA	U2 SDA TOP ENCLOSURE ROOF	3,318.00 SF	-	-	54,946	339	35.02 /MH	11,887	66,833
			METAL, INSULATED- USER DEFINED	REAGENT PREP ENCLOSURE SUPERSTRUCTURE	2,500.00 SF	-	-	19,425	862	35.02 /MH	30,190	49,615
			METAL, INSULATED- USER DEFINED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	3,600.00 SF	-	-	27,972	1,241	35.02 /MH	43,473	71,445
			ROOFING					**157,289**	**2,782**		**97,436**	**254,725**
		24.41.00	**SIDING**									
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	U1 SDA TOP ENCLOSURE SIDING	2,450.00 SF	-	-	40,572	251	79.59 /MH	19,948	60,520
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	U2 SDA TOP ENCLOSURE SIDING	2,450.00 SF	-	-	40,572	251	79.59 /MH	19,948	60,520
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	REAGENT PREP ENCLOSURE	10,000.00 SF	-	-	165,600	1,023	79.59 /MH	81,420	247,020
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	14,400.00 SF	-	-	238,464	1,473	79.59 /MH	117,244	355,708
			METAL, UNINSULATED, 24 GA, GALVANIZED CORROGATED	U1 BAGHOUSE SKIRTS 6x(83'+63) x30' tall '	26,260.00 SF	-	-	85,345	1,238	79.59 /MH	98,496	183,841
			METAL, UNINSULATED, 24 GA, GALVANIZED CORROGATED	U2 BAGHOUSE SKIRTS 6x(83'+63) x30' tall '	26,280.00 SF	-	-	85,410	1,238	79.59 /MH	98,571	183,981
			SIDING					**655,963**	**5,473**		**435,626**	**1,091,589**
		24.99.00	**ARCHITECTURAL, MISCELLANEOUS**									
			PENTHOUSE HEATING	U1 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	64.10 /MH	4,715	68,715
			PENTHOUSE LIGHTING	U1 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	82.05 /MH	6,036	70,036
			PENTHOUSE FIRE PROTECTION	U1 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	32,000	37	82.05 /MH	3,018	35,018
			PENTHOUSE HEATING	U2 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	64.10 /MH	4,715	68,715
			PENTHOUSE LIGHTING	U2 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	82.05 /MH	6,036	70,036
			PENTHOUSE FIRE PROTECTION	U2 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	32,000	37	82.05 /MH	3,018	35,018
			ARCHITECTURAL, MISCELLANEOUS - USER DEFINED	U1 BAGHOUSE SKIRTS MANDOORS	3.00 EA	-	-	1,500	28	51.10 /MH	1,410	2,910
			ARCHITECTURAL, MISCELLANEOUS - USER DEFINED	U2 BAGHOUSE SKIRTS MANDOORS	3.00 EA	-	-	1,500	28	51.10 /MH	1,410	2,910
			ARCHITECTURAL, MISCELLANEOUS					**323,000**	**423**		**30,358**	**353,358**
			ARCHITECTURAL					**1,484,952**	**10,794**		**784,604**	**2,269,556**
	31.00.00		**MECHANICAL EQUIPMENT**									
		31.41.00	**FIRE PROTECTION EQUIPMENT & SYSTEM**									
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	REAGENT PREP ENCLOSURE 50'X50' FIRE PROTECTION ALLOWANCE	5,000.00 SF	-	-	27,500	385	68.48 /MH	26,369	53,869
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	BYPRODUCTS RECYCLE EQUIPMENT BLDG' FIRE PROTECTION ALLOWANCE	10,800.00 SF	-	-	59,400	832	68.48 /MH	56,956	116,356
			FIRE PROTECTION EQUIPMENT & SYSTEM					**86,900**	**1,217**		**83,325**	**170,225**
		31.83.00	**TANK**									
			TANK - MOVE OIL TANK FROM USED OIL SHED AND REINSTALL AT WASTE MANAGEMENT FACILITY	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	1.00 EA	-	-	-	345	90.81 /MH	31,314	31,314
			TANK						**345**		**31,314**	**31,314**
			MECHANICAL EQUIPMENT					**86,900**	**1,562**		**114,639**	**201,539**
	34.00.00		**HVAC**									
		34.99.00	**HVAC, MISCELLANEOUS**									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	REAGENT PREP ENCLOSURE 50'X50' LIGHTING ALLOWANCE	5,000.00 SF	-	-	55,000	57	64.10 /MH	3,684	58,684
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	BYPRODUCTS RECYCLE EQUIPMENT BLDG LIGHTING ALLOWANCE	10,800.00 SF	-	-	118,800	124	64.10 /MH	7,957	126,757
			HVAC, MISCELLANEOUS					**173,800**	**182**		**11,641**	**185,441**
			HVAC					**173,800**	**182**		**11,641**	**185,441**
	36.00.00		**INSULATION**									
		36.13.00	**DUCT**									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		36.13.00	DUCT									
			MINERAL WOOL INSULATION, 4 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	U1 BAGHOUSE INSUILATION TOP, SIDES AND HOPPERS	141,831.00 SF	-	-	850,986	35,050	68.76 /MH	2,410,051	3,261,037
			MINERAL WOOL INSULATION, 4 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	U2 BAGHOUSE INSULATIOIN - TOPS, SIDES AND HOPPERS	141,831.00 SF	-	-	850,986	35,050	68.76 /MH	2,410,051	3,261,037
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA SHELL INSULATION	40,167.00 SF	-	-	261,086	10,388	68.76 /MH	714,280	975,366
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA ROOF INSULATION	11,019.00 SF	-	-	71,624	2,850	68.76 /MH	195,948	267,572
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA SHELL INSULATION	40,167.00 SF	-	-	261,086	10,388	68.76 /MH	714,280	975,366
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA ROOF INSULATION	11,019.00 SF	-	-	71,624	2,850	68.76 /MH	195,948	267,572
			DUCT					2,367,390	96,576		6,640,559	9,007,949
			INSULATION					2,367,390	96,576		6,640,559	9,007,949
	41.00.00		ELECTRICAL EQUIPMENT									
		41.37.00	LIGHTING ACCESSORY (FIXTURE)									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	REAGENT PREP ENCLOSURE 50'X50' LIGHTING ALLOWANCE	5,000.00 SF	-	-	55,000	57	63.63 /MH	3,657	58,657
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	BYPRODUCTS RECYCLE EQUIPMENT BLDG LIGHTING ALLOWANCE	10,800.00 SF	-	-	118,800	124	63.63 /MH	7,899	126,699
			LIGHTING ACCESSORY (FIXTURE)					173,800	182		11,556	185,356
			ELECTRICAL EQUIPMENT					173,800	182		11,556	185,356
			101 FGD ISLAND FOUNDATIONS AND ENCLOSURES					14,838,628	254,893		18,939,033	33,777,661
102			REAGENT HANDLING SYSTEM									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			PILE - 18" AUGER CAST X 60' LONG	UNLOADING SHED 200' X 75 WIDE	63.00 EA	-	-	120,204	1,666	108.46 /MH	180,642	300,846
			PILING					120,204	1,666		180,642	300,846
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	SUBSTRUCTURE 2200 TON LIME STORAGE SILOS	100.00 EA	-	-	185,700	2,529	108.46 /MH	274,267	459,967
			CAISSON					185,700	2,529		274,267	459,967
		21.71.00	TRACKWORK									
			RAIL, TIE & BALLAST - 136 LB/YD	REAGENT HANDLING SYSTEM UPGRADE AND EXTEND LIME RAIL TRACK TO AVOID BLOCKING ACCESS BY 150 CAR COAL TRAINS	9,060.00 TF	-	-	1,540,200	15,621	81.27 /MH	1,269,493	2,809,693
			TRACKWORK - EXTEND LIME RAIL SPUR AND RELOCATE SWITCH 2060 FT	RELOCATE COAL TRACK SWITCH TO WEST TO AVOID INTERFERENCE WITH 150 CAR COAL TRAINS	1.00 LS	-	-	374,000	7,989	81.27 /MH	649,226	1,023,226
			TRACKWORK					1,914,200	23,609		1,918,719	3,832,919
			CIVIL WORK					2,220,104	27,803		2,373,628	4,593,732
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	SUBSTRUCTURE 2-2200 TON LIME STORAGE SILOS	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			FOUNDATION, 4500 PSI - COMPOSITE RATE	UNLOADING SHED 200' X 75 WIDE	925.00 CY	-	-	212,750	7,443	59.71 /MH	444,393	657,143
			CONCRETE					350,750	12,270		732,649	1,083,399
			CONCRETE					350,750	12,270		732,649	1,083,399
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA,	UNLOADING SHED 200' X 75 WIDE x15' TALL	15,000.00 SF	-	-	525,000	4,828	92.62 /MH	447,131	972,131
			PRE-ENGINEERED BUILDING					525,000	4,828		447,131	972,131
			ARCHITECTURAL					525,000	4,828		447,131	972,131
	26.00.00		MISCELLANEOUS STRUCTURAL ITEM									
		26.13.00	CONCRETE SILO									
			CONCRETE SILO - 2200 TON LIME STORAGE SILO	ERECTED - 46' DIA X 154' TALL EA - OPTION 2	2.00 LS	6,000,000				59.71 /MH		6,000,000

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		26.13.00	CONCRETE SILO									
			CONCRETE SILO - BIN VENT FILTERS	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - LEVEL INDICATOR	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - VACUUM PRESSURE RELIEF VALVE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - MANHOLE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO			6,000,000			0			6,000,000
			MISCELLANEOUS STRUCTURAL ITEM			6,000,000			0			6,000,000
	31.00.00		MECHANICAL EQUIPMENT									
		31.25.00	CRANES & HOISTS									
			CRANES & HOISTS - & TROLLEYS ALLOWANCE	REAGENT HANDLING SYSTEM	1.00 LT	-	275,000	-		68.48 /MH		275,000
			CRANES & HOISTS				275,000					275,000
			MECHANICAL EQUIPMENT				275,000					275,000
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.14.00	MATERIAL HANDLING EQUIPMENT									
			LIME HANDLING SYSTEM - 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM		1.00 LS	-	500,000	-	3,306	68.48 /MH	226,378	726,378
			LIME HANDLING SYSTEM - VACUUM EXHAUSTER WITH SOUND ENCLOSURES	INCLUDED WITH 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	2.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - RECEIVING PANS UNDER RAIL CARS	INCLUDED WITH 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	1.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - FILTER SEPARATORS ON TOP OF SILO	INCLUDED WITH 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	1.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - 25 TPH PNEUMATIC TRANSPORT SYSTEM		1.00 LS	-	500,000	-	3,306	68.48 /MH	226,378	726,378
			LIME HANDLING SYSTEM - PRESSURE BLOWERS WITH SOUND ENCLOSURES	INCLUDED WITH 25 TPH PNEUMATIC TRANSPORT SYSTEM	3.00 LS	-		-		/MH		
			LIME HANDLING SYSTEM - PRESSURE FEEDERS	INCLUDED WITH 25 TPH PNEUMATIC TRANSPORT SYSTEM	1.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - SPARE PARTS FOR STARTUP AND SPECIAL TOOLS		1.00 LS	-	8,000	-		68.48 /MH		8,000
			LIME HANDLING SYSTEM - FREIGHT		1.00 LS	-	50,000	-		68.48 /MH		50,000
			MATERIAL HANDLING EQUIPMENT				1,058,000		6,611		452,755	1,510,755
		33.41.00	MOBILE YARD EQUIPMENT									
			MOBILE YARD EQUIPMENT - TRACKMOBILE	REAGENT HANDLING SYSTEM	1.00 EA	-	225,000	-		68.48 /MH		225,000
			MOBILE YARD EQUIPMENT				225,000					225,000
		33.51.00	RAIL CAR UNLOADER									
			RAIL CAR UNLOADER -	IN UNLOADING SHED 200'X75' WIDE	1.00 LT	-	225,000	-	3,103	92.62 /MH	287,441	512,441
			RAIL CAR UNLOADER				225,000		3,103		287,441	512,441
			MATERIAL HANDLING EQUIPMENT				1,508,000		9,715		740,197	2,248,197
	34.00.00		HVAC									
		34.99.00	HVAC, MISCELLANEOUS									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	2-2200 TON LIME STORAGE SILOS	3,600.00 SF	-	-	39,600	41	64.10 /MH	2,652	42,252
			HVAC, MISCELLANEOUS					39,600	41		2,652	42,252
			HVAC					39,600	41		2,652	42,252
	35.00.00		PIPING									
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			8 IN DIA, SCH 40, 8" VACUUM CONVEY PIPING WITH 4 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	500.00 LF	-	38,000		540	77.36 /MH	41,792	79,792
			12 IN DIA, 3/8 IN STD- 2500 LF OF 10"/12" TRANSPORT PRESSURE PIPING W 8 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRANSPORT SYSTEM	2,500.00 LF	-	225,000		3,966	77.36 /MH	306,772	531,772
			CARBON STEEL, STRAIGHT RUN				263,000		4,506		348,565	611,565
			PIPING				263,000		4,506		348,565	611,565
	41.00.00		ELECTRICAL EQUIPMENT									
		41.37.00	LIGHTING ACCESSORY (FIXTURE)									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	4200 TON LIME STORAGE SILO	2,500.00 SF	-	-	27,500	29	63.63 /MH	1,828	29,328
			LIGHTING ACCESSORY (FIXTURE)					27,500	29		1,828	29,328
			ELECTRICAL EQUIPMENT					27,500	29		1,828	29,328
			102 REAGENT HANDLING SYSTEM			6,000,000	2,046,000	3,162,954	59,192		4,646,650	15,855,604
105			BYPRODUCT HANDLING SYSTEM									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
	21.00.00		CIVIL WORK									
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	ASH SILO AND FGD BYPRODUCT SILOS	125.00 EA	-	-	232,125	3,161	108.46 /MH	342,833	574,958
			CAISSON					232,125	3,161		342,833	574,958
			CIVIL WORK					232,125	3,161		342,833	574,958
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	FGD BYPRODUCT SILOS	614.00 CY	-	-	141,220	4,940	59.71 /MH	294,981	436,201
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	FLY ASH BLENDING SILO	67.00 CY	-	-	15,410	539	59.71 /MH	32,188	47,598
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	FOR TRUCK SCALES	144.00 CY	-	-	33,120	1,159	59.71 /MH	69,181	102,301
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	MISC	100.00 CY	-	-	23,000	805	59.71 /MH	48,043	71,043
			CONCRETE					212,750	7,443		444,393	657,143
			CONCRETE					212,750	7,443		444,393	657,143
	23.00.00		STEEL									
		23.13.75	SILO									
			NEW 250 TON FLYASH BLENDING BIN SILO - 24FT DIA X 72 FT HIGH - ERECTION AND FREIGHT INCLUDED	SILO	1.00 EA		275,000		2,839	73.12 /MH	207,594	482,594
			SILO				275,000		2,839		207,594	482,594
			STEEL				275,000		2,839		207,594	482,594
	26.00.00		MISCELLANEOUS STRUCTURAL ITEM									
		26.13.00	CONCRETE SILO									
			CONCRETE SILO - 3000 TON FGD BYPRODUCT SILO	ERECTED - 52' DIA X 162' TALL EA	2.00 LS	7,600,000				59.71 /MH		7,600,000
			CONCRETE SILO - BIN VENT FILTERS	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - LEVEL INDICATOR	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - VACUUM PRESSURE RELIEF VALVE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - MANHOLE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - SPARE PARTS FOR STARTUP AND SPECIAL TOOLS		1.00 LS	-	10,000			73.12 /MH		10,000
			CONCRETE SILO - FREIGHT		1.00 LS	-	70,000			73.12 /MH		70,000
			CONCRETE SILO			7,600,000	80,000		0			7,680,000
			MISCELLANEOUS STRUCTURAL ITEM			7,600,000	80,000		0			7,680,000
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.13.00	BYPRODUCT HANDLING EQUIPMENT									
			PNEUMATIC ASH CONVEYORS	EQUIPMENT INCLUDES FREIGHT	1.00 LS	-	5,655,000	-		73.12 /MH		5,655,000
			PNEUMATIC ASH CONVEYORS	INSTALLATION COST	1.00 LT	-		-	79,293	73.12 /MH	5,797,912	5,797,912
			BLOWERS, PRESSURE FEEDERS, TRANSPORT PIPING AND VACUUM / PRESSURE RELIEF VALVES	INCLUDED ABOVE	1.00 LT	-		-		73.12 /MH		
			-FOUR PIN MIXERS BELOW CONCRETE SILOS INCL ALL VALVES AND ACCESSORIES		1.00 LT	-	540,000	-	3,347	73.12 /MH	244,742	784,742
			-DRY UNLOADING SPOUT BELOW THE PRODUCT SILO		2.00 EA	-	60,000	-	258	73.12 /MH	18,877	78,877
			AIRSLIDE CONVEYORS FROM BLENDING BIN MIXER/PIPE CONVEYOR, INCL ALL VALVES AND ACCESSORIES		4.00 EA	-	80,000	-	688	73.12 /MH	50,327	130,327
			BYPRODUCT HANDLING EQUIPMENT				6,335,000		83,587		6,111,857	12,446,857
		33.57.00	SCALE									
			SCALE - NEW TRUCK SCALES	BYPRODUCT HANDLING SYSTEM	2.00 EA	-	182,000	-	460	68.48 /MH	31,485	213,485
			SCALE				182,000		460		31,485	213,485
			MATERIAL HANDLING EQUIPMENT				6,517,000		84,046		6,143,342	12,660,342
	34.00.00		HVAC									
		34.37.00	DUST COLLECTOR									
			DUST COLLECTOR - INSTALLED COST		1.00 LS	113,100	-			64.10 /MH		113,100
			DUST COLLECTOR			113,100						113,100
			HVAC			113,100						113,100
	35.00.00		PIPING									
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			12 IN DIA, 3/8 IN STD	CONVEYOR PIPING	5,000.00 LF	-	-	496,000	7,931	77.36 /MH	613,545	1,109,545
			12 IN DIA, 3/8 IN STD	12" TIE IN PIPING TO BYPRODUCT SILO	1,500.00 LF	-	-	148,800	2,379	77.36 /MH	184,063	332,863

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			12 IN DIA, 3/8 IN STD	FROM THE EXISTING 50 TPH FLY ASH PRESSURE SYSTEM	1,500.00 LF	-	-	148,800	2,379	77.36 /MH	184,063	332,863
			CARBON STEEL, STRAIGHT RUN					644,800	10,310		797,608	1,442,408
			PIPING					644,800	10,310		797,608	1,442,408
			105 BYPRODUCT HANDLING SYSTEM			7,713,100	6,872,000	1,089,675	107,800		7,935,771	23,610,546
111			FLUE GAS SYSTEM									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			PILE - 18" AUGER CAST X 60' LONG	UNIT 1 FLUE GAS SYSTEM	138.00 EA	-	-	263,304	3,648	108.46 /MH	395,692	658,996
			PILE - 18" AUGER CAST X 60' LONG	UNIT 2 FLUE GAS SYSTEM	138.00 EA	-	-	263,304	3,648	108.46 /MH	395,692	658,996
			PILING					526,608	7,297		791,384	1,317,992
			CIVIL WORK					526,608	7,297		791,384	1,317,992
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	UNIT 1 FLUE GAS SYSTEM	966.00 CY	-	-	222,180	7,772	59.71 /MH	464,091	686,271
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	UNIT 2 FLUE GAS SYSTEM	966.00 CY	-	-	222,180	7,772	59.71 /MH	464,091	686,271
			CONCRETE					444,360	15,545		928,182	1,372,542
			CONCRETE					444,360	15,545		928,182	1,372,542
	23.00.00		STEEL									
		23.15.00	DUCTWORK									
			PANEL CONSTRUCTION, DUCT PLATE WITH STIFFENERS, INTERNAL TRUSSES, AND TURNING VANES	UNIT 1 FLUE GAS SYSTEM - INCLUDED IN ALSTOM'S QUOTE	TN	-	-			97.25 /MH		
			PANEL CONSTRUCTION, DUCT PLATE WITH STIFFENERS, INTERNAL TRUSSES, AND TURNING VANES	UNIT 2 FLUE GAS SYSTEM - INCLUDED IN ALSTOM'S QUOTE	TN	-	-			97.25 /MH		
		23.21.00	GIRDER									
			ROLLED SHAPE GIRDER - USER DEFINED	UNIT 1 FLUE GAS SYSTEM - INCLUDED IN ALSTOM'S QUOTE	TN	-	-			92.62 /MH		
			ROLLED SHAPE GIRDER - USER DEFINED	UNIT 2 FLUE GAS SYSTEM - INCLUDED IN ALSTOM'S QUOTE	TN	-	-			92.62 /MH		
	27.00.00		PAINTING & COATING									
		27.17.00	PAINTING									
			PAINTING - CHIMNEY	UNIT 1 FLUE GAS SYSTEM	1.00 LT	-	-	110,000	4,109	47.61 /MH	195,639	305,639
			PAINTING					110,000	4,109		195,639	305,639
			PAINTING & COATING					110,000	4,109		195,639	305,639
	31.00.00		MECHANICAL EQUIPMENT									
		31.27.00	DAMPERS & ACCESSORIES									
			DAMPERS & ACCESSORIES	UNIT 1 FLUE GAS SYSTEM - INCLUDED IN ALSTOM'S QUOTE	SF	-				97.25 /MH		
			DAMPERS & ACCESSORIES	UNIT 2 FLUE GAS SYSTEM - INCLUDED IN ALSTOM'S QUOTE	SF	-				97.25 /MH		
		31.33.00	EXPANSION JOINT									
			EXPANSION JOINT	UNIT 1 FLUE GAS SYSTEM - INCLUDED IN ALSTOM'S QUOTE	LF	-				97.25 /MH		
			EXPANSION JOINT	UNIT 2 FLUE GAS SYSTEM - INCLUDED IN ALSTOM'S QUOTE	LF	-				97.25 /MH		
	36.00.00		INSULATION									
		36.13.00	DUCT									
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	UNIT 1 FLUE GAS SYSTEM	168,220.00 SF	-	-	1,093,430	43,505	68.76 /MH	2,991,416	4,084,846
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	UNIT 2 FLUE GAS SYSTEM	168,220.00 SF	-	-	1,093,430	43,505	68.76 /MH	2,991,416	4,084,846
			DUCT					2,186,860	87,010		5,982,831	8,169,691
			INSULATION					2,186,860	87,010		5,982,831	8,169,691
			111 FLUE GAS SYSTEM					3,267,828	113,961		7,898,036	11,165,864
121			CIVIL BOP									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
	21.00.00		**CIVIL WORK**									
		21.14.00	**STRIP & STOCKPILE TOPSOIL**									
			STRIP & STOCKPILE TOPSOIL - 12"		300,000.00 SF	-	-		690	182.33 /MH	125,745	125,745
			STRIP & STOCKPILE TOPSOIL - ONSITE		40,000.00 CY	-	-		5,287	182.33 /MH	964,044	964,044
			STRIP & STOCKPILE TOPSOIL - 12"	SITE GRADING	600,000.00 SF	-	-		1,379	182.33 /MH	251,490	251,490
			STRIP & STOCKPILE TOPSOIL - ONSITE	SITE GRADING	160,000.00 CY	-	-		21,149	182.33 /MH	3,856,175	3,856,175
			STRIP & STOCKPILE TOPSOIL						**28,506**		**5,197,453**	**5,197,453**
		21.17.00	**EXCAVATION**									
			MASS EXCAVATION, COMMON EARTH USING 1.5 CY BACKHOE AND (6) 12 CY DUMP TRUCKS, 4 MI ROUNDTRIP	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	7,000.00 CY	-	-		523	182.33 /MH	95,356	95,356
			EXCAVATION - EXCAVATION , BACKFILL & COMPACT ALL FOUNDATIONS		12,600.00 CY	-	-		4,345	79.31 /MH	344,588	344,588
			EXCAVATION						**4,868**		**439,945**	**439,945**
		21.19.00	**DISPOSAL**									
			DISPOSAL OF EXCESS MATERIAL USING DUMP TRUCK, 4 MI ROUND TRIP	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	7,000.00 CY	-	-		483	79.31 /MH	38,288	38,288
			DISPOSAL						**483**		**38,288**	**38,288**
		21.20.00	**BACKFILL**									
			FOUNDATION BACKFILL, PREVIOUSLY EXCAVATED MATERIAL	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	1,000.00 CY	-	-		172	79.31 /MH	13,674	13,674
			BACKFILL						**172**		**13,674**	**13,674**
		21.39.00	**STORM DRAINAGE UTILITIES**									
			STORM SEWER WORK	SITE GRADING	1.00 LT	-	-	110,000	2,299	72.14 /MH	165,839	275,839
			STORM DRAINAGE UTILITIES					**110,000**	**2,299**		**165,839**	**275,839**
		21.41.00	**EROSION AND SEDIMENTATION CONTROL**									
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK		33,334.00 SY	-	-	355,007	1,149	97.31 /MH	111,853	466,860
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK	SITE GRADING	66,667.00 SY	-	-	710,004	2,299	97.31 /MH	223,702	933,706
			EROSION AND SEDIMENTATION CONTROL					**1,065,011**	**3,448**		**335,555**	**1,400,566**
		21.57.00	**ROAD, PARKING AREA, & SURFACED AREA**									
			BITUMINOUS ROAD - ROAD UPGRADE	BYPRODUCT HAUL ROAD - EAST OF COAL PILE	10,000.00 LF	-	-	500,000	8,046	78.37 /MH	630,563	1,130,563
			BITUMINOUS ROAD - ELIMINATE CHICANE CURVES AT LOW PRESSURE SERVICE WATER PUMPS		1.00 LT	-	-	500,000		78.37 /MH		500,000
			BITUMINOUS ASPHALT (10,000 - 49,999 SF) ROADWORK 24' WIDE 4" ASPHALT	SITE GRADING	1,668.00 LF	-	-	201,828	2,013	78.37 /MH	157,767	359,595
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW BYPASS LANE (ON WEST SIDE)	9,000.00 LF	-	-	603,000	1,655	78.37 /MH	129,716	732,716
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW LEFT TURN LANE (SOUTH BOUND)	3,000.00 LF	-	-	201,000	552	78.37 /MH	43,239	244,239
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW MERGE LANE (NORTH BOUND)	4,175.00 LF	-	-	279,725	768	78.37 /MH	60,174	339,899
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW RIGHT TURN LANE (NORTH BOUND)	4,000.00 LF	-	-	268,000	736	78.37 /MH	57,651	325,651
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	CONTRACTOR HAUL ROAD (HWY 46 SPUR), UPGRADE, REMOVE EXISTING ASPHALT, SUBGRADE PREP NEW BASE AND NEW ASPHALT	4,250.00 LF	-	-	514,250	3,126	78.37 /MH	245,019	759,269
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	CONTRACTOR HAUL ROAD (HWY 46 SPUR), EXTENSION, 24' WIDE	580.00 LF	-	-	84,100	907	78.37 /MH	71,055	155,155
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	WIDENING OF EXISTING MAIN PLANT ROAD FROM CONTRACTOR HAUL ROAD (HWY 46 SPUR) TO MAIN GUARD HOUSE	2,900.00 LF	-	-	194,300	1,767	78.37 /MH	138,454	332,754
			ROAD, PARKING AREA, & SURFACED AREA					**3,346,203**	**19,569**		**1,533,638**	**4,879,841**
		21.71.00	**TRACKWORK**									
			SIGNAL SYSTEM - RR CROSSING SIGNALS AND GATES	CONTRACTOR HAUL ROAD (HWY 46 SPUR) CROSSING	1.00 LS	220,000	-			/MH		220,000
			TRACKWORK			**220,000**						**220,000**
		21.99.00	**CIVIL WORK, MISCELLANEOUS**									
			CIVIL WORK - CONSTRUCTION LAYDOWN AREAS	FENCING, POWER ETC...	10.00 AC	-	-	780,000	9,195	79.31 /MH	729,287	1,509,287

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			CIVIL WORK, MISCELLANEOUS					780,000	9,195		729,287	1,509,287
			CIVIL WORK			220,000		5,301,214	68,540		8,453,679	13,974,892
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	75.00 CY	-	-	17,250	603	59.71 /MH	36,032	53,282
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	555.00 CY	-	-	127,650	4,466	59.71 /MH	266,636	394,286
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' BYPRODUCT AREA, TRUCK SCALE HOUSE	6.00 CY	-	-	1,380	48	59.71 /MH	2,883	4,263
			CONCRETE FOUNDATIONS	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	1,800.00 CY	-	-	216,000	2,586	59.71 /MH	154,422	370,422
			CONCRETE					362,280	7,703		459,973	822,253
		22.15.00	EMBEDMENT									
			EMBEDMENTS, CARBON STEEL	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	10,000.00 LB	-	-	30,000	575	51.10 /MH	29,368	59,368
			EMBEDMENT					30,000	575		29,368	59,368
		22.17.00	FORMWORK									
			BUILT UP INSTALL & STRIP	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	11,000.00 SF	-	-	27,500	2,529	81.61 /MH	206,370	233,870
			FORMWORK					27,500	2,529		206,370	233,870
		22.25.00	REINFORCING									
			UNCOATED A615 GR60	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	135.00 TN	-	-	138,375	2,793	56.35 /MH	157,391	295,766
			REINFORCING					138,375	2,793		157,391	295,766
			CONCRETE					558,155	13,600		853,102	1,411,257
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA, 45 FT X 45 FT	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	56,700	791	92.62 /MH	73,298	129,998
			SHELL ONLY, STEEL UNINSULATED 22 GA, 200 FT X 75 FT x 15' TALL	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	420,000	5,862	92.62 /MH	542,945	962,945
			PRE-ENGINEERED BUILDING	8' X 10' BYPRODUCT AREA, TRUCK SCALE HOUSE	1.00 LT	-	-	10,000	115	92.62 /MH	10,646	20,646
			PRE-ENGINEERED BUILDING					486,700	6,768		626,888	1,113,588
		24.41.00	SIDING									
			INSULATION, 2 IN THICK FIBERGLASS,	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	3,240.00 SF	-	-	3,888	37	79.59 /MH	2,964	6,852
			INSULATION, 2 IN THICK FIBERGLASS,	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	8,250.00 SF	-	-	9,900	95	79.59 /MH	7,547	17,447
			SIDING					13,788	132		10,511	24,299
			ARCHITECTURAL					500,488	6,900		637,400	1,137,888
	26.00.00		MISCELLANEOUS STRUCTURAL ITEM									
		26.99.00	MISCELLANEOUS STRUCTURAL ITEM, MISCELLANEOUS									
			MISCELLANEOUS STRUCTURAL ITEM - WATER INTAKE PUMP STRUCTURE - ONE BAY		1.00 LS	-	-	1,110,000	15,537	92.62 /MH	1,439,017	2,549,017
			MISCELLANEOUS STRUCTURAL ITEM, MISCELLANEOUS					1,110,000	15,537		1,439,017	2,549,017
			MISCELLANEOUS STRUCTURAL ITEM					1,110,000	15,537		1,439,017	2,549,017
	27.00.00		PAINTING & COATING									
		27.17.00	PAINTING									
			PAINTING - ALLOWANCE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	15,000	172	47.61 /MH	8,209	23,209
			PAINTING					15,000	172		8,209	23,209
			PAINTING & COATING					15,000	172		8,209	23,209
	31.00.00		MECHANICAL EQUIPMENT									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	11,138	156	68.48 /MH	10,679	21,817
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	NEW WAREHOUSE BUILDING 200'X75'X15' TALL, FIRE PROTECTION ALLOWANCE	15,000.00 SF	-	-	82,500	1,155	68.48 /MH	79,106	161,606
			FIRE PROTECTION EQUIPMENT & SYSTEM					93,638	1,311		89,786	183,423
			MECHANICAL EQUIPMENT					93,638	1,311		89,786	183,423
	34.00.00		HVAC									
		34.99.00	HVAC, MISCELLANEOUS									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	22,275	23	64.10 /MH	1,492	23,767
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	165,000	172	64.10 /MH	11,052	176,052
			HVAC, MISCELLANEOUS					187,275	196		12,544	199,819
			HVAC					187,275	196		12,544	199,819
	36.00.00		INSULATION									
		36.99.00	INSULATION, MISCELLANEOUS									
			INSULATION - ROOF INSULATION	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	2,430	23	51.10 /MH	1,189	3,619
			INSULATION - ROOF INSULATION	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	18,000	172	51.10 /MH	8,810	26,810
			INSULATION, MISCELLANEOUS					20,430	196		10,000	30,430
			INSULATION					20,430	196		10,000	30,430
	41.00.00		ELECTRICAL EQUIPMENT									
		41.37.00	LIGHTING ACCESSORY (FIXTURE)									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	22,275	23	63.63 /MH	1,481	23,756
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL, LIGHTING ALLOWANCE	15,000.00 SF	-	-	165,000	172	63.63 /MH	10,971	175,971
			LIGHTING ACCESSORY (FIXTURE)					187,275	196		12,452	199,727
		41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS									
			ELECTRICAL EQUIPMENT, MISCELLANEOUS -	ADD BAY TO EXISTING INTAKE STRUCTURE FOR 3RD PUMP	1.00 LT	-	-	100,000	230	82.05 /MH	18,862	118,862
			ELECTRICAL EQUIPMENT, MISCELLANEOUS					100,000	230		18,862	118,862
			ELECTRICAL EQUIPMENT					287,275	426		31,314	318,589
	71.00.00		PROJECT INDIRECT									
		71.25.00	CONSULTANT, THIRD PARTY									
			CONSULTANT - SUBSURFACE INVESTIGATION		1.00 LS	200,000	-			/MH		200,000
			CONSULTANT - GEOTECHNICAL		1.00 LS	150,000	-			/MH		150,000
			CONSULTANT, THIRD PARTY			350,000						350,000
			PROJECT INDIRECT			350,000						350,000
			121 CIVIL BOP			**570,000**		**8,073,474**	**106,878**		**11,535,049**	**20,178,523**
151			**MECHANICAL BOP**									
	11.00.00		DEMOLITION									
		11.21.00	CIVIL WORK									
			CIVIL WORK - DIG AND REFILL PIPE TRENCH	BYPRODUCT PIPE FROM RACK	100.00 LF	-	-		172	79.31 /MH	13,674	13,674
			CIVIL WORK - DIG AND REFILL PIPE TRENCH	REAGENT UNLOADING PIPE FROM RACK	200.00 LF	-	-		345	79.31 /MH	27,348	27,348
			CIVIL WORK						517		41,022	41,022
			DEMOLITION						517		41,022	41,022
	21.00.00		CIVIL WORK									
		21.17.00	EXCAVATION									
			EXCAVATION - 6" PIPE 4' DEEP PIPE TRENCH & BEDDING		1,430.00 LF	-	-	8,680	526	79.31 /MH	41,715	50,395
			EXCAVATION - 6" PIPE 4' DEEP PIPE TRENCH & BEDDING		750.00 LF	-	-	4,553	276	79.31 /MH	21,879	26,431
			EXCAVATION - 3" PIPE 4' DEEP PIPE TRENCH & BEDDING		3,000.00 LF	-	-	12,750	966	79.31 /MH	76,575	89,325
			EXCAVATION - 3" PIPE 4' DEEP PIPE TRENCH & BEDDING		1,000.00 LF	-	-	4,250	322	79.31 /MH	25,525	29,775
			EXCAVATION - 3" PIPE 4' DEEP PIPE TRENCH & BEDDING		5,260.00 LF	-	-	22,355	1,693	79.31 /MH	134,262	156,617
			EXCAVATION - 8" PIPE 4' DEEP PIPE TRENCH & BEDDING		1,340.00 LF	-	-	9,929	539	79.31 /MH	42,754	52,684
			EXCAVATION - 36" PIPE 4' DEEP PIPE TRENCH & BEDDING	RIVER WATER PIPE TIE IN	20.00 LF	-	-	733	21	79.31 /MH	1,677	2,411
			EXCAVATION - 32" PIPE 4' DEEP PIPE TRENCH & BEDDING	LPSW PIPE	2,100.00 LS	-	-	60,375	1,859	79.31 /MH	147,407	207,782

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		21.17.00	EXCAVATION									
			EXCAVATION - 10" PIPE 4' DEEP PIPE TRENCH & BEDDING	RECYCLE ASH WATER PIPE DISCHARGE BURIED	1,800.00 LF	-	-	15,930	786	79.31 /MH	62,354	78,284
			EXCAVATION - 4" PIPE 4' DEEP PIPE TRENCH & BEDDING	LEACHATE PIPING	3,500.00 LF	-	-	16,905	1,167	79.31 /MH	92,528	109,433
			EXCAVATION					156,460	8,154		646,677	803,138
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	TANK FOUNDATIONS	76.00 EA	-	-	141,132	1,922	108.46 /MH	208,443	349,575
			2.5 FT DIA X 30 FT DEEP CAISSON	COMMON PIPE RACK FOUNDATIONS	186.00 EA	-	-	345,402	4,703	108.46 /MH	510,136	855,538
			2.5 FT DIA X 30 FT DEEP CAISSON	BYPRODUCT PIPE RACK FOUNDATIONS	94.00 EA	-	-	174,558	2,377	108.46 /MH	257,811	432,369
			2.5 FT DIA X 30 FT DEEP CAISSON	REAGENT UNLOADING PIPE RACK FOUNDATIONS	16.00 EA	-	-	29,712	405	108.46 /MH	43,883	73,595
			CAISSON					690,804	9,407		1,020,272	1,711,076
			CIVIL WORK					847,264	17,561		1,666,949	2,514,214
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SPREAD FOOTING FOUNDATION, 4500 PSI - COMPOSITE RATE	3X 35' DIA TANK FDN	81.00 CY	-	-	18,630	652	59.71 /MH	38,914	57,544
			CONCRETE FOUNDATIONS - COMPOSITE RATE	COMMON PIPE RACK FOUNDATIONS	207.00 CY	-	-	47,610	1,666	59.71 /MH	99,448	147,058
			CONCRETE FOUNDATIONS - COMPOSITE RATE	BYPRODUCT PIPE RACK FOUNDATIONS	105.00 CY	-	-	24,150	845	59.71 /MH	50,445	74,595
			CONCRETE FOUNDATIONS - COMPOSITE RATE	REAGENT UNLOADING PIPE RACK FOUNDATIONS	18.00 CY	-	-	4,140	145	59.71 /MH	8,648	12,788
			CONCRETE					94,530	3,307		197,455	291,985
			CONCRETE					94,530	3,307		197,455	291,985
	23.00.00		STEEL									
		23.21.00	GIRDER									
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	COMMON 500'LX20'W, 400'Lx15'W,400'Lx9'W, ALL 20' HIGH	196.00 TN	-	-	531,160	3,830	92.62 /MH	354,724	885,884
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	BYPRODUCT PIPE RACK, 650LF X6 WIDE X 20' HIGH	39.00 TN	-	-	105,690	762	92.62 /MH	70,583	176,273
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	REAGENT UNLOADING PIPE RACK, 100LF X 6' WIDE X 20' HIGH	6.00 TN	-	-	16,260	117	92.62 /MH	10,859	27,119
			GIRDER					653,110	4,709		436,166	1,089,276
			STEEL					653,110	4,709		436,166	1,089,276
	27.00.00		PAINTING & COATING									
		27.13.00	COATING									
			COATING - CHIMNEY - ACID RESISTANT COATING TOP 100 FT OUTSIDE SHELL		1.00 LS	270,000	-			47.61 /MH		270,000
			COATING			270,000						270,000
			PAINTING & COATING			270,000						270,000
	31.00.00		MECHANICAL EQUIPMENT									
		31.17.00	COMPRESSOR & ACCESSORIES									
			AIR COMPRESSOR, CENTRIFUGAL - 250 SCFM EA @ 200 PSIG	SERVICE AIR	2.00 EA	-	310,000	-	92	68.48 /MH	6,297	316,297
			AIR COMPRESSOR, CENTRIFUGAL - 250 SCFM EA @ 200 PSIG	INSTRUMENT AIR	2.00 EA	-	310,000	-	92	68.48 /MH	6,297	316,297
			AIR DRYER - W/FILTERS, 250 NET SCFM EA	SERVICE AIR	2.00 EA	-	33,400	-	74	68.48 /MH	5,038	38,438
			AIR DRYER - W/FILTERS, 250 NET SCFM EA	INSTRUMENT AIR	2.00 EA	-	33,400	-	74	68.48 /MH	5,038	38,438
			AIR RECEIVER - 1,000 GALLON EA	SERVICE AIR	2.00 EA	-	11,200	-	37	68.48 /MH	2,519	13,719
			AIR RECEIVER - 1,000 GALLON EA	INSTRUMENT AIR	2.00 EA	-	11,200	-	37	68.48 /MH	2,519	13,719
			COMPRESSOR & ACCESSORIES				709,200		405		27,707	736,907
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									
			DELUGE - POWER TRANSFORMERS		3.00 EA	-	-	127,500	1,959	77.36 /MH	151,519	279,019
			FIRE PROTECTION EQUIPMENT & SYSTEM					127,500	1,959		151,519	279,019
		31.65.00	HEAT EXCHANGER									
			HEAT EXCHANGER - SLAKER WATER HEATER 3" IN-LINE, 475 KW		4.00 EA	-	220,000	-	368	63.63 /MH	23,404	243,404
			HEAT EXCHANGER				220,000		368		23,404	243,404
		31.75.00	PUMP									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		31.75.00	**PUMP**									
			CENTRIFUGAL, HORIZONTAL, SINGLE STAGE - MAKEUP WATER PUMPS, 2600 GPM, 200 TDH		2.00 EA	-	96,000	-	577	68.48 /MH	39,514	135,514
			CENTRIFUGAL, HORIZONTAL, SINGLE STAGE - RECYCLE ASH WATER PUMP, 50 HP		3.00 EA	-	72,000	-	221	68.48 /MH	15,113	87,113
			CENTRIFUGAL, HORIZONTAL, SINGLE STAGE - LIME SLAKING WATER PIUMPS, 50 HP		2.00 EA	-	48,000	-	147	68.48 /MH	10,075	58,075
			CENTRIFUGAL, VERTICAL, CANNED - LEACHATE PUMPS, 50 HP		2.00 EA	-	134,000	-	828	68.48 /MH	56,673	190,673
			CENTRIFUGAL, VERTICAL, WET PIT - LPSW PUMP, 650 HP		1.00 EA	-	188,000	-	690	68.48 /MH	47,228	235,228
			SUMP, CENTRIFUGAL, WET BEARING - REGENT PREP/RECYCLE SUMP, 120GPM, 150 TDH		4.00 EA	-	220,000	-	276	68.48 /MH	18,891	238,891
			SUMP, CENTRIFUGAL, WET BEARING - LIME SILO & UNLOADING AREA SUMP 120 GPM @ 150 TDH		2.00 EA	-	88,000	-	138	68.48 /MH	9,446	97,446
			SUMP, CENTRIFUGAL, WET BEARING - WASTE ASH SILO AREA SUMP 120GPM @150 TDH		2.00 EA	-	88,000	-	138	68.48 /MH	9,446	97,446
			SUMP, CENTRIFUGAL, WET BEARING - WASTEWATER FORWARDING PUMP TO RECYCLED SLURRY, 100 GPM@150 TDH		4.00 EA	-	28,800	-	294	68.48 /MH	20,150	48,950
			SUMP, SUBMERSIBLE - RECYCLE ASH WATER TANK SUPPLY PUMP, 100 HP		2.00 EA	-	77,000	-	690	68.48 /MH	47,228	124,228
			PUMP				**1,039,800**		**3,998**		**273,763**	**1,313,563**
		31.83.00	**TANK**									
			ATMOSPHERIC, FIELD FABRICATED - LIME SLAKING WATER TANK, 175,000 GALLON	35' DIA X 24' HIGH	1.00 EA	220,000		-		90.81 /MH		220,000
			ATMOSPHERIC, FIELD FABRICATED - RECYCLE ASH WATER TANK, 250,000 GALLON	35' DIA X 36' HIGH	2.00 EA	508,000		-		90.81 /MH		508,000
			TANK			**728,000**						**728,000**
			MECHANICAL EQUIPMENT			**728,000**	**1,969,000**	**127,500**	**6,729**		**476,392**	**3,300,892**
	35.00.00		**PIPING**									
		35.13.01	**SS 304, ABOVE GROUND, PROCESS AREA**									
			1 IN DIA, SCH 40S		1,520.00 LF	-	-	32,832	1,974	77.36 /MH	152,728	185,560
			1.5 IN DIA, SCH 40S		1,380.00 LF	-	-	52,302	2,094	77.36 /MH	161,976	214,278
			2 IN DIA, SCH 40S		2,070.00 LF	-	-	113,022	3,426	77.36 /MH	265,051	378,073
			SS 304, ABOVE GROUND, PROCESS AREA					**198,156**	**7,494**		**579,755**	**777,911**
		35.13.10	**CARBON STEEL, ABOVE GROUND, PROCESS AREA**									
			1 IN DIA, SCH 80		260.00 LF	-	-	2,314	305	77.36 /MH	23,581	25,895
			2 IN DIA, SCH 80		2,260.00 LF	-	-	48,138	3,273	77.36 /MH	253,207	301,345
			2.5 IN DIA, SCH 40		1,000.00 LF	-	-	15,400	1,437	77.36 /MH	111,149	126,549
			3 IN DIA, SCH 40		7,160.00 LF	-	-	125,300	11,028	77.36 /MH	853,130	978,430
			3 IN DIA, SCH 80		1,760.00 LF	-	-	38,720	3,055	77.36 /MH	236,313	275,033
			4 IN DIA, SCH 40		1,000.00 LF	-	-	22,600	1,701	77.36 /MH	131,601	154,201
			6 IN DIA, SCH 40		880.00 LF	-	-	28,248	1,629	77.36 /MH	125,981	154,229
			6 IN DIA, SCH 40 VACUUM PIPE		2,260.00 LF	-	-	72,546	4,182	77.36 /MH	323,543	396,089
			8 IN DIA, SCH 80		3,520.00 LF	-	-	256,608	9,832	77.36 /MH	760,582	1,017,190
			CARBON STEEL, ABOVE GROUND, PROCESS AREA					**609,874**	**36,441**		**2,819,087**	**3,428,961**
		35.13.36	**DUCTILE IRON, ABOVE GROUND, PROCESS AREA**									
			12 IN DIA, - ASHCOLITE PIPE		1,620.00 LF	-	-	162,000	3,594	72.14 /MH	259,256	421,256
			DUCTILE IRON, ABOVE GROUND, PROCESS AREA					**162,000**	**3,594**		**259,256**	**421,256**
		35.14.10	**CARBON STEEL, STRAIGHT RUN**									
			6 IN DIA, SCH 40, LIME SLAKING TANK MAKEUP	LIME SLAKING TANK MAKEUP	1,200.00 LF	-	-	27,480	1,214	77.36 /MH	93,899	121,379
			8 IN DIA, SCH 40, LIME SLAKING TANK MAKEUP	LIME SLAKING TANK MAKEUP	450.00 LF	-	-	13,905	486	77.36 /MH	37,613	51,518
			8 IN DIA, SCH 40, RECYCLE ASH WATER PIPING	RECYCLE ASH WATER PIPING	2,000.00 LF	-	-	61,800	2,161	77.36 /MH	167,169	228,969
			10 IN DIA, SCH 40, RECYCLE ASH TANK MAKEUP	RECYCLE ASH TANK MAKEUP	450.00 LF	-	-	24,660	610	77.36 /MH	47,216	71,876
			CARBON STEEL, STRAIGHT RUN					**127,845**	**4,471**		**345,897**	**473,742**
		35.15.10	**CARBON STEEL, BURIED**									
			3 IN DIA, SCH 40, WRAPPED		3,000.00 LF	-	-	51,000	2,241	77.36 /MH	173,393	224,393
			4 IN DIA, SCH 40, WRAPPED, LEACHATE PIPING	LEACHATE PIPING	3,500.00 LF	-	-	72,800	2,856	77.36 /MH	220,965	293,765
			6 IN DIA, SCH 40, WRAPPED		750.00 LF	-	-	23,925	776	77.36 /MH	60,021	83,946
			10 IN DIA, SCH 40, WRAPPED, RECYCLE ASH WATER PIPE DISCHARGE BURIED	RECYCLE ASH WATER PIPE DISCHARGE BURIED	1,800.00 LF	-	-	119,700	2,441	77.36 /MH	188,865	308,565
			32 IN DIA, 3/8 IN STD, WRAPPED - LPSW PIPE	LPSW PIPE	2,100.00 LF	-	-	638,610	11,079	77.36 /MH	857,095	1,495,705

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		35.15.10	CARBON STEEL, BURIED									
			36 IN DIA, 3/8 IN STD, WRAPPED - RIVER WATER PIPE	RIVER WATER PIPE - TIE IN	20.00 LF	-	-	6,772	138	77.36 /MH	10,706	17,478
			CARBON STEEL, BURIED					912,807	19,533		1,511,045	2,423,852
		35.15.25	FRP, BURIED									
			3 IN DIA, TAPER		1,000.00 LF	-	-	14,800	460	77.36 /MH	35,568	50,368
			3 IN DIA, TAPER FRP/HDPE PIPE		2,380.00 LF	-	-	35,224	1,094	77.36 /MH	84,651	119,875
			FRP, BURIED					50,024	1,554		120,219	170,243
		35.15.30	HDPE, BURIED									
			6 IN DIA, DR 9		1,430.00 LF	-	-	12,870	1,134	77.36 /MH	87,737	100,607
			8 IN DIA, DR 9		1,340.00 LF	-	-	20,770	1,278	77.36 /MH	98,896	119,666
			HDPE, BURIED					33,640	2,413		186,633	220,273
		35.36.00	PIPE SUPPORTS, RACK									
			SUPPORT SLEEPERS	BYPRODUCT PIPE, 1750LF	125.00 EA	-	-	43,750	575	77.36 /MH	44,460	88,210
			SUPPORT SLEEPERS	REAGENT UNLOADING PIPE, 1500LF	108.00 EA	-	-	37,800	497	77.36 /MH	38,413	76,213
			PIPE SUPPORTS, RACK					81,550	1,071		82,873	164,423
		35.45.00	VALVES									
			VALVE - 36" 150 LB CS BUTTERFLY, FLANGED		2.00 EA	-	-	79,920	96	77.36 /MH	7,398	87,318
			VALVE - 12" 150 LB CS KNIFE GATE, FLANGED		6.00 EA	-	-	20,160	195	77.36 /MH	15,099	35,259
			VALVE - 12" 150 LB CS GATE VALVE, FLANGED		2.00 EA	-	-	8,920	65	77.36 /MH	5,033	13,953
			VALVE - 10" 150 LB CS SWING CHECK, FLANGED		2.00 EA	-	-	9,200	55	77.36 /MH	4,268	13,468
			VALVE - 10" 150 LB CS BUTTERFLY, FLANGED		5.00 EA	-	-	22,200	138	77.36 /MH	10,670	32,870
			VALVE - 8" 150 LB CS GATE, FLANGED		20.00 EA	-	-	100,000	425	77.36 /MH	32,900	132,900
			VALVE - 6" 150 LB CS GATE, FLANGED		6.00 EA	-	-	19,800	110	77.36 /MH	8,536	28,336
			VALVE - 6" 150 LB CS AIR OPERATED GATE, FLANGED		4.00 EA	-	-	20,400	74	77.36 /MH	5,691	26,091
			VALVE - 6" 150 LB CS AIR OPERATED GLOBE, FLANGED		4.00 EA	-	-	20,400	74	77.36 /MH	5,691	26,091
			VALVE - 6" 150 LB CS SWING CHECK, FLANGED		2.00 EA	-	-	3,400	37	77.36 /MH	2,845	6,245
			VALVE - 4" 150 LB CS GATE, FLANGED		3.00 EA	-	-	3,825	25	77.36 /MH	1,921	5,746
			VALVE - 3" AND BELOW CS FOR SERVICE WATER ISOLATION		120.00 EA	-	-	1,224,000	1,076	77.36 /MH	83,229	1,307,229
			VALVE - 3" AND BELOW CS FOR SERVICE AIR ISOLATION		120.00 EA	-	-	1,224,000	1,076	77.36 /MH	83,229	1,307,229
			VALVE - 3" 150 LB CS GATE, FLANGED		20.00 EA	-	-	15,000	179	77.36 /MH	13,871	28,871
			VALVE - 3" CS PST IND FOR FP 250 LB		6.00 EA	-	-	6,600	54	77.36 /MH	4,161	10,761
			VALVE - 2" AND ABOVE BRONZE VALVES FOR INSTRUMENT AIR ISOLATION		600.00 EA	-	-	78,000	501	77.36 /MH	38,787	116,787
			VALVE - 1" CS FLANGED		4.00 EA	-	-	880	21	77.36 /MH	1,636	2,516
			VALVE - 6" CI POST INDICATOR 250 LB., MECHANICAL JOINT WITH BOXES BURIED VALVE		6.00 EA	-	-	4,080	28	77.36 /MH	2,134	6,214
			VALVES					2,860,785	4,228		327,099	3,187,884
			PIPING					5,036,681	80,799		6,231,866	11,268,547
	36.00.00		INSULATION									
		36.17.01	PIPE, CALCIUM SILICATE W/ALUMINUM JACKETING									
			CALCIUM SILICATE W/ALUMINUM JACKETING - 8" PIPE 1.5" THICK		2,520.00 LF	-	-	16,380	487	68.76 /MH	33,460	49,840
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 3" PIPE		1,260.00 LF	-	-	3,591	155	68.76 /MH	10,655	14,246
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 3" PIPE		5,660.00 LF	-	-	16,131	696	68.76 /MH	47,865	63,996
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 2.5" PIPE		380.00 LS	-	-	1,083	47	68.76 /MH	3,214	4,297
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 2.0" PIPE		4,140.00 LS	-	-	10,309	476	68.76 /MH	32,720	43,029
			PIPE, CALCIUM SILICATE W/ALUMINUM JACKETING					47,494	1,860		127,914	175,408
			INSULATION					47,494	1,860		127,914	175,408
	41.00.00		ELECTRICAL EQUIPMENT									
		41.33.00	HEAT TRACING									
			HEAT TRACING - 8" PIPE		2,520.00 LS	-	-	18,749	43	63.63 /MH	2,765	21,513
			HEAT TRACING - 3" PIPE		1,260.00 LF	-	-	9,374	22	63.63 /MH	1,382	10,757
			HEAT TRACING - 3" PIPE		5,660.00 LF	-	-	42,110	98	63.63 /MH	6,209	48,320
			HEAT TRACING - 2.5" PIPE		380.00 LS	-	-	2,827	7	63.63 /MH	417	3,244
			HEAT TRACING - 2.0" PIPE		440.00 LS	-	-	3,274	8	63.63 /MH	483	3,756
			HEAT TRACING					76,334	177		11,256	87,590
			ELECTRICAL EQUIPMENT					76,334	177		11,256	87,590
			151 MECHANICAL BOP			998,000	1,969,000	6,882,913	115,659		9,189,021	19,038,934

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
190			**DEMOLITION / RELOCATION**									
	11.00.00		**DEMOLITION**									
		11.21.00	**CIVIL WORK**									
			CIVIL WORK - REMOVE FENCING & GATES	HAZARDOUS MATERIAL ACCUMULATION BLDG	1,133.00 LF	-	-		91	107.10 /MH	9,763	9,763
			CIVIL WORK - DIG AND REFILL PIPE TRENCH	TRENCH N.1784.33 FROM E905' TO 1180'	550.00 LF	-	-		948	79.31 /MH	75,208	75,208
			CIVIL WORK - REMOVE DRAINAGE DITCH	DRAINAGE DITCH E970 FROM N2055 'TO N1350'	705.00 LF	-	-		1,216	79.31 /MH	96,403	96,403
			CIVIL WORK - REMOVE DRAINAGE DITCH	DRAINAGE DITCH e1350 from n970' to n1180'	210.00 LF	-	-		362	79.31 /MH	28,716	28,716
			CIVIL WORK - DEMO AREA PAVEMENT	ASH HANDLING / ELECT BLDG	1.00 LS	-	-		115	107.10 /MH	12,310	12,310
			CIVIL WORK						**2,732**		**222,400**	**222,400**
		11.22.00	**CONCRETE**									
			CONCRETE FOUNDATION - HAZARDOUS MATERIAL ACCUMULATION BLDG	HAZARDOUS MATERIAL ACCUMULATION BLDG, 50'X50'X20'	80.00 CY	-	-		230	107.10 /MH	24,621	24,621
			CONCRETE FOUNDATION - HAZARDOUS MATERIAL ACCUMULATION BLDG	HAZARDOUS MATERIAL ACCUMULATION BLDG, HAZMAT PAVEMENT DEMO	12.00 CY	-	-		61	107.10 /MH	6,574	6,574
			CONCRETE FOUNDATION - ASH HANDLING MAINT BLDG	ASH HANDLING / ELECT BLDG FDN	225.00 CY	-	-		647	107.10 /MH	69,246	69,246
			CONCRETE FOUNDATION - PAVING & FOUNDATION DEMO	FLOURESCENT LIGHT TUBE DISPOSAL SHED FDN	2.00 CY	-	-		10	107.10 /MH	1,096	1,096
			CONCRETE FOUNDATION - PAVING & FOUNDATION DEMO	USED OIL SHED DEMO	35.00 CY	-	-		101	107.10 /MH	10,772	10,772
			CONCRETE						**1,049**		**112,307**	**112,307**
		11.23.00	**STEEL**									
			STRUCTURAL STEEL DISASSEMBLE BLDG STEEL & TOOL CRIB FOR RELOCATION	ASH HANDLING / ELECT BLDG	52.00 TN	-	-		359	107.10 /MH	38,408	38,408
			STEEL						**359**		**38,408**	**38,408**
		11.24.00	**ARCHITECTURAL**									
			ARCHITECTURAL - HAZARDOUS MATERIAL ACCUMULATION BLDG 50'X50'X20'	HAZARDOUS MATERIAL ACCUMULATION BLDG, 50'X50'X20'	50,000.00 CF	-	-		632	107.10 /MH	67,707	67,707
			ARCHITECTURAL - HAZARDOUS MATERIAL ACCUMULATION BLDG 50'X50'X20'	HAZARDOUS MATERIAL ACCUMULATION BLDG, CONTAINER DISPOSAL AREA	1.00 LT	-	-		287	107.10 /MH	30,776	30,776
			ARCHITECTURAL - DEMO EXISTING INSULATED SIDING & ROOFING , DEMO INTERIOR OFFICES	ASH HANDLING / ELECT BLDG	15,000.00 CF	-	-		862	107.10 /MH	92,328	92,328
			ARCHITECTURAL - BLDG DEMO	COAL DUMPER AIR COMPRESSOR DEMOLITION	100.00 SF	-	-		11	107.10 /MH	1,231	1,231
			ARCHITECTURAL - BLDG DEMO	USED OIL SHED DEMO	600.00 SF	-	-		8	107.10 /MH	812	812
			ARCHITECTURAL						**1,801**		**192,854**	**192,854**
		11.31.00	**MECHANICAL EQUIPMENT**									
			MECHANICAL EQUIPMENT - DEMOLISH SEPTIC TANKS	ASH HANDLING / ELECT BLDG	2.00 EA	-	-		0	107.10 /MH	25	25
			MECHANICAL EQUIPMENT - REMOVE 15 TN BRIDGE CRANE (50 FT SPAN) , CRANE SUPPORT STEEL AND 3 JIB CRANES FGOR RELOCATION	ASH HANDLING / ELECT BLDG	21.00 TN	-	-		290	92.62 /MH	26,828	26,828
			MECHANICAL EQUIPMENT						**290**		**26,852**	**26,852**
		11.35.00	**PIPING**									
			PIPING - REMOVE 12" BA PIPE IN PIPE TRENCH	TRENCH N.1784.33 FROM E905' TO 1180'	550.00 LF	-	-		87	107.10 /MH	9,276	9,276
			PIPING - REMOVE 10" FA PIPE	TRENCH N.1784.33 FROM E905' TO 1180'	550.00 LF	-	-		76	107.10 /MH	8,125	8,125
			PIPING						**162**		**17,401**	**17,401**
		11.99.00	**DEMOLITION, MISCELLANEOUS**									
			DEMOLITION - MISC	ALLOWANCE	1.00 LT	-	-		2,299	92.62 /MH	212,920	212,920
			DEMOLITION, MISCELLANEOUS						**2,299**		**212,920**	**212,920**
			DEMOLITION						**8,691**		**823,142**	**823,142**
	21.00.00		**CIVIL WORK**									
		21.16.00	**GENERAL EARTHWORK**									
			EARTHWORK - COVER AREA WITH BACKFILL AND GRADE	HAZARDOUS MATERIAL ACCUMULATION BLDG	300.00 CY	-	-	4,800	138	182.33 /MH	25,149	29,949
			EARTHWORK - COVER AREA WITH BACKFILL AND GRADE	ASH HANDLING / ELECT BLDG	1,000.00 CY	-	-	16,000	460	182.33 /MH	83,830	99,830
			EARTHWORK - COVER AREA WITH BACKFILL AND GRADE 250'X250'X2'	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG) AREA FILL	5,000.00 CY	-	-	80,000	259	182.33 /MH	47,154	127,154
			GENERAL EARTHWORK				100,800		**856**		**156,133**	**256,933**
		21.17.00	**EXCAVATION**									
			EXCAVATION - ALLOWANCE FOR NEW DITCHES	WASTE MANAGEMENT FACILITY (	1,200.00 CY	-	-		276	79.31 /MH	21,879	21,879

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		21.17.00	EXCAVATION									
			EXCAVATION - ALLOWANCE FOR NEW DITCHES	REPLACES HAZMAT BLDG) AREA FILL	1,200.00 CY	-	-		276	79.31 /MH	21,879	21,879
			EXCAVATION						276		21,879	21,879
		21.20.00	BACKFILL									
			FOUNDATION BACKFILL, PREVIOUSLY EXCAVATED MATERIAL, ALLOWANCE FOR OLD DITCHES	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG) AREA FILL	100.00 CY	-	-		17	79.31 /MH	1,367	1,367
			BACKFILL						17		1,367	1,367
		21.21.00	MASS FILL									
			MASS FILL, COMMON EARTH USING DUMP TRUCK, 2 MI ROUND TRIP, ALLWANCE FOR MISC ADDITIONAL FILL	RELOCATED BLDGS	1.00 LT	-	-	30,000	345	79.31 /MH	27,348	57,348
			MASS FILL					30,000	345		27,348	57,348
		21.39.00	STORM DRAINAGE UTILITIES									
			EXTEND CULVERTS UNDER ROAD	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG) AREA FILL	48.00 LF	-	-	4,800	166	79.31 /MH	13,127	17,927
			STORM DRAINAGE UTILITIES					4,800	166		13,127	17,927
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			EROSION AND SEDIMENTATION CONTROL - ALLOWANCE	RELOCATED BLDGS	1.00 LS	-	-	20,000	345	36.12 /MH	12,455	32,455
			EROSION AND SEDIMENTATION CONTROL					20,000	345		12,455	32,455
		21.43.00	FENCEWORK									
			FABRIC, WIRE & POSTS, CHAIN LINK FENCE, GALVANIZED, 6 FT TALL, 6 GAGE 3 STRANDS OF BARB WIRE, 2 IN POST AT 10 FT O.C.	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	800.00 FT	-	-	18,880	92	36.12 /MH	3,321	22,201
			VEHICLE GATE, 14 FT WIDE BY 7 FT TALL	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	4.00 EA	-	-	4,000	110	36.12 /MH	3,986	7,986
			FENCEWORK					22,880	202		7,307	30,187
		21.47.00	LANDSCAPING									
			LANDSCAPING - ALLOWANCE FOR PAVING GRADING & SEEDING	RELOCATED BLDGS	1.00 LS	-	-	40,000	460	36.12 /MH	16,607	56,607
			LANDSCAPING					40,000	460		16,607	56,607
		21.57.00	ROAD, PARKING AREA, & SURFACED AREA									
			BITUMINOUS ASPHALT (10,000 - 49,999 SF) ASHPALT PAVING FOR TRUCK TURNAROUND , DRIVEWAY AND AROUND BLDG	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	43,000.00 SF	-	-	216,720	1,236	78.37 /MH	96,836	313,556
			ROAD, PARKING AREA, & SURFACED AREA					216,720	1,236		96,836	313,556
			CIVIL WORK					435,200	3,902		353,060	788,260
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	320.00 CY	-	-	73,600	2,575	59.71 /MH	153,736	227,336
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)- CONTAINER DISPOSAL SLAB & APRON	550.00 CY	-	-	126,500	4,425	59.71 /MH	264,234	390,734
			CONCRETE FOUNDATIONS - COMPOSITE RATE	ACI PORT STAIRTOWER FDNS	60.00 CY	-	-	13,800	483	59.71 /MH	28,826	42,626
			CONCRETE					213,900	7,483		446,796	660,696
			CONCRETE					213,900	7,483		446,796	660,696
	23.00.00		STEEL									
		23.17.00	GALLERY									
			GALVANIZED GRATING, 1 1/4" DEEP x 3/16" BEARING BAR WITH HOLD DOWN CLIPS	ACI PORT STAIR TOWERS AND PLATFORMS	728.00 SF	-	-	10,920	84	66.07 /MH	5,529	16,449
			DOUBLE PIPE HANDRAIL WITH POSTS AND GUARD PLATES, PAINTED	ACI PORT STAIR TOWERS AND PLATFORMS	436.00 LF	-	-	23,108	90	66.07 /MH	5,960	29,068
			STAIR SYSTEM	ACI PORT STAIR TOWERS AND PLATFORMS	896.00 SF	-	-	81,536	1,184	66.07 /MH	78,251	159,787
			GALLERY					115,564	1,358		89,740	205,304
		23.21.00	GIRDER									
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	UNIT 2 ACI PIPE RACK OVER ROADWAY, 35LF X 23 WIDE X 20' HIGH	1.26 TN	-	-	3,415	25	92.62 /MH	2,280	5,695

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			GIRDER					3,415	25		2,280	5,695
		23.25.00	ROLLED SHAPE									
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, TWO COAT PAINT	ACI PORT STAIRTOWER FRAMING - 2 TOWERS	4.40 TN	-	-	15,752	111	92.62 /MH	10,305	26,057
			REASSEMBLE ASH HANDLING/ELEC BLDG METAL FRAME, PURLINS & GIRTS AS NEW LABOR SHOP	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	50.00 TN	-	-		1,379	92.62 /MH	127,752	127,752
			ROLLED SHAPE					15,752	1,491		138,057	153,809
			STEEL					134,731	2,873		230,077	364,808
	24.00.00		ARCHITECTURAL									
		24.15.00	DOOR (INCL. FRAME & HARDWARE)									
			DOOR (INCL. FRAME & HARDWARE) - ROLL UP DOOR MAN DOOR ETC...	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 LS	-	-	5,000	92	51.10 /MH	4,699	9,699
			DOOR (INCL. FRAME & HARDWARE)					5,000	92		4,699	9,699
		24.27.00	MASONRY									
			BLOCK, CONCRETE, 8 IN, HOLLOW REINFORCED, ALTERNATE COURSES	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	850.00 SF	-	-	4,242	106	53.08 /MH	5,601	9,842
			MASONRY					4,242	106		5,601	9,842
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA,	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	5,000.00 SF	-	-	140,000	1,954	92.62 /MH	180,982	320,982
			PRE-ENGINEERED BUILDING					140,000	1,954		180,982	320,982
		24.37.00	ROOFING									
			METAL, INSULATED- NEW INSULATED SIDING & ROOFING	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	6,500.00 SF	-	-	50,505	2,241	35.02 /MH	78,493	128,998
			ROOFING					50,505	2,241		78,493	128,998
		24.41.00	SIDING									
			METAL, INSULATED, NEW INSULATED SIDING & ROOFING	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	8,500.00 SF	-	-	140,760	870	79.59 /MH	69,207	209,967
			SIDING					140,760	870		69,207	209,967
		24.99.00	ARCHITECTURAL, MISCELLANEOUS									
			ARCHITECTURAL, MISCELLANEOUS - OFFICE ALLOWANCE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 LS	-	-	100,000	2,299	51.10 /MH	117,471	217,471
			ARCHITECTURAL, MISCELLANEOUS - TOOL CRIB	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	1.00 LS	-	-	5,000	92	51.10 /MH	4,699	9,699
			ARCHITECTURAL, MISCELLANEOUS					105,000	2,391		122,170	227,170
			ARCHITECTURAL					445,507	7,653		461,151	906,658
	27.00.00		PAINTING & COATING									
		27.17.00	PAINTING									
			PAINTING - ALLOWANCE	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	2,025	23	47.61 /MH	1,108	3,133
			PAINTING					2,025	23		1,108	3,133
			PAINTING & COATING					2,025	23		1,108	3,133
	31.00.00		MECHANICAL EQUIPMENT									
		31.25.00	CRANES & HOISTS									
			BRIDGE CRANE - INSTALL SALVAGED 15 TN BRIDGE CRANE AND 2 JIB CRANES WITH EXISTING SUPPORT STEEL	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	21.00 TN	-	-	-	290	92.62 /MH	26,828	26,828
			BRIDGE CRANE - LOAD TEST & CERTIFY BRIDGE CRANE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 EA	-	-	-	230	92.62 /MH	21,292	21,292
			MOTORIZED HOIST - 1 TON	RELOCATED FROM PRESENT PORT LOCATIOIN	2.00 EA	-	-	-	138	68.48 /MH	9,446	9,446
			CRANES & HOISTS						657		57,565	57,565
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 LT	-	-	10,000	138	68.48 /MH	9,446	19,446
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	WASTE MANAGEMENT FACILITY (	5,000.00 SF	-	-	27,500	385	68.48 /MH	26,369	53,869

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	REPLACES HAZMAT BLDG)	5,000.00 SF	-	-	27,500	385	68.48 /MH	26,369	53,869
			FIRE PROTECTION EQUIPMENT & SYSTEM					37,500	523		35,814	73,314
		31.51.00	MERCURY REMOVAL EQUIPMENT									
			ACTIVATED CARBON INJECTION (ACI) - LANCE RELOCATIONS	RELOCATED FROM PRESENT PORT LOCATIOIN (16 PER UNIT)	32.00 EA	-	-	-	368	68.48 /MH	25,188	25,188
			ACTIVATED CARBON INJECTION (ACI) - 40 HP BLOWERS	NEW BLOWERS (2 PER UNIT)	4.00 EA	-	-	80,000	184	68.48 /MH	12,594	92,594
			ACTIVATED CARBON INJECTION (ACI) - REMOVE EXISTING 20 HP BLOWERS	REMOVE EXISTING	2.00 EA	-	-	-	23	68.48 /MH	1,574	1,574
			MERCURY REMOVAL EQUIPMENT					80,000	575		39,356	119,356
			MECHANICAL EQUIPMENT					117,500	1,755		132,736	250,236
	34.00.00		HVAC									
		34.99.00	HVAC, MISCELLANEOUS									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	2,100.00 SF	-	-	23,100	24	64.10 /MH	1,547	24,647
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	2,100.00 SF	-	-	23,100	24	64.10 /MH	1,547	24,647
			HVAC, MISCELLANEOUS					46,200	48		3,094	49,294
			HVAC					46,200	48		3,094	49,294
	35.00.00		PIPING									
		35.13.25	FRP, ABOVE GROUND, PROCESS AREA									
			1.5 IN DIA, TAPER	INJECTION PORTS	12.00 LF	-	-	353	6	77.36 /MH	437	790
			2 IN DIA, TAPER	INJECTION PORTS	16.00 LF	-	-	421	9	77.36 /MH	697	1,118
			3 IN DIA, TAPER	INJECTION PORTS	40.00 LF	-	-	1,032	31	77.36 /MH	2,383	3,415
			FRP, ABOVE GROUND, PROCESS AREA					1,806	45		3,518	5,323
		35.14.25	FRP, STRAIGHT RUN									
			4 IN DIA, TAPER	NEW ACI PIPING	600.00 LF	-	-	12,660	400	77.36 /MH	30,944	43,604
			FRP, STRAIGHT RUN					12,660	400		30,944	43,604
		35.36.00	PIPE SUPPORTS, RACK									
			U-BOLT FOR 4 IN PIPE	ACI PIPE	27.00 EA	-	-	81	62	77.36 /MH	4,802	4,883
			SUPPORT SLEEPERS	ACI PIPE 330 LF	17.00 EA	-	-	5,950	78	77.36 /MH	6,047	11,997
			SUPPORT FOR 4 IN DIA PIPE - USER DEFINED		2.00 EA	-	-	306	18	77.36 /MH	1,423	1,729
			SUPPORT FOR 3 IN DIA PIPE - USER DEFINED		4.00 EA	-	-	576	32	77.36 /MH	2,490	3,066
			PIPE SUPPORTS, RACK					6,913	191		14,761	21,674
		35.45.00	VALVES									
			VALVE - 4" 150 LB CS GATE, FLANGED	ACI AUTO MATIC ISOLATION VALVES (RELOCATE 4 PER UNIT)	8.00 EA	-	-	160	66	77.36 /MH	5,122	5,282
			VALVES					160	66		5,122	5,282
			PIPING					21,539	702		54,344	75,883
	41.00.00		ELECTRICAL EQUIPMENT									
		41.37.00	LIGHTING ACCESSORY (FIXTURE)									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	6,500.00 SF	-	-	71,500	75	63.63 /MH	4,754	76,254
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	5,000.00 SF	-	-	55,000	57	63.63 /MH	3,657	58,657
			LIGHTING ACCESSORY (FIXTURE)					126,500	132		8,411	134,911
		41.46.00	MOTOR CONTROL CENTER (MCC), COMPONENT									
			FVN STARTER - #4,	NEW BLOWERS	3.00 EA	-	-	14,700	55	63.63 /MH	3,511	18,211
			MOTOR CONTROL CENTER (MCC), COMPONENT					14,700	55		3,511	18,211
			ELECTRICAL EQUIPMENT					141,200	187		11,921	153,121
	42.00.00		RACEWAY, CABLE TRAY & CONDUIT									
		42.15.23	CONDUIT, FLEXIBLE SEALTIGHT ASSEMBLY									
			1-1/2 IN DIA, 3 FT LONG INCLUDING (2) CONNECTORS	NEW BLOWERS	3.00 EA	-	-	258	4	61.79 /MH	266	524
			CONDUIT, FLEXIBLE SEALTIGHT ASSEMBLY					258	4		266	524
		42.15.37	CONDUIT, RGS									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		42.15.37	CONDUIT, RGS									
			3/4 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	HOIST	450.00 LF	-	-	1,319	100	61.79 /MH	6,200	7,519
			1-1/2 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	NEW BLOWERS	400.00 LF	-	-	2,688	131	61.79 /MH	8,068	10,756
			CONDUIT, RGS					4,007	231		14,269	18,275
			RACEWAY, CABLE TRAY & CONDUIT					4,264	235		14,535	18,799
	43.00.00		CABLE									
		43.10.00	CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION									
			CONTROL/INSTRUMENTATION/COMMUNICATION TERMINATION - MISC	ACI RELOCATION	600.00 LF	-	-	1,920	55	82.05 /MH	4,527	6,447
			CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION					1,920	55		4,527	6,447
		43.20.00	600V CABLE & TERMINATION									
			600V #8 3/C CU EPR TS-CPE	HOIST	500.00 LF	-	-	3,280	14	82.05 /MH	1,179	4,459
			600V #4/0 3/C W/G CU EPR TS-CPE	NEW BLOWERS	450.00 LF	-	-	10,728	72	82.05 /MH	5,942	16,670
			TERMINATION - COMPRESSION LUG, #8, 2 HOLE, COPPER	HOIST	12.00 EA	-	-	78	4	82.05 /MH	340	418
			TERMINATION - COMPRESSION LUG, #4, 2 HOLE, COPPER	NEW BLOWERS	12.00 EA	-	-	111	7	82.05 /MH	566	677
			600V CABLE & TERMINATION					14,197	98		8,026	22,223
			CABLE					16,117	153		12,553	28,670
	44.00.00		CONTROL & INSTRUMENTATION									
		44.21.00	INSTRUMENT									
			ACCOUSTIC MONITOR	RELOCATE TO NEW INJECTION LANCES	6.00 EA	-	-		28	64.68 /MH	1,784	1,784
			INSTRUMENT						28		1,784	1,784
			CONTROL & INSTRUMENTATION						28		1,784	1,784
	71.00.00		PROJECT INDIRECT									
		71.25.00	CONSULTANT, THIRD PARTY									
			COMPUTATIONAL FLUID DYNAMIC ANALYSIS (CFD)	ACI SYSTEM	1.00 LS	100,000	-			/MH		100,000
			CONSULTANT, THIRD PARTY			100,000						100,000
			PROJECT INDIRECT			100,000						100,000
			190 DEMOLITION / RELOCATION			**100,000**		**1,578,182**	**33,735**		**2,546,302**	**4,224,484**
201			**ELECTRICAL BOP SYSTEM**									
	21.00.00		CIVIL WORK									
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	U1 MAIN ELECT BLDG 40'X100'	23.00 EA	-	-	42,711	582	108.46 /MH	63,081	105,792
			2.5 FT DIA X 30 FT DEEP CAISSON	2 UAT AND 1 SST TRANSFORMER SUBSTRUCTURE	36.00 EA	-	-	66,852	910	108.46 /MH	98,736	165,588
			2.5 FT DIA X 30 FT DEEP CAISSON	BUS DUCT SUPPORTS	167.00 EA	-	-	310,119	4,223	108.46 /MH	458,025	768,144
			2.5 FT DIA X 30 FT DEEP CAISSON	OVERHEAD TRANSMISSION LINE STRUCTURAL - INCLUDES 115 KV DISCONNECT SWITCH FOUNDATION	10.00 EA	-	-	18,570	253	108.46 /MH	27,427	45,997
			2.5 FT DIA X 30 FT DEEP CAISSON	U2 MAIN ELECT BLDG 40'X100'	23.00 EA	-	-	42,711	582	108.46 /MH	63,081	105,792
			CAISSON					480,963	6,549		710,351	1,191,314
			CIVIL WORK					480,963	6,549		710,351	1,191,314
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			CONCRETE FOUNDATIONS - COMPOSITE RATE	U1 MAIN ELECT BLDG 40'X100'	300.00 CY	-	-	69,000	2,414	59.71 /MH	144,128	213,128
			CONCRETE FOUNDATIONS - COMPOSITE RATE	2 UAT AND 1 SST TRANSFORMER SUBSTRUCTURE	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			CONCRETE FOUNDATIONS - COMPOSITE RATE	BUS DUCT SUPPORTS	333.00 CY	-	-	76,590	2,679	59.71 /MH	159,982	236,572
			CONCRETE FOUNDATIONS - COMPOSITE RATE	OVERHEAD TRANSMISSION LINE STRUCTURAL	50.00 CY	-	-	11,500	402	59.71 /MH	24,021	35,521
			CONCRETE FOUNDATIONS - COMPOSITE RATE	U2 MAIN ELECT BLDG 40'X100'	300.00 CY	-	-	69,000	2,414	59.71 /MH	144,128	213,128
			CONCRETE					364,090	12,737		760,513	1,124,603
			CONCRETE					364,090	12,737		760,513	1,124,603
	23.00.00		STEEL									
		23.99.00	STEEL, MISCELLANEOUS									
			STEEL, MISCELLANEOUS - AUX SUPPORT STEEL	AUX SUPPORT STEEL	100.00 TN	-	-	271,000	1,954	92.62 /MH	180,982	451,982

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		23.99.00	STEEL, MISCELLANEOUS									
			STEEL, MISCELLANEOUS -	BUS DUCT SUPPORTS	167.00 TN	-	-	452,570	3,263	92.62 /MH	302,239	754,809
			STEEL, MISCELLANEOUS -	OVERHEAD TRANSMISSION LINE STRUCTURAL	15.00 TN	-	-	40,650	293	92.62 /MH	27,147	67,797
			STEEL, MISCELLANEOUS					764,220	5,510		510,368	1,274,588
			STEEL					764,220	5,510		510,368	1,274,588
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U1 MAIN ELECT BLDG 40'X100' FURNISH ONLY	1.00 EA	-	504,000		4,598	51.10 /MH	234,943	738,943
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U1 MAIN ELECT BLDG 40'X100' INSTALLATION	1.00 EA	-			414	92.62 /MH	38,326	38,326
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U2 MAIN ELECT BLDG 40'X100' FURNISH ONLY	1.00 EA	-	504,000		4,598	51.10 /MH	234,943	738,943
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U2 MAIN ELECT BLDG 40'X100' INSTALLATION	1.00 EA	-			414	92.62 /MH	38,326	38,326
			PRE-ENGINEERED BUILDING				1,008,000		10,023		546,536	1,554,536
			ARCHITECTURAL				1,008,000		10,023		546,536	1,554,536
	41.00.00		ELECTRICAL EQUIPMENT									
		41.13.00	BUS DUCT									
			ISO PHASE, SELF COOLED	TAP BUS EXTENSIONS	200.00 LF	-	315,000		4,828	63.63 /MH	307,179	622,179
			NON SEGREGATED - (600V) (2000A) FGD ONLY		800.00 LF	-	588,000		5,517	63.63 /MH	351,062	939,062
			BUS DUCT				903,000		10,345		658,241	1,561,241
		41.45.00	MOTOR CONTROL CENTER (MCC), COMPLETE									
			MOTOR CONTROL CENTER (MCC), COMPLETE - 480V FGD		12.00 EA	-	636,000		5,931	63.63 /MH	377,392	1,013,392
			MOTOR CONTROL CENTER (MCC), COMPLETE				636,000		5,931		377,392	1,013,392
		41.51.00	POWER TRANSFORMER									
			STARTUP, RESERVE AUXILIARY (RAT) - 36/48 MVA 115/6.9/6.9 KV	LABOR INCLUDES DRESS OUT AND FILL	1.00 EA	-	875,000		1,379	63.63 /MH	87,766	962,766
			STARTUP, RESERVE AUXILIARY (RAT) - 36/48 MVA 115/6.9/6.9 KV	HEAVY HAUL FROM RAIL TO PAD	1.00 EA	-	95,000			/MH		95,000
			UNIT AUXILIARY - 36/48 MVA 25/6.9/6.9 KV	LABOR INCLUDES DRESS OUT AND FILL	2.00 EA	-	1,700,000		2,759	63.63 /MH	175,531	1,875,531
			UNIT AUXILIARY - 36/48 MVA 25/6.9/6.9 KV	HEAVY HAUL FROM RAIL TO PAD	2.00 EA	-	190,000			/MH		190,000
			POWER TRANSFORMER - 6.9-.48 kV UNIT SUBSTATION X FMRS - 2000 KVA		4.00 EA	-	360,000		667	63.63 /MH	42,420	402,420
			POWER TRANSFORMER - 6.9-.48 kV UNIT SUBSTATION X FMRS - 1500 KVA		4.00 EA	-	300,000		598	63.63 /MH	38,032	338,032
			POWER TRANSFORMER				3,520,000		5,402		343,748	3,863,748
		41.55.00	SWITCHGEAR, COMPLETE									
			480 V - REAGENT SWITCHGEAR		4.00 EA	-	212,000		1,977	63.63 /MH	125,797	337,797
			480 V - 480V FGD SWITCHGEAR		4.00 EA	-	840,000		4,138	63.63 /MH	263,297	1,103,297
			6.9 KV - SWITCHGEAR FGD		4.00 EA	-	1,680,000		14,713	63.63 /MH	936,166	2,616,166
			6.9 KV - SWITCHGEAR WALK IN TYPE		3.00 EA	-	660,000		5,810	63.63 /MH	369,712	1,029,712
			SWITCHGEAR, COMPLETE				3,392,000		26,638		1,694,972	5,086,972
		41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS									
			ELECTRICAL EQUIPMENT, MISCELLANEOUS AUX POWER EQUIPMENT		1.00 LT	-	2,840,000		11,494	63.63 /MH	731,379	3,571,379
			ELECTRICAL EQUIPMENT, MISCELLANEOUS				2,840,000		11,494		731,379	3,571,379
			ELECTRICAL EQUIPMENT				11,291,000		59,810		3,805,732	15,096,732
	42.00.00		RACEWAY, CABLE TRAY & CONDUIT									
		42.13.00	CABLE TRAY									
			CABLE TRAY - ALLOTMENT		1.00 LT	-	-	505,000	33,333	61.79 /MH	2,059,667	2,564,667
			CABLE TRAY					505,000	33,333		2,059,667	2,564,667
		42.15.37	CONDUIT, RGS									
			XX IN DIA - CONDUIT ALLOTMENT		1.00 LT	-	-	90,000	74,138	61.79 /MH	4,580,983	4,670,983
			CONDUIT, RGS					90,000	74,138		4,580,983	4,670,983
		42.18.00	DUCT BANK									

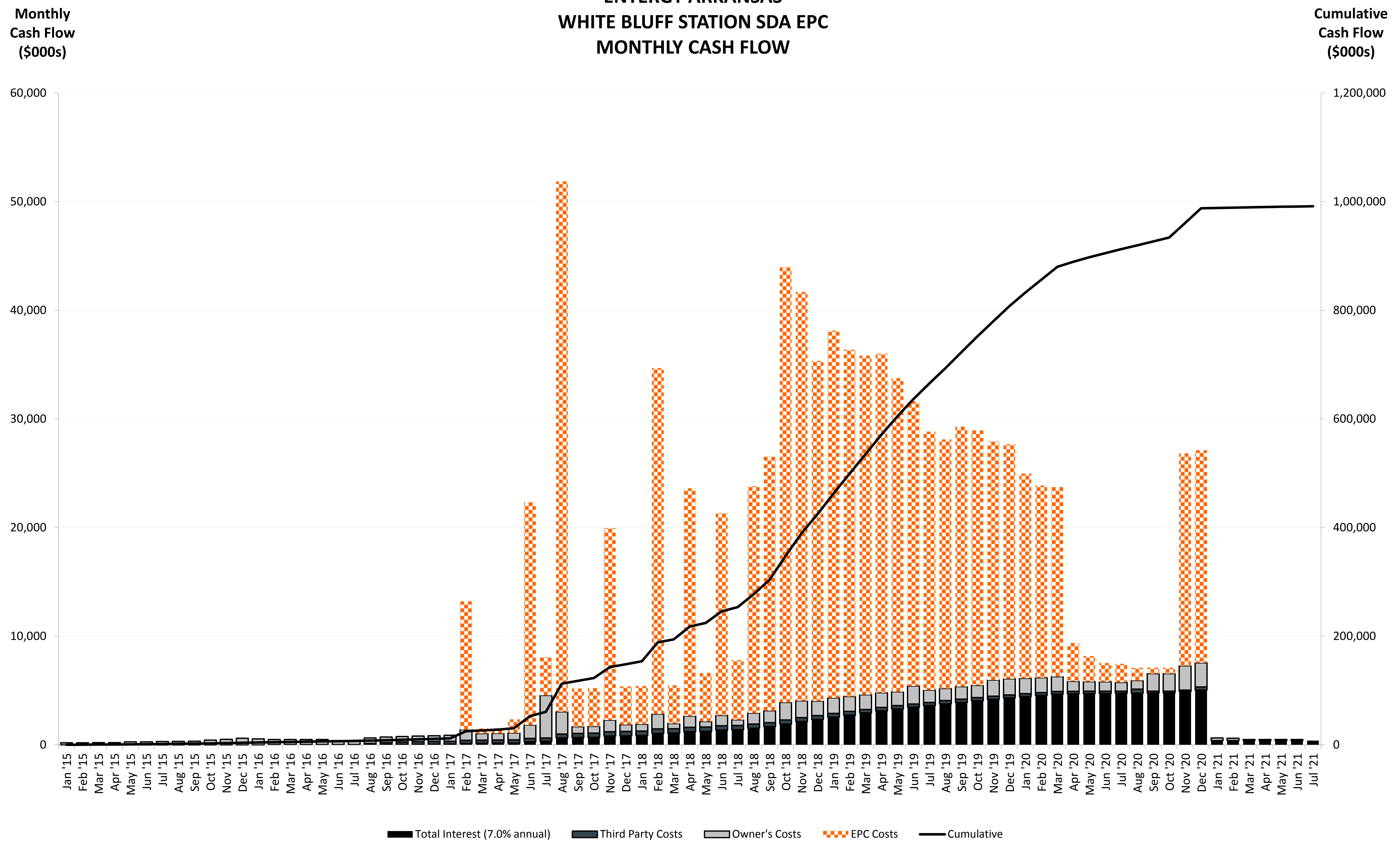
Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		42.18.00	DUCT BANK									
			DUCT BANK - UNDERGROUND DUCT BANKS NOT APPLICABLE		LT	-	-			61.79 /MH		
			RACEWAY, CABLE TRAY & CONDUIT					595,000	107,471		6,640,649	7,235,649
	43.00.00		CABLE									
		43.10.00	CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION									
			CONTROL/INSTRUMENTATION/COMMUNICATION TERMINATION - MISC		201,600.00 LF	-	-	645,120	18,538	82.05 /MH	1,521,037	2,166,157
			CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION					645,120	18,538		1,521,037	2,166,157
		43.20.00	600V CABLE & TERMINATION									
			600V CABLE - MISC		218,000.00 LF	-	-	1,881,340	30,069	82.05 /MH	2,467,159	4,348,499
			600V CABLE & TERMINATION					1,881,340	30,069		2,467,159	4,348,499
		43.40.00	5/8KV CABLE & TERMINATION									
			5/8KV #750 KCMIL 1/C CU EPR TS-CPE , FEEDS TO 8KV SWGR BLDG		225,000.00 LF	-	-	5,415,750	23,276	82.05 /MH	1,909,784	7,325,534
			5/8KV MISC		40,200.00 LF	-	-	297,480	10,628	82.05 /MH	871,993	1,169,473
			5/8KV CABLE & TERMINATION					5,713,230	33,903		2,781,778	8,495,008
		43.50.00	15KV CABLE & TERMINATION									
			15KV CABLE - MISC		22,300.00 LF	-	-	206,721	5,895	82.05 /MH	483,718	690,439
			15KV CABLE & TERMINATION					206,721	5,895		483,718	690,439
			CABLE					8,446,411	88,406		7,253,692	15,700,103
	51.00.00		SUBSTATION, SWITCHYARD & TRANSMISSION LINE									
		51.15.27	CIRCUIT BREAKER									
			CIRCUIT BREAKER - SWITCHYARD BAY AND 3 BREAKERS	ADDITION OF A SWITCHYARD BAY IS AVOIDED BY PLACING THE NEW SST NEXT TO THE EXISTING SST AND USING THE SAME OVERHEAD LINE.	0.00 LT	-				55.78 /MH		
		51.15.53	DISCONNECT SWITCH									
			115KV, 1200A, VERTICAL BREAK SWITCH WITH INSULATORS,INCLUDING GROUND SWITCH AND WITHOUT MOTORIZED OPERATOR	FOR ISOLATION OF RAT	1.00 EA	-	-	15,000	69	55.78 /MH	3,847	18,847
			DISCONNECT SWITCH					15,000	69		3,847	18,847
			SUBSTATION, SWITCHYARD & TRANSMISSION LINE					15,000	69		3,847	18,847
			201 ELECTRICAL BOP SYSTEM				**12,299,000**	**10,665,684**	**290,576**		**20,231,688**	**43,196,372**
211			**INSTRUMENTATION AND CONTROLS BOP SYSTEM**									
	44.00.00		CONTROL & INSTRUMENTATION									
		44.13.00	CONTROL SYSTEM									
			DISTRIBUTED CONTROL SYSTEM (DCS) - I/O POINTS	ESTIMATED BOP 2000 I/O POINTS, (ANOTHER 1000 POINTS PER UNIT ARE INCLUDED IN THE DFGD PROPOSAL PRICES AND ARE NOT INCLUDED HERE)	1.00 LT	-	1,500,000		2,299	64.68 /MH	148,690	1,648,690
			CONTROL SYSTEM				1,500,000		2,299		148,690	1,648,690
		44.21.00	INSTRUMENT									
			INSTRUMENT - BOP INSTRUMENTS		1.00 LT	-	-	478,000	7,946	82.05 /MH	651,967	1,129,967
			INSTRUMENT - THERMOCOUPLES IN STACK ENTRANCE W ALARM		1.00 LT	-	-	100,000		82.05 /MH		100,000
			INSTRUMENT					578,000	7,946		651,967	1,229,967
		44.25.00	MONITORING EQUIPMENT									
			CONTINUOUS EMISSION MONITORING SYSTEM (CEMS) - REFURBISHING		2.00 EA	-	-	460,000	625	64.68 /MH	40,444	500,444
			MONITORING EQUIPMENT - LOCAL HMI		3.00 EA	-	-	45,000	14	64.68 /MH	892	45,892

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			MONITORING EQUIPMENT					505,000	639		41,336	546,336
			CONTROL & INSTRUMENTATION				1,500,000	1,083,000	10,884		841,993	3,424,993
			211 INSTRUMENTATION AND CONTROLS BOP SYSTEM				**1,500,000**	**1,083,000**	**10,884**		**841,993**	**3,424,993**

ATTACHMENT 2

Conceptual Capital Cost Estimate Cash Flow

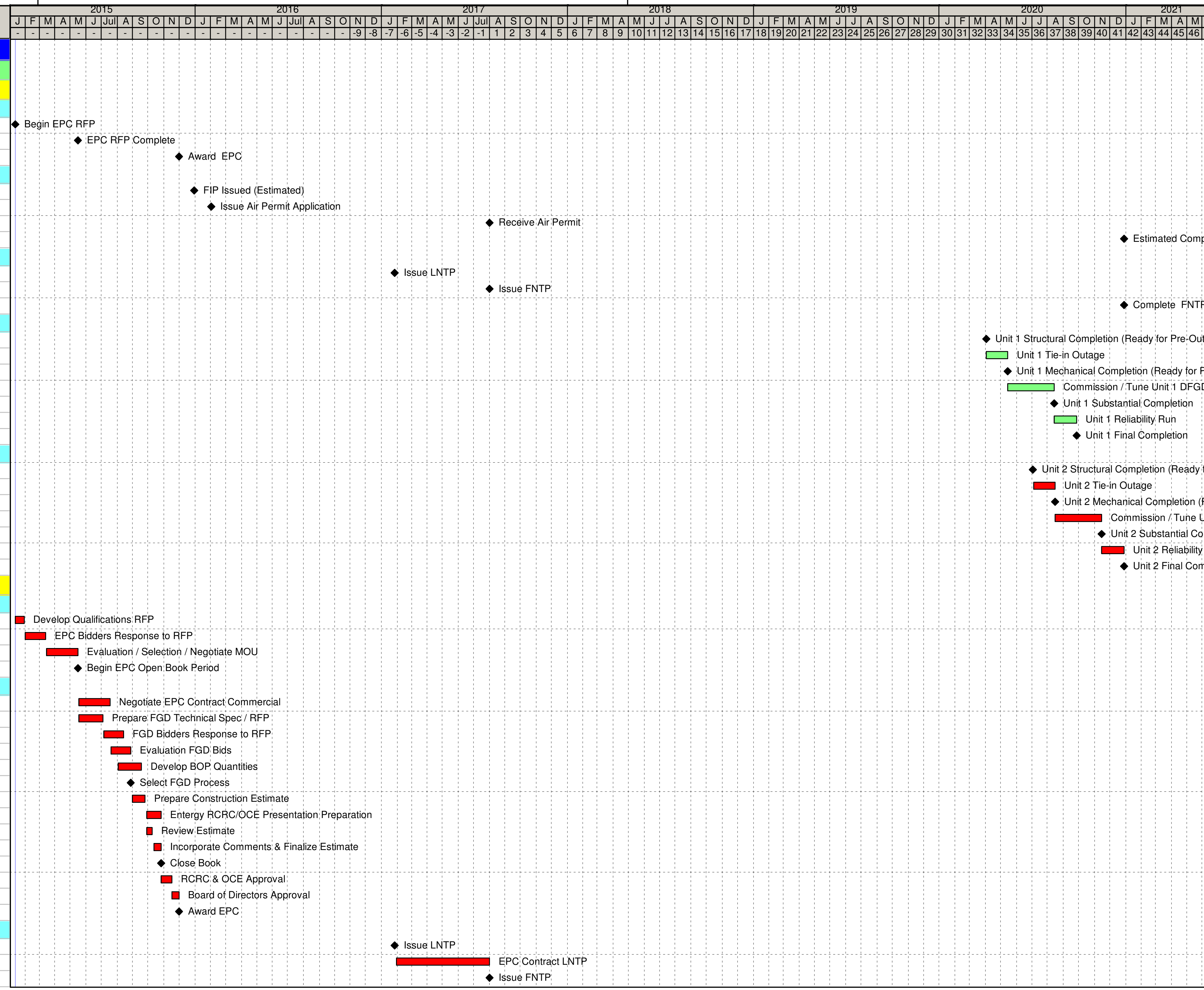
ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
MONTHLY CASH FLOW



ATTACHMENT 3

Level 1 Preliminary Execution Schedule

Activity ID	Activity Name	Ori Dur	Start	Finish
WHITE BLUFF FGD SCHEDULE (December 2020)		1556	13-Jan-15	29-Dec-20
Milestones		1556	13-Jan-15	29-Dec-20
Project Milestones		1556	13-Jan-15	29-Dec-20
EPC RFP		225	13-Jan-15	30-Nov-15
MS010	Begin EPC RFP	0	13-Jan-15	
MS100	EPC RFP Complete	0		15-May-15
MS225	Award EPC	0		30-Nov-15
Permitting		1272	30-Dec-15	29-Dec-20
MS275	FIP Issued (Estimated)	0		30-Dec-15
MS015	Issue Air Permit Application	0		02-Feb-16
MS020	Receive Air Permit	0		31-Jul-17
MS285	Estimated Compliance Date	0		29-Dec-20
LNTP/FNTP		998	27-Jan-17	28-Dec-20
MS260	Issue LNTP	0		27-Jan-17
MS030	Issue FNTP	0		31-Jul-17
MS265	Complete FNTP Period	0		28-Dec-20
Unit 1 & Common Outage, Start-Up & Commissioning		178	02-Apr-20	27-Sep-20
MS0100	Unit 1 Structural Completion (Ready for Pre-Outage)	0		02-Apr-20
MS0110	Unit 1 Tie-in Outage	42	03-Apr-20	14-May-20
MS0120	Unit 1 Mechanical Completion (Ready for Flue Gas)	0		14-May-20
MS0130	Commission / Tune Unit 1 DFGD System	91	15-May-20	13-Aug-20
MS0140	Unit 1 Substantial Completion	0		13-Aug-20
MS0150	Unit 1 Reliability Run	45	14-Aug-20	27-Sep-20
MS0160	Unit 1 Final Completion	0		27-Sep-20*
Unit 2 Outage, Start-Up & Commissioning		179	03-Jul-20	29-Dec-20
MS0200	Unit 2 Structural Completion (Ready for Pre-Outage)	0		03-Jul-20
MS0210	Unit 2 Tie-in Outage	43	04-Jul-20	15-Aug-20
MS0220	Unit 2 Mechanical Completion (Ready for Flue Gas)	0		15-Aug-20
MS0230	Commission / Tune Unit 2 DFGD System	91	16-Aug-20	14-Nov-20
MS0240	Unit 2 Substantial Completion	0		14-Nov-20
MS0250	Unit 2 Reliability Run	45	15-Nov-20	29-Dec-20
MS0260	Unit 2 Final Completion	0		29-Dec-20
Project Overview		1556	13-Jan-15	29-Dec-20
EPC RFP		89	13-Jan-15	15-May-15
OV1000	Develop Qualifications RFP	14	13-Jan-15	30-Jan-15
OV1010	EPC Bidders Response to RFP	30	02-Feb-15	13-Mar-15
OV1020	Evaluation / Selection / Negotiate MOU	45	16-Mar-15	15-May-15
OV1040	Begin EPC Open Book Period	0		15-May-15
EPC Development Phase		141	18-May-15	30-Nov-15
OV1030	Negotiate EPC Contract Commercial	45	18-May-15	17-Jul-15
OV1050	Prepare FGD Technical Spec / RFP	35	18-May-15	03-Jul-15
OV1060	FGD Bidders Response to RFP	30	06-Jul-15	14-Aug-15
OV1070	Evaluation FGD Bids	30	20-Jul-15	28-Aug-15
OV1090	Develop BOP Quantities	35	03-Aug-15	18-Sep-15
OV1080	Select FGD Process	0		28-Aug-15
OV1100	Prepare Construction Estimate	20	31-Aug-15	25-Sep-15
OV1110	Entergy RCRC/OCE Presentation Preparation	21	28-Sep-15	26-Oct-15
OV1103	Review Estimate	10	28-Sep-15	09-Oct-15
OV1105	Incorporate Comments & Finalize Estimate	11	12-Oct-15	26-Oct-15
OV1120	Close Book	0		26-Oct-15
OV1130	RCRC & OCE Approval	15	27-Oct-15	16-Nov-15
OV1140	Board of Directors Approval	10	17-Nov-15	30-Nov-15
OV1145	Award EPC	0		30-Nov-15
LNTP		132	27-Jan-17	01-Aug-17
OV1150	Issue LNTP	0		27-Jan-17
OV1160	EPC Contract LNTP	132	30-Jan-17	01-Aug-17
OV1170	Issue FNTP	0		01-Aug-17



Remaining Work
Actual Work
WBS Summary
Critical Remaining Work
Milestone

TASK filter: Exclude WBS Activities_1.

Activity ID	Activity Name	Orig Dur	Start	Finish
FNTP		890	02-Aug-17	29-Dec-20
OV1180	EPC Contract FNTP Period	889	02-Aug-17	28-Dec-20
OV1230	Compliance Deadline	0		29-Dec-20*
EPC Milestones		1292	30-Nov-15	29-Dec-20
Engineering		308	07-Sep-17	26-Nov-18
EPC325	Common Sitework Dwg IFC	0		07-Sep-17
EPC345	U1 SDA Foundation IFC	0		20-Oct-17
EPC340	Common Freeze General Arrangements	0		13-Nov-17
EPC510	U2 SDA Foundation IFC	0		16-Jan-18
EPC350	U1 ID Fan Foundation IFC	0		03-Apr-18
EPC320	Common Electrical Single Lines IFC	0		13-Apr-18
EPC485	U2 ID Fan Foundation IFC	0		22-Jun-18
EPC355	ALL P&IDs IFC	0		18-Jul-18
EPC240	All Master Schematics IFC	0		26-Nov-18
Procurement		858	30-Nov-15	19-Apr-19
EPC010	Award EPC	0		30-Nov-15
EPC100	Award Dry FGD System	0		27-Jan-17
EPC110	Award ID Fans	0		09-Aug-17
EPC335	Award DCS	0		08-Dec-17
EPC315	Award Transformers	0		15-Jan-18
EPC545	Award Transformers Delivery Complete	0		30-Nov-18
EPC535	Award ID Fans Delivery Complete	0		07-Jan-19
EPC415	Common DCS FAT Complete	0		18-Mar-19
EPC540	Award DCS Delivery Complete	0		15-Apr-19
EPC530	Dry FGD System Delivery Complete	0		19-Apr-19
Unit 1 & Common Construction & Commissioning		677	30-Jan-18	28-Sep-20
EPC425	Common ALL U/G Piping Installation Complete	0		30-Jan-18
EPC370	U1 Fabric Filter Foundation Installation Complete	0		01-Jun-18
EPC360	U1 SDA Foundation Installation Complete	0		05-Jun-18
EPC365	U1 ID Fan Foundation Installation Complete	0		30-Oct-18
EPC395	Common Electrical Equipment Bldg Foundation Complete	0		16-Nov-18
EPC405	Common Transformers Foundation Complete	0		14-Dec-18
EPC460	Common Pipe Rack FoundationComplete	0		17-Dec-18
EPC400	Common Electrical Equipment Bldg Erection Complete	0		11-Jan-19
EPC390	Common Pipe Rack Erection Complete	0		11-Feb-19
EPC310	U1 All Foundations Installation Complete	0		02-Apr-19
EPC410	Common Transformers Erection Complete	0		05-Jun-19
EPC435	Common Ready for Aux Power Backfeed	0		02-Jul-19
EPC380	U1 ID Fan Installation Complete	0		25-Jul-19
EPC420	Common Training Plan Ready for Start of Training	0		29-Aug-19
EPC385	U1 Fabric Filter Erection Complete	0		09-Sep-19
EPC375	U1 SDA Erection Complete	0		28-Nov-19
EPC440	U1 Structural Completion (Ready for Outage)	0		02-Apr-20
EPC445	U1 Mechanical Completion	0		14-May-20
EPC450	U1 Substantial Completion	0		13-Aug-20
EPC455	U1 Final Completion	0		28-Sep-20
Unit 2 Construction & Commissioning		593	31-Aug-18	29-Dec-20
EPC475	U2 Fabric Filter Foundation Installation Complete	0		31-Aug-18
EPC515	U2 SDA Foundation Installation Complete	0		04-Sep-18
EPC490	U2 ID Fan Foundation Installation Complete	0		29-Jan-19
EPC465	U2 All Foundations Installation Complete	0		02-Apr-19
EPC495	U2 ID Fan Installation Complete	0		16-Sep-19
EPC470	U2 Fabric Filter Erection Complete	0		09-Dec-19
EPC505	U2 SDA Erection Complete	0		28-Feb-20
EPC520	U2 Structural Completion (Ready for Outage)	0		03-Jul-20
EPC500	U2 Mechanical Completion	0		17-Aug-20
EPC525	U2 Substantial Completion	0		16-Nov-20
EPC480	U2 Final Completion	0		29-Dec-20

Remaining Work — Actual Work — WBS Summary
Critical Remaining Work — Milestone

TASK filter: Exclude WBS Activities_1.

Activity ID	Activity Name	Ori Dur	Start	Finish	2015 – 2021
Payment Milestones		1401	28-Feb-17	29-Dec-20	
Unit 1 & Common		1308	28-Feb-17	27-Sep-20	
PAY001	Payment 001 - DFGD Award	1	28-Feb-17	28-Feb-17	Payment 001 - DFGD Award
PAY002	Payment 002 - Initial Design Info from DFGD Supplier - Flow ...	1	29-Mar-17	29-Mar-17	Payment 002 - Initial Design Info from DFGD Supplier - Flow Diagrams, Mass Balances
PAY003	Payment 003 - Parent Company Guarantee Document	1	30-Mar-17	30-Mar-17	Payment 003 - Parent Company Guarantee Document
PAY004	Payment 004 - Initial Design Info from DFGD Supplier - P&IDs...	1	28-Apr-17	28-Apr-17	Payment 004 - Initial Design Info from DFGD Supplier - P&IDs for Owner Rvw
PAY006	Payment 006 - NTE Load Diagrams for SDA & FF	1	28-Apr-17	28-Apr-17	Payment 006 - NTE Load Diagrams for SDA & FF
PAY008	Payment 008 - Initial Design Info from DFGD Supplier - 1st Iss...	1	28-Apr-17	28-Apr-17	Payment 008 - Initial Design Info from DFGD Supplier - 1st Issue of 3D CAD Model Issued for Owner Rvw
PAY005	Payment 005 - Project Specific GA's - Issued for Owner Rvw	1	25-May-17	25-May-17	Payment 005 - Project Specific GA's - Issued for Owner Rvw
PAY013	Payment 013 - Initial Design Info from DFGD Supplier - Projec...	1	25-May-17	25-May-17	Payment 013 - Initial Design Info from DFGD Supplier - Project Specific Equipment List
PAY009	Payment 009 - FERC Retirement Information - Preliminary	1	30-Jun-17	30-Jun-17	Payment 009 - FERC Retirement Information - Preliminary
PAY011	Payment 011 - Award Atomizers	1	31-Jul-17	31-Jul-17	Payment 011 - Award Atomizers
PAY007	Payment 007 - Award ID Booster Fans	1	22-Aug-17	22-Aug-17	Payment 007 - Award ID Booster Fans
PAY015	Payment 015 - NTE Load Diagrams - Lime Storage & Prep Sy...	1	22-Aug-17	22-Aug-17	Payment 015 - NTE Load Diagrams - Lime Storage & Prep System - Issued for Owners Rvw
PAY027	Payment 027 - Receive Permits for Construction - Req'd Tier ...	1	25-Aug-17	25-Aug-17	Payment 027 - Receive Permits for Construction - Req'd Tier 2 Reports (AR DOEM) - Air Space Obstruction Permit for Crane
PAY028	Payment 028 - Mobilize On Site	1	26-Aug-17	26-Aug-17	Payment 028 - Mobilize On Site
PAY012	Payment 012 - Award Lime System	1	28-Aug-17	28-Aug-17	Payment 012 - Award Lime System
PAY014	Payment 014 - Flue Gas Ductwork Procurement Initiated - PO...	1	28-Sep-17	28-Sep-17	Payment 014 - Flue Gas Ductwork Procurement Initiated - PO for SDA Shell/Casing
PAY030	Payment 030 - Office Complex & Fab Areas Set-Up - Office Tr...	1	28-Sep-17	28-Sep-17	Payment 030 - Office Complex & Fab Areas Set-Up - Office Trailers Set with Elect/Plumbing
PAY016	Payment 016 - Initial EI&C Design Info - Project Specific Proc...	1	24-Oct-17	24-Oct-17	Payment 016 - Initial EI&C Design Info - Project Specific Process Control Description - Issued for Owners Rvw
PAY010	Payment 010 - NTE Load Diagrams - ID Booster Fans	1	22-Nov-17	22-Nov-17	Payment 010 - NTE Load Diagrams - ID Booster Fans
PAY017	Payment 017 - Flue Gas Ductwork Procurement Initiated - U1 ...	1	28-Nov-17	28-Nov-17	Payment 017 - Flue Gas Ductwork Procurement Initiated - U1 SDA Inlet Duct PO
PAY018	Payment 018 - Structural Steel Procurement - SDA Support St...	1	26-Dec-17	27-Dec-17	Payment 018 - Structural Steel Procurement - SDA Support Steel PO
PAY022	Payment 022 - Award DCS	1	26-Dec-17	27-Dec-17	Payment 022 - Award DCS
PAY024	Payment 024 - Flue Gas Ductwork Start Fab - Ductwork	1	26-Dec-17	27-Dec-17	Payment 024 - Flue Gas Ductwork Start Fab - Ductwork
PAY019	Payment 019 - Strucutural Steel Fab Sched - Schedule for Fa...	1	26-Jan-18	26-Jan-18	Payment 019 - Strucutural Steel Fab Sched - Schedule for Fab - Issued for Owner Rvw
PAY020	Payment 020 - SDA Design Dwgs - SDA Access Steel Dwgs (...	1	28-Feb-18	28-Feb-18	Payment 020 - SDA Design Dwgs - SDA Access Steel Dwgs (Rel for Fab)
PAY021	Payment 021 - Fabric Filter Design Dwgs - Fabric Filter Acces...	1	28-Feb-18	28-Feb-18	Payment 021 - Fabric Filter Design Dwgs - Fabric Filter Access Steel Dwgs (Rel for Fab)
PAY023	Payment 023 - Award Fabric Filter Bags & Cages	1	30-Apr-18	30-Apr-18	Payment 023 - Award Fabric Filter Bags & Cages
PAY025	Payment 025 - Structural Steel Start Fab - Steel Members	1	30-May-18	30-May-18	Payment 025 - Structural Steel Start Fab - Steel Members
PAY026	Payment 026 - Design Info from DFGD Supplier - Physical Flo...	1	30-Jun-18	30-Jun-18	Payment 026 - Design Info from DFGD Supplier - Physical Flow Model Completed - Issued for Owners Rvw
PAY033	Payment 033 - U1 Fabric Filter Delivery - FF Plenum Walls & ...	1	30-Jun-18	30-Jun-18	Payment 033 - U1 Fabric Filter Delivery - FF Plenum Walls & Hoppers
PAY034	Payment 034 - U1 SDA Structural Steel Delivery	1	30-Jun-18	30-Jun-18	Payment 034 - U1 SDA Structural Steel Delivery
PAY035	Payment 035 - U1 Duct Delivery (50% On-Site)	1	25-Jul-18	25-Jul-18	Payment 035 - U1 Duct Delivery (50% On-Site)
PAY032	Payment 032 - Lime Storage & Prep Sys Delivery - Silos, Tan...	1	23-Aug-18	23-Aug-18	Payment 032 - Lime Storage & Prep Sys Delivery - Silos, Tanks, Slakers & Pumps
PAY029	Payment 029 - U1 SDA Delivery - Ring Girder & Cone Section	1	28-Sep-18	28-Sep-18	Payment 029 - U1 SDA Delivery - Ring Girder & Cone Section
PAY036	Payment 036 - U1 SDA - A Support Steel Erection Complete	1	28-Nov-18	28-Nov-18	Payment 036 - U1 SDA - A Support Steel Erection Complete
PAY042	Payment 042 - U1 SDA - C Support Steel Erection Complete	1	28-Nov-18	28-Nov-18	Payment 042 - U1 SDA - C Support Steel Erection Complete
PAY037	Payment 037 - U1 SDA - A Duct Support Steel Complete	1	28-Dec-18	28-Dec-18	Payment 037 - U1 SDA - A Duct Support Steel Complete
PAY038	Payment 038 - U1 Fabric Filter Struct Steel Delivery - Grid Ste...	1	28-Dec-18	28-Dec-18	Payment 038 - U1 Fabric Filter Struct Steel Delivery - Grid Steel & Structural Support Steel
PAY031	Payment 031 - U1 & U2 Booster Fan Delivery - Fans-Motors-L...	1	26-Jan-19	26-Jan-19	Payment 031 - U1 & U2 Booster Fan Delivery - Fans-Motors-Lube Oil On Site
PAY041	Payment 041 - U1 SDA - A Inlet Duct Erection Complete	1	30-Apr-19	30-Apr-19	Payment 041 - U1 SDA - A Inlet Duct Erection Complete
PAY043	Payment 043 - U1 SDA - A Outlet Duct Erection Complete	1	30-May-19	30-May-19	Payment 043 - U1 SDA - A Outlet Duct Erection Complete
PAY054	Payment 054 - DCS Equipment Delivery	1	28-Jun-19	28-Jun-19	Payment 054 - DCS Equipment Delivery
PAY044	Payment 044 - U1 SDA - A Vessel Shell/Roof Complete	1	29-Jun-19	29-Jun-19	Payment 044 - U1 SDA - A Vessel Shell/Roof Complete
PAY047	Payment 047 - U1 SDA - B Inlet Duct Erection Complete	1	29-Jun-19	29-Jun-19	Payment 047 - U1 SDA - B Inlet Duct Erection Complete
PAY049	Payment 049 - U1 SDA - B Outlet Duct Erection Complete	1	31-Jul-19	31-Jul-19	Payment 049 - U1 SDA - B Outlet Duct Erection Complete
PAY057	Payment 057 - U1 Booster Fans Erection Complete	1	01-Aug-19	01-Aug-19	Payment 057 - U1 Booster Fans Erection Complete
PAY051	Payment 051 - U1 SDA - C Inlet Duct Erection Complete	1	28-Aug-19	28-Aug-19	Payment 051 - U1 SDA - C Inlet Duct Erection Complete
PAY052	Payment 052 - U1 SDA - C Outlet Duct Erection Complete	1	28-Aug-19	28-Aug-19	Payment 052 - U1 SDA - C Outlet Duct Erection Complete
PAY048	Payment 048 - U1 SDA - B Vessel Shell/Roof Complete	1	27-Sep-19	27-Sep-19	Payment 048 - U1 SDA - B Vessel Shell/Roof Complete
PAY050	Payment 050 - U1 Fabric Filter - B Hoppers/Wall/Roof Complete	1	27-Sep-19	27-Sep-19	Payment 050 - U1 Fabric Filter - B Hoppers/Wall/Roof Complete
PAY059	Payment 059 - U1 Fabric Filter - C Hoppers/Wall/Roof Complete	1	27-Sep-19	27-Sep-19	Payment 059 - U1 Fabric Filter - C Hoppers/Wall/Roof Complete
PAY064	Payment 064 - Operating & Maintenance Manuals	1	28-Sep-19	28-Sep-19	Payment 064 - Operating & Maintenance Manuals
PAY053	Payment 053 - U1 SDA - C Vessel Shell/Roof Complete	1	28-Nov-19	28-Nov-19	Payment 053 - U1 SDA - C Vessel Shell/Roof Complete
PAY074	Payment 074 - U1 Structural Completion	1	02-Apr-20	02-Apr-20	Payment 074 - U1 Structural Completion
PAY077	Payment 077 - U1 Duct Tie-In Complete	1	29-Apr-20	29-Apr-20	Payment 077 - U1 Duct Tie-In Complete
PAY078	Payment 078 - U1 Mechanical Completion	1	15-May-20	15-May-20	Payment 078 - U1 Mechanical Completion
PAY080	Payment 080 - U1 Substantial Completion	1	13-Aug-20	13-Aug-20	Payment 080 - U1 Substantial Com

Remaining Work | Actual Work | WBS Summary
Critical Remaining Work | Milestone

TASK filter: Exclude WBS Activities_1.

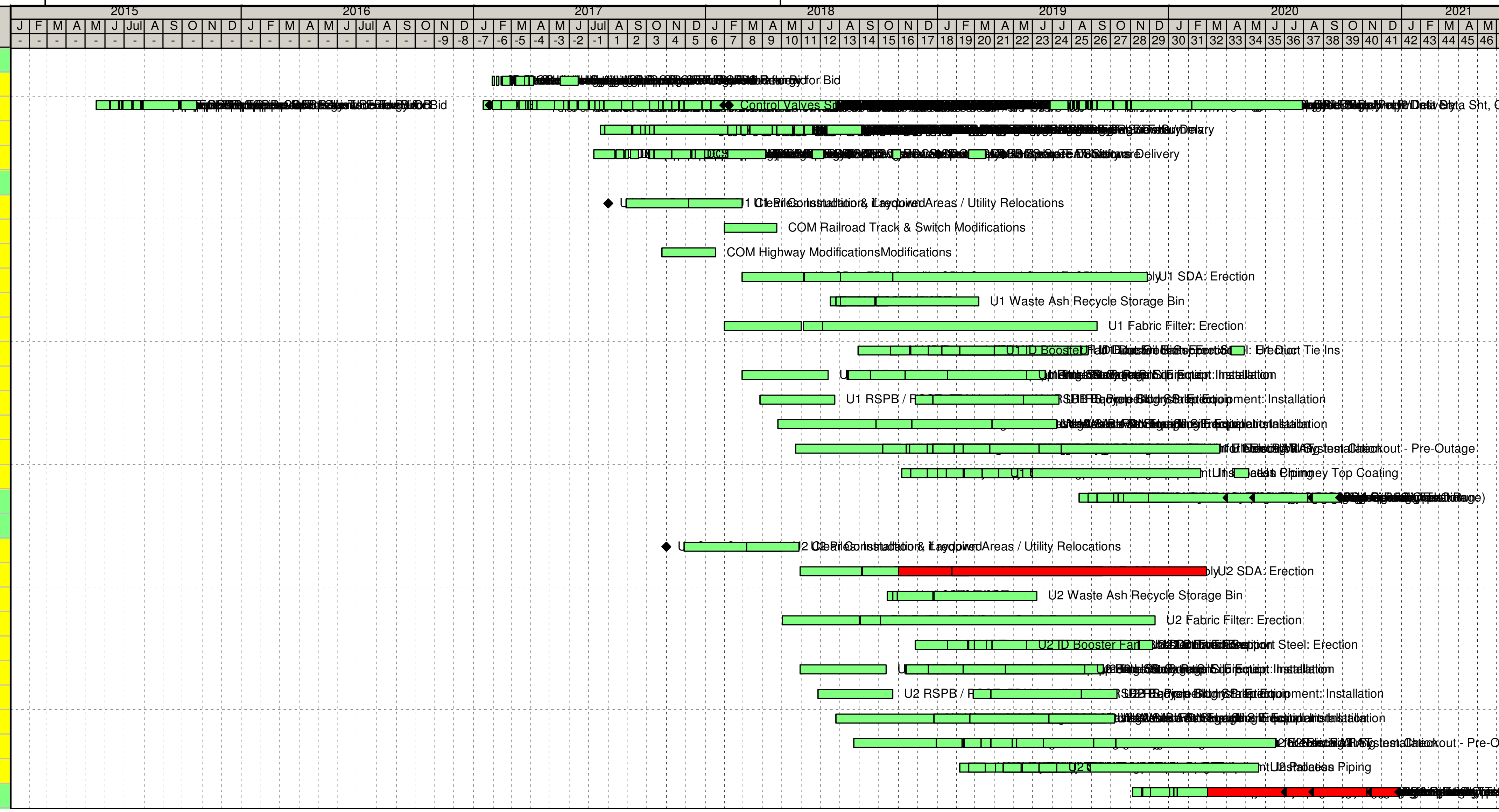
WHITE BLUFF FGD SCHEDULE (December 2020) 29-May-15 15:26

Activity ID	Activity Name	Orig Dur	Start	Finish
PAY079	Payment 079 - U1 Performance Test Report	1	14-Aug-20	14-Aug-20
PAY082	Payment 082 - U1 FERC Retirement Information	1	27-Aug-20	27-Aug-20
PAY089	Payment 089 - U1 Final Completion	1	27-Sep-20	27-Sep-20
Unit 2		830	22-Sep-18	29-Dec-20
PAY046	Payment 046 - U2 SDA Structural Steel Delivery	1	22-Sep-18	22-Sep-18
PAY045	Payment 045 - U2 Fabric Filter Delivery - FF Plenum Walls & ...	1	27-Oct-18	27-Oct-18
PAY040	Payment 040 - U2 SDA Delivery - Ring Girder & Cone Section	1	28-Nov-18	28-Nov-18
PAY039	Payment 039 - U2 Duct Delivery (50% On-Site)	1	28-Dec-18	28-Dec-18
PAY056	Payment 056 - U2 SDA - A Support Steel Complete	1	28-Dec-18	28-Dec-18
PAY063	Payment 063 - U2 SDA - B Support Steel Complete	1	28-Jan-19	28-Jan-19
PAY067	Payment 067 - U2 SDA - C Support Steel Complete	1	30-Mar-19	30-Mar-19
PAY062	Payment 062 - U2 SDA - A Inlet Duct Erection Complete	1	29-Jun-19	29-Jun-19
PAY055	Payment 055 - U2 SDA - A Inlet Duct Support Steel Complete	1	30-Jun-19	30-Jun-19
PAY058	Payment 058 - U2 SDA - B Inlet Duct Support Steel Complete	1	31-Jul-19	31-Jul-19
PAY060	Payment 060 - U2 SDA - C Inlet Duct Support Steel Complete	1	28-Aug-19	28-Aug-19
PAY066	Payment 066 - U2 SDA - B Inlet Duct Erection Complete	1	28-Aug-19	28-Aug-19
PAY061	Payment 061 - U2 SDA - A Vessel Shell/Roof Complete	1	29-Aug-19	29-Aug-19
PAY068	Payment 068 - U2 SDA - A Outlet Duct Erection Complete	1	27-Sep-19	27-Sep-19
PAY072	Payment 072 - U2 SDA - B Support Steel Complete	1	27-Sep-19	27-Sep-19
PAY065	Payment 065 - U2 SDA - B Vessel Shell/Roof Complete	1	29-Oct-19	29-Oct-19
PAY076	Payment 076 - U2 Booster Fans Erection Complete	1	29-Oct-19	29-Oct-19
PAY069	Payment 069 - U2 Fabric Filter - A Hoppers/Wall/Roof Complete	1	28-Nov-19	28-Nov-19
PAY071	Payment 071 - U2 SDA - C Inlet Duct Erection Complete	1	28-Nov-19	28-Nov-19
PAY075	Payment 075 - U2 SDA - C Outlet Duct Erection Complete	1	28-Nov-19	28-Nov-19
PAY073	Payment 073 - U2 Fabric Filter - B Hoppers/Wall/Roof Complete	1	27-Dec-19	27-Dec-19
PAY070	Payment 070 - U2 SDA - C Vessel Shell/Roof Complete	1	28-Dec-19	28-Dec-19
PAY081	Payment 081 - U2 Structural Completion	1	04-Jul-20	04-Jul-20
PAY084	Payment 084 - U2 Duct Tie-In Complete	1	16-Aug-20	16-Aug-20
PAY085	Payment 085 - U2 Mechanical Completion	1	16-Aug-20	16-Aug-20
PAY087	Payment 087 - Demobilization Complete	1	28-Oct-20	28-Oct-20
PAY088	Payment 088 - U2 FERC Retirement Information	1	28-Oct-20	28-Oct-20
PAY086	Payment 086 - U2 Substantial Completion	1	15-Nov-20	15-Nov-20
PAY083	Payment 083 - Removal of Fabrication Tables Complete	1	28-Nov-20	28-Nov-20
PAY090	Payment 090 - U2 Final Completion	1	29-Dec-20	29-Dec-20
Permitting		949	29-Sep-15	27-Jun-19
Air Permit		465	29-Sep-15	31-Jul-17
Title V Operating Permit		310	09-Apr-18	27-Jun-19
TRAX Boiler Pressure Analysis		81	16-Mar-15	08-Jul-15
U1 Engineering		540	30-Jan-17	15-Mar-19
U1 General Engineering & Design		507	30-Jan-17	29-Jan-19
U1 C/S/A Engineering and Design		500	30-Jan-17	18-Jan-19
U1 Mechanical Engineering		364	13-Feb-17	18-Jul-18
U1 Mechanical Design		309	01-May-17	18-Jul-18
U1 Electrical Engineering		344	30-Jan-17	05-Jun-18
U1 Electrical Design		520	27-Feb-17	15-Mar-19
U1 I&C Engineering		368	06-Apr-17	17-Sep-18
U2 Engineering		630	30-Jan-17	28-Jun-19
U2 General Engineering & Design		590	30-Jan-17	03-May-19
U2 C/S/A Engineering and Design		587	30-Jan-17	30-Apr-19
U2 Mechanical Engineering		455	30-Jan-17	26-Oct-18
U2 Mechanical Design		389	02-May-17	26-Oct-18
U2 Electrical Engineering		434	30-Jan-17	27-Sep-18
U2 Electrical Design		610	27-Feb-17	28-Jun-19
U2 I&C Engineering		460	24-Mar-17	27-Dec-18

Remaining Work · Actual Work · WBS Summary · Critical Remaining Work · Milestone

TASK filter: Exclude WBS Activities_1.

Activity ID	Activity Name	Ori Dur	Start	Finish
	Procurement	1357	18-May-15	28-Jul-20
	C/S/A Procurement	98	30-Jan-17	15-Jun-17
	Mechanical Procurement	1357	18-May-15	28-Jul-20
	Electrical Procurement	347	20-Jul-17	30-Nov-18
	I&C Procurement	448	10-Jul-17	15-Apr-19
	U1 Construction	720	02-Aug-17	05-May-20
	U1 Sitework	150	02-Aug-17	27-Feb-18
	U1 Railroad Track & Switch Mods	60	31-Jan-18	24-Apr-18
	U1 Highway Mods	60	25-Oct-17	16-Jan-18
	U1 SDA	457	28-Feb-18	28-Nov-19
	U1 Field Fabricated Tanks	170	16-Jul-18	08-Mar-19
	U1 Fabric Filter	419	31-Jan-18	09-Sep-19
	U1 ID Booster Fans / Ductwork	436	29-Aug-18	29-Apr-20
	U1 Lime Slurry	343	28-Feb-18	21-Jun-19
	U1 Recycle Slurry	337	29-Mar-18	12-Jul-19
	U1 Byproduct Handling	314	25-Apr-18	08-Jul-19
	U1 Auxiliary Power	478	23-May-18	20-Mar-20
	U1 Balance of Plant	390	07-Nov-18	05-May-20
	U1 System Testing and Commissioning	294	13-Aug-19	27-Sep-20
	U2 Construction	686	01-Nov-17	17-Jun-20
	U2 Sitework	150	01-Nov-17	29-May-18
	U2 SDA	458	30-May-18	28-Feb-20
	U2 Field Fabricated Tanks	170	15-Oct-18	07-Jun-19
	U2 Fabric Filter	419	02-May-18	09-Dec-19
	U2 ID Booster Fans / Ductwork	268	28-Nov-18	07-Dec-19
	U2 Lime Slurry	343	30-May-18	20-Sep-19
	U2 Recycle Slurry	337	28-Jun-18	11-Oct-19
	U2 Byproduct Handling	314	25-Jul-18	07-Oct-19
	U2 Auxiliary Power	476	22-Aug-18	17-Jun-20
	U2 Balance of Plant	337	06-Feb-19	21-May-20
	U2 System Testing and Commissioning	301	05-Nov-19	29-Dec-20



Remaining Work
Actual Work
WBS Summary
Critical Remaining Work
Milestone

TASK filter: Exclude WBS Activities_1.

ATTACHMENT 4

Milestone Progress Payment Schedule

Attachment 4

MONTHLY PROGRESS PAYMENT SCHEDULE

Month	Date	Milestone	Individual Payment (%)	Cumulative Payment (%)
1	Feb-17	Award Dry FGD Contract Execution	1.51	1.51
2	Mar-17	DFGD Supplier - Process Flow Diagrams and Mass Balances	0.06	1.57
3	Apr-17	DFGD Supplier - P&ID Drawings	0.06	1.63
4	May-17	DFGD Supplier - General Arrangement Drawings	0.16	1.79
		NTE Load Diagrams		
5	Jun-17	DFGD Supplier - Preliminary 3D CAD Model	2.62	4.41
		Award Booster Fans		
6	Jul-17	NTE Load Diagrams	0.45	4.86
		Award Atomizers		
7	Aug-17	DFGD Supplier - Equipment Lists	6.24	11.10
		Award Lime System		
8	Sep-17	Flue Gas Ductwork Procurement Initiated	0.45	11.55
9	Oct-17	Initial EI&C Design Information	0.45	12.00
		NTE Load Diagrams		
10	Nov-17	Flue Gas Ductwork Procurement Initiated	2.26	14.26
11	Dec-17	Structural Steel Procurement Initiated	0.45	14.71
12	Jan-18	Structural Steel Fabrication Schedule Complete	0.45	15.16
13	Feb-18	SDA and Fabric Filter Design Drawings	4.07	19.23
14	Mar-18	Award DCS	0.45	19.68
15	Apr-18	Award Fabric Filter Bags and Cages	2.68	22.36
		Flue Gas Ductwork Start of Fabrication		
16	May-18	Structural Steel Start of Fabrication	0.57	22.93
17	Jun-18	Physical Flow Model Completed	2.38	25.31
18	Jul-18	Receive Permits for Construction	0.70	26.01
19	Aug-18	Mobilize On-Site	2.67	28.68
20	Sep-18	Unit 1 SDA Delivery	2.99	31.67
		Office Complex and Fabrication Areas Set-Up		
21	Oct-18	Unit 1 and Unit 2 Booster Fan Delivery	5.12	36.79
		Lime Storage and Preparation System Delivery		
		Unit 1 Fabric Filter Delivery		
22	Nov-18	Unit 1 SDA Structural Steel Delivery	4.81	41.60
		Unit 1 Duct Delivery		
		Unit 1 SDA-A Support Steel Erection Complete		
23	Dec-18	Unit 1 SDA-A Inlet Duct Support Steel Complete	4.00	45.60
		Unit 1 Fabric Filter Structural Steel Delivery		
		Unit 2 Duct Delivery		
24	Jan-19	Unit 2 SDA Delivery	4.32	49.92
		Unit 1 SDA-A Inlet Duct Erection Complete		
		Unit 1 SDA-C Support Steel Erection Complete		
25	Feb-19	Unit 1 SDA-A Outlet Duct Erection Complete	4.08	54.00
		Unit 1 SDA-A Vessel Shell/Roof Complete		
		Unit 2 Fabric Filter Delivery		
26	Mar-19	Unit 2 Structural Steel Delivery	3.99	57.99
		Unit 1 SDA-B Inlet Duct Erection Complete		
		Unit 1 Fabric Filter-B Hoppers/Wall/Roof Complete		

Attachment 4

MONTHLY PROGRESS PAYMENT SCHEDULE

Month	Date	Milestone	Individual Payment (%)	Cumulative Payment (%)
27	Apr-19	Unit 1 SDA-B Vessel Shell/Roof Complete	3.99	61.98
		Unit 1 SDA-B Outlet Duct Erection Complete		
		Unit 1 Fabric Filter-B Hoppers/Wall/Roof Complete		
28	May-19	Unit 1 SDA-C Inlet Duct Erection Complete	3.69	65.67
		Unit 1 SDA-C Outlet Duct Erection Complete		
29	Jun-19	Unit 1 SDA-C Vessel Shell/Roof Complete	3.35	69.02
		DCS Equipment Delivery		
		Unit 2 SDA-A Inlet Duct Support Steel Complete		
		Unit 2 SDA-A Support Steel Complete		
30	Jul-19	Unit 1 Booster Fans Erection Complete	3.04	72.06
		Unit 2 SDA-B Inlet Duct Support Steel Complete		
		Unit 1 Fabric Filter-C Hoppers/Wall/Roof Complete		
31	Aug-19	Unit 2 SDA-C Inlet Duct Support Steel Complete	2.93	74.99
		Unit 2 SDA-A Vessel Shell/Roof Complete		
		Unit 2 SDA-A Inlet Duct Erection Complete		
32	Sep-19	Unit 2 SDA-B Support Steel Complete	3.06	78.05
		Operating and Maintenance Manuals		
33	Oct-19	Unit 2 SDA-B Vessel Shell/Roof Complete	3.00	81.05
		Unit 2 SDA-B Inlet Duct Erection Complete		
		Unit 2 SDA-C Support Steel Complete		
34	Nov-19	Unit 2 SDA-A Outlet Duct Erection Complete	2.81	83.86
		Unit 2 Fabric Filter-A Hoppers/Wall/Roof Complete		
35	Dec-19	Unit 2 SDA-C Vessel Shell/Roof Complete	2.76	86.62
		Unit 2 SDA-C Inlet Duct Erection Complete		
36	Jan-20	Unit 2 SDA-B Outlet Duct Erection Complete	2.41	89.03
		Unit 2 Fabric Filter-B Hoppers/Wall/Roof Complete		
		Unit 1 Structural Completion		
37	Feb-20	Unit 2 SDA-C Outlet Duct Erection Complete	2.26	91.29
		Unit 2 Booster Fans Erection Complete		
38	Mar-20	Unit 1 Duct Tie-In Complete	2.23	93.52
39	Apr-20	Unit 1 Mechanical Completion	0.45	93.97
40	May-20	Unit 1 Performance Test Report	0.30	94.27
41	Jun-20	Unit 1 Substantial Completion	0.22	94.49
		Unit 2 Structural Completion		
42	Jul-20	Removal of Fabrication Tables Complete	0.22	94.71
43	Aug-20	Unit 2 Duct Tie-In Complete	0.15	94.86
44	Sep-20	Unit 2 Mechanical Completion	0.07	94.93
45	Oct-20	Unit 2 Substantial Completion	0.07	95.00
		Demobilization Complete		
46	Nov-20	Unit 1 Final Acceptance	2.50	97.50
47	Dec-20	Unit 2 Final Acceptance	2.50	100.00

ATTACHMENT 5

S&L Estimating Documentation:

Indirects and Construction Equipment included in Crew Rates

Indirects and Construction Equipment included in Crew Rates

Typical Construction Equipment included in our Crew Rates

- Air compressor
- Air tugger
- Crane, 5 ton
- Crane, 15 ton mobile
- Crane, 35 ton
- Crane, 50 ton
- Crane, 60 ton
- Dozer
- Finishing machine
- Flat bed trailer
- Fork lift
- Front end loader
- Generator
- Grader
- Pickup truck
- Powdered riding buggy
- Roller, sheepsfoot
- Roller, vibratory
- Radial saw
- Scraper
- Stress relieving machine
- Tremie
- Truck mounted concrete pump
- Vibrator
- Water wagon
- Welding machine
- Wire puller

Site Indirects included in Crew Rates

- Job Supervision-Field Staff
- Administration-Field Staff
- Personnel Hiring
- Craft Superintendents
- Safety / Purchasing/Expediting-Field Staff
- Material Control-Field Staff
- Engineering Liaison-Field Staff
- Project Controls-Field Staff
- Cost/Schedule Controls-Field Staff
- Quality Control Inspection-Field Staff
- Project Office Supplies-Field Staff
- Computer Expenses
- Service Trucks/Supplies
- Field and Shop Mechanics and Supplies
- Subcontract Administration
- Warehousing-Field Staff
- Field Surveying
- Water & Ice
- Sanitation and Cleanup
- Move In/Move Out
- Detours/Barricades/Flags
- Security
- Temp. Utilities/Distr/Hookup
- Temporary Site Improvement
- Temporary Facilities/Buildings
- Utilities Consumption
- Employee Expenses
- Legal Expenses/Claims
- Permits and Fees
- Timekeeping

ATTACHMENT 6

S&L Estimating Documentation:

Escalation Projections

Entergy
White Bluff DGFD Project
Escalation Projections

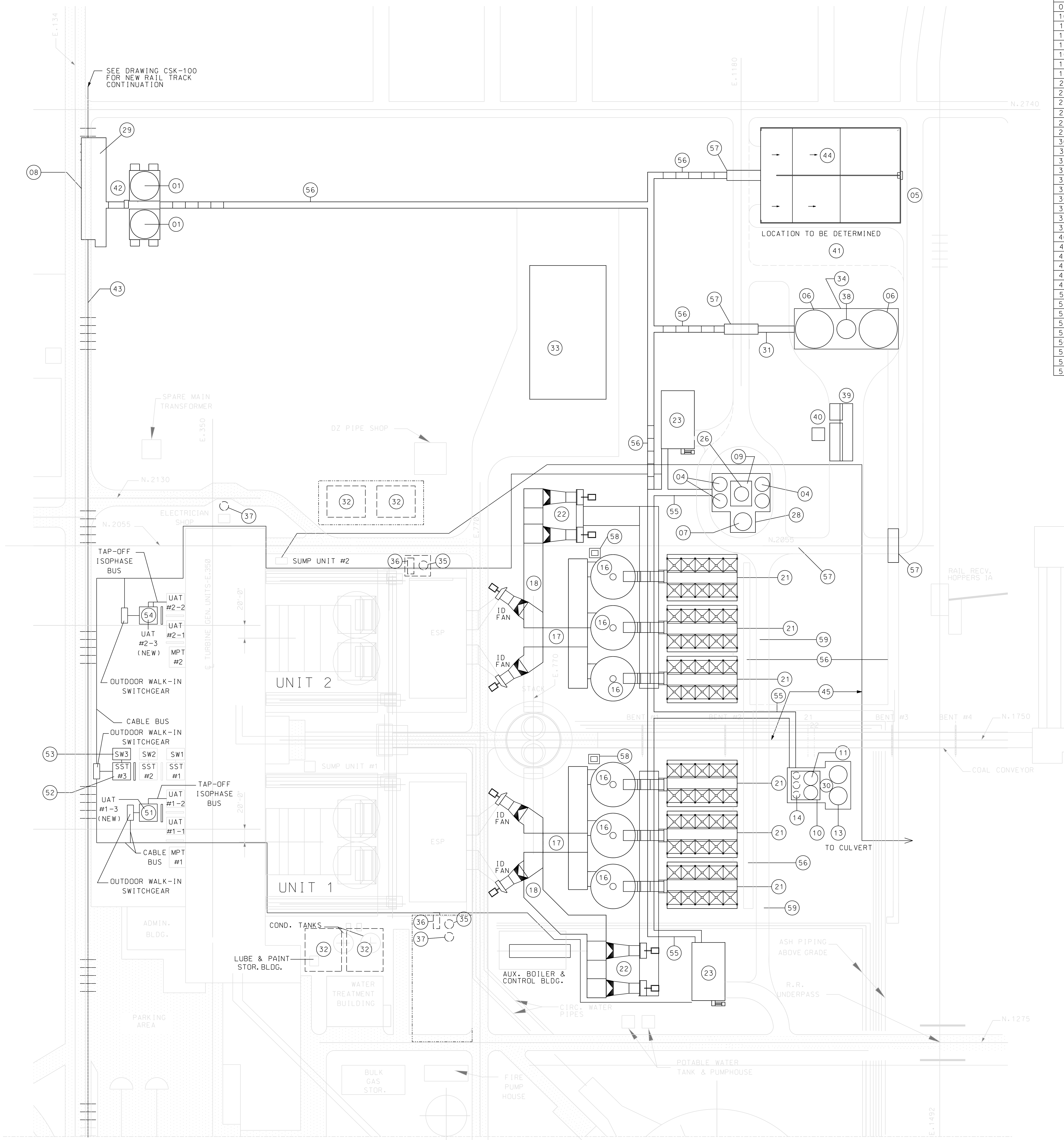
Basis: Pine Bluff Arkansas Labor rates as published in RS Means	Yearly Base Rates + Fringes										
Craft Description	2009	2010	2011	2012	2013	2014	% increase in past 1 year	% increase in past 2 years	% increase in past 3 years	% increase in past 5 years	Projected Potential overall % labor increase next 5 years.
Boilermaker	$38.59	$41.59	$41.59	$41.59	$43.10	$44.39	2.99%	6.73%	6.73%	15.03%	
Iron worker	$28.06	$30.44	$30.44	$30.44	$32.05	$34.00	6.08%	11.70%	11.70%	21.17%	
Pipe Fitter	$25.28	$31.65	$31.65	$31.65	$35.56	$35.56	0.00%	12.35%	12.35%	40.66%	
Electrician	$35.74	$35.74	$35.74	$35.74	$36.95	$36.95	0.00%	3.39%	3.39%	3.39%	
Common Laborer	$16.83	$17.47	$17.47	$17.47	$17.47	$17.47	0.00%	0.00%	0.00%	3.80%	
Average increase in five major crafts							1.82%	6.83%	6.83%	16.81%	**18%**

Misc Material and Equipment (Please see Note 1)	% increase in past 3 years	% increase in past 5 years	Projected Potential overall % increase next 5 years.
Construction & Building Index	8%	15%	17.00%
Material Price, Construction Mat.	8%	7%	10.00%
Plant Cost Index	no increase	slightly negative	5.00%
Civil Work	8%	14%	15.00%
Steel - ductwork	no increase	slightly negative	8.00%
Steel - rolled shape	8%	no increase	10.00%
Architectural	5%	4%	8.00%
Overall mechanical equipment	4%	1%	7.00%
Overall piping	6%	11%	12.00%
Overall electrical equipment	9%	17%	18.00%
Raceway, Cable Tray, & Conduit	8%	slightly negative	10.00%
Electrical cable	14%	7%	15.00%
Controls & Instrumentation	1%	1%	5.00%
Average overall increase for Power back-fit projects	**7%**	**9%**	**11%**

Note 1: From major industrial sources such as BLS, Chemical Engineering, Handy Whitman, ENR Commodity pricing (20 city average),

ATTACHMENT 7

Conceptual General Arrangement Drawing



LEGEND	
01	LIME STORAGE SILOS
03	NOT USED
04	LIME SLURRY FEED TANKS
05	BYPRODUCT HAUL ROAD
06	BYPRODUCT STORAGE SILOS
07	SLAKING WATER STORAGE TANK
08	TRAIN UNLOADING SHED
09	LIME PREPARATION BUILDING
10	BYPRODUCT RECYCLE EQUIPMENT BUILDING
11	BYPRODUCT RECYCLE DAY BINS
13	BYPRODUCT RECYCLE MAKE-UP WATER TANKS
14	BYPRODUCT RECYCLE SLURRY TANKS
16	SPRAY DRYER ABSORBERS
17	SDA FLUE GAS INLET DUCTS
18	BOOSTER FAN DISCHARGE
21	BAG HOUSES
22	BOOSTER FANS
23	COMPRESSOR / ELECTRICAL BUILDINGS
26	LIME DAY BIN
28	LIME PREPARATION AREA
29	LIME UNLOADING EQUIPMENT ROOM
30	BYPRODUCT RECYCLE AREA
31	ELEVATED BOP CONTRACTOR UTILITY RACK
32	FUTURE PROVISION SPACE FOR SCRS
33	FGD SPARE PARTS WAREHOUSE
34	BYPRODUCT HANDLING AREA
35	ACI SILOS
36	ACI ELECTRICAL BUILDINGS
37	CHI TANK
38	FLY ASH SILO
39	TRUCK SCALES
40	TRUCK SCALE HOUSE
41	BYPRODUCT TRUCK PARKING
42	LIME UNLOADING AND STORAGE AREA
43	RAIL SPUR
44	PROCESS WATER RETENTION PONDS
45	PROPOSED GRATED CONCRETE TRENCH
51	UNIT AUX. TRANSFORMER UNIT 1
52	STARTUP / STANDBY TRANSFORMER COMMON (UNITS 1&2)
53	SWITCH
54	UNIT AUX. TRANSFORMER UNIT 2
55	ELEVATED FGD CONTRACTOR UTILITY RACK
56	BOP SLEEPER RACK
57	BOP TRENCH
58	SDA PENTHOUSE ELEVATOR
59	CRANE MAINTENANCE AISLE

HOLD INFORMATION

NO.	DATE	DESCRIPTION

CONTRACTOR/INSTALLER SHALL TAKE ALL APPROPRIATE PRECAUTIONS TO ENSURE THE SAFETY OF ALL PEOPLE LOCATED ON THE WORK SITE, INCLUDING CONTRACTOR'S/INSTALLER'S PERSONNEL (OR THAT OF ITS SUB-CONTRACTOR(S)) PERFORMING THE WORK.

RELEASE INFORMATION

REV.	DATE	DESCRIPTION

ISSUE PURPOSE: ISSUED FOR STUDY

SPECIFICATION: -

PROJECT NO.: 13138-001

I HEREBY CERTIFY THAT THIS ENGINEERING DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT PERSONAL SUPERVISION AND THAT I AM A DULY LICENSED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF ARKANSAS.

ENTER NAME
ENTER DATE

MY LICENSE RENEWAL DATE IS: ENTER DATE
PAGES OR SHEETS COVERED BY THIS SEAL:
THIS DOCUMENT ONLY.

CAD FILE NAME: M-GA-001.DGN

PREPARED BY: D.J.MERRICK

REVIEWED BY: G.A.RIVERA

APPROVED BY: S.C.MCHONE

ANY MODIFICATION OR ADDITION TO THIS DRAWING BY AN ORGANIZATION OTHER THAN SARGENT & LUNDY, IS NOT THE RESPONSIBILITY OF SARGENT & LUNDY.

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WWW.SARGENTLUNDY.COM
CERTIFICATE OF AUTHORIZATION NO. 6938

Entergy

PROJECT

WHITE BLUFF STATION
UNITS 1 & 2
ENTERGY

DRAWING TITLE

GENERAL ARRANGEMENT
SDA SITE DEVELOPMENT

PRELIMINARY
NOT FOR
CONSTRUCTION

NORTH

60' 0 60' 120' 180'
GRAPHIC SCALE

DRAWING SCALE
1" = 60'-0"

DRAWING NUMBER	REVISION
M-GA-001	N/A

SHEET 1 OF 1

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ATTACHMENT 8

Entergy Basis of Contingency

WB FGD Project

Risk Register

Contingency Estimate					
Estimate Total w/o Contingency, IDC, Escalation	**$ 740,968,200**				
	P90	**P80**	**P70**	**P60**	**P50**
Risk Contingency	**$ 35,870,000**	**$ 27,220,000**	**$ 20,550,000**	**$ 16,210,000**	**$ 13,090,000**
Estimate Uncertainty Contingency	**$ 95,350,000**	**$ 66,600,000**	**$ 41,540,000**	**$ 21,330,000**	**$ (290,000)**
Unknown Risk Contingency	**$ 18,560,000**	**$ 17,380,000**	**$ 16,450,000**	**$ 15,610,000**	**$ 14,810,000**
Total Contingency	$ 149,780,000	$ 111,200,000	$ 78,540,000	$ 53,150,000	$ 27,610,000
Percentage of Total	20%	15%	11%	7%	4%
Total Estimate w/ Contingency	$ 890,748,200	$ 852,168,200	$ 819,508,200	$ 794,118,200	$ 768,578,200

Project Delivery Standard

	Estimate Characteristic			Resulting Range	
Estimate class	**Maturity level of project definition** **expressed as % of complete engineering**	**End usage** **typical purpose of estimate**	**Methodology** **typical estimating method**	**Estimate accuracy range** **typical variation in low & high ranges**	**Target contingency range**
Class 5	0 to 2%	Rough Order of Magnitude (ROM)	Capacity factored, parametric models, judgment, or analogy	-50 to +100%	30 to 50%
Class 4	1 to 15%	Feasibility	Equipment factored or parametric models	-30 to +50%	25 to 40%
Class 3	10 to 50%	Funding Authorization	Semi-detailed unit costs with assembly level line items	-20 to +30%	15 to 30%
Class 2	30 to 90%	Control	Detailed unit costs with forced detailed take-off	-15 to +20%	5 to 20%
Class 1	50 to 100%	Check Estimate	Detailed unit cost with detailed take-off	-10 to +15%	2 to 7%

ESTIMATE UNCERTAINTY

Risk Category	Description of Risk	Quantitative Risk Analysis					Status / Comments
		Estimate Total w/out Contingency	Min ($)	Expected	Max ($)	QRA Comments	
Estimate Uncertainty	**EPC Contract**	$ 752,912,300	($188,228,075)	$0	$188,228,075	From S&L estimate report, the project definition and accuracy of the individual components in this estimate result in an overall accuracy of +/- 25%.	
Estimate Uncertainty	**Owner's Costs**	$ 58,546,000	($11,709,200)	$0	$17,563,800	Estimate from Entergy, estimate is considered a Class 3 (+30% to -20%).	Entergy Indirects were calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the internal loaders estimate.
Estimate Uncertainty	**Third Party Services**	$ 12,544,000	($3,136,000)	$0	$3,136,000	From S&L estimate report, estimate is considered a Class 3 (+25% to -25%)	

WB FGD Project
Risk Register

UNKNOWN RISK								
		Quantitative Risk Analysis						
Risk Category	Description of Risk	Estimate Total w/out Contingency	Min ($)	Expected	Max ($)	QRA Comments	Status / Comments
Unknown Risks	**UNKNOWN RISKS:** This is part of the calculation for the overall contingency to include in the project budget.	$ 740,968,200	$ 7,409,682	$ 14,819,364	$ 22,229,046	Estimating standard guidance. Min = 1%, Exp = 2%, Max = 3%	Due to lack of historical data and current project development, there are a range of potential impacts from unknown risks not yet captured in the estimate uncertainty and identified risks, Entergy contingency guidance is to use 1% - 3% of the total estimate without contingency. This item can be captured in the risk register and modeled with the identified risks when estimating contingency.

IDENTIFIED RISKS

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-007	Budget	**PROJECT BUDGET - CRAFT LABOR - PER DIEM RATE RISK:** This risk is related to the required craft labor per diem increasing due to the high demand of craft labor, at a percentage greater than the estimated rate.	ALL	3	2	0	0	**6**	Low	An increase to per diem to attract labor will increase the project total estimate.	45%	$0	$0	$4,290,000	Yes	The estimated Per Diem is $13M. Assume a 33% increase as a max.	
2014-002	Budget	**PROJECT BUDGET - CRAFT LABOR - WAGE RATE ESCALATION:** This risk is related to wage rates rising, at a rate greater than the rate used in the estimate, due to the high demand for craft labor.	ALL	3	3	0	0	**9**	Low	Received rates over 10-year period from S&L. Range has fluctuated from 0% to 21.23% during that period. Current economic conditions indicate a high probability of craft labor rates increasing beyond the current projection of 3.35% provided by S&L.	45%	($19,700,000)	$0	$42,300,000	Yes	Received rates over 10-year period from S&L. Looked at range and average high and low rates. Expected escalation rate is 3.35%. Assumed Min rate of 1.675% and Max rate of 6.7%. Results in potential increase of $42.3M over current escalation estimate and potential decrease of $19.7M.	
2014-001	Budget	**PROJECT BUDGET - IDC:** This risk is related to the cost of capital increasing over the life of the project, at a rate different than the current estimated escalation rate.	ALL	1	5	0	2	**7**	Low	The EPA Cost Control Manual uses a rate of 7% which was used for the estimate. Historical EAI AFUDC rates have been under 7%.	5%	$0	$0	$25,000,000	Yes	Assumes an index rate of 7.5%; this results in an increase of ~$25M over current IDC estimate.	
2014-006	Budget	**PROJECT BUDGET - CAPITAL SUSPENSE ADJUSTMENTS:** The risk is related to Capital Suspense increasing over the life of the project from the current Entergy forecasted rate.	ALL	2	3	1	1	**10**	Low	Adjustment of rates impact the project total estimate.	25%	$0	$0	$0	No	Entergy Indirects will be calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the internal loaders estimate.	

WB FGD Project
Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-005	Budget	**PROJECT BUDGET - EPC MATERIAL ESCALATION:** Project material cost may be subject to escalation	ALL	1	3	0	1	**4**	Low	Material escalation is included in the project estimate.	5%	$0	$0	$0	No	Material escalation is included in the project estimate. The estimate uncertainty addresses the risk of the amount of material and the material escalation rate being different than the current forecasted rates.	
2014-003	Budget	**PROJECT BUDGET - LIME ESCALATION:** Project lime cost may be subject to escalation different than the estimated rate.	ALL	3	1	0	0	**3**	Low	Assume that lime escalation rate will increase during project.	45%	$0	$0	$0	No	Budgeted Lime escalation rate is 2.15%. The estimate uncertainty addresses the risk of the amount of material and the escalation rate being different than the current forecasted escalation rate.	
2014-005	Budget	**PROJECT BUDGET - MATERIAL LOADER ADJUSTMENTS:** The risk is related to the material loaders increasing over the life of the project from the current Entergy forecasted loaders.	ALL	4	1	0	0	**4**	Low	Probability that Material Loaders will change over life of the project.	20%	$0	$0	$0	No	Entergy Indirects will be calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the internal loaders estimate.	
2014-004	Budget	**PROJECT BUDGET - PAYROLL LOADER ADJUSTMENTS:** The risk is related to the payroll loaders increasing over the life of the project from the current Entergy forecasted loaders.	ALL	4	2	0	0	**8**	Low	Probability that Payroll Loaders will change over the life of the project.	70%	$0	$0	$0	No	Entergy Indirects will be calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the Entergy Payroll estimate.	
2014-006	Budget	**SALES TAX:** Risk that the sales tax rate will change and add additional costs to the project.	ALL	2	1	0	0	**2**	Low	Probability that the Sales Tax will change order the life of the project.	20%	$0	$0	$0	No	The risk associated with a Sales Tax change will be included in the estimate uncertainty, which also includes the risk of the quantity of materials subject to sales tax.	

WB FGD Project
Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING: Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Quantitative Risk Analysis: Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	Status / Comments
2014-010	Eng	**DESIGN CRITERIA:** Design criteria is missing information, or information is incorrect resulting in changes to the technical specifications and requirements during the project. The risk would result in re-engineering / re-work.	ALL	2	3	3	1	**14**	Medium Low	The Owner's Engineer (S&L) has performed Engineering Studies in 2009 and 2013. The revised Design Criteria document reflects the current project requirements.	20%	$0	$5,000,000	$25,000,000	Yes	Assumption that the design criteria accurately reflects the requirements of the project, any corrections will have minimal impact to detailed design. Min is 0%, Expected is 1%, Max is 5% of EPC Direct Costs $500M.	
2014-011	Eng	**ENGINEERING SUPPORT:** Inadequate support to review EPC contractor's design to ensure it meets Entergy requirements. The risk would result in re-engineering / re-work.	ALL	1	3	3	2	**8**	Low	The Project will use an Owner's Engineer to augment staff requirements to mitigate this risk. This risk is the potential for redesign based on inadequate reviews.	5%	$0	$5,000,000	$25,000,000	Yes	Assumption that there will be minimal rework based on inadequate Entergy review of EPC contractor design. Min is 0%, Expected is 1%, Max is 5% of EPC Direct Costs $500M.	
2014-012	Eng	**SCOPE GAP OR CHANGES:** Work scope not defined in EPC contract, and not identified/unforeseen conditions in project budget. Risk would result in additional scope to EPC contract.	ALL	2	4	3	2	**18**	Medium Low	Low probability due to 2009 and 2013 studies. BOP scope not as defined as FGD island. There is only minimal engineering complete at this stage. Also, risk covers the potential for additional design requirements over base FGD design to meet Entergy standard designs.	20%	$5,000,000	$15,000,000	$45,000,000	Yes	Assumption that any missed scope will not be significant, there is an Open Book period for development. Assume minimum of 1% of the $500M FGD direct costs, 3% expected, 9% max.	
2014-013	Eng	**TECHNOLOGY - BAGHOUSE**: The baghouse on each of the units fails to meet the PM emissions limits.	ALL	1	3	5	5	**13**	Medium Low	Low probability due to proven technologies will be specified, and EPC contract will have vendor guarantees.	5%	$0	$0	$0	No	Not included in QRA. Final payment of EPC contract will be based on successful demonstration of performance.	
2014-014	Eng	**TECHNOLOGY - Dry FGD**: The selection of the technology to meet the emission limits with margin is insufficient to meet the required limits.	ALL	1	3	5	5	**13**	Medium Low	Low probability due to proven technologies will be specified, and EPC contract will have vendor guarantees.	5%	$0	$0	$0	No	Not included in QRA. Final payment of EPC contract will be based on successful demonstration of performance.	

WB FGD Project
Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-015	Env	**AIR PERMIT (AR) - DELAY**: Delay in receiving the permit, for an additional 6 months (24 total).	ALL	1	2	3	3	**8**	Low	Cost impact to expedite project to stay on schedule as a result in the delay. The current timeline of 18 months accounts for some expected delay.	5%	$0	$0	$3,000,000	Yes	Assume $500k/month for up to 6 mo of delay. This would be prior to FNTP.	In the current timeline, there is some schedule float that could be used. Entergy could release FNTP prior to receipt of the air permit.
2014-016	Env	**ASH DISPOSAL:** EPA determines that combustion byproducts are a hazardous waste resulting in need to utilize other material to stabilize scrubber byproduct.	ALL	1	1	0	3	**4**	Low	Cost impact: possible HAZMAT training and treatment of ash. Still would landfill on site. Loss of ash sales.	5%	$0	$0	$150,000	Yes	Assume some additional training, and minimal equipment modifications.	Most ash will be collected in the ESP. This risk would be addressed by a separate project.
2014-018	Env	**COMPLIANCE RULE - Vacated or Delayed:** If the rule is vacated or delayed, what is the impact?	ALL	1	2	0	0	**2**	Low	Assume delay prior to project approval but same compliance period to comply. Cost impact: engineering, payroll, AFUDC during delay period.	5%	$0	$0	$3,000,000	Yes	Project delayed prior to LNTP. Assume $500k/month for 6 months.	
2014-017	Env	**ASH DISPOSAL:** The ADEQ might impose the same permit restriction as it did at the Flint Creek Plant and not allow WB to route landfill leachate directly to the surge pond.	ALL	3	0	0	1	**3**	Low	Project will not increase probablility to occurrence; plant O&M risk. Cost impact: treatment of leachate prior to sending to surge pond.	45%	$0	$0	$0	No	Plant O&M risk.	
2014-019	EPC	**CONSTRUCTION DELAYS:** Construction delays could negatively affect the project and ability to meet a compliance date target. It includes the following contractor identified risks: 1) Damage or late delivery of equipment and materials 2) Weather impact to craft productivity and full or partial site shutdown 3) Craft productivity 4) Labor availability of pipefitters, welders, and electricians	WB1	2	2	3	2	**14**	Medium Low	The contracting strategy will use schedule incentives to maintain the schedule. The labor availability risk will be shared with the contractor, craft labor escalation is a separate risk item.	20%	$0	$4,000,000	$16,000,000	Yes	These delay estimates represent Owner's costs due to the delay (AFUDC, labor) 0-8 mo delay at $2M/month. Current schedule reflects adequate available time for the EPC contractor to account for these delays. Escalation is a separate risk.	Identified risks will be assigned to the EPC contractor.

WB FGD Project
Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING: Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Quantitative Risk Analysis: Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	Status / Comments
2014-021	EPC	**Delay in FNTP:** Delay in Entergy issuing FNTP	ALL	2	2	2	3	**14**	Medium Low	Delay in issuing FNTP. Delays for receipt of the air permit or regulatory approval are separately identified risks.	20%	$0	$3,000,000	$6,000,000	Yes	Assume EPC contractor request compensation for the FNTP delay (equipment contracts, etc). ($1M/month delay)	
2014-022	EPC	**Delay in LNTP:** Delay in Entergy issuing LNTP	ALL	2	2	2	3	**14**	Medium Low	Delay in receiving internal approvals.	20%	$0	$1,500,000	$3,000,000	Yes	Assume EPC contractor request compensation for the LNTP delay (equipment contracts, etc). ($0.5M/month delay)	
2014-023	EPC	**EPC CONTRACT EQUIPMENT VALUE:** Equipment estimate uncertainty during the period from when the contract price is developed to the LNTP.	ALL	2	4	0	1	**10**	Low	The time between the Open Book Period and LNTP is approximately 14 months.	20%	$0	$8,000,000	$20,000,000	Yes	Risk of price changes for $400M of the EPC contract, subject to 14 months between negotiation and award. Min = 0%, Exp = 2%, Max = 5%	
2014-024	EPC	**EPC CONTRACT:** Negotiated EPC fee	ALL	2	4	0	2	**12**	Medium Low	EPC Fee assumed to be in the 8%-15% range.	20%	($12,000,000)	$0	$12,000,000	Yes	Estimate includes a 10% fee or ~$60M. Min = 8% fee, Max = 12% fee.	
2014-069	EPC	**EPC CREDIT RISK:** EPC contractor default on contractor (EPC procurement costs)	ALL	1	1	1	3	**5**	Low	Entergy will work with qualified vendors that have had a credit risk review.	5%	$0	$0	$7,500,000	Yes	Estimate of EPC procurement costs, negotiating, and potential incrase on contract value. To account for procurement activities, Max 1% of EPC value	

WB FGD Project
Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING: Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Quantitative Risk Analysis: Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	Status / Comments
2014-070	EPC	**EPC CREDIT RISK:** EPC contractor default on contractor (schedule delay)	ALL	1	5	5	5	**15**	Low	Entergy will work with qualified vendors that have had a credit risk review.	5%	$0	$0	$36,000,000	Yes	Default of the EPC contractor would result in delay of project to procure and onboard a new contractor. For this calculation, the EPC contractor is assumed to default during construction. Apply amount of IDC ($4M/mo) plus carrying costs of Entergy costs ($500k/mo) at this date through end of project to the expected delays (max: 8 mo).	
2014-032	EPC	**SCHEDULE - Delayed:** Change in project schedule due to longer compliance timeline.	ALL	1	1	1	1	**3**	Low	Assume that, if compliance date is delayed, then all costs will shift accordingly. Incremental costs would be maintaining internal staff in the interim, IDC.	5%	$0	$0	$12,000,000	Yes	Assume delay would be known before contract award, when the FIP or SIP is issued. Delay of min = 0 mo, exp = 0 mo, max = 24 mo @ $500k/mo	
2014-033	EPC	**SCHEDULE - Shorter Compliance Timeline:** Change in project schedule that shortens compliance timeline.	ALL	1	4	0	3	**7**	Low	Assume that labor costs and costs to expidite equipment would increase to comply with earlier timeline.	5%	$0	$0	$30,000,000	Yes	Assumption that current schedule has some float, add $ for premium time, less IDC costs. Assume 15% increase of estimated craft labor of ~$200M.	
2014-035	EPC	**UN-IDENTIFIED UNDERGROUND OBSTRUCTION:** Claims for extra work for un-identified underground pipe, etc.	ALL	2	3	2	2	**14**	Medium Low	Project plans to perform exploration work to identify unknown underground obstructions during the Open Book period. This risk if realized will increase the EPC contract price.	20%	$0	$500,000	$3,000,000	Yes	Assumption that any missed scope will not be significant. Schedule delays of $500k/month.	

WB FGD Project
Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-036	EPC	**WEATHER-RELATED DELAYS:** Extreme weather can greatly affect craft productivity and result in partial or complete site shutdown. Such weather conditions can increase the risk and provide the basis for a contractor claim for a change order.	ALL	1	1	3	2	**6**	Low	The project is subject to extreme weather events. This risk will be further developed during the Open Book period.	5%	$0	$4,000,000	$12,000,000	Yes	These delay estimates represent Owner's costs due to the delay (AFUDC, labor) 0-6 mo delay at $2M/month. Assumption that the current schedule has sufficient float to mitigate this risk. The Open Book period will be used to develop a more detailed schedule.	The project execution plan is to perform a majority of the construction prior to any outage. Weather risks will be assigned to the EPC contractor.
2014-020	EPC	**CONSTRUCTION DELAYS:** Construction delays could negatively affect the project and ability to meet a compliance date target. It includes the following contractor identified risks: 1) Damage or late delivery of equipment and materials 2) Weather impact to craft productivity and full or partial site shutdown 3) Craft productivity 4) Labor availability of pipefitters, welders, and electricians	WB2	2	2	3	2	**14**	Medium Low	The contracting strategy will use schedule incentives to maintain the schedule. The labor availability risk will be shared with the contractor, craft labor escalation is a separate risk item.	20%	$0	$0	$0	No	Risk QRA combined with EPC Construction Delays for WB1. Current schedule reflects adequate available time for the EPC contractor to account for these delays. Escalation is a separate risk.	Identified risks will be assigned to the EPC contractor.
2014-008	EPC	**LABOR:** Schedule delays due to union labor disputes.	ALL	1	2	2	2	**6**	Low	Using non-union labor.	5%	$0	$0	$0	No	Using non-union labor.	

WB FGD Project
Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-027	EPC	**OPEN BOOK PERIOD**: Change in contract terms (Limitiation of Liability) during EPC contract negotiations.	ALL	1	3	0	1	**4**	Low	The RFP process to select the EPC contractor will require the contractor to state required terms for an EPC contractor prior to their selection. The Open Book period should not increase their project risk profile, which would be a driver for a change in their terms.	5%	$0	$0	$0	No	Not included in QRA. Project estimate includes estimate uncertainty for this risk.	
2014-028	EPC	**OPEN BOOK PERIOD**: Change in rates from EPC contractor during open book period.	ALL	1	1	0	1	**2**	Low	The EPC contractor's labor and equipment rates will be negotiated during the Open Book period to develop the contract price.	5%	$0	$0	$0	No	Not included in QRA. Project estimate includes estimate uncertainty for this risk.	
2014-029	EPC	**OPEN BOOK PERIOD**: Unable to negotiate a fixed price contract.	ALL	1	0	0	0	**0**	Low	The scope and schedule of this project are sufficient to meet the project goals. There is no indication that this risk is probable.	5%	$0	$0	$0	No	Not included in QRA.	
2014-030	EPC	**POOR PERFORMANCE BY CONTRACTOR ON PROJECT:** Risk of claims and change orders increases if contractor expects and/or experiences loss on the project.	ALL	1	1	2	1	**4**	Low	Risk exists for contractor claims, project controls will be in-place to support Entergy. Risk is for total claims greater than the amount of contingency.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-031	EPC	**POOR QUALITY OF CONTRACTOR WORK**: Schedule impact due to rework and adverse affect on long-term plant operation.	ALL	1	1	2	1	**4**	Low	EPC bidders will be selected based on Entergy experience and previous work experience.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	

WB FGD Project
Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-034	EPC	**SCOPE OR DESIGN PROBLEMS:** Poor scope, technical design, or unclear technical requirements could result in change orders with added cost and/or schedule delay or an end product that does meet customer needs	ALL	3	3	3	2	**24**	Medium Low	Complicated project with many interfaces to exisitng facility. Assume multiple small change orders.	45%	$0	$0	$0	No	Not included in QRA. This risk is similar to Engineering risks. Project estimate includes estimate uncertainty for this risk.	
2014-037	EPC	**POOR PERFORMANCE:** Contractor does not meet schedule or performance requirements.	ALL	2	1	2	1	**8**	Low	Risk exists for contractor claims, project controls will be in-place to support Entergy.	20%	$0	$0	$12,000,000	Yes	These delay estimates represent Owner's costs due to the delay (AFUDC, labor) 0-6 mo delay at $2M/month.	
2014-038	Goal	**COMPLIANCE - NON-COMPLIANCE**: The new emission standards cannot be met by the units.	ALL	1	5	5	5	**15**	Medium Low	Industry information shows that the emission compliance levels can be met with the available tecnologies.	5%	$0	$0	$0	No	Cost estimate is beyond project value.	
2014-053	Ops	**LONG TERM OPERATION - CAPACITY:** Unit derate or capacity restriction resulting from control technologies.	ALL	1	1	1	1	**3**	Low	Unit capacity will be affected by this project. It will be defined and a guarantee will be negotiated with the EPC contractor.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	Review this risk after Open Book Period to determine capacity impact of project.
2014-054	Ops	**LONG TERM OPERATION - INCREASED O&M:** Increases to the unit's O&M due to control technology.	ALL	1	1	1	1	**3**	Low	Additional O&M will be required by this project. It will be defined when the technology is selected during the Open Book period.	5%	$0	$0	$0	No	Not a project risk.	Review this risk after Open Book Period to determine O&M impact of project.
2014-055	Ops	**LONG TERM OPERATION - OPERATOR INTERFACE:** An increase in training requirements due to control technology.	ALL	1	1	1	1	**3**	Low	Additional Operator interface will be required by this project.	5%	$0	$0	$0	No	Not a project risk.	Additional Operations staff is included in the project estimate. Review this risk after Open Book Period to determine impact of project.

WB FGD Project
Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING: Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Quantitative Risk Analysis: Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	Status / Comments
2014-056	Ops	**LONG TERM OPERATION - RELIABILITY:** Impacts to the unit's reliability.	ALL	1	1	1	1	**3**	Low	The EPC contract will require equipment guarantees and system redundancy to provide reliability.	5%	$0	$0	$0	No	Not a project risk.	Review this risk after Open Book Period to determine O&M impact of project.
2014-057	Permiting	**Department of Transportation:** Impact of schedule delay due to permitting the road modification.	ALL	1	1	1	0	**2**	Low	Unable to determine risk until Open Book Period to understand permit time required and date when road modification must be in place.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	Review this risk after Open Book Period to determine O&M impact of project.
2014-058	Permitting	**REGULATION CHANGE:** Change in future regulation to lower emission limits or 30-day rolling average.	ALL	1	1	0	0	**1**	Low	Need additional information, this would be a future project. Technology for FGD has not been determined	5%	$0	$0	$0	No	Risk will be mitigated during technology selection.	
2014-040	PM	**INTERNAL APPROVALS:** Possible delays due to delay of internal approval of contracts	ALL	2	1	1	2	**8**	Low	Risk exists with the challenges of obtaining internal approvals.	20%	$0	$0	$1,500,000	Yes	Assume internal project team continues to support Board approval during the regulatory and permitting periods. (Assume $500k/mo).	
2014-041	PM	**ISSUE RESOLUTION:** Possible schedule delays due to non-resolution of issues as they arise.	ALL	2	2	3	2	**14**	Medium Low	Risk exists for undefined issues.	20%	$4,500,000	$9,000,000	$13,500,000	Yes	Undefined issues may impact schedule & project scope. (Assume AFUDC ($4M) + Owner's costs ($500k) per month) Min = 1 mo, expected = 2 mo, max = 3 mo)	
2014-039	PM	**COMMUNICATIONS:** Possible schedule delays and costs increases due to poor communication between all parties	ALL	1	1	2	2	**5**	Low	Risk exists for contractor claims. The contracting strategy using only one EPC contractor should minimize this risk.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $. Adequate staffing of project is a separate risk.	

WB FGD Project
Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-042	PM	**MANAGEMENT - INSUFFICIENT INTERNAL PROJECT STAFF:** Insufficient Internal project resources - unable to meet schedule. Project costs increase.	ALL	2	2	0	2	**8**	Low	Internal labor costs would be higher than budgeted.	20%	$0	$0	$0	No	Project will plan to use outside contractors to staff project.	
2014-043	PM	**MANAGEMENT - PRUDENCY DETERMINATION:** The project team is unable to justify and document project decisions and the related costs to defend decisions as prudent in future rate cases. Mitigation includes processes for contemporaneous documentation.	ALL	1	1	1	3	**5**	Low	The project will follow project delivery standards, risk should be minimal.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-044	PM	**PROJECT CONTROLS:** Project has insufficient project controls / oversight / documentation to manage and control cost.	ALL	1	3	0	4	**7**	Low	Stage Gate process requires project controls. Generic project costs would be higher than budgeted.	5%	$0	$0	$0	No	Additional staff included in the project estimate to cover PEI oversight of project.	
2014-045	PM	**RECORDS MANAGEMENT:** Document control is insufficient leading to inability to support Regulatory Recovery	ALL	1	1	1	3	**5**	Low	The project will follow project delivery standards, risk should be minimal.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-048	PM	**SCOPE CHANGES:** Possible delays or increased cost due to improperly managed project scope changes.	ALL	1	2	2	2	**6**	Low	Potential delays due to internal decisions in a timely manner.	5%	$0	$0	$0	No	Not included in QRA. Missed scope part of the Engineering risks.	

WB FGD Project
Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING: Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Quantitative Risk Analysis: Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	Status / Comments
2014-059	Reg	**REGULATORY - DELAY:** Regulatory delays could negatively affect the project schedule. The expected duration is estimated to be 18 months.	ALL	2	2	5	4	**22**	Medium Low	Project schedule assumes 18 mo to receive approval. If additional time is required, Entergy may choose to issue FNTP prior to receipt to avoid potential costs.	20%	$0	$0	$3,000,000	Yes	Assumption that current schedule has some float, add $ for premium time, less AFUDC costs. ($0.5M/month delay)	
2014-068	Schedule	**SCHEDULE - FORCE MAJEURE** - Increase in cost of project due to force majeure	ALL	1	1	1	1	**3**	Low	BAR insurance will be in place.	5%	$0	$0	$10,000,000	Yes	Insurance deductible is expected to be structured similar to other projects. $500,000 deductible for flood, 5% of insured value for Named Windstorm with min of $1,000,000 and max of $10,000,000.	
2014-062	Schedule	**COMPLIANCE - DEADLINE**: Risk that the project will not meet the deadline?	ALL	1	3	4	3	**10**	Low	Current timeline has sufficient time to develop project.	5%	$0	$0	$0	No	Current schedule reflects adequate available time to complete the project. EPC contract will include schedule requirements.	
2014-063	Schedule	**OUTAGE SCHEDULE:** Outage schedule moves from current schedule dates.	WB1	2	1	1	1	**6**	Low	Project expects the current scheduled outages to move to meet project requirements.	20%	$0	$0	$0	No	Schedule flexibility is expected.	
2014-064	Schedule	**OUTAGE SCHEDULE:** Outage schedule moves from current schedule dates.	WB2	2	1	1	1	**6**	Low	Project expects the current scheduled outages to move to meet project requirements.	20%	$0	$0	$0	No	Schedule flexibility is expected.	
2014-066	Schedule	**SCHEDULE INSUFFICIENT:** EPC Contractor does not provide schedule with sufficient level of detail to coordinate activities	ALL	1	1	1	1	**3**	Low	EPC contract will require detailed project schedule. Entergy project controls will be in-place to support schedule development and maintenance.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-067	Supply Chain	**LIME AVAILABILITY:** Will the required lime for the long term operation be available?	ALL	1	1	1	1	**3**	Low	S&L study did not identify lime availability concerns.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	

Probability and Impact Definition

Probability Rating	Probability Definition (Likelihood of Occurrence)	Discreet Value for QRA
1	Less than or equal to 10 % Probability of Occurrence	5%
2	Greater than 10% but less that 30 % Probability of Occurrence	20%
3	Greater than 30% but less that 60 % Probability of Occurrence	45%
4	Greater than 60% but less that 80 % Probability of Occurrence	70%
5	Greater than 80% Probability of Occurrence	90%

Cost Impact Rating	Cost Impact Value (Impact to Entergy Cost only) (Project Cost = $500M)	Min Cost Impact (QRA)	Most Likely Cost Impact (QRA)	Max Cost Impact (QRA)
1	(<0.5% of project cost)	$ 100,000	$ 1,000,000	$ 2,500,000
2	(0.5% - 1.4% of project cost)	$ 2,500,000	$ 4,750,000	$ 7,000,000
3	(1.5% - 2.9% of project cost)	$ 7,000,000	$ 11,000,000	$ 15,000,000
4	(3% - 4.9% of project cost)	$ 15,000,000	$ 20,000,000	$ 25,000,000
5	(>5% of project cost)	$ 25,000,000	$ 37,500,000	$ 50,000,000

Schedule Impact Rating	Schedule Impact Value (Impact to Affected Summary Activity)	Min Schedule Impact (QRA)	Most Likely Schedule Impact (QRA)	Max Schedule Impact (QRA)
1	Less than 30 days	0	15	30
2	Between 30 and 60 Calendar days	30	45	60
3	Between 60 and 90 Calendar days	60	75	90
4	Between 90 and 150 calendar days	90	120	150
5	Between 150 and 210 calendar days	150	180	210

Other Impact Rating	Other Effect on Project (Regulatory/Legal, Safety, Company Reputation and Quality) - more details below
1	No impact
2	Minimal Impact
3	Moderate Impact
4	Significant Impact
5	Severe Impact

Other Impact Value	IMPACT (Effect on Project)
1	Has no impact on (**Company Reputation**)
	Has no impact on quality (**Quality**)
	Not likely to result in injury or illness (**Safety**)
	No impact on timely CPCN or full cost recovery (**Regulatory/Legal**)
2	Has limited impact on (**Company Reputation**)
	Quality issue has minimal impact on project (**Quality**)
	Has a direct, minor impact on a near miss driver, an OSHA RA driver, or human error mechanism. Is an emerging
	CPCN delayed by less than 1 month and/or cost disallowance up to $7,500,000 (**Regulatory/Legal**)
3	Has moderate impact on (**Company Reputation**)
	Quality issue affects work activities and requires application of the corrective action program (**Quality**)
	Will create a near miss driver, an OSHA RA driver, or human error mechanism. An emerging safety issue where a
	CPCN delayed between 1-3 months and/or cost disallowance between $7,500,000 and $12,500,000
4	Has significant impact on (**Company Reputation**)
	Quality issue requires immediate management attention (**Quality**)
	Will create a near miss driver, an OSHA RA driver, or human error mechanism. No workaround is present.
	CPCN delayed between 3-5 months and/or cost disallowance between $12,500,000 and $20,000,000
5	Has severe impact on (**Company Reputation**)
	Quality issue requires work stoppage (**Quality**)
	Likely to cause one or more deaths (**Safety**)
	CPCN delayed more than 5 months and/or cost disallowance greater than $20,000,000 (**Regulatory/Legal**)

* The Project manager should establish clear thresholds for financial impact at the outset of the project. These should be articulated in the Project Execution Plan and be approved in accordance with the provisions of the Project Management Manual.

ENTERGY ARKANSAS, INC.

WHITE BLUFF

DSI COST ESTIMATE BASIS DOCUMENT

SL-014000
Final, Rev. 0
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Project 13027-002

Prepared by

Sargent & Lundy LLC

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CONTENTS

1. PURPOSE

Entergy has requested that Sargent & Lundy (S&L) evaluate installation of a new dry sorbent injection (DSI) system on the units at White Bluff to control sulfur dioxide (SO_2) emissions. The purpose of this document is to define the project scope and identify the assumptions that were used as the basis for the operating and maintenance (O&M) and the capital cost estimates.

2. TECHNOLOGY DESCRIPTION

DSI is a proven technology, which has only recently been implemented, for moderate removal of SO_2 and other acid gases from coal-fired power plants. It involves injection of sodium-based sorbents into the ductwork after the boiler and prior to the particulate collection device. DSI is a relatively low capital cost, moderate SO_2 removal alternative to wet or dry FGD systems. No slurry equipment or separate reactor vessel is required with a DSI system. With the proper temperature profile and stoichiometry, the sorbent can effectively react with $SO_2$and other acid gases in the flue gas. The resulting particulate matter is removed from the flue gas by a particulate collection device, typically an existing electrostatic precipitator (ESP).

The typical DSI sorbents include sodium bicarbonate ($NaHCO_3$) and Trona ($Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O$). Sorbent injection into the ductwork (downstream of the boiler and upstream of the ESP) has been tested in the industry using sodium-based sorbents. The process works through neutralization of SO_2 and other acid gases with the caustic sorbent; the neutralization occurs as long as the sorbent remains in contact with the gas. Sorbent injection has been proven effective on a variety of pulverized coal-fired boilers using a range of low to high sulfur coals. It is considered a commercial technology although with a limited supplier base due to the historically limited interest.

The DSI process produces a dry byproduct which can be landfilled. The waste products will contain sodium sulfate and sulfite ($NaSO_3$/$NaSO_4$) along with the unused sorbent and the normal fly ash. These wastes will be collected in the ESP and can be transported with conventional pneumatic fly ash handling equipment. The waste from sodium-based sorbents will have relatively high concentrations of soluble salts, which may affect the byproduct handling. With the addition of dry sorbent byproducts fly ash cannot be sold for reuse.

3. APPROACH

The project capital and O&M cost estimates are based on project-specific information, including:

- An engineer-procure-construct (EPC) contracting strategy with the DSI technology supplier providing the main process equipment, including reagent storage, milling, conveyance, and injection lances.
- Reagent injection at the air preheater (APH) outlet, upstream of the existing ESP. The cost to rebuild/upgrade the ESP was included to ensure there is no increase in PM emissions as a significant quantity of reagent will be added upstream of the existing ESP.
- On-site disposal of DSI byproduct using upgraded ESP ash handling equipment. The byproduct will be collected in the existing ESP in conjunction with the fly ash from the units; no additional blending equipment is required.
- Reagent injection rates based on 50% SO_2 removal from a design inlet concentration of 0.76 lb SO_2/MMBtu, based on the highest 5% of SO_2 emissions from 2009 through 2013.
  - Annual operating costs will be based on 50% SO_2 removal from an uncontrolled SO_2 rate of 0.57 lb SO_2/MMBtu, based on the annual heat input weighted average emission from 2009 through 2013.
  - The system will be designed to control emissions to meet a permit limit of 0.35 lb/MMBtu on a 30-boiler day rolling average, based on a maximum 30-day average SO_2 emission rate of 0.66 lb/MMBtu from 2014 through 2016.
- Trona was used as the DSI reagent for the purposes of this estimate.
- Increase in carbon consumption by 1 lb/mmacf to mitigate any impacts on mercury performance associated with ACI/DSI interference and mitigate potential for a brown plume.
- A high level conceptual system design, based on the estimated injection rate, was used as input to the DSI cost estimate. The following were estimated based on previous projects and scaled for the predicted dry sorbent injection rate for White Bluff:
  - Auxiliary power consumption
  - Annual reagent consumption
  - Additional carbon consumption
  - Additional water consumption
  - Additional waste production
  - Reagent storage silos
  - Quantity of mills
  - Quantity of blower trains

The total plant capital cost estimate includes the following:

- Equipment and material
- Installation labor
- Indirect field costs
- Freight
- General and Administration
- Erection contractor profit
- Engineering, Procurement and Project Services
- Spare parts/initial fills (other than reagent)
- EPC Fee

As part of this project, S&L estimated the costs for Owner's services and costs outside of the EPC contract including the following:

- Owner's Costs
- Owner's Engineer
- Construction Management Support
- Startup and Commissioning Support
- Performance Testing
- Contingency
- Escalation
- Interest During Construction

Cost Estimate 34018A provided in Attachment 1 represents the total cost to Entergy to install DSI technology on a single unit at White Bluff (Unit 1 or 2) including the EPC Contract price and all additional Owner's costs and third party services.

The total unit O&M cost estimate includes the following:

- Waste disposal (DSI waste + increased carbon + unsold fly ash)
- Loss of revenue from fly ash sales
- Reagent consumption (including increased carbon consumption)
- Auxiliary power consumption
- Low quality water consumption for mill cleaning
- Operating labor
- Maintenance material
- Maintenance labor

The O&M Cost Estimate and Capital Cost Estimate 34018A were developed using the assumptions and scope provided in this document. The project definition and accuracy corresponds to a study level estimate as defined in U.S.EPA's Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual. The costs provided in this report are in 2016 dollars.

4. CAPITAL AND O&M COST ESTIMATE TECHNICAL BASIS

4.1 DESIGN INPUTS AND ASSUMPTIONS

The following assumptions were made for the design basis for the White Bluff DSI Systems:

- Design SO_2 inlet concentration of 0.76 lb SO_2/MMBtu.
- SO_2 inlet concentration of 0.57 lb SO_2/MMBtu for annual operating costs.
- Design SO_2 removal efficiency of 50% (defined by injection rate, described in Section 4.1.1)
- Annual capacity factor of 71.2% (annual average capacity factor for White Bluff Units 1 and 2 based on historical heat input from 2009 through 2013).
- Reagent injection at the APH outlet, upstream of the existing ESP.
- Reagent delivery by rail.
- Existing activated carbon silo storage time will be reduced, rather than adding additional or larger storage silos to the system.
- Compliance deadline of three years from the effective date of the rule.

Before proceeding with a DSI project, a demonstration test should be completed at White Bluff to confirm the feasibility of DSI technology at White Bluff and quantify the potential BOP impacts associated with the project, such as impacts to the ESP performance, interference with mercury control technologies, and leachability of the byproduct.

4.1.1 ESP/Ash Handling Modifications

The DSI system, as defined in this report would require an estimated Trona injection rate of approximately 22,000 lb/hour to achieve 50% reduction at the design SO_2 inlet concentration. This injection rate would result in an increase in the particulate loading to the ESP of almost 40% from the current ash loading, due to the DSI byproducts and unreacted DSI reagent.

The addition of sodium compounds to the fly ash lowers the overall resistivity of the particulate being captured as well as shifting the particle size distribution. These changes have been shown to improve the removal efficiency of an ESP; in some cases this increase has been shown to offset the increased particulate loading to the ESP.

ESP performance can also be negatively impacted by a significant increase in particulate loading associated with the high reagent injection rates required for SO_2 control. It is uncertain whether modifications to the ESPs and ash handling systems would be required to accommodate the addition of DSI at White Bluff. However, at the very high injection rates expected for this project, an ESP rebuild will likely be required to ensure the PM emissions stay below the PSD threshold. Therefore, the capital cost estimate includes the costs to completely rebuild the existing ESPs and ash handling systems at White Bluff.

The size and condition of the existing ESP can play a critical role in the overall performance of DSI. In order to evaluate the existing White Bluff ESP with respect to future operation with DSI, S&L used the EPA program ESPVI 4.0W Performance Prediction Model (ESPVI 4.0W) to simulate the baseline and future operating scenarios, as described below. In addition, S&L contacted an ESP vendor to provide input relating to installation of DSI upstream of the existing ESPs at White Bluff.

The baseline operation was established using various design inputs for the units (as needed by the ESPVI 4.0W model), recent operating data and stack emissions to estimate the efficiency at which the ESP is currently operating. ESPVI 4.0W showed that at the baseline operating conditions the White Bluff ESP operates at approximately 99.7% removal of the total inlet loading, corresponding to a filterable PM emission limit of 0.0155 lb/MMBtu.

ESPs operate at a constant efficiency assuming the operating conditions (such as temperature, ash resistivity, or flue gas velocity) stay the same. DSI can impact some of the operating conditions, specifically ash resistivity and particle size distribution. The addition of DSI thus could result in a higher efficiency than the same ESP, without DSI, could achieve.

The ESPVI 4.0W model was developed prior to the introduction of DSI technology and has not been updated to account for the impacts of adding sorbents upstream of the ESP. However, the model was used to predict the high level impact and/or limitations of installing DSI technology by modifying some of the inputs to simulate the characteristics of a fly ash/sodium sorbent mixture.

Based on the modified ash resistivity and adjusted particle sizes associated with the addition of DSI, the baseline ESPVI 4.0W model was used to estimate the predicted removal efficiency for the White Bluff ESP with DSI, as defined in this report, and assuming all other operating conditions remained the same. ESPVI 4.0W showed an overall removal efficiency which was very similar to the current ESP removal efficiency and resulted in an increase in particulate emissions with the additional loading from the DSI system.

Based on the results from ESPVI 4.0W, the White Bluff ESP may be operating at a marginally higher reduction efficiency with the installation of DSI; however, the loading to the ESP is also increasing significantly. Therefore, the modeling showed that even though the ESP efficiency may increase, the overall PM emissions will still be higher than the current level. This evaluation supports the conclusion that improvement of the existing ESP in conjunction with the DSI project is necessary to avoid increasing PM emissions.

In addition to the modeling that was performed using ESPVI 4.0W, S&L also engaged a vendor experienced with ESP retrofits to provide costs and expertise associated with injection of DSI on an existing ESP. As part of their budgetary quote, the supplier indicated that "while the ESPs are large they are still an efficiency machine and overcoming the new total inlet loading of over 73,000 lb/hr[1] will be extremely difficult to achieve the requested 0.015 lbs/MMBtu outlet PM emissions, without retrofitting the entire ESPs to BART technology. Essentially, the ESPs will need to be rebuilt to 'as-new' condition with the most state-of-the-art technology options" (see Attachment 2).

Finally, in addition to the performance of the ESP, the increased loading will also have an impact on the ash handling system. Therefore, for the purposes of this cost estimate, based on the significant increase in loading, modifications to the ash handling equipment were included in the cost estimate.

4.1.2 Landfill Modifications

The sodium byproducts (salts) that are produced when Trona reacts with SO_2 and other acid gases, along with the unreacted sorbent are soluble in water. The resulting waste collected in the particulate collection device will need to be disposed of in a landfill that is lined and has a leachate collection system. With the addition of DSI, White Bluff will no longer be able to sell their fly ash for beneficial re-use due to the solubility of the sodium salts which would be

[1] The 73,000 lb/hr loading reflects the design fly ash loading plus the additional loading from the DSI injection (byproduct/unreacted sorbent).

present in the waste. The cost to maintain a landfill and open new cells is included in the typical maintenance budget of a plant. It was assumed, that any future landfill cells would include lining and leachate collection; therefore, no landfill modifications will be required to accommodate the addition of DSI and no costs were included in this estimate.

4.2 TOTAL INSTALLED CAPITAL INVESTMENT

The DSI system supplier will provide all of the equipment related to storing, milling, conveying and injecting the reagent; in this case, the system is designed for Trona. The remaining BOP scope will be provided by the EPC Contractor. In addition, the EPC Contractor will install/construct the entire system including the equipment provided by the DSI system supplier.

Quantities were developed based on limited project design effort, project experience of a plant of comparable size and then adjusted based on actual size and capacity differences and also taking into consideration the specific site layout based on the general arrangement. In most cases, the costs for bulk materials and equipment were derived from S&L database and recent vendor or manufacturer's quote for similar items on other projects. The scope of work for the capital cost estimate is broken out by the following areas:

4.2.1 DSI Area (Single Unit)

a. Reagent Storage Silos:
- Twelve silos capable of storing approximately 14 days of sorbent per unit, 4,200-tons storage total, including substructure
- 14' diameter and 125' high, each
- 350-tons working storage, each
- Continuous level detection systems
- One bin vent filter per silo
- Live bottom hopper outlets
- Rotary airlock assemblies

b. Reagent conveying systems:
- 4 trains (4 x 50%)
- Pneumatic pressure blowers (1 x100% per train)
- One dehumidifier and chiller per train

c. Reagent Milling
- One 7-tph mill per train
- One set of bypass piping per mill

d. Reagent Injection
- Splitters with piping to two APH outlets
- Six injection lances per injection location

e. Concrete foundations including piles for all reagent silo, blower, and mill areas; the approximate footprint for DSI Area is 165’ x 125’

f. Buildings, enclosures, and roofs, including:
   - Blower Building, approximately 25’ x 100’
   - Electrical Building; approximately 15’ x 20’
   - Mill Building; approximately 40 x 80’
   - Dehumidifier Roof; approximately 30’ x 125’
   - Heat Exchanger Roof; approximately 10’ x 80’

g. Geotechnical and subsurface investigation contractor work, including hydro excavation

h. Equipment pricing based on recent vendor pricing for a similar project.

4.2.2 Reagent Handling System

The conceptual design basis for the reagent handling system is to unload two cars at a time. Based on the estimated injection rate and typical railcar capacities, it is anticipated that approximately 20 railcars will be required each week per unit assuming a 100% capacity factor. The reagent handling system includes modification to the existing rail spur on-site to accommodate storage and handling of the reagent railcars. It was assumed that the reagent will be delivered via a 25-car unit train as a maximum. The following equipment and components are included in the cost estimate as part of the reagent handling system:

a. Reagent rail car unloader:
   - System consists of mobile receiving pad and associated vacuum pneumatic connection equipment to unload railcar
   - Enclosed railcar unloading building; approximately 200’ x 75’
   - Trackmobile used to haul and queue the rail cars before and after unloading; capable of moving approximately 25 cars at once.

b. Reagent unloading systems:
   - Two trains (2 x 100%)
   - Pneumatic pressure blowers (1 x 100%) per train
   - One conveying air dehumidifier and chiller per train
   - Pneumatic conveying piping located on an above-grade sleeper pipe rack
   - The equipment pricing included in this estimate is based on recent firm pricing for similar projects. The basis of the conceptual design is a typical UCC arrangement and equipment.

c. Rail track spur extension to north to allow reagent train to be unloaded and cars to be stored on site, designed for 136 lb rail to be consistent with existing coal spurs

4.2.3 ESP/Ash Handling Modifications

a. ESP Rebuild – Based on the budgetary quote provided in Attachment 2.

b. Ash Handling Modifications – Equipment pricing based on recent vendor pricing for a similar project.

4.2.4 Civil Work

a. Site grading

b. Soil removal earthwork

c. Excavation, backfill, and compaction for all foundations

d. Development of a new laydown area, approximately 2 acres, including site preparation, fencing, and temporary power. It was assumed that this area would be located on existing plant property, and does not require land to be purchased.

4.2.5 Mechanical Work

a. Allowance of $975,000 provided for mechanical system including transport piping, pipe rack, instrument/service air and other miscellaneous items based on recent in-house cost estimates for similar projects.

4.2.6 Demolition/Relocation

a. Allowance of $650,000 is provided for demolition and relocation of existing equipment and infrastructure which may interfere with the new DSI system based on recent in-house cost estimates for similar projects.

4.2.7 Electrical

a. Allowance of $3,575,000 is provided for electrical equipment upgrades and modifications based on recent in-house cost estimates for similar projects.

4.2.8 Instrumentation

a. Allowance of $520,000 provided for DCS upgrades and added instrumentation based on recent in-house cost estimates for similar projects.

4.2.9 Labor Costs

Installation/labor costs were included in the base estimate under the direct costs. Manhours are estimated for each item in the base estimate and are based on the type of work and typical estimates for similar work. The labor costs are based on the labor wage rates and labor crews developed by S&L.

a. Labor Wage Rates

Crew labor rates were developed using prevailing craft rates and fringe benefits and state specific worker's compensation rates as published in the 2016 edition of R.S. Means Labor Rates for Pine Bluff, Arkansas area. Costs were added to cover FICA, workers compensation, all applicable taxes, small tools, incidentals, construction equipment, and contractor's overhead. State specific workman's compensation rates are from R.S. Means. A 1.15 geographic labor productivity multiplier is included based on the Compass International Construction Yearbook for Arkansas. The crew rates do not include an allowance for weather related delays.

b. Labor crews

Construction/erection labor cost is based on the use of applicable construction crews typically required for projects of this type. The construction crew costs were specifically developed for utility industry and are proprietary to S&L. The prevailing craft rates are incorporated into work crews appropriate for the activities; and include costs for small tools, construction equipment, insurance, and site overheads.

4.2.10 Other Direct and Construction Indirect Costs

In addition to the base labor costs, other construction indirect costs for the project were broken out in the estimate as well as other contractor direct costs. The following items were included as other direct and construction indirect costs.

a. Scaffolding and Consumables
b. Premiums and per diems ($10 per hour)
c. Overtime at five 10-hour shifts per week
d. Freight on construction materials
e. Contractor's General & Administration Fees (included at 10% of total direct costs)
f. Contractor's Profit (included at 5% of total direct costs)
g. Sales tax was included in the cost estimate at 8.125%.

Freight on the DSI System equipment was not included in the cost estimate.

4.2.11 EPC Indirect Costs

The final contribution to the overall EPC project price are the EPC Contractor's indirect costs; these include the EPC engineering services, startup spare parts and initial fills, technical field advisors, and the EPC risk fee.

a. EPC Engineering Services

The EPC engineering services was estimated based on recent projects with similar scopes and schedules. The total cost of the EPC engineering services was estimated to be $4,000,000.

b. Startup Spare Parts and Initial Fills

An allowance has been included for initial fills for equipment, including first fills for lubrication of any motorized equipment. The initial fill of Trona was not included in the EPC Contractor's scope, as this will be supplied by the Owner and is covered as part of the Owner's Costs. The total cost of the initial fills was estimated to be $75,000.

c. Technical Field Advisors (Vendors)

Allowances were included for equipment supplier's technical field advisory services based on an estimated 150 man-days. The estimate includes technical field advisors for the DSI system supplier (including DSI system subcontractors) and the DCS supplier. The total cost of the technical field advisors was estimated to be $300,000.

d. EPC Risk Fee

An EPC approach provides an alternative which is expected to reduce risk for Entergy by placing the responsibility for the project on a single entity, the EPC Contractor. The EPC risk fee is a premium charged by the contractor which accounts for the additional coordination and management of the project as well as the additional risk assumed by the contractor. Based on S&L's experience with recent EPC projects, an EPC risk fee was included at 10% of the total EPC project costs.

4.2.12 Owner's Costs and Services

Outside of the EPC Contractor's total cost, Entergy will incur other costs associated with the project, such as services procured from third parties (including Owner's engineer, construction management support, startup and commissioning support and performance testing), and other project related costs.

a. Owner's Costs

Owner's Costs are direct costs that the Owner incurs over the life of the project. The following items are real costs Entergy will incur to install DSI at White Bluff based on the scope and schedule of this project:

- Internal Labor
- Internal Indirects
- Travel Expenses
- Legal Services
- Builders Risk Insurance
- Initial Fills (Reagent)

Owner's costs were included in the estimate at 8% of the total project cost.

b. Construction Management Support

The construction management support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform the tasks, and therefore it will be outsourced. The cost of labor is based on present day cost. The total cost of the construction management support was estimated to be $1,500,000.

c. Startup and Commissioning Support

The startup and commissioning support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform the tasks, and therefore it will be outsourced. The total cost of the startup and commissioning support was estimated to be $300,000.

d. Owner's Engineer

The Owner's Engineer cost was developed as a high level estimate based on a typical scope for Owner's Engineer work for this type of project; including the following tasks:

- Conceptual Study Support
- EPC Specification Supporting Documents
- Project Schedule Development
- EPC Specification Development
- EPC Bid Evaluation and Contract Conformance
- General Project Support
  - Monthly Project Status Meetings
  - Weekly Teleconferences
  - Overall Coordination
  - Project Administration
  - Site Visits and Travel
- Permitting Support
- Design Review of Drawing Submittals
- Technical support during design, fabrication, construction, commissioning, and testing
- Equipment vendor QA/QC audits

The total cost of the Owner's Engineer was estimated to be $1,750,000.

e. Performance testing

The cost for performance testing was developed as a factored estimate using costs from projects of similar scope. This cost includes the testing, performed by a third-party contractor hired by the Owner, and also includes the cost for S&L's assistance in the following tasks:

- Development of the test protocol
- Procuring the services of the testing contractor
- Overseeing the performance test campaign
- Evaluating the results of the testing with respect to guarantee compliance

The estimate for the third party testing contractor is based on the assumption that the contractor would be onsite for up to 3 days. The total cost of the Performance Testing was estimated to be $175,000.

f. Contingency

Contingency is included in the estimate to cover the uncertainty associated with the project costs. The cost estimate includes a recommended contingency of 25%, which is consistent with cost estimating guidelines for a conceptual design and the current level of project definition. Contingency was applied to the total project costs before escalation.

g. Escalation

Escalation was included in the estimate based on a typical schedule for implementation of a DSI system at an escalation rate of 2.15% on equipment and materials and 3.35% on labor and indirects. These escalation rates were developed by S&L based on recent pricing and in-house escalation projections.

h. Interest During Construction

Interest during construction (IDC) accounts for the time value of money associated with the distribution of construction cash flows over the construction period. IDC was applied to the total EPC project costs including contingency. The IDC was calculated based on a typical schedule for implementation of a DSI system and a typical interest rate of 7.8% per year which was assumed based on a low interest market environment.

4.3 VARIABLE OPERATING AND MAINTENANCE COSTS

The following unit costs were used to develop the variable O&M costs for each reagent specific system. All of these values, with the exception of the reagent costs, were provided by Entergy. The reagent costs are based on recent pricing received by S&L for another project.

Table 4-1: Unit Pricing for Utilities (Provided by Entergy)

Unit Cost	Units	Value
Trona	$/ton	$205
Activated Carbon	$/ton	$1,700
Low Quality Water	$/1000 gal	$0.53
Byproduct Disposal	$/ton	$7.50
Fly Ash Revenue	$/ton	$5.85
Aux Power Cost [1]	$/MWh	$41.02

Note 1: Entergy provided auxiliary power costs for the first year of operation.

Table 4-2 below summarizes the consumption rates estimated as well as the first year variable O&M costs for each case. The reagent consumption rate was developed using a normalized stoichiometric ratio (NSR) of 1.3 which is consistent with test data for similar projects.

Table 4-2: Variable O&M Rates and First Year Costs

	Units	Value
DSI System Parameters		
Reagent Consumption	lb/hr	16,500
Increased Carbon Consumption	lb/hr	210
DSI Waste Production + Increased Carbon + Unsold Fly Ash[3]	lb/hr	40,700
Aux Power Consumption	kW	1,700
Low Quality Water Consumption	gpm	4

	Units	Value
First Year[1] Variable O&M Costs (@CF[2])		
Reagent Cost	$/year	$10,548,500
Waste Disposal Cost (DSI Waste + Increased Carbon + Unsold Fly Ash)	$/year	$951,900
Increased Carbon Consumption Cost	$/year	$1,113,000
Aux Power Cost	$/year	$434,900
Low Quality Water Cost	$/year	$800
Loss of Fly Ash Sales[3]	$/year	$496,000
Total First Year Variable O&M Cost	**$/year**	**$13,545,100**

Note 1: First year costs are provided in $2016.

Note 2: The first year costs are calculated using an annual capacity factor of 71.2%.

Note 3: Assumes 57% of the station's fly ash was being sold on an annual basis for an average of approximately $5.85 per ton (based on historical data from Entergy).

4.4 FIXED O&M COSTS

The fixed O&M costs for the systems consist of operating personnel as well as maintenance costs (including material and labor). The recommended staffing additions for the DSI system are 9 personnel for one system.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (maintenance and labor) were estimated to be approximately 0.3% of the project capital. Items such as track work and civil work would be considered high capital cost items with little to no maintenance. Table 4-3 below summarizes the first year fixed O&M costs for the design and typical cases.

Table 4-3: First Year Fixed O&M Costs

First Year[1] Fixed O&M Costs	**Units**	**Value**
Operating Labor[2]	$/year	$1,066,000
Maintenance Material	$/year	$180,000
Maintenance Labor	$/year	$120,000
Total First Year Fixed O&M Cost	**$/year**	**$1,366,000**

Note 1: First year costs are provided in $2016.

Note 2: Operating labor costs are based on a labor rate of $56.95, which was provided by Entergy.

Note 3: Installation of systems on a single unit would require 9 operators total.

5. ATTACHMENTS

1. White Bluff Station DSI System EPC Conceptual Cost Estimate, Sargent & Lundy Estimate No. 34018A
2. ESP Rebuild Budgetary Quote

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
DSI SYSTEM EPC

Estimator	A. KOCI
Labor rate table	16ARPBL
Project No.	13027-004
Estimate Date	10/20/2016
Reviewed By	MNO
Approved By	MNO
Estimate No.	34018A
Cost index	ARPBL

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
DSI SYSTEM EPC

Area	Description	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Total Cost
101	UNIT 1 OR 2 (SINGLE UNIT) DSI AREA	3,359,550	15,000,000	527,160	18,441	11,107,036	29,993,746
102	REAGENT HANDLING SYSTEM	1,505,400	1,360,000	1,218,523	26,487	1,956,963	6,040,885
103	ESP/ASH HANDLING MODIFICATIONS	50,000,000	1,050,000		9,885	680,982	51,730,982
104	EARTHWORK			79,496	2,169	183,755	263,251
105	UPGRADE PLANT ENTRANCE						
106	LAYDOWN AREAS			156,000	1,839	146,722	302,722
107	MECHANICAL MISCELLANEOUS	975,000					975,000
108	DEMOLITION / RELOCATION COSTS	650,000					650,000
109	ELECTRICAL	3,575,000					3,575,000
110	INSTRUMENTATION	520,000					520,000
	TOTAL DIRECT	60,584,950	17,410,000	1,981,179	58,822	14,075,457	94,051,586

Estimate Totals

Description	Amount	Totals	Hours
Direct Costs:			
Labor	14,075,457		58,822
Material	1,981,179		
Subcontract	60,584,950		
Process Equipment	17,410,000		
	94,051,586	**94,051,586**	
Other Direct & Construction Indirect Costs:			
91-1 Scaffolding	985,000		
91-2 Cost Due To OT 5-10's	1,859,000		
91-4 Per Diem	588,000		
91-5 Consumables	141,414		
91-6 Freight on Material	99,000		
91-8 Sales Tax	2,384,000		
91-9 Contractors G&A	1,990,000		
91-10 Contractors Profit	994,000		
	9,040,414	**103,092,000**	
Indirect Costs:			
93-1 Engineering Services	4,000,000		
93-4 SU/S Parts/ Initial Fills	75,000		
93-5 Technical Field Advisors	300,000		
93-8 EPC Fee	10,747,000		
	15,122,000	**118,214,000**	
Escalation:			
96-1 Escalation on Material	137,000		
96-2 Escalation on Labor	1,693,000		
96-3 Escalation on Subcontract	5,238,000		
96-4 Escalation on Process Eq	926,000		
96-5 Escalation on Indirects	1,261,000		
	9,255,000	**127,469,000**	
Total EPC Cost		***127,469,000***	
Owner's Costs:			
99-1 Owner's Costs	9,457,000		
	9,457,000	**136,926,000**	
Third Party Services:			
100 CM Oversight	1,500,000		
101 Start-Up Oversight	300,000		
102 Owner's Engineer	1,750,000		
103 Performance Testing	175,000		
	3,725,000	**140,651,000**	
Project Contingency :			
110 Project Contingency	32,851,000		
	32,851,000	**173,502,000**	
Escalation Addition:			
120 Escalation on Lines 99-110	960,000		
	960,000	**174,462,000**	
Interest During Construction:			
130 Interest During Constr.	15,649,000		
	15,649,000	**190,111,000**	
Total		***190,111,000***	

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
101			**UNIT 1 OR 2 (SINGLE UNIT) DSI AREA**									
	21.00.00		**CIVIL WORK**									
		21.53.00	**PILING**									
			AUGER CAST GROUT PILE, 18 IN DIA BY 80 FT LONG	DSI AREA FOUNDATIONS INCLUDING REAGENT SILOS	323.00 EA	1,162,800	-	-		108.88 /MH		1,162,800
			PILE - MOB/DEMOB		1.00 LS	100,000	-			108.88 /MH		100,000
			PILING			**1,262,800**						**1,262,800**
		21.98.00	**CIVIL WORK,TESTING**									
			AUGER CAST GROUT PILE - TESTING		1.00 LS	65,000	-	-		-	-	65,000
			CIVIL WORK,TESTING			**65,000**						**65,000**
			CIVIL WORK			**1,327,800**						**1,327,800**
	22.00.00		**CONCRETE**									
		22.13.00	**CONCRETE**									
			CONCRETE FOUNDATIONS - COMPOSITE RATE	DSI AREA FOUNDATIONS INCLUDING REAGENT SILOS	2,292.00 CY	-	-	527,160	18,441	60.03 /MH	1,107,036	1,634,196
			CONCRETE					**527,160**	**18,441**		**1,107,036**	**1,634,196**
			CONCRETE					**527,160**	**18,441**		**1,107,036**	**1,634,196**
	23.00.00		**STEEL**									
		23.25.00	**ROLLED SHAPE**									
			BUILDING MIX, TWO COAT PAINTED		TN	-	-			93.00 /MH		
	24.00.00		**ARCHITECTURAL**									
		24.35.00	**PRE-ENGINEERED BUILDING**									
			SHELL INCLUDING ELECTRICAL & HVAC-STEEL INSULATED 22 GA	BLOWER BUILDING 25 FT X 100 FT	2,500.00 SF	500,000	-			93.00 /MH		500,000
			SHELL INCLUDING ELECTRICAL & HVAC-STEEL INSULATED 22 GA	ELECTRICAL BUILDING 15 FT X 20 FT	300.00 SF	105,000	-			93.00 /MH		105,000
			SHELL INCLUDING ELECTRICAL & HVAC-STEEL INSULATED 22 GA	MILL BUILDING 40 FT X 80 FT	3,200.00 SF	640,000	-			93.00 /MH		640,000
			SHELL - ROOF ONLY AREA	DEHUMIDIFIER - 30 FT X 125 FT	3,750.00 SF	318,750	-			93.00 /MH		318,750
			SHELL - ROOF ONLY AREA	HEAT EXCHANGER - 10 FT X 80 FT	800.00 SF	68,000	-			93.00 /MH		68,000
			PRE-ENGINEERED BUILDING			**1,631,750**						**1,631,750**
		24.37.00	**ROOFING**									
			METAL, INSULATED, 2 IN GALVANIZED, PAINTED, 22 GA	DSI AREA ENCLOSURE ROOF	SF	-	-			35.25 /MH		
		24.41.00	**SIDING**									
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	DSI AREA ENCLOSURE SIDING	SF	-	-			79.98 /MH		
		24.99.00	**ARCHITECTURAL, MISCELLANEOUS**									
			HEATING	DSI AREA	SF	-	-			64.51 /MH		
			LIGHTING	DSI AREA	SF	-	-			82.56 /MH		
			FIRE PROTECTION	DSI AREA	SF	-	-			82.56 /MH		
			ARCHITECTURAL			**1,631,750**						**1,631,750**
	31.00.00		**MECHANICAL EQUIPMENT**									
		31.99.00	**MECHANICAL EQUIPMENT, MISCELLANEOUS**									
			DSI SYSTEM EQUIPMENT	EQUIPMENT COST FOR UNIT 1 OR 2 (SINGLE UNIT)	1.00 LS		15,000,000	-		/MH	10,000,000	25,000,000
			STORAGE SILOS WITH BIN VENT FILTERS (~14 DAYS STORAGE)	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			BLOWERS, HEAT EXCHANGERS, DEHUMIDIFIERS	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			MILLING EQUIPMENT	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			PIPING SYSTEMS	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			COMPRESSORS	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			FLOW MODELING	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			MECHANICAL EQUIPMENT, MISCELLANEOUS				**15,000,000**				**10,000,000**	**25,000,000**
			MECHANICAL EQUIPMENT				**15,000,000**				**10,000,000**	**25,000,000**
	71.00.00		**PROJECT INDIRECT**									
		71.25.00	**CONSULTANT, THIRD PARTY**									
			CONSULTANT - SUBSURFACE INVESTIGATION		1.00 LS	250,000	-			/MH		250,000
			CONSULTANT - GEOTECHNICAL		1.00 LS	150,000	-			/MH		150,000

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			CONSULTANT, THIRD PARTY			400,000						400,000
			PROJECT INDIRECT			400,000						400,000
			101 UNIT 1 OR 2 (SINGLE UNIT) DSI AREA			**3,359,550**	**15,000,000**	**527,160**	**18,441**		**11,107,036**	**29,993,746**
102			**REAGENT HANDLING SYSTEM**									
	21.00.00		CIVIL WORK									
		21.14.00	STRIP & STOCKPILE TOPSOIL									
			STRIP & STOCKPILE TOPSOIL - 12"	EXTEND REAGENT RAIL TRACK	90,000.00 SF	-	-		207	182.87 /MH	37,835	37,835
			STRIP & STOCKPILE TOPSOIL						207		37,835	37,835
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK	EXTEND REAGENT RAIL TRACK	10,000.00 SY	-	-	106,500	345	97.70 /MH	33,690	140,190
			EROSION AND SEDIMENTATION CONTROL					106,500	345		33,690	140,190
		21.53.00	PILING									
			AUGER CAST GROUT PILE, 18 IN DIA BY 80 FT LONG	UNLOADING SHED 200' X 75' WIDE	64.00 EA	230,400	-	-	0	108.88 /MH	1	230,401
			PILING			230,400			0		1	230,401
		21.71.00	TRACKWORK									
			RAIL, TIE & BALLAST - 136 LB/YD	EXTEND REAGENT RAIL TRACK	4,500.00 TF	-	-	765,000	7,759	81.75 /MH	634,267	1,399,267
			TRACKWORK					765,000	7,759		634,267	1,399,267
			CIVIL WORK			230,400		871,500	8,310		705,793	1,807,693
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			FOUNDATION, 4500 PSI - COMPOSITE RATE	UNLOADING SHED 200' X 75' WIDE	926.00 CY	-	-	212,980	7,451	60.03 /MH	447,258	660,238
			CONCRETE					212,980	7,451		447,258	660,238
			CONCRETE					212,980	7,451		447,258	660,238
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA,	UNLOADING SHED 200' X 75' WIDE x 20' TALL	15,000.00 SF	1,275,000	-			93.00 /MH		1,275,000
			PRE-ENGINEERED BUILDING			1,275,000						1,275,000
			ARCHITECTURAL			1,275,000						1,275,000
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.14.00	MATERIAL HANDLING EQUIPMENT									
			REAGENT PNEUMATIC TRAIN UNLOADING EQUIPMENT		2.00 LS	-	1,000,000	-	6,611	68.89 /MH	455,466	1,455,466
			MATERIAL HANDLING EQUIPMENT				1,000,000		6,611		455,466	1,455,466
		33.41.00	MOBILE YARD EQUIPMENT									
			MOBILE YARD EQUIPMENT - TRACKMOBILE	REAGENT HANDLING SYSTEM	1.00 EA	-	225,000	-		68.89 /MH		225,000
			MOBILE YARD EQUIPMENT				225,000					225,000
		33.51.00	RAIL CAR UNLOADER									
			RAIL CAR UNLOADER	IN UNLOADING SHED 200' X 75' WIDE	1.00 LT	-	135,000	-	1,862	93.00 /MH	173,172	308,172
			RAIL CAR UNLOADER				135,000		1,862		173,172	308,172
			MATERIAL HANDLING EQUIPMENT				1,360,000		8,474		628,638	1,988,638
	35.00.00		PIPING									
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			8 IN DIA, SCH 40, 8" VACUUM CONVEY PIPING WITH 4 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	250.00 LF	-	-	10,043	270	77.80 /MH	21,015	31,057
			12 IN DIA, 3/8 IN STD- 2500 LF OF 10"/12" TRANSPORT PRESSURE PIPING W 8 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRANSPORT SYSTEM	1,250.00 LF	-	-	124,000	1,983	77.80 /MH	154,259	278,259
			CARBON STEEL, STRAIGHT RUN					134,043	2,253		175,274	309,316
			PIPING					134,043	2,253		175,274	309,316
			102 REAGENT HANDLING SYSTEM			**1,505,400**	**1,360,000**	**1,218,523**	**26,487**		**1,956,963**	**6,040,885**
103			**ESP/ASH HANDLING MODIFICATIONS**									
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.99.00	MATERIAL HANDLING EQUIPMENT, MISCELLANEOUS									
			ESP EQUIPMENT MODIFICATION	FULL REBUILD OF ESP, INCLUDING INSTALLATION COST	1.00 LS	50,000,000	-	-		68.89 /MH		50,000,000

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		33.99.00	MATERIAL HANDLING EQUIPMENT, MISCELLANEOUS									
			ASH HANDLING COMPONENT MODIFICATION	ALLOWANCE	1.00 LS		1,050,000	-	9,885	68.89 /MH	680,982	1,730,982
			MATERIAL HANDLING EQUIPMENT, MISCELLANEOUS			50,000,000	1,050,000		9,885		680,982	51,730,982
			MATERIAL HANDLING EQUIPMENT			50,000,000	1,050,000		9,885		680,982	51,730,982
			103 ESP/ASH HANDLING MODIFICATIONS			50,000,000	1,050,000		9,885		680,982	51,730,982
104			EARTHWORK									
	21.00.00		CIVIL WORK									
		21.14.00	STRIP & STOCKPILE TOPSOIL									
			STRIP & STOCKPILE TOPSOIL - 12"	SITE GRADING ALLOWANCE	30,000.00 SF	-	-		69	182.87 /MH	12,612	12,612
			STRIP & STOCKPILE TOPSOIL - ONSITE	BUILDINGS	600.00 CY	-	-		79	182.87 /MH	14,503	14,503
			STRIP & STOCKPILE TOPSOIL						148		27,115	27,115
		21.17.00	EXCAVATION									
			EXCAVATION - EXCAVATION , BACKFILL & COMPACT ALL FOUNDATIONS	BUILDINGS	2,860.00 CY	-	-		986	79.78 /MH	78,680	78,680
			EXCAVATION						986		78,680	78,680
		21.39.00	STORM DRAINAGE UTILITIES									
			STORM SEWER WORK	SITE GRADING ALLOWANCE	1.00 LT	-	-	44,000	920	72.57 /MH	66,731	110,731
			STORM DRAINAGE UTILITIES					44,000	920		66,731	110,731
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK	SITE GRADING ALLOWANCE	3,333.00 SY	-	-	35,496	115	97.70 /MH	11,229	46,725
			EROSION AND SEDIMENTATION CONTROL					35,496	115		11,229	46,725
			CIVIL WORK					79,496	2,169		183,755	263,251
			104 EARTHWORK					79,496	2,169		183,755	263,251
105			UPGRADE PLANT ENTRANCE									
	21.00.00		CIVIL WORK									
		21.57.00	ROAD, PARKING AREA, & SURFACED AREA									
			UPGRADE PLANT ENTRANCE	WORK NOT REQUIRED	0.00 LF	-	-			78.79 /MH		
106			LAYDOWN AREAS									
	21.00.00		CIVIL WORK									
		21.99.00	CIVIL WORK, MISCELLANEOUS									
			CIVIL WORK - CONSTRUCTION LAYDOWN AREAS	FENCING, POWER ETC...	2.00 AC	-	-	156,000	1,839	79.78 /MH	146,722	302,722
			CIVIL WORK, MISCELLANEOUS					156,000	1,839		146,722	302,722
			CIVIL WORK					156,000	1,839		146,722	302,722
			106 LAYDOWN AREAS					156,000	1,839		146,722	302,722
107			MECHANICAL MISCELLANEOUS									
	31.00.00		MECHANICAL EQUIPMENT									
		31.99.00	MECHANICAL EQUIPMENT, MISCELLANEOUS									
			MECHANICAL EQUIPMENT	INCLUDES PIPE RACK - ALLOWANCE SUBCONTRACT COST	1.00 LS	975,000	-	-		68.89 /MH		975,000
			MECHANICAL EQUIPMENT, MISCELLANEOUS			975,000						975,000
			MECHANICAL EQUIPMENT			975,000						975,000
			107 MECHANICAL MISCELLANEOUS			975,000						975,000
108			DEMOLITION / RELOCATION COSTS									
	11.00.00		DEMOLITION									
		11.99.00	DEMOLITION, MISCELLANEOUS									
			DEMOLITION AND RELOCATION	ALLOWANCE - SUBCONTRACT COST	1.00 LS	650,000	-			107.47 /MH		650,000
			DEMOLITION, MISCELLANEOUS			650,000						650,000
			DEMOLITION			650,000						650,000
			108 DEMOLITION / RELOCATION COSTS			650,000						650,000
109			ELECTRICAL									
	41.00.00		ELECTRICAL EQUIPMENT									
		41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS									
			ELECTRICAL EQUIPMENT, MISCELLANEOUS	ALLOWANCE - SUBCONTRACT COST	1.00 LS	3,575,000	-			64.04 /MH		3,575,000
			ELECTRICAL EQUIPMENT, MISCELLANEOUS			3,575,000						3,575,000
			ELECTRICAL EQUIPMENT			3,575,000						3,575,000
			109 ELECTRICAL			**3,575,000**						**3,575,000**
110			**INSTRUMENTATION**									
	44.00.00		CONTROL & INSTRUMENTATION									
		44.99.00	CONTROL & INSTRUMENTATION, ALLOWANCE									
			CONTROL & INSTRUMENTATION	ALLOWANCE - SUBCONTRACT COST	1.00 LS	520,000	-			65.15 /MH		520,000
			CONTROL & INSTRUMENTATION, ALLOWANCE			520,000						520,000
			CONTROL & INSTRUMENTATION			520,000						520,000
			110 INSTRUMENTATION			**520,000**						**520,000**

27881 Clemens Road
Westlake, OH 44145
Phone: 440.899.3888
Fax: 440.899.3890

October 17, 2016

Sargent & Lundy
Attention: Danielle Flagg
55 East Monroe Street
Chicago, IL 60603

Subject: Fuel Tech, Inc. (FTI) Estimate #16-B-111 Rev1
Confidential Client ESP Retrofit
High Level Estimate

Dear Ms. Flagg,

In response to Sargent & Lundy's (S&L)'s recent request, Fuel Tech, Inc. (FTI), has assembled a high level estimate for the materials and installation necessary to retrofit Sargent & Lundy's "Confidential Client" Electrostatic Precipitators. Please consider the pricing as +/- 30% for high level budgetary estimation purposes.

The ESPs have been evaluated by our engineering staff and the estimate includes the most comprehensive improvements possible. Improvements that we have included in the estimate to increase performance and reliability include all new internals; collecting plates at 16" wide plate spacing, rigid discharge electrodes, top-rapped MIGI rapper conversion with increased rapping sectionalization, increased high voltage frame electrical sectionalization, and the addition of high frequency power supplies.

The estimates and information provided above are based upon FTI's historical information and experience, and should be used for accounting purposes ONLY. Should S&L want to move forward with a more in-depth budgetary proposal, FTI can provide such a document with additional lead-time. Thank you for your interest in our products and services, and we will continue to support Sargent & Lundy's efforts in any way practical for this and other opportunities. Should you require any additional information regarding this submittal, please contact me directly.

Respectfully,

Dustin Ekey
Regional Sales Manager

FTI Budgetary Proposal #16-B-111 Rev 1

Sargent & Lundy Confidential Client ESP Retrofit

Submitted by:

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27881 Clemens Road
Westlake, Ohio 44145
CONFIDENTIAL

EXECUTIVE SUMMARY

<u>Sargent & Lundy – Confidential Client ESP Rebuild Budgetary Request:</u>

In accordance with Sargent & Lundy's RFQ dated September 30, 2016, Fuel Tech, Inc. (FTI) has provided a high level estimate based on historical data to engineer, design, supply, and deliver an ESP Retrofit based on the provided information as follows;

A confidential client is currently evaluating the costs associated with rebuilding an existing ESP. As part of this project, the client will potentially be installing dry sorbent injection (DSI) upstream of the upgraded ESP.

The following summarizes the ESP design of the unit being evaluated:

- PC Walther original OEM installed in the early 1980s.
- Consists of four (4) identical ESP casings, with two (2) casings on top of the other two (2) casings; AKA "Piggybacked".
- Each ESP casing has eight (8) mechanical fields, two (2) mechanical fields wide by four (4) mechanical fields deep.
- Each field is 14' in length and contains forty-four (44) collecting electrodes with forty-three (43) gas passages.
- The collecting electrodes are 48' in height with 12" plate spacing.
- The total collecting surface area is 1,900,000 ft^2.
- Design flue gas flowrate is approximately 3,500,000 acfm, and a design velocity of 5 feet per second.
- The SCA of the existing ESP is approximately 540 ft^2/MMacfm.
- The overall dimension for each ESP is approximately 85'L x 90'W x 50'H.
- Each gas passage has discharge frame electrodes.
- The system is equipped with a Walther tumbling hammer rapper system.
- There are eight (8) T/R sets on each ESP, with a total of thirty-two (32).

ESP rebuild design and performance considerations:

- Achieve an outlet PM emissions rate of 0.015 lb/MMBtu or lower.
- Design inlet ash loading of 55,000 lb/hr.
- Non-halogenated PAC is injected at 150 lb/hr.
- Trona will be injected at 22,500 lb/hr, resulting in an increased particulate loading of 18,200 lb/hr to the ESP.
- Inlet flue gas temperature up to 315 deg F.

Fuel Tech, Inc. – Retrofitted ESP Arrangement and Summary:

While the existing ESPs are considered to be relatively large by industry standards, the design information provided shows that 22,500 lb/hr of Trona will be injected in addition to the existing inlet ash loading is 55,000 lb/hr. With this being said, while the ESPs are large they are still an efficiency machine and overcoming the new total inlet loading of over 73,000 lb/hr will be extremely difficult to achieve the requested 0.015 lbs/MMbtu outlet PM emissions, without retrofitting the entire ESPs to BART technology. Essentially, the ESPs will need to be rebuilt to "as-new" condition with the most state-of-the-art technology options. At the very least, new internals and electrical control systems would require new:

- Assembled Panel Collecting Electrodes
- Rigid Discharge Electrodes
- Top-Rapped MIGI Style Rapper Conversion
- All new Hot Roof, Cold Roof, and Penthouse
- Heated Purge Air Systems
- High Frequency Switch-Mode Power Supplies (SMPS)
- New Access Doors
- All new 3-Phase Electrical Supply Wiring
- New Controllers
- New Hopper Arrangement

Retrofit ESP Arrangement; Quantities are for one (1) ESP, there are four (4) ESPs total:

Number of ESP's / Unit:	4
Mechanical Fields & Size / ESP:	6 @ 9'
Electrical Fields & Size / ESP:	12 @ 4.5'
Chambers / ESP:	2
Gas Passages / Chamber:	33
Collecting Plates / Chamber:	32
Collecting Plate Height:	44'
Plate Spacing:	16"
RDE's / ESP:	1,536
Rapping Arrangment:	Top Rapped – MIGI
Collecting System Rappers / ESP:	176
Discharge System Rappers / ESP:	48
High Frequency Power Supplies / ESP:	16

The amount of planning, engineering, material supply, installation, and installation oversight necessary for a project listed above will be very significant. Pricing estimation can be found below.

High-Level Pricing Estimation for one (1) Confidential Unit including all four (4) ESPs:

Pricing estimate is based upon +/- 30%

The total budgetary estimate to provide ESP materials and engineering: **$ 20,000,000.00**

The total budgetary estimate to provide non-union installation: **$ 30,000,000.00**

*Note: The estimates and information provided above are based upon FTI's historical information and experience, and should be used for accounting purposes ONLY. Should S&L want to move forward with a more in-depth budgetary proposal, FTI can provide such a document with additional lead-time.

ENTERGY ARKANSAS, INC.

WHITE BLUFF

ENHANCED DSI COST ESTIMATE BASIS DOCUMENT

SL-014001
Final, Rev. 0
August 3, 2017
Project 13027-002

Prepared by

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000

CONTENTS

1. PURPOSE

Entergy has requested that Sargent & Lundy (S&L) evaluate installation of an enhanced dry sorbent injection (DSI) system utilizing a baghouse in conjunction with the DSI system at White Bluff to control sulfur dioxide (SO_2) emissions. The purpose of this document is to define the project scope and identify the assumptions that were used as the basis for the operating and maintenance (O&M) and the capital cost estimates.

2. TECHNOLOGY DESCRIPTION

DSI is a proven technology, which has only recently been implemented, for moderate removal of $SO_2$and other acid gases from coal-fired power plants. It involves injection of sodium-based sorbents into the ductwork after the boiler and prior to the particulate collection device. DSI is considered a relatively low capital cost, moderate SO_2 removal alternative to wet or dry FGD systems. No slurry equipment or separate reactor vessel is required with a DSI system. With the proper temperature profile and stoichiometry, the sorbent can effectively react with $SO_2$and other acid gases in the flue gas. The resulting particulate matter is removed from the flue gas by a particulate collection device, typically an existing electrostatic precipitator (ESP). The performance of DSI technology has been shown to be enhanced by implementation with a downstream fabric filter or baghouse. A baghouse increases the overall residence time due to longer ductwork and additional contact through the filter cake which builds up on the bags. The additional residence time improves performance and in some applications has resulted in much higher achievable removal efficiencies than traditional DSI technology upstream of an existing ESP.

The typical DSI sorbents include sodium bicarbonate ($NaHCO_3$) and Trona ($Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O$). Sorbent injection into the ductwork (downstream of the boiler and upstream of the ESP or baghouse) has been tested in the industry using sodium-based sorbents. The process works through neutralization of SO_2 and other acid gases with the caustic sorbent; the neutralization occurs as long as the sorbent remains in contact with the gas. Sorbent injection has been proven effective on a variety of pulverized coal-fired boilers using a range of low to high sulfur coals. It is considered a commercial technology although with a limited supplier base due to the historically limited interest.

The DSI process produces a dry byproduct which can be landfilled. The waste products will contain sodium sulfate and sulfite ($NaSO_3$/$NaSO_4$) along with the unused sorbent and the normal fly ash. These wastes will be collected in a baghouse and can be transported with conventional pneumatic fly ash handling equipment. The waste from sodium-based sorbents will have relatively high concentrations of soluble salts, which may affect the byproduct handling. With the addition of dry sorbent byproducts fly ash cannot be sold for reuse.

3. APPROACH

The project capital and O&M cost estimates are based on project-specific information, including:

- An engineer-procure-construct (EPC) contracting strategy with the DSI technology supplier providing the main process equipment, including reagent storage, milling, conveyance, injection lances, baghouse, and booster fans.
- Installation of a pulse jet fabric filter (PJFF) downstream of the existing ESPs to assist in SO_2 removal efficiency and capture of the DSI byproduct.
- Installation of new booster fans to account for increased draft pressure loss mainly due to the baghouse.
- Reagent injection at the ESP outlet, upstream of a new baghouse to collect flyash separately and preserve flyash sales
- On-site disposal of DSI byproduct, including flyash blending equipment for stabilization.
- Reagent injection rates based on 80% SO_2 removal from a design inlet concentration of 0.76 lb SO_2/MMBtu, based on the highest 5% of SO_2 emissions from 2009 through 2013.
  - Annual operating costs will be based on 80% SO_2 removal from an uncontrolled SO_2 rate of 0.57 lb SO_2/MMBtu, based on the annual heat input weighted average emission from 2009 through 2013.
  - The system will be designed to control emissions to meet a permit limit of 0.15 lb/MMBtu on a 30-boiler day rolling average, based on a maximum 30-day average SO_2 emission rate of 0.66 lb/MMBtu from 2009 through 2013.
- Trona was used as the DSI reagent for the purposes of this estimate.

- A high level conceptual system design, based on the estimated injection rate, was used as input to the Enhanced DSI cost estimate. The following were estimated based on previous projects and scaled for the predicted dry sorbent injection rate for White Bluff:
  - Auxiliary power consumption
  - Annual reagent consumption
  - Additional carbon consumption
  - Additional water consumption
  - Additional waste production
  - Reagent storage silos
  - Quantity of mills
  - Quantity of blower trains

The fabric filter and ID fan equipment costs are scaled based on flue gas volume in comparison to industry data and recent budgetary cost estimates.

The total plant capital cost estimate includes the following:

- Equipment and material
- Installation labor
- Indirect field costs
- Freight
- General and Administration
- Erection contractor profit
- Engineering, Procurement and Project Services
- Spare parts/initial fills (other than reagent)
- EPC Fee

As part of this project, S&L estimated the costs for Owner's services and costs outside of the EPC contract including the following:

- Owner's Costs
- Owner's Engineer
- Construction Management Support
- Startup and Commissioning Support
- Performance Testing
- Contingency
- Escalation
- Interest During Construction

Cost Estimate 34019A provided in Attachment 1 represents the total cost to Entergy to install Enhanced DSI technology on a single unit at White Bluff (Unit 1 or 2) including the EPC Contract price and all additional Owner's costs and third party services.

The total unit O&M cost estimate includes the following:

- Waste disposal (DSI waste)
- Reagent consumption
- Auxiliary power consumption
- Low quality water consumption for mill cleaning
- PJFF bag and cage replacement
- Operating labor
- Maintenance material
- Maintenance labor

The O&M Cost Estimate and Capital Cost Estimate 34019A were developed using the assumptions and scope provided in this document. The project definition and accuracy corresponds to a study level estimate as defined in U.S.EPA's Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual. The costs provided in this report are in 2016 dollars.

4. CAPITAL AND O&M COST ESTIMATE TECHNICAL BASIS

4.1 DESIGN INPUTS AND ASSUMPTIONS

The following assumptions were made for the design basis for the White Bluff DSI Systems:

- Design SO_2 inlet concentration of 0.76 lb SO_2/MMBtu.
- SO_2 inlet concentration of 0.57 lb SO_2/MMBtu for annual operating costs.
- Design SO_2 removal efficiency of 80%
- Annual capacity factor of 72.1% (annual average capacity factor for White Bluff Units 1 and 2 based on historical heat input from 2009 through 2013).
- Reagent injection at the ESP outlet, upstream of the new baghouse.
- Reagent delivery by rail.
- Compliance deadline of three years from the effective date of the rule.

Before proceeding with a DSI project, a demonstration test should be completed at White Bluff to confirm the feasibility of DSI technology at White Bluff and quantify the potential BOP impacts associated with the project, such as leachability of the byproduct.

4.1.1 Landfill Modifications

The sodium byproducts (salts) that are produced when Trona reacts with SO_2 and other acid gases, along with the unreacted sorbent are soluble in water. The resulting waste collected in the particulate collection device will need to be disposed of in a landfill that is lined and has a leachate collection system. With the addition of DSI, White Bluff will no longer be able to sell their fly ash for beneficial re-use due to the solubility of the sodium salts which would be present in the waste. The cost to maintain a landfill and open new cells is included in the typical maintenance budget of a plant. It was assumed, that any future landfill cells would include lining and leachate collection; therefore, no landfill modifications will be required to accommodate the addition of DSI and no costs were included in this estimate.

4.2 TOTAL INSTALLED CAPITAL INVESTMENT

The DSI system supplier will provide all of the equipment related to storing, milling, conveying and injecting the reagent; in this case, the system is designed for Trona. The baghouse area equipment, ID fan equipment, and the remaining BOP scope will be provided by the EPC Contractor. In addition, the EPC Contractor will install/construct the entire system including the equipment provided by the DSI system supplier.

Quantities were developed based on limited project design effort, project experience of a plant of comparable size and then adjusted based on actual size and capacity differences and also taking into consideration the specific site layout based on the general arrangement. In most cases, the costs for bulk materials and equipment were derived from S&L database and recent vendor or manufacturer's quote for similar items on other projects. The scope of work for the capital cost estimate is broken out by the following areas:

4.2.1 DSI Area (Single Unit)

a. Reagent Storage Silos:
- Twenty silos capable of storing approximately 14 days of sorbent per unit, 7,000-tons storage total, including substructure
- 14' diameter and 125' high, each
- 350-tons working storage, each
- Continuous level detection systems
- One bin vent filter per silo
- Live bottom hopper outlets
- Rotary airlock assemblies

b. Reagent conveying systems:
- 5 trains (5 x 33%)
- Pneumatic pressure blowers (1 x100% per train)
- One dehumidifier and chiller per train

c. Reagent Milling
- One 7-tph mill per train
- One set of bypass piping per mill

d. Reagent Injection
- Splitters with piping to two ESP outlets
- Six injection lances per injection location

e. Concrete foundations including piles for all reagent silo, blower, and mill areas; the approximate footprint for DSI Area is 160' x 200'

f. Buildings, enclosures, and roofs, including:
- Blower Building, approximately 25' x 125'
- Electrical Building; approximately 30' x 20'
- Mill Building; approximately 50' x 100'
- Dehumidifier Roof; approximately 30' x 160'
- Heat Exchanger Roof; approximately 10' x 100'

g. Geotechnical and subsurface investigation contractor work, including hydro excavation

h. Equipment pricing based on recent vendor pricing for a similar project.

4.2.2 Reagent Handling System

The conceptual design basis for the reagent handling system is to unload three cars at a time. Based on the estimated injection rate and typical railcar capacities, it is anticipated that approximately 35 railcars will be required each week per unit assuming a 100% capacity factor. The reagent handling system includes modification to the existing rail spur on-site to accommodate storage and handling of the reagent railcars. It was assumed that the reagent will be delivered via a 25-car unit train as a maximum. The following equipment and components are included in the cost estimate as part of the reagent handling system:

a. Reagent rail car unloader:
- System consists of mobile receiving pad and associated vacuum pneumatic connection equipment to unload railcar
- Enclosed railcar unloading building; approximately 300' x 75'
- Trackmobile used to haul and queue the rail cars before and after unloading; capable of moving approximately 25 cars at once.

b. Reagent unloading systems:
- Three trains (3 x 100%)
- Pneumatic pressure blowers (1 x 100%) per train
- One conveying air dehumidifier and chiller per train

- Pneumatic conveying piping located on an above-grade sleeper pipe rack
- The equipment pricing included in this estimate is based on recent firm pricing for similar projects. The basis of the conceptual design is a typical UCC arrangement and equipment.

c. Rail track spur extension to north to allow reagent train to be unloaded and cars to be stored on site, designed for 136 lb rail to be consistent with existing coal spurs

4.2.3 Byproduct Handling

a. Two DSI by-product storage silos (approximately 7-day capacity) with bin vent filter, fluidizing system, and four unloading conditioners (pin mixers)

b. One common fly ash blending bin with bin vent filter, fluidizing system, and four pneumatic airslide conveyors

c. Water pumps and associated piping for unloading conditioners at both silos

d. Compressed air system for air operated valves

e. Storage silo substructure and superstructure

f. Concrete foundations including piles for silos

g. Continuous level detection system

h. One lot pneumatic conveying piping located on an above grade pipe rack

i. Two truck scales and substructure

j. Cost estimate based on a recent budgetary proposal for similar project

4.2.4 Baghouse Area

a. New baghouse, including pulse jet cleaning system and all appurtenances

b. Two casings with 8 compartments

c. 10 meter bags and cages

d. 6” insulation with lagging

e. Enclosure around hopper area

f. Baghouse area foundations including 18” auger cast piles 60’ long

g. Equipment pricing based on recent pricing for similar projects

4.2.5 Ductwork and Supports

a. ID fan outlet to Baghouse inlet:

- Two ID fan outlet ducts, combine to a single duct to carry flue gas to the new baghouse
- Carbon steel, ¼ in.
- Velocity, 3,600 fpm

b. Baghouse outlet to Booster fans
   - A single baghouse outlet duct which splits into two booster fan inlets.
   - Carbon steel, ¼ in.
   - Velocity, 3,600 fpm

c. Booster fan outlet to the stack inlet ductwork and supports:
   - Two booster fan inlets, combine to a single duct which connects to the existing chimney breeching duct.
   - Carbon steel, ¼ in.
   - Velocity, 3,600 fpm

d. Dampers and expansion joints

e. 6" insulation and lagging

f. Steel support structure and concrete mat foundations for all new flue gas ductwork

4.2.6 ID Booster Fans

a. Two, approximately 4,000 hp, axial booster fans sized to overcome pressure drop associated with baghouse

b. Includes motors - no spare motor included

c. Booster fan area foundations

4.2.7 Civil Work

a. Site grading

b. Soil removal earthwork

c. Excavation, backfill, and compaction for all foundations

d. Development of a new laydown area, approximately 4 acres, including site preparation, fencing, and temporary power. It was assumed that this area would be located on existing plant property, and does not require land to be purchased.

4.2.8 Mechanical Work

a. Allowance of $2,600,000 provided for mechanical system including transport piping, pipe rack, instrument/service air and other miscellaneous items based on recent in-house cost estimates for similar projects.

4.2.9 Demolition/Relocation

a. Allowance of $975,000 is provided for demolition and relocation of existing equipment and infrastructure which may interfere with the new DSI system based on recent in-house cost estimates for similar projects.

4.2.10 Electrical

a. Allowance of $16,250,000 is provided for electrical equipment upgrades and modifications based on recent in-house cost estimates for similar projects.

4.2.11 Instrumentation

a. Allowance of $2,210,000 provided for DCS upgrades and added instrumentation based on recent in-house cost estimates for similar projects.

4.2.12 Labor Costs

Installation/labor costs were included in the base estimate under the direct costs. Manhours are estimated for each item in the base estimate and are based on the type of work and typical estimates for similar work. The labor costs are based on the labor wage rates and labor crews developed by S&L.

a. Labor Wage Rates

Crew labor rates were developed using prevailing craft rates and fringe benefits and state specific worker's compensation rates as published in the 2016 edition of R.S. Means Labor Rates for Pine Bluff, Arkansas area. Costs were added to cover FICA, workers compensation, all applicable taxes, small tools, incidentals, construction equipment, and contractor's overhead. State specific workman's compensation rates are from R.S. Means. A 1.15 geographic labor productivity multiplier is included based on the Compass International Construction Yearbook for Arkansas. The crew rates do not include an allowance for weather related delays.

b. Labor crews

Construction/erection labor cost is based on the use of applicable construction crews typically required for projects of this type. The construction crew costs were specifically developed for utility industry and are proprietary to S&L. The prevailing craft rates are incorporated into work crews appropriate for the activities; and include costs for small tools, construction equipment, insurance, and site overheads.

4.2.13 Other Direct and Construction Indirect Costs

In addition to the base labor costs, other construction indirect costs for the project were broken out in the estimate as well as other contractor direct costs. The following items were included as other direct and construction indirect costs.

a. Scaffolding and Consumables

b. Premiums and per diems ($10 per hour)

c. Overtime at five 10-hour shifts per week

d. Freight on construction materials

e. Contractor's General & Administration Fees (included at 10% of total direct costs)

f. Contractor's Profit (included at 5% of total direct costs)

g. Sales tax was included at 8.125%.

Freight on the DSI System equipment was not included in the cost estimate.

4.2.14 EPC Indirect Costs

The final contribution to the overall EPC project price are the EPC Contractor's indirect costs; these include the EPC engineering services, startup spare parts and initial fills, technical field advisors, and the EPC risk fee.

a. EPC Engineering Services

The EPC engineering services was estimated based on recent projects with similar scopes and schedules. The total cost of the EPC engineering services was estimated to be $10,000,000.

b. Startup Spare Parts and Initial Fills

An allowance has been included for initial fills for equipment, including first fills for lubrication of any motorized equipment. The initial fill of Trona was not included in the EPC Contractor's scope, as this will be supplied by the Owner and is covered as part of the Owner's Costs. The total cost of the initial fills was estimated to be $150,000.

c. Technical Field Advisors (Vendors)

Allowances were included for equipment supplier's technical field advisory services based on an estimated 200 man-days. The estimate includes technical field advisors for the DSI system supplier (including DSI system subcontractors) and the DCS supplier. The total cost of the technical field advisors was estimated to be $400,000.

d. EPC Risk Fee

An EPC approach provides an alternative which is expected to reduce risk for Entergy by placing the responsibility for the project on a single entity, the EPC Contractor. The EPC risk fee is a premium charged by the contractor which accounts for the additional coordination and management of the project as well as the additional risk assumed by the contractor. Based on S&L's experience with recent EPC projects, an EPC risk fee was included at 10% of the total EPC project costs.

4.2.15 Owner's Costs and Services

Outside of the EPC Contractor's total cost, Entergy will incur other costs associated with the project, such as services procured from third parties (including Owner's engineer, construction management support, startup and commissioning support and performance testing), and other project related costs.

a. Owner's Costs

Owner's Costs are direct costs that the Owner incurs over the life of the project. The following items are real costs Entergy will incur to install DSI at White Bluff based on the scope and schedule of this project:

- Internal Labor
- Internal Indirects
- Travel Expenses
- Legal Services
- Builders Risk Insurance
- Initial Fills (Reagent)

Owner's costs were included in the estimate at 8% of the total project cost.

b. Construction Management Support

The construction management support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform the tasks, and therefore it will be outsourced. The cost of labor is based on present day cost. The total cost of the construction management support was estimated to be $2,500,000.

c. Startup and Commissioning Support

The startup and commissioning support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform the tasks, and therefore it will be outsourced. The total cost of the startup and commissioning support was estimated to be $350,000.

d. Owner's Engineer

The Owner's Engineer cost was developed as a high level estimate based on a typical scope for Owner's Engineer work for this type of project; including the following tasks:

- Conceptual Study Support
- EPC Specification Supporting Documents
- Project Schedule Development
- EPC Specification Development
- EPC Bid Evaluation and Contract Conformance
- General Project Support
  - Monthly Project Status Meetings
  - Weekly Teleconferences
  - Overall Coordination
  - Project Administration
  - Site Visits and Travel

- Permitting Support
- Design Review of Drawing Submittals
- Technical support during design, fabrication, construction, commissioning, and testing
- Equipment vendor QA/QC audits

The total cost of the Owner's Engineer was estimated to be $2,750,000.

e. Performance testing

The cost for performance testing was developed as a factored estimate using costs from projects of similar scope. This cost includes the testing, performed by a third-party contractor hired by the Owner, and also includes the cost for S&L's assistance in the following tasks:

- Development of the test protocol
- Procuring the services of the testing contractor
- Overseeing the performance test campaign
- Evaluating the results of the testing with respect to guarantee compliance

The estimate for the third party testing contractor is based on the assumption that the contractor would be onsite for up to 3 days. The total cost of the Performance Testing was estimated to be $175,000.

f. Contingency

Contingency is included in the estimate to cover the uncertainty associated with the project costs. The cost estimate includes a recommended contingency of 25%, which is consistent with cost estimating guidelines for a conceptual design and the current level of project definition. Contingency was applied to the total project costs before escalation.

g. Escalation

Escalation was included in the estimate based on a typical schedule for implementation of a DSI system at an escalation rate of 2.15% on equipment and materials and 3.35% on labor and indirects. These escalation rates were developed by S&L based on recent pricing and in-house escalation projections.

h. Interest During Construction

Interest during construction (IDC) accounts for the time value of money associated with the distribution of construction cash flows over the construction period. IDC was applied to the total EPC project costs including contingency. The IDC was calculated based on a typical schedule for implementation of a DSI system and a typical interest rate of 7.8% per year which was assumed based on a low interest market environment.

4.3 VARIABLE OPERATING AND MAINTENANCE COSTS

The following unit costs were used to develop the variable O&M costs for each reagent specific system. All of these values, with the exception of the reagent costs, were provided by Entergy. The reagent costs are based on recent pricing received by S&L for another project.

Table 4-1: Unit Pricing for Utilities (Provided by Entergy)

Unit Cost	Units	Value
Trona	$/ton	$205
Low Quality Water	$/1000 gal	$0.53
Bag Cost [1]	$/bag	100.00
Cage Cost [1]	$/cage	30.00
Waste Disposal	$/ton	$7.50
Aux Power Cost [2]	$/MWh	$41.02

Note 1: Bags will be replaced every 3 years and cages will be replaced every 9 years.

Note 2: Entergy provided auxiliary power costs for the first year of operation.

Table 4-2 below summarizes the consumption rates estimated as well as the first year variable O&M costs for each case. The reagent consumption rate was developed using a normalized stoichiometric ratio (NSR) of 2.4 which is consistent with test data for similar projects.

Table 4-2: Variable O&M Rates and First Year Costs

	Units	Value
DSI System Parameters		
Reagent Consumption	lb/hr	30,400
DSI Waste Production	lb/hr	24,100
Aux Power Consumption	kW	8,800
Low Quality Water Consumption	gpm	6
First Year[1] Variable O&M Costs (@CF[2])		
Reagent Cost	$/year	$19,434,900
Waste Disposal Cost	$/year	$563,700
Aux Power Cost	$/year	$2,251,500
Low Quality Water Cost	$/year	$1,200
Bag and Cage Replacement Cost	$/year	$1,796,000
Total First Year Variable O&M Cost	**$/year**	**$24,047,300**

Note 1: First year costs are provided in $2016.

Note 2: The first year costs are calculated using an annual capacity factor of 72.1%.

4.4 FIXED O&M COSTS

The fixed O&M costs for the systems consist of operating personnel as well as maintenance costs (including material and labor). The recommended staffing additions for the DSI system are 9 personnel for one system.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (maintenance and labor) were estimated to be approximately 0.5% of the project capital. Items such as track work and civil work would be considered high capital cost items with little to no maintenance.

Table 4-3 below summarizes the first year fixed O&M costs for the design and typical cases.

Table 4-3: First Year Fixed O&M Costs

First Year[1] Fixed O&M Costs	Units	Value
Operating Labor[2]	$/year	$1,066,000
Maintenance Material	$/year	$645,000
Maintenance Labor	$/year	$430,000
Total First Year Fixed O&M Cost	**$/year**	**$2,141,000**

Note 1: First year costs are provided in $2016.

Note 2: Operating labor costs are based on a labor rate of $56.95, which was provided by Entergy.

Note 3: Installation of systems on a single unit would require 9 operators total.

5. ATTACHMENTS

1. White Bluff Station Enhanced DSI System EPC Conceptual Cost Estimate, Sargent & Lundy Estimate No. 34019A

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
ENHANCED DSI SYSTEM W/BAGHOUSE EPC

Estimator	A. KOCI
Labor rate table	16ARPBL
Project No.	13027-004
Estimate Date	10/20/2016
Reviewed By	MNO
Approved By	MNO
Estimate No.	34019A
Cost index	ARPBL

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
ENHANCED DSI SYSTEM W/BAGHOUSE EPC

Area	Description	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Total Cost
101	UNIT 1 OR 2 (SINGLE UNIT) DSI AREA	4,693,000	20,500,000	817,880	28,611	15,417,548	41,428,428
102	REAGENT HANDLING SYSTEM	2,258,100	2,445,000	1,325,013	35,380	2,581,496	8,609,609
103	BYPRODUCT HANDLING SYSTEM	7,713,100	6,872,000	853,055	76,615	5,670,075	21,108,230
104	UNIT 1 OR 2 FLUE GAS SYSTEM	496,800	240,000	8,136,840	162,932	14,173,748	23,047,388
105	UNIT 1 OR 2 BOOSTER FANS		5,400,000	212,595	27,391	1,888,104	7,500,699
106	UNIT 1 OR 2 BAGHOUSE	1,173,600	20,000,000	3,638,113	85,175	19,008,734	43,820,447
107	EARTHWORK			2,021,832	44,398	5,879,245	7,901,077
108	LAYDOWN AREAS			312,000	3,678	293,444	605,444
109	MECHANICAL MISCELLANEOUS	2,600,000					2,600,000
110	DEMOLITION/RELOCATION	975,000					975,000
111	ACI RELOCATION	100,000		146,775	1,954	135,859	382,635
112	ELECTRICAL	16,250,000					16,250,000
113	INSTRUMENTATION	2,210,000					2,210,000
	TOTAL DIRECT	38,469,600	55,457,000	17,464,103	466,134	65,048,253	176,438,956

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
ENHANCED DSI SYSTEM W/BAGHOUSE EPC

Estimate Totals

Description	Amount	Totals	Hours
Direct Costs:			
Labor	65,048,253		466,134
Material	17,464,103		
Subcontract	38,469,600		
Process Equipment	55,457,000		
	176,438,956	**176,438,956**	
Other Direct & Construction Indirect Costs:			
91-1 Scaffolding	4,553,000		
91-2 Cost Due To OT 5-10's	8,760,000		
91-4 Per Diem	4,661,000		
91-5 Consumables	650,044		
91-6 Freight on Material	873,000		
91-8 Sales Tax	2,897,000		
91-9 Contractors G&A	10,350,000		
91-10 Contractors Profit	5,175,000		
	37,919,044	**214,358,000**	
Indirect Costs:			
93-1 Engineering Services	10,000,000		
93-4 SU/S Parts/ Initial Fills	150,000		
93-5 Technical Field Advisors	400,000		
93-8 EPC Fee	22,491,000		
	33,041,000	**247,399,000**	
Escalation:			
96-1 Escalation on Material	1,212,000		
96-2 Escalation on Labor	8,026,000		
96-3 Escalation on Subcontract	3,326,000		
96-4 Escalation on Process Eq	2,948,000		
96-5 Escalation on Indirects	2,756,000		
	18,268,000	**265,667,000**	
Total EPC Cost		***265,667,000***	
Owner's Costs:			
99-1 Owner's Costs	19,792,000		
	19,792,000	**285,459,000**	
Third Party Services:			
100 CM Oversight	2,500,000		
101 Start-Up Oversight	350,000		
102 Owner's Engineer	2,750,000		
103 Performance Testing	175,000		
	5,775,000	**291,234,000**	
Project Contingency :			
110 Project Contingency	68,242,000		
	68,242,000	**359,476,000**	
Escalation Addition:			
120 Escalation on Lines 99-110	1,893,000		
	1,893,000	**361,369,000**	
Interest During Construction:			
130 Interest During Constr.	32,375,000		
	32,375,000	**393,744,000**	
Total		***393,744,000***	

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
101			**UNIT 1 OR 2 (SINGLE UNIT) DSI AREA**									
	21.00.00		**CIVIL WORK**									
		21.53.00	**PILING**									
			AUGER CAST GROUT PILE, 18 IN DIA BY 60 FT LONG	DSI AREA FOUNDATIONS INCLUDING REAGENT SILOS	500.00 EA	1,800,000	-	-		108.88 /MH		1,800,000
			PILE - MOB/DEMOB		1.00 LS	100,000	-			108.88 /MH		100,000
			PILING			**1,900,000**						**1,900,000**
		21.98.00	**CIVIL WORK,TESTING**									
			AUGER CAST GROUT PILE - TESTING		1.00 LS	65,000	-	-		-	-	65,000
			CIVIL WORK,TESTING			**65,000**						**65,000**
			CIVIL WORK			**1,965,000**						**1,965,000**
	22.00.00		**CONCRETE**									
		22.13.00	**CONCRETE**									
			CONCRETE FOUNDATIONS - COMPOSITE RATE	DSI AREA FOUNDATIONS INCLUDING REAGENT SILOS	3,556.00 CY	-	-	817,880	28,611	60.03 /MH	1,717,548	2,535,428
			CONCRETE					**817,880**	**28,611**		**1,717,548**	**2,535,428**
			CONCRETE					**817,880**	**28,611**		**1,717,548**	**2,535,428**
	23.00.00		**STEEL**									
		23.25.00	**ROLLED SHAPE**									
			BUILDING MIX, TWO COAT PAINTED		TN	-	-			93.00 /MH		
	24.00.00		**ARCHITECTURAL**									
		24.35.00	**PRE-ENGINEERED BUILDING**									
			SHELL INCLUDING ELECTRICAL & HVAC-STEEL INSULATED 22 GA	BLOWER BUILDING 25 FT X 125 FT	3,125.00 SF	625,000	-			93.00 /MH		625,000
			SHELL INCLUDING ELECTRICAL & HVAC-STEEL INSULATED 22 GA	ELECTRICAL BUILDING 30 FT X 20 FT	600.00 SF	210,000	-			93.00 /MH		210,000
			SHELL INCLUDING ELECTRICAL & HVAC-STEEL INSULATED 22 GA	MILL BUILDING 50 FT X 100 FT	5,000.00 SF	1,000,000	-			93.00 /MH		1,000,000
			SHELL - ROOF ONLY AREA	DEHUMIDIFIER - 30 FT X 160 FT	4,800.00 SF	408,000	-			93.00 /MH		408,000
			SHELL - ROOF ONLY AREA	HEAT EXCHANGER - 10 FT X 100 FT	1,000.00 SF	85,000	-			93.00 /MH		85,000
			PRE-ENGINEERED BUILDING			**2,328,000**						**2,328,000**
		24.37.00	**ROOFING**									
			METAL, INSULATED, 2 IN GALVANIZED, PAINTED, 22 GA	DSI AREA ENCLOSURE ROOF	SF	-	-			35.25 /MH		
		24.41.00	**SIDING**									
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	DSI AREA ENCLOSURE SIDING	SF	-	-			79.98 /MH		
		24.99.00	**ARCHITECTURAL, MISCELLANEOUS**									
			HEATING	DSI AREA	SF	-	-			64.51 /MH		
			LIGHTING	DSI AREA	SF	-	-			82.56 /MH		
			FIRE PROTECTION	DSI AREA	SF	-	-			82.56 /MH		
			ARCHITECTURAL			**2,328,000**						**2,328,000**
	31.00.00		**MECHANICAL EQUIPMENT**									
		31.99.00	**MECHANICAL EQUIPMENT, MISCELLANEOUS**									
			DSI SYSTEM EQUIPMENT	EQUIPMENT COST FOR UNIT 1 OR 2 (SINGLE UNIT)	1.00 LS		20,500,000	-		/MH	13,700,000	34,200,000
			STORAGE SILOS WITH BIN VENT FILTERS (~14 DAYS STORAGE)	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			BLOWERS, HEAT EXCHANGERS, DEHUMIDIFIERS	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			MILLING EQUIPMENT	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			PIPING SYSTEMS	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			COMPRESSORS	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			FLOW MODELING	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			MECHANICAL EQUIPMENT, MISCELLANEOUS				**20,500,000**				**13,700,000**	**34,200,000**
			MECHANICAL EQUIPMENT				**20,500,000**				**13,700,000**	**34,200,000**
	71.00.00		**PROJECT INDIRECT**									
		71.25.00	**CONSULTANT, THIRD PARTY**									
			CONSULTANT - SUBSURFACE INVESTIGATION		1.00 LS	250,000	-			/MH		250,000
			CONSULTANT - GEOTECHNICAL		1.00 LS	150,000	-			/MH		150,000

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			CONSULTANT, THIRD PARTY			400,000						400,000
			PROJECT INDIRECT			400,000						400,000
			101 UNIT 1 OR 2 (SINGLE UNIT) DSI AREA			**4,693,000**	**20,500,000**	**817,880**	**28,611**		**15,417,548**	**41,428,428**
102			**REAGENT HANDLING SYSTEM**									
	21.00.00		CIVIL WORK									
		21.14.00	STRIP & STOCKPILE TOPSOIL									
			STRIP & STOCKPILE TOPSOIL - 12"	EXTEND REAGENT RAIL TRACK	90,000.00 SF	-	-		207	182.87 /MH	37,835	37,835
			STRIP & STOCKPILE TOPSOIL						207		37,835	37,835
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK	EXTEND REAGENT RAIL TRACK	10,000.00 SY	-	-	106,500	345	97.70 /MH	33,690	140,190
			EROSION AND SEDIMENTATION CONTROL					106,500	345		33,690	140,190
		21.53.00	PILING									
			AUGER CAST GROUT PILE, 18 IN DIA BY 60 FT LONG	UNLOADING SHED 300' X 75' WIDE	96.00 EA	345,600	-	-		108.88 /MH		345,600
			PILING			345,600						345,600
		21.71.00	TRACKWORK									
			RAIL, TIE & BALLAST - 136 LB/YD	EXTEND REAGENT RAIL TRACK	4,500.00 TF	-	-	765,000	7,759	81.75 /MH	634,267	1,399,267
			TRACKWORK					765,000	7,759		634,267	1,399,267
			CIVIL WORK			345,600		871,500	8,310		705,792	1,922,892
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			FOUNDATION, 4500 PSI - COMPOSITE RATE	UNLOADING SHED 300' X 75' WIDE	1,389.00 CY	-	-	319,470	11,176	60.03 /MH	670,887	990,357
			CONCRETE					319,470	11,176		670,887	990,357
			CONCRETE					319,470	11,176		670,887	990,357
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA,	UNLOADING SHED 300' X 75' WIDE x 20' TALL	22,500.00 SF	1,912,500	-			93.00 /MH		1,912,500
			PRE-ENGINEERED BUILDING			1,912,500						1,912,500
			ARCHITECTURAL			1,912,500						1,912,500
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.14.00	MATERIAL HANDLING EQUIPMENT									
			REAGENT PNEUMATIC TRAIN UNLOADING EQUIPMENT		3.00 LS	-	1,500,000	-	9,917	68.89 /MH	683,199	2,183,199
			MATERIAL HANDLING EQUIPMENT				1,500,000		9,917		683,199	2,183,199
		33.41.00	MOBILE YARD EQUIPMENT									
			MOBILE YARD EQUIPMENT - TRACKMOBILE	REAGENT HANDLING SYSTEM	3.00 EA	-	675,000	-		68.89 /MH		675,000
			MOBILE YARD EQUIPMENT				675,000					675,000
		33.51.00	RAIL CAR UNLOADER									
			RAIL CAR UNLOADER	IN UNLOADING SHED 300' X 75' WIDE	2.00 LT	-	270,000	-	3,724	93.00 /MH	346,345	616,345
			RAIL CAR UNLOADER				270,000		3,724		346,345	616,345
			MATERIAL HANDLING EQUIPMENT				2,445,000		13,641		1,029,544	3,474,544
	35.00.00		PIPING									
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			8 IN DIA, SCH 40, 8" VACUUM CONVEY PIPING WITH 4 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	250.00 LF	-	-	10,043	270	77.80 /MH	21,015	31,057
			12 IN DIA, 3/8 IN STD- 2500 LF OF 10"/12" TRANSPORT PRESSURE PIPING W 8 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRANSPORT SYSTEM	1,250.00 LF	-	-	124,000	1,983	77.80 /MH	154,259	278,259
			CARBON STEEL, STRAIGHT RUN					134,043	2,253		175,274	309,316
			PIPING					134,043	2,253		175,274	309,316
			102 REAGENT HANDLING SYSTEM			**2,258,100**	**2,445,000**	**1,325,013**	**35,380**		**2,581,496**	**8,609,609**
103			**BYPRODUCT HANDLING SYSTEM**									
	21.00.00		CIVIL WORK									
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	ASH SILO AND DSI BYPRODUCT SILOS	125.00 EA	-	-	232,125	3,161	108.88 /MH	344,161	576,286
			CAISSON					232,125	3,161		344,161	576,286

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
ENHANCED DSI SYSTEM W/BAGHOUSE EPC

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			CIVIL WORK					**232,125**	**3,161**		**344,161**	**576,286**
	22.00.00		**CONCRETE**									
		22.13.00	**CONCRETE**									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	DSI BYPRODUCT SILOS	614.00 CY	-	-	141,220	4,940	60.03 /MH	296,562	437,782
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	FLY ASH BLENDING SILO	67.00 CY	-	-	15,410	539	60.03 /MH	32,361	47,771
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	FOR TRUCK SCALES	144.00 CY	-	-	33,120	1,159	60.03 /MH	69,552	102,672
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	MISC	100.00 CY	-	-	23,000	805	60.03 /MH	48,300	71,300
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' BYPRODUCT AREA, TRUCK SCALE HOUSE	6.00 CY	-	-	1,380	48	60.03 /MH	2,898	4,278
			CONCRETE					**214,130**	**7,491**		**449,673**	**663,803**
			CONCRETE					**214,130**	**7,491**		**449,673**	**663,803**
	23.00.00		**STEEL**									
		23.13.75	**SILO**									
			NEW 250 TON FLYASH BLENDING BIN SILO - 24FT DIA X 72 FT HIGH - ERECTION AND FREIGHT INCLUDED	SILO	1.00 EA		275,000		2,839	73.51 /MH	208,701	483,701
			SILO				**275,000**		**2,839**		**208,701**	**483,701**
			STEEL				**275,000**		**2,839**		**208,701**	**483,701**
	24.00.00		**ARCHITECTURAL**									
		24.35.00	**PRE-ENGINEERED BUILDING**									
			PRE-ENGINEERED BUILDING	8' X 10' BYPRODUCT AREA, TRUCK SCALE HOUSE	1.00 LT	-	-	10,000	115	93.00 /MH	10,690	20,690
			PRE-ENGINEERED BUILDING					**10,000**	**115**		**10,690**	**20,690**
			ARCHITECTURAL					**10,000**	**115**		**10,690**	**20,690**
	26.00.00		**MISCELLANEOUS STRUCTURAL ITEM**									
		26.13.00	**CONCRETE SILO**									
			CONCRETE SILO - DSI BYPRODUCT SILO	ERECTED - 52' DIA	2.00 LS	7,600,000				60.03 /MH		7,600,000
			CONCRETE SILO - BIN VENT FILTERS	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - LEVEL INDICATOR	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - VACUUM PRESSURE RELIEF VALVE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - MANHOLE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - SPARE PARTS FOR STARTUP AND SPECIAL TOOLS		1.00 LS	-	10,000			73.51 /MH		10,000
			CONCRETE SILO - FREIGHT		1.00 LS	-	70,000			73.51 /MH		70,000
			CONCRETE SILO			**7,600,000**	**80,000**		**0**			**7,680,000**
			MISCELLANEOUS STRUCTURAL ITEM			**7,600,000**	**80,000**		**0**			**7,680,000**
	33.00.00		**MATERIAL HANDLING EQUIPMENT**									
		33.13.00	**BYPRODUCT HANDLING EQUIPMENT**									
			PNEUMATIC ASH CONVEYORS	EQUIPMENT INCLUDES FREIGHT	1.00 LS	-	5,655,000	-		73.51 /MH		5,655,000
			PNEUMATIC ASH CONVEYORS	INSTALLATION COST	1.00 LT	-		-	51,910	73.51 /MH	3,815,929	3,815,929
			BLOWERS, PRESSURE FEEDERS, TRANSPORT PIPING AND VACUUM / PRESSURE RELIEF VALVES	INCLUDED ABOVE	1.00 LT	-		-		73.51 /MH		
			-DRY UNLOADING SPOUT BELOW THE PRODUCT SILO		2.00 EA	-	60,000	-	258	73.51 /MH	18,977	78,977
			AIRSLIDE CONVEYORS FROM BLENDING BIN MIXER/PIPE CONVEYOR, INCL ALL VALVES AND ACCESSORIES		4.00 EA	-	80,000	-	688	73.51 /MH	50,595	130,595
			-FOUR PIN MIXERS BELOW CONCRETE SILOS INCL ALL VALVES AND ACCESSORIES		1.00 LT	-	540,000	-	3,347	73.51 /MH	246,047	786,047
			BYPRODUCT HANDLING EQUIPMENT				**6,335,000**		**56,204**		**4,131,549**	**10,466,549**
		33.57.00	**SCALE**									
			SCALE - NEW TRUCK SCALES	BYPRODUCT HANDLING SYSTEM	2.00 EA	-	182,000	-	460	68.89 /MH	31,674	213,674
			SCALE				**182,000**		**460**		**31,674**	**213,674**
			MATERIAL HANDLING EQUIPMENT				**6,517,000**		**56,664**		**4,163,223**	**10,680,223**
	34.00.00		**HVAC**									
		34.37.00	**DUST COLLECTOR**									
			DUST COLLECTOR - INSTALLED COST		1.00 LS	113,100	-			64.51 /MH		113,100
			DUST COLLECTOR			**113,100**						**113,100**

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			HVAC			113,100						113,100
	35.00.00		PIPING									
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			12 IN DIA, 3/8 IN STD	CONVEYOR PIPING	2,500.00 LF	-	-	248,000	3,966	77.80 /MH	308,517	556,517
			12 IN DIA, 3/8 IN STD	12" TIE IN PIPING TO BYPRODUCT SILO FROM THE EXISTING 50 TPH FLY ASH PRESSURE SYSTEM	1,500.00 LF	-	-	148,800	2,379	77.80 /MH	185,110	333,910
			CARBON STEEL, STRAIGHT RUN					396,800	6,345		493,628	890,428
			PIPING					396,800	6,345		493,628	890,428
			103 BYPRODUCT HANDLING SYSTEM			7,713,100	6,872,000	853,055	76,615		5,670,075	21,108,230
104			UNIT 1 OR 2 FLUE GAS SYSTEM									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			AUGER CAST GROUT PILE, 18 IN DIA BY 60 FT LONG		138.00 EA	496,800	-	-		108.88 /MH		496,800
			PILING			496,800						496,800
			CIVIL WORK			496,800						496,800
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE		966.00 CY	-	-	222,180	7,772	60.03 /MH	466,578	688,758
			CONCRETE					222,180	7,772		466,578	688,758
			CONCRETE					222,180	7,772		466,578	688,758
	23.00.00		STEEL									
		23.15.00	DUCTWORK									
			PANEL CONSTRUCTION, DUCT PLATE WITH STIFFENERS, INTERNAL TRUSSES, AND TURNING VANES		867.40 TN	-	-	2,819,050	59,821	97.70 /MH	5,844,481	8,663,531
			DUCTWORK					2,819,050	59,821		5,844,481	8,663,531
		23.21.00	GIRDER									
			ROLLED SHAPE STEEL		1,308.00 TN	-	-	3,544,680	45,103	93.00 /MH	4,194,621	7,739,301
			GIRDER					3,544,680	45,103		4,194,621	7,739,301
			STEEL					6,363,730	104,924		10,039,102	16,402,832
	31.00.00		MECHANICAL EQUIPMENT									
		31.27.00	DAMPERS & ACCESSORIES									
			DAMPERS & ACCESSORIES		800.00 SF	-	240,000		1,471	97.70 /MH	143,743	383,743
			DAMPERS & ACCESSORIES				240,000		1,471		143,743	383,743
		31.33.00	EXPANSION JOINT									
			EXPANSION JOINTS		1,830.00 LF	-		457,500	5,259	97.70 /MH	513,767	971,267
			EXPANSION JOINT					457,500	5,259		513,767	971,267
			MECHANICAL EQUIPMENT				240,000	457,500	6,730		657,510	1,355,010
	36.00.00		INSULATION									
		36.13.00	DUCT									
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE		168,220.00 SF	-	-	1,093,430	43,505	69.20 /MH	3,010,558	4,103,988
			DUCT					1,093,430	43,505		3,010,558	4,103,988
			INSULATION					1,093,430	43,505		3,010,558	4,103,988
			104 UNIT 1 OR 2 FLUE GAS SYSTEM			496,800	240,000	8,136,840	162,932		14,173,748	23,047,388
105			UNIT 1 OR 2 BOOSTER FANS									
	21.00.00		CIVIL WORK									
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON		40.00 EA	-	-	74,280	1,011	108.88 /MH	110,131	184,411
			CAISSON					74,280	1,011		110,131	184,411
			CIVIL WORK					74,280	1,011		110,131	184,411
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		22.13.00	CONCRETE									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE		600.00 CY	-	-	138,000	4,828	60.03 /MH	289,800	427,800
			CONCRETE					138,000	4,828		289,800	427,800
			CONCRETE					138,000	4,828		289,800	427,800
	31.00.00		MECHANICAL EQUIPMENT									
		31.35.00	FANS & ACCESSORIES (EXCL HVAC)									
			BOOSTER FAN 1.8 MACFM, 4000 HP MOTOR		2.00 EA	-	5,400,000	-	10,345	68.89 /MH	712,655	6,112,655
			FANS & ACCESSORIES (EXCL HVAC)				5,400,000		10,345		712,655	6,112,655
			MECHANICAL EQUIPMENT				5,400,000		10,345		712,655	6,112,655
	36.00.00		INSULATION									
		36.15.00	EQUIPMENT									
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED ON GROUND		1,500.00 SF	-	-	315	11,207	69.20 /MH	775,517	775,832
			EQUIPMENT					315	11,207		775,517	775,832
			INSULATION					315	11,207		775,517	775,832
			105 UNIT 1 OR 2 BOOSTER FANS				**5,400,000**	**212,595**	**27,391**		**1,888,104**	**7,500,699**
106			**UNIT 1 OR 2 BAGHOUSE**									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			AUGER CAST GROUT PILE, 18 IN DIA BY 60 FT LONG		326.00 EA	1,173,600	-	-		108.88 /MH		1,173,600
			PILING			1,173,600						1,173,600
			CIVIL WORK			1,173,600						1,173,600
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			CONCRETE FOUNDATIONS - COMPOSITE RATE		2,260.00 CY	-	-	519,800	18,184	60.03 /MH	1,091,580	1,611,380
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' COMPRESSOR BLDG	6.00 CY	-	-	1,380	48	60.03 /MH	2,898	4,278
			CONCRETE					521,180	18,232		1,094,478	1,615,658
			CONCRETE					521,180	18,232		1,094,478	1,615,658
	23.00.00		STEEL									
		23.25.00	ROLLED SHAPE									
			BUILDING MIX, GALVANIZED	UNIT 1 BAGHOUSE	560.00 TN	-	-	1,534,400	10,299	93.00 /MH	957,793	2,492,193
			ROLLED SHAPE					1,534,400	10,299		957,793	2,492,193
			STEEL					1,534,400	10,299		957,793	2,492,193
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			PRE-ENGINEERED BUILDING	8' X 10' COMPRESSOR BLDG	1.00 LT	-	-	20,000	115	93.00 /MH	10,690	30,690
			PRE-ENGINEERED BUILDING					20,000	115		10,690	30,690
		24.41.00	SIDING									
			METAL, UNINSULATED, 24 GA, GALVANIZED CORROGATED	BAGHOUSE SKIRTS	68,112.00 SF	-	-	221,364	3,210	79.98 /MH	256,726	478,090
			SIDING					221,364	3,210		256,726	478,090
		24.99.00	ARCHITECTURAL, MISCELLANEOUS									
			MISCELLANEOUS	BAGHOUSE SKIRTS MANDOORS	4.00 EA	-	-	2,000	37	51.46 /MH	1,893	3,893
			ARCHITECTURAL, MISCELLANEOUS					2,000	37		1,893	3,893
			ARCHITECTURAL					243,364	3,362		269,308	512,672
	31.00.00		MECHANICAL EQUIPMENT									
		31.57.00	PARTICULATE REMOVAL									
			BAGHOUSE SYSTEM - INCLUDES PENTHOUSE, BYPASS, DAMPERS, EXP. JOINTS, TUBESHEETS, BAGS, CAGES, CLEANING PIPING, VALVES, BLOWERS, ETC.		1.00 LS	-	20,000,000	-		/MH	13,000,000	33,000,000
			PARTICULATE REMOVAL				20,000,000				13,000,000	33,000,000
			MECHANICAL EQUIPMENT				20,000,000				13,000,000	33,000,000
	36.00.00		INSULATION									
		36.13.00	DUCT									

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
ENHANCED DSI SYSTEM W/BAGHOUSE EPC

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		36.13.00	DUCT									
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	BAGHOUSE INSUILATION TOP, SIDES AND HOPPERS	206,026.00 SF	-	-	1,339,169	53,283	69.20 /MH	3,687,155	5,026,324
			DUCT					1,339,169	53,283		3,687,155	5,026,324
			INSULATION					1,339,169	53,283		3,687,155	5,026,324
			106 UNIT 1 OR 2 BAGHOUSE			**1,173,600**	**20,000,000**	**3,638,113**	**85,175**		**19,008,734**	**43,820,447**
107			**EARTHWORK**									
	21.00.00		CIVIL WORK									
		21.14.00	STRIP & STOCKPILE TOPSOIL									
			STRIP & STOCKPILE TOPSOIL - 12"	SITE GRADING	600,000.00 SF	-	-		1,379	182.87 /MH	252,234	252,234
			STRIP & STOCKPILE TOPSOIL - ONSITE	SITE GRADING	160,000.00 CY	-	-		21,149	182.87 /MH	3,867,595	3,867,595
			STRIP & STOCKPILE TOPSOIL						22,529		4,119,830	4,119,830
		21.17.00	EXCAVATION									
			EXCAVATION - EXCAVATION , BACKFILL & COMPACT ALL FOUNDATIONS		20,917.00 CY	-	-		7,213	79.78 /MH	575,434	575,434
			EXCAVATION						7,213		575,434	575,434
		21.39.00	STORM DRAINAGE UTILITIES									
			STORM SEWER WORK	SITE GRADING	1.00 LT	-	-	110,000	2,299	72.57 /MH	166,828	276,828
			STORM DRAINAGE UTILITIES					110,000	2,299		166,828	276,828
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK	SITE GRADING	66,667.00 SY	-	-	710,004	2,299	97.70 /MH	224,599	934,602
			EROSION AND SEDIMENTATION CONTROL					710,004	2,299		224,599	934,602
		21.57.00	ROAD, PARKING AREA, & SURFACED AREA									
			BITUMINOUS ROAD - ROAD UPGRADE	BYPRODUCT HAUL ROAD - EAST OF COAL PILE	10,000.00 LF	-	-	500,000	8,046	78.79 /MH	633,943	1,133,943
			BITUMINOUS ROAD - ELIMINATE CHICANE CURVES AT LOW PRESSURE SERVICE WATER PUMPS		1.00 LT	-	-	500,000		78.79 /MH		500,000
			BITUMINOUS ASPHALT (10,000 - 49,999 SF) ROADWORK 24' WIDE 4" ASPHALT	SITE GRADING	1,668.00 LF	-	-	201,828	2,013	78.79 /MH	158,612	360,440
			ROAD, PARKING AREA, & SURFACED AREA					1,201,828	10,059		792,555	1,994,383
			CIVIL WORK					2,021,832	44,398		5,879,245	7,901,077
			107 EARTHWORK					**2,021,832**	**44,398**		**5,879,245**	**7,901,077**
108			**LAYDOWN AREAS**									
	21.00.00		CIVIL WORK									
		21.99.00	CIVIL WORK, MISCELLANEOUS									
			CIVIL WORK - CONSTRUCTION LAYDOWN AREAS	FENCING, POWER ETC...	4.00 AC	-	-	312,000	3,678	79.78 /MH	293,444	605,444
			CIVIL WORK, MISCELLANEOUS					312,000	3,678		293,444	605,444
			CIVIL WORK					312,000	3,678		293,444	605,444
			108 LAYDOWN AREAS					**312,000**	**3,678**		**293,444**	**605,444**
109			**MECHANICAL MISCELLANEOUS**									
	31.00.00		MECHANICAL EQUIPMENT									
		31.99.00	MECHANICAL EQUIPMENT, MISCELLANEOUS									
			MECHANICAL EQUIPMENT	INCLUDES PIPE RACK - ALLOWANCE	1.00 LS	2,600,000	-	-		68.89 /MH		2,600,000
			MECHANICAL EQUIPMENT, MISCELLANEOUS			2,600,000						2,600,000
			MECHANICAL EQUIPMENT			2,600,000						2,600,000
			109 MECHANICAL MISCELLANEOUS			**2,600,000**						**2,600,000**
110			**DEMOLITION/RELOCATION**									
	11.00.00		DEMOLITION									
		11.99.00	DEMOLITION, MISCELLANEOUS									
			DEMOLITION AND RELOCATION	ALLOWANCE	1.00 LS	975,000	-			107.47 /MH		975,000
			DEMOLITION, MISCELLANEOUS			975,000						975,000
			DEMOLITION			975,000						975,000
			110 DEMOLITION/RELOCATION			**975,000**						**975,000**
111			**ACI RELOCATION**									
	22.00.00		CONCRETE									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		22.13.00	CONCRETE									
			CONCRETE FOUNDATIONS - COMPOSITE RATE	ACI PORT STAIRTOWER FDNS	30.00 CY	-	-	6,900	241	60.03 /MH	14,490	21,390
			CONCRETE					6,900	241		14,490	21,390
			CONCRETE					6,900	241		14,490	21,390
	23.00.00		STEEL									
		23.17.00	GALLERY									
			GALVANIZED GRATING, 1 1/4" DEEP x 3/16" BEARING BAR WITH HOLD DOWN CLIPS	ACI PORT STAIR TOWERS AND PLATFORMS	364.00 SF	-	-	5,460	42	66.40 /MH	2,778	8,238
			DOUBLE PIPE HANDRAIL WITH POSTS AND GUARD PLATES, PAINTED	ACI PORT STAIR TOWERS AND PLATFORMS	218.00 LF	-	-	11,554	45	66.40 /MH	2,995	14,549
			STAIR SYSTEM -	ACI PORT STAIR TOWERS AND PLATFORMS	448.00 SF	-	-	40,768	592	66.40 /MH	39,321	80,089
			GALLERY					57,782	679		45,094	102,876
		23.21.00	GIRDER									
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	ACI PIPE RACK OVER ROADWAY, 35LF X 23 WIDE X 20' HIGH	1.26 TN	-	-	3,415	25	93.00 /MH	2,290	5,704
			GIRDER					3,415	25		2,290	5,704
		23.25.00	ROLLED SHAPE									
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, TWO COAT PAINT	ACI PORT STAIRTOWER FRAMING - 1 TOWER	2.20 TN	-	-	7,876	56	93.00 /MH	5,174	13,050
			ROLLED SHAPE					7,876	56		5,174	13,050
			STEEL					69,073	759		52,558	121,630
	31.00.00		MECHANICAL EQUIPMENT									
		31.25.00	CRANES & HOISTS									
			MOTORIZED HOIST - 1 TON	RELOCATED FROM PRESENT PORT LOCATIOIN	1.00 EA	-	-	-	69	68.89 /MH	4,751	4,751
			CRANES & HOISTS						69		4,751	4,751
		31.51.00	MERCURY REMOVAL EQUIPMENT									
			ACTIVATED CARBON INJECTION (ACI) - LANCE RELOCATIONS	RELOCATED FROM PRESENT PORT LOCATIOIN (16 PER UNIT)	16.00 EA	-	-	-	184	68.89 /MH	12,669	12,669
			ACTIVATED CARBON INJECTION (ACI) - 40 HP BLOWERS	NEW BLOWERS (2 PER UNIT)	2.00 EA	-	-	40,000	92	68.89 /MH	6,335	46,335
			ACTIVATED CARBON INJECTION (ACI) - REMOVE EXISTING 20 HP BLOWERS	REMOVE EXISTING	1.00 EA	-	-	-	11	68.89 /MH	792	792
			MERCURY REMOVAL EQUIPMENT					40,000	287		19,796	59,796
			MECHANICAL EQUIPMENT					40,000	356		24,547	64,547
	35.00.00		PIPING									
		35.13.25	FRP, ABOVE GROUND, PROCESS AREA									
			1.5 IN DIA, TAPER	INJECTION PORTS	6.00 LF	-	-	176	3	77.80 /MH	220	396
			2 IN DIA, TAPER	INJECTION PORTS	8.00 LF	-	-	210	5	77.80 /MH	351	561
			3 IN DIA, TAPER	INJECTION PORTS	20.00 LF	-	-	516	15	77.80 /MH	1,198	1,714
			FRP, ABOVE GROUND, PROCESS AREA					903	23		1,769	2,672
		35.14.25	FRP, STRAIGHT RUN									
			4 IN DIA, TAPER	NEW ACI PIPING	300.00 LF	-	-	6,330	200	77.80 /MH	15,560	21,890
			FRP, STRAIGHT RUN					6,330	200		15,560	21,890
		35.36.00	PIPE SUPPORTS, RACK									
			U-BOLT FOR 4 IN PIPE	ACI PIPE	13.50 EA	-	-	41	31	77.80 /MH	2,414	2,455
			SUPPORT SLEEPERS	ACI PIPE	8.50 EA	-	-	2,975	39	77.80 /MH	3,040	6,015
			SUPPORT FOR 4 IN DIA PIPE - USER DEFINED		1.00 EA	-	-	153	9	77.80 /MH	715	868
			SUPPORT FOR 3 IN DIA PIPE - USER DEFINED		2.00 EA	-	-	288	16	77.80 /MH	1,252	1,540
			PIPE SUPPORTS, RACK					3,457	95		7,422	10,879
		35.45.00	VALVES									
			VALVE - 4" 150 LB CS GATE, FLANGED	ACI AUTO MATIC ISOLATION VALVES (RELOCATE 4 PER UNIT)	4.00 EA	-	-	80	33	77.80 /MH	2,575	2,655
			VALVES					80	33		2,575	2,655
			PIPING					10,769	351		27,327	38,096
	41.00.00		ELECTRICAL EQUIPMENT									
		41.46.00	MOTOR CONTROL CENTER (MCC), COMPONENT									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		41.46.00	MOTOR CONTROL CENTER (MCC), COMPONENT									
			FVN STARTER - #4,	NEW BLOWERS	2.00 EA	-	-	9,800	37	64.04 /MH	2,355	12,155
			MOTOR CONTROL CENTER (MCC), COMPONENT					9,800	37		2,355	12,155
			ELECTRICAL EQUIPMENT					9,800	37		2,355	12,155
	42.00.00		RACEWAY, CABLE TRAY & CONDUIT									
		42.15.23	CONDUIT, FLEXIBLE SEALTIGHT ASSEMBLY									
			1-1/2 IN DIA, 3 FT LONG INCLUDING (2) CONNECTORS	NEW BLOWERS	2.00 EA	-	-	172	3	62.27 /MH	179	351
			CONDUIT, FLEXIBLE SEALTIGHT ASSEMBLY					172	3		179	351
		42.15.37	CONDUIT, RGS									
			3/4 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	HOIST	225.00 LF	-	-	659	50	62.27 /MH	3,124	3,783
			1-1/2 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	NEW BLOWERS	200.00 LF	-	-	1,344	65	62.27 /MH	4,065	5,409
			CONDUIT, RGS					2,003	115		7,190	9,193
			RACEWAY, CABLE TRAY & CONDUIT					2,175	118		7,369	9,544
	43.00.00		CABLE									
		43.10.00	CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION									
			CONTROL/INSTRUMENTATION/COMMUNICATION TERMINATION - MISC	ACI RELOCATION	300.00 LF	-	-	960	28	82.56 /MH	2,278	3,238
			CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION					960	28		2,278	3,238
		43.20.00	600V CABLE & TERMINATION									
			600V #8 3/C CU EPR TS-CPE	HOIST	250.00 LF	-	-	1,640	7	82.56 /MH	593	2,233
			600V #4/0 3/C W/G CU EPR TS-CPE	NEW BLOWERS	225.00 LF	-	-	5,364	36	82.56 /MH	2,989	8,353
			TERMINATION - COMPRESSION LUG, #8, 2 HOLE, COPPER	HOIST	6.00 EA	-	-	39	2	82.56 /MH	171	210
			TERMINATION - COMPRESSION LUG, #4, 2 HOLE, COPPER	NEW BLOWERS	6.00 EA	-	-	56	3	82.56 /MH	285	340
			600V CABLE & TERMINATION					7,099	49		4,038	11,136
			CABLE					8,059	76		6,315	14,374
	44.00.00		CONTROL & INSTRUMENTATION									
		44.21.00	INSTRUMENT									
			ACCOUSTIC MONITOR	RELOCATE TO NEW INJECTION LANCES	3.00 EA	-	-		14	65.15 /MH	899	899
			INSTRUMENT						14		899	899
			CONTROL & INSTRUMENTATION						14		899	899
	71.00.00		PROJECT INDIRECT									
		71.25.00	CONSULTANT, THIRD PARTY									
			COMPUTATIONAL FLUID DYNAMIC ANALYSIS (CFD)	ACI SYSTEM	1.00 LS	100,000	-			/MH		100,000
			CONSULTANT, THIRD PARTY			100,000						100,000
			PROJECT INDIRECT			100,000						100,000
			111 ACI RELOCATION			**100,000**		**146,775**	**1,954**		**135,859**	**382,635**
112			**ELECTRICAL**									
	41.00.00		ELECTRICAL EQUIPMENT									
		41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS									
			ELECTRICAL EQUIPMENT, MISCELLANEOUS	ALLOWANCE	1.00 LS	16,250,000	-			64.04 /MH		16,250,000
			ELECTRICAL EQUIPMENT, MISCELLANEOUS			16,250,000						16,250,000
			ELECTRICAL EQUIPMENT			16,250,000						16,250,000
			112 ELECTRICAL			**16,250,000**						**16,250,000**
113			**INSTRUMENTATION**									
	44.00.00		CONTROL & INSTRUMENTATION									
		44.99.00	CONTROL & INSTRUMENTATION, ALLOWANCE									
			CONTROL & INSTRUMENTATION	ALLOWANCE	1.00 LS	2,210,000	-			65.15 /MH		2,210,000
			CONTROL & INSTRUMENTATION, ALLOWANCE			2,210,000						2,210,000
			CONTROL & INSTRUMENTATION			2,210,000						2,210,000
			113 INSTRUMENTATION			**2,210,000**						**2,210,000**

Table B-8. Baseline Visibility Impairment Attributable to Unit 1 by Pollutant

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek							
2001	2.912	1.505	38	74.33	25.34	0.17	0.15
2002	2.048	1.306	29	61.53	34.59	0.83	3.04
2003	4.020	1.053	32	47.92	50.35	0.35	1.39
Upper Buffalo							
2001	2.089	1.051	30	68.58	31.17	0.26	0.00
2002	1.438	0.742	15	79.11	20.19	0.37	0.32
2003	1.773	1.033	24	79.79	19.92	0.28	0.00
Hercules Glades							
2001	1.643	0.925	24	90.21	9.56	0.23	0.00
2002	1.184	0.567	10	74.20	25.45	0.25	0.10
2003	1.977	0.704	15	86.02	13.73	0.25	0.00
Mingo							
2001	1.538	0.802	16	51.46	48.03	0.39	0.12
2002	0.898	0.708	21	54.87	44.82	0.31	0.01
2003	1.003	0.666	14	57.31	41.18	0.41	1.11

Table B-9. Baseline Visibility Impairment Attributable to Unit 2 by Pollutant

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek							
2001	2.994	1.533	39	36.23	60.75	0.74	2.28
2002	2.098	1.322	29	59.43	36.53	0.82	3.22
2003	4.084	1.059	32	96.37	3.38	0.24	0.01
Upper Buffalo							
2001	2.066	1.059	30	66.54	33.21	0.26	0.00
2002	1.447	0.739	16	77.57	21.71	0.37	0.35
2003	1.791	1.030	25	78.24	21.46	0.28	0.00
Hercules Glades							
2001	1.665	0.912	25	89.39	10.38	0.23	0.00
2002	1.185	0.568	11	72.38	27.26	0.25	0.11
2003	1.947	0.720	16	40.35	58.44	0.40	0.82
Mingo							
2001	1.580	0.819	15	81.62	17.93	0.33	0.12
2002	0.886	0.719	20	58.93	40.66	0.19	0.22
2003	0.999	0.678	14	55.08	43.36	0.40	1.17

APPENDIX C. REFINED PM SPECIATION CALCULATIONS

PM Speciation Calculations

Entergy White Bluff
Unit 1 Boiler - 2009-2013 Baseline

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using only ESP for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions **(Bold** values from Table 1.1-5.)															
Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mmBtu)	Particle Type	Particle Ext.Coef.
PC-DB	0.0256	0.0156	0.0087	0.6	0.0069	0.0067	1	0.0003	10	**0.010**	**0.008**	SO4	3*f(RH)	**0.002**	SOA	4

	Controlled PM10 Emissions **(Bold** Values from Table 1.1-6.)															
Boiler Type	Total PM10 (lb/ton)	Filterable (lb/ton)	Coarse (lb/ton)	Ext. Coef.	Fine (lb/ton)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/ton)	Ext. Coef.	Condensible (lb/ton)	CPM IOR (lb/ton)	Particle Type	Particle Ext.Coef.	CPM OR (lb/ton)	Particle Type	Particle Ext.Coef.
PC-DB	0.440	**0.268**	0.149	0.6	**0.119**	0.115	1	0.004	10	0.172	0.137	SO4	3*f(RH)	0.034	SOA	4

	Controlled PM10 Emissions															
Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.	CPM OR (% of Total)	Particle Type	Particle Ext.Coef.
PC-DB	100%	60.9%	33.9%	0.6	27.1%	26.1%	1	1.0%	10	39.1%	31.2%	SO4	3*f(RH)	7.8%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions **(Bold** Value is **Input** by user.)															
Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. Coef.	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)	Particle Type	Particle Ext.Coef.
PC-DB	**119.2**	72.7	40.4	0.6	32.3	31.1	1	1.2	10	46.6	37.3	SO4	3	9.3	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	**40.38**	**lb/hr**	(PMC)
Fine Soil	**31.11**	**lb/hr**	(PMF)
Fine EC	**1.20**	**lb/hr**	(EC)
CPM OR	**9.31**	**lb/hr**	(SOA)
CMP IOR	**5.11**	**lb/hr**	(SO_4)

Entergy White Bluff
Unit 1 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012				Page Reference	
TSAR	=	Total sulfuric acid release			
	=	$\{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$		4-11 (Eqn 4-10)	
	=	44,739.30 lb/year			
where:					
EM_{Comb}	=	H_2SO_4 manufactured from combustion		4-1 (Eqn 4-1)	
	=	K * F1 * E2			
	=	172,605.31 lb/year			
where	K =	Units conversion factor		4-1	
	=	3,063 lb H_2SO_4/ton SO_2		4-1	
	F1 =	Fuel Impact Factor		4-1	
	=	0.0019 *unitless*		4-6 (Table 4-1 for Subbituminous/PRB Coal)	
	E2 =	SO_2 emission rate		4-1	
	=	29,661.00 tons/yr (max day during 2014-2016)		Entergy CAMD data	
EM_{SCR}	=	H_2SO_4 manufactured from SCR/SNCR		4-7	
	=	0 lb/year		SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)	
EM_{FGC}	=	H_2SO_4 manufactured from flue gas conditioning			
	=	$K_e * B * f_e * I_s * F3_{FGC}$	$EM_{FGC\_beforeAPH}$ = 0.00 lb/year	4-9 (Eqn 4-7)	
			$EM_{FGC\_afterAPH}$ = 0.00 lb/year		
where	K_e =	Conversion factor		4-9	
	=	3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)		4-10 (Text Box B)	
	B =	Coal burn		4-9	
	=	82.12 TBtu/yr (max day during 2014-2016)		Entergy CAMD data	
	f_e =	Operating factor of FGC system - the fraction of coal burn when the FGC operates		4-9	
	=	0 *unitless*		No SO_3 FGC	
	I_s =	SO_3 injection rate		4-9	
	=	N/A ppmv at 6% O_2, wet		default value =	7 ppmv if before APH
	$F3_{FGC}$ =	Technology impact factor		4-9	5 ppmv if after APH
	=	0.17 *unitless*		4-9 (for PRB coal)	
$NH3_{SCR}$	=	Ammonia slip produced from SCR/SNCR		4-13	
	=	0 lb/year		SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)	
$F2_{APH}$	=	Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is positive		4-12	
	=	0.36 for air heater		4-18 (Table 4-3 for PRB)	
$NH3_{FGC}$	=	Ammonia produced from FGC		4-14	
	=	$K_e * B * f_e * I_{NH3}$	$NH3_{FGC\_beforeAPH}$ = 0.00 lb/year	4-14 (Eqn 4-14)	
			$NH3_{FGC\_afterAPH}$ = 0.00 lb/year		
where	K_e =	*3,799*		*see above*	
	B =	*82.12*		*see above*	
	f_e =	*0* unitless		No Ammonia FGC	
	I_{NH3} =	NH_3 injection for dual FGC		4-14	
	=	N/A ppmv at 6% O_2, wet		default value =	3 ppmv
$F2_X$	=	Technology impact factors for processes downstream of the APH (product of all that apply)		4-12	
	=	0.72 for cold-side ESP		4-20 (Table 4-4 for PRB)	

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
   "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

PM Speciation Calculations

Entergy White Bluff
Unit 2 Boiler - 2009-2013 Baseline

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using only ESP for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)																
Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mmBtu)	Particle Type	Particle Ext.Coef.
PC-DB	0.0256	0.0156	0.0087	0.6	0.0069	0.0067	1	0.0003	10	**0.010**	**0.008**	SO4	3*f(RH)	**0.002**	SOA	4

	Controlled PM10 Emissions (**Bold** Values from Table 1.1-6.)															
Boiler Type	Total PM10 (lb/ton)	Filterable (lb/ton)	Coarse (lb/ton)	Ext. Coef.	Fine (lb/ton)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/ton)	Ext. Coef.	Condensible (lb/ton)	CPM IOR (lb/ton)	Particle Type	Particle Ext.Coef.	CPM OR (lb/ton)	Particle Type	Particle Ext.Coef.
PC-DB	0.440	**0.268**	0.149	0.6	**0.119**	0.115	1	0.004	10	0.172	0.137	SO4	3*f(RH)	0.034	SOA	4

	Controlled PM10 Emissions															
Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.	CPM OR (% of Total)	Particle Type	Particle Ext.Coef.
PC-DB	100%	60.9%	33.9%	0.6	27.1%	26.1%	1	1.0%	10	39.1%	31.2%	SO4	3*f(RH)	7.8%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions (**Bold** Value is **Input** by user.)															
Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. Coef.	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)	Particle Type	Particle Ext.Coef.
PC-DB	**119.2**	72.7	40.4	0.6	32.3	31.1	1	1.2	10	46.6	37.3	SO4	3	9.3	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	**40.38 lb/hr**	(PMC)
Fine Soil	**31.11 lb/hr**	(PMF)
Fine EC	**1.20 lb/hr**	(EC)
CPM OR	**9.31 lb/hr**	(SOA)
CMP IOR	**4.99 lb/hr**	(SO_4)

Entergy White Bluff
Unit 2 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012				**Page Reference**		
TSAR	= Total sulfuric acid release					
	= $\{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$			4-11 (Eqn 4-10)		
	= 43,750.51 lb/year					
where:						
EM_{Comb} =	H_2SO_4 manufactured from combustion			4-1 (Eqn 4-1)		
=	K * F1 * E2					
=	168,790.55 lb/year					
where K =	Units conversion factor			4-1		
=	3,063 lb H_2SO_4/ton SO_2			4-1		
F1 =	Fuel Impact Factor			4-1		
=	0.0019 *unitless*			4-6 (Table 4-1 for Subbituminous/PRB Coal)		
E2 =	SO_2 emission rate			4-1		
=	29,005.46 tons/yr (max day during 2014-2016)			Entergy CAMD data		
EM_{SCR} =	H_2SO_4 manufactured from SCR/SNCR			4-7		
=	0 lb/year			SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)		
EM_{FGC} =	H_2SO_4 manufactured from flue gas conditioning					
=	$K_e * B * f_e * I_s * F3_{FGC}$	$EM_{FGC\_beforeAPH}$ = 0.00	lb/year	4-9 (Eqn 4-7)		
		$EM_{FGC\_afterAPH}$ = 0.00	lb/year			
where K_e =	Conversion factor			4-9		
=	3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)			4-10 (Text Box B)		
B =	Coal burn			4-9		
=	77.87 TBtu/yr (max day during 2014-2016)			Entergy CAMD data		
f_e =	Operating factor of FGC system - the fraction of coal burn when the FGC operates			4-9		
=	0 *unitless*			No SO_3 FGC		
I_s =	SO_3 injection rate			4-9		
=	N/A ppmv at 6% O_2, wet			default value =	7	ppmv if before APH
$F3_{FGC}$ =	Technology impact factor			4-9	5	ppmv if after APH
=	0.17 *unitless*			4-9 (for PRB coal)		
$NH3_{SCR}$ =	Ammonia slip produced from SCR/SNCR			4-13		
=	0 lb/year			SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)		
$F2_{APH}$ =	Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is positive			4-12		
=	0.36 for air heater			4-18 (Table 4-3 for PRB)		
$NH3_{FGC}$ =	Ammonia produced from FGC			4-14		
=	$K_e * B * f_e * I_{NH3}$	$NH3_{FGC\_beforeAPH}$ = 0.00	lb/year	4-14 (Eqn 4-14)		
		$NH3_{FGC\_afterAPH}$ = 0.00	lb/year			
where K_e =	*3,799*			*see above*		
B =	*77.87*			*see above*		
f_e =	*0* unitless			No Ammonia FGC		
I_{NH3} =	NH_3 injection for dual FGC			4-14		
=	N/A ppmv at 6% O_2, wet			default value =	3	ppmv
$F2_X$ =	Technology impact factors for processes downstream of the APH (product of all that apply)			4-12		
=	0.72 for cold-side ESP			4-20 (Table 4-4 for PRB)		

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
"Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

PM Speciation Calculations

Entergy White Bluff
Unit 1 Boiler - Fuel switch to Low Sulfur Coal

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using only ESP for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)															
Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mmBtu)	Particle Type	Particle Ext.Coef.
PC-DB	0.0256	0.0156	0.0087	0.6	0.0069	0.0067	1	0.0003	10	**0.010**	**0.008**	SO4	3*f(RH)	**0.002**	SOA	4

	Controlled PM10 Emissions (**Bold** Values from Table 1.1-6.)															
Boiler Type	Total PM10 (lb/ton)	Filterable (lb/ton)	Coarse (lb/ton)	Ext. Coef.	Fine (lb/ton)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/ton)	Ext. Coef.	Condensible (lb/ton)	CPM IOR (lb/ton)	Particle Type	Particle Ext.Coef.	CPM OR (lb/ton)	Particle Type	Particle Ext.Coef.
PC-DB	0.440	**0.268**	0.149	0.6	**0.119**	0.115	1	0.004	10	0.172	0.137	SO4	3*f(RH)	0.034	SOA	4

	Controlled PM10 Emissions															
Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.	CPM OR (% of Total)	Particle Type	Particle Ext.Coef.
PC-DB	100%	60.9%	33.9%	0.6	27.1%	26.1%	1	1.0%	10	39.1%	31.2%	SO4	3*f(RH)	7.8%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions (**Bold** Value is **Input** by user.)															
Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. Coef.	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)	Particle Type	Particle Ext.Coef.
PC-DB	**119.2**	72.7	40.4	0.6	32.3	31.1	1	1.2	10	46.6	37.3	SO4	3	9.3	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	**40.38 lb/hr**	(PMC)
Fine Soil	**31.11 lb/hr**	(PMF)
Fine EC	**1.20 lb/hr**	(EC)
CPM OR	**9.31 lb/hr**	(SOA)
CMP IOR	**4.05 lb/hr**	(SO_4)

Entergy White Bluff
Unit 1 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012				Page Reference	
TSAR	=	Total sulfuric acid release			
	=	$\{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$		4-11 (Eqn 4-10)	
	=	35,477.40 lb/year			
where:					
EM_{Comb}	=	H_2SO_4 manufactured from combustion		4-1 (Eqn 4-1)	
	=	K * F1 * E2			
	=	136,872.70 lb/year			
where	K =	Units conversion factor		4-1	
	=	3,063 lb H_2SO_4/ton SO_2		4-1	
	F1 =	Fuel Impact Factor		4-1	
	=	0.0019 *unitless*		4-6 (Table 4-1 for Subbituminous/PRB Coal)	
	E2 =	SO_2 emission rate		4-1	
	=	23,520.60 tons/yr (max day during 2014-2016)		Based on controlled emission factor (lb/MMBtu) and Maximum Unit Heat Input	
EM_{SCR}	=	H_2SO_4 manufactured from SCR/SNCR		4-7	
	=	0 lb/year		SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)	
EM_{FGC}	=	H_2SO_4 manufactured from flue gas conditioning			
	=	$K_e * B * f_e * I_s * F3_{FGC}$	$EM_{FGC\_beforeAPH}$ = 0.00 lb/year	4-9 (Eqn 4-7)	
			$EM_{FGC\_afterAPH}$ = 0.00 lb/year		
where	K_e =	Conversion factor		4-9	
	=	3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)		4-10 (Text Box B)	
	B =	Coal burn		4-9	
	=	82.12 TBtu/yr (max day during 2014-2016)		Entergy CAMD data	
	f_e =	Operating factor of FGC system - the fraction of coal burn when the FGC operates		4-9	
	=	0 *unitless*		No SO_3 FGC	
	I_s =	SO_3 injection rate		4-9	
	=	N/A ppmv at 6% O_2, wet		default value =	7 ppmv if before APH
	$F3_{FGC}$ =	Technology impact factor		4-9	5 ppmv if after APH
	=	0.17 *unitless*		4-9 (for PRB coal)	
$NH3_{SCR}$	=	Ammonia slip produced from SCR/SNCR		4-13	
	=	0 lb/year		SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)	
$F2_{APH}$	=	Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is positive		4-12	
	=	0.36 for air heater		4-18 (Table 4-3 for PRB)	
$NH3_{FGC}$	=	Ammonia produced from FGC		4-14	
	=	$K_e * B * f_e * I_{NH3}$	$NH3_{FGC\_beforeAPH}$ = 0.00 lb/year	4-14 (Eqn 4-14)	
			$NH3_{FGC\_afterAPH}$ = 0.00 lb/year		
where	K_e =	*3,799*		*see above*	
	B =	*82.12*		*see above*	
	f_e =	*0* unitless		No Ammonia FGC	
	I_{NH3} =	NH_3 injection for dual FGC		4-14	
	=	N/A ppmv at 6% O_2, wet		default value =	3 ppmv
$F2_X$	=	Technology impact factors for processes downstream of the APH (product of all that apply)		4-12	
	=	0.72 for cold-side ESP		4-20 (Table 4-4 for PRB)	

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
   "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

PM Speciation Calculations

Entergy White Bluff
Unit 2 Boiler - Fuel switch to Low Sulfur Coal

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using only ESP for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)															
Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mmBtu)	Particle Type	Particle Ext.Coef.
PC-DB	0.0256	0.0156	0.0087	0.6	0.0069	0.0067	1	0.0003	10	**0.010**	**0.008**	SO4	3*f(RH)	**0.002**	SOA	4

	Controlled PM10 Emissions (**Bold** Values from Table 1.1-6.)															
Boiler Type	Total PM10 (lb/ton)	Filterable (lb/ton)	Coarse (lb/ton)	Ext. Coef.	Fine (lb/ton)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/ton)	Ext. Coef.	Condensible (lb/ton)	CPM IOR (lb/ton)	Particle Type	Particle Ext.Coef.	CPM OR (lb/ton)	Particle Type	Particle Ext.Coef.
PC-DB	0.440	**0.268**	0.149	0.6	**0.119**	0.115	1	0.004	10	0.172	0.137	SO4	3*f(RH)	0.034	SOA	4

	Controlled PM10 Emissions															
Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.	CPM OR (% of Total)	Particle Type	Particle Ext.Coef.
PC-DB	100%	60.9%	33.9%	0.6	27.1%	26.1%	1	1.0%	10	39.1%	31.2%	SO4	3*f(RH)	7.8%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions (**Bold** Value is **Input** by user.)															
Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. Coef.	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)	Particle Type	Particle Ext.Coef.
PC-DB	**119.2**	72.7	40.4	0.6	32.3	31.1	1	1.2	10	46.6	37.3	SO4	3	9.3	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	**40.38**	**lb/hr**	(PMC)
Fine Soil	**31.11**	**lb/hr**	(PMF)
Fine EC	**1.20**	**lb/hr**	(EC)
CPM OR	**9.31**	**lb/hr**	(SOA)
CMP IOR	**4.05**	**lb/hr**	(SO_4)

PM Speciation Calculations

Entergy White Bluff
Unit 2 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012						Page Reference	
TSAR	=	Total sulfuric acid release					
	=	$\{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$				4-11 (Eqn 4-10)	
	=	35,477.40 lb/year					
where:							
EM_{Comb}	=	H_2SO_4 manufactured from combustion				4-1 (Eqn 4-1)	
	=	K * F1 * E2					
	=	136,872.70 lb/year					
where	K =	Units conversion factor				4-1	
	=	3,063 lb H_2SO_4/ton SO_2				4-1	
	F1 =	Fuel Impact Factor				4-1	
	=	0.0019 *unitless*				4-6 (Table 4-1 for Subbituminous/PRB Coal)	
	E2 =	SO_2 emission rate				4-1	
	=	23,520.60 tons/yr (max day during 2014-2016)				Based on controlled emission factor (lb/MMBtu) and Maximum Unit Heat Input	
EM_{SCR}	=	H_2SO_4 manufactured from SCR/SNCR				4-7	
	=	0 lb/year				SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)	
EM_{FGC}	=	H_2SO_4 manufactured from flue gas conditioning					
	=	$K_e * B * f_e * I_s * F3_{FGC}$	$EM_{FGC\_beforeAPH}$ =	0.00	lb/year	4-9 (Eqn 4-7)	
			$EM_{FGC\_afterAPH}$ =	0.00	lb/year		
where	K_e =	Conversion factor				4-9	
	=	3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)				4-10 (Text Box B)	
	B =	Coal burn				4-9	
	=	77.87 TBtu/yr (max day during 2014-2016)				Entergy CAMD data	
	f_e =	Operating factor of FGC system - the fraction of coal burn when the FGC operates				4-9	
	=	0 *unitless*				No SO_3 FGC	
	I_s =	SO_3 injection rate				4-9	
	=	N/A ppmv at 6% O_2, wet				default value =	7 ppmv if before APH
	$F3_{FGC}$ =	Technology impact factor				4-9	5 ppmv if after APH
	=	0.17 *unitless*				4-9 (for PRB coal)	
$NH3_{SCR}$	=	Ammonia slip produced from SCR/SNCR				4-13	
	=	0 lb/year				SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)	
$F2_{APH}$	=	Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is positive				4-12	
	=	0.36 for air heater				4-18 (Table 4-3 for PRB)	
$NH3_{FGC}$	=	Ammonia produced from FGC				4-14	
	=	$K_e * B * f_e * I_{NH3}$	$NH3_{FGC\_beforeAPH}$ =	0.00	lb/year	4-14 (Eqn 4-14)	
			$NH3_{FGC\_afterAPH}$ =	0.00	lb/year		
where	K_e =	*3,799*				*see above*	
	B =	*77.87*				*see above*	
	f_e =	*0* unitless				No Ammonia FGC	
	I_{NH3} =	NH_3 injection for dual FGC				4-14	
	=	N/A ppmv at 6% O_2, wet				default value =	3 ppmv
$F2_X$	=	Technology impact factors for processes downstream of the APH (product of all that apply)				4-12	
	=	0.72 for cold-side ESP				4-20 (Table 4-4 for PRB)	

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
   "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

PM Speciation Calculations

Entergy White Bluff
Unit 1 Boiler - DSI with ESP

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using FGD + ESP for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)															
Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mmBtu)	Particle Type	Particle Ext.Coef.
PC-DB	0.0356	0.0156	0.0087	0.6	0.0069	0.0067	1	0.0003	10	**0.020**	**0.016**	SO4	3*f(RH)	**0.004**	SOA	4

	Controlled PM10 Emissions (**Bold** Values from Table 1.1-6.)															
Boiler Type	Total PM10 (lb/ton)	Filterable (lb/ton)	Coarse (lb/ton)	Ext. Coef.	Fine (lb/ton)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/ton)	Ext. Coef.	Condensible (lb/ton)	CPM IOR (lb/ton)	Particle Type	Particle Ext.Coef.	CPM OR (lb/ton)	Particle Type	Particle Ext.Coef.
PC-DB	0.612	**0.268**	0.149	0.6	**0.119**	0.115	1	0.004	10	0.343	0.275	SO4	3*f(RH)	0.069	SOA	4

	Controlled PM10 Emissions															
Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.	CPM OR (% of Total)	Particle Type	Particle Ext.Coef.
PC-DB	100%	43.8%	24.4%	0.6	19.5%	18.8%	1	0.7%	10	56.2%	44.9%	SO4	3*f(RH)	11.2%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions (**Bold** Value is **Input** by user.)															
Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. Coef.	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)	Particle Type	Particle Ext.Coef.
PC-DB	**119.2**	52.3	29.0	0.6	23.2	22.4	1	0.9	10	67.0	53.6	SO4	3	13.4	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	**29.04 lb/hr**	(PMC)
Fine Soil	**22.37 lb/hr**	(PMF)
Fine EC	**0.86 lb/hr**	(EC)
CPM OR	**13.40 lb/hr**	(SOA)
CMP IOR	**0.47 lb/hr**	(SO_4)

PM Speciation Calculations

Entergy White Bluff
Unit 1 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012	**Page Reference**
TSAR = Total sulfuric acid release	
= $\{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$	4-11 (Eqn 4-10)
= 20,695.15 lb/year	
where:	
EM_{Comb} = H_2SO_4 manufactured from combustion	4-1 (Eqn 4-1)
= K * F1 * E2	
= 79,842.41 lb/year	
where K = Units conversion factor	4-1
= 3,063 lb H_2SO_4/ton SO_2	4-1
F1 = Fuel Impact Factor	4-1
= 0.0019 *unitless*	4-6 (Table 4-1 for Subbituminous/PRB Coal)
E2 = SO_2 emission rate	4-1
= 13,720.35 tons/yr (max day during 2014-2016)	Based on controlled emission factor (lb/MMBtu) and Maximum Unit Heat Input
EM_{SCR} = H_2SO_4 manufactured from SCR/SNCR	4-7
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
EM_{FGC} = H_2SO_4 manufactured from flue gas conditioning	
= $K_e * B * f_e * I_s * F3_{FGC}$ $EM_{FGC\_beforeAPH}$ = 0.00 lb/year	4-9 (Eqn 4-7)
$EM_{FGC\_afterAPH}$ = 0.00 lb/year	
where K_e = Conversion factor	4-9
= 3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
B = Coal burn	4-9
= 82.12 TBtu/yr (max day during 2014-2016)	Entergy CAMD data
f_e = Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
= 0 *unitless*	No SO_3 FGC
I_s = SO_3 injection rate	4-9
= N/A ppmv at 6% O_2, wet	default value = 7 ppmv if before APH
$F3_{FGC}$ = Technology impact factor	4-9 5 ppmv if after APH
= 0.17 *unitless*	4-9 (for PRB coal)
$NH3_{SCR}$ = Ammonia slip produced from SCR/SNCR	4-13
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
$F2_{APH}$ = Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is positive	4-12
= 0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$ = Ammonia produced from FGC	4-14
= $K_e * B * f_e * I_{NH3}$ $NH3_{FGC\_beforeAPH}$ = 0.00 lb/year	4-14 (Eqn 4-14)
$NH3_{FGC\_afterAPH}$ = 0.00 lb/year	
where K_e = *3,799*	*see above*
B = *82.12*	*see above*
f_e = *0* unitless	No Ammonia FGC
I_{NH3} = NH_3 injection for dual FGC	4-14
= N/A ppmv at 6% O_2, wet	default value = 3 ppmv
$F2_X$ = Technology impact factors for processes downstream of the APH (product of all that apply)	4-12
= 0.72 for cold-side ESP	4-20 (Table 4-4 for PRB)
$TSAR_{ALKINJ}$ = $(TSAR_{Comb+SCR+FGC}) * F3_{ALKINJ}$	3-9 (Eqn 3-10, DSI)
$TSAR_{Comb+SCR+FGC}$ = 20,695.15 lb/year	
$F3_{ALKINJ}$ = 0.2 Default of 0.2 indicates 80% removal of H2SO4	3-9
= 4,139.03 lb/year	

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm)
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
"Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012.
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

Entergy White Bluff
Unit 2 Boiler - DSI with ESP

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using FGD + ESP for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mmBtu)	Particle Type	Particle Ext.Coef.
	Controlled PM10 Emissions **(Bold** values from Table 1.1-5.)															
PC-DB	0.0356	0.0156	0.0087	0.6	0.0069	0.0067	1	0.0003	10	**0.020**	**0.016**	SO4	3*f(RH)	**0.004**	SOA	4

Boiler Type	Total PM10 (lb/ton)	Filterable (lb/ton)	Coarse (lb/ton)	Ext. Coef.	Fine (lb/ton)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/ton)	Ext. Coef.	Condensible (lb/ton)	CPM IOR (lb/ton)	Particle Type	Particle Ext.Coef.	CPM OR (lb/ton)	Particle Type	Particle Ext.Coef.
	Controlled PM10 Emissions **(Bold** Values from Table 1.1-6.)															
PC-DB	0.612	**0.268**	0.149	0.6	**0.119**	0.115	1	0.004	10	0.343	0.275	SO4	3*f(RH)	0.069	SOA	4

Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.	CPM OR (% of Total)	Particle Type	Particle Ext.Coef.
	Controlled PM10 Emissions															
PC-DB	100%	43.8%	24.4%	0.6	19.5%	18.8%	1	0.7%	10	56.2%	44.9%	SO4	3*f(RH)	11.2%	SOA	4

If you are given Total PM10 emissions in lb/hr:

Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. Coef.	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)	Particle Type	Particle Ext.Coef.
	Controlled PM10 Emissions **(Bold** Value is **Input** by user.)															
PC-DB	**119.2**	52.3	29.0	0.6	23.2	22.4	1	0.9	10	67.0	53.6	SO4	3	13.4	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	**29.04 lb/hr**	(PMC)
Fine Soil	**22.37 lb/hr**	(PMF)
Fine EC	**0.86 lb/hr**	(EC)
CPM OR	**13.40 lb/hr**	(SOA)
CMP IOR	**0.47 lb/hr**	(SO_4)

PM Speciation Calculations

Entergy White Bluff
Unit 2 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012			Page Reference
TSAR	=	Total sulfuric acid release	
	=	{[(EM_{Comb} + EM_{SCR} + $EM_{FGC\_beforeAPH}$) - ($NH3_{SCR}$ + $NH3_{FGC\_beforeAPH}$)] * $F2_{APH}$ + ($EM_{FGC\_afterAPH}$ - $NH3_{FGC\_afterAPH}$)} * $F2_x$	4-11 (Eqn 4-10)
	=	20,695.15 lb/year	
where:			
EM_{Comb}	=	H_2SO_4 manufactured from combustion	4-1 (Eqn 4-1)
	=	K * F1 * E2	
	=	79,842.41 lb/year	
where K	=	Units conversion factor	4-1
	=	3,063 lb H_2SO_4/ton SO_2	4-1
F1	=	Fuel Impact Factor	4-1
	=	0.0019 *unitless*	4-6 (Table 4-1 for Subbituminous/PRB Coal)
E2	=	SO_2 emission rate	4-1
	=	13,720.35 tons/yr (max day during 2014-2016)	Based on controlled emission factor (lb/MMBtu) and Maximum Unit Heat Input
EM_{SCR}	=	H_2SO_4 manufactured from SCR/SNCR	4-7
	=	0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
EM_{FGC}	=	H_2SO_4 manufactured from flue gas conditioning	
	=	K_e * B * f_e * I_s * $F3_{FGC}$ $EM_{FGC\_beforeAPH}$ = 0.00 lb/year; $EM_{FGC\_afterAPH}$ = 0.00 lb/year	4-9 (Eqn 4-7)
where K_e	=	Conversion factor	4-9
	=	3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
B	=	Coal burn	4-9
	=	77.87 TBtu/yr (max day during 2014-2016)	Entergy CAMD data
f_e	=	Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
	=	0 *unitless*	No SO_3 FGC
I_s	=	SO_3 injection rate	4-9
	=	N/A ppmv at 6% O_2, wet	default value = 7 ppmv if before APH
$F3_{FGC}$	=	Technology impact factor	4-9 5 ppmv if after APH
	=	0.17 *unitless*	4-9 (for PRB coal)
$NH3_{SCR}$	=	Ammonia slip produced from SCR/SNCR	4-13
	=	0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
$F2_{APH}$	=	Technology impact factor for APH; only apply if [(EM_{Comb} + EM_{SCR} + $EM_{FGC\_beforeAPH}$) - ($NH3_{SCR}$ + $NH3_{FGC\_beforeAPH}$)] is positive	4-12
	=	0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$	=	Ammonia produced from FGC	4-14
	=	K_e * B * f_e * I_{NH3} $NH3_{FGC\_beforeAPH}$ = 0.00 lb/year; *$NH3_{FGC\_afterAPH}$* = 0.00 lb/year	4-14 (Eqn 4-14)
where K_e	=	*3,799*	*see above*
B	=	*77.87*	*see above*
f_e	=	*0* unitless	No Ammonia FGC
I_{NH3}	=	NH_3 injection for dual FGC	4-14
	=	N/A ppmv at 6% O_2, wet	default value = 3 ppmv
$F2_X$	=	Technology impact factors for processes downstream of the APH (product of all that apply)	4-12
	=	0.72 for cold-side ESP	4-20 (Table 4-4 for PRB)

$TSAR_{ALKINJ}$	=	($TSAR_{Comb+SCR+FGC}$) * $F3_{ALKINJ}$	3-9 (Eqn 3-10, DSI)
$TSAR_{Comb+SCR+FGC}$	=	20,695.15 lb/year	
$F3_{ALKINJ}$	=	0.2 Default of 0.2 indicates 80% removal of H2SO4	3-9
	=	4,139.03 lb/year	

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm)
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
"Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012.
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

Entergy White Bluff
Unit 1 Boiler - DSI with ESP and Fabric Filter

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using FGD+FF for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)

Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mmBtu)	Particle Type	Particle Ext.Coef.
PC-DB	0.0258	0.0058	0.0029	0.6	0.0029	0.0028	1	0.00011	10	**0.020**	**0.016**	SO4	3*f(RH)	**0.004**	SOA	4

Controlled PM10 Emissions (**Bold** Values from Table 1.1-6.)

Boiler Type	Total PM10 (lb/ton)	Filterable (lb/ton)	Coarse (lb/ton)	Ext. Coef.	Fine (lb/ton)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/ton)	Ext. Coef.	Condensible (lb/ton)	CPM IOR (lb/ton)	Particle Type	Particle Ext.Coef.	CPM OR (lb/ton)	Particle Type	Particle Ext.Coef.
PC-DB	0.443	**0.099**	0.050	0.6	**0.050**	0.048	1	0.0018	10	0.343	0.275	SO4	3*f(RH)	0.069	SOA	4

Controlled PM10 Emissions

Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.	CPM OR (% of Total)	Particle Type	Particle Ext.Coef.
PC-DB	100%	22.4%	11.2%	0.6	11.2%	10.8%	1	0.4%	10	77.6%	62.1%	SO4	3*f(RH)	15.5%	SOA	4

If you are given Total PM10 emissions in lb/hr:

Controlled PM10 Emissions (**Bold** Value is **Input** by user.)

Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. Coef.	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)	Particle Type	Particle Ext.Coef.
PC-DB	**119.2**	26.7	13.4	0.6	13.4	12.9	1	0.5	10	92.5	74.0	SO4	3	18.5	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	**13.37**	**lb/hr**	(PMC)
Fine Soil	**12.87**	**lb/hr**	(PMF)
Fine EC	**0.49**	**lb/hr**	(EC)
CPM OR	**18.50**	**lb/hr**	(SOA)
CMP IOR	**0.02**	**lb/hr**	(SO_4)

Entergy White Bluff
Unit 1 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012			**Page Reference**
TSAR	=	Total sulfuric acid release	
	=	$\{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$	4-11 (Eqn 4-10)
	=	886.94 lb/year	
where:			
EM_{Comb}	=	H_2SO_4 manufactured from combustion	4-1 (Eqn 4-1)
	=	K * F1 * E2	
	=	34,218.18 lb/year	
where	K =	Units conversion factor	4-1
	=	3,063 lb H_2SO_4/ton SO_2	4-1
	F1 =	Fuel Impact Factor	4-1
	=	0.0019 *unitless*	4-6 (Table 4-1 for Subbituminous/PRB Coal)
	E2 =	SO_2 emission rate	4-1
	=	5,880.15 tons/yr (max day during 2014-2016)	Based on controlled emission factor (lb/MMBtu) and Maximum Unit Heat Input
EM_{SCR}	=	H_2SO_4 manufactured from SCR/SNCR	4-7
	=	0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
EM_{FGC}	=	H_2SO_4 manufactured from flue gas conditioning	
	=	K_e * B * f_e * I_s * $F3_{FGC}$ — $EM_{FGC\_beforeAPH}$ = 0.00 lb/year	4-9 (Eqn 4-7)
		$EM_{FGC\_afterAPH}$ = 0.00 lb/year	
where	K_e =	Conversion factor	4-9
	=	3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
	B =	Coal burn	4-9
	=	82.12 TBtu/yr (max day during 2014-2016)	Entergy CAMD data
	f_e =	Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
	=	0 *unitless*	No SO_3 FGC
	I_s =	SO_3 injection rate	4-9
	=	N/A ppmv at 6% O_2, wet	default value = 7 ppmv if before APH
	$F3_{FGC}$ =	Technology impact factor	4-9 — 5 ppmv if after APH
	=	0.17 *unitless*	4-9 (for PRB coal)
$NH3_{SCR}$	=	Ammonia slip produced from SCR/SNCR	4-13
	=	0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
$F2_{APH}$	=	Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is positive	4-12
	=	0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$	=	Ammonia produced from FGC	4-14
	=	K_e * B * f_e * I_{NH3} — $NH3_{FGC\_beforeAPH}$ = 0.00 lb/year	4-14 (Eqn 4-14)
		$NH3_{FGC\_afterAPH}$ = 0.00 lb/year	
where	K_e =	*3,799*	*see above*
	B =	*82.12*	*see above*
	f_e =	*0 unitless*	No Ammonia FGC
	I_{NH3} =	NH_3 injection for dual FGC	4-14
	=	N/A ppmv at 6% O_2, wet	default value = 3 ppmv
$F2_X$	=	Technology impact factors for processes downstream of the APH (product of all that apply)	4-12
	=	0.72 for cold-side ESP	4-20 (Table 4-4 for PRB)
	=	0.1 for baghouse in addition to ESP (per S&L report for Enhanced DSI)	4-20 (Table 4-4)
	=	0.072 product of all factors	
$TSAR_{ALKINJ}$	=	$(TSAR_{Comb+SCR+FGC}) * F3_{ALKINJ}$	3-9 (Eqn 3-10, DSI)
	$TSAR_{Comb+SCR+FGC}$ =	886.94 lb/year	
	$F3_{ALKINJ}$ =	0.2 Default of 0.2 indicates 80% removal of H2SO4	3-9
	=	177.39 lb/year	

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm)
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
   "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012.
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

PM Speciation Calculations

Entergy White Bluff
Unit 2 Boiler - DSI with ESP and Fabric Filter

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using FGD+FF for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions **(Bold** values from Table 1.1-5.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/ton)	Coef.	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/mmBtu)	Type	Ext.Coef.	(lb/mmBtu)	Type	Ext.Coef.
PC-DB	0.0258	0.0058	0.0029	0.6	0.0029	0.0028	1	0.00011	10	**0.020**	**0.016**	SO4	3*f(RH)	**0.004**	SOA	4

	Controlled PM10 Emissions **(Bold** Values from Table 1.1-6.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/ton)	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Type	Ext.Coef.	(lb/ton)	Type	Ext.Coef.
PC-DB	0.443	**0.099**	0.050	0.6	**0.050**	0.048	1	0.0018	10	0.343	0.275	SO4	3*f(RH)	0.069	SOA	4

	Controlled PM10 Emissions															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(% of Total)	(% of Total)	(% of Total)	Coef.	(% of Total)	(% of Total)	Coef.	(% of Total)	Coef.	(% of Total)	(% of Total)	Type	Ext.Coef.	(% of Total)	Type	Ext.Coef.
PC-DB	100%	22.4%	11.2%	0.6	11.2%	10.8%	1	0.4%	10	77.6%	62.1%	SO4	3*f(RH)	15.5%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions **(Bold** Value is **Input** by user.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/hr)	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Type	Ext.Coef.	(lb/hr)	Type	Ext.Coef.
PC-DB	**119.2**	26.7	13.4	0.6	13.4	12.9	1	0.5	10	92.5	74.0	SO4	3	18.5	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	**13.37 lb/hr**	(PMC)
Fine Soil	**12.87 lb/hr**	(PMF)
Fine EC	**0.49 lb/hr**	(EC)
CPM OR	**18.50 lb/hr**	(SOA)
CMP IOR	**0.02 lb/hr**	(SO_4)

Entergy White Bluff
Unit 2 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012	Page Reference
TSAR = Total sulfuric acid release	
= $\{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$	4-11 (Eqn 4-10)
= 886.94 lb/year	
where:	
EM_{Comb} = H_2SO_4 manufactured from combustion	4-1 (Eqn 4-1)
= K * F1 * E2	
= 34,218.18 lb/year	
where K = Units conversion factor	4-1
= 3,063 lb H_2SO_4/ton SO_2	4-1
F1 = Fuel Impact Factor	4-1
= 0.0019 *unitless*	4-6 (Table 4-1 for Subbituminous/PRB Coal)
E2 = SO_2 emission rate	4-1
= 5,880.15 tons/yr (max day during 2014-2016)	Based on controlled emission factor (lb/MMBtu) and Maximum Unit Heat Input
EM_{SCR} = H_2SO_4 manufactured from SCR/SNCR	4-7
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
EM_{FGC} = H_2SO_4 manufactured from flue gas conditioning	
= $K_e * B * f_e * I_s * F3_{FGC}$; $EM_{FGC\_beforeAPH}$ = 0.00 lb/year	4-9 (Eqn 4-7)
$EM_{FGC\_afterAPH}$ = 0.00 lb/year	
where K_e = Conversion factor	4-9
= 3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
B = Coal burn	4-9
= 77.87 TBtu/yr (max day during 2014-2016)	Entergy CAMD data
f_e = Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
= 0 *unitless*	No SO_3 FGC
I_s = SO_3 injection rate	4-9
= N/A ppmv at 6% O_2, wet	default value = 7 ppmv if before APH
$F3_{FGC}$ = Technology impact factor	4-9 ; 5 ppmv if after APH
= 0.17 *unitless*	4-9 (for PRB coal)
$NH3_{SCR}$ = Ammonia slip produced from SCR/SNCR	4-13
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
$F2_{APH}$ = Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is positive	4-12
= 0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$ = Ammonia produced from FGC	4-14
= $K_e * B * f_e * I_{NH3}$; $NH3_{FGC\_beforeAPH}$ = 0.00 lb/year	4-14 (Eqn 4-14)
$NH3_{FGC\_afterAPH}$ = 0.00 lb/year	
where K_e = *3,799*	*see above*
B = *77.87*	*see above*
f_e = *0 unitless*	No Ammonia FGC
I_{NH3} = NH_3 injection for dual FGC	4-14
= N/A ppmv at 6% O_2, wet	default value = 3 ppmv
$F2_X$ = Technology impact factors for processes downstream of the APH (product of all that apply)	4-12
= 0.72 for cold-side ESP	4-20 (Table 4-4 for PRB)
= 0.1 for baghouse in addition to ESP (per S&L report for Enhanced DSI)	4-20 (Table 4-4)
= 0.072 product of all factors	
$TSAR_{ALKINJ}$ = $(TSAR_{Comb+SCR+FGC}) * F3_{ALKINJ}$	3-9 (Eqn 3-10, DSI)
$TSAR_{Comb+SCR+FGC}$ = 886.94 lb/year	
$F3_{ALKINJ}$ = 0.2 Default of 0.2 indicates 80% removal of H2SO4	3-9
= 177.39 lb/year	

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm)
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
"Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012.
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

PM Speciation Calculations

Entergy White Bluff
Unit 1 Boiler - DFGD with Fabric Filter

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using FGD+FF for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

Boiler	Controlled PM10 Emissions **(Bold** values from Table 1.1-5.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/ton)	Coef.	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/mmBtu)	Type	Ext.Coef.	(lb/mmBtu)	Type	Ext.Coef.
PC-DB	0.0258	0.0058	0.0029	0.6	0.0029	0.0028	1	0.00011	10	**0.020**	**0.016**	SO4	3*f(RH)	**0.004**	SOA	4

Boiler	Controlled PM10 Emissions **(Bold** Values from Table 1.1-6.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/ton)	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Type	Ext.Coef.	(lb/ton)	Type	Ext.Coef.
PC-DB	0.443	**0.099**	0.050	0.6	**0.050**	0.048	1	0.0018	10	0.343	0.275	SO4	3*f(RH)	0.069	SOA	4

Boiler	Controlled PM10 Emissions															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(% of Total)	(% of Total)	(% of Total)	Coef.	(% of Total)	(% of Total)	Coef.	(% of Total)	Coef.	(% of Total)	(% of Total)	Type	Ext.Coef.	(% of Total)	Type	Ext.Coef.
PC-DB	100%	22.4%	11.2%	0.6	11.2%	10.8%	1	0.4%	10	77.6%	62.1%	SO4	3*f(RH)	15.5%	SOA	4

If you are given Total PM10 emissions in lb/hr:

Boiler	Controlled PM10 Emissions **(Bold** Value is **Input** by user.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/hr)	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Type	Ext.Coef.	(lb/hr)	Type	Ext.Coef.
PC-DB	**119.2**	26.7	13.4	0.6	13.4	12.9	1	0.5	10	92.5	74.0	SO4	3	18.5	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	**13.37 lb/hr**	(PMC)
Fine Soil	**12.87 lb/hr**	(PMF)
Fine EC	**0.49 lb/hr**	(EC)
CPM OR	**18.50 lb/hr**	(SOA)
CMP IOR	**0.01 lb/hr**	(SO_4)

Entergy White Bluff
Unit 1 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012			Page Reference
TSAR		= Total sulfuric acid release	
		= $\{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$	4-11 (Eqn 4-10)
		= 49.27 lb/year	
where:			
EM_{Comb}	=	H_2SO_4 manufactured from combustion	4-1 (Eqn 4-1)
	=	K * F1 * E2	
	=	13,687.27 lb/year	
where	K =	Units conversion factor	4-1
	=	3,063 lb H_2SO_4/ton SO_2	4-1
	F1 =	Fuel Impact Factor	4-1
	=	0.0019 *unitless*	4-6 (Table 4-1 for Subbituminous/PRB Coal)
	E2 =	SO_2 emission rate	4-1
	=	2,352.06 tons/yr (max day during 2014-2016)	Based on controlled emission factor (lb/MMBtu) and Maximum Unit Heat Input
EM_{SCR}	=	H_2SO_4 manufactured from SCR/SNCR	4-7
	=	0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
EM_{FGC}	=	H_2SO_4 manufactured from flue gas conditioning	
	=	$K_e * B * f_e * I_s * F3_{FGC}$ — $EM_{FGC\_beforeAPH}$ = 0.00 lb/year	4-9 (Eqn 4-7)
		$EM_{FGC\_afterAPH}$ = 0.00 lb/year	
where	K_e =	Conversion factor	4-9
	=	3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
	B =	Coal burn	4-9
	=	82.12 TBtu/yr (max day during 2014-2016)	Entergy CAMD data
	f_e =	Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
	=	0 *unitless*	No SO_3 FGC
	I_s =	SO_3 injection rate	4-9
	=	N/A ppmv at 6% O_2, wet	default value = 7 ppmv if before APH
	$F3_{FGC}$ =	Technology impact factor	4-9 — 5 ppmv if after APH
	=	0.17 *unitless*	4-9 (for PRB coal)
$NH3_{SCR}$	=	Ammonia slip produced from SCR/SNCR	4-13
	=	0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
$F2_{APH}$	=	Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is positive	4-12
	=	0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$	=	Ammonia produced from FGC	4-14
	=	$K_e * B * f_e * I_{NH3}$ — $NH3_{FGC\_beforeAPH}$ = 0.00 lb/year	4-14 (Eqn 4-14)
		$NH3_{FGC\_afterAPH}$ = 0.00 lb/year	
where	K_e =	*3,799*	*see above*
	B =	*82.12*	*see above*
	f_e =	*0* unitless	No Ammonia FGC
	I_{NH3} =	NH_3 injection for dual FGC	4-14
	=	N/A ppmv at 6% O_2, wet	default value = 3 ppmv
$F2_X$	=	Technology impact factors for processes downstream of the APH (product of all that apply)	4-12
	=	0.01 for dry FGD and baghouse	4-20 (Table 4-4 for PRB)

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
   "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

PM Speciation Calculations

Entergy White Bluff
Unit 2 Boiler - DFGD with Fabric Filter

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using FGD+FF for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions **(Bold** values from Table 1.1-5.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/ton)	Coef.	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/mmBtu)	Type	Ext.Coef.	(lb/mmBtu)	Type	Ext.Coef.
PC-DB	0.0258	0.0058	0.0029	0.6	0.0029	0.0028	1	0.00011	10	**0.020**	**0.016**	SO4	3*f(RH)	**0.004**	SOA	4

	Controlled PM10 Emissions **(Bold** Values from Table 1.1-6.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/ton)	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Type	Ext.Coef.	(lb/ton)	Type	Ext.Coef.
PC-DB	0.443	**0.099**	0.050	0.6	**0.050**	0.048	1	0.0018	10	0.343	0.275	SO4	3*f(RH)	0.069	SOA	4

	Controlled PM10 Emissions															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(% of Total)	(% of Total)	(% of Total)	Coef.	(% of Total)	(% of Total)	Coef.	(% of Total)	Coef.	(% of Total)	(% of Total)	Type	Ext.Coef.	(% of Total)	Type	Ext.Coef.
PC-DB	100%	22.4%	11.2%	0.6	11.2%	10.8%	1	0.4%	10	77.6%	62.1%	SO4	3*f(RH)	15.5%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions **(Bold** Value is **Input** by user.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/hr)	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Type	Ext.Coef.	(lb/hr)	Type	Ext.Coef.
PC-DB	**119.2**	26.7	13.4	0.6	13.4	12.9	1	0.5	10	92.5	74.0	SO4	3	18.5	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	**13.37 lb/hr**	(PMC)
Fine Soil	**12.87 lb/hr**	(PMF)
Fine EC	**0.49 lb/hr**	(EC)
CPM OR	**18.50 lb/hr**	(SOA)
CMP IOR	**0.01 lb/hr**	(SO_4)

PM Speciation Calculations

Entergy White Bluff
Unit 2 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012			**Page Reference**
TSAR	=	Total sulfuric acid release	
	=	$\{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$	4-11 (Eqn 4-10)
	=	49.27 lb/year	
where:			
EM_{Comb}	=	H_2SO_4 manufactured from combustion	4-1 (Eqn 4-1)
	=	K * F1 * E2	
	=	13,687.27 lb/year	
where	K =	Units conversion factor	4-1
	=	3,063 lb H_2SO_4/ton SO_2	4-1
	F1 =	Fuel Impact Factor	4-1
	=	0.0019 *unitless*	4-6 (Table 4-1 for Subbituminous/PRB Coal)
	E2 =	SO_2 emission rate	4-1
	=	2,352.06 tons/yr (max day during 2014-2016)	Based on controlled emission factor (lb/MMBtu) and Maximum Unit Heat Input
EM_{SCR}	=	H_2SO_4 manufactured from SCR/SNCR	4-7
	=	0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
EM_{FGC}	=	H_2SO_4 manufactured from flue gas conditioning	
	=	$K_e * B * f_e * I_s * F3_{FGC}$ $EM_{FGC\_beforeAPH}$ = 0.00 lb/year	4-9 (Eqn 4-7)
		$EM_{FGC\_afterAPH}$ = 0.00 lb/year	
where	K_e =	Conversion factor	4-9
	=	3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
	B =	Coal burn	4-9
	=	77.87 TBtu/yr (max day during 2014-2016)	Entergy CAMD data
	f_e =	Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
	=	0 *unitless*	No SO_3 FGC
	I_s =	SO_3 injection rate	4-9
	=	N/A ppmv at 6% O_2, wet	default value = 7 ppmv if before APH
	$F3_{FGC}$ =	Technology impact factor	4-9 5 ppmv if after APH
	=	0.17 *unitless*	4-9 (for PRB coal)
$NH3_{SCR}$	=	Ammonia slip produced from SCR/SNCR	4-13
	=	0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
$F2_{APH}$	=	Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is positive	4-12
	=	0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$	=	Ammonia produced from FGC	4-14
	=	$K_e * B * f_e * I_{NH3}$ $NH3_{FGC\_beforeAPH}$ = 0.00 lb/year	4-14 (Eqn 4-14)
		$NH3_{FGC\_afterAPH}$ = 0.00 lb/year	
where	K_e =	*3,799*	*see above*
	B =	*77.87*	*see above*
	f_e =	*0* unitless	No Ammonia FGC
	I_{NH3} =	NH_3 injection for dual FGC	4-14
	=	N/A ppmv at 6% O_2, wet	default value = 3 ppmv
$F2_X$	=	Technology impact factors for processes downstream of the APH (product of all that apply)	4-12
	=	0.01 for dry FGD and baghouse	4-20 (Table 4-4 for PRB)

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
"Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

Entergy Services, Inc., on behalf of Entergy Arkansas, Inc.
White Bluff Steam Electric Station
Redfield, Arkansas (AFIN 35-00110)

Updated BART Five-Factor Analysis for SO_2 for Units 1 and 2

Submitted to:

Arkansas Department of Environmental Quality (ADEQ)
Office of Air Quality
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North Little Rock, AR 72118-5317

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August 18, 2017

Trinity Project 173702.0014

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1 EXECUTIVE SUMMARY

This report provides an update to the Best Available Retrofit Technology (BART) Five Factor Analysis for sulfur dioxide (SO_2) for Unit 1 (SN-01) and Unit 2 (SN-02) at Entergy Arkansas, Inc.'s (EAI's) White Bluff Steam Electric Station (White Bluff) as well as revising the SO_2 BART conclusion. EAI submitted the original BART Five Factor Analysis to the Arkansas Department of Environmental Quality (ADEQ) on February 21, 2013, with revisions on June 10, 2013 and October 15, 2013.

- Unit 1 (SN-01) is a primary boiler with a maximum net power rating of 850 megawatts (MW) and a nominal heat input capacity of 8,950 million British thermal units per hour (MMBtu/hr). The boiler burns sub-bituminous or bituminous coal[1] as the primary fuel and No. 2 fuel oil or biofuel as a start-up fuel, and it is currently equipped with an electrostatic precipitator (ESP) for particulate matter (PM) control.
- Unit 2 (SN-02) is identical in design to Unit 1. It is a primary boiler with a maximum net power rating of 850 MW and a nominal heat input capacity of 8,950 MMBtu/hr. The boiler burns sub-bituminous or bituminous coal[2] as the primary fuel and No. 2 fuel oil or biofuel as a start-up fuel, and it is currently equipped with an ESP for PM control.

Specific updates incorporated in this version of the report are outlined below.

1.1 REPORT UPDATES

This report includes the following updates to the previous SO_2 Five Factor Analysis for White Bluff Units 1 and 2:

1. Updating the baseline period to 2009-2013.

2. Incorporating new information regarding the remaining useful life (RUL) of the units.

3. Incorporating a new control scenario representing combustion of only low-sulfur coal (LSC).

4. Incorporating additional information (i.e., cost information and modeling results) related to control options involving Dry Sorbent Injection (DSI).

5. Updating all modeling to reflect the newest methodologies for dividing ("speciating") particulate matter (PM or PM_{10})[3] emissions into its constituents.

6. Updating the SO_2 BART conclusion in consideration of the new information and updates listed above.

---

[1] The coal-fired units at White Bluff primarily burn sub-bituminous coal, but are permitted to burn bituminous or sub-bituminous coal. Only sub-bituminous coals were burned during the baseline periods evaluated in this analysis.

[2] Ibid.

[3] All PM represented in this report is assumed to have a mass mean diameter smaller than ten microns.

1.2 SUMMARY OF UPDATED BART FIVE FACTOR ANALYSIS

Trinity conducted the below five-step analysis based on EPA's BART Guidelines[4] in 40 CFR Part 51 and other EPA guidance[5] to evaluate SO_2 BART for Units 1 and 2:

1. Identifying all available retrofit control technologies;
2. Eliminating technically infeasible control technologies;
3. Evaluating the control effectiveness of remaining control technologies;
4. Evaluating impacts and documenting the results; and
5. Evaluating visibility impacts.

The updated BART Five Factor Analysis concludes that combustion of LSC constitutes BART for Unit 1 and Unit 2 in light of the updated RUL. The proposed BART emission rate for SO_2 is 0.6 pounds per MMBtu (lb/MMBtu) on a rolling 30-day average.

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[4] The BART guidelines were published as amendments to EPA's Regional Haze Rule (RHR) at 40 CFR 51.308 on July 6, 2005.

[5] April 26, 2012, letter from Mr. Guy Donaldson, EPA Region VI, to Mr. Anthony Davis, ADEQ.

2 INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to pristine conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to pristine conditions in 156 specific areas across the United States known as Class I areas. The CAA defines Class I areas as certain national parks (larger than 6,000 acres), wilderness areas (larger than 5,000 acres), national memorial parks (larger than 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the Best Available Retrofit Technology (BART) rule, which included guidance for making source-specific BART determinations. The BART rule defines BART-eligible sources as sources that meet the following criteria:

(1) Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant,
(2) Began operation between August 7, 1962, and August 7, 1977, and
(3) Are included as one of the 26 listed source categories in the guidance.

A BART-eligible source is subject to BART if the source is "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." For the purpose of determining which sources are subject to BART, a 1.0 Δdv change or more from an individual source is considered to "cause" visibility impairment, and a change of 0.5 Δdv is considered to "contribute" to impairment, which therefore establishes 0.5 Δdv as a numerical screening threshold for subject-to-BART determinations.[6] According to the BART guidelines, the CALPUFF modeling system (CALPUFF) or any other appropriate dispersion model can be used to predict the visibility impacts.[7] The model-predicted visibility impact, specifically when using CALPUFF the 98th percentile impact measured against natural background (and not the maximum impact), is compared to the 0.5 Δdv threshold to determine if the source is anticipated to cause or contribute to the visibility impairment.[8]

Once it is determined that a source is subject to BART, a BART determination must address air pollution control measures for the source. The visibility regulations define BART as follows:

> *…an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by…[a BART-eligible source]. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the cost of compliance, the energy and non-air quality*

[6] "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule," 70 Fed. Reg. 39,116-18 (July 6, 2005).

[7] Trinity and EAI assert that CALPUFF is not the most appropriate model for estimating visibility impacts. Due to its numerous inherent limitations (e.g., limited chemistry mechanism, distance limitations, blanket background ammonia values, etc.), CALPUFF does not yield reliable results. Furthermore, CALPUFF is no longer an EPA-preferred model, which further indicates CALPUFF's unreliability. More advanced models like the Comprehensive Air Quality Model with Extensions (CAMx)—if processed appropriately—can yield more reliable characterizations of visibility impairment. Nevertheless (without waiver), CALPUFF modeling will continue to be presented in this report for consistency with past submittals.

[8] Id. at 39,163.

environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

The BART Guidelines state that a BART determination should address the following five statutory factors:

1. Existing controls;
2. Cost of controls;
3. Energy and non-air quality environmental impacts;
4. Remaining useful life of the source; and
5. Degree of visibility improvement as a result of controls.

Further, the BART Guidelines indicate that the five basic steps in a BART analysis can be summarized as follows:

1. Identify all available retrofit control technologies;
2. Eliminate technically infeasible control technologies;
3. Evaluate the control effectiveness of remaining control technologies;
4. Evaluate impacts and document the results; and
5. Evaluate visibility impacts.

As described in the above-referenced, previous submittals, the boilers at White Bluff meet the three BART-eligibility criteria, and the existing visibility impairment is modeled at greater than 0.5 Δdv in at least one Class I area. Thus, the White Bluff units are subject to BART.

3 EXISTING EMISSIONS AND BASELINE VISIBILITY IMPAIRMENT

Five Factor Analyses require the determination of unit-specific baseline visibility impairment values to which any post-control scenarios can be compared. The unit-specific baseline modeling analyses are built upon, but are distinguished from, the baseline (a.k.a., "screening") modeling for the collection of BART eligible units at each source that is completed to determine if a BART eligible source is subject to BART. EAI is not updating the subject-to-BART determination at this time.

This section summarizes the baseline visibility impairment attributable to each of White Bluff's units based on CALPUFF air quality modeling conducted by Trinity.[9] Trinity conducted the modeling using the same protocol, methodologies, and inputs (except where specifically updated as described in this report) as presented in the October 15, 2013 submittal. The protocol and details method descriptions are not included with this report because nothing has changed and the CALMET dataset developed per the protocol has been used – and approved by EPA – numerous times since its development.

While this report updates the BART Five Factor Analysis for SO_2 emissions specifically, BART modeling must consider emissions of all visibility-affecting pollutants (VAP), including SO_2, oxides of nitrogen (NO_X), and speciated particulate matter, including filterable coarse particulate matter (PMc), filterable fine particulate matter (PMf), elemental carbon (EC), inorganic condensable particulate matter (IOR CPM) as sulfates (SO_4), and organic condensable particulate matter (OR CPM), also referred to as secondary organic aerosols (SOA).

3.1 BASELINE EMISSION RATES

The updated modeled NO_X and SO_2 emission rates for Unit 1 and Unit 2 are the highest actual 24-hour emission rates based on Clean Air Markets Database (CAMD) data from 2009-2013.[10] The updated modeled PM_{10} emission rates for Unit 1 and Unit 2 are based on emission factors from AP-42 for filterable PM_{10} and condensable PM (with a 99.5 percent control efficiency for ESP applied to the PM_{10} filterable fraction) used in conjunction with the average 2009-2013 coal heating value and ash content (as a percentage of mass).[11] Emission rates for specific PM_{10} species were calculated using the monitored filterable PM rate and the National Park Service (NPS) "speciation spreadsheet" for *Dry Bottom Boiler Burning Pulverized Coal using only ESP*[12] except for SO_4, which was calculated using an Electric Power Research Institute (EPRI) methodology that considers the SO_2 to SO_4 conversion rate and SO_4 reduction factors for various downstream equipment.[13] Table 3-1 summarizes the emission rates that were modeled for SO_2, NO_X, and PM_{10}, including the speciated PM_{10} emissions.

---

[9] See footnote 7, above.

[10] The use of this baseline is a conservative approach. EAI would be justified in using a more recent baseline with lower emissions that would result in higher cost effectiveness values.

[11] AP-42, Chapter 1 External Combustion Sources, Section 1.1 Bituminous and Subbituminous Coal Combustion, Table 1.1-5, page 1.1-24 (September 1998).

[12] The baseline speciation is based on the NPS Workbook for a Dry Bottom Boiler burning Pulverized Coal using an ESP. Based on average 2009-2013 values, the following input values were used: heating value of 8,587 Btu/lb, 0.27% sulfur, 4.96% ash, 8,950 MMBtu/hr heat input, and a baseline total PM_{10} emission rate of 119.2 lb/hr at both White Bluff Unit 1 and Unit 2. NPS: http://www.nature.nps.gov/air/Permits/ect/index.cfm.

[13] Electric Power Research Institute (EPRI) Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: EPRI, Technical Update, Palo Alto, CA: March 2012. 1023790.

Table 3-1. Baseline Maximum 24-hour Emission Rates (As Hourly Equivalents)

Unit	SO_2 (lb/hr)	NO_X (lb/hr)	Total PM_{10} (lb/hr)	SO_4 (lb/hr)	PM_c (lb/hr)	PM_f (lb/hr)	SOA (lb/hr)	EC (lb/hr)
SN-01	6,771.9	3,355.4	119.2	5.1	40.4	31.1	9.3	1.2
SN-02	6,622.3	3,590.5	119.2	5.0	40.4	31.1	9.3	1.2

3.2 BASELINE VISIBILITY IMPAIRMENT

Trinity conducted modeling to estimate the current visibility impairment attributable to Unit 1 and Unit 2 in four Class I Areas: Caney Creek Wilderness (CACR), Upper Buffalo Wilderness (UPBU), Hercules Glades Wilderness (HERC), and Mingo Wilderness (MING) using the CALPUFF dispersion model.[14] Table 3-2 provides a summary of the modeled visibility impairment attributable to Unit 1 and Unit 2 based on the emission rates shown in Table 3-1. This table shows the 98th percentile impacts in Δdv and the number of days with impacts greater than 0.5 Δdv.

Table 3-2. Baseline Visibility Impairment

Unit	Year [A]	CACR		UPBU		HERC		MING	
		98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5
SN-01	2001	1.505	38	1.051	30	0.925	24	0.802	16
	2002	1.306	29	0.742	15	0.567	10	0.708	21
	2003	1.053	32	1.033	24	0.704	15	0.666	14
SN-02	2001	1.533	39	1.059	30	0.912	25	0.819	15
	2002	1.322	29	0.739	16	0.568	11	0.719	20
	2003	1.059	32	1.03	25	0.72	16	0.678	14

[A] Meteorological data year modeled.

[14] Due to an EPA-requested change in meteorological data (to a refined, or "NO OBS = 0", dataset), which excluded the Sipsey Class 1 Area from the modeling domain, Sipsey was not included in this analysis. See also footnote 7 above.

4.1 IDENTIFICATION OF AVAILABLE RETROFIT SO_2 CONTROL TECHNOLOGIES FOR UNIT 1 AND UNIT 2

The boilers burn primarily coal. Sulfur oxides, SO_X, are generated during coal combustion from the oxidation of sulfur contained in the fuel. SO_X emissions are almost entirely dependent on the sulfur content of the fuel and are generally not affected by boiler size or burner design. SO_X emissions from conventional combustion systems are predominantly in the form of SO_2. Since SO_2 is the predominant sulfur compound emitted from Unit 1 and Unit 2, the BART analysis is specific to emissions of SO_2. Reductions in emissions of SO_2 are expected to reduce visibility impairment by reducing sulfate (SO_4) formation.

Step 1 of the top-down control review is to identify available retrofit control options for SO_2. The available SO_2 retrofit control technologies for Unit 1 and Unit 2 are summarized in Table 4-1.

Table 4-1. Available SO_2 Control Technologies for Unit 1 and Unit 2

SO_2 Control Technologies
Fuel Switching – Low-Sulfur Coal (LSC)
Dry Sorbent Injection (DSI)
Dry / Semi-Dry Flue Gas Desulfurization (DFGD), e.g., Spray Dryer Absorber (SDA)
Wet Scrubbing, i.e., Wet Flue Gas Desulfurization (WFGD)

4.2 ELIMINATE TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES FOR UNIT 1 AND UNIT 2

Step 2 of the BART determination is to eliminate technically infeasible SO_2 control technologies that were identified in Step 1.

4.2.1 Fuel Switching - Low-Sulfur Coal

With an achievable emission level of 0.6 lb/MMBtu, switching to LSC can reduce SO_2 emissions by approximately 8.75 percent compared to baseline levels.[15]

4.2.2 Dry Sorbent Injection

DSI involves the injection of a sorbent (e.g., Trona) into the exhaust gas stream where acid gases such as hydrogen chloride (HCl) and SO_2 react with and become entrained in the sorbent. The stream then passes through a particulate control device to remove the sorbent along with the entrained SO_2. The process was developed as a lower cost FGD option because the mixing of the SO_2 and sorbent occurs directly in the exhaust gas stream rather than in a separate vessel. Sorbent injection control efficiency depends on residence time, gas stream temperature, and limitations of the particulate control device.

[15] Calculated based on a comparison of the maximum 30 boiler operating day SO_2 emission rate during the baseline period to the proposed limit for low-sulfur coal of 0.6 lb/MMBtu.

DSI is a technically feasible yet seldom used technology for moderate to high removal of SO_2 from coal-fired power plants, with limited full-scale installations for SO_2 control. A significant amount of testing of DSI for SO_2 control has been performed in recent years. This testing has shown that a wide range of performance is achievable (up to 80 or 90 percent SO_2 reduction in some cases). However, this testing has also shown that there are many factors that can impact the performance of these reagents, including particle size (milling), residence time, temperature, and the particulate collection equipment. The primary lesson learned through this testing is that each unit is unique, with various factors that can impact the achievable performance or required reagent feed rate. Different performance has even been seen on sister units. Therefore, it is critical to perform a demonstration or Proof of Concept test at each facility.

A demonstration has not to-date been performed on the White Bluff units to show the achievable SO_2 control and associated reagent feed rates. The cost reports developed by S&L, included in Appendix A, show predicted performance and required reagent rates based on Sargent & Lundy's (S&L's) extensive experience with DSI testing and previous work with the White Bluff units. Two DSI technologies are considered for White Bluff: "DSI", which would utilize the existing ESP, and "enhanced DSI", which would include installation of a fabric filter or baghouse. Enhanced DSI should achieve greater SO_2 reductions because the installation of a fabric filter increases residence time and improves collection efficiency to allow more sorbent to be injected. The S&L reports present predicted performance levels (SO_2 emission rates) for DSI and enhanced DSI of 0.35 lb/MMBtu and 0.15 lb/MMBtu, respectively. Because the actual performance and required reagent rates may vary from the predicted values due to unforeseen site-specific conditions, it is possible that the capital and annual costs represented in the S&L reports, and in Section 4.4.2 of this report, could also vary. If a significantly higher injection rate were actually required to achieve the same performance level (SO_2 emission rate) then the capital and annual costs, and corresponding cost-effectiveness of the DSI technologies, could dramatically increase.

Furthermore, DSI has yet to be demonstrated on similarly sized units to those at White Bluff. An important consideration for DSI technology is the design throughput of the system, beyond just the size and achievable performance (SO_2 emission rate). The largest DSI system installed and operating has a design feed rate of 12 tons/hour, while most of the installed systems inject approximately five to six tons/hour. The predicted injection rate for the White Bluff enhanced DSI case is approximately 15 tons/hour. The greater the injection rates, the more issues associated with supply and delivery logistics that arise. At 15 tons/hour (per unit) White Bluff would consume one railcar (100-ton capacity) of Trona every 3.3 hours if both units are operating at full load.

Prior to moving forward with DSI technology as a compliance strategy, a demonstration test would need to be performed to confirm the feasibility, achievable performance and balance of plant impacts (brown plume formation, ash handling modifications, landfill/leachate considerations and impact to mercury control). The balance of plant impacts have been addressed as part of the S&L cost reports based on typical assumptions, but would also be impacted should the design injection rate vary. Any compliance strategy which were to rely on DSI technology would need to be contingent on successful completion of a demonstration test.

4.2.3 Dry / Semi-Dry Flue Gas Desulfurization

Of the various designs for dry or semi-dry FGD systems, the most popular is the Spray Dryer Absorber (SDA) design. In the SDA design, a fine mist of lime slurry is sprayed into an absorption tower where the SO_2 is absorbed by the slurry droplets. The absorption of the SO_2 leads to the formation of calcium sulfite and calcium sulfate within the droplets. The heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the tower, resulting in the formation of a dry powder that is carried out with the gas and collected with a fabric filter.

SDA systems can achieve control efficiencies ranging from 60 to 95 percent.[16] SDA is a technically feasible option for control of SO_2 from Unit 1 and Unit 2. Based on a site-specific study completed by S&L, SDA could technically achieve an SO_2 emission rate of 0.06 lb/MMBtu at Unit 1 and Unit 2.

4.2.4 Wet Flue Gas Desulfurization

While WFGD is technically feasible, it is not expected to achieve significant reductions beyond DFGD/SDA and was eliminated in the previous analyses and in EPA's final regulations (SIP approval and FIP). Accordingly, WFGD is not considered further in this analysis.

4.3 RANK OF TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS BY EFFECTIVENESS FOR UNIT 1 AND UNIT 2

The third step in the BART analysis is to rank the technically feasible options according to their effectiveness in reducing SO_2.
Table 4-2Table 4-2 provides a ranking of the control levels for the controls listed in the previous section.

Table 4-2. Control Effectiveness of Technically Feasible SO_2 Control Technologies

Control Technology	Achievable Emission Rate (lb/MMBtu) [A]
Semi-Dry Scrubber (SDA)	0.06
Enhanced DSI	0.15
DSI	0.35
Low Sulfur Coal	0.6

4.4 EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS FOR UNIT 1 AND UNIT 2

The fourth step in the BART analysis is the impact analysis, which evaluates the impacts for the control options deemed feasible in Step 2. This analysis typically is conducted to demonstrate that the most effective control technology does not necessarily constitute BART. The BART guidelines list the four factors to be considered in the impact analysis:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The RUL of the source

Because the RUL of the source directly affects the cost of compliance, RUL is considered first.

[16] EPA Basic Concepts in Environmental Sciences, Module 6: Air Pollutants and Control Techniques http://www.epa.gov/eogapti1/module6/sulfur/control/control.htm

4.4.1 Remaining Useful Life

EAI anticipates Unit 1 and Unit 2 will cease to use coal by end of year 2028, and, upon acceptance of the BART determinations contained herein in an approved SIP, is prepared to take an enforceable restriction to this effect.

4.4.2 Cost of Compliance

The capital costs and annual operating and maintenance costs for the considered control options, except for the LSC option, were developed by S&L and are included in Appendix A. The annual cost increase due to burning only LSC is based on a cost premium of $0.50 per ton, which was the premium provided to EAI's fuel purchasing department by its coal suppliers. For the S&L-developed costs, two sets of values are presented. The first, in Table 4-3, is the actual cost estimated for each unit and control option. The second, in Table 4-4Table 4-4, is the estimated cost after excluding cost items that EPA has historically claimed should not be accounted for in BART cost effectiveness calculations. An example of an excluded cost is Allowance for Funds Used During Construction (AFUDC). AFUDC represents the interest expense incurred on the investment in a large capital project, such as a FGD installation, which can take several years to complete (≥ 5 years). Although interest expenses will certainly be incurred on such a project, and AFUDC is typically considered as part of the capital cost of such a project for standard accounting and rate-making purposes, EPA Region 6 has expressed concern with the inclusion of AFUDC and certain other costs. EAI disagrees and believes that determining the cost effectiveness of the control options must realistically reflect the actual cost of compliance. *See* EAI's comments on the proposed FIP.[17] Nonetheless, for completeness, this analysis shows a range of cost effectiveness both including AFUDC and other costs and excluding those costs.

Trinity annualized the capital costs based on capital recovery periods reflecting the total amount of time that the control option could be employed until the unit ceases to use coal at the end of 2028. For the purpose of this report, the start of operation for the SDA option is assumed to be the end of 2021.[18] Therefore, the capital recovery period for SDA is set at seven (7) years (2028 – 2021 = 7 years). The LSC and DSI options can be employed two (2) years earlier than SDA which, for purposes of this report, is assumed to be the end of 2019. Therefore, the capital recovery period for these control options is set at nine (9) years (2028 – 2019 = 9 years).

Trinity determined the values for annual tons of SO_2 reduced by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. The baseline annual emission rate was based on the average rate for the 2009-2013 baseline period.[19] The controlled annual emission rates were based on the lb/MMBtu levels listed in Table 4-2 multiplied by the future annual heat input, which was based on the average actual heat input from CAMD for the 2009-2013 baseline period. For the LSC scenario, "controlled" annual emission rates were based on an 8.75 percent decrease compared to baseline annual emission rates, which is estimated by comparing the maximum 30-boiler operating day rolling average to the controlled emission rate of 0.6 lb/MMBtu.

The cost effectiveness in dollars per ton of SO_2 reduced was determined by dividing the annualized cost of control by the annual tons reduced. Table 4-3 presents a summary of the cost effectiveness for each control

[17] Entergy Arkansas Inc. "Comments On the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas" (EPA Docket ID No. EPA-R06-OAR-2015-0189), August 7, 2015, pp. 10-11.

[18] October 27, 2021 per 81 Fed. Reg. Vol. 81, p. 66416. However, given that actual installation would take at least five years, SDA likely could not be installed until 2023 or later.

[19] As noted above, this is a conservative baseline, and EAI would have been justified in using a more recent baseline with lower emissions that would have resulted in generally higher cost effectiveness values.

option. The cost of switching to low sulfur coal is less than $1,200/ton of SO_2 reduced. The actual cost effectiveness of the add-on controls is economically infeasible at more than $7,000/ton of SO_2 reduced. It's noted (without waiver) that the cost effectiveness of add-on controls even when excluding certain costs for which EPA has expressed concern (e.g., AFUDC), but that will be incurred as explained above, also results in economic infeasibility, at more than approximately $5,400/ton.[20]

Table 4-3. Summary of SO_2 Controls Cost Effectiveness for Unit 1 and Unit 2 Based on Actual Costs

Unit & Control Option	Baseline Emission Rate (tpy)	Controlled Emission Rate (tpy)	Capital Cost ($MM)	Annualized Capital Cost ($MM/yr)	Annual O&M Cost ($MM/yr)	Average Cost Effective-ness ($/ton)	Incremental Cost Effective-ness v. LSC ($/ton)
SN-01 – LSC	15,939	14,544	0	0	1.60	1,150	
SN-02 – LSC	16,034	14,631	0	0	1.61	1,148	
SN-01 – DSI	15,939	9,770	190.11	29.18	14.91	7,148	8,900
SN-02 – DSI	16,034	9,807	190.11	29.18	14.91	7,081	8,807
SN-01 – Enhanced DSI	15,939	4,187	393.74	60.44	26.19	7,372	8,209
SN-02 – Enhanced DSI	16,034	4,203	393.74	60.44	26.19	7,322	8,153
SN-01 – SDA	15,939	1,675	495.74	92.01	9.60	7,124	7,771
SN-02 – SDA	16,034	1,681	495.74	92.01	9.60	7,080	7,722

Table 4-4. Summary of SO_2 Controls Cost Effectiveness for Unit 1 and Unit 2 Based on Costs Adjusted for EPA-Exclusions for Illustration Purposes

Unit & Control Option	Baseline Emission Rate (tpy)	Controlled Emission Rate (tpy)	Capital Cost ($MM)	Annualized Capital Cost ($MM/yr)	Annual O&M Cost ($MM/yr)	Average Cost Effective-ness ($/ton)	Incremental Cost Effective-ness v. LSC ($/ton)
SN-01 – LSC	15,939	14,544	0	0	1.60	1,150	
SN-02 – LSC	16,034	14,631	0	0	1.61	1,148	
SN-01 – DSI	15,939	9,770	154.79	23.76	14.91	6,269	7,764
SN-02 – DSI	16,034	9,807	154.79	23.76	14.91	6,211	7,683
SN-01 – Enhanced DSI	15,939	4,187	321.42	49.34	26.19	6,427	7,137
SN-02 – Enhanced DSI	16,034	4,203	321.42	49.34	26.19	6,384	7,088
SN-01 – SDA	15,939	1,675	364.83	67.71	9.60	5,420	5,883
SN-02 – SDA	16,034	1,681	364.83	67.71	9.60	5,387	5,846

[20] Issues raised on appeal of the federal plan include EPA's use of undervalued cost of controls. However, without waiver of any claims or arguments, EPA's estimates also support the conclusion that SDA is not cost effective. Using EPA's estimates of capital cost ($247,709,875), total O&M cost ($16,877,127), and emissions reductions (14,363 tpy for Unit 1 and 15,221 tpy for Unit 2), adjusted only to consider the shortened remaining useful life value discussed above, the average cost effectiveness values for SDA are $4,376/ton for Unit 1 and $4,129 for Unit 2.

4.4.3 Energy Impacts and Non-Air Quality Impacts

There are numerous energy impacts and adverse non-air quality environmental impacts associated with the add-on controls under consideration. Some examples related to the use of DSI include (a) the need for substantial storage and transportation – both delivery via rail and conveyance on site – of Trona, (b) the forced abandonment of the beneficial re-use of fly ash, and (c) potential negative impacts on the PM control device.[21] These impacts are more fully addressed for all the considered control options in the S&L reports included in Appendix A.

4.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE SO_2 CONTROLS FOR UNIT 1 AND UNIT 2

Trinity conducted an impact analysis to assess the visibility improvement achieved. The impact analysis compared the impacts associated with the baseline emission rates to the impacts associated with the maximum emission rates representative of each control option.

Table 4-5 summarizes the lb/hr emission rates that were modeled to reflect each control option. The NO_X and total PM_{10} emission rates were modeled at the revised 2009-2013 baseline rates. The applicable NPS speciation spreadsheets were relied upon to determine emission rates for PM species.[22,23,24] SO_4 emission rates were independently calculated using an EPRI methodology that considers the SO_2 to SO_4 conversion rate and SO_4 reduction factors for various downstream equipment.[25]

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[21] Sargent & Lundy, *Entergy Arkansas, Inc. White Bluff DSI Cost Estimate Basis Document*, SL-014000 Final, Rev. 0, August 3, 2017, pp. 6-10. *See* Appendix A of this report.

[22] Low sulfur coal PM speciation is based on the NPS Workbook for a Dry Bottom Boiler burning Pulverized Coal using an ESP. The following values were input: heating value of 8,587 Btu/lb, 0.27% sulfur, 4.96% ash, 8,950 MMBtu/hr heat input, and a baseline total PM_{10} emission rate of 119.2 lb/hr at White Bluff Unit 1 and Unit 2. NPS: http://www.nature.nps.gov/air/Permits/ect/index.cfm.

[23] DSI and Enhanced DSI PM speciations are based on the NPS workbooks for a Dry Bottom Boiler burning Pulverized Coal using an FGD system with an ESP or Fabric Filter. The following values were input: heating value of 8,587 Btu/lb, 0.27% sulfur, 4.96% ash, 8,950 MMBtu/hr heat input, and a baseline total PM_{10} emission rate of 119.2 lb/hr at White Bluff Unit 1 and Unit 2. NPS: Ibid.

[24] DFGD speciation is based on the NPS workbook for a Dry Bottom Boiler burning Pulverized Coal using an FGD system with a Fabric Filter. The following values were input: heating value of 8,587 Btu/lb, 0.27% sulfur, 4.96% ash, 8,950 MMBtu/hr, and a baseline total PM_{10} emission rate of 119.2 lb/hr at White Bluff Unit 1 and Unit 2. NPS: Ibid.

[25] Electric Power Research Institute (EPRI) Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: EPRI, Technical Update, Palo Alto, CA: March 2012. 1023790.

Table 4-5. Emission Rates Modeled to Reflect SO_2 Controls for Unit 1 and Unit 2

Unit & Control Option	SO_2 (lb/hr)	SO_4 [A] (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	EC (lb/hr)	SOA (lb/hr)	Total PM_{10} (lb/hr)
SN-01 – LSC	5,370.0	4.0	3,355.4	40.4	31.1	1.2	9.3	119.2
SN-02 – LSC	5,370.0	4.0	3,590.5	40.4	31.1	1.2	9.3	119.2
SN-01 – DSI	3,132.5	0.5	3,355.4	29.0	22.4	0.9	13.4	119.2
SN-02 – DSI	3,132.5	0.5	3,590.5	29.0	22.4	0.9	13.4	119.2
SN-01 – Enhanced DSI	1,342.5	0.02	3,355.4	13.4	12.9	0.5	18.5	119.2
SN-02 – Enhanced DSI	1,342.5	0.02	3,590.5	13.4	12.9	0.5	18.5	119.2
SN-01 – SDA	537.0	0.01	3,355.4	13.4	12.9	0.5	18.5	119.2
SN-02 – SDA	537.0	0.01	3,590.5	13.4	12.9	0.5	18.5	119.2

[A] SO_4 as it is displayed in this table represents ammonium sulfate.

Comparisons of the existing/baseline visibility impacts and the post-control visibility impacts are provided in Table 4-6 and Table 4-7.

Table 4-6. Summary of CALPUFF-Modeled Visibility Impacts from SO_2 Controls for Unit 1 (Across All Modeled Years, 2001-2003)

Scenario	CACR		UBPU		HERC		MING	
	98% Impact (Δdv)	# Days > 0.5 Δdv	98% Impact (Δdv)	# Days > 0.5 Δdv	98% Impact (Δdv)	# Days > 0.5 Δdv	98% Impact (Δdv)	# Days > 0.5 Δdv
Baseline	1.505	99	1.051	69	0.925	49	0.802	51
LSC	1.376	89	0.908	54	0.758	34	0.687	40
Improvement over baseline	*0.129*	*10*	*0.143*	*15*	*0.167*	*15*	*0.115*	*11*
DSI	1.197	64	0.676	30	0.584	19	0.469	17
Improvement over baseline	*0.308*	*35*	*0.375*	*39*	*0.341*	*30*	*0.333*	*34*
Improvement over LSC	*0.179*	*25*	*0.232*	*24*	*0.174*	*15*	*0.218*	*23*
Enhanced DSI	1.013	41	0.496	14	0.458	11	0.366	6
Improvement over baseline	*0.492*	*58*	*0.555*	*55*	*0.467*	*38*	*0.436*	*45*
Improvement over LSC	*0.363*	*48*	*0.412*	*40*	*0.300*	*23*	*0.321*	*34*
Improvement over DSI	*0.184*	*23*	*0.180*	*16*	*0.126*	*8*	*0.103*	*11*
SDA	0.902	35	0.409	7	0.400	6	0.298	2
Improvement over baseline	*0.603*	*64*	*0.642*	*62*	*0.525*	*43*	*0.504*	*49*
Improvement over LSC	*0.474*	*54*	*0.499*	*47*	*0.358*	*28*	*0.389*	*38*
Improvement over DSI	*0.295*	*29*	*0.267*	*23*	*0.184*	*13*	*0.171*	*15*
Improvement over Enhanced DSI	*0.111*	*6*	*0.087*	*7*	*0.058*	*5*	*0.068*	*4*

Table 4-7. Summary of CALPUFF-Modeled Visibility Impacts from SO_2 Controls for Unit 2 (Across All Modeled Years, 2001-2003)

Scenario	CACR		UBPU		HERC		MING	
	98% Impact (Δdv)	# Days > 0.5 Δdv	98% Impact (Δdv)	# Days > 0.5 Δdv	98% Impact (Δdv)	# Days > 0.5 Δdv	98% Impact (Δdv)	# Days > 0.5 Δdv
Baseline	1.533	100	1.059	71	0.912	52	0.819	49
LSC	1.436	89	0.932	55	0.775	35	0.697	41
Improvement over baseline	*0.097*	*11*	*0.127*	*16*	*0.137*	*17*	*0.122*	*8*
DSI	1.259	66	0.700	31	0.609	19	0.486	18
Improvement over baseline	*0.274*	*34*	*0.359*	*40*	*0.303*	*33*	*0.333*	*31*
Improvement over LSC	*0.177*	*23*	*0.232*	*24*	*0.166*	*16*	*0.211*	*23*
Enhanced DSI	1.073	42	0.528	17	0.483	12	0.384	7
Improvement over baseline	*0.460*	*58*	*0.531*	*54*	*0.429*	*40*	*0.435*	*42*
Improvement over LSC	*0.363*	*47*	*0.404*	*38*	*0.292*	*23*	*0.313*	*34*
Improvement over DSI	*0.186*	*24*	*0.172*	*14*	*0.126*	*7*	*0.102*	*11*
SDA	0.959	37	0.427	12	0.426	8	0.318	3
Improvement over baseline	*0.574*	*63*	*0.632*	*59*	*0.486*	*44*	*0.501*	*46*
Improvement over LSC	*0.477*	*52*	*0.505*	*43*	*0.349*	*27*	*0.379*	*38*
Improvement over DSI	*0.300*	*29*	*0.273*	*19*	*0.183*	*11*	*0.168*	*15*
Improvement over Enhanced DSI	*0.114*	*5*	*0.101*	*5*	*0.057*	*4*	*0.066*	*4*

4.6 BART FOR SO_2 FOR UNIT 1 AND UNIT 2

Based on the costs of the control options listed above, BART for Unit 1 and Unit 2, when considering the updated RUL, would be an emission level of 0.6 lb/MMBtu based on the use of low-sulfur coal.

APPENDIX A. CONTROL COST INFORMATION

SO_2 CONTROL COST INFORMATION – LAST UPDATED AUGUST 2017

Table B-8. Baseline Visibility Impairment Attributable to Unit 1 by Pollutant

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek							
2001	2.912	1.505	38	74.33	25.34	0.17	0.15
2002	2.048	1.306	29	61.53	34.59	0.83	3.04
2003	4.020	1.053	32	47.92	50.35	0.35	1.39
Upper Buffalo							
2001	2.089	1.051	30	68.58	31.17	0.26	0.00
2002	1.438	0.742	15	79.11	20.19	0.37	0.32
2003	1.773	1.033	24	79.79	19.92	0.28	0.00
Hercules Glades							
2001	1.643	0.925	24	90.21	9.56	0.23	0.00
2002	1.184	0.567	10	74.20	25.45	0.25	0.10
2003	1.977	0.704	15	86.02	13.73	0.25	0.00
Mingo							
2001	1.538	0.802	16	51.46	48.03	0.39	0.12
2002	0.898	0.708	21	54.87	44.82	0.31	0.01
2003	1.003	0.666	14	57.31	41.18	0.41	1.11

Table B-9. Baseline Visibility Impairment Attributable to Unit 2 by Pollutant

Year	Maximum (Δdv)	98^{th} Percentile (Δdv)	No. of Days with $\Delta dv \geq$ 0.5	98^{th} Percentile % SO_4	98^{th} Percentile % NO_3	98^{th} Percentile % PM_{10}	98^{th} Percentile % NO_2
Caney Creek							
2001	2.994	1.533	39	36.23	60.75	0.74	2.28
2002	2.098	1.322	29	59.43	36.53	0.82	3.22
2003	4.084	1.059	32	96.37	3.38	0.24	0.01
Upper Buffalo							
2001	2.066	1.059	30	66.54	33.21	0.26	0.00
2002	1.447	0.739	16	77.57	21.71	0.37	0.35
2003	1.791	1.030	25	78.24	21.46	0.28	0.00
Hercules Glades							
2001	1.665	0.912	25	89.39	10.38	0.23	0.00
2002	1.185	0.568	11	72.38	27.26	0.25	0.11
2003	1.947	0.720	16	40.35	58.44	0.40	0.82
Mingo							
2001	1.580	0.819	15	81.62	17.93	0.33	0.12
2002	0.886	0.719	20	58.93	40.66	0.19	0.22
2003	0.999	0.678	14	55.08	43.36	0.40	1.17

APPENDIX C. REFINED PM SPECIATION CALCULATIONS

ENTERGY ARKANSAS, INC.

WHITE BLUFF

DSI COST ESTIMATE BASIS DOCUMENT

SL-014000
Final, Rev. 1
April 5, 2018
Project 13027-002

Prepared by

Sargent & Lundy LLC

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1. PURPOSE

Entergy has requested that Sargent & Lundy (S&L) evaluate installation of a new dry sorbent injection (DSI) system on the units at White Bluff to control sulfur dioxide (SO_2) emissions. The purpose of this document is to define the project scope and identify the assumptions that were used as the basis for the operating and maintenance (O&M) and the capital cost estimates.

2. TECHNOLOGY DESCRIPTION

DSI is a proven technology, which has only recently been implemented, for moderate removal of SO_2 and other acid gases from coal-fired power plants. It involves injection of sodium-based sorbents into the ductwork after the boiler and prior to the particulate collection device. DSI is a relatively low capital cost, moderate SO_2 removal alternative to wet or dry FGD systems. No slurry equipment or separate reactor vessel is required with a DSI system. With the proper temperature profile and stoichiometry, the sorbent can effectively react with $SO_2$and other acid gases in the flue gas. The resulting particulate matter is removed from the flue gas by a particulate collection device, typically an existing electrostatic precipitator (ESP).

The typical DSI sorbents include sodium bicarbonate ($NaHCO_3$) and Trona ($Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O$). Sorbent injection into the ductwork (downstream of the boiler and upstream of the ESP) has been tested in the industry using sodium-based sorbents. The process works through neutralization of SO_2 and other acid gases with the caustic sorbent; the neutralization occurs as long as the sorbent remains in contact with the gas. Sorbent injection has been proven effective on a variety of pulverized coal-fired boilers using a range of low to high sulfur coals. It is considered a commercial technology although with a limited supplier base due to the historically limited interest.

The DSI process produces a dry byproduct which can be landfilled. The waste products will contain sodium sulfate and sulfite ($NaSO_3$/$NaSO_4$) along with the unused sorbent and the normal fly ash. These wastes will be collected in the ESP and can be transported with conventional pneumatic fly ash handling equipment. The waste from sodium-based sorbents will have relatively high concentrations of soluble salts, which may affect the byproduct handling. With the addition of dry sorbent byproducts fly ash cannot be sold for reuse.

3. APPROACH

The project capital and O&M cost estimates are based on project-specific information, including:

- An engineer-procure-construct (EPC) contracting strategy with the DSI technology supplier providing the main process equipment, including reagent storage, milling, conveyance, and injection lances.
- Reagent injection at the air preheater (APH) outlet, upstream of the existing ESP. The cost to rebuild/upgrade the ESP was included to ensure there is no increase in PM emissions as a significant quantity of reagent will be added upstream of the existing ESP.
- On-site disposal of DSI byproduct using upgraded ESP ash handling equipment. The byproduct will be collected in the existing ESP in conjunction with the fly ash from the units; no additional blending equipment is required.
- Reagent injection rates based on 50% SO_2 removal from a design inlet concentration of 0.76 lb SO_2/MMBtu, based on the highest 5% of SO_2 emissions from 2009 through 2013.
  - Annual operating costs will be based on 50% SO_2 removal from an uncontrolled SO_2 rate of 0.57 lb SO_2/MMBtu, based on the annual heat input weighted average emission from 2009 through 2013.
  - The system will be designed to control emissions to meet a permit limit of 0.35 lb/MMBtu on a 30-boiler day rolling average, based on a maximum 30-day average SO_2 emission rate of 0.66 lb/MMBtu from 2009 through 2013.
- Trona was used as the DSI reagent for the purposes of this estimate.
- Increase in carbon consumption by 1 lb/mmacf to mitigate any impacts on mercury performance associated with ACI/DSI interference and mitigate potential for a brown plume.
- A high level conceptual system design, based on the estimated injection rate, was used as input to the DSI cost estimate. The following were estimated based on previous projects and scaled for the predicted dry sorbent injection rate for White Bluff:
  - Auxiliary power consumption
  - Annual reagent consumption
  - Additional carbon consumption
  - Additional water consumption
  - Additional waste production
  - Reagent storage silos
  - Quantity of mills
  - Quantity of blower trains

The total plant capital cost estimate includes the following:

- Equipment and material
- Installation labor
- Indirect field costs
- Freight
- General and Administration
- Erection contractor profit
- Engineering, Procurement and Project Services
- Spare parts/initial fills (other than reagent)
- EPC Fee

As part of this project, S&L estimated the costs for Owner's services and costs outside of the EPC contract including the following:

- Owner's Costs
- Owner's Engineer
- Construction Management Support
- Startup and Commissioning Support
- Performance Testing
- Contingency
- Escalation
- Interest During Construction

Cost Estimate 34018A provided in Attachment 1 represents the total cost to Entergy to install DSI technology on a single unit at White Bluff (Unit 1 or 2) including the EPC Contract price and all additional Owner's costs and third party services.

The total unit O&M cost estimate includes the following:

- Waste disposal (DSI waste + increased carbon + unsold fly ash)
- Loss of revenue from fly ash sales
- Reagent consumption (including increased carbon consumption)
- Auxiliary power consumption
- Low quality water consumption for mill cleaning
- Operating labor
- Maintenance material
- Maintenance labor

The O&M Cost Estimate and Capital Cost Estimate 34018A were developed using the assumptions and scope provided in this document. The project definition and accuracy corresponds to a study level estimate as defined in U.S.EPA's Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual. The costs provided in this report are in 2016 dollars.

4. CAPITAL AND O&M COST ESTIMATE TECHNICAL BASIS

4.1 DESIGN INPUTS AND ASSUMPTIONS

The following assumptions were made for the design basis for the White Bluff DSI Systems:

- Design SO_2 inlet concentration of 0.76 lb SO_2/MMBtu.
- SO_2 inlet concentration of 0.57 lb SO_2/MMBtu for annual operating costs.
- Design SO_2 removal efficiency of 50% (defined by injection rate, described in Section 4.1.1)
- Annual capacity factor of 71.2% (annual average capacity factor for White Bluff Units 1 and 2 based on historical heat input from 2009 through 2013).
- Reagent injection at the APH outlet, upstream of the existing ESP.
- Reagent delivery by rail.
- Existing activated carbon silo storage time will be reduced, rather than adding additional or larger storage silos to the system.
- Compliance deadline of three years from the effective date of the rule.

Before proceeding with a DSI project, a demonstration test should be completed at White Bluff to confirm the feasibility of DSI technology at White Bluff and quantify the potential BOP impacts associated with the project, such as impacts to the ESP performance, interference with mercury control technologies, and leachability of the byproduct.

4.1.1 ESP/Ash Handling Modifications

The DSI system, as defined in this report would require an estimated Trona injection rate of approximately 22,000 lb/hour to achieve 50% reduction at the design SO_2 inlet concentration. This injection rate would result in an increase in the particulate loading to the ESP of almost 40% from the current ash loading, due to the DSI byproducts and unreacted DSI reagent.

The addition of sodium compounds to the fly ash lowers the overall resistivity of the particulate being captured as well as shifting the particle size distribution. These changes have been shown to improve the removal efficiency of an ESP; in some cases this increase has been shown to offset the increased particulate loading to the ESP.

ESP performance can also be negatively impacted by a significant increase in particulate loading associated with the high reagent injection rates required for SO_2 control. It is uncertain whether modifications to the ESPs and ash handling systems would be required to accommodate the addition of DSI at White Bluff. However, at the very high injection rates expected for this project, an ESP rebuild will likely be required to ensure the PM emissions stay below the PSD threshold. Therefore, the capital cost estimate includes the costs to completely rebuild the existing ESPs and ash handling systems at White Bluff.

The size and condition of the existing ESP can play a critical role in the overall performance of DSI. In order to evaluate the existing White Bluff ESP with respect to future operation with DSI, S&L used the EPA program ESPVI 4.0W Performance Prediction Model (ESPVI 4.0W) to simulate the baseline and future operating scenarios, as described below. In addition, S&L contacted an ESP vendor to provide input relating to installation of DSI upstream of the existing ESPs at White Bluff.

The baseline operation was established using various design inputs for the units (as needed by the ESPVI 4.0W model), recent operating data and stack emissions to estimate the efficiency at which the ESP is currently operating. ESPVI 4.0W showed that at the baseline operating conditions the White Bluff ESP operates at approximately 99.7% removal of the total inlet loading, corresponding to a filterable PM emission limit of 0.0155 lb/MMBtu.

ESPs operate at a constant efficiency assuming the operating conditions (such as temperature, ash resistivity, or flue gas velocity) stay the same. DSI can impact some of the operating conditions, specifically ash resistivity and particle size distribution. The addition of DSI thus could result in a higher efficiency than the same ESP, without DSI, could achieve.

The ESPVI 4.0W model was developed prior to the introduction of DSI technology and has not been updated to account for the impacts of adding sorbents upstream of the ESP. However, the model was used to predict the high level impact and/or limitations of installing DSI technology by modifying some of the inputs to simulate the characteristics of a fly ash/sodium sorbent mixture.

Based on the modified ash resistivity and adjusted particle sizes associated with the addition of DSI, the baseline ESPVI 4.0W model was used to estimate the predicted removal efficiency for the White Bluff ESP with DSI, as defined in this report, and assuming all other operating conditions remained the same. ESPVI 4.0W showed an overall removal efficiency which was very similar to the current ESP removal efficiency and resulted in an increase in particulate emissions with the additional loading from the DSI system.

Based on the results from ESPVI 4.0W, the White Bluff ESP may be operating at a marginally higher reduction efficiency with the installation of DSI; however, the loading to the ESP is also increasing significantly. Therefore, the modeling showed that even though the ESP efficiency may increase, the overall PM emissions will still be higher than the current level. This evaluation supports the conclusion that improvement of the existing ESP in conjunction with the DSI project is necessary to avoid increasing PM emissions.

In addition to the modeling that was performed using ESPVI 4.0W, S&L also engaged a vendor experienced with ESP retrofits to provide costs and expertise associated with injection of DSI on an existing ESP. As part of their budgetary quote, the supplier indicated that "while the ESPs are large they are still an efficiency machine and overcoming the new total inlet loading of over 73,000 lb/hr[1] will be extremely difficult to achieve the requested 0.015 lbs/MMBtu outlet PM emissions, without retrofitting the entire ESPs to BART technology. Essentially, the ESPs will need to be rebuilt to 'as-new' condition with the most state-of-the-art technology options" (see Attachment 2).

Finally, in addition to the performance of the ESP, the increased loading will also have an impact on the ash handling system. Therefore, for the purposes of this cost estimate, based on the significant increase in loading, modifications to the ash handling equipment were included in the cost estimate.

4.1.2 Landfill Modifications

The sodium byproducts (salts) that are produced when Trona reacts with SO_2 and other acid gases, along with the unreacted sorbent are soluble in water. The resulting waste collected in the particulate collection device will need to be disposed of in a landfill that is lined and has a leachate collection system. With the addition of DSI, White Bluff will no longer be able to sell their fly ash for beneficial re-use due to the solubility of the sodium salts which would be

[1] The 73,000 lb/hr loading reflects the design fly ash loading plus the additional loading from the DSI injection (byproduct/unreacted sorbent).

present in the waste. The cost to maintain a landfill and open new cells is included in the typical maintenance budget of a plant. It was assumed, that any future landfill cells would include lining and leachate collection; therefore, no landfill modifications will be required to accommodate the addition of DSI and no costs were included in this estimate.

4.2 TOTAL INSTALLED CAPITAL INVESTMENT

The DSI system supplier will provide all of the equipment related to storing, milling, conveying and injecting the reagent; in this case, the system is designed for Trona. The remaining BOP scope will be provided by the EPC Contractor. In addition, the EPC Contractor will install/construct the entire system including the equipment provided by the DSI system supplier.

Quantities were developed based on limited project design effort, project experience of a plant of comparable size and then adjusted based on actual size and capacity differences and also taking into consideration the specific site layout based on the general arrangement. In most cases, the costs for bulk materials and equipment were derived from S&L database and recent vendor or manufacturer's quote for similar items on other projects. The scope of work for the capital cost estimate is broken out by the following areas:

4.2.1 DSI Area (Single Unit)

a. Reagent Storage Silos:
- Twelve silos capable of storing approximately 14 days of sorbent per unit, 4,200-tons storage total, including substructure
- 14' diameter and 125' high, each
- 350-tons working storage, each
- Continuous level detection systems
- One bin vent filter per silo
- Live bottom hopper outlets
- Rotary airlock assemblies

b. Reagent conveying systems:
- 4 trains (4 x 50%)
- Pneumatic pressure blowers (1 x100% per train)
- One dehumidifier and chiller per train

c. Reagent Milling
- One 7-tph mill per train
- One set of bypass piping per mill

d. Reagent Injection
- Splitters with piping to two APH outlets
- Six injection lances per injection location

e. Concrete foundations including piles for all reagent silo, blower, and mill areas; the approximate footprint for DSI Area is 165’ x 125’

f. Buildings, enclosures, and roofs, including:
- Blower Building, approximately 25’ x 100’
- Electrical Building; approximately 15’ x 20’
- Mill Building; approximately 40 x 80’
- Dehumidifier Roof; approximately 30’ x 125’
- Heat Exchanger Roof; approximately 10’ x 80’

g. Geotechnical and subsurface investigation contractor work, including hydro excavation

h. Equipment pricing based on recent vendor pricing for a similar project.

4.2.2 Reagent Handling System

The conceptual design basis for the reagent handling system is to unload two cars at a time. Based on the estimated injection rate and typical railcar capacities, it is anticipated that approximately 20 railcars will be required each week per unit assuming a 100% capacity factor. The reagent handling system includes modification to the existing rail spur on-site to accommodate storage and handling of the reagent railcars. It was assumed that the reagent will be delivered via a 25-car unit train as a maximum. The following equipment and components are included in the cost estimate as part of the reagent handling system:

a. Reagent rail car unloader:
- System consists of mobile receiving pad and associated vacuum pneumatic connection equipment to unload railcar
- Enclosed railcar unloading building; approximately 200’ x 75’
- Trackmobile used to haul and queue the rail cars before and after unloading; capable of moving approximately 25 cars at once.

b. Reagent unloading systems:
- Two trains (2 x 100%)
- Pneumatic pressure blowers (1 x 100%) per train
- One conveying air dehumidifier and chiller per train
- Pneumatic conveying piping located on an above-grade sleeper pipe rack
- The equipment pricing included in this estimate is based on recent firm pricing for similar projects. The basis of the conceptual design is a typical UCC arrangement and equipment.

c. Rail track spur extension to north to allow reagent train to be unloaded and cars to be stored on site, designed for 136 lb rail to be consistent with existing coal spurs

4.2.3 ESP/Ash Handling Modifications

a. ESP Rebuild – Based on the budgetary quote provided in Attachment 2.

b. Ash Handling Modifications – Equipment pricing based on recent vendor pricing for a similar project.

4.2.4 Civil Work

a. Site grading

b. Soil removal earthwork

c. Excavation, backfill, and compaction for all foundations

d. Development of a new laydown area, approximately 2 acres, including site preparation, fencing, and temporary power. It was assumed that this area would be located on existing plant property, and does not require land to be purchased.

4.2.5 Mechanical Work

a. Allowance of $975,000 provided for mechanical system including transport piping, pipe rack, instrument/service air and other miscellaneous items based on recent in-house cost estimates for similar projects.

4.2.6 Demolition/Relocation

a. Allowance of $650,000 is provided for demolition and relocation of existing equipment and infrastructure which may interfere with the new DSI system based on recent in-house cost estimates for similar projects.

4.2.7 Electrical

a. Allowance of $3,575,000 is provided for electrical equipment upgrades and modifications based on recent in-house cost estimates for similar projects.

4.2.8 Instrumentation

a. Allowance of $520,000 provided for DCS upgrades and added instrumentation based on recent in-house cost estimates for similar projects.

4.2.9 Labor Costs

Installation/labor costs were included in the base estimate under the direct costs. Manhours are estimated for each item in the base estimate and are based on the type of work and typical estimates for similar work. The labor costs are based on the labor wage rates and labor crews developed by S&L.

a. Labor Wage Rates

Crew labor rates were developed using prevailing craft rates and fringe benefits and state specific worker's compensation rates as published in the 2016 edition of R.S. Means Labor Rates for Pine Bluff, Arkansas area. Costs were added to cover FICA, workers compensation, all applicable taxes, small tools, incidentals, construction equipment, and contractor's overhead. State specific workman's compensation rates are from R.S. Means. A 1.15 geographic labor productivity multiplier is included based on the Compass International Construction Yearbook for Arkansas. The crew rates do not include an allowance for weather related delays.

b. Labor crews

Construction/erection labor cost is based on the use of applicable construction crews typically required for projects of this type. The construction crew costs were specifically developed for utility industry and are proprietary to S&L. The prevailing craft rates are incorporated into work crews appropriate for the activities; and include costs for small tools, construction equipment, insurance, and site overheads.

4.2.10 Other Direct and Construction Indirect Costs

In addition to the base labor costs, other construction indirect costs for the project were broken out in the estimate as well as other contractor direct costs. The following items were included as other direct and construction indirect costs.

a. Scaffolding and Consumables

b. Premiums and per diems ($10 per hour)

c. Overtime at five 10-hour shifts per week

d. Freight on construction materials

e. Contractor's General & Administration Fees (included at 10% of total direct costs)

f. Contractor's Profit (included at 5% of total direct costs)

g. Sales tax was included in the cost estimate at 8.125%.

Freight on the DSI System equipment was not included in the cost estimate.

4.2.11 EPC Indirect Costs

The final contribution to the overall EPC project price are the EPC Contractor's indirect costs; these include the EPC engineering services, startup spare parts and initial fills, technical field advisors, and the EPC risk fee.

a. EPC Engineering Services

The EPC engineering services was estimated based on recent projects with similar scopes and schedules. The total cost of the EPC engineering services was estimated to be $4,000,000.

b. Startup Spare Parts and Initial Fills

An allowance has been included for initial fills for equipment, including first fills for lubrication of any motorized equipment. The initial fill of Trona was not included in the EPC Contractor's scope, as this will be supplied by the Owner and is covered as part of the Owner's Costs. The total cost of the initial fills was estimated to be $75,000.

c. Technical Field Advisors (Vendors)

Allowances were included for equipment supplier's technical field advisory services based on an estimated 150 man-days. The estimate includes technical field advisors for the DSI system supplier (including DSI system subcontractors) and the DCS supplier. The total cost of the technical field advisors was estimated to be $300,000.

d. EPC Risk Fee

An EPC approach provides an alternative which is expected to reduce risk for Entergy by placing the responsibility for the project on a single entity, the EPC Contractor. The EPC risk fee is a premium charged by the contractor which accounts for the additional coordination and management of the project as well as the additional risk assumed by the contractor. Based on S&L's experience with recent EPC projects, an EPC risk fee was included at 10% of the total EPC project costs.

4.2.12 Owner's Costs and Services

Outside of the EPC Contractor's total cost, Entergy will incur other costs associated with the project, such as services procured from third parties (including Owner's engineer, construction management support, startup and commissioning support and performance testing), and other project related costs.

a. Owner's Costs

Owner's Costs are direct costs that the Owner incurs over the life of the project. The following items are real costs Entergy will incur to install DSI at White Bluff based on the scope and schedule of this project:

- Internal Labor
- Internal Indirects
- Travel Expenses
- Legal Services
- Builders Risk Insurance
- Initial Fills (Reagent)

Owner's costs were included in the estimate at 8% of the total project cost.

b. Construction Management Support

The construction management support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform the tasks, and therefore it will be outsourced. The cost of labor is based on present day cost. The total cost of the construction management support was estimated to be $1,500,000.

c. Startup and Commissioning Support

The startup and commissioning support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform the tasks, and therefore it will be outsourced. The total cost of the startup and commissioning support was estimated to be $300,000.

d. Owner's Engineer

The Owner's Engineer cost was developed as a high level estimate based on a typical scope for Owner's Engineer work for this type of project; including the following tasks:

- Conceptual Study Support
- EPC Specification Supporting Documents
- Project Schedule Development
- EPC Specification Development
- EPC Bid Evaluation and Contract Conformance
- General Project Support
  - Monthly Project Status Meetings
  - Weekly Teleconferences
  - Overall Coordination
  - Project Administration
  - Site Visits and Travel
- Permitting Support
- Design Review of Drawing Submittals
- Technical support during design, fabrication, construction, commissioning, and testing
- Equipment vendor QA/QC audits

The total cost of the Owner's Engineer was estimated to be $1,750,000.

e. Performance testing

The cost for performance testing was developed as a factored estimate using costs from projects of similar scope. This cost includes the testing, performed by a third-party contractor hired by the Owner, and also includes the cost for S&L's assistance in the following tasks:

- Development of the test protocol
- Procuring the services of the testing contractor
- Overseeing the performance test campaign
- Evaluating the results of the testing with respect to guarantee compliance

The estimate for the third party testing contractor is based on the assumption that the contractor would be onsite for up to 3 days. The total cost of the Performance Testing was estimated to be $175,000.

f. Contingency

Contingency is included in the estimate to cover the uncertainty associated with the project costs. The cost estimate includes a recommended contingency of 25%, which is consistent with cost estimating guidelines for a conceptual design and the current level of project definition. Contingency was applied to the total project costs before escalation.

g. Escalation

Escalation was included in the estimate based on a typical schedule for implementation of a DSI system at an escalation rate of 2.15% on equipment and materials and 3.35% on labor and indirects. These escalation rates were developed by S&L based on recent pricing and in-house escalation projections.

h. Interest During Construction

Interest during construction (IDC) accounts for the time value of money associated with the distribution of construction cash flows over the construction period. IDC was applied to the total EPC project costs including contingency. The IDC was calculated based on a typical schedule for implementation of a DSI system and a typical interest rate of 7.8% per year which was assumed based on a low interest market environment.

4.3 VARIABLE OPERATING AND MAINTENANCE COSTS

The following unit costs were used to develop the variable O&M costs for each reagent specific system. All of these values, with the exception of the reagent costs, were provided by Entergy. The reagent costs are based on recent pricing received by S&L for another project.

Table 4-1: Unit Pricing for Utilities (Provided by Entergy)

Unit Cost	Units	Value
Trona	$/ton	$205
Activated Carbon	$/ton	$1,700
Low Quality Water	$/1000 gal	$0.53
Byproduct Disposal	$/ton	$7.50
Fly Ash Revenue	$/ton	$5.85
Aux Power Cost [1]	$/MWh	$41.02

Note 1: Entergy provided auxiliary power costs for the first year of operation.

Table 4-2 below summarizes the consumption rates estimated as well as the first year variable O&M costs for each case. The reagent consumption rate was developed using a normalized stoichiometric ratio (NSR) of 1.3 which is consistent with test data for similar projects.

Table 4-2: Variable O&M Rates and First Year Costs

	Units	Value
DSI System Parameters		
Reagent Consumption	lb/hr	16,500
Increased Carbon Consumption	lb/hr	210
DSI Waste Production + Increased Carbon + Unsold Fly Ash[3]	lb/hr	40,700
Aux Power Consumption	kW	1,700
Low Quality Water Consumption	gpm	4

	Units	Value
First Year[1] Variable O&M Costs (@CF[2])		
Reagent Cost	$/year	$10,548,500
Waste Disposal Cost (DSI Waste + Increased Carbon + Unsold Fly Ash)	$/year	$951,900
Increased Carbon Consumption Cost	$/year	$1,113,000
Aux Power Cost	$/year	$434,900
Low Quality Water Cost	$/year	$800
Loss of Fly Ash Sales[3]	$/year	$496,000
Total First Year Variable O&M Cost	**$/year**	**$13,545,100**

Note 1: First year costs are provided in $2016.

Note 2: The first year costs are calculated using an annual capacity factor of 71.2%.

Note 3: Assumes 57% of the station's fly ash was being sold on an annual basis for an average of approximately $5.85 per ton (based on historical data from Entergy).

4.4 FIXED O&M COSTS

The fixed O&M costs for the systems consist of operating personnel as well as maintenance costs (including material and labor). The recommended staffing additions for the DSI system are 9 personnel for one system.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (maintenance and labor) were estimated to be approximately 0.3% of the project capital. Items such as track work and civil work would be considered high capital cost items with little to no maintenance. Table 4-3 below summarizes the first year fixed O&M costs for the design and typical cases.

Table 4-3: First Year Fixed O&M Costs

First Year[1] Fixed O&M Costs	Units	Value
Operating Labor[2]	$/year	$1,066,000
Maintenance Material	$/year	$180,000
Maintenance Labor	$/year	$120,000
Total First Year Fixed O&M Cost	**$/year**	**$1,366,000**

Note 1: First year costs are provided in $2016.

Note 2: Operating labor costs are based on a labor rate of $56.95, which was provided by Entergy.

Note 3: Installation of systems on a single unit would require 9 operators total.

5. ATTACHMENTS

1. White Bluff Station DSI System EPC Conceptual Cost Estimate, Sargent & Lundy Estimate No. 34018A
2. ESP Rebuild Budgetary Quote

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
DSI SYSTEM EPC

Estimator	A. KOCI
Labor rate table	16ARPBL
Project No.	13027-004
Estimate Date	10/20/2016
Reviewed By	MNO
Approved By	MNO
Estimate No.	34018A
Cost index	ARPBL

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
DSI SYSTEM EPC

Area	Description	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Total Cost
101	UNIT 1 OR 2 (SINGLE UNIT) DSI AREA	3,359,550	15,000,000	527,160	18,441	11,107,036	29,993,746
102	REAGENT HANDLING SYSTEM	1,505,400	1,360,000	1,218,523	26,487	1,956,963	6,040,885
103	ESP/ASH HANDLING MODIFICATIONS	50,000,000	1,050,000		9,885	680,982	51,730,982
104	EARTHWORK			79,496	2,169	183,755	263,251
105	UPGRADE PLANT ENTRANCE						
106	LAYDOWN AREAS			156,000	1,839	146,722	302,722
107	MECHANICAL MISCELLANEOUS	975,000					975,000
108	DEMOLITION / RELOCATION COSTS	650,000					650,000
109	ELECTRICAL	3,575,000					3,575,000
110	INSTRUMENTATION	520,000					520,000
	TOTAL DIRECT	60,584,950	17,410,000	1,981,179	58,822	14,075,457	94,051,586

Estimate Totals

Description	Amount	Totals	Hours
Direct Costs:			
Labor	14,075,457		58,822
Material	1,981,179		
Subcontract	60,584,950		
Process Equipment	17,410,000		
	94,051,586	**94,051,586**	
Other Direct & Construction Indirect Costs:			
91-1 Scaffolding	985,000		
91-2 Cost Due To OT 5-10's	1,859,000		
91-4 Per Diem	588,000		
91-5 Consumables	141,414		
91-6 Freight on Material	99,000		
91-8 Sales Tax	2,384,000		
91-9 Contractors G&A	1,990,000		
91-10 Contractors Profit	994,000		
	9,040,414	**103,092,000**	
Indirect Costs:			
93-1 Engineering Services	4,000,000		
93-4 SU/S Parts/ Initial Fills	75,000		
93-5 Technical Field Advisors	300,000		
93-8 EPC Fee	10,747,000		
	15,122,000	**118,214,000**	
Escalation:			
96-1 Escalation on Material	137,000		
96-2 Escalation on Labor	1,693,000		
96-3 Escalation on Subcontract	5,238,000		
96-4 Escalation on Process Eq	926,000		
96-5 Escalation on Indirects	1,261,000		
	9,255,000	**127,469,000**	
Total EPC Cost		***127,469,000***	
Owner's Costs:			
99-1 Owner's Costs	9,457,000		
	9,457,000	**136,926,000**	
Third Party Services:			
100 CM Oversight	1,500,000		
101 Start-Up Oversight	300,000		
102 Owner's Engineer	1,750,000		
103 Performance Testing	175,000		
	3,725,000	**140,651,000**	
Project Contingency :			
110 Project Contingency	32,851,000		
	32,851,000	**173,502,000**	
Escalation Addition:			
120 Escalation on Lines 99-110	960,000		
	960,000	**174,462,000**	
Interest During Construction:			
130 Interest During Constr.	15,649,000		
	15,649,000	**190,111,000**	
Total		***190,111,000***	

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
101			**UNIT 1 OR 2 (SINGLE UNIT) DSI AREA**									
	21.00.00		**CIVIL WORK**									
		21.53.00	**PILING**									
			AUGER CAST GROUT PILE, 18 IN DIA BY 80 FT LONG	DSI AREA FOUNDATIONS INCLUDING REAGENT SILOS	323.00 EA	1,162,800	-	-		108.88 /MH		1,162,800
			PILE - MOB/DEMOB		1.00 LS	100,000	-			108.88 /MH		100,000
			PILING			**1,262,800**						**1,262,800**
		21.98.00	**CIVIL WORK,TESTING**									
			AUGER CAST GROUT PILE - TESTING		1.00 LS	65,000	-	-		-	-	65,000
			CIVIL WORK,TESTING			**65,000**						**65,000**
			CIVIL WORK			**1,327,800**						**1,327,800**
	22.00.00		**CONCRETE**									
		22.13.00	**CONCRETE**									
			CONCRETE FOUNDATIONS - COMPOSITE RATE	DSI AREA FOUNDATIONS INCLUDING REAGENT SILOS	2,292.00 CY	-	-	527,160	18,441	60.03 /MH	1,107,036	1,634,196
			CONCRETE					**527,160**	**18,441**		**1,107,036**	**1,634,196**
			CONCRETE					**527,160**	**18,441**		**1,107,036**	**1,634,196**
	23.00.00		**STEEL**									
		23.25.00	**ROLLED SHAPE**									
			BUILDING MIX, TWO COAT PAINTED		TN	-	-			93.00 /MH		
	24.00.00		**ARCHITECTURAL**									
		24.35.00	**PRE-ENGINEERED BUILDING**									
			SHELL INCLUDING ELECTRICAL & HVAC-STEEL INSULATED 22 GA	BLOWER BUILDING 25 FT X 100 FT	2,500.00 SF	500,000	-			93.00 /MH		500,000
			SHELL INCLUDING ELECTRICAL & HVAC-STEEL INSULATED 22 GA	ELECTRICAL BUILDING 15 FT X 20 FT	300.00 SF	105,000	-			93.00 /MH		105,000
			SHELL INCLUDING ELECTRICAL & HVAC-STEEL INSULATED 22 GA	MILL BUILDING 40 FT X 80 FT	3,200.00 SF	640,000	-			93.00 /MH		640,000
			SHELL - ROOF ONLY AREA	DEHUMIDIFIER - 30 FT X 125 FT	3,750.00 SF	318,750	-			93.00 /MH		318,750
			SHELL - ROOF ONLY AREA	HEAT EXCHANGER - 10 FT X 80 FT	800.00 SF	68,000	-			93.00 /MH		68,000
			PRE-ENGINEERED BUILDING			**1,631,750**						**1,631,750**
		24.37.00	**ROOFING**									
			METAL, INSULATED, 2 IN GALVANIZED, PAINTED, 22 GA	DSI AREA ENCLOSURE ROOF	SF	-	-			35.25 /MH		
		24.41.00	**SIDING**									
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	DSI AREA ENCLOSURE SIDING	SF	-	-			79.98 /MH		
		24.99.00	**ARCHITECTURAL, MISCELLANEOUS**									
			HEATING	DSI AREA	SF	-	-			64.51 /MH		
			LIGHTING	DSI AREA	SF	-	-			82.56 /MH		
			FIRE PROTECTION	DSI AREA	SF	-	-			82.56 /MH		
			ARCHITECTURAL			**1,631,750**						**1,631,750**
	31.00.00		**MECHANICAL EQUIPMENT**									
		31.99.00	**MECHANICAL EQUIPMENT, MISCELLANEOUS**									
			DSI SYSTEM EQUIPMENT	EQUIPMENT COST FOR UNIT 1 OR 2 (SINGLE UNIT)	1.00 LS		15,000,000	-		/MH	10,000,000	25,000,000
			STORAGE SILOS WITH BIN VENT FILTERS (~14 DAYS STORAGE)	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			BLOWERS, HEAT EXCHANGERS, DEHUMIDIFIERS	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			MILLING EQUIPMENT	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			PIPING SYSTEMS	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			COMPRESSORS	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			FLOW MODELING	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			MECHANICAL EQUIPMENT, MISCELLANEOUS				**15,000,000**				**10,000,000**	**25,000,000**
			MECHANICAL EQUIPMENT				**15,000,000**				**10,000,000**	**25,000,000**
	71.00.00		**PROJECT INDIRECT**									
		71.25.00	**CONSULTANT, THIRD PARTY**									
			CONSULTANT - SUBSURFACE INVESTIGATION		1.00 LS	250,000	-			/MH		250,000
			CONSULTANT - GEOTECHNICAL		1.00 LS	150,000	-			/MH		150,000

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			CONSULTANT, THIRD PARTY			400,000						400,000
			PROJECT INDIRECT			400,000						400,000
			101 UNIT 1 OR 2 (SINGLE UNIT) DSI AREA			3,359,550	15,000,000	527,160	18,441		11,107,036	29,993,746
102			REAGENT HANDLING SYSTEM									
	21.00.00		CIVIL WORK									
		21.14.00	STRIP & STOCKPILE TOPSOIL									
			STRIP & STOCKPILE TOPSOIL - 12"	EXTEND REAGENT RAIL TRACK	90,000.00 SF	-	-		207	182.87 /MH	37,835	37,835
			STRIP & STOCKPILE TOPSOIL						207		37,835	37,835
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK	EXTEND REAGENT RAIL TRACK	10,000.00 SY	-	-	106,500	345	97.70 /MH	33,690	140,190
			EROSION AND SEDIMENTATION CONTROL					106,500	345		33,690	140,190
		21.53.00	PILING									
			AUGER CAST GROUT PILE, 18 IN DIA BY 80 FT LONG	UNLOADING SHED 200' X 75' WIDE	64.00 EA	230,400	-	-	0	108.88 /MH	1	230,401
			PILING			230,400			0		1	230,401
		21.71.00	TRACKWORK									
			RAIL, TIE & BALLAST - 136 LB/YD	EXTEND REAGENT RAIL TRACK	4,500.00 TF	-	-	765,000	7,759	81.75 /MH	634,267	1,399,267
			TRACKWORK					765,000	7,759		634,267	1,399,267
			CIVIL WORK			230,400		871,500	8,310		705,793	1,807,693
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			FOUNDATION, 4500 PSI - COMPOSITE RATE	UNLOADING SHED 200' X 75' WIDE	926.00 CY	-	-	212,980	7,451	60.03 /MH	447,258	660,238
			CONCRETE					212,980	7,451		447,258	660,238
			CONCRETE					212,980	7,451		447,258	660,238
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA,	UNLOADING SHED 200' X 75' WIDE x 20' TALL	15,000.00 SF	1,275,000	-			93.00 /MH		1,275,000
			PRE-ENGINEERED BUILDING			1,275,000						1,275,000
			ARCHITECTURAL			1,275,000						1,275,000
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.14.00	MATERIAL HANDLING EQUIPMENT									
			REAGENT PNEUMATIC TRAIN UNLOADING EQUIPMENT		2.00 LS	-	1,000,000	-	6,611	68.89 /MH	455,466	1,455,466
			MATERIAL HANDLING EQUIPMENT				1,000,000		6,611		455,466	1,455,466
		33.41.00	MOBILE YARD EQUIPMENT									
			MOBILE YARD EQUIPMENT - TRACKMOBILE	REAGENT HANDLING SYSTEM	1.00 EA	-	225,000	-		68.89 /MH		225,000
			MOBILE YARD EQUIPMENT				225,000					225,000
		33.51.00	RAIL CAR UNLOADER									
			RAIL CAR UNLOADER	IN UNLOADING SHED 200' X 75' WIDE	1.00 LT	-	135,000	-	1,862	93.00 /MH	173,172	308,172
			RAIL CAR UNLOADER				135,000		1,862		173,172	308,172
			MATERIAL HANDLING EQUIPMENT				1,360,000		8,474		628,638	1,988,638
	35.00.00		PIPING									
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			8 IN DIA, SCH 40, 8" VACUUM CONVEY PIPING WITH 4 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	250.00 LF	-	-	10,043	270	77.80 /MH	21,015	31,057
			12 IN DIA, 3/8 IN STD- 2500 LF OF 10"/12" TRANSPORT PRESSURE PIPING W 8 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRANSPORT SYSTEM	1,250.00 LF	-	-	124,000	1,983	77.80 /MH	154,259	278,259
			CARBON STEEL, STRAIGHT RUN					134,043	2,253		175,274	309,316
			PIPING					134,043	2,253		175,274	309,316
			102 REAGENT HANDLING SYSTEM			1,505,400	1,360,000	1,218,523	26,487		1,956,963	6,040,885
103			ESP/ASH HANDLING MODIFICATIONS									
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.99.00	MATERIAL HANDLING EQUIPMENT, MISCELLANEOUS									
			ESP EQUIPMENT MODIFICATION	FULL REBUILD OF ESP, INCLUDING INSTALLATION COST	1.00 LS	50,000,000	-	-		68.89 /MH		50,000,000

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		33.99.00	MATERIAL HANDLING EQUIPMENT, MISCELLANEOUS									
			ASH HANDLING COMPONENT MODIFICATION	ALLOWANCE	1.00 LS		1,050,000	-	9,885	68.89 /MH	680,982	1,730,982
			MATERIAL HANDLING EQUIPMENT, MISCELLANEOUS			50,000,000	1,050,000		9,885		680,982	51,730,982
			MATERIAL HANDLING EQUIPMENT			50,000,000	1,050,000		9,885		680,982	51,730,982
			103 ESP/ASH HANDLING MODIFICATIONS			**50,000,000**	**1,050,000**		**9,885**		**680,982**	**51,730,982**
104			**EARTHWORK**									
	21.00.00		CIVIL WORK									
		21.14.00	STRIP & STOCKPILE TOPSOIL									
			STRIP & STOCKPILE TOPSOIL - 12"	SITE GRADING ALLOWANCE	30,000.00 SF	-	-		69	182.87 /MH	12,612	12,612
			STRIP & STOCKPILE TOPSOIL - ONSITE	BUILDINGS	600.00 CY	-	-		79	182.87 /MH	14,503	14,503
			STRIP & STOCKPILE TOPSOIL						148		27,115	27,115
		21.17.00	EXCAVATION									
			EXCAVATION - EXCAVATION , BACKFILL & COMPACT ALL FOUNDATIONS	BUILDINGS	2,860.00 CY	-	-		986	79.78 /MH	78,680	78,680
			EXCAVATION						986		78,680	78,680
		21.39.00	STORM DRAINAGE UTILITIES									
			STORM SEWER WORK	SITE GRADING ALLOWANCE	1.00 LT	-	-	44,000	920	72.57 /MH	66,731	110,731
			STORM DRAINAGE UTILITIES					44,000	920		66,731	110,731
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK	SITE GRADING ALLOWANCE	3,333.00 SY	-	-	35,496	115	97.70 /MH	11,229	46,725
			EROSION AND SEDIMENTATION CONTROL					35,496	115		11,229	46,725
			CIVIL WORK					79,496	2,169		183,755	263,251
			104 EARTHWORK					**79,496**	**2,169**		**183,755**	**263,251**
105			**UPGRADE PLANT ENTRANCE**									
	21.00.00		CIVIL WORK									
		21.57.00	ROAD, PARKING AREA, & SURFACED AREA									
			UPGRADE PLANT ENTRANCE	WORK NOT REQUIRED	0.00 LF	-	-			78.79 /MH		
106			**LAYDOWN AREAS**									
	21.00.00		CIVIL WORK									
		21.99.00	CIVIL WORK, MISCELLANEOUS									
			CIVIL WORK - CONSTRUCTION LAYDOWN AREAS	FENCING, POWER ETC...	2.00 AC	-	-	156,000	1,839	79.78 /MH	146,722	302,722
			CIVIL WORK, MISCELLANEOUS					156,000	1,839		146,722	302,722
			CIVIL WORK					156,000	1,839		146,722	302,722
			106 LAYDOWN AREAS					**156,000**	**1,839**		**146,722**	**302,722**
107			**MECHANICAL MISCELLANEOUS**									
	31.00.00		MECHANICAL EQUIPMENT									
		31.99.00	MECHANICAL EQUIPMENT, MISCELLANEOUS									
			MECHANICAL EQUIPMENT	INCLUDES PIPE RACK - ALLOWANCE SUBCONTRACT COST	1.00 LS	975,000	-	-		68.89 /MH		975,000
			MECHANICAL EQUIPMENT, MISCELLANEOUS			975,000						975,000
			MECHANICAL EQUIPMENT			975,000						975,000
			107 MECHANICAL MISCELLANEOUS			**975,000**						**975,000**
108			**DEMOLITION / RELOCATION COSTS**									
	11.00.00		DEMOLITION									
		11.99.00	DEMOLITION, MISCELLANEOUS									
			DEMOLITION AND RELOCATION	ALLOWANCE - SUBCONTRACT COST	1.00 LS	650,000	-			107.47 /MH		650,000
			DEMOLITION, MISCELLANEOUS			650,000						650,000
			DEMOLITION			650,000						650,000
			108 DEMOLITION / RELOCATION COSTS			**650,000**						**650,000**
109			**ELECTRICAL**									
	41.00.00		ELECTRICAL EQUIPMENT									
		41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS									
			ELECTRICAL EQUIPMENT, MISCELLANEOUS	ALLOWANCE - SUBCONTRACT COST	1.00 LS	3,575,000	-			64.04 /MH		3,575,000
			ELECTRICAL EQUIPMENT, MISCELLANEOUS			3,575,000						3,575,000
			ELECTRICAL EQUIPMENT			3,575,000						3,575,000
			109 ELECTRICAL			3,575,000						3,575,000
110			INSTRUMENTATION									
	44.00.00		CONTROL & INSTRUMENTATION									
		44.99.00	CONTROL & INSTRUMENTATION, ALLOWANCE									
			CONTROL & INSTRUMENTATION	ALLOWANCE - SUBCONTRACT COST	1.00 LS	520,000	-			65.15 /MH		520,000
			CONTROL & INSTRUMENTATION, ALLOWANCE			520,000						520,000
			CONTROL & INSTRUMENTATION			520,000						520,000
			110 INSTRUMENTATION			520,000						520,000

FUEL TECH
Technologies to enable clean efficient energy

27881 Clemens Road
Westlake, OH 44145
Phone: 440.899.3888
Fax: 440.899.3890

October 17, 2016

Sargent & Lundy
Attention: Danielle Flagg
55 East Monroe Street
Chicago, IL 60603

Subject: Fuel Tech, Inc. (FTI) Estimate #16-B-111 Rev1
Confidential Client ESP Retrofit
High Level Estimate

Dear Ms. Flagg,

In response to Sargent & Lundy's (S&L)'s recent request, Fuel Tech, Inc. (FTI), has assembled a high level estimate for the materials and installation necessary to retrofit Sargent & Lundy's "Confidential Client" Electrostatic Precipitators. Please consider the pricing as +/- 30% for high level budgetary estimation purposes.

The ESPs have been evaluated by our engineering staff and the estimate includes the most comprehensive improvements possible. Improvements that we have included in the estimate to increase performance and reliability include all new internals; collecting plates at 16" wide plate spacing, rigid discharge electrodes, top-rapped MIGI rapper conversion with increased rapping sectionalization, increased high voltage frame electrical sectionalization, and the addition of high frequency power supplies.

The estimates and information provided above are based upon FTI's historical information and experience, and should be used for accounting purposes ONLY. Should S&L want to move forward with a more in-depth budgetary proposal, FTI can provide such a document with additional lead-time. Thank you for your interest in our products and services, and we will continue to support Sargent & Lundy's efforts in any way practical for this and other opportunities. Should you require any additional information regarding this submittal, please contact me directly.

Respectfully,

Dustin Ekey
Regional Sales Manager

FTI Budgetary Proposal #16-B-111 Rev 1

Sargent & Lundy Confidential Client ESP Retrofit

Submitted by:

27881 Clemens Road
Westlake, Ohio 44145
P: 440.539.8792
www.ftek.com

EXECUTIVE SUMMARY

Sargent & Lundy – Confidential Client ESP Rebuild Budgetary Request:

In accordance with Sargent & Lundy's RFQ dated September 30, 2016, Fuel Tech, Inc. (FTI) has provided a high level estimate based on historical data to engineer, design, supply, and deliver an ESP Retrofit based on the provided information as follows;

A confidential client is currently evaluating the costs associated with rebuilding an existing ESP. As part of this project, the client will potentially be installing dry sorbent injection (DSI) upstream of the upgraded ESP.

The following summarizes the ESP design of the unit being evaluated:

- PC Walther original OEM installed in the early 1980s.
- Consists of four (4) identical ESP casings, with two (2) casings on top of the other two (2) casings; AKA "Piggybacked".
- Each ESP casing has eight (8) mechanical fields, two (2) mechanical fields wide by four (4) mechanical fields deep.
- Each field is 14' in length and contains forty-four (44) collecting electrodes with forty-three (43) gas passages.
- The collecting electrodes are 48' in height with 12" plate spacing.
- The total collecting surface area is 1,900,000 ft^2.
- Design flue gas flowrate is approximately 3,500,000 acfm, and a design velocity of 5 feet per second.
- The SCA of the existing ESP is approximately 540 ft^2/MMacfm.
- The overall dimension for each ESP is approximately 85'L x 90'W x 50'H.
- Each gas passage has discharge frame electrodes.
- The system is equipped with a Walther tumbling hammer rapper system.
- There are eight (8) T/R sets on each ESP, with a total of thirty-two (32).

ESP rebuild design and performance considerations:

- Achieve an outlet PM emissions rate of 0.015 lb/MMBtu or lower.
- Design inlet ash loading of 55,000 lb/hr.
- Non-halogenated PAC is injected at 150 lb/hr.
- Trona will be injected at 22,500 lb/hr, resulting in an increased particulate loading of 18,200 lb/hr to the ESP.
- Inlet flue gas temperature up to 315 deg F.

Fuel Tech, Inc. – Retrofitted ESP Arrangement and Summary:

While the existing ESPs are considered to be relatively large by industry standards, the design information provided shows that 22,500 lb/hr of Trona will be injected in addition to the existing inlet ash loading is 55,000 lb/hr. With this being said, while the ESPs are large they are still an efficiency machine and overcoming the new total inlet loading of over 73,000 lb/hr will be extremely difficult to achieve the requested 0.015 lbs/MMbtu outlet PM emissions, without retrofitting the entire ESPs to BART technology. Essentially, the ESPs will need to be rebuilt to "as-new" condition with the most state-of-the-art technology options. At the very least, new internals and electrical control systems would require new:

- Assembled Panel Collecting Electrodes
- Rigid Discharge Electrodes
- Top-Rapped MIGI Style Rapper Conversion
- All new Hot Roof, Cold Roof, and Penthouse
- Heated Purge Air Systems
- High Frequency Switch-Mode Power Supplies (SMPS)
- New Access Doors
- All new 3-Phase Electrical Supply Wiring
- New Controllers
- New Hopper Arrangement

Retrofit ESP Arrangement; Quantities are for one (1) ESP, there are four (4) ESPs total:

Number of ESP's / Unit:	4
Mechanical Fields & Size / ESP:	6 @ 9'
Electrical Fields & Size / ESP:	12 @ 4.5'
Chambers / ESP:	2
Gas Passages / Chamber:	33
Collecting Plates / Chamber:	32
Collecting Plate Height:	44'
Plate Spacing:	16"
RDE's / ESP:	1,536
Rapping Arrangment:	Top Rapped – MIGI
Collecting System Rappers / ESP:	176
Discharge System Rappers / ESP:	48
High Frequency Power Supplies / ESP:	16

The amount of planning, engineering, material supply, installation, and installation oversight necessary for a project listed above will be very significant. Pricing estimation can be found below.

High-Level Pricing Estimation for one (1) Confidential Unit including all four (4) ESPs:

Pricing estimate is based upon +/- 30%

The total budgetary estimate to provide ESP materials and engineering: **$ 20,000,000.00**

The total budgetary estimate to provide non-union installation: **$ 30,000,000.00**

*Note: The estimates and information provided above are based upon FTI's historical information and experience, and should be used for accounting purposes ONLY. Should S&L want to move forward with a more in-depth budgetary proposal, FTI can provide such a document with additional lead-time.

Entergy Arkansas Inc.

Comments

On the Proposed Regional Haze and Interstate Visibility Transport

Federal Implementation Plan for Arkansas

Docket No. EPA-R06-OAR-2015-0189

Submitted on:
August 7, 2015

To:
U.S. Environmental Protection Agency
1445 Ross Avenue, Suite 700
Dallas, Texas 75202-2733

Via:
http://www.regulations.gov
Docket ID No. EPA-R06-OAR-2015-0189

TABLE OF CONTENTS

EXHIBITS

A. *Review of EPA's Cost Analysis for Arkansas Regional Haze Proposed Federal Implementation Plan*, Report No. SL-012913, Sargent & Lundy (July 2015).

B. *White Bluff Dry FGD Cost Estimate and Technical Basis*, Report No. SL-012831, Sargent & Lundy (July 2015).

C. *Regional Haze Modeling Assessment Report, Entergy Arkansas, Inc. - Independence Plant*, Trinity Consultants (August 4, 2015).

D. *IMPROVE Data Statistical Analysis*, Trinity Consultants (July 2015).

E. *Just-Noticeable Differences in Atmospheric Haze*, Ronald C. Henry, Department of Civil and Environmental Engineering, University of Southern California, Los Angeles, Air & Waste Management Association (2002).

F. Excerpts from *Tangential Low NOx (TLN3) System for Entergy White Bluff Units 1 & 2*, Foster Wheeler North America Corp. Proposal to Entergy (Oct. 13, 2011).

G. Memorandum from Steve deMello, Project Manager, Amec Foster Wheeler North America Corp., to Michael P. Fallon, P.E., Entergy (July 30, 2015).

H. *Evaluation of the CALPUFF Modeling System Margin of Error for a BART Analysis, Entergy Services, Inc. - Lake Catherine Plant*, Trinity Consultants (Aug. 4, 2015).

I. Entergy Arkansas Inc.'s Comments on the Proposed Approval and Promulgation of Implementation Plans; Interstate Transport State Implementation Plan; Arkansas, Interstate Transport State Implementation Plan to Address Pollution Affecting Visibility, Docket No. EPA-R06-OAR-2008-0633.

ENTERGY ARKANSAS INC.
COMMENTS ON THE PROPOSED REGIONAL HAZE
AND INTERSTATE VISIBILITY TRANSPORT
FEDERAL IMPLEMENTATION PLAN FOR ARKANSAS

EPA-R06-OAR-2015-0189

I. INTRODUCTION

On April 8, 2015, the U. S. Environmental Protection Agency ("EPA" or "Agency") published in the *Federal Register*, at 80 Fed. Reg. 18,944, a proposed Federal Implementation Plan ("FIP") to address certain regional haze and visibility transport requirements for the State of Arkansas ("Proposed FIP" or "Proposal"). The Proposed FIP would address the requirements of the Regional Haze Rule and interstate visibility transport for those portions of Arkansas' State Implementation Plan ("SIP") that EPA previously had disapproved. *See* 77 Fed. Reg. 14,604 (Mar. 12, 2012). The Proposed FIP addresses the requirements for Best Available Retrofit Technology ("BART") for those sources for which EPA did not approve Arkansas' BART determinations, Reasonable Progress Goals ("RPGs"), reasonable progress controls and a long-term strategy, as well as the interstate visibility transport requirements for pollutants that affect visibility in Class I areas in nearby states.

Entergy Arkansas Inc. ("EAI" or "Entergy") owns and operates three facilities that EPA proposes to regulate under the FIP: White Bluff Electric Power Plant ("White Bluff"); Independence Steam Electric Station ("Independence"); and Lake Catherine Plant ("Lake Catherine"). EPA is proposing sulfur dioxide ("SO_2") and nitrogen oxides ("NOx") BART limits for White Bluff Units 1 and 2, and SO_2, NOx, and particulate matter ("PM") BART limits for the Auxiliary Boiler at White Bluff. EPA also is proposing a NOx BART limit for Unit 4 at Lake Catherine. Finally, EPA is proposing emissions limits at Independence to meet reasonable progress requirements and is seeking comment on two alternative options. Under Option 1, EPA is proposing SO_2 and NOx emission limits for Units 1 and 2 at Independence. Under Option 2, EPA is proposing only SO_2 emission limits for Units 1 and 2. EPA also is soliciting comment on any alternative control measures for White Bluff Units 1 and 2 and Independence Units 1 and 2 that would address the BART and reasonable progress requirements for these four units for the current regional haze planning period.

In these comments, Entergy discusses its legal and technical concerns with the Proposed FIP. Entergy appreciates EPA's consideration of these comments, and urges EPA to make Entergy's suggested changes and issue a final FIP that provides visibility benefits without overly burdening EAI's customers and co-owners.

II. EXECUTIVE SUMMARY

The Regional Haze Program is intended to achieve gradual and steady improvement in visibility at Class I areas over the course of 64 years. The program was established under the Clean Air Act ("CAA") as a long-term program to allow major emitting sources to install controls or be phased out in a rational and economical manner to ultimately achieve natural visibility conditions at all Class I areas in the United States. The program also is intended to recognize that regional haze is a *regional* problem; one that benefits from broad programmatic changes and the retirement of sources as they reach the end of their useful lives. EPA's Proposed FIP for Arkansas largely abandons this approach, ignores the significant improvements in visibility in Arkansas' Class I areas that already have occurred, fails to account for the improvements that are anticipated to occur based on other regulatory programs, and seeks to impose more than $2 billion in costs on EAI's customers and co-owners despite the lack of any need for, or benefit from, such a massive investment.

Entergy proposes a more reasonable, long-term, multi-unit approach to address regional haze in the Arkansas Class I areas that achieves reasonable progress, is consistent with the statutory scheme and allows Entergy to manage its generation fleet in a reliable and economic manner. In particular, Entergy proposes the following: (1) to achieve early SO_2 reductions by accepting lower SO_2 emission rate limitations at both White Bluff and Independence; (2) to achieve NOx reductions by installing NOx control technology on all four units within three years of the final FIP's effective date; and (3) to commit to the permanent cessation of coal-fired operations at White Bluff by 2028. Based on modeling by Entergy (which EPA should have conducted but failed to undertake), the difference in visibility at the Arkansas Class I areas between the proposed FIP controls and Entergy's proposal is imperceptibly small (*see* Section III.D.2 below) and does not warrant an investment of over $2 billion in scrubber technology at the plants.

Entergy's comments address a range of issues raised by the Proposal. Two issues are most critical. First, with respect to White Bluff, Entergy proposes to cease all coal-fired operations at the two coal-fired units in 2027 and 2028. This proposal necessarily changes the BART analysis for White Bluff. Because of Entergy's proposed commitment to stop burning coal, EPA's proposal to establish BART limits for White Bluff based on the installation of dry flue gas desulfurization ("FGD" or "scrubbers") must be rejected. Under the current schedule for finalizing the FIP, the scrubbers would not be installed until at least 2021, which would leave only six to seven years for EAI to recoup the approximately $1 billion in investment for dry scrubber installation. That cannot be justified economically or environmentally. Economically, the short amortization period would drive the costs of the scrubbers to over $7,500-$8,500 per ton of SO_2 removed. Environmentally, EPA projects that visibility will improve in each of Arkansas' Class I areas only by approximately one-fifth of a deciview ("dv") as a result of the proposed FIP controls on all sources in Arkansas; an amount that is absolutely undetectable. Controls on White Bluff would achieve merely a fraction of that amount.

Second, EPA's proposal to require SO_2 and NOx limits based on the installation of dry scrubbers and NOx controls on the two coal-fired units at Independence cannot be justified for the first planning period. Independence is not a BART-eligible source.[1] Accordingly, EPA may impose emission reduction requirements on Independence under the Regional Haze Program *only* to the extent *necessary* to achieve reasonable progress towards natural visibility levels. *See* 42 U.S.C. § 7491(b)(2) (implementation plans must "contain such emission limits ... as may be *necessary* to make reasonable progress") (emphasis added). The visibility in Arkansas' Class I

[1] Despite the fact that Independence is not a BART-eligible source under the Clean Air Act, EPA's analysis in the Proposal essentially and improperly treated it as such.

areas already has improved substantially in the past 10 years such that the haze index for both Class I areas currently is well below the uniform rate of progress ("URP" or "glide path") that EPA uses to ensure reasonable progress towards natural visibility conditions and that EPA had previously approved for Arkansas.[2] Based on the negligible visibility benefit from installing scrubbers at Independence, the cost of the controls is an astounding $1.33 billion to $1.53 billion per deciview improvement. *See* Section III.C.3 below. Scrubbers at Independence are simply not necessary to ensure that visibility in Arkansas' Class I areas remains below the URP, nor are they justifiable based on EPA's own analysis of the visibility benefits resulting from such a huge investment.[3]

Arkansas' Class I areas, the Caney Creek Wilderness Area ("Caney Creek") and the Upper Buffalo Wilderness Area ("Upper Buffalo"), have seen marked improvement in visibility since the start of regional haze monitoring. Based on the Interagency Monitoring of Protected Visual Environment ("IMPROVE") data, which reflects monitored visibility impairment in Class I areas, the haze index for the 20% worst ("W20") days of visibility has been steadily improving as a result of reduced emissions within Arkansas and because of broader industrial and energy trends in other states. According to modeling performed by the Central Regional Air Planning Association ("CENRAP"),[4] all of Arkansas' elevated point sources (including all power plants and large industrial sources) account for only about 2.7% and 2.3% of total light extinction within Caney Creek and Upper Buffalo, respectively. The overwhelming visibility impact comes from non-Arkansas point sources and mobile sources. Because of the Mercury and Air Toxic Standards ("MATS") rule,[5] the continuing benefits of the Clean Air Interstate Rule ("CAIR"), the next phase of the Cross State Air Pollution Rule ("CSAPR"), and implementation of the soon-to-be-released revised 8-hour ozone National Ambient Air Quality Standards ("NAAQS"), along with continuing reductions in emissions from mobile sources, the visibility at Caney Creek and Upper Buffalo will continue to improve. Based on the visibility trends in both Class I areas, the imposition of BART controls, and Entergy's proposed interim controls and proposed commitment to cease coal burning at White Bluff, no further action will be necessary to ensure that Arkansas' Class I areas remain below the URP until at least 2028 and likely even longer as a result of emissions controls that will be required by future regulatory programs and planned retirements of numerous electric generating units.

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[2] 76 Fed. Reg. 64,186, 64,194-95 (Oct. 17, 2011).

[3] The Class I areas outside of Arkansas that are potentially affected by emissions from Arkansas, similarly, are below the URP and do not need additional reductions to achieve reasonable progress or their long-term visibility goals.

[4] CENRAP is a regional planning organization that includes nine states – Nebraska, Kansas, Oklahoma, Texas, Minnesota, Iowa, Missouri, Arkansas, and Louisiana. Five such regional organizations are funded by EPA to address the interstate transport nature of the regional haze pollutants. The primary objective of these organizations is to evaluate technical information to better understand the impact of the affiliated states on national strategy and to develop regional strategies to reduce emissions of particulate matter and other pollutants leading to regional haze.

[5] In spite of the Supreme Court decision in *Michigan v. EPA*, 135 S.Ct. 2699 (2015), which held that EPA must evaluate costs in determining whether it is appropriate and necessary to regulate hazardous air pollutant emissions from electric generating units ("EGUs"), several EGUs already have installed controls to comply with MATS or have undertaken other steps to reduce their emissions. Even if the rule is stayed or vacated while EPA undertakes its cost analysis, Entergy expects that the rule will go forward before the end of this planning period along with the associated emission reductions.

EPA acknowledges that controls on Independence are not needed for Arkansas to achieve the URP. 80 Fed. Reg. at 18,992 ("We believe it is appropriate to evaluate Entergy Independence even though Arkansas Class I areas and those outside Arkansas most significantly impacted by Arkansas sources are projected to meet the URP for the first planning period."). Indeed, after the proposed BART controls are installed and White Bluff ceases coal-fired operations, Arkansas sources will not approach the URP, or glide path, for at least another decade. Entergy's analysis, based on the actual visibility impairment data, shows that Caney Creek will remain below the glide path until at least 2032 and Upper Buffalo until at least 2028 with no additional controls on in-state sources. *See* Section III.D.2 below (Figures 13 and 14). Imposing controls on Independence is simply not necessary or justified to achieve reasonable progress towards natural visibility in Arkansas' Class I areas.

EPA's reasonable progress analysis and justification for proposing stringent emission limitations at Independence are not legally defensible under the Regional Haze Program based on the costs and lack of visibility benefits of the proposed limits. EPA suggests it is only logical to require Independence to install controls because its SO_2 emissions are large and because it would be cost effective to control them. Cost effectiveness is a factor in deciding the degree of controls necessary to establish RPGs, but it is not an independent basis for imposing controls and does not determine reasonable progress goals. In this case, installing the controls on Independence that would be necessary to meet the proposed emission limits will cost EAI's customers and co-owners in excess of $1 billion. While the cost per ton of SO_2 removed may be within the range that might support a BART determination, it is nonetheless high in the context of reasonable progress controls, particularly where the benefits are small and reductions are not needed to demonstrate that Arkansas is making reasonable progress towards achieving natural visibility conditions at its Class I areas. Accordingly, Entergy objects to the RPGs that EPA is proposing for Arkansas.

EPA also improperly relied on CALPUFF modeling to justify the proposed controls at Independence, vastly overstating the impact of emissions from Independence and the benefits of installing controls. CALPUFF modeling, a single source puff model, is not an appropriate model to determine or project reasonable progress benefits. Reasonable progress is determined by evaluating the overall visibility values in Class I areas and the projected trends in visibility as a result of emissions, controls and operations at all sources contributing to visibility impairment. EPA has recognized in recent rulemakings that CALPUFF cannot do this and it is therefore arbitrary and capricious for EPA to rely on CALPUFF for this purpose here.

Entergy is prepared to offer meaningful interim emission reductions to complement its proposed commitment to cease coal-fired operations at White Bluff and assure that Arkansas remains on a path that is below the URP for the long term. Entergy proposes to meet more stringent SO_2 limits at both White Bluff and Independence beginning in 2018. In addition, Entergy proposes to install low NOx burners ("LNB") and separated overfire air ("SOFA") on both White Bluff and Independence within three years of the final FIP's effective date, assuring that there will be both near-term and long-term visibility benefits.

III. COMMENTS

A. Entergy Proposes To Cease Coal-Fired Operations At White Bluff By 2028 As Part Of A Long-Term, Multi-Unit Regional Haze Plan.

EPA's proposed BART determination for White Bluff appears to be based, in general, on the White Bluff five-factor BART analysis that Entergy provided to the Arkansas Department of Environmental Quality ("ADEQ") in October 2013 ("Revised White Bluff BART Analysis"),[6] which assumed White Bluff Units 1 and 2 would continue to combust coal for the foreseeable future. As part of a multi-unit plan to improve visibility and to better manage its generation assets for reliability and costs, Entergy proposes to cease burning coal at White Bluff Units 1 and 2 by 2027 and 2028, one unit per year, and is prepared to take an enforceable commitment to that effect.[7]

As a result of Entergy's proposal, EPA's proposed BART determination for White Bluff Units 1 and 2 has been rendered inapplicable. Entergy's proposal for White Bluff requires EPA to undertake a new BART analysis to address the remaining useful coal-fired life of the units. In addition, EPA used outdated costs in its BART analysis, improperly eliminated millions of dollars in costs necessary to install controls on White Bluff, and did not consider site-specific factors that will affect the cost calculation. When the appropriate dry scrubber costs are considered along with the units' remaining useful coal-fired life, the average cost effectiveness of dry FGD increases to a range of over $7,500 to $8,500 per ton at the White Bluff units, costs that are far too high to constitute BART.

1. EPA must take the remaining useful life of the White Bluff units into account in the BART analysis.

The CAA and EPA regulations dictate that EPA and states consider the remaining useful life of a source in BART determinations, which factors into the cost of compliance in the BART analysis. 42 U.S.C. § 7491(g)(2); 40 C.F.R. § 51.308(e)(1)(ii)(A). EPA's guidance provides a specific time period for amortization of the costs of controls where a unit's remaining useful life is limited.

> If the remaining useful life exceeds the amortization period, then the remaining useful life has essentially no effect on the control costs and on the BART determination process. Where the remaining useful life is less than the time period for amortizing costs, [EPA advises] us[ing] this shorter time period in [the BART] cost calculations.

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[6] Revised BART Five Factor Analysis, White Bluff Steam Electric Station (Oct. 2013), EPA Docket ID EPA-R06-OAR-2015-0189-0045. *See* 80 Fed. Reg. at 18,969-75. However, Entergy is confused by EPA's references in the Proposal to AEP's modeling and assumptions with respect to the BART analysis for White Bluff. *See id.* at 18,969. The references to AEP make it unclear whether EPA actually used Entergy's Revised White Bluff BART Analysis in evaluating the BART controls for White Bluff. EPA needs to confirm that it reviewed and analyzed Entergy's Revised White Bluff BART Analysis.

[7] Entergy anticipates that its compliance with a final FIP, including installing dry scrubbers or, in the alternative, ceasing coal-fired operation at White Bluff, will be subject to Arkansas Public Service Commission hearing and review.

Guidelines for BART Determinations Under the Regional Haze Rule, 40 C.F.R. Part 51, App. Y, Section IV.D.4.k ("BART Guidelines").

BART controls that may be cost effective using the standard amortization period (typically 20-30 years) may no longer be cost effective when a source's remaining useful life is factored into the analysis. *See* 79 Fed. Reg. 74,818, 74,837 (Dec. 16, 2014) ("Proposed Texas Regional Haze FIP") ("[CENRAP] noted that for sources with a relatively short remaining useful life, this consideration would have weighed more heavily against a determination that controlling those sources would have been reasonable.").

EPA determined that remaining useful life was not a meaningful factor for White Bluff given Entergy's previous plans to continue coal-fired operation at White Bluff. *See* 80 Fed. Reg. at 18,971, Tables 34 and 35 (using 30 years and the life of the equipment); Technical Support Document for the SDA Control Cost Analysis for the Entergy White Bluff and Independence Facilities Arkansas Regional Haze Federal Implementation Plan (SO_2 Cost TSD), at 16 ("we typically assume a 30 year equipment life for scrubbers, as we do here."). As a result, EPA concluded that dry scrubbers on White Bluff would have an average cost effectiveness at Unit 1 of \$2,227/ton and at Unit 2 of \$2,101/ton. 80 Fed. Reg. at 18,971, Table 32. These cost estimates were based on a 30-year amortization period for the controls, an amortization period that is consistent with EPA's Control Cost Manual when a unit's remaining useful life is not limited. *EPA Air Pollution Control Cost Manual* (Jan. 2002) ("Control Cost Manual").[8]

Now, however, given Entergy's proposed commitment to cease coal-fired operation at White Bluff by 2027-2028, EPA will need to revise its BART analysis to take the remaining useful life of the units into account. The CAA requires that BART controls be installed "as expeditiously as practicable," but no later than five years from approval of a regional haze SIP or the issuance of a FIP. 42 U.S.C. § 7491(b)(2)(A), (g)(4); 40 C.F.R. § 51.308(e)(1)(iv). In this case, EPA has stated that it is unable to finalize the FIP until after December 15, 2015,[9] which means that any final FIP cannot have an effective date earlier than sometime in 2016. Thus, the scrubbers would be installed and operational, at the earliest, in 2021.[10] In light of Entergy's proposed commitment to cease coal-fired operations at the units in 2027 and 2028, the amortization period will be approximately six to seven years. This has a significant impact on the cost calculation, resulting in much higher costs compared to the emissions reductions achieved.

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[8] The Control Cost Manual is available at http://www.epa.gov/ttncatc1/dir1/c_allchs.pdf

[9] EPA's Response to Letter/Order (Dkt. No. 52) at 2, *Sierra Club v. McCarthy*, No. 14-cv-00643 (Jul. 15, 2015 E.D.Ark.).

[10] EPA has proposed to allow White Bluff the full five years to install the scrubbers and meet the BART SO_2 emission limits. 80 Fed. Reg. at 18,973. Entergy agrees with EPA that such major emissions control technology could not be designed, contracted for, and installed any earlier than five years from the effective date of the final regional haze FIP.

2. EPA's analysis of the costs to install dry scrubbers at White Bluff is replete with errors and artificially improves the cost effectiveness of scrubber installation at White Bluff.

EPA's analysis of the cost and cost effectiveness of installing dry scrubbers at White Bluff contains numerous flawed methodologies, incorrect assumptions and mistakes, all of which seem designed to artificially lower the actual costs of installing dry scrubbers and improve the supposed cost effectiveness of the controls. Sargent & Lundy ("S&L") has undertaken a thorough analysis of EPA's SO_2 Cost TSD and provided a report, *Report of EPA's Cost Analysis Arkansas Regional Haze Proposed Federal Implementation Plan*, No. SL-012913, Sargent & Lundy (July 2015) ("S&L FIP Cost Report") (attached as Exhibit A and incorporated by reference herein). The S&L FIP Cost Report demonstrates that EPA incorrectly specified the SO_2 emissions baseline for White Bluff, which increased expected emissions. EPA then improperly used maximum monthly emissions to estimate the tonnage reduction achievable with the scrubbers to reduce the cost per ton, and incorrectly eliminated approximately $100 million in costs that EPA's own Control Cost Manual says should be included.

(i) EPA arbitrarily eliminated two of five years in calculating baseline emissions for White Bluff.

The BART Guidelines state that baseline emissions from existing sources "should represent a realistic depiction of anticipated annual emissions for the source." 40 C.F.R. Part 51, App. Y, Section IV.D.4.d.1. In general, for the existing sources, facilities should estimate the anticipated annual emissions based upon actual emissions from a baseline period. Entergy originally had used the 2001 - 2003 baseline period. *See* Revised White Bluff BART Analysis at 4-1. EPA looked at the five-year period between 2009 and 2013, SO_2 Cost TSD at 13, Table 7, but inexplicably excluded the maximum and minimum years during this five-year period. *Id*. The effect of excluding these two years is to increase artificially the emissions baseline for White Bluff. S&L FIP Cost Report at 3. There is no reasoned explanation for excluding two of the five recent years' of emissions data in calculating the baseline. EPA should use the average emissions from all five years to determine the baseline as it is more representative of the anticipated annual emissions from the White Bluff units.

(ii) EPA uses an incorrect methodology that artificially inflates the SO_2 emission reductions achievable with scrubbers.

After having incorrectly identified the baseline emissions for White Bluff, EPA then apparently ignores the baseline emissions when estimating the SO_2 reductions that are achievable with the scrubbers. In an apparent attempt to inflate the emission reductions achievable at White Bluff through the installation of scrubbers, EPA identified the maximum monthly SO_2 emission rate in the baseline period of 2009 to 2013 for each unit and then calculated the percent reduction that would be required to achieve a controlled emission rate of 0.06 lb/MMBtu. *See* White Bluff_R6 cost revisions2.xlsx, "Cost Effectiveness" tab, EPA Docket ID EPA-R06-OAR-2015-0189-0093. The percent reduction calculated was then multiplied by the baseline emission tons to determine the tons of SO_2 reduced. *Id*. This methodology is patently incorrect. It assumes the baseline emissions are based on maximum monthly averages, which significantly overstates the annual averages actually used to calculate baseline emissions.

To correctly estimate the SO_2 emission reductions, EPA must multiply the outlet emission rate of 0.06 lb/MMBtu by the average heat input to the boiler (MMBtu/year) from the five-year baseline period. S&L FIP Cost Report at 3. As detailed in the S&L FIP Cost Report, EPA's inappropriate use of maximum monthly emission rates overstates the achievable emission reductions at White Bluff by between 150 and 900 tons per year. *Id*. at 4, Table 2.

(iii) EPA improperly underestimates the costs by approximately $200 million to justify scrubbers at White Bluff.

EPA based its cost calculations for dry FGD on the costs provided by Entergy in its Revised White Bluff BART Analysis, and presented its analysis of the costs for scrubber installation at White Bluff in its SO_2 Cost TSD. However, EPA's analysis is full of errors, which resulted in an underestimation of the scrubber costs at White Bluff by approximately $200 million.

First, the costs in the Revised White Bluff BART Analysis are significantly outdated, and EPA failed to adequately account for this factor in its analysis. The costs for a dry scrubber provided in the Revised White Bluff BART Analysis were based on (1) a study provided to Entergy by S&L in 2009, which provided a line-itemized cost estimate that included contractor equipment, material, and labor costs for two semi-dry scrubbing systems; and (2) costs provided by Alstom in December 2009 to supply two semi-dry scrubbing systems, escalated by 10% based on updated price information from Alstom. SO_2 Cost TSD, at 2. However, even with the updated cost information from Alstom, the information provided in the Revised White Bluff BART Analysis is now at least five years out of date and significantly undervalues the costs of installing dry scrubbers at White Bluff. EPA attempted to address this issue by escalating the Alstom cost information to 2013 dollars using the Chemical Engineering Plant Cost Indices ("CEPCI"). However, EPA's use of the CEPCI inadequately escalated the projected vendor costs. According to S&L, EPA underestimated escalation significantly using the CEPCI – by over $36 million – rather than using updated vendor pricing. S&L FIP Cost Report at 11. Further, this underestimation of the cost escalation was carried throughout EPA's analysis in the SO_2 Cost TSD and resulted in a total underestimation of the costs for scrubber installation of over $85 million. *Id*. at 12, Table 7.

Second, EPA improperly excluded from the cost calculation legitimate costs that Entergy would incur to install dry scrubbers at White Bluff. EPA incorrectly eliminated over $115 million in costs from Entergy's cost analysis. *See* S&L FIP Cost Report at 8, 10. EPA mistakenly assumed certain Balance of Plant ("BOP") costs were included in the Alstom scope of work, so it eliminated these costs as duplicative. As the S&L FIP Cost Report explains, EPA improperly eliminated several BOP costs from Entergy's cost analysis:

- costs for the reagent handling system;
- costs for the ductwork to supply the flue gas to the SDA and the ductwork from booster fans to the existing chimney;

- the costs to apply an acid resistant coating to the chimney shell to protect the concrete from downwash effects;

- the costs associated with replacing the continuous emissions monitoring systems ("CEMS") and associated recalibration and testing costs; and

- costs calculated as percentages of the BOP equipment, material and labor costs.

Id. at 7-8. In total, by eliminating these costs, EPA underestimated the BOP costs by approximately $31 million. *Id*. at 8. EPA also suggested that the costs for one absorber vessel could be eliminated but cited no basis for its assumption that two absorber vessels are adequate for White Bluff. Entergy disagrees with EPA's assumption regarding the number of absorber vessels for White Bluff. *See* S&L FIP Cost Report at 17.

EPA also eliminated approximately $41.7 million for Entergy's Owner's costs,[11] despite the fact that such costs are allowed under EPA's Coal Quality Environmental Cost ("CUECost") model. *Id*. at 10. EPA claimed that such costs had not been documented, were duplicative of other costs or did not appear to be valid costs under the Control Cost Manual methodology. 80 Fed. Reg. at 18,971. For example, EPA improperly eliminated Entergy's capital suspense costs without explaining why such costs were duplicative of other costs or not valid under the Control Cost Manual methodology. Capital expenditure costs include both direct assigned and allocated expenses. Allocated expenses represent overhead costs associated with administrators, engineers and supervisors to the capital projects for which they provide services. Each function at Entergy charges its overhead costs to a "Capital Suspense" project, which is then allocated to the appropriate capital project. Capital suspense, therefore, is a distribution of overhead costs associated with administrators, engineers, and supervisors and includes function specific rates and Administrative and General ("A&G") (Corporate Accounting) rates. Because capital suspense costs are a portion of total capital expenditure costs, these costs are not duplicative of other costs.[12] For example, capital suspense costs do not include labor, administrative, and related elements that are present in Entergy's Internal Control costs. *See* SO_2 Cost TSD at 9. It was entirely proper for Entergy to include these costs in its control technology cost estimates. According to EPA's Control Cost Manual, overhead costs should be counted in the total annual cost of a project. Total annual cost is comprised of direct costs, indirect costs, and recovery credits. Control Cost Manual at 2-7. Indirect costs specifically include overhead costs. *Id.* at 2-8; 3-32.

Third, EPA significantly under-estimated the direct Operating and Maintenance ("O&M") costs projected for the scrubbers by using its Integrated Planning Model ("IPM") Spray Dryer Absorber ("SDA") cost model to scale the O&M costs rather than estimating these costs using current utility pricing information. *See* SO_2 Cost TSD at 14, Table 8. The IPM model includes several assumptions that fail to take into account site-specific factors. S&L FIP Cost Report at 13-14. Accordingly, the IPM model is not consistent with the BART Guidelines,

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[11] These same improper exclusions were made with respect to EPA's analysis of BART controls for NOx at White Bluff and Lake Catherine Unit 4.

[12] Entergy had previously supplied this information on capital suspense costs to EPA. *See* 80. Fed. Reg. at 18,971, n. 55.

which requires a source-specific evaluation of controls costs. BART Guidelines, at Section IV.D.5 . EPA also erroneously scaled the indirect annual costs, all of which were estimated as percentages of capital cost, by using a scaling factor that did not depend at all on the capital costs. *See* S&L FIP Cost Report at 17.

Fourth, in the design for the dry scrubbers, the Revised White Bluff BART Analysis had assumed that White Bluff would burn a coal corresponding to an uncontrolled SO_2 emission rate of 2.0 lb/MMBtu, which is in excess of the sulfur level of the coals the units have historically burned. EPA criticized Entergy for this assumption and revised the White Bluff baseline emission rates and projected post-control emission rates used for the cost effectiveness analysis. *See* SO_2 Cost TSD at 12-14. However, it is proper, when conducting a BART cost analysis, to consider future fuel flexibility. The BART Guidelines advise that "[t]he baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source." 70 Fed. Reg. 39,104, 39,167 (July 6, 2005) (codified at 40 C.F.R. Part 51 App. Y). Although the BART Guidelines explain that anticipated annual emissions are *generally* estimated based on annual emissions from a baseline period assuming conditions of past practice, *id*. at 39,167-68, EPA has approved BART determinations that assume "worst-case coal scenarios." *See* Proposed Arizona Regional Haze FIP, 79 Fed. Reg. 9,318, 9,325-26 (Feb. 18, 2014); Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. 58,570, 58,584-85 (Sept. 21, 2011). Hourly CEMS data confirm that EPA's selection of 0.68 lb/MMBtu as the design basis for the capital costs is completely inadequate and would not achieve compliance with the FIP-proposed emission limit of 0.06 lb/MMbtu unless fuel sulfur limitations were imposed. Based on historical data and potential fuels that can be fired at White Bluff, 1.2 lb/MMBtu is an appropriate fuel sulfur level to design dry FGD systems for White Bluff. *See* S&L FIP Cost Report at 15-16.

If Entergy were constrained as to the type of coal that it could burn at White Bluff after the installation of controls, it would be necessary to reflect such a constraint in the cost of compliance, as it would force Entergy to continue purchasing higher-cost, low sulfur coal. Historically, Entergy has purchased lower sulfur coal than required by permit to ensure full compliance with applicable emission rates and to minimize costs of compliance with market-based emission programs. If White Bluff were to install BART controls, such considerations would become less meaningful and lower-cost, higher sulfur coal would enable Entergy to meet its BART obligations for less cost. Nonetheless, in the S&L FIP Cost Report, S&L used White Bluff's current emission rate of 0.68 lb/MMBtu to evaluate site-specific O&M costs. S&L FIP Cost Report at 15.

Finally, although Entergy removed Allowance for Funds Used During Construction ("AFUDC") from the final Revised White Bluff BART Analysis in response to comments from EPA on the Proposed White Bluff BART Analysis, Entergy disagrees with EPA that AFUDC should not be considered in the control costs.[13] AFUDC is the time value of money on the investment in the technology that is incurred during the construction, which could reach $30 million to $60 million during the 30-46 months of construction that would be needed to install

[13] As noted in the Revised White Bluff BART Analysis, Entergy revised its five-factor analysis of controls at White Bluff as requested by EPA staff in an effort to expedite consideration of the analysis but expressly reserved the ability to include AFUDC in future cost control analyses. Revised White Bluff BART Analysis, at 5-4.

major control equipment such as scrubbers on a large unit. AFUDC includes the interest as part of the capital cost, which is standard accounting and rate-making treatment of such costs and it was appropriate for Entergy to have initially included AFUDC in the White Bluff control costs. In its comments on the Proposed White Bluff BART Analysis, EPA claimed that AFUDC is not allowed by EPA's Control Cost Manual because "the CCM uses overnight costing methodology." EPA Region 6 Comments on White Bluff BART Analysis, at 1 (Aug. 21, 2013) EPA Docket ID EPA-R06-OAR-2015-0189-0044. However, contrary to EPA's assertion, the Control Cost Manual does not even address the use of the overnight methodology as being the basis for estimating costs. *See* S&L FIP Cost Report at 6. In fact, the calculation provided as an example in the Control Cost Manual specifically includes AFUDC as a variable. Control Cost Manual at 1-32, 2-44. The fact that the example "assumes" AFUDC is equal to zero does not reflect a decision by EPA that AFUDC should be excluded from emissions control costs, but instead is an explicit recognition of that category of costs.

EPA also has claimed that the U.S. Energy Information Administration ("EIA") uses overnight costs to project plant costs. *See* S&L FIP Cost Report at 6. However, this is a mischaracterization of the EIA methodology. According to EIA, "[s]tarting from overnight cost estimates, EIA's electricity modeling explicitly takes account of the time required to bring each generating technology online and the costs of financing construction in the period before a plant becomes operational." EIA, *Updated Capital Cost Estimates for Electricity Generation Plants*, at 2, n.2 (Nov. 2010).[14] Despite EPA's claims, the Control Cost Manual does not preclude inclusion of AFUDC and the EIA specifically takes such costs into account for an electric generating unit. Accordingly, the costs of controls for dry scrubbers at White Bluff should appropriately include AFUDC.

3. The costs for dry scrubbers at White Bluff, based on current estimates, are too high to constitute BART.

EPA's use of outdated costs in its cost calculation, its exclusion of certain legitimate costs for the construction of dry scrubbers, and its failure to take into consideration fuel flexibility at White Bluff renders EPA's analysis artificially low and inappropriate for evaluating the cost effectiveness of dry scrubbers on White Bluff for regional haze purposes. To correct EPA's deficiencies, Entergy commissioned a revised dry FGD cost analysis from S&L that takes into account the current costs for dry scrubber installation as compared to the costs that would have been incurred in 2009 or 2010. *See White Bluff Dry FGD Cost Estimate and Technical Basis*, Report No. SL-012831, Sargent & Lundy (July 2015) ("2015 S&L FGD Report") (attached as Exhibit B and incorporated by reference herein). The 2015 S&L FGD Report also takes into account site-specific factors at White Bluff that have an effect on costs. Finally, the study also uses the current SO_2 emission rates at White Bluff for the O&M costs. For the capital cost estimate, S&L uses a design basis of 1.2 lb/MMBtu sulfur coal. As explained in the S&L FIP Cost Report, the current maximum monthly average emission rates are not an appropriate basis for sizing the scrubbers. The equipment must be sized to handle the maximum short-term emission rate. S&L FIP Cost Report at 14-15.

[14] Available at http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf.

The Revised White Bluff BART Analysis had estimated the costs to install dry scrubbers at White Bluff to be approximately $670 million. Revised White Bluff BART Analysis, at 5-6, Table 5-3. The 2015 S&L FGD Report estimates that the total costs of dry scrubbers at White Bluff will be in excess of $1 billion. 2015 S&L FGD Report at ES-1. When the remaining useful coal-fired life of these units is factored into the analysis, dry FGD installation at White Bluff would be indisputably cost-prohibitive.

Based on the S&L analysis, operating the dry FGD systems at White Bluff for only six to seven years would result in an average cost effectiveness of **$7,689-$8,599**/ton at Unit 1 and of **$7,642-$8,546**/ton at Unit 2. S&L FIP Cost Report at 23, Table 11. EPA has determined costs of substantially less than this magnitude to be cost-prohibitive on numerous occasions, including in this very same rulemaking. For example, for AECC McClellan Unit 1, even though EPA claimed that "[s]witching to diesel is projected to result in considerable visibility improvement," EPA rejected SO_2 BART limits based on switching to diesel because EPA determined that diesel, with an average cost effectiveness of $7,145/ SO_2 ton removed, was not "cost-effective in view of the incremental visibility improvement." 80 Fed. Reg. at 18,959. EPA also rejected combustion controls as NOx BART for AECC McClellan Unit 1 based on an average cost effectiveness of $6,261/NOx ton removed, which, according to EPA "is not within the range of what we generally consider to be cost-effective." *Id*. at 18,961. Further, EPA declined to impose dry FGD as BART in Arizona, where the average cost effectiveness was estimated to be $5,091/ton. Proposed Arizona Regional Haze FIP, 79 Fed. Reg. at 9,331-33; Final Arizona Regional Haze FIP, 79 Fed. Reg. 52,420, 52,436 (Sept. 3, 2014). In North Dakota, EPA approved the state's determination that a cost effectiveness of $6,525 per ton was excessive for NOx controls and did not constitute BART. Proposed North Dakota FIP, 76 Fed. Reg. at 58,630; Final North Dakota Regional Haze FIP, 77 Fed. Reg. 20,894, 20,896 (Apr. 6, 2012). And, in Montana, EPA concluded that certain SO_2 controls with a cost effectiveness of $5,442/ton and $6,365/ton were not cost effective. Proposed Montana Regional Haze FIP, 77 Fed. Reg. 23,988, 24,047 (Apr. 20, 2012); Final Montana Regional Haze FIP; 77 Fed. Reg. 57,864, 57,866 (Sept. 18, 2012). Notably, although EPA found that dry sorbent injection was cost effective on a cost-per-ton basis, 77 Fed. Reg. at 24,047, EPA concluded that the costs were not justified by the visibility improvement, which it calculated to be $30 million per deciview. 77 Fed. Reg. at 57,895. This is magnitudes lower than the cost-per-deciview of dry FGD at White Bluff Units 1 and 2, which, for Unit 1, would be approximately **$3.1 billion** per deciview at Caney Creek and **$2.7 billion** per deciview at Upper Buffalo and, for Unit 2, approximately **$2.9 billion** per decivew at Caney Creek and **$2.6 billion** per deciview at Upper Buffalo.[15]

[15] These numbers were calculated from the deciview improvement attributable to White Bluff Units 1 and 2 based on EPA's "scaling methodology." *See* 80 Fed. Reg. 18,997. This methodology results in an improvement at Caney Creek of .036 dv from Unit 1 and .038 from Unit 2 and an improvement at Upper Buffalo of .040 from Unit 1 and .043 from Unit 2. Even if the deciview improvements projected from EPA's CALPUFF modeling were used, *see* 80 Fed. Reg. at 18,972, the $/deciview calculation would not support the installation of dry FGD as BART at White Bluff. Entergy estimates that the costs based on the CALPUFF modeled improvement for Unit 1 would be approximately $135 million per deciview at Caney Creek and $144 million per deciview at Upper Buffalo and, at Unit 2, the costs would be approximately $145 million per deciview at Caney Creek and $143 million per deciview at Upper Buffalo.

The CAA requires that a BART determination consider the degree of anticipated visibility improvement. 42 U.S.C. § 7491(g)(2). Accordingly, EPA cannot mandate that a source "spend millions of dollars for new technology that will have no appreciable effect on the haze." *Am. Corn Growers v. EPA*, 291 F.3d 1, 7 (D.C. Cir. 2002). However, EPA's proposed controls do exactly this. The improvements predicted at Caney Creek and Upper Buffalo from controls on White Bluff Units 1 and 2 based on EPA's scaling methodology are only a fraction of a deciview. Even the CALPUFF predicted visibility improvements at Caney Creek and Upper Buffalo from the installation of dry FGD at White Bluff Units 1 and 2 are less than 1 deciview from each unit, *see* 80 Fed. Reg. 18,972, making them imperceptible to the human eye. *See* Section III.C.2.iii below. The massive cost of installing dry scrubbers at White Bluff to achieve these insignificant improvements, whether on a dollar per deciview basis or a dollar per ton basis, would be *much higher* than the costs that EPA has previously rejected as BART and that EPA proposes to reject as BART in this Proposed Rule. Accordingly, the installation of dry scrubbers cannot be considered BART for SO_2 at White Bluff.

4. Emissions reductions at White Bluff will be achieved through interim controls.

In addition to its plan to cease combusting coal at White Bluff by 2028, Entergy proposes to meet interim SO_2 emission rate reductions prior to 2028 through a reduction in the units' permitted SO_2 emission rates. The units currently have a permitted 3-hour average SO_2 limit of 1.2 lb/MMBtu. Entergy proposes to lower this limit to a rolling 30-day average limit of 0.6 lb/MMBtu beginning in 2018.

NOx BART for all EGUs in Arkansas, including White Bluff, should be compliance with CSAPR given that EPA already has determined that CSAPR is better than BART. 77 Fed. Reg. 33,642 (June 7, 2012). EPA has proposed to take this same approach in the Texas Regional Haze FIP and has approved several state regional haze SIPs that adopted this approach. Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,821; *see also* Proposed Pennsylvania SIP Approval, 80 Fed. Reg. 2,841, 2,844 (Jan. 21, 2015); Final Minnesota SIP Approval, 77 Fed. Reg. 34,801, 34,801-02 (June 12, 2012). EPA should adopt this same approach in the final Arkansas Regional Haze FIP and provide that compliance with CSAPR is NOx BART for all of Arkansas' EGUs.

However, in the event EPA continues to require Arkansas' EGUs to meet source-specific NOx BART limits in the final FIP, Entergy proposes that the units meet a rolling 30-boiler operating day average NOx limit of 1,342.5 lb NOx/hr. This limit is based on the installation of LNB/SOFA and Entergy would be prepared to meet this limit no later than three years from the effective date of the final rule.[16] *See* 79 Fed. Reg. at 18,974-75. Although the cost effectiveness

[16] As explained further in Section III.E below, this limit is different from the limit that Entergy proposed as NOx BART in its Revised White Bluff BART Analysis. The revised limit is necessary due to the changed operating conditions at White Bluff over the past few years. The plant is now economically dispatched through the Midcontinent Independent System Operator ("MISO") and is spending greater amounts of time at lower load than it did in 2013, when the Revised White Bluff BART Analysis was submitted to ADEQ, and in prior years. The emissions guarantee that Entergy received from Foster Wheeler, the vendor that Entergy has selected to supply the NOx control technology, only applies to loads of 50% of capacity or greater. Therefore, a revised limit is necessary

of installing LNB/SOFA would significantly decrease as a result of a revised remaining useful life analysis for the units, if EPA does not adopt its CSAPR equals BART approach for Arkansas, Entergy is prepared to install these controls as part of its comprehensive visibility improvement proposal.

This combination of CSAPR compliance or, in the alternative, LNB/SOFA installation, and acceptance of a lower SO_2 emission rate through the remaining useful coal-fired life of the White Bluff units should be determined to be BART for White Bluff. No additional controls are justified given Entergy's proposal to limit the number of years of coal-fired operation at White Bluff.

B. EPA's Reasonable Progress Analysis And Proposed Determination Are Inconsistent With Other Regional Haze Development Processes.

1. EPA's reasonable progress analysis does not follow prior actions.

For reasonable progress purposes, EPA failed to undertake an appropriate reasonable progress analysis, including the crucial first step of determining whether additional controls are, in fact, necessary for Arkansas to make reasonable progress. *See* Section III.C below. EPA targeted only Independence in its analysis and subsequent decision to impose SO_2 and NOx limitations on the two coal-fired units at Independence. By focusing solely on Independence, EPA's reasonable progress analysis for the proposed Arkansas FIP abandons the analytical approach and determinative standards that guided previous reasonable progress analyses and determinations. In place of the criteria and procedures that EPA established in its own guidance or utilized and applied in previous approvals/disapprovals of regional haze SIPs or promulgation of regional haze FIPs, EPA made the arbitrary decision to review Independence simply because it believes "it would be unreasonable to ignore" the facility. 80 Fed. Reg. at 18,992. EPA failed to consider any lesser level of controls, the relative costs of such controls, the effectiveness of the controls in improving visibility or the cost per deciview improvement associated with the proposed controls.

EPA arbitrarily elected to propose controls for Independence that are unnecessary for Arkansas to demonstrate reasonable progress, provide no perceptible visibility improvement and exceed the cost estimates documented for other sources under other approved plans where EPA declined to impose reasonable progress controls. Further, EPA failed to follow its own guidance, which indicates that "States should consider a broad array of sources and activities when deciding which sources or source categories contribute significantly to visibility impairment." *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program*, at 3-2 (June 1, 2007) ("Reasonable Progress Guidance").[17] The arbitrary evaluation process that EPA followed in the Proposal not only distorts the goals and objectives of the Regional Haze Program, but it also is contrary to EPA's own requirements for uniformity and regional consistency.

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to ensure that the White Bluff units can comply with the NOx limit at the lower loads that have become a more common operating condition for the units.

[17] Available at http://www.epa.gov/ttn/caaa/t1/memoranda/reasonable_progress_guid071307.pdf.

(i) EPA failed to determine visibility impact and the scope of Arkansas sources' contribution to visibility impairment.

EPA's singular attention on Independence for reasonable progress controls is unsubstantiated and is patently arbitrary and capricious. Despite identifying the 10 largest point sources of SO_2 and NOx within Arkansas, EPA focused only on the top three: White Bluff, Independence, and Flint Creek. Because White Bluff and Flint Creek are subject to BART, EPA concluded that no additional controls are necessary at those sources and the subsequent reasonable progress analysis fell solely on Independence. *Id.* at 18,991-92. Other than stating that these plants are the three largest sources, EPA provides no explanation for ignoring the other seven large point sources.[18]

EPA's failure to assess and document the contribution to visibility impairment at any relevant Class I area from *any* Arkansas point source, including Independence, is contrary to past rulemakings and is completely inconsistent with the detailed approach taken by EPA Region 6 in its promulgation of the regional haze FIP for Texas. *See generally*, Proposed Texas Regional Haze FIP, 79 Fed. Reg. 74,818. There, the Agency completed a multi-step evaluation that included: Q/D analysis (i.e., total emissions – 24-hour maximum annualized – divided by distance to the Class I area) for each Texas point source and relevant Class I area to identify those point sources requiring further evaluation,[19] a photochemical modeling scenario utilizing source apportionment to quantify visibility impacts from the sources identified in the Q/D analysis,[20] and an extinction percentage threshold to arrive at what EPA claimed was a common breakpoint in potential visibility improvement.[21] This analysis was key to the development of EPA's approach for proposing appropriate controls by indicating for which sources the installation of controls are needed and would be worthwhile. *See id.*at 74,839 (explaining that the results "suggest that controlling a small number of sources will result in visibility benefits at both Class I areas, and that rather than evaluating controls at all facilities identified by Texas combined, a subset of those facilities (and some additional facilities not identified) may be reasonable.").

EPA took this same approach in other states. *See* Proposed Arizona Regional Haze FIP, 79 Fed. Reg. at 9,352-53; Proposed Montana Regional Haze FIP, 77 Fed. Reg. at 24,058-59; and Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. at 58,624-26. By notable contrast, EPA's Region 6 office did not perform *any* evaluation to identify *any* Arkansas point sources contributing to visibility impairment (or the scope of contribution) at Caney Creek or Upper Buffalo. EPA also performed multi-source emissions analysis using CAMx in most of those other states rather than looking only at the potential impact on visibility using the CALPUFF,

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[18] EPA must provide a reasoned basis for failing to analyze whether these other emission sources should be evaluated for reasonable progress purposes. Indeed, EPA should have conducted multi-source modeling to demonstrate that the other six largest point sources in Arkansas do not contribute to visibility impairment in the Arkansas Class I areas.

[19] *Technical Support Document for the Oklahoma and Texas Regional Haze Federal Implementation Plans (FIP TSD)*, Appendix A at A-4 (Nov. 2014) ("TX FIP TSD").

[20] *Id.* at A-15 – A-26.

[21] *Id.* at A-49.

single source model, as it did in Arkansas. *See* Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,877-78; Proposed Montana Regional Haze FIP, 77 Fed. Reg. at 24,050; Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. at 58,635.

EPA proceeded to complete the required four-factor reasonable progress analysis in those other states only after narrowing the list of potential point sources. Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,872. *See also* Proposed Arizona Regional Haze FIP, 79 Fed. Reg. at 9,138, 9,352-53 (Feb. 18, 2014); Proposed Montana Regional Haze FIP, 77 Fed. Reg. 23,988, 24,058-59 (Apr. 20, 2012); and Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. 58,570, 58,624-26 (Sept. 21, 2011). No doubt, this process was utilized because the Regional Haze Rule requires that additional controls for proposed emission reductions, as identified in an implementation plan, *must be needed to achieve reasonable progress*.[22] EPA's failure to follow these same procedures in the Arkansas Proposed FIP is completely inconsistent with its prior actions and renders the Proposed FIP arbitrary and capricious.

(ii) EPA's review and determination of cost effectiveness is inconsistent with other state programs.

EPA's disregard for consistent reasonable progress review and analysis continued into the required four-factor analysis. After making the unsubstantiated and unsupportable determination to target only Independence, EPA applied different dollar per ton cost effectiveness thresholds for proposed controls at the plant, which are out of line with the standards applied in other regional haze SIPs and FIPs. Specifically, EPA's Proposal attempts to justify a cost effectiveness of dry FGD at Independence totaling \$2,477/SO_2 ton removed for Unit 1 and \$2,686/SO_2 ton removed for Unit 2. 80 Fed. Reg. at 18,944. This far exceeds the cost threshold approved by EPA for reasonable progress controls for other states. *See* Section III.C.3 below.

(iii) EPA's evaluation and application of NOx control requirements is inconsistent with other state programs.

EPA's decision to evaluate *and propose* NOx controls at Independence stands completely opposite its decision not to even evaluate NOx controls for Texas' point sources despite similar visibility conditions. *See* Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,873 ("we are limiting our analyses to consideration of SO_2 controls for these EGU sources, as our modeling indicates that the impacts from these sources on the 20% worst days are primarily due to sulfate emissions."). EPA's decision in this Proposal to impose NOx limits on Independence is inexplicable given the very low visibility improvement projected and the fact that such limits are completely unnecessary for Arkansas to stay below the URP. *See* 40 C.F.R. §§ 51.308(d)(1)(ii) and (d)(3) (explaining that "emission reduction measures" must be necessary to achieve reasonable progress goals). Visibility at Arkansas' Class I areas is only insignificantly impacted by all Arkansas point sources, even less so by point source contributions of NOx, and almost not

[22] *See* 40 C.F.R. §§ 51.308(d)(1)(i)(B) and (d)(3). Logic dictates that if a point source's contribution to visibility impairment is determined to be insignificant then additional controls are not necessary to achieve reasonable progress.

at all by Independence. *See* Section III.C.2 below. Further, Arkansas has sufficiently documented that those same Class I areas remain well ahead of the approved URP. *See* Section III.C.1 below.

2. EPA is obliged to act consistently in promulgating rules.

Reviewed individually, the issues identified above evidence an unjustified and inconsistent application of the Regional Haze Rule. Collectively, they demonstrate EPA's complete disregard for consistent review and uniform evaluation that is required by regulation. EPA's consistency regulations strive for "standardiz[ed] criteria, procedures and policies" when "implementing and enforcing the act." 40 C.F.R. §§ 56.3(a) and (b). They further oblige the Agency to ensure that actions taken under the Clean Air Act: (1) "[a]re carried out fairly and in a manner that is consistent with the Act and Agency policy as set forth in the Agency rules and program directives" and (2) "[a]re as consistent as reasonably possible with activities of other Regional Offices." 40 C.F.R. § 56.5(a).

In EPA's Arkansas FIP Proposal, EPA abandoned the standardized criteria, procedures and policies that had been used in other regional haze SIPs/FIPs. Even more remarkable, EPA's failure to complete a necessary reasonable progress analysis is the same justification EPA used to reject Arkansas' SIP proposal in the first instance. *See* 80 Fed. Reg. at 18,991 (noting that EPA's partial disapproval of the Arkansas regional haze SIP was based, in part, on the "finding that Arkansas did not complete a reasonable progress analysis and did not properly demonstrate that additional controls were not reasonable").

C. Installing Scrubbers At Independence Is Not Necessary To Demonstrate Reasonable Progress And Cannot Be Justified At This Time.

Units 1 and 2 at the Independence Station are not subject to BART. 80 Fed. Reg. at 18,991. EPA nonetheless treats the units as if they were subject-to-BART units by ignoring whether controls at the units are needed to improve visibility and looking only at whether controls are "cost effective." EPA must first determine that further actions are necessary in Arkansas beyond BART to ensure that visibility improvement is continuing on or below the glide path. *See* 42 U.S.C. § 7491(b)(2) (implementation plans must "contain such emission limits, schedules of compliance and other measures as may be *necessary* to make reasonable progress.") (emphasis added); Reasonable Progress Guidance at 4-1 ("Given the significant emissions reductions that we anticipate to result from BART" and other Clean Air Act programs "it may be all that is necessary to achieve reasonable progress in the first planning period."). Only if further action is *necessary* for reasonable progress may EPA require additional controls and, even then, EPA must evaluate which controls are appropriate based on the statutory factors. *See* 42 U.S.C. § 7491(g)(1). EPA failed to do this here.

Arkansas' Class I areas, even without the proposed BART controls, are significantly below the URP and are on track to remain so for the next several years. Nonetheless, EPA has proposed to require emissions limits at Independence Units 1 and 2 based on the installation of SO_2 and NOx controls, ostensibly to achieve reasonable progress, and has offered two options for comment. Under Option 1, each coal-fired unit at Independence would be required to meet a rolling 30-day average SO_2 emission limit of 0.06 lb/MMBtu based on the installation and operation of dry FGD systems, and a rolling 30-day average NOx emission limit of 0.15 lb/MMBtu based on the installation and operation of LNB/SOFA. *Id*. at 18,994, 18,997. Under Option 2, the Independence coal-fired units would be required to meet only the SO_2 limit. *Id*. at 18,994.

EPA's justification for imposing SO_2 and NOx emission limits on Independence is not based on rational policy, legal or environmental grounds and, as a result, it is arbitrary and capricious. EPA's primary justification for proposing reasonable progress limits at Independence is that "it would be unreasonable to ignore a source representing more than a third of the State's SO_2 emissions and a significant portion of NOx point source emissions." *Id*. at 18,992. EPA further supports its conclusion that emission limits based on the installation of major control technology are justified based on a finding that the proposed controls at Independence are cost effective. *Id*. at 18,994-97. However, the fact that a source, which is not subject to BART, may have significant SO_2 or NOx emissions, or that it would be cost effective to control such emissions, is irrelevant for reasonable progress purposes. EPA has not used such an inapplicable and inadequate justification to identify sources for control under a reasonable progress analysis in any other Regional Haze FIP. EPA did not appropriately analyze which sources, if any, should be controlled for reasonable progress and did not follow the procedures it has regularly used in other regional haze FIPS. *See* Section III.B above. Further, emission limits on Independence during at least the first planning period are unnecessary to demonstrate reasonable progress as Arkansas already is below the glide path for the first planning period.

EPA also improperly relied on CALPUFF modeling in its reasonable progress analysis and, as a result, has significantly over-estimated Independence's contribution to visibility impairment and the deciview improvement that would result from the installation and operation of emissions controls at Independence.[23] The visibility impairment at Arkansas' two Class I areas is caused overwhelmingly by point sources outside of the state, secondary organic aerosols - biogenic ("SOAB"), mobile sources, and Arkansas area sources,[24] not by Arkansas point sources such as power plants. EPA's singular focus on Independence will not result in any meaningful improvement in visibility at Caney Creek or Upper Buffalo and will not affect Arkansas' continued progress toward the 2064 natural visibility goal, but will cost EAI's customers and co-owners over $1 billion.

1. Controls on Independence do not further the goal of the Regional Haze Program.

The goal of the Regional Haze Program is the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I areas resulting from manmade air pollution. 42 U.S.C. § 7491(a)(1). Notably, the goal is not simply to reduce

[23] It is noteworthy that EPA issued, on July 29, 2015, a proposal to remove CALPUFF from EPA's preferred list of dispersion models used for Clean Air Act purposes. 80 Fed. Reg. 45,340 (July 29, 2015).

[24] EPA defines an area source as "a collection of similar emission units within a geographic area." EPA, *Introduction to Area Source Emission Inventory Development*, at 1.1-3 (Jan. 2001) *available at* http://www.epa.gov/ttnchie1/eiip/techreport/volume03/iii01_apr2001.pdf. "Area sources collectively represent individual sources that are small and numerous, and that have not been inventoried as specific point, mobile, or biogenic sources. Individual sources are typically grouped with other like sources into area source categories." *Id*.

emissions for the sole purpose of achieving emission reductions; rather, the program is designed to reduce emissions *where necessary* to remedy and prevent visibility impairment. 42 U.S.C. § 7491(b)(2). The program undertakes a gradual approach toward this goal, to assure that reasonable progress is being made while accounting for economic and technological constraints. The program is not designed to achieve the ultimate goal of eliminating visibility impairment immediately but, rather, over time. As EPA itself noted when establishing the Regional Haze Rule, which provides the states with a 64-year period to reach natural visibility conditions at Class I areas:

> [a]dvancements in technology and changes in economic factors will likely provide opportunities for implementation of new cost effective control measures to assure reasonable progress. The structure of EPA's rule is designed to require States, through the SIP process, to review the statutory factors on a periodic basis and determine appropriate changes to their strategies based on that review.

64 Fed. Reg. 35,714, 35,752 (July 1, 1999). EPA takes this extended period of time into account in providing guidance to the states on establishing their RPGs: "you should take into account the fact that the long-term goal of no manmade impairment encompasses several planning periods. It is reasonable for you to defer reductions to later planning periods in order to maintain a consistent glidepath toward the long-term goal." Reasonable Progress Guidance at 1-4; *see also id*. at 4-1 ("Given the significant emissions reductions that we anticipate to result from BART" and other Clean Air Act programs "it may be all that is necessary to achieve reasonable progress in the first planning period for some States.").

Thus, the threshold question is whether reductions in a source's emissions are *necessary* to achieve reasonable progress for the planning period under consideration. 42 U.S.C. § 7491(b)(2) (requiring regional haze implementation plans to contain measures "necessary to make reasonable progress toward meeting the national goal") (emphasis added). Here, where Arkansas is already below the URP for this planning period and projected to remain so for more than a decade, the answer is clearly no. EPA's proposed imposition of unnecessary controls is clearly unreasonable. *See Michigan v. EPA*, 135 S.Ct. at 2706 (requiring EPA's regulatory requirements to be "within the scope of its lawful authority" and its decision-making process to be "logical and rational").

(i) Arkansas' Class I areas are, and will remain, below the glide path well beyond the first planning period.

The proposed emission limits for Independence are not necessary to achieve reasonable progress because ADEQ has demonstrated that Caney Creek and Upper Buffalo will be below the glide path in 2018. State of Arkansas, *State Implementation Plan Review for the Five-Year Regional Haze Progress Report*, at 55-56 (May 2015) ("Arkansas Five-Year Progress Report").[25] Specifically, Caney Creek and Upper Buffalo have both shown improved visibility for the most impaired and least impaired days since 2001 and are projected to continue to improve. The current five-year average shows that, as of 2011, Caney Creek has achieved 73%

[25] Available at http://www.adeq.state.ar.us/air/planning/pdfs/ar_5yr_prog_rep_review-final-6-2-2015.pdf.

of Arkansas' 2018 RPG of 3.88 dv and Upper Buffalo has achieved 66% of Arkansas' 2018 RPG of 3.75 dv. Arkansas Five-Year Progress Report at 60. Based on the five-year rolling averages and projected data, both Class I areas are on schedule to achieve their 2018 RPGs for the 20% worst days. *Id*. at 55, 57. Data from Caney Creek and Upper Buffalo show that the goal of no visibility degradation on the 20% best days will be achieved and that visibility has and will continue to improve. *Id*. at 42-43. EPA acknowledges these facts in the Proposal: "Arkansas Class I areas and those outside of Arkansas most significantly impacted by Arkansas sources are projected to meet the URP for the first planning period." 80 Fed. Reg. at 18,992. As a result of emission reductions achieved through regional and national programs, including MATS, CAIR, and CSAPR, future Clean Air Act programs such as implementation of the 1-hour SO_2 NAAQS, the revised ozone NAAQS and the Clean Power Plan, as well as the reductions for White Bluff and Independence that Entergy is proposing and the BART controls that EPA has proposed for the other sources in Arkansas, there is every reason to project continued improvement in visibility in Caney Creek and Upper Buffalo well beyond 2018.[26]

Entergy has conducted additional modeling using the Comprehensive Air Quality Model with Extensions ("CAMx") and statistical analysis that supports this conclusion. The CAMx modeling demonstrates that the haze index at Caney Creek and Upper Buffalo will remain below the URP for many years to come.[27] Recent IMPROVE monitoring data show that the haze index has been consistently below the URP in both Caney Creek and Upper Buffalo. Trinity Consultants, Inc. ("Trinity") also performed statistical analyses on the data from both Caney Creek and Upper Buffalo to statistically project the haze index trend through 2018.[28] Using a Ranked Statistical Analysis, the haze index for the average of the W20 days in 2018 is projected to be 20.07 dv at Caney Creek and 20.91 dv at Upper Buffalo.[29] These numbers are far below the URP for the first planning period and demonstrate that no source in Arkansas, including Independence, needs to install controls for Arkansas to remain below the glide path. *See* Figures 1 and 2.

[26] The 5-Year Progress Report for Missouri also demonstrates that Mingo and Hercules Glades are on track to meet the 2018 visibility goals and Missouri has determined that further reductions are not necessary. *Missouri Regional Haze Plan: 5-Year Progress Report*, at 4, 17 (Aug. 29, 2014) ("The [monitoring] analyses in the 2009 RH plan demonstrate that the 2018 visibility goals for Mingo and Hercules Glades will be largely achieved from Electric Generating Unit (EGU) emission reductions resulting from the federal Clean Air Interstate Rule (CAIR) program."); *see also* Proposed Missouri SIP, 77 Fed. Reg. 11,958, 11,966 (Feb. 28, 2012) ("EPA proposes to find that Missouri has appropriately established goals that provide for reasonable progress towards achieving natural visibility conditions."); Final Missouri SIP, 77 Fed. Reg. 38,007 (June 26, 2012).

[27] The CAMx modeling was conducted by Trinity Consultants, Inc. Trinity's *Regional Haze Modeling Assessment Report*, which describes the CAMx modeling methodology that Trinity used to evaluate the visibility improvement of controls at Independence and White Bluff, is provided as Exhibit C to these comments.

[28] Trinity's report identifying why a statistical analysis was performed on the IMPROVE data and why the Ranked Statistical Analysis was selected is included as Exhibit D to these comments and incorporated by reference herein. *IMPROVE Data Statistical Analysis*, Trinity Consultants (July 2015) ("Trinity Report").

[29] Trinity also performed a Trend Statistical Analysis of the data, which projects even lower visibility impairment of 18.02 dv at Caney Creek and 20.44 dv at Upper Buffalo, Trinity Report at Section 3.1, but Entergy is using the more robust and conservative Ranked Statistical Analysis to demonstrate the expected trend in visibility impairment.

Figure 1

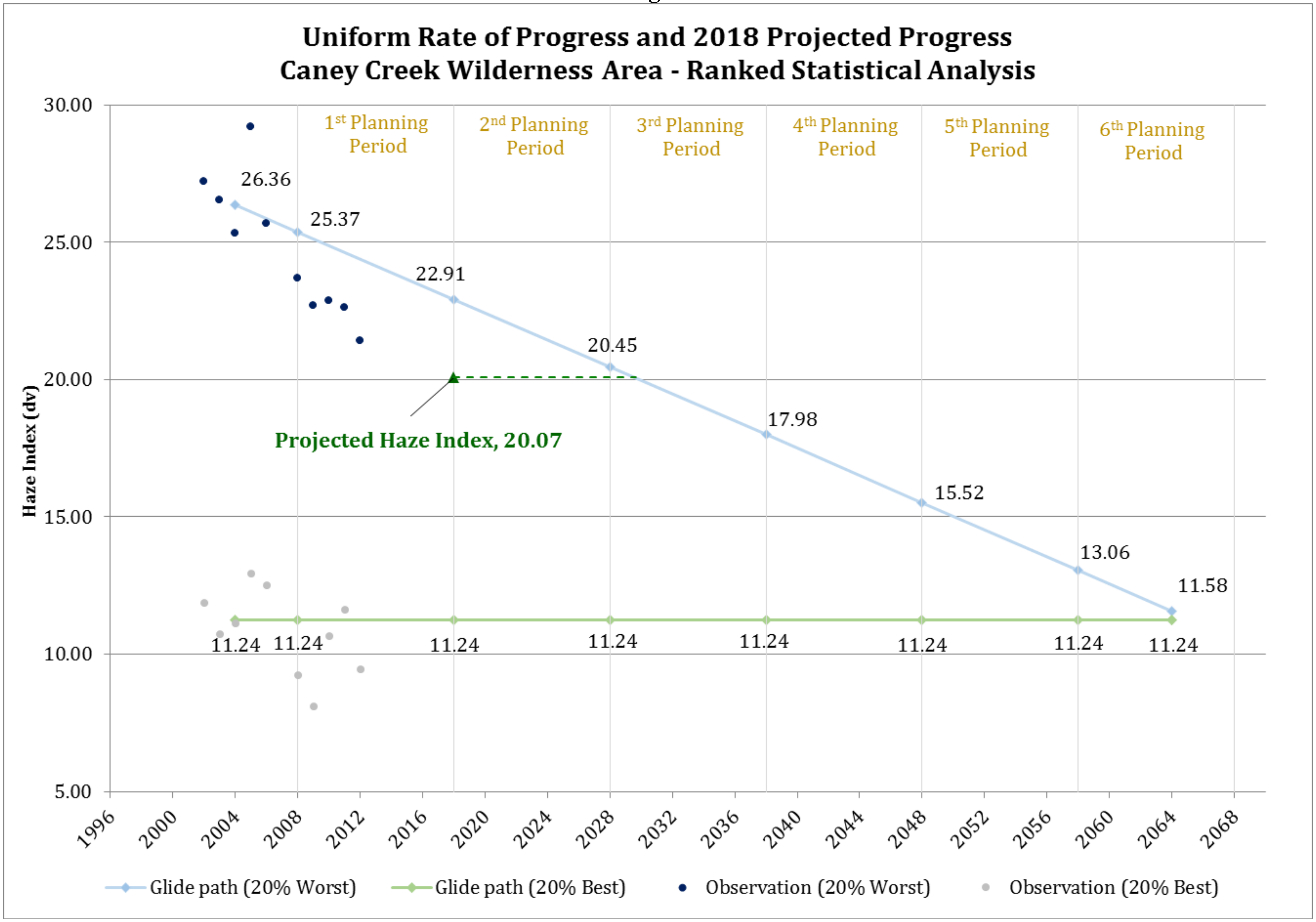
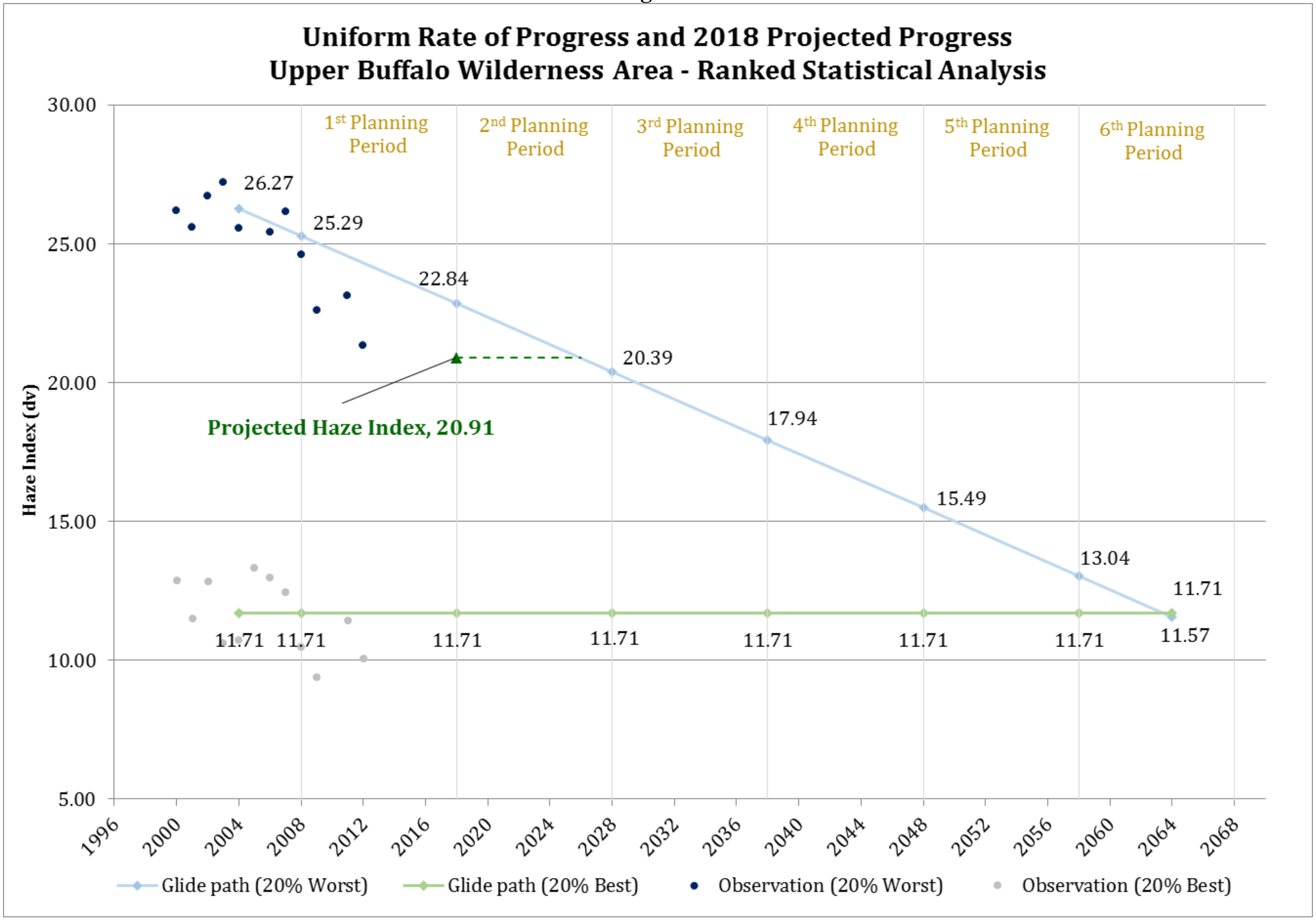

Uniform Rate of Progress and 2018 Projected Progress
Caney Creek Wilderness Area - Ranked Statistical Analysis
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.36
25.37
22.91
20.45
17.98
15.52
13.06
11.58
Projected Haze Index, 20.07
11.24
1996
2000
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)

Figure 2



Uniform Rate of Progress and 2018 Projected Progress
Upper Buffalo Wilderness Area - Ranked Statistical Analysis
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.27
25.29
22.84
20.39
17.94
15.49
13.04
11.71
11.57
Projected Haze Index, 20.91
11.71 11.71 11.71 11.71 11.71 11.71 11.71
1996 2000 2004 2008 2012 2016 2020 2024 2028 2032 2036 2040 2044 2048 2052 2056 2060 2064 2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)

Figures 1 and 2 show the data plots for the 20% worst days and the 20% best days from the IMPROVE network for Caney Creek and Upper Buffalo, respectively. These plots demonstrate that the W20 days since 2007 have consistently been below the URP and that visibility is improving faster than the URP. Trinity applied a Ranked Statistical Analysis to all of the haze index values calculated using the new IMPROVE equation and the data from the IMPROVE monitoring network and constructed a future projection curve to statistically project the haze index at Caney Creek and Upper Buffalo in 2018. Trinity Report at Section 3.2. As demonstrated in Figure 1, the Ranked Statistical Analysis indicates that the haze index in 2018 at Caney Creek will be 20.07 dv, which is 2.84 dv below the URP. Indeed, if EPA does nothing at all (i.e., imposes no BART limits on sources in Arkansas or emission limits on Independence), Caney Creek would not approach the glide path until 2030. Figure 2 shows very similar results for Upper Buffalo, which would not approach the glide path until at least 2026. In light of these projections, which align with ADEQ's glide path demonstrations (*see* Arkansas Five-Year Progress Report at 57-60), SO_2 and NOx emission limits at Independence are unnecessary for reasonable progress purposes for at least a decade.

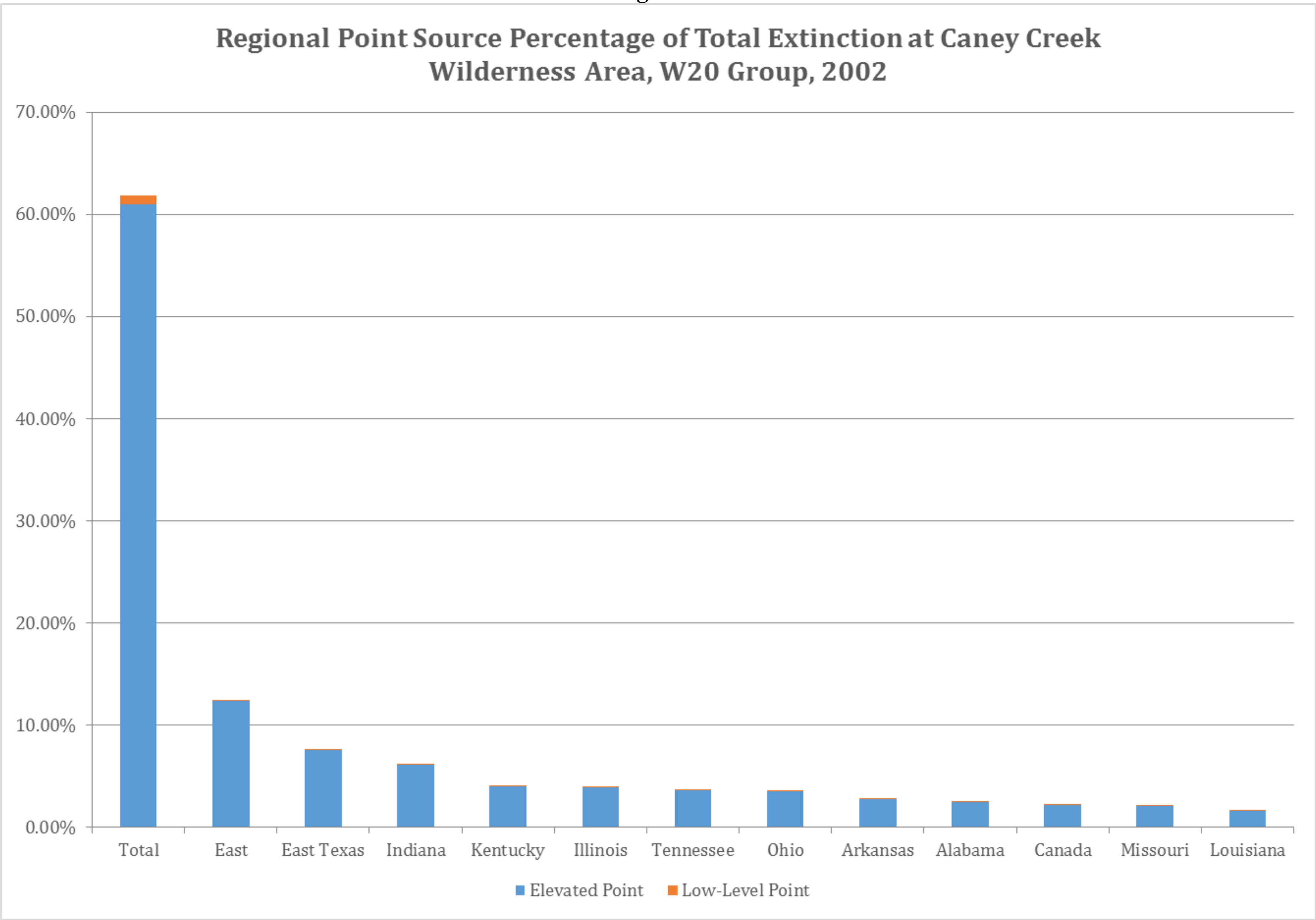
Notably, the Ranked Statistical Analysis conservatively assumes that there will be no additional emissions reductions resulting in visibility improvements after 2018, including emissions reductions from out-of-state sources, which cause over 50% of the visibility impairment in Arkansas Class I areas, or from area and mobile sources, which account for approximately 9.25% of the visibility impairment at Caney Creek and 9.68% at Upper Buffalo.[30] Assuming that MATS achieves the emissions reductions that EPA projects in terms of acid gas controls and retirements,[31] that CSAPR tightens the SO_2 emission budgets in the second phase, that sources will be forced to make additional SO_2 and NOx reductions to comply with the 1-hour SO_2 NAAQS and the revised ozone NAAQS, and that the Phase 2 CAFE fuel economy standards drive further reductions from mobile sources, the haze index in Caney Creek and Upper Buffalo will continue to improve beyond 2018 without controls on Independence.

(ii) Emissions from out-of-state sources and Arkansas mobile and area sources have a more significant impact on Arkansas' Class I areas.

In the Proposal, EPA's reasonable progress analysis primarily focuses on point source contributions to light extinction at Caney Creek and Upper Buffalo. As a result, EPA chose to limit its evaluation of potential reasonable progress controls solely to Arkansas' largest emitting point sources, and, specifically, to Independence. However, as demonstrated in Figures 3 and 4 below, Arkansas point sources are relatively insignificant contributors to visibility impairment in Caney Creek and Upper Buffalo compared to most of the other regions modeled by CENRAP and are not even the biggest source group contributor in Arkansas to visibility impairment in these Class I areas.[32]

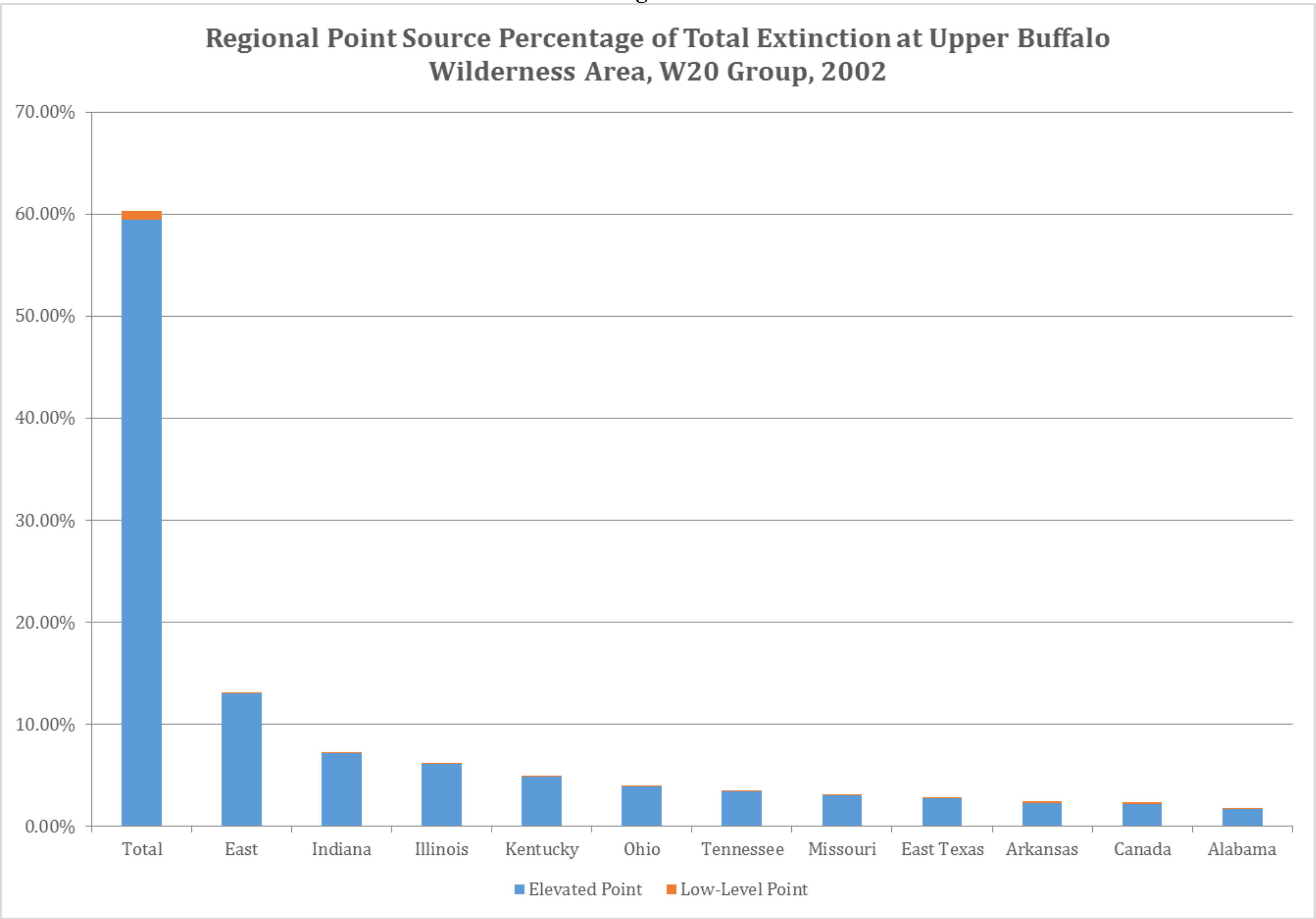
[30] These percentages are based on CENRAP's Particulate Matter Source Apportionment Technique ("PSAT") tool.
[31] Entergy expects the MATS Rule will go forward before the end of this planning period along with the associated emission reductions. *See* footnote 5 above.
[32] Figures 3 and 4, as well as Figures 5 and 6, were developed by extracting the modeled source apportionment extinction data from the CENRAP PSAT tool for Caney Creek and Upper Buffalo. The data obtained were organized by geographic region and source category, so that the individual contribution of each source category in each geographic region could be determined.

Figure 3



Regional Point Source Percentage of Total Extinction at Caney Creek Wilderness Area, W20 Group, 2002
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
Total
East
East Texas
Indiana
Kentucky
Illinois
Tennessee
Ohio
Arkansas
Alabama
Canada
Missouri
Louisiana
Elevated Point
Low-Level Point

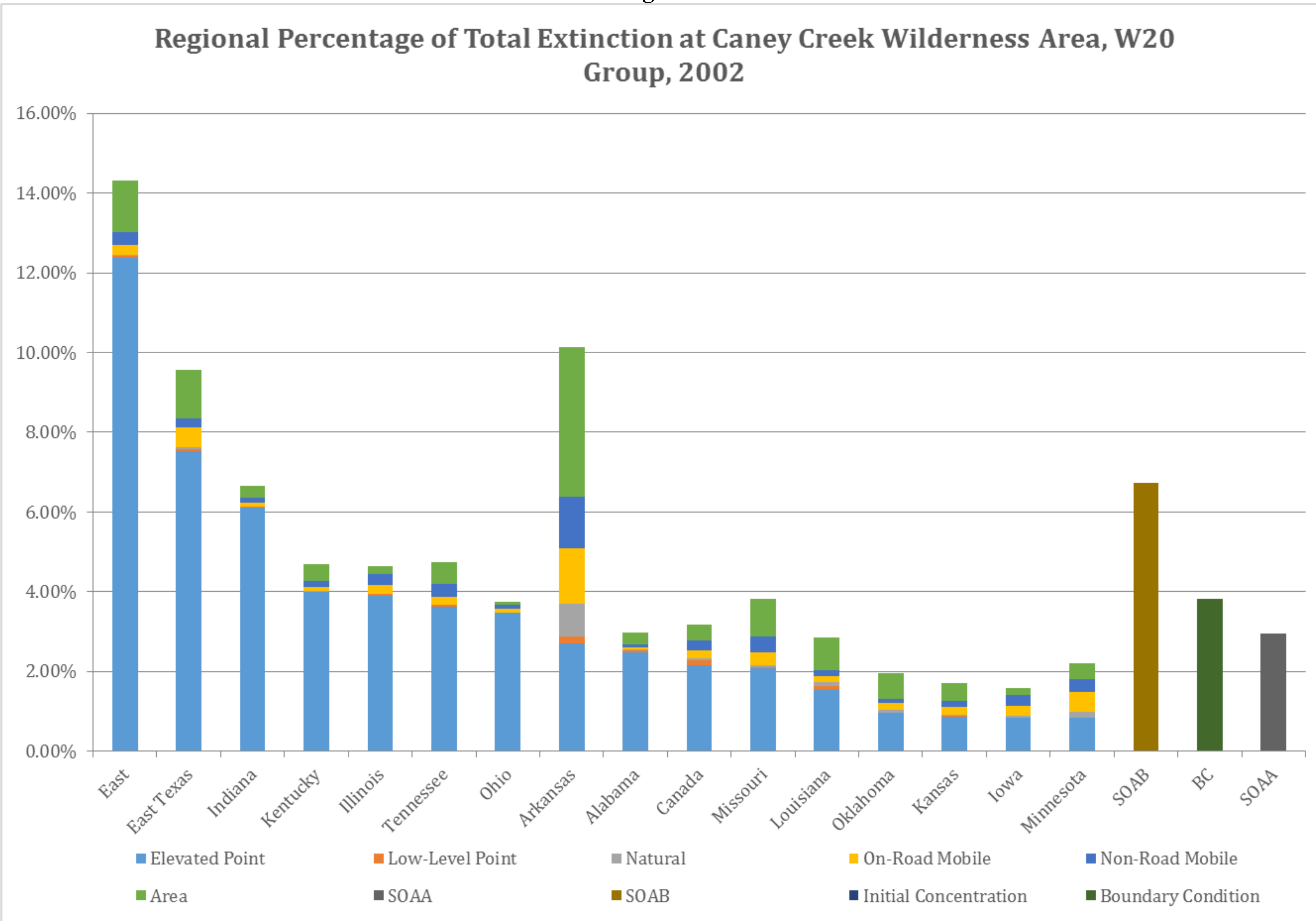
Figure 4


Regional Point Source Percentage of Total Extinction at Upper Buffalo Wilderness Area, W20 Group, 2002
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
Total
East
Indiana
Illinois
Kentucky
Ohio
Tennessee
Missouri
East Texas
Arkansas
Canada
Alabama
Elevated Point
Low-Level Point

Figures 3 and 4 display the modeled percent contribution of elevated and low-level point sources to the total light extinction from the significantly contributing geographic regions. Also included in these figures is the combined total percentage contribution from all point sources in all geographic regions. Of a total point source contribution of 61.85% at Caney Creek in 2002, Arkansas's point sources contributed only **2.87%**, making Arkansas the eighth highest point source contributor. Similarly, of the 60.35% total point source contribution at Upper Buffalo in 2002, Arkansas was the ninth highest point source contributor with only a **2.47%** contribution.

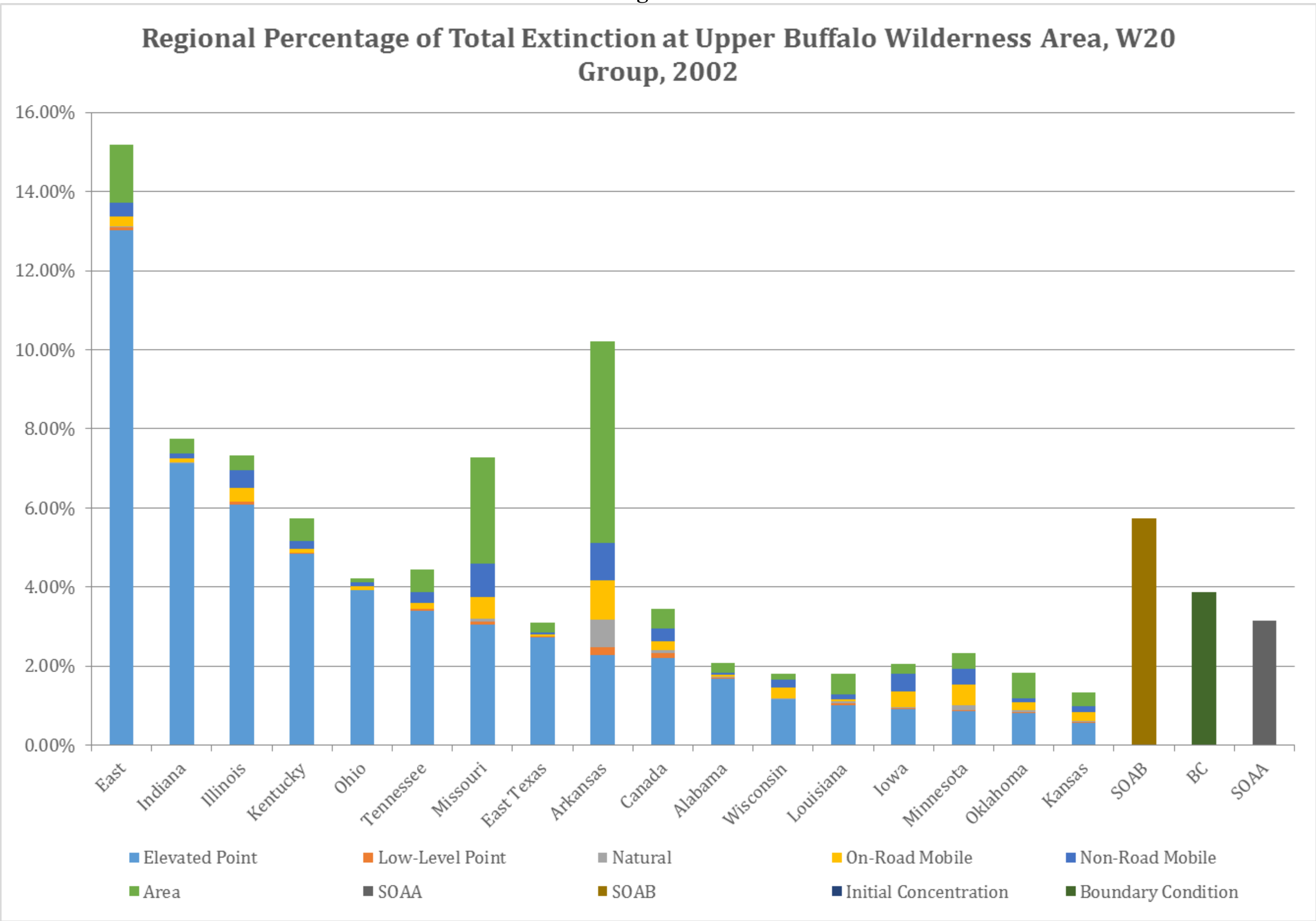
In addition, unlike these other regions, where point sources contribute the majority of visibility impairment to Arkansas' Class I areas, most of Arkansas' share of the contribution to visibility impairment comes from Arkansas area and mobile sources, not point sources. *See* Figures 5 and 6 below.

Figure 5



Regional Percentage of Total Extinction at Caney Creek Wilderness Area, W20 Group, 2002
16.00%
14.00%
12.00%
10.00%
8.00%
6.00%
4.00%
2.00%
0.00%
East
East Texas
Indiana
Kentucky
Illinois
Tennessee
Ohio
Arkansas
Alabama
Canada
Missouri
Louisiana
Oklahoma
Kansas
Iowa
Minnesota
SOAB
BC
SOAA
Elevated Point
Low-Level Point
Natural
On-Road Mobile
Non-Road Mobile
Area
SOAA
SOAB
Initial Concentration
Boundary Condition

Figure 6



Regional Percentage of Total Extinction at Upper Buffalo Wilderness Area, W20 Group, 2002
16.00%
14.00%
12.00%
10.00%
8.00%
6.00%
4.00%
2.00%
0.00%
East
Indiana
Illinois
Kentucky
Ohio
Tennessee
Missouri
East Texas
Arkansas
Canada
Alabama
Wisconsin
Louisiana
Iowa
Minnesota
Oklahoma
Kansas
SOAB
BC
SOAA
Elevated Point
Low-Level Point
Natural
On-Road Mobile
Non-Road Mobile
Area
SOAA
SOAB
Initial Concentration
Boundary Condition

At Caney Creek, Arkansas area sources contribute **3.75%** of the overall extinction while Arkansas' combined point source category (i.e., elevated and low-level point sources) contribute only **2.87%**. Even more significantly, Arkansas area sources contributed **5.09%** towards extinction at Upper Buffalo compared to **2.47%** from the combined Arkansas point sources.

Independence's emissions, which comprise only a portion of Arkansas' point source emissions, have even less of an effect on light extinction in either Class I area. As a result, installing emissions controls on Independence will not meaningfully change the haze index at either Class I area.

(iii) Emissions from out-of-state sources will continue to improve.

Entergy's analysis demonstrates that Arkansas' Class I areas will remain below the glide path in the first planning period and well into the second based on actual data (*see* Section III.C.1.i above); however, the analysis also demonstrates that, due to continued emissions reductions at sources outside of Arkansas, these reductions will continue, furthering Arkansas' progress towards background visibility, without controls on Independence. Point source emissions from the other states included in CENRAP's modeling have been steadily decreasing since the early 2000's and that trend is expected to continue. Indeed, a number of sources in East Coast states have recently announced retirements. The U.S. Energy Information Administration predicts that 60 gigawatts of coal-fired power plant capacity will retire by 2020.[33] These units are significant contributors to visibility impairment at Caney Creek and Upper Buffalo and their retirement will further improve visibility. The second phase of CSAPR, the 1-hour SO_2 NAAQS and the revised ozone NAAQS also will result in significant reductions in SO_2 and NOx emissions from the largest point source contributors to Caney Creek and Upper Buffalo, which are all located outside of Arkansas. *See* Figures 7 and 8 (demonstrating declining emissions trends and the contributions of EGUs).

[33] http://www.eia.gov/todayinenergy/detail.cfm?id=15031#

Figure 7

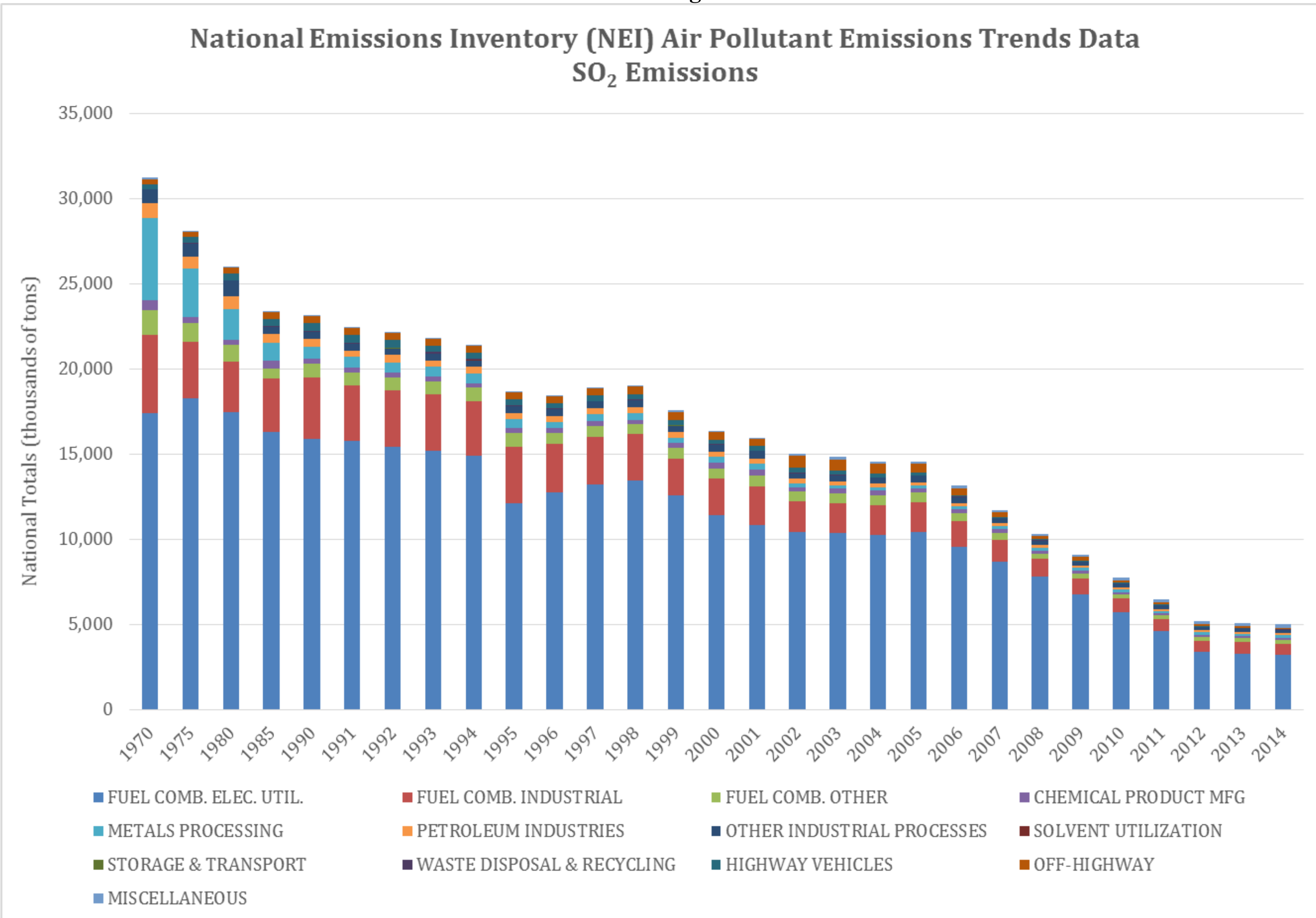
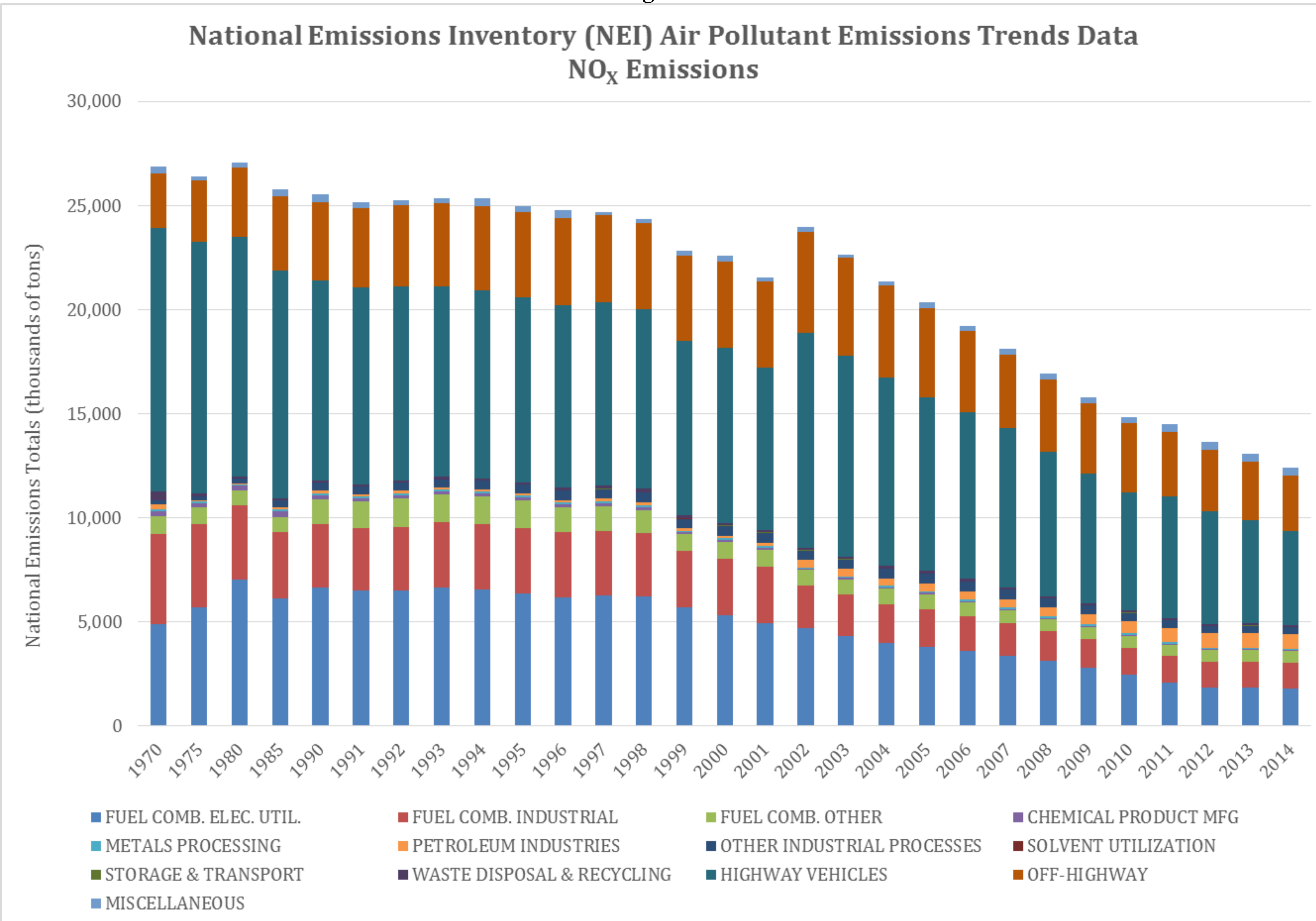

National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data
SO_2 Emissions
National Totals (thousands of tons)
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
1970
1975
1980
1985
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
FUEL COMB. ELEC. UTIL.
FUEL COMB. INDUSTRIAL
FUEL COMB. OTHER
CHEMICAL PRODUCT MFG
METALS PROCESSING
PETROLEUM INDUSTRIES
OTHER INDUSTRIAL PROCESSES
SOLVENT UTILIZATION
STORAGE & TRANSPORT
WASTE DISPOSAL & RECYCLING
HIGHWAY VEHICLES
OFF-HIGHWAY
MISCELLANEOUS

Figure 8



National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data
NO_X Emissions
National Emissions Totals (thousands of tons)
30,000
25,000
20,000
15,000
10,000
5,000
0
1970
1975
1980
1985
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
FUEL COMB. ELEC. UTIL.
FUEL COMB. INDUSTRIAL
FUEL COMB. OTHER
CHEMICAL PRODUCT MFG
METALS PROCESSING
PETROLEUM INDUSTRIES
OTHER INDUSTRIAL PROCESSES
SOLVENT UTILIZATION
STORAGE & TRANSPORT
WASTE DISPOSAL & RECYCLING
HIGHWAY VEHICLES
OFF-HIGHWAY
MISCELLANEOUS

According to EPA's Reasonable Progress Guidance, the Agency should have taken the emissions reductions anticipated from CSAPR, as well as other Clean Air Act programs, into account in setting the proposed RPGs for Arkansas:

> Given the significant emissions reductions that we anticipate to result from BART, the CAIR, and the implementation of other CAA programs, including the ozone and $PM_{2.5}$ NAAQS, for many States this will be an important step in determining your RPG, and it may be all that is necessary to achieve reasonable progress in the first planning period for some States.

Reasonable Progress Guidance at 4-1. EPA completely failed to undertake this "important step" in proposing the RPGs for Arkansas and instead simply focused on controls at Independence.

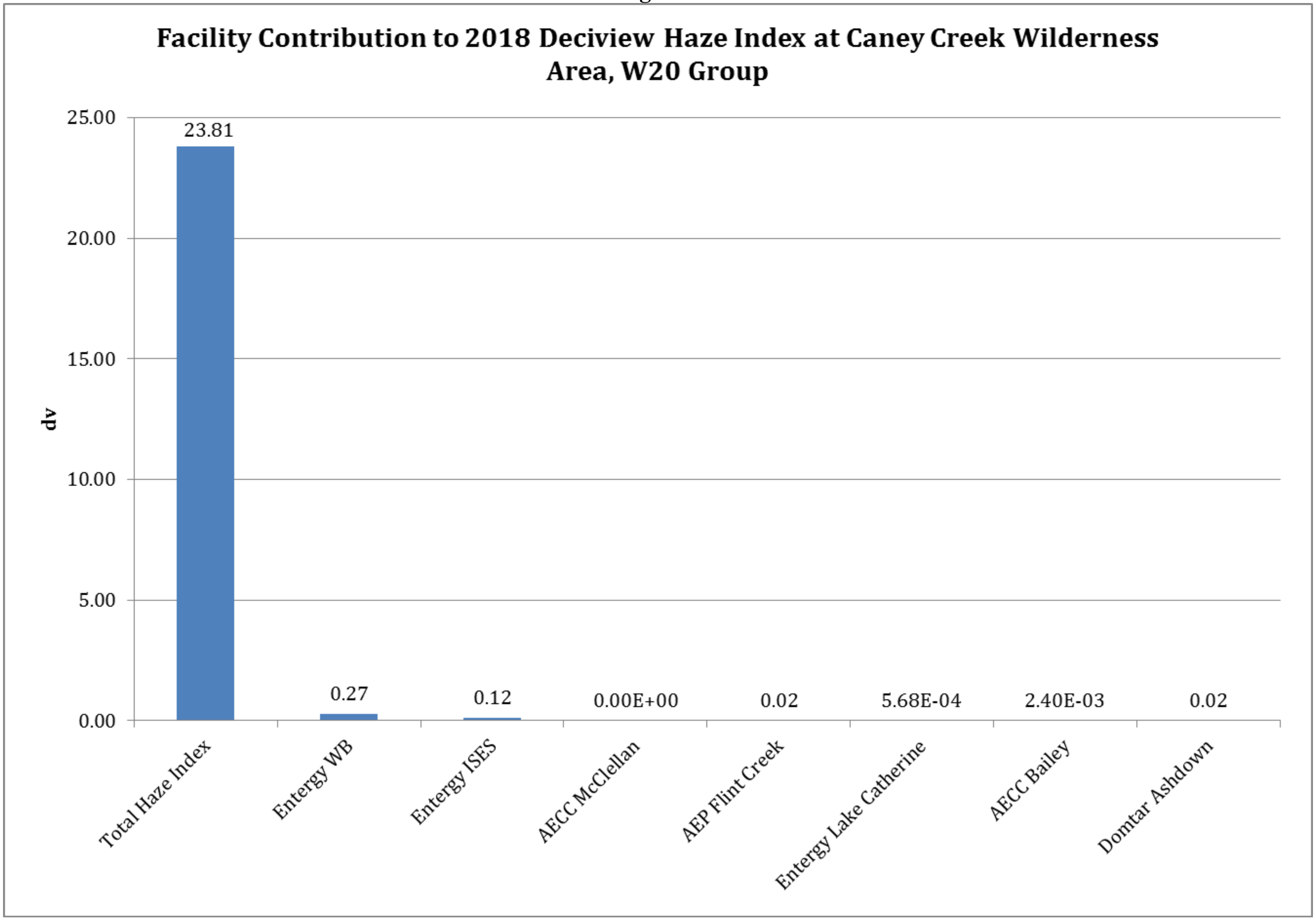
2. Installation of controls on Independence Units 1 and 2 cannot be justified because of the de-minimis benefit toward reasonable progress.

EPA's own analysis counsels against imposing emission limits on Independence. EPA asserts that CENRAP modeling shows that sulfate from *all* point sources included in the regional modeling is projected to contribute to 57% of the total light extinction at Caney Creek on the W20 days in 2018 and 43% of the total light extinction at Upper Buffalo. 80 Fed. Reg. at 18,990. However, EPA recognizes that the CENRAP modeling also demonstrates that sulfate from all (elevated and low level) *Arkansas* point sources is projected to be responsible for only 3.58% of the total light extinction at Caney Creek and 3.20% at Upper Buffalo. *Id*. The contribution of Arkansas point sources' nitrate emissions to visibility impairment at Arkansas' Class I areas is even more insignificant. According to EPA's analysis, nitrate from *all* point sources included in the regional modeling is projected to account for only 3% of the total light extinction at the Caney Creek and Upper Buffalo Class I areas, with nitrate from *Arkansas* point sources being responsible for only 0.29% of the total light extinction at Caney Creek and 0.25% at Upper Buffalo. *Id*. The Independence units' share of emissions to this minimal contribution from Arkansas point sources to visibility impairment at Caney Creek and Upper Buffalo is even less.

Entergy's CAMx modeling confirms that Independence's contribution to visibility impairment is insignificant in both Class I areas. Independence is projected to contribute to only 0.119 dv of visibility impairment at Caney Creek and Upper Buffalo on W20 days in 2018. *See* Figures 9 and 10.[34] This reflects only one half of one percent of the visibility impairment, based on modeling, on the W20 days in either Caney Creek or Upper Buffalo. Yet, based on such a miniscule contribution and with no credible explanation, EPA arbitrarily concludes that SO_2 and NOx controls at Independence are warranted.

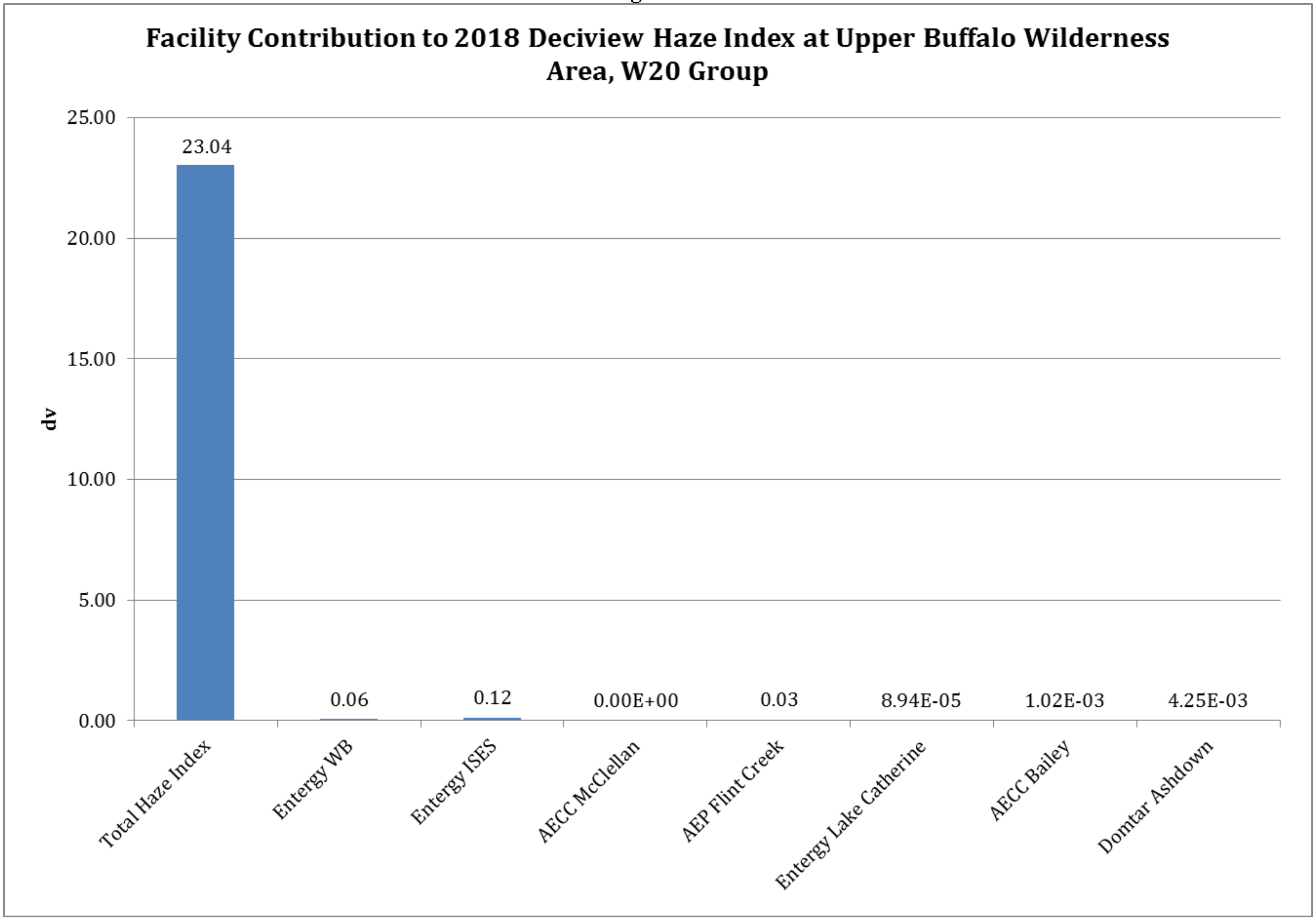
[34] Figures 9 and 10 assume no FIP controls on any of the Arkansas sources. Also, the total haze index values presented in Figures 9 and 10 are based on Entergy's CAMx model predicted total contribution calculated using the new IMPROVE equation, whereas the projected haze index values in Figures 1, 2, and 11 - 14 are based on Trinity's Ranked Statistical Analysis and represent the average haze index for the W20 days. *See* Section III.C.1.i, above.

Figure 9



Facility Contribution to 2018 Deciview Haze Index at Caney Creek Wilderness Area, W20 Group
dv
25.00
20.00
15.00
10.00
5.00
0.00
23.81
0.27
0.12
0.00E+00
0.02
5.68E-04
2.40E-03
0.02
Total Haze Index
Entergy WB
Entergy ISES
AECC McClellan
AEP Flint Creek
Entergy Lake Catherine
AECC Bailey
Domtar Ashdown

Figure 10



Facility Contribution to 2018 Deciview Haze Index at Upper Buffalo Wilderness Area, W20 Group
25.00
20.00
15.00
10.00
5.00
0.00
dv
23.04
0.06
0.12
0.00E+00
0.03
8.94E-05
1.02E-03
4.25E-03
Total Haze Index
Entergy WB
Entergy ISES
AECC McClellan
AEP Flint Creek
Entergy Lake Catherine
AECC Bailey
Domtar Ashdown

(i) CALPUFF modeling cannot be used to justify reasonable progress controls at Independence.

Entergy acknowledges that, under the Regional Haze Rule, "the URP does not establish a 'safe harbor' for the state in setting its reasonable progress goals." 80 Fed. Reg. at 18,992 (referencing 64 Fed. Reg. at 35,732). Nonetheless, EPA must demonstrate that additional controls are rational and economically justifiable and that the amount of progress that would result will be "reasonable based upon the statutory factors." *Id*. EPA has explained that this requires a consideration of the projected visibility benefit expected from the controls. *Id*. at 18,993.

EPA admits that it did not perform refined, multi-state modeling to determine the amount of visibility improvements that would be achieved through the installation of controls because it would be difficult, time-consuming, and expensive. Instead, the Agency took a "thumbnail" approach in an attempt to justify the proposed controls based on how long it would take to achieve background levels. 80 Fed. Reg. at 18,997-98. EPA's use of CALPUFF, a single source model, for evaluating the reasonable progress benefits of installing controls at Independence is misplaced and clearly in error. CALPUFF is not appropriate for reasonable progress purposes as it addresses a fundamentally different question than a proper reasonable progress analysis. TX FIP TSD at A-35. As EPA itself has recognized, CALPUFF is overly simplistic and greatly overstates the effect of single source emissions. BART Guidelines, 70 Fed. Reg. 39,104, 39,121 (July 6, 2005) ("there are other features of our recommended modeling approach that are likely to overstate the actual visibility effects of an individual source. Most important, the simplified chemistry in the model tends to magnify the actual visibility effects of that source."). CALPUFF also fails to show the effects of multiple sources, and is much less sophisticated in its treatment of the chemical interactions of the different pollutants in the atmosphere than CAMx.

EPA has recognized that CAMx, a photochemical transport 3-dimensional grid model, is a more appropriate modeling tool for reasonable progress purposes. Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,877-78. BART analyses assess the impact of a single facility based on the maximum or 98th percentile impacts, regardless of whether the Class I area was actually experiencing high visibility impairment on any given day. Since CALPUFF does not conduct an analysis considering all the emissions from all potential sources, some of the days with the worst model-predicted concentrations could be days that are not significantly impaired. Reasonable progress modeling using a photochemical model, such as CAMx, allows EPA to evaluate impacts from a source (with all other sources included in the modeling) on a Class I area's best and worst days. *Id*. at 74,878.

The draft *EPA Modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze* (Dec. 2014) ("Draft Modeling Guidance") discusses the use of photochemical grid models and notes that Community Multiscale Air Quality Model ("CMAQ") and CAMx are the most commonly used models for attainment demonstrations. The Draft Modeling Guidance specifically notes that "a modeling based demonstration of the impacts of an emissions control scenario... as part of a regional haze assessment usually necessitates the application of a chemical transport grid model." Draft Modeling Guidance at 22.[35] Throughout the Draft Modeling Guidance, the discussion is focused on items specific to photochemical grid models such as CAMx, including emissions inventories, supporting models, pre-processors, and applying a model to changes in visibility.

According to the Draft Guidance, "the emission sources included in the analysis must be comprehensive, including emissions from all source categories" (i.e., point sources, non-point stationary sources, on-road and non-road mobile sources, fires, and biogenic sources) and "'all' sources of emissions." *Id*. at 32, 36. A CAMx modeling analysis includes a comprehensive inventory, capturing each of these source categories, which are then available to react with available precursors. By using the comprehensive inventory, this limits the amount of precursors available to react with the emissions from a facility or source in question. This has been referred to by EPA as a "dirty background analysis." CALPUFF analyses conducted in support of BART determinations do not consider the full inventory of sources and thus do not account for other pollutants challenging and consuming precursor emissions. As such, ammonia and other precursor pollutants are more fully available to react with a facility's emissions and generate haze impacts in a modeled simulation using CALPUFF. This is referred to by EPA as a "clean background analysis." Therefore, the use of CALPUFF does not reflect the interaction of pollutants in the atmosphere as accurately as CAMx does.

Notably, EPA recently issued a proposal on July 29, 2015, which would remove CALPUFF from EPA's preferred list of air dispersion models in its *Guideline on Air Quality Models* ("Guideline"), in Appendix W to 40 C.F.R. Part 51. Although EPA states that the proposed changes to the Guideline would not affect its recommendation that CALPUFF be used in the BART determination process, EPA made no such assurances regarding the use of CALPUFF for a reasonable progress analysis. Instead, EPA's proposal emphasizes the use of chemical transport models for assessing visibility impacts from a single source or small group of sources. According to the Agency,

> Chemical transport models are well suited for the purpose of estimating long-range impacts of secondary pollutants, such as $PM_{2.5}$, that contribute to regional haze and other secondary pollutants, such as ozone, that contribute to negative impacts on vegetation through deposition processes. These multiple needs require a full chemistry photochemical model capable of representing both gas, particle, and aqueous phase chemistry for $PM_{2.5}$, haze, and ozone.

80 Fed. Reg. at 45,349. CALPUFF is clearly inferior in this regard.

Indeed, EPA's *Interagency Workgroup on Air Quality Modeling Phase 3 Summary Report: Long Range Transport and Air Quality Related Values*,[36] which EPA has made available as a supporting document for the proposed revisions to Appendix W, makes clear that CALPUFF should not be used for a reasonable progress analysis. The report explains that, "[a] modeling system that treats emissions from all known anthropogenic and biogenic emissions sources with

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[35] The Draft Modeling Guidance is available at http://www.epa.gov/scram001/guidance/guide/Draft_O3-PM-RH_Modeling_Guidance-2014.pdf.
[36] Docket ID EPA-HQ-OAR-2015-0310-0004.

realistic chemical and physical transformations should be utilized to estimate future visibility conditions at a Class I area. The most appropriate tool that contains these qualities is a photochemical grid model [such as CAMx]." *Id.* at 6. It further explains that "the results from a BART determination or similar modeling using CALPUFF cannot be directly compared to estimated impacts of emissions controls from a single source on a reasonable progress goal…. Lagrangian puff models are not ideal for reasonable progress demonstrations since they typically characterize one or a small group of sources." *Id.* at 9.

(ii) The CALPUFF modeling vastly overstates the potential visibility improvement from controls on Independence.

EPA's CALPUFF modeling indicates that the SO_2 and NOx emission limits proposed for Independence will result in a 1.952 dv improvement in Caney Creek and a 1.782 dv improvement in Upper Buffalo. *See* Summary of Additional Modeling for Entergy Independence, at 8, Table 5 (Apr. 2015), EPA Docket ID EPA-R06-OAR-2015-0189-0147. However, this range is vastly overstated. Based on the current monitored visibility levels in Caney Creek and Upper Buffalo, the W20 days show that the visibility impairment in 2018 will be approximately 23 to 24 dv. EPA recognizes that sulfate from all of Arkansas' point sources are projected to be responsible for only about 3.6% of total light extinction at Arkansas' Class I areas based on CENRAP modeling. 80 Fed. Reg. at 18,990. This means that sulfate from *all* Arkansas point sources are projected to be responsible for only about 0.83 - 0.86 dv of impairment (23-24 dv x 3.6%). For nitrates, EPA projects that Arkansas point source emissions will account for, at most, 0.29% of the total light extinction at Arkansas' Class I areas. *Id*. at 18,990. Independence's SO_2 and NOx emissions contribute only a portion to the sulfate and nitrate percentages estimated from Arkansas point sources. It would, therefore, be impossible for the SO_2 and NOx limits proposed for Independence to result in deciview improvements at Caney Creek and Upper Buffalo of 1.952 dv and 1.782 dv, respectively. This simple example demonstrates the obvious flaw in EPA's use of CALPUFF for its reasonable progress analysis and, thus, its justification for imposing emission limits on Independence despite the fact that the Class I areas are below the URP.

Another illustration demonstrates why CALPUFF greatly overstates the benefits of overall visibility benefits from proposed emission limits. In the Proposal, EPA projects the visibility benefits from the proposed BART controls based on CALPUFF modeling. Based on CALPUFF, EPA's proposed BART limits at White Bluff, Flint Creek Power Plant, Carl E. Bailey Generating Station, John L. McClellan Generating Station, Lake Catherine and Domtar Ashdown Power Boilers will result in projected combined visibility benefits of approximately 4.3 dv at Caney Creek.[37] *See* Figure 11 below. Based on a statistical projection of the haze index in Caney Creek (*see* Section III.C.1 above), that would result in a haze index of 15.76 dv, which would put Caney Creek closer to natural background levels than the glide path. The URP

[37] Trinity derived the 4.3 dv improvement from the CALPUFF modeling by determining the total extinction (in inverse megameters) from each proposed BART source, adding them together, and then calculating the deciview improvement. The resulting 4.3 dv improvement is over five times the total visibility impact attributed to all point sources in Arkansas based on CENRAP's CAMx modeling and 14 times the impact attributed to point sources based on Entergy's current CAMx modeling.

would not reach that haze level until approximately 2048.[38] Indeed, even if you ascribed the CALPUFF-projected benefits to Caney Creek based on the recent IMPROVE levels (approximately 22 dv between 2009 and 2012), the projected haze index would drop to 17.7 dv, which indicates no further action should be needed to remain below the URP until approximately 2038.

[38] The projected haze index at Upper Buffalo of 18.05 dv would keep Upper Buffalo below the glide path until approximately 2038 - the end of the third planning period. *See* Figure 12.

Figure 11

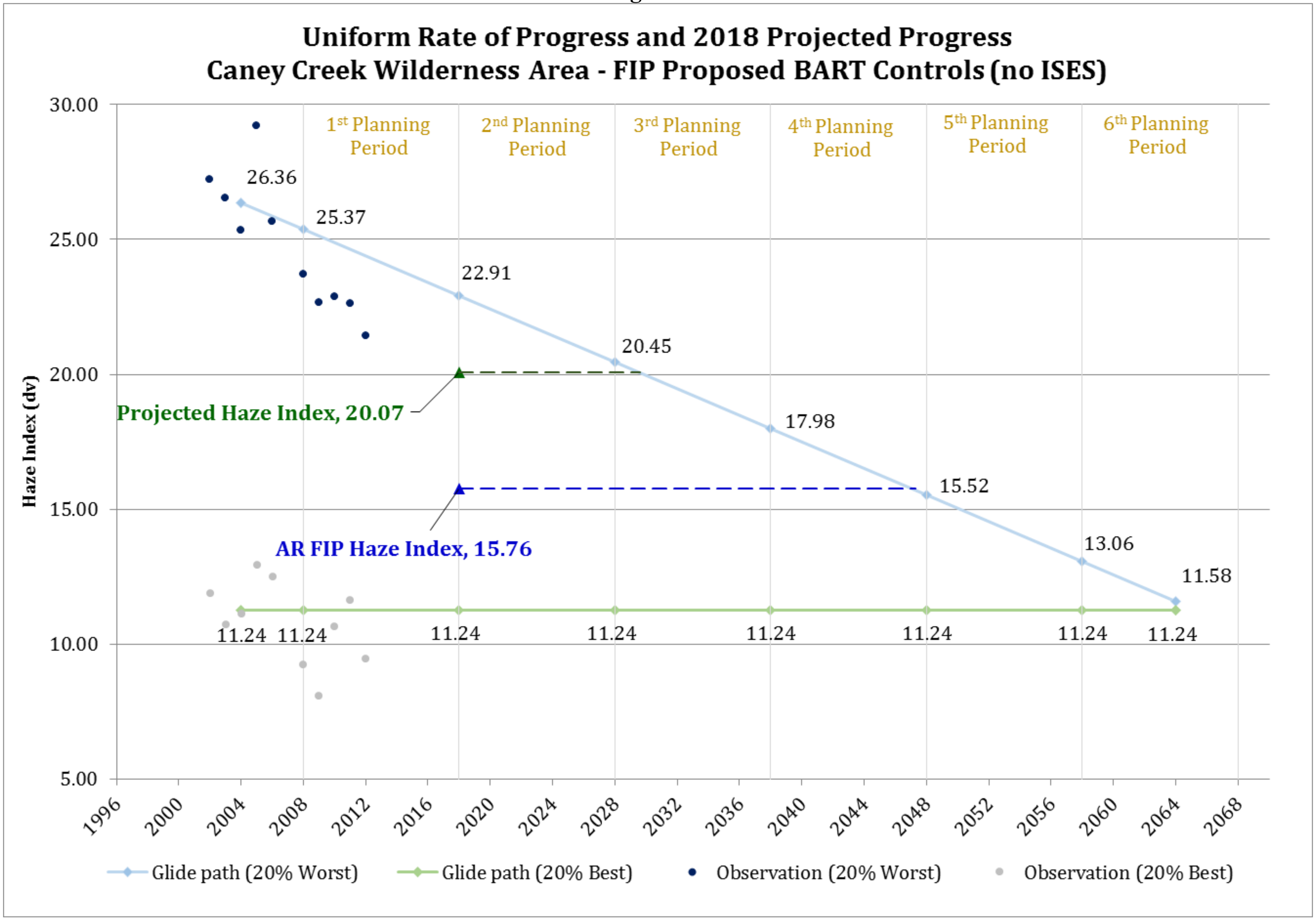
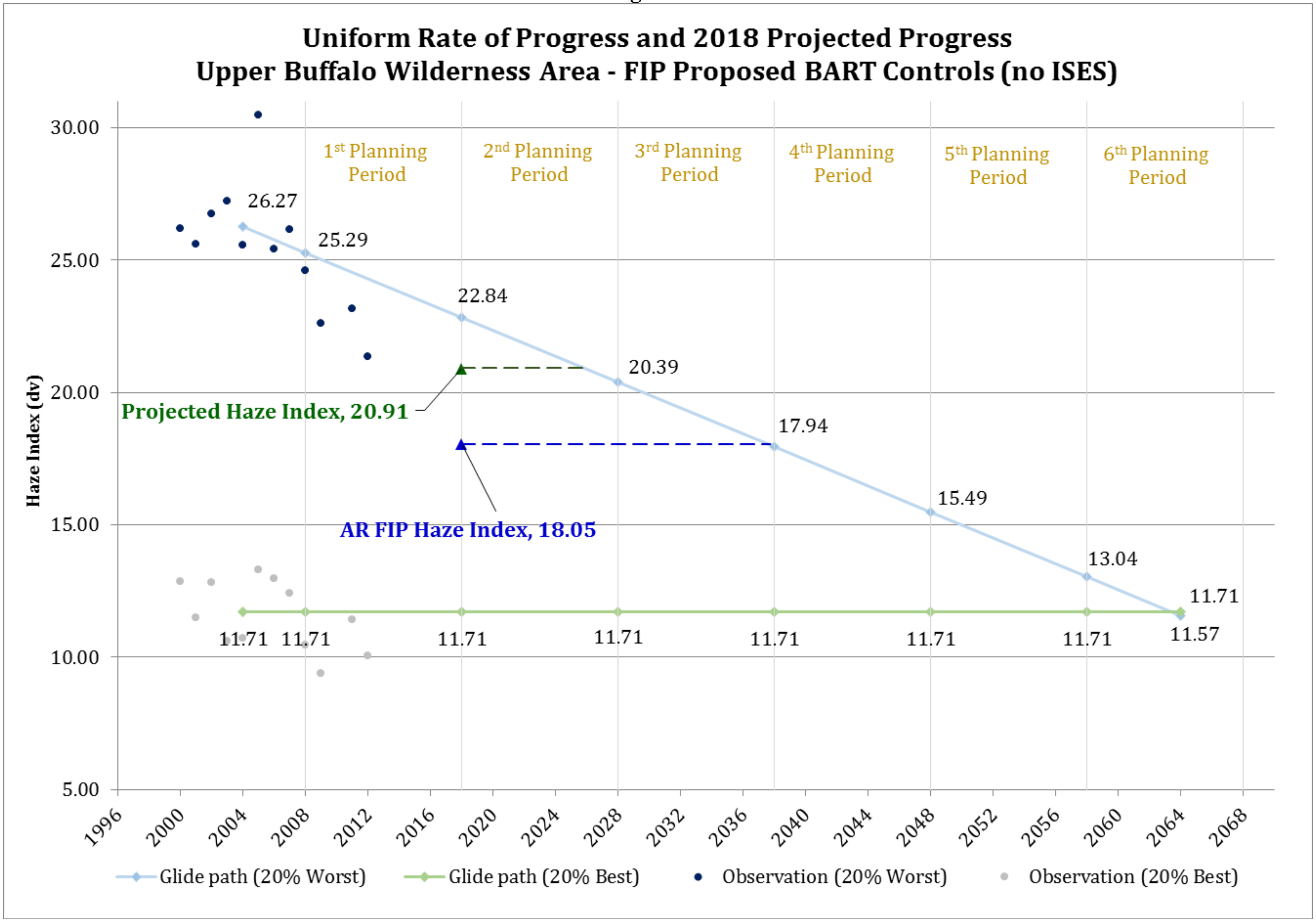

Uniform Rate of Progress and 2018 Projected Progress
Caney Creek Wilderness Area - FIP Proposed BART Controls (no ISES)
30.00
25.00
20.00
15.00
10.00
5.00
Haze Index (dv)
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.36
25.37
22.91
20.45
17.98
15.52
13.06
11.58
Projected Haze Index, 20.07
AR FIP Haze Index, 15.76
11.24
11.24
11.24
11.24
11.24
11.24
11.24
11.24
1996
2000
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)

Figure 12



Uniform Rate of Progress and 2018 Projected Progress
Upper Buffalo Wilderness Area - FIP Proposed BART Controls (no ISES)
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.27
25.29
22.84
20.39
17.94
15.49
13.04
11.71
11.57
Projected Haze Index, 20.91
AR FIP Haze Index, 18.05
11.71
1996
2000
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)

If EPA insists on relying on CALPUFF to evaluate the projected visibility benefits of requiring controls on Independence, it must be consistent and use CALPUFF to evaluate the need for such controls for purposes of demonstrating reasonable progress. As demonstrated in Figures 11 and 12, controls at Independence cannot be justified for reasonable progress based on the CALPUFF results, which predict an improvement of several deciviews solely from BART controls.

(iii) Controls on Independence will not yield perceptible visibility benefits.

As demonstrated above, EPA's CALPUFF modeling greatly overstates the visibility benefits that would result from installing controls at Independence and should be disregarded. Further, when EPA used the CENRAP model (an appropriate multi-source model) to assess overall visibility impairment, EPA concluded that the cumulative benefit of installing all of the controls in the Proposed FIP – all BART controls plus controls at Independence – would result in visibility benefits at Caney Creek of only 0.21 dv and at Upper Buffalo of only 0.19 dv. 80 Fed. Reg. at 18,998, Table 67. Since Independence represents only approximately 36% of the SO_2 point source emissions and 21% of the point source NOx emissions in Arkansas, *see id*. at 18,991, one can ascribe only a minor portion of this projected insignificant deciview improvement to controls on Independence (approximately **0.08** dv at Caney Creek and **0.07** dv at Upper Buffalo).[39] Based on this, installation of controls on Independence will yield no discernible visibility improvements.

Not only does this demonstrate the illogic of relying on CALPUFF for reasonable progress, it demonstrates that the realistic benefits resulting from installing controls at Independence will be inconsequential and will contribute virtually nothing to visibility improvement at either Class I area. According to EPA, one deciview reflects "perceptible changes" in visibility. *See* Proposed Regional Haze Rule, 62 Fed. Reg. 41,138, 41,145 (July 31, 1997) ("A one deciview change in haziness is a small but noticeable change in haziness under most circumstances when viewing scenes in mandatory Class I Federal areas."). Thus, the measure of visibility improvement is based on *noticeable changes*. By EPA's own standard, a total deciview improvement at Caney Creek of 0.21 dv from the installation of controls at all of the proposed FIP sources would not be perceptible to the human eye. Likewise, a total deciview improvement at Upper Buffalo of 0.19 dv would not be discernable. Independence's contribution to the deciview improvements EPA projects based on the CENRAP modeling would be much less; nowhere close to the 1.95 dv and 1.78 dv improvement that EPA is claiming based on CALPUFF.[40] Requiring imperceptible visibility improvements is simply unreasonable. The

[39] These values are the calculated improvement based on EPA's "scaling methodology." *See* 80 Fed. Reg. at 18,997.

[40] Even if the CALPUFF results were accurate, it is highly unlikely that such improvements would be perceptible. Studies have demonstrated that not only is the deciview scale not uniform in perception over a wide range of visibility conditions, but a 1-deciview change in visibility is not even perceptible to the human eye. *See* Exhibit E, *Just-Noticeable Differences in Atmospheric Haze*, Ronald C. Henry, Department of Civil and Environmental Engineering, University of Southern California, Los Angeles, Air & Waste Manage. Assoc. (2002). Instead, according to the Study, deciview improvements likely would need to be in the range of 2 to 5 dv to be perceptible. *Id*. at 1242, Figure 2.

CAA requires only "reasonable progress, not the *most* reasonable progress." *North Dakota v. EPA*, 730 F.3d 750, 767 (8th Cir. 2013).

In addition, the demonstration methodology used by EPA is unscientific. EPA used a ratio of emission rates from BART sources to Arkansas point sources to scale the modeled predicted haze index. First, there is no evidence to prove that the CAMx predicted modeling results are linearly correlated with emission rates. In fact, the CAMx modeling fundamentally is based on photochemical reactions. Therefore, the relationship between variation in the emission rates and predicted concentration is complicated. *See Chemical Characteristics of Inorganic Ammonium Salts in $PM_{2.5}$ in the Atmosphere of Beijing (China)*, A. Ianniello, F. Spataro, G. Esposito, I. Allegrini, M. Hu, and T. Zhu, 11 Atmos. Chem. Phys., at 10804 (2011).[41] For example, due to a high chemical affinity, an ammonia molecule reacts with SO_2 molecules to form sulfate before reacting with NOx molecules to form nitrate. If abundant SO_2 is present in the atmosphere, any increase in NOx emissions will not result in a linear increase in nitrate formation. As a result, there may not be any increase in the predicted regional haze. On the contrary, if abundant NOx molecules are present, then any reduction in SO_2 molecules will not result in a significant reduction in haze as NOx will substitute the reduced SO_2 in the reaction. Second, a deciview is a logarithmic scale based on the concept that one deciview is the minimum change in the visibility perceptible to a human observer. *See* 40 C.F.R. § 51.301 (definition of "deciview"). As such, deciviews cannot be added or subtracted directly. Therefore, fractioning or scaling deciviews based on emission rates is illogical.

(iv) EPA has offered no justification for requiring controls to achieve reasonable progress for this planning period when the controls cannot even be installed until the next planning period.

EPA further exceeds its authority by proposing to require controls in the name of achieving reasonable progress during the first planning period even though the emissions reductions the Agency proposes would not be achieved until well into the second planning period. The Proposed FIP covers a planning period of 2008-2018. The major SO_2 emissions control technology that would have to be installed at Independence to meet the proposed SO_2 emission rate limitation cannot be designed, constructed and operational in less than five years.[42] Given the likely effective date of the FIP in 2016, SO_2 controls at Independence could not be installed and operational before sometime in 2021.[43]

Adopting a reasonable progress goal for the first planning period based on the installation of controls that will not be completed until well after the deadline to achieve that reasonable progress goal makes no sense, and EPA has completely failed to explain why it is appropriate. Indeed, EPA will have multiple bites at this apple – there are still four more planning periods

[41] Available at http://www.atmos-chem-phys.net/11/10803/2011/acp-11-10803-2011.pdf.

[42] EPA recognizes this timeframe is necessary for the installation of SO_2 controls at Independence by proposing that Independence meet the SO_2 emissions limits no later than five years after the effective date of the final rule. 80 Fed. Reg. at 18,994. Entergy agrees with EPA's conclusion that a five-year timeframe would be necessary for the installation of controls at Independence.

[43] The Proposed FIP provides for NOx emission limitations to be met three years after the effective date of the FIP, which would not be earlier than sometime in 2019.

during which the necessity of reasonable progress controls can be evaluated. Controls on Independence should not be considered until these subsequent planning periods, and should not be imposed for a planning period that will have ended by the time any emissions reductions can be achieved at Independence. This is consistent with EPA's Reasonable Progress Guidance: "It is reasonable for [a state] to defer reductions to later planning periods in order to maintain a consistent glidepath toward the long-term goal." Reasonable Progress Guidance at 1-4.

3. The proposed controls are not cost effective.

EPA's secondary justification for imposing controls on Independence is that it is, in EPA's opinion, cost effective to do so. 80 Fed. Reg. at 18,994-97. First, EPA's cost analysis for the proposed controls at Independence relies upon the control cost analysis for White Bluff, *see* SO_2 Cost TSD at 16, which is inappropriate. By simply relying on its White Bluff cost analysis without undertaking a site-specific analysis for Independence, EPA did not follow the steps necessary to identify the costs of controls for reasonable progress purposes. EPA's Reasonable Progress Guidance requires that EPA (1) identify the emissions units to be controlled; (2) identify the design parameters for the controls; and (3) develop cost estimates based upon those design parameters. Reasonable Progress Guidance at 5-1.

Second, even if the White Bluff cost analysis were sufficiently indicative of the costs to install controls at Independence, Entergy disagrees with EPA's estimated costs for the installation of dry scrubbers at White Bluff. *See* Section III.A.2 above. Assuming that dry FGD controls at Independence would cost the same as at White Bluff, the controls at Independence also would cost over $1 billion. *See* Section III.A.3 above. This is not cost effective on a $/ton basis for reasonable progress purposes as it would result in $4,234 per ton of SO_2 removed at Independence Unit 1 and $3,909 per ton of SO_2 removed at Independence Unit 2.

Finally, even if EPA's cost analysis as detailed in the SO_2 Cost TSD were correct, EPA's determination that the controls are cost effective is an insufficient basis to conclude that they must be installed for reasonable progress purposes.

(i) Requiring over $1 billion in controls at Independence to achieve an unnecessary and imperceptible change in visibility at Arkansas' Class I areas is patently unreasonable.

Despite the flaws in EPA's analysis of Entergy's costs, EPA concludes that dry FGD is cost effective at $2,477 per ton of SO_2 removed for Independence Unit 1 and $2,286 per ton of SO_2 removed for Unit 2. 80 Fed. Reg. at 18,994. Dry FGD is not cost effective for reasonable progress controls. These costs are higher than other cost per ton thresholds in RPG determinations in EPA-approved SIPs. The Kentucky Regional Haze SIP, 76 Fed. Reg. 78,194, 78,206 (Dec. 16, 2011), used $2,000 per ton SO_2 as a screening threshold for cost effectiveness based on CAIR. In the North Carolina Regional Haze SIP, 77 Fed. Reg. 11,858, 11,870 (Feb. 28, 2012), EPA approved the state's decision not to implement reasonable progress controls due to limited improvement in visibility even though cost effectiveness values were described as ranging "from 912 to 1,922 dollars per ton of SO_2 removed ($/ton SO_2), and the average costs per utility system ranged from $1,231 to $1,375/ton SO_2." EPA's estimated cost effectiveness of dry FGD at Independence is significantly higher than these thresholds, at $2,477/$SO_2$ ton removed for Unit 1 and \$2,286/SO_2 ton removed for Unit 2. 80 Fed. Reg. at 18,994. Further, EPA has indicated that control costs found to be reasonable in the BART context may nonetheless be considered too costly in the reasonable progress context. *See* Final North Dakota SIP Approval/Disapproval, 77 Fed. Reg. 20,894, 20,936 (Apr. 6, 2012) (accepting North Dakota's determination that a level of \$2,593 per ton of SO_2 removed was not reasonable and too costly in the reasonable progress context even though it is within the range EPA "ha[s] considered reasonable in the BART context"). Despite these prior actions, EPA unreasonably concludes that the proposed controls at Independence are cost effective for reasonable progress purposes.

Additionally, EPA failed to consider the cost effectiveness of the controls relative to the visibility benefit that would result. EPA's own guidance notes that for "individual, large scale sources, simple cost effectiveness estimates based on a dollar-per-ton calculation may not be as meaningful as a dollar-per-deciview calculation." Reasonable Progress Guidance at 5-2. Here, EPA gave no consideration to the dollar-per-deciview resulting from installing scrubbers at Independence. If EPA had done so, it would recognize that the costs are approximately **\$1.33 billion** per dv improvement at Caney Creek and **\$1.53 billion** per dv improvement at Upper Buffalo. *See* S&L FIP Cost Report at 21, Table 8. Where additional visibility improvement is not needed to remain below the glide path, such an exorbitant cost cannot be justified. *See Nat'l Parks Conservation Ass'n v. EPA*, 788 F.3d 1134, 1149 (9th Cir. 2015) ("*NPCA*") (upholding EPA's decision not to require reasonable progress controls because of lack of cost-effectiveness, finding reasonable EPA's explanation that "cost of compliance is only one of the four statutory requirements for reasonable progress analysis.").

(ii) EPA inappropriately revised Entergy's control cost analysis by eliminating consideration of proper costs.

EPA's cost estimates are artificially low because they fail to account for key considerations. As discussed above in Section III.A.2, EPA unjustifiably revised important aspects of Entergy's Revised White Bluff BART Analysis, upon which the reasonable progress controls cost analysis for Independence is based. At the least, EPA must re-evaluate the costs of controls based upon the 2015 S&L FGD Cost Estimate, attached as Exhibit B.

As discussed in Section III.A.3 above, S&L estimated that the costs of dry FGD at White Bluff Units 1 and 2 would be over \$1 billion, which is approximately 220% higher than EPA's estimate. Based on the 2015 S&L FGD Cost Estimate, and assuming a 30-year life for the dry FGD systems at Independence and identical costs, this results in an average cost effectiveness at Independence Unit 1 of \$4,234 and of \$3,909 at Independence Unit 2, which, as noted above, is much higher than cost per ton thresholds EPA rejected for reasonable progress determinations in other states. As importantly, the cost per deciview improvement that would result from installing these controls is estimated at approximately \$1.33 billion at Caney Creek and \$1.53 billion at Upper Buffalo. *See* S&L FIP Cost Report at 21, Table 8. Such a massive investment cannot be justified in light of the continuous improvement in visibility being achieved at both Caney Creek and Upper Buffalo.

D. EPA Should Adopt Entergy's Proposed Alternative Approach For White Bluff And Independence.

EPA has requested public comment on any alternative SO_2 and NOx control measures that would address the regional haze requirements for White Bluff Units 1 and 2 and Independence Units 1 and 2 for this planning period. 80 Fed. Reg. at 18,997. According to EPA, this includes, but is not limited to, a combination of early unit shutdowns and other emissions control measures at the four units that would achieve *greater* reasonable progress than the BART and reasonable progress requirements that EPA has proposed for the first planning period. *See id.*

1. EPA has no legal basis for requiring that a four-unit approach achieve greater reasonable progress.

EPA has offered no legal basis for its claim that an alternative four-unit approach must achieve *greater* reasonable progress than the controls that EPA has proposed, 80 Fed. Reg. at 18,997, and Entergy disagrees that such a requirement is applicable or mandated by the Clean Air Act or EPA's own Regional Haze Rule. Neither the Act nor EPA's rules impose such a requirement. To the contrary, EPA noted in the final Regional Haze Rule that states have discretion to determine what control measures must be implemented to achieve reasonable progress. 64 Fed. Reg. at 35,721. EPA further explained that "States may conclude that control strategies specifically for protection of visibility are not needed at this time because the analyses may show that existing measures are sufficient to meet reasonable progress goals." *Id.* Indeed, not only is it up to the states to determine how much must be done to ensure reasonable progress, but states conceivably could conclude that *nothing* must be done. There is no provision setting a "floor" for reasonable progress.[44]

2. Entergy's proposed approach achieves virtually identical visibility benefits as the Proposal for over $2 billion less.

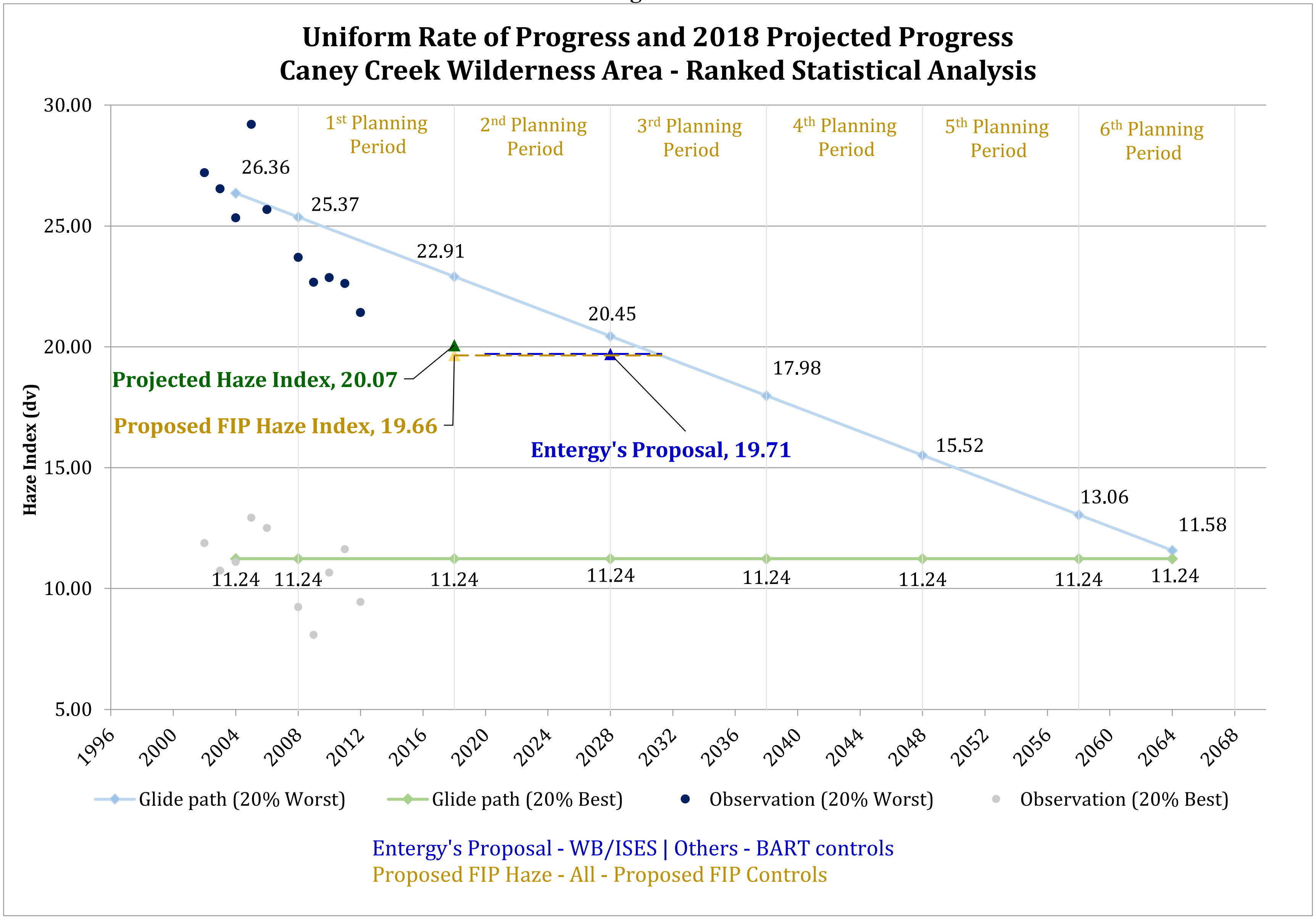
Entergy is proposing near-term interim controls and the cessation of coal combustion at White Bluff by 2028. Entergy also is proposing to meet lower SO_2 emission rates at all four units by 2018, and proposes to install LNB/SOFA at all four units and meet a 30-day rolling average NOx emission rate of 1,342.5 lb NOx/hr, within three years after the effective date of the final FIP.[45] This combination of controls and lower SO_2 emission rates will ensure that the Class I areas achieve virtually the same reasonable progress as EPA's Proposal but at a cost of over $2 billion less than the Proposal. *See* Figures 13 and 14 below, which compare the projected 2018 haze index at each Arkansas Class I area based on the Ranked Statistical Analysis, to the

[44] While states that opt to implement an emissions trading program or other alternative measure rather than require sources to install, operate, and maintain BART *are* required to demonstrate that this alternative will achieve greater reasonable progress than would be achieved through the installation of source-specific BART, 40 C.F.R. § 51.308(e)(2), Entergy is not proposing a BART alternative. Rather, under Entergy's four-unit approach, the NOx control measures and lower SO_2 emission rate proposed for White Bluff would constitute BART for White Bluff while the NOx control measures and lower SO_2 emission rate proposed for Independence are more than sufficient for reasonable progress purposes for this planning period.

[45] Entergy's rationale for the proposed NOx rate is discussed in Section III.E. below.

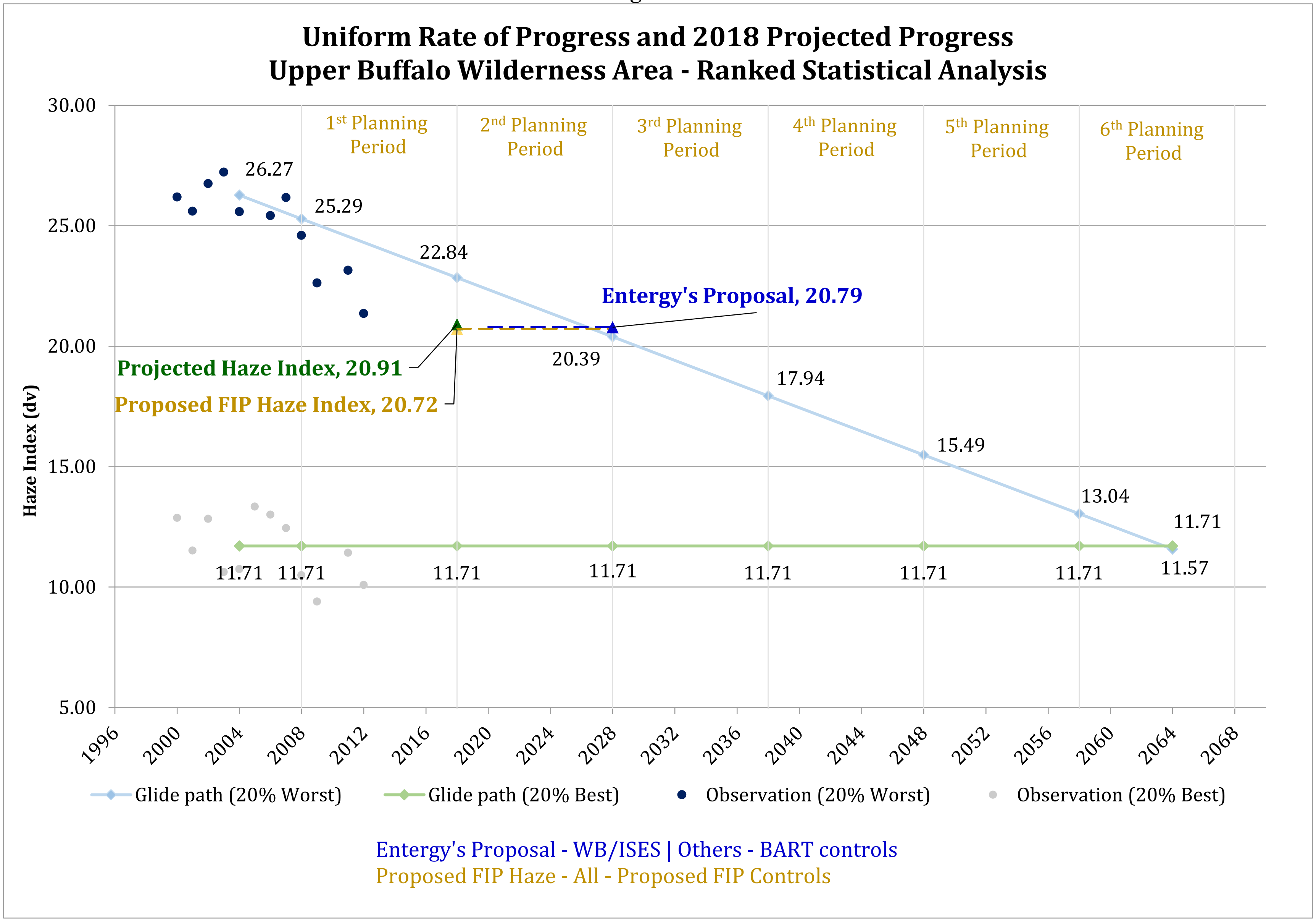
deciview improvements projected for the following scenarios (1) Entergy's proposed controls, based on the cessation of coal-fired operations at White Bluff (referred to as "WB") and the installation of LNB/SOFA and lower SO_2 emission rate at Independence (referred to as "ISES"); and (2) installation of the Proposed FIP controls at all BART sources and Independence. Based on Entergy's modeling, the difference in the haze index between the proposed FIP controls and Entergy's proposal is 0.05 dv at Caney Creek and 0.07 at Upper Buffalo; differences that are too trivial to justify a $2 billion investment at White Bluff and Independence for the installation of dry FGD.

Figure 13



Uniform Rate of Progress and 2018 Projected Progress
Caney Creek Wilderness Area - Ranked Statistical Analysis
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
26.36
25.37
22.91
20.45
17.98
15.52
13.06
11.58
11.24
Projected Haze Index, 20.07
Proposed FIP Haze Index, 19.66
Entergy's Proposal, 19.71
1996
2000
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)
Entergy's Proposal - WB/ISES | Others - BART controls
Proposed FIP Haze - All - Proposed FIP Controls

Figure 14


Uniform Rate of Progress and 2018 Projected Progress
Upper Buffalo Wilderness Area - Ranked Statistical Analysis
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.27
25.29
22.84
Entergy's Proposal, 20.79
20.39
17.94
15.49
13.04
11.71
11.57
Projected Haze Index, 20.91
Proposed FIP Haze Index, 20.72
11.71 11.71 11.71 11.71 11.71 11.71 11.71
1996 2000 2004 2008 2012 2016 2020 2024 2028 2032 2036 2040 2044 2048 2052 2056 2060 2064 2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)
Entergy's Proposal - WB/ISES | Others - BART controls
Proposed FIP Haze - All - Proposed FIP Controls

Entergy's proposed approach with respect to White Bluff and Independence makes sense in light of the long-term objectives of the Regional Haze Program, the high capital costs for scrubbers, and the significant long-term environmental co-benefits from the cessation of coal-firing at the White Bluff units. Arkansas' Five-Year Progress Report demonstrates that the state currently is below the glide path for Caney Creek and Upper Buffalo, and expects to remain so through at least 2018. *See* Section III.C.1 above. Entergy's approach would help ensure that Arkansas remains below the glide path throughout the second planning period, and will produce very large additional reductions in NOx, SO_2, and PM heading into the third planning period.

Ultimately, Entergy's approach would achieve more than 170,000 tons of NOx reductions from White Bluff than the proposed FIP would achieve. While scrubbers would reduce SO_2 emissions substantially, the total visibility benefits from ceasing to use coal are at least as great. Entergy's approach also would achieve multi-pollutant co-benefits. Prior to 2028, SO_2 and NOx would be reduced, which would result in reductions in ozone and $PM_{2.5}$. Starting in 2028, Entergy's approach would produce even greater reductions in emissions of SO_2, NOx and $PM_{2.5}$, as well as achieving reductions in mercury and other hazardous air pollutants, and CO_2/CO_2e. It would reduce annual greenhouse gas emissions by approximately 11.74 million tons per year, a 275 million ton lifetime benefit over EPA's Proposal. Additionally, the elimination of coal combustion in 2027 and 2028 would reduce rail and truck traffic, allow for the closure of landfills, and reduce water usage, in addition to other environmental benefits.

3. EPA should adopt RPGs for Arkansas that reflect Entergy's proposal.

Entergy opposes the RPGs that EPA has proposed for Caney Creek and Upper Buffalo. The RPGs reflect the approved portions of Arkansas' Regional Haze SIP, the proposed FIP BART controls, and the controls proposed for Independence. 80 Fed. Reg. at 18,997. For all of the reasons discussed above in Section III.C, controls at Independence for reasonable progress purposes are not justified and including the emissions reductions based on the installation of dry FGD and LNB/SOFA at Independence renders EPA's RPGs arbitrary and capricious. EPA should recalculate the RPGs based on Entergy's proposed approach for controlling emissions at White Bluff and Independence.

E. The Proposed NOx Limits For White Bluff And Independence Cannot Be Achieved Based On The Plants' Current Operating Conditions.

The NOx emission limits proposed by Entergy for the units at White Bluff and Independence are based on the emission rate for LNB/SOFA of 0.15 lb/MMBtu that Entergy proposed in the Revised White Bluff BART Analysis. At the time Entergy submitted the Revised White Bluff BART Analysis in October 2013, all four of the coal-fired units at White Bluff and Independence were operated as base load units and spent the overwhelming majority of their operating time at loads of greater than 50% of unit capacity. Since submitting the Revised White Bluff BART Analysis,[46] Entergy transitioned to MISO in December 2013. MISO utilizes an economic dispatch model to determine which EGUs within its service territory are

[46] Entergy notes that EPA relied upon the Revised White Bluff BART Analysis to evaluate controls for Independence.

dispatched to operate and the operating load (MW) for each unit. Initially the MISO operating environment resulted in similar unit dispatch schedules for White Bluff and Independence, with all four units primarily dispatched as base-load units with some load-following operation. However, beginning in December 2014, the units at both White Bluff and Independence began to be dispatched primarily as load-following units. Since December 2014, the White Bluff and Independence units have been dispatched less frequently and, when dispatched, have spent significantly more time at low operating rates of less than 50% of unit capacity.

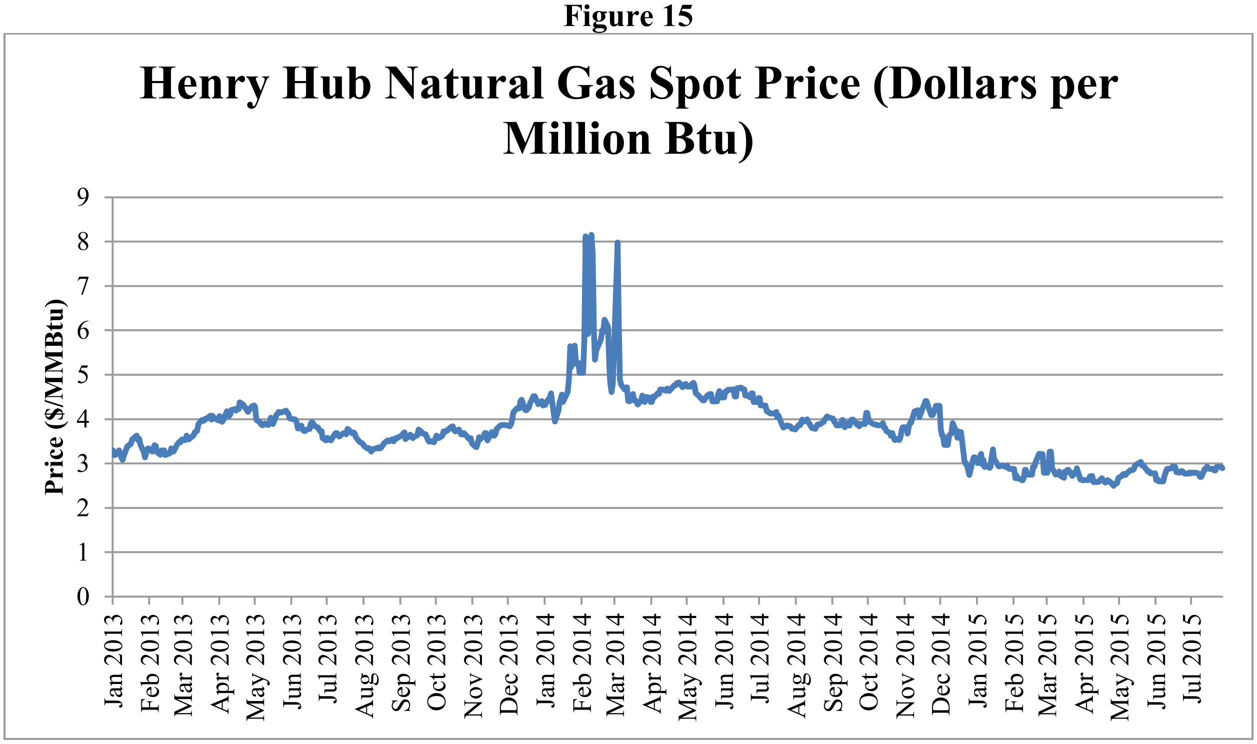
The impact of this change in dispatch of the units can be seen in the following table. The data for 2015 (through June 30) reflects a significant increase in the percentage of time that each unit is dispatched at less than 50% of operating capacity. Three of the four units have spent greater than 40% of their 2015 operating hours at less than 50% of capacity, and the two Independence units have spent nearly half of their operating time at less than 50% of capacity.

	WB1		WB2		ISES1		ISES2	
	# of Hours <50% Load	% of Operating Hours <50% Load	# of Hours <50% Load	% of Operating Hours <50% Load	# of Hours <50% Load	% of Operating Hours <50% Load	# of Hours <50% Load	% of Operating Hours <50% Load
2013	624	7.96%	606	7.95%	797	10.99%	979	11.60%
2014	959	12.39%	784	10.32%	818	10.39%	1069	13.69%
2015 (YTD)*	1444	42.84%	681	27.54%	1278	48.03%	1267	49.40%

* 2015 YTD represents Jan-June 2015

This change in dispatch coincided with a sharp drop in natural gas prices which can be seen in Figure 15 below. This drop in gas prices to near $3 per MMBtu has been sustained since December 2014, and Entergy has no reason to expect any significant increase in gas pricing in the near future.

Figure 15



This change in dispatch for the units at both White Bluff and Independence is significant with regard to NOx emissions as the LNB/SOFA system is designed to operate primarily in the range of 50-100% of unit load. Entergy has selected Foster Wheeler as the LNB/SOFA vendor for White Bluff and has only been able to obtain a guarantee of less than 0.15 lb/MMBtu for operating loads in the range of 50-100% of unit capacity.[47] Since the available emission guarantee does not cover unit operation at less than 50% of capacity, Entergy requested a memorandum from Foster Wheeler regarding the impact of unit operation at less than 50% capacity on NOx emission rates. This memorandum is attached as Exhibit G to these comments. Based on input from the LNB/SOFA vendor, Entergy does not believe that the proposed emission rate of 0.15 lb/MMBtu is consistently achievable under all operating conditions. Even with a 30-day averaging period for the proposed limit, a unit which is frequently dispatched at less than 50% of capacity may not be able to achieve compliance.

This was not perceived as an issue at the time that the Revised White Bluff BART Analysis was prepared and submitted to ADEQ by Entergy as, historically and at that time, the units were operated almost exclusively as base-load units and spent less than 10% of their operating time at less than 50% of unit capacity. In the current dispatch environment, with some units spending nearly 50% of their operating time outside of the control range for LNB/SOFA, Entergy can no longer be confident that the units will be able to achieve compliance with a limit of 0.15 lb/MMBtu on a 30-day rolling average basis.

The concern arises from low-load operation during which periods of higher NOx emissions, on a lb/MMBtu basis, would not be expected to correspond to an increase in the maximum mass emission rate (lb/hr) from the units as any increase in the emission rate on a lb/MMBtu basis would be expected to be more than offset by the lower unit operating rate in MMBtu/hr to arrive at a mass emission rate (lb/hr).

To address the potential for a higher NOx emission rate (lb/MMBtu basis) at operating rates of less than 50% of unit capacity, Entergy proposes a rolling 30-boiler operating day average emission rate of 1,342.5 lb NOx/hr at each coal-fired unit at White Bluff and Independence. In the alternative, if EPA believes that a lb/MMBtu limit is necessary for the units, Entergy proposes a bifurcated NOx emission limit for each unit at both White Bluff and Independence as follows.

> For all unit operation (0-100% of capacity), a limit of 1,342.5 lb NOx/hr, based on a rolling 30-boiler operating day average.
>
> And;

---

[47] This range is referred to as the "control range" by Foster Wheeler. *See* Exhibit F, p. 46, for Foster Wheeler's emissions guarantee. The load ranges identified in the emissions guarantee equate to 50% to 100% of the White Bluff units' operating capacity. Entergy added .01 lb/MMBtu to Foster Wheeler's emissions guarantee to account for fluctuations in NOx emissions from the units. Controlled NOx emissions fluctuate during normal boiler operation in response to a number of design/operating parameters including, but not necessarily limited to: inlet NOx concentrations, boiler load, load changes, particulate matter loading, flue gas temperatures and flue gas velocities. A compliance margin above the vendor's emissions guarantee is recommended for establishing an enforceable limit to address such fluctuations.

For unit operation at 50-100% of capacity, a limit of 0.15 lb NOx/MMBtu, based on a rolling 30-boiler operating day average, to include only those hours for which the unit was dispatched at 50% or greater of maximum capacity.

This alternative approach would ensure that the units are operated in compliance with the LNB/SOFA design within the control range of 50-100% of capacity while providing Entergy with flexibility in demonstrating compliance. The lb/hr limit, which would apply to all operating hours, will ensure that the 30-day average emission rates remain below those on which both EPA and Entergy relied to project visibility improvements from the proposed NOx emission reductions.

F. The NOx BART Determination For Lake Catherine Unit 4 Should Be No Controls.

1. Visibility Improvement From Controls On Lake Catherine Unit 4 Cannot Be Reasonably Anticipated.

EPA has proposed NOx BART controls for Lake Catherine Unit 4 based on the installation of burners out of service ("BOOS"). *See* 80 Fed. Reg. at 18,978. To justify the visibility improvement resulting from installation of the proposed controls, EPA relied on the CALPUFF dispersion modeling system without assessing the reliability of the model to predict very small changes in visibility. In *NPCA*, the Ninth Circuit concluded that EPA had failed to justify that predicted visibility improvements were "reasonably anticipated," as required by the Clean Air Act, where the improvements were so insignificant that they were within the CALPUFF model's margin of error. *NPCA*, 788 F.3d 1134, 1146-47.

On behalf of Entergy, Trinity completed a quantitative analysis to evaluate the margin of error in the CALPUFF model for Lake Catherine Unit 4. As part of this analysis, Trinity modeled the following three scenarios:

- All BART – Includes all sources subject to BART, modeled using Pre-BART representations;
- Pre-BART – Includes only Lake Catherine Unit 4, modeled based on the current permit representation; and
- Post-BART – Includes only Lake Catherine Unit 4, modeled using Post-BART emission rate and stack parameters.

Trinity calculated the average difference between modeled values obtained using CALPUFF (including the CENRAP background) and IMPROVE monitored values for Caney Creek and Upper Buffalo for each of the three modeling scenarios. Trinity compared the regional haze design value format of average W20 days visibility for this analysis. Specifically the following comparisons were made:

- Modeled vs Measured W20 Days: The W20 days based on IMPROVE measurements were selected for each Class I area and compared with the CALPUFF results from the corresponding days.

- Measured vs. Modeled W20 Days: The W20 days based on CALPUFF modeling results were selected considering only days when IMPROVE measurements were taken. Modeled values were then compared to the IMPROVE measurements from the corresponding days.

- Measured and Modeled W20 Days: The W20 days based on IMPROVE measurements were selected and compared with the W20 days based on CALPUFF modeling disregarding temporal correlation.

A complete discussion of Trinity's analysis and results is presented in *Evaluation of the CALPUFF Modeling System Margin of Error for a BART Analysis, Entergy Services, Inc. - Lake Catherine Plant*, Trinity Consultants (Aug. 4, 2015). ("CALPUFF Margin of Error Report"), which is attached as Exhibit H and is hereby incorporated by reference. As demonstrated in the CALPUFF Margin of Error Report, the Pre-BART impact from Lake Catherine Unit 4 at Caney Creek and Upper Buffalo is inconsequential when compared with the IMPROVE measurements, which capture the impact of all other sources, including Lake Catherine, on the Class I areas.

The proposed NOx BART controls for Lake Catherine Unit 4 will result in visibility improvements that are even more inconsequential and cannot accurately be predicted by CALPUFF. Based on Trinity's analysis, the minimum calculated margin of error for CALPUFF for Lake Catherine Unit 4 is 0.93 dv. The CALPUFF predicted visibility improvement associated with EPA's proposed BART controls for Lake Catherine Unit 4 at Caney Creek and Upper Buffalo falls within this margin of error. *See* 80 Fed. Reg. at 18,978, Table 42. As such, the visibility improvements at each of these Class I areas associated with the proposed BART controls for Unit 4 cannot "reasonably be anticipated." 42 U.S.C. § 7491(g)(2); *see NPCA*, 788 F.3d 1134, 1146-47. Accordingly, EPA has not adequately demonstrated that it is appropriate to require NOx BART controls on Lake Catherine Unit 4.

2. Source-Specific Controls Should Not Be Imposed On Lake Catherine Unit 4.

If EPA finalizes a determination that Lake Catherine Unit 4 should be subject to NOx BART controls, EPA should not impose source-specific NOx controls on Lake Catherine Unit 4 but should instead find that CSAPR is better than NOx BART in Arkansas for all EGUs, as discussed in Section III.A.4 above. Compliance with CSAPR will ensure that NOx emissions from Arkansas' EGUs are limited and will improve visibility in Arkansas' Class I areas.

EPA also had evaluated controls other than BOOS for Lake Catherine Unit 4. *See* 80 Fed. Reg. at 18,976-78. Similar to BOOS, however, these controls would result in imperceptible visibility improvements in Arkansas' Class I areas. Although Entergy did not evaluate the margin of error with respect to the CALPUFF predicted visibility improvement from these other controls, EPA had rejected these controls as NOx BART for Lake Catherine Unit 4 based on costs and Entergy agrees with EPA's determination that these controls should not be considered as NOx BART for Lake Catherine Unit 4. Specifically, Entergy agrees with EPA that the incremental cost effectiveness of installing LNB/SOFA at Lake Catherine Unit 4 cannot be justified as BART. *See id*. at 18,978. Similarly, the installation of LNB/SOFA and selective non-catalytic reduction ("SNCR") or selective catalytic reduction ("SCR") cannot be justified as

BART based on either average cost effectiveness or incremental cost effectiveness. *Id*. Lake Catherine Unit 4 is a peaking unit and operated at only a two percent capacity factor in 2014. [48] The estimated incremental costs of installation of LNB/SOFA (at $14,246/ton), SNCR (at $16,029/ton), and SCR (at $11,767/ton) are simply not warranted for a unit that operates so infrequently. *See id.* at 18,978. Installation of these controls would require a massive capital investment and significant operation and maintenance costs that are impracticable for a peaking unit.

G. EPA Improperly Considered The Cumulative Visibility Improvement At All Class I Areas.

EPA's reliance on a "cumulative visibility improvement" metric is arbitrary and capricious, and has no basis in law. In assessing the visibility improvements that are predicted to be achieved through the installation of proposed controls at White Bluff, Lake Catherine, and Independence, EPA totaled the predicted improvements at all affected Class I areas to yield a cumulative visibility improvement associated with each facility. *See* 80 Fed. Reg. at 18,972 (Tables 34 and 35); 18,974 (Tables 37 and 38); 18,978 (Table 42); 18,994 (Table 64). EPA appears to have relied upon the cumulative visibility improvement across the four affected Class I areas to support its proposed NOx BART determination for Lake Catherine. 80 Fed. Reg. 18,978 (where EPA identified the cumulative visibility impact in its rationale for the Lake Catherine "Proposed NOx BART Determination"). It is improper for EPA to rely upon the cumulative visibility improvement across all affected Class I areas. BART and reasonable progress determinations instead should be based on the predicted visibility improvements at individual Class I areas.

The preamble to the BART Guidelines states that the focus of an analysis of visibility improvements associated with BART controls is to be on the "nearest Class I area" to the facility in question. 70 Fed. Reg. 39,104, 39,170 (July 6, 2005) ("One important element of the [modeling] protocol is in establishing the receptors that will be used in the model. The receptors that you use should be located in the *nearest* Class I area with sufficient density to identify the likely visibility effects of the source.") (emphasis added). While the Rule allows consideration of impacts at other nearby Class I areas, it is for the purpose of "determin(ing) whether effects at those areas *may be greater than* at the *nearest* Class I area." *Id.* (emphasis added). Summing the predicted visibility improvements at multiple Class I areas does not facilitate a determination that effects at more distant Class I areas are more significant than those at the closest Class I area.

In addition to having no basis in EPA's own regulations, the cumulative metric is deceptive and provides no information that could be used to assess whether any single Class I area would experience perceivable visibility improvements as a result of BART or reasonable progress controls. For example, EPA appears to have selected BOOS as NOx BART for Lake Catherine in part because it would achieve a cumulative visibility improvement across the four affected Class I areas of 1.215 dv. 80 Fed. Reg. at 18,978. But the cumulative metric masks the

[48] Entergy's current resource planning assumption is that Lake Catherine Unit 4 will be de-activated in mid-2025, though no final decision to this effect has yet been made.

fact that no individual Class I area would experience any discernible visibility improvement. Instead, Mingo would experience a 0.196 dv improvement, Hercules-Glades would experience a 0.175 dv improvement, Upper Buffalo would experience a 0.248 dv improvement, and Caney Creek would experience a 0.596 dv improvement. *See id.* These are imperceptible levels of improvement that do not justify installation of controls.[49] The metric therefore equates imperceptible visibility "benefits" in different areas with a much larger and indisputably discernible visibility improvement in a single area.

On a practical level, reliance on a cumulative visibility improvement is illogical. Deciview improvements at multiple areas cannot be added together to form a meaningful metric. As discussed in Section III.C.2 above, a deciview is a logarithmic scale based on the concept that one deciview is the minimum change in visibility perceptible to a human observer. Deciviews cannot be directly added or subtracted. To add or subtract the haze, one must add or subtract the total extinction values and then recalculate the haze index in deciviews. Considering the Class I areas addressed in the Proposal are hundreds of kilometers away from each other, particles from one Class I area cannot contribute to or improve the light extinction at another Class I area, therefore, adding or subtracting light extinction values is not an accurate representation of reality and would be illogical. In simple terms, a visitor to a Class I area cannot benefit from any visibility improvement that might be occurring at another Class I area. The cumulative metric represents an illusory visibility benefit; it is an improvement that cannot be perceived and therefore provides no indication of whether the proposed controls will contribute to the goal of the Regional Haze Program: to reduce human perception of visibility impairment in Class I areas. This cumulative visibility metric should be eliminated from any consideration of whether proposed controls will result in visibility improvement, including for the Lake Catherine BART analysis.

H. EPA Must Address The Requirements Of Executive Orders 12866 And 13211.

EPA claims that the Proposal is not a "significant regulatory action" under Executive Order 12866. 80 Fed. Reg. at 18,999. Entergy disagrees. The Proposal's implementation cost to EAI alone of over $2 billion exceeds the $100 million threshold for economic significance. "By virtue of [the] longstanding Executive Order [12866] applying to significant rules issued under the Clean Air Act (as well as other statutes), the Agency must systematically assess the regulation's costs and benefits." *Michigan v. EPA*, 135 S.Ct. at 2715 (Kagan, J. dissenting). EPA states that the Proposal is not generally applicable, and therefore not subject to Executive Order 12866, because the rule "only proposes source specific requirements for particular, identified facilities (six total)." 80 Fed. Reg. at 18,999. However, a count of the number of entities regulated under a rule is not indicative of the general applicability or the significance of the economic impacts of the rule. Requiring additional controls at power plants initiates a cascade of impacts, including changes in the regional distribution of electricity and rates of thousands of electricity customers in multiple states. These far-reaching impacts merit

[49] As discussed above in Section III.F.1, EPA did not perform an analysis to confirm that the model predictions are not within the model's margin of error and, therefore, EPA has not justified that the predicted visibility improvements are "reasonably anticipated."

classifying the Proposed FIP as a regulation with general applicability and significant economic impact.

Entergy also disagrees with EPA's conclusion that the Agency is not required to assess the energy impacts of the Proposed FIP under Executive Order 13211. 80 Fed. Reg. at 19,000. The Proposal will have a significant impact on the supply, distribution, and use of energy. Installation of additional controls will require outages at multiple power plants, altering the normal supply and distribution of energy. Additionally, the more than $2 billion cost of implementing the Proposed FIP will be imposed upon EAI's customers and co-owners, impacting energy use as electricity rates climb.

EPA must prepare a cost/benefit analysis and evaluate the energy impacts of the Proposed FIP and issue these analyses for public comment before finalizing the FIP.

I. Additional Comments.

- Entergy agrees with EPA's proposal that the existing emission limits at the White Bluff Auxiliary Boiler satisfy BART for SO_2, NOx, and PM. 80 Fed. Reg. at 18,975.

- Entergy agrees that 2009-2011 should be used as the baseline period for NOx for White Bluff Units 1 and 2. 80 Fed. Reg. at 18,969.

- If EPA finalizes a source-specific NOx BART limit for Lake Catherine Unit 4, Entergy requests that EPA confirm that the unit may continue to conduct monitoring pursuant to 40 C.F.R. Part 75 Appendix E so long as it qualifies as a peaking unit. In the Proposal, EPA appears to have assumed that Unit 4 currently operates "full" NOx CEMS with a continuous NOx analyzer pursuant to 40 C.F.R. Part 60. However, because Unit 4 meets the definition of a peaking unit under 40 C.F.R. Part 75, and the unit is not subject to any NSPS Part 60 standards, Entergy does not currently operate a NOx analyzer for the unit. Under Part 75, Unit 4 qualifies as an Appendix E unit, allowing the unit to utilize a NOx correlation curve to estimate emissions and only monitor heat input and exhaust O_2 concentration.

- Entergy agrees with EPA's conclusion that wet scrubbers do not constitute BART for White Bluff and should not be installed at Independence to meet reasonable progress requirements. 80 Fed. Reg. at 18,972, 18,993.

- Entergy agrees with EPA that LNB/SOFA/SNCR or LNB/SOFA/SCR cannot be justified as BART for White Bluff based on the incremental cost effectiveness of the controls. 80 Fed. Reg. at 18,974.

- Entergy disagrees that the proposed regional haze FIP will satisfy the requirements of CAA Section 110(a)(2)(D)(i)(II), 80 Fed. Reg. at 18,998, for the reasons explained in Entergy's comments on EPA's proposed disapproval of Arkansas' SIP revision addressing interference with other states' programs for visibility protection for the 2006 revised 24-hour $PM_{2.5}$ NAAQS. These comments are attached as Exhibit I and are hereby incorporated by reference.

IV. CONCLUSION

Entergy appreciates the opportunity to comment on the Proposed FIP. Entergy strongly urges EPA to adopt a comprehensive approach to regional haze that would involve the four coal-fired units at Independence and White Bluff, as Entergy as proposed, without requiring expensive, unnecessary scrubber technology. Such an approach would ensure superior, long-term visibility benefits than would the Proposed FIP. It also would deliver important non-haze environmental benefits, including a dramatic decrease in GHG emissions, large reductions in SO_2 emissions that also contribute to long-range $PM_{2.5}$ issues, and large reductions in ozone (and $PM_{2.5}$)-forming NOx emissions. Entergy respectfully requests that EPA amend the Proposed FIP as described in these comments.

Respectfully submitted,

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Entergy Services, Inc.

ENTERGY ARKANSAS, INC.

REVIEW OF EPA'S COST ANALYSIS FOR ARKANSAS REGIONAL HAZE PROPOSED FEDERAL IMPLEMENTATION PLAN

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ATTACHMENTS

EXECUTIVE SUMMARY

On April 8, 2015, the U.S. Environmental Protection Agency (EPA) published in the *Federal Register* a proposed rule that would partially approve and partially disapprove specific portions of the Arkansas State Implementation Plan (AR SIP) and issue a Federal Implementation Plan (FIP) that would regulate a group of Arkansas electric generating units (EGUs).[1] In this rule, EPA proposes to require additional SO_2 emission reductions that would require retrofitting new FGD systems on Entergy's White Bluff Station Units 1 and 2 and Entergy's Independence Station Units 1 and 2.

Sargent & Lundy (S&L) was contracted by Entergy to review EPA's proposed cost modifications as described in its Technical Support Document entitled, "Technical Support Document for EPA's Proposed Action on the Arkansas Regional Haze Federal Implementation Plan," hereinafter referred to as "FIP TSD," including one if its appendices, entitled "Appendix A. Technical Support Document for the SDA Control Cost Analysis for the Entergy White Bluff and Independence Facilities Arkansas Regional Haze Federal Implementation Plant (SO_2 Cost TSD)," hereinafter referred to as "Cost TSD."

Cost-effectiveness is influenced by two variables: the total annualized cost to retrofit dry FGD systems ($/yr) and the corresponding reduction in annual SO_2 emissions (tons per year "tpy"). EPA's approach does not accurately calculate either variable.

Based on our review, the following items in EPA's analysis were identified to result in overstating the tons of SO_2 removed:

- After defining a baseline SO_2 emission period of between 2009 and 2013, EPA arbitrarily excluded the years with the maximum and minimum annual averages;
- When calculating SO_2 emission reductions due to FGD retrofits, EPA incorrectly used maximum monthly averages for baseline SO_2 emissions; and
- A controlled SO_2 limit of 0.06 lb/MMBtu is not a realistic or sustainable value to maintain on a long-term basis when considering the normal variation in operation that occurs at all coal-fueled facilities.

In addition, the following items in EPA's analysis were identified to result in understating the annualized cost of the dry FGD retrofit:

- EPA subtracted over $23 million in BOP costs for both units because they mistakenly believed the equipment to be included in Alstom's scope;
- Because EPA mistakenly removed BOP cost items that should be included in the estimate, they over-estimated and misapplied percent reductions to other cost items, resulting in cost subtractions of over $7 million for both units;

[1] *See* 80 Fed. Reg. 18,944 (April 8, 2015).

- EPA removed over $41 million per unit in Owner's Costs despite the fact that these are real costs that the Entergy will incur;
- EPA under-estimated cost escalation, and in some cases de-escalated costs, by relying on cost indices rather than using vendor pricing information, all of which resulted in under-estimating costs by more than $42 million per unit;
- EPA incorrectly utilized the IPM model, which is not designed to evaluated site-specific costs, to verify O&M costs at White Bluff;
- EPA scaled capital costs to a design fuel of 0.68 lb/MMBtu, which when compared to operating data, is completely insufficient to ensure compliance with the proposed emission limits for nearly half of the time;
- While we agree that O&M costs should be based on 0.68 lb/MMBtu, EPA's methodology to scale direct O&M costs based on fuel sulfur levels is incorrect and resulted in under-estimating these costs by over $5 million per unit;
- EPA incorrectly scaled indirect O&M costs using fuel sulfur levels, despite these costs being estimated as percentages of capital cost, which resulted in under-estimating these costs by over $4 million; and
- EPA used a remaining useful life of 30 years, when Entergy is proposing to cease coal-fired operations on these units in 2027 and 2028, resulting in a remaining useful life of 6 or 7 years.

As discussed above, S&L's analysis reveals that EPA overstates the cost-effectiveness ($/ton of SO_2 removed) to retrofit dry FGD systems at White Bluff Units 1 and 2, which EPA proposes to require in its FIP. In its approach, EPA understated the annualized cost of the control systems and overstated the tons of SO_2 that would be removed by its FIP-imposed FGD retrofits. To better address EPA's questions on scope and cost items which it did not understand, S&L has prepared an updated cost report to clarify and provide further detail around scope items and cost items included in the estimate.[2] The corrected and updated cost-effectiveness for both White Bluff units is greater than $7500/ton, which is clearly not cost effective.

With respect to EPA's Reasonable Progress Goal (RPG) analysis for SO_2 controls, EPA did not follow its own guidance document when conducting its four factor analysis of Independence. EPA failed to consider lower cost options that could reduce SO_2 emissions at Independence and instead concluded that BART-level controls were required to meet RPG. EPA did not prepare cost estimates based on design parameters for FGD systems retrofit at Independence, as required by their RPG guidance document. EPA did not conduct a dollar-per-deciview analysis, as recommended in its RPG document for these analyses to demonstrate the benefit of retrofitting dry FGD at Independence accounting for visibility benefits. When applying annualized costs to projected visibility improvements the result is over $1.3 billion/Δdv for Caney Creek and over $1.5 billion/Δdv for Upper Buffalo, which is clearly not cost effective.

[2] *See* S&L Report #012831 ("White Bluff Dry FGD Cost Estimate and Technical Basis") (July 2015).

1. INTRODUCTION

On April 8, 2015, the U.S. Environmental Protection Agency (EPA) published in the *Federal Register* a proposed rule that would partially approve and partially disapprove specific portions of the Arkansas State Implementation Plan (AR SIP) and issue a Federal Implementation Plan (FIP) that would regulate a group of Arkansas electric generating units (EGUs).[3] In this rule, EPA proposes to require additional SO_2 emission reductions that would require retrofitting new FGD systems on Entergy's White Bluff Station Units 1 and 2 and Entergy's Independence Station Units 1 and 2.

Sargent & Lundy (S&L) was contracted by Entergy to review EPA's proposed cost modifications as described in its Technical Support Document entitled, "Technical Support Document for EPA's Proposed Action on the Arkansas Regional Haze Federal Implementation Plan," hereinafter referred to as "FIP TSD," including one if its appendices, entitled "Appendix A. Technical Support Document for the SDA Control Cost Analysis for the Entergy White Bluff and Independence Facilities Arkansas Regional Haze Federal Implementation Plant (SO_2 Cost TSD)," hereinafter referred to as "Cost TSD."

S&L's experience in the electric power industry, as well as our experience with the Entergy facilities makes us uniquely qualified to perform this review. S&L has considerable experience with the federal and state environmental regulations affecting power plant operations, as well as the specification, evaluation, selection, and implementation of emission control technologies for both gas- and coal-fueled utility power facilities, including extensive experience with various FGD technologies. For example, since 2000, S&L has provided, or is currently providing, engineering services for the implementation of over 40 wet FGD projects, 30 dry FGD projects, and 25 dry sorbent injection (DSI) projects, all of which are technologies that are used to control SO_2 emissions. Our first-hand experience with these technologies provides us with a thorough understanding of both capital and operating and maintenance (O&M) costs associated with these technologies, as well as providing us with a comprehensive understanding of the achievable emission rates and limitations of these technologies.

S&L's analysis reveals that EPA overstates the cost-effectiveness ($/ton of SO_2 removed) to retrofit dry FGD systems at White Bluff Units 1 and 2, which EPA proposes to require in its FIP. Cost-effectiveness is influenced by two variables: the total annualized cost of retrofit dry FGD systems ($/yr) and the corresponding reduction in annual SO_2 emissions (tons per year "tpy"). EPA's approach does not accurately calculate either variable. In its approach, EPA understated the annualized cost of the control systems and overstated the tons of SO_2 that would be removed by its FIP-imposed FGD retrofits.

[3] *See* 80 Fed. Reg. 18,944 (April 8, 2015).

2. Comments to the FIP TSD – SO_2 Emission Reduction Errors

The majority of S&L's comments are relative to EPA's Cost TSD; however, we note that in its FIP TSD, EPA incorrectly estimates both baseline emissions and SO_2 emission reductions that would result from the retrofit of dry FGD systems at White Bluff station. In addition, in proposing emission rates for White Bluff station, EPA proposed SO_2 emission limits that are consistent with performance guarantees offered by dry FGD suppliers during initial performance testing, not emission rates that are achievable over the 30-year life EPA assumed in its analysis. The following sections describe EPA's flawed analysis contained in the FIP TSD.

2.1 Baseline Emission Rates

Although baseline emission rates identified in Entergy's original BART analysis[4] were calculated based on the average annual emission rates from 2001 to 2003, in the FIP TSD, EPA redefines baseline emission by using a 3-year average of annual average SO_2 emissions from the years 2009 to 2013, excluding the years with the maximum and minimum annual averages.[5]

We can find no reason to reject EPA's selection of 2009 to 2013 as the baseline period as it represents more recent operation. However, the approach used by EPA to exclude the maximum and minimum values is entirely arbitrary and EPA does not explain how this approach represents a more realistic depiction of anticipated emissions from the existing sources.

The BART Guidelines state that baseline emissions from existing sources "should represent a realistic depiction of anticipated annual emissions for the source."[6] In general, for the existing sources, facilities should estimate the anticipated annual emissions based upon actual emissions from a baseline period.[7] However, EPA provides no explanation or analysis to demonstrate that the approach taken results in a realistic depiction of anticipated annual emissions from White Bluff and Independence. In addition, there is no basis for concluding that EPA's approach of excluding actual emissions data more accurately represents the actual operation of the units. Finally, to our knowledge, with the exception of EPA's proposed Texas FIP, this approach has not been used previously by EPA as a methodology for evaluating baseline emissions in other evaluations (and even if EPA had done so, it is not justified here).

The following table shows a comparison between the baseline emissions as established using EPA's approach and baseline emissions calculated as a straight average for various timeframes within the 2009-2013 period.

[4] Revised Bart Five Factor Analysis, White Bluff Steam Electric Station, Redfield, Arkansas, October 2013, Trinity Consultants.
[5] *See* EPA-R06-OAR-2015-0189-0093-White Bluff_R6 cost revisions2.xlsx, under Annual Emissions.
[6] 40 CFR Part 51 Appendix Y.
[7] *Id.*

Table 1: Comparison of Baseline SO_2 Emissions for White Bluff and Independence

Unit	EPA Approach 3 Year Average* (tons)	3 Year Average 2009-2011 (tons)	3 Year Average 2010-2012 (tons)	3 Year Average 2011-2013 (tons)	5 Year Average 2009-2013 (tons)
White Bluff 1	15,816	15,745	15,395	15,826	15,939
White Bluff 2	16,697	15,582	15,217	16,697	16,034
Independence 1	14,269	14,160	15,486	14,707	14,258
Independence 2	15,511	14,673	15,196	16,035	15,407

*EPA's approach includes 2009-2013 3-year average, excluding maximum and minimum years.

With the exception of White Bluff 1, EPA's approach of eliminating the maximum and minimum values results in higher baseline SO_2 emissions compared to averaging the entire 5-year period. In all cases, there is at least one other approach that would result in lower baseline SO_2 emissions compared to EPA's approach. By overestimating the baseline SO_2 emissions, EPA overstates the amount of SO_2 that would be removed and, thus, overstates the cost-effectiveness of the FGD retrofit projects.

2.2 SO_2 Emission Reduction

SO_2 emission reductions were estimated incorrectly by EPA for White Bluff and Independence. For each unit, EPA identified the maximum monthly SO_2 emission rate in the baseline period of 2009 to 2013 and then calculated the percent reduction that would be required to achieve a controlled emission rate of 0.06 lb/MMBtu. The percent reduction calculated was then multiplied by the baseline emission tons to determine the tons of SO_2 reduced. This methodology is incorrect because it assumes the baseline emissions calculated in the previous section are based on maximum monthly averages, which are significantly higher than the annual averages actually used to calculate baseline emissions.

The correct way to project the SO_2 emission reduction is to multiply the outlet emission rate of 0.06 lb/MMBtu by the average heat input to the boiler (MMBtu/year) from the baseline period. For example, the average heat input to White Bluff 1 over the baseline period of 2009 to 2013 was 55,829,551 MMBtu/year. Multiplying by 0.06 lb/MMBtu and then converting from pounds to tons results in estimated SO_2 emission reductions of 14,264 tons per year, as compared to EPA's 14,363. This method has been utilized by S&L on previous BART analyses, and has been accepted previously by EPA.

Table 2: SO_2 Emission Reductions for White Bluff and Independence

Unit	**EPA Approach** Using Maximum Monthly **SO_2 emission and 3-Year Baseline (tons)**	Using **5-Year Average** Heat Input and Baseline **(tons)**
White Bluff 1	14,363	14,264
White Bluff 2	15,221	14,353
Independence 1	12,912	12,607
Independence 2	13,990	13,655

Table 2 compares EPA's incorrect methodology to estimate SO_2 emission reductions at the Entergy Units to the more accurate methodology described above of using the 5-year average heat input from the baseline period. EPA's methodology overestimated the SO_2 emission reduction in all cases and therefore overstates the cost-effectiveness of the FGD retrofits at each unit.

2.3 SO_2 Emission Rate

EPA proposed SO_2 emission rates based on the assumption that a retrofit dry FGD will achieve a controlled SO_2 emission rate of 0.06 lb/MMBtu. In our experience, this assumption is unrealistic and cannot be sustained on a continuous, long-term basis. In several places, EPA cites the IPM dry FGD cost development document, which states: the "[r]ecommended SO_2 emission floor = 0.08 lb/MMBtu."[8]

EPA's proposal is too stringent to be achievable with the retrofit of an existing unit. A controlled SO_2 limit of 0.06 lb/MMBtu is not a realistic or sustainable value to maintain on a long-term basis when considering the normal variation in operation that occurs at all coal-fueled facilities. As noted in the IPM dry FGD document, the 0.06 lb/MMBtu emission rate corresponds to the lowest available SO_2 emission guarantees from dry FGD suppliers. Compliance with a vendor's guarantee value is typically demonstrated during very short term testing conducted at ideal operating conditions. Vendor guarantees do not reflect controlled emission rates that may be achievable on a consistent long-term basis as the unit operation varies from design conditions.

Dry FGD control systems, like all large air pollution control systems, are not steady state control systems, and controlled SO_2 emissions will continually fluctuate in response to changing operating parameters. Operating parameters that may affect SO_2 emissions include the fuel sulfur content, boiler load, load changes, flue gas flow rate, and flue gas temperatures, all of which continually change during normal operation of the boiler.

[8] Sargent & Lundy LLC, *IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology*, March 2013.

Furthermore, as shown in Table 3, S&L investigated permit limits for dry FGD projects for Spray Dryer Absorber (SDA) projects similar to the dry FGD technology proposed for the White Bluff units, and Circulating Dry Scrubber (CDS) technology, which are more efficient dry scrubber systems because of increased flue gas and reagent contact through the use of a fluidized bed. As indicated, the lowest permit value for all units retrofitting dry FGD systems with averaging periods of 30 days was 0.09 lb/MMBtu, and that includes the more efficient CDS dry FGD systems. The last unit shown in the table includes the lowest permit limit of any of the dry FGD systems listed, but this value still contains the necessary margin because the averaging period is much longer (i.e. 12 months), and because the dry FGD system was installed as part of a new boiler project, so it was incorporated into the new unit design which inherently minimizes some of the design challenges associated with retrofitting, where non-ideal layouts can lead to non-ideal flow distribution inside the absorbers.

Projecting future emissions using the anticipated control system vendor guarantee (i.e., 0.06 lb/MMBtu) as EPA did is overly aggressive and provides no margin for normal operating conditions or long-term operation. A reasonable margin between the vendor guarantee value or design target, and the projected actual long-term achievable emission rate is needed to allow for normal fluctuations in the controlled emissions. In S&L's opinion, an operating margin of at least 0.02 lb/MMBtu between the vendor guarantee and projected long-term emission rate is reasonable. As indicated in Table, using a limit of 0.08 lb/MMBtu to provide the recommended margin would still be an aggressive permit limit compared to other dry FGD projects.

Table 3: SO_2 Permit Limits for Dry FGD Projects

Reference Plant	Permit SO_2 Limit	Permit Averaging Period
Plant 1 (SDA)	0.09 lb/MMBtu	30 day rolling
Plant 2 (SDA)	0.10 lb/MMBtu	30 day rolling
Plant 3 (SDA)	0.10 lb/MMBtu	30 day rolling
Plant 4 (SDA)	0.10 lb/MMBtu	30 day rolling
Plant 5 (SDA)	0.10 lb/MMBtu	30 day rolling
Plant 6 (SDA)	0.10 lb/MMBtu	30 day rolling
Plant 7 (CDS)	0.09 lb/MMBtu	30 day rolling
Plant 8 (CDS)	0.10 lb/MMBtu	30 day rolling
Plant 9 (CDS)*	0.07 lb/MMBtu	12-month rolling average

*This unit was a new unit, not a retrofit

EPA's approach to estimating controlled SO_2 emission rates is incorrect and based on a misunderstanding of the actual performance and operation of dry FGD technology. By using this approach, EPA is overestimating the tons of SO_2 removed and thus overstating the cost-effectiveness of the retrofit FGD control systems.

3. Comments to the Cost TSD – Annualized Cost Errors

S&L's remaining comments are focused on EPA's Cost TSD. Our comments follow the same organization of EPA's Cost TSD document and are contained in the following sections.

3.1 Cost TSD, Section 2 – SDA Cost Analysis Methodology

EPA states that the "Control Cost Manual uses the overnight method of cost estimating, widely used in the utility industry.[9]" To support this conclusion, EPA references its own characterization of the CCM methodology published in the preamble to the Oklahoma Regional Haze FIP.[10] Using the overnight methodology, EPA removed certain costs from the SDA cost estimate, including Owner's costs and interest incurred during the construction period. We disagree that the CCM describes an overnight approach to calculating capital costs. The CCM does not once define or even mention the overnight methodology as being the basis for estimating costs. Rather, the CCM describes a constant dollar approach that annualizes all capital costs and O&M costs (on a constant-dollar basis) over the useful life of the project.

In the Oklahoma rule EPA cited to an Energy Information Administration (EIA) document as support for using the overnight cost estimating concept. In fact, EPA stated that "EIA presents all of its projected plant costs in terms of overnight costs."[11] However, this is a mischaracterization of the methodology the EIA uses to develop capital costs for new power generation. The EIA document upon which EPA relied includes a clarifying footnote that states: "Starting from overnight cost estimates, EIA's electricity modeling explicitly takes account of the time required to bring each generating technology online and the costs of financing construction in the period before a plant becomes operational."[12] Therefore, EIA cost evaluations take into account financing costs, including AFUDC, one of the line items EPA insisted that Entergy remove[13] from the SDA capital cost estimate

Finally, EPA states that the overnight method is appropriate for BART determinations "because it allows different pollution controls equipment to be compared in a meaningful manner."[14] However, excluding financing costs will bias the cost-effectiveness comparison toward the high-capital options with extended construction periods. Project financing costs such as AFUDC may be minimal on projects that do not require significant capital and with short construction periods, but can be very significant on projects with large capital costs and extended construction periods. Excluding financing costs from the capital cost estimate results in the high-capital cost option appearing more cost-effective. Including financing costs allows the analyst to compare projects with varying capital requirements and varying construction periods.

[9] Cost TSD, page 1.
[10] *Id.*
[11] *Id.*
[12] EIA, *Updated Capital Cost Estimates for Electricity Generation Plants*, November 2010, pg. 2.
[13] *See* August 21, 2013 email from Dayana Medina of EPA Region 6 to Mary Pettyjohn of the Arkansas DEQ.
[14] *Cost TSD, page 1.*

3.2 Cost TSD Section 2.3 – Use of the 2009 Alstom Cost Analysis

EPA invited Entergy to clarify certain issues associated with Alstom's 2010 quotation, including a misunderstanding regarding the scope of the dry FGD vendor's contract. In S&L Report #012831 of our comments, we have included a report that explicitly describes the scope of supply for the dry FGD vendor as compared to the balance of plant (BOP) scope of work. EPA made several incorrect assumptions regarding Alstom's scope that led to incorrect adjustments to the BOP cost estimate, as described in Section 3.3 of our comments. Furthermore, EPA's approach to escalating the Alstom quotation was incorrect as described in Section 3.5 of our comments.

3.3 Cost TSD Section 2.4 – Use of the S&L Balance of Plant Costs

EPA mistakenly subtracted BOP costs because they mistakenly believed the equipment to be included in Alstom's scope. As described in S&L Report #012831, the reagent handling system, which feeds the dry FGD supplier's reagent preparation system were not included in Alstom's scope. The "Dry FGD Island" supplied by the dry FGD vendor includes lime day bins, slakers, slurry transfer tanks, slurry transfer pumps, slurry storage tanks, and slurry feed pumps. The BOP system includes the cost associated with the "Reagent Handling System," which includes a rail delivery and unloading system for the lime, new rail spur, renovation of existing rail spur, delivery shed building, long-term storage silos, and a pneumatic conveying system to transfer the lime reagent from the long-term storage silos to the day bins, which are within the dry FGD vendor's scope.

We agree with EPA's comment that including the NO_X control equipment for Units 1 and 2 was an oversight and should not be incorporated into the Dry FGD estimates.

EPA mistakenly subtracted a total of $1,754,000 from the BOP quote because they mistakenly believed that all of the ductwork to be in Alstom's scope. The Dry FGD supplier's scope only includes ductwork between the dry FGD, the baghouse, and the booster fans. The ductwork to supply the flue gas to the SDA and the ductwork from booster fans to the existing chimney are within the BOP scope.

EPA mistakenly deleted a total of $255,000 to paint the Chimney because it did not understand this line item. Due to lower temperatures and higher moisture of the flue gas, downwash from the gas is more likely to occur and can lead to acid attack of concrete on the chimney shell; therefore, the costs to apply an acid resistant coating to the top 50 feet of the existing chimney shell was included in the estimate.

EPA mistakenly removed a total of $390,000 for costs associating with replacing and recalibrating the Continuous Emission Monitoring Systems (CEMS). The CEMS equipment reflected in Entergy's BART analysis was required because the existing CEMS was not capable of measuring SO_2 concentrations in the controlled range with Dry FGD technology. The costs included in the original estimate to cover replacement of the existing equipment with new equipment rated for the lower SO_2 concentrations as well as the cost to calibrate and certify these monitors including conducting a Relative Accuracy Test Audit (RATA) test.

Based on these comments, we have corrected EPA's cost subtractions in Table 4.

Table 4: Excluded BOP Costs (Corrected, Total for Both Units)

	Equipment	Material	Labor	Total
Total BOP Cost	$45,561,000	$35,120,000	$80,863,000	$161,544,000
Eliminate U1 NO_X Equipment	$3,622,000	$1,600,000	$3,073,000	$8,295,000
Eliminate U2 NO_X Equipment	$3,622,000	$1,600,000	$3,073,000	$8,295,000
Total Eliminated Cost	$7,244,000	$3,200,000	$6,146,000	$16,590,000
% BOP Items Reduced	15.90	9.11	7.60	N/A

EPA then adjusted additional cost items in the BOP estimate that were either percentages of the equipment, material, and labor costs or were related to equipment, material, and labor costs. EPA adjusted these items by applying the % reduction in cost of equipment, material and labor. Since EPA mistakenly removed cost items that should be included in the estimate, they over-estimated and misapplied percent reduction to the other items. In Table 4, we correct EPA's adjustments to remaining Entergy BOP costs by employing EPA's methodology but reducing the percentage factors to the values indicated in Table 5.

EPA excluded a total of $51,733,667 from the estimate, but Tables 4 and 5 show that only $20,724,543 was justified because NO_X control equipment had been included. Because of EPA's misconception as to the scope of work included in the BOP and Alstom estimates, they mistakenly concluded that costs were double-counted and removed $31,009,123 (total for both units) in costs that should be included. This resulted in EPA overstating the cost-effectiveness to retrofit dry FGD systems at White Bluff.

Table 5: Adjustment to Remaining Entergy BOP Costs (Total for Both Units)

	EPA Cost TSD Reductions				Corrected Reductions*			
DESCRIPTION	Equipment	Material	Labor	Total	Equipment	Material	Labor	Total
MOBILIZE/DEMOBILIZE @ 1% OF LABOR	$0	$0	$0	$0	$0	$0	$0	$0
MOBILIZE/DEMOBILIZE @ 1% OF LABOR	$0	$0	$546,061	$546,061	$0	$0	$656,036	$656,036
MOBILIZE/DEMOBILIZE @ 1% OF LABOR	$0	$0	$0	$0	$0	$0	$0	$0
COST DUE TO OVERTIME - 5-10'S	$0	$0	$7,970,183	$7,970,183	$0	$0	$9,575,359	$9,575,359
COST DUE TO OVERTIME - 5-10'S	$0	$0	$0	$0	$0	$0	$0	$0
PER DIEM - @ $10 PER HOUR	$0	$0	$7,888,659	$7,888,659	$0	$0	$9,477,416	$9,477,416
PER DIEM - @ $10 PER HOUR	$0	$0	$0	$0	$0	$0	$0	$0
SPARE PARTS @ 1% OF EQUIPMENT	$0	$0	$0	$0	$0	$0	$0	$0
SPARE PARTS @ 1% OF EQUIPMENT	$327,060	$0	$0	$327,060	$400,318	$0	$0	$400,318
FREIGHT @ 5% OF MATERIAL	$0	$0	$0	$0	$0	$0	$0	$0
FREIGHT @ 5% OF MATERIAL	$0	$1,413,404	$0	$1,413,404	$0	$1,596,000	$0	$1,596,000
GENERAL & ADMINISTRATIVE (G&A) @ 5% OF MATERIAL AND LABOR	$0	$0	$0	$0	$0	$0	$0	$0
GENERAL & ADMINISTRATIVE (G&A) @ 5% OFMATERIAL AND LABOR	$0	$1,413,404	$2,417,281	$3,830,686	$0	$1,596,000	$2,904,116	$4,500,116
GENERAL & ADMINISTRATIVE (G&A) @ 5% OF MATERIAL AND LABOR	$0	$0	$1,119,810	$1,119,810	$0	$0	$1,345,337	$1,345,337
PROFIT @ 10% OF MATERIAL AND LABOR	$0	$0	$0	$0	$0	$0	$0	$0
PROFIT @ 10% OF MATERIAL AND LABOR	$0	$2,826,809	$4,833,794	$7,660,602	$0	$3,192,000	$5,807,308	$8,999,308
PROFIT @ 10% OF MATERIAL AND LABOR	$0	$0	$2,240,388	$2,240,388	$0	$0	$2,691,597	$2,691,597
NON CONTRACTOR INDIRECTS	$0	$0	$0	$0	$0	$0	$0	$0
ENGINEERING - BOP	$0	$0	$7,579,481	$7,579,481	$0	$0	$9,105,970	$9,105,970
Totals				$40,576,333				$48,347,457
Reduction in Remaining BOP Costs				$11,905,667				$4,134,543
Excluded BOP Costs from Table 4								$16,590,000
TOTAL BOP Reduction								**$20,724,543**

*Same methodology used as EPA but percentages applied are from Table 4

3.4 Cost TSD Section 2.5 – Undocumented or Disallowed Cost Items

Owner's Costs include a variety of costs incurred by the owner to support the air pollution control project. Owner's Costs are project-specific, but generally include costs incurred by the Owner to manage the project, hire and retain staff to support the project, and costs associated with third party assistance associated with project development and financing. Owner's Costs typically include, but may not necessarily be limited to:

- Site investigations (geotechnical, hydrology, etc.) for project design
- Environmental permitting/approvals
- Insurance during construction
- Site security during construction
- Transmission interconnection (if applicable)
- Fuel interconnection (if applicable)
- Owner's mobilization costs
- Owner's project management and support staff
- Insurance advisor
- Labor relations consultant
- Tax consultant
- Financial advisor
- Legal advisor
- Market consultant
- Community relations/community outreach program.

Owner's Costs are real costs that the owner will incur during the project and are typically included in cost estimates prepared for large air pollution control retrofit projects. In fact, U.S. EPA's Coal Quality Environmental Cost (CUECost) model includes Owner's Costs (or "Home Office" costs) in its air pollution control system cost estimating workbook and interrelated set of spreadsheets.[15] CUECost uses a factor of 10% of the total installed cost to estimate Owner's Costs and Engineering Costs for limestone forced oxidation and lime spray dryer control systems.

To address the items in this section, we included a section in S&L Report #012831 that describes Entergy's Owner's costs and how they were developed. We believe EPA deleted these Owner's costs because EPA did not understand how they were defined and therefore, incorrectly assumed that they did not reflect real costs to Entergy. In total, EPA removed $41,741,743 per unit from the original estimate which should be included. Removing these costs resulted in EPA overstating the cost-effectiveness to retrofit dry FGD systems at White Bluff and Independence. Detailed explanations of these costs are included in S&L Report #012831 to help EPA understand

15 *See*, Coal Utility Environmental Cost (CUECost) Workbook Development Documentation Version 5.0, prepared by U.S. EPA, September 2009, pages 17 and 34.
Appendix B, pages B-3 and B-6.

these costs.

3.5 Cost TSD Section 2.6 – Escalation

We agree with EPA's assertion that the application of escalation is allowed by the CCM.[16] However, EPA's method of using Chemical Engineering Plant Cost Indices (CEPCI) to escalate costs to the year 2013 resulted in severely underestimating the costs associated with escalation. CEPCI are sometimes used to estimate escalation by multiplying base costs by the ratio of the index for the year costs are to be escalated to the index for the year in which the costs were originally generated. For example, EPA used CEPCI from 2009 (521.9) and 2013 (550.8) to escalate the FGD costs from a 2009 basis to a 2013 basis. Thus, EPA applied the following formula, 550.8/521.9*$247,856,184 to obtain an estimated 2013 FGD cost of $261,581,119 for both units.

Rather than estimating escalation of Alstom's pricing from 2010, S&L (on behalf of Entergy) requested updated FGD pricing from Alstom in 2013[17]. We agree with a reference cited in the CCM and authored by EPA which states, "At best [cost indices] provide a cloudy mirror…there is no substitute for current price information obtained from suppliers of those goods and services."[18] Nothing illustrates EPA's conclusion that cost indices are not to be substituted for supplier information better than comparing EPA's escalation rate to the actual escalation rate indicated in Alstom's budgetary quotations as shown in Table 6.

Table 6: Alstom Quotation Comparison (Total for Both Units)

Parameter	EPA	Vendor Quotation
FGD Cost 2009	$247,856,184	$247,856,184
FGD Cost 2013	$261,581,119	$297,904,000
Average Escalation	1.36%	4.7% per year

As shown in Table 6, EPA underestimated escalation significantly, resulting in underestimating the 2013 dry FGD costs by $36,322,881 (total for both units). In fact, EPA applied CEPCI indices in several instances from 2008 that *de-escalated* costs, resulting in lower costs in 2013 as compared to 2008. We note specifically that EPA's cost calculations ignored the updated 2012 direct annual costs provided by Entergy, and instead included the 2008 costs.[19] Table 7 summarizes how EPA incorrectly estimated escalation in its analysis for White Bluff Unit 1 and corrects that by applying an average escalation rate of 4.7% to match the Alstom quotation. We note that information from Alstom showed their pricing escalated nearly equivalently for

[16] *See* Cost TSD, Section 2.6, page 8
[17] Updated FGD pricing from Alstom is used as the basis of the 2015 cost estimate documented in S&L Report #012831.
[18] Escalation Indexes for Air Pollution Control Costs, United States Environmental Protection Agency, October 1995, pp. 3-4.
[19] *See*, EPA-R06-OAR-2015-0189-0093-White Bluff_R6 cost revisions2.xlsx, tab "Entergy Costs"

equipment/material (~4.8%) and for installation (~4.6%). Since the difference was negligible we applied the average 4.7% in the revised costs shown in Table 7. EPA's underestimation of cost escalation carried through their analysis and resulted in an incorrect reduction in the cost estimate of over $42 million per unit.

Table 7: Summary of EPA's Escalation Errors (Per Unit)[20]

Item	Entergy	EPA (2013)	Corrected Costs Including Escalation (2013)	Escalation Costs Omitted by EPA
Total Contractor Costs* (2010)	$156,974,274	$161,676,662	$180,164,213	$18,487,550
Contingency (2010)	$20,875,711	$21,501,073	$23,959,697	$2,458,624
Balance of Plant (2008)**	$102,085,500	$75,145,724	$115,401,842	$13,316,342
Balance of Plant Indirect Costs (2012) ***	$9,768,175	$0	$10,227,279	$1,494,175
Misc Contract Labor (2012)	$4,583,719	$0	$4,799,154	$215,435
Entergy Internal Costs (2012)	$20,076,644	$0	$21,020,246	$943,602
Capital suspense (2012)	$8,348,276	$0	$8,740,645	$392,369
Total Capital Investment (TCI)		$258,323,459	$319,525,752	
Direct Annual Costs (2008)	$7,901,369	$7,790,140	$9,941,130	$2,150,990
Indirect Annual Costs				
Overhead (2008)	$2,572,707	$2,536,491	$3,236,859	$700,368
Administrative Charges @ 2% of TCI		$5,166,469	$6,390,515	$1,224,046
Property Tax @ 1% of TCI		$2,583,235	$3,195,258	$612,023
Insurance @ 1% of TCI		$2,583,235	$3,195,258	$612,023
Total Indirect Annual Costs		$12,869,429	$16,017,889	
Total Escalation Costs Underestimated by EPA				**$42,607,547**

* This item reflects the updated dry FGD pricing received in 2013
** As EPA did, this item subtracts the excluded BOP costs discussed in Section 3.3 before applying the escalation
*** In the Cost TSD, EPA incorrectly used the 2008 BOP Indirect Costs from the Revised Bart Five Factor Analysis, SDA Cost analysis rather than the 2012 BOP Indirect Costs as identified. The differential between the 2008 and 2012 BOP Indirect Costs ($1,035,071) was included in the column for Escalation Costs Omitted by EPA.

[20] *See* Cost TSD, Table 5 on page 10

3.6 Cost TSD Section 2.7 – Operating and Maintenance (O&M) Costs

Although EPA claims in its proposal that it relied on the methods and principals contained within the Control Cost Manual in developing its individual control technology cost estimates, in the supporting Cost TSD EPA stated that "we can compare Entergy's O&M costs to those obtained through the use of our IPM SDA cost model."[21]

The IPM model and the Control Cost Manual provide two entirely different approaches to calculating control system capital and O&M costs. IPM is described by EPA as a multi-regional, dynamic, deterministic linear programming model used by EPA to analyze system-wide impacts of air emissions policies on the U.S. electric power sector in the 48 contiguous states and the District of Columbia.[22] The model has been used by EPA to analyze impacts associated with proposed regulatory programs such as the Clean Air Interstate Rule (CAIR) and Mercury and Air Toxics Standard (MATS). The primary purpose of the model is to provide forecasts of least-cost capacity expansion, electricity dispatch and emission control strategies for meeting energy demand and environmental, transmission, dispatch and reliability constraints. The model includes cost modules for various air quality control technologies, and S&L developed the cost algorithms used in the IPM model to estimate costs associated with DSI, SDA, and wet FGD control systems.[23] The IPM model is not referred to in either the Control Cost Manual or the BART Guidelines as an acceptable tool to develop site specific capital or O&M cost estimates.

Cost algorithms in the IPM model were developed based on a statistical evaluation of cost data available from various industry publications, and do not take into consideration site-specific cost issues.[24] The primary purpose of the IPM cost modules is to provide generic order-of-magnitude costs for various air quality control technologies that can be applied to the electric power generating industry on a system-wide basis, not on an individual unit basis. By necessity, the cost algorithms were designed to require minimal site-specific information available from publicly available sources. Because of the limited number of site-specific inputs, the IPM cost algorithms provide order-of-magnitude control system cost estimates, but they do not provide case-by-case project-specific cost estimates meeting the requirements of the BART Guidelines, nor do the IPM equations incorporate the cost estimating methodology described in the Control Cost Manual.

Regarding O&M costs for SDA FGD systems, the IPM model includes the following assumptions that are not consistent with a site-specific O&M cost estimates:

- A fixed quantity of additional personnel to operate the equipment is included, not accounting for site-specific project and staffing needs;

[21] *See* Cost TSD, Section 2.7, page 9.
[22] *See*, EPA website: www.epa.gov/airmarkt/progsregs/epa-ipm/.
[23] *See*, e.g., IPM Model- Updates to Cost and Performance for APC Technologies Wet FGD Cost Development Methodology, Sargent & Lundy LLC, March 2013.
[24] *Id.*, at page 1.

- While we agree with the general practice of estimating maintenance material and labor costs as percentage of capital costs, the IPM model does not estimate site-specific capital costs sufficiently upon which to apply this percentage, and the assumed percentage cannot be modified to accommodate project specific requirements;
- The assumptions incorporated in the maintenance material and labor costs are propagated into the administrative labor item, and is therefore limited by the same items as the previous item;
- Reagent consumption assumes a stoichiometry that cannot be modified to match vendor-supplied guarantees for a specific application;
- Reagent consumption also depends upon a flue gas temperature into the SDA of 300°F and cannot be modified to apply site-specific temperatures;
- Reagent consumption also depends upon lime purity, which the IPM model assumes to be 90% and cannot be modified to match actual reagent supply information;
- The IPM model estimates water consumption based on gas flow and fuel sulfur levels instead of performing site-specific calculations using actual fuel properties and operating conditions;
- Waste generation is a function of the assumed lime stoichiometry discussed above as well as an assumed moisture content of 10% that cannot be modified to match vendor-supplied mass balances for specific applications; and
- The SDA flue gas pressure drop estimate included in the IPM model is an average value based on flue gas flow rate and sulfur levels instead of performing site-specific calculations that consider the actual fuel properties, operating conditions, and actual equipment sizing and arrangement.

EPA's use of IPM to benchmark O&M costs is thus not an appropriate choice for a unit-specific analysis consistent with BART guidelines. By relying on the IPM cost modules to verify dry FGD O&M costs, EPA did not adequately evaluate and account for potential project-specific site constraints that Entergy would incur to operate the FGD control systems EPA is proposing. In addition, using the IPM cost algorithms to calculate FGD control system capital or O&M costs is inconsistent with the case-by-case BART cost analysis described in the BART Guidelines for at least two reasons. First, the IPM model does not account for unit-specific design and operating parameters that can affect control system design and costs, including operating costs. Second, the IPM cost equations do not take into consideration site-specific conditions that could affect the O&M costs to operate the control system.

Please see additional comments in the next section of our comments (3.7), addressing EPA's adjustment of the O&M cost estimates to account for lower coal sulfur.

3.7 Cost TSD Section 3.1 – Entergy's Coal Sulfur Assumption

EPA states that an uncontrolled SO_2 emission rate of 2.0 lb/MMBtu at White Bluff is "far in excess of sulfur level of the coals it has historically burned," and concludes, "[t]hus Entergy has costed SO_2 scrubber systems for the White Bluff facility that are overdesigned compared to its historical needs." Based on this conclusion, EPA adjusts the capital and O&M costs using a design sulfur level selected by EPA. While we agree with EPA that direct O&M costs be revised to 0.68 lb/MMBtu, this sulfur level is completely inadequate for the Dry FGD equipment design basis.

EPA correctly assumes that the 2.0 lb/MMBtu design basis was to preserve fuel flexibility, but their conclusions that, "either (1) this higher cost be balanced against its greater SO_2 reduction potential, or (2) that the scrubber system's capability and cost be adjusted down to match the facility's historical emissions," are without basis and inconsistent with BART guidelines.

The SO_2 emission reduction calculation depends upon the baseline emissions, baseline heat input, and the required outlet emission rate (see Section 2.2 of our comments). SO_2 emission reduction does not depend on the fuel sulfur levels selected for FGD system design, neither the BART guidelines nor the CCM address evaluating potential future SO_2 reduction based on design fuels as part of the BART analysis or cost estimating methodology. Therefore, EPA's first conclusion that the higher costs be balanced against greater SO_2 reduction potential is inconsistent with BART requirements and has no basis.

Although the BART guidelines and the CCM both account for the development of a design basis, there are no specific requirements that air pollution control design be tied to historical operating trends. Therefore, EPA's second conclusion that capital costs must be adjusted to match historical emissions is arbitrary and without basis.

Based on its erroneous conclusions, EPA selected a maximum monthly fuel sulfur level of 0.68 lb/MMBtu as the design basis used to estimate the capital costs. Figure 1 illustrates why the use of White Bluff's maximum monthly fuel sulfur level is completely insufficient. The ability to reduce SO_2 emissions depends critically upon the amount of reagent, or lime that can be added to the FGD system. With a 0.68 lb/MMBtu design basis, the reagent preparation and delivery equipment would be inadequately sized to add lime when sulfur levels increase beyond that level. As shown in Figure 1, EPA's design basis would result in emissions above the proposed emission rate for almost half of the operating time. This design approach would require limiting fuel sulfur levels to below 0.68 lb/MMBtu to ensure continuous compliance. If this is the approach EPA is intending, then the cost analysis would need to be revised to incorporate significant additional costs associated with fuel purchasing limitations. We did not include any additional O&M costs associated with fuel limitations because we believe EPA selected the design basis due to a lack of experience rather than intending to place enforceable limits on fuel purchasing at White Bluff station.

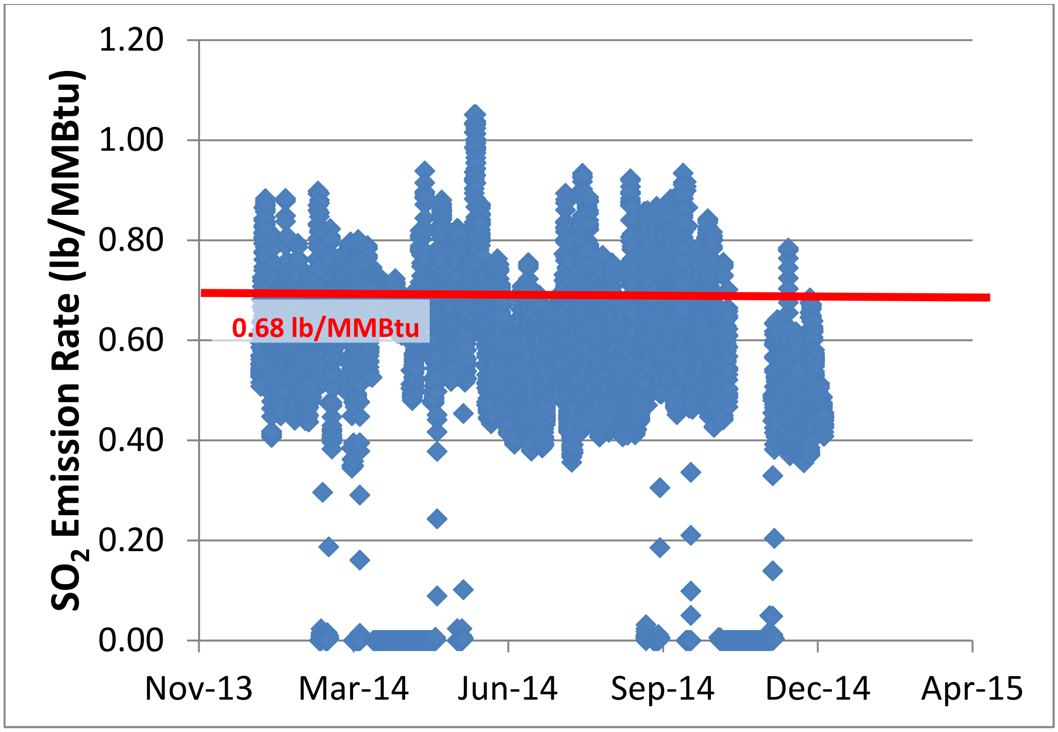

Figure 1: 2014 SO_2 Emissions for White Bluff 1[25]

While we believe that the 2008 design basis of 2.0 lb/MMBtu was appropriate at that time based on the potential to fire fuels with higher sulfur levels, based on more recent information, Entergy now believes that they will not purchase fuels with sulfur levels higher than 1.2 lb/MMBtu. The operating data shown in Figure 1 confirms that 1.2 lb/MMBtu would result in a design basis that would ensure continued compliance with EPA's proposed FIP emission rates. Therefore, we have provided a revised cost estimate based on 1.2 lb/MMBtu. To illustrate the small difference in capital costs associated with the revised design basis (1.2 lb/MMBtu versus 0.68 lb/MMBtu), S&L has included a sensitivity analysis in S&L Report #012831.

As discussed previously, we agree that it is appropriate to base direct O&M cost estimates on 0.68 lb/MMBtu fuel sulfur levels to represent average operational costs. However, EPA's adjustment factor of 0.5823 applied to direct O&M costs severely underestimated these costs. In agreement with EPA's sulfur basis, S&L developed O&M costs for the 0.68 lb/MMBtu operating case in S&L Report #012831 based on site specific consumption rate estimates and unit costs. Our report estimated O&M costs including direct variable and fixed O&M costs to be a total of $10,166,000 per unit in the first year. By comparison, EPA's calculation scales direct O&M costs of $7,790,140 by 0.5823, resulting in direct O&M costs of $4,536,199 per unit being

[25] Downloaded from EPA's Clean Air Market Database.

included in its cost-effectiveness calculation.[26] This methodology underestimated direct O&M costs by $5,629,801 per unit.

In addition, EPA applied the same O&M factor of 0.5823 to the indirect annual costs, including overhead, administrative charges, property tax and insurance, all of which depend on capital cost.[27] Therefore, assuming EPA's capital cost scaling methodology for capital cost is correct (which we do not believe is the case), then EPA should have applied the 0.9584 factor used to correct capital costs to the indirect annual costs. EPA's methodology underestimated indirect O&M costs by $4,840,192 per unit.

3.8 Cost TSD Section 4.1 – EPA's Conservatism in Cost Estimating

EPA lists two assumptions it believes are conservative in its Cost TSD. In one assumption, EPA noted that amortization from the 2008 S&L cost analysis was 40 years, but they lowered the remaining useful life to 30 years, which increases the cost-effectiveness. EPA's estimate is not conservative with regard to equipment life because, as EPA states, they, "typically assume a 30 year equipment life for scrubbers,"[28]and the 2008 amortization value from S&L was not intended to be used to conduct the BART analysis. Furthermore, as discussed in Section 3.9, the actual remaining life of these units is far below what EPA assumed.

In the second assumption, EPA concludes that two absorber vessels are not required and, thus, a 7% cost savings that could have been realized was not applied. We do not believe EPA is qualified to design dry FGD systems, and therefore not qualified to evaluate the number of vessels that are suitable for White Bluff. Dry FGD systems of this type have not been applied to units of this size, and the dry FGD supplier quoted three absorber vessels for this application based on their expertise. EPA cites no reference where fewer absorber vessels have been installed for a unit with an identical design basis, and therefore its assertion that two absorber vessels is adequate is arbitrary and without basis.

3.9 Remaining Useful Life

EPA states, "With regard to consideration of the remaining useful life of the units, we are not aware of any enforceable shutdown date for the Entergy White Bluff Plant, nor did Entergy's evaluation indicate any future planned shutdown."[29] Therefore, EPA utilized 30-years as the remaining useful life in its cost-effectiveness calculations. As stated in Entergy's comments to the proposed rule, Entergy proposes to cease coal-firing at the White Bluff units between 2027 and 2028. The proposed rule requires that the FGD controls and White Bluff be operational 5 years after the effective date of the rule. Assuming the effective date of the final rule is one year after the comment period closes, then the White Bluff FGD's will need to be operating by July of

[26] *See*, EPA-R06-OAR-2015-0189-0093-White Bluff_R6 cost revisions2.xlsx, tab "Cost-Effectiveness" Cell D4.
[27] *Id.*
[28] Cost TSD, Section 4.1 page 16.
[29] AR FIP TSD, p. 80.

2021. Based on the coal-cessation dates of White Bluff Units 1 and 2, the remaining useful life of these FGD systems is therefore between 6 and 7 years, instead of 30 years used in EPA's analysis.

4. Cost TSD Section 5 – Inclusion of Independence under Reasonable Progress Goals (RPGs)

EPA included Entergy's Independence Plant in its RPG analysis based on annual emissions from the facility.[30] It is beyond the scope of S&L's comments to address the basis upon which EPA decided to include Independence in its RPG analysis for Caney Creek and Upper Buffalo. Instead, our comments focus on the inconsistencies and errors included in EPA's RPG analysis for the Independence station.

In EPA's RPG analysis for SO_2 Controls, EPA concluded that the units at White Bluff and Independence Stations are similar enough to apply "the total annualized dry FGD and wet FGD costs [they] developed for the White Bluff units to the Independence units."[31] EPA then calculates the cost-effectiveness to retrofit FGD systems at Independence by adjusting the White Bluff cost effectiveness calculations to account for the differences in SO_2 emissions at Independence. This approach is flawed for several reasons. First, this approach includes all of the errors in EPA's cost-effectiveness analysis for White Bluff as described in the preceding sections, including errors in calculating baseline emissions, errors in calculating emission reductions, and errors associated with estimating annualized costs. Second, applying the White Bluff annualized costs to Independence is inconsistent with EPA's RPG guidance which requires cost estimates based on design parameters be developed for air pollution control systems.

To determine whether air pollution controls would be required at Independence Units 1 & 2 to meet the Reasonable Progress Goals at Caney Creek and Upper Buffalo, EPA conducted an RPG four factor analysis. The four factor analysis is described in EPA's RPG Guidance Document, and includes an evaluation of: (a) costs of compliance; (b) time necessary for compliance; (c) energy and non-air impacts; and (d) the remaining useful life of the source.[32] Regarding the first factor listed, costs of compliance, EPA suggests that, for stationary sources, the following steps be performed:

a) Identify the emissions units to be controlled;

b) Identify the design parameters for emission controls; and

c) Develop cost estimates based upon those design parameters[33]

EPA did not perform steps b and c of the RPG compliance cost evaluation. Rather, EPA relied upon an EIA database comparison as well as an aerial photo comparison of the two units to justify applying the White Bluff FGD costs to Independence. The EIA information does not contain any information that would be used to set the design basis for either FGD system;

[30] *See* 80 Fed. Reg. 18,991 (April 8, 2015).
[31] *Id.*, at page 18,992.
[32] *See* "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," U.S. EPA June 1, 2007, pg 1-3.
[33] *Id.*, at page 5-1.

therefore it cannot be used to conclude the FGD system design at Independence would be identical to White Bluff. Furthermore, EPA's use of aerial photos to indicate visual similarities between White Bluff and Independence ignores many site-specific factors that cannot be captured in a Google Earth image downloaded from the internet. Some of the site-specific factors that EPA did not account for by using this approach and which could result in different costs to retrofit FGD technology at Independence as compared to White Bluff include:

- EPA proposes the same timeline for compliance for White Bluff and Independence which will add significant labor costs due to the amount of skilled labor that would be required to construct four FGD systems in the same time period;
- EPA did not review plant operating data, such as flue gas temperatures, which affect flue gas volume, potentially requiring different equipment sizing for Independence;
- EPA did not review operating and maintenance practices at Independence, which could result in different O&M costs;
- EPA did not assess differences in underground utility interferences that could potentially change the equipment arrangement at Independence;
- EPA did not conduct subsurface geotechnical investigations to determine differences in soil conditions or distances to reach bedrock that would impact foundation design or seismic design requirements;
- EPA did not assess other seismic design requirements such as seismic risk or magnitude of potential earthquakes to determine steel design differences that may be required; and
- EPA did not assess differences in wind loads which could impact foundation and structural steel design.

In its guidance document, EPA states, "[f]or additional guidance on applying the cost of compliance factor to stationary sources, you may wish to consult the BART guidelines."[34] We note that, for EPA's RPG analysis for Independence, EPA did not revisit any of the steps required as part of a BART analysis; therefore, EPA ignored other lower cost technologies or methodologies to reduce SO_2 emissions at Independence station. EPA's inherent assumption is that BART-level SO_2 reductions are required at Independence to meet the RPGs, but it does not adequately support that assumption. EPA modeled visibility impacts of SO_2 reductions assuming FGD systems would be retrofitted at Independence, but they failed to conduct modeling using any other technology or methodology that could provide more cost-effective SO_2 reductions.

Finally, EPA also states in its RPG guidance document that for, "individual, large scale sources, simple cost effectiveness estimates based on a dollar-per-ton calculation may not be as meaningful as a dollar-per-deciview calculation."[35] EPA's CENRAP modeling showed that the cumulative benefit of installing all of the controls proposed in the FIP would result in visibility benefits at Caney Creek of only 0.21 dv and at Upper Buffalo of only 0.19 dv.[36] Considering that

[34] *Id.*, at page 5-1.
[35] *Id.*, at page 5-2.
[36] *See* 80 Fed. Reg. 18,998, Table 67.

Independence represents only approximately 36% of the SO_2 point source emissions and 29% of the point source NO_X emissions in Arkansas, Entergy estimated the visibility improvement due to retrofitting FGD systems at Independence would be approximately 0.08 dv at Caney Creek and 0.07 dv at Upper Buffalo. Although we do not support EPA's use of the White Bluff cost estimates for Independence, we applied the White Bluff costs to retrofit dry FGD and the estimated visibility improvement due to retrofitting dry FGD systems at Independence to estimate dollar-per-deciview as suggested in EPA's RPG guidance document. Table 8 shows that retrofitting dry FGD systems at Independence is clearly not cost effective when considering the insignificant visibility improvements.

Table 8: Dollar-Per-Deciview Reduction for Dry FGD at Independence

Class I Area	Caney Creek	Upper Buffalo
Estimated Visibility Improvement[37]	0.08	0.07
Revised Annualized Costs[38]	\$106,765,022	\$106,765,022
\$/Δdv	\$1,334,562,775	\$1,525,214,600

[37] The CENRAP modeling includes SO_2 and NO_X impacts; therefore, the numbers shown likely overestimate the visibility improvement based solely on SO_2 reductions.
[38] Annualized costs for Retrofitting Dry FGD at White Bluff 1 and 2 from S&L Report #012831 were used assuming a 30-year remaining useful life.

5. CONCLUSION

S&L reviewed the approach EPA takes in its proposed FIP for Arkansas, including EPA's determination of costs for retrofit dry FGD scrubbers, and EPA's evaluation of annual SO_2 emission reductions. Our analysis identifies several areas where EPA overstates the cost-effectiveness ($/ton of SO_2 removed) of the dry FGD retrofits that EPA would require in its FIP. As discussed in this analysis, cost-effectiveness is influenced by two variables: the total annualized cost to retrofit FGD controls ($/yr) and the corresponding reduction in annual SO_2 emissions (tons per year "tpy"). EPA's approach does not accurately calculate either variable. Table 9 shows how the approach EPA took understated the annualized cost of the control systems and the adjustments S&L made to correct EPA's errors.

Table 9: Adjustments to EPA's Annualized Cost for a Single Unit at White Bluff

Item	Total Capital Investment ($)	Annualized Cost ($/year)
EPA FIP	$247,537,295	$31,981,230
Corrected BOP Cost Exclusions	$263,041,857	$33,230,898
Corrected Owner's Cost Exclusions	$304,783,600	$36,595,282
Corrected Escalation	$347,391,147	$40,029,450
Corrected Operating Costs	$347,391,147	$50,499,444
Remaining Useful Lifetime Adjustment*	$347,391,147	$86,975,068 to $95,381,830
2015 Estimate (S&L Report #012831) *	**$536,185,000**	**$109,681,936 to $122,657,613**
Differential from EPA FIP*	**+ $99,853,852**	**+ $54,993,838 to $63,400,600**

* Entergy proposes to cease to use coal at White Bluff 1 and 2 between 2027 and 2028; therefore, the annualized costs are shown as a range based on a remaining useful life of 6 or 7 years.

In addition, Table 10 shows how EPA's approach overstated the tons of SO_2 that would be removed by its FIP-imposed dry FGD and the adjustments S&L made to correct EPA's mistakes.

Table 10: Adjustments to EPA's SO_2 Emission Reductions

Item	White Bluff 1 (tons)	White Bluff 2 (tons)
EPA FIP	14,363	15,221
Corrected Baseline Emission Calculation	14,474	14,617
Corrected SO_2 Emission Reduction Calculation	14,264	14,353
Differential from EPA FIP	**-99**	**-868**

EPA's errors resulted in severely overstating the cost-effectiveness to retrofit dry FGD systems at White Bluff 1 and 2 (and then by extension in its reasonable progress analysis for Independence 1 and 2). Table 11 summarizes how EPA's errors systematically underestimated cost and overstated the cost-effectiveness to install these dry FGD systems. As Table 11 indicates when the errors are corrected and updated costs incorporated, retrofitting dry FGD systems at these units is clearly not cost-effective.

Table 11: Summary Cost-Effectiveness Impacts

Item	White Bluff 1 ($/ton)	White Bluff 2 ($/ton)
EPA's Cost Effectiveness	$2,227	$2,101
Corrected Baseline Emission Calculation	$2,210	$2,188
Corrected SO_2 Emission Reduction Calculation	$2,242	$2,228
Corrected BOP Cost Exclusions	$2,330	$2,315
Corrected Owner's Cost Exclusions	$2,566	$2,550
Corrected Escalation	$2,806	$2,789
Corrected Operating Cost	$3,540	$3,518
Corrected Remaining Useful Life *	$6,097 to $6,687	$6,060 to $6,646
2015 Estimate (S&L Report #012831) *	**$7,689 to $8,599**	**$7,642 to $8,546**
Differential from EPA FIP[1]	**+ $5,462 to $6,372**	**+ $5,541 to $6,445**

* Entergy proposes to cease to use coal at White Bluff Units 1 and 2 between 2027 and 2028; therefore, the cost effectiveness values are shown as a range based on a remaining useful life of 6 or 7 years.

With respect to EPA's RPG analysis for SO_2 controls, EPA did not follow its own guidance document when conducting its four factor analysis of Independence. EPA failed to consider lower cost options that could reduce SO_2 emissions at Independence and instead concluded that BART-level controls were required to meet RPG. EPA did not prepare cost estimates based on design parameters for FGD systems retrofit at Independence, as required by their RPG guidance document. EPA did not conduct a dollar-per-deciview analysis, as recommended in its RPG document for these analyses, to demonstrate the benefit of retrofitting dry FGD at Independence accounting for visibility benefits. When applying annualized costs to projected visibility improvements the result is **over $1.3 billion/Δdv** for Caney Creek and **over $1.5 billion/Δdv** for Upper Buffalo, which is clearly not cost effective.

White Bluff 1	EPA FIP	Corrected Baseline Emissions	Corrected Heat Input and Emission Reduction	Section 2.4, Excluded BOP Costs	Section 2.5, Excluded Owner's Costs	Section 2.6, Incorrect Escalation	Section 2.7, Corrected Operating Cost	Remaining Useful Lifetime Adjustment (7 Year Life)	Remaining Useful Lifetime Adjustment (6 Year Life)	2015 Capital Cost Estimate (S&L Report # 012831 - 7 Year Life)	2015 Capital Cost Estimate (S&L Report # 012831 - 6 Year Life)
Total Annualized Cost	$31,981,230	$31,981,230	$31,981,230	$33,230,898	$36,595,282	$40,029,450	$50,499,444	$86,975,068	$95,381,830	$109,681,936	$122,657,613
Interest Rate (%)	7	7	7	7	7	7	7	7	7	7	7
Equipment Lifetime (years)	30	30	30	30	30	30	30	7	6	7	6
Capital Recovery Factor (CRF)	0.0806	0.0806	0.0806	0.0806	0.0806	0.0806	0.0806	0.1856	0.2098	0.1856	0.2098
SO2 Emission Rate (lbs/MMBtu)[2]	0.65	0.65	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used
Baseline Heat Input (MMBtu/yr)[1]	Not Used	Not Used	55,829,551	55,829,551	55,829,551	55,829,551	55,829,551	55,829,551	55,829,551	55,829,551	55,829,551
Controlled SO2 Emission Rate (%)	90.81	90.81	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used
Controlled SO2 Emission Rate (lb/MMBtu)[3]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
SO2 Emission Baseline (tons)	15,816	15,939	15,939	15,939	15,939	15,939	15,939	15,939	15,939	15,939	15,939
SO2 Emission Reduction (tons)	14,363	14,474	14,264	14,264	14,264	14,264	14,264	14,264	14,264	14,264	14,264
Cost Effectiveness ($/ton)	$2,227	$2,210	$2,242	$2,330	$2,566	$2,806	$3,540	$6,097	$6,687	$7,689	$8,599
White Bluff 2											
Total Annualized Cost	$31,981,230	$31,981,230	$31,981,230	$33,230,898	$36,595,282	$40,029,450	$50,499,444	$86,975,068	$95,381,830	$109,681,936	$122,657,613
Interest Rate (%)	7	7	7	7	7	7	7	7	7	7	7
Equipment Lifetime (years)	30	30	30	30	30	30	30	7	6	7	6
Capital Recovery Factor (CRF)	0.0806	0.0806	0.0806	0.0806	0.0806	0.0806	0.0806	0.1856	0.2098	0.1856	0.2098
SO2 Emission Rate (lbs/MMBtu)	0.68	0.68	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used
Baseline Heat Input (MMBtu/yr)[1]	49,108,824	47,158,824	56,042,262	56,042,262	56,042,262	56,042,262	56,042,262	56,042,262	56,042,262	56,042,262	56,042,262
Controlled SO2 Emission Rate (%)	91.16	91.16	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used
Controlled SO2 Emission Rate (lb/MMBtu)[3]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
SO2 Emission Baseline (tons)	16,697	16,034	16,034	16,034	16,034	16,034	16,034	16,034	16,034	16,034	16,034
SO2 Emission Reduction (tons)	15,221	14,617	14,353	14,353	14,353	14,353	14,353	14,353	14,353	14,353	14,353
Cost Effectiveness ($/ton)	$2,101	$2,188	$2,228	$2,315	$2,550	$2,789	$3,518	$6,060	$6,646	$7,642	$8,546

1 - EPA did not list the heat input. EPA's analysis incorrectly assumes the annual averageheat input as being the baseline SO_2 emissions (tpy) divided by the monthly maximum emission rate (lb/MMBtu)

2- EPA incorrectly applied the maximum maximum monthly SO_2 emission rate to determine the % reduction in SO_2 to achieve 0.06

3- EPA did not include this item. SO_2 emission reduction is corrected to calculate it as [baseline annual average heat input (MMBtu/Yr)] * [the controlled SO_2 emission rate (lb/MMBtu)]*[2000 lb/ton]

ENTERGY ARKANSAS, INC.

WHITE BLUFF DRY FGD

COST ESTIMATE AND TECHNICAL BASIS

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Prepared by

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EXECUTIVE SUMMARY

The purpose of this study is to estimate the total capital investment and operating and maintenance (O&M) costs associated with installing dry flue gas desulfurization (FGD) technology on White Bluff Units 1&2 using an Engineer, Procure, Construct (EPC) contracting strategy. A preliminary conceptual design was developed for implementation of dry FGD technology at the White Bluff station to serve as the technical basis of the capital and O&M estimates.

The capital cost estimate includes the following components which comprise the total cost the Owner will incur to install dry FGD technology at White Bluff:

- FGD Island Cost supplied by a Dry FGD System Supplier including the main process equipment
- Balance of Plant Cost including auxiliary equipment and systems, foundations and buildings, site work, demolition and relocation
- Other Direct and Construction Indirect Costs including labor premiums, freight, contractor's G&A and profit
- Indirect Costs including engineering, startup spare parts, technical field advisors, and the additional fee associated with an EPC contracting strategy
- Escalation and Interest During Construction associated with the project duration for implementation of a large air quality control technology
- Owner's Costs including internal labor, insurance, and initial lime reagent fill
- Third Party Services including construction management oversight, start-up and commissioning oversight, Owner's Engineer services, and performance testing
- Project Contingency to cover unknown and undefined scope associated with the project which would result in additional cost to the Owner

The total capital investment to install dry FGD on White Bluff Units 1 and 2 was estimated to be $1,072,370,000. The project definition and accuracy of the individual components included in this estimate result in an overall accuracy of ±20-25%. In addition, the O&M costs were estimated to be approximately $10,166,000 per year per unit and include the cost of lime (reagent), byproduct disposal, auxiliary power, water, replacement bags and cages, maintenance costs, and operating labor.

1. PURPOSE

The purpose of this study is to estimate the total capital investment and operating and maintenance costs associated with installing dry flue gas desulfurization (FGD) technology on White Bluff Units 1&2. This report documents the conceptual design and technical basis for the dry FGD cost estimate.

2. APPROACH

2.1 TECHNOLOGY SELECTION

Sargent & Lundy (S&L) previously performed an evaluation of wet and dry FGD technology for Entergy's White Bluff Station. The evaluation included development of a preliminary conceptual design for both wet and dry FGD systems at the White Bluff station. The preliminary designs were used as the basis of an evaluation which compared the overall economics of each system, including capital and operating costs. The study concluded that a dry FGD system had an economic advantage over wet FGD when the design coal sulfur is below 3 lb SO_2/MMBtu. Based on the current market and potential future regulations, dry FGD technology would have an economic advantage over wet FGD for SO_2 reduction at the White Bluff station.

2.2 CONTRACTING APPROACH

Many utilities elect to utilize a one contract engineer-procure-construct (EPC) approach for major retrofit projects, such as large FGD projects. The EPC approach allows the Owner to contract with one entity which then manages the overall project. The EPC Contractor procures the material, equipment and services needed to complete the project and the EPC Contractor takes full responsibility for the equipment and work supplied by each of its subcontractors.

With this approach the Owner takes on less risk in the overall management and coordination of the project. However, shifting this risk to the EPC Contractor increases the total price for the EPC contract; "Whilst there are… numerous advantages to using an EPC contract, there are some disadvantages. These include the fact that it can result in a higher contract price than alternative contractual structures. This higher price is a result of a number of factors not least of which is the allocation of almost all the construction risk to the contractor."[1] The additional cost due to an EPC contracting approach is represented in our cost estimate as an EPC Risk Fee.

The Owner's control over design details of the system is limited, using this contracting strategy, to the requirements specified in the contract. This results in an additional upfront effort for the Owner and the Owner's Engineer to thoroughly define the project in the specification. Whatever is not defined will be excluded from the EPC Contractor's scope resulting in potential change orders. The Owner and Owner's Engineer are also responsible for reviewing the EPC Contractor's submitted design drawings and schedules to ensure what has been agreed upon in the final contract is included.

2.3 CAPITAL COST DEVELOPMENT

The capital cost estimate is based on project-specific information, including:

- A preliminary conceptual design developed for implementation of dry FGD technology at the White Bluff station.
- An engineer-procure-construct (EPC) contracting strategy.
- A Dry FGD System Supplier, subcontracted by the EPC Contractor, providing the main process equipment as a complete FGD Island.
- The FGD Island equipment and installation cost is based on a budgetary proposal received from Alstom in September 2013. The budgetary proposal is based on installing SDA technology on both of the White Bluff units.

The capital cost estimate includes the following components which comprise the total price of the EPC Contract to complete the work:

- Equipment and material
- Installation labor
- Demolition and Relocation work
- Indirect field costs and BOP engineering
- Freight on Materials
- General and Administration
- Erection contractor profit

[1] "EPC Contracts in the Power Sector", prepared by DLA Piper, 2011, page 6. See: https://www.dlapiper.com/

- Engineering, Procurement and Project Services
- Spare parts
- EPC Fee
- Escalation

The equipment design basis is summarized in Section 3 of this report and the scope of the estimate is summarized in Section 4. The project definition and accuracy of the individual components included in this estimate result in an overall accuracy of ±20-25%.

In order to estimate the *total plant* capital cost for installation of FGD at White Bluff, the following costs which would be incurred outside of the scope of the EPC contract were included:

- Owner's Costs
- Third Party Services – Construction Management Oversight
- Third Party Services – Startup and Commissioning Oversight
- Third Party Services – Owner's Engineer
- Third Party Services – Performance Testing
- Project Contingency
- Interest During Construction or Allowance for Funds Used During Construction

The cash flow provided in Attachment 2 is based on a monthly progress payment schedule developed using the preliminary execution schedule included in Attachment 3. Specific details regarding the milestones making up the payment schedule are listed in Attachment 4. Below is a summary of those activities that represent major or large payment milestones.

Month	Date	Milestone
1	February 2017	Award EPC Contract Execution
5	June 2017	EPC Contractor Procures Major Equipment
7	August 2017	EPC Contractor Procures Major Equipment
10	November 2017	Flue Gas Ductwork Procurement Initiated by EPC Contractor
13	February 2018	SDA and Fabric Filter Design Drawings
15	April 2018	Award Fabric Filter Bags and Cages Flue Gas Ductwork Start of Fabrication
17	June 2018	Physical Flow Model Completed

Month	Date	Milestone
19	August 2018	Mobilize On-Site
20-38	September 2018 to March 2020	Construction Activities
41	June 2020	Unit 1 Substantial Completion
45	October 2020	Unit 2 Substantial Completion
		Demobilization Complete
46	November 2020	Unit 1 Final Acceptance
47	December 2020	Unit 2 Final Acceptance

Each monthly cash outlay in the cash flow is broken down by category (labor, equipment and materials, and indirect costs).

3. DRY FGD CONCEPTUAL DESIGN AND SYSTEM COMPONENTS

A conceptual design for the implementation of Dry FGD at the White Bluff station was developed by Sargent & Lundy LLC (S&L) as a precursor to the development of the cost estimate. A general arrangement drawing showing the conceptual design is included in Attachment 7. The dry FGD conceptual design was developed for each of the following subsystems:

3.1 DRY FGD ISLAND

3.1.1 Reagent Preparation System

Lime will be supplied to the lime day bins from the long-term storage silo located in the Reagent Handling Area and supplied by the EPC Contractor. The lime day bins, located in the Reagent Preparation Area and provided by the Dry FGD System Supplier, will each have a storage capacity to supply the plant with lime reagent for 24 hours when firing 1.2 lb SO_2/mmBtu coal.

Lime from the day bin will be gravity-fed through feeders to a lime slaker, where the lime will be slaked (mixed with low pressure service water and converted from calcium oxide to calcium hydroxide slurry). The plant will have a total of two lime slaking trains (2 x 100%), each sized to process enough lime slurry to supply the entire plant. Each lime slaker will discharge to a lime slurry transfer tank, which is equipped with two lime slurry transfer pumps which will feed into the lime slurry storage tanks. The common lime slurry storage tanks will each be sized for 12 hours of storage for the entire plant when burning a 1.2 lb SO_2/mmBtu coal. The lime day bin, slaking trains, and lime slurry tanks are sized to provide the necessary reagent slurry to both units simultaneously. The lime slurry tanks are built with cross-ties such that either slurry tank can feed either the Unit 1 or Unit 2 FGD systems.

A total of four lime slurry feed pumps (two per unit), each sized for 100% flow to one unit, will pump the lime slurry from the storage tanks to the SDAs through one of 2 x 100% piping loops, and return unused slurry back to the lime slurry storage tank. The closed-loop reagent supply line requires a flow velocity between 4-10 fps to avoid any solids buildup in the piping. Because of this, the pumping requirement is higher than the actual SDA requirement and must be sufficiently greater than the slurry flow that is pumped into the absorbers to allow the returning flow to remain above 4 fps.

3.1.2 Absorbers

Three absorbers, each treating 33⅓% of the flue gas are provided for each unit. Depending on the supplier and the type of atomizer normally used, there may be one rotary atomizer per absorber with a shared spare (B&W), three rotary atomizers per absorber with one or more shared spares (Alstom, basis of the estimate), or multiple dual-fluid atomizers with 15% shared spares (Siemens). The cost estimate includes contingency to capture the possibility of any of these designs.

3.1.3 Baghouse

Each SDA will be paired with a pulse-jet baghouse with a gross air-to-cloth ratio of approximately 3.2-3.4 ft/min. The filter bags in each baghouse are cleaned by pulses of compressed air. The air compressors will be 4 x 33% for the station and are included in the scope of the baghouse supplier.

3.1.4 Byproduct Recycle System

The reaction byproducts from the absorbers will be collected in the baghouses and a portion of the collected material will be recycled. The baghouse hoppers will be emptied through air lock feeders and pneumatically conveyed to two recycle day bins located in the Byproduct Recycle Area and supplied by the Dry FGD System Supplier, which are common for both units. The air-lock feeders are installed without a spare. One recycle day bin is located in the recycle train for each unit. The common byproduct recycle day bins (one per unit) provide 8-hours of storage when burning 1.2 lb SO_2/mmBtu coal.

Each byproduct recycle day bin is equipped with two recycle slurry preparation systems. The byproduct in each recycle day bin is gravimetrically conveyed to one of two systems where the byproduct is slurried with water (cooling tower blowdown). The byproduct recycle slurry is stored in one of four plant wide recycle slurry tanks, two per unit (combined 4-hour storage capacity).

Two recycle water make-up tanks are located in the recycle area with a capacity of 250,000 gallons (to be supplied by the EPC Contractor). The recycled by-product slurry will be combined with fresh lime slurry for feed to the SDA atomizers. Recycle feed slurry pumps (4 x 100%, two installed per unit) will be used to transfer the recycle slurry from the recycle slurry tanks to the atomizers. In addition, all recycle feed lines are provided in a loop configuration as with the reagent system, with a complete redundant loop to allow unhindered operation due to any pluggage of pumps or feed piping.

3.2 REAGENT HANDLING SYSTEM

As part of the conceptual design, several lime delivery methods were evaluated and it was determined that rail delivery provided the best alternative for White Bluff based on ease of implementation, overall plant interface, and lowest evaluated cost (in terms of required capital investment and delivered cost of lime). Therefore, the basis of the estimate is delivery of lime via hopper-bottom railcars with truck unloading as a backup. In order to accommodate rail delivery to the site, a new rail spur will be constructed from the existing track bordering the west side of the plant. Lime trains will enter and exit the station from this spur. A trackmobile car positioner will position railcars, two at a time, in the enclosed delivery shed for unloading. The cost estimate includes the capital cost associated with railcar unloading, including the new rail spur and the renovation of the existing rail spur to handle lime delivery. A vacuum pneumatic system will unload the railcars into either of the two (2) lime storage silos. The lime storage silos will be sized for supply of reagent for 14 days of storage at full load when firing 1.2 lb SO2/mmBtu coal. Lime from the long-term storage silos will be pneumatically transferred to two lime day bins located in the Reagent Preparation Area and supplied by the Dry FGD System Supplier.

3.3 BYPRODUCT HANDLING SYSTEM

Excess FGD byproduct from the recycle system will be pneumatically conveyed to either of the two common long- term FGD byproduct storage silos. The two long-term FGD byproduct storage silos are each sized to handle the byproduct for a total of 7 days of storage when firing the 1.2 lb SO_2/mmBtu coal. The byproduct will be mixed with a small amount of fly ash and water to form a final product which contains approximately 65% FGD byproduct, 5% fly ash, and 30% water. In order to achieve this mixture, a common fly ash blending bin (7-day storage) will be located near the new byproduct silos. The feed rate of fly ash discharged from the blending bin is controlled to maintain the ratio of byproduct to fly ash. A pneumatic airslide conveyor will discharge fly ash directly into an unloading conditioner, simultaneously mixing fly ash with the proper ratios of water and FGD byproduct (discharged from the silo). The wetted byproduct/fly ash mixture is then loading into dump trucks, which will deposit the FGD byproduct in a final storage location in the landfill. A bulldozer will maintain the landfill pile. The capital cost for the silos, conveying system and byproduct/fly ash blending system is included in the cost estimate. As part of the conceptual design, the existing landfill was evaluated and was determined to have sufficient capacity to accommodate the addition of FGD byproduct. Therefore no costs were included in the capital estimate for the (existing) landfill. In addition, it was assumed that the existing haul trucks would be used to transport the FGD byproduct.

3.4 FLUE GAS HANDLING SYSTEM

The flue gas from the existing ID fans will be ducted to the absorbers. The gases from the absorbers will be ducted to the baghouses to collect the reaction by-products and residual fly ash. Two axial booster fans (2 x 50% for each unit) will be located downstream of the absorbers and baghouse; the booster ID fans can be provided by the Dry FGD System Supplier or the EPC Contractor. Due to the dry condition of the scrubbed flue gas, the existing stack and liners will be used for the retrofit case.

The existing chimney and carbon steel liners were evaluated as part of the conceptual design and were deemed to be suitable for a dry FGD application. In addition, the top 50 feet of the existing chimney liners are constructed of 316 stainless steel so an acid resistant coating on the liner is not required. However, downwash may result in acid attack and discoloration on the outer concrete shell of the chimney; it was determined that an acid resistant coating to the top 100 feet of the concrete shell is recommended; therefore, the cost estimate includes the coating of the top 100 feet of the chimney's outer concrete shell.

3.5 ELECTRICAL BOP SYSTEM

The existing auxiliary power system was evaluated as part of the conceptual design for the White Bluff dry FGD system. In order to feed the new dry FGD and other BOP equipment, significant modifications and additions to the existing power system are required. These include installation of new auxiliary transformers, medium- and low-voltage switchgear buses, motor control centers (MCCs) and upgrades to the isolated phase tap-off buses.

3.6 I&C BOP SYSTEM

As part of the conceptual design, the existing control system was evaluated to determine the required modifications necessary to implement dry FGD technology at the White Bluff station. The dry FGD system will be controlled using a new Foxboro I/A system which will integrate with the existing power block Foxboro I/A system. The control processors, I/O cabinets, and other system components will be located in the new electrical equipment building (EEB) for each unit. Two HMIs will be installed in the new EEB for each unit to provide any local controls for the lime preparation and byproduct recycle systems provided by the Dry FGD System Supplier. The baghouse will be controlled through the Allen-Bradley ControlLogix PLC and the ID booster fans will be controlled through the existing Foxboro I/A system controller(s), which are used to control boiler air and furnace pressure.

4. CAPITAL AND O&M COST ESTIMATE TECHNICAL BASIS

The following summarizes the design inputs used as the basis for the White Bluff dry FGD Systems:

- Design SO_2 inlet concentration of 1.2 lb SO_2/MMBtu for equipment design.
- SO_2 inlet concentration of 0.68 lb SO_2/MMBtu for annual operating costs.
- Design SO_2 outlet concentration of 0.06 lb SO_2/MMBtu.
- Annual capacity factor of 72.46% (based on Entergy's future operating profile).
- Compliance deadline of December 2020.

4.1 EPC CONTRACT PRICE

The Dry FGD System Supplier will provide all of the equipment within the FGD Island. The FGD Island will include the Reagent Preparation Equipment, Absorber Area Equipment, Baghouse Area Equipment and the Byproduct Recycle Equipment. The booster ID fans could be provided by either the Dry FGD System Supplier or the EPC Contractor; the basis of this estimate is supply of the booster fans by the Dry FGD System Supplier. The EPC Contractor will provide the remaining BOP scope in order to provide a complete and operable FGD system. In addition, the EPC Contractor will install/construct the entire system including the equipment provided by the DFGD supplier.

The scope of work for the cost estimate is broken out by area below:

1. Dry FGD Island
    a. Reagent Preparation System, common to both units:
        - Two lime day bins, 24-hours storage each
        - Two detention lime slakers at 100% capacity, each with a grit screen, gravimetric feeder
        - Two lime slurry transfer tanks
        - Four slurry transfer centrifugal pumps
        - Two lime slurry storage tanks
        - Four slurry feed centrifugal pumps
        - Cost estimate based on budgetary proposal from Alstom; the budgetary proposal is based on a design sulfur of 2.0 lb/MMBtu, cost adjustments were included in the estimate for a lower design sulfur of 1.2 lb/MMBtu. These cost adjustments were developed by estimating the differential equipment cost for the reagent preparation and waste handling equipment. The impacted equipment is identified in Section 4.5 which discusses the sulfur design basis sensitivity.

b. Absorber Area, per unit
- Three absorber vessels per unit, with access doors
- Rotary atomizers, two spare atomizers included
- Vessel material carbon steel, ¼ in. – ⅝ in. carbon steel
- Heating and ventilation
- Vacuum piping
- SDA Superstructure
- Cost estimate based on budgetary proposal from Alstom

c. Baghouse Area, per unit
- New baghouse, including pulse jet cleaning system and all appurtenances
- Cost estimate based on budgetary proposal from Alstom

d. Byproduct Recycle System, per unit (located remotely in common location for both units)
- One recycle silo with bin vent filter per unit, 8-hour total capacity
- Two recycle mix tanks per unit
- Two recycle slurry tanks per unit, with two recycle slurry centrifugal pumps per unit
- Agitators for each tank
- Baghouse ash handling system common to both units
- Rotary air-lock valves from baghouse hopper outlets to pressure pneumatic conveying system (60-degree typical)
- Pneumatic pressure blowers (8 x 33⅓ %)
- Cost estimate based on budgetary proposal from Alstom

e. ID Booster Fans, per unit
- Two approximately 5,200 hp axial booster fans per unit sized to overcome pressure drop associated with FGD and baghouse
- Includes motors - no spare motor included
- Cost estimate based on budgetary proposal from Alstom
- Dampers from ID fan to booster fans (cost estimated separately, not included in Alstom budgetary proposal)

2. <u>FGD Island Foundations and Enclosures</u>

a. Absorber tower foundations including caissons

b. Baghouse area foundations including 18” auger cast piles 60’ long

c. Booster fan area foundations

d. 6" insulation with lagging for Absorbers and Baghouses (cost estimated separately, not included in Alstom budgetary proposal)

e. Penthouse enclosure for Absorbers located in FGD Island (cost estimated separately, not included in Alstom budgetary proposal)

f. Two elevators (one for each unit) to provide maintenance access to Absorber and Baghouse Areas

g. Enclosure around hoppers for Baghouses located in FGD Island (cost estimated separately, not included in Alstom budgetary proposal)

h. Lime preparation building for Reagent Preparation Area in FGD Island, 50' x 50' x 50', including substructure and superstructure (cost estimated separately, not included in Alstom budgetary proposal)

i. Byproduct recycle building for Byproduct Recycle Area in FGD Island, 60' x 60' x 60', including substructure and superstructure (cost estimated separately, not included in Alstom budgetary proposal)

3. Reagent Storage and Handling, common to both units:

a. Lime rail car unloader:
- Lime delivery via 25-car unit train
- System consists of mobile receiving pan and associated vacuum pneumatic equipment to unload railcar through railcar bottom hoppers
- Enclosed railcar unloading building
- One vacuum pneumatic system operating to unload a car
- Pneumatic vacuum exhausters (2 x 100%)
- Filter separator with vacuum-to-pressure transfer hopper and valves
- One lot of pneumatic conveying piping located on an above-grade sleeper pipe rack
- Cost estimate based on vendor quote from United Conveyor Corporation (UCC) for a similar unit

b. Lime storage silos:
- Two silos, 14-days storage and capable of storing a train load of lime, 2,400-tons storage total, including substructure and superstructure
- 32' diameter and 95' height to top
- 1,200-tons storage, each
- Continuous level detection systems
- Bin vent filters
- Live bottom hopper outlets
- Rotary airlock assemblies

- Lime transfer systems:
  - Pressure pneumatic conveying system from lime storage silos to lime day bins
  - Pneumatic pressure blowers (3 x 100%)
  - One lot of pneumatic conveying piping located on an elevated pipe rack

c. Concrete foundations including caissons for all material silos

d. Concrete foundations for pneumatic conveying blowers and exhausters

4. <u>Byproduct Handling System, common to both units</u>

a. Two FGD by-product storage silos (7-day capacity each, common to both units) with bin vent filter, fluidizing system, and two unloading conditioners (one operating, one spare per silo)

b. One common fly ash blending, 7-day storage bin with bin vent filter, fluidizing system, and four pneumatic airslide conveyors

c. Water pumps and associated piping for unloading conditioners (pin mixers) at both silos

d. Compressed air system for air operated valves

e. Storage silo substructure and superstructure

f. Continuous level detection system

g. One lot pneumatic conveying piping located on an above grade pipe rack

h. Two truck scales and substructure

i. Existing road improvements for truck haulage to existing landfill

j. Cost estimate based on budgetary proposal from UCC for similar project

k. Concrete foundations including caissons for all material silos

l. Concrete foundations for pneumatic conveying blowers and exhausters

5. <u>Flue Gas Handling System, per unit</u>

a. ID fan outlet to absorber inlet ductwork and supports:
   - Carbon steel, ¼ in.
   - Velocity, 3,600 fpm
   - 6” insulation with lagging

b. Absorber outlet to baghouse inlet ductwork and supports:
   - Carbon steel, ¼ in.
   - Velocity, 3,600 fpm
   - 6” insulation with lagging

c. Baghouse outlet to new booster fans and fan outlet to the stack inlet ductwork and supports:
   - Carbon steel, ¼ in.
   - Velocity, 3,600 fpm
   - 6” insulation with lagging

d. Concrete foundations for all flue gas ductwork

e. Epoxy trowel coating on top 100 feet of outside of chimney shell

6. Civil BOP

a. Roadwork

b. Site grading

c. Soil removal earthwork

d. Excavation, backfill, and compaction for all foundations

e. Storm sewer work

f. Two-cell pond for wastewater storage of process water/slurry

g. Laydown Area
   - Development of a new laydown area, approximately 10 acres, including site preparation, fencing, and temporary power. It was assumed that this area would be located on existing plant property, and does not required land to be purchased.

h. Highway Intersection Upgrade to provide sufficient plant access for construction period
   - New Bypass Lane on Westside of Highway 365
   - New Southbound Left Turn Lane on Highway 365
   - New Northbound Merge Lane on Highway 365
   - New Northbound Right Turn Lane on Highway 365
   - Extension and upgrade of existing Contractor Haul Road (Highway 46 Spur) to Highway 365
   - Widening of the existing Main Plant Road from the Contractor Haul Road (Highway 46 Spur) to Main Guard House
   - Track crossing signal system at Haul Road (Highway 46 Spur) track crossing

i. New warehouse building 200’ x 75’ x 15’, including substructure and superstructure.

7. Mechanical BOP System

a. Interconnecting piping, above-ground and buried

b. Valves for interconnecting piping, above-ground and buried

c. Lime slaking water storage tank, 115,000-gallon capacity

d. Slaker water 3” in-line heaters, 475 kW each

e. Recycle make-up water tanks, 2 x 250,000-gallon capacity

f. Pipe Racks, common to both units
   - Between lime railcar unloading enclosure and lime silos
   - Between lime silos and lime day bins
   - From baghouse hoppers to recycle silos and FGD by-product silo
   - From lime slurry storage tanks to absorber
   - From recycle slurry storage tank to absorber
   - Concrete foundations including caissons for all pipe racks
   - Shallow concrete foundations for other miscellaneous structures

g. BOP Pumps
   - Three by-product recycle water forwarding pumps to recycle slurry, 1000 gpm @ 150’ TDH
   - Four reagent prep/recycle sump pumps, 120 gpm @ 150’ TDH
   - Two lime silo and unloading area sump pumps, 120 gpm @ 150’ TDH
   - Two by-product ash silo area sump pumps, 120 gpm @ 150’ TDH
   - Two by-product recycle make-up water tank supply pumps, 2600 gpm @ 200’ TDH
   - Two lime slaking water pumps, 750 gpm @ 100’ TDH
   - One new Low Pressure Service Water (LPSW) pump, 20,000 gpm @ 100’ TDH, including new intake structure, piping and valves
   - Two leachate pumps, 50 hp

h. Instrument Air System, common to both units
   - Air compressors; 2 x 100%, 250 scfm each @ 100 psig
   - IA dryers w/filters; 2 x 100%, 250 net scfm each
   - Air receivers; 2 x 100%
   - Instrument air piping to every silo or day bin, bin vent and reagent preparation/recycle area
   - Heat-traced piping

i. Service Air System, common to both units
   - Air compressors; 2 x 100%
   - Air receivers; 2 x 100%

j. Field painting
   - Multiple coat system used for exposed ductwork only
   - Inorganic zinc primer and polyurethane system used for steel
   - Allowance for underground piping shop coatings built into piping cost

8. Demolition and Relocation
    a. Hazardous material accumulation building
    b. Ash handling maintenance building
    c. Drainage ditch
    d. Pipe trench
    e. Fabrication shop
    f. Existing contractor electrical hook up
    g. Existing drainage ditches, rerouted with new concrete trenches
    h. Relocation of ACI injection location from the air heater inlet to upstream of the DFGD
    i. Rail Yard Extension, common to both units
        - Extend rail spur to north to allow lime train to be unloaded and cars to be stored on site, designed for 136 lb rail to be consistent with existing coal spurs
    j. Fire Protection System Modifications
        - Deluge system has been included for the new transformers
        - Allowances have been included for fire protection in all of the new buildings; including piping and post indicator valves
        - The new fire protection systems will tie-in to the existing system on-site. It was assumed that the current capacity of the plant fire protections system is sufficient to accommodate the new systems; an evaluation of the current system capacity was not performed.

9. Electrical BOP System
    a. One 115-kV, 1200A isolation disconnect switch
    b. One startup transformer
    c. Two unit auxiliary transformers (UAT)
    d. Three medium-voltage (6.9-kV) switchgear buses (outdoor walk-in type)
    e. Two medium-voltage (6.9-kV) double ended switchgear per unit (total of two)
    f. Two 480-V double ended switchgear buses per unit (total of four)
    g. Six 480-V motor control centers per unit (total of twelve)
    h. Four 6.9-kV/480-V step-down transformers per unit (total of eight)
    i. Two isolated phase UAT tap bus extensions
    j. Non-segregated phase bus
    k. Medium-voltage cable
    l. Low voltage, control and instrumentation cable, as necessary
    m. Two electrical equipment buildings

10. Instrumentation and Controls BOP System

    a. Controls System based on an estimated number of I/O points:
        - Approximately 1,000 I/O points are required for each unit's DFGD system (including reagent preparation), for a total of 2,000 I/O points the cost of which is included in Alstom budgetary proposal pricing.
        - Approximately 2,000 I/O points for the common areas at the station, located outside of the DFGD Island.

    b. CEMS, per unit
        - Existing CEMS analyzers for both units will be recalibrated and recertified; if the existing CEMS analyzers cannot be recalibrated for lower SO_2 emission, new CEMS analyzers will be installed.

11. Labor Costs

    Installation/labor costs were included in the base estimate under the direct costs. Manhours are estimated for each item in the base estimate and are based on the type of work and typical estimates for similar work. The labor costs are based on the labor wage rates and labor crews developed by S&L.

    a. Labor Wage Rates

       Crew labor rates were developed using prevailing craft rates, fringe benefits and state specific worker's compensation rates as published in the 2015 edition of R.S. Means Labor Rates for Pine Bluff, Arkansas area. Costs were added to cover FICA, workers compensation, all applicable taxes, small tools, incidentals, construction equipment, and contractor's overhead. A 1.15 geographic labor productivity multiplier is included based on the Compass International Construction Yearbook for Arkansas. The crew rates do not include an allowance for weather related delays.

    b. Labor crews

       Construction/erection labor cost is based on the use of applicable construction crews typically required for projects of this type. The construction crew costs were specifically developed for utility industry and are proprietary to S&L. The prevailing craft rates are incorporated into work crews appropriate for the activities, and include costs for small tools, construction equipment, insurance, and site overheads.

12. Other Direct and Construction Indirect Costs

    In addition to the base labor costs, other construction indirect costs for the project were broken out in the estimate as well as other contractor direct costs. The following items were included as other direct and construction indirect costs.

    a. Scaffolding and Consumables

    b. Premiums and per diems ($10 per hour)

    c. Overtime is included based on five 10-hour shifts per week work schedule

d. Freight on construction materials

e. Contractor's General & Administration Fees (included at 10% of total direct and construction indirect costs)

f. Contractor's Profit (included at 5% of total direct and construction indirect costs)

13. EPC Indirect Costs

The final contribution to the overall EPC project price are the EPC Contractor's indirect costs; these include the EPC engineering services, startup spare parts and initial fills, technical field advisors, and the EPC risk fee.

a. EPC Engineering Services

The EPC engineering services was estimated based on recent projects with similar scopes and schedules. The total cost of the EPC engineering services was estimated to be $23,000,000 without escalation.

b. Startup Spare Parts and Initial Fills

An allowance has been included for initial fills for equipment, including first fills for lubrication of any motorized equipment. The initial fill of pebble lime was not included in the EPC Contractor's scope, as this is considered to be an operating cost rather than a capital expense. The initial fill of pebble lime is included in the Owner's costs.

c. Technical Field Advisors (Vendors)

Allowances were included for equipment supplier's technical field advisory services based on an estimated 300 man-days. The estimate includes technical field advisors for the FGD system supplier (including FGD system subcontractors) and the DCS supplier.

d. EPC Risk Fee

An EPC approach provides an alternative which is expected to reduce risk for Entergy by placing the responsibility for the project on a single entity, the EPC Contractor. The EPC Risk Fee is a premium included by the contractor which accounts for the additional coordination and management of the project as well as the additional risk assumed by the contractor (See Section 2.2 for a discussion on the contracting strategy and the EPC Risk Fee). Based on S&L's experience with recent EPC projects, an EPC Risk Fee was included at 10% of the total EPC project costs.

14. Escalation

Escalation was included in the estimate based on the preliminary execution schedule at an escalation rate of 2.15% on equipment and materials and 3.35% on labor and indirects. These escalation rates were developed by S&L based on recent pricing and in-house escalation projections.

For commodities and equipment related to power plant construction, S&L tracks over 200 U.S. indices from major industrial sources such as BLS, Chemical Engineering, Handy Whitman, and Engineering News Records. S&L reviews the various indices in order to develop an overall average and then evaluates the change in the indices over the last three years and the last five years. Based on this analysis, an annual rate of 2.15%/year escalation is projected for commodities and equipment for the time frame for the project.

S&L uses RS Means as the basis for estimating labor craft rates. In order to project the escalation rate for the estimate, S&L reviewed five major craft labor types typically used in the power plant industry over the last five years using the average cost of craft labor. Based on this information, S&L projected an annual rate of 3.35%/year escalation on labor and indirects.

15. Sales Tax

    Sales Tax is included in the estimate, and was applied at a rate of 8.125% on all material costs.

4.2 OVERALL PROJECT COSTS FOR CAPITAL ESTIMATE

Outside of the EPC Contractor's total cost, Entergy will incur other costs associated with the project, such as Owner's costs, services procured from third parties (including Owner's engineer, construction management support, startup and commissioning support and performance testing), and other project related costs. The following summarizes the additional project costs to Entergy associated with installing dry FGD at the White Bluff Station:

1. Owner's Costs (by Entergy)

   Owner's Costs are direct costs that the Owner incurs over the life of the project. Entergy estimated the cost for the following items which would be real costs Entergy would incur based on the scope and schedule of this project:

   a. Internal Labor – For all major projects, Entergy assigns internal resources to manage the project from initiation through development, contracting, installation, and commissioning. Internal labor includes personnel from several departments including Capital Project Management & Technology, Engineering, Fossil Operations, Legal, Environmental Services, Supply Chain, Risk Management, Finance, Regulatory, and the Operating Company. The internal labor is estimated based on a proposed staffing plan, developed from the project scope and preliminary schedule using average wage rates. Costs are based on the following anticipated staffing levels:

      - Project Development (through EPC Award) – 25 months, equivalent of 10 people
      - Project Execution (beginning at EPC Award) – 53 months, equivalent of 22 people

   b. Internal Indirects – Indirect costs incurred by Entergy include a payroll allocation, materials and supplies allocation, a depreciation allocation, and capital suspense allocation. The payroll allocation includes payroll overhead costs for items such as employee benefits. The materials and supplies allocation is used to distribute the overhead costs of managing storerooms that are used to procure, track, and issue material and supplies. The depreciation allocation distributes depreciation and amortization expenses for the new assets. Capital suspense is a distribution of overhead costs associated with administrators, engineers, and supervisors and includes function specific rates and A&G (Corporate Accounting) rates.

c. Travel Expenses –Travel expenses are included to support the oversight of the project, including travel for site-visits, monthly status meetings, critical design reviews, etc. Travel expenses are estimated based on projects with similar schedules and scope.

d. Legal Services – Legal services are contracted from external law firms. These services include contract and regulatory compliance support. Entergy estimated the cost of the legal services based on recent EPC projects.

e. Builders Risk Insurance - Builder's Risk Insurance is included in the estimate and covers the materials, equipment, and labor associated with a large scale construction project in case of physical loss or damage. The estimated is based on estimated project value and schedules.

f. Initial Fills - Entergy will procure a supply contract for pebble lime to the station. Under this contract, Entergy will arrange to provide the initial fill of pebble lime to the station for startup, commissioning, and performance testing. A 120 day supply of pebble lime for both units has been included in the estimate based on the reagent pricing identified in Section 4.3.

2. Third Party Services – Construction Management Oversight

The construction management support was estimated based on the proposed staffing plan shown below, developed from the overall project scope and the preliminary schedule. It was assumed that Entergy will not have the internal support personnel required to perform this task, and therefore it will be outsourced. The cost of labor is based on present day cost, without escalation. Travel and living expenses are based on the current per diem rate for the White Bluff area of $129/day. Costs are based on the following anticipated staffing levels:

a. Home Office Support – 15 months, 1 person

b. On-Site Construction Manager – 35 months, 1 person

c. On-Site Construction Admin/Project Controls Engineer – 35 months, 1 person

d. Construction Field Engineers – 31.5 months, 2 people

The total cost of the Construction Management Support was estimated to be $4,969,000 without escalation.

3. Third Party Services – Startup and Commissioning Oversight

The startup and commissioning support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform this task, and therefore it will be outsourced. Costs are based on the following anticipated staffing levels:

a. Commissioning Support Specialists – 8 months, 2 people

The total cost of the startup and commissioning support was estimated to be $550,000 without escalation.

4. Third Party Services – Owner's Engineer

The Owner's Engineer cost includes scope as summarized below and was estimated based on the preliminary project schedule, including assumptions on manpower requirements, as well as a comparison cost to other projects with similar scope.

The cost of labor is based on present day cost, without escalation. Costs are based on the following scope for the Owner's Engineer work:

a. Conceptual Study Support
b. EPC Specification Supporting Documents
c. Project Schedule Development
d. EPC Specification Development
e. EPC Bid Evaluation and Contract Conformance
f. General Project Support
    - Monthly Project Status Meetings
    - Weekly Teleconferences
    - Overall Coordination
    - Project Administration
    - Site Visits and Travel
g. Permitting (Construction Permits and Modification to Title V and Solid Waste Permits)
h. Design Review of Drawing Submittals
i. Technical support during design, fabrication, construction, commissioning, and testing
j. Equipment vendor QA/QC audits

The total cost of the Owner's Engineer was estimated to be $6,750,000 without escalation.

5. Third Party Services – Performance testing

The cost for performance testing was developed as a factored estimate using costs from projects of similar scope. This cost includes the testing, performed by a third-party contractor hired by the Owner, and also includes the cost for S&L's assistance in the following tasks:

a. Development of the test protocol
b. Procuring the services of the testing contractor
c. Overseeing the performance test campaign
d. Evaluating the results of the testing with respect to guarantee compliance

The estimate for the third party testing contractor is based on the assumption that the contractor would be onsite for up to 3 days for each unit.

The total cost of the Performance Testing was estimated to be $275,000 without escalation.

6. Project Contingency

Project contingency is included in the estimate to cover the uncertainty associated with the project costs, and was developed utilizing Entergy's procedure for developing a project's contingency. The process includes developing three components of contingency:

a. Risk Contingency: This category of contingency is developed with the use of a Risk Register that is used to identify risks that may impact the project. Each risk in the Risk Register is analyzed to determine the probability of the risk and the impacts of the risk to the project.

b. Estimate Uncertainty: This category of contingency uses the estimate accuracy classifications to develop an appropriate level of contingency. Entergy has adopted expected accuracy ranges for estimates with upper and lower boundaries for each class of costs estimate. These ranges recognize the uncertainty that exists in the technical engineering and project management deliverables that define scope.

c. Unknown/Emergent Risks: This category of contingency is used to account for any issues that arise during the project that are not contained within the risk register or to cover any costs associated with unanticipated changes in project scope.

A cost qualitative risk assessment (QRA) was performed using Palisade Corporation's @RISK software. QRAs are used to validate the reasonableness of cost estimates, provide confidence for cost projections, and help establish a reasonable level of contingency based on risk-weighted estimates and project risk profiles. The QRA identifies various confidence levels that the contingency amount is sufficient for the project. For this estimate's cost QRA, an 80% confidence level was selected which means the project is 80% likely to be completed at or below the calculated value. The 80% confidence level results in a contingency value of 15% of the total project cost before escalation and IDC. This level of contingency is within Entergy's guidelines for target contingency range for this class of estimate. The contingency estimate is included in Attachment 8.

7. Escalation on Owner's Costs

Escalation was included in the estimate at an escalation rate 3.35% on the Owner's costs. This escalation rate is based on the rate developed by S&L for labor and indirects above.

8. Interest During Construction

Interest during construction (IDC) accounts for the time value of money associated with the distribution of construction cash flows over the construction period. IDC was applied to the total EPC project costs including contingency. The IDC was calculated based on the milestone payment schedule included in Attachment 4 and a typical interest rate of 7.0% per year which was assumed based on a low interest market environment.

4.3 VARIABLE OPERATING AND MAINTENANCE COSTS

The following unit costs were used to develop the variable Operating and Maintenance (O&M) costs. All of these values, with the exception of the reagent costs, were provided by Entergy and are consistent with typical industry values. The reagent costs are based on recent supplier quotes received for White Bluff.

Table 4-1: Unit Pricing for Utilities (Provided by Entergy)

Unit Cost	Units	Value
Pebble Lime	$/ton	$130.0
High Quality Water	$/1000 gal	$2.00
Low Quality Water	$/1000 gal	$0.53
Byproduct Disposal	$/ton	$7.50
Aux Power Cost	$/MWh	$43.35

Table 4-2 below summarizes the consumption rates estimated as well as the first year variable O&M costs for the Dry FGD system.

Table 4-2: Variable O&M Rates and First Year Costs, per Unit

	Units	Design 0.68 lb SO_2/MMBtu
Dry FGD System Parameters		
Reagent Consumption	lb/hr	7,000
Byproduct Waste Production	lb/hr	16,000
Aux Power Consumption	kW	11,000
High Quality Water Consumption	gpm	75
Low Quality Water Consumption	gpm	775
First Year[1] Variable O&M Costs (@CF[2])		
Reagent Cost	$/year	$2,888,000
Byproduct Waste Disposal Cost	$/year	$380,000
Aux Power Cost	$/year	$3,027,000
Water Cost	$/year	$214,000
Bag and Cage Replacement Cost	$/year	$372,000
Total First Year Variable O&M Cost	**$/year**	**$6,881,000**

Note 1: First year costs are provided in $2015.

Note 2: The first year costs are calculated using an annual capacity factor of 72.46%.

4.4 FIXED OPERATING AND MAINTENANCE COSTS

The fixed O&M costs for the systems consist of operating personnel as well as maintenance costs (including material and labor). Based on the conceptual design for the dry FGD system, the estimated staffing additions are 28 personnel for two systems on adjacent units.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (maintenance and labor) were estimated to be approximately 1.3% of the project capital. This is a lower value than typical because items such as track work and civil work are high capital cost items with little to no maintenance.

Table 4-3 below summarizes the first year fixed O&M costs for the design and typical cases.

Table 4-3: First Year Fixed O&M Costs for Dry FGD, per Unit

First Year[1] Fixed O&M Costs	Units	Design 0.68 lb SO_2/MMBtu
Operating Labor[2]	$/year	$1,660,000
Maintenance Material	$/year	$975,000
Maintenance Labor	$/year	$650,000
Total First Year Fixed O&M Cost	**$/year**	**$3,285,000**

Note 1: First year costs are provided in $2015.

Note 2: Operating labor costs are based on a labor rate of $56.95, which was provided by Entergy.

Note 3: Installation of systems on both units would require 28 operators total. For accounting purposes, this is considered 14 operators per unit.

4.5 SULFUR DESIGN BASIS SENSITIVITY

The average sulfur content of coal received at the White Bluff station is 0.68 lb SO_2/MMBtu; however, the White Bluff station has the ability to receive coal with sulfur content up to 1.2 lb SO_2/MMBtu. In order to provide a system which is capable of meeting the design SO_2 emission rate on a continuous basis through the range of coals delivered to site, the FGD equipment must be designed for the maximum coal sulfur which could be burned in the units.

S&L evaluated the incremental cost impact of designing the FGD system for an inlet sulfur of 1.2 lb SO_2/MMBtu versus a lower inlet sulfur of 0.68 lb SO_2/MMBtu. It is important to note that the majority of the components within the FGD Island are designed to accommodate the maximum volumetric flue gas flowrate from the unit. The size and cost of these components, primarily the absorber vessels, baghouses, and ID fans, remains the same regardless of the inlet design sulfur. In addition, the majority of the BOP scope items which have been included in the capital cost estimate would remain constant regardless of the inlet design sulfur.

The primary equipment which is impacted by the design inlet sulfur would be the reagent handling, reagent preparation, and the waste handling systems. The inlet sulfur has a direct impact on the quantity of SO_2 which is being removed in the FGD system, and therefore a direct impact on the required lime (reagent) consumption rate as well as the quantity of byproduct produced. The following areas and associated equipment are impacted by adjusting the design inlet sulfur:

a. Reagent Storage and Handling System:
   - Two long-term storage silos

b. Reagent Preparation System (FGD Island):
   - Two lime day bins
   - Two detention lime slakers
   - Two lime slurry storage tanks

c. By-product Handling System:
   - Two FGD by-product storage silos

The quantity of byproduct which is recycled through the system to achieve the required performance will remain relatively constant regardless of inlet design sulfur and is therefore not impacted. In addition, the lime slurry and byproduct recycle are continuously circulated in a loop to the units and back to the storage tanks; therefore, a variation in the design sulfur would not significantly impact the sizing of the recycle storage equipment, pumps or piping systems.

The cost differential was determined by vendor quotes who were requested to provide equipment costs for design capacities at each of the design sulfur levels; this is the same approach used to adjust the Alstom budgetary proposal from a design sulfur of 2.0 lb/MMBtu to 1.2 lb/MMBtu for the cost estimate. The following table summarizes the cost differential for the equipment identified above that is impacted by the sulfur design basis:

Equipment	Design Capacity @ 1.2 lb/MMBtu	Design Capacity @ 0.68 lb/MMBtu	Cost Reduction for 1.2 to 0.68 lb/MMBtu[1]
Two long-term storage silos	2,200 tons each	1,200 tons each	- $4,332,000
Two lime day bins	650 tons each	300 tons each	- $272,000

Two detention lime slakers	13 tons/hour each	7 tons/hour each	- $113,000
Two lime slurry storage tanks	2,000 tons each	1,000 tons each	- $373,000
Two FGD by-product storage silos	3,000 tons each	1,750 tons each	- $2,400,000
		TOTAL Differential	**- $7,490,000**

Note 1: Cost Reduction shows the reduction in direct installed capital cost including reductions associated with BOP, i.e. reduced foundation sizes.

The reduction in the total direct installed costs associated with reducing the design sulfur level from 1.2 lb SO_2/MMBtu to 0.68 lb SO_2/MMBtu is approximately $7.5M.

5. SUMMARY

The cost estimate for the White Bluff Units 1&2 Dry FGD systems is based on the addition of two SDA FGD systems for SO_2 removal. The attached capital estimate for the White Bluff Dry FGD system is based on this technical basis.

6. ATTACHMENTS

1. White Bluff DFGD Project Units 1 and 2 Conceptual Capital Cost Estimate, Sargent & Lundy Estimate No. 33387A
2. White Bluff DFGD Project Units 1 and 2 Conceptual Cost Estimate Cash Flow, Sargent & Lundy Estimate No. 33387A
3. White Bluff DFGD Project Units 1 and 2 Level 1 Preliminary Execution Schedule
4. Monthly Progress Payment Schedule for White Bluff DFGD Project
5. S&L Estimating Documentation: Indirects and Construction Equipment included in Crew Rates
6. S&L Estimating Documentation: Escalation Projections
7. White Bluff DFGD Project Units 1 and 2 Conceptual General Arrangement Drawing
8. Entergy Basis of Contingency

ATTACHMENT 1

Conceptual Capital Cost Estimate

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Estimator	A. KOCI
Labor rate table	15ARPBL
Project No.	13027-002
Client	ENTERGY ARKANSAS
Station Name	WHITE BLUFF
Unit	1 & 2
Estimate Date	06/29/2015
Reviewed By	BA
Approved By	MNO
Estimate No.	33387A
Cost index	ARPBL

Project Cost Estimate Totals

Description	Amount	Totals	Hours
Direct Costs:			
Labor	104,382,058		1,309,072
Material	64,284,799		
Subcontract	313,285,100		
Process Equipment	23,517,000		
	505,468,957	**505,468,957**	
Other Direct & Construction Indirect Costs:			
91-1 Scaffolding	7,306,743		
91-2 Cost Due To OT 5-10's	14,545,500		
91-4 Per Diem	13,090,700		
91-5 Consumables	1,043,800		
91-6 Freight on Material	3,214,200		
91-8 Sales Tax	8,928,800		
91-9 Contractors G&A	20,987,700		
91-10 Contractors Profit	10,493,800		
	79,611,243	**585,080,200**	
Indirect Costs:			
93-1 Engineering Services	23,000,000		
93-4 SU/S Parts/ Initial Fills	300,000		
93-5 Technical Field Advisors	600,000		
93-8 EPC Fee	60,898,000		
	84,798,000	**669,878,200**	
Escalation:			
96-1 Escalation on Material	7,632,000		
96-2 Escalation on Labor	23,480,200		
96-3 Escalation on Subcontract	37,428,800		
96-4 Escalation on Process Eq	2,158,600		
96-5 Escalation on Indirects	12,334,500		
	83,034,100	**752,912,300**	
Total EPC Cost		***752,912,300***	
Owner's Costs:			
99-1 Owner's Costs	58,546,000		
	58,546,000	**811,458,300**	
Third Party Services:			
100 CM Oversight	4,969,000		
102 Start-up Oversight	550,000		
103 Owner's Engineer	6,750,000		
104 Performance Testing	275,000		
	12,544,000	**824,002,300**	
Project Contingency :			
110 Project Contingency	111,145,700		
	111,145,700	**935,148,000**	
Escalation Addition:			
120 Escalation on Lines 99-110	2,273,000		
	2,273,000	**937,421,000**	
Interest During Construction:			
130 Interest During Constr.	134,949,000		
	134,949,000	**1,072,370,000**	
Total		***1,072,370,000***	

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Area	Description	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Total Cost
10	FGD ISLAND	297,904,000	(1,649,000)		-7,814	(680,533)	295,574,467
101	FGD ISLAND FOUNDATIONS AND ENCLOSURES			14,838,628	254,893	18,939,033	33,777,661
102	REAGENT HANDLING SYSTEM	6,000,000	2,046,000	3,162,954	59,192	4,646,650	15,855,604
105	BYPRODUCT HANDLING SYSTEM	7,713,100	6,872,000	1,089,675	107,800	7,935,771	23,610,546
111	FLUE GAS SYSTEM		480,000	16,910,288	337,269	29,197,085	46,587,373
121	CIVIL BOP	570,000		8,073,474	106,878	11,535,049	20,178,523
151	MECHANICAL BOP	998,000	1,969,000	6,882,913	115,659	9,189,021	19,038,934
190	DEMOLITION / RELOCATION	100,000		1,578,182	33,735	2,546,302	4,224,484
201	ELECTRICAL BOP SYSTEM		12,299,000	10,665,684	290,576	20,231,688	43,196,372
211	INSTRUMENTATION AND CONTROLS BOP SYSTEM		1,500,000	1,083,000	10,884	841,993	3,424,993
	TOTAL DIRECT	313,285,100	23,517,000	64,284,799	1,309,072	104,382,058	505,468,956

Note: Negative costs included in the cost estimate are due to adjustments to the FGD Budgetary Proposal which was based on a design sulfur of 2.0 lb/MMBTU. Cost adjustments are included to adjust the design sulfur basis to 1.2 lb/MMBTU.

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
10			**FGD ISLAND**									
	23.00.00		**STEEL**									
		23.13.75	**SILO**									
			SILO - LIME DAY BINS 650 TONS - EQUIPMENT ONLY	CREDIT FOR REDUCTION FROM 1200 TONS	-2.00 LS		(273,000)			73.12 /MH		(273,000)
			SILO - LIME DAY BINS 650 TONS - LABOR ONLY	CREDIT FOR REDUCTION FROM 1200 TONS	-2.00 LS				-690	73.12 /MH	(50,428)	(50,428)
			SILO				**(273,000)**		**-690**		**(50,428)**	**(323,428)**
			STEEL				**(273,000)**		**-690**		**(50,428)**	**(323,428)**
	31.00.00		**MECHANICAL EQUIPMENT**									
		31.45.00	**FGD EQUIPMENT**									
			DRY FGD -UNITS 1 & 2 FGD ISLAND - EQUIPMENT	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	152,030,000		-		97.28 /MH		152,030,000
			DRY FGD -UNITS 1 & 2 FGD ISLAND - INSTALLATION COST	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	145,874,000		-		97.28 /MH		145,874,000
			DRY FGD - INLUDES ABSORBERS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES BAGHOUSES	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES REGEANT PREP EQUIPMENT FROM DAY SILOS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES BYPRODUCT RECYCLE PREPARATION EQUIPMENT	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES ID BOOSTER FANS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES PROCESS INSTRUMENTATION AND DCS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES INTERCONNECTING WIRING, PIPING ETC... WITHIN FGD ISLAND	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES DUCTWORK FROM INLET FLANGE TO OUTLET BOOSTER FAN FLANGE	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			FLOW MODEL	INCLUDED WITH ALSTOM PROPOSAL	1.00 LT	-		-		/MH		
			REAGENT PREPARATION - LIME SLURRY FEED TANKS - EQUIPMENT ONLY	REDUCTION IN SIZE TO 2000 TON FROM 3900 TONS BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 LT	-	(1,300,000)	-		90.81 /MH		(1,300,000)
			REAGENT PREPARATION - LIME SLURRY FEED TANKS - LABOR	REDUCTION IN SIZE TO 2000 TON FROM 3900 TONS BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 LT	-		-	-6,370	90.81 /MH	(578,470)	(578,470)
			FGD EQUIPMENT			**297,904,000**	**(1,300,000)**		**-6,370**		**(578,470)**	**296,025,530**
			MECHANICAL EQUIPMENT			**297,904,000**	**(1,300,000)**		**-6,370**		**(578,470)**	**296,025,530**
	33.00.00		**MATERIAL HANDLING EQUIPMENT**									
		33.14.00	**MATERIAL HANDLING EQUIPMENT**									
			MATERIAL HANDLING SYSTEM - LIME SLAKING TRAIN - REDUCTION FROM 25 TPH TO 13 TPH - EQUIPMENT ONLY	CREDIT BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 EA	-	(76,000)	-		68.48 /MH		(76,000)
			MATERIAL HANDLING SYSTEM - LIME SLAKING TRAIN - REDUCTION FROM 25 TPH TO 13 TPH - LABOR ONLY	CREDIT BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 EA	-		-	-754	68.48 /MH	(51,635)	(51,635)
			MATERIAL HANDLING EQUIPMENT				**(76,000)**		**-754**		**(51,635)**	**(127,635)**
			MATERIAL HANDLING EQUIPMENT				**(76,000)**		**-754**		**(51,635)**	**(127,635)**
			10 FGD ISLAND			**297,904,000**	**(1,649,000)**		**-7,814**		**(680,533)**	**295,574,467**
101			**FGD ISLAND FOUNDATIONS AND ENCLOSURES**									
	21.00.00		**CIVIL WORK**									
		21.53.00	**PILING**									
			PILE - 18" AUGER CAST X 60' LONG	UNIT 1 BAGHOUSE FDN	252.00 EA	-	-	480,816	6,662	108.46 /MH	722,568	1,203,384
			PILE - 18" AUGER CAST X 60' LONG	UNIT 2 BAGHOUSE FDN	252.00 EA	-	-	480,816	6,662	108.46 /MH	722,568	1,203,384
			PILING					**961,632**	**13,324**		**1,445,136**	**2,406,768**
		21.54.00	**CAISSON**									
			2.5 FT DIA X 30 FT DEEP CAISSON	ABSORBER TOWERS FOUNDATIONS	180.00 EA	-	-	334,260	4,552	108.46 /MH	493,680	827,940
			2.5 FT DIA X 30 FT DEEP CAISSON	ABSORBER TOWERS FOUNDATIONS	180.00 EA	-	-	334,260	4,552	108.46 /MH	493,680	827,940
			2.5 FT DIA X 30 FT DEEP CAISSON	REAGENT PREP ENCLOSURE 50'X50' SUBSTRUCTURE	50.00 EA	-	-	92,850	1,264	108.46 /MH	137,133	229,983
			2.5 FT DIA X 30 FT DEEP CAISSON	BYPRODUCTS RECYCLE EQUIPMENT BLDG 60' X 60' SUBSTRUCTURE	72.00 EA	-	-	133,704	1,821	108.46 /MH	197,472	331,176
			2.5 FT DIA X 30 FT DEEP CAISSON	UNIT 1 BOOSTER FAN FOUNDATION	40.00 EA	-	-	74,280	1,011	108.46 /MH	109,707	183,987
			2.5 FT DIA X 30 FT DEEP CAISSON	UNIT 2 BOOSTER FAN FOUNDATION	40.00 EA	-	-	74,280	1,011	108.46 /MH	109,707	183,987
			CAISSON					**1,043,634**	**14,211**		**1,541,379**	**2,585,013**

Exhibit B to EAI Comments

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			CIVIL WORK					**2,005,266**	**27,536**		**2,986,515**	**4,991,781**
	22.00.00		**CONCRETE**									
		22.13.00	**CONCRETE**									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	REAGENT PREP ENCLOSURE 50'X50' SUBSTRUCTURE	300.00 CY	-	-	69,000	2,414	59.71 /MH	144,128	213,128
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	BYPRODUCTS RECYCLE EQUIPMENT BLDG 60' X 60' SUBSTRUCTURE	432.00 CY	-	-	99,360	3,476	59.71 /MH	207,544	306,904
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	UNIT 1 BOOSTER FAN FOUNDATION	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	UNIT 2 BOOSTER FAN FOUNDATION	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			CONCRETE FOUNDATIONS - COMPOSITE RATE	ABSORBER TOWER FOUNDATION	1,300.00 CY	-	-	299,000	10,460	59.71 /MH	624,553	923,553
			CONCRETE FOUNDATIONS - COMPOSITE RATE	ABSORBER TOWERS FOUNDATIONS	1,300.00 CY	-	-	299,000	10,460	59.71 /MH	624,553	923,553
			CONCRETE FOUNDATIONS - COMPOSITE RATE	LIME SLURRY FEED TANKS	400.00 CY	-	-	92,000	3,218	59.71 /MH	192,170	284,170
			CONCRETE FOUNDATIONS - COMPOSITE RATE	UNIT 1 BAGHOUSE FDN 3 FDNS 83'X63'X3'	1,743.00 CY	-	-	400,890	14,024	59.71 /MH	837,381	1,238,271
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' UNIT 1 BAGHOUSE AREA, COMPRESSOR BLDG	6.00 CY	-	-	1,380	48	59.71 /MH	2,883	4,263
			CONCRETE FOUNDATIONS - COMPOSITE RATE	UNIT 2 BAGHOUSE FDN 3 FDNS 83'X63'X3'	1,743.00 CY	-	-	400,890	14,024	59.71 /MH	837,381	1,238,271
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' UNIT 2 BAGHOUSE AREA, TRUCK SCALE HOUSE	6.00 CY	-	-	1,380	48	59.71 /MH	2,883	4,263
			CONCRETE					**1,938,900**	**67,828**		**4,049,985**	**5,988,885**
			CONCRETE					**1,938,900**	**67,828**		**4,049,985**	**5,988,885**
	23.00.00		**STEEL**									
		23.17.00	**GALLERY**									
			GALVANIZED GRATING, 1 1/4" DEEP x 3/16" BEARING BAR WITH HOLD DOWN CLIPS	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	4,000.00 SF	-	-	60,000	460	66.07 /MH	30,377	90,377
			GALVANIZED GRATING, 1 1/4" DEEP x 3/16" BEARING BAR WITH HOLD DOWN CLIPS	BYPRODUCTS RECYCLE EQUIPMENT BLDG	5,760.00 SF	-	-	86,400	662	66.07 /MH	43,743	130,143
			3" HEAVY DUTY GRATING	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	200.00 SF	-	-	11,200	39	66.07 /MH	2,582	13,782
			DOUBLE PIPE HANDRAIL WITH POSTS AND GUARD PLATES, PAINTED	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	3,000.00 LF	-	-	159,000	621	66.07 /MH	41,009	200,009
			DOUBLE PIPE HANDRAIL WITH POSTS AND GUARD PLATES, PAINTED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	4,320.00 LF	-	-	228,960	894	66.07 /MH	59,053	288,013
			SELF CLOSING SWING GATE - USER DEFINED	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	40.00 EA	-	-	11,200	184	66.07 /MH	12,151	23,351
			SELF CLOSING SWING GATE - USER DEFINED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	58.00 EA	-	-	16,240	267	66.07 /MH	17,619	33,859
			LADDER	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	800.00 LF	-	-	40,000	368	66.07 /MH	24,302	64,302
			LADDER	BYPRODUCTS RECYCLE EQUIPMENT BLDG	1,100.00 LF	-	-	55,000	506	66.07 /MH	33,415	88,415
			STAIR SYSTEM	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	2,400.00 SF	-	-	218,400	3,172	66.07 /MH	209,601	428,001
			STAIR SYSTEM	BYPRODUCTS RECYCLE EQUIPMENT BLDG	3,500.00 SF	-	-	318,500	4,626	66.07 /MH	305,669	624,169
			GALLERY					**1,204,900**	**11,798**		**779,520**	**1,984,420**
		23.25.00	**ROLLED SHAPE**									
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, TWO COAT PAINT	REAGENT PREP ENCLOSURE 50'X50' GALLERY SUPPORT	200.00 TN	-	-	716,000	5,057	92.62 /MH	468,423	1,184,423
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, TWO COAT PAINT	BYPRODUCTS RECYCLE EQUIPMENT BLDG	288.00 TN	-	-	1,031,040	7,283	92.62 /MH	674,529	1,705,569
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, GALVANIZED	U1 BAGHOUSE SKIRTS STEEL GIRTS	36.00 TN	-	-	138,240	910	92.62 /MH	84,316	222,556
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, GALVANIZED	U2 BAGHOUSE SKIRTS STEEL GIRTS	36.00 TN	-	-	138,240	910	92.62 /MH	84,316	222,556
			BUILDING MIX, TWO COAT PAINTED		50.00 TN	-	-	128,000	920	92.62 /MH	85,168	213,168
			BUILDING MIX, TWO COAT PAINTED		50.00 TN	-	-	128,000	920	92.62 /MH	85,168	213,168
			BUILDING MIX, TWO COAT PAINTED	REAGENT PREP ENCLOSURE SUPERSTRUCTURE	500.00 TN	-	-	1,280,000	9,195	92.62 /MH	851,678	2,131,678
			BUILDING MIX, TWO COAT PAINTED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	720.00 TN	-	-	1,843,200	13,241	92.62 /MH	1,226,417	3,069,617
			ROLLED SHAPE					**5,402,720**	**38,437**		**3,560,015**	**8,962,735**
			STEEL					**6,607,620**	**50,235**		**4,339,534**	**10,947,154**
	24.00.00		**ARCHITECTURAL**									
		24.17.00	**ELEVATOR**									
			PASSENGER, TRACTION, 4 STOPS, 3500LB, 350 FT/MIN	SCHINDLER ELEVATOR BUDGET	1.00 LS	-	-	159,350	943	106.04 /MH	99,946	259,296
			PASSENGER, TRACTION, 4 STOPS, 3500LB, 350 FT/MIN	SCHINDLER ELEVATOR BUDGET	1.00 LS	-	-	159,350	943	106.04 /MH	99,946	259,296

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			ELEVATOR					318,700	1,885		199,892	518,592
		24.35.00	PRE-ENGINEERED BUILDING									
			PRE-ENGINEERED BUILDING	8' X 10' UNIT 1 BAGHOUSE AREA, COMPRESSOR BLDG	1.00 LT	-	-	20,000	115	92.62 /MH	10,646	30,646
			PRE-ENGINEERED BUILDING	8' X 10' UNIT 2 BAGHOUSE AREA, TRUCK SCALE HOUSE	1.00 LT	-	-	10,000	115	92.62 /MH	10,646	20,646
			PRE-ENGINEERED BUILDING					30,000	230		21,292	51,292
		24.37.00	ROOFING									
			METAL, INSULATED, 2 IN GALVANIZED, PAINTED, 22 GA	U1 SDA TOP ENCLOSURE ROOF	3,318.00 SF	-	-	54,946	339	35.02 /MH	11,887	66,833
			METAL, INSULATED, 2 IN GALVANIZED, PAINTED, 22 GA	U2 SDA TOP ENCLOSURE ROOF	3,318.00 SF	-	-	54,946	339	35.02 /MH	11,887	66,833
			METAL, INSULATED- USER DEFINED	REAGENT PREP ENCLOSURE SUPERSTRUCTURE	2,500.00 SF	-	-	19,425	862	35.02 /MH	30,190	49,615
			METAL, INSULATED- USER DEFINED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	3,600.00 SF	-	-	27,972	1,241	35.02 /MH	43,473	71,445
			ROOFING					157,289	2,782		97,436	254,725
		24.41.00	SIDING									
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	U1 SDA TOP ENCLOSURE SIDING	2,450.00 SF	-	-	40,572	251	79.59 /MH	19,948	60,520
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	U2 SDA TOP ENCLOSURE SIDING	2,450.00 SF	-	-	40,572	251	79.59 /MH	19,948	60,520
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	REAGENT PREP ENCLOSURE	10,000.00 SF	-	-	165,600	1,023	79.59 /MH	81,420	247,020
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	14,400.00 SF	-	-	238,464	1,473	79.59 /MH	117,244	355,708
			METAL, UNINSULATED, 24 GA, GALVANIZED CORROGATED	U1 BAGHOUSE SKIRTS 6x(83'+63) x30' tall '	26,260.00 SF	-	-	85,345	1,238	79.59 /MH	98,496	183,841
			METAL, UNINSULATED, 24 GA, GALVANIZED CORROGATED	U2 BAGHOUSE SKIRTS 6x(83'+63) x30' tall '	26,280.00 SF	-	-	85,410	1,238	79.59 /MH	98,571	183,981
			SIDING					655,963	5,473		435,626	1,091,589
		24.99.00	ARCHITECTURAL, MISCELLANEOUS									
			PENTHOUSE HEATING	U1 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	64.10 /MH	4,715	68,715
			PENTHOUSE LIGHTING	U1 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	82.05 /MH	6,036	70,036
			PENTHOUSE FIRE PROTECTION	U1 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	32,000	37	82.05 /MH	3,018	35,018
			PENTHOUSE HEATING	U2 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	64.10 /MH	4,715	68,715
			PENTHOUSE LIGHTING	U2 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	82.05 /MH	6,036	70,036
			PENTHOUSE FIRE PROTECTION	U2 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	32,000	37	82.05 /MH	3,018	35,018
			ARCHITECTURAL, MISCELLANEOUS - USER DEFINED	U1 BAGHOUSE SKIRTS MANDOORS	3.00 EA	-	-	1,500	28	51.10 /MH	1,410	2,910
			ARCHITECTURAL, MISCELLANEOUS - USER DEFINED	U2 BAGHOUSE SKIRTS MANDOORS	3.00 EA	-	-	1,500	28	51.10 /MH	1,410	2,910
			ARCHITECTURAL, MISCELLANEOUS					323,000	423		30,358	353,358
			ARCHITECTURAL					1,484,952	10,794		784,604	2,269,556
	31.00.00		MECHANICAL EQUIPMENT									
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	REAGENT PREP ENCLOSURE 50'X50' FIRE PROTECTION ALLOWANCE	5,000.00 SF	-	-	27,500	385	68.48 /MH	26,369	53,869
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	BYPRODUCTS RECYCLE EQUIPMENT BLDG' FIRE PROTECTION ALLOWANCE	10,800.00 SF	-	-	59,400	832	68.48 /MH	56,956	116,356
			FIRE PROTECTION EQUIPMENT & SYSTEM					86,900	1,217		83,325	170,225
		31.83.00	TANK									
			TANK - MOVE OIL TANK FROM USED OIL SHED AND REINSTALL AT WASTE MANAGEMENT FACILITY	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	1.00 EA	-	-	-	345	90.81 /MH	31,314	31,314
			TANK						345		31,314	31,314
			MECHANICAL EQUIPMENT					86,900	1,562		114,639	201,539
	34.00.00		HVAC									
		34.99.00	HVAC, MISCELLANEOUS									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	REAGENT PREP ENCLOSURE 50'X50' LIGHTING ALLOWANCE	5,000.00 SF	-	-	55,000	57	64.10 /MH	3,684	58,684
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	BYPRODUCTS RECYCLE EQUIPMENT BLDG LIGHTING ALLOWANCE	10,800.00 SF	-	-	118,800	124	64.10 /MH	7,957	126,757
			HVAC, MISCELLANEOUS					173,800	182		11,641	185,441
			HVAC					173,800	182		11,641	185,441
	36.00.00		INSULATION									
		36.13.00	DUCT									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		36.13.00	DUCT									
			MINERAL WOOL INSULATION, 4 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	U1 BAGHOUSE INSUILATION TOP, SIDES AND HOPPERS	141,831.00 SF	-	-	850,986	35,050	68.76 /MH	2,410,051	3,261,037
			MINERAL WOOL INSULATION, 4 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	U2 BAGHOUSE INSULATIOIN - TOPS, SIDES AND HOPPERS	141,831.00 SF	-	-	850,986	35,050	68.76 /MH	2,410,051	3,261,037
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA SHELL INSULATION	40,167.00 SF	-	-	261,086	10,388	68.76 /MH	714,280	975,366
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA ROOF INSULATION	11,019.00 SF	-	-	71,624	2,850	68.76 /MH	195,948	267,572
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA SHELL INSULATION	40,167.00 SF	-	-	261,086	10,388	68.76 /MH	714,280	975,366
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA ROOF INSULATION	11,019.00 SF	-	-	71,624	2,850	68.76 /MH	195,948	267,572
			DUCT					2,367,390	96,576		6,640,559	9,007,949
			INSULATION					2,367,390	96,576		6,640,559	9,007,949
	41.00.00		ELECTRICAL EQUIPMENT									
		41.37.00	LIGHTING ACCESSORY (FIXTURE)									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	REAGENT PREP ENCLOSURE 50'X50' LIGHTING ALLOWANCE	5,000.00 SF	-	-	55,000	57	63.63 /MH	3,657	58,657
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	BYPRODUCTS RECYCLE EQUIPMENT BLDG LIGHTING ALLOWANCE	10,800.00 SF	-	-	118,800	124	63.63 /MH	7,899	126,699
			LIGHTING ACCESSORY (FIXTURE)					173,800	182		11,556	185,356
			ELECTRICAL EQUIPMENT					173,800	182		11,556	185,356
			101 FGD ISLAND FOUNDATIONS AND ENCLOSURES					**14,838,628**	**254,893**		**18,939,033**	**33,777,661**
102			**REAGENT HANDLING SYSTEM**									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			PILE - 18" AUGER CAST X 60' LONG	UNLOADING SHED 200' X 75 WIDE	63.00 EA	-	-	120,204	1,666	108.46 /MH	180,642	300,846
			PILING					120,204	1,666		180,642	300,846
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	SUBSTRUCTURE 2200 TON LIME STORAGE SILOS	100.00 EA	-	-	185,700	2,529	108.46 /MH	274,267	459,967
			CAISSON					185,700	2,529		274,267	459,967
		21.71.00	TRACKWORK									
			RAIL, TIE & BALLAST - 136 LB/YD	REAGENT HANDLING SYSTEM UPGRADE AND EXTEND LIME RAIL TRACK TO AVOID BLOCKING ACCESS BY 150 CAR COAL TRAINS	9,060.00 TF	-	-	1,540,200	15,621	81.27 /MH	1,269,493	2,809,693
			TRACKWORK - EXTEND LIME RAIL SPUR AND RELOCATE SWITCH 2060 FT	RELOCATE COAL TRACK SWITCH TO WEST TO AVOID INTERFERENCE WITH 150 CAR COAL TRAINS	1.00 LS	-	-	374,000	7,989	81.27 /MH	649,226	1,023,226
			TRACKWORK					1,914,200	23,609		1,918,719	3,832,919
			CIVIL WORK					2,220,104	27,803		2,373,628	4,593,732
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	SUBSTRUCTURE 2-2200 TON LIME STORAGE SILOS	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			FOUNDATION, 4500 PSI - COMPOSITE RATE	UNLOADING SHED 200' X 75 WIDE	925.00 CY	-	-	212,750	7,443	59.71 /MH	444,393	657,143
			CONCRETE					350,750	12,270		732,649	1,083,399
			CONCRETE					350,750	12,270		732,649	1,083,399
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA,	UNLOADING SHED 200' X 75 WIDE x15' TALL	15,000.00 SF	-	-	525,000	4,828	92.62 /MH	447,131	972,131
			PRE-ENGINEERED BUILDING					525,000	4,828		447,131	972,131
			ARCHITECTURAL					525,000	4,828		447,131	972,131
	26.00.00		MISCELLANEOUS STRUCTURAL ITEM									
		26.13.00	CONCRETE SILO									
			CONCRETE SILO - 2200 TON LIME STORAGE SILO	ERECTED - 46' DIA X 154' TALL EA - OPTION 2	2.00 LS	6,000,000				59.71 /MH		6,000,000

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		26.13.00	CONCRETE SILO									
			CONCRETE SILO - BIN VENT FILTERS	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - LEVEL INDICATOR	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - VACUUM PRESSURE RELIEF VALVE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - MANHOLE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO			6,000,000			0			6,000,000
			MISCELLANEOUS STRUCTURAL ITEM			6,000,000			0			6,000,000
	31.00.00		MECHANICAL EQUIPMENT									
		31.25.00	CRANES & HOISTS									
			CRANES & HOISTS - & TROLLEYS ALLOWANCE	REAGENT HANDLING SYSTEM	1.00 LT	-	275,000	-		68.48 /MH		275,000
			CRANES & HOISTS				275,000					275,000
			MECHANICAL EQUIPMENT				275,000					275,000
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.14.00	MATERIAL HANDLING EQUIPMENT									
			LIME HANDLING SYSTEM - 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM		1.00 LS	-	500,000	-	3,306	68.48 /MH	226,378	726,378
			LIME HANDLING SYSTEM - VACUUM EXHAUSTER WITH SOUND ENCLOSURES	INCLUDED WITH 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	2.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - RECEIVING PANS UNDER RAIL CARS	INCLUDED WITH 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	1.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - FILTER SEPARATORS ON TOP OF SILO	INCLUDED WITH 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	1.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - 25 TPH PNEUMATIC TRANSPORT SYSTEM		1.00 LS	-	500,000	-	3,306	68.48 /MH	226,378	726,378
			LIME HANDLING SYSTEM - PRESSURE BLOWERS WITH SOUND ENCLOSURES	INCLUDED WITH 25 TPH PNEUMATIC TRANSPORT SYSTEM	3.00 LS	-		-		/MH		
			LIME HANDLING SYSTEM - PRESSURE FEEDERS	INCLUDED WITH 25 TPH PNEUMATIC TRANSPORT SYSTEM	1.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - SPARE PARTS FOR STARTUP AND SPECIAL TOOLS		1.00 LS	-	8,000	-		68.48 /MH		8,000
			LIME HANDLING SYSTEM - FREIGHT		1.00 LS	-	50,000	-		68.48 /MH		50,000
			MATERIAL HANDLING EQUIPMENT				1,058,000		6,611		452,755	1,510,755
		33.41.00	MOBILE YARD EQUIPMENT									
			MOBILE YARD EQUIPMENT - TRACKMOBILE	REAGENT HANDLING SYSTEM	1.00 EA	-	225,000	-		68.48 /MH		225,000
			MOBILE YARD EQUIPMENT				225,000					225,000
		33.51.00	RAIL CAR UNLOADER									
			RAIL CAR UNLOADER -	IN UNLOADING SHED 200'X75' WIDE	1.00 LT	-	225,000	-	3,103	92.62 /MH	287,441	512,441
			RAIL CAR UNLOADER				225,000		3,103		287,441	512,441
			MATERIAL HANDLING EQUIPMENT				1,508,000		9,715		740,197	2,248,197
	34.00.00		HVAC									
		34.99.00	HVAC, MISCELLANEOUS									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	2-2200 TON LIME STORAGE SILOS	3,600.00 SF	-	-	39,600	41	64.10 /MH	2,652	42,252
			HVAC, MISCELLANEOUS					39,600	41		2,652	42,252
			HVAC					39,600	41		2,652	42,252
	35.00.00		PIPING									
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			8 IN DIA, SCH 40, 8" VACUUM CONVEY PIPING WITH 4 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	500.00 LF	-	38,000		540	77.36 /MH	41,792	79,792
			12 IN DIA, 3/8 IN STD- 2500 LF OF 10"/12" TRANSPORT PRESSURE PIPING W 8 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRANSPORT SYSTEM	2,500.00 LF	-	225,000		3,966	77.36 /MH	306,772	531,772
			CARBON STEEL, STRAIGHT RUN				263,000		4,506		348,565	611,565
			PIPING				263,000		4,506		348,565	611,565
	41.00.00		ELECTRICAL EQUIPMENT									
		41.37.00	LIGHTING ACCESSORY (FIXTURE)									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	4200 TON LIME STORAGE SILO	2,500.00 SF	-	-	27,500	29	63.63 /MH	1,828	29,328
			LIGHTING ACCESSORY (FIXTURE)					27,500	29		1,828	29,328
			ELECTRICAL EQUIPMENT					27,500	29		1,828	29,328
			102 REAGENT HANDLING SYSTEM			**6,000,000**	**2,046,000**	**3,162,954**	**59,192**		**4,646,650**	**15,855,604**
105			**BYPRODUCT HANDLING SYSTEM**									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
	21.00.00		CIVIL WORK									
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	ASH SILO AND FGD BYPRODUCT SILOS	125.00 EA	-	-	232,125	3,161	108.46 /MH	342,833	574,958
			CAISSON					232,125	3,161		342,833	574,958
			CIVIL WORK					232,125	3,161		342,833	574,958
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	FGD BYPRODUCT SILOS	614.00 CY	-	-	141,220	4,940	59.71 /MH	294,981	436,201
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	FLY ASH BLENDING SILO	67.00 CY	-	-	15,410	539	59.71 /MH	32,188	47,598
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	FOR TRUCK SCALES	144.00 CY	-	-	33,120	1,159	59.71 /MH	69,181	102,301
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	MISC	100.00 CY	-	-	23,000	805	59.71 /MH	48,043	71,043
			CONCRETE					212,750	7,443		444,393	657,143
			CONCRETE					212,750	7,443		444,393	657,143
	23.00.00		STEEL									
		23.13.75	SILO									
			NEW 250 TON FLYASH BLENDING BIN SILO - 24FT DIA X 72 FT HIGH - ERECTION AND FREIGHT INCLUDED	SILO	1.00 EA		275,000		2,839	73.12 /MH	207,594	482,594
			SILO				275,000		2,839		207,594	482,594
			STEEL				275,000		2,839		207,594	482,594
	26.00.00		MISCELLANEOUS STRUCTURAL ITEM									
		26.13.00	CONCRETE SILO									
			CONCRETE SILO - 3000 TON FGD BYPRODUCT SILO	ERECTED - 52' DIA X 162' TALL EA	2.00 LS	7,600,000				59.71 /MH		7,600,000
			CONCRETE SILO - BIN VENT FILTERS	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - LEVEL INDICATOR	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - VACUUM PRESSURE RELIEF VALVE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - MANHOLE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - SPARE PARTS FOR STARTUP AND SPECIAL TOOLS		1.00 LS	-	10,000			73.12 /MH		10,000
			CONCRETE SILO - FREIGHT		1.00 LS	-	70,000			73.12 /MH		70,000
			CONCRETE SILO			7,600,000	80,000		0			7,680,000
			MISCELLANEOUS STRUCTURAL ITEM			7,600,000	80,000		0			7,680,000
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.13.00	BYPRODUCT HANDLING EQUIPMENT									
			PNEUMATIC ASH CONVEYORS	EQUIPMENT INCLUDES FREIGHT	1.00 LS	-	5,655,000	-		73.12 /MH		5,655,000
			PNEUMATIC ASH CONVEYORS	INSTALLATION COST	1.00 LT	-		-	79,293	73.12 /MH	5,797,912	5,797,912
			BLOWERS, PRESSURE FEEDERS, TRANSPORT PIPING AND VACUUM / PRESSURE RELIEF VALVES	INCLUDED ABOVE	1.00 LT	-		-		73.12 /MH		
			-FOUR PIN MIXERS BELOW CONCRETE SILOS INCL ALL VALVES AND ACCESSORIES		1.00 LT	-	540,000	-	3,347	73.12 /MH	244,742	784,742
			-DRY UNLOADING SPOUT BELOW THE PRODUCT SILO		2.00 EA	-	60,000	-	258	73.12 /MH	18,877	78,877
			AIRSLIDE CONVEYORS FROM BLENDING BIN MIXER/PIPE CONVEYOR, INCL ALL VALVES AND ACCESSORIES		4.00 EA	-	80,000	-	688	73.12 /MH	50,327	130,327
			BYPRODUCT HANDLING EQUIPMENT				6,335,000		83,587		6,111,857	12,446,857
		33.57.00	SCALE									
			SCALE - NEW TRUCK SCALES	BYPRODUCT HANDLING SYSTEM	2.00 EA	-	182,000	-	460	68.48 /MH	31,485	213,485
			SCALE				182,000		460		31,485	213,485
			MATERIAL HANDLING EQUIPMENT				6,517,000		84,046		6,143,342	12,660,342
	34.00.00		HVAC									
		34.37.00	DUST COLLECTOR									
			DUST COLLECTOR - INSTALLED COST		1.00 LS	113,100	-			64.10 /MH		113,100
			DUST COLLECTOR			113,100						113,100
			HVAC			113,100						113,100
	35.00.00		PIPING									
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			12 IN DIA, 3/8 IN STD	CONVEYOR PIPING	5,000.00 LF	-	-	496,000	7,931	77.36 /MH	613,545	1,109,545
			12 IN DIA, 3/8 IN STD	12" TIE IN PIPING TO BYPRODUCT SILO	1,500.00 LF	-	-	148,800	2,379	77.36 /MH	184,063	332,863

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			12 IN DIA, 3/8 IN STD	FROM THE EXISTING 50 TPH FLY ASH PRESSURE SYSTEM	1,500.00 LF	-	-	148,800	2,379	77.36 /MH	184,063	332,863
			CARBON STEEL, STRAIGHT RUN					644,800	10,310		797,608	1,442,408
			PIPING					644,800	10,310		797,608	1,442,408
			105 BYPRODUCT HANDLING SYSTEM			7,713,100	6,872,000	1,089,675	107,800		7,935,771	23,610,546
111			**FLUE GAS SYSTEM**									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			PILE - 18" AUGER CAST X 60' LONG	UNIT 1 FLUE GAS SYSTEM	138.00 EA	-	-	263,304	3,648	108.46 /MH	395,692	658,996
			PILE - 18" AUGER CAST X 60' LONG	UNIT 2 FLUE GAS SYSTEM	138.00 EA	-	-	263,304	3,648	108.46 /MH	395,692	658,996
			PILING					526,608	7,297		791,384	1,317,992
			CIVIL WORK					526,608	7,297		791,384	1,317,992
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	UNIT 1 FLUE GAS SYSTEM	966.00 CY	-	-	222,180	7,772	59.71 /MH	464,091	686,271
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	UNIT 2 FLUE GAS SYSTEM	966.00 CY	-	-	222,180	7,772	59.71 /MH	464,091	686,271
			CONCRETE					444,360	15,545		928,182	1,372,542
			CONCRETE					444,360	15,545		928,182	1,372,542
	23.00.00		STEEL									
		23.15.00	DUCTWORK									
			PANEL CONSTRUCTION, DUCT PLATE WITH STIFFENERS, INTERNAL TRUSSES, AND TURNING VANES	UNIT 1 FLUE GAS SYSTEM - MATERIAL NOT COVERED BY ALSTOM	867.40 TN	-	-	2,819,050	59,821	97.25 /MH	5,817,562	8,636,612
			PANEL CONSTRUCTION, DUCT PLATE WITH STIFFENERS, INTERNAL TRUSSES, AND TURNING VANES	UNIT 2 FLUE GAS SYSTEM - MATERIAL NOT COVERED BY ALSTOM	867.40 TN	-	-	2,819,050	59,821	97.25 /MH	5,817,562	8,636,612
			DUCTWORK					5,638,100	119,641		11,635,124	17,273,224
		23.21.00	GIRDER									
			ROLLED SHAPE GIRDER - USER DEFINED	UNIT 1 FLUE GAS SYSTEM	1,308.00 TN	-	-	3,544,680	45,103	92.62 /MH	4,177,481	7,722,161
			ROLLED SHAPE GIRDER - USER DEFINED	UNIT 2 FLUE GAS SYSTEM	1,308.00 TN	-	-	3,544,680	45,103	92.62 /MH	4,177,481	7,722,161
			GIRDER					7,089,360	90,207		8,354,963	15,444,323
			STEEL					12,727,460	209,848		19,990,087	32,717,547
	27.00.00		PAINTING & COATING									
		27.17.00	PAINTING									
			PAINTING - CHIMNEY	UNIT 1 FLUE GAS SYSTEM	1.00 LT	-	-	110,000	4,109	47.61 /MH	195,639	305,639
			PAINTING					110,000	4,109		195,639	305,639
			PAINTING & COATING					110,000	4,109		195,639	305,639
	31.00.00		MECHANICAL EQUIPMENT									
		31.27.00	DAMPERS & ACCESSORIES									
			DAMPERS & ACCESSORIES - USER DEFINED	UNIT 1 FLUE GAS SYSTEM	800.00 SF	-	240,000		1,471	97.25 /MH	143,080	383,080
			DAMPERS & ACCESSORIES - USER DEFINED	UNIT 2 FLUE GAS SYSTEM	800.00 SF	-	240,000		1,471	97.25 /MH	143,080	383,080
			DAMPERS & ACCESSORIES				480,000		2,943		286,161	766,161
		31.33.00	EXPANSION JOINT									
			EXPANSION JOINT	UNIT 1 FLUE GAS SYSTEM	1,830.00 LF	-		457,500	5,259	97.25 /MH	511,401	968,901
			EXPANSION JOINT	UNIT 2 FLUE GAS SYSTEM	1,830.00 LF	-		457,500	5,259	97.25 /MH	511,401	968,901
			EXPANSION JOINT					915,000	10,517		1,022,802	1,937,802
			MECHANICAL EQUIPMENT				480,000	915,000	13,460		1,308,963	2,703,963
	36.00.00		INSULATION									
		36.13.00	DUCT									
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	UNIT 1 FLUE GAS SYSTEM	168,220.00 SF	-	-	1,093,430	43,505	68.76 /MH	2,991,416	4,084,846
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	UNIT 2 FLUE GAS SYSTEM	168,220.00 SF	-	-	1,093,430	43,505	68.76 /MH	2,991,416	4,084,846
			DUCT					2,186,860	87,010		5,982,831	8,169,691
			INSULATION					2,186,860	87,010		5,982,831	8,169,691

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			111 FLUE GAS SYSTEM				**480,000**	**16,910,288**	**337,269**		**29,197,085**	**46,587,373**
121			**CIVIL BOP**									
	21.00.00		**CIVIL WORK**									
		21.14.00	**STRIP & STOCKPILE TOPSOIL**									
			STRIP & STOCKPILE TOPSOIL - 12"		300,000.00 SF	-	-		690	182.33 /MH	125,745	125,745
			STRIP & STOCKPILE TOPSOIL - ONSITE		40,000.00 CY	-	-		5,287	182.33 /MH	964,044	964,044
			STRIP & STOCKPILE TOPSOIL - 12"	SITE GRADING	600,000.00 SF	-	-		1,379	182.33 /MH	251,490	251,490
			STRIP & STOCKPILE TOPSOIL - ONSITE	SITE GRADING	160,000.00 CY	-	-		21,149	182.33 /MH	3,856,175	3,856,175
			STRIP & STOCKPILE TOPSOIL						**28,506**		**5,197,453**	**5,197,453**
		21.17.00	**EXCAVATION**									
			MASS EXCAVATION, COMMON EARTH USING 1.5 CY BACKHOE AND (6) 12 CY DUMP TRUCKS, 4 MI ROUNDTRIP	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	7,000.00 CY	-	-		523	182.33 /MH	95,356	95,356
			EXCAVATION - EXCAVATION , BACKFILL & COMPACT ALL FOUNDATIONS		12,600.00 CY	-	-		4,345	79.31 /MH	344,588	344,588
			EXCAVATION						**4,868**		**439,945**	**439,945**
		21.19.00	**DISPOSAL**									
			DISPOSAL OF EXCESS MATERIAL USING DUMP TRUCK, 4 MI ROUND TRIP	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	7,000.00 CY	-	-		483	79.31 /MH	38,288	38,288
			DISPOSAL						**483**		**38,288**	**38,288**
		21.20.00	**BACKFILL**									
			FOUNDATION BACKFILL, PREVIOUSLY EXCAVATED MATERIAL	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	1,000.00 CY	-	-		172	79.31 /MH	13,674	13,674
			BACKFILL						**172**		**13,674**	**13,674**
		21.39.00	**STORM DRAINAGE UTILITIES**									
			STORM SEWER WORK	SITE GRADING	1.00 LT	-	-	110,000	2,299	72.14 /MH	165,839	275,839
			STORM DRAINAGE UTILITIES					**110,000**	**2,299**		**165,839**	**275,839**
		21.41.00	**EROSION AND SEDIMENTATION CONTROL**									
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK		33,334.00 SY	-	-	355,007	1,149	97.31 /MH	111,853	466,860
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK	SITE GRADING	66,667.00 SY	-	-	710,004	2,299	97.31 /MH	223,702	933,706
			EROSION AND SEDIMENTATION CONTROL					**1,065,011**	**3,448**		**335,555**	**1,400,566**
		21.57.00	**ROAD, PARKING AREA, & SURFACED AREA**									
			BITUMINOUS ROAD - ROAD UPGRADE	BYPRODUCT HAUL ROAD - EAST OF COAL PILE	10,000.00 LF	-	-	500,000	8,046	78.37 /MH	630,563	1,130,563
			BITUMINOUS ROAD - ELIMINATE CHICANE CURVES AT LOW PRESSURE SERVICE WATER PUMPS		1.00 LT	-	-	500,000		78.37 /MH		500,000
			BITUMINOUS ASPHALT (10,000 - 49,999 SF) ROADWORK 24' WIDE 4" ASPHALT	SITE GRADING	1,668.00 LF	-	-	201,828	2,013	78.37 /MH	157,767	359,595
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW BYPASS LANE (ON WEST SIDE)	9,000.00 LF	-	-	603,000	1,655	78.37 /MH	129,716	732,716
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW LEFT TURN LANE (SOUTH BOUND)	3,000.00 LF	-	-	201,000	552	78.37 /MH	43,239	244,239
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW MERGE LANE (NORTH BOUND)	4,175.00 LF	-	-	279,725	768	78.37 /MH	60,174	339,899
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW RIGHT TURN LANE (NORTH BOUND)	4,000.00 LF	-	-	268,000	736	78.37 /MH	57,651	325,651
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	CONTRACTOR HAUL ROAD (HWY 46 SPUR), UPGRADE, REMOVE EXISTING ASPHALT, SUBGRADE PREP NEW BASE AND NEW ASPHALT	4,250.00 LF	-	-	514,250	3,126	78.37 /MH	245,019	759,269
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	CONTRACTOR HAUL ROAD (HWY 46 SPUR), EXTENSION, 24' WIDE	580.00 LF	-	-	84,100	907	78.37 /MH	71,055	155,155
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	WIDENING OF EXISTING MAIN PLANT ROAD FROM CONTRACTOR HAUL ROAD (HWY 46 SPUR) TO MAIN GUARD HOUSE	2,900.00 LF	-	-	194,300	1,767	78.37 /MH	138,454	332,754
			ROAD, PARKING AREA, & SURFACED AREA					**3,346,203**	**19,569**		**1,533,638**	**4,879,841**
		21.71.00	**TRACKWORK**									
			SIGNAL SYSTEM - RR CROSSING SIGNALS AND GATES	CONTRACTOR HAUL ROAD (HWY 46 SPUR) CROSSING	1.00 LS	220,000	-			/MH		220,000
			TRACKWORK			**220,000**						**220,000**
		21.99.00	**CIVIL WORK, MISCELLANEOUS**									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		21.99.00	**CIVIL WORK, MISCELLANEOUS**									
			CIVIL WORK - CONSTRUCTION LAYDOWN AREAS	FENCING, POWER ETC...	10.00 AC	-	-	780,000	9,195	79.31 /MH	729,287	1,509,287
			CIVIL WORK, MISCELLANEOUS					**780,000**	**9,195**		**729,287**	**1,509,287**
			CIVIL WORK			**220,000**		**5,301,214**	**68,540**		**8,453,679**	**13,974,892**
	22.00.00		**CONCRETE**									
		22.13.00	**CONCRETE**									
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	75.00 CY	-	-	17,250	603	59.71 /MH	36,032	53,282
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	555.00 CY	-	-	127,650	4,466	59.71 /MH	266,636	394,286
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' BYPRODUCT AREA, TRUCK SCALE HOUSE	6.00 CY	-	-	1,380	48	59.71 /MH	2,883	4,263
			CONCRETE FOUNDATIONS	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	1,800.00 CY	-	-	216,000	2,586	59.71 /MH	154,422	370,422
			CONCRETE					**362,280**	**7,703**		**459,973**	**822,253**
		22.15.00	**EMBEDMENT**									
			EMBEDMENTS, CARBON STEEL	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	10,000.00 LB	-	-	30,000	575	51.10 /MH	29,368	59,368
			EMBEDMENT					**30,000**	**575**		**29,368**	**59,368**
		22.17.00	**FORMWORK**									
			BUILT UP INSTALL & STRIP	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	11,000.00 SF	-	-	27,500	2,529	81.61 /MH	206,370	233,870
			FORMWORK					**27,500**	**2,529**		**206,370**	**233,870**
		22.25.00	**REINFORCING**									
			UNCOATED A615 GR60	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	135.00 TN	-	-	138,375	2,793	56.35 /MH	157,391	295,766
			REINFORCING					**138,375**	**2,793**		**157,391**	**295,766**
			CONCRETE					**558,155**	**13,600**		**853,102**	**1,411,257**
	24.00.00		**ARCHITECTURAL**									
		24.35.00	**PRE-ENGINEERED BUILDING**									
			SHELL ONLY, STEEL UNINSULATED 22 GA, 45 FT X 45 FT	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	56,700	791	92.62 /MH	73,298	129,998
			SHELL ONLY, STEEL UNINSULATED 22 GA, 200 FT X 75 FT x 15' TALL	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	420,000	5,862	92.62 /MH	542,945	962,945
			PRE-ENGINEERED BUILDING	8' X 10' BYPRODUCT AREA, TRUCK SCALE HOUSE	1.00 LT	-	-	10,000	115	92.62 /MH	10,646	20,646
			PRE-ENGINEERED BUILDING					**486,700**	**6,768**		**626,888**	**1,113,588**
		24.41.00	**SIDING**									
			INSULATION, 2 IN THICK FIBERGLASS,	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	3,240.00 SF	-	-	3,888	37	79.59 /MH	2,964	6,852
			INSULATION, 2 IN THICK FIBERGLASS,	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	8,250.00 SF	-	-	9,900	95	79.59 /MH	7,547	17,447
			SIDING					**13,788**	**132**		**10,511**	**24,299**
			ARCHITECTURAL					**500,488**	**6,900**		**637,400**	**1,137,888**
	26.00.00		**MISCELLANEOUS STRUCTURAL ITEM**									
		26.99.00	**MISCELLANEOUS STRUCTURAL ITEM, MISCELLANEOUS**									
			MISCELLANEOUS STRUCTURAL ITEM - WATER INTAKE PUMP STRUCTURE - ONE BAY		1.00 LS	-	-	1,110,000	15,537	92.62 /MH	1,439,017	2,549,017
			MISCELLANEOUS STRUCTURAL ITEM, MISCELLANEOUS					**1,110,000**	**15,537**		**1,439,017**	**2,549,017**
			MISCELLANEOUS STRUCTURAL ITEM					**1,110,000**	**15,537**		**1,439,017**	**2,549,017**
	27.00.00		**PAINTING & COATING**									
		27.17.00	**PAINTING**									
			PAINTING - ALLOWANCE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	15,000	172	47.61 /MH	8,209	23,209
			PAINTING					**15,000**	**172**		**8,209**	**23,209**
			PAINTING & COATING					**15,000**	**172**		**8,209**	**23,209**

Exhibit B to EAI Comments

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
	31.00.00		**MECHANICAL EQUIPMENT**									
		31.41.00	**FIRE PROTECTION EQUIPMENT & SYSTEM**									
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	11,138	156	68.48 /MH	10,679	21,817
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	NEW WAREHOUSE BUILDING 200'X75'X15' TALL, FIRE PROTECTION ALLOWANCE	15,000.00 SF	-	-	82,500	1,155	68.48 /MH	79,106	161,606
			FIRE PROTECTION EQUIPMENT & SYSTEM					**93,638**	**1,311**		**89,786**	**183,423**
			MECHANICAL EQUIPMENT					**93,638**	**1,311**		**89,786**	**183,423**
	34.00.00		**HVAC**									
		34.99.00	**HVAC, MISCELLANEOUS**									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	22,275	23	64.10 /MH	1,492	23,767
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	165,000	172	64.10 /MH	11,052	176,052
			HVAC, MISCELLANEOUS					**187,275**	**196**		**12,544**	**199,819**
			HVAC					**187,275**	**196**		**12,544**	**199,819**
	36.00.00		**INSULATION**									
		36.99.00	**INSULATION, MISCELLANEOUS**									
			INSULATION - ROOF INSULATION	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	2,430	23	51.10 /MH	1,189	3,619
			INSULATION - ROOF INSULATION	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	18,000	172	51.10 /MH	8,810	26,810
			INSULATION, MISCELLANEOUS					**20,430**	**196**		**10,000**	**30,430**
			INSULATION					**20,430**	**196**		**10,000**	**30,430**
	41.00.00		**ELECTRICAL EQUIPMENT**									
		41.37.00	**LIGHTING ACCESSORY (FIXTURE)**									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	22,275	23	63.63 /MH	1,481	23,756
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL, LIGHTING ALLOWANCE	15,000.00 SF	-	-	165,000	172	63.63 /MH	10,971	175,971
			LIGHTING ACCESSORY (FIXTURE)					**187,275**	**196**		**12,452**	**199,727**
		41.99.00	**ELECTRICAL EQUIPMENT, MISCELLANEOUS**									
			ELECTRICAL EQUIPMENT, MISCELLANEOUS -	ADD BAY TO EXISTING INTAKE STRUCTURE FOR 3RD PUMP	1.00 LT	-	-	100,000	230	82.05 /MH	18,862	118,862
			ELECTRICAL EQUIPMENT, MISCELLANEOUS					**100,000**	**230**		**18,862**	**118,862**
			ELECTRICAL EQUIPMENT					**287,275**	**426**		**31,314**	**318,589**
	71.00.00		**PROJECT INDIRECT**									
		71.25.00	**CONSULTANT, THIRD PARTY**									
			CONSULTANT - SUBSURFACE INVESTIGATION		1.00 LS	200,000	-			/MH		200,000
			CONSULTANT - GEOTECHNICAL		1.00 LS	150,000	-			/MH		150,000
			CONSULTANT, THIRD PARTY			**350,000**						**350,000**
			PROJECT INDIRECT			**350,000**						**350,000**
			121 CIVIL BOP			**570,000**		**8,073,474**	**106,878**		**11,535,049**	**20,178,523**
151			**MECHANICAL BOP**									
	11.00.00		**DEMOLITION**									
		11.21.00	**CIVIL WORK**									
			CIVIL WORK - DIG AND REFILL PIPE TRENCH	BYPRODUCT PIPE FROM RACK	100.00 LF	-	-		172	79.31 /MH	13,674	13,674
			CIVIL WORK - DIG AND REFILL PIPE TRENCH	REAGENT UNLOADING PIPE FROM RACK	200.00 LF	-	-		345	79.31 /MH	27,348	27,348
			CIVIL WORK						**517**		**41,022**	**41,022**
			DEMOLITION						**517**		**41,022**	**41,022**
	21.00.00		**CIVIL WORK**									
		21.17.00	**EXCAVATION**									
			EXCAVATION - 6" PIPE 4' DEEP PIPE TRENCH & BEDDING		1,430.00 LF	-	-	8,680	526	79.31 /MH	41,715	50,395
			EXCAVATION - 6" PIPE 4' DEEP PIPE TRENCH & BEDDING		750.00 LF	-	-	4,553	276	79.31 /MH	21,879	26,431
			EXCAVATION - 3" PIPE 4' DEEP PIPE TRENCH & BEDDING		3,000.00 LF	-	-	12,750	966	79.31 /MH	76,575	89,325
			EXCAVATION - 3" PIPE 4' DEEP PIPE TRENCH & BEDDING		1,000.00 LF	-	-	4,250	322	79.31 /MH	25,525	29,775
			EXCAVATION - 3" PIPE 4' DEEP PIPE TRENCH & BEDDING		5,260.00 LF	-	-	22,355	1,693	79.31 /MH	134,262	156,617
			EXCAVATION - 8" PIPE 4' DEEP PIPE TRENCH & BEDDING		1,340.00 LF	-	-	9,929	539	79.31 /MH	42,754	52,684

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		21.17.00	**EXCAVATION**									
			EXCAVATION - 36" PIPE 4' DEEP PIPE TRENCH & BEDDING	RIVER WATER PIPE TIE IN	20.00 LF	-	-	733	21	79.31 /MH	1,677	2,411
			EXCAVATION - 32" PIPE 4' DEEP PIPE TRENCH & BEDDING	LPSW PIPE	2,100.00 LS	-	-	60,375	1,859	79.31 /MH	147,407	207,782
			EXCAVATION - 10" PIPE 4' DEEP PIPE TRENCH & BEDDING	RECYCLE ASH WATER PIPE DISCHARGE BURIED	1,800.00 LF	-	-	15,930	786	79.31 /MH	62,354	78,284
			EXCAVATION - 4" PIPE 4' DEEP PIPE TRENCH & BEDDING	LEACHATE PIPING	3,500.00 LF	-	-	16,905	1,167	79.31 /MH	92,528	109,433
			EXCAVATION					**156,460**	**8,154**		**646,677**	**803,138**
		21.54.00	**CAISSON**									
			2.5 FT DIA X 30 FT DEEP CAISSON	TANK FOUNDATIONS	76.00 EA	-	-	141,132	1,922	108.46 /MH	208,443	349,575
			2.5 FT DIA X 30 FT DEEP CAISSON	COMMON PIPE RACK FOUNDATIONS	186.00 EA	-	-	345,402	4,703	108.46 /MH	510,136	855,538
			2.5 FT DIA X 30 FT DEEP CAISSON	BYPRODUCT PIPE RACK FOUNDATIONS	94.00 EA	-	-	174,558	2,377	108.46 /MH	257,811	432,369
			2.5 FT DIA X 30 FT DEEP CAISSON	REAGENT UNLOADING PIPE RACK FOUNDATIONS	16.00 EA	-	-	29,712	405	108.46 /MH	43,883	73,595
			CAISSON					**690,804**	**9,407**		**1,020,272**	**1,711,076**
			CIVIL WORK					**847,264**	**17,561**		**1,666,949**	**2,514,214**
	22.00.00		**CONCRETE**									
		22.13.00	**CONCRETE**									
			SPREAD FOOTING FOUNDATION, 4500 PSI - COMPOSITE RATE	3X 35' DIA TANK FDN	81.00 CY	-	-	18,630	652	59.71 /MH	38,914	57,544
			CONCRETE FOUNDATIONS - COMPOSITE RATE	COMMON PIPE RACK FOUNDATIONS	207.00 CY	-	-	47,610	1,666	59.71 /MH	99,448	147,058
			CONCRETE FOUNDATIONS - COMPOSITE RATE	BYPRODUCT PIPE RACK FOUNDATIONS	105.00 CY	-	-	24,150	845	59.71 /MH	50,445	74,595
			CONCRETE FOUNDATIONS - COMPOSITE RATE	REAGENT UNLOADING PIPE RACK FOUNDATIONS	18.00 CY	-	-	4,140	145	59.71 /MH	8,648	12,788
			CONCRETE					**94,530**	**3,307**		**197,455**	**291,985**
			CONCRETE					**94,530**	**3,307**		**197,455**	**291,985**
	23.00.00		**STEEL**									
		23.21.00	**GIRDER**									
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	COMMON 500'LX20'W, 400'Lx15'W,400'Lx9'W, ALL 20' HIGH	196.00 TN	-	-	531,160	3,830	92.62 /MH	354,724	885,884
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	BYPRODUCT PIPE RACK, 650LF X6 WIDE X 20' HIGH	39.00 TN	-	-	105,690	762	92.62 /MH	70,583	176,273
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	REAGENT UNLOADING PIPE RACK, 100LF X 6' WIDE X 20' HIGH	6.00 TN	-	-	16,260	117	92.62 /MH	10,859	27,119
			GIRDER					**653,110**	**4,709**		**436,166**	**1,089,276**
			STEEL					**653,110**	**4,709**		**436,166**	**1,089,276**
	27.00.00		**PAINTING & COATING**									
		27.13.00	**COATING**									
			COATING - CHIMNEY - ACID RESISTANT COATING TOP 100 FT OUTSIDE SHELL		1.00 LS	270,000	-			47.61 /MH		270,000
			COATING			**270,000**						**270,000**
			PAINTING & COATING			**270,000**						**270,000**
	31.00.00		**MECHANICAL EQUIPMENT**									
		31.17.00	**COMPRESSOR & ACCESSORIES**									
			AIR COMPRESSOR, CENTRIFUGAL - 250 SCFM EA @ 200 PSIG	SERVICE AIR	2.00 EA	-	310,000	-	92	68.48 /MH	6,297	316,297
			AIR COMPRESSOR, CENTRIFUGAL - 250 SCFM EA @ 200 PSIG	INSTRUMENT AIR	2.00 EA	-	310,000	-	92	68.48 /MH	6,297	316,297
			AIR DRYER - W/FILTERS, 250 NET SCFM EA	SERVICE AIR	2.00 EA	-	33,400	-	74	68.48 /MH	5,038	38,438
			AIR DRYER - W/FILTERS, 250 NET SCFM EA	INSTRUMENT AIR	2.00 EA	-	33,400	-	74	68.48 /MH	5,038	38,438
			AIR RECEIVER - 1,000 GALLON EA	SERVICE AIR	2.00 EA	-	11,200	-	37	68.48 /MH	2,519	13,719
			AIR RECEIVER - 1,000 GALLON EA	INSTRUMENT AIR	2.00 EA	-	11,200	-	37	68.48 /MH	2,519	13,719
			COMPRESSOR & ACCESSORIES				**709,200**		**405**		**27,707**	**736,907**
		31.41.00	**FIRE PROTECTION EQUIPMENT & SYSTEM**									
			DELUGE - POWER TRANSFORMERS		3.00 EA	-	-	127,500	1,959	77.36 /MH	151,519	279,019
			FIRE PROTECTION EQUIPMENT & SYSTEM					**127,500**	**1,959**		**151,519**	**279,019**
		31.65.00	**HEAT EXCHANGER**									
			HEAT EXCHANGER - SLAKER WATER HEATER 3" IN-LINE, 475 KW		4.00 EA	-	220,000	-	368	63.63 /MH	23,404	243,404
			HEAT EXCHANGER				**220,000**		**368**		**23,404**	**243,404**

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		31.75.00	**PUMP**									
			CENTRIFUGAL, HORIZONTAL, SINGLE STAGE - MAKEUP WATER PUMPS, 2600 GPM, 200 TDH		2.00 EA	-	96,000	-	577	68.48 /MH	39,514	135,514
			CENTRIFUGAL, HORIZONTAL, SINGLE STAGE - RECYCLE ASH WATER PUMP, 50 HP		3.00 EA	-	72,000	-	221	68.48 /MH	15,113	87,113
			CENTRIFUGAL, HORIZONTAL, SINGLE STAGE - LIME SLAKING WATER PIUMPS, 50 HP		2.00 EA	-	48,000	-	147	68.48 /MH	10,075	58,075
			CENTRIFUGAL, VERTICAL, CANNED - LEACHATE PUMPS, 50 HP		2.00 EA	-	134,000	-	828	68.48 /MH	56,673	190,673
			CENTRIFUGAL, VERTICAL, WET PIT - LPSW PUMP, 650 HP		1.00 EA	-	188,000	-	690	68.48 /MH	47,228	235,228
			SUMP, CENTRIFUGAL, WET BEARING - REGENT PREP/RECYCLE SUMP, 120GPM, 150 TDH		4.00 EA	-	220,000	-	276	68.48 /MH	18,891	238,891
			SUMP, CENTRIFUGAL, WET BEARING - LIME SILO & UNLOADING AREA SUMP 120 GPM @ 150 TDH		2.00 EA	-	88,000	-	138	68.48 /MH	9,446	97,446
			SUMP, CENTRIFUGAL, WET BEARING - WASTE ASH SILO AREA SUMP 120GPM @150 TDH		2.00 EA	-	88,000	-	138	68.48 /MH	9,446	97,446
			SUMP, CENTRIFUGAL, WET BEARING - WASTEWATER FORWARDING PUMP TO RECYCLED SLURRY, 100 GPM@150 TDH		4.00 EA	-	28,800	-	294	68.48 /MH	20,150	48,950
			SUMP, SUBMERSIBLE - RECYCLE ASH WATER TANK SUPPLY PUMP, 100 HP		2.00 EA	-	77,000	-	690	68.48 /MH	47,228	124,228
			PUMP				**1,039,800**		**3,998**		**273,763**	**1,313,563**
		31.83.00	**TANK**									
			ATMOSPHERIC, FIELD FABRICATED - LIME SLAKING WATER TANK, 175,000 GALLON	35' DIA X 24' HIGH	1.00 EA	220,000		-		90.81 /MH		220,000
			ATMOSPHERIC, FIELD FABRICATED - RECYCLE ASH WATER TANK, 250,000 GALLON	35' DIA X 36' HIGH	2.00 EA	508,000		-		90.81 /MH		508,000
			TANK			**728,000**						**728,000**
			MECHANICAL EQUIPMENT			**728,000**	**1,969,000**	**127,500**	**6,729**		**476,392**	**3,300,892**
	35.00.00		**PIPING**									
		35.13.01	**SS 304, ABOVE GROUND, PROCESS AREA**									
			1 IN DIA, SCH 40S		1,520.00 LF	-	-	32,832	1,974	77.36 /MH	152,728	185,560
			1.5 IN DIA, SCH 40S		1,380.00 LF	-	-	52,302	2,094	77.36 /MH	161,976	214,278
			2 IN DIA, SCH 40S		2,070.00 LF	-	-	113,022	3,426	77.36 /MH	265,051	378,073
			SS 304, ABOVE GROUND, PROCESS AREA					**198,156**	**7,494**		**579,755**	**777,911**
		35.13.10	**CARBON STEEL, ABOVE GROUND, PROCESS AREA**									
			1 IN DIA, SCH 80		260.00 LF	-	-	2,314	305	77.36 /MH	23,581	25,895
			2 IN DIA, SCH 80		2,260.00 LF	-	-	48,138	3,273	77.36 /MH	253,207	301,345
			2.5 IN DIA, SCH 40		1,000.00 LF	-	-	15,400	1,437	77.36 /MH	111,149	126,549
			3 IN DIA, SCH 40		7,160.00 LF	-	-	125,300	11,028	77.36 /MH	853,130	978,430
			3 IN DIA, SCH 80		1,760.00 LF	-	-	38,720	3,055	77.36 /MH	236,313	275,033
			4 IN DIA, SCH 40		1,000.00 LF	-	-	22,600	1,701	77.36 /MH	131,601	154,201
			6 IN DIA, SCH 40		880.00 LF	-	-	28,248	1,629	77.36 /MH	125,981	154,229
			6 IN DIA, SCH 40 VACUUM PIPE		2,260.00 LF	-	-	72,546	4,182	77.36 /MH	323,543	396,089
			8 IN DIA, SCH 80		3,520.00 LF	-	-	256,608	9,832	77.36 /MH	760,582	1,017,190
			CARBON STEEL, ABOVE GROUND, PROCESS AREA					**609,874**	**36,441**		**2,819,087**	**3,428,961**
		35.13.36	**DUCTILE IRON, ABOVE GROUND, PROCESS AREA**									
			12 IN DIA, - ASHCOLITE PIPE		1,620.00 LF	-	-	162,000	3,594	72.14 /MH	259,256	421,256
			DUCTILE IRON, ABOVE GROUND, PROCESS AREA					**162,000**	**3,594**		**259,256**	**421,256**
		35.14.10	**CARBON STEEL, STRAIGHT RUN**									
			6 IN DIA, SCH 40, LIME SLAKING TANK MAKEUP	LIME SLAKING TANK MAKEUP	1,200.00 LF	-	-	27,480	1,214	77.36 /MH	93,899	121,379
			8 IN DIA, SCH 40, LIME SLAKING TANK MAKEUP	LIME SLAKING TANK MAKEUP	450.00 LF	-	-	13,905	486	77.36 /MH	37,613	51,518
			8 IN DIA, SCH 40, RECYCLE ASH WATER PIPING	RECYCLE ASH WATER PIPING	2,000.00 LF	-	-	61,800	2,161	77.36 /MH	167,169	228,969
			10 IN DIA, SCH 40, RECYCLE ASH TANK MAKEUP	RECYCLE ASH TANK MAKEUP	450.00 LF	-	-	24,660	610	77.36 /MH	47,216	71,876
			CARBON STEEL, STRAIGHT RUN					**127,845**	**4,471**		**345,897**	**473,742**
		35.15.10	**CARBON STEEL, BURIED**									
			3 IN DIA, SCH 40, WRAPPED		3,000.00 LF	-	-	51,000	2,241	77.36 /MH	173,393	224,393
			4 IN DIA, SCH 40, WRAPPED, LEACHATE PIPING	LEACHATE PIPING	3,500.00 LF	-	-	72,800	2,856	77.36 /MH	220,965	293,765
			6 IN DIA, SCH 40, WRAPPED		750.00 LF	-	-	23,925	776	77.36 /MH	60,021	83,946
			10 IN DIA, SCH 40, WRAPPED, RECYCLE ASH WATER PIPE DISCHARGE BURIED	RECYCLE ASH WATER PIPE DISCHARGE BURIED	4,800.00 LF	-	-	119,700	2,441	77.36 /MH	188,865	308,565

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		35.15.10	**CARBON STEEL, BURIED**									
			32 IN DIA, 3/8 IN STD, WRAPPED - LPSW PIPE	LPSW PIPE	2,100.00 LF	-	-	638,610	11,079	77.36 /MH	857,095	1,495,705
			36 IN DIA, 3/8 IN STD, WRAPPED - RIVER WATER PIPE	RIVER WATER PIPE - TIE IN	20.00 LF	-	-	6,772	138	77.36 /MH	10,706	17,478
			CARBON STEEL, BURIED					**912,807**	**19,533**		**1,511,045**	**2,423,852**
		35.15.25	**FRP, BURIED**									
			3 IN DIA, TAPER		1,000.00 LF	-	-	14,800	460	77.36 /MH	35,568	50,368
			3 IN DIA, TAPER FRP/HDPE PIPE		2,380.00 LF	-	-	35,224	1,094	77.36 /MH	84,651	119,875
			FRP, BURIED					**50,024**	**1,554**		**120,219**	**170,243**
		35.15.30	**HDPE, BURIED**									
			6 IN DIA, DR 9		1,430.00 LF	-	-	12,870	1,134	77.36 /MH	87,737	100,607
			8 IN DIA, DR 9		1,340.00 LF	-	-	20,770	1,278	77.36 /MH	98,896	119,666
			HDPE, BURIED					**33,640**	**2,413**		**186,633**	**220,273**
		35.36.00	**PIPE SUPPORTS, RACK**									
			SUPPORT SLEEPERS	BYPRODUCT PIPE, 1750LF	125.00 EA	-	-	43,750	575	77.36 /MH	44,460	88,210
			SUPPORT SLEEPERS	REAGENT UNLOADING PIPE, 1500LF	108.00 EA	-	-	37,800	497	77.36 /MH	38,413	76,213
			PIPE SUPPORTS, RACK					**81,550**	**1,071**		**82,873**	**164,423**
		35.45.00	**VALVES**									
			VALVE - 36" 150 LB CS BUTTERFLY, FLANGED		2.00 EA	-	-	79,920	96	77.36 /MH	7,398	87,318
			VALVE - 12" 150 LB CS KNIFE GATE, FLANGED		6.00 EA	-	-	20,160	195	77.36 /MH	15,099	35,259
			VALVE - 12" 150 LB CS GATE VALVE, FLANGED		2.00 EA	-	-	8,920	65	77.36 /MH	5,033	13,953
			VALVE - 10" 150 LB CS SWING CHECK, FLANGED		2.00 EA	-	-	9,200	55	77.36 /MH	4,268	13,468
			VALVE - 10" 150 LB CS BUTTERFLY, FLANGED		5.00 EA	-	-	22,200	138	77.36 /MH	10,670	32,870
			VALVE - 8" 150 LB CS GATE, FLANGED		20.00 EA	-	-	100,000	425	77.36 /MH	32,900	132,900
			VALVE - 6" 150 LB CS GATE, FLANGED		6.00 EA	-	-	19,800	110	77.36 /MH	8,536	28,336
			VALVE - 6" 150 LB CS AIR OPERATED GATE, FLANGED		4.00 EA	-	-	20,400	74	77.36 /MH	5,691	26,091
			VALVE - 6" 150 LB CS AIR OPERATED GLOBE, FLANGED		4.00 EA	-	-	20,400	74	77.36 /MH	5,691	26,091
			VALVE - 6" 150 LB CS SWING CHECK, FLANGED		2.00 EA	-	-	3,400	37	77.36 /MH	2,845	6,245
			VALVE - 4" 150 LB CS GATE, FLANGED		3.00 EA	-	-	3,825	25	77.36 /MH	1,921	5,746
			VALVE - 3" AND BELOW CS FOR SERVICE WATER ISOLATION		120.00 EA	-	-	1,224,000	1,076	77.36 /MH	83,229	1,307,229
			VALVE - 3" AND BELOW CS FOR SERVICE AIR ISOLATION		120.00 EA	-	-	1,224,000	1,076	77.36 /MH	83,229	1,307,229
			VALVE - 3" 150 LB CS GATE, FLANGED		20.00 EA	-	-	15,000	179	77.36 /MH	13,871	28,871
			VALVE - 3" CS PST IND FOR FP 250 LB		6.00 EA	-	-	6,600	54	77.36 /MH	4,161	10,761
			VALVE - 2" AND ABOVE BRONZE VALVES FOR INSTRUMENT AIR ISOLATION		600.00 EA	-	-	78,000	501	77.36 /MH	38,787	116,787
			VALVE - 1" CS FLANGED		4.00 EA	-	-	880	21	77.36 /MH	1,636	2,516
			VALVE - 6" CI POST INDICATOR 250 LB., MECHANICAL JOINT WITH BOXES BURIED VALVE		6.00 EA	-	-	4,080	28	77.36 /MH	2,134	6,214
			VALVES					**2,860,785**	**4,228**		**327,099**	**3,187,884**
			PIPING					**5,036,681**	**80,799**		**6,231,866**	**11,268,547**
	36.00.00		**INSULATION**									
		36.17.01	**PIPE, CALCIUM SILICATE W/ALUMINUM JACKETING**									
			CALCIUM SILICATE W/ALUMINUM JACKETING - 8" PIPE 1.5" THICK		2,520.00 LF	-	-	16,380	487	68.76 /MH	33,460	49,840
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 3" PIPE		1,260.00 LF	-	-	3,591	155	68.76 /MH	10,655	14,246
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 3" PIPE		5,660.00 LF	-	-	16,131	696	68.76 /MH	47,865	63,996
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 2.5" PIPE		380.00 LS	-	-	1,083	47	68.76 /MH	3,214	4,297
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 2.0" PIPE		4,140.00 LS	-	-	10,309	476	68.76 /MH	32,720	43,029
			PIPE, CALCIUM SILICATE W/ALUMINUM JACKETING					**47,494**	**1,860**		**127,914**	**175,408**
			INSULATION					**47,494**	**1,860**		**127,914**	**175,408**
	41.00.00		**ELECTRICAL EQUIPMENT**									
		41.33.00	**HEAT TRACING**									
			HEAT TRACING - 8" PIPE		2,520.00 LS	-	-	18,749	43	63.63 /MH	2,765	21,513
			HEAT TRACING - 3" PIPE		1,260.00 LF	-	-	9,374	22	63.63 /MH	1,382	10,757
			HEAT TRACING - 3" PIPE		5,660.00 LF	-	-	42,110	98	63.63 /MH	6,209	48,320
			HEAT TRACING - 2.5" PIPE		380.00 LS	-	-	2,827	7	63.63 /MH	417	3,244
			HEAT TRACING - 2.0" PIPE		440.00 LS	-	-	3,274	8	63.63 /MH	483	3,756
			HEAT TRACING					**76,334**	**177**		**11,256**	**87,590**
			ELECTRICAL EQUIPMENT					**76,334**	**177**		**11,256**	**87,590**

Exhibit B to EAI Comments

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			151 MECHANICAL BOP			**998,000**	**1,969,000**	**6,882,913**	**115,659**		**9,189,021**	**19,038,934**
190			**DEMOLITION / RELOCATION**									
	11.00.00		DEMOLITION									
		11.21.00	CIVIL WORK									
			CIVIL WORK - REMOVE FENCING & GATES	HAZARDOUS MATERIAL ACCUMULATION BLDG	1,133.00 LF	-	-		91	107.10 /MH	9,763	9,763
			CIVIL WORK - DIG AND REFILL PIPE TRENCH	TRENCH N.1784.33 FROM E905' TO 1180'	550.00 LF	-	-		948	79.31 /MH	75,208	75,208
			CIVIL WORK - REMOVE DRAINAGE DITCH	DRAINAGE DITCH E970 FROM N2055 'TO N1350'	705.00 LF	-	-		1,216	79.31 /MH	96,403	96,403
			CIVIL WORK - REMOVE DRAINAGE DITCH	DRAINAGE DITCH e1350 from n970' to n1180'	210.00 LF	-	-		362	79.31 /MH	28,716	28,716
			CIVIL WORK - DEMO AREA PAVEMENT	ASH HANDLING / ELECT BLDG	1.00 LS	-	-		115	107.10 /MH	12,310	12,310
			CIVIL WORK						2,732		222,400	222,400
		11.22.00	CONCRETE									
			CONCRETE FOUNDATION - HAZARDOUS MATERIAL ACCUMULATION BLDG	HAZARDOUS MATERIAL ACCUMULATION BLDG, 50'X50'X20'	80.00 CY	-	-		230	107.10 /MH	24,621	24,621
			CONCRETE FOUNDATION - HAZARDOUS MATERIAL ACCUMULATION BLDG	HAZARDOUS MATERIAL ACCUMULATION BLDG, HAZMAT PAVEMENT DEMO	12.00 CY	-	-		61	107.10 /MH	6,574	6,574
			CONCRETE FOUNDATION - ASH HANDLING MAINT BLDG	ASH HANDLING / ELECT BLDG FDN	225.00 CY	-	-		647	107.10 /MH	69,246	69,246
			CONCRETE FOUNDATION - PAVING & FOUNDATION DEMO	FLOURESCENT LIGHT TUBE DISPOSAL SHED FDN	2.00 CY	-	-		10	107.10 /MH	1,096	1,096
			CONCRETE FOUNDATION - PAVING & FOUNDATION DEMO	USED OIL SHED DEMO	35.00 CY	-	-		101	107.10 /MH	10,772	10,772
			CONCRETE						1,049		112,307	112,307
		11.23.00	STEEL									
			STRUCTURAL STEEL DISASSEMBLE BLDG STEEL & TOOL CRIB FOR RELOCATION	ASH HANDLING / ELECT BLDG	52.00 TN	-	-		359	107.10 /MH	38,408	38,408
			STEEL						359		38,408	38,408
		11.24.00	ARCHITECTURAL									
			ARCHITECTURAL - HAZARDOUS MATERIAL ACCUMULATION BLDG 50'X50'X20'	HAZARDOUS MATERIAL ACCUMULATION BLDG, 50'X50'X20'	50,000.00 CF	-	-		632	107.10 /MH	67,707	67,707
			ARCHITECTURAL - HAZARDOUS MATERIAL ACCUMULATION BLDG 50'X50'X20'	HAZARDOUS MATERIAL ACCUMULATION BLDG, CONTAINER DISPOSAL AREA	1.00 LT	-	-		287	107.10 /MH	30,776	30,776
			ARCHITECTURAL - DEMO EXISTING INSULATED SIDING & ROOFING , DEMO INTERIOR OFFICES	ASH HANDLING / ELECT BLDG	15,000.00 CF	-	-		862	107.10 /MH	92,328	92,328
			ARCHITECTURAL - BLDG DEMO	COAL DUMPER AIR COMPRESSOR DEMOLITION	100.00 SF	-	-		11	107.10 /MH	1,231	1,231
			ARCHITECTURAL - BLDG DEMO	USED OIL SHED DEMO	600.00 SF	-	-		8	107.10 /MH	812	812
			ARCHITECTURAL						1,801		192,854	192,854
		11.31.00	MECHANICAL EQUIPMENT									
			MECHANICAL EQUIPMENT - DEMOLISH SEPTIC TANKS	ASH HANDLING / ELECT BLDG	2.00 EA	-	-		0	107.10 /MH	25	25
			MECHANICAL EQUIPMENT - REMOVE 15 TN BRIDGE CRANE (50 FT SPAN) , CRANE SUPPORT STEEL AND 3 JIB CRANES FGOR RELOCATION	ASH HANDLING / ELECT BLDG	21.00 TN	-	-		290	92.62 /MH	26,828	26,828
			MECHANICAL EQUIPMENT						290		26,852	26,852
		11.35.00	PIPING									
			PIPING - REMOVE 12" BA PIPE IN PIPE TRENCH	TRENCH N.1784.33 FROM E905' TO 1180'	550.00 LF	-	-		87	107.10 /MH	9,276	9,276
			PIPING - REMOVE 10" FA PIPE	TRENCH N.1784.33 FROM E905' TO 1180'	550.00 LF	-	-		76	107.10 /MH	8,125	8,125
			PIPING						162		17,401	17,401
		11.99.00	DEMOLITION, MISCELLANEOUS									
			DEMOLITION - MISC	ALLOWANCE	1.00 LT	-	-		2,299	92.62 /MH	212,920	212,920
			DEMOLITION, MISCELLANEOUS						2,299		212,920	212,920
			DEMOLITION						8,691		823,142	823,142
	21.00.00		CIVIL WORK									
		21.16.00	GENERAL EARTHWORK									
			EARTHWORK - COVER AREA WITH BACKFILL AND GRADE	HAZARDOUS MATERIAL ACCUMULATION BLDG	300.00 CY	-	-	4,800	138	182.33 /MH	25,149	29,949
			EARTHWORK - COVER AREA WITH BACKFILL AND GRADE	ASH HANDLING / ELECT BLDG	1,000.00 CY	-	-	16,000	460	182.33 /MH	83,830	99,830
			EARTHWORK - COVER AREA WITH BACKFILL AND GRADE 250'X250'X2'	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG) AREA FILL	5,000.00 CY	-	-	80,000	259	182.33 /MH	47,154	127,154
			GENERAL EARTHWORK					100,800	856		156,133	256,933

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		21.17.00	EXCAVATION									
			EXCAVATION - ALLOWANCE FOR NEW DITCHES	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG) AREA FILL	1,200.00 CY	-	-		276	79.31 /MH	21,879	21,879
			EXCAVATION						276		21,879	21,879
		21.20.00	BACKFILL									
			FOUNDATION BACKFILL, PREVIOUSLY EXCAVATED MATERIAL, ALLOWANCE FOR OLD DITCHES	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG) AREA FILL	100.00 CY	-	-		17	79.31 /MH	1,367	1,367
			BACKFILL						17		1,367	1,367
		21.21.00	MASS FILL									
			MASS FILL, COMMON EARTH USING DUMP TRUCK, 2 MI ROUND TRIP, ALLWANCE FOR MISC ADDITIONAL FILL	RELOCATED BLDGS	1.00 LT	-	-	30,000	345	79.31 /MH	27,348	57,348
			MASS FILL					30,000	345		27,348	57,348
		21.39.00	STORM DRAINAGE UTILITIES									
			EXTEND CULVERTS UNDER ROAD	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG) AREA FILL	48.00 LF	-	-	4,800	166	79.31 /MH	13,127	17,927
			STORM DRAINAGE UTILITIES					4,800	166		13,127	17,927
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			EROSION AND SEDIMENTATION CONTROL - ALLOWANCE	RELOCATED BLDGS	1.00 LS	-	-	20,000	345	36.12 /MH	12,455	32,455
			EROSION AND SEDIMENTATION CONTROL					20,000	345		12,455	32,455
		21.43.00	FENCEWORK									
			FABRIC, WIRE & POSTS, CHAIN LINK FENCE, GALVANIZED, 6 FT TALL, 6 GAGE 3 STRANDS OF BARB WIRE, 2 IN POST AT 10 FT O.C.	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	800.00 FT	-	-	18,880	92	36.12 /MH	3,321	22,201
			VEHICLE GATE, 14 FT WIDE BY 7 FT TALL	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	4.00 EA	-	-	4,000	110	36.12 /MH	3,986	7,986
			FENCEWORK					22,880	202		7,307	30,187
		21.47.00	LANDSCAPING									
			LANDSCAPING - ALLOWANCE FOR PAVING GRADING & SEEDING	RELOCATED BLDGS	1.00 LS	-	-	40,000	460	36.12 /MH	16,607	56,607
			LANDSCAPING					40,000	460		16,607	56,607
		21.57.00	ROAD, PARKING AREA, & SURFACED AREA									
			BITUMINOUS ASPHALT (10,000 - 49,999 SF) ASHPALT PAVING FOR TRUCK TURNAROUND , DRIVEWAY AND AROUND BLDG	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	43,000.00 SF	-	-	216,720	1,236	78.37 /MH	96,836	313,556
			ROAD, PARKING AREA, & SURFACED AREA					216,720	1,236		96,836	313,556
			CIVIL WORK					435,200	3,902		353,060	788,260
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	320.00 CY	-	-	73,600	2,575	59.71 /MH	153,736	227,336
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)- CONTAINER DISPOSAL SLAB & APRON	550.00 CY	-	-	126,500	4,425	59.71 /MH	264,234	390,734
			CONCRETE FOUNDATIONS - COMPOSITE RATE	ACI PORT STAIRTOWER FDNS	60.00 CY	-	-	13,800	483	59.71 /MH	28,826	42,626
			CONCRETE					213,900	7,483		446,796	660,696
			CONCRETE					213,900	7,483		446,796	660,696
	23.00.00		STEEL									
		23.17.00	GALLERY									
			GALVANIZED GRATING, 1 1/4" DEEP x 3/16" BEARING BAR WITH HOLD DOWN CLIPS	ACI PORT STAIR TOWERS AND PLATFORMS	728.00 SF	-	-	10,920	84	66.07 /MH	5,529	16,449
			DOUBLE PIPE HANDRAIL WITH POSTS AND GUARD PLATES, PAINTED	ACI PORT STAIR TOWERS AND PLATFORMS	436.00 LF	-	-	23,108	90	66.07 /MH	5,960	29,068
			STAIR SYSTEM	ACI PORT STAIR TOWERS AND PLATFORMS	896.00 SF	-	-	81,536	1,184	66.07 /MH	78,251	159,787
			GALLERY					115,564	1,358		89,740	205,304
		23.21.00	GIRDER									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		23.21.00	GIRDER									
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	UNIT 2 ACI PIPE RACK OVER ROADWAY, 35LF X 23 WIDE X 20' HIGH	1.26 TN	-	-	3,415	25	92.62 /MH	2,280	5,695
			GIRDER					3,415	25		2,280	5,695
		23.25.00	ROLLED SHAPE									
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, TWO COAT PAINT	ACI PORT STAIRTOWER FRAMING - 2 TOWERS	4.40 TN	-	-	15,752	111	92.62 /MH	10,305	26,057
			REASSEMBLE ASH HANDLING/ELEC BLDG METAL FRAME, PURLINS & GIRTS AS NEW LABOR SHOP	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	50.00 TN	-	-		1,379	92.62 /MH	127,752	127,752
			ROLLED SHAPE					15,752	1,491		138,057	153,809
			STEEL					134,731	2,873		230,077	364,808
	24.00.00		ARCHITECTURAL									
		24.15.00	DOOR (INCL. FRAME & HARDWARE)									
			DOOR (INCL. FRAME & HARDWARE) - ROLL UP DOOR MAN DOOR ETC...	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 LS	-	-	5,000	92	51.10 /MH	4,699	9,699
			DOOR (INCL. FRAME & HARDWARE)					5,000	92		4,699	9,699
		24.27.00	MASONRY									
			BLOCK, CONCRETE, 8 IN, HOLLOW REINFORCED, ALTERNATE COURSES	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	850.00 SF	-	-	4,242	106	53.08 /MH	5,601	9,842
			MASONRY					4,242	106		5,601	9,842
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA,	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	5,000.00 SF	-	-	140,000	1,954	92.62 /MH	180,982	320,982
			PRE-ENGINEERED BUILDING					140,000	1,954		180,982	320,982
		24.37.00	ROOFING									
			METAL, INSULATED- NEW INSULATED SIDING & ROOFING	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	6,500.00 SF	-	-	50,505	2,241	35.02 /MH	78,493	128,998
			ROOFING					50,505	2,241		78,493	128,998
		24.41.00	SIDING									
			METAL, INSULATED, NEW INSULATED SIDING & ROOFING	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	8,500.00 SF	-	-	140,760	870	79.59 /MH	69,207	209,967
			SIDING					140,760	870		69,207	209,967
		24.99.00	ARCHITECTURAL, MISCELLANEOUS									
			ARCHITECTURAL, MISCELLANEOUS - OFFICE ALLOWANCE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 LS	-	-	100,000	2,299	51.10 /MH	117,471	217,471
			ARCHITECTURAL, MISCELLANEOUS - TOOL CRIB	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	1.00 LS	-	-	5,000	92	51.10 /MH	4,699	9,699
			ARCHITECTURAL, MISCELLANEOUS					105,000	2,391		122,170	227,170
			ARCHITECTURAL					445,507	7,653		461,151	906,658
	27.00.00		PAINTING & COATING									
		27.17.00	PAINTING									
			PAINTING - ALLOWANCE	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	2,025	23	47.61 /MH	1,108	3,133
			PAINTING					2,025	23		1,108	3,133
			PAINTING & COATING					2,025	23		1,108	3,133
	31.00.00		MECHANICAL EQUIPMENT									
		31.25.00	CRANES & HOISTS									
			BRIDGE CRANE - INSTALL SALVAGED 15 TN BRIDGE CRANE AND 2 JIB CRANES WITH EXISTING SUPPORT STEEL	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	21.00 TN	-	-	-	290	92.62 /MH	26,828	26,828
			BRIDGE CRANE - LOAD TEST & CERTIFY BRIDGE CRANE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 EA	-	-	-	230	92.62 /MH	21,292	21,292
			MOTORIZED HOIST - 1 TON	RELOCATED FROM PRESENT PORT LOCATIOIN	2.00 EA	-	-	-	138	68.48 /MH	9,446	9,446
			CRANES & HOISTS						657		57,565	57,565
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 LT	-	-	10,000	138	68.48 /MH	9,446	19,446
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	5,000.00 SF	-	-	27,500	385	68.48 /MH	26,369	53,869
			FIRE PROTECTION EQUIPMENT & SYSTEM					37,500	523		35,814	73,314
		31.51.00	MERCURY REMOVAL EQUIPMENT									
			ACTIVATED CARBON INJECTION (ACI) - LANCE RELOCATIONS	RELOCATED FROM PRESENT PORT LOCATIOIN (16 PER UNIT)	32.00 EA	-	-	-	368	68.48 /MH	25,188	25,188
			ACTIVATED CARBON INJECTION (ACI) - 40 HP BLOWERS	NEW BLOWERS (2 PER UNIT)	4.00 EA	-	-	80,000	184	68.48 /MH	12,594	92,594
			ACTIVATED CARBON INJECTION (ACI) - REMOVE EXISTING 20 HP BLOWERS	REMOVE EXISTING	2.00 EA	-	-	-	23	68.48 /MH	1,574	1,574
			MERCURY REMOVAL EQUIPMENT					80,000	575		39,356	119,356
			MECHANICAL EQUIPMENT					117,500	1,755		132,736	250,236
	34.00.00		HVAC									
		34.99.00	HVAC, MISCELLANEOUS									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	2,100.00 SF	-	-	23,100	24	64.10 /MH	1,547	24,647
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	2,100.00 SF	-	-	23,100	24	64.10 /MH	1,547	24,647
			HVAC, MISCELLANEOUS					46,200	48		3,094	49,294
			HVAC					46,200	48		3,094	49,294
	35.00.00		PIPING									
		35.13.25	FRP, ABOVE GROUND, PROCESS AREA									
			1.5 IN DIA, TAPER	INJECTION PORTS	12.00 LF	-	-	353	6	77.36 /MH	437	790
			2 IN DIA, TAPER	INJECTION PORTS	16.00 LF	-	-	421	9	77.36 /MH	697	1,118
			3 IN DIA, TAPER	INJECTION PORTS	40.00 LF	-	-	1,032	31	77.36 /MH	2,383	3,415
			FRP, ABOVE GROUND, PROCESS AREA					1,806	45		3,518	5,323
		35.14.25	FRP, STRAIGHT RUN									
			4 IN DIA, TAPER	NEW ACI PIPING	600.00 LF	-	-	12,660	400	77.36 /MH	30,944	43,604
			FRP, STRAIGHT RUN					12,660	400		30,944	43,604
		35.36.00	PIPE SUPPORTS, RACK									
			U-BOLT FOR 4 IN PIPE	ACI PIPE	27.00 EA	-	-	81	62	77.36 /MH	4,802	4,883
			SUPPORT SLEEPERS	ACI PIPE 330 LF	17.00 EA	-	-	5,950	78	77.36 /MH	6,047	11,997
			SUPPORT FOR 4 IN DIA PIPE - USER DEFINED		2.00 EA	-	-	306	18	77.36 /MH	1,423	1,729
			SUPPORT FOR 3 IN DIA PIPE - USER DEFINED		4.00 EA	-	-	576	32	77.36 /MH	2,490	3,066
			PIPE SUPPORTS, RACK					6,913	191		14,761	21,674
		35.45.00	VALVES									
			VALVE - 4" 150 LB CS GATE, FLANGED	ACI AUTO MATIC ISOLATION VALVES (RELOCATE 4 PER UNIT)	8.00 EA	-	-	160	66	77.36 /MH	5,122	5,282
			VALVES					160	66		5,122	5,282
			PIPING					21,539	702		54,344	75,883
	41.00.00		ELECTRICAL EQUIPMENT									
		41.37.00	LIGHTING ACCESSORY (FIXTURE)									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	6,500.00 SF	-	-	71,500	75	63.63 /MH	4,754	76,254
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	5,000.00 SF	-	-	55,000	57	63.63 /MH	3,657	58,657
			LIGHTING ACCESSORY (FIXTURE)					126,500	132		8,411	134,911
		41.46.00	MOTOR CONTROL CENTER (MCC), COMPONENT									
			FVN STARTER - #4,	NEW BLOWERS	3.00 EA	-	-	14,700	55	63.63 /MH	3,511	18,211
			MOTOR CONTROL CENTER (MCC), COMPONENT					14,700	55		3,511	18,211
			ELECTRICAL EQUIPMENT					141,200	187		11,921	153,121
	42.00.00		RACEWAY, CABLE TRAY & CONDUIT									
		42.15.23	CONDUIT, FLEXIBLE SEALTIGHT ASSEMBLY									
			1-1/2 IN DIA, 3 FT LONG INCLUDING (2) CONNECTORS	NEW BLOWERS	3.00 EA	-	-	258	4	61.79 /MH	266	524
			CONDUIT, FLEXIBLE SEALTIGHT ASSEMBLY					258	4		266	524

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		42.15.37	CONDUIT, RGS									
			3/4 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	HOIST	450.00 LF	-	-	1,319	100	61.79 /MH	6,200	7,519
			1-1/2 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	NEW BLOWERS	400.00 LF	-	-	2,688	131	61.79 /MH	8,068	10,756
			CONDUIT, RGS					4,007	231		14,269	18,275
			RACEWAY, CABLE TRAY & CONDUIT					4,264	235		14,535	18,799
	43.00.00		CABLE									
		43.10.00	CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION									
			CONTROL/INSTRUMENTATION/COMMUNICATION TERMINATION - MISC	ACI RELOCATION	600.00 LF	-	-	1,920	55	82.05 /MH	4,527	6,447
			CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION					1,920	55		4,527	6,447
		43.20.00	600V CABLE & TERMINATION									
			600V #8 3/C CU EPR TS-CPE	HOIST	500.00 LF	-	-	3,280	14	82.05 /MH	1,179	4,459
			600V #4/0 3/C W/G CU EPR TS-CPE	NEW BLOWERS	450.00 LF	-	-	10,728	72	82.05 /MH	5,942	16,670
			TERMINATION - COMPRESSION LUG, #8, 2 HOLE, COPPER	HOIST	12.00 EA	-	-	78	4	82.05 /MH	340	418
			TERMINATION - COMPRESSION LUG, #4, 2 HOLE, COPPER	NEW BLOWERS	12.00 EA	-	-	111	7	82.05 /MH	566	677
			600V CABLE & TERMINATION					14,197	98		8,026	22,223
			CABLE					16,117	153		12,553	28,670
	44.00.00		CONTROL & INSTRUMENTATION									
		44.21.00	INSTRUMENT									
			ACCOUSTIC MONITOR	RELOCATE TO NEW INJECTION LANCES	6.00 EA	-	-		28	64.68 /MH	1,784	1,784
			INSTRUMENT						28		1,784	1,784
			CONTROL & INSTRUMENTATION						28		1,784	1,784
	71.00.00		PROJECT INDIRECT									
		71.25.00	CONSULTANT, THIRD PARTY									
			COMPUTATIONAL FLUID DYNAMIC ANALYSIS (CFD)	ACI SYSTEM	1.00 LS	100,000	-			/MH		100,000
			CONSULTANT, THIRD PARTY			100,000						100,000
			PROJECT INDIRECT			100,000						100,000
			190 DEMOLITION / RELOCATION			**100,000**		**1,578,182**	**33,735**		**2,546,302**	**4,224,484**
201			**ELECTRICAL BOP SYSTEM**									
	21.00.00		CIVIL WORK									
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	U1 MAIN ELECT BLDG 40'X100'	23.00 EA	-	-	42,711	582	108.46 /MH	63,081	105,792
			2.5 FT DIA X 30 FT DEEP CAISSON	2 UAT AND 1 SST TRANSFORMER SUBSTRUCTURE	36.00 EA	-	-	66,852	910	108.46 /MH	98,736	165,588
			2.5 FT DIA X 30 FT DEEP CAISSON	BUS DUCT SUPPORTS	167.00 EA	-	-	310,119	4,223	108.46 /MH	458,025	768,144
			2.5 FT DIA X 30 FT DEEP CAISSON	OVERHEAD TRANSMISSION LINE STRUCTURAL - INCLUDES 115 KV DISCONNECT SWITCH FOUNDATION	10.00 EA	-	-	18,570	253	108.46 /MH	27,427	45,997
			2.5 FT DIA X 30 FT DEEP CAISSON	U2 MAIN ELECT BLDG 40'X100'	23.00 EA	-	-	42,711	582	108.46 /MH	63,081	105,792
			CAISSON					480,963	6,549		710,351	1,191,314
			CIVIL WORK					480,963	6,549		710,351	1,191,314
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			CONCRETE FOUNDATIONS - COMPOSITE RATE	U1 MAIN ELECT BLDG 40'X100'	300.00 CY	-	-	69,000	2,414	59.71 /MH	144,128	213,128
			CONCRETE FOUNDATIONS - COMPOSITE RATE	2 UAT AND 1 SST TRANSFORMER SUBSTRUCTURE	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			CONCRETE FOUNDATIONS - COMPOSITE RATE	BUS DUCT SUPPORTS	333.00 CY	-	-	76,590	2,679	59.71 /MH	159,982	236,572
			CONCRETE FOUNDATIONS - COMPOSITE RATE	OVERHEAD TRANSMISSION LINE STRUCTURAL	50.00 CY	-	-	11,500	402	59.71 /MH	24,021	35,521
			CONCRETE FOUNDATIONS - COMPOSITE RATE	U2 MAIN ELECT BLDG 40'X100'	300.00 CY	-	-	69,000	2,414	59.71 /MH	144,128	213,128
			CONCRETE					364,090	12,737		760,513	1,124,603
			CONCRETE					364,090	12,737		760,513	1,124,603
	23.00.00		STEEL									
		23.99.00	STEEL, MISCELLANEOUS									

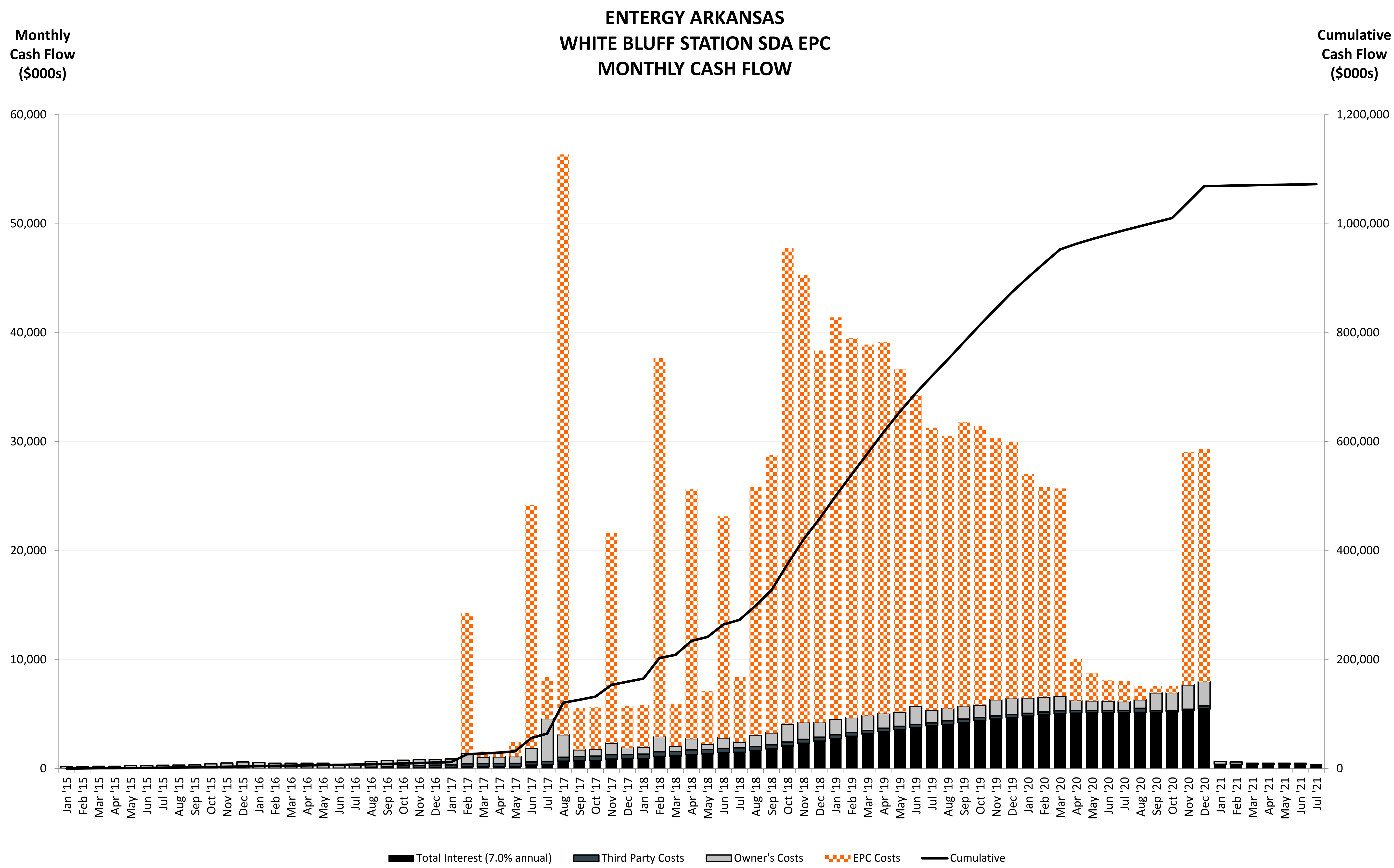
Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		23.99.00	**STEEL, MISCELLANEOUS**									
			STEEL, MISCELLANEOUS - AUX SUPPORT STEEL	AUX SUPPORT STEEL	100.00 TN	-	-	271,000	1,954	92.62 /MH	180,982	451,982
			STEEL, MISCELLANEOUS -	BUS DUCT SUPPORTS	167.00 TN	-	-	452,570	3,263	92.62 /MH	302,239	754,809
			STEEL, MISCELLANEOUS -	OVERHEAD TRANSMISSION LINE STRUCTURAL	15.00 TN	-	-	40,650	293	92.62 /MH	27,147	67,797
			STEEL, MISCELLANEOUS					**764,220**	**5,510**		**510,368**	**1,274,588**
			STEEL					**764,220**	**5,510**		**510,368**	**1,274,588**
	24.00.00		**ARCHITECTURAL**									
		24.35.00	**PRE-ENGINEERED BUILDING**									
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U1 MAIN ELECT BLDG 40'X100' FURNISH ONLY	1.00 EA	-	504,000		4,598	51.10 /MH	234,943	738,943
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U1 MAIN ELECT BLDG 40'X100' INSTALLATION	1.00 EA	-			414	92.62 /MH	38,326	38,326
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U2 MAIN ELECT BLDG 40'X100' FURNISH ONLY	1.00 EA	-	504,000		4,598	51.10 /MH	234,943	738,943
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U2 MAIN ELECT BLDG 40'X100' INSTALLATION	1.00 EA	-			414	92.62 /MH	38,326	38,326
			PRE-ENGINEERED BUILDING				**1,008,000**		**10,023**		**546,536**	**1,554,536**
			ARCHITECTURAL				**1,008,000**		**10,023**		**546,536**	**1,554,536**
	41.00.00		**ELECTRICAL EQUIPMENT**									
		41.13.00	**BUS DUCT**									
			ISO PHASE, SELF COOLED	TAP BUS EXTENSIONS	200.00 LF	-	315,000		4,828	63.63 /MH	307,179	622,179
			NON SEGREGATED - (600V) (2000A) FGD ONLY		800.00 LF	-	588,000		5,517	63.63 /MH	351,062	939,062
			BUS DUCT				**903,000**		**10,345**		**658,241**	**1,561,241**
		41.45.00	**MOTOR CONTROL CENTER (MCC), COMPLETE**									
			MOTOR CONTROL CENTER (MCC), COMPLETE - 480V FGD		12.00 EA	-	636,000		5,931	63.63 /MH	377,392	1,013,392
			MOTOR CONTROL CENTER (MCC), COMPLETE				**636,000**		**5,931**		**377,392**	**1,013,392**
		41.51.00	**POWER TRANSFORMER**									
			STARTUP, RESERVE AUXILIARY (RAT) - 36/48 MVA 115/6.9/6.9 KV	LABOR INCLUDES DRESS OUT AND FILL	1.00 EA	-	875,000		1,379	63.63 /MH	87,766	962,766
			STARTUP, RESERVE AUXILIARY (RAT) - 36/48 MVA 115/6.9/6.9 KV	HEAVY HAUL FROM RAIL TO PAD	1.00 EA	-	95,000			/MH		95,000
			UNIT AUXILIARY - 36/48 MVA 25/6.9/6.9 KV	LABOR INCLUDES DRESS OUT AND FILL	2.00 EA	-	1,700,000		2,759	63.63 /MH	175,531	1,875,531
			UNIT AUXILIARY - 36/48 MVA 25/6.9/6.9 KV	HEAVY HAUL FROM RAIL TO PAD	2.00 EA	-	190,000			/MH		190,000
			POWER TRANSFORMER - 6.9-.48 kV UNIT SUBSTATION X FMRS - 2000 KVA		4.00 EA	-	360,000		667	63.63 /MH	42,420	402,420
			POWER TRANSFORMER - 6.9-.48 kV UNIT SUBSTATION X FMRS - 1500 KVA		4.00 EA	-	300,000		598	63.63 /MH	38,032	338,032
			POWER TRANSFORMER				**3,520,000**		**5,402**		**343,748**	**3,863,748**
		41.55.00	**SWITCHGEAR, COMPLETE**									
			480 V - REAGENT SWITCHGEAR		4.00 EA	-	212,000		1,977	63.63 /MH	125,797	337,797
			480 V - 480V FGD SWITCHGEAR		4.00 EA	-	840,000		4,138	63.63 /MH	263,297	1,103,297
			6.9 KV - SWITCHGEAR FGD		4.00 EA	-	1,680,000		14,713	63.63 /MH	936,166	2,616,166
			6.9 KV - SWITCHGEAR WALK IN TYPE		3.00 EA	-	660,000		5,810	63.63 /MH	369,712	1,029,712
			SWITCHGEAR, COMPLETE				**3,392,000**		**26,638**		**1,694,972**	**5,086,972**
		41.99.00	**ELECTRICAL EQUIPMENT, MISCELLANEOUS**									
			ELECTRICAL EQUIPMENT, MISCELLANEOUS AUX POWER EQUIPMENT		1.00 LT	-	2,840,000		11,494	63.63 /MH	731,379	3,571,379
			ELECTRICAL EQUIPMENT, MISCELLANEOUS				**2,840,000**		**11,494**		**731,379**	**3,571,379**
			ELECTRICAL EQUIPMENT				**11,291,000**		**59,810**		**3,805,732**	**15,096,732**
	42.00.00		**RACEWAY, CABLE TRAY & CONDUIT**									
		42.13.00	**CABLE TRAY**									
			CABLE TRAY - ALLOTMENT		1.00 LT	-	-	505,000	33,333	61.79 /MH	2,059,667	2,564,667
			CABLE TRAY					**505,000**	**33,333**		**2,059,667**	**2,564,667**
		42.15.37	**CONDUIT, RGS**									
			XX IN DIA - CONDUIT ALLOTMENT		1.00 LT	-	-	90,000	74,138	61.79 /MH	4,580,983	4,670,983
			CONDUIT, RGS					**90,000**	**74,138**		**4,580,983**	**4,670,983**
		42.18.00	**DUCT BANK**									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		42.18.00	**DUCT BANK**									
			DUCT BANK - UNDERGROUND DUCT BANKS NOT APPLICABLE		LT	-	-			61.79 /MH		
			RACEWAY, CABLE TRAY & CONDUIT					**595,000**	**107,471**		**6,640,649**	**7,235,649**
	43.00.00		**CABLE**									
		43.10.00	**CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION**									
			CONTROL/INSTRUMENTATION/COMMUNICATION TERMINATION - MISC		201,600.00 LF	-	-	645,120	18,538	82.05 /MH	1,521,037	2,166,157
			CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION					**645,120**	**18,538**		**1,521,037**	**2,166,157**
		43.20.00	**600V CABLE & TERMINATION**									
			600V CABLE - MISC		218,000.00 LF	-	-	1,881,340	30,069	82.05 /MH	2,467,159	4,348,499
			600V CABLE & TERMINATION					**1,881,340**	**30,069**		**2,467,159**	**4,348,499**
		43.40.00	**5/8KV CABLE & TERMINATION**									
			5/8KV #750 KCMIL 1/C CU EPR TS-CPE , FEEDS TO 8KV SWGR BLDG		225,000.00 LF	-	-	5,415,750	23,276	82.05 /MH	1,909,784	7,325,534
			5/8KV MISC		40,200.00 LF	-	-	297,480	10,628	82.05 /MH	871,993	1,169,473
			5/8KV CABLE & TERMINATION					**5,713,230**	**33,903**		**2,781,778**	**8,495,008**
		43.50.00	**15KV CABLE & TERMINATION**									
			15KV CABLE - MISC		22,300.00 LF	-	-	206,721	5,895	82.05 /MH	483,718	690,439
			15KV CABLE & TERMINATION					**206,721**	**5,895**		**483,718**	**690,439**
			CABLE					**8,446,411**	**88,406**		**7,253,692**	**15,700,103**
	51.00.00		**SUBSTATION, SWITCHYARD & TRANSMISSION LINE**									
		51.15.27	**CIRCUIT BREAKER**									
			CIRCUIT BREAKER - SWITCHYARD BAY AND 3 BREAKERS	ADDITION OF A SWITCHYARD BAY IS AVOIDED BY PLACING THE NEW SST NEXT TO THE EXISTING SST AND USING THE SAME OVERHEAD LINE.	0.00 LT	-				55.78 /MH		
		51.15.53	**DISCONNECT SWITCH**									
			115KV, 1200A, VERTICAL BREAK SWITCH WITH INSULATORS,INCLUDING GROUND SWITCH AND WITHOUT MOTORIZED OPERATOR	FOR ISOLATION OF RAT	1.00 EA	-	-	15,000	69	55.78 /MH	3,847	18,847
			DISCONNECT SWITCH					**15,000**	**69**		**3,847**	**18,847**
			SUBSTATION, SWITCHYARD & TRANSMISSION LINE					**15,000**	**69**		**3,847**	**18,847**
			201 ELECTRICAL BOP SYSTEM				**12,299,000**	**10,665,684**	**290,576**		**20,231,688**	**43,196,372**
211			**INSTRUMENTATION AND CONTROLS BOP SYSTEM**									
	44.00.00		**CONTROL & INSTRUMENTATION**									
		44.13.00	**CONTROL SYSTEM**									
			DISTRIBUTED CONTROL SYSTEM (DCS) - I/O POINTS	ESTIMATED BOP 2000 I/O POINTS, (ANOTHER 1000 POINTS PER UNIT ARE INCLUDED IN THE DFGD PROPOSAL PRICES AND ARE NOT INCLUDED HERE)	1.00 LT	-	1,500,000		2,299	64.68 /MH	148,690	1,648,690
			CONTROL SYSTEM				**1,500,000**		**2,299**		**148,690**	**1,648,690**
		44.21.00	**INSTRUMENT**									
			INSTRUMENT - BOP INSTRUMENTS		1.00 LT	-	-	478,000	7,946	82.05 /MH	651,967	1,129,967
			INSTRUMENT - THERMOCOUPLES IN STACK ENTRANCE W ALARM		1.00 LT	-	-	100,000		82.05 /MH		100,000
			INSTRUMENT					**578,000**	**7,946**		**651,967**	**1,229,967**
		44.25.00	**MONITORING EQUIPMENT**									
			CONTINUOUS EMISSION MONITORING SYSTEM (CEMS) - REFURBISHING		2.00 EA	-	-	460,000	625	64.68 /MH	40,444	500,444
			MONITORING EQUIPMENT - LOCAL HMI		3.00 EA	-	-	45,000	14	64.68 /MH	892	45,892

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			MONITORING EQUIPMENT					505,000	639		41,336	546,336
			CONTROL & INSTRUMENTATION				1,500,000	1,083,000	10,884		841,993	3,424,993
			211 INSTRUMENTATION AND CONTROLS				**1,500,000**	**1,083,000**	**10,884**		**841,993**	**3,424,993**
			BOP SYSTEM									

ATTACHMENT 2

Conceptual Capital Cost Estimate Cash Flow



ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
MONTHLY CASH FLOW
Monthly
Cash Flow
($000s)
Cumulative
Cash Flow
($000s)
60,000
50,000
40,000
30,000
20,000
10,000
0
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
Jan '15
Jul '21
Total Interest (7.0% annual)
Third Party Costs
Owner's Costs
EPC Costs
Cumulative

ATTACHMENT 3

Level 1 Preliminary Execution Schedule

Activity ID	Activity Name	Orig Dur	Start	Finish
WHITE BLUFF FGD SCHEDULE (December 2020)		1556	13-Jan-15	29-Dec-20
Milestones		1556	13-Jan-15	29-Dec-20
Project Milestones		1556	13-Jan-15	29-Dec-20
EPC RFP		225	13-Jan-15	30-Nov-15
MS010	Begin EPC RFP	0	13-Jan-15	
MS100	EPC RFP Complete	0		15-May-15
MS225	Award EPC	0		30-Nov-15
Permitting		1272	30-Dec-15	29-Dec-20
MS275	FIP Issued (Estimated)	0		30-Dec-15
MS015	Issue Air Permit Application	0		02-Feb-16
MS020	Receive Air Permit	0		31-Jul-17
MS285	Estimated Compliance Date	0		29-Dec-20
LNTP/FNTP		998	27-Jan-17	28-Dec-20
MS260	Issue LNTP	0		27-Jan-17
MS030	Issue FNTP	0		31-Jul-17
MS265	Complete FNTP Period	0		28-Dec-20
Unit 1 & Common Outage, Start-Up & Commissioning		178	02-Apr-20	27-Sep-20
MS0100	Unit 1 Structural Completion (Ready for Pre-Outage)	0		02-Apr-20
MS0110	Unit 1 Tie-in Outage	42	03-Apr-20	14-May-20
MS0120	Unit 1 Mechanical Completion (Ready for Flue Gas)	0		14-May-20
MS0130	Commission / Tune Unit 1 DFGD System	91	15-May-20	13-Aug-20
MS0140	Unit 1 Substantial Completion	0		13-Aug-20
MS0150	Unit 1 Reliability Run	45	14-Aug-20	27-Sep-20
MS0160	Unit 1 Final Completion	0		27-Sep-20*
Unit 2 Outage, Start-Up & Commissioning		179	03-Jul-20	29-Dec-20
MS0200	Unit 2 Structural Completion (Ready for Pre-Outage)	0		03-Jul-20
MS0210	Unit 2 Tie-in Outage	43	04-Jul-20	15-Aug-20
MS0220	Unit 2 Mechanical Completion (Ready for Flue Gas)	0		15-Aug-20
MS0230	Commission / Tune Unit 2 DFGD System	91	16-Aug-20	14-Nov-20
MS0240	Unit 2 Substantial Completion	0		14-Nov-20
MS0250	Unit 2 Reliability Run	45	15-Nov-20	29-Dec-20
MS0260	Unit 2 Final Completion	0		29-Dec-20
Project Overview		1556	13-Jan-15	29-Dec-20
EPC RFP		89	13-Jan-15	15-May-15
OV1000	Develop Qualifications RFP	14	13-Jan-15	30-Jan-15
OV1010	EPC Bidders Response to RFP	30	02-Feb-15	13-Mar-15
OV1020	Evaluation / Selection / Negotiate MOU	45	16-Mar-15	15-May-15
OV1040	Begin EPC Open Book Period	0		15-May-15
EPC Development Phase		141	18-May-15	30-Nov-15
OV1030	Negotiate EPC Contract Commercial	45	18-May-15	17-Jul-15
OV1050	Prepare FGD Technical Spec / RFP	35	18-May-15	03-Jul-15
OV1060	FGD Bidders Response to RFP	30	06-Jul-15	14-Aug-15
OV1070	Evaluation FGD Bids	30	20-Jul-15	28-Aug-15
OV1090	Develop BOP Quantities	35	03-Aug-15	18-Sep-15
OV1080	Select FGD Process	0		28-Aug-15
OV1100	Prepare Construction Estimate	20	31-Aug-15	25-Sep-15
OV1110	Entergy RCRC/OCE Presentation Preparation	21	28-Sep-15	26-Oct-15
OV1103	Review Estimate	10	28-Sep-15	09-Oct-15
OV1105	Incorporate Comments & Finalize Estimate	11	12-Oct-15	26-Oct-15
OV1120	Close Book	0		26-Oct-15
OV1130	RCRC & OCE Approval	15	27-Oct-15	16-Nov-15
OV1140	Board of Directors Approval	10	17-Nov-15	30-Nov-15
OV1145	Award EPC	0		30-Nov-15
LNTP		132	27-Jan-17	01-Aug-17
OV1150	Issue LNTP	0		27-Jan-17
OV1160	EPC Contract LNTP	132	30-Jan-17	01-Aug-17
OV1170	Issue FNTP	0		01-Aug-17

Remaining Work | Actual Work | WBS Summary
Critical Remaining Work | Milestone

TASK filter: Exclude WBS Activities_1.

Exhibit B to EAI Comments

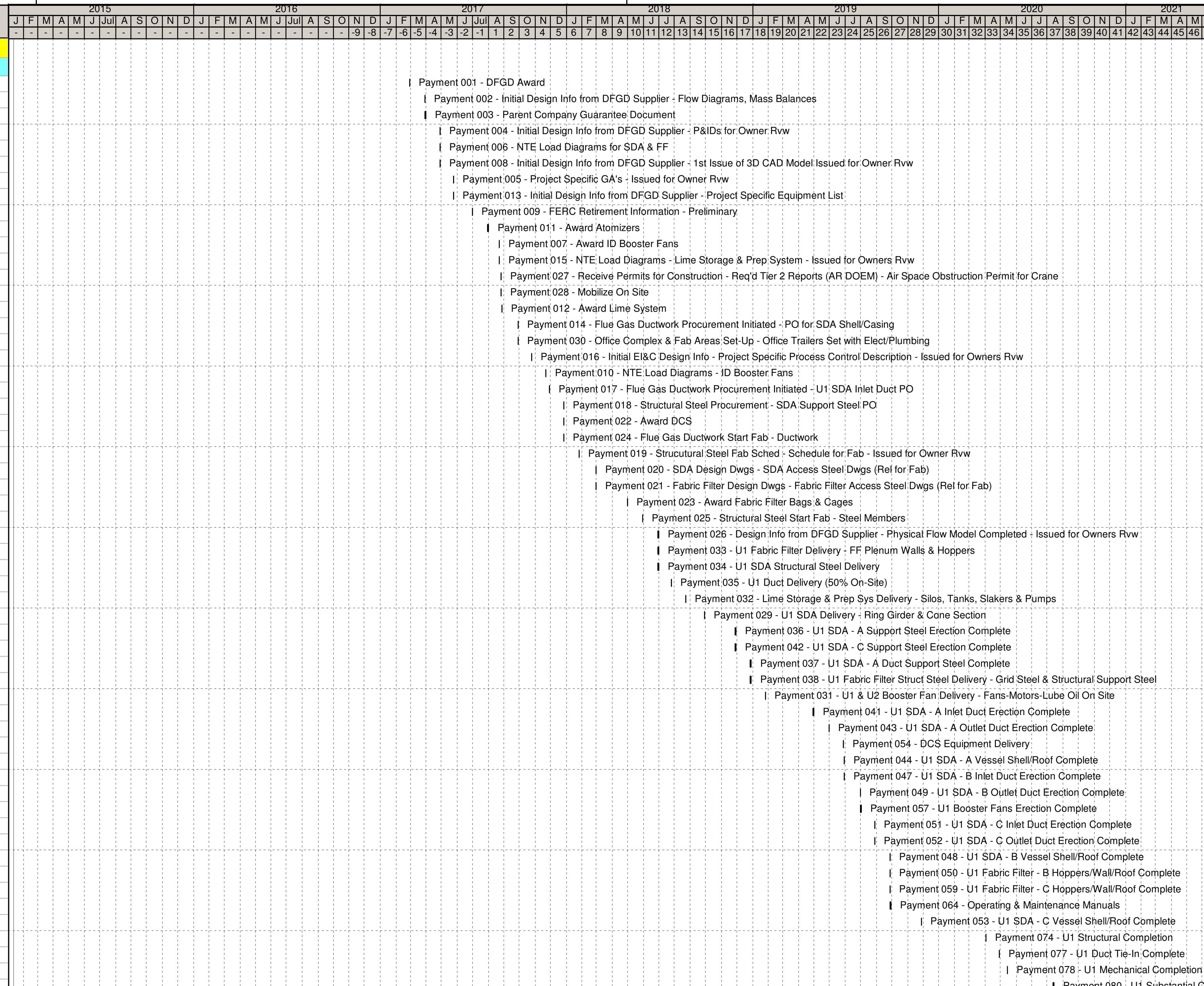
Activity ID	Activity Name	Ori Dur	Start	Finish
FNTP		890	02-Aug-17	29-Dec-20
OV1180	EPC Contract FNTP Period	889	02-Aug-17	28-Dec-20
OV1230	Compliance Deadline	0		29-Dec-20*
EPC Milestones		1292	30-Nov-15	29-Dec-20
Engineering		308	07-Sep-17	26-Nov-18
EPC325	Common Sitework Dwg IFC	0		07-Sep-17
EPC345	U1 SDA Foundation IFC	0		20-Oct-17
EPC340	Common Freeze General Arrangements	0		13-Nov-17
EPC510	U2 SDA Foundation IFC	0		16-Jan-18
EPC350	U1 ID Fan Foundation IFC	0		03-Apr-18
EPC320	Common Electrical Single Lines IFC	0		13-Apr-18
EPC485	U2 ID Fan Foundation IFC	0		22-Jun-18
EPC355	ALL P&IDs IFC	0		18-Jul-18
EPC240	All Master Schematics IFC	0		26-Nov-18
Procurement		858	30-Nov-15	19-Apr-19
EPC010	Award EPC	0		30-Nov-15
EPC100	Award Dry FGD System	0		27-Jan-17
EPC110	Award ID Fans	0		09-Aug-17
EPC335	Award DCS	0		08-Dec-17
EPC315	Award Transformers	0		15-Jan-18
EPC545	Award Transformers Delivery Complete	0		30-Nov-18
EPC535	Award ID Fans Delivery Complete	0		07-Jan-19
EPC415	Common DCS FAT Complete	0		18-Mar-19
EPC540	Award DCS Delivery Complete	0		15-Apr-19
EPC530	Dry FGD System Delivery Complete	0		19-Apr-19
Unit 1 & Common Construction & Commissioning		677	30-Jan-18	28-Sep-20
EPC425	Common ALL U/G Piping Installation Complete	0		30-Jan-18
EPC370	U1 Fabric Filter Foundation Installation Complete	0		01-Jun-18
EPC360	U1 SDA Foundation Installation Complete	0		05-Jun-18
EPC365	U1 ID Fan Foundation Installation Complete	0		30-Oct-18
EPC395	Common Electrical Equipment Bldg Foundation Complete	0		16-Nov-18
EPC405	Common Transformers Foundation Complete	0		14-Dec-18
EPC460	Common Pipe Rack FoundationComplete	0		17-Dec-18
EPC400	Common Electrical Equipment Bldg Erection Complete	0		11-Jan-19
EPC390	Common Pipe Rack Erection Complete	0		11-Feb-19
EPC310	U1 All Foundations Installation Complete	0		02-Apr-19
EPC410	Common Transformers Erection Complete	0		05-Jun-19
EPC435	Common Ready for Aux Power Backfeed	0		02-Jul-19
EPC380	U1 ID Fan Installation Complete	0		25-Jul-19
EPC420	Common Training Plan Ready for Start of Training	0		29-Aug-19
EPC385	U1 Fabric Filter Erection Complete	0		09-Sep-19
EPC375	U1 SDA Erection Complete	0		28-Nov-19
EPC440	U1 Structural Completion (Ready for Outage)	0		02-Apr-20
EPC445	U1 Mechanical Completion	0		14-May-20
EPC450	U1 Substantial Completion	0		13-Aug-20
EPC455	U1 Final Completion	0		28-Sep-20
Unit 2 Construction & Commissioning		593	31-Aug-18	29-Dec-20
EPC475	U2 Fabric Filter Foundation Installation Complete	0		31-Aug-18
EPC515	U2 SDA Foundation Installation Complete	0		04-Sep-18
EPC490	U2 ID Fan Foundation Installation Complete	0		29-Jan-19
EPC465	U2 All Foundations Installation Complete	0		02-Apr-19
EPC495	U2 ID Fan Installation Complete	0		16-Sep-19
EPC470	U2 Fabric Filter Erection Complete	0		09-Dec-19
EPC505	U2 SDA Erection Complete	0		28-Feb-20
EPC520	U2 Structural Completion (Ready for Outage)	0		03-Jul-20
EPC500	U2 Mechanical Completion	0		17-Aug-20
EPC525	U2 Substantial Completion	0		16-Nov-20
EPC480	U2 Final Completion	0		29-Dec-20

Remaining Work — Actual Work — WBS Summary
Critical Remaining Work — Milestone

TASK filter: Exclude WBS Activities_1.

Exhibit B to EAI Comments

Activity ID	Activity Name	Orig Dur	Start	Finish
Payment Milestones		1401	28-Feb-17	29-Dec-20
Unit 1 & Common		1308	28-Feb-17	27-Sep-20
PAY001	Payment 001 - DFGD Award	1	28-Feb-17	28-Feb-17
PAY002	Payment 002 - Initial Design Info from DFGD Supplier - Flow ...	1	29-Mar-17	29-Mar-17
PAY003	Payment 003 - Parent Company Guarantee Document	1	30-Mar-17	30-Mar-17
PAY004	Payment 004 - Initial Design Info from DFGD Supplier - P&IDs...	1	28-Apr-17	28-Apr-17
PAY006	Payment 006 - NTE Load Diagrams for SDA & FF	1	28-Apr-17	28-Apr-17
PAY008	Payment 008 - Initial Design Info from DFGD Supplier - 1st Iss...	1	28-Apr-17	28-Apr-17
PAY005	Payment 005 - Project Specific GA's - Issued for Owner Rvw	1	25-May-17	25-May-17
PAY013	Payment 013 - Initial Design Info from DFGD Supplier - Projec...	1	25-May-17	25-May-17
PAY009	Payment 009 - FERC Retirement Information - Preliminary	1	30-Jun-17	30-Jun-17
PAY011	Payment 011 - Award Atomizers	1	31-Jul-17	31-Jul-17
PAY007	Payment 007 - Award ID Booster Fans	1	22-Aug-17	22-Aug-17
PAY015	Payment 015 - NTE Load Diagrams - Lime Storage & Prep Sy...	1	22-Aug-17	22-Aug-17
PAY027	Payment 027 - Receive Permits for Construction - Req'd Tier ...	1	25-Aug-17	25-Aug-17
PAY028	Payment 028 - Mobilize On Site	1	26-Aug-17	26-Aug-17
PAY012	Payment 012 - Award Lime System	1	28-Aug-17	28-Aug-17
PAY014	Payment 014 - Flue Gas Ductwork Procurement Initiated - PO...	1	28-Sep-17	28-Sep-17
PAY030	Payment 030 - Office Complex & Fab Areas Set-Up - Office Tr...	1	28-Sep-17	28-Sep-17
PAY016	Payment 016 - Initial EI&C Design Info - Project Specific Proc...	1	24-Oct-17	24-Oct-17
PAY010	Payment 010 - NTE Load Diagrams - ID Booster Fans	1	22-Nov-17	22-Nov-17
PAY017	Payment 017 - Flue Gas Ductwork Procurement Initiated - U1 ...	1	28-Nov-17	28-Nov-17
PAY018	Payment 018 - Structural Steel Procurement - SDA Support St...	1	26-Dec-17	27-Dec-17
PAY022	Payment 022 - Award DCS	1	26-Dec-17	27-Dec-17
PAY024	Payment 024 - Flue Gas Ductwork Start Fab - Ductwork	1	26-Dec-17	27-Dec-17
PAY019	Payment 019 - Strucutural Steel Fab Sched - Schedule for Fa...	1	26-Jan-18	26-Jan-18
PAY020	Payment 020 - SDA Design Dwgs - SDA Access Steel Dwgs (...	1	28-Feb-18	28-Feb-18
PAY021	Payment 021 - Fabric Filter Design Dwgs - Fabric Filter Acces...	1	28-Feb-18	28-Feb-18
PAY023	Payment 023 - Award Fabric Filter Bags & Cages	1	30-Apr-18	30-Apr-18
PAY025	Payment 025 - Structural Steel Start Fab - Steel Members	1	30-May-18	30-May-18
PAY026	Payment 026 - Design Info from DFGD Supplier - Physical Flo...	1	30-Jun-18	30-Jun-18
PAY033	Payment 033 - U1 Fabric Filter Delivery - FF Plenum Walls & ...	1	30-Jun-18	30-Jun-18
PAY034	Payment 034 - U1 SDA Structural Steel Delivery	1	30-Jun-18	30-Jun-18
PAY035	Payment 035 - U1 Duct Delivery (50% On-Site)	1	25-Jul-18	25-Jul-18
PAY032	Payment 032 - Lime Storage & Prep Sys Delivery - Silos, Tan...	1	23-Aug-18	23-Aug-18
PAY029	Payment 029 - U1 SDA Delivery - Ring Girder & Cone Section	1	28-Sep-18	28-Sep-18
PAY036	Payment 036 - U1 SDA - A Support Steel Erection Complete	1	28-Nov-18	28-Nov-18
PAY042	Payment 042 - U1 SDA - C Support Steel Erection Complete	1	28-Nov-18	28-Nov-18
PAY037	Payment 037 - U1 SDA - A Duct Support Steel Complete	1	28-Dec-18	28-Dec-18
PAY038	Payment 038 - U1 Fabric Filter Struct Steel Delivery - Grid Ste...	1	28-Dec-18	28-Dec-18
PAY031	Payment 031 - U1 & U2 Booster Fan Delivery - Fans-Motors-L...	1	26-Jan-19	26-Jan-19
PAY041	Payment 041 - U1 SDA - A Inlet Duct Erection Complete	1	30-Apr-19	30-Apr-19
PAY043	Payment 043 - U1 SDA - A Outlet Duct Erection Complete	1	30-May-19	30-May-19
PAY054	Payment 054 - DCS Equipment Delivery	1	28-Jun-19	28-Jun-19
PAY044	Payment 044 - U1 SDA - A Vessel Shell/Roof Complete	1	29-Jun-19	29-Jun-19
PAY047	Payment 047 - U1 SDA - B Inlet Duct Erection Complete	1	29-Jun-19	29-Jun-19
PAY049	Payment 049 - U1 SDA - B Outlet Duct Erection Complete	1	31-Jul-19	31-Jul-19
PAY057	Payment 057 - U1 Booster Fans Erection Complete	1	01-Aug-19	01-Aug-19
PAY051	Payment 051 - U1 SDA - C Inlet Duct Erection Complete	1	28-Aug-19	28-Aug-19
PAY052	Payment 052 - U1 SDA - C Outlet Duct Erection Complete	1	28-Aug-19	28-Aug-19
PAY048	Payment 048 - U1 SDA - B Vessel Shell/Roof Complete	1	27-Sep-19	27-Sep-19
PAY050	Payment 050 - U1 Fabric Filter - B Hoppers/Wall/Roof Complete	1	27-Sep-19	27-Sep-19
PAY059	Payment 059 - U1 Fabric Filter - C Hoppers/Wall/Roof Complete	1	27-Sep-19	27-Sep-19
PAY064	Payment 064 - Operating & Maintenance Manuals	1	28-Sep-19	28-Sep-19
PAY053	Payment 053 - U1 SDA - C Vessel Shell/Roof Complete	1	28-Nov-19	28-Nov-19
PAY074	Payment 074 - U1 Structural Completion	1	02-Apr-20	02-Apr-20
PAY077	Payment 077 - U1 Duct Tie-In Complete	1	29-Apr-20	29-Apr-20
PAY078	Payment 078 - U1 Mechanical Completion	1	15-May-20	15-May-20
PAY080	Payment 080 - U1 Substantial Completion	1	13-Aug-20	13-Aug-20



Remaining Work | Actual Work | WBS Summary
Critical Remaining Work | Milestone

TASK filter: Exclude WBS Activities_1.

Exhibit B to EAI Comments

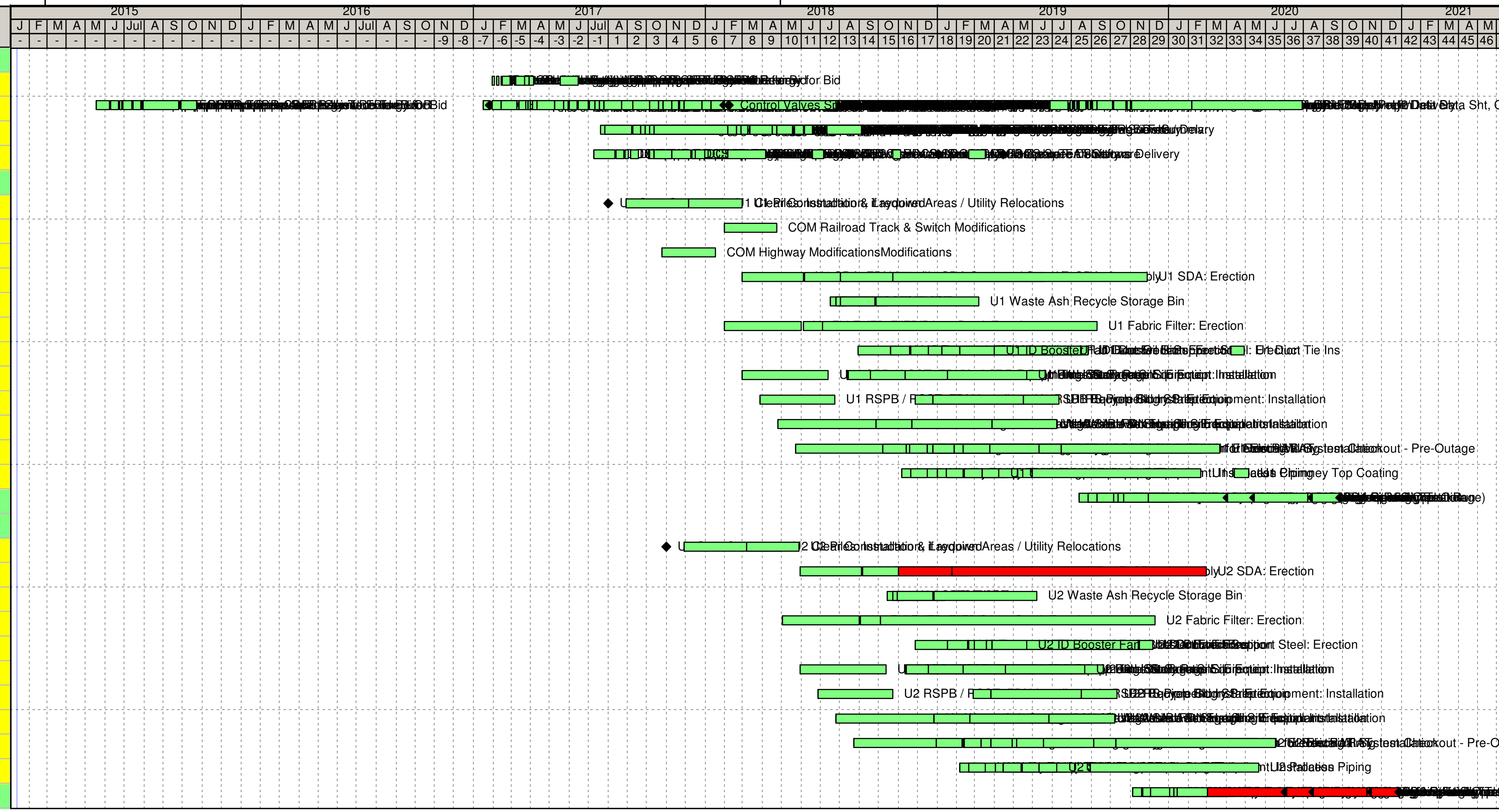
Activity ID	Activity Name	Orig Dur	Start	Finish
PAY079	Payment 079 - U1 Performance Test Report	1	14-Aug-20	14-Aug-20
PAY082	Payment 082 - U1 FERC Retirement Information	1	27-Aug-20	27-Aug-20
PAY089	Payment 089 - U1 Final Completion	1	27-Sep-20	27-Sep-20
Unit 2		830	22-Sep-18	29-Dec-20
PAY046	Payment 046 - U2 SDA Structural Steel Delivery	1	22-Sep-18	22-Sep-18
PAY045	Payment 045 - U2 Fabric Filter Delivery - FF Plenum Walls & ...	1	27-Oct-18	27-Oct-18
PAY040	Payment 040 - U2 SDA Delivery - Ring Girder & Cone Section	1	28-Nov-18	28-Nov-18
PAY039	Payment 039 - U2 Duct Delivery (50% On-Site)	1	28-Dec-18	28-Dec-18
PAY056	Payment 056 - U2 SDA - A Support Steel Complete	1	28-Dec-18	28-Dec-18
PAY063	Payment 063 - U2 SDA - B Support Steel Complete	1	28-Jan-19	28-Jan-19
PAY067	Payment 067 - U2 SDA - C Support Steel Complete	1	30-Mar-19	30-Mar-19
PAY062	Payment 062 - U2 SDA - A Inlet Duct Erection Complete	1	29-Jun-19	29-Jun-19
PAY055	Payment 055 - U2 SDA - A Inlet Duct Support Steel Complete	1	30-Jun-19	30-Jun-19
PAY058	Payment 058 - U2 SDA - B Inlet Duct Support Steel Complete	1	31-Jul-19	31-Jul-19
PAY060	Payment 060 - U2 SDA - C Inlet Duct Support Steel Complete	1	28-Aug-19	28-Aug-19
PAY066	Payment 066 - U2 SDA - B Inlet Duct Erection Complete	1	28-Aug-19	28-Aug-19
PAY061	Payment 061 - U2 SDA - A Vessel Shell/Roof Complete	1	29-Aug-19	29-Aug-19
PAY068	Payment 068 - U2 SDA - A Outlet Duct Erection Complete	1	27-Sep-19	27-Sep-19
PAY072	Payment 072 - U2 SDA - B Support Steel Complete	1	27-Sep-19	27-Sep-19
PAY065	Payment 065 - U2 SDA - B Vessel Shell/Roof Complete	1	29-Oct-19	29-Oct-19
PAY076	Payment 076 - U2 Booster Fans Erection Complete	1	29-Oct-19	29-Oct-19
PAY069	Payment 069 - U2 Fabric Filter - A Hoppers/Wall/Roof Complete	1	28-Nov-19	28-Nov-19
PAY071	Payment 071 - U2 SDA - C Inlet Duct Erection Complete	1	28-Nov-19	28-Nov-19
PAY075	Payment 075 - U2 SDA - C Outlet Duct Erection Complete	1	28-Nov-19	28-Nov-19
PAY073	Payment 073 - U2 Fabric Filter - B Hoppers/Wall/Roof Complete	1	27-Dec-19	27-Dec-19
PAY070	Payment 070 - U2 SDA - C Vessel Shell/Roof Complete	1	28-Dec-19	28-Dec-19
PAY081	Payment 081 - U2 Structural Completion	1	04-Jul-20	04-Jul-20
PAY084	Payment 084 - U2 Duct Tie-In Complete	1	16-Aug-20	16-Aug-20
PAY085	Payment 085 - U2 Mechanical Completion	1	16-Aug-20	16-Aug-20
PAY087	Payment 087 - Demobilization Complete	1	28-Oct-20	28-Oct-20
PAY088	Payment 088 - U2 FERC Retirement Information	1	28-Oct-20	28-Oct-20
PAY086	Payment 086 - U2 Substantial Completion	1	15-Nov-20	15-Nov-20
PAY083	Payment 083 - Removal of Fabrication Tables Complete	1	28-Nov-20	28-Nov-20
PAY090	Payment 090 - U2 Final Completion	1	29-Dec-20	29-Dec-20
Permitting		949	29-Sep-15	27-Jun-19
Air Permit		465	29-Sep-15	31-Jul-17
Title V Operating Permit		310	09-Apr-18	27-Jun-19
TRAX Boiler Pressure Analysis		81	16-Mar-15	08-Jul-15
U1 Engineering		540	30-Jan-17	15-Mar-19
U1 General Engineering & Design		507	30-Jan-17	29-Jan-19
U1 C/S/A Engineering and Design		500	30-Jan-17	18-Jan-19
U1 Mechanical Engineering		364	13-Feb-17	18-Jul-18
U1 Mechanical Design		309	01-May-17	18-Jul-18
U1 Electrical Engineering		344	30-Jan-17	05-Jun-18
U1 Electrical Design		520	27-Feb-17	15-Mar-19
U1 I&C Engineering		368	06-Apr-17	17-Sep-18
U2 Engineering		630	30-Jan-17	28-Jun-19
U2 General Engineering & Design		590	30-Jan-17	03-May-19
U2 C/S/A Engineering and Design		587	30-Jan-17	30-Apr-19
U2 Mechanical Engineering		455	30-Jan-17	26-Oct-18
U2 Mechanical Design		389	02-May-17	26-Oct-18
U2 Electrical Engineering		434	30-Jan-17	27-Sep-18
U2 Electrical Design		610	27-Feb-17	28-Jun-19
U2 I&C Engineering		460	24-Mar-17	27-Dec-18

Remaining Work — Actual Work — WBS Summary
Critical Remaining Work — Milestone

TASK filter: Exclude WBS Activities_1.

Exhibit B to EAI Comments

Activity ID	Activity Name	Ori Dur	Start	Finish
Procurement		1357	18-May-15	28-Jul-20
C/S/A Procurement		98	30-Jan-17	15-Jun-17
Mechanical Procurement		1357	18-May-15	28-Jul-20
Electrical Procurement		347	20-Jul-17	30-Nov-18
I&C Procurement		448	10-Jul-17	15-Apr-19
U1 Construction		720	02-Aug-17	05-May-20
U1 Sitework		150	02-Aug-17	27-Feb-18
U1 Railroad Track & Switch Mods		60	31-Jan-18	24-Apr-18
U1 Highway Mods		60	25-Oct-17	16-Jan-18
U1 SDA		457	28-Feb-18	28-Nov-19
U1 Field Fabricated Tanks		170	16-Jul-18	08-Mar-19
U1 Fabric Filter		419	31-Jan-18	09-Sep-19
U1 ID Booster Fans / Ductwork		436	29-Aug-18	29-Apr-20
U1 Lime Slurry		343	28-Feb-18	21-Jun-19
U1 Recycle Slurry		337	29-Mar-18	12-Jul-19
U1 Byproduct Handling		314	25-Apr-18	08-Jul-19
U1 Auxiliary Power		478	23-May-18	20-Mar-20
U1 Balance of Plant		390	07-Nov-18	05-May-20
U1 System Testing and Commissioning		294	13-Aug-19	27-Sep-20
U2 Construction		686	01-Nov-17	27-Jun-20
U2 Sitework		150	01-Nov-17	29-May-18
U2 SDA		458	30-May-18	28-Feb-20
U2 Field Fabricated Tanks		170	15-Oct-18	07-Jun-19
U2 Fabric Filter		419	02-May-18	09-Dec-19
U2 ID Booster Fans / Ductwork		268	28-Nov-18	07-Dec-19
U2 Lime Slurry		343	30-May-18	20-Sep-19
U2 Recycle Slurry		337	28-Jun-18	11-Oct-19
U2 Byproduct Handling		314	25-Jul-18	07-Oct-19
U2 Auxiliary Power		476	22-Aug-18	17-Jun-20
U2 Balance of Plant		337	06-Feb-19	21-May-20
U2 System Testing and Commissioning		301	05-Nov-19	29-Dec-20



Remaining Work | Actual Work | WBS Summary
Critical Remaining Work | Milestone

TASK filter: Exclude WBS Activities_1.

Exhibit B to EAI Comments

ATTACHMENT 4

Milestone Progress Payment Schedule

Attachment 4

MONTHLY PROGRESS PAYMENT SCHEDULE

Month	Date	Milestone	Individual Payment (%)	Cumulative Payment (%)
1	Feb-17	Award Dry FGD Contract Execution	1.51	1.51
2	Mar-17	DFGD Supplier - Process Flow Diagrams and Mass Balances	0.06	1.57
3	Apr-17	DFGD Supplier - P&ID Drawings	0.06	1.63
4	May-17	DFGD Supplier - General Arrangement Drawings NTE Load Diagrams	0.16	1.79
5	Jun-17	DFGD Supplier - Preliminary 3D CAD Model Award Booster Fans	2.62	4.41
6	Jul-17	NTE Load Diagrams Award Atomizers	0.45	4.86
7	Aug-17	DFGD Supplier - Equipment Lists Award Lime System	6.24	11.10
8	Sep-17	Flue Gas Ductwork Procurement Initiated	0.45	11.55
9	Oct-17	Initial EI&C Design Information NTE Load Diagrams	0.45	12.00
10	Nov-17	Flue Gas Ductwork Procurement Initiated	2.26	14.26
11	Dec-17	Structural Steel Procurement Initiated	0.45	14.71
12	Jan-18	Structural Steel Fabrication Schedule Complete	0.45	15.16
13	Feb-18	SDA and Fabric Filter Design Drawings	4.07	19.23
14	Mar-18	Award DCS	0.45	19.68
15	Apr-18	Award Fabric Filter Bags and Cages Flue Gas Ductwork Start of Fabrication	2.68	22.36
16	May-18	Structural Steel Start of Fabrication	0.57	22.93
17	Jun-18	Physical Flow Model Completed	2.38	25.31
18	Jul-18	Receive Permits for Construction	0.70	26.01
19	Aug-18	Mobilize On-Site	2.67	28.68
20	Sep-18	Unit 1 SDA Delivery Office Complex and Fabrication Areas Set-Up	2.99	31.67
21	Oct-18	Unit 1 and Unit 2 Booster Fan Delivery Lime Storage and Preparation System Delivery Unit 1 Fabric Filter Delivery	5.12	36.79
22	Nov-18	Unit 1 SDA Structural Steel Delivery Unit 1 Duct Delivery Unit 1 SDA-A Support Steel Erection Complete	4.81	41.60
23	Dec-18	Unit 1 SDA-A Inlet Duct Support Steel Complete Unit 1 Fabric Filter Structural Steel Delivery Unit 2 Duct Delivery	4.00	45.60
24	Jan-19	Unit 2 SDA Delivery Unit 1 SDA-A Inlet Duct Erection Complete Unit 1 SDA-C Support Steel Erection Complete	4.32	49.92
25	Feb-19	Unit 1 SDA-A Outlet Duct Erection Complete Unit 1 SDA-A Vessel Shell/Roof Complete Unit 2 Fabric Filter Delivery	4.08	54.00
26	Mar-19	Unit 2 Structural Steel Delivery Unit 1 SDA-B Inlet Duct Erection Complete Unit 1 Fabric Filter-B Hoppers/Wall/Roof Complete	3.99	57.99

Attachment 4

MONTHLY PROGRESS PAYMENT SCHEDULE

Month	Date	Milestone	Individual Payment (%)	Cumulative Payment (%)
27	Apr-19	Unit 1 SDA-B Vessel Shell/Roof Complete	3.99	61.98
		Unit 1 SDA-B Outlet Duct Erection Complete		
		Unit 1 Fabric Filter-B Hoppers/Wall/Roof Complete		
28	May-19	Unit 1 SDA-C Inlet Duct Erection Complete	3.69	65.67
		Unit 1 SDA-C Outlet Duct Erection Complete		
29	Jun-19	Unit 1 SDA-C Vessel Shell/Roof Complete	3.35	69.02
		DCS Equipment Delivery		
		Unit 2 SDA-A Inlet Duct Support Steel Complete		
		Unit 2 SDA-A Support Steel Complete		
30	Jul-19	Unit 1 Booster Fans Erection Complete	3.04	72.06
		Unit 2 SDA-B Inlet Duct Support Steel Complete		
		Unit 1 Fabric Filter-C Hoppers/Wall/Roof Complete		
31	Aug-19	Unit 2 SDA-C Inlet Duct Support Steel Complete	2.93	74.99
		Unit 2 SDA-A Vessel Shell/Roof Complete		
		Unit 2 SDA-A Inlet Duct Erection Complete		
32	Sep-19	Unit 2 SDA-B Support Steel Complete	3.06	78.05
		Operating and Maintenance Manuals		
33	Oct-19	Unit 2 SDA-B Vessel Shell/Roof Complete	3.00	81.05
		Unit 2 SDA-B Inlet Duct Erection Complete		
		Unit 2 SDA-C Support Steel Complete		
34	Nov-19	Unit 2 SDA-A Outlet Duct Erection Complete	2.81	83.86
		Unit 2 Fabric Filter-A Hoppers/Wall/Roof Complete		
35	Dec-19	Unit 2 SDA-C Vessel Shell/Roof Complete	2.76	86.62
		Unit 2 SDA-C Inlet Duct Erection Complete		
36	Jan-20	Unit 2 SDA-B Outlet Duct Erection Complete	2.41	89.03
		Unit 2 Fabric Filter-B Hoppers/Wall/Roof Complete		
		Unit 1 Structural Completion		
37	Feb-20	Unit 2 SDA-C Outlet Duct Erection Complete	2.26	91.29
		Unit 2 Booster Fans Erection Complete		
38	Mar-20	Unit 1 Duct Tie-In Complete	2.23	93.52
39	Apr-20	Unit 1 Mechanical Completion	0.45	93.97
40	May-20	Unit 1 Performance Test Report	0.30	94.27
41	Jun-20	Unit 1 Substantial Completion	0.22	94.49
		Unit 2 Structural Completion		
42	Jul-20	Removal of Fabrication Tables Complete	0.22	94.71
43	Aug-20	Unit 2 Duct Tie-In Complete	0.15	94.86
44	Sep-20	Unit 2 Mechanical Completion	0.07	94.93
45	Oct-20	Unit 2 Substantial Completion	0.07	95.00
		Demobilization Complete		
46	Nov-20	Unit 1 Final Acceptance	2.50	97.50
47	Dec-20	Unit 2 Final Acceptance	2.50	100.00

ATTACHMENT 5

S&L Estimating Documentation:

Indirects and Construction Equipment included in Crew Rates

Indirects and Construction Equipment included in Crew Rates

Typical Construction Equipment included in our Crew Rates

- Air compressor
- Air tugger
- Crane, 5 ton
- Crane, 15 ton mobile
- Crane, 35 ton
- Crane, 50 ton
- Crane, 60 ton
- Dozer
- Finishing machine
- Flat bed trailer
- Fork lift
- Front end loader
- Generator
- Grader
- Pickup truck
- Powdered riding buggy
- Roller, sheepsfoot
- Roller, vibratory
- Radial saw
- Scraper
- Stress relieving machine
- Tremie
- Truck mounted concrete pump
- Vibrator
- Water wagon
- Welding machine
- Wire puller

Site Indirects included in Crew Rates

- Job Supervision-Field Staff
- Administration-Field Staff
- Personnel Hiring
- Craft Superintendents
- Safety / Purchasing/Expediting-Field Staff
- Material Control-Field Staff
- Engineering Liaison-Field Staff
- Project Controls-Field Staff
- Cost/Schedule Controls-Field Staff
- Quality Control Inspection-Field Staff
- Project Office Supplies-Field Staff
- Computer Expenses
- Service Trucks/Supplies
- Field and Shop Mechanics and Supplies
- Subcontract Administration
- Warehousing-Field Staff
- Field Surveying
- Water & Ice
- Sanitation and Cleanup
- Move In/Move Out
- Detours/Barricades/Flags
- Security
- Temp. Utilities/Distr/Hookup
- Temporary Site Improvement
- Temporary Facilities/Buildings
- Utilities Consumption
- Employee Expenses
- Legal Expenses/Claims
- Permits and Fees
- Timekeeping

ATTACHMENT 6

S&L Estimating Documentation:

Escalation Projections

Entergy
White Bluff DGFD Project
Escalation Projections

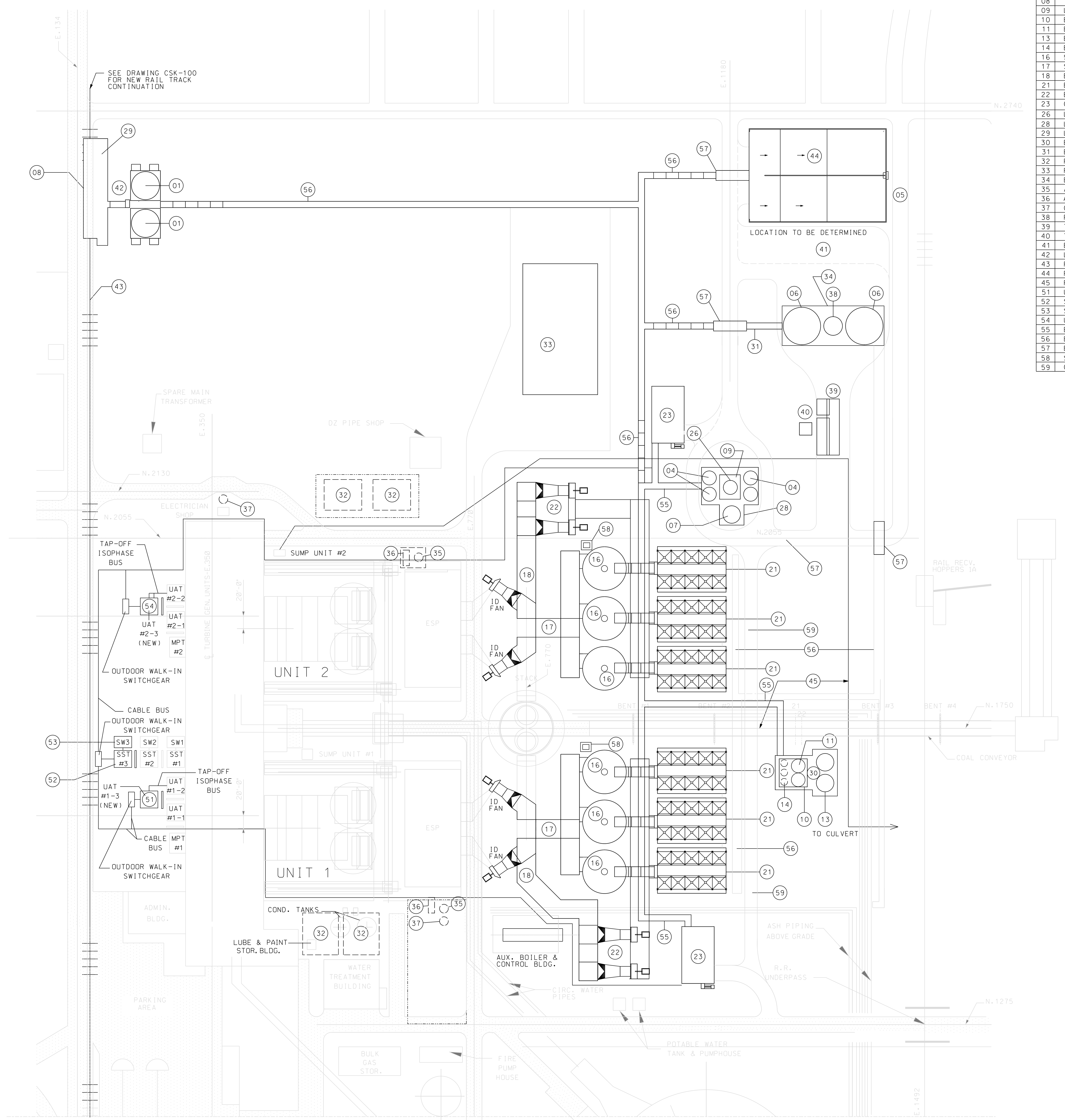
Basis: Pine Bluff Arkansas Labor rates as published in RS Means	Yearly Base Rates + Fringes										
Craft Description	2009	2010	2011	2012	2013	2014	% increase in past 1 year	% increase in past 2 years	% increase in past 3 years	% increase in past 5 years	Projected Potential overall % labor increase next 5 years.
Boilermaker	$38.59	$41.59	$41.59	$41.59	$43.10	$44.39	2.99%	6.73%	6.73%	15.03%	
Iron worker	$28.06	$30.44	$30.44	$30.44	$32.05	$34.00	6.08%	11.70%	11.70%	21.17%	
Pipe Fitter	$25.28	$31.65	$31.65	$31.65	$35.56	$35.56	0.00%	12.35%	12.35%	40.66%	
Electrician	$35.74	$35.74	$35.74	$35.74	$36.95	$36.95	0.00%	3.39%	3.39%	3.39%	
Common Laborer	$16.83	$17.47	$17.47	$17.47	$17.47	$17.47	0.00%	0.00%	0.00%	3.80%	
Average increase in five major crafts							1.82%	6.83%	6.83%	16.81%	**18%**

Misc Material and Equipment (Please see Note 1)									% increase in past 3 years	% increase in past 5 years	Projected Potential overall % increase next 5 years.
Construction & Building Index									8%	15%	17.00%
Material Price, Construction Mat.									8%	7%	10.00%
Plant Cost Index									no increase	slightly negative	5.00%
Civil Work									8%	14%	15.00%
Steel - ductwork									no increase	slightly negative	8.00%
Steel - rolled shape									8%	no increase	10.00%
Architectural									5%	4%	8.00%
Overall mechanical equipment									4%	1%	7.00%
Overall piping									6%	11%	12.00%
Overall electrical equipment									9%	17%	18.00%
Raceway, Cable Tray, & Conduit									8%	slightly negative	10.00%
Electrical cable									14%	7%	15.00%
Controls & Instrumentation									1%	1%	5.00%
Average overall increase for Power back-fit projects									**7%**	**9%**	**11%**

Note 1: From major industrial sources such as BLS, Chemical Engineering, Handy Whitman, ENR Commodity pricing (20 city average),

ATTACHMENT 7

Conceptual General Arrangement Drawing



LEGEND	
01	LIME STORAGE SILOS
03	NOT USED
04	LIME SLURRY FEED TANKS
05	BYPRODUCT HAUL ROAD
06	BYPRODUCT STORAGE SILOS
07	SLAKING WATER STORAGE TANK
08	TRAIN UNLOADING SHED
09	LIME PREPARATION BUILDING
10	BYPRODUCT RECYCLE EQUIPMENT BUILDING
11	BYPRODUCT RECYCLE DAY BINS
13	BYPRODUCT RECYCLE MAKE-UP WATER TANKS
14	BYPRODUCT RECYCLE SLURRY TANKS
16	SPRAY DRYER ABSORBERS
17	SDA FLUE GAS INLET DUCTS
18	BOOSTER FAN DISCHARGE
21	BAG HOUSES
22	BOOSTER FANS
23	COMPRESSOR / ELECTRICAL BUILDINGS
26	LIME DAY BIN
28	LIME PREPARATION AREA
29	LIME UNLOADING EQUIPMENT ROOM
30	BYPRODUCT RECYCLE AREA
31	ELEVATED BOP CONTRACTOR UTILITY RACK
32	FUTURE PROVISION SPACE FOR SCRS
33	FGD SPARE PARTS WAREHOUSE
34	BYPRODUCT HANDLING AREA
35	ACI SILOS
36	ACI ELECTRICAL BUILDINGS
37	CHI TANK
38	FLY ASH SILO
39	TRUCK SCALES
40	TRUCK SCALE HOUSE
41	BYPRODUCT TRUCK PARKING
42	LIME UNLOADING AND STORAGE AREA
43	RAIL SPUR
44	PROCESS WATER RETENTION PONDS
45	PROPOSED GRATED CONCRETE TRENCH
51	UNIT AUX. TRANSFORMER UNIT 1
52	STARTUP / STANDBY TRANSFORMER COMMON (UNITS 1&2)
53	SWITCH
54	UNIT AUX. TRANSFORMER UNIT 2
55	ELEVATED FGD CONTRACTOR UTILITY RACK
56	BOP SLEEPER RACK
57	BOP TRENCH
58	SDA PENTHOUSE ELEVATOR
59	CRANE MAINTENANCE AISLE

HOLD INFORMATION

NO.	DATE	DESCRIPTION

CONTRACTOR/INSTALLER SHALL TAKE ALL APPROPRIATE PRECAUTIONS TO ENSURE THE SAFETY OF ALL PEOPLE LOCATED ON THE WORK SITE, INCLUDING CONTRACTOR'S/INSTALLER'S PERSONNEL (OR THAT OF ITS SUB-CONTRACTOR(S)) PERFORMING THE WORK.

RELEASE INFORMATION

REV.	DATE	DESCRIPTION

ISSUE PURPOSE: ISSUED FOR STUDY

SPECIFICATION: -

PROJECT NO.: 13138-001

I HEREBY CERTIFY THAT THIS ENGINEERING DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT PERSONAL SUPERVISION AND THAT I AM A DULY LICENSED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF ARKANSAS.

ENTER NAME
ENTER DATE

MY LICENSE RENEWAL DATE IS: ENTER DATE
PAGES OR SHEETS COVERED BY THIS SEAL:
THIS DOCUMENT ONLY.

CAD FILE NAME: M-GA-001.DGN

PREPARED BY: D.J.MERRICK

REVIEWED BY: G.A.RIVERA

APPROVED BY: S.C.MCHONE

ANY MODIFICATION OR ADDITION TO THIS DRAWING BY AN ORGANIZATION OTHER THAN SARGENT & LUNDY, IS NOT THE RESPONSIBILITY OF SARGENT & LUNDY.

Sargent & Lundy LLC

SARGENT & LUNDY LLC
55 EAST MONROE STREET
CHICAGO, ILLINOIS 60603-5780
WWW.SARGENTLUNDY.COM
CERTIFICATE OF AUTHORIZATION NO. 6938

Entergy

PROJECT

WHITE BLUFF STATION
UNITS 1 & 2
ENTERGY

DRAWING TITLE

GENERAL ARRANGEMENT
SDA SITE DEVELOPMENT

DRAWING NUMBER	REVISION
M-GA-001	N/A

SHEET 1 OF 1

PRELIMINARY
NOT FOR CONSTRUCTION

NORTH

60' 0 60' 120' 180'
GRAPHIC SCALE
DRAWING SCALE
1" = 60'-0"

ATTACHMENT 8

Entergy Basis of Contingency

WB FGD Project
Risk Register

Contingency Estimate					
Estimate Total w/o Contingency, IDC, Escalation	**$ 740,968,200**				
	P90	**P80**	**P70**	**P60**	**P50**
Risk Contingency	**$ 35,870,000**	**$ 27,220,000**	**$ 20,550,000**	**$ 16,210,000**	**$ 13,090,000**
Estimate Uncertainty Contingency	**$ 95,350,000**	**$ 66,600,000**	**$ 41,540,000**	**$ 21,330,000**	**$ (290,000)**
Unknown Risk Contingency	**$ 18,560,000**	**$ 17,380,000**	**$ 16,450,000**	**$ 15,610,000**	**$ 14,810,000**
Total Contingency	$ 149,780,000	$ 111,200,000	$ 78,540,000	$ 53,150,000	$ 27,610,000
Percentage of Total	20%	15%	11%	7%	4%
Total Estimate w/ Contingency	$ 890,748,200	$ 852,168,200	$ 819,508,200	$ 794,118,200	$ 768,578,200

Project Delivery Standard

	Estimate Characteristic			**Resulting Range**	
Estimate class	**Maturity level of project definition** **expressed as % of complete engineering**	**End usage** **typical purpose of estimate**	**Methodology** **typical estimating method**	**Estimate accuracy range** **typical variation in low & high ranges**	**Target contingency range**
Class 5	0 to 2%	Rough Order of Magnitude (ROM)	Capacity factored, parametric models, judgment, or analogy	-50 to +100%	30 to 50%
Class 4	1 to 15%	Feasibility	Equipment factored or parametric models	-30 to +50%	25 to 40%
Class 3	10 to 50%	Funding Authorization	Semi-detailed unit costs with assembly level line items	-20 to +30%	15 to 30%
Class 2	30 to 90%	Control	Detailed unit costs with forced detailed take-off	-15 to +20%	5 to 20%
Class 1	50 to 100%	Check Estimate	Detailed unit cost with detailed take-off	-10 to +15%	2 to 7%

ESTIMATE UNCERTAINTY

Risk Category	Description of Risk	Quantitative Risk Analysis					Status / Comments
		Estimate Total w/out Contingency	Min ($)	Expected	Max ($)	QRA Comments	
Estimate Uncertainty	**EPC Contract**	$ 752,912,300	($188,228,075)	$0	$188,228,075	From S&L estimate report, the project definition and accuracy of the individual components in this estimate result in an overall accuracy of +/- 25%.	
Estimate Uncertainty	**Owner's Costs**	$ 58,546,000	($11,709,200)	$0	$17,563,800	Estimate from Entergy, estimate is considered a Class 3 (+30% to -20%).	Entergy Indirects were calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the internal loaders estimate.
Estimate Uncertainty	**Third Party Services**	$ 12,544,000	($3,136,000)	$0	$3,136,000	From S&L estimate report, estimate is considered a Class 3 (+25% to -25%)	

WB FGD Project
Risk Register

UNKNOWN RISK							
		Quantitative Risk Analysis					
Risk Category	Description of Risk	Estimate Total w/out Contingency	Min ($)	Expected	Max ($)	QRA Comments	Status / Comments
Unknown Risks	**UNKNOWN RISKS:** This is part of the calculation for the overall contingency to include in the project budget.	$ 740,968,200	$ 7,409,682	$ 14,819,364	$ 22,229,046	Estimating standard guidance. Min = 1%, Exp = 2%, Max = 3%	Due to lack of historical data and current project development, there are a range of potential impacts from unknown risks not yet captured in the estimate uncertainty and identified risks, Entergy contingency guidance is to use 1% - 3% of the total estimate without contingency. This item can be captured in the risk register and modeled with the identified risks when estimating contingency.

WB FGD Project
Risk Register

IDENTIFIED RISKS																		
				SCORING							Quantitative Risk Analysis							
Risk ID	Risk Category	Description of Risk	Unit	Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	Status / Comments
2014-007	Budget	**PROJECT BUDGET - CRAFT LABOR - PER DIEM RATE RISK:** This risk is related to the required craft labor per diem increasing due to the high demand of craft labor, at a percentage greater than the estimated rate.	ALL	3	2	0	0	**6**	Low	An increase to per diem to attract labor will increase the project total estimate.	45%	$0	$0	$4,290,000	Yes	The estimated Per Diem is $13M. Assume a 33% increase as a max.	
2014-002	Budget	**PROJECT BUDGET - CRAFT LABOR - WAGE RATE ESCALATION:** This risk is related to wage rates rising, at a rate greater than the rate used in the estimate, due to the high demand for craft labor.	ALL	3	3	0	0	**9**	Low	Received rates over 10-year period from S&L. Range has fluctuated from 0% to 21.23% during that period. Current economic conditions indicate a high probability of craft labor rates increasing beyond the current projection of 3.35% provided by S&L.	45%	($19,700,000)	$0	$42,300,000	Yes	Received rates over 10-year period from S&L. Looked at range and average high and low rates. Expected escalation rate is 3.35%. Assumed Min rate of 1.675% and Max rate of 6.7%. Results in potential increase of $42.3M over current escalation estimate and potential decrease of $19.7M.	
2014-001	Budget	**PROJECT BUDGET - IDC:** This risk is related to the cost of capital increasing over the life of the project, at a rate different than the current estimated escalation rate.	ALL	1	5	0	2	**7**	Low	The EPA Cost Control Manual uses a rate of 7% which was used for the estimate. Historical EAI AFUDC rates have been under 7%.	5%	$0	$0	$25,000,000	Yes	Assumes an index rate of 7.5%; this results in an increase of ~$25M over current IDC estimate.	
2014-006	Budget	**PROJECT BUDGET - CAPITAL SUSPENSE ADJUSTMENTS:** The risk is related to Capital Suspense increasing over the life of the project from the current Entergy forecasted rate.	ALL	2	3	1	1	**10**	Low	Adjustment of rates impact the project total estimate.	25%	$0	$0	$0	No	Entergy Indirects will be calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the internal loaders estimate.	

Risk ID	Risk Category	Description of Risk	Unit	Prob. Rating & History (SCORING)	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability (Quantitative Risk Analysis)	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	Status / Comments
2014-005	Budget	**PROJECT BUDGET - EPC MATERIAL ESCALATION:** Project material cost may be subject to escalation	ALL	1	3	0	1	**4**	Low	Material escalation is included in the project estimate.	5%	$0	$0	$0	No	Material escalation is included in the project estimate. The estimate uncertainty addresses the risk of the amount of material and the material escalation rate being different than the current forecasted rates.	
2014-003	Budget	**PROJECT BUDGET - LIME ESCALATION:** Project lime cost may be subject to escalation different than the estimated rate.	ALL	3	1	0	0	**3**	Low	Assume that lime escalation rate will increase during project.	45%	$0	$0	$0	No	Budgeted Lime escalation rate is 2.15%. The estimate uncertainty addresses the risk of the amount of material and the escalation rate being different than the current forecasted escalation rate.	
2014-005	Budget	**PROJECT BUDGET - MATERIAL LOADER ADJUSTMENTS:** The risk is related to the material loaders increasing over the life of the project from the current Entergy forecasted loaders.	ALL	4	1	0	0	**4**	Low	Probability that Material Loaders will change over life of the project.	20%	$0	$0	$0	No	Entergy Indirects will be calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the internal loaders estimate.	
2014-004	Budget	**PROJECT BUDGET - PAYROLL LOADER ADJUSTMENTS:** The risk is related to the payroll loaders increasing over the life of the project from the current Entergy forecasted loaders.	ALL	4	2	0	0	**8**	Low	Probability that Payroll Loaders will change over the life of the project.	70%	$0	$0	$0	No	Entergy Indirects will be calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the Entergy Payroll estimate.	
2014-006	Budget	**SALES TAX:** Risk that the sales tax rate will change and add additional costs to the project.	ALL	2	1	0	0	**2**	Low	Probability that the Sales Tax will change order the life of the project.	20%	$0	$0	$0	No	The risk associated with a Sales Tax change will be included in the estimate uncertainty, which also includes the risk of the quantity of materials subject to sales tax.	

Risk ID	Risk Category	Description of Risk	Unit	SCORING Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Quantitative Risk Analysis Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	Status / Comments
2014-010	Eng	**DESIGN CRITERIA:** Design criteria is missing information, or information is incorrect resulting in changes to the technical specifications and requirements during the project. The risk would result in re-engineering / re-work.	ALL	2	3	3	1	**14**	Medium Low	The Owner's Engineer (S&L) has performed Engineering Studies in 2009 and 2013. The revised Design Criteria document reflects the current project requirements.	20%	$0	$5,000,000	$25,000,000	Yes	Assumption that the design criteria accurately reflects the requirements of the project, any corrections will have minimal impact to detailed design. Min is 0%, Expected is 1%, Max is 5% of EPC Direct Costs $500M.	
2014-011	Eng	**ENGINEERING SUPPORT:** Inadequate support to review EPC contractor's design to ensure it meets Entergy requirements. The risk would result in re-engineering / re-work.	ALL	1	3	3	2	**8**	Low	The Project will use an Owner's Engineer to augment staff requirements to mitigate this risk. This risk is the potential for redesign based on inadequate reviews.	5%	$0	$5,000,000	$25,000,000	Yes	Assumption that there will be minimal rework based on inadequate Entergy review of EPC contractor design. Min is 0%, Expected is 1%, Max is 5% of EPC Direct Costs $500M.	
2014-012	Eng	**SCOPE GAP OR CHANGES:** Work scope not defined in EPC contract, and not identified/unforeseen conditions in project budget. Risk would result in additional scope to EPC contract.	ALL	2	4	3	2	**18**	Medium Low	Low probability due to 2009 and 2013 studies. BOP scope not as defined as FGD island. There is only minimal engineering complete at this stage. Also, risk covers the potential for additional design requirements over base FGD design to meet Entergy standard designs.	20%	$5,000,000	$15,000,000	$45,000,000	Yes	Assumption that any missed scope will not be significant, there is an Open Book period for development. Assume minimum of 1% of the $500M FGD direct costs, 3% expected, 9% max.	
2014-013	Eng	**TECHNOLOGY - BAGHOUSE**: The baghouse on each of the units fails to meet the PM emissions limits.	ALL	1	3	5	5	**13**	Medium Low	Low probability due to proven technologies will be specified, and EPC contract will have vendor guarantees.	5%	$0	$0	$0	No	Not included in QRA. Final payment of EPC contract will be based on successful demonstration of performance.	
2014-014	Eng	**TECHNOLOGY - Dry FGD**: The selection of the technology to meet the emission limits with margin is insufficient to meet the required limits.	ALL	1	3	5	5	**13**	Medium Low	Low probability due to proven technologies will be specified, and EPC contract will have vendor guarantees.	5%	$0	$0	$0	No	Not included in QRA. Final payment of EPC contract will be based on successful demonstration of performance.	

WB FGD Project
Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING: Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Quantitative Risk Analysis: Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	Status / Comments
2014-015	Env	**AIR PERMIT (AR) - DELAY**: Delay in receiving the permit, for an additional 6 months (24 total).	ALL	1	2	3	3	**8**	Low	Cost impact to expedite project to stay on schedule as a result in the delay. The current timeline of 18 months accounts for some expected delay.	5%	$0	$0	$3,000,000	Yes	Assume $500k/month for up to 6 mo of delay. This would be prior to FNTP.	In the current timeline, there is some schedule float that could be used. Entergy could release FNTP prior to receipt of the air permit.
2014-016	Env	**ASH DISPOSAL:** EPA determines that combustion byproducts are a hazardous waste resulting in need to utilize other material to stabilize scrubber byproduct.	ALL	1	1	0	3	**4**	Low	Cost impact: possible HAZMAT training and treatment of ash. Still would landfill on site. Loss of ash sales.	5%	$0	$0	$150,000	Yes	Assume some additional training, and minimal equipment modifications.	Most ash will be collected in the ESP. This risk would be addressed by a separate project.
2014-018	Env	**COMPLIANCE RULE - Vacated or Delayed:** If the rule is vacated or delayed, what is the impact?	ALL	1	2	0	0	**2**	Low	Assume delay prior to project approval but same compliance period to comply. Cost impact: engineering, payroll, AFUDC during delay period.	5%	$0	$0	$3,000,000	Yes	Project delayed prior to LNTP. Assume $500k/month for 6 months.	
2014-017	Env	**ASH DISPOSAL:** The ADEQ might impose the same permit restriction as it did at the Flint Creek Plant and not allow WB to route landfill leachate directly to the surge pond.	ALL	3	0	0	1	**3**	Low	Project will not increase probablility to occurrence; plant O&M risk. Cost impact: treatment of leachate prior to sending to surge pond.	45%	$0	$0	$0	No	Plant O&M risk.	
2014-019	EPC	**CONSTRUCTION DELAYS:** Construction delays could negatively affect the project and ability to meet a compliance date target. It includes the following contractor identified risks: 1) Damage or late delivery of equipment and materials 2) Weather impact to craft productivity and full or partial site shutdown 3) Craft productivity 4) Labor availability of pipefitters, welders, and electricians	WB1	2	2	3	2	**14**	Medium Low	The contracting strategy will use schedule incentives to maintain the schedule. The labor availability risk will be shared with the contractor, craft labor escalation is a separate risk item.	20%	$0	$4,000,000	$16,000,000	Yes	These delay estimates represent Owner's costs due to the delay (AFUDC, labor) 0-8 mo delay at $2M/month. Current schedule reflects adequate available time for the EPC contractor to account for these delays. Escalation is a separate risk.	Identified risks will be assigned to the EPC contractor.

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2014-021	EPC	**Delay in FNTP:** Delay in Entergy issuing FNTP	ALL	2	2	2	3	**14**	Medium Low	Delay in issuing FNTP. Delays for receipt of the air permit or regulatory approval are separately identified risks.	20%	$0	$3,000,000	$6,000,000	Yes	Assume EPC contractor request compensation for the FNTP delay (equipment contracts, etc). ($1M/month delay)	
2014-022	EPC	**Delay in LNTP:** Delay in Entergy issuing LNTP	ALL	2	2	2	3	**14**	Medium Low	Delay in receiving internal approvals.	20%	$0	$1,500,000	$3,000,000	Yes	Assume EPC contractor request compensation for the LNTP delay (equipment contracts, etc). ($0.5M/month delay)	
2014-023	EPC	**EPC CONTRACT EQUIPMENT VALUE:** Equipment estimate uncertainty during the period from when the contract price is developed to the LNTP.	ALL	2	4	0	1	**10**	Low	The time between the Open Book Period and LNTP is approximately 14 months.	20%	$0	$8,000,000	$20,000,000	Yes	Risk of price changes for $400M of the EPC contract, subject to 14 months between negotiation and award. Min = 0%, Exp = 2%, Max = 5%	
2014-024	EPC	**EPC CONTRACT:** Negotiated EPC fee	ALL	2	4	0	2	**12**	Medium Low	EPC Fee assumed to be in the 8%-15% range.	20%	($12,000,000)	$0	$12,000,000	Yes	Estimate includes a 10% fee or ~$60M. Min = 8% fee, Max = 12% fee.	
2014-069	EPC	**EPC CREDIT RISK:** EPC contractor default on contractor (EPC procurement costs)	ALL	1	1	1	3	**5**	Low	Entergy will work with qualified vendors that have had a credit risk review.	5%	$0	$0	$7,500,000	Yes	Estimate of EPC procurement costs, negotiating, and potential incrase on contract value. To account for procurement activities, Max 1% of EPC value	

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2014-070	EPC	**EPC CREDIT RISK:** EPC contractor default on contractor (schedule delay)	ALL	1	5	5	5	**15**	Low	Entergy will work with qualified vendors that have had a credit risk review.	5%	$0	$0	$36,000,000	Yes	Default of the EPC contractor would result in delay of project to procure and onboard a new contractor. For this calculation, the EPC contractor is assumed to default during construction. Apply amount of IDC ($4M/mo) plus carrying costs of Entergy costs ($500k/mo) at this date through end of project to the expected delays (max: 8 mo).	
2014-032	EPC	**SCHEDULE - Delayed:** Change in project schedule due to longer compliance timeline.	ALL	1	1	1	1	**3**	Low	Assume that, if compliance date is delayed, then all costs will shift accordingly. Incremental costs would be maintaining internal staff in the interim, IDC.	5%	$0	$0	$12,000,000	Yes	Assume delay would be known before contract award, when the FIP or SIP is issued. Delay of min = 0 mo, exp = 0 mo, max = 24 mo @ $500k/mo	
2014-033	EPC	**SCHEDULE - Shorter Compliance Timeline:** Change in project schedule that shortens compliance timeline.	ALL	1	4	0	3	**7**	Low	Assume that labor costs and costs to expidite equipment would increase to comply with earlier timeline.	5%	$0	$0	$30,000,000	Yes	Assumption that current schedule has some float, add $ for premium time, less IDC costs. Assume 15% increase of estimated craft labor of ~$200M.	
2014-035	EPC	**UN-IDENTIFIED UNDERGROUND OBSTRUCTION:** Claims for extra work for un-identified underground pipe, etc.	ALL	2	3	2	2	**14**	Medium Low	Project plans to perform exploration work to identify unknown underground obstructions during the Open Book period. This risk if realized will increase the EPC contract price.	20%	$0	$500,000	$3,000,000	Yes	Assumption that any missed scope will not be significant. Schedule delays of $500k/month.	

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2014-036	EPC	**WEATHER-RELATED DELAYS:** Extreme weather can greatly affect craft productivity and result in partial or complete site shutdown. Such weather conditions can increase the risk and provide the basis for a contractor claim for a change order.	ALL	1	1	3	2	**6**	Low	The project is subject to extreme weather events. This risk will be further developed during the Open Book period.	5%	$0	$4,000,000	$12,000,000	Yes	These delay estimates represent Owner's costs due to the delay (AFUDC, labor) 0-6 mo delay at $2M/month. Assumption that the current schedule has sufficient float to mitigate this risk. The Open Book period will be used to develop a more detailed schedule.	The project execution plan is to perform a majority of the construction prior to any outage. Weather risks will be assigned to the EPC contractor.
2014-020	EPC	**CONSTRUCTION DELAYS:** Construction delays could negatively affect the project and ability to meet a compliance date target. It includes the following contractor identified risks: 1) Damage or late delivery of equipment and materials 2) Weather impact to craft productivity and full or partial site shutdown 3) Craft productivity 4) Labor availability of pipefitters, welders, and electricians	WB2	2	2	3	2	**14**	Medium Low	The contracting strategy will use schedule incentives to maintain the schedule. The labor availability risk will be shared with the contractor, craft labor escalation is a separate risk item.	20%	$0	$0	$0	No	Risk QRA combined with EPC Construction Delays for WB1. Current schedule reflects adequate available time for the EPC contractor to account for these delays. Escalation is a separate risk.	Identified risks will be assigned to the EPC contractor.
2014-008	EPC	**LABOR:** Schedule delays due to union labor disputes.	ALL	1	2	2	2	**6**	Low	Using non-union labor.	5%	$0	$0	$0	No	Using non-union labor.	

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2014-027	EPC	**OPEN BOOK PERIOD**: Change in contract terms (Limitiation of Liability) during EPC contract negotiations.	ALL	1	3	0	1	**4**	Low	The RFP process to select the EPC contractor will require the contractor to state required terms for an EPC contractor prior to their selection. The Open Book period should not increase their project risk profile, which would be a driver for a change in their terms.	5%	$0	$0	$0	No	Not included in QRA. Project estimate includes estimate uncertainty for this risk.	
2014-028	EPC	**OPEN BOOK PERIOD**: Change in rates from EPC contractor during open book period.	ALL	1	1	0	1	**2**	Low	The EPC contractor's labor and equipment rates will be negotiated during the Open Book period to develop the contract price.	5%	$0	$0	$0	No	Not included in QRA. Project estimate includes estimate uncertainty for this risk.	
2014-029	EPC	**OPEN BOOK PERIOD**: Unable to negotiate a fixed price contract.	ALL	1	0	0	0	**0**	Low	The scope and schedule of this project are sufficient to meet the project goals. There is no indication that this risk is probable.	5%	$0	$0	$0	No	Not included in QRA.	
2014-030	EPC	**POOR PERFORMANCE BY CONTRACTOR ON PROJECT:** Risk of claims and change orders increases if contractor expects and/or experiences loss on the project.	ALL	1	1	2	1	**4**	Low	Risk exists for contractor claims, project controls will be in-place to support Entergy. Risk is for total claims greater than the amount of contingency.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-031	EPC	**POOR QUALITY OF CONTRACTOR WORK**: Schedule impact due to rework and adverse affect on long-term plant operation.	ALL	1	1	2	1	**4**	Low	EPC bidders will be selected based on Entergy experience and previous work experience.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	

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2014-034	EPC	**SCOPE OR DESIGN PROBLEMS:** Poor scope, technical design, or unclear technical requirements could result in change orders with added cost and/or schedule delay or an end product that does meet customer needs	ALL	3	3	3	2	**24**	Medium Low	Complicated project with many interfaces to exisitng facility. Assume multiple small change orders.	45%	$0	$0	$0	No	Not included in QRA. This risk is similar to Engineering risks. Project estimate includes estimate uncertainty for this risk.	
2014-037	EPC	**POOR PERFORMANCE:** Contractor does not meet schedule or performance requirements.	ALL	2	1	2	1	**8**	Low	Risk exists for contractor claims, project controls will be in-place to support Entergy.	20%	$0	$0	$12,000,000	Yes	These delay estimates represent Owner's costs due to the delay (AFUDC, labor) 0-6 mo delay at $2M/month.	
2014-038	Goal	**COMPLIANCE - NON-COMPLIANCE**: The new emission standards cannot be met by the units.	ALL	1	5	5	5	**15**	Medium Low	Industry information shows that the emission compliance levels can be met with the available tecnologies.	5%	$0	$0	$0	No	Cost estimate is beyond project value.	
2014-053	Ops	**LONG TERM OPERATION - CAPACITY:** Unit derate or capacity restriction resulting from control technologies.	ALL	1	1	1	1	**3**	Low	Unit capacity will be affected by this project. It will be defined and a guarantee will be negotiated with the EPC contractor.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	Review this risk after Open Book Period to determine capacity impact of project.
2014-054	Ops	**LONG TERM OPERATION - INCREASED O&M:** Increases to the unit's O&M due to control technology.	ALL	1	1	1	1	**3**	Low	Additional O&M will be required by this project. It will be defined when the technology is selected during the Open Book period.	5%	$0	$0	$0	No	Not a project risk.	Review this risk after Open Book Period to determine O&M impact of project.
2014-055	Ops	**LONG TERM OPERATION - OPERATOR INTERFACE:** An increase in training requirements due to control technology.	ALL	1	1	1	1	**3**	Low	Additional Operator interface will be required by this project.	5%	$0	$0	$0	No	Not a project risk.	Additional Operations staff is included in the project estimate. Review this risk after Open Book Period to determine impact of project.

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2014-056	Ops	**LONG TERM OPERATION - RELIABILITY:** Impacts to the unit's reliability.	ALL	1	1	1	1	**3**	Low	The EPC contract will require equipment guarantees and system redundancy to provide reliability.	5%	$0	$0	$0	No	Not a project risk.	Review this risk after Open Book Period to determine O&M impact of project.
2014-057	Permiting	**Department of Transportation:** Impact of schedule delay due to permitting the road modification.	ALL	1	1	1	0	**2**	Low	Unable to determine risk until Open Book Period to understand permit time required and date when road modification must be in place.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	Review this risk after Open Book Period to determine O&M impact of project.
2014-058	Permitting	**REGULATION CHANGE:** Change in future regulation to lower emission limits or 30-day rolling average.	ALL	1	1	0	0	**1**	Low	Need additional information, this would be a future project. Technology for FGD has not been determined	5%	$0	$0	$0	No	Risk will be mitigated during technology selection.	
2014-040	PM	**INTERNAL APPROVALS:** Possible delays due to delay of internal approval of contracts	ALL	2	1	1	2	**8**	Low	Risk exists with the challenges of obtaining internal approvals.	20%	$0	$0	$1,500,000	Yes	Assume internal project team continues to support Board approval during the regulatory and permitting periods. (Assume $500k/mo).	
2014-041	PM	**ISSUE RESOLUTION:** Possible schedule delays due to non-resolution of issues as they arise.	ALL	2	2	3	2	**14**	Medium Low	Risk exists for undefined issues.	20%	$4,500,000	$9,000,000	$13,500,000	Yes	Undefined issues may impact schedule & project scope. (Assume AFUDC ($4M) + Owner's costs ($500k) per month) Min = 1 mo, expected = 2 mo, max = 3 mo)	
2014-039	PM	**COMMUNICATIONS:** Possible schedule delays and costs increases due to poor communication between all parties	ALL	1	1	2	2	**5**	Low	Risk exists for contractor claims. The contracting strategy using only one EPC contractor should minimize this risk.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $. Adequate staffing of project is a separate risk.	

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2014-042	PM	**MANAGEMENT - INSUFFICIENT INTERNAL PROJECT STAFF:** Insufficient Internal project resources - unable to meet schedule. Project costs increase.	ALL	2	2	0	2	**8**	Low	Internal labor costs would be higher than budgeted.	20%	$0	$0	$0	No	Project will plan to use outside contractors to staff project.	
2014-043	PM	**MANAGEMENT - PRUDENCY DETERMINATION:** The project team is unable to justify and document project decisions and the related costs to defend decisions as prudent in future rate cases. Mitigation includes processes for contemporaneous documentation.	ALL	1	1	1	3	**5**	Low	The project will follow project delivery standards, risk should be minimal.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-044	PM	**PROJECT CONTROLS:** Project has insufficient project controls / oversight / documentation to manage and control cost.	ALL	1	3	0	4	**7**	Low	Stage Gate process requires project controls. Generic project costs would be higher than budgeted.	5%	$0	$0	$0	No	Additional staff included in the project estimate to cover PEI oversight of project.	
2014-045	PM	**RECORDS MANAGEMENT:** Document control is insufficient leading to inability to support Regulatory Recovery	ALL	1	1	1	3	**5**	Low	The project will follow project delivery standards, risk should be minimal.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-048	PM	**SCOPE CHANGES:** Possible delays or increased cost due to improperly managed project scope changes.	ALL	1	2	2	2	**6**	Low	Potential delays due to internal decisions in a timely manner.	5%	$0	$0	$0	No	Not included in QRA. Missed scope part of the Engineering risks.	

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2014-059	Reg	**REGULATORY - DELAY:** Regulatory delays could negatively affect the project schedule. The expected duration is estimated to be 18 months.	ALL	2	2	5	4	**22**	Medium Low	Project schedule assumes 18 mo to receive approval. If additional time is required, Entergy may choose to issue FNTP prior to receipt to avoid potential costs.	20%	$0	$0	$3,000,000	Yes	Assumption that current schedule has some float, add $ for premium time, less AFUDC costs. ($0.5M/month delay)	
2014-068	Schedule	**SCHEDULE - FORCE MAJEURE** - Increase in cost of project due to force majeure	ALL	1	1	1	1	**3**	Low	BAR insurance will be in place.	5%	$0	$0	$10,000,000	Yes	Insurance deductible is expected to be structured similar to other projects. $500,000 deductible for flood, 5% of insured value for Named Windstorm with min of $1,000,000 and max of $10,000,000.	
2014-062	Schedule	**COMPLIANCE - DEADLINE**: Risk that the project will not meet the deadline?	ALL	1	3	4	3	**10**	Low	Current timeline has sufficient time to develop project.	5%	$0	$0	$0	No	Current schedule reflects adequate available time to complete the project. EPC contract will include schedule requirements.	
2014-063	Schedule	**OUTAGE SCHEDULE:** Outage schedule moves from current schedule dates.	WB1	2	1	1	1	**6**	Low	Project expects the current scheduled outages to move to meet project requirements.	20%	$0	$0	$0	No	Schedule flexibility is expected.	
2014-064	Schedule	**OUTAGE SCHEDULE:** Outage schedule moves from current schedule dates.	WB2	2	1	1	1	**6**	Low	Project expects the current scheduled outages to move to meet project requirements.	20%	$0	$0	$0	No	Schedule flexibility is expected.	
2014-066	Schedule	**SCHEDULE INSUFFICIENT:** EPC Contractor does not provide schedule with sufficient level of detail to coordinate activities	ALL	1	1	1	1	**3**	Low	EPC contract will require detailed project schedule. Entergy project controls will be in-place to support schedule development and maintenance.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-067	Supply Chain	**LIME AVAILABILITY:** Will the required lime for the long term operation be available?	ALL	1	1	1	1	**3**	Low	S&L study did not identify lime availability concerns.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	

Probability and Impact Definition

Probability Rating	Probability Definition (Likelihood of Occurrence)	Discreet Value for QRA
1	Less than or equal to 10 % Probability of Occurrence	5%
2	Greater than 10% but less that 30 % Probability of Occurrence	20%
3	Greater than 30% but less that 60 % Probability of Occurrence	45%
4	Greater than 60% but less that 80 % Probability of Occurrence	70%
5	Greater than 80% Probability of Occurrence	90%

Cost Impact Rating	Cost Impact Value (Impact to Entergy Cost only) (Project Cost = $500M)	Min Cost Impact (QRA)	Most Likely Cost Impact (QRA)	Max Cost Impact (QRA)
1	(<0.5% of project cost)	$ 100,000	$ 1,000,000	$ 2,500,000
2	(0.5% - 1.4% of project cost)	$ 2,500,000	$ 4,750,000	$ 7,000,000
3	(1.5% - 2.9% of project cost)	$ 7,000,000	$ 11,000,000	$ 15,000,000
4	(3% - 4.9% of project cost)	$ 15,000,000	$ 20,000,000	$ 25,000,000
5	(>5% of project cost)	$ 25,000,000	$ 37,500,000	$ 50,000,000

Schedule Impact Rating	Schedule Impact Value (Impact to Affected Summary Activity)	Min Schedule Impact (QRA)	Most Likely Schedule Impact (QRA)	Max Schedule Impact (QRA)
1	Less than 30 days	0	15	30
2	Between 30 and 60 Calendar days	30	45	60
3	Between 60 and 90 Calendar days	60	75	90
4	Between 90 and 150 calendar days	90	120	150
5	Between 150 and 210 calendar days	150	180	210

Other Impact Rating	Other Effect on Project (Regulatory/Legal, Safety, Company Reputation and Quality) - more details below
1	No impact
2	Minimal Impact
3	Moderate Impact
4	Significant Impact
5	Severe Impact

Other Impact Value	IMPACT (Effect on Project)
1	Has no impact on (**Company Reputation**)
	Has no impact on quality (**Quality**)
	Not likely to result in injury or illness (**Safety**)
	No impact on timely CPCN or full cost recovery (**Regulatory/Legal**)
2	Has limited impact on (**Company Reputation**)
	Quality issue has minimal impact on project (**Quality**)
	Has a direct, minor impact on a near miss driver, an OSHA RA driver, or human error mechanism. Is an emerging
	CPCN delayed by less than 1 month and/or cost disallowance up to $7,500,000 (**Regulatory/Legal**)
3	Has moderate impact on (**Company Reputation**)
	Quality issue affects work activities and requires application of the corrective action program (**Quality**)
	Will create a near miss driver, an OSHA RA driver, or human error mechanism. An emerging safety issue where a
	CPCN delayed between 1-3 months and/or cost disallowance between $7,500,000 and $12,500,000
4	Has significant impact on (**Company Reputation**)
	Quality issue requires immediate management attention (**Quality**)
	Will create a near miss driver, an OSHA RA driver, or human error mechanism. No workaround is present.
	CPCN delayed between 3-5 months and/or cost disallowance between $12,500,000 and $20,000,000
5	Has severe impact on (**Company Reputation**)
	Quality issue requires work stoppage (**Quality**)
	Likely to cause one or more deaths (**Safety**)
	CPCN delayed more than 5 months and/or cost disallowance greater than $20,000,000 (**Regulatory/Legal**)

* The Project manager should establish clear thresholds for financial impact at the outset of the project. These should be articulated in the Project Execution Plan and be approved in accordance with the provisions of the Project Management Manual.

REGIONAL HAZE MODELING ASSESSMENT REPORT

Entergy Arkansas, Inc. > Independence Plant

Entergy®
THE POWER OF PEOPLE℠

Prepared By:

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August 4, 2015

Project 154401.0074

Trinity Consultants

Environmental solutions delivered uncommonly well

Exhibit C to EAI Comments

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1. EXECUTIVE SUMMARY

On April 8, 2015, the United States Environmental Protection Agency (EPA) published a proposed Federal Implementation Plan (FIP) to address regional haze and visibility transport requirements for the State of Arkansas. Within the proposed Arkansas FIP, the EPA addressed the portions of the Arkansas State Implementation Plan (SIP) that the EPA disapproved in its final action, published March 12, 2012.[1] In addition to addressing the control requirements for Arkansas sources determined to be subject to Best Available Retrofit Technology (BART), the EPA also addresses the Reasonable Progress Goals (RPGs) for Class I areas in Arkansas and reasonable progress control requirements to achieve these RPGs. Specifically, the EPA proposed to meet RPGs by presenting two options for controlling emissions from the Entergy Arkansas, Inc. (Entergy) Independence Plant, which is not subject to BART.

In order to assess the reasonableness of the proposed control options for Electric Generating Units (EGUs) 1 and 2 at the Entergy Independence Plant (Independence units), as well as the EGUs at Entergy's White Bluff Plant (White Bluff units), the Comprehensive Air Quality Model with Extensions (CAMx) was used to perform regional haze modeling. This analysis was based on the CAMx regional haze modeling originally performed by the Central Regional Air Planning Association (CENRAP).

This report has been prepared to describe the modeling methodology used to evaluate Entergy's proposed control measures for emissions of sulfur dioxide (SO_2) and oxides of nitrogen (NO_X) from the Independence and White Bluff units, as alternatives to the EPA's proposed control options. Entergy proposes a comprehensive approach to regional haze, involving the installation of low NO_X burners (LNB) and separated overfire air (SOFA) and a reduction in permitted SO_2 emission rates for the Independence units and White Bluff units, and the cessation of coal combustion at White Bluff by 2028. In addition to Entergy's proposed control scenario, the controls proposed in the Arkansas FIP were also evaluated using CAMx so that the expected visibility improvements from each scenario could be compared to EPA's proposed controls. The modeling methodology was developed in accordance with the original CENRAP modeling and takes into account Arkansas's two Class I areas, the Caney Creek Wilderness Area (Caney Creek) and the Upper Buffalo Wilderness Area (Upper Buffalo).

[1] Environmental Protection Agency. Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze. Federal Register Volume 77, Number 48. March 12, 2012.

The regional haze assessment involves the determination of the total light extinction, the contribution of each selected emissions source to the total light extinction, and an analysis of the uniform rate of progress (URP) curves for Caney Creek and Upper Buffalo. This regional haze modeling analysis was performed using the advanced photochemical modeling software CAMx. The CAMx modeling system is a publicly available computer modeling system for the integrated assessment of photochemical and particulate air pollution. A description of the modeling files, domain, model simulation steps, and analysis methodologies are discussed in detail in the following subsections.

2.1. EPA PHOTOCHEMICAL MODELING PLATFORM

This analysis builds on the modeling of 2002 and 2018 emissions conducted previously by CENRAP and subsequently updated by ENVIRON for the EPA to aid in the development of the EPA's proposed Oklahoma and Texas Regional Haze FIP.[2] ENVIRON's 2018 baseline scenario is based on input data originally developed by CENRAP and enhanced by ENVIRON to provide higher resolution results and to accommodate more recent versions of CAMx and associated pre-processors. 2018 emissions data used in this baseline scenario were projected with growth and control factors from the 2002 emissions data obtained from the 2002 National Emissions Inventory (NEI).[3]

2.1.1. Modeling Domain

Figure 2-1 below presents the modeling domain used in the CENRAP regional haze assessment. This nested grid configuration of the CAMx domain includes the following grids:

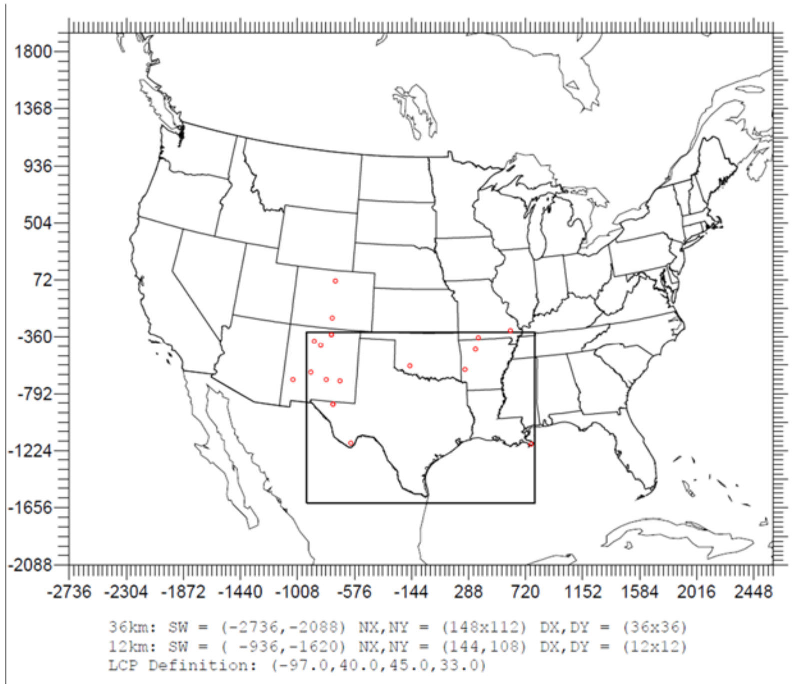
- RPO_36km: This grid contains 36 kilometer (km) grid cells covering all of the continental U.S., along with southern Canada, northern Mexico, and portions of the Gulf of Mexico, Atlantic Ocean, and Pacific Ocean.
- Regional_12km: This nested grid contains 12 km grid cells covering all of Texas, Arkansas, and Louisiana, a majority of Oklahoma, and parts of Mississippi, Tennessee, Missouri, and New Mexico.

All modeling domain grids are projected in the Lambert Conformal Conic (LCC) map projection. The 36 km grid is also the domain used by the Regional Planning Organizations (RPOs) of which CENRAP is an example. The 12 km grid was developed by ENVIRON to allow for minimizing the effects of the boundary conditions on the 12 km grid since the boundary condition information is passed from the 36 km to the 12 km grid. The modeling domain contains locations of Interagency Monitoring of Protected Visual Environments (IMPROVE) sites which correspond to the Arkansas Class I areas, Caney Creek and Upper Buffalo, which are under consideration in the assessment of RPGs in the Arkansas FIP.

[2] Snyder, Erik, Michael Feldman, and Joe Kordzi. "Technical Support Document for the Oklahoma and Texas Regional Haze Federal Implementation Plans." U.S. EPA. November 2014.

[3] Nopmongcol, Uarporn, et al. Memo to Ellen Belk, EPA Region 6. "2018 Base Case CAMx Simulation, Texas Regional Haze Evaluation." September 16, 2013.

Figure 2-1. EPA and ENVIRON Photochemical Modeling Platform Domain[4]



2.1.2. Emissions Inventory

The CAMx model requires emissions in an hourly, speciated format. The Sparse Matrix Operator Kernel Emissions (SMOKE) pre-processor is used to process emissions data of various types of regional haze precursor emissions into a temporally and spatially allocated format. The SMOKE emissions pre-processor was configured to match the EPA's specifications and then used to process the emissions inventories used in this assessment. Version 3.1 of SMOKE was utilized in this analysis to be consistent with the EPA. The 2018 baseline scenario emissions data was used as the basis for this analysis. Each of the modeling scenarios required specific updates to the Arkansas FIP selected sources; therefore, these emissions points were updated in inventories separately from the other point source inventories and were merged into a single CAMx inventory file once SMOKE processing was complete.

2.1.3. Other CAMx Input Data

The remaining input data required to run CAMx, including but not limited to meteorological data, land-use files, albedo-haze-ozone inputs, photolysis rates, boundary and initial conditions, were unchanged from the original 2018 baseline scenario files.[5]

---

[4] Nopmongcol, Uarporn, et al. Memo to Ellen Belk, EPA Region 6. "2018 Base Case CAMx Simulation, Texas Regional Haze Evaluation." September 16, 2013.

[5] Nopmongcol, Uarporn and Greg Yarwood. Memo to Ellen Belk, EPA Region 6. "2002 Baseline CAMx Simulation, Texas Regional Haze Evaluation." February 21, 2013.

2.2. ENTERGY SCENARIO ONE – BASELINE SCENARIO

The purpose of the baseline scenario is to develop a baseline level of total modeled light extinction at Caney Creek and Upper Buffalo. Additionally, the CAMx Particulate Source Apportionment Tool (PSAT) was used to trace the specific impacts of the Independence and White Bluff units as well as the remaining Arkansas sources subject to BART. In this way, the uncontrolled contribution of each source could be determined. As additional modeling is performed, the contributions of equipment from each scenario can be compared against the baseline contributions to determine the relative improvement or deterioration in visibility that can be expected due to application of various control options.

2.2.1. Emissions Inventory Updates

This regional haze assessment was based on the 2018 baseline scenario performed by ENVIRON. ENVIRON obtained the 2018 emissions inventory developed by CENRAP and incorporated selected updates, including but not limited to the addition of several new units and one new facility, the removal of several shutdown units, and the update of emission rates due to recently installed controls on selected units. Additionally, ENVIRON incorporated updates specific to the Oklahoma and Texas FIP determinations.[6]

It was noted during Entergy's initial review of these emissions inventories that two of the Arkansas sources subject to BART were not present. These two sources were the Entergy Lake Catherine Unit 4 (Lake Catherine unit) and the Arkansas Electric Cooperative Corporation (AECC) Carl E. Bailey Generating Station Unit 1 (Bailey Station unit). It is believed that the growth and control factors originally used by CENRAP to project the 2018 emissions inventory may be responsible for the proposed removal of the Bailey Station unit while the Lake Catherine unit appears to have been excluded from the original CENRAP modeling. Therefore, these two units were added into the emissions inventory for Entergy's baseline scenario.

Further review of the CENRAP inventories also indicated that the stack parameters for some of the Arkansas sources subject to BART were no longer representative of actual operations. The geographic coordinates of several sources, including the Independence and White Bluff units, were likewise found to point to inaccurate locations. The stack parameters and source locations of the Arkansas sources subject to BART were therefore updated to more accurately represent the current stack characteristics.

Additionally, since the growth and control factors estimated controlled emission rate values for the Arkansas FIP selected sources, it was necessary to revise the emission rates of these sources with uncontrolled values. The Arkansas sources subject to BART, excluding the White Bluff units, were given emission rates equal to the pre-controlled values based on the 2002 NEI data. The five selected Entergy units (from the Independence Plant, the White Bluff Plant, and the Lake Catherine Plant) were updated with revised emission rates provided by Entergy representing the uncontrolled actual emissions.

A table summarizing the emission rates of the Entergy units modeled in each scenario is included in Appendix A.

2.3. ENTERGY SCENARIO TWO – ENTERGY'S PROPOSED CONTROL APPROACH

With this modeling scenario, Entergy intends to determine the expected visibility benefits of the proposed alternative to the Arkansas FIP's determinations. As discussed in earlier sections, the proposed alternative scenario includes the installation of interim controls (e.g., LNB/SOFA) on the Independence and White Bluff

[6] Nopmongcol, Uarporn, et al. Memo to Ellen Belk, EPA Region 6. "2018 Base Case CAMx Simulation, Texas Regional Haze Evaluation." September 16, 2013.

units, the reduction of SO_2 emissions, and the ultimate cessation of coal combustion at the White Bluff facility. For the purposes of this assessment, control efficiencies were applied to the NO_X and SO_2 emissions rates for the Independence units while all White Bluff emissions sources were removed from the emissions inventories to signify the cessation of coal combustion.

2.3.1. Emissions Inventory Updates

Entergy's baseline scenario (Scenario One) served as the basis for Entergy's Proposed Scenario. Specific emissions inventory updates include the removal of all White Bluff Plant point sources from the emissions inventories and the revision of the emission rates of Entergy's Independence units and the Arkansas sources subject to BART. The Arkansas BART sources were modeled with the proposed post-control emission rates identified in the Arkansas FIP while the Independence units were modeled with the limited control efficiencies proposed by Entergy.

2.4. ENTERGY SCENARIO THREE – PROPOSED ARKANSAS FIP SCENARIO

The purpose of the Proposed Arkansas FIP Scenario is to determine the projected regional haze impacts of applying the controls proposed to be required by the Arkansas FIP. Therefore, all Arkansas sources determined to be subject to BART and the Independence units were modeled with the control rates proposed in the Arkansas FIP.

2.4.1. Emissions Inventory Updates

Entergy's baseline scenario (Scenario One) also served as the basis for the Proposed Arkansas FIP Scenario. Specific inventory updates include the revision of the emission rates of all Arkansas BART sources and the Independence units to the proposed post-control emission rates identified in the Arkansas FIP.

CAMx model outputs were post-processed and analyzed to determine the visibility effects of each of the Arkansas FIP sources. In order to obtain comparable results to EPA's CAMx modeling, the same post-processing approach was utilized, which involves the conversion of binary CAMx output files into a readable format, the extraction of relevant regional haze pollutant concentration information, and the calculation of relative response factors (RRF) using EPA's Modeled Attainment Test Software (MATS). Calculation workbooks also provided by the EPA were then used to determine visibility impacts. The full post-processing procedure used to analyze each modeling scenario is discussed in detail below.

3.1.1. Introduction to Atmospheric Visibility

The primary purpose of the Regional Haze Rule is to improve visibility at mandatory Class I areas. In practical terms, visibility at Class I areas is most simply measured as the farthest distance that can naturally be seen by an average human. Light waves diffract and are absorbed as they pass through and around particles and molecules in the atmosphere. The level of visibility therefore naturally decreases at greater distances as light waves come into contact with a greater number of these miniscule obstacles. This scattering of light waves is called Rayleigh scattering. In eastern areas of the United States, it is estimated that without the effects of anthropogenic pollution, visibility is naturally limited to a distance of approximately 90 miles, while in western areas the natural visible range is approximately 140 miles.[7]

As atmospheric concentrations of particles and molecules increase, the level of visibility further decreases since light waves can potentially interact with a larger number of obstacles at equivalent distances. Therefore, pollution from both anthropogenic and non-anthropogenic sources can have a significant effect on visibility in Class I areas. The primary contributors to visibility impairment include sulfates, nitrates, organic carbon, elemental carbon, crustal material, and sea salt."[8, 9]

In addition to visual range, another useful visibility measurement is the light extinction coefficient, which represents the gradual decrease in light intensity due to absorption and scattering. The light extinction coefficient can be calculated using measured concentrations of the primary contributing species to visibility impairment.[10] At Class I areas, the concentrations of these species are monitored by the Interagency Monitoring of Protected Visual Environments (IMPROVE), which analyzes 24-hour duration samples every 3 days. In 1999, an equation to estimate light extinction based on available IMPROVE data was incorporated into the Regional Haze Rule (Old IMPROVE equation). In 2007, a revised equation was developed to reduce "bias for high and low light extinction extremes" and to make the equation "more consistent with the recent atmospheric aerosol literature." This equation is given as follows:

---

[7] United States Environmental Protection Agency. *Visibility in Mandatory Federal Class I Areas (1994-1998): A Report to Congress*. EPA-452/R-01-008. Chapter 1 – Introduction to Visibility Issues. November 2001.

[8] Ibid.

[9] Kumar, Naresh, et al. "Revised Algorithm for Estimating Light Extinction from IMPROVE Particle Speciation Data." Journal of the Air & Waste Management Association JAWMA 57.11 (2007): 1326-336.

[10] United States Environmental Protection Agency. *Visibility in Mandatory Federal Class I Areas (1994-1998): A Report to Congress*. EPA-452/R-01-008. Chapter 1 – Introduction to Visibility Issues. November 2001.

$$
\begin{aligned}
b_{ext} = 2.2\ & \times f_S(RH) \times [Small\ Sulfate] \\
& + 4.8 \times f_L(RH) \times [Large\ Sulfate] \\
& + 2.4 \times f_S(RH) \times [Small\ Nitrate] \\
& + 5.1 \times f_L(RH) \times [Large\ Nitrate] \\
& + 2.8 \times [Small\ Organic\ Mass] \\
& + 6.1 \times [Large\ Organic\ Mass] \\
& + 10 \times [Elemental\ Carbon] \\
& + 1 \times [Fine\ Soil] \\
& + 1.7 \times f_{SS}(RH) \times [Sea\ Salt] \\
& + 0.6 \times [Coarse\ Mass] \\
& + Rayleigh\ Scattering\ (Site\ Specific) \\
& + 0.33 \times [NO_2(ppb)]
\end{aligned}
$$

Where b_{ext} represents the light extinction coefficient in inverse megameters (Mm^{-1}), and individual species concentrations are shown in brackets with units of micrograms per cubic meter ($\mu g/m^3$). The f_L and f_S terms are unitless water growth factors given as functions of relative humidity (RH) for concentrations of large and small sulfates and nitrates, while f_{SS} represents the water growth factor for sea salt concentrations. The numerical constants given in the equation (e.g., 2.2) represent dry mass extinction efficiency terms in units of square meters per gram (m^2/g).[11]

Because the units for the light extinction coefficient (MM^{-1}) are difficult to conceptualize and compare in practical terms, the deciview haze index (dv) was developed. The deciview haze index is calculated as a function of the ratio of the calculated light extinction coefficient to the approximate average extinction value due to Rayleigh scattering alone (10 Mm^{-1}).

$$
Deciview\ Haze\ Index\ (dv) = 10 \times \ln\left(\frac{b_{ext}\ [Mm^{-1}]}{10\ [Mm^{-1}]}\right)
$$

The deciview scale provides a simpler representation of visibility deterioration, with natural conditions having a calculated deciview haze index of approximately zero, depending on the site-specific level of Rayleigh scattering.[12]

3.1.2. MATS Processing

The raw CAMx output data most relevant to this regional haze assessment includes an overall average concentration file and a source apportionment concentration file, for each grid utilized (i.e., 12 km and 36 km grids) and for all modeled dates. These raw output files are in Fortran binary and are based on the Urban Airshed Model (UAM) convention. Several post-processor utility programs are used to convert these UAM formatted output files into MATS ready comma separated value (CSV) input files for individual source groups identified by PSAT.

MATS forecasts the level of visibility at Class I areas by using post-processed CAMx modeling output in accordance with monitoring data from the IMPROVE program. The three primary files required to run MATS are

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[11] Kumar, Naresh, et al. "Revised Algorithm for Estimating Light Extinction from IMPROVE Particle Speciation Data." Journal of the Air & Waste Management Association JAWMA 57.11 (2007): 1326-336.

[12] United States Environmental Protection Agency. *Visibility in Mandatory Federal Class I Areas (1994-1998): A Report to Congress*. EPA-452/R-01-008. Chapter 1 – Introduction to Visibility Issues. November 2001.

the base year model CAMx output, the future year model CAMx output, and the IMPROVE monitoring data. For the purposes of this modeling assessment, 2002 was selected as the base year. The 2018 future year model output refers to each of the CSV files created. The IMPROVE monitoring data is provided as sample data in the MATS software package download from the EPA.

First, MATS uses the IMPROVE monitoring data to identify the 20% best and 20% worst visibility days at each Class I area for the base year, 2002. Using the base year modeled output data on these exact same 20% best and 20% worst days, MATS calculates the average 20% best and 20% worst modeled concentrations of each of the pollutants identified (e.g., sulfates, nitrates, etc.). MATS then performs the same calculations using the same days with the 2018 future year model data. These values are next used to calculate relative response factor (RRF) values, which are ratios of future year modeled concentrations to base year modeled concentrations, both predicted near the same Class I area. The result of this step is a set of best and worst RRF values calculated for all identified species at each Class I area. These RRF values are used in accordance with IMPROVE monitoring data to forecast future deciview haze index values.

The final output from the MATS analysis includes, but is not limited to, the best and worst RRF values calculated for each species and Class I area, the best and worst average daily deciview haze index values for each valid year and Class I area, and the annual average deciview haze index values for each Class I area. In order to perform the required calculations for the PSAT source contribution analysis, all eleven PSAT-negated CSV files were also processed by MATS so that specific PSAT-negated RRF values could be calculated for each PSAT source. These RRF values represent the relative response of each modeled pollutant concentration resulting from the removal of each PSAT source.

3.1.3. PSAT Source Contribution Analysis

The PSAT source contribution analysis determines the individual impact of each PSAT source on visibility at Class I areas. As described in earlier sections, the impacts of the Arkansas BART sources and Entergy's Independence units were traced by the CAMx PSAT tool. The source apportionment CAMx output files were post-processed through MATS to calculate RRF values, which were then used in contribution analysis workbooks provided by the EPA. The calculations in these workbooks are based on the New IMPROVE equation, the IMPROVE monitor data, and the RRF values calculated by MATS.

The contribution analysis workbooks are designed to retrieve the monitored concentrations of visibility impairing pollutants associated with the 20% worst visibility days from 2002 (base year) IMPROVE data, and to multiply them by the 2018 future year RRF values as well as the PSAT-negated RRF values associated with each PSAT source. The resulting values are input to the New IMPROVE equation, which calculates the 2018 projected light extinction values for each of the 20% worst days. These extinction values are averaged and converted into deciview haze index values. PSAT-negated haze index values represent the total 2018 deciview haze index value minus the contribution of the individual PSAT source.

The individual impact of each PSAT source is calculated as the difference between the total 2018 future year haze index value and each PSAT-negated haze index value. For this assessment, the contributions of individual sources located at the same facility were combined in order to compare facility contributions. Figures 3-1 and 3-2 display the uncontrolled baseline scenario facility contributions to deciview haze index for Caney Creek and Upper Buffalo, respectively.

Figure 3-1. Contribution Analysis Results for the Baseline Modeling Scenario at the Caney Creek Wilderness Area

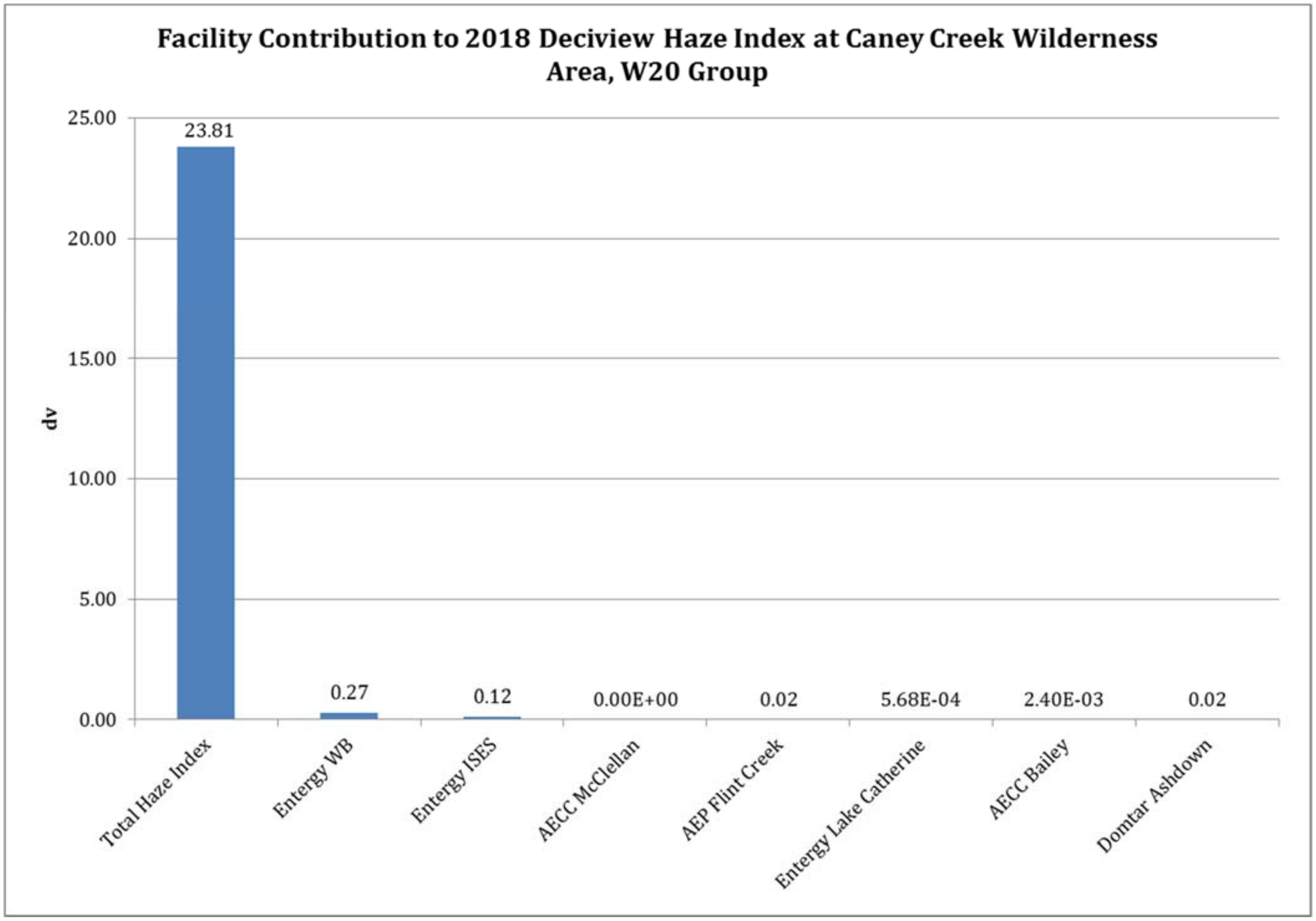
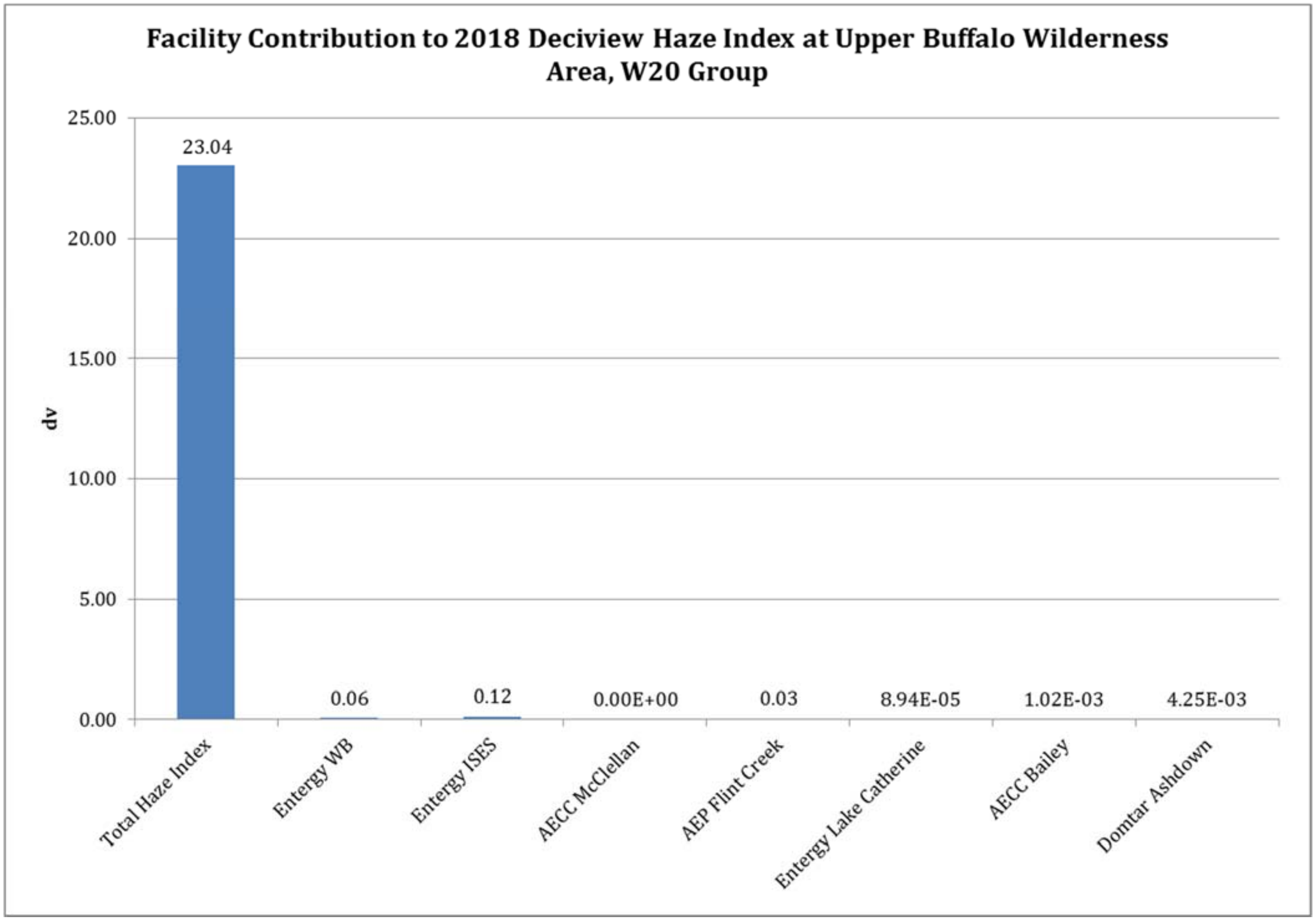


Figure 3-2. Contribution Analysis Results for the Baseline Modeling Scenario at the Upper Buffalo Wilderness Area



3.1.4. Uniform Rate of Progress Curve Analysis

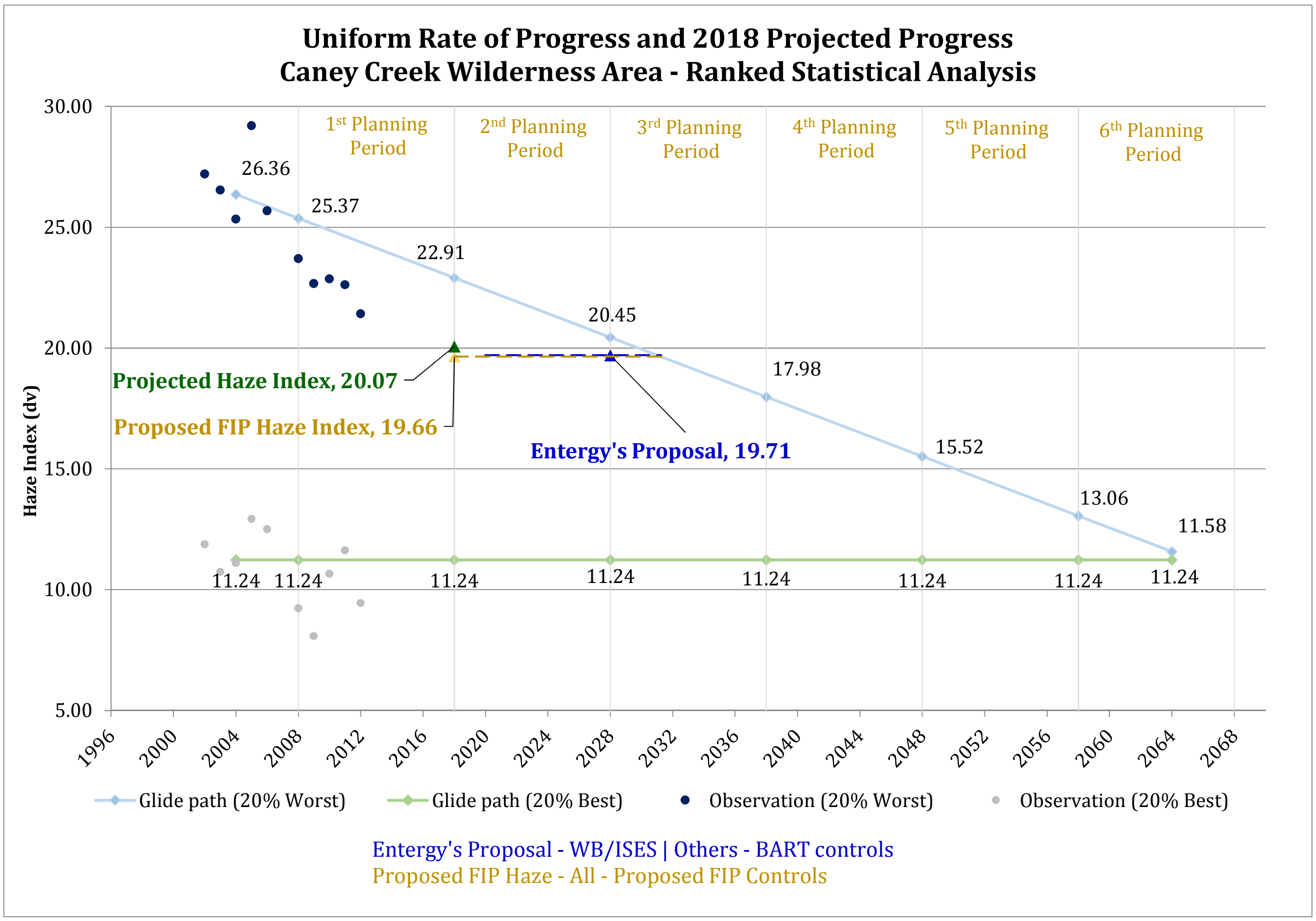
Title 40 of the Code of Federal Regulations (CFR) Part 51 requires that SIPs "analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064."[13] This requirement is demonstrated by creating a URP graph, which shows the rate at which the 20% worst deciview (dv) haze index values are required to improve from year to year in order to reach natural visibility conditions by 2064. The URP graphs are derived from actual observed data for each Class I area collected through the IMPROVE program. The URP graphs are typically initiated in 2004 based on average 2002-2004 IMPROVE data, which was used to calculate the average observed haze index for the 20% worst days and 20% best days. The 2004 initial haze index values are then projected into the future at the minimum rate required to attain natural visibility conditions by 2064. Figures 3-3 and 3-4 display URP curves for Caney Creek and Upper Buffalo, respectively.

Each of these figures display the 20% best and 20% worst URP curves, the average of the 20% best and 20% worst observed deciview haze index values for each year of complete IMPROVE data, and projected haze index values for each modeled scenario. The Projected Haze Index values are obtained from a statistical analysis

[13] *Regional Haze Program Requirements.* 40 CFR §51.308(d)(1)(i)(B).

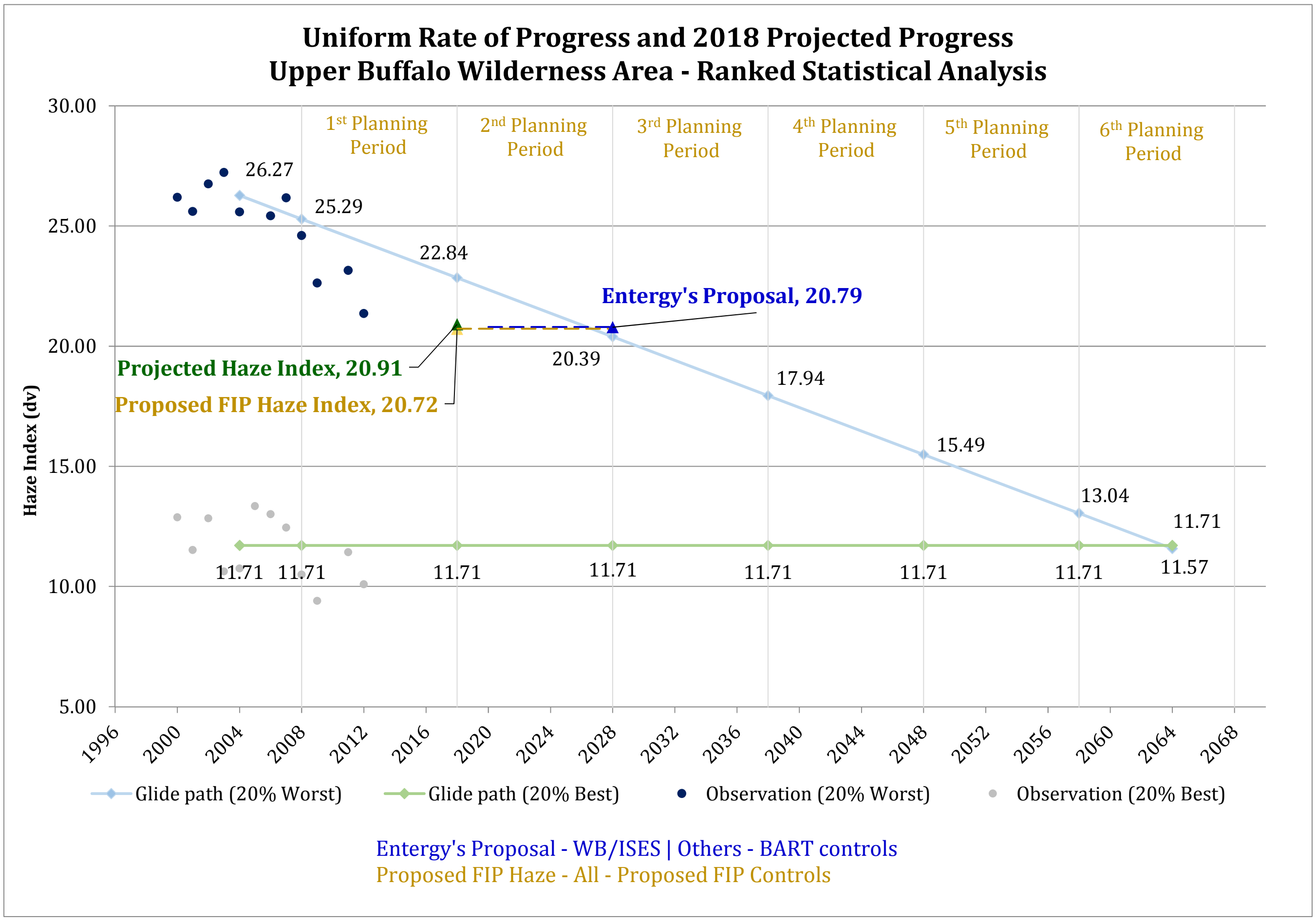
performed using the full set of IMPROVE data for both Caney Creek and Upper Buffalo.[14] The scenario-specific haze index values are calculated by first converting the model-predicted five-year averaged haze index values obtained from MATS into total extinction values in Mm^{-1}. The predicted improvement associated with each scenario is then calculated by finding the difference between the extinction values from the scenario of interest (i.e., Proposed FIP or Entergy's Proposal) and the uncontrolled baseline scenario. The improvement from each scenario is then subtracted from the Projected Haze Index value and converted back into deciviews to obtain scenario-specific haze index values.

Figure 3-3. Uniform Rate of Progress Analysis Results for the Proposed Control Scenarios at the Caney Creek Wilderness Area



[14] Trinity Consultants. "IMPROVE Data Statistical Analysis: Discussion and Methodology for IMPROVE Data Statistical Analysis." July 2015.

Figure 3-4. Uniform Rate of Progress Analysis Results for the Proposed Control Scenarios at the Upper Buffalo Wilderness Area



Appendix Table A-1. Modeled Emission Rates for the Entergy Independence and White Bluff Units

	Uncontrolled Baseline (tpy)		Entergy's Proposal (tpy)		Arkansas FIP (tpy)	
Unit	**NO_X**	**SO_2**	**NO_X**	**SO_2**	**NO_X**	**SO_2**
Independence Unit 1	6,313	14,258	3,150	12,154	3,619	1,357
Independence Unit 2	6,516	15,407	3,347	13,162	3,167	1,521
White Bluff Unit 1	7,580	15,939	--[1]	--[1]	4,145	1,453
White Bluff Unit 2	8,145	16,034	--[1]	--[1]	4,060	1,476
Lake Catherine Unit 4	1,228	3.26	564	3.26	564	3.26

[1] Entergy's Proposal includes the cessation of coal combustion at White Bluff.

IMPROVE DATA STATISTICAL ANALYSIS

Entergy Arkansas Inc.

Entergy

THE POWER OF PEOPLE℠

Discussion and Methodology for IMPROVE Data Statistical Analysis

Prepared By:

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July 2015

Project 154401.0074

Trinity Consultants

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Trinity Consultants Inc. (Trinity) was tasked with conducting a statistical analysis of observed visibility data gathered through the Interagency Monitoring of Protected Visual Environment (IMPROVE) program to statistically determine the future trends in the regional haze index values. Trinity conducted a simple Trend Statistical Analysis and more robust Ranked Statistical Analysis to determine the projected haze index in 2018.

[1] Environmental Protection Agency. Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze. Federal Register Volume 77, Number 48. March 12, 2012.

2. INTRODUCTION

Title 40 of the Code of Federal Regulations (CFR) Part 51 requires that SIP "analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064."[2] This requirement is demonstrated by creating a Uniform Rate of Progress (URP) graph, which shows the rate at which the 20% worst deciview (dv) haze index values are required to improve from year to year in order to reach natural visibility conditions by 2064. The URP graphs, also known as glide paths, are derived from actual observed data for each Class I area collected through the IMPROVE program. The URP graphs typically were initiated in 2004 based on average 2002 – 2004 IMPROVE data, which was used to calculate the average observed haze index for the 20% worst days and 20% best days. The 2004 values were then projected into the future to intersect with the 20% best days observed value by 2064. To demonstrate attainment with this glide path, the Central Regional Air Planning Association (CENRAP) used the Comprehensive Air Quality Model with Extensions (CAMx) to perform regional haze modeling. The model-predicted haze index values based on the future projected emission rates are used to compare with the glide path proposed value in 2018, the end of the 1st planning period. Figures 2-1 and 2-2 display the uniform rate of progress glide paths for the Caney Creek Wilderness Area (Caney Creek) and the Upper Buffalo Wilderness Area (Upper Buffalo) along with the CENRAP projected haze index.

In addition to the glide paths for the 20% worst days and 20% best days, the URP graphs also present the observed 20% worst and 20% best haze index values from the IMPROVE monitoring observational data for 2002 to 2012. As presented in Figures 2-1 and 2-2 for Caney Creek and Upper Buffalo, respectively, the observed values are well below the glide path with a consistent downward trend in the observations. This downward trend is consistent with the historical (2002 – 2011) trend in decreasing sulfur dioxide (SO_2) emissions from tier 1 sources located in the states contributing significantly to the Caney Creek and Upper Buffalo Class I Areas. Figure 2-3 presents the National Emissions Inventory (NEI) SO_2 emissions from 2002, 2005, 2008, and 2011. Pursuant to the NEI emissions data, the SO_2 emissions have significantly decreased since 2005 to 2011 in all source categories, including especially a more than 50% drop due to fuel combustion from electric utilities and a 67% drop in the fuel combustion from industrial sources. Based on the significant downward trend in the observed data and the actual SO_2 emissions data, the future haze index value in 2018 is expected to be lower than the currently predicted glide path. The lower haze index value in 2018 will be additionally supported by the anticipated implementation of regulations further curbing emissions.

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[2] *Regional Haze Program Requirements.* 40 CFR §51.308(d)(1)(i)(B).

Figure 2-1. Caney Creek Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress

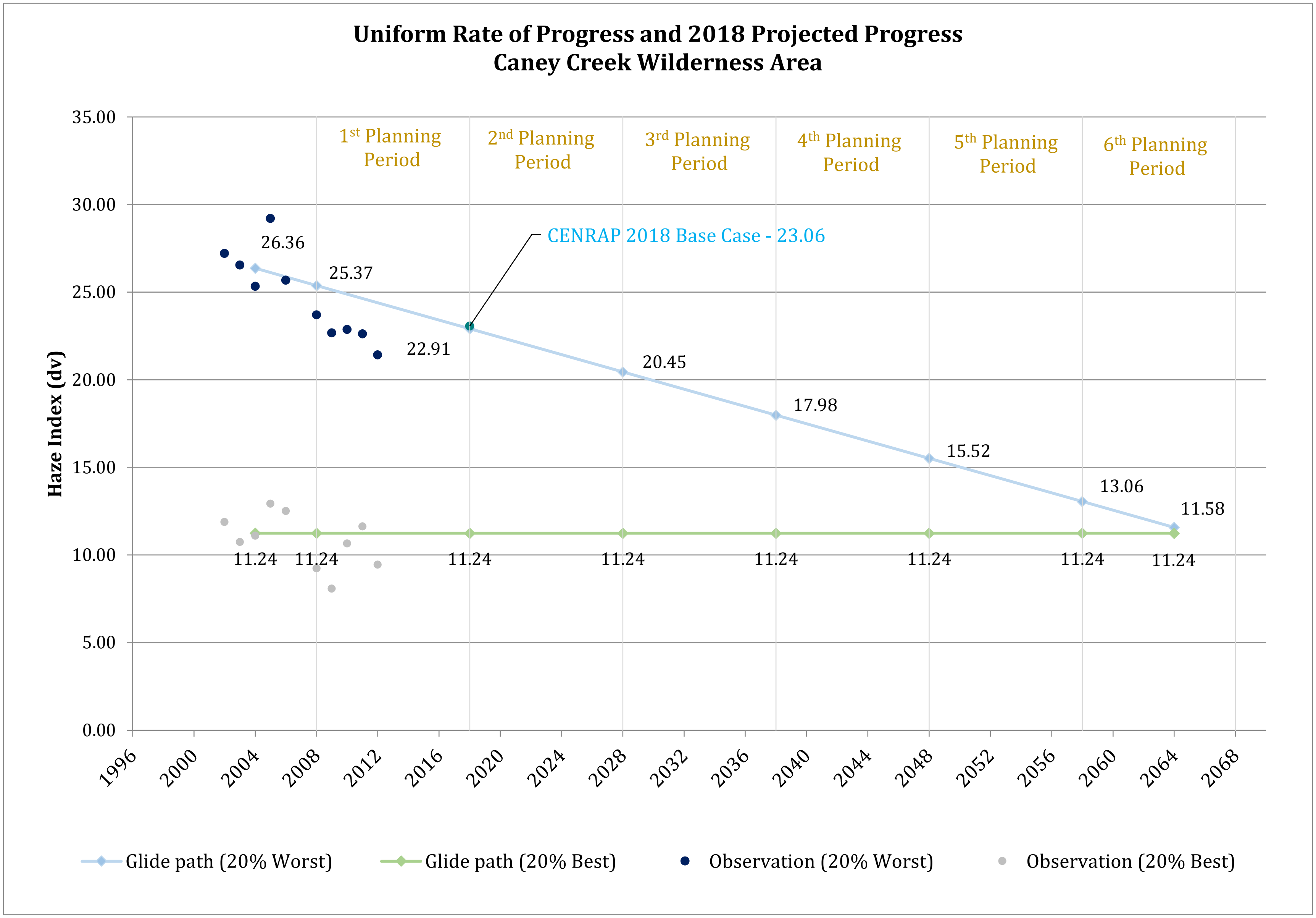


Figure 2-2. Upper Buffalo Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress

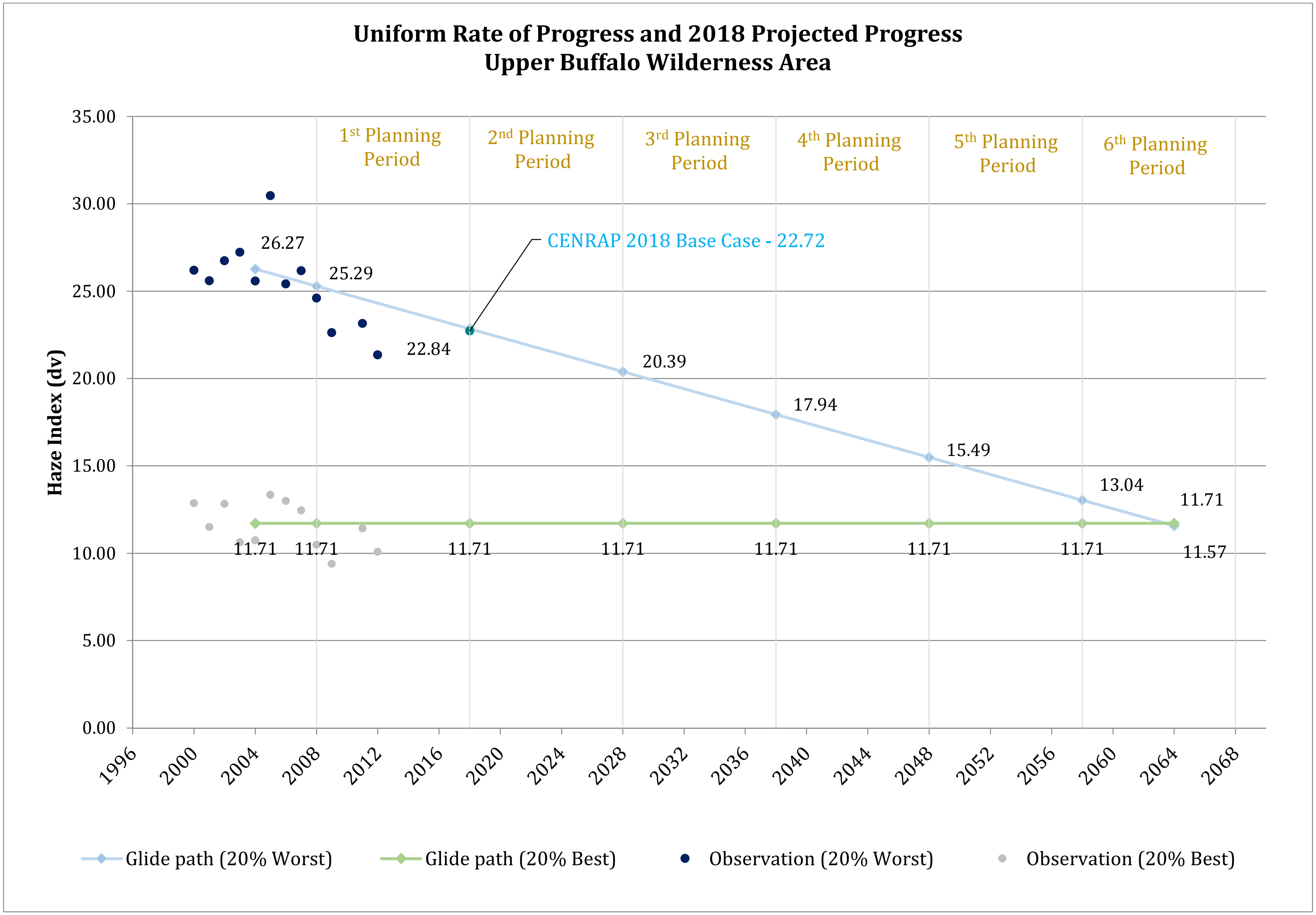
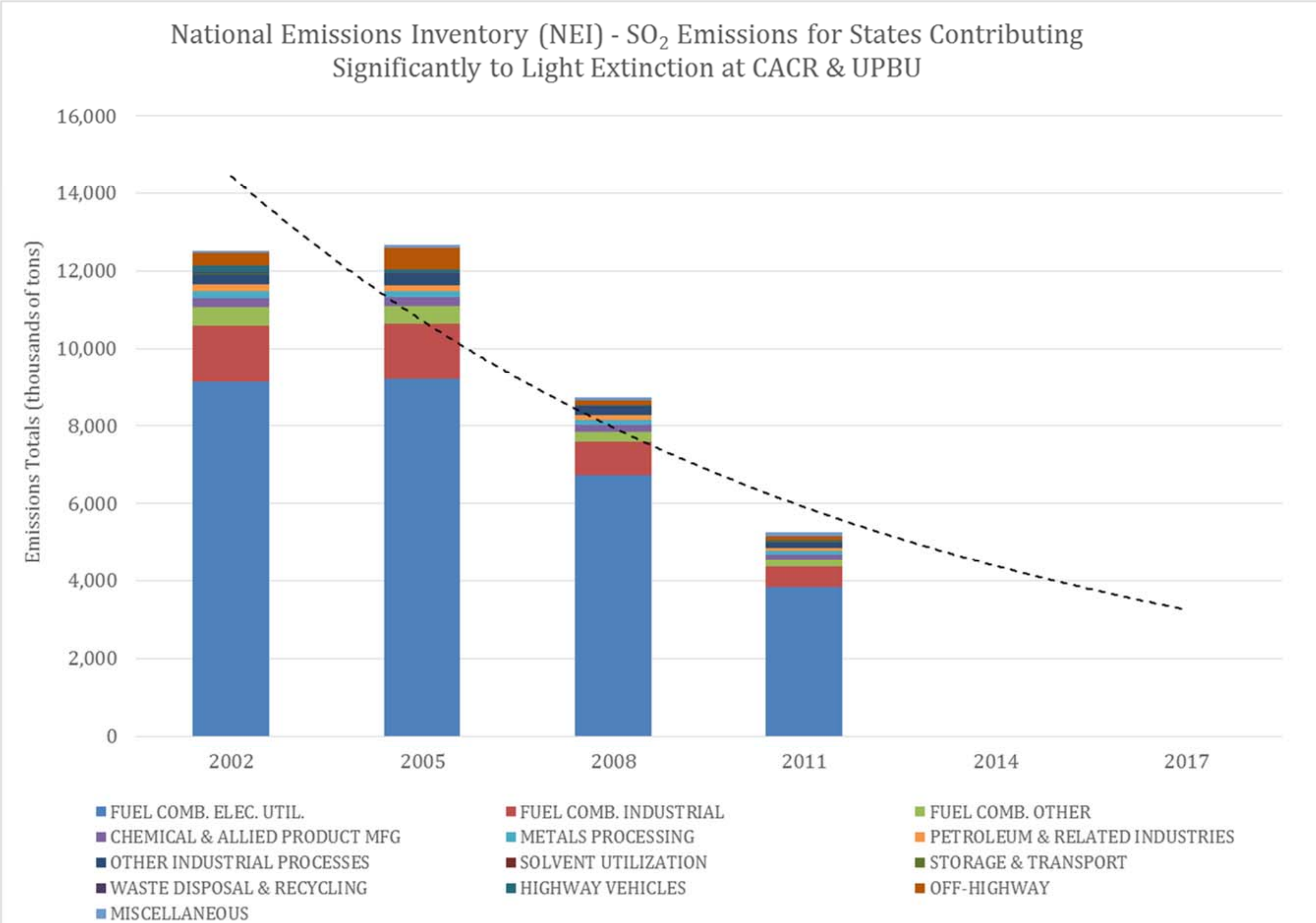


Figure 2-3. National Emissions Inventory (NEI) – SO_2 Emissions for States Contributing Significantly to Light Extinction at Caney Creek and Upper Buffalo



Based on the above, when looking at the observed values, the CENRAP model predicted regional haze value for 2018 is overly conservative and over predicting the future haze index. Although the predicted 2018 haze index values are good conservative estimates for attainment demonstrations, the values are misleading when assessing the effect of proposed controls on single sources. Additionally, the CENRAP CAMx model predicted haze index does not account for the observed values and the trend predicted if an assessment occurred evaluating the observed values. Therefore, instead of using the CENRAP CAMx predicted 2018 haze index to understand the effect of the control options, a statistically derived projected haze index must be used.

In order to statistically calculate the future deciview haze index values using observed data instead of relying on the CENRAP modeling, two statistical analyses were performed and evaluated to determine the most appropriate analysis for predicting the haze index values based on observed data:

- Trend Analysis
- Ranked Statistical Analysis

Each of these analyses are summarized in Section 3 of this report.

3.1. TREND STATISTICAL ANALYSIS

A trend analysis using a simple least squares linear regression based on the annual average values was performed. Using this simple "Trend Analysis" methodology, the projected 2018 deciview haze index values of **18.02** dv and **20.44** dv were determined for Caney Creek and Upper Buffalo, respectively. Figures 3-1 and 3-2 present the uniform rate of progress glide paths for Caney Creek and Upper Buffalo when the 2018 projected haze index is based on the statistical trend of the observed data. These values are estimated without consideration of additional controls added as a result of the proposed FIP. Presented alongside these projected values are the estimated values that would result from adopting the proposed FIP controls (Proposed FIP Haze Index) as well as the controls proposed by Entergy (Entergy's proposal). Entergy's proposal includes meeting more stringent SO_2 emission rates at ISES and Entergy's White Bluff plant (WB) by 2018, the installation of low nitrogen oxides (NO_X) burners at ISES and WB, and the cessation of coal combustion at the WB plant by 2028.

This statistical analysis is not, however, a realistic model for expected visibility improvement since this trend is based on a limited set of data—the 20% worst deciview haze index values for each year—which may not be representative of the complete set of IMPROVE data. Therefore, a more extensive statistical analysis was performed to predict future deciview haze index values based on the full set of IMPROVE observation data.

A review of the IMPROVE data sets for both Caney Creek and Upper Buffalo indicate that there is no convincing correlation between the observed deciview haze index value and the date of observation. That is, there is no detectable temporal trend in the IMRPOVE data. However, as shown in Figure 3-3, the maximum, third quartile, median, first quartile, and minimum data points do indicate a consistent downward trend from year to year, which suggests that over time, from year to year and month to month, the first highest, second highest, third highest, etc. observed values will follow a trend which can be used to predict future values.

IMPROVE data obtained for both Caney Creek and Upper Buffalo spanned the years 2000 to 2012 where data is taken every three days. However, both IMPROVE data sets contain regions of time for which data is not available. Because some years have less data points than other years, it is therefore impossible to predict future deciview haze index values using the n^{th} largest value without introducing unnecessary biased skew. For example, the Caney Creek IMPROVE data for 2000 includes only 52 values while 2004 contains 122 values. Therefore, the 52^{nd} highest value (also the minimum value) for 2000 is 4.04 dv while the 52^{nd} highest value for 2004 is 20.00 dv. Since it would be inappropriate to compare the minimum value of 2000 with a value closer to the median of 2004, further refinement to the methodology is required.

One option is to simply remove years with data not meeting a defined criteria for completeness. This option, however, is not preferred because it discounts a large quantity of valuable data. Additionally, this option only slightly reduces the potential for skew described above. The final chosen methodology (Ranked Statistical Analysis) addresses both of these issues by minimizing the skew due to incomplete data while maximizing the usage of available data.

Figure 3-1. Caney Creek Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress with Trend Analysis.

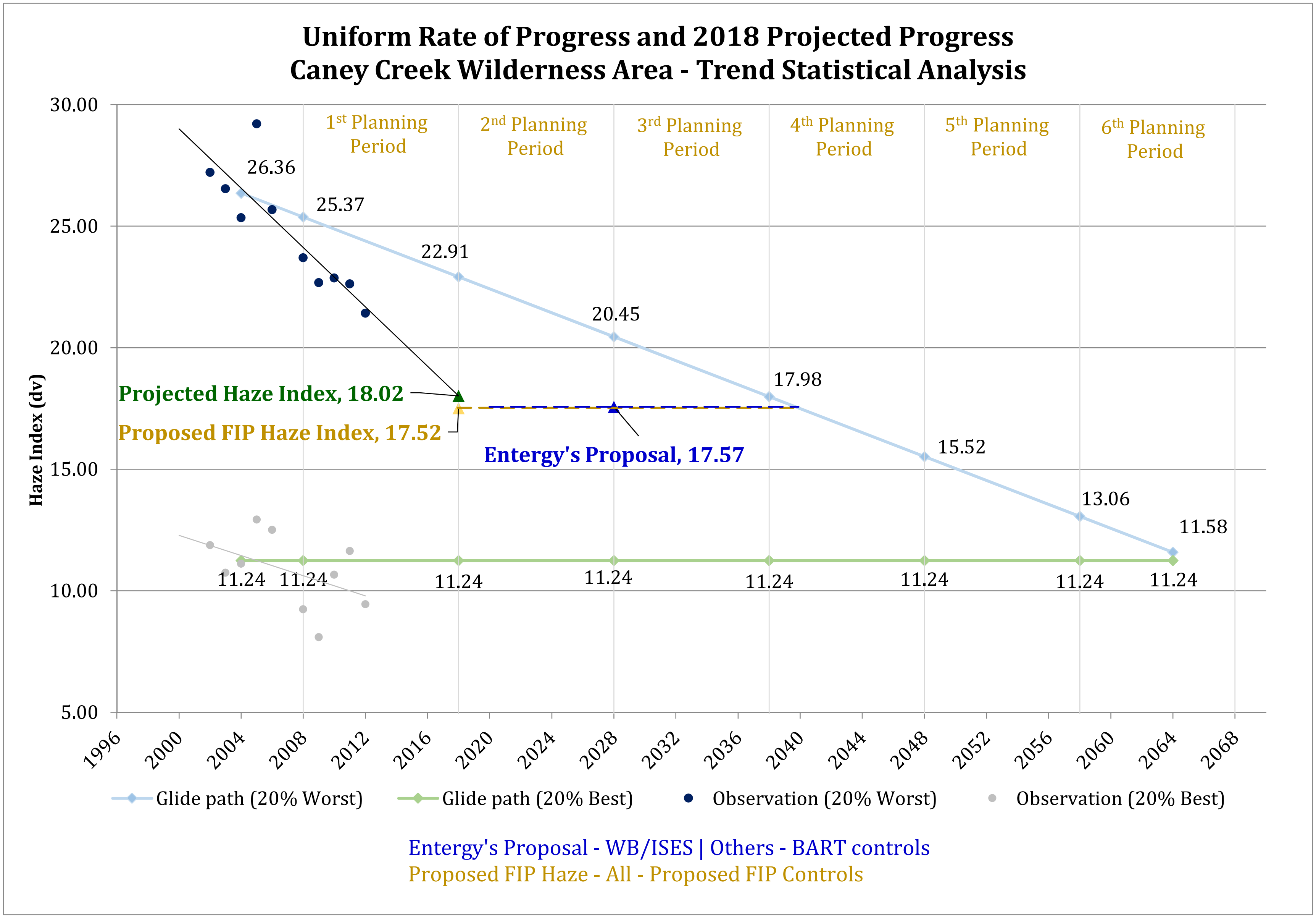


Exhibit D to EAI Comments

Figure 3-2. Upper Buffalo Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress with Trend Analysis.

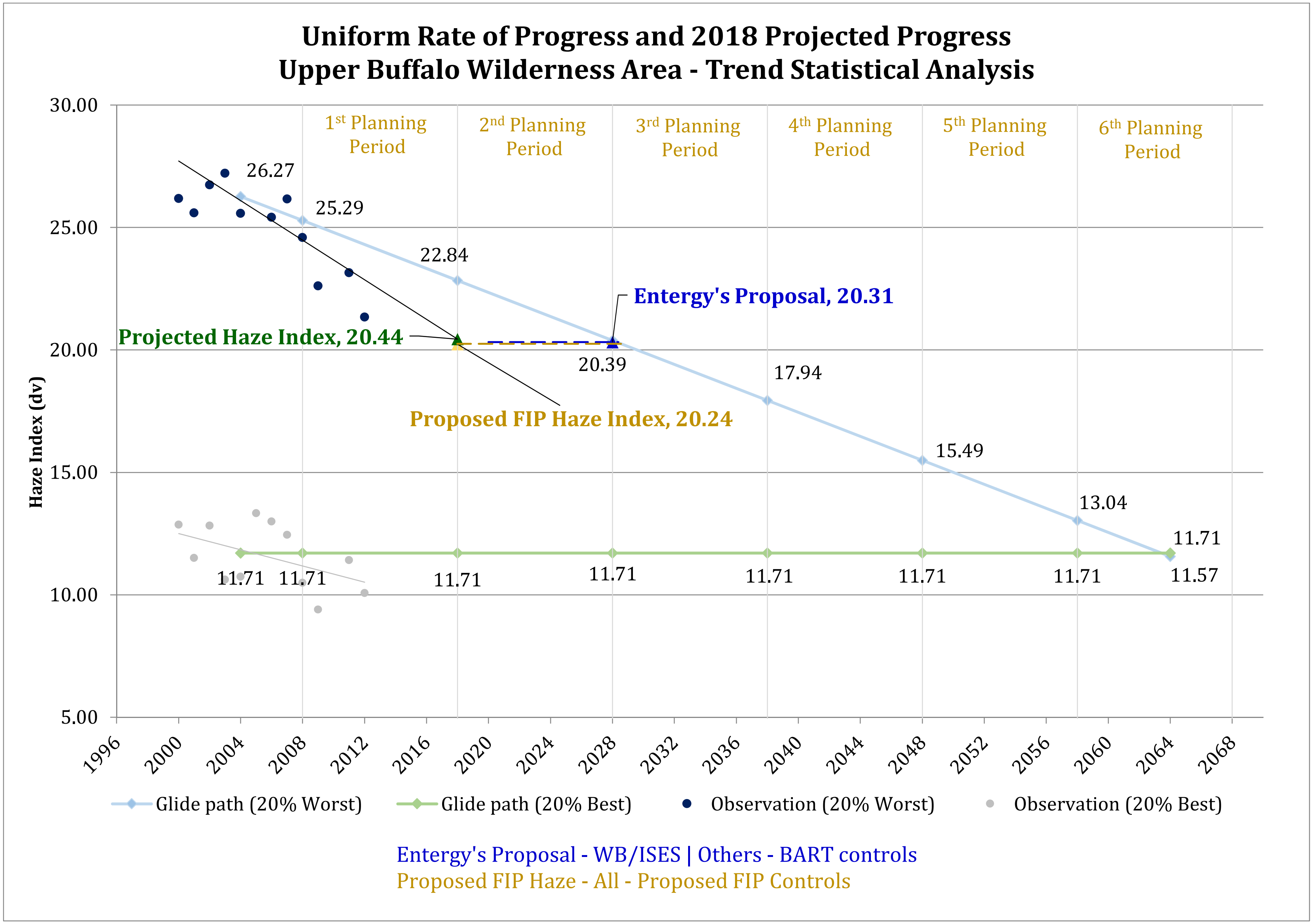
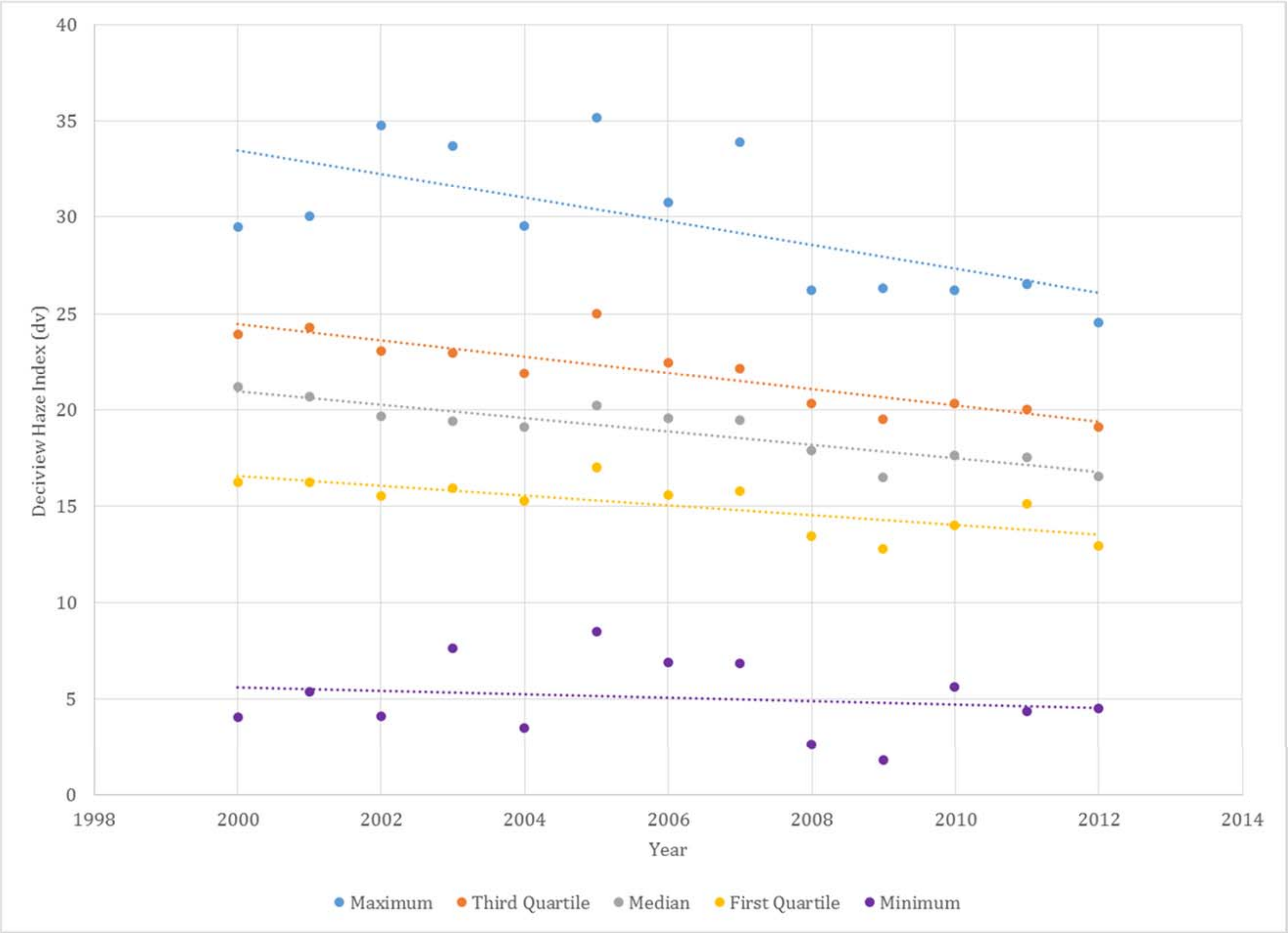


Figure 3-3. Observed Trends in Statistical Values for Caney Creek IMPROVE data.



3.2. RANKED STATISTICAL ANALYSIS

The chosen methodology, described as Ranked Statistical Analysis, begins with the chronological organization of the IMPROVE data from every year, as displayed in Table 3-1 as an example. It was determined that a month of data is incomplete for a year if less than nine (9) days of data points are available (eight days for February) for that month. This completion criteria corresponds to approximately overall 90% completeness. Table 3-2 presents the resulting completeness determinations of each month and year for Caney Creek. If a given month has less than nine out of thirteen years of complete data, that month is discounted from the calculations and is not considered in the future projections. As shown in Table 3-2, April only had eight years of complete data for Caney Creek; therefore, April was not considered in the projections. Once the completeness determination was completed, the haze index values for each complete month and year were then ranked so that the values for each month from year to year were aligned in descending order. Table 3-3 presents the ranked observations for Caney Creek for the complete years of January data as an example. These ranked monthly values were used to predict the daily haze index values for each month of the year 2018. Using this set of predicted 2018 values, the 2018 average of the 20% worst days for visibility was calculated to be **20.07** dv for Caney Creek and **20.91** dv for Upper Buffalo. Figures 3-4 and 3-5 display these predicted 2018 values in relation to the URP curves for each Class I Area. Also displayed are the estimated proposed FIP haze index and the haze index based on Entergy's proposed controls.

The haze index values predicted using the Ranked Statistical Analysis are consistent with the downward trend from the observed values and are more conservative than the Trend Analysis. The Trend Analysis relies on the sampling data generated from average worst 20% days IMPROVE data and therefore, the sampling data is limited to only one (1) value per year. This limited size of sampling can induce some bias in the statistical analysis. However, the statistical samples in the Ranked Statistical Analysis, unlike the Trend Analysis, includes at least nine (9) values per month or a minimum of 108 data points for each complete year. The sample data used for the Ranked Trend Analysis included at least 8 complete years or a minimum of 860 data points. The use of this large data sample in the Ranked Statistical Analysis makes this analysis more robust and un-biased in predicting the projected trends. The use of a larger sample point ranked on a monthly basis also preserves the temporal and diurnal patterns in the observed data. By predicting monthly future values, these diurnal and temporal pattern are sustained in the statistical analysis and therefore, reduce the bias due to missing values.

Based on statistical analysis completed, the Ranked Statistical Analysis is more appropriate for determining the downward trend in the haze index based on IMPROVE observed data. When comparing the ranked versus trend analyses, the trend analysis would suggest the programs external to the Regional Haze rule will have a more profound effect on the glide path which will approach the natural background in 2028 and 2042 for Caney Creek and Upper Buffalo, respectively. When looking at the more conservative Ranked Statistical Analysis, the URP will be approached after 2038/2044 for Caney Creek and Upper Buffalo, respectively, but well before the 2064 deadline. Under either approach, analysis of the data trends show that the rate of visibility improvement is outpacing the URP graphs at both Caney Creek and Upper Buffalo.

Table 3-1. Chronological Deciview Haze Index Values Observed in January at the Caney Creek Wilderness Area

Julian Day	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
1	--	--	--	--	14.59	--	--	--	10.24	18.60	--	--	11.70
2	--	--	21.27	--	--	--	--	--	--	--	20.47	--	--
3	--	--	--	19.27	--	--	--	18.54	--	--	--	14.72	--
4	--	--	--	--	13.18	11.69	--	--	--	22.85	--	--	14.80
5	--	--	17.81	--	--	--	6.88	--	--	--	17.32	--	--
6	--	--	--	20.09	--	--	--	23.10	--	--	--	12.71	--
7	--	--	--	--	15.61	10.71	--	--	--	10.80	--	--	18.88
8	--	--	18.18	--	--	--	13.96	--	--	--	14.95	--	--
9	--	--	--	20.33	--	--	--	6.86	--	--	--	12.89	--
10	--	--	--	--	29.56	14.03	--	--	--	26.11	--	--	12.66
11	--	--	14.41	--	--	--	13.61	--	--	--	18.43	--	--
12	--	--	--	15.61	--	--	--	13.10	--	--	--	20.13	--
13	--	--	--	--	26.26	17.13	--	--	--	15.40	--	--	6.80
14	--	--	10.42	--	--	--	7.68	--	--	--	19.31	--	--
15	--	--	--	27.57	--	--	--	--	--	--	--	25.25	--
16	--	--	--	--	19.61	24.99	--	--	--	14.47	--	--	14.97
17	--	--	21.57	--	--	--	17.86	--	--	--	18.75	--	--
18	--	--	--	15.35	--	--	--	--	--	--	--	19.63	--
19	--	22.79	--	--	19.40	--	--	--	--	19.58	--	--	--
20	--	--	--	--	--	--	18.74	--	--	--	18.14	--	--
21	--	--	--	21.74	--	--	--	--	--	--	--	12.33	--
22	--	21.70	--	--	24.23	20.17	--	--	--	21.15	--	--	18.07
23	--	--	15.85	--	--	--	13.47	--	--	--	13.43	--	--
24	--	--	--	17.45	--	--	--	16.37	--	--	--	21.59	--
25	--	--	--	--	11.67	21.57	--	--	15.07	21.52	--	--	4.52
26	--	--	14.01	--	--	--	9.72	--	--	--	7.38	--	--
27	--	--	--	25.98	--	--	--	19.94	--	--	--	17.15	--
28	--	22.76	--	--	14.65	19.52	--	--	18.43	20.24	--	--	10.71
29	--	--	20.39	--	--	--	12.82	--	--	--	11.21	--	--
30	--	--	--	17.81	--	--	--	15.78	--	--	--	20.67	--
31	--	13.34	--	--	19.07	17.61	--	--	10.74	8.28	--	--	19.91

Table 3-2. Determination of Monthly and Yearly Data Completeness for the Caney Creek Wilderness Area

Month	Total Number Days	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Number of Complete Years
January	31	No	No	Yes	Yes	Yes	Yes	Yes	No	No	Yes	Yes	Yes	Yes	9
February	28	No	No	No	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	9
March	31	No	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	11
April	30	No	No	Yes	Yes	Yes	Yes	Yes	No	No	No	Yes	Yes	Yes	8
May	31	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	12
June	30	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	11
July	31	No	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes	10
August	32	No	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	No	No	Yes	9
September	30	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	11
October	30	Yes	No	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	No	Yes	10
November	30	Yes	No	Yes	Yes	Yes	Yes	No	No	Yes	No	Yes	Yes	Yes	9
December	31	No	No	Yes	Yes	Yes	No	Yes	No	Yes	Yes	Yes	Yes	Yes	9

Table 3-3. Ranked Deciview Haze Index Values for the Caney Creek Wilderness Area in January

	2002	2003	2004	2005	2006	2009	2010	2011	2012	Number of Days with Data
1	21.57	27.57	29.56	24.99	18.74	26.11	20.47	25.25	18.88	9
2	21.27	25.98	26.26	21.57	17.86	22.85	19.31	21.59	18.07	9
3	20.39	21.74	24.23	20.17	13.96	21.52	18.75	20.13	14.97	9
4	18.18	20.33	19.61	19.52	13.61	21.15	18.43	19.63	14.80	9
5	17.81	20.09	19.40	17.61	13.47	19.58	18.14	17.15	12.66	9
6	15.85	19.27	15.61	17.13	12.82	18.60	17.32	14.72	11.70	9
7	14.41	17.45	14.59	14.03	9.72	15.40	14.95	12.89	10.71	9
8	14.01	15.61	13.18	11.69	7.68	14.47	13.43	12.71	6.80	9
9	10.42	15.35	11.67	10.71	6.88	10.80	7.38	12.33	4.52	9
10	--	--	--	--	--	--	--	--	--	0
11	--	--	--	--	--	--	--	--	--	0

Figure 3-4. Caney Creek Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress with Ranked Statistical Analysis

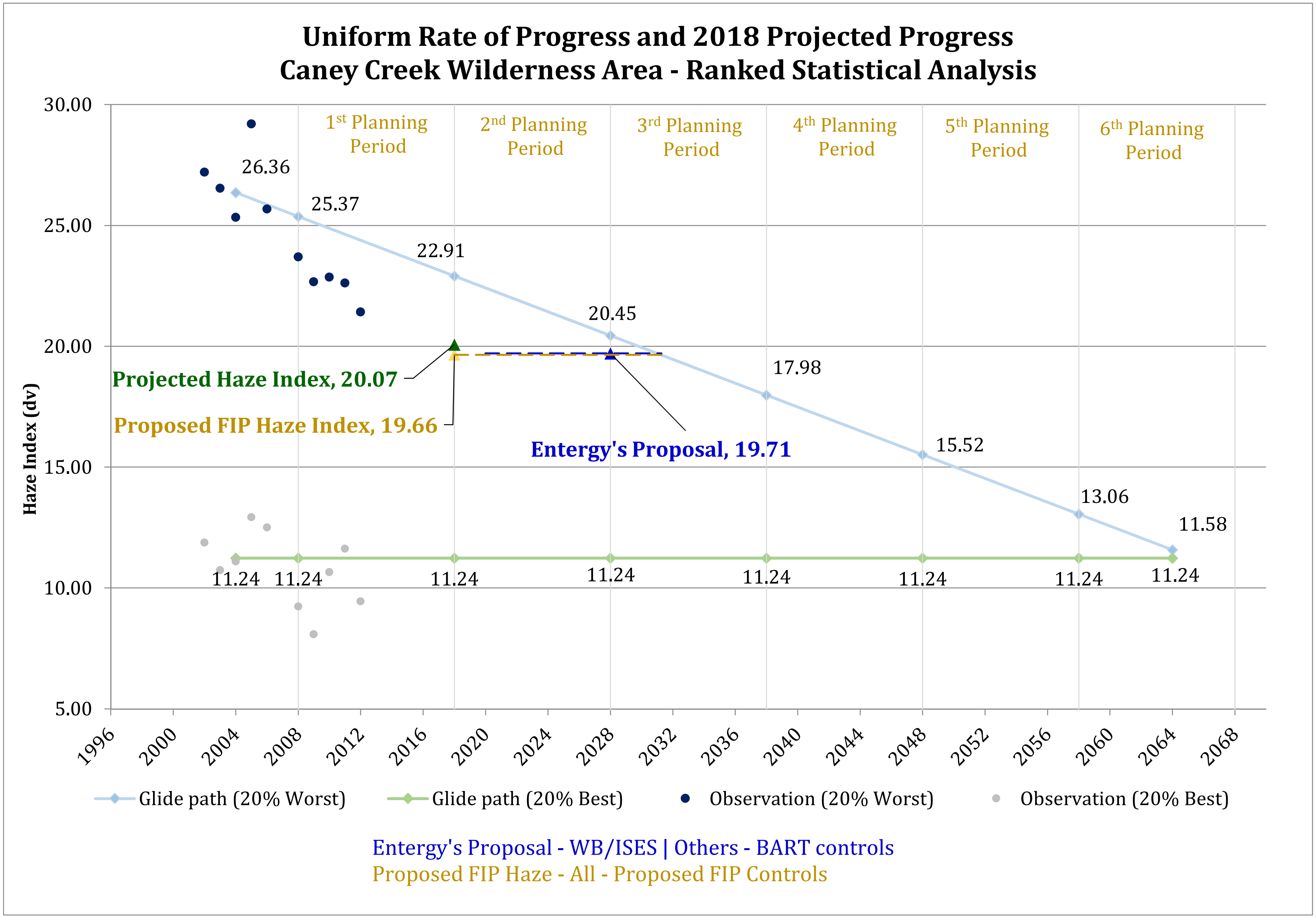
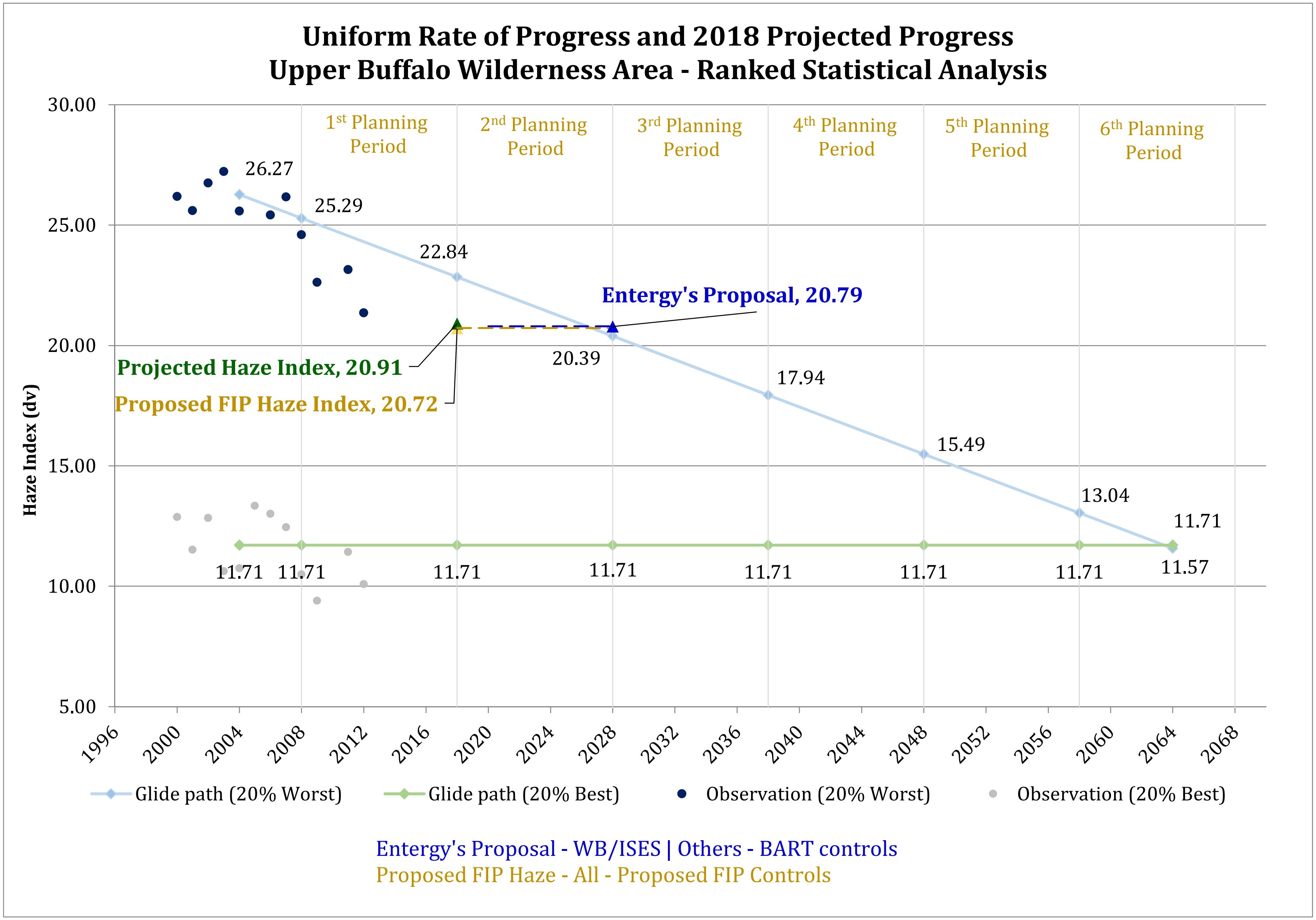


Figure 3-5. Upper Buffalo Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress with Ranked Statistical Analysis



TECHNICAL PAPER

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Just-Noticeable Differences in Atmospheric Haze

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ABSTRACT

This article examines the only available experimental data taken in the natural environment on the ability of an observer to perceive small, incremental changes in the colorfulness of objects seen through atmospheric haze and estimates an appropriate just-noticeable difference (JND) from these data. This experimentally determined threshold of perception is compared to changes in the deciview scale. Based on these experimental results, the deciview scale is found to not be uniform over a wide range of visibility conditions, as has been previously claimed. In addition, a 1-deciview change never produces a perceptible change in haze, as defined by a 95% probability of producing a measurable change in the colorfulness of an object seen through the haze.

INTRODUCTION

Section 169A of the Clean Air Act sets a national goal of protecting visibility in national parks and other pristine areas. Under regulations promulgated in 1980, the U.S. Environmental Protection Agency (EPA) has taken specific regulatory action to protect visibility in the Grand Canyon National Park by reducing emissions of sulfur dioxide from the Navajo Electric Generating Station near the eastern end of the Grand Canyon and from the Mohave Power Plant at the western end. However, current concerns about visibility degradation stem from regional haze that is difficult or impossible to attribute to individual sources of air pollution. This issue is addressed by regional haze regulations that set a goal of making reasonable progress toward improving regional visibility in five-year increments, leading to the attainment of "natural conditions" by 2064.[1] Progress is to be measured by an innovative visibility metric for regulatory purposes known as the deciview,[2] used instead of visual range or other visibility metrics because it "expresses uniform changes in haziness in terms of common increments across the entire range of visibility conditions, from pristine to extremely hazy conditions."[1] One goal of this article is to assess this and other claims about the deciview scale in light of actual measurements of the perception of haziness. Since the deciview scale is meant to quantify small, just-noticeable differences (JNDs) in visibility, a review of the basic concepts of thresholds and JNDs is given.

IMPLICATIONS

Current regulations use the deciview to quantify a perceptible change in regional haze. Based on the results of this article, changes in atmospheric extinction required to meet regional haze regulations calculated using deciviews would probably be too small, sometimes much too small. In addition, these regulations require that progress be assessed over five-year intervals. In this way, the burden of reducing emissions is spread evenly over many years. However, since deciviews are not uniform in perception, it may be that the actual improvement in visibility will not be uniform.

Perceptual Threshold Concepts

For all the senses, thresholds are necessary—otherwise we would be constantly distracted by small, inconsequential changes in the environment. A background of random noise, some from the environment and some produced inside our own sensory organs, would make it next to impossible to form a stable view of the world. Our vision would be like the grainy, speckled images produced by night vision cameras. On a more basic scientific level, the study of thresholds of the senses has led to a deeper understanding of sensory physiology and how our vision and other senses function. For this reason, virtually all studies of thresholds of vision have been carried out under controlled laboratory conditions.

Since laboratory conditions seldom mimic the natural environment, thresholds so determined are generally not useful in predicting perception in the complex natural world. As an example of the drastic effect that experimental conditions can have on perception, consider an experiment to determine the ability of an observer to perceive the difference in the length of two strings—or to put it another way, to determine the threshold for perception of the difference in the length of two strings, or the JND. If the two strings are widely separated when presented to the observer, the threshold will be much greater than if the two strings are presented side by side. The visual equivalent of this is the use of a split image to determine the ability to distinguish color. If two colors are seen as two halves of a disk, the JND is very small, but if one

Exhibit E to EAI Comments

color is presented as a full disk, followed a few seconds later by the other color, the JND will be much larger. The topic of the background on which the colors are seen is also important (e.g., if it is black or a complex scene). In general, many conditions influence thresholds; for this reason, the results of laboratory experiments should be applied with great caution to the natural environment. Thus, this article will report and analyze data taken in a unique experiment in the natural environment with a goal of determining a JND in atmospheric haze.

In the above discussion, the terms "threshold" and "JND" have been freely used, but not defined. The naïve definition of a threshold or JND is clear: It is the smallest amount, or change in, a physical stimulus that is detectable. Ideally, a 1-JND change in a stimulus such as contrast or color would always result in the observer seeing a change, and anything less would not. Of course, the senses do not work in this simple on-off manner. In actuality, as the change in the physical stimulus increases, the probability that the observer will detect the change increases as well. Thus, thresholds and JNDs have always been defined by a probability of detection. Furthermore, the sensitivity of people's senses varies from person to person and during a person's life. Even if each person had a single, idealized threshold, the response of the general population would be best described by a probability of detection.

Repeated matching by the method of adjustments is one of the oldest methods of determining a JND. Falmagne[3] described this and other methods to quantify perception. Briefly, the observer is shown a target color and a variable test color and is asked to adjust the test color until it matches the target. Taking random starting points, the matching procedure is repeated as often as is practical. Since the observer has judged the matching color to be the same as the target color, the variability in the matches is a measure of a JND around the target. The standard deviation of the matches is one measure of this variability that is often used; another is the difference between the 75th and the 25th percentile of the match distribution. The method of adjustments has been replaced in laboratory studies by methods that give less control to the observer and more to the researcher and therefore improve the reproducibility of the results (unfortunately, these methods are impractical for field studies). However, JNDs are still defined by some measure related to the probability of detection. The final determination of the value of a JND or threshold is really dependent on how the measurements are made and how the data are interpreted. For the experimental data used in this article, the method of adjustments was used and a JND related to the standard deviation of repeated matches was defined.

Atmospheric Visibility Concepts

In the classical theory of atmospheric visibility, the threshold of contrast perception, that is, the threshold for perception of a large, dark object on the horizon, is assumed to be 2%.[4] This number is somewhat arbitrary. The Federal Aviation Administration (FAA) has taken the more conservative value of 5.5% as a contrast threshold for the definition of visual range, presumably because approaching aircraft seen from a cockpit are usually neither large nor dark. The common formula for visual range, using the 2% threshold, is

$$V_R = \frac{-\ln(0.02)}{b_{ext}} = \frac{3.9}{b_{ext}} \qquad (1)$$

where b_{ext} is the extinction coefficient of the atmosphere, which is assumed to be homogeneous. The extinction coefficient in the denominator of the formula can be thought of as the fraction of light that is lost as it traverses 1 m of air. For completely clear air, b_{ext} has a value of about 10×10^{-6} m^{-1} or 10 Mm^{-1}, or a visual range of about 390 km. More typically, particles in the air usually increase the extinction coefficient to 150–300 Mm^{-1} or more. Typical visual ranges are about 10 km in the eastern United States and 50 km or more in the western United States. Closely related to b_{ext} and visual range is the more general concept of optical depth. For a target at a distance x, this is defined as xb_{ext}. It is dimensionless; if b_{ext} is held constant it represents distance, and if the distance is constant, it represents changes in b_{ext}. From eq 1, the visual range corresponds to an optical depth of 3.9, and a distance of about one quarter of the visual range is equivalent to an optical depth of 1.

Despite lacking a firm psychophysical or experimental basis, the visual range defined by the 2% threshold has stood the test of time. However, while visual range has proven to be a good surrogate for atmospheric visibility for the aviation community, it is of limited value in addressing the concerns of the air quality community. Unlike aviation, where poor visibility is of greatest interest, the air quality community is primarily concerned with relatively small changes in good visibility. Pitchford and Malm[2] have proposed the deciview as a visibility indicator more suited to air quality regulations. If the extinction coefficient is given in Mm^{-1}, then deciview is defined as

$$v = 10\ln(b_{ext}/10) \qquad (2)$$

Current regional haze visibility regulations state that:

(1) A 1-deciview change in haziness is a small, but noticeable, change in haziness under most circumstances when viewing scenes in Class I areas.

(2) Deciview units are uniform in perception over a wide range of visibility conditions; that is, a 1-deciview change is just perceptible regardless of the visibility conditions.[1]

The next section describes a color matching experiment in the Great Smoky Mountains National Park. The results of this experiment are used to estimate a just-noticeable change in haze based on color perception. The validity of the claims for deciviews will be evaluated by comparison to experimental estimates of JNDs.

EXPERIMENTAL DATA

During summer 1995, a group of researchers from universities, government agencies, and private companies conducted the SouthEast Aerosol and Visibility Study (SEAVS) in the Great Smoky Mountains National Park. The SEAVS focused largely on aerosol composition,[5,6] airborne particle size distribution,[7,8] and the role of water in the aerosol.[9-11] However, the SEAVS had a number of other aspects, including a study of the perception of color through atmospheric haze.[12] The methods and primary results of the color perception study are described below.

The perceived colors of natural targets were quantified by color matching using a specially constructed visual colorimeter.[13] An observer looked at some scene element, such as a barn or green field, with one eye. The observer looked with the other eye in the visual colorimeter at a color spot, which the observer adjusted to match the color of the target. The perceived color was recorded as the amount of red, green, and blue light in the color match. At the same time, the spectrum of the light coming from the target was measured by a telespectroradiometer. A color appearance model was applied to produce measures of the perceived color as recorded by the visual colorimeter and as calculated from the spectrum.[14]

Of most interest here are the hue and colorfulness. The hue is what most people call the color—red, green, blue, yellow, and so on. It is quantified as a mixture of pure red, green, blue, or yellow lights. The colorfulness is the degree to which the hue is expressed; it is similar to the concept of saturation. A deep red color would have a colorfulness of about 100, while a colorfulness of 10 or less is almost achromatic (i.e., white or gray).

Two observers (Mahadev and Urquito) made color matches of a set of natural targets during the SEAVS. These observers were both males in their 20s with normal color vision. Each had received extensive training in color matching using the visual colorimeter. The scattering coefficient of the atmosphere was measured by a nearby nephelometer; particle absorption was small and its contribution to the extinction coefficient ignored. The full details of the experiment are found in Mahadev.[15]

The perception study found that viewing through a semitransparent atmosphere affected the perception of hue and colorfulness in a highly nonlinear way. The eye appeared to split the light coming from the target into two parts, the haze and the target. The result was that as the haze increased, the hue of the target as seen by the observer remained constant. However, because the increasing haze scattered more light into the sight path, the hue calculated from the spectrum became bluer. To the observer, the main effect of haze was to decrease the perceived colorfulness. Furthermore, the decrease in colorfulness seemed to be exponential with optical depth (optical depth is the dimensionless product of the extinction coefficient and distance):

$$M(\tau) = M_0 \exp(-\tau) \tag{3}$$

where $M(\tau)$ is the colorfulness of the object at optical depth τ and M_0 is the colorfulness at zero optical depth (i.e., no haze). M_0 is also known as the inherent colorfulness. The colorfulness of the horizon was assumed to be small enough to be taken as zero—the horizon was perceived to be white. This result implies that a JND in colorfulness can be taken to be a JND in haze.

JND in Colorfulness

Estimates of JNDs in colorfulness were based on sets of repeated color matches made during periods when the observing conditions (cloud cover, haze level, and lighting) were judged to be constant or nearly so. Observer Urquito made six sets of repeated matches.[15] Figure 1 is a plot of all the repeated observations of the colorfulness of the red barn roof made by this observer versus optical depth. The exponential fit given by eq 1 is fairly good ($R^2 = 0.68$). The error bars in the figure are twice the standard deviation given in Table 1. They show that one set

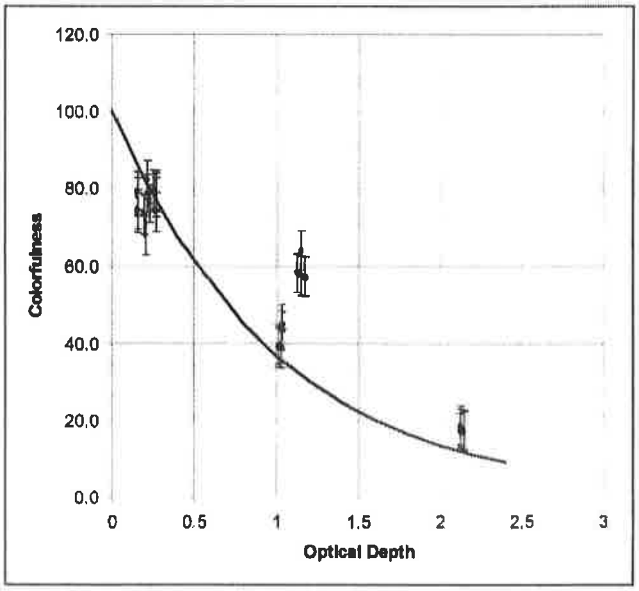

Figure 1. Colorfulness vs. optical depth for observer Urquito for repeated observations of the red barn roof. The line is an exponential fit as in eq 1, and the error bars are two times the standard deviation given in Table 2.

Exhibit E to EAI Comments

Table 1. Repeated measurements of the red barn roof by observer Mahadev.

Date	Time	Scattering Coefficient $(Mm)^{-1}$	Visual Range (km)	Colorfulness Spectra	Colorfulness Perceived	Spectra Hue % Red	Spectra Hue % Blue	Perceived Hue % Red	Perceived Hue % Blue
7/29/95	10:20 a.m.	37	105.7	38.0	42.2	53	47	97	3
7/29/95	10:46 a.m.	39	100.3	38.9	45.6	40	60	92	8
7/29/95	10:54 a.m.	39	100.3	39.9	45.4	38	62	99	1
7/29/95	11:03 a.m.	42	93.1	35.6	46.3	52	48	92	8
7/29/95	11:12 a.m.	42	93.1	37.5	44.9	53	47	93	7
7/25/95	11:49 a.m.	65	60.2	31.2	41.1	50	50	88	12
7/25/95	12:01 p.m.	65	60.2	30.8	45.1	42	58	84	16
7/25/95	12:12 p.m.	65	60.2	30.4	44.1	53	47	91	9
7/25/95	12:19 p.m.	65	60.2	29.4	43.0	54	46	91	9
7/25/95	12:24 p.m.	65	60.2	29.2	48.4	47	53	93	7
8/11/95	9:46 a.m.	157	24.9	37.6	29.2	19	81	97	3
8/11/95	9:57 a.m.	157	24.9	37.2	28.8	22	78	98	2
8/11/95	10:07 a.m.	157	24.9	37.5	29.2	23	77	98	2
8/11/95	10:16 a.m.	161	24.3	36.3	34.9	24	76	98	2
8/11/95	10:21 a.m.	161	24.3	36.7	29.5	23	77	98	2
8/14/95	10:12 a.m.	311	12.6	44.4	18.2	9	91	91	9
8/14/95	10:18 a.m.	312	12.5	44.0	18.4	8	92	97	3
8/14/95	10:30 a.m.	313	12.5	44.8	17.6	7	93	95	5
8/14/95	10:34 a.m.	313	12.5	44.7	18.1	7	93	94	6
8/14/95	10:38 a.m.	313	12.5	44.3	18.3	8	92	94	6
8/18/95	11:00 a.m.	595	6.6	35.3	9.7	2	98	81	19
8/18/95	10:46 a.m.	616	6.4	35.4	6.8	2	98	98	2
8/18/95	10:50 a.m.	616	6.4	35.2	9.4	2	98	91	9
8/18/95	10:53 a.m.	616	6.4	35.0	7.3	2	98	99	1
8/18/95	10:57 a.m.	616	6.4	35.7	10.0	2	98	97	3

of repeated measurements had colorfulness values that deviated much more than 2 sigma from the exponential line. However, the spread of these values about the mean was about the same as other observations for the same optical depth. This shows that the variability in the colorfulness numbers is not affected by systematic observer bias in the average colorfulness, and that the variability will be used to define the JND. The observations of the same target by the other observer are discussed in detail below.

Table 1 gives the results of five sets of repeated matches by observer Mahadev for the roof of a red barn about 3.5 km distant. Table 1 is sorted by the extinction coefficient so that one can easily see that the perceived hue did not change with increasing haze, but that the hue derived from the spectrum changed from red to blue. Colorfulness had the opposite behavior; the perceived values decreased with increasing haze and the values from the spectrum stayed about the same. Two-way analysis of variance was applied to estimate the random error in the sets of repeated measurements in Table 1. This analysis was repeated for both observers' matches of five additional natural targets. The results are given in Table 2. The standard deviation for both observers was 2.05, as calculated from the average of the variances. Although viewing conditions were chosen to be constant, some of this variability was due to small changes in atmospheric conditions.

Based on these results, one can define the JND in colorfulness in many ways. One appropriate definition for this application is based on the following thought experiment. An observer matches a target with the visual colorimeter and determines the colorfulness to be C_1. The extinction coefficient of the atmosphere is decreased, so the colorfulness of the target is increased by an amount ΔC. The observer matches the target again to get the new colorfulness C_2. A JND is defined as the value of ΔC that gives a 95% probability that $C_2 - C_1 > 0$. Assume that C_1 and C_2 are normal random variables with standard deviation s and means C_0 and $C_0+\Delta C$, respectively (statistical analysis of the SEAVS color matching data confirms that this is a good assumption). Then $C_2 - C_1$ is a normal random variable with mean ΔC and standard deviation $2^{1/2}\sigma$. The value of ΔC needed to ensure a 95% probability that $C_1 - C_2 > 0$ is given by $2^{1/2}\sigma F(0.95)$, where $F(0.95)$ is the inverse of the cumulative standard normal distribution and is equal to 1.645. Thus, the colorfulness JND is taken to be $2^{1/2}\sigma F(0.95) = 2.326\sigma$. From Table 2, using the data for both observers gives $\sigma = 2.05$, and a 1 colorfulness JND is 4.8. This value of σ includes the effects of small random variations in natural illumination, which should be included for this application because they are inevitably present, but makes the value of a colorfulness JND a bit larger than it would be otherwise.

Table 2. Standard deviations of colorfulness for repeated matches of natural targets.

Target	Observer M	Observer U	Distance (km)
White silo	0.91	1.33	3.54
Red roof	1.93	2.41	3.54
Near green meadow	2.93	2.15	3.86
Green hills	2.15	3.46	5.15
Far green meadow	1.45	1.64	10.46
Horizon sky	1.53	1.19	
Average	1.92	2.17	
Number of observations	55	60	

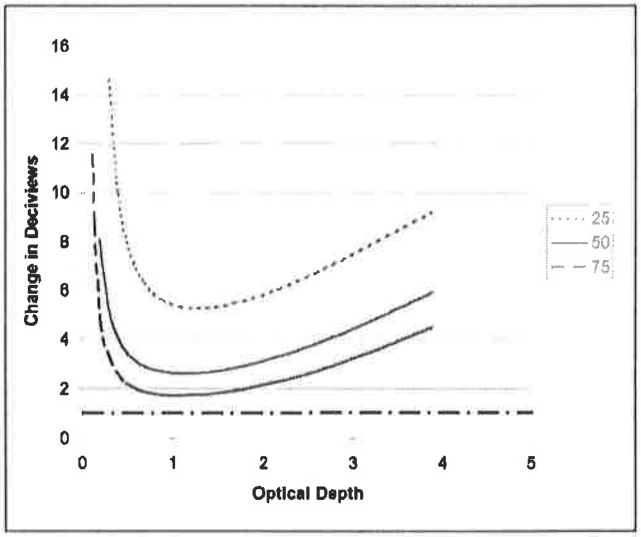

Figure 2. Change in deciviews needed to produce a just-noticeable increase in colorfulness for objects with an inherent colorfulness of 25, 50, and 75. The horizontal dashed dotted line represents what would be expected if a 1-deciview change were actually a uniform measure of haze perception.

Deciviews and Colorfulness JNDs

Relationships between colorfulness, deciviews, and optical depth are derived below; these will be applied to test the validity of the properties of deciviews given in the regional haze regulations.

From eqs 2 and 3, an expression for deciviews v as a function of colorfulness M is derived:

$$v = 10\ln\left(-\frac{1}{10x}\ln\left(\frac{M}{M_0}\right)\right) \quad (4)$$

For a given optical depth and inherent colorfulness, the equations above were used to calculate the change in deciviews needed to give a 1-JND increase in colorfulness, using 4.8 as a JND. Figure 2 is a plot of the results as a function of optical depth for objects with three levels of inherent colorfulness. These levels of inherent colorfulness represent a reasonable range for natural targets.[12] As might be expected, more colorful objects are more sensitive to changes in atmospheric haze. Perhaps unexpectedly, the figure shows that landscape features at a distance corresponding to an optical depth of 1–2 are the most sensitive to changes in extinction as measured by deciviews. This range corresponds to one quarter to one half of the visual range. Landscape features outside this range are much less sensitive to changes in haze. If the deciview scale were perceptually uniform, as claimed in the regional haze rules, then the lines in the figure would be horizontal, or at least approximately so. However, the change in deciviews needed to produce a 1-JND change in colorfulness varied a great deal with optical depth and inherent colorfulness. The figure also shows that a 1-JND change in colorfulness always requires more than a 1-deciview change, sometimes much more.

DISCUSSION AND CONCLUSIONS

Regional atmospheric haze affects visibility by producing a visible haze layer that limits the visual range, reduces contrast, and deceases the colorfulness of objects seen though the haze. Of these three effects of haze, the decrease in colorfulness may be the most important and sensitive visual cue. Visual range is not often useful for judging the effects of small changes in extinction. For example, a change in visual range from 50 to 60 km will not be noticed if the most distant landscape feature is at 25 km. The effect of haze on contrast is a better candidate as an indicator of change in haze; however, perceived contrast, like perceived hue, is affected in a nonlinear fashion by the semitransparent nature of haze and is not a sensitive indicator of changes in atmospheric haze.[16] Experimental data have shown that colorfulness is a sensitive measure of changes in haze, so this article has used it to define just-noticeable changes in atmospheric haze.

A just-noticeable decrease in atmospheric haze is defined as a decrease in extinction that would produce a 95% probability of a measurable increase in colorfulness of an object seen through the haze. From the experimental evidence from the two young male observers, a JND in colorfulness was 4.8. For the population in general, this number is certainly too low, since all visual functions decline with age. Thus, the conclusions below about the deciview scale based on this number are understated for the general population.

Analysis of the experimental data showed that for a JND in atmospheric haze as defined above:

(1) The deciview scale is not uniform in perception over a wide range of visibility conditions. In fact, the change in deciviews needed to be noticeable

varies greatly depending on the optical distance of the landscape feature and its inherent colorfulness.

(2) A 1-deciview change is never noticeable.

What are the implications of these results for measuring progress toward reducing regional haze using the deciview metric? This is difficult to judge because the current proposals are very complex, using particulate measurements and relative humidity to estimate the extinction coefficient and average deciviews for the 20% most-impaired and 20% least-impaired days. The goal is to show no change on the least-impaired days and improvement on the most-impaired days, leading to natural conditions by 2064.[17]

The results of this article highlight a possible flaw in this regulatory scheme based on the deciview metric. An unstated assumption is that the nature of the scenic vista can be ignored—that is, a given deciview change will affect the perception of all landscape features in all scenes in the same way. Figure 2 shows that this is approximately true only if all the important landscape features have nearly the same inherent colorfulness and are at distances that correspond to an optical depth of between 1 and 2, or about one quarter to one half of the visual range. In this limited case, the deciview is indeed a uniform metric. However, most scenic vistas do not fit these restrictions and, by Figure 2, will require greater decreases in extinction as measured by deciviews to show a perceptible change. The result is that the emission reductions required by the proposed regulatory analysis are likely to produce much smaller improvements in perceived effects of regional haze than expected. The EPA guidance documents provide an example of an eastern scenic vista with a baseline of 27 deciviews and natural conditions of 11.[17] The decrease in extinction to reach natural conditions by 2064 is 0.35 deciview/yr, or 1.75 deciviews in five years. This five-year reduction should, according to the regulations, result in a noticeable change in regional haze. However, the results herein predict that there would very likely be no noticeable difference in any actual scenic vista in the region as a result of the required emission reductions.

Regional haze rules also call for a uniform rate of improvement in visibility (measured in deciviews) that is needed to go from current conditions to natural conditions by 2064. Since the deciview scale is not uniform in perception over a wide range of visibility conditions, this requirement is also flawed and will not result in uniform improvement in perceived visibility.

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Exhibit E to EAI Comments

FOSTER WHEELER NORTH AMERICA CORP
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TANGENTIAL LOW NOx (TLN3) SYSTEM

FOR

ENTERGY
WHITE BLUFF UNITS 1& 2

Proposal No. 65-130582-00 Rev. 0
October 13, 2011

PROPIETARY AND CONFIDENTIAL INFORMATION

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3.3 Foster Wheeler's Tangential Low NOx (TLN) Systems

3.3.1 Design Philosophy

Foster Wheeler North America Corp's (FWNAC) Tangential Low NOx (TLN) Combustion Systems provide industrial and utility boiler owners with an alternative solution to their NOx compliance needs. Our philosophy is to provide our clients with the highest value low NOx system.

- Our systems are designed to maximize NOx reduction efficiency while minimizing the impact on combustion performance or unit operation. An extensive support team of experienced technical and project specialists backs our commitment.

- We focus on designing systems that minimize changes to the furnace and / or the boiler house. This reduces installation time and costs for the owner.

- We believe each TLN application should complement the unit's operational capabilities as well as the range of current and future fuels.

- We believe that each TLN system should provide years of reliable service. All T-fired windbox components are manufactured in either our own facilities or per our specifications by high quality suppliers.

- A team of experienced and qualified tangential firing engineers, project managers, service engineers and suppliers supports each project. Our goal is to make each of your TLN retrofits your most favorable project.

Our system technology is supported by a continuous commitment to improve performance and reliability. For example our on-line real-time, ECT coal flow distribution, velocity and particle size monitoring technology combined with our CADM system allows fuel and air to be more balanced for lower CO and higher combustion efficiency.

Currently there are numerous tangentially coal fired utility units equipped with Foster Wheeler's TLN systems (see Experience List in Appendix). Fuels being fired range from lignite and PRB through low and higher sulfur eastern bituminous coals. NOx reductions exceeding 70 percent and NOx levels below 0.10 lb/MBtu are being achieved.

3.3.2 FWNAC's TLN Systems

Foster Wheeler's Tangential Low NOx (TLN) firing systems are based on the application of secondary air staging technology commonly referred to as "overfire air". Both in-windbox and separated secondary air-staging arrangements are applied depending on current windbox configurations and the desired level of NOx reduction. Staging of secondary combustion air has been well documented throughout the international boiler industry to be the single most effective technique for reducing NOx emissions from tangentially fired boilers. By redirecting a portion of the combustion air above the upper fuel elevation, fuel nitrogen conversion and thermal NOx production is reduced. Control of this staging process through proper nozzle and damper design is critical in order to maximize combustion efficiency and component longevity. Depending on the unit configuration and required NOx reductions, Foster Wheeler can offer several high value options. These include the TLN1, TLN2 and TLN3 arrangements, which are shown below in **Figure 3.**

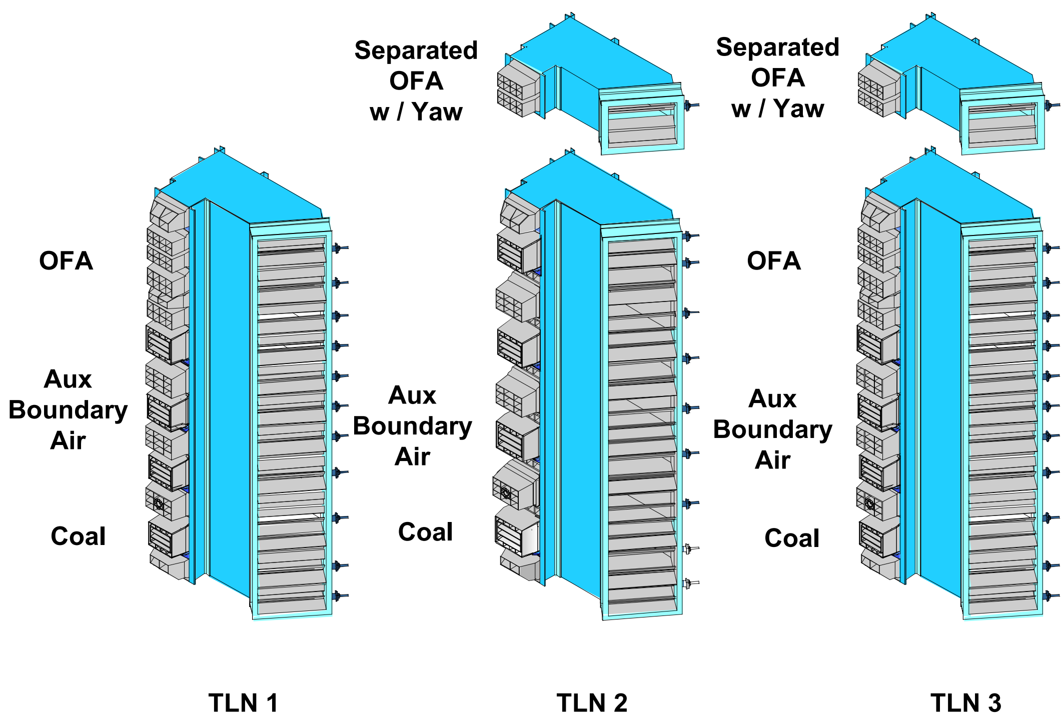

Figure 3 - FWNAC Tangential Low NOx (TLN) Configurations

Foster Wheeler's **TLN2** system consists of adding a single level of separated overfire air above the main firing zone to provide the required vertical air staging effect. Due to increased spacing from the upper coal elevation, separated overfire arrangements provide significantly higher NOx reduction efficiencies as compared with "in-windbox" arrangements. Nozzle tips and/or air flow control dampers in the main windboxes are often resized or modified as part of such retrofits. Foster Wheeler's proprietary computer-modeling program is used to ensure that proper airflow distribution control and air/coal mixing is maintained throughout the unit load range with the new SOFA addition.

The **TLN3** system consists of adding a single level of separated overfire air to units that already have an in-windbox OFA. Other applications of the TLN3 arrangements are units where interferences do not permit placement of an adequate single overfire air windbox level. Nozzle tips and air flow control dampers in the main windboxes are often upgraded or modified in accordance with computer modeling results or to meet specific unit or fuel requirements. These modifications ensure that proper airflow distribution control and air/coal mixing is maintained. Both the TLN2 and TLN3 have demonstrated up to 75% NOx reduction.

3.3.3 Combustion Computational Fluid Dynamics - Option

Foster Wheeler is offering a Computational Fluid Dynamics (CFD) study of furnace thermodynamics to validate boiler performance before and after installation of the SOFA system. CFD analysis is an inherently man-hour intensive process because the ability of the CFD model to provide accurate predictions is predicated on the accuracy of the model and thus requires that each existing system (boiler) be manually detailed in the program prior to use. CFD can therefore be a somewhat expensive undertaking.

FWNAC feels obligated to inform Entergy that the results of CFD modeling have never altered the design, predictions or guarantees associated with a TLN retrofit and can therefore be somewhat of an extraneous exercise unless applied to validate a specific, unique design feature. In other words, should Entergy find the cost/benefit associated with use of CFD to be less than satisfactory, solace should be found in the fact that it will only service to confirm the design being offered.

Should Entergy desire to proceed with use of Foster Wheeler's Combustion CFD program, on both White Bluff units, the model will extend from the burner fronts up through the leading edge of the first bank of the finishing superheater.

Vital to any OFA design is full penetration of the air jets into the furnace gas stream to insure turbulent mixing with the bulk of the rising flue gases. This is accomplished by choosing appropriate nozzle velocities and sizes. Foster Wheeler has studied jet

4 DESCRIPTION OF PROPOSED FWNAC TLN3 SYSTEM

4.1 Proposed TLN3 System for White Bluff Units 1 and 2

Based on Entergy's requirements and FWNAC's evaluation of the current unit operation, FWNAC is proposing our TLN3 system. This system will consist of the following specific components and features.

The proposed FWNAC modifications to Entergy's White Bluff Units 1 and 2 are shown on FWNAC proposal drawings attached in the Appendix.

a) A SINGLE level of new separated SOFA windboxes will be provided as part of the FWNAC TLN3 system. This would consist of eight (8) new SOFA windboxes. To minimize physical changes to the boiler house, the new Overfire Air windboxes would be installed in the front and rear walls above the existing windboxes. The SOFA windboxes would be designed to supply the appropriate amount of combustion air as Overfire Air. Each new windbox will be provided along with new water wall panels and the necessary connecting ductwork, hangers, expansion joints and steel modifications to interface with the secondary air ducts. Each windbox will be fitted with nozzle tips, turning vanes, access doors, air control dampers with actuators (Kinetrol 147-130-1900 Fail Open Spring return Actuator with Siemens PS2 Single Acting Smart Positioner) and static pressure taps to provide total Overfire Air control. Manual "set and forget" horizontal yaw and vertical tilt capability would be provided in the SOFA to help control CO as well as back end gas temperature and oxygen profiles. The yaw linkage, manual tilt gearbox and damper drives will be accessible from the sides of each windbox.

   A CFD air flow model will be developed that includes the secondary air ducts, SOFA ducts, windboxes and burners to ensure balanced air flow.

b) Platform, railing, sootblowers, and sootblower piping may need to be modified where required to accommodate the addition of the separated over fire air system.

c) New FW Double Shroud (DS) type nozzle tips and associated linkage hardware will be supplied. These will be 100% compatible with the existing coal nozzle and tilt linkage. The new nozzle tip, which includes a patented (US Patent No. 6,260,491) cooling feature, will also be reconfigured to further help stage more air to the SOFA compartments to provide additional NOx reduction benefits.

d) The 23¼ inch high upper CCOFA compartment will be modified with a crotch cooling plate on the top and a restrictor plate on the bottom to reduce the outlet height to 19 ¼ inches. A new, one piece FWNAC DS style nozzle tip will be provided. This tip will be the same tip as the lower CCOFA and bottom air tips. This interchangeability will reduce stocking and maintenance costs.

e) The 23¼ inch high lower CCOFA compartment will be fitted with restrictor plates and a new DS style nozzle tip exactly like the upper CCOFA nozzle tip.

f) The fuel piping to the refuse compartment is currently blanked off, with no future plans for firing this compartment. As a top end air, this 24 inch high compartment will be fitted with restrictor plates and a new DS style nozzle tip exactly like the CCOFA nozzles.

g) The outlet flow area of each 27¼ inch high auxiliary air compartment will be reduced with restrictor plates for velocity compensation. Each compartment will be fitted with one (1) new, one piece FWNAC DS style type boundary air auxiliary nozzle tip. The nozzle tip is designed to provide the necessary velocity, air flow distribution and direction control to benefit NOx emissions and fireball shaping while maximizing combustion efficiency.

h) The 27¼ inch high oil warm-up compartment will also be reduced with restrictor plates for velocity compensation and modified with a similar tip, with the center of the tip to accommodate the existing oil gun. However, due to the presence of the oil warm-up gun, this tip will not yaw.

i) The existing bottom end air compartments will be fitted with new, one piece reduced free area nozzle tips. These tips will be interchangeable with the CCOFA tips.

j) As an integral part of the TLN3 system, the Lower Furnace Stoichiometry Control (LFSC) system will be provided. These systems help reduce the dark lower furnace hopper conditions typically associated with deep-staged combustion systems. It is comprised of a single air nozzle tip with external manual tilt installed in the bottom end air compartment. This will be used to direct combustion air into the lower furnace hopper area, further controlling lower furnace smoky conditions, slagging and CO formation that might occur during ultra low NOx deep staged operation.

k) All coal, auxiliary air and CCOFA windbox compartments will be modified with FWNAC's damper venturi plates to improve air flow distribution control over a larger load range.

7 PERFORMANCE GUARANTEES & CONDITIONS

7.1 Performance Guarantees

The following Performance Guarantees contained within this section 7.1 are the **exclusive performance guarantees** offered by FWNAC relating to the equipment supplied by FWNAC. Any graphs, stated performance values, predictions or discussions in other sections of the proposal or in the specification fill-in sheets shall not be construed as performance guarantees.

- Three (3) one hour tests will be conducted for NOx, CO, LOI, main steam temperature and reheat steam temperature at MCR. Three (3) one hour tests will also be conducted for main and reheat steam temperatures at Guarantee Point Load and Control Load. The guarantees will be considered met if the average of each guarantee value over the three (3) test periods meets the guarantee values offered below by FWNAC.

  A thirty (30) day rolling average test will also be conducted for NOx and CO emissions. This test may be conducted for 45 day period to allow for selection of the data for the 30 day period. Only data to be included will be that while the unit is operating between Control Load and MCR. Data will be excluded while the unit is at upset condition.

- All performance conditions, test methods, and referenced fuels/ranges of fuels as defined in Section 7.2 of this proposal are considered a prerequisite for the guarantees. All sampling must ensure that a representative average of the flue gas emissions and fly ash sample is taken.

7.1.1 NOx Emissions

<u>MCR (6,023 klb/hr main steam flow)</u>

- **NOx will average less than or equal to 0.12 lb/MBtu for the average of three (3) one hour tests**

<u>Control Load (3,000 klb/hr main steam flow) to MCR (6,023 klb/hr main steam flow)</u>

- **NOx will average less than or equal to 0.14 lb/MBtu over a 30 day period**

7.1.2 Carbon Monoxide (CO)

MCR (6,023 klb/hr main steam flow)

- **CO will average less than or equal to 0.15 lb/MBtu (185 ppm measured at 3.0% O2 dry) for the average of three (3) one hour tests**

Control Load (3,000 klb/hr main steam flow) to MCR (6,023 klb/hr main steam flow)

- **CO will average less than or equal to 0.15 lb/MBtu (185 ppm measured at 3.0% O2 dry) over a 30 day period**

7.1.3 Fly Ash LOI

MCR (6,023 klb/hr main steam flow)

- **Fly ash LOI will average less than or equal to 1.0% for the average of three (3) one hour tests**

7.1.4 Superheat (SH) Steam Temperatures

MCR (6,023 klb/hr main steam flow)

- **980 ±10°F** for the average of three (3) one hour tests

Guarantee Point (5,400 klb/hr main steam flow)

- **980 ±10°F** for the average of three (3) one hour tests

Control Load (3,000 klb/hr main steam flow)

- **980 ±10°F** for the average of three (3) one hour tests

7.1.5 Reheat (RH) Steam Temperatures

MCR (6,023 klb/hr main steam flow)

- **1000 ±10°F** for the average of three (3) one hour tests

Guarantee Point (5,400 klb/hr main steam flow)

July 30, 2015
Ref: Tangential Low NOx

Michael P. Fallon, P.E.
Entergy – Boiler Process Owner
White Bluff & Lake Catherine

Dear Mike;

Tangential low NOx systems that use separated overfire air are designed to provide significant reductions in NOx across the control range of the boiler, which is normally from 50 to 100 percent of steam flow. These systems work in the control range because the heat input across this range is sufficient to safely redirect a substantial portion of combustion air through the overfire air registers. When this is done combustion zone airflow is sub stoichiometric and oxygen there is reduced to the point where much of the elemental nitrogen in the fuel and combustion air can pass through the boiler without oxidizing.

Overfire air cannot be fully utilized for NOx abatement below the control range because net heat input is not sufficient to allow the combustion zone in the furnace to safely run in a sub stoichiometric condition. When a boiler runs below the control range NOx concentrations can be elevated above the levels achievable at higher loads, even though the tons of NOx emitted is less due to the reduced amount of fuel and air.

I hope this memo answers your question.

Steve deMello
Project Manager
Amec Foster Wheeler North America Corp.
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EVALUATION OF THE CALPUFF MODELING SYSTEM MARGIN OF ERROR FOR A BART ANALYSIS

Entergy Arkansas, Inc. > Lake Catherine Plant

Entergy

THE POWER OF PEOPLE℠

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August 4, 2015

Project 154401.0074

Trinity Consultants

Environmental solutions delivered uncommonly well

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1. EXECUTIVE SUMMARY

On April 8, 2015, the United States Environmental Protection Agency (EPA) published the Arkansas Regional Haze Federal Implementation Plan (FIP) to address regional haze and visibility transport requirements for the State of Arkansas. As part of the FIP, EPA proposed nitrogen oxide (NO_X) controls for the Entergy Arkansas, Inc. (Entergy) Lake Catherine Plant Unit 4, which is subject to Best Available Retrofit Technology (BART).[1] In order to justify the visibility improvement as a result of installation of the proposed controls, EPA relied on the CALPUFF dispersion modeling system (CALPUFF) without assessing the reliability of the model to predict small changes in visibility.

Entergy completed a quantitative analysis to evaluate the margin of error in the CALPUFF analysis for Lake Catherine Unit 4 and determined the visibility improvements relied upon in the proposed Arkansas FIP are within the model's margin of error. Specifically, the incremental visibility improvements predicted by CALPUFF at the Caney Creek Wilderness Area (Caney Creek) and Upper Buffalo Wilderness Area (Upper Buffalo) Class I areas are within the margins of error calculated for each Class I area. Moreover, the visibility improvement values are within the *lowest* margin of error for both Class I areas. Because of this, EPA cannot *reasonably anticipate* visibility benefits from the proposed controls for Lake Catherine Unit 4. *See National Parks Conservation Ass'n v. EPA*, 788 F.3d 1134, 1146–47 (9th Cir. 2015) ("Montana Case") (holding that EPA must offer a reasoned explanation of its conclusion that a visibility improvement could be reasonably anticipated when the improvement is within CALPUFF's margin of error).

This report is organized as follows: Section 2 provides background on the Lake Catherine Plant and EPA's proposed BART requirements, Section 3 outlines the methodology used in the Lake Catherine analysis, Section 4 summarizes the results of the analysis, and Section 5 presents several case studies comparing modeled values to monitored values.

[1] Proposed Arkansas Regional Haze FIP, 80 Fed. Reg. 18,943 (Apr. 8, 2015).

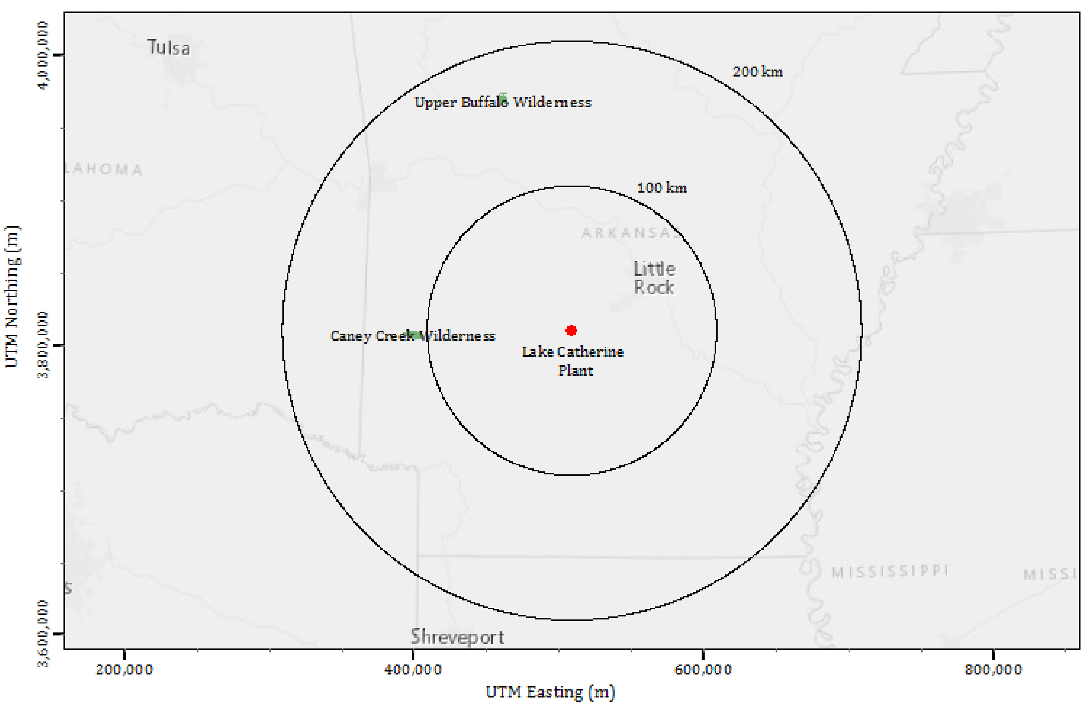
Entergy owns and operates the Lake Catherine Plant located at 141 W. County Line Road in Malvern, Arkansas. The Lake Catherine Plant operates one emission unit – Unit 4 – that is an affected source under the BART provisions of the EPA's Regional Haze Rule, which is codified in Title 40 of the Code of Federal Regulations (40 CFR) Part 51. Unit 4 is a tangentially-fired boiler with a nominal heat input rate of 5,850 Million British thermal units per hour (MMBtu/hr) and a nominal net power rating of 558 megawatts (MW). The boiler is permitted to fire natural gas and No. 6 fuel oil; however, the unit has not fired fuel oil since the 2001-2003 baseline period and Entergy does not plan to burn fuel oil in the unit in the foreseeable future.

On April 18, 2015, EPA proposed a FIP to address requirements related to regional haze for those portions of the Arkansas State Implementation Plan (SIP) that were disapproved on March 12, 2012.[2] The FIP includes NO_X BART requirements for Lake Catherine Unit 4.

2.1. CLASS I AREAS

Per the FIP, there are two (2) Class I areas in Arkansas that are impacted by Unit 4 at the Lake Catherine Plant: Caney Creek and Upper Buffalo. Caney Creek is approximately 100 km west and Upper Buffalo is approximately 160 km north of the Lake Catherine Plant. The locations of the Class I areas with respect to the Lake Catherine Plant are shown in Figure 2-1 below. Table 2-1 summarizes the baseline visibility impairment attributable to Unit 4 at each of these Class I areas as determined by CALPUFF.[3]

Figure 2-1. Location of Lake Catherine Plant with Respect to Arkansas Class I Areas



[2] FR Vol. 80, No. 84, May 1, 2015.

[3] Ibid.

Table 2-1. Baseline Visibility Impairment

Emission Unit		Caney Creek	Upper Buffalo
Unit 4	Maximum (Δdv)[1]	3.480	2.044
	98th Percentile(Δdv)[1]	1.371	0.489

1. Values shown are for natural gas combustion.

2.2. PROPOSED BART FOR THE LAKE CATHERINE PLANT

The proposed NO_X BART for Lake Catherine Unit 4 is summarized below.

2.2.1. NO_X BART

In the proposed FIP, EPA determined that NO_X BART for Unit 4 for the natural gas scenario is an emission limit of 0.22 pounds per MMBtu (lb/MMBtu) on a 30 boiler-operating-day rolling averaging basis, based on the installation and operation of Burners out of Service (BOOS).[4] The projected visibility improvement at Caney Creek and Upper Buffalo based on CALPUFF modeling is shown in Table 2-2 below.

Table 2-2. Projected Visibility Improvement

Emission Unit	Pollutant	Caney Creek (Δdv)	Upper Buffalo (Δdv)
Unit 4	NO_X	0.596	0.248

[4] Per the FIP, "BOOS is a staged combustion technique in which fuel is introduced through operational burners in the lower furnace zone to create fuel-rich conditions, while not introducing fuel to other burners."

In completing the BART five factor analysis for Lake Catherine Unit 4, EPA relied on the visibility improvement as predicted by CALPUFF without assessing the ability of the model to accurately predict small changes in visibility. In order to assess the magnitude of visibility that could reasonably be anticipated for the Lake Catherine case, Trinity conducted a margin of error analysis similar to the one completed for the Colstrip Generating Station ("Colstrip Station") by TRC Environmental Corporation (TRC) that was the basis for PPL Montana's comments on the CALPUFF model in the Montana Case.[5] The following sections outline the methodology that was used to complete this analysis for the Lake Catherine Plant. This study is necessary due to the dissimilarities in the geographical and meteorological conditions between the Lake Catherine Plant and the Colstrip Station at issue in the Montana Case.

3.1. MODEL SELECTION

The BART Guidelines recommend using the CALPUFF Modeling System to determine the visibility impairment attributable to a BART-eligible source. This analysis was completed using CALPUFF Version 5.84, POSTUTIL Version 1.52, and CALPOST Version 6.221, the model versions utilized in the Arkansas BART analyses. Entergy used refined meteorological data consistent with the meteorological data used for other BART sources in Arkansas. On July 26, 2012, the Arkansas Department of Environmental Quality (ADEQ) updated its original (June 7, 2006) protocol including CALPUFF modeling components and the background concentrations in CALPOST. The CALMET data and parameters are based on the modeling protocol that was first submitted on January 23, 2008 on behalf of Oklahoma Gas & Electric and upon which all recent BART analysis in Arkansas have been based. This protocol summarizes modeling methods and procedures that were followed to predict visibility impairment for several BART-eligible sources located in Oklahoma as part of the BART analyses for these sources.

3.2. MODELED SCENARIOS

As part of this analysis Entergy modeled the following three scenarios:

1. ALL BART: Includes all sources subject to BART modeled using Pre-BART representations;
2. Pre-BART: Includes only the Lake Catherine Plant BART eligible source modeled based on its current permit representations; and
3. Post-BART: Includes only the Lake Catherine Plant BART eligible source modeled using the Post-BART emission rate and stack parameters.

3.3. BACKGROUND VALUES

The primary objective of this analysis was to compare the model predicted data to monitored data at each Class I area to identify the modeling margin of error in predicting visibility compared to observed values. BART modeling using CALPUFF is conducted to determine the impact of a facility on a Class I area without consideration of emissions/impacts from other sources. This type of analysis uses only natural background

[5] *See* "Accuracy of Visibility Protocol Modeling in BART Evaluations" prepared by Gale F. Hoffnagle, TRC Environmental Corporation, June 15, 2012. PPL Montana relied on this analysis in its comments alleging that the incremental visibility improvement predicted by EPA at Colstrip Station were within CALPUFF's margin of error. *See* PPL Montana, LLC's Comments on Proposed Regional Haze Federal Implementation Plan for the State of Montana at 8–11, Docket ID EPA-R08-OAR-2011-0851-0211 (2012).

conditions, referred to by EPA as a "clean background" analysis. As such, comparing model predicted output directly from the CALPUFF Modeling System to monitoring data does not represent a like-kind comparison as it is missing contribution from other sources. In order to obtain an estimate of the impact of other emission sources (i.e., point, non-point, mobile, biogenic, etc.), Entergy obtained a background value from CAMx modeling completed for the Central Regional Air Planning Association (CENRAP) by ENVIRON using the CENRAP PM Source Apportionment Technology (PSAT) Tool.[6] The CENRAP's CAMx analysis was completed for actual emissions from 2002; therefore, the background value from 2002 was added to the CALPUFF predicted impacts for all modeling scenarios and compared to 2002 IMPROVE data for Caney Creek and Upper Buffalo.

3.4. MODELED VERSUS MEASURED STATISTICS AND MARGIN OF ERROR

Entergy calculated the average difference between modeled values obtained using the CALPUFF Modeling System (including the CENRAP background) and IMPROVE monitored values for Caney Creek and Upper Buffalo for each of the three (3) modeling scenarios described previously. Unlike BART analyses where the 98th percentile values are compared to the dv impact level, Entergy utilized the regional haze design value format of average worst 20% days for this analysis. Since the CENRAP background value is from the 2002 calendar year, this comparison was only completed for 2002. Specifically the following comparisons were made:

- Modeled vs Measured 20% Worst Days: The worst 20% days based on IMPROVE measurements were selected for each Class I area and compared with the CALPUFF results from the corresponding days.
- Measured vs. Modeled 20% Worst Days: The worst 20% days based on CALPUFF modeling results were selected considering only days when IMPROVE measurements were taken. Modeled values were then compared to the IMPROVE measurements from the corresponding days.
- Measured and Modeled 20% Worst Days: The worst 20% days based on IMPROVE measurements were selected and compared with the worst 20% days based on CALPUFF modeling results disregarding temporal correlation.

Entergy used these average differences to determine the lowest overall margin of error for each Class I area. Entergy also examined how the modeled visibility impacts from the Lake Catherine Pre-BART scenario, excluding background, compared with the IMPROVE measurements at Caney Creek and Upper Buffalo. This provides an indication of the magnitude of the contribution from Lake Catherine Unit 4 to the total visibility impairment reflected in the IMPROVE measurements.

[6] See the CENRAP TSD and the August 27, 2007 CENRAP PSAT tool - CENRAP_PSAT_Tool_ENVIRON_Aug27_2007.mdb

The following sections summarize the results of the analyses completed for the Lake Catherine Plant.

4.1. MODELED VERSUS MEASURED STATISTICS AND MARGIN OF ERROR

Table 4-1 below summarizes the average difference between the modeled versus measured 20% worst days (20% worst-days based on measured values), measured versus modeled 20% worst days (20% worst-days selected based on modeled values), and modeled and measured 20% worst days (comparison of values from 20% worst modeled days and 20% worst measured days not temporally paired). Consistent with the study assessing CALPUFF modeling for the Colstrip Station, CALPUFF consistently over predicts when compared to IMPROVE observations.

Table 4-1. Summary of Modeled Versus Measured Statistics

Model Scenario	Modeled vs. Measured Statistics	CACR (Mm-1)	CACR (dv)	UPBU (Mm-1)	UPBU (dv)
All BART Sources	Modeled vs. Measured 20% Worst Days Average Difference	28.69	1.40	22.18	1.09
	Measured vs. Modeled 20% Worst Days Average Difference	45.64	6.47	51.65	6.09
	Modeled & Measured 20% Worst Days Average Difference	25.52	1.16	20.09	0.93
Lake Catherine Pre-BART	Modeled vs. Measured 20% Worst Days Average Difference	28.60	1.39	21.98	1.07
	Measured vs. Modeled 20% Worst Days Average Difference	41.79	5.89	64.46	7.86
	Modeled & Measured 20% Worst Days Average Difference	27.88	1.34	21.50	1.04
Lake Catherine Post-BART	Modeled vs. Measured 20% Worst Days Average Difference	28.81	1.40	22.01	1.07
	Measured vs. Modeled 20% Worst Days Average Difference	41.25	5.85	66.86	8.24
	Modeled & Measured 20% Worst Days Average Difference	28.42	1.38	21.74	1.05
	Average	**32.95**	**2.92**	**34.72**	**3.16**
	Maximum	**45.64**	**6.47**	**66.86**	**8.24**
	Minimum	**25.52**	**1.16**	**20.09**	**0.93**

The lowest calculated margin of error at Upper Buffalo is 0.93 dv. A larger margin of error, 1.16 dv, was calculated for Caney Creek. As shown in Table 4-2 below, the CALPUFF predicted visibility improvement at Caney Creek and Upper Buffalo obtained from the Arkansas FIP is within the margin of error calculated for each Class I area. Moreover, the predicted visibility improvement is within the lowest margin of error of 0.93 dv regardless of the Class I area. This analysis suggests that the formulation associated with CALPUFF forces the model to predict a value for a given scenario regardless of the accuracy of the value. Moreover, the model predicted number at these lower ranges may not necessarily result in the actual visibility improvement, as the numbers can very well be within the uncertainty in the prediction.

According to the BART guidance, use of 98th percentile or 8th highest value of model prediction is used to reduce the effect of uncertainty in the CALPUFF models. The Lake Catherine analysis uses the worst 20% days or 24 high values to determine the margin of error, thus providing additional data points for the analysis rather than just one data point (i.e., 98th percentile). The use of worst 20% days is consistent with the calculations associated with the reasonable progress goals. Use of the 98th percentile does not address the real issue, that the CALPUFF model is predicting visibility improvements for Lake Catherine that fall within the model's margin of error for this case, thus the projected visibility improvements cannot be *reasonably anticipated* as is required by the Clean Air Act. As stated in the Montana Case, "The issue is not the *perceptibility* of the proposed improvements, but the model's ability to anticipate improvements at a level allegedly within its margin of error, whether perceptible or not to the human eye."[7] EPA has failed to address how CALPUFF can be used as the basis for BART determinations when the predicted visibility improvements in many cases are lower than the calculated margin of error. Due to the uncertainty in the model's ability to predict small visibility improvements, the visibility benefits anticipated from the AR FIP proposed controls on Lake Catherine Unit 4 cannot be *reasonably anticipated*.

Table 4-2. Projected Visibility Improvement from Lake Catherine Margin of Error

Emission Units	Baseline Visibility Impact (dv)	Visibility Improvement from Baseline (Δdv)	Calculated Margin of Error (dv)
Lake Catherine Unit 4			
Caney Creek Wilderness Area	1.371	0.596	1.16
Upper Buffalo Wilderness Area	0.532	0.248	0.93

[1] Data obtained from the proposed AR FIP (FR Vol. 80, No. 67) - https://federalregister.gov/a/2015-06726

[7] Montana Case, at 1147.

4.1.1. Caney Creek Measured Versus Modeled Comparisons

The following plots show comparisons of the CALPUFF predicted impacts from Lake Catherine Unit 4, Pre-BART control, to the IMPROVE measurements from 2002 at Caney Creek.

Figure 4-1. Measured vs. Modeled Total Extinction on 20% Worst Measured Days at Caney Creek Wilderness Area in 2002 – Lake Catherine Pre-BART

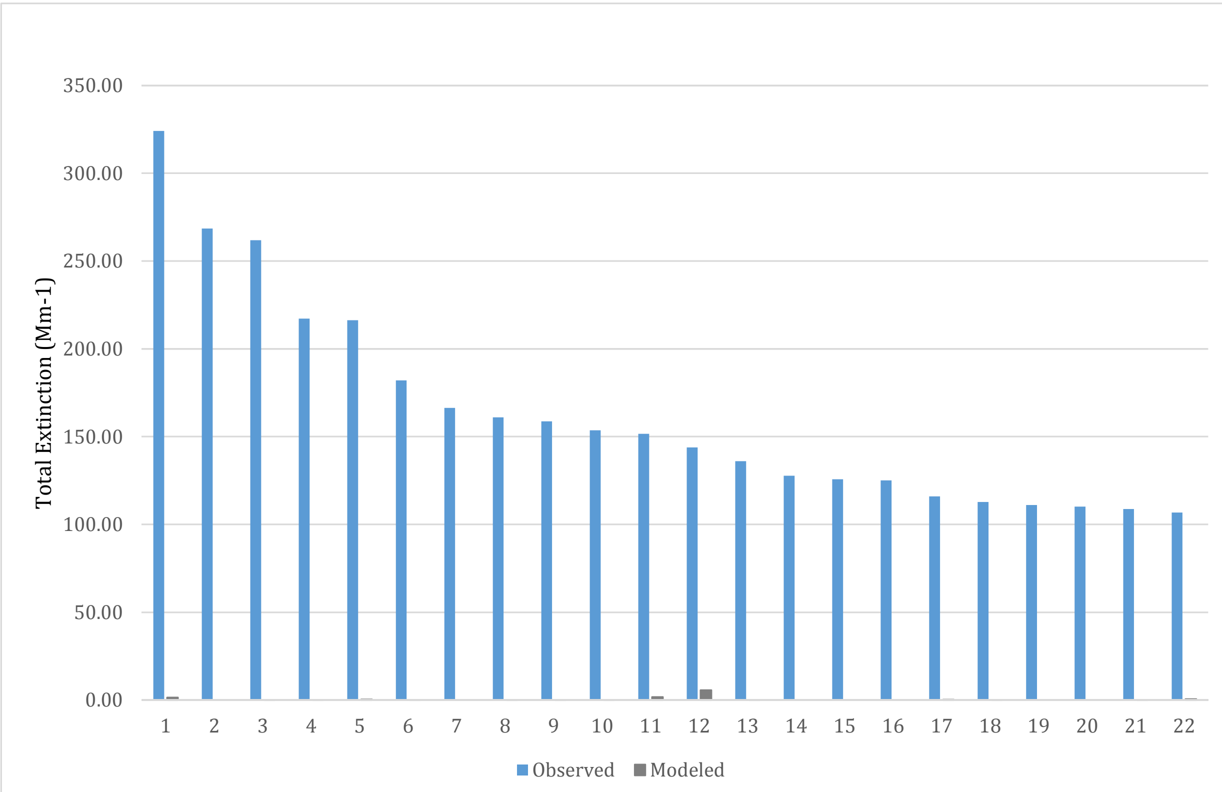


Exhibit H to EAI Comments

Figure 4-2. Measured vs. Modeled Total Extinction on 20% Worst Modeled Days at Caney Creek Wilderness Area in 2002 – Lake Catherine Pre-BART

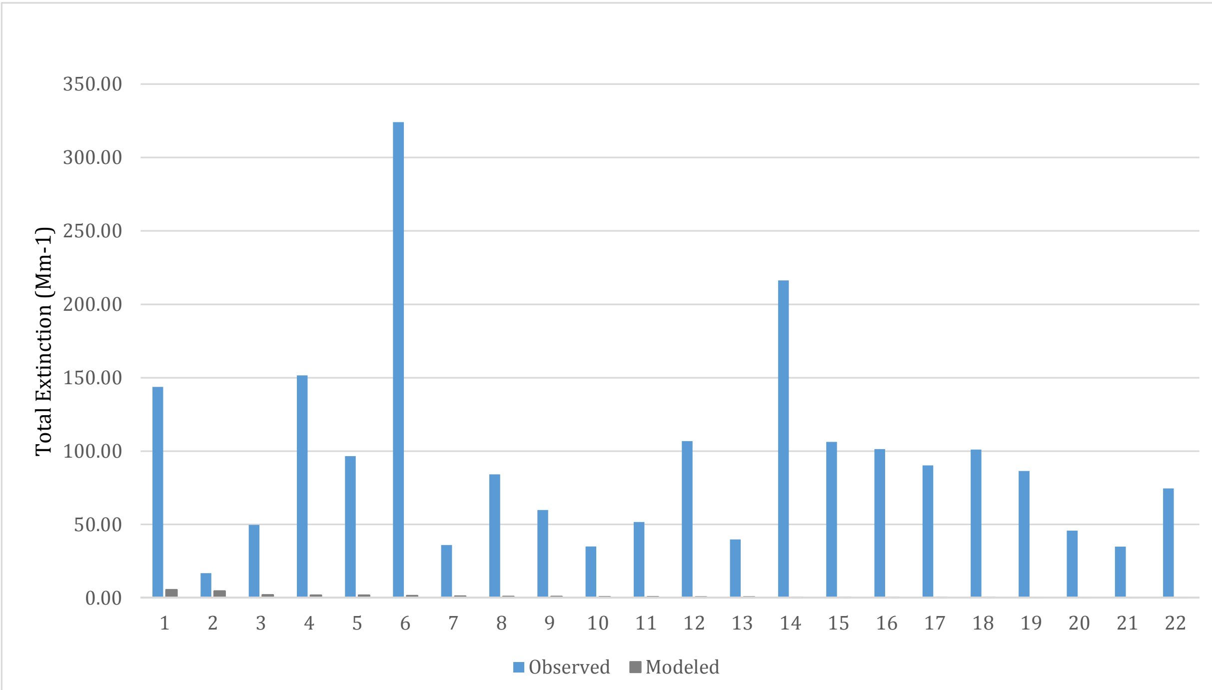
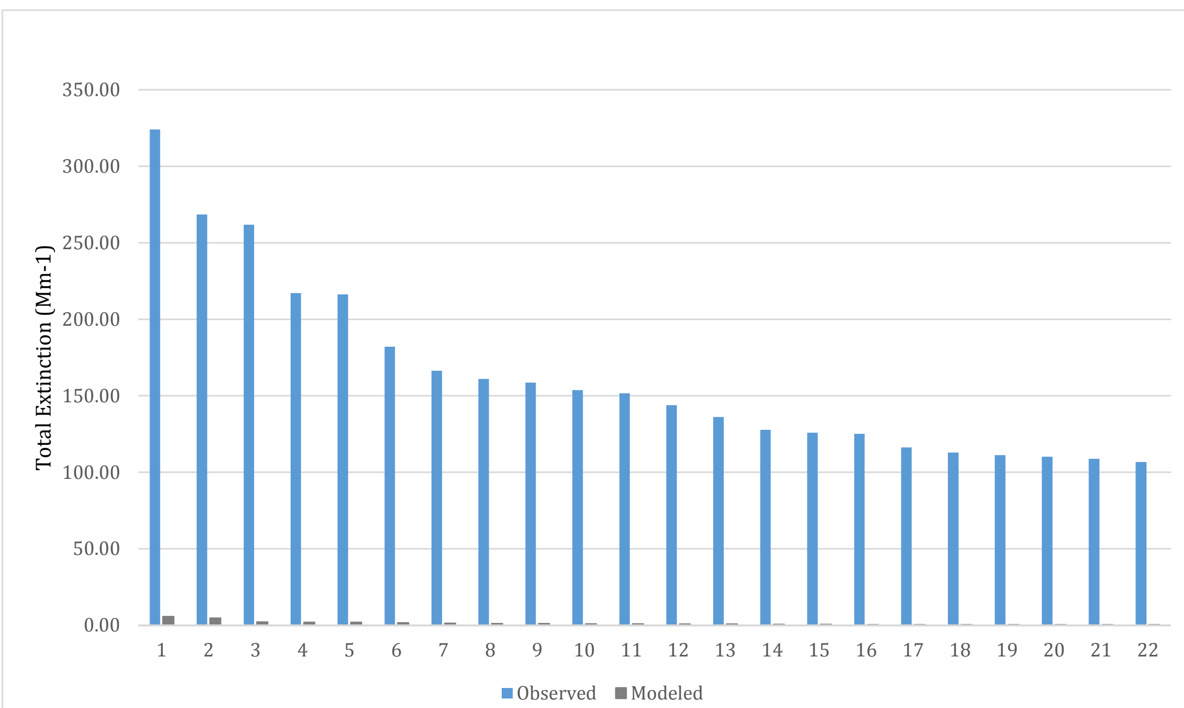


Figure 4-3. Measured and Modeled 20% Worst Days Total Extinction at Caney Creek Wilderness Area in 2002 – Lake Catherine Pre-BART



As demonstrated by the plots above, the Pre-BART impact from Lake Catherine Unit 4 is inconsequential when compared with the IMPROVE measurements, which capture the impact of all sources, including Lake Catherine, on the Class I area. This indicates that the contribution from the Lake Catherine Plant to overall visibility impairment at Caney Creek is negligible.

4.1.2. Upper Buffalo Measured Versus Modeled Comparisons

The following plots show comparisons of the CALPUFF predicted impacts from Lake Catherine Unit 4, Pre-BART control, to the IMPROVE measurements from 2002 for Upper Buffalo.

Figure 4-4. Measured vs. Modeled Total Extinction on 20% Worst Measured Days at Upper Buffalo Wilderness Area in 2002 – Lake Catherine Pre-BART

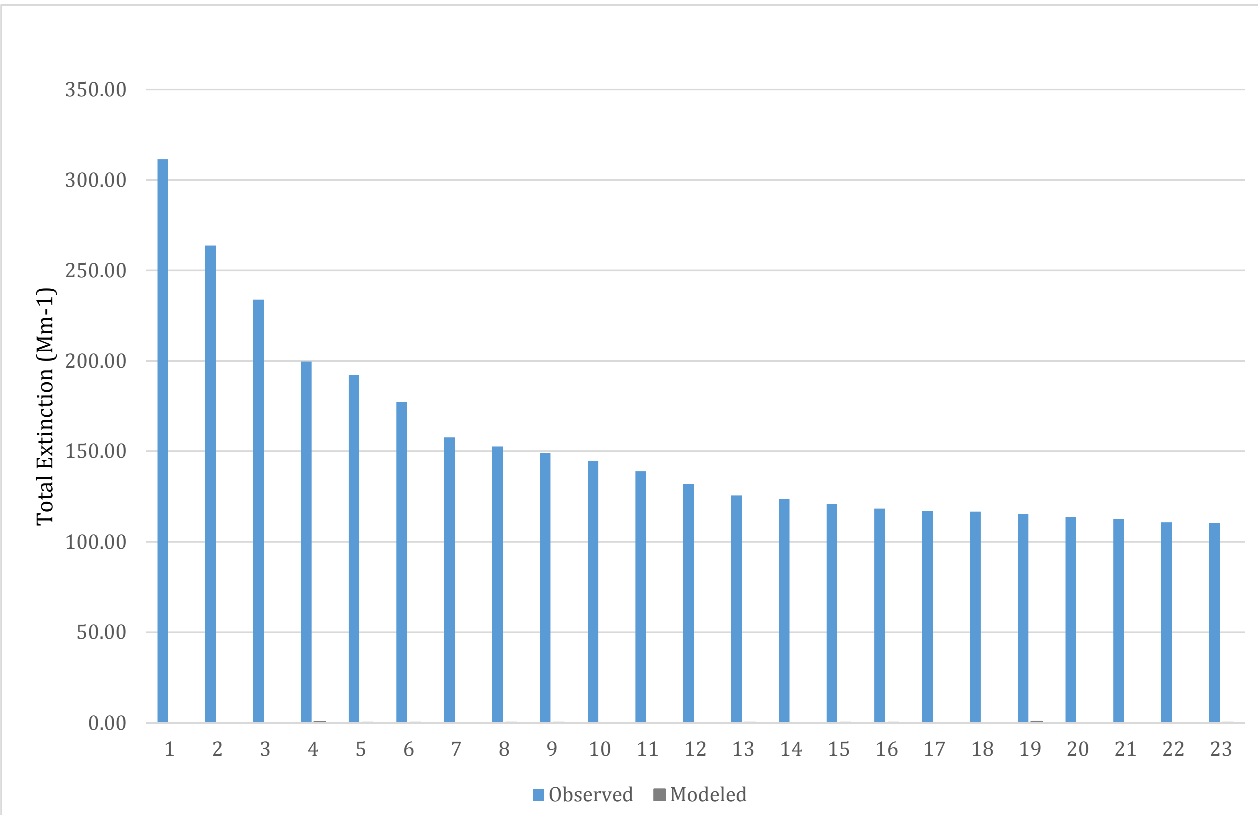


Exhibit H to EAI Comments

Figure 4-5. Measured vs. Modeled Total Extinction on 20% Worst Modeled Days at Upper Buffalo Wilderness Area in 2002 – Lake Catherine Pre-BART

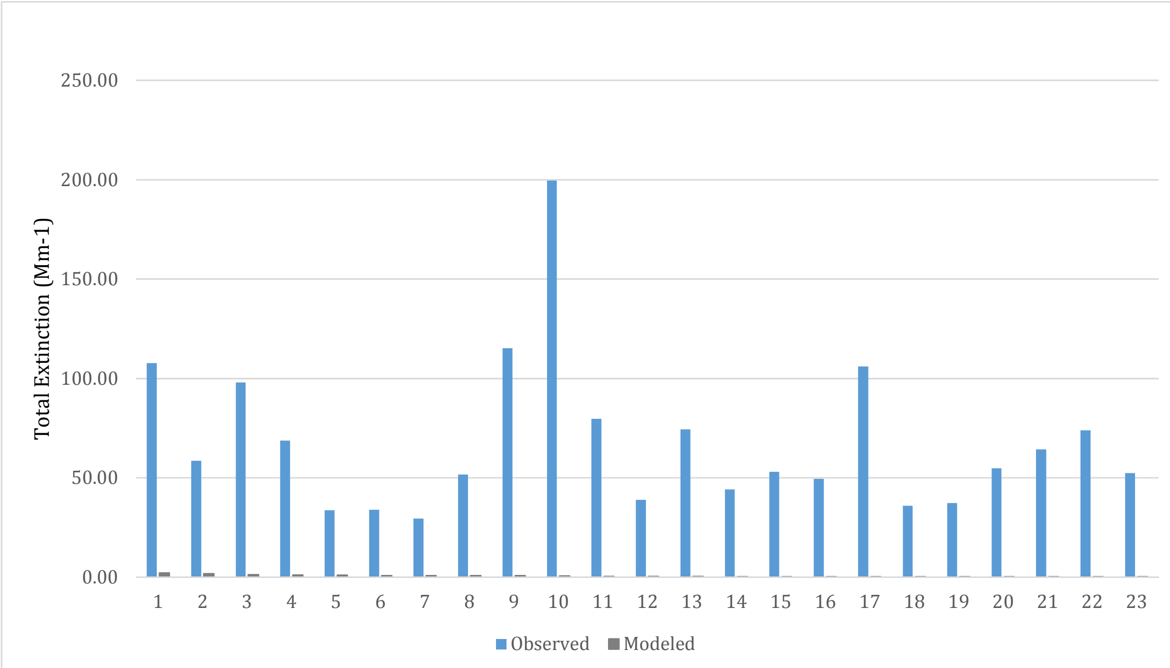
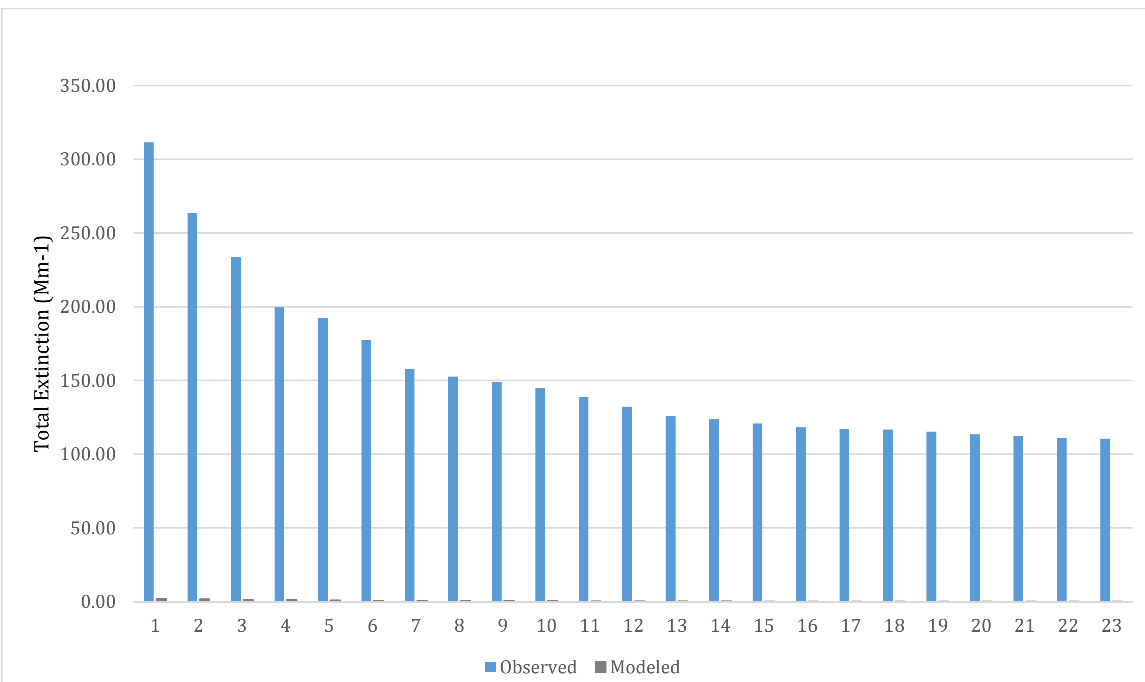


Figure 4-6. Measured and Modeled 20% Worst Days Total Extinction at Upper Buffalo Wilderness Area in 2002 – Lake Catherine Pre-BART



As was the case for Caney Creek, the Pre-BART impact from Lake Catherine Unit 4 is inconsequential when compared with the IMPROVE measurements, which capture the impact of all sources, including Lake Catherine. Thus, the contribution from the Lake Catherine Plant to visibility impairment at Upper Buffalo is negligible.

In June of 2012, TRC wrote a paper entitled *Accuracy of Visibility Protocol Modeling in BART Evaluations*.[8] This paper discussed several case studies comparing modeled values from CALPUFF to measured values from the IMPROVE monitoring network. PPL Montana relied on this study in its successful challenge to the Montana FIP, for its argument that EPA failed to explain why it could reasonably anticipate a visibility improvement when the improvement was within CALPUFF's margin of error.[9,10] An overview of several case studies comparing CALPUFF modeled to measured values, including the study relied upon in the Montana Case, are provided below for reference.

The CALPUFF version approved by EPA for use in BART analyses is Version 5.84, which was released on June 23, 2007.[11] Comparisons of modeled to monitored values demonstrate a significant improvement in model performance.

5.1. MOHAVE GENERATING STATION

CALPUFF modeling completed for the Mohave Generating Station (Mohave Station) showed that the 1,590 megawatt (Mw) coal-fired power plant was causing visibility impacts of 2.31 dv at the Grand Canyon National Park. The plant was permanently shut down in 2005. A review of monitored visibility at IMPROVE stations as close as 90 km to the plant showed no change in either nitrate concentrations or visibility impacts subsequent to the closure of the plant. The measured visibility impairment at the Grand Canyon National Park during the three years prior to (2003-2005) and subsequent to the permanent shutdown (2006-2008) of the Mohave Station were analyzed.[12] Based on a review of data from three (3) IMPROVE monitoring sites, summarized in Table 5-1 below, the changes in visibility were not statistically significant.

Table 5-1. Mohave Visibility Impairment – Before and After

IMPROVE Monitor	2003-2005 (dv)	2006-2008 (dv)	Difference (dv)
Meadview	8.24	8.23	0
Indian Gardens	8.92	8.86	0.1
Hance Camp	6.54	6.61	-0.14

While the actual change at the nearest monitor between pre- and post-shutdown of the Mohave Station, Meadview, was zero dv, the CALPUFF results indicated that visibility impairment caused by the Mohave Station

[8] Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012.

[9] Montana Case, at 1146–47.

[10] 42 U.S.C. 7491(g)(2).

[11] Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012. Although numerous updates have been released since that time, EPA still relies on an outdated version of the model despite the fact that considerable advancements have been made. Newer versions of CALPUFF include more complex chemistry which allows for more accurate representation of sulfate and nitrate formation by considering ozone chemistry, organic aerosol formation, inorganic gas particle equilibrium, and aqueous phase transformation.

[12] Jonathan Terhorst and Mark Berkman, *Effect of Coal-fired Power Generation on Visibility in a Nearby National Park*, Atmospheric Environment 44, 2010.

was twice the level detectable by the human eye.[13] The maximum CALPUFF predicted visibility impairment was 3.94 dv over 3 years, with a 98th percentile visibility impairment of 2.31 dv from the Mohave Station. Based on the IMPROVE monitoring data, CALPUFF highly overestimated the visibility impairment attributable to the Mohave Station. In reality, the Mohave Station had essentially no impact on the visibility impairment at the Grand Canyon National Park as documented by the change in monitoring values pre- and post-shutdown.

5.2. CRAIG STATION

The Craig Station is located approximately 90 km west of the Mt. Zirkel Wilderness Area (Mt. Zirkel) in northwestern Colorado. A study was completed during the development of the Colorado Regional Haze SIP to compare CALPUFF predicted impacts for the Craig Station to IMPROVE data at Mt. Zirkel.[14] Modeled impacts for the Craig Station on the highest 25 days were compared against IMPROVE data, which includes impacts from all other sources (e.g., other point sources, area sources, mobile sources, etc.). The results showed that the modeled impacts from the Craig Station exceeded the monitored values on 14 out of 19 days, and in some instances by a significant amount. Given that the IMPROVE data reflects the cumulative impact of all sources, both within Colorado and outside of the state, the magnitude of the CALPUFF model over-prediction is severe. Although there is another large power plant located between the Craig Station and Mt. Zirkel, the modeled impacts from the Craig Station alone were larger than the monitored values for all sources combined, which further highlights the degree of over prediction. The modeled values were on average ten times the IMPROVE monitored values (i.e., 9.56 Mm^{-1}).[15]

5.3. NORTH DAKOTA SIP

In the development of the North Dakota Regional Haze SIP, the North Dakota Department of Health (NDDH) relied on photochemical modeling conducted by the Western Regional Air Partnership (WRAP) to determine the impact of sources located outside of the state, as well as non-utility sources in North Dakota.[16] CALPUFF was utilized to determine the impacts of utility sources within the state; however, NDDH utilized alternate options in the CALPUFF model to address known areas of inaccuracy. The specific areas where they deviated from the EPA BART prescribed approach include:

- Consideration of boundary conditions based on CMAQ modeling, rather than ignoring the impact of sources outside of the domain as is done in the EPA approach;
- Puff splitting;
- Diffusion coefficients based on actual measurements of turbulence rather than the 1952 Pasquill-Gifford diffusion confidents required by the EPA approach;
- Meteorological data from the National Center for Environmental Predictions (NCEP) Rapid Update Cycle (RUC) forecast model; and
- Use of hourly average ammonia concentrations instead of an annual average value.

The resulting CALPUFF values were then compared to IMPROVE monitoring data from the South Unit at Theodore Roosevelt National Park, as summarized in Table 5-2 below.[17]

---

[13] Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012.

[14] Gale Hoffnagle, Evaluation of Craig BART Modeling for Regional Haze Analysis, testimony before the Colorado Air Quality Commission, November 18, 2010.

[15] Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012.

[16] North Dakota State Implementation Plan, February 24, 2010.

[17] North Dakota State Implementation Plan, Chapter 8, February 24, 2010.

A review of extinction values showed that the average difference between measured and modeled extinction was 0.37 Mm^{-1} with a standard deviation of 12.6 Mm^{-1}.[18] EPA rejected NDDH's modeling on the basis that it included impacts from other sources rather than evaluating the impairment due to BART sources against the natural background visibility impairment ("dirty" background analysis vs. "clean" background analysis). EPA did not specifically comment on the accuracy of NDDH's CALPUFF modeling. Even with the revisions to the modeling methodology applied by NDDH, the margin of error was still 0.39 dv on average.[19]

Table 5-2. NDDH Measured versus Modeled Nitrate Concentrations

Theodore Roosevelt South Unit	Observed ($\mu g/m^3$)	Predicted ($\mu g/m^3$)
98th Percentile	2.03	2.06
90th Percentile	1.21	1.21
Average of 20% Worst Days	1.42	1.41
Annual Average	0.53	0.53

5.4. COLSTRIP GENERATING STATION

As briefly described above, TRC conducted an analysis of measured versus modeled visibility impacts for the Colstrip Station located in eastern Montana, which is partially owned and operated by PPL Montana, LLC. TRC specifically completed comparisons for the worst 20% measured days and worst 20% modeled days (where a corresponding measurement was available). The study found that CALPUFF significantly over predicted impacts from the Colstrip Station, as impacts from this source alone were frequently higher than the monitored values, which include all sources (e.g., point, area, mobile) as well as the Colstrip Station. Modeled nitrate extinction from the Colstrip Station alone was higher than the monitored values on 11 out of 22 of the worst 20% modeled days at the Theodore Roosevelt IMPROVE monitoring site. At the UL Bend Wilderness Area IMPROVE monitor, modeled nitrate extinction from the Colstrip Station exceeded the monitored values on 11 out of 28 of the worst 20% modeled days. At the North Absaroka IMPROVE site, the impact from the Colstrip Station was over predicted on 9 out of 20 days of the worst 20% modeled days. At the Yellowstone IMPROVE site there are 10 days when the modeled extinction from the Colstrip Station exceeded the monitored values for the worst 20% modeled days.

Based on this analysis, PPL Montana, LLC, the operator and partial owner, challenged EPA's BART analysis for Colstrip Station arguing that EPA could not "reasonably anticipat[e] as required by the [Clean Air Act]" the maximum predicted visibility improvement for Colstrip Units 1 and 2 because the incremental visibility improvement was within the model's margin of error.[20] The U.S. Court of Appeals for the Ninth Circuit concluded that EPA's response that low levels of visibility impairment must be addressed regardless of whether the visibility improvements are perceptible to the human did not resolve how EPA can reasonably anticipate visibility improvements within a model's margin of error.[21] Given the small magnitude of the CALPUFF predicted visibility improvements for Entergy's Lake Catherine Unit 4, Entergy similarly questioned whether EPA can

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[18] These statistics are based on the exclusion of January 26, 2002 which was an outlier.

[19] [19] Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012.

[20] Montana Case, at 1146.

[21] *Id*.

reasonably anticipate visibility improvement from additional controls on the Lake Catherine Plant. As such, Trinity utilized a similar methodology to determine the CALPUFF margin of error specifically for the Lake Catherine analysis. Trinity's analysis is summarized in detail within Sections 4 *Modeling Methodology* and 5 *Results* of this report. As documented in the results section, the visibility benefits anticipated from the AR FIP proposed controls on Lake Catherine Unit 4 cannot be *reasonably anticipated* because the visibility improvements are within CALPUFF's margin of error.

6. CONCLUSIONS

Based on the analysis completed for the Entergy Lake Catherine Plant, the minimum calculated margin of error for CALPUFF for the Lake Catherine Plant is 0.93 dv. The CALPUFF predicted visibility improvements associated with EPA's proposed BART for Lake Catherine Unit 4 at Caney Creek and Upper Buffalo fall within this margin of error. As such, the visibility improvements at each of these Class I areas associated with the proposed BART cannot be *reasonably anticipated*, as is required by the Clean Air Act.[22]

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[22] 42 U.S.C. 7491(g)(2).

Entergy Arkansas Inc.

Comments on the Proposed Approval and Promulgation of Implementation Plans; Arkansas; Interstate Transport State Implementation Plan to Address Pollution Affecting Visibility

Docket No. EPA-R06-OAR-2008-0633

Submitted on:
August 5, 2015

To:
U.S. Environmental Protection Agency
1445 Ross Avenue, Suite 700
Dallas, Texas 75202-2733

Via:
http://www.regulations.gov

ENTERGY ARKANSAS INC.

COMMENTS ON THE PROPOSED APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS; ARKANSAS; INTERSTATE TRANSPORT STATE IMPLEMENTATION PLAN TO ADDRESS POLLUTION AFFECTING VISIBILITY

EPA-R06-OAR-2008-0633

I. INTRODUCTION

On July 6, 2015, the U.S. Environmental Protection Agency ("EPA" or "Agency") published in the *Federal Register*, at 80 Fed. Reg. 38419, a proposed rule that would disapprove a revision to the State Implementation Plan ("SIP") submitted by the State of Arkansas on September 16, 2009, for the purpose of addressing the requirements of the Clean Air Act ("CAA") regarding interference with other states' programs for visibility protection for the 2006 revised 24-hour fine particulate matter ("$PM_{2.5}$") National Ambient Air Quality Standard ("NAAQS") ("Proposed Rule" or "Proposal"). Section 110(a)(2)(D)(i)(II) of the CAA, which EPA identifies as "Prong 4," requires that SIPs contain provisions to prohibit emissions from within the state from interfering with measures required to be included in the implementation plan for any other state under the visibility protection provisions of Part C of the CAA. EPA has interpreted this "good neighbor" provision as requiring states to include in their SIPs measures to prohibit emissions that would interfere with the reasonable progress goals set to protect Class I areas in other states. 80 Fed. Reg. at 38420. In addition to proposing to disapprove Arkansas' Prong 4 SIP submittal, EPA is proposing that the regional haze Federal Implementation Plan ("FIP") that the Agency proposed on April 8, 2015, *see* 80 Fed. Reg. 18944, remedies the deficiency created by the proposed disapproval of Arkansas' submittal.

Entergy Arkansas Inc. ("EAI" or "Entergy") owns and operates three facilities that EPA would regulate under the regional haze FIP: White Bluff Electric Power Plant ("White Bluff"); Independence Steam Electric Station ("Independence"); and Lake Catherine Plant ("Lake Catherine"). As proposed, the regional haze FIP would impose Best Available Retrofit Technology ("BART") emission limits on White Bluff Units 1 and 2, the Auxiliary Boiler at White Bluff, and Unit 4 at Lake Catherine, as well as reasonable progress emission limits on Units 1 and 2 at Independence. As a result, EPA's proposal that the proposed regional haze FIP would satisfy Arkansas' Prong 4 obligation directly and significantly impacts Entergy.

In these comments, Entergy discusses its legal concerns with the Proposed Rule. Entergy appreciates EPA's consideration of these comments.

II. COMMENTS

A. Arkansas' SIP Satisfied Prong 4, Rendering Reliance on EPA's Proposed Regional Haze FIP Unnecessary.

EPA argues that Arkansas' SIP submittal fails to satisfy Prong 4 for two reasons. First, although Arkansas indicated in its SIP submittal that it complies with the Prong 4 requirement, it did not explain how it meets the requirement. 80 Fed. Reg. at 38421. Second, in 2012, EPA partially disapproved the SIP revision submitted by Arkansas in 2008 to address the regional haze requirements, including disapproving a large portion of Arkansas' BART determinations. *See* 77 Fed. Reg. 14604 (Mar. 12, 2012). As a result, EPA contends, the corresponding emission reductions from Arkansas sources upon which other states had relied in their regional haze SIPs would not take place. *Id.* EPA therefore proposes that its proposed regional haze FIP is necessary to address the requirement regarding interference with other states' programs for visibility protection for the 2006 $PM_{2.5}$ NAAQS. *Id.* at 38422.

Contrary to EPA's position, the Arkansas SIP submittal satisfies Prong 4, rendering the regional haze FIP unnecessary to address interference with other states' visibility SIPs. First, the SIP submittal does explain how it complies with Prong 4 by specifically identifying the state regulations that ensure emissions from Arkansas sources will not interfere with other states' regional haze SIPs. Second, while EPA has issued guidance documents stating that Prong 4 may be satisfied through the promulgation of a regional haze SIP, this is not the *only* way in which a state may meet its obligation. *See* Guidance for State Implementation Plan Submissions to Meet Current Outstanding Obligations Under Section 110(a)(2)(D)(i) for the 8-hour Ozone and $PM_{2.5}$ National Ambient Air Quality Standards, at 9-10 (Aug. 15, 2006).[1] Indeed, EPA itself has acknowledged states may satisfy Prong 4 by something other than an EPA-approved regional haze SIP. 76 Fed. Reg. 8326, 8328 (Feb. 14, 2011) (Proposed Approval and Promulgation of State Implementation Plans; State of Colorado; Interstate Transport of Pollution Revisions for the 1997 8-Hour Ozone and 1997 $PM_{2.5}$ NAAQS: "Interference With Visibility" Requirement).

In its SIP submittal, Arkansas indicated that Prong 4 was satisfied by (1) the EPA-approved Arkansas Pollution Control and Ecology Commission's Regulation 19, Regulations of the Arkansas Plan of Implementation for Air Pollution Control, Chapter 14; (2) A.C.A. § 8-4-311(a)(2), which authorizes ADEQ to advise, consult, and cooperate with other agencies of the state, political subdivisions, industries, other states, the federal government, and with affected groups to control or abate air pollution and to prevent new air pollution; and (3) A.C.A. § 8-4-311(a)(8), which authorizes ADEQ to represent the state in all matters pertaining to the plans,

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[1] Guidance issued after submittal of the Arkansas' SIP revision on September 16, 2009, similarly indicates that a regional haze SIP is not the exclusive way in which a state may demonstrate compliance with Prong 4. *See* Guidance on SIP Elements Required Under Sections 110(a)(1) and (2) for the 2006 24-Hour Fine Particle National Ambient Air Quality Standards, at 5-6 (Sep. 25, 2009); Guidance on Infrastructure State Implementation Plan Elements Under Clean Air Act Sections 110(a)(1) and 110(a)(2), at 34 (Sep. 13, 2013) ("A state air agency may elect to satisfy prong 4 by providing, as an alternative to relying on its regional haze SIP alone, a demonstration in its infrastructure SIP submission that emissions within its jurisdiction do not interfere with other air agencies' plans to protect visibility.") ("2013 Guidance").

procedures, or negotiations for interstate compacts in relation to air pollution control. Prong 4 SIP Submittal Attachment at 2.[2] This was sufficient to comply with Prong 4, because it identifies the regulatory mechanisms through which Arkansas works with other states to ensure that its emissions do not interfere with visibility efforts. Arkansas emissions cause and contribute to visibility impairment primarily in two Class I areas in Missouri, Hercules Glades Wilderness Area and Mingo National Wildlife Refuge, and potentially other Class I areas in Oklahoma, Kentucky, Illinois and Louisiana. Proposed Approval Regional Haze Interstate Transport SIP, 76 Fed. Reg. 64,186, 64,193, 64,215 (Oct. 17, 2011); Final Approval Regional Haze Interstate Transport SIP, 77 Fed. Reg. 14604, 14623 (Mar. 12, 2012). Of these states, only Missouri relied upon anticipated BART controls from sources in Arkansas when developing its regional haze SIP. *See* Missouri Regional Haze SIP, at 45 (June 25, 2009).[3] Subsequent to EPA's partial disapproval of the Arkansas BART limits, Missouri released a 5-Year Progress Report demonstrating that Mingo and Hercules Glades are on track to meet the 2018 visibility goals. Missouri Regional Haze Plan: 5-Year Progress Report, at 4, 17 (Aug. 29, 2014).[4] Missouri concluded that this progress was the result of emissions reductions at Missouri sources and that further reductions are not necessary. *Id.* at 1, 4, 17. Thus, Missouri has determined that no additional measures are needed in Arkansas to prevent Arkansas sources from interfering with Missouri's reasonable progress efforts.

B. EPA's Proposal to Rely on its Proposed FIP Is Premature and Violates the Notice and Comment Requirement.

EPA proposes to find that the requirements of Prong 4 will be satisfied by the combination of the emission control measures in the proposed regional haze FIP, and the already approved portions of the Arkansas regional haze SIP. 80 Fed. Reg. at 38422. It is inappropriate for EPA to propose such a finding when the Agency has not yet finalized its regional haze FIP. As EPA recognizes, the Agency cannot finalize this proposal unless and until it finalizes its action on the regional haze FIP. *See id*. Depending upon the comments submitted to EPA on the proposed FIP, the final regional haze FIP could be substantially different from the proposal. For example, Entergy intends to submit comments on the proposed regional haze FIP objecting to the proposed BART limits for White Bluff and the proposed reasonable progress limits for Independence. Entergy also has identified numerous legal and technical deficiencies in the proposed FIP, which will be discussed in detail in Entergy's comments on the proposed FIP.

It is impossible to know, during the comment period on this rulemaking, whether the final FIP will rectify these problems. Because significant changes could be made to the final FIP, because these changes are unforeseeable, and because Entergy has significant concerns that the final FIP may be legally and technically deficient, it is unreasonable to request public comment on a proposal that the final FIP will satisfy Prong 4. This is a clear violation of EPA's obligation under the Administrative Procedure Act to provide adequate notice and opportunity to comment on a proposed rule. 5 U.S.C. § 553. EPA should defer requesting public comment on this issue until after the Arkansas regional haze FIP has been finalized.

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[2] Docket ID EPA-R06-OAR-2008-0633-0006.
[3] http://dnr.mo.gov/env/apcp/reghaze/moreghaze-09rev.pdf.
[4] http://dnr.mo.gov/env/apcp/reghaze/complete-RegionalHaze-5-yr-Rpt-submittal.pdf.

III. CONCLUSION

Entergy appreciates the opportunity to comment on the Proposed Rule. For the reasons explained in these comments, Entergy strongly urges EPA to approve the Arkansas Prong 4 SIP submittal. In the alternative, Entergy requests that EPA defer issuing a final rule until after (1) the final regional haze FIP for Arkansas has been issued, and (2) EPA has reopened the comment period for this Proposal to allow interested parties to comment on EPA's proposal that the final Arkansas regional haze FIP satisfies Arkansas' Prong 4 requirements.

Respectfully submitted,

Kelly M. McQueen
Assistant General Counsel – Environmental (Lead)
Entergy Services, Inc.

These are late comments that were submitted to us outside of the comment period for our proposed rulemaking. These comments are not considered as part of the Administrative Record for our Arkansas Regional Haze and Interstate Visibility Transport FIP rulemaking EPA-R06-OAR-2015-0189.

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Kelly McQueen
Assistant General Counsel

August 8, 2016

Mr. Guy Donaldson
Chief, Air Planning Section (6PD-L)
U.S. Environmental Protection Agency
Region 6
1445 Ross Avenue, Suite 700
Dallas, TX 75202-2733

Re: Request for EPA to Consider and Amend Administrative Record Regarding Material New Information for the Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas, Docket No. EPA-R06-OAR-2015-0189

Dear Mr. Donaldson:

Entergy Arkansas Inc. ("EAI") respectfully requests that the U.S. Environmental Protection Agency ("EPA") incorporate into the above docket the attached Supplemental Comments and supporting information regarding EPA's analysis of the best available retrofit technology ("BART") requirements in the final Regional Haze and Interstate Visibility Transport Federal Implementation Plan ("FIP") for Arkansas ("Supplemental Comments"). Although the comment period on the proposed rule has closed, EPA has the authority and discretion to consider the attached Supplemental Comments and supporting information. The material submitted corrects one of the fundamental bases of EAI's October 2013 *Revised BART Five Factor Analysis – White Bluff Steam Electric Station* ("October 2013 Five Factor Analysis"). This information is thus crucial to ensuring that EPA has the most accurate, complete, and timely information, and EAI respectfully requests that EPA consider this information and include it as part of the record.

The Supplemental Comments provide critically important information that (1) became available after the comment period closed, and (2) goes to core issues in the rulemaking.

Specifically, the comments provide information on current operations and emissions at the White Bluff Steam Electric Station ("White Bluff"), as well as future projected operations at White Bluff, which necessitate corrections to EAI's October 2013 Five Factor Analysis. Since the date of EAI's Comments on the proposed FIP, dated August 7, 2015 ("EAI Comments"), due largely to market conditions, including lower natural gas prices and dispatch of the White Bluff units through the Midcontinent Independent System Operator ("MISO"), and EAI's ongoing long range resource planning, EAI's assumed remaining useful life ("RUL") of the two coal-fired units at White Bluff has changed.[1]

The Supplemental Comments demonstrate that, based on the adjustment to the RULs, in addition to other changes described in the Supplemental Comments and Exhibit 1 (*Update to the Revised BART Five Factor Analysis for White Bluff Steam Electric Station Units 1 and 2*), the sulfur dioxide ("SO_2") control technology proposed as BART for White Bluff is economically infeasible/unjustifiable. EAI now projects the RULs to be four and five years from the proposed date of compliance with the FIP, with one unit ceasing coal fired operation at the end of 2025 and the other unit at the end of 2026.

Additionally, Exhibit 2 of the Supplemental Comments includes an evaluation of the most recent monitoring ("IMPROVE") data for the two Arkansas Class I areas, Caney Creek Wilderness Area ("Caney Creek") and Upper Buffalo Wilderness Area ("Upper Buffalo). This evaluation shows that visibility impairment continues to decline and trend downward at a steeper slope than the uniform rate of progress ("URP") glidepaths for both Class I areas in Arkansas. Additionally, the updated IMPROVE data further confirm that both Caney Creek and Upper Buffalo already have surpassed the reasonable progress goals ("RPGs") that EPA has proposed for these Class I areas. Accordingly, reasonable progress controls during the first planning period are not necessary to achieve the proposed RPGs.

All of the information presented in EAI's Supplemental Comments is relevant and material to EPA's decision making, and must be considered by EPA and be part of the record to ensure full and reasoned decision making based on all pertinent and current facts. Thank you for considering these Supplemental Comments, and we will be happy to answer any follow up questions.

Sincerely,

Kelly M. McQueen
Assistant General Counsel – Environmental (Lead)
Entergy Services, Inc.

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[1] The RULs discussed in this letter and the Supplemental Comments are based on an assumption that the FIP will be finalized this year and require SO_2 controls to be installed within five years. *See* EAI Comments at 6.

Attachments:

Supplemental Comments of Entergy Arkansas, Inc., including:

- Exhibit 1 – *Update to the Revised BART Five Factor Analysis for White Bluff Steam Electric Station Units 1 and 2*, Trinity Consultants (Aug. 8, 2016)

- Exhibit 2 – *Assessment of Recent Class I Area IMPROVE Monitoring Data*, Trinity Consultants, (Aug. 8, 2016)

cc: Becky Keogh, Director, Arkansas Department of Environmental Quality

Entergy Arkansas Inc.

Supplemental Comments

On the Proposed Regional Haze and Interstate Visibility Transport

Federal Implementation Plan for Arkansas

Docket No. EPA-R06-OAR-2015-0189

Submitted on:
August 8, 2016

To:
U.S. Environmental Protection Agency
1445 Ross Avenue, Suite 700
Dallas, Texas 75202-2733

I. INTRODUCTION

During the comment period on the proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas ("Proposed FIP"),[2] Entergy Arkansas Inc. ("EAI") submitted comments addressing the proposed sulfur dioxide ("SO_2") and nitrogen oxide ("NOx") best available retrofit technology ("BART") requirements for the two coal-fired units at the White Bluff Steam Electric Station ("White Bluff").[3] Specifically, for SO_2 BART, EAI submitted comments proposing to end coal-fired usage at the two White Bluff units by the end of 2027 for one unit and by the end of 2028 for the other unit, which limited their remaining useful lives for the purposes of calculating the cost effectiveness of the proposed SO_2 BART control technology. For NOx BART, EAI proposed a compound pound per hour/pound per million btu limitation for the White Bluff units in the event that EPA did not finalize a determination that meeting the Cross State Air Pollution Rule ("CSAPR") in Arkansas was more effective than source-specific NOx BART. EAI proposed a pound per hour limitation due to concerns that the White Bluff units would not be able to meet EPA's proposed NOx BART limit of 0.15 lb NOx/mmBtu at loads of less than 50 percent of capacity. Finally, EAI submitted IMPROVE data demonstrating that visibility is improving at a greater rate than the glidepaths for the two Arkansas Class I areas and that, as a result, reasonable progress controls on Arkansas sources are unnecessary during the first regional haze planning period.

Since the close of the comment period, new information has become available that revises EAI's assumptions for the proposed SO_2 and NOx BART requirements for the White Bluff units. Due to recent market conditions, which EAI expects will continue for the foreseeable future, the White Bluff coal-fired units have been dispatched less and are operating at lower annual average capacity factors. As a result and consistent with EAI's long-range plans, EAI now anticipates that it will cease combusting coal at the White Bluff units by the end of 2026[4], which further limits their remaining useful lives than EAI proposed in its Comments and definitively demonstrates that the cost of SO_2 control technology at White Bluff is not cost effective. Accordingly, EAI requests EPA to determine SO_2 BART for each of the White Bluff coal-fired units to be either a 30-boiler operating day emission rate of 0.06 lb SO_2/mmBtu based on the installation of the previously proposed SO_2 controls or the cessation of operation of the coal-fired units by the end of 2026 as an alternative to the installation of the costly controls, as described more fully below. In addition, EAI has refined its proposed NOx BART emission rate limitation to ensure that the White Bluff units will be able to meet the limitations at lower capacity factors. Finally, more recent Interagency Monitoring of Protected Visual Environments ("IMPROVE") data further support EAI's Comments that reasonable progress controls are unnecessary for visibility improvement at Arkansas' two Class I areas during the first planning

[2] 80 Fed. Reg. 18,944 (Apr. 8, 2015).

[3] *See* Entergy Arkansas Inc. Comments on the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas (Aug. 7, 2015); Docket No. EPA-R06-OAR-2015-0189-0166 ("EAI Comments"). These Supplemental Comments do not waive any argument or issue raised in EAI's Comments.

[4] As outlined in EAI's recent Integrated Resource Plan and consistent with its long-term strategy to diversify its fuel portfolio, this timeline – as opposed to EPA's proposed FIP requirements - would better allow EAI time to replace the units' capacity and develop other supply options including renewables and energy efficiency while continuing to provide reliable service at the lowest cost possible.

period. The recent IMPROVE data show that visibility in both Class I areas in Arkansas, Caney Creek Wilderness Area ("Caney Creek") and Upper Buffalo Wilderness Area ("Upper Buffalo), is already better than both the uniform rate of progress ("URP") goals for the first planning period and the reasonable progress goals ("RPGs") that EPA proposed for the two Class I areas.

EAI's Supplemental Comments and recommended SO_2 and NOx BART determinations address issues on which EPA requested comment during the comment period and support the comments that EAI previously submitted to EPA.[5] Accordingly, it is appropriate that EPA consider these Supplemental Comments before finalizing the Arkansas Regional Haze FIP.

II. COMMENTS

A. Corrections to the October 2013 White Bluff Five Factor Analysis

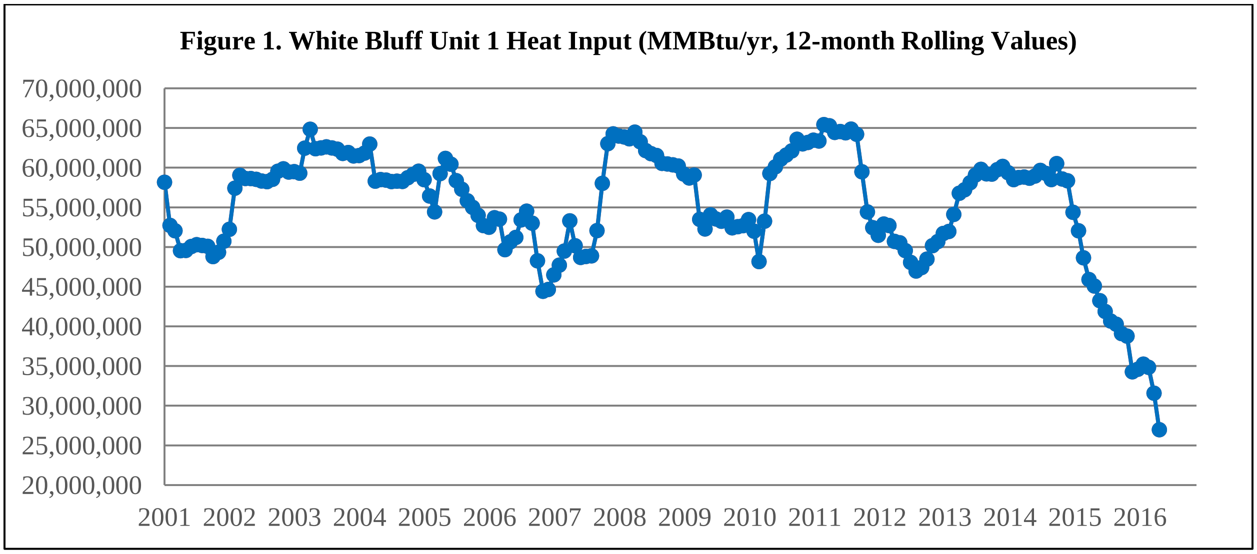
At the time EAI submitted its Comments on the Proposed FIP, EAI proposed that it would cease burning coal at the two coal-fired units at White Bluff in 2027 and 2028.[6] This changed the calculation of the costs of installing and operating SO_2 control technology on the units due to their limited remaining useful life ("RUL") of six to seven years and demonstrated that EPA's proposed SO2 BART was not feasible.[7] Since that time, there have been notable changes in the market conditions affecting dispatch of the White Bluff units. Specifically, natural gas prices have dropped sharply and are anticipated to continue to remain low.[8] The decline in natural gas prices, coupled with the White Bluff units' dispatch through the Midcontinent Independent System Operator ("MISO"), have significantly decreased the units' annual average capacity factors as compared to their prior historical annual average capacity factors. Figures 1 & 2 below illustrate this change in operation of the units.

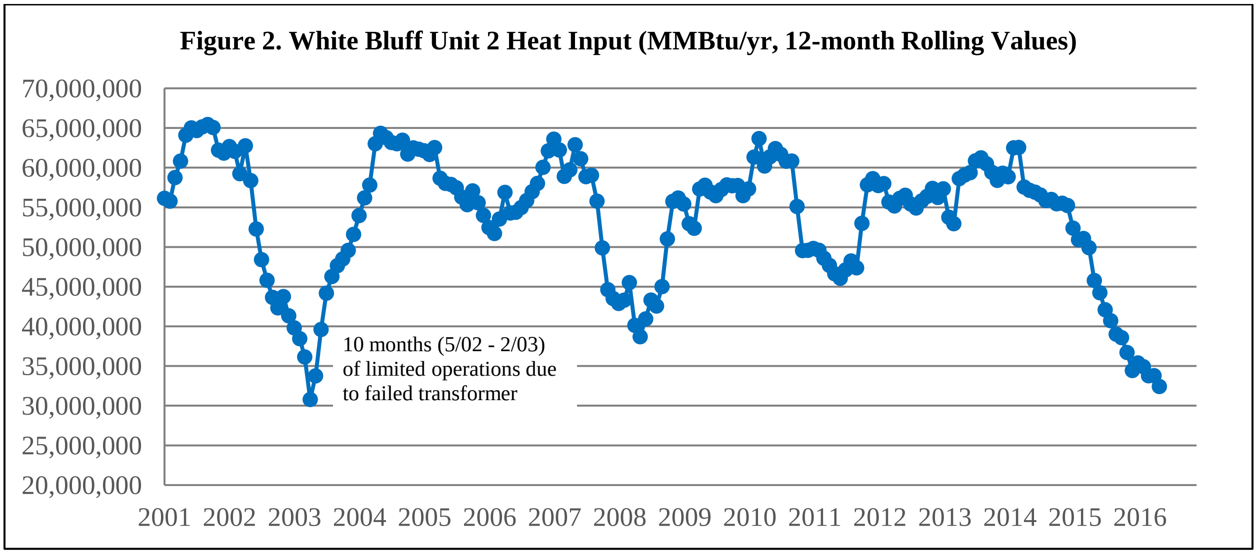
[5] *See* EAI Comments at Sections III. A, C and E.

[6] *Id*. at 5.

[7] The RULs are based on an assumption that the FIP will be finalized this year and require controls to be installed within five years. *See id*. at 6.

[8] *See Annual Energy Outlook 2016 Early Release: Annotated Summary of Two Cases*, U.S. Energy Information Administration, at 50 (May 17, 2016), available at https://www.eia.gov/forecasts/aeo/er/pdf/0383er(2016).pdf.





Due to the changes in market conditions at White Bluff resulting from the lower natural gas prices and lower dispatch of the White Bluff coal-fired units through MISO and consistent with EAI's ongoing resource planning, EAI has revised its analysis of the continued operation of the White Bluff units and projects that the units will cease combusting coal by the end of 2025 and the end of 2026.[9] This necessitates a change to the amortization period for SO_2 controls, since the units are not anticipated to continue operating beyond 2026. EAI further projects that one of the White Bluff units will operate at a capacity factor of 50 percent or less during 2025.

The limited RULs for the two White Bluff units, coupled with the 50 percent capacity factor operating constraint on one unit in 2025 (hereafter both are referred to as "operation restrictions"), necessitate corrections to EAI's October 2013 *Revised BART Five Factor Analysis – White Bluff Steam Electric Station* ("October 2013 Five Factor Analysis"). Specifically, as

[9] At this time, EAI is unable to make a final determination as to which unit will cease operation first.

discussed further in the attached report prepared by Trinity Consultants, *Update to the BART Five Factor Analysis for White Bluff Steam Electric Station Units 1 and 2* (Aug. 8, 2016) (Exhibit 1 to these Supplemental Comments), when the operation restrictions are taken into account for the two White Bluff units, the costs of installing the proposed SO_2 BART control technology, spray dryer absorber ("SDA") technology, is unjustifiable at White Bluff. Based on the detailed cost analysis prepared in 2015 by Sargent & Lundy,[10] the cost effectiveness of SDA would range from approximately $10,400 to $11,800 per ton.[11] Even using EPA's cost projections, which EAI believes ignores significant cost elements of such a project,[12] the costs are in excess of $5,000 per ton.[13] These are unacceptably high cost effectiveness values and cannot be considered BART for the White Bluff units.

Given their short RULs of four or five years, as demonstrated in Exhibit 1, the proposed SO_2 BART controls for the White Bluff units are not cost effective. As a result, SO_2 BART for the units should be *no additional controls*.[14] EAI requests that the final Arkansas regional haze FIP explicitly provide EAI with the option for SO_2 BART of either an emission limitation of 0.06 lb SO_2/mmBtu on a 30-boiler operating day average, or a binding requirement that (1) one unit will cease coal fired operation by the end of 2025 and the other unit by the end of 2026, and (2) one unit will be limited to a capacity factor of no greater than 50 percent in 2025.

B. NOx BART Limit for White Bluff

If EPA does not provide that compliance with CSAPR satisfies the NOx BART requirements for Arkansas' electric generating units,[15] EAI's Comments proposed that the White Bluff units meet a rolling 30-boiler operating day average NOx limit of 1,342.5 lb NOx/hr, based on the installation of low NOx burners and separated overfire air for all periods of operation and, additionally, a rolling 30-boiler operating day average NOx emission rate of 0.15 lb NOx/mmBtu for unit operation at 50-100 percent of capacity.[16] EAI proposed the pound per hour limit due to concerns that the vendor Entergy selected to supply the NOx control technology would only guarantee EPA's proposed NOx BART rate of 0.15 lb NOx/mmBtu for loads of 50 percent of capacity or greater.[17] Given the updated capacity factor information for the White Bluff units as discussed above in Section II.A, EAI has even greater concerns that the units will be unable to meet EPA's proposed 30-boiler operating day average NOx BART limit of 0.15 lb NOx/mmBtu for significant periods of time.

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[10] Exhibit B to EAI Comments.

[11] Exhibit 1 at 1-2.

[12] *See* EAI Comments at 8-11.

[13] Exhibit 1 at 3.

[14] EAI continues to propose that, as an interim SO_2 reduction measure, the White Bluff units would take a limit on their permitted SO_2 emission rates of 0.6 lb SO_2/mmBtu on a rolling 30-day average basis beginning three years from the effective date of the final FIP through ceasing operation. This is a 50 percent reduction from their current permitted limits. EAI Comments at 13.

[15] *Id.*

[16] *Id*. at 13-14; 51-52.

[17] *Id*. at 13, n. 16; 51.

EAI continues to request that, if EPA rejects a determination that CSAPR equals BART for Arkansas, EPA should adopt a pound per hour limitation for the White Bluff units when they are operating at a low capacity factor. EAI has refined its analysis of the proposed NOx limitation, however, and now proposes the following limits as NOx BART for each of the White Bluff units:

i. For unit operation at 0-49.9 percent of capacity, a limit of 1,305 lb NOx/hr, based on a 30-boiler operating day rolling average and

ii. For unit operation at 50-100 percent of capacity, a limit of 0.15 lb NOx/mmBtu based on a 30-boiler operating day rolling average to include only those hours for which the unit was dispatched at 50 percent or greater of maximum capacity.

EAI believes the revised rate of 1,305 lb NOx/hr is achievable and appropriate as NOx BART for the White Bluff units for periods when the White Bluff units are operating at a low capacity factor.

C. Most Recent IMPROVE Data

In the EAI Comments, EAI presented IMPROVE monitoring data showing that the haze index has been consistently below the uniform rate of progress ("URP") in both Caney Creek and Upper Buffalo.[18] As a result, reasonable progress controls for the first planning period are unnecessary.[19] This conclusion is bolstered by more recent IMPROVE monitoring data that has become available subsequent to the close of the comment period. As discussed further in Trinity's Report, *Assessment of Recent Class I Area IMPROVE Monitoring Data*, Trinity Consultants, (Aug. 8, 2016) (Exhibit 2 to these Supplemental Comments), the IMPROVE data for January 2014 through September 2015 show that visibility continues to improve by a greater amount than the URPs in Caney Creek and Upper Buffalo.[20]

In addition, the recent IMPROVE data further confirm that visibility in the two Arkansas Class I areas is already better than the RPGs that EPA proposed for the areas. EPA proposed to set the RPG for the 20 percent worst days at 22.27 deciviews ("dv") for Caney Creek and at 22.33 dv for Upper Buffalo.[21] The recent IMPROVE data for both Class I areas demonstrate that the areas already are exceeding the proposed RPGs, as well as Arkansas' RPGs and that visibility impairment is continuing to trend downward.[22]

Given that Caney Creek and Upper Buffalo already have surpassed the URP goals, Arkansas' RPGs, and EPA's proposed RPGs for the first planning period, reasonable progress

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[18] *Id*. at 20-23.

[19] *See generally*, *id*. at 17-43 (discussion of why reasonable progress controls are unnecessary at the Independence Steam Electric Station during the first planning period).

[20] Exhibit 2 at 1-3.

[21] 80 Fed. Reg. at 18,997.

[22] Exhibit 2 at 3.

controls during the first planning period are *not necessary* to ensure reasonable progress towards the natural visibility goal. *See* 42 U.S.C. § 7491(b)(2) (requiring regional haze implementation plans to contain measures "necessary to make reasonable progress toward meeting the national goal").

III. CONCLUSION

The operation restrictions for the White Bluff coal-fired units and attendant cost information provided in these Supplemental Comments and in Exhibit 1 demonstrate that the BART determination for SO_2 for the White Bluff coal-fired units should be no additional controls. For SO_2 BART, the final Arkansas regional haze FIP should provide EAI with the option for the White Bluff coal-fired units of either meeting an emission limitation of 0.06 lb SO_2/mmBtu on a 30-boiler operating day average, or a binding requirement that (1) one unit will cease operation by the end of 2025 and the other unit by the end of 2026, and (2) one unit will be limited to a capacity factor of no greater than 50 percent in 2025.

Further, the most recent IMPROVE data provided in Exhibit 2 demonstrate that visibility already is better in Arkansas' Class I areas than the URP goals, Arkansas' RPGs or EPA's proposed RPGs for the first planning period. As a result, no additional controls are necessary to make reasonable progress towards reducing visibility impairment at the two Arkansas Class I areas for the first planning period.

The information in these Supplemental Comments and attached Exhibits, which was not available during the comment period on the proposed FIP, is current and highly relevant as it goes to three of the issues at the core of the rulemaking–the SO_2 BART determination for White Bluff, the NOx BART limits for White Bluff, and the need for reasonable progress controls during the first planning period. Accordingly, EAI respectfully requests that EPA include these Supplemental Comments and attached Exhibits in the administrative record for the Proposed FIP and incorporate this information into the Agency's analysis of SO_2 and NOx BART for White Bluff and the reasonable progress requirements for the first regional haze planning period.

UPDATE TO THE BART FIVE FACTOR ANALYSIS FOR WHITE BLUFF STEAM ELECTRIC STATION UNITS 1 AND 2 REDFIELD, ARKANSAS (AFIN 35-00110)

Prepared By:

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August 8, 2016

Entergy
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Trinity Consultants

Update to the BART Five Factor Analysis for White Bluff Steam Electric Station Units 1 and 2

This report contains updated control cost calculations for the SO_2 and NO_X BART Five Factor Analyses for White Bluff Units 1 and 2 (SN-01 and SN-02). The update is necessary to consider new information regarding the remaining useful life ("RUL") of the units,[1] which affects the capital recovery period for the proposed BART controls, i.e., for SO_2 control, Spray Dryer Absorber technology ("SDA"). This new information was not available when the *Revised BART Five Factor Analysis – White Bluff Steam Electric Station* was submitted on October 15, 2013.

EAI anticipates one of the two coal-fired units will cease operating in 2025 and the other unit in 2026. Based on FIP promulgation in 2016 and a five-year compliance timeline, this means that whichever unit ceases operations in 2025 would have an RUL of four (4) years and the other unit would have an RUL of five (5) years. Additionally, one of the units will operate at a capacity factor (CF) of no greater than 50 percent in the year 2025. Together, the RULs and CF limitation are referred to herein as "the operation restrictions".

Updated SO_2 Control Costs

The update to consider the operation restrictions results in average cost effectiveness values for SDA of between approximately $10,400 and $11,800 per ton of SO_2 removed depending on which of the two units has an RUL of four years and which has an RUL of five years. This entire range of average cost effectiveness is infeasible as BART.

The updated emissions and cost effectiveness calculations for SDA based on the operation restrictions are presented in Table 1 and Table 2 for Unit 1 and Unit 2, respectively. The emissions information and capital and O&M cost estimates are based on Sargent & Lundy's 2015 report.[2] Using instead the emissions information and capital and O&M cost estimates from EPA's proposed FIP Technical Support Document, Appendix A, the average cost effectiveness estimates for SDA are between approximately $5,000 and $5,900 per ton of SO_2 removed. Summaries of these estimates are shown in Tables 3 and 4. Even these unrealistic and artificially low cost values are also economically infeasible.

[1] Remaining useful life is one of five factors to be considered in the BART impact analysis. The other four factors are cost of compliance, energy impacts, non-air quality environmental impacts, and visibility improvement.
[2] Sargent & Lundy LLC, *Entergy Arkansas, Inc. - White Bluff Dry FGD Cost Estimate and Technical Basis*, Report No. SL-012831 (July 2015)(Exhibit B to EAI's Comments on the proposed FIP).

Table 1. SDA Cost Effectiveness - White Bluff Unit 1

Baseline Emission Rate (tpy)	15,939	
Controlled Emission Level (lb/MMBtu)	0.06	
Controlled Emission Rate (tpy)	1,675	
Emissions Reduction (tpy) [1]	14,264	13,414
Total Capital Investment ($)	536,185,000	
Interest Rate (%)	7	
Capital Recovery Period = RUL (Years)	4	5
Capital Recovery Factor (CRF)	0.295	0.244
Annualized Capital Costs ($/yr)	158,296,888	130,770,532
Direct Variable and Fixed O&M Costs ($/yr) [2]	10,166,000	9,560,422
Total Annual Costs ($/yr)	168,462,888	140,330,954
Cost Effectiveness ($/ton)	11,810	10,461

[1] A 50 % capacity factor (CF) during 2025 is incorporated by subtracting from the 5-year RUL annual-average reduction value an amount equal to the annual-average reduction value scaled from the baseline CF to 50 %.

[2] Annual O&M costs are adjusted, assuming a linear relationship, to reflect the 50 % capacity factor during 2025 using the same method described above for the emissions reduction adjustment.

Table 2. SDA Cost Effectiveness - White Bluff Unit 2

Baseline Emission Rate (tpy)	16,034	
Controlled Emission Level (lb/MMBtu)	0.06	
Controlled Emission Rate (tpy)	1,681	
Emissions Reduction (tpy) [1]	14,353	13,490
Total Capital Investment ($)	536,185,000	
Interest Rate (%)	7	
Capital Recovery Period = RUL (Years)	4	5
Capital Recovery Factor (CRF)	0.295	0.244
Annualized Capital Costs ($/yr)	158,296,888	130,770,532
Direct Variable and Fixed O&M Costs ($/yr) [2]	10,166,000	9,555,003
Total Annual Costs ($/yr)	168,462,888	140,325,535
Cost Effectiveness ($/ton)	11,737	10,402

[1] A 50 % capacity factor (CF) during 2025 is incorporated by subtracting from the 5-year RUL annual-average reduction value an amount equal to the annual-average reduction value scaled from the baseline CF to 50 %.

[2] Annual O&M costs are adjusted, assuming a linear relationship, to reflect the 50 % capacity factor during 2025 using the same method described above for the emissions reduction adjustment.

Table 3. SDA Cost Effectiveness - White Bluff Unit 1 ***Using FIP Information***

Baseline Emission Rate (tpy)	15,816	
Controlled Emission Level (lb/MMBtu)	0.06	
Controlled Emission Rate (tpy)	1,453	
Emissions Reduction (tpy) [1]	14,363	13,534
Total Capital Investment ($)	247,537,295	
Interest Rate (%)	7	
Capital Recovery Period = RUL (Years)	4	5
Capital Recovery Factor (CRF)	0.295	0.244
Annualized Capital Costs ($/yr)	73,079,969	60,372,043
Direct Variable and Fixed O&M Costs ($/yr) [2]	12,029,724	11,335,696
Total Annual Costs ($/yr)	85,109,693	71,707,739
Cost Effectiveness ($/ton)	5,926	5,298

[1] A 50 % capacity factor (CF) during 2025 is incorporated by subtracting from the 5-year RUL annual-average reduction value an amount equal to the annual-average reduction value scaled from the baseline CF to 50 %.

[2] Annual O&M costs are adjusted, assuming a linear relationship, to reflect the 50 % capacity factor during 2025 using the same method described above for the emissions reduction adjustment.

Table 4. SDA Cost Effectiveness - White Bluff Unit 2 ***Using FIP Information***

Baseline Emission Rate (tpy)	16,697	
Controlled Emission Level (lb/MMBtu)	0.06	
Controlled Emission Rate (tpy)	1,476	
Emissions Reduction (tpy) [1]	15,221	14,266
Total Capital Investment ($)	247,537,295	
Interest Rate (%)	7	
Capital Recovery Period = RUL (Years)	4	5
Capital Recovery Factor (CRF)	0.295	0.244
Annualized Capital Costs ($/yr)	73,079,969	60,372,043
Direct Variable and Fixed O&M Costs ($/yr) [2]	12,029,724	11,275,230
Total Annual Costs ($/yr)	85,109,693	71,647,273
Cost Effectiveness ($/ton)	5,592	5,022

[1] A 50 % capacity factor (CF) during 2025 is incorporated by subtracting from the 5-year RUL annual-average reduction value an amount equal to the annual-average reduction value scaled from the baseline CF to 50 %.

[2] Annual O&M costs are adjusted, assuming a linear relationship, to reflect the 50 % capacity factor during 2025 using the same method described above for the emissions reduction adjustment.

Updated NO_X Control Costs

Consideration of the operation restrictions results in NO_X control cost effectiveness estimate changes as summarized in Table 5. The proposed BART control technology remains LNB+SOFA as presented in the October 15, 2013 *Revised BART Five Factor Analysis – White Bluff Steam Electric Station* at the emission rates presented in EAI's August 8, 2016, supplemental comments.

Table 5. NOx Controls Cost Effectiveness

	Baseline Emission Rate	Controlled Emission Level	Controlled Emission Rate [1]	NOx Reduced	NOx Reduced for 5-Year RUL [2]	Capital Cost	Annualized Capital Cost, 4-year RUL	Annualized Capital Cost, 5-year RUL	Annual O&M Cost, 4-year RUL	Annual O&M Cost, 5-year RUL [3]	Total Annual Cost	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(lb/MMBtu)	(tpy)	(tpy)	(tpy)	($)	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)	($/ton)	($/ton)
SN-01 LNB/SOFA	7,249	0.15	4,145	3,104	2,919	10,461,206	3,088,442	2,551,391	319,887	300,831	2,852,222 - 3,408,329	977 - 1,098	
SN-01 LNB/SOFA/SNCR	7,249	0.13	3,592	3,657	3,439	21,371,325	6,309,416	5,212,267	4,849,000	4,560,150	9,772,417 - 11,158,416	2,842 - 3,051	13,314 - 14,022
SN-01 LNB/SOFA/SCR	7,249	0.055	1,520	5,729	5,388	230,329,138	67,999,638	56,175,134	3,444,000	3,238,844	59,413,978 - 71,443,638	11,027 - 12,470	22,910 - 29,087
SN-02 LNB/SOFA	8,185	0.15	4,060	4,125	3,877	14,488,206	4,277,326	3,533,539	312,838	294,036	3,827,575 - 4,590,164	987 - 1,113	
SN-02 LNB/SOFA/SNCR	8,185	0.13	3,519	4,666	4,386	25,398,325	7,498,300	6,194,415	4,853,000	4,561,325	10,755,740 - 12,351,300	2,452 - 2,647	13,615 - 14,336
SN-02 LNB/SOFA/SCR	8,185	0.055	1,489	6,697	6,294	206,747,898	61,037,793	50,423,889	3,466,000	3,257,686	53,681,575 - 64,503,793	8,529 - 9,632	20,626 - 25,688

[1] The future annual heat input was estimated by multiplying the average hourly heat input from CAMD for 2009-2011 for each boiler by the average number of operating hours for each boiler from 2009-2011.

[2] A 50 % capacity factor (CF) during 2025 is incorporated by subtracting from the 5-year RUL annual-average reduction value an amount equal to the annual-average reduction value scaled from the baseline CF to 50 %.

[2] Annual O&M costs are adjusted, assuming a linear relationship, to reflect the 50 % capacity factor during 2025 using the same method described above for the emission emissions reduction adjustment.

ASSESSMENT OF RECENT CLASS I AREA IMPROVE MONITORING DATA

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August 8, 2016

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Assessment of Recent Class I Area IMPROVE Monitoring Data

Since the August 7, 2015 submittal of Trinity Consultant's *Regional Haze Modeling Assessment Report – Entergy Arkansas, Inc. – Independence Plant* (Trinity's report), measured concentration data for January 2014 through September 2015 from the Interagency Monitoring of Protected Visual Environments ("IMPROVE") network of Class I area monitors has become available. It is prudent to review this data for the two Arkansas Class I areas – Caney Creek ("CACR") and Upper Buffalo ("UPBU") – to determine if the trends identified in Trinity's report continue.

A summary of all available haze index values – from 2002 through 2015 (average of first nine months) – are shown in the following tables. As explained in Trinity's report, the IMPROVE equation is applied to the concentration data to calculate light extinction (Mm^{-1}), and then light extinction is converted to haze index (dv).

Table 1. Haze Indices for Caney Creek

Year	Observed 20% Worst Haze Index (dv)	Observed 20% Best Haze Index (dv)
2002	27.21	11.88
2003	26.54	10.74
2004	25.34	11.11
2005	29.21	12.93
2006	25.68	12.51
2008	23.70	9.24
2009	22.68	8.09
2010	22.94	10.76
2011	22.67	11.71
2012	21.49	9.54
2013	21.35	8.61
2014	20.72	8.52
2015	20.67	8.35

Table 2. Haze Indices for Upper Buffalo

Year	Observed 20% Worst Haze Index (dv)	Observed 20% Best Haze Index (dv)
2002	26.74	12.83
2003	27.22	10.62
2004	25.58	10.74
2005	30.47	13.34
2006	25.42	13.00
2007	26.17	12.45
2008	24.60	10.49
2009	22.62	9.40
2011	23.21	11.51
2012	21.56	10.31
2013	21.25	8.60
2014	20.49	8.13
2015	20.45	7.81

The following figures illustrate how these measured values compare to the Uniform Rate of Progress ("URP") curves for each area. The figures are updates to Figures 3-3 and 3-4 of Trinity's report, and, as such, also show the projected haze index values based on the scenario-specific modeling summarized in Trinity's report.

Figure 1. Caney Creek Observed Haze Index, Uniform Rate of Progress, and Projected Haze Index

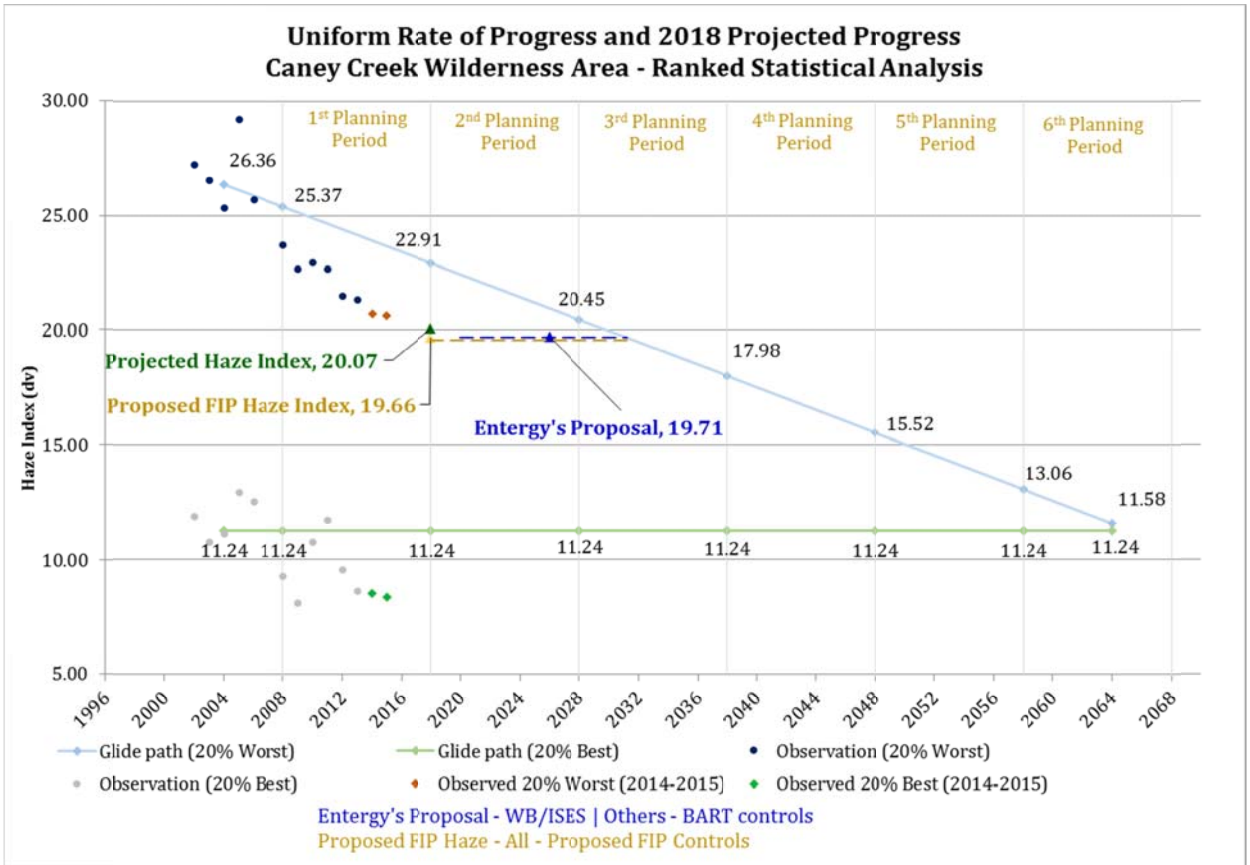
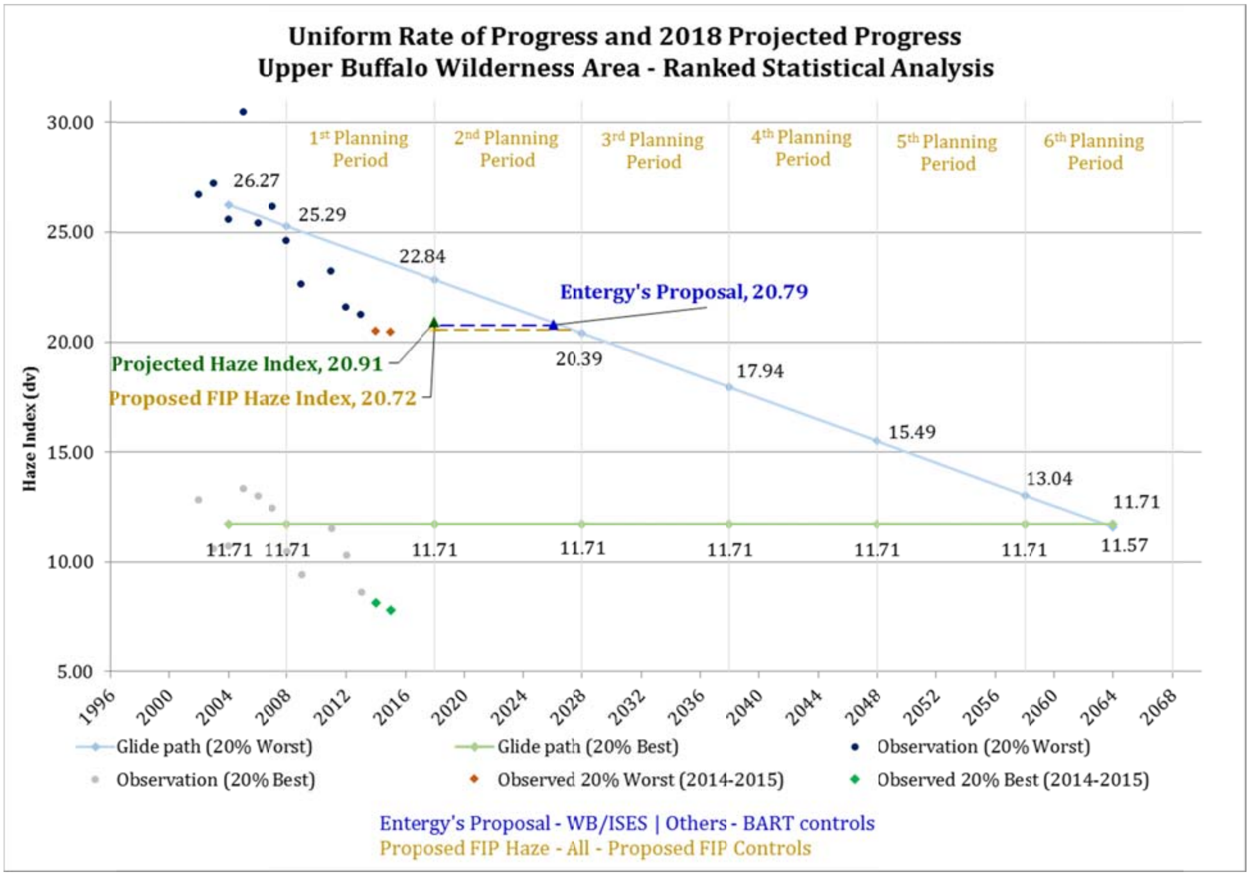


Exhibit 2 to EAI Supplemental Comments

Figure 2. Upper Buffalo Observed Haze Index, Uniform Rate of Progress, and Projected Haze Index



As shown above, the actual visibility impairment at CACR and UPBU have continued to decrease through September 2015. The average 20 percent worst haze indices for CACR decreased from 21.49 dv in 2012 to 20.67 in 2015. Similarly, visibility improved at UPBU, where the average 20 percent worst haze indices decreased from 21.56 dv in 2012 to 20.45 dv in 2015. As shown in the figures and table below, these values are significantly less than (i.e., better than), and ahead of schedule of, the Reasonable Progress Goals (RPGs) proposed by ADEQ[1] of 22.48 dv by 2018 for the 20 percent worst days at CACR and 22.52 dv by 2018 for the 20 percent worst days at UPBU, and those proposed by EPA[2] of 22.27 dv for CACR and 22.33 dv for UPBU.

Table 3. 2018 Reasonable Progress Goals Compared to 2015 Visibility for the 20 % Worst Days

Class I Area	ADEQ-Proposed RPG for 2018 (dv)	EPA-Proposed RPG for 2018 (dv)	Actual Visibility in 2015 (dv)
Caney Creek	22.48	22.27	20.67
Upper Buffalo	22.52	22.33	20.45

[1] Arkansas's 2008 Regional Haze State Implementation Plan (SIP).
[2] April 18, 2015 proposed Arkansas Regional Haze Federal Implementation Plan (FIP).

Figure 3. Caney Creek Observed Haze Index, 20% Worst Days, and Proposed Reasonable Progress Goals

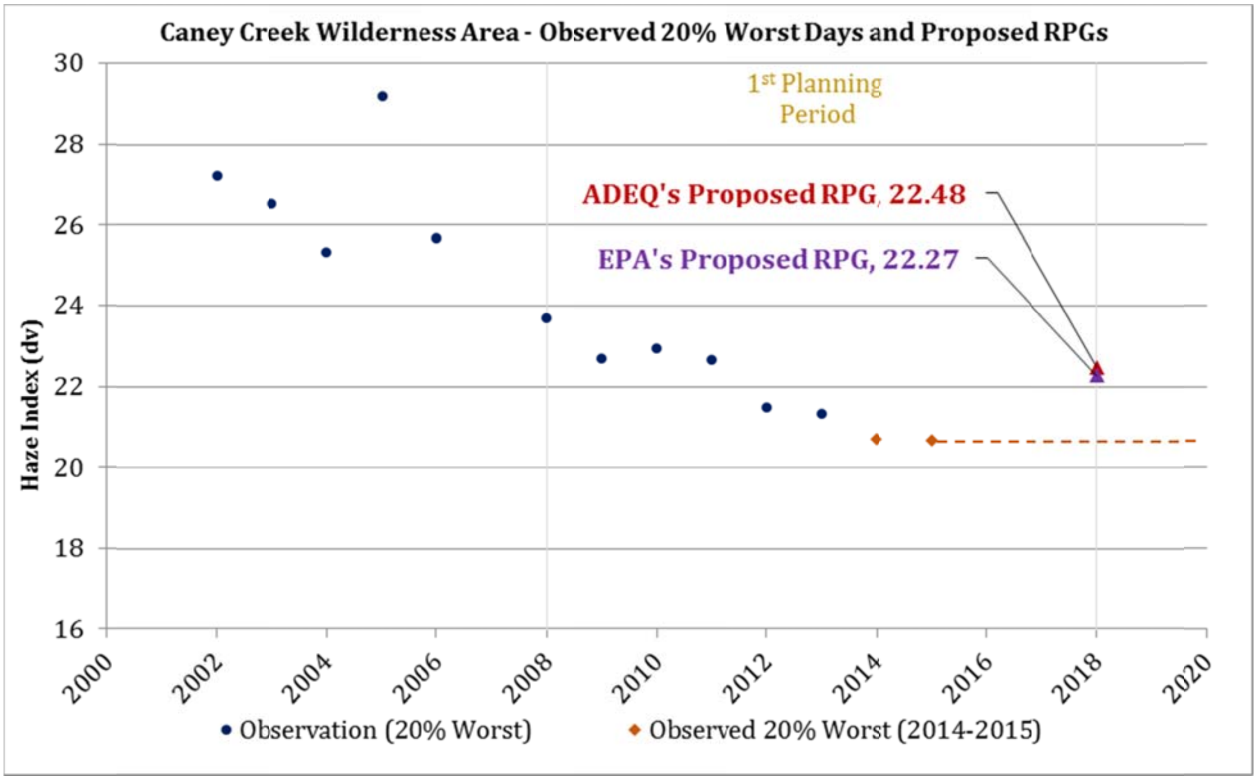
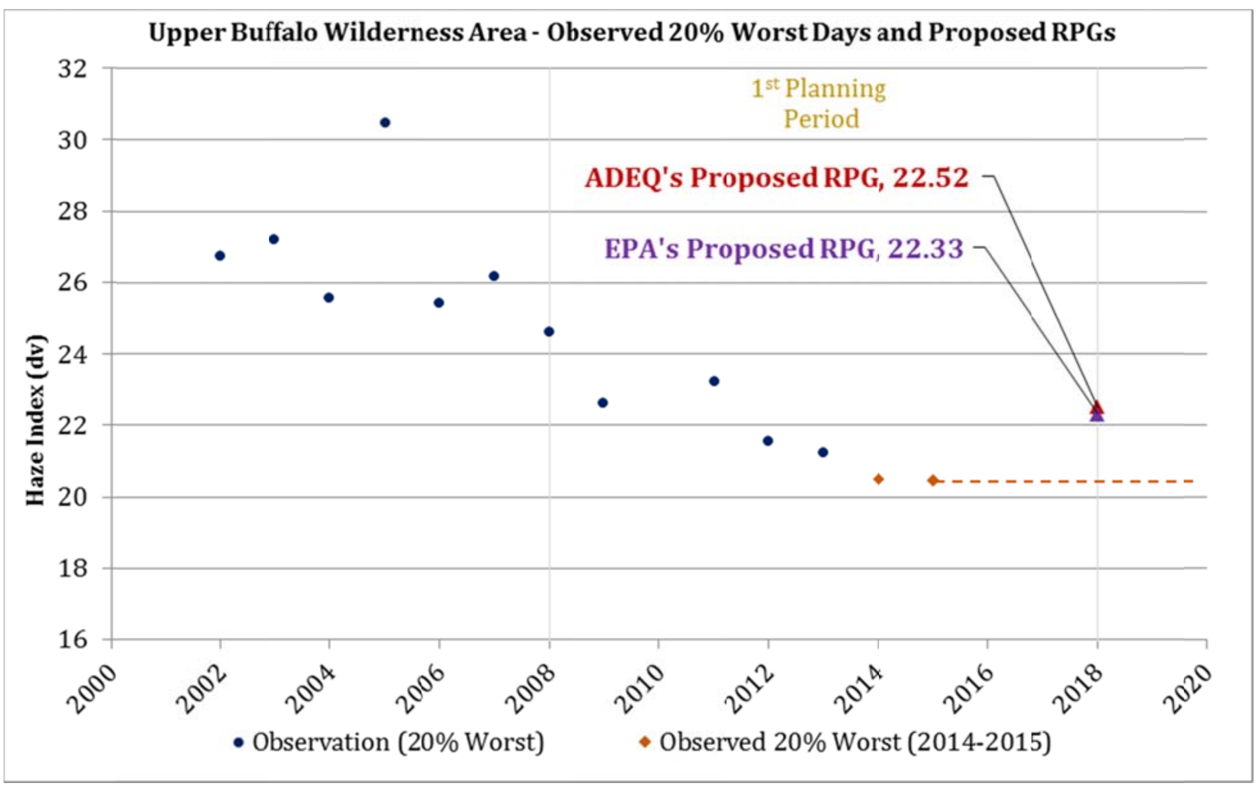


Figure 4. Upper Buffalo Observed Haze Index, 20% Worst Days, and Proposed Reasonable Progress Goals



This cell style indicates value provided by Entergy in August 18, 2017 Revised BART Analysis for White Bluff

This cell style indicates calculated value

	Baseline Emission Rate	Controlled Emission Rate	Capital Costs	Annualized Capital Costs ($MM/yr)	Annual O&M Costs $(MM/yr)	Total Annual Costs ($)	Average Cost-Effectiveness ($/ton)	Incremental Cost-Effectiveness (v. LSC
SN-01 LSC	15939	14,544	-	-	1.60	1,600,000	1,150	
SN-02 LSC	16034	14,631	-	-	1.61	1,610,000	1,148	
SN-01 DSI	15939	9,770	154.79	23.76	14.91	38,670,000	6,269	7764
SN-02 DSI	16034	9,807	154.79	23.76	14.91	38,670,000	6,211	7683
SN-01 Enhanced DSI	15939	4,187	321.42	49.34	26.19	75,530,000	6,427	7137
SN-02 Enhanced DSI	16034	4,203	321.42	49.34	26.19	75,530,000	6,384	7088
SN-01 Dry FGD	15939	1,675	364.83	67.71	9.60	77,310,000	5,420	5883
SN-02 Dry FGD	16034	1,681	364.83	67.71	9.60	77,310,000	5,387	5846

	Average Cost Effective	Average Incremental Cost-Effectiveness
LSC	1,149	
DSI	6,240	7,724
Enhanced DSI	6,406	7,113
Dry FGD	5,404	5,865

Unit 1	Improvement over Baseline (98th Percentile Impact)				$ per deciview			
Scenario	CACR	UBPU	HERC	MING	CACR	UBPU	HERC	MING
LSC	0.129	0.143	0.167	0.115	12,403,101	11,188,811	9,580,838	13,913,043
DSI	0.308	0.375	0.341	0.333	125,551,948	103,120,000	113,401,760	116,126,126
Enhanced DSI	0.492	0.555	0.467	0.436	153,516,260	136,090,090	161,734,475	173,233,945
SDA	0.603	0.642	0.525	0.504	128,208,955	120,420,561	147,257,143	153,392,857

Unit 2	Improvement over Baseline (98th Percentile Impact)				$ per deciview			
Scenario	CACR	UBPU	HERC	MING	CACR	UBPU	HERC	MING
LSC	0.097	0.127	0.137	0.122	16,597,938	12,677,165	11,751,825	13,196,721
DSI	0.274	0.359	0.303	0.333	141,131,387	107,715,877	127,623,762	116,126,126
Enhanced DSI	0.46	0.531	0.429	0.435	164,195,652	142,241,055	176,060,606	173,632,184
SDA	0.574	0.632	0.486	0.501	134,686,411	122,325,949	159,074,074	154,311,377

	Average Improvement over Baseline (98th Percentile Impact)			
	CACR	UBPU	HERC	MING
LSC	0.113	0.135	0.152	0.119
DSI	0.291	0.367	0.322	0.333
Enhanced DSI	0.476	0.543	0.448	0.436
SDA	0.589	0.637	0.506	0.503

	Average $ Per Deciview			
	CACR	UBPU	HERC	MING
LSC	14,500,519	11,932,988	10,666,332	13,554,882
DSI	133,341,667	105,417,939	120,512,761	116,126,126
Enhanced DSI	158,855,956	139,165,572	168,897,541	173,433,064
SDA	131,447,683	121,373,255	153,165,608	153,852,117

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Kelly McQueen
Assistant General Counsel

April 3, 2018

Ms. Tricia Treece
Office of Air Quality
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118

Re: Supplement to Comments Submitted by Entergy Arkansas, Inc. on ADEQ's Draft Phase II Regional Haze SIP: SO_2 Compliance Deadline for White Bluff Electric Generating Station

Dear Ms. Treece:

On February 2, 2018, Entergy Arkansas, Inc. ("EAI") submitted comments on the draft Phase II state implementation plan ("SIP") to address certain regional haze requirements, which ADEQ released for comment on October 31, 2017 ("Draft SIP"). The Draft SIP proposed rolling 30-boiler operating day sulfur dioxide ("SO_2") limits of 0.6 lb/mmBTU for each of the two coal-fired electric generating units at White Bluff. The SO_2 limits are based on ADEQ's determination that a switch to low sulfur coal constitutes best available retrofit technology ("BART") for the White Bluff units. ADEQ proposed a compliance deadline of three years from the date of the U.S. EPA's final approval of the SIP to allow EAI sufficient time to make the switch to low sulfur coal at White Bluff.

As a follow up to public comments on the Draft SIP, ADEQ has requested additional support for EAI's need for three years to meet the SO_2 BART limits. As EAI explained in its comments on the Draft SIP, the company's practice is to contract for a portion of its coal supply for up to three years in advance and the company also is required to keep a reserve supply of coal on site to ensure that the White Bluff units can continue to operate in the event of a fuel supply disruption. EAI Comments on the Draft SIP at 7-8 (Feb. 2, 2018).

The current coal contracts limit the sulfur content of delivered coal to 1.2 lb/mmBTU or less. Although the coal delivered to White Bluff has lately been of lower sulfur content, our experience is that the sulfur content can vary widely, which means that White Bluff cannot ensure that it will receive coal with a low enough sulfur content to ensure compliance with the BART SO_2 limits until the company has had sufficient time to negotiate new contracts and the existing coal pile has been depleted and replaced with lower sulfur content coal. This is because, even if EAI were to purchase lower sulfur coal for the uncontracted portion of its projected coal supply needs over the next few years, White Bluff does not have fuel blending capability on site sufficient to ensure compliance with the SO_2 BART limits. Although the plant can achieve crude fuel "blending" by simultaneously feeding coal from the stockpile and directly from a train, the plant does not track the sulfur content of coal fed onto the stockpile and thus cannot accurately calculate the expected SO_2 emissions where a portion of the total coal feed is from the stockpile and a portion is fed directly from a train. In addition, due to minimum belt speeds, this crude blending ability is limited at low-load and/or single-unit operating scenarios.

For the next three years, EAI forecasts its coal consumption to be between 11.5 and 12.4 million tons per year, approximately half of which can be attributed to White Bluff. EAI currently has contracted for 9.9 million tons of coal for 2018 under the sulfur specification of <.9 lbs/mmBtu. For 2019, the forecast is for 11.5 million tons of coal, approximately 6 million tons of which already has been contracted with a sulfur specification of <.7 lbs/mmBtu. For 2020, EAI forecasts needing 12.4 million tons, and has contacted for 3 million tons to date, also with a sulfur specification of <.7 lbs/mmBtu. If EAI were to cancel its current contracts, the company would face significant financial penalties. The contractual provisions relating to penalties for cancellation are confidential and could be subject to litigation, so EAI is unable to divulge this information to ADEQ. Before making any purchasing decisions on lower sulfur coal that has not previously been used at White Bluff, EAI will need to allow time to conduct test burns.

Given the current coal contracts and the fuel blending limitations, it would be difficult for the White Bluff units to assure compliance in less than three years with the rolling 30-boiler operating day SO_2 emission limits of 0.6 lb/mmBTU and the plant would risk exceeding the limits. Accordingly, EAI requests that ADEQ finalize a three-year compliance deadline for the White Bluff units to meet the SO_2 BART limits.

If you have any questions about this information, please contact David Triplett at (501) 377-4030.

Sincerely,

Kelly M. McQueen
Assistant General Counsel – Environmental (Lead)
Entergy Services, Inc.

ARKANSAS
DEPARTMENT OF ENVIRONMENTAL QUALITY

In the Matter of:

ENTERGY ARKANSAS, INC.

LIS No. 18-073

White Bluff
1100 White Bluff Road
Redfield, AR 72132
AFIN: 35-00110

Lake Catherine
141 West County Line Road
Jones Mill, AR 72105
AFIN: 30-00011

Independence
555 Point Ferry Rd.
Newark, AR 72203
AFIN: 32-00042

ADMINISTRATIVE ORDER

This Administrative Order (AO) is issued pursuant to the authority delegated under the federal Clean Air Act, 42 U.S.C. § 7401 *et seq*., and the federal regulations issued thereunder. In addition, this AO is issued pursuant to the authority of the Arkansas Water and Air Pollution Control Act, Act 472 of 1949, as amended, codified at Ark Code Ann. § 8-4-101 *et seq*., including Ark. Code Ann. § 8-4-311.

The issues herein having been settled by agreement between Entergy Arkansas, Inc. (ENTERGY ARKANSAS) and the Director of the Arkansas Department of Environmental Quality (ADEQ), it is hereby stipulated that the following STATEMENT OF BASIS and ORDER AND AGREEMENT be entered. ADEQ and ENTERGY ARKANSAS hereby agree to the entry of this AO in order to satisfy first planning period requirements associated with the Regional Haze Rule, 40 C.F.R. Part 51 Subpart P, and 40 C.F.R. Part 51, Appendix Y.

STATEMENT OF BASIS

1. ENTERGY ARKANSAS is an Arkansas Corporation with its principal headquarters in Little Rock, Arkansas.

2. On July 1, 1999, the United States Environmental Protection Agency (U.S. EPA) published regulations to address visibility impairment in the nation's Class I areas. 64 Fed. Reg. 35714. On July 6, 2005, the U.S. EPA published an amendment to Best Available Retrofit

Technology (BART) requirements included in the 1999 regulations. 70 Fed. Reg. 39103. Collectively, these regulations are commonly known as the "Regional Haze Rule," codified at 40 C.F.R. §§ 51.300–51.309.

3. Two Class I areas in Arkansas are covered by the Regional Haze Rule: Caney Creek Wilderness Area (Caney Creek) and the Upper Buffalo Wilderness Area (Upper Buffalo).

4. To meet the requirements of the Regional Haze Rule, states must submit state implementation plans (SIPs) implementing the requirements of the Regional Haze Rule to the U.S. EPA for approval. *Id.* Each Regional Haze SIP for the first planning period must contain "emission limitations" representing BART and schedules for compliance with BART for each BART-eligible source that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area...." 40 C.F.R. § 51.308(e).

5. BART-eligible sources include those sources that: (1) have the potential to emit 250 tons or more of a visibility-impairing air pollutant; (2) were in existence on August 7, 1977, but not in operation prior to August 7, 1962; and (3) whose operations fall within one or more of the specifically listed source categories in 40 C.F.R. § 51.301 (including fossil fuel-fired boilers of more than 250 million British thermal units per hour [MMBtu/hr] heat input). 40 C.F.R. Part 51, Appendix Y(I)(C)(1), *and* 42 U.S.C. § 7491(b)(2)(A).

6. ADEQ determined that the following four (4) units are BART-eligible sources:

   a. White Bluff Unit 1 (SN-01);

   b. White Bluff Unit 2 (SN-02);

   c. White Bluff Auxiliary Boiler (SN-05); and

   d. Lake Catherine Unit 4 (SN-03).

7. BART or an alternative to BART is required for any BART-eligible source that emits any air pollutant that may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I Area. 42 U.S.C. § 7491(b)(2)(a); 40 C.F.R. § 51.308(e). All four units (4) listed in Paragraph 6 were determined by ADEQ to be subject-to-BART in Arkansas's 2008 Regional Haze SIP. EPA approved the subject-to-BART determinations for all four units in 2012 but disapproved other elements of the SIP. 77 FR 14604 (March 1, 2012).

8. EPA issued a federal implementation plan (FIP) in 2016 to address disapproved portions of the SIP. 81 FR 66332 (September 27, 2016). The FIP imposes BART requirements on the four (4) units identified in Paragraph 6 and controls for reasonable progress on Independence Unit 1 (SN-01) and Independence Unit 2 (SN-02). For sulfur dioxide, the FIP requires White Bluff Unit 1 (SN-01) and White Bluff Unit 2 (SN-02) and Independence Unit 1 (SN-01) and Independence Unit 2 (SN-02) to install scrubbers by October 27, 2021.

9. The State of Arkansas and ENTERGY ARKANSAS petitioned the U.S. Court of Appeals for the Eighth Circuit for review of the FIP, including the sulfur dioxide requirements; which

petitions were consolidated with appeals by other parties in *State of Arkansas v. EPA*, No. 16-4270.

10. In furtherance of resolution of some or all of the issues raised in *State of Arkansas v. EPA*, ADEQ is developing SIP revisions to replace the FIP.

11. On August 18, 2017, ENTERGY ARKANSAS provided to ADEQ a revised BART analysis. Based on updated information provided by ENTERGY ARKANSAS since the August 18, 2017 submittal, which included ENTERGY ARKANSAS's anticipated plans to cease burning coal at White Bluff by December 31, 2028, ADEQ determined that low sulfur coal constitutes BART for White Bluff Unit 1 (SN-01) and White Bluff Unit 2 (SN-02).

12. In comments submitted on ADEQ's October 2017 proposed Regional Haze SIP revision, ENTERGY ARKANSAS proposed inclusion of a requirement for low sulfur coal at Independence Unit 1 (SN-01) and Unit 2 (SN-02) as part of Arkansas's long term strategy for the first planning period as a SIP-strengthening measure. Although such limits are not necessary for the purposes of ensuring reasonable progress during the first planning period, visibility benefits are anticipated during the second planning period from this voluntarily proposed SIP-strengthening measure.

13. The Regional Haze Rule requires comprehensive periodic revisions of implementation plans for regional haze at 40 C.F.R. § 51.308(f) in which each state, including Arkansas, must revise and submit its regional haze SIP revision to EPA in 2021, 2028, "and every ten years thereafter."

14. ADEQ considers the requirements set forth in the ORDER AND AGREEMENT to be "applicable requirements" within the meaning of Title V of the Clean Air Act. The addition of these applicable requirements necessitates the reopening of the respective permits for the White Bluff, Lake Catherine, and Independence facilities in order to incorporate the applicable requirements. 40 C.F.R. § 70.7(f)(1)(i).

ORDER AND AGREEMENT

WHEREFORE, without any admission by ENTERGY ARKANSAS of the factual and legal allegations contained herein, ADEQ and ENTERGY ARKANSAS do hereby stipulate and agree as follows:

1. ENTERGY ARKANSAS shall comply with all requirements set forth in this Order and Agreement.

2. To meet BART for sulfur dioxide, White Bluff Unit 1 (SN-01) and White Bluff Unit 2 (SN-02) shall each comply with an emission limit of 0.60 pounds of sulfur dioxide per million British thermal units (0.60 lb/MMBtu) on a rolling 30-boiler-operating-day averaging period within three years of the effective date of this AO.

3. Compliance with Paragraph 2 in this Order and Agreement shall be determined by using data from a continuous emission monitoring system.

4. Consistent with ENTERGY ARKANSAS's representations to ADEQ in its Updated Five Factor Analysis for White Bluff, White Bluff Unit 1 (SN-01) and White Bluff Unit 2 (SN-02) shall permanently cease coal-fired operations by no later than December 31, 2028.

5. As of the effective date of this AO, White Bluff Auxiliary Boiler (SN-05) shall comply with BART by complying with the following emission limits:

   a. 105.2 pounds of sulfur dioxide per hour (105.2 lb/hr);

   b. 32.2 pounds of nitrogen oxides per hour (32.2 lb/hr); and

   c. 4.5 pounds of particulate matter per hour (4.5 lb/hr).

6. Independence Unit 1 (SN-01) and Independence Unit 2 (SN-02) shall each comply with an emission limit of 0.60 pounds of sulfur dioxide per million British thermal units (0.60 lb/MMBtu) on a rolling 30-boiler-operating-day averaging period within three years of the effective date of this AO.

7. Compliance with Paragraph 6 in this Order and Agreement shall be determined by using data from a continuous emission monitoring system.

8. As of the effective date of this AO, Lake Catherine Unit 4 (SN-03) shall burn only pipeline quality natural gas.

9. A violation of this AO shall be considered unlawful under Ark. Code Ann § 8-4-217 and subject to the penalties set forth in Ark. Code Ann § 8-4-103 in the same manner as a violation of a permit issued by ADEQ.

10. ENTERGY ARKANSAS shall submit permit modification applications to ADEQ for the Lake Catherine, White Bluff, and Independence facilities in order to incorporate the applicable requirements of this AO no later than eighteen (18) months after the effective date of this AO.

11. Prior to the execution of any agreement for the transfer of ownership or operation of the White Bluff, Lake Catherine, or Independence facilities, ENTERGY ARKANSAS shall provide notice of and a copy of this AO to the proposed transferee. No transfer of ownership or operation of any portion of the White Bluff, Lake Catherine, or Independence facilities shall relieve ENTERGY ARKANSAS of its obligation to ensure that the terms of the AO are implemented unless, at least 30 days prior to such transfer, ENTERGY ARKANSAS provides written notice of the prospective transfer to EPA Region 6 and ADEQ, and the prospective transferee executes an AO with ADEQ prior to the effective date of the transfer providing for continued compliance with the terms set forth in the AO. The Notice of Transfer shall clearly identify the parties responsible for any existing violations of this AO. Any attempt to transfer ownership or operation of the White Bluff, Lake Catherine, or Independence facilities without complying with this Paragraph constitutes a violation of this AO.

12. Nothing contained in this AO shall relieve ENTERGY ARKANSAS of any obligations imposed by any other applicable local, state, or federal laws, nor, except as specifically provided herein, shall this AO be deemed in any way to relieve ENTERGY ARKANSAS of responsibilities contained in the permit.

13. If the U.S. Congress or a federal court takes action on the Arkansas Regional Haze SIP revision or Regional Haze Rule resulting in the alteration of compliance requirements of the AO including deadlines or other requirements, in whole or in part, then the AO shall be enforceable only to the extent it is federally enforceable.

14. If any provision or requirement of this AO pertaining to the Lake Catherine, White Bluff, or Independence facilities is disapproved by EPA, all provisions or requirements specifically pertaining to that facility shall be severed and rendered inoperative, and the remaining provisions of this AO shall continue to be binding on the parties.

15. This AO is effective upon execution by the Director of ADEQ.

16. By virtue of the signature appearing below, the individual represents that he or she is either an Officer or authorized representative of ENTERGY ARKANSAS.

SO ORDERED THIS 7th DAY OF August, 2018.

Becky W Keogh

Becky W. Keogh, Director
Arkansas Department of Environmental Quality

APPROVED AS TO FORM AND CONTENT:

Entergy Arkansas, Inc.

Laura Landreaux

By Laura Landreaux
Its President and CEO
Date 8/7/2018

Entergy

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G. Tracy Johnson, Manager
Arkansas Environmental Support

AR-13-052

June 25, 2013

Mr. Mike Bates
Chief, Air Division
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118

RE: Entergy Arkansas, Inc. – Lake Catherine Plant
Revised BART Five-Factor Analysis
Permit No. 1717-AOP-R5, AFIN 30-00011

Dear Mr. Bates:

Please find attached a revised and updated Best Available Retrofit Technology (BART) Five-Factor Analysis (FFA) for Unit 4 located at the Entergy Arkansas, Inc – Lake Catherine Plant. This updated FFA was completed in order to incorporate revisions made to the analysis in response to questions received from EPA Region 6 staff regarding the initial FFA which was submitted on March 4, 2013.

In addition to the revised FFA document, we have enclosed a question and answer document in which we directly respond to each specific issue raised in EPA's comments.

We appreciate ADEQ's consideration of this analysis and additional supporting information. Should you or your staff have any questions regarding this submittal, please contact me at (501) 377-4033 or David Triplett at (501) 377-4030.

Sincerely,

G. Tracy Johnson

G. Tracy Johnson
Manager, Arkansas Environmental Support

GTJ/dct

CC: Mary Pettyjohn, ADEQ (via email)

REVISED BART FIVE FACTOR ANALYSIS

LAKE CATHERINE STEAM ELECTRIC STATION

MALVERN, ARKANSAS (AFIN 30-00011)

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Trinity Project No. 123701.0053

June 2013

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1. EXECUTIVE SUMMARY

This report is a revision to the "BART Five Factor Analysis" submitted to ADEQ on March 4, 2013 and is being submitted to provide a comprehensive document that encompasses the determination of the Best Available Retrofit Technology (BART) for Entergy Arkansas, Inc.'s (Entergy's) BART-affected electric generating unit (EGU), Unit 4 at the Lake Catherine plant including revisions made in response to EPA's comments and suggestions on the previous submittal. The BART determination for each pollutant has not changed.

Unit 4 is a tangentially-fired boiler with a nominal net power rating of 558 MW and a nominal heat input capacity of 5,850 million British thermal units per hour (MMBtu/hr) that is permitted to burn natural gas and No. 6 fuel oil. Entergy does not project to burn fuel oil at Lake Catherine Unit 4 in the foreseeable future, so emissions from fuel oil are not considered in this analysis. If conditions change such that it becomes economic to burn fuel oil, a five factor analysis will be submitted for approval in the State Implementation Plan (SIP). The combustion of fuel oil would not occur until final SIP approval.

BART determinations for SO_2 and PM_{10} based on the use of natural gas were approved in EPA's March 12, 2012 final rule. The determinations result in no SO_2 or PM_{10} controls needed during natural gas combustion.

Based on modeling performed for this analysis, combined emissions of nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter with a mass mean diameter smaller than ten microns (PM_{10}) from Lake Catherine Unit 4 are predicted to cause or contribute greater than 0.5 delta deciviews (Δdv) to visibility impairment in four Class I Areas: Caney Creek Wilderness (CACR), Upper Buffalo Wilderness (UPBU), Hercules Glades Wilderness (HERC), and Mingo Wilderness (MING)[1]. The contributions of the SO_2 and PM_{10} emissions to the visibility impairment are negligible when compared to the contribution of NO_X.

A summary of the existing visibility impairment attributable to the boiler based on the default natural conditions is provided in Table 1-1. The visibility impairment summarized in Table 1-1 is based on recent modeling conducted by Trinity Consultants (Trinity) using emissions data based on a combination of stack testing, Continuous Emission Monitoring System (CEMS) data as reported to EPA's Clean Air Markets Database (CAMD), and AP-42 emission factors as further described in Section 4 of this report.

TABLE 1-1. EXISTING VISIBILITY IMPAIRMENT ATTRIBUTABLE TO UNIT 4

CACR		UPBU		HERC		MING	
98th % Δdv	**Days > 0.5 Δdv**	**98th % Δdv**	**Days > 0.5 Δdv**	**98th % Δdv**	**Days > 0.5 Δdv**	**98th % Δdv**	**Days > 0.5 Δdv**
1.371	80	0.532	21	0.387	8	0.429	7

[1] Sipsey Wilderness was included in the Arkansas Department of Environmental Quality's (ADEQ's) original BART analyses, but is not included in this analysis because the EPA-requested change in meteorological data (to a refined, or "NO OBS = 0", dataset; *see* Section 3 and Appendix B) excludes Sipsey from the modeling domain.

Trinity used the EPA's BART guidelines in 40 CFR Part 51[2] to determine BART for Unit 4. Specifically, Trinity conducted a five-step analysis to determine BART for NO_X that included the following:

1. Identifying all available retrofit control technologies;
2. Eliminating technically infeasible control technologies;
3. Evaluating the control effectiveness of remaining control technologies;
4. Evaluating impacts and document the results;
5. Evaluating visibility impacts.

The BART analysis concludes that for NO_X, the achievement of an emission rate of 0.24 lb/MMBtu through the installation and use of Burners Out of Service (BOOS) represents BART.[3]

[2] The BART guidelines were published as amendments to the EPA's Regional Haze Rule (RHR) in 40 CFR Part 51, Section 308 on July 6, 2005.

[3] EPA recently issued a final rule allowing states that are subject to the Cross-State Air Pollution Rule (CSAPR) trading program for seasonal NO_X to rely on the reductions achieved through that trading program to satisfy the regional haze program requirements for units subject to BART. "Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available Technology (BART) Determinations, Limited SIP Disapprovals and Federal Implementation Plans," 77 Fed. Reg. 33651 (June 7, 2012). On August 21, 2012, the D.C. Circuit in a 2-1 decision vacated CSAPR (*EME Homer City Generation v. EPA*, --F. 3d --, No. 11-1302 (D.C. Cir. 2012), and the Clean Air Interstate Rule (CAIR) remains in effect until a replacement rule, if any, is promulgated. If CSAPR ultimately is upheld and implemented in Arkansas, Entergy may rely on CSAPR to satisfy its NO_X regional haze obligations at Unit 4. Alternatively, if CSAPR is vacated and CAIR remains in place, Entergy may rely on CAIR to satisfy its NO_X obligations under BART as EPA has previously determined that the CAIR season NO_X trading program provides greater visibility improvement than BART.

2. INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to pristine conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to pristine conditions in 156 specific areas across the United States known as Class I areas. The CAA defines Class I areas as certain national parks (larger than 6,000 acres), wilderness areas (larger than 5,000 acres), national memorial parks (larger than 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the Best Available Retrofit Technology (BART) rule, which included guidance for making source-specific BART determinations.[4] The BART rule defines BART-eligible sources as sources that meet the following criteria:

(1) Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant;
(2) Began operation between August 7, 1962, and August 7, 1977; and
(3) Are included as one of the 26 listed source categories in the guidance.

A BART-eligible source is subject to BART if the source is "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." EPA has determined that a source is reasonably anticipated to cause or contribute to visibility impairment if the 98th percentile visibility impacts from the source are modeled to be greater than 0.5 delta deciviews (Δdv) when compared against a natural background.[5] Air quality modeling is the tool that is used to determine a source's visibility impacts.

Once it is determined that a source is subject to BART, a BART determination must address air pollution control measures for the source. The visibility regulations define BART as follows:

> *…an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by…[a BART-eligible source]. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the cost of compliance, the energy and non air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.*

Specifically, the BART rule states that a BART determination should address the following five statutory factors:

---

4 The BART guidelines were published as amendments to the EPA's RHR in 40 CFR Part 51, Section 308.

5 The original modeling for Arkansas sources relied on screening met data and, as such, reviewed the maximum impact rather than the 98th percentile impact. Use of the 98th percentile impact based on the use of refined met data (such as that used in the modeling conducted as part of this BART analysis) is consistent with both the EPA's 2005 BART rule and the 2005 Central Regional Air Planning Association (CENRAP) BART modeling guidelines.

1. Existing controls
2. Cost of controls
3. Energy and non-air quality environmental impacts
4. Remaining useful life of the source
5. Degree of visibility improvement as a result of controls

Further, the BART rule indicates that the five basic steps in a BART analysis can be summarized as follows:

1. Identify all available retrofit control technologies;
2. Eliminate technically infeasible control technologies;
3. Evaluate the control effectiveness of remaining control technologies;
4. Evaluate impacts and document the results;
5. Evaluate visibility impacts.

A BART determination should be made for each visibility-affecting pollutant (VAP) by following the five steps listed above for each VAP.

Unit 4 meets the three BART-eligibility criteria described above, and the existing visibility impairment attributable to the boiler is greater than 0.5 Δdv in at least one Class I area. Thus, Unit 4 is subject to BART. Details of the existing/baseline emissions and the contribution of the emissions to visibility impairment can be found in Section 4. The VAPs emitted by the boiler include NO_X, SO_2, and PM_{10} of various forms (filterable coarse particulate matter [PM_c], filterable fine particulate matter [PM_f], elemental carbon [EC], inorganic condensable particulate matter [IOR CPM] as sulfates [SO_4], and organic condensable particulate matter [OR CPM] also referred to as secondary organic aerosols [SOA]).

3. MODELING METHODOLOGIES AND PROCEDURES

This section summarizes the dispersion modeling methodologies and procedures applied in this BART analysis. All dispersion modeling has been conducted using the CALPUFF modeling system, consisting of the CALPUFF dispersion model, the CALMET meteorological data processor, and the CALPOST post-processing program. These methodologies and procedures are consistent with the ADEQ modeling protocol submitted to EPA in June 2012.

CALPUFF is a multi-layer, multi-species, non-steady-state puff dispersion model, which can simulate the effects of time and space varying meteorological conditions on pollutant transport, transformation, and removal. CALPUFF uses three-dimensional meteorological fields developed by the CALMET model. In addition to meteorological data, several other input files are used by the CALPUFF model to specify source and receptor parameters. The selection and control of CALPUFF options are determined by user-specific inputs contained in the control file. This file contains all of the necessary information to define a model run (e.g., starting date, run length, grid specifications, technical options, output options). CALPOST processes concentration, deposition, and visibility impacts based on pollutant specific concentrations predicted by CALPUFF.

3.1 CALMET AND CALPUFF

The CALPUFF data and parameters are based on the 2005 BART modeling guidelines prepared for CENRAP. The CALMET data and parameters are based on the modeling protocol included in Appendix B. Note that the protocol included in Appendix B summarizes modeling methods and procedures that were followed to predict visibility impairment as part of the BART analyses for several BART-eligible sources located in Oklahoma, the first of which was Oklahoma Gas & Electric in 2007. The CALMET dataset developed per this protocol has been used – and approved by EPA – numerous times since its development.

3.2 CALPOST

The CALPOST visibility processing completed for this BART analysis is based on the October 2010 guidance from the Federal Land Managers Air Quality Related Values Workgroup (FLAG)[6].

Visibility impairment is quantified using the light extinction coefficient (b_{ext}), which is expressed in terms of the haze index expressed in deciviews (dv). The haze index (*HI*) is calculated as follows:

$$HI\,(\mathrm{dv}) = 10\ln\left(\frac{b_{ext}}{10}\right)$$

The impact of a source is determined by comparing the *HI* attributable to a source relative to estimated natural background conditions. The change in the haze index, in deciviews, also referred to

[6] The 2010 FLAG guidance, which was issued in draft form on July 8, 2008, and published as final guidance in December 2010, makes technical revisions to the previous guidance issued in December 2000.

as “delta dv,” or Δdv, based on the source and background light extinction is based on the following equation:

$$\Delta \mathrm{dv} = 10 * \ln\left[\frac{\mathrm{b_{ext,\ background}} + \mathrm{b_{ext,\ source}}}{\mathrm{b_{ext,\ background}}}\right]$$

The Interagency Monitoring of Protected Visual Environments (IMPROVE) workgroup adopted an equation for predicting light extinction as part of the 2010 FLAG guidance (often referred to as the new IMPROVE equation). The new IMPROVE equation is as follows:

$$b_{ext} = \begin{array}{l} 2.2 f_S(RH)[\mathrm{NH_4(SO_4)_2}]_{\mathrm{Small}} + 4.8 f_L(RH)[\mathrm{NH_4(SO_4)_2}]_{\mathrm{Large}} + \\ 2.4 f_S(RH)[\mathrm{NH_4NO_3}]_{\mathrm{Small}} + 5.1 f_L(RH)[\mathrm{NH_4NO_3}]_{\mathrm{Large}} + \\ 2.8[\mathrm{OC}]_{\mathrm{Small}} + 6.1[\mathrm{OC}]_{\mathrm{Large}} + 10[\mathrm{EC}] + 1[\mathrm{PMF}] + 0.6[\mathrm{PMC}] + \\ 1.4 f_{SS}(RH)[\mathrm{Sea\ Salt}] + b_{\mathrm{Site-specific\ Rayleigh Scattering}} + 0.33[\mathrm{NO_2}] \end{array}$$

Visibility impairment predictions relied upon in this BART analysis used the equation shown above. The use of this equation is referred to as “Method 8” in the CALPOST control file. The use of Method 8 requires that one of five different “modes” be selected. The modes specify the approach for addressing the growth of hygroscopic particles due to moisture in the atmosphere. “Mode 5” has been used in this BART analysis. Mode 5 addresses moisture in the atmosphere in a similar way as to “Method 6”, where “Method 6” is specified as the preferred approach for use with the old IMPROVE equation in the CENRAP BART modeling protocol.

CALPOST Method 8, Mode 5 requires the following:

- Annual average concentrations reflecting natural background for various particles and for sea salt
- Monthly Relative Humidity (RH) adjustment factors for large and small ammonium sulfates and nitrates and for sea salts
- Rayleigh scattering parameter corrected for site-specific elevation

Tables 3-1 to Table 3-4 below show the values for the data described above that were input to CALPOST for use with Method 8, Mode 5. The values were obtained from the 2010 FLAG guidance.

TABLE 3-1. ANNUAL AVERAGE BACKGROUND CONCENTRATION

Class I Area	$(NH_4)_2SO_4$ (µg/m^3)	NH_4NO_3 (µg/m^3)	OM (µg/m^3)	EC (µg/m^3)	Soil (µg/m^3)	CM (µg/m^3)	Sea Salt (µg/m^3)	Rayleigh (Mm^{-1})
CACR	0.23	0.1	1.8	0.02	0.5	3	0.03	11
UPBU	0.23	0.1	1.8	0.02	0.5	3	0.03	11
HERC	0.23	0.1	1.8	0.02	0.5	3	0.02	11
MING	0.23	0.1	1.83	0.02	0.51	3.05	0.04	12

TABLE 3-2. F_L(RH) LARGE RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CACR	2.77	2.53	2.37	2.43	2.68	2.71	2.59	2.6	2.71	2.69	2.67	2.79
UPBU	2.71	2.48	2.31	2.33	2.61	2.64	2.57	2.59	2.71	2.58	2.59	2.72
HERC	2.7	2.48	2.3	2.3	2.57	2.59	2.56	2.6	2.69	2.54	2.57	2.72
MING	2.73	2.52	2.34	2.28	2.53	2.6	2.64	2.67	2.71	2.56	2.56	2.73

TABLE 3-3. F_S(RH) SMALL RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CACR	3.85	3.44	3.14	3.24	3.66	3.71	3.49	3.51	3.73	3.72	3.68	3.88
UPBU	3.73	3.33	3.03	3.07	3.54	3.57	3.43	3.5	3.71	3.51	3.52	3.74
HERC	3.7	3.33	3.01	3.01	3.47	3.48	3.41	3.51	3.67	3.43	3.46	3.73
MING	3.74	3.38	3.07	2.97	3.39	3.52	3.57	3.64	3.72	3.47	3.43	3.74

TABLE 3-4. F_{SS}(RH) SEA SALT RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CACR	3.9	3.52	3.31	3.41	3.83	3.88	3.69	3.68	3.82	3.76	3.77	3.93
UPBU	3.85	3.47	3.23	3.27	3.72	3.78	3.69	3.7	3.84	3.64	3.67	3.86
HERC	3.86	3.51	3.23	3.22	3.66	3.72	3.69	3.73	3.81	3.57	3.65	3.88
MING	3.92	3.58	3.3	3.19	3.58	3.72	3.8	3.82	3.85	3.61	3.66	3.9

4. EXISTING EMISSIONS AND VISIBILITY IMPAIRMENT

This section summarizes the existing (i.e., baseline) visibility impairment attributable to Unit 4 based on air quality modeling conducted by Trinity.

4.1 NO_X, SO_2, AND PM_{10} BASELINE EMISSION RATES

Table 4-1 summarizes the emission rates that were modeled for SO_2, NO_X, and PM_{10}, including the speciated PM_{10} emissions. The SO_2 and NO_X emission rates are the highest actual 24-hour emission rates based on 2001-2003 continuous emissions monitoring system (CEMS).[7] Please note that CEMS data from these years is representative of burning only natural gas.

The emission rates for the PM_{10} species reflect the breakdown of the filterable and condensable PM_{10} determined from AP-42 Table 1.4-2 *Combustion of Natural Gas*. All filterable PM was assumed to be elemental carbon, as this is the assumption that the National Park Service (NPS) uses for filterable PM_{10} from natural gas fired combustion turbines, and the NPS does not have a speciation analysis specific to gas fired boilers. All of the condensable PM was assumed to be SOA, except for a small fraction of the condensable PM that was estimated to be SO_4. One-third of the estimated SO_2 emissions were separated and adjusted for differences in molecular weight to represent SO_4 emissions. This essentially double counts some of the fuel sulfur based emissions as SO_2 but also as SO_4. Since pipeline natural gas contains very little sulfur, both the SO_2 and SO_4 emission rates are very low.

TABLE 4-1. BASELINE MAXIMUM 24-HOUR SO_2, NO_X, AND PM_{10} EMISSION RATES (AS HOURLY EQUIVALENTS)

Unit	SO_2[8] (lb/hr)	NO_X[9] (lb/hr)	Total PM_{10} (lb/hr)	SO_4 (lb/hr)	PM_c (lb/hr)	PM_f (lb/hr)	SOA (lb/hr)	EC (lb/hr)
Unit 4	3.1	2,456.4	44.3	1.5	0.0	0.0	31.8	11.0

4.2 BASELINE VISIBILITY IMPAIRMENT

Trinity conducted modeling to determine the visibility impairment attributable to Unit 4 in four Class I Areas: Caney Creek Wilderness (CACR), Upper Buffalo Wilderness (UPBU), Hercules Glades Wilderness (HERC), and Mingo Wilderness (MING) using the CALPUFF dispersion model. Table 4-2 provides a summary of the modeled visibility impairment attributable to Unit 4 at CACR, UPBU, HERC, and MING based on the emission rates shown in Table 4-1. Table 4-2 the maximum

7 *See* Appendix C

8 The SO_2 hourly rate was derived from EPA's CAMD. The 2001-2003 max daily rate was 74 lb/day. *See* Appendix C.

9 The NO_x hourly rate was derived from EPA's CAMD. The 2001-2003 max daily rate was 58,954 lb/day. *See* Appendix C.

impairment in Δdv, the 98th percentile impacts in Δdv, and the number of days with impacts greater than 0.5 Δdv as well as the breakdown by pollutant species for the 98th percentile impact.

As BART is determined on a unit-by-unit basis, this baseline modeling is presented to show how the BART proposed controls will cause improvement, at least on a relative basis.

All of the CALMET, CALPUFF, and CALPOST modeling files used to generate these results are included as part of the electronic files submitted with this document.

TABLE 4-2. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO LAKE CATHERINE, UNIT 4 BY POLLUTANT

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Day with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek Wilderness							
2001	3.480	1.371	31	0.49	85.13	0.00	8.55
2002	3.318	0.909	21	0.31	92.53	0.00	4.18
2003	3.276	1.233	28	0.43	85.66	0.00	7.76
Upper Buffalo Wilderness							
2001	1.478	0.489	7	0.33	89.54	0.00	5.99
2002	0.916	0.532	9	0.22	96.29	0.00	1.26
2003	2.044	0.412	5	0.21	97.36	0.00	0.30
Hercules Glades Wilderness							
2001	0.760	0.387	4	0.30	91.12	0.00	4.92
2002	1.016	0.313	2	0.39	88.73	0.00	6.08
2003	0.881	0.311	2	0.38	93.27	0.00	2.57
Mingo Wilderness							
2001	0.511	0.237	1	0.30	92.55	0.00	3.17
2002	0.763	0.429	5	0.32	96.25	0.00	0.44
2003	0.516	0.214	1	0.18	98.08	0.00	0.10

5. SO_2 BART EVALUATION

A BART determination for SO_2 based on the use of natural gas was approved in EPA's March 12, 2012, final rule. The determination results in no SO_2 controls needed during natural gas combustion.[10]

[10] "Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze. Final Rule," 77 Fed. Reg. 14604 (March 12, 2012).

6.1 IDENTIFICATION OF AVAILABLE RETROFIT NO_X CONTROL TECHNOLOGIES

Nitrogen oxides, NO_X, are produced during fuel combustion when nitrogen contained in both the fuel and the combustion air is exposed to high temperatures. The origin of the nitrogen (i.e. fuel vs. combustion air) has lead to the use of the terms "thermal" NO_X and "fuel" NO_X when describing NO_X emissions. Thermal NO_X emissions are produced when elemental nitrogen in the combustion air is exposed to a high temperature zone and oxidized. Fuel NO_X emissions are created during the rapid oxidation of nitrogen compounds contained in the fuel.

Nitrogen oxide (NO) is typically the predominant form of NO_X from fossil fuel combustion. Nitrogen dioxide (NO_2) makes up the remainder of the NO_X. The formation of NO_X compounds in utility boilers is sensitive to the method of firing. In tangentially-fired boilers, such as Unit 4, a single rotating flame is created in the center of the furnace, rather than the discrete flames produced by burners in the wall-fired boilers. Tangentially fired boilers typically have lower uncontrolled NO_X emissions than wall-fired boilers. Therefore baseline NO_X emission rates can vary significantly from plant to plant due to method of firing as well as several other factors.

Step 1 of the BART determination is the identification of all available retrofit NO_X control technologies. The available retrofit NO_X control technologies are summarized in Table 6-1.

NO_X emissions controls, as listed in Table 6-1, can be categorized as combustion or post-combustion controls. Combustion controls, including Burners Out of Service (BOOS), flue gas recirculation (FGR), overfire air / separated overfire air (SOFA), and Low NO_x Burners (LNB), reduce the peak flame temperature and excess air in the furnace which minimizes NO_X formation. Post-combustion controls, such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR), convert NO_X in the flue gas to molecular nitrogen and water.

TABLE 6-1. AVAILABLE NO_X CONTROL TECHNOLOGIES FOR UNIT 4

NO_X Control Technologies	
Combustion Controls	Burners Out of Service (BOOS) Flue Gas Recirculation (FGR) Separated Overfire Air (SOFA) Low NO_x Burners (LNB)
Post-Combustion Controls	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR)

6.2 ELIMINATE TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES

Step 2 of the BART determination is to eliminate technically infeasible NO_X control technologies that were identified in Step 1.

6.2.1 COMBUSTION CONTROLS

6.2.1.1 BURNERS OUT OF SERVICE (BOOS)

BOOS is a staged combustion technique whereby fuel is introduced though operational burners in the lower furnace zone to create fuel-rich conditions, while not introducing fuel to other burners. Additional air is then supplied to the non-operational burners to complete combustion. By removing fuel from certain zones, the temperature is reduced, and the production of thermal NO_X is also reduced. When operated without additional controls, the estimated controlled NO_X level for Unit 4 operating with BOOS is 0.24 lb/MMBtu.[11] This control is a technically feasible option for the control of NO_X from Unit 4.

6.2.1.2 FLUE GAS RECIRCULATION (FGR)

FGR uses flue gas as an inert material to reduce flame temperatures. In a typical flue gas recirculation system, flue gas is collected from the combustion chamber or stack and returned to the burner via a duct and blower. The addition of flue gas reduces the oxygen content of the "combustion air" (air + flue gas) in the burner. The lower oxygen level in the combustion zone reduces flame temperatures; which in turn reduces thermal NO_X formation. When operated without additional controls, the estimated controlled NO_X level for Unit 4 operating with FGR is 0.19 lb/MMBtu.[12] This control is a technically feasible option for the control of NO_X from Unit 4.

6.2.1.3 SEPARATED OVERFIRE AIR (SOFA)

SOFA diverts a portion of the total combustion air from the burners and injects it through separate air ports above the top level of burners. Staging of the combustion air creates an initial fuel-rich combustion zone with a lower peak flame temperature. This reduces the formation of thermal NO_X by lowering combustion temperature and limiting the availability of oxygen in the combustion zone where NO_X is most likely to be formed. When operated without additional controls, SOFA results in estimated NO_X emissions for gas fired boilers of 0.2-0.4 lb/MMBtu.[13] This control is a technically feasible option for the control of NO_X from Unit 4.

6.2.1.4 LOW NO_X BURNERS

LNB technology utilizes advanced burner design to reduce NO_X formation through the restriction of oxygen, lowering of flame temperature, and/or reduced residence time. NO_X creation rates typically peak at oxygen levels of five to seven percent.[14] LNB is a staged combustion process that is designed to split fuel combustion into two zones. In the primary zone, NO_X formation is

[11] Sargent & Lundy May 16, 2013 NOx Control Technology Cost and Performance Study (S&L 2013 Study).

[12] *Id.*

[13] "Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options." Utility Boiler section. July 1994.

[14] http://www.energysolutionscenter.org/boilerburner/Workshop/RCTCombustion.htm.

limited by one of two methods. Under staged fuel-rich conditions, low oxygen levels limit flame temperatures resulting in less NO_X formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel-lean conditions, excess air will reduce flame temperature to reduce NO_X formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NO_X formation.

When operated without additional controls, LNB results in estimated NO_X emissions for gas fired boilers of approximately 0.25 lb/MMBtu.[15] When combined with SOFA, the estimated NO_X control level is 0.19 lb/MMBtu.[16] LNB systems are technically feasible for the control of NO_X from Unit 4.

6.2.2 POST COMBUSTION CONTROLS

6.2.2.1 SELECTIVE CATALYTIC REDUCTION (SCR)

SCR refers to the process in which NO_X is reduced by ammonia over a heterogeneous catalyst in the presence of oxygen. The process is termed selective because the ammonia preferentially reacts with NO_X rather than oxygen, although the oxygen enhances the reaction and is a necessary component of the process. The overall reactions are:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

The SCR process requires a reactor, a catalyst, and an ammonia storage and injection system. The effectiveness of an SCR system is dependent on a variety of factors, including the inlet NO_X concentration, the exhaust temperature, the ammonia injection rate, and the type of catalyst. When combined with SOFA and LNB, the estimated NO_X control level is 0.03 lb/MMBtu.[17] This control is a technically feasible option for the control of NO_X from Unit 4.

6.2.2.2 SELECTIVE NON-CATALYTIC REDUCTION (SNCR)

In SNCR systems, a reagent is injected into the flue gas in the furnace within an appropriate temperature window. The NO_X and reagent (ammonia or urea) react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. The SNCR reagent storage and handling systems are similar to those for SCR systems. However, both ammonia and urea SNCR processes require three or four times as much reagent as SCR systems to achieve similar NO_X reductions. When combined with SOFA and LNB, the estimated NO_X

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[15] "Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options." Utility Boiler section. July 1994.
[16] S&L 2013 Study.
[17] *Id.*

control level is 0.14 lb/MMBtu.[18] This control is being evaluated as a technically feasible option for the control of NO_X from Unit 4; however this technology is not adaptable to all gas-fired boilers.

6.3 Rank of Technically feasible NO_X Control Options by Effectiveness

The third step in the BART analysis is to rank the technically feasible options according to effectiveness. Table 6-2 provides a ranking of the control levels for the controls listed in the previous section for Unit 4.

Table 6-2. Control Effectiveness of Technically Feasible NO_X Control Technologies

Control Technology	Estimated Controlled Level for Unit 4 (lb/MMBtu)
SOFA	0.30
LNB	0.25
BOOS	0.24
LNB/SOFA OR FGR	0.19
LNB/SOFA + SNCR	0.14
LNB/SOFA + SCR	0.03

6.4 Evaluation of Impacts for Feasible NO_X Controls

Step four for the BART analysis is the impact analysis. The BART determination guidelines list four factors to be considered in the impact analysis:

- ▲ Cost of compliance
- ▲ Energy impacts
- ▲ Non-air quality impacts; and
- ▲ The remaining useful life of the source

6.4.1 Cost of Compliance

The capital costs, operating costs, and cost effectiveness of BOOS, LNB/SOFA, LNB/SOFA/SNCR and LNB/SOFA/SCR were estimated for the cost analysis. Since FGR results in the same controlled emission level as LNB/SOFA but at a higher cost[19], FGR is not considered further in the analysis.

[18] S&L 2013 Study.
[19] *Id.*

Control Costs

Control costs were calculated using cost estimates developed by Sargent and Lundy. The capital costs were annualized over a 15-year period and then added to the annual operating costs to obtain the total annualized costs.

The capital and operating cost estimates are provided in Appendix A of this report.

Annual Tons Reduced

The annual tons reduced that were used in the cost effectiveness calculations were determined by subtracting the estimated controlled annual emission rate from the baseline annual emission rate.

The baseline annual emission rate was calculated using the baseline emission level of 0.48 lb/MMBtu and an annual heat input reflecting a ten percent capacity factor.[20]

EPA states in the BART guidelines that *"The baseline emission rate should represent a realistic depiction of anticipated annual emissions for the source."* While the average annual capacity factor for Unit 4 from 2001-2003, which are the baseline years from which the peak daily NO_X emission rate was determined as described in Section 4 of this report, was approximately 20 percent, Entergy anticipates that future utilization of Unit 4 will remain in the range of 10 percent, which is consistent with the recent operating history of the unit.

Table 6-3 below illustrates the annual capacity factor values for Unit 4 over the past ten years (2003-2012). Typical utilization of this unit has been less than 5 percent on an annual basis. Utilization in 2012 was slightly higher than 10 percent due to anomalous grid reliability issues which resulted in a need for greater utilization. These issues are not expected to arise in future years and future annual capacity factors are expected to be comparable to those experienced by the unit in 2003-2011. EPA has stated that they agree that the unit has historically operated at less than a 10 percent capacity factor and that a source may calculate baseline emissions based on a continuation of past practice.[21] A 10 percent capacity factor has been used for this analysis as a conservative estimate.

TABLE 6-3. LAKE CATHERINE UNIT 4 CAPACITY FACTORS

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
10.4	3.2	4.2	0.5	0.7	2.7	3.0	3.1	2.3	12.8

The controlled annual emission rates were based on lb/MMBtu levels believed to be achievable from the control technologies multiplied by the annual heat input. The annual heat input used to calculate the annual controlled emission rates was the same heat input that was used to calculate baseline annual emissions.

[20] The annual heat input reflecting a 10% annual capacity factor is 5,124,600 MMBtu/yr (5,850 MMBtu/hr * 8760 hrs/yr * 10% = 5,124,600 MMBtu/yr).

[21] 77 Fed. Reg. 14641.

Cost Effectiveness

The cost effectiveness in dollars per ton of NO_X reduced was determined by dividing the annualized cost of control by the annual tons reduced. An incremental cost analyses was also performed to show the incremental increase in the cost of controls when compared to BOOS. The costs effectiveness analysis is summarized in Table 6-4.

In the BART guidelines, EPA calculated that for all types of boilers other than cyclone boilers, combustion control technology is generally more cost-effective than post-combustion controls. EPA estimates that approximately 75 percent of the BART units (non-cyclone) could meet the presumptive NO_X limits at a cost of $100 to $1,000 per ton of NO_X removed based on the use of combustion control technology.[22] For the units that could not meet the presumptive limits using combustion control technology, EPA estimates that almost all of these sources could meet the presumptive limits using advanced combustion controls. The EPA estimates that the costs of such controls are usually less than $1,500 per ton of NO_X removed.[23]

Table 6-4 indicates that the cost effectiveness of BOOS is approximately $150 per ton of NO_X removed. Further, the incremental cost effectiveness of LNB/SOFA over BOOS is approximately $9,000/ton, while the incremental cost of LNB/SOFA/SNCR over LNB/SOFA is approximately $17,000/ton and the incremental cost LNB/SOFA/SCR over LNB/SOFA is approximately $14,000/ton.

Table 6-4 also summarizes the improvement in the maximum of the 98th percentile visibility impairment results due to each control technology. Details of the post-control modeling results are provided later in Section 6.5, but this summary is presented here for convenience. As Table 6-4 clearly shows, BOOS results in over 0.5 Δdv of visibility improvement when compared the baseline visibility impairment. While LNB/SOFA, LNB/SOFA/SNCR, and LNB/SOFA/SCR offer some additional visibility improvement over BOOS, up to a maximum of 0.672 Δdv of additional improvement for LNB/SOFA/SCR, the very high incremental costs when compared to BOOS cannot be justified.

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22 "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART Determinations; Final Rule.) 77 Fed. Reg. 39134-39135 (July 6, 2005).

23 *Id.*

TABLE 6-4. SUMMARY OF COST EFFECTIVENESS FOR UNIT 4 NO_X CONTROLS

	Baseline Emission Rate	Controlled Emission Level	Annual Heat Input[1]	Controlled Emission Rate	NOx Reduced	Capital Cost	Annual Capital Cost	Annual Fixed O&M	Annualized Variable O&M	Total Annual Cost	Cost Effectiveness	Incremental Cost[3]	Incremental Visbility Improvement [2]
	(tpy)	(lb/MMBtu)	(MMBtu/yr)	(tpy)	(ton/yr)	($)	($/yr)	($/yr)	($/yr)	($/yr)	($/ton)	($/ton)	(dv)
BOOS	1,236	0.24	5,124,600	618	618	893,000	71,964	21,000	0	92,964	150	-	0.536
LNB/SOFA	1,236	0.19	5,124,600	495	742	11,845,025	954,548	210,000	19,034	1,183,582	1,596	8,822	0.152
LNB/OFA/SNCR	1,236	0.14	5,124,600	371	865	29,295,494	2,360,819	489,000	462,000	3,311,819	3,827	17,214	0.306
LNB/OFA/SCR	1,236	0.03	5,124,600	77	1159	79,152,952	6,378,652	568,000	268,000	7,214,652	6,223	14,440	0.672

1. The annual heat input reflects a 10% annual capacity factor (5,850 MMBtu/hr * 8760 hrs/yr * 10% = 5,124,600 MMBtu/yr)

2. The incremental visibility improvement for BOOS is the maximum visibility improvement in the 98th percentile impact compared to baseline (See Table 6-9). The incremental visibility improvement for LNB/OFA, LNB/OFA/SNCR, and LNB/SOFA/SCR is the difference between the maximum improvement due to LNB/OFA, LNB/SOFA/SNCR or LNB/SOFA/SCR in the four Class I areas considered in the analysis less the maximum visibility improvement in the four Class I areas from BOOS (See Table 6-9).

3. The incremental cost for LNB/SOFA is calculated in comparison to BOOS while the incremental costs for LNB/SOFA + SNCR and LNB/SOFA + SCR are calculated in comparison to LNB/SOFA alone.

6.4.2 ENERGY IMPACTS & NON-AIR IMPACTS

As noted in Table 6-4, SCR and SNCR systems are capable of achieving additional NO_X reductions when compared to combustion controls such as BOOS, LNB, or SOFA. However, both SCR and SNCR systems create additional energy and/or non-air environmental impacts. SCR and SNCR systems require electricity to operate the ancillary equipment. The need for electricity to help power some of the ancillary equipment creates a demand for energy that currently does not exist.

SCR and SNCR can potentially cause significant environmental impacts. The primary avenue is related to the storage of ammonia. The storage of aqueous ammonia above 10,000 lbs is regulated by a risk management program (RMP), since the accidental release of ammonia has the potential to cause serious injury and death to persons in the vicinity of the release. Additionally, SCR and SNCR will likely also cause the release of unreacted ammonia to the atmosphere. This is referred to as ammonia slip. Ammonia slip from SCR and SNCR systems occurs either from ammonia injection at temperatures too low for effective reaction with NO_X, leading to an excess of unreacted ammonia, or from over-injection of reagent leading to uneven distribution; which also leads to an excess of unreacted ammonia. Ammonia released from SCR and SNCR systems will react with sulfates and nitrates in the atmosphere to form ammonium sulfate and ammonium nitrate. Together, ammonium sulfate and ammonium nitrate are the predominant sources of regional haze.

Another environmental impact associated with SCR is the disposal of catalyst waste. To maintain NO_X-removal effectiveness, the catalyst in an SCR system must periodically be cleaned, regenerated, or replaced. Cleaning and regeneration are preferred, but eventually the catalyst reaches the end of its useful life and must be replaced. Ideally the exhausted catalyst can be recycled for reuse, however, if the condition of the spent catalyst does not warrant recycling or a market is unavailable, the old catalyst must be disposed of. Current regulatory interpretations indicate spent SCR catalysts are exempted from hazardous waste regulation via 40 CFR § 261.4(b)(4) (Bevill Exemption) as flue gas emission control wastes. However, ongoing efforts by EPA to increase regulatory oversight of coal combustion residuals could alter that exemption, and create the potential that spent SCR catalysts would be characterized as hazardous wastes, hence increasing the cost of disposal. Regardless of the regulatory treatment of the waste, the disposal creates additional potential financial and environmental impacts associated with an SCR system.

6.4.3 REMAINING USEFUL LIFE

The remaining useful life of Unit 4 is sufficiently long such that it does not affect the BART analysis.

6.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE NO_X CONTROLS

A final impact analysis was conducted to assess the visibility improvement for existing emission rates when compared to the emission rates associated with BOOS, LNB/SOFA, LNB/SOFA/SNCR, and

LNB/SOFA/SCR. Section 4 of this report documented the existing visibility impairment attributable to Unit 4. In order to assess the visibility improvement associated with BOOS, LNB/SOFA, SCR and SNCR systems, the NO_X emission rates associated with the control systems were modeled using CALPUFF. The controlled emission level associated with BOOS is 0.24 lb/MMBtu; the controlled emission level associated with an LNB/SOFA system is 0.19 lb/MMBtu; the controlled emission level associated with an LNB/SOFA/SNCR system is 0.14 lb/MMBtu, and the controlled emission level associated with an LNB/SOFA/SCR system is 0.03 lb/MMBtu. These levels were multiplied by the maximum heat input (5,850 MMBtu/hr) to derive hourly the hourly emission rates used in the modeling.

Tables 6-5 through 6-8 summarize the NO_X emission rates that were modeled to reflect the BOOS, LNB/SOFA, LNB/SOFA/SNCR and LNB/SOFA/SCR control options. The emission rates for the other pollutants shown in Tables 6-5 through 6-8 are the same as in the baseline modeling.

TABLE 6-5. SUMMARY OF EMISSION RATES MODELED TO REFLECT BOOS FOR NO_X CONTROL

	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
Unit 4	3.1	1.5	1,404.0	0.0	0.0	31.8	11.0	44.3

TABLE 6-6. SUMMARY OF EMISSION RATES MODELED TO REFLECT LNB/SOFA FOR NO_X CONTROL

	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
Unit 4	3.1	1.5	1,111.5	0.0	0.0	31.8	11.0	44.3

TABLE 6-7. SUMMARY OF EMISSION RATES MODELED TO REFLECT LNB/SOFA + SNCR FOR NO_X CONTROL

	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
Unit 4	3.1	1.5	819.0	0.0	0.0	31.8	11.0	44.3

TABLE 6-8. SUMMARY OF EMISSION RATES MODELED TO REFLECT LNB/SOFA + SCR FOR NO_X CONTROL

	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
Unit 4	3.1	1.5	175.5	0.0	0.0	31.8	11.0	44.3

Table 6-9 provides a comparison of the existing visibility impairment and the visibility impairment associated with the addition of NO_X controls on Unit 4 in all affected Class I areas, including the maximum modeled visibility impact, 98th percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv.

TABLE 6-9. SUMMARY OF VISIBILITY IMPROVEMENT ASSOCIATED WITH NO_X CONTROL SYSTEM ON UNIT 4 (2001-2003)

	Caney Creek Wilderness			**Upper Buffalo Wilderness**			**Hercules Glades Wilderness**			**Mingo NWR**		
	Maximum Impact (Δdv)	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**
Existing Emission Rate	3.480	1.371	80	2.044	0.532	21	1.016	0.387	8	0.763	0.429	7
BOOS	2.154	0.835	37	1.232	0.307	11	0.6	0.229	2	0.447	0.253	0
Post Control Improvement	*1.326*	*0.536*	*43*	*0.812*	*0.225*	*10*	*0.416*	*0.158*	*6*	*0.316*	*0.176*	*7*
LNB/SOFA	1.759	0.683	28	0.996	0.25	9	0.482	0.185	0	0.358	0.204	0
Incremental Post Control Improvement over BOOS	*0.395*	*0.152*	*9*	*0.236*	*0.057*	*2*	*0.118*	*0.044*	*2*	*0.089*	*0.049*	*0*
LNB/SOFA/SNCR	1.349	0.529	16	0.755	0.193	4	0.362	0.141	0	0.268	0.154	0
Incremental Post Control Improvement over BOOS	*0.805*	*0.306*	*21*	*0.477*	*0.114*	*7*	*0.238*	*0.088*	*2*	*0.179*	*0.099*	*0*
LNB/SOFA/SCR	0.452	0.163	0	0.211	0.057	0	0.101	0.043	0	0.082	0.042	0
Incremental Post Control Improvement over BOOS	*1.702*	*0.672*	*37*	*1.021*	*0.25*	*11*	*0.499*	*0.186*	*2*	*0.365*	*0.211*	*0*

†The visibility improvement shown in the table has been calculated from 98th percentile baseline and controlled impacts that include more decimal places than what is shown in the table. Due to rounding of the baseline and controlled 98th percentile impacts shown in the table, the visibility improvement calculated from the baseline and controlled 98th percentile impacts shown in the table may be slightly different than the visibility improvement reflected in the table.

As shown in Table 6-9, based on visibility predictions from the CALPUFF modeling system, the operation of a BOOS will result in up to a 0.536 Δdv improvement (depending on the Class I area) to the existing visibility impairment attributable to Unit 4. This visibility improvement increases by 0.152 Δdv for LNB/SOFA (0.835-0.683 = 0.152), 0.306 Δdv for LNB/SOFA/SNCR (0.835-0.529 = 0.306), and 0.672 Δdv for LNB/SOFA/SCR (.835-0.163 = 0.672).

For convenience, Table 6-10 provides a condensed summary of these predicted improvements alongside the estimated control costs. The incremental visibility benefit of going from BOOS to either LNB/SOFA, LNB/SOFA/SCNR or LNB/SOFA/SCR is clearly not justified by the high incremental cost difference. The control technologies are very expensive from an initial capital investment and prohibitively more expensive from an incremental cost effectiveness standpoint than BOOS.

TABLE 6-10. INCREMENTAL COST EFFECTIVENESS FOR UNIT 4 WITH CLASS I AREA IMPROVEMENT (2001-2003)

Control Description	NOx Emissions (lb/MMBtu)	Control Eff. From Baseline (%)	Emission Reduction from Baseline (tons/yr)	Installed Cost ($)	Total Annual Control Cost ($)	Pollution Control Cost ($/ton)	Incremental Cost[1] ($/ton)	Class I Area	Baseline 98th Percentile Δdv	Controlled 98th Percentile Δdv	Improvement in 98th Percentile Δdv	Baseline # Days > 0.5 Δdv	Controlled # Days > 0.5 Δdv
BOOS	0.24	50%	618	893,000	92,964	150	-	Caney Creek	1.371	0.835	0.536	80	37
								Hercules-Glades	0.387	0.229	0.158	8	2
								Mingo	0.429	0.253	0.176	7	0
								Upper Buffalo	0.532	0.307	0.225	21	11
LNB/SOFA	0.19	60%	742	11,845,025	1,183,582	1,596	8,822	Caney Creek	1.371	0.683	0.688	80	28
								Hercules-Glades	0.387	0.185	0.202	8	0
								Mingo	0.429	0.204	0.225	7	0
								Upper Buffalo	0.532	0.250	0.282	21	9
LNB/SOFA + SNCR	0.14	70%	865	29,295,494	3,311,819	3,827	17,214	Caney Creek	1.371	0.529	0.842	80	16
								Hercules-Glades	0.387	0.141	0.246	8	0
								Mingo	0.429	0.154	0.275	7	0
								Upper Buffalo	0.532	0.193	0.339	21	4
LNB/SOFA + SCR	0.03	94%	1,159	79,152,952	7,214,652	6,223	14,440	Caney Creek	1.371	0.163	1.208	80	0
								Hercules-Glades	0.387	0.043	0.344	8	0
								Mingo	0.429	0.042	0.387	7	0
								Upper Buffalo	0.532	0.057	0.475	21	0

1. The incremental cost for LNB/SOFA is calculated in comparison to BOOS while the incremental costs for LNB/SOFA + SNCR and LNB/SOFA + SCR are calculated in comparison to LNB/SOFA alone.

6.6 PROPOSED BART FOR NO_X

Entergy proposes a BART emission rate of 0.24 lb/MMBtu on a 30-day rolling average basis, achievable through use of BOOS at Unit 4.[24]

[24] If CSAPR is upheld and implemented in Arkansas, Entergy will rely on CSAPR to satisfy its regional haze obligations at Lake Catherine. If CSAPR is vacated and CAIR remains in effect, EPA's prior determination that the reductions provided under CAIR's seasonal NO_X trading program provide greater visibility improvements than BART should allow Entergy to rely on the seasonal CAIR program to satisfy its NO_X obligations under BART.

7. PM_{10} BART EVALUATION

A BART determination for PM_{10} based on the use of natural gas was approved in EPA's March 12, 2012, final rule. The determination results in no PM_{10} controls needed during natural gas combustion.[25]

[25] "Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze. Final Rule," 77 Fed. Reg. 14604 (March 12, 2012).

APPENDIX A

CONTROL COST CALCULATIONS

BOOS Capital and O&M Cost Estimate	
Operational Data	
N/A	
Capital Cost	
Implementation Cost[1]	893,000
Capital Recovery Factor (CRF)[2]	0.08
Annual Costs	
Fixed O&M Costs[3]	21,000
Variable O&M Costs[4]	0
Annualized Implementation Cost	71,964
Total Annual Costs	92,964

1: It is anticipated that BOOS can be implemented on the unit without any capital expenditures. The one-time costs associated with BOOS implementation would instead be incorporated into the facility's O&M budget for the fiscal year. In order to provide an apples-to-apples comparison with the other NOx control options, these one-time additional O&M costs were treated as if the cost were a capital expenditure. This cost is is based the Sargent & Lundy 5/16/2013 NOx Control Technology Cost and Performance Study.

2: CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life
Equipment CRF, 30-yr actual service life, 7% interest

3: The fixed O&M cost estimate for BOOS is based on the fixed O&M cost estimate for BOOS as provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study

4: The variable O&M cost estimate for BOOS is based on the variable O&M cost estimate for BOOS as provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study

LNB-SOFA Capital and O&M Cost Estimate

Operational Data	
Maximum HI (MMBtu/hr)	5850
Average Annual Operating Hours, 2009-2011	1205
Capital Cost	
Installed Capital Cost[1]	11,845,025
Capital Recovery Factor (CRF)[2]	0.08
Annual Costs	
Fixed O&M Costs[3]	210,000
Variable O&M Costs[4]	19,034
Annualized Capital Cost	954,548
Total Annual Costs	1,183,582

1: The installed capital cost estimate for LNB/OFA + SNCR is based on the installed capital cost estimate provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study ($8,762,000) plus additional cost not accounted for in the S&L cost estimate, including cost for permitting and legal/regulatory support (estimated by Entergy to be $112,500), cost for Entergy employee labor and loaders (estimated by Entergy to be $1,634,363), cost for capital suspense (estimated by Entergy to be $751,978), and cost for AFUDC (estimated by Entergy to be $584,184) .

2: CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life

Equipment CRF, 30-yr actual service life, 7% interest

3: The fixed O&M cost estimate for LNB/OFA is based on the fixed O&M cost estimate for LNB/OFA as provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study

4: The variable O&M cost estimate for LNB/OFA is based on an equation documented in the Eastern Research Group report "Analysis of Combustion Controls for Reducing NOx Emissions from Coal-fired EGUs in the WRAP Region" September 6, 2005. Section 4.3.1 and Appendix D as shown below.

Variable O&M = (0.027 mills/kW-hr/1000) x (1 kW-hr/10,000 Btu) x H x C x 10^6 Btu/mmBtu

Where:
H = Annual operating hours
C = Boiler design capacity (mmBtu/hr)
Note: The variable rate used for variable O&M costs was 0.027 mills/kW-hr. This is the rate listed in Appedix D

LNB-OFA + SNCR Capital and O&M Cost Estimate

Operational Data	
Maximum HI (MMBtu/hr)	5850
Average Annual Operating Hours, 2009-2011	1205
Capital Cost	
Installed Capital Cost[1]	29,295,494
Capital Recovery Factor (CRF)[2]	0.08
Annual Costs[3]	
Fixed O&M Costs	489,000
Variable O&M Costs	462,000
Annualized Capital Cost	2,360,819
Total Annual Costs	3,311,819

1: The installed capital cost estimate for LNB/OFA + SNCR is based on the installed capital cost estimate provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study ($24,269,000) plus additional cost not accounted for in the S&L cost estimate, including cost for permitting and legal/regulatory support (estimated by Entergy to be $112,500), cost for Entergy employee labor and loaders (estimated by Entergy to be $1,634,363), cost for capital suspense (estimated by Entergy to be $1,821,939), and cost for AFUDC (estimated by Entergy to be $1,457,962 for each unit) .

2: CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life
Equipment CRF, 30-yr actual service life, 7% interest

3: The fixed O&M cost estimate for LNB/OFA + SNCR is based on the fixed O&M cost estimate for LNB/OFA + SNCR as provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study

4: The variable O&M cost estimates are based on the cost estimates provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study. Adding LNB/OFA to SNCR makes the variable O&M costs less than that of SNCR alone due to a lower NOx concentration and resulting less reagent usage.

LNB-OFA + SCR Capital and O&M Cost Estimate

Operational Data	
Maximum HI (MMBtu/hr)	5850
Annual Operating Hours, 2009-2011	1205
Capital Costs[1]	
Installed Capital Cost	79,152,952
Capital Recovery Factor (CRF)[2]	0.08
Annual Costs[3]	
Fixed O&M Costs	568,000
Variable O&M Costs	268,000
Annualized Capital Cost	6,378,652
Total Annual Costs	7,214,652

1: The installed capital cost estimate for LNB/OFA + SCR is based on the installed capital cost estimate provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study ($68,349,000) plus additional cost not accounted for in the S&L cost estimate, including cost for permitting and legal/regulatory support (estimated by Entergy to be $387,500), cost for Entergy employee labor and loaders (estimated by Entergy to be $1,634,363), cost for capital suspense (estimated by Entergy to be $4,888,377), and cost for AFUDC (estimated by Entergy to be $3,956,212) .

2: CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life

Equipment CRF, 30-yr actual service life, 7% interest

3: All O&M cost estimateswere provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study

4: The variable O&M cost estimates are based on the cost estimates provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study. Adding LNB/OFA to SCR makes the variable O&M costs less than that of SCR alone due to a lower NOx concentration and resulting less reagent usage.

APPENDIX B

MODELING PROTOCOL

As stated in Section 3.1, the meteorological data used in the analyses presented in this report was originally developed in 2007 and was first used in a BART determination for Oklahoma Gas & Electric. Because the development of a set of CALMET/CALPUFF meteorological data is so intensive, this same dataset has been used numerous times since 2007 for various other BART projects in EPA Region 6. The protocol that accompanied the original development has followed the dataset in each case and is doing so here again.

APPENDIX C

CEMS DATA FROM CAMD FOR 2001 TO 2003

CALMET DATA PROCESSING PROTOCOL ▲ BART DETERMINATION
OKLAHOMA GAS & ELECTRIC

MUSKOGEE GENERATING STATION
SEMINOLE GENERATING STATION
SOONER GENERATING STATION

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Project 083701.0004

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1. INTRODUCTION

Oklahoma Gas & Electric (OG&E) owns and operates three electric generating stations near Muskogee, Oklahoma (Muskogee Generating Station), Seminole, Oklahoma (Seminole Generating Station), and Stillwater, Oklahoma (Sooner Generating Station). These generating stations are considered eligible to be regulated under the U.S. Environmental Protection Agency's (EPA) Best Available Retrofit Technology (BART) provisions of the Regional Haze Rule. This protocol describes the proposed methodology for conducting the CALMET data processing for the refined CALPUFF BART modeling analysis for OG&E's Muskogee, Seminole, and Sooner Generating Stations. A detailed CALPUFF BART modeling protocol will be submitted in the near future and will include a discussion of the CALPUFF parameters as well as the post processing methodologies to be used in the refined modeling analysis for each station.

1.1 BEST AVAILABLE RETROFIT TECHNOLOGY RULE BACKGROUND

On July 1, 1999, the U.S. Environmental EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to improve visibility in 156 specific areas across with United States, known as Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence on August 7, 1977.

On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the BART rule, which included guidance for making source-specific Best Available Retrofit Technology (BART) determinations. The BART rule defines BART-eligible sources as sources that meet the following criteria:

(1) Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant,
(2) Began operation between August 7, 1962 and August 7, 1977, and
(3) Are listed as one of the 26 listed source categories in the guidance.

A BART-eligible source is not automatically subject to BART. Rather, BART-eligible sources are subject-to-BART if the sources are "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." EPA has determined that sources are reasonably anticipated to cause or contribute to visibility impairment if the visibility impacts from a source are greater than 0.5 deciviews (dv) when compared against a natural background.

Air quality modeling is the tool that is used to determine a source's visibility impacts. States have the authority to exempt certain BART-eligible sources from installing BART controls if the results of the dispersion modeling demonstrate that the source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I area. Further, states also have the authority to define the modeling procedures for conducting modeling related to making BART determinations.

1.2 OBJECTIVE

The objective of this document is to provide a protocol summarizing the modeling methods and procedures that will be followed to conduct the CALMET data processing necessary to complete a refined CALPUFF modeling analysis for the OG&E generating stations discussed above. The modeling methods and procedures contained in this protocol and the CALPUFF protocol yet to be submitted will be used to determine appropriate controls for OG&E's BART-eligible sources that can reasonably be anticipated to reduce the sources' effects on or contribution to visibility impairment in the surrounding Class I areas. It is OG&E's intent to determine a combination of emissions controls that will reduce the impact of each generating station to a degree that the 98th percentile of the visibility impact predicted by the model due to all the BART eligible sources at each station collectively is below EPA's recommended visibility contribution threshold of 0.5 Δdv.

1.3 LOCATION OF SOURCES AND RELEVANT CLASS I AREAS

The sources listed in Table 1-1 are the sources that have been identified by OG&E as sources that meet the three criteria for BART-eligible sources.

TABLE 1-1. BART-ELIGIBLE SOURCES

EPN	Description
	Muskogee Sources
Unit 4	5,480 MMBtu/hr Coal Fired Boiler
Unit 5	5,480 MMBtu/hr Coal Fired Boiler
	Seminole Sources
SM1	5,480 MMBtu/hr Natural Gas Fired Boiler
SM2	5,480 MMBtu/hr Natural Gas Fired Boiler
SM3	5,496 MMBtu/hr Natural Gas Fired Boiler
	Sooner Sources
Unit 1	5,116 MMBtu/hr Coal Fired Boiler
Unit 2	5,116 MMBtu/hr Coal Fired Boiler

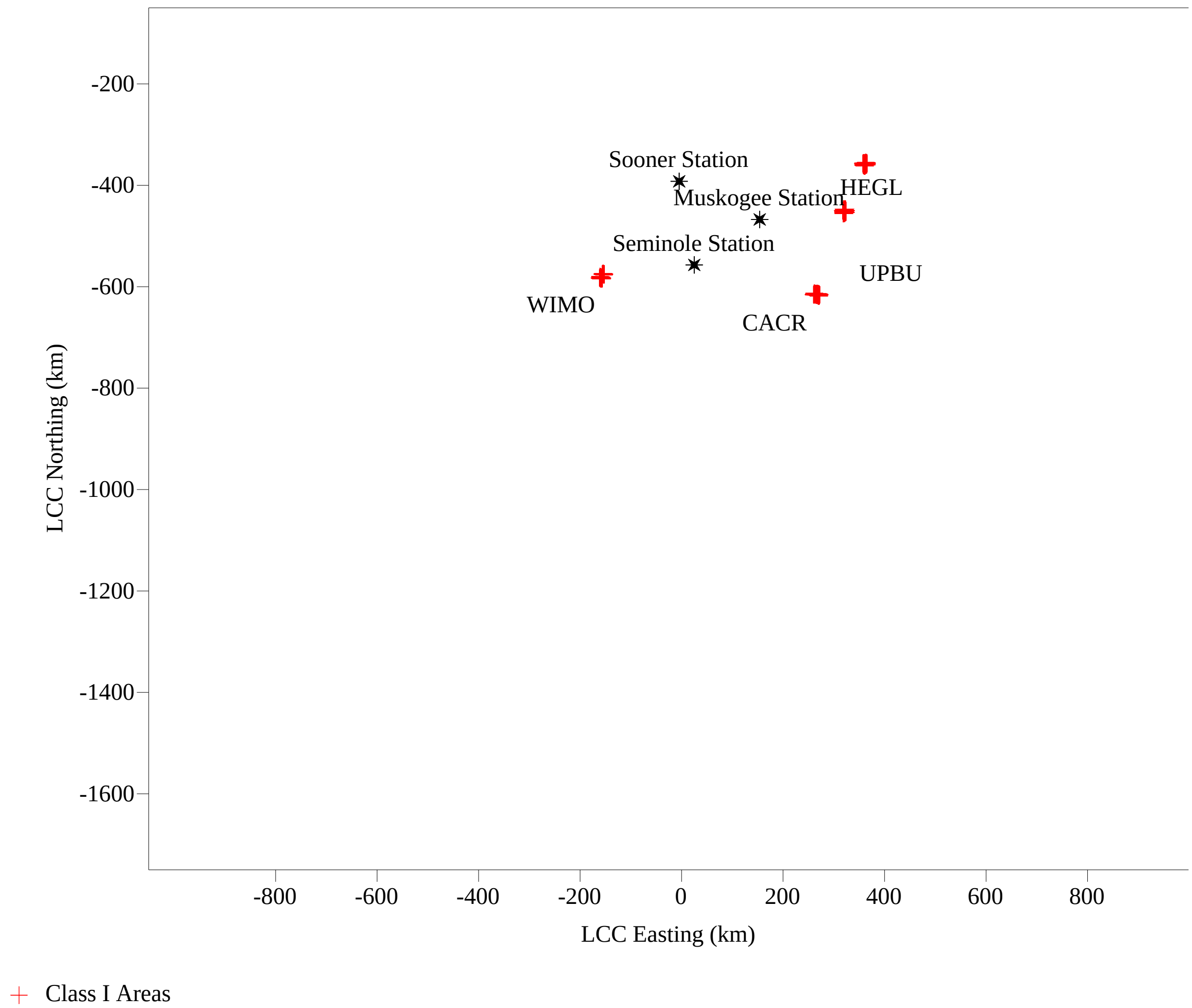
As required in CENRAP's BART Modeling Guidelines, Class I areas within 300 km of each station will be included in each analysis. The following table summarizes the distances of the four closest Class I areas to each station. As seen from this summary, some Class I areas are more than 300 km from the certain stations. However, in order to demonstrate that each station will not have an adverse effect on the visibility at any of the four nearest Class I areas, OG&E has opted to include those Class I areas more than 300 km away in this analysis. Note that the distances listed in the table below are the distances between the stations and the closest border of the Class I areas.

TABLE 1-2. DISTANCE FROM STATION TO SURROUNDING CLASS I AREAS

	CACR	HEGL	UPBU	WIMO
Muskogee	180	230	164	324
Seminole	242	386	310	178
Sooner	345	363	327	234

A plot of the Class I areas with respect to the each station is provided in Figure 1-1.

FIGURE 1-1. PLOT OF SOURCES AND NEAREST CLASS I AREAS



2. CALPUFF MODEL SYSTEM

The main components of the CALPUFF modeling system are CALMET, CALPUFF, and CALPOST. CALMET is the meteorological model that generates hourly three-dimensional meteorological fields such as wind and temperature. CALPUFF simulates the non-steady state transport, dispersion, and chemical transformation of air pollutants emitted from a source in "puffs". CALPUFF calculates hourly concentrations of visibility affecting pollutants at each specified receptor in a modeling domain. CALPOST is the post-processor for CALPUFF that computes visibility impacts from a source based on the visibility affecting pollutant concentrations that were output by CALPUFF.

2.1 MODEL VERSIONS

The versions of the CALPUFF modeling system programs that are proposed for conducting OG&E's BART modeling are listed in Table 2-1. A detailed refined CALPUFF BART modeling protocol will be submitted in the near future.

TABLE 2-1. CALPUFF MODELING SYSTEM VERSIONS

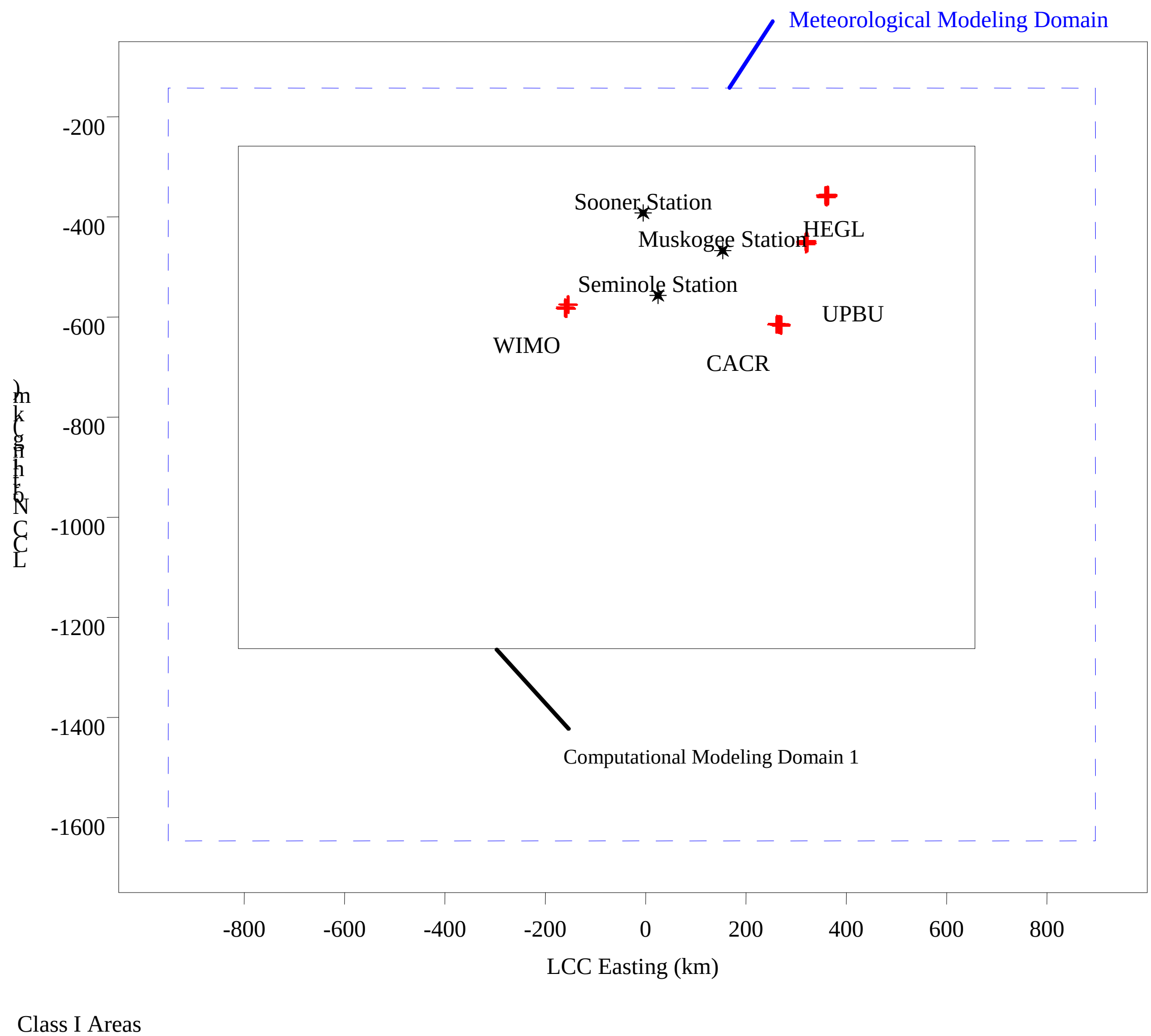
Processor	Version	Level
TERREL	3.3	030402
CTGCOMP	2.21	030402
CTGPROC	2.63	050128
MAKEGEO	2.2	030402
CALMET	5.53a	040716
CALPUFF	5.8	070623
POSTUTIL	1.3	030402
CALPOST	5.51	030709

2.2 MODELING DOMAIN

The CALPUFF modeling system utilizes three modeling grids: the meteorological grid, the computational grid, and the sampling grid. The meteorological grid is the system of grid points at which meteorological fields are developed with CALMET. The computational grid determines the computational area for a CALPUFF run. Puffs are advected and tracked only while within the computational grid. The meteorological grid is defined so that it covers the areas of concern and gives enough marginal buffer area for puff transport and dispersion. A plot of the proposed meteorological modeling domain with respect to the Class I areas being modeled is also provided in

Figure 2-1. The computational domain will be set to extend at least 50 km in all directions beyond the Muskogee, Seminole, and Sooner Generating Stations and the Class I areas of interest. Note that the map projection for the modeling domain will be Lambert Conformal Conic (LCC) and the datum will be the World Geodetic System 84 (WGS-84). The reference point for the modeling domain is Latitude 40ºN, Longitude 97ºW. The southwest corner will be set to -951.547 km LCC, -1646.637 km LCC corresponding to Latitude 24.813 ºN and Longitude 87.778ºW. The meteorological grid spacing will be 4 km, resulting in 462 grid points in the X direction and 376 grid points in the Y direction.

FIGURE 2-1. REFINED METEOROLOGICAL MODELING DOMAIN



3. CALMET

The EPA Approved Version of the CALMET meteorological processor will be used to generate the meteorological data for CALPUFF. CALMET is the meteorological processor that compiles meteorological data from raw observations of surface and upper air conditions, precipitation measurements, mesoscale model output, and geophysical parameters into a single hourly, gridded data set for input into CALPUFF. CALMET will be used to assimilate data for 2001- 2003 using National Weather Service (NWS) surface station observations, upper air station observations, precipitation station observations, buoy station observations (for overwater areas), and mesoscale model output to develop the meteorological field.

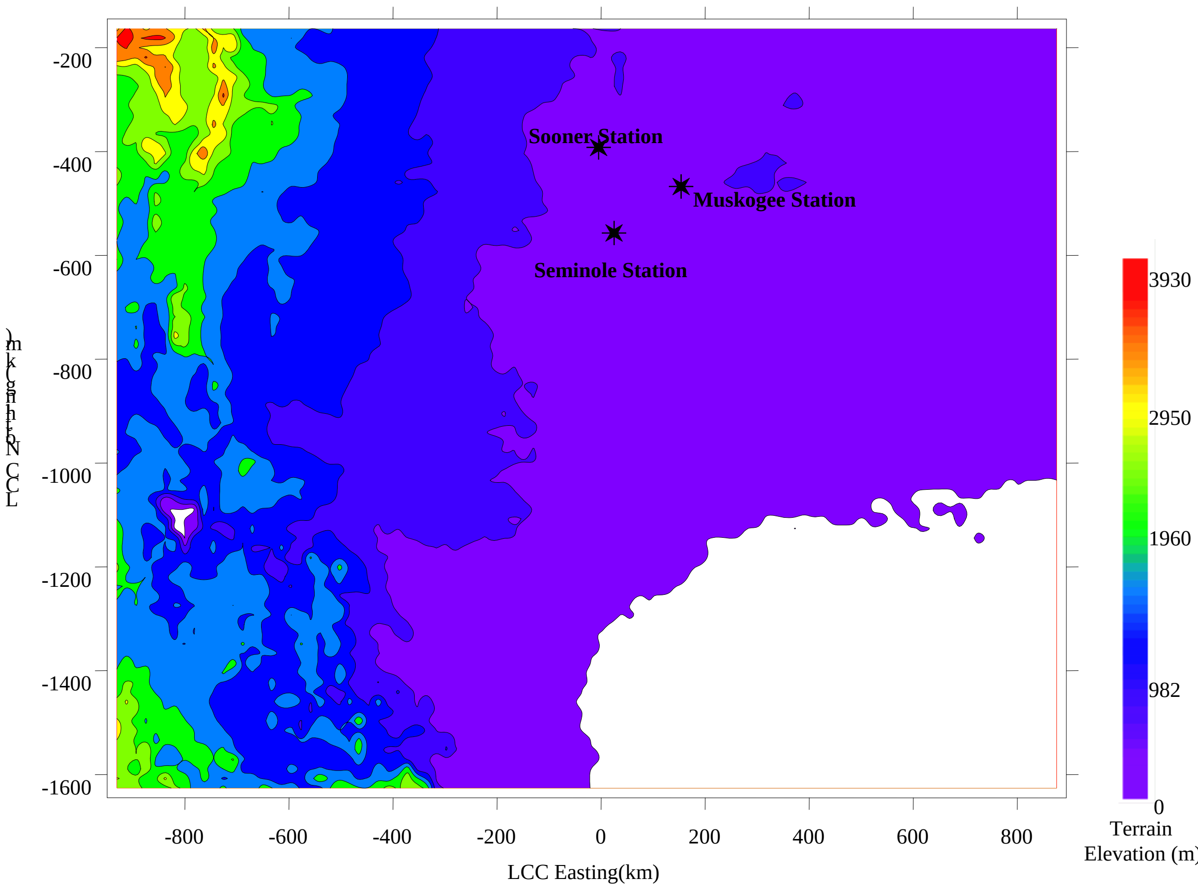
3.1 GEOPHYSICAL DATA

CALMET requires geophysical data to characterize the terrain and land use parameters that potentially affect dispersion. Terrain features affect flows and create turbulence in the atmosphere and are potentially subjected to higher concentrations of elevated puffs. Different land uses exhibit variable characteristics such as surface roughness, albedo, Bowen ratio, and leaf-area index that also effect turbulence and dispersion.

3.1.1 TERRAIN DATA

Terrain data will be obtained from the United States Geological Survey (USGS) in 1-degree (1:250,000 scale or approximately 90 meter resolution) digital format. The USGS terrain data will then be processed by the TERREL program to generate grid-cell elevation averages across the modeling domain. A plot of the land elevations based on the USGS data for the modeling domain is provided in Figure 3-1.

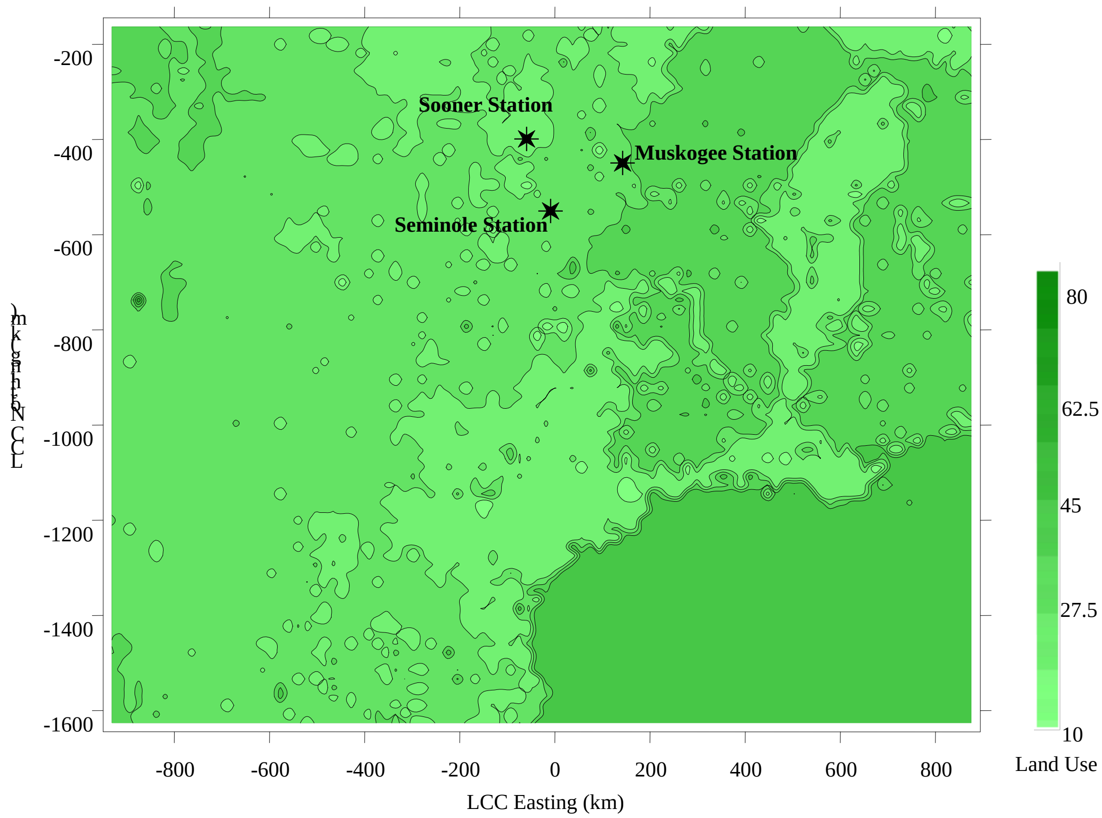
FIGURE 3-1. PLOT OF LAND ELEVATION USING USGS TERRAIN DATA



3.1.2 LAND USE DATA

The land use land cover (LULC) data from the USGS North American land cover characteristics data base in the Lambert Azimuthal equal area map projection will be used in order to determine the land use within the modeling domain. The LULC data will be processed by the CTGPROC program which will generate land use for each grid cell across the modeling domain. A plot of the land use based on the USGS data for the modeling domain is provided in Figure 3-2.

FIGURE 3-2. PLOT OF LAND USE USING USGS LULC DATA



3.1.3 COMPILING TERRAIN AND LAND USE DATA

The terrain data files output by the TERELL program and the LULC files output by the CTGPROC program will be uploaded into the MAKEGEO program to create a geophysical data file that will be input into CALMET.

3.2 METEOROLOGICAL DATA

CALMET will be used to assimilate data for 2001, 2002, and 2003 using mesoscale model output and National Weather Service (NWS) surface station observations, upper air station observations, precipitation station observations, and National Oceanic and Atmosphere Administrations (NOAA) buoy station observations to develop the meteorological field.

3.2.1 MESOSCALE MODEL METEOROLOGICAL DATA

Hourly mesoscale data will also be used as the initial guess field in developing the CALMET meteorological data. It is OG&E's intent to use the following 5th generation mesoscale model meteorological data sets (or MM5 data) in the analysis:

- 2001 MM5 data at 12 km resolution generated by the U.S. EPA
- 2002 MM5 data at 36 km resolution generated by the Iowa DNR

- 2003 MM5 data set at 36 km resolution generated by the Midwest RPO

The specific MM5 data that will be used are subsets of the data listed above. As the contractor to CENRAP for developing the meteorological data sets for the BART modeling, Alpine Geophysics extracted three subsets of MM5 data for each year from 2001 to 2003 from the data sets listed above using the CALMM5 extraction program. The three subsets covered the northern, central, and southern portions of CENRAP. TXI is proposing to use the southern set of the extracted MM5 data.

The 2001 southern subset of the extracted MM5 data includes 30 files that are broken into 10 to 11 day increments (3 files per month). The 2002 and 2003 southern subsets of extracted MM5 data include 12 files each of which are broken into 30 to 31 day increment files (1 file per month). Note that the 2001 to 2003 MM5 data extracted by Alpine Geophysics will not be able to be used directly in the modeling analysis. To run the Alpine Geophysics extracted MM data in the EPA approved CALMET program, each of the MM5 files will need to be adjusted by appending an additional six (6) hours, at a minimum, to the end of each file to account for the shift in time zones from the Greenwich Mean Time (GMT) prepared Alpine Geophysics data to Time Zone 6 for this analysis. No change to the data will occur.

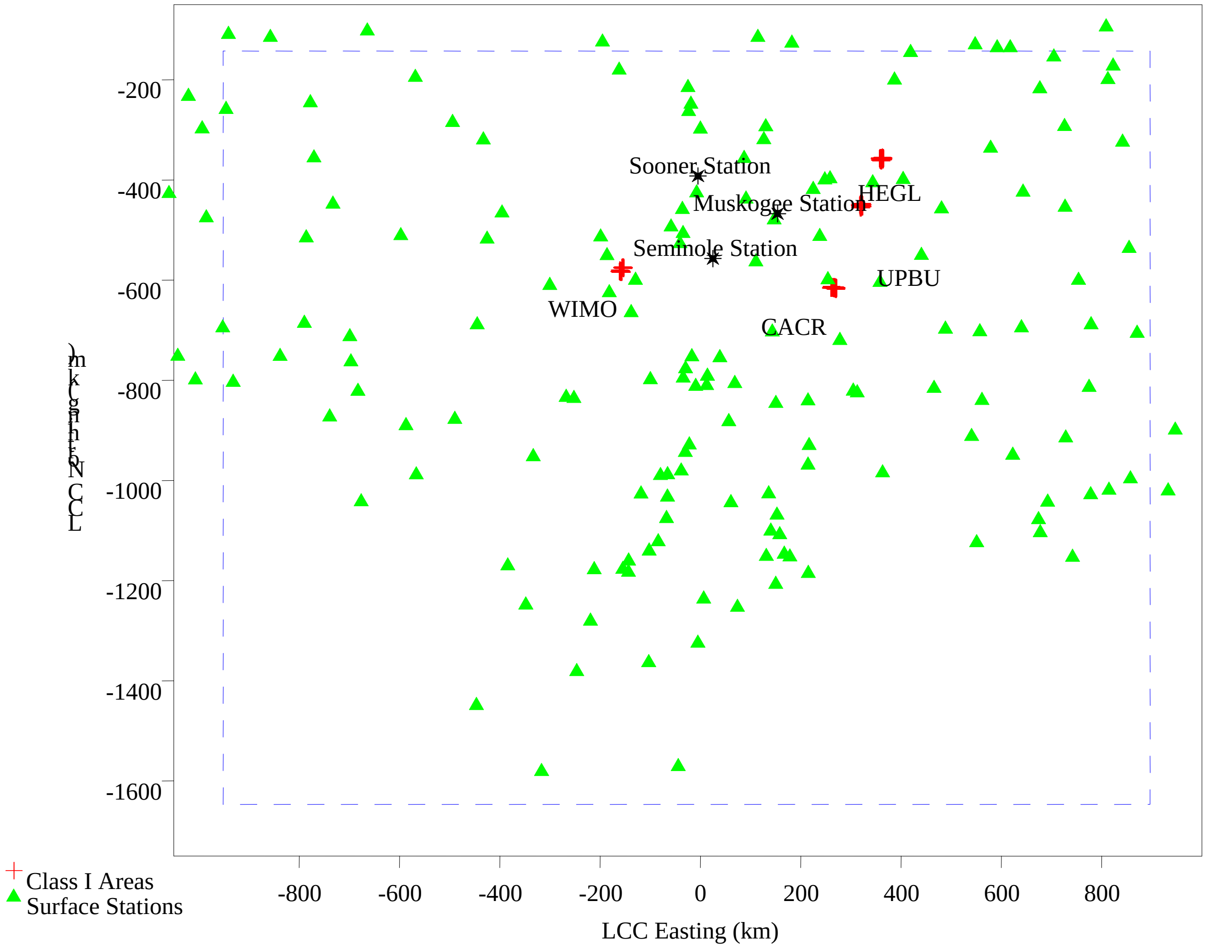
The time periods covered by the data in each of the MM5 files extracted by Alpine Geophysics include a specific number of calendar days, where the data starts at Hour 0 in GMT for the first calendar day and ends at Hour 23 in GMT on the last calendar day. In order to run CALMET in the local standard time (LST), which is necessary since the surface meteorological observations are recorded in LST, there must be hours of MM5 data referenced in a CALMET run that match the LST observation hours. Since the LST hours in Central Standard Time (CST) are 6 hours behind GMT, it is necessary to adjust the data in each MM5 file so that the time periods covered in the files match CST.

Based on the above discussion, the Alpine Geophysics MM5 data will not be used directly. Instead the data files will be modified to add 8 additional hours of data to the end of each file from the beginning of the subsequent file. CALMET will then be run using the appended MM5 data to generate a contiguous set of CALMET output files. The converted MM5 data files occupy approximately 1.2 terabytes (TB) of hard drive space.

3.2.2 SURFACE METEOROLOGICAL DATA

Parameters affecting turbulent dispersion that are observed hourly at surface stations include wind speed and direction, temperature, cloud cover and ceiling, relative humidity, and precipitation type. It is OG&E's intent to use the surface stations listed in Table A-1 of Appendix A. The locations of the surface stations with respect to the modeling domain are shown in Figure 3-3. The stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA's SMERGE program.

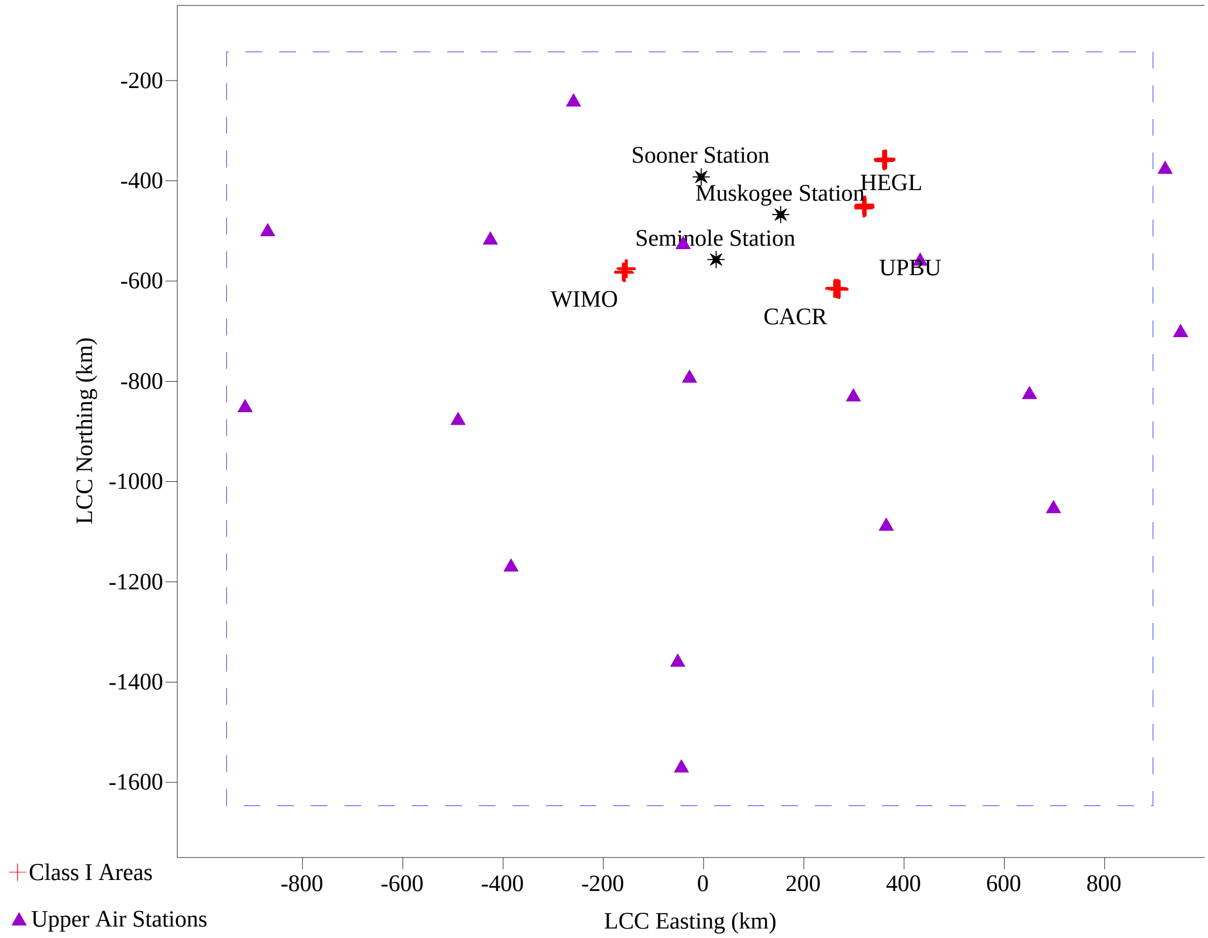
FIGURE 3-3. PLOT OF SURFACE STATION LOCATIONS



3.2.3 UPPER AIR METEOROLOGICAL DATA

Observations of meteorological conditions in the upper atmosphere provide a profile of turbulence from the surface through the depth of the boundary layer in which dispersion occurs. Upper air data are collected by balloons launched simultaneously across the observation network at 0000 Greenwich Mean Time (GMT) (6 o'clock PM in Oklahoma) and 1200 GMT (6 o'clock AM in Oklahoma). Sensors observe pressure, wind speed and direction, and temperature (among other parameters) as the balloon rises through the atmosphere. The upper air observation network is less dense than surface observation points since upper air conditions vary less and are generally not as affected by local effects (e.g., terrain or water bodies). The upper air stations that are proposed for this analysis are listed in Table A-2 of Appendix A. The locations of the upper air stations with respect to the modeling domain are shown in Figure 3-4. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA's READ62 program.

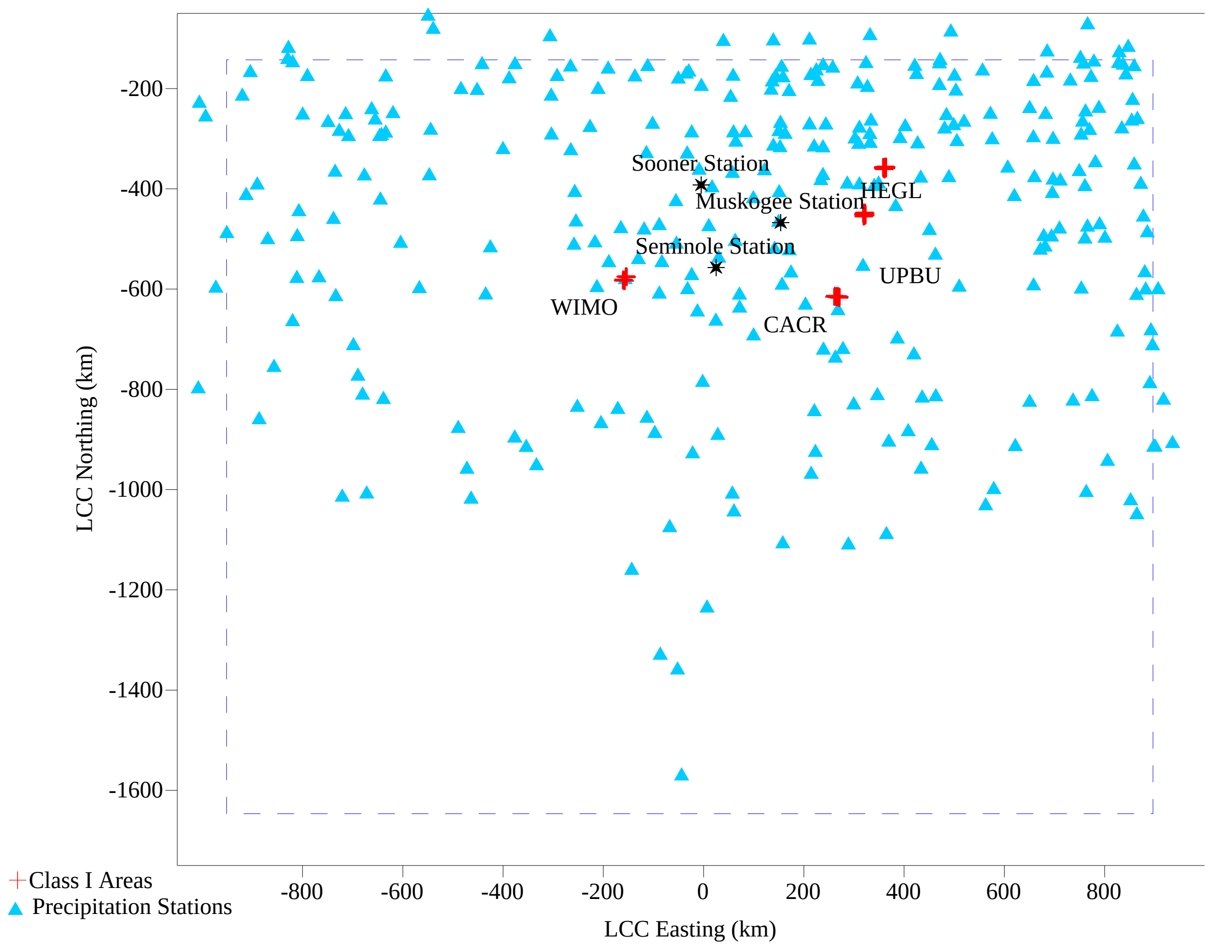
FIGURE 3-4. PLOT OF UPPER AIR STATIONS LOCATIONS



3.2.4 PRECIPITATION METEOROLOGICAL DATA

The effects of chemical transformation and deposition processes on ambient pollutant concentrations will be considered in this analysis. Therefore, it is necessary to include observations of precipitation in the CALMET analysis. The precipitation stations that are proposed for this analysis are listed in Table A-3 of Appendix A. The locations of the precipitation stations with respect to the modeling domain are shown in Figure 3-5. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA's PMERGE program.

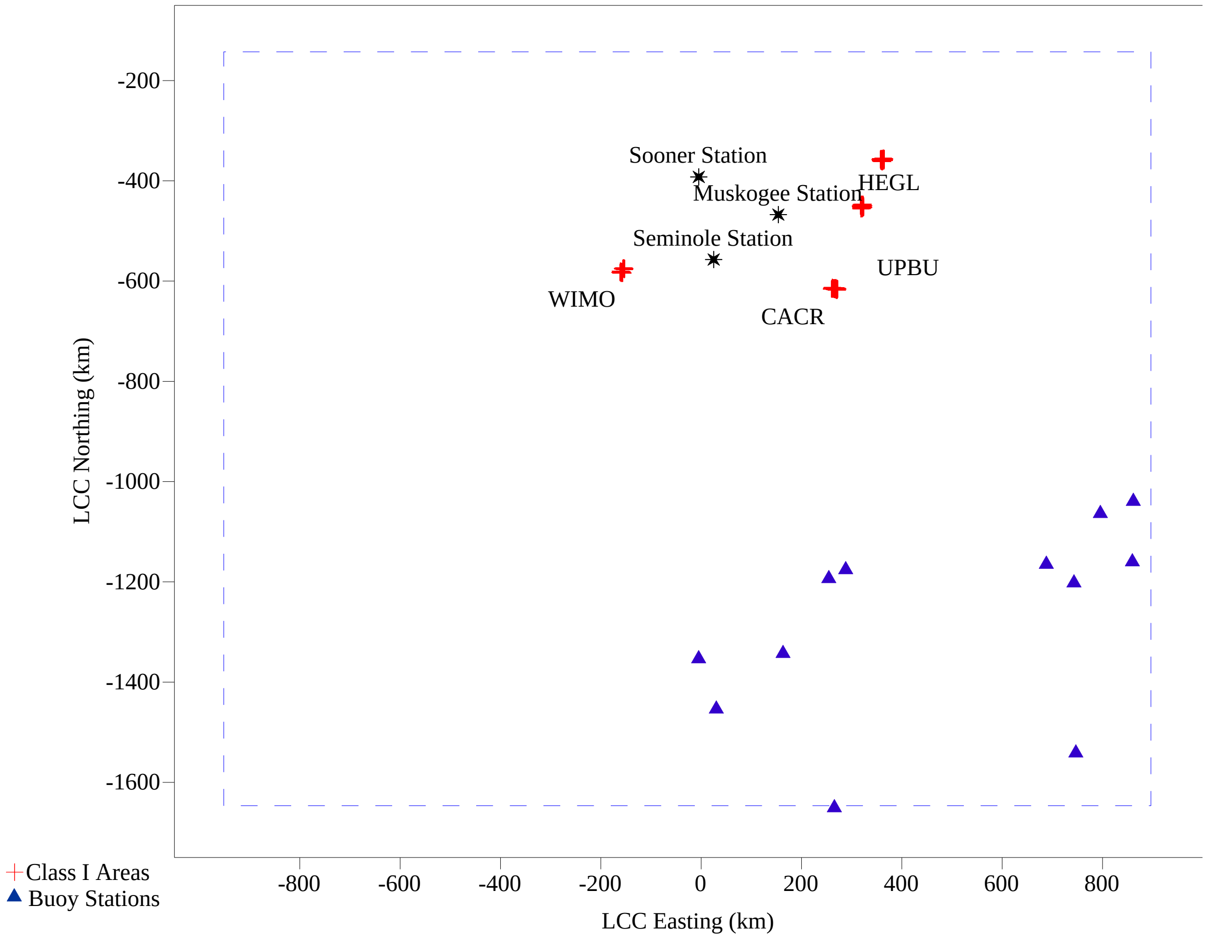
FIGURE 3-5. PLOT OF PRECIPITATION METEOROLOGICAL STATIONS



3.2.5 BUOY METEOROLOGICAL DATA

The effects of land/sea breeze on ambient pollutant concentrations will be considered in this analysis. Therefore, it is necessary to include observations of buoy stations in the CALMET analysis. The buoy stations that are proposed for this analysis are listed in Table A-4 of Appendix A. The locations of the buoy stations with respect to the modeling domain are shown in Figure 3-6. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain along the coastline. Data from the stations will be prepared by filling missing hour records with the CALMET missing parameter value (9999). No adjustments to the data will occur.

FIGURE 3-6. PLOT OF BUOY METEOROLOGICAL STATIONS



3.3 CALMET CONTROL PARAMETERS

Appendix B provides a sample CALMET input file used in OG&E's modeling analysis. A few details of the CALMET model setup for sensitive parameters are also discussed below.

3.3.1 VERTICAL METEOROLOGICAL PROFILE

The height of the top vertical layer will be set to 3,500 meters. This height corresponds to the top sounding pressure level for which upper air observation data will be relied upon. The vertical dimension of the domain will be divided into 12 layers with the maximum elevations for each layer shown in Table 3-1. The vertical dimensions are weighted towards the surface to resolve the mixing layer while using a somewhat coarser resolution for the layers aloft.

TABLE 3-1. VERTICAL LAYERS OF THE CALMET METEOROLOGICAL DOMAIN

Layer	Elevation (m)
1	20
2	40
3	60
4	80
5	100
6	150
7	200
8	250
9	500
10	1000
11	2000
12	3500

CALMET allows for a bias value to be applied to each of the vertical layers. The bias settings for each vertical layer determine the relative weight given to the vertically extrapolated surface and upper air wind and temperature observations. The initial guess fields are computed with an inverse distance weighting ($1/r^2$) of the surface and upper air data. The initial guess fields may be modified by a layer dependent bias factor. Values for the bias factor may range from -1 to +1. A bias of -1 eliminates upper-air observations in the $1/r^2$ interpolations used to initialize the vertical wind fields. Conversely, a bias of +1 eliminates the surface observations in the interpolations for this layer. Normally, bias is set to zero (0) for each vertical layer, such that the upper air and surface observations are given equal weight in the $1/r^2$ interpolations. The biases for each layer of the proposed modeling domain will be set to zero.

CALMET allows for vertical extrapolation of surface wind observations to layers aloft to be skipped if the surface station is close to the upper air station. Alternatively, CALMET allows data from all surface stations to be extrapolated. The CALMET parameter that controls this setting is IEXTRP. Setting IEXTRP to a value less than zero (0) means that layer 1 data from upper air soundings is ignored in any vertical extrapolations. IEXTRP will be set to -4 for this analysis (i.e., the similarity theory is used to extrapolate the surface winds into the layers aloft, which provides more information on observed local effects to the upper layers).

3.3.2 INFLUENCES OF OBSERVATIONS

Step 1 wind fields will be based on an initial guess using MM5 data and refined to reflect terrain affects. Step 2 wind fields will adjust the Step 1 wind field by incorporating the influence of local observations. An inverse distance method is used to determine the influence of observations to the Step 1 wind field. RMAX1 and RMAX2 define the radius of influence for data from surface stations to land in the surface layer and data from upper air stations to land in the layers aloft. In general, RMAX1 and RMAX2 are used to exclude observations from being inappropriately included in the development of the Step 2

wind field if the distance from an observation station to a grid point exceeds the maximum radius of influence.

If the distance from an observation station to a grid point is less than the value set for RMAX, the observation data will be used in the development of the Step 2 wind field. R1 represents the distance from a surface observation station at which the surface observation and the Step 1 wind field are weighted equally. R2 represents the comparable distance for winds aloft. R1 and R2 are used to weight the observation data with respect to the MM5 data that was used to generate the Step 1 wind field. Large values for R1 and R2 give more weight to the observations, where as small values give more weight to the MM5 data.

In this BART modeling analysis, RMAX 1 will be set to 20 km, and R1 will be set to 10 km. This will limit the influence of the surface observation data from all surface stations to 20 km from each station, and will equally weight the MM5 and observation data at 10 km. RMAX2 will be set to 50 km, and R2 will be set to 25 km. This will limit the influence of the upper air observation data from all surface stations to 50 km from each station, and will equally weight the MM5 and observation data at 25 km. These settings of radius of influence will allow for adequate weighting of the MM5 data and the observation data across the modeling domain due to the vast domain to be modeled. RAMX 3 will be set to 500 km.

TABLE A-1. LIST OF SURFACE METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	KDYS	69019	-267.672	-834.095	96.9968	39.9925
2	KNPA	72222	932.565	-1020.909	97.0110	39.9908
3	KBFM	72223	857.471	-996.829	97.0101	39.9910
4	KGZH	72227	946.767	-899.515	97.0112	39.9919
5	KTCL	72228	870.843	-706.104	97.0103	39.9936
6	KNEW	53917	674.172	-1078.342	97.0080	39.9903
7	KNBG	12958	677.719	-1104.227	97.0080	39.9900
8	BVE	12884	741.996	-1153.463	97.0088	39.9896
9	KPTN	72232	550.88	-1124.295	97.0065	39.9898
10	KMEI	13865	774.911	-814.225	97.0092	39.9926
11	KPIB	72234	728.416	-915.165	97.0086	39.9917
12	KGLH	72235	557.072	-703.097	97.0066	39.9936
13	KHEZ	11111	540.777	-912.22	97.0064	39.9918
14	KMCB	11112	622.755	-949.618	97.0074	39.9914
15	KGWO	11113	640.102	-695.286	97.0076	39.9937
16	KASD	72236	692.381	-1043.261	97.0082	39.9906
17	KPOE	72239	363.294	-984.839	97.0043	39.9911
18	KBAZ	72241	-102.133	-1140.886	96.9988	39.9897
19	KGLS	72242	215.108	-1185.604	97.0025	39.9893
20	KDWH	11114	140.413	-1101.174	97.0017	39.9900
21	KIAH	12960	158.266	-1108.37	97.0019	39.9900
22	KHOU	72243	167.147	-1147.402	97.0020	39.9896
23	KEFD	12906	178.551	-1152.782	97.0021	39.9896
24	KCXO	72244	152.739	-1069.309	97.0018	39.9903
25	KCLL	11115	60.898	-1044.381	97.0007	39.9906
26	KLFK	93987	214.643	-969.355	97.0025	39.9912
27	KUTS	11116	136.056	-1026.773	97.0016	39.9907
28	KTYR	11117	150.451	-846.207	97.0018	39.9924
29	KCRS	72246	56.655	-882.642	97.0007	39.9920
30	KGGG	72247	214.572	-841.163	97.0025	39.9924
31	KGKY	11118	-9.365	-812.25	96.9999	39.9927
32	KDTN	72248	304.827	-821.713	97.0036	39.9926
33	KBAD	11119	312.743	-825.101	97.0037	39.9925
34	KMLU	11120	465.834	-816.211	97.0055	39.9926
35	KTVR	11121	561.446	-840.225	97.0066	39.9924
36	KTRL	11122	68.599	-806.417	97.0008	39.9927
37	KOCH	72249	216.81	-930.252	97.0026	39.9916
38	KBRO	12919	-44.167	-1571.387	96.9995	39.9858

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
39	KALI	72251	-103.012	-1363.74	96.9988	39.9877
40	KLRD	12920	-246.548	-1381.603	96.9971	39.9875
41	KSSF	72252	-143.386	-1183.35	96.9983	39.9893
42	KRKP	11123	-4.965	-1324.914	96.9999	39.9880
43	KCOT	11124	-219.097	-1280.964	96.9974	39.9884
44	KLBX	11125	150.245	-1207.466	97.0018	39.9891
45	KSAT	12921	-143.024	-1160.935	96.9983	39.9895
46	KHDO	12962	-211.702	-1178.172	96.9975	39.9894
47	KSKF	72253	-154.625	-1177.555	96.9982	39.9894
48	KHYI	11126	-84.156	-1122.487	96.9990	39.9899
49	KTKI	72254	38.788	-754.791	97.0005	39.9932
50	KBMQ	11127	-118.39	-1027.031	96.9986	39.9907
51	KATT	11128	-67.587	-1075.97	96.9992	39.9903
52	KSGR	11129	131.478	-1151.702	97.0016	39.9896
53	KGTU	11130	-65.624	-1033.173	96.9992	39.9907
54	KVCT	12912	6.587	-1236.788	97.0001	39.9888
55	KPSX	72255	73.878	-1253.33	97.0009	39.9887
56	KACT	13959	-22.12	-929.156	96.9997	39.9916
57	KPWG	72256	-30.147	-944.073	96.9996	39.9915
58	KILE	72257	-65.288	-988.507	96.9992	39.9911
59	KGRK	11131	-79.643	-990.173	96.9991	39.9911
60	KTPL	11132	-38.203	-981.19	96.9996	39.9911
61	KPRX	13960	143.317	-703.663	97.0017	39.9936
62	KDTO	72258	-17.018	-752.974	96.9998	39.9932
63	KAFW	11133	-29.564	-777.061	96.9997	39.9930
64	KFTW	72259	-34.302	-795.502	96.9996	39.9928
65	KMWL	11134	-99.769	-798.767	96.9988	39.9928
66	KRBD	11135	12.453	-810.467	97.0002	39.9927
67	KDRT	11136	-384.069	-1170.59	96.9955	39.9894
68	KFST	22010	-566.418	-988.838	96.9933	39.9911
69	KGDP	72261	-739.127	-873.302	96.9913	39.9921
70	KSJT	72262	-333.338	-952.54	96.9961	39.9914
71	KMRF	23034	-676.265	-1042.616	96.9920	39.9906
72	KMAF	72264	-489.668	-878.107	96.9942	39.9921
73	KINK	23023	-586.882	-890.654	96.9931	39.9920
74	KABI	72265	-252.044	-836.353	96.9970	39.9924
75	KLBB	13962	-445.006	-689.313	96.9948	39.9938
76	KATS	11137	-696.818	-763.258	96.9918	39.9931
77	KCQC	11138	-785.757	-515.724	96.9907	39.9953
78	KROW	23009	-698.822	-712.898	96.9918	39.9936
79	KSRR	72268	-789.593	-686.226	96.9907	39.9938
80	KCNM	11139	-682.79	-822.109	96.9919	39.9926
81	KALM	36870	-838.056	-752.338	96.9901	39.9932
82	KLRU	72269	-931.527	-804.112	96.9890	39.9927
83	KTCS	72271	-952.353	-695.469	96.9888	39.9937

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
84	KSVC	93063	-1042.03	-752.033	96.9877	39.9932
85	KDMN	72272	-1006.77	-799.231	96.9881	39.9928
86	KMSL	72323	854.846	-536.687	97.0101	39.9952
87	KPOF	72330	578.62	-336.733	97.0068	39.9970
88	KGTR	11140	779.065	-689.108	97.0092	39.9938
89	KTUP	93862	753.875	-600.337	97.0089	39.9946
90	KMKL	72334	727.051	-454.383	97.0086	39.9959
91	KLRF	72340	440.654	-550.661	97.0052	39.9950
92	KHKA	11141	643.365	-424.419	97.0076	39.9962
93	KHOT	72341	358.094	-604.603	97.0042	39.9945
94	KTXK	11142	278.022	-720.623	97.0033	39.9935
95	KLLQ	72342	488.655	-698.008	97.0058	39.9937
96	KMWT	72343	254.18	-599.224	97.0030	39.9946
97	KFSM	13964	237.97	-512.87	97.0028	39.9954
98	KSLG	72344	224.881	-419.064	97.0027	39.9962
99	KVBT	11143	248.074	-399.892	97.0029	39.9964
100	KHRO	11144	343.525	-405.601	97.0041	39.9963
101	KFLP	11145	404.239	-399.142	97.0048	39.9964
102	KBVX	11146	480.712	-457.853	97.0057	39.9959
103	KROG	11147	258.44	-397.685	97.0031	39.9964
104	KSPS	13966	-138.053	-664.886	96.9984	39.9940
105	KHBR	72352	-186.121	-551.123	96.9978	39.9950
106	KCSM	11148	-198.844	-513.911	96.9977	39.9954
107	KFDR	11149	-181.653	-625.205	96.9979	39.9944
108	KGOK	72353	-35.905	-458.97	96.9996	39.9959
109	KTIK	72354	-34.581	-506.938	96.9996	39.9954
110	KPWA	11150	-58.596	-493.951	96.9993	39.9955
111	KSWO	11151	-7.42	-425.828	96.9999	39.9962
112	KMKO	72355	146.972	-479.879	97.0017	39.9957
113	KRVS	72356	91.059	-438.276	97.0011	39.9960
114	KBVO	11152	87.136	-357.069	97.0010	39.9968
115	KMLC	11153	110.647	-563.566	97.0013	39.9949
116	KOUN	72357	-40.731	-527.298	96.9995	39.9952
117	KLAW	11154	-129.405	-600.222	96.9985	39.9946
118	KCDS	72360	-300.297	-610.668	96.9965	39.9945
119	KGNT	72362	-985.117	-475.563	96.9884	39.9957
120	KGUP	11155	-1059.48	-427.151	96.9875	39.9961
121	KAMA	23047	-425.319	-518.171	96.9950	39.9953
122	KBGD	72363	-395.603	-466.083	96.9953	39.9958
123	KFMN	72365	-993.449	-297.944	96.9883	39.9973
124	KSKX	72366	-770.464	-355.855	96.9909	39.9968
125	KTCC	23048	-597.271	-511.241	96.9930	39.9954
126	KLVS	23054	-732.565	-448.329	96.9914	39.9960
127	KEHR	72423	812.573	-199.695	97.0096	39.9982
128	KEVV	93817	822.929	-172.715	97.0097	39.9984

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
129	KMVN	72433	704.666	-154.54	97.0083	39.9986
130	KMDH	11156	676.745	-218.041	97.0080	39.9980
131	KBLV	11157	617.659	-136.018	97.0073	39.9988
132	KSUS	3966	547.898	-130.122	97.0065	39.9988
133	KPAH	3816	725.985	-293.319	97.0086	39.9974
134	KJEF	72445	419.01	-145.496	97.0050	39.9987
135	KAIZ	11158	387.096	-200.609	97.0046	39.9982
136	KIXD	72447	182.322	-126.913	97.0022	39.9989
137	KWLD	72450	0	-298.57	97.0000	39.9973
138	KAAO	11159	-18.976	-248.773	96.9998	39.9978
139	KIAB	11160	-23.392	-263.471	96.9997	39.9976
140	KEWK	11161	-24.645	-215.58	96.9997	39.9981
141	KGBD	72451	-161.892	-180.781	96.9981	39.9984
142	KHYS	11162	-195.191	-124.723	96.9977	39.9989
143	KCFV	11163	126.442	-319.698	97.0015	39.9971
144	KFOE	72456	114.618	-115.26	97.0014	39.9990
145	KEHA	72460	-432.761	-320.089	96.9949	39.9971
146	KALS	72462	-777.592	-245.892	96.9908	39.9978
147	KDRO	11164	-945.713	-259.163	96.9888	39.9977
148	KLHX	72463	-568.426	-195.178	96.9933	39.9982
149	KSPD	2128	-494.076	-285.176	96.9942	39.9974
150	KCOS	93037	-664.022	-102.596	96.9922	39.9991
151	KGUC	72467	-857.452	-115.301	96.9899	39.9990
152	KMTJ	93013	-940.981	-109.358	96.9889	39.9990
153	KCEZ	72476	-1020.87	-233.14	96.9880	39.9979
154	KCPS	72531	591.652	-136.14	97.0070	39.9988
155	KLWV	72534	808.939	-94.46	97.0096	39.9992
156	KPPF	74543	130.433	-293.855	97.0015	39.9973
157	KHOP	74671	841.751	-324.569	97.0099	39.9971
158	KBIX	74768	778.252	-1028.514	97.0092	39.9907
159	KPQL	11165	814.599	-1019.583	97.0096	39.9908
160	MMPG	76243	-348.007	-1248.779	96.9959	39.9887
161	MMMV	76342	-446.576	-1449.334	96.9947	39.9869
162	MMMY	76394	-316.664	-1581.176	96.9963	39.9857

TABLE A-2. LIST OF UPPER AIR METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	KABQ	23050	-869.46	-501.713	96.9897	39.9955
2	KAMA	23047	-425.319	-518.171	96.9950	39.9953
3	KBMX	53823	951.609	-702.935	97.0112	39.9936
4	KBNA	13897	920.739	-377.164	97.0109	39.9966
5	KBRO	12919	-44.167	-1571.39	96.9995	39.9858
6	KCRP	12924	-51.535	-1360.35	96.9994	39.9877
7	KDDC	13985	-259.352	-242.681	96.9969	39.9978
8	KDRT	22010	-384.069	-1170.59	96.9955	39.9894
9	KEPZ	3020	-914.558	-852.552	96.9892	39.9923
10	KFWD	3990	-28.034	-793.745	96.9997	39.9928
11	KJAN	3940	650.105	-826.452	97.0077	39.9925
12	KLCH	3937	364.461	-1089.15	97.0043	39.9902
13	KLZK	3952	432.063	-560.441	97.0051	39.9949
14	KMAF	23023	-489.668	-878.107	96.9942	39.9921
15	KOUN	3948	-40.731	-527.298	96.9995	39.9952
16	KSHV	13957	298.869	-831.166	97.0035	39.9925
17	KSIL	53813	698.079	-1054.03	97.0082	39.9905

TABLE A-3. LIST OF PRECIPITATION METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	ADDI	10063	906.825	-601.428	97.0107	39.9946
2	ALBE	10140	917.606	-821.64	97.0108	39.9926
3	BERR	10748	892.454	-683.388	97.0105	39.9938
4	HALE	13620	881.928	-601.878	97.0104	39.9946
5	HAMT	13645	863.663	-612.725	97.0102	39.9945
6	JACK	14193	898.014	-915.623	97.0106	39.9917
7	MBLE	15478	851.953	-1022.41	97.0101	39.9908
8	MUSC	15749	880.113	-567.484	97.0104	39.9949
9	PETE	16370	935.558	-908.259	97.0110	39.9918
10	THOM	18178	900.858	-915.326	97.0106	39.9917
11	TUSC	18385	895.631	-713.223	97.0106	39.9936
12	VERN	18517	825.585	-685.773	97.0098	39.9938
13	BEEB	30530	462.394	-532.485	97.0055	39.9952
14	BRIG	30900	318.015	-554.857	97.0038	39.9950
15	CALI	31140	419.619	-731.44	97.0050	39.9934
16	CAMD	31152	386.546	-699.659	97.0046	39.9937
17	DIER	32020	268.114	-643.184	97.0032	39.9942
18	EURE	32356	286.738	-390.862	97.0034	39.9965
19	GILB	32794	383.362	-435.625	97.0045	39.9961
20	GREE	32978	450.594	-483.201	97.0053	39.9956
21	STUT	36920	509.943	-596.328	97.0060	39.9946
22	TEXA	37048	278.022	-720.623	97.0033	39.9935
23	ALAM	50130	-749.044	-267.856	96.9912	39.9976
24	ARAP	50304	-441.903	-152.324	96.9948	39.9986
25	COCH	51713	-819.794	-148.582	96.9903	39.9987
26	CRES	51959	-828.107	-119.911	96.9902	39.9989
27	GRAN	53477	-451.781	-203.82	96.9947	39.9982
28	GUNN	53662	-829.573	-141.995	96.9902	39.9987
29	HUGO	54172	-539.364	-81.948	96.9936	39.9993
30	JOHN	54388	-483.95	-201.915	96.9943	39.9982
31	KIM	54538	-544.501	-283.337	96.9936	39.9974
32	MESA	55531	-993.391	-256.696	96.9883	39.9977
33	ORDW	56136	-549.552	-55.741	96.9935	39.9995
34	OURA	56203	-904.197	-168.246	96.9893	39.9985
35	PLEA	56591	-1005.94	-229.472	96.9881	39.9979
36	PUEB	56740	-633.961	-176.872	96.9925	39.9984
37	TYE	57320	-662.095	-242.254	96.9922	39.9978
38	SAGU	57337	-790.269	-176.061	96.9907	39.9984

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
39	SANL	57428	-726.777	-285.47	96.9914	39.9974
40	SHEP	57572	-714.046	-252.189	96.9916	39.9977
41	TELL	58204	-920.205	-215.382	96.9891	39.9981
42	TERC	58220	-708.229	-296.023	96.9916	39.9973
43	TRIN	58429	-642.489	-293.805	96.9924	39.9973
44	TRLK	58436	-646.185	-295.727	96.9924	39.9973
45	WALS	58781	-654.989	-262.821	96.9923	39.9976
46	WHIT	58997	-619.615	-250.12	96.9927	39.9977
47	ASHL	110281	684.787	-169.285	97.0081	39.9985
48	CAIR	111166	697.177	-301.436	97.0082	39.9973
49	CARM	111302	772.938	-177.782	97.0091	39.9984
50	CISN	111664	758.146	-151.446	97.0090	39.9986
51	FLOR	113109	751.801	-139.837	97.0089	39.9987
52	HARR	113879	762.044	-246.62	97.0090	39.9978
53	KASK	114629	650.464	-239.886	97.0077	39.9978
54	LAWR	114957	829.038	-128.708	97.0098	39.9988
55	MTCA	115888	827.797	-149.966	97.0098	39.9986
56	MURP	115983	682.261	-251.649	97.0081	39.9977
57	NEWT	116159	766.098	-72.902	97.0090	39.9993
58	REND	117187	731.633	-185.058	97.0086	39.9983
59	SMIT	118020	770.027	-283.638	97.0091	39.9974
60	SPAR	118147	658.275	-185.973	97.0078	39.9983
61	VAND	118781	685.449	-127.048	97.0081	39.9989
62	WEST	119193	778.655	-147.215	97.0092	39.9987
63	EVAN	122738	842.476	-172.871	97.0100	39.9984
64	NEWB	126151	855.854	-223.713	97.0101	39.9980
65	PRIN	127125	836.901	-153.449	97.0099	39.9986
66	STEN	128442	859.099	-156.613	97.0101	39.9986
67	JTML	128967	788.703	-239.572	97.0093	39.9978
68	ARLI	140326	-101.734	-271.373	96.9988	39.9976
69	BAZI	140620	-210.423	-201.758	96.9975	39.9982
70	BEAU	140637	59.762	-288.39	97.0007	39.9974
71	BONN	140957	211.236	-103.29	97.0025	39.9991
72	CALD	141233	-32.689	-330.586	96.9996	39.9970
73	CASS	141351	54.006	-217.645	97.0006	39.9980
74	CENT	141404	170.503	-206.038	97.0020	39.9981
75	CHAN	141427	150.257	-286.094	97.0018	39.9974
76	CLIN	141612	155.623	-157.682	97.0018	39.9986
77	COLL	141730	-265.465	-156.95	96.9969	39.9986
78	COLU	141740	220.541	-316.555	97.0026	39.9971

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
79	CONC	141867	58.918	-175.589	97.0007	39.9984
80	DODG	142164	-226.497	-277.655	96.9973	39.9975
81	ELKH	142432	-400.112	-321.784	96.9953	39.9971
82	ENGL	142560	-264.927	-324.066	96.9969	39.9971
83	ERIE	142582	162.669	-291.383	97.0019	39.9974
84	FALL	142686	83.491	-288.177	97.0010	39.9974
85	GALA	142938	-136.931	-176.83	96.9984	39.9984
86	GARD	142980	-304.059	-215.308	96.9964	39.9981
87	GREN	143248	64.308	-307.161	97.0008	39.9972
88	HAYS	143527	-190.307	-161.342	96.9978	39.9985
89	HEAL	143554	-292.133	-175.921	96.9966	39.9984
90	HILL	143686	214.018	-174.006	97.0025	39.9984
91	INDE	143954	139.335	-315.058	97.0016	39.9972
92	IOLA	143984	153.451	-269.438	97.0018	39.9976
93	JOHR	144104	134.784	-203.41	97.0016	39.9982
94	KANO	144178	-50.289	-181.177	96.9994	39.9984
95	KIOW	144341	-113.967	-329.843	96.9987	39.9970
96	MARI	145039	-4.343	-195.712	97.0000	39.9982
97	MELV	145210	137.104	-186.781	97.0016	39.9983
98	MILF	145306	39.504	-106.05	97.0005	39.9990
99	MOUD	145536	152.624	-318.136	97.0018	39.9971
100	OAKL	145888	-306.378	-96.814	96.9964	39.9991
101	OTTA	146128	158.639	-178.635	97.0019	39.9984
102	POMO	146498	143.864	-176.707	97.0017	39.9984
103	SALI	147160	-29.426	-166.908	96.9997	39.9985
104	SMOL	147551	-34.639	-171.31	96.9996	39.9985
105	STAN	147756	225.026	-164.85	97.0027	39.9985
106	SUBL	147922	-303.514	-292.808	96.9964	39.9974
107	TOPE	148167	139.116	-104.91	97.0016	39.9991
108	TRIB	148235	-387.855	-180.643	96.9954	39.9984
109	UNIO	148293	211.43	-272.537	97.0025	39.9975
110	WALL	148535	-376.076	-152.432	96.9956	39.9986
111	WICH	148830	-23.729	-288.579	96.9997	39.9974
112	WILS	148946	-111.502	-156.22	96.9987	39.9986
113	BENT	150611	781.608	-348.109	97.0092	39.9969
114	CALH	151227	865.268	-261.635	97.0102	39.9976
115	CLTN	151631	749.287	-365.634	97.0088	39.9967
116	HERN	153798	859.01	-352.458	97.0101	39.9968
117	MADI	155067	854.116	-265.064	97.0101	39.9976
118	PADU	156110	753.185	-293.024	97.0089	39.9974

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
119	PCTN	156580	834.464	-280.496	97.0099	39.9975
120	ALEX	160103	433.824	-959.253	97.0051	39.9913
121	BATN	160549	562.794	-1032.4	97.0066	39.9907
122	CALH	161411	436.113	-817.451	97.0052	39.9926
123	CLNT	161899	578.969	-999.986	97.0068	39.9910
124	JENA	164696	455.225	-912.366	97.0054	39.9918
125	LACM	165078	364.784	-1089.92	97.0043	39.9901
126	MIND	166244	346.708	-812.651	97.0041	39.9927
127	MONR	166314	463.225	-814.905	97.0055	39.9926
128	NATC	166582	369.451	-905.316	97.0044	39.9918
129	SHRE	168440	299.526	-831.143	97.0035	39.9925
130	WINN	169803	408.309	-884.596	97.0048	39.9920
131	BROK	221094	621.827	-914.236	97.0073	39.9917
132	CONE	221900	737.007	-823.513	97.0087	39.9926
133	JAKS	224472	650.361	-826.097	97.0077	39.9925
134	LEAK	224966	805.886	-943.78	97.0095	39.9915
135	MERI	225776	774.942	-814.558	97.0092	39.9926
136	SARD	227815	658.33	-593.661	97.0078	39.9946
137	SAUC	227840	763.399	-1005.93	97.0090	39.9909
138	TUPE	229003	753.571	-600.03	97.0089	39.9946
139	ADVA	230022	657.892	-298.102	97.0078	39.9973
140	ALEY	230088	505.348	-305.864	97.0060	39.9972
141	BOLI	230789	331.651	-291.689	97.0039	39.9974
142	CASV	231383	310.855	-392.187	97.0037	39.9965
143	CLER	231674	575.868	-302.209	97.0068	39.9973
144	CLTT	231711	307.465	-190.83	97.0036	39.9983
145	COLU	231791	421.287	-155.672	97.0050	39.9986
146	DREX	232331	228.23	-185.776	97.0027	39.9983
147	ELM	232568	257.758	-159.419	97.0030	39.9986
148	FULT	233079	470.408	-150.668	97.0056	39.9986
149	HOME	233999	619.93	-415.469	97.0073	39.9962
150	JEFF	234271	424.774	-172.095	97.0050	39.9984
151	JOPL	234315	238.245	-318.262	97.0028	39.9971
152	LEBA	234825	402.239	-276.263	97.0048	39.9975
153	LICK	234919	480.849	-280.775	97.0057	39.9975
154	LOCK	235027	302.048	-300.612	97.0036	39.9973
155	MALD	235207	659.982	-377.876	97.0078	39.9966
156	MARS	235298	332.062	-94.655	97.0039	39.9991
157	MAFD	235307	391.968	-300.033	97.0046	39.9973
158	MCES	235415	471.737	-143.942	97.0056	39.9987

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
159	MILL	235594	309.516	-311.398	97.0037	39.9972
160	MTGV	235834	426.937	-310.43	97.0050	39.9972
161	NVAD	235987	243.915	-272.715	97.0029	39.9975
162	OZRK	236460	349.133	-390.626	97.0041	39.9965
163	PDTD	236777	334.055	-265.018	97.0039	39.9976
164	POTO	236826	572.215	-251.455	97.0068	39.9977
165	ROLL	237263	484.503	-253.958	97.0057	39.9977
166	ROSE	237300	500.59	-175.393	97.0059	39.9984
167	SALE	237506	498.94	-274.122	97.0059	39.9975
168	SENE	237656	233.959	-383.703	97.0028	39.9965
169	SPRC	237967	238.112	-373.616	97.0028	39.9966
170	SPVL	237976	332.385	-309.374	97.0039	39.9972
171	STEE	238043	503.354	-205.135	97.0059	39.9981
172	STOK	238082	310.911	-279.239	97.0037	39.9975
173	SWSP	238223	324.053	-150.325	97.0038	39.9986
174	TRKD	238252	340.418	-395.428	97.0040	39.9964
175	TRUM	238466	326.883	-197.796	97.0039	39.9982
176	UNIT	238524	238.567	-154.494	97.0028	39.9986
177	VIBU	238609	519.633	-267.258	97.0061	39.9976
178	VIEN	238620	470.383	-193.872	97.0056	39.9983
179	WAPP	238700	606.68	-358.746	97.0072	39.9968
180	WASG	238746	556.425	-164.993	97.0066	39.9985
181	WEST	238880	489.373	-377.809	97.0058	39.9966
182	ALBU	290234	-869.46	-501.713	96.9897	39.9955
183	ARTE	290600	-689.529	-773.897	96.9919	39.9930
184	AUGU	290640	-973.07	-598.391	96.9885	39.9946
185	CARL	291469	-680.335	-811.474	96.9920	39.9927
186	CARR	291515	-819.836	-665.132	96.9903	39.9940
187	CLAY	291887	-547.124	-374.102	96.9935	39.9966
188	CLOV	291939	-566.973	-599.296	96.9933	39.9946
189	CUBA	292241	-890.304	-392.495	96.9895	39.9965
190	CUBE	292250	-951.142	-489.293	96.9888	39.9956
191	DEMI	292436	-1007.99	-799.087	96.9881	39.9928
192	DURA	292665	-767.148	-577.618	96.9909	39.9948
193	EANT	292700	-735.089	-366.94	96.9913	39.9967
194	LAVG	294862	-738.245	-461.163	96.9913	39.9958
195	PROG	297094	-811.39	-578.971	96.9904	39.9948
196	RAMO	297254	-733.737	-615.175	96.9913	39.9944
197	ROSW	297610	-698.544	-712.921	96.9918	39.9936
198	ROY	297638	-644.735	-422.422	96.9924	39.9962

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
199	SANT	298085	-807.375	-445.708	96.9905	39.9960
200	SPRI	298501	-676.681	-374.272	96.9920	39.9966
201	STAY	298518	-810.491	-495.501	96.9904	39.9955
202	TNMN	299031	-912.488	-413.425	96.9892	39.9963
203	TUCU	299156	-604.359	-508.834	96.9929	39.9954
204	WAST	299569	-638.605	-820.288	96.9925	39.9926
205	WISD	299686	-856.967	-756.366	96.9899	39.9932
206	AIRS	340179	-212.731	-597.062	96.9975	39.9946
207	ARDM	340292	-12.242	-645.633	96.9999	39.9942
208	BENG	340670	174.368	-568.011	97.0021	39.9949
209	CANE	341437	71.857	-637.935	97.0009	39.9942
210	CHRT	341544	203.233	-632.067	97.0024	39.9943
211	CHAN	341684	10.494	-475.655	97.0001	39.9957
212	CHIK	341750	-83.175	-547.26	96.9990	39.9951
213	CCTY	342334	-165	-479.536	96.9981	39.9957
214	DUNC	342654	-88.38	-610.04	96.9990	39.9945
215	ELKC	342849	-216.769	-507.879	96.9974	39.9954
216	FORT	343281	-129.964	-541.113	96.9985	39.9951
217	GEAR	343497	-118.53	-482.187	96.9986	39.9956
218	HENN	344052	-31.964	-601.206	96.9996	39.9946
219	HOBA	344202	-189.062	-547.36	96.9978	39.9951
220	KING	344865	24.538	-664.103	97.0003	39.9940
221	LKEU	344975	141.702	-520.6	97.0017	39.9953
222	LEHI	345108	71.634	-612.05	97.0009	39.9945
223	MACI	345463	-254.63	-466.154	96.9970	39.9958
224	MALL	345589	-55.127	-425.644	96.9994	39.9962
225	MAYF	345648	-258.49	-512.583	96.9970	39.9954
226	MUSK	346130	149.764	-466.905	97.0018	39.9958
227	NOWA	346485	121.551	-364.038	97.0014	39.9967
228	OKAR	346620	-88.424	-473.338	96.9990	39.9957
229	OKEM	346638	63.188	-504.958	97.0008	39.9954
230	OKLA	346661	-54.198	-510.562	96.9994	39.9954
231	PAOL	346859	-23.665	-573.142	96.9997	39.9948
232	PAWH	346935	57.704	-369.174	97.0007	39.9967
233	PAWN	346944	16.927	-398.139	97.0002	39.9964
234	PONC	347196	-8.871	-363.068	96.9999	39.9967
235	PRYO	347309	150.763	-407.824	97.0018	39.9963
236	SHAT	348101	-256.963	-407.368	96.9970	39.9963
237	STIG	348497	171.02	-523.736	97.0020	39.9953
238	TULS	348992	99.361	-419.873	97.0012	39.9962

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
239	TUSK	349023	156.629	-592.395	97.0019	39.9946
240	WMWR	349629	-156.42	-581.308	96.9982	39.9947
241	WOLF	349748	30.212	-538.388	97.0004	39.9951
242	BOLI	400876	760.886	-500.256	97.0090	39.9955
243	BROW	401150	710.048	-480.346	97.0084	39.9957
244	CETR	401587	877.35	-456.294	97.0104	39.9959
245	DICS	402489	872.14	-391.132	97.0103	39.9965
246	DYER	402680	695.792	-409.316	97.0082	39.9963
247	GRNF	403697	760.795	-395.69	97.0090	39.9964
248	JSNN	404561	765.932	-476.414	97.0090	39.9957
249	LWER	405089	885.291	-487.757	97.0105	39.9956
250	LEXI	405210	790.003	-471.897	97.0093	39.9957
251	MASO	405720	694.163	-496.166	97.0082	39.9955
252	MEMP	405954	671.8	-522.492	97.0079	39.9953
253	MWFO	405956	681.292	-516.15	97.0080	39.9953
254	MUNF	406358	678.65	-495.241	97.0080	39.9955
255	SAMB	408065	697.077	-382.536	97.0082	39.9965
256	SAVA	408108	800.788	-498.682	97.0095	39.9955
257	UNCY	409219	711.595	-384.605	97.0084	39.9965
258	ABIL	410016	-251.753	-836.027	96.9970	39.9924
259	AMAR	410211	-425.302	-517.839	96.9950	39.9953
260	AUST	410428	-67.587	-1075.97	96.9992	39.9903
261	BRWN	411136	-43.861	-1571.39	96.9995	39.9858
262	COST	411889	60.611	-1044.72	97.0007	39.9906
263	COCR	412015	-51.832	-1360.01	96.9994	39.9877
264	CROS	412131	-204.599	-868.469	96.9976	39.9922
265	DFWT	412242	-1.867	-786.341	97.0000	39.9929
266	EAST	412715	-171.024	-840.253	96.9980	39.9924
267	ELPA	412797	-886.583	-860.763	96.9895	39.9922
268	HICO	414137	-97.323	-888.181	96.9989	39.9920
269	HUST	414300	157.976	-1108.38	97.0019	39.9900
270	KRES	414880	-434.746	-611.717	96.9949	39.9945
271	LKCK	414975	99.734	-693.521	97.0012	39.9937
272	LNGV	415348	220.962	-844.674	97.0026	39.9924
273	LUFK	415424	214.652	-969.69	97.0025	39.9912
274	MATH	415661	-86.438	-1330.47	96.9990	39.9880
275	MIDR	415890	-489.385	-878.123	96.9942	39.9921
276	MTLK	416104	-672.024	-1008.98	96.9921	39.9909
277	NACO	416177	223.065	-925.966	97.0026	39.9916
278	NAVA	416210	28.358	-892.028	97.0003	39.9919

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
279	NEWB	416270	239.111	-721.818	97.0028	39.9935
280	BPAT	417174	288.962	-1110.65	97.0034	39.9900
281	RANK	417431	-472.048	-959.488	96.9944	39.9913
282	SAAG	417943	-333.338	-952.54	96.9961	39.9914
283	SAAT	417945	-143.322	-1161.27	96.9983	39.9895
284	SHEF	418252	-463.759	-1019.19	96.9945	39.9908
285	STEP	418623	-112.988	-857.918	96.9987	39.9922
286	STER	418630	-376.683	-897.195	96.9956	39.9919
287	VALE	419270	-720.749	-1015.17	96.9915	39.9908
288	VICT	419364	6.882	-1236.45	97.0001	39.9888
289	WACO	419419	-21.834	-928.823	96.9997	39.9916
290	WATR	419499	-353.767	-916.015	96.9958	39.9917
291	WHEE	419665	57.489	-1008.99	97.0007	39.9909
292	WPDM	419916	262.792	-737.786	97.0031	39.9933
293	DORA	232302	433.256	-378.797	97.0051	39.9966
294	DIXN	112353	756.057	-267.193	97.0089	39.9976
295	DAUP	12172	864.408	-1050.41	97.0102	39.9905
296	FREV	123104	847.031	-117.884	97.0100	39.9989
297	WARR	18673	890.447	-788.703	97.0105	39.9929
298	MDTN	235562	493.264	-87.222	97.0058	39.9992

TABLE A-4. LIST OF OVER WATER METEOROLOGICAL STATIONS

Number	Station ID	Input file Name	LCC East (km)	LCC North (km)	Long	Lat
1	42001	42001	746.874	-1541.35	89.67	25.9
2	42002	42002	265.486	-1650.616	94.42	25.19
3	42007	42007	795.674	-1063.667	88.77	30.09
4	42019	42019	163.178	-1342.917	95.36	27.91
5	42020	42020	30.212	-1453.738	96.7	26.94
6	42035	42035	254.465	-1193.539	94.41	29.25
7	42040	42040	859.497	-1160.066	88.21	29.18
8	BURL1	42045	743.116	-1202.117	89.43	28.9
9	DPIA1	42046	861.385	-1039.466	88.07	30.25
10	GDIL1	42047	687.984	-1164.910	89.96	29.27
11	PTAT2	42048	-4.980	-1353.398	97.05	27.83
12	SRST2	42049	288.163	-1175.682	94.05	29.67

Entergy Arkansas, Inc.
Lake Catherine - Unit 4
CEMS Data from CAMD

Date	SO2 (tons)	Avg. NOx Rate (lb/MMBtu)	NOx (tons)	Heat Input (MMBtu)
1/1/2001	0.014	0.202	4.787	46,087
1/2/2001	0.015	0.2243	5.535	48,831
1/3/2001	0.016	0.2324	6.465	54,856
1/4/2001	0.015	0.2472	6.835	51,150
1/5/2001	0.015	0.2295	5.827	48,783
1/6/2001	0.014	0.2258	5.828	48,253
1/7/2001	0.01	0.161	2.72	32,070
1/8/2001	0.013	0.1819	4.203	41,767
1/9/2001	0.014	0.207	5.35	45,700
1/10/2001	0.013	0.1957	4.699	43,529
1/11/2001	0.012	0.1942	4.459	41,573
1/12/2001	0.015	0.2103	6.049	50,330
1/13/2001	0.013	0.1802	4.325	42,266
1/14/2001	0.009	0.148	2.24	30,269
1/15/2001	0.01	0.1638	2.999	34,364
1/16/2001	0.012	0.1739	3.935	41,489
1/17/2001	0.013	0.1896	4.397	41,694
1/18/2001	0.015	0.2143	5.91	51,559
1/19/2001	0.012	0.1832	3.987	40,093
1/20/2001	0.01	0.1459	2.602	32,991
1/21/2001	0.012	0.1796	4.014	41,428
1/22/2001	0.013	0.1769	4.102	42,797
1/23/2001	0.013	0.185	4.93	42,499
1/24/2001	0.01	0.145	2.436	32,177
1/25/2001	0.011	0.1736	3.66	37,899
1/26/2001	0.013	0.1962	5.122	43,715
1/27/2001	0.009	0.1487	2.3	29,992
1/28/2001	0.008	0.1265	1.786	28,231
1/29/2001	0.012	0.1878	4.319	39,764
1/30/2001	0.01	0.1594	2.883	33,206
1/31/2001	0.01	0.1529	2.646	32,017
2/5/2001	0.006	0.086	1.466	20,118
2/6/2001	0.016	0.2086	6.165	53,744
2/7/2001	0.009	0.1866	3.213	31,084
2/18/2001	0.001	0.0188	0.038	3,928
2/19/2001	0.007	0.0982	1.368	24,718
2/20/2001	0.009	0.1274	1.913	29,778
2/21/2001	0.01	0.1512	2.869	34,778
2/22/2001	0.017	0.2335	7.695	56,681
2/23/2001	0.012	0.1743	3.807	39,905
2/24/2001	0.009	0.1102	1.623	29,044

2/25/2001	0.009	0.13	1.917	29,477
2/26/2001	0.009	0.1329	2.099	30,616
2/27/2001	0.003	0.1306	0.7	10,554
3/4/2001	0.001	0.0184	0.034	3,433
3/5/2001	0.002	0.0515	0.267	7,045
3/6/2001	0.014	0.221	6.083	48,166
3/7/2001	0.015	0.1927	5.478	48,645
3/8/2001	0.012	0.1555	3.269	38,946
3/9/2001	0.015	0.1743	4.568	50,545
3/10/2001	0.011	0.1549	2.964	35,761
3/11/2001	0.01	0.1379	2.435	33,295
3/12/2001	0.012	0.158	3.691	39,661
3/13/2001	0.012	0.1647	3.496	39,647
3/14/2001	0.009	0.1211	1.73	28,569
3/15/2001	0.01	0.141	2.735	33,742
3/16/2001	0.009	0.1279	1.961	30,403
3/17/2001	0.011	0.1602	3.19	36,852
3/18/2001	0.009	0.119	1.786	29,585
3/19/2001	0.014	0.207	5.529	47,177
3/20/2001	0.018	0.2443	8.471	59,677
3/21/2001	0.012	0.1685	3.87	39,580
3/22/2001	0.01	0.142	2.625	33,865
3/23/2001	0.012	0.1767	4.124	40,557
3/24/2001	0.012	0.1817	4.169	40,503
3/25/2001	0.011	0.1617	3.538	37,819
3/26/2001	0.021	0.2919	11.813	68,929
3/27/2001	0.018	0.2611	8.918	60,896
3/28/2001	0.02	0.2639	10.097	67,036
3/29/2001	0.014	0.1788	4.609	45,838
3/30/2001	0.016	0.2006	5.744	52,185
3/31/2001	0.011	0.159	3.131	37,184
4/1/2001	0.013	0.1752	4.115	42,033
4/2/2001	0.02	0.2338	8.676	66,851
4/3/2001	0.02	0.2369	8.8	66,241
4/4/2001	0.017	0.2038	6.068	55,481
4/5/2001	0.018	0.2004	6.511	60,051
4/6/2001	0.016	0.1907	5.821	52,912
4/7/2001	0.018	0.2262	7.664	59,423
4/8/2001	0.018	0.2364	8.721	58,721
4/9/2001	0.023	0.2954	12.863	76,082
4/10/2001	0.019	0.2176	7.726	64,086
4/11/2001	0.018	0.2098	6.773	58,358
4/12/2001	0.016	0.2128	6.479	54,940
4/13/2001	0.013	0.1945	4.508	42,639

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4/14/2001	0.013	0.1562	3.497	42,801
4/15/2001	0.012	0.1644	3.577	40,030
4/16/2001	0.018	0.251	9.291	61,371
4/17/2001	0.014	0.167	4.133	45,200
4/18/2001	0.016	0.2087	6.585	52,319
4/19/2001	0.016	0.1903	5.171	51,766
4/20/2001	0.015	0.1854	4.984	49,224
4/21/2001	0.018	0.217	7.923	60,062
4/22/2001	0.014	0.1674	4.429	45,026
4/23/2001	0.022	0.3043	13.43	74,361
4/24/2001	0.016	0.2062	5.866	52,154
4/25/2001	0.011	0.1527	3.108	37,695
4/26/2001	0.017	0.2286	7.555	56,092
4/27/2001	0.016	0.2169	7.077	51,677
4/28/2001	0.015	0.1953	5.461	48,962
4/29/2001	0.014	0.1772	4.859	47,124
4/30/2001	0.017	0.2	6.797	56,452
5/1/2001	0.023	0.3154	14.69	78,193
5/2/2001	0.022	0.2717	11.62	71,844
5/3/2001	0.018	0.2036	7.091	61,269
5/4/2001	0.016	0.2144	7.245	54,351
5/6/2001	0.002	0.0339	0.123	5,083
5/7/2001	0.015	0.1868	5.25	50,120
5/8/2001	0.011	0.1553	3.234	37,663
5/9/2001	0.017	0.2099	7.313	57,056
5/10/2001	0.021	0.2753	11.622	69,100
5/11/2001	0.015	0.2005	5.819	51,008
5/12/2001	0.014	0.1828	4.776	45,391
5/13/2001	0.012	0.189	4.196	39,970
5/14/2001	0.015	0.1792	5.128	50,519
5/15/2001	0.02	0.2335	9.346	65,047
5/16/2001	0.019	0.2378	9.333	63,118
5/17/2001	0.02	0.2367	8.716	66,585
5/18/2001	0.016	0.184	5.893	52,147
5/19/2001	0.014	0.167	4.463	45,811
5/20/2001	0.013	0.1558	3.867	44,248
5/21/2001	0.011	0.1592	3.108	37,242
5/22/2001	0.008	0.153	2.12	27,721
5/23/2001	0.012	0.1763	3.876	39,538
5/24/2001	0.01	0.1579	3.086	34,319
5/25/2001	0.009	0.1198	1.699	28,368
5/26/2001	0.013	0.1813	4.857	43,433
5/27/2001	0.013	0.1806	4.355	42,547
5/28/2001	0.011	0.1718	3.231	35,115

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5/29/2001	0.013	0.1931	5.097	43,171
5/30/2001	0.012	0.1745	3.803	40,685
5/31/2001	0.01	0.1417	2.62	33,567
6/1/2001	0.012	0.1624	3.551	39,572
6/2/2001	0.015	0.1946	5.796	49,384
6/3/2001	0.013	0.1658	4.242	44,794
6/4/2001	0.015	0.1862	5.395	50,776
6/5/2001	0.014	0.1903	5.198	46,681
6/6/2001	0.01	0.1415	2.706	34,818
6/7/2001	0.01	0.147	2.676	34,163
6/8/2001	0.013	0.1805	4.463	44,347
6/9/2001	0.01	0.1477	2.744	33,898
6/10/2001	0.012	0.1572	3.357	38,638
6/11/2001	0.017	0.2095	7.511	57,735
6/12/2001	0.019	0.2257	8.151	62,453
6/13/2001	0.019	0.2262	8.396	63,287
6/14/2001	0.019	0.218	7.851	62,402
6/15/2001	0.017	0.2161	7.572	57,158
6/16/2001	0.017	0.2303	7.86	57,767
6/17/2001	0.015	0.1928	5.518	50,985
6/18/2001	0.011	0.154	3.944	37,549
6/19/2001	0.003	0.0882	0.39	8,841
7/4/2001	0	0.012	0.002	340
7/5/2001	0.007	0.0781	1.602	24,168
7/6/2001	0.017	0.2128	7.052	56,775
7/7/2001	0.018	0.2179	7.562	60,597
7/8/2001	0.012	0.1569	3.968	39,226
7/9/2001	0.006	0.0961	1.025	21,338
7/10/2001	0.012	0.1546	4.264	41,608
7/11/2001	0.019	0.2223	8.412	63,578
7/12/2001	0.013	0.1621	4.021	43,458
7/13/2001	0.011	0.157	3.255	37,270
7/14/2001	0.013	0.1955	4.735	42,380
7/15/2001	0.013	0.1699	4.156	41,999
7/16/2001	0.019	0.2452	9.083	61,972
7/17/2001	0.019	0.2417	9.109	64,826
7/18/2001	0.016	0.2237	8.871	53,151
7/19/2001	0.007	0.1258	2.653	23,336
7/20/2001	0.019	0.249	9.25	64,264
7/21/2001	0.02	0.2328	8.491	65,463
7/22/2001	0.02	0.2443	9.321	68,224
7/23/2001	0.02	0.224	8.157	65,909
7/24/2001	0.02	0.2445	9.159	67,299
7/25/2001	0.019	0.2355	8.694	64,989

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7/26/2001	0.013	0.1794	4.211	43,236
7/27/2001	0.013	0.1774	4.508	44,375
7/28/2001	0.019	0.2528	10.205	63,064
7/29/2001	0.019	0.2475	9.877	63,148
7/30/2001	0.022	0.2758	12.376	71,671
7/31/2001	0.022	0.2781	12.547	72,866
8/1/2001	0.019	0.2373	9.073	62,425
8/2/2001	0.021	0.2795	12.222	69,430
8/4/2001	0.016	0.1885	7.963	54,373
8/5/2001	0.021	0.2535	11.118	69,392
8/6/2001	0.025	0.2972	15.248	84,978
8/7/2001	0.025	0.2612	12.576	82,822
8/8/2001	0.025	0.3036	14.997	82,983
8/9/2001	0.025	0.3064	14.974	82,680
8/10/2001	0.019	0.2215	8.202	63,423
8/12/2001	0.013	0.1633	5.452	44,824
8/13/2001	0.006	0.1483	1.688	19,487
8/14/2001	0.002	0.0623	0.246	5,337
8/15/2001	0.008	0.1385	2.604	25,423
8/16/2001	0.018	0.2429	8.743	60,910
8/17/2001	0.018	0.2434	9.046	60,599
8/18/2001	0.015	0.1771	4.996	50,262
8/19/2001	0.014	0.1915	5.261	48,081
8/20/2001	0.018	0.2217	8.411	61,514
8/21/2001	0.021	0.2575	11.024	69,191
8/22/2001	0.017	0.2267	7.102	55,132
8/23/2001	0.016	0.1806	5.129	51,909
8/24/2001	0.022	0.2213	8.506	72,974
8/25/2001	0.022	0.2256	8.811	72,126
8/26/2001	0.02	0.2177	7.642	65,753
8/27/2001	0.02	0.2303	7.848	66,030
8/28/2001	0.021	0.2293	8.581	70,504
8/29/2001	0.021	0.2264	8.509	71,148
8/30/2001	0.022	0.2056	7.903	72,119
8/31/2001	0.015	0.1776	4.423	48,572
9/4/2001	0.017	0.1992	8.364	57,635
9/5/2001	0.02	0.2337	9.682	65,332
9/6/2001	0.024	0.2887	13.929	80,508
9/7/2001	0.026	0.3046	15.043	87,673
9/8/2001	0.019	0.2353	8.989	64,371
9/9/2001	0.012	0.1626	3.702	40,954
9/10/2001	0.019	0.2765	11.064	64,465
9/11/2001	0.015	0.2078	5.686	49,648
9/12/2001	0.02	0.2698	11.86	67,987

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9/13/2001	0.023	0.287	13.566	75,247
9/14/2001	0.015	0.2122	6.49	50,987
9/15/2001	0.012	0.1745	4.057	41,586
9/16/2001	0.01	0.1532	2.834	34,143
9/17/2001	0.018	0.2053	7.027	59,845
9/18/2001	0.017	0.1845	5.837	55,340
9/19/2001	0.02	0.29	12.096	67,446
9/20/2001	0.014	0.1873	5.165	48,024
9/21/2001	0.015	0.1985	5.829	50,294
9/22/2001	0.017	0.2183	7.653	56,805
9/23/2001	0.009	0.1337	2.095	30,464
9/24/2001	0.011	0.153	3.113	36,686
9/25/2001	0.009	0.1394	2.293	31,182
9/26/2001	0.009	0.1375	2.009	29,212
9/27/2001	0.013	0.1991	4.898	43,804
9/28/2001	0.011	0.1601	3.348	38,249
9/29/2001	0.009	0.1273	1.879	29,507
9/30/2001	0.009	0.1299	1.915	29,494
10/1/2001	0.016	0.2279	7.078	54,478
10/2/2001	0.02	0.2719	10.453	67,704
10/3/2001	0.021	0.2808	11.517	70,491
10/4/2001	0.018	0.217	7.058	59,238
10/5/2001	0.017	0.2193	6.911	58,101
10/6/2001	0.011	0.1701	3.541	37,099
10/7/2001	0.012	0.173	4.088	40,906
10/8/2001	0.018	0.2333	7.922	60,878
10/9/2001	0.021	0.2618	10.653	71,124
10/10/2001	0.025	0.3041	14.046	84,843
10/11/2001	0.022	0.2695	10.787	72,705
10/12/2001	0.014	0.1858	4.721	46,018
10/13/2001	0.009	0.1202	1.806	30,005
10/14/2001	0.009	0.1397	2.083	29,826
10/15/2001	0.014	0.1868	4.97	46,963
10/16/2001	0.015	0.1948	5.346	50,101
10/17/2001	0.014	0.1865	5.001	46,094
10/18/2001	0.015	0.2042	5.707	49,980
10/19/2001	0.016	0.1879	5.568	54,454
10/20/2001	0.011	0.1695	3.665	38,306
10/21/2001	0.014	0.2021	5.378	46,550
10/22/2001	0.017	0.2118	7.204	57,917
10/23/2001	0.019	0.2224	8.303	64,766
10/24/2001	0.02	0.2506	9.924	68,044
10/25/2001	0.014	0.1916	4.787	46,344
10/26/2001	0.012	0.1569	3.256	39,305

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10/27/2001	0.014	0.1796	4.434	45,299
10/28/2001	0.012	0.1632	3.641	40,671
10/29/2001	0.019	0.2607	9.652	64,118
10/30/2001	0.012	0.1614	3.716	41,285
10/31/2001	0.007	0.1413	1.716	22,574
11/2/2001	0.001	0.005	0.006	2,211
11/3/2001	0.012	0.1404	3.282	38,466
11/4/2001	0.009	0.1343	2.105	30,533
11/5/2001	0.017	0.2186	6.839	55,453
11/6/2001	0.019	0.2791	9.677	62,493
11/7/2001	0.022	0.3063	13.163	74,177
11/8/2001	0.016	0.226	6.573	53,905
11/9/2001	0.017	0.2095	6.302	56,263
11/10/2001	0.011	0.1513	2.83	35,031
11/11/2001	0.009	0.1295	1.881	29,044
11/12/2001	0.023	0.3233	14.175	76,017
11/13/2001	0.018	0.2403	8.093	59,969
11/14/2001	0.022	0.32	13.545	73,986
11/15/2001	0.019	0.2603	9.307	64,252
11/16/2001	0.02	0.2591	9.545	66,804
11/17/2001	0.015	0.2233	6.084	49,215
11/18/2001	0.01	0.1308	2.387	33,118
11/19/2001	0.015	0.1822	4.938	50,936
11/20/2001	0.014	0.181	4.702	46,801
11/21/2001	0.013	0.1629	3.929	42,621
11/28/2001	0.002	0.0235	0.15	7,641
11/29/2001	0.014	0.1843	4.9	47,614
11/30/2001	0.013	0.154	3.552	42,054
12/1/2001	0.013	0.1705	3.903	41,932
12/2/2001	0.011	0.1418	2.96	36,214
12/3/2001	0.012	0.1432	3.148	40,199
12/4/2001	0.009	0.1379	2.27	31,592
12/24/2001	0.002	0.0137	0.043	6,050
12/25/2001	0.01	0.1203	2.38	34,423
12/26/2001	0.013	0.1618	4.148	43,510
12/27/2001	0.014	0.1483	3.732	45,410
12/28/2001	0.011	0.1311	2.488	35,588
12/29/2001	0.011	0.1445	3.136	37,497
12/30/2001	0.015	0.1716	4.954	48,976
12/31/2001	0.012	0.1348	2.943	39,026
1/1/2002	0.011	0.1289	2.741	37,107
1/2/2002	0.019	0.2159	7.77	62,305
1/3/2002	0.014	0.1767	4.509	47,734
1/4/2002	0.013	0.1619	3.518	42,761

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1/5/2002	0.015	0.1869	4.642	49,164
1/6/2002	0.011	0.1285	2.462	35,085
1/7/2002	0.014	0.1835	4.424	46,324
1/8/2002	0.012	0.1583	3.56	41,383
1/9/2002	0.009	0.1222	1.888	28,489
2/9/2002	0.016	0.011	0.296	52,507
2/10/2002	0.02	0.0207	0.606	66,669
2/11/2002	0.011	0.1331	2.365	36,624
2/12/2002	0.011	0.1611	3.084	36,846
2/13/2002	0.01	0.1785	3.229	34,397
2/14/2002	0.013	0.2097	4.987	43,360
2/15/2002	0.014	0.2086	5.029	45,459
2/16/2002	0.012	0.2087	4.505	41,526
2/17/2002	0.01	0.1814	2.984	31,880
2/18/2002	0.011	0.1988	3.921	37,465
2/19/2002	0.014	0.1981	4.872	45,380
2/20/2002	0.014	0.2173	5.256	45,213
2/21/2002	0.017	0.2381	6.925	55,851
2/22/2002	0.014	0.2127	5.232	46,535
2/23/2002	0.014	0.2037	4.945	46,575
2/24/2002	0.01	0.1896	3.281	32,913
2/25/2002	0.009	0.1759	2.747	30,582
2/26/2002	0.012	0.1834	3.845	41,052
2/27/2002	0.013	0.1826	3.942	42,493
2/28/2002	0.01	0.1566	2.711	34,015
3/1/2002	0.006	0.2166	2.028	18,483
3/15/2002	0.002	0.0235	0.123	7,253
3/16/2002	0.015	0.2207	5.787	49,573
3/17/2002	0.013	0.2006	4.429	42,117
3/18/2002	0.015	0.2198	5.663	49,072
3/19/2002	0.013	0.2061	4.707	42,893
3/20/2002	0.014	0.2145	5.842	47,868
3/21/2002	0.018	0.2544	8.371	59,345
3/22/2002	0.018	0.2707	9.128	58,545
3/23/2002	0.011	0.192	3.909	37,607
3/24/2002	0.011	0.1744	3.501	37,051
3/25/2002	0.019	0.2433	8.382	62,097
3/26/2002	0.018	0.2377	7.865	60,967
3/27/2002	0.014	0.2157	5.6	47,319
3/31/2002	0.001	0.0128	0.016	2,498
4/1/2002	0.012	0.1843	4.136	40,687
4/2/2002	0.014	0.2243	5.561	46,508
4/3/2002	0.015	0.2472	6.462	49,758
4/4/2002	0.014	0.2277	6.031	48,076

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4/5/2002	0.012	0.2001	4.283	40,215
4/6/2002	0.011	0.191	3.747	37,023
4/7/2002	0.011	0.1853	3.678	36,988
4/8/2002	0.009	0.1468	2.22	30,245
4/9/2002	0.01	0.172	2.907	32,815
4/10/2002	0.013	0.2167	4.962	43,831
4/11/2002	0.016	0.2274	6.512	54,319
4/12/2002	0.016	0.2247	6.09	51,709
4/13/2002	0.017	0.2069	6.17	55,381
4/14/2002	0.013	0.1926	4.747	44,077
4/15/2002	0.018	0.2423	7.569	59,682
4/16/2002	0.019	0.2365	7.739	63,103
4/17/2002	0.02	0.2336	8.481	67,506
4/18/2002	0.018	0.224	7.316	61,168
4/19/2002	0.02	0.2517	8.836	65,022
5/2/2002	0.001	0.0148	0.017	2,211
5/3/2002	0.007	0.0993	1.714	24,898
5/4/2002	0.012	0.1863	3.914	40,781
5/5/2002	0.011	0.1728	3.337	37,451
5/6/2002	0.018	0.2097	6.908	59,594
5/7/2002	0.019	0.2303	8.425	64,152
5/8/2002	0.023	0.2361	9.35	75,224
5/9/2002	0.016	0.2122	5.898	52,439
5/10/2002	0.013	0.1986	4.614	44,164
5/11/2002	0.014	0.1765	4.683	47,444
5/12/2002	0.017	0.191	5.519	55,482
5/13/2002	0.009	0.1702	2.581	30,206
5/14/2002	0.009	0.161	2.348	29,134
5/15/2002	0.011	0.173	3.44	37,392
5/16/2002	0.021	0.2479	9.731	69,029
5/17/2002	0.012	0.2209	5.043	41,299
5/18/2002	0.01	0.188	3.206	33,448
5/19/2002	0.009	0.1645	2.379	28,929
5/20/2002	0.004	0.1594	1.021	12,647
6/1/2002	0.002	0.0113	0.034	5,847
6/2/2002	0.019	0.2273	9.398	63,706
6/3/2002	0.024	0.2836	13.792	81,176
6/4/2002	0.022	0.2306	9.943	73,180
6/5/2002	0.018	0.2241	7.916	61,459
6/6/2002	0.015	0.1971	5.382	48,636
6/7/2002	0.013	0.1934	4.553	43,848
6/8/2002	0.015	0.186	4.854	49,505
6/9/2002	0.013	0.1597	3.658	44,556
6/10/2002	0.017	0.1751	5.207	55,339

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6/11/2002	0.016	0.1805	5.309	53,865
6/12/2002	0.017	0.1882	5.673	55,975
6/13/2002	0.017	0.1988	6.108	56,375
6/14/2002	0.011	0.1794	3.37	36,087
6/15/2002	0.013	0.1893	4.432	44,130
6/16/2002	0.011	0.169	3.104	35,720
6/17/2002	0.014	0.2101	5.291	47,773
6/18/2002	0.014	0.2049	5.253	47,076
6/19/2002	0.016	0.1944	5.498	52,049
6/20/2002	0.016	0.1911	5.7	54,348
6/21/2002	0.016	0.1905	5.506	53,336
6/22/2002	0.016	0.1816	5.251	54,099
6/23/2002	0.018	0.2016	6.77	59,249
6/24/2002	0.022	0.2445	10.128	72,397
6/25/2002	0.022	0.2426	10.262	72,043
6/26/2002	0.018	0.1814	5.963	60,244
6/27/2002	0.015	0.1849	4.94	50,555
6/28/2002	0.015	0.1851	5.1	51,646
6/29/2002	0.021	0.2412	9.898	69,078
6/30/2002	0.021	0.2355	9.247	68,381
7/1/2002	0.019	0.2164	7.691	64,385
7/2/2002	0.018	0.197	6.338	59,640
7/3/2002	0.017	0.1985	6.01	55,029
7/4/2002	0.019	0.2203	7.709	62,456
7/5/2002	0.021	0.2533	10.409	70,091
7/6/2002	0.021	0.2369	9.529	69,859
7/7/2002	0.02	0.2567	10.354	68,153
7/8/2002	0.024	0.2977	13.867	78,883
7/9/2002	0.022	0.2421	10.008	73,374
7/10/2002	0.019	0.2155	7.915	64,969
7/11/2002	0.006	0.1143	1.23	18,875
7/12/2002	0.013	0.168	3.94	43,917
7/13/2002	0.013	0.1685	3.834	43,460
7/14/2002	0.013	0.1713	3.981	42,789
7/15/2002	0.018	0.2131	7.348	59,142
7/16/2002	0.016	0.1863	5.406	53,142
7/17/2002	0.015	0.1769	4.941	51,354
7/18/2002	0.013	0.1603	3.517	42,566
7/19/2002	0.015	0.1703	4.591	50,001
7/20/2002	0.019	0.2103	7.674	63,309
7/21/2002	0.02	0.211	8.165	66,038
7/22/2002	0.018	0.1994	6.706	59,449
7/23/2002	0.017	0.1995	6.439	56,379
7/24/2002	0.014	0.1683	4.345	47,462

7/25/2002	0.018	0.2057	7.026	59,366
7/26/2002	0.019	0.2195	7.913	61,670
7/27/2002	0.02	0.2344	9.085	65,785
7/28/2002	0.02	0.2329	9.219	66,319
7/29/2002	0.018	0.2211	7.091	60,135
7/30/2002	0.019	0.1987	7.016	62,413
7/31/2002	0.02	0.2116	8.065	67,140
8/1/2002	0.02	0.2348	9.19	67,723
8/2/2002	0.02	0.2204	8.544	65,919
8/3/2002	0.021	0.233	9.727	71,119
8/4/2002	0.022	0.2389	10.048	72,709
8/5/2002	0.023	0.2528	11.034	76,430
8/6/2002	0.022	0.2487	10.381	72,419
8/7/2002	0.02	0.2277	8.971	66,020
8/8/2002	0.016	0.1953	5.712	54,134
8/9/2002	0.02	0.2207	8.389	66,924
8/10/2002	0.019	0.2229	8.173	63,200
8/11/2002	0.019	0.2428	9.007	64,645
8/12/2002	0.019	0.2223	8.197	63,315
8/13/2002	0.015	0.177	4.992	51,591
8/14/2002	0.013	0.1615	3.639	44,028
8/15/2002	0.014	0.1525	3.574	45,965
8/16/2002	0.014	0.178	4.527	47,668
8/17/2002	0.02	0.2145	8.039	66,775
8/18/2002	0.021	0.2241	9.121	71,329
8/19/2002	0.022	0.2147	8.779	72,190
8/20/2002	0.019	0.2123	8	64,039
8/21/2002	0.021	0.2276	9.215	69,432
8/22/2002	0.021	0.2321	9.377	71,456
8/23/2002	0.023	0.235	9.958	75,098
8/24/2002	0.023	0.2532	10.574	78,007
8/25/2002	0.003	0.1184	0.839	9,352
8/26/2002	0.016	0.1796	6.672	54,640
8/27/2002	0.018	0.2074	7.099	59,167
8/28/2002	0.017	0.2014	7.045	57,669
8/29/2002	0.015	0.1921	5.529	51,098
8/30/2002	0.017	0.2171	7.671	57,804
8/31/2002	0.015	0.1841	5.165	51,198
9/1/2002	0.014	0.1783	4.742	48,187
9/2/2002	0.02	0.2379	9.75	67,051
9/3/2002	0.022	0.2633	11.663	74,026
9/4/2002	0.022	0.2336	10.178	73,496
9/5/2002	0.021	0.2239	9.081	69,350
9/6/2002	0.019	0.2164	8.132	63,607

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9/7/2002	0	0.142	0.077	1,086
9/8/2002	0.002	0.0866	0.477	7,847
9/9/2002	0.02	0.2438	9.69	68,073
9/10/2002	0.022	0.2685	12.292	74,588
9/11/2002	0.02	0.2608	10.642	66,892
9/12/2002	0.017	0.227	7.805	55,975
9/13/2002	0.016	0.2185	6.919	54,441
9/14/2002	0.017	0.201	6.647	58,026
9/15/2002	0.015	0.1733	4.41	48,560
9/16/2002	0.015	0.1741	4.554	49,299
9/17/2002	0.014	0.1813	4.473	46,893
9/18/2002	0.019	0.2025	7.282	62,050
9/19/2002	0.015	0.1645	4.117	48,986
9/20/2002	0.016	0.1949	5.813	54,811
9/21/2002	0.017	0.2213	7.779	57,523
9/22/2002	0.015	0.1887	4.946	48,475
9/23/2002	0.017	0.2053	6.094	57,656
9/24/2002	0.009	0.1612	2.532	31,042
9/25/2002	0.009	0.1522	2.184	28,696
9/26/2002	0.009	0.1447	2.192	30,380
9/27/2002	0.016	0.1781	5.067	53,614
9/28/2002	0.02	0.2236	9.112	65,596
9/29/2002	0.018	0.2112	7.366	58,893
9/30/2002	0.024	0.2666	12.481	79,285
10/1/2002	0.02	0.22	8.269	65,225
10/2/2002	0.017	0.1763	5.171	55,756
10/3/2002	0.01	0.148	2.42	32,066
10/4/2002	0.024	0.2682	12.474	81,557
10/5/2002	0.02	0.2543	9.726	68,123
10/6/2002	0.021	0.2488	10.73	70,725
10/7/2002	0.017	0.2079	6.327	55,178
10/8/2002	0.009	0.1534	2.324	30,329
10/9/2002	0.011	0.1682	3.296	37,760
10/10/2002	0.011	0.1739	3.359	37,865
10/11/2002	0.013	0.1826	3.949	42,777
10/12/2002	0.016	0.1726	4.821	52,701
10/13/2002	0.012	0.1787	3.52	38,416
10/14/2002	0.014	0.1891	4.577	45,296
10/15/2002	0.011	0.1567	2.851	35,609
10/16/2002	0.012	0.1799	3.735	39,422
10/17/2002	0.009	0.1603	2.453	28,618
10/20/2002	0.002	0.0122	0.036	5,771
10/21/2002	0.018	0.2094	7.817	62,036
10/22/2002	0.02	0.2096	7.478	65,071

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10/23/2002	0.013	0.1826	4.527	44,437
10/24/2002	0.015	0.1721	4.372	49,483
10/25/2002	0.014	0.1658	4.185	47,824
10/26/2002	0.011	0.1546	2.944	35,938
10/27/2002	0.013	0.1601	3.608	43,240
10/28/2002	0.02	0.2088	7.729	65,115
10/29/2002	0.016	0.194	5.532	54,367
10/30/2002	0.015	0.188	4.794	48,862
10/31/2002	0.011	0.1581	2.904	35,231
11/1/2002	0.011	0.1485	2.819	36,574
11/2/2002	0.01	0.145	2.383	31,903
11/3/2002	0.011	0.1482	2.848	35,811
11/4/2002	0.023	0.2648	12.133	78,254
11/5/2002	0.021	0.2342	9.378	68,889
11/6/2002	0.015	0.1738	4.608	49,173
11/7/2002	0.02	0.2313	8.749	65,161
11/8/2002	0.017	0.1781	5.178	56,524
11/9/2002	0.009	0.136	2.161	31,346
11/10/2002	0.01	0.1448	2.362	31,887
11/11/2002	0.013	0.1856	4.725	44,136
2/14/2003	0.001	0.015	0.013	1,699
2/16/2003	0.001	0.008	0.018	4,605
2/17/2003	0.017	0.007	0.196	55,932
2/18/2003	0.012	0.1238	2.05	41,073
2/19/2003	0.003	0.1366	0.708	9,395
3/28/2003	0.002	0.0242	0.107	7,599
3/29/2003	0.013	0.1843	4.455	44,910
3/30/2003	0.011	0.1648	3.195	37,684
3/31/2003	0.011	0.1599	3.049	37,123
4/1/2003	0.009	0.1645	2.533	30,638
4/2/2003	0.009	0.1578	2.455	30,591
4/3/2003	0.006	0.1202	1.32	19,515
4/4/2003	0.005	0.102	0.967	15,489
4/5/2003	0.009	0.1568	2.442	30,236
4/6/2003	0.009	0.1436	2.17	29,975
4/7/2003	0.011	0.15	3.071	37,476
4/8/2003	0.012	0.1548	3.05	38,738
4/9/2003	0.015	0.1841	5.177	50,011
4/10/2003	0.01	0.141	2.445	34,069
4/11/2003	0.009	0.1414	2.113	29,972
4/12/2003	0.009	0.1431	2.162	30,296
4/13/2003	0.008	0.1405	1.976	28,127
4/14/2003	0.01	0.1486	2.56	33,621
4/15/2003	0.007	0.1452	1.758	24,188

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4/25/2003	0.003	0.0553	0.492	11,035
4/26/2003	0.01	0.1436	2.364	32,877
4/27/2003	0.01	0.1418	2.309	31,985
4/28/2003	0.008	0.1336	1.711	25,610
5/9/2003	0.004	0.0611	0.614	12,647
5/10/2003	0.017	0.2021	6.54	57,405
5/11/2003	0.01	0.1643	2.778	32,877
5/12/2003	0.01	0.17	3.027	34,463
5/13/2003	0.01	0.1454	2.497	33,067
5/14/2003	0.008	0.1238	1.727	27,904
5/15/2003	0.009	0.1203	1.765	28,349
5/16/2003	0.009	0.129	2.082	31,551
5/17/2003	0.008	0.1178	1.644	27,919
5/18/2003	0.01	0.1452	2.588	34,093
5/19/2003	0.016	0.1815	4.992	51,799
5/20/2003	0.004	0.1189	0.738	11,975
6/1/2003	0.002	0.0204	0.091	7,884
6/2/2003	0.01	0.125	2.122	33,776
6/3/2003	0.009	0.1308	1.946	29,693
6/4/2003	0.01	0.1464	2.454	32,222
6/5/2003	0.007	0.1192	1.338	21,933
6/6/2003	0.007	0.1182	1.317	21,747
6/7/2003	0.006	0.1135	1.1	19,380
6/8/2003	0.006	0.1165	1.136	19,497
6/9/2003	0.002	0.1092	0.387	6,865
6/30/2003	0.002	0.0148	0.051	6,666
7/1/2003	0.01	0.1128	1.846	32,090
7/2/2003	0.01	0.1271	2.185	32,181
7/3/2003	0.01	0.136	2.453	33,123
7/4/2003	0.006	0.0813	1.036	21,649
7/5/2003	0.007	0.1085	1.225	21,943
7/6/2003	0.009	0.1127	1.813	29,175
7/7/2003	0.012	0.138	3.41	40,692
7/8/2003	0.011	0.1252	2.581	36,435
7/9/2003	0.01	0.1078	2.01	34,360
7/10/2003	0.007	0.1007	1.228	23,077
7/11/2003	0.01	0.1343	2.455	33,518
7/12/2003	0.01	0.1307	2.379	32,929
7/13/2003	0.009	0.1247	1.94	29,003
7/14/2003	0.013	0.1405	3.51	43,006
7/15/2003	0.015	0.185	4.892	50,793
7/16/2003	0.014	0.1793	5.3	47,457
7/17/2003	0.013	0.1686	3.913	42,782
7/18/2003	0.013	0.165	4.07	43,826

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7/19/2003	0.008	0.1224	1.76	25,804
7/20/2003	0.01	0.1375	2.73	34,139
7/21/2003	0.013	0.1501	3.85	44,737
7/22/2003	0.006	0.103	1.121	21,104
7/23/2003	0.006	0.1008	1.011	19,929
7/24/2003	0.006	0.1075	1.072	19,935
7/25/2003	0.009	0.1438	2.495	31,066
7/26/2003	0.011	0.1486	3.135	35,801
7/27/2003	0.013	0.173	5.431	44,064
7/28/2003	0.017	0.2069	6.998	58,049
7/29/2003	0.011	0.1515	3.021	36,394
7/30/2003	0.007	0.1108	1.516	24,235
7/31/2003	0.009	0.1397	2.345	31,381
8/1/2003	0.01	0.1266	2.392	34,091
8/2/2003	0.006	0.092	0.892	19,398
8/3/2003	0.006	0.0904	0.875	19,360
8/4/2003	0.009	0.1192	2.303	30,760
8/5/2003	0.01	0.1227	2.572	34,455
8/6/2003	0.008	0.1203	1.763	26,244
8/7/2003	0.008	0.1309	1.829	25,444
8/8/2003	0.008	0.1298	2.097	27,401
8/9/2003	0.007	0.1191	1.409	22,463
8/10/2003	0.006	0.1079	1.061	19,660
8/11/2003	0.006	0.1075	1.061	19,738
8/12/2003	0.006	0.1095	1.08	19,725
8/13/2003	0.006	0.1065	1.048	19,690
8/14/2003	0.008	0.1326	2.107	28,151
8/15/2003	0.01	0.1322	2.58	33,848
8/16/2003	0.013	0.1526	3.956	42,216
8/17/2003	0.013	0.1577	4.289	43,090
8/18/2003	0.014	0.1655	4.59	47,382
8/19/2003	0.014	0.1708	5.163	46,902
8/20/2003	0.015	0.1618	5.32	49,507
8/21/2003	0.014	0.1881	5.674	48,299
8/22/2003	0.012	0.166	3.744	41,589
8/23/2003	0.01	0.1376	2.684	32,518
8/24/2003	0.01	0.1334	2.577	33,755
8/25/2003	0.014	0.1732	4.318	45,380
8/26/2003	0.013	0.1547	3.525	42,822
8/27/2003	0.01	0.1459	2.67	33,331
8/28/2003	0.01	0.1498	2.62	32,451
8/29/2003	0.013	0.1693	3.995	43,374
8/30/2003	0.012	0.1627	3.506	40,500
8/31/2003	0.006	0.0985	0.948	19,262

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9/1/2003	0.01	0.1333	2.529	33,302
9/2/2003	0.008	0.1248	1.888	27,757
9/3/2003	0.008	0.1173	1.595	25,074
9/4/2003	0.008	0.1225	1.797	26,458
9/5/2003	0.006	0.105	1.099	20,221
9/6/2003	0.006	0.1046	1.019	19,416
9/7/2003	0.006	0.1108	1.228	21,382
9/8/2003	0.009	0.1403	2.307	29,597
9/9/2003	0.01	0.1442	2.718	32,493
9/10/2003	0.009	0.1393	2.427	30,284
9/11/2003	0.008	0.126	1.829	26,313
9/12/2003	0.006	0.1015	0.992	19,325
9/13/2003	0.009	0.1308	2.093	28,954
9/14/2003	0.007	0.1298	1.696	24,158
9/15/2003	0.007	0.129	1.71	24,800
9/16/2003	0.007	0.1279	1.697	24,474
9/17/2003	0.007	0.1288	1.716	24,273
9/18/2003	0.007	0.1259	1.509	22,736
9/19/2003	0.006	0.1163	1.157	19,547
9/20/2003	0.008	0.1318	1.753	25,392
9/21/2003	0.007	0.1188	1.465	23,212
9/22/2003	0.01	0.1355	2.401	34,680
9/23/2003	0.009	0.1447	2.381	31,309
9/24/2003	0.01	0.1484	2.635	34,458
9/25/2003	0.01	0.1461	2.608	32,192
9/26/2003	0.011	0.1719	3.773	37,670
9/27/2003	0.012	0.1762	4.114	40,712
9/28/2003	0.006	0.1263	1.249	19,773
9/29/2003	0.006	0.1286	1.388	21,146
9/30/2003	0.007	0.1355	1.688	23,273
10/1/2003	0.006	0.1358	1.542	21,627
10/5/2003	0.002	0.0366	0.114	5,808
10/6/2003	0.01	0.1548	2.763	32,216
10/7/2003	0.013	0.1837	4.234	44,450
10/8/2003	0.009	0.156	2.64	30,400
10/18/2003	0	0.0105	0.007	1,196
10/19/2003	0.009	0.1316	2.367	28,415
10/20/2003	0.015	0.1955	5.096	51,193
10/21/2003	0.017	0.2215	7.467	57,794
10/22/2003	0.028	0.3428	16.509	93,036
10/23/2003	0.025	0.2927	12.561	82,673
10/24/2003	0.024	0.2452	9.877	79,990
10/25/2003	0.03	0.3455	17.916	98,845
10/26/2003	0.023	0.2924	12.033	78,223

Entergy Arkansas, Inc.
Lake Catherine - Unit 4
CEMS Data from CAMD

10/27/2003	0.012	0.1688	3.629	38,963
10/28/2003	0.012	0.1751	3.723	38,838
10/29/2003	0.01	0.1726	3.271	34,783
10/30/2003	0.008	0.1362	1.893	25,485
10/31/2003	0.005	0.1143	1.042	17,440
11/9/2003	0.002	0.0359	0.172	7,344
11/10/2003	0.006	0.1283	1.306	20,363
11/11/2003	0.026	0.3002	15.338	85,158
11/12/2003	0.037	0.4825	29.477	122,153
11/13/2003	0.02	0.3162	14.539	67,701
11/14/2003	0.016	0.2494	9.144	53,543
11/15/2003	0.023	0.309	14.475	76,658
11/16/2003	0.014	0.2057	7.065	47,591
11/17/2003	0.011	0.1664	3.785	37,220
11/18/2003	0.004	0.1328	0.842	11,838
12/11/2003	0.001	0.024	0.051	3,992
12/12/2003	0.008	0.1213	1.843	25,998
12/13/2003	0.009	0.137	2.2	28,738
12/14/2003	0.006	0.118	1.209	20,460
12/15/2003	0.009	0.1466	2.348	30,084
Max (tpd) -->	0.037		29.477	
Max (lb/hr) -->	3.1		2456.4	

Note: Dates with no operation/emissions not shown

APPENDIX D

SARGENT & LUNDY NO_X CONTROL TECHNOLOGY STUDY

Prepared for
Gill Elrod Ragon Owen & Sherman, P.A.

NOx Control Technology Cost and Performance Study

Entergy Services, Inc.
White Bluff & Lake Catherine

SL-011439
Final Report
Rev. 4

May 16, 2013
Project No.: 13027-001

Prepared by

Sargent & Lundy LLC

55 East Monroe Street
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White Bluff & Lake Catherine
NOx Control Technology Cost and Performance Study

ISSUE SUMMARY AND APPROVAL PAGE

This is to certify that this report has been prepared, reviewed and approved in accordance with Sargent & Lundy's Standard Operating Procedure SOP-0405, which is based on ANSI/ISO/ASSQC Q9001 Quality Management Systems.

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ENTERGY SERVICES, INC.

WHITE BLUFF AND LAKE CATHERINE

NO_X CONTROL TECHNOLOGY COST AND PERFORMANCE STUDY

CERTIFICATION PAGE

Sargent & Lundy, L.L.C. is registered in the State of Arkansas to practice engineering. The registration number is 620.

I certify that this study was prepared by me or under my supervision and that I am a registered professional engineer under the laws of the State of Arkansas.

Certified By: Sean C. McHone   Date: 5/16/2013

Seal:

STATE OF ARKANSAS
LICENSED PROFESSIONAL ENGINEER
No. 15308
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5/16/2013

Issue:	Date:	Certified By:	Pages Certified:

1. INTRODUCTION

1.1. OBJECTIVE

The intent of this study is to provide Gill Elrod Ragon Owen & Sherman, P.A. with a technology evaluation and cost estimates for available methods of NOx control at two Entergy stations including: White Bluff – Units 1 & 2, the White Bluff Auxiliary Boiler, and Lake Catherine – Unit 4. The information developed in this study will be used to create a BART analysis, for compliance with Arkansas DEQ regulations.

1.2. UNIT DESCRIPTIONS

1.2.1. White Bluff - Units 1 & 2

White Bluff - Units 1 & 2 are Alstom-designed, tangentially-fired, pulverized-coal fueled units, rated at 815 MWnet and 844 MWnet respectively. Powder River Basin coal is the primary fuel source for Units 1 & 2. Currently, the units have no NOx controls installed.

1.2.2. White Bluff Auxiliary Boiler

The White Bluff Auxiliary boiler is a small industrial boiler capable of producing 140,000 lb/hr of steam, used for startup of the White Bluff coal units. The auxiliary boiler combusts No. 2 Diesel Oil, and does not have any existing NOx controls.

1.2.3. Lake Catherine - Unit 4

Lake Catherine - Unit 4 is an Alstom-designed, tangentially-fired, natural gas fueled unit, capable of generating 558 MWnet. The unit was originally designed as a dual-fuel unit, able to use natural gas or No. 2 Fuel Oil as fuel. This evaluation will be for natural gas firing only. If No. 2 Fuel Oil is to be combusted in the future, a separate BART analysis will be submitted. The unit currently has no NOx controls.

1.3. ESTIMATE METHODOLOGY

1.3.1. Capital Cost Estimates

S&L's capital cost estimates for retrofit NOx control technologies for White Bluff Units 1&2, White Bluff Auxiliary Boiler and Lake Catherine – Unit 4 encompass the equipment, material, labor, and all other required direct costs. The underlying assumption is that the project will be implemented on a multiple-contracting basis. The capital cost estimates provided herein are "total plant cost," and include the following:

- Equipment and material
- Installation labor
- Indirect field costs and BOP engineering
- Contingency (percentage varies with project size)
- Erection contractor profit (at 10% of material and labor)
- General and administration (at 5% of material and labor)
- Freight on material (at 5% of material)
- Freight on equipment (included with equipment costs)
- Sales/use tax (not included)
- Startup and commissioning (at 1% of construction cost)
- Spare parts (included with equipment costs)
- Consumables (0.5% of material and labor)

Owner's engineering and other Owner's costs were not included. Engineering, Procurement & Project Services and Contingency varied depending on the size of the project. License fees and royalties are not expected for the proposed control strategies. The Basis of Estimate and capital costs are summarized in Appendix A.

Capital cost estimates were calculated in one of three ways. In some cases, vendors were contacted to provide budgetary estimates for equipment and labor. These vendor's costs were used to create Total Installed Cost Estimates. In situations where Sargent & Lundy had performed cost estimates for these units previously, the existing cost estimates were updated to reflect current equipment, labor, and currency values. Remaining cost estimates were developed from similar projects that Sargent & Lundy has completed and adjusted for unit size.

1.3.2. Operating and Maintenance Cost Estimates

Operating and Maintenance Costs for White Bluff - Units 1 & 2 and Lake Catherine – Unit 4 were developed from similar projects Sargent & Lundy has completed. Costs were applied to the units on a $/kW basis, and assuming a 10% capacity factor for Lake Catherine – Unit 4, and 76% for White Bluff—Units 1 & 2. Operating and Maintenance Costs include the following costs:

- Fixed Operating and Maintenance
- Variable Operating and Maintenance
- Fuel Impact Costs

For the White Bluff Auxiliary boiler, costs were developed using Office of Air Quality Planning and Standards (OAQPS) calculations, assuming a 10% capacity factor.

1.4. DESIGN TARGET vs. COMPLIANCE NO_X EMISSION RATES

NOx control systems retrofit onto existing coal or gas-fired boilers are typically designed to achieve varying levels of NOx removal efficiencies from 10%-94%, depending on the control technologies selected. Controlled NOx emissions fluctuate during normal boiler operation in response to a number of design/operating parameters including, but not necessarily limited to: inlet NOx concentrations, boiler load, load changes, particulate matter loading, flue gas temperatures, flue gas velocities and mixing, catalyst volume and surface area, NH_3:NOx stoichiometric ratio, catalyst age and activity, and the quantity of ammonia slip deemed to be acceptable.

The “design target” NOx emission rate is the rate that a NOx control technology vendor would be willing to guarantee. Based on engineering judgment, and taking into consideration emissions data from existing coal- and gas-fired sources, a compliance margin above the design target is recommended for high removal efficiency/low emission rate technologies (such as SCR) to establish an enforceable permit limit based on long-term (e.g., annual average) emissions. Additional compliance margin would be required to establish enforceable permit limits based on shorter-term averaging times. For example, S&L recommends a compliance margin of 0.02 to 0.03 lb/MMBtu for coal units and 0.01 to 0.02 lb/MMBtu for gas units above the design target emission rate for permit limits based on a 30-day rolling average for control strategies including SCR. The NOx control technology emission rates for strategies including SCR in this report have been adjusted to include margin for compliance. The permit level NOx emission rates for SCR are higher by 0.02 to 0.03 lb/MMBtu for coal units and 0.01 to 0.02 lb/MMBtu for gas units.

2. WHITE BLUFF - UNITS 1 & 2

2.1. FUEL SWITCHING OPTIONS

2.1.1. Natural Gas

For White Bluff Units 1 & 2, fuel switching is not a feasible option. Typically, units could be switched from coal to natural gas or propane for NOx reductions. The nearest natural gas pipeline to the White Bluff facility is approximately 20 miles away. Construction of a pipeline is currently estimated at $2M per mile resulting in a cost of $40M to bring natural gas to the site, not including the additional upgrades the boiler would require to burn natural gas instead of coal.

2.1.2. Propane

White Bluff – Units 1 & 2 are each over 800 MWnet. Units of this size require more heat input than can practically be achieved with a propane delivery and storage system. Since a propane pipeline is not available, fuel switching to propane is not a feasible option.

2.2. COMBUSTION CONTROLS

2.2.1. Low NOx Burners and Over-Fire Air

Low NOx burners (LNB) limit NOx formation by controlling both the stoichiometric and temperature profiles of the combustion flame in each burner flame envelope. Control is achieved with design features that regulate the aerodynamic distribution and mixing of the fuel and air, yielding reduced oxygen (O_2) in the primary combustion zone, reduced flame temperature, and reduced residence time at peak combustion temperatures. The combination of these techniques produces lower NOx emissions during the combustion process.

OFA involves injecting combustion air downstream of the fuel-rich primary combustion zone by using over-fire air or side-fired air ports. The fuel-rich mixture that is fed to the burners reduces the flame temperature and oxygen concentration thus reducing the formation of thermal NOx. Generally, OFA is more effective when used with low nitrogen content fuels such as natural gas and propane, since OFA is more effective in controlling thermal NOx rather than fuel NOx.

LNB + OFA is a technically feasible retrofit solution for White Bluff - Units 1 & 2. The combination of LNB + OFA is capable of achieving a NOx emission rate of 0.15 lb/MMBtu. From Unit 1's baseline emissions of 0.33 lb/MMBtu, this is approximately 54.5% NOx removal efficiency. A removal efficiency of 61.5% can be expected for Unit 2, with a baseline NOx of 0.39 lb/MMBtu.

2.2.2. Flue Gas Recirculation (FGR)

NOx reduction efficiency data for coal-fired units with FGR are limited. The amount of NOx reduction achievable with FGR depends primarily on the fuel nitrogen content and amount of FGR used. Generally, FGR is more effective when used with low nitrogen content fuels such as natural gas and propane, since FGR is more effective in controlling thermal NOx rather than fuel NOx. Industry experience with FGR on coal-fired units for steam temperature control has shown very high maintenance on the gas recirculation fans due to erosion and corrosion. Many of the units with FGR for steam temperature control have removed the recirculation fans from service. The NOx control achievable on tangentially fired units like White Bluff – Units 1&2 with LNB+OFA has been comparable to that of FGR at lower capital and O&M cost. Currently, FGR technology is not offered by OEMs for coal-fired units. For these reasons, FGR is not a feasible technology for the White Bluff coal-fired units.

2.2.3. Neural Network

Neural Network (NN) systems are on-line enhancements to digital control systems (DCS) and plant information systems that improve boiler performance parameters such as heat rate, NOx emissions, and CO levels. The Neural Network model is based on historical data and parametric test data. The software applies an optimizing procedure to identify the best set points for the boiler, which are implemented without operator intervention (closed loop), or, at the plant's discretion, conveyed to the plant operators for implementation (open loop).

A Neural Network system is a technically feasible retrofit option for the White Bluff units. A NN is already installed for monitoring and controlling heat rate at White Bluff – Units 1&2. The reprogrammed

NN would be optimized first for minimizing NOx emissions and second for heat rate. It is possible that heat rate may increase as a result. Based on information available from vendors, it is expected that Neural Network technology on a coal-fired boiler can maintain the guaranteed performance of low NOx burners and potentially can achieve approximately 10% NOx reduction over a period of years, resulting in NOx emission rates of 0.30 lb/MMBtu, at max load for Unit 1, and of 0.35 lb/MMBtu for Unit 2. The cost for modifying the existing NNs at White Bluff is estimated to be approximately $250,000 per unit.

2.3. POST COMBUSTION CONTROLS

2.3.1. Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) involves the direct injection of ammonia (NH_3) or urea ($(CO(NH_2)_2)$) into the furnace at high flue gas temperatures (approximately 1600 ºF – 2000 ºF). The ammonia or urea reacts with NOx in the flue gas to produce N_2 and water as shown in the following equations:

$$(CO(NH_2)_2) + 2NO + \frac{1}{2}O_2 \rightarrow 2H_2O + CO_2 + 2N_2$$

$$2NH_3 + 2NO + \frac{1}{2}O_2 \rightarrow 2N_2 + 3H_2O$$

Flue gas temperature at the point of reactant injection can greatly affect NOx removal efficiencies and the quantity of NH_3 or urea that will pass through the furnace unreacted (referred to as NH_3 slip). In general, SNCR reactions are effective at a temperature range of 1600 ºF – 2000 ºF. At temperatures below the desired operating range, the NOx reduction reactions diminish and unreacted NH_3 emissions increase. Above the desired temperature range, NH_3 is oxidized to NOx resulting in low NOx reduction efficiencies.

Mixing of the reactant and flue gas within the reaction zone is also an important factor to SNCR performance. In large boilers, the physical distance over which reagent must be dispersed increases, and the surface area/volume ratio of the convective pass decreases. Both of these factors make it difficult to achieve good mixing of reagent and flue gas, delivery of reagent in the proper temperature window, and sufficient residence time of the reactant and flue gas in that temperature window.

The temperatures and residence times required for an SNCR system make it a feasible option for NOx reduction for White Bluff - Units 1 & 2. Based on vendor input, a unit with no additional controls and a baseline NOx of 0.33 lb/MMBtu could see a 26.5% NOx reduction, for an outlet rate of 0.24 lb/MMBtu on Unit 1. For Unit 2, with a baseline NOx of 0.39 lb/MMBtu could see a 26.5% reduction to an outlet rate of 0.29 lb/MMBtu.

SNCR systems can also be installed in conjunction with LNB + OFA controls. On these coupled systems, the starting NOx of approximately 0.15 lb/MMBtu can be reduced to 0.13 lb/MMBtu, for a total reduction (LNB + OFA + SNCR) of around 61% for Unit 1 and 67% for Unit 2. In addition to the SNCR equipment, the process requires additional demineralized water at a rate of 170 gpm. An additional water treatment system capable of providing the required flows is included in the capital cost. The cost of the SNCR equipment for the combination technology would be approximately 10% lower based on the lower starting NOx rate with LNB/OFA.

2.3.2. Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) involves injecting ammonia into boiler flue gas in the presence of a catalyst to reduce NOx to N_2 and water. The overall SCR reactions are:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$8NH_3 + 4NO_2 + 2O_2 \rightarrow 6N_2 + 12H_2O$$

The optimal temperature range depends on the type of catalyst used, but is typically between 560 °F and 800 °F to maximize NOx reduction efficiency and minimize ammonium sulfate formation. Below this range, ammonium sulfate is formed resulting in catalyst deactivation. Above the optimum temperature, the catalyst will sinter and thus deactivate rapidly. Another factor affecting SCR performance is the condition of the catalyst material. As the catalyst degrades over time or is damaged, NOx removal decreases which is typically compensated by increased ammonia slip.

SCR has been installed on many large coal-fired and some gas-fired boilers and is considered a feasible technology. Because of the expense of the reagent, SCR systems are usually installed on units with existing LNB + OFA systems, or the upgrades are done simultaneously. At White Bluff, an SCR+LNB/OFA system is capable of removing approximately 90% of NOx emissions on a continuous long-term basis. With a starting NOx of 0.33 lb/MMBtu (Unit 1) to 0.39 lb/MMBtu (Unit 2), an SCR can be expected to achieve permitted emissions compliance at 0.055 lb/MMBtu.

2.4. CAPITAL COSTS

Capital costs for the technically feasible control options for the White Bluff coal units are listed in Table 2.1. The cost of SCR on White Bluff – Unit 1 is higher than for White Bluff – Unit 2 because the ductwork arrangement is different and there is more total ductwork, support steel, and foundations for Unit 1.

Table 2.1: Expected NOx Emissions and Capital Costs, White Bluff Units 1 & 2

Technology	**Controlled NOx (lb/MMBTU)**		**Unit 1 Total Installed Capital Cost (2012$)**	**Unit 2 Total Installed Capital Cost (2012$)**
	Unit 1	Unit 2		
Baseline	0.33	0.39	NA	NA
LNB + OFA	0.15	0.15	7,804,000[1]	11,831,000
Neural Network	0.30	0.35	250,000[2]	250,000[2]
SNCR	0.24	0.29	9,372,000	9,372,000
SNCR (+ LNB/OFA)	0.13	0.13	16,290,000[1]	20,317,000
SCR (+ LNB/OFA)	0.055	0.055	202,601,000	178,240,000

1. LNB/OFA material already purchased for Unit 1. The total cost to Entergy would be the same for Unit 1 as shown for Unit 2.
2. The cost for modifying the existing neural networks on Units 1 & 2.

2.5. OPERATING AND MAINTENANCE COSTS

Annual Operating and Maintenance costs for each of the feasible technologies for White Bluff Units 1 & 2 are shown in Table 2.2. Costs were calculated assuming full load operation, and a capacity factor (C.F.) of 76%.

Table 2.2: Operating and Maintenance Costs, White Bluff – Units 1 & 2 (Based on a C.F. of 76%)

	Unit 1			**Unit 2**		
Technology	**Variable O&M[1] Costs (2012$)**	**Fixed O&M Costs (2012$)**	**Total O&M Costs (2012$)**	**Variable O&M[1] Costs (2012$)**	**Fixed O&M Costs (2012$)**	**Total O&M Costs (2012$)**
LNB + OFA	--	142,000	142,000	--	142,000	142,000
Neural Network	--	50,000	50,000	--	50,000	50,000
SNCR	5,658,000	169,000	5,827,000	6,671,000	169,000	6,840,000
SNCR (+ LNB/OFA)	4,538,000	311,000	4,849,000	4,542,000	311,000	4,853,000
SCR (+ LNB/OFA)	2,836,000	608,000	3,444,000	2,858,000	608,000	3,466,000

Note 1: Variable O&M includes fuel cost impacts.

Note 2: The current costs of ammonia and urea are highly volatile and may exceed the values used in this report.

3. WHITE BLUFF AUXILIARY BOILER

3.1. FUEL SWITCHING

The White Bluff auxiliary boiler is a B&W, single burner boiler, firing No. 2 diesel oil, rated at 140,000 lb/hr of steam. Fuel switching to natural gas or propane is not practical because the nearest natural gas pipeline is 20 miles from the site. The costs to convert the White Bluff aux boiler to either natural gas or propane would not be justified based on the low capacity factor.

3.2. COMBUSTION CONTROLS

3.2.1. Low NOx Burners + Over-Fire Air

For an auxiliary boiler such as the one at White Bluff, NOx reduction can be achieved with a combination of technologies. LNB + OFA for aux boilers achieve NOx reduction under the same principles as a coal boiler. By modifying temperatures and fuel-rich areas, less NOx is generated. LNB + OFA are feasible technologies for auxiliary boilers, and vendor data indicates that the White Bluff Aux Boiler could achieve 35% reduction with LNB + OFA, for a final emission of 0.11 lb/MMBtu. The baseline NOx emissions from the White Bluff aux boiler are calculated using US EPA's AP-42 emissions factors.

3.2.2. Flue Gas Recirculation

NOx reduction efficiency data for oil-fired units with FGR are limited. The amount of NOx reduction achievable with FGR depends primarily on the fuel nitrogen content and amount of FGR used. Generally, FGR is more effective when used with low nitrogen content fuels such as natural gas and propane, since FGR is more effective in controlling thermal NOx rather than fuel NOx. FGR is a feasible technology for the White Bluff auxiliary boiler. With a recirculation of 15% of the flue gas, the unit could expect to see 13% NOx removal, for an outlet of 0.149 lb/MMBtu.

3.2.3. Low NOx Burners + Over-fire Air + Flue Gas Recirculation

These three technologies are often installed simultaneously for greater NOx reduction. A vendor has proposed that for the White Bluff aux boiler, a combination of LNB + OFA + FGR will reduce the NOx from 0.171 lb/MMBtu to 0.100 lb/MMBtu when burning No. 2 Fuel Oil. This reduction of 42% will come from a new LNB and OFA system and the recirculation of 15% of the flue gas flow.

3.2.4. Neural Network

The White Bluff Auxiliary Boiler is not a candidate for a neural network (NN) because there are few controllable variables to be optimized. The aux boiler also uses a relatively new PLC control system.

3.3. POST COMBUSTION CONTROLS

3.3.1. Selective Non-Catalytic Reduction

SNCR control has proven to be difficult to apply to industrial boilers because of the temperature and mixing requirements, especially industrial boilers that modulate or cycle frequently. In order to effectively reduce NOx emissions, the reactant (ammonia or urea) must be injected into the flue gas within a specific flue gas temperature window, and must remain within that temperature window for a sufficient residence time. In industrial boilers that cycle frequently, the location of the specific exhaust gas temperature window is constantly changing. Thus, SNCR has not been effective on industrial boilers that have high turndown capabilities and modulate or cycle frequently. Based on the temperature and residence time requirements associated with effective NOx reduction, the planned use of the auxiliary boiler, and the limited availability of SNCR control systems for industrial boilers, it has been determined that SNCR is not technically feasible for the White Bluff auxiliary boiler.

3.3.2. Selective Catalytic Reduction

SCR for NOx control on auxiliary boilers is not common, because of their cycling operation, and the use of fuel oil. SCRs have critical operating temperature ranges, which are difficult to achieve and maintain in short periods of time. Because of the sulfur content of diesel oil, the SCR catalyst can become poisoned, resulting in a lower NOx removal efficiency. With this lower efficiency and high cost, an SCR is not considered a feasible technology.

3.4. CAPITAL COST ESTIMATES

Capital costs for the technically feasible control options for the White Bluff Auxiliary Boiler are listed in Table 3.1.

Table 3.1: Expected NOx Emissions and Capital Costs, White Bluff Units 1 & 2

Technology	Controlled NOx	Total Installed Capital Cost (2012$)
Baseline	0.171	--
LNB	0.111	255,000
OFA	0.137	231,000
FGR	0.149	366,000
LNB + OFA + FGR	0.100	852,000

3.5. OPERATING AND MAINTENANCE COST ESTIMATES

Annual Operating and Maintenance costs for each of the feasible technologies for White Bluff Units 1 & 2 are shown in Table 3.2. Costs were calculated assuming full load operation and a capacity factor (C.F.) of 10%.

Table 3.2: White Bluff Auxiliary Boiler Operating and Maintenance Costs (Based on a C.F. of 10%)

Technology	Variable O&M Costs (2012$)	Fixed O&M Costs (2012$)	Total O&M Costs (2012$)
LNB	4,000	4,000	8,000
OFA	5,000	4,000	9,000
FGR	0	7,000	7,000
LNB + OFA + FGR	9,000	15,000	24,000

4. LAKE CATHERINE - UNIT 4

4.1. FUEL SWITCHING

Lake Catherine - Unit 4 already combusts natural gas, which has the lowest NOx formation of potential fuels. Because fuel switching would not result in a lower NOx emission rate, it is not a feasible option for NOx control.

4.2. COMBUSTION CONTROLS

4.2.1. Burners-Out-Of-Service

Burners-Out-Of-Service (BOOS) allows operators to stop fuel flow to certain burners in the boiler (typically the top level of burners), while air flow is maintained. By removing fuel from the top row of burners, the combustion air becomes over-fire air and the production of thermal NOx is reduced. While the reduction of NOx can be significant, the tradeoff is a reduced generating capacity, if no further modifications to the firing system are made. BOOS is a feasible technology for Lake Catherine - Unit 4. Testing of BOOS at Lake Catherine by Entropy Technology & Environmental Consultants, Inc. (ETEC) with the top levels of burners out resulted in a maximum load of 405 MW, a 28% reduction in capacity, and NOx levels of 0.12 lb/MMBtu, a reduction of 55% from the baseline while using the existing burners.

Recovery of the lost unit capacity is possible by increasing the fuel fired in the three levels of burners that remain in service. The burners remaining in service would have to increase fuel throughput by 25%. The natural gas piping to each burner may also have to be increased in size for the higher fuel flow rates. ETEC, Inc. has experience with several units similar in design to Lake Catherine – Unit 4 that have been able to achieve full capacity by increasing the original “high” burner header pressure (BHP) to increase fuel flow to the burners (See Appendix D). The increase in BHP from 42 to 50 psig at Lake Catherine – Unit 4 would increase fuel flow by 25% and the burners would be operated “fuel rich”, lowering NOx formation. Using this approach would reduce NOx emissions at a small capital cost. The costs for BOOS with recovery of full unit capacity were based on vendor cost information for a previous project adjusted on a $/kW basis to Lake Catherine – Unit 4 and escalated to 2012. The cost provided does not include any modifications to the boiler. A boiler OEM or consultant would need to evaluate the existing fuel piping, superheat and reheat attemperation sprays, tube metal temperatures and burner tilt positions for the new operating conditions. The expected NOx reduction would range from 40% at low load to 50% at full load and NOx levels of 0.24 lb/MMBtu.

4.2.2. Low NOx Burners + Over-Fire Air

Low NOx Burners and Over-Fire Air for a gas-fired unit function similarly to coal-fired boilers, as discussed for White Bluff - Units 1 & 2. By controlling the temperature and stoichiometric profiles, the NOx produced as a result of thermal processes is reduced.

LNB + OFA are commonly installed on gas-fired units of this size, and are a feasible retrofit technology for Lake Catherine - Unit 4. With the installation of LNB + OFA, Lake Catherine could expect a 60% reduction in NOx, from 0.4825 lb/MMBtu to 0.19 lb/MMBtu.

4.2.3. Flue Gas Recirculation

Flue Gas Recirculation (FGR) reduces NOx by recirculating flue gas to the furnace. This recirculated gas has lower oxygen content than ambient air usually used for combustion. Lower oxygen and lower flame temperatures reduces thermal NOx formation. FGR can be installed on a unit in two ways. Traditional FGR installations require a new recirculation fan. Induced FGR, or IFGR, installs ductwork from the air preheater outlet to the suction of the existing forced draft fan. IFGR does not require a separate fan, but due to FD fan capacity restrictions, IFGR is not available at higher loads, because the forced draft fans were not designed for the higher air and gas flow rate.

FGR is technically feasible on Lake Catherine - Unit 4 and can result in reductions of 60%. For Unit 4, this would be equivalent to NOx emissions of 0.19 lb/MMBtu.

4.2.4. Water Injection

Water injection operates on similar principles to LNB + OFA and FGR. By injecting water into the furnace, the temperature of the flue gas is reduced, thereby reducing the amount of thermal NOx formed.

Water injection is a feasible technology for Lake Catherine - Unit 4, and can reduce NOx emissions by 9% at full load. Water injection is typically used as a trimming technology at high load. On Unit 4, the emissions would be lowered from the baseline of 0.4825 lb/MMBtu to 0.44 lb/MMBtu.

4.2.5. Neural Network

Lake Catherine – Unit 4 could also install a neural network (NN) but for the low capacity factor and current lack of NOx CEMS, a NN would not be practical. Several of the other technologies would provide greater NOx reductions.

4.3. POST COMBUSTION CONTROLS

4.3.1. Selective Non-Catalytic Reduction

Selective Non-Catalytic Reduction for gas-fired units operates under the same principles as SNCR for coal-fired units, with a few design changes. One of the keys of SNCR design is adequate chemical distribution at the right temperature for the reaction. Lake Catherine - Unit 4 has horizontal superheat platens, which requires multiple-nozzle lances to distribute the urea; the gas pattern does not provide adequate distribution. The reaction and temperature requirements are the same for gas-fired boilers as they are for coal-fired units.

SNCR has been installed on boilers such as Lake Catherine 4 and is considered a feasible technology, although the residence time in the desired temperature zone is lower for a gas-fired unit and the temperature window moves as unit load changes. The unit could expect to see reductions in NOx from the baseline of 0.4825 lb/MMBtu to 0.29 lb/MMBtu, or approximately 40% reduction at full load. In addition to the SNCR equipment, the process requires additional demineralized water at a rate of 85 gpm. An additional water treatment system capable of providing the required flows is included in the capital cost.

SNCR can be combined with LNB/OFA to achieve a combined NOx removal efficiency of 70% for an outlet emission of approximately 0.14 lb/MMBtu,

4.3.2. Selective Catalytic Reduction

Selective Catalytic Reduction units are similar for gas and coal-fired units. Ammonia or urea reagent reacts with NOx to form nitrogen and water, in the presence of a catalyst. Because gas boilers do not have particulate control or sulfur dioxide control, they typically have a shorter distance from the economizer outlet to the stack, which may result in long ductwork runs to and from the SCR.

SCR is a feasible technology for Lake Catherine - Unit 4. Combined with a LNB + OFA installation, which is typical of SCR installations, the unit could achieve a combined NOx removal efficiency of 94%, for a permitted outlet NOx of 0.03 lb/MMBtu at full load. This includes a margin for compliance as discussed in Section 1.4. Without the LNB + OFA installed, the SCR can also be designed to achieve 90% removal efficiency for an outlet emission of approximately 0.05 lb/MMBtu.

4.4. CAPITAL COST ESTIMATES

Capital costs for the technically feasible control options for Lake Catherine - Unit 4 are listed in Table 4.1.

Table 4.1: Expected NOx Emissions and Capital Costs, Lake Catherine Unit 4

Technology	**Controlled NOx (lb/MMBtu)**	**Total Installed Capital Cost (2012$)**
Baseline	0.4825[1]	--
BOOS (at full capacity)	0.24	893,000
LNB / OFA	0.19	8,762,000
IFGR (below 500 MW)	0.39	2,166,000
FGR	0.19	11,489,000
Water Injection	0.44	2,177,000
SNCR	0.29	15,507,000
SNCR (+ LNB/OFA)	0.14	24,269,000
SCR	0.05	59,587,000
SCR (+ LNB/OFA)	0.03	68,349,000

Note 1: The baseline NOx rate is the maximum daily emission rate from the 2001-2003 baseline period.

4.5. OPERATING AND MAINTENANCE COST ESTIMATES

Annual Operating and Maintenance costs for each of the feasible technologies for Lake Catherine - Unit 4 are shown in Table 4.2. Costs were calculated assuming full load operation, and a capacity factor (C.F. of 10%).

Table 4.2: Annual Operating and Maintenance Costs, Lake Catherine Unit 4 (Based on C.F. of 10%)

Technology	**Variable O&M[1,2] Costs (2012$)**	**Fixed O&M Costs (2012$)**	**Total O&M Costs (2012$)**
BOOS	--	21,000	21,000
LNB + OFA	--	210,000	210,000
IFGR	--	52,000	52,000
FGR	142,000	207,000	349,000
Water Injection	486,000	52,000	538,000
SNCR	1,640,000	279,000	1,919,000
SNCR (+ LNB/OFA)	462,000	489,000	951,000
SCR	254,000	358,000	612,000
SCR (+ LNB/OFA)	268,000	568,000	836,000

Note 1: Variable O&M includes fuel cost impacts.

Note 2: The current costs of ammonia and urea are highly volatile and may exceed the values used in this report.

APPENDIX A: CAPITAL COST ESTIMATE

1. BASIS OF ESTIMATES

2. CONCEPTUAL COST ESTIMATE SUMMARY SHEETS

Basis of Estimate

Estimates:
31813A – Lake Catherine, Unit 4 - Low NOx Burners and Over Fired Air
31814A – Lake Catherine, Unit 4 - SCR
31815A – Lake Catherine, Unit 4 - SNCR
31816A – White Bluff, Unit 1 - Low NOx Burners and Over Fired Air
31817A – White Bluff, Unit 1 – SCR
31818A – White Bluff, Unit 2 – SCR
31819A – White Bluff, Units 1 and 2 – SNCR
31820A – White Bluff, Auxiliary Boiler – Low NOx Burners, Over Fired Air, and Flue Gas Recirculation
31832A – White Bluff, Unit 2 - Low NOx Burners and Over Fired Air

General Information

Project Type – Compliance study for Lake Catherine Unit 4 and White Bluff Station Units 1&2.
Type of estimates – Conceptual Cost Estimate for the SCR Case and Order of Magnitude Cost Estimates for all other cases.
Project location – White Bluff: Close to Pine Bluff, Arkansas; Lake Catherine: Close to Mahern, AR
MW rating: White Bluff Unit 1: 815 MW, Unit 2: 844 MW; Lake Catherine Unit 4: 558 MW
Unique site issues – Existing Site.
Contracting strategy – Multiple Lump Sum.

The major components of the capital cost consist of equipment, field materials and supplies, direct labor, indirect field labor, and indirect construction costs. The capital cost was determined through the process of estimating the cost of equipment, components and bulk quantity.

The cost estimates are based largely on Sargent & Lundy LLC experience on similar projects. Detailed engineering has not been performed to firm up the project details, and specific site characteristics have not been fully analyzed. We have attempted to assign allowances where necessary to cover issues that are likely to arise but are not clearly quantified at this time.

Estimate Development

The cost estimates for the Low NOx Burners/Over Fired Air cases were based on a previous estimate prepared in 2011. Equipment costs were escalated to current pricing level. Also, material and labor have been updated to 2012 pricing.
Cost estimates for the SNCR technology (two cases) were based on budgetary quotes received from engineering and on previous estimates.
The cost estimates for the White Bluff SCR was mainly based on similar size and scope cost estimates from other projects and structural takeoffs from engineering. All equipment common to both Units was divided evenly between the two estimates.
The cost estimate for Lake Catherine SCR was adjusted from another cost estimate for a gas fired power station.
White Bluff's auxiliary boiler cost estimate for Low NOx Burners/Over Fired Air/Flue Gas Recirculation was also adjusted from a similar project.

Pricing and Quantities

The data used to develop these estimates is based on using material and equipment types and sizes typically used in a power plant.
Equipment and material costs were estimated on the basis of S&L in house data, vendor catalogs, industry publications and other related projects. In most cases, the costs for bulk materials and equipment were derived from recent vendor or manufacturer's quote for similar items on other projects. Where actual or specific information regarding equipment specifications was available, that information was used to size and quantify material and equipment requirements. Where information was not furnished or was not adequate, requirements were assumed and estimated based on information available from project estimates of similar type and size.

Quantities contained herein are intended to be reasonable and representative of projects of this type. All quantity data was developed internally by S&L. Quantities were developed based on project experience of a plant of comparable size and then adjusted based on actual size and capacity differences and also taking into consideration the specific site layout based on the general arrangement drawing. While project specifics will certainly have an impact on these quantities, we feel they are appropriate for a study at this level.

Labor Wage Rates

Labor Profile – Union

Labor wage rate selected for the estimate - 2012 Union rates for Pine Bluff, Arkansas. Base craft rates are as published in RS Means Labor Rates for the Construction Industry, 2012 Edition. The craft rates are then incorporated into work crews appropriate for the activities by adding allowances for small tools, construction equipment, insurance, and site overheads to arrive at crew rates detailed in the cost estimate. A 1.15 regional labor productivity multiplier is included based on the Compass International Global Construction Yearbook.

Labor Work Schedule and Incentives - Assumed 5x10 work week for regular work and 7x10 work week for outage work. 10% of the work is assumed to be outage related.

Project Direct & Construction Indirect Costs

The estimate is constructed in such a manner where most of the direct construction costs are determined directly and several direct construction cost accounts are determined indirectly by taking a percentage of the directly determined costs and are identified as “Variable Accounts”. These percentages are based on our experience with similar type and size projects. Sales tax is specific to location. Listed below are the variable accounts.

- Cost of overtime – 5-10’s Hour Days and Outage Work at a 7-10 Schedule
- Subsistence (per diem) – not included
- Consumables – 0.5% of material and labor
- Freight on Equipment - included with equipment cost
- Freight on Material @ 5% of material
- Spare Parts – included with equipment costs
- Contractors G&A Expense @ 10%
- Contractors Profit @ 5%

Project Indirect Costs

Included are the following:

- Engineering, Procurement & Project Services varied depending on the size of the project estimated.
    - 31813A @ 19% of construction cost
    - 31814A @ 8% of construction cost
    - 31815A @ 8% of construction cost
    - 31816A @ 16% of construction cost
    - 31817A @ 6% of construction cost
    - 31818A @ 6% of construction cost
    - 31819A @ 8% of construction cost
    - 31820A @ 12% of construction cost
    - 31832A @ 16% of construction cost
- Construction Management varied depending on the size of the project estimated.
    - 31813A @ 6% of construction cost
    - 31814A @ 3% of construction cost
    - 31815A @ 2% of construction cost
    - 31816A @ 6% of construction cost
    - 31817A @ 2% of construction cost

- 31818A @ 2% of construction cost
- 31819A @ 2% of construction cost
- 31820A @ 0% of construction cost
- 31832A @ 6% of construction cost

- Craft start-up and commission support @ 1% of construction cost
- General Owner's Costs, including Owners Engineering & Bond Fees – not included
- EPC Fee – not included

These percentages are based on our experience with similar type and size projects.

Escalation

Not included.

Contingency

The contingency rates vary for each project based on the project's size. The rates are based on past history of similar projects. This rate relates to pricing and quantity variation in the specific scope estimated. The contingency does not cover new scope outside of what has been estimated, only the variation in the defined scope. This is a composite rate and already takes into account the plus and minuses of expected actual costs. The rate does not represent the high range of all costs, nor is it expected that the project will experience all actual costs be realized at the maximum value of their range of variation.

Exclusions

There are items that have been specifically excluded from the estimate. In order to establish the overall project costs, the following items must also be accounted for. This list is for information only and is not intended to be all inclusive.

- Permitting costs
- Rock excavation
- Remediation of soil for hazardous materials
- Power outage cost during construction

Assumptions

- No rock excavation, no dewatering
- Assumed that asbestos removal or lead paint abatement will not be required.
- No obstruction for the ammonia pipe routing. 6" clearing & grubbing of existing terrain is included, no tree removal.
- Directional boring underneath the existing railroad tracks is included, but with no major interferences or obstructions.
- Electrical equipment and wiring installation is based on non-hazardous location.
- Adjustments for plant unit size were made based on good engineering practice. Actual design and quantities may be significantly different than the quantities shown in the estimates.

Estimate Totals

Description	Amount	Totals	
Labor	331,677		
Material	125,263		
Subcontract	2,850,000		
Equipment			
Other	2,000,000		
	5,306,940	5,306,940	USD
91-1 Scaffolding	46,000		
91-2 OT Working 5-10 Hour Days	41,000		
91-3 OT Working 7-10 Hr Days			
91-4 Per Diem			
91-5 Consumables	2,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	6,000		
91-9 Freight on Process Equip.	100,000		
91-10 Sales Tax			
91-11 Contractor's G&A Expense	65,000		
91-12 Contractor's Profit	32,000		
	292,000	5,598,940	USD
93-1 EP&P Services	1,064,000		
93-2 CM Support	168,000		
93-3 Start-Up/Commissioning	56,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	1,288,000	6,886,940	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	50,000		
94-4 Contingency on Labor	145,000		
94-5 Contingency on Sub.	713,000		
94-6 Contingency on Equipment	525,000		
94-7 Contingency on Indirect	386,000		
	1,819,000	8,705,940	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		8,705,940	USD
98 - Interest During Constr			
		8,705,940	USD
Total		8,705,940	USD

Estimate Totals

Description	Amount	Totals	
Labor	19,780,000		
Material	15,815,652		
Subcontract	2,590,000		
Equipment			
Other	8,290,000		
	46,475,652	46,475,652	USD
91-1 Scaffolding			
91-2 OT Working 5-10 Hour Days			
91-3 OT Working 7-10 Hr Days			
91-4 Per Diem			
91-5 Consumables			
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material			
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense			
91-12 Contractor's Profit			
		46,475,652	USD
93-1 EP&P Services	3,718,100		
93-2 CM Support	1,394,300		
93-3 Start-Up/Commissioning	464,800		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	5,577,200	52,052,852	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	2,372,400		
94-4 Contingency on Labor	2,967,000		
94-5 Contingency on Sub.	388,500		
94-6 Contingency on Equipment	1,243,500		
94-7 Contingency on Indirect	836,600		
	7,808,000	59,860,852	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		59,860,852	USD
98 - Interest During Constr			
		59,860,852	USD
Total		59,860,852	USD

Estimate Totals

Description	Amount	Totals	
Labor	2,629,958		
Material	1,083,165		
Subcontract	80,600		
Equipment			
Other	6,193,056		
	9,986,779	9,986,779	USD
91-1 Scaffolding	445,600		
91-2 OT Working 5-10 Hour Days	311,700		
91-3 OT Working 7-10 Hr Days	99,200		
91-4 Per Diem			
91-5 Consumables	18,600		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	54,200		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	458,800		
91-12 Contractor's Profit	229,500		
	1,617,600	11,604,379	USD
93-1 EP&P Services	928,400		
93-2 CM Support	232,100		
93-3 Start-Up/Commissioning	116,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	1,276,500	12,880,879	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	390,000		
94-4 Contingency on Labor	1,209,300		
94-5 Contingency on Sub.	24,200		
94-6 Contingency on Equipment	619,300		
94-7 Contingency on Indirect	383,000		
	2,625,800	15,506,679	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		15,506,679	USD
98 - Interest During Constr			
		15,506,679	USD
Total		15,506,679	USD

Estimate Totals

Description	Amount	Totals	
Labor	653,648		
Material	306,347		
Subcontract	3,700,000		
Equipment			
Other			
	4,659,995	4,659,995	USD
91-1 Scaffolding	48,000		
91-2 OT Working 5-10 Hour Days	77,000		
91-3 OT Working 7-10 Hr Days	24,000		
91-4 Per Diem			
91-5 Consumables	5,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	15,000		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	112,000		
91-12 Contractor's Profit	55,000		
	336,000	4,995,995	USD
93-1 EP&P Services	799,000		
93-2 CM Support	300,000		
93-3 Start-Up/Commissioning	50,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	1,149,000	6,144,995	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	110,000		
94-4 Contingency on Labor	279,000		
94-5 Contingency on Sub.	925,000		
94-6 Contingency on Equipment			
94-7 Contingency on Indirect	345,000		
	1,659,000	7,803,995	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		7,803,995	USD
98 - Interest During Constr			
		7,803,995	USD
Total		7,803,995	USD

Estimate Totals

Description	Amount	Totals	
Labor	2,255,791		
Material	1,089,242		
Subcontract	68,100		
Equipment			
Other	1,948,100		
	5,361,233	5,361,233	USD
91-1 Scaffolding	368,000		
91-2 OT Working 5-10 Hour Days	267,300		
91-3 OT Working 7-10 Hr Days	85,100		
91-4 Per Diem			
91-5 Consumables	16,700		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	54,500		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	408,200		
91-12 Contractor's Profit	204,100		
	1,403,900	6,765,133	USD
93-1 EP&P Services	541,200		
93-2 CM Support	135,300		
93-3 Start-Up/Commissioning	67,700		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	744,200	7,509,333	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	392,100		
94-4 Contingency on Labor	1,032,500		
94-5 Contingency on Sub.	20,400		
94-6 Contingency on Equipment	194,800		
94-7 Contingency on Indirect	223,300		
	1,863,100	9,372,433	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		9,372,433	USD
98 - Interest During Constr			
		9,372,433	USD
Total		9,372,433	USD

Estimate Totals

Description	Amount	Totals	
Labor	56,778,212		
Material	34,013,262		
Subcontract	8,156,000		
Equipment			
Other	21,324,260		
	120,271,734	120,271,734	USD
91-1 Scaffolding	2,270,000		
91-2 OT Working 5-10 Hour Days	6,730,000		
91-3 OT Working 7-10 Hr Days	2,142,000		
91-4 Per Diem			
91-5 Consumables	454,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	1,701,000		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	10,238,000		
91-12 Contractor's Profit	5,120,000		
	28,655,000	148,926,734	USD
93-1 EP&P Services	8,936,000		
93-2 CM Support	2,979,000		
93-3 Start-Up/Commissioning	1,489,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	13,404,000	162,330,734	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	8,163,000		
94-4 Contingency on Labor	15,726,000		
94-5 Contingency on Sub.	1,631,000		
94-6 Contingency on Equipment	4,265,000		
94-7 Contingency on Indirect	2,681,000		
	32,466,000	194,796,734	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		194,796,734	USD
98 - Interest During Constr			
		194,796,734	USD
Total		194,796,734	USD

Estimate Totals

Description	Amount	Totals	
Labor	653,648		
Material	306,347		
Subcontract	3,700,000		
Equipment			
Other	2,600,000		
	7,259,995	7,259,995	USD
91-1 Scaffolding	48,000		
91-2 OT Working 5-10 Hour Days	77,000		
91-3 OT Working 7-10 Hr Days	24,000		
91-4 Per Diem			
91-5 Consumables	5,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	15,000		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	112,000		
91-12 Contractor's Profit	55,000		
	336,000	7,595,995	USD
93-1 EP&P Services	1,215,000		
93-2 CM Support	456,000		
93-3 Start-Up/Commissioning	76,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	1,747,000	9,342,995	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	110,000		
94-4 Contingency on Labor	279,000		
94-5 Contingency on Sub.	925,000		
94-6 Contingency on Equipment	650,000		
94-7 Contingency on Indirect	524,000		
	2,488,000	11,830,995	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		11,830,995	USD
98 - Interest During Constr			
		11,830,995	USD
Total		11,830,995	USD

Estimate Totals

Description	Amount	Totals	
Labor	2,255,791		
Material	1,089,242		
Subcontract	68,100		
Equipment			
Other	1,948,100		
	5,361,233	5,361,233	USD
91-1 Scaffolding	368,000		
91-2 OT Working 5-10 Hour Days	267,300		
91-3 OT Working 7-10 Hr Days	85,100		
91-4 Per Diem			
91-5 Consumables	16,700		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	54,500		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	408,200		
91-12 Contractor's Profit	204,100		
	1,403,900	6,765,133	USD
93-1 EP&P Services	541,200		
93-2 CM Support	135,300		
93-3 Start-Up/Commissioning	67,700		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	744,200	7,509,333	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	392,100		
94-4 Contingency on Labor	1,032,500		
94-5 Contingency on Sub.	20,400		
94-6 Contingency on Equipment	194,800		
94-7 Contingency on Indirect	223,300		
	1,863,100	9,372,433	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		9,372,433	USD
98 - Interest During Constr			
		9,372,433	USD
Total		9,372,433	USD

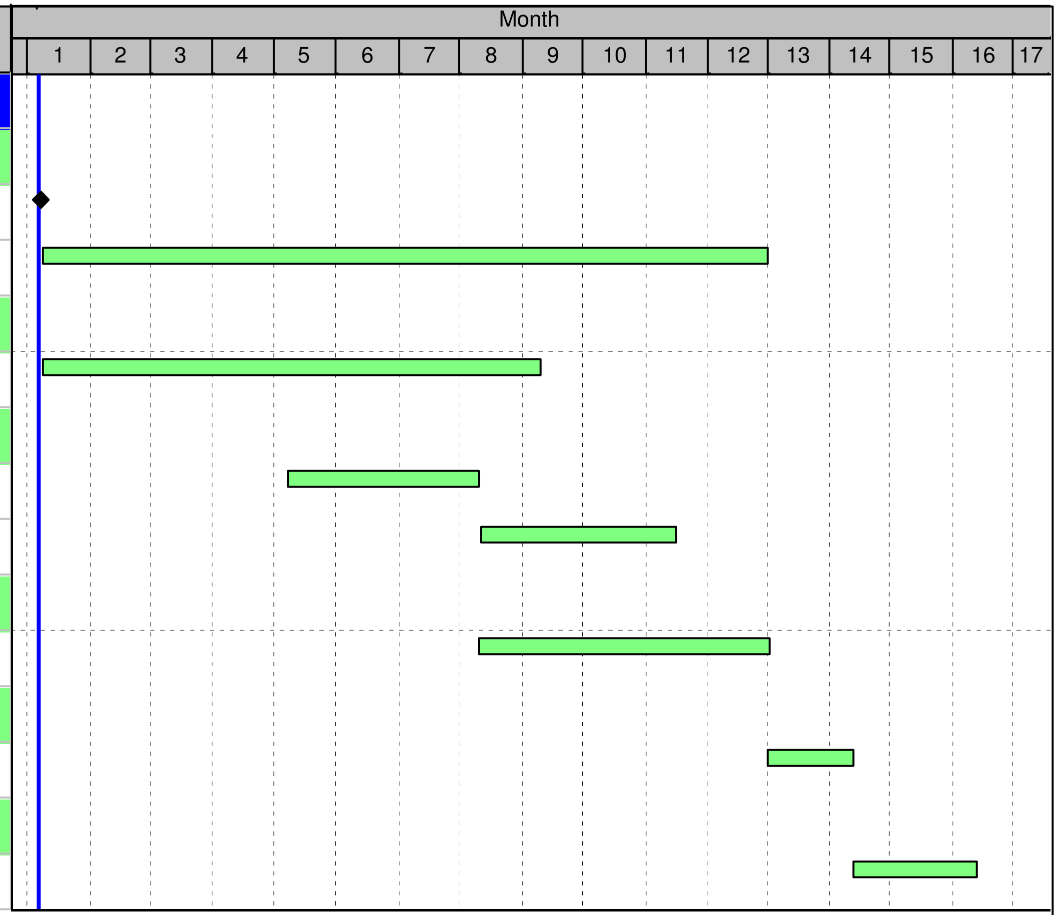
Estimate Totals

Description	Amount	Totals	
Labor	48,597,255		
Material	26,751,692		
Subcontract	6,577,640		
Equipment			
Other	21,324,260		
	103,250,847	103,250,847	USD
91-1 Scaffolding	1,884,000		
91-2 OT Working 5-10 Hour Days	5,759,000		
91-3 OT Working 7-10 Hr Days	1,834,000		
91-4 Per Diem			
91-5 Consumables	377,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	1,338,000		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	8,520,000		
91-12 Contractor's Profit	4,261,000		
	23,973,000	127,223,847	USD
93-1 EP&P Services	7,633,000		
93-2 CM Support	2,544,000		
93-3 Start-Up/Commissioning	1,272,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	11,449,000	138,672,847	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	6,421,000		
94-4 Contingency on Labor	13,444,000		
94-5 Contingency on Sub.	1,316,000		
94-6 Contingency on Equipment	4,265,000		
94-7 Contingency on Indirect	2,290,000		
	27,736,000	166,408,847	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		166,408,847	USD
98 - Interest During Constr			
		166,408,847	USD
Total		166,408,847	USD

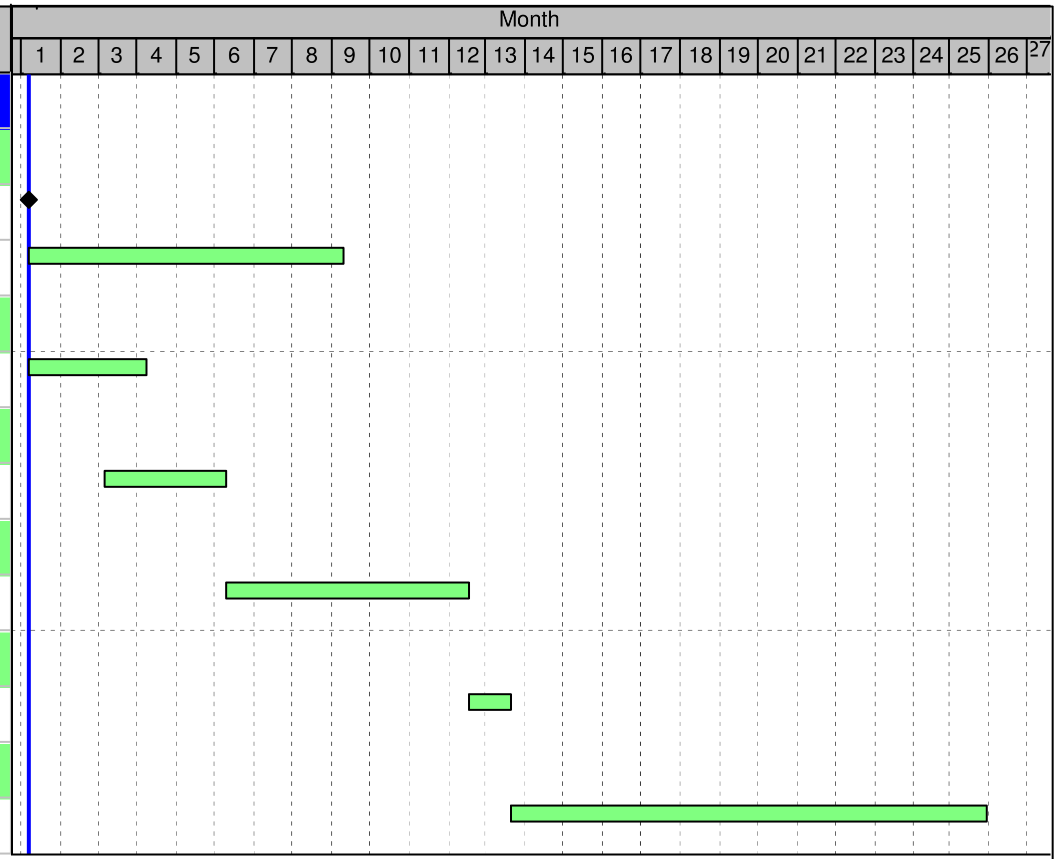
APPENDIX B

1. ESTIMATED PROJECT SCHEDULES

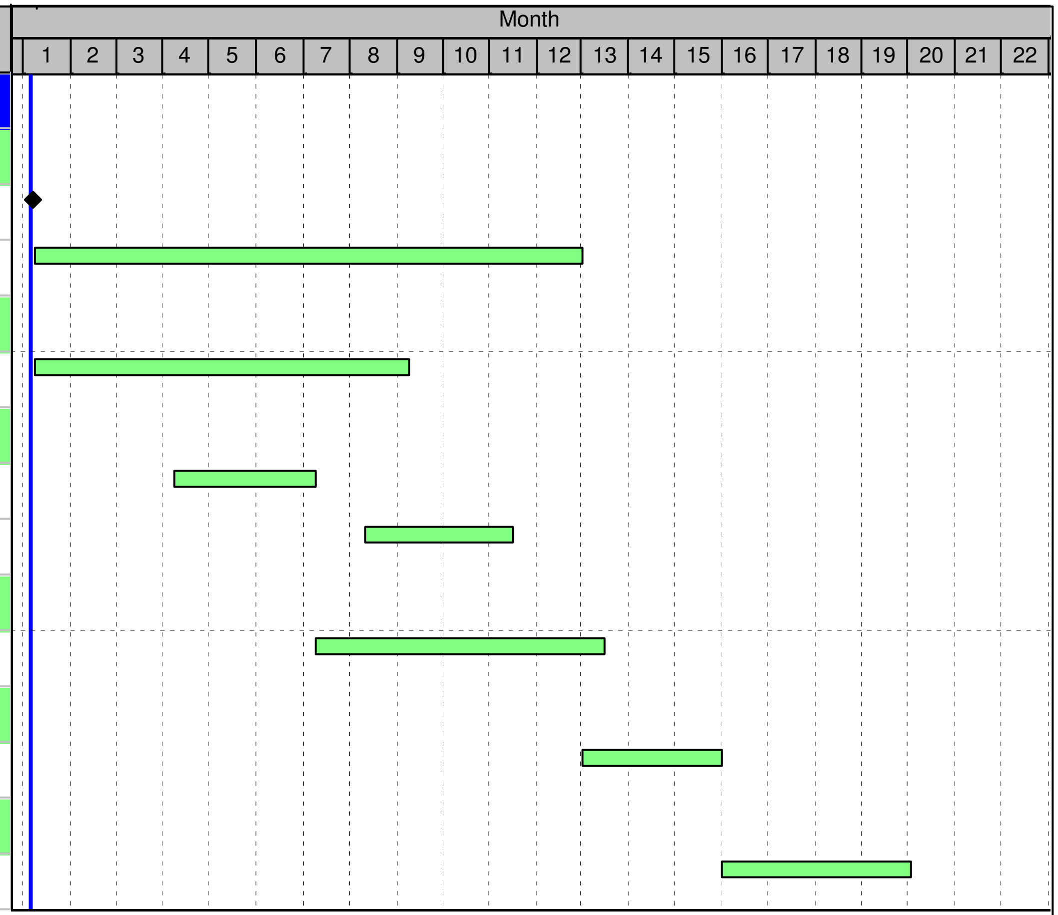
.	Activity ID	Activity Name	Org Dur (months)
		Entergy - NOx Strategy Study - Aux Boiler (LNB/OFA/F...	15m
		Permitting	12m
	A1000	Project Authorization	0m
	A1010	Air Permit - Prepare/Review/Approve	12m
		Engineering	8m
	A1020	Engineering	8m
		Procurement of Major Equipment	6m
	A1030	LNB/OFA Spec - Prep/Bid/Eval/Award	3m
	A1070	GWC Spec - Prep/Bid/Eval/Award	3m
		Vendor Engineering/Fab/Delivery	5m
	A1040	LNB/OFA Vendor Engineering/Fabrication/Delivery	5m
		Installation	1m
	A1050	Installation	1m
		Commissioning & Start-Up	2m
	A1060	Commissioning & Start-Up	2m



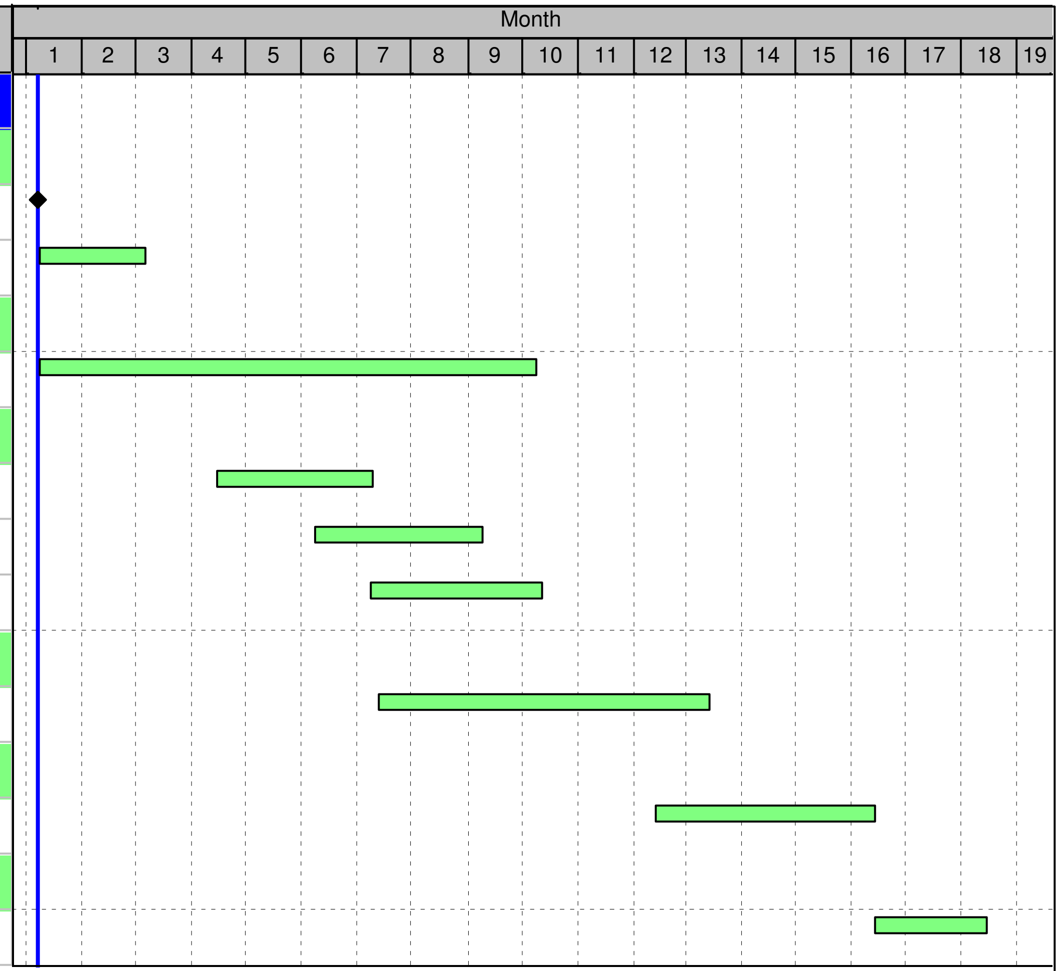
Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Neural Network	24m
	Permitting	8m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	8m
	Engineering	3m
A1020	Engineering	3m
	Procurement of Major Equipment	3m
A1030	Neural Network Spec - Prep/Bid/Eval/Award	3m
	Vendor Engineering/Fab/Delivery	6m
A1040	NN Vendor Engineering/Fabrication/Delivery	6m
	Installation	1m
A1050	Installation	1m
	Commissioning & Start-Up	12m
A1060	Commissioning & Start-Up	12m



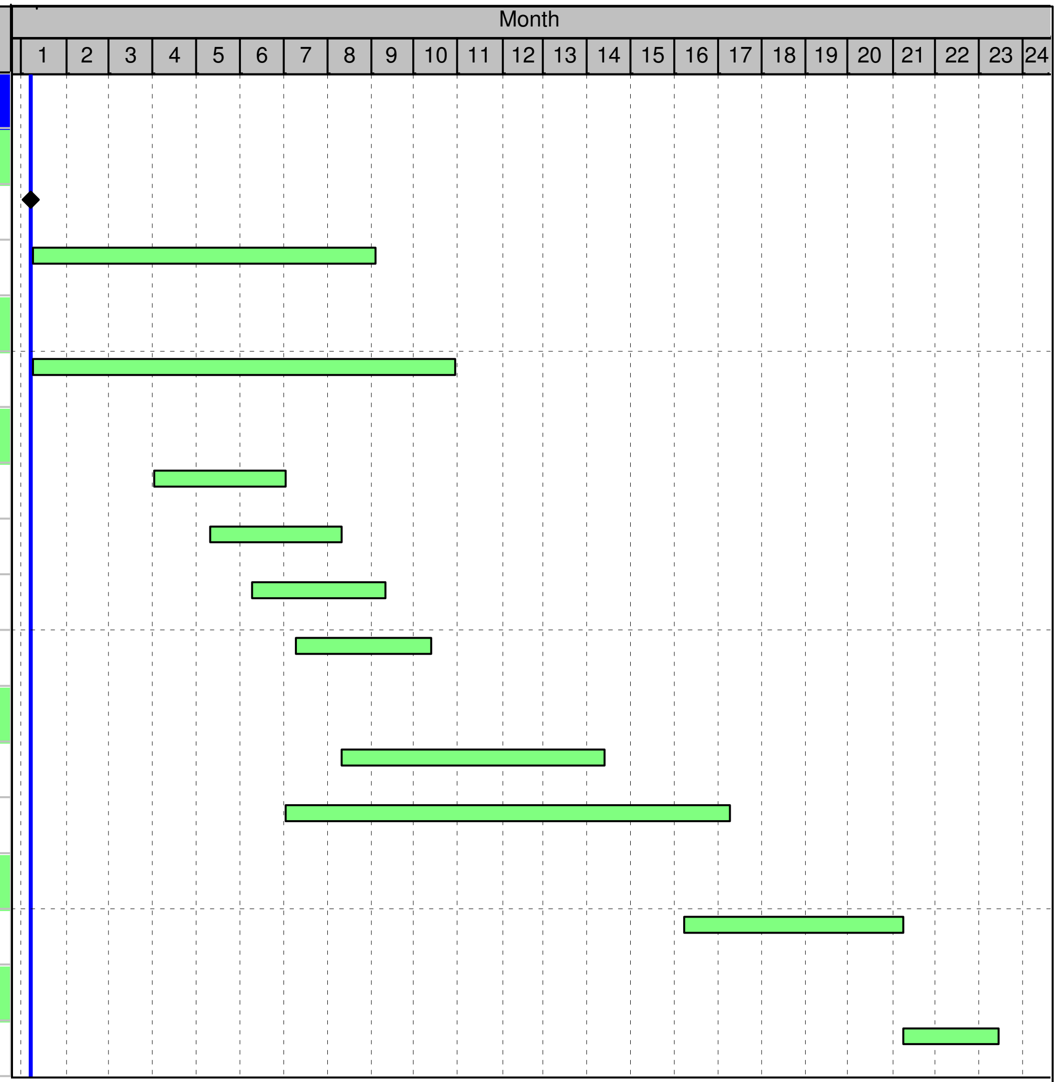
Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Low NOx Burners/Over ...	19m
	Permitting	12m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	12m
	Engineering	8m
A1020	Engineering	8m
	Procurement of Major Equipment	7m
A1030	LNB/OFA Spec - Prep/Bid/Eval/Award	3m
A1070	GWC Spec - Prep/Bid/Eval/Award	3m
	Vendor Engineering/Fab/Delivery	6m
A1040	LNB/OFA Vendor Engineering/Fabrication/Delivery	6m
	Installation	3m
A1050	Installation	3m
	Commissioning & Start-Up	4m
A1060	Commissioning & Start-Up	4m



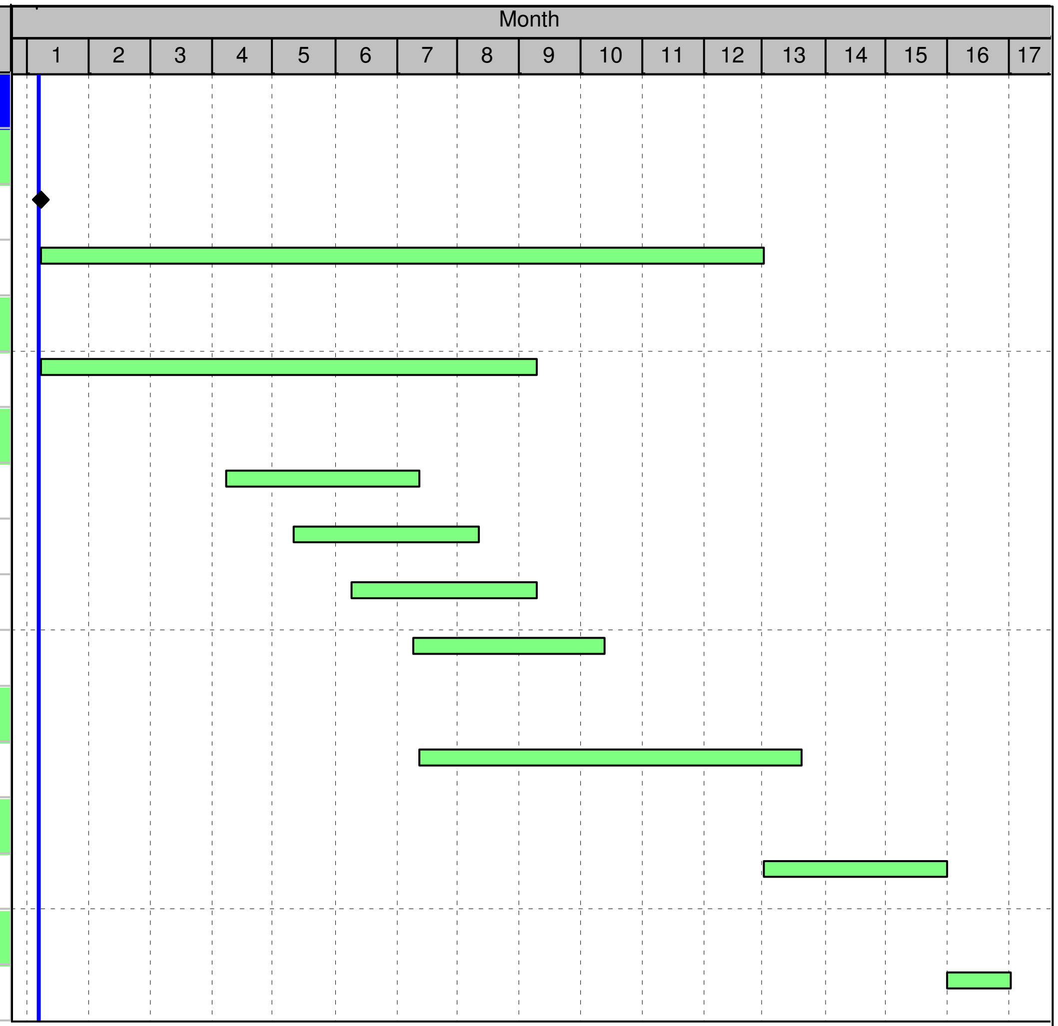
Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Induced Flue Gas Recir...	17m
	Permitting	2m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	2m
	Engineering	9m
A1020	BOP Engineering	9m
	Procurement of Major Equipment	6m
A1140	FGR Duct Procurement Spec - Prep/Bid/Eval/Award	3m
A1030	Mech Install Spec - Prep/Bid/Eval/Award	3m
A1120	Elec Install Spec - Prep/Bid/Eval/Award	3m
	Vendor Engineering/Fab/Delivery	6m
A1040	FGR Duct Vendor Engineering/Fabrication/Delivery	6m
	Installation	4m
A1050	Installation	4m
	Commissioning & Start-Up	2m
A1060	Commissioning & Start-Up	2m



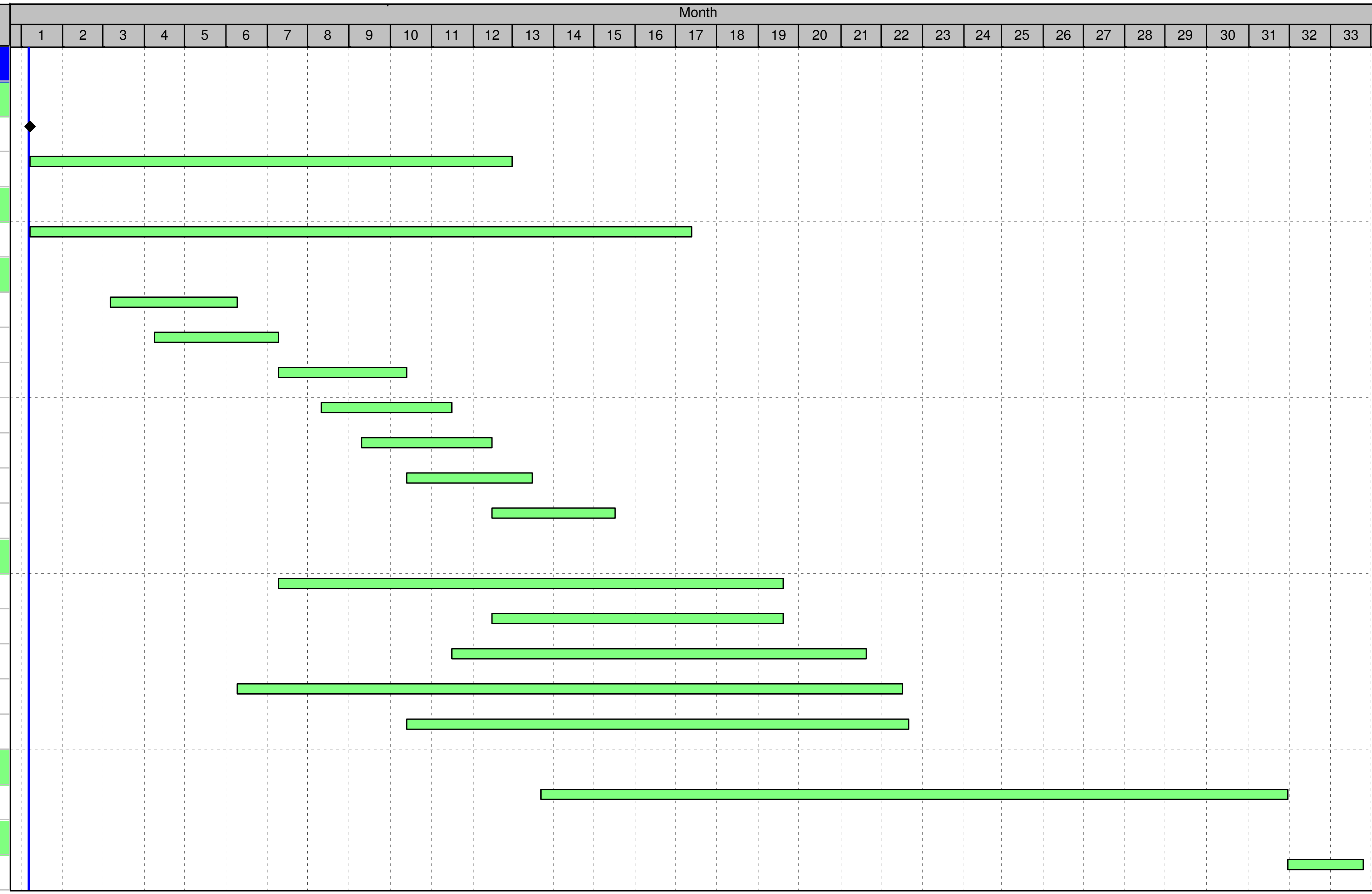
Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Flue Gas Recirculation ...	22m
	Permitting	8m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	8m
	Engineering	10m
A1020	BOP Engineering	10m
	Procurement of Major Equipment	6m
A1150	FGR Fan Procurement Spec - Prep/Bid/Eval/Award	3m
A1140	FGR Duct Procurement Spec - Prep/Bid/Eval/Award	3m
A1030	Mech Install Spec - Prep/Bid/Eval/Award	3m
A1120	Elec Install Spec - Prep/Bid/Eval/Award	3m
	Vendor Engineering/Fab/Delivery	10m
A1040	FGR Duct Vendor Engineering/Fabrication/Delivery	6m
A1160	FGR Fan Vendor Engineering/Fabrication/Delivery	10m
	Installation	5m
A1050	Installation	5m
	Commissioning & Start-Up	2m
A1060	Commissioning & Start-Up	2m



Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Selective Non-Catalytic ...	16m
	Permitting	12m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	12m
	Engineering	8m
A1020	BOP Engineering	8m
	Procurement of Major Equipment	6m
A1030	SNCR Spec - Prep/Bid/Eval/Award	3m
A1070	Civil/Structural Installation Spec - Prep/Bid/Eval/Award	3m
A1080	Mech Installation Spec - Prep/Bid/Eval/Award	3m
A1090	Elec/I&C Installation Spec - Prep/Bid/Eval/Award	3m
	Vendor Engineering/Fab/Delivery	6m
A1040	SNCR Vendor Engineering/Fabrication/Delivery	6m
	Installation	3m
A1050	Installation	3m
	Commissioning & Start-Up	1m
A1060	Commissioning & Start-Up	1m



Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Selective Catalytic Red...	32m
	Permitting	12m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	12m
	Engineering	16m
A1020	BOP Engineering	16m
	Procurement of Major Equipment	12m
A1140	Ammonia Injection System Procurement Spec - Prep/Bid/Eval/Award	3m
A1150	Catalyst Procurement Spec - Prep/Bid/Eval/Award	3m
A1170	Fan Spec - Prep/Bid/Eval/Award	3m
A1190	Ductwork Spec - Prep/Bid/Eval/Award	3m
A1130	Structural Steel Spec - Prep/Bid/Eval/Award	3m
A1030	Mech Install Spec - Prep/Bid/Eval/Award	3m
A1120	Elec Install Spec - Prep/Bid/Eval/Award	3m
	Vendor Engineering/Fab/Delivery	16m
A1160	Catalyst Vendor Engineering/Fabrication/Delivery	12m
A1210	Structural Steel Vendor Engineering/Fabrication/Delivery	7m
A1200	Ductwork Vendor Engineering/Fabrication/Delivery	10m
A1040	Ammonia Injection System Vendor Engineering/Fabrication/Delivery	16m
A1180	Fan Vendor Engineering/Fabrication/Delivery	12m
	Installation	18m
A1050	Installation	18m
	Commissioning & Start-Up	2m
A1060	Commissioning & Start-Up	2m



APPENDIX C

1. OPERATING AND MAINTENANCE COST ESTIMATES

NO_X Compliance Costs

Unit Name White Bluff 1

Unit Data		Reagent Costs	
Size (Gross kW)	815,000	Aq.Ammonia $/t	$700
Average NOx Emission Rate (lb/MMBtu at full load)	**0.33**	An.Ammonia $/t	$400
Nominal Max. Boiler Heat Input (mmBtu/hr)	8,950.0	Urea $/t	$350
Avg. Heat Rate (Btu/kwh)	10,981.6	N/F-T Urea $/t	$618
Aux. Power (kw)	-	Coal Cost, $/Mbtu	2.650
Est. Capacity Factor (%)	76.00		
Boiler Type	T/F	Water Cost, $/1000 gal (3)	2
Boiler Eff. (%)	84	Electricity, $/MWh	41.50
Estimated NOx, tons/day Max	**26.936**		
Emission Limit, tons	-		
NOx Sales/Buy rate, $/ton	-		
Fuel -	PRB		
Seasonal Days	153		
Basis	0		
Analysis - Enter "0" for Annual and 1 for Seasonal			
CF For Variable O&M	76.00		

Technology	Estimated Reduction from Baseline	Emission Rate After Control	Tons of NOx Emission, Seasonal/Annual	Tons of NOx Removed, season/annual	Estimated Capital Cost		Operating & Maintenance Cost: Fixed O&M	Variable O&M, season or yr	Fuel Impact, season or yr
	%	(lb/mmBtu)	tons	tons	$/kW	$/unit	$/yr	$/@CF	$/@CF
LNB + OFA (Note 5)	54.5	0.15	4,469	5,363	9.6	$7,804,000	$142,000	$0	$0
Neural Net	10.0	0.30	8,848	983	0.3	$250,000	$50,000	$0	$0
Full SNCR	26.5	0.24	7,229	2,602	11.5	$9,372,000	$169,000	$5,377,000	$281,000
LNB+OFA+Full SNCR	61.4	0.13	3,799	6,033	20.0	$16,290,000	$311,000	$4,154,000	$384,000
LNB+OFA+Full SCR	83.3	0.055	1,639	8,193	248.6	$202,601,000	$608,000	$2,836,000	$0

(1) Aux. Power cost is calculated based on variation in capacity factor
(2) Assumed water cost of $2/1000 gallons.
(3) Assumed that 15% urea will be used for SNCR technology.
(4) Assumed that initial catalyst life is 12,000 hours
(5) LNB/OFA material already purchased for Unit 1. The total cost to Entergy would be the same for Unit 1 as shown for Unit 2.
(6) For SCR technology, the variable O&M costs are based on operating at NOx outlet emissions marginally below the compliance emission rate.

Unit Name White Bluff 2

Unit Data		Reagent Costs	
Size (Gross kW)	844,000	Aq.Ammonia $/t	$700
Average NOx Emission Rate (lb/MMBtu at full load)	**0.39**	An.Ammonia $/t	$400
Nominal Max. Boiler Heat Input (mmBtu/hr)	8,950.0	Urea $/t	$350
Avg. Heat Rate (Btu/kwh)	10,604.3	N/F-T Urea $/t	$618
Aux. Power (kw)	-	Coal Cost, $/Mbtu	2.650
Est. Capacity Factor (%)	76.00		
Boiler Type	T/F	Water Cost, $/1000 gal (3)	2
Boiler Eff. (%)	84	Electricity, $/MWh	41.50
Estimated NOx, tons/day Max	**31.833**		
Emission Limit, tons	-		
NOx Sales/Buy rate, $/ton	-		
Fuel -	PRB		
Seasonal Days	153		
Basis	0		
Analysis - Enter "0" for Annual and 1 for Seasonal			
CF For Variable O&M	76.00		

Technology	Estimated Reduction from Baseline	Emission Rate After Control	Tons of NOx Emission, Seasonal/Annual	Tons of NOx Removed, season/annual	Estimated Capital Cost		Operating & Maintenance Cost Fixed O&M	Variable O&M, season or yr	Fuel Impact, season or yr
	%	(lb/mmBtu)	tons	tons	$/kW	$/unit	$/yr	$/@CF	$/@CF
LNB + OFA	61.5	0.15	4,469	7,150	14.0	$11,831,000	$142,000	$0	$0
Neural Net	10.0	0.35	10,457	1,162	0.3	$250,000	$50,000	$0	$0
Full SNCR	26.5	0.29	8,544	3,076	11.1	$9,372,000	$169,000	$6,338,000	$333,000
LNB+OFA+Full SNCR	67.3	0.13	3,799	7,821	24.1	$20,317,000	$311,000	$4,158,000	$384,000
LNB+OFA+Full SCR	85.9	0.055	1,639	9,981	211.2	$178,240,000	$608,000	$2,858,000	$0

(1) Aux. Power cost is calculated based on variation in capacity factor
(2) Assumed water cost of $2/1000 gallons.
(3) Assumed that 15% urea will be used for SNCR technology.
(4) Assumed that initial catalyst life is 12,000 hours
(5) For SCR technology, the variable O&M costs are based on operating at NOx outlet emissions marginally below the compliance emission rate.

NO_X Compliance Costs

Unit name Lake Catherine Unit 4

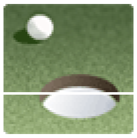
Unit Data		Reagent Costs	
Size (Gross kW)	558,000	Aq.Ammonia $/t	$700
Average NOx Emission Rate (lb/MMBtu)	0.4825	An.Ammonia $/t	$400
Nominal Max. Boiler Heat Input (mmBtu/hr)	5,850.0	Urea $/t	$350
Avg. Heat Rate (Btu/kwh)	10,483.9	N/F-T Urea $/t	$618
Aux. Power (kw)	-	Gas Cost, $/MBtu	4.900
Est. Capacity Factor (%)	10.00	Water Cost, $/1000 gal (3)	2
Boiler Type	T/F	Electricity, $/MWh	41.50
Boiler Eff. (%)	82		
Estimated NOx, tons/day Max	3.387		
Emission Limit, tons	-		
NOx Sales/Buy rate, $/ton	2500.0		
Fuel	Gas		
Seasonal Days	153		
Basis	0		
Analysis - Enter "0" for Annual and 1 for Seasonal			
CF For Variable O&M	10.00		

Technology	Estimated Reduction from Baseline	Emission Rate After Control	Tons of NOx Emission, Seasonal/Annual	Tons of NOx Removed, season/annual	Estimated Capital Cost		Operating & Maintenance Cost Fixed O&M	Variable O&M, season or yr	Fuel Impact, season or yr
	%	(lb/mmBtu)	tons	tons	$/kW	$/unit	$/yr	$/@CF	$/@CF
Baseline	0	0.4825							
BOOS (at 558 MW)	50.0	0.24	618	618	1.6	$893,000	$21,000	$0	$0
LNB + OFA	60.0	0.19	495	742	15.7	$8,762,000	$210,000	$0	$0
SCR	90.0	0.05	124	1,113	106.8	$59,587,000	$358,000	$254,000	$0
SNCR	40.0	0.29	742	495	27.8	$15,507,000	$279,000	$1,542,000	$98,000
Water Injection	9.1	0.44	1,124	113	3.9	$2,177,000	$52,000	$18,000	$468,000
IFGR (below 500 MW)	19.0	0.39	1,001	235	3.9	$2,166,000	$52,000	$0	$0
FGR	60.0	0.19	495	742	20.6	$11,489,000	$207,000	$142,000	$0
LNB/OFA + SNCR	70.0	0.14	371	865	43.5	$24,269,000	$489,000	$393,000	$69,000
LNB/OFA + SCR	94.0	0.03	74	1,162	122.5	$68,349,000	$568,000	$268,000	$0

(1) Aux. Power cost is calculated based on variation in capacity factor
(2) Assumed water cost of $2/1000 gallons.
(3) Assumed that 15% urea will be used for SNCR technology.
(4) Assumed that initial catalyst life is 40,000 hours.
(5) Water Injection is used only for trimming at high load. Approximately 66% of Hours are affected.
(6) For SCR technology, the variable O&M costs are based on operating at NOx outlet emissions marginally below the compliance emission rate.

APPENDIX D

1. BOOS AT FULL UNIT LOAD



To: DAVID H PARK/Sargentlundy@Sargentlundy,
Cc:
Bcc:
Subject: Fw: BOOS for NOx Control
From: STEVE M KATZBERGER/Sargentlundy - Thursday 03/28/2013 03:32 PM

From: Stephen Wood [mailto:swood@etecinc.net]
Sent: Monday, March 25, 2013 2:20 PM
To: HANTZ, JOSEPH
Subject: BOOS for NOx Control

Joe,

The attached PDF file contains background information on utilizing burners out of service for NOx control, as well as, predicted Lake Catherine Unit 4 burner header pressures and NOx emissions, utilizing the top burner elevation out of service (4BOOS). If you have any questions, please let me know.

Regards,

Steve Wood
Principal Officer
Entropy Technology & Environmental Consultants, Inc. (ETEC Inc.)
12337 Jones Rd. Suite 414
Houston, TX 77070
Ph: 281-807-7007
Cell: 713-253-8230
Fax: 281-807-1414
Website: www.etecinc.net

 BOOS for NOx Control.pdf

Combustion Modification (BOOS) for NOx Control

Implementation of Burner Out Of Service (BOOS) operation is a practical and cost-effective means for achieving staged combustion (i.e., modifying burner stoichoimetry to reduce NOx emissions formation) on an existing gas/oil fired electric utility boiler. Utilizing BOOS operation for NOx control is well documented in the literature, e.g., EPA 456/F-99-006R "Nitrogen Oxides (NOx), Why And How They Are Controlled", November 1999, and EPRI TR-108181 "Retrofit NOx Control Guidelines for Gas- and Oil-Fired Boilers, Version 2.0", June 1997, among numerous others.

The technique of BOOS operation involves terminating the fuel flow to selected burners on the top elevation while leaving the air registers open. The remaining burners operate fuel-rich, thereby limiting oxygen availability, lowering peak flame temperatures, and reducing NOx formation. The un-reacted products combine with the air from the above terminated-fuel burners to complete burnout before exiting the furnace. I have personally been involved with implementing BOOS operation on virtually every gas fired electric utility boiler design across the country since the mid 1970's. In almost every case, the original "high" burner header pressure (BHP) set point had to be increased to accommodate BOOS operation. No adverse operational or maintenance problems corresponding to BOOS implementation have been reported.

BOOS operation can be a very effective NOx reduction technology, depending on the degree of staging, as shown for Ninemile Unit 4 (750 mw CE Tangential Fired) in Figure 1. The corresponding BOOS pattern is shown in Figure 2. The BHP corresponding to 4BOOS operation on Lake Catherine Unit 4 is shown in Figure 3. The "High" BHP set point would need to be increased from 42 to 50 psig. The predicted NOx emissions corresponding to 4BOOS operation are presented in Figure 4.

Figure 1- Stoichiometry Modification (BOOS) NOx Reduction

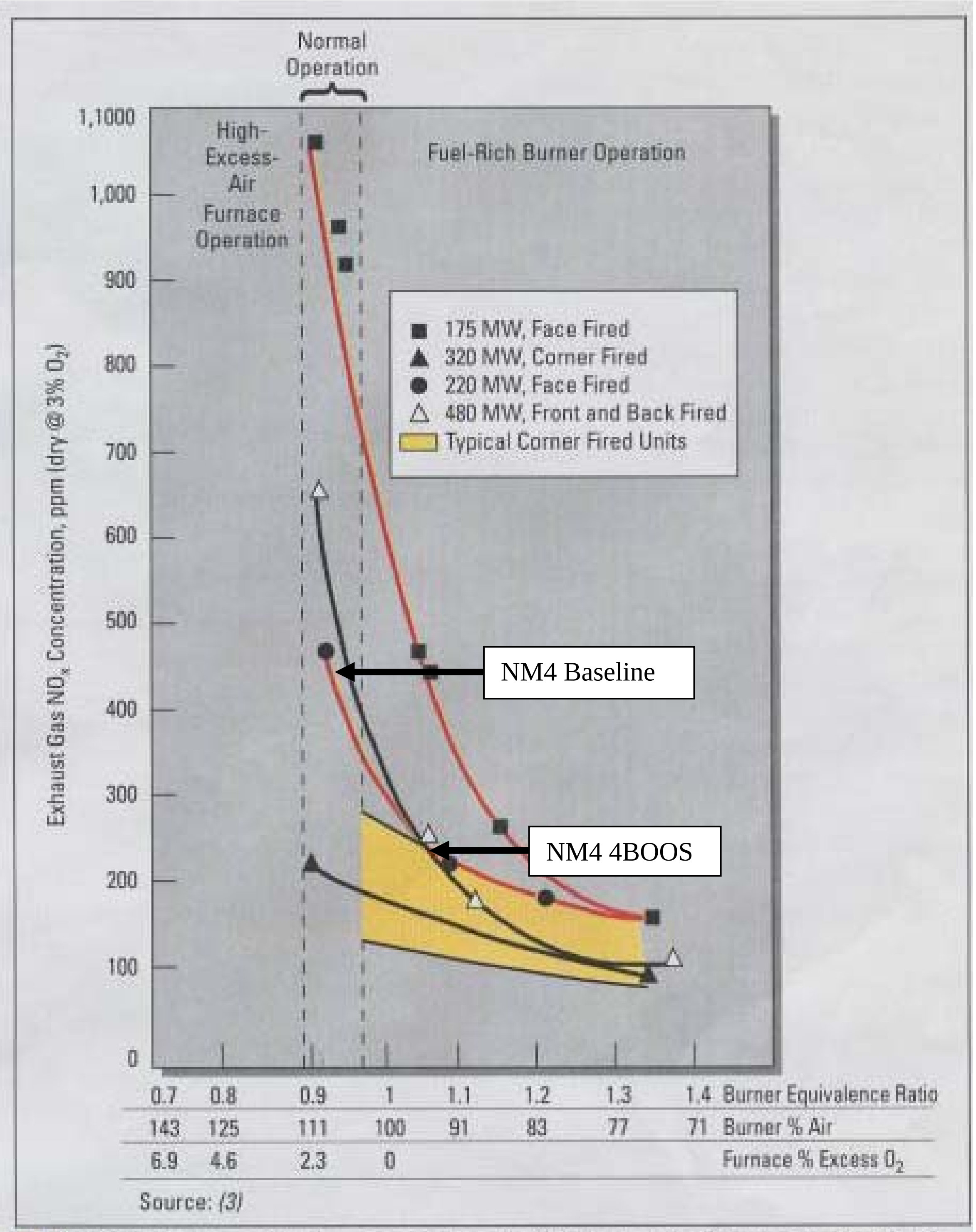


Figure 2. Burners-out-of-service can be an effective combustion staging technique.

Figure 2- Ninemile Units 4 and 5 BOOS Pattern
(Top Elevation Out of Service & Air Registers Open)

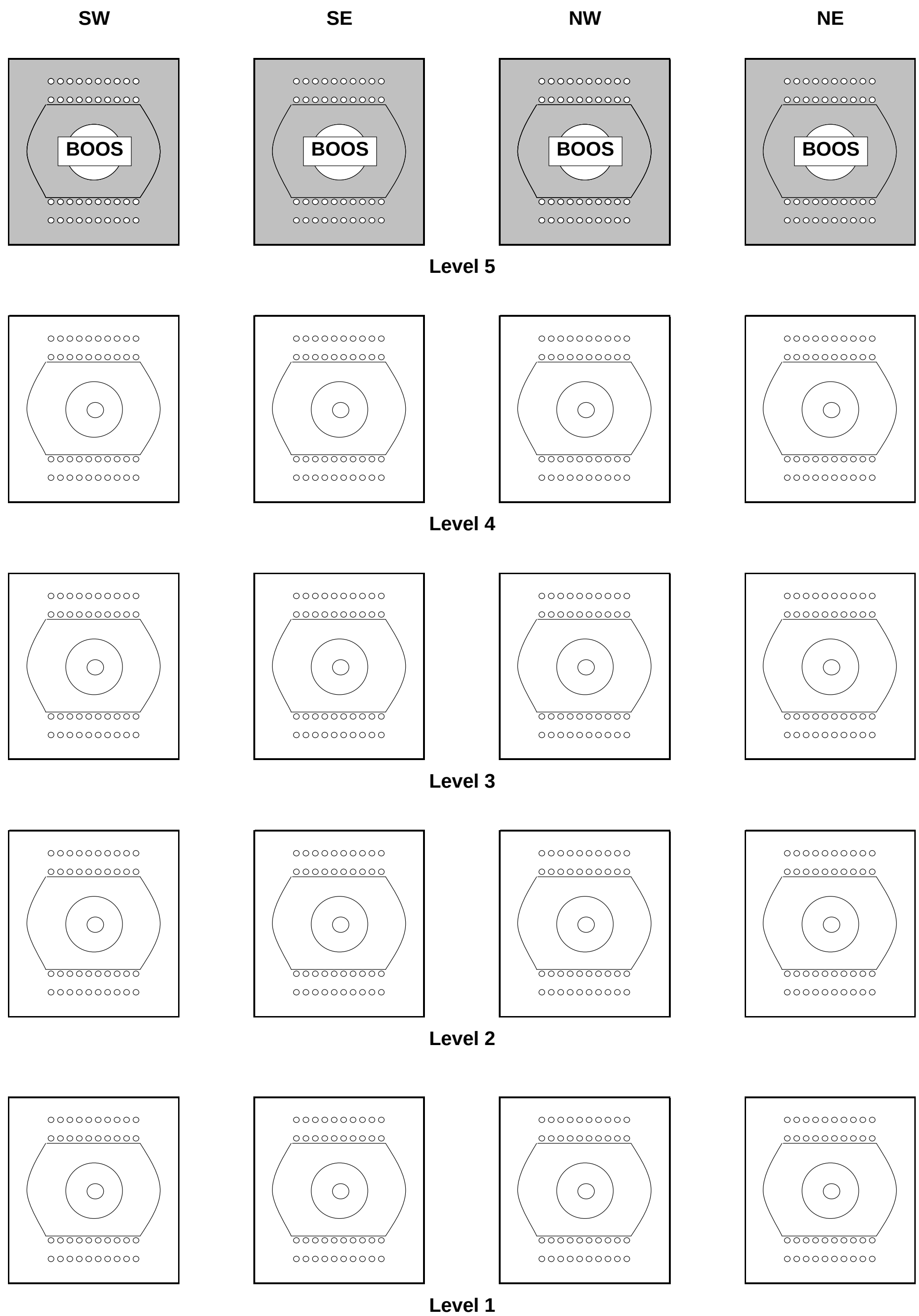


Figure 3- Lake Catherine Unit 4 Burner Header Pressure

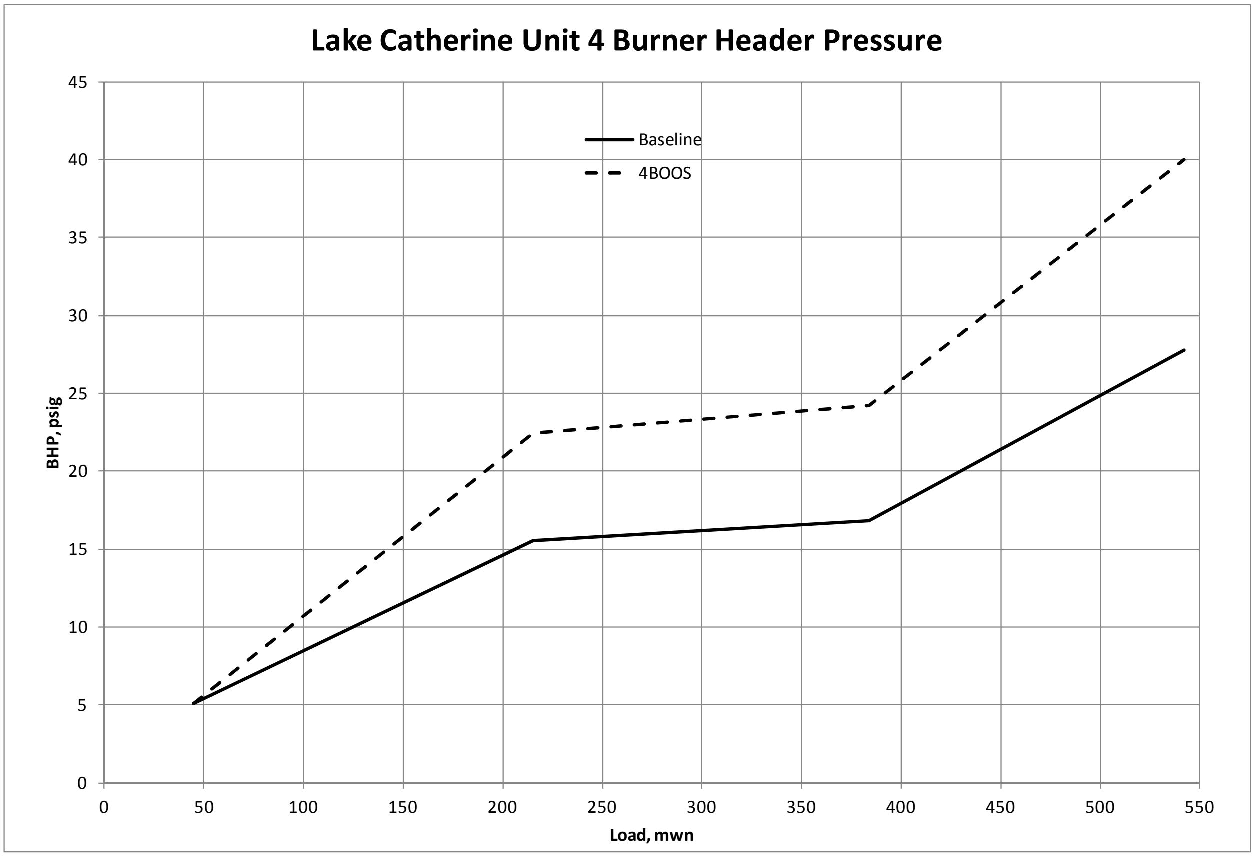
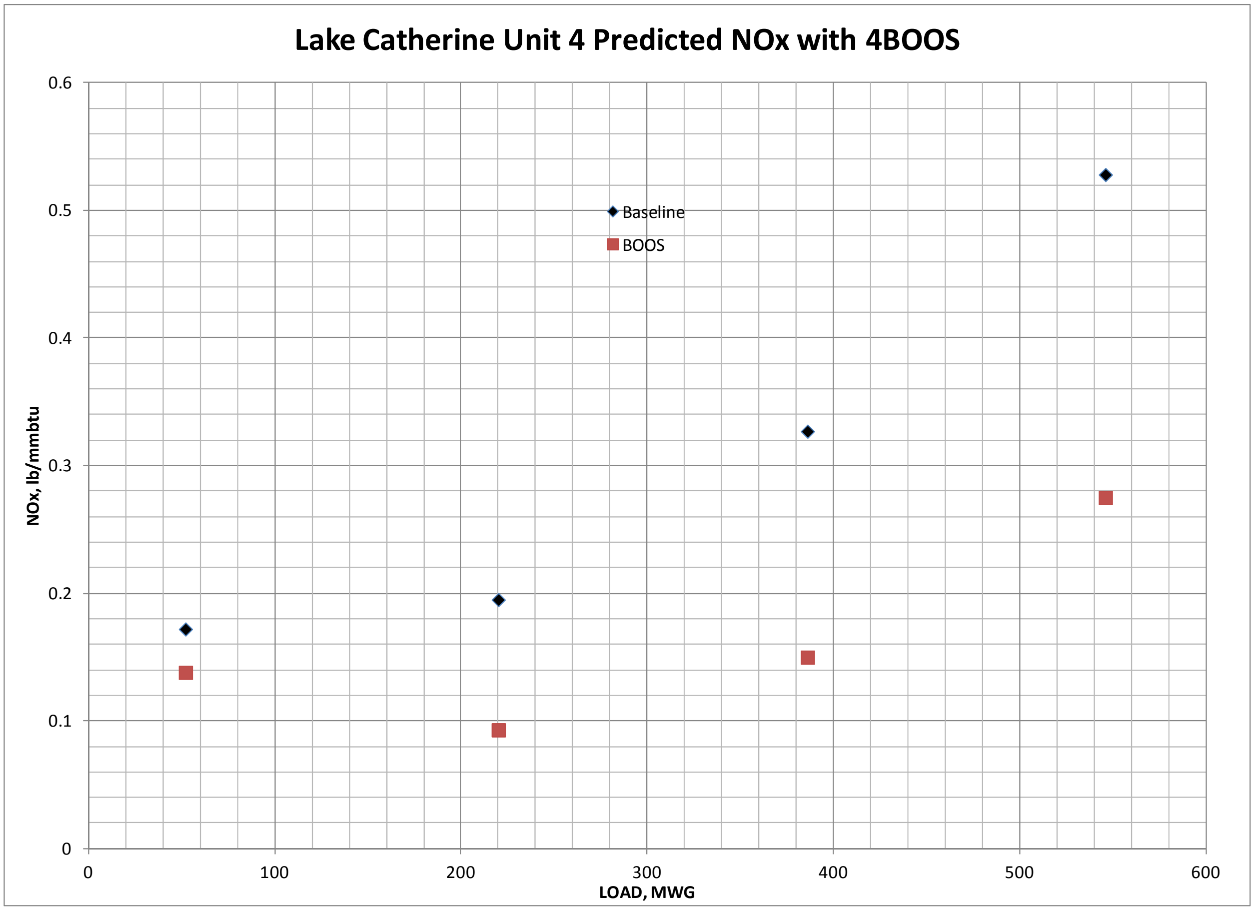


Figure 4- Lake Catherine Unit 4 NOx Emissions Prediction



CENRAP_PSAT_Tool_ENVIRON_Aug27_2007.mdb

This type of file (Microsoft Access Database) cannot be converted to PDF and included with the SIP. This file is available upon request.

For questions or requesting copies of available files, contact Tricia Treece via email at treecep@adeq.state.ar.us or by phone at 501-682-0055

Facility	Location		Data Period	SO2 (tpy) (Data Period Average)	Distance (km)			
	Latitude	Longitude			Upper Buffalo	Caney Creek	Mingo	Hercules Glade
ENTERGY ARKANSAS-INDEPENDENCE	35.677703	-91.41205	2014 - 2016	22,531	179.2	276.7	174.5	172.4
PLUM POINT ENERGY STATION STATION UNIT 1	35.657176	-89.94928	2014 - 2016	2,759	311.3	396.5	145	287.4
FUTUREFUEL CHEMICAL COMPANY	35.722567	-91.52498	2013 - 2015	2,837	168.5	270.5	161.4	177
EVERGREEN PACKAGING-PINE BLUFF	34.229307	-91.94748	2013 - 2015	986	221.5	191	337.7	283.3
ALBEMARLE CORPORATION-SOUTH PLANT	33.177437	-93.21603	2013 - 2015	1,382	293.3	152.2	502.4	387
SWEPCO-JOHN W TURK JR POWER PLANT	33.652797	-93.80628	2014 - 2016	908	242.5	82.4	487.2	341.6
ASH GROVE CEMENT CO./Foreman Plant	33.695302	-94.42302	2013 - 2015	369	251.8	81.4	523.6	354.1
NUCOR-YAMATO STEEL COMPANY	35.908502	-89.77582	2013 - 2015	301	325.9	421.2	121.5	291.9

Facility	Q/d			
	Upper Buffalo	Caney Creek	Mingo	Hercules Glade
	SO2	SO2	SO2	SO2
ENTERGY ARKANSAS-INDEPENDENCE	126	81	129.12	130.69
PLUM POINT ENERGY STATION STATION UNIT 1	9	7	19.03	9.60
FUTUREFUEL CHEMICAL COMPANY	17	10	17.58	16.03
EVERGREEN PACKAGING-PINE BLUFF	4	5	2.92	3.48
ALBEMARLE CORPORATION-SOUTH PLANT	5	9	2.75	3.57
SWEPCO-JOHN W TURK JR POWER PLANT	4	11	1.86	2.66
ASH GROVE CEMENT CO./Foreman Plant	1	5	0.70	1.04
NUCOR-YAMATO STEEL COMPANY	1	1	2.48	1.03

Entergy Services, Inc., on behalf of Entergy Arkansas, Inc.

Analysis of Reasonable Progress
Arkansas Regional Haze Program
First Planning Period

Submitted to:

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1. EXECUTIVE SUMMARY

This report provides an update to the monitoring information originally provided by Entergy Arkansas, Inc. (EAI) and Trinity Consultants (Trinity) on August 7, 2015[1] and updated on November 15, 2016[2], and analyzes Reasonable Progress for the Regional Haze Program's first planning period (ending in 2018) – specifically addressing the controls that would be needed to meet the emission limits for EAI's Independence units in the final Arkansas Regional Haze Federal Implementation Plan (FIP).[3]

The Interagency Monitoring of Protected Visual Environments (IMPROVE) has established a network of monitoring stations at mandatory Federal Class I areas across the country to measure and record visibility parameters from the atmosphere, such as sulfate and nitrate particles. From this monitoring data, visibility impairment, or haze, is determined. As of the date of this report, the most recent annual summary available is for calendar year 2015. Though the complete dataset and summary for 2016 is not yet available, un-summarized monitoring data up to July 31, 2016 are available. From this, current visibility conditions can be derived.

As presented in this report, visibility at the Class I areas in Arkansas – Caney Creek Wilderness Area (CACR) and Upper Buffalo Wilderness Area (UPBU) – has improved at a rate faster than necessary to maintain the Uniform Rate of Progress (URP) towards the Regional Haze Program goal of elimination of manmade visibility impairment by 2064. The monitoring data demonstrate that visibility improvement at these Class I areas currently exceeds EPA's goals for the first planning period even though the majority of the emission controls prescribed by the FIP have yet to be installed. The same can be said of the two Class I areas in Missouri – Mingo Wilderness Area (MING) and Hercules-Glades Wilderness Area (HEGL) – as documented in Missouri's Five-Year Progress Report to EPA.[4]

The FIP mandates NO_X and SO_2 emission limits for EAI's Independence units 1 and 2 to achieve reasonable progress towards the Regional Haze Program goal. However, due to the current and forecasted status of visibility in the Class I areas, the planned compliance strategies for Best Available Retrofit Technology (BART) requirements (*e.g.*, the cessation of coal burning at EAI's White Bluff facility in 2028),[5] implementation of other Clean Air Act (CAA) programs such as the

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[1] Trinity Consultants, *Regional Haze Modeling Assessment Report – Entergy Arkansas, Inc. – Independence Plant*, August 7, 2015 (Trinity Project No. 154401.0074), submitted as an Exhibit C to Entergy Arkansas, Inc.'s *Comments On the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas*.

[2] Trinity Consultants, *Assessment of Recent Class I Area IMPROVE Monitoring Data*, November 15, 2016 (Trinity Project No. 163701.0059).

[3] Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Final Rule, 81 Fed. Reg. 66,332 – 66,421 (September 27, 2016).

[4] State of Missouri Regional Haze 5-Year Progress Report (https://dnr.mo.gov/env/apcp/reghaze/complete-RegionalHaze-5-yr-Rpt-submittal.pdf), August 29, 2014, p. 17.

[5] The emissions control technologies on which the BART SO_2 and NO_X emissions limits are based are identified in Appendix C. Certain of the units subject to the FIP also intend to install NO_X emissions controls to meet CSAPR. For example, EAI is planning to install low NO_X burners and separated overfire air at White Bluff and Independence to comply with CSAPR's ozone season NO_X program.

Cross State Air Pollution Rule (CSAPR), and considering the four reasonable progress factors[6] (including EAI's proposed cessation of coal use at Independence by 2030 as part of resolving the 8th Circuit Court of Appeals FIP litigation), the emission limits required by the FIP for EAI's Independence units 1 and 2 are not necessary.

[6] EAI asserts that consideration of these factors is not necessary with respect to Arkansas' sources for the first planning period. However, without waiver, the four factors are addressed herein to provide a more comprehensive evaluation of reasonable progress for Arkansas' Class I areas.

2. INTRODUCTION TO VISIBILITY AND HAZE INDEX

Visibility is most simply measured as the farthest distance that can naturally be seen by an average human. Light waves diffract and are absorbed as they pass through and around particles and molecules in the atmosphere. The level of visibility therefore naturally decreases at greater distances as light waves come into contact with a greater number of these miniscule obstacles. This natural scattering of light waves is called Rayleigh scattering. Additionally, both anthropogenic (manmade) and non-anthropogenic sources of pollution, which result in increased atmospheric concentrations of particles and molecules, have an effect on visibility. The primary contributors to visibility impairment or "light extinction" include sulfates, nitrates, organic carbon, elemental carbon, crustal material, and sea salt."[7,8] Through the Interagency Monitoring of Protected Visual Environments (IMPROVE) program, concentrations of these species are monitored at each mandatory Federal Class I area[9] every three (3) days for 24 hours. The species concentrations are converted to light extinction using the Revised IMPROVE Equation:[10,11]

Equation 1. Revised IMPROVE Equation

$$
\begin{aligned}
b_{ext} = 2.2 \; & \times f_S(RH) \times [Small\ Sulfate] \\
& + 4.8 \times f_L(RH) \times [Large\ Sulfate] \\
& + 2.4 \times f_S(RH) \times [Small\ Nitrate] \\
& + 5.1 \times f_L(RH) \times [Large\ Nitrate] \\
& + 2.8 \times [Small\ Organic\ Mass] \\
& + 6.1 \times [Large\ Organic\ Mass] \\
& + 10 \times [Elemental\ Carbon] \\
& + 1 \times [Fine\ Soil] \\
& + 1.7 \times f_{SS}(RH) \times [Sea\ Salt] \\
& + 0.6 \times [Coarse\ Mass] \\
& + Rayleigh\ Scattering\ (Site\ Specific) \\
& + 0.33 \times [NO_2(ppb)]
\end{aligned}
$$

Where b_{ext} represents the light extinction coefficient in inverse megameters (Mm^{-1}), and individual species concentrations are shown in brackets with units of micrograms per cubic meter ($\mu g/m^3$). The f_L and f_S terms are unitless water growth factors given as functions of relative humidity (RH) for concentrations of large and small sulfates and nitrates, while f_{SS} represents the water growth factor for sea salt concentrations. The numerical constants given in the equation (e.g., 2.2) represent

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7 U.S. EPA, *Visibility in Mandatory Federal Class I Areas (1994-1998): A Report to Congress*. EPA-452/R-01-008. Chapter 1 – Introduction to Visibility Issues. November 2001.

8 Kumar, Naresh, et al. "Revised Algorithm for Estimating Light Extinction from IMPROVE Particle Speciation Data." Journal of the Air & Waste Management Association JAWMA 57.11 (2007): 1326-336.

9 Mandatory Federal Class I areas included all international parks (IP), national wilderness areas exceeding 5,000 acres, national memorial parks exceeding 5,000 acres, and national parks exceeding 6,000 acres, in existence on August 7, 1977, and are listed, by state, in 40 Code of Federal Regulations §§81.401 – 437.

10 In 1999, an equation to estimate light extinction based on available IMPROVE data was incorporated into the Regional Haze Rule (Old IMPROVE Equation). In 2007, a revised equation was developed to reduce "bias for high and low light extinction extremes" and to make the equation "more consistent with the recent atmospheric aerosol literature (Revised IMPROVE Equation).

11 U.S. EPA, *Visibility in Mandatory Federal Class I Areas (1994-1998): A Report to Congress*. EPA-452/R-01-008. Chapter 1 – Introduction to Visibility Issues. November 2001.

dry mass extinction efficiency terms in units of square meters per gram (m^2/g).[12] Measurements and calculated light extinction values are published by IMPROVE on a Colorado State University webpage.[13]

Because the units for light extinction (Mm^{-1}) are difficult to conceptualize and compare in practical terms, the haze index (deciview or dv) was developed. The haze index is calculated as a function of the ratio of the calculated light extinction coefficient to the approximate average extinction value due to Rayleigh scattering alone (10 Mm^{-1}).

Equation 2. Formula for Haze Index (dv)

$$Haze\ Index\ (dv) = 10 \times \ln\left(\frac{b_{ext}\ [Mm^{-1}]}{10\ [Mm^{-1}]}\right)$$

The deciview scale provides a simpler representation of visibility deterioration, with natural conditions having a calculated haze index of approximately zero deciviews, depending on the site-specific level of Rayleigh scattering.[14] The larger the haze index, the more degradation of visibility at a particular location. According to EPA, a one-deciview change represents a "small but noticeable change in haziness".[15] Other studies, however, have suggested that a "1-deciview change never produces a perceptible change in haze."[16]

[12] Kumar, Naresh, et al. "Revised Algorithm for Estimating Light Extinction from IMPROVE Particle Speciation Data." Journal of the Air & Waste Management Association JAWMA 57.11 (2007): 1326-336.
[13] IMPROVE. Regional Haze Rule Summary data through 1988-2015. (http://views.cira.colostate.edu/fed/SiteBrowser/Default.aspx)
[14] U.S. EPA, *Visibility in Mandatory Federal Class I Areas (1994-1998): A Report to Congress*. EPA-452/R-01-008. Chapter 1 – Introduction to Visibility Issues. November 2001.
[15] Regional Haze Regulations; Final Rule, 64 Fed. Reg. 35,725 - 35,727 (July 1, 1999).
[16] Ronald C. Henry, "Just-Noticeable Differences in Atmospheric Haze," Journal of the Air & Waste Management Association, Vol. 52 at 1,238 (October 2002).

3. REGIONAL HAZE RULE

Section 169A of the Clean Air Act (CAA) requires implementation plans which address visibility protection for federal Class I areas to include "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal" of elimination of manmade visibility impairment at such areas.[17] To effectuate the CAA's national visibility goal, EPA promulgated the Regional Haze Rule, which has as its own goal to achieve natural visibility conditions in each Class I area by 2064.[18] There are two federal Class I areas located in Arkansas for which measures are required to make reasonable progress: Caney Creek Wilderness Area (CACR) and Upper Buffalo Wilderness Area (UPBU).

When tracking the progress of remedying visibility impairment at a particular Class I area based on measured data, EPA recommends taking the average of the haze indices, in deciviews, associated with the 20 percent most impaired days of the year (*i.e.*, "20 percent worst") and the 20 percent least impaired days of the year (*i.e.*, "20 percent best").[19] To achieve the goal, the average haze index for the 20 percent worst days must improve to meet the level of the 20 percent best days, and the 20 percent best days value must not degrade.[20]

A "glidepath" from the 20 percent worst days average to the 20 percent best days average is defined for each Class I area. It is called the Uniform Rate of Progress ("URP"). The URP is a straight line from baseline visibility conditions (average 20 percent worst days as of 2004) to natural visibility conditions (to be achieved in 2064 for the 20 percent worst days). The slope of that line is the difference between the two conditions divided by the 60-year program. The URPs for CACR and UPBU are presented in Figure 3-1 and Figure 3-2, respectively.

In addition to establishing URPs for each Class I area, as part of each state's Long Term Strategy, states (or EPA) also establish Reasonable Progress Goals (RPGs) for each area for the end of each planning period, i.e., 2018, 2028, and so on. The 2018 RPGs set by EPA for the Arkansas Class I areas are 22.47 dv for CACR and 22.51 dv for UPBU.[21]

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[17] 42 U.S.C. § 7491(b)(2).

[18] Regional Haze Regulations; Final Rule, 64 Fed. Reg. 35,732 and 35,766 (July 1, 1999).

[19] Regional Haze Regulations; Final Rule, 64 Fed. Reg. 35.728 and 35,730 (July 1, 1999).

[20] Regional Haze Regulations; Final Rule, 64 Fed. Reg. 35.730 and 35,734 (July 1, 1999).

[21] Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Final Rule, 81 Fed. Reg. 66,354 (September 27, 2016).

Figure 3-1. CACR Uniform Rate of Progress

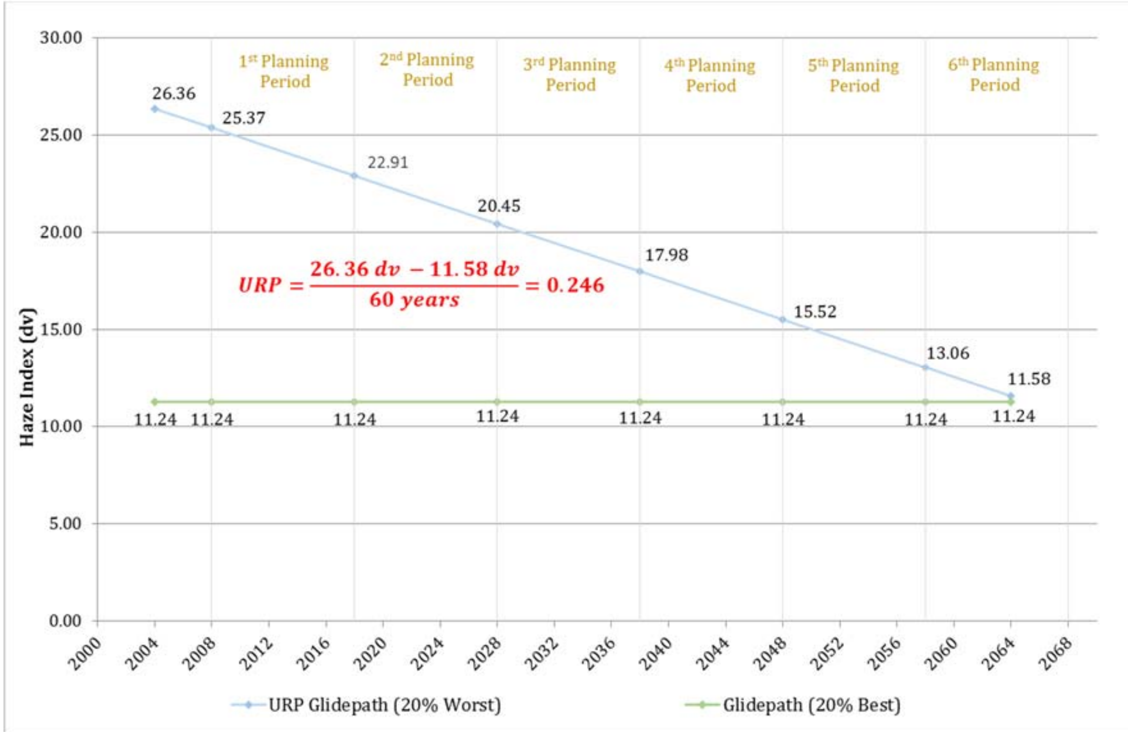
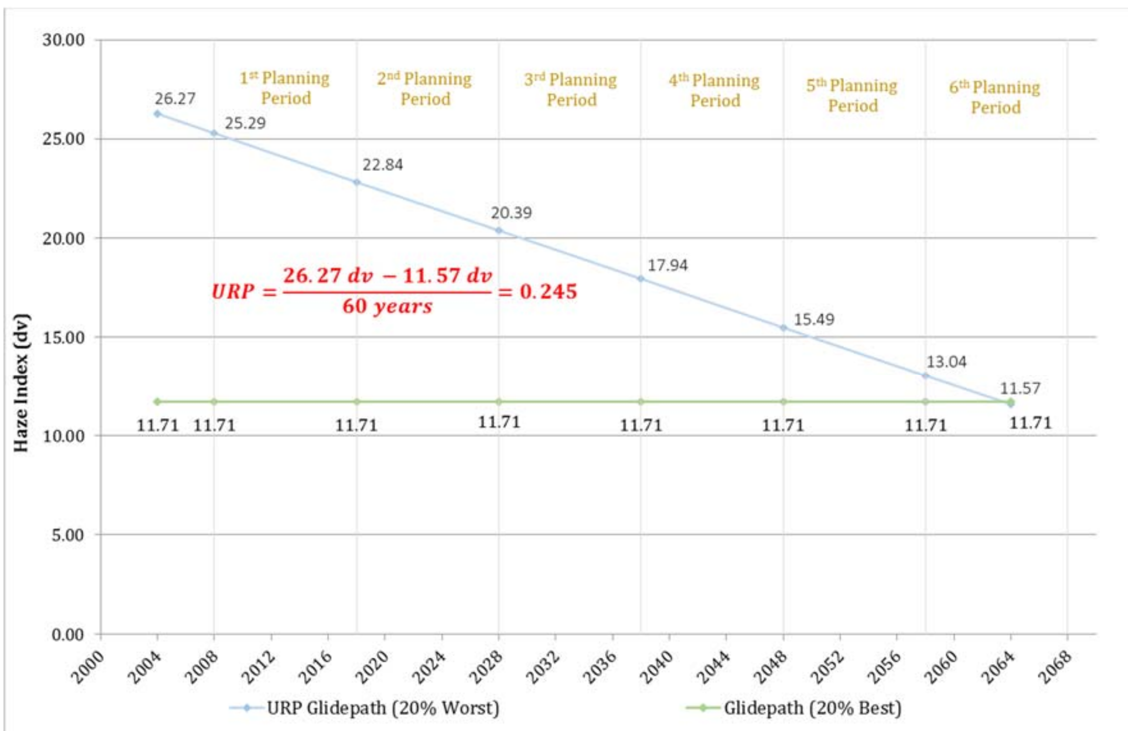


Figure 3-2. UPBU Uniform Rate of Progress



4. RECENT IMPROVE MONITORING DATA

The most recent and complete summary of annual monitoring data available from IMPROVE for CACR and UPBU covers the year 2015. However, as of the date of this report, non-summarized data through July 31, 2016, is available and can be used to calculate the light extinction coefficients (see Equation 1) and haze indices (see Equation 2) for January through July of 2016. Trinity obtained the non-summarized data and compiled an independent summary for January through July of 2016.[22] The species-specific and total light extinction and haze index values for the averages of the 20 percent worst days and the 20 percent best days for the first half of 2016 are shown in Table 4-1.

Table 4-1. Independent Summary of Monitoring Data for January 1, 2016 through July 31, 2016

	20 Percent Worst Days Average		20 Percent Best Days Average	
Light Extinction Value (Mm^{-1})	**CACR**	**UPBU**	**CACR**	**UPBU**
Sulfate	31.46	28.84	4.72	4.80
Nitrate	16.86	21.03	1.04	1.17
Organics	18.49	17.81	2.21	2.31
Carbon	2.96	3.58	0.32	0.38
Soil	3.20	2.78	0.10	0.10
Coarse PM	6.78	6.86	1.41	1.20
Sea Salt	1.12	0.81	0.06	0.06
Total Light Extinction (Mm^{-1})	74.30	72.85	24.75	26.72
Haze Index (dv)	**19.90**	**19.67**	**8.83**	**9.67**

Table 4-2 presents a summary of the annual-average haze index values for each year from 2002 to 2016 (based on first half of the year).[23]

Table 4-2. Summary of Annual Average Haze Index Values from 2002 through 2016

	20 Percent Worst Days Average		20 Percent Best Days Average	
Year	**CACR**	**UPBU**	**CACR**	**UPBU**
2002	27.21	26.74	11.88	12.83
2003	26.54	27.22	10.74	10.62
2004	25.34	25.58	11.11	10.74
2005	29.21	30.47	12.93	13.34
2006	25.68	25.42	12.51	13.00
2007	--	26.17	--	12.45
2008	23.70	24.60	9.24	10.49
2009	22.68	22.62	8.09	9.40
2010	22.94	--	10.76	--
2011	22.67	23.21	11.71	11.51
2012	21.49	21.56	9.54	10.31
2013	21.35	21.25	8.61	8.60
2014	20.72	20.49	8.52	8.13
2015	20.41	19.96	7.03	7.50
2016	19.90	19.67	8.83	9.67

[22] The calculations and data summarizing method were confirmed by downloading and processing the un-summarized data for 2014 and then comparing the results to the values in the 2014 summary found online.
[23] Summarized data are not available for CACR for 2007, UPBU for 2010, and MING for 2002 through 2005.

5. MONITORING DATA COMPARED TO REGIONAL HAZE GOALS

Figure 5-1 and Figure 5-2 present, for CACR and UPBU, respectively, comparisons of the observed haze index values (*see* Section 4) for each year of IMPROVE data, including values from the first half of 2016, to the URPs (*see* Section 3). The same comparisons are shown for the two Missouri Class I areas in Appendix B.

Figure 5-1. CACR Monitored Observations Compared to Uniform Rate of Progress

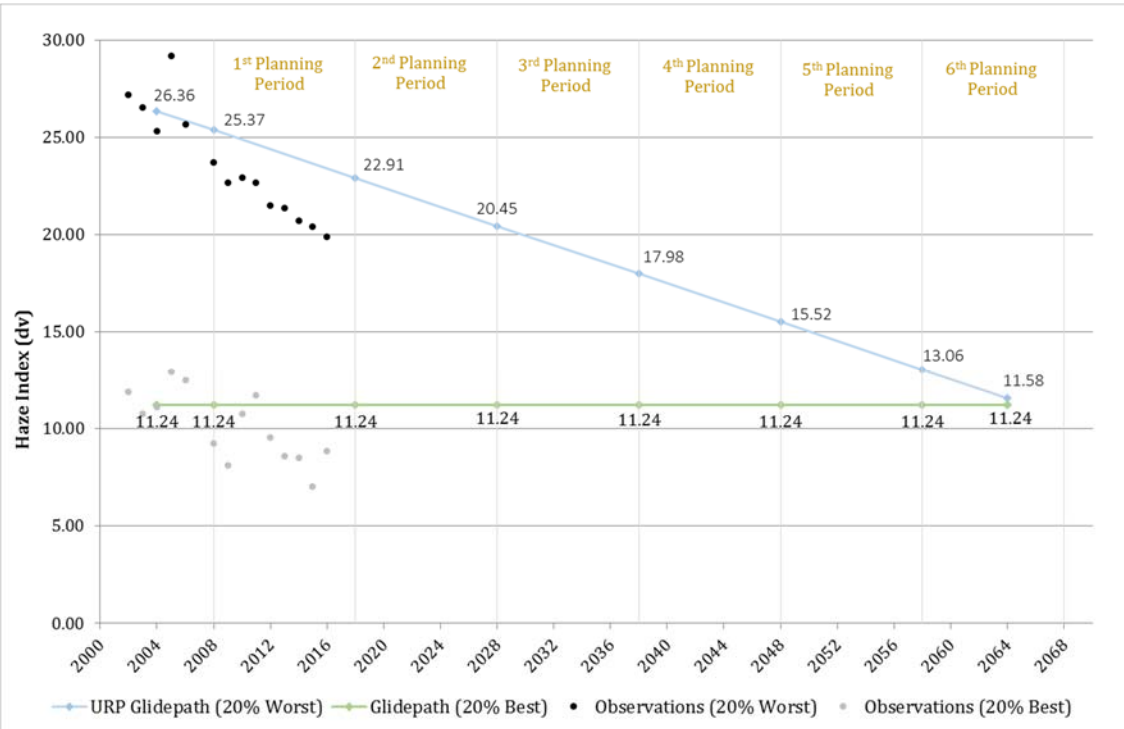
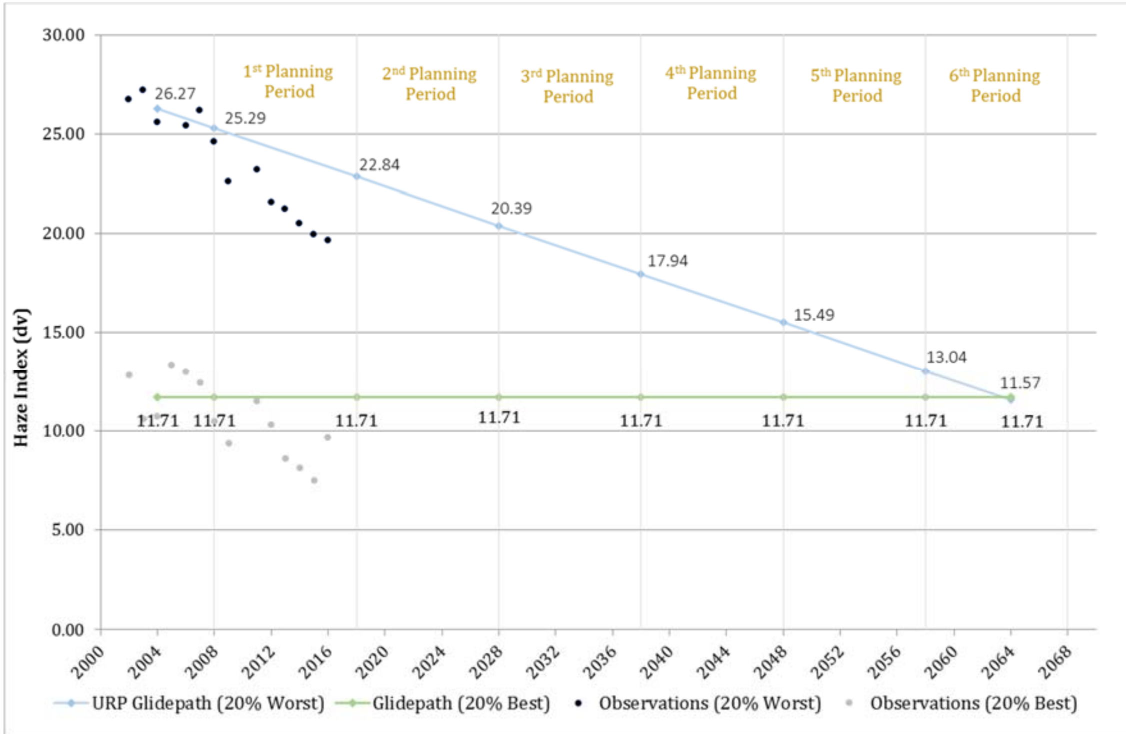


Figure 5-2. UPBU Monitored Observations Compared to Uniform Rate of Progress



As seen in the figures above, the actual visibility impairment, measured as the average of the 20 percent worst days each year, at these Class I areas has declined sharply from 2002 through July of 2016 (the most recent available data). According to the monitor data, the current (January through July 2016) observed 20 percent worst days average haze index values are below the URP values for 2018 as well as the 2018 RPG values. Table 5-1 presents a comparison of the 2016 observed values and the 2018 RPG values.

Table 5-1. 2016 Observed Haze Index Values Compared to 2018 URPs and RPGs

Class I Area	Observed 20 Percent Worst Days Average for 2016 (first half year)	RPG for 2018	Observed Value as % of RPG
CACR	19.90	22.47	88.6 %
UPBU	19.67	22.51	87.4 %

6. REGIONAL HAZE REQUIREMENTS FOR FIRST PLANNING PERIOD

The visibility improvement in the Class I areas that are presented in previous sections of this report have been achieved without installation of any controls for BART or Reasonable Progress at Arkansas' point sources during the time period covered by the visibility index values presented above. Appendix C identifies the emissions control technologies on which the FIP's BART emissions limits are based. To meet the emission limits determined to represent reasonable progress towards the national visibility goal for the first planning period under the FIP, Independence must install NO_X controls by April 27, 2018, and SO_2 controls by October 27, 2021.[24] However, these controls are clearly unnecessary to maintain the URP during the first planning period. Visibility improvement is already on an accelerated pace such that the rate of progress towards the national visibility goal exceeds the uniform rate necessary to remedy visibility impairment at CACR and UPBU by 2064. Given the visibility conditions and the Arkansas sources' ongoing environmental compliance strategies across the CAA programs, it should be concluded that no further measures are necessary for Arkansas to make reasonable progress toward the Regional Haze Program national goal in the first planning period.

This conclusion is consistent with EPA's own guidance to the states, which advises a long-term view of reasonable progress: "you should take into account the fact that the long-term goal of no manmade impairment encompasses several planning periods. It is reasonable for you to defer reductions to later planning periods in order to maintain a consistent glidepath toward the long-term goal."[25] Also, "[g]iven the significant emissions reductions that we anticipate to result from BART…and other Clean Air Act programs…it may be all that is necessary to achieve reasonable progress in the first planning period for some States."[26]

Specifically, the Reasonable Progress emission limits in the FIP--which would require the installation of Spray Dry Absorbers (SDA) on EAI's Independence units 1 and 2--are unnecessary for Arkansas to make reasonable progress toward meeting the national goal in the first planning period. EPA's primary justification for proposing Reasonable Progress limits at Independence is that "it would be unreasonable to ignore a source representing more than a third of the State's SO_2 emissions and a significant portion of NO_X point source emissions."[27] EPA further supports its conclusion that emission limits based on the installation of major control technology are justified based on a finding that the proposed controls at Independence are cost effective.[28] However, the fact that a source may have significant emissions, or that it would be cost effective to control such

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24 Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Final Rule, 81 Fed. Reg. 66,332 - 66,421 (September 27, 2016). The SO_2 compliance date was reiterated by EPA on September 11, 2017, in 82 Fed. Reg. 42,639. EPA proposed to extend the NO_X compliance deadline by 21 months to January 27, 2020, in 82 Fed. Reg. 32,284 (July 13, 2017).

25 U.S. EPA, *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program*, June 1, 2007, p. 1-4.

26 Ibid, p. 4-1.

27 Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Final Rule, 81 Fed. Reg. 18,992 (September 27, 2016).

28 Ibid, pp. 18,994-97. As noted in EAI's comments on the Proposed FIP, however, EPA's cost calculations substantially underestimated the costs to install dry scrubbers at Independence and an accurate estimate of the costs would have rendered the controls not cost effective for reasonable progress purposes. Entergy Arkansas, Inc. Comments on the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas, at 44 (Aug. 7, 2015), EPA Docket No. EPA-R06-OAR-2015-0189-0166 ("EAI Comments").

emissions, is irrelevant for Reasonable Progress purposes for the reasons stated above. Moreover, as discussed below, the FIP-required emission limits at Independence--allegedly established to achieve reasonable progress for the first planning period despite that fact that visibility at Arkansas' Class I areas is already better than EPA's own RPGs for that period--are unreasonable in consideration of the four statutory factors for evaluating the feasibility of reasonable progress requirements.[29]

A. **The non-air quality environmental impacts of SDA at Independence.** Non-air quality environmental impacts of SDA primarily relate to available water resources and waste byproducts. SDA systems consume a significant quantity of water, and the required water must be relatively clean. In addition, SDA systems also generate a large waste byproduct stream, containing calcium salts, which must be landfilled. If not fixated during the disposal process, the calcium salts are soluble and may dissolve and appear in the landfill leachate.

B. **The cost of compliance, time necessary for compliance, and remaining useful life (RUL) of the Independence coal units.** As part of resolving the 8th Circuit FIP appeal litigation, Entergy proposes to cease to combust coal at the Independence units by the end of 2030. When the coal units' RUL is properly considered along with the time necessary for compliance with the SO_2 emission limit (*e.g*. the 5-year compliance deadline in the FIP), the costs of compliance for each unit are approximately $4,000/ton of SO_2 removed according to EPA's own cost estimates.[30] These costs are not reasonable or cost-effective.

   Figure 6-1 presents cost effectiveness values for SDA for the Independence units calculated using the spreadsheet developed by EPA for the FIP[31], revised to reflect a 9-year equipment life. The 9-year life is based on a 2030 date for the end of the coal-burning life and, conservatively, on the FIP's compliance date of 2021.[32]

[29] 42 U.S.C. § 7491(g)(1). EAI asserts that consideration of these factors is not required because no further measures are necessary for Arkansas to make reasonable progress toward the Regional Haze Program national goal during the first planning period. However, without waiver, the four factors are addressed herein to provide a more comprehensive evaluation of reasonable progress for Arkansas' Class I areas.

[30] All cost values in this report are presented solely for the purpose of this report and without waiving previously documented positions regarding proper cost estimating methods and inputs. *See* EAI Comments at 7-11.

[31] "White Bluff_R6 cost revisions2-revised.xlsx" from EPA Docket EPA-R06-OAR-2015-0189-0205. Before revising the equipment life value, the cost effectiveness ($/ton) results matched the values presented in the final FIP: $2,853/ton and $2,634/ton for Unit 1 and Unit 2, respectively.

[32] Considering the current state of the FIP and the replacement SIP that Arkansas is developing, a more realistic compliance date would be 2023 – five years from an anticipated final approval of the SIP in 2018. The five-year compliance timeline is the minimum necessary for engineering, procuring, installing, and commissioning a SDA.

Figure 6-1. EPA Estimated Cost Effectiveness for SDA for Independence Units 1 and 2, Revised to Consider a Shortened Remaining Useful Life

Independence Unit 1		
Item	Corrected White Bluff Cost to 0.68 lbs/MMBtu	Comments
Total Annualized Cost	$54,903,656	Assumed same as White Bluff Unit 1
Interest Rate (%)	7	
Equipment Lifetime (years)	9	
Capital Recovery Factor (CRF)	0.1535	
SO2 Emission Rate (lbs/MMBtu)	0.63	Max monthly value from 2009-2013 for Unit 1
Controlled SO2 Emission Rate (%)	90.49	Assume 95%. If outlet < 0.06 lbs/MMBtu, then assume % control for 0.06 lbs/MMBtu.
SO2 Emission Baseline (tons)	14,269	3 -yr avg. 2009-2013 for Unit 1, excluding max and min
SO2 Emission Reduction (tons)	12,912	
Cost Effectiveness ($/ton)	$4,252	

Independence Unit 2		
Item	Corrected White Bluff Cost to 0.68 lbs/MMBtu	Comments
Total Annualized Cost	$54,903,656	Assumed same as White Bluff Unit 1
Interest Rate (%)	7	
Equipment Lifetime (years)	9	
Capital Recovery Factor (CRF)	0.1535	
SO2 Emission Rate (lbs/MMBtu)	0.61	Max monthly value from 2009-2013 for Unit 2
Controlled SO2 Emission Rate (%)	90.19	Assume 95%. If outlet < 0.06 lbs/MMBtu, then assume % control for 0.06 lbs/MMBtu.
SO2 Emission Baseline (tons)	15,511	3 -yr avg. 2009-2013 for Unit 2, excluding max and min
SO2 Emission Reduction (tons)	13,990	
Cost Effectiveness ($/ton)	$3,925	

(red text reflects revised equipment life values; no other inputs or equations/cell-references were changed; yellow-highlighting is original to EPA's spreadsheet;)

A. **The minimal contribution that the Independence units – and Arkansas point sources in general – have on visibility impacts in the Class I areas.** As documented in EAI's comments on the proposed FIP[33] and further explained in Appendix A to this report, the emissions from Independence are one of many factors contributing to haze at Arkansas' Class I areas but have only a minimal impact on visibility impairment. Therefore, emissions controls at Independence would have no discernable impact on visibility.

[33] *See* EAI Comments at 17-43.

7. LONG TERM STRATEGY CONSIDERATIONS

Visibility impairment has steadily declined throughout the first planning period. The reductions in visibility-impairing emissions have occurred across nearly the entire spectrum of source types – from point sources to areas sources and mobile sources. It is expected that further improvements will be more difficult as visibility impairment values move closer to natural conditions. For example, the difficulty of even quantifying improvements from area sources was recognized by EPA when it agreed not to evaluate such sources for Reasonable Progress controls in the first planning period.[34] As documented in Appendix A, the single largest source type influencing Arkansas' share of the contribution to visibility impairment is area sources (not point sources like Independence). However, planned emissions decreases, e.g., resulting from the implementation of CSAPR and the increasingly more stringent National Ambient Air Quality Standards (NAAQS)[35], should cause visibility impairment to continue to decline. The cessation of coal usage at both White Bluff in 2028 and at Independence in 2030 will supplement these decreases.

[34] Approval and Promulgation of Implementation Plans; Arkansas; Approval of Regional Haze State Implementation Plan Revision and Withdrawal of Federal Implementation Plan for NO_X for Electric Generating Units in Arkansas; Proposed Rule, 82 Fed. Reg. 42,632 (September 11, 2017).

[35] The Arkansas Department of Environmental Quality (ADEQ), in consultation with Federal Land Managers and other states, addressed additional ongoing air pollution control programs as well as mitigation of construction activities, source retirements/replacements, smoke management, and other visibility-affecting measures related to all sources – major and minor stationary sources, mobile sources, and area sources – as part of its Long Term Strategy in its September 9, 2008 *State of Arkansas Regional Haze Rule State Implementation Plan.*

APPENDIX A: ANALYSIS OF SOURCE CATEGORY AND SOURCE-SPECIFIC CONTRIBUTIONS TO CLASS I AREA VISIBILITY IMPACTS

All data presented in this Appendix were extracted from the modeled source apportionment extinction data from the Central Regional Air Planning Association (CENRAP) Particulate Matter Source Apportionment Technique (PSAT) tool. The data were organized by geographic region and source category, so that the individual contribution of each source category in each geographic region could be determined.

EPA's Reasonable Progress analysis primarily focused on point source contributions to light extinction at CACR and UPBU. As a result, EPA chose to limit its evaluation of potential Reasonable Progress controls solely to Arkansas' largest emitting point sources - specifically, to Independence. However, Arkansas point sources are relatively insignificant contributors to visibility impairment in CACR and UPBU compared to most of the other regions modeled by CENRAP and are not even the biggest source group contributor in Arkansas to visibility impairment in these Class I areas.

Figures A-1 and A-2 display the modeled percent contribution of elevated and low-level point sources to the total light extinction at CACR and UPBU from the significantly contributing geographic regions.[36] Also included in these figures is the combined total percentage contribution from all point sources in all geographic regions. As shown in the CACR figure, of a total point source contribution of 61.85 percent at CACR in 2002, Arkansas's point sources contributed only 2.87 percent, making Arkansas point sources only the eighth highest point source contributor. Similarly, of the 60.35 percent total point source contribution at UPBU in 2002, Arkansas point sources were the ninth highest point source contributor with only a 2.47 percent contribution.

[36] These figures were originally presented as Figure 3 and Figure 4 in Entergy Arkansas Inc., *Comments On the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas*, Docket No. EPA-R06-OAR-2015-0189, August 7, 2015.

Figure A-1. Regional Point Source Percentage of Total Extinction at CACR (20 Percent Worst, 2002)

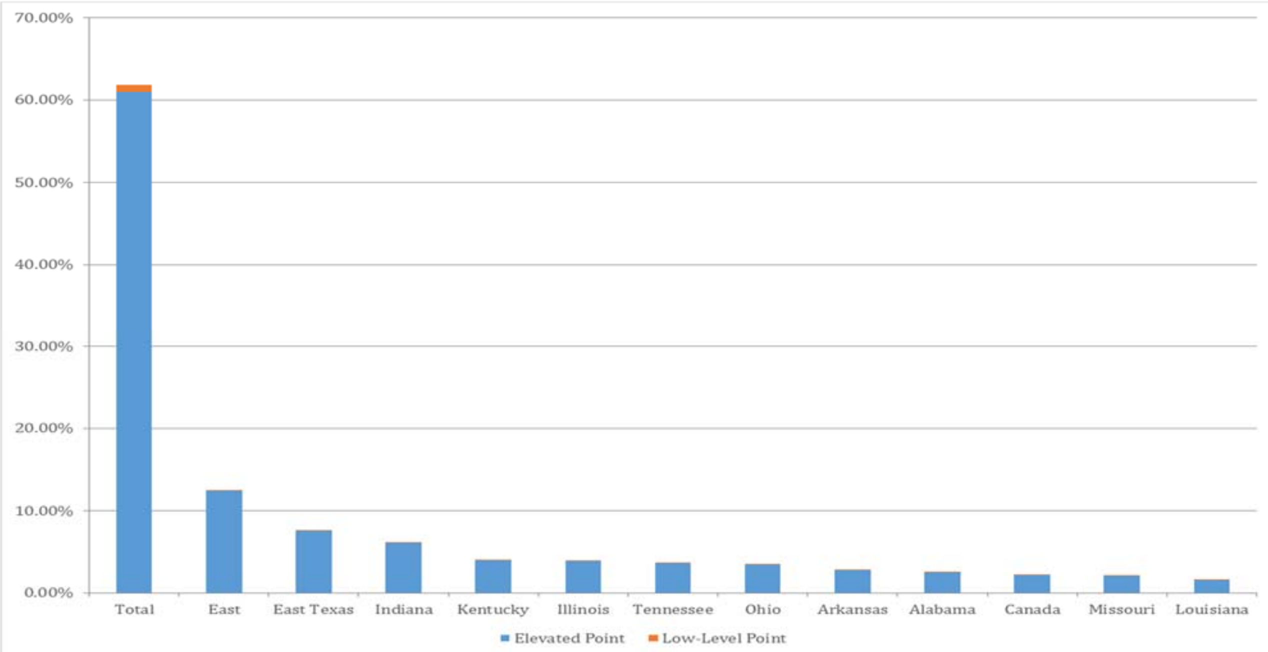
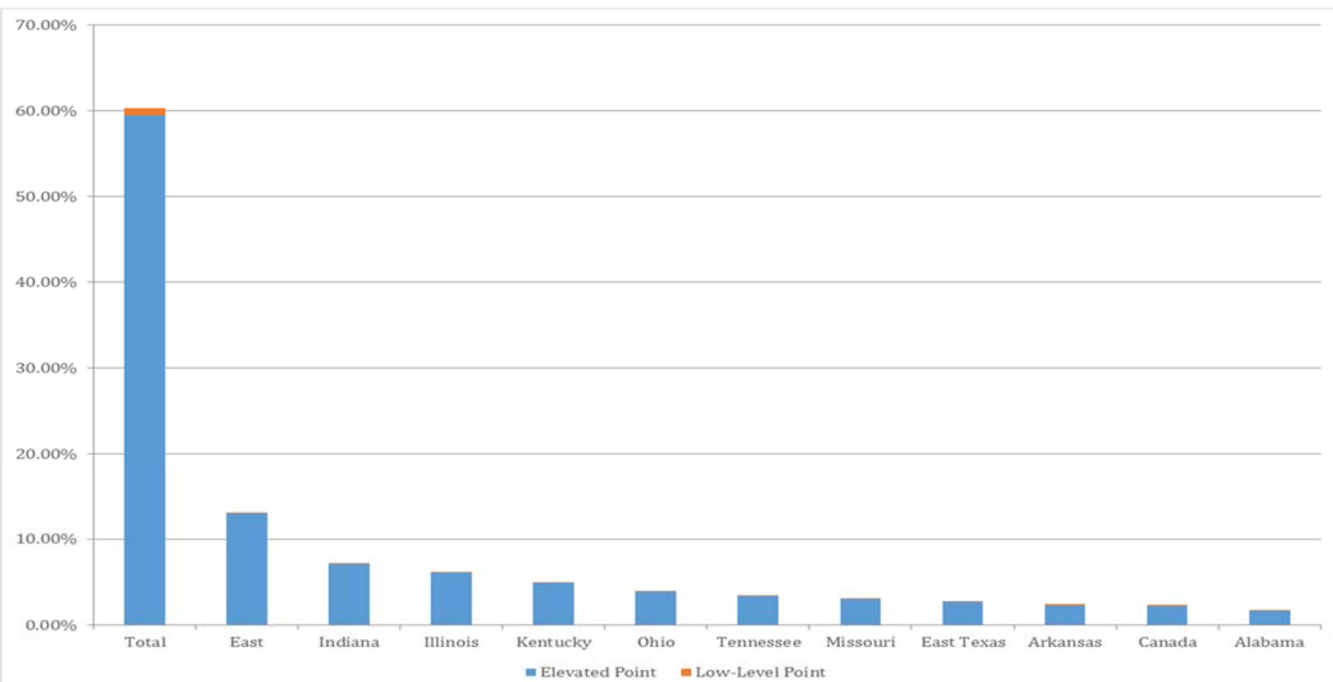


Figure A-2. Regional Point Source Percentage of Total Extinction at UPBU (20 Percent Worst, 2002)



In addition, as demonstrated in Figures A-3 and A-4 below, most of Arkansas' share of the contribution to visibility impairment comes from area and mobile sources, not point sources.[37] At

[37] These figures were originally presented as Figure 5 and Figure 6 in Entergy Arkansas Inc., *Comments On the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas*, Docket No. EPA-R06-OAR-2015-0189, August 7, 2015.

CACR, Arkansas area sources contribute 3.75 percent of the overall extinction and Arkansas' combined point source category (*i.e.*, elevated and low-level point sources) contributes only 2.87 percent. Even more significantly, Arkansas area sources contributed 5.09 percent towards extinction at UPBU compared to 2.47 percent from the combined Arkansas point sources.

Figure A-3. Regional Percentage of Total Extinction at CACR (20 Percent Worst, 2002)

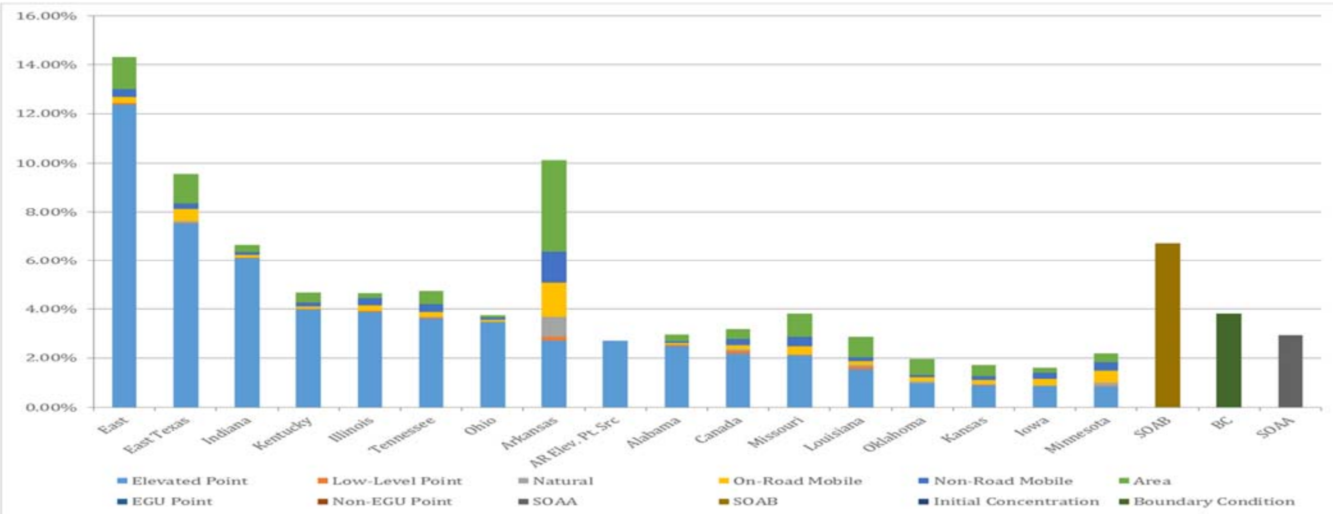
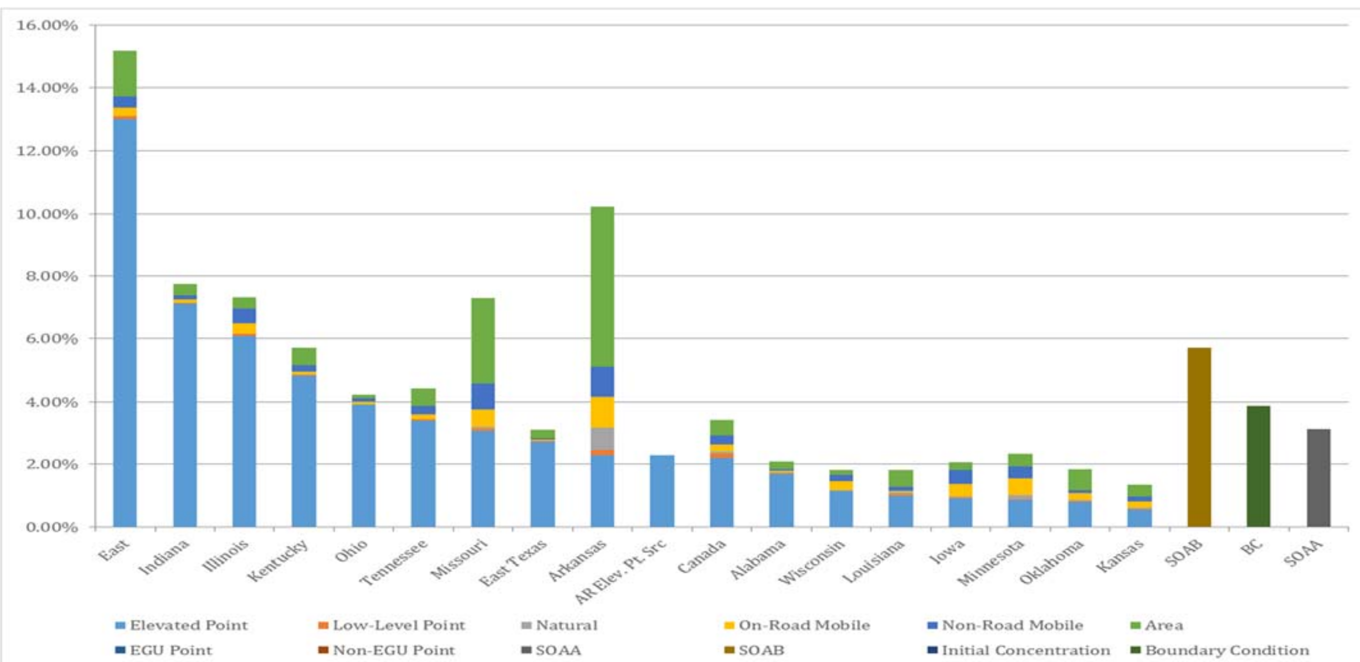


Figure A-4. Regional Percentage of Total Extinction at UPBU (20 Percent Worst, 2002)



On a source-specific (Independence-only) basis, the contribution is even smaller. CENRAP's predictive modeling demonstrates that sulfate from all (elevated and low level) Arkansas point sources is responsible for 3.58 percent of the total light extinction at CACR and 3.20 percent at UPBU; and nitrate from Arkansas point sources is responsible for 0.29 percent of the total light extinction at CACR and 0.25 percent at UPBU.[38] The Independence units' share of emissions to this minimal contribution from Arkansas point sources to visibility impairment is even less. EAI and Trinity submitted CAMx modeling showing that the contribution to visibility impairment by Independence is less than one half of one percent of the visibility impairment in both Arkansas Class I areas.[39]

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[38] Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Final Rule, 81 Fed. Reg. 18,990 (September 27, 2016).

[39] Entergy Arkansas Inc., *Comments On the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas*, Docket No. EPA-R06-OAR-2015-0189, August 7, 2015.

APPENDIX B: OBSERVATIONS COMPARED TO UNIFORM RATES OF PROGRESS FOR MISSOURI'S CLASS I AREAS

Figure B-1. MING Monitored Observations Compared to Uniform Rate of Progress

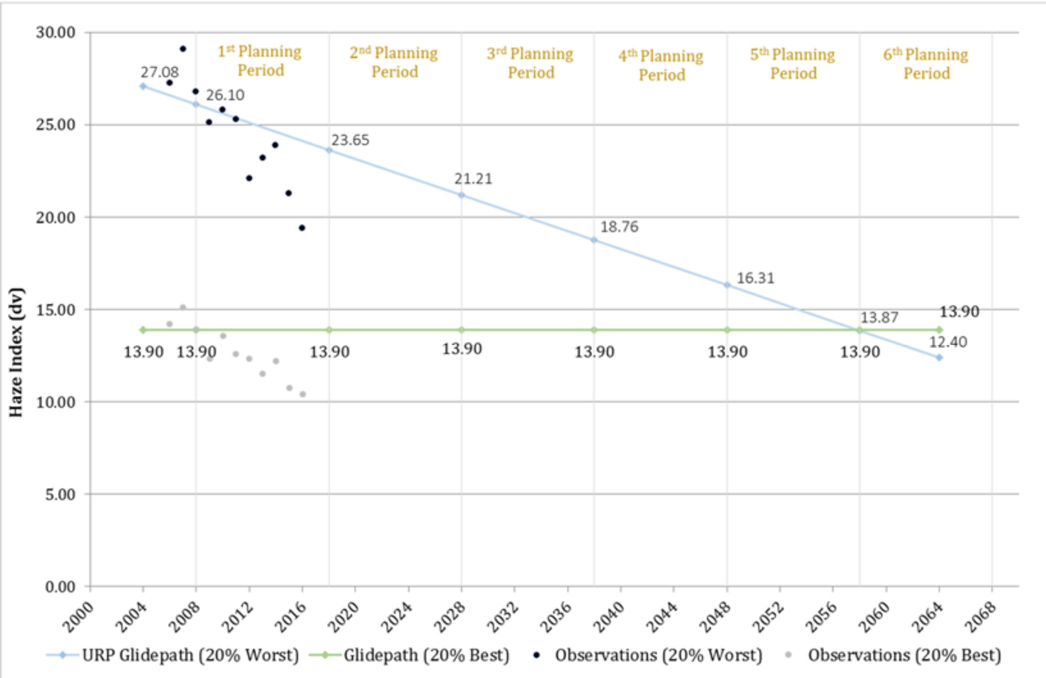
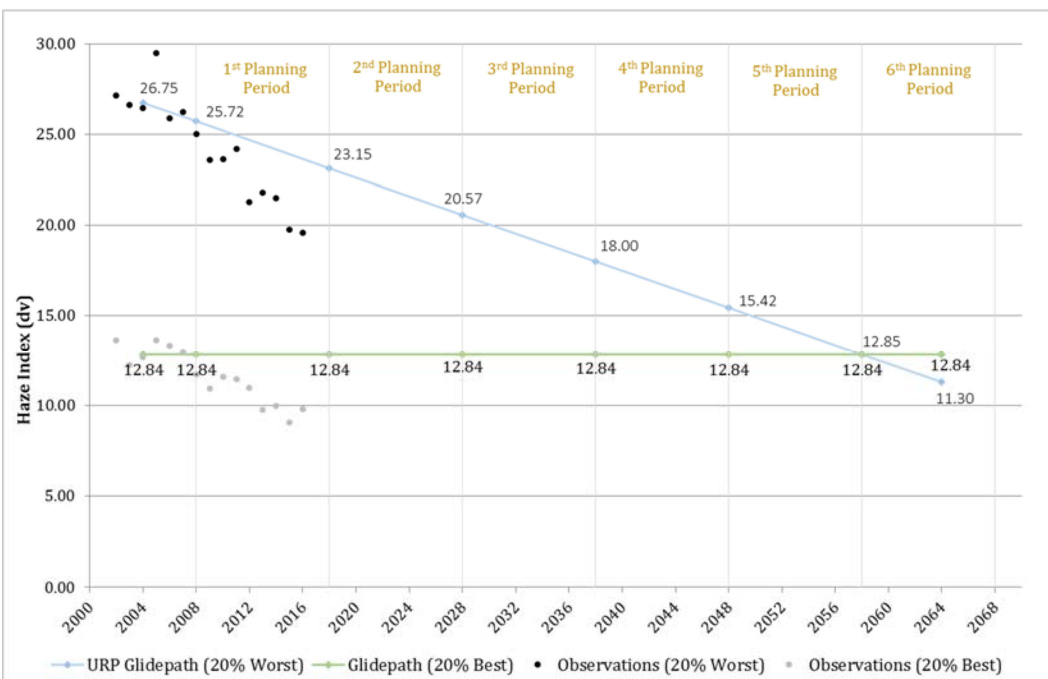


Figure B-2. HEGL Monitored Observations Compared to Uniform Rate of Progress



APPENDIX C: CONTROLS ON WHICH THE BART EMISSIONS LIMITS ARE BASED

The FIP's BART emission limits are based on the following emissions control technologies:[40]

Company	Facility	Unit	Controls	Compliance Deadline
AEP/SWEPCO	Flint Creek	1	Novel Integrated Desulfurization (NID)	April 27, 2018
			Low NO_X Burners & Over Fire Air (LNB/OFA)	April 27, 2018
AECC	Bailey	1	Fuel sulfur content limit	October 27, 2021
AECC	McClellan	1	Fuel sulfur content limit	October 27, 2021
EAI	White Bluff	1	Spray Dry Absorber (SDA)	October 27, 2021
			LNB/OFA	April 27, 2018
		2	SDA	October 27, 2021
			LNB/OFA	April 27, 2018
EAI	Lake Catherine	4	Burners Out Of Service (BOOS)	October 27, 2019
Domtar	Ashdown	Boiler 2	Additional scrubbing reagent	October 27, 2021
			LNB	October 27, 2021

[40] Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Final Rule, 81 Fed. Reg. 66,332 - 66,421 (September 27, 2016).

Exhibit I

Entergy Services, Inc., on behalf of Entergy Arkansas, Inc.

Supplemental Information
Analysis of Reasonable Progress
Arkansas Regional Haze Program
First Planning Period

Submitted to:

Arkansas Department of Environmental Quality (ADEQ)
Office of Air Quality
5301 Northshore Drive
North Little Rock, AR 72118-5317

Prepared By:

TRINITY CONSULTANTS
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February 2, 2018

Trinity Project 183702.0022

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1. INTRODUCTION

This report provides an update to the monitoring information originally provided by Entergy Arkansas, Inc. (EAI) and Trinity Consultants (Trinity) on August 7, 2015,[1] which was updated on November 15, 2016,[2] and September 27, 2017[3]. As of the September 27, 2017 update, only data for the first half of 2016 was available. Raw monitoring ("observed") data for all months of 2016 are now available and are summarized herein. This report provide supplemental information only. The previous reports should be reviewed for explanations of how the raw data was summarized, how the deciview metric is calculated, and other background information.

Additionally, this report provides site-specific control cost estimates developed by Sargent & Lundy (S&L) for the Independence Steam Electric Station (Independence). These costs can be compared to the cost values developed by EPA for the FIP, the costs used by ADEQ for the SIP, and the costs that were presented – revised to reflect a 9-year equipment life – in the September 27, 2017 report.

[1] Trinity Consultants, *Regional Haze Modeling Assessment Report – Entergy Arkansas, Inc. – Independence Plant* (August 7, 2015) (Trinity Project No. 154401.0074), submitted as an Exhibit C to Entergy Arkansas, Inc.'s *Comments On the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas*.

[2] Trinity Consultants, *Assessment of Recent Class I Area IMPROVE Monitoring Data* (November 15, 2016) (Trinity Project No. 163701.0059).

[3] Trinity Consultants, Analysis of Reasonable Progress - Arkansas Regional Haze Program - First Planning Period (September 27, 2017) (Trinity Project No. 173702.0014).

2. UPDATED IMPROVE MONITORING DATA

The most recent summary of annual monitoring data available from IMPROVE for CACR and UPBU has been completed through the year 2015. As of the date of this report, non-summarized data through December 31, 2016, is available and can be used to calculate the light extinction coefficients and haze indices for 2016. Trinity obtained the non-summarized data and compiled an independent summary for 2016. The species-specific and total light extinction and haze index values for the averages of the 20 percent worst days[4] and the 20 percent best days for 2016 are shown in Table 2-1.

Table 2-1. Independent Summary of Monitoring Data for 2016

	20 Percent Worst Days Average		20 Percent Best Days Average	
Light Extinction Value (Mm^{-1})	**CACR**	**UPBU**	**CACR**	**UPBU**
Sulfate	31.32	31.42	5.64	5.99
Nitrate	14.15	17.25	0.98	1.21
Organics	17.18	16.74	2.59	2.64
Carbon	3.11	3.38	0.41	0.44
Soil	2.64	2.34	0.11	0.11
Coarse PM	6.17	6.41	1.31	1.39
Sea Salt	1.07	0.76	0.08	0.07
Total Light Extinction (Mm^{-1})	70.08	70.12	25.31	26.32
Haze Index (dv)	**19.35**	**19.33**	**9.07**	**9.56**

Table 2-2 presents a summary of the annual-average haze index values for each year from 2002 to 2016.

[4] The revised Regional Haze Rule published on January 10, 2017, changed the definition of the "most impaired days" but is only applicable to the second and subsequent planning periods. Accordingly, this report uses the definition of the most impaired days that is applicable to the first planning period.

Table 2-2. Summary of Annual Average Haze Index Values from 2002 through 2016

Year	20 Percent Worst Days Average		20 Percent Best Days Average	
	CACR	UPBU	CACR	UPBU
2002	27.21	26.74	11.88	12.83
2003	26.54	27.22	10.74	10.62
2004	25.34	25.58	11.11	10.74
2005	29.21	30.47	12.93	13.34
2006	25.68	25.42	12.51	13.00
2007	--[A]	26.17	--[A]	12.45
2008	23.70	24.60	9.24	10.49
2009	22.68	22.62	8.09	9.40
2010	22.94	--[A]	10.76	--[A]
2011	22.67	23.21	11.71	11.51
2012	21.49	21.56	9.54	10.31
2013	21.35	21.25	8.61	8.60
2014	20.72	20.49	8.52	8.13
2015	20.41	19.96	7.03	7.50
2016	19.35	19.33	9.07	9.56

[A] Summarized data are not available for CACR for 2007 and UPBU for 2010.

Figure 2-1 and Figure 2-2 present, for CACR and UPBU, respectively, comparisons of the observed haze index values for each year of IMPROVE data, including independently summarized values from 2016, to the Uniform Rate of Progress (URP) line established for each area. The same comparisons are shown for the two Missouri Class I areas in Appendix A.

Figure 2-1. CACR Monitored Observations Compared to Uniform Rate of Progress

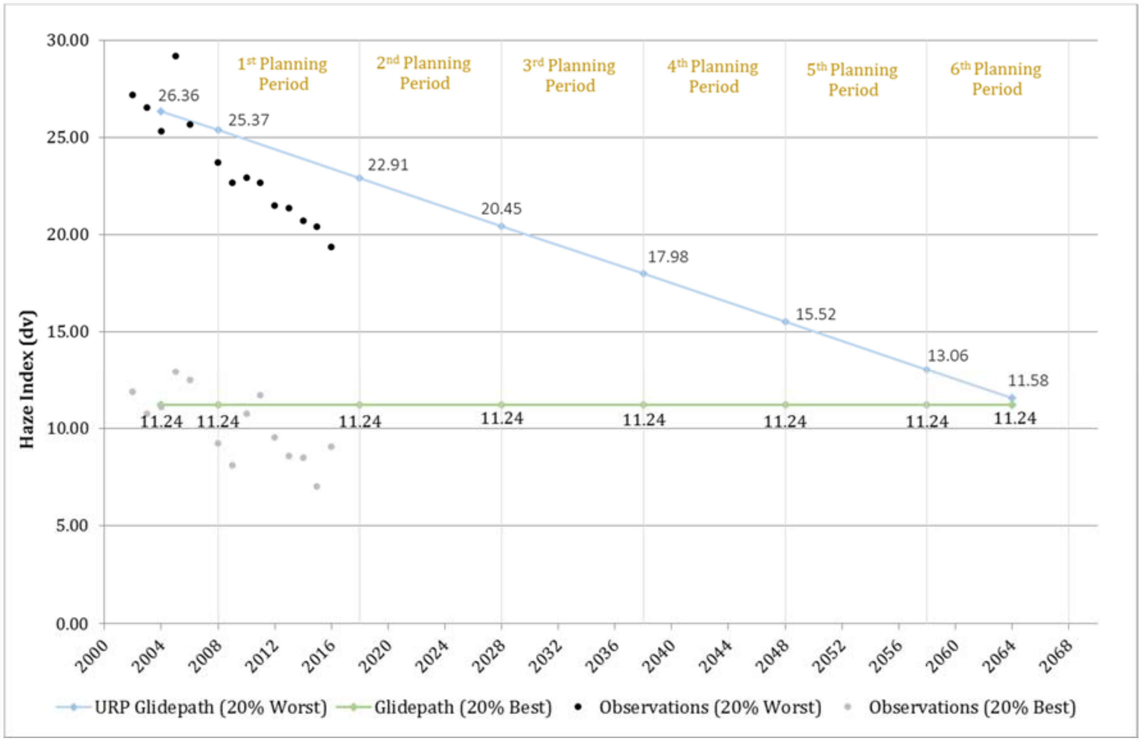
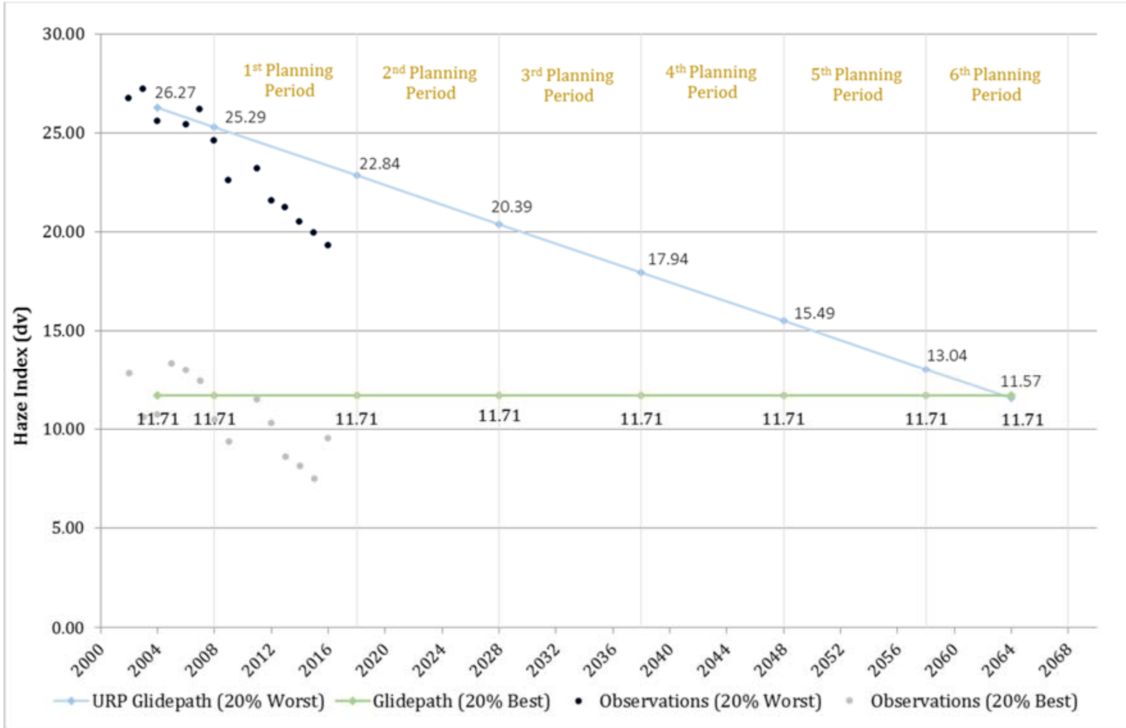


Figure 2-2. UPBU Monitored Observations Compared to Uniform Rate of Progress



As seen in the figures above, the actual observed visibility impairment at these Class I areas has declined sharply from 2002 through 2016 (the most recent available data). According to the monitor data, the current observed 20 percent worst days average haze index values are below the URP values for 2018 as well as the 2018 Reasonable Progress Goals (RPGs) that EPA set in the Arkansas Regional Haze Federal Implementation Plan,[5] meaning that Arkansas has achieved more than is necessary to demonstrate reasonable progress for the first planning period. Table 2-3 presents a comparison of the 2016 observed values and the 2018 RPG values.

Table 2-3. 2016 Observed Haze Index Values Compared to 2018 URPs and RPGs

Class I Area	Observed 20 Percent Worst Days Average for 2016 (first half year)	RPG for 2018	Observed Value as % of RPG
CACR	19.35	22.47	86.1 %
UPBU	19.33	22.51	85.9 %

[5] 81 Fed. Reg. 66,332 (September 27, 2016).

3. SITE-SPECIFIC COST INFORMATION FOR INDEPENDENCE

Site-specific control cost estimates were recently developed by Sargent & Lundy (S&L) for Dry Flue Gas Desulfurization (DFGD) at Independence. Based on these estimates, the cost of compliance is more than $6,600/ton for Unit 1 and more than $6,100/ton for Unit 2. S&L's detailed report is included in Appendix B of this report, and a summary is provided in Table 3-1, below. Two sets of values are presented: "Actual" costs as estimated by S&L and "Adjusted" values based on S&L's estimates after excluding cost items that EPA has historically claimed should not be accounted for in cost effectiveness calculations.[6] Even using these adjusted costs, the cost of compliance would be more than $5,000/ton for Unit 1 and more than $4,600/ton for Unit 2.

Table 3-1. Summary of Site-Specific Control Cost Estimates – Actual and Adjusted Values

Actual Costs	**Unit 1**	**Unit 2**
Capital ($)	491,893,500	491,893,500
Capital Recovery Factor [A]	0.1535	0.1535
Annualized Capital ($/yr)	75,505,652	75,505,652
Annual O&M ($/yr)	8,809,000	8,809,000
Total Annual Cost ($/yr)	84,314,652	84,314,652
SO_2 Emissions Reduction (ton/yr) [B]	12,608	13,655
Cost Effectiveness ($/ton)	6,688	6,175
Adjusted Costs	**Unit 1**	**Unit 2**
Capital ($)	355,391,500	355,391,500
Capital Recovery Factor [A]	0.1535	0.1535
Annualized Capital ($/yr)	54,552,595	54,552,595
Annual O&M ($/yr)	8,809,000	8,809,000
Total Annual Cost ($/yr)	63,361,595	63,361,595
SO_2 Emissions Reduction (ton/yr) [B]	12,608	13,655
Cost Effectiveness ($/ton)	5,026	4,640

[A] Based on a nine-year amortization period and 7 % interest.

[B] EAI's emissions reduction value differs from EPA's value because of a difference in how the average baseline emissions were calculated. EAI simply averaged the five annual values for 2009-2013. EPA took a three-year average over the same time period after excluding the minimum and maximum values.

[6] An example of an excluded cost is Allowance for Funds Used During Construction (AFUDC). AFUDC represents the interest expense incurred on the investment in a large capital project, such as a FGD installation, which can take several years to complete (≥ 5 years). Although interest expenses will certainly be incurred on such a project, and AFUDC is typically considered as part of the capital cost of such a project for standard accounting and rate-making purposes, EPA Region 6 has expressed concern with the inclusion of AFUDC and certain other costs. EAI disagrees and believes that determining the cost effectiveness of the control options must realistically reflect the actual cost of compliance. *See* EAI's comments on the proposed FIP. Nonetheless, for completeness, this report shows a range of cost effectiveness both including AFUDC and other costs and excluding those costs.

APPENDIX A: OBSERVATIONS COMPARED TO UNIFORM RATES OF PROGRESS FOR MISSOURI'S CLASS I AREAS

Figure A-1. MING Monitored Observations Compared to Uniform Rate of Progress

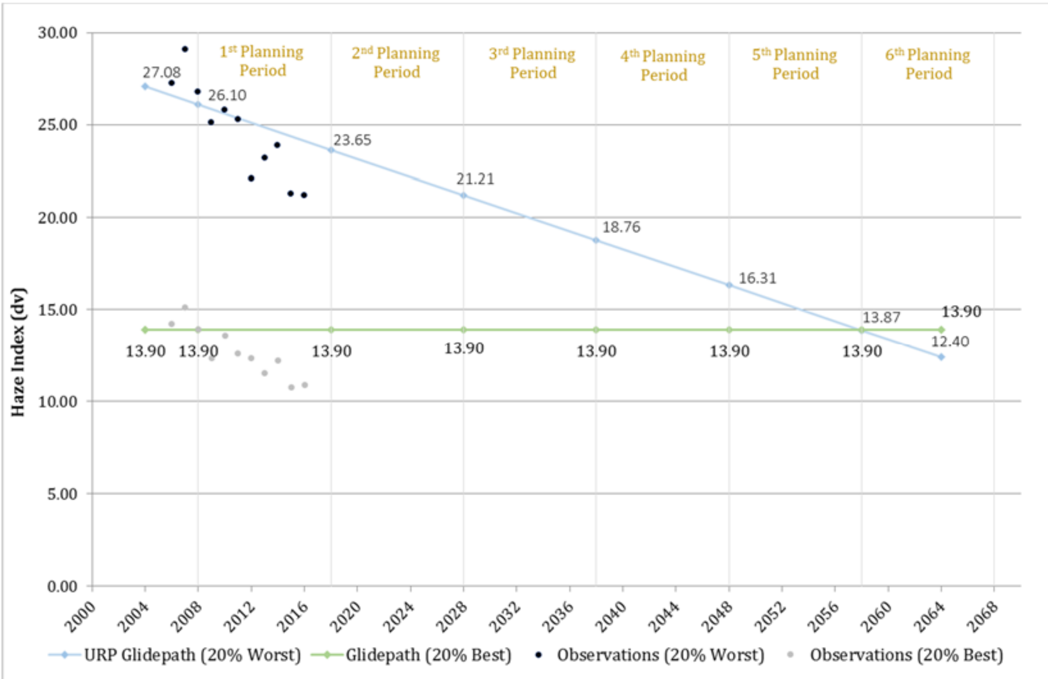
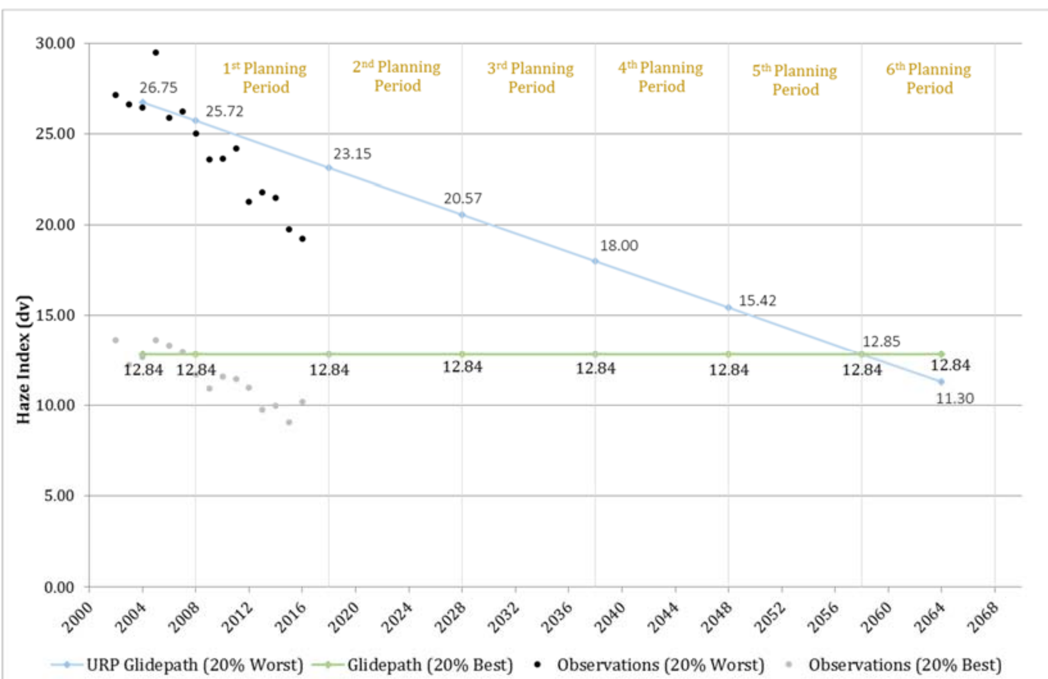


Figure A-2. HEGL Monitored Observations Compared to Uniform Rate of Progress



APPENDIX B: CONTROL COST INFORMATION

ENTERGY ARKANSAS, INC.

INDEPENDENCE DRY FGD

COST ESTIMATE AND TECHNICAL BASIS

SL-014308
Final, Rev. 0
January 31, 2018
Project 13027-004

Prepared by

Sargent & Lundy LLC

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1. PURPOSE

The purpose of this study is to estimate the total capital investment and operating and maintenance costs associated with installing dry flue gas desulfurization (FGD) technology on Independence Units 1&2. This report documents the conceptual design and technical basis for the dry FGD cost estimate.

2. TECHNOLOGY DESCRIPTION

2.1.1. Reagent Preparation System

Lime will be supplied to the lime day bins from the long-term storage silo located in the Reagent Handling Area and supplied by the EPC Contractor. The lime day bins, located in the Reagent Preparation Area and provided by the Dry FGD System Supplier, will each have a storage capacity to supply the plant with lime reagent for 24 hours when firing 1.2 lb SO_2/mmBtu coal.

Lime from the day bin will be gravity-fed through feeders to a lime slaker, where the lime will be slaked (mixed with low pressure service water and converted from calcium oxide to calcium hydroxide slurry). The plant will have a total of two lime slaking trains (2 x 100%), each sized to process enough lime slurry to supply the entire plant. Each lime slaker will discharge to a lime slurry transfer tank, which is equipped with two lime slurry transfer pumps which will feed into the lime slurry storage tanks. The common lime slurry storage tanks will each be sized for 12 hours of storage for the entire plant when burning a 1.2 lb SO_2/mmBtu coal. The lime day bin, slaking trains, and lime slurry tanks are sized to provide the necessary reagent slurry to both units simultaneously. The lime slurry tanks are built with cross-ties such that either slurry tank can feed either the Unit 1 or Unit 2 FGD systems.

A total of four lime slurry feed pumps (two per unit), each sized for 100% flow to one unit, will pump the lime slurry from the storage tanks to the SDAs through one of 2 x 100% piping loops, and return unused slurry back to the lime slurry storage tank. The closed-loop reagent supply line requires a flow velocity between 4-10 fps to avoid any solids buildup in the piping. Because of this, the pumping requirement is higher than the actual SDA requirement and must be sufficiently greater than the slurry flow that is pumped into the absorbers to allow the returning flow to remain above 4 fps.

2.1.2. Absorbers

Three absorbers, each treating 33⅓% of the flue gas are provided for each unit. Depending on the supplier and the type of atomizer normally used, there may be one rotary atomizer per absorber with a shared spare (B&W), three rotary atomizers per absorber with one or more shared spares (Alstom, basis of the estimate), or multiple dual-fluid atomizers with 15% shared spares (Siemens). The cost estimate includes contingency to capture the possibility of any of these designs.

2.1.3. Baghouse

Each SDA will be paired with a pulse-jet baghouse with a gross air-to-cloth ratio of approximately 3.2-3.4 ft/min. The filter bags in each baghouse are cleaned by pulses of compressed air. The air compressors will be 4 x 33% for the station and are included in the scope of the baghouse supplier.

2.1.4. Byproduct Recycle System

The reaction byproducts from the absorbers will be collected in the baghouses and a portion of the collected material will be recycled. The baghouse hoppers will be emptied through air lock feeders and pneumatically conveyed to two recycle day bins located in the Byproduct Recycle Area and supplied by the Dry FGD System Supplier, which are common for both units. The air-lock feeders are installed without a spare. One recycle day bin is located in the recycle train for each unit. The common byproduct recycle day bins (one per unit) provide 8-hours of storage when burning 1.2 lb SO_2/mmBtu coal.

Each byproduct recycle day bin is equipped with two recycle slurry preparation systems. The byproduct in each recycle day bin is gravimetrically conveyed to one of two systems where the byproduct is slurried with water (cooling tower blowdown). The byproduct recycle slurry is stored in one of four plant wide recycle slurry tanks, two per unit (combined 4-hour storage capacity).

Two recycle water make-up tanks are located in the recycle area. The recycled by-product slurry will be combined with fresh lime slurry for feed to the SDA atomizers. Recycle feed slurry pumps (4 x 100%, two installed per unit) will be used to transfer the recycle slurry from the recycle slurry tanks to the atomizers. In addition, all recycle feed lines are provided in a loop configuration as with the reagent system, with a complete redundant loop to allow unhindered operation due to any pluggage of pumps or feed piping.

2.1.5. Reagent Handling System

The basis of the estimate is delivery of lime via hopper-bottom railcars with truck unloading as a backup. In order to accommodate rail delivery to the site, a new rail spur will be constructed from the existing track on the plant site for unloading. A trackmobile car positioner will position railcars, two at a time, in the enclosed delivery shed for unloading. A vacuum pneumatic system will unload the railcars into either of the two (2) lime storage silos. The lime storage silos will be sized for supply of reagent for 14 days of storage at full load when firing 1.2 lb SO2/mmBtu coal. Lime from the long-term storage silos will be pneumatically transferred to two lime day bins located in the Reagent Preparation Area and supplied by the Dry FGD System Supplier.

2.1.6. Byproduct Handling System

Excess FGD byproduct from the recycle system will be pneumatically conveyed to either of the two common long- term FGD byproduct storage silos. The two long-term FGD byproduct storage silos are each sized to handle the byproduct for a total of 7 days of storage when firing the 1.2 lb SO_2/mmBtu coal. The byproduct will be mixed with a small amount of fly ash and water to form a final product which contains approximately 65% FGD byproduct, 5% fly ash, and 30% water. In order to achieve this mixture, a common fly ash blending bin (7-day storage) will be located near the new byproduct silos. The wetted byproduct/fly ash mixture is then loading into dump trucks, which will deposit the FGD byproduct in a final storage location in the landfill. It is assumed that the existing landfill will have sufficient capacity to accommodate the addition of FGD byproduct. Therefore no costs were included in the capital estimate for the (existing) landfill.

2.1.7. Flue Gas Handling System

The flue gas from the existing ID fans will be ducted to the absorbers. The gases from the absorbers will be ducted to the baghouses to collect the reaction by-products and residual fly ash. Two axial booster fans (2 x 50% for each unit) will be located downstream of the absorbers and baghouse; the booster ID fans can be provided by the Dry FGD System Supplier or the EPC Contractor. Due to the dry condition of the scrubbed flue gas, the existing stack and liners will be used for the retrofit case.

2.1.8. Electrical BOP System

In order to feed the new dry FGD and other BOP equipment, significant modifications and additions to the existing power system would be required. These include, at a minimum, installation of new auxiliary transformers, medium- and low-voltage switchgear buses, motor control centers (MCCs) and upgrades to the isolated phase tap-off buses. As a detailed conceptual design was not developed an allowance was included for the Electrical BOP Scope.

2.1.9. I&C BOP System

The dry FGD system will be integrated into the existing DCS system. The baghouse will be controlled through a PLC and the ID booster fans will be integrated into the existing DCS system. As a detailed conceptual design was not developed an allowance was included for the I&C BOP Scope.

3. APPROACH

The project capital and O&M cost estimates are based on project-specific information, including:

- An engineer-procure-construct (EPC) contracting strategy with the Dry FGD technology supplier providing the main process equipment as a complete FGD Island.
- On-site disposal of Dry FGD byproduct using new ash handling equipment. The byproduct will be collected in the new fabric filter and blended with fly ash prior to disposal.
- Reagent injection rates based on achieving an outlet SO_2 emission rate of 0.06 lb SO_2/MMBtu from a design inlet concentration of 1.20 lb SO_2/MMBtu, based on the sulfur limit in the fuel supply contracts.
    - Annual operating costs will be based on an uncontrolled SO_2 rate of 0.49 lb SO_2/MMBtu, based on the annual heat input weighted average emission from 2009 through 2013.
    - The system will be designed to control emissions to meet a permit limit of 0.06 SO_2/MMBtu, based on the required permit limits in the EPA Arkansas FIP.

- A high level conceptual system design was used as input to the Dry FGD cost estimate. The following were estimated based on previous projects and scaled for the predicted dry sorbent injection rate for Independence:
  - Auxiliary power consumption
  - Annual reagent consumption
  - Equipment Sparing and Quantities
  - BOP Allowances (Mechanical, Electrical and I&C)

The total plant capital cost estimate includes the following:

- Equipment and material
- Installation labor
- Demolition and Relocation work
- Indirect field costs and BOP engineering
- Freight on Materials
- General and Administration
- Erection contractor profit
- Engineering, Procurement and Project Services
- Spare parts/initial fills (other than reagent)
- EPC Fee

As part of this project, S&L estimated the costs for Owner's services and costs outside of the EPC contract including the following:

- Owner's Costs
- Owner's Engineer
- Construction Management Support
- Startup and Commissioning Support
- Performance Testing
- Contingency
- Escalation
- Interest During Construction

Cost Estimate 34261 provided in Attachment 1 represents the total cost to Entergy to install Dry FGD technology on both units at Independence (Unit 1 and 2) including the EPC Contract price and all additional Owner's costs and third party services.

The total unit O&M cost estimate includes the following:

- Waste disposal (Dry FGD waste)
- Reagent consumption
- Auxiliary power consumption
- Water consumption for reagent and byproduct handling
- Operating labor
- Maintenance material
- Maintenance labor

The O&M Cost Estimate and Capital Cost Estimate were developed using the assumptions and scope provided in this document. The project definition and accuracy corresponds to a study level estimate as defined in U.S.EPA's Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual. The costs provided in this report are in 2017 dollars.

4. CAPITAL AND O&M COST ESTIMATE TECHNICAL BASIS

4.1. DESIGN INPUTS AND ASSUMPTIONS

The following summarizes the design inputs used as the basis for the Independence dry FGD Systems:

- Design SO_2 inlet concentration of 1.2 lb SO_2/MMBtu for equipment design, based on the current coal contract sulfur limit.
- SO_2 inlet concentration of 0.49 lb SO_2/MMBtu for annual operating costs, based on the annual heat input weighted average emission from 2009 through 2013.
- Design SO_2 outlet concentration of 0.06 lb SO_2/MMBtu.
- Annual capacity factor of 75.0% (annual average capacity factor for Independence Units 1 and 2 based on historical heat input from 2009 through 2013).
- Project duration of five years.

4.2. TOTAL INSTALLED CAPITAL INVESTMENT

The Dry FGD System Supplier will provide all of the equipment within the FGD Island. The FGD Island will include the Reagent Preparation Equipment, Absorber Area Equipment, Baghouse Area Equipment and the Byproduct Recycle Equipment. The booster ID fans could be provided by either the Dry FGD System Supplier or the EPC Contractor; the basis of this estimate is supply of the booster fans by the Dry FGD System Supplier. The EPC Contractor will provide the remaining BOP scope in order to provide a complete and operable FGD system. In addition, the EPC Contractor will install/construct the entire system including the equipment provided by the DFGD supplier. The scope of work for the cost estimate is broken out by the following areas:

4.2.1. Dry FGD Island

a. Reagent Preparation System, common to both units:
   - Two lime day bins, 24-hours storage each
   - Two detention lime slakers at 100% capacity, each with a grit screen, gravimetric feeder
   - Two lime slurry transfer tanks
   - Four slurry transfer centrifugal pumps
   - Two lime slurry storage tanks
   - Four slurry feed centrifugal pumps
   - Cost estimate based on budgetary proposal from Alstom; the budgetary proposal is based on a design sulfur of 2.0 lb/MMBtu, cost adjustments were included in the estimate for a lower design sulfur of 1.2 lb/MMBtu. These cost adjustments were developed by estimating the differential equipment cost for the reagent preparation and waste handling equipment. The impacted equipment is identified in Section 4.5 which discusses the sulfur design basis sensitivity.

b. Absorber Area, per unit
   - Three absorber vessels per unit, with access doors
   - Rotary atomizers, two spare atomizers included
   - Vessel material carbon steel, ¼ in. – ⅝ in. carbon steel
   - Heating and ventilation
   - Vacuum piping
   - SDA Superstructure
   - Cost estimate based on budgetary proposal from Alstom

c. Baghouse Area, per unit
  - New baghouse, including pulse jet cleaning system and all appurtenances
  - Cost estimate based on budgetary proposal from Alstom

d. Byproduct Recycle System, per unit (located remotely in common location for both units)
  - One recycle silo with bin vent filter per unit, 8-hour total capacity
  - Two recycle mix tanks per unit
  - Two recycle slurry tanks per unit, with two recycle slurry centrifugal pumps per unit
  - Agitators for each tank
  - Baghouse ash handling system common to both units
  - Rotary air-lock valves from baghouse hopper outlets to pressure pneumatic conveying system (60-degree typical)
  - Pneumatic pressure blowers (8 x 33⅓ %)
  - Cost estimate based on budgetary proposal from Alstom

e. ID Booster Fans, per unit
  - Two approximately 5,200 hp axial booster fans per unit sized to overcome pressure drop associated with FGD and baghouse
  - Includes motors - no spare motor included
  - Cost estimate based on budgetary proposal from Alstom
  - Dampers from ID fan to booster fans (cost estimated separately, not included in Alstom budgetary proposal)

f. Interconnecting Ductwork, per unit
  - ID fan outlet to absorber inlet ductwork and supports; carbon steel, ¼ in, design velocity, 3,600 fpm
  - Absorber outlet to baghouse inlet ductwork and supports; carbon steel, ¼ in, design velocity, 3,600 fpm
  - Baghouse outlet to new booster fans and fan outlet to the stack inlet ductwork and supports; carbon steel, ¼ in, design velocity, 3,600 fpm

4.2.2. <u>FGD Island BOP</u>

a. Absorber tower foundations including caissons

b. Baghouse area foundations including 18” auger cast piles 60’ long

c. Booster fan area foundations

d. Concrete foundations for all flue gas ductwork

e. 6” insulation with lagging for Absorbers, Baghouses and Ductwork

f. Penthouse enclosure for Absorbers located in FGD Island

g. Two elevators (one for each unit) to provide maintenance access to Absorber and Baghouse Areas

h. Enclosure around hoppers for Baghouses located in FGD Island

i. Lime preparation building for Reagent Preparation Area in FGD Island, including substructure and superstructure

j. Byproduct recycle building for Byproduct Recycle Area in FGD Island, including substructure and superstructure

4.2.3. <u>Reagent Storage and Handling, common to both units:</u>

a. Lime rail car unloader:
- Lime delivery via 25-car unit train
- System consists of mobile receiving pan and associated vacuum pneumatic equipment to unload railcar through railcar bottom hoppers
- Enclosed railcar unloading building
- One vacuum pneumatic system operating to unload a car
- Pneumatic vacuum exhausters (2 x 100%)
- Filter separator with vacuum-to-pressure transfer hopper and valves
- Cost estimate based on vendor quote for a similar unit

b. Lime storage silos:
- Two lime storage silos, (14-day capacity each, common to both units) with bin vent filter, including substructure and superstructure
- 1,000-tons storage, each
- Continuous level detection systems
- Live bottom hopper outlets
- Rotary airlock assemblies
- Lime transfer systems:
  - Pressure pneumatic conveying system from lime storage silos to lime day bins
  - Pneumatic pressure blowers
  - One lot of pneumatic conveying piping located on an elevated pipe rack

c. Concrete foundations including caissons for all material silos

d. Concrete foundations for pneumatic conveying blowers and exhausters

4.2.4. Byproduct Handling System, common to both units

a. Two FGD by-product storage silos (7-day capacity each, common to both units) with bin vent filter, fluidizing system, and two unloading conditioners (one operating, one spare per silo), including substructure and superstructure

b. One common fly ash blending, 7-day storage bin with bin vent filter, fluidizing system, and four pneumatic airslide conveyors

c. Water pumps and associated piping for unloading conditioners (pin mixers) at both silos

d. Continuous level detection system

e. Two truck scales and substructure

f. Concrete foundations including caissons for all material silos

g. Concrete foundations for pneumatic conveying blowers and exhausters

h. Allowance for existing road improvements for truck haulage to existing landfill

4.2.5. Civil BOP

a. Site grading

b. Soil removal earthwork

c. Excavation, backfill, and compaction for all foundations

d. Development of a new laydown area, approximately 10 acres, including site preparation, fencing, and temporary power. It was assumed that this area would be located on existing plant property, and does not require land to be purchased.

4.2.6. Mechanical BOP System

a. Interconnecting piping, above-ground and buried

b. Valves for interconnecting piping, above-ground and buried

c. Lime slaking water storage tank, 175,000-gallon capacity

d. Recycle make-up water tanks, 2 x 200,000-gallon capacity

e. Pipe Racks, common to both units
   - Between lime railcar unloading enclosure and lime silos
   - Between lime silos and lime day bins
   - From baghouse hoppers to recycle silos and FGD by-product silo
   - From lime slurry storage tanks to absorber
   - From recycle slurry storage tank to absorber
   - Concrete foundations including caissons for all pipe racks
   - Shallow concrete foundations for other miscellaneous structures

f. BOP Pumps
   - Three by-product recycle water forwarding pumps to recycle slurry
   - Four reagent prep/recycle sump pumps
   - Two lime silo and unloading area sump pumps
   - Two by-product ash silo area sump pumps
   - Two by-product recycle make-up water tank supply pumps
   - Two lime slaking water pumps

g. Instrument Air System, common to both units
   - Air compressors; 2 x 100%,
   - IA dryers w/filters; 2 x 100%,
   - Air receivers; 2 x 100%
   - Instrument air piping to every silo or day bin, bin vent and reagent preparation/recycle area
   - Heat-traced piping

h. Service Air System, common to both units
   - Air compressors; 2 x 100%
   - Air receivers; 2 x 100%

i. Field painting
   - Multiple coat system used for exposed ductwork only
   - Inorganic zinc primer and polyurethane system used for steel
   - Allowance for underground piping shop coatings built into piping cost

4.2.7. <u>Demolition and Relocation</u>

a. Allowance of $1,800,000, plus labor costs, is included for demolition and relocation of existing equipment and infrastructure which may interfere with the new Dry FGD system. This allowance is based on recent in-house cost estimates for similar projects.

4.2.8. <u>Electrical BOP System</u>

a. Allowances of $13,900,000, $8,500,000 and $1,400,000, plus labor costs, are included for electrical equipment upgrades and modifications, cables and conduits/raceway, respectively. These allowances are based on recent in-house cost estimates for similar projects.

4.2.9. <u>Instrumentation and Controls BOP System</u>

a. Allowance of $1,585,000, plus labor costs, is include for DCS upgrades and added instrumentation. This allowance is based on recent in-house cost estimates for similar projects.

4.2.10. Labor Costs

Installation/labor costs were included in the base estimate under the direct costs. Manhours are estimated for each item in the base estimate and are based on the type of work and typical estimates for similar work. The labor costs are based on the labor wage rates and labor crews developed by S&L.

a. Labor Wage Rates

   Crew labor rates were developed using prevailing craft rates, fringe benefits and state specific worker's compensation rates as published in the 2017 edition of R.S. Means Labor Rates for Pine Bluff, Arkansas area. Costs were added to cover FICA, workers compensation, all applicable taxes, small tools, incidentals, construction equipment, and contractor's overhead. A 1.15 geographic labor productivity multiplier is included based on the Compass International Construction Yearbook for Arkansas. The crew rates do not include an allowance for weather related delays.

b. Labor crews

   Construction/erection labor cost is based on the use of applicable construction crews typically required for projects of this type. The construction crew costs were specifically developed for utility industry and are proprietary to S&L. The prevailing craft rates are incorporated into work crews appropriate for the activities, and include costs for small tools, construction equipment, insurance, and site overheads.

4.2.11. Other Direct and Construction Indirect Costs

In addition to the base labor costs, other construction indirect costs for the project were broken out in the estimate as well as other contractor direct costs. The following items were included as other direct and construction indirect costs.

a. Scaffolding and Consumables
b. Premiums and per diems ($10 per hour)
c. Overtime is included based on five 10-hour shifts per week work schedule
d. Freight on construction materials
e. Contractor's General & Administration Fees (included at 10% of total direct and construction indirect costs)
f. Contractor's Profit (included at 5% of total direct and construction indirect costs)

4.2.12. EPC Indirect Costs

The final contribution to the overall EPC project price are the EPC Contractor's indirect costs; these include the EPC engineering services, startup spare parts and initial fills, technical field advisors, and the EPC risk fee.

a. EPC Engineering Services

The EPC engineering services was estimated based on recent projects with similar scopes and schedules. The total cost of the EPC engineering services was estimated to be $23,000,000.

b. Startup Spare Parts and Initial Fills

An allowance has been included for initial fills for equipment, including first fills for lubrication of any motorized equipment. The initial fill of pebble lime was not included in the EPC Contractor's scope, as this is considered to be an operating cost rather than a capital expense. The initial fill of pebble lime is included in the Owner's costs. The total cost of the initial fills was estimated to be $300,000.

c. Technical Field Advisors (Vendors)

Allowances were included for equipment supplier's technical field advisory services based on an estimated 600 man-days. The estimate includes technical field advisors for the FGD system supplier (including FGD system subcontractors) and the DCS supplier. The total cost of the technical field advisors was estimated to be $600,000.

d. EPC Risk Fee

An EPC approach provides an alternative which is expected to reduce risk for Entergy by placing the responsibility for the project on a single entity, the EPC Contractor. The EPC risk fee is a premium charged by the contractor which accounts for the additional coordination and management of the project as well as the additional risk assumed by the contractor. Based on S&L's experience with recent EPC projects, an EPC risk fee was included at 10% of the total EPC project costs.

4.2.13. Owner's Costs and Services

Outside of the EPC Contractor's total cost, Entergy will incur other costs associated with the project, such as services procured from third parties (including Owner's engineer, construction management support, startup and commissioning support and performance testing), and other project related costs.

a. Owner's Costs

Owner's Costs are direct costs that the Owner incurs over the life of the project. The following items are real costs Entergy will incur to install DSI at Independence based on the scope and schedule of this project:

- Internal Labor
- Internal Indirects

- Travel Expenses
- Legal Services
- Builders Risk Insurance
- Initial Fills (Reagent)

Owner's costs were included in the estimate at 8% of the total project cost.

b. Construction Management Support

The construction management support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform the tasks, and therefore it will be outsourced. The cost of labor is based on present day cost. The total cost of the construction management support was estimated to be $4,969,000.

c. Startup and Commissioning Support

The startup and commissioning support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform the tasks, and therefore it will be outsourced. The total cost of the startup and commissioning support was estimated to be $550,000.

d. Owner's Engineer

The Owner's Engineer cost was developed as a high level estimate based on a typical scope for Owner's Engineer work for this type of project; including the following tasks:

- Conceptual Study Support
- EPC Specification Supporting Documents
- Project Schedule Development
- EPC Specification Development
- EPC Bid Evaluation and Contract Conformance
- General Project Support
    - Monthly Project Status Meetings
    - Weekly Teleconferences
    - Overall Coordination
    - Project Administration
    - Site Visits and Travel
- Permitting Support
- Design Review of Drawing Submittals
- Technical support during design, fabrication, construction, commissioning, and testing

- Equipment vendor QA/QC audits

The total cost of the Owner's Engineer was estimated to be $6,500,000.

e. Performance testing

The cost for performance testing was developed as a factored estimate using costs from projects of similar scope. This cost includes the testing, performed by a third-party contractor hired by the Owner, and also includes the cost for S&L's assistance in the following tasks:

- Development of the test protocol
- Procuring the services of the testing contractor
- Overseeing the performance test campaign
- Evaluating the results of the testing with respect to guarantee compliance

The estimate for the third party testing contractor is based on the assumption that the contractor would be onsite for up to 5 days. The total cost of the Performance Testing was estimated to be $275,000.

f. Contingency

Contingency is included in the estimate to cover the uncertainty associated with the project costs. The cost estimate includes a recommended contingency of 15% (due to a greater extent of project definition), which is consistent with cost estimating guidelines for a conceptual design and the current level of project definition. Contingency was applied to the total project costs before escalation.

g. Escalation

Escalation was included in the estimate based on a typical schedule for implementation of a Dry FGD system at an escalation rate of 2.15% on equipment and materials and 3.35% on labor and indirects. These escalation rates were developed by S&L based on recent pricing and in-house escalation projections.

h. Interest During Construction

Interest during construction (IDC) accounts for the time value of money associated with the distribution of construction cash flows over the construction period. IDC was applied to the total EPC project costs including contingency. The IDC was calculated based on a typical schedule for implementation of a DSI system and a typical interest rate of 7.8% per year which was assumed based on a low interest market environment.

4.3. VARIABLE OPERATING AND MAINTENANCE COSTS

The following unit costs were used to develop the variable Operating and Maintenance (O&M) costs. All of these values, with the exception of the reagent costs, were provided by Entergy or are typical industry values confirmed by Entergy. The reagent costs are based on recent supplier quotes for the area.

Table 4-1: Unit Pricing for Utilities (Provided by Entergy)

Unit Cost	Units	Value
Pebble Lime	$/ton	$130.0
High Quality Water	$/1000 gal	$2.00
Low Quality Water	$/1000 gal	$0.50
Byproduct Disposal	$/ton	$7.50
Aux Power Cost[1]	$/MWh	$43.35

Note 1: Entergy provided auxiliary power costs for the first year of operation.

Table 4-2 below summarizes the consumption rates estimated as well as the first year variable O&M costs for the Dry FGD system.

Table 4-2: Variable O&M Rates and First Year Costs, per Unit

	Units	Value
Dry FGD System Parameters		
Reagent Consumption	lb/hr	4,800
Byproduct Waste Production	lb/hr	10,600
Aux Power Consumption	kW	10,000
High Quality Water Consumption	gpm	50
Low Quality Water Consumption	gpm	880
First Year[1] Variable O&M Costs (@CF[2])		
Reagent Cost	$/year	$2,050,000
Byproduct Waste Disposal Cost	$/year	$261,000
Aux Power Cost	$/year	$2,628,000
Water Cost	$/year	$213,000
Bag and Cage Replacement Cost	$/year	$372,000
Total First Year Variable O&M Cost	**$/year**	**$5,524,000**

Note 1: First year costs are provided in $2017.

Note 2: The first year costs are calculated using an annual capacity factor of 75.0%.

4.4. FIXED OPERATING AND MAINTENANCE COSTS

The fixed O&M costs for the systems consist of operating personnel as well as maintenance costs (including material and labor). Based on the conceptual design for the dry FGD system, the estimated staffing additions are 28 personnel for two systems on adjacent units.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (maintenance and labor) were estimated to be approximately 1.3% of the project capital. This is a lower value than typical because items such as track work and civil work are high capital cost items with little to no maintenance.

Table 4-3 below summarizes the first year fixed O&M costs for the design and typical cases.

Table 4-1: First Year Fixed O&M Costs for Dry FGD, per Unit

First Year[1] Fixed O&M Costs	Units	Value
Operating Labor[2]	$/year	$1,660,000
Maintenance Material	$/year	$975,000
Maintenance Labor	$/year	$650,000
Total First Year Fixed O&M Cost	**$/year**	**$3,285,000**

Note 1: First year costs are provided in $2017.

Note 2: Operating labor costs are based on a labor rate of $56.95, which was provided by Entergy.

Note 3: Installation of systems on both units would require 28 operators total. For accounting purposes, this is considered 14 operators per unit.

5. SUMMARY

The cost estimate for the Independence Units 1&2 Dry FGD systems is based on the addition of two SDA FGD systems for SO_2 removal. The attached capital estimate for the Independence Dry FGD system is based on this technical basis and is presented in 2017 dollars.

6. ATTACHMENTS

1. Independence DFGD Project Units 1 and 2 Conceptual Capital Cost Estimate, Sargent & Lundy Estimate No. 34261

ENTERGY ARKANSAS
INDEPENDENCE STATION DRY (SDA) FGD
CONCEPTUAL COST ESTIMATE

Estimator	A. KOCI
Labor rate table	17ARPBL
Project No.	13027-004
Estimate Date	10/04/2017
Reviewed By	GA
Approved By	BA
Estimate No.	34261A
Cost index	ARPBL

ENTERGY ARKANSAS
INDEPENDENCE STATION DRY (SDA) FGD
CONCEPTUAL COST ESTIMATE

Area	Description	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Total Cost
101	FGD ISLAND	147,908,000	150,000,000	16,508,216	343,779	26,553,044	340,969,260
102	REAGENT HANDLING SYSTEM	5,830,400	2,591,000	1,325,175	39,706	3,315,997	13,062,572
105	BYPRODUCT HANDLING SYSTEM	6,120,000	6,810,000	792,075	103,041	8,417,500	22,139,575
121	CIVIL BOP	350,000		3,731,841	63,706	8,336,292	12,418,133
151	MECHANICAL BOP	720,000	1,647,000	5,962,113	88,963	8,343,711	16,672,824
190	DEMOLITION / RELOCATION			1,800,000	33,333	3,276,667	5,076,667
201	ELECTRICAL BOP SYSTEM		12,300,000	11,500,000	284,184	22,691,518	46,491,518
211	INSTRUMENTATION AND CONTROLS BOP SYSTEM		1,500,000	1,085,000	10,920	789,374	3,374,374
	TOTAL DIRECT	160,928,400	174,848,000	42,704,420	967,632	81,724,103	460,204,922

Estimate Totals

Description	Amount	Totals	Hours
Direct Costs:			
Labor	81,724,103		967,632
Material	42,704,420		
Subcontract	160,928,400		
Process Equipment	174,848,000		
	460,204,923	**460,204,923**	
Other Direct & Construction Indirect Costs:			
91-1 Scaffolding	5,721,000		
91-2 Cost Due To OT 5-10's	11,337,000		
91-4 Per Diem	9,676,000		
91-5 Consumables	817,077		
91-6 Freight on Material	2,135,000		
91-8 Sales Tax	7,566,000		
91-9 Contractors G&A	15,776,000		
91-10 Contractors Profit	7,888,000		
	60,916,077	**521,121,000**	
Indirect Costs:			
93-1 Engineering Services	23,000,000		
93-4 SU/S Parts/ Initial Fills	300,000		
93-5 Technical Field Advisors	600,000		
93-8 EPC Fee	54,502,000		
	78,402,000	**599,523,000**	
Escalation:			
96-1 Escalation on Material	5,731,000		
96-2 Escalation on Labor	20,520,000		
96-3 Escalation on Subcontract	26,919,000		
96-4 Escalation on Process Eq	17,974,000		
96-5 Escalation on Indirects	12,802,000		
	83,946,000	**683,469,000**	
Total EPC Cost		***683,469,000***	
Owner's Costs:			
99-1 Owner's Costs	47,962,000		
	47,962,000	**731,431,000**	
Third Party Services:			
100 CM Oversight	4,969,000		
102 Start-up Oversight	550,000		
103 Owner's Engineer	6,500,000		
104 Performance Testing	275,000		
	12,294,000	**743,725,000**	
Project Contingency :			
110 Project Contingency	98,966,000		
	98,966,000	**842,691,000**	
Escalation Addition:			
120 Escalation on Lines 99-110	8,897,000		
	8,897,000	**851,588,000**	
Interest During Construction:			
130 Interest During Constr.	132,199,000		
	132,199,000	**983,787,000**	
Total		***983,787,000***	

ENTERGY ARKANSAS
INDEPENDENCE STATION DRY (SDA) FGD
CONCEPTUAL COST ESTIMATE

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
101			FGD ISLAND									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			PILE - MOB/DEMOB		1.00 LS	100,000	-			115.48 /MH		100,000
			PILE - 18" AUGER CAST X 60' LONG	UNIT 1 DUCTWORK (NOT INCLUDED IN FGD ISLAND SCOPE)	138.00 EA	496,800	-			115.48 /MH		496,800
			PILE - 18" AUGER CAST X 60' LONG	UNIT 2 DUCTWORK (NOT INCLUDED IN FGD ISLAND SCOPE)	138.00 EA	496,800	-			115.48 /MH		496,800
			PILE - 18" AUGER CAST X 60' LONG	UNIT 1 BAGHOUSE FDN	252.00 EA	907,200	-			115.48 /MH		907,200
			PILE - 18" AUGER CAST X 60' LONG	UNIT 2 BAGHOUSE FDN	252.00 EA	907,200	-			115.48 /MH		907,200
			PILING			2,908,000						2,908,000
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	ABSORBER TOWERS FOUNDATIONS	180.00 EA	-	-	334,260	4,552	115.48 /MH	525,633	859,893
			2.5 FT DIA X 30 FT DEEP CAISSON	ABSORBER TOWERS FOUNDATIONS	180.00 EA	-	-	334,260	4,552	115.48 /MH	525,633	859,893
			2.5 FT DIA X 30 FT DEEP CAISSON	REAGENT PREP ENCLOSURE 50'X50' SUBSTRUCTURE	50.00 EA	-	-	92,850	1,264	115.48 /MH	146,009	238,859
			2.5 FT DIA X 30 FT DEEP CAISSON	BYPRODUCTS RECYCLE EQUIPMENT BLDG 60' X 60' SUBSTRUCTURE	72.00 EA	-	-	133,704	1,821	115.48 /MH	210,253	343,957
			2.5 FT DIA X 30 FT DEEP CAISSON	UNIT 1 BOOSTER FAN FOUNDATION	40.00 EA	-	-	74,280	1,011	115.48 /MH	116,807	191,087
			2.5 FT DIA X 30 FT DEEP CAISSON	UNIT 2 BOOSTER FAN FOUNDATION	40.00 EA	-	-	74,280	1,011	115.48 /MH	116,807	191,087
			CAISSON					1,043,634	14,211		1,641,143	2,684,777
			CIVIL WORK			2,908,000		1,043,634	14,211		1,641,143	5,592,777
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	REAGENT PREP ENCLOSURE 50'X50' SUBSTRUCTURE	300.00 CY	-	-	69,000	2,414	68.52 /MH	165,393	234,393
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	BYPRODUCTS RECYCLE EQUIPMENT BLDG 60' X 60' SUBSTRUCTURE	432.00 CY	-	-	99,360	3,476	68.52 /MH	238,166	337,526
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	UNIT 1 BOOSTER FAN FOUNDATION	600.00 CY	-	-	138,000	4,828	68.52 /MH	330,786	468,786
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	UNIT 2 BOOSTER FAN FOUNDATION	600.00 CY	-	-	138,000	4,828	68.52 /MH	330,786	468,786
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	UNIT 1 DUCTWORK (NOT INCLUDED IN FGD ISLAND SCOPE)	966.00 CY	-	-	222,180	7,772	68.52 /MH	532,566	754,746
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	UNIT 2 DUCTWORK (NOT INCLUDED IN FGD ISLAND SCOPE)	966.00 CY	-	-	222,180	7,772	68.52 /MH	532,566	754,746
			CONCRETE FOUNDATIONS - COMPOSITE RATE	ABSORBER TOWER FOUNDATION	1,300.00 CY	-	-	299,000	10,460	68.52 /MH	716,703	1,015,703
			CONCRETE FOUNDATIONS - COMPOSITE RATE	ABSORBER TOWERS FOUNDATIONS	1,300.00 CY	-	-	299,000	10,460	68.52 /MH	716,703	1,015,703
			CONCRETE FOUNDATIONS - COMPOSITE RATE	LIME SLURRY FEED TANKS	400.00 CY	-	-	92,000	3,218	68.52 /MH	220,524	312,524
			CONCRETE FOUNDATIONS - COMPOSITE RATE	UNIT 1 BAGHOUSE FDN 3 FDNS 83'X63'X3'	1,743.00 CY	-	-	400,890	14,024	68.52 /MH	960,934	1,361,824
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' UNIT 1 BAGHOUSE AREA, COMPRESSOR BLDG	6.00 CY	-	-	1,380	48	68.52 /MH	3,308	4,688
			CONCRETE FOUNDATIONS - COMPOSITE RATE	UNIT 2 BAGHOUSE FDN 3 FDNS 83'X63'X3'	1,743.00 CY	-	-	400,890	14,024	68.52 /MH	960,934	1,361,824
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' UNIT 2 BAGHOUSE AREA, TRUCK SCALE HOUSE	6.00 CY	-	-	1,380	48	68.52 /MH	3,308	4,688
			CONCRETE					2,383,260	83,372		5,712,678	8,095,938
			CONCRETE					2,383,260	83,372		5,712,678	8,095,938
	23.00.00		STEEL									
		23.17.00	GALLERY									
			GALVANIZED GRATING, 1 1/4" DEEP x 3/16" BEARING BAR WITH HOLD DOWN CLIPS	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	4,000.00 SF	-	-	60,000	460	72.48 /MH	33,324	93,324
			GALVANIZED GRATING, 1 1/4" DEEP x 3/16" BEARING BAR WITH HOLD DOWN CLIPS	BYPRODUCTS RECYCLE EQUIPMENT BLDG	5,760.00 SF	-	-	86,400	662	72.48 /MH	47,987	134,387
			3" HEAVY DUTY GRATING	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	200.00 SF	-	-	11,200	39	72.48 /MH	2,833	14,033
			DOUBLE PIPE HANDRAIL WITH POSTS AND GUARD PLATES, PAINTED	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	3,000.00 LF	-	-	159,000	621	72.48 /MH	44,988	203,988
			DOUBLE PIPE HANDRAIL WITH POSTS AND GUARD PLATES, PAINTED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	4,320.00 LF	-	-	228,960	894	72.48 /MH	64,782	293,742
			SELF CLOSING SWING GATE - USER DEFINED	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	40.00 EA	-	-	11,200	184	72.48 /MH	13,330	24,530
			SELF CLOSING SWING GATE - USER DEFINED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	58.00 EA	-	-	16,240	267	72.48 /MH	19,328	35,568
			LADDER	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	800.00 LF	-	-	40,000	368	72.48 /MH	26,659	66,659
			LADDER	BYPRODUCTS RECYCLE EQUIPMENT BLDG	1,100.00 LF	-	-	55,000	506	72.48 /MH	36,657	91,657
			STAIR SYSTEM	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	2,400.00 SF	-	-	218,400	3,172	72.48 /MH	229,937	448,337

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		23.17.00	GALLERY									
			STAIR SYSTEM	BYPRODUCTS RECYCLE EQUIPMENT BLDG	3,500.00 SF	-	-	318,500	4,626	72.48 /MH	335,324	653,824
			GALLERY					1,204,900	11,798		855,147	2,060,047
		23.25.00	ROLLED SHAPE									
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, TWO COAT PAINT	REAGENT PREP ENCLOSURE 50'X50' GALLERY SUPPORT	200.00 TN	-	-	716,000	5,057	98.30 /MH	497,149	1,213,149
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, TWO COAT PAINT	BYPRODUCTS RECYCLE EQUIPMENT BLDG	288.00 TN	-	-	1,031,040	7,283	98.30 /MH	715,895	1,746,935
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, GALVANIZED	U1 BAGHOUSE SKIRTS STEEL GIRTS	36.00 TN	-	-	138,240	910	98.30 /MH	89,487	227,727
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, GALVANIZED	U2 BAGHOUSE SKIRTS STEEL GIRTS	36.00 TN	-	-	138,240	910	98.30 /MH	89,487	227,727
			BUILDING MIX, TWO COAT PAINTED		50.00 TN	-	-	128,000	920	98.30 /MH	90,391	218,391
			BUILDING MIX, TWO COAT PAINTED		50.00 TN	-	-	128,000	920	98.30 /MH	90,391	218,391
			BUILDING MIX, TWO COAT PAINTED	REAGENT PREP ENCLOSURE SUPERSTRUCTURE	500.00 TN	-	-	1,280,000	9,195	98.30 /MH	903,908	2,183,908
			BUILDING MIX, TWO COAT PAINTED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	720.00 TN	-	-	1,843,200	13,241	98.30 /MH	1,301,628	3,144,828
			ROLLED SHAPE					5,402,720	38,437		3,778,336	9,181,056
			STEEL					6,607,620	50,235		4,633,483	11,241,103
	24.00.00		ARCHITECTURAL									
		24.17.00	ELEVATOR									
			PASSENGER, TRACTION, 4 STOPS, 3500LB, 350 FT/MIN	SCHINDLER ELEVATOR BUDGET	2.00 LS	-	-	318,700	1,885	114.46 /MH	215,764	534,464
			ELEVATOR					318,700	1,885		215,764	534,464
		24.35.00	PRE-ENGINEERED BUILDING									
			PRE-ENGINEERED BUILDING	8' X 10' UNIT 1 BAGHOUSE AREA, COMPRESSOR BLDG	1.00 LT	-	-	20,000	115	98.30 /MH	11,299	31,299
			PRE-ENGINEERED BUILDING	8' X 10' UNIT 2 BAGHOUSE AREA, TRUCK SCALE HOUSE	1.00 LT	-	-	10,000	115	98.30 /MH	11,299	21,299
			PRE-ENGINEERED BUILDING					30,000	230		22,598	52,598
		24.37.00	ROOFING									
			METAL, INSULATED, 2 IN GALVANIZED, PAINTED, 22 GA	U1 SDA TOP ENCLOSURE ROOF	3,318.00 SF	-	-	54,946	339	60.10 /MH	20,400	75,346
			METAL, INSULATED, 2 IN GALVANIZED, PAINTED, 22 GA	U2 SDA TOP ENCLOSURE ROOF	3,318.00 SF	-	-	54,946	339	60.10 /MH	20,400	75,346
			METAL, INSULATED- USER DEFINED	REAGENT PREP ENCLOSURE SUPERSTRUCTURE	2,500.00 SF	-	-	19,425	862	60.10 /MH	51,810	71,235
			METAL, INSULATED- USER DEFINED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	3,600.00 SF	-	-	27,972	1,241	60.10 /MH	74,607	102,579
			ROOFING					157,289	2,782		167,216	324,506
		24.41.00	SIDING									
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	U1 SDA TOP ENCLOSURE SIDING	2,450.00 SF	-	-	40,572	251	87.92 /MH	22,036	62,608
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	U2 SDA TOP ENCLOSURE SIDING	2,450.00 SF	-	-	40,572	251	87.92 /MH	22,036	62,608
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	REAGENT PREP ENCLOSURE	10,000.00 SF	-	-	165,600	1,023	87.92 /MH	89,941	255,541
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	14,400.00 SF	-	-	238,464	1,473	87.92 /MH	129,515	367,979
			METAL, UNINSULATED, 24 GA, GALVANIZED CORROGATED	U1 BAGHOUSE SKIRTS 6x(83'+63) x30' tall '	26,260.00 SF	-	-	85,345	1,238	87.92 /MH	108,805	194,150
			METAL, UNINSULATED, 24 GA, GALVANIZED CORROGATED	U2 BAGHOUSE SKIRTS 6x(83'+63) x30' tall '	26,280.00 SF	-	-	85,410	1,238	87.92 /MH	108,887	194,297
			SIDING					655,963	5,473		481,220	1,137,183
		24.99.00	ARCHITECTURAL, MISCELLANEOUS									
			PENTHOUSE HEATING	U1 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	73.32 /MH	5,394	69,394
			PENTHOUSE LIGHTING	U1 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	84.60 /MH	6,223	70,223
			PENTHOUSE FIRE PROTECTION	U1 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	32,000	37	84.60 /MH	3,112	35,112
			PENTHOUSE HEATING	U2 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	73.32 /MH	5,394	69,394
			PENTHOUSE LIGHTING	U2 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	84.60 /MH	6,223	70,223
			PENTHOUSE FIRE PROTECTION	U2 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	32,000	37	84.60 /MH	3,112	35,112
			ARCHITECTURAL, MISCELLANEOUS - USER DEFINED	U1 BAGHOUSE SKIRTS MANDOORS	3.00 EA	-	-	1,500	28	58.15 /MH	1,604	3,104
			ARCHITECTURAL, MISCELLANEOUS - USER DEFINED	U2 BAGHOUSE SKIRTS MANDOORS	3.00 EA	-	-	1,500	28	58.15 /MH	1,604	3,104
			ARCHITECTURAL, MISCELLANEOUS					323,000	423		32,666	355,666
			ARCHITECTURAL					1,484,952	10,794		919,463	2,404,415
	31.00.00		MECHANICAL EQUIPMENT									
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		31.41.00	**FIRE PROTECTION EQUIPMENT & SYSTEM**									
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	REAGENT PREP ENCLOSURE 50'X50' FIRE PROTECTION ALLOWANCE	5,000.00 SF	-	-	27,500	385	75.53 /MH	29,083	56,583
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	BYPRODUCTS RECYCLE EQUIPMENT BLDG' FIRE PROTECTION ALLOWANCE	10,800.00 SF	-	-	59,400	832	75.53 /MH	62,820	122,220
			FIRE PROTECTION EQUIPMENT & SYSTEM					**86,900**	**1,217**		**91,904**	**178,804**
		31.45.00	**FGD EQUIPMENT**									
			DRY FGD ISLAND -UNITS 1 & 2 FGD SYSTEMS	INCLUDES ABSORBERS, BAGHOUSES, REAGENT PREP, BYPRODUCT RECYCLE, ID BOOSTER FANS, CONTROLS, PIPING, DUCTWORK, AND WIRING WITHIN FGD ISLAND (BASED ON RECENT BUDGETARY QUOTE FROM SIMILARLY SIZED PROJECT)	1.00 LS		150,000,000	-		100.38 /MH		150,000,000
			DRY FGD ISLAND -UNITS 1 & 2 FGD SYSTEMS	INSTALLATION COST FOR DRY FGD ISLAND INCLUDING ITEMS LISTED ABOVE	1.00 LS	145,000,000		-		100.38 /MH		145,000,000
			FGD EQUIPMENT			**145,000,000**	**150,000,000**					**295,000,000**
			MECHANICAL EQUIPMENT			**145,000,000**	**150,000,000**	**86,900**	**1,217**		**91,904**	**295,178,804**
	34.00.00		**HVAC**									
		34.99.00	**HVAC, MISCELLANEOUS**									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	REAGENT PREP ENCLOSURE 50'X50' LIGHTING ALLOWANCE	5,000.00 SF	-	-	55,000	57	73.32 /MH	4,214	59,214
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	BYPRODUCTS RECYCLE EQUIPMENT BLDG LIGHTING ALLOWANCE	10,800.00 SF	-	-	118,800	124	73.32 /MH	9,102	127,902
			HVAC, MISCELLANEOUS					**173,800**	**182**		**13,316**	**187,116**
			HVAC					**173,800**	**182**		**13,316**	**187,116**
	36.00.00		**INSULATION**									
		36.13.00	**DUCT**									
			MINERAL WOOL INSULATION, 4 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	U1 BAGHOUSE INSUILATION TOP, SIDES AND HOPPERS	141,831.00 SF	-	-	850,986	35,050	73.69 /MH	2,582,848	3,433,834
			MINERAL WOOL INSULATION, 4 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	U2 BAGHOUSE INSULATIOIN - TOPS, SIDES AND HOPPERS	141,831.00 SF	-	-	850,986	35,050	73.69 /MH	2,582,848	3,433,834
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA SHELL INSULATION	40,167.00 SF	-	-	261,086	10,388	73.69 /MH	765,493	1,026,578
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA ROOF INSULATION	11,019.00 SF	-	-	71,624	2,850	73.69 /MH	209,997	281,621
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA SHELL INSULATION	40,167.00 SF	-	-	261,086	10,388	73.69 /MH	765,493	1,026,578
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA ROOF INSULATION	11,019.00 SF	-	-	71,624	2,850	73.69 /MH	209,997	281,621
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	UNIT 1 DUCTWORK (NOT INCLUDED IN FGD ISLAND SCOPE)	168,220.00 SF	-	-	1,093,430	43,505	73.69 /MH	3,205,896	4,299,326
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	UNIT 2 DUCTWORK (NOT INCLUDED IN FGD ISLAND SCOPE)	168,220.00 SF	-	-	1,093,430	43,505	73.69 /MH	3,205,896	4,299,326
			DUCT					**4,554,250**	**183,586**		**13,528,470**	**18,082,720**
			INSULATION					**4,554,250**	**183,586**		**13,528,470**	**18,082,720**
	41.00.00		**ELECTRICAL EQUIPMENT**									
		41.37.00	**LIGHTING ACCESSORY (FIXTURE)**									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	REAGENT PREP ENCLOSURE 50'X50' LIGHTING ALLOWANCE	5,000.00 SF	-	-	55,000	57	69.31 /MH	3,983	58,983
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	BYPRODUCTS RECYCLE EQUIPMENT BLDG LIGHTING ALLOWANCE	10,800.00 SF	-	-	118,800	124	69.31 /MH	8,604	127,404
			LIGHTING ACCESSORY (FIXTURE)					**173,800**	**182**		**12,587**	**186,387**
			ELECTRICAL EQUIPMENT					**173,800**	**182**		**12,587**	**186,387**
			101 FGD ISLAND			**147,908,000**	**150,000,000**	**16,508,216**	**343,779**		**26,553,044**	**340,969,260**
102			**REAGENT HANDLING SYSTEM**									
	21.00.00		**CIVIL WORK**									
		21.14.00	**STRIP & STOCKPILE TOPSOIL**									
			STRIP & STOCKPILE TOPSOIL - 12"	EXTEND REAGENT RAIL TRACK	22,500.00 SF	-	-		52	185.95 /MH	9,618	9,618
			STRIP & STOCKPILE TOPSOIL						**52**		**9,618**	**9,618**
		21.41.00	**EROSION AND SEDIMENTATION CONTROL**									
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK	EXTEND REAGENT RAIL TRACK	2,500.00 SY	-	-	26,625	86	103.37 /MH	8,911	35,536

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			EROSION AND SEDIMENTATION CONTROL					**26,625**	**86**		**8,911**	**35,536**
		21.53.00	**PILING**									
			PILE - 18" AUGER CAST X 60' LONG	UNLOADING SHED 200' X 75 WIDE	64.00 EA	230,400	-			115.48 /MH		230,400
			PILING			**230,400**						**230,400**
		21.54.00	**CAISSON**									
			2.5 FT DIA X 30 FT DEEP CAISSON	SUBSTRUCTURE 2200 TON LIME STORAGE SILOS	100.00 EA	-	-	185,700	2,529	115.48 /MH	292,018	477,718
			CAISSON					**185,700**	**2,529**		**292,018**	**477,718**
		21.71.00	**TRACKWORK**									
			LIME RAILCAR UNLOADING SPUR	ALLOWANCE	1,000.00 LF	-	-	170,000	1,724	87.32 /MH	150,552	320,552
			TRACKWORK					**170,000**	**1,724**		**150,552**	**320,552**
			CIVIL WORK			**230,400**		**382,325**	**4,391**		**461,099**	**1,073,824**
	22.00.00		**CONCRETE**									
		22.13.00	**CONCRETE**									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	SUBSTRUCTURE 2-2,000 TON LIME STORAGE SILOS	600.00 CY	-	-	138,000	4,828	68.52 /MH	330,786	468,786
			FOUNDATION, 4500 PSI - COMPOSITE RATE	UNLOADING SHED 200' X 75 WIDE	925.00 CY	-	-	212,750	7,443	68.52 /MH	509,962	722,712
			CONCRETE					**350,750**	**12,270**		**840,748**	**1,191,498**
			CONCRETE					**350,750**	**12,270**		**840,748**	**1,191,498**
	24.00.00		**ARCHITECTURAL**									
		24.35.00	**PRE-ENGINEERED BUILDING**									
			SHELL ONLY, STEEL UNINSULATED 22 GA,	UNLOADING SHED 200' X 75 WIDE x15' TALL	15,000.00 SF	-	-	525,000	4,828	98.30 /MH	474,552	999,552
			PRE-ENGINEERED BUILDING					**525,000**	**4,828**		**474,552**	**999,552**
			ARCHITECTURAL					**525,000**	**4,828**		**474,552**	**999,552**
	26.00.00		**MISCELLANEOUS STRUCTURAL ITEM**									
		26.13.00	**CONCRETE SILO**									
			CONCRETE SILO - 2,000 TON LIME STORAGE SILO	SUBCONTRACT - ERECTED	2.00 LS	5,600,000				68.52 /MH		5,600,000
			CONCRETE SILO - BIN VENT FILTERS	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - LEVEL INDICATOR	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - VACUUM PRESSURE RELIEF VALVE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - MANHOLE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO			**5,600,000**			**0**			**5,600,000**
			MISCELLANEOUS STRUCTURAL ITEM			**5,600,000**			**0**			**5,600,000**
	31.00.00		**MECHANICAL EQUIPMENT**									
		31.25.00	**CRANES & HOISTS**									
			CRANES & HOISTS & TROLLEYS	REAGENT HANDLING SYSTEM ALLOWANCE	1.00 LT	-	275,000	-		75.53 /MH		275,000
			CRANES & HOISTS				**275,000**					**275,000**
			MECHANICAL EQUIPMENT				**275,000**					**275,000**
	33.00.00		**MATERIAL HANDLING EQUIPMENT**									
		33.14.00	**MATERIAL HANDLING EQUIPMENT**									
			LIME HANDLING SYSTEM - 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM		1.00 LS	-	500,000	-	3,306	75.53 /MH	249,683	749,683
			LIME HANDLING SYSTEM - VACUUM EXHAUSTER WITH SOUND ENCLOSURES	INCLUDED WITH 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	2.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - RECEIVING PANS UNDER RAIL CARS	INCLUDED WITH 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	1.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - FILTER SEPARATORS ON TOP OF SILO	INCLUDED WITH 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	1.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - 25 TPH PNEUMATIC TRANSPORT SYSTEM		2.00 LS	-	1,000,000	-	6,611	75.53 /MH	499,366	1,499,366
			LIME HANDLING SYSTEM - PRESSURE BLOWERS WITH SOUND ENCLOSURES	INCLUDED WITH 25 TPH PNEUMATIC TRANSPORT SYSTEM	3.00 LS	-		-		/MH		
			LIME HANDLING SYSTEM - PRESSURE FEEDERS	INCLUDED WITH 25 TPH PNEUMATIC TRANSPORT SYSTEM	1.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - SPARE PARTS FOR STARTUP AND SPECIAL TOOLS		1.00 LS	-	8,000	-		75.53 /MH		8,000
			LIME HANDLING SYSTEM - FREIGHT		1.00 LS	-	50,000	-		75.53 /MH		50,000
			MATERIAL HANDLING EQUIPMENT				**1,558,000**		**9,917**		**749,049**	**2,307,049**
		33.41.00	**MOBILE YARD EQUIPMENT**									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		33.41.00	MOBILE YARD EQUIPMENT									
			MOBILE YARD EQUIPMENT - TRACKMOBILE	REAGENT HANDLING SYSTEM	1.00 EA	-	225,000	-		75.53 /MH		225,000
			MOBILE YARD EQUIPMENT				225,000					225,000
		33.51.00	RAIL CAR UNLOADER									
			RAIL CAR UNLOADER -	IN UNLOADING SHED 200'X75' WIDE	2.00 LT	-	270,000	-	3,724	98.30 /MH	366,083	636,083
			RAIL CAR UNLOADER				270,000		3,724		366,083	636,083
			MATERIAL HANDLING EQUIPMENT				2,053,000		13,641		1,115,132	3,168,132
	34.00.00		HVAC									
		34.99.00	HVAC, MISCELLANEOUS									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	2-2000 TON LIME STORAGE SILOS	3,600.00 SF	-	-	39,600	41	73.32 /MH	3,034	42,634
			HVAC, MISCELLANEOUS					39,600	41		3,034	42,634
			HVAC					39,600	41		3,034	42,634
	35.00.00		PIPING									
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			8 IN DIA, SCH 40, 8" VACUUM CONVEY PIPING WITH 4 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	500.00 LF	-	38,000		540	93.09 /MH	50,290	88,290
			12 IN DIA, 3/8 IN STD- 2500 LF OF 10"/12" TRANSPORT PRESSURE PIPING W 8 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRANSPORT SYSTEM	2,500.00 LF	-	225,000		3,966	93.09 /MH	369,150	594,150
			CARBON STEEL, STRAIGHT RUN				263,000		4,506		419,440	682,440
			PIPING				263,000		4,506		419,440	682,440
	41.00.00		ELECTRICAL EQUIPMENT									
		41.37.00	LIGHTING ACCESSORY (FIXTURE)									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	2-2000 TON LIME STORAGE SILO	2,500.00 SF	-	-	27,500	29	69.31 /MH	1,992	29,492
			LIGHTING ACCESSORY (FIXTURE)					27,500	29		1,992	29,492
			ELECTRICAL EQUIPMENT					27,500	29		1,992	29,492
			102 REAGENT HANDLING SYSTEM			**5,830,400**	**2,591,000**	**1,325,175**	**39,706**		**3,315,997**	**13,062,572**
105			**BYPRODUCT HANDLING SYSTEM**									
	21.00.00		CIVIL WORK									
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	ASH SILO AND FGD BYPRODUCT SILOS	125.00 EA	-	-	232,125	3,161	115.48 /MH	365,023	597,148
			CAISSON					232,125	3,161		365,023	597,148
			CIVIL WORK					232,125	3,161		365,023	597,148
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	FGD BYPRODUCT SILOS	614.00 CY	-	-	141,220	4,940	68.52 /MH	338,505	479,725
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	FLY ASH BLENDING SILO	67.00 CY	-	-	15,410	539	68.52 /MH	36,938	52,348
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	FOR TRUCK SCALES	144.00 CY	-	-	33,120	1,159	68.52 /MH	79,389	112,509
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	MISC	100.00 CY	-	-	23,000	805	68.52 /MH	55,131	78,131
			CONCRETE					212,750	7,443		509,962	722,712
			CONCRETE					212,750	7,443		509,962	722,712
	23.00.00		STEEL									
		23.13.75	SILO									
			NEW 250 TON FLYASH BLENDING BIN SILO - 24FT DIA X 72 FT HIGH - ERECTION AND FREIGHT INCLUDED	SILO	1.00 EA		275,000		2,839	80.89 /MH	229,653	504,653
			SILO				275,000		2,839		229,653	504,653
			STEEL				275,000		2,839		229,653	504,653
	26.00.00		MISCELLANEOUS STRUCTURAL ITEM									
		26.13.00	CONCRETE SILO									
			CONCRETE SILO - 2-2,200 TON FGD BYPRODUCT SILO	SUBCONTRACTED - ERECTED	2.00 LS	6,000,000				68.52 /MH		6,000,000
			CONCRETE SILO - BIN VENT FILTERS	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - LEVEL INDICATOR	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - VACUUM PRESSURE RELIEF VALVE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - MANHOLE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			CONCRETE SILO			**6,000,000**			**0**			**6,000,000**
			MISCELLANEOUS STRUCTURAL ITEM			**6,000,000**			**0**			**6,000,000**
	33.00.00		**MATERIAL HANDLING EQUIPMENT**									
		33.13.00	**BYPRODUCT HANDLING EQUIPMENT**									
			PNEUMATIC ASH CONVEYORS	EQUIPMENT INCLUDES FREIGHT	1.00 LS	-	5,655,000	-		80.89 /MH		5,655,000
			PNEUMATIC ASH CONVEYORS	INSTALLATION COST	1.00 LT	-		-	79,293	80.89 /MH	6,414,019	6,414,019
			BLOWERS, PRESSURE FEEDERS, TRANSPORT PIPING AND VACUUM / PRESSURE RELIEF VALVES	INCLUDED ABOVE	1.00 LT	-		-		80.89 /MH		
			-FOUR PIN MIXERS BELOW CONCRETE SILOS INCL ALL VALVES AND ACCESSORIES		1.00 LT	-	540,000	-	3,347	80.89 /MH	270,749	810,749
			-DRY UNLOADING SPOUT BELOW THE PRODUCT SILO		2.00 EA	-	60,000	-	258	80.89 /MH	20,883	80,883
			AIRSLIDE CONVEYORS FROM BLENDING BIN MIXER/PIPE CONVEYOR, INCL ALL VALVES AND ACCESSORIES		4.00 EA	-	80,000	-	688	80.89 /MH	55,675	135,675
			BYPRODUCT HANDLING EQUIPMENT				**6,335,000**		**83,587**		**6,761,325**	**13,096,325**
		33.57.00	**SCALE**									
			SCALE - NEW TRUCK SCALES	BYPRODUCT HANDLING SYSTEM	2.00 EA	-	200,000	-	460	75.53 /MH	34,726	234,726
			SCALE				**200,000**		**460**		**34,726**	**234,726**
			MATERIAL HANDLING EQUIPMENT				**6,535,000**		**84,046**		**6,796,052**	**13,331,052**
	34.00.00		**HVAC**									
		34.37.00	**DUST COLLECTOR**									
			DUST COLLECTOR - INSTALLED COST		1.00 LS	120,000	-			73.32 /MH		120,000
			DUST COLLECTOR			**120,000**						**120,000**
			HVAC			**120,000**						**120,000**
	35.00.00		**PIPING**									
		35.14.10	**CARBON STEEL, STRAIGHT RUN**									
			12 IN DIA, 3/8 IN STD	CONVEYOR PIPING	2,000.00 LF	-	-	198,400	3,172	93.09 /MH	295,320	493,720
			12 IN DIA, 3/8 IN STD	12" TIE IN PIPING TO BYPRODUCT SILO FROM THE EXISTING 50 TPH FLY ASH PRESSURE SYSTEM	1,500.00 LF	-	-	148,800	2,379	93.09 /MH	221,490	370,290
			CARBON STEEL, STRAIGHT RUN					**347,200**	**5,552**		**516,810**	**864,010**
			PIPING					**347,200**	**5,552**		**516,810**	**864,010**
			105 BYPRODUCT HANDLING SYSTEM			**6,120,000**	**6,810,000**	**792,075**	**103,041**		**8,417,500**	**22,139,575**
121			**CIVIL BOP**									
	21.00.00		**CIVIL WORK**									
		21.14.00	**STRIP & STOCKPILE TOPSOIL**									
			STRIP & STOCKPILE TOPSOIL - 12"		300,000.00 SF	-	-		690	185.95 /MH	128,241	128,241
			STRIP & STOCKPILE TOPSOIL - ONSITE		40,000.00 CY	-	-		5,287	185.95 /MH	983,184	983,184
			STRIP & STOCKPILE TOPSOIL - 12"	SITE GRADING	600,000.00 SF	-	-		1,379	185.95 /MH	256,483	256,483
			STRIP & STOCKPILE TOPSOIL - ONSITE	SITE GRADING	160,000.00 CY	-	-		21,149	185.95 /MH	3,932,736	3,932,736
			STRIP & STOCKPILE TOPSOIL						**28,506**		**5,300,644**	**5,300,644**
		21.17.00	**EXCAVATION**									
			EXCAVATION - EXCAVATION , BACKFILL & COMPACT	ALL FOUNDATIONS	12,600.00 CY	-	-		4,345	84.40 /MH	366,703	366,703
			EXCAVATION						**4,345**		**366,703**	**366,703**
		21.39.00	**STORM DRAINAGE UTILITIES**									
			STORM SEWER WORK	SITE GRADING	1.00 LT	-	-	110,000	2,299	86.33 /MH	198,460	308,460
			STORM DRAINAGE UTILITIES					**110,000**	**2,299**		**198,460**	**308,460**
		21.41.00	**EROSION AND SEDIMENTATION CONTROL**									
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK		33,334.00 SY	-	-	355,007	1,149	103.37 /MH	118,818	473,826
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK	SITE GRADING	66,667.00 SY	-	-	710,004	2,299	103.37 /MH	237,633	947,637
			EROSION AND SEDIMENTATION CONTROL					**1,065,011**	**3,448**		**356,452**	**1,421,462**
		21.57.00	**ROAD, PARKING AREA, & SURFACED AREA**									
			ONSITE ROAD UPGRADES	ALLOWANCE	1.00 LS	-	-	700,000	3,483	86.08 /MH	299,796	999,796
			ROAD, PARKING AREA, & SURFACED AREA					**700,000**	**3,483**		**299,796**	**999,796**
		21.99.00	**CIVIL WORK, MISCELLANEOUS**									
			CIVIL WORK - CONSTRUCTION LAYDOWN AREAS	FENCING, POWER ETC...	10.00 AC	-	-	842,400	9,195	84.40 /MH	776,092	1,618,492

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			CIVIL WORK, MISCELLANEOUS					**842,400**	**9,195**		**776,092**	**1,618,492**
			CIVIL WORK					**2,717,411**	**51,276**		**7,298,147**	**10,015,557**
	22.00.00		**CONCRETE**									
		22.13.00	**CONCRETE**									
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	555.00 CY	-	-	127,650	4,466	68.52 /MH	305,977	433,627
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' BYPRODUCT AREA, TRUCK SCALE HOUSE	6.00 CY	-	-	1,380	48	68.52 /MH	3,308	4,688
			CONCRETE					**129,030**	**4,514**		**309,285**	**438,315**
			CONCRETE					**129,030**	**4,514**		**309,285**	**438,315**
	24.00.00		**ARCHITECTURAL**									
		24.35.00	**PRE-ENGINEERED BUILDING**									
			SHELL ONLY, STEEL UNINSULATED 22 GA, 200 FT X 75 FT x 15' TALL	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	420,000	5,862	98.30 /MH	576,241	996,241
			PRE-ENGINEERED BUILDING	8' X 10' BYPRODUCT AREA, TRUCK SCALE HOUSE	1.00 LT	-	-	10,000	115	98.30 /MH	11,299	21,299
			PRE-ENGINEERED BUILDING					**430,000**	**5,977**		**587,540**	**1,017,540**
		24.41.00	**SIDING**									
			INSULATION, 2 IN THICK FIBERGLASS,	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	8,250.00 SF	-	-	9,900	95	87.92 /MH	8,337	18,237
			SIDING					**9,900**	**95**		**8,337**	**18,237**
			ARCHITECTURAL					**439,900**	**6,072**		**595,877**	**1,035,777**
	27.00.00		**PAINTING & COATING**									
		27.17.00	**PAINTING**									
			PAINTING - ALLOWANCE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	15,000	172	64.47 /MH	11,116	26,116
			PAINTING					**15,000**	**172**		**11,116**	**26,116**
			PAINTING & COATING					**15,000**	**172**		**11,116**	**26,116**
	31.00.00		**MECHANICAL EQUIPMENT**									
		31.41.00	**FIRE PROTECTION EQUIPMENT & SYSTEM**									
			FIRE PROTECTION EQUIPMENT & SYSTEM	NEW WAREHOUSE BUILDING 200'X75'X15' TALL, FIRE PROTECTION ALLOWANCE	15,000.00 SF	-	-	82,500	1,155	75.53 /MH	87,250	169,750
			FIRE PROTECTION EQUIPMENT & SYSTEM					**82,500**	**1,155**		**87,250**	**169,750**
			MECHANICAL EQUIPMENT					**82,500**	**1,155**		**87,250**	**169,750**
	34.00.00		**HVAC**									
		34.99.00	**HVAC, MISCELLANEOUS**									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	165,000	172	73.32 /MH	12,641	177,641
			HVAC, MISCELLANEOUS					**165,000**	**172**		**12,641**	**177,641**
			HVAC					**165,000**	**172**		**12,641**	**177,641**
	36.00.00		**INSULATION**									
		36.99.00	**INSULATION, MISCELLANEOUS**									
			INSULATION - ROOF INSULATION	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	18,000	172	58.15 /MH	10,026	28,026
			INSULATION, MISCELLANEOUS					**18,000**	**172**		**10,026**	**28,026**
			INSULATION					**18,000**	**172**		**10,026**	**28,026**
	41.00.00		**ELECTRICAL EQUIPMENT**									
		41.37.00	**LIGHTING ACCESSORY (FIXTURE)**									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL, LIGHTING ALLOWANCE	15,000.00 SF	-	-	165,000	172	69.31 /MH	11,950	176,950
			LIGHTING ACCESSORY (FIXTURE)					**165,000**	**172**		**11,950**	**176,950**
			ELECTRICAL EQUIPMENT					**165,000**	**172**		**11,950**	**176,950**
	71.00.00		**PROJECT INDIRECT**									
		71.25.00	**CONSULTANT, THIRD PARTY**									
			CONSULTANT - SUBSURFACE INVESTIGATION		1.00 LS	200,000	-			/MH		200,000
			CONSULTANT - GEOTECHNICAL		1.00 LS	150,000	-			/MH		150,000

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			CONSULTANT, THIRD PARTY			350,000						350,000
			PROJECT INDIRECT			350,000						350,000
			121 CIVIL BOP			**350,000**		**3,731,841**	**63,706**		**8,336,292**	**12,418,133**
151			**MECHANICAL BOP**									
	21.00.00		CIVIL WORK									
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	TANK FOUNDATIONS	76.00 EA	-	-	141,132	1,922	115.48 /MH	221,934	363,066
			2.5 FT DIA X 30 FT DEEP CAISSON	COMMON PIPE RACK FOUNDATIONS	223.00 EA	-	-	414,111	5,639	115.48 /MH	651,201	1,065,312
			2.5 FT DIA X 30 FT DEEP CAISSON	BYPRODUCT PIPE RACK FOUNDATIONS	57.00 EA	-	-	105,849	1,441	115.48 /MH	166,450	272,299
			2.5 FT DIA X 30 FT DEEP CAISSON	REAGENT UNLOADING PIPE RACK FOUNDATIONS	32.00 EA	-	-	59,424	809	115.48 /MH	93,446	152,870
			CAISSON					720,516	9,811		1,133,031	1,853,547
			CIVIL WORK					720,516	9,811		1,133,031	1,853,547
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SPREAD FOOTING FOUNDATION, 4500 PSI - COMPOSITE RATE	3X 35' DIA TANK FDN	81.00 CY	-	-	18,630	652	68.52 /MH	44,656	63,286
			CONCRETE FOUNDATIONS - COMPOSITE RATE	COMMON PIPE RACK FOUNDATIONS	250.00 CY	-	-	57,500	2,011	68.52 /MH	137,828	195,328
			CONCRETE FOUNDATIONS - COMPOSITE RATE	BYPRODUCT PIPE RACK FOUNDATIONS	65.00 CY	-	-	14,950	523	68.52 /MH	35,835	50,785
			CONCRETE FOUNDATIONS - COMPOSITE RATE	REAGENT UNLOADING PIPE RACK FOUNDATIONS	36.00 CY	-	-	8,280	290	68.52 /MH	19,847	28,127
			CONCRETE					99,360	3,476		238,166	337,526
			CONCRETE					99,360	3,476		238,166	337,526
	23.00.00		STEEL									
		23.21.00	GIRDER									
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	COMMON 750'LX20'W, 550'Lx15'W, ALL 20' HIGH	235.00 TN	-	-	636,850	4,592	98.30 /MH	451,389	1,088,239
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	BYPRODUCT PIPE RACK, 200'LX12'W X 20' HIGH	24.00 TN	-	-	65,040	469	98.30 /MH	46,099	111,139
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	REAGENT UNLOADING PIPE RACK, 200'LX6' WIDE X 20' HIGH	12.00 TN	-	-	32,520	234	98.30 /MH	23,050	55,570
			GIRDER					734,410	5,295		520,538	1,254,948
			STEEL					734,410	5,295		520,538	1,254,948
	31.00.00		MECHANICAL EQUIPMENT									
		31.17.00	COMPRESSOR & ACCESSORIES									
			AIR COMPRESSOR, CENTRIFUGAL - 250 SCFM EA @ 200 PSIG	SERVICE AIR	2.00 EA	-	310,000	-	92	75.53 /MH	6,945	316,945
			AIR COMPRESSOR, CENTRIFUGAL - 250 SCFM EA @ 200 PSIG	INSTRUMENT AIR	2.00 EA	-	310,000	-	92	75.53 /MH	6,945	316,945
			AIR DRYER - W/FILTERS, 250 NET SCFM EA	SERVICE AIR	2.00 EA	-	33,400	-	74	75.53 /MH	5,556	38,956
			AIR DRYER - W/FILTERS, 250 NET SCFM EA	INSTRUMENT AIR	2.00 EA	-	33,400	-	74	75.53 /MH	5,556	38,956
			AIR RECEIVER - 1,000 GALLON EA	SERVICE AIR	2.00 EA	-	11,200	-	37	75.53 /MH	2,778	13,978
			AIR RECEIVER - 1,000 GALLON EA	INSTRUMENT AIR	2.00 EA	-	11,200	-	37	75.53 /MH	2,778	13,978
			COMPRESSOR & ACCESSORIES				709,200		405		30,559	739,759
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									
			DELUGE - POWER TRANSFORMERS		3.00 EA	-	-	127,500	1,959	93.09 /MH	182,328	309,828
			FIRE PROTECTION EQUIPMENT & SYSTEM					127,500	1,959		182,328	309,828
		31.65.00	HEAT EXCHANGER									
			HEAT EXCHANGER - SLAKER WATER HEATER 3" IN-LINE, 475 KW		4.00 EA	-	220,000	-	368	69.31 /MH	25,493	245,493
			HEAT EXCHANGER				220,000		368		25,493	245,493
		31.75.00	PUMP									
			CENTRIFUGAL, HORIZONTAL, SINGLE STAGE - MAKEUP WATER PUMPS, 2600 GPM, 200 TDH		2.00 EA	-	96,000	-	577	75.53 /MH	43,582	139,582
			CENTRIFUGAL, HORIZONTAL, SINGLE STAGE - RECYCLE ASH WATER PUMP, 50 HP		3.00 EA	-	72,000	-	221	75.53 /MH	16,669	88,669
			CENTRIFUGAL, HORIZONTAL, SINGLE STAGE - LIME SLAKING WATER PIUMPS, 50 HP		2.00 EA	-	48,000	-	147	75.53 /MH	11,112	59,112
			SUMP, CENTRIFUGAL, WET BEARING - REGENT PREP/RECYCLE SUMP, 120GPM, 150 TDH		4.00 EA	-	220,000	-	276	75.53 /MH	20,836	240,836
			SUMP, CENTRIFUGAL, WET BEARING - LIME SILO & UNLOADING AREA SUMP 120 GPM @ 150 TDH		2.00 EA	-	88,000	-	138	75.53 /MH	10,418	98,418

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		31.75.00	PUMP									
			SUMP, CENTRIFUGAL, WET BEARING - WASTE ASH SILO AREA SUMP 120GPM @150 TDH		2.00 EA	-	88,000	-	138	75.53 /MH	10,418	98,418
			SUMP, CENTRIFUGAL, WET BEARING - WASTEWATER FORWARDING PUMP TO RECYCLED SLURRY, 100 GPM@150 TDH		4.00 EA	-	28,800	-	294	75.53 /MH	22,225	51,025
			SUMP, SUBMERSIBLE - RECYCLE ASH WATER TANK SUPPLY PUMP, 100 HP		2.00 EA	-	77,000	-	690	75.53 /MH	52,090	129,090
			PUMP				717,800		2,480		187,349	905,149
		31.83.00	TANK									
			ATMOSPHERIC, FIELD FABRICATED - LIME SLAKING WATER TANK, 175,000 GALLON	35' DIA X 24' HIGH	1.00 EA	220,000		-		94.32 /MH		220,000
			ATMOSPHERIC, FIELD FABRICATED - RECYCLE ASH WATER TANK, 200,000 GALLON	35' DIA X 30' HIGH	2.00 EA	500,000		-		94.32 /MH		500,000
			TANK			720,000						720,000
			MECHANICAL EQUIPMENT			720,000	1,647,000	127,500	5,211		425,730	2,920,230
	35.00.00		PIPING									
		35.13.01	SS 304, ABOVE GROUND, PROCESS AREA									
			1 IN DIA, SCH 40S		1,520.00 LF	-	-	32,832	1,974	93.09 /MH	183,783	216,615
			1.5 IN DIA, SCH 40S		1,380.00 LF	-	-	52,302	2,094	93.09 /MH	194,911	247,213
			2 IN DIA, SCH 40S		2,070.00 LF	-	-	113,022	3,426	93.09 /MH	318,946	431,968
			SS 304, ABOVE GROUND, PROCESS AREA					198,156	7,494		697,640	895,796
		35.13.10	CARBON STEEL, ABOVE GROUND, PROCESS AREA									
			1 IN DIA, SCH 80		260.00 LF	-	-	2,314	305	93.09 /MH	28,376	30,690
			2 IN DIA, SCH 80		2,260.00 LF	-	-	48,138	3,273	93.09 /MH	304,693	352,831
			2.5 IN DIA, SCH 40		1,000.00 LF	-	-	15,400	1,437	93.09 /MH	133,750	149,150
			3 IN DIA, SCH 40		7,160.00 LF	-	-	125,300	11,028	93.09 /MH	1,026,601	1,151,901
			3 IN DIA, SCH 80		1,760.00 LF	-	-	38,720	3,055	93.09 /MH	284,363	323,083
			4 IN DIA, SCH 40		1,000.00 LF	-	-	22,600	1,701	93.09 /MH	158,360	180,960
			6 IN DIA, SCH 40		880.00 LF	-	-	28,248	1,629	93.09 /MH	151,598	179,846
			6 IN DIA, SCH 40 VACUUM PIPE		2,260.00 LF	-	-	72,546	4,182	93.09 /MH	389,330	461,876
			8 IN DIA, SCH 80		3,520.00 LF	-	-	256,608	9,832	93.09 /MH	915,235	1,171,843
			CARBON STEEL, ABOVE GROUND, PROCESS AREA					609,874	36,441		3,392,307	4,002,181
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			6 IN DIA, SCH 40, LIME SLAKING TANK MAKEUP	LIME SLAKING TANK MAKEUP	1,200.00 LF	-	-	27,480	1,214	93.09 /MH	112,992	140,472
			8 IN DIA, SCH 40, LIME SLAKING TANK MAKEUP	LIME SLAKING TANK MAKEUP	450.00 LF	-	-	13,905	486	93.09 /MH	45,261	59,166
			8 IN DIA, SCH 40, RECYCLE ASH WATER PIPING	RECYCLE ASH WATER PIPING	2,000.00 LF	-	-	61,800	2,161	93.09 /MH	201,160	262,960
			10 IN DIA, SCH 40, RECYCLE ASH TANK MAKEUP	RECYCLE ASH TANK MAKEUP	450.00 LF	-	-	24,660	610	93.09 /MH	56,817	81,477
			CARBON STEEL, STRAIGHT RUN					127,845	4,471		416,230	544,075
		35.15.10	CARBON STEEL, BURIED									
			3 IN DIA, SCH 40, WRAPPED		3,000.00 LF	-	-	51,000	2,241	93.09 /MH	208,650	259,650
			6 IN DIA, SCH 40, WRAPPED		750.00 LF	-	-	23,925	776	93.09 /MH	72,225	96,150
			10 IN DIA, SCH 40, WRAPPED, RECYCLE ASH WATER PIPE DISCHARGE BURIED	RECYCLE ASH WATER PIPE DISCHARGE BURIED	1,800.00 LF	-	-	119,700	2,441	93.09 /MH	227,268	346,968
			CARBON STEEL, BURIED					194,625	5,459		508,143	702,768
		35.15.25	FRP, BURIED									
			3 IN DIA, TAPER		1,000.00 LF	-	-	14,800	460	93.09 /MH	42,800	57,600
			3 IN DIA, TAPER FRP/HDPE PIPE		2,380.00 LF	-	-	35,224	1,094	93.09 /MH	101,864	137,088
			FRP, BURIED					50,024	1,554		144,664	194,688
		35.15.30	HDPE, BURIED									
			6 IN DIA, DR 9		1,430.00 LF	-	-	12,870	1,134	93.09 /MH	105,577	118,447
			8 IN DIA, DR 9		1,340.00 LF	-	-	20,770	1,278	93.09 /MH	119,005	139,775
			HDPE, BURIED					33,640	2,413		224,582	258,222
		35.36.00	PIPE SUPPORTS, RACK									
			SUPPORT SLEEPERS	BYPRODUCT PIPE, 1750LF	125.00 EA	-	-	43,750	575	93.09 /MH	53,500	97,250
			SUPPORT SLEEPERS	REAGENT UNLOADING PIPE, 1500LF	108.00 EA	-	-	37,800	497	93.09 /MH	46,224	84,024
			PIPE SUPPORTS, RACK					81,550	1,071		99,724	181,274
		35.45.00	VALVES									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		35.45.00	VALVES									
			VALVE - 36" 150 LB CS BUTTERFLY, FLANGED		2.00 EA	-	-	79,920	96	93.09 /MH	8,902	88,822
			VALVE - 12" 150 LB CS KNIFE GATE, FLANGED		6.00 EA	-	-	20,160	195	93.09 /MH	18,169	38,329
			VALVE - 12" 150 LB CS GATE VALVE, FLANGED		2.00 EA	-	-	8,920	65	93.09 /MH	6,056	14,976
			VALVE - 10" 150 LB CS SWING CHECK, FLANGED		2.00 EA	-	-	9,200	55	93.09 /MH	5,136	14,336
			VALVE - 10" 150 LB CS BUTTERFLY, FLANGED		5.00 EA	-	-	22,200	138	93.09 /MH	12,840	35,040
			VALVE - 8" 150 LB CS GATE, FLANGED		20.00 EA	-	-	100,000	425	93.09 /MH	39,590	139,590
			VALVE - 6" 150 LB CS GATE, FLANGED		6.00 EA	-	-	19,800	110	93.09 /MH	10,272	30,072
			VALVE - 6" 150 LB CS AIR OPERATED GATE, FLANGED		4.00 EA	-	-	20,400	74	93.09 /MH	6,848	27,248
			VALVE - 6" 150 LB CS AIR OPERATED GLOBE, FLANGED		4.00 EA	-	-	20,400	74	93.09 /MH	6,848	27,248
			VALVE - 6" 150 LB CS SWING CHECK, FLANGED		2.00 EA	-	-	3,400	37	93.09 /MH	3,424	6,824
			VALVE - 4" 150 LB CS GATE, FLANGED		3.00 EA	-	-	3,825	25	93.09 /MH	2,311	6,136
			VALVE - 3" AND BELOW CS FOR SERVICE WATER ISOLATION		120.00 EA	-	-	1,224,000	1,076	93.09 /MH	100,152	1,324,152
			VALVE - 3" AND BELOW CS FOR SERVICE AIR ISOLATION		120.00 EA	-	-	1,224,000	1,076	93.09 /MH	100,152	1,324,152
			VALVE - 3" 150 LB CS GATE, FLANGED		20.00 EA	-	-	15,000	179	93.09 /MH	16,692	31,692
			VALVE - 3" CS PST IND FOR FP 250 LB		6.00 EA	-	-	6,600	54	93.09 /MH	5,008	11,608
			VALVE - 2" AND ABOVE BRONZE VALVES FOR INSTRUMENT AIR ISOLATION		600.00 EA	-	-	78,000	501	93.09 /MH	46,673	124,673
			VALVE - 1" CS FLANGED		4.00 EA	-	-	880	21	93.09 /MH	1,969	2,849
			VALVE - 6" CI POST INDICATOR 250 LB., MECHANICAL JOINT WITH BOXES BURIED VALVE		6.00 EA	-	-	4,080	28	93.09 /MH	2,568	6,648
			VALVES					2,860,785	4,228		393,610	3,254,395
			PIPING					4,156,499	63,131		5,876,900	10,033,399
	36.00.00		INSULATION									
		36.17.01	PIPE, CALCIUM SILICATE W/ALUMINUM JACKETING									
			CALCIUM SILICATE W/ALUMINUM JACKETING - 8" PIPE 1.5" THICK		2,520.00 LF	-	-	16,380	487	73.69 /MH	35,859	52,239
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 3" PIPE		1,260.00 LF	-	-	3,591	155	73.69 /MH	11,419	15,010
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 3" PIPE		5,660.00 LF	-	-	16,131	696	73.69 /MH	51,297	67,428
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 2.5" PIPE		380.00 LS	-	-	1,083	47	73.69 /MH	3,444	4,527
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 2.0" PIPE		4,140.00 LS	-	-	10,309	476	73.69 /MH	35,066	45,375
			PIPE, CALCIUM SILICATE W/ALUMINUM JACKETING					47,494	1,860		137,085	184,579
			INSULATION					47,494	1,860		137,085	184,579
	41.00.00		ELECTRICAL EQUIPMENT									
		41.33.00	HEAT TRACING									
			HEAT TRACING - 8" PIPE		2,520.00 LS	-	-	18,749	43	69.31 /MH	3,011	21,760
			HEAT TRACING - 3" PIPE		1,260.00 LF	-	-	9,374	22	69.31 /MH	1,506	10,880
			HEAT TRACING - 3" PIPE		5,660.00 LF	-	-	42,110	98	69.31 /MH	6,764	48,874
			HEAT TRACING - 2.5" PIPE		380.00 LS	-	-	2,827	7	69.31 /MH	454	3,281
			HEAT TRACING - 2.0" PIPE		440.00 LS	-	-	3,274	8	69.31 /MH	526	3,799
			HEAT TRACING					76,334	177		12,261	88,595
			ELECTRICAL EQUIPMENT					76,334	177		12,261	88,595
			151 MECHANICAL BOP			**720,000**	**1,647,000**	**5,962,113**	**88,963**		**8,343,711**	**16,672,824**
190			**DEMOLITION / RELOCATION**									
	11.00.00		DEMOLITION									
		11.99.00	DEMOLITION, MISCELLANEOUS									
			DEMOLITION - MISC	ALLOWANCE	1.00 LT	-	-	1,800,000	33,333	98.30 /MH	3,276,667	5,076,667
			DEMOLITION, MISCELLANEOUS					1,800,000	33,333		3,276,667	5,076,667
			DEMOLITION					1,800,000	33,333		3,276,667	5,076,667
			190 DEMOLITION / RELOCATION					**1,800,000**	**33,333**		**3,276,667**	**5,076,667**
201			**ELECTRICAL BOP SYSTEM**									
	41.00.00		ELECTRICAL EQUIPMENT									
		41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS									
			ELECTRICAL EQUIPMENT AND MISCELLANEOUS COMPONENTS	ALLOWANCE	1.00 LT	-	12,300,000	1,600,000	88,322	69.31 /MH	6,121,587	20,021,587
			ELECTRICAL COMMODITIES - CABLE	ALLOWANCE	1.00 LT	-		8,500,000	88,391	84.60 /MH	7,477,862	15,977,862
			ELECTRICAL COMMODITIES - CONDUITS, RACEWAY, ETC.	ALLOWANCE	1.00 LT	-		1,400,000	107,471	84.60 /MH	9,092,069	10,492,069
			ELECTRICAL EQUIPMENT, MISCELLANEOUS				12,300,000	11,500,000	284,184		22,691,518	46,491,518
			ELECTRICAL EQUIPMENT				12,300,000	11,500,000	284,184		22,691,518	46,491,518

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			201 ELECTRICAL BOP SYSTEM				**12,300,000**	**11,500,000**	**284,184**		**22,691,518**	**46,491,518**
211			**INSTRUMENTATION AND CONTROLS BOP SYSTEM**									
	44.00.00		**CONTROL & INSTRUMENTATION**									
		44.99.00	**CONTROL & INSTRUMENTATION, MISCELLANEOUS**									
			CONTROL & INSTRUMENTATION - MISC	ALLOWANCE	1.00 LT	-	1,500,000	1,085,000	10,920	72.29 /MH	789,374	3,374,374
			CONTROL & INSTRUMENTATION, MISCELLANEOUS				**1,500,000**	**1,085,000**	**10,920**		**789,374**	**3,374,374**
			CONTROL & INSTRUMENTATION				**1,500,000**	**1,085,000**	**10,920**		**789,374**	**3,374,374**
			211 INSTRUMENTATION AND CONTROLS BOP SYSTEM				**1,500,000**	**1,085,000**	**10,920**		**789,374**	**3,374,374**

	EPA Estimates b... Bl...
Actual Costs	
Capital ($)	
Capital Recovery Factor	
Annualized Capital ($/yr)	
Annual O&M ($/yr)	
Total Annual Cost ($/yr)	
SO_2 Emissions Reduction (ton/yr)	
Cost Effectiveness ($/ton)	
Adjusted Costs	**Unit 1**
Capital ($)	247,751,669
Capital Recovery Factor	0.0806
Annualized Capital ($/yr)	19,965,416
Annual O&M ($/yr)	16,877,127
Total Annual Cost ($/yr)	36,842,543
SO_2 Emissions Reduction (ton/yr)	12,912
Cost Effectiveness ($/ton)	2,853

CRF = (i(1+i)^n)/(((1+i)^n)-1)
interest
n (remaining useful life or RUL)

* Entergy estimates were provided in Exhibit I to their comments on the pr

ɔased on White ɹff	Entergy Estimates based on Independence-specific costs and 9 year RUL*		ADEQ Estimates based on Independence-specific costs and 30 year RUL	
	Unit 1	**Unit 2**	**Unit 1**	**Unit 2**
	491,893,500	491,893,500	491,893,500	491,893,500
	0.1535	0.1535	0.0806	0.0806
	75,505,652	75,505,652	39,639,928	39,639,928
	8,809,000	8,809,000	8,809,000	8,809,000
	84,314,652	84,314,652	48,448,928	48,448,928
	12,608	13,655	12,608	13,655
	6,688	6,175	3,843	3,548
Unit 2	**Unit 1**	**Unit 2**	**Unit 1**	**Unit 2**
247,751,669	355,391,500	355,391,500	355,391,500	355,391,500
0.0806	0.1535	0.1535	0.0806	0.0806
19,965,416	54,552,595	54,552,595	28,639,723	28,639,723
16,877,127	8,809,000	8,809,000	8,809,000	8,809,000
36,842,543	63,361,595	63,361,595	37,448,723	37,448,723
13,990	12,608	13,655	12,608	13,655
2,634	5,026	4,640	2,970	2,742

0.15348647	0.080586404
0.07	0.07
9	30

ɔposed SIP.

This workbook has been updated to contain the calculations to estimate new RPGs for the 20% worst days for Caney Creek and Upper Buffalo accounting for controls under BART and RP in the proposed SIP. This workbook and methodology were originally developed by EPA Region 6.

2018 - all SIP controls required by 2018 as well as adjustment for additional emissions at AECC Bailey and Lake Catherine based on recent actual emissions

Description of Methodology -
1) 2018 CENRAP CAMx PSAT results for Arkansas point sources for sulfate and nitrate at each Arkansas Class I area from CENRAP-PSAT-Tool-ENVIRON-Aug27-2007.mdb are scaled by the ratios of (2018 CENRAP Arkansas point source emissions minus reduction due to FIP controls required by end of 2018) divided by 2018 CENRAP Arkansas point source emissions for SO2 and NOx

2) Total extinction at each Arkansas Class I area from 2018 CENRAP CAMx modeling is adjusted to reflect the scaled down contributions from sulfate and nitrate
3) Percent reduction in total extinction between scaled value and modeled 2018 CENRAP CAMx value is calculated
4) Calculated percentage reduction is appled to 2018 CENRAP CMAQ calculated extinction (CENRAP TSD)
5) Total extinction is converted to dv

Description of worksheets -

2018 - Calculations for 2018 RPG based on scaling Arkansas sulfate and nitrate point source impacts from CAMx PSAt modeling results by change in emissions due to controls in place in 2018

EPA CAMD - annual emission inventory data for sources for EGUs subject to EPA's FIP. Data from EPA Air Markets Program data, available at: http://ampd.epa.gov/ampd/

DAYSoftheWK - Calculates the number of Mondays, weekdays, saturdays, and Sundays for each month needed to estimate annual emissions for representative EI data. See CENRAP TSD Section 2 for additional information

2002 CENRAP EI - Facility annual emissions estimated from daily emission values for Monday, Weekday, Sat, and Sun for each month from Pechan CENRAP EI Summary Project_Final Aug 2007.mdb

2018 CENRAP EI - Facility annual emissions estimated from daily emission values for Monday, Weekday, Sat, and Sun for each month from Pechan CENRAP EI Summary Project_Final Aug 2007.mdb

CSAPR - Quantification of emission reductions anticipated from CSAPR based on 2017 and 2018 (and beyond) allocations

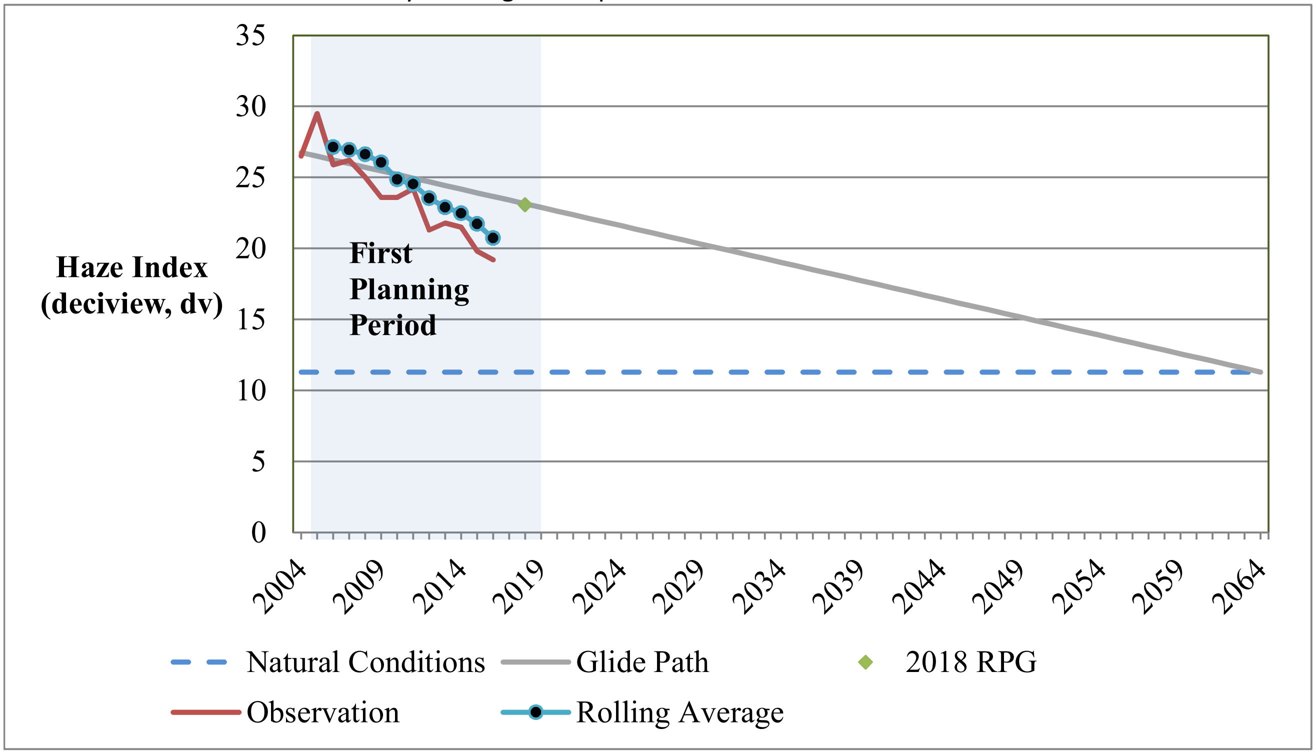
CAMD Unit O3 Season - Ozone season emissions from Arkansas EGUS for 2014 - 2016

site	year	Observation	Rolling Average	2018 RPG	Glide Path	Natural Conditions
HEGL1	2002	27.2				11.3
HEGL1	2003	26.6				11.3
HEGL1	2004	26.5			26.75	11.3
HEGL1	2005	29.5			26.4925	11.3
HEGL1	2006	25.9	27.14		26.235	11.3
HEGL1	2007	26.2	26.94		25.9775	11.3
HEGL1	2008	25	26.62		25.72	11.3
HEGL1	2009	23.6	26.04		25.4625	11.3
HEGL1	2010	23.6	24.86		25.205	11.3
HEGL1	2011	24.2	24.52		24.9475	11.3
HEGL1	2012	21.3	23.54		24.69	11.3
HEGL1	2013	21.8	22.9		24.4325	11.3
HEGL1	2014	21.5	22.48		24.175	11.3
HEGL1	2015	19.8	21.72		23.9175	11.3
	2016	19.2	20.72		23.66	11.3
	2017				23.4025	11.3
	2018			23.06001	23.145	11.3
	2019				22.8875	11.3
	2020				22.63	11.3
	2021				22.3725	11.3
	2022				22.115	11.3
	2023				21.8575	11.3
	2024				21.6	11.3
	2025				21.3425	11.3
	2026				21.085	11.3
	2027				20.8275	11.3
	2028				20.57	11.3
	2029				20.3125	11.3
	2030				20.055	11.3
	2031				19.7975	11.3
	2032				19.54	11.3
	2033				19.2825	11.3
	2034				19.025	11.3
	2035				18.7675	11.3
	2036				18.51	11.3
	2037				18.2525	11.3
	2038				17.995	11.3
	2039				17.7375	11.3
	2040				17.48	11.3
	2041				17.2225	11.3
	2042				16.965	11.3
	2043				16.7075	11.3
	2044				16.45	11.3
	2045				16.1925	11.3

2046	15.935	11.3
2047	15.6775	11.3
2048	15.42	11.3
2049	15.1625	11.3
2050	14.905	11.3
2051	14.6475	11.3
2052	14.39	11.3
2053	14.1325	11.3
2054	13.875	11.3
2055	13.6175	11.3
2056	13.36	11.3
2057	13.1025	11.3
2058	12.845	11.3
2059	12.5875	11.3
2060	12.33	11.3
2061	12.0725	11.3
2062	11.815	11.3
2063	11.5575	11.3
2064	11.3	11.3

URP 0.2575

26.75 baseline is from Missouri 5-year Progress Report.



Appendix F

CENRAP Technical Support Document

Draft Report

Technical Support Document for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation Plans

Prepared for:
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September 12, 2007

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1.0 INTRODUCTION

This Technical Support Document (TSD) describes the Central Regional Air Planning Association (CENRAP) regional emissions and air quality modeling to support the central states Regional Haze Rule (RHR) State Implementation Plans (SIPs). The CENRAP 2002 annual emissions and air quality modeling was performed by the contractor team of ENVIRON International Corporation (ENVIRON) and the University of California at Riverside (UCR).

1.1 Background

The 1977 Clean Air Act Amendments (CAAA) added a new Section 169A for the protection of visibility in Federal Class I areas (specific national parks, wilderness areas and wildlife refuges). Section 169A(a)(1) of the CAAA established the national goal for visibility protection: "Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution." The CAAA require States to submit SIPs containing emission limits, schedules of compliance and to "promulgate regulations to assure reasonable progress toward meeting the national goal" (Section 169A(a)(4)). In response to these mandates EPA promulgated the Regional Haze Rule (RHR) on July 1, 1999 that requires States to "establish goals (expressed in deciviews) that provide for reasonable progress towards achieving natural visibility conditions" at Class I areas. The States' RHR SIPs are due December 17, 2007 and an important component of the SIP will be the 2018 Reasonable Progress Goals (RPGs) toward achieving natural conditions in 2064. Regional air quality models are used to project visibility to 2018 to determine the level of visibility improvement that is expected to be achieved in 2018. This information, along with other sources, can be used by the states to assist in setting their 2018 RPGs.

CENRAP is one of five Regional Planning Organizations (RPOs) that have responsibility for coordinating development of SIPs and Tribal Implementation Plans (TIPs) in selected areas of the U.S. to address the requirements of the RHR. CENRAP is a regional partnership of states, tribes, federal agencies, stakeholders and citizen groups established to initiate and coordinate activities associated with the management of regional haze and other air quality issues within the CENRAP states. The CENRAP region includes states and tribal lands located within the boundaries of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Nebraska, Oklahoma and Texas.

The CENRAP Emissions and Air Quality Modeling Team is composed of staff from ENVIRON and UCR, with assistance and coordination from the CENRAP states, tribes, federal agencies and stakeholders. The ENVIRON/UCR Team performs the emissions and air quality modeling simulations for states and tribes within the CENRAP region, providing analytical results used in developing implementation plans under the RHR. Figure 1-1 shows the states included in each of the five RPOs in the U.S., including CENRAP. Table 1-1 lists the Class I areas within the CENRAP states.

CENRAP is performing emissions and air quality modeling to project visibility to 2018. The modeling results will be used to determine the level of visibility improvement expected in 2018 under various emission scenarios. States will use these results to assist in determining their 2018 RPGs toward achieving natural conditions in 2064.

Figure 1-1. Regional Planning Organizations engaged in Regional Haze Modeling.

Table 1-1. Federal Mandated Class I Areas in the CENRAP States.

Class I Area	Acreage	Federal Land Manager	Public Law
Arkansas			
Caney Creek Wilderness Area	14,460	USDA-FS	93-622
Upper Buffalo Wilderness Area	12,018	USDA-FS	93-622
Louisiana			
Breton Wilderness Area	5,000+	USDI-FWS	93-632
Minnesota			
Boundary Waters Canoe Area Wilderness	810,088	USDA-FS	99-577
Voyageurs National Park	114,964	USDI-NP	99-261
Missouri			
Hercules-Glade Wilderness Area	12,314	USDA-FS	94-557
Mingo Wilderness Area	8,000	USDI-FWS	95-557
Oklahoma			
Wichita Mountains Wilderness	8,900	USDI-FWS	91-504
Texas			
Big Bend National Park	708,118	USDI-NP	74-157
Guadalupe Mountains National Park	76,292	USDI-NP	89-667

1.2 CENRAP Organizational Structure and Work Groups

The governing body of CENRAP is the Policy Oversight Group (POG) that is made up of voting members representing states and tribes within the CENRAP region and non-voting members representing local agencies, the EPA and other federal agencies. The work of CENRAP is accomplished through five standing workgroups:

- Monitoring;
- Emissions Inventory;
- Modeling;
- Communications; and
- Implementation and Control Strategies.

Participation in workgroups is open to all interested parties and the POG may form additional ad hoc workgroups to address specific issues (e.g., a Data Analysis workgroup was formed).

The RHR requires the states, and the tribes that may elect to, submit the first SIPs and TIPs that address progress toward natural conditions at federally mandated Class I areas by December 17, 2007. 40 CFR 51.308 (Section 308) discusses the following four core requirements to be included in SIPs/TIPs and Best Available Retrofit Technology (BART) requirements:

1. Reasonable progress goals;
2. Calculations of baseline and natural visibility conditions;
3. A Long-term strategy for regional haze;
4. A Monitoring strategy and other implementation plan requirements; and
5. BART requirements for regional haze visibility impairment.

One of CENRAP's goals is to provide support to states and tribes to meet each of these requirements of the RHR and to develop scientifically supportable, economical and effective control strategies that the states and tribes may adopt to reduce anthropogenic effects on visibility impairment at Class I areas. One component of CENRAP's support to states and tribes as part of compliance with the RHR is performing emissions and air quality modeling. These activities were implemented to:

- obtain a better understanding of the causes of visibility impairment and to identify potential mitigation measures for visibility impairment at Class I areas;
- to evaluate the effects of alternative control strategies for improving visibility; and
- to project future-year air quality and visibility conditions.

In October 2004, CENRAP selected the team of ENVIRON and UCR to perform their Emissions and Air Quality Modeling.

The CENRAP Emissions and Air Quality Modeling Team performs regional haze analyses by operating regional scale, three-dimensional air quality models that simulate the emissions, chemical transformations, and transport of gaseous and particulate matter (PM) species and consequently the effects on visibility in Class I Areas in the central U.S. A key element of this work includes the integration of emissions inventories and emissions models with regional transport models. The general services provided by the CENRAP Emissions and Air Quality Modeling Team include, but are not limited to:

- Emissions processing and modeling;
- Air quality and visibility modeling simulations;
- Analysis, display, and reporting of modeling results; and
- Storage/quality assurance of the modeling input and output files.

The CENRAP 2002 annual Emissions and Air Quality Modeling Team performs work for the CENRAP Modeling Workgroup through direction from the CENRAP Technical Director and CENRAP Executive Director.

1.3 Overview of 2002 Annual Emissions and Air Quality Modeling Approach

The CENRAP 2002 annual emissions and air quality modeling was initiated on October 16, 2004 and involved the preparation of numerous databases, model simulations, presentations and reports. Much of the modeling analyses have been posted to the CENRAP modeling website at: http://pah.cert.ucr.edu/aqm/cenrap/index.shtml. There were numerous versions and iterations of the modeling and interim results. The results presented in this TSD focus on the final modeling results and key findings in their development. The reader is referred to the modeling website for interim products.

1.3.1 Modeling Protocol

A Modeling Protocol was prepared at the outset of the study to serve as a road map for performing the CENRAP emissions and air quality modeling and to communicate the modeling plans to the CENRAP participants. The Modeling Protocol was prepared following EPA guidance for preparation at the time it was prepared (EPA, 1991; 1999, 2001) and took into account CENRAP's long-term plan (CENRAP, 2003) and the modeling needs of the RHR SIPs. The first version (Version 1.0) of the Modeling Protocol was dated November 19, 2004. Based on comments received from CENRAP, the Modeling Protocol was updated to the current Version 2.0 (Morris et al., 2004a) that was dated December 8, 2004. This Modeling Protocol can be found on the CENRAP modeling Website at:

http://pah.cert.ucr.edu/aqm/cenrap/docs/CENRAP_Draft2.0_Modeling_Protocol_120804.pdf

1.3.2 Quality Assurance Project Plan (QAPP)

A Quality Assurance Project Plan (QAPP) was prepared for the CENRAP emissions and air quality modeling study that described the quality management functions performed by the modeling team. The QAPP was prepared and was based on the national consensus standards for quality assurance (ANSI/ASQC, 1994), followed EPA's guidelines for quality assurance project plans for modeling (EPA, 2002) and for QAPPs (EPA, 2001) and took into account the recommendations from the North American Research Strategy for Tropospheric Ozone (NARSTO) Quality Handbook for modeling projects (NARSTO, 1998). The EPA and NARSTO guidance documents were developed specifically for modeling projects, which have different quality assurance concerns than environmental monitoring data collection projects. The work performed in this project involves modeling at the basic research level and for regulatory/planning applications. In order to use model outputs for these purposes, it must be established that each model is scientifically sound, robust, and defensible. This is accomplished by following a project planning process that incorporates the following elements as described in the EPA modeling guidance document:

- A systematic planning process including identification of assessments and related performance criteria;
- Peer reviewed theory and equations;
- A carefully designed life-cycle development process that minimizes errors;
- Documentation of any changes from original plans;
- Clear documentation of assumptions, theory, and parameterization that is detailed enough so others can understand the model output;
- Input data and parameters that are accurate and appropriate for the analysis; and
- Output data that can be used to help inform decision makers.

The CENRAP QAPP can be found at:

http://pah.cert.ucr.edu/aqm/cenrap/docs/CENRAP_QAPP_Nov_24_2004.pdf).

A key component of the CENRAP emissions and air quality modeling QAPP was the graphical display of model inputs and outputs and multiple peer-review of each step of the modeling process. This was accomplished through use of the CENRAP modeling website where modelers posted displays of work products (e.g., emissions plots, model outputs, etc.) for review by the CENRAP modeling team, modeling workgroup and others. This website can be found at: http://pah.cert.ucr.edu/aqm/cenrap/index.shtml.

1.3.3 Model Selection

The selection of the meteorological, emissions and air quality models for the CENRAP regional haze modeling was based on a review of previous regional haze modeling studies performed in the CENRAP region (e.g., Pitchford et al., 2004; Pun, Chen and Seigneur, 2004; Tonnesen and Morris 2004) as well as elsewhere in the United States (e.g., Morris et al, 2004a; Tonnesen et al., 2003; Baker, 2004). The CENRAP emissions and air quality Modeling Protocol (Morris et al., 2004a) provides details on the justification for model selection and the formulation of the different models. Based on previous work (e.g., CENRAP, WRAP, VISTAS, MRPO, BRAVO and EPA), CENRAP selected the following models for use in modeling PM and regional haze in the central states:

- **MM5:** The Pennsylvania State University/National Center for Atmospheric Research (PSU/NCAR) Mesoscale Meteorological Model (MM5 Version 3.6 MPP) is a non-hydrostatic, prognostic meteorological model routinely used for urban- and regional-scale photochemical, fine particulate, and regional haze regulatory modeling studies (Anthes and Warner, 1978; Chen and Dudhia, 2001; Stauffer and Seaman, 1990, 1991; Xiu and Pleim, 2000).

- **SMOKE**: The Sparse Matrix Operator Kernel Emissions (SMOKE) modeling system is an emissions modeling system that generates hourly gridded speciated emission inputs of mobile, non-road, area, point, fire and biogenic emission sources for photochemical grid models. (Coats, 1995; Houyoux and Vukovich, 1999). As with most ‘emissions models’, SMOKE is principally an *emission processing system* and not a true *emissions modeling system* in which emissions estimates are simulated from ‘first principles’. This means that, with the exception of mobile and biogenic sources, its purpose is to provide an efficient tool for converting an existing base emissions inventory data into the hourly, gridded, speciated, and formatted emission files required by an air quality model.

- **CMAQ:** EPA’s Models-3/Community Multiscale Air Quality (CMAQ) modeling system is a ‘One-Atmosphere’ photochemical grid model capable of addressing ozone, PM, visibility and acid deposition at a regional scale for extended periods of time (Dennis, et al., 1996; Byun et al., 1998a; Byun and Ching, 1999, Pleim et al., 2003).

- **CAMx:** ENVIRON’s Comprehensive Air Quality Model with Extensions (CAMx) modeling system is also a state-of-science ‘One-Atmosphere’ photochemical grid model capable of addressing ozone, PM, visibility and acid deposition at a regional scale for extended periods of time. (ENVIRON, 2006).

1.3.3.1 MM5 Meteorological Model Configuration for CENRAP Annual Modeling

Application of the MM5 for the 2002 annual modeling on a 36 km grid for the continental US was performed by the Iowa Department of Natural Resources (IDNR; Johnson, 2007). Details of the 2002 36 km MM5 model application and evaluation procedures carried out by IDNR may be found in Johnson, 2007. Application of the MM5 model on a 12 km grid covering the Central States for portions of 2002 was performed by EPA Region VII and the Texas Commission on Environmental Quality (TCEQ).

The MM5 (Version 3.63) configuration used in the generation of the meteorological modeling datasets consists of the following (see Table 1-2 for more details):

- 36 km grid with 34 vertical layers;
- 12 km nested grid for episodic modeling;
- For 12 km runs use two way nesting (without feedback) within the 36 km grid;
- Initialization and boundary conditions from Eta analysis fields;
  - Eta 3D and surface analysis data (ds609.2);
  - Not using NCEP global tropospheric SST data (ds083.0) ;
  - Observational enhancement (LITTLE_R)
    - NCEP ADP surface obs (ds464.0)
    - NCEP ADP upper-air obs (ds353.4)
- Pleim-Xiu (P-X) land-surface model (LSM);
- Pleim-Chang Asymmetric Convective Mixing (ACM) PBL model;
- Kain-Fritsch 2 cumulus parameterization;
- Mixed phase (Reisner 1) cloud microphysics;
- Rapid Radiative Transfer Model (RRTM) radiation;
- No Shallow Convection (ISHALLO=0);
- Standard 3D FDDA analysis nudging outside of PBL; and
- Surface nudging of the winds only.

1.3.3.2 SMOKE Emissions Model Configuration for CENRAP Annual Modeling

SMOKE supports area, mobile, fire and point source emission processing and includes biogenic emissions modeling through a rewrite of the Biogenic Emission Inventory System, version 3 (BEIS3) (see, http://www.epa.gov/ttn/chief/software.html#pcbeis). SMOKE has been available since 1996, and has been used for emissions processing in a number of regional air quality modeling applications. In 1998 and 1999, SMOKE was redesigned and improved with the support of the U.S. Environmental Protection Agency (EPA), for use with EPA's Models-3/CMAQ (http://www.epa.gov/asmdnerl/models3). The primary purposes of the SMOKE redesign were support of: (a) emissions processing with user-selected chemical mechanisms and (b) emissions processing for reactivity assessments.

As an emissions processing system, SMOKE has far fewer 'science configuration' options compared with the MM5 and CMAQ models. Table 1-3 summarizes the version of the SMOKE system that was used and the sources of data that were employed in constructing the required modeling inventories.

1.3.3.3 CMAQ Air Quality Model Configuration for CENRAP Annual Modeling

CENRAP used CMAQ Version 4.5 with the "SOAmods enhancement", described below, and used the model configuration as shown in Table 1-4. The model was set up and exercised on the same 36 km grid that was used by WRAP and VISTAS, the 36 km RPO national grid. CENRAP performed 12 km CMAQ sensitivity tests and found little change in model performance with a large penalty in computation time. Consequently, at the February 7, 2006 CENRAP Modeling

Workgroup Meeting a decision was made to proceed with the CENRAP emissions and air quality modeling using just the 36 km national RPO grid (Morris et al., 2006a).

Initial CMAQ 2002 simulations performed by VISTAS found that the model greatly underestimates organic mass carbon (OMC) concentrations, especially in the summer. A review of the CMAQ formulation found that it failed to treat Secondary Organic Aerosol (SOA) formation from sesquiterpenes and isoprene and also failed to account for the fact that SOA can become polymerized so that it is no longer volatile and stays in the particle form. Thus, VISTAS updated the CMAQ SOA module to include these missing processes and found much improved OMC model performance (Morris et al., 2006c). CENRAP tested the CMAQ Version 4.5 with SOAmods enhancement and found it performed much better for OMC than the standard versions of CMAQ Version 4.5. Therefore, CMAQ Version 4.5, with the enhanced SOAmods (Morris et al., 2006c), was adopted for the CENRAP modeling. CMAQ Version 4.5 is available from the CMAS center (www.cmascenter.org).

1.3.3.4 CAMx Air Quality Model Configuration for CENRAP Annual Modeling

CAMx Version 4.40 was applied using similar options as used by CMAQ. CAMx was used initially in side-by-side comparisons with CMAQ. Comparative model performance results and other factors for CAMx V4 and CMAQ V4.4 with SOAmods were presented at the February 7, 2006 CENRAP modeling workgroup meetings that found (Morris et al., 2006b):

- No one model was consistently performing better than the other over all species and averaging times.
- Both models performed well for sulfate.
- CMAQ's winter nitrate over-prediction tendency not as large as CAMx's.
- CAMx performed slightly better than CMAQ for elemental carbon (EC).
- CMAQ performed much better than CAMx for organic mass carbon (OMC).
- Both models over-predicted Soil and under-predicted coarse mass (CM).
- CMAQ ran faster than CAMx due to MPI multi-processing capability.
- CAMx required much less disk space than CMAQ.

Based on these factors, CMAQ was selected as the lead air quality model for the CENRAP regional haze modeling with CAMx the secondary corroborative model. However, CAMx also contained a PM Source Apportionment Technology (PSAT) capability that was used widely in the CENRAP modeling. Table 1-4 lists the main CAMx configuration used for the CENRAP annual modeling that was selected, in part, to be consistent with the CMAQ model configuration (Table 1-4). One exception to this was that the CAMx PSAT simulations used the Bott advection solver rather than the PPM advection solver. The PPM advection solver is typically used in the standard CAMx and CMAQ runs. Bott, however, is more computationally efficient and the high computational requirements of the CAMx PSAT runs dictated this choice.

Table 1-2. MM5 Meteorological Model Configuration for CENRAP 2002 Annual Modeling (Johnson, 2007).

Science Options	Configuration	Details/Comments
Model Code	MM5 version 3.63	Grell et al., 1994
Horizontal Grid Mesh	36 km	
36 km grid	165 x 129 dot points	RPO MM5 Grid
Vertical Grid Mesh	34 layers	Vertically varying; sigma pressure coordinate system
Grid Interaction	No Feedback	IFEED=0
Initialization	Eta first guess fields/LittleR	
Boundary Conditions	Eta first guess fields/LittleR	
Microphysics	Reisner I Mixed Ice	Look up table
Cumulus Scheme	Kain-Fritsch 2	On 36 and 12 km Grids
Planetary Boundary Layer	ACM PBL	
Radiation	RRTM	
Vegetation Data	USGS	24 Category Scheme
Land Surface Model	Pleim-Xiu Land Surface Model (LSM)	
Shallow Convection	None	
Sea Surface Temperature	Eta Skin	Spatially varying
Thermal Roughness	Garratt	
Snow Cover Effects	None	
4D Data Assimilation	Analysis Nudging on 36 and 12	
Surface Nudging	Wind Field Only	
Integration Time Step	90 seconds	
Simulation Periods	Annual 2002 for 36 km	12 km episodic only
Platform	Linux Cluster	Done at IDNR[1]

[1] Twelve km episodic modeling completed by EPA Region VII and the Texas Commission on Environmental Quality.

Table 1-3. SMOKE Emissions Model Configuration for CENRAP Annual Modeling.

Emissions Component	Configuration	Details/Comments
Emissions Model	SMOKE Version 2.3	Several versions of SMOKE used during course of the study
Horizontal Grid Mesh	36 km	
36 km grid	148 x 112 cells	RPO National Grid
Area Source Emissions	CENRAP Domain: CENRAP State 2002 EI	Updated '02 developed by CENRAP states (Pechan, 2005d,e)
	Other States: '02 NEI augmented with other 2002	Generated from EPA NEI02 v.1 and RPO interaction (Pechan, 2005c)
On-Road Mobile Sources	CENRAP Domain: CENRAP VMT data	Updated '02 developed by CENRAP states (Reid et al., 2004a)
	Other States: EPA '02 NEI augmented with other 2002	Generated from EPA NEI02 v.1 and RPO interaction (Pechan, 2005c)
Point Sources	CENRAP Domain: CENRAP State 2002 EI	Updated '02 developed by CENRAP states and stakeholders (Pechan, 2005a,b)
	Other States: EPA '02 NEI augmented with other 2002	Generated from EPA NEI02 v.1 and RPO interaction (Pechan, 2005c)
Off-Road Mobile Sources	CENRAP Domain: CENRAP State 2002 EI	Updated '02 developed by CENRAP states (Pechan, 2005d,e)
	Other States: EPA '02 NEI augmented with other 2002	Generated from EPA NEI02 v.1 and RPO interaction (Pechan, 2005c)
Biogenic Sources	SMOKE BEIS-3	BELD3 vegetative database
Mexican Sources	1999 Emissions for 2002 and 2018	http://www.epa.gov/ttn/chief/net/mexico.html; (ERG, 2006)
Canadian Sources	2000 Emissions for 2002 and 2020 Emissions for 2018	http://www.epa.gov/ttn/chief/net/canada.html
Temporal Adjustments	Seasonal, day, hour	Based on latest collected information and CEM-based profiles
Chemical Speciation	Revised CBM-IV Chemical Speciation	Updated January 2004
Gridding	Revised EPA Spatial Surrogates Used	Gridding of surrogates from http://www.epa.gov/ttn/chief/emch/spatial/
Growth and Controls	CENRAP developed	Pechan (2005a,b)
Quality Assurance	QA Tools in SMOKE 2.0	Follow QAPP (Morris and Tonnesen, 2004) and QA refinements (Morris and Tonnesen, 2006)
Simulation Periods	Annual 2002 for 36 km	Episodic periods at 12 km

Table 1-4. CMAQ Air Quality Model Configuration for CENRAP Annual Modeling.

Science Options	Configuration	Details/Comments
Model Code	CMAQ Version 4.5 w/ SOAmods	Secondary Organic Aerosol enhancements as described by Morris et al., (2006c)
Horizontal Grid Mesh	36 km annual	36 km covering continental U.S; some episodic 12 km sensitivity runs were also performed
36 km grid	148 x 112 cells	RPO National Grid
Vertical Grid Mesh	19 Layers	First 17 layers sync'd w/ MM5
Grid Interaction	One-way nesting	
Initial Conditions	~15 days full spin-up	Separately run 4 quarters of 2002
Boundary Conditions	2002 GEOS-CHEM day-specific	2002 GEOS-CHEM day specific 3-hour average data
Emissions		
Baseline Emissions Processing	See SMOKE model configuration	MM5 Meteorology input to SMOKE, CMAQ
Sub-grid-scale Plumes	No Plume-in-Grid (PinG)	
Chemistry		
Gas Phase Chemistry	CBM-IV	
Aerosol Chemistry	AE3/ISORROPIA	
Secondary Organic Aerosols	Secondary Organic Aerosol Model (SORGAM) w/ SOAmods update	Schell et al., (2001); Morris et al., (2006c)
Cloud Chemistry	RADM-type aqueous chemistry	Includes subgrid cloud processes
N2O5 Reaction Probability	0.01 – 0.001	
Meteorological Processor	MCIP Version 2.3	Includes dry deposition and snow cover updates
Horizontal Transport		
Numerical Scheme	PPM advection solver	
Eddy Diffusivity Scheme	K-theory with Kh grid size dependence	Multiscale Smagorinsky (1963) approach
Vertical Transport		
Eddy Diffusivity Scheme	K-theory	
Diffusivity Lower Limit	Kzmin = 0.1 to 1.0	Land use dependent Kzmin
Deposition Scheme	M3dry	Directly linked to Pleim-Xiu Land Surface Model parameters
Numerics		
Gas Phase Chemistry Solver	Euler Backward Iterative (EBI) solver	
Horizontal Advection Scheme	Piecewise Parabolic Method (PPM) scheme	
Simulation Periods	Annual 2002 for 36 km	Episodic periods at 12 km
Integration Time Step	Calculated Internally	15 minute coupling time step

Table 1-5. CAMx Air Quality Model Configuration for CENRAP Annual Modeling.

Science Options	Configuration	Details
Model Code	CAMx Version 4.40	Available at: www.camx.com
Horizontal Grid Mesh	36 km annual	36 km covering continental U.S
36 km grid	148 x 112 cells	
Vertical Grid Mesh	19 Layers	17 Layers sync'd w/ MM5
Grid Interaction	Two-way nesting	
Initial Conditions	~15 days full spin-up	Separately run 4 quarters of 2002
Boundary Conditions	2002 GEOS-CHEM day-specific	2002 GEOS-CHEM day specific 3-hour average data
Emissions		
Baseline Emissions Processing	See SMOKE model configuration	MM5 Meteorology input to SMOKE, CAMx
Sub-grid-scale Plumes	No Plume-in-Grid (PinG)	Consistent with CMAQ
Chemistry		
Gas Phase Chemistry	CBM-IV	with Isoprene updates
Aerosol Chemistry	ISORROPIA equilibrium	Dynamic and hybrid also available but not used
Secondary Organic Aerosols	SOAP	
Cloud Chemistry	RADM-type aqueous chemistry	Alternative is CMU multi-section aqueous chemistry
N2O5 Reaction Probability	None	
Meteorological Processor	MM5CAMx	
Horizontal Transport		
Eddy Diffusivity Scheme	K-theory with Kh grid size dependence	
Vertical Transport		
Eddy Diffusivity Scheme	K-Theory	
Diffusivity Lower Limit	Kzmin = 0.1 to 1.0	Land use dependent Kzmin
Planetary Boundary Layer	No Patch	
Deposition Scheme	Wesely	
Numerics		
Gas Phase Chemistry Solver	CMC Fast Solver	
Horizontal Advection Scheme	Piecewise Parabolic Method (PPM) scheme. PSAT w/ Bott scheme.	
Simulation Periods	Annual 2002 at 36 km	
Integration Time Step	Wind speed dependent	

1.3.4 Modeling Domains

The CENRAP emissions and air quality modeling was conducted on the 36 km national RPO domain as depicted in Figure 1-2. This domain consists of a 148 by 112 array of 36 km by 36 km grid cells and covers the continental United States. Sensitivity simulations were also performed for episodes on a 12 km modeling domain covering the central states, however the results were very similar to the 36 km results so CENRAP elected to proceed with the 2002 annual modeling using the 36 km domain for computational efficiency (Morris et al., 2006a).

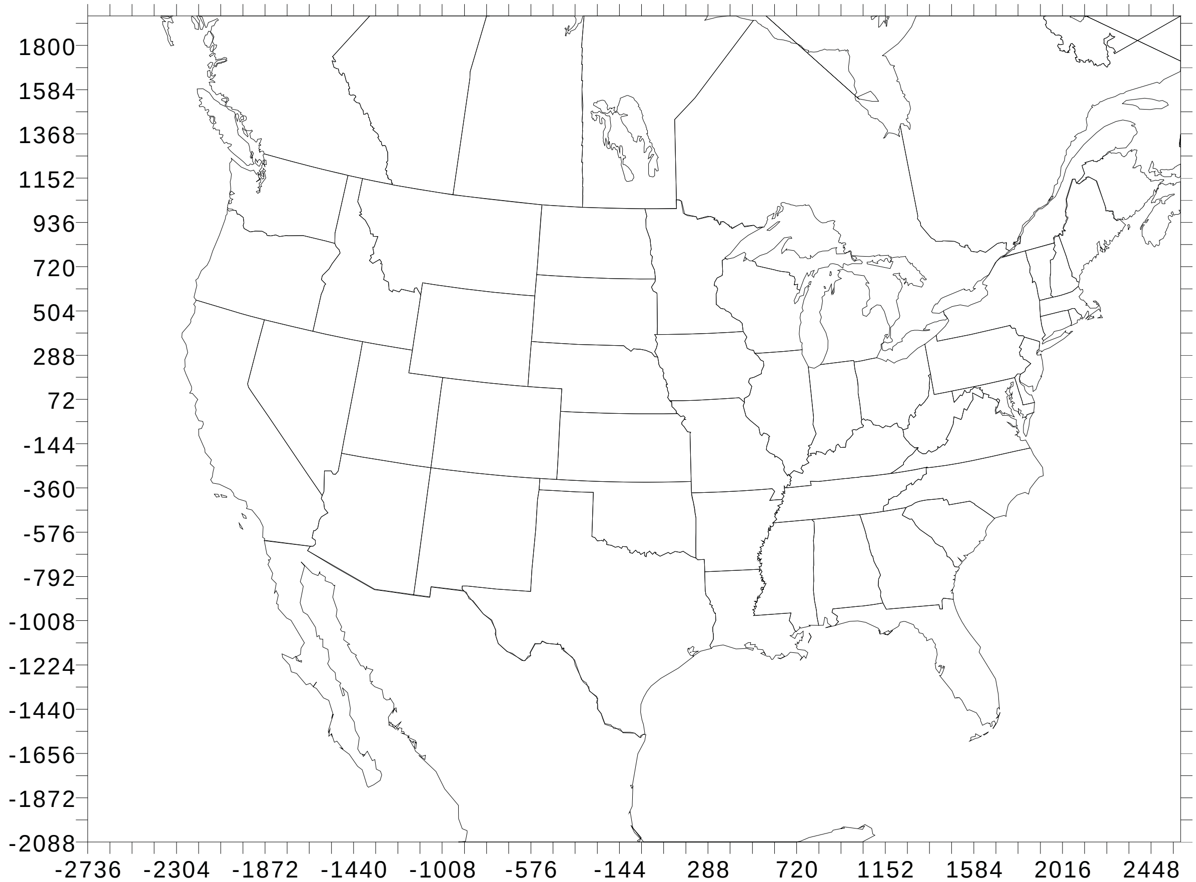


Figure 1-2. National Inter-RPO 36 km modeling domain used for the CENRAP 2002 annual SMOKE, CMAQ and CAMx modeling.

1.3.5 Vertical Structure of Modeling Domain

The MM5 meteorological model was exercised using 34 vertical layers from the surface to a pressure level of 100 mb (approximately 15 km above ground level). Both the CMAQ and CAMx air quality models can employ layer collapsing in which vertical layers in the MM5 are combined in the air quality model, which improves computational efficiency. The sensitivity of the CMAQ model estimates to the number of vertical layers was evaluated by the Western Regional Air Partnership (WRAP) and Visibility Improvements State and Tribal Association of the Southeast (VISTAS) (Tonnesen et al., 2005; 2006; Morris et al., 2004a). CMAQ model simulations were performed with no layer collapsing (i.e., the same 34 layers as used by MM5) and with various levels of layer collapsing. These studies found that using 19 vertical layers up to 100 mb (i.e., same model top as MM5) and matching the eight lowest MM5 vertical layers near the surface produced nearly identical results as with no layer collapsing. They also found that very aggressive layer collapsing (e.g., 34 to 12 layers) produced results with substantial differences compared to no layer collapsing. Therefore, based on the WRAP/VISTAS sensitivity analysis, CENRAP adopted the 19 vertical layer configuration up to the 100 mb model top. Figure 1-3 displays the definition of the 34 MM5 vertical layers and how they were collapsed to 19 vertical layers in the air quality modeling performed by CENRAP.

MM5					CMAQ 19L				
Layer	Sigma	Pres(mb)	Height(m	Depth(m)	Layer	Sigma	Pres(mb)	Height(m)	Depth(m)
34	**0.000**	**100**	**14662**	**1841**	**19**	**0.000**	**100**	**14662**	**6536**
33	0.050	145	12822	1466		0.050	145		
32	0.100	190	11356	1228		0.100	190		
31	0.150	235	10127	1062		0.150	235		
30	0.200	280	9066	939		0.200	280		
29	**0.250**	**325**	**8127**	**843**	**18**	**0.250**	**325**	**8127**	**2966**
28	0.300	370	7284	767		0.300	370		
27	0.350	415	6517	704		0.350	415		
26	0.400	460	5812	652		0.400	460		
25	**0.450**	**505**	**5160**	**607**	**17**	**0.450**	**505**	**5160**	**1712**
24	0.500	550	4553	569		0.500	550		
23	0.550	595	3984	536		0.550	595		
22	**0.600**	**640**	**3448**	**506**	**16**	**0.600**	**640**	**3448**	**986**
21	0.650	685	2942	480		0.650	685		
20	**0.700**	**730**	**2462**	**367**	**15**	**0.700**	**730**	**2462**	**633**
19	0.740	766	2095	266		0.740	766		
18	**0.770**	**793**	**1828**	**259**	**14**	**0.770**	**793**	**1828**	**428**
17	0.800	820	1569	169		0.800	820		
16	**0.820**	**838**	**1400**	**166**	**13**	**0.820**	**838**	**1400**	**329**
15	0.840	856	1235	163		0.840	856		
14	**0.860**	**874**	**1071**	**160**	**12**	**0.860**	**874**	**1071**	**160**
13	0.880	892	911	158	**11**	**0.880**	**892**	**911**	**158**
12	**0.900**	**910**	**753**	**78**	**10**	**0.900**	**910**	**753**	**155**
11	0.910	919	675	77		0.910	919		
10	**0.920**	**928**	**598**	**77**	**9**	**0.920**	**928**	**598**	**153**
9	0.930	937	521	76		0.930	937		
8	**0.940**	**946**	**445**	**76**	**8**	**0.940**	**946**	**445**	**76**
7	**0.950**	**955**	**369**	**75**	**7**	**0.950**	**955**	**369**	**75**
6	**0.960**	**964**	**294**	**74**	**6**	**0.960**	**964**	**294**	**74**
5	**0.970**	**973**	**220**	**74**	**5**	**0.970**	**973**	**220**	**74**
4	**0.980**	**982**	**146**	**37**	**4**	**0.980**	**982**	**146**	**37**
3	**0.985**	**986.5**	**109**	**37**	**3**	**0.985**	**986.5**	**109**	**37**
2	**0.990**	**991**	**73**	**36**	**2**	**0.990**	**991**	**73**	**36**
1	**0.995**	**995.5**	**36**	**36**	**1**	**0.995**	**995.5**	**36**	**36**
0	**1.000**	**1000 0 0**		**0**	**0**	**1.000**	**1000 0 0**		

Figure 1-3. MM5 34 vertical layer definitions and scheme for collapsing the 34 layers down to 19 layers for the CENRAP CMAQ and CAMx 2002 annual modeling.

1.3.6 2002 Calendar Year Selection

The calendar year 2002 was selected for CENRAP regional haze annual modeling as described in the CENRAP Modeling Protocol (Morris et al., 2004a). EPA's applicable guidance on $PM_{2.5}$/Regional Haze modeling at that time (EPA, 2001) identified specific goals to consider when selecting modeling periods for use in demonstrating reasonable progress in attaining the regional haze goals. However, since there is much in common with the goals for selecting episodes for annual and episodic $PM_{2.5}$ attainment demonstrations as well as regional haze, EPA's current guidance addresses all three in a common document. (EPA, 2007) At the time of the modeling period selection EPA had also published an updated summary of $PM_{2.5}$ and Regional Haze Modeling Guidance (Timin, 2002) that served, in some respects, as an interim placeholder until the final guidance was issued as part of the $PM_{2.5}$/regional haze NAAQS implementation process that was ultimately published in April 2007 (EPA, 2007). The interim EPA modeling guidance for episode selection (EPA, 2001; Timin, 2002) was consistent with the final EPA regional haze modeling guidance (EPA, 2007).

EPA recommends that the selection of a modeling period derive from three principal criteria:

- A variety of meteorological conditions should be covered that includes the types of meteorological conditions that produce the worst 20 percent and best 20 percent visibility days at Class I areas in the CENRAP States during the 2000-2004 baseline period;

- To the extent possible, the modeling data base should include days for which enhanced data bases (i.e. beyond routine aerometric and emissions monitoring) are available; and

- Sufficient days should be available such that relative response factors (RRFs) can be based on several (i.e., $\geq$ 15) days.

For regional haze modeling, the guidance goes further by suggesting that the preferred approach is to model a full, *representative* year (EPA, 2001, pg. 188). Moreover, the required RRF values should be based on model results averaged over the 20 percent worst and 20 percent best visibility days determined for each Class I area based on monitoring data from the 2000 – 2004 baseline period. More recent EPA guidance (Timin, 2002) suggests that states should model at least 10 worst and 10 best visibility days at each Class 1 area. EPA also lists several 'other considerations' to bear in mind when choosing potential PM/regional haze episodes including: (a) choose periods which have already been modeled, (b) choose periods which are drawn from the years upon which the current design values are based, (c) include weekend days among those chosen, and (d) choose modeling periods that meet as many episode selection criteria as possible in the maximum number of nonattainment or Class I areas as possible.

Due to limited available resources CENRAP was restricted to modeling a single calendar year. The RHR uses the five-year baseline of 2000-2004 period as the starting point for projecting future-year visibility. Thus, the modeling year should be selected from this five-year baseline period. The 2002 calendar year, which lies in the middle of the 2000-2004 Baseline, was selected for the following reasons:

- Based on available information, 2002 appears to be a fairly typical year in terms of meteorology for the 5-year Baseline period of 2000-2004;

- 2003 and 2004 appeared to be colder and wetter than typical in the eastern US;

- The enhanced IMPROVE and IMPROVE Protocol and Supersites PM monitoring data were fully operational by 2002. Much less IMPROVE monitoring data was available during 2000-2001, especially in the CENRAP region;

- IMPROVE data for 2003 and 2004 were not yet available at the time that the CENRAP modeling was initiated; and

- 2002 was being used by the other RPOs.

1.3.7 Initial Concentrations and Boundary Conditions

The CMAQ and CAMx models were operated separately for each of four quarters of the 2002 year using a ~15 day spin up period (i.e., the models were started approximately 15 days before the first day of interest in each quarter in order to limit the influence of the assumed initial concentrations, e.g., start June 15 for quarter 3 whose first day of interest is July 1). Sensitivity simulations demonstrated that with ~15 initialization days, the influence of initial concentrations (ICs) was minimal using the 36 km Inter-RPO continental U.S. modeling domain. Consequently, clean ICs were specified in the CMAQ and CAMx modeling using a ~15 day spin up period.

Boundary Conditions (BCs) (i.e., the assumed concentrations along the later edges of the 36 km modeling domain, see Figure 1-2) were based on a 2002 simulation by the GEOS-CHEM global circulation/chemistry model. GEOS-CHEM is a three-dimensional global chemistry model driven by assimilated meteorological observations from the Goddard Earth Observing System (GEOS) of the NASA Global Modeling and Assimilation Office. It is applied by research groups around the world to a wide range of atmospheric composition problems, including future climates and planetary atmospheres using general circulation model meteorology to drive the model. Central management and support of the model is provided by the Atmospheric Chemistry Modeling Group at Harvard University.

A joint RPO study was performed, coordinated by VISTAS, in which Harvard University applied the GEOS-CHEM global model for the 2002 calendar year (Jacob, Park and Logan, 2005). The University of Houston (UH) was retained to process the 2002 GEOS-CHEM output into BCs for the CMAQ model (Byun, 2004). The GEOS-CHEM simulations for the RPOs used GEOS meteorological observations for the year 2002. These were obtained from the Global Modeling and Assimilation Office(GMAO) as a 6-hourly archive (3-hour for surface quantities such as mixing depths). The data through August 2002 were from the GEOS-3 assimilation, with horizontal resolution of 1^ox1^o and 55 vertical layers. The data after August 2002 were from the updated GEOS-4 assimilation, with horizontal resolution of 1^ox1.25^o and 48 vertical layers (note 1^o latitude is equal to approximately 110 km). The GEOS-CHEM output was processed by mapping the GEOS-CHEM chemical compounds to the species in the CBM-IV chemical mechanism used by CMAQ/CAMx and mapping the GEOS-CHEM vertical layers to the 19 layer vertical layer structure used by CMAQ/CAMx in the CENRAP modeling (Byun, 2004). The results were day-specific three-hourly BC inputs for the CMAQ model. The CMAQ2CAMx processor was then used to transform the CMAQ day-specific 3-hourly BCs to the format used by CAMx.

There were several quality assurance (QA) checks of the BCs generated from the 2002 GEOS-CHEM output. The first QA/QC check was a range check to assure reasonable values. The BCs were compared against the GEOS-CHEM outputs to assure the mapping and interpolation was performed correctly. The code used to map the GEOS-CHEM output to the CMAQ BC format was obtained from UH, reviewed and the BC generation duplicated for several time periods during 2002.

1.3.8 Emissions Input Preparation

The CENRAP SMOKE emissions modeling was based on an updated 2002 emissions data for the U.S. (Pechan, 2005c,e; Reid et al., 2004a,b), 1999 emissions data for Mexico (ERG, 2006), and 2000 emissions data for Canada. These data were used to generate a final base 2002 Base G Typical (Typ02G) annual emissions database. Numerous iterations of the emissions modeling were conducted using interim databases before arriving at the final Base G emission inventories (e.g., Morris et al., 2005). The 2018 Base G base case emissions (Base18G) for most source categories in the U.S. were based on projections of the 2002 inventory assuming growth and control (Pechan, 2005d). 2018 EGU emissions were based on the run 2.1.9 of the Integrated Planning Model (IPM) updated by the CENRAP states. Canadian emissions for the Base18G scenario were based on a 2020 inventory, whereas the Mexican 1999 inventory was held constant for 2018.

The Typ02G and Base18G emission inventories represent significant improvements to the preliminary emissions modeling performed by CENRAP (Morris et al., 2005). While the preliminary 2002 modeling served its purpose to develop the infrastructure for modeling large emissions data sets and producing annual emissions simulations, much of the input data (both as inventories and ancillary data) were placeholders for actual 2002 data that were being prepared through calendar year 2005. As these actual 2002 data sets became available, they were integrated into the SMOKE modeling and QA system that was developed during the preliminary modeling, to produce a high-quality emissions data set for use in the final CMAQ and CAMx modeling. The addition of entirely new inventory categories, like marine shipping, added complexity to the modeling. By the end of the emissions data collection phase, there were 23 separate emissions processing streams covering a variety of sources categories necessary to general model-ready emission inputs for the 2002 calendar year.

Details on the emissions modeling are provided in Chapter 2 with additional information contained in Appendix B.

1.3.9 Meteorological Input Preparation

The 2002 36 km MM5 meteorological modeling was conducted by the Iowa Department of Natural Resources (IDNR) who also performed a preliminary model performance evaluation (Johnson, 2007). CENRAP performed an additional MM5 evaluation of the CENRAP 2002 36 km MM5 simulation that included a comparative evaluation against the final VISTAS 2002 36 km MM5 and an interim WRAP 2002 36 km simulation (Kemball-Cook et al., 2004). Kemball-Cook and co-workers (2004) found the following in the comparative evaluation of the CENRAP, WRAP and VISTAS 2002 36 km MM5 simulations, (details are provided in Appendix A):

Surface Meteorological Performance within the CENRAP Region

- The three MM5 simulations (CENRAP, VISTAS and WRAP) obtained comparable model performance for winds and humidity that were within model performance benchmarks.
- The WRAP MM5 simulation obtained better temperature model performance than the other two simulations due to the use of surface temperature data assimilation.
    - In the final WRAP MM5 simulation the use of surface temperature assimilation was dropped because it introduced instability in the vertical structure of the atmosphere.
- For all three runs, the Northern CENRAP domain had a cold bias in winter and a warm bias in summer.

Surface Meteorological Performance outside the CENRAP Region

- All three runs had similar surface wind model performance in the western U.S. that was outside the model performance benchmarks
- For temperature, the WRAP MM5 simulation had the best performance overall due to the surface temperature data assimilation that was dropped in the final WRAP run.
- The three runs had comparable humidity performance, although WRAP exhibited a larger wet bias in the summer and the southwestern U.S.

Upper-Air Meteorological Performance

- The VISTAS and CENRAP MM5 simulations were better able to reproduce the deep convective summer boundary layers compared to the WRAP MM5 simulations, which exhibited a smoother decrease in temperature with increase in altitude.
- CENRAP and VISTAS MM5 simulations better simulated the surface temperature inversions than WRAP.
- WRAP was better able to simulate the surface temperature.
- All three models exhibited similar vertical wind profiles.

Precipitation Performance

- In winter, all three MM5 simulations exhibited similar, fairly good, performance in reproducing the spatial distribution and magnitudes of the monthly average observed precipitation.
- In summer, all runs had a wet bias, particularly in the desert southwest where the interim WRAP run had the largest wet bias.

In conclusion, the VISTAS simulation appeared to perform best, the CENRAP MM5 model performance was generally between the VISTAS and WRAP performance, with performance more similar to VISTAS than WRAP. Although the interim WRAP MM5 simulation performed best for surface temperature due to the surface temperature data assimilation, the surface temperature assimilation degraded the MM5 upper-air performance including the ability to assimilate surface inversions and was ultimately dropped from the final WRAP MM5 simulations (Kemball-Cook et al., 2005).

The IDNR 12 km[2] MM5 simulations were also evaluated and compared with the performance of the 36 km MM5 simulation (Johnson et al., 2007). The IDNR 36 km and 12 km MM5 model performance was similar (Johnson, 2007), which supported the findings of the CMAQ and CAMx 36 and 12 km sensitivity simulations that there was little benefit of using a 12 km grid for simulating regional haze at rural Class I areas (Morris et al., 2006a). However, as noted by Tonnesen and co-workers (2005; 2006) and EPA modeling guidance (1991; 1999; 2001; 2007) this finding does not necessarily hold for 8-hour ozone and $PM_{2.5}$ modeling that is characterized by sharper concentration gradients and frequently occurs in the urban environment as compared to the more rural nature of regional haze.

1.3.10 Photolysis Rates Model Inputs

Several chemical reactions in the atmosphere are initiated by the photodissociation of various trace gases. To accurately represent the complex chemical transformations in the atmosphere, accurate estimates of these photodissociation rates must be made. The Models-3/CMAQ system includes the JPROC processor, which calculates a table of clear-sky photolysis rates (or J-values) for a specific date. JPROC uses default values for total aerosol loading and provides the option to use default ozone column data or to use measured total ozone column data. These data come from the Total Ozone Mapping Spectrometer (TOMS) satellite data. TOMS data that is available at 24-hour averages was obtained from http://toms.gsfc.nasa.gov/eptoms/ep.html. Day-specific TOMS data was used in the CMAQ radiation model (JPROC) to calculate photolysis rates. The TOMS data were missing or erroneous for several periods in 2002: August 2-12; June 10; and November 18-19. Thus, the TOMS data for August 1, 2002 was used for August 2-7 and TOMS data for August 13 was used for August 8-12. Similarly, TOMS data for June 9 was used for June 10 and data for August 17 was used for August 18-19. Note that the total column of ozone in the atmosphere is dominated by stratospheric ozone which has very little day-to-day variability so the use of TOMS data within a week or two of an actual day introduces minimal uncertainties in the modeling analysis.

JPROC produces a "look-up" table that provides photolysis rates as a function of latitude, altitude, and time (in terms of the number of hours of deviation from local noon, or hour angle). In the current CMAQ implementation, the J-values are calculated for six latitudinal bands (10º, 20º, 30º, 40º, 50º, and 60º N), seven altitudes (0 km, 1 km, 2 km, 3 km, 4 km, 5 km, and 10 km), and hourly values up to ∀8 hours of deviation from local noon. During model calculations, photolysis rates for each model grid cell are estimated by first interpolating the clear-sky photolysis rates from the look-up table using the grid cell latitude, altitude, and hour angle, followed by applying a cloud correction (attenuation) factor based on the cloud inputs from MM5.

The photolysis rates input file was prepared as separate look-up tables for each simulation day. Photolysis files are ASCII files that were visually checked for selected days to verify that photolysis are within the expected ranges.

[2] The IDNR twelve 12 km annual simulation domain was not sufficient for CENRAP's needs, thus Bret Anderson with EPA Region 7 in cooperation with Texas completed an episodic 12km simulation on a larger domain.

The Tropospheric Ultraviolet and Visible (TUV) Radiation Model (http://cprm.acd.ucar.edu/Models/TUV/) is used to generate the photolysis rates input file for CAMx. TOMS ozone data and land use data were used to develop the CAMx Albedo/Haze/Ozone input file for 2002. As for CMAQ, the missing TOMS data period in the fall of 2002 was filled-in using observed TOMS data on either side of the missing period using the same procedures as described above for CMAQ. Default land use specific albedo values were used and a constant haze value used, corresponding to rural conditions over North America.

1.3.11 Air Quality Input Preparation

Air quality data used with the CMAQ and CAMx modeling systems include: (1) Initial Concentrations (ICs) that are the assumed initial three-dimensional concentrations throughout the modeling domain.; (2) the Boundary Conditions (BCs) that are the concentrations assumed along the lateral edges of the RPO national 36 km modeling domain; and (3) air quality observations that are used in the model performance evaluation (MPE). The MPE is discussed in Section 3 and Appendix C of this TSD.

As noted in Section 1.3.7, CMAQ default clean Initial Concentrations (ICs) were used along with an approximately 15 day spin up (initialization) period to eliminate any significant influence of the ICs on the modeled concentrations for the days of interest. The same ICs were used with CAMx as well. Both CMAQ and CAMx were run for each quarter of the year. Each quarter's model run was initialized 15 days prior to the first day of interest (e.g., for quarter 3, Jul-Aug-Sep, the model was initialized on June 15, 2002 with the first modeling day of interest July 1, 2002). The CMAQ Boundary Conditions (BCs) for the Inter-RPO 36 km continental U.S. grid (Figure 1-2) were based on day-specific 3-hour averages from the output of the GEOS-CHEM global simulation model of 2002 (Jacob, Park and Logan, 2005). The 2002 GEOS-CHEM output was mapped to the species and vertical layer structure of CMAQ and interpolated to the lateral boundaries of the 36 km grid shown in Figure 1-2 (Byun, 2004).

Table 1-6 summarizes the surface air quality monitoring networks and the number of sites available in the CENRAP region that were used in the model performance evaluation. Data from these monitoring networks were also used to evaluate the CMAQ and CAMx models outside of the CENRAP region.

Table 1-6. Ground-level ambient data monitoring networks and stations available in the CENRAP states for calendar year 2002 used in the model performance evaluation.

Monitoring Network	Chemical Species Measured	Sampling Frequency; Duration	Approximate Number of Monitors
IMPROVE	Speciated $PM_{2.5}$ and PM_{10}	1 in 3 days; 24 hr	11
CASTNET	Speciated $PM_{2.5}$, Ozone	Hourly, Weekly; 1 hr, 1 Week	3
NADP	WSO4, WNO3, WNH4	Weekly	23
EPA-STN	Speciated $PM_{2.5}$	Varies; Varies	12
AIRS/AQS	CO, NO, NO_2, NO_x, O_3	Hourly; Hourly	25

1.3.12 2002 Base Case Modeling and Model Performance Evaluation

The CMAQ and CAMx models were evaluated against ambient measurements of PM species, gas-phase species and wet deposition. Table 1-6 summarizes the networks used in the model evaluation, the species measured and the averaging times and frequency of the measurements. Numerous iterations of CMAQ and CAMx 2002 base case simulations and model performance evaluations were conducted during the course of the CENRAP modeling study, most of which have been posted on the CENRAP modeling website (http://pah.cert.ucr.edu/aqm/cenrap/cmaq.shtml) and presented in previous reports and presentations for CENRAP (e.g., Morris et al., 2005; 2006a,b). Details on the final 2002 Base F 36 km CMAQ base case modeling performance evaluation are provided in Chapter 3 and Appendix C (because of the similarity between 2002 Base F and 2002 Base G and resource constraints the model evaluation was not re-conducted for Base G). In general, the model performance of the CMAQ and CAMx models for sulfate (SO4) and elemental carbon (EC) was good. Model performance for nitrate (NO3) was variable, with a summer underestimation and winter overestimation bias. Performance for organic mass carbon (OMC) was also variable, with the inclusion of the SOAmods enhancement in CMAQ Version 4.5 greatly improving the CMAQ summer OMC model performance (Morris et al., 2006c). Model performance for Soil and coarse mass (CM) was generally poor. Part of the poor performance for Soil and CM is believed to be due to measurement-model incommensurability. The IMPROVE measured values are due, in part, to local fugitive dust sources that are not captured in the model's emission inputs and the 36 km grid resolution is not conducive to modeling localized events.

1.3.13 2018 Modeling and Visibility Projections

Emissions for the 2018 base case were generated following the procedures discussed in Section 1.3.8 and Chapter 2. 2018 emissions for Electrical Generating Units (EGUs) were based on simulations of the Integrated Planning Model (IPM) that took into the account the effects of the Clean Air Interstate Rule (CAIR) on emissions from EGUs in CAIR states using an IPM realization of a CAIR cap-and-trade program. Emissions for on-road and non-road mobile sources were based on activity growth and emissions factors from the EPA MOBILE6 and NONROAD models, respectively. Area sources and non-EGU point sources were grown to 2018 levels (Pechan, 2005d). The Canadian year 2000 emissions inventory was replaced by a Canadian 2020 emissions inventory for the 2018 CMAQ/CAMx simulations. The following sources were assumed to remain constant between the 2002 and 2018 base case simulations:

- Biogenic VOC and NOx emissions from the BEIS3 biogenic emissions model;
- Wind blown dust associated with non-agricultural sources (i.e., natural wind blown fugitive dust);
- Off-shore emissions associated with off-shore marine and oil and gas production activities;
- Emissions from wildfires;
- Emissions from Mexico; and
- Global transport (i.e., emissions due to BCs from the 2002 GEOS-CHEM global chemistry model.

The results from the 2002 and 2018 CMAQ and CAMx simulations were used to project 2018 PM levels from which 2018 visibility estimates were obtained. The 2002 and 2018 modeling results were used in a relative sense to scale the observed PM concentrations from the 2000-2004 Baseline and the IMPROVE monitoring network to obtain the 2018 PM projections. The 2018/2002 modeled scaling factors are called Relative Response Factors (RRFs) and are constructed as the ratio of modeling results for the 2018 model simulation to the 2002 model simulation. Two important regional haze metrics are the average visibility for the worst 20 percent and best 20 percent days from the 2000-2004 five-year Baseline. For the 2018 visibility projections, EPA guidance recommends developing Class I area and PM species specific RRFs using the average modeling results for the worst 20 percent days during the 2002 modeling period and the 2002 and 2018 emission scenarios. The results of the CENRAP 2018 visibility projections following EPA guidance procedures (EPA, 2007a) are provided in Chapter 4 and Appendix D. CENRAP has also developed alternative procedures for visibility projections that are discussed in Chapter 5 and Appendix D. For example, much of the coarse mass (CM) impacts at Class I area IMPROVE monitors is believed to be natural and primarily from local sources that are subgrid-scale to the modeled 36 km grid so are not represented in the modeling. So, one alternative visibility projection approach is to set the RRF for CM to 1.0. That is, the CM impacts in 2018 are assumed to be the same as in the observed 2000-2004 Baseline. Similarly, the Soil impacts at IMPROVE monitors are likely mainly due to local dust sources so another alternative approach is to set the RRFs for both CM and Soil to 1.0.

The 2018 visibility projections for the worst 20 percent days are compared against a 2018 point on the Uniform Rate of Progress (URP) glidepath or the “2018 URP point”. The 2018 URP point is obtained by constructing a linear visibility glidepath in deciviews from the observed 2000-2004 Baseline (EPA, 2003a) for the worst 20 percent days to the 2064 Natural Conditions (EPA, 2003b; Pitchford, 2006). Where the linear glidepath crosses the year 2018 is the 2018 URP point. States may use the modeled 2018 visibility to help define their 2018 RPG in their RHR SIPs. The 2018 URP point is used as a benchmark to help judge the 2018 modeled visibility projections and the state’s RPG. However, as noted in EPA’s RPG guidance “The glidepath is not a presumptive target, and States may establish a RPG that provides for greater, lesser, or equivalent visibility improvement as that described by the glidepath” (EPA, 2007b). Chapter 4 and Appendix D present the 2018 visibility projections for the CENRAP Class I areas and their comparisons with the 2018 URP point using EPA default visibility projection procedures (EPA, 2007a) and EPA default URP glidepaths (EPA, 2003a,b; 2007b).

Various techniques have been developed to display the 2018 visibility modeling results including “DotPlots” that display the 2018 visibility projections as a percentage of meeting the 2018 point on the URP glidepath. A value of 100% on the DotPlot indicates that the Class I area is predicted to meet the 2018 point on the URP glidepath. Over 100% means the 2018 visibility projection obtains more visibility improvements (reductions) than required to meet the 2018 point on the URP glidepath (i.e., projected value is below the glidepath). And less than 100% indicates that fewer visibility improvements are projected than are needed to meet the 2018 point URP on the glidepath (i.e., above the glidepath). Figure 1-4 displays a DotPlot that compares the 2018 visibility projections from the CENRAP 2018 Base G CMAQ simulation with the 2018 URP point using the EPA default RRFs and alternative RRFs that set the CM and Soil RRFs to unity (i.e., assume CM and Soil are natural so remain unchanged from the 2000-2004 Baseline). For these results, the 2018 visibility projections at the Hercules Glade (HEGL1) Class I area meets the 2018 point on the URP glidepath (100%), whereas the 2018 visibility projections at Caney

Creek (CACR), Mingo (MING) and Upper Buffalo (UPBU) achieve more visibility improvements than needed to meet the 2018 URP point so are below the 2018 URP glidepath. However, the 2018 visibility projections at Breton Island comes up slightly short (~5%) of meeting the 2018 point on the URP glidepath and Wichita Mountains (WIMO) comes up approximately 40% short of meeting the 2018 point on the URP glidepath. Class I areas at the northern (e.g., VOYA, BOWA and ISLE) and southern (e.g., BIBE and GUMO) boundaries of the U.S. also fall short of achieving the 2018 URP point. High contributions of international transport and/or natural sources (e.g., wind blown dust) affect the ability of these Class I areas to be on the URP glidepath. These issues are discussed in more detail in Chapters 4 and 5.

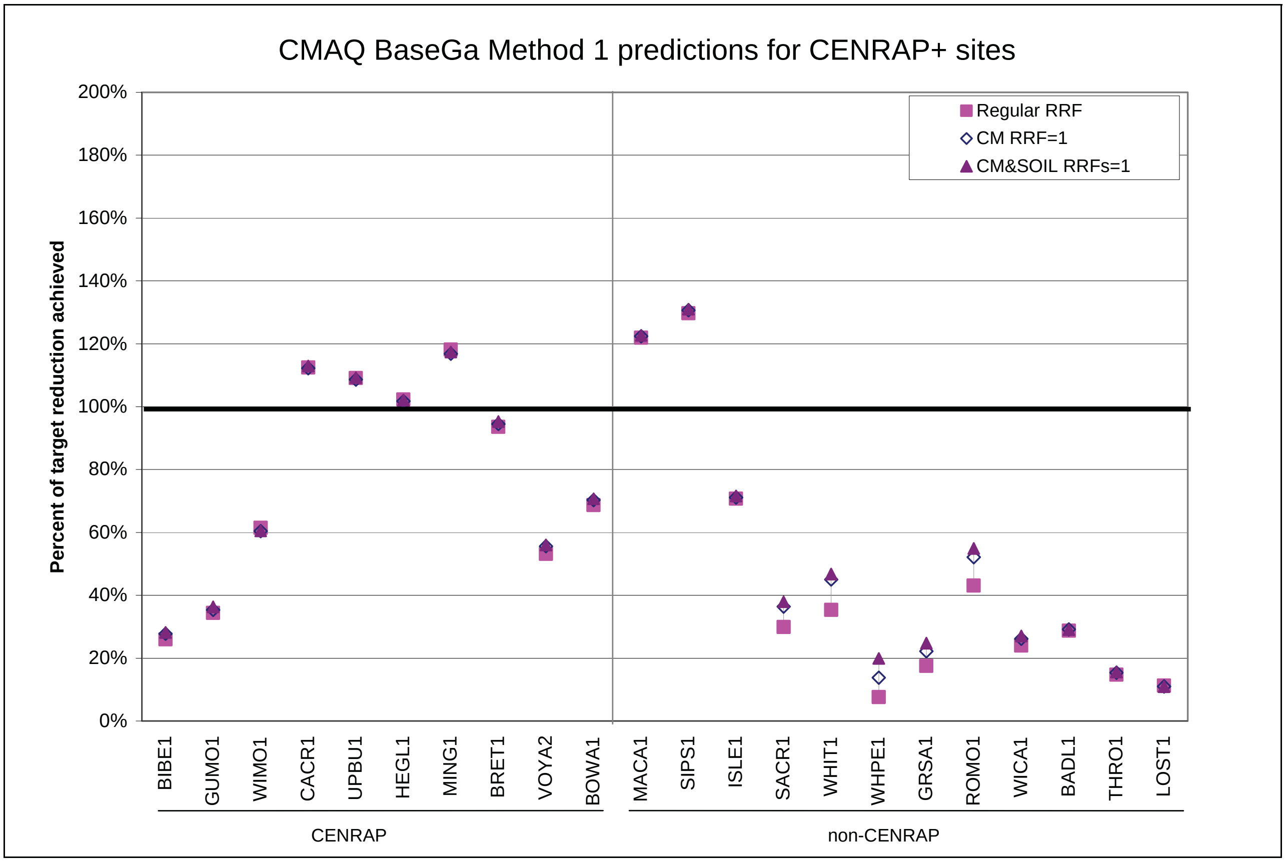


Figure 1-4. 2018 visibility projections expressed as a percent of meeting the 2018 URP point for the 2018 BaseG CMAQ base case simulation using the EPA default (EPA, 2007) Regular RRF and alternative projections procedures that set the RRFs for CM=1.0 and CM&SOIL=1.0.

1.3.14 Additional Supporting Analysis

CENRAP performed numerous supporting analyses of its modeling results including analyzing alternative glidepaths and 2018 projection Approaches and performing confirmatory analysis of the 2018 visibility projections. Details on the additional supporting analysis are contained discussed in Chapter 5, which include:

- The CENRAP 2018 visibility projections were compared with those generated by VISTAS and MRPO. There was close agreement between the CENRAP and VISTAS 2018 visibility projections at almost all common Class I areas. With the only exception being Breton Island where the CENRAP's projections were slightly more optimistic than VISTAS'. The MRPO 2018 visibility projections were less optimistic than CENRAP's at the four Arkansas-Missouri Class I area that may have been due to CENRAP's BART emission controls in CENRAP states not included in the 2018 MRPO inventory.
- Extinction based glidepaths were developed and the CENRAP 2018 visibility projections were shown to produce nearly identical estimates of achieving the 2018 URP point when using total extinction glidepaths as when the linear deciview glidepaths were used. With the extinction based glidepaths the analysis of 2018 URP could be made on a PM species-by-species basis where it was shown that 2018 extinctions due to SO4 and, to a lesser extent, NO3 and EC, achieve the URP, but the other species do not and in fact extinction due to Soil and CM is projected to get worse.
- 2018 visibility projections were made using EPA's new Modeled Attainment Test Software (MATS) program and the CENRAP Typ02G and Base18G modeling results. The CENRAP 2018 visibility projections exactly agreed with those generated by MATS with three exceptions: Breton Island, Boundary Waters and Mingo Class I areas, At these three Class I areas MATS did not produce any 2018 visibility projections due to insufficient data in the raw IMPROVE database to produce a valid observed 2000-2004 Baseline. CENRAP used filled data for these three Class I areas.
- PM Source Apportionment Technology (PSAT) modeling was conducted to estimate the contributions to visibility impairment at Class I areas by source region (e.g., states) and major source category. Source contributions were obtained for a 2002 and 2018 base case and the PSAT modeling results were implemented in a PSAT Visualization Tool that was provided to CENRAP states and others. Major findings from the PSAT source apportionment modeling include the following:
    - Sulfate from elevated point sources was the highest source category contribution to visibility impairment at CENRAP Class I areas for the worst 20 percent days.
    - International transport contributed significantly to visibility impairment at CENRAP Class I areas on the southern (BIBE and GUMO) and northern (BOWA and VOYA) borders of the U.S. and to a lesser extent at WIMO as well.
- Alternative visibility projections were made assuming that coarse mass (CM) alone and CM and Soil were natural in origin that confirmed the original 2018 visibility projections.
- Visibility projections were made using an alternative model (CAMx) that verified the projections made by CMAQ.
- The effects of International Transport were examined several ways and found that the inability of the 2018 visibility projections to achieve the 2018 URP point at the northern and southern border Class I areas was due to high contributions due to International Transport.

- Visibility trends for the worst 20 percent days, best 20 percent days and all monitored days were analyzed at CENRAP Class I areas using the period of record IMPROVE observations. At most Class I areas there was insufficient years of data to produce a discernable trend. In addition, there was significant year-to-year variability in visibility impairment with episodic events (e.g., wildfires and wind blown dust) confounding the analysis.

1.4 Organization of the Report

Chapter 1 of this TSD presents background, an overview of the approach and summary of the results of the CENRAP meteorological, emissions and air quality modeling. Appendix A contains more details on the meteorological model evaluation discussed in Chapter 1. Details on the emissions modeling are provided in Chapter 2 and Appendix B. The model performance evaluation is given in Chapter 3 and Appendix C. The 2018 visibility projections and comparisons with the 2018 URP point are provided in Chapter 4 with more details given in Appendix D. Chapter 5 contains additional supporting analysis with details on the PM source apportionment modeling and alternative projections provided in Appendices E and F, respectively. Chapter 6 lists the references cited in the report.

2.0 EMISSIONS MODELING

2.1 Emissions Modeling Overview

For the emissions modeling work conducted in support of CENRAP air quality modeling, we used updated 2002 emissions data for the U.S., 1999 emissions data for Mexico, and 2000 emissions data for Canada to generate a final base 2002 Base G Typical (Typ02G) annual emissions database. Numerous iterations of the emissions modeling were conducted using interim databases before arriving at the final Base G emission inventories. The 2002 and 2018 emissions inventories and ancillary modeling data were provided by CENRAP emissions inventory contractors (Pechan and CEP, 2005c,e; Reid et al., 2004a,b; Coe and Reid, 2003), other Regional Planning Organizations (RPOs) and EPA. Building from the CENRAP preliminary 2002 database (Pechan and CEP. 2005e) and 2018 projections (Pechan, 2005d), we integrated several updates to the inventories and ancillary data to create final emissions input files; the final simulations are referred to as 2002 Typical and 2018 Base G, or Typ02G and Base18G. We used the Sparse Matrix Operator Kernel Emissions (SMOKE) version 2.1 processing system (CEP, 2004) to prepare the inventories for input to the air quality modeling systems. The SMOKE simulations documented in this report include emissions generated for annual CMAQ and CAMx simulations at a 36-km model grid resolution, and a short-term CMAQ test simulation at a 12-km model grid resolution. We performed the modeling and quality assurance (QA) work based on the CENRAP modeling Quality Assurance Project Plan (QAPP; Morris and Tonnesen, 2004) and Modeling Protocol (Morris et al., 2004a).

The Typ02G and Base18G emission inventories represent significant improvements to the preliminary emissions modeling performed by CENRAP (Morris et al., 2005). While the preliminary 2002 modeling served its purpose to develop the infrastructure for modeling large emissions data sets and producing annual emissions simulations, much of the input data (both as inventories and ancillary data) were placeholders for actual 2002 data that were being prepared through calendar year 2005. As these actual 2002 data sets became available, they were integrated into the SMOKE modeling and QA system that was developed during the preliminary modeling, to produce a high-quality emissions data set for use in the final CMAQ and CAMx modeling. The addition of entirely new inventory categories, like marine shipping, added complexity to the modeling. By the end of the emissions data collection phase, there were 23 separate emissions processing streams covering a variety of sources categories necessary to general model-ready emission inputs for the 2002 calendar year.

2.1.1 SMOKE Emissions Modeling System Background

The purpose of SMOKE (or any emissions processor) is to process the raw emissions reported by states and EPA into gridded hourly speciated emissions required by the air quality model. Emission inventories are typically available as an annual total emissions value for each emissions source, or perhaps with an average-day emissions value. The air quality models, however, typically require emissions data on an hourly basis, for each model grid cell (and perhaps model layer), and for each model species. Consequently, emissions processing involves (at a minimum) transformation of emission inventory data by temporal allocation, chemical speciation, spatial allocation, and perhaps layer assignment, to achieve the input requirements of the air quality model. For the CENRAP modeling effort, all of these steps were needed. In addition, CENRAP processing requires special MOBILE6 processing and growth and control of emissions for the future-year inventories. Finally, the biogenic emission processing using BEIS2 includes additional processing steps. SMOKE formulates emissions modeling in terms of sparse matrix operations. Figure 2-1 shows an example of how the matrix approach organizes the emissions processing steps for anthropogenic emissions, with the final step that creates the model-ready emissions being the merging of all the different processing streams of emissions into a total emissions input file for the air quality model. Figure 2-1 does not include all the potential processing steps, which can be different for each source category in SMOKE, but does include the major processing steps listed in the previous paragraph, except the layer assignment. Specifically, the inventory emissions are arranged as a vector of emissions, with associated vectors that include characteristics about the sources such as its state and county or source classification code (SCC). SMOKE also creates matrices that will apply the gridding, speciation, and temporal factors to the vector of emissions. In many cases, these matrices are independent from one another, and can therefore be generated in parallel. The processing approach ends with the merge step, which combines the inventory emissions vector (now an hourly inventory file) with the control, speciation, and gridding matrices to create model-ready emissions.

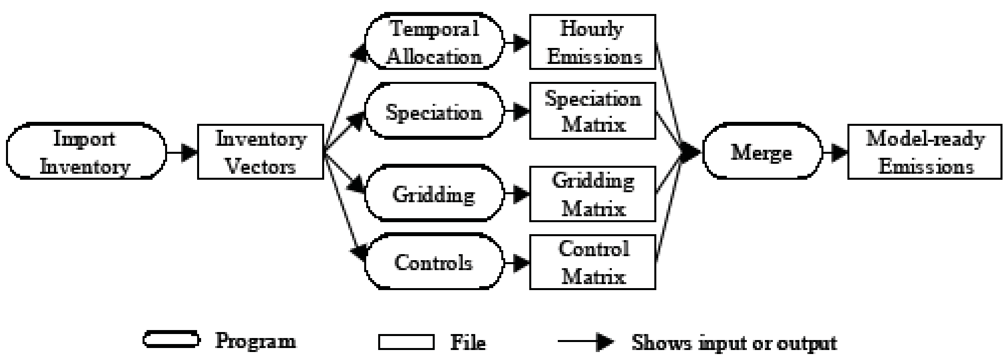


Figure 2-1. Flow diagram of major SMOKE processing steps needed by all source categories.

Temporal processing includes both seasonal or monthly adjustments and day-of-week adjustments. Emissions are known to be quite different for a typical weekday versus a typical Saturday or Sunday. For the day-of-week temporal processing step, emissions may be processed using representative Monday, weekday, Saturday, and Sunday for each month; we refer to this type of processing here as MWSS processing (note that because SMOKE operates in Greenwich Mean Time [GMT] then Monday would include some of local time Sunday so needs to be processed separately from the typical weekday). This approach significantly reduces the number of times the temporal processing step must be run. In the sections below, we have identified the cases in which we have used the MWSS processing approach. Figure 2-2 provides a schematic diagram of SMOKE/BEIS2 processing steps used in this project to generate biogenic emissions rates for Volatile Organic Compounds (VOCs) and oxides of nitrogen (NOx). Because biogenic emissions are temperature sensitive, they are generated for each day of 2002 using day-specific meteorological conditions from the MM5 meteorological model.

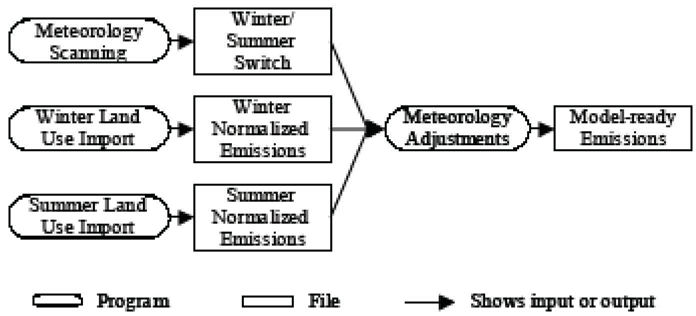


Figure 2-2. Flow diagram of SMOKE/BEIS2 processing steps.

2.1.2 SMOKE Scripts

The scripts are the interface that emissions modelers use to run SMOKE and define the set up and databases used in the emissions modeling so are important for anyone wishing to reproduce the CENRAP SMOKE emissions modeling. Many iterations of the CENRAP SMOKE emissions modeling were performed using updated and corrected emissions data and assumptions resulting in the creation of numerous SMOKE modeling scripts during the course of the study. For the CENRAP annual 2002 SMOKE emissions modeling, the default SMOKE script set up, which is based on source categories, was used to configure the scripts. We made several modifications to the default SMOKE scripts to modularize them, add error checking loops, and break up the report and logs directories by source category. The result is one script for each major source category being modeled that calls all of the SMOKE programs required for simulating that source category. 16 major source categories were modeled by SMOKE for CENRAP. An addition seven SMOKE scripts were also run to set up the emissions modeling. Table 2-1 lists all of the SMOKE scripts used for the 2002 base year modeling and the SMOKE programs called by each script. In addition to the source-specific scripts listed in Table 2-1, we also listed the SMOKE utility scripts that actually call executables, manage the log files, and manage the configuration of the SMOKE simulations.

Table 2-1. Summary of SMOKE scripts.

Source Category	Script Name	SMOKE Programs/Functions
Area	/home/aqm2/edss2/cenrap02f/subsys/smoke/ scripts/run/36km/smk_ar_base02f.csh	smkinev, grdmat, spcmat, temporal, smkmerge, smkreport
Area fire	/home/aqm2/edss2/cenrap02f/subsys/smoke/ scripts/run/36km/smk_arf_base02f.csh	smkinev, grdmat, spcmat, temporal, smkmerge, smkreport
Offshore Area	/home/aqm2/edss2/cenrap02f/subsys/smoke/ scripts/run/36km/smk_ofsar_base02f.csh	smkinev, grdmat, spcmat, temporal, smkmerge, smkreport
Non-road* Mobile	/home/aqm2/edss2/cenrap02f/subsys/smoke/ scripts/run/36km/smk_nr_base02f.csh	smkinev, grdmat, spcmat, temporal, smkmerge, smkreport
Fugitive dust	/home/aqm2/edss2/cenrap02f/subsys/smoke/ scripts/run/36km/smk_fd_base02f.csh	smkinev, grdmat, spcmat, temporal, smkmerge, smkreport
Road dust	/home/aqm2/edss2/cenrap02f/subsys/smoke/ scripts/run/36km/smk_rd_base02f.csh	smkinev, grdmat, spcmat, temporal, smkmerge, smkreport
Ammonia*	/home/aqm2/edss2/cenrap02f/subsys/smoke/ scripts/run/36km/smk_nh3_base02f.csh	smkinev, grdmat, spcmat, temporal, smkmerge, smkreport
On-road Mobile (non-VMT-based)	/home/aqm2/edss2/cenrap02f/subsys/smoke/ scripts/run/36km/smk_mb_base02f.csh	smkinev, grdmat, spcmat, temporal, smkmerge, smkreport
On-road non-US Mobile (non-VMT-based)	/home/aqm2/edss2/cenrap02f/subsys/smoke/ scripts/run/36km/smk_nusm_base02f.csh	smkinev, grdmat, spcmat, temporal, smkmerge, smkreport
On-road Mobile (VMT-based)	/home/aqm2/edss2/cenrap02f/subsys/smoke/ scripts/run/36km/smk_mbv_base02f.csh	smkinev, mbsetup, grdmat, spcmat, premobl, emisfac, temporal, smkmerge, smkreport
WRAP Oil and Gas	/home/aqm2/edss2/cenrap02f/subsys/smoke/ scripts/run/36km/smk_wog_base02f.csh	smkinev, grdmat, spcmat, temporal, smkmerge, smkreport
Point	/home/aqm2/edss2/cenrap02f/subsys/smoke/ scripts/run/36km/smk_pt_base02f.csh	smkinev, grdmat, spcmat, laypoint, temporal, smkmerge, smkreport
Offshore point	/home/aqm2/edss2/cenrap02f/subsys/smoke/ scripts/run/36km/smk_ofs_base02f.csh	smkinev, grdmat, spcmat, laypoint, temporal, smkmerge, smkreport
Canadian Point fires	/home/aqm2/edss2/cenrap02f/subsys/smoke/ scripts/run/36km/smk_bsf_base02f.csh	smkinev, grdmat, spcmat, laypoint, temporal, smkmerge, smkreport
All point fires	/home/aqm2/edss2/cenrap02f/subsys/smoke/ scripts/run/36km/smk_alf_base02f.csh	smkinev, grdmat, spcmat, laypoint, temporal, smkmerge, smkreport
Biogenec	/home/aqm2/edss2/cenrap02f/subsys/smoke/ scripts/run/36km/smk_bg_base02f.csh	Normbies3, tmpbies3, smkmerge
n/a	/home/aqm2/edss2/cenrap02f/subsys/smoke/ scripts/run/make_invdir.csh	builds output file names and directories
n/a	/home/aqm2/edss2/cenrap02f/subsys/smoke/ scripts/run/smk_run.csh	Calls SMOKE executables for everything but projection, controls, and QA
n/a	/home/aqm2/edss2/cenrap02f/subsys/smoke/ scripts/run/qa_run.csh	Calls the SMOKE executables for running QA program & names the input/output directories for reports
n/a	/home/aqm2/edss2/cenrap02f/subsys/smoke/ scripts/run/36km/smoke_calls.csh	Calls smk_run.csh, qa_run.csh, configuration and management
n/a	/home/aqm2/edss2/cenrap02f/subsys/smoke/ Assignes/ASSIGNES.cenrap_base02f.cmaq.cb4p25	Sets up the environment variables for use of SMOKE
n/a	/home/aqm2/edss2/cenrap02f/subsys/smoke/ Assignes/smk_mkdir	Creates the input/output directories
n/a	/home/aqm2/edss2/cenrap02f/subsys/smoke/ Assignes/setmerge_files.scr	Sets up the output environment variables for the smkmerge program

* The nr and nh3 where farther divided to nrm and nry and nh3m and nh3y for the monthly/seasonal and yearly inventories

2.1.3 SMOKE Directory Structures

The SMOKE directories can be divided into three broad categories:

1. Program Directories: These directories contain the model source code, assigns files, scripts and executables needed to run SMOKE.
2. Input Directors: These directories contain the raw emissions inventories, the meteorological data and the ancillary input files.
3. Output Directories: These directories contain all of the output from the model. Also, the output directories contain the MOBILE6 input files.

The directories are described in the Table 2-2. The final pre-merged emission file names and sources of the data re provided in Appendix B.

Table 2-2. Summary of SMOKE directories.

Category	Directory Location	Directory Contents
Program	/home/aqm2/edss2/ cenrap02f/subsys/smoke/src	SMOKE source code
	/home/aqm2/edss2/ cenrap02f/subsys/smoke/assigns	SMOKE assigns files
	/home/aqm2/edss2/ cenrap02f/subsys/smoke/scripts	SMOKE make and run scripts
	/home/aqm2/edss2/ cenrap02f/subsys/smoke/Linux2_x86pg	SMOKE executables
Input	/home/aqm2/edss2/ cenrap02f/data/met	MCIP out metrology files
	/home/aqm2/edss2/ cenrap02f/data/ge_dat	SMOKE ancillary input files
	/home/aqm2/edss2/ cenrap02f/data/inventory/cenrap2002	Raw emissions inventory files
Output	/home/aqm2/edss2/ cenrap02f/data/run_base02f/static	Non-time dependent SMOKE intermediate outputs and MOBILE6 inputs
	/home/aqm2/edss2/ cenrap02f/ data/run_base02f/scenario	Time dependent SMOKE intermediate outputs
	/home/aqm2/edss2/ cenrap02f/data/run_base02f/outputs	Model-ready SMOKE outputs
	/home/aqm2/edss2/ cenrap02f/data/reports	SMOKE QA reports

2.1.4 SMOKE Configuration

SMOKE was configured to generate emissions for all months of 2002 on the 36-km unified RPO modeling domain (Figure 1-2). For the anthropogenic emissions sources that use hourly meteorology and daily or hourly data (i.e., on-road mobile sources, point sources with CEM data, point source fires and biogenic sources) we configured SMOKE to represent the daily emissions explicitly. For the non-meteorology dependent emissions, we used a representative Saturday, Sunday, Monday, and weekday for each month as surrogate days for the entire month's emissions (we refer to this as the MWSS processing approach). For these non-meteorology dependent emissions sources we explicitly represented the holidays as Sundays. Table 2-3 lists the days that we modeled as representative days in the months that we simulated for the 2002 base year modeling. Table 2-4 lists the holidays in 2002 that were modeled as Sundays.

Table 2-3: Representative model days for 2002 base year simulation.

Saturday	Sunday	Monday	Weekday
January 5	January 6	January 7	January 4
February 2	February 3	February 4	February 5
March 2	March 3	March 4	March 5
April 6	April 7	April 8	April 2
May 4	May 5	May 6	May 7
June 8	June 9	June 3	June 4
July 6	July 7	July 8	July 3
August 3	August 4	August 5	August 6
September 7	September 8	September 9	September 10
October 5	October 6	October 7	October 8
November 2	November 3	November 4	November 5
December 7	December 8	December 9	December 10

Table 2-4: 2002 modeled holidays.

Holiday	Date
New Years	January 1, 2002 January 2, 2002
Good Friday	March 29, 2002 March 30, 2002
Memorial Day	May 27, 2002 May 28, 2002
Independence Day	July 4, 2002 July 5, 2002
Labor Day	September 2, 2002 September 3, 2002
Thanksgiving Holiday	November 28-30, 2002
Christmas Holiday	December 24-26, 2002

We used the designations in Table 2-5 to determine which months fell into each season when temporally allocating the seasonal emissions inventories. Some of the inventories for the Electrical Generating Units (EGUs) were received for Winter and Summer. Table 2-6 determines which months fell into each season

Table 2-5. Assignments of months to four seasons for use of seasonal inventory files in SMOKE.

Month	Season
January	Winter
February	Winter
March	Spring
April	Spring
May	Spring
June	Summer
July	Summer
August	Summer
September	Fall
October	Fall
November	Fall
December	Winter

Table 2-6. Assignments of months to two seasons for use of seasonal inventory files in SMOKE.

Month	Season
January	Winter
February	Winter
March	Winter
April	Winter
May	Summer
June	Summer
July	Summer
August	Summer
September	Summer
October	Winter
November	Winter
December	Winter

2.1.5 SMOKE Processing Categories

Emissions inventories are typically divided into area, on-road mobile, non-road mobile, point, and biogenic source categories. These divisions arise from differing methods for preparing the inventories, different characteristics and attributes of the categories, and how the emissions are processed through models. Generally, emissions inventories are divided into the following source categories, which we refer to later as "SMOKE processing categories."

- Stationary Area Sources: Sources that are treated as being spread over a spatial extent (usually a county or air district) and that are not movable (as compared to non-road mobile and on-road mobile sources). Because it is not possible to collect the emissions at each point of emission, they are estimated over larger regions. Examples of stationary area sources are residential heating and architectural coatings. Numerous sources, such as dry cleaning facilities, may be treated either as stationary area sources or as point sources.

- On-Road Mobile Sources: Vehicular sources that travel on roadways. These sources can be computed either as being spread over a spatial extent or as being assigned to a line location (called a link). Data in on-road inventories can be either emissions or activity data. Activity data consist of vehicle miles traveled (VMT) and, optionally, vehicle speed. Activity data are used when SMOKE will be computing emission factors via another model, such as MOBILE6 (U.S. EPA, 2005). Examples of on-road mobile sources include light-duty gasoline vehicles and heavy-duty diesel vehicles.

- Non-Road Mobile Sources: These sources are engines that do not always travel on roadways. They encompass a wide variety of source types from lawn and garden equipment to locomotives and airplanes. Emission estimates for most non-road sources come from EPA's NONROAD model (OFFROAD in California). The exceptions are emissions for locomotives, airplanes, pleasure craft and commercial marine vessels.

- Point Sources: These are sources that are identified by point locations, typically because they are regulated and their locations are available in regulatory reports. In addition, elevated point sources will have their emissions allocated vertically through the model layers, as opposed to being emitted into only the first model layer. Point sources are often further subdivided into electric generating unit (EGU) sources and non-EGU sources, particularly in criteria inventories in which EGUs are a primary source of NO_x and SO_2. Examples of non-EGU point sources include chemical manufacturers and furniture refinishers. Point sources are included in both criteria and toxics inventories.

- Biogenic Land Use Data: Biogenic land use data characterize the types of vegetation that exist in either county-total or grid cell values. The biogenic land use data in North America are available using two different sets of land use categories: the Biogenic Emissions Landcover Database (BELD) version 2 (BELD2), and the BELD version 3 (BELD3) (CEP, 2004b).

In addition to these standard SMOKE processing categories, we have added other categories either to represent specific emissions processes more accurately or to integrate emissions data that are not compatible with SMOKE. Examples of emissions sectors that fall outside of the SMOKE processing categories include emissions generated from process-based models for representing windblown dust and agricultural ammonia (NH_3) sources. An emissions category with data that are not compatible with SMOKE is one with gridded emissions data sets, such as commercial marine sources. Another nonstandard emissions category that we modeled was emissions from fires. All of the emissions categories that we used to build CENRAP simulations are described in detail in the following sections.

Continuing the enhancement of the emissions source categories that we initiated during the preliminary 2002 modeling, we further refined the categories from the standard definitions listed above to include more explicit emissions sectors. The advantage of using more detailed definitions of the source categories is that it leads to more flexibility in designing control strategies, substituting new inventory or profile data into the modeling, managing the input and output data from SMOKE and conducting QA of the SMOKE outputs. The major drawback to defining more emissions source categories is the increased level of complexity and computational requirements (run times and disk space) that results from having a larger number of input data sets. Another motivation behind separating the various emissions categories is related to the size and flexibility of the input data. Some data sets, like the CENRAP on-road mobile inventory, were so large that we had to process them separately from the rest of the sources in the on-road sector due to computational constraints. We also separated the non-road mobile and ammonia sectors into yearly and monthly inventories to facilitate the application of uniform monthly temporal profiles to the monthly data. Additional details about how we prepared the emissions inventories and ancillary data for modeling are described in Sections 2.2 through 2.16. Table 2-7 summarizes the entire group of source sectors that composed simulation Typ02G. Each emissions sector listed in the table represents an explicit SMOKE simulation. As discussed in Section 2.1.2 below, after finishing all of the source-specific simulations, we used SMOKE to combine all of the data into a single file for each day for input to the air quality modeling systems. Each subsection on the emissions sectors describes each sector in terms of the SMOKE processing category, the year covered by the inventory, and the source(s) of the data.

Additional details about the inventories are also provided, including any modifications that we made to prepare them for input into SMOKE.

Table 2-7. CENRAP Typ02G emissions categories.

Emissions Sector	Abbreviation*
Fires as Point Sources (WRAP, CENRAP, VISTAS)	Alf
Area Sources (All domain)	ar
CENRAP area fires	arf
Area fires, Anthropogenic (All domain, excluding WRAP and CENRAP)	arfa
Area fires, Wild (All domain, excluding WRAP)	arfw
Biogenic	b3
Ontario, Canada, point-source fires	bsf
Fugitive dust	fd
WRAP on-road mobile	mb
CENRAP on-road mobile	mbv_CENRAP
Other US on-road mobile	mbv
Monthly CENRAP/MRPO anthropogenic NH_3	nh3m
Ammonia from annual inventory (CENRAP)	nh3y
WRAP anthropogenic NH_3	nh3
Seasonal/Monthly non-road mobile (WRAP, CENRAP, MW)	nrm
Annual non-road mobile	nry
On-road Mobile (Non-US)	nusm
Offshore shipping (Gulf, Atlantic)	ofs
Offshore area (Gulf)	ofsar
Stationary point (All domain, including offshore)	pt
Road dust	rd
Windblown dust (All domain)	wb_dust
WRAP oil and gas	wog

*These abbreviations are used in the file naming of the SMOKE output files for each sector.

Emissions models such as SMOKE are computer programs that convert annual or daily estimates of emissions at the state or county level to hourly emissions fluxes on a uniform spatial grid that are formatted for input to an air quality model. For the Typ02G and Base18G emission inventories we prepared emissions for CMAQ version 4.5 using SMOKE version 2.1 on the UCR Linux computing cluster. SMOKE integrates annual county-level emissions inventories with source-based temporal, spatial, and chemical allocation profiles to create hourly emissions fluxes on a predefined model grid. For elevated sources that require allocation of the emissions to the vertical model layers, SMOKE integrates meteorology data to derive dynamic vertical profiles. In addition to its capacity to represent the standard emissions processing categories, SMOKE is also instrumented with the Biogenic Emissions Inventory System, version 3 (BEIS3) model for estimating biogenic emissions fluxes (U.S. EPA, 2004) and the MOBILE6 model for estimating on-road mobile emissions fluxes from county-level vehicle activity data (U.S. EPA, 2005a).

SMOKE uses C-Shell scripts as user interfaces to set configuration options and call executables. SMOKE is designed with flexible QA capabilities to generate standard and custom reports for checking the emissions modeling process. After modeling all of the source categories individually, including those categories generated outside of SMOKE, we used SMOKE to merge all of the categories together to create a single CMAQ input file per simulation day. Also, for use in the CAMx modeling, we converted the CMAQ-ready emissions estimates to CAMx-ready files using the CMAQ2CAMx converter. Additional technical details about the version of SMOKE used for final simulations are available from CEP (2004b). All scripts, data, and executables used to generate the Typ02G and Base18G emissions for CMAQ and CAMx are archived on the CENRAP computing cluster.

2.1.6 2002 and 2018 Data Sources

This section describes the procedures that the CENRAP followed to collect and prepare all emissions data for Typ02G and Base18G simulations. We discuss the sources of all inventory and ancillary data used for simulations. CENRAP worked with emissions inventory contractors, other RPOs, and EPA to collect all of the data that constitute the simulation. Table 2-8 lists all of the contacts for the various U.S. anthropogenic emission inventories we used. For the CENRAP inventories, this table lists the contacts for the contractors who prepared the inventories; for the non-CENRAP inventories it lists the contacts at the RPOs who provided us inventory data. We obtained the emissions inventories for Canada and Mexico from the U.S. EPA Emissions Factors and Inventory Group (EFIG) via the Clearinghouse for Inventories and Emissions Factors (CHIEF) website (http://www.epa.gov/ttn/chief/index.html).

Table 2-8. CENRAP anthropogenic emissions inventory contacts.

Source Category	Emissions Data Contact
WRAP	
All	Tom Moore, Western Governors' Association Phone: (970) 491-8837 Email: mooret@cira.colostate.edu
CENRAP	
2002 Consolidated Inventory	Randy Strait, E.H. Pechan & Assoc., Inc. Phone: 919-493-3144 Email: rstrait@pechan.com
NH3 Inventory, Prescribed and Agricultural Fires, and On-road mobile emissions	Dana Sullivan, Sonoma Technology, Inc. Phone: 707-665-9900 Email: dana@sonomatech.com
Gulf Off-shore platform and support vessel emissions	Holly Ensz, Minerals Management Service Phone: (504) 736-2536 Email: holli.ensz@mms.gov
VISTAS	
All	Greg Stella, Alpine Geophysics, LLC, Phone: 828-675-9045 Email: gms@alpinegeophysics.com
MANE-VU	
All	Megan Schuster, MARAMA, Baltimore, MD USA Phone: 410-467-0170 Email: mschuster@marama.org
MRPO	
All	Mark Janssen, LADCO, Des Plaines, IL, USA Phone: 847-296-2181 Email:janssen@ladco.org

As mentioned above, the refinement of these inventories involved splitting some of the inventory files into more specific source sectors. As the stationary-area-source emissions sector has traditionally been a catch-all for many types of sources, this is the inventory sector that required the greatest amount of preparation. Upon receiving all stationary-area-source inventories we extracted fugitive dust, road dust, anthropogenic NH_3, and for the non-WRAP U.S. inventories, stage II refueling sources. We retained the dust sources as separate categories that we would further refine with the application of transport factors (see Section 2.8).

We collected the ancillary data used for SMOKE modeling from several sources. SMOKE ancillary modeling data include:

- Temporal and chemical allocation factors by state, county, and source classification code (SCC);
- Spatial surrogates and cross-reference files for allocating county-level emissions to the model grid;
- Hourly gridded meteorology data;
- Stack defaults for elevated point sources;
- MOBILE6 configuration files;
- A Federal Implementation Standards (FIPS) codes (i.e., country/state/county codes) definition file;

- A Source Category Classification (SCC) codes definition file;
- A pollutant definition file; and
- Biogenic emission factors.

Except for the meteorology data and the MOBILE6 configuration files, we used default data sets provided by EPA as the basis for all of the ancillary data except for temporal profiles used for Electric Generating Units (EGUs). These profiles were developed based on CEM data from 2000 through 2003 (Pechan and CEP, 2005c). CENRAP provided the meteorology data for the simulations at 36-km and 12-km grid resolutions (Johnson, 2007). The inventory contractor who prepared the MOBILE6 inventories provided the MOBILE6 configuration files either directly or via an RPO representative; details about the sources of the MOBILE6 inputs are provided in Section 2.4. We made minor modifications to the chemical allocation, pollutant definition, and country/state/county codes files for new sources, pollutants, or counties contained in the inventories that we had not previously modeled. We made major modifications to the temporal and spatial allocation inputs, as described below.

2.1.7 Temporal Allocation

Temporally allocating annual, daily, or hourly emissions inventories in SMOKE involves combining a temporal cross-reference file and a temporal profiles file.

- Temporal cross-reference files associate monthly, weekly, and diurnal temporal profile codes with specific inventory sources, through a combination of a FIPS (country/state/county) code, an SCC, and sometimes for point sources, facility and unit identification codes.
- Temporal profiles files contain coded monthly, weekly, and diurnal profiles in terms of a percentage of emissions allocated to each temporal unit (e.g., percentage of emissions per month, weekday, or hour).

As a starting point for the temporal allocation data for simulations, we used the files generated by emission inventory contractors (Pechan and CEP, 2005c). Based on guidance from the developers of some of the inventory files, we enhanced the temporal profiles and assignments for some source categories (Pechan, 2005b).

We modified the temporal allocation data for the simulations to improve the representation of temporal emissions patterns for certain source categories. We implemented the adjusted profiles in SMOKE by modifying the temporal cross-reference file for the applicable FIPS and SCC combinations.

Updated temporal profiles for EGUs were made available for MRPO in the MRPO Base K inventory. Since the non-road emissions for IA and MN were monthly emissions developed by MRPO, new temporal profiles were created for all the SCCs in these emissions files for these two states only. The monthly profile was uniform and the weekly and diurnal profiles were kept the same as were modeled for the rest of the country.

An updated temporal profile, profile 485, based on NOAA 1971-2000 population weighted average heating degree days for home heating area source emissions was obtained from

VISTAS. This profile provided state specific updates for home heating emissions and was applied to the full inventory in place of profile 17XX.

Other additions to the Base02G temporal allocation data included updates that made by other RPOs that are applicable to their inventories. These other updates to the temporal allocation files included

- VISTAS continuous emissions monitoring (CEM)-specific profiles for EGUs in the VISTAS states;
- VISTAS agricultural burning profiles;
- Wildfire and prescribed fire profiles developed by VISTAS for the entire U.S.;
- MANE-VU on-road mobile profiles;
- WRAP weekly and diurnal road dust profiles;
- WRAP diurnal wildfire, agricultural fire, and prescribed fire profiles; and
- WRAP on-road mobile weekly and diurnal profiles.

Finally, for all of the monthly and seasonal emissions inventories, we modified the temporal cross-reference files to apply uniform monthly profiles to the sources contained in these inventories. The monthly variability is inherent in monthly and seasonal inventories and does not need to be reapplied through the temporal allocation process in SMOKE. The inventories to which we applied uniform monthly temporal profiles included:

- WRAP, CENRAP, and MRPO non-road mobile sources;
- WRAP on-road mobile sources;
- WRAP road dust; and
- CENRAP anthropogenic ammonia.

2.1.8 Spatial Allocation

SMOKE uses spatial surrogates and SCC cross-reference files to allocate county-level emissions inventories to model grid cells. Geographic information system (GIS)-calculated fractional land use values define the percentage of a grid cell that is covered by standard sets of land use categories. For example, spatial surrogates can define a grid cell as being 50% urban, 10% forest, and 40% agricultural. In addition to land use categories, spatial surrogates can also be defined by demographic or industrial units, such as population or commercial area. Similar to the temporal allocation data, an accompanying spatial cross-reference file associates the spatial surrogates (indexed with a numeric code) to SCCs. Spatial allocation with surrogates is applicable only to area and mobile sources that are provided on a county level basis. Point sources are located in the model grid cells by SMOKE based on the latitude-longitude coordinates of each source. Biogenic emissions are estimated based on 1-km^2 gridded land use information that is mapped to the model grid using a processing program such as the Multimedia Integrated Modeling System (MIMS) Spatial Allocator (CEP, 2004).

We used various sources of spatial surrogate information for the U.S., Canada, and Mexico inventories in the simulations. For the U.S. and Canadian sources, we used the EPA unified surrogates available through the EFIG web site (EPA, 2005c). For the 36-km grid, EPA provides these data already formatted for SMOKE on the RPO Unified 36-km domain that we used for the simulations. We modified the spatial surrogates for Canada on the RPO Unified 36-km domain by adopting several surrogate categories that were enhanced by the WRAP. Table 2-9 provides details about the new Canadian spatial surrogates that were developed by the WRAP and used for CENRAP simulations. For modeling Mexico, we used Shapefiles developed for the Big Bend Regional Aerosol and Visibility Observations Study (BRAVO) modeling to create surrogates for Mexico on the RPO Unified 36-km domain (EPA, 2005c).

Table 2-9. New Canadian spatial surrogates.

Attribute	Base02a Code	Shapefile	Reference
Land area	950	can_land93_land	Natural Resources Canada (1993) AVHRR land cover data
Water area	951	can_land93_water	Natural Resources Canada (1993) AVHRR land cover data
Forest land area	952	can_land93_forest	Natural Resources Canada (1993) AVHRR land cover data
Agricultural land area	953	can_land93_agri	Natural Resources Canada (1993) AVHRR land cover data
Urban land area	954	can_land93_urban	Natural Resources Canada (1993) AVHRR land cover data
Rural land area	955	can_land93_rural	Natural Resources Canada (1993) AVHRR land cover data
Airports	956	can_airport	U.S. DOT Bureau of Transportation Statistics (2005) NORTAD 1:1,000,000 scale data
Ports	957	can_port	U.S. DOT Bureau of Transportation Statistics (2005) NORTAD 1:1,000,000 scale data
Roads	958	can_road1m	Natural Resources Canada (2001) National Scale Frameworks data
Rail	959	can_rail1m	Natural Resources Canada (1999) National Scale Frameworks data

2.2 Stationary Point Source Emissions

Stationary-point-source emissions data for SMOKE consist of (1) Inventory Data Analyzer (IDA)-formatted inventory files; (2) ancillary data for allocating the inventories in space, time, and to the Carbon Bond-IV chemistry mechanism used in CMAQ and CAMx; and (3) meteorology data for calculating plume rise from the elevated point sources. This section describes where CENRAP obtained these data, how we modeled them, and the types of QA that we performed to ensure that SMOKE processed the data as expected.

2.2.1 Data Sources

For the stationary-point-source inventories in Typ02G and Base18G, we used actual 2002 data developed by the RPOs for the U.S., version 2 of the year 2000 Canadian inventory, and the BRAVO 1999 Mexican inventory. The BRAVO inventory was updated with entirely new inventories for the six northern states of Mexico for stationary area, as well as stationary point, on-road mobile, and off-road mobile sources. Emissions for the southern states of Mexico were included for the first time in CENRAP simulations Typ02G and Base18G. These data were provided by ERG, Inc., who completed an updated 1999 emissions inventory for northern Mexico (ERG, 2006b) and delivered these data to the WRAP. The CENRAP stationary-point inventory consisted of annual county-level and tribal data provided in August of 2005 (Pechan and CEP, 2005e). The WRAP (ERG, 2006a) and VISTAS Base G (MACTEC, 2006) stationary-point inventories consisted of an annual data set and monthly CEM data for selected EGUs. The WRAP and VISTAS provided these data directly to CENRAP. We downloaded the MANE-VU stationary-point inventories from the MANE-VU web sites. MRPO base K data was downloaded and processed for SMOKE modeling by Alpine Geophysics under contract from MARAMA. UCR entered into a nondisclosure agreement with Environment Canada to obtain version 2 of the 2000 Canadian point-source inventory. This inventory represented a major improvement over the version of the data that we had used in the preliminary 2002 modeling.

Reductions anticipated from BART controls for electric generating units (EGU) in Oklahoma, Arkansas, Kansas, and Nebraska were included in projections of 2018 emissions. These anticipated reductions were based on actual operating conditions and estimated control efficiencies from utilities.

Newly permitted coal-fired utilities were included in 2018 projections. Conservatively, no IPM projected new units were removed from the simulation with the addition of the permitted facilities.

Due to missing or clearly erroneous stack parameters, several facilities in CENRAP states were relegated to default stack profiles based on SCC in the NEI QA process. Prioritizing for the largest emissions sources, these default parameters were corrected by CENRAP States and updated files were provided to modeling contractors. Final IDA input files Typ02G and Base18G for point sources reflect State corrections.

For coal-fired point and area sources, The EPA Office of Air Quality and Planning Standards (OAQPS) determined that the organic carbon fraction in the speciation profile code "NCOAL" was not representative of most coal combustion occurring in the U.S. This profile has an organic carbon fraction of 20%, which includes an adjustment factor of 1.2 to account for other atoms (like oxygen) attached to the carbon. OAQPS has reverted back to the profile code "22001" for coal combustion, which has an organic carbon fraction of 1.07% (again including the 1.2 factor adjustment). This is the same profile that EPA used for previous rulemaking efforts including the Heavy Duty Diesel Rule and Non-Road Rule, which were proposed (and publicly reviewed) prior to the introduction of the NCOAL profile.

The consensus in OAQPS is that the NCOAL profile has a high organic carbon percentage because it is based on measurements of combustion of lignite coal. With the exception of Texas, lignite is not widely used in the U.S.. Thus, OAQPS staff stopped relying on this profile as a national default profile. A new coal speciation profile developed based on Eastern bituminous coal combustion (since much of the coal burned in the U.S. is of this type) is being developed by EPA's Office of Research and Development but was not completed for this study.

The profile recently developed for MRPO by Carnegie Mellon was provided to CENRAP and is representative of combustion of eastern bituminous coal. This profile is a more appropriate profile for most facilities in the U.S. than the default NCOAL profile.

Additionally, the "22001" profile has been flagged as problematic because of the apparent inadvertent switching of the organic carbon and elemental carbon fractions, which are 1.07% and 1.83% respectively. The report discovering the discrepancy in the profile did not offer a clear alternative to correct the problem (MACTEC, 2003).

CENRAP has continued to use the NCOAL factor for facilities burning lignite in North Dakota and Texas. For the remainder of the U.S., the MRPO profile, CMU, was used. The NCOAL factor was modified reducing the organic carbon by half and assigning the remainder to $PM_{2.5}$. The modification was at the request of Texas and was reflective of the original study for the NCOAL factor conducted in Texas (Chow, 2005). Table 2-10 summarizes the $PM_{2.5}$ speciation profiles for the NCOAL, 2201 and CMU speciation profiles for coal burning sources.

Table 2-10. PM 2.5 speciation profiles for coal-burning sources.

Profile	POC	PEC	PNO3	PSO4	PM2.5
NCOAL	0.1000	0.0100	0.0050	0.1600	0.7250
22001	0.0107	0.0183	0.0000	0.1190	0.8520
CMU	0.0263	0.0315	0.0036	0.0447	0.8938

Final simulations used improved temporal allocation and speciation information relative to the preliminary 2002 modeling; the rest of the ancillary data for modeling stationary point sources stayed the same (Mansell et al., 2005).

2.2.2 Emissions Processing

For Typ02G and Base18G simulations we configured SMOKE to process the annual inventories for the U.S., Canada, and Mexico and process hourly CEM data for the VISTAS. We configured SMOKE to allocate these emissions up to model layer 15 (approximately 2,500 m AGL), which roughly corresponds to the maximum planetary boundary layer (PBL) heights across the entire domain throughout the year. As coarse particulate matter (PMC) is not an inventory pollutant but is required by the air quality models as input species, we used SMOKE to calculate PMC during the processing as (PM_{10} - $PM_{2.5}$). With the SMOKE option WKDAY_NORMALIZE set to “No,” we treated the annual inventories based on the assumption that they represent average-day data based on a seven-day week, rather than average weekday data. We also assumed that all of the volatile organic compound (VOC) emissions in the inventories are reactive organic gas (ROG), and thus used SMOKE to convert the VOC to total organic gas (TOG) before converting the emissions into CB-IV speciation for the air quality models. To capture the differences in diurnal patterns that are contained in the CEM temporal profiles for VISTAS and CENRAP states (Base02F), we configured SMOKE to generate daily temporal matrices, as opposed to using a Monday-weekday-Saturday-Sunday (MWSS) temporal allocation approach.

To QA the stationary-point emissions, we used the procedures in the CENRAP emissions modeling QA protocol (Morris and Tonnesen, 2004) and a suite of graphical summaries. We used tabulated summaries of the input data and SMOKE script settings to document the data and configuration of SMOKE for all simulations. These QA graphics are available on the web site at: http://pah.cert.ucr.edu/aqm/cenrap/emissions.shtml

2.2.3 Uncertainties and Recommendations

There were issues with the stationary-point emissions that we left unresolved at the completion of the Typ02G and Base18G emissions modeling either because we did not feel they would have a major impact on the modeling results in CENRAP states or because we did not have alternative approaches and they represented the best available information. Canadian emissions for 2000 were found to have a significant number of missing stack parameters. These stacks when modeled with default parameters frequently resulted in lower plume heights. Stack parameters for 2000 were corrected based on cross referencing sources with the 2005 Canadian inventory for the largest emitting points. Stack parameters for many of the sources with lower emissions remain incorrect, but are assumed to have a less significant impact on CENRAP Class I areas. The 2020 projected emissions for Canada were obtained as air quality model-ready files from EPA. EPA has not confirmed that missing stack parameters were corrected for the projected inventory. It is assumed that they were not corrected and default parameters were used instead. Given confidentiality issues that surround Canadian inventories, EPA processed emissions represent the best available data.

2.3 Stationary Area Sources

Stationary-area-source emissions data for SMOKE consist of IDA-formatted inventory files and ancillary data for allocating the inventories in space, time, and to the Carbon Bond-IV chemistry mechanism used in CMAQ and CAMx. This section describes where we obtained these data, how we modeled them, and the types of QA that we performed to ensure that SMOKE processed the data as expected.

2.3.1 Data Sources

For the stationary area source inventories in the Typ02G and Base18G simulations, we used actual 2002 data developed by the RPOs for the U.S., version 2 of the year 2000 Canadian inventory, and the updated Mexican inventory, http://www.epa.gov/ttn/chief/net/mexico.html. The BRAVO inventory was updated with entirely new inventories for the six northern states of Mexico for stationary area, as well as stationary point, on-road mobile, and off-road mobile sources. Emissions for the southern states of Mexico were included for the first time in CENRAP simulations Typ02G and Base18G. The CENRAP stationary-area inventory consisted of annual county-level and tribal data provided by in August of 2005 (Pechan and CEP, 2005e). The WRAP (ERG, 2006a) and VISTAS Base G (MACTEC, 2006) stationary-area inventories consisted of an annual data set. We downloaded the MANE-VU stationary-area inventories from the MANE-VU web sites. MRPO base K data was downloaded and processed for SMOKE modeling by Alpine Geophysics under contract from MARAMA.

To prepare the stationary-area inventories for modeling, we made several modifications to the files by removing selected sources either to model them as separate source categories or to omit them from simulations completely. Using guidance provided by EPA (EPA, 2004b), we extracted fugitive and road dust sources from all stationary-area inventories for adjustment by transport factors and modeling as separate source categories (see Section 2.8). We also extracted and discarded the stage II refueling sources (Table 2-11) from the U.S. inventories; we modeled these sources with MOBILE6 as part of the on-road mobile-source emissions. We left the stage II refueling emissions in the WRAP stationary-area inventory because the on-road mobile inventory that we received for this region did not contain these emissions.

Table 2-11. Refueling SCCs removed from the non-WRAP U.S. stationary-area inventory.

SCC	Description
2501060100	Storage and Transport Petroleum and Petroleum Product Storage Gasoline Service Stations Stage 2: Total
2501060101	Storage and Transport Petroleum and Petroleum Product Storage Gasoline Service Stations Stage 2: Displacement Loss/Uncontrolled
2501060102	Storage and Transport Petroleum and Petroleum Product Storage Gasoline Service Stations Stage 2: Displacement Loss/Controlled
2501060103	Storage and Transport Petroleum and Petroleum Product Storage Gasoline Service Stations Stage 2: Spillage
2501070100	Storage and Transport Petroleum and Petroleum Product Storage Diesel Service Stations Stage 2: Total
2501070101	Storage and Transport Petroleum and Petroleum Product Storage Diesel Service Stations Stage 2: Displacement Loss/Uncontrolled
2501070102	Storage and Transport Petroleum and Petroleum Product Storage Diesel Service Stations Stage 2: Displacement Loss/Controlled
2501070103	Storage and Transport Petroleum and Petroleum Product Storage Diesel Service Stations Stage 2: Spillage

Other steps that we took to prepare the stationary-area inventories included confirming that there is no overlap between the anthropogenic NH_3 inventory (Section 2.9) and stationary area sources, and moving area-source fires in each regional inventory to separate files. In addition to these inventory modifications we made a few changes to the ancillary data files for simulation Typ02G, as described next.

Simulation Typ02G used improved temporal and spatial allocation information relative to the preliminary 2002 modeling; the rest of the ancillary data for modeling stationary area sources stayed the same as in the preliminary 2002 modeling (Mansell et al., 2005). We adopted enhanced spatial allocation data with additional area-based surrogates for Canada (Table 2-9), and added surrogates for a missing county in Colorado (Broomfield) from WRAP modeling and QA work. The WRAP had noticed when looking at the Canadian data for the preliminary 2002 modeling that forest fire emissions from the Canadian area-source inventory, which are relatively large sources of CO, NO_x, and $PM_{2.5}$, were being allocated to a surrogate for logging activities. They found similar discrepancies for other area and non-road SCCs in Canada. To improve the representation of the Canadian emissions, we adopted several land-area-based surrogates developed by the WRAP, such as forested land area, urban land area, and rural land area, and made the accompanying additions to the spatial cross-reference file to associate inventory SCCs with these surrogates. We also added spatial surrogates for Broomfield County, CO; this county was included in the inventory but was not included in the base EPA surrogates (this county was recently created from portions of other counties).

Improvements to the temporal allocation data for simulation Typ02G included the addition of several FIPS-specific profiles provided by VISTAS and CENRAP contractors (Pechan 2005b). These temporal profiles listed in Table 2-12 targeted mainly fire and agricultural NH_3 sources, such as open burning and livestock operations, respectively.

Table 2-12. New Temporal Profile Assignments for CENRAP Area Source SCCs.

SCC	Description	Month	Week	Diurnal	Recommendation Based on Profile Data for SCC	Description of Similar SCC used to Recommend Profiles
2310001000	Industrial Processes; Oil and Gas Production: SIC 13;All Processes : On-shore; Total: All Processes	262	7	26	2310000000	Industrial Processes;Oil and Gas Production: SIC 13;All Processes;Total: All Processes
2310002000	Industrial Processes;Oil and Gas Production: SIC 13;All Processes : Off-shore;Total: All Processes	262	7	26	2310000000	Industrial Processes;Oil and Gas Production: SIC 13;All Processes;Total: All Processes
2461870999	Solvent Utilization;Miscellaneous Non-industrial: Commercial;Pesticide Application: Non-Agricultural;Not Elsewhere Classified	258	7	26	2461800000	Solvent Utilization;Miscellaneous Non-industrial: Commercial;Pesticide Application: All Processes;Total: All Solvent Types
2805009200	Miscellaneous Area Sources;Agriculture Production - Livestock;Poultry production - broilers;Manure handling and storage	1500	7	26	2805009300	Miscellaneous Area Sources;Agriculture Production - Livestock;Poultry production - broilers;Land application of manure
2805021100	Miscellaneous Area Sources;Agriculture Production - Livestock;Dairy cattle - scrape dairy;Confinement	1500	7	26	2805021300	Miscellaneous Area Sources;Agriculture Production - Livestock;Dairy cattle - scrape dairy;Land application of manure
2805021200	Miscellaneous Area Sources;Agriculture Production - Livestock;Dairy cattle - scrape dairy;Manure handling and storage	1500	7	26	2805021300	Miscellaneous Area Sources;Agriculture Production - Livestock;Dairy cattle - scrape dairy;Land application of manure
2805023100	Miscellaneous Area Sources;Agriculture Production - Livestock;Dairy cattle - drylot/pasture dairy;Confinement	1500	7	26	2805023300	Miscellaneous Area Sources;Agriculture Production - Livestock;Dairy cattle - drylot/pasture dairy;Land application of manure
2805023200	Miscellaneous Area Sources;Agriculture Production - Livestock;Dairy cattle - drylot/pasture dairy;Manure handling and storage	1500	7	26	2805023300	Miscellaneous Area Sources;Agriculture Production - Livestock;Dairy cattle - drylot/pasture dairy;Land application of manure
2810020000	Miscellaneous Area Sources;Other Combustion;Prescribed Burning of Rangeland;Total	3	11	13	2810015000	Miscellaneous Area Sources;Other Combustion;Prescribed Burning for Forest Management;Total

2.3.2 Emissions Processing

For simulations Typ02G and Base18G we configured SMOKE to process the annual stationary-area-source inventories for the U.S., Canada, and Mexico. As PMC is not an inventory pollutant but is required by the air quality models as input species, we used SMOKE to calculate PMC during the processing as (PM_{10} - $PM_{2.5}$). With the SMOKE option WKDAY_NORMALIZE set to "Yes," we treated the annual stationary-area inventories based on the assumption that they represent average weekday data, causing SMOKE to renormalize the data to a seven-day estimate before applying any temporal adjustments. We also assumed that all of the VOC emissions in the inventories are ROG and thus used SMOKE to convert the VOC to TOG before converting the emissions into CB-IV speciation for the air quality models. We configured SMOKE to use a MWSS temporal allocation approach, as opposed to a daily temporal approach.

To QA the stationary-area emissions, we used the procedures in the CENRAP modeling QAPP and Modeling Protocol (Morris and Tonnesen, 2004; Morris et al., 2004a) and a suite of graphical summaries. We used tabulated summaries of the input data and SMOKE script settings to document the data and configuration of SMOKE for all simulations. The graphical QA summaries include, for all emissions output species, daily spatial plots summed across all model layers, daily time-series plots, and annual time-series plots. These QA graphics are available on the UCR/CENRAP web site at http://pah.cert.ucr.edu/aqm/cenrap/emissions.shtml .

2.3.3 Uncertainties and Recommendations

Most of the issues that we encountered with the stationary area sources related to the removal of certain SCCs from the base inventories for inclusion as other source categories or complete omission from simulations. We spent considerable effort on ensuring that we did not have overlap between the area inventory and the other sectors that explicitly represent sources traditionally contained in the area inventory, such as NH_3 and dust.

Both the Canadian and Mexican inventories presented minor problems that we resolved for simulation Typ02G but that can be addressed more thoroughly in future simulations. The Canadian inventory we used contained data only at the province level, essentially equivalent to a statewide rather than county-level inventory. A higher resolution inventory would have allowed us to use higher-resolution and more accurate spatial allocation data. Future modeling that uses Canadian data should move to the newly released municipality-level year 2000 inventories for Canada.

There was a discrepancy between the state and county coding in the Mexican inventory and the SMOKE file that defines acceptable FIPS codes. Differences in the ordering of the Mexican state names between these two data sets led to some of the Mexican inventory sources being mislabeled in the SMOKE QA reports. The state codes in the inventory and spatial surrogate files for two Mexican states were changed to be consistent with the SMOKE country/state/county codes file.

2.4 On-Road Mobile Sources

On-road mobile-source emissions data for SMOKE consist of IDA-formatted emissions and vehicle activity inventory files, and ancillary data for allocating the inventories in space, time, and to the Carbon Bond-IV chemistry mechanism used in CMAQ and CAMx. This section describes where we obtained these data, how we modeled them, and the types of QA that we performed to ensure that SMOKE processed the data as expected.

2.4.1 Data Sources

The SMOKE processing for CENRAP included two approaches for processing on-road mobile sources depending on the source of the data provided. The first approach was to compute mobile emissions values prior to providing them to SMOKE; we call this the pre-computed emissions approach. The second approach was to provide SMOKE with VMT data, meteorology data, and MOBILE6 inputs, and let the SMOKE/MOBILE6 module compute the mobile emissions based on these data; we call this the VMT approach. These approaches are not mutually exclusive for a single SMOKE run; therefore, we performed single SMOKE runs in which both approaches were used as follows:

- Annual VMT for computing CO, NO_x, VOC, SO2, NH3 and PM using MOBILE6 for all CENRAP States.
- Pre-computed, seasonal MOBILE6-based emissions of all pollutants for the 13 WRAP states that included pre-speciated $PM_{2.5}$ data.
- Annual VMT for computing CO, NO_x, VOC, SO2, NH3 and PM using MOBILE6 for the rest of the United States (VISTAS, MRPO and MANE-VU).
- Pre-computed, annual 1999 emissions of all pollutants for Mexico.
- Pre-computed, annual 2000 emissions of all pollutants for Canada.

For the CENRAP states, STI provided VMT data and MOBILE6 input files for all counties in the CENRAP region (Reid et al., 2004a). MOBILE6 input files were provided only for the months of January and July for 2002. MOBILE6 input files for the remaining months of 2002 had to be generated. These data were then processed within SMOKE. Using one set of MOBILE6 input files for each county in the CENRAP states resulted in compute memory requirements that were to large to process all CENRAP states together. Therefore the on-road mobile processing for the CENRAP states was split into two groups for SMOKE processing. The resulting gridded emissions data files were then merged together to obtain an on-road mobile source emissions file for the entire CENRAP region.

For the WRAP states we used actual 2002 data split into California and non-California seasonal inventories that were provided by the WRAP (Pollack et al., 2006). In addition to the standard criteria pollutants, these files contained pre-speciated $PM_{2.5}$ emissions. For the rest of the U.S. we used annual county-level activity and speed inventories with monthly, county-level MOBILE6 inputs, and hourly meteorology to estimate the hourly emissions with the SMOKE/MOBILE6 module. For the non-U.S. inventories, we used version 2 of the year 2000 Canadian inventory and the updated 1999 Mexican inventory pre-computed mobile source emissions.

2.4.2 Emissions Processing

For the Typ02G emissions modeling we configured SMOKE to process the annual on-road mobile emissions inventory data for the WRAP, Canada, and Mexico as pre-computed inventories. For the non-WRAP states, we used the SMOKE/MOBILE6 integration to process the annual activity inventories and monthly, county-based roadway information. The WRAP inventories contained pre-computed speciated PM emissions (Pollack et al, 2006) so the SMOKE PM speciation module was not used. The WRAP on-road mobile inventories were developed to represent seven-day (weekly) average emissions (as compared to the area source inventory, which represented average weekday emissions). As actual weekly average emissions, we configured SMOKE to process the WRAP on-road mobile source emissions by setting WKDAY_NORMALIZE to "No" in which case the emissions are adjusted to represent weekday and Saturday and Sunday emissions (as in contrast to the area sources where the emissions are just adjusted for Saturday and Sunday). We also assumed that all of the VOC emissions in the inventories are ROG and used SMOKE to convert the VOC to TOG before converting the emissions into CB-IV speciation for the air quality models. We configured SMOKE to create day-of-week specific rather than MWSS, temporal profiles because the WRAP on-road mobile temporal profiles contain weekly profiles that vary across the weekdays.

As noted previously, the large number of county roadway inputs for MOBILE6 processed for the non-WRAP portion of the U.S. required us to split the states mobile-source processing into three subsets because of computer memory limitations. Separate MOBILE6 input files were used for each separate county for CENRAP states, where as one MOBILE6 input file was used for several counties outside of the CENRAP region. The three subsets consisted of two sets of SMOKE/MOBILE6 simulations for the CENRAP and a simulation that computed on-road mobile emissions for the MRPO, VISTAS, and MANE-VU states. We configured MOBILE6 to use weekly temperature averaging for computing these emissions within SMOKE.

To QA the on-road mobile emissions, we used the CENRAP emissions modeling QA protocol (Morris and Tonnesen, 2004; Morris et al., 2004a) and a suite of graphical summaries. We used tabulated summaries of the input data and SMOKE script settings to document the data and configuration of SMOKE for simulations Typ02G and Base18G. The graphical QA summaries include, for all emissions output species, daily spatial plots, daily time-series plots, and annual time-series plots. These graphics are available at http://pah.cert.ucr.edu/aqm/cenrap/qa_base02b36.shtml#mb

2.4.3 Uncertainties and Recommendations

We approached the on-road mobile emissions preparation for simulation Typ02G from three different directions, which were based on the form of the input inventories and ancillary emissions data for different regions of the modeling domain:

- The WRAP region used emissions estimates pre-computed with EMFAC for California and MOBILE6 for the rest of WRAP states and processed like area sources with SMOKE adjusted from weekly to day-of-week emissions.
- The CENRAP, VISTAS, MRPO, and MANE-VU states used county-level activity data to compute emissions with the SMOKE/MOBILE6 module.

- The non-U.S. parts of the domain also had pre-computer on-road mobile source emissions so used an area-source approach for processing with SMOKE.

Different approaches for modeling a single emissions sector adds complexity and additional sources of error and inconsistencies to the modeling because of the different assumptions that went into the preparation of the input data. For example, refueling emissions from the on-road mobile sector are represented in the WRAP area-source sector but are computed with MOBILE6 for the rest of the U.S. Not using MOBILE6-based emissions for the non-U.S. portion of the domain neglects the effects of the actual 2002 meteorology on these emissions. Applying MOBILE6 outside of the U.S. is currently not possible because MOBILE6 is instrumented only for calculating emissions for the U.S. automotive fleet. The result of using MOBILE6 to calculate U.S. emissions and not using it to calculate the non-U.S. on-road mobile emissions estimates is that the non-U.S. emissions are not specific to this modeling year and the 2002 meteorological conditions, whereas the U.S. emissions are 2002-specific.

While we used the best available information to compute the on-road mobile emissions for the various portions of the modeling domain, inconsistent approaches for representing these emissions may lead to unnatural emissions gradients along political boundaries. We recommend for future work a unified approach for at least the U.S. inventories, where either we use MOBILE6 in SMOKE for the entire domain (or alternative emissions model such as CONCEPT), or we calculate the emissions with MOBILE6 outside of SMOKE and then use the resulting county-based emissions inventories.

2.5 Non-Road Mobile Sources

Non-road mobile source emissions data for SMOKE consist of annual, seasonal, and monthly IDA-formatted emission inventory files and ancillary data for allocating the inventories in space, time, and to the Carbon Bond-IV chemistry mechanism used in CMAQ and CAMx. This section describes where we obtained these data, how we modeled them, and the types of QA that we performed to ensure that SMOKE processed the data as expected.

2.5.1 Data Sources

The non-road mobile-source inventories in the Typ02G and Base18G emissions modeling used actual 2002 data developed by the RPOs for the U.S., version 2 of the year 2000 Canadian inventory and the improved 1999 Mexican inventory. The U.S. inventories consisted of annual, seasonal, and monthly inventories; the non-U.S. inventories were annual data. Pechan provided the CENRAP inventories divided between annual data for aircraft, locomotive, and commercial marine and annual files for all other non-road sources (Pechan and CEP, 2005e). Minnesota substituted the monthly MRPO Base K non-road inventory for the CENRAP inventory in their state. Iowa substituted the monthly estimates for non-road agricultural sources from the MRPO base K inventory for the CENRAP inventory. Texas provided estimates for 2002 non-road emissions in lieu of the CENRAP prepared inventory. WRAP provided non-road inventories divided between California and non-California seasonal inventories, further subdivided into aircraft, locomotives, shipping, and all other non-road mobile sources (Pollack et al., 2006). Note that the California Air Resources Board uses their own OFFROAD model for California non-road emissions, whereas the EPA NONROAD model is used for the rest of the states (with the exception of locomotives, aircraft and shipping). With these data WRAP also provided temporal adjustments to apply to the inventories to split them between weekday and weekend emissions. We used these weekday/weekend splits to derive new weekly temporal profiles for the WRAP sources. The MRPO base K monthly non-road inventories were obtained from MRPO in NIF format and were converted to SMOKE format by Wendy Vit of the Missouri DNR. The VISTAS Base G and MANE-VU non-road mobile inventories consisted of annual county-level data (Pechan and CEP, 2005c). We received these inventories directly from the respective RPO inventory representatives. We received the Canadian 2000 inventory version 2 from the U.S. EPA EFIG (EPA, 2005d). For Mexico we used the improved 1999 inventory available at http://www.epa.gov/ttn/chief/net/mexico.html.

Along with adding the WRAP weekday/weekend emissions splits to the temporal allocation files, we also created temporal input files that apply a flat, uniform monthly profile to the monthly and seasonal non-road inventories. With the monthly and seasonal variability inherent in these inventories, we avoided applying redundant monthly profiles by splitting the inventories into seasonal/monthly and annual data. We applied the uniform monthly temporal profiles to the seasonal/monthly inventories and non-uniform monthly temporal profiles to the annual inventories. How the non-road emissions inventory data were split into those with monthly/seasonal emission and those with annual emissions is provided in Table 2-13.

Table 2-13. Non-road mobile-source inventory temporal configuration.

Region	Source	Temporal Coverage
WRAP (non-CA)	Non-road mobile	Seasonal
WRAP (CA)	Non-road mobile	Seasonal
WRAP	Aircraft	Seasonal
WRAP	Locomotive	Annual
WRAP	In-port and near-shore shipping	Annual
CENRAP	All non-road	Annual
CENRAP, IA	Non road Ag.	Monthly
VISTAS	All non-road	Annual
MRPO and MN	All non-road	Monthly
MANE-VU	All non-road	Annual
Canada	All non-road	Annual
Mexico	All non-road	Annual

Iowa elected to use the CENRAP-sponsored inventory for all of the non-road categories except for the agricultural equipment categories provided in Table 2-14. For these agricultural equipment categories, Iowa elected to use the Midwest RPO Base K inventory because this inventory provided improvements to the temporal allocation of emissions for the agricultural sector. The Base K inventory includes monthly emissions. The monthly emissions are used in the SMOKE IDA files for modeling.

Table 2-14. Non-road agricultural emissions categories where the MRPO Base K inventory was used instead of the CENRAP inventory in Iowa.

SCC	SCC Description
22600050xx	Off-highway Vehicle Gasoline, 2-Stroke: Agricultural Equipment (2 SCCs);
22650050xx	Off-highway Vehicle Gasoline, 4-Stroke: Agricultural Equipment (11 SCCs);
22670050xx	LPG : Agricultural Equipment (3 SCCs);
22680050xx	CNG : Agricultural Equipment (3 SCCs); and
22700050xx	Off-highway Vehicle Diesel : Agricultural Equipment (11 SCCs).

Texas provided annual and daily emissions for CO, CO_2, NO_x, VOC, SO_2, PM10-FIL, and PM25-FIL for several oil and gas field equipment non-road categories (Table 2-15). Texas provided authorization to change the pollutant codes from PM10-FIL to PM10-PRI and PM25-FIL to PM25-PRI.

Table 2-15. Non-road oil and gas development equipment categories that Texas provided emissions to be used instead of the CENRAP inventory.

SCC	SCC Description
2265010010	Off-highway Vehicle Gasoline, 4-Stroke : Industrial Equipment: Other Oil Field Equipment;
2268010010	CNG : Industrial Equipment : Other Oil Field Equipment; and
2270010010	Off-highway Vehicle Diesel : Industrial Equipment : Other Oil Field Equipment

Lancaster County Nebraska provided its own non-road inventory for SCC 2260000000 (Off-highway Vehicle Gasoline, 2-Stroke : 2-Stroke Gasoline except Rail and Marine: All). The CENRAP-sponsored inventories for SCCs starting with 226 in Lancaster County were removed to correct double-counting of emissions. This adjustment was made by Pechan for Base02b modeling.

2.5.2 Emissions Processing

We configured SMOKE to process all of the non-road mobile emissions inventory data as area-like inventories using spatial surrogates to grid the county-level emissions. As the WRAP inventories contained pre-computed PM emissions, we did not have to use SMOKE to compute coarse mass PM (PMC). The WRAP non-road mobile inventories represented seven-day average emissions (different from the area inventory, which represented weekday average emissions). As actual weekly average emissions, we configured SMOKE to process them by setting WKDAY_NORMALIZE to “No.” For the rest of the non-road mobile inventories we processed the data as weekday average data by setting WKDAY_NORMALIZE to “Yes.” We also assumed that all of the VOC emissions in the inventories are ROG and used SMOKE to convert the VOC to TOG before converting the emissions into CB-IV speciation for the air quality models. We configured SMOKE to create MWSS temporal intermediates rather than daily temporal files because the non-road mobile sources do not use weekly temporal profiles that vary across the weekdays, but do have very different emissions on weekdays versus weekend days.

We divided the non-road mobile emissions modeling based on whether the data were annual or seasonal/monthly inventories. This split facilitated the application of uniform monthly temporal profiles to the seasonal/monthly inventories. After processing the non-road emissions as two separate categories, non-road yearly and non-road monthly, we combined them with the rest of the emissions sectors to create model-ready emissions for CMAQ and CAMx.
To QA the non-road mobile emissions we used the procedures in the CENRAP emissions modeling QAPP (Morris and Tonnesen, 2004) and Modeling Protocol (Morris et al., 2004a) and a suite of graphical summaries. We used tabulated summaries of the input data and SMOKE script settings to document the data and configuration of SMOKE for simulations. The graphical QA summaries include, for all emissions output species, daily spatial plots, daily time-series plots, and annual time-series plots. These QA graphics are available at http://pah.cert.ucr.edu/aqm/cenrap/qa_base02f36.shtml#nr

2.5.3 Uncertainties and Recommendations

We prepared non-road mobile emissions using a combination of inventories having different temporal resolutions and various forms of ancillary data. These different combinations of information may lead to inconsistencies in how these emissions are represented across the modeling domain. In addition, the Canadian inventories contain only province-level information and thus have low-resolution spatial and temporal profiles applied to them. The Mexican non-road emissions are deficient in the number of different SCCs contained in the inventory and the availability of spatial surrogates that are applicable to non-road mobile sources. Improvements to the temporal profiles and spatial surrogates could provide a more consistent approach to representing the non-road emissions across the entire modeling domain.

2.6 Biogenic Sources

Biogenic emissions data for SMOKE consist of input files to the BEIS3 model (EPA, 2004a). BEIS3 is a system integrated into SMOKE for deriving emissions estimates of biogenic gas-phase pollutants from land use information, emissions factors for different plant species, and hourly, gridded meteorology data. The results of BEIS3 modeling are hourly, gridded emissions fluxes formatted for input to CMAQ or CAMx. This section describes the sources of the BEIS3 input data that we used for the Typ02G and Base18G emissions, how we modeled these data and the types of QA that were performed to ensure that SMOKE processed the data as expected.

2.6.1 Data Sources

The BELD3 land use data and biogenic emissions factors that were developed during the WRAP preliminary 2002 modeling were used for the CENRAP biogenic emissions modeling (Tonnesen et al., 2005). These data included BELD3 1-km resolution land use estimates and version 0.98 of the BELD emissions factors. Since the WRAP and CENRAP use the same 36 km Inter-RPO continental U.S. modeling domain, CENRAP was able to leverage of the WRAP work performed previously.

2.6.2 Emissions Processing

We used BEIS3.12 integrated in SMOKE to prepare emissions for the simulations. Most of the preparation for the biogenic emissions processing was completed during the preliminary 2002 modeling (Morris et al., 2005). As the modeling domains did not change from the preliminary 2002 to the final modeling, we re-used the gridded land use data and vegetation emissions factors that we prepared for the preliminary simulations.

To QA the biogenic emissions, we used the CENRAP emissions modeling QAPP (Morris and Tonnesen, 2004) and Modeling Protocol (Morris et al., 2004a) and a suite of graphical summaries. We used tabulated summaries of the input data and SMOKE script settings to document the data and configuration of SMOKE for simulation Base02b. The graphical QA summaries include, for all emissions output species, daily spatial plots, daily time-series plots, and annual time-series plots. These QA graphics are available at http://pah.cert.ucr.edu/aqm/cenrap/qa_base02b36.shtml#b3

2.6.3 Uncertainties and Recommendations

The use of newer versions of BEIS (BEIS3.13) and the new MEGAN biogenic emissions models should be considered in future modeling.

2.7 Fire Emissions

Fire emissions data for SMOKE have traditionally been represented as county-level area-source inventories that were placed in only the first vertical model layer. We advanced the representation of fire emissions for air quality modeling by preparing portions of the inventory data as point sources with specific latitude-longitude coordinates for each fire centroid and pre-computed plume rise parameters that were derived from individual fire characteristics. These new inventories were based on the fire data products prepared by a CENRAP emission contractor (Reid et al., 2004b) and modified by the project team to be properly modeled as point sources. These data consist of annual, daily, and hourly IDA-formatted emissions inventory files and ancillary data for allocating the inventories in space, time, and to the Carbon Bond-IV chemistry mechanism used in CMAQ and CAMx. This section describes where we obtained these data, how we modeled them, and the types of QA performed to ensure that SMOKE processed the fire emissions data as expected.

2.7.1 Data Sources

The fire inventories in the Typ02G emissions inventory were held constant through Base18G. We used actual 2002 fire data developed by the RPOs for the U.S., version 2 of the year 2000 Canadian inventory fire data, and actual 2002 fire data for Ontario, Canada. The inventories used consisted of both area and point source data for the U.S., Canada, and Mexico. Sonoma Technology, Inc. provided the fire emissions for the CENRAP states (Reid et al., 2004b). Air Sciences provided us with the WRAP inventories divided among six different fire categories: wildfires, agricultural fires, wildland fire use, natural prescribed, anthropogenic prescribed, and non-Federal rangeland fires (Air Sciences, 2007a). These inventories consisted of annual, daily, and hourly IDA-formatted files with information on daily emissions totals and hourly plume characteristics for each fire. We received similar fire emission inventories for the other RPOS (Air Sciences, 2007b). We modeled these sources with the rest of the stationary-area-source sector.

CENRAP received data for 54 fires that occurred in Ontario during the year 2002. Information on the data code abbreviations, data definitions, and data units used in the raw data files was obtained from Mr. Rob Luik (Data Management Specialist) at the Ontario Ministry of Natural Resources (Rob.Luik@MNR. gov.on.ca). Emissions for each fire were estimated using the Emission Production Model (EPM)/CONSUME within the BlueSky framework. A fire identification code is needed to track individual fires throughout the processing. The unique fire identification code was created for each fire by concatenating the FIRE_NUMBER and CUR_DIST fields of the original data. The fire identification code also contains the FIPS code of the fire; this information is not used by BlueSky but is needed by BlueSky2Inv, the utility program that converts the BlueSky output to the SMOKE inventory format. The FIPS code 135000 was used for all fires with longitudes east of –90°, and FIPS code 135059 was used for fires west of –90°. These FIPS codes were used to ensure that the fires would be assigned the correct time zones in later SMOKE processing. Some of the dates provided in the original data included hourly information. In all cases, the hourly information was not used leaving all data at a daily resolution.

2.7.2 Emissions Processing

SMOKE is instrumented to distribute point-source-formatted fire inventories to the vertical model layers either by using a pre-computed plume rise approach or by computing the plume rise dynamically using actual 2002 meteorology. We applied both approaches for modeling point-source fire emissions in simulation Typ02G. For the pre-computed plume rise approach, SMOKE reads an annual inventory file with information on fire locations, a daily inventory file with daily emission totals for each fire, and an hourly inventory file with hourly plume bottom, plume top, and layer 1 fractions for each fire. SMOKE uses this information to locate the fires on the horizontal model grid and to distribute the plume of each fire vertically to the model layers. Because some of these fires have plumes that reach the model top, we set the number of emissions layers for processing these inventories to the full 19 layers of the meteorology. We applied this approach to the point-source fires for the WRAP, CENRAP and VISTAS regions.
The alternative plume rise approach uses information on fuel loading and the heat flux of the fires to distribute the fires vertically to the model layers. The data are provided to SMOKE in the form of an annual inventory with information on fire locations and a daily inventory with daily emission totals for each fire, daily heat flux, and daily fuel loading. We applied this approach to the point-source fires for Ontario, Canada.

All of the point-source fires used diurnal temporal profiles and speciation profiles for VOC and $PM_{2.5}$ developed by Air Sciences (2007a) during the preliminary 2002 modeling (Morris et al., 2005).

We modeled the area-source fires for U.S. and Canada as standard stationary area sources. We applied monthly temporal profiles provided by RPOs, flat weekly temporal profiles, and the diurnal profiles developed by Air Sciences for WRAP fires (Air Sciences, 2007a), and for the rest of the RPOs we used diurnal profiles that were provided by them (Air Sciences, 2007b). We used the forestland area surrogate to distribute these emissions from the county or province level in the inventories to the model grid cells.

To QA the fire emissions, we used the procedure in the CENRAP emissions modeling QA protocol (Environ, 2004) and a suite of graphical summaries. We used tabulated summaries of the input data and SMOKE script settings to document the data and configuration of SMOKE for simulation Typ02G. The graphical QA summaries include, for all emissions output species, daily spatial plots, daily time-series plots, annual time-series plots, and vertical profiles. These QA graphics are available at: http://pah.cert.ucr.edu/aqm/cenrap/qa_typ02g36.shtml.

2.7.3 Uncertainties and Recommendations

We used forestland spatial surrogates to distribute these county level (province level for Canada) data to the model grid. Using spatial surrogates to locate fires is a crude approach that results in the artificial smearing of the emissions over too large an area. This issue can be remedied by moving to a point-source approach for representing these fires, similar to the approach used by Air Sciences for preparing the WRAP fire inventories.

2.8 Dust Emissions

Dust emissions data for SMOKE have traditionally taken the form of county-level stationary-area-source inventories. As these emissions are correlated to meteorology, land use, and vegetative cover, we made several changes to how dust emissions are simulated by SMOKE to take these parameters into consideration. This section describes where we obtained data for windblown, fugitive, and road dust sources, how we modeled them, and the types of QA performed to ensure that SMOKE processed the data as expected.

2.8.1 Data Sources

For the fugitive dust and road dust inventories in the Typ02G emission scenario, we used actual 2002 data developed by the RPOs for the U.S., version 2 of the year 2000 Canadian inventory, and the BRAVO 1999 Mexican inventory. We extracted the fugitive dust inventories from the stationary-area inventories for each of the RPOs, Mexico, and Canada. Before modeling these data we further divided them into construction/mining sources and agricultural sources. We defined the fugitive dust sources in the Base02f modeling based on guidance provided by EPA (2004b). WRAP provide road dust emission inventories (Pollack et al., 2006). For the rest of the RPOs and Canada, we extracted the road dust SCCs from the stationary-area-source inventories. The BRAVO 1999 Mexico inventory did not contain any road dust SCCs. Table 2-16 lists the SCCs for the various fugitive and road dust sources that we modeled in the Base02f and Typ02G inventories. We applied near-source capture transport factors that are based on county-level vegetative cover to the fugitive and road dust inventories to prepare them for input to the air quality models.

For windblown dust, we used gridded emissions prepared outside of SMOKE using a land use and meteorology-based model developed under funding from the WRAP by ENVIRON and UC-Riverside (Mansell, 2005; Mansell et al., 2005).

Table 2-16. Fugitive and road dust SCCs.

Dust Category	SCCs
Fugitive dust (construction and mining)	2275085000, 2311000000, 2311010000, 2311010070, 2311020000, 2311030000, 2325000000, 2305070000, 2530000020, 2530000100, 2530000120
Fugitive dust (agricultural)	2801000003, 2801000005, 2801000008, 2805001000
Road dust	2294000000, 2296000000

2.8.2 Emissions Processing

We modeled the fugitive and road dust inventories through SMOKE using an area-source approach. We modeled these data on the assumption that they represented weekday, rather than seven-day week, emissions and thus used the SMOKE setting WKDAY_NORMALIZE to convert the data to a seven-day average. We configured SMOKE to compute PMC during the processing as (PM_{10} - $PM_{2.5}$). Usually the records with dust do not include any other pollutants such as VOC, and NOx. For the few records that did include pollutants other than the PM we

split the records where the PMs processed with dust and the non PMs processed with the area. We configured SMOKE to create MWSS temporal intermediates rather than daily temporal files because the dust sources do not use weekly temporal profiles that vary across the weekdays.
As noted above, we used SMOKE to apply near-source transport factors to the raw fugitive and road dust inventories to prepare them for input to the air quality models. We used U.S. transport factors from work done by Pace (2005) and a 2001 land use/land cover database to develop a SMOKE input file of county and SCC-based transport factors for the U.S., Canada, and Mexico. We applied these factors to create a new set of inventories adjusted for these transport factors for all regions except VISTAS; the VISTAS dust sources that we received already had the transport factors applied to them.

We calculated the windblown dust emissions outside of SMOKE using an internally developed, process-based model. By "process-based" we refer to an emissions model that integrates information about the processes that lead to the emissions of interest, in this case windblown dust. The process-based windblown dust model developed by the WRAP considers wind speeds, precipitation history, and soil types to derive gridded dust fluxes resulting from wind disturbances for the modeling domain. More information on this model, its modes of operation, and the configuration used for simulation Base02a are available in Mansell et al. (2005).
To QA the fire emissions, we used the procedures in the CENRAP emissions modeling QAPP (Morris and Tonnesen, 2004) and Modeling Protocol (Morris et al., 2004a) and a suite of graphical summaries. We used tabulated summaries of the input data and SMOKE script settings to document the data and configuration of SMOKE for Base02f emissions. The graphical QA summaries include, for all emissions output species, daily spatial plots, daily time-series plots, and annual time-series plots. These QA graphics are available at http://pah.cert.ucr.edu/aqm/cenrap/qa_base02f36.shtml#fd for fugitive dust, http://pah.cert.ucr.edu/aqm/cenrap/qa_base02f36.shtml#rd for road dust, and http://pah.cert.ucr.edu/aqm/cenrap/qa_base02b36.shtml#wbd for windblown dust.

2.8.3 Uncertainties and Recommendations

There are several improvements that should be made to the dust emissions modeling in future simulations. We will expand the list of fugitive dust SCCs that we extract from the stationary-area-source inventories for application of transport factors. This expanded list is based on recent work by EPA (2004b). We will also explore improvements to the assumptions that we used for generating emissions with the WRAP windblown dust model. Areas of improvement in the windblown dust model include refinements to the land use data and soil characteristics, additional information about agricultural activities in the WRAP and CENRAP regions, detailed model evaluation on targeted windblown dust case studies, and the application of snow-cover and vegetative transport factors to these emissions (Mansell et al., 2005).

2.9 Ammonia Emissions

Ammonia (NH_3) emissions from agricultural activities are a major source of ammonia and are dependent on many different environmental parameters, such as meteorology, crop and soil types, and land use. CENRAP developed NH_3 emissions for the CENRAP states (Pechan and CEP, 2005e). Ammonia emissions were estimated for 13 source categories using the Carnegie Mellon University (CMU) model and supplemental technical work; 80% of technical work was dedicated to improving emissions estimates for two source categories—livestock production and fertilizer use. For these two categories, as well as biogenic sources, improvements were made to the activity data and/or emission factors used by the CMU model. For four other source categories (industrial point sources, landfills, ammonia refrigeration, and non-road mobile sources), emissions estimates were prepared independently of the CMU model, and for the remaining six source categories (publicly owned treatment works, wildfires, domestic animals, wild animals, human respiration, and on-road mobile sources), emissions estimates were derived by running the CMU model with no alterations.

CENRAP NH_3 model emissions estimates were combined with data provided by the other RPOs to represent agricultural NH_3 emissions in simulations Typ02G and Base18G.

2.9.1 Data Sources

The WRAP provided NH_3 emissions using the WRAP NH_3 model (Mansell et al, 2005) that generated emissions for the following sectors: domestic sources, wild animals, fertilizers, soils, and livestock. MWRPO provided monthly IDA-formatted inventories reflective of base K to CENRAP that they produced from process-based models of their own, along with temporal profiles and spatial cross-reference information for these sources. Iowa elected to use the MWRPO estimates of NH_3 emissions for fertilizer application, livestock, and wastewater treatment or SCC 28017XXXXX, 28050XXXXX, and 2630020000 respectively. Minnesota reviewed the MWRPO inventory and chose to move forward with the CENRAP developed data set. The rest of the U.S., Canada, and Mexico had agricultural NH_3 emissions contained within their annual stationary-area-source inventories.

2.9.2 Emissions Processing

The WRAP NH_3 emissions were processed outside of SMOKE using the WRAP NH_3 model and provided to CENRAP as gridded, hourly emissions in network common data form (NetCDF) files. CENRAP and MWRPO provided monthly IDA-formatted, county-level NH_3 inventories that were developed separately with process-based models. We modeled these emissions like area sources with SMOKE, applying the temporal profiles and the spatial cross-referencing developed for CENRAP that we received from the MWRPO. The agricultural NH_3 emissions for the rest of the RPOs, Canada, and Mexico are contained within their stationary-area inventories. We applied the SMOKE default temporal profiles and spatial surrogates to all non-process-based NH_3 emissions.

To QA the NH_3 emissions, we used the procedures in the CENRAP modeling QAPP (Morris and Tonnesen, 2004) and Modeling Protocol (Morris et al., 2004a) and a suite of graphical summaries. We used tabulated summaries of the input data and SMOKE script settings to document the data and configuration of SMOKE for simulations Typ02G and Base18G. The graphical QA summaries include, for all emissions output species, daily spatial plots, daily time-series plots, and annual time-series plots. These QA graphics are available at http://pah.cert.ucr.edu/aqm/cenrap/index.shtml

2.9.3 Uncertainties and Recommendations

Like the other emissions categories that have traditionally been represented as stationary area sources, the agricultural NH_3 emissions sector is affected by interregional inconsistencies in the way these emissions are represented.

During the QA of the Base02a emissions, the WRAP discovered a problem with their soil NH_3 estimates. The emission factor for soil NH_3 that were used in developing these data produced too high an emission estimate from this sector. For simulations Base02B through Typ02G, we therefore removed the soil NH_3 sector completely from the WRAP domain. In future simulations we will include these emissions with a revised emission factor for NH_3 emissions from soils.

2.10 Oil and Gas Emissions

Emissions from oil and gas development activities have been poorly characterized in the past. Simulations These emissions have been sporadically reported by some states in their stationary-area-source inventories, but for the most part were missing from our preliminary modeling. In the Typ02G and Base18G simulations, significant effort was made to better represent oil and gas production emissions explicitly as both area and point sources.

2.10.1 Data Sources

Emissions from oil and gas production activities for the CENRAP states were included with the other CENRAP state emission source categories (Pechan and CEP, 2005e). We received oil and gas production emissions inventories for the WRAP states and for tribal lands in the WRAP region as stationary-area-source and stationary-point-source IDA-formatted inventories. ERG, Inc. provided the point-source inventories with the rest of the stationary-point data (ERG, 2006a). ENVIRON provided the area-source oil and gas inventories for non-CA WRAP states and for tribal lands in the WRAP region, along with spatial surrogates for allocating these data to the model grid (Russell and Pollack. 2005). Oil and gas production emissions data for outside of the WRAP region are contained in the stationary-area inventories.

2.10.2 Emissions Processing

We modeled the WRAP point-source oil and gas production emissions in combination with the rest of the stationary-point-source emissions. We modeled the WRAP area-source oil and gas production emissions explicitly as a separate category that included WRAP and tribal inventories. These data represent weekly average emissions and did not require any renormalization within SMOKE. We used spatial surrogates generated by ENVIRON to allocate these annual county-level emissions to the model grid. For all oil and gas emissions, we applied flat temporal profiles to create hourly inputs to CMAQ and CAMx.

2.10.3 Uncertainties and Recommendations

In future 2002 modeling California oil and gas production emissions should be replaced with revised data provided by the California Air Resources Board (CARB). In addition, WRAP has updated their oil and gas production inventory for the base and future years in a Phase II work effort that substantially improved the emissions inventory estimates (Bar-Ilan et al., 2007).

2.11 MMS Off-shore Gulf of Mexico Emissions

Offshore area point source emissions include emissions in the Gulf of Mexico and off the coast of California that are associated with oil and gas drilling platforms.

2.11.1 Data Sources

We obtained year 2000 IDA-formatted point-source inventories for oil and gas platforms in the Gulf of Mexico from the Minerals Management Service (MMS) web site:
http://www.gomr.mms.gov/homepg/regulate/environ/airquality/gulfwide_emission_inventory/2000GulfwideEmissionInventory.html

We combined these with point-source data for coastal California provided to us by CARB during the preliminary 2002 modeling. We also obtained gridded area source emissions for platforms in the Gulf of Mexico from the MMS that we converted to the CENRAP 36-km model grid.

The 2000 MMS Gulf wide Emission Inventory was updated as of June 2006 to account for a change in vessel emissions in the non-point source (non-platform) database file. The point source (platform) emission inventory database file has not changed from the original version. Area source emissions from offshore activities in the Gulf of Mexico were developed from the latest estimates provided by the Minerals Management Service (MMS). The MMS inventory includes both platform and non-platform sources. The non-platform area source emissions estimates are spatially allocated to lease blocks and protraction units throughout the Gulf of Mexico. Temporal and spatial allocation cross-reference data were developed from the MMS inventory data and formatted for input to the SMOKE emissions model by Carolina Environmental Programs. These data were provided to the CENRAP emissions modeling team for implementation within SMOKE. The spatial allocation surrogates were provided for 4-km grid cells. The UCR team used these surrogates and developed surrogates for 36-km grid cells. Because these data are references to lease blocks/protraction units, rather than counties, this source category was processed separately form all other emissions using a customized reference data and SMOKE run scripts.

We modeled the offshore point and area sources as separate categories in the simulations. We used SMOKE to locate the offshore point sources on the model grid and to vertically allocate them into 15 model layers.

To QA the offshore platform emissions, we used the procedures in the CENRAP modeling QAPP (Morris and Tonnesen, 2004) and Modeling Protocol (Morris et al., 20042) and a suite of graphical summaries. We used tabulated summaries of the input data and SMOKE script settings to document the data and configuration of SMOKE for simulation Base02a. The graphical QA summaries include, for all emissions output species, daily spatial plots, daily time-series plots, and annual time-series plots. These QA graphics are available at http://pah.cert.ucr.edu/aqm/cenrap/index.shtml for the point and area sources.

2.11.2 Uncertainties and Recommendations

While the MMS data that we used were an improvement over previously modeled Gulf of Mexico platform inventories, the data were developed for a different modeling application that covered only the extreme northwestern portion of the Gulf, so they are missing large areas of the region of the Gulf that contain drilling platforms. The California offshore inventory represents an initial attempt at compiling an emission inventory for this area and contains very few sources. Future simulations will focus on improving these emissions by expanding the coverage of the offshore platform inventories for both the Gulf of Mexico and the Pacific Coast.

2.12 Off-shore Shipping Emissions

Emission inventory development for regional- and continental-scale air quality modeling has historically neglected offshore emissions sources beyond 25 miles offshore. Concern over the environmental effects of commercial shipping emissions in the Pacific on the coastal states in the WRAP region led to the development of a commercial marine shipping inventory for the Pacific. This inventory of off-shore marine vessels emissions made a substantial difference in some of the coastal western PM estimates (e.g., SO4). VISTAS developed an off-shore marine vessels inventory for the entire modeling domain that included the Pacific and Atlantic Oceans and the Gulf Of Mexico. For Typ02G and Base18G emission inventories CENRAP adopted the offshore shipping inventories developed by VISTAS.

2.12.1 Data Sources

Initially we obtained gridded annual commercial marine shipping emissions for the Pacific on the 36-km model grid from WRAP for inclusion in CENRAP simulations in the Base F modeling (Pollack et al., 2006). The commercial marine inventory contains all of the criteria pollutants contained in the non-road mobile-source inventory: CO, NO_x, VOC, NH_3, SO_2, PM_{10}, and $PM_{2.5}$. This inventory was subsequently updated in the Typ02G and Base18G modeling with the VISTAS off-shore commercial marine emissions inventory that covered the Gulf of Mexico and the Atlantic and Pacific Oceans and was based on the EPA/ARB SOx Emissions Control Area (SECA) program. Dr. James Corbett (University of Delaware) analyzed off-shore marine vessel data and worked with ENVIRON/ICF to convert to gridded emissions for the SECA grid. ENVIRON then provided SO_2, NO_X, PM and VOC emissions for the RPO 36-km grid.

2.12.2 Emissions Processing

The commercial marine shipping inventory was not processed through SMOKE. VISTAS provided the data to the as gridded text files on the 36-km model grid. These data were reformatted to the NetCDF CMAQ input format with a utility developed by UCR. The VOC inventory was converted to CB-IV speciation and the NO_x and $PM_{2.5}$ inventory pollutants to CMAQ input species with SMOKE chemical profiles for commercial shipping sources. No temporal adjustments were applied to these emissions; they use uniform monthly, daily, and diurnal profiles. An SCC for commercial marine vessels within the MMS inventory (SCC CM80002200) was accounted for in the commercial marine inventory developed for VISTAS. The duplicate emissions were removed from the MMS inventory prior to processing emissions

for Base G simulations. The duplicated emissions amounted to 19,000 TPY of NO_X and 3,184 TPY of SO_2. For simulation Typ02G and Base18G we received binary netCDF file from ENVIRON for one day and that day was used for every day of the year.
To QA the commercial marine shipping emissions, we used the procedures in the CENRAP modeling QAPP (Morris and Tonnesen, 2004) and Modeling Protocol (Morris et al., 2004a) and a suite of graphical summaries. The graphical QA summaries include, for all emissions output species, daily spatial plots, daily time-series plots, and annual time-series plots. These QA graphics are available at http://pah.cert.ucr.edu/aqm/cenrap/index.shtml.

2.12.3 Uncertainties and Recommendations

As a first attempt at representing shipping emissions in the Pacific in international waters, the WRAP and VISTAS 2002 commercial shipping inventory is a breakthrough in a historically neglected emissions category. As the RPOs evaluate the effects of these emissions on the air quality modeling, we anticipate that there will be refinements to the temporal profiles and to the vertical allocation of the emissions. Many of the stacks of large commercial ships contained in this inventory extend vertically above the first model layer. Future versions of this inventory should use higher-resolution temporal adjustments and should allocate the emissions to the appropriate model layers. Off-shore marine shipping activity is projected to increase. However, there are also the potential for emission controls on this source category (e.g., SECA program). Given these two off setting activities, the 2002 off-shore marine shipping emissions were assumed to be unchanged going from 2002 to 2018. Better estimates of 2018 marine emissions are being developed that should be considered in future modeling activities.

2.13 2018 Growth and Control

Base18G was based on grown inventories assuming on-the-books control strategies. CENRAP contracted with Pechan to deliver growth and control data for CENRAP and to consolidate growth and control information for other RPOs where available (Pechan, 2005d). The data are applicable to all source categories and pollutants included in the CENRAP 2002 emission inventory. This includes the following pollutants: sulfur oxides (SO_x), oxides of nitrogen (NO_x), volatile organic compounds (VOC), carbon monoxide (CO), ammonia (NH_3), and primary PM_{10} and $PM_{2.5}$. Some source categories were held constant between 2002 and 2018 because either stagnant growth was deemed appropriate or insufficient data was available to adequately project future growth or controls. These source categories include the following:

- Wind Blown Dust from non-agricultural land use categories.
- Emissions from wildfires.
- Emissions from Mexico.
- Global transport sources (i.e., the 2002 GEOS-CHEM boundary conditions).

2.13.1 Data Sources

CENRAP contracted with Pechan to provide growth and control factors to be applied with SMOKE for the CENRAP region (Pechan, 2005d). These growth and control parameters were based on growth estimates derived from EGAS 5.0 and control estimates assumed for implementation of federal regulations and on-the-books state and local control programs. Emissions projections for electric generating units were developed for the RPOs with the Integrated Planning Model (IPM). The RPO 2.1.9 IPM results were subsequently modified by VISTAS, MRPO and CENRAP to reflect planned new construction and controls. The WRAP provided 2018 EGU estimates developed in coordination with State and Industry stakeholders. VISTAS, MWRPO and the WRAP provided emissions for 2018, having applied growth and control factors outside of SMOKE processing. EPA provided SMOKE processed emissions, applying both growth and controls, for Canada for the year 2020. These emissions were provided on the RPO 36-km grid. However, emissions were inexplicably processed for an alternative vertical structure. Alpine Geophysics, under contract to VISTAS reallocated the emissions through the vertical layers to more accurately reflect the vertical structure applied uniformly by the RPOs. The modified data was obtained directly from Alpine Geophysics. Emissions from Mexico were held constant between the inventory year 1999 and modeled 2002 and 2018. Improvements to the Mexican inventory have been continuously made between generation of the original BRAVO inventory and the present improved 1999 inventory. However, given the continued uncertainties in the improved inventory, no future year projections where attempted by CENRAP.

2.13.2 Emissions Processing

Growth and control factors developed by Pechan (2005d) for Arkansas did not match the final delivered inventory for Arkansas. Arkansas underwent major revisions to point and facility IDs in mid-2005. These updates were not available by the delivery date of the growth and control parameters. In coordination with Arkansas, a cross-walk was developed to correct the point and facility IDs.

The assumptions that went into the development of controls for engines covered under the RICE MACT were not consistent with the final rule. Rule penetration values for CENRAP states were adjusted to more accurately reflect the impact of the final rule.

The impact of the refinery global settlements was not incorporated into CENRAP modeling until the base G simulations. Control assumptions provided by EPA and referenced in EPA CAIR modeling were applied to the 2018 inventory. These reductions primarily impacted SO_2 emissions; however, NO_X reductions were applied in Oklahoma, Louisiana, and Minnesota.

2.13.3 Uncertainties and Recommendations

The impact of control programs is an area of uncertainty that will need continued review as the programs are implemented. Development of growth and control assumptions for Mexico will be necessary for continued refinement of the impact of international transport. CENRAP obtained estimates of increased prescribed burn activity for the Forest Service after processing of the base G simulations was underway. These estimates of increased activity should be reviewed for inclusion in future simulations. EPA developed 2020 estimates of Canadian emissions are assumed to include erroneous stack parameters previously addressed in the 2000 emissions processing. Further review of this data set is recommended.

2.14 2018 Base G C1 Control Sensitivity

CENRAP conducted a control sensitivity evaluating the impact of point source reductions given a maximum dollar per ton control level. The intent of the control sensitivity was to generate information on the impact of possible control strategies in support of the consultation process. The strategies were grouped together under a common set of criteria and not specifically identified by the states. The results of the modeling were not intended to be prescriptive; instead, they were intended to be a starting point for control discussions that would require much greater refinement.

2.14.1 Data Sources

CENRAP contracted with Alpine Geophysics to provide an evaluation of possible additional controls for the 2018 CENRAP point source inventory. These controls were in addition to on-the-books and BART controls assumed in the development of Base18F and Base18G emission scenarios. Base18F IDA files were enhanced with additional information on base level controls. The enhanced dataset was then linked with the control data contained in the 2006 release of EPA's AirControlNet software. Alpine developed cost curves for NO_X and SO_2 in 2005 dollars for the Base18F CENRAP point source inventory. Staff from Iowa DNR and Kansas DHE worked in conjunction to add area of influence data (Alpine Geophysics, 2006) and distance calculations to each Class I area in CENRAP. A variety of dollar per ton control levels were evaluated. CENRAP elected to base the sensitivity on a maximum control cost of $5,000 per ton. This selection was made with the understanding that the cost data under-represented the true cost of retrofit controls and did not take in to consideration more recent market fluctuations impacting costs of controls and construction. CENRAP refined the selection by applying controls to only those sources that met the criteria that the ratio of their emissions in tons per year to their distance to any Class I area in kilometers be less than 5. This distance weighting criteria allowed the sensitivity to focus on those sources with the greatest impact. Additional controls for other RPOs were not considered in this evaluation.

2.14.2 Emissions Processing

Sources considered for control were removed from the IDA files. Growth and control assumptions were applied outside of SMOKE and delivered to UCR as 2018 emissions. Stack parameter changes as a result of additional controls were not considered in this analysis.

2.14.3 Uncertainties and Recommendations

Given uncertainties in control costs more refined analyses should include an evaluation of retrofit control costs under present values.

2.15 Emissions Summaries

Appendix B provides details on the source of the emission files used in the CENRAP Typ02G and Base18G modeling. Also in Appendix B are sample emission summary plots, additional plots are available on the CENREAP modeling website:
http://pah.cert.ucr.edu/aqm/cenrap/emissions.shtml.

CENRAP has contracted with E.H. Pechan and Associates to provide emissions summaries used in the final Typ02G and Base18G modeling in Excel spreadsheets and in an Access database that are available on the CENRAP website (http://www.cenrap.org/projects.asp#). Figures 2-3 through 2-9 display the, respectively, SO2, NOx, VOC, PM2.5, PM10, NH3 and CO anthropogenic emissions for the CENRAP states and the Typ02G and Base18G emission scenarios. Emissions are broken down by major source sector. For the state of Texas the emissions are broken by three groups, northeast Texas, southeast Texas and remainder of Texas (west Texas).

For most states, EGUs are the largest contributor to SO2 emissions (Figure 2-3). As EGU SO2 emissions are generally projected to be reduced in the future, most states show a reduction in total SO2 emissions from 2002 to 2018. One exception to this is Louisiana for which non-EGU point source SO2 emissions are greater than for EGU and are projected to increase from 2002 to 2018. The reasons for these increases are unclear, but the growth factors for non-EGU points should be examined more carefully.

NOx emissions are fairly evenly distributed across non-EGU point, EGU point, non-road mobile, on-road mobile and area sources for the 2002 Typ02G emissions scenario (Figure 2-4). In 2018, the contributions of on-road mobile source NOx emissions is reduced dramatically, with some states also showing reductions in EGU NOx emissions as well, resulting in all states exhibiting lower NOx emissions in 2018 than 2002.

VOC emissions are dominated by area, non-road mobile, on-road mobile and non-EGU point sources in both 2002 and 2018 (Figure 2-5). VOC emissions from on-road and non-road mobile source are projected to go down in the future, whereas VOC emissions from non-EGU point and, especially, area sources are projected to increase. Thus, whether a state's total VOC emissions increase or decrease depends on the relative contributions of mobile versus area sources and the level of increase in area source VOC emissions. Note that the VOC emissions listed in Figure 2-5 do not include biogenic VOC emissions that would be greater than the anthropogenic VOC emissions shown in Figure 2-5. Note that because biogenic VOC emissions are processed using the SMOKE/BEIS module on the 36 km grid, state-wide biogenic VOC emissions summaries are not readily available.

Primary $PM_{2.5}$ emissions are primarily from road dust and fugitive dust, and for some states fires (Figure 2-6). Kansas, Oklahoma, Louisiana and Texas all have large contributions from fires not seen in the other states. Road dust and fugitive dust are the most dominate source categories for coarse particulate as well (Figure 2-7).

CENRAP developed a separate ammonia emissions for 13 categories using the CMU model including livestock and fertilizer that dominates the ammonia emissions across the CENRAP states (Figure 2-8). Several states also have significant ammonia contributions from non-EGU point sources, whereas others do not.

CO emissions are dominated by the on-road and non-road mobile source sectors (Figure 2-9). However, states with fires also see large CO contributions from them as well. On-road mobile source CO emissions are projected to go down substantially from 2002 to 2018, whereas the other source categories are flat.

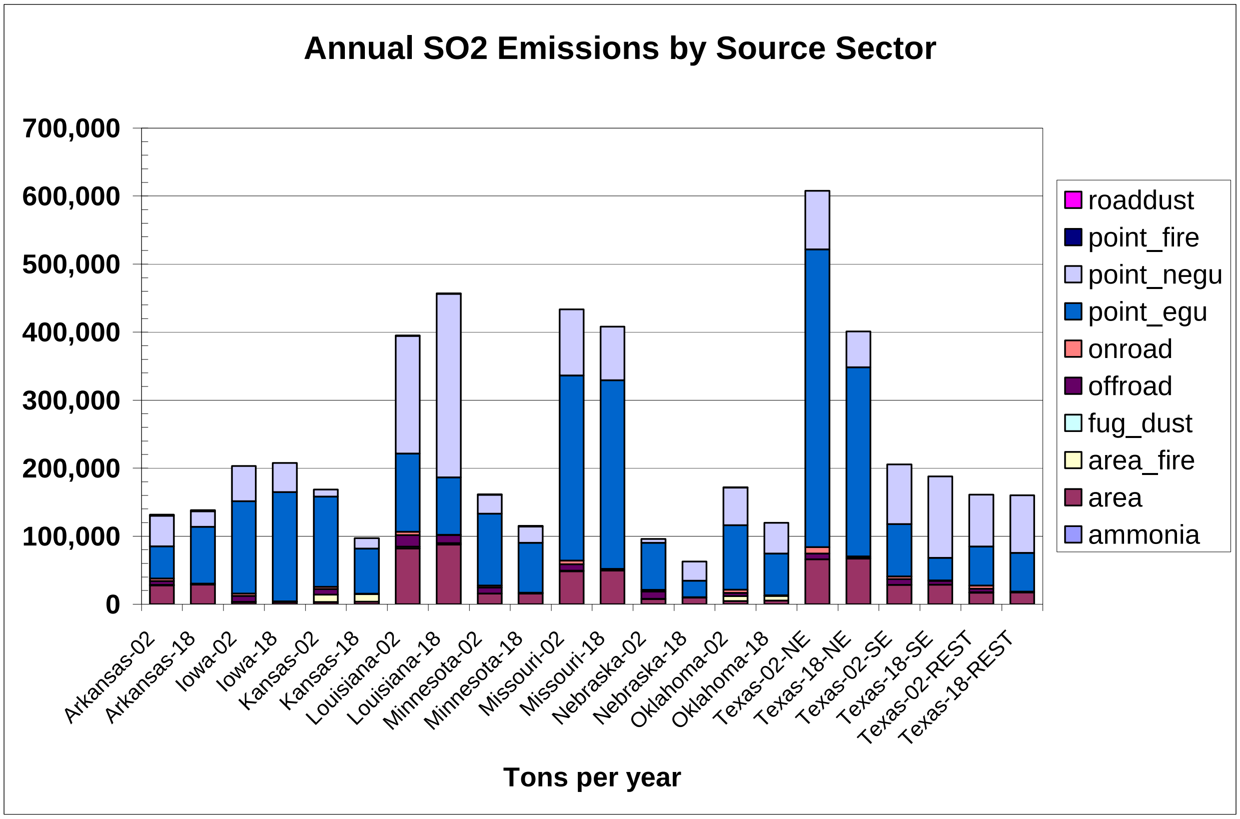


Figure 2-3. Summary of Typ02G and Base18G SO2 emissions by CENRAP state and major source sector (tons per year).

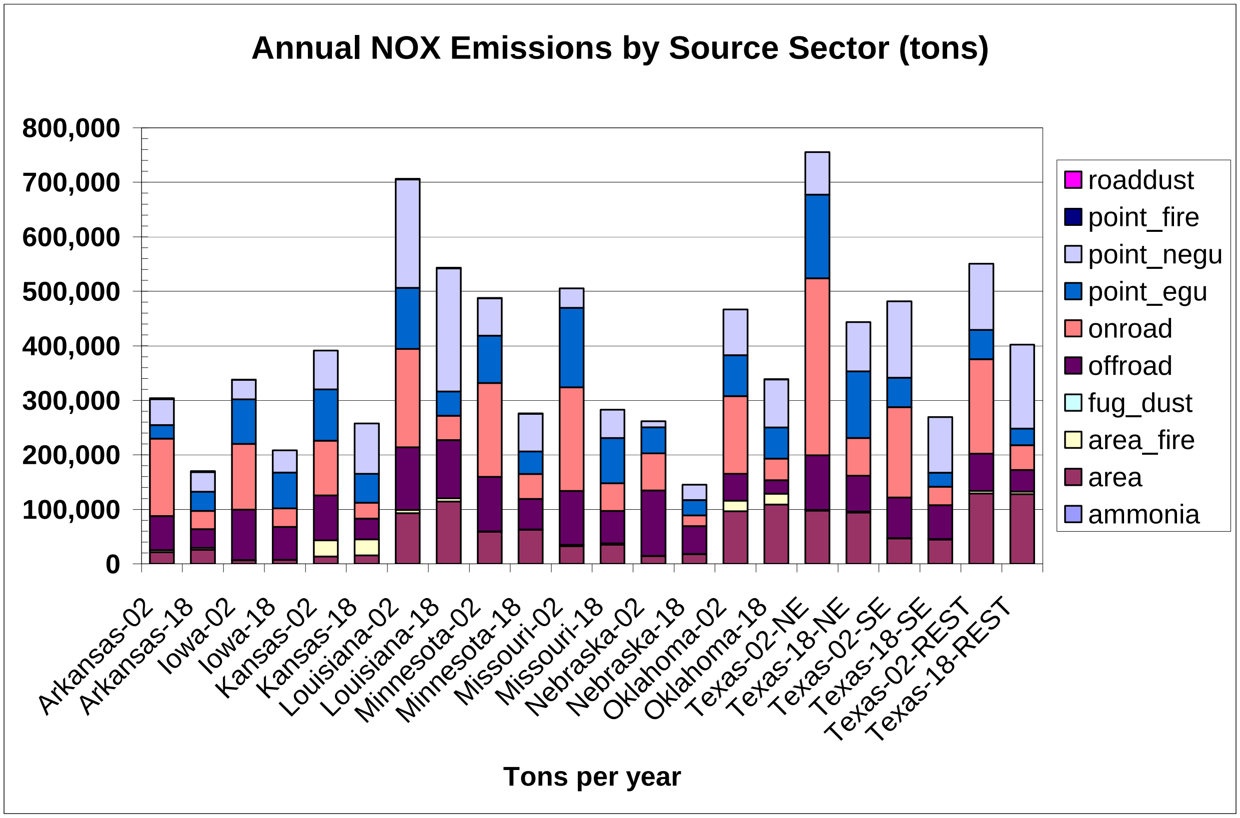


Figure 2-4. Summary of Typ02G and Base18G NOx emissions by CENRAP state and major source sector (tons per year).

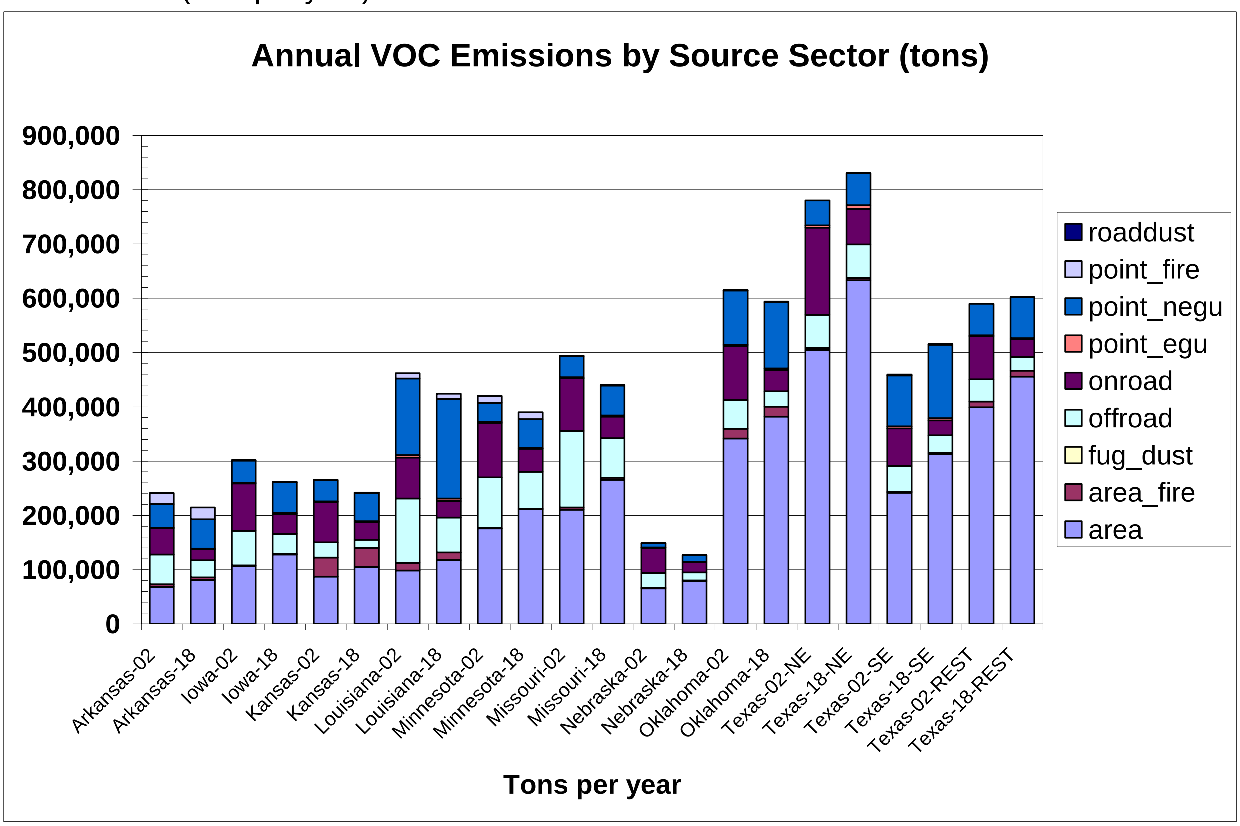


Figure 2-5. Summary of Typ02G and Base18G VOC emissions by CENRAP state and major source sector (tons per year).

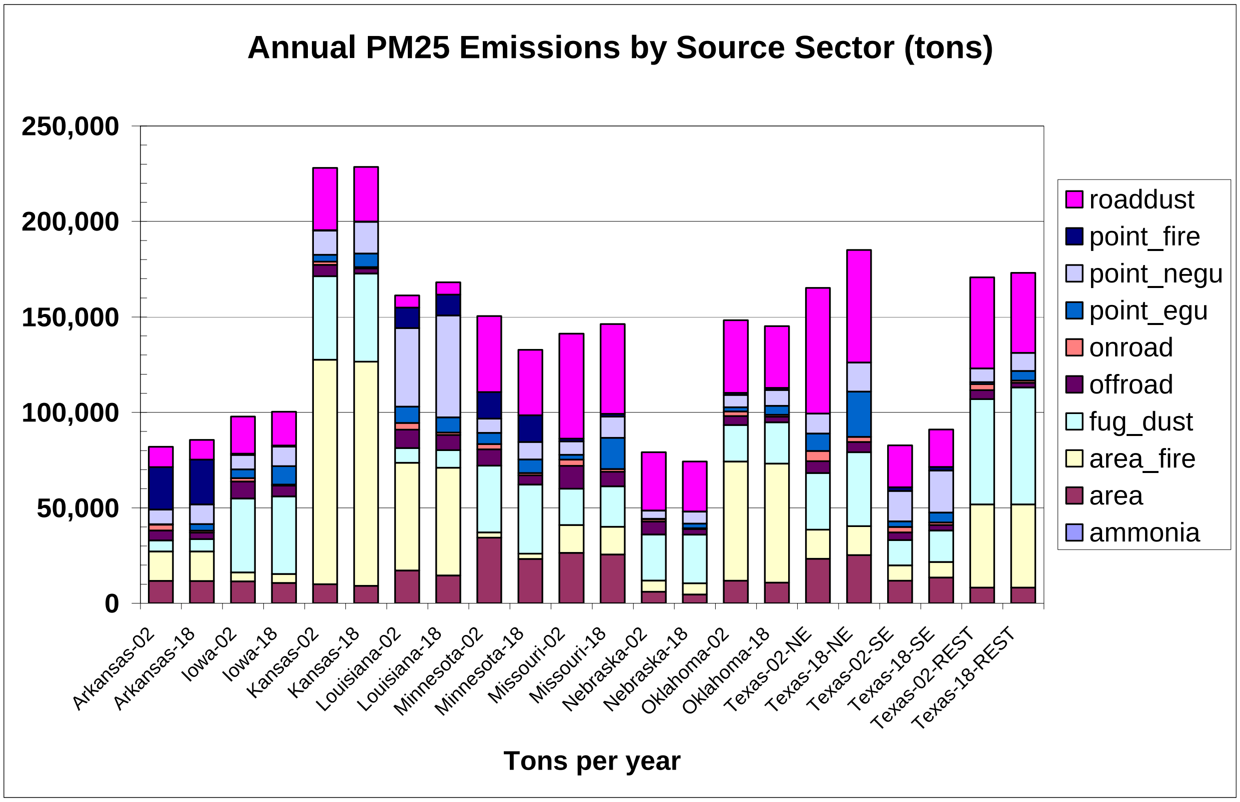


Figure 2-6. Summary of Typ02G and Base18G PM2.5 emissions by CENRAP state and major source sector (tons per year).

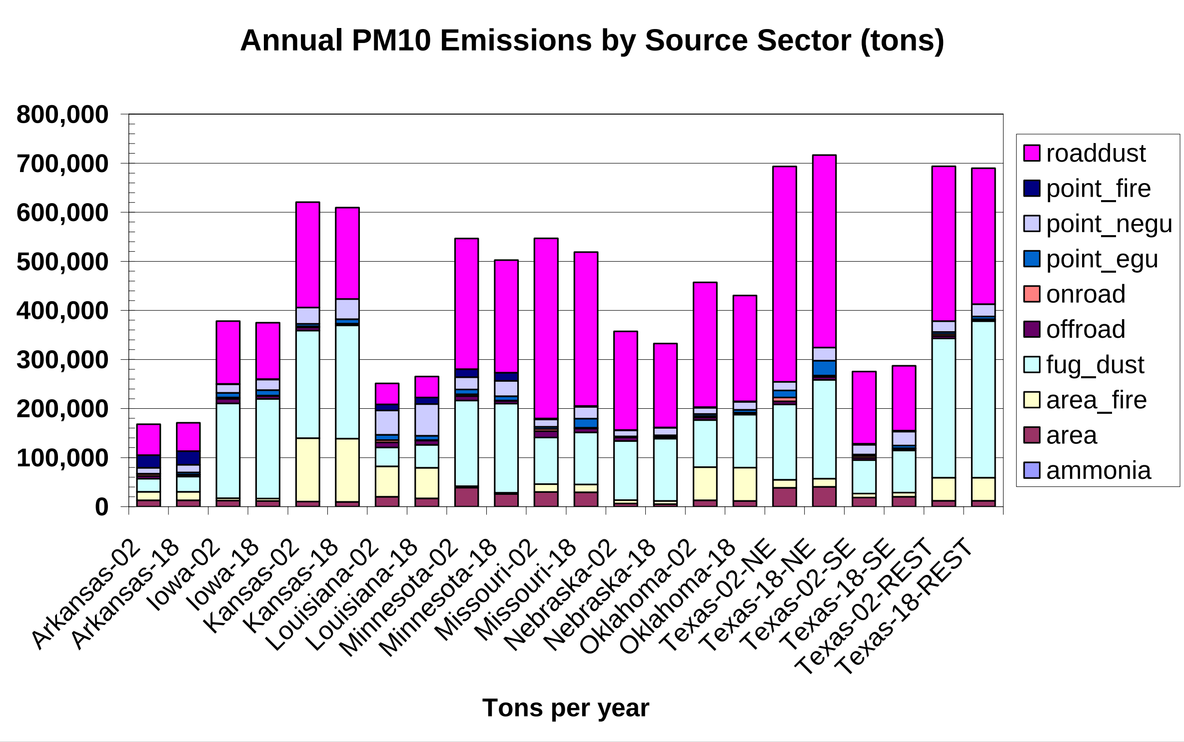


Figure 2-7. Summary of Typ02G and Base18G PM10 emissions by CENRAP state and major source sector (tons per year).

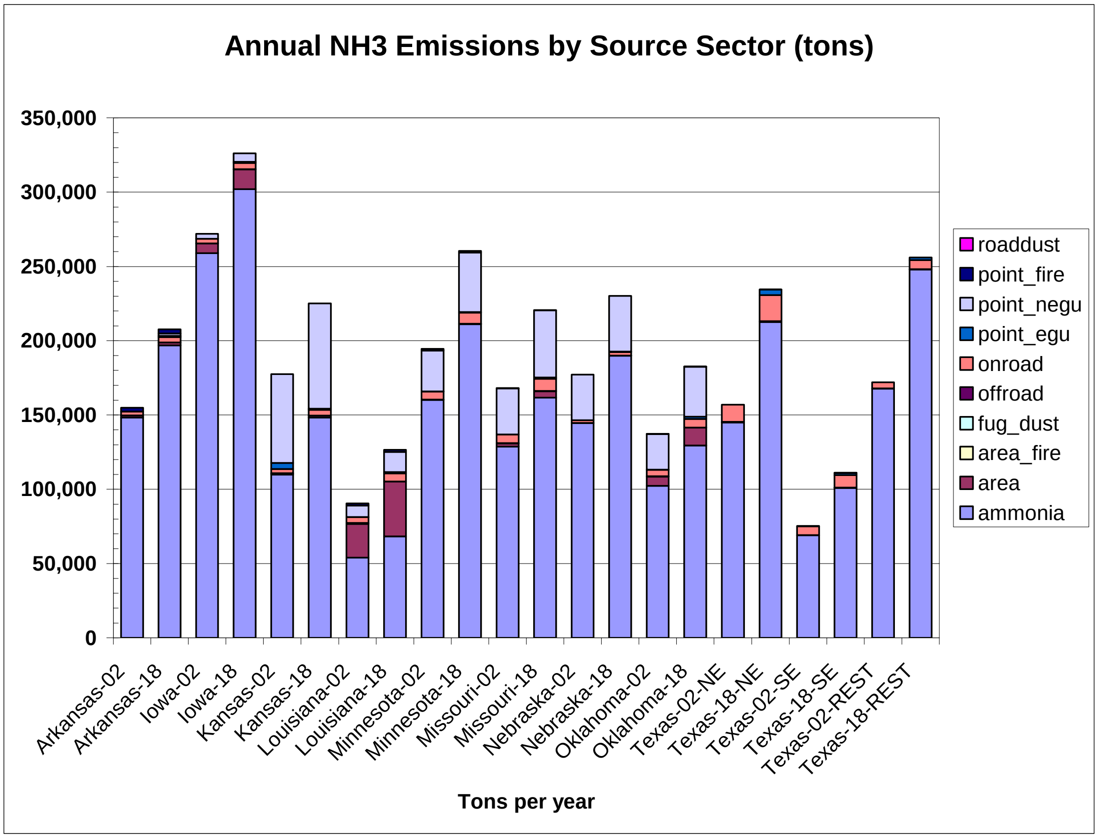


Figure 2-8. Summary of Typ02G and Base18G NH3 emissions by CENRAP state and major source sector (tons per year).

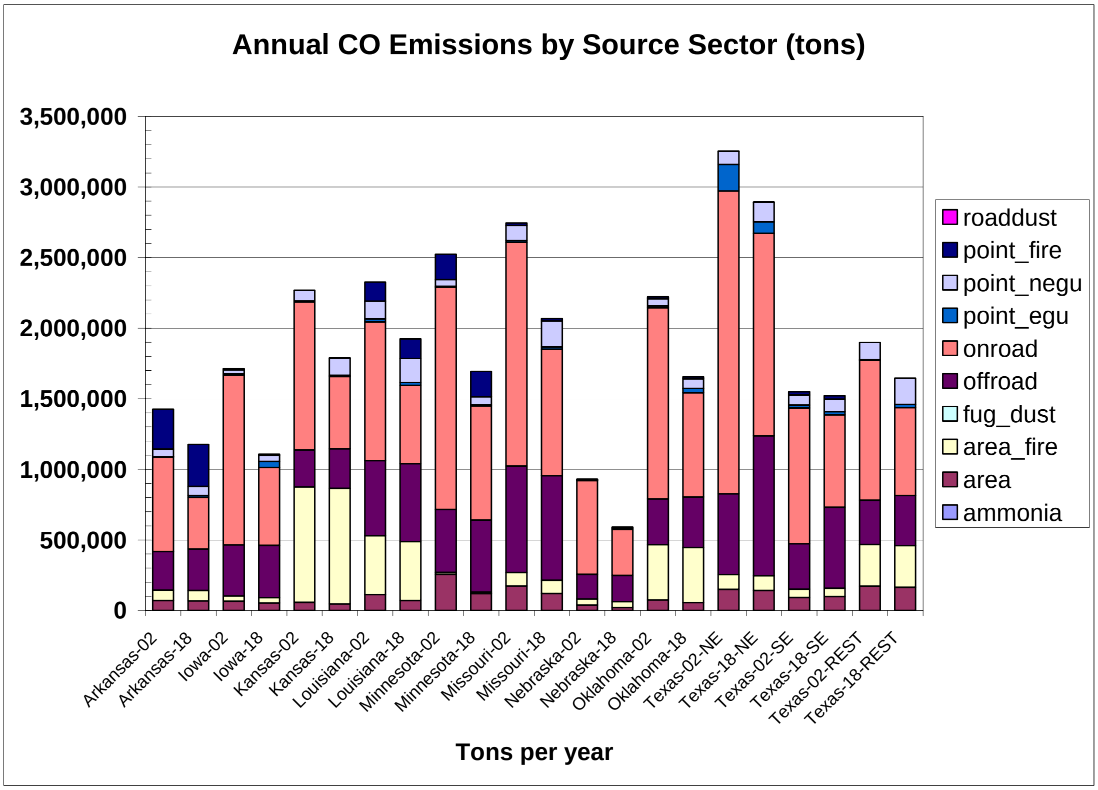


Figure 2-9. Summary of Typ02G and Base18G CO emissions by CENRAP state and major source sector (tons per year).

3.0 MODEL PERFORMANCE EVALUATION

In this Chapter we summarize the CMAQ model performance for the final 2002 36 km Base F base case simulation. Because the 2002 Base F CMAQ simulation produced nearly identical results in the U.S. as the final 2002 Base G simulation and limited resource availability, CENRAP elected not to redo the model evaluation for the 2002 Base G case. This model performance focuses on the ability of the model to predict PM species within the CENRAP region. Details on the model performance are provided in Appendix C. Previously we have documented model performance of interim versions of model base case simulations in reports (Morris et al., 2005) and presentations to the CENRAP Work Groups and POG (e.g., Morris et al., 2006a,b).

3.1 Evaluation Methodology

EPA's integrated ozone, $PM_{2.5}$ and regional haze modeling guidance calls for a comprehensive, multi-layered approach to model performance testing, consisting of the four major components: operational, diagnostic, mechanistic (or scientific) and probabilistic (EPA, 2007). The CMAQ model performance evaluation effort focused on the first two components, namely:

- **Operational Evaluation**: Tests the ability of the model to estimate PM concentrations (both fine and coarse) and the components at PM_{10} and $PM_{2.5}$ including the quantities used to characterize visibility (i.e., sulfate, nitrate, ammonium, organic carbon, elemental carbon, other $PM_{2.5}$, and coarse matter ($PM_{2.5-10}$). This evaluation examines whether the measurements are properly represented by the model predictions but does not necessarily ensure that the model is getting "the right answer for the right reason"; and

- **Diagnostic Evaluation:** Tests the ability of the model to predict visibility and extinction, PM chemical composition including PM precursors (e.g., SOx, NOx, and NH_3) and associated oxidants (e.g., ozone and nitric acid); PM size distribution; temporal variation; spatial variation; mass fluxes; and components of light extinction (i.e., scattering and absorption).

In this final model performance evaluation for the 2002 Typical Base F CMAQ simulation, the operational evaluation has been given the greatest attention since this is the primary thrust of EPA's modeling guidance. However, we have also examined certain diagnostic features dealing with the model's ability to simulate sub-regional, monthly, diurnal, gas phase and aerosol concentration distributions. In the course of the CENRAP air quality modeling and other modeling processes, numerous diagnostic sensitivity tests were performed to investigate and improve model performance. Key diagnostic tests that were performed and the results are discussed on the CENRAP modeling website: http://pah.cert.ucr.edu/aqm/cenrap/index.shtml.

3.2 Ambient Air Quality Data used in the Evaluation

The ground-level model evaluation database for 2002 was compiled by the modeling team using several routine and research-grade databases. The first is the routine gas-phase concentration measurements for ozone, SO_2, NO_2 and CO archived in EPA's Aerometric Information Retrieval System (AIRS) Air Quality System (AQS) database. Other sources of observed information come from the various PM monitoring networks in the U.S. These include the Interagency Monitoring of Protected Visual Environments (IMPROVE); Clean Air Status and Trends Network (CASTNET); EPA Speciation Trends Network (STN) of $PM_{2.5}$ species; and National Acid Deposition Program (NADP). During the course of the CENRAP modeling, the numerous base case simulations were evaluated across the continental U.S. (e.g., Morris et al., 2005). In this section and in Appendix C we focus our evaluation on model performance within the CENRAP region.

3.2 Operational Model Evaluation Approach

The CENRAP modeling databases will be used to develop the visibility State Implementation Plan (SIP) as required by the Regional Haze Rule (RHR). Accordingly, the primary focus of the operational evaluation in this report is on the six components of fine particulate ($PM_{2.5}$) and coarse mass ($PM_{2.5-10}$) within the CENRAP region that are used to characterize visibility at Class I areas:

- Sulfate (SO4);
- Particulate Nitrate (NO3);
- Elemental Carbon (EC);
- Organic Mass Carbon (OMC);
- Other inorganic fine particulate (IP or Soil); and
- Coarse Mass (CM).

The model performance for ozone, precursors, and product species (e.g., SO_4 , NO_3, NH_4 and HNO_3) is also evaluated to build confidence that the modeling system is sufficiently reliable to project future-year visibility.

3.3 Model Performance Goals and Criteria

The issue of model performance goals for PM species is an area of ongoing research and debate. For ozone modeling, EPA has established performance goals for 1-hour ozone: normalized mean bias and gross error of #±15% and #35%, respectively (EPA, 1991). EPA's draft fine particulate modeling guidance notes that performance goals for ozone should be viewed as upper bounds of model performance that PM models may not be able to always achieve and that we should demand better model performance for PM components that make up a larger fraction of the PM mass than those that are minor contributors (EPA, 2001). EPA's final modeling guidance does not list any specific model performance goals for PM and visibility modeling and instead provides a summary of PM model performance across several historical applications that can be used for comparisons, if desired. Measuring PM species is not as precise as ozone monitoring. In fact, the uncertainty in measurement techniques for some PM species is likely to exceed the more stringent model performance goals, such as those for ozone. For example, recent comparisons of the PM species measurements using the IMPROVE and STN measurement technologies found uncertainties of approximately ∀20% (SO4) to ∀50% (EC) (Solomon et al., 2004).

For the CENRAP modeling we have adopted three levels of model performance goals and criteria for bias and gross error as listed in Table 3-1. Note that we are not suggesting that these performance goals be adopted as guidance. Rather, we are just using them to frame and put the PM model performance into context and to facilitate model performance intercomparison across episodes, species, models and sensitivity tests.

Table 3-1. Model performance goals and criteria used to assist in interpreting modeling results.

Fractional Bias	Fractional Gross Error	Comment
#∀15%	#35%	Ozone model performance goal for which PM model performance would be considered "good" – note that for many PM species measurement uncertainties may exceed this goal.
#∀30%	#50%	Proposed PM model performance goal that we would hope each PM species could meet
#∀60%	#75%	Proposed PM criteria above which indicates potential fundamental problems with the modeling system.

As noted in EPA's PM modeling guidance, less abundant PM species should have less stringent performance goals (EPA, 2001; 2007). Accordingly, we are also using performance goals that are a continuous function of average concentrations, as proposed by Dr. James Boylan at the Georgia Department of Natural Resources (GA DNR), that have the following features (Boylan, 2004):

- Asymptotically approaching proposed performance goals or criteria (i.e., the ∀30%/50% and ∀60%/75% bias/error levels listed in Table 3-1) when the mean of the observed concentrations are greater than 2.5 ug/m^3.

- Approaching 200% error and ∀200% bias when the mean of the observed concentrations are extremely small.

Bias and error are plotted as a function of average concentrations. As the mean concentration approaches zero, the bias performance goal and criteria flare out to ∀200% creating a horn shape, hence the name "Bugle Plots". Dr. Boylan has defined three Zones of model performance: Zone 1 meets the ∀30%/50% bias/error performance goal and is considered "good" model performance; Zone 2 lies between the ∀30%/50% performance goal and ∀60%/75% performance criteria and is an area where concern for model performance is raised; and Zone 3 lies above the ∀60%/75% performance criteria and is an area of questionable model performance.

3.4 Key Measures of Model Performance

Although we have generated numerous statistical performance measures (see Table C-2 in Appendix C) that are available on the CENRAP modeling website, when comparing model performance across months, subdomains, networks, grid resolution, models, studies, etc. it is useful to have a few key measurement statistics to be used to facilitate the comparisons. It is also useful to have a subset of months within the 2002 year that can represent the entire year so that a more focused evaluation can be conducted. We have found that the Mean Fractional Bias and Mean Fractional Gross Error appear to be the most consistent descriptive measure of model performance (Morris et al., 2004b; 2005). The Fractional Bias and Error are normalized by the average of the observed and predicted value (see Table C-2) because it provides descriptive power across different magnitudes of the model and observed concentrations and is bounded by -200% to +200%. This is in contrast to the normalized bias and error (as recommended for ozone performance goals, EPA, 1991) that is normalized by just the observed value so can "blow up" to infinity as the observed value approaches zero. In Appendix C we perform a focused evaluation of model performance for PM and gaseous species and four months of the 2002 year that are used to represent the seasonal variation in performance:

- January
- April
- July
- October

Scatter plots of model predictions and observations for each PM species are presented for each of the four months along with performance statistics and predicted and observed time series plots at each CENRAP Class I area. Summary plots of monthly fractional bias and error are also presented.

3.5 Operational Model Performance Evaluation

A summary of the operational evaluation is presented below. Just the monthly fractional bias performance metrics for each PM species using bar charts and Bugle Plots are presented in this section. The reader is referred to Appendix C for the complete model performance evaluation.

3.5.1 Sulfate (SO4) Model Performance

Figure 3-1 compares the monthly SO4 fractional bias across the CENRAP region for the IMPROVE, STN and CASTNet monitoring networks. An underprediction bias is clearly evident the first 8-10 months of the year. This underestimation bias is greatest across the CASTNet network which persists throughout the year. The SO4 underprediction is not as severe for the STN network and it is minimal by August becoming a slight overprediction in September. For the IMPROVE network, the SO4 fractional bias is < ±20% for the first 2 and last 3 months of the year and ranges from -30% to -50% for the late Spring and Summer months.

Figure 3-1 also includes a Bugle Plot of monthly SO4 fractional bias statistics (for Bugle Plot of fractional gross error see Appendix C) and compares them against the proposed PM model performance goal and criteria (see Table 3-1). For the STN network, SO4 model performance meets the proposed performance goal for all months. For the IMPROVE network, approximately half of the months achieve the proposed PM performance goal with the other half outside of the goal, but within the performance criteria. Across the CASTNet network, most months are outside of the proposed goal but are within the criteria. The CASTNet fractional bias for some months is right at the performance criteria (≤±60%). With the exception of two IMPROVE months, the monthly SO4 fractional bias performance statistics achieve the proposed PM model performance goal.

3.5.2 Nitrate (NO3) Model Performance

Monthly NO3 model performance across the CENRAP region is characterized by a summer underestimation and winter overestimation bias (Figure 3-2). The summer underestimation bias is more severe, exceeding -100%. Whereas, the winter overestimation bias is approximately 50%. So based on statistics alone, it appears the summer underestimation bias is a bigger concern than the winter overestimation bias. However, the Bugle Plots in the bottom part of Figure 3-2 show that the summer underestimation bias occurs when NO3 is very low and is not an important component of PM and visibility impairment. These summer values occur in the flared horn part of the Bugle Plot and the summer NO3 performance, in most cases, achieves the model performance goal and always achieves the performance criteria. Whereas, the winter overstated NO3 performance for the most part doesn't meet the performance goal and there are some months/networks that also don't meet the performance criteria.

3.5.3 Organic Matter Carbon (OMC) Model Performance

The OMC monthly fractional bias across IMPROVE and STN sites in the CENRAP region are shown in Figure 3-3. The fractional bias for OMC at the IMPROVE sites is quite good throughout the year with values generally within ±20%, albeit with a slight winter overestimation and summer underestimation bias. At the urban STN sites, the model exhibits an underestimation bias throughout the year that ranges from -20% to -50%. The urban underestimation of OMC is a fairly common occurrence and suggests there may be missing sources of organic aerosol emissions in the modeling inventory.

The good performance of the model for OMC at the IMPROVE sites is also reflected in the Bugle Plot (Figure 3-3, bottom) with the bias achieving the proposed PM model performance goal for all months of the year. At the STN sites, however, the OMC bias falls between the proposed PM model performance goal and criteria, with error right at the goal for most months.

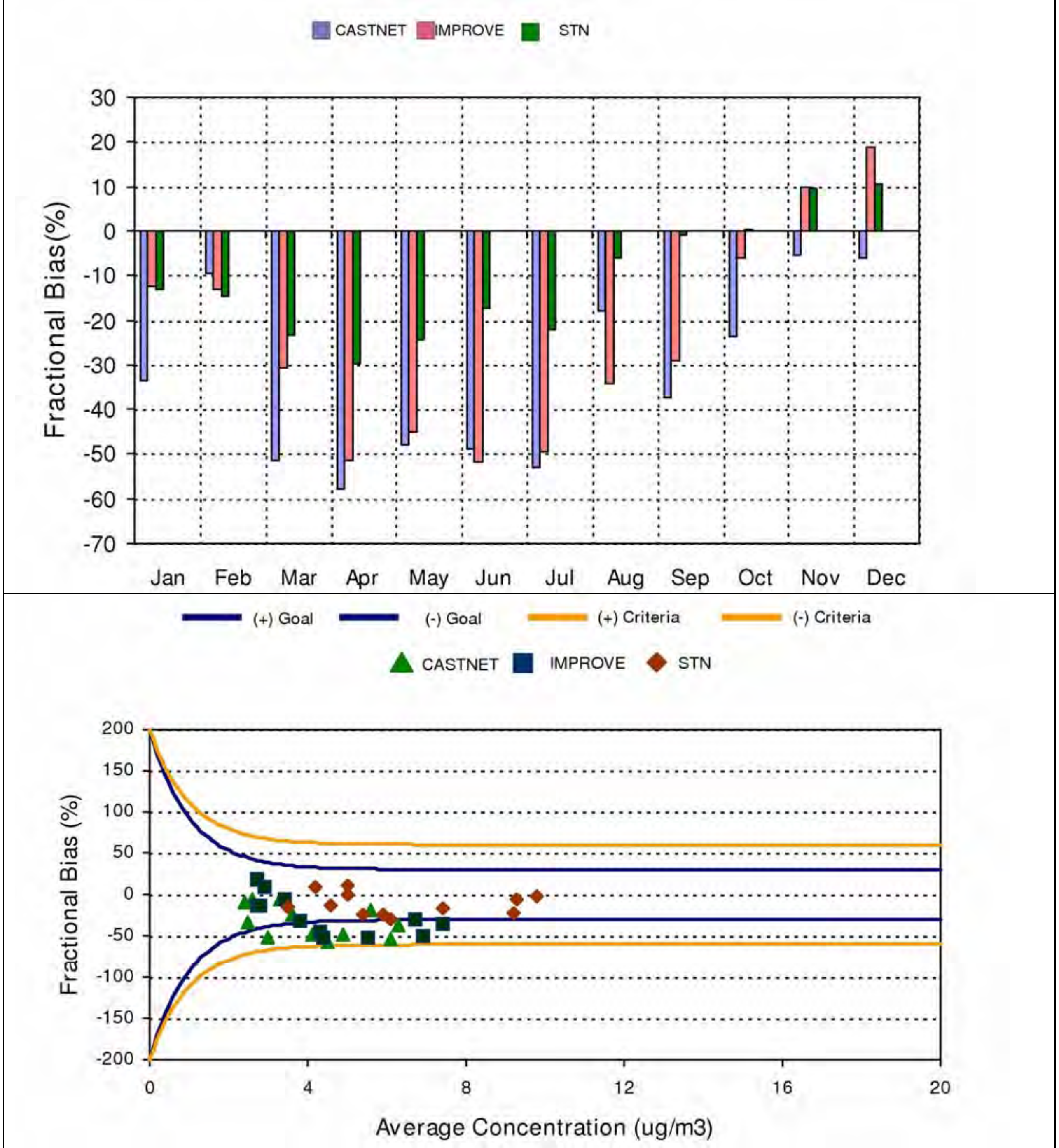


Figure 3-1. Monthly fractional bias (%) for sulfate (SO4) across the CENRAP region for the CMAQ 2002 36 km Base F base case simulation.

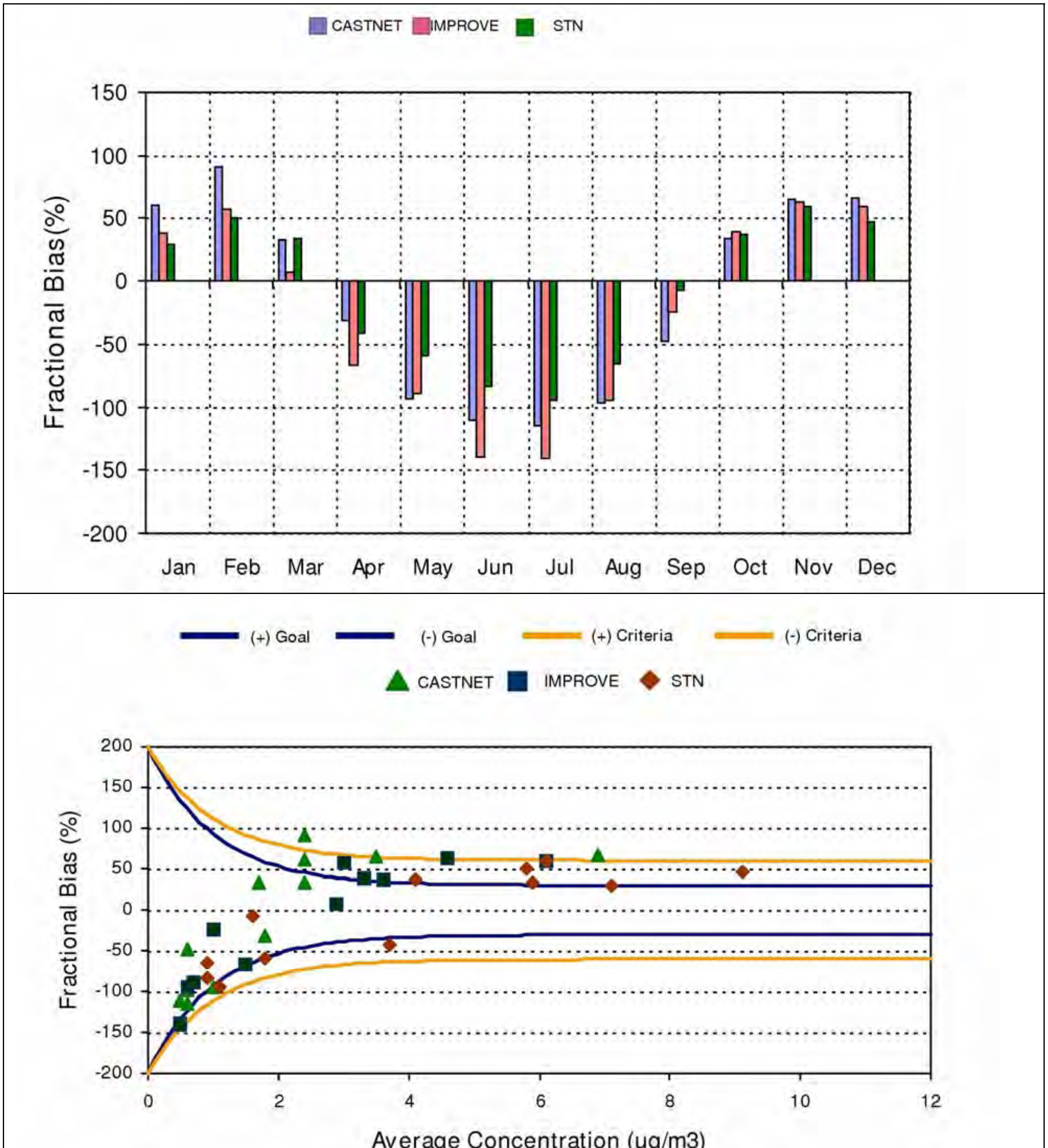


Figure 3-2. Monthly fractional bias (%) for nitrate (NO3) across the CENRAP region for the CMAQ 2002 36 km Base F base case simulation.

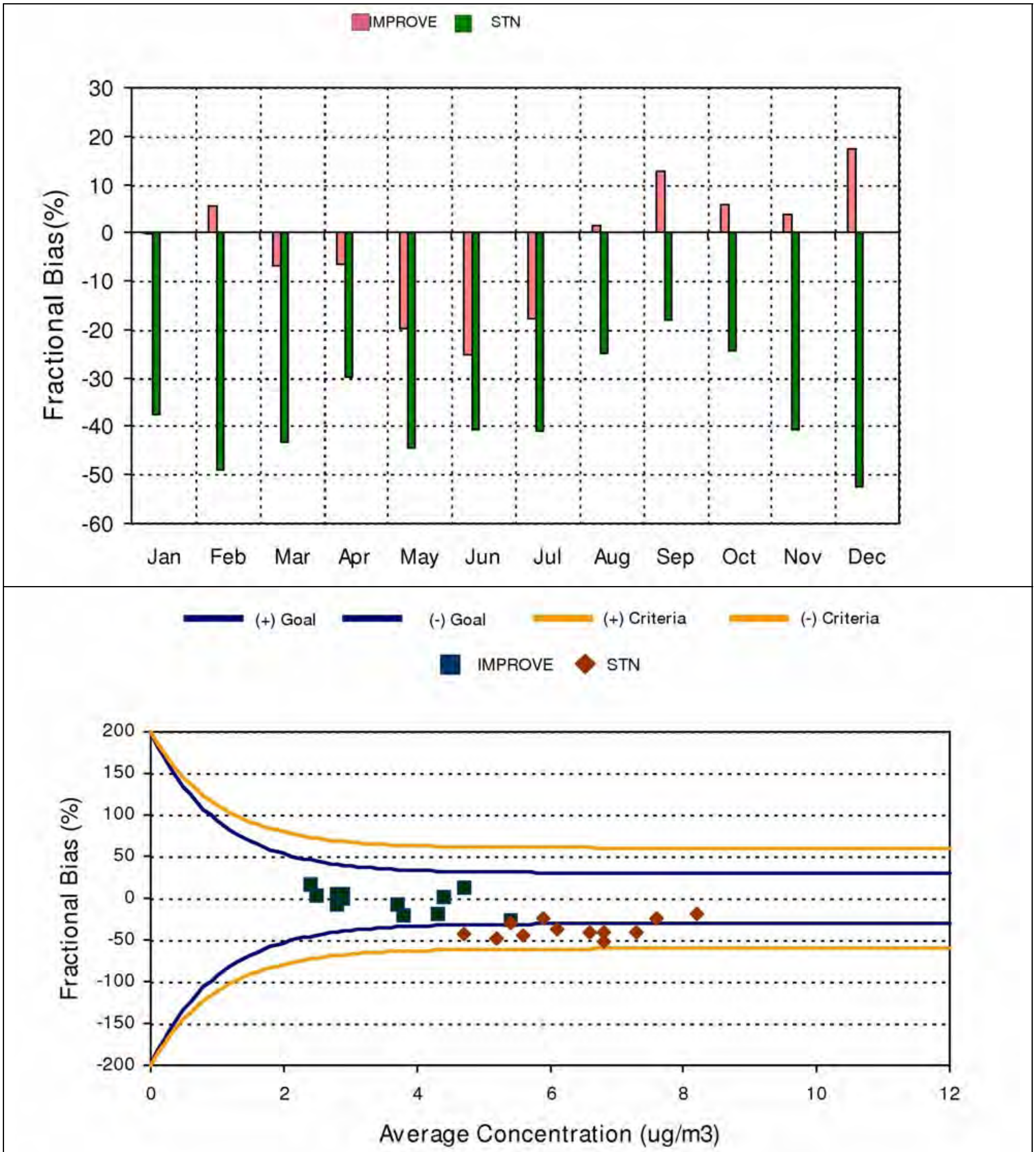


Figure 3-3. Monthly fractional bias (%) for organic matter carbon (OMC) across the CENRAP region for the CMAQ 2002 36 km Base F base case simulation.

3.5.4 Elemental Carbon (EC) Model Performance

The monthly average bias for EC across the IMPROVE and STN monitors in the CENRAP region are shown in Figure 3-4. The STN network exhibits small fractional bias year round, whereas the IMPROVE monitoring network exhibits a large underprediction bias in the summer months (-40% to -70%) and much smaller bias in the winter. The Bugle Plot puts the EC performance in context. The low EC concentrations at the IMPROVE sites results in bias values in the horn of the Bugle Plot. Thus, EC bias achieves the proposed PM performance goal for all months of the year.

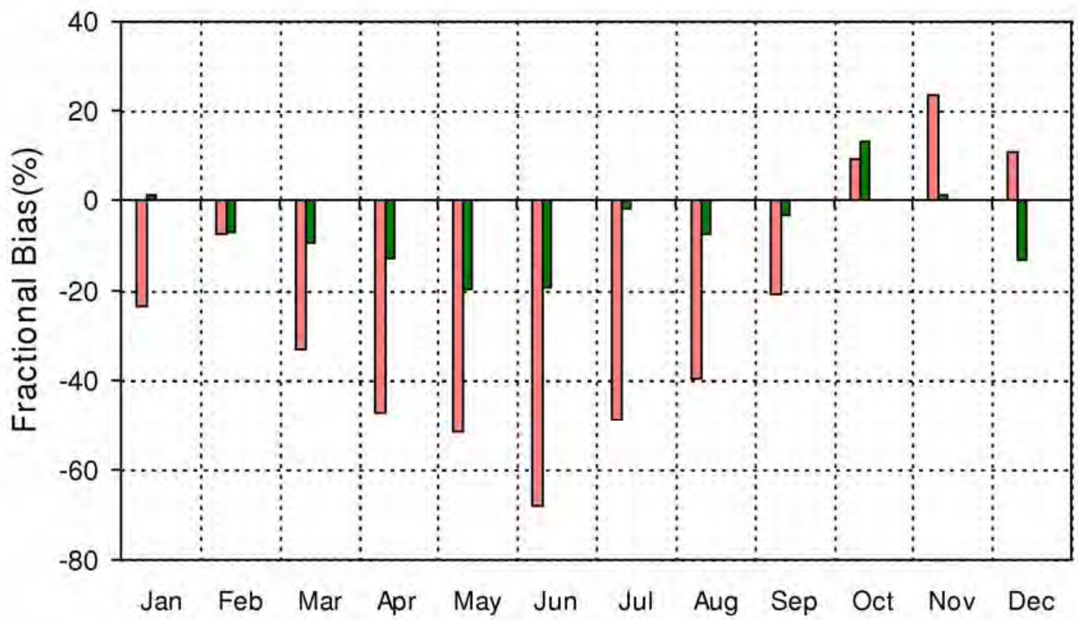
3.5.5 Other $PM_{2.5}$ (Soil) Model Performance

Figure 3-5 displays the monthly variation in the Soil fractional bias using IMPROVE measurements in the CENRAP region. During the winter months, the model exhibits a very large (> 100%) overestimation bias. With the exception of July, the summer monthly bias is toward a slight overprediction but generally less than 20%. The July underestimation bias appears to be driven by impacts of high Soil values from wind blown dust events (e.g., see July 2002 discussion in Appendix C). The Bugle Plot indicates that the summer Soil performance achieves the PM performance goal, a few months in the Spring/Fall period fall between the performance goal and criteria and the winter Soil performance exceeds the model performance criteria. Thus, the Soil performance is a cause for concern.

3.5.6 Coarse Mass (CM) Model Performance

The monthly average fractional bias values for CM are shown in Figure 3-6. In the winter the underprediction bias is typically in the -60% to -80% range. In the late Spring and Summer the underprediction bias ranges from -120% to -160%. As this underprediction bias is nearly systematic (i.e., an underprediction almost always occurs), then the fractional errors are the same magnitude as the bias.

The Bugle Plots clearly show that the CM model performance is a problem. The monthly bias exceeds both the performance goal and criteria for almost every month of the year.



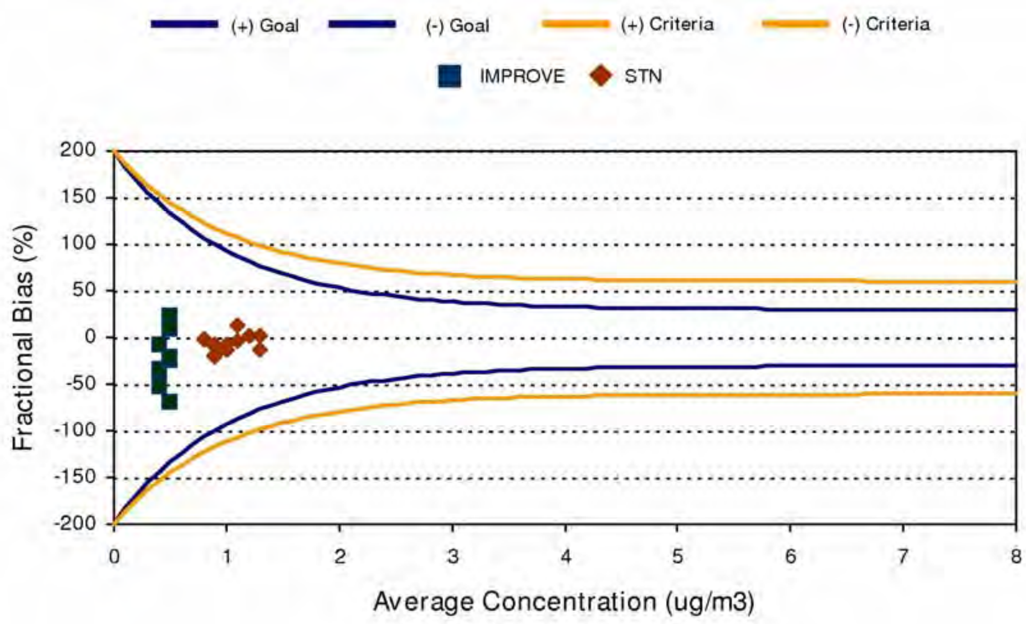


Figure 3-4. Monthly fractional bias (%) for elemental carbon (EC) across the CENRAP region for the CMAQ 2002 36 km Base F base case simulation.

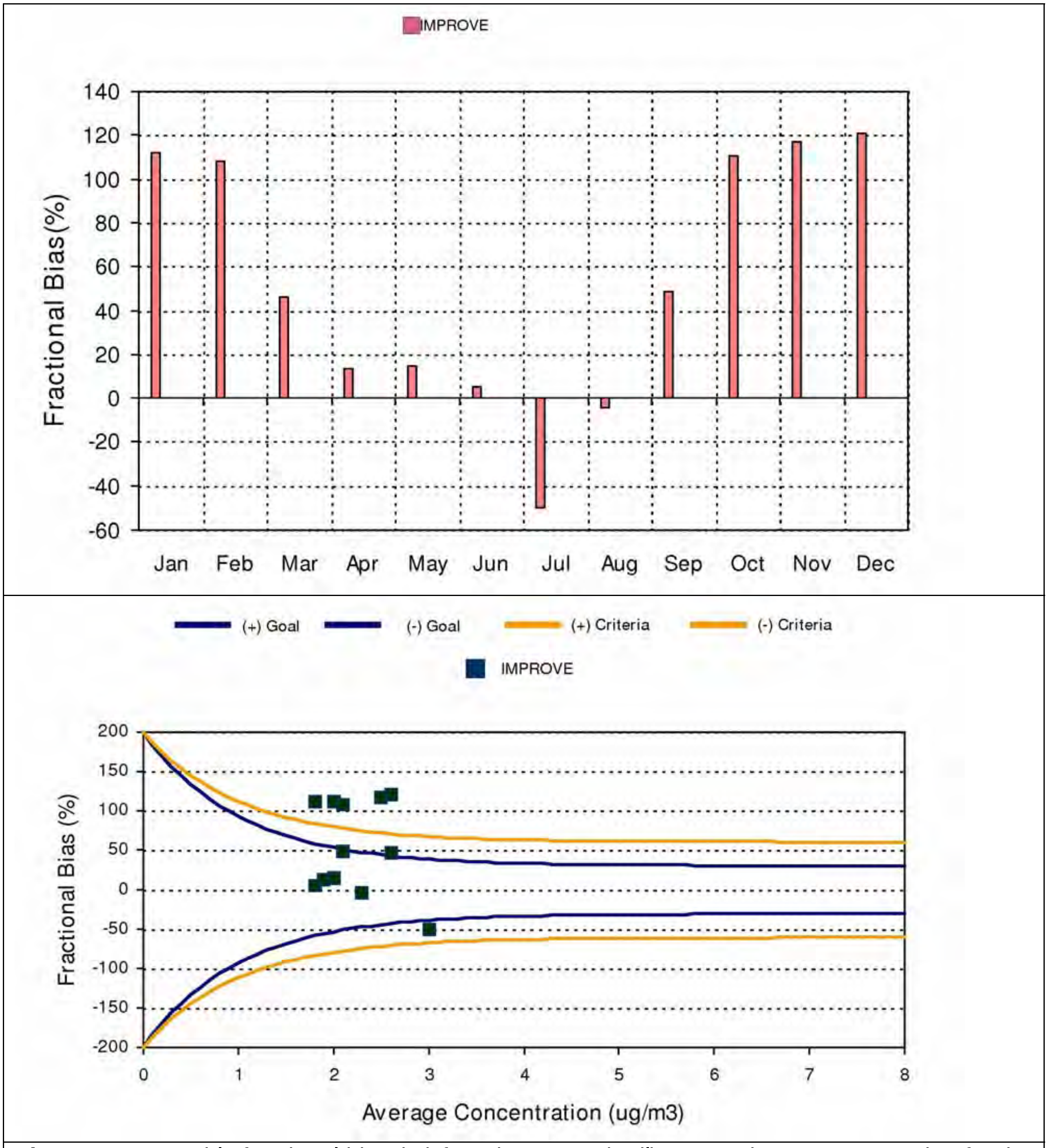


Figure 3-5. Monthly fractional bias (%) for other $PM_{2.5}$ (Soil) across the CENRAP region for the CMAQ 2002 36 km Base F base case simulation.

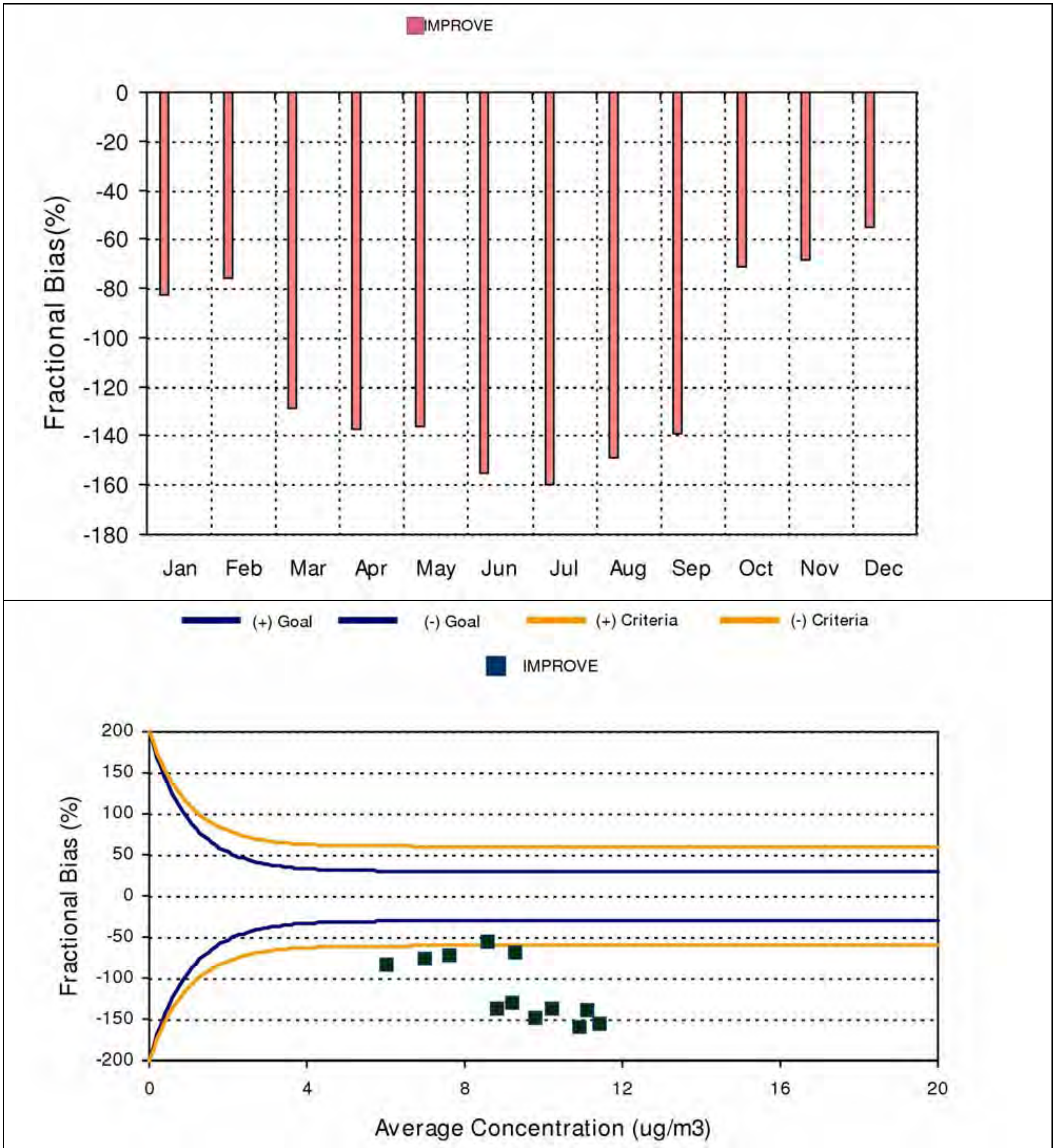


Figure 3-6. Monthly fractional bias (%) for coarse mass (CM) across the CENRAP region for the CMAQ 2002 36 km Base F base case simulation.

3.6 Diagnostic Model Performance Evaluation

The CASTNet and AQS networks also measure gas-phase species that are PM precursor or related species. The diagnostic evaluation of the 2002 36 km Base F CMAQ base case simulation for these compounds and the four seasonal months are presented in Appendix C. The displays for January are provided below as an example; the reader is referred to Appendix C for the rest of the monthly displays.

The CASTNet network measures weekly average samples of SO2, SO4, NO2, HNO3, NO3 and NH4. The AQS network collects hourly measurements of SO2, NO2, O3 and CO. A comparison of the SO2 and SO4 performance provides insight into whether the SO4 formation rate may be too slow or fast. For example, if SO4 is underestimated and SO2 is overestimated that may indicate chemical conversion rates that are too slow. Analyzing the performance for SO4, HNO3, NO3, Total NO3 and NH4 provides insight into the equilibrium of these species. For example, if Total NO3 performs well but HNO3 and NO3 do not, then there may be issues associated with the partitioning between the gaseous and particulate phases of nitrate. Causes for incorrect HNO3/NO3 partitioning could include inadequate ammonia emissions and/or poorly characterized meteorological conditions (e.g., temperature).

3.6.1 Diagnostic Model Performance in January 2002

In January, SO2 is overstated across both the CASTNet and AQS sites with fractional bias values of 38% (Figure 3-7) and 31% (Figure 3-8), respectively. SO4 is understated by -34% across the CASTNet monitors (Figure 3-7) and -12% and -13% for the IMPROVE and STN networks (Figure C-4a). Wet SO4 deposition is also overstated in January (+40%, Figure C-4a). Given that SO2 emissions are well characterized, these results suggest that the January SO4 underestimation may be partly due to understated transformation rates of SO2 to SO4 and overstated wet SO4 deposition.

Total NO3 is overestimated by 35% on average across the CASTNet sites in the CENRAP region in January (Figure 3-7). HNO3 is underestimated (-34%) and particle NO3 is overestimated (+61%) suggesting there are gas/particle equilibrium issues. An analysis of the time series of the four CASTNet stations reveals that NO3, HNO3 and NH4 performance is actually very reasonable at the west Texas site and the HNO3 underestimation and NO3 overestimation bias is coming from the east Kansas, central Arkansas and northern Minnesota CASTNet sites (see Figure C-3 for site locations). One potential contributor for this performance problem could be overstated NH3 emissions. However, the Total NO3 overestimation bias suggests that the model estimated NOx oxidation rate may be too high in January.

The SO2, NO2, O3 and CO performance across the AQS sites in January is shown in Figure 3-8. The AQS monitoring network is primarily an urban-oriented network. So, it is not surprising that the model is underestimating concentrations of primary emissions when a 36 km grid is used. NO2 is underestimated by approximately 5%, and CO by approximately 67%. Ozone is also underestimated on average, especially the maximum values above 60 ppb.

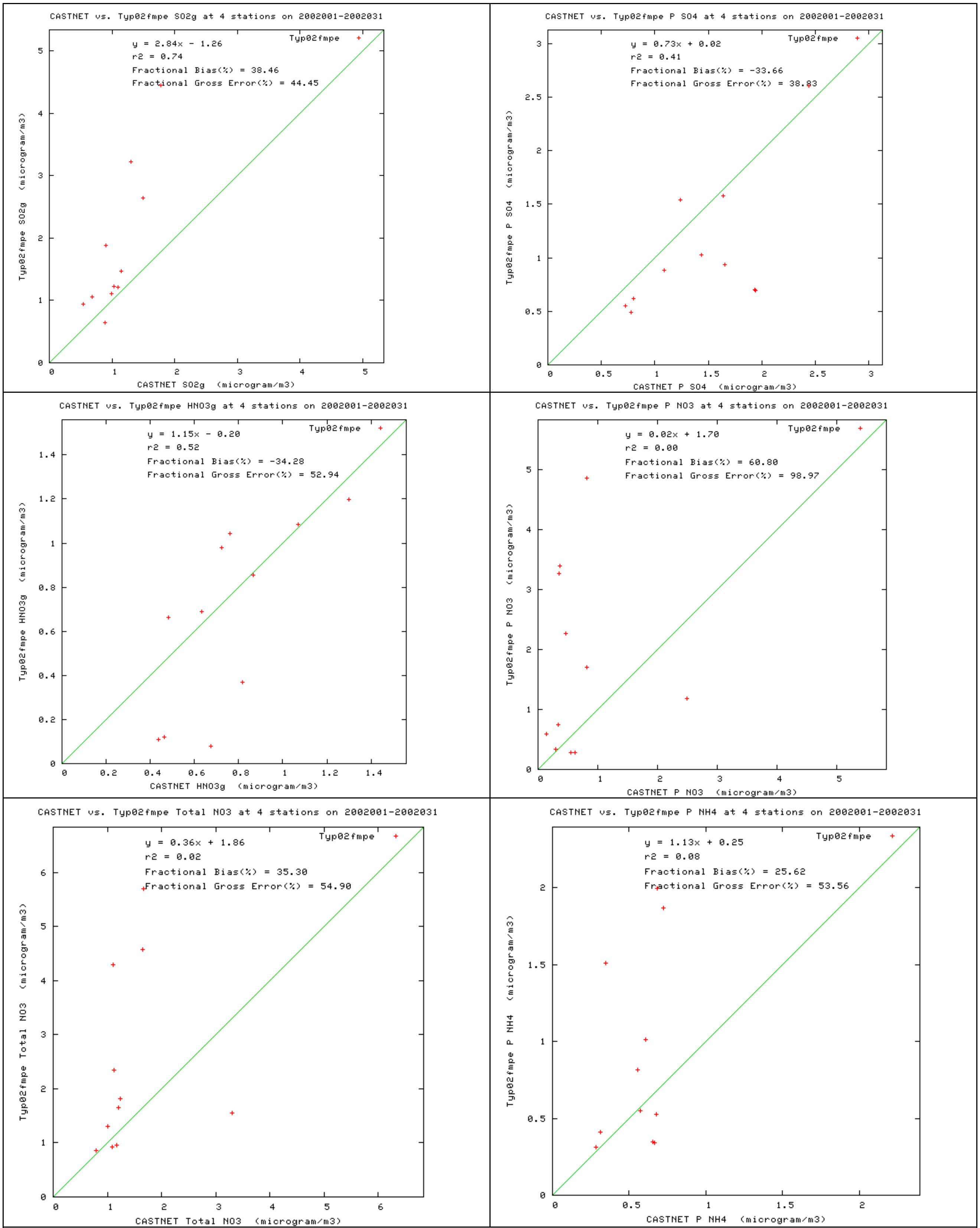


Figure 3-7. January 2002 performance at CENRAP CASTNet sites for SO2 (top left), SO4 (top right), HNO3 (middle left), NO3 (middle right), Total NO3 (bottom left) and NH4 (bottom right).

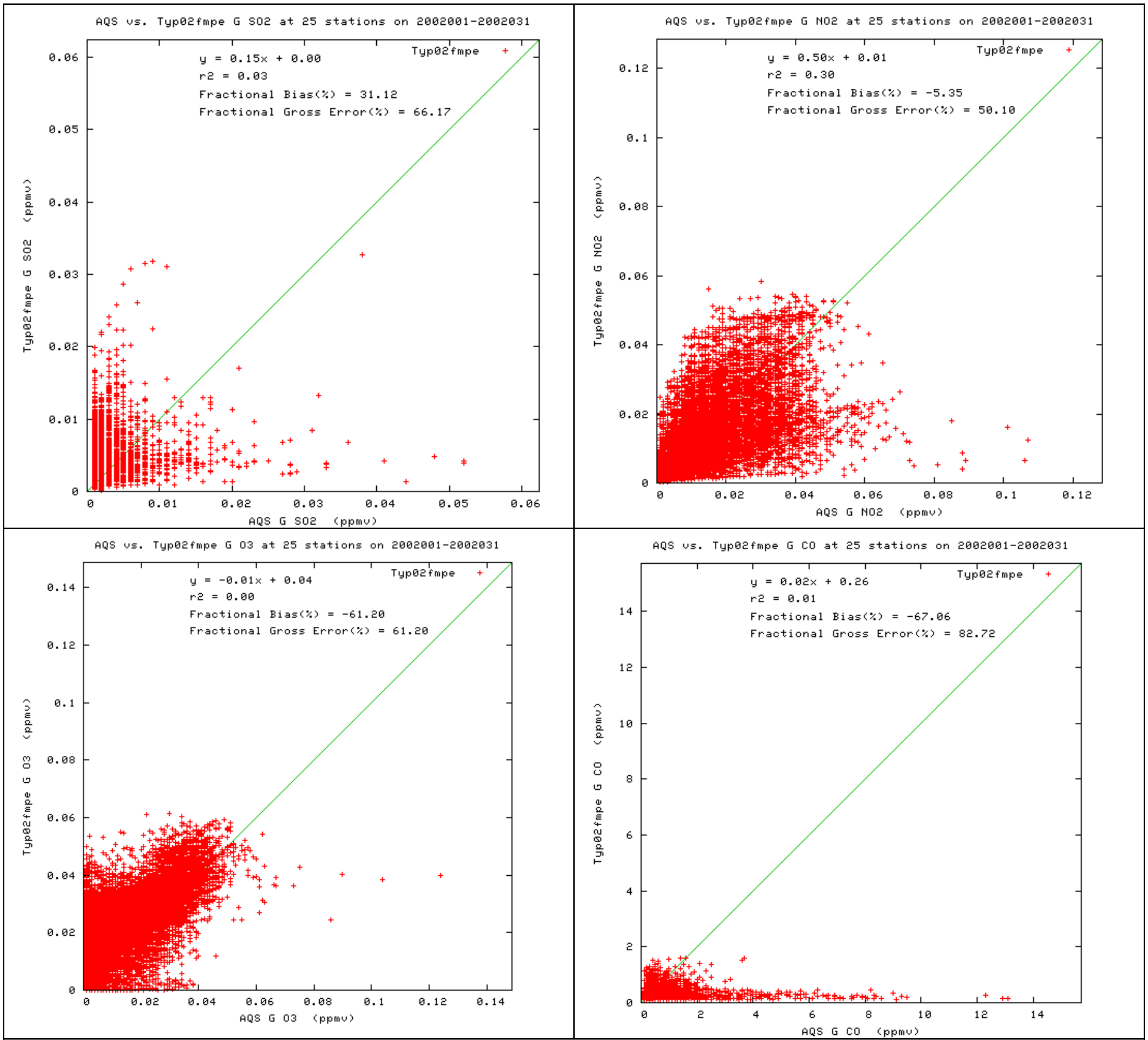


Figure 3-8. January 2002 performance at CENRAP AQS sites for SO2 (top left), NO2 (top right), O3 (bottom left) and CO (bottom right).

3.6.2 Diagnostic Model Performance In April

In April there is an average SO2 overestimation bias across the CASTNet (+15%) and underestimation bias across the AQS (-10%) networks (Figures C-42 and C-43). SO4 is underestimated across all networks by -30% to -58% (Figure C-5a). The wet SO4 deposition bias is near zero. Both SO2 and SO4 are underestimated at the west Texas CASTNet monitor in April suggesting SO2 emissions in Mexico are likely understated.

The HNO3 performance in April is interesting with almost perfect agreement except for 5 modeled-observed comparisons that drives the average underprediction bias of -29% (Figure C-42). On Julian Day 102 there is high HNO3 at the MN, KS and OK CASTNet sites that is not captured by the model. Given that HNO3, NO3 and Total NO3 are all underestimated by about the same amount (-30%), then part of the underestimation bias is likely due to too slow oxidation of NOx.

There is a lot of scatter in the NO2 and O3 performance that is more or less centered on the 1:1 line of perfect agreement with bias values of -8% and -21%, respectively (Figure C-43). CO is underestimated by -72% with the model unable to predict CO concentrations above 1 ppm due to the use of the coarse 36 km grid spacing. Mobile sources produce a vast majority of the CO emissions. So, AQS monitors for CO compliance are located near roadways, which are not simulated well using a 36 km grid.

3.6.3 Diagnostic Model Performance In July

In July SO2 is slightly underestimated across the CASTNet (-5%) and AQS (-12%) networks (Figures C-44 and C-45). SO4 is more significantly underestimated across all networks (-22% to -53%, as shown in Figure C-6a). Since wet deposition SO4 is also underestimated, it is unclear why all sulfur species are underestimated.

The nitrate species are also all underestimated with the Total NO3 bias (-56%) being between the HNO3 bias (-35%) and NO3 bias (-115%). The modeled NO3 values are all near zero with little correlation with the observations, whereas the observed HNO3 and Total NO3 is tracked well with correlation coefficients of 0.74 and 0.76. These results suggest that the July NO3 model performance problem is partly due to insufficient formation of Total NO3, but mainly due to incorrect partitioning of the Total NO3.

Again, there is abundant scatter in the AQS NO2 scatter plot for July (Figure C-45) resulting in a low bias (0%) but high error (65%). Ozone performance also exhibits a low bias (-15%) and error (20%), but the model is incapable of simulating ozone above 100 ppb. Although CO performance in July is better than the previous months, it still has a large underestimation bias of 82%.

3.6.4 Diagnostic Model Performance In October

SO2 is overstated in October across the CASTNet (+28%) and AQS (+33%) sites (Figures C-46 and C-47). Although SO4 is understated across the CASTNet sites (-24%), the bias across the IMPROVE (-6%) and STN (0%) sites are near zero (Figure C-7a).

Performance for HNO3 is fairly good with a low bias (+12%) and error (30%). But NO3 is overstated (+34%) leading to an overstatement of Total NO3 (+37%). The overstatement of NO3 leads to an overstatement of NH4 as well (Figure C-46)

As seen in the other months, NO2 exhibits a lot of scatter resulting in a low correlation (0.22) and high error (61%) but low bias (12%). The model tends to underpredict the high and overpredict the low O3 observations resulting in a -29% bias and low correlation coefficient. CO is also underpredicted (-76%) for the reasons discussed previously.

3.7 Performance at CENRAP Class I Areas for the Worst and Best 20 Percent Days

In this section, and in section C.5 of Appendix C, we present the results of the model performance evaluation at each of the CENRAP Class I areas for the worst and best 20 percent days. Performance on these days is critical since they are the days used in the 2018 visibility projections discussed in Chapter 4. For each Class I area we compared the predicted and observed extinction of the worst and best 20 percent days below. In Appendix C the PM species-specific extinction is also compared for the worst 20 percent days.

3.7.1 Caney Creek (CACR) Arkansas

The ability of the CMAQ model to estimate visibility extinction at the CACR Class I area on the 2002 worst and best 20 percent days is provide in Figures 3-9 and C-48. On most of the worst 20 percent days at CACR total extinction is dominated by SO4 extinction with some extinction due to OMC. On four of the worst 20 percent days extinction is dominated by NO3. The average extinction across the worst 20 percent days is underestimated by -33% (Figure 3-9), which is primarily due to a -51% underestimation of SO4 extinction combined with a 6% overestimation of NO3 extinction (Figure C-48). Performance for OMC extinction at CACR on the worst 20 percent days is pretty good with a -20% bias and 36% error. EC extinction is systematically underestimated. Soil extinction has low bias (-19%) buts lots of scatter and high error (74%), while CM extinction is greatly underestimated (bias of -153%).

On the best 20 percent days at CACR the observed extinction ranges from 20 to 40 Mm^{-1}. Whereas, the modeled extinction has a much larger range from 15 to 120 Mm^{-1}. Much of the modeled overestimation of total extinction on the best 20% days (+44% bias) is due to NO3 overestimation (+94% bias).

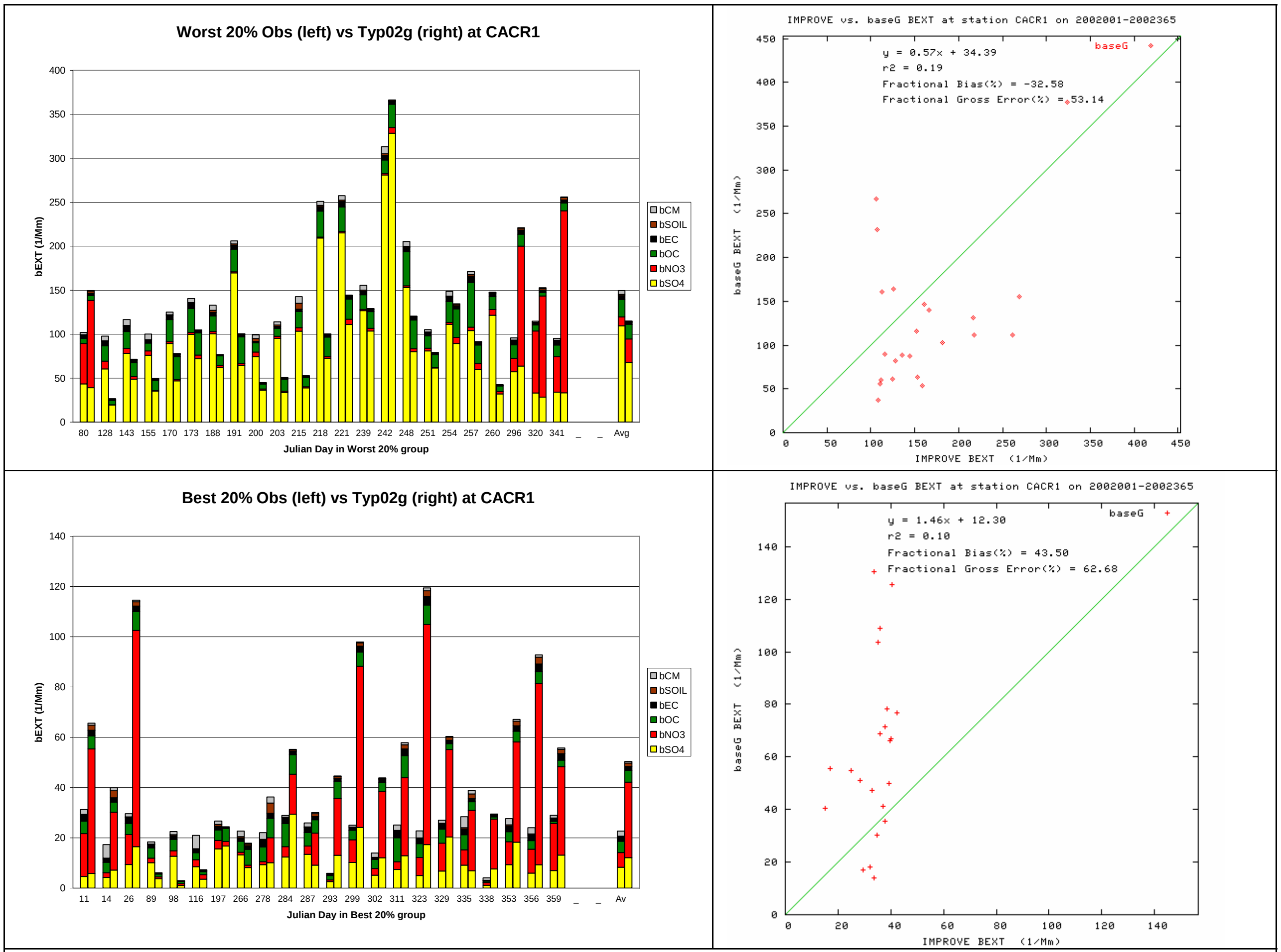


Figure 3-9. Daily extinction model performance at Caney Creek (CACR), Arkansas for the worst (top) and best (bottom) 20 percent days during 2002.

3.7.2 Upper Buffalo (UPBU) Arkansas

Model performance at the UPBU Class I area for the worst and best 20 percent days is shown in Figures 3-10 and C-49. On most of the worst 20 percent days at UPBU, visibility impairment is dominated by SO4, although there are also two high NO3 days. The model underestimates the average of the total extinction on the worst 20 percent days at UPBU by -40% (Figure 3-10), which is due to an underestimation of extinction due to SO4, OMC and CM by -46%, -33% and -179%, respectively.

On the best 20 percent days at UPBU, the model performs reasonably well with a low bias (2%) and error (42%). But again, the model has a much wider range in extinction values across the best 20 percent days (15 to 120 Mm^{-1}) than observed (20 to 45 Mm^{-1}). There are five days in which the modeled NO3 overprediction is quite severe and when those days are removed the range in the modeled and observed extinction on the best 20 percent days is quite similar to the observed, although the model gets much cleaner on the very cleanest modeled days.

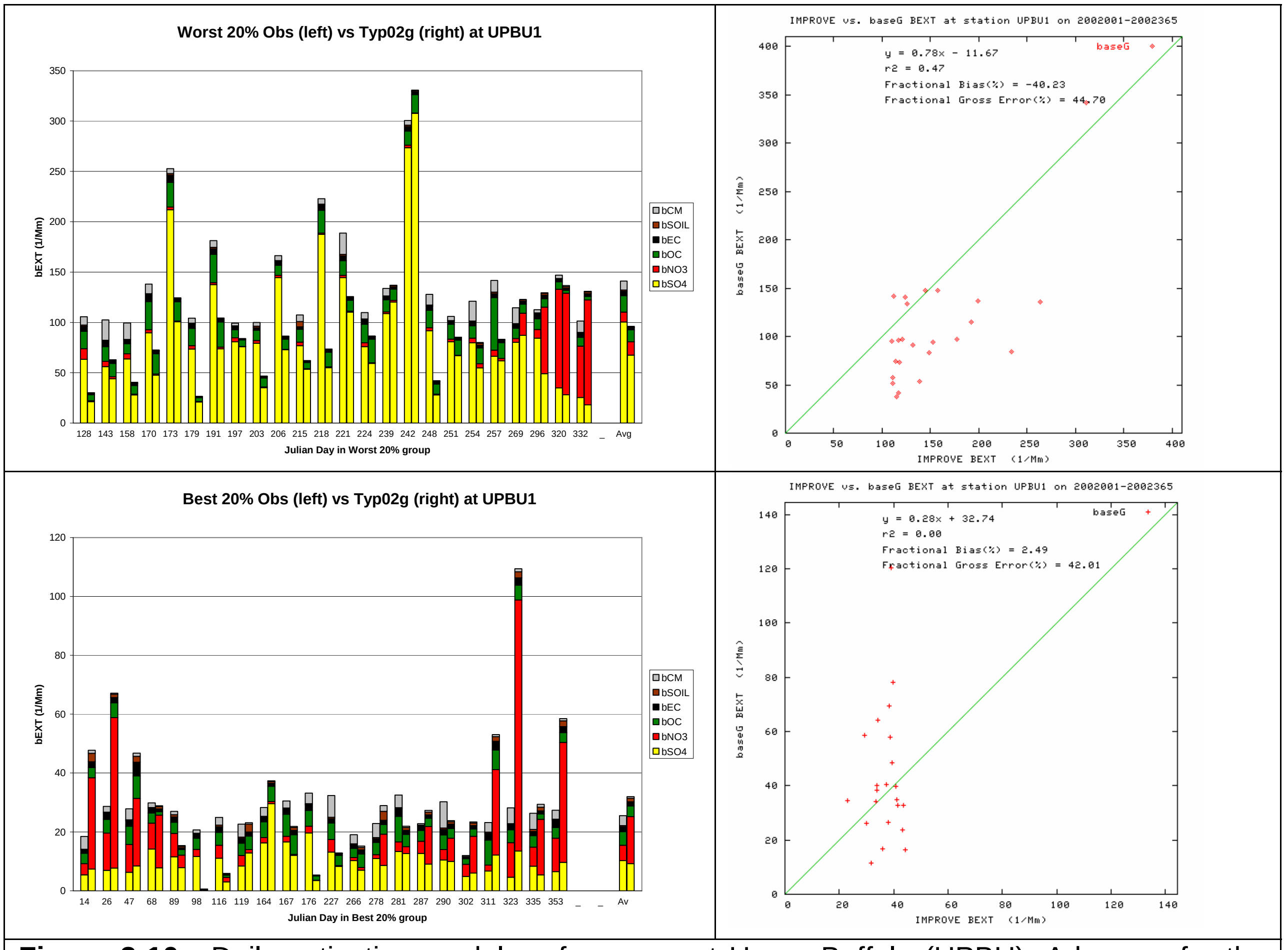


Figure 3-10. Daily extinction model performance at Upper Buffalo (UPBU), Arkansas for the worst (top) and best (bottom) 20 percent days during 2002.

3.7.3 Breton Island (BRET), Louisiana

The observed total extinction on the worst 20 percent days at Breton Island is underestimated by -71% (Figure 3-11), which is due to an underestimation of each component of extinction (Figure C-50) by from -50% to -70% (SO4, OMC and Soil) to over -100% (EC and CM). The observed extinction on the worst 20 percent days ranges from 90 to 170 Mm^{-1}, whereas the modeled values drop down to as low as approximately 15 Mm^{-1}. On the best 20 percent days the range of the observed and modeled extinction is similar (roughly 10 to 50 Mm^{-1}) that results in a reasonably low bias (-22%), but there is little agreement on which days are higher or lower resulting in a lot of scatter and high error (54%).

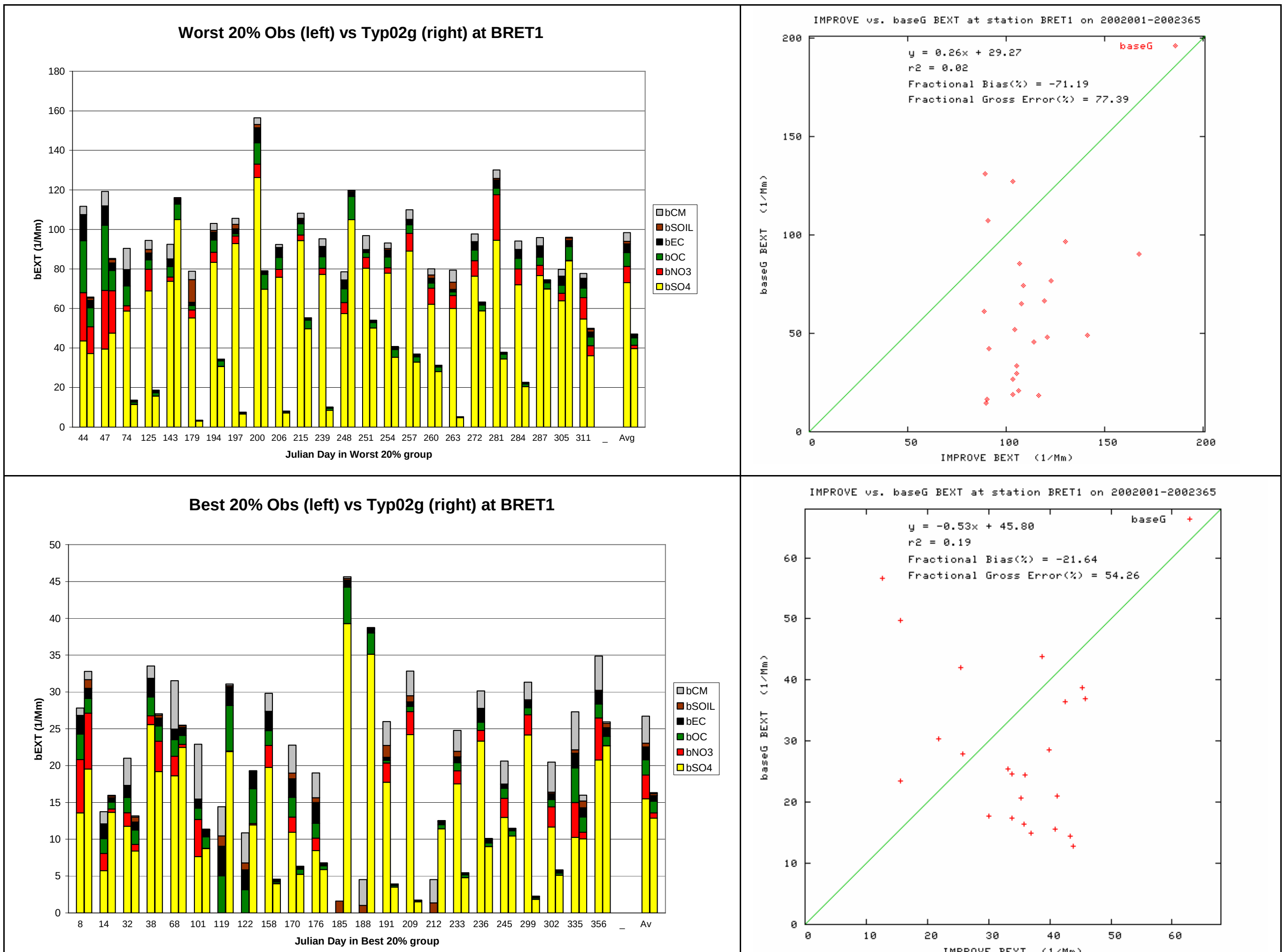


Figure 3-11. Daily extinction model performance at Breton Island (BRET), Louisiana for the worst (top) and best (bottom) 20 percent days during 2002.

3.7.4 Boundary Waters (BOWA), Minnesota

There are three types of days during the worst 20 percent days at BOWA: SO4 days, OMC days and NO3 days (Figure 3-12). The two high OMC days are likely fire impact events that the model captures to some extent on one day and not on the other. On the five high (> 20 Mm^{-1}) NO3 extinction days the model predicts the observed extinction well on three days and overestimates by a factor of 3-4 on the other two high NO3 days. SO4 is underestimated by -43% on average across the worst 20 percent days at BOWA.

With the exception of two days, the model reproduces the total extinction for the best 20 percent days at BOWA quite well with a bias and error value of +14% and 22% (Figure 3-12). Without these two days, the modeled and observed extinction both range between 15 and 25 Mm^{-1}.

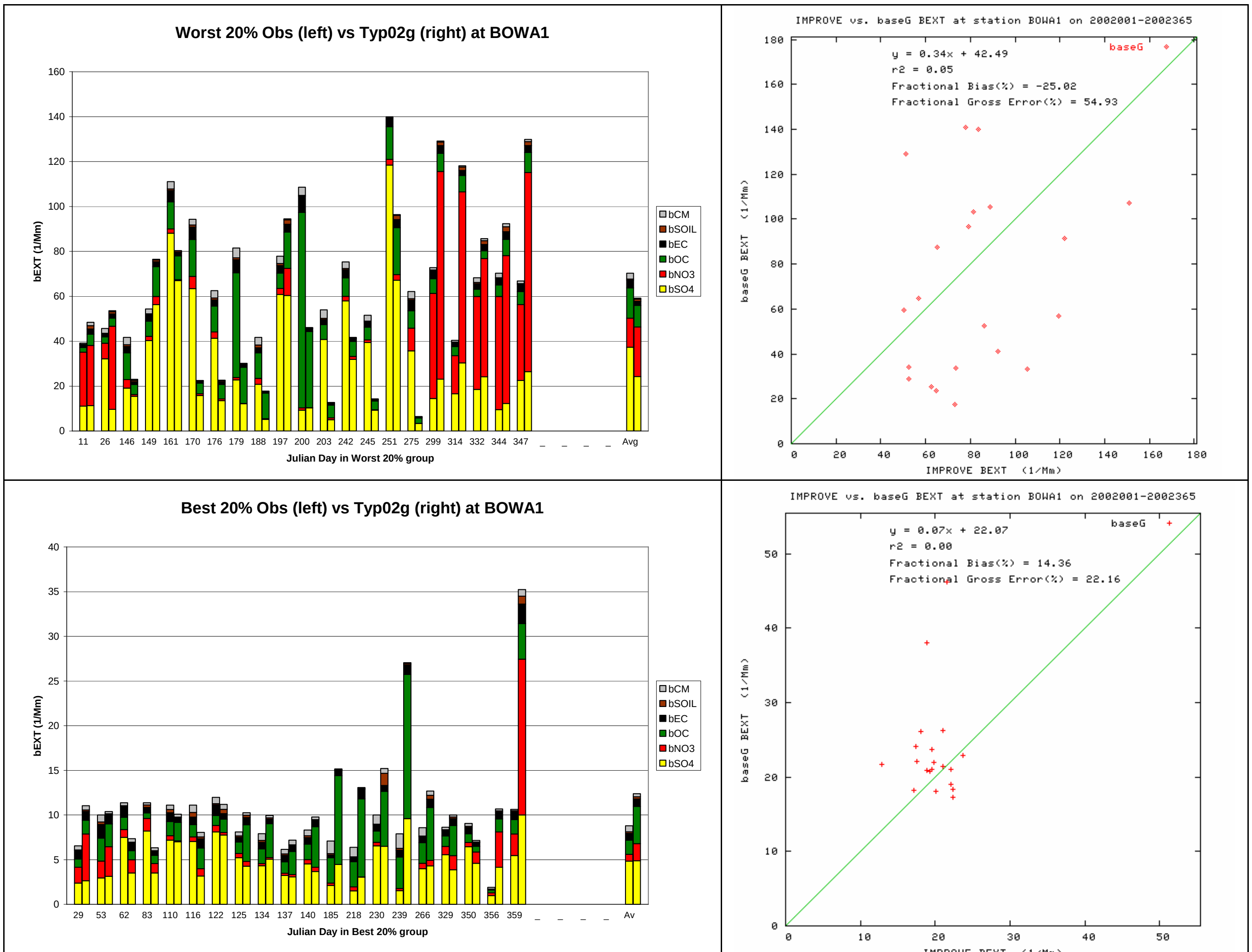


Figure 3-12. Daily extinction model performance at Boundary Waters (BOWA), Minnesota for the worst (top) and best (bottom) 20 percent days during 2002.

3.7.5 Voyageurs (VOYA) Minnesota

VOYA is also characterized by SO4, NO3 and OMC days (Figure 3-13). Julian Days 179 and 200 are high OMC days that were also high OMC days at BOWA again indicating impacts from fires in the area that is not fully captured by the model. SO4 and NO3 performance is fairly good and, without the fire days, OMC performance looks good as well (Figure C-52). On the best 20 percent days there is one day the modeled extinction is much higher than observed and a few others that are somewhat higher, but for most of the best 20 percent days the modeled extinction is comparable to the observed values.

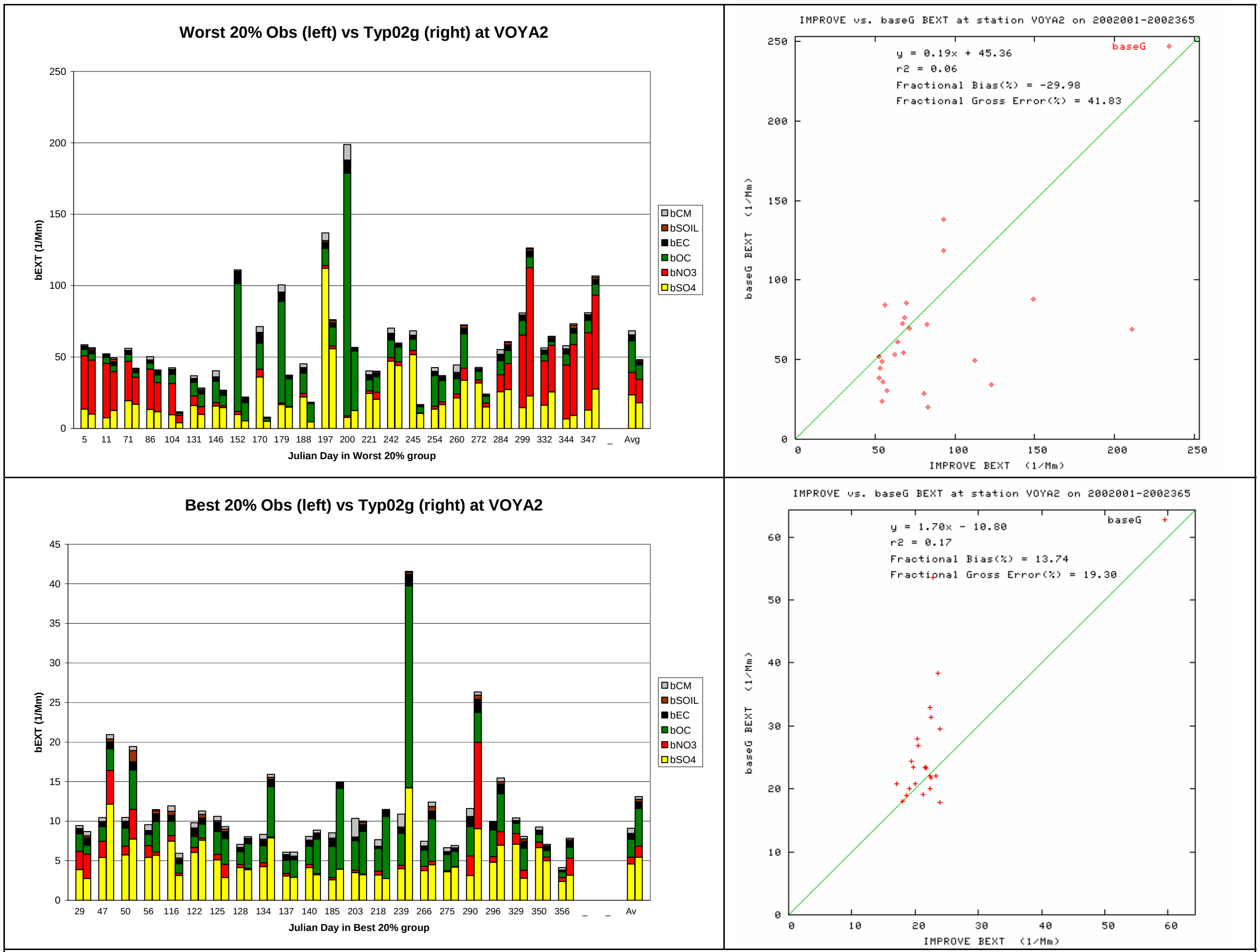


Figure 3-13. Daily extinction model performance at Voyageurs (VOYA), Minnesota for the worst (top) and best (bottom) 20 percent days during 2002.

3.7.6 Hercules Glade (HEGL) Missouri

On most of the worst 20 percent days at HEGL the observed extinction ranges from 120 to 220 Mm^{-1} whereas model extinction ranges from 50 to 170 Mm^{-1} (Figure 3-14). However, there is one extreme day with extinction approaching 400 Mm^{-1} that the model does a very good job in replicating. Over all the days there is a modest underestimation bias in SO4 (-39%) and OMC (-39%) extinction, larger underestimation bias in EC (-62%) and CM (-118%) extinction and overestimation bias in Soil (+30%) extinction (Figure C-53).

On the best 20 percent days there is one day where the model overstates the observed extinction by approximately a factor of four and a handful of other days that the model overstates the extinction by a factor of 2 or so, but most of the days both the model and observed extinction sites are around 40 Mm^{-1} ±10 Mm^{-1}. On the best 20 percent days, when the observed extinction is overstated, it is due to overstatement of the NO3.

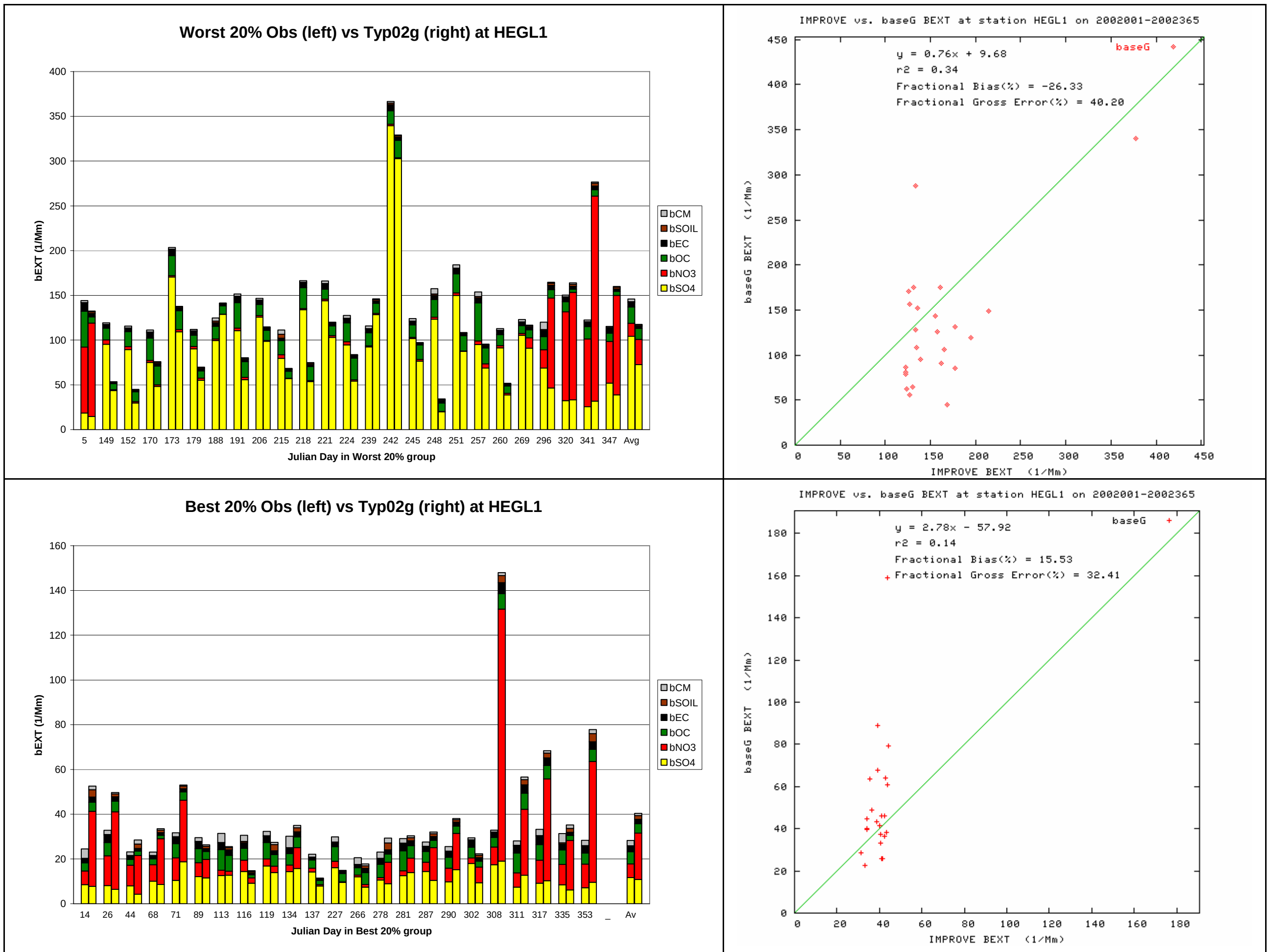


Figure 3-14. Daily extinction model performance at Hercules Glade (HEGL), Missouri for the worst (top) and best (bottom) 20 percent days during 2002.

3.7.7 Mingo (MING) Missouri

The worst 20 percent days at MING are mainly high SO4 days with a few high NO3 days that the model reproduces reasonably well resulting in low bias (+10%) and error (38%) for total extinction (Figure 3-15). The PM species specific performance is fairly good with low bias for SO4 (+4%), good agreement with NO3 on high NO3 days except for one day, low OMC (+23%) and EC (+3%) bias and larger bias in EC (+37%) and CM (-105%) extinction (Figure C-54).

For the best 20 percent days, there is one day the model is way too high due to overstated NO3 extinction and a few other days the model overstates the observed extinction that is usually due to overpredicted NO3, but on most of the best 20 percent days the modeled extinction is comparable to the observed values. This results in low bias (+12%) and error (36%) for total extinction at MING for the best 20 percent days.

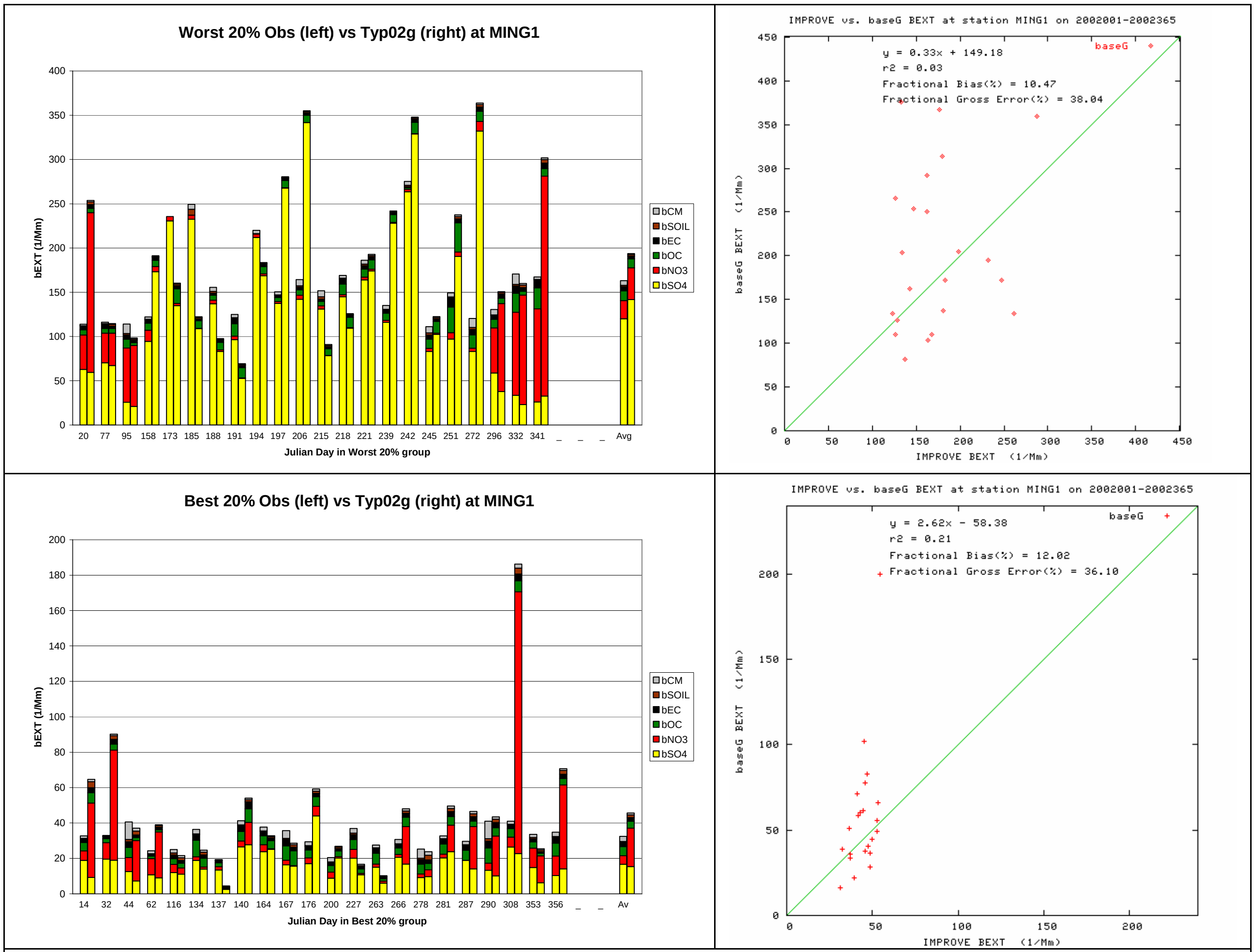


Figure 3-15. Daily extinction model performance at Mingo (MING), Missouri for the worst (top) and best (bottom) 20 percent days during 2002.

3.7.8 Wichita Mountains (WIMO), Oklahoma

With the exception of an overprediction on day 344 due to NO3, observed total extinction on the worst 20 percent days at WIMO is understated with a bias of -42% (Figure 3-16) that is primarily due to an underestimation of extinction due to SO4 (-48%) and OMC (-69%) (Figure C-55).

CMAQ total extinction performance for the average of the best 20 percent days at WIMO is characterized by an overestimation bias (+21%) on most days that is primarily due to NO3 overprediction on several days. Again the modeled range of extinction on the best 20 percent days (12-60 Mm^{-1}) is much greater than observed (20-35 Mm^{-1}).

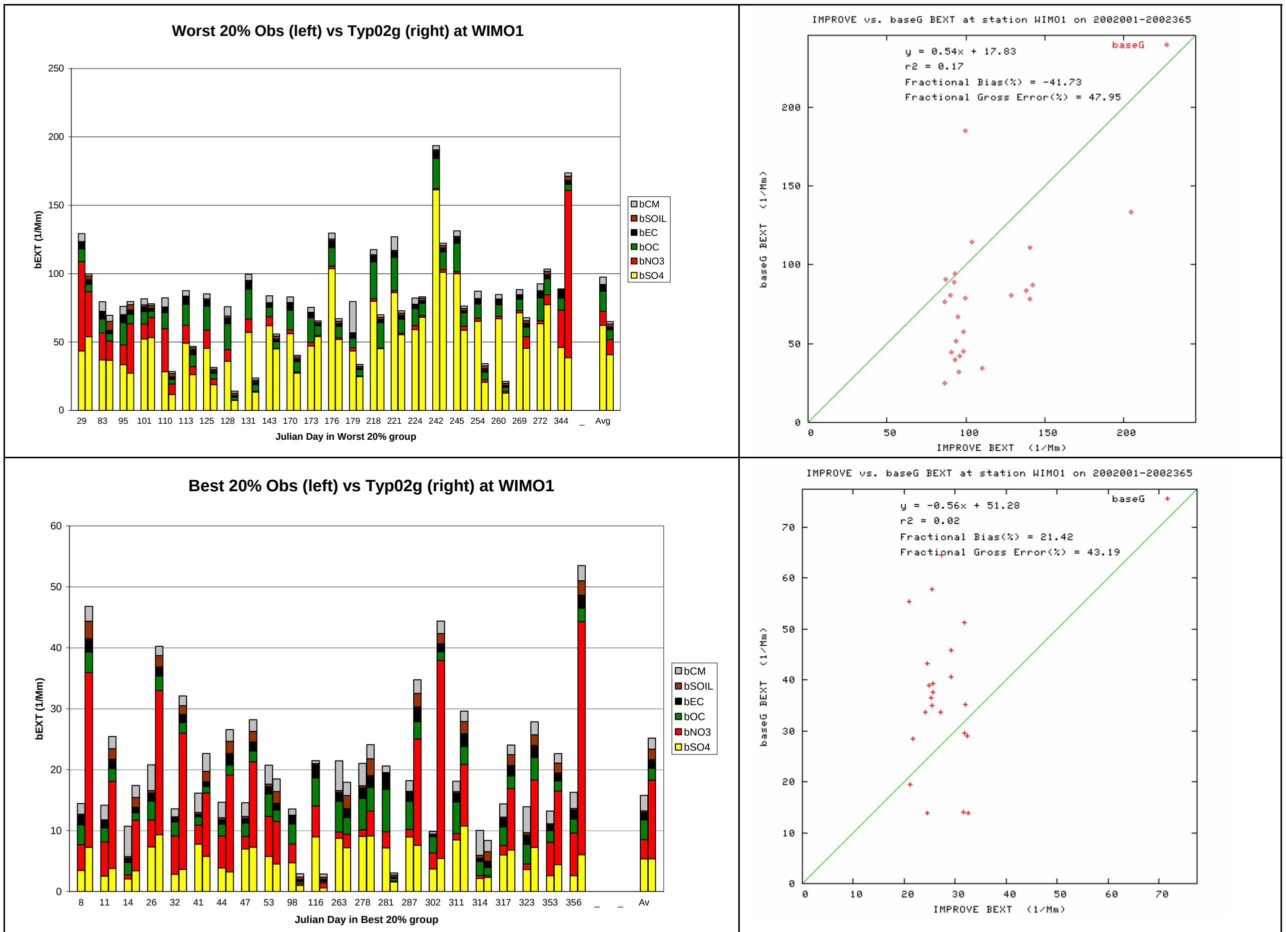


Figure 3-16. Daily extinction model performance at Wichita Mountains (WIMO), Oklahoma for the worst (top) and best (bottom) 20 percent days during 2002.

3.7.9 Big Bend (BIBE) Texas

The observed extinction on the worst 20 percent days at BIBE is underpredicted on almost every day resulting in a fractional bias value of -72% (Figure 3-17). Every component of extinction is underestimated on average for the worst 20 percent days (Figure C-56) with the underestimation bias ranging from -24% (OMC) to -162% (CM). SO4 extinction, that typically represents the largest component of the total extinction is understated by -94%.

The model does a better job in predicting the total extinction at BIBE for the best 20 percent days with average fractional bias and error values of +13% and 19% (Figure 3-17). With the exception of one day that the observed extinction is overestimated by approximately a factor of 2, the modeled and observed extinction on the best 20 percent days at BIBE are both within 12 to 25 Mm^{-1}. However, there are some mismatches with the components of extinction with the model estimating much lower contributions due to Soil and CM.

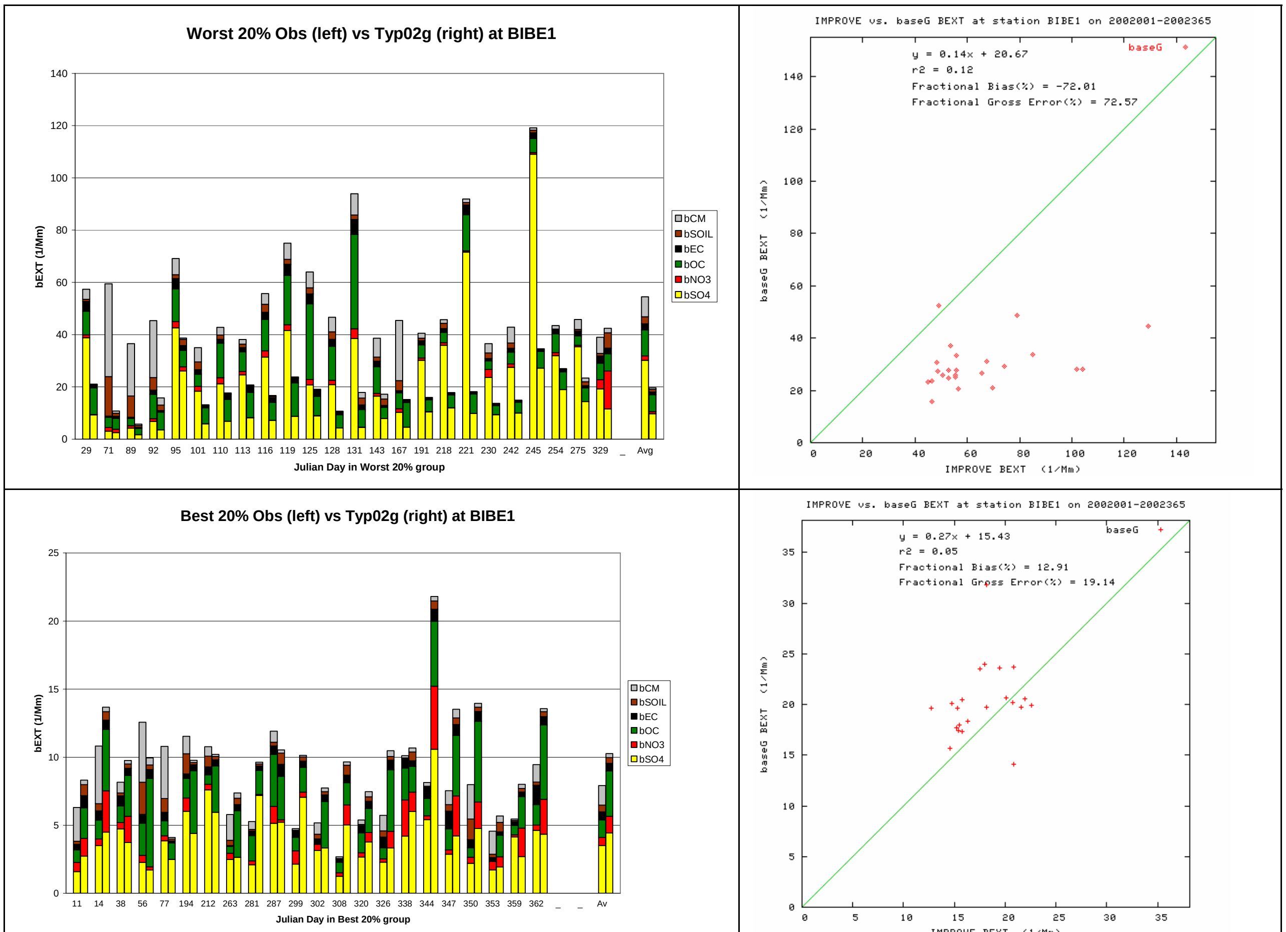


Figure 3-17. Daily extinction model performance at Big Bend (BIBE), Texas for the worst (top) and best (bottom) 20 percent days during 2002.

3.7.10 Guadalupe Mountains (GUMO) Texas

Most of the worst 20 percent days at GUMO are high dust days with high Soil and CM that is not captured by the model (Figure 3-18). Extinction due to Soil and CM on the worst 20 percent days is underestimated by -105% and -191%, respectively (Figure C-57). Better performance is seen on the best 20 percent days with bias and error for total extinction of 8% and 21%, but the model still understates Soil and CM.

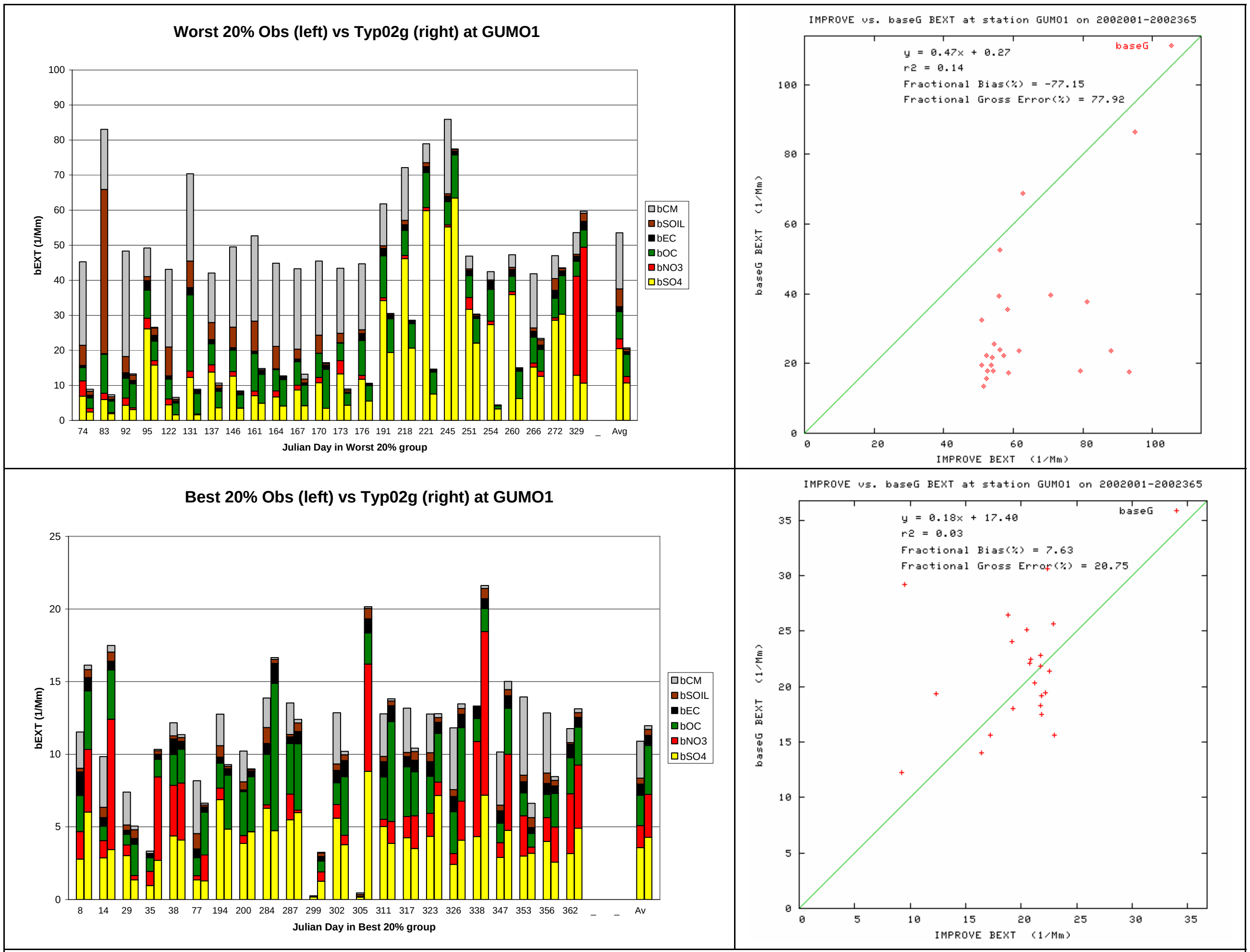


Figure 3-18. Daily extinction model performance at Guadalupe Mountains (GUMO), Texas for the worst (top) and best (bottom) 20 percent days during 2002.

3.8 Model Performance Evaluation Conclusions

The model performance evaluation reveals that the model is performing best for SO4, OMC and EC. Soil performance is mixed with a winter overestimation bias with lower bias and higher error in the summer. CM performance is poor year round. The operational evaluation reveals that SO4 performance usually achieves the PM model performance goal and always achieves the model performance criteria, although it does have an underestimation bias that is greatest in the summer. NO3 performance is characterized by a winter overestimation bias with an even greater summer underestimation bias. However, the summer underestimation bias occurs when NO3 is very low and when it is not an important component of the observed or predicted PM mass concentrations or component of visibility impairment. Performance for OMC meets the model performance goal year round at the IMPROVE sites, but is characterized by an underestimation bias at the more urban STN sites. EC exhibits very low bias at the STN sites and a summer underestimation bias at the IMPROVE sites, but meets the model performance goal throughout the year. Soil has a winter overestimation bias that is outside of the model performance goal and criteria raising questions whether the model should be used for this species. Finally, CM performance is extremely poor with an underprediction bias that is outside of the performance goal and criteria. We suspect that much of the CM concentrations measured at the IMPROVE sites is due to highly localized emissions from fugitive dust sources that are not included in the emissions inventory and would be difficult to simulate using 36 km regional modeling.

Performance for the worst 20 percent days at the CENRAP Class I areas is generally characterized by an underestimation bias. Performance at the BRET, BIBE and GUMO Class I areas for the worst 20 percent days is particularly suspect and care should be taken in the interpretation of the visibility projections at these three Class I areas.

The CMAQ 2002 36 km model appears to be working well enough to reliably make future-year projections for changes in SO4, NO3, EC and OMC at the rural Class I areas. Performance for Soil and especially CM is suspect enough that care should be taken in interpreting these modeling results. The model evaluation focused on the model’s ability to predict the components of light extinction mainly at the Class I areas. Additional analysis would have to be undertaken to examine the model’s ability to simulate ozone and fine particulate to address 8-hour ozone and $PM_{2.5}$ attainment issues.

4.0 VISIBILITY PROJECTIONS

This section presents the future-year visibility projections for Class I areas within and near the CENRAP states and their comparison with the 2018 Uniform Rate of Progress (URP) point. As noted in Chapter 1, the Regional Haze Rule (RHR) requires states with Class I areas to develop State Implementation Plans (SIPs) that include reasonable progress goals (RPGs) for improving visibility in each Class I area and emission reduction measures to meet those goals. For the initial SIPs due in December 2007, states are required to adopt RPGs for improving visibility from Baseline Conditions. The 2000-2004 five-year period is used to define Baseline Conditions and the first future progress period is 2018. A state is required to set RPGs for each Class I area in the state for two visibility metrics:

- Provide for an improvement in visibility for the most impaired visibility days (i.e., the worst 20 percent days); and

- Ensure no degradation in visibility for the least impaired visibility days (i.e., the best 20 percent days).

The goal of the RPGs is to provide for a rate of improvement sufficient to be on a course to attain "Natural Conditions" by 2064. States are to define controls to meet RPGs every 10 years, starting in 2018, which defines progress periods ending in 2018, 2028, 2038, 2048, 2058 and finally 2064. States will determine whether they are meeting their goals by comparing visibility conditions from one five-year period to another (e.g., 2000-2004 to 2013-2017). As stated in 40 CFR 51.308 (d) (1), baseline visibility conditions, reasonable progress goals, and changes in visibility must be expressed in terms of deciview (dv) units. The haze index (HI) metric of visibility impairment, in deciviews, is derived from light extinction (b_{ext}) as follows:

$$HI = 10 \ln (b_{ext}/10),$$

Where light extinction (b_{ext}) is expressed in terms of inverse megameters ($Mm^{-1} = 10^{-6} m^{-1}$). Light extinction (b_{ext}) is calculated using the observed fine particulate concentrations from the IMPROVE monitors using either the original or the new IMPROVE aerosol extinction equation. Both equations are discussed below.

4.1 Guidance for Visibility Projections

EPA has published several guidance documents that relate to how modeling results should be used to project future-year visibility and how states should define RPGs:

> "Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$ and Regional Haze" (EPA, 2007a).
>
> "Guidance for Tracking Progress Under the Regional Haze Rule" (EPA, 2003a).
>
> "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule" (EPA, 2003b).

"Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program" (EPA, 2007b).

The first EPA modeling guidance document listed above (EPA, 2007) discusses the use of modeling results to project future-year visibility. The second EPA guidance document (EPA, 2003a) focuses on monitored visibility, how to define the visibility Baseline Conditions and how to track visibility goals. The third EPA guidance document discusses procedures for defining Natural Conditions for a Class I area. Natural Conditions are the visibility goal for 2064. Although states may propose alternative approaches for defining Natural Conditions, in this section we use the default Natural Conditions at Class I areas (EPA, 2003b; Pitchford, 2006). The final EPA guidance document discusses how states should define their RPGs and their relationship to the 2018 URP point.

The EPA documents discussed above are followed for the visibility projections presented in this section with one notable exception. Some of the EPA documents are based on the original IMPROVE equation (e.g., EPA, 2003a, b). The CENRAP visibility projections are based on the new IMPROVE equation, although projections based on the original IMPROVE equation are also presented as an alternative approach in Chapter 5. EPA guidance allows for using either the original or the new IMPROVE equation (EPA, 2007a; Timin, 2007). CENRAP, along with the other RPOs, have elected to use the new IMPROVE equation for their visibility projections.

4.2 Calculation of Visibility and 2018 URP Point from IMPROVE Measurements

EPA guidance recommends using the model in a relative sense to project future-year visibility conditions (EPA, 2007a). This projection is made using Relative Response Factors (RRFs) that are defined as the ratio of the future-year modeling results to the base-year modeling results. The RRFs are applied to the baseline visibility conditions to project future-year visibility. The major features of EPA's recommended visibility projection approach are as follows (EPA, 2003a,b; 2007a):

- Monitored data are used to define current visibility Baseline Conditions using IMPROVE monitoring data from the 2000-2004 five-year base period.

- Monitored concentrations of PM_{10} are divided into six major components, the first five of which are assumed to be $PM_{2.5}$ and the sixth is coarse mass (CM or $PM_{2.5-10}$).
  - SO4 (sulfate) that is assumed to be ammonium sulfate [$(NH_4)_2SO_4$];
  - NO3 (particulate nitrate) that is assumed to be ammonium nitrate [NH_4NO_3];
  - OC (organic carbon) that is assumed to be total organic mass carbon (OMC)
  - EC (elemental carbon);
  - IP (other fine inorganic particulate or Soil); and
  - CM (coarse mass).

- Models are used in a relative sense to develop RRFs between baseline and future predicted concentrations of each component.

- PM component-specific RRFs are multiplied by observed Baseline monitored values to estimate future-year PM component concentrations.

- Estimates of future-year component concentrations are consolidated to provide an estimate of future-year air quality and visibility using either the original or new IMPROVE equation.

- Future-year model projected visibility is compared with the 2018 point on the URP glidepath to assist in evaluating the visibility improvements.

- It is assumed that all measured sulfate is in the form of ammonium sulfate [$(NH_4)_2SO_4$] and all particulate nitrate is in the form of ammonium nitrate [NH_4NO_3].

In order to facilitate tracking visibility progress, three important visibility concepts are required for each Class I area:

Baseline Conditions: Baseline Conditions represent visibility for the 20 percent best (B20%) and 20 percent worst (W20%) visibility days for the initial five-year baseline period of the regional haze program. Baseline Conditions are calculated using IMPROVE monitor data collected during the 2000-2004 five-year period and are the starting point in 2004 for the URP glidepath and 2018 visibility projections.

Natural Conditions: Estimates of natural visibility conditions for the best 20 percent and worst 20 percent days at a Class I area (i.e., visibility conditions that would be experienced in the absence of human-caused impairment). EPA has defined a set of default Natural Conditions for the original IMPROVE equation (EPA, 2003b) that has been updated to the new IMPROVE equation by the Natural Haze Levels II Committee (Pitchford, 2006) that we have used in this Chapter.

2018 URP Point: The 2018 Uniform Rate of Progress (URP) point is defined by defining a linear glidepath in deciviews starting with the 2000-2004 Baseline Conditions in 2004 and ending at Natural Conditions in 2064. Where the linear glidepath passes through 2018 is the 2018 URP point in deciviews.

4.2.1 Calculation of Visibility from IMPROVE PM Measurements

Baseline Conditions for Class I areas are calculated using the procedures in EPA's guidance document (EPA, 2003a) and fine and coarse particulate matter concentrations measured at IMPROVE monitors (Malm et al, 2000; Debell et al., 2006). Currently, each Class I area in the CENRAP domain has an associated IMPROVE monitor. The IMPROVE monitors do not directly measure visibility, but instead measure speciated fine particulate ($PM_{2.5}$) and total $PM_{2.5}$ and PM_{10} mass concentrations from which visibility is obtained through the IMPROVE equation.

Visibility conditions are estimated starting with the IMPROVE 24-hour average mass measurements for six PM species:

- Sulfate [$(NH_4)_2SO_4$];
- Particulate Nitrate [$(NH_4NO_3$];
- Organic Matter Carbon or Organic Mass by Carbon [OMC];
- Elemental Carbon [EC] or Light Absorbing Carbon [LAC];
- Other fine particulate [Soil]; and
- Coarse Matter or Coarse Mass [CM].

The IMPROVE monitors do not directly measure some of these species so assumptions are made as to how the IMPROVE measurements can be adjusted and combined to obtain these six components of light extinction. For example, in the IMPROVE equation sulfate and particulate nitrate are assumed to be completely neutralized by ammonium. In addition, only the fine mode ($PM_{2.5}$) of PM is speciated by the IMPROVE monitor to obtain sulfate and nitrate measurements (that is, any coarse mode sulfate and nitrate in the real atmosphere may be present in the CM IMPROVE measurement). Concentrations for the above six components of light extinction in the IMPROVE equation are obtained from the IMPROVE measured species using the mappings shown in Table 4-1:

Table 4-1. Definition of IMPROVE PM Components from Measured IMPROVE Species.

IMPROVE Component	IMPROVE Measured Species
Sulfate	1.375 x (3 x S)
Nitrate	1.29 x NO_3^-
OMC	1.4*OC (original IMPROVE) and 1.8*OC (new IMPROVE)
LAC	EC
Soil	2.2*AL + 2.49*SI + 1.63*CA + 2.42*FE + 1.94*TI
CM	MT – MF

Where:

- S is elemental sulfur as determined from proton induced x-ray emissions (PIXE) analysis of the IMPROVE Module A[1]. To estimate the mass of the sulfate ion ($SO_4^=$), S is multiplied by 3 to account the presence of oxygen. If S is missing then the sulfate (SO_4) measured by ion chromatography analysis of the Module B is used to replace (3 x S). For the IMPROVE aerosol extinction calculation, Sulfate is assumed to be completely neutralized by ammonium (1.375 x SO_4).
- NO_3^- is the particulate nitrate measured by ion chromatography analysis of the Module B. For the IMPROVE aerosol extinction calculation, it is assumed to be completely neutralized by ammonium (1.29 x NO_3^-).
- The IMPROVE Organic Carbon (OC) measurements are multiplied by 1.4 to obtain Organic Mass Carbon (OMC) using the original IMPROVE equation and multiplied by 1.8 for the new IMPROVE equation. This adjustment of the measured OC accounts for mass due to other elements in the OMC besides Carbon.
- Elemental Carbon (EC) is also referred to as Light Absorbing Carbon (LAC).

[1] The IMPROVE sampler consists of four independent modules (A, B, C and D). Each module incorporates a separate inlet, filter pack and pump assembly and are controlled by a common timing mechanism. Module A measures fine PM mass and elements. Module B measures sulfate and nitrate ions. Module C measures EC and OC. Module D measures PM_{10} mass. (see http://vista.cira.colostate.edu/improve/ for more details).

- Soil is determined as a sum of the masses of those elements (measured by PIXE) predominantly associated with soil (Al, Si, Ca, Fe, K and Ti), adjusted to account for oxygen associated with the common oxide forms. Since K and FE are products of the combustion of vegetation, they are both represented in the formula by 0.6 x Fe and K is not shown explicitly.
- MT and MF are total PM_{10} and $PM_{2.5}$ mass, respectively.

4.2.1.1 Original and New IMPROVE Equations

Associated with each PM species is an extinction efficiency that converts concentrations (in $\mu g/m^3$) to light extinction (in inverse megameters, Mm^{-1}). Sulfate and nitrate are hygroscopic which means that they can absorb water from the atmosphere which changes their extinction efficiency. This is accounted for through relative humidity adjustment factors [f(RH)] that increase the particle's extinction efficiency with increasing RH to account for the particles taking on water Note that some OMC may also have hygroscopic properties, but the IMPROVE equations assume OMC is non-hygroscopic.

There are currently two IMPROVE equations that are used to convert the measured PM concentrations to light extinction, the original (or old) and the new IMPROVE equations.

4.2.1.1.1 Original IMPROVE Equation

The original IMPROVE equation that converts PM species concentrations to light extinction is given as follows:

$$b_{Sulfate} = 3 \times f(RH) \times [Sulfate]$$
$$b_{Nitrate} = 3 \times f(RH) \times [Nitrate]$$
$$b_{EC} = 10 \times [EC]$$
$$b_{OMC} = 4 \times [OMC]$$
$$b_{Soil} = 1 \times [Soil]$$
$$b_{CM} = 0.6 \times [CM]$$

Monthly average f(RH) factors are used as recommended in EPA's guidance (EPA, 2003a). These values are available in the final EPA guidance document (EPA, 2003a) and at: ftp://ftp.saic.com/raleigh/RegionalHaze_2002FRHcurve/fRH_analysis/.

The total light extinction (b_{ext}) is assumed to be the sum of the light extinction due to the six PM species listed above plus Rayleigh (blue sky) background (b_{Ray}) that is assumed to be 10 Mm^{-1}.

$$b_{ext} = b_{Ray} + b_{Sulfate} + b_{Nitrate} + b_{EC} + b_{OMC} + b_{Soil} + b_{CM}$$

The total light extinction (b_{ext}) in Mm^{-1} is related to visual range (VR) in km using the following relationship:

$$VR = 3912 / b_{ext},$$

for b_{ext} in Mm^{-1}.

The Regional Haze Rule requires that visibility be expressed in terms of a haze index (HI) in units of deciviews (dv), which is calculated as follows:

$$HI = 10 \ln(b_{ext}/10)$$

4.2.1.1.2 New IMPROVE Equation

The new IMPROVE equation is nonlinear in SO4, NO3 and OMC concentrations accounting for the different light scattering efficiency characteristics as a function of concentrations for these three species. It is expressed as follows:

$$b_{Sulfate} = 2.2 \times f_S(RH) \times [\text{Small Sulfate}] + 4.8\ f_S(RH) \times [\text{Large Sulfate}]$$
$$b_{Nitrate} = 2.4 \times f_S(RH) \times [\text{Small Nitrate}] + 5.1\ f_S(RH) \times [\text{Large Nitrate}]$$
$$b_{EC} = 10 \times [\text{Elemental Carbon}]$$
$$b_{OMC} = 2.8 \times [\text{Small Organic Mass}] + 6.1 \times [\text{Large Organic Mass}]$$
$$b_{Soil} = 1 \times [\text{Fine Soil}]$$
$$b_{CM} = 0.6 \times [\text{Coarse Mass}]$$
$$b_{NaCl} = 1.7 \times f_{SS}(RH) \times [\text{Sea Salt}]$$
$$b_{NO2} = 0.33 \times [NO_2\ (ppb)]$$

The total Sulfate, Nitrate and OMC are each split into two fractions, representing small and large size distributions of those components. As noted in Table 4-1, the OMC is 1.8 times the IMPROVE OC measurement in the new IMPROVE algorithm, compared to 1.4 times the IMPROVE OC measurement in the original IMPROVE equation. New terms have been added for Sea Salt (important for coastal areas and possibly other areas)and for light absorption by NO2 (only used where NO2 observations are available). As none of the CENRAP Class I area IMPROVE sites measure NO2 concentrations, then this component of the new IMPROVE equations was not used. Site-specific Rayleigh scattering for each IMPROVE monitoring site is used in the new IMPROVE equation, as compared to a constant 10 Mm^{-1} value assumed in the original IMPROVE equation.

The apportionment of the Small and Large components of Sulfate, Nitrate and Organic Mass is done as follows:

$$[\text{Large Sulfate}] = [\text{Total Sulfate}] / 20 \times [\text{Total Sulfate}], \text{ for } [\text{Total Sulfate}] < 20\ \mu g/m^3$$

$$[\text{Large Sulfate}] = [\text{Total Sulfate}], \text{ for } [\text{Total Sulfate}] \geq 20\ \mu g/m^3$$

$$[\text{Small Sulfate}] = [\text{Total Sulfate}] - [\text{Large Sulfate}]$$

The same equations are used to apportion Total Nitrate and Total OMC among their Large and Small components.

The total extinction (b_{ext}) in the new IMPROVE equations is the sum of all the extinction components associated with each PM species. The new IMPROVE equation adds Sea Salt and

NO_2 as noted above. In addition, site-specific Rayleigh background is used with the new IMPROVE equation:

$$b_{ext} \quad = \quad b_{Ray} + b_{Sulfate} + b_{Nitrate} + b_{EC} + b_{OMC} + b_{Soil} + b_{CM} + b_{NaCl} + b_{NO2}$$

The Haze Index (HI) and Visual Range (VR) are calculated from the total extinction from the new IMPROVE equation using the same formulas as given above for the original IMPROVE equation.

4.2.1.1.3 Justification for Using the New IMPROVE Equation

The new IMPROVE equation was developed using the latest scientific information on PM species extinction properties combined with fitting reconstructed light extinction based on IMPROVE measured PM and NO2 concentrations with actual co-located measured light extinction (e.g., nephelometer measurements). Figure 4-1 displays example comparisons of 24-hour light extinction using the original and new IMPROVE equations compared against 24-hour nephelometer measurements of light extinction at the Great Smoky Mountains Class I area IMPROVE monitor. The original IMPROVE equation has a bias toward understating light extinction at the high end and overstating it at the low end, whereas the new IMPROVE equation does a better job in estimating light extinction from measured PM at all extinction levels. Because the new IMPROVE equation is based on more recent science and fits the observed light extinction values better, the CENRAP states have elected to perform their primary visibility projections using the new IMPROVE equation. Results using the original IMPROVE equation are presented in Section 5 as an alternative approach.

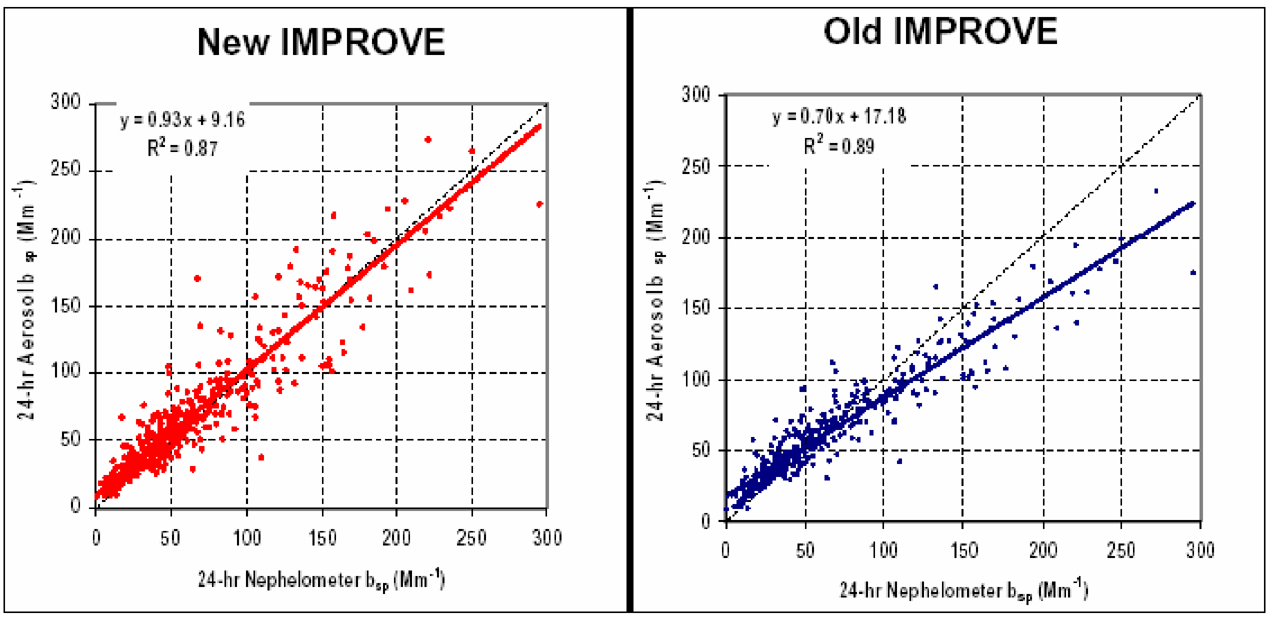


Figure 4-1. Comparisons of observed light extinction with reconstructed light extinction using the new (left) and original (right) IMPROVE equations at the Great Smoky Mountains National Park.

4.2.2 Calculation of the Baseline Conditions

The visibility Baseline Conditions for the worst 20 percent and best 20 percent days is calculated from the IMPROVE observations from the 2000-2004 period for each Class I area following EPA's guidance (EPA, 2003a). The basic procedures for calculating the Baseline Conditions are as follows:

1. Determine whether the observed IMPROVE data for each site and year satisfies EPA's minimal data capture criteria (EPA, 2003a). If there are less than three years with valid data capture for the 2000-2004 Baseline then the Baseline Conditions can not be calculated and data filling is needed.
2. For each year in the 2000-2004 period with sufficient valid data, rank the visibility in terms of extinction or deciview using either the original or new IMPROVE equation and monthly average f(RH) factors (EPA, 2003a).
3. For the worst 20 percent days, extract the 20% most impaired visibility days for each year (similarly for best 20 percent days extract 20% cleanest days). With a complete yearly data capture of IMPROVE 1:3 day sampling frequency this would result in 24 worst 20 percent and 24 best 20 percent days in a year.
4. For each worst 20 percent (or best 20 percent) day in each year, calculate 24-hour average visibility extinction using the IMPROVE measurements and either the original and new IMPROVE equation, convert the daily extinction to daily deciview and then average across each year to get yearly average deciview extinction for the worst 20 percent (or best 20 percent) days for each valid year from the 2000-2004 period.
5. Average the annual average deciview worst 20 percent (or best 20 percent) days deciview across each valid year in the 2000-2004 period (minimum of 3 valid years required) to get the worst 20 percent (or best 20 percent) Baseline Conditions.

4.2.3 Data Filling for Sites with Insufficient Valid Data to Calculate Baseline Conditions

Three CENRAP Class I areas did not contain sufficient IMPROVE observations during the five-year 2000-2004 Baseline to have three valid years of data from which Baseline Conditions could be constructed: Breton Island (BRET), Louisiana; Boundary Waters (BOWA), Minnesota and Mingo (MING), Missouri. For these three Class I areas, data filling was used to obtain sufficient data so that at least three-years of valid data were available from which Baseline Conditions could be calculated. These data filled IMPROVE databases were prepared and made available on the VIEWS website. More information on the data filling procedures can be found at the VIEWS website: (http://vista.cira.colostate.edu/views/).

4.2.4 Natural Conditions

EPA has published default Natural Conditions for Annual Average and the worst 20 percent and best 20 percent days based on the original IMPROVE equation (EPA, 2003b). These default Natural Conditions have been updated to the new IMPROVE equation by the Natural Haze Levels II Committee (Pitchford, 2006). These default Natural Conditions are used as the anchor point for the glidepaths in 2064 and are provided in Appendix D for the CENRAP Class I areas.

4.2.5 2018 URP Point

The 2018 point on the Uniform Rate of Progress (URP) glidepath is constructed by generating a linear glidepath in deciviews from the Baseline Conditions in 2004 to Natural Conditions in 2064. Where the linear glidepath crosses 2018 is the 2018 point on the URP glidepath or the 2018 URP point. Figure 4-2 displays an example linear glidepath for the Caney Creek Class I area in Arkansas. There are three years of sufficient valid IMPROVE data during the 2000-2004 Baseline (2002, 2003 and 2004) with values of 27.21, 26.52 and 25.34 dv resulting in worst 20 percent Baseline Conditions of 26.36 dv that is placed as the starting point in 2004 for the glidepath. The ending point for the glidepath is 11.58 dv which is the default Natural Conditions for the worst 20 percent days (EPA, 2003b; Pitchford, 2006). The linear glidepath crosses 2018 at 22.91 dv which becomes the 2018 URP point.

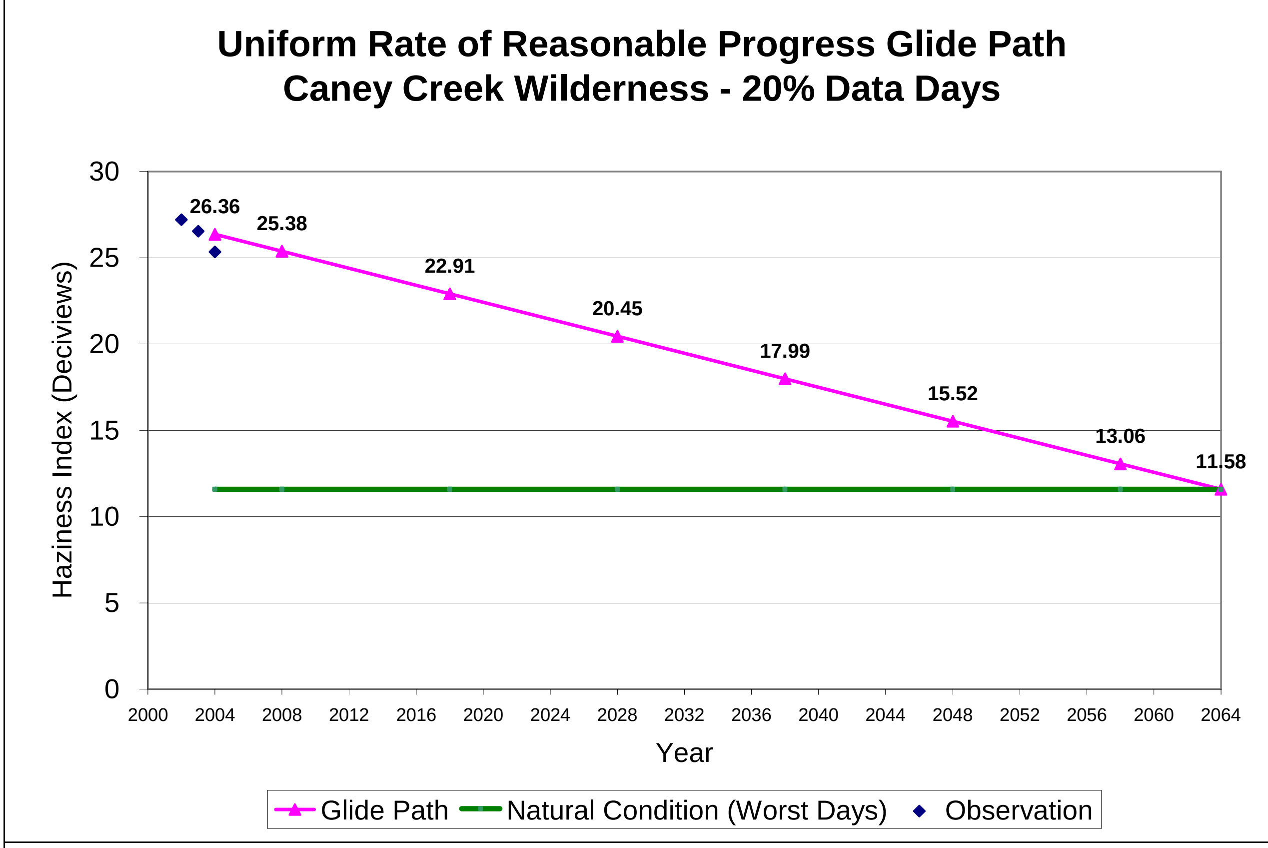


Figure 4-2. Linear Glidepath for Caney Creek (CACR), Arkansas that linearly connects the 26.36 dv Baseline Conditions in 2004 with the 11.58 dv Natural Conditions in 2064 resulting in a 22.91 dv 2018 URP Point.

4.3 EPA Default Approach to Visibility Projections

For CENRAP's model application for a single year (2002), EPA's regional haze modeling guidance recommends developing Class I area-specific and PM species-specific RRFs based on the average concentrations for the worst 20 percent days from 2002 (EPA, 2007). Thus, this is the methodology used to project 2018 visibility estimates in this section. For example, if $SO4(2002)_i$ and $SO4(2018)_i$ are the model estimated sulfate concentrations for the 2002 worst 20 percent days (i=1…N) at a given Class I area for the 2002 and 2018 emission scenarios then the RRF for sulfate and this Class I area is given by:

$$RRF(SO4)_i \quad = \quad \sum SO4(2018)_i \,/\, \sum SO4(2002)_i$$

4.3.1 Mapping of Modeling Results to the IMPROVE Measurements

As noted above, to project future-year visibility at Class I areas the modeling results are used in a relative sense to scale current observed visibility for the worst 20 percent and best 20 percent visibility days using RRFs that are the ratio of modeling results for the future-year to current-year. This scaling is done separately for each of the six components of light extinction in the IMPROVE equations. The CMAQ modeled species do not necessarily exactly match up with the IMPROVE PM species, thus assumptions must be made to map the modeled species to the IMPROVE PM species for the purpose of projecting visibility improvements. For example, CMAQ explicitly simulates ammonium and sulfate may or may not be fully neutralized in the model by ammonium, whereas the IMPROVE equations assume sulfate is fully neutralized by ammonium. For the CMAQ Version 4.5 (September 15, 2005 release) model, the mapping of modeled species to IMPROVE equation PM species is listed in Table 4-2.

Table 4-2. Mapping of CMAQ V4.5 modeled species concentrations to IMPROVE PM components.

IMPROVE Component	CMAQ V4.3 Species
Sulfate	1.375 x (ASO4J + ASO4I)
Nitrate	1.29 x (ANO3J + ANO3I)
LAC	AECJ + AECI
OMC	AORGAJ + AORGAI + AORGPAJ + AORGPAI + AORGBJ + AORGBI
Soil	A25J + A25I
CM	ACORS + ASEAS + ASOIL

For the CENRAP visibility projections using the 2002 Typical and 2018 base case Base G emission scenarios, the secondary organic aerosol (SOA) module in CMAQ V4.5 was modified (SOAmods) to include additional processes related to the generation of SOA from biogenic emissions. In particular, three new species have been added that represent SOA products from biogenic emission compounds that is not included in the standard version of CMAQ V4.5 (Morris et al., 2006c):

- ASOC1 – SOA from biogenic sources (e.g., terpenes and isoprene) that has become polymerized so is no longer volatile.
- ASOC2 – SOA from biogenic sesquiterpene and higher reactivity and higher yield monoterpene emissions.
- ASOC3 – SOA from biogenic isoprene emissions.

Thus, the species mapping for Organic Mass Carbon (OMC) and the CMAQ V4.5 SOAmods version of the model used in CENRAP 2018 visibility projections is as given in Table 4-2 only with the addition of the three new biogenic SOA species to OMC as follows:

> OMC = AORGAJ + AORGAI + AORGPAJ + AORGPAI + AORGBJ + AORGBI + ASOC1 + ASOC2 + ASOC3

4.3.2 Using Modeling Results to Project Changes in Visibility

Modeling results are used in a relative fashion to project future-year visibility using relative response factors (RRFs). RRFs are expressed as the ratio of the modeling results for the future-year to the results of the base year (2018/2002) and are Class I area and PM species specific. RRFs are applied to the Baseline Condition observed PM species to project future-year PM levels from which visibility can be assessed using the IMPROVE equations listed above. The following six steps are used to project future-year visibility for the worst 20 percent and best 20 percent visibility days (discussion is for worst 20 percent days but also applies to best 20 percent days):

1. For each Class I area and each monitored day, daily visibility is ranked using IMPROVE data and IMPROVE equation (either original or new IMPROVE equation) for each year from the five-year baseline period (2000-2004) to identify the worst 20 percent visibility days for each year from the five-year baseline (see Baseline Conditions discussion above).

2. Use an air quality model to simulate a base year period (ideally the five-year Baseline period of 2000-2004, but for CENRAP just the 2002 annual period was simulated) and a future-year (e.g., 2018) and use the resulting information to develop Class I area-specific RRFs for each of the six components of light extinction in the IMPROVE equation (SO4, NO3, EC, OMC, Soil and CM).

3. Multiply the RRF times the measured 24-hour PM concentration data for each day from the worst 20 percent days in each year from the five-year Baseline period to obtain projected future-year 24-hour PM concentrations for the worst 20 percent days and the five-year Baseline.

4. Compute the future-year daily extinction using the IMPROVE equation and the projected PM concentrations for each of the worst 20 percent days in the five-year baseline from Step 3.

5. For each of the worst 20 percent days within each year of the five-year baseline, convert the future-year daily extinction to deciview and average the daily deciview values within each of the five years separately to obtain five-years (or as many years with valid data in the 2000-2004 Baseline) of average deciview visibility for the worst 20 percent days.

6. Average the five-years of average deciview visibility to obtain the future-year visibility Haze Index estimate that is the future-year estimated visibility.

In calculating the RRFs, EPA draft guidance recommends selecting estimated PM species concentrations "near" the monitor by taking a spatial average of PM concentrations across a grid cell resolution dependent NX by NY array of cells centered on the grid containing the monitor. The NX x NY array of cells is grid resolution specific with EPA recommending that NX=NY=1 for 36 km grids, NX=NY=3 for 12 km grids and NX=NY=7 for 4 km grids (EPA, 2007). For the CENRAP 2002 36 km modeling, just the model estimates for the grid cell containing the monitor was used (i.e., NX=NY=1).

4.4 EPA Default 2018 Visibility at CENRAP and Nearby Class I areas and Comparisons to 2018 URP Goals

Using the EPA default visibility projection procedure described in Section 4.3 and the CENRAP 2002 Typical Base G and 2018 Base Case Base G CMAQ modeling results, 2018 visibility projections were made for CENRAP and nearby Class I areas. Appendix D details the 2018 Base G visibility projections for each Class I area in the CENRAP region using the new IMPROVE equation. Results for the Caney Creek (CACR), Arkansas Class I area are discussed in Section 4.4.1 below Displays for other CENRAP Class I areas are provided in Appendix D and summarized in Section 4.4.2

4.4.1 Example 2018 Base G Visibility Projections for Caney Creek, Arkansas

The 2018 visibility projections for the Caney Creek (CACR), Arkansas Class I area given in Figure D-1 in Appendix D are reproduced in Figure 4-3 and described below.

4.4.1.1 EPA Default 2018 Visibility Projections

The 2018 Base G visibility projection using the EPA default method (EPA, 2007a) and comparison with the 2018 URP point for the worst 20 percent days and the CACR Class I area is shown in Figure 4-3a. The 2000-2004 Baseline Conditions for CACR is 26.36 dv and the 2018 URP point is 22.91 dv so that a 3.45 dv reduction in visibility for the worst 20 percent days is needed to meet the 2018 URP point. The 2018 Base G CMAQ projected visibility is 22.48 dv so that the modeling predicts more visibility improvements (3.88 dv reduction) than required to meet the 2018 URP point (3.45 dv reduction). When looking at visibility projections across several Class I areas, it has been useful to present the 2018 visibility projections as a percentage of meeting the 2018 URP point; where 100% is meeting the point, greater than 100% surpassing the point (i.e., below the glidepath) and less than 100% means that less visibility improvement is achieved than needed to meet the 2018 URP point. For 2018 Base G CMAQ modeling at CACR, we achieve 112% of the visibility reduction needed to meet the 2018 URP point. Note that meeting the 2018 URP point is not a requirement of the RHR SIPs, rather it just serves as a benchmark to compare progress toward Natural Conditions in 2064 and is designed to help states in selecting their 2018 RPGs. As clearly stated in EPA guidance "The glidepath is not a presumptive target, and States may establish a RPG that provides for greater, lesser, or equivalent improvement as that described by the glidepath" (EPA, 2007b).

The 2018 Base G CMAQ visibility projections for the best 20 percent days and CACR is shown in Figure 4-3b. Recall the RHR goal for this visibility metric is no worsening of the visibility for the best 20 percent days. The Baseline Conditions for the best 20 percent days at CACR is 11.24 dv. The 2018 Base G projected visibility for the best 20 percent days is 10.35 dv, which represents a 0.89 dv visibility improvement for the best 20 percent days at CACR and demonstrating no worsening in visibility for the best 20 percent days.

Figure 4-3c displays "StackedBar Chart" plots of observed and model estimated extinction for each of the worst 20 percent days in 2002 and the 2002 Typical Base G CMAQ simulation and the average across the worst 20 percent days. This figure allows a comparison of how well the model is reproducing the observed extinction at CACR for the worst 20 percent days in 2002 and the breakdown of the PM components that are contributing to visibility impairment (more details on model performance were presented in Chapter 3). The 2002 worst 20 percent days at CACR are dominated by SO4 days (yellow), although during the winter there are also three days dominated by NO3 (Julian Days 80, 320 and 341). For most of the worst 20 percent days at CACR, the model reproduces the observed extinction reasonably well, although it does tend to understate SO4 on a few days and overstate NO3 on the four winter days. The observed average extinction across the 2002 worst 20 percent days at CACR is 150 Mm^{-1}, compared to a modeled value that is 23% lower (115 Mm^{-1}).

Figure 4-3d displays "Boxplots" of differences in modeled extinction for the 2002 worst 20 percent days between the 2018 Base G and 2002 Typical Base G CMAQ simulations. On most days SO4 is the largest component of the extinction that is estimated to be reduced at CACR on the worst 20 percent days. The exception to this is for the winter NO3 days where NO3 is the largest component of extinction that is reduced. The modeling results are not used directly in the visibility projections, rather they are used to develop the PM-species specific RRFs. That is, an important attribute in Figures 4-3c and 4-3d is the relative changes in the modeled PM species averaged across the worst 20 percent days that are represented by the last bar in each figure and provide insight into the RRFs used in the visibility projections. These results are summarized in Table 4-3 below. Table 4-3 compares the average extinction across the 2002 worst 20 percent days at CACR from the measured IMPROVE data, the modeled values and the modeled change in extinction between the 2018 and 2002 emissions scenarios. Although the results in Table 4-3 are not RRFs (RRFs are based on ratios of concentrations not extinction) they do show how the RRFs may magnify or deflate the importance of a modeled PM species. For example, the model estimates that approximately 23% (26.66 Mm^{-1}) of the visibility extinction average across the worst 20 percent days is due to NO3, whereas it is only 7% in the observed values (10.22 Mm^{-1}). So the modeled ~40% reduction in NO3 between the 2018 and 2002 scenarios is applied to the smaller observed NO3 value to obtain the 2018 projected NO3 value making NO3 a smaller portion of the 2018 projected visibility than the 2018 modeled visibility. On the other hand, the modeled SO4 extinction is less than observed so that its importance in the 2018 projections is much greater than in the modeled 2018 SO4 values.

Table 4-3. Observed and Modeled Extinction by Species Averaged Across the Worst 20 Percent Days in 2002 at CACR.

	2002 Average Observed W20% (Mm^{-1})	2002 Average Modeled W20% (Mm^{-1})	2018-2002 Reduction (Mm^{-1})	2018-2002 Reduction (%)
bSO4	109.50	67.90	-24.47	-36%
bNO3	10.22	26.66	-10.90	-41%
bOMC	19.65	16.68	-2.12	-13%
bEC	4.38	2.32	-0.67	-29%
bSOIL	1.43	1.04	+0.21	+20%
bCM	4.30	0.37	-0.01	-3%

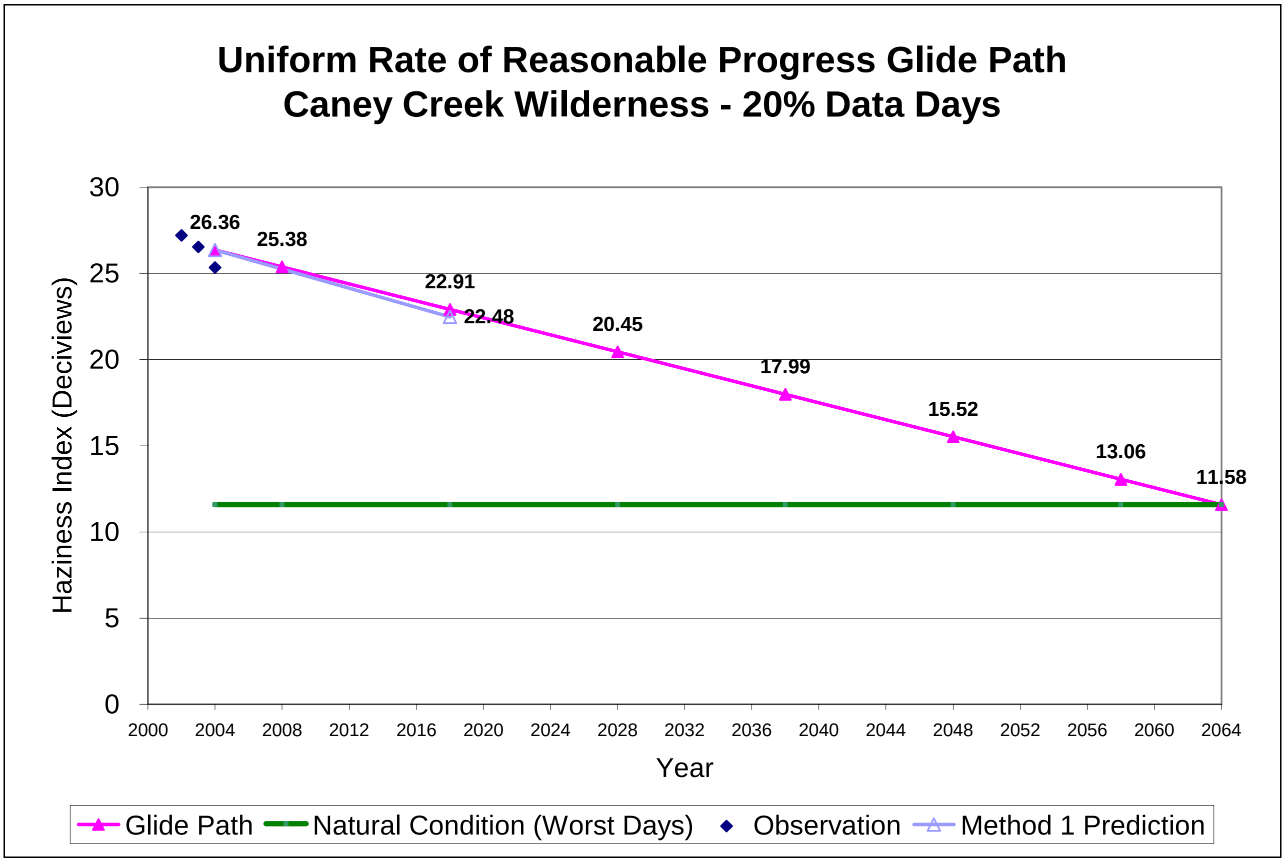


Figure 4-3a. 2018 Visibility Projections and 2018 URP Glidepaths in Deciview for Caney Creek (CACR), Arkansas and Worst 20 Percent (W20%) days Using 2002/2018 Base G CMAQ 36 km Modeling Results.

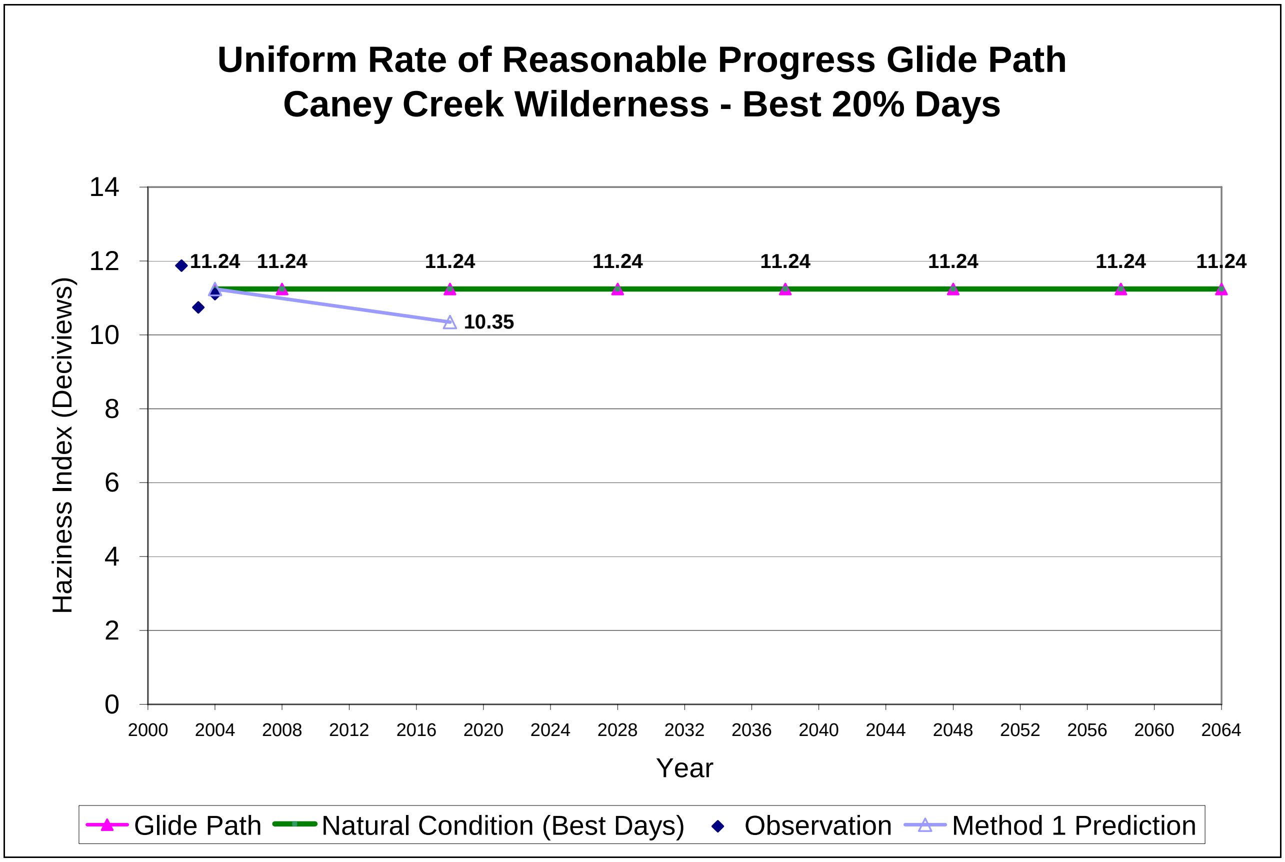


Figure 4-3b. 2018 Visibility Projections and 2018 URP Glidepaths in Deciview for CACR, Arkansas and Best 20 Percent (B20%) days Using 2002/2018 Base G CMAQ 36 m Modeling Results.

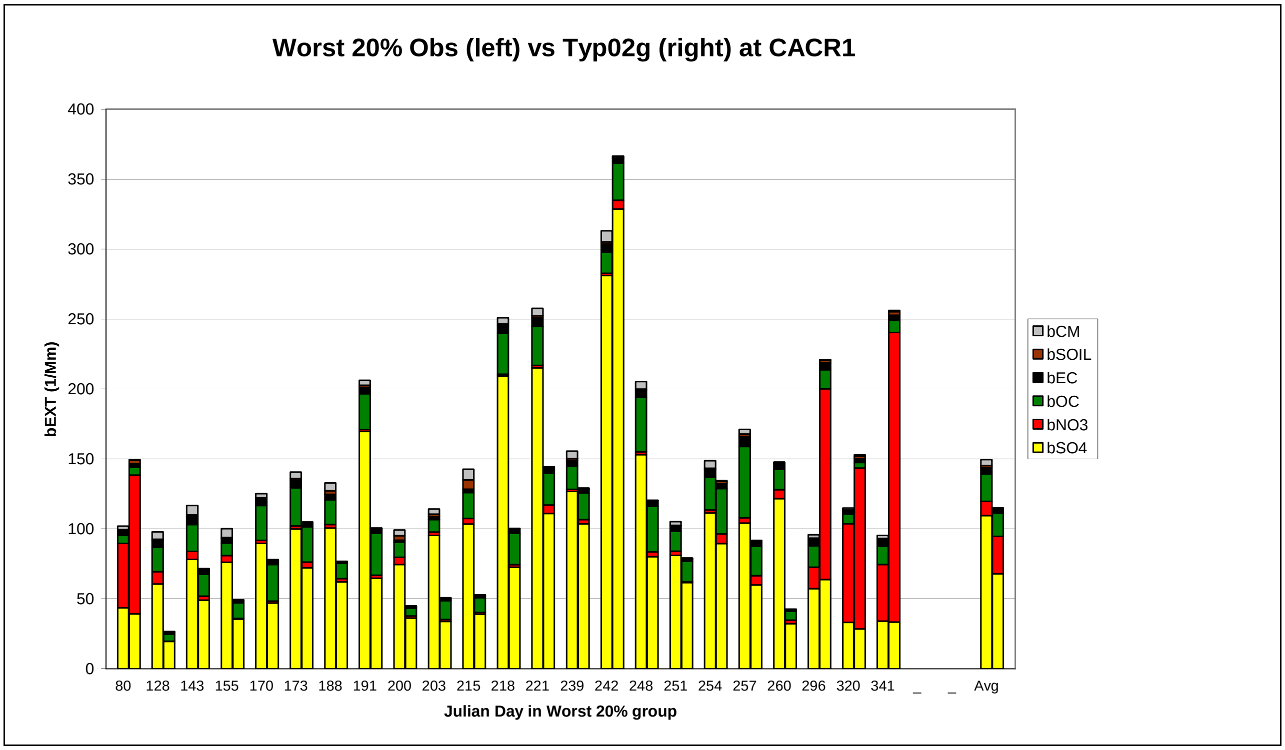


Figure 4-3c. Comparison of Observed (left) and 2002 Base G Modeled (right) Daily Extinction for Caney Creek (CACR), Arkansas and Worst 20 Percent (W20%) days in 2002.

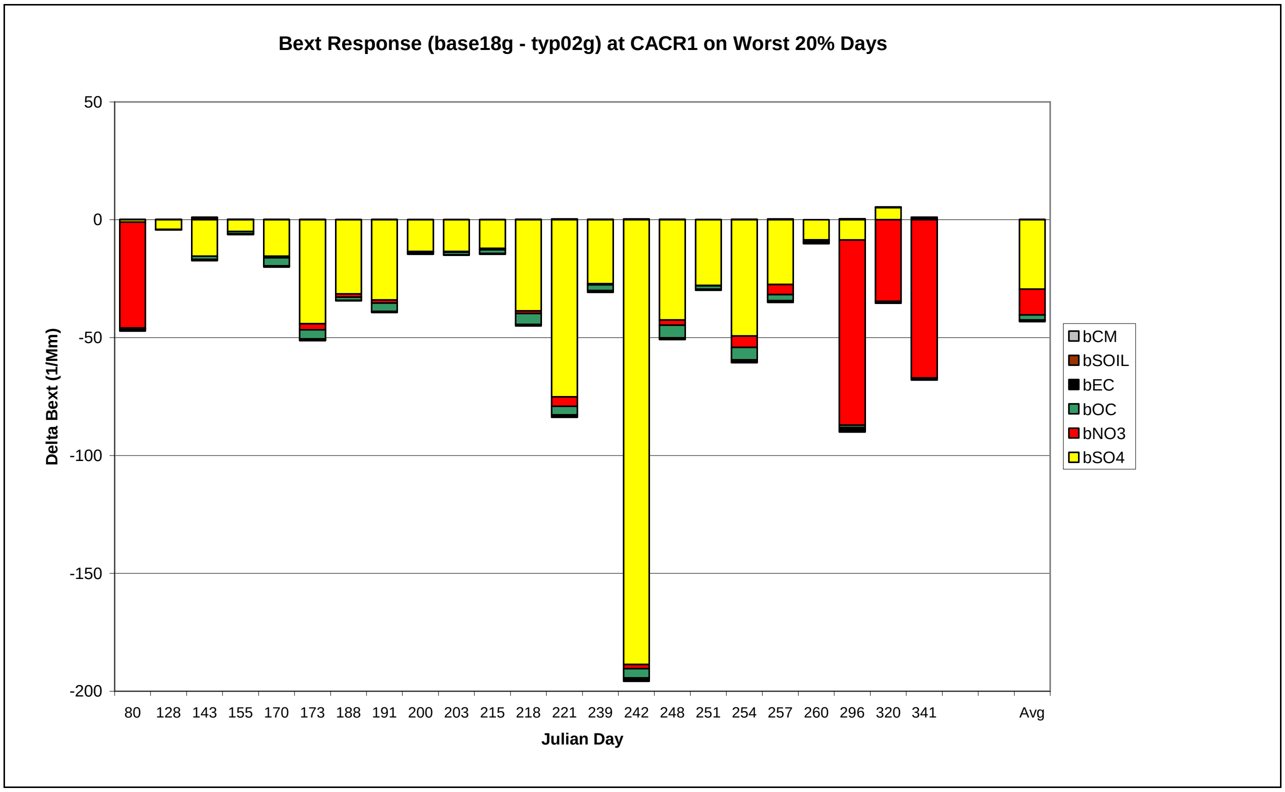


Figure 4-3d. Differences in Modeled 2002 and 2018 Base G CMAQ Results (2018-2002) Daily Extinction for Caney Creek (CACR), Arkansas and Worst 20 Percent (W20%) Days in 2002.

4.4.2 Summary 2018 Visibility Projections Across Class I Areas

Figure 4-4 displays a "DotPlot" of 2018 visibility projections using the 2002 Typical and 2018 base case Base G CMAQ 36 km modeling results. DotPlots present the 2018 visibility projections as a percentage of meeting the 2018 URP point. For example, at CACR the 2018 Base G modeling achieved 112% of the visibility reduction needed to meet the 2018 URP point so the dot under CACR is plotted at 112%. Class I areas' with dots above 100% surpass the 2018 URP point (i.e., are below the glidepath), whereas Class I areas' with dots that are under 100% fail to meet the 2018 URP point. Figure 4-4 summarizes the 2018 visibility projections using the EPA default "Regular RRF" and the two alternatives where CM is assumed to be natural (CM RRF=1) and both CM and Soil are assumed to be natural (CM&SOIL RRF=1). When CM or CM&SOIL are assumed to be natural that means that we assume the same CM or CM&SOIL occurs in the 2018 future-year as in the 2000-2004 Baseline Conditions. For the CENRAP sites, the EPA default and alternative projection, assuming CM alone or CM and Soil are natural, techniques produced similar results.

At the four eastern CENRAP Class I area sites close to the Mississippi River (CACR, UPBU, HEGL and MING), the 2018 visibility projections meet (HEGL) or surpass the 2018 URP point. Breton Island Class I area (BRET) comes up 6% short of meeting the 2018 URP point (i.e., 94% of the URP point). Wichita Mountains Class I area (WIMO) comes up approximately 40% short of the 2018 URP point. The two northern Class I areas (BOWA and VOYA) also come up about 40% short of meeting the 2018 URP point (i.e., achieve 69% and 53% of the visibility improvement needed to meet the 2018 URP point). The two Texas Class I areas only achieve

26% (BIBE) and 34% (GUMO) of the visibility improvement needed to meet the 2018 URP point for the worst 20 percent days. As discussed in more detail in Chapter 5, much of the difficulty for the Texas and some of the other CENRAP Class I areas in meeting the 2018 URP point is due to large contributions due to international transport, much of which (e.g., Mexico and global transport) is assumed to remain unchanged from 2002 to 2018.

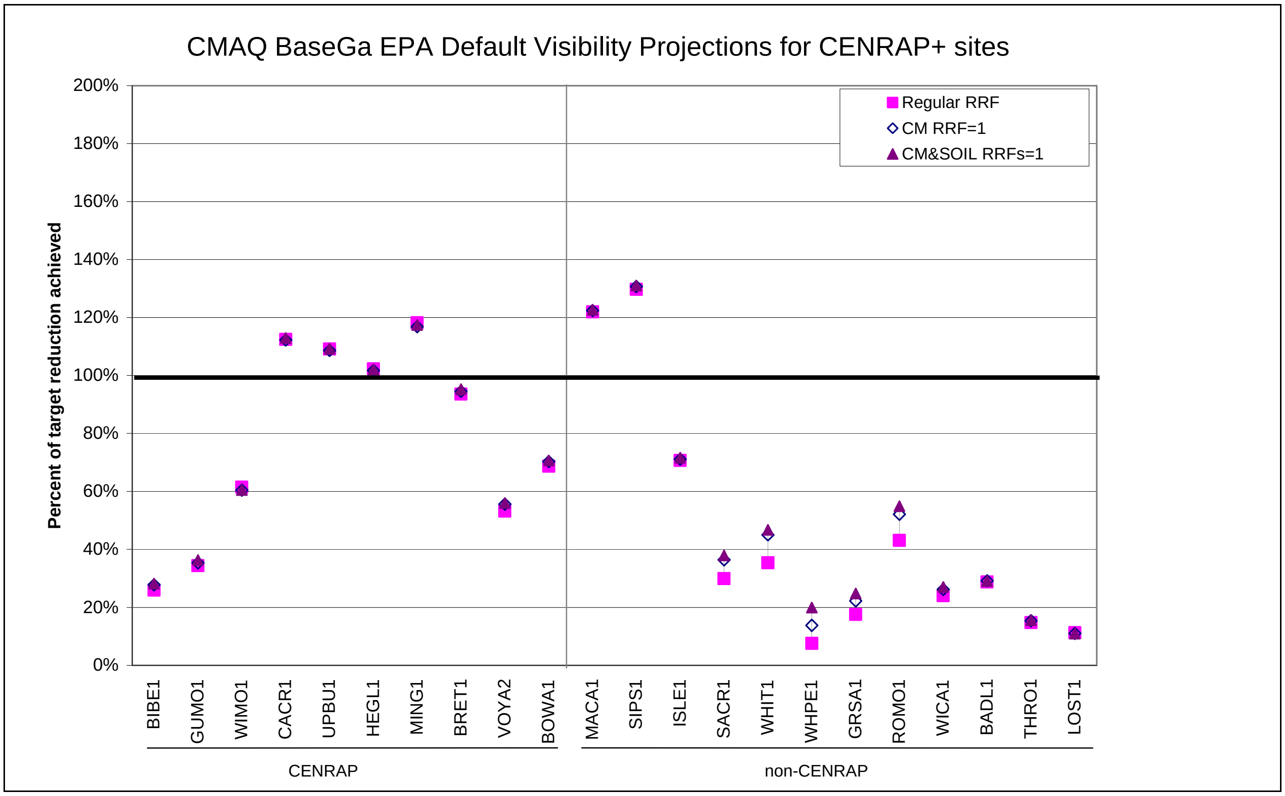


Figure 4-4. 2018 Base G CMAQ Visibility Projections for CENRAP and Nearby Class I areas Using DotPlots that Express 2018 Visibility as a Percentage of Meeting the 2018 URP Point On the Deciview Linear Glidepath.

Figure 4-5 displays the model estimated absolute change in extinction (Mm^{-1}) averaged across the 2002 worst 20 percent days at Class I areas in and near the CENRAP region. The largest modeled reductions are in SO4 extinction. Figure 4-6 displays the percent change in the projected PM extinction by PM species for each CENRAP and nearby Class I area average across the worst 20 percent days (i.e., the relative modeled change). The four CENRAP Class I areas that meet the 2018 URP point (CACR, UPBU, HEGL and MING) are characterized by large SO4, NO3 and EC extinction reductions (30-40%) with small Soil increases. At the other CENRAP Class I areas, however, there are lower levels of SO4, NO3 and EC extinction reductions and even some NO3 increases (BIBE). At the non-CENRAP Class I areas, the two VISTAS Class I areas (MACA and SIPS) have large reductions in SO4 extinction (~50%), whereas the WRAP Class I areas SO4 extinction reductions are much smaller.

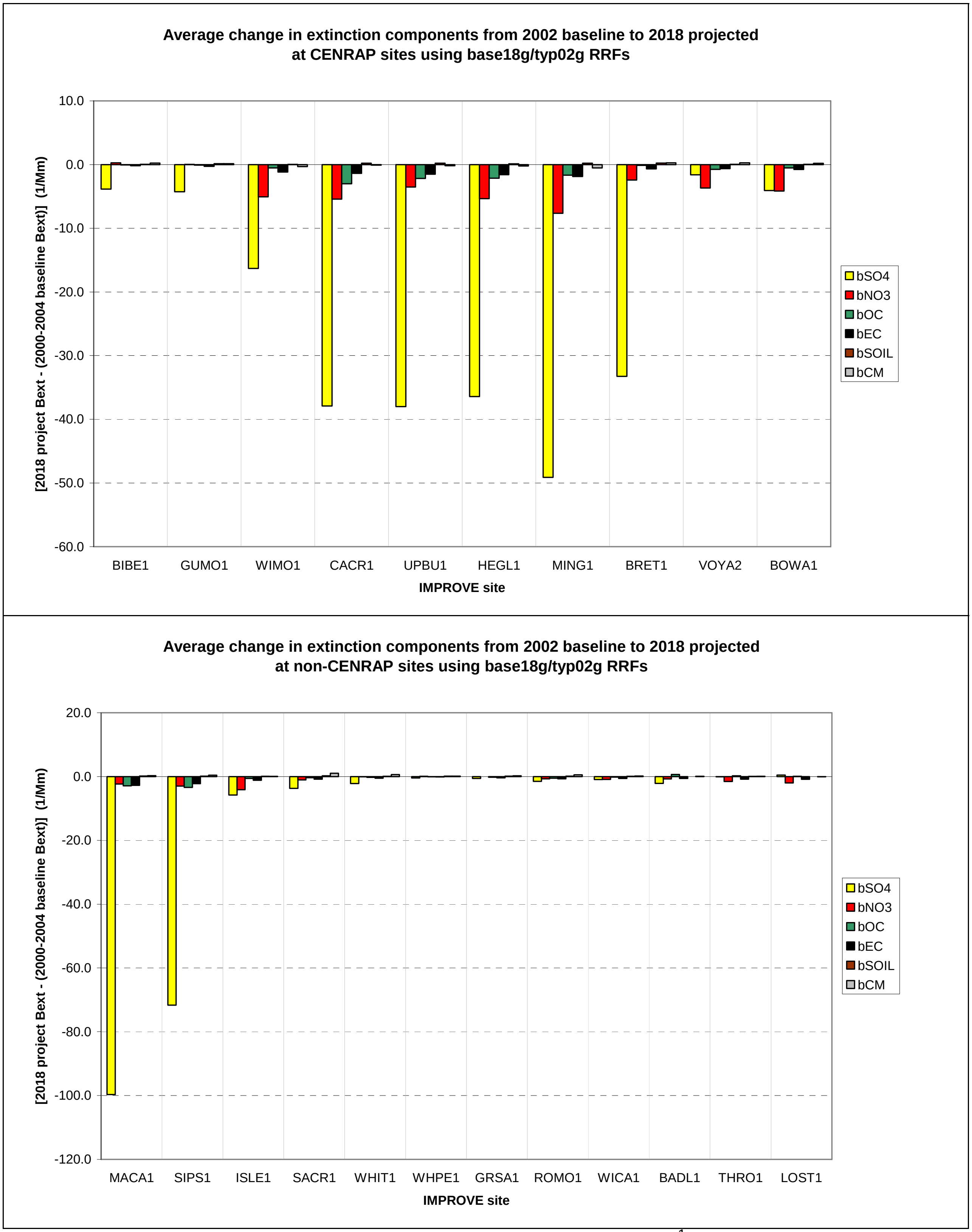
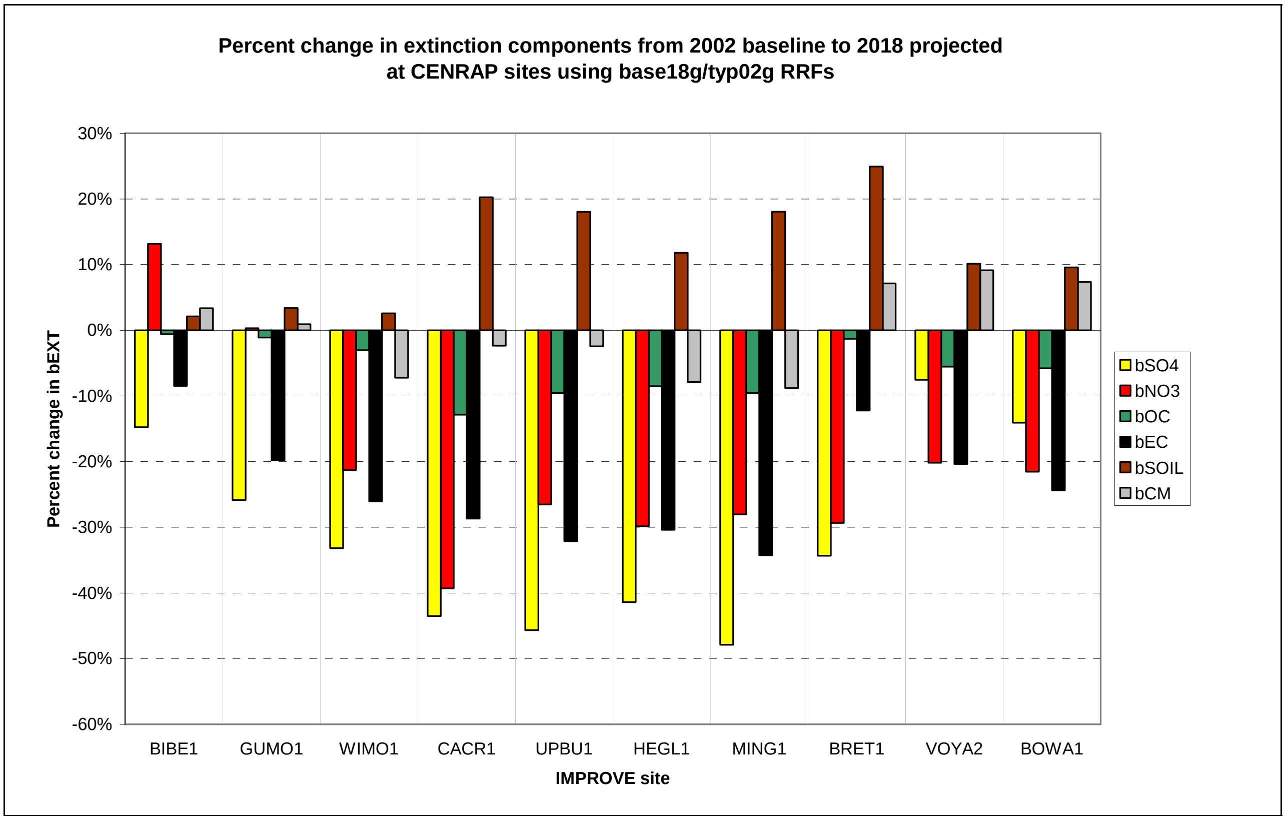


Figure 4-5. Absolute Model Estimated Changes in Extinction (Mm^{-1}) by PM Species for Class I Areas in the CENRAP region (top) and Near the CENRAP region (bottom).



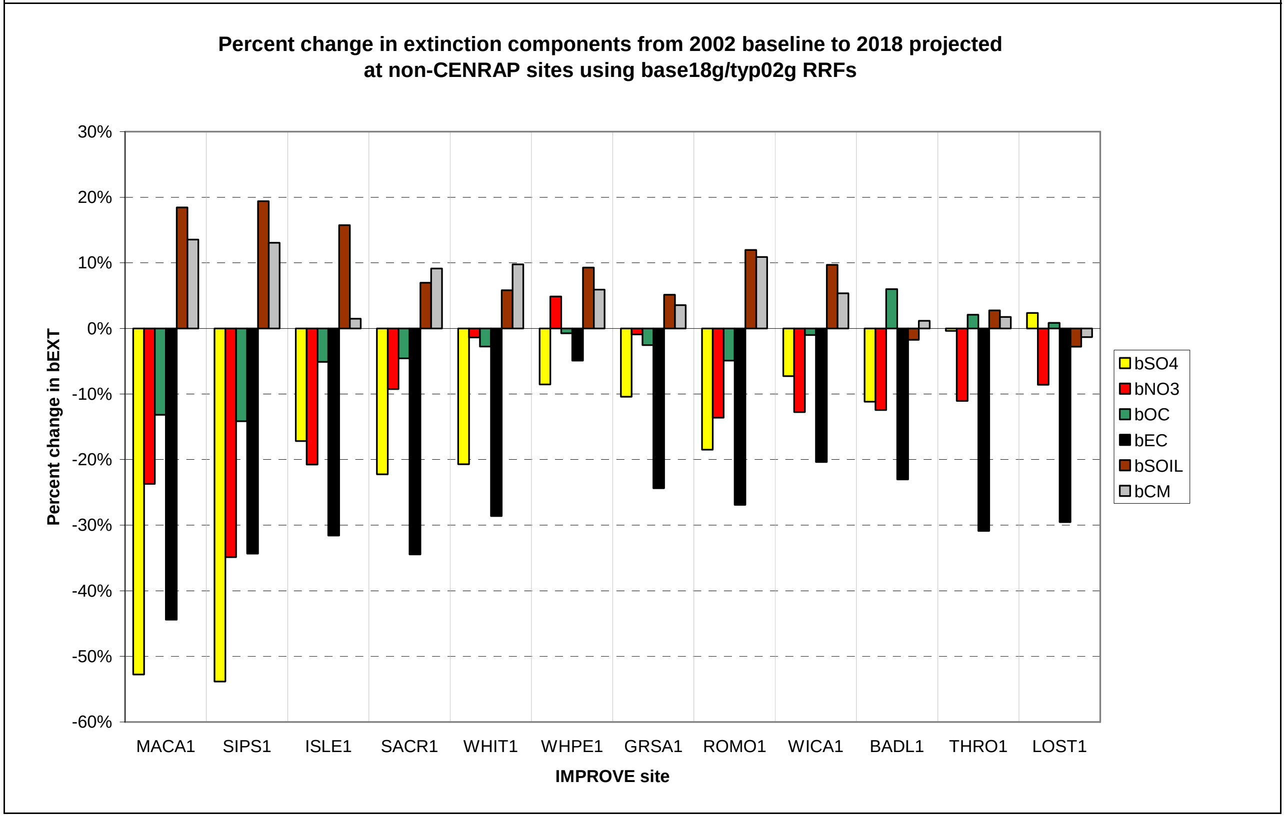


Figure 4-6. Percent Change In Modeled Extinction by PM Species Averaged Across the 2002 Worst 20 Percent Days for Class I areas in the CENRAP region (top) and Near the CENRAP region (bottom).

4.5 2018 Visibility Projections for Base G C1 Control Scenario

The 2018 visibility projections based on the CMAQ simulations for the 2018 Base G C1 Control Strategy simulations are presented in this section. The C1 Control Strategy results in reductions mainly in SO2 and NOx emissions from point sources in the CENRAP states. Consequently, PM improvements are limited to mainly SO4 and NO3 concentration reductions in the CENRAP states. Figure 4-7 displays the differences in CMAQ-estimated annual average SO4 and NO3 concentrations between the 2018 Base G base case and the 2018 Base G C1 Control Strategy case; the differences in all other PM species (with the exception of NH4) were negligible (see: http://pah.cert.ucr.edu/aqm/cenrap/cmaq.shtml#base18gc1vsbase18g). Annual average SO4 concentration reductions of over a quarter of a μg/m^3 are estimated to occur in northeast Texas, east Oklahoma, Missouri, northeast Arkansas and up into Iowa and Illinois. There are much lower reductions in NO3 that cover a similar area.

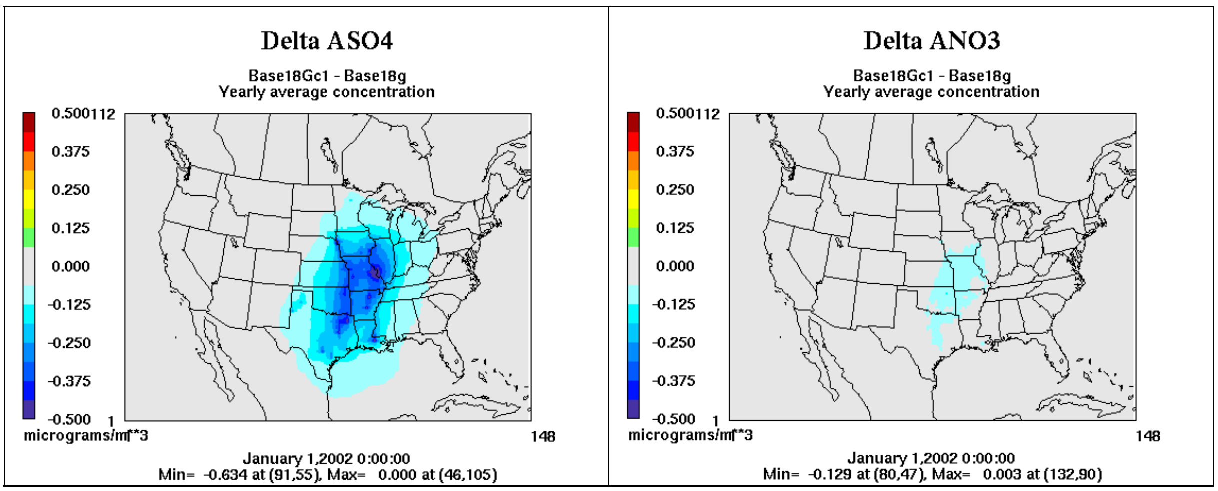


Figure 4-7. CMAQ-Estimated Reductions in Annual Average SO4 (left) and NO3 (right) Fine Particle Concentrations Between the 2018 Base G Base Case and 2018 Base G C1 Control Strategy Case.

Figure 4-8 displays the DotPlot comparisons of the 2018 visibility projections for 2018 Base G and 2018 Base G C1 Control Strategy emission scenarios. The additional controls in the C1 Control Strategy are projected to result in visibility improvements for the worst 20 percent days at Class I areas throughout and near the CENRAP region. Sites are closer to being on the glide path by 10 to 30 percent. For Breton Island this makes a difference of not meeting the 2018 URP point in 2018 Base G (94%) to surpassing the URP point in the C1 Control Strategy (106%).

Table 4-4 presents a tabular summary of the information presented in Figure 4-8, including the Baseline, 2018 URP point, and 2018 projected visibility for the Base G and C1 Control Strategy simulations.

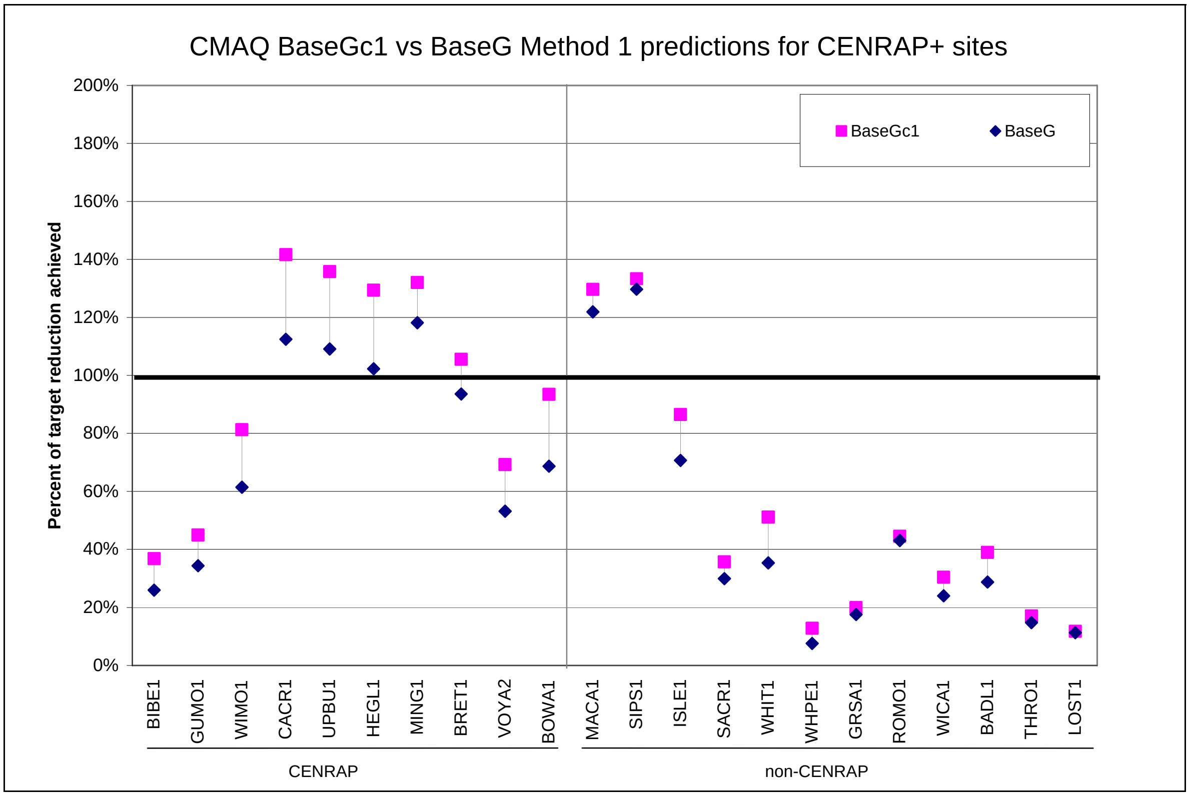


Figure 4-8. 2018 Visibility Projections as a Percentage of Meeting the 2018 URP Point (i.e., DotPlot) for the 2018 Base G and 2018 Base G C1 Control Strategy Emission Scenarios.

Table 4-4. 2000-2004 Baseline, 2018 URP Point, and Projected 2018 Visibility and Percent of Meeting the 2018 URP Point for the 2018 Base G and 2018 C1 Control Strategy CMAQ Simulations.

Class I Area Name	State	ID	Lat.	Lon.	00/04 Baseline Condit.	2018 URP Point	2018 Base G Base Case		2018 Base G C1 Control Strategy	
			(deg)	(deg)	(dv)	(dv)	(dv)	(%)	(dv)	(%)
Badlands NP	SD	BADL1	43.81	-102.36	17.14	15.02	16.53	29%	16.31	39%
Big Bend NP	TX	BIBE1	29.33	-103.31	17.30	14.93	16.69	26%	16.43	37%
Boundary Waters Canoe Area	MN	BOWA1	48.06	-91.43	19.58	17.72	18.30	69%	17.84	93%
Breton	LA	BRET1	29.87	-88.82	25.73	22.51	22.72	94%	22.34	106%
Caney Creek Wilderness	AR	CACR1	34.41	-94.08	26.36	22.91	22.48	112%	21.48	142%
Great Sand Dunes NM	CO	GRSA1	37.77	-105.57	12.78	11.35	12.53	18%	12.49	20%
Guadalupe Mountains NP	TX	GUMO1	31.91	-104.85	17.19	14.74	16.35	34%	16.09	45%
Hercules-Glades Wilderness	MO	HEGL1	36.68	-92.9	26.75	23.14	23.06	102%	22.09	129%
Isle Royale NP	MI	ISLE1	48.01	-88.83	20.74	18.78	19.36	71%	19.05	87%
Lostwood	ND	LOST1	48.59	-102.46	19.57	16.87	19.27	11%	19.26	12%
Mammoth Cave NP	KY	MACA1	37.20	-86.15	31.37	26.64	25.60	122%	25.23	130%
Mingo	MO	MING1	37.00	-90.19	28.02	24.37	23.71	118%	23.21	132%
Rocky Mountain NP	CO	ROMO1	40.35	-105.7	13.83	12.29	13.17	43%	13.14	45%
Salt Creek	NM	SACR1	33.6	-104.41	18.03	15.41	17.25	30%	17.10	36%
Sipsey Wilderness	AL	SIPS1	34.32	-87.44	29.03	24.82	23.57	130%	23.42	133%
Theodore Roosevelt NP	ND	THRO1	46.96	-103.46	17.74	15.42	17.40	15%	17.34	17%
Upper Buffalo Wilderness	AR	UPBU1	36.17	-92.41	26.27	22.84	22.52	109%	21.61	136%
Voyageurs NP	MN	VOYA2	48.47	-92.8	19.27	17.58	18.37	53%	18.10	69%
White Mountain Wilderness	NM	WHIT1	33.48	-105.85	13.70	12.11	13.14	35%	12.89	51%
Wheeler Peak Wilderness	NM	WHPE1	36.57	-105.4	10.41	9.49	10.34	8%	10.30	13%
Wind Cave NP	SD	WICA1	43.58	-103.47	15.84	13.94	15.39	24%	15.26	30%
Wichita Mountains	OK	WIMO1	34.75	-98.65	23.81	20.01	21.47	61%	20.72	81%

5.0 ADDITIONAL SUPPORTING ANALYSIS

This Chapter presents additional supporting analysis to the modeled 2018 visibility projections provided in Chapter 4. This supporting analysis may be used by the states in their RHR SIPs, along with their factor analysis, to assist in setting their 2018 RPGs for the worst 20 percent days and best 20 percent days.

5.1 Comparison of CENRAP 2018 Visibility Projections with Other Groups

2018 visibility projections for CENRAP and nearby Class I area have also been performed by the other RPOs. Thus, it is useful to compare the CENRAP 2018 visibility projections with those from the other RPOs as a quality assurance (QA) check and to foster confidence in the CENRAP modeling results.

5.1.1 Comparison of CENRAP, VISTAS, MRPO and WRAP Visibility Projections

The CENRAP 2018 Base G visibility projections were compared to the following other RPO visibility projections:

- VISTAS 2018 visibility projections based on their CMAQ 12 km 2002 annual modeling results for the 2002 Base G and 2018 Base G2a emissions scenarios.
- MRPO 2018 visibility projections based on their CAMx 36 km 2002 annual modeling for the Run 4 Scenario 1a (R4S1a) emissions scenario.
- WRAP 2018 visibility results based on their Plan02b and Base18b CMAQ 36 km modeling of the 2002 calendar year.

Figure 5-1 displays a DotPlot comparison of the four RPO visibility projections expressed as a percentage of achieving the 2018 URP point at CENRAP and nearby Class I areas. For the four CENRAP Class I areas just west of the Mississippi River in Arkansas and Missouri (CACR, UPBU, HEGL and MING), 2018 visibility projections are available from the CENRAP, VISTAS and MRPO RPOs. At HEGL, the three RPOs 2018 visibility projections are in close agreement with each other (estimated to achieve 99%, 101% and 95% of the 2018 URP point). The CENRAP and VISTAS 2018 visibility projections are also very close at the other three Arkansas-Missouri CENRAP Class I areas: CACR (112% and 116%), UPBU (109% and 112%) and MING (118% and 114%). But the MRPO 2018 visibility projections are approximately 12 to 25 percentage points lower than the CENRAP and VISTAS projections at these three Class I areas, with values of 97% to 100%. The reasons why the MRPO 2018 visibility projections are less optimistic than CENRAP and VISTAS are unclear. However, the MRPO focused on visibility projections at their northern Class I areas and likely did not use the latest CENRAP emission estimates. In addition, the CENRAP 2018 visibility projections included BART controls on several sources in CENRAP states not included in the MRPO projections. Such BART controls are even more important in those states not covered by CAIR.

For the Breton Island (BRET) Class I area, 2018 visibility projections are available from CENRAP and VISTAS. CENRAP estimates that BRET will achieve 94% of the URP point and

VISTAS is slightly less optimistic with an 84% value. One potential contributor to this is that emissions from off-shore marine vessel emissions in the oil and gas production areas of the Gulf of Mexico are double counted in the VISTAS Base G modeling. As these emissions were assumed to remain unchanged between 2002 and 2018, the double counting of their emissions will result in stiffer RRFs than there should be and consequently less visibility benefits in 2018. This double counting also occurred in the CENRAP Base F modeling but was corrected in Base G. The double counting occurred because off-shore marine vessels were present in both the MMS off-shore oil/gas development inventory for the Gulf of Mexico and the VISTAS off-shore marine vessel inventory for the Pacific and Atlanta Oceans and the Gulf of Mexico. VISTAS intends to correct this double counting in their next round of modeling.

At the two northern Minnesota Class I areas (BOWA and VOYA), the MRPO 2018 visibility projections (93% and 92%) exhibit more visibility improvements than CENRAP's (69% and 53%). This is believed to be due to higher contributions to visibility impairment from Canada in the CENRAP modeling. Figure 5-2 displays the CENRAP 2002 Base F total SO2 emissions and their differences with the 2018 Base F SO2 emissions. The SO2 emissions in Alberta Canada appear to be much higher and more wide spread when compared to the other provinces in Canada and emissions in the U.S. states. Also, there is a very large SO2 source in northern Manitoba (> 10^5 tons/year). The Alberta SO2 emissions may be overstated in the CENRAP modeling, which would overstate the Canadian contribution to visibility impairment. The western boundary of the MRPO modeling domain was east of the Rocky Mountains so did not include Alberta. CENRAP confirmed that the Alberta emissions and the source in Manitoba were present in the emissions provided by Canada. Air parcels from Canada are generally associated with clean visibility conditions at the northern Minnesota Class I areas with the worst 20 percent days generally occurring under conditions with a southerly wind component. However, in 2002 some of the worst 20 percent days did occur with transport out of Canada. For example, Figure 5-3 displays back trajectories off of the VIEWS website for two of the worst 20 percent days at Voyageurs National Park (Julian Days 347 and 332). These back trajectories suggest that the potentially overstated emissions in Alberta would have an impact at VOYA during the worst 20 percent days in 2002.

At the VISTAS Mammoth Cave (MACA), Kentucky Class I area, VISTAS, CENRAP and the MRPO estimated that 2018 visibility for the worst 20 percent days will achieve, respectively, 122%, 123% and 102% of the 2018 URP point. The close agreement between the VISTAS (122%) and CENRAP (123%) 2018 visibility projections for MACA is encouraging. Why MRPO is 20 percentage points lower is unclear, but may be due to using earlier versions of the VISTAS and CENRAP emissions. The 2018 visibility projections at Sipsey (SIPS), Alabama estimated by VISTAS (127%) and CENRAP (130%) are also extremely close.

Both the CENRAP and WRAP 2018 visibility projections agree that the WRAP Class I areas fail to achieve the 2018 URP point by a wide margin, with values achieving only ~40% or less of the 2018 URP point. The CENRAP 2018 visibility projections agrees well with the WRAP values at Great Sands (GRSA), Colorado (18% vs. 15%), Badlands (BADL), South Dakota (24% vs. 31%), Theodore Roosevelt, North Dakota (15% vs. 11%) and Lostwood (LOST), Montana (11% vs. 14%). There is also reasonable agreement between CENRAP and WRAP 2018 visibility projections at Salt Creek (SACR), New Mexico (30% vs. 12%), Rocky Mountain (ROMO), Colorado (43% vs. 30%), and Wind Cave (WICA), South Dakota (24% vs. 6%). There are two WRAP Class I areas, White Mountains (WHIT) and Wheeler Peak (WEPE), where the WRAP

2018 visibility projections estimate that visibility will degrade for the worst 20 percent days (i.e., negative percent of achieving the 2018 URP point), whereas CENRAP estimates visibility improvements. The reasons for these differences are unclear.

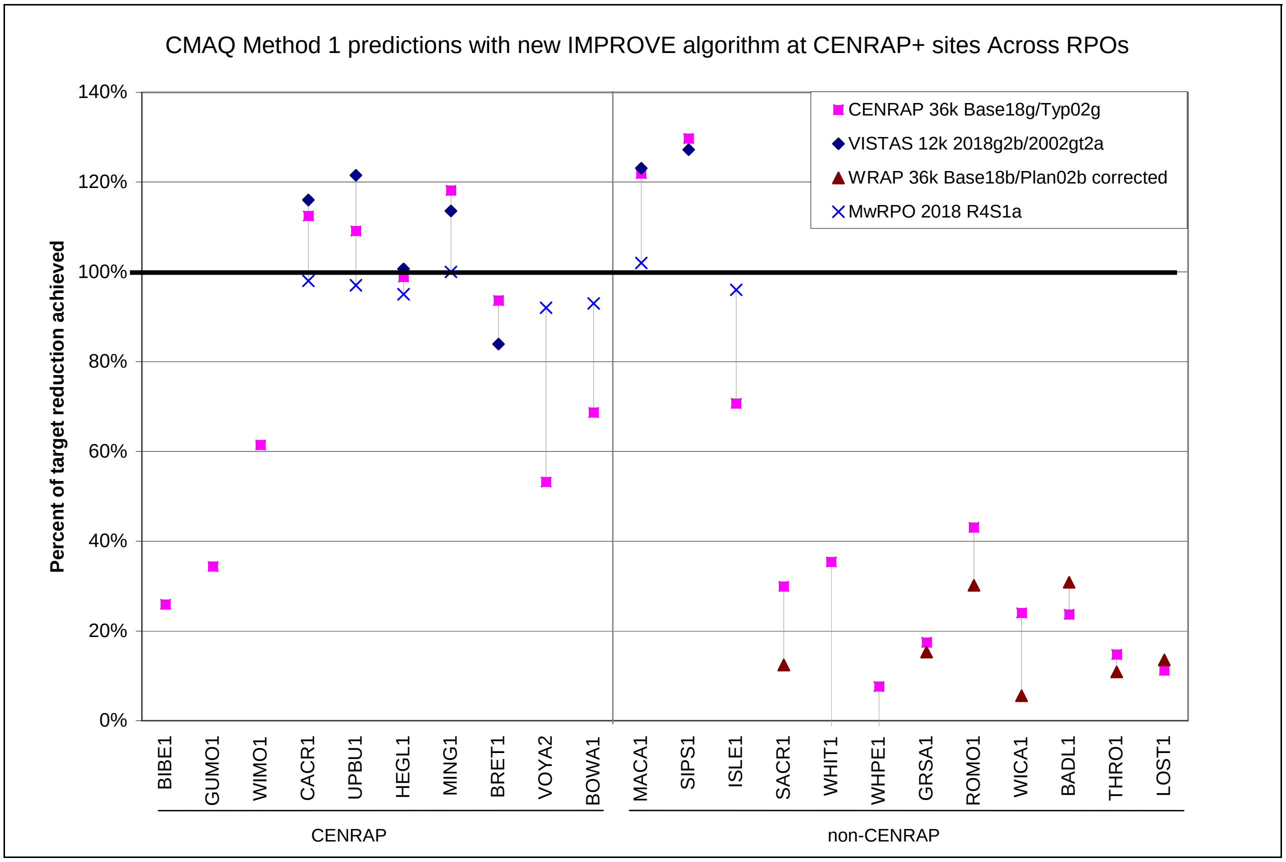


Figure 5-1. DotPlot comparing the CENRAP, VISTAS, MRPO and WRAP 2018 visibility projections expressed as a percentage of achieving the 2018 URP goal.

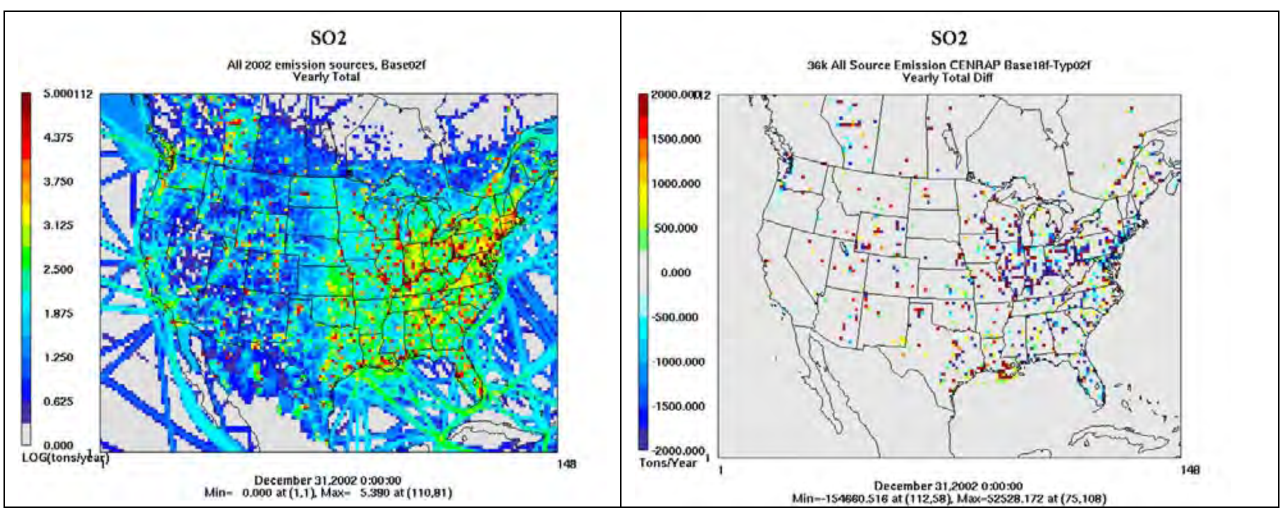


Figure 5-2. 2002 Base F SO2 emissions (left) as LOG10(tons/year) and differences in 2018 and 2002 Base F SO2 emissions (tons/year).

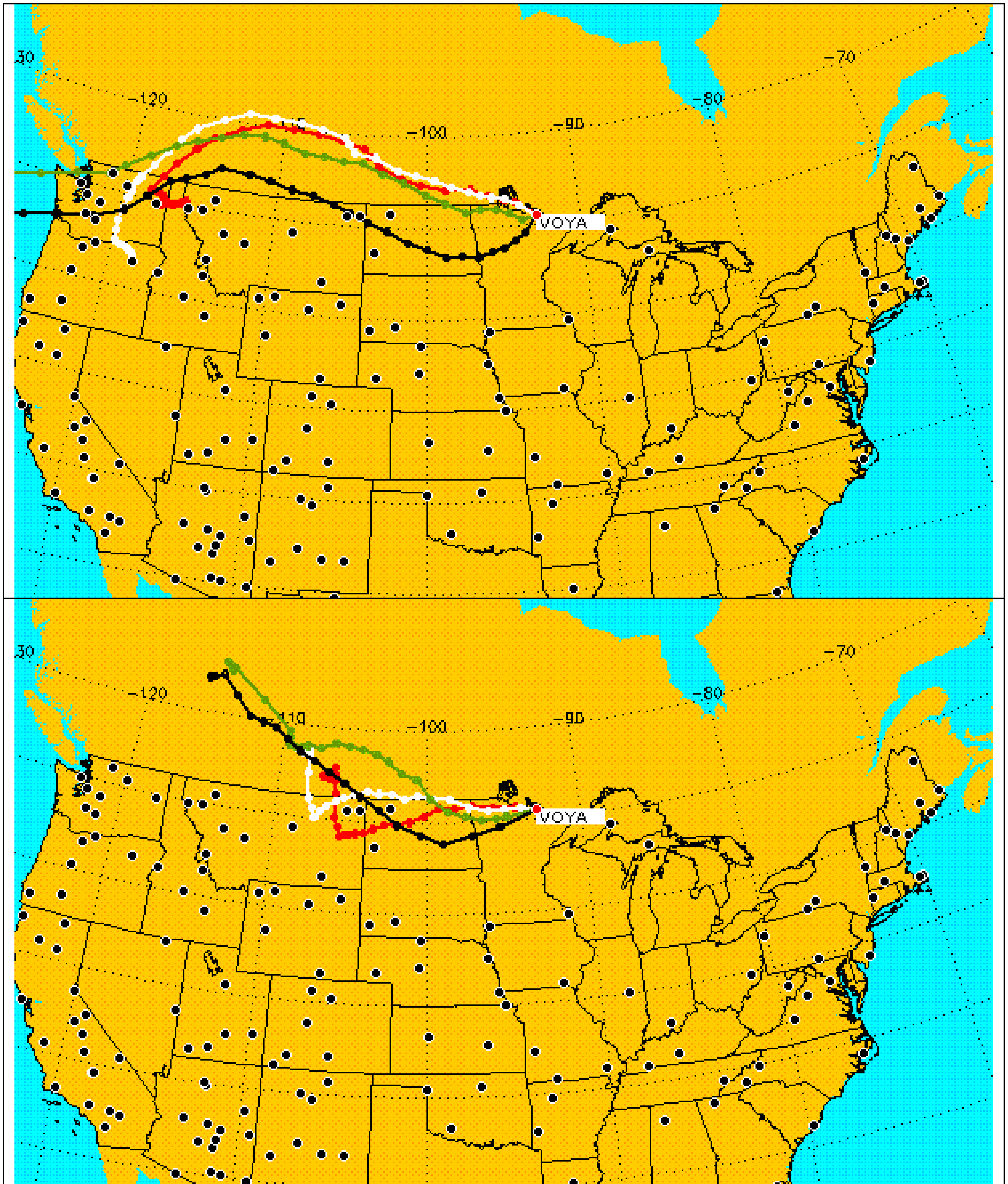


Figure 5-3. Exampled back trajectories to Voyageurs National Park for two of the worst 20 percent days from 2002: December 13, 2002 (Julian Day 347) and November 28, 2002 (Julian Day 332).

5.2 Extinction and PM Species Specific Visibility Projections and Comparisons to 2018 URP Point

It is useful to examine 2018 visibility projections by PM species to determine how each PM component of visibility is changing as both a diagnostic analysis of the visibility projections as well as whether species that are associated more with anthropogenic emissions (e.g., SO4 and NO3) are being reduced substantially compared to those that are less influenced by anthropogenic emissions (e.g., Soil and CM). However, because deciview is the natural logarithm of total extinction, such comparisons can not be made using the deciview scale and must be made using extinction. The linear glidepath from which the 2018 URP points are derived are based on deciview, thus to examine corresponding glidepath using extinction the curvature associated with the logarithmic transformation of the linear deciview glidepath to extinction must be accounted for in the extinction glidepath.

5.2.1 Total Extinction Glidepaths

Figure 5-4 displays a total extinction based glidepath for Caney Creek that is based on the EPA default deciview linear glidepath counterpart shown in Figure 4-3a. That is, the deciview linear glidepath defined by the line connecting the 26.36 dv Baseline Conditions at 2004 to the 11.58 dv Natural Conditions in 2064. The glidepath points in 2008, 2018, 2028, etc. from the linear deciview glidepath (Figure 4-3a) are turned into extinction (Bext) [Bext = 10 exp(dv/10)] to create the curved extinction glidepath that exactly match the linear deciview glidepath points. Note that the 2000-2004 Baseline using the curved extinction glidepath is slightly different than if you just converted the deciview baseline to extinction because the logarithm relationship is performed before the averaging, but they are extremely close. Using the extinction curved glidepath, the 2018 URP point is a reduction of the Baseline 145.10 Mm^{-1} to 98.88 Mm^{-1} (a 46.22 Mm^{-1} reduction). The modeled 2018 visibility projection in extinction is 97.54 Mm^{-1}, a 47.56 Mm^{-1} reduction, which achieves 103% of the reduction needed to achieve the 2018 URP point. Note that this compares with achieving 112% of the 2018 URP reduction point when using the deciview linear glidepath. The percent of achieving the 2018 URP point using the linear deciview and curved extinction glidepaths will rarely be the same due to the logarithmic relationship between the two visibility metrics and the fact that averaging within and across years in the deciview calculations occur after the logarithms have been applied. The greater the difference in extinction across the worst 20 percent days in a year and averaged across the years in the 2000-2004 Baseline and the greater number of years available from the 2000-2004 Baseline may result in greater differences in the 2018 URP points using the linear deciview and the curved extinction glidepaths.

Appendix F contains total extinction curved glidepaths for all the CENRAP Class I areas and Figure 5-5 contains a DotPlot that compares the percent of achieving the 2018 URP point at each CENRAP Class I area using the 2018 Base G modeling results and the linear deciview and curved extinction glidepaths. At most CENRAP Class I areas the ability of the 2018 modeling results to achieve the 2018 URP point is the same using either the deciview or extinction glidepaths. There are some differences at GUMO, BOWA and VOYA Class I areas which are due to these Class I areas having more complete data during the 2000-2004 Baseline period and therefore more years in the Baseline than other Class I areas as well as having variations in extinction across the worst 20 percent days and years (Appendix F). In any event, the closeness of the ability of the model to achieve the 2018 URP point using either the extinction or deciview glidepath verifies the validity of the extinction based glidepaths and allows for the construction of PM species specific glidepaths in extinction to gain insight into how each component of extinction is being reduced to achieve a uniform rate of progress toward natural conditions in 2064.

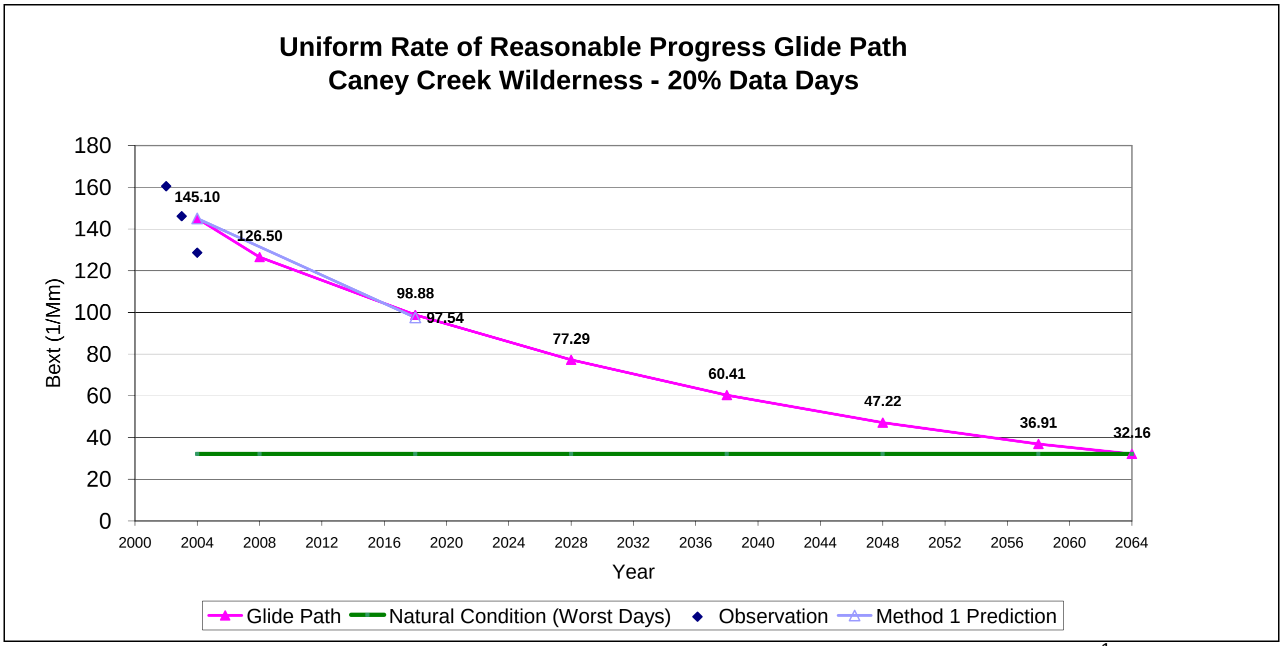


Figure 5-4. 2018 Visibility Projections and 2018 URP Glidepaths in extinction (Mm^{-1}) for Caney Creek (CACR), Arkansas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

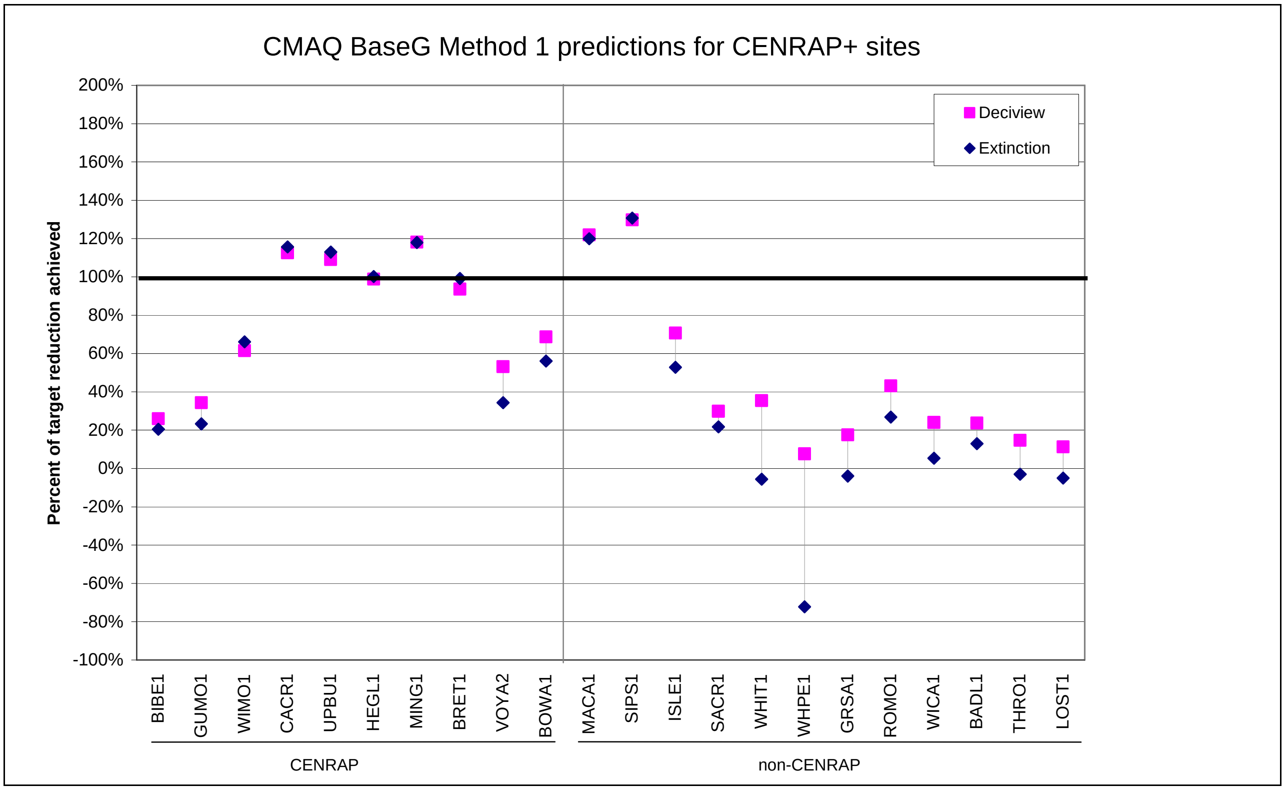


Figure 5-5. CMAQ 2018 Base G visibility projections and comparison of ability to achieve the 2018 URP point using the EPA default deciview and alternative total extinction Glidepaths.

5.2.2 PM Species specific Glidepaths

The VIEWS website (http://vista.cira.colostate.edu/views/) has posted PM species specific Natural Conditions based on the new IMPROVE equation. Using these PM species specific Natural Conditions and the curved extinction glidepaths we can evaluate how well visibility extinction achieves the 2018 URP point on a species-by-species basis. The PM species specific glidepaths are constructing starting with a Baseline at 2004 averaging the extinction for each PM species measured using the 2000-2004 IMPROVE observations and ending with the Natural Conditions in 2064 from the VIEWS website. Points in the glidepath for the years in between 2004 and 2064 are constructed based on the relative differences in the 2004 Baseline and 2064 Natural Conditions PM species extinction such that the total extinction due to all PM species at each interim year adds up to the same as the total extinction on the extinction-based glidepath (e.g., Figure 5-3). For example, for the CACR SO4 extinction glidepath the 2018 URP point is generated from the 2004 and 2064 SO4 extinction (BSO4) and the 2004, 2018 and 2064 total extinction (BTOT) as follows:

$$
\begin{aligned}
\text{BSO4\_2018} &= \text{BSO4\_2004} - [(\text{BSO4\_2004} - \text{BSO4\_2064})/ \\
&\quad (\text{BTOT\_2004} - \text{BTOT\_2064})] \times (\text{BTOT\_2004} - \text{BTOT\_2018}) \\
&= 87.05 - [(87.05 - 3.20)/(145.10 - 32.16)] \times (145.10 - 98.88) \\
&= 52.73\ \text{Mm}^{-1}
\end{aligned}
$$

Note that the SO4 2018 URP point in Figure 5-5 and F-1b (52.77 Mm-1) does not exactly match the 52.73 Mm^{-1} calculated due to round off error in the above calculation that only used numbers with precision to the nearest hundredth.

As there are larger differences between the Baseline and Natural PM species extinction for some species, then the rate of improvement to achieve a species specific 2018 URP point will vary across PM species. For example, current Baseline extinction values for Soil and CM tend to be closer to Natural Conditions than extinction due to SO4 and NO3. Consequently the rate of progress to achieve the 2018 URP point for Soil and CM will be less than for SO4 and NO3.

Appendix F contains the PM species specific glidepaths compares them to the modeled 2018 projections for all CENRAP Class I areas. The species specific results for the CACR Class I area in Figure F-1 are reproduced in Figure 5-6. The modeled rate of SO4 and NO3 extinction reduction is greater than the PM species specific glidepaths and both achieve the species specific 2018 URP point by achieving 111% and 104% of the reduction needed to achieve the 2018 URP point. The modeled rate of extinction improvement at CACR for EC and OC is less than the species specific glidepath achieving only 65% and 75% of the reduction needed to achieve the species specific 2018 URP point. The PM species specific glidepath for Soil is flat because the Baseline and Natural Conditions (1.12 Mm^{-1}) are the same. This does not mean that anthropogenic emissions of Soil do not contribute on worst 20 percent days at CACR. It just points to a mismatch between the current set of worst 20 percent days and those in 2064 under Natural Conditions. The worst 20 percent days in 2064 under Natural Conditions will be dominated by wind blown dust days when Soil and CM may be higher than during the current set of worst 20 percent days that are dominated by SO4, NO3 and OMC. Thus, the Soil and CM glidepaths tend to be flatter and in some cases may even have an upward trend for some Class I areas (see Appendix F). Soil is projected to increase at CACR in 2018 so does not achieve its species specific URP point. Little reduction in CM is also seen by 2018. As discussed previously, this is due in part to incompatibilities between the measured Soil and CM values at the IMPROVE monitor and the modeled Soil and CM species. In the model, a large component of the Soil and CM in the inventory is due to paved and unpaved road dust. These emissions are directly related to Vehicles Miles Traveled (VMT). VMT is projected to increase in future-years resulting in increases in road dust emissions. At the IMPROVE monitor, much of the measured Soil and CM is likely due to local dust events that are not simulated by the model using a 36 km grid resolution. Thus, the 2018 projections for Soil and CM are likely applying modeled changes due to road dust to local Soil and CM concentrations that in reality are likely natural and should remain unchanged in the future year. This is why alternative 2018 modeled projection approaches have been developed that assume that CM and CM and Soil are natural so remain unchanged in the future-year (see Section 5.5).

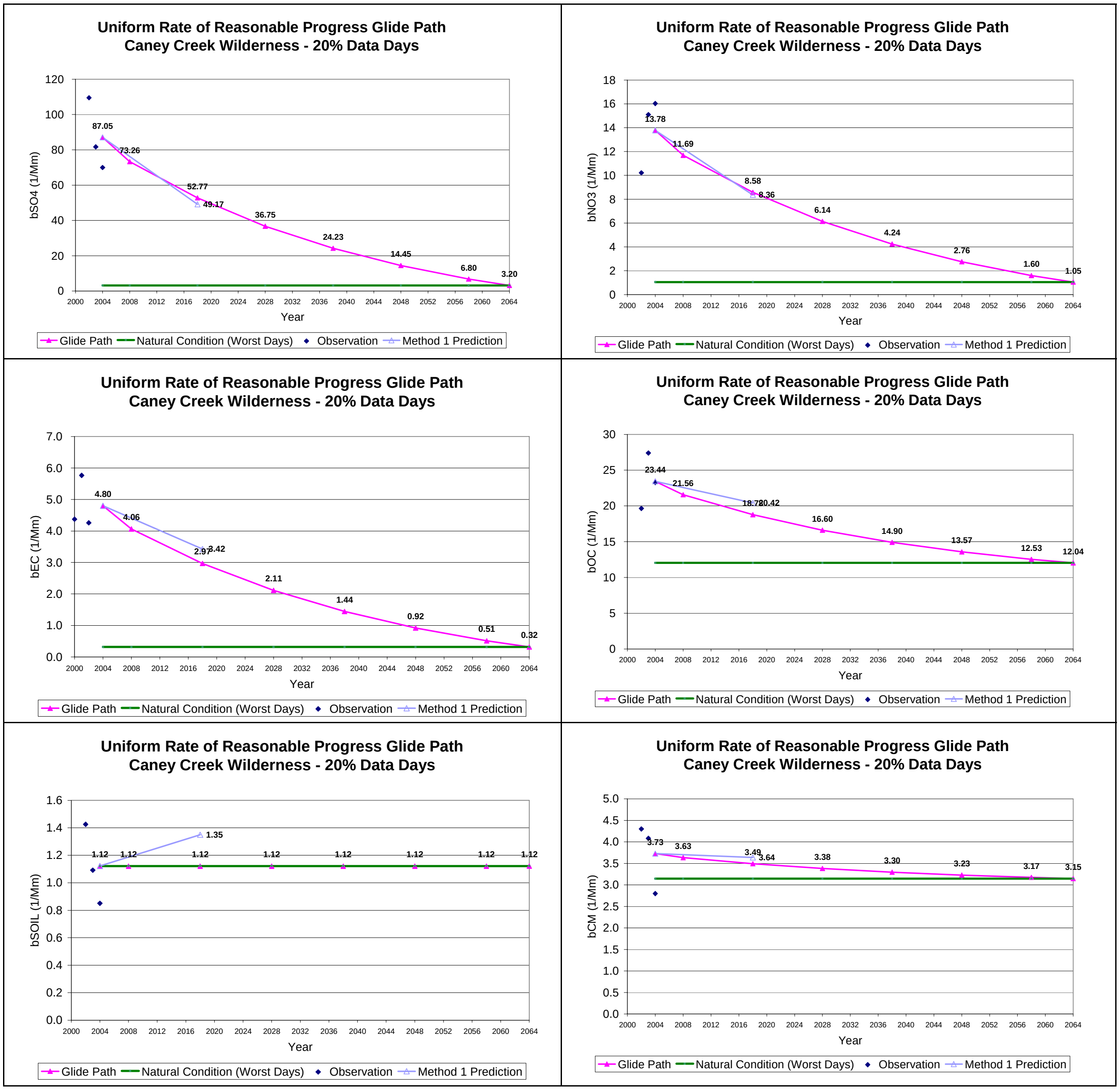


Figure 5-6. 2018 Visibility Projections and 2018 URP Glidepaths for SO4 (top left), NO3 (top right), EC (middle left), OMC (middle right), Soil (bottom left) and CM (bottom right) in extinction (Mm^{-1}) for Caney Creek (CACR), Arkansas and Worst 20 Percent Days using 2002/2018 Base G CMAQ 36 km modeling results.

Figure 5-7 displays a DotPlot that compares the 2018 projected total and PM species specific extinction with the 2018 URP points. These results show that SO4 is most frequently achieving its 2018 URP point at those Class I areas that achieve the deciview URP point. Reductions in NO3 and EC also sometimes achieve their species specific URP point.

There are some anomalies in the species specific projections and glidepaths that bear mention and point to areas where better estimates of emissions growth and Natural Conditions are needed needed. The increase in 2018 Soil projections is not an isolated incident at CACR and occurs at other CENRAP Class I areas. There are three CENRAP Class I areas that "achieve" the Soil specific 2018 URP point (HEGL, BOWA and VOYA). An examination of these glidepaths and visibility projections (Figures F-4f, F-5f and F-6f) reveals that the current Baseline Conditions Soil at these three Class I areas is actually less than the 2064 Natural Conditions so that the glidepath is an accent rather than reduction (Figures F-4g, F-5g and F-6g). In these three cases to "achieve" the 2018 URP point the modeling results must increase the projected Soil extinction, which is why these three Class I areas "achieve" their 2018 URP point for Soil. Clearly, the 2018 URP point for Soil is not very meaningful under these conditions. The current Baseline Conditions for OMC at BRET and BOWA is also less than the Natural Conditions resulting in anomalous glidepaths (Figure F-3e and F-4e).

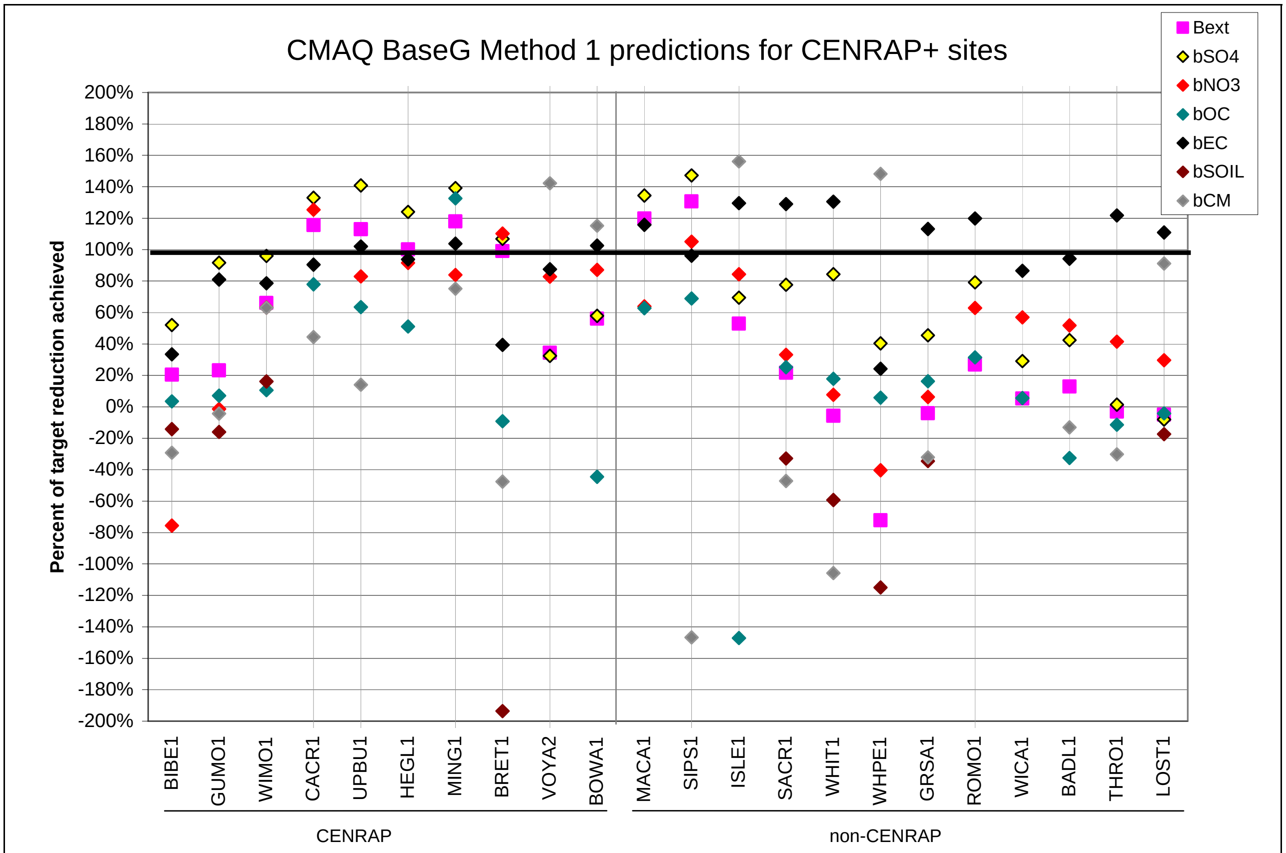


Figure 5-7. Ability of total and species specific 2018 visibility projections to achieve 2018 URP points.

5.3 Alternative 2018 Visibility Projection Software

The CENRAP 2018 visibility projections were made using software developed by the CENRAP modeling team. PM concentrations in the 36 km grid cells containing each of the Class I area IMPROVE monitoring sites were extracted using the UCR Analysis Tool. These modeling data were then ported into Excel spreadsheets that also include the filled RHR IMPROVE database available from the VIEWS website along with the EPA default Natural Conditions (EPA, 2003b). Excel macros are then used to perform the visibility projections using the EPA default procedures described in Chapter 4 and alternative procedures described in this Chapter.

EPA is developing a Modeled Attainment Test Software (MATS) program that codifies the 8-hour ozone, $PM_{2.5}$ and visibility projection procedures given in EPA's latest air quality modeling guidance (EPA, 2007a). The June 2007 release of the beta version of MATS is capable of performing 8-hour ozone and visibility projections; MATS is still under development for making $PM_{2.5}$ projections. The June 2007 beta versions of MATS was applied to the CENRAP 2002 and 2018 Base G 36 km CMAQ results and the resultant 2018 visibility projections were compared with the CENRAP values using the EPA default projection approach (see Chapter 4) at CENRAP and nearby Class I areas. The projected 2018 visibility estimates using the CENRAP and EPA MATS software are shown in Table 5-1. The biggest differences in the two 2018 visibility projections are for the Boundary Waters (BOWA). Breton Island (BRET), and Mingo (MING) Class I areas where MATS produces no 2018 visibility projections. This is because there is insufficient capture of valid IMPROVE PM measurements within the 2000-2004 five-year baseline to generate three years of annual visibility estimates that is the minimum needed to develop the Baseline Conditions following EPA's guidance (EPA, 2003a). For the CENRAP projections, data filling was used to fill out the IMPROVE measurements with sufficient data so that Baseline Conditions could be calculated at these three Class I areas. At 14 of the remaining 17 Class I areas, the CENRAP and MATS 2018 visibility projections agree exactly to within a hundredth of a deciview. At the three sites that are different (BIBE, GUMO and ISLE) the difference is 0.01 dv, which is 0.06 percent or less. These differences are likely due to round off errors in the calculations and are not significant. These results verify the consistency with the CENRAP spreadsheet based and EPA MATS software for projecting future-year visibility estimates.

Table 5-1. Comparison of CENRAP and EPA MATS 2018 visibility projections at CENRAP and nearby Class I areas.

	2018 Visibility Projections		2000-2004 Baseline Conditions	
Site	**MATS (dv)**	**CENRAP (dv)**	**MATS (dv)**	**CENRAP (dv)**
BADL	16.53	16.53	17.14	17.14
BIBE	16.70	16.69	17.30	17.30
BOWA	NA	18.30	NA	19.58
BRET	NA	22.72	NA	25.73
CACR	22.48	22.48	26.36	26.36
GRSA	12.53	12.53	12.78	12.78
GUMO	16.36	16.35	17.19	17.19
HEGL	23.06	23.06	26.75	26.75
ISLE	19.35	19.36	20.74	20.74
LOST	19.27	19.27	19.57	19.57
MACA	25.60	25.60	31.37	31.37
MING	NA	23.71	NA	28.02
ROMO	13.17	13.17	13.83	13.83
SACR	17.25	17.25	18.03	18.03
SIPS	23.57	23.57	29.03	29.03
THRO	17.40	17.40	17.74	17.74
UPBU	22.52	22.52	26.27	26.27
VOYA	18.37	18.37	19.27	19.27
WHIT	13.14	13.14	13.70	13.70
WHPE	10.34	10.34	10.41	10.41
WICA	15.39	15.39	15.84	15.84
WIMO	21.47	21.47	23.81	23.81

NA = Not Available

5.4 PM Source Apportionment Modeling

The PM Source Apportionment Technology (PSAT) was used to obtain PM source apportionment by geographic regions and major source category for the CENRAP 2002 and 2018 Base E base case conditions. PSAT uses reactive tracers that operated in parallel to the CAMx host model using the same emissions, transport, chemical transformation and deposition rates as the host model to account for the contributions of user specified source regions and categories to PM concentrations throughout the modeling domain. Details on the formulation of the CAMx PSAT source apportionment can be found in the CAMx user's guidance (ENVIRON, 2006; www.camx.com).

5.4.1 Definition of CENRAP 2002 and 2018 PM Source Apportionment Modeling

PSAT calculated PM source apportionment for user defined source groups. Source groups are usually defined by specifying a source region map of geographic regions where source contributions are desired and providing source categories as input so that source group would consist of a geographic region plus source category (e.g., on-road mobile source emissions from Oklahoma). Although other source group configurations and even individual sources may be specified. For the CENRAP PSAT application, a source region map was used that divided up the modeling domain into 30 geographic source regions as shown in Figure 5-8. The 2002 and 2018 emissions inventories were divided into six source categories. The 30 geographic source regions consisted of CENRAP and nearby states, with Texas divided into 3 regions, remainder of the western and eastern States, Gulf of Mexico, Canada and Mexico. The original intent of the CENRAP PSAT analysis was to obtain separate contributions due to on-road mobile, non-road mobile, area, natural, EGU point and non-EGU point sources. However, the CAMx emissions for the PSAT runs were based on the CMAQ pre-merged 3-D emission files. Since all point sources were contained in a single CMAQ pre-merged emissions file, then the separate source apportionment modeling of EGU and non-EGU point sources was not possible. The six source categories that were separately tracked in the PSAT PM source apportionment modeling were:

- Elevated point sources;
- Low-level point sources (i.e., point source emissions emitted into layer 1 of the model);
- On-Road Mobile Sources;
- Non-Road Mobile Sources;
- Area Sources; and
- Natural Sources.

Natural Sources included biogenic VOC and NOx emissions from the BEIS3 biogenic emissions model, emissions from wildfires and emissions from wind blown dust due to non-agriculture land use types.

PM source apportionment in PSAT is available for five families of PM tracers: (1) Sulfate; (2) Nitrate and Ammonium; (3) Secondary Organic Aerosols (SOA); (4) Primary PM; and (5) mercury. The CENRAP PSAT 2002 and 2018 applications used three of the PSAT families of tracers and did not use the SOA and mercury families. For SOA, the standard CAMx model output was used that partitions SOA into an anthropogenic (SOAA) and biogenic (SOAB) components.

The PSAT results were extracted at the CENRAP and nearby Class I areas and the contributions for the average of the worst 20 percent and best 20 percent days were processed. A PSAT Visualization Tool was developed that can be used by States, Tribes and others to generate displays of the contributions of source regions and categories to visibility impairment for the average of the worst 20 percent and best 20 percent days at each CENRAP and nearby Class I areas.

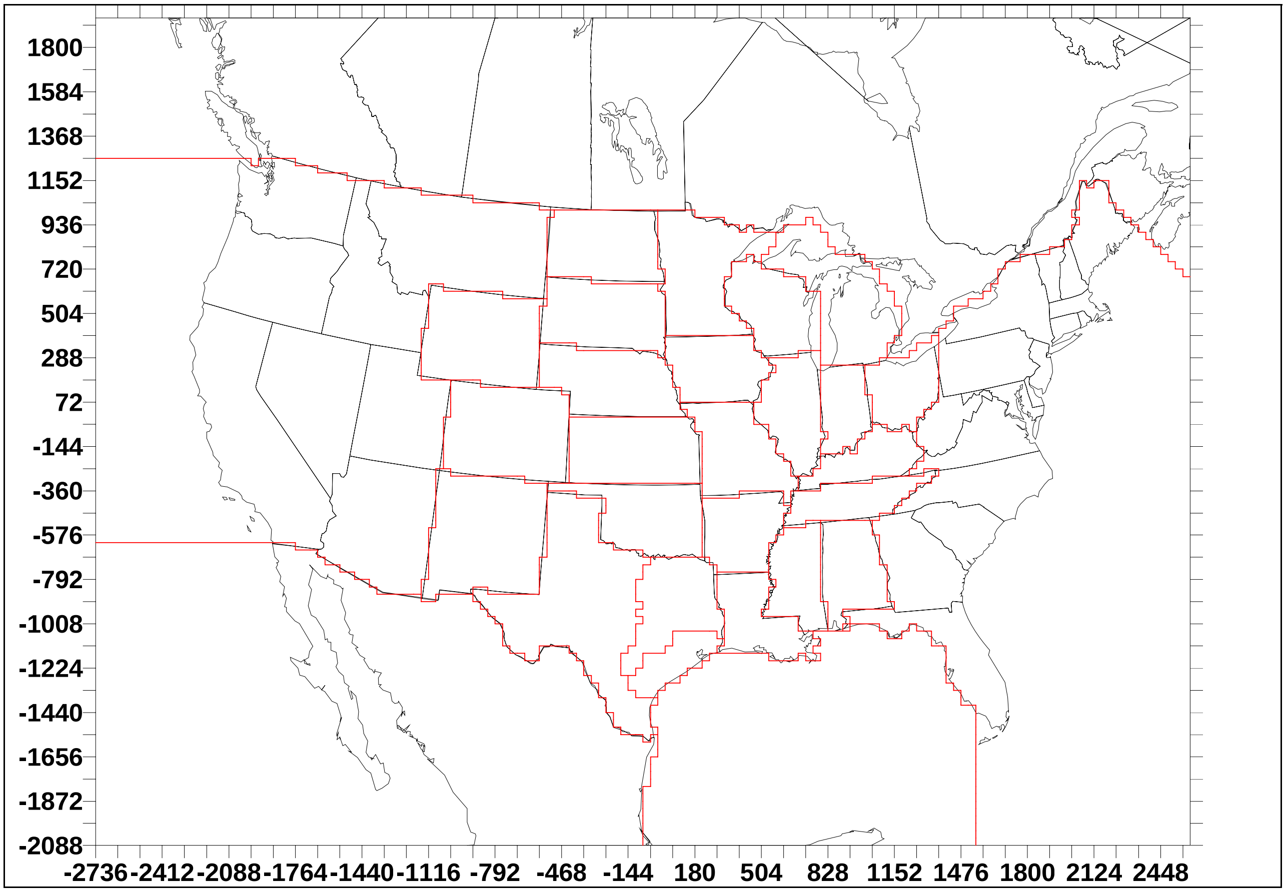


Figure 5-8. 30 source regions used in the CENRAP 2002 and 2018 CAMx PSAT PM source apportionment modeling.

5.4.2 CENRAP PSAT Visualization Tool

The PSAT Visualization Tool allows CENRAP States, Tribes and others to visualize the CENRAP 2002 and 2018 PSAT modeling results and identify which source regions, categories and PM species are contributing to visibility impairment at Class I areas for the average of the worst 20 percent and best 20 percent visibility days. The Visualization Tool is currently available on the CENRAP website (http://www.cenrap.org) under Projects. The Tool can generate bar charts of source contributions at Class I areas. It can be run in a receptor oriented mode where it identifies the contributions of PM species and source regions and categories to visibility impairment on the worst and best 20 percent days. It can also be run in a source oriented mode to examine an individual source region's (State's) contribution to visibility impairment at downwind Class I areas on the worst and best 20% days. The original IMPROVE equation is used to convert the PM species concentrations to extinction.

There are 14 air quality analysis metrics in the Tool:

> W20% Modeled Bext: The source region, source category and PM species contributions to the extinction (Bext) at a Class I area estimated by the model averaged across the worst 20 percent days in 2002.

W20% Projected Bext: The source region, source category and PM species contributions to the extinction (Bext) at a Class I area projected by the model averaged across the worst 20 percent days in the 2000-2004 Baseline.

W20% Modeled USAnthro: The source region, source category and PM species contributions to the extinction (Bext) at a Class I area for just U.S. anthropogenic emission source categories estimated by the model averaged across the worst 20 percent days in 2002.

W20% Projected USAnthro: The source region, source category and PM species contributions to the extinction (Bext) at a Class I area for just U.S. anthropogenic emission source categories projected by the model averaged across the worst 20 percent days in the 2000-2004 Baseline.

Emissions: Emissions by source region, source category and PM precursor. Precursors include SOx, NOx, primary organic aerosol (POA), primary elemental carbon (PEC) other primary fine particulate (FCRS+FPRM) and coarse mass (CCRS+CPRM). Emissions for four days have been extracted and implemented in the Tool.

Control Effectiveness: Control effectiveness is defined as the PM contribution divided by the emissions of the primary precursor. For example the SO4 contribution divided by the SO2 emissions.

Visualization Tool results are available for visibility contributions on both an absolute (Mm^{-1}) and percentage basis. When looking at contributions at a given Class I area, contributions can be examined in terms of PM species, source regions and/or source categories. Results are available for both the current year (2002 modeled or 2000-2004 projected) and future year (2018). The "2002 W20% Project Bext" metric applies the 2002 PSAT modeled source apportionment to the observed 2000-2004 Baseline extinction keeping the relative contributions of source groups to each PM species (e.g., SO4, NO3, etc.) the same averaged across the 2002 worst 20 percent days but scaling their magnitudes up or down based on the ratio of the 2000-2004 Baseline to the 2002 modeling results. Similarly, the "2018 W20% Projected" metric uses the relative contributions of the 2018 PSAT results from each source group and scales them according to the differences in the 2018 projected PM species to the 2018 modeled PM species for the average of the worst 20 percent days. The US Anthropogenic metrics just include source groups associated with U.S. man-made emissions (i.e., non-Natural source categories from states and Gulf of Mexico source regions) so excludes contributions from Canada and Mexico, Boundary Conditions, SOA from biogenic sources and the natural source category (biogenic NOx, wildfires and wind blown dust).

5.4.3 Source Contributions to Visibility Impairment at Class I Areas

Appendix E displays example contributions of PM species, source regions and source categories to visibility impairment for the worst and best 20 percent days at the CENRAP Class I areas. Some of the results from Figure E-1 for the CACR Class I area are reproduced in Figures 5-9, 5-10 and 5-11 below.

5.4.3.1 Caney Creek (CACR) Arkansas

2002 visibility impairment for the worst 20 percent days at CACR is primarily due to SO4 from elevated point sources that contributes over half (66.3 Mm^{-1}) of the total extinction of 118.8 Mm^{-1} (Figure E-1a and 5-8 left). By 2018, the total extinction at CACR for the worst 20 percent days is reduced by approximately one third (38.5 Mm^{-1}) which is primarily due to reductions in SO4 extinction from elevated point sources (from 66.3 to 37.3 Mm^{-1}) as well as reductions in visibility impairment from on-road and non-road mobile sources. Even with such large reductions in SO4 from point sources in 2018, extinction due to elevated point sources is still the highest contributor to visibility impairment on the worst 20 percent days contributing over half (41.8 Mm^{-1}) of the total extinction in 2018 of 80.3 Mm^{-1}, with area sources the next most important source category contributing 16.0 Mm^{-1} (~20%).

The geographic source apportionment for the worst 20 percent says at CACR is shown in Figures 5-10, E-1c and E-1d. Elevated point sources from the eastern source region is the largest contributor in 2002 contributing almost 18 Mm^{-1} that is reduced by over a factor of three in 2018 to approximately 5 Mm^{-1}. By 2018, Arkansas is the largest contributor to extinction at CACR for the 20 percent worst days followed by East Texas, the large Eastern U.S. region and then SOA due to biogenic sources. Figures E-1e ranks the source group contributions to extinction on the worst 20 percent days at CACR with Elevated Point Sources from East Texas being the highest contributor to total extinction, similar results are seen when examining extinction at CACR for the worst 20 percent days due to just SO4 and NO3 (Figure E-1f).

For the best 20 percent days at CACR (Figures 5-11, E-1g-j), SO4 is still a major contributor but no where near as dominate as seen for the worst 20 percent days, but elevated point is still the largest contributing source category Local contributions from within Arkansas contribute the most to the average of extinction across the best 20 percent days at CACR.

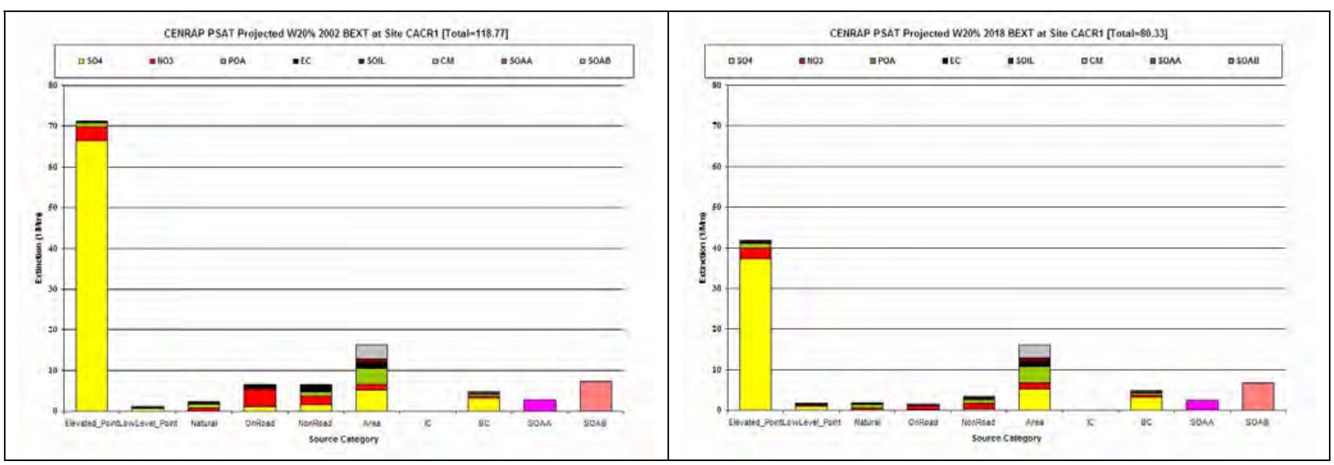


Figure 5-9. PSAT source category by PM species contributions to the average 2000-2004 Baseline and 2018 projected extinction (Mm^{-1}) for the worst 20 percent visibility days at Caney Creek (CACR), Arkansas.

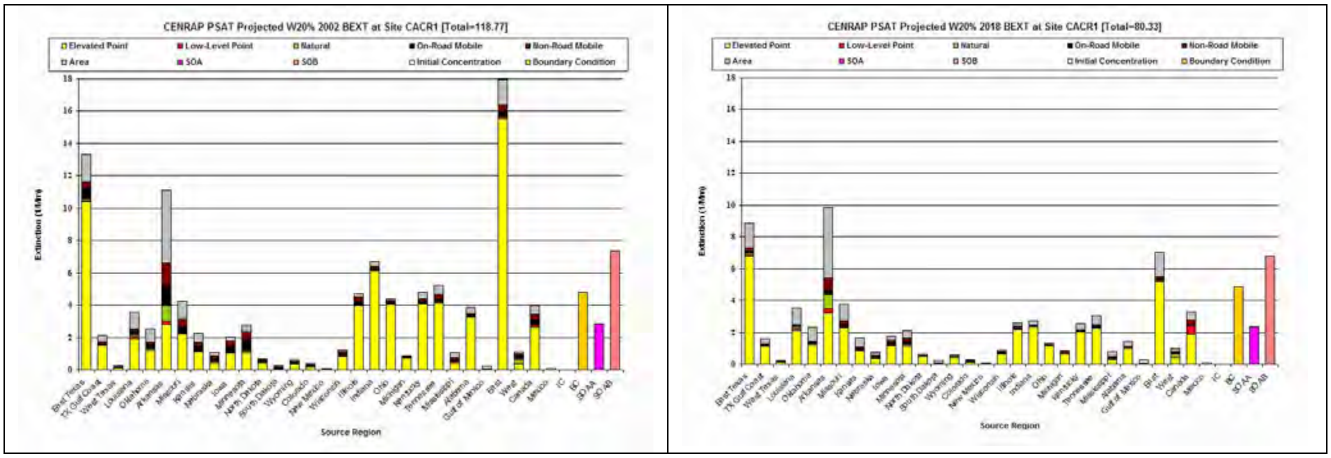


Figure 5-10. PSAT source region by source category contributions to the average 2000-2004 Baseline and 2018 projected extinction (Mm^{-1}) for the worst 20 percent visibility days at Caney Creek (CACR), Arkansas.

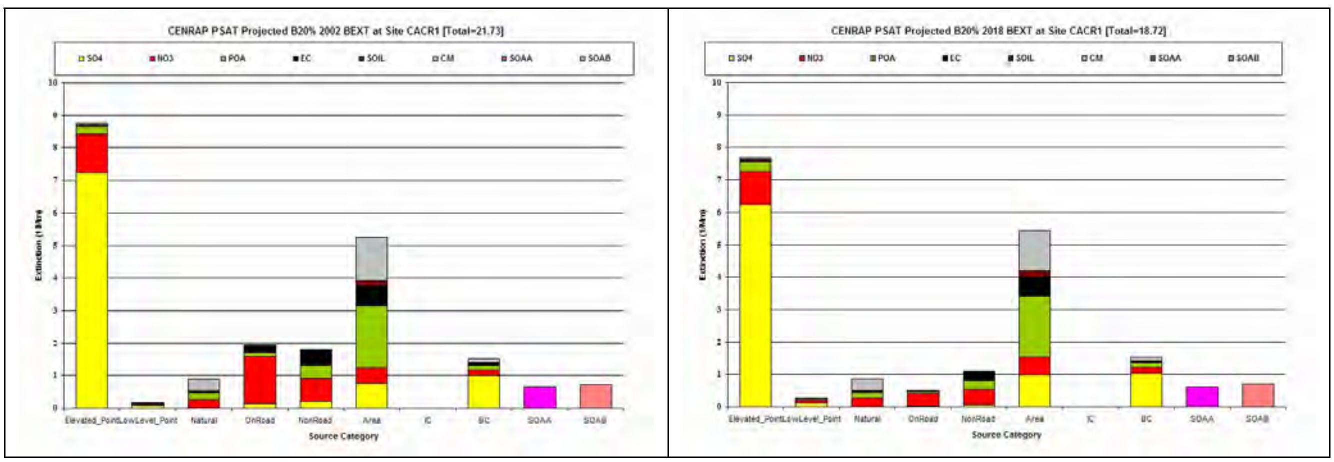


Figure 5-11. PSAT source category by PM species contributions to the average 2000-2004 Baseline and 2018 projected extinction (Mm^{-1}) for the best 20 percent visibility days at Caney Creek (CACR), Arkansas.

5.4.3.2 Upper Buffalo (UPBU) Arkansas

The contributions to extinction on the worst 20 percent days at UPBU (Figure E-2) is similar to CACR only with less contributions from East Texas and more from Missouri, Illinois and Indiana. By 2018, the top five highest contributing source groups to the average extinction on the worst 20 percent days are as follows: Arkansas Elevated Point; SOA from biogenics; Boundary Conditions, East Elevated Points, and Illinois Elevated Points (Figure E-2e). On the best 20 percent days at UPBU visibility impairment is primarily due to Arkansas and adjacent states Oklahoma, Missouri, and Kansas).

5.4.3.3 Breton Island (BRET) Missouri

Visibility impairment for the worst 20 percent days at Breton Island is primarily (69%) due to elevated point sources that contribute 77.7 Mm^{-1} out of a total of 122.2 Mm^{-1} (Figure E-3a). Although the contribution of elevated point sources is reduced substantially by 2018, they still contribute over half of the total extinction (101.1 Mm^{-1}) on the worst 20 percent days at BRET (Figure E-3b). The top five contributing source groups to 2018 visibility impairment at BRET for the worst 20 percent days are: Louisiana Elevated Point Sources; Boundary Conditions; East Elevated Point Sources; Gulf of Mexico Area Sources and Louisiana Area Sources. Gulf of Mexico Area sources includes off shore shipping and oil and gas development emissions; note that for the PSAT simulation the off-shore marine shipping emissions were double counted which was corrected in the Base G emission scenarios used in the 2018 visibility projections discussed in Chapter 4.

5.4.3.4 Boundary Waters (BOWA) Minnesota

As seen for the other Class I areas, elevated point sources contribute the largest amount (47%) to visibility impairment at BOWA for the worst 20 percent days in 2002 (Figure E-4a). However, unlike many of the other Class I areas, there is little reductions (~10%) in the elevated point source contributions going from 2002 (29.0 Mm^{-1}) to 2018 (26.2 Mm^{-1}) (Figures E-4a and E-4b). This is because there is a slight increase in the contributions of elevated point sources in Minnesota from 2002 to 2018 (Figures E-4c and E-4d) that is the highest contributing source group (Figure E-4e). Note that the 2018 emission scenario includes growth and CAIR controls but no BART controls. For the best 20 percent days, the largest contributing source group by far is Boundary Conditions (i.e., global transport) followed by Minnesota and Canada (Figures E-4g-j).

5.4.3.5 Voyageurs (VOYA) Minnesota

Results for VOYA are similar to BOWA with Minnesota, Canada and Boundary Conditions contributing the most to visibility impairment on the worst and best 20 percent days (Figure E-5).

5.4.3.6 Hercules Glade (HEGL) Missouri

Elevated point sources contribute over half to the total extinction for the worst 20 percent days at HEGL in 2002 (Figures E-6a and E-6b). Going from 2002 to 2018 the contributions due to elevated point sources, on-road mobile and non-road mobile are reduced substantially, but the contributions due to the other sources remain unchanged. The largest source group contributing to visibility impairment on the worst 20 percents days is area sources from Missouri in both 2002 and 2018 (Figures E-6c and E-6d). Since area emissions are not reduced much between 2002 and 2018 and Missouri elevated point sources are mostly unchanged because the IPM model assumed Missouri CAIR sources would buy credits, then the Missouri contributions is only reduced a little going from 2002 to 2018 (from ~18 Mm-1 to ~16 Mm-1). However, the contributions due to the Eastern U.S., Illinois and Indiana are reduced substantially. Missouri is by far the largest contribution to visibility impairment at UPBU on the best 20 percent days as well with area sources from Missouri being the largest source category (Figures E-6h through E-6j).

5.4.3.7 Mingo (MING) Missouri

The substantial improvements in visibility impairment at MING for the worst 20 percent days from 2002 (141 Mm^{-1}) to 2018 (96 Mm^{-1}) is primarily due to reductions in SO4 from non-Missouri elevated point sources (Figures E-7a through E-7d). Even so, with the exception of the top contributing Missouri area sources the largest contributing source groups to 2018 visibility impairment for the worst 20 percent days are still elevated point sources from several CAIR states (Illinois, Indiana, Missouri, East; Figure E-7e). Missouri is the largest contributor to visibility on the best 20 percent days followed by Boundary Conditions and Illinois (Figure E-7i-j).

5.4.3.8 Wichita Mountains (WIMO) Oklahoma

Elevated point sources are the largest contributors to visibility impairment on the worst 20 percent days at WIMO in both 2002 and 2018 (Figures E-8a and E-8b). East Texas followed closely by Oklahoma are the largest contributing source regions in 2002, but by 2018 the reverse is true (Figures E-8c and E-8d). By 2018 the largest contributing source group to visibility impairment on the worst 20 percent days at WIMO is global transport (i.e., boundary conditions) followed by Oklahoma Area Sources and East Texas Elevated Point sources (Figure E-8e). Oklahoma Area Sources is the largest contributor to visibility impairment on the best 20 percent days at WIMO (Figures E-8g-j).

5.4.3.9 Big Bend (BIBE) Texas

Elevated point sources (~17 Mm^{-1}) followed by Boundary Conditions (~12 $Mm^{-}1$) are the largest contributions to total extinction (46 Mm^{-1}) on the worst 20 percent days at BIBE in 2002 (Figure E-9a). In 2018 there is very little (~2 Mm^{-1}) reduction in the contributions of elevated point sources and no reductions in global transport resulting in little reductions (~7%) in visibility impairment on the worst 20 percent days from 2002 (46 Mm^{-1}) to 2018 (43 Mm^{-1}). This is due to the extremely large contributions of emissions from Mexico in both 2002 (Figure E-9c) and 2018 (Figure E-9d). In fact, the four highest contributing source groups to visibility impairment at BIBE for the worst 20 percent days are assumed to be unchanged from 2002 to 2018: Boundary Conditions, Mexico Elevated Points, West Texas Natural and Mexico Natural (Figure E-9e). For the best 20 percent days at BIBE, West Texas, Mexico and Boundary Conditions are the highest three contributors to visibility impairment (Figures E-9g-j).

5.4.3.10 Guadalupe Mountains (GUMO) Texas

The large contribution of CM to visibility impairment at GUMO is clearly evident in the source apportionment modeling results (Figures E-10a-b). These sources are about evenly divided in the modeling between natural sources and area sources. Since these source categories are not reduced in the future year then there is little reduction in extinction from 2002 to 2018 (50 to 45

Mm^{-1}) and what reductions there are come from Elevated Point Sources. Sources in West Texas, Mexico, Boundary Conditions and New Mexico are the largest contributing source regions for both the worst 20 percent days (Figure E-10c-e) and best 20 percent days (Figures E-10g-j).

5.5 Alternative Visibility Projection Procedures

In this section we analyze several alternative visibility projection procedures from the EPA's default approach (EPA, 2007a) used in Chapter 4.

5.5.1 Treatment of Coarse Mass and Soil

As noted previously, much of the coarse mass (CM) and, to a lesser extent, Soil measured at the IMPROVE monitor is likely due to local wind blown dust that is natural in origin and not captured by the model. Consequently, even using the modeling results in a relative sense with the RRFs may not be appropriate for projecting CM and Soil. If CM and Soil are in fact local impacts due to wind blown dust from natural lands, then it would be appropriate to assume they are natural and remain unchanged from the 2000-2004 Baseline to 2018. This is probably certainly appropriate for CM because CM is primarily due to fugitive dust and it has a very short transport distance that is subgrid-scale to the model. In fact the model evaluation discussed in Chapter 3 and Appendix C clearly shows a large underprediction bias for CM that is likely due to local fugitive dust impacts at the IMPROVE monitor. For Soil this is less clear as fine particles can be transported over longer distances and is produced by anthropogenic sources, such as combustion and road dust, as well as natural sources. We initially performed two CM and Soil sensitivity tests, the first assumed CM was all natural so remains unchanged from the 2000-2004 Baseline to 2018 (i.e., set the RRF for CM equal to 1.0). The second sensitivity test assumed both CM and Soil were natural so set RRFs for both of them to 1.0. A comment from an FLM noted that we know some of the Soil is likely anthropogenic in origin. So it was suggested to subtract the 2002 base case modeled Soil from the observed values for the 2002 worst 20 percent days and assume that the remainder (if any) was natural so hold the rest of the Soil constant in 2018 and add to the 2018 modeled Soil values.

The results of the CM and Soil visibility projection sensitivity analysis are shown in the DotPlot in Figure 5-12. The CM and Soil visibility projection sensitivity analysis has little effect on the 2018 visibility projections at the CENRAP Class I areas. Even GUMO, which has a large CM and Soil component, shows very little sensitivity. This is probably because the CM at GUMO is likely dominated by wind blown dust that was assumed constant from 2002 to 2018 so the RRF calculated using the default EPA method is near 1.0 anyway. Some larger sensitivity is seen at several WRAP Class I areas. It is encouraging that CENRAP 2018 visibility projections are not sensitive to the CM and Soil components of the modeling which are highly uncertain.

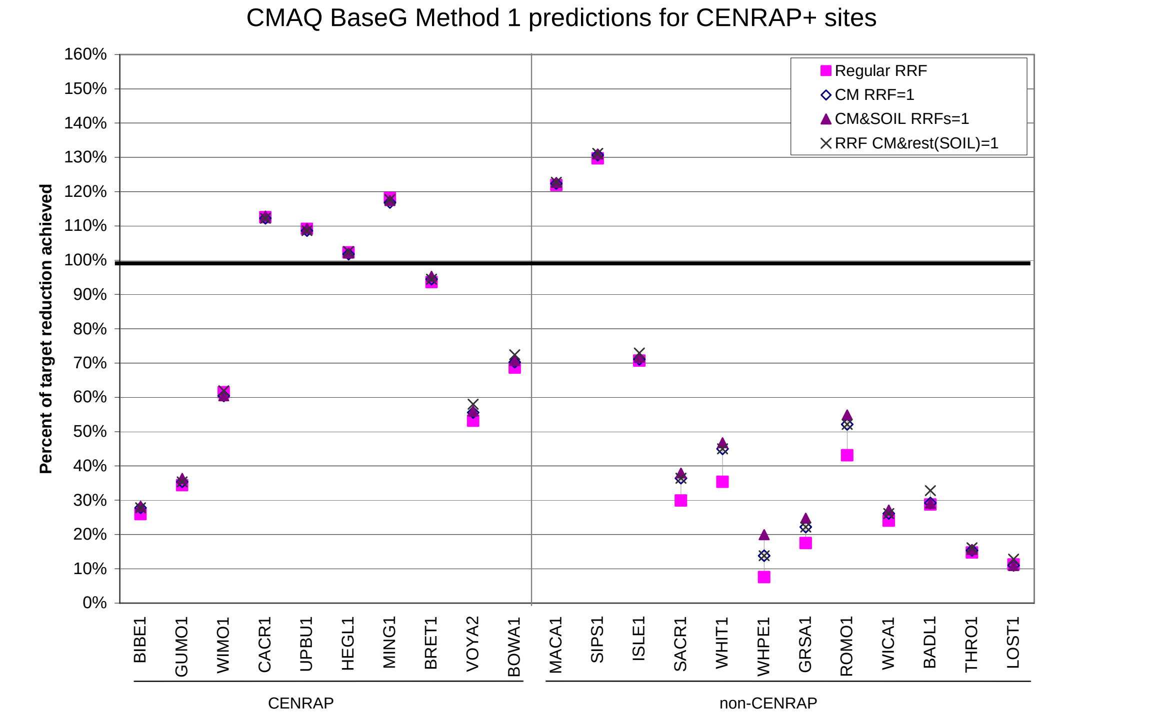


Figure 5-12. Sensitivity of 2018 visibility projections to various methods that assume all CM, all CM and Soil and all CM and part of the Soil is natural.

5.6 Alternative Model

The CAMx model was also run for a 2002 and 2018 base case scenarios with earlier versions of the CENRAP emissions (Base E modified to eliminate double counting of some area fire emissions) than the final CMAQ 2002 Base G modeling. The CAMx 2002 and 2018 output was processed the same way that the CMAQ results were to generate 2018 visibility projections at the CENRAP and nearby Class I areas that were compared with the 2018 URP point. Figure 5-13 summarizes the CAMx 2018 visibility projections using the new IMPROVE algorithm (NIA) in a DotPlot and compares them with the CMAQ 2018 Base G results (from Figure 5-12). The CMAQ and CAMx 2018 visibility projections are remarkably similar. The four Arkansas and Missouri Class I areas are projected to achieve the 2018 URP point by almost the exact same amount by the two models. The two Texas Class I areas are projected to come up short of achieving the 2018 URP point by the same amount by the two models. The largest differences are seen at BRET, and to a lesser extent BOWA and VOYA. At BRET the CAMx 2018 visibility projections are much less optimistic (< 80%) in achieving the 2018 URP point than CMAQ (> 90%). And CMAQ is slightly less optimistic than CAMx in achieving the 2018 URP point for the two northern Minnesota Class I areas. The reasons for these differences are unclear but could be partially due to the emissions updates in the final CMAQ Base G run that included eliminating the double counting of off-shore marine emissions in the Gulf of Mexico that was present in the CAMx simulation, which makes it more difficult to get visibility improvements at BRET since it is influenced by sources in the Gulf. Corrections to stack parameters for Canadian point sources were also made for the final Base G. The general close agreement of the CAMx 2018 visibility projections to the final CMAQ values is encouraging and good QA check.

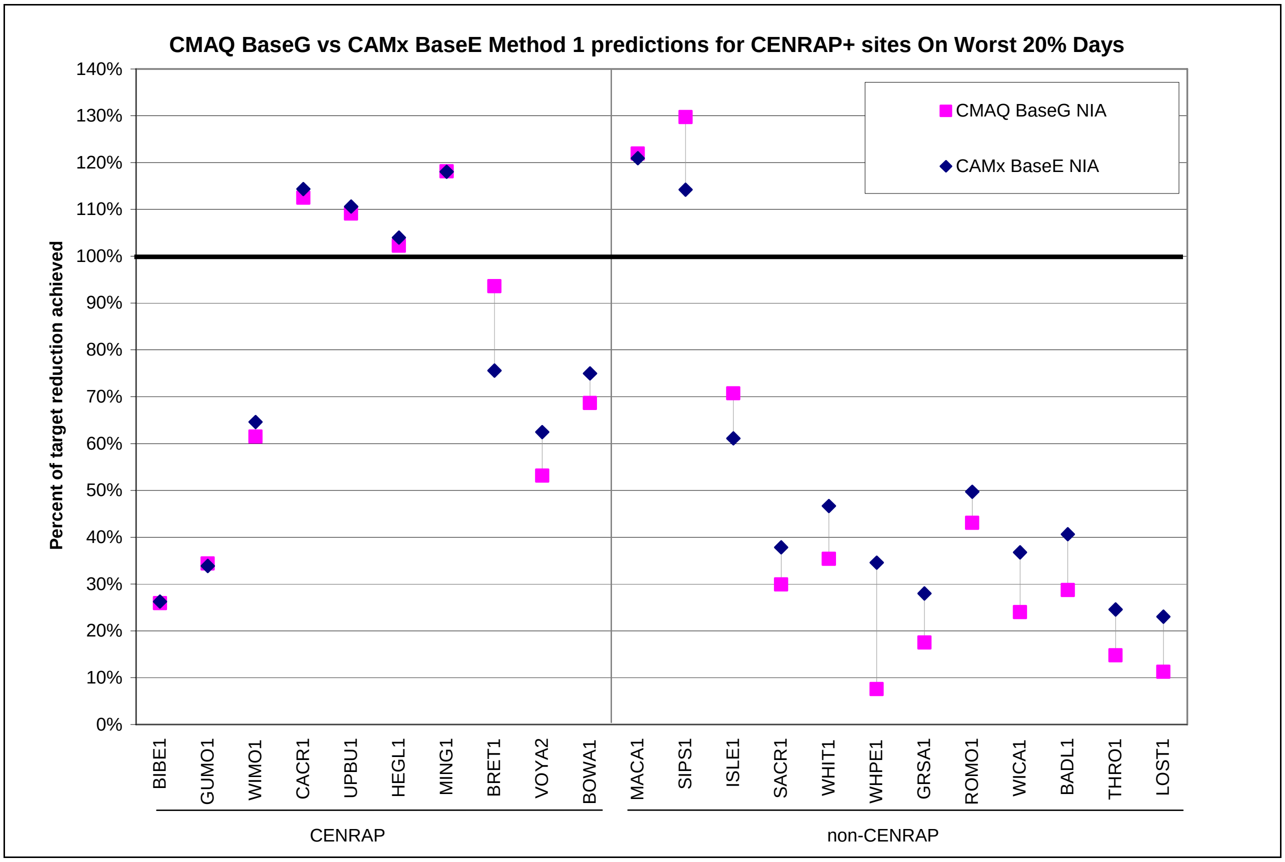


Figure 5-13. Comparison of CAMx 2018 visibility projections with 2018 URP points for CENRAP and nearby Class I areas.

5.7 Effects of International Transport on 2018 Visibility Projections

As seen in the PM source apportionment modeling discussed in Section 5.4, there is significant contributions of international sources to visibility impairment at many CENRAP Class I areas for the worst 20 percent days. With the exception of Canada, where we used a year 2000 inventory for the 2002 base case modeling and a 2020 inventory for the 2018 inventory, international sources were assumed to be constant between 2002 and 2018. Thus, Class I areas that are heavily impacted by contributions of international transport will have a difficult time achieving the 2018 URP point since international sources are assumed to remain constant. The CAMx PSAT runs discussed previously provide a framework for quantitatively assessing the contributions of international transport to the visibility projections and whether reasonable progress toward natural conditions is being achieved in the 2018 modeling.

There are several source regions (Figure 5-8) and source categories in the PSAT modeling that include international sources:

- Mexico Anthropogenic Sources (assumed all international);
- Canada Anthropogenic Sources (assumed all international);
- Gulf of Mexico (assumed all U.S. sources);
- Pacific and Atlanta Ocean (assumed all U.S. sources); and
- Boundary Conditions (assumed half international and half natural sources).

Although it can be argued that Mexico and Canada are not truly international due to the presence of numerous U.S. corporations in Mexico along with free trade among the two countries, states and federal government have no jurisdiction to regulate industry in these two countries so they are considered international in these calculations. The Gulf of Mexico includes off-shore oil and gas production facilities, support vessels and aircraft and off-shore marine shipping. Given that emissions from the oil and gas production can be regulated by the U.S., then the Gulf of Mexico is not considered an international source. Emissions from off-shore shipping in the Pacific and Atlantic Oceans are also currently not regulated by the U.S. government. However, there are current efforts to apply some regulations to these emissions so for these calculations they were not assumed to be international sources. Finally, the Boundary Conditions (BCs) for the CENRAP modeling were generated from a 2002 simulation of the GEOS-CHEM global chemistry model and held constant in 2018. These BCs would include contributions from international sources as well as natural sources, so need to be split. For the sensitivity calculations discussed below we assumed that the BCs were half due to natural and half due to international sources. This results in international sources being defined as follows:

International Contribution = Mexico Anthro + Canada Anthro + ½ BCs

Two methods were examined to see what the effects of international sources on 2018 visibility projections and a Class I areas ability to achieve the 2018 URP point:

<u>Elimination of International Contributions to 2018 Visibility Projections</u>: In this method the contribution of international emissions is taken out of the 2018 visibility projections and examined to see whether the new visibility projection achieves the URP point. If so, then international sources are hindering a Class I area in achieving the 2018 URP point, which suggests that the 2018 URP point is not a reasonable value for an RPG.

<u>Visibility Projections and Glidepaths Based on Controllable Visibility Impairment</u>: The second method would look at the visibility projections for just the U.S. controllable portion of the visibility impairment. The glidepath end point in 2064 would be to eliminate the U.S. man-made contributions to visibility impairment on the worst 20 percent days.

Note that this analysis is performed solely for providing states and others additional information on which Class I areas the modeling suggest are unduly influenced by International Transport.

5.7.1 Elimination of International Contributions to 2018 Visibility Projections

This method was also discussed in a recent technical brief prepared by the Electric Power Research Institute (EPRI), only in EPRI's analysis they used results from a global chemistry model and VISTAS CMAQ runs with no global anthropogenic emissions (EPRI, 2007). Thus, before discussing our results of this analysis using PSAT, we discuss EPRI's analysis.

5.7.1.1 EPRI's Analysis of Effects of International Contributions

EPRI funded Harvard University to perform annual simulations of the GEOS-Chem global chemistry model (http://www-as.harvard.edu/chemistry/trop/geos/) for annual simulations with and without non-U.S. anthropogenic emissions to determine the contributions of international transport to PM and visibility. The EPRI Harvard GEOS-Chem simulations were performed for 2001. Figure 5-14 and 5-15 compare the annual average ammonium sulfate, ammonium nitrate organic mass carbon (OMC, also called OCM) and elemental carbon (EC) due to the GEOS-Chem global modeling and the CAMx PSAT source apportionment modeling. The similarity of the results for ammonium sulfate is remarkable (Figure 5-14). Both methods estimate that the annual average ammonium sulfate contribution due to international sources ranges from 0.4 to 1.0 $\mu g/m^3$ across the Class I areas. There is less agreement between the two methods for ammonium nitrate due in part to a CAMx overestimation issue that is likely due in part to how ammonia emissions were classified as being anthropogenic or not in the no U.S. anthropogenic emissions simulations (Figure 5-15). Better agreement is seen between the two methods international contributions of OMC and EC, although CAMx estimates higher contributions than GEOS-Chem.

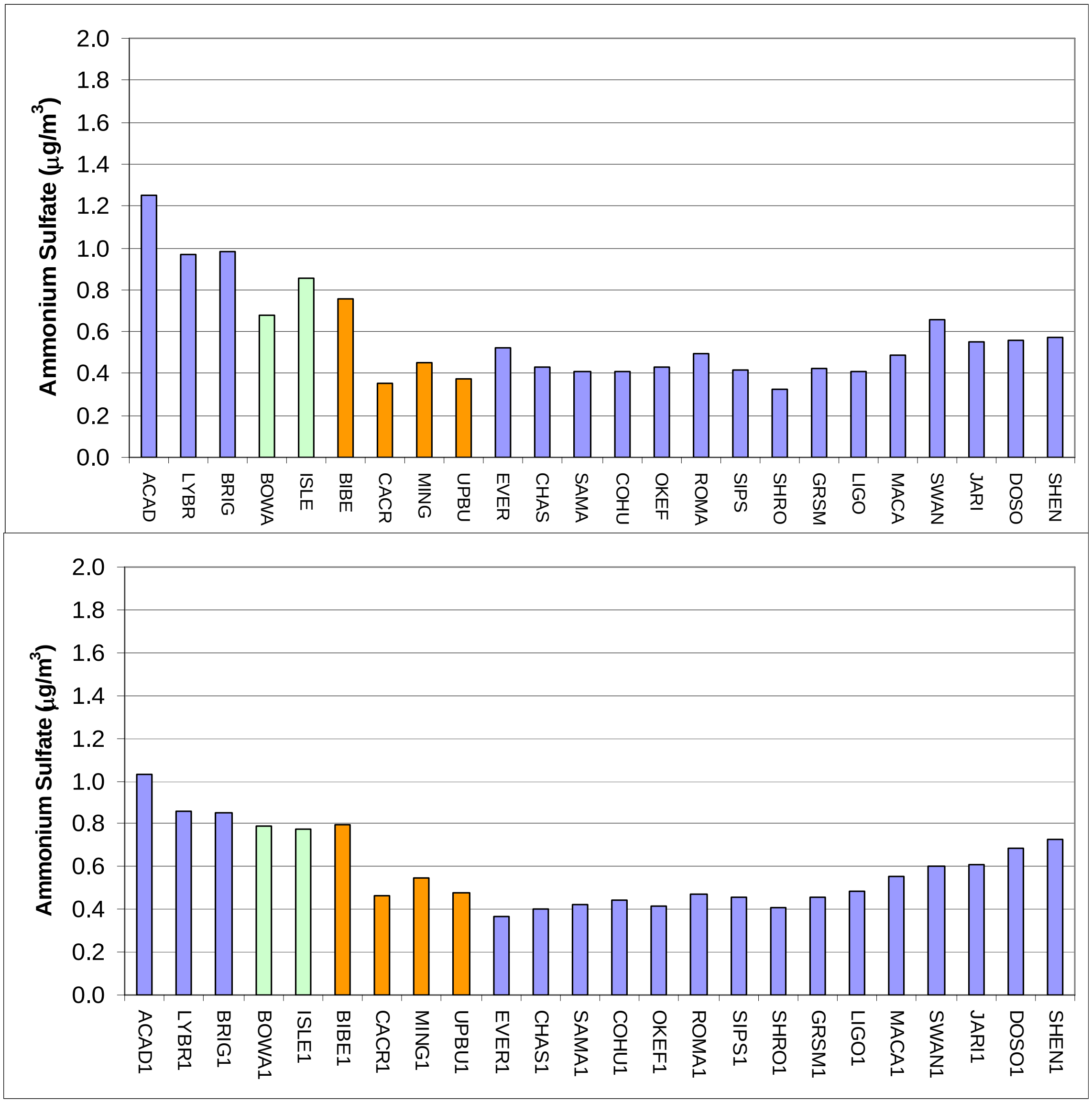


Figure 5-14. Comparison of EPRI Harvard GEOS-Chem global chemistry (top) and CENRAP PSAT (bottom) international source contributions to ammonium sulfate at Class I areas.

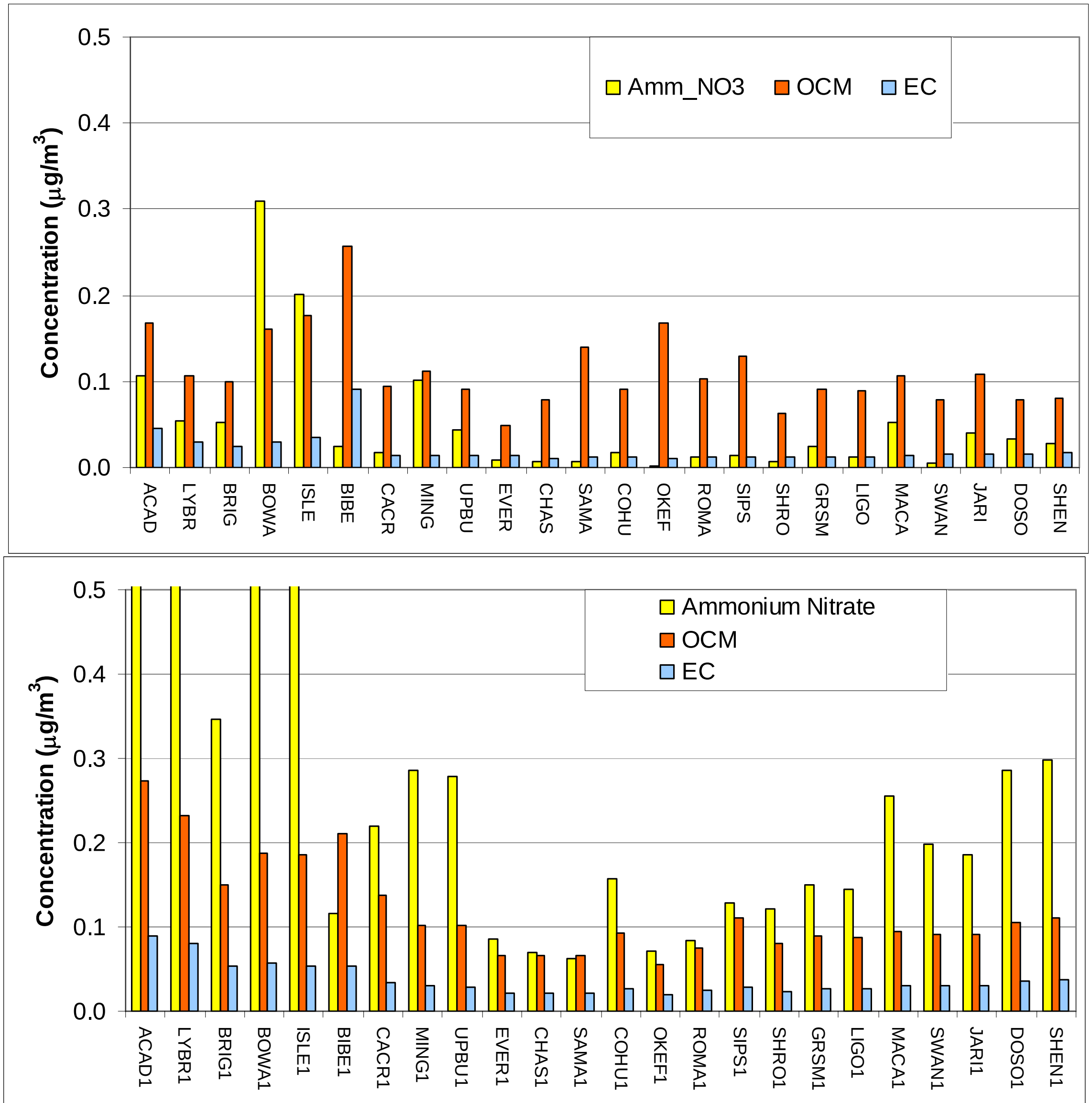


Figure 5-15. Comparison of EPRI Harvard GEOS-Chem global chemistry (top) and CENRAP PSAT (bottom) international source contributions to ammonium nitrate, organic carbon mass (OCM or OMC) and elemental carbon (EC) at Class I areas.

The EPRI technical brief used the VISTAS CMAQ runs to adjust the modeled 2018 visibility projections to eliminate the effect of international transport and compared them to the 2018 URP point. For the Boundary Waters, Voyageurs, Isle Royal and Seney Class I areas the standard 2018 visibility projections did not achieve the 2018 URP point. However, when the effect of transboundary pollutions was removed the 2018 URP point was essentially achieved or more than achieved at all four Class I areas.

5.7.1.2 CENRAP Results From Elimination International Transport

Because the elimination of the international sources from the 2018 visibility projections results in a portion of the total light extinction, then these comparisons with the 2018 URP points were done using extinction glidepaths and projections rather than deciview. In Section 5.2.1 we demonstrated that the level of achieving the 2018 URP point was almost identical at CENRAP Class I areas whether the linear deciview or curved extinction glidepaths were used. The PSAT source apportionment was used to determine the contribution to the projected extinction in 2018 due to international sources. As noted above, international sources were assumed to be due to anthropogenic emissions in Mexico and Canada and half of the Boundary Conditions.

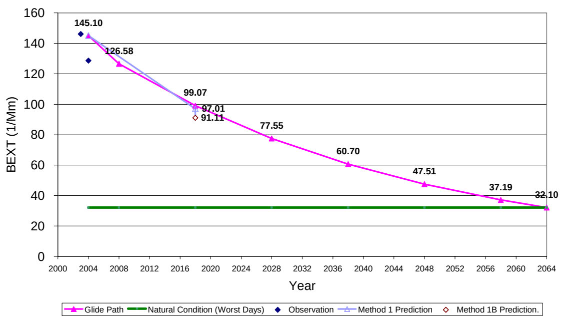
Figure 5-16 shows the standard CAMx extinction glidepaths and 2018 visibility projections and the 2018 visibility projections when the contributions of international sources is eliminated. CACR, which achieved the 2018 URP point by 104%, achieves it by even more when international sources are eliminated (117%). UPBU that barely achieved the 2018 URP point by 102% achieves it by 116% without international emissions.

BRET comes up short of achieving the 2018 URP point when international emission are included (76%) as well as when they are eliminated (92%), although it is much closer (recall contributions of Gulf of Mexico to visibility impairment at BRET that is assumed in this analysis to be of U.S. origin). Eliminating international transport emissions makes of difference of meeting the 2018 URP point without them (120%) to not meeting it with them (64%) at BOWA. Similarly at VOYA the standard 2018 visibility projections do not achieve the 2018 URP point (54%), whereas it is achieved by a far margin when international sources are eliminated (132%).

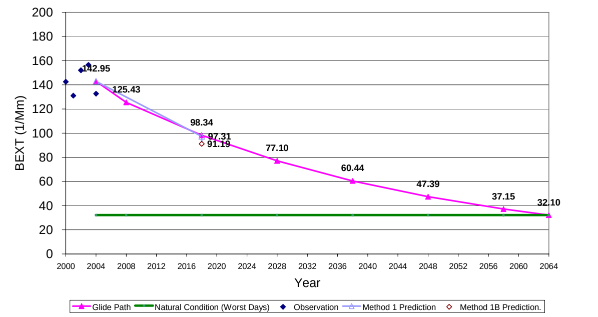
HEGL comes up short achieving the 2018 URP point when international sources are included (95%), but achieves it when they are eliminated (107%). Recall the standard CAMx deciview visibility projections barely achieved the URP point even when international emissions are included (Figure 5-13). MING achieves the 2018 URP point with (106%) and without (116%) international sources. WIMO does not achieve the 2018 URP point when international contributions are eliminated.

International sources have by far the largest effect at BIBE. Whereas the standard 2018 visibility projections only achieved 27% of the reductions needed to achieve the 2018 URP point, elimination of the international source contributions achieves 172% of the reduction needed. GUMO comes up short in achieving the 2018 URP point when international sources are included (31%), but achieves it when they are not (107%).

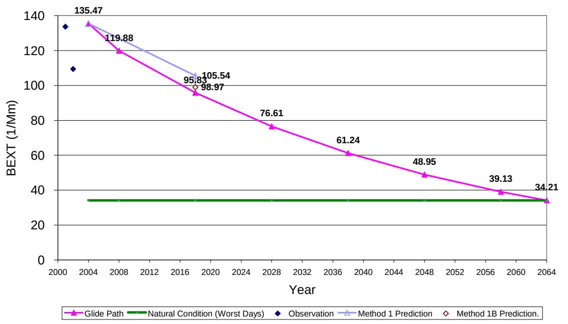
Uniform Rate of Reasonable Progress Glide Path
Caney Creek Wilderness - Worst 20% Days



Uniform Rate of Reasonable Progress Glide Path
Upper Buffalo Wilderness - Worst 20% Days



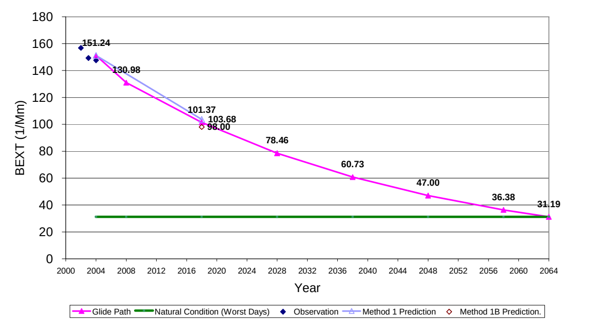
Uniform Rate of Reasonable Progress Glide Path
Breton - Worst 20% Days



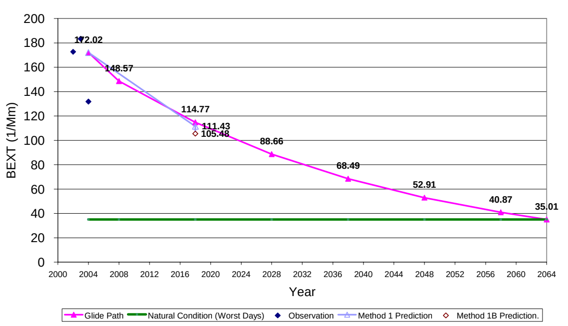
Uniform Rate of Reasonable Progress Glide Path
Boundary Waters - Worst 20% Days

Uniform Rate of Reasonable Progress Glide Path
Voyageurs NP - Worst 20% Days

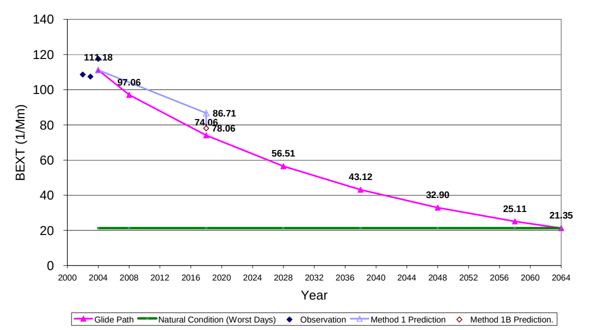
Uniform Rate of Reasonable Progress Glide Path
Hercules-Glades Wilderness - Worst 20% Days



Uniform Rate of Reasonable Progress Glide Path
Mingo - Worst 20% Days



Uniform Rate of Reasonable Progress Glide Path
Wichita Mountains - Worst 20% Days



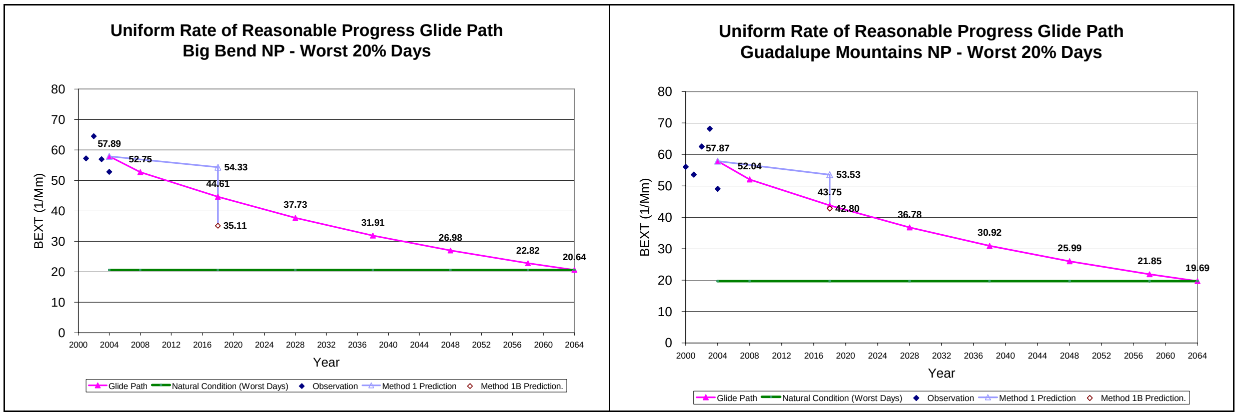


Figure 5-16. Elimination of international sources from 2018 visibility projections and comparison with 2018 URP point at CENRAP Class I areas.

5.7.2 Glidepaths Based on Controllable Extinction

Another alternative glidepath that was examined using the CAMx PSAT source apportionment results was based on the U.S. anthropogenic emissions contributions to visibility impairment on the worst 20 percent days at the CENRAP Class I areas. The RHR strives to achieve "natural visibility conditions" by 2064 and defines natural conditions as conditions that would exist "in the absence of human caused impairment". As shown above, anthropogenic emissions from international sources contribute significantly to visibility impairment at many of the CENRAP Class I areas making the RHR objective not practical if contributions from such sources are not reduced. Given that states and EPA have no jurisdiction over international sources, then we can not assume they will be controlled and have therefore held most of them constant at 2002 levels. For such Class I areas with high contributions from international sources, the comparison with the 2018 URP point is not very meaningful since the 2018 URP assumes such sources will be reduced. A more meaningful comparison would be to focus on the U.S. man-made contributions to visibility impairment at the Class I areas and develop a URP glidepath and 2018 URP point that is aimed at eliminating the U.S. anthropogenic emissions contributions to visibility impairment at Class I areas for the worst 20 percent days in 2064.

The CAMx 2002 base case PSAT PM source apportionment results were processed to identify the portion of the 2000-2004 Baseline extinction that was due to U.S. anthropogenic emissions (i.e., man-made sources). The contributions of source groups that included on-road mobile, non-road mobile, elevated point sources, low-level point sources and area sources from the PSAT source regions covering the U.S. states and Gulf of Mexico (Figure 5-8) were assumed to make up the U.S. anthropogenic contributions (i.e., excluding the Natural source category, all sources from the Mexico and Canada source regions and boundary conditions). Note that off-shore marine emissions in the Pacific and Atlantic Oceans and Gulf of Mexico were included in the U.S. anthropogenic emissions definition because they were in source regions associated with states or the Gulf of Mexico. As off-shore marine emissions may not be controllable by U.S. agencies and they were assumed to remain unchanged going from 2002 to 2018, then the 2018 visibility projections for the U.S. anthropogenic component are overstated.

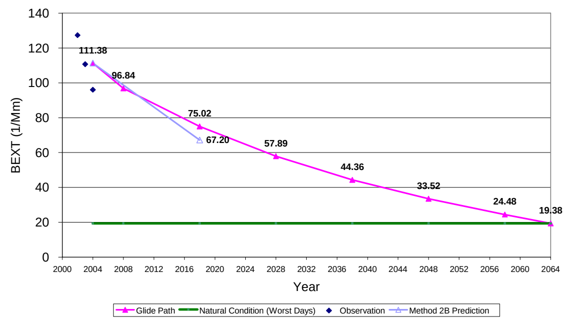
The 2064 objective for the U.S. anthropogenic emissions glidepath would be no contributions on the worst 20 percent days. This does not mean the 2064 U.S. anthropogenic extinction objective is zero, rather the U.S. anthropogenic plus natural background is less than the Natural Conditions for the worst 20 percent days. The PSAT results were used to define the natural background contributions on the current worst 20 percent days which was subtracted from the EPA default Natural Conditions to obtain the 2064 objective for the U.S. anthropogenic emissions contributions. Here the PSAT derived natural background was defined as the sum of the contributions from the Natural source category, secondary organic aerosol from biogenic sources (SOAB) and half of the boundary conditions. For example, Figure 5-17 top left displays the US anthropogenic emissions glidepath for CACR. The PSAT natural sources contribution (=Natural Source Category + SOAB + ½ BC) is approximately 13 Mm^{-1} so that is subtracted from the 2064 Natural Background (~32 Mm^{-1}, see figure 5-16) to obtain a 2064 end point of ~19 Mm^{-1} for the glidepath. The 2002 PSAT results applied to the 2000-2004 Baseline extinction estimates that 111 Mm^{-1} of the extinction is due to U.S. anthropogenic emissions which form the starting point for the glidepath. The curvature in the US anthropogenic glidepath is introduced the same way as for the extinction based glidepath to account for the logarithmic relationship between extinction and deciview.

Figure 5-17 displays the U.S. anthropogenic emissions extinction glidepaths and comparison with the 2018 visibility projections for extinction due to U.S. anthropogenic emissions on the worst 20 percent days. As seen by the standard linear deciview glidepaths discussed in Chapter 4, the U.S. anthropogenic emissions 2018 URP point is achieved by a wide margin at the four Class I areas in Arkansas and Missouri (CACR, UPBU, HRGL and MING). BRET that achieved 94% of the 2018 URP point obtains similar results using the U.S. anthropogenic emissions glidepath achieving 96% of the 2018 URP point. As discussed above, the inclusion of the off-shore marine emissions in the U.S. anthropogenic emissions will greatly affect the BRET Class I area so that actual reduction in U.S. anthropogenic emissions extinction would be greater and may even achieve the 2018 URP point if off-shore marine vessels were classified as not being part of the U.S..

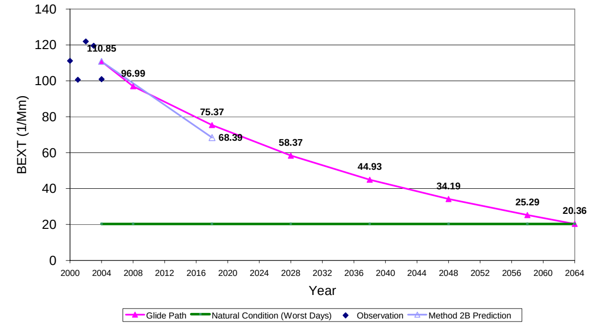
The BOWA and VOYA northern Minnesota Class I areas achieved, respectively, 69% and 53% of the 2018 URP point using the standard EPA default deciview glidepaths and projection techniques (Figure 4-4). Using the U.S. anthropogenic glidepaths BOWA and VOYA achieve 92% and 86% of the 2018 point, respectively (Figure 5-17). WIMO that came up approximately 40% short of achieving the 2018 URP point using the deciview glidepath comes up under 20% short using the U.S. anthropogenic emissions glidepath.

The two Texas Class I areas also come up short in achieving the 2018 URP point using the U.S. anthropogenic emissions glidepaths, but not as short as when the linear deciview glidepaths are used. BIBE increases from 26% to 67% and GUMO increases from 34% to 49%. One reason these two Class I areas fail to achieve the 2018 point for U.S. anthropogenic emissions is because of the high contributions of Soil and CM and little change in precursor emissions of these species between 2002 and 2018.

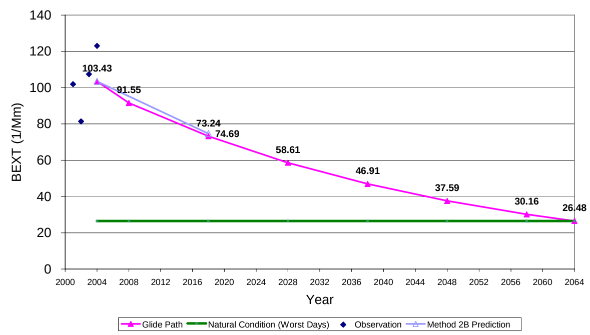
Uniform Rate of Reasonable Progress Glide Path
Caney Creek Wilderness - Worst 20% Days



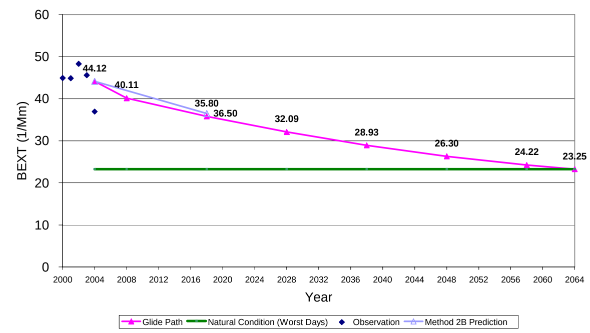
Uniform Rate of Reasonable Progress Glide Path
Upper Buffalo Wilderness - Worst 20% Days



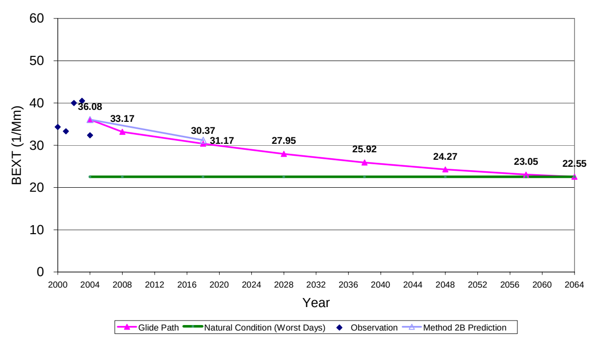
Uniform Rate of Reasonable Progress Glide Path
Breton - Worst 20% Days



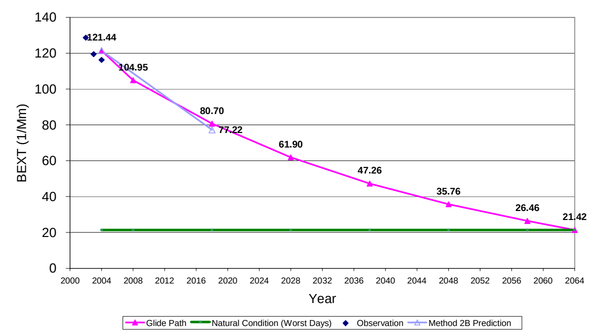
Uniform Rate of Reasonable Progress Glide Path
Boundary Waters - Worst 20% Days



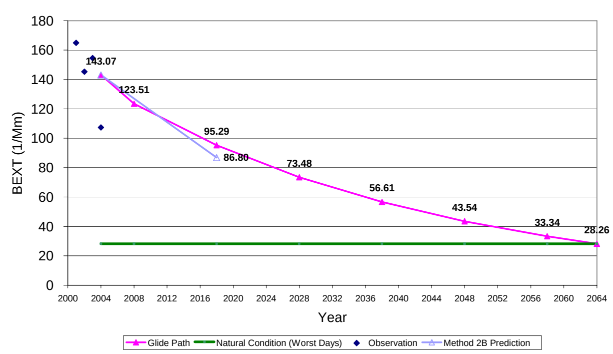
Uniform Rate of Reasonable Progress Glide Path
Voyageurs NP - Worst 20% Days



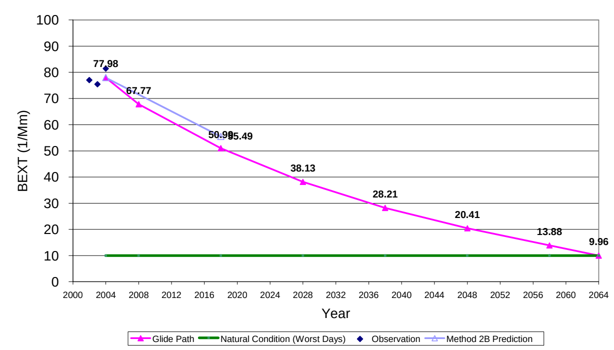
Uniform Rate of Reasonable Progress Glide Path
Hercules-Glades Wilderness - Worst 20% Days



Uniform Rate of Reasonable Progress Glide Path
Mingo - Worst 20% Days



Uniform Rate of Reasonable Progress Glide Path
Wichita Mountains - Worst 20% Days



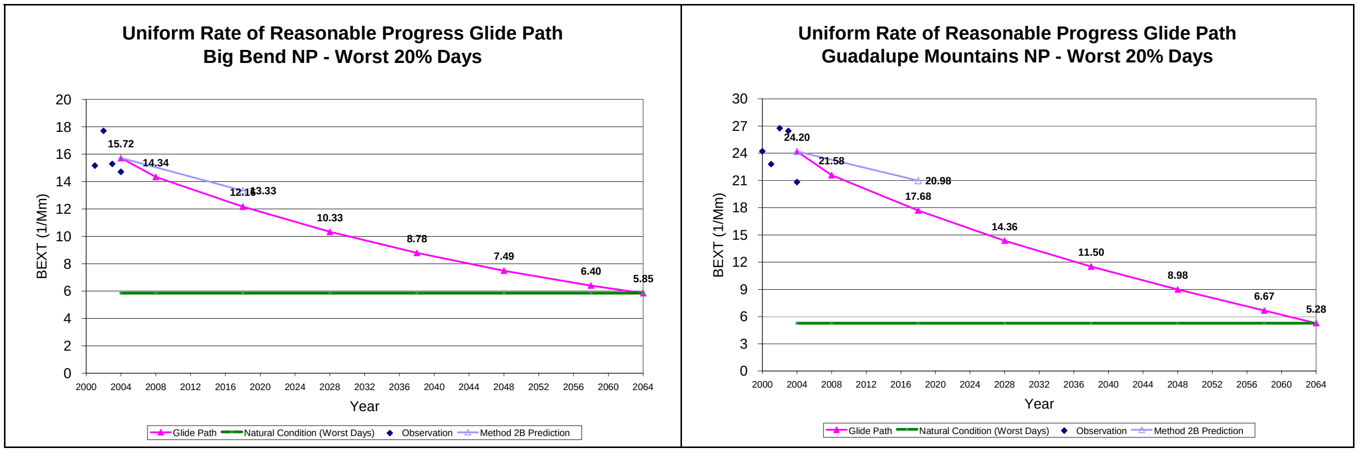


Figure 5-17. Glidepaths and 2018 visibility projections based on visibility due to U.S. anthropogenic emissions at CENRAP Class I areas.

5.8 Use of Original IMPROVE Equation

2018 visibility projections were also made using the CENRAP Typ02g and Base18g CMAQ modeling results and the original (old) IMPROVE equation. Figure 5-18 displays a DotPlot that compares the 2018 Base G visibility projections using the new IMPROVE algorithm (NIA) and the original IMPROVE algorithm (OIA). In general the new IMPROVE equation results in more optimistic 2018 visibility projections than the original IMPROVE equation. For the Texas and WRAP Class I areas, the 2018 visibility projections are nearly identical using the two IMPROVE equations. For the four Class I areas in Arkansas and Missouri the 2018 visibility projections using the new IMPROVE equation are from 7 to 21 percentage points more optimistic than the original IMPROVE equation. In the case of UPBU, HEGL and MING the 2018 visibility projections go from not achieving to achieving the 29018 URP point when switching from the old to new IMPROVE equation.

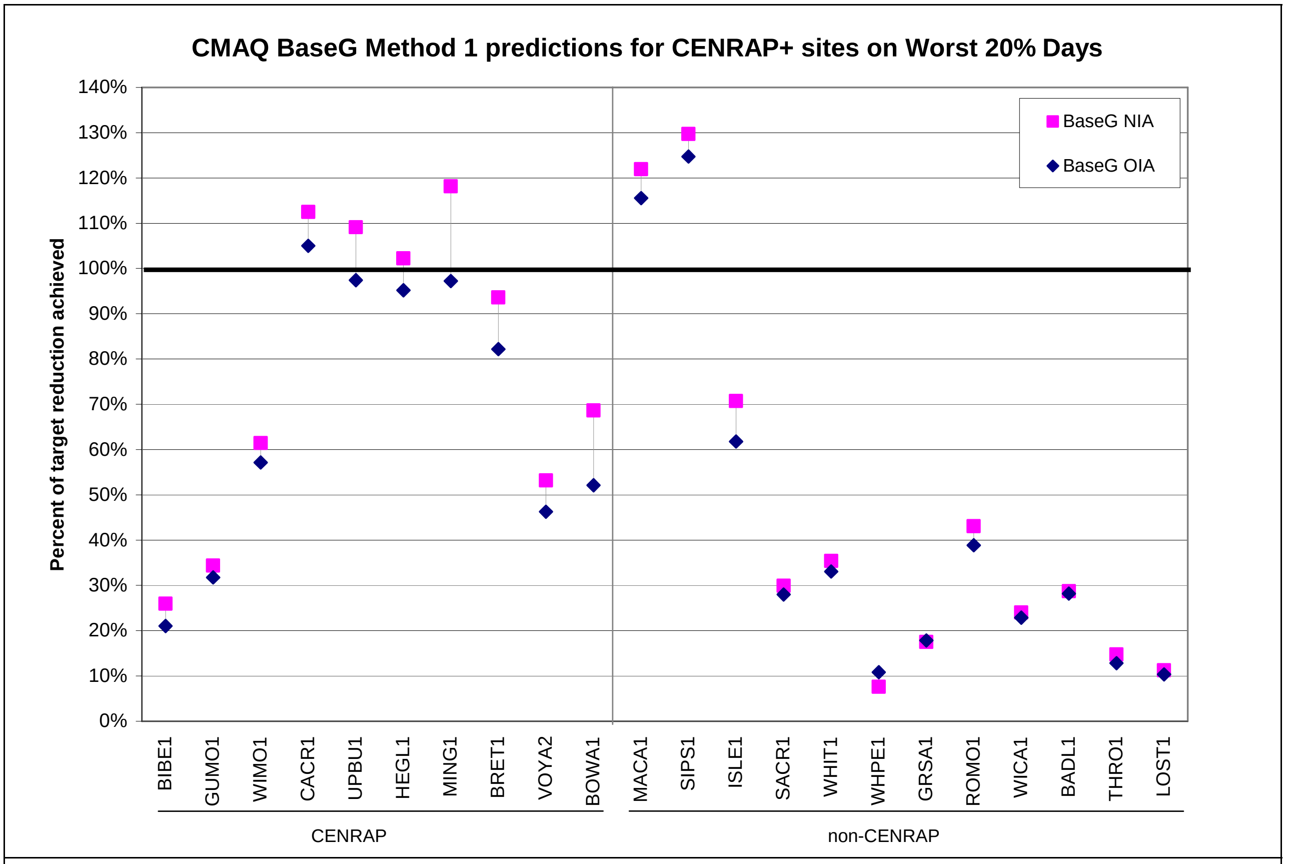


Figure 5-18. Comparison of 2018 Base G visibility projections using the New (NIA) and Old (OIA) IMPROVE algorithms expressed as a percentage of achieving the 2018 URP point visibility improvements.

5.9 Visibility Trends

Figure 5-19 displays trends in visibility impairment at the CENRAP Class I areas using the period of record of measurements at the associated IMPROVE monitor and the new IMPROVE equation. These trends include trends for the worst 20 percent days, the best 20 percent days and all IMPROVE sampled days during a year. The EPA guidance procedures were used to construct the worst and best 20 percent days that includes a minimum data capture requirement (EPA, 2003a), whereas no such minimum data capture was applied when looking at the "annual average" of all IMPROVE sampled days trends. So care must be taken when analyzing trends for the all sampled IMPROVE days trends as there could be large missing periods with high or low extinction that are not being account for. The WRAP Technical Support System (TSS) website was used to calculate the visibility trends at the CENRAP Class I areas that includes IMPROVE data from start of recording through 2004 and includes no data filling (see: http://vista.cira.colostate.edu/TSS/Default.aspx) .

Trends in visibility at CACR has three years of data (2002-2004) for the worst and best 20 percent days and fives years for the IMPROVE sampled days trends. Although it is hard to come to any conclusions regarding trends with just three years of data, there does seem to be a general downward trend, that is also supported by the five year trend in the IMPROVE sampled days.

A much longer trend plot is available for UPBU that includes 12 years of data for the worst and best 20 percent days (Figure 5-19b). Although there is a lot of a year-to-year variation in the visibility trends with cleaner years occurring in 1997, 2001 and 2004, there does appear to be a slight trend toward improved visibility at UPBU.

There is insufficient data to calculate the worst or best 20 percent days visibility for any year at the BRET Class I area so only the IMPROVE sampled days trends are presented (Figure 5-19c). The trends at BRET are inconclusive and given the large amounts of missing data at this site it is difficult to interpret the results.

There is also a lot of missing years in the worst and best 20 percent days for the BOWA Class I area making it difficult to interpret (Figure 5-19d). But visibility appears to be more impaired in the early 1990s than in more current years so improvements have been seen. VOYA has five years of valid data and shows worsening visibility for 2000-2003, and then improved visibility in 2004. It is unclear whether the 2004 improved visibility is a trend or just due to variations in meteorology so no conclusions can be drawn.

Although a downward trend in visibility impairment appears to be occurring at the two Missouri Class I areas (Figure 5-19f-g), given that there are only three years available for HEGL and lots of missing data for MING these trends are inconclusive.

Three years (2002-2004) of visibility trends for the worst and best 20 percent days are available for WIMO (Figure 5-19h). The most impaired year from the three years for the worst 20 percent days is the most recent (2004). Again, the time period is too short to draw any conclusions on trends in visibility at WIMO.

The two Texas Class I areas have a relatively long period of record. There is a lot of year-to-year variability in the visibility measurements that make interpreting the trends difficult. 1998 appears to be an anomalously high visibility impairment year at BIBE and due to the much higher OMC extinction indicates that the year was likely impacted by smoke from fires. GUMO has lots of year to year variability in CM and Soil which are likely due to occurrences of impacts due to wind blown dust. Even taking Soil and CM out of the interpretation it is difficult to interpret ay trend in visibility at the two Texas Class I areas. The higher visibility impairment in 1998 and 1999 suggests a downward trend but that may be just due to more adverse meteorological and natural emissions (e.g., wildfires) in these two years than any real long term trend.

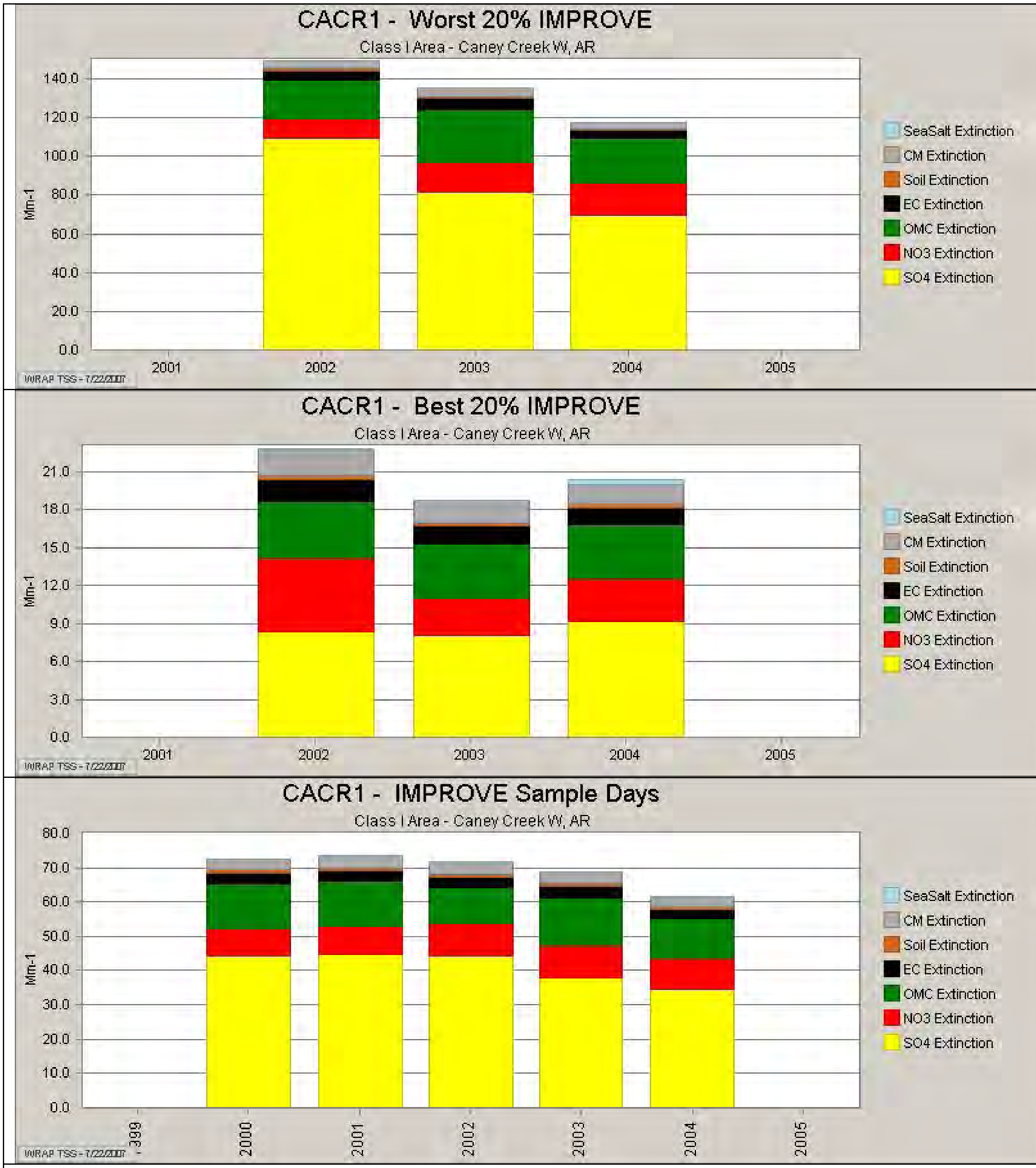


Figure 5-19a. Time series of observed IMPROVE reconstructed light extinction (New IMPROVE) at Caney Creek (CACR), Arkansas for the average of the Worst 20 Percent days (top), Best 20 Percent days (middle) days and all IMPROVE sampling days during the period of record.

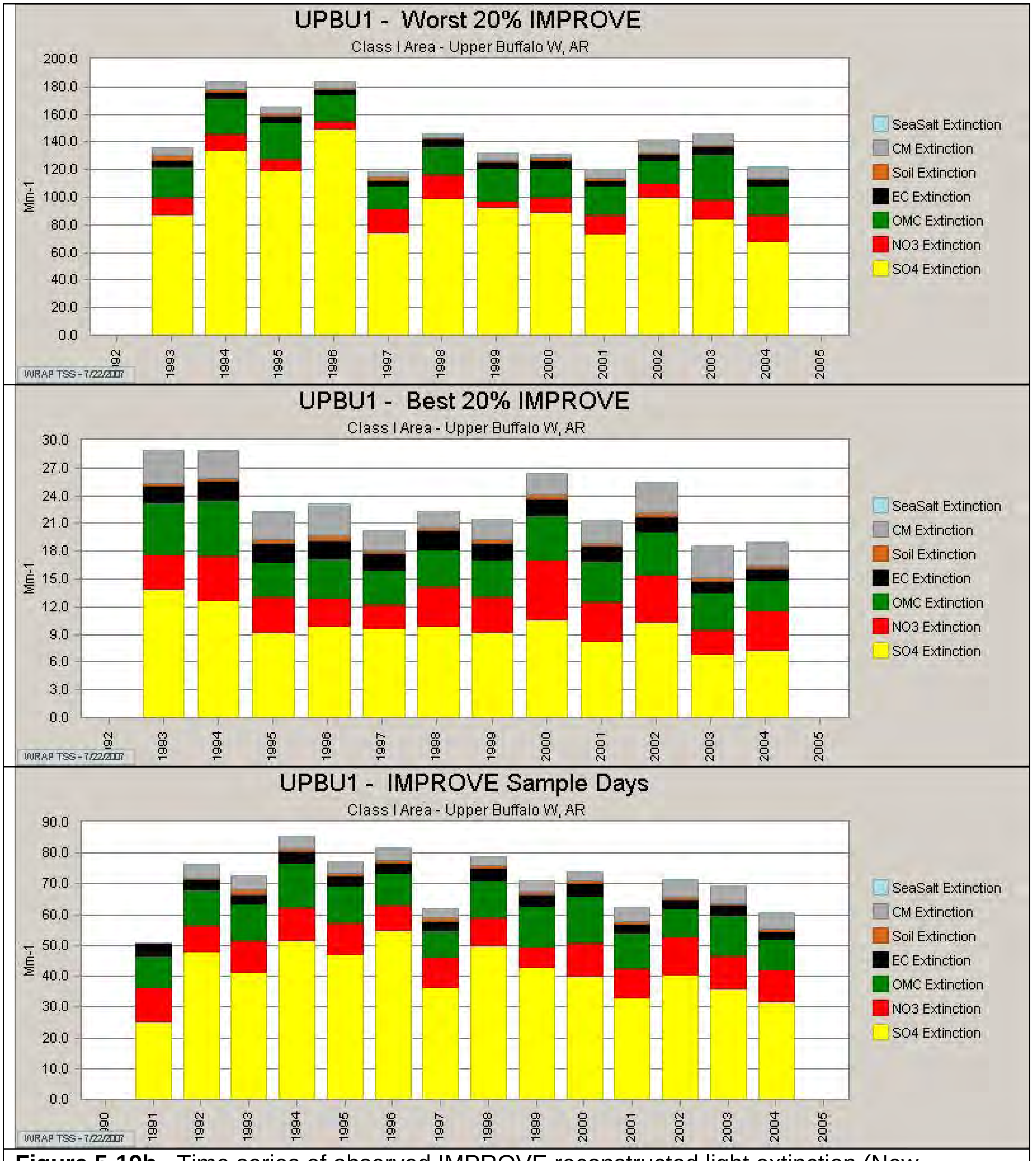


Figure 5-19b. Time series of observed IMPROVE reconstructed light extinction (New IMPROVE) at Upper Buffalo (UPBU), Arkansas for the average of the Worst 20 Percent days (top), Best 20 Percent days (middle) days and all IMPROVE sampling days during the period of record.

Insufficient Data to Calculate Best 20 Percent days at BRET

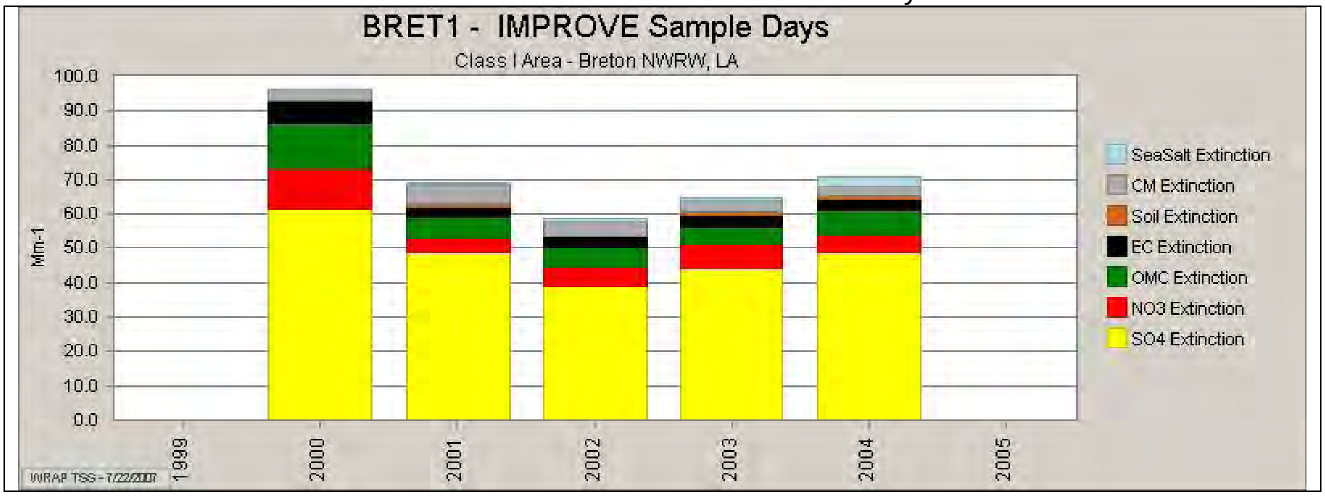


Figure 5-19c. Time series of observed IMPROVE reconstructed light extinction (New IMPROVE) at Breton Island (BRET), Louisiana for the average of the Worst 20 Percent days (top), Best 20 Percent days (middle) days and all IMPROVE sampling days during the period of record.

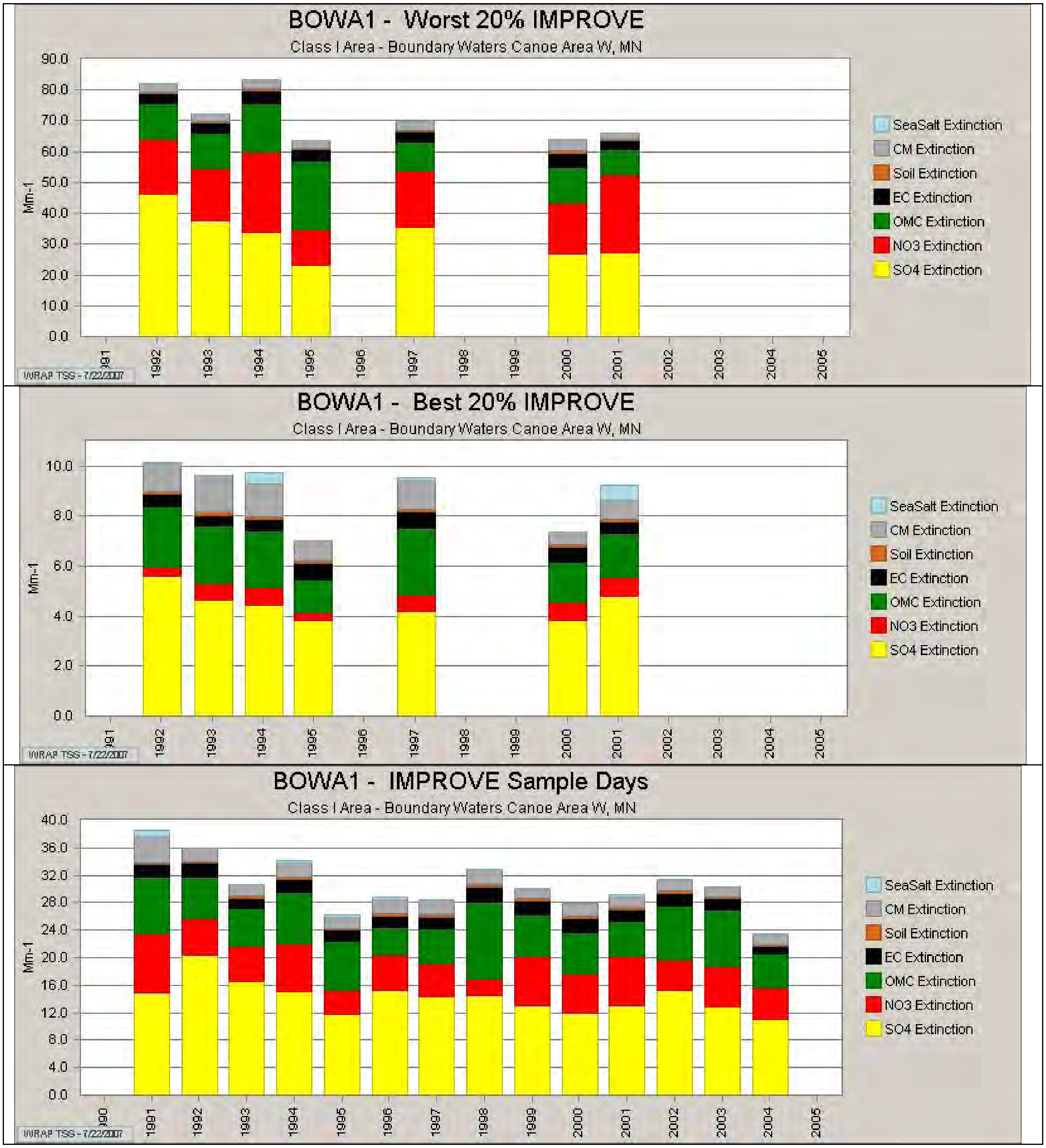


Figure 5-19d. Time series of observed IMPROVE reconstructed light extinction (New IMPROVE) at Boundary Waters (BOWA), Minnesota for the average of the Worst 20 Percent days (top), Best 20 Percent days (middle) days and all IMPROVE sampling days during the period of record.

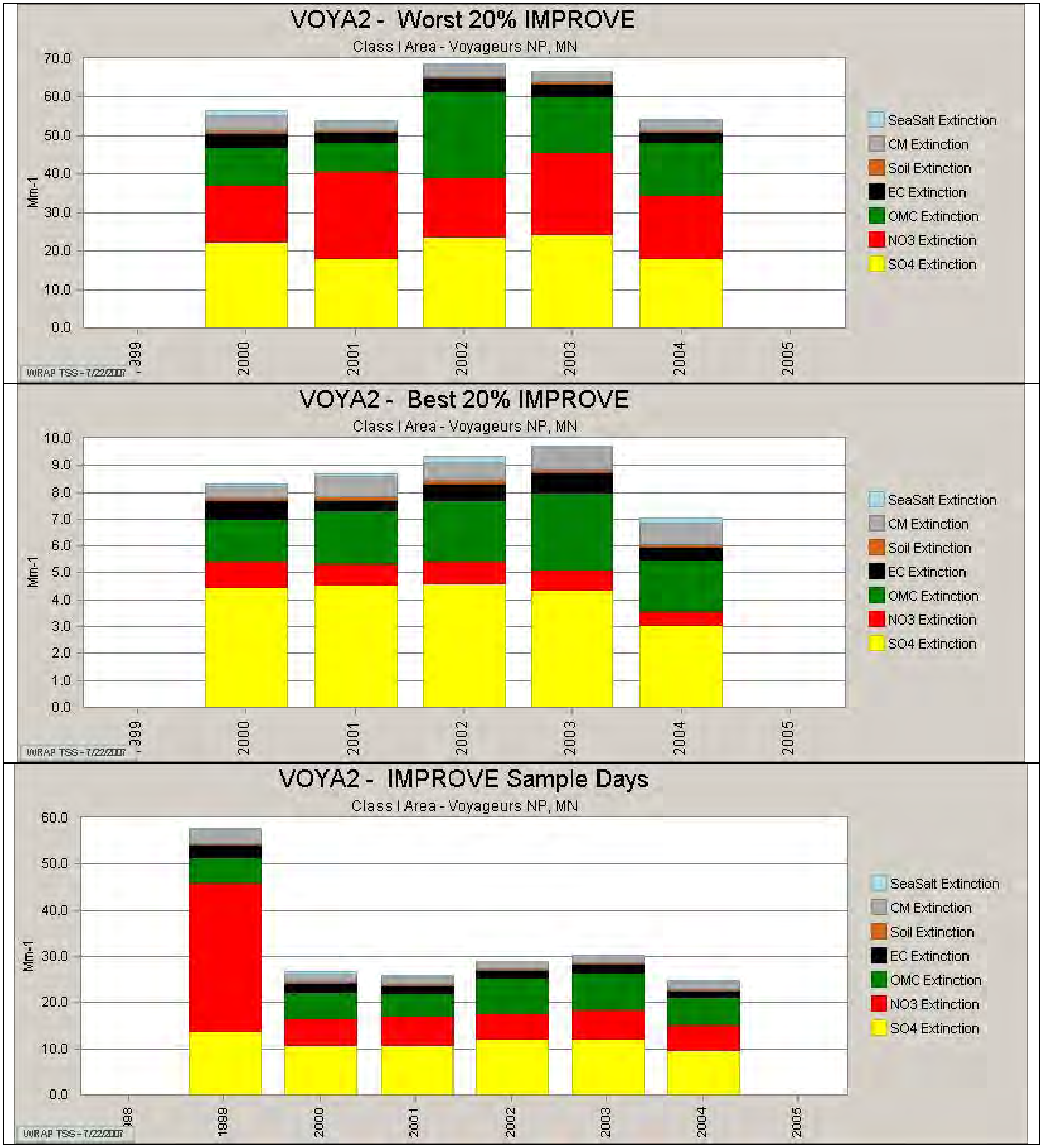


Figure 5-19e. Time series of observed IMPROVE reconstructed light extinction (New IMPROVE) at Voyageurs (VOYA), Minnesota for the average of the Worst 20 Percent days (top), Best 20 Percent days (middle) days and all IMPROVE sampling days during the period of record.

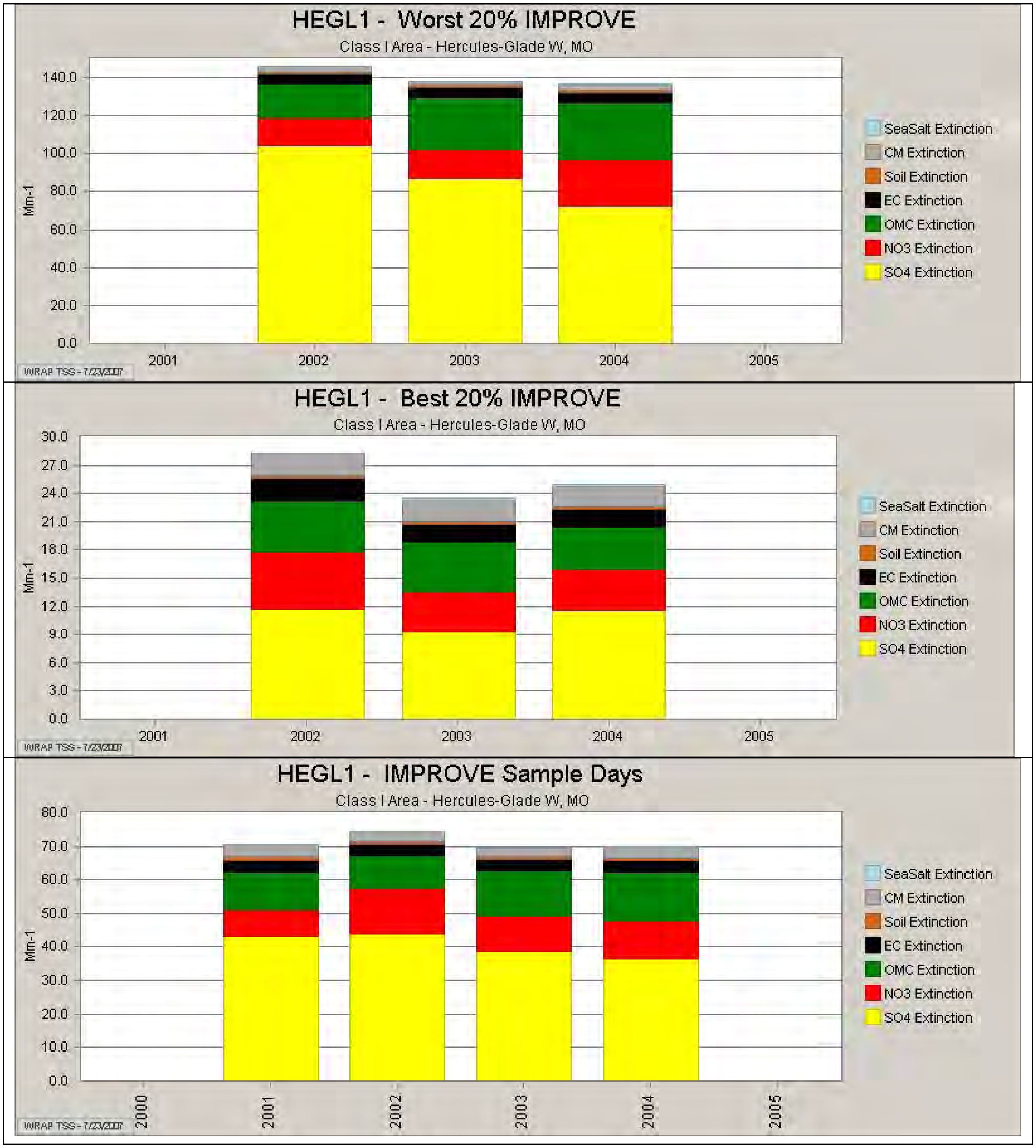


Figure 5-19f. Time series of observed IMPROVE reconstructed light extinction (New IMPROVE) at Hercules Glade (HEGL), Missouri for the average of the Worst 20 Percent days (top), Best 20 Percent days (middle) days and all IMPROVE sampling days during the period of record.

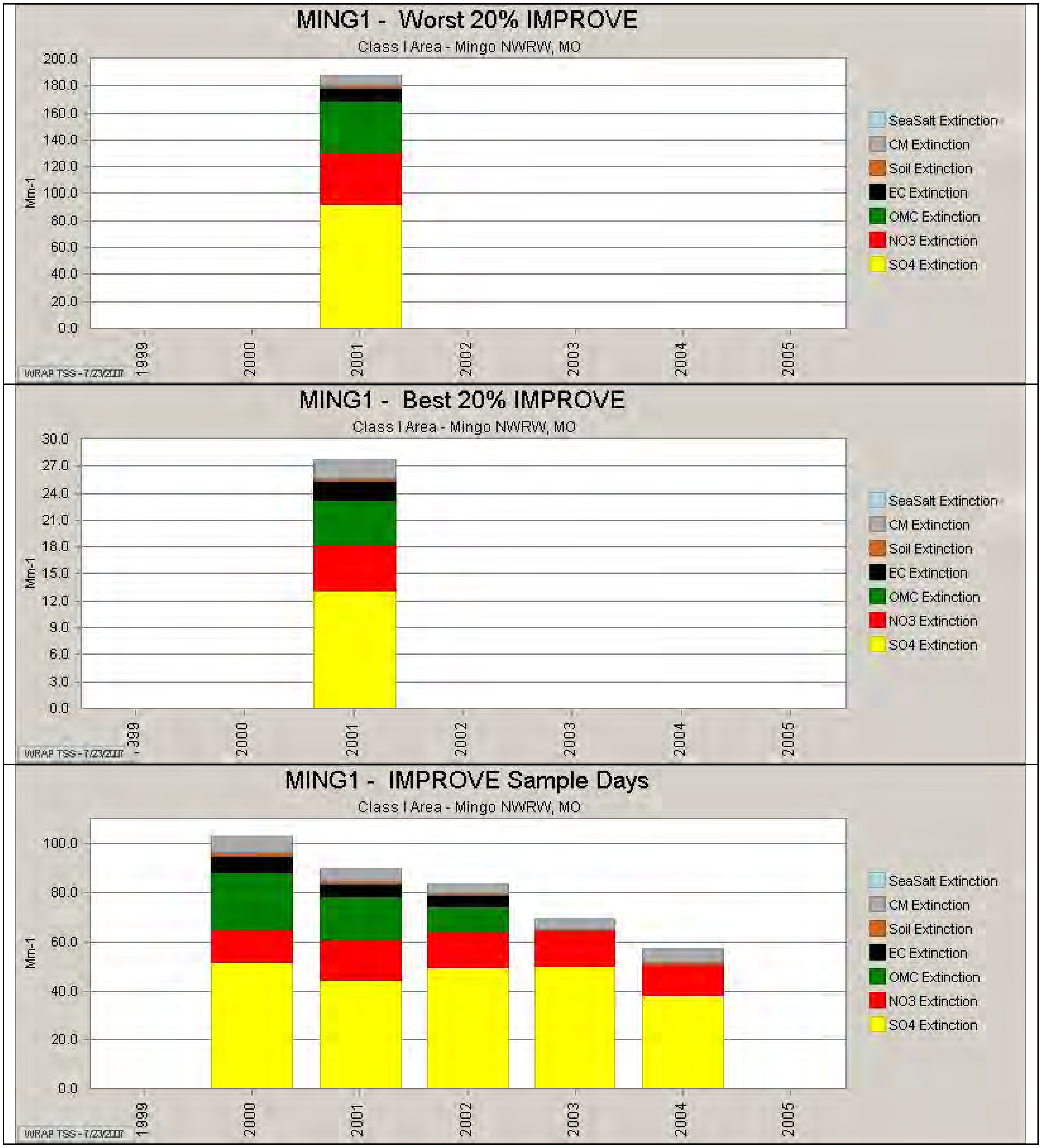


Figure 5-19g. Time series of observed IMPROVE reconstructed light extinction (New IMPROVE) at Mingo (MING), Missouri for the average of the Worst 20 Percent days (top), Best 20 Percent days (middle) days and all IMPROVE sampling days during the period of record.

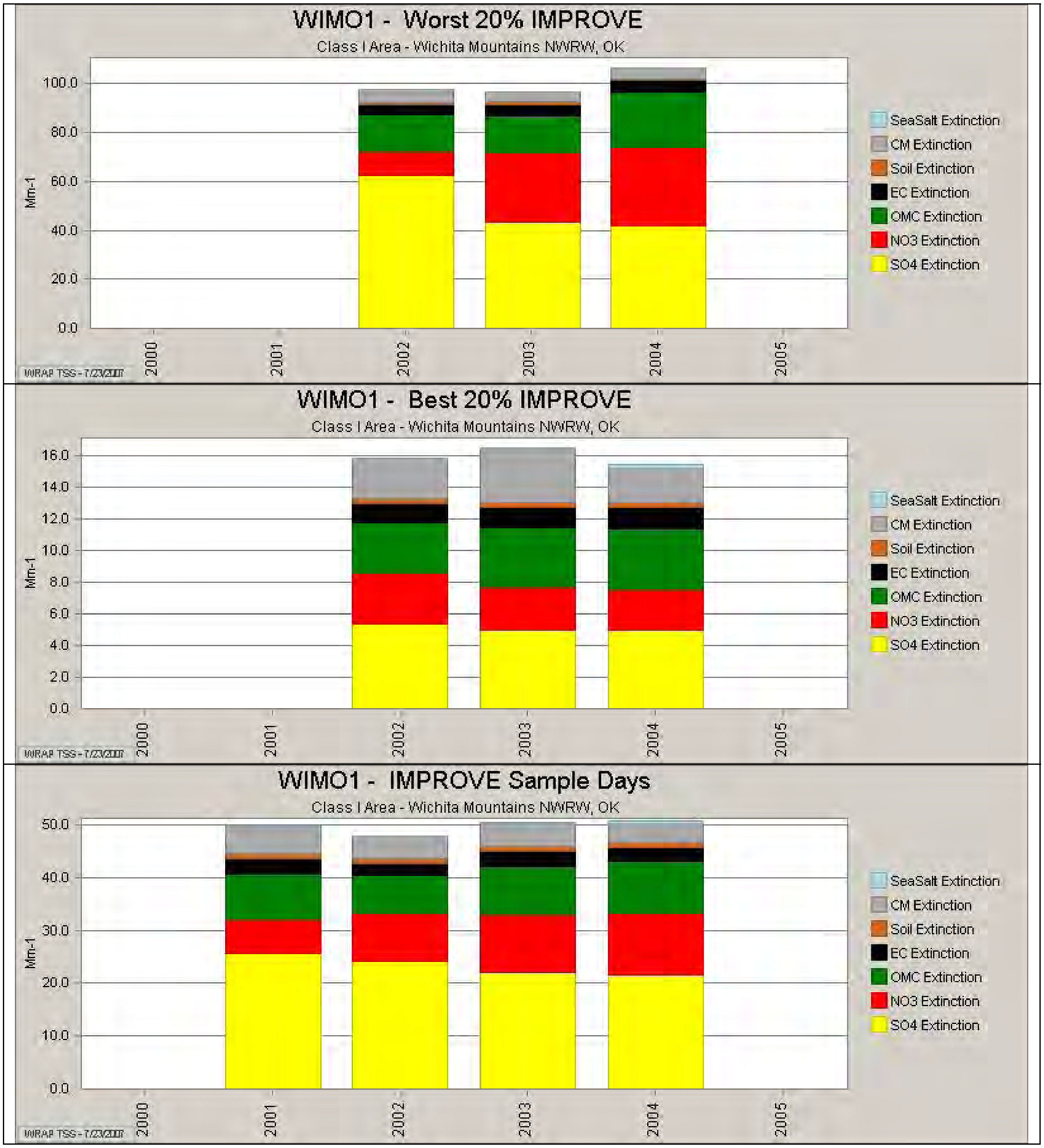


Figure 5-19h. Time series of observed IMPROVE reconstructed light extinction (New IMPROVE) at Wichita Mountains (WIMO), Oklahoma for the average of the Worst 20 Percent days (top), Best 20 Percent days (middle) days and all IMPROVE sampling days during the period of record.

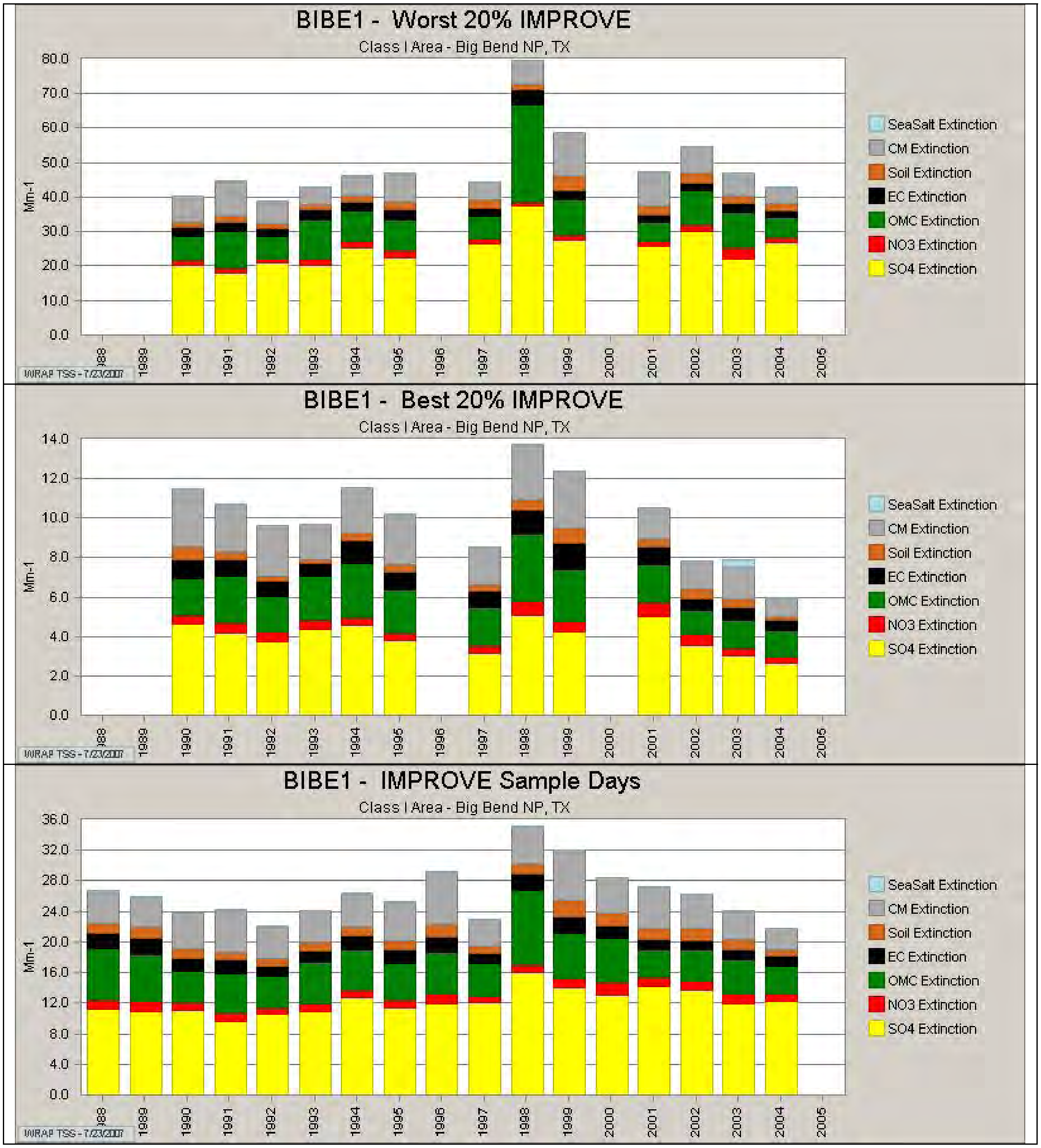


Figure 5-19i. Time series of observed IMPROVE reconstructed light extinction (New IMPROVE) at Big Bend (BIBE), Texas for the average of the Worst 20 Percent days (top), Best 20 Percent days (middle) days and all IMPROVE sampling days during the period of record.

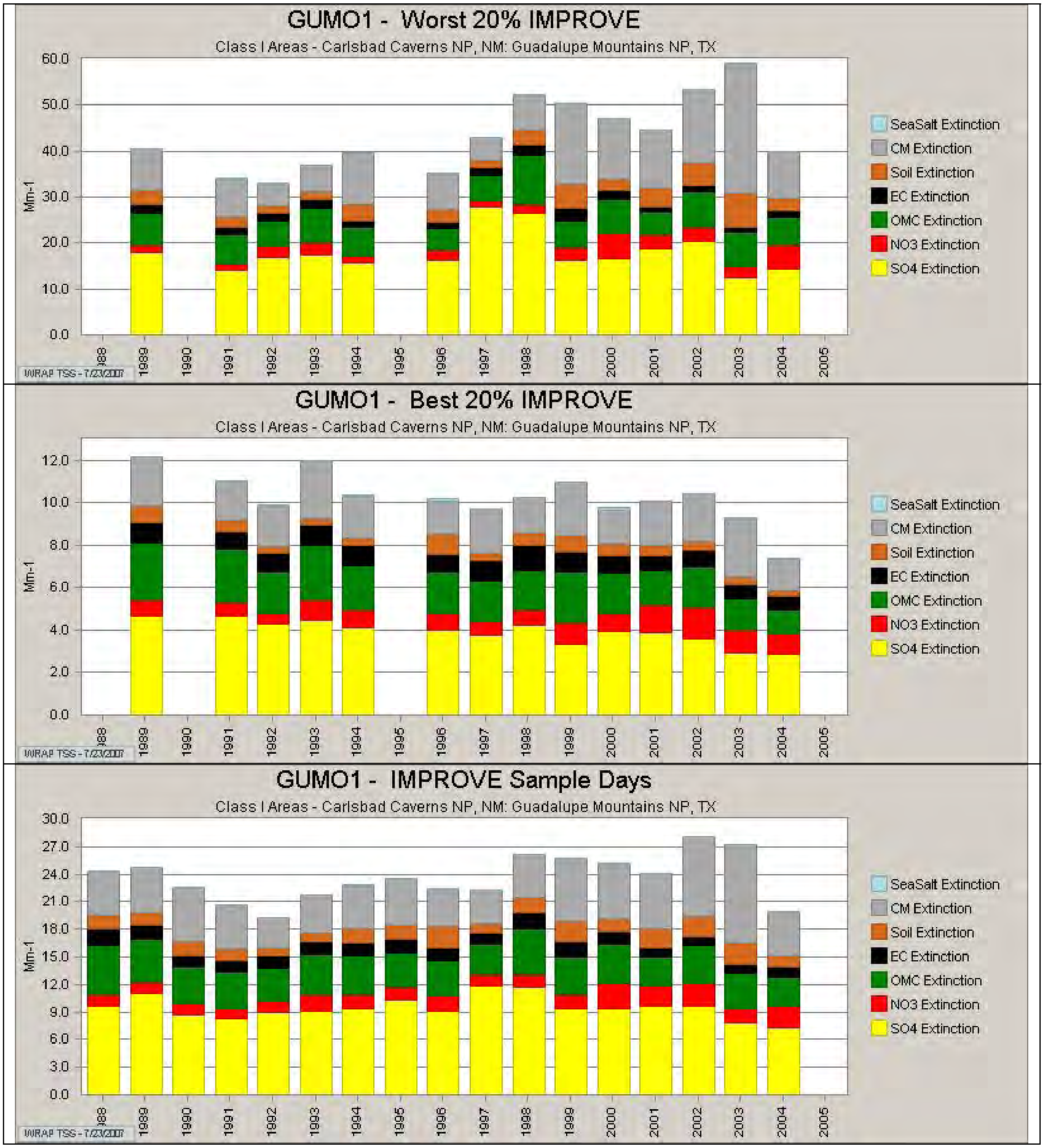


Figure 5-19j. Time series of observed IMPROVE reconstructed light extinction (New IMPROVE) at Guadalupe Mountains (GUMO), Texas for the average of the Worst 20 Percent days (top), Best 20 Percent days (middle) days and all IMPROVE sampling days during the period of record.

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APPENDIX A

Model Performance Evaluation of the 2002 36 km MM5 Meteorological Model Simulation used in the CENRAP Modeling and Comparison to VISTAS Final 2002 36 km MM5 and WRAP Interim 2002 36 km MM5 Simulations

The CENRAP 2002 36 km MM5 simulation (Johnson, 2007) was evaluated against observed surface and upper-air meteorological observations and observed precipitation amounts and its performance was compared against the VISTAS final and the WRAP interim 2002 36 km MM5 simulations. The CENRAP, VISTAS and WRAP 2002 36 km MM5 simulations used several common science options:

- Lambert Conformal Projection with center at (97°, 40°) and standard parallels at (33°, 45°).
- 164 by 128 36 km by 36 km horizontal grids covering the continental U.S. and adjacent regions.
- 34 vertical layers up to 100 mb (~15 km AGL).
- Pleim-Xiu Land Surface Module (LSM).
- Asymmetric Convective Mixing (ACM) Planetary Boundary Layer (PBL) model.
- RRTM long-wave radiation.
- Dudhia short-wave radiation.
- No Shallow convection.

However, there were some differences in the choice of science options:

- VISTAS and CENRAP MM5 simulations used the Kain Fritsch 2 cumulus parameterization, whereas WRAP MM5 used Kain Fritsch 1.
- VISTAS and CENRAP MM5 simulations used the Reisner 1 moist physics while WRAP MM5 used Reisner 2.
- All three MM5 simulations used Four Dimensional Data Assimilation (FDDA analysis nudging at the surface for winds, but WRAP also used surface analysis nudging to temperature and moisture.
- All three MM5 simulations used analysis nudging FDDA above the PNL to winds, temperature and moisture.

Much of the difference in the model performance for the three MM5 simulations was related to the surface temperature and moisture analysis nudging used in the interim WRAP MM5 simulations that resulted in better surface temperature model performance, but caused instabilities resulting in degradation in meteorological model performance above the surface. The final WRAP 2002 36 km MM5 simulation did not use the surface temperature and moisture FDDA and used the Betts-Miller cumulus scheme instead of Kain Fritsch that resulted in much improved meteorological model performance in the western States (Kemball-Cook et al., 2005).

A.1 Surface Meteorological Model Performance

The performance of the three MM5 simulations at the surface was evaluated through comparisons against observed surface wind, temperature and humidity measurements from the ds472 observational database. The METSTAT program was used to evaluate the MM5 simulations for each month of 2002 and across the 11 subdomains shown in Figure A-1. These subdomains are as follows:

1 = Pacific NW
2 = SW
3 = North
4 = Desert SW
5 = CenrapN
6 = CenrapS
7 = Great Lakes
8 = Ohio Valley
9 = SE
10 = NE
11 = MidAtlantic

Emery and Tai (2001) have developed model performance benchmarks by analyzing over 30 MM5RAMS meteorological model simulations and tabulating the typical level of performance that a good meteorological model achieves. These performance benchmarks are not intended to be pass/fail grades; rather they provide a framework to evaluate the model performance against past applications. Since many of the past MM5/RAMS meteorological model simulations that the benchmarks were developed from were in support of urban ozone modeling that are typically fairly stagnant conditions with little or no precipitation and involved multiple iterations to achieve the final base case simulation. Thus, we may not expect the 2002 annual MM5 simulations to achieve a similar level of performance given the complicating factors of precipitation and complex terrain associate with many Class I areas in the west. Table A-1 lists the meteorological model performance benchmarks for wind speed, wind direction, temperature and humidity.

Table A-1. Meteorological model performance benchmarks (Source: Emery et al., 1999).

Statistic	Wind Speed	Wind Direction	Temperature	Humidity
RMSE	≤ 2 m/s			
Mean Bias	≤ ±0.5 m/s	≤ ±10°	≤ ±0.5 K	≤ ±1.0 g/kg
Index of Agreement	≤ 0.6		≤ 0.8	≤ 0.6
Gross Error		≤ 30°	≤ 2.0 K	≤ 2.0 g/kg

Below we present the evaluation of the CENRAP, VISTAS and interim WRAP 2002 36 km MM5 simulations against surface meteorological observations for the four seasonal months of January, March, July and October and the CENRAP North (CenrapN) and CENRAP South (CenrapS) subdomains (i.e., subdomains 5 and 6 in Figure A-1). The surface evaluation of the three MM5 2002 36 km simulations outside of the CENRAP subdomains can be found in Kemball-Cook et al., (2004).

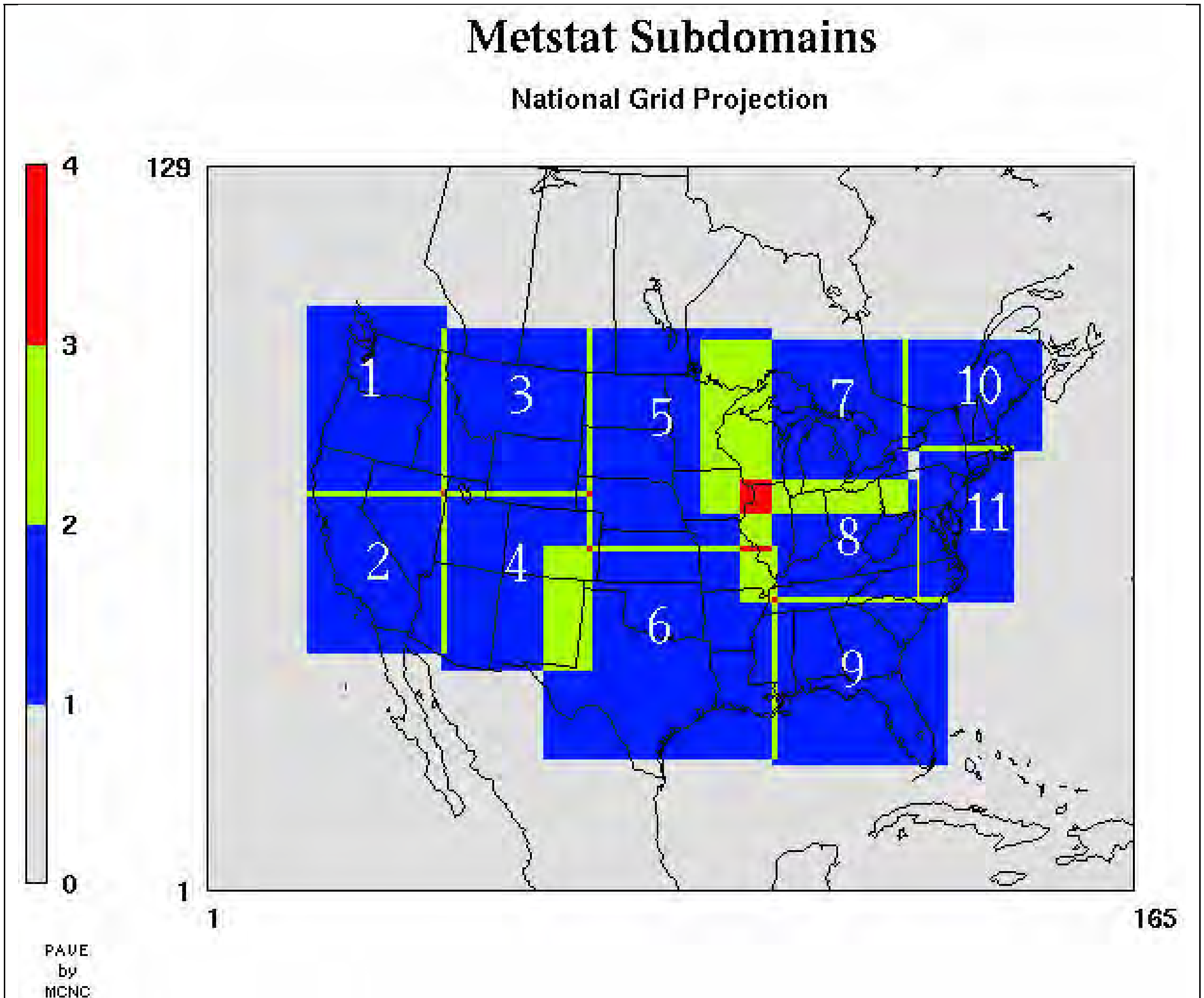


Figure A-1. Eleven subdomains where monthly evaluation of the MM5 simulations surface model performance was evaluated.

A.1.1 Temperature

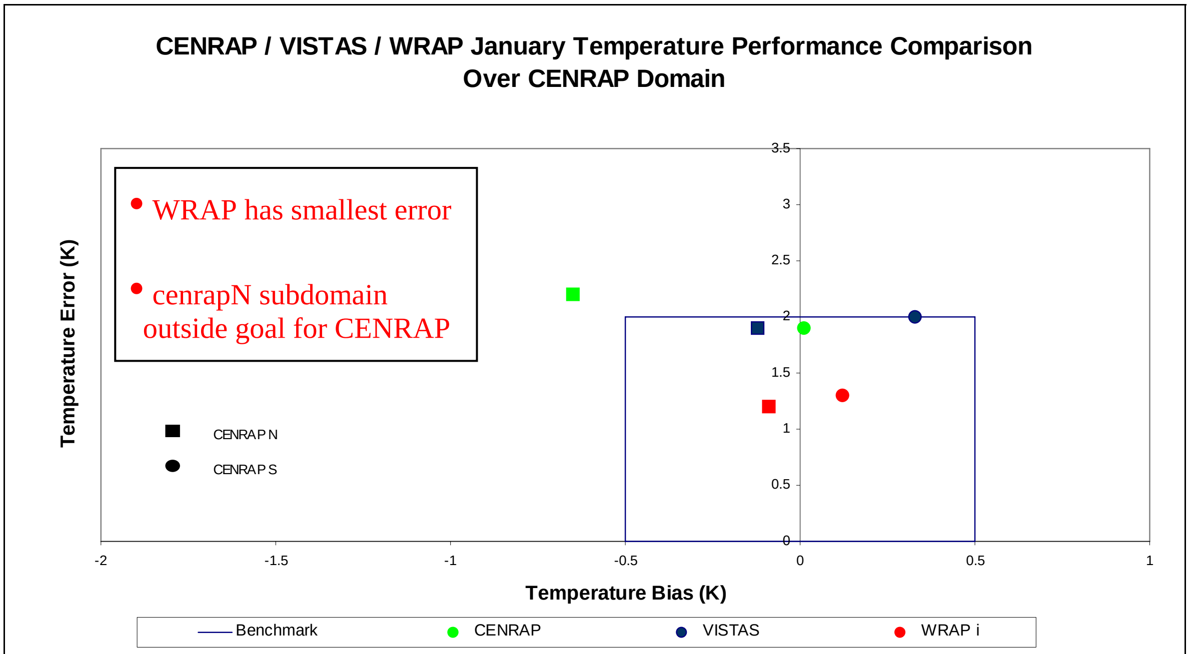
Figure A-2 displays the surface temperature model performance for the CENRAP, VISTAS and WRAP 2002 36 km MM5 simulations in the CenrapN and CenrapS subdomains and the months of January, March, July and October. The WRAP MM5 simulations are performing best for January temperature in both CENRAP domains exhibiting low bias and the lowest error that are within the benchmark. The VISTAS MM5 rum is performing next best with bias well within the benchmark and error within but close to the error benchmark. The CENRAP MM5 simulation performs well for the CenrapS domain with zero bias and error within, but approaching the benchmark. However, the CENRAP performance for the CenrapN domain does not achieve the performance benchmarks due to a too cold bias.

The temperature performance in March is similar to January with both the VISTAS and WRAP MM5 simulations achieving the benchmark for both CENRAP subdomains. Again the CENRAP MM5 simulation has a near zero bias and achieves the error benchmark in the CenrapS subdomain, but is too cold in the CenrapN domain falling out of the bias benchmark range.

In July the three simulations achieve the temperature benchmark in both CENRAP subdomains, although the WRAP MM5 simulations is cooler with the CenrapS bias right at the -0.5 K lower bound benchmark. The CENRAP MM5 simulation is slightly warmer than the VISTAS MM5 simulation.

In October, all three MM5 simulations achieve the temperature performance benchmarks. The WRAP MM5 simulation performs best with near zero bias and lower error than either the VISTAS or CENRAP simulations. The VISTAS and CENRAP MM5 simulations exhibit nearly identical temperature performance in October with a near zero bias for the CenrapS subdomain and a cool bias for the CenrapN subdomain.

In conclusion, the WRAP MM5 simulation is always performing best for surface temperature with the lowest bias and usually the lowest error. The VISTAS MM5 simulations is performing next best as the CENRAP MM5 simulations exhibits a cool bias for the CenrapN subdomain in January and March that exceed the performance benchmarks.



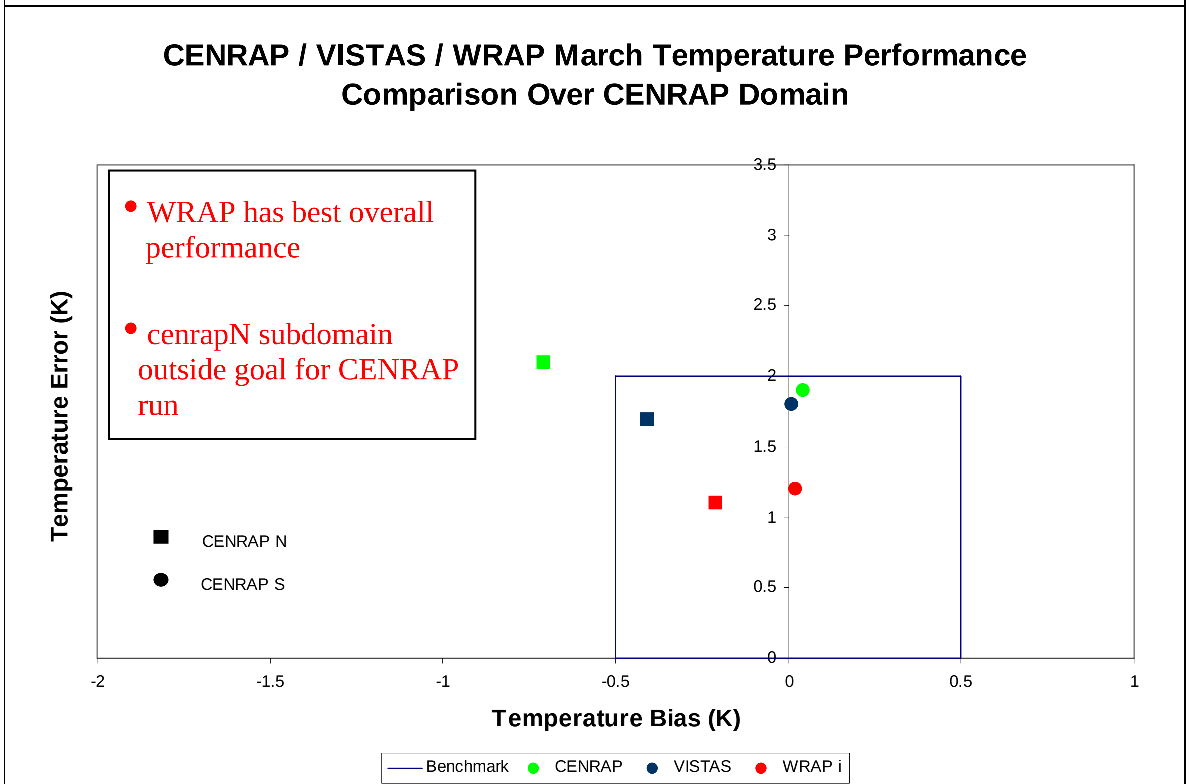
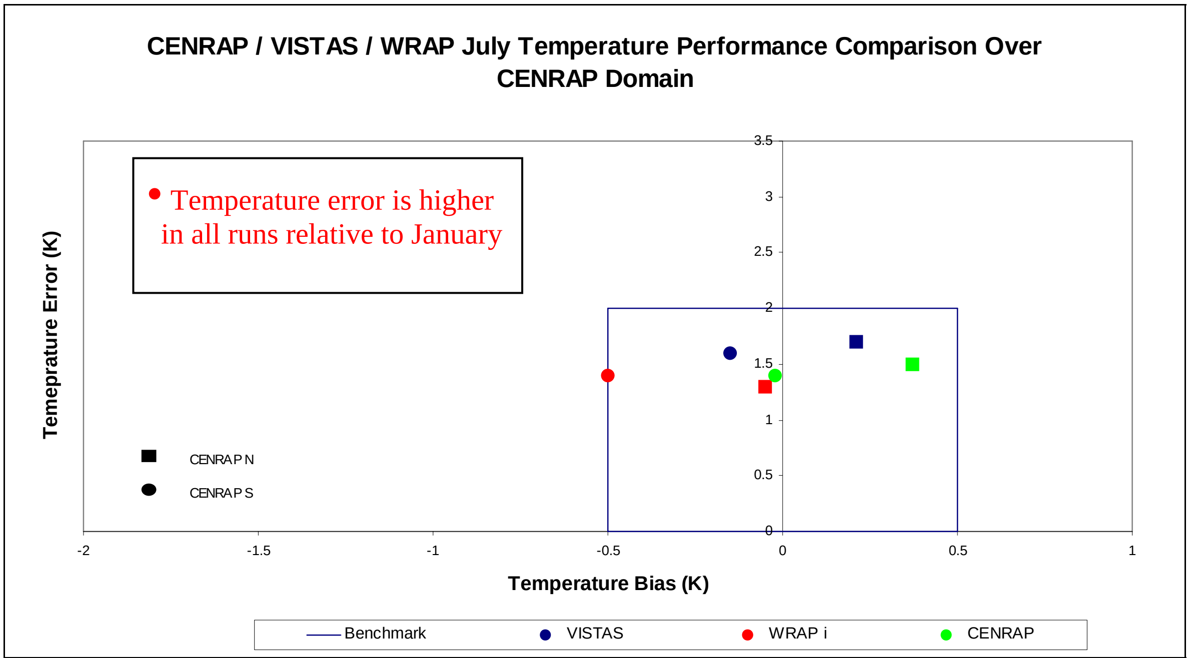


Figure A-2a. Temperature performance for the CENRAP, VISTAS and interim WRAP 2002 36 km MM5 simulations, the CenrapN and CenrapS subdomains and January (top) and March (bottom).



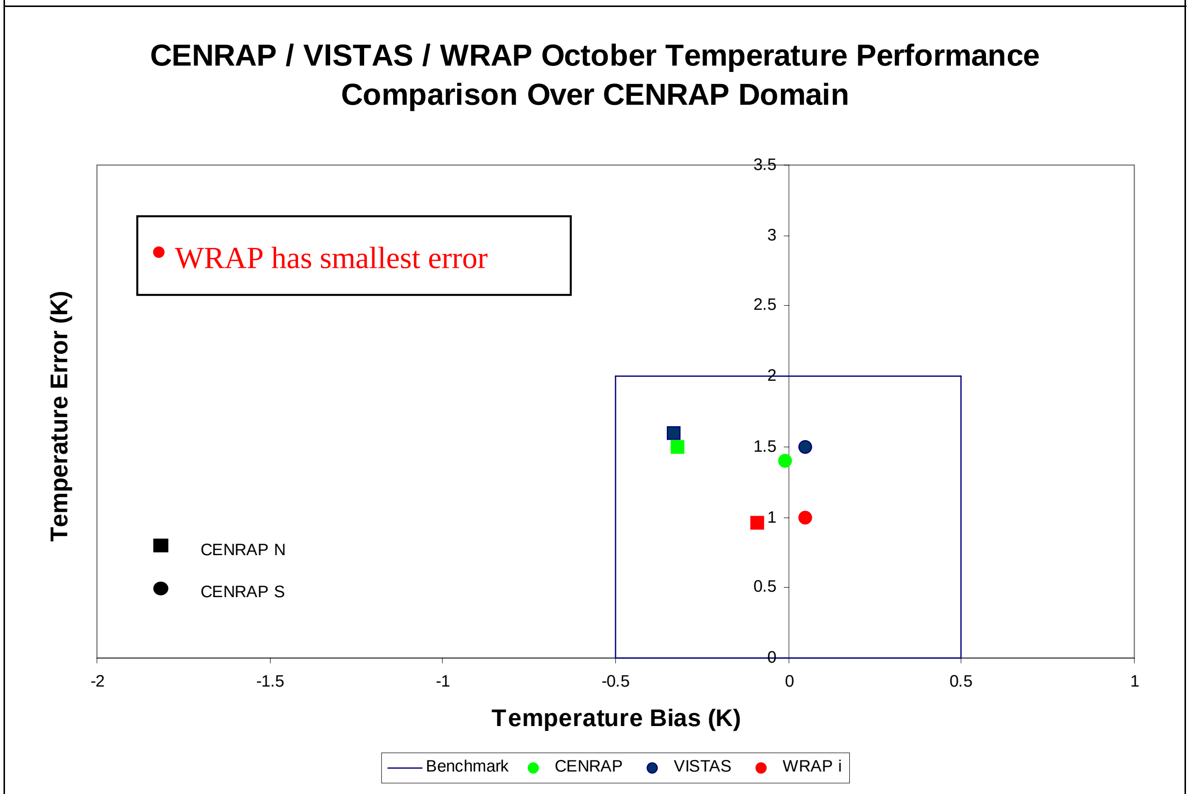
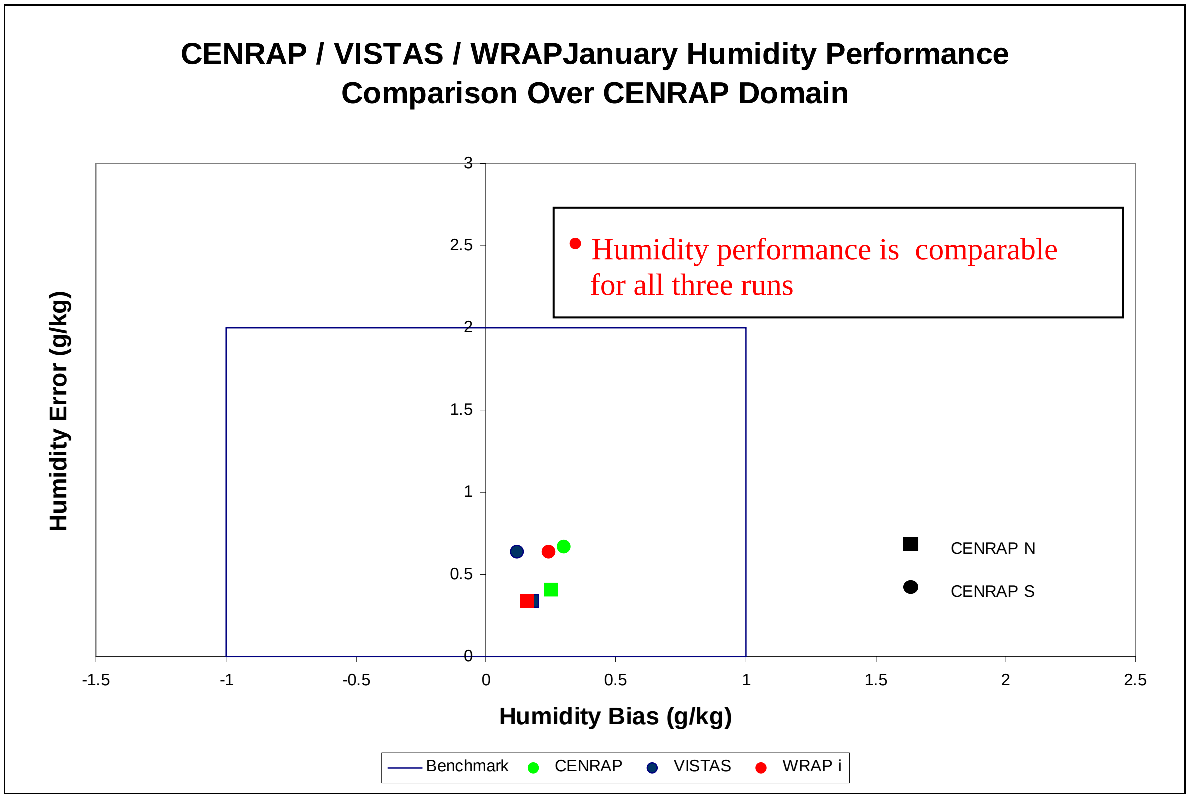


Figure A-2b. Temperature performance for the CENRAP, VISTAS and interim WRAP 2002 36 km MM5 simulations, the CenrapN and CenrapS subdomains and July (top) and October (bottom).

A.1.2 Humidity

The humidity performance for the three MM5 simulations is comparable and always achieves the performance benchmarks. The humidity bias is always near zero for all three runs and four months. In January, March and October the humidity error is at or less than half of the 2.0 g/kg benchmark. However, in July there is more error in the humidity with it within but approaching the benchmark value for all three models.

In conclusion, all three MM5 simulations achieved the humidity benchmark performance goals for all months studied. No model simulation exhibited superior performance over another.



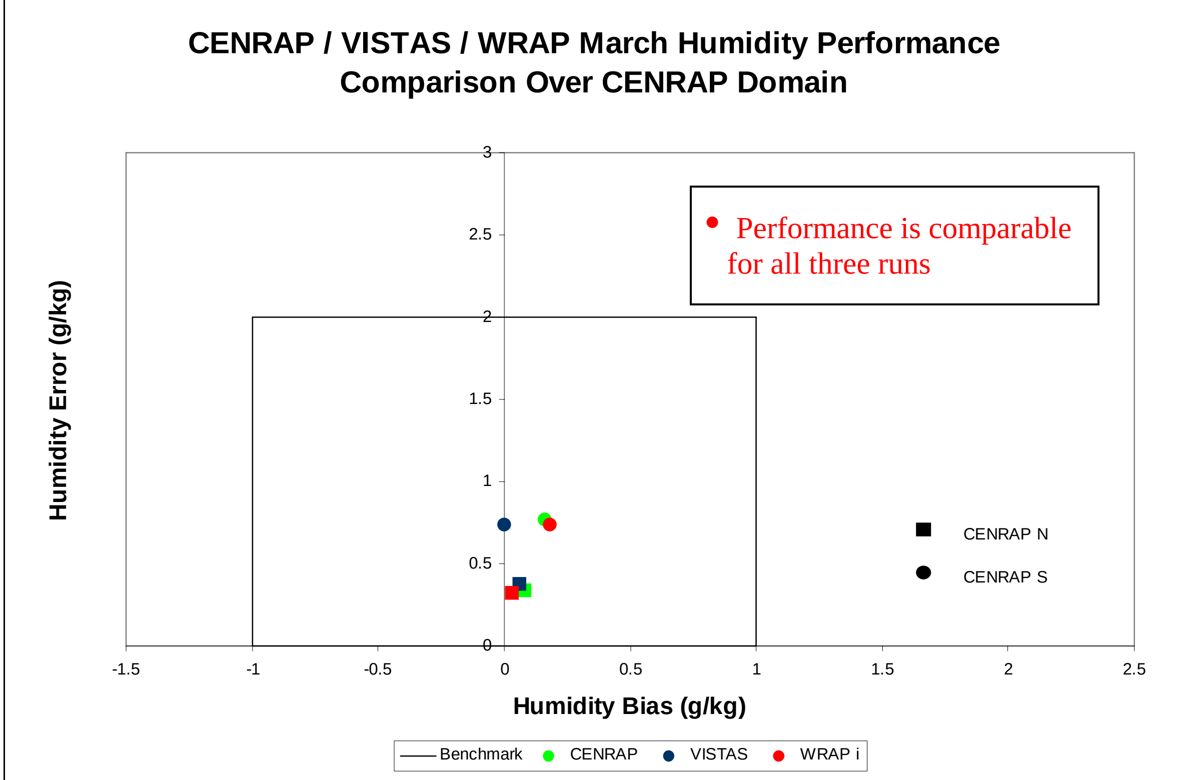
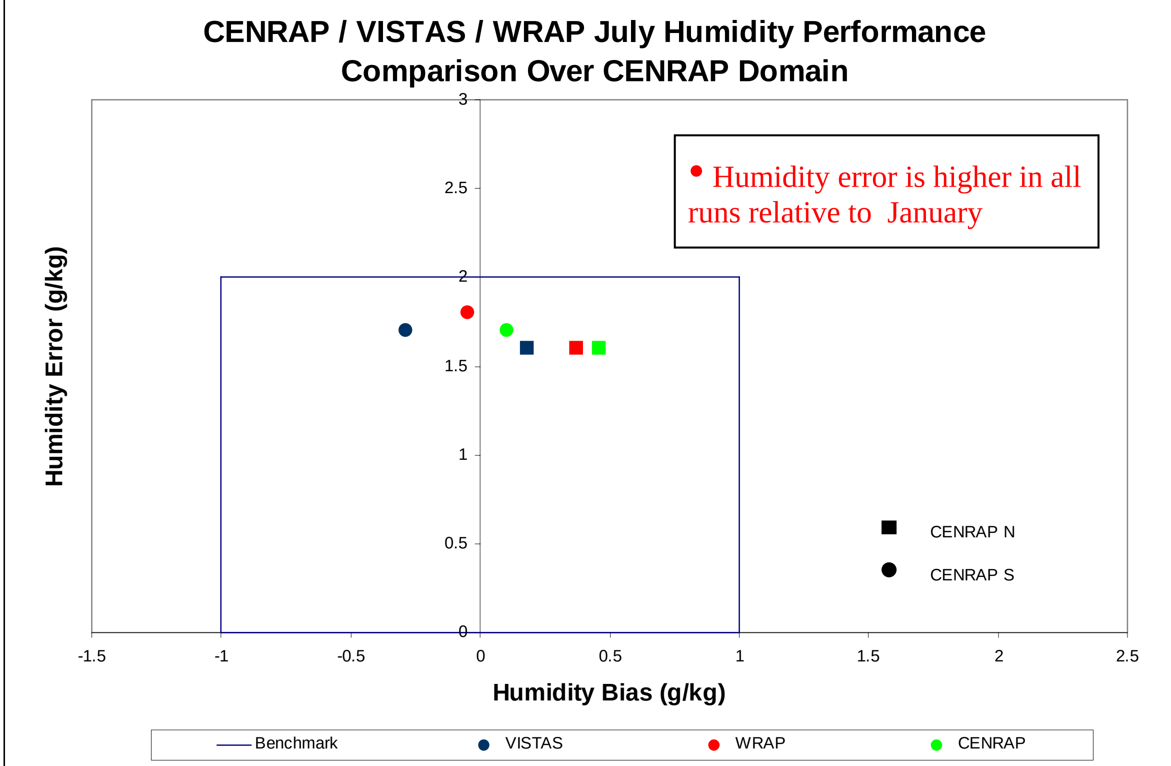


Figure A-3a. Humidity performance for the CENRAP, VISTAS and interim WRAP 2002 36 km MM5 simulations, the CenrapN and CenrapS subdomains and January (top) and March (bottom).



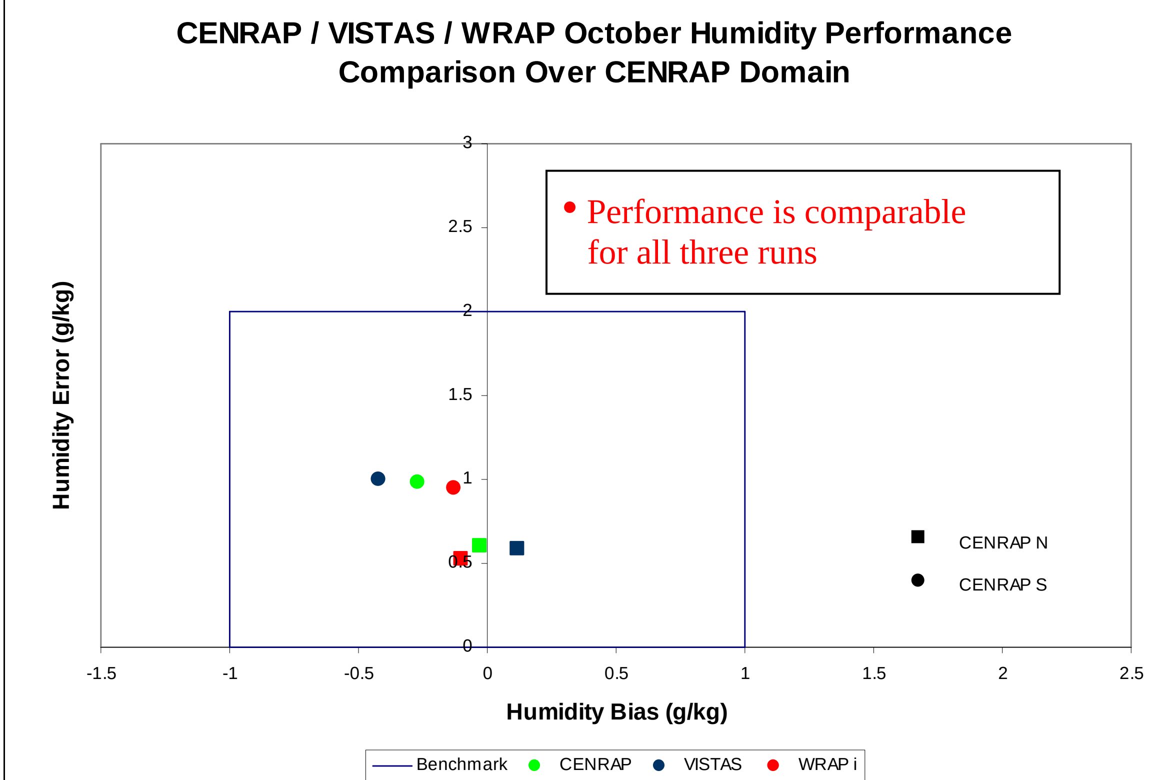


Figure A-3b. Humidity performance for the CENRAP, VISTAS and interim WRAP 2002 36 km MM5 simulations, the CenrapN and CenrapS subdomains and July (top) and October (bottom).

A.1.3 Winds

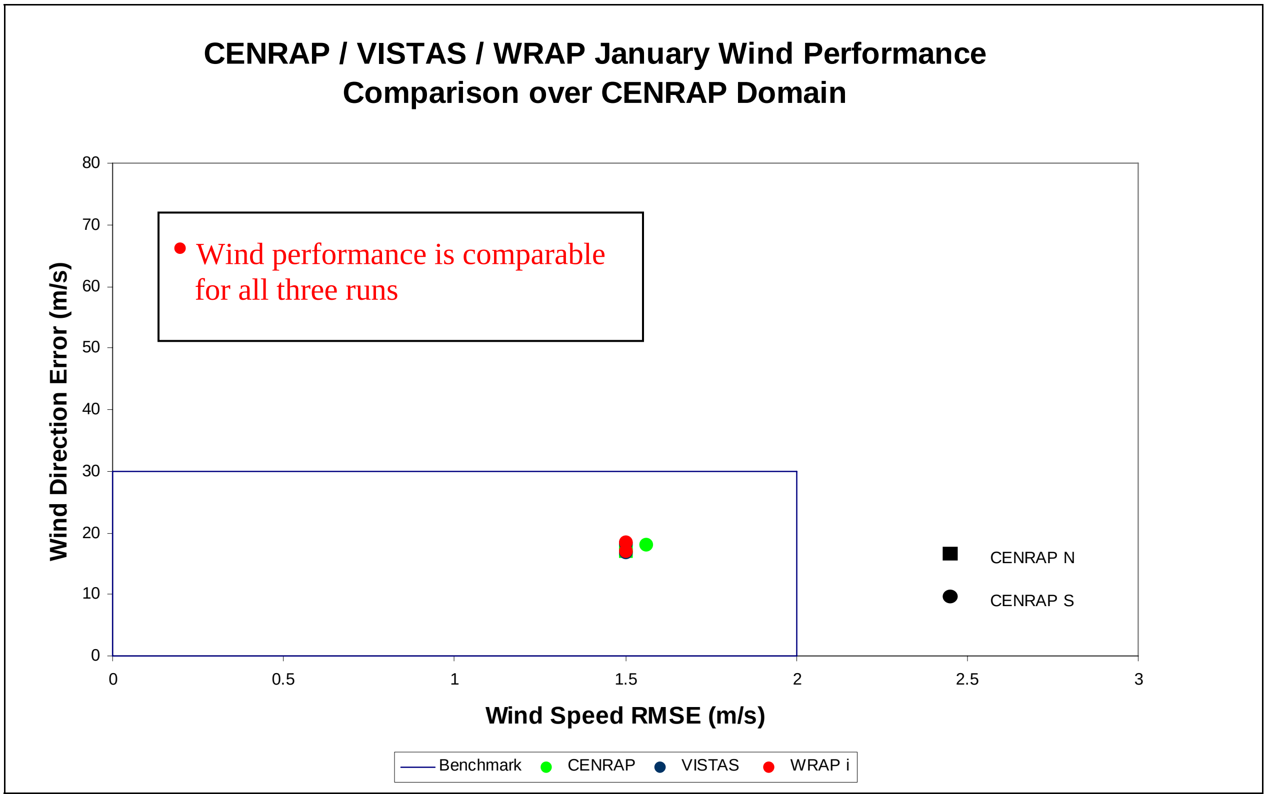
The model performance for wind speed and direction and January is almost identical and within the benchmarks for all three models and both CENRAP subdomains. In fact, the performance is so close the CenrapS symbols are plotted over and obliterate the CenrapN performance symbols.

In March, the wind performance is within the benchmark for all three MM5 simulations, which exhibit similar performance statistics. The wind performance in the CenrapS subdomain is slightly better than CenrapN with the CENRAP MM5 simulations showing the largest wind speed RMSE in the CenrapN subdomain, although still within the benchmarks.

Slight degraded wind direction performance is seen in July with the error increases to just below 20 degrees to just below the 30 degree benchmark value for all three models. Similar wind speed RMSE is seen for all three models.

The October wind performance is within the benchmarks for all three models with performance between that seen for January/March and July.

In summary, the models exhibited similar model performance for surface wind speed and direction.



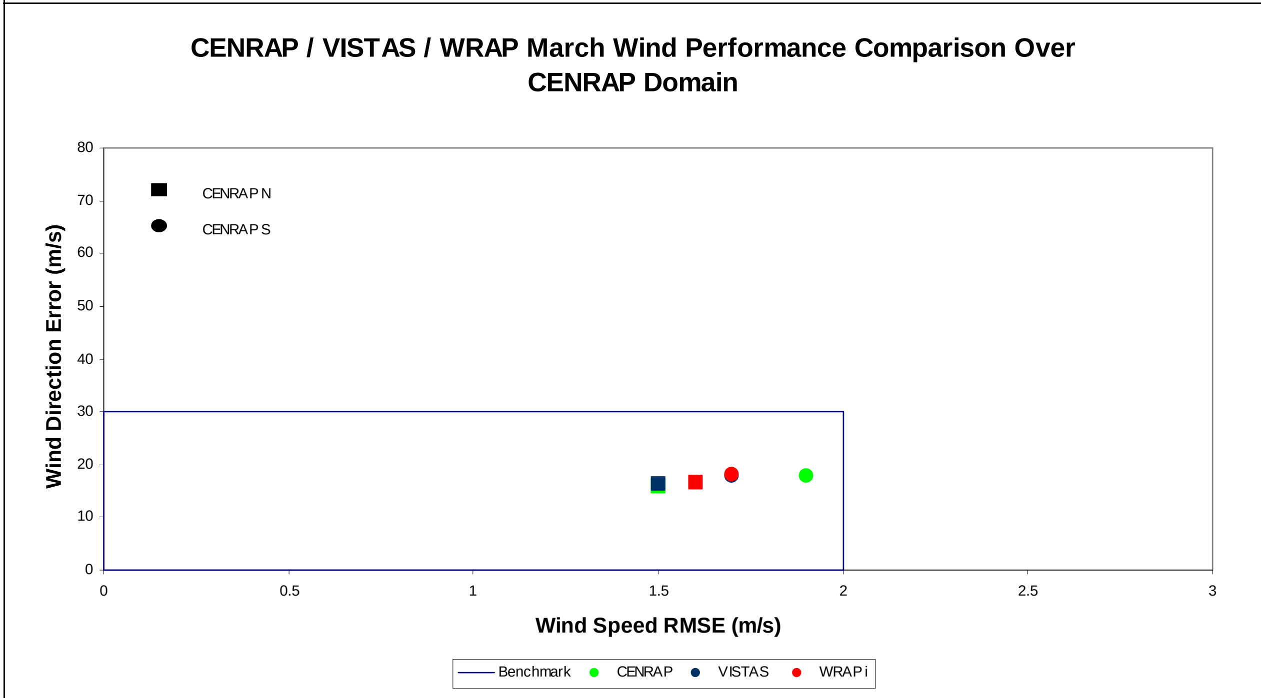
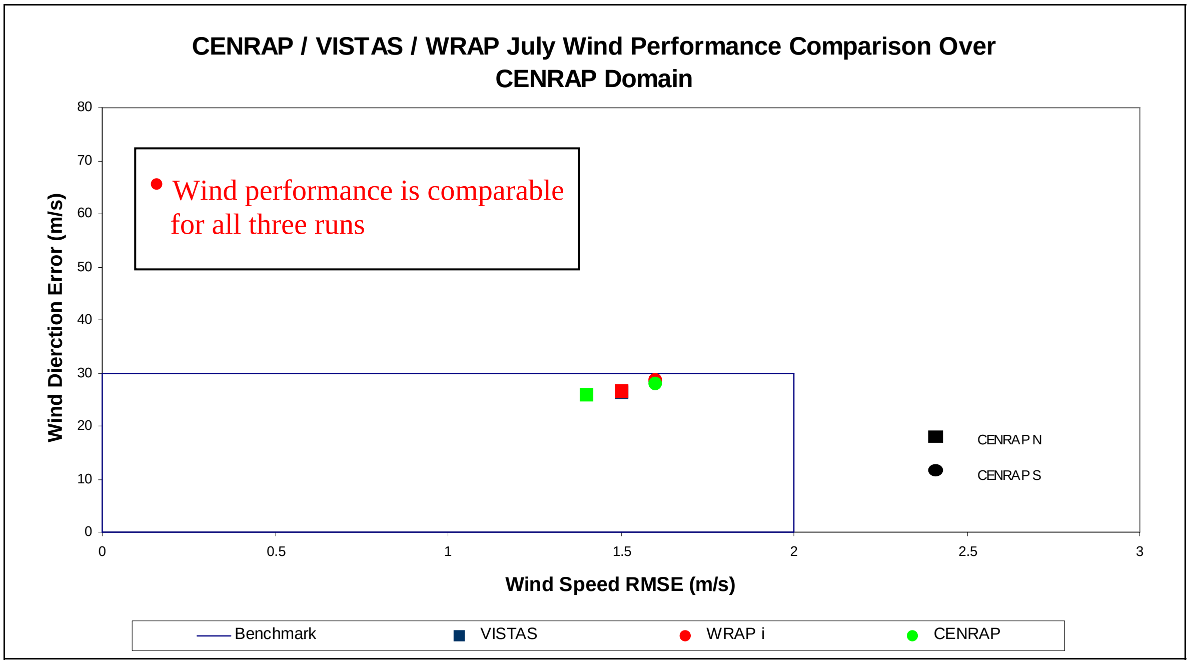


Figure A-4a. Wind Speed and Wind Direction performance for the CENRAP, VISTAS and interim WRAP 2002 36 km MM5 simulations, the CenrapN and CenrapS subdomains and January (top) and March (bottom).



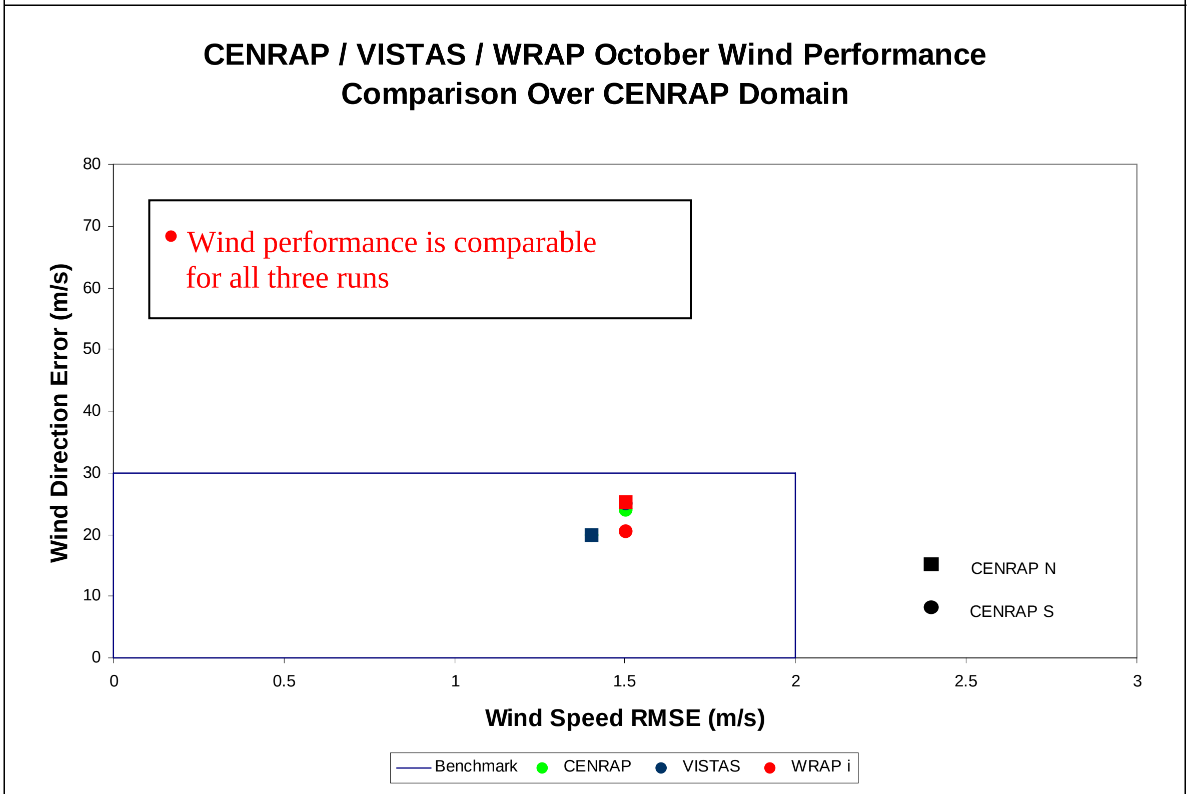


Figure A-4b. Wind Speed and Wind Direction performance for the CENRAP, VISTAS and interim WRAP 2002 36 km MM5 simulations, the CenrapN and CenrapS subdomains and July (top) and October (bottom).

A.2 Upper-Air Meteorological Evaluation

Figure A-5 displays an example comparison of the vertical profile of predicted and observed winds and temperature for Midland, Texas and January 7 2002 at 12 GMT (6am LST) and for July 16, 2002 at 00 GMT (6pm LST). Above the surface, all three models do a good job in replicating the observed temperature, dew point temperature and winds at 6a on January 7, 2002. Although the WRAP MM5 simulation predicts the surface temperature better than the other two simulations, the vertical structure of the temperature and the surface temperature inversion is not reproduced as well.

All three models understate the afternoon PBL depth on July 16, 2002 at Midland Texas. This phenomenon was seen at other sites as well.

The upper-air meteorological model evaluation found that all three models had difficulty reproducing the observed nocturnal inversion. The day time convective mixing depths were also typically underestimated.

Although the WRAP MM5 simulation reproduced the surface temperature the best of the three models, it was worst at reproducing the observed vertical temperature structure and resultant level of mixing. These results are likely due to the surface data assimilation of temperature employed by the WRAP interim MM5 simulation and resulted in WRAP eliminating the surface temperature and humidity FDDA in their final simulation.

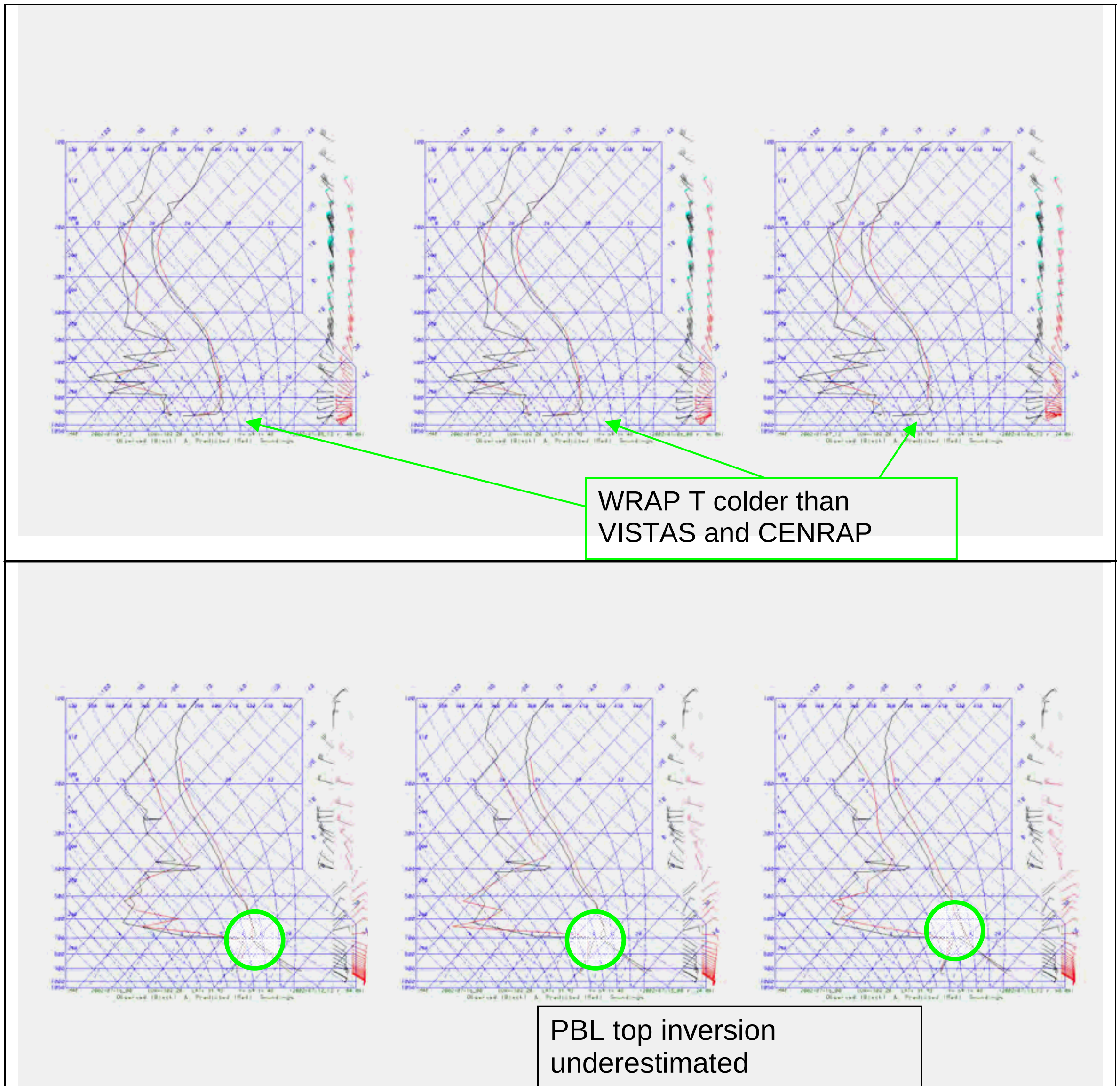


Figure A-5. Comparison of predicted and observed vertical temperature, dew point and winds profiles for the CENRAP (left), VISTAS (middle) and WRAP (right) at Midland Texas on January 7, 2002 at 12 GMT (top) and July 16, 2002 at 00 GMT (bottom).

A.4 Precipitation Model Performance Evaluation

The three MM5 model simulation precipitation estimates were evaluated by comparing the monthly average spatial distributions and amounts with observed values from the observed CPC 0.25 by 0.25 degree (approximately 28 km by 28 km) gridded analysis fields. The CPC analysis fields are gridded from on U.S. land-based observations, consequently the gridded observed fields are not available over the oceans and Canada and Mexico. The CPC observed monthly average precipitation fields were displayed using the MM5 modeling domain. The MM5 total precipitation estimates were accumulated for a month and plotted. Here total precipitation includes both explicit large scale synoptic precipitation as well as the subgrid-scale convective precipitation from the cumulus parameterization (Kain Fritsch 1 or 2).

Figures A-6 through A-9 display the monthly average precipitation fields for the months of January, March, July and October and the CPC observed and CENRAP, VISTAS and interim WRAP MM5 simulations. In January (Figure A-6), all three models reproduce the observed monthly average precipitation well with enhanced predicted and observed precipitation over the Pacific Northwest and the Appalachian Mountains. The MM5 simulations also estimated enhanced precipitation in off-shore areas north of Seattle, over the Atlantic Ocean and in the Gulf of Mexico that can not be either confirmed or refuted by the CPC observations. MM5 does overstate the amount of precipitation in January over the northern CENRAP region including over Minnesota, Iowa and Nebraska.

The three models also do a good job in reproducing the observed spatial distribution and amounts of the precipitation in March 2002 (Figure A-7). Elevated precipitation areas in the Pacific Northwest and across the lower Midwest from Arkansas and up into the Ohio River Valley and adjacent areas. The MM5 simulations do understate the highest observed precipitation amounts in Arkansas. The MM5 simulations also overstate the amount of precipitation in the desert southwest (Four Corners) area in March.

The MM5 monthly average precipitation performance is dramatically worse in July 2002 (Figure A-8). Precipitation is overstated by all three MM5 simulations throughout the U.S. and particularly in the southern states, from Arkansas across Texas to the southeastern U.S. particularly Florida South and North Carolina. This over-prediction bias is due to convective precipitation from the cumulus parameterization (either Kain Fritsch 1 or 2). This overactive precipitation is the result of the over-prediction bias I humidity seen in many subdomains (see Table A-3b and Kemball-Cook et al., 2004a).

In October 2002, the three MM5 simulations reproduced the observed monthly average rainfall fairly well across the U.S. (Figure A-9). The models predict the location of the maximum precipitation in southern Louisiana well, but under-predict the magnitude, which may be due to a slight spatial displacement offshore in the Gulf of Mexico. The MM5 simulations understate the precipitation over the CENRAP region, which explains the dry humidity bias in the CenrapS subdomain in October (Figure A-3b).

In conclusion, the three MM5 simulations do a good job in simulating the observed precipitation when it is due to synoptic weather systems. However, when precipitation is due to convective activity as seen in July that is simulated by the MM5 cumulus parameterization, MM5 greatly overstates the precipitation amounts. This is particularly pronounced in the southern states from the Four Corners area to Florida with the interim WRAP simulation exhibiting the largest over-prediction bias. In the final WRAP MM5 simulation the Betts-Miller cumulus parameterization was used that greatly reduced the convective precipitation amounts resulting in better model performance (Kemball-Cook et al., 2005). However, an overestimation bias under convective precipitation conditions still was present.

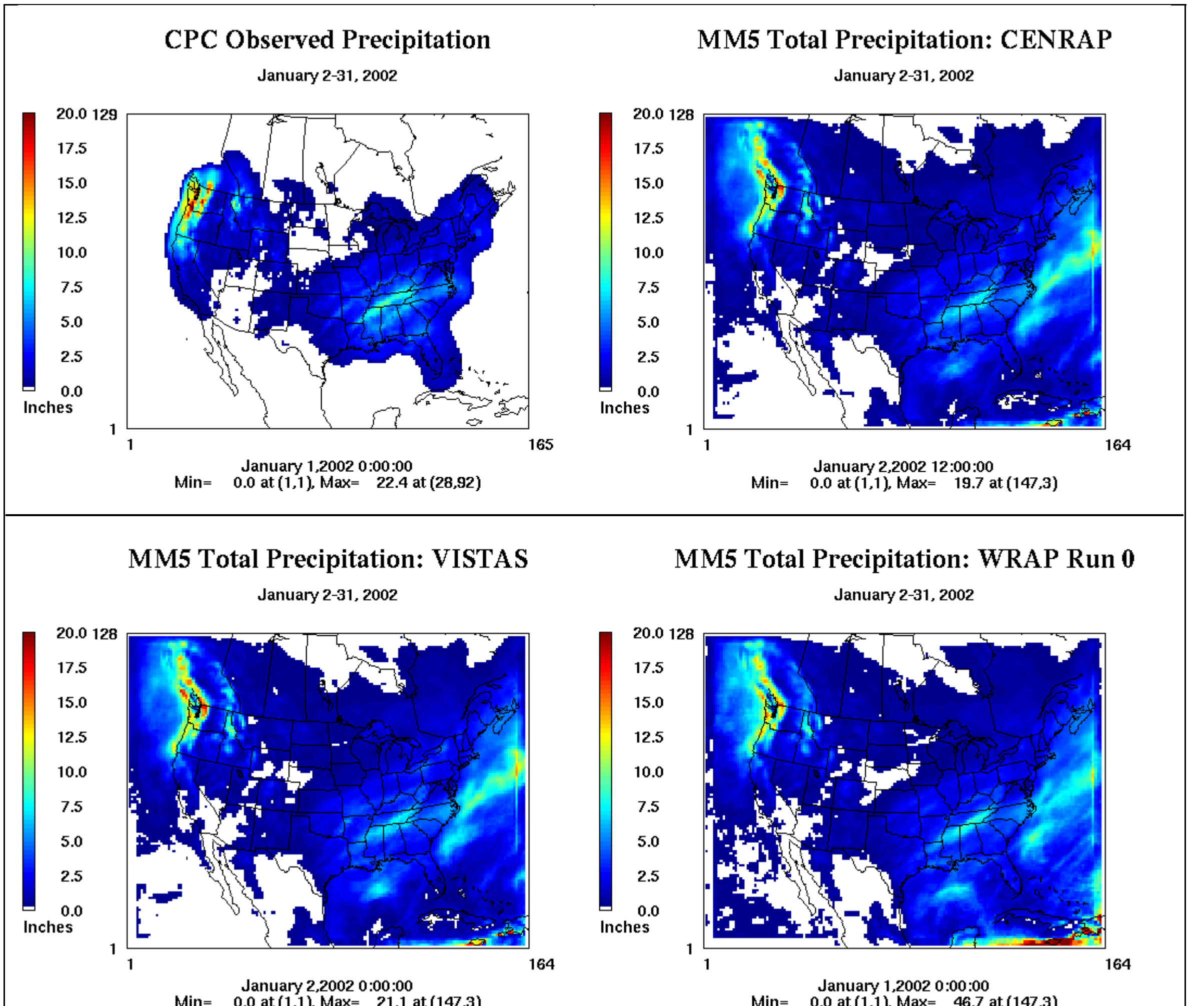


Figure A-6. Comparison of January 2002 observed monthly average precipitation (top left) with predicted values for the CENRAP (top right), VISTAS (bottom left) and WRAP (bottom right January 2002 simulation (note: observed precipitation not valid over water due to lack of measurements).

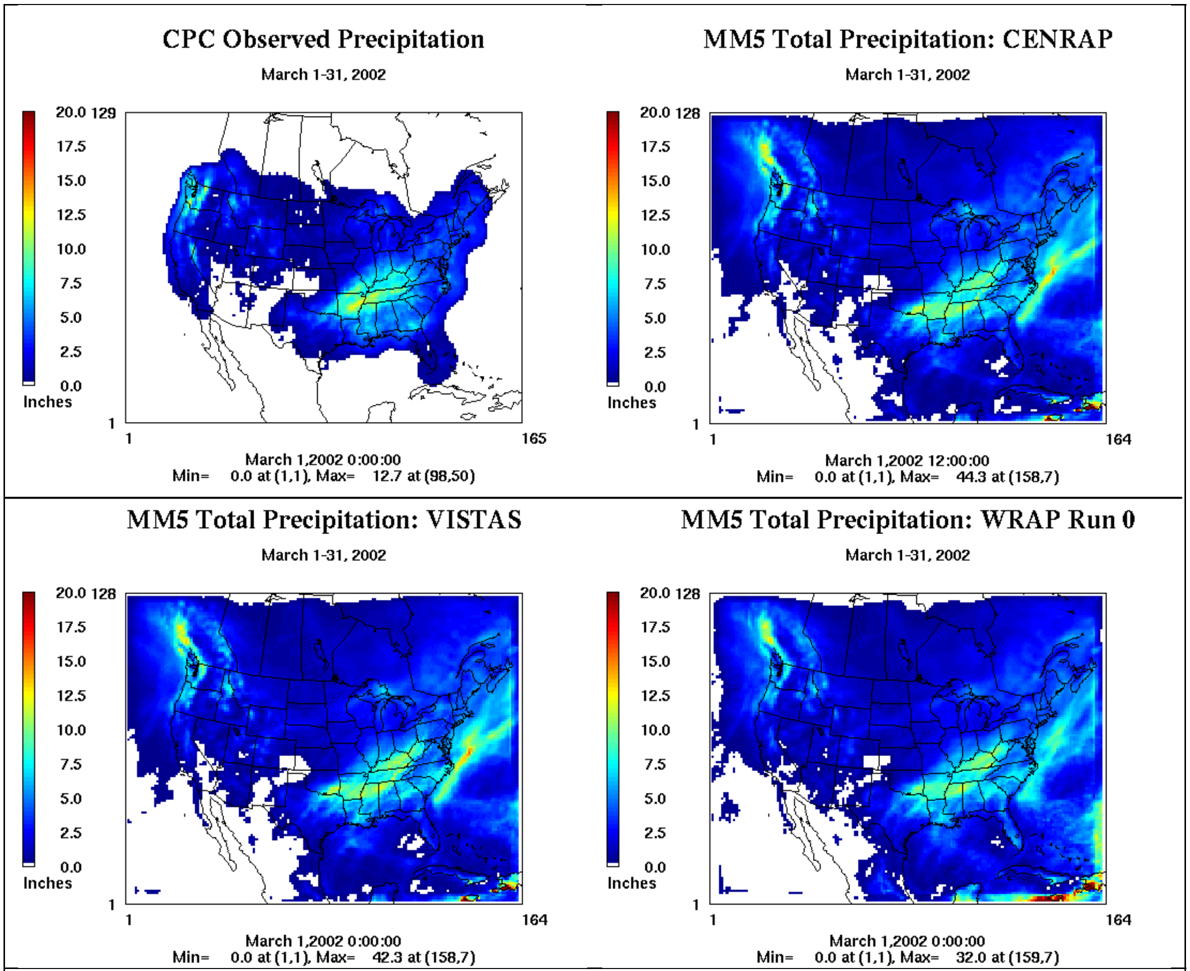


Figure A-7. Comparison of March 2002 observed monthly average precipitation (top left) with predicted values for the CENRAP (top right), VISTAS (bottom left) and WRAP (bottom right January 2002 simulation (note: observed precipitation not valid over water due to lack of measurements).

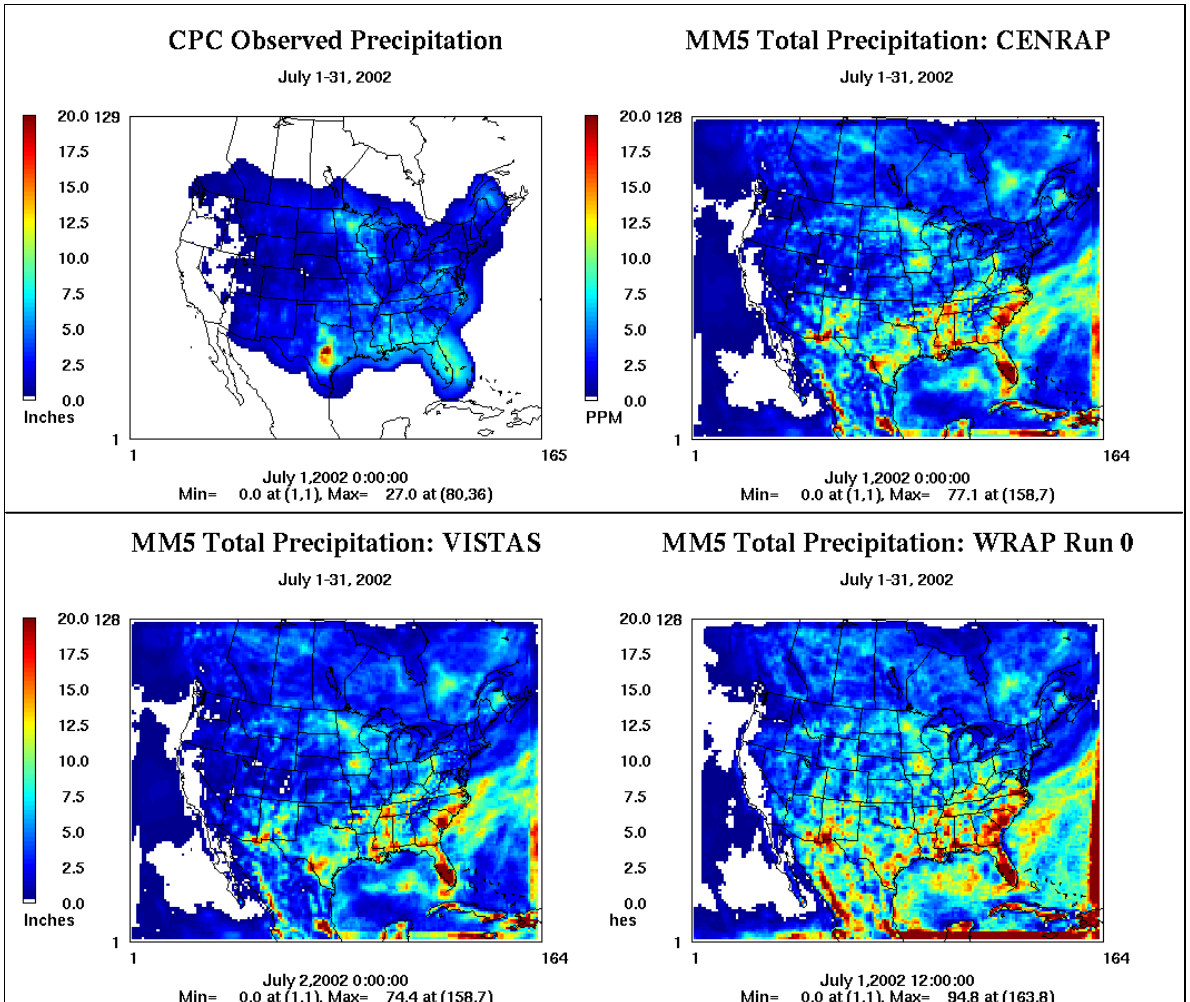


Figure A-8. Comparison of July 2002 observed monthly average precipitation (top left) with predicted values for the CENRAP (top right), VISTAS (bottom left) and WRAP (bottom right) (note: observed precipitation not valid over water due to lack of measurements).

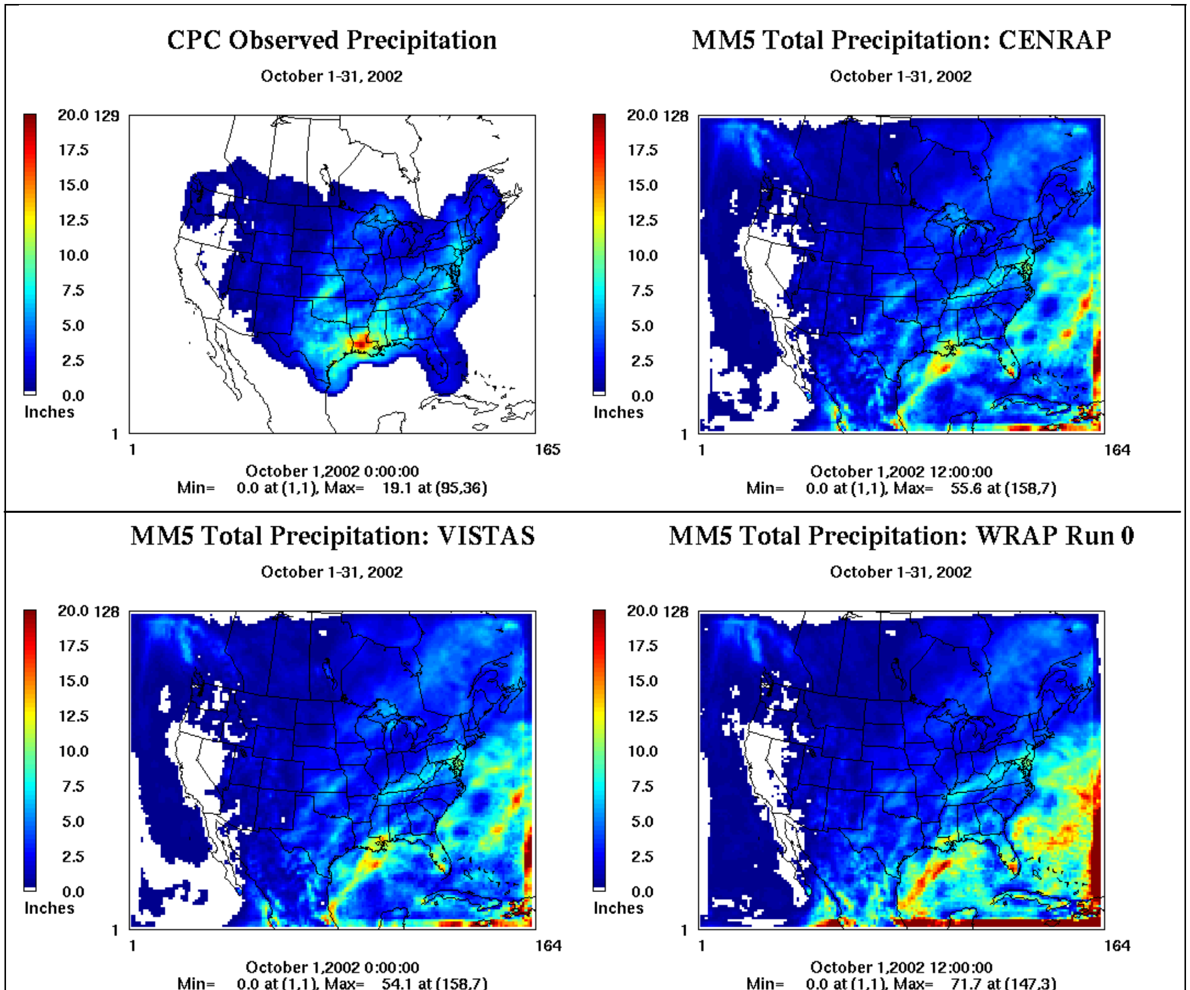


Figure A-9. Comparison of October 2002 observed monthly average precipitation (top left) with predicted values for the CENRAP (top right), VISTAS (bottom left) and WRAP (bottom right) (note: observed precipitation not valid over water due to lack of measurements).

APPENDIX B

File Names, Data Source and Type and Description of Emissions Used in the 2002 Typical and 2018 Base G Emissions Inventories

Table A-1. CENRAP 2002 Typical Base G (Typ02G) emissions inventory.

Filename	Source	Data type	Description
1 Stationary Area Sources			
arinv_Mexico99phase3_border_20051027v4_noDust_noFire.ida	**ERG**	**Text**	**1999 BRAVO Mexico inventory for the six Northern states; annual**
arinv_Mexico99phase3_interior_ERG_Oct06_noDust_noFire.ida	**ERG**	**Text**	**1999 BRAVO Mexico inventory for the Southern states; annual**
arinv_nodust_noOilGas_CA2002_111105.ida	**ERG**	**Test**	**California 2002 inventory; annual**
arinv_noDUST_noREF_vistas_2002g_2453908.ida	**Alpine Geophysics**	**Test**	**VISTAS 2002 inventory; annual**
arinv_nodust_wrap2002_v1_noCAWANDORUT_081205.ida	**ERG**	**Text**	**WRAP 2002 inventory for AZ, CO, ID, MT, NM, NV, SD, and WY ; annual**
arinv_nodust_wrap2002_v2_WANDORUT_102105.ida	**ERG**	**Text**	**WRAP 2002 inventory for ND, OR, UT, and WA; annual**
arinv_NoFire_CANADA2000_v2.ida	**Environment, Canada 011205**		**2000 Canada inventory; annual**
arinv_NoFire_noDUST_noREF_mrpok_2002_20jun2006.ida	**Alpine Geophysics**	**Text**	**MWRPO 2002 inventory; annual**
arinv_NoFire_nodust_ref_mane-vu2002_011705.ida	**MARAM web site**	**Text**	**MANE_VU 2002 inventory, annual**
arinv_NoFire_nodust_ref_nh3_cenrap2002_081705.ida	**Pechan**	**Text**	**CENRAP 2002 inventory; annual**
arinv_vistas2002_TypicalFires2610000_112704.ida	**Alpine Geophysics**	**Text**	**VISTAS 2002 inventory for SCC 2610000500**
2 Fugitive Dust			
fdinv1_CA2002_v2_wfac_111105.ida	**ERG**	**Text**	**CA 2002 inventory; extracted from stationary area inventory using initial list of SCCs; transport fractions applied; annual**
fdinv1_CANADA2000_v2_wfac.ida	**Environment Canada**	**Text**	**Canada 2000 inventory; extracted from stationary area inventory using initial list of SCCs; transport fractions applied; annual**
fdinv1_cenrap2002_wfac_081705.ida	**Pechan**	**Text**	**CENRAP 2002 inventory; extracted from stationary area inventory using initial list of SCCs; transport fractions applied; annual**
fdinv1_manevu2002_wfac_011705.ida	**MARMA web site**	**Text**	**MANE-VU2002 inventory; extracted from stationary area inventory using initial list of SCCs; transport fractions applied; annual**
fdinv1_Mexico99phase3_border_20051027v4_wTfac.ida	**MARMA web site**	**Text**	**Mexico Northern states 1999 inventory; extracted from stationary area inventory using initial list of**

Filename	Source	Data type	Description
			SCCs; transport fractions applied; annual
fdinv1_Mexico99phase3_interior_ERG_Oct06_wo_pmfac.ida	**ERG**	**Text**	**Mexico Southern states 1999 inventory; extracted from stationary area inventory using initial list of SCCs; no transport fractions applied; annual**
fdinv1_mrpok_2002_20jun2006_w_tfrac.ida	**Alpine Geophysics**	**Text**	**MWRPO 2002 inventory; extracted from stationary area inventory using initial list of SCCs; transport fractions applied; annual**
fdinv1_vistas_2002g_2453908_w_pmfac.ida	**Alpine Geophysics**	**Text**	**VISTAS 2002 inventory; extracted from stationary area inventory using initial list of SCCs; transport fractions applied; annual**
fdinv1_wrap2002_wfac_noCAWANDORUT_081205.ida	**ERG**	**Text**	**WRAP 2002 inventory; extracted from stationary area inventory using initial list of SCCs; transport fractions applied; annual**
fdinv1_wrap2002_wfac_WANDORUT_102105.ida	**ERG**	**Text**	**WRAP 2002 inventory; extracted from stationary area inventory using initial list of SCCs; transport fractions applied; annual**
fdinv2_CA2002_111105.w_tfrac.ida	**ERG**	**Text**	**CA 2002 inventory; extracted from stationary area inventory using extended list of SCCs; transport fractions applied; annual**
fdinv2_CANADA_v2.w_tfrac.ida	**Environment Canada**	**Text**	**Canada 2000 inventory; extracted from stationary area inventory using extended list of SCCs; transport fractions applied; annual**
fdinv2_cenrap2002_081705.w_tfrac.ida	**Pechan**	**Text**	**CENRAP 2002 inventory; extracted from stationary area inventory using extended list of SCCs; transport fractions applied; annual**
fdinv2_mane-vu2002_011705.w_tfrac.ida	**MARAMA web site**	**Text**	**MANE-VU2002 inventory; extracted from stationary area inventory using extended list of SCCs; transport fractions applied; annual**
fdinv2_vistas_2002g_2453908_w_pmfac.ida	**Alpine Geophysics**	**Text**	**VISTAS 2002 inventory; extracted from stationary area inventory using extended list of SCCs; transport**

Filename	Source	Data type	Description
			fractions applied; annual
fdinv2_wrap2002_v1_noCAWANDORUT_081205.w_tfrac.ida	**ERG**	**Text**	**WRAP 2002 inventory; extracted from stationary area inventory using extended list of SCCs; transport fractions applied; annual**
fdinv2_wrap2002_v2_WANDORUT_102105.w_tfrac.ida	**ERG**	**Text**	**WRAP 2002 inventory; extracted from stationary area inventory using extended list of SCCs; transport fractions applied; annual**
3 Road Dust			
rdinv_CA2002_v2_wfac_111105.ida	**Environ**	**Text**	**California 2002 inventory; extracted from stationary area inventory; transport fractions applied; annual**
rdinv_CANADA2000_v2_wfac.ida	**Environment Canada**	**Text**	**Canada 2000 inventory; extracted from stationary area inventory; transport fractions applied; annual**
rdinv_cenrap2002_wfac_081705.ida	**Pechan**	**Text**	**CENRAP 2002 inventory; extracted from stationary area inventory; transport fractions applied; annual**
rdinv_manevu2002_wfac.ida	**Alpine Geophysics**	**Text**	**MANE-VU 2002 inventory; extracted from stationary area inventory; transport fractions applied; annual**
rdinv_vistas_2002g_2453908_w_pmfac.txt	**Alpine Geophysics**	**Text**	**VISTAS 2002 inventory; extracted from stationary area inventory; transport fractions applied; annual**
rdinv_wrap2002_wfac_${season}_082205.ida	**ENVIRON**	**Text**	**WRAP 2002 inventory; transport fractions applied; seasonal**
4 Ammonia			
arinv_nh3_2002_mrpok_${month}_3may2006.ida	**Alpine Geophysics**	**Text**	**MWRPO 2002 agricultural ammonia inventory; monthly**
arinv_nh3_cenrap02_082406__${month}.ida	**Pechan**	**Text**	**CENRAP 2002 xxxx inventory; monthly**
CENRAP_AREA_MISC_SMOKE_INPUT_NH3_MONTH_ ${month}_072805_NoBio.txt	**Pechan**	**Text**	**CENRAP 2002 xxxx inventory; monthly**
NH3_CENRAP_ANN.082506.txt	**Pechan**	**Text**	**CENRAP 2002 xxxx inventory; annual**
CENRAP_AREA_MISC_SMOKE_INPUT_ANN_STATE_071905.txt	**Pechan**	**Text**	**CENRAP 2002 xxxx inventory; annual**
5 WRAP Ammonia			
nh3gts_l.2002###.1.WRAP36.base02b_nosoil.ncf	**Environ**	**Binary, netCDF**	**Includes domestic, livestock, fertilizer, and wild life gridded inventory; daily**
6 Area Anthropogenic Fires			
arfinv_anthro_cenrap2002_081705.ida	**Pechan**	**Text**	**CENRAP 2002 inventory; extracted**

Filename	Source	Data type	Description
			from stationary area inventory; annual
AREA_BURNING_SMOKE_INPUT_ANN_TX_NELI_071905.txt	**Pechan**	**Text**	**CENRAP 2002 inventory; extracted from stationary area inventory; annual**
arfinv_anthro_CANADA2000_v2.ida	**Environment Canada**	**Text**	**Canada 2000 inventory; extracted from stationary area inventory; annual**
arfinv_anthro_mane-vu2002_011705.ida	**MARAM web site**	**Text**	**MANE-VU2002 inventory; extracted from stationary area inventory; annual**
arfinv_anthro_Mexico99phase3_border_20051027v4.ida	**ERG**	**Text**	**Mexico 1999 inventory for Northern states; extracted from stationary area inventory; annual**
arfinv_anthro_Mexico99phase3_interior_ERG_Oct06.ida	**ERG**	**Text**	**Mexico 1999 inventory for Southern states inventory; extracted from stationary area inventory; annual**
arfinv_anthro_mrpok_2002_20jun2006.ida	**Alpine Geophysics**	**Text**	**MWRPO 2002 inventory; extracted from stationary area inventory; annual**
arfinv_anthro_vistas2002_TypicalFires_No2610000_112704.ida	**Alpine Geophysics**	**Text**	**VISTAS 2002 inventory; annual**
7 Area Wild Fires			
arfinv_wf_CANADA2000_v2.ida	**Environment Canada**	**Text**	**Canada 2000 inventory; extracted from stationary area inventory; annual**
arfinv_wf_cenrap2002_081705.ida	**Pechan**	**Text**	**CENRAP 2002 inventory; extracted from stationary area inventory; annual**
arfinv_wf_mane-vu2002_011705.ida	**MARAM web site**	**Text**	**MANE-VU 2002 inventory; extracted from stationary area inventory; annual**
arfinv_wf_Mexico99phase3_border_20051027v4.ida	**ERG**	**Text**	**Mexico 1999 inventory for Northern states inventory; extracted from stationary area inventory; annual**
arfinv_wf_Mexico99phase3_interior_ERG_Oct06.ida	**ERG**	**Text**	**Mexico 1999 inventory for Southern states inventory; extracted from stationary area inventory; annual**
arfinv_wf_mrpok_2002_20jun2006.ida	**Alpine Geophysics**	**Text**	**MWRPO 2002 inventory; extracted from stationary area inventory; annual**
arfinv_wf_vistas2002_TypicalFires_No2610000_112704.ida	**Alpine**	**Text**	**VISTAS 2002 inventory; annual**

Filename	Source	Data type	Description
	Geophysics		
8 Offshore Area Sources (Gulf of Mexico)			
CO_noCM.txt	**MMS**	**Text**	**Commercial marines records were removed; they are modeled in offshore shipping**
NOX_noCM.txt	**MMS**	**Text**	**Commercial marines records were removed; they are modeled in offshore shipping**
PM_noCM.txt	**MMS**	**Text**	**Commercial marines records were removed; they are modeled in offshore shipping**
SO2_noCM.txt	**MMS**	**Text**	**Commercial marines records were removed; they are modeled in offshore shipping**
VOC_noCM.txt	**MMS**	**Text**	**Commercial marines records were removed; they are modeled in offshore shipping**
9 Non Road (Annual Inventory)			
arinv_marine_mrpok_2002_27apr2006.ida	**Alpine Geophysics**	**Text**	**MWRPO 2002 Marine inventory; annual**
marinv_vistas_2002g_2453972.ida	**Alpine Geophysics**	**Text**	**VISTAS 2002 Marine inventory; annual**
nrinv_CANADA2000_v2_aircraft.ida	**Environment Canada**	**Text**	**Canada 2000 aircraft inventory; extracted from non-road inventory; annual**
nrinv_CANADA2000_v2.ida	**Environment Canada**	**Text**	**Canada 2000 inventory; annual**
nrinv_CANADA2000_v2_locomotive.ida	**Environment Canada**	**Text**	**Canada 2000 locomotive inventory; extracted from non-road inventory; annual**
nrinv_CANADA2000_v2_marine.ida	**Environment Canada**	**Text**	**Canada 2000 marine inventory; extracted from non-road inventory; annual**
nrinv_cenrap2002_annual_071305.ida	**Pechan**	**Text**	**CENRAP 2002 inventory; annual**
nrinv_mane-vu2002_052505.ida	**MARAM web site**	**Text**	**MANE_VU 2002 inventory; annual**
nrinv_mane-vu2002_aircraft_052505.ida	**MARAM web site**	**Text**	**MANE-VU 2002 aircraft inventory; extracted from non-road inventory; annual**
nrinv_mane-vu2002_locomotive_052505.ida	**MARAM web site**	**Text**	**MANE-VU 2002 locomotive inventory; extracted from non-road inventory; annual**
nrinv_mane-vu2002_shipping_052505.ida	**MARAM web site**	**Text**	**MANE-VU 2002 marine inventory;**

Filename	Source	Data type	Description
			extracted from non-road inventory; annual
nrinv_Mexico1999_ERG_Aircraft_Locomotive_Rec_102705.ida	**ERG**	**Text**	**Mexico 1999 aircraft and locomotive inventory; annual**
nrinv_Mexico99phase3_border_20061025v4.ida	**ERG**	**Text**	**Mexico 1999 inventory for Northern states; annual**
nrinv_Mexico99phase3_interior_ERG_Oct06.ida	**ERG**	**Text**	**Mexico 1999 inventory for Southern states; annual**
nrinv_vistas_2002g_2453908.ida	**Alpine Geophysics**	**Text**	**VISTAS 2002 inventory; annual**
nrinv_wrap2002_InshoreMarine_annual_tpd_080205.ida	**ENVIRON**	**Text**	**WRAP marine inventory; annual**
nrinv_wrap2002_v2_locomotive_annual_tpd_102705.ida	**ENVIRON**	**Text**	**WRAP locomotive inventory; annual**
11 Non Road (Monthly and Seasonal Inventory)			
nrinv_2002_mrpok_$month_3may2006.ida	**Missouri DNR**	**Text**	**MWRPO 2002 inventory; monthly**
nrinv_CA2002_v2_OffRoad_${season}_103105.ida	**EENVIRON**	**Text**	**California 2002 inventory, seasonal**
nrinv_cenrap2002_$month_082806.ida	**Pechan**	**Text**	**CENRAP 2002 inventory; monthly**
nrinv_wrap2002_nonCA_${season}_060705.ida	**ENVIRON**	**Text**	**WRAP 2002 inventory, monthly**
nrinv_wrap2002_v2_Aircraft_${season}_103105.ida	**ENVIRON**	**Text**	**WRAP 2002 aircraft inventory; seasonal**
12 Stationary Point			
pthour_2002typ_baseg_${month}_28jun2006.ems	**Alpine Geophysics**	**Text**	**VISTAS 2002 hourly inventory for the EGUs; monthly**
egu_ptinv_vistas_2002typ_baseg_2453909.ida	**Alpine Geophysics**	**Text**	**VISTAS 2002 EGUs inventory; annual**
negu_ptinv_vistas_2002typ_baseg_2453909.ida	**Alpine Geophysics**	**Text**	**VISTAS 2002 non EGUs inventory, annual**
ptinv_CA2002_101405.ida	**ERG**	**Text**	**California 2002 inventory; annual**
ptinv_CA2002_CARBofs_v1.ida	**ARB**	**Text**	**California 2002 offshore inventory; annual**
Ptinv_CANADA2000_v2_032407.ida	**Environment Canada**	**Text**	**Canada 2000 inventory; annual**
Ptinv_cenrap2002_033007.ida	**Pechan**	**Text**	**CENRAP 2002 inventory; annual**
ptinv_egu_2002_mrpok_1may2006.ida	**Alpine Geophysics**	**Text**	**MWRPO 2002 EGUs inventory; annual**
ptinv_mane-vu2002_v2_${WINSUM}_041905.ida	**MARAM web site**	**Text**	**MANE-VU 2002 inventory, seasonal; winter summer**
ptinv_Mexico99phase3_border_20061025v4.ida	**ERG**	**Text**	**Mexico 1999 inventory for Northern states; annual**
ptinv_Mexico99phase3_interior_ERG_Oct06.ida	**ERG**	**Text**	**Mexico 1999 inventory for Southern states; annual**
ptinv_negu_2002_mrpok_1may2006.ida		**Text**	**MWRPO 2002 non EGUs inventory;**

Filename	Source	Data type	Description
			annual
ptinv_wrap2002_AKAZMTNMORUTWAWY_102405.ida	ERG	Text	WRAP 2002 inventory for AK, AZ, MT, NM, OR, UT, WA, and WY; annual
tinv_wrap2002_v2_NVIDSDNDCO_090805.ida	ERG	Text	WRAP 2002 inventory for NV, ID, SD, ND, and CO; annual
ptinv_WRAPTribes2002_102005.ida	ERG	Text	WRAP/Tribes 2002 inventory; annual
13 Offshore Point (Gulf)			
CO.afs.gwei2000.20000801.latlong.ida	MMS	Text	
PM10.afs.gwei2000.20000801.latlong.ida	MMS	Text	
SO2.afs.gwei2000.20000801.latlong.ida	MMS	Text	
NOX.afs.gwei2000.20000801.latlong.ida	MMS	Text	
PM2_5.afs.gwei2000.20000801.latlong.ida	MMS	Text	
VOC.afs.gwei2000.20000801.latlong.ida	MMS	Text	
14 On Road Mobile (Emissions)			
mbinv_wrap2002_v2_noCA_${season}_101305.ida	ENVIRON	Text	WRAP 2002 inventory; seasonal
mbinv_CA2002_v2_${season}_102705.ida	ENVIRON	Text	California 2002 inventory; seasonal
mbinv_CANADA2000.ida	Environment Canada	Text	Canada 2000 inventory; annual
mbinv_Mexico99phase3_border_20051021v4.ida	ERG	Text	Mexico 1999 inventory for Northern states; annual
mbinv_Mexico99phase3_interior_ERG_Oct06.ida	ERG	Text	Mexico 1999 inventory for Southern states; annual
15 On Road Mobile (Activities, VMT)			
mbinv#_vmt_cenrap.ida	STI	Text	CENRAP 2002 inventory; divided into three files; annual
mbinv_2002_vmt_mane-vu.ida	MARAM web site	Text	MANE-VU 2002 inventory; annual
mbinv_mrpo_02f_vmt_02may06.ida	Alpine Geophysics	Text	MWRPO 2002 inventory; annual
mbinv_vistas_02g_vmt_12jun06.ida	Alpine Geophysics	Text	VISTAS 2002 inventory; annual
16 Point Fires			
ptday_2002CENRAP_ptfires_mon##.ida	STI	Text	CENRAP 2002 prescribed fires; daily emissions; monthly
ptday_agfires_##_vistas.ida	Alpine Geophysics	Text	VISTA 2002 all fire sources; daily emissions; monthly
PTDAY_200504051315_wrap2002_nfr.mon##.ida	AirSciences	Text	WRAP 2002 non federal rangeland fires; daily emissions; monthly
PTDAY_200507011516_wrap2002_agf_base.mon##.ida	AirSciences	Text	WRAP 2002 Ag. Fires; daily emissions; monthly
PTDAY_200510210936_wrap2002_wild_base.mon##.ida	AirSciences	Text	WRAP 2002 wild fires; daily emissions; monthly

Filename	Source	Data type	Description
PTDAY_200510211022_wrap2002_wfu_base.mon##.ida	**AirSciences**	**Text**	**WRAP 2002 wild fire use; daily emissions; monthly**
PTDAY_200510211029_wrap2002_rx_base.mon##.ida	**AirSciences**	**Text**	**WRAP 2002 prescribed fires; daily emissions; monthly**
pthour_2002CENRAP_ptfires_mon##.ida	**STI**	**Text**	**CENRAP 2002 prescribed fires; hourly plume distribution; monthly**
pthour_agfires_##_vistas.ida	**Alpine Geophysics**	**Text**	**VISTA 2002 all fire sources; hourly plume distribution; monthly**
PTHOUR_200504051315_wrap2002_nfr.mon##.ida	**AirSciences**	**Text**	**WRAP 2002 non federal rangeland; hourly plume distribution; monthly**
PTHOUR_200507011516_wrap2002_agf_base.mon##.ida	**AirSciences**	**Text**	**WRAP 2002 Ag. Fires; hourly plume distribution; monthly**
PTHOUR_200510210936_wrap2002_wild_base.mon##.ida	**AirSciences**	**Text**	**WRAP 2002 wild fires; hourly plume distribution; monthly**
PTHOUR_200510211022_wrap2002_wfu_base.mon##.ida	**AirSciences**	**Text**	**WRAP 2002 wild fire use; hourly plume disributution; monthly**
PTHOUR_200510211029_wrap2002_rx_base.mon##.ida	**AirSciences**	**Text**	**WRAP 2002 prescribed fires; hourly plume distribution; monthly**
ptinv_2002CENRAP_ptfires_mon##.ida	**STI**	**Text**	**CENRAP 2002 prescribed fires; fire location info.; monthly**
ptinv_agfires_##_vistas.ida	**Alpine Geophysics**	**Text**	**VISTA 2002 all fire sourcesfire location info; monthly**
PTINV_200504051315_wrap2002_nfr.mon##.ida	**AirSciences**	**Text**	**WRAP 2002 non federal rangeland fires; fire location info; monthly**
PTINV_200507011516_wrap2002_agf_base.mon##.ida	**AirSciences**	**Text**	**WRAP 2002 Ag. Fires; fire location info.; monthly**
PTINV_200510210936_wrap2002_wild_base.mon##.ida	**AirSciences**	**Text**	**WRAP 2002 wild fires; fire location info.; monthly**
PTINV_200510211022_wrap2002_wfu_base.mon##.ida	**AirSciences**	**Text**	**WRAP 2002 wild fire use; fire location info.; monthly**
PTINV_200510211029_wrap2002_rx_base.mon##.ida	**AirSciences**	**Text**	**WRAP 2002 prescribed fires; fire location; monthly**
ptday.ontario_fires.2002.txt.ida	**Environment Canada**	**Text**	**Ontario/Canada wild fires; daily emissions and fire info.; monthly**
ptinv.ontario_fires.2002.txt.ida	**Environment Canada**	**Text**	**Ontario/Canada wild fires; fire location info.; monthly**
17 Biogenecs			
b3fac.beis3_efac_v0.98.txt	**EPA**	**Text**	**Version 0.98 biogenic emission factors**
b3_a.VISTAS36_148X112.beld3_v2.ncf	**Alpine Geophysics**	**Binary**	**Gridded land use**
b3_b.VISTAS36_148X112.beld3_v2.ncf	**Alpine**	**Binary**	**Gridded land use**

Filename	Source	Data type	Description
	Geophysics		
b3_t.VISTAS36_148X112.beld3_v2.ncf	**Alpine Geophysics**	**Binary**	**Gridded land use**
18 Windblown Dust			
wb_dust_ii_cenrap_cmaq_RPO36_2002###_agadj_tf_b.ncf	**ENVIRON/UCR**	**Binary; netCDF**	**Domain wide wind blown dust emissions from WRAP wind blown dust model; hourly**
19 WRAP Oil and Gas			
arinv_CA2002_v2_OilGas_111105.ida	**ENVIRON**	**Text**	**California 2002 oil and gas inventory; annual**
arinv_wrap2002_v2_OilGas_annual_082505.ida	**ENVIRON**	**Text**	**WRAP 2002 oil and gas inventory; annual**
20 Offshore Shipping			
ofsgts_l.2002###.1.vista36.baseg_2002.shipping.ncf	**ENVIRON/VISTAS**	**Binary; netCDF**	**Pacific, Gulf of Mex. and Atlantic 2002 Offshore shipping inventory; daily**

Table A-2. CENRAP 2018 Base G (Base18G) emissions inventory.

Filename	Source	Data type	Description
1 Stationary Area Sources			
arinv_Mexico99phase3_border_20051027v4_noDust_noFire.ida	**ERG**	**Text**	**1999 BRAVO Mexico inventory for the six Northern states; annual**
arinv_Mexico99phase3_interior_ERG_Oct06_noDust_noFire.ida	**ERG**	**Text**	**1999 BRAVO Mexico inventory for the Southern states; annual**
arinv_CA2018_112205.ida	**ERG**	**Text**	**California 2018 inventory; annual**
arinv_NoDust_NoREF_vistas_2018g_2453922.ida	**Alpine Geophysics**	**Test**	**VISTAS 2018 inventory; annual**
arinv_wrap2018.091205.ida	**ERG**	**Text**	**WRAP 2018 inventory; annual**
arinv_canada_2020_noDust_NoFire.ida	**Environment, Canada**		**Canada 2020 inventory; annual**
arinv_NoFire_NoDust_NoREF_mrpok_2018_22aug2006.ida	**Alpine Geophysics**	**Text**	**MWRPO 2018 inventory; annual**
arinv_mane_vu_2018v3_1_NoDust_NoFire.ida		**Text**	**MANE_VU 2018 inventory, annual**
arinv_NoFire_nodust_ref_nh3_cenrap2002-2018_101606.ida	**UCR; grown from 2002**	**Text**	**CENRAP 2018 inventory; annual**
arinv_vistas_baseg_2018t_lofire_11feb2007_scc2610000500.ida	**Alpine Geophysics**	**Text**	**VISTAS 2018 inventory for SCC 2610000500**
2 Fugitive Dust			
fdinv1.CA2018_wfac.ida	**ERG**	**Text**	**CA 2018 inventory; extracted from stationary area inventory using initial list of SCCs; transport fractions applied; annual**
fdinv1.canada_2020.wTfac.ida	**Environment Canada**	**Text**	**Canada 2000 inventory; extracted from stationary area inventory using initial list of SCCs; transport fractions applied; annual**
fdinv1.cenrap2002_2018_wfac.ida	**UCR; grown from 2002**	**Text**	**CENRAP 2018 inventory; extracted from stationary area inventory using initial list of SCCs; transport fractions applied; annual**
fdinv1.mane_vu2018_wfac.ida	**MARAM web site**	**Text**	**MANE-VU 2018 inventory; extracted from stationary area inventory using initial list of SCCs; transport fractions**

Filename	Source	Data type	Description
			applied; annual
fdinv1_Mexico99phase3_border_20051027v4_wTfac.ida	**ERG**	**Text**	**Mexico Northern states 1999 inventory; extracted from stationary area inventory using initial list of SCCs; transport fractions applied; annual**
fdinv1_Mexico99phase3_interior_ERG_Oct06_wo_pmfac.ida	**ERG**	**Text**	**Mexico Southern states 1999 inventory; extracted from stationary area inventory using initial list of SCCs; no transport fractions applied; annual**
fdinv1_mrpok_2018_22aug2006_wfac.ida	**Alpine Geophysics**	**Text**	**MWRPO 2018 inventory; extracted from stationary area inventory using initial list of SCCs; transport fractions applied; annual**
fdinv1_vistas_2018g_2453922_w_pmfac.ida	**Alpine Geophysics**	**Text**	**VISTAS 2018 inventory; extracted from stationary area inventory using initial list of SCCs; transport fractions applied; annual**
fdinv1.wrap2018_wfac.ida	**ERG**	**Text**	**WRAP 2018 inventory; extracted from stationary area inventory using initial list of SCCs; transport fractions applied; annual**
fdinv2.CA2018_wfac.ida	**ERG**	**Text**	**CA 2018 inventory; extracted from stationary area inventory using extended list of SCCs; transport fractions applied; annual**
fdinv2.canada_2020.wTfac.ida	**Environment Canada**	**Text**	**Canada 2020 inventory; extracted from stationary area inventory using extended list of SCCs; transport fractions applied; annual**
fdinv2.cenrap2002_2018_wfac.ida	**UCR; grown from 2002**	**Text**	**CENRAP 2018 inventory; extracted from stationary area inventory using extended list of SCCs; transport fractions applied; annual**
fdinv2.mane-vu2018_wfac.ida	**MARAM web site**	**Text**	**MANE-VU 2018 inventory;**

Filename	Source	Data type	Description
			extracted from stationary area inventory using extended list of SCCs; transport fractions applied; annual
fdinv2_vistas_2018g_2453922_w_pmfac.ida	**Alpine Geophysics**	**Text**	**VISTAS 2018 inventory; extracted from stationary area inventory using extended list of SCCs; transport fractions applied; annual**
fdinv2_wrap2018.091205_wfac.ida	**ERG**	**Text**	**WRAP 2018 inventory; extracted from stationary area inventory using extended list of SCCs; transport fractions applied; annual**
3 Road Dust			
rdinv.CA2018_wfac.ida	**Environ**	**Text**	**California 2018 inventory; extracted from stationary area inventory; transport fractions applied; annual**
rdinv_canada_2020_wTfac.ida	**Environment Canada**	**Text**	**Canada 2020 inventory; extracted from stationary area inventory; transport fractions applied; annual**
rdinv.cnrap2002_2018.wfac.ida	**UCR; grown from 2002**	**Text**	**CENRAP 2018 inventory; extracted from stationary area inventory; transport fractions applied; annual**
rdinv_mane_vu_2018v3_1_wTfac.ida	**MARAM web site**	**Text**	**MANE-VU 2018 inventory; extracted from stationary area inventory; transport fractions applied; annual**
rdinv_vistas_vistas_2018g_2453922_w_pmfac.ida	**Alpine Geophysics**	**Text**	**VISTAS 2018 inventory; extracted from stationary area inventory; transport fractions applied; annual**
rdinv.wrap2018_wfac_${season}.ida	**ENVIRON**	**Text**	**WRAP 2018 inventory; transport fractions applied; seasonal**
4 Ammonia			
arinv_nh3_2018_mrpok_${month}_22aug2006.ida	**Alpine Geophysics**	**Text**	**MWRPO 2018 agricultural ammonia inventory; monthly**
nh3minv.cenrap2018gr_18.apr.ida	**UCR; grown from 2002**	**Text**	**CENRAP 2018 xxxx inventory; monthly**

Filename	Source	Data type	Description
nh3inv.misc.cnrap2002_2018.feb.ida	**UCR; grown from 2002**	**Text**	**CENRAP 2018 xxxx inventory; monthly**
nh3yinv.annual.cnrap2002_2018.100406.ida	**UCR; grown from 2002**	**Text**	**CENRAP 2018 xxxx inventory; annual**
nh3inv.misc_annual.cnrap2002_2018.ida	**UCR; grown from 2002**	**Text**	**CENRAP 2018 xxxx inventory; annual**
5 WRAP Ammonia			
nh3gts_l.2002###.1.WRAP36.base02b_nosoil.ncf	**Environ**	**Binary, netCDF**	**Includes domestic, livestock, fertilizer, and wild life gridded inventory; daily**
6 Area Anthropogenic Fires			
arfinv_anthro_cenrap2002_081705.ida	**Pechan**	**Text**	**CENRAP 2002 inventory; extracted from stationary area inventory; annual**
AREA_BURNING_SMOKE_INPUT_ANN_TX_NELI_071905.txt	**Pechan**	**Text**	**CENRAP 2002 inventory; extracted from stationary area inventory; annual**
arfinv_anthro_canda2020.ida	**Environment Canada**	**Text**	**Canada 2000 inventory; extracted from stationary area inventory; annual**
arfinv_anthro_mane_vu_2018v3_1.ida	**MARAM web site**	**Text**	**MANE-VU 2018 inventory; extracted from stationary area inventory; annual**
arfinv_anthro_Mexico99phase3_border_20051027v4.ida	**ERG**	**Text**	**Mexico 1999 inventory for Northern states; extracted from stationary area inventory; annual**
arfinv_anthro_Mexico99phase3_interior_ERG_Oct06.ida	**ERG**	**Text**	**Mexico 1999 inventory for Southern states inventory; extracted from stationary area inventory; annual**
arfinv_anthro_mrpok_2018_22aug2006.ida	**Alpine Geophysics**	**Text**	**MWRPO 2018 inventory; extracted from stationary area inventory; annual**
arfinv_anthro_vistas_baseg_2018t_11feb2007_NOscc2610000500.ida	**Alpine Geophysics**	**Text**	**VISTAS 2018 inventory; annual**
7 Area Wild Fires			
arfinv_wf_canada2020.ida	**Environment Canada**	**Text**	**Canada 2020 inventory; extracted from stationary area inventory; annual**
arfinv_wf_cenrap2002-2018_101606.ida	**UCR; grown from 2002**	**Text**	**CENRAP 2018 inventory; extracted from stationary area inventory; annual**

Filename	Source	Data type	Description
arfinv_wf_mane_vu_2018v3_1.ida	**MARAM web site**	**Text**	**MANE-VU 2018 inventory; extracted from stationary area inventory; annual**
arfinv_wf_Mexico99phase3_border_20051027v4.ida	**ERG**	**Text**	**Mexico 1999 inventory for Northern states inventory; extracted from stationary area inventory; annual**
arfinv_wf_Mexico99phase3_interior_ERG_Oct06.ida	**ERG**	**Text**	**Mexico 1999 inventory for Southern states inventory; extracted from stationary area inventory; annual**
arfinv_wf_mrpok_2018_22aug2006.ida	**Alpine Geophysics**	**Text**	**MWRPO 2018 inventory; extracted from stationary area inventory; annual**
arfinv_wf_vistas_baseg_2018t_11feb2007_NOscc2610000500.ida	**Alpine Geophysics**	**Text**	**VISTAS 2018 inventory; annual**
8 Offshore Area Sources (Gulf of Mexico)			
ofsarinv.cnrap2002_2018_noCM.ida	**UCR; grown from 2002**	**Text**	**Commercial marines records were removed; they are modeled in offshore shipping; all pollutants; annual**
9 Non Road (Annual Inventory)			
arinv_mar_mrpok_2018_22aug2006.ida		**Text**	**MWRPO 2018 Marine inventory; annual**
marinv_vistas_2018g_2453972.ida	**Alpine Geophysics**	**Text**	**VISTAS 2018 Marine inventory; annual**
NONROAD2020_Canada.ida	**Environment Canada**	**Text**	**Canada 2020 aircraft inventory; extracted from non-road inventory; annual**
CENRAP_2018_Fnl_Nrd_Emissions091506.ida	**Pecahn**	**Text**	**CENRAP 2018 inventory; annual**
nrinv_mane_vu_2018v3_1.ida	**MARAM web site**	**Text**	**MANE_VU 2018 inventory; annual**
nrinv_Mexico1999_ERG_Aircraft_Locomotive_Rec_102705.ida	**ERG**	**Text**	**Mexico 1999 aircraft and locomotive inventory; annual**
nrinv_Mexico99phase3_border_20061025v4.ida	**ERG**	**Text**	**Mexico 1999 inventory for Northern states; annual**
nrinv_Mexico99phase3_interior_ERG_Oct06.ida	**ERG**	**Text**	**Mexico 1999 inventory for Southern states; annual**
nrinv_vistas_2018g_2453908.ida	**Alpine Geophysics**	**Text**	**VISTAS 2018 inventory; annual**
nrinv_wrap2018_Locomotive_annual_tpd_111805.ida	**ENVIRON**	**Text**	**WRAP 2018 locomotive inventory; annual**

Filename	Source	Data type	Description
11 Non Road (Monthly and Seasonal Inventory)			
nrinv_2018_mrpok_apr_22aug2006.ida	**Alpine Geophysics**	**Text**	**MWRPO 2018 inventory; monthly**
nrinv_CA2018_win_111805.ida	**EENVIRON**	**Text**	**California 2018 inventory, seasonal**
2018NONROAD_AG_IA_${month}.ida	**Missouri DNR**	**Text**	**CENRAP/IA 2018 inventory; monthly**
nrinv.mrpok.minn.apr_2018.011306.ida	**Missouri DNR**	**Text**	**CENRAP/MN 2018 inventory; monthly**
nrinv_WRAP2018_${season}_102105.ida	**ENVIRON**	**Text**	**WRAP 2018 inventory, monthly**
nrinv_WRAP2018_Aircraft_${season}.111805.ida	**ENVIRON**	**Text**	**WRAP 2018 aircraft inventory; seasonal**
12 Stationary Point			
pthour_2018_baseg_sep_2453993.ems	**Alpine Geophysics**	**Text**	**VISTAS 2018 hourly inventory for the EGUs; monthly**
ptinv_egu_18_vistas_g_2453993.ida	**Alpine Geophysics**	**Text**	**VISTAS 2018 EGUs inventory; annual**
ptinv_nonEGU_vistas_2018_baseg_2453957.ida	**Alpine Geophysics**	**Text**	**VISTAS 2018 non EGUs inventory, annual**
pgts3d_l.2002###.1.cmaq.cb4p25.us36b.CANADA_20i01.19L.ncf	**EPA**	**Binary; netCDF**	**Canada 2020 inventory; daily**
Ptinv_cenrap2018_EGU_${WINSUM}_annual_050407.ida	**CENRAP**	**Text**	**CENRAP 2018 EGUs inventory, seasonal; winter summer**
ptinv_o.cenrap2002_2018_nonEGU050307.ida	**UCR; grown from 2002**	**Text**	**CENRAP 2018 non EGUs inventory; annual**
ptinv_cenrapNonegu_2018_050707_refin_new_sources.ida	**CENRAP**	**Text**	**CENRAP 2018 Additional sources; annual**
ptinv_egu_2018_mrpok_11sep006.ida	**Alpine Geophysics**	**Text**	**MWRPO 2002 EGUs inventory; annual**
Ptinv_manevu2018_EGU_${WINSUM}_ANNUAL_080805.ida	**MARAM web site**	**Text**	**MANE-VU 2018 EGUs inventory, seasonal; winter summer**
ptinv_manevu2018_nonEGU_112105.ida		**Text**	**MANE-VU 2018 non EGUs inventory, annual**
ptinv_Mexico99phase3_border_20061025v4.ida	**ERG**	**Text**	**Mexico 1999 inventory for Northern states; annual**
ptinv_Mexico99phase3_interior_ERG_Oct06.ida	**ERG**	**Text**	**Mexico 1999 inventory for Southern states; annual**
ptinv_negu_2018_mrpok_23aug2006.ida	**Alpine Geophysics**	**Text**	**MWRPO 2018 non EGUs inventory; annual**
ptinv_wrap2018_NoOG_050406.ida	**ERG**	**Text**	**WRAP 2018 inventory; no oil and gas; annual**

Filename	Source	Data type	Description
ptinv_wrap2018_OG_091205.ida	**ERG**	**Text**	**WRAP 2018 inventory; oil and gas; annual**
ptinv_WRAPTribes2018_NoOG_091205.ida	**ERG**	**Text**	**WRAP/Tribes 2018 inventory; no oil and gas annual**
ptinv_WRAPTribes2018_OG_091205.ida	**ERG**		**WRAP/Tribes 2018 inventory; oil and gas annual**
13 Offshore Point (Gulf)			
ofsinv_o_CO.cnrap2002_2018.ida	**UCR; grown from 2002 emissions**	**Text**	
ofsinv_o_NOX.cnrap2002_2018.ida	**UCR; grown from 2002 emissions**	**Text**	
ofsinv_o_PM10.cnrap2002_2018.ida	**UCR; grown from 2002 emissions**	**Text**	
ofsinv_o_PM2_5.cnrap2002_2018.ida	**UCR; grown from 2002 emissions**	**Text**	
ofsinv_o_SO2.cnrap2002_2018.ida	**UCR; grown from 2002 emissions**	**Text**	
ofsinv_o_VOC.cnrap2002_2018.ida	**UCR; grown from 2002 emissions**	**Text**	
14 On Road Mobile (Emissions)			
mbinv_WRAP2018_aut_102105.ida	**ENVIRON**	**Text**	**WRAP 2018 inventory; seasonal**
mbinv_CA2018_win_111805.ida	**ENVIRON**	**Text**	**California 2018 inventory; seasonal**
mbinv_CANADA2020.ida	**Environment Canada**	**Text**	**Canada 2020 inventory; annual**
mbinv_Mexico99phase3_border_20051021v4.ida	**ERG**	**Text**	**Mexico 1999 inventory for Northern states; annual**
mbinv_Mexico99phase3_interior_ERG_Oct06.ida	**ERG**	**Text**	**Mexico 1999 inventory for Southern states; annual**
15 On Road Mobile (Activities, VMT)			
mbinv.mbv#_vmt_cenrap2018_072005.ida	**STI**	**Text**	**CENRAP 2018 inventory; divided into tow files; annual**
mbinv_vmt_manevu2018_update.ida	**MARAM web site**	**Text**	**MANE-VU 2018 inventory; annual**
mbinv_mrpo_18f_vmt_11aug06.ida	**Alpine Geophysics**	**Text**	**MWRPO 2018 inventory; annual**
mbinv_vistas_18g_vmt_12jun06.ida	**Alpine Geophysics**	**Text**	**VISTAS 2018 inventory; annual**
16 Point Fires			
ptday_2002CENRAP_ptfires_mon##.ida	**STI**	**Text**	**CENRAP 2002 prescribed fires; daily emissions; monthly**
ptday.plume.vistasG2_2018.##.ida	**Alpine**	**Text**	**VISTA 2018 all fire sources; daily**

Filename	Source	Data type	Description
	Geophysics		**emissions; monthly**
PTDAY_200504051315_wrap2002_nfr.mon##.ida	**AirSciences**	**Text**	**WRAP 2002 non federal rangeland fires; daily emissions; monthly**
PTDAY_200604272314_wrap02_04_agf.mon##.ida	**AirSciences**	**Text**	**WRAP 2002-4 Ag. Fires; daily emissions; monthly**
PTDAY_200510210936_wrap2002_wild_base.mon##.ida	**AirSciences**	**Text**	**WRAP 2002 wild fires; daily emissions; monthly**
PTDAY_200510211022_wrap2002_wfu_base.mon##.ida	**AirSciences**	**Text**	**WRAP 2002 wild fire use; daily emissions; monthly**
PTDAY_200604281056_wrap02_04_arx.mon##.ida	**AirSciences**	**Text**	**WRAP 2002-4 prescribed fires; daily emissions; monthly**
PTDAY_200604281056_wrap02_04_nrx.mon##.ida	**AirSciences**	**Text**	**WRAP 2002-4 natural prescribed fires; daily emissions; monthly**
pthour_2002CENRAP_ptfires_mon##.ida	**STI**	**Text**	**CENRAP 2002 anthro. prescribed fires; hourly plume distribution; monthly**
pthour.plume.vistasG2_2018.##.ida	**Alpine Geophysics**	**Text**	**VISTA 2002 all fire sources; hourly plume distribution; monthly**
PTHOUR_200504051315_wrap2002_nfr.mon##.ida	**AirSciences**	**Text**	**WRAP 2002 non federal rangeland; hourly plume distribution; monthly**
PTHOUR_200604272314_wrap02_04_agf.mon##.ida	**AirSciences**	**Text**	**WRAP 2002 Ag. Fires; hourly plume distribution; monthly**
PTHOUR_200510210936_wrap2002_wild_base.mon##.ida	**AirSciences**	**Text**	**WRAP 2002 wild fires; hourly plume distribution; monthly**
PTHOUR_200510211022_wrap2002_wfu_base.mon##.ida	**AirSciences**	**Text**	**WRAP 2002 wild fire use; hourly plume disributution; monthly**
PTHOUR_200604281056_wrap02_04_arx.mon##.ida	**AirSciences**	**Text**	**WRAP 2002 natural prescribed fires; hourly plume distribution; monthly**
PTHOUR_200604281056_wrap02_04_nrx.mon##.ida	**AirSciences**	**Text**	**WRAP 2002 anthro. prescribed fires; hourly plume distribution; monthly**
ptinv_2002CENRAP_ptfires_mon##.ida	**STI**	**Text**	**CENRAP 2002 prescribed fires; fire location info.; monthly**
ptinv.plume.vistasG2_2018.11.ida	**Alpine Geophysics**	**Text**	**VISTA 2002 all fire sourcesfire location info; monthly**
PTINV_200504051315_wrap2002_nfr.mon##.ida	**AirSciences**	**Text**	**WRAP 2002 non federal rangeland fires; fire location info; monthly**

Filename	Source	Data type	Description
PTINV_200507011516_wrap2002_agf_base.mon##.ida	**AirSciences**	**Text**	**WRAP 2002 Ag. Fires; fire location info.; monthly**
PTINV_200510210936_wrap2002_wild_base.mon##.ida	**AirSciences**	**Text**	**WRAP 2002 wild fires; fire location info.; monthly**
PTINV_200604272314_wrap02_04_agf.mon##.ida	**AirSciences**	**Text**	**WRAP 2002 wild fire use; fire location info.; monthly**
PTINV_200604281056_wrap02_04_arx.mon##.ida	**AirSciences**	**Text**	**WRAP 2002 anthro. prescribed fires; fire location; monthly**
PTINV_200604281056_wrap02_04_nrx.mon##.ida	**AirSciences**		**WRAP 2002 natural prescribed fires; fire location; monthly**
ptday.ontario_fires.2002.txt.ida	**Environment Canada**	**Text**	**Ontario/Canada wild fires; daily emissions and fire info.; monthly**
ptinv.ontario_fires.2002.txt.ida	**Environment Canada**	**Text**	**Ontario/Canada wild fires; fire location info.; monthly**
17 Biogenecs			
b3fac.beis3_efac_v0.98.txt	**EPA**	**Text**	**Version 0.98 biogenic emission factors**
b3_a.VISTAS36_148X112.beld3_v2.ncf	**Alpine Geophysics**	**Binary**	**Gridded land use**
b3_b.VISTAS36_148X112.beld3_v2.ncf	**Alpine Geophysics**	**Binary**	**Gridded land use**
b3_t.VISTAS36_148X112.beld3_v2.ncf	**Alpine Geophysics**	**Binary**	**Gridded land use**
18 Windblown Dust			
wb_dust_ii_cenrap_cmaq_RPO36_2002###_agadj_tf_b.ncf	**ENVIRON/UCR**	**Binary; netCDF**	**Domain wide wind blown dust emissions from WRAP wind blown dust model; hourly**
19 WRAP Oil and Gas			
arinv_CA2018_OilGas_112205.ida	**ENVIRON**	**Text**	**California 2018 oil and gas inventory; annual**
oginv_WRAP2018_annual_tpd_111605.ida	**ENVIRON**	**Text**	**WRAP 2018 oil and gas inventory; annual**
20 Offshore Shipping			
ofsgts_l.2002###.1.vista36.baseg_2002.shipping.ncf	**ENVIRON/VISTAS**	**Binary; netCDF**	**Pacific, Gulf of Mex. and Atlantic 2002 Offshore shipping inventory; daily**

APPENDIX C

Model Performance Evaluation for the CMAQ 2002 Base F Base Case Simulation in the CENRAP Region

C.1 2002 Typical Base F Model Performance Evaluation Scenario

This Appendix presents the operational evaluation of the CMAQ model for the 2002 36 km Typical Base F emissions scenario. The final CENRAP 2002 and 2018 emissions scenarios used in the 2018 visibility projections was Base G. The main differences between Base G and Base F emissions inventories were updated Mexican emissions in the northern states, addition of Mexican emissions in the southern states that were not included in CENRAP's emission inventories prior to Base G and correction of a few point source stack parameters and emissions in the CENRAP states and Canada (see: http://pah.cert.ucr.edu/aqm/cenrap/QA_typ02g36.plots/log_inv_categ_Typ02g.doc). Figure C-1 displays the differences in annual average $PM_{2.5}$ and ozone concentrations between the 2002 Typical Base G and Base F simulations. Most of the differences in the two simulations are concentrations within Mexico where no monitoring data were available for the model evaluation. Thus, given the very small differences between the 2002 Typical Base F and G base case simulations, the model performance evaluation is presented for just the 2002 Typical Base F simulation (for additional comparisons of Base G and F see: http://pah.cert.ucr.edu/aqm/cenrap/cmaq.shtml#typ02gvstyp02f_mpe).

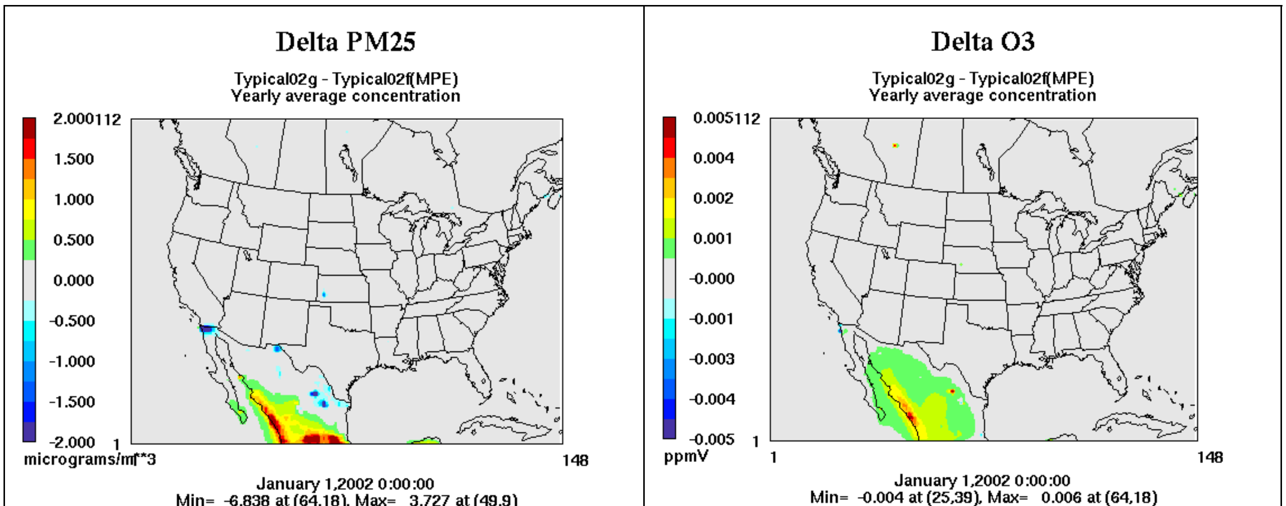


Figure C-1. Comparison of differences in annual average $PM_{2.5}$ (left) and ozone concentrations between 2002 Typical Base G and F (Base G – Base F).

The CENRAP emissions and air quality modeling initially conducted 2002 base case modeling for two 2002 base case emissions scenarios: a 2002 Actual emissions base case; and a 2002 Typical emissions base case. For the 2002 Actual base case, day-specific SO2 and NOx emissions for large stationary point sources were used based on measured continuous emissions monitoring (CEM) data along with actual 2002 fire emissions In the 2002 Typical base case, emissions for large stationary sources and fires were more representative of the 2000-2004 Baseline period. For large stationary sources' typical emissions, 5-years of CEM data were analyzed and typical seasonal and diurnally varying emissions were defined for when the sources where operating For the typical fire emissions, the locations of the 2002 Actual fire emissions were retained, but the intensity was reduced or increased to match the average conditions over the 5-year Baseline. The original intent of the CENRAP modeling of both a 2002 Actual and Typical base cases was to use the 2002 Actual base case for the model performance evaluation and the 2002 Typical base case with the 2018 emission scenario for the 2018 visibility projections.

The need to generate both the 2002 Typical and Actual base case inventories and perform CMAQ model simulations each time an emissions update or correction to the modeling occurred became burdensome and potentially could compromise the CENRAP schedule and available resources. For the Base F vintage emissions database, a model performance evaluation was conducted that compared the model performance of the 2002 Actual and Typical Base F CMAQ base case simulations to determine whether use of the Actual emissions substantially changed the interpretation of the model performance. The maximum change in model performance between the 2002 Actual and Typical base case was for sulfate and occurred during the summer months, when sulfate is the highest. Figure C-2 displays sulfate (SO4), nitrate (NO3), elemental carbon (EC) and organic matter carbon (OMC) performance for July 2002 across IMPROVE sites in the CENRAP region for the 2002 36 km Actual and Typical Base F CMAQ base case simulations. Although differences in predicted 24-hour SO4 concentrations are sometimes discernable in the scatter plot, the basic model performance conclusions remains the same and the difference in fractional bias (-48% vs. -49%) and fraction error (58% vs. 59%) are not significant. Similarly, the difference in NO3 model performance between the Actual and Typical Base F simulations are not significant. The performance of the CMAQ Actual and Typical simulation for EC and OMC is essentially identical. Given the similarity of the 2002 Base F Actual and Typical model performance evaluation, future CENRAP CMAQ model performance analysis were just performed on the Typical simulation.

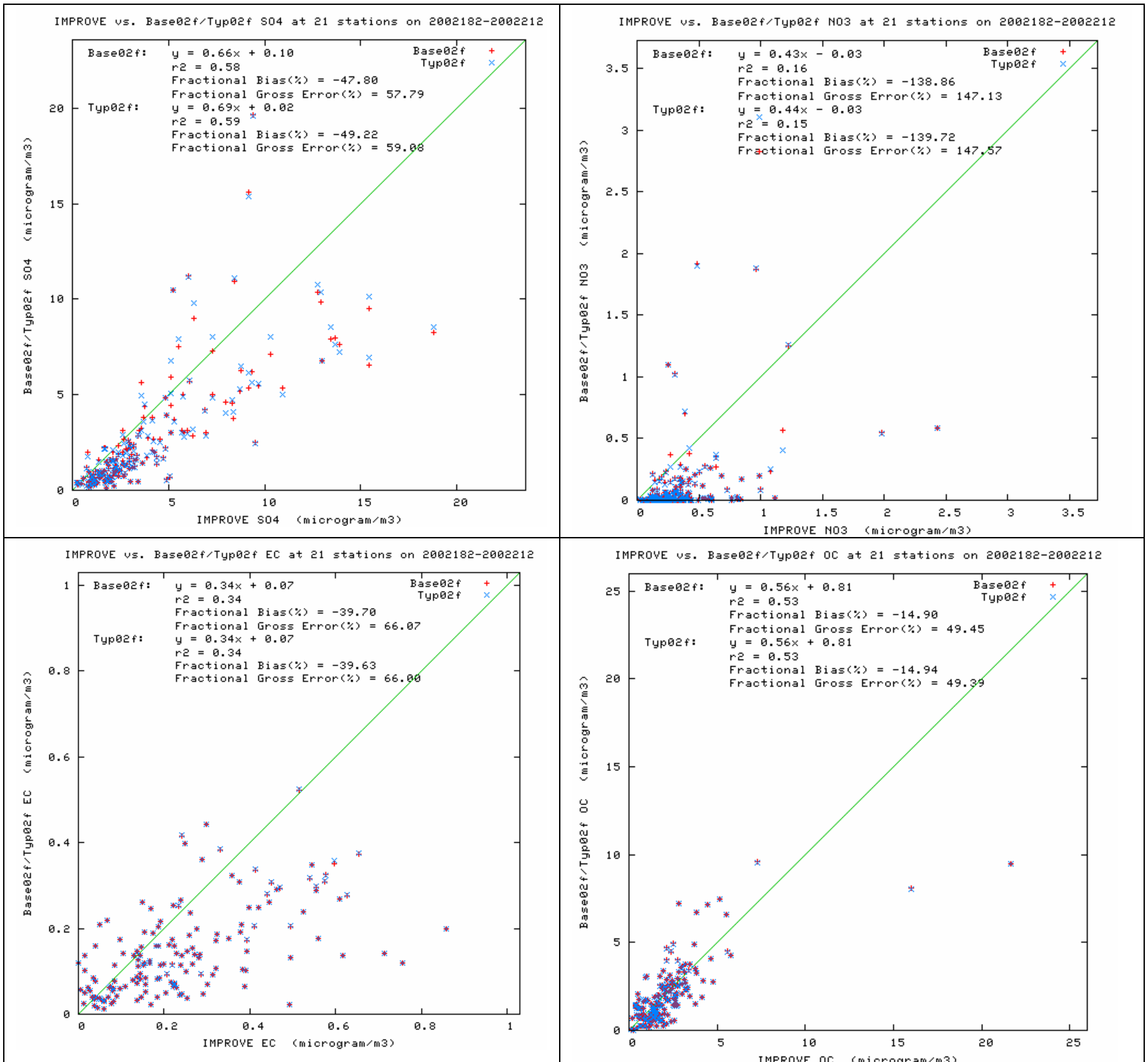


Figure C-2. Comparison of SO4 (top left), NO3 (top right), EC (bottom left) and OMC (bottom right) model performance for July 2002, the CENRAP region and the 2002 36 km Base F Actual (red) and Typical (blue) CMAQ base case simulation.

C.2 CMAQ Evaluation Methodology

EPA's integrated ozone, $PM_{2.5}$ and regional haze modeling guidance calls for a comprehensive, multi-layered approach to model performance testing, consisting of the four major components: operational, diagnostic, mechanistic (or scientific) and probabilistic (EPA, 2007). The CMAQ model performance evaluation effort focused on the first two components, namely:

- **Operational Evaluation**: Tests the ability of the model to estimate PM concentrations (both fine and coarse) and the components at PM_{10} and $PM_{2.5}$ including the quantities used to characterize visibility (i.e., sulfate, nitrate, ammonium, organic carbon, elemental carbon, other $PM_{2.5}$, and coarse matter ($PM_{2.5-10}$). This evaluation examines whether the measurements are properly represented by the model predictions but does not necessarily ensure that the model is getting "the right answer for the right reason"; and

- **Diagnostic Evaluation:** Tests the ability of the model to predict visibility and extinction, PM chemical composition including PM precursors (e.g., SOx, NOx, and NH_3) and associated oxidants (e.g., ozone and nitric acid); PM size distribution; temporal variation; spatial variation; mass fluxes; and components of light extinction (i.e., scattering and absorption).

The diagnostic evaluation also includes the performance of diagnostic tests to better understand model performance and identify potential flaws in the modeling system that can be corrected. The diagnostic evaluation may also includes the use of "probing tools" to understand why the model obtains a given prediction; probing tools include Process Analysis (PA), decoupled direct method (DDM) and source apportionment (SA).

In this final model performance evaluation for the 2002 Typical Base F CMAQ simulation, the operational evaluation has been given the greatest attention since this is the primarily thrust of EPA's modeling guidance. However, we have also examined certain diagnostic features dealing with the model's ability to simulate sub-regional and monthly/diurnal gas phase and aerosol concentration distributions. In the course of the CENRAP and other modeling process numerous diagnostic sensitivity tests were performed to investigate and improve model performance. Key diagnostic tests performed are discussed and the results for the rest are available on the CENRAP modeling website: http://pah.cert.ucr.edu/aqm/cenrap/index.shtml.

C.2.1 Ambient Air Quality Data for CENRAP Model Evaluation

The ground-level model evaluation database for 2002 was compiled by the modeling team using several routine and research-grade databases. The first is the routine gas-phase concentration measurements for ozone, NO, NO_2 and CO archived in EPA's Aerometric Information Retrieval System (AIRS) Air Quality System (AQS) database. Other sources of observed information come from the various PM monitoring networks in the U.S. These include the: (a) Interagency Monitoring of Protected Visual Environments (IMPROVE); (b) Clean Air Status and Trends Network (CASTNET); (c) Southeastern Aerosol Research and Characterization (SEARCH); (d) EPA Federal Reference Method $PM_{2.5}$ and PM_{10} Mass Networks (EPA-FRM); (e) EPA Speciation Trends Network (STN) of $PM_{2.5}$ species; and (f) National Acid Deposition Network (NADP). These PM monitoring networks may also provide ozone and other gas phase precursors and product species, and visibility measurements at some sites. During the course of the CENRAP modeling, the numerous base case simulations were evaluated across the continental U.S. In this section we focus our evaluation on model performance within the CENRAP region. Table C-1 summarizes the observations collected at each monitoring network within the CENRAP region and their sampling frequency with Figure C-3 displaying the locations of the monitors for the various monitoring networks operating in the CENRAP region during 2002.

Table C-1. Ambient monitoring data available in the CENRAP region during 2002.

Monitoring Network	Chemical Species Measured	Sampling Frequency; Duration
IMPROVE	Speciated $PM_{2.5}$ and PM_{10}	1 in 3 days; 24 hr
CASTNET	Speciated $PM_{2.5}$, Ozone	Hourly, Weekly; 1 hr, Week
SEARCH	24-hr PM_{25} (FRM Mass, OC, BC, SO_4, NO_3, NH_4, Elem.); 24-hr PM coarse (SO_4, NO_3, NH_4, elements); Hourly $PM_{2.5}$ (Mass, SO_4, NO_3, NH_4, EC, TC); and Hourly gases (O_3, NO, NO_2, NO_y, HNO_3, SO_2, CO)	Daily, Hourly;
NADP	WSO_4, WNO_3, WNH_4	Weekly
EPA-FRM	Only total fine mass ($PM_{2.5}$)	1 in 3 days; 24 hr
EPA-STN	Speciated $PM_{2.5}$	Varies; Varies
AIRS/AQS	CO, NO, NO_2, NO_x, O_3	Hourly; Hourly

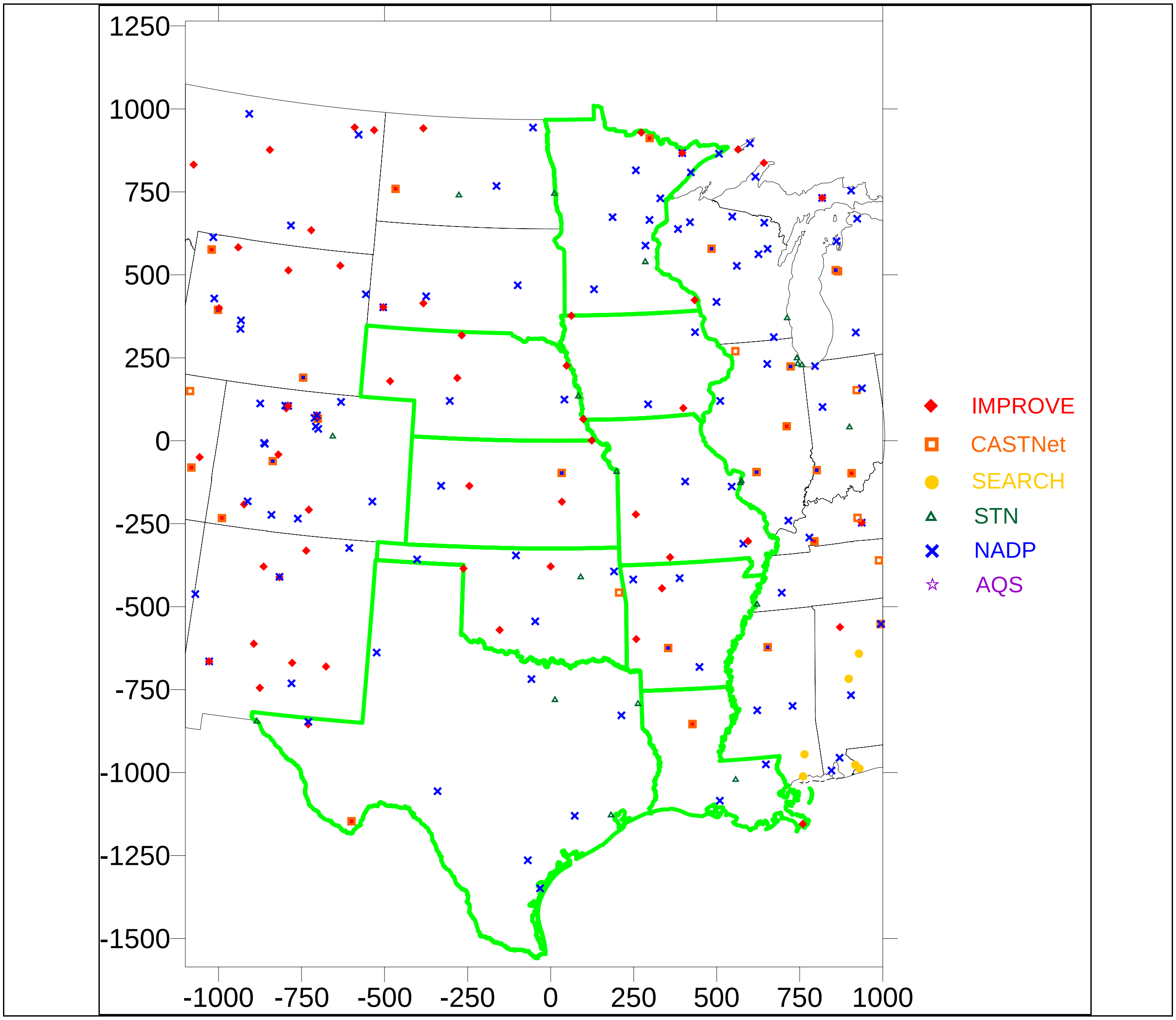


Figure C-3. Locations of surface monitors within the CENRAP states for sites operating during 2002.

C.2.2 Scope of CMAQ Model Performance Evaluation

The primary focus of the CMAQ Base F evaluation is on how well the model is able to replicate observed concentrations gas-phase pollutants and precursors, the various components of $PM_{2.5}$, total observed mass of $PM_{2.5}$, and wet deposition amounts. The CMAQ operational evaluation, model outputs are compared statistically and graphically with observational data obtained from the IMPROVE, CASTNet, STN, NADP and AQS monitoring networks. Because the SEARCH network is located in the southeastern U.S. (VISTAS region) outside of the CENRAP region, it is not a major component of our evaluation. Also, since the EPA-FRM network focuses on just $PM_{2.5}$ mass measurements primarily in $PM_{2.5}$ nonattainment or near nonattainment areas it is not very relevant for simulating regional haze at mainly remote Class I areas so is also not used in our model performance evaluation. The primary focus of the operational evaluation of the CMAQ 2002 Base F simulation is the performance of PM components in the CENRAP region for predicting regional haze at Class I areas.

Many statistical performance measures have been calculated using the different monitoring networks and across the different model performance subdomains (e.g., RPO regions). Table C-2 lists the definitions of the model performance evaluation statistical metrics. These performance metrics are routinely generate by the UCR Analysis Tool and are available on the project website. Many of them are measures of bias and error that are somewhat redundant.

Table C-2. Statistical Measures Used in the CENRAP CMAQ Model Evaluation.

Statistical Measure	Shorthand Notation	Mathematical Expression	Notes
Accuracy of paired peak (***A***$_p$)	**Paired_Peak**	$\frac{P - O_{peak}}{O_{peak}}$	P_{peak} = paired (in both time and space) peak prediction
Coefficient of determination (***r***^{2})	**Coef_Determ**	$\frac{\left[\sum_{i=1}^{N}(P_i - \overline{P})(O_i - \overline{O})\right]^2}{\sum_{i=1}^{N}(P_i - \overline{P})^2 \sum_{i=1}^{N}(O_i - \overline{O})^2}$	P_i = prediction at time and location i; O_i = observation at time and location i; $\overline{P}$ = arithmetic average of P_i, i=1,2,…, N; $\overline{O}$ = arithmetic average of O_i, i=1,2,…,N
Normalized Mean Error (***NME***)	**Norm_Mean_Err**	$\frac{\sum_{i=1}^{N}\lvert P_i - O_i\rvert}{\sum_{i=1}^{N} O_i}$	Reported as %
Root Mean Square Error (***RMSE***)	**Rt_Mean_Sqr_Err**	$\left[\frac{1}{N}\sum_{i=1}^{N}\left(P_i - O_i\right)^2\right]^{1/2}$	Reported as %
Fractional Gross Error (***F$_E$***)	**Frac_Gross_Err**	$\frac{2}{N}\sum_{i=1}^{N}\left\lvert\frac{P_i - O_i}{P_i + O_i}\right\rvert$	Reported as %
Mean Absolute Gross Error (***MAGE***)	**Mean_Abs_G_Err**	$\frac{1}{N}\sum_{i=1}^{N}\lvert P_i - O_i\rvert$	
Mean Normalized Gross Error (***MNGE***)	**Mean_Norm_G_Err**	$\frac{1}{N}\sum_{i=1}^{N}\frac{\lvert P_i - O_i\rvert}{O_i}$	Reported as %
Mean Bias (***MB***)	**Mean_Bias**	$\frac{1}{N}\sum_{i=1}^{N}\left(P_i - O_i\right)$	Reported as concentration (e.g., µg/m^3)

Statistical Measure	Shorthand Notation	Mathematical Expression	Notes
Mean Normalized Bias (***MNB***)	**Mean_Norm_Bias**	$\frac{1}{N}\sum_{i=1}^{N}\frac{(P_i - O_i)}{O_i}$	Reported as %
Mean Fractionalized Bias (Fractional Bias, ***MFB***)	**Mean_Fract_Bias**	$\frac{2}{N}\sum_{i=1}^{N}\left(\frac{P_i - O_i}{P_i + O_i}\right)$	Reported as %
Normalized Mean Bias **(*NMB*)**	**Norm_Mean_Bias**	$\frac{\sum_{i=1}^{N}(P_i - O_i)}{\sum_{i=1}^{N}O_i}$	Reported as %
Bias Factor (***BF***)	**Bias Factor**	$\frac{1}{N}\sum_{i=1}^{N}\left(\frac{P_i}{O_i}\right)$	Reported as BF:1 or 1: BF or in fractional notation (BF/1 or 1/BF).

C.2.3 Operational Model Evaluation Approach

The CENRAP modeling databases will be used to develop the visibility State Implementation Plan (SIP) due in December 2007 as required by the Regional Haze Rule (RHR). Accordingly, the primary focus of the operational evaluation is on the six components of fine particulate ($PM_{2.5}$) and Coarse Matter ($PM_{2.5\text{-}10}$) within the CENRAP region that are used to characterize visibility at Class I areas:

- Sulfate (SO4);
- Particulate Nitrate (NO3);
- Elemental Carbon (EC);
- Organic Mass Carbon (OMC);
- Other inorganic fine particulate (IP or Soil); and
- Coarse Matter (CM).

The model performance for ozone and precursor and product species (e.g., SO_2 and HNO_3) is also evaluated to build confidence that the modeling system is sufficiently reliable to project future-year visibility.

C.2.5 Performance Evaluation Tools

One of the many challenges in evaluating an annual PM/ozone model simulation is how to synthesize model performance given the shear volume of output from an annual simulation. The model is run on a 148 x 112 x 19 grid with approximately 30 species producing hourly outputs for each day of the year. This results in approximately 90 trillion concentration estimates that are produced for an annual simulation. Thus, the synthesis and interpretation of numerous graphical and tabular displays of model performance into a few concise and descriptive displays that identify the most salient features of model performance is necessary. As part of the CENRAP modeling, as well as work performed by WRAP, VISTAS, MRPO and MANE-VU, several analysis tools and summary displays have been developed and are used:

> UCR Analysis Tools: The University of California at Riverside (UCR) Analysis Tools have been used extensively to evaluate the CMAQ and CAMx models for CENRAP (e.g., Morris et al., 2005), WRAP (Tonnesen et al., 2004), VISTAS (Morris et al., 2004) as well as other studies and are run on a Linux platform separately for each network. Numerous graphical displays of model performance are automatically generated using gnuplot. The software generates the following summary and graphical displays of model performance:
>
> - Tabular statistical measures (see Table C-2);
> - Time Series Plots for each site and species; and
> - Scatter Plots for each species by allsite_allday, allday_onesite and allsite_oneday.
>
> The UCR Analysis Tool is run for a specific subregion (e.g., by RPO region) and for selected monitoring networks. Because each monitoring network has its own measurement artifacts, the model is evaluated separately for each monitoring network.
>
> Summary Bias/Error Plots: The modeling team has developed additional displays of model performance statistics that elucidate model performance in a concise manner: (1) monthly time series plots of average bias and error; (2) soccer plots that display bias versus error and compares them to model performance goals and criteria; and (3) tools to analyze visibility model performance for the worst and best 20 percent visibility days that are used in visibility projections.
>
> GA DNR Analysis Plots: Dr. James Boylan of the Georgia Department of Natural Resources has extended the concept in EPA's draft PM fine particulate and regional haze modeling guidance that model performance for species that make up a major contribution to visibility impairment be subjected to more stringent goals than species that are minor contributors by developing concentration-dependent performance goals and "Bugle Plots" to display them (Boylan, 2004).

The evaluation of the CENRAP 2002 36 km Base F CMAQ simulation used each of the analysis tools listed above taking advantage of their different descriptive and complimentary nature. The use of these analysis tools generated thousands of statistical measures and graphical displays of model performance that cannot all be displayed in this report. The modeling team has gone through the plots and measures using slide shows to identify those displays that are most descriptive in conveying model performance so should be included in this TSD. The complete set of model performance statistics and graphical performance displays can be found on the CENRAP modeling Website at:

> http://pah.cert.ucr.edu/aqm/cenrap/cmaq.shtml#cmaq_typ02f_mpe

Note that model performance statistics are calculated separately for each of the monitoring networks. Different PM measurement technology can produce different measurement values even when measuring the same air parcel. Thus, when calculating model performance metrics, measurements in different networks are not mixed.

C.2.4 Subdomains Analyzed

CENRAP has been analyzing model performance in five subdomains corresponding to the states contained in the five RPOs (see Figure 1-1):

- CENRAP
- MRPO
- VISTAS
- MANE-VU
- WRAP

As CENRAP has refined its emissions inventory, the changes in model performance from one 2002 base case to another has diminished to the point where little has changed in the last few iterations. Thus, the CMAQ 2002 36 km Base F evaluation presented in this section was just performed for the CENRAP region and the reader is referred to the modeling Website (http://pah.cert.ucr.edu/aqm/cenrap/cmaq.shtml) and Morris and co-workers (2005) for the evaluation outside of the CENRAP region and the diagnostic model evaluation.

C.2.5 Model Performance Goals and Criteria

The issue of model performance goals for PM species is an area of ongoing research and debate. For ozone modeling, EPA has established performance goals for 1-hour ozone normalized mean bias and gross error of #±15% and #35%, respectively (EPA, 1991). EPA's draft fine particulate modeling guidance notes that performance goals for ozone should be viewed as upper bounds of model performance that PM models may not be able to always achieve and we should demand better model performance for PM components that make up a larger fraction of the PM mass than those that are minor contributors (EPA, 2001). EPA's final modeling guidance does not list any specific model performance goals for PM and visibility modeling and instead provides a summary of PM model performance across several historical applications that can be used for comparisons if desired. Measuring PM species is not as precise as ozone monitoring. In fact, the differences in measurement techniques for some species likely exceed the more stringent performance goals, such as those for ozone. For example, recent comparisons of the PM species measurements using the IMPROVE and STN measurement technologies found differences of approximately ∀20% (SO4) to ∀50% (EC) (Solomon et al., 2004).

For the CENRAP, VISTAS and WRAP modeling we have adopted three levels of model performance goals and criteria for bias and gross error as listed in Table C-3. Note that we are not suggesting that these performance goals be adopted as guidance or that they are the most appropriate goals to use. Rather, we are just using them to frame and put the PM model performance into context and to facilitate model performance intercomparison across episodes, species, models and sensitivity tests.

Table C-3. Model performance goals and criteria used to assist in interpreting modeling results.

Fractional Bias	Fractional Error	Comment
#∀15%	#35%	Ozone model performance goal for which PM model performance would be considered good – note that for many PM species measurement uncertainties may exceed this goal.
#∀30%	#50%	Proposed PM model performance goal that we would hope each PM species could meet
#∀60%	#75%	Proposed PM criteria above which indicates potential fundamental problems with the modeling system.

As noted in EPA's PM modeling guidance, less abundant PM species should have less stringent performance goals (EPA, 2001; 2007). Accordingly, we are also using performance goals that are a continuous function of average concentrations, as proposed by Dr. James Boylan at the Georgia Department of Natural Resources (GA DNR), that have the following features (Boylan, 2004):

- Asymptotically approaching proposed performance goals or criteria (i.e., the ∀30%/50% and ∀60%/75% bias/error levels listed in Table C-1) when the mean of the observed concentrations are greater than 2.5 ug/m^3.
- Approaching 200% error and ∀200% bias when the mean of the observed concentrations are extremely small.

Bias and error are plotted as a function of average concentrations. As the mean concentration approach zero, the bias performance goal and criteria flare out to ∀200% creating a horn shape, hence the name "Bugle Plots". Dr. Boylan has defined three Zones of model performance: Zone 1 meets the ∀30%/50% bias/error performance goal and is considered "good" model performance; Zone 2 lies between the ∀30%/50% performance goal and ∀60%/75% performance criteria and is an area where concern for model performance is raised; and Zone 3 lies above the ∀60%/75% performance criteria and is an area of questionable model performance.

C.2.6 Performance Time Periods

The CMAQ 2002 36 km Base F evaluation, model performance statistics and graphical displays are generated monthly using the native averaging times of each monitoring network (i.e., 24-hour for IMPROVE and STN; weekly for CASTNet and NADP; and hourly for AQS). As the focus of the RHR is on daily average visibility that is calculated from daily average PM species concentrations then the evaluation of the model for 24-hour concentrations is particularly relevant. The RHR places particular emphasis on the Worst 20% (W20%) and Best 20% (B20%) days at Class I areas. Thus, we also place particular emphasis on the model performance for PM species on the W20% and B20% days during 2002 at Class I areas.

C.2.7 Key Measures of Model Performance

Although we have generated numerous statistical performance measures (see Table C-2) that are available on the CENRAP modeling website, when comparing model performance across months, subdomains, networks, grid resolution, models, studies, etc. it is useful to have a few key measurement statistics to be used to facilitate the comparisons. It is also useful to have a subset of the 2002 year that can represent the entire year so that a more focused evaluation can be conducted. We have found that the Mean Fractional Bias and Mean Fractional Gross Error appear to be the most consistent descriptive measure of model performance (Morris et al., 2004b; 2005). The Fractional Bias and Error normalize by the average of the observed and predicted value (see Table C-2) because it provides descriptive power across different magnitudes of the model and observed concentrations and is bounded by -200% to +200%. This is in contrast to the normalized bias and error (as recommended for ozone performance goals, EPA, 1991) that is normalized by just the observed value so can "blow up" to infinity as the observed value approaches zero. Below we perform a focused evaluation of model performance for four months of the 2002 year that are used to represent the seasonal variation in performance:

- January
- April
- July
- October

We also present fractional bias and error for all months of 2002 using time series and bugle plots.

C.3 Operational Model Performance Evaluation in the CENRAP Region

In the following discussions we use selected monthly scatter plots, time series plots and model performance statistical measures from the UCR Analysis Tools application to the 2002 CMAQ Base F base case simulation in an operational evaluation of the model for PM species. We focus on the six main components of PM that are used to project visibility.

C.3.1 Sulfate (SO4) Monthly Model Performance

C.3.1.1 SO4 in January 2002

Figure C-4a displays scatter plots of predicted and observed SO4 concentrations or wet depositions for sites in the CENRAP regions using observations from the IMPROVE, STN, CASTNet and NADP monitoring networks; the IMPROVE and STN SO4 concentrations are 24-hour averages whereas the CASTNet SO4 concentrations and NADP SO4 wet deposition are weekly averages. The January SO4 performance at the IMPROVE and STN networks in the CENRAP region is quite good with low fractional bias (-12% to -13%) and some scatter (fractional error of 42% and 34%) but centered in the 1:1 line of perfect agreement. There is a net SO4 underestimation bias in January across the CASTNet network (fractional bias of -34%) with wet SO4 deposition overstated on average across the NADP sites in the CENRAP region (+40% fractional bias). Whether the overstated SO4 wet deposition is a contributor to the SO4 concentration underestimation bias is unclear, but it is in the correct direction to account for it.

The time series comparisons of predicted and observed 24-hour SO4 concentrations at CENRAP Class I area IMPROVE sites during January 2002 shown in Figure C-4b are quite encouraging. Although there are some days and sites with mismatches (e.g., January 26 at BOWA and VOYA) and sites with systematic performance problems (SO4 underestimated at BIBE), the time series in generally are quite good with the model tracking the observed temp[oral variation in daily sulfate in January and some sites exhibiting remarkable agreement (e.g., MING).

Figure C-4c displays the spatial variations in the predicted and IMPROVE observed SO4 concentrations for January 20, 23, 26 and 29, 2002, which are four consecutive days of IMPROVE monitoring using its 1:3 day monitoring frequency. On January 20 both the model and observations agree on that an elevated sulfate clouds is entering the CENRAP region across southern Illinois and Missouri. There is a sharp SO4 concentration gradient going east to west with both the model and observations estimating relatively clean SO4 values over Colorado. By January 23 the model and observations agree that elevated SO4 exists along a diagonal orientation from Chicago to East Texas. Although there are some SO4 model/observed spatial mismatches on this day (e.g., northern Louisiana and western Arkansas) the model generally reproduces the areas of elevated and low observed SO4. By January 29 the model and observations agree that SO4 has cleaned out of the CENRAP region. Although there are elevated SO4 observations in western North Dakota and northern Minnesota not reflected in the model. On January 29 there is an elevated tongue of SO3 entering the CENRAP region through southern Illinois stretching to the southwest almost to Big Bend in western Texas. Observed SO4 is measured at Big Bend but the modeled high SO4 is slightly east of there. There is very good agreement on this day between the predicted and observed spatial distribution of SO4.

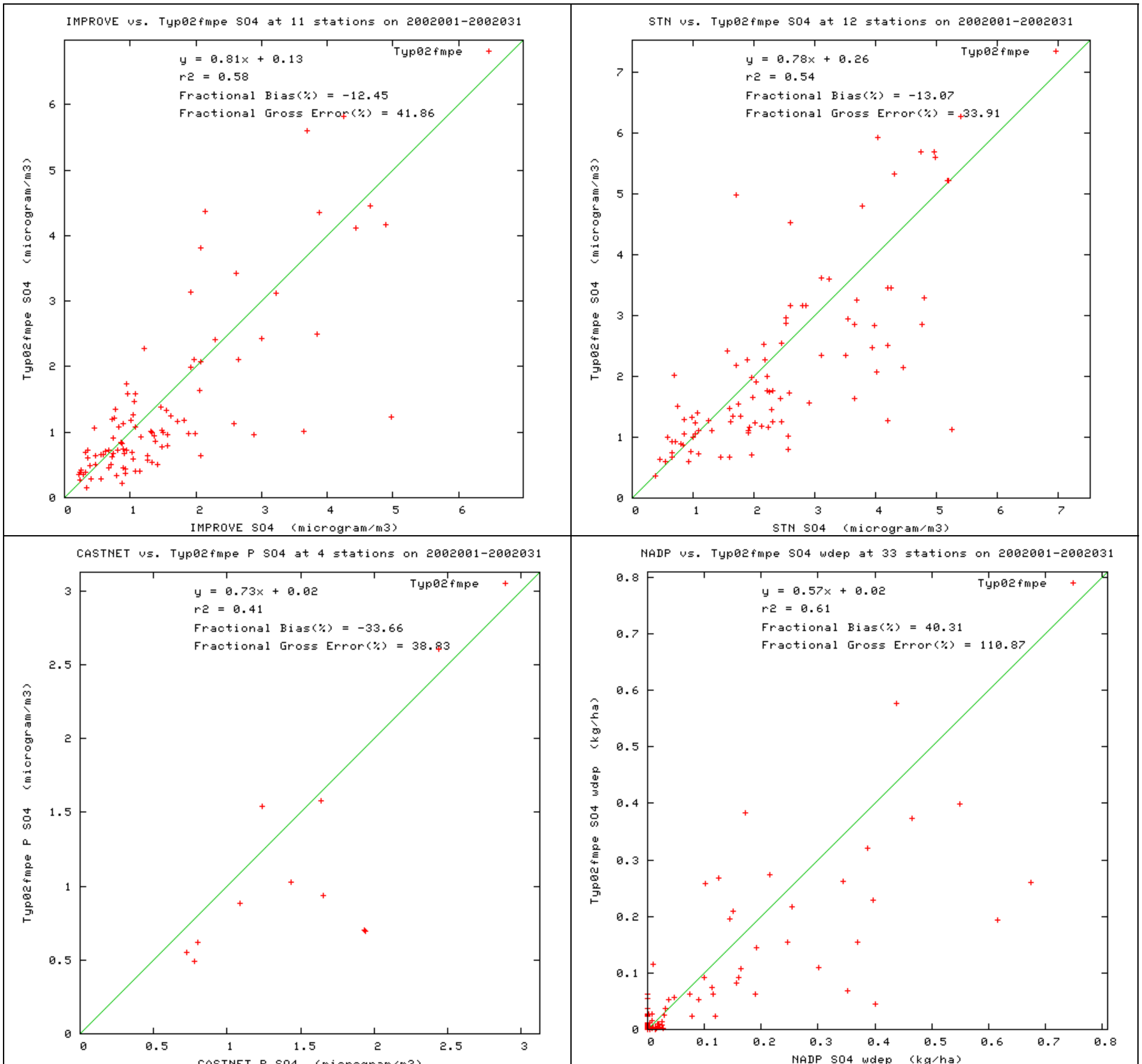
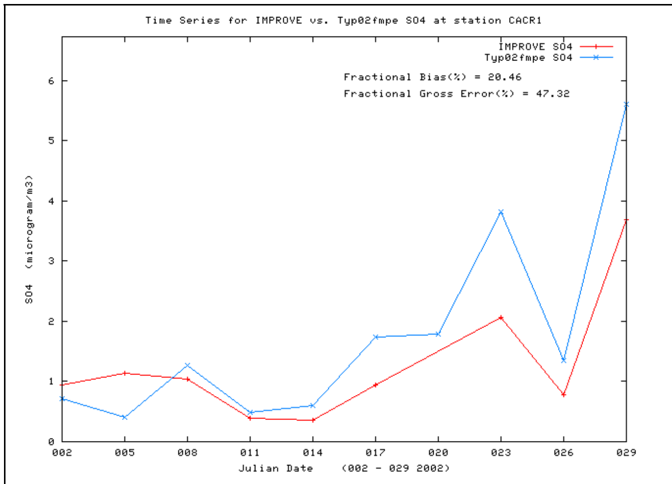
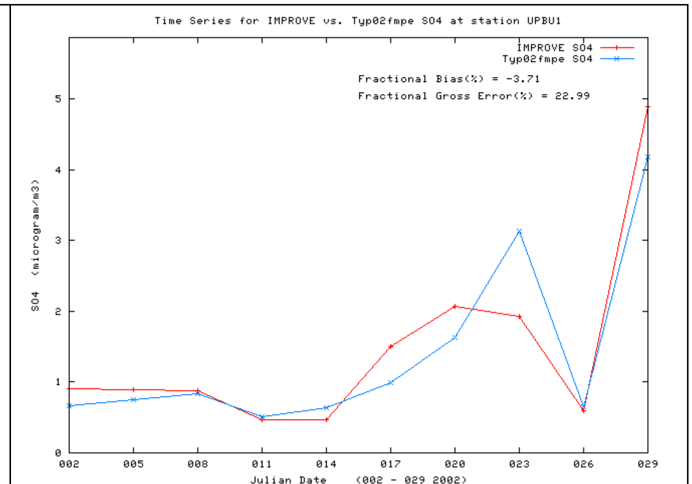
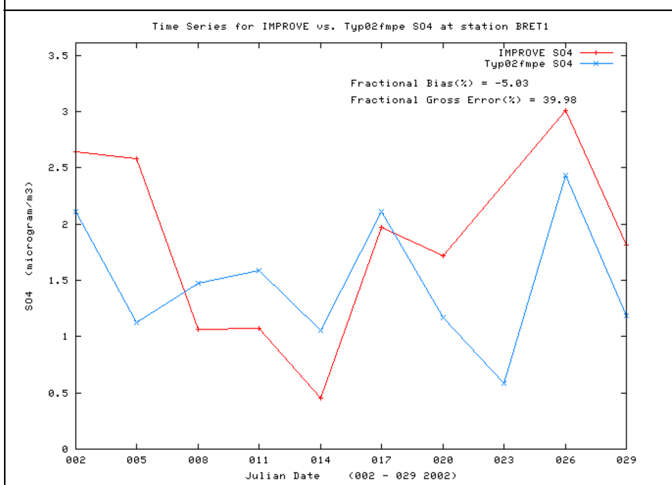
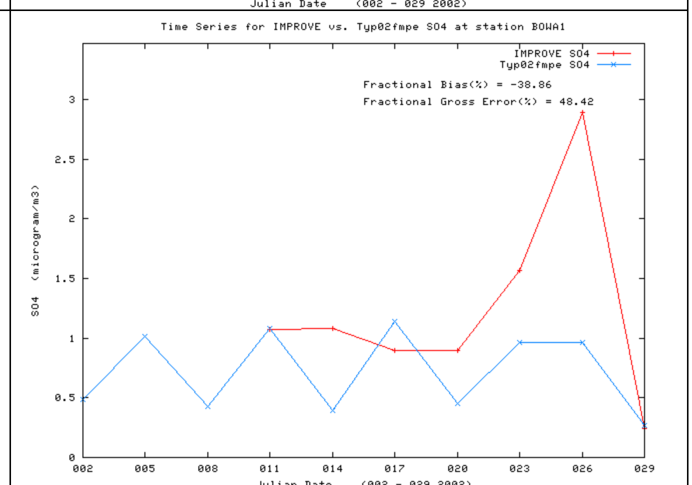


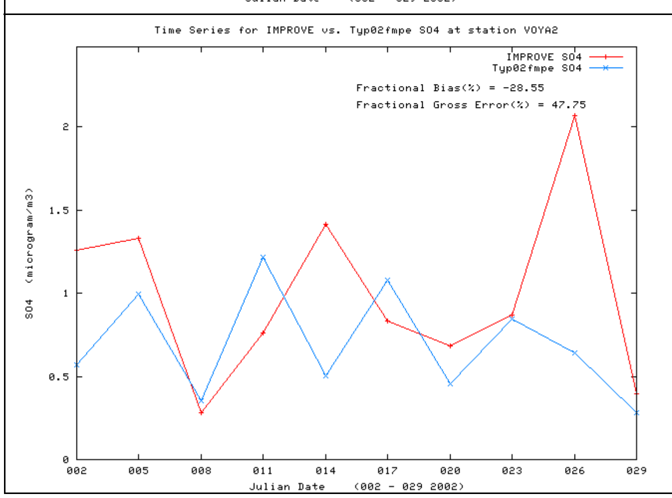
Figure C-4a. Scatter plots of predicted and observed sulfate (SO4) concentrations for January 2002 and sites in the CENRAP region using IMPROVE (top left), STN (top right), CASTNet (bottom left) and NADP monitoring networks using the CMAQ 2002 36 km Base F base case simulation.

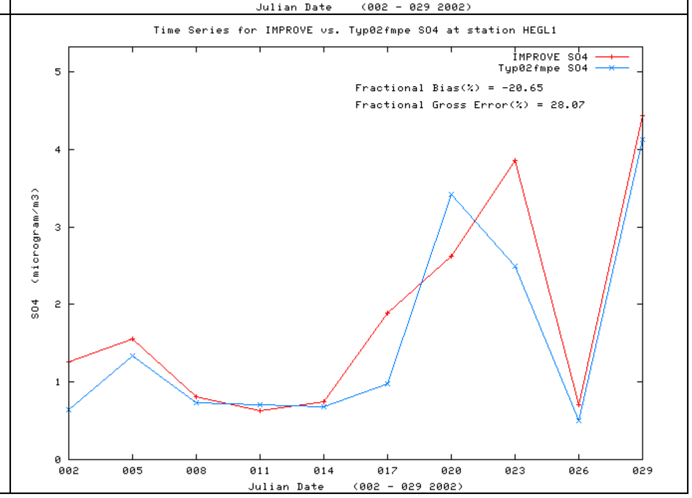

Time Series for IMPROVE vs. Typ02fmpe SO4 at station CACR1
IMPROVE SO4
Typ02fmpe SO4
Fractional Bias(%) = 20.46
Fractional Gross Error(%) = 47.32
SO4 (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe SO4 at station UPBU1
IMPROVE SO4
Typ02fmpe SO4
Fractional Bias(%) = -3.71
Fractional Gross Error(%) = 22.99
SO4 (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe SO4 at station BRET1
IMPROVE SO4
Typ02fmpe SO4
Fractional Bias(%) = -5.03
Fractional Gross Error(%) = 39.98
SO4 (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe SO4 at station BOWA1
IMPROVE SO4
Typ02fmpe SO4
Fractional Bias(%) = -38.86
Fractional Gross Error(%) = 48.42
SO4 (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe SO4 at station VOYA2
IMPROVE SO4
Typ02fmpe SO4
Fractional Bias(%) = -28.55
Fractional Gross Error(%) = 47.75
SO4 (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe SO4 at station HEGL1
IMPROVE SO4
Typ02fmpe SO4
Fractional Bias(%) = -20.65
Fractional Gross Error(%) = 28.07
SO4 (microgram/m3)
Julian Date (002 - 029 2002)

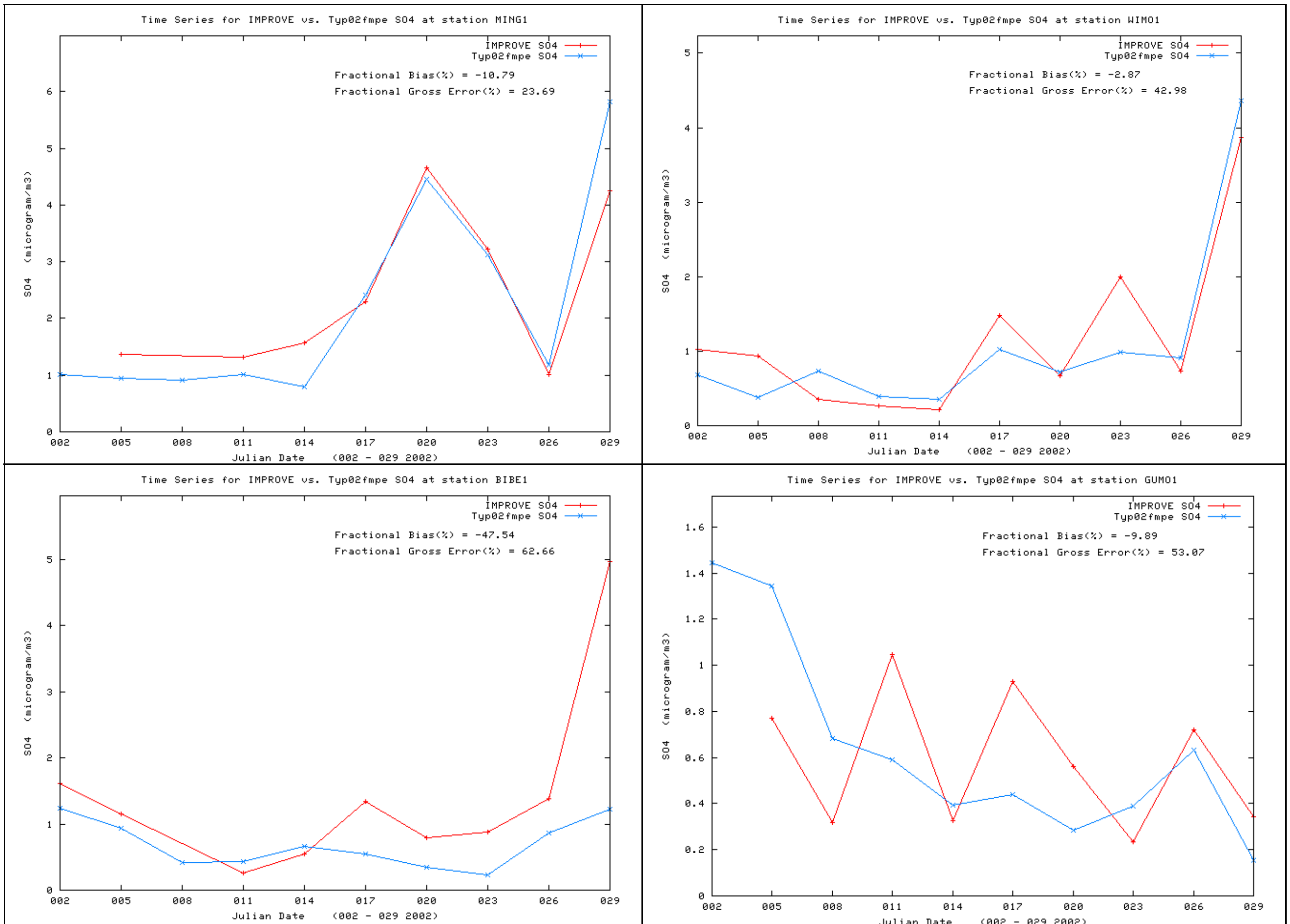


Figure C-4b. Time series of predicted and observed 24-hour sulfate (SO4) concentrations at CENRAP IMPROVE CLASS I AREA sites in January 2002 for CMAQ 2002 36 km Base F base case simulation.

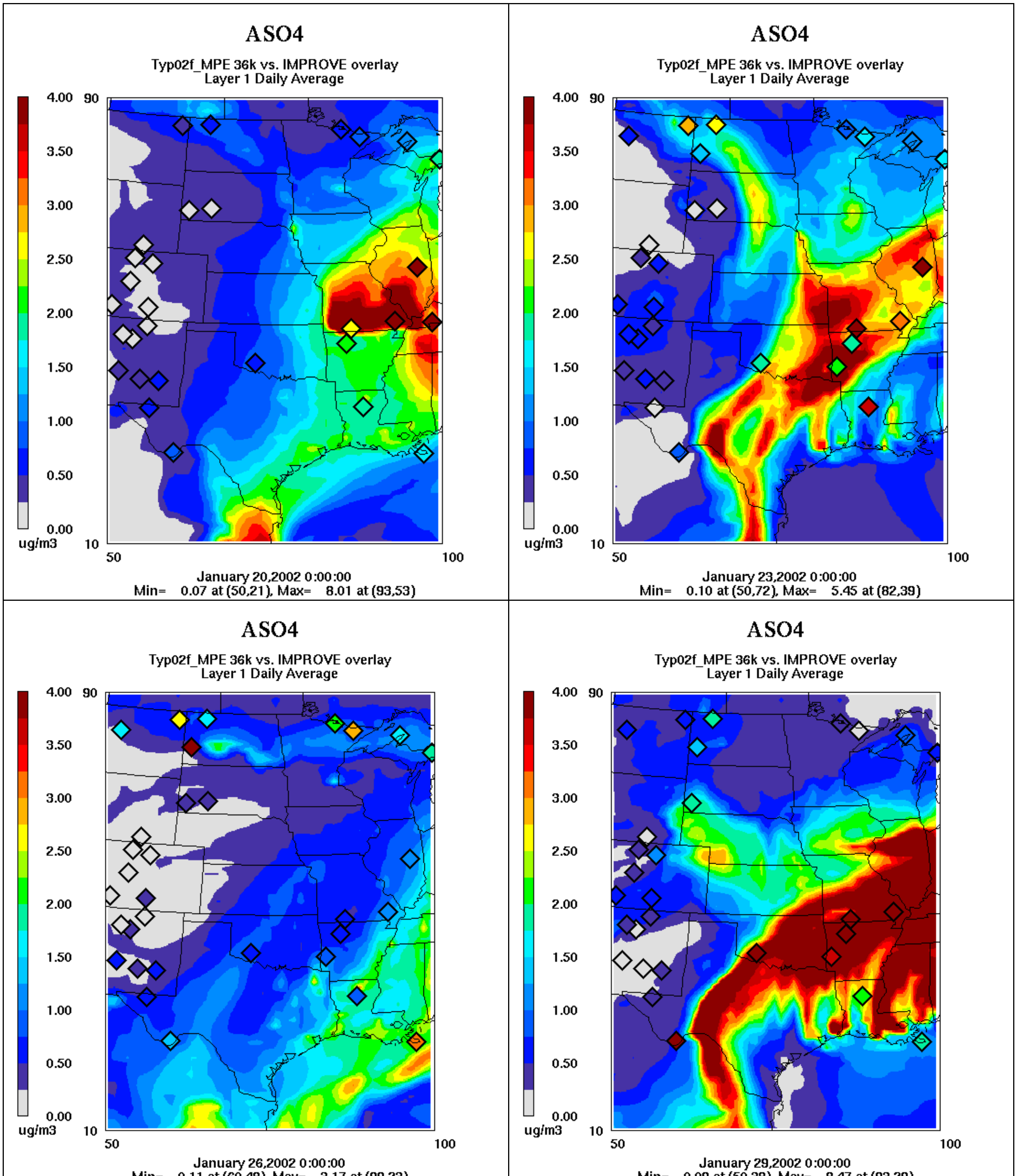


Figure C-4c. Spatial plot comparisons of the predicted and IMPROVE observed 24-hour SO4 concentrations for January 20, 23, 26 and 29, 2002.

C.3.1.2 SO4 in April 2002

In April CMAQ underestimates the observed SO4 in the CENRAP region with fractional bias values of -52%, -30% and -58% across the IMPROVE, STN and CASTNet networks (Figure C-5a). The fractional bias for wet SO4 deposition is quite low (3%) albeit with a lot of scatter which is reflected in high fractional error (78%). The ability of the model to reproduce the temporal variability of the April observed SO4 concentrations at the IMPROVE sites is quite variable. The SO4 under-prediction bias is clearly present at several sites (e.g., HEGL, BIBE and GUMO), whereas there is quite good agreement at others (UPBU, BRET and VOYA). Comparisons of the spatial distributions of the predicted and observed SO4 concentrations on April 5, 8, 11 and 14 are shown in Figure C-5c. On April 5 the model reproduces the half circle of elevated SO4 across Texas-Louisiana, but appears to not be as large an area as observed coming up short from some of the sites (e.g., BIBE and GUMO). Model and observations agree that April 8 is a relatively low SO4 day in the CENRAP region with just a small intrusion of elevated values across Mississippi. On April 14 the model has two separate clouds of elevated SO4, one over East Texas-Louisiana and one over northeastern Illinois and eastward with a clean area in between in southern Missouri. The observations agree except that it has these two elevated SO4 areas connected with the southern Missouri area not as clean as in the model.

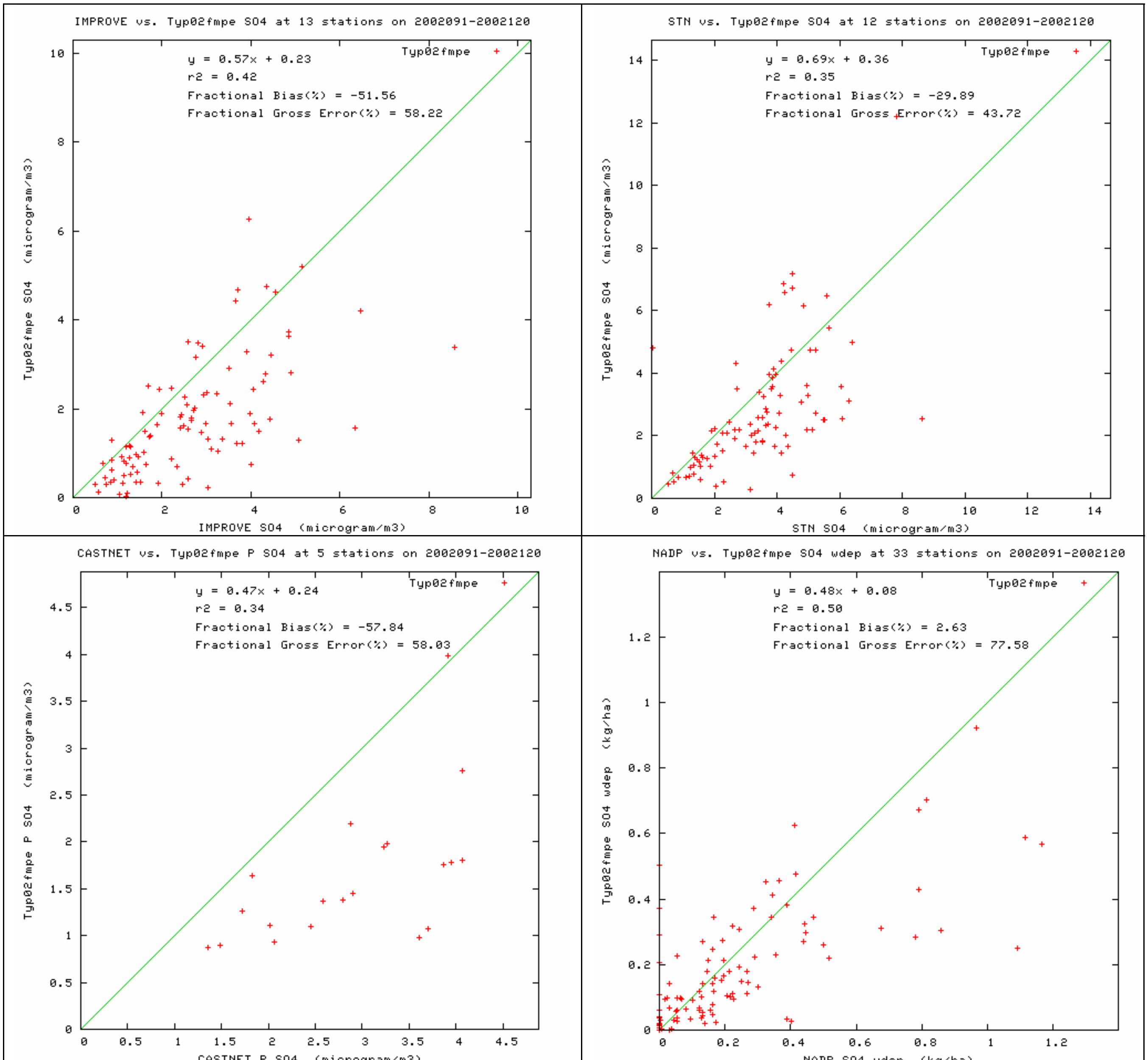
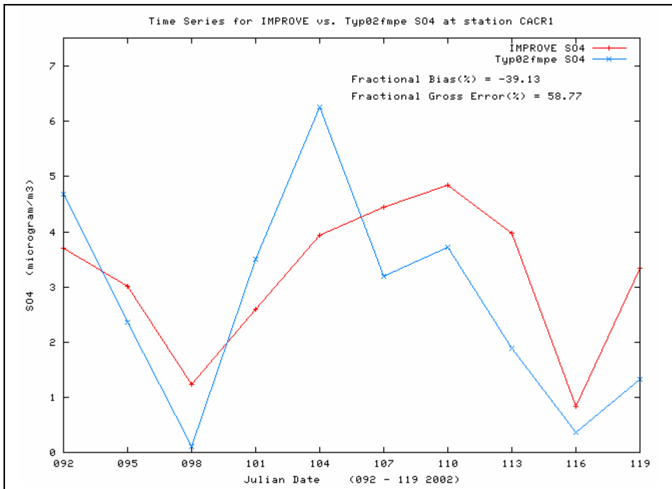
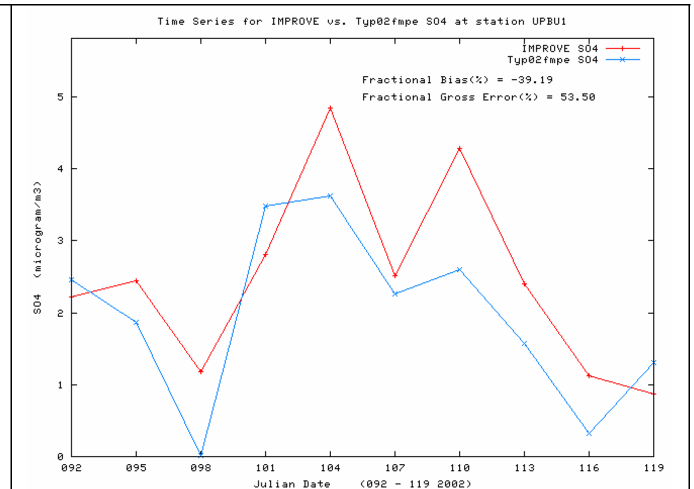
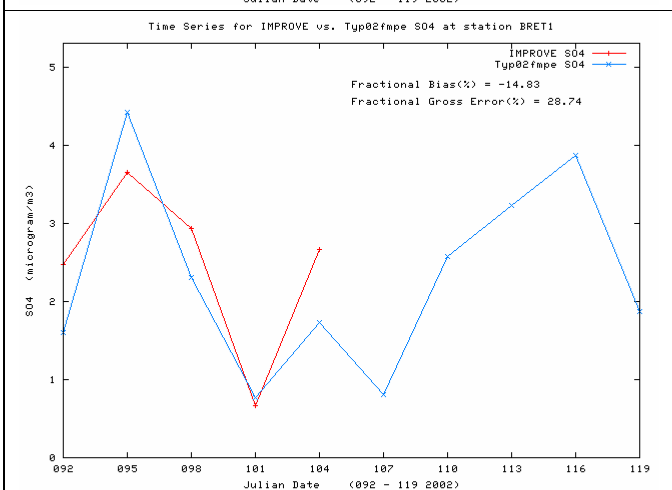
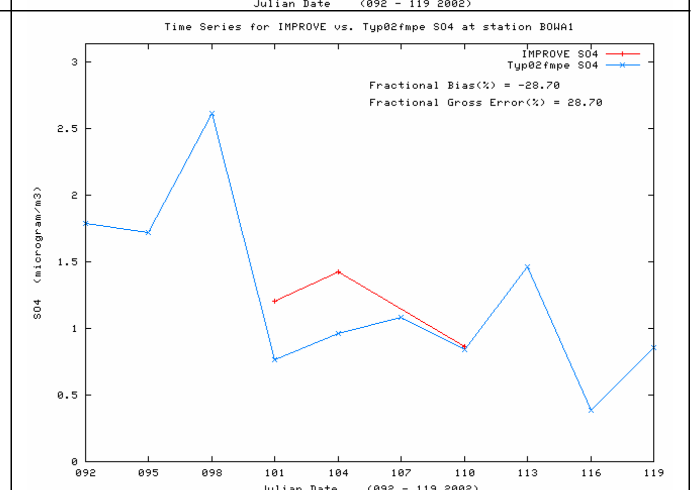


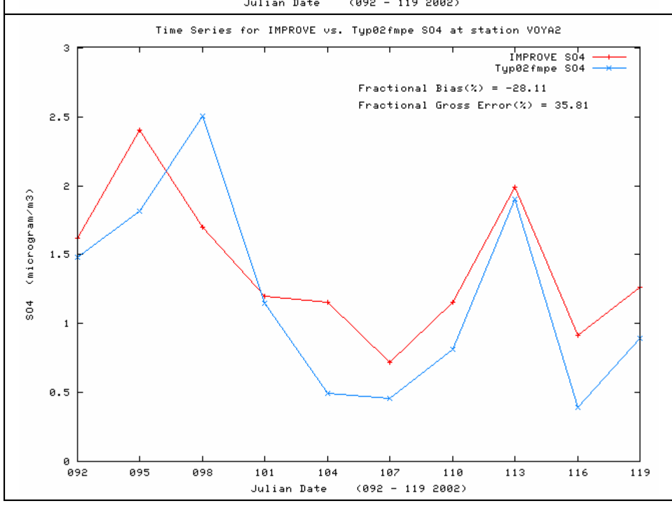
Figure C-5a. Scatter plots of predicted and observed sulfate (SO4) concentrations for April 2002 and sites in the CENRAP region using IMPROVE (top left), STN (top right), CASTNet (bottom left) and NADP monitoring networks using the CMAQ 2002 36 km Base F base case simulation.

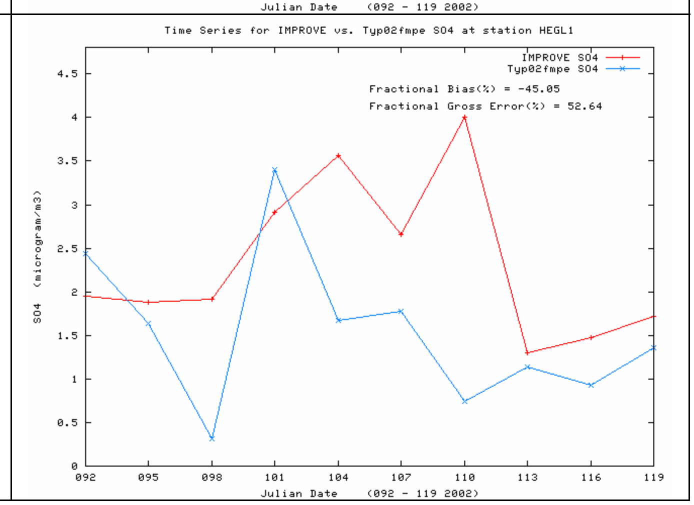

Time Series for IMPROVE vs. Typ02fmpe SO4 at station CACR1
IMPROVE SO4
Typ02fmpe SO4
Fractional Bias(%) = -39.13
Fractional Gross Error(%) = 58.77
SO4 (microgram/m3)
Julian Date (092 - 119 2002)


Time Series for IMPROVE vs. Typ02fmpe SO4 at station UPBU1
IMPROVE SO4
Typ02fmpe SO4
Fractional Bias(%) = -39.19
Fractional Gross Error(%) = 53.50
SO4 (microgram/m3)
Julian Date (092 - 119 2002)


Time Series for IMPROVE vs. Typ02fmpe SO4 at station BRET1
IMPROVE SO4
Typ02fmpe SO4
Fractional Bias(%) = -14.83
Fractional Gross Error(%) = 28.74
SO4 (microgram/m3)
Julian Date (092 - 119 2002)


Time Series for IMPROVE vs. Typ02fmpe SO4 at station BOWA1
IMPROVE SO4
Typ02fmpe SO4
Fractional Bias(%) = -28.70
Fractional Gross Error(%) = 28.70
SO4 (microgram/m3)
Julian Date (092 - 119 2002)


Time Series for IMPROVE vs. Typ02fmpe SO4 at station VOYA2
IMPROVE SO4
Typ02fmpe SO4
Fractional Bias(%) = -28.11
Fractional Gross Error(%) = 35.81
SO4 (microgram/m3)
Julian Date (092 - 119 2002)


Time Series for IMPROVE vs. Typ02fmpe SO4 at station HEGL1
IMPROVE SO4
Typ02fmpe SO4
Fractional Bias(%) = -45.05
Fractional Gross Error(%) = 52.64
SO4 (microgram/m3)
Julian Date (092 - 119 2002)

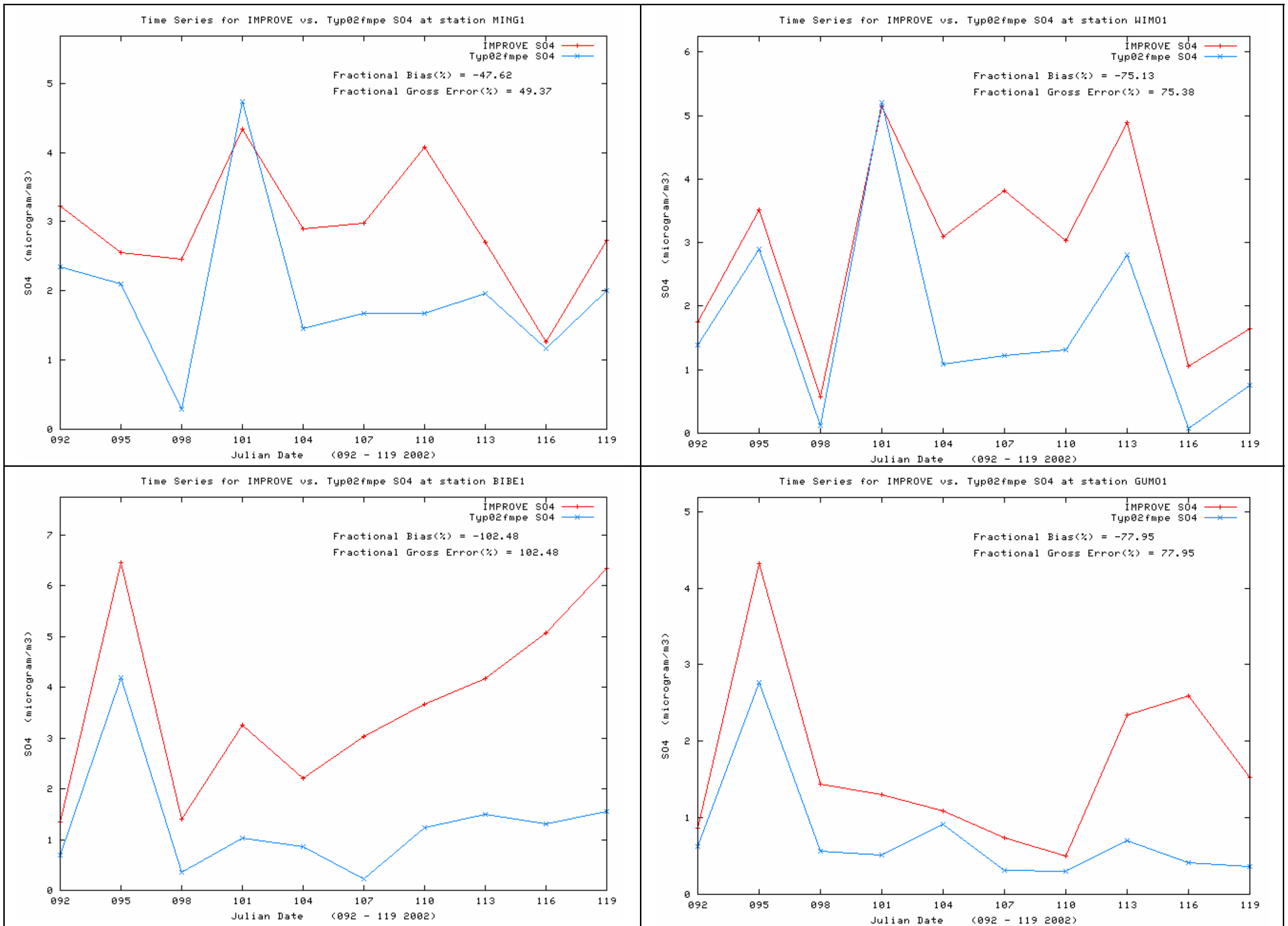


Figure C-5b. Time series of predicted and observed 24-hour sulfate (SO4) concentrations at CENRAP IMPROVE CLASS I AREA sites in April 2002 for CMAQ 2002 36 km Base F base case simulation.

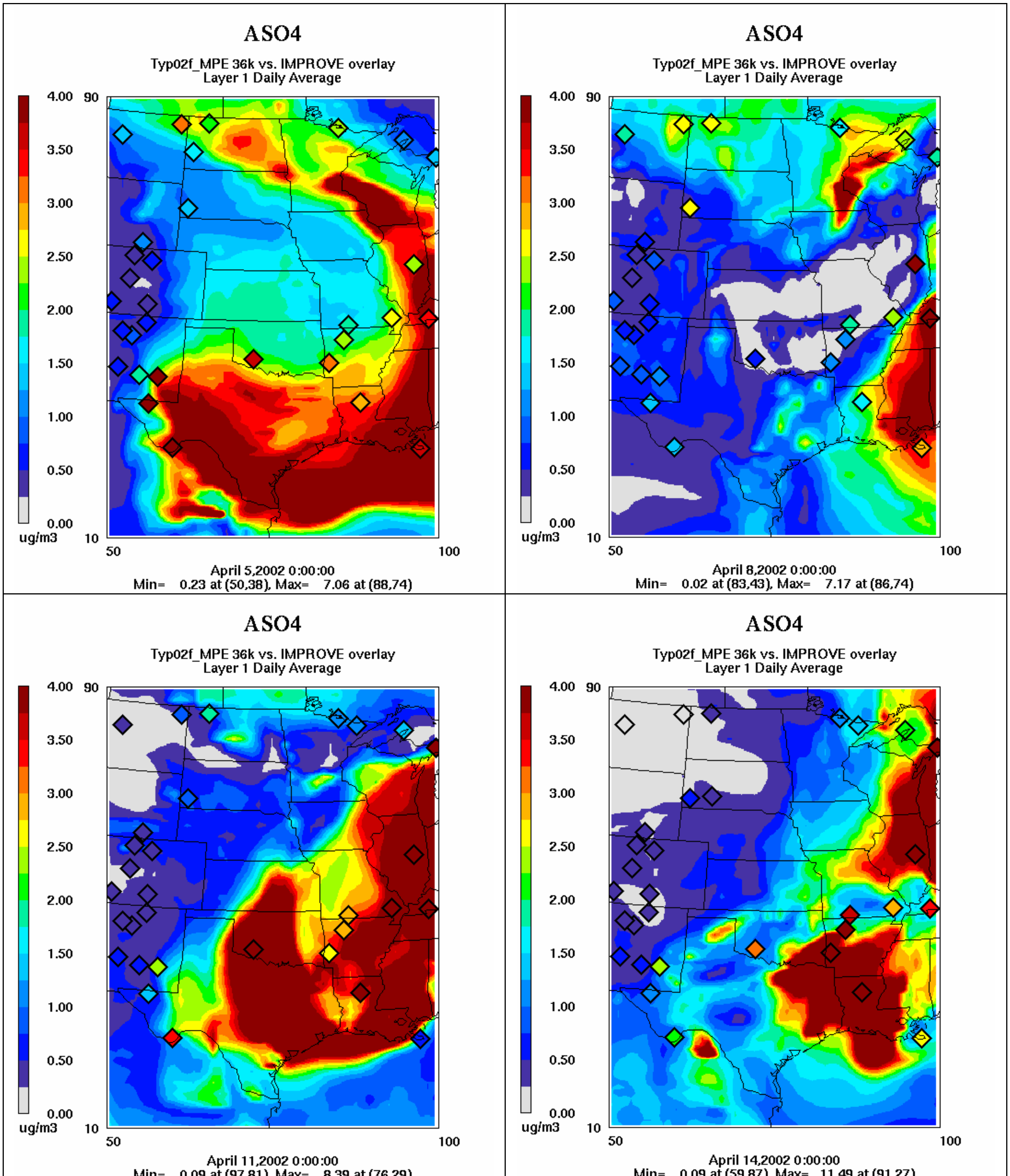


Figure C-5c. Spatial plot comparisons of the predicted and IMPROVE observed 24-hour SO4 concentrations for April 5, 8, 11 and 14, 2002.

C.3.1.3 SO4 in July 2002

SO4 concentrations are also underestimated by CMAQ in July (Figure C-6a) with fractional bias value ranging from -22 to -52%. Wet SO4 deposition is slightly overstated (22%) with a lot of scatter (83% error). The July SO4 under-prediction bias is also reflected in the time series plots (Figure C-6b). Comparisons of the predicted and observed spatial distribution of SO4 in the CENRAP region for July 7, 10, 13 and 16, 2002 are shown in Figure C-6c. In general the model and observations agree on the locations of the elevated SO4, except that the observed extent is somewhat larger so that the modeled elevated SO4 fails to impact some of the sites on the edge of the elevated cloud of SO4 (e.g., Big Bend, Guadalupe Mountains and northwestern Oklahoma).

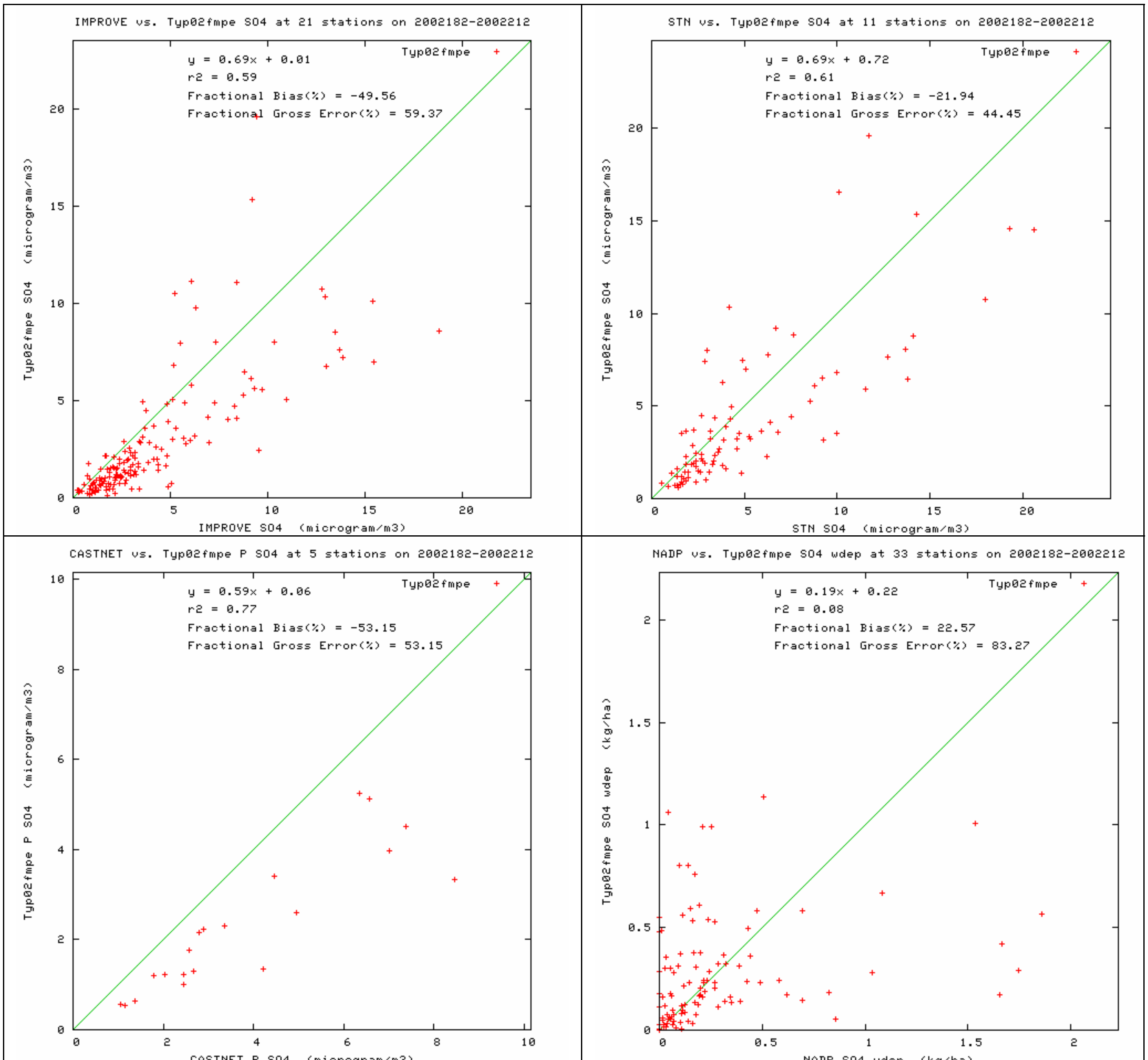
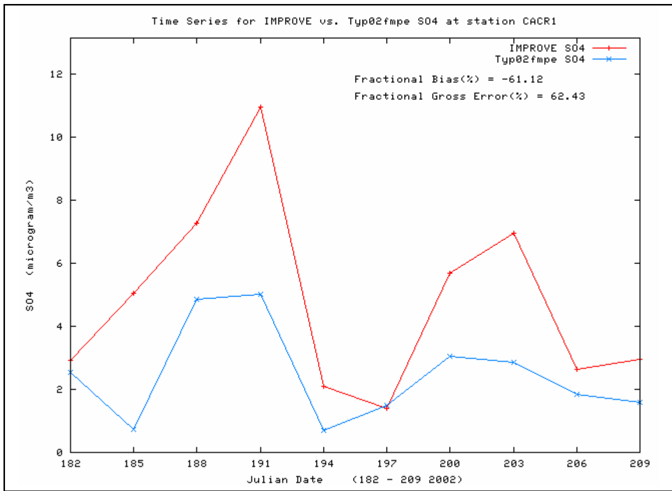
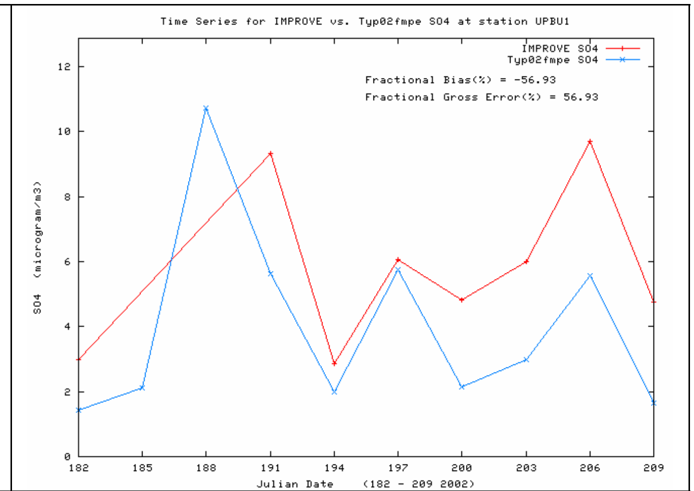
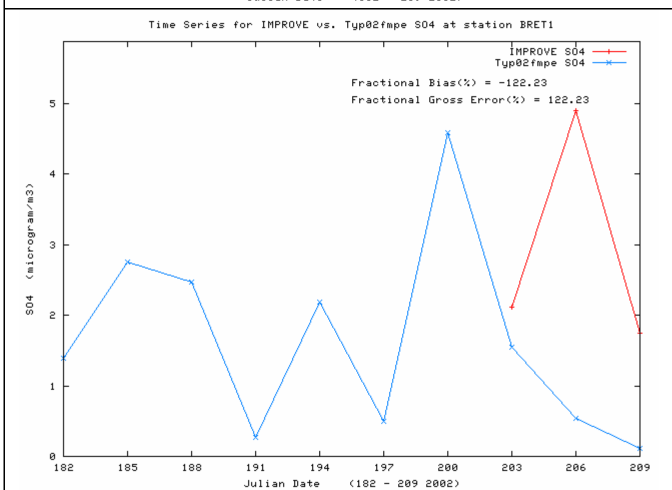
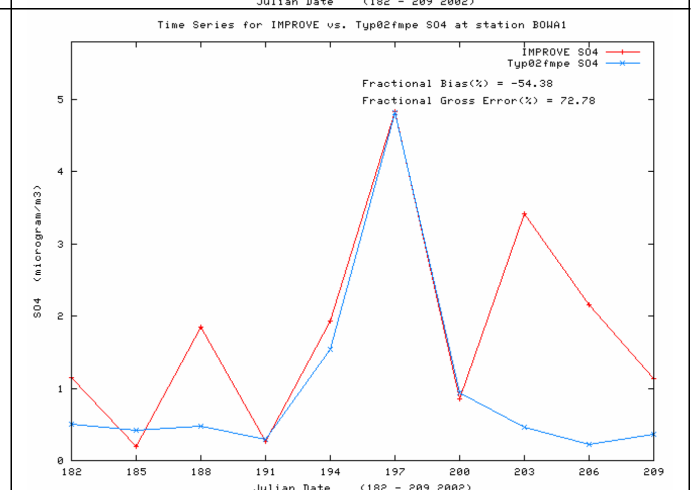


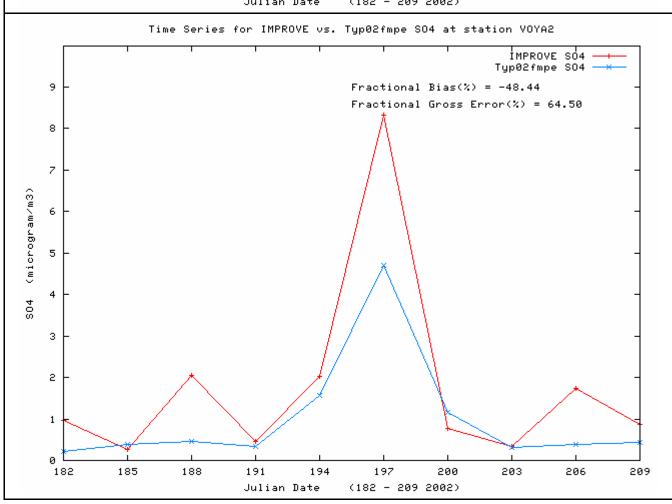
Figure C-6a. Scatter plots of predicted and observed sulfate (SO4) concentrations for July 2002 and sites in the CENRAP region using IMPROVE (top left), STN (top right), CASTNet (bottom left) and NADP monitoring networks using the CMAQ 2002 36 km Base F base case simulation.

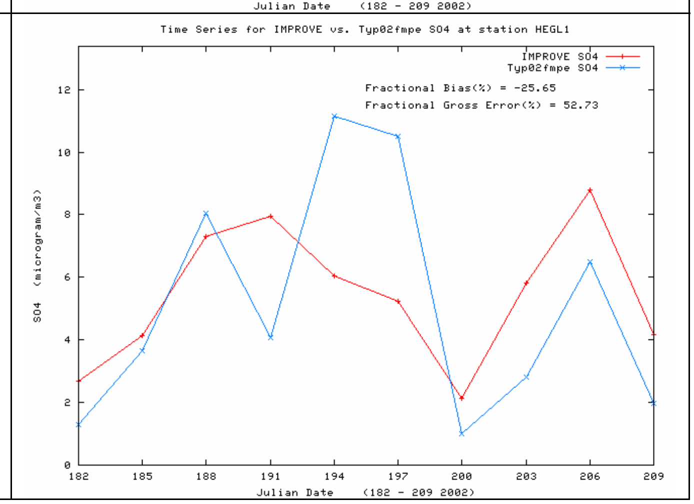

Time Series for IMPROVE vs. Typ02fmpe SO4 at station CACR1
IMPROVE SO4
Typ02fmpe SO4
Fractional Bias(%) = -61.12
Fractional Gross Error(%) = 62.43
SO4 (microgram/m3)
Julian Date (182 - 209 2002)


Time Series for IMPROVE vs. Typ02fmpe SO4 at station UPBU1
IMPROVE SO4
Typ02fmpe SO4
Fractional Bias(%) = -56.93
Fractional Gross Error(%) = 56.93
SO4 (microgram/m3)
Julian Date (182 - 209 2002)


Time Series for IMPROVE vs. Typ02fmpe SO4 at station BRET1
IMPROVE SO4
Typ02fmpe SO4
Fractional Bias(%) = -122.23
Fractional Gross Error(%) = 122.23
SO4 (microgram/m3)
Julian Date (182 - 209 2002)


Time Series for IMPROVE vs. Typ02fmpe SO4 at station BOWA1
IMPROVE SO4
Typ02fmpe SO4
Fractional Bias(%) = -54.38
Fractional Gross Error(%) = 72.78
SO4 (microgram/m3)
Julian Date (182 - 209 2002)


Time Series for IMPROVE vs. Typ02fmpe SO4 at station VOYA2
IMPROVE SO4
Typ02fmpe SO4
Fractional Bias(%) = -48.44
Fractional Gross Error(%) = 64.50
SO4 (microgram/m3)
Julian Date (182 - 209 2002)


Time Series for IMPROVE vs. Typ02fmpe SO4 at station HEGL1
IMPROVE SO4
Typ02fmpe SO4
Fractional Bias(%) = -25.65
Fractional Gross Error(%) = 52.73
SO4 (microgram/m3)
Julian Date (182 - 209 2002)

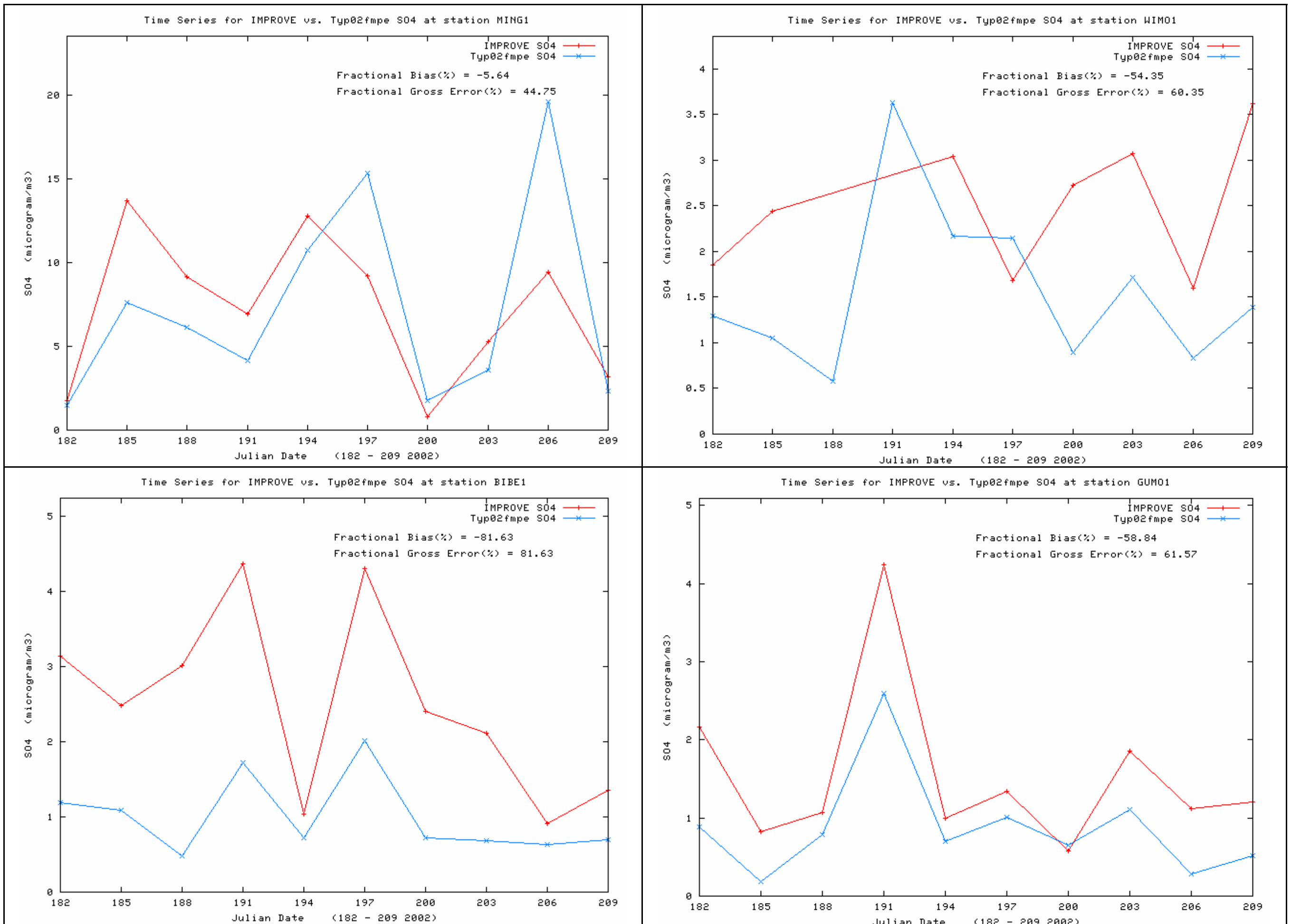


Figure C-6b. Time series of predicted and observed 24-hour sulfate (SO4) concentrations at CENRAP IMPROVE CLASS I AREA sites in July 2002 for CMAQ 2002 36 km Base F base case simulation.

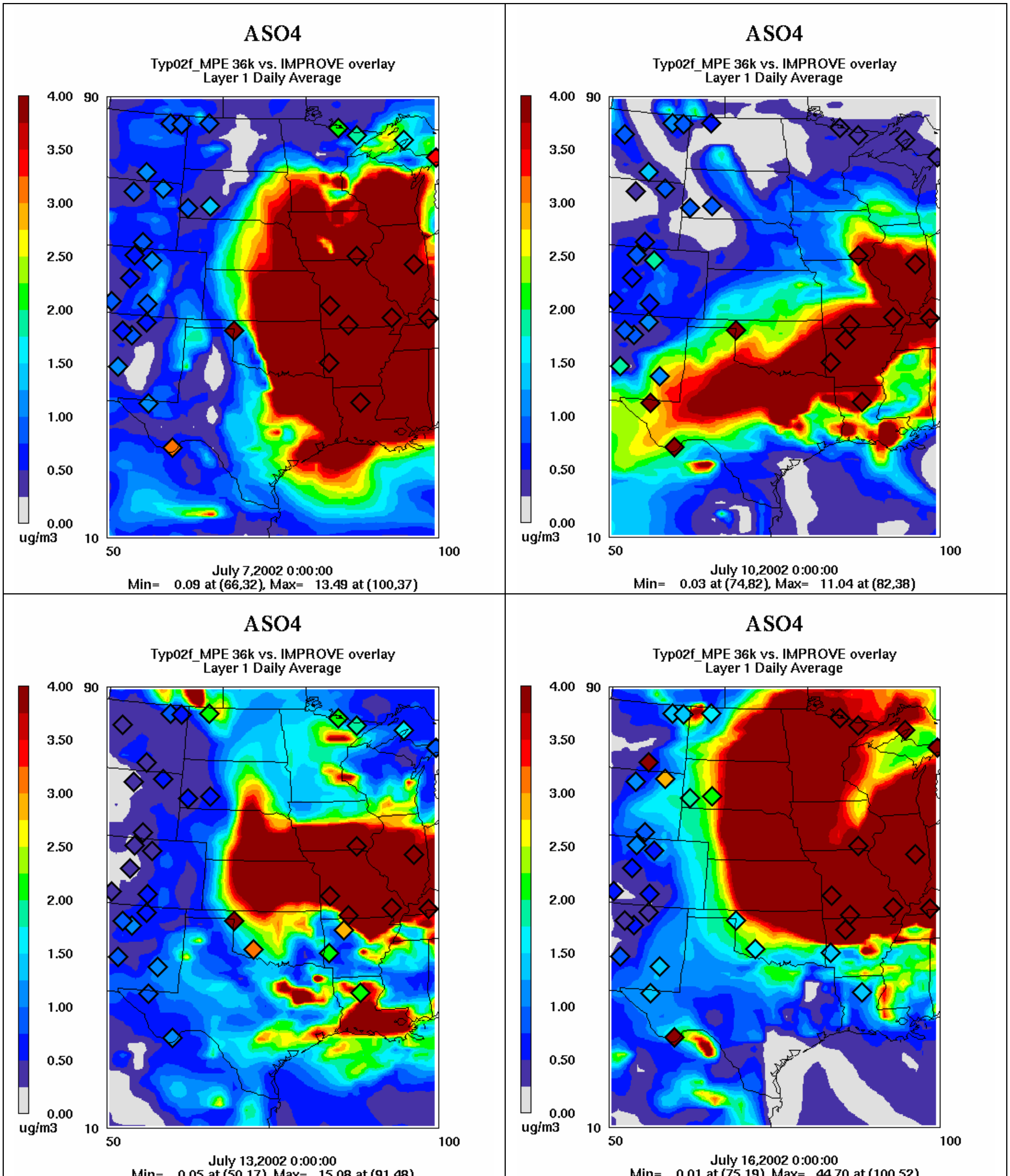


Figure C-6c. Spatial plot comparisons of the predicted and IMPROVE observed 24-hour SO4 concentrations for July 7, 10, 13 and 16, 2002.

C.3.1.4 SO4 in October 2002

In October 2002, CMAQ is doing a better job of reproducing the observed SO4 concentrations with much lower fractional bias values (-6%, 0% and -23%) and fractional errors < 40% (Figure C-7a). The observed SO4 time series are also reproduced well by the model, although an under-prediction bias is clearly evident at Big Bend, Guadalupe Mountains and Wichita Mountains. The model also reproduces the observed spatial distribution of SO4 well in October (Figure C-7c).

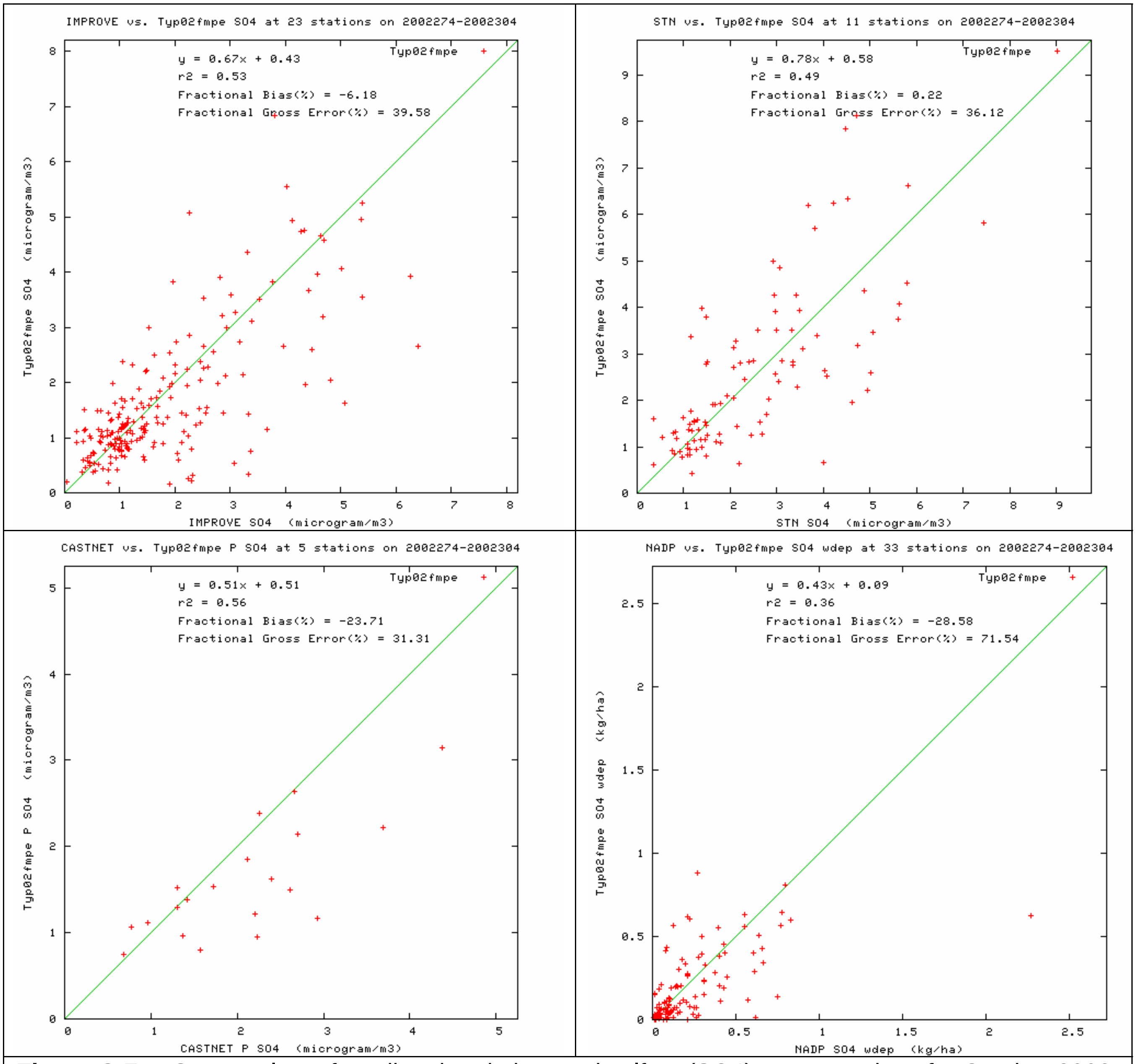
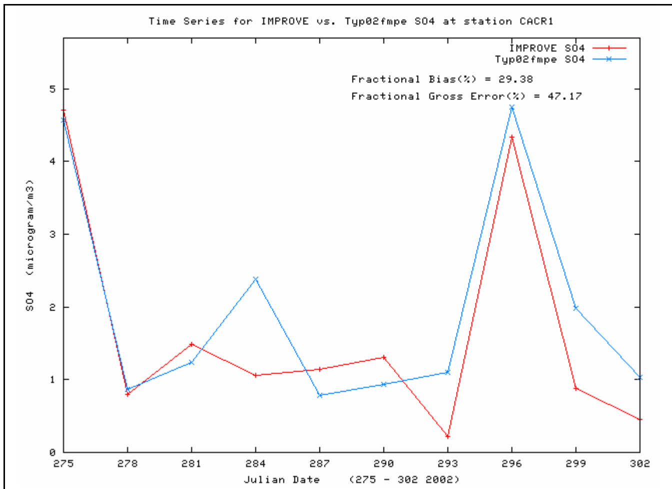
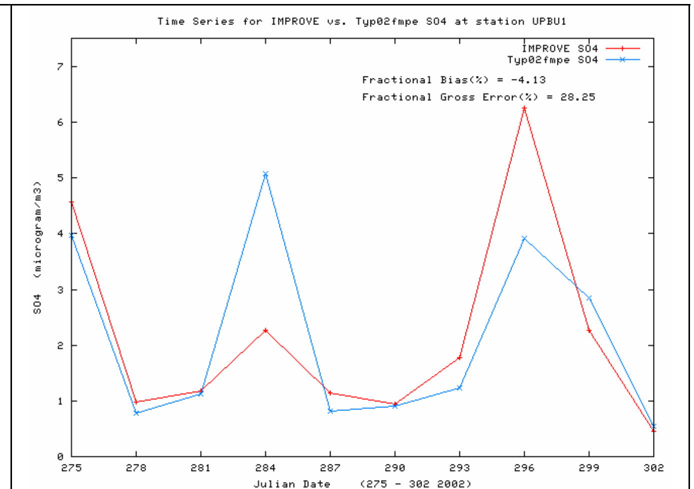
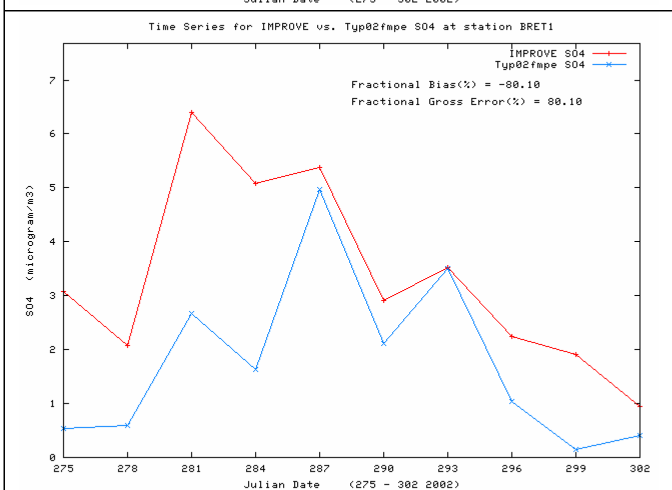
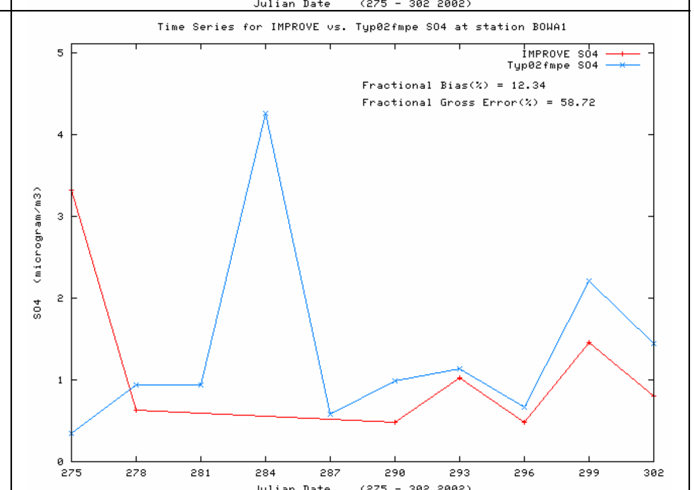


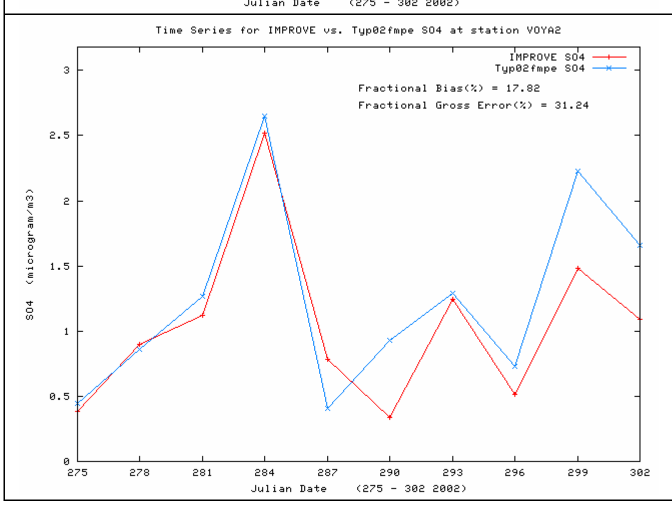
Figure C-7a. Scatter plots of predicted and observed sulfate (SO4) concentrations for October 2002 and sites in the CENRAP region using IMPROVE (top left), STN (top right), CASTNet (bottom left) and NADP monitoring networks using the CMAQ 2002 36 km Base F base case simulation.

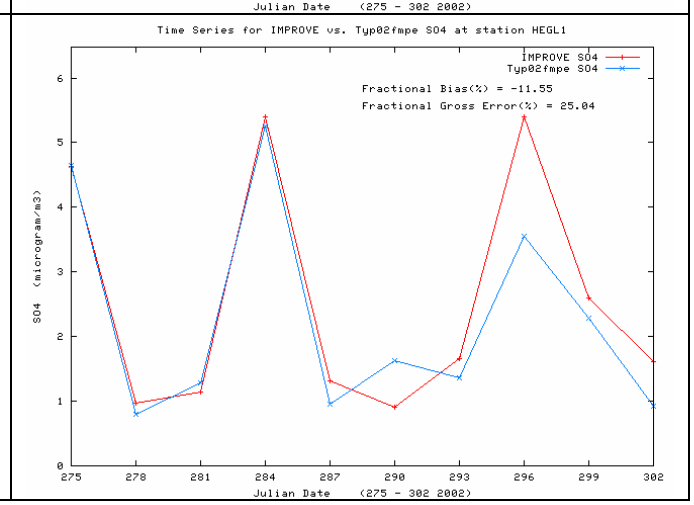

Time Series for IMPROVE vs. Typ02fmpe SO4 at station CACR1
IMPROVE SO4
Typ02fmpe SO4
Fractional Bias(%) = 29.38
Fractional Gross Error(%) = 47.17
SO4 (microgram/m3)
Julian Date (275 - 302 2002)


Time Series for IMPROVE vs. Typ02fmpe SO4 at station UPBU1
IMPROVE SO4
Typ02fmpe SO4
Fractional Bias(%) = -4.13
Fractional Gross Error(%) = 28.25
SO4 (microgram/m3)
Julian Date (275 - 302 2002)


Time Series for IMPROVE vs. Typ02fmpe SO4 at station BRET1
IMPROVE SO4
Typ02fmpe SO4
Fractional Bias(%) = -80.10
Fractional Gross Error(%) = 80.10
SO4 (microgram/m3)
Julian Date (275 - 302 2002)


Time Series for IMPROVE vs. Typ02fmpe SO4 at station BOWA1
IMPROVE SO4
Typ02fmpe SO4
Fractional Bias(%) = 12.34
Fractional Gross Error(%) = 58.72
SO4 (microgram/m3)
Julian Date (275 - 302 2002)


Time Series for IMPROVE vs. Typ02fmpe SO4 at station VOYA2
IMPROVE SO4
Typ02fmpe SO4
Fractional Bias(%) = 17.82
Fractional Gross Error(%) = 31.24
SO4 (microgram/m3)
Julian Date (275 - 302 2002)


Time Series for IMPROVE vs. Typ02fmpe SO4 at station HEGL1
IMPROVE SO4
Typ02fmpe SO4
Fractional Bias(%) = -11.55
Fractional Gross Error(%) = 25.04
SO4 (microgram/m3)
Julian Date (275 - 302 2002)

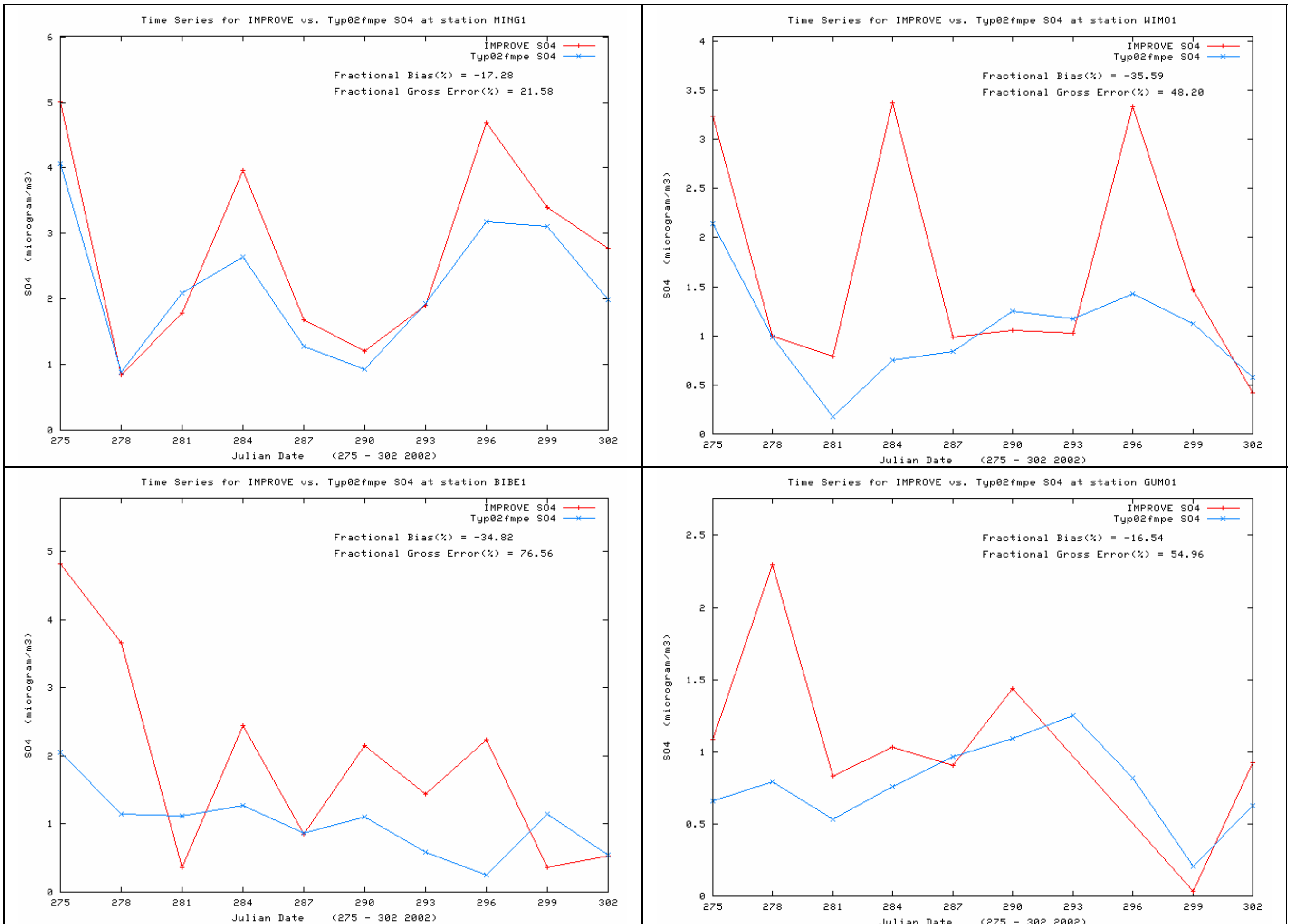


Figure C-7b. Time series of predicted and observed 24-hour sulfate (SO4) concentrations at CENRAP IMPROVE CLASS I AREA sites in October 2002 for CMAQ 2002 36 km Base F base case simulation.

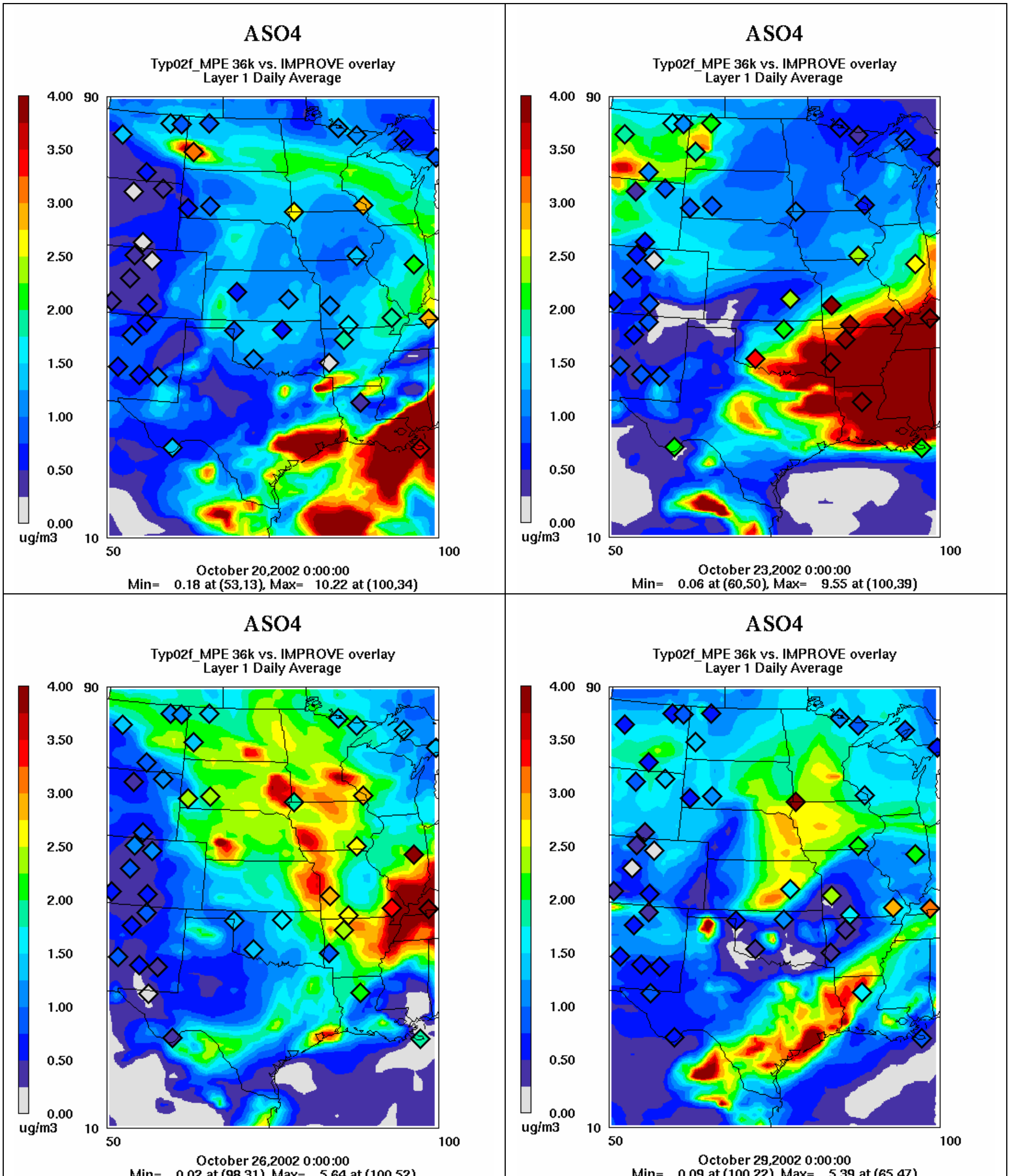


Figure C-7c. Spatial plot comparisons of the predicted and IMPROVE observed 24-hour SO4 concentrations for October 20, 23, 26 and 29, 2002.

C.3.1.5 SO4 Monthly Bias and Error

Figure C-8 compares the monthly SO4 fractional bias and error across the CENRAP region for the three monitoring networks. The under-prediction bias is clearly evident the first 8-10 months of the year. This underestimation bias is greatest across the CASTNet network which persists through out the year and is least for the STN network where it disappears by August-September. The monthly SO4 fractional errors are generally between 30% and 60% and are greatest in the summer when SO4 concentrations are the highest.

Figure C-9 presents a Bugle Plot of monthly So4 fractional bias and error statistics and compares them against the proposed PM model performance goal and criteria (see Table C-3). For the STN network, it appears that SO4 performance for all months achieves the proposed PM model performance goal. For the IMPROVE network, approximately half of the months achieve the proposed PM performance goal with the other half exceed the goal but within the performance criteria. Across the CASTNet network most months exceed the proposed goal and are within the criteria. Although the CASTNet fractional bias for some months is right at the criteria (≤±60%). With the exception of two IMPROVE months, all of the monthly SO4 fractional error performance statistics achieve the proposed PM model performance goal.

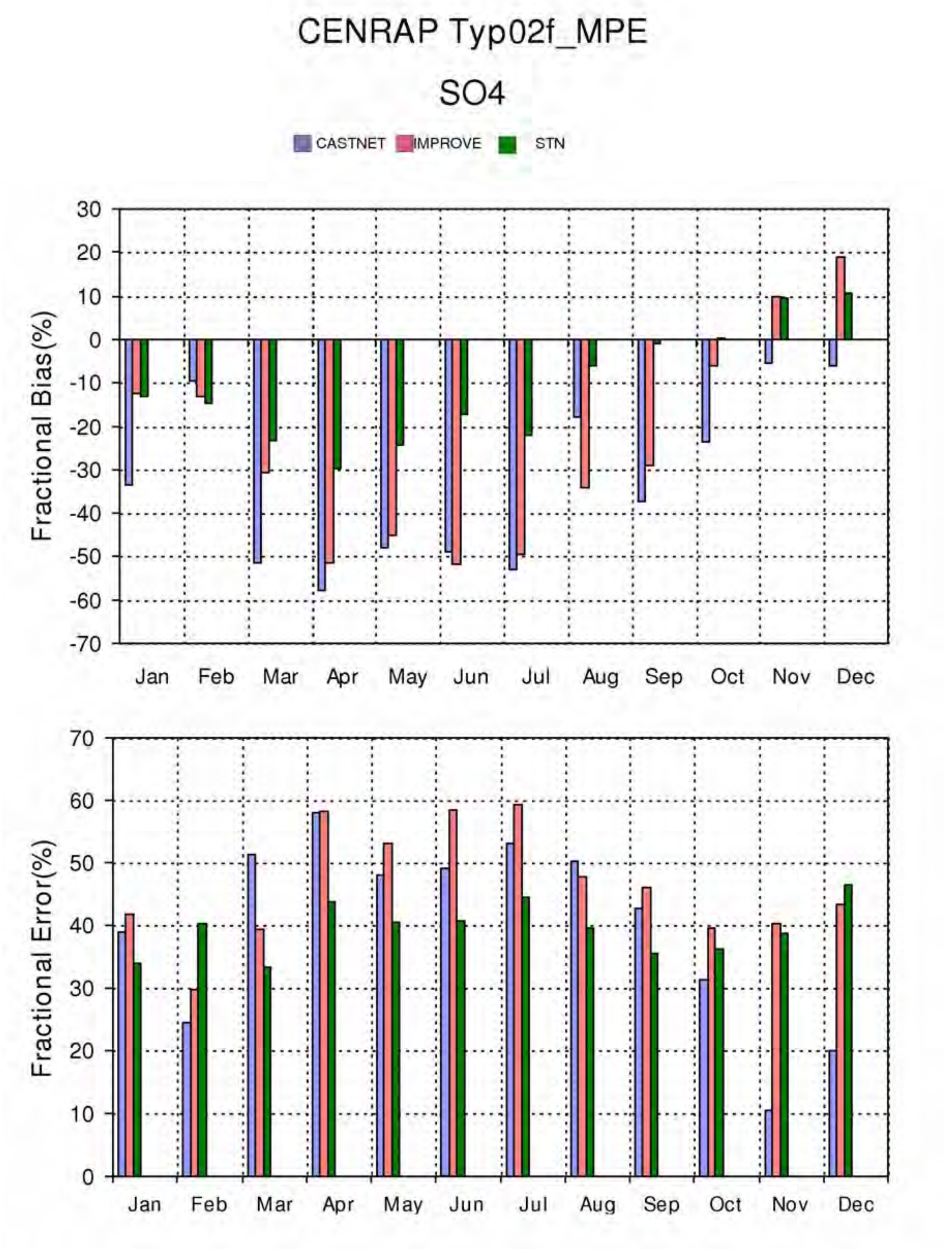


Figure C-8. Monthly SO4 fractional bias (top) and fractional gross error (bottom) statistical measures for IMPROVE, STN and CASTNet monitoring sites in the CENRAP region.

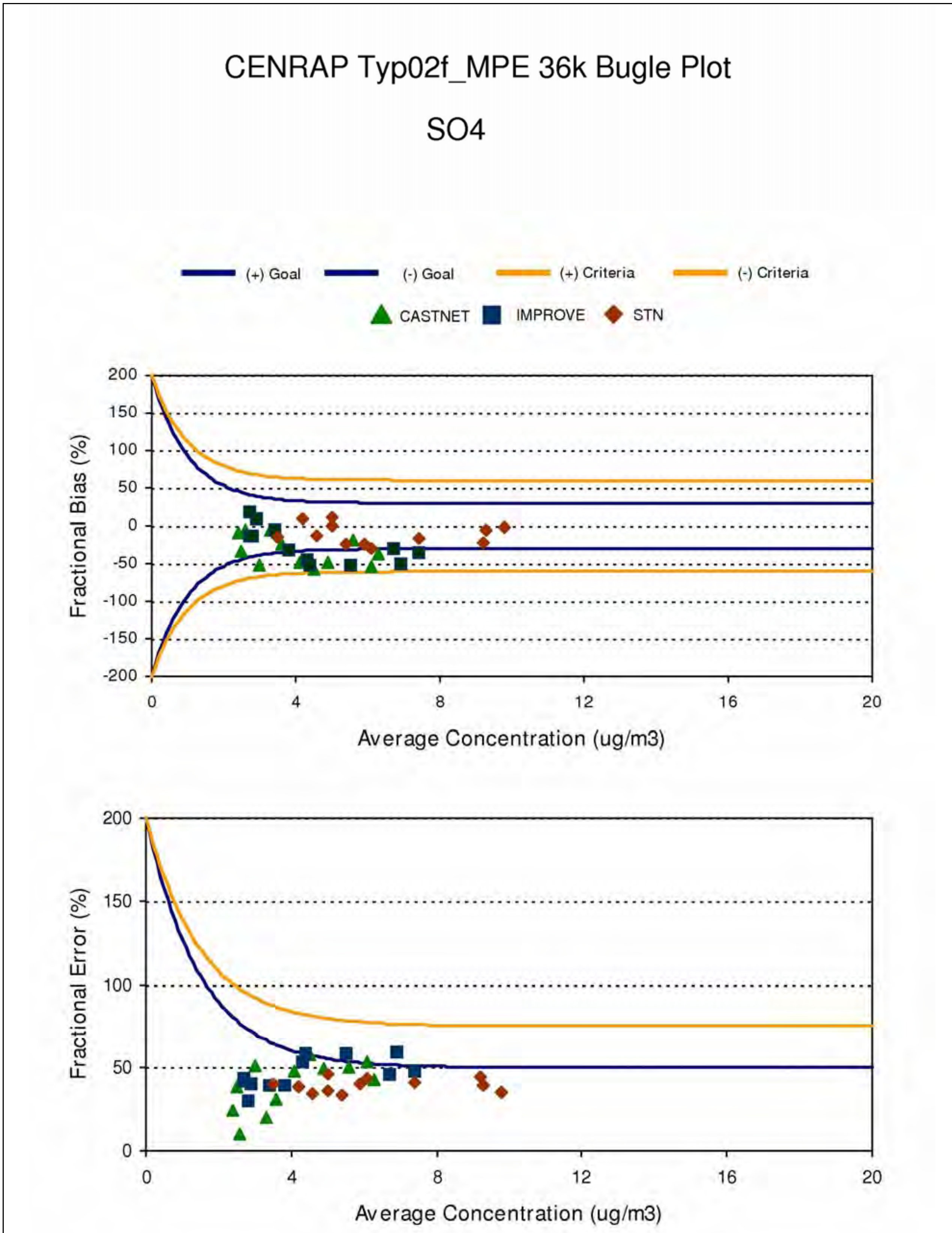


Figure C-9. Bugle Plots of monthly fractional bias (top) and fractional gross error (bottom) and comparisons with model performance goals and criteria for SO4 and IMPROVE, STN and CASTNet monitoring sites in the CENRAP region.

C.3.2 Nitrate (NO3) Monthly Model Performance

The following sections discuss the monthly NO3 model performance across the IMPROVE, STN and CASTNet monitoring networks in the CENRAP region.

C.3.2.1 NO3 in January 2002

January NO3 CMAQ model performance is characterized by an overestimation bias across the CENRAP region (Figure C-10a). The fractional bias values for the IMPROVE, STN and CASTNet networks are 38%, 29% and 61%. Unlike SO4, wet deposition of NO3 is also overstated in January (43%). Fractional errors range from 90%-100% for the IMPROVE and CASTNet networks and are lower (54%) for the STN network and higher (114%) for the NADP network.

With the exception of Breton Island and Big Bend, the model NO3 over-prediction bias occurs at the other 8 CENRAP Class I areas (Figure C-10b). The observed time series is reproduced reasonable well at a couple sites, such as Wichita Mountains and the first half of January for Voyageurs. However, for most sites the observed NO3 time series is not reproduced very well and is extremely poorly reproduced for Breton Island, Big Bend and Guadalupe Mountains.

The model typically estimates a larger area of elevated NO3 concentrations than is observed. This is shown for January 20, 23, 26 and 29 in Figure C-10c. Whereas the model exhibits large areas of brown indicated daily average NO3 concentrations of 4 $\mu g/m^3$ or higher, the observed values of this high rarely occur and are usually limited to the central Illinois site. On January 20 the model estimates the entire eastern half of the CENRAP region should be covered by elevated NO3 concentrations, whereas the observations indicate much lower values. On January 23 the modeled elevated NO3 concentrations lies between the IMPROVE monitoring sites, although the central Illinois site suggests high NO3 did occur in the region. The observations on January 26 also suggest lower NO3 than the model is predicting. On January 29 the model estimates elevated NO3 from the central Illinois site to Wichita Mountains, Oklahoma that is supported by these two observations. In general, the model is estimating more wide-spread elevated NO3 concentrations than observed, whereas the observations suggest that the elevated NO3 occurrences is less frequent and more spotty.

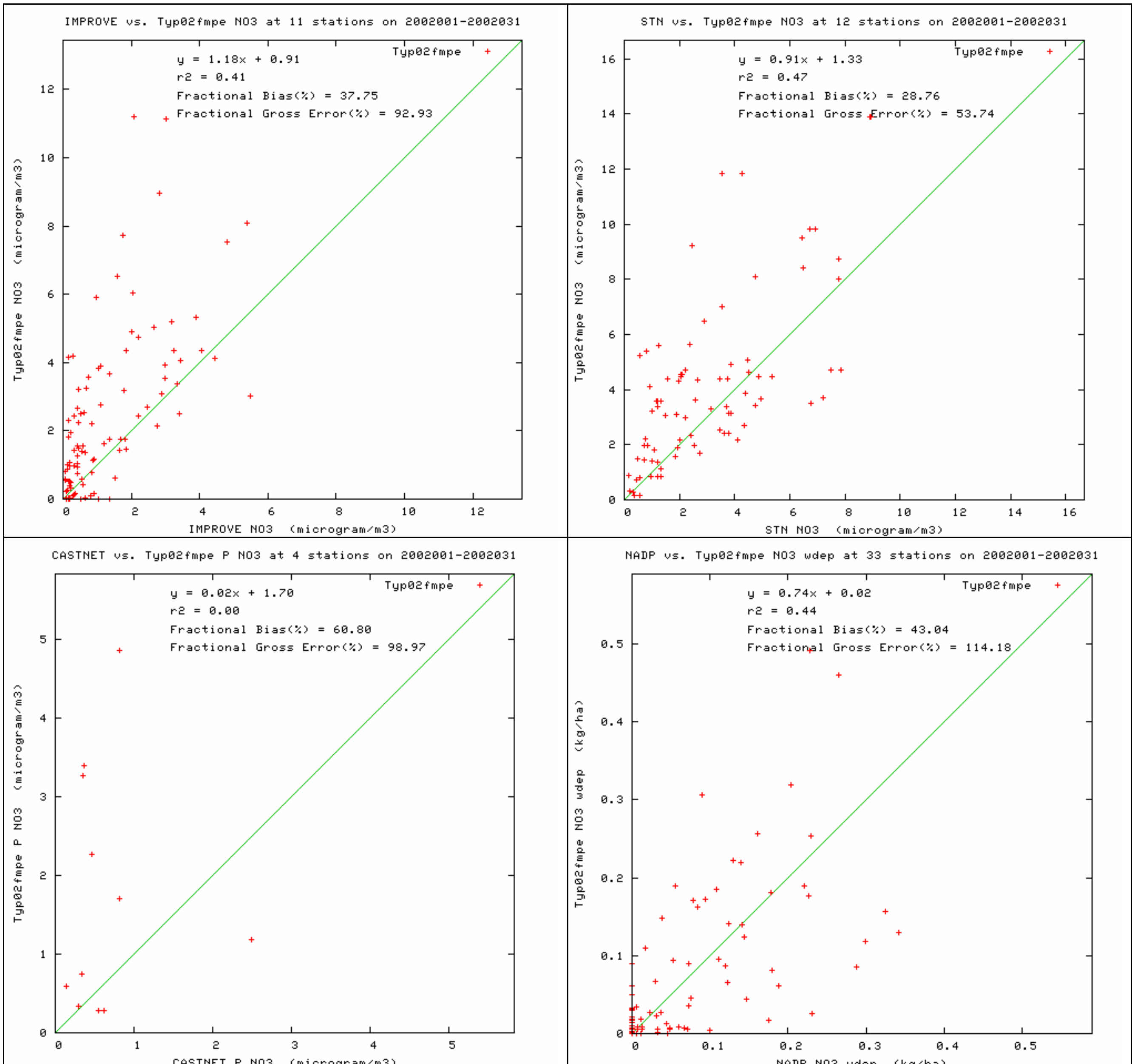
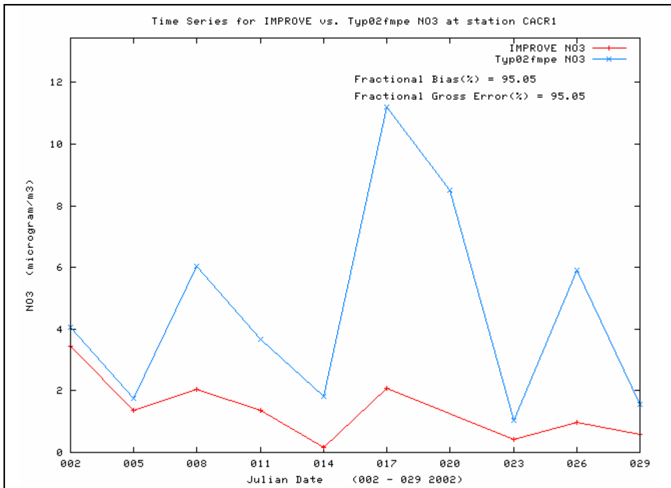
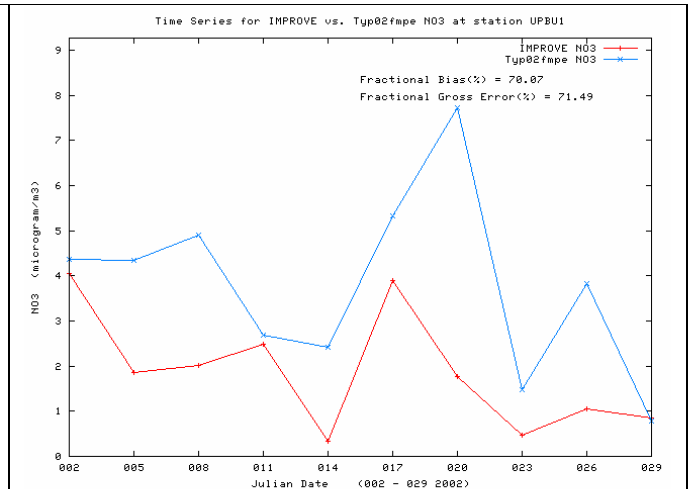
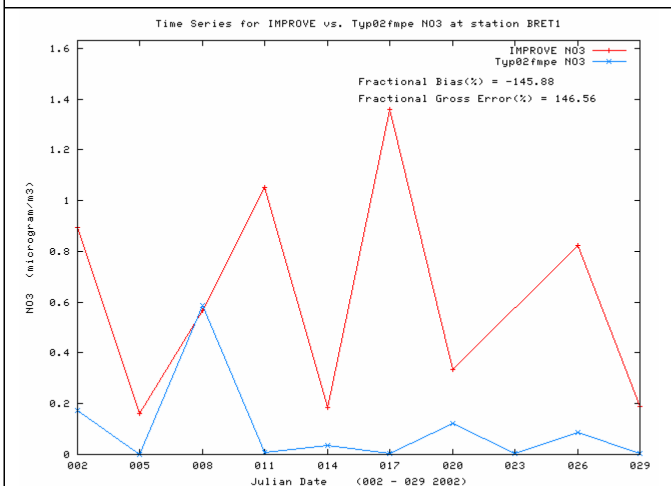
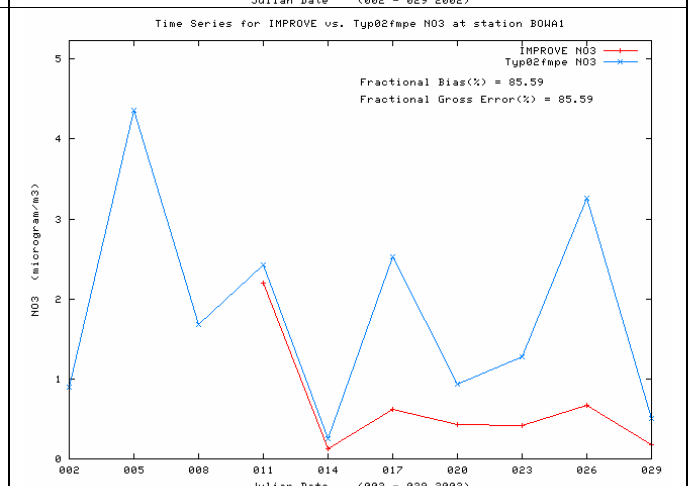


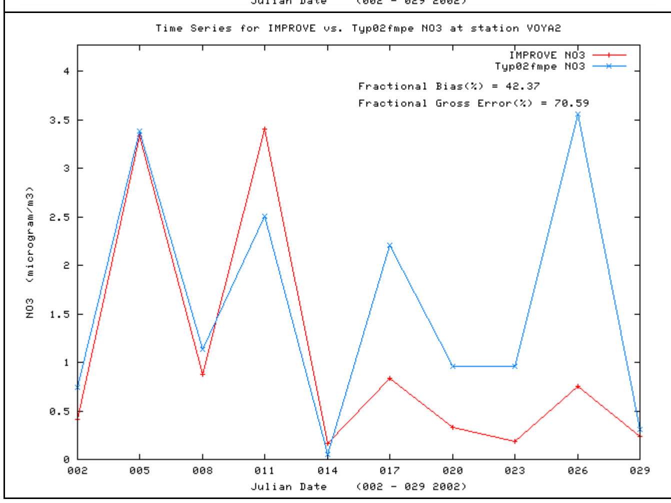
Figure C-10a. Scatter plots of predicted and observed nitrate (NO3) concentrations for January 2002 and sites in the CENRAP region using IMPROVE (top left), STN (top right), CASTNet (bottom left) and NADP monitoring networks using the CMAQ 2002 36 km Base F base case simulation.

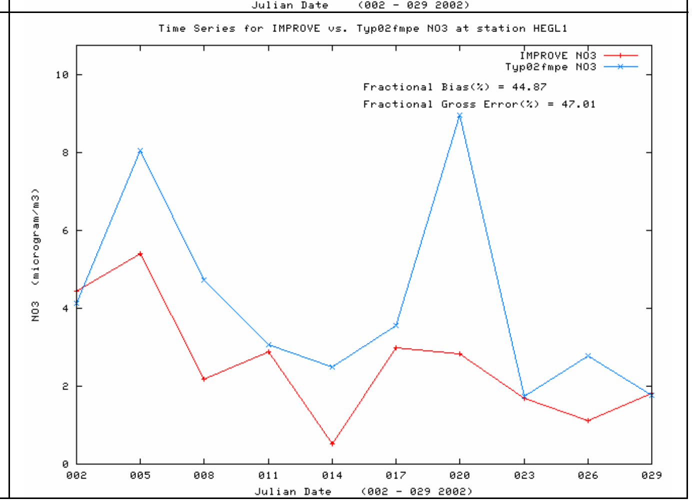

Time Series for IMPROVE vs. Typ02fmpe NO3 at station CACR1
IMPROVE NO3
Typ02fmpe NO3
Fractional Bias(%) = 95.05
Fractional Gross Error(%) = 95.05
NO3 (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe NO3 at station UPBU1
IMPROVE NO3
Typ02fmpe NO3
Fractional Bias(%) = 70.07
Fractional Gross Error(%) = 71.49
NO3 (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe NO3 at station BRET1
IMPROVE NO3
Typ02fmpe NO3
Fractional Bias(%) = -145.88
Fractional Gross Error(%) = 146.56
NO3 (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe NO3 at station BOWA1
IMPROVE NO3
Typ02fmpe NO3
Fractional Bias(%) = 85.59
Fractional Gross Error(%) = 85.59
NO3 (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe NO3 at station VOYA2
IMPROVE NO3
Typ02fmpe NO3
Fractional Bias(%) = 42.37
Fractional Gross Error(%) = 70.59
NO3 (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe NO3 at station HEGL1
IMPROVE NO3
Typ02fmpe NO3
Fractional Bias(%) = 44.87
Fractional Gross Error(%) = 47.01
NO3 (microgram/m3)
Julian Date (002 - 029 2002)

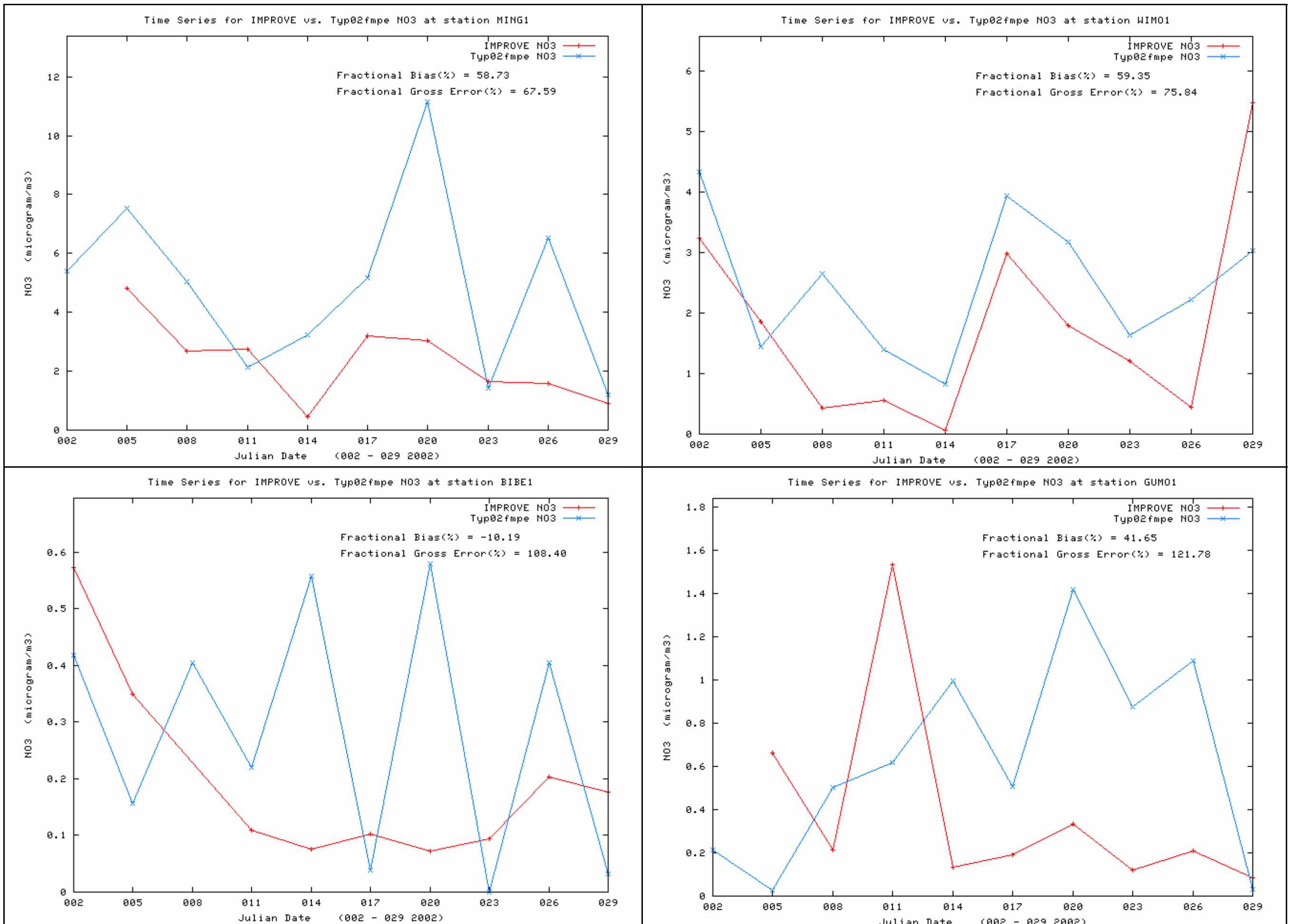


Figure C-10b. Time series of predicted and observed 24-hour nitrate (NO3) concentrations at CENRAP IMPROVE CLASS I AREA sites in January 2002 for CMAQ 2002 36 km Base F base case simulation.

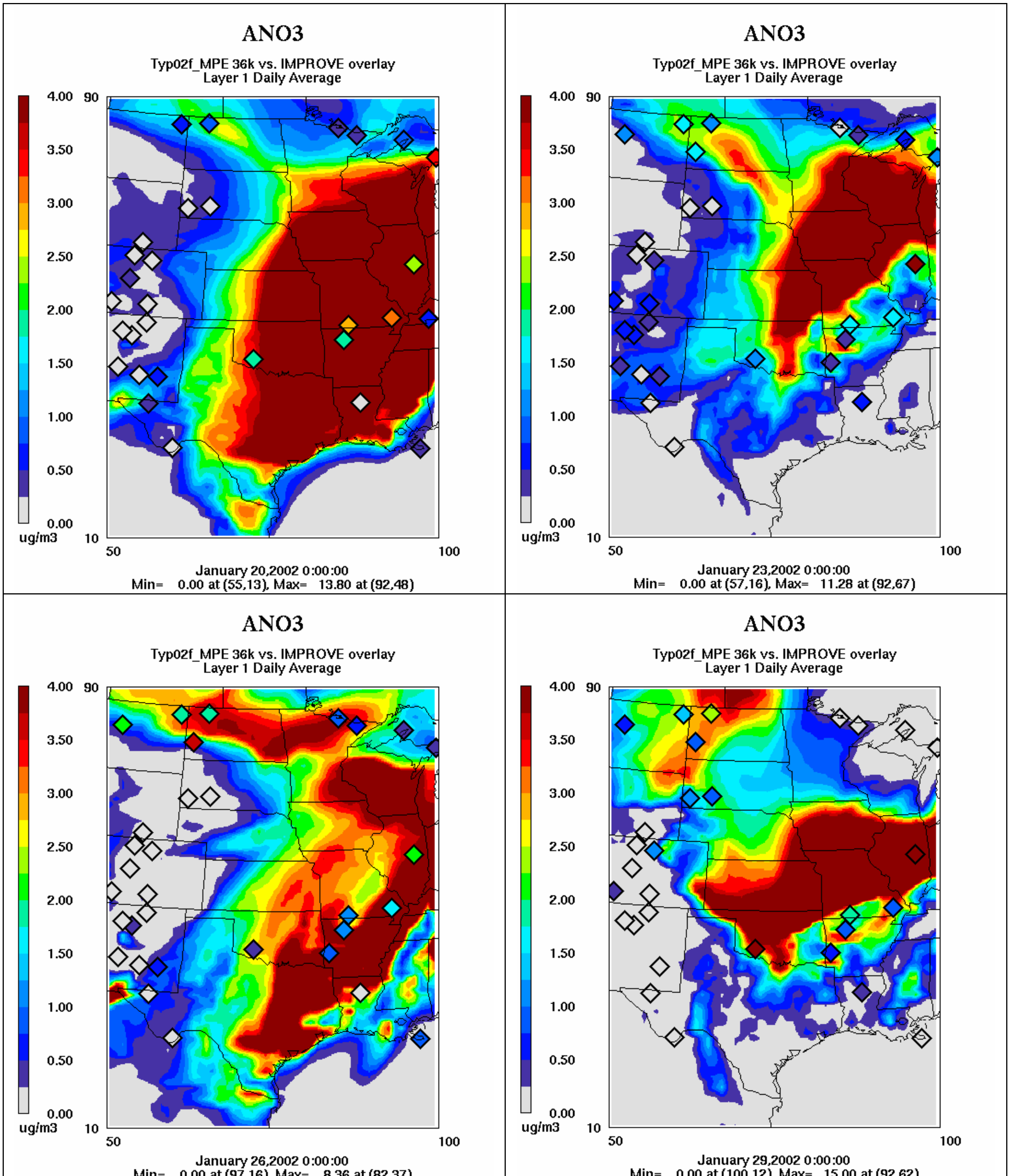


Figure C-10c. Spatial plot comparisons of the predicted and IMPROVE observed 24-hour NO3 concentrations for January 20, 23, 26 and 29, 2002.

C.3.2.2 NO3 in April 2002

Unlike the NO3 overestimation bias of January, the April NO3 performance is characterized by an underestimation bias (Figure C-11a). This under-prediction bias appears to be driven by near zero model predictions when the observed values are small (< 1 μg/m^3), but positive. This effect is especially noticeable in the NO3 time series (Figure C-11b) where at several sites the modeled NO3 concentrations foes to zero (e.g., BRET, BIBE, GUMO), whereas the observed values has an approximately 0.2 μg/m3 floor. The spatial maps suggest that the large April NO3 under-prediction bias indicated by the performance statistics is not as bad as they suggest (Figure C-11c). Mostly the model is predicting low NO3 values where low values are observed, just that the model approaches zero which results in a large relative difference with the observe values.

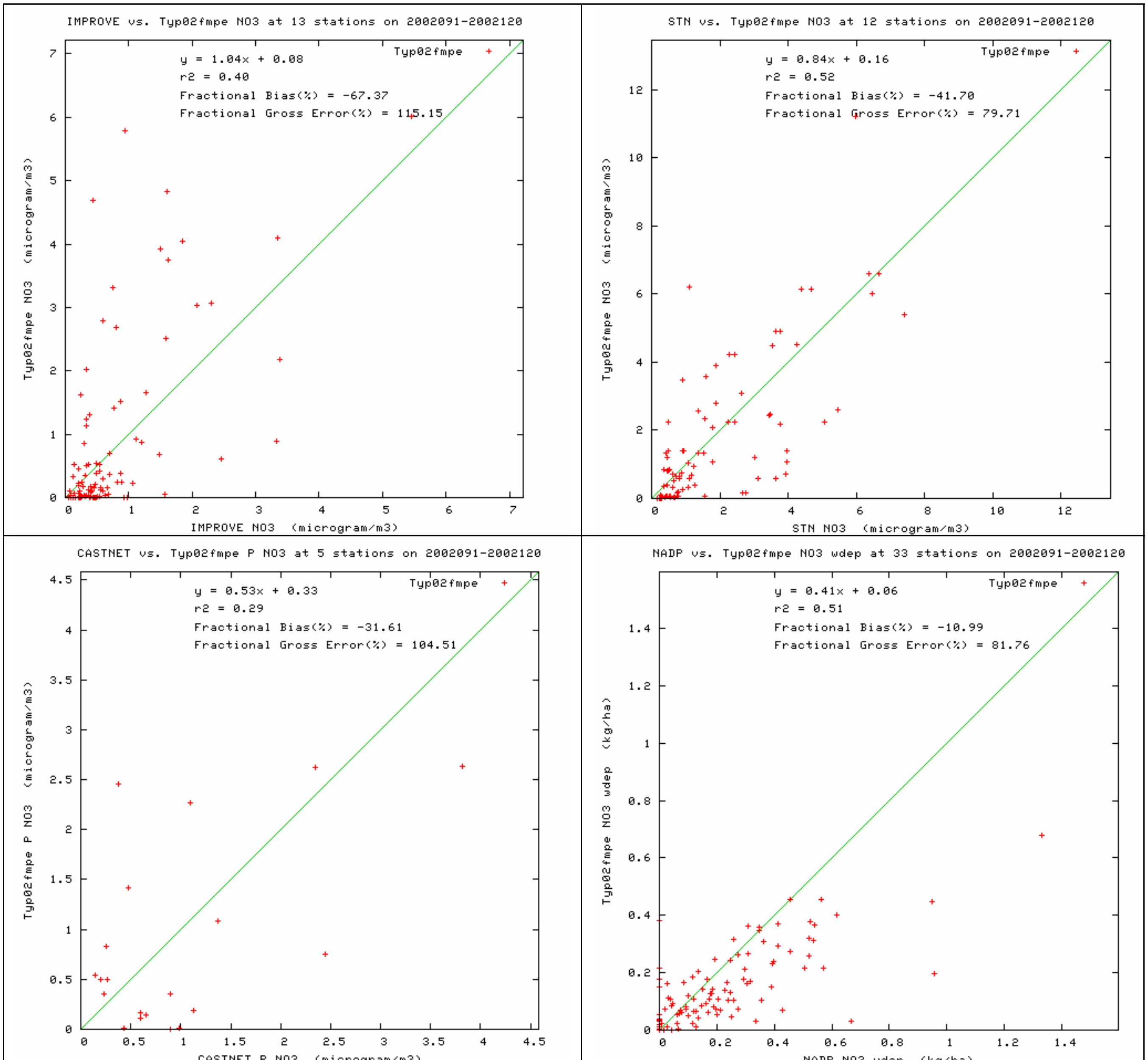
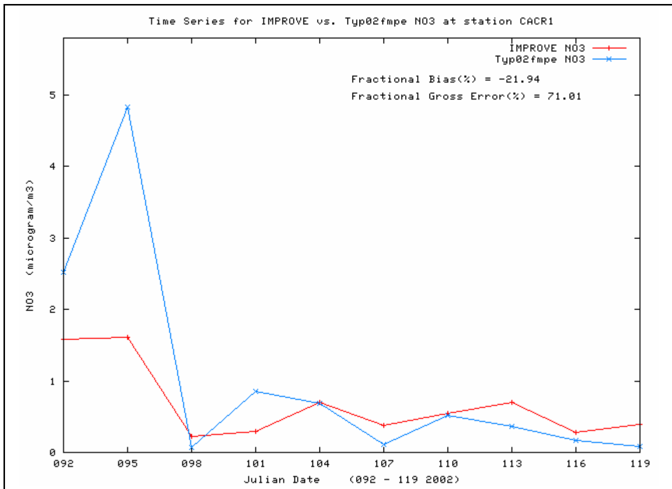
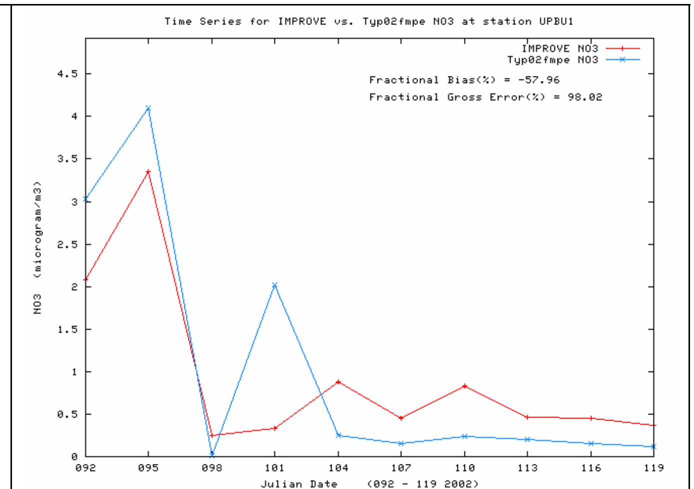
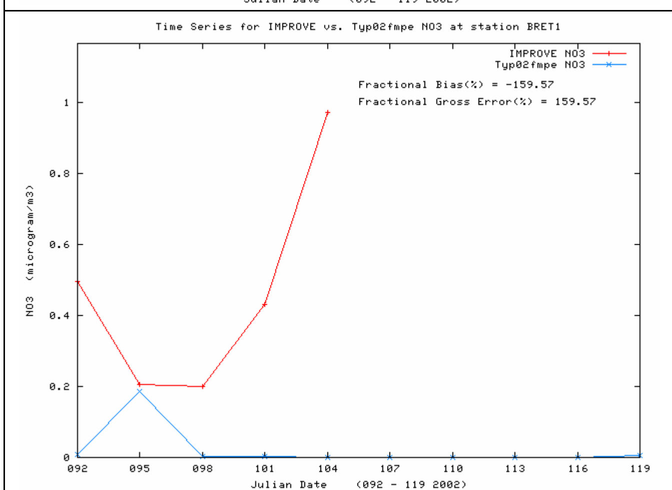
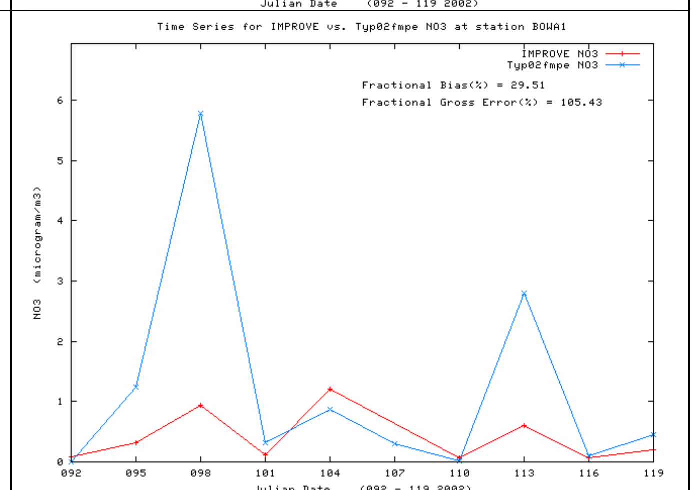


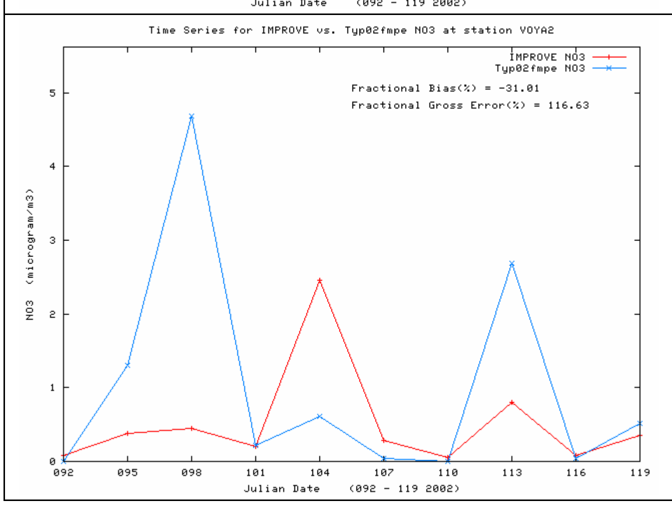
Figure C-11a. Scatter plots of predicted and observed nitrate (NO3) concentrations for April 2002 and sites in the CENRAP region using IMPROVE (top left), STN (top right), CASTNet (bottom left) and NADP monitoring networks using the CMAQ 2002 36 km Base F base case simulation.

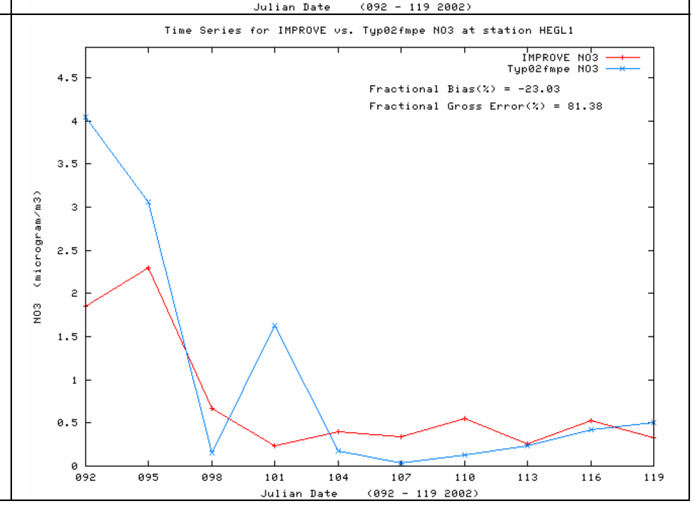

Time Series for IMPROVE vs. Typ02fmpe NO3 at station CACR1
IMPROVE NO3
Typ02fmpe NO3
Fractional Bias(%) = -21.94
Fractional Gross Error(%) = 71.01
NO3 (microgram/m3)
092 095 098 101 104 107 110 113 116 119
Julian Date (092 - 119 2002)


Time Series for IMPROVE vs. Typ02fmpe NO3 at station UPBU1
IMPROVE NO3
Typ02fmpe NO3
Fractional Bias(%) = -57.96
Fractional Gross Error(%) = 98.02
NO3 (microgram/m3)
092 095 098 101 104 107 110 113 116 119
Julian Date (092 - 119 2002)


Time Series for IMPROVE vs. Typ02fmpe NO3 at station BRET1
IMPROVE NO3
Typ02fmpe NO3
Fractional Bias(%) = -159.57
Fractional Gross Error(%) = 159.57
NO3 (microgram/m3)
092 095 098 101 104 107 110 113 116 119
Julian Date (092 - 119 2002)


Time Series for IMPROVE vs. Typ02fmpe NO3 at station BOWA1
IMPROVE NO3
Typ02fmpe NO3
Fractional Bias(%) = 29.51
Fractional Gross Error(%) = 105.43
NO3 (microgram/m3)
092 095 098 101 104 107 110 113 116 119
Julian Date (092 - 119 2002)


Time Series for IMPROVE vs. Typ02fmpe NO3 at station VOYA2
IMPROVE NO3
Typ02fmpe NO3
Fractional Bias(%) = -31.01
Fractional Gross Error(%) = 116.63
NO3 (microgram/m3)
092 095 098 101 104 107 110 113 116 119
Julian Date (092 - 119 2002)


Time Series for IMPROVE vs. Typ02fmpe NO3 at station HEGL1
IMPROVE NO3
Typ02fmpe NO3
Fractional Bias(%) = -23.03
Fractional Gross Error(%) = 81.38
NO3 (microgram/m3)
092 095 098 101 104 107 110 113 116 119
Julian Date (092 - 119 2002)

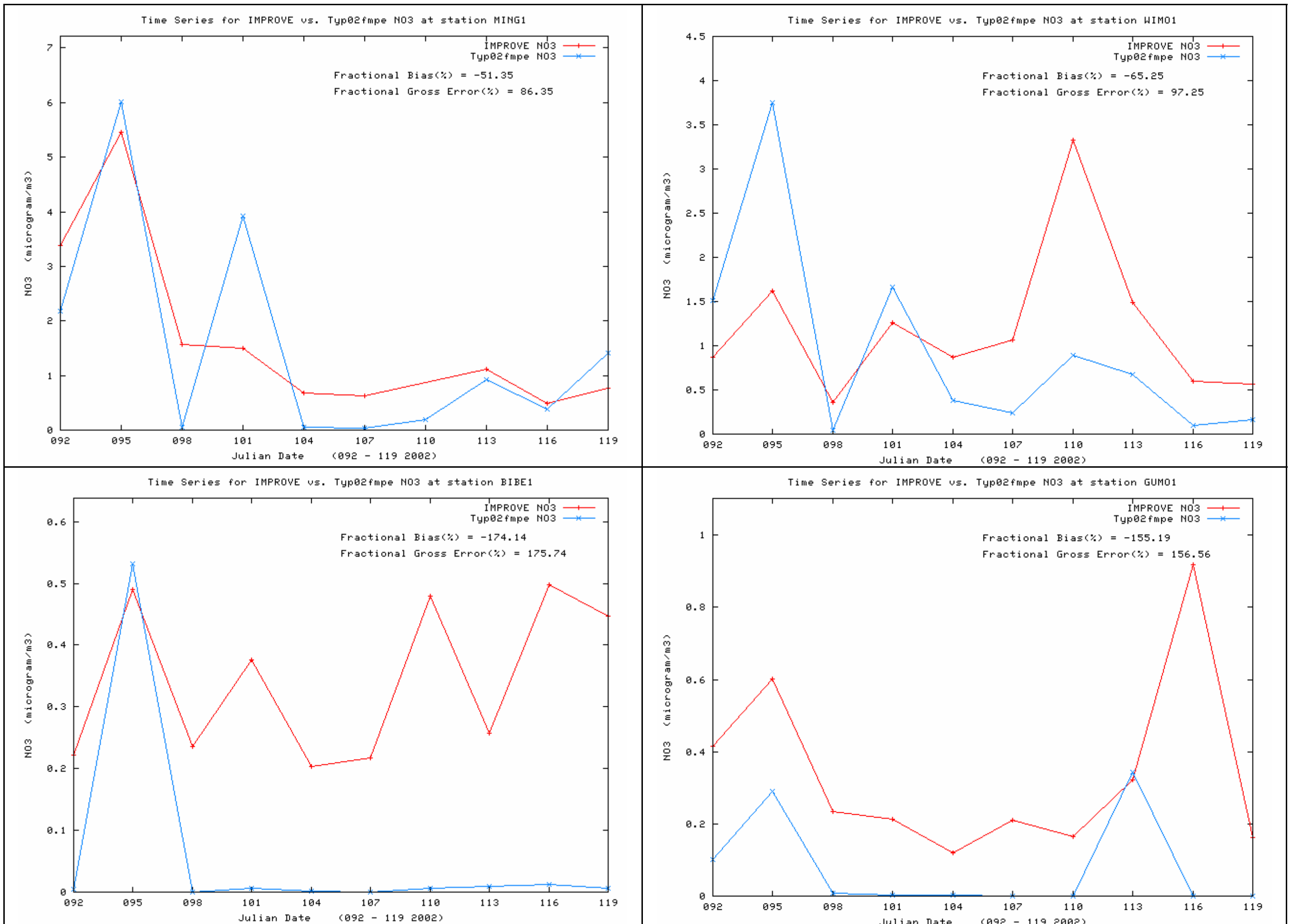


Figure C-11b. Time series of predicted and observed 24-hour nitrate (NO3) concentrations at CENRAP IMPROVE CLASS I AREA sites in April 2002 for CMAQ 2002 36 km Base F base case simulation.

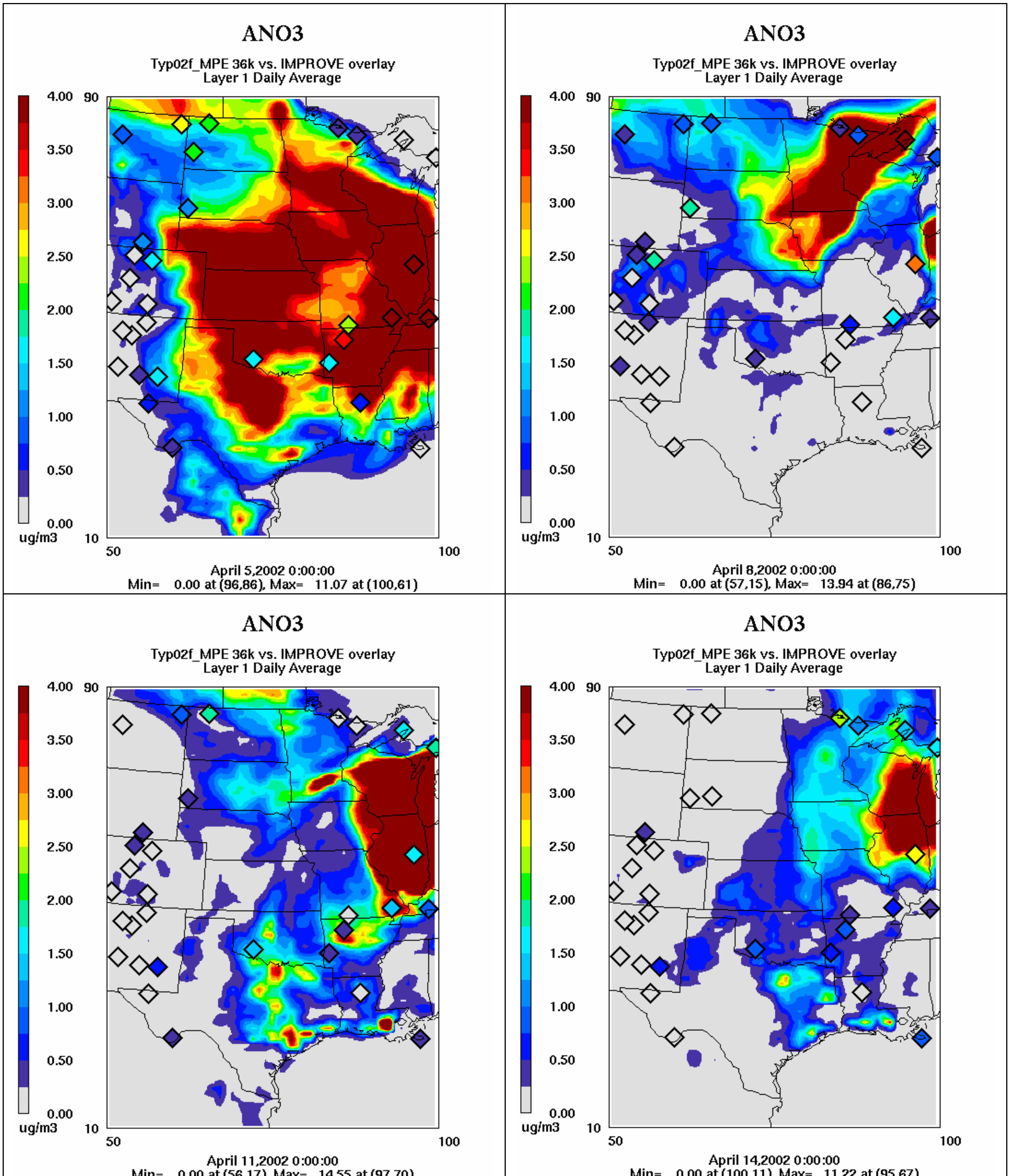


Figure C-11c. Spatial plot comparisons of the predicted and IMPROVE observed 24-hour NO3 concentrations for April 5, 8, 11 and 14, 2002.

C.3.2.3 NO3 in July 2002

NO3 performance in July 2002 is also characterized by a large under-prediction bias that is driven by the frequent occurrence of near zero modeled values (Figure C-12). Both the model and observations agree that NO3 is mostly extremely low in July, just the model produces near zero values and resultant poor performance statistics.

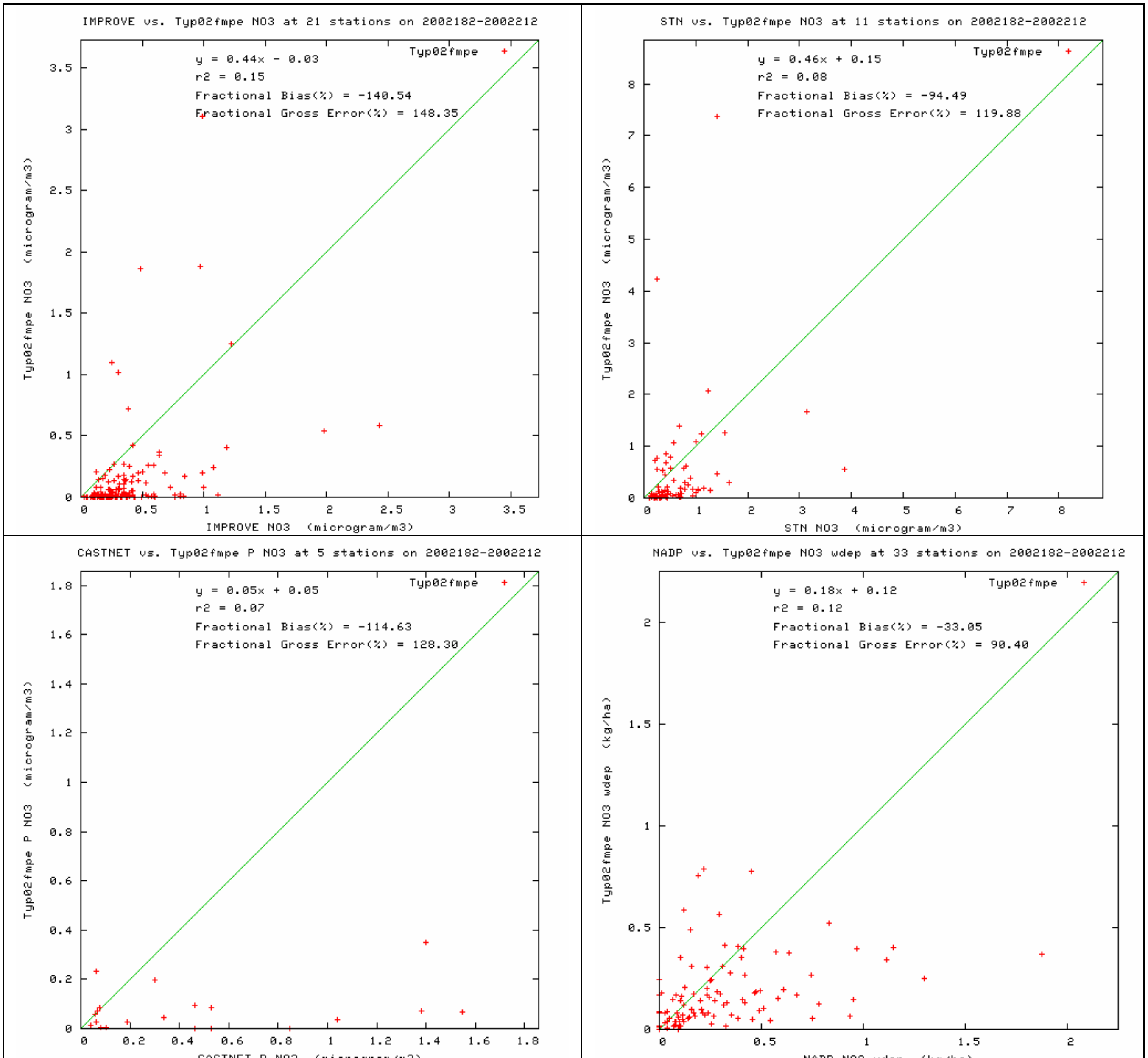
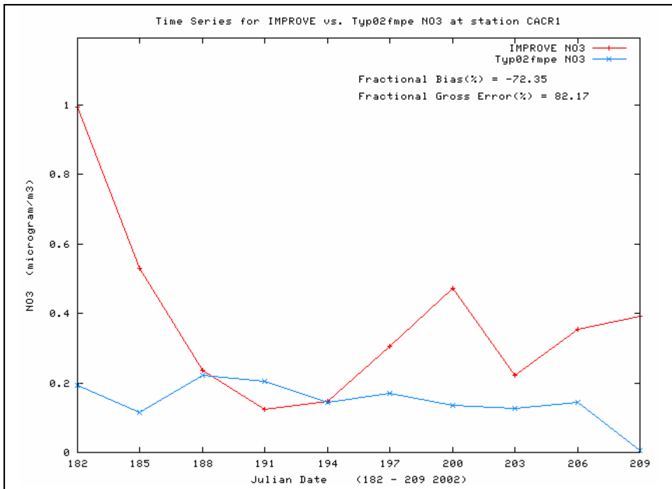
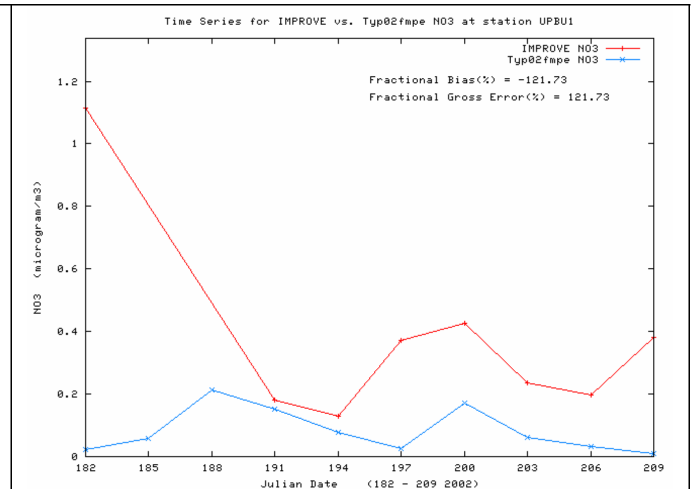
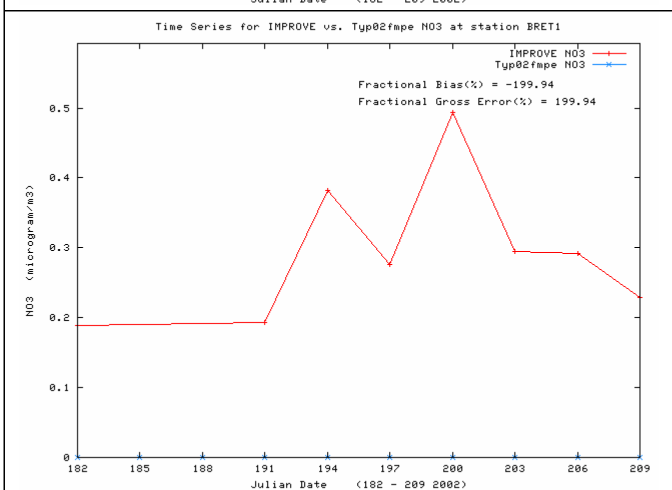
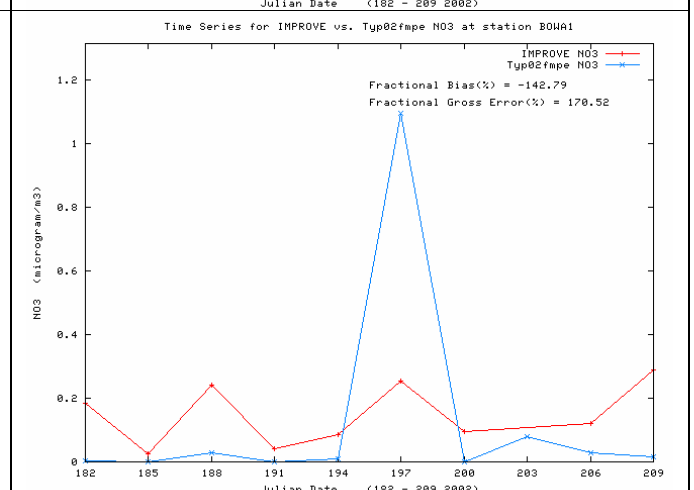


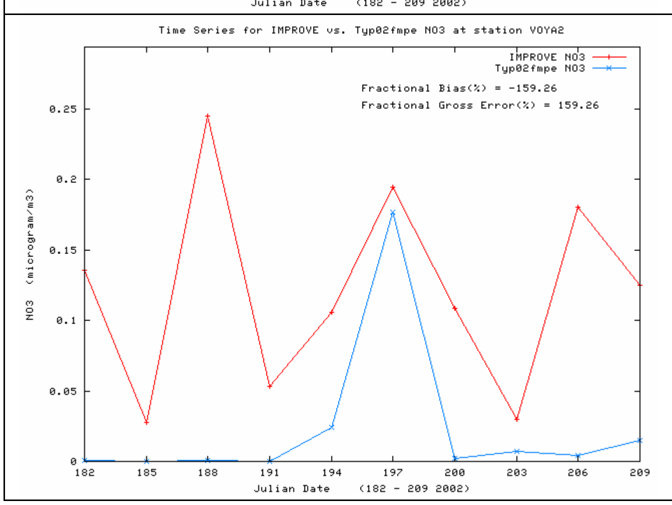
Figure C-12a. Scatter plots of predicted and observed nitrate (NO3) concentrations for July 2002 and sites in the CENRAP region using IMPROVE (top left), STN (top right), CASTNet (bottom left) and NADP monitoring networks using the CMAQ 2002 36 km Base F base case simulation.

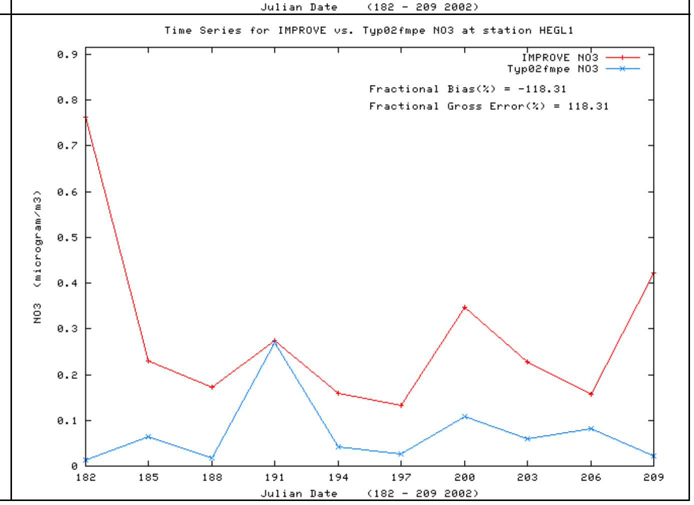

Time Series for IMPROVE vs. Typ02fmpe NO3 at station CACR1
IMPROVE NO3
Typ02fmpe NO3
Fractional Bias(%) = -72.35
Fractional Gross Error(%) = 82.17
NO3 (microgram/m3)
0
0.2
0.4
0.6
0.8
1
182 185 188 191 194 197 200 203 206 209
Julian Date (182 - 209 2002)


Time Series for IMPROVE vs. Typ02fmpe NO3 at station UPBU1
IMPROVE NO3
Typ02fmpe NO3
Fractional Bias(%) = -121.73
Fractional Gross Error(%) = 121.73
NO3 (microgram/m3)
0
0.2
0.4
0.6
0.8
1
1.2
182 185 188 191 194 197 200 203 206 209
Julian Date (182 - 209 2002)


Time Series for IMPROVE vs. Typ02fmpe NO3 at station BRET1
IMPROVE NO3
Typ02fmpe NO3
Fractional Bias(%) = -199.94
Fractional Gross Error(%) = 199.94
NO3 (microgram/m3)
0
0.1
0.2
0.3
0.4
0.5
182 185 188 191 194 197 200 203 206 209
Julian Date (182 - 209 2002)


Time Series for IMPROVE vs. Typ02fmpe NO3 at station BOWA1
IMPROVE NO3
Typ02fmpe NO3
Fractional Bias(%) = -142.79
Fractional Gross Error(%) = 170.52
NO3 (microgram/m3)
0
0.2
0.4
0.6
0.8
1
1.2
182 185 188 191 194 197 200 203 206 209
Julian Date (182 - 209 2002)


Time Series for IMPROVE vs. Typ02fmpe NO3 at station VOYA2
IMPROVE NO3
Typ02fmpe NO3
Fractional Bias(%) = -159.26
Fractional Gross Error(%) = 159.26
NO3 (microgram/m3)
0
0.05
0.1
0.15
0.2
0.25
182 185 188 191 194 197 200 203 206 209
Julian Date (182 - 209 2002)


Time Series for IMPROVE vs. Typ02fmpe NO3 at station HEGL1
IMPROVE NO3
Typ02fmpe NO3
Fractional Bias(%) = -118.31
Fractional Gross Error(%) = 118.31
NO3 (microgram/m3)
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
182 185 188 191 194 197 200 203 206 209
Julian Date (182 - 209 2002)

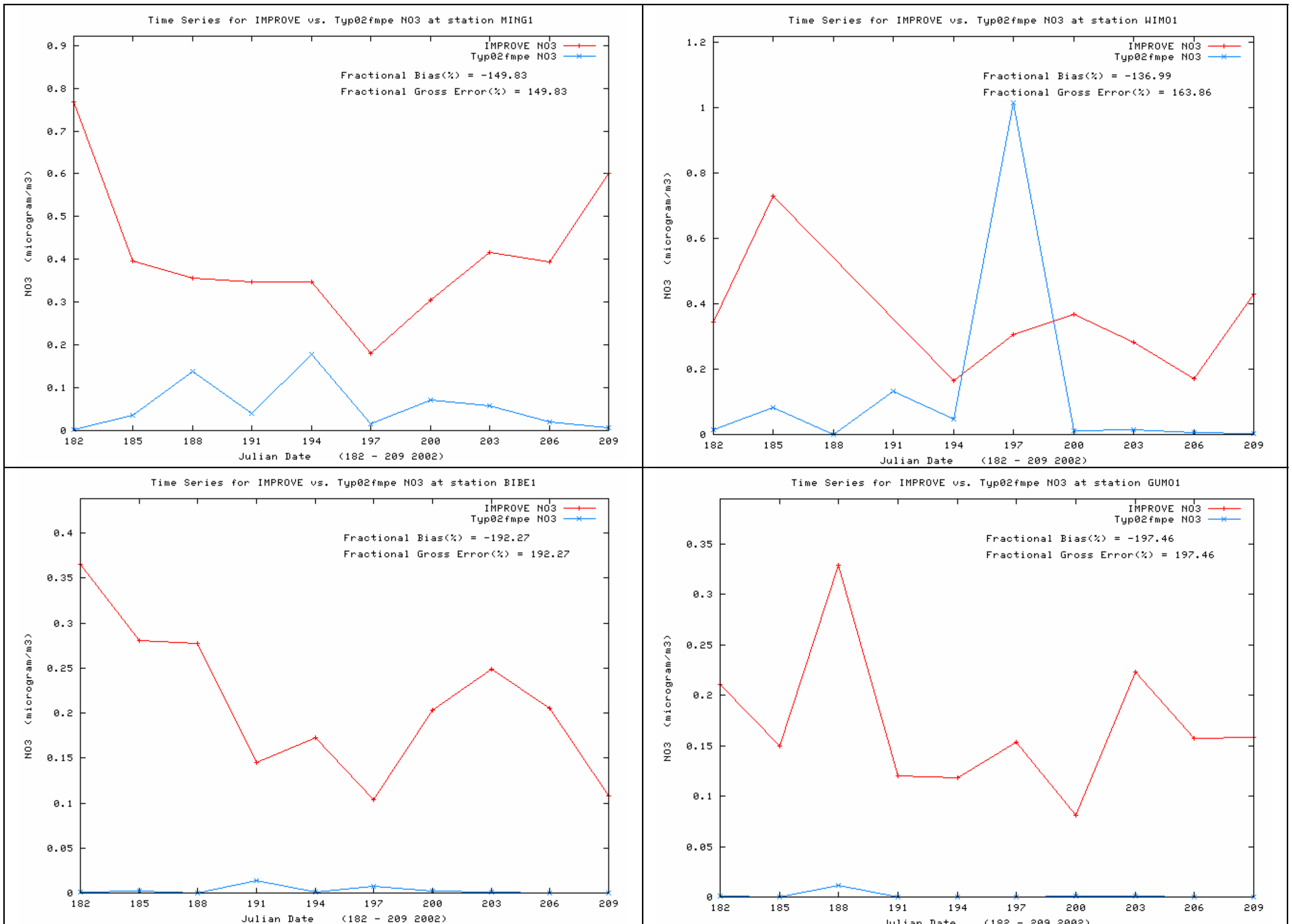


Figure C-12b. Time series of predicted and observed 24-hour nitrate (NO3) concentrations at CENRAP IMPROVE CLASS I AREA sites in July 2002 for CMAQ 2002 36 km Base F base case simulation.

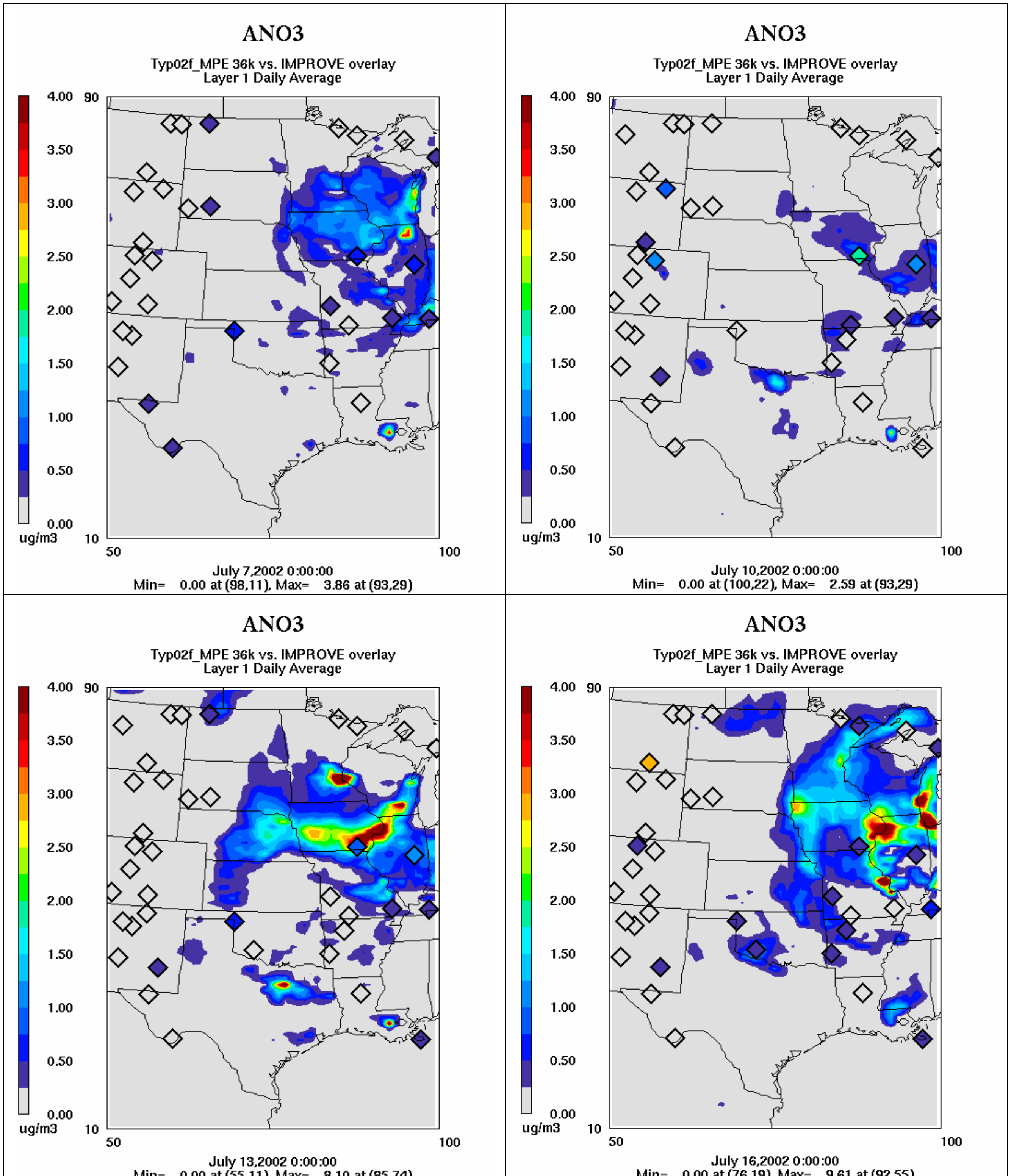


Figure C-12c. Spatial plot comparisons of the predicted and IMPROVE observed 24-hour NO3 concentrations for July 7, 10, 13 and 16, 2002.

C.3.2.4 NO3 in October 2002

Like January and unlike April and July, in October the model has a net NO3 overestimation bias of about 30%-40% (Figure C-13a). This overestimation bias occurs at all sites but BRET, BIBE and GUMO that exhibit a NO3 underestimation bias (Figure C-13b). The spatial maps suggest that the modeled elevated NO3 concentrations are more wide-spread and less spotty than observed.

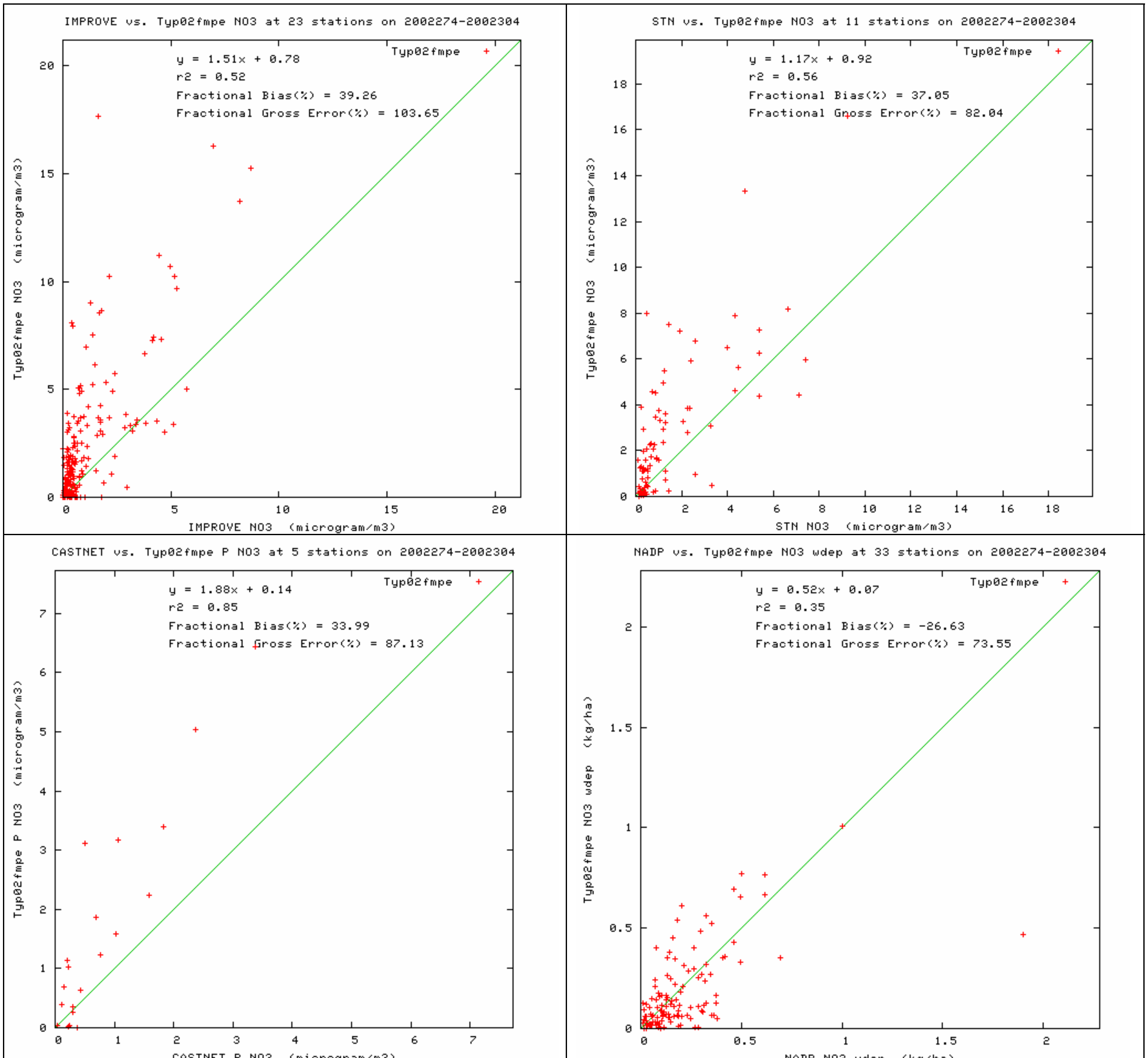
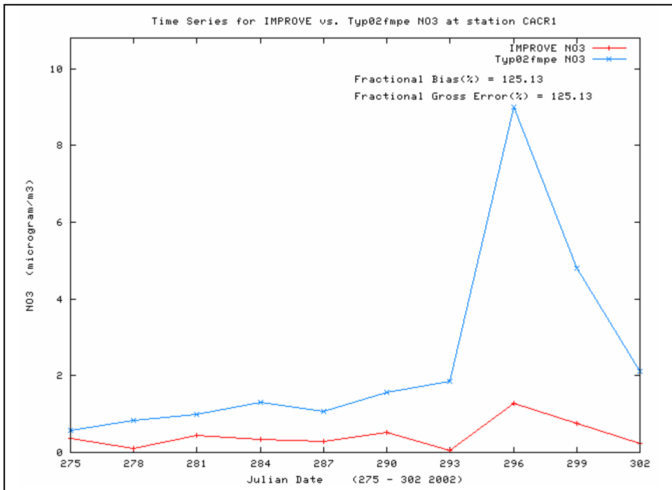
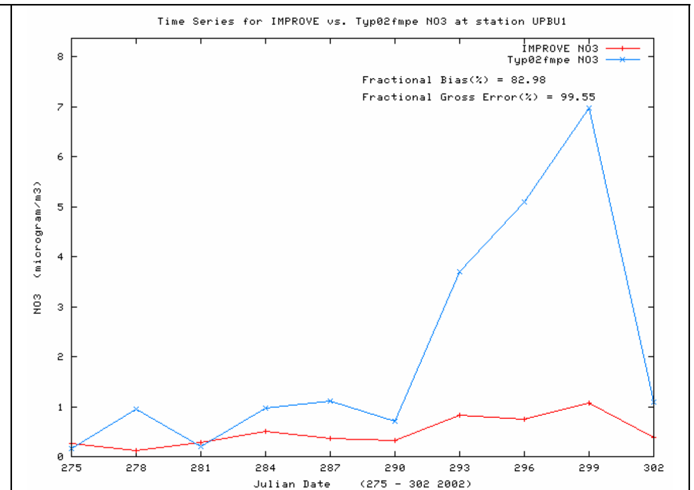
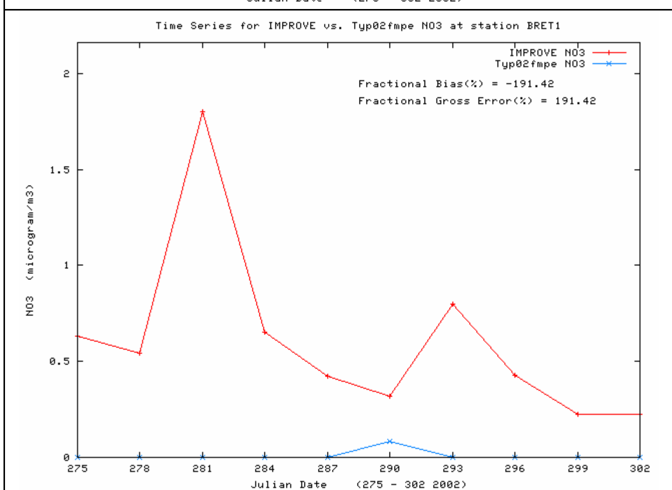
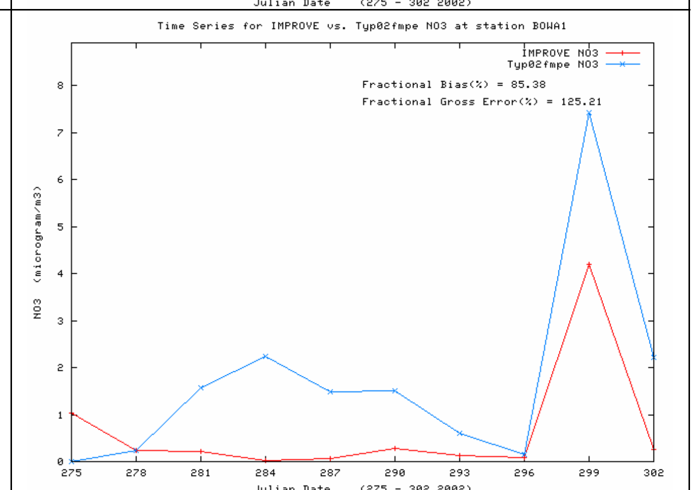


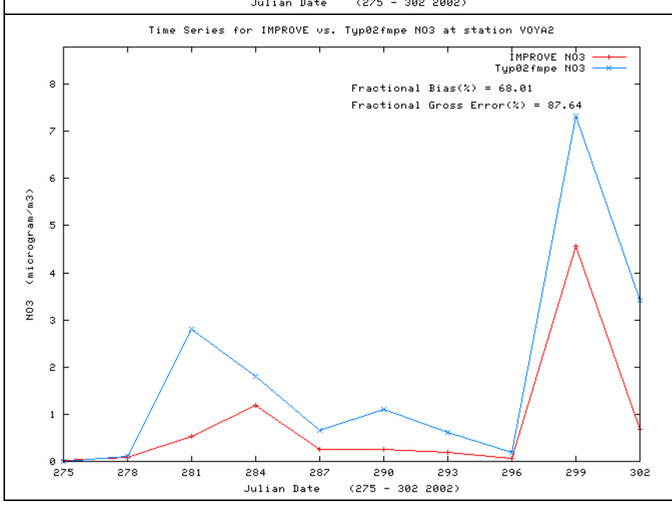
Figure C-13a. Scatter plots of predicted and observed nitrate (NO3) concentrations for October 2002 and sites in the CENRAP region using IMPROVE (top left), STN (top right), CASTNet (bottom left) and NADP monitoring networks using the CMAQ 2002 36 km Base F base case simulation.

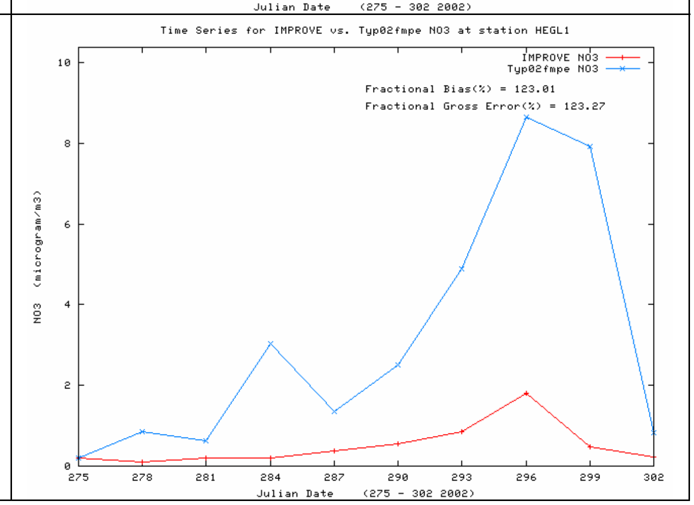

Time Series for IMPROVE vs. Typ02fmpe NO3 at station CACR1
IMPROVE NO3
Typ02fmpe NO3
Fractional Bias(%) = 125.13
Fractional Gross Error(%) = 125.13
NO3 (microgram/m3)
Julian Date (275 - 302 2002)


Time Series for IMPROVE vs. Typ02fmpe NO3 at station UPBU1
IMPROVE NO3
Typ02fmpe NO3
Fractional Bias(%) = 82.98
Fractional Gross Error(%) = 99.55
NO3 (microgram/m3)
Julian Date (275 - 302 2002)


Time Series for IMPROVE vs. Typ02fmpe NO3 at station BRET1
IMPROVE NO3
Typ02fmpe NO3
Fractional Bias(%) = -191.42
Fractional Gross Error(%) = 191.42
NO3 (microgram/m3)
Julian Date (275 - 302 2002)


Time Series for IMPROVE vs. Typ02fmpe NO3 at station BOWA1
IMPROVE NO3
Typ02fmpe NO3
Fractional Bias(%) = 85.38
Fractional Gross Error(%) = 125.21
NO3 (microgram/m3)
Julian Date (275 - 302 2002)


Time Series for IMPROVE vs. Typ02fmpe NO3 at station VOYA2
IMPROVE NO3
Typ02fmpe NO3
Fractional Bias(%) = 68.01
Fractional Gross Error(%) = 87.64
NO3 (microgram/m3)
Julian Date (275 - 302 2002)


Time Series for IMPROVE vs. Typ02fmpe NO3 at station HEGL1
IMPROVE NO3
Typ02fmpe NO3
Fractional Bias(%) = 123.01
Fractional Gross Error(%) = 123.27
NO3 (microgram/m3)
Julian Date (275 - 302 2002)

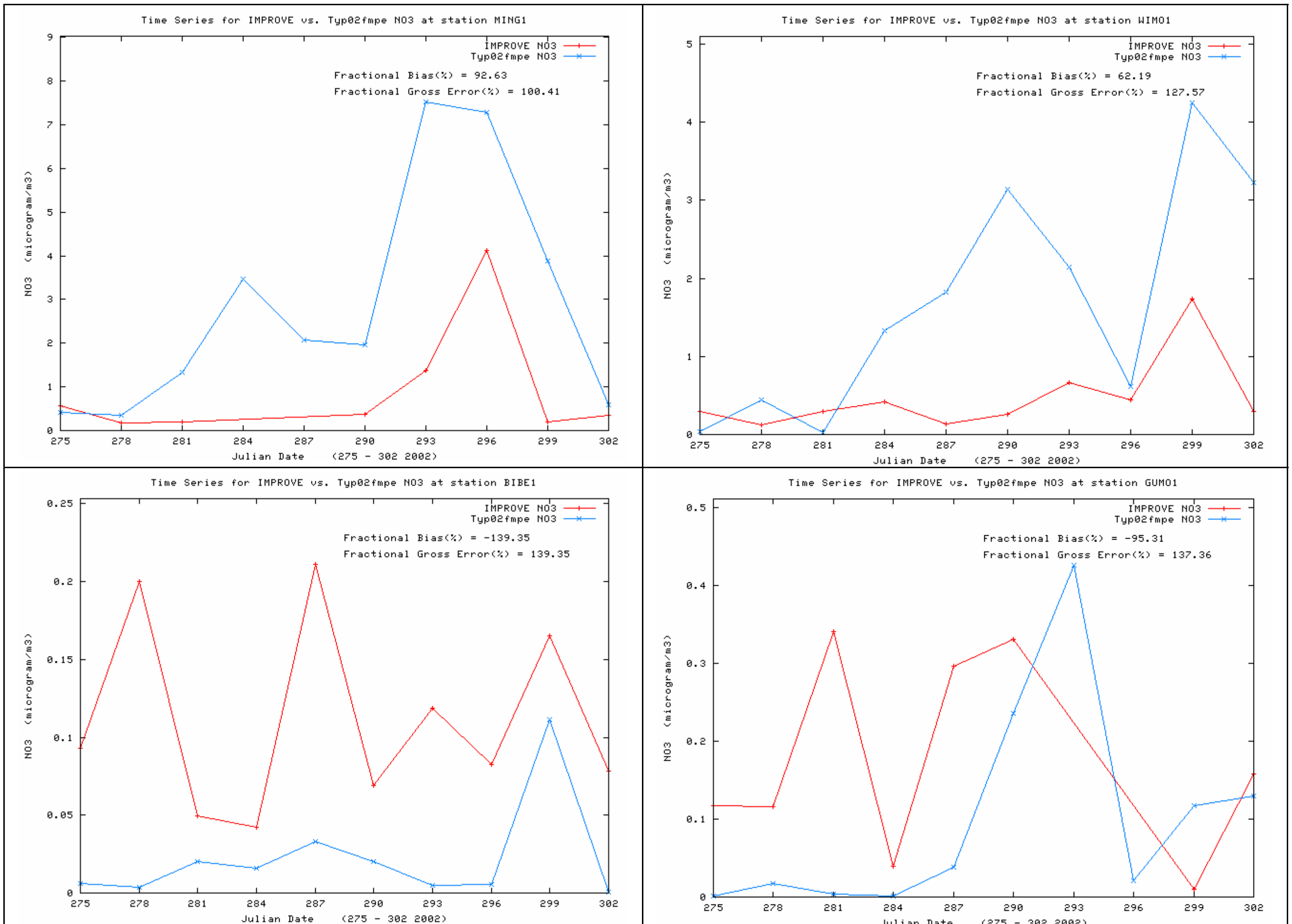


Figure C-13b. Time series of predicted and observed 24-hour nitrate (NO3) concentrations at CENRAP IMPROVE CLASS I AREA sites in October 2002 for CMAQ 2002 36 km Base F base case simulation.

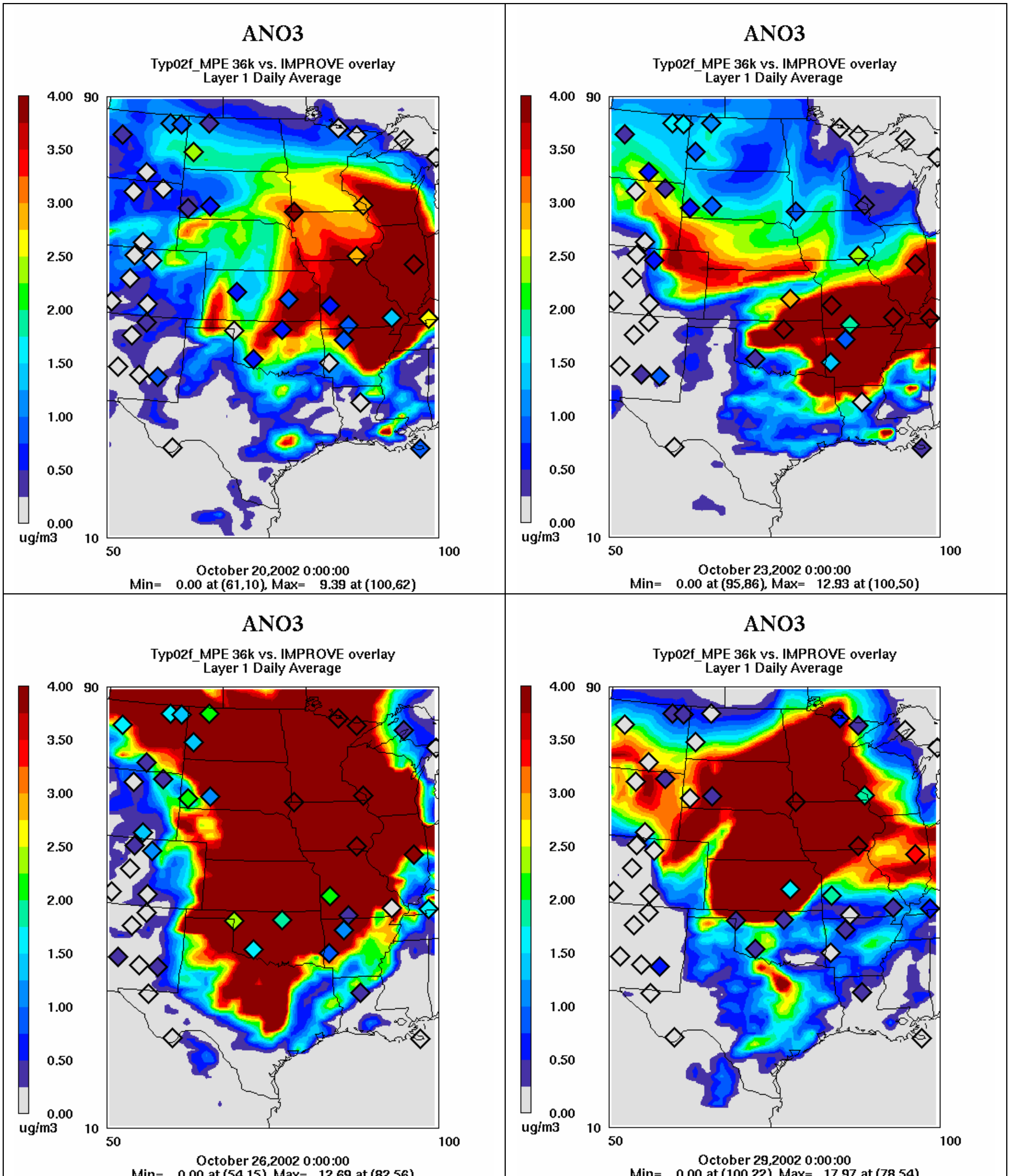


Figure C-13c. Spatial plot comparisons of the predicted and IMPROVE observed 24-hour NO3 concentrations for October 20, 23, 26 and 29, 2002.

C.3.2.5 NO3 Monthly Bias and Error

The monthly fractional bias values for NO3 clearly show the summer underestimation and winter overestimation bias (Figure C-14). The summer underestimation bias is more severe exceeding -100%, whereas the winter overestimation is closer to 50%. The fractional errors in the summer are also greater than in the winter with some values exceeding 100%. So based on statistics alone, it appears the summer underestimation bias is a bigger concern than the winter overestimation bias. However, the Bugle Plots in Figure C-15 paint a different picture entirely. The summer underestimation bias occurred when NO3 is low and is not an important component of PM and visibility impairment. These summer values occur in the flared horn part of the Bugle Plot and in fact the summer NO3 performance mostly achieves the model performance goal and always achieves the performance criteria. Whereas the winter overstated NO3 performance mostly doesn't meet the performance goal and there are even some months/networks that don't meet the performance criteria.

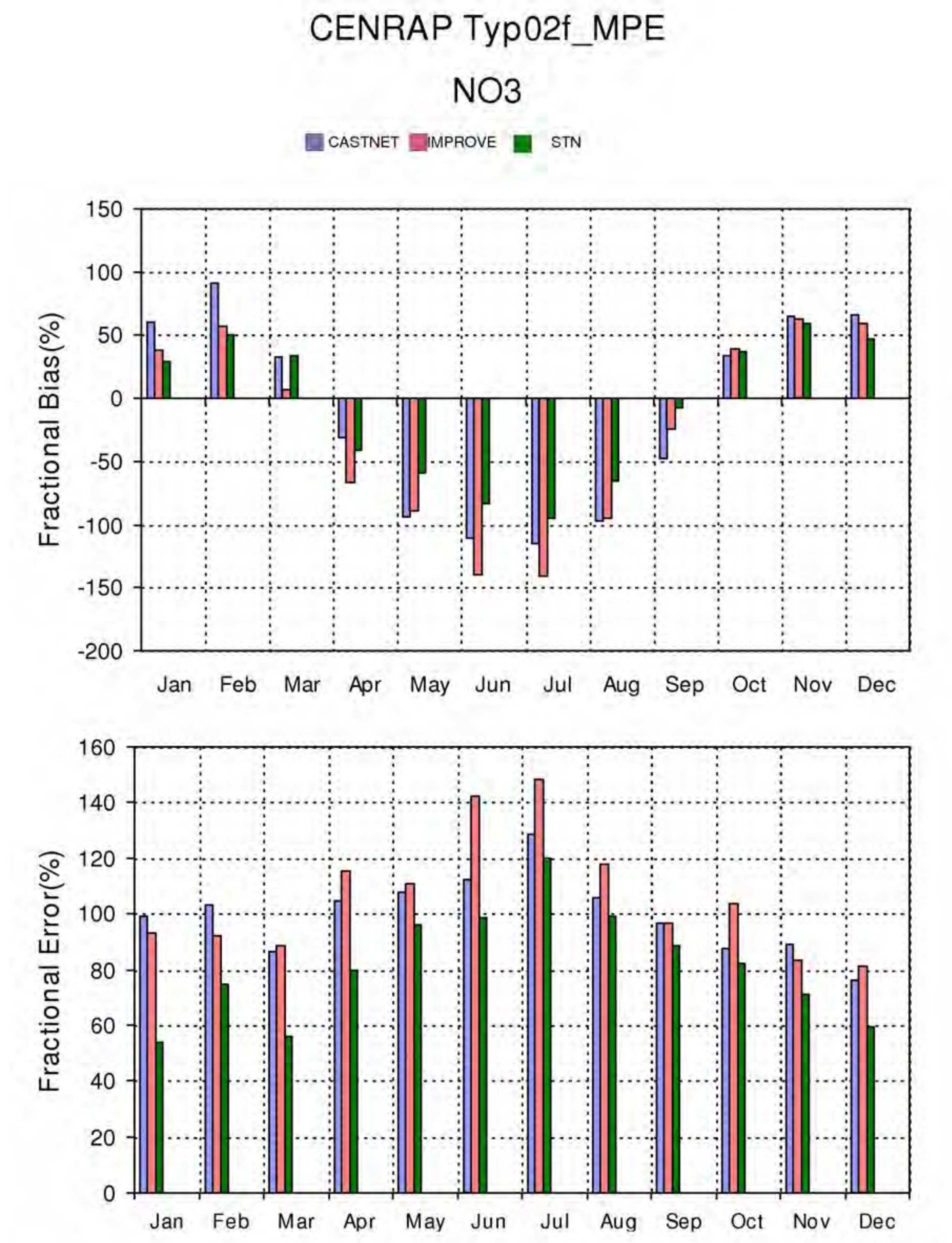


Figure C-14. Monthly NO3 fractional bias (top) and fractional gross error (bottom) statistical measures for IMPROVE, STN and CASTNet monitoring sites in the CENRAP region.

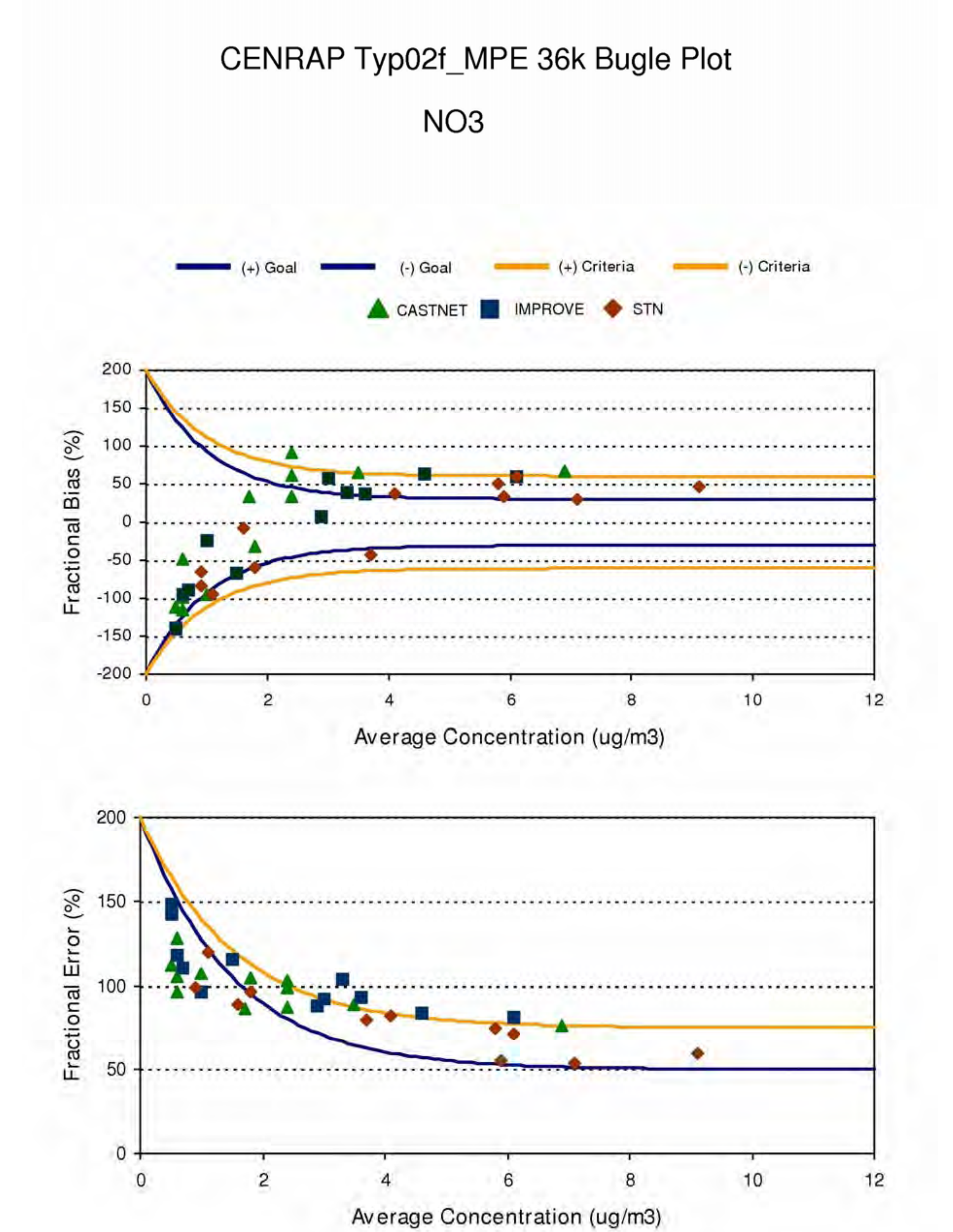


Figure C-15. Bugle Plots of monthly fractional bias (top) and fractional gross error (bottom) and comparisons with model performance goals and criteria for NO3 and IMPROVE, STN and CASTNet monitoring sites in the CENRAP region.

C.3.3 Organic Matter Carbon (OMC) Monthly Model Performance

Organic Matter Carbon (OMC) model performance is presented below. There is incommensurability between the observed and modeled OMC, the model provides estimates of OMC that includes Organic Carbon (OC) as well as other elements attached to the OC (e.g., oxygen), whereas the monitoring networks measure just the carbon component of OMC (i.e., OC). Consequently, the measured OC must be adjusted to OMC for comparison with the model to account for the additional elements attached to the carbon. The OMC/OC ratio is not constant and depends in part on the age of the OMC with fresh OMC having lower OMC/OC ratios than aged OMC. The original IMPROVE equation used an OMC/OC ratio of 1.4 based mainly on urban-oriented measurements. The new IMPROVE equation uses an OMC/OC ratio of 1.8 reflecting the fact that OMC at the more rural IMPROVE monitors is more aged than urban OMC. Thus, selecting a single OMC/OC ratio for adjusting the measured OC to OMC for the model evaluation is somewhat problematic when we have both urban (STN) and rural (IMPPROVE) monitors. In addition, measured OC also has substantial uncertainty with different measurement techniques differing by as much as 50% (Solomon et al., 2005). A 1.4 OMC/OC ratio was used to convert the measured OC to OMC for the model performance evaluation.

C.3.3.1 OMC in January 2002

Figure C-16a displays scatter plots and performance statistics for January OMC model performance across the IMPROVE and STN sites in the CENRAP region. OMC model performance is fairly with near zero bias across the IMPROVE sites, -38% underestimation bias across the STN sites and errors of ~50%. The underestimation of OMC at the urban STN sites is a common occurrence in air quality modeling and may indicate a missing source of urban OMC. With the exception of an underestimation bias at Breton Island and an over-prediction bias at the two Texas IMPORVE sites (BIBE and GUMO), the model reproduces the observed OMC time series in January fairly well. The modeled spatial distribution of OMC is in general agreement with the observations although it sometimes captures the elevated values on some days (e.g., January 29, 2002 in central Illinois) and misses it on others (e.g., January 26, 2002 at Mingo).

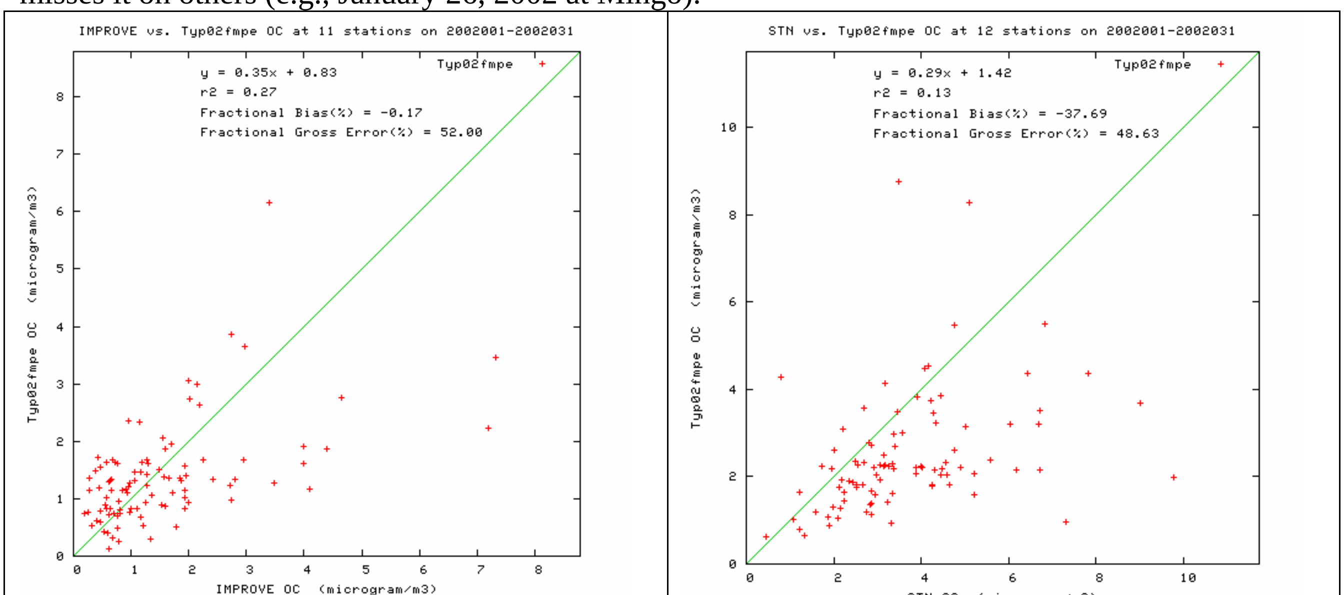
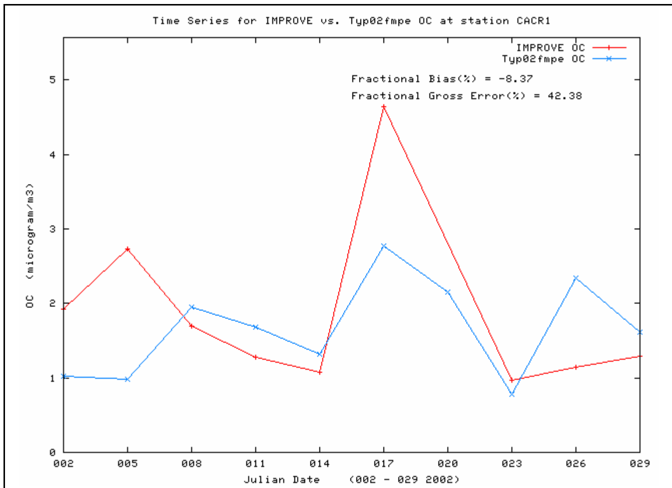
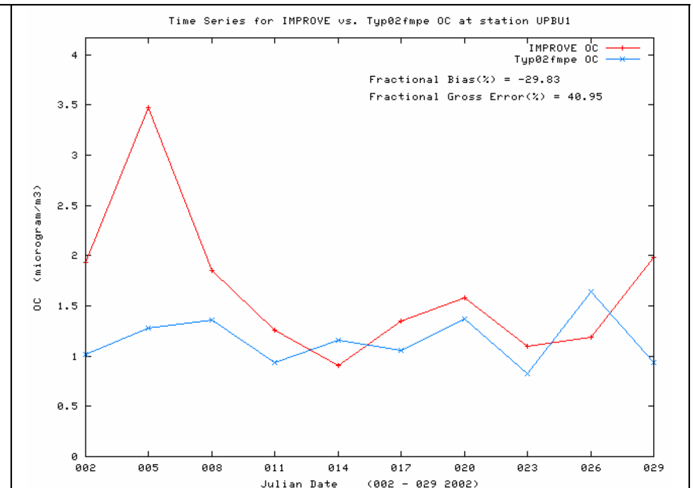
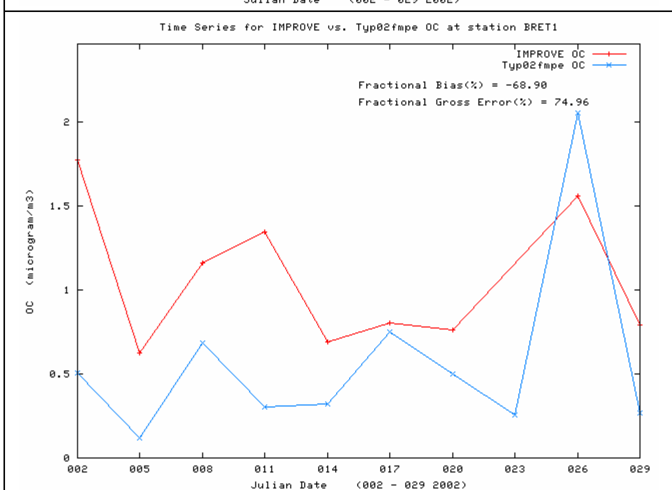
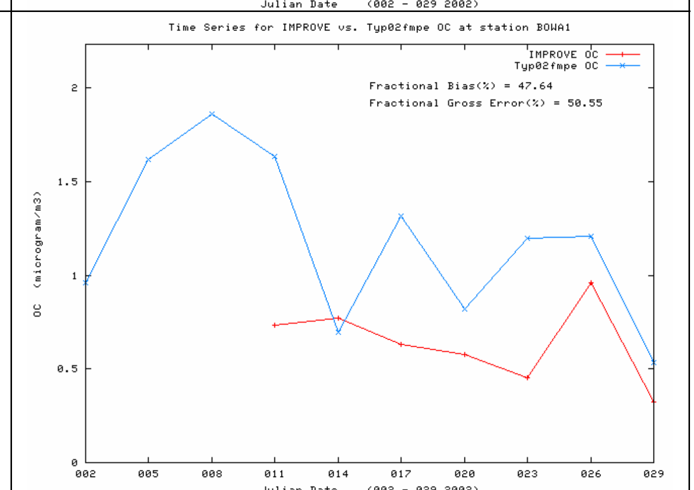


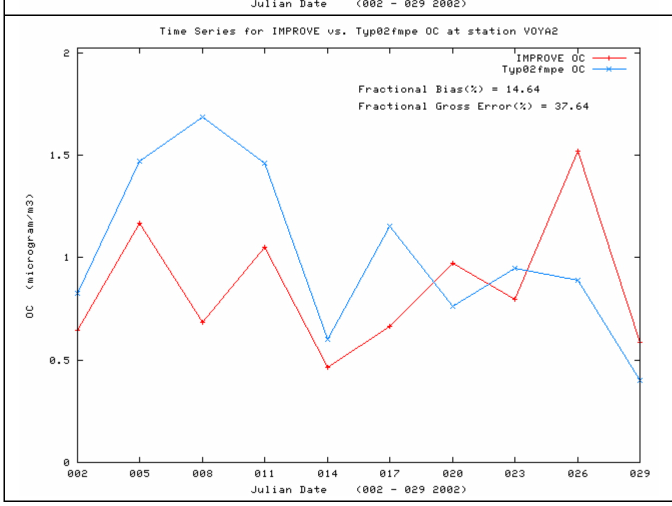
Figure C-16a. Scatter plots of predicted and observed organic matter carbon (OMC) concentrations for January 2002 and sites in the CENRAP region using IMPROVE (left) and STN (right) monitoring networks using the CMAQ 2002 36 km Base F base case simulation.

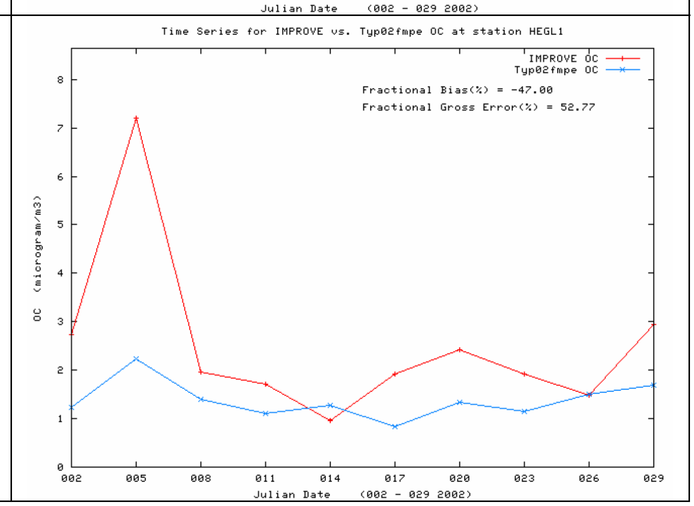

Time Series for IMPROVE vs. Typ02fmpe OC at station CACR1
IMPROVE OC
Typ02fmpe OC
Fractional Bias(%) = -8.37
Fractional Gross Error(%) = 42.38
OC (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe OC at station UPBU1
IMPROVE OC
Typ02fmpe OC
Fractional Bias(%) = -29.83
Fractional Gross Error(%) = 40.95
OC (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe OC at station BRET1
IMPROVE OC
Typ02fmpe OC
Fractional Bias(%) = -68.90
Fractional Gross Error(%) = 74.96
OC (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe OC at station BOWA1
IMPROVE OC
Typ02fmpe OC
Fractional Bias(%) = 47.64
Fractional Gross Error(%) = 50.55
OC (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe OC at station VOYA2
IMPROVE OC
Typ02fmpe OC
Fractional Bias(%) = 14.64
Fractional Gross Error(%) = 37.64
OC (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe OC at station HEGL1
IMPROVE OC
Typ02fmpe OC
Fractional Bias(%) = -47.00
Fractional Gross Error(%) = 52.77
OC (microgram/m3)
Julian Date (002 - 029 2002)

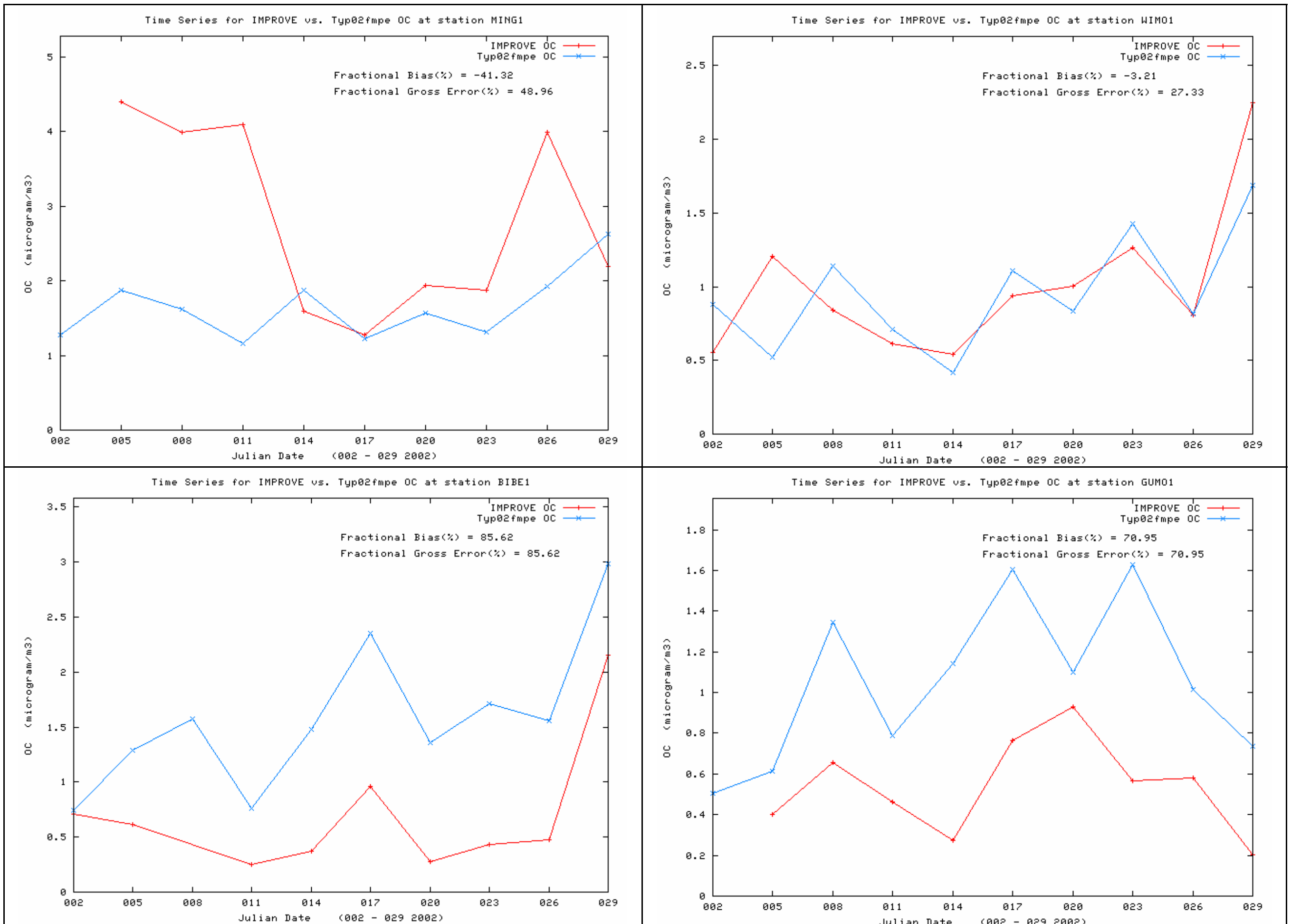


Figure C-16b. Time series of predicted and observed 24-hour organic matter carbon (OMC) concentrations at CENRAP IMPROVE CLASS I AREA sites in January 2002 for CMAQ 2002 36 km Base F base case simulation.

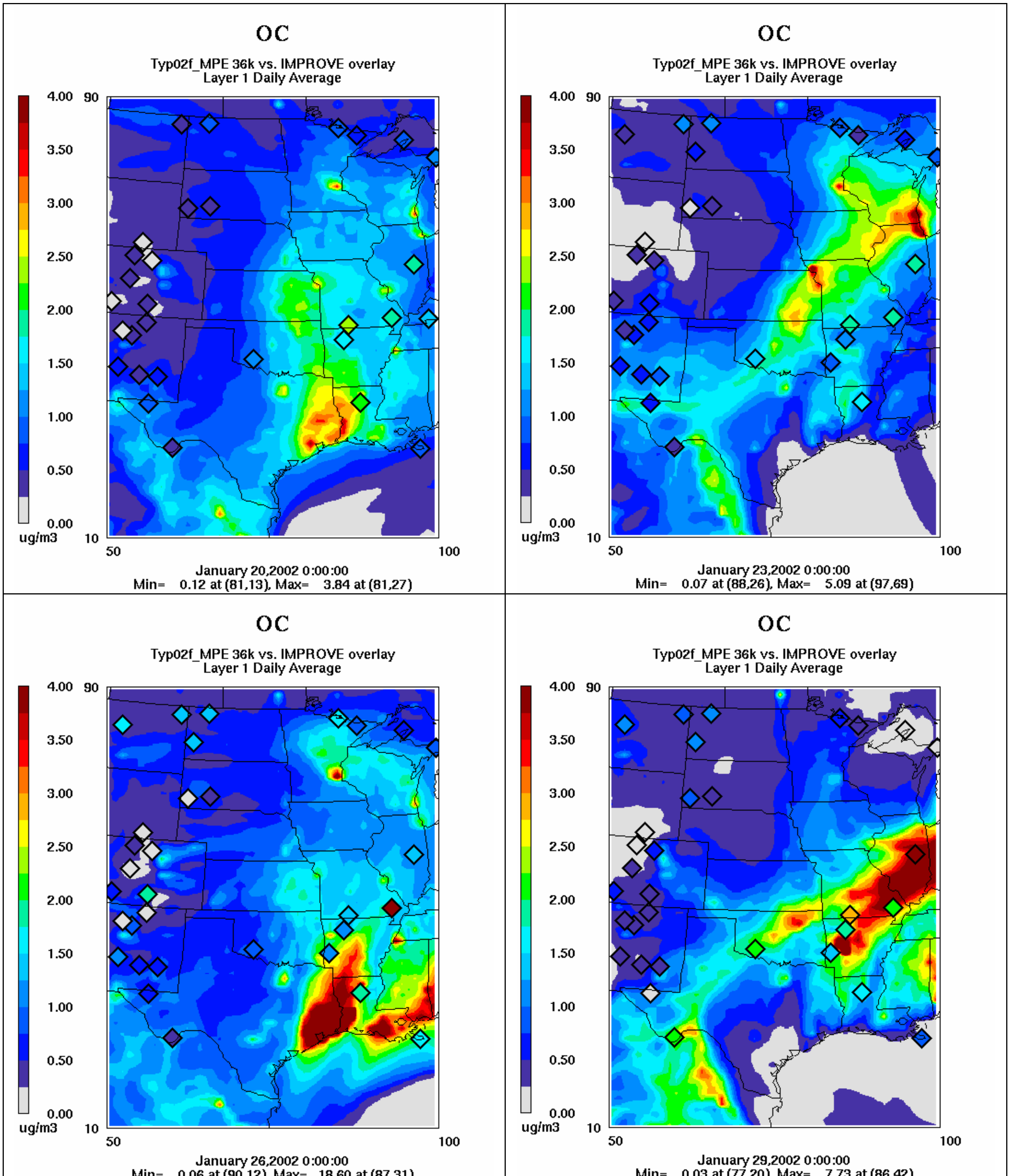


Figure C-16c. Spatial plot comparisons of the predicted and IMPROVE observed 24-hour OMC concentrations for January 20, 23, 26 and 29, 2002.

C.3.3.2 OMC in April 2002

The OMC performance in April is also fairly reasonable, again bias across the IMPROVE monitors is near zero (-7%), an underestimation bias exists across the STN sites (-30%) and errors are near 50% (Figure C-17a). The time series comparisons (Figure C-17b) are also reasonable with the model generally agreeing on the magnitudes of the observed OMC, but with an underestimation bias at several sites (e.g., MING and WIMO). The observed spatial distribution of OMCV appears to be much spottier than predicted (Figure C-17c). Thus, when the model reproduces an elevated observed OMC value like at UPBU on April 5th, it overestimates OMC at neighboring sites that have lower values (e.g., HEGL).

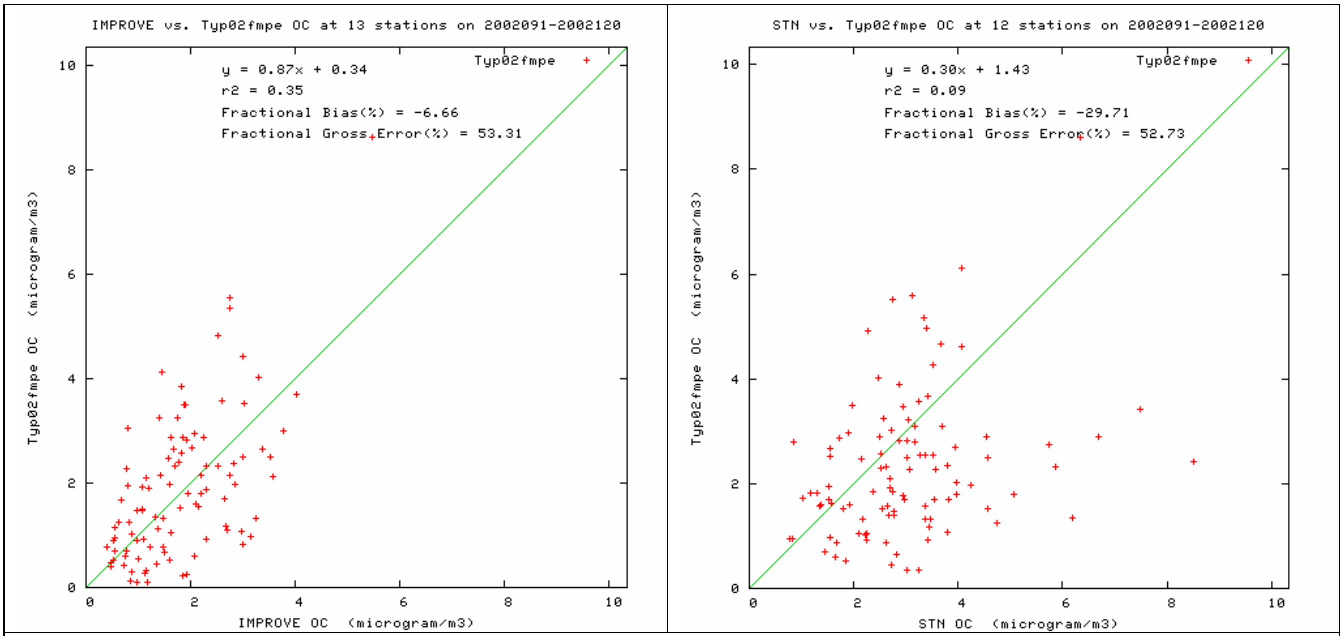
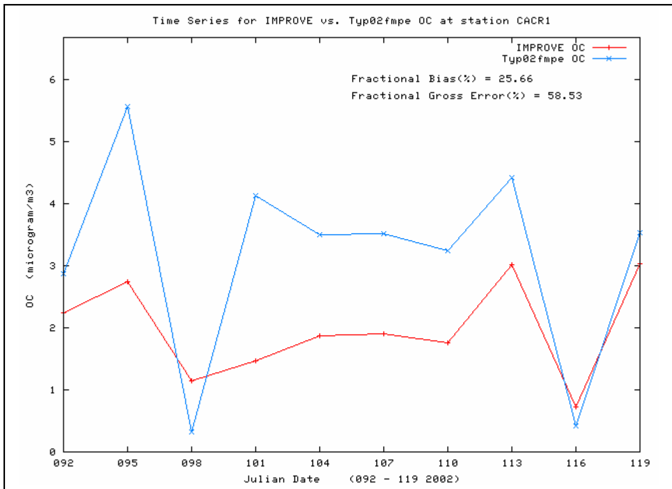
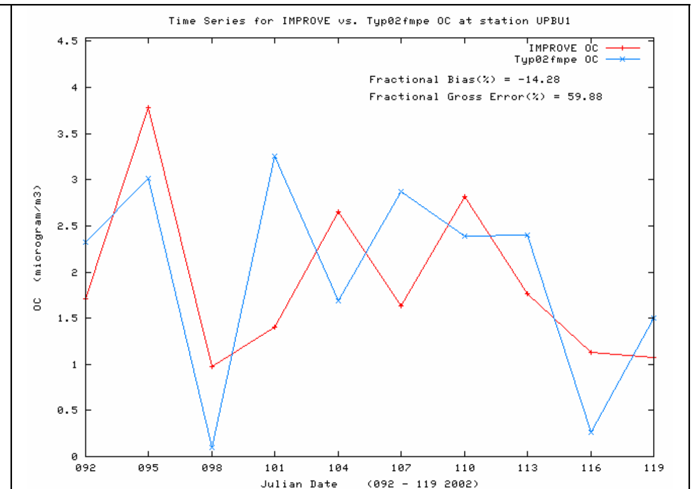
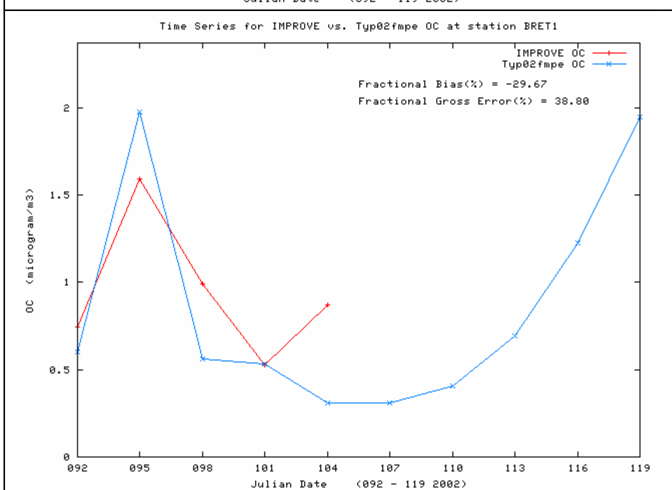
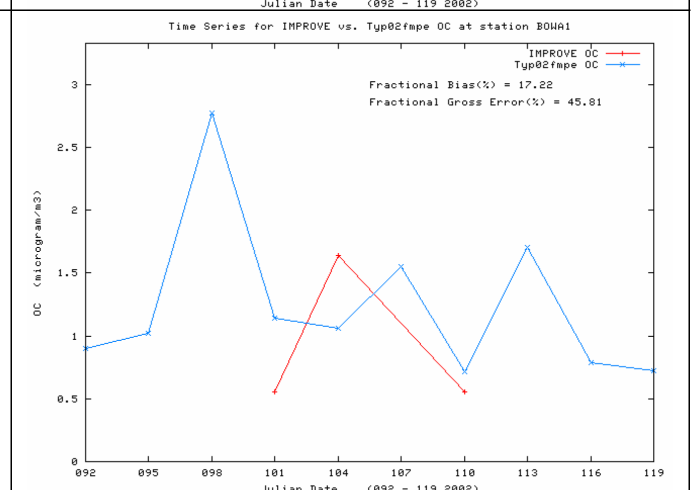


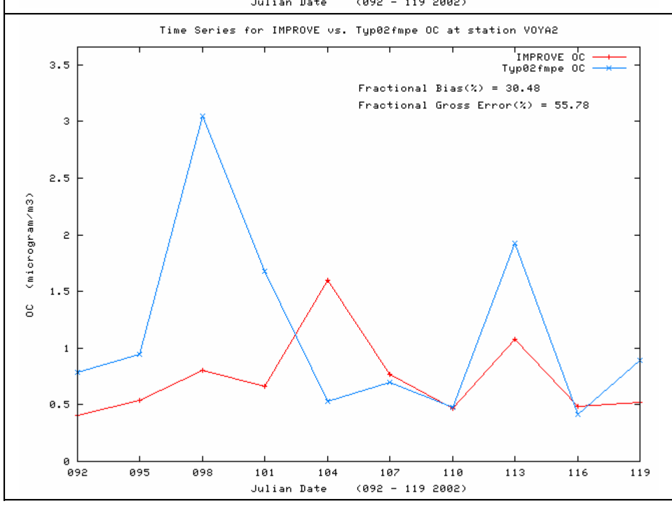
Figure C-17a. Scatter plots of predicted and observed organic matter carbon (OMC) concentrations for April 2002 and sites in the CENRAP region using IMPROVE (left) and STN (right) monitoring networks using the CMAQ 2002 36 km Base F base case simulation.

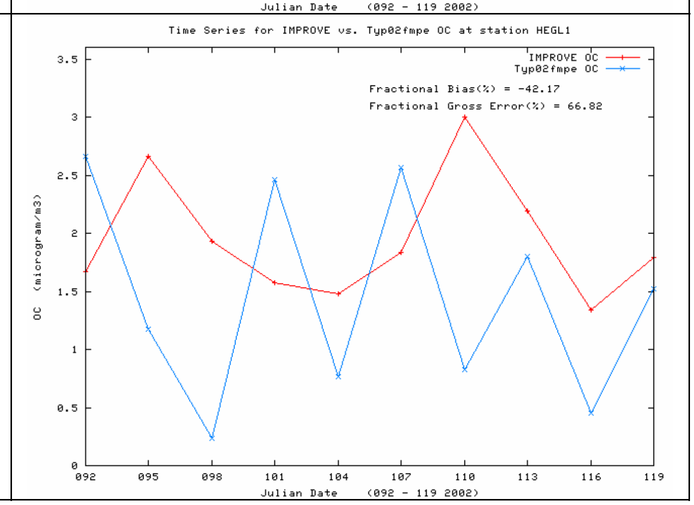

Time Series for IMPROVE vs. Typ02fmpe OC at station CACR1
IMPROVE OC
Typ02fmpe OC
Fractional Bias(%) = 25.66
Fractional Gross Error(%) = 58.53
OC (microgram/m3)
Julian Date (092 - 119 2002)


Time Series for IMPROVE vs. Typ02fmpe OC at station UPBU1
IMPROVE OC
Typ02fmpe OC
Fractional Bias(%) = -14.28
Fractional Gross Error(%) = 59.88
OC (microgram/m3)
Julian Date (092 - 119 2002)


Time Series for IMPROVE vs. Typ02fmpe OC at station BRET1
IMPROVE OC
Typ02fmpe OC
Fractional Bias(%) = -29.67
Fractional Gross Error(%) = 38.80
OC (microgram/m3)
Julian Date (092 - 119 2002)


Time Series for IMPROVE vs. Typ02fmpe OC at station BOWA1
IMPROVE OC
Typ02fmpe OC
Fractional Bias(%) = 17.22
Fractional Gross Error(%) = 45.81
OC (microgram/m3)
Julian Date (092 - 119 2002)


Time Series for IMPROVE vs. Typ02fmpe OC at station VOYA2
IMPROVE OC
Typ02fmpe OC
Fractional Bias(%) = 30.48
Fractional Gross Error(%) = 55.78
OC (microgram/m3)
Julian Date (092 - 119 2002)


Time Series for IMPROVE vs. Typ02fmpe OC at station HEGL1
IMPROVE OC
Typ02fmpe OC
Fractional Bias(%) = -42.17
Fractional Gross Error(%) = 66.82
OC (microgram/m3)
Julian Date (092 - 119 2002)

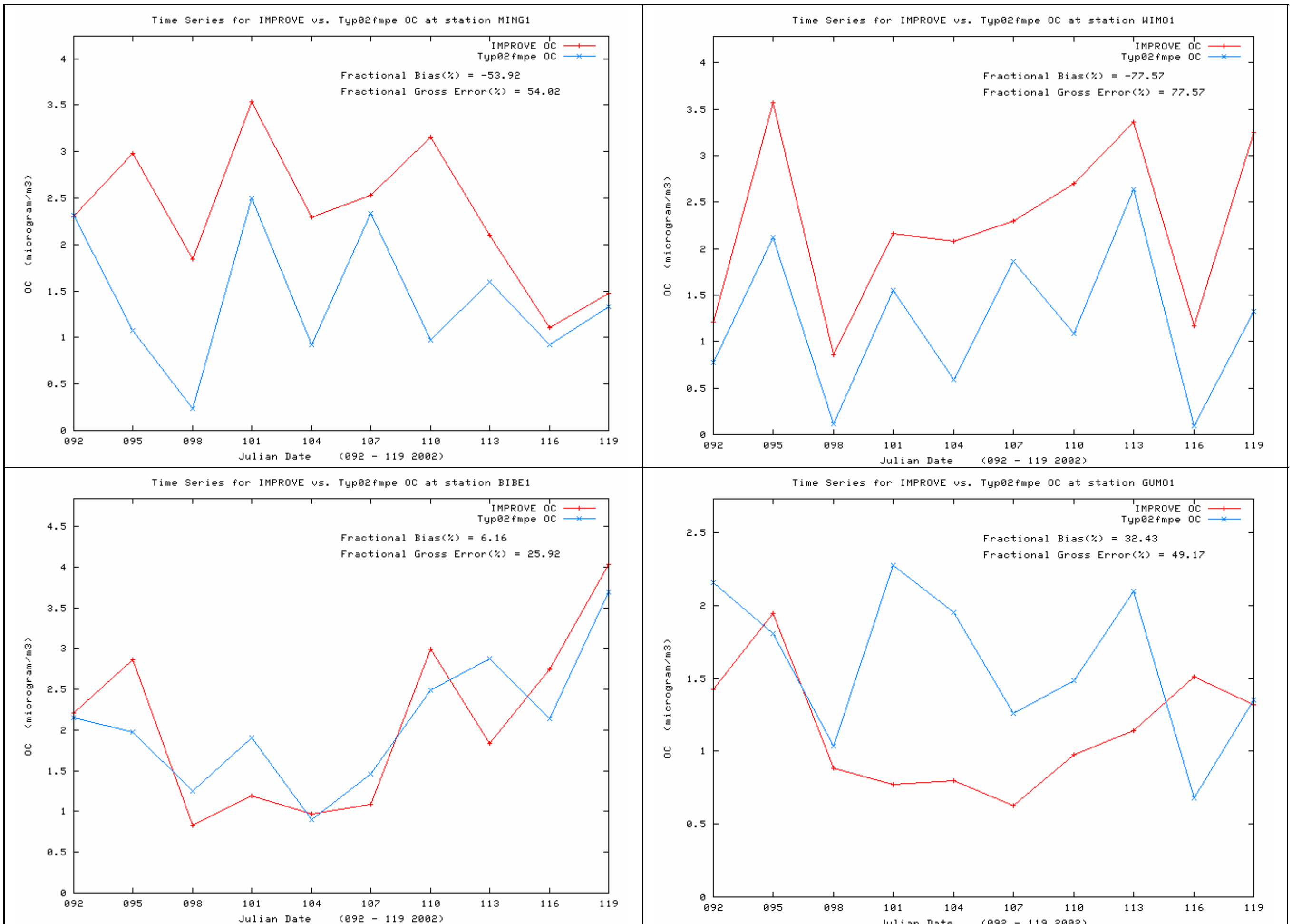


Figure C-17b. Time series of predicted and observed 24-hour organic matter carbon (OMC) concentrations at CENRAP IMPROVE CLASS I AREA sites in April 2002 for CMAQ 2002 36 km Base F base case simulation.

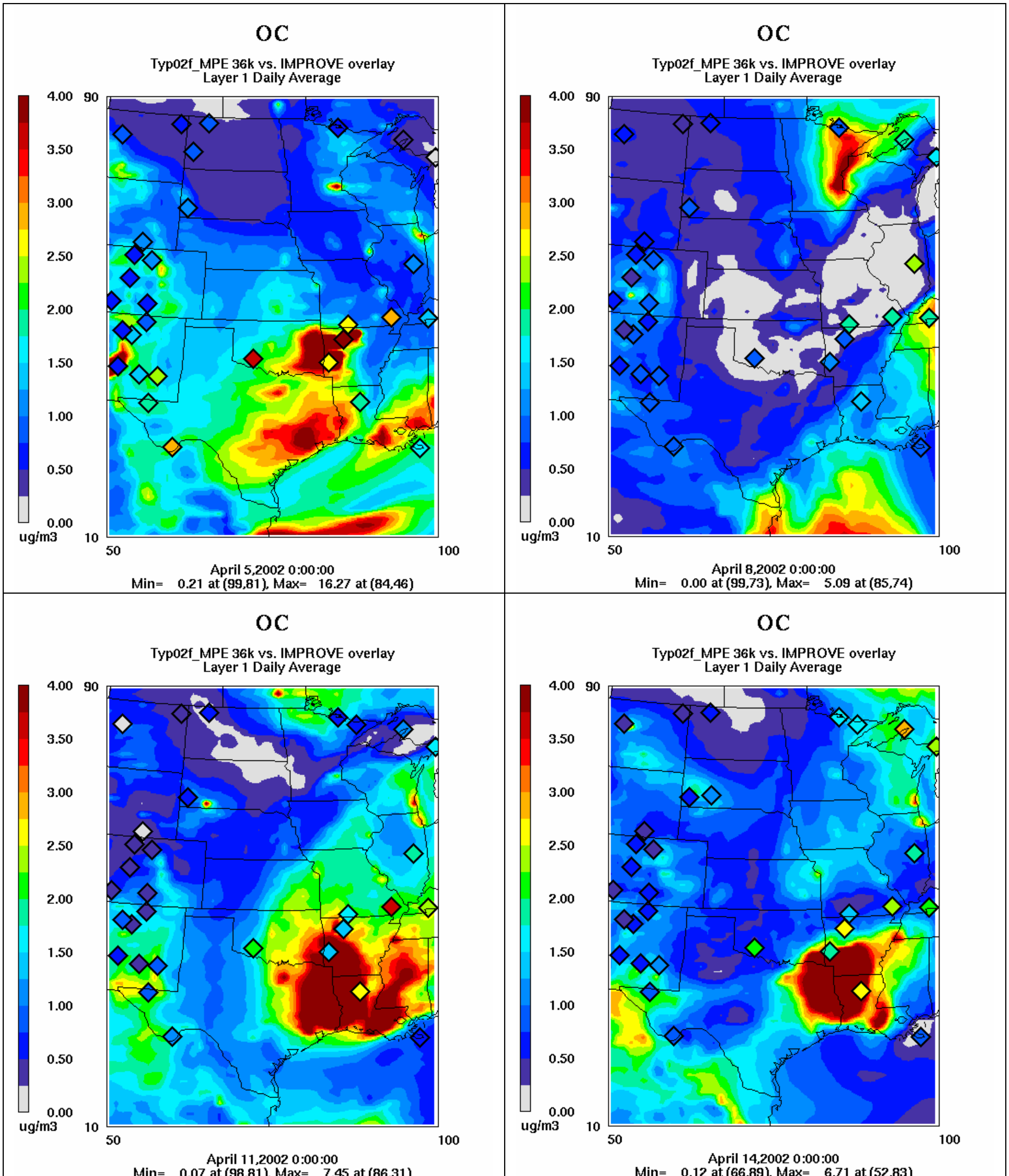


Figure C-17c. Spatial plot comparisons of the predicted and IMPROVE observed 24-hour OMC concentrations for April 5, 8, 11 and 14, 2002.

C.3.3.3 OMC in July 2002

Modeled and observed OMC are higher in July due to the impacts of more secondary organic aerosols (SOA) and fires. OMC bias values of -18% and -41% exist across the IMPROVE and STN networks in July (Figure C-18a). Two of the observed OMC values at the IMPROVE sites are very high (> 15 $\mu g/m^3$). An examination of the time series plots (Figure C-18b) reveals that these two values occur on Julian Day 200 and the two northern Minnesota sites (VOYA and BOWA) and are likely due to fire impacts. The model is also estimating elevated OMC at these sites on these two days, but not as high as observed. At most sites the model is racking the temporal variation of the observed OMC reasonably well. OMC data for MING were missing in July 2002. The model reproduces the observed high OMC in northern Minnesota and centered on Louisiana and adjacent areas on July 7 and 10 quite well, but also predicts elevated OMC in the Denver area that is not reflected in the observations (Figure C-18c). The model is exhibiting less skill in predicting the spatial distribution of the observed OMC on July 13 and 16.

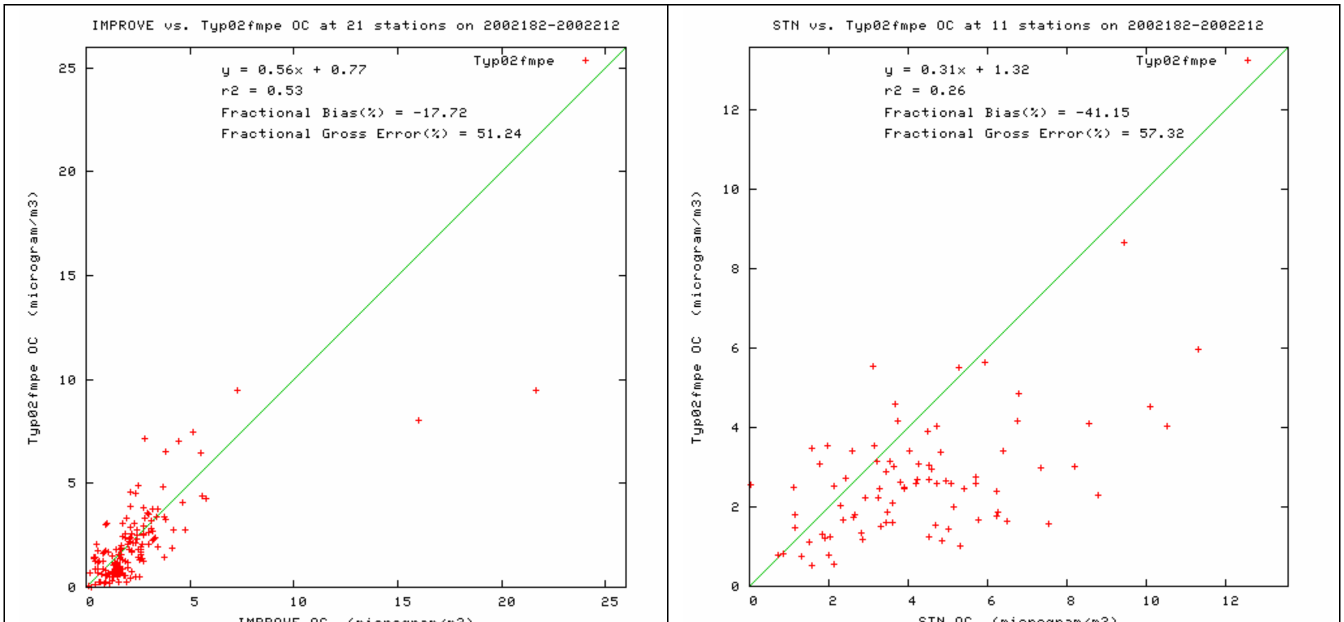
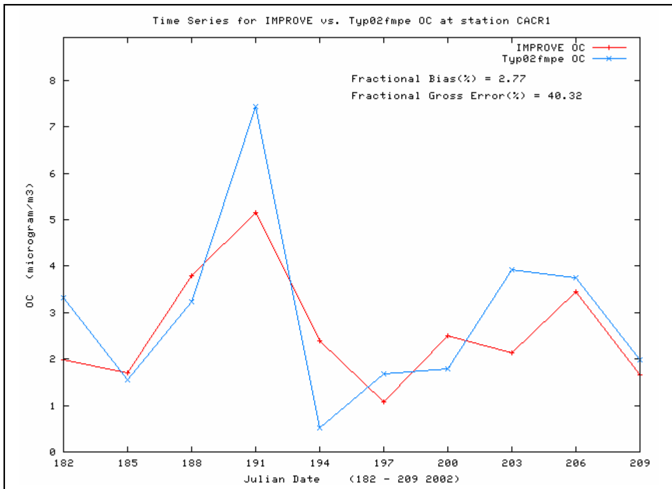
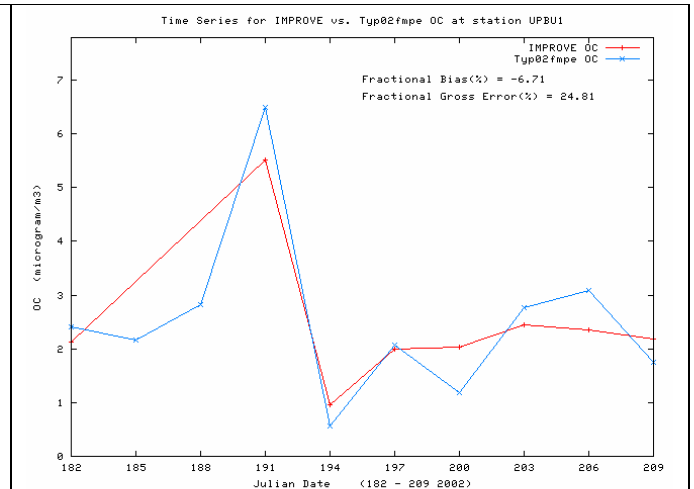
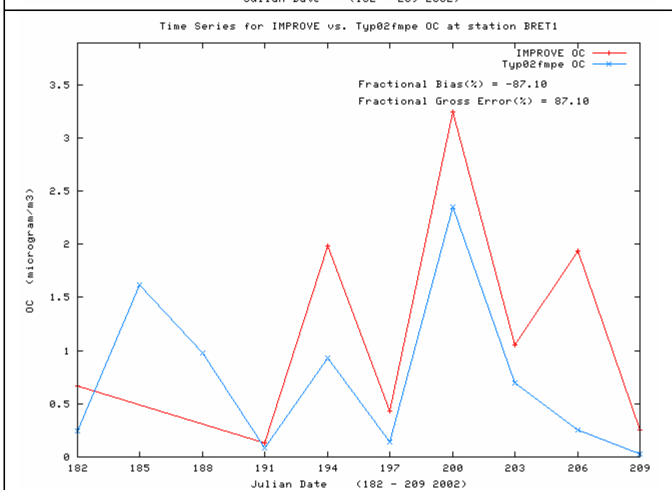
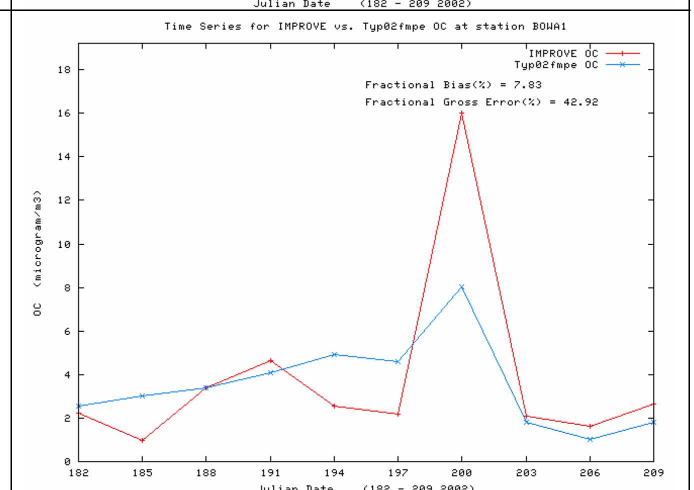


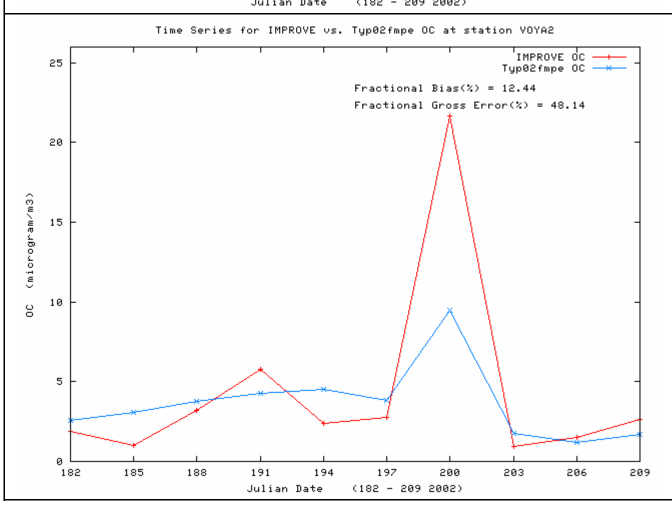
Figure C-18a. Scatter plots of predicted and observed organic matter carbon (OMC) concentrations for July 2002 and sites in the CENRAP region using IMPROVE (left) and STN (right) monitoring networks using the CMAQ 2002 36 km Base F base case simulation.

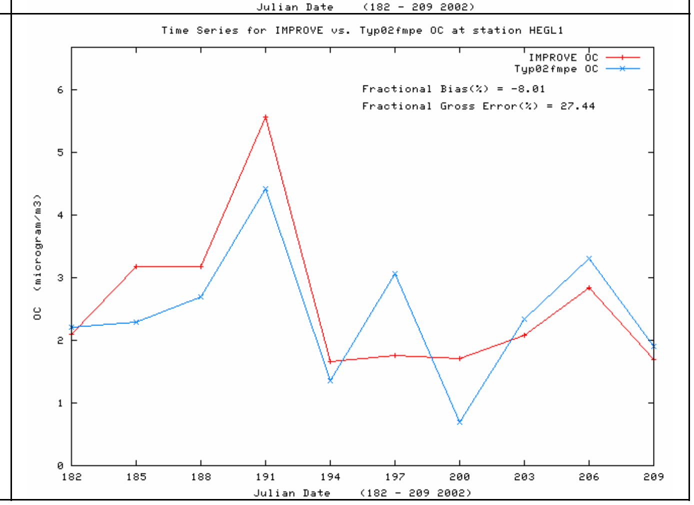

Time Series for IMPROVE vs. Typ02fmpe OC at station CACR1
IMPROVE OC
Typ02fmpe OC
Fractional Bias(%) = 2.77
Fractional Gross Error(%) = 40.32
OC (microgram/m3)
Julian Date (182 - 209 2002)


Time Series for IMPROVE vs. Typ02fmpe OC at station UPBU1
IMPROVE OC
Typ02fmpe OC
Fractional Bias(%) = -6.71
Fractional Gross Error(%) = 24.81
OC (microgram/m3)
Julian Date (182 - 209 2002)


Time Series for IMPROVE vs. Typ02fmpe OC at station BRET1
IMPROVE OC
Typ02fmpe OC
Fractional Bias(%) = -87.10
Fractional Gross Error(%) = 87.10
OC (microgram/m3)
Julian Date (182 - 209 2002)


Time Series for IMPROVE vs. Typ02fmpe OC at station BOWA1
IMPROVE OC
Typ02fmpe OC
Fractional Bias(%) = 7.83
Fractional Gross Error(%) = 42.92
OC (microgram/m3)
Julian Date (182 - 209 2002)


Time Series for IMPROVE vs. Typ02fmpe OC at station VOYA2
IMPROVE OC
Typ02fmpe OC
Fractional Bias(%) = 12.44
Fractional Gross Error(%) = 48.14
OC (microgram/m3)
Julian Date (182 - 209 2002)


Time Series for IMPROVE vs. Typ02fmpe OC at station HEGL1
IMPROVE OC
Typ02fmpe OC
Fractional Bias(%) = -8.01
Fractional Gross Error(%) = 27.44
OC (microgram/m3)
Julian Date (182 - 209 2002)

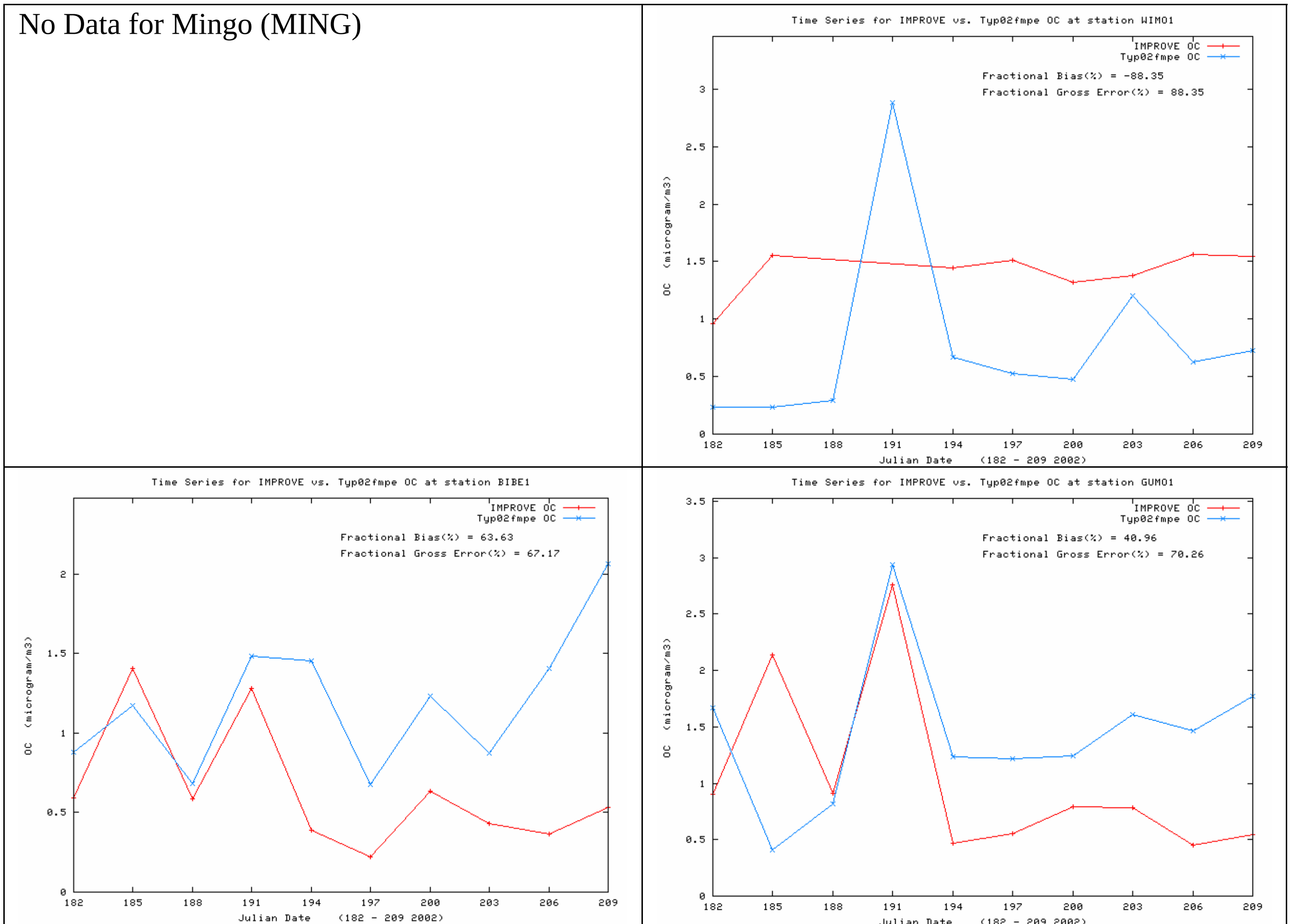


Figure C-18b. Time series of predicted and observed 24-hour organic matter carbon (OMC) concentrations at CENRAP IMPROVE CLASS I AREA sites in July 2002 for CMAQ 2002 36 km Base F base case simulation.

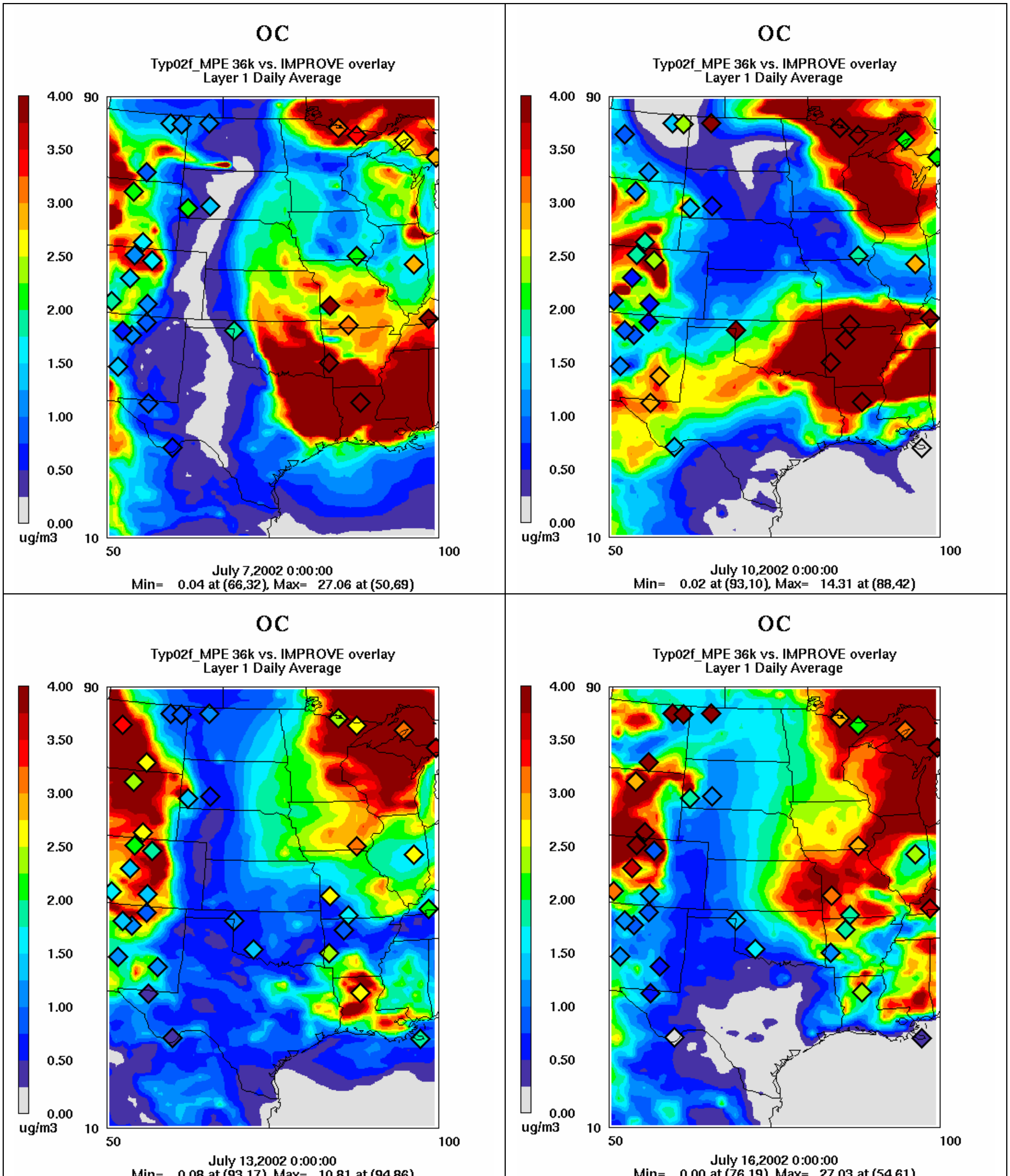


Figure C-18c. Spatial plot comparisons of the predicted and IMPROVE observed 24-hour OMC concentrations for July 7, 10, 13 and 16, 2002.

C.3.3.4 OMC in October 2002

OMC model performance in October 2002 is similar to the other months with near zero bias across the IMPROVE sites and an underestimation bias across the STN sites in the CENRAP region (Figure C-19a). Although OMC overestimation bias occurs at the Texas sites (BIBE and GUMO), the model is exhibiting remarkable ability to reproduce the observed temporal variation in OMC at several of the sites (e.g., CACR, UPBU, VOYA and HEGL; Figure C-19b). The model also performs reasonable well in reproducing the day to day and spatial variability in the observed OMC (Figure C-19c).

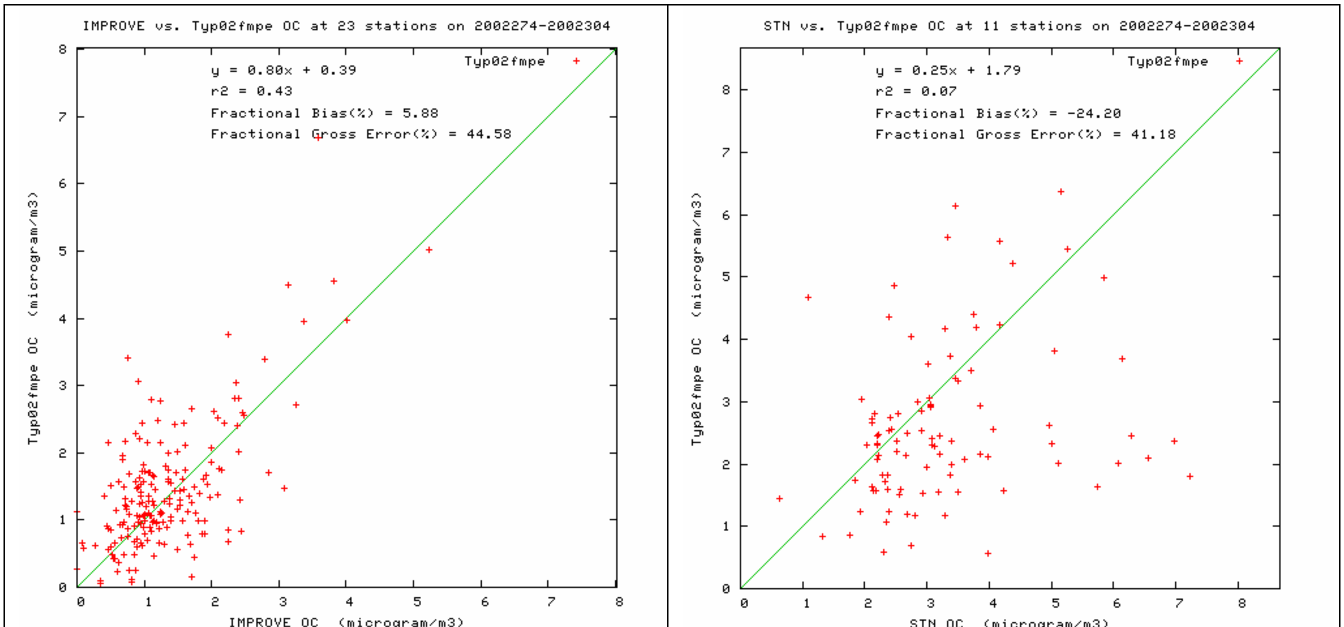
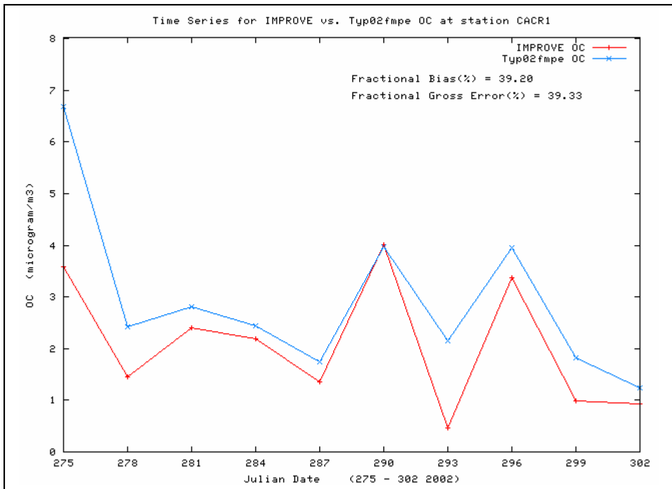
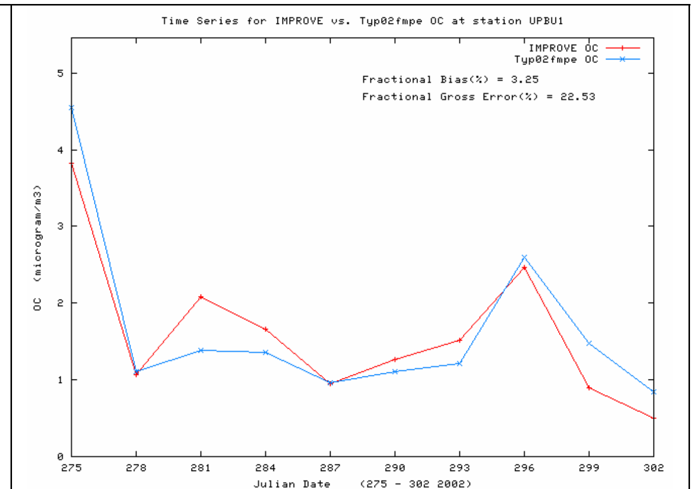
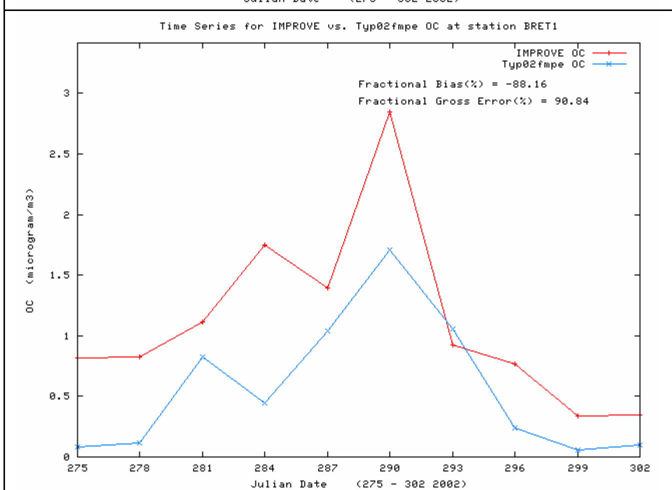
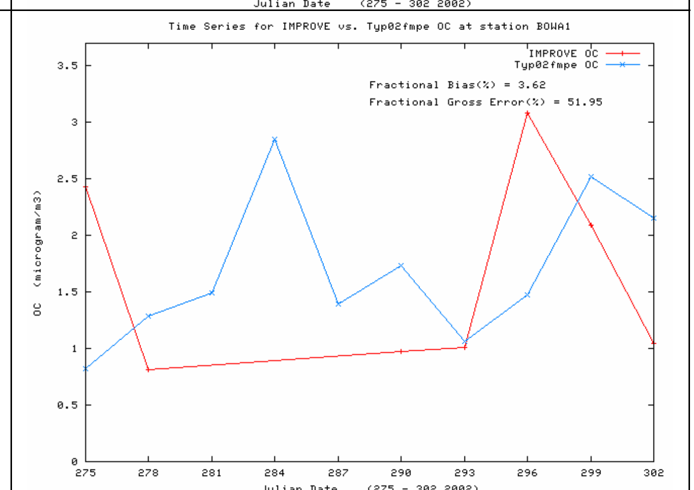


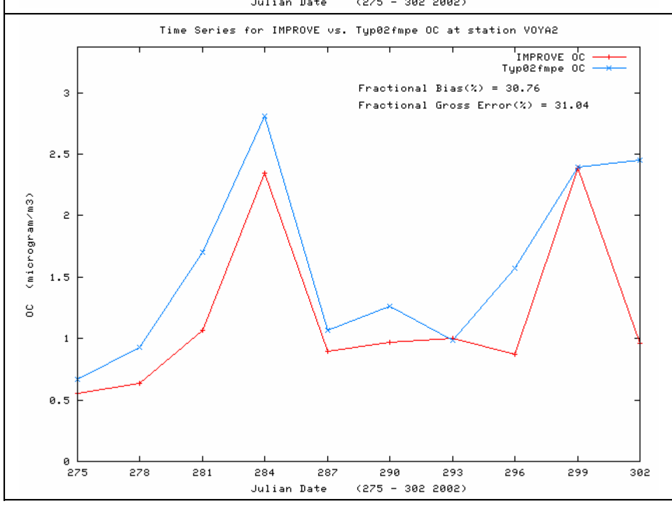
Figure C-19a. Scatter plots of predicted and observed organic matter carbon (OMC) concentrations for October 2002 and sites in the CENRAP region using IMPROVE (left) and STN (right) monitoring networks using the CMAQ 2002 36 km Base F base case simulation.

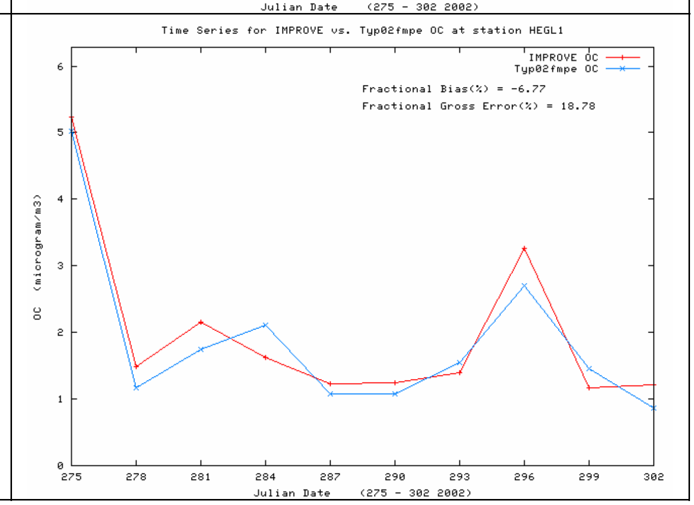

Time Series for IMPROVE vs. Typ02fmpe OC at station CACR1
IMPROVE OC
Typ02fmpe OC
Fractional Bias(%) = 39.20
Fractional Gross Error(%) = 39.33
OC (microgram/m3)
Julian Date (275 - 302 2002)


Time Series for IMPROVE vs. Typ02fmpe OC at station UPBU1
IMPROVE OC
Typ02fmpe OC
Fractional Bias(%) = 3.25
Fractional Gross Error(%) = 22.53
OC (microgram/m3)
Julian Date (275 - 302 2002)

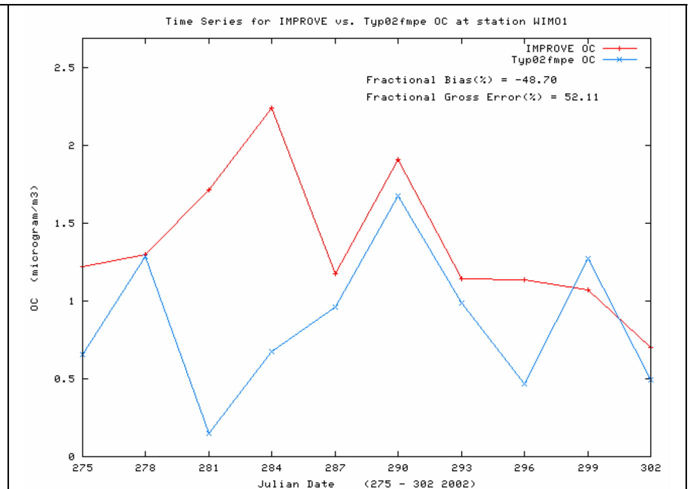

Time Series for IMPROVE vs. Typ02fmpe OC at station BRET1
IMPROVE OC
Typ02fmpe OC
Fractional Bias(%) = -88.16
Fractional Gross Error(%) = 90.84
OC (microgram/m3)
Julian Date (275 - 302 2002)

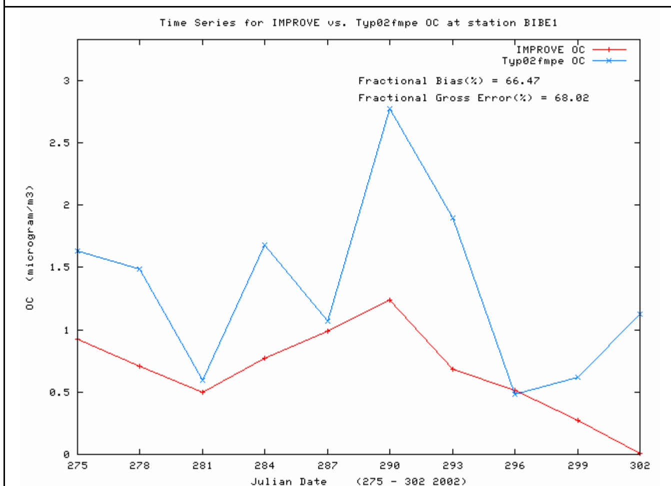

Time Series for IMPROVE vs. Typ02fmpe OC at station BOWA1
IMPROVE OC
Typ02fmpe OC
Fractional Bias(%) = 3.62
Fractional Gross Error(%) = 51.95
OC (microgram/m3)
Julian Date (275 - 302 2002)


Time Series for IMPROVE vs. Typ02fmpe OC at station VOYA2
IMPROVE OC
Typ02fmpe OC
Fractional Bias(%) = 30.76
Fractional Gross Error(%) = 31.04
OC (microgram/m3)
Julian Date (275 - 302 2002)


Time Series for IMPROVE vs. Typ02fmpe OC at station HEGL1
IMPROVE OC
Typ02fmpe OC
Fractional Bias(%) = -6.77
Fractional Gross Error(%) = 18.78
OC (microgram/m3)
Julian Date (275 - 302 2002)

No Data for Mingo (MING)





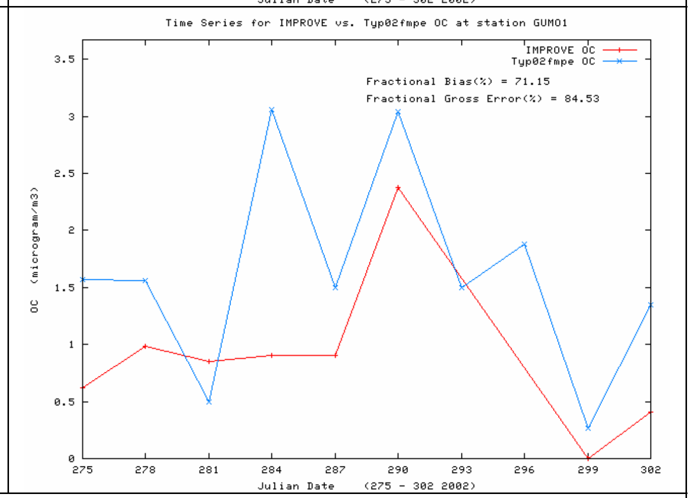


Figure C-19b. Time series of predicted and observed 24-hour organic matter carbon (OMC) concentrations at CENRAP IMPROVE CLASS I AREA sites in October 2002 for CMAQ 2002 36 km Base F base case simulation.

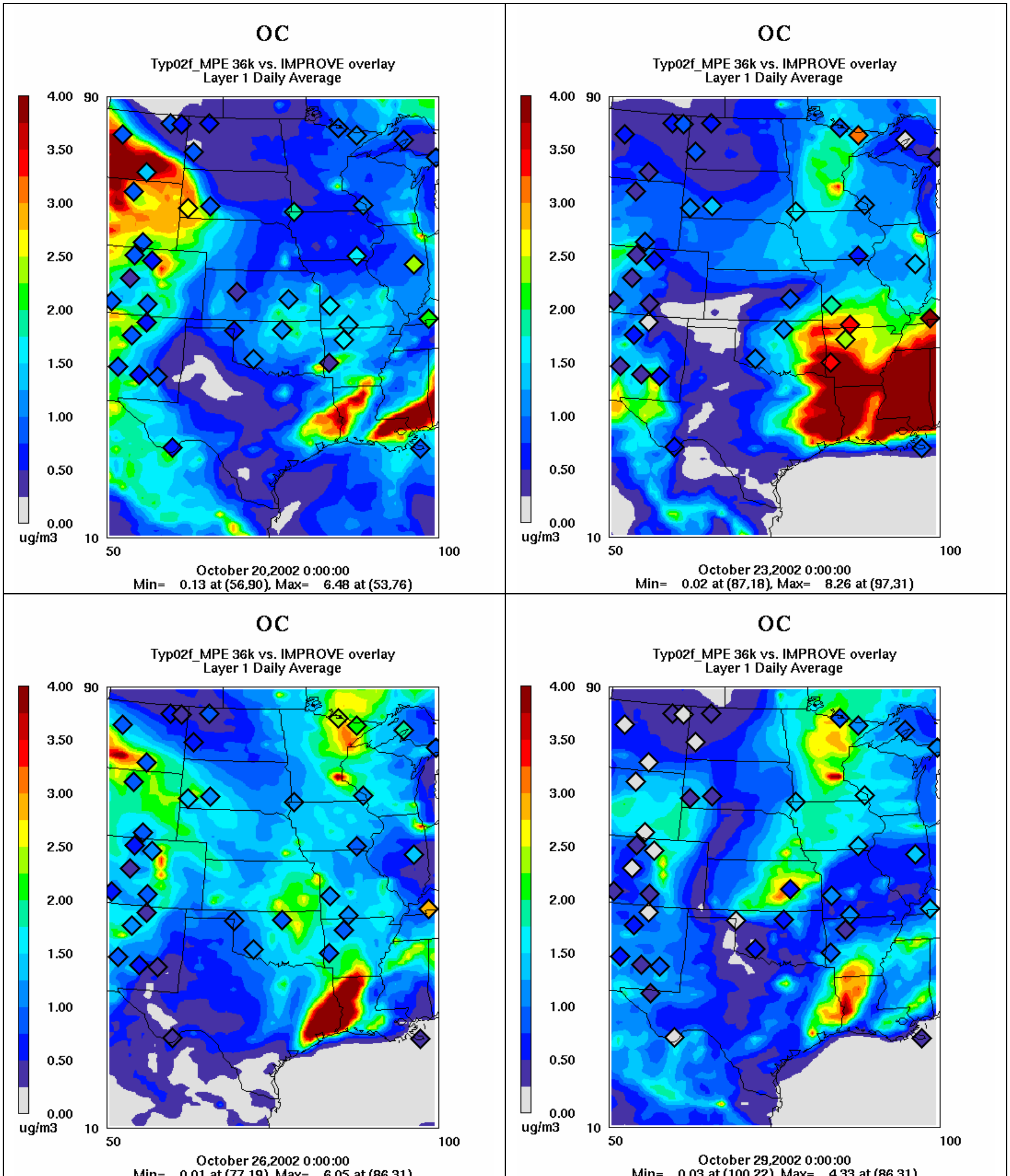


Figure C-19c. Spatial plot comparisons of the predicted and IMPROVE observed 24-hour OMC concentrations for October 20, 23, 26 and 29, 2002.

C.3.3.5 OMC Monthly Bias and Error

The OMC monthly bias and error across IMPROVE and STN sites in the CENRAP region are shown in Figure C-20. The bias performance for OMC at the IMPROVE sites are quite good throughout the year with values generally within ±20%, albeit with a slight winter overestimation and summer underestimation bias. At the urban STN sites the model exhibits an underestimation bias throughout the year that ranges from -20% to -50%. Fractional errors are mostly within 40% to 60% with the STN network generally exhibiting more error than IMPROVE.

The good performance of the model for OMC at the IMPROVE sites is also reflected in the Bugle Plot (Figure C-21) with the bias and error achieving the proposed PM model performance goal for all months of the year. At the STN sites, however, the OMC bias falls between the proposed PM model performance goal and criteria, with error right at the goal for most months.

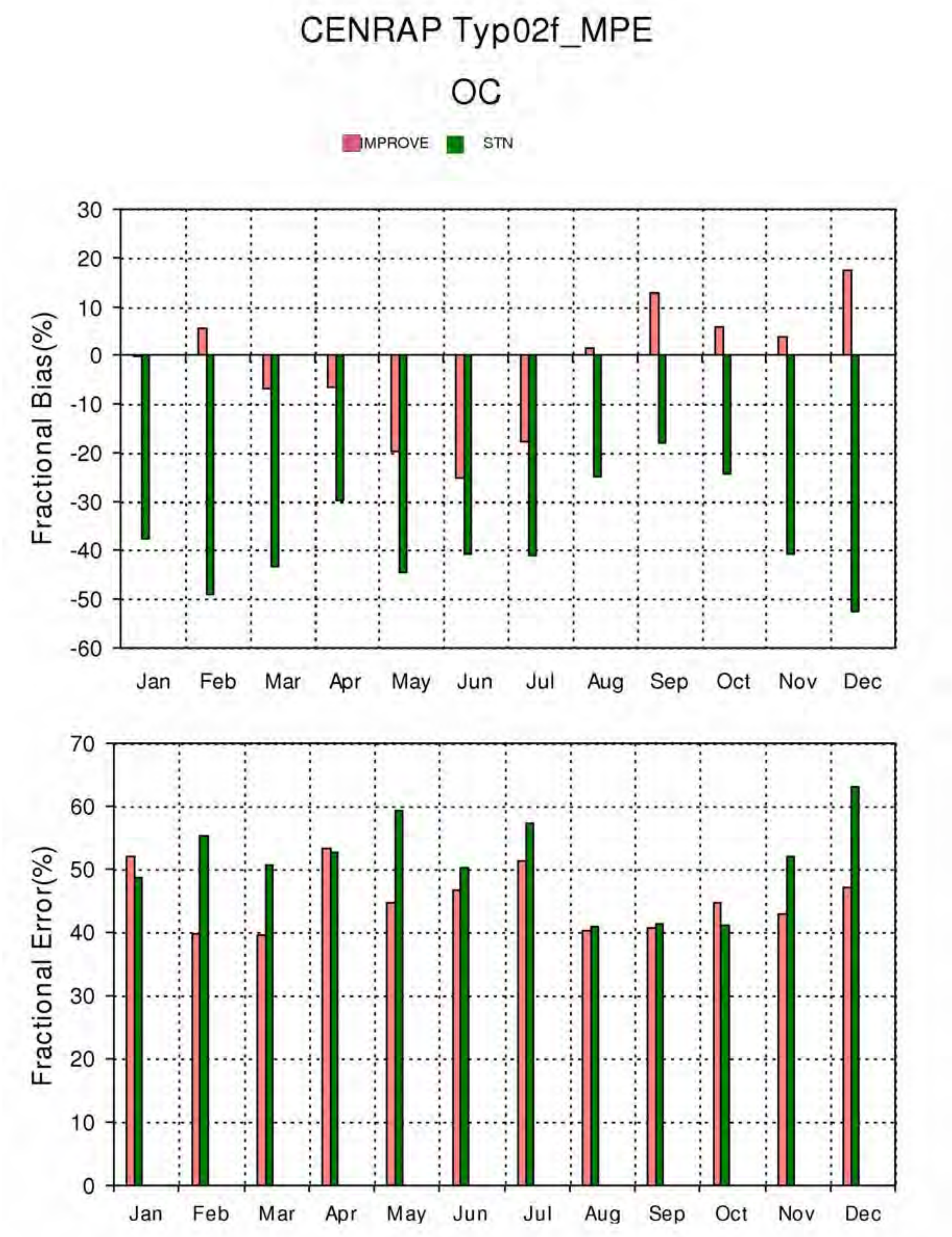


Figure C-20. Monthly OMC fractional bias (top) and fractional gross error (bottom) statistical measures for IMPROVE and STN monitoring sites in the CENRAP region.

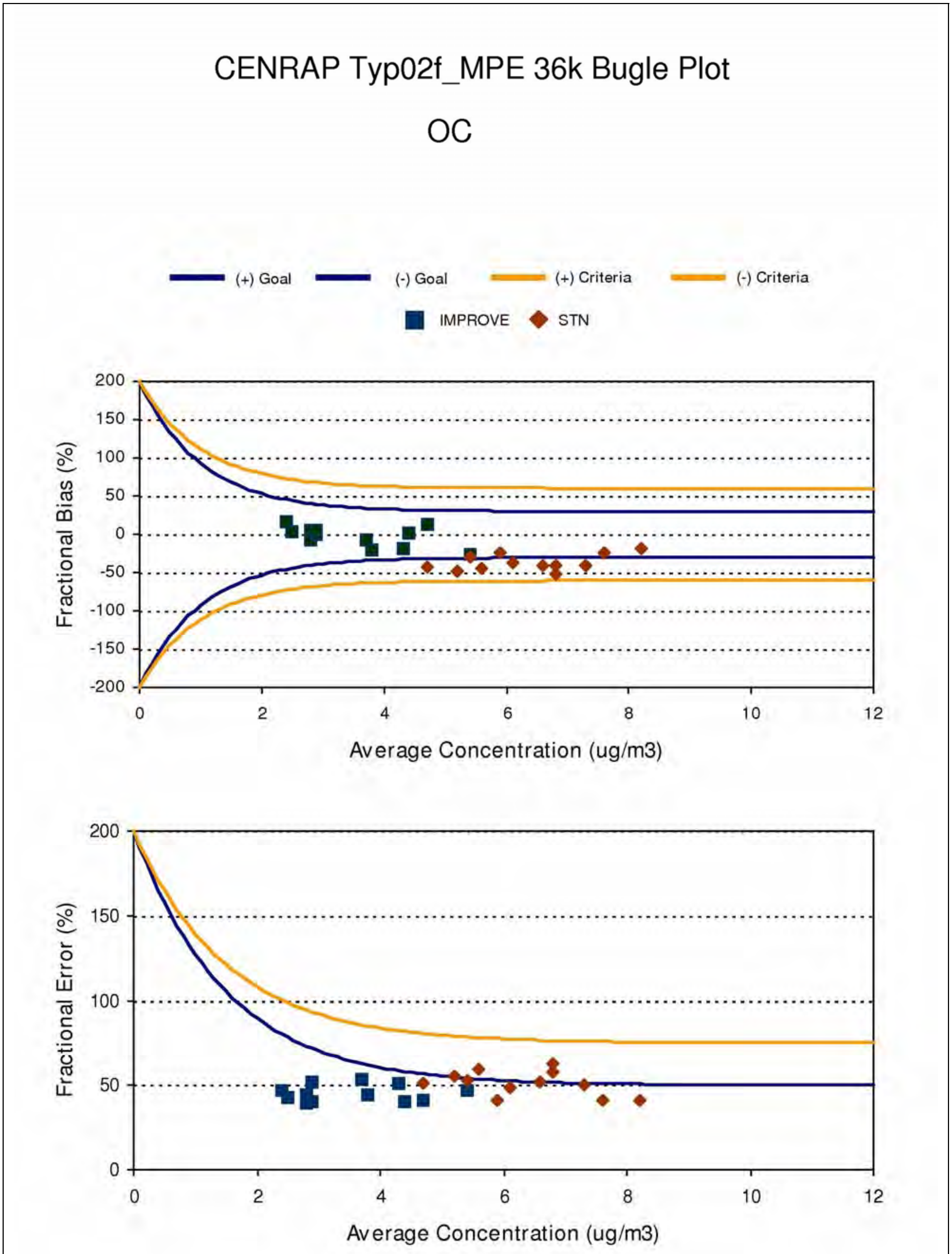


Figure C-21. Bugle Plots of monthly fractional bias (top) and fractional gross error (bottom) and comparisons with model performance goals and criteria for OMC and IMPROVE and STN monitoring sites in the CENRAP region.

C.3.4 Elemental Carbon (EC) Monthly Model Performance

Elemental Carbon (EC) measurements are also uncertain, with the IMPROVE and STN using different measurement technologies with different measurement artifacts.

C.3.4.1 EC in January 2002

Although there is a lot of scatter in the January EC scatter plots at the IMPROVE and STN sites, the bias is fairly low (-24% and 1%) with errors in the 40%-50% range (Figure C-22a). The time series comparisons (Figure C-22b) suggest an EC underestimation bias at BRET and an overestimation bias at the northern Minnesota sites (VOYA and BOWA). The model generally agrees with the observed spatial distribution of EC in January with higher values on the eastern than western portions of the CENRAP region (Figure C-22c).

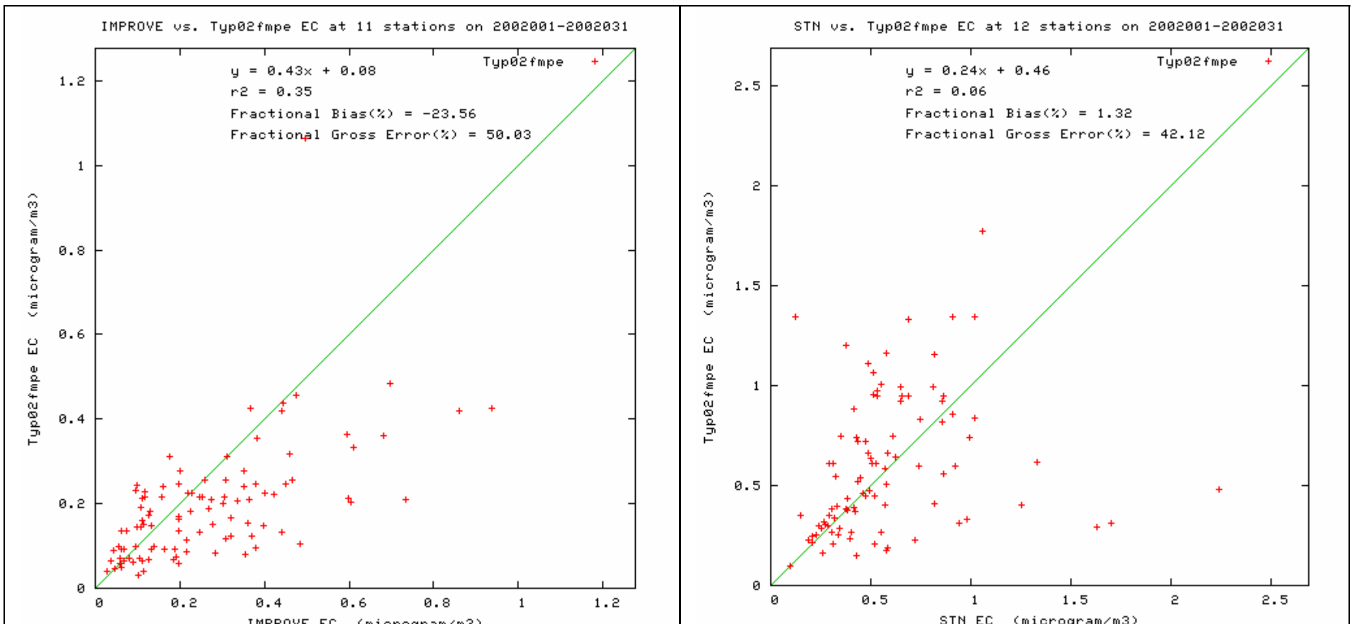
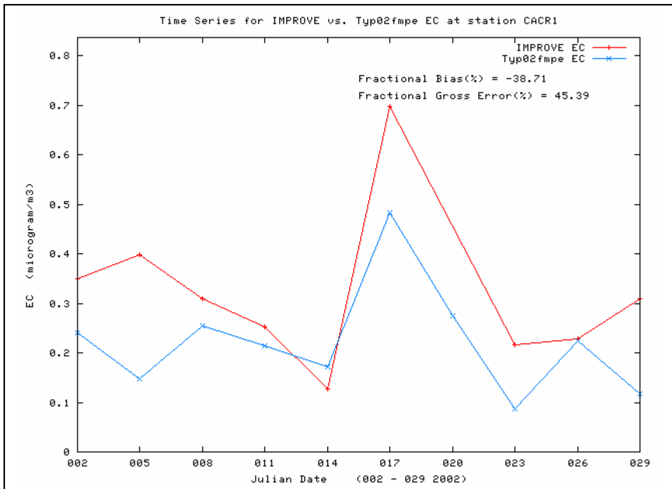
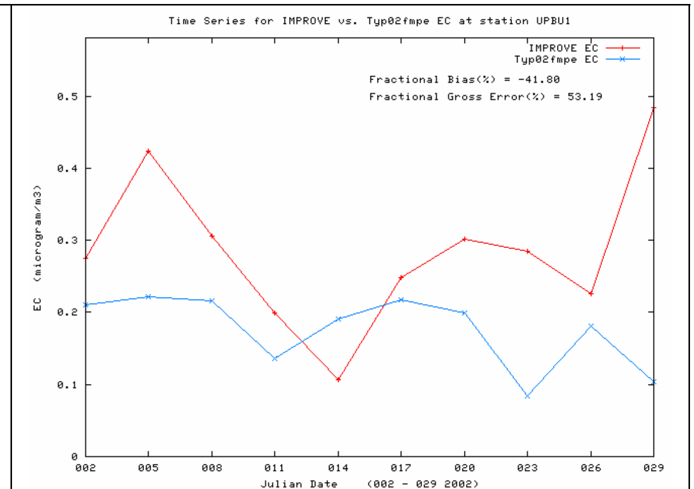
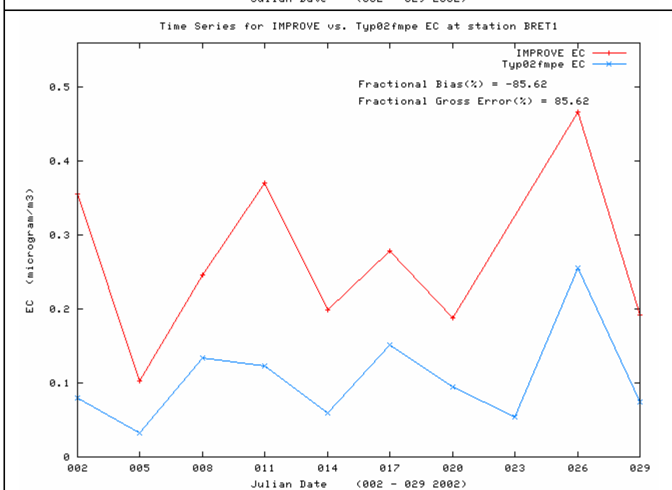
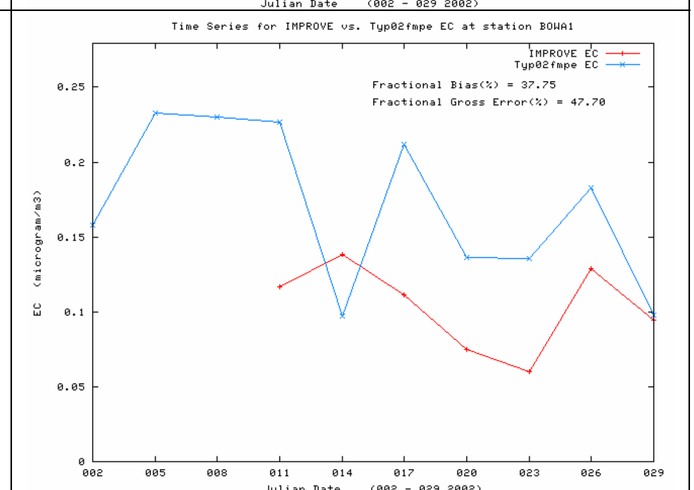


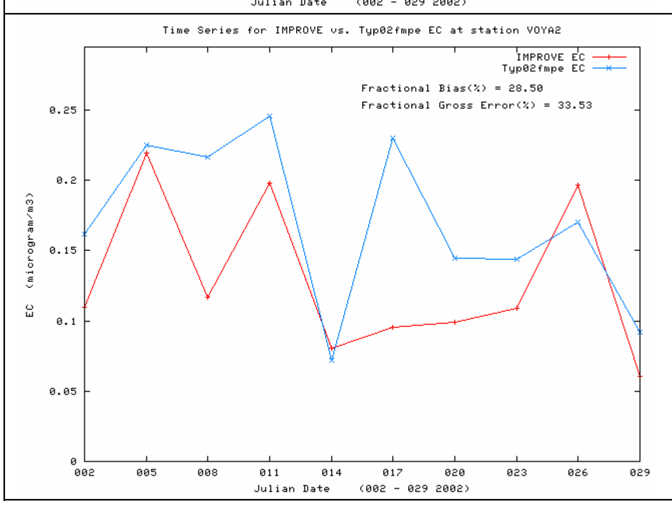
Figure C-22a. Scatter plots of predicted and observed elemental carbon (EC) concentrations for January 2002 and sites in the CENRAP region using IMPROVE (left) and STN (right) monitoring networks using the CMAQ 2002 36 km Base F base case simulation.

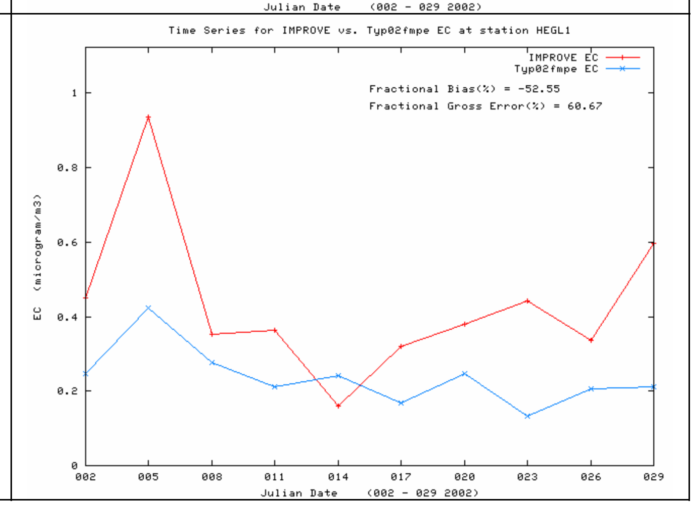

Time Series for IMPROVE vs. Typ02fmpe EC at station CACR1
IMPROVE EC
Typ02fmpe EC
Fractional Bias(%) = -38.71
Fractional Gross Error(%) = 45.39
EC (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe EC at station UPBU1
IMPROVE EC
Typ02fmpe EC
Fractional Bias(%) = -41.80
Fractional Gross Error(%) = 53.19
EC (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe EC at station BRET1
IMPROVE EC
Typ02fmpe EC
Fractional Bias(%) = -85.62
Fractional Gross Error(%) = 85.62
EC (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe EC at station BOWA1
IMPROVE EC
Typ02fmpe EC
Fractional Bias(%) = 37.75
Fractional Gross Error(%) = 47.70
EC (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe EC at station VOYA2
IMPROVE EC
Typ02fmpe EC
Fractional Bias(%) = 28.50
Fractional Gross Error(%) = 33.53
EC (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe EC at station HEGL1
IMPROVE EC
Typ02fmpe EC
Fractional Bias(%) = -52.55
Fractional Gross Error(%) = 60.67
EC (microgram/m3)
Julian Date (002 - 029 2002)

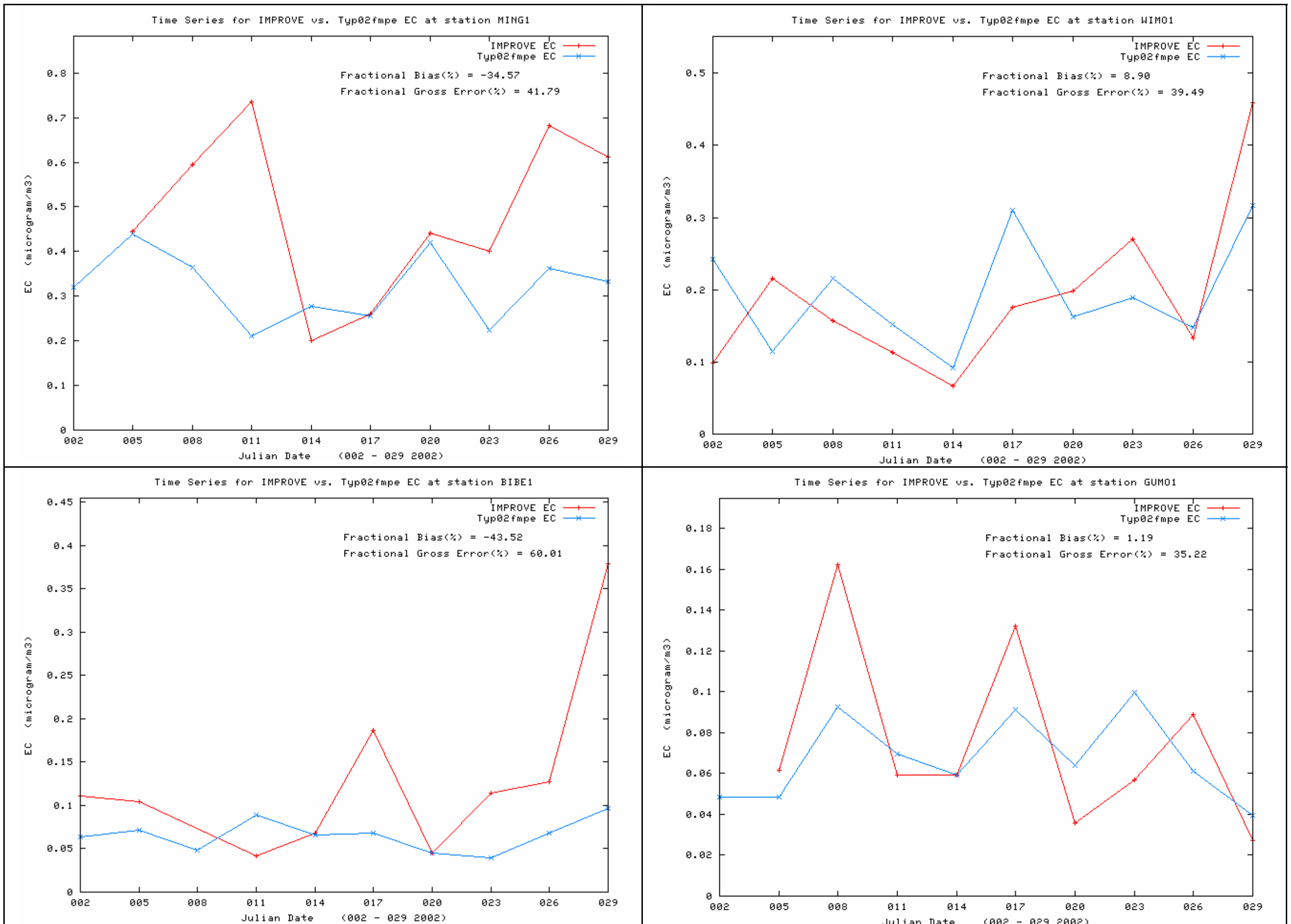


Figure C-22b. Time series of predicted and observed 24-hour elemental carbon (EC) concentrations at CENRAP IMPROVE CLASS I AREA sites in January 2002 for CMAQ 2002 36 km Base F base case simulation.

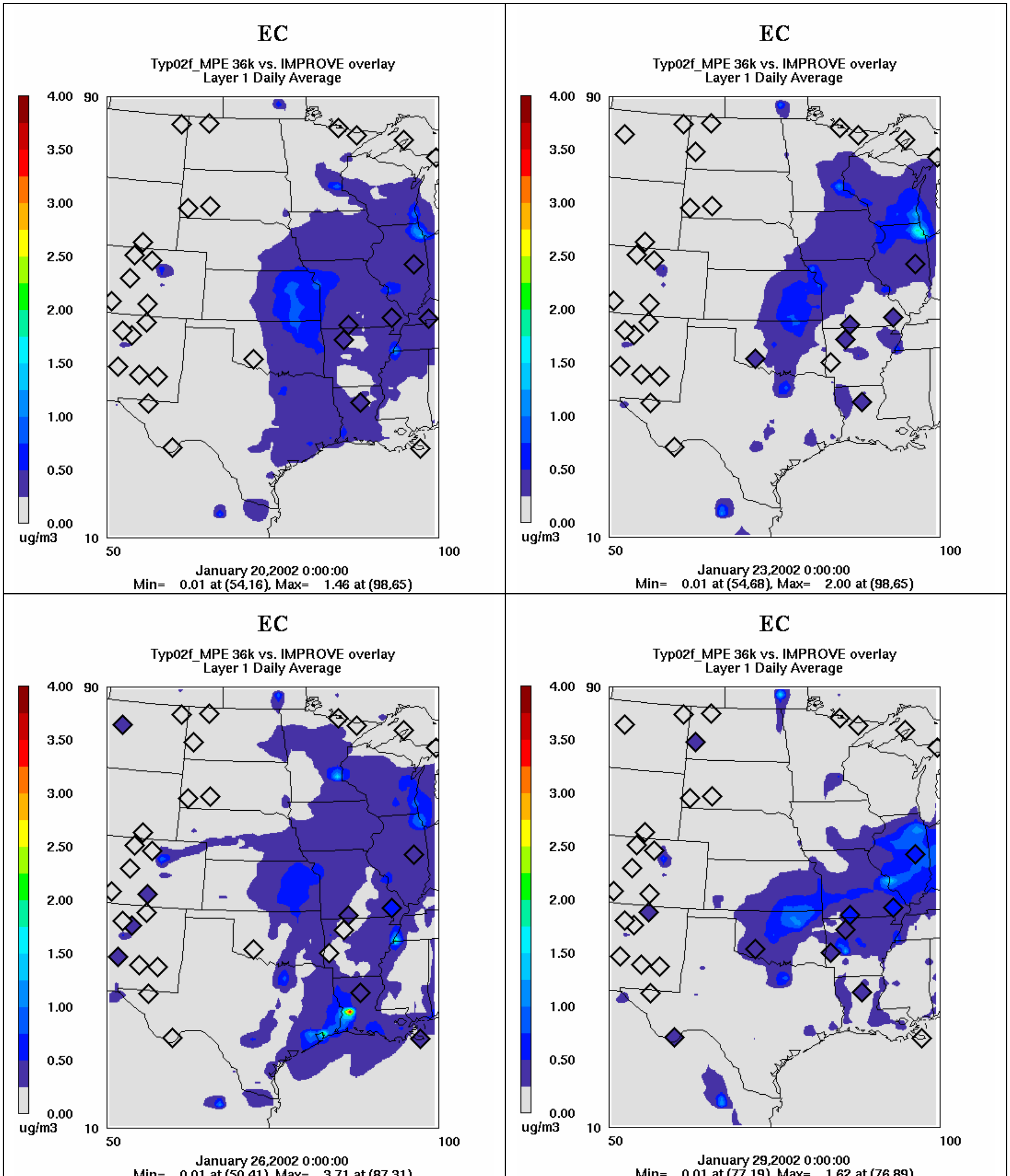


Figure C-22c. Spatial plot comparisons of the predicted and IMPROVE observed 24-hour EC concentrations for January 20, 23, 26 and 29, 2002.

C.3.4.2 EC in April 2002

EC is underestimated at the IMPROVE sites in April (bias of -48%), but reproduced well at the STN sites (bias of -13%). Although EC is underestimated at the IMPROVE sites both the model and observations agree that EC concentrations are very small and not a significant component of the PM budget. The model fails to capture the day-to-day variability in the observed EC at the IMPROVE sites and exhibits a systematic under-prediction tendency at some sites (Figure C-23b). On April 5 and 11 the model reproduces the spatial distribution of the observed EC reasonable well with higher values in the eastern than western portion of the CENRAP region. But on April 8 and 14 the model is much to clean in the eastern portion of the CENRAP region (Figure C-23c).

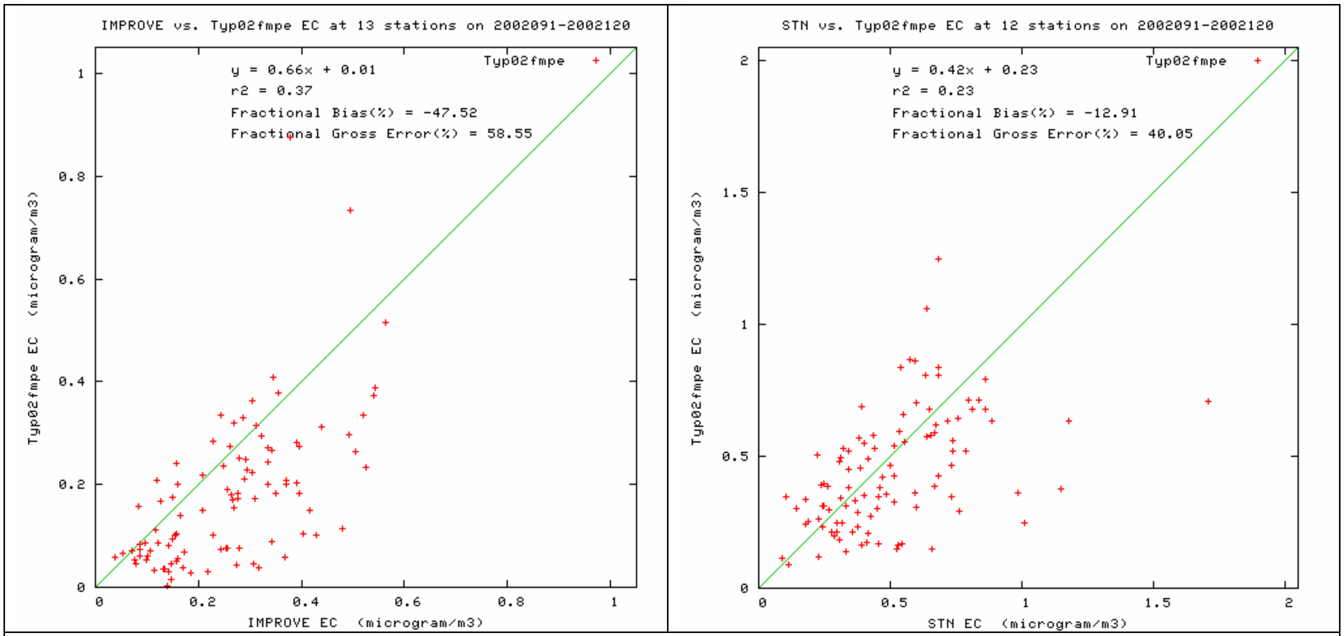
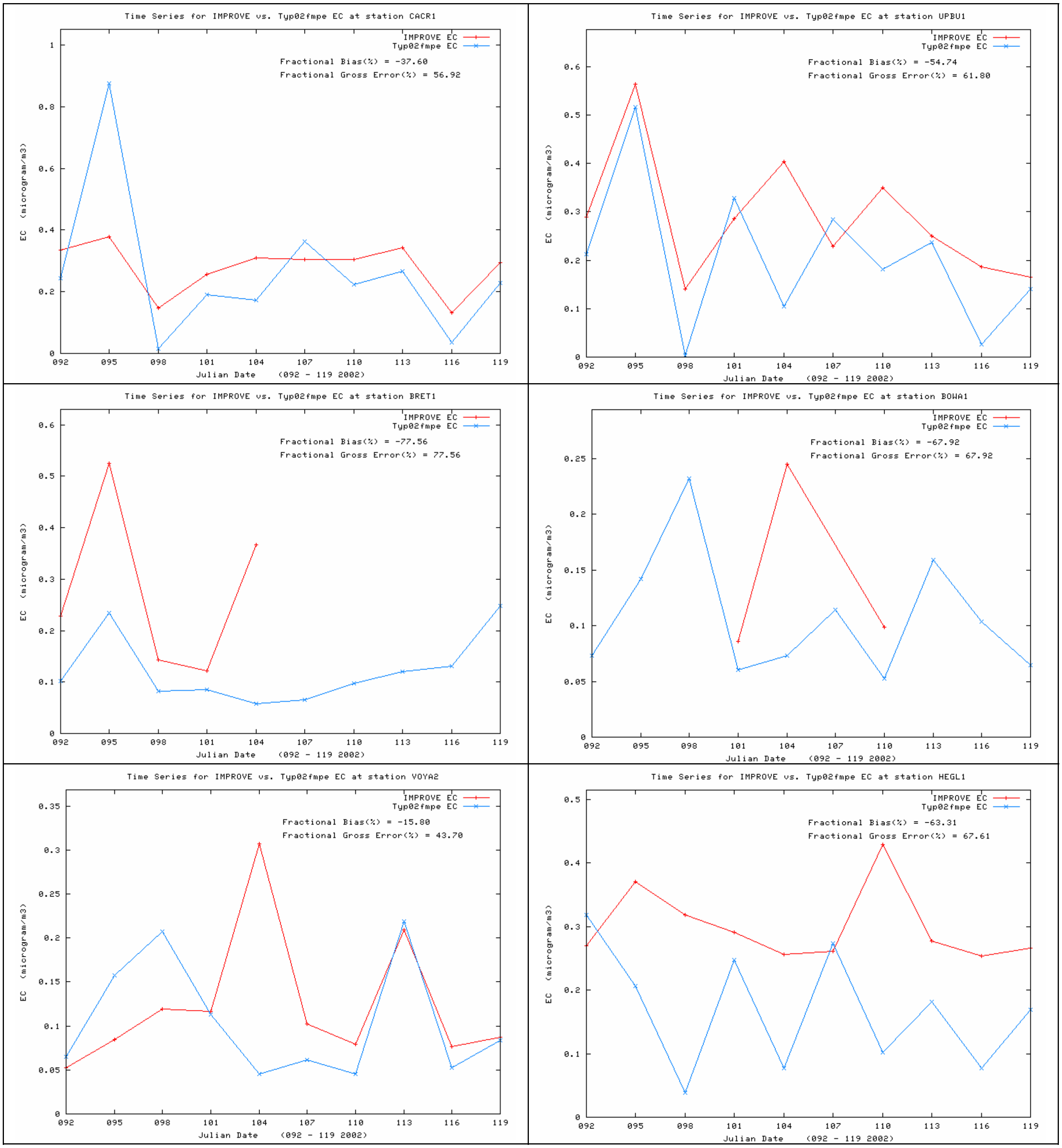


Figure C-23a. Scatter plots of predicted and observed elemental carbon (EC) concentrations for April 2002 and sites in the CENRAP region using IMPROVE (left) and STN (right) monitoring networks using the CMAQ 2002 36 km Base F base case simulation


Time Series for IMPROVE vs. Typ02fmpe EC at station CACR1
IMPROVE EC
Typ02fmpe EC
Fractional Bias(%) = -37.60
Fractional Gross Error(%) = 56.92
EC (microgram/m3)
Julian Date (092 - 119 2002)
Time Series for IMPROVE vs. Typ02fmpe EC at station UPBU1
IMPROVE EC
Typ02fmpe EC
Fractional Bias(%) = -54.74
Fractional Gross Error(%) = 61.80
EC (microgram/m3)
Julian Date (092 - 119 2002)
Time Series for IMPROVE vs. Typ02fmpe EC at station BRET1
IMPROVE EC
Typ02fmpe EC
Fractional Bias(%) = -77.56
Fractional Gross Error(%) = 77.56
EC (microgram/m3)
Julian Date (092 - 119 2002)
Time Series for IMPROVE vs. Typ02fmpe EC at station BOWA1
IMPROVE EC
Typ02fmpe EC
Fractional Bias(%) = -67.92
Fractional Gross Error(%) = 67.92
EC (microgram/m3)
Julian Date (092 - 119 2002)
Time Series for IMPROVE vs. Typ02fmpe EC at station VOYA2
IMPROVE EC
Typ02fmpe EC
Fractional Bias(%) = -15.80
Fractional Gross Error(%) = 43.70
EC (microgram/m3)
Julian Date (092 - 119 2002)
Time Series for IMPROVE vs. Typ02fmpe EC at station HEGL1
IMPROVE EC
Typ02fmpe EC
Fractional Bias(%) = -63.31
Fractional Gross Error(%) = 67.61
EC (microgram/m3)
Julian Date (092 - 119 2002)

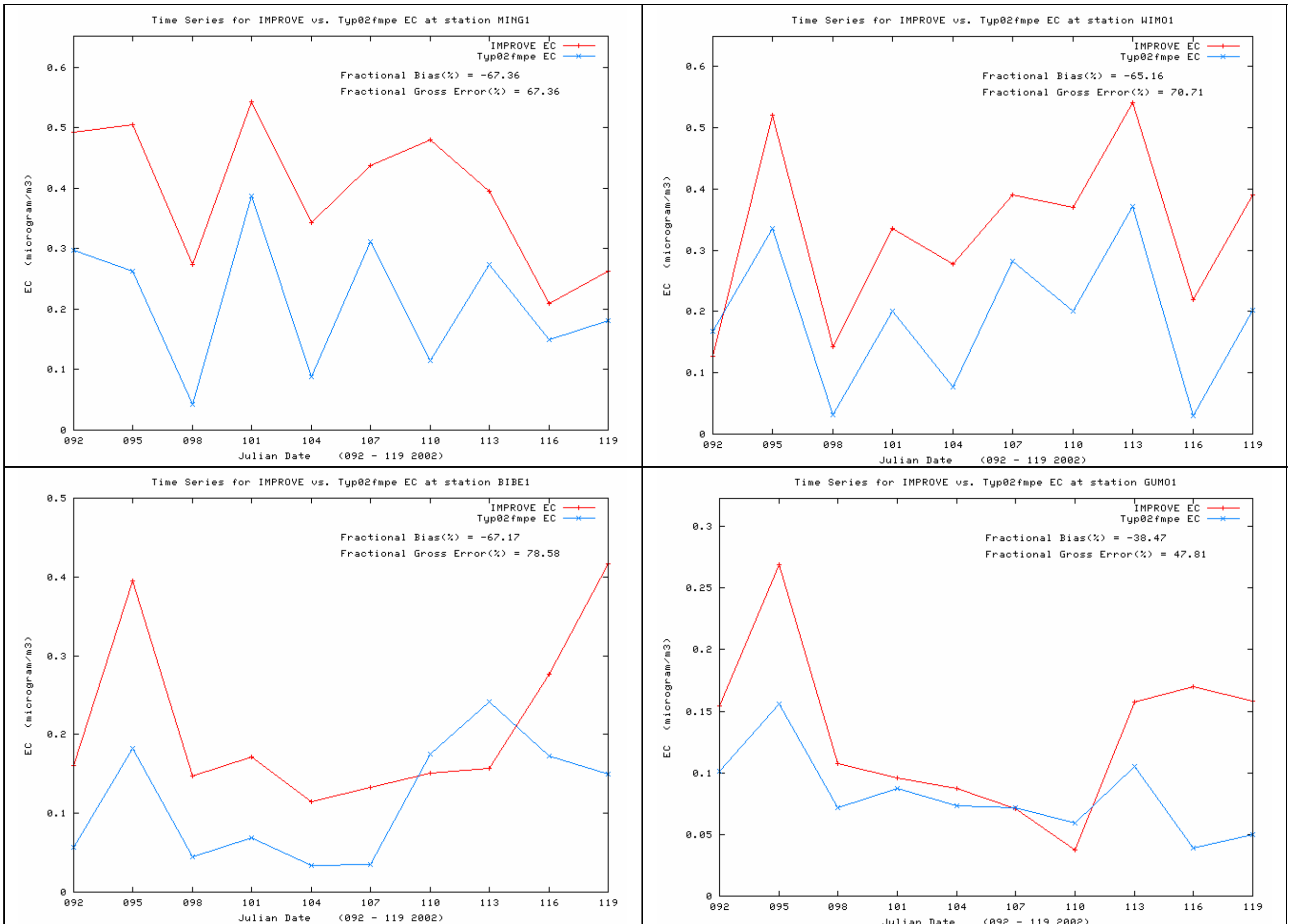


Figure C-23b. Time series of predicted and observed 24-hour elemental carbon (EC) concentrations at CENRAP IMPROVE CLASS I AREA sites in April 2002 for CMAQ 2002 36 km Base F base case simulation.

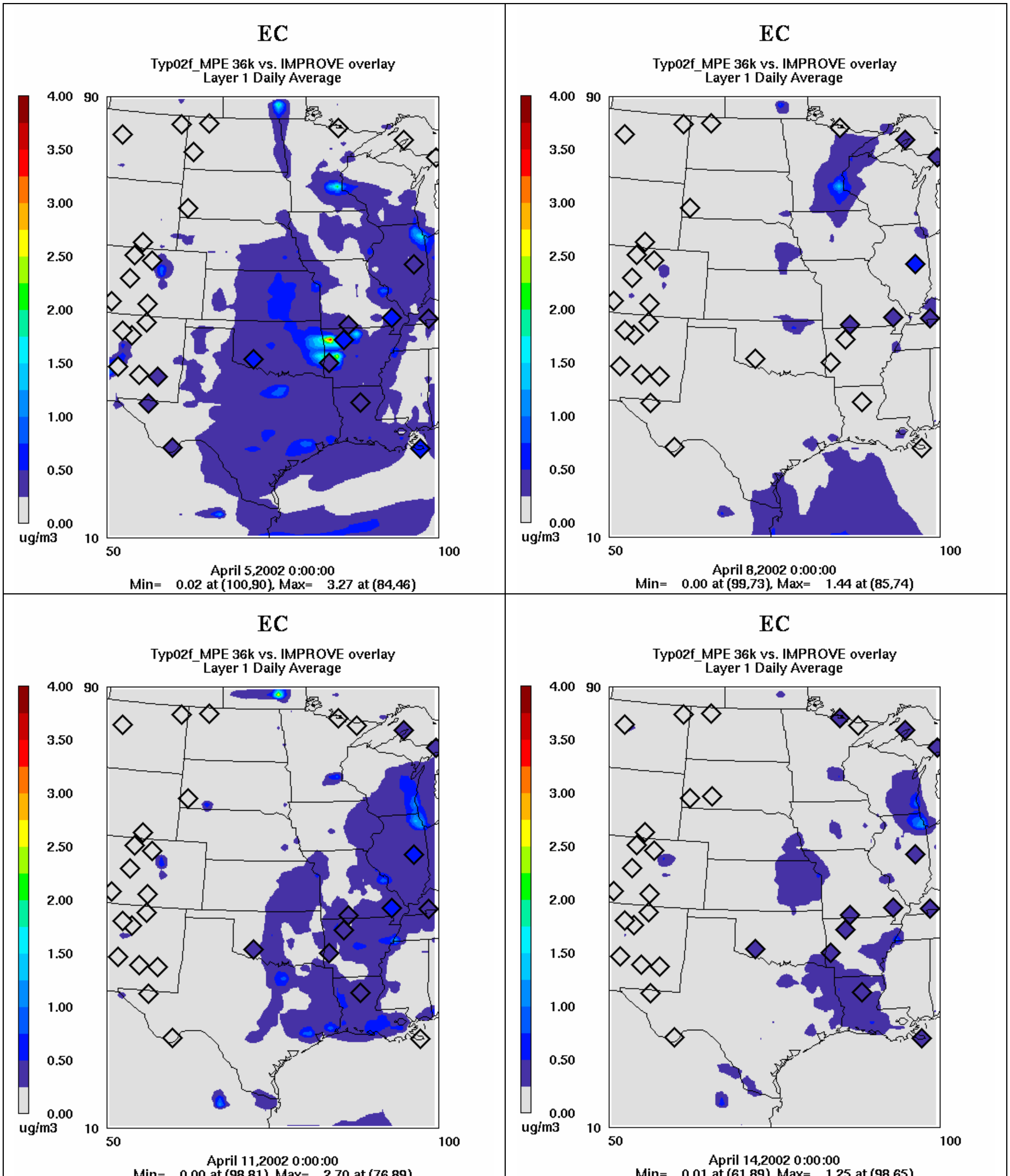


Figure C-23c. Spatial plot comparisons of the predicted and IMPROVE observed 24-hour EC concentrations for April 5, 8, 11 and 14, 2002.

C.3.3.3 EC in July 2002

July EC performance is similar to the other months with near zero bias across he STN sites and an underestimation bias across the IMPROVE sites (Figure C-24). Again the model and observations agree that EC is low in July and not a significant component of visibility impairment.

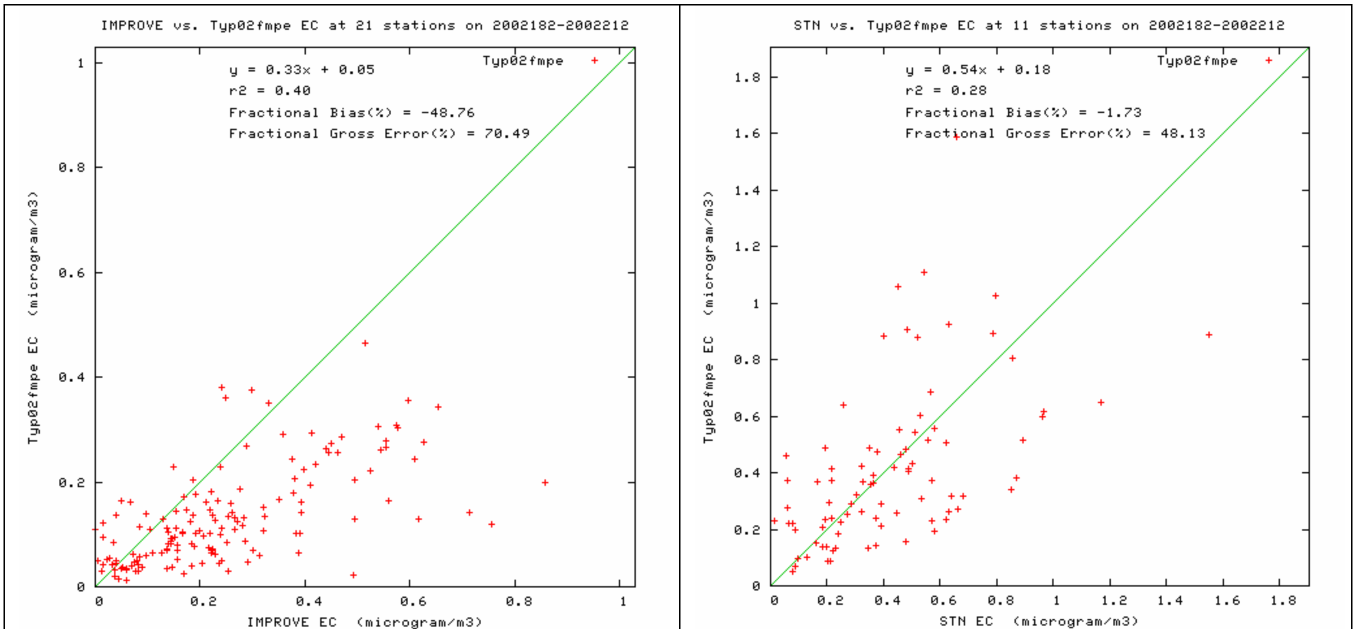
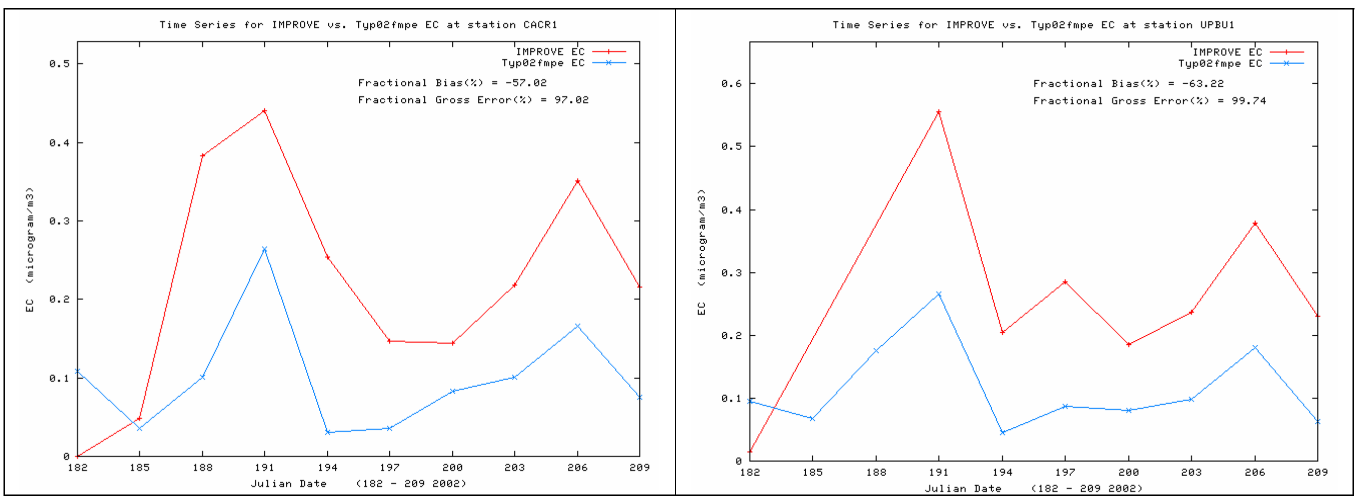
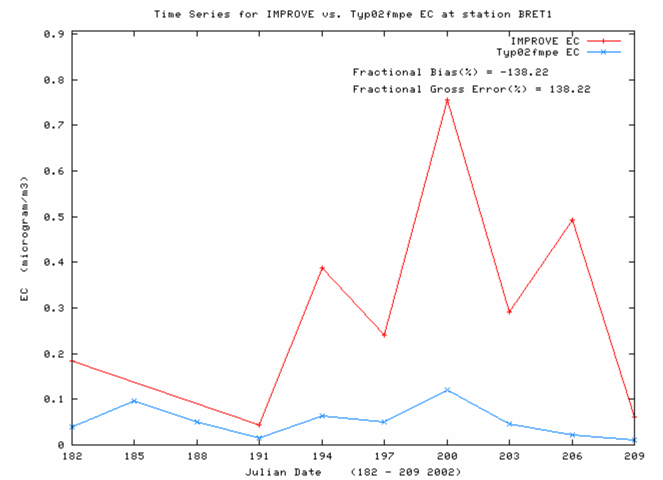
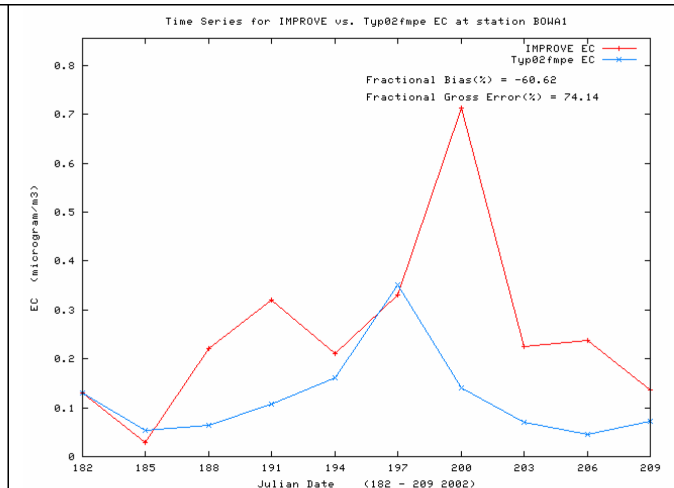
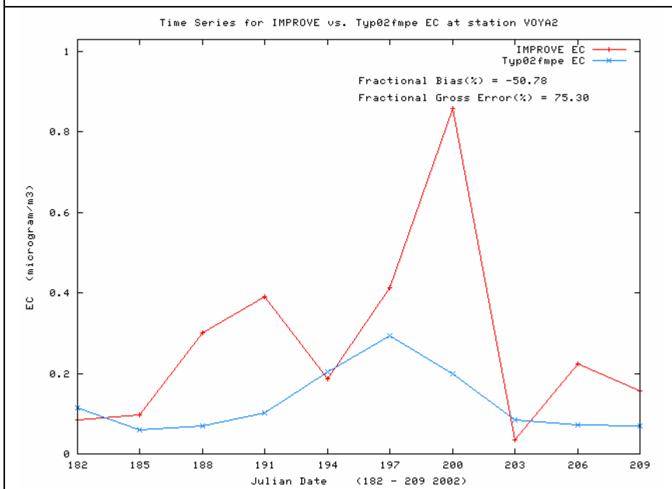


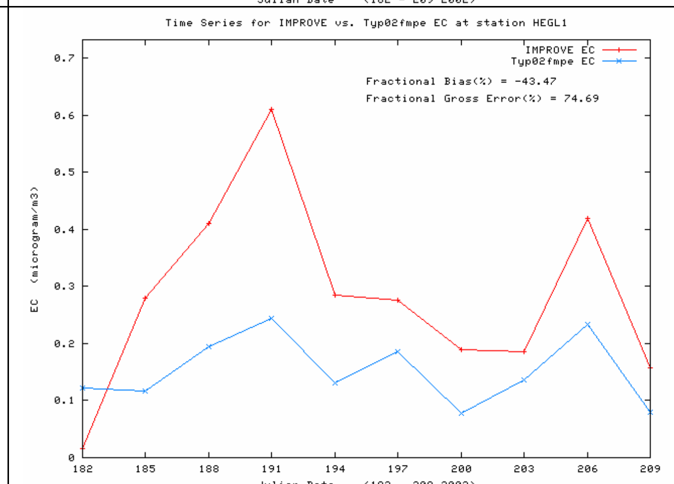
Figure C-24a. Scatter plots of predicted and observed elemental carbon (EC) concentrations for July 2002 and sites in the CENRAP region using IMPROVE (left) and STN (right) monitoring networks using the CMAQ 2002 36 km Base F base case simulation.



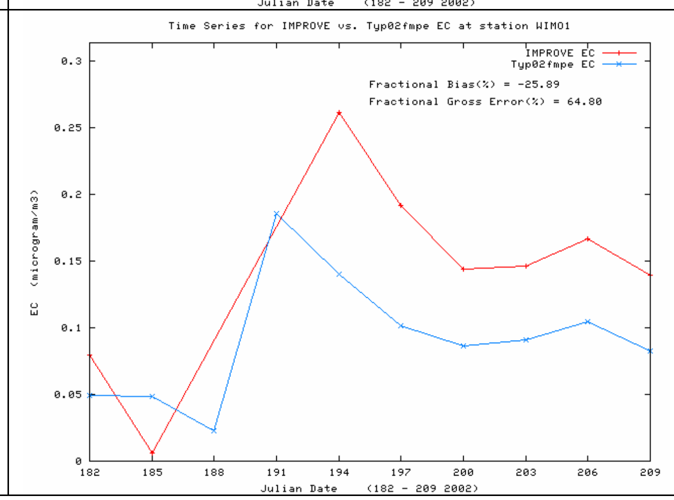








No Data for Mingo (MING)



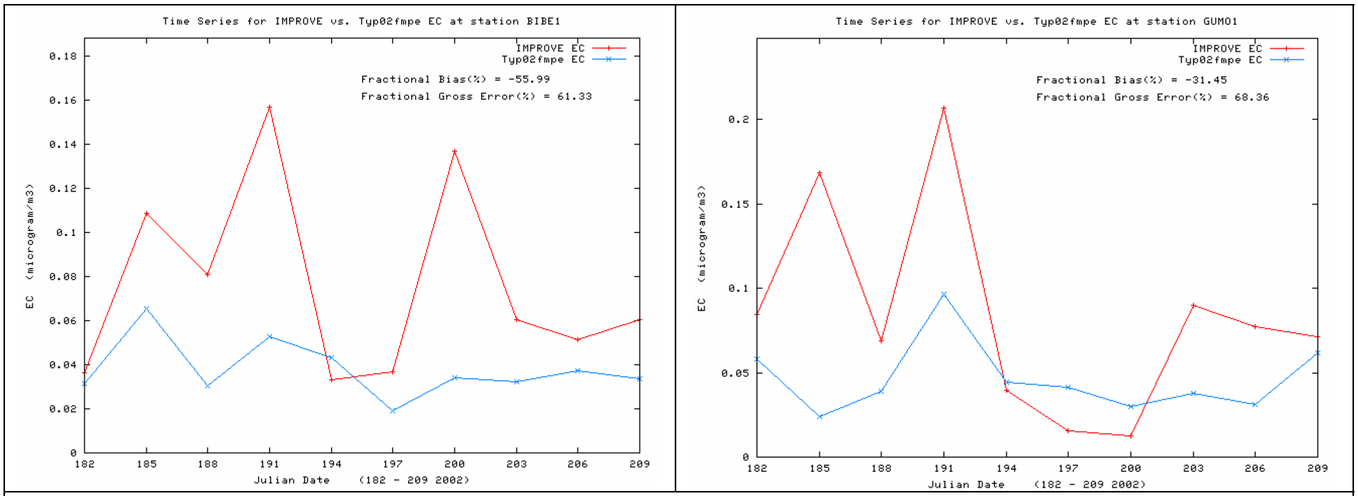


Figure C-24b. Time series of predicted and observed 24-hour elemental carbon (EC) concentrations at CENRAP IMPROVE CLASS I AREA sites in July 2002 for CMAQ 2002 36 km Base F base case simulation.

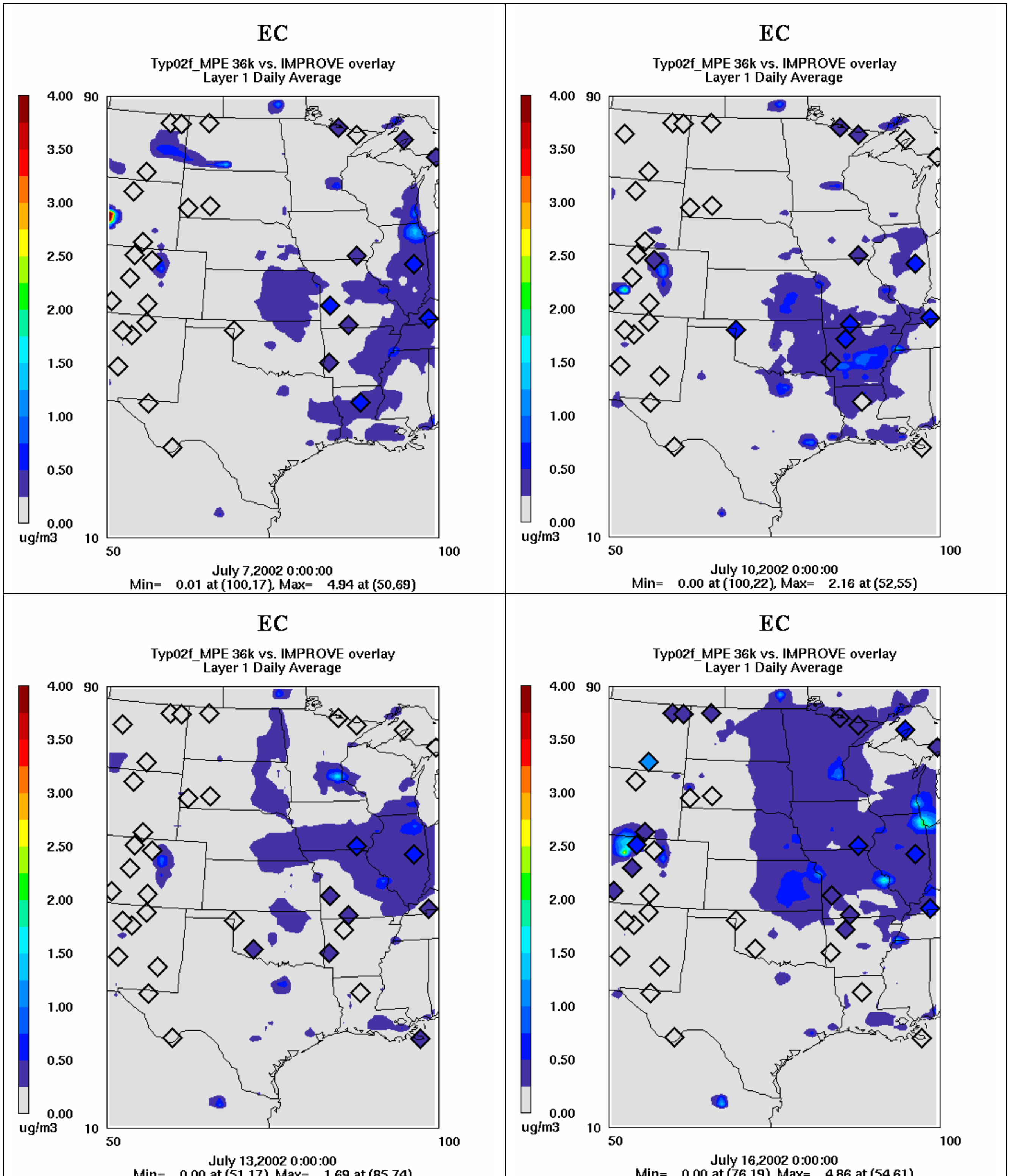


Figure C-24c. Spatial plot comparisons of the predicted and IMPROVE observed 24-hour EC concentrations for July 7, 10, 13 and 16, 2002.

C.3.4.4 EC in October 2002

EC performance is improved at the IMPROVE sites in October with lower bias (9%) than the previous months where an under-prediction tendency was seen (Figure C-25a). EC bias is also fairly low at the STN sites with errors across both networks of approximately 50%. Although there is a systematic underestimation of EC at BRET, the agreement between the predicted and observed October time series (Figure C-25b) is remarkable at several sites (e.g., CACR, UPBU, VOYA and HEGL).

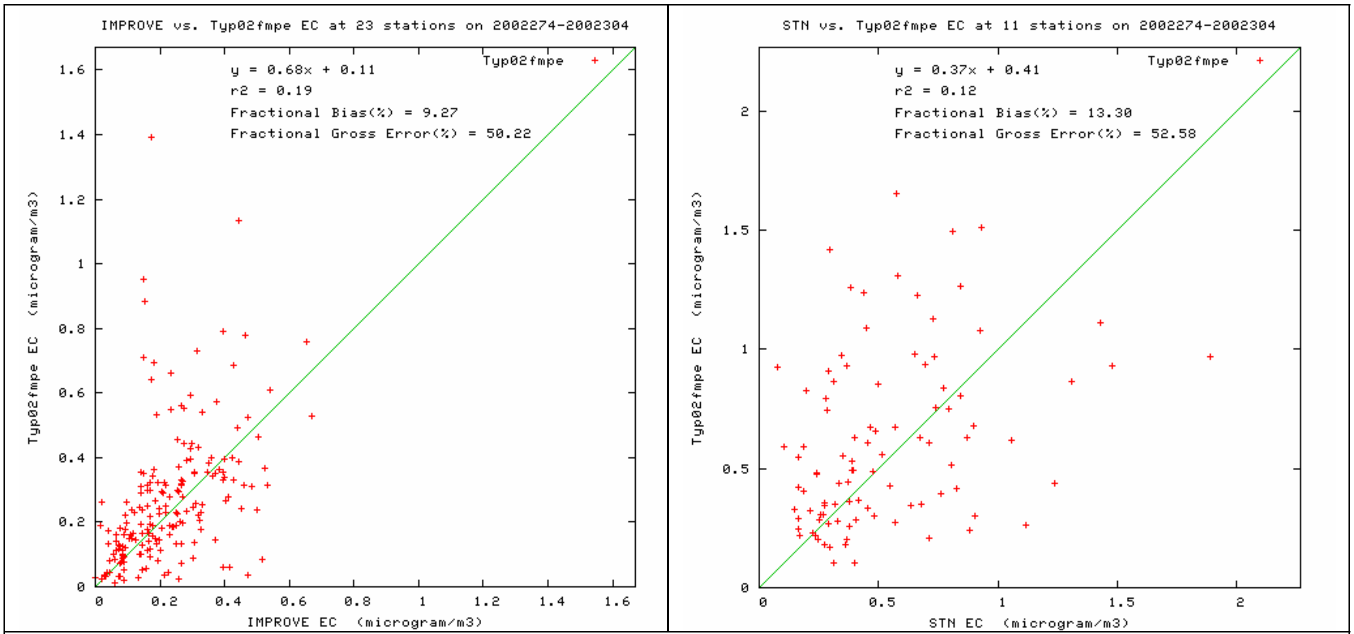
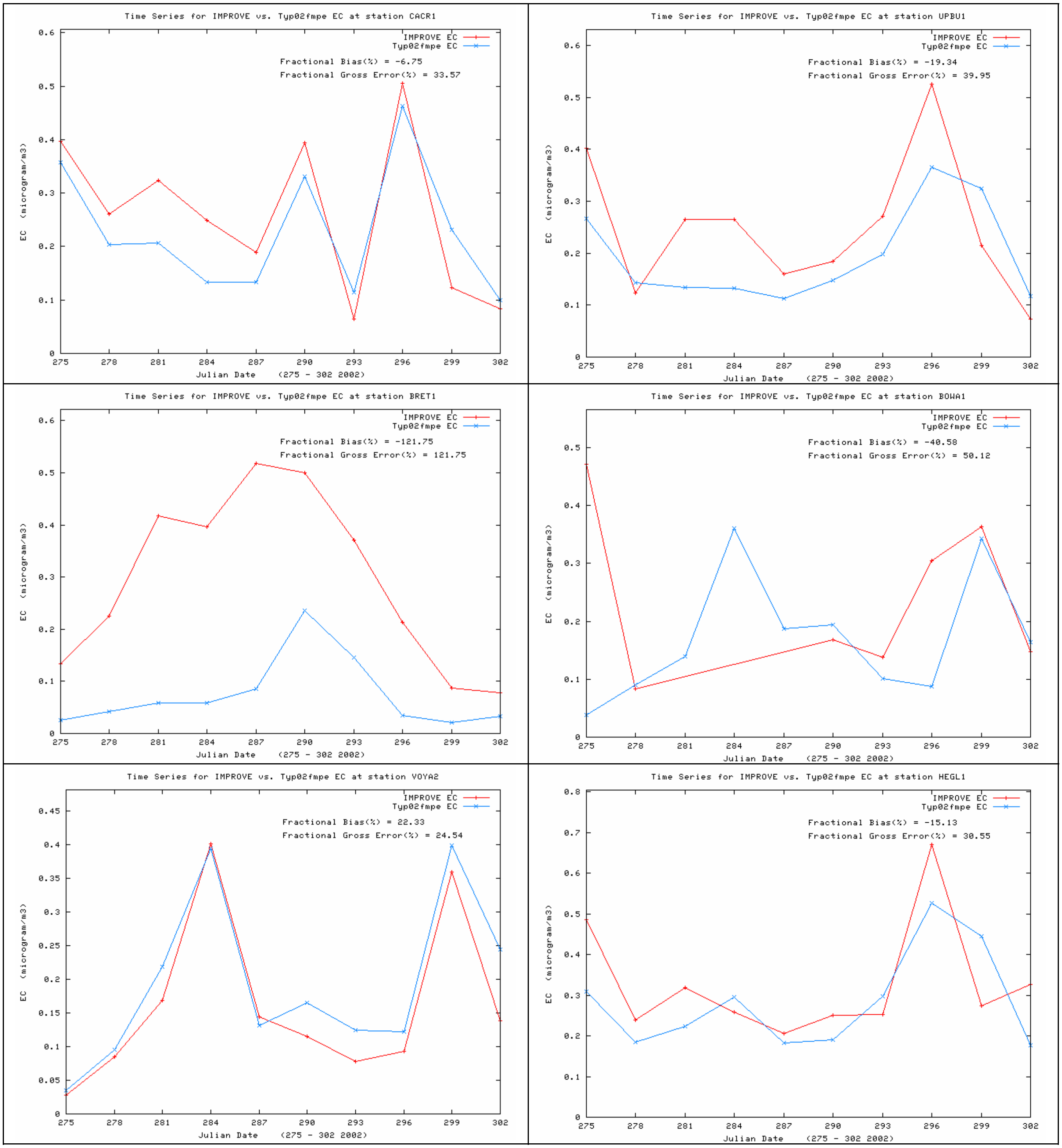
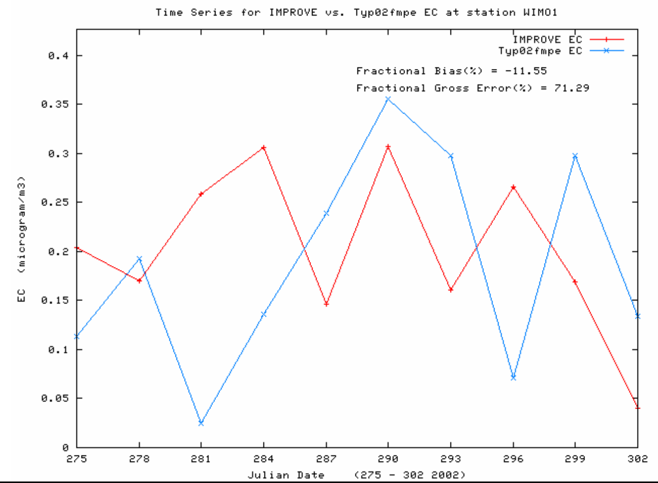


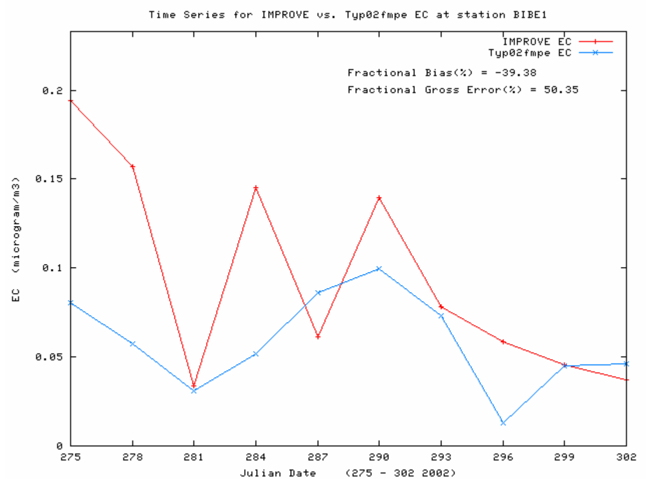
Figure C-25a. Scatter plots of predicted and observed elemental carbon (EC) concentrations for October 2002 and sites in the CENRAP region using IMPROVE (left) and STN (right) monitoring networks using the CMAQ 2002 36 km Base F base case simulation.



Time Series for IMPROVE vs. Typ02fmpe EC at station CACR1
IMPROVE EC
Typ02fmpe EC
Fractional Bias(%) = -6.75
Fractional Gross Error(%) = 33.57
EC (microgram/m3)
Julian Date (275 - 302 2002)
Time Series for IMPROVE vs. Typ02fmpe EC at station UPBU1
IMPROVE EC
Typ02fmpe EC
Fractional Bias(%) = -19.34
Fractional Gross Error(%) = 39.95
EC (microgram/m3)
Julian Date (275 - 302 2002)
Time Series for IMPROVE vs. Typ02fmpe EC at station BRET1
IMPROVE EC
Typ02fmpe EC
Fractional Bias(%) = -121.75
Fractional Gross Error(%) = 121.75
EC (microgram/m3)
Julian Date (275 - 302 2002)
Time Series for IMPROVE vs. Typ02fmpe EC at station BOWA1
IMPROVE EC
Typ02fmpe EC
Fractional Bias(%) = -40.58
Fractional Gross Error(%) = 50.12
EC (microgram/m3)
Julian Date (275 - 302 2002)
Time Series for IMPROVE vs. Typ02fmpe EC at station VOYA2
IMPROVE EC
Typ02fmpe EC
Fractional Bias(%) = 22.33
Fractional Gross Error(%) = 24.54
EC (microgram/m3)
Julian Date (275 - 302 2002)
Time Series for IMPROVE vs. Typ02fmpe EC at station HEGL1
IMPROVE EC
Typ02fmpe EC
Fractional Bias(%) = -15.13
Fractional Gross Error(%) = 30.55
EC (microgram/m3)
Julian Date (275 - 302 2002)

No Data for Mingo (MING)





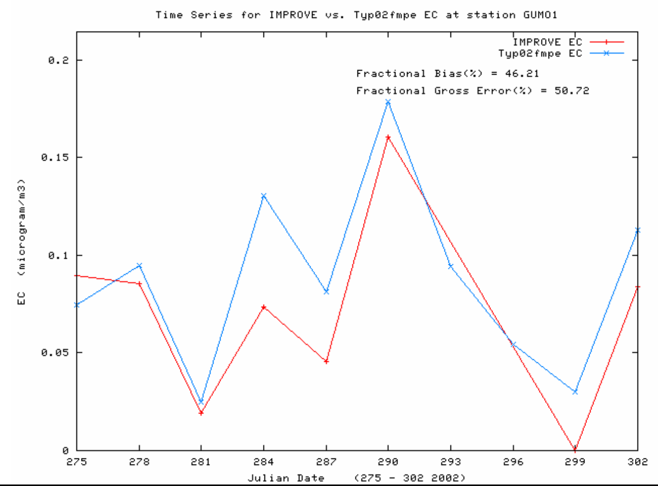


Figure C-25b. Time series of predicted and observed 24-hour elemental carbon (EC) concentrations at CENRAP IMPROVE CLASS I AREA sites in October 2002 for CMAQ 2002 36 km Base F base case simulation.

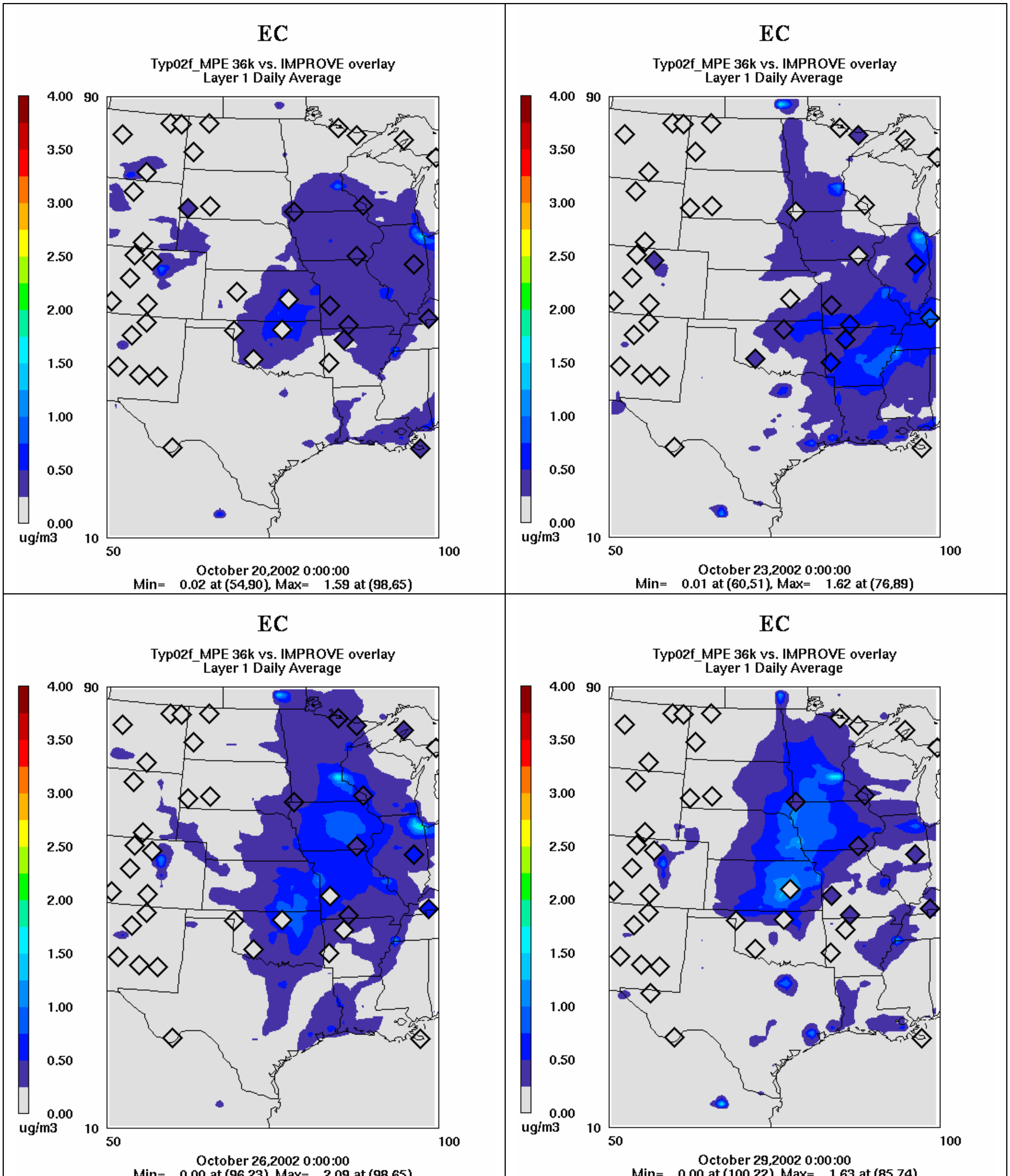


Figure C-25c. Spatial plot comparisons of the predicted and IMPROVE observed 24-hour EC concentrations for October 20, 23, 26 and 29, 2002.

C.3.4.5 EC Monthly Bias and Error

The monthly average bias and error for EC across the IMPROVE and STN monitors in the CENRAP region are shown in Figure C-26. The STN network exhibits low bias year round, whereas the IMPROVE monitoring network exhibits a large under-prediction bias in the summer months (-40% to -60%) and much lower EC bias in the winter. The errors in the IMPROVE summer EC performance are also quite high (60% to 80%), whereas during the winter the IMPROVE errors are in the 40% to 50% range which is also where the STN errors reside year round.

The Bugle Plot puts the EC performance in context (Figure C-27). The low EC concentrations put the IMPROVE EC performance in the horn of the Bugle Plot so that it achieves the proposed PM performance goal for all months of the year.

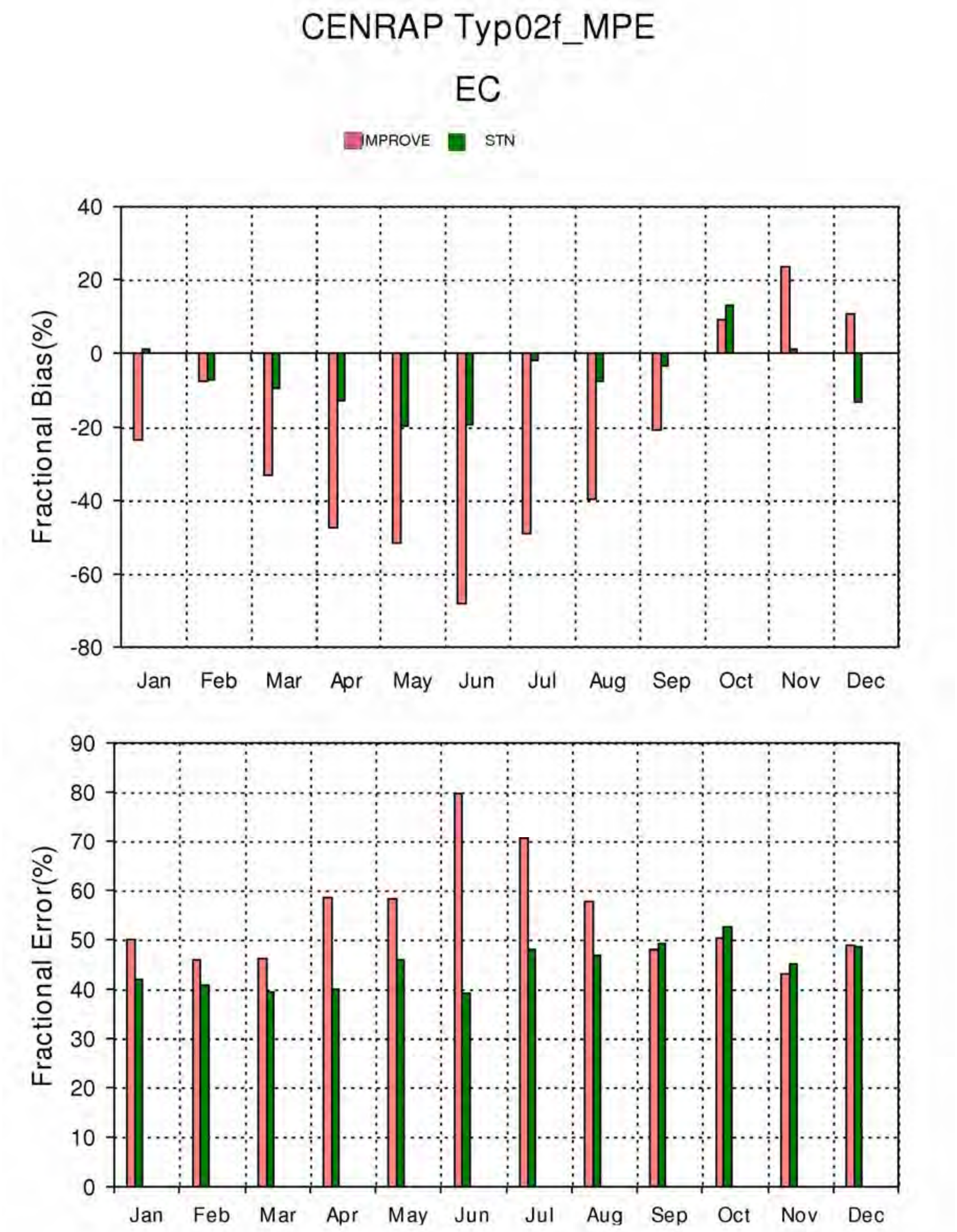


Figure C-26. Monthly EC fractional bias (top) and fractional gross error (bottom) statistical measures for IMPROVE and STN monitoring sites in the CENRAP region.

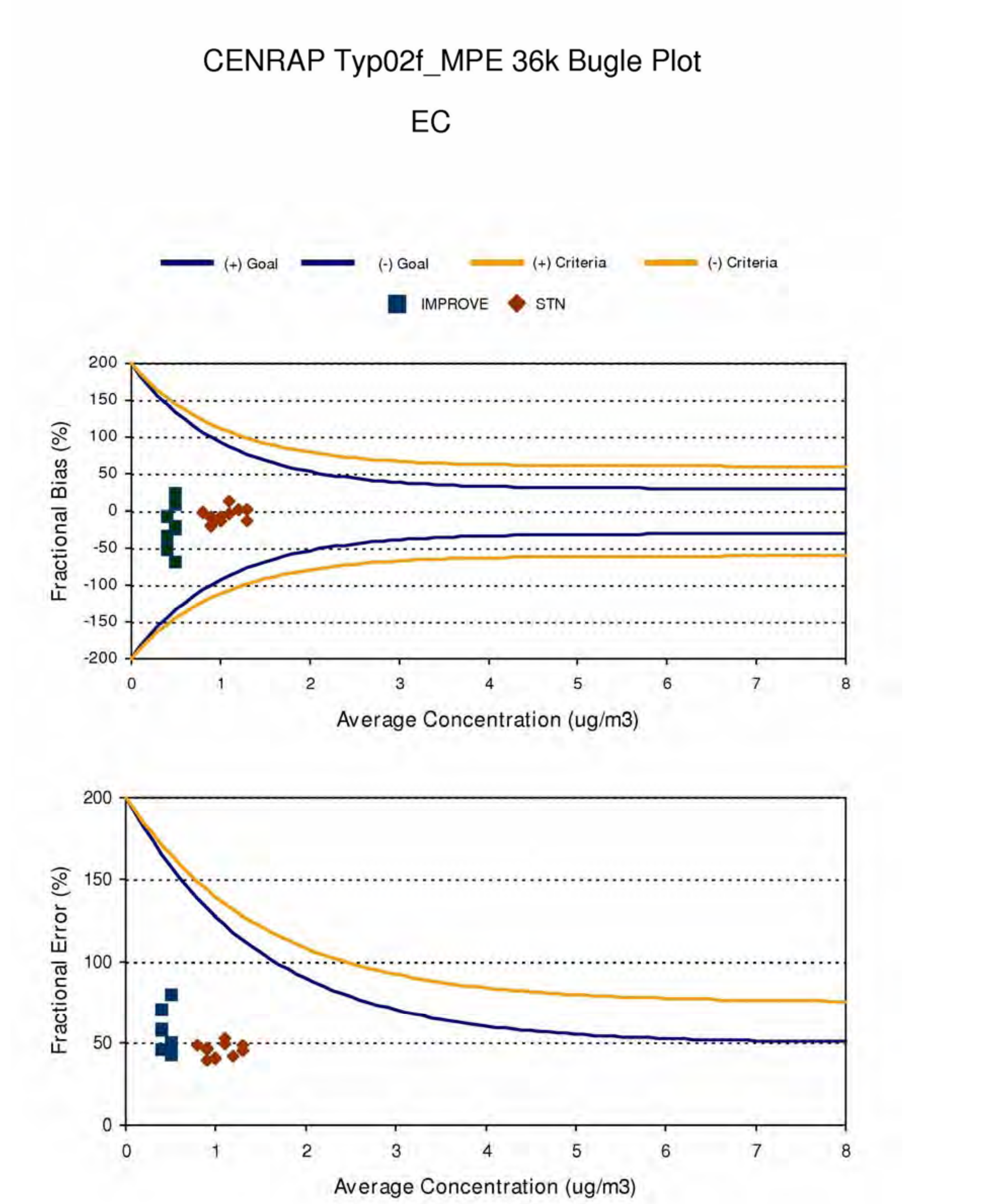


Figure C-27. Bugle Plots of monthly fractional bias (top) and fractional gross error (bottom) and comparisons with model performance goals and criteria for EC and IMPROVE and STN monitoring sites in the CENRAP region.

C.3.5 Other $PM_{2.5}$ (Soil) Monthly Model Performance

There are also model-measurement incommensurability problems with the other $PM_{2.5}$ (Soil) species. Whereas the IMPROVE Soil species is built up from measure elements, the modeled other $PM_{2.5}$ concentrations are based on emissions speciation profiles that likely include other species besides just elements. Soil is only collected at the IMPROVE monitors.

C.3.5.1 Soil in January 2002

The model greatly overestimates the Soil species at IMPORVE sites in January (Figure C-28a). The fractional bias exceeds 100% with errors of almost 130%. With the possible exception of the two Texas sites, the model Soil overestimation bias occurs across all of the CENRAP Class I areas in January (Figure C-28b). The model also does a poor job in reproducing the spatial variability of the observed Soil with a general overestimation tendency except at GUMO where it fails to reproduce the high Soil events.

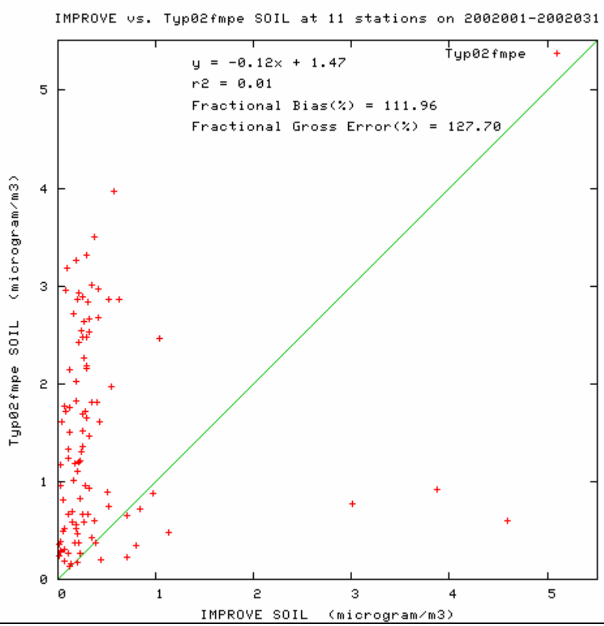
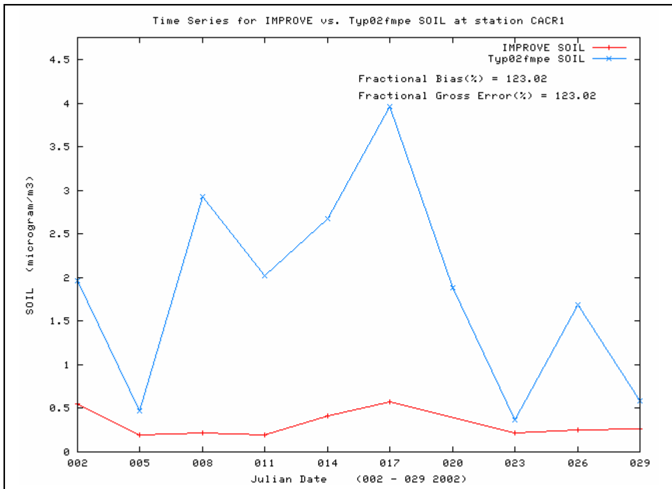
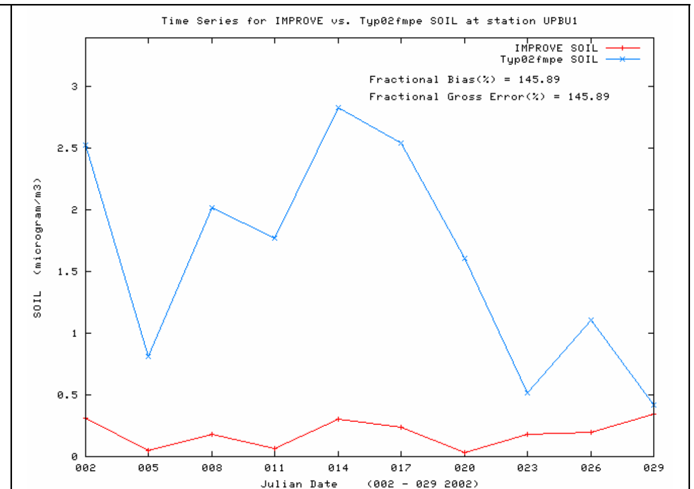
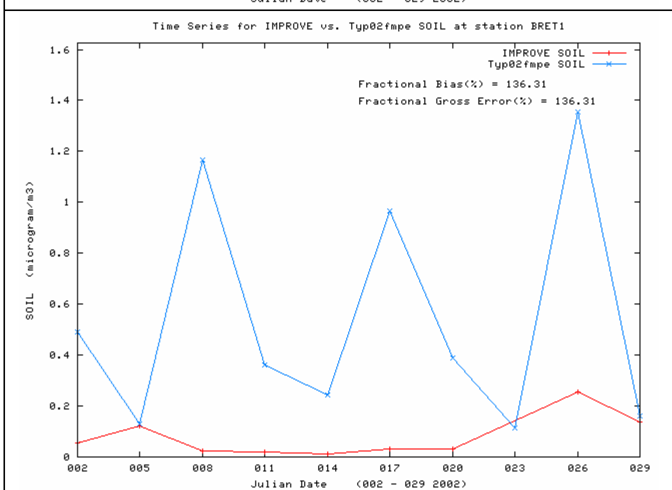
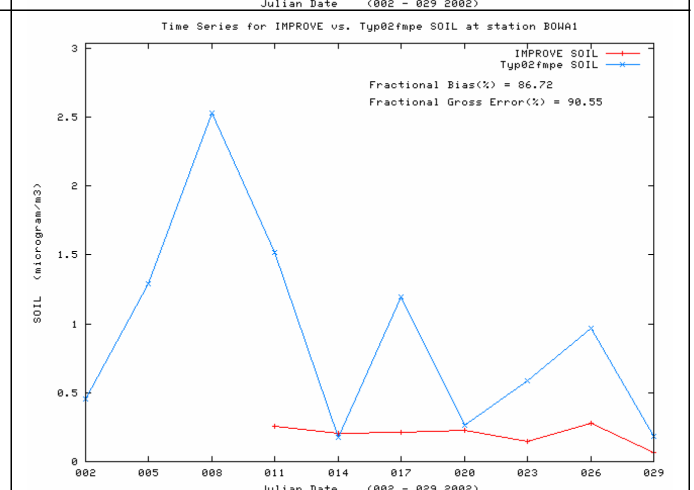


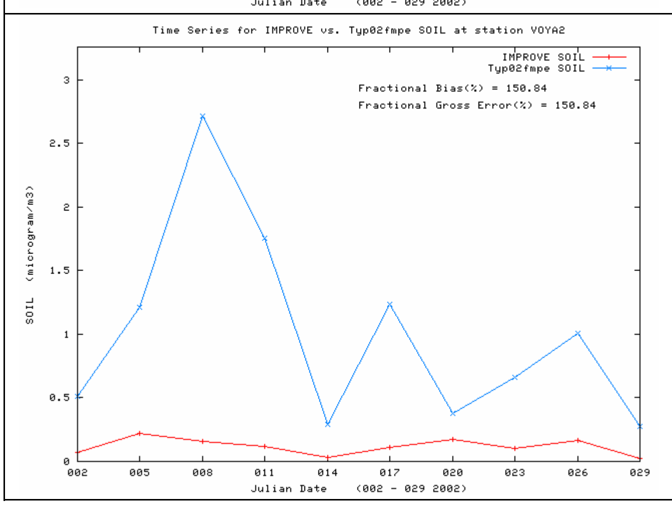
Figure C-28a. Scatter plots of predicted and observed other $PM_{2.5}$ (Soil) concentrations for January 2002 and sites in the CENRAP region using IMPROVE monitoring network and the CMAQ 2002 36 km Base F base case simulation.

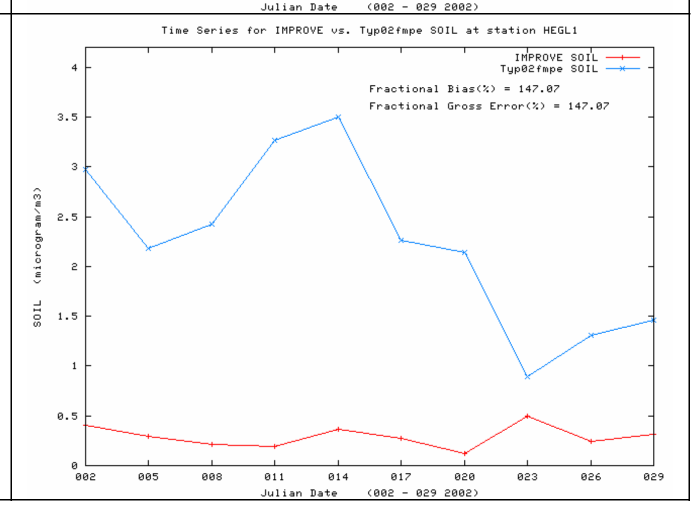

Time Series for IMPROVE vs. Typ02fmpe SOIL at station CACR1
IMPROVE SOIL
Typ02fmpe SOIL
Fractional Bias(%) = 123.02
Fractional Gross Error(%) = 123.02
SOIL (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe SOIL at station UPBU1
IMPROVE SOIL
Typ02fmpe SOIL
Fractional Bias(%) = 145.89
Fractional Gross Error(%) = 145.89
SOIL (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe SOIL at station BRET1
IMPROVE SOIL
Typ02fmpe SOIL
Fractional Bias(%) = 136.31
Fractional Gross Error(%) = 136.31
SOIL (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe SOIL at station BOWA1
IMPROVE SOIL
Typ02fmpe SOIL
Fractional Bias(%) = 86.72
Fractional Gross Error(%) = 90.55
SOIL (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe SOIL at station VOYA2
IMPROVE SOIL
Typ02fmpe SOIL
Fractional Bias(%) = 150.84
Fractional Gross Error(%) = 150.84
SOIL (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe SOIL at station HEGL1
IMPROVE SOIL
Typ02fmpe SOIL
Fractional Bias(%) = 147.07
Fractional Gross Error(%) = 147.07
SOIL (microgram/m3)
Julian Date (002 - 029 2002)

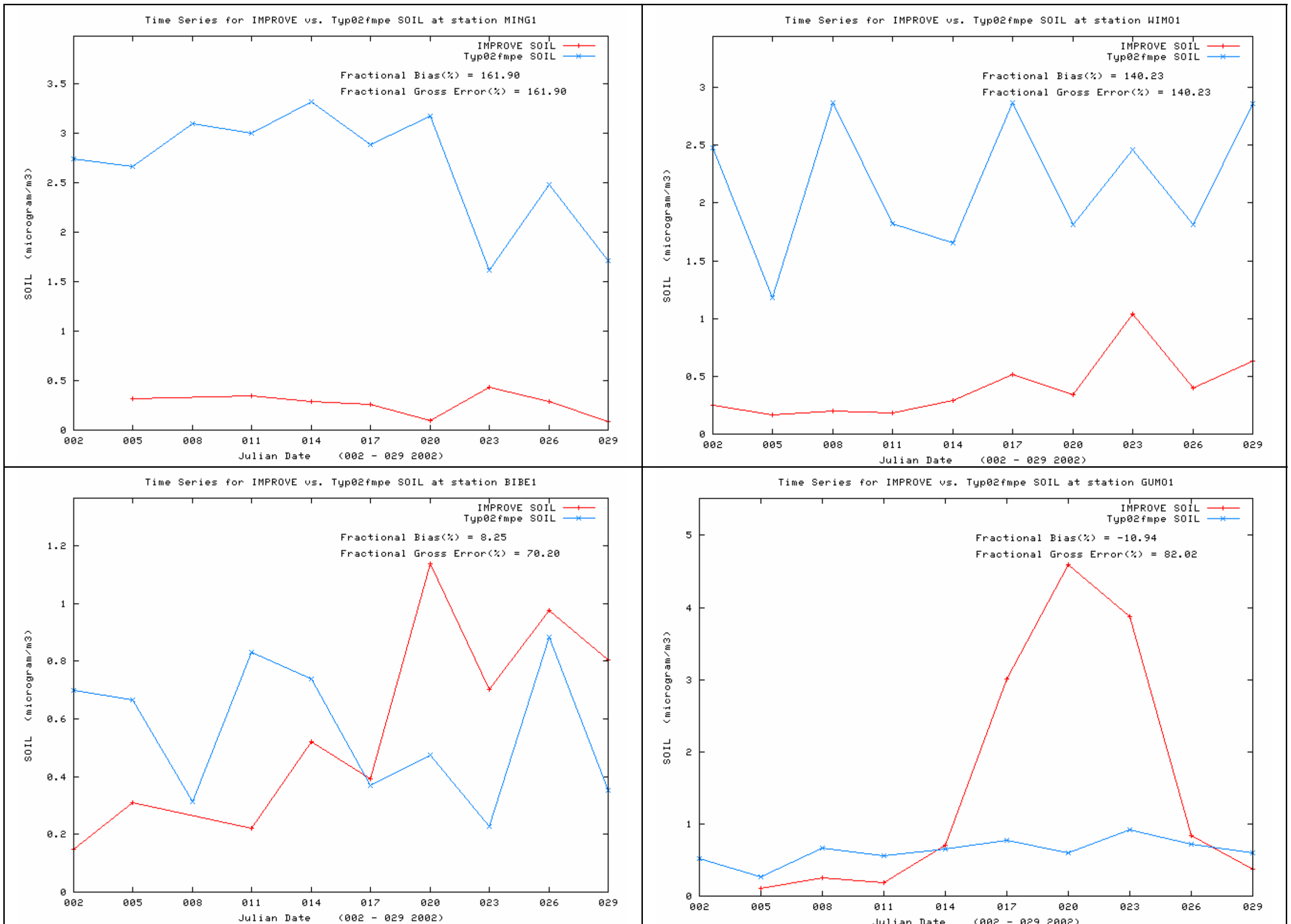


Figure C-28b. Time series of predicted and observed 24-hour other $PM_{2.5}$ (Soil) concentrations at CENRAP IMPROVE CLASS I AREA sites in January 2002 for CMAQ 2002 36 km Base F base case simulation.

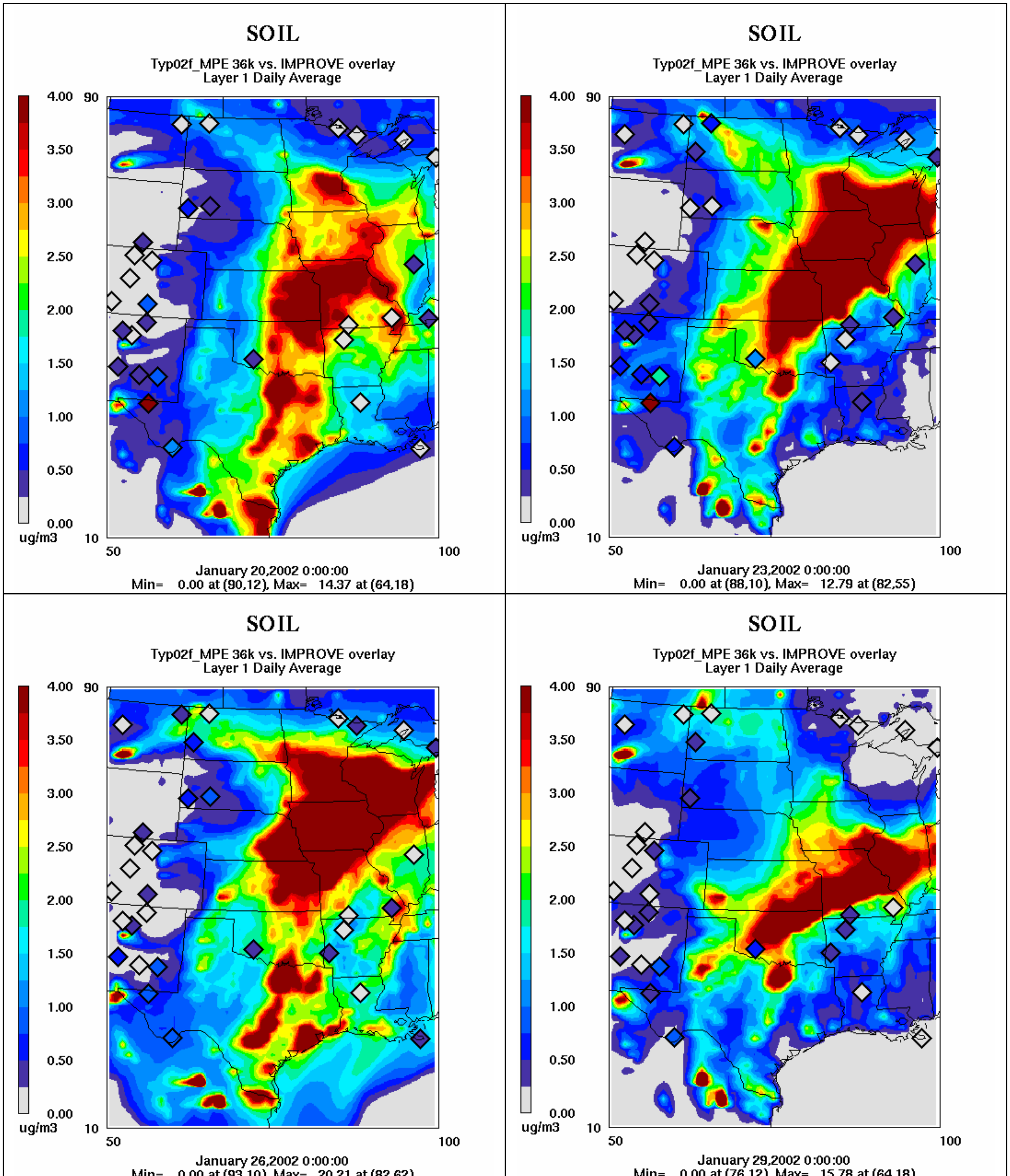


Figure C-28c. Spatial plot comparisons of the predicted and IMPROVE observed 24-hour Soil concentrations for January 20, 23, 26 and 29, 2002.

C.3.5.2 Soil in April 2002

The model does a better job in reproducing the overall magnitude of the Soil measurements in April with a bias of 13% (Figure C-29a). But it exhibits little skill with lots of scatter and an error of 81%. The model is generally exhibiting a lot more day-to-day variability than observed with the observed daily time series much flatter than the modeled values (Figure C-29b). The modeled and observed spatial variability in Soil on April 5, 8, 11 and 14 are shown in Figure C-29c. Although the model exhibits large day-to-day variability, the observations do not reflect what the model predicts.

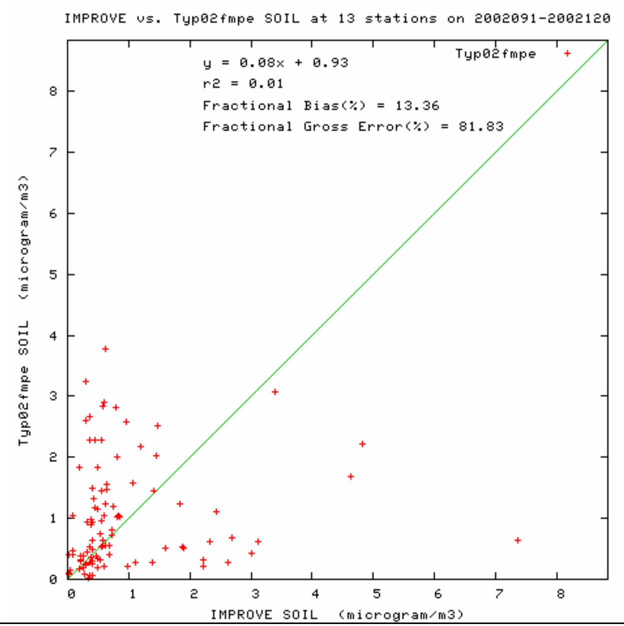
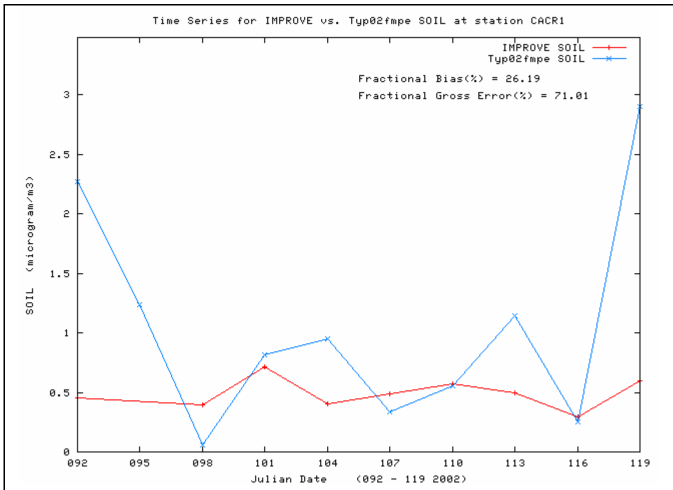
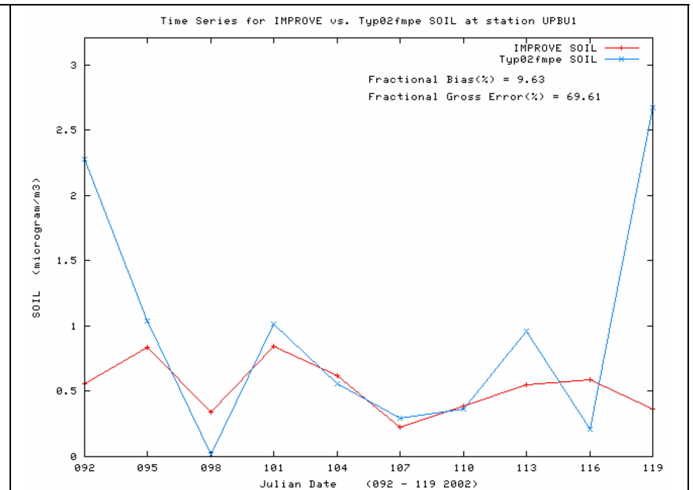
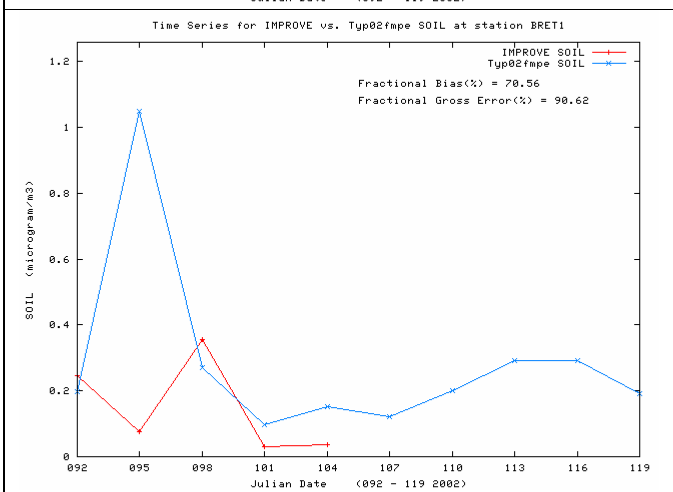
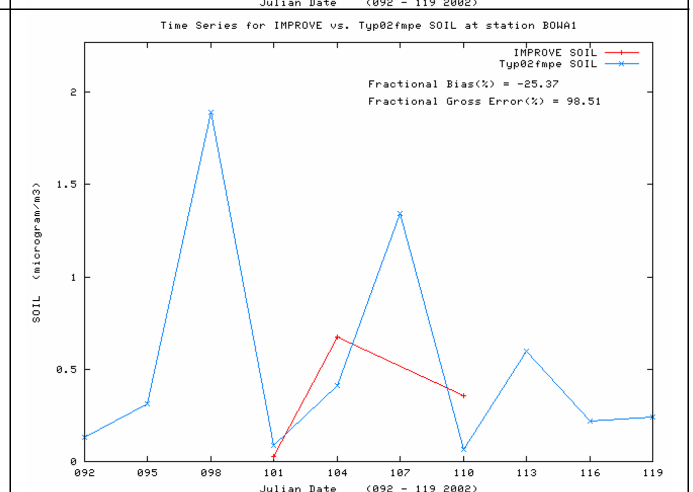


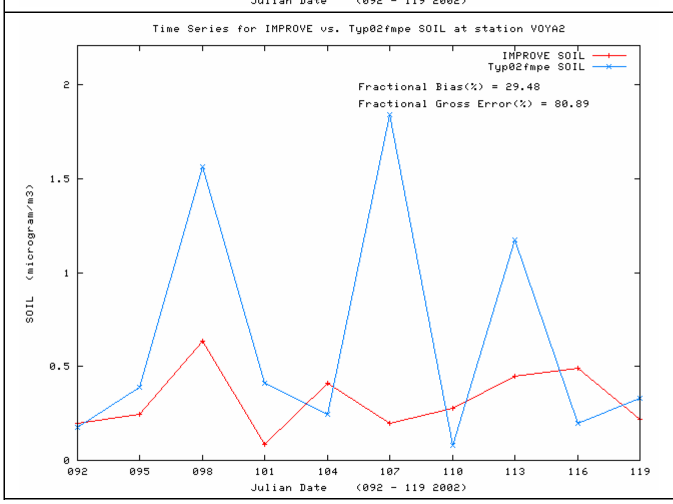
Figure C-29a. Scatter plots of predicted and observed other $PM_{2.5}$ (Soil) concentrations for April 2002 and sites in the CENRAP region using IMPROVE monitoring networks using the CMAQ 2002 36 km Base F base case simulation.

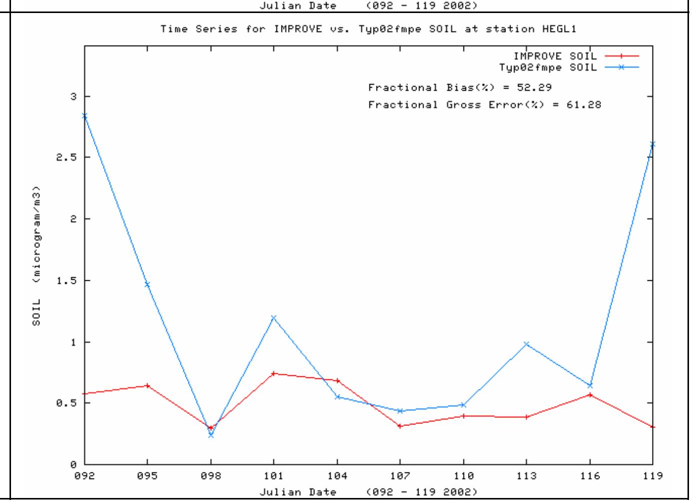

Time Series for IMPROVE vs. Typ02fmpe SOIL at station CACR1
IMPROVE SOIL
Typ02fmpe SOIL
Fractional Bias(%) = 26.19
Fractional Gross Error(%) = 71.01
SOIL (microgram/m3)
Julian Date (092 - 119 2002)


Time Series for IMPROVE vs. Typ02fmpe SOIL at station UPBU1
IMPROVE SOIL
Typ02fmpe SOIL
Fractional Bias(%) = 9.63
Fractional Gross Error(%) = 69.61
SOIL (microgram/m3)
Julian Date (092 - 119 2002)


Time Series for IMPROVE vs. Typ02fmpe SOIL at station BRET1
IMPROVE SOIL
Typ02fmpe SOIL
Fractional Bias(%) = 70.56
Fractional Gross Error(%) = 90.62
SOIL (microgram/m3)
Julian Date (092 - 119 2002)


Time Series for IMPROVE vs. Typ02fmpe SOIL at station BOWA1
IMPROVE SOIL
Typ02fmpe SOIL
Fractional Bias(%) = -25.37
Fractional Gross Error(%) = 98.51
SOIL (microgram/m3)
Julian Date (092 - 119 2002)


Time Series for IMPROVE vs. Typ02fmpe SOIL at station VOYA2
IMPROVE SOIL
Typ02fmpe SOIL
Fractional Bias(%) = 29.48
Fractional Gross Error(%) = 80.89
SOIL (microgram/m3)
Julian Date (092 - 119 2002)


Time Series for IMPROVE vs. Typ02fmpe SOIL at station HEGL1
IMPROVE SOIL
Typ02fmpe SOIL
Fractional Bias(%) = 52.29
Fractional Gross Error(%) = 61.28
SOIL (microgram/m3)
Julian Date (092 - 119 2002)

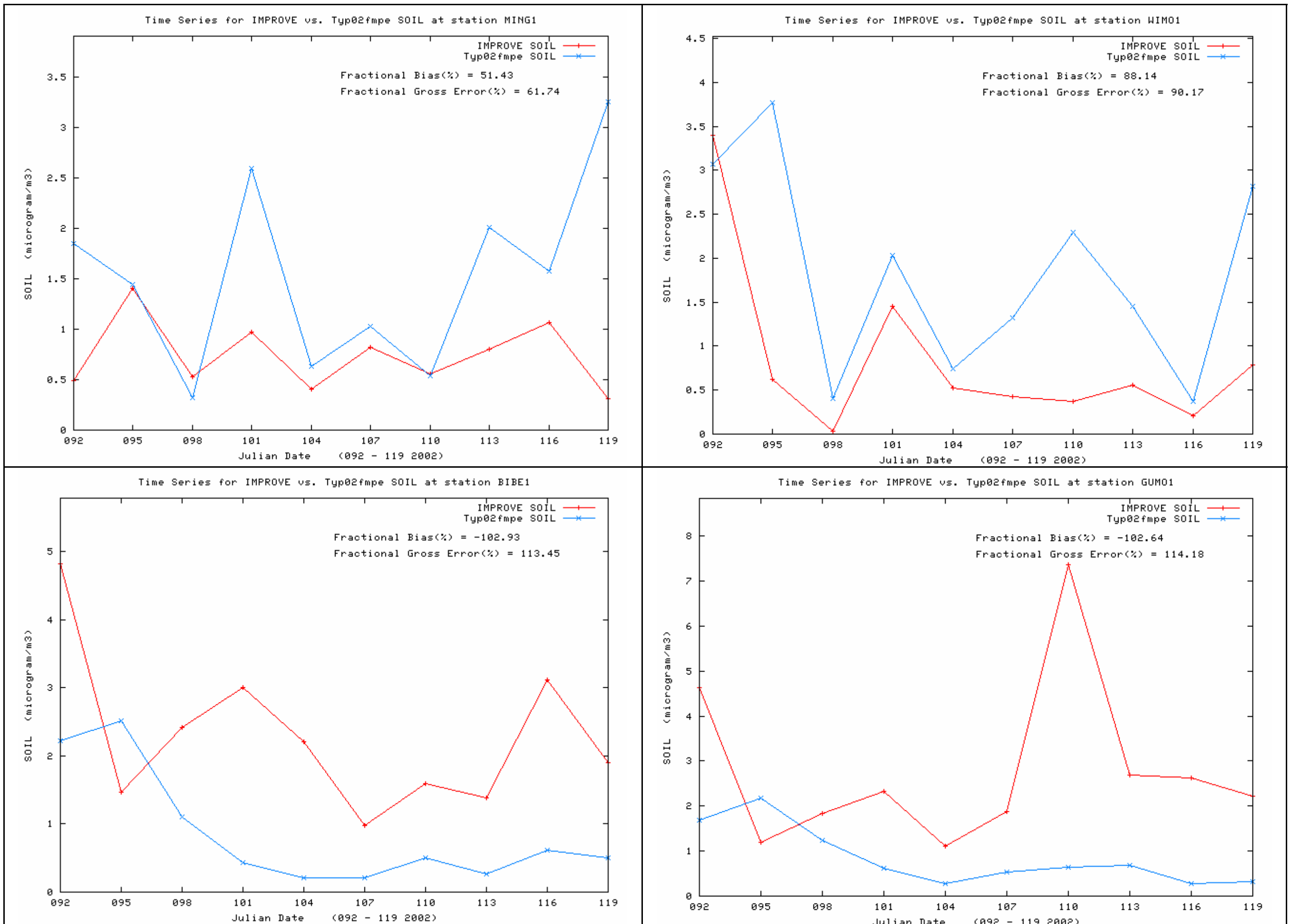


Figure C-29b. Time series of predicted and observed 24-hour other $PM_{2.5}$ (Soil) concentrations at CENRAP IMPROVE CLASS I AREA sites in April 2002 for CMAQ 2002 36 km Base F base case simulation.

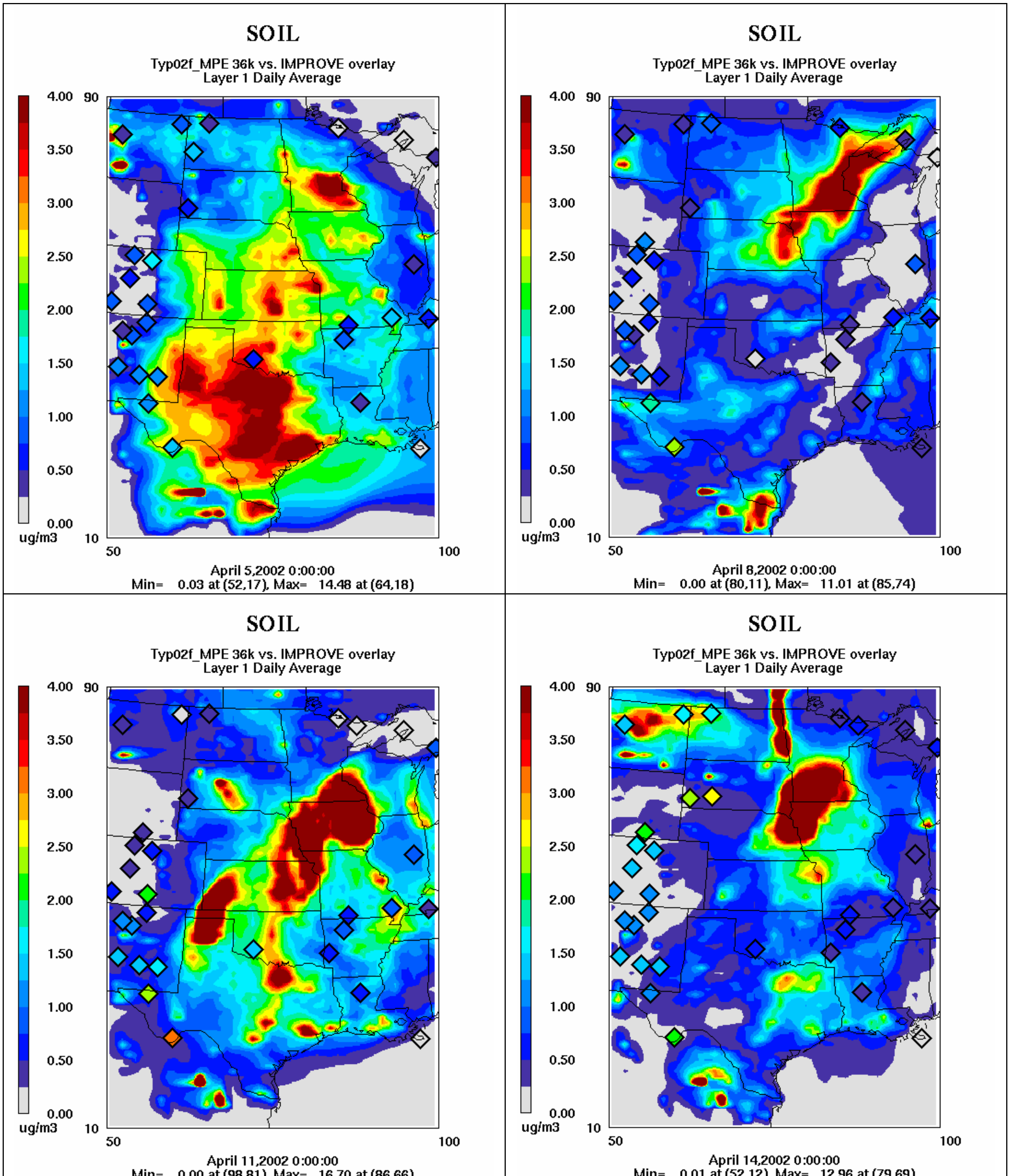


Figure C-29c. Spatial plot comparisons of the predicted and IMPROVE observed 24-hour Soil concentrations for April 5, 8, 11 and 14, 2002.

C.3.5.3 Soil in July 2002

The -50% Soil under-prediction bias seen in July appears to be driven to several high Soil measurements (Figure C-30a). An observed high Soil event took place on July 1 (Julian Day 182) across the Arkansas and Missouri Class I areas that all observed Soil values in excess of 15 $\mu g/m^3$. This event was not captured by the model. With the exception of a systematic Soil underestimation bias at the two Texas sites and missing these high Soil events, the model generally reproduces the magnitudes of the Soil observations in July.

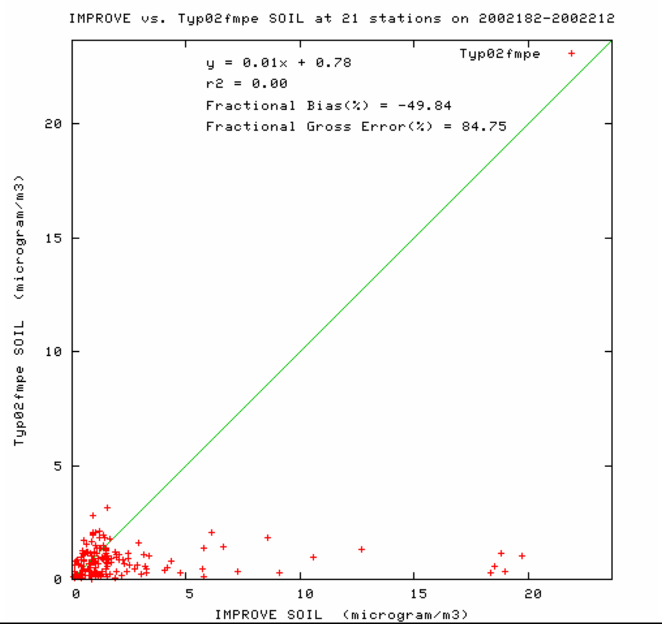
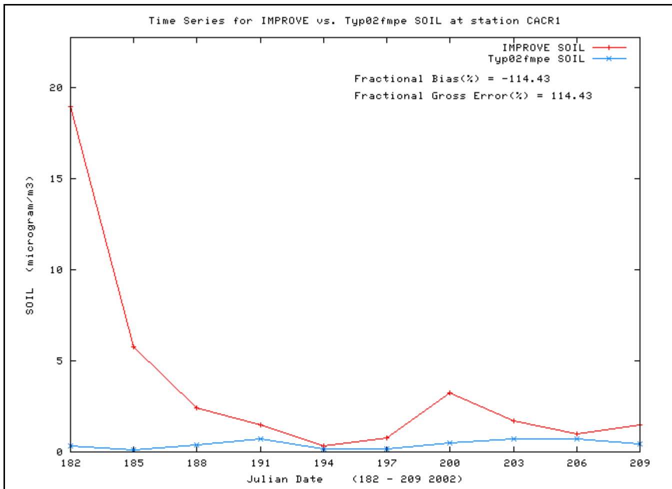
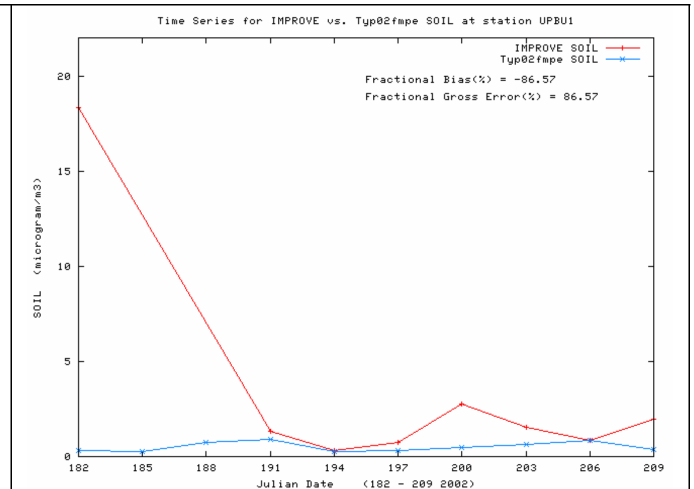
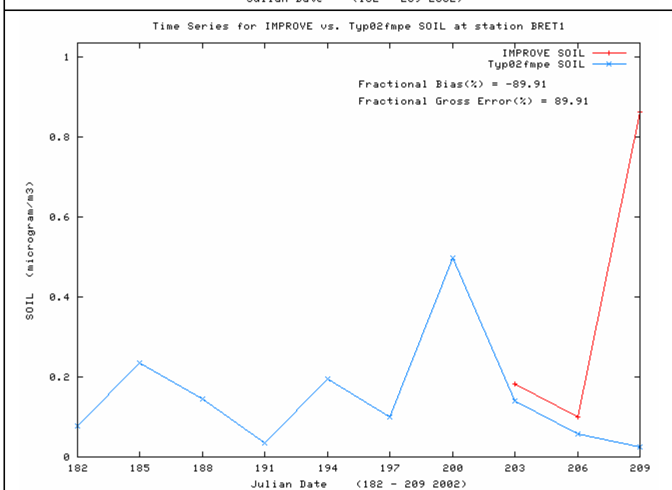
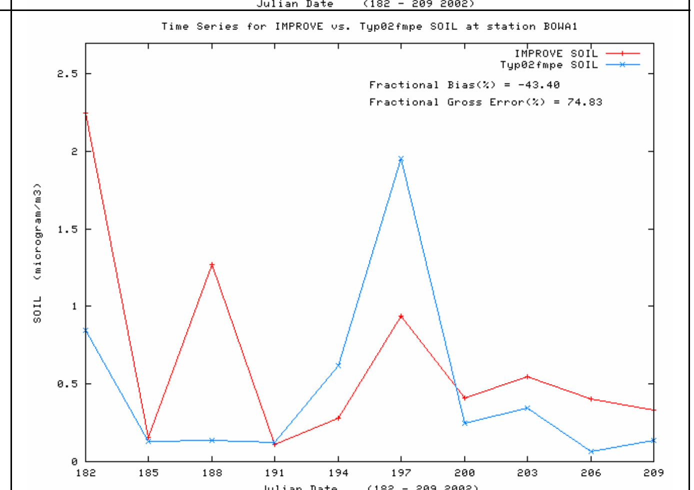


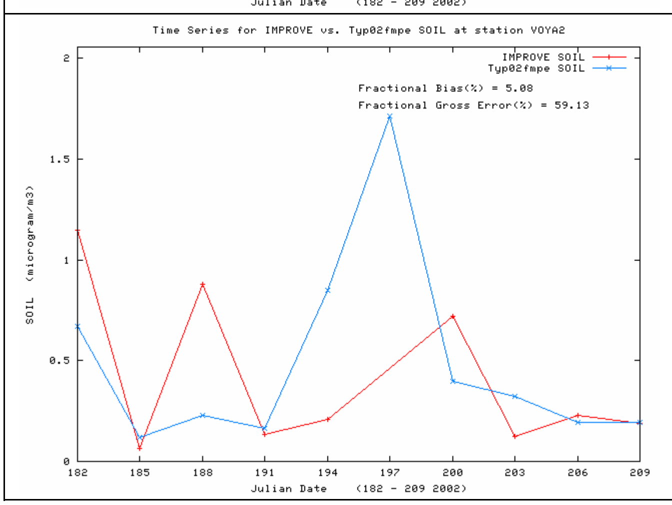
Figure C-30a. Scatter plots of predicted and observed other $PM_{2.5}$ (Soil) concentrations for July 2002 and sites in the CENRAP region using IMPROVE monitoring networks using the CMAQ 2002 36 km Base F base case simulation.

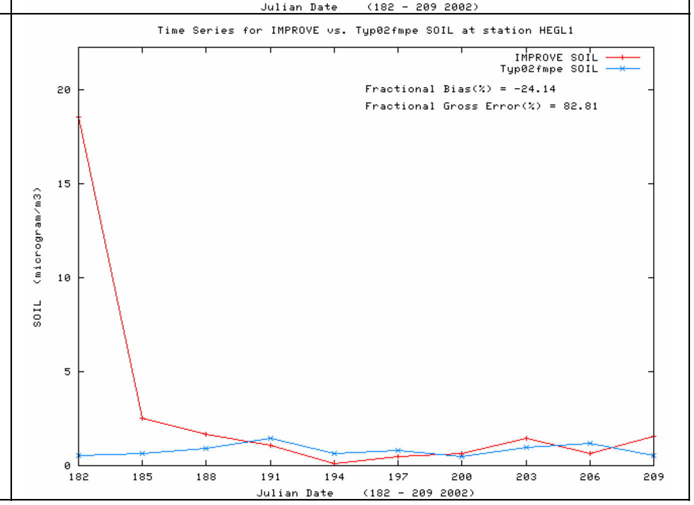

Time Series for IMPROVE vs. Typ02fmpe SOIL at station CACR1
IMPROVE SOIL
Typ02fmpe SOIL
Fractional Bias(%) = -114.43
Fractional Gross Error(%) = 114.43
SOIL (microgram/m3)
Julian Date (182 - 209 2002)


Time Series for IMPROVE vs. Typ02fmpe SOIL at station UPBU1
IMPROVE SOIL
Typ02fmpe SOIL
Fractional Bias(%) = -86.57
Fractional Gross Error(%) = 86.57
SOIL (microgram/m3)
Julian Date (182 - 209 2002)


Time Series for IMPROVE vs. Typ02fmpe SOIL at station BRET1
IMPROVE SOIL
Typ02fmpe SOIL
Fractional Bias(%) = -89.91
Fractional Gross Error(%) = 89.91
SOIL (microgram/m3)
Julian Date (182 - 209 2002)


Time Series for IMPROVE vs. Typ02fmpe SOIL at station BOWA1
IMPROVE SOIL
Typ02fmpe SOIL
Fractional Bias(%) = -43.40
Fractional Gross Error(%) = 74.83
SOIL (microgram/m3)
Julian Date (182 - 209 2002)


Time Series for IMPROVE vs. Typ02fmpe SOIL at station VOYA2
IMPROVE SOIL
Typ02fmpe SOIL
Fractional Bias(%) = 5.08
Fractional Gross Error(%) = 59.13
SOIL (microgram/m3)
Julian Date (182 - 209 2002)


Time Series for IMPROVE vs. Typ02fmpe SOIL at station HEGL1
IMPROVE SOIL
Typ02fmpe SOIL
Fractional Bias(%) = -24.14
Fractional Gross Error(%) = 82.81
SOIL (microgram/m3)
Julian Date (182 - 209 2002)

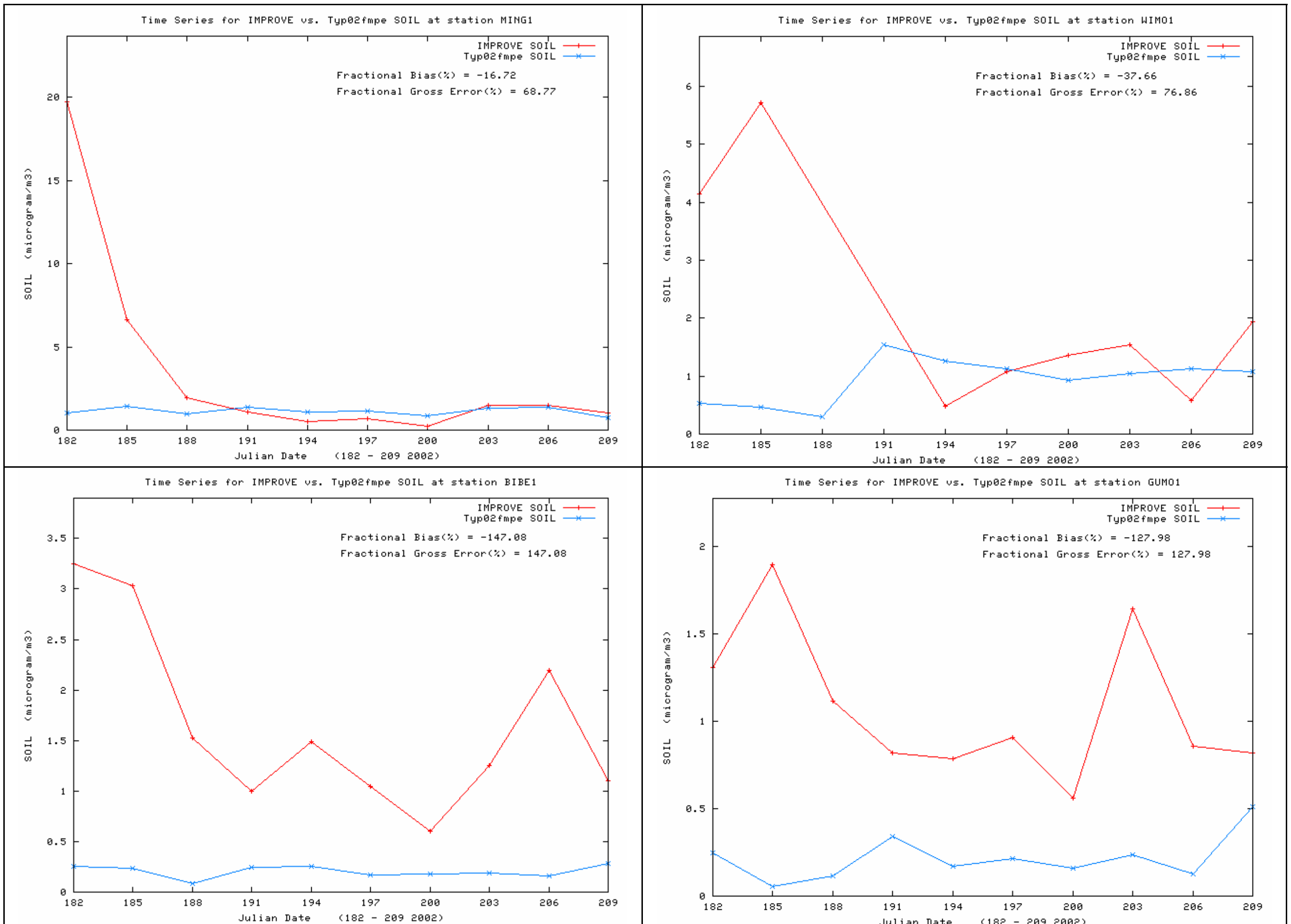


Figure C-30b. Time series of predicted and observed 24-hour other $PM_{2.5}$ (Soil) concentrations at CENRAP IMPROVE sites in July 2002 for CMAQ 2002 36 km Base F base case simulation.

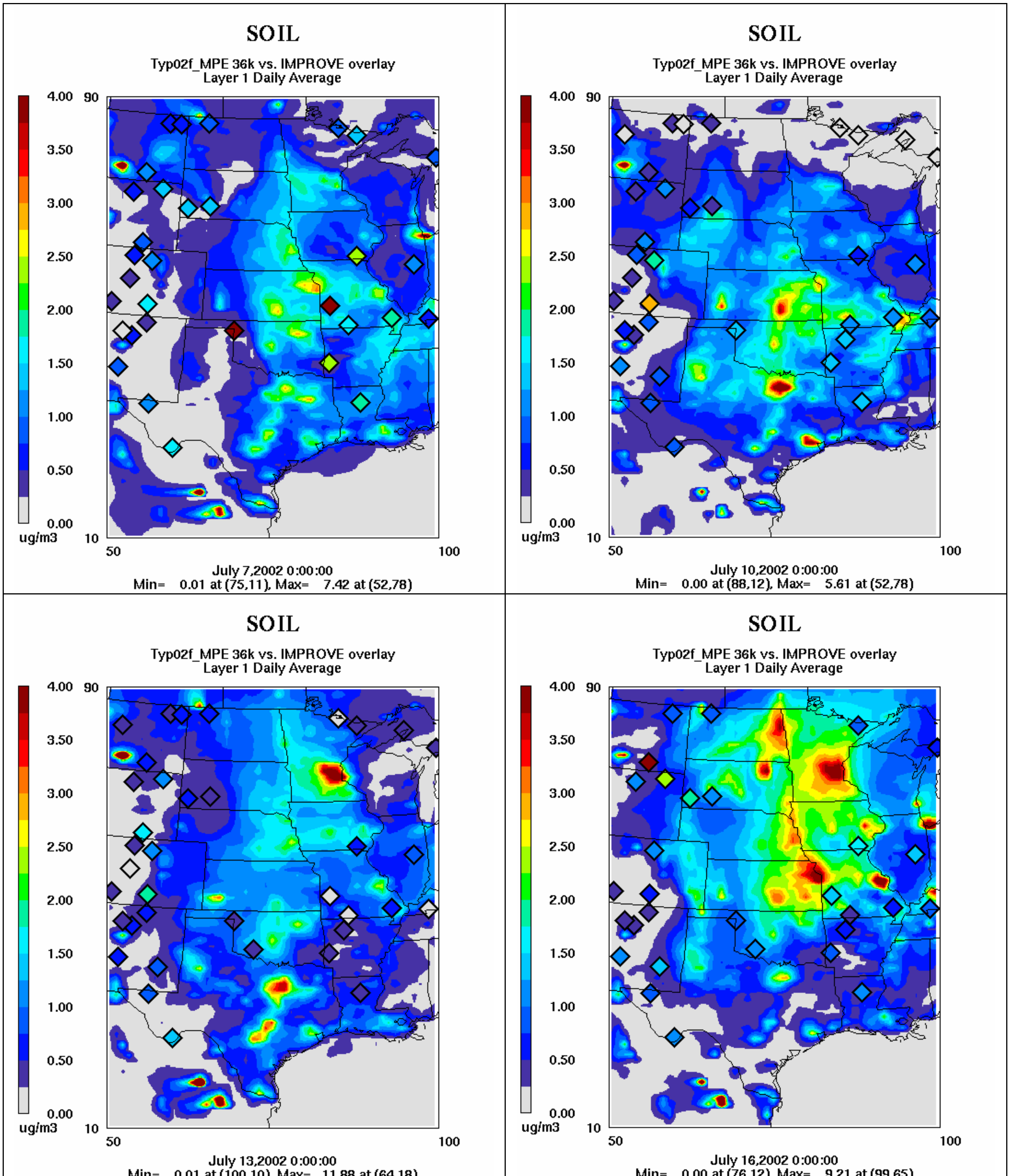


Figure C-30c. Spatial plot comparisons of the predicted and IMPROVE observed 24-hour Soil concentrations for July 7, 10, 13 and 16, 2002.

C.3.5.4 Soil in October 2002

The nearly systematic Soil over-prediction bias seen in January returns in October (Figure C-31a). Except for the two Texas sites, BRET and BOWA, the model overstates the observed Soil during all days of October at the other monitoring sites (Figure C-31b). The model is predicting elevated Soil concentrations in the OK-KS-MO-IA area that is not reflected in the measurements (Figure C-31c).

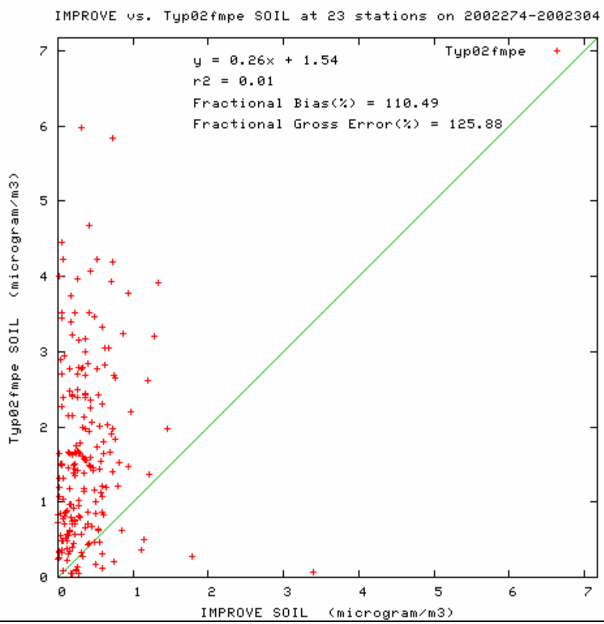
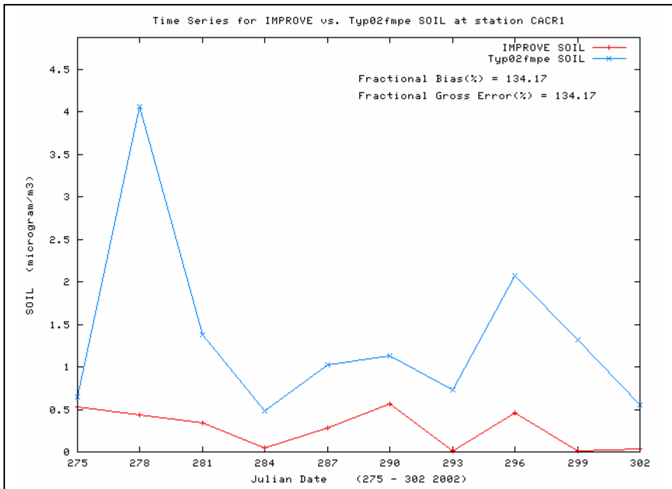
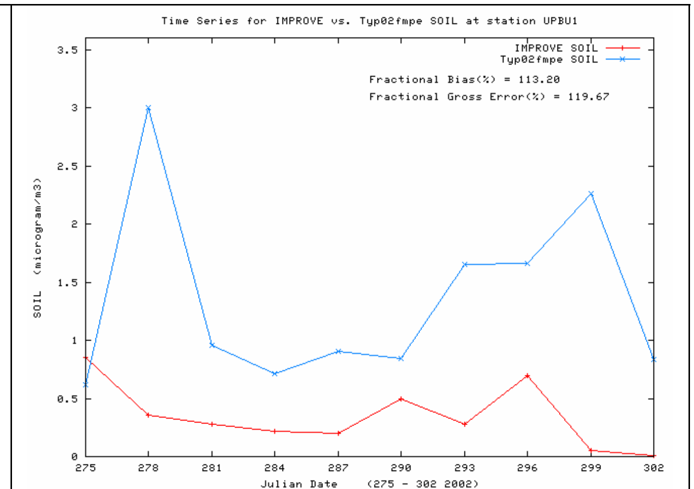
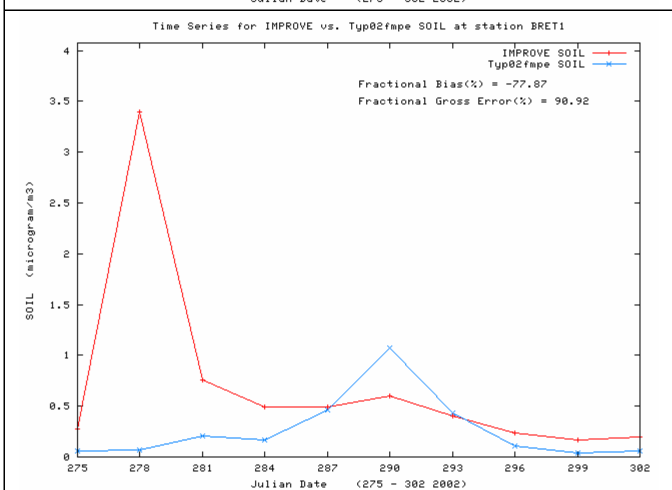
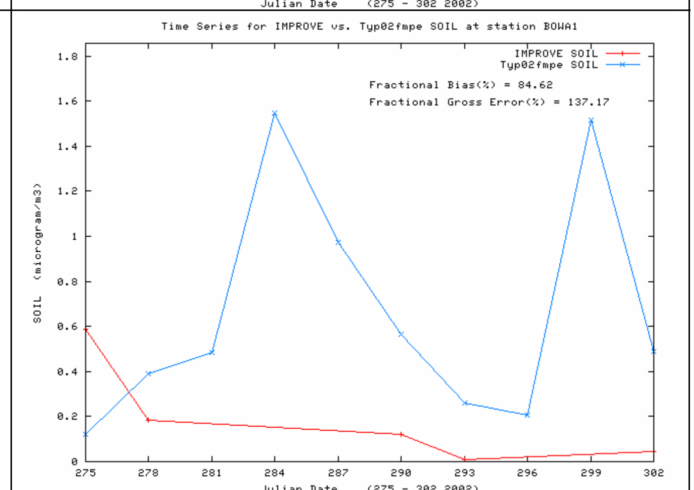


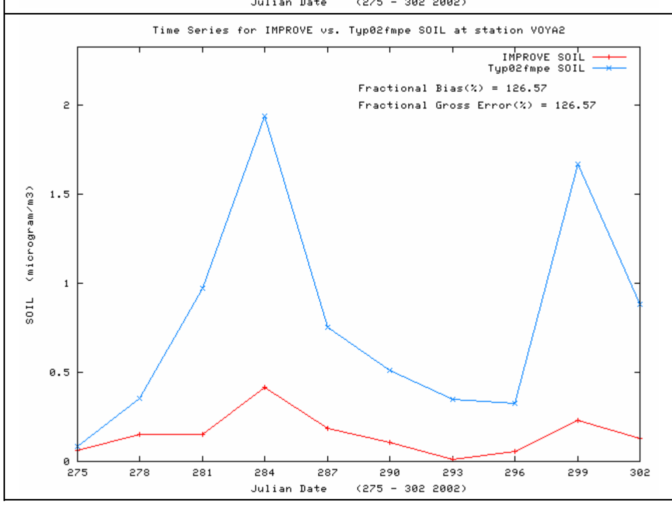
Figure C-31a. Scatter plots of predicted and observed other $PM_{2.5}$ (Soil) concentrations for October 2002 and sites in the CENRAP region using IMPROVE monitoring networks using the CMAQ 2002 36 km Base F base case simulation.

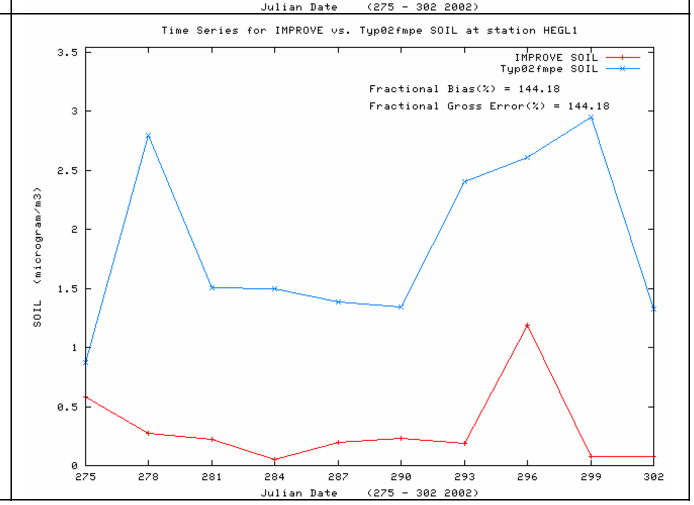

Time Series for IMPROVE vs. Typ02fmpe SOIL at station CACR1
IMPROVE SOIL
Typ02fmpe SOIL
Fractional Bias(%) = 134.17
Fractional Gross Error(%) = 134.17
SOIL (microgram/m3)
Julian Date (275 - 302 2002)


Time Series for IMPROVE vs. Typ02fmpe SOIL at station UPBU1
IMPROVE SOIL
Typ02fmpe SOIL
Fractional Bias(%) = 113.20
Fractional Gross Error(%) = 119.67
SOIL (microgram/m3)
Julian Date (275 - 302 2002)


Time Series for IMPROVE vs. Typ02fmpe SOIL at station BRET1
IMPROVE SOIL
Typ02fmpe SOIL
Fractional Bias(%) = -77.87
Fractional Gross Error(%) = 90.92
SOIL (microgram/m3)
Julian Date (275 - 302 2002)


Time Series for IMPROVE vs. Typ02fmpe SOIL at station BOWA1
IMPROVE SOIL
Typ02fmpe SOIL
Fractional Bias(%) = 84.62
Fractional Gross Error(%) = 137.17
SOIL (microgram/m3)
Julian Date (275 - 302 2002)


Time Series for IMPROVE vs. Typ02fmpe SOIL at station VOYA2
IMPROVE SOIL
Typ02fmpe SOIL
Fractional Bias(%) = 126.57
Fractional Gross Error(%) = 126.57
SOIL (microgram/m3)
Julian Date (275 - 302 2002)


Time Series for IMPROVE vs. Typ02fmpe SOIL at station HEGL1
IMPROVE SOIL
Typ02fmpe SOIL
Fractional Bias(%) = 144.18
Fractional Gross Error(%) = 144.18
SOIL (microgram/m3)
Julian Date (275 - 302 2002)

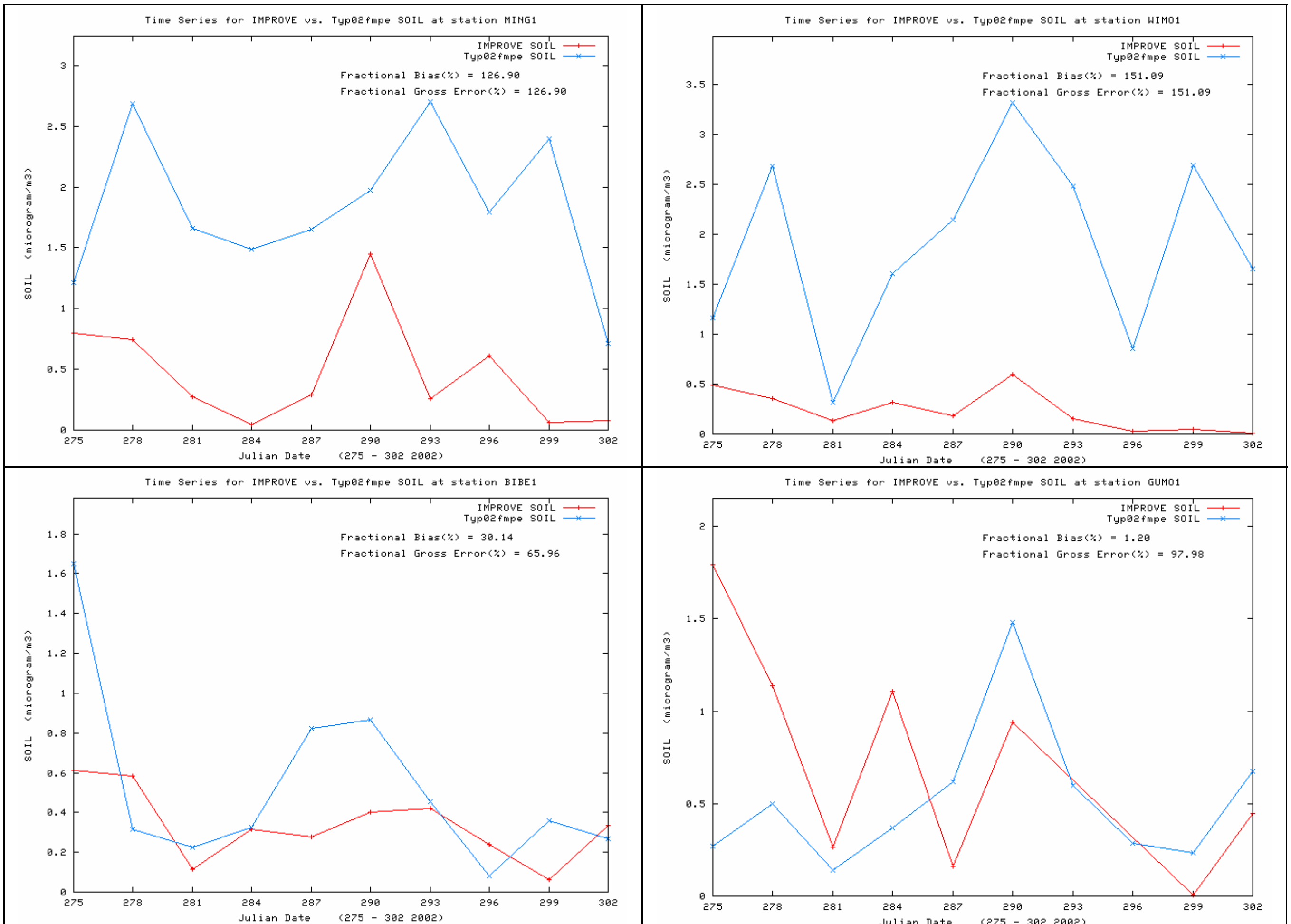


Figure C-31b. Time series of predicted and observed 24-hour other $PM_{2.5}$ (Soil) concentrations at CENRAP IMPROVE CLASS I AREA sites in October 2002 for CMAQ 2002 36 km Base F base case simulation.

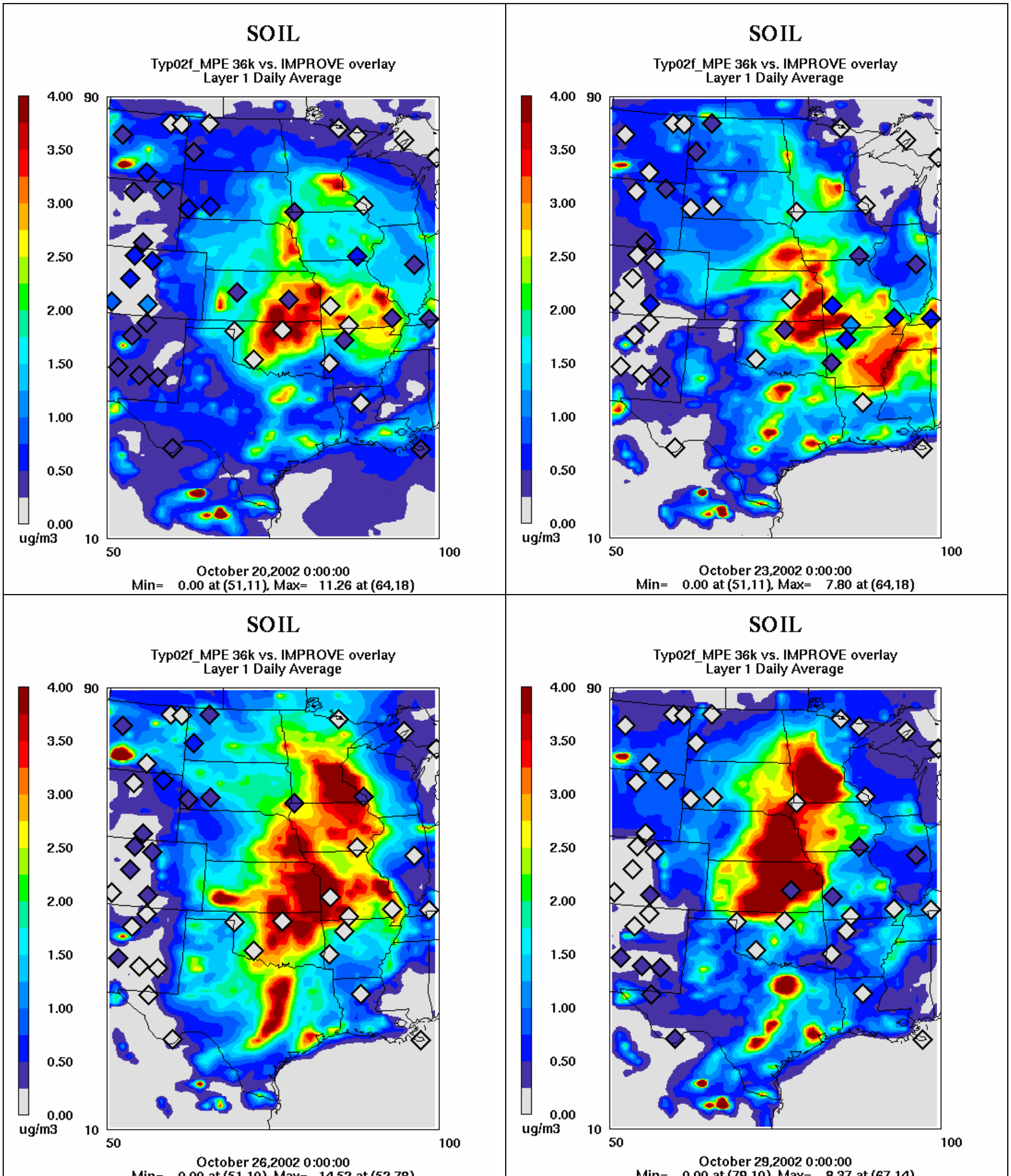


Figure C-31c. Spatial plot comparisons of the predicted and IMPROVE observed 24-hour Soil concentrations for October 20, 23, 26 and 29, 2002.

C.3.5.5 Soil Monthly Bias and Error

Figure C-32 displays the monthly variation in the Soil bias and error. During the winter months the model exhibits a very large (> 100%) overestimation bias with large errors as well. With the exception of July, in the summer the model bias is a slight over-prediction but generally less than 20% with errors of 60% to 80%. The Bugle Plot indicates that the summer Soil performance achieves the PM performance goal, a few months in the Spring/Fall period fall between the performance goal and criteria and the winter Soil performance exceeds the model performance criteria by a far margin. Thus, the Soil performance is a cause for concern.

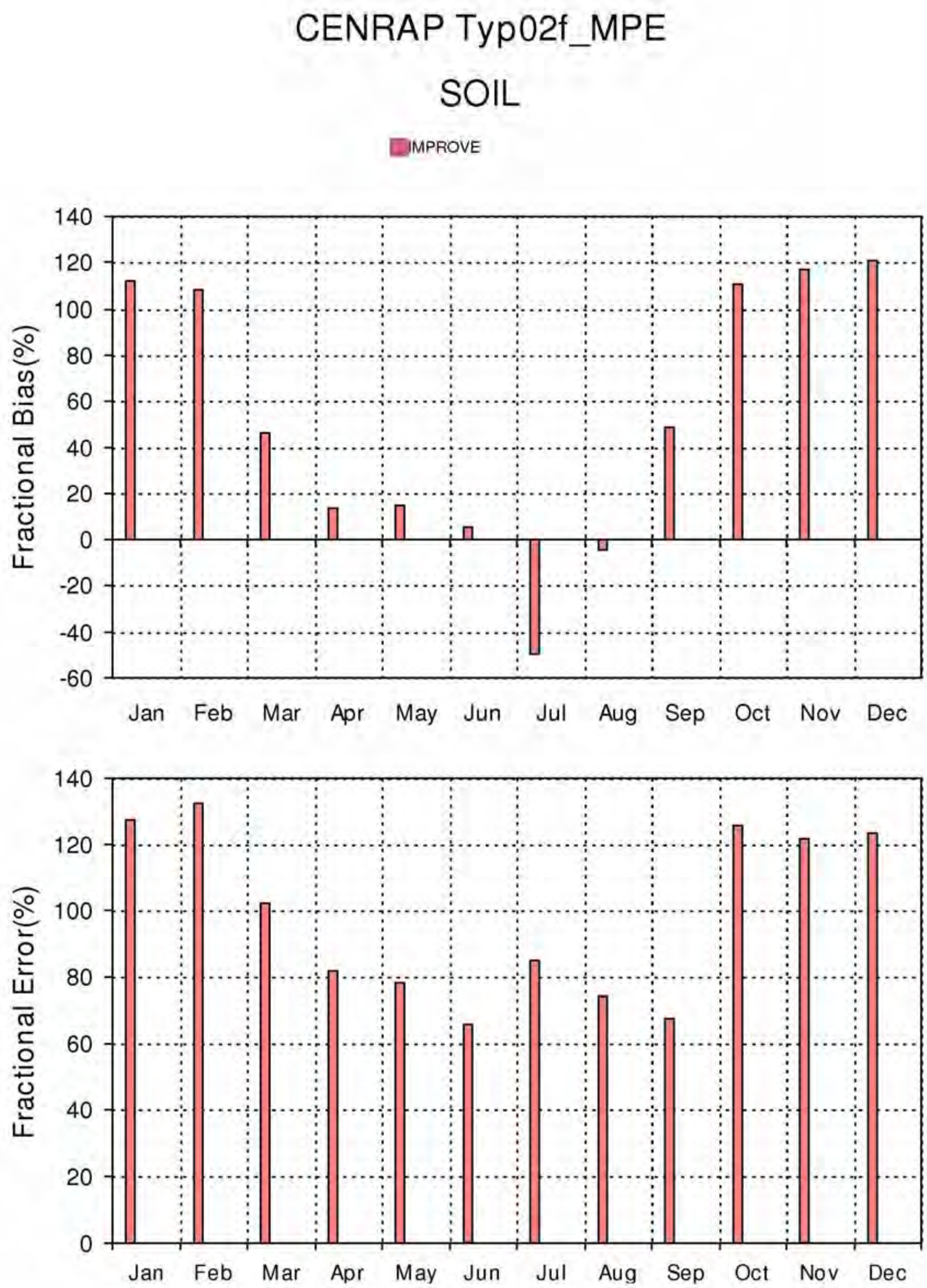


Figure C-32. Monthly Soil fractional bias (top) and fractional gross error (bottom) statistical measures for IMPROVE, STN and CASTNet monitoring sites in the CENRAP region.

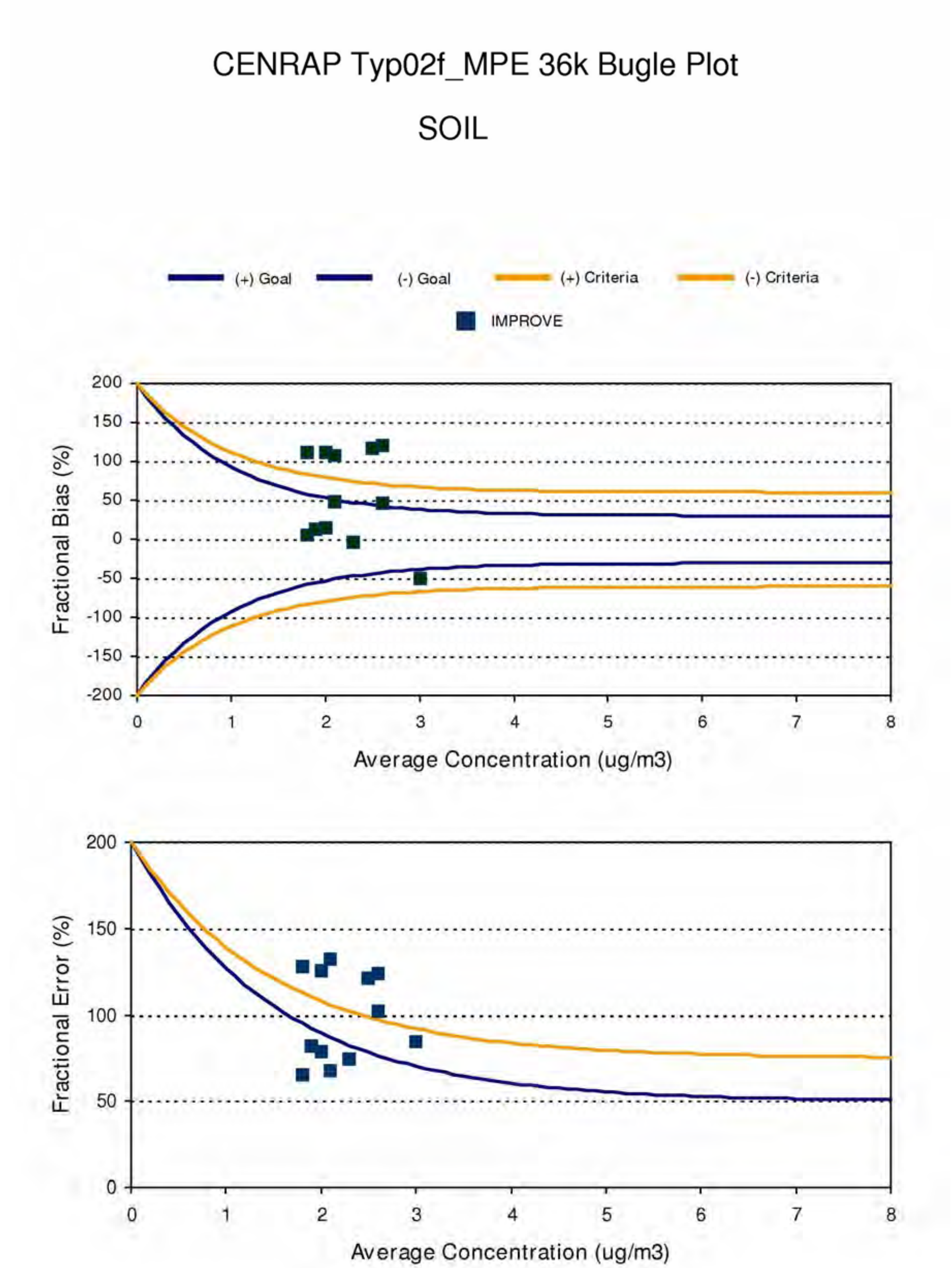


Figure C-33. Bugle Plots of monthly fractional bias (top) and fractional gross error (bottom) and comparisons with model performance goals and criteria for Soil and IMPROVE monitoring sites in the CENRAP region.

C.3.6 Coarse Mass (CM) Monthly Model Performance

The IMPROVE coarse mass (CM) measurement is taken as the difference between the PM_{10} and $PM_{2.5}$ mass measurement. Any SO4 or NO3 in the coarse mode will be in the CM measurement. The model, on the other hand, only includes primary CM. Any coarse SO4 or NO3 will be in the SO4 and NO3 modeled species.

C.3.6.1 CM in January 2002

The model underestimates the observed CM in January with a fractional bias of -83% (Figure C-34a). Although the model appears to reproduce CM at some sites (e.g., VOYA) at the two Texas sites the bias is approximately -150% (Figure C-34b). The observed spatial distribution of CM in January is not reproduced by the model at all (Figure C-34c). Whereas the observations indicate high CM concentrations in the west Texas-New Mexico area, the model estimates elevated CM in northeast Texas, through Oklahoma, Kansas, Iowa and into southern Minnesota. Although the CM measurements at WIMO in this area are also elevated, the rest of the high modeled CM values fall in between the IMPROVE monitors so can not be verified or refuted by the measurements.

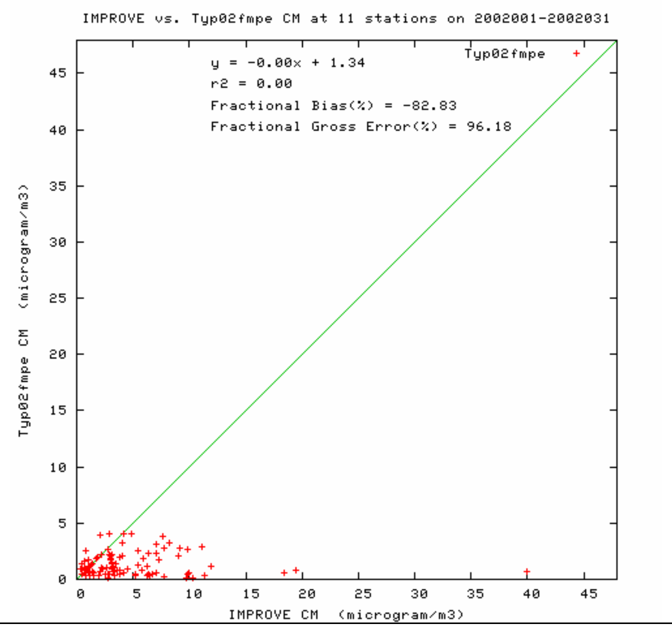
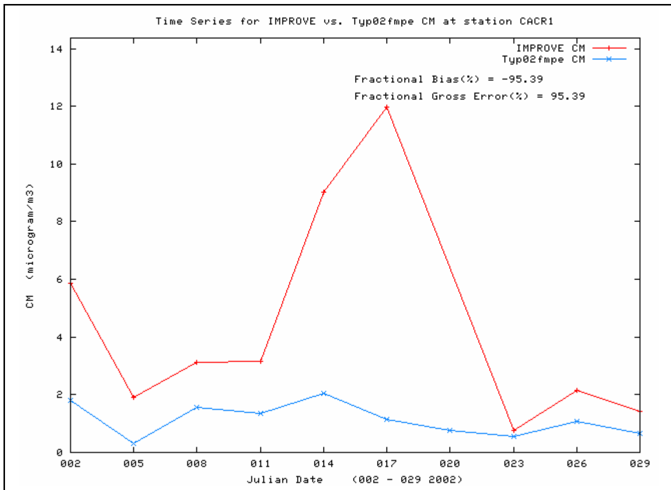
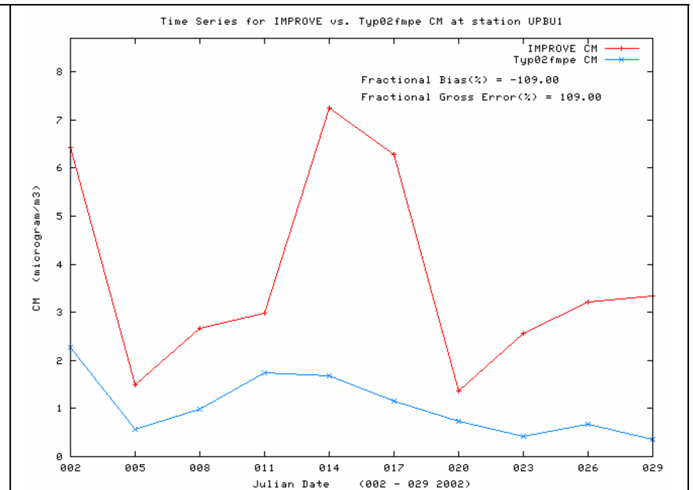
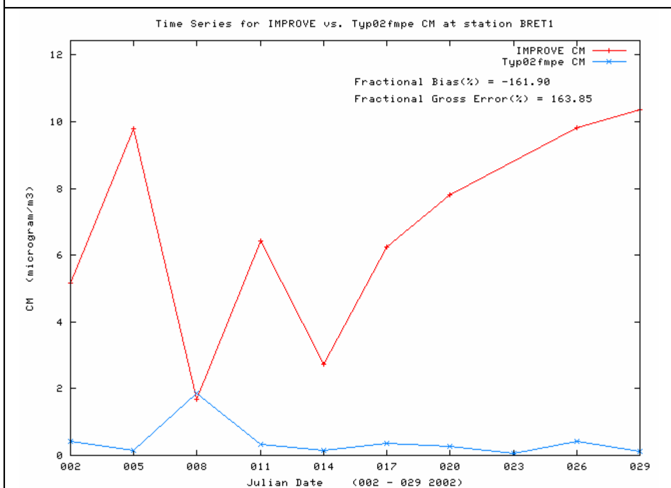
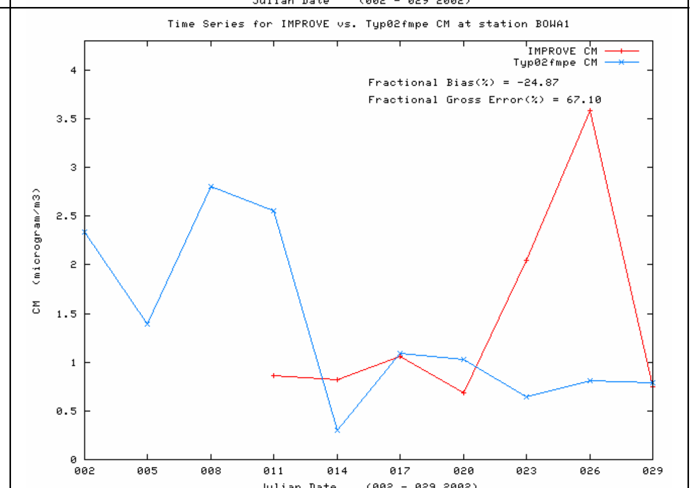


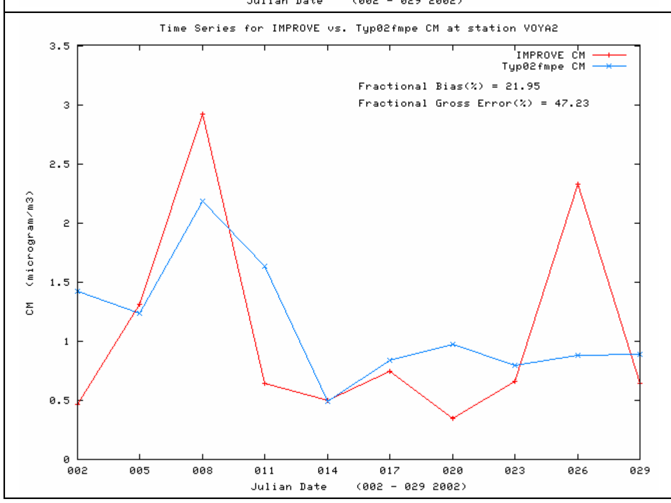
Figure C-34a. Scatter plots of predicted and observed coarse mass (CM) concentrations for January 2002 and sites in the CENRAP region using IMPROVE monitoring networks using the CMAQ 2002 36 km Base F base case simulation.

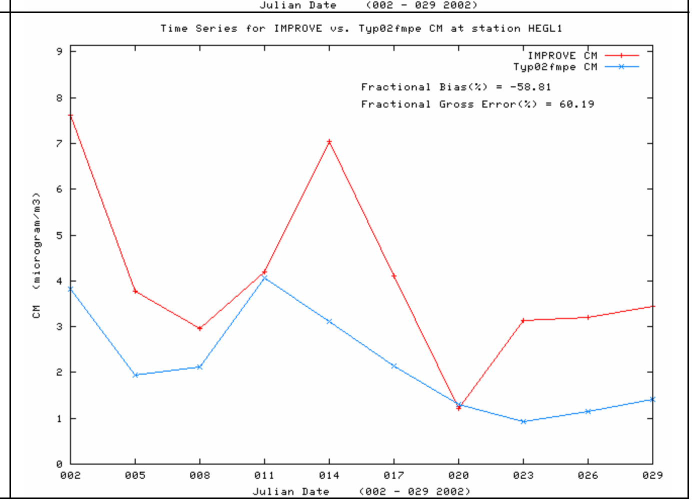

Time Series for IMPROVE vs. Typ02fmpe CM at station CACR1
IMPROVE CM
Typ02fmpe CM
Fractional Bias(%) = -95.39
Fractional Gross Error(%) = 95.39
CM (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe CM at station UPBU1
IMPROVE CM
Typ02fmpe CM
Fractional Bias(%) = -109.00
Fractional Gross Error(%) = 109.00
CM (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe CM at station BRET1
IMPROVE CM
Typ02fmpe CM
Fractional Bias(%) = -161.90
Fractional Gross Error(%) = 163.85
CM (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe CM at station BOWA1
IMPROVE CM
Typ02fmpe CM
Fractional Bias(%) = -24.87
Fractional Gross Error(%) = 67.10
CM (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe CM at station VOYA2
IMPROVE CM
Typ02fmpe CM
Fractional Bias(%) = 21.95
Fractional Gross Error(%) = 47.23
CM (microgram/m3)
Julian Date (002 - 029 2002)


Time Series for IMPROVE vs. Typ02fmpe CM at station HEGL1
IMPROVE CM
Typ02fmpe CM
Fractional Bias(%) = -58.81
Fractional Gross Error(%) = 60.19
CM (microgram/m3)
Julian Date (002 - 029 2002)

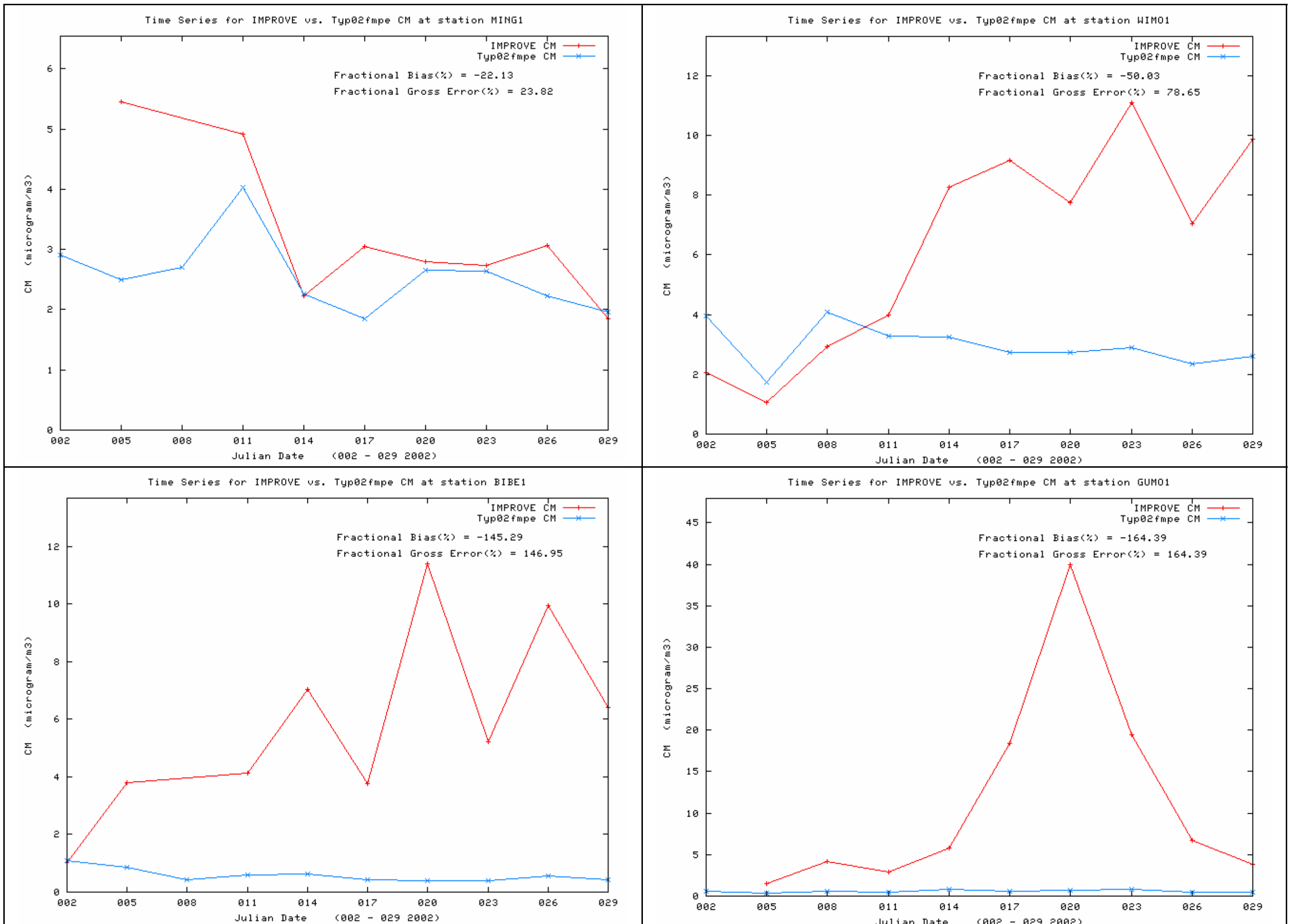


Figure C-34b. Time series of predicted and observed 24-hour coarse mass (CM) concentrations at CENRAP IMPROVE CLASS I AREA sites in January 2002 for CMAQ 2002 36 km Base F base case simulation.

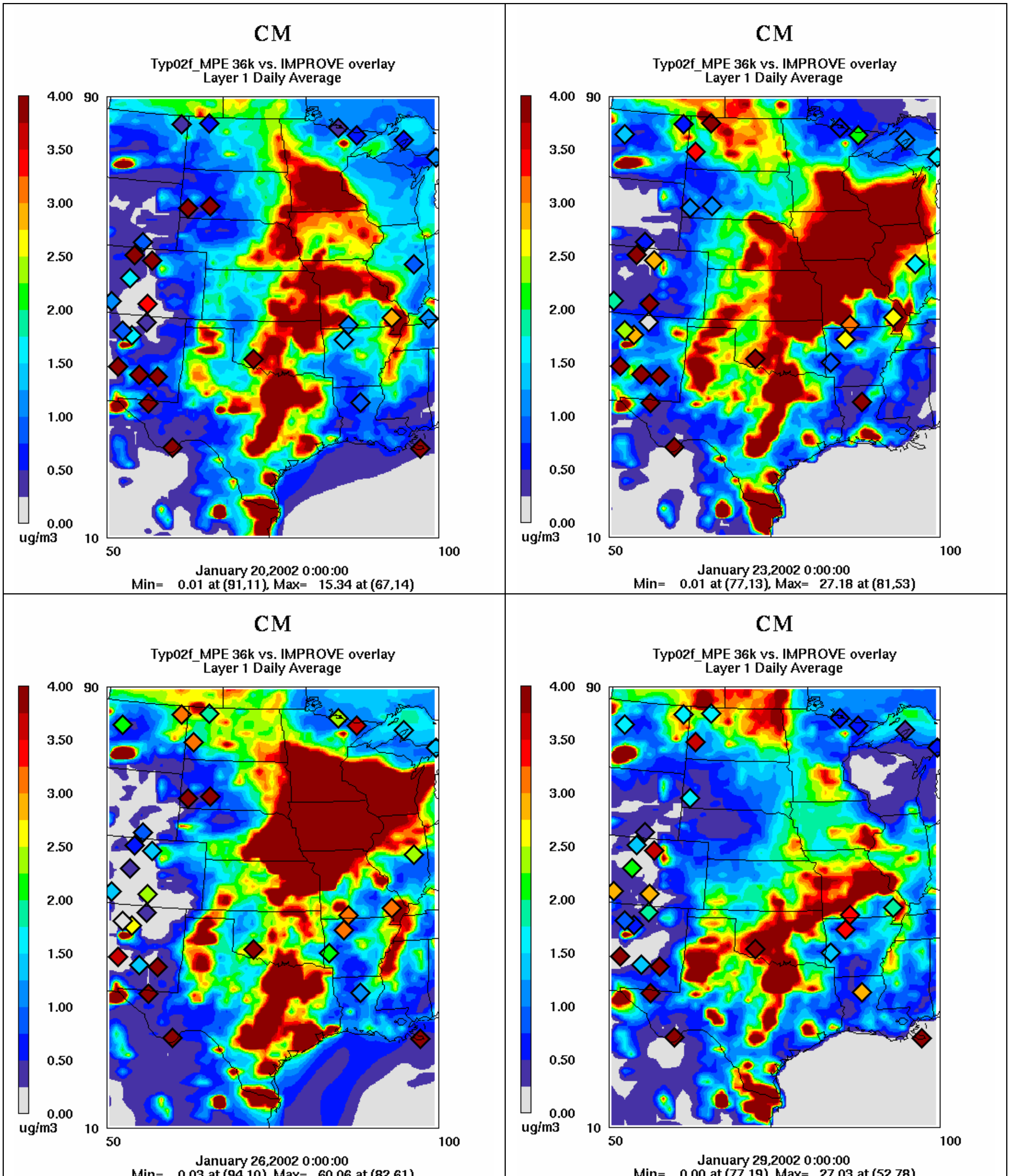


Figure C-34c. Spatial plot comparisons of the predicted and IMPROVE observed 24-hour CM concentrations for January 20, 23, 26 and 29, 2002.

C.3.6.2 CM in April 2002

The CM underestimation bias is even greater in April (-137%) and occurs at all IMPROVE sites (Figure C-35).

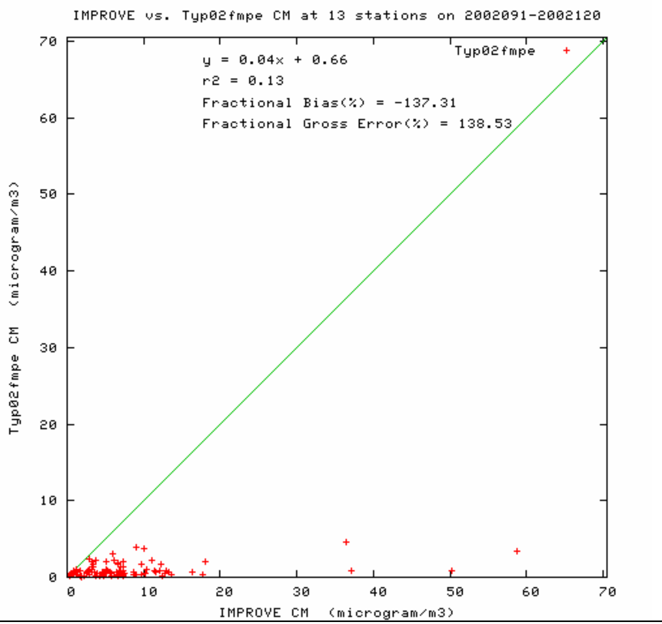
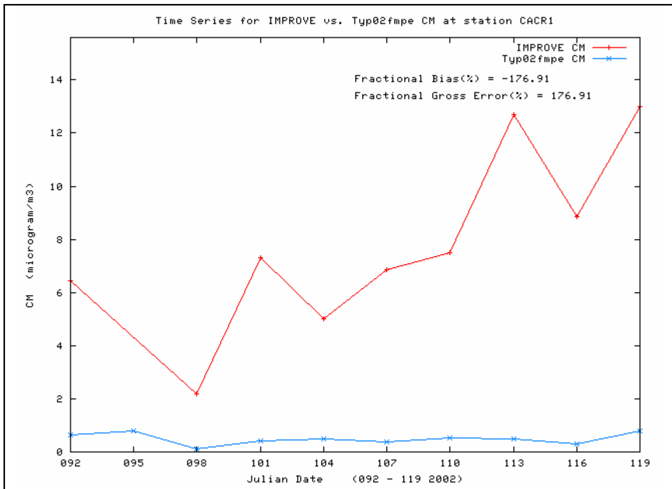
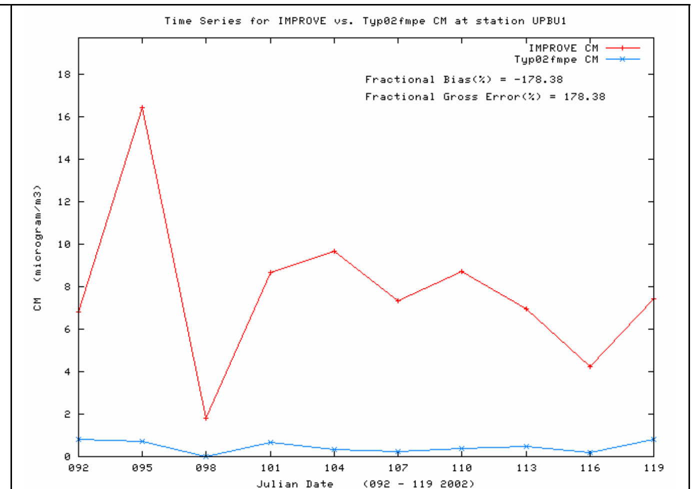
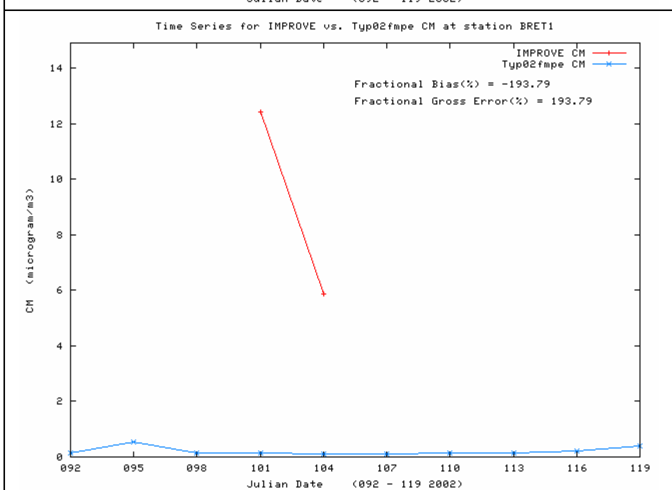
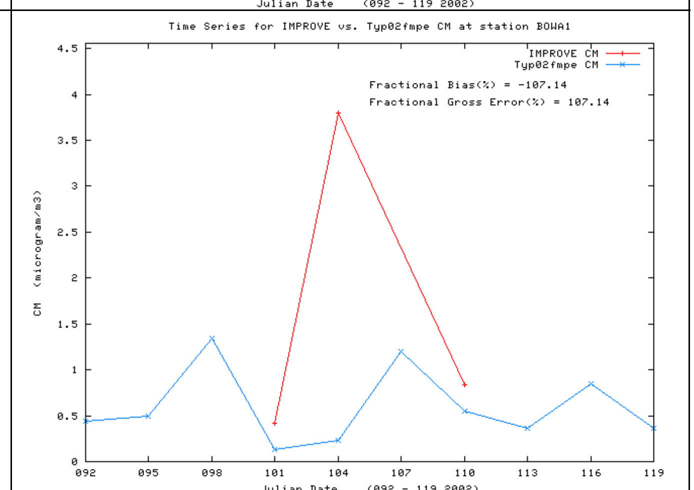


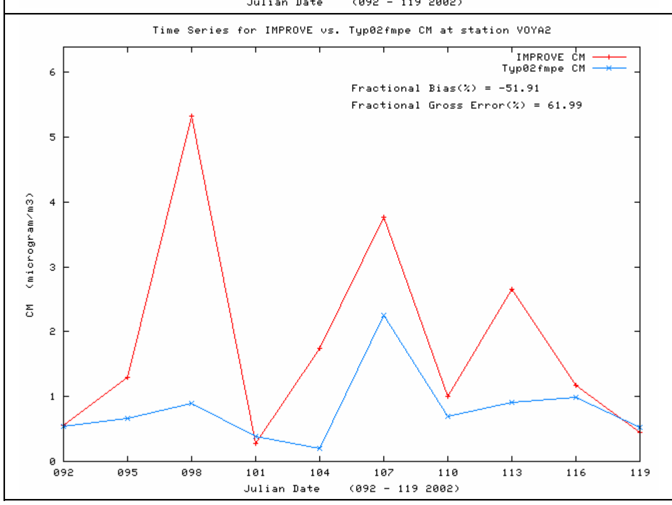
Figure C-35a. Scatter plots of predicted and observed coarse mass (CM) concentrations for April 2002 and sites in the CENRAP region using IMPROVE monitoring networks using the CMAQ 2002 36 km Base F base case simulation.

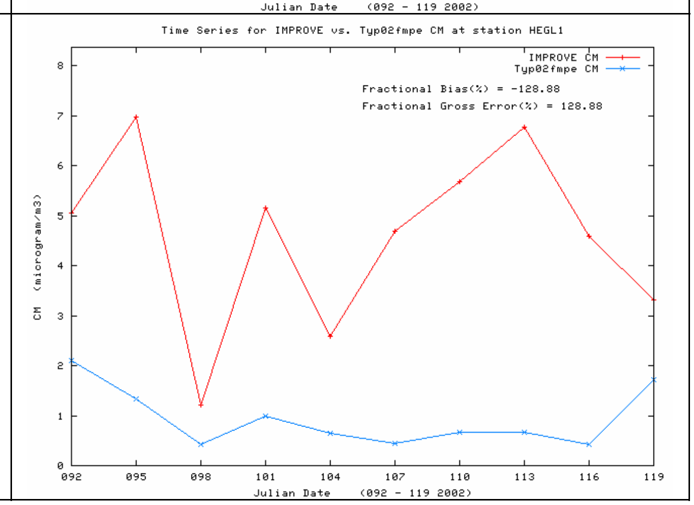

Time Series for IMPROVE vs. Typ02fmpe CM at station CACR1
IMPROVE CM
Typ02fmpe CM
Fractional Bias(%) = -176.91
Fractional Gross Error(%) = 176.91
CM (microgram/m3)
Julian Date (092 - 119 2002)


Time Series for IMPROVE vs. Typ02fmpe CM at station UPBU1
IMPROVE CM
Typ02fmpe CM
Fractional Bias(%) = -178.38
Fractional Gross Error(%) = 178.38
CM (microgram/m3)
Julian Date (092 - 119 2002)


Time Series for IMPROVE vs. Typ02fmpe CM at station BRET1
IMPROVE CM
Typ02fmpe CM
Fractional Bias(%) = -193.79
Fractional Gross Error(%) = 193.79
CM (microgram/m3)
Julian Date (092 - 119 2002)


Time Series for IMPROVE vs. Typ02fmpe CM at station BOWA1
IMPROVE CM
Typ02fmpe CM
Fractional Bias(%) = -107.14
Fractional Gross Error(%) = 107.14
CM (microgram/m3)
Julian Date (092 - 119 2002)


Time Series for IMPROVE vs. Typ02fmpe CM at station VOYA2
IMPROVE CM
Typ02fmpe CM
Fractional Bias(%) = -51.91
Fractional Gross Error(%) = 61.99
CM (microgram/m3)
Julian Date (092 - 119 2002)


Time Series for IMPROVE vs. Typ02fmpe CM at station HEGL1
IMPROVE CM
Typ02fmpe CM
Fractional Bias(%) = -128.88
Fractional Gross Error(%) = 128.88
CM (microgram/m3)
Julian Date (092 - 119 2002)

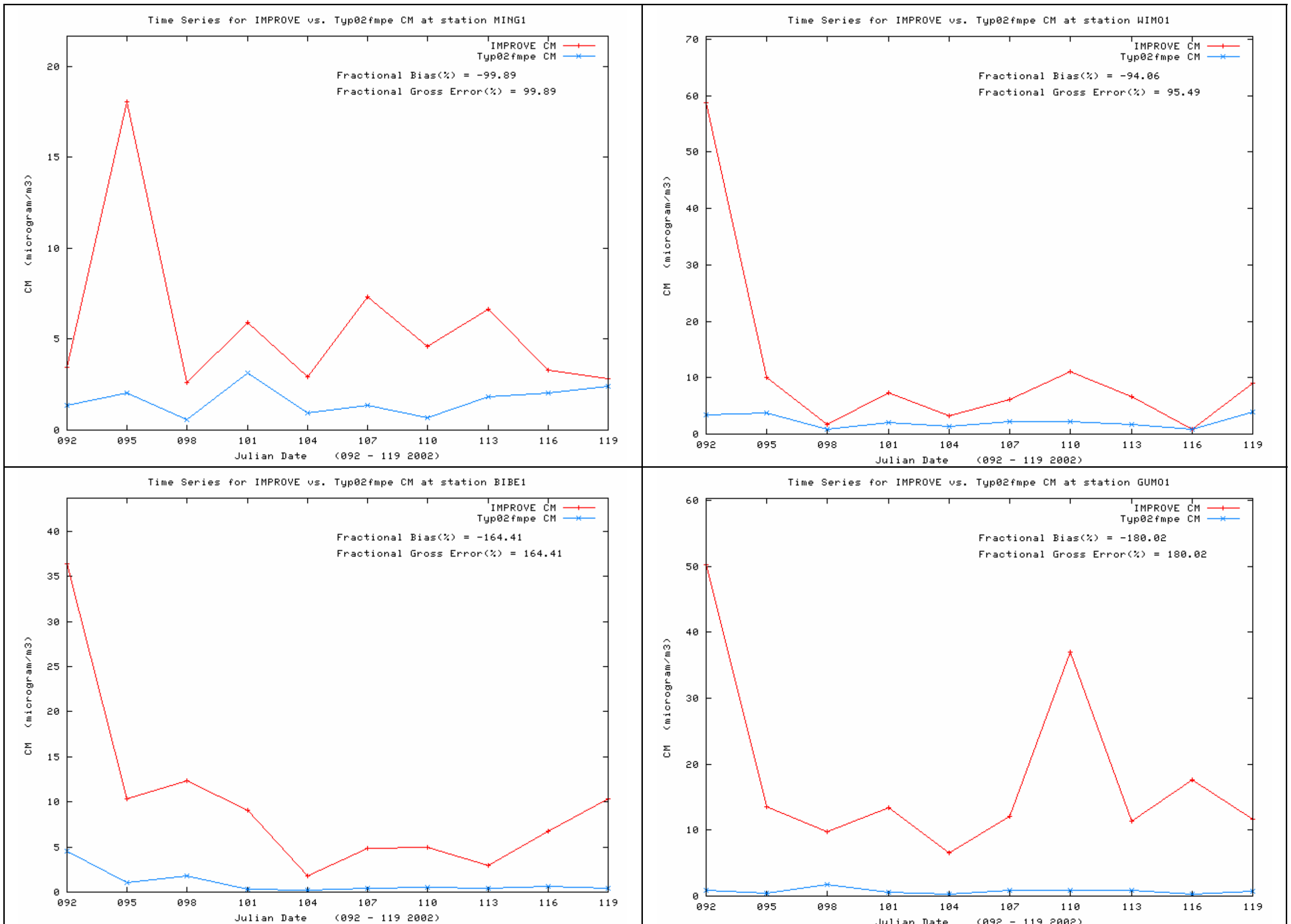


Figure C-35b. Time series of predicted and observed 24-hour coarse mass (CM) concentrations at CENRAP IMPROVE CLASS I AREA sites in April 2002 for CMAQ 2002 36 km Base F base case simulation.

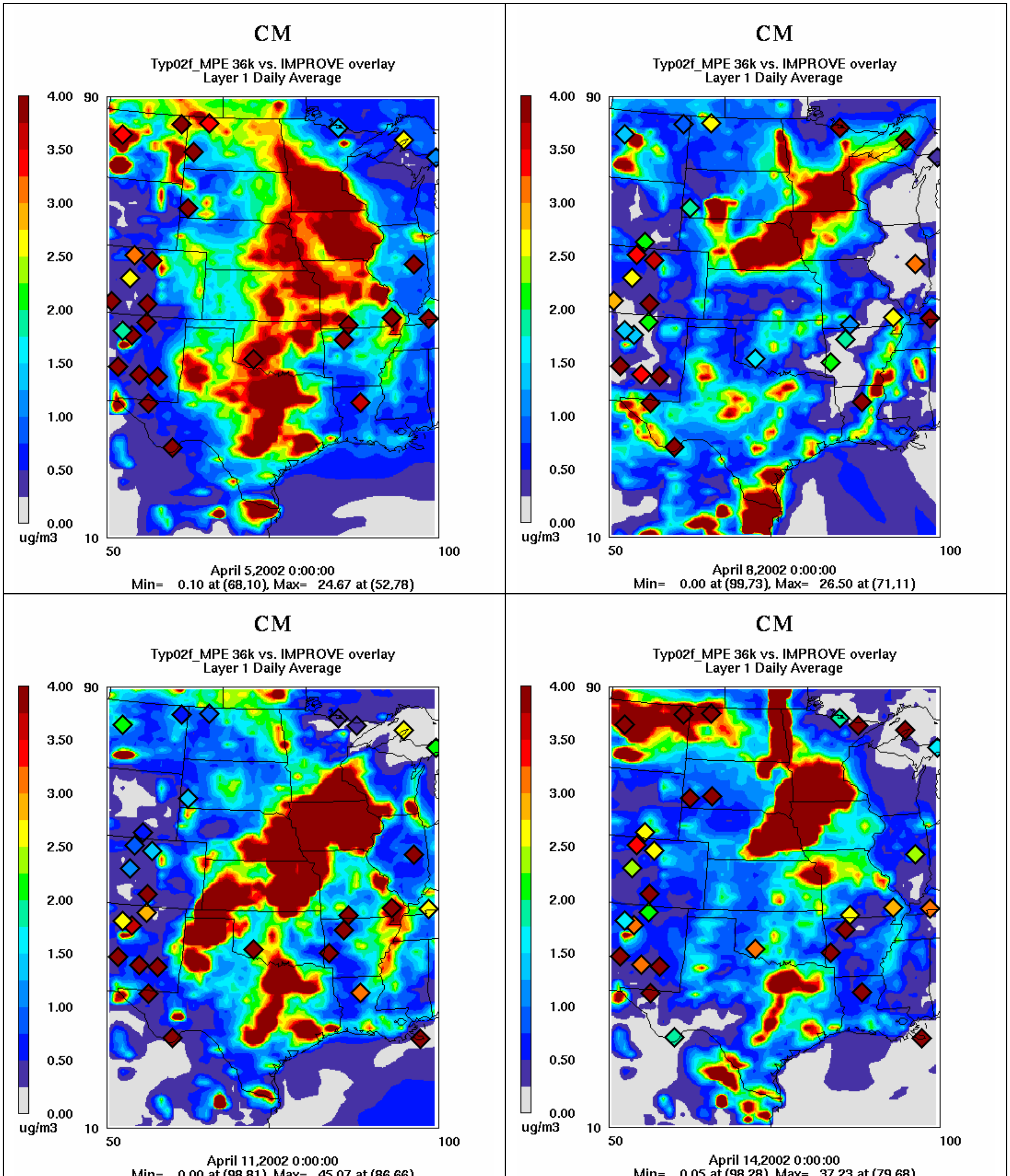


Figure C-35c. Spatial plot comparisons of the predicted and IMPROVE observed 24-hour CM concentrations for April 5, 8, 11 and 14, 2002.

C.3.6.3 CM in July 2002

CM performance in July is also very poor with a fractional bias value of -160% (Figure C-36).

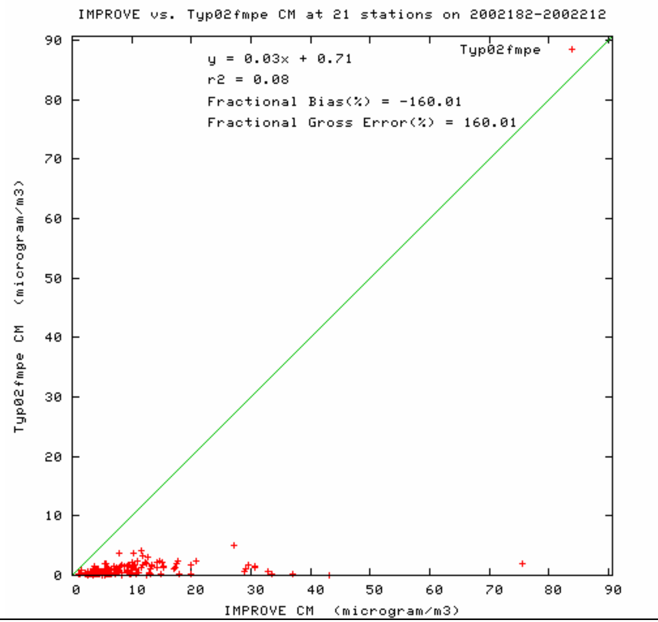
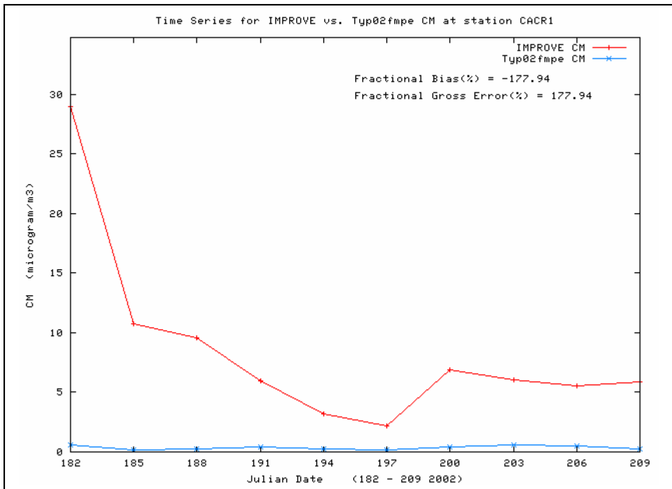
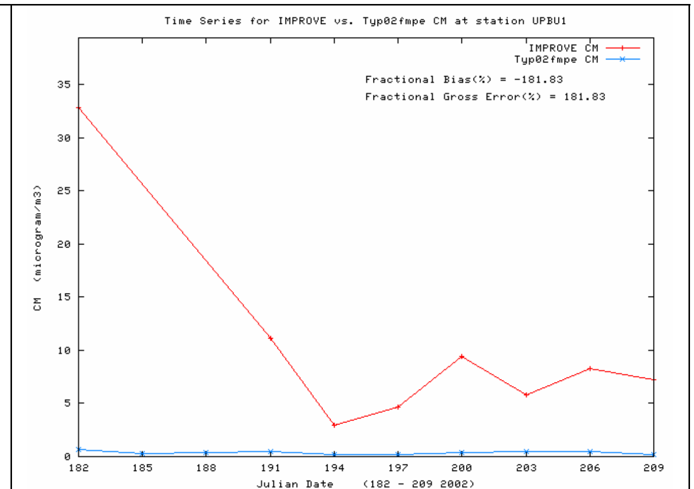


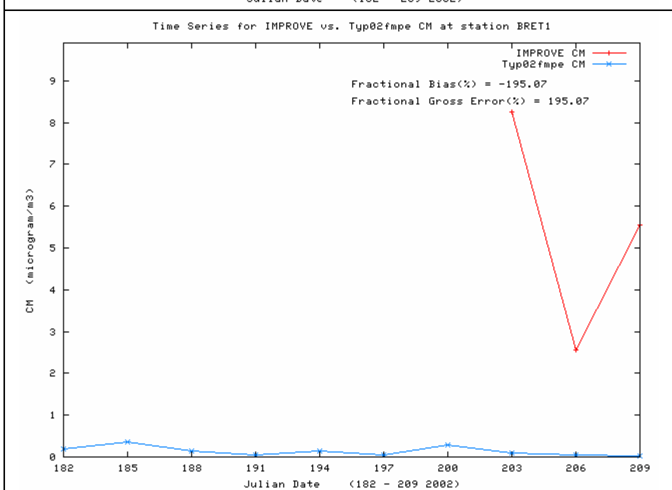
Figure C-36a. Scatter plots of predicted and observed coarse mass (CM) concentrations for July 2002 and sites in the CENRAP region using IMPROVE monitoring networks using the CMAQ 2002 36 km Base F base case simulation.



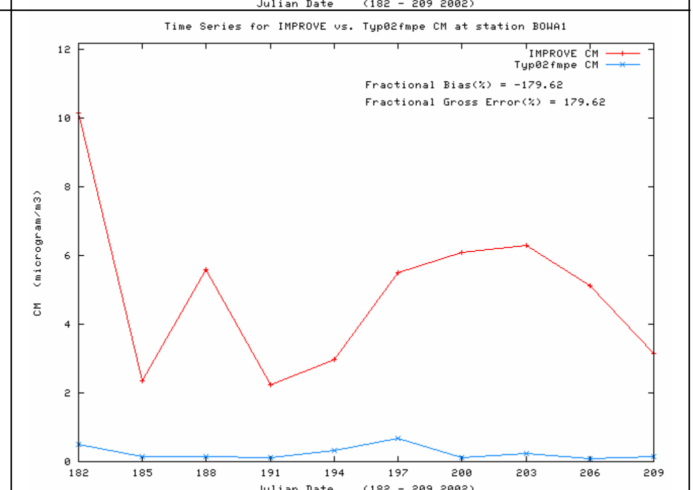
Time Series for IMPROVE vs. Typ02fmpe CM at station CACR1
IMPROVE CM
Typ02fmpe CM
Fractional Bias(%) = -177.94
Fractional Gross Error(%) = 177.94
CM (microgram/m3)
Julian Date (182 - 209 2002)



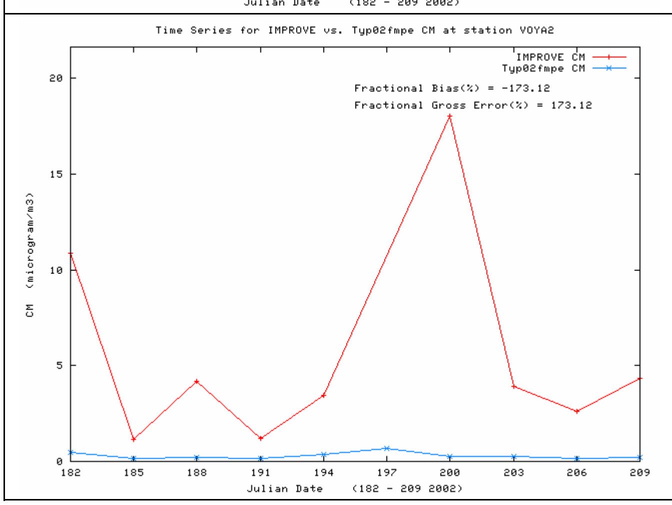
Time Series for IMPROVE vs. Typ02fmpe CM at station UPBU1
IMPROVE CM
Typ02fmpe CM
Fractional Bias(%) = -181.83
Fractional Gross Error(%) = 181.83
CM (microgram/m3)
Julian Date (182 - 209 2002)



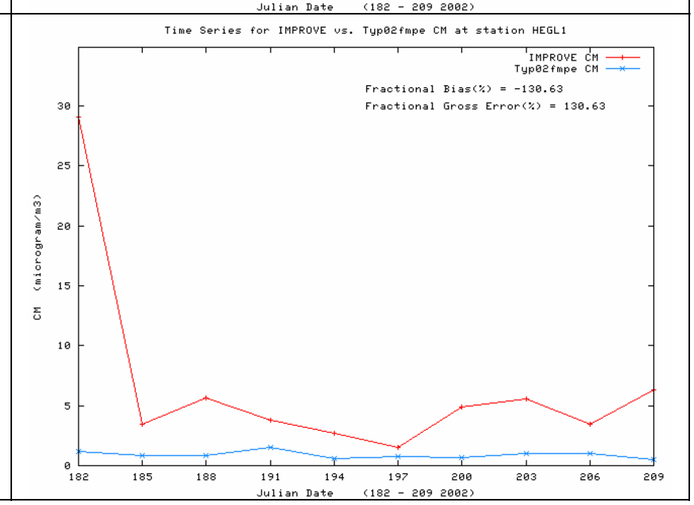
Time Series for IMPROVE vs. Typ02fmpe CM at station BRET1
IMPROVE CM
Typ02fmpe CM
Fractional Bias(%) = -195.07
Fractional Gross Error(%) = 195.07
CM (microgram/m3)
Julian Date (182 - 209 2002)



Time Series for IMPROVE vs. Typ02fmpe CM at station BOWA1
IMPROVE CM
Typ02fmpe CM
Fractional Bias(%) = -179.62
Fractional Gross Error(%) = 179.62
CM (microgram/m3)
Julian Date (182 - 209 2002)



Time Series for IMPROVE vs. Typ02fmpe CM at station VOYA2
IMPROVE CM
Typ02fmpe CM
Fractional Bias(%) = -173.12
Fractional Gross Error(%) = 173.12
CM (microgram/m3)
Julian Date (182 - 209 2002)



Time Series for IMPROVE vs. Typ02fmpe CM at station HEGL1
IMPROVE CM
Typ02fmpe CM
Fractional Bias(%) = -130.63
Fractional Gross Error(%) = 130.63
CM (microgram/m3)
Julian Date (182 - 209 2002)

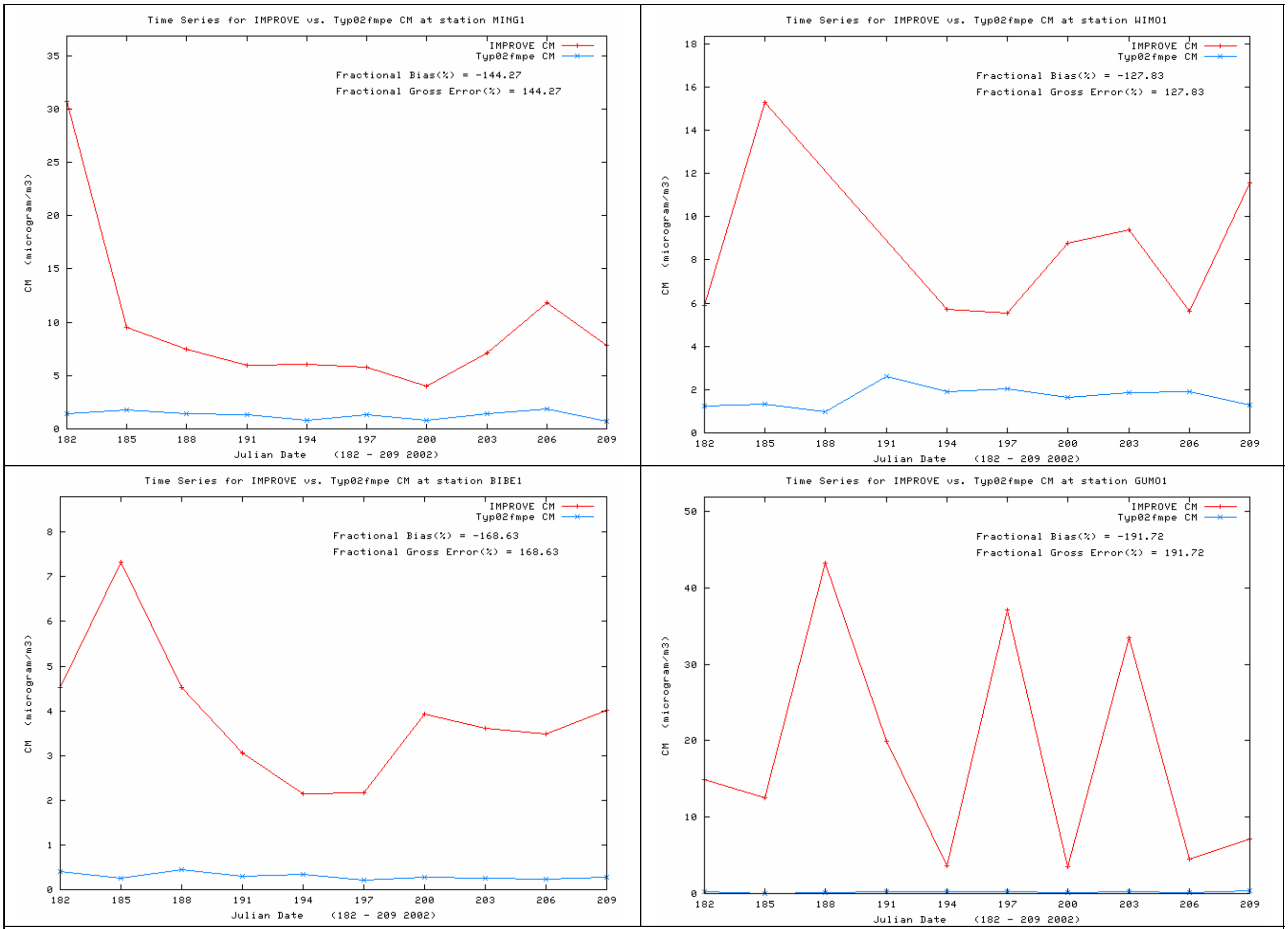


Figure C-36b. Time series of predicted and observed 24-hour coarse mass (CM) concentrations at CENRAP IMPROVE CLASS I AREA sites in July 2002 for CMAQ 2002 36 km Base F base case simulation.

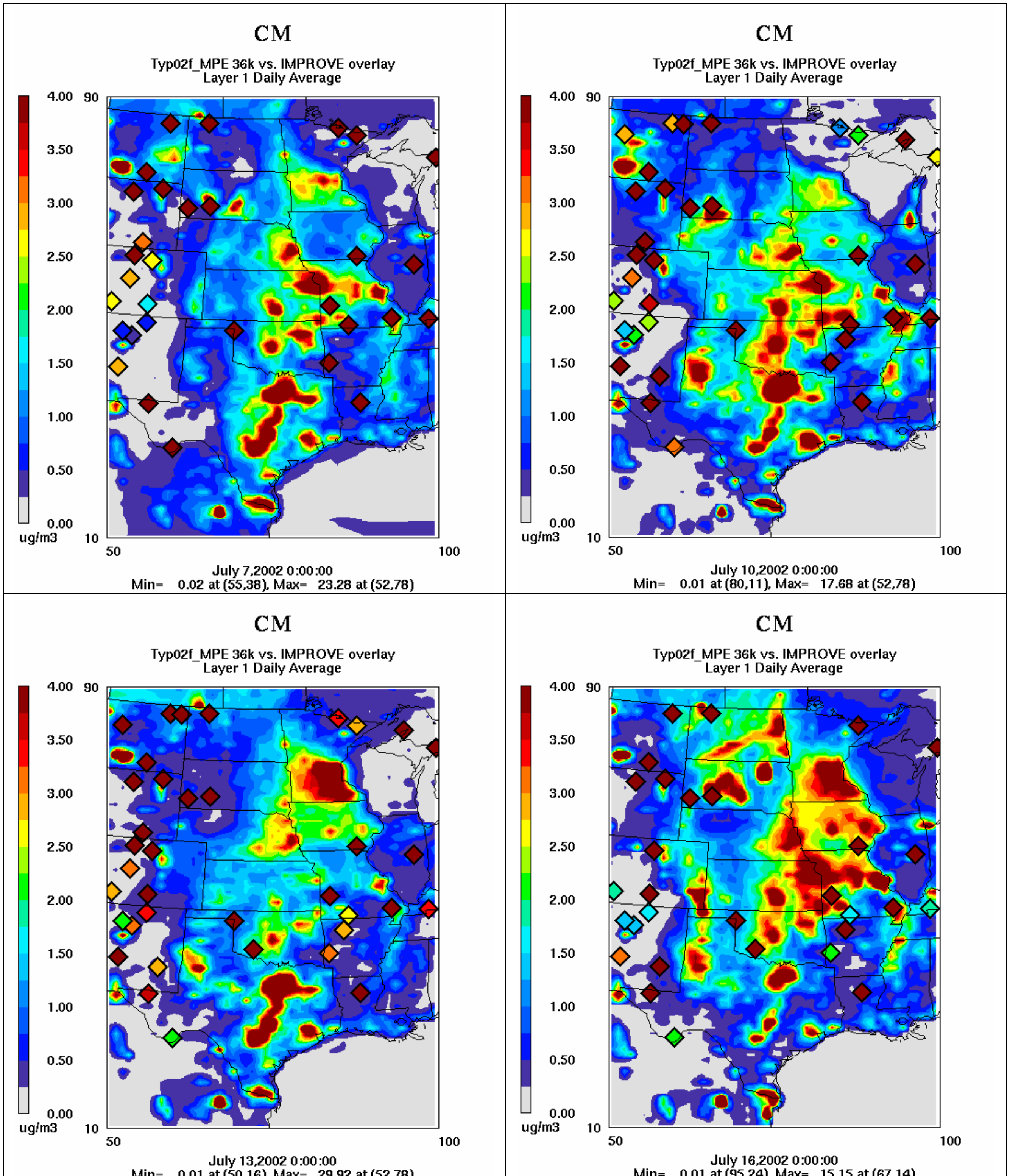


Figure C-36c. Spatial plot comparisons of the predicted and IMPROVE observed 24-hour CM concentrations for July 7, 10, 13 and 16, 2002.

C.3.6.4 CM in October 2002

CM is also underestimated in October, although the overestimation bias (-72%) is not as great as seen in July (Figure C-37).

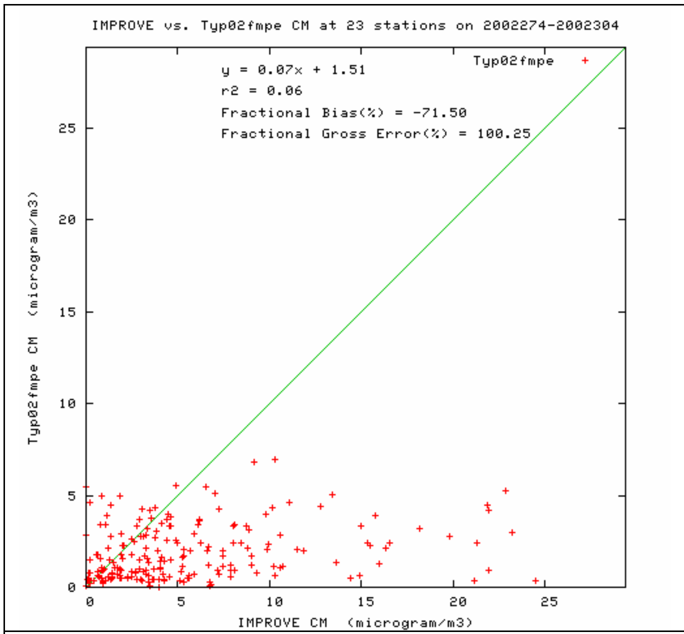
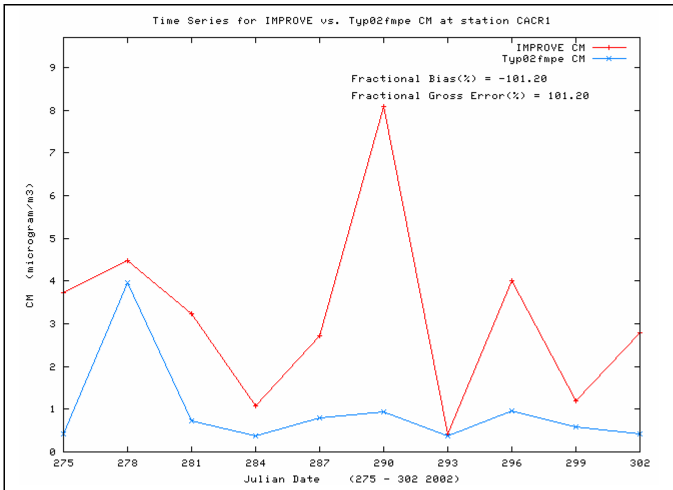
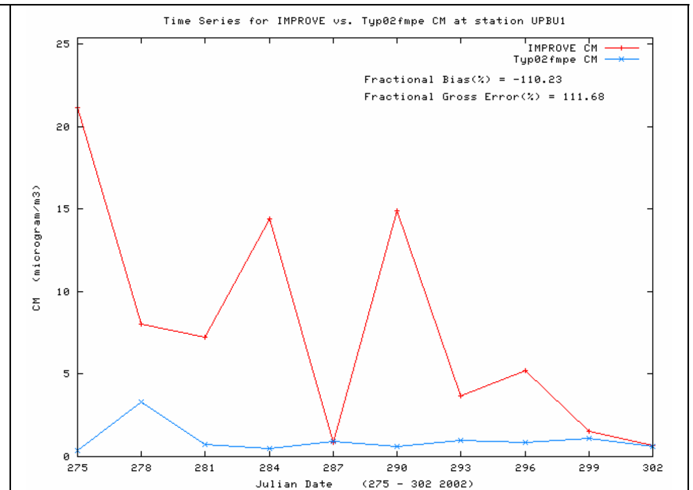
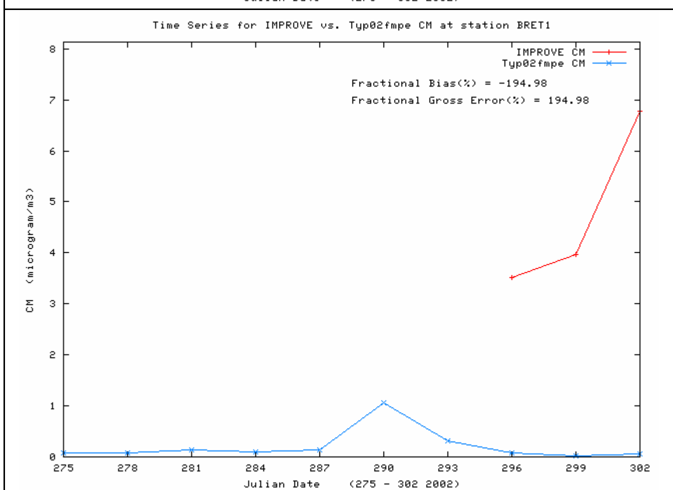
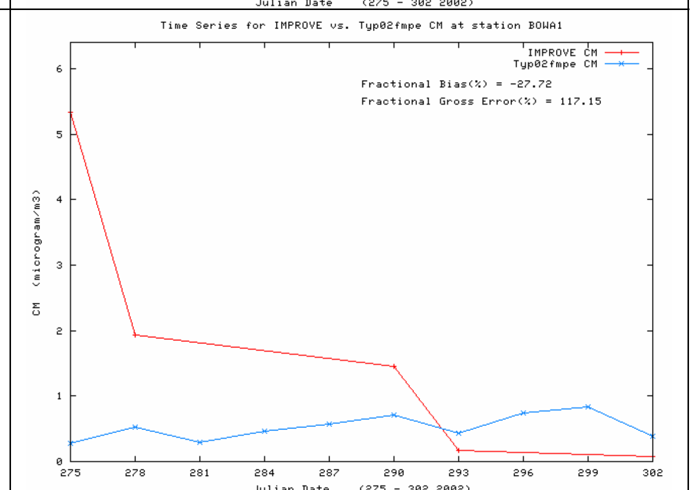


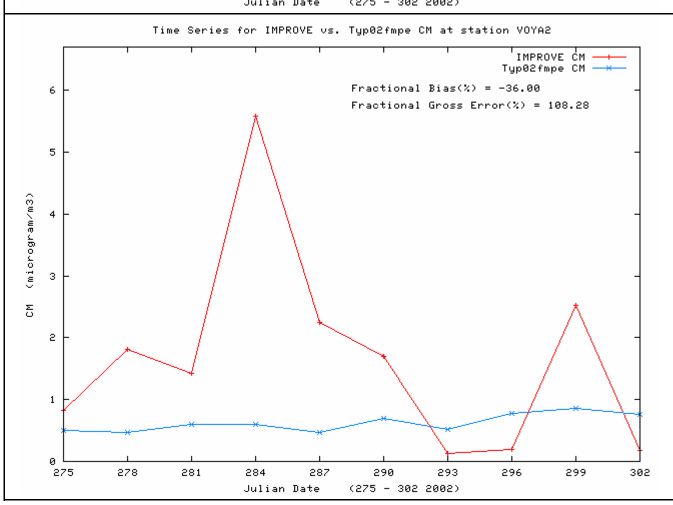
Figure C-37a. Scatter plots of predicted and observed coarse mass (CM) concentrations for October 2002 and sites in the CENRAP region using IMPROVE monitoring networks using the CMAQ 2002 36 km Base F base case simulation.

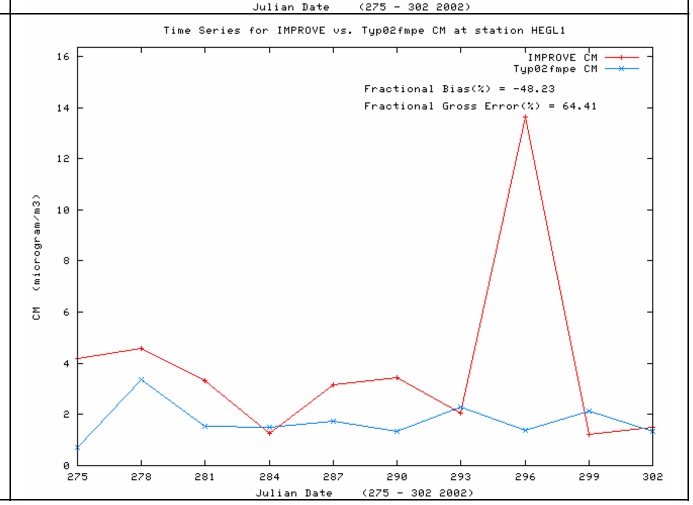

Time Series for IMPROVE vs. Typ02fmpe CM at station CACR1
IMPROVE CM
Typ02fmpe CM
Fractional Bias(%) = -101.20
Fractional Gross Error(%) = 101.20
CM (microgram/m3)
Julian Date (275 - 302 2002)


Time Series for IMPROVE vs. Typ02fmpe CM at station UPBU1
IMPROVE CM
Typ02fmpe CM
Fractional Bias(%) = -110.23
Fractional Gross Error(%) = 111.68
CM (microgram/m3)
Julian Date (275 - 302 2002)


Time Series for IMPROVE vs. Typ02fmpe CM at station BRET1
IMPROVE CM
Typ02fmpe CM
Fractional Bias(%) = -194.98
Fractional Gross Error(%) = 194.98
CM (microgram/m3)
Julian Date (275 - 302 2002)


Time Series for IMPROVE vs. Typ02fmpe CM at station BOWA1
IMPROVE CM
Typ02fmpe CM
Fractional Bias(%) = -27.72
Fractional Gross Error(%) = 117.15
CM (microgram/m3)
Julian Date (275 - 302 2002)


Time Series for IMPROVE vs. Typ02fmpe CM at station VOYA2
IMPROVE CM
Typ02fmpe CM
Fractional Bias(%) = -36.00
Fractional Gross Error(%) = 108.28
CM (microgram/m3)
Julian Date (275 - 302 2002)


Time Series for IMPROVE vs. Typ02fmpe CM at station HEGL1
IMPROVE CM
Typ02fmpe CM
Fractional Bias(%) = -48.23
Fractional Gross Error(%) = 64.41
CM (microgram/m3)
Julian Date (275 - 302 2002)

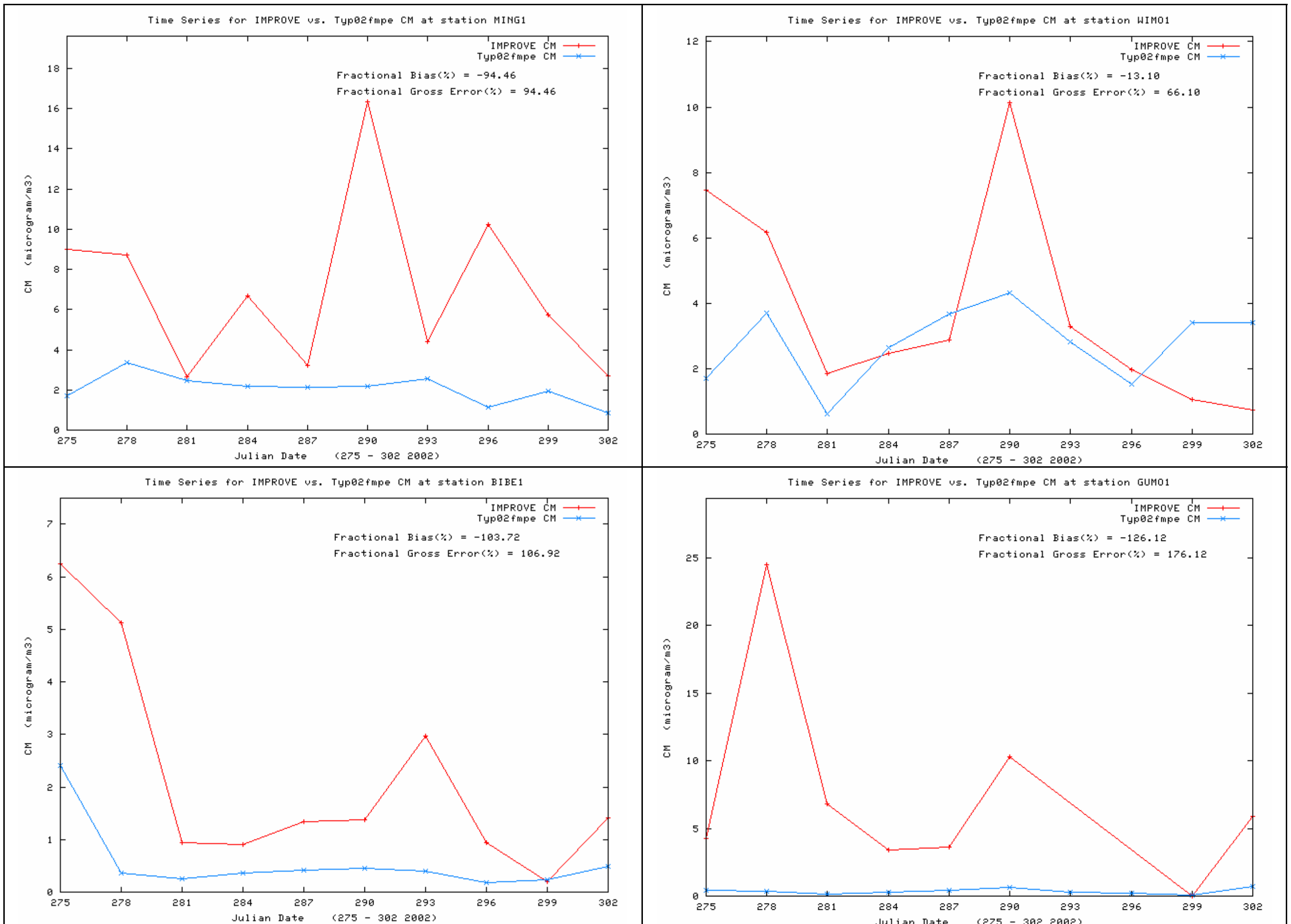


Figure C-37b. Time series of predicted and observed 24-hour coarse mass (CM) concentrations at CENRAP IMPROVE CLASS I AREA sites in October 2002 for CMAQ 2002 36 km Base F base case simulation.

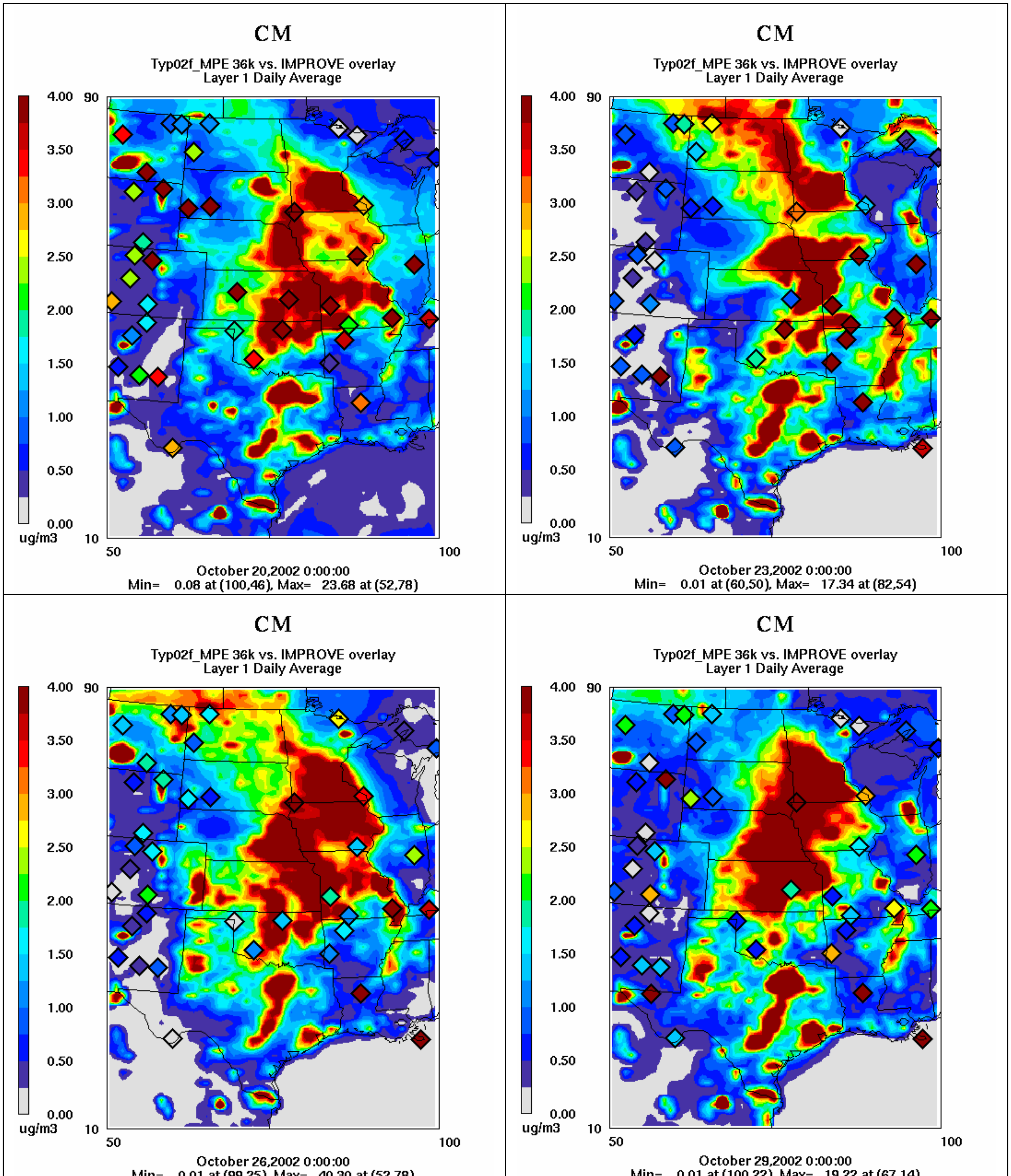


Figure C-37c. Spatial plot comparisons of the predicted and IMPROVE observed 24-hour CM concentrations for October 20, 23, 26 and 29, 2002.

C.3.6.5 CM Monthly Bias and Error

The monthly average fractional bias and error values for CM are shown in Figure C-38. In the winter the under-prediction bias is typically in the -60% to -80% range. In the late Spring and Summer the under-prediction bias ranges from -120% to -160%. As this under-prediction bias is nearly systematic, then the errors are the same magnitude as the bias.

The Bugle Plots clearly show that the CM model performance is a problem. The monthly bias exceeds both the performance goal and criteria for almost every month of the year. The error criteria are also exceeded for all months of the year.

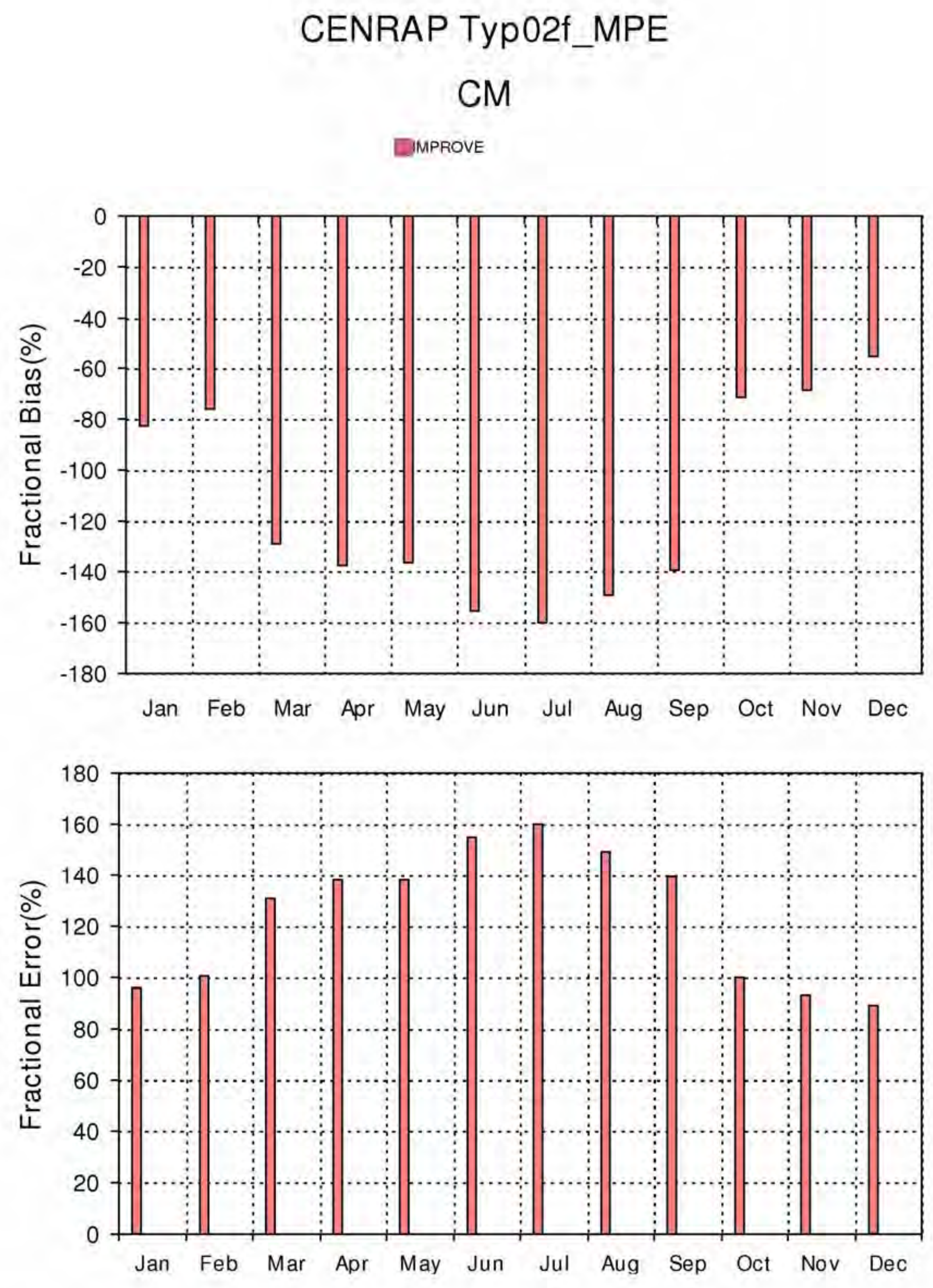


Figure C-38. Monthly CM fractional bias (top) and fractional gross error (bottom) statistical measures for IMPROVE monitoring sites in the CENRAP region.

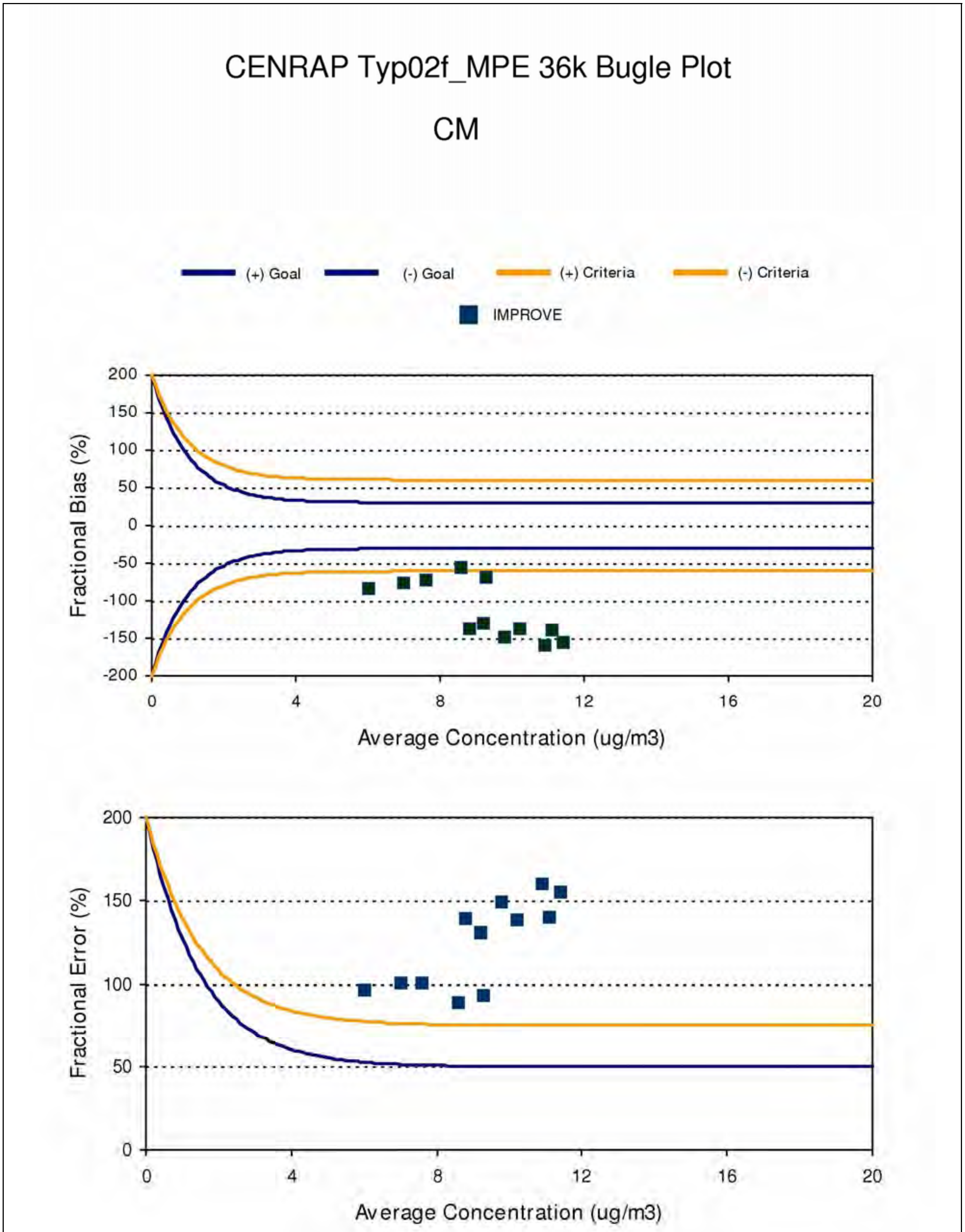


Figure C-39. Bugle Plots of monthly fractional bias (top) and fractional gross error (bottom) and comparisons with model performance goals and criteria for CM and IMPROVE monitoring sites in the CENRAP region.

C.4 Diagnostic Model Evaluation for Gas-Phase and Precursor Species

The CASTNet and AQS networks also measure gas-phase species that are PM precursor or related species. The diagnostic evaluation of the 2002 36 km Base F CMAQ base case simulation for these compounds and the four seasonal months presented previously is provided below.

The CASTNet network measures weekly average samples of SO2, SO4, NO2, HNO3, NO3 and NH4. The AQS network collects hourly measurements of SO2, NO2, O3 and CO. A comparison of the SO2 and SO4 performance provides insight into whether the SO4 formation rate may be too slow or fast. For example, if SO4 is underestimated and SO2 is overestimated that may indicate too slow chemical conversion rate. Analyzing the performance for SO4, HNO3, NO3, Total NO3 and NH4 provides insight into the equilibrium of these species. For example, if Total NO3 performs well but HNO3 and NO3 do not, then there may be issues associated with the partitioning between the gaseous and particle phases of nitrate.

C.4.1 Diagnostic Model Performance in January 2002

In January, SO2 is overstated across both the CASTNet and AQS sites with fractional bias values of 38% (Figure C-40) and 31% (Figure C-41), respectively. SO4 is understated by -34% across the CASTNet monitors (Figure C-40) and -12% and -13% for the IMPROVE and STN networks (Figure C-4a). As noted previously, wet SO4 deposition is also overstated in January (+40%, Figure C-4a). Given that SO2 emissions are well characterized, these results suggest that the January SO4 underestimation may be partly due to understated transformation rates of So2 to SO4 and overstated wet SO4 deposition.

Total NO3 is overestimated by 35% on average across the CASTNet sites in the CENRAP region in January (Figure C-40). HNO3 is underestimated (-34%) and particle NO3 is overestimated (+61%) suggesting there are gas/particle equilibrium issues. An analysis of the time series of the four CASTNet stations reveals that NO3, HNO3 and NH4 performance is actually very reasonable at the west Texas and the HNO3 underestimation and NO3 overestimation bias is coming from the east Kansas, central Arkansas and northern Minnesota CASTNet sites. One potential contributor for this performance problem is overstated NH3 emissions. However the overstated Total NO3 suggests that the model estimated NOx oxidation rate may be too high in January.

The SO2, NO2, O3 and CO performance across the AQS sites in January is shown in Figure C-41. The AQS monitoring network is primarily an urban-oriented network so it is not surprising that the model is underestimating concentrations of primary emissions like NO2 (-5%) and particularly CO (-67%) when a 36 km grid is used. Ozone is also underestimated on average, especially the maximum values above 60 ppb.

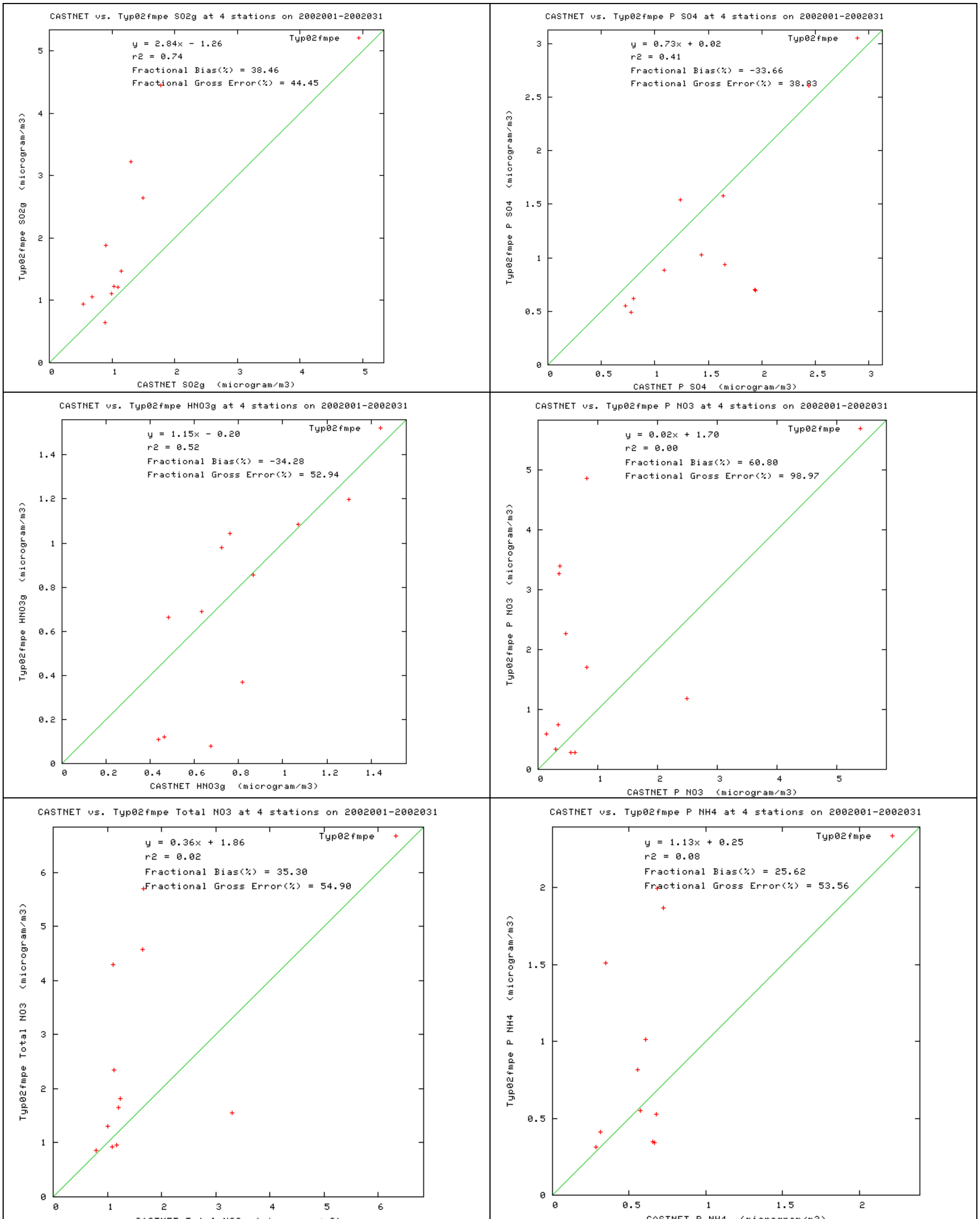


Figure C-40. January 2002 performance at CENRAP CASTNet sites for SO2 (top left), SO4 (top right), HNO3 (middle left), NO3 (middle right), Ttoal NO3 (bottom left) and NH4 (bottom right).

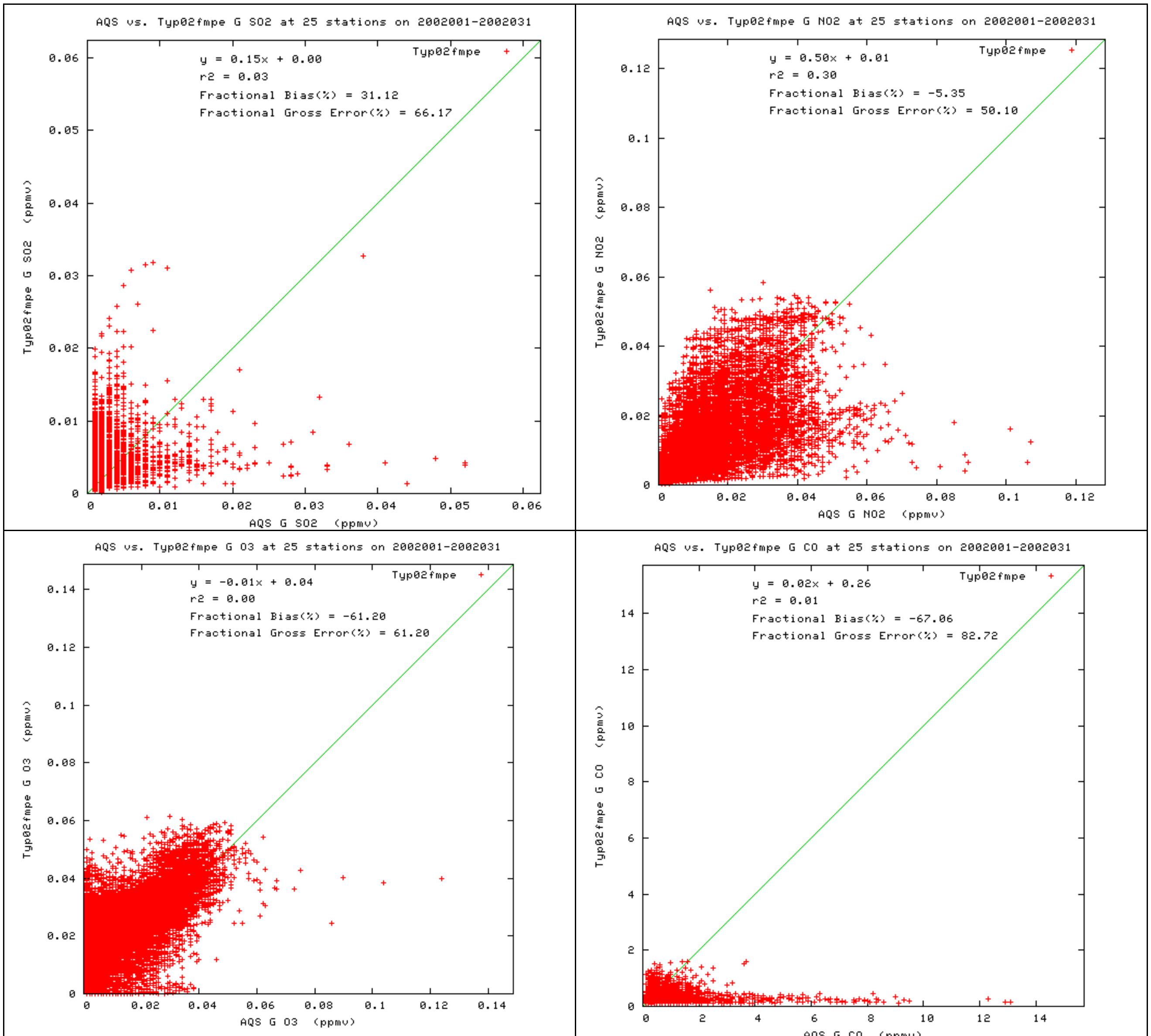


Figure C-41. January 2002 performance at CENRAP AQS sites for SO2 (top left), NO2 (top right), O3 (bottom left) and CO (bottom right).

C.4.2 Diagnostic Model Performance In April

In April there is an average SO_2 overestimation bias across the CASTNet (+15%) and underestimation bias across the AQS (-10%) networks (Figures C-42 and C-43). SO_4 is underestimated across all networks by -30% to -58% (Figure C-5a). The wet SO_4 deposition bias is near zero. Both SO_2 and SO_4 are underestimated at the west Texas CASTNet monitor in April suggesting SO_2 emissions in Mexico are likely understated.

The HNO_3 performance in April is interesting with almost perfect agreement except for 5 modeled-observed comparisons that drives the average under-prediction bias of -29%. On Julian Day 102 there is high HNO_3 at the MN, KS and OK CASTNet sites that is not captured by the model. Given that HNO_3, NO_3 and Total NO_3 are all underestimated by about the same amount (-30%), then part of the underestimation bias is likely due to too slow oxidation of NO_x.

There is a lot of scatter in the NO_2 and O_3 performance that is more or less centered on the 1:1 line of perfect agreement with bias values of -8% and -21%, respectively (Figure C-43). CO is underestimated by -72% with the model unable to predict CO concentrations above 1 $\mu g/m^3$ due to the use of the coarse 36 km grid spacing. Mobile sources produce a vast majority of the CO emissions so AQS monitors for CO compliance are located near roadways, which are not simulated well using a 36 km grid.

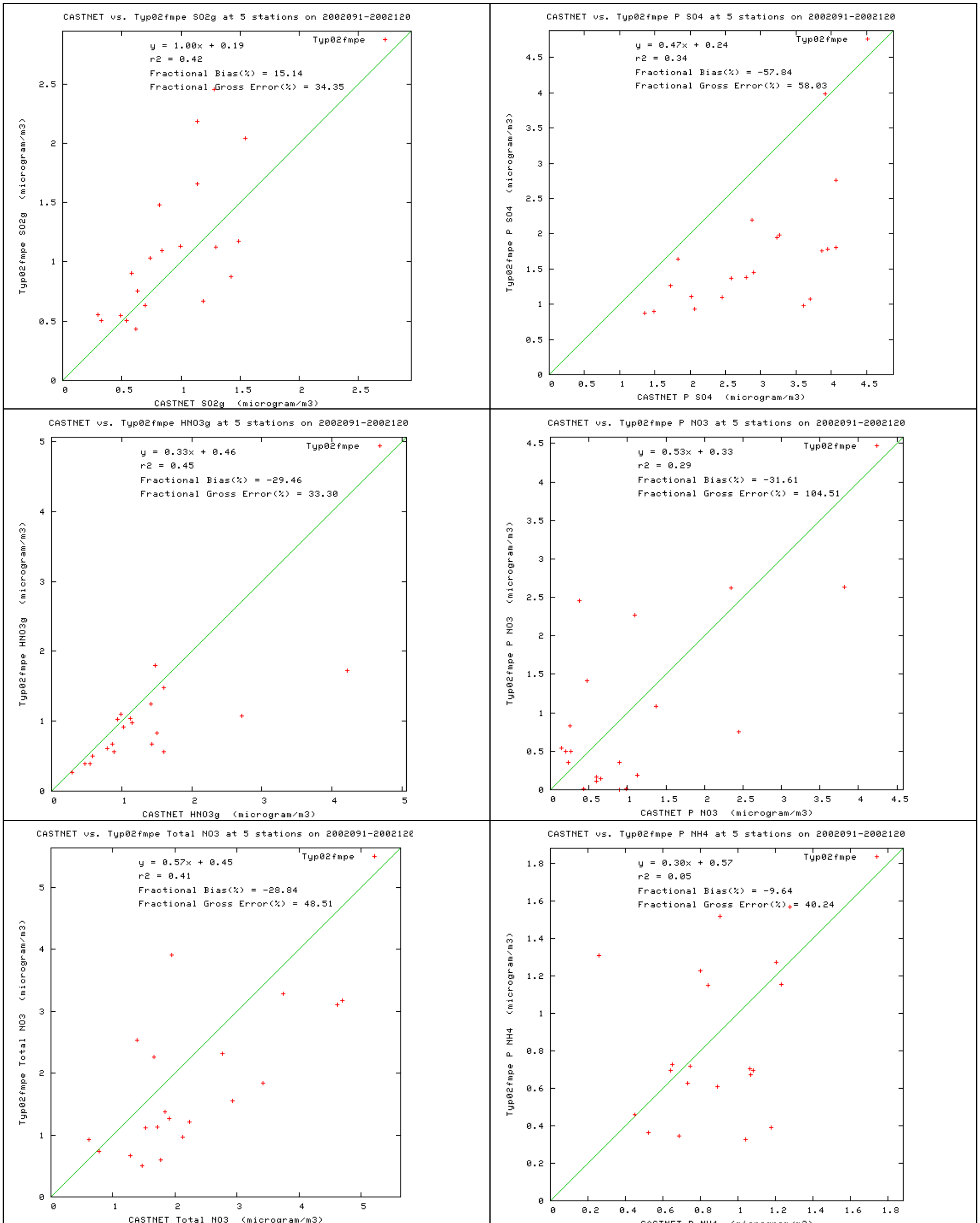


Figure C-42 April 2002 performance at CENRAP CASTNet sites for SO2 (top left), SO4 (top right), HNO3 (middle left), NO3 (middle right), Total NO3 (bottom left) and NH4 (bottom right).

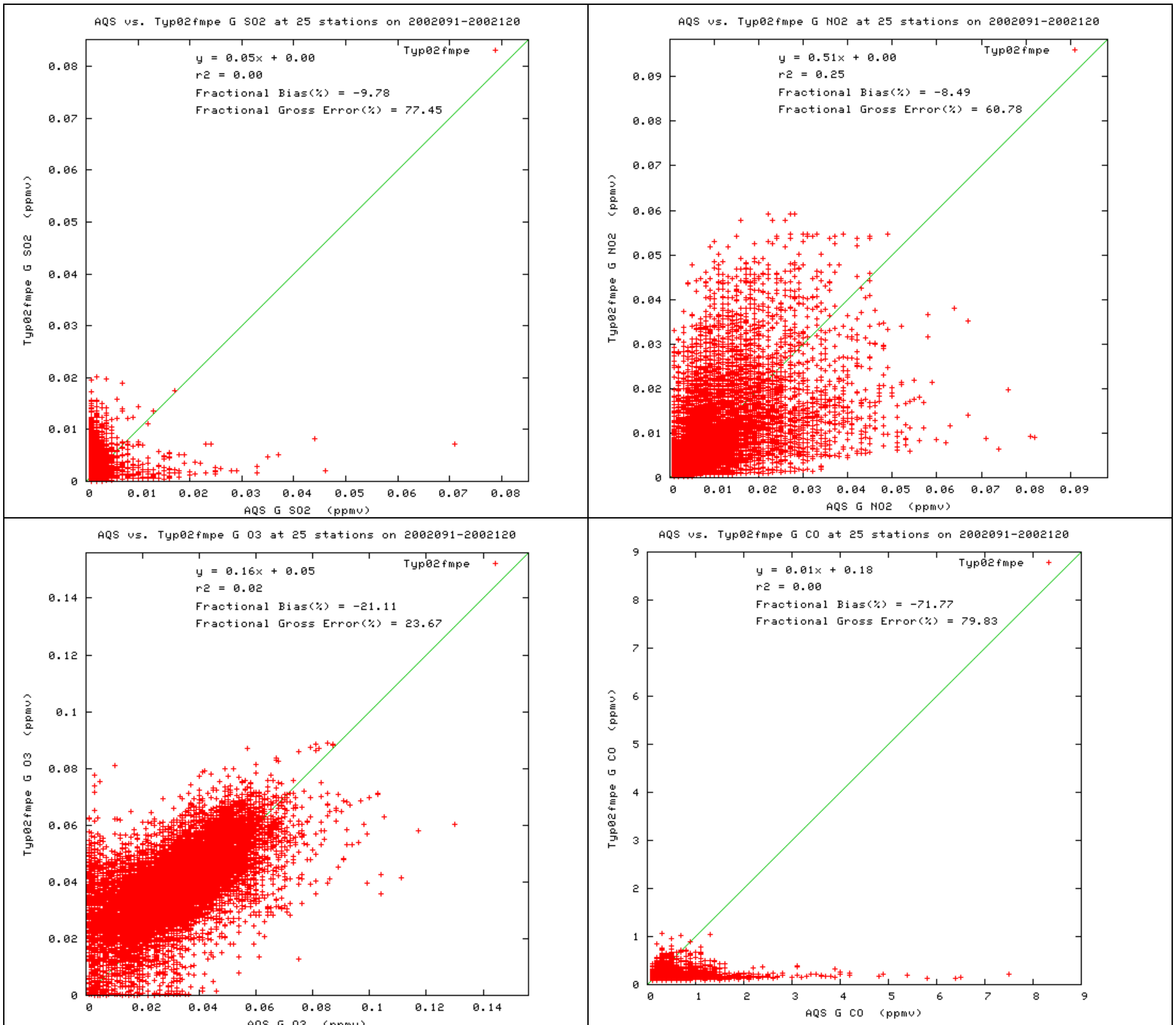


Figure C-43 April 2002 performance at CENRAP AQS sites for SO2 (top left), NO2 (top right), O3 (bottom left) and CO (bottom right).

C.4.3 Diagnostic Model Performance In July

In July SO2 is slightly underestimated across the CASTNet (-5%) and AQS (-12%) networks (Figures C-44 and C-45) and SO4 is more significantly underestimated across all networks (-22% to -53%, Figure C-6a). Since wet SO4 is also underestimated it is unclear the reasons for why all sulfur species are underestimated.

The nitrate species are also all underestimated with the Total NO3 bias (-56%) being between the HNO3 bias (-35%) and NO3 bias (-115%). The modeled NO3 values are all near zero with little correlation with the observations, whereas the observed HNO3 and Total NO3 is tracked well with correlation coefficients of 0.74 and 0.76. These results suggest that the July NO3 model performance problem is partly due to insufficient formation of Total NO3 and mainly due to too little incorrect partitioning of the Total NO3 into the particle NO3.

Again there is lots of scatter in the AQS NO2 scatter plot for July (Figure C-45) resulting in a low bias (0%) but high error (65%). Ozone performance also exhibits a low bias (-15%) and error (20%), but the model is incapable of simulating ozone above 100 ppb. Although CO performance in July is better than the previous months, it still has a large underestimation bias (-82%).

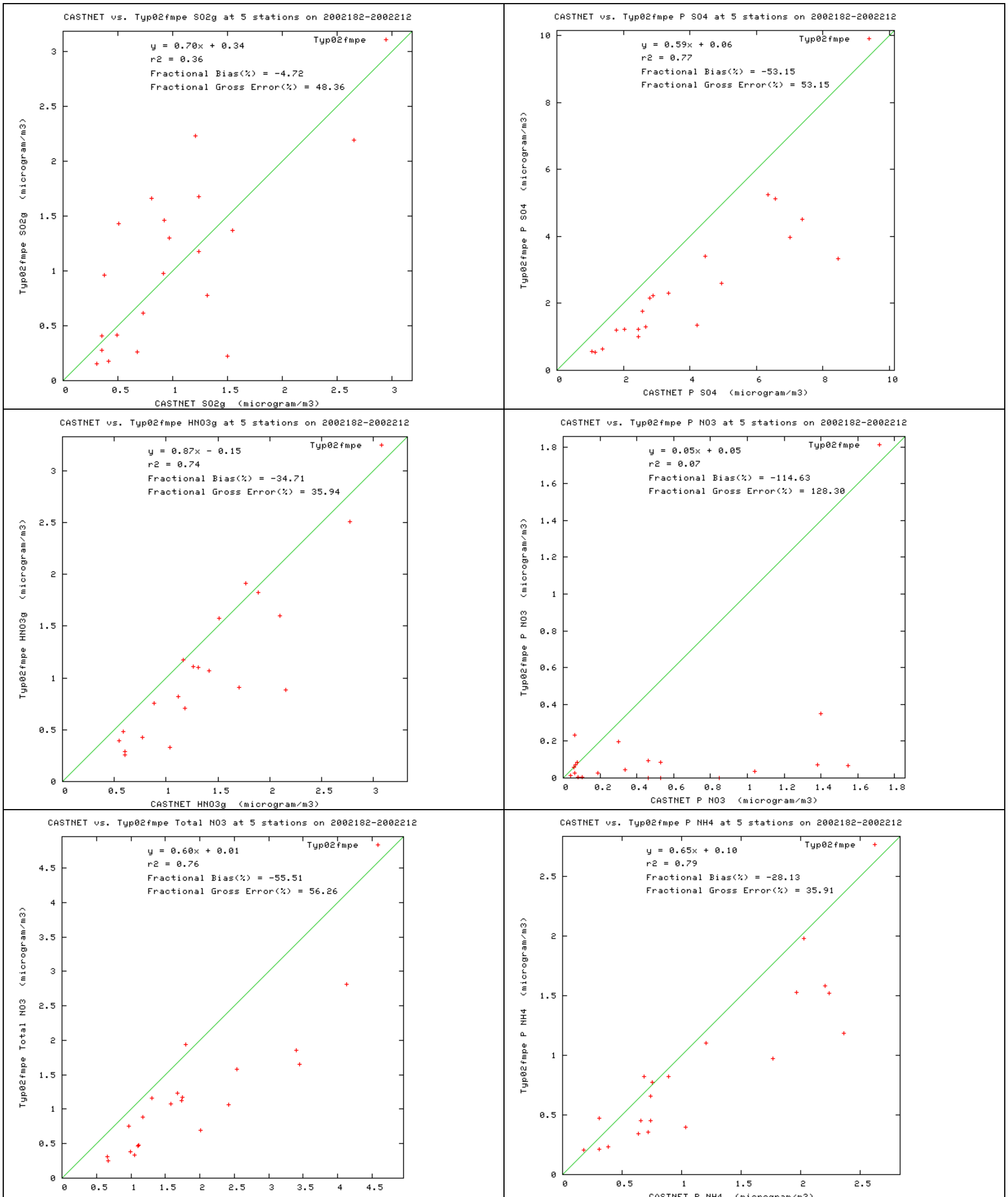


Figure C-44 July 2002 performance at CENRAP CASTNet sites for SO2 (top left), SO4 (top right), HNO3 (middle left), NO3 (middle right), Total NO3 (bottom left) and NH4 (bottom right).

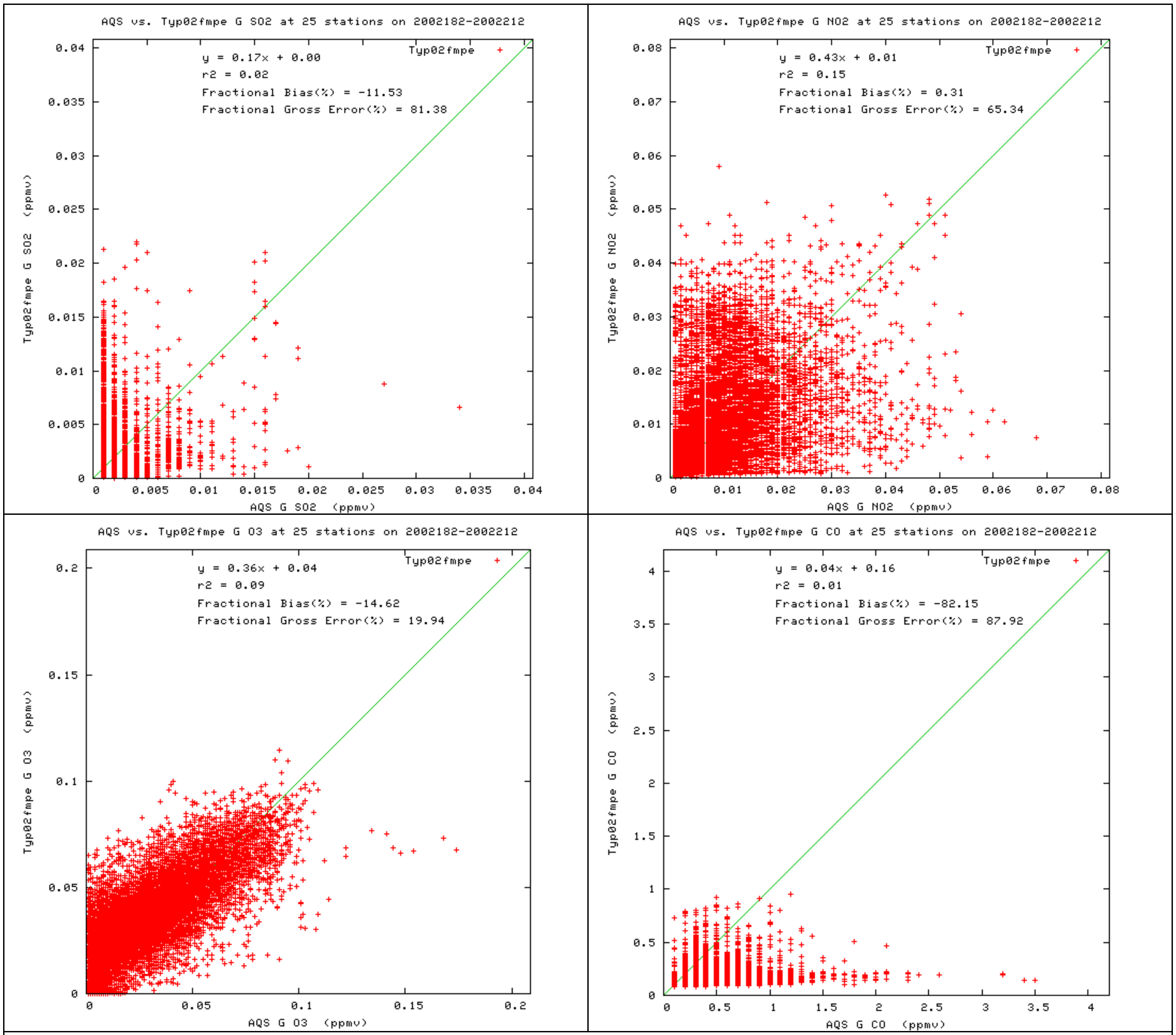


Figure C-45 July 2002 performance at CENRAP AQS sites for SO2 (top left), NO2 (top right), O3 (bottom left) and CO (bottom right).

C.4.4 Diagnostic Model Performance In October

SO2 is overstated in October across the CASTNet (+28%) and AQS (+33%) sites (Figures C-46 and C-47). Although SO4 is understated across the CASTNet sites (-24%), the bias across the IMPROVE (-6%) and STN (0%) sites are near zero (Figure C-7a).

Performance for HNO3 is fairly good with a low bias (+12%) and error (30%). But NO3 is overstated (+34%) leading to an overstatement of Total NO3 (+37%). The overstatement of NO3 leads to an overstatement of NH4 as well (Figure C-46)

As seen in the other months, NO2 exhibits a lot of scatter resulting in a low correlation (0.22) and high error (61%) but low bias (12%). The model tends to under-predict the high and over-predict the low O3 observations resulting in a -29% bias and low correlation coefficient. CO is also under-predicted (-76%) for the reasons discussed previously.

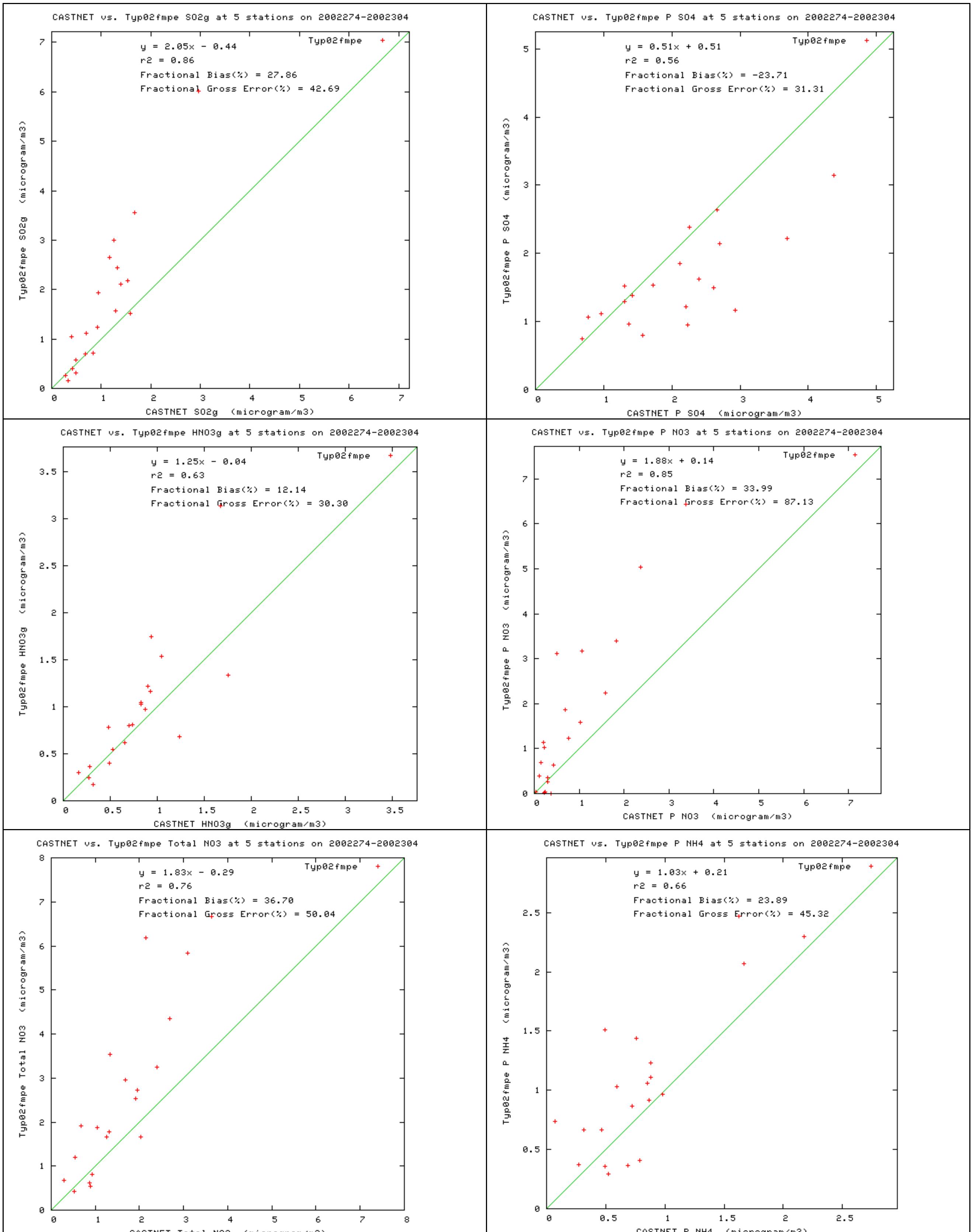


Figure C-46 October 2002 performance at CENRAP CASTNet sites for SO2 (top left), SO4 (top right), HNO3 (middle left), NO3 (middle right), Total NO3 (bottom left) and NH4 (bottom right).

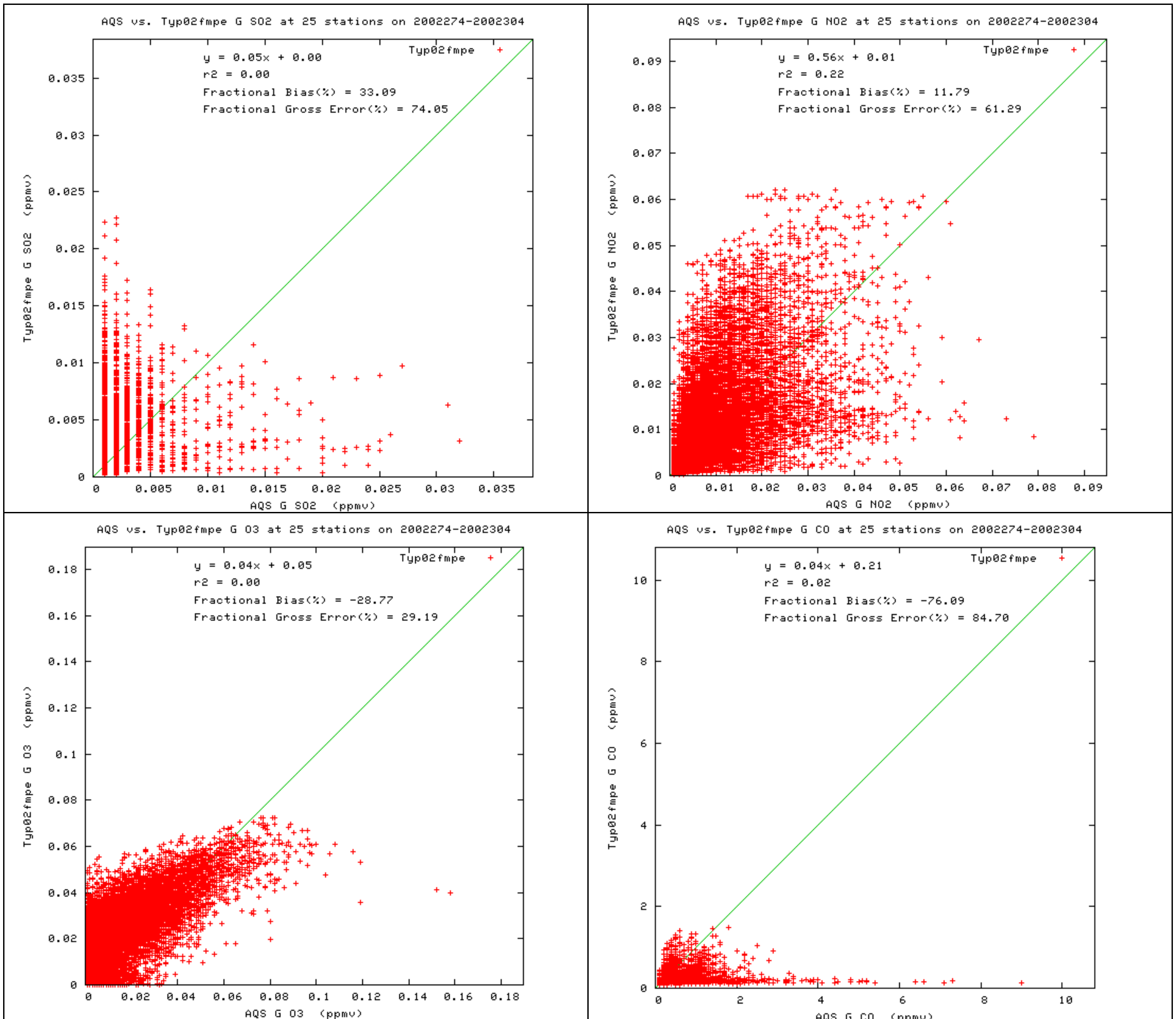


Figure C-47 October 2002 performance at CENRAP AQS sites for SO2 (top left), NO2 (top right), O3 (bottom left) and CO (bottom right).

C.5 Evaluation at Class I Areas for the Worst and Best 20 Percent Days

In this section, and in section C.5 of Appendix C, we present the results of the model performance evaluation at each of the CENRAP Class I areas for the worst and best 20 percent days. Performance on these days is critical since they are the days used in the 2018 visibility projections discussed in Chapter 4. For each Class I area we compared the predicted and observed total extinction (these figures are in Chapter 3) and PM species-specific extinction for the worst and best 20 percent days in 2002.

C.5.1 Caney Creek (CACR) Arkansas

The ability of the CMAQ model to estimate visibility extinction at the CACR Class I area on the 2002 worst and best 20 percent days is provide in Figures 3-9 and C-48. On most of the worst 20 percent days at CACR total extinction is dominated by SO4 extinction with some extinction due to OMC. On four of the worst 20 percent days extinction is dominated by NO3. The average extinction across the worst 20 percent days is underestimated by -33% (Figure 3-9), which is primarily due to a -51% underestimation of SO4 extinction combined with a 6% overestimation of NO3 extinction (Figure C-48). Performance for OMC extinction at CACR on the worst 20 percent days is pretty good with a -20% bias and 36% error, EC extinction is systematically underestimated, Soil extinction has low bias (-19%) buts lots of scatter and high error (74%), while CM extinction is greatly underestimated (bias of -153%).

On the best 20 percent days at CACR the observed extinction ranges from 20 to 40 Mm^{-1}, whereas then modeled extinction has a much larger range from 15 to 120 Mm^{-1}. Much of the modeled overestimation of total extinction on the best 20% days (+44% bias) is due to NO3 overestimation (+94% bias).

C.5.2 Upper Buffalo (UOBU) Arkansas

Model performance at the UPBU Class I area for the worst and best 20 percent days is shown in Figures 3-10 and C-49. On most of the worst 20 percent days at UPBU visibility impairment is dominated by SO4, although there are also two high NO3 days. The model underestimates the average of the total extinction on the worst 20 percent days at UPBU by -40% (Figure 3-10), which is due to an underestimation of extinction due to SO4, OMC and CM by, respectively,
-46%, -33% and -179%.

On the best 20 percent days at UPBU, the model performs reasonably well with a low bias (2%) and error (42%). But again the model has a much wider range in extinction values across the best 20 percent days (15 to 120 Mm^{-1}) than observed (20 to 45 Mm^{-1}). There are five days in which the modeled NO3 over-prediction is quite severe and when those days are removed the range in the modeled and observed extinction on the best 20 percent days is quite similar, although the model gets much cleaner on the very cleanest modeled days.

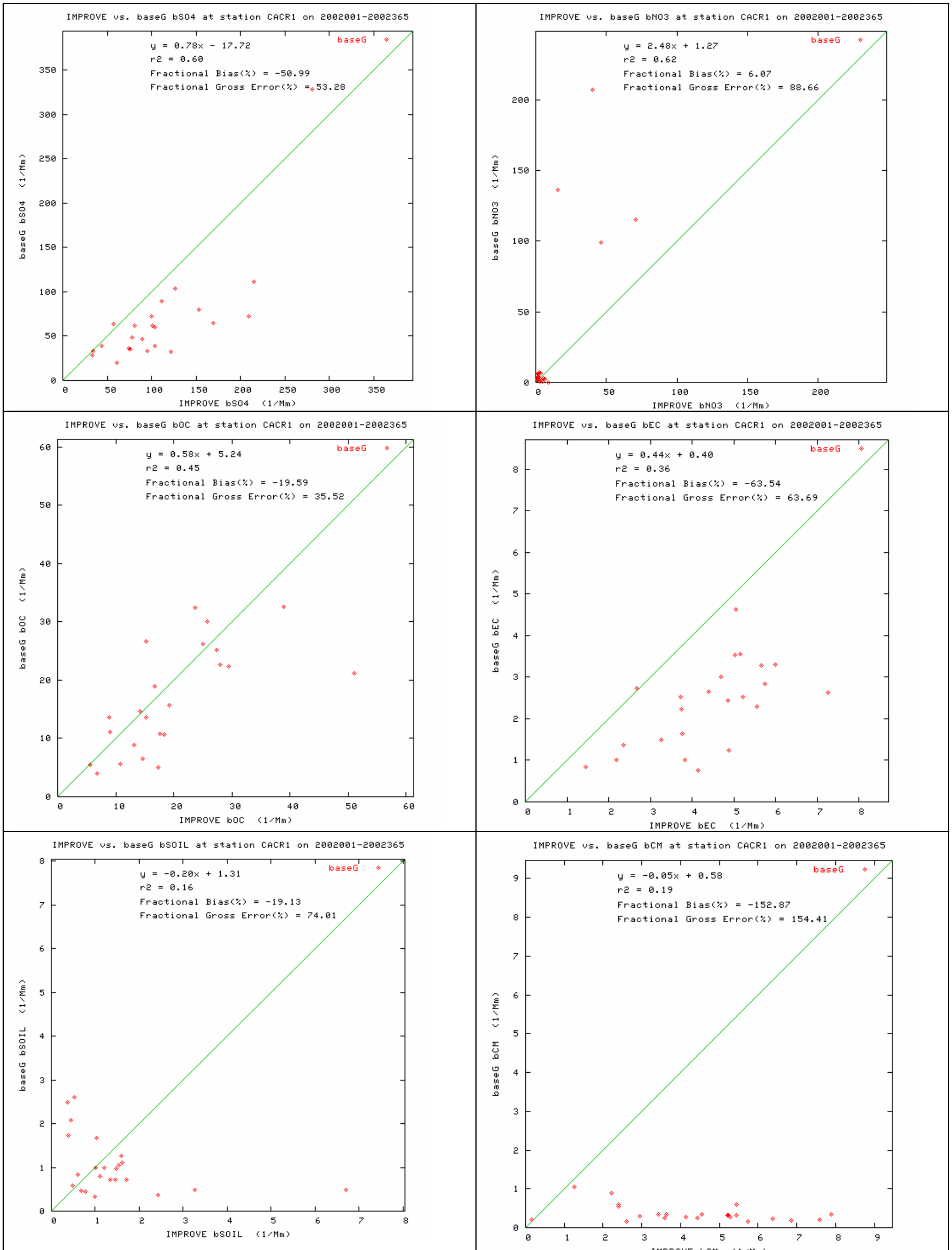


Figure C-48. PM species extinction model performance at Caney Creek (CACR) for the worst 20 percent days during 2002.

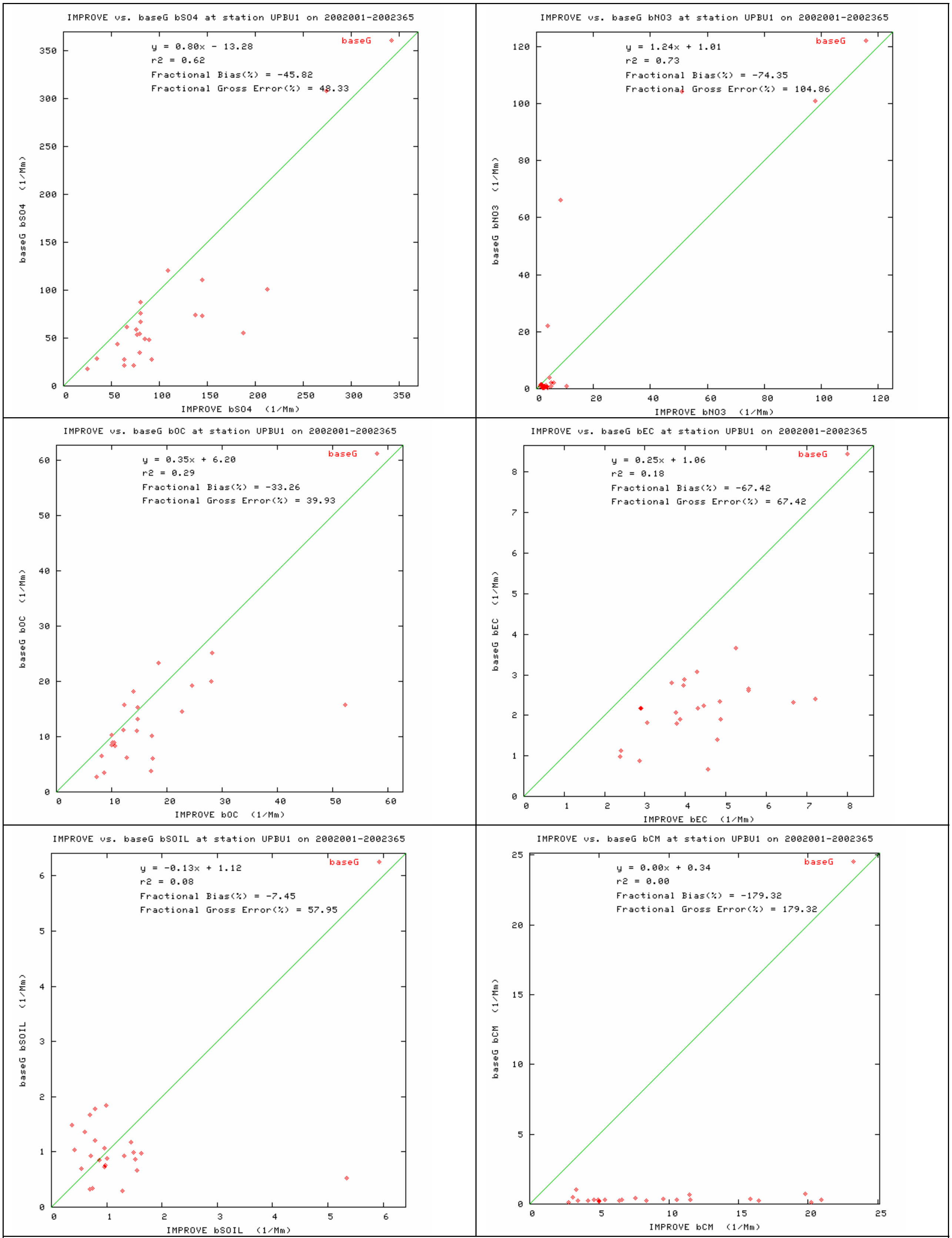


Figure C-49. PM species extinction model performance at Upper Buffalo (UPBU) for the worst 20 percent days during 2002.

C.5.3 Breton Island (BRET), Louisiana

The observed total extinction on the worst 20 percent days at Breton Island is underestimated by -71% (Figure 3-11), which is due to an underestimation of each component of extinction (Figure C-50) by from -50% to -70% (SO4, OMC and Soil) to over -100% (EC and CM). The observed extinction on the worst 20 percent days ranges from 90 to 170 Mm^{-1}, whereas the modeled values drop down to as low as approximately 15 Mm^{-1}. On the best 20 percent days the range of the observed and modeled extinction is similarly (roughly 10 to 50 Mm^{-1}) that results in a reasonably low bias (-22%), but there is little agreement on which days are higher or lower resulting in a lot of scatter and high error (54%).

C.5.4 Boundary Waters (BOWA), Minnesota

There are three types of days during the worst 20 percent days at BOWA, SO4 days, OMC days and NO3 days (Figure 3-12). The two high OMC days are likely fire impact events that the model captures to some extent on one day and not on the other. On the five high (> 20 Mm^{-1}) NO3 extinction days the model predicts the observed extinction well on three days and overestimates by a factor of 3-4 on the other two high NO3 days. SO4 in underestimate by -43% on average across the worst 20 percent days at BOWA.

With the exception of two days, the model reproduces the total extinction for the best 20 percent days at BOWA quite well with a bias and error value of +14% and 22% (Figure 3-12). Without these two days, the modeled and observed extinction both range between 15 and 25 Mm^{-1}.

C.5.5 Voyageurs (VOYA) Minnesota

VOYA is also characterized by SO4, NO3 and OMC days (Figure 3-13). Julian Days 179 and 200 are high OMC days that were also high OMC days at BOWA again indicating impacts from fires in the area that is not fully captured by the model. SO4 and NO3 extinction is fairly good and, without the fire days, OMC performance looks good as well (Figure C-52). On the best 20 percent days there is one day the modeled extinction is much higher than observed and a few others that are somewhat higher, but for most of the best 20 percent days the modeled extinction is comparable to the observed values.

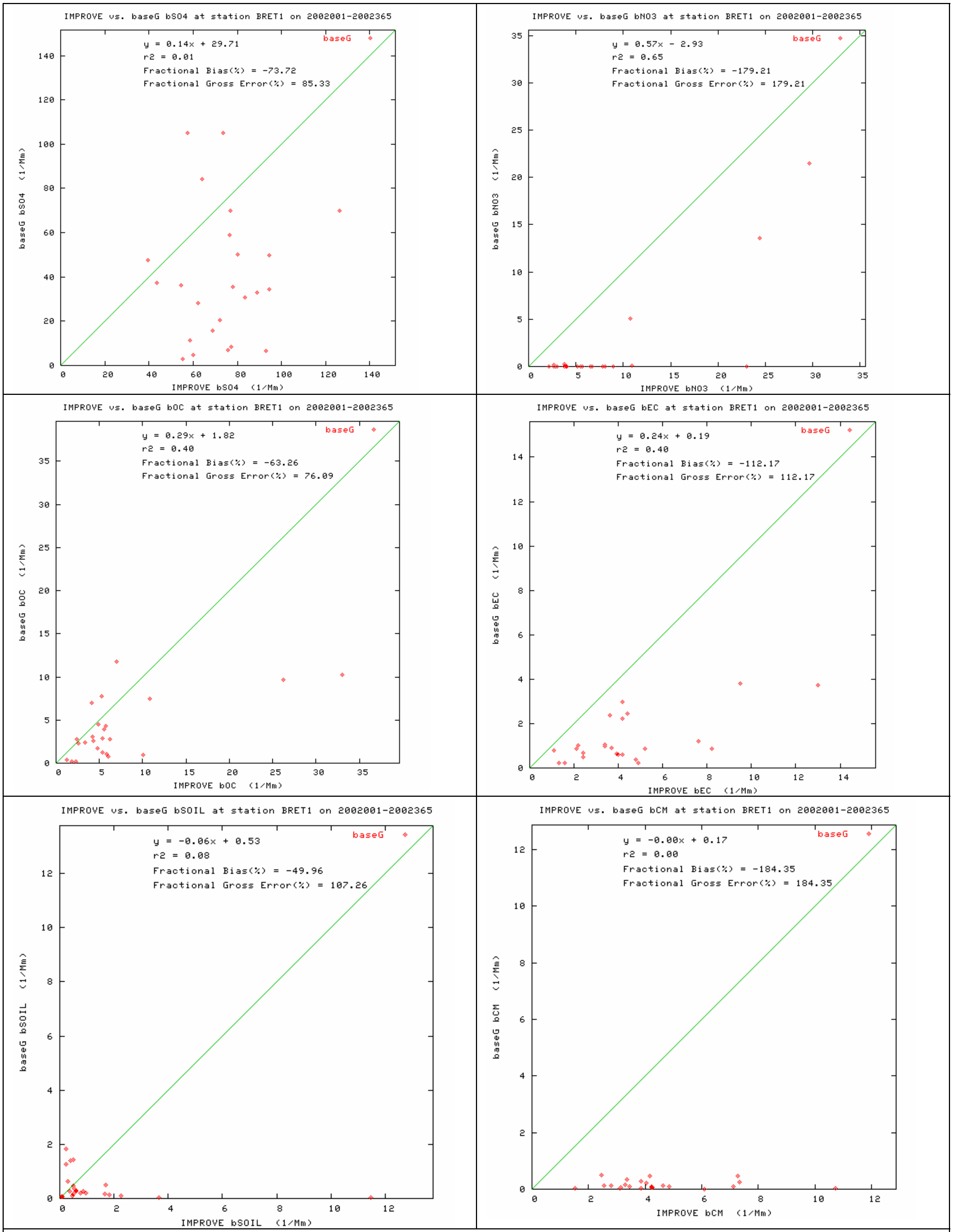


Figure C-50. PM species extinction model performance at Breton Island (BRET) for the worst 20 percent days during 2002.

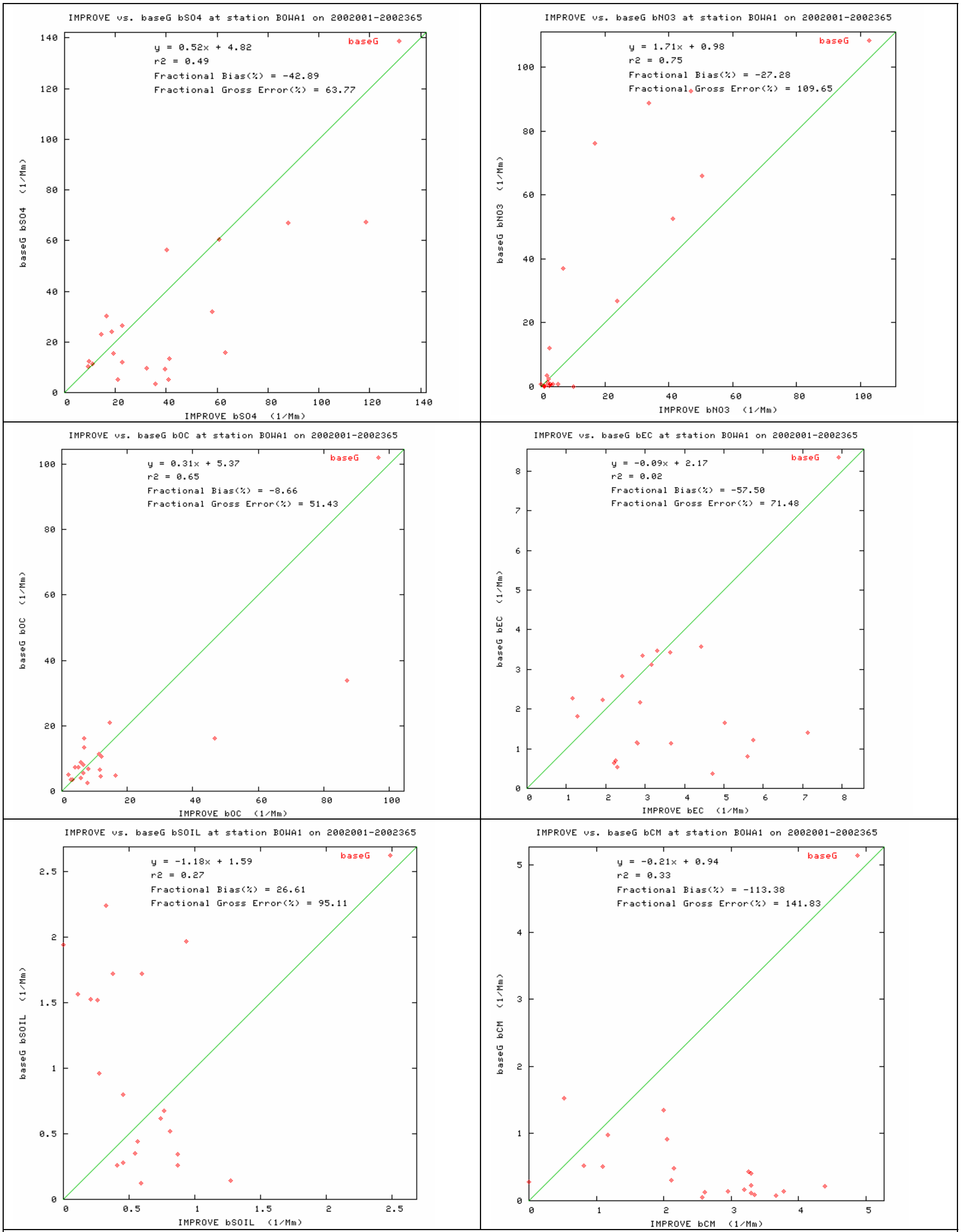


Figure C-51. PM species extinction model performance at Boundary Waters (BOWA) for the worst 20 percent days during 2002.

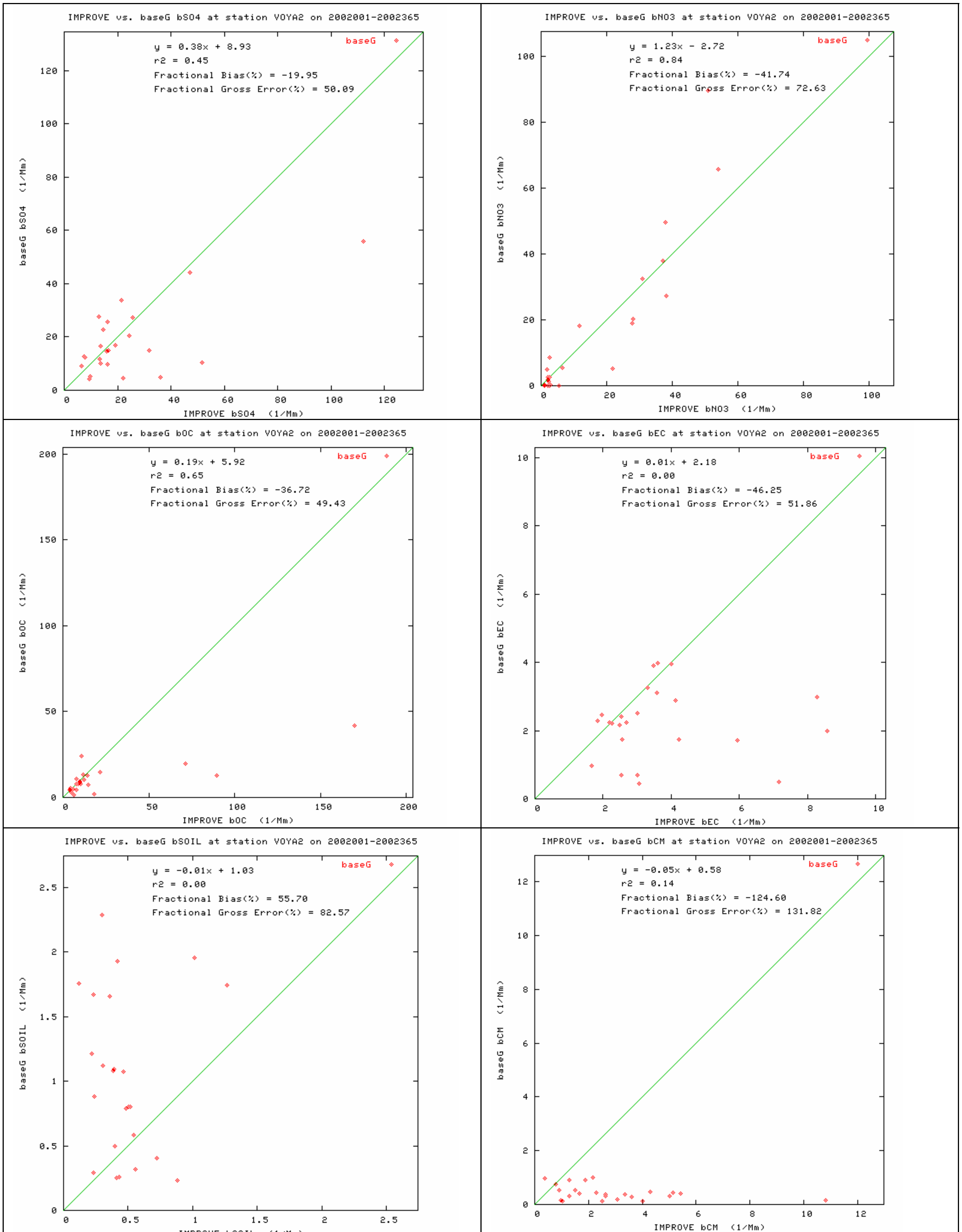


Figure C-52. PM species extinction model performance at Voyageurs (VOYA) for the worst 20 percent days during 2002.

C.5.6 Hercules Glade (HEGL) Missouri

On most of the worst 20 percent days at HEGL the observed extinction ranges from 120 to 220 Mm^{-1} whereas model extinction ranging from 50 to 170 Mm^{-1} (Figure 3-14). However, there is one extreme day with extinction approaching 400 Mm^{-1} that the model does a very good job in replicating. Over all the days there is a modest underestimation bias in SO4 (-39%) and OMC (-39%) extinction, larger underestimation bias in EC (-62%) and CM (-118%) extinction and overestimation bias in Soil (+30%) extinction (Figure C-53).

On the best 20 percent days there is one day where the model overstates the observed extinction by approximately a factor of four and a handful of other days that the model overstates the extinction by a factor of 2 or so, but most of the days both the model and observed extinction sites are around 40 Mm^{-1} plus or minus about 10 Mm^{-1}. On the best 20 percent days when the observed extinction is overstated it is due to overstatement of the NO3.

C.5.7 Mingo (MING) Missouri

The worst 20 percent days at Ming are mainly high SO4 days with a few high NO3 days that the model reproduces reasonably well resulting in low bias (+10%) and error (38%) for total extinction (Figure 3-15). The PM species specific performance is fairly good with low bias for SO4 (+4%), good agreement with NO3 on high NO3 days except for one day, low OMC (+23%) and EC (+3%) bias and larger bias in EC (+37%) and CM (-105%) extinction (Figure C-54).

For the best 20 percent days, there is one day the model is way to high due to overstated NO3 extinction and a few other days the model overstates the observed extinction that is usually due to overrated NO3, but on most of the best 20 percent days the modeled extinction is comparable to the observed values. This results in low bias (+12%) and error (36%) for total extinction at MING for the best 20 percent days.

C.5.8 Wichita Mountains (WIMO), Oklahoma

With the exception of an over-prediction on day 344 due to NO3, observed total extinction on the worst 20 percent days at WIMO is understated with a bias of -42% (Figure 3-16) that is primarily due to an underestimation of extinction due to SO4 (-48%) and OMC (-69%) (Figure C-55).

CMAQ total extinction performance for the average of the best 20 percent days at WIMO is characterized by an overestimation bias (+21%) on most days that is primarily due to NO3 over-prediction on several days. Again the modeled range of extinction on the best 20 percent days (12-60 Mm^{-1}) is much greater than observed (20-35 Mm^{-1}).

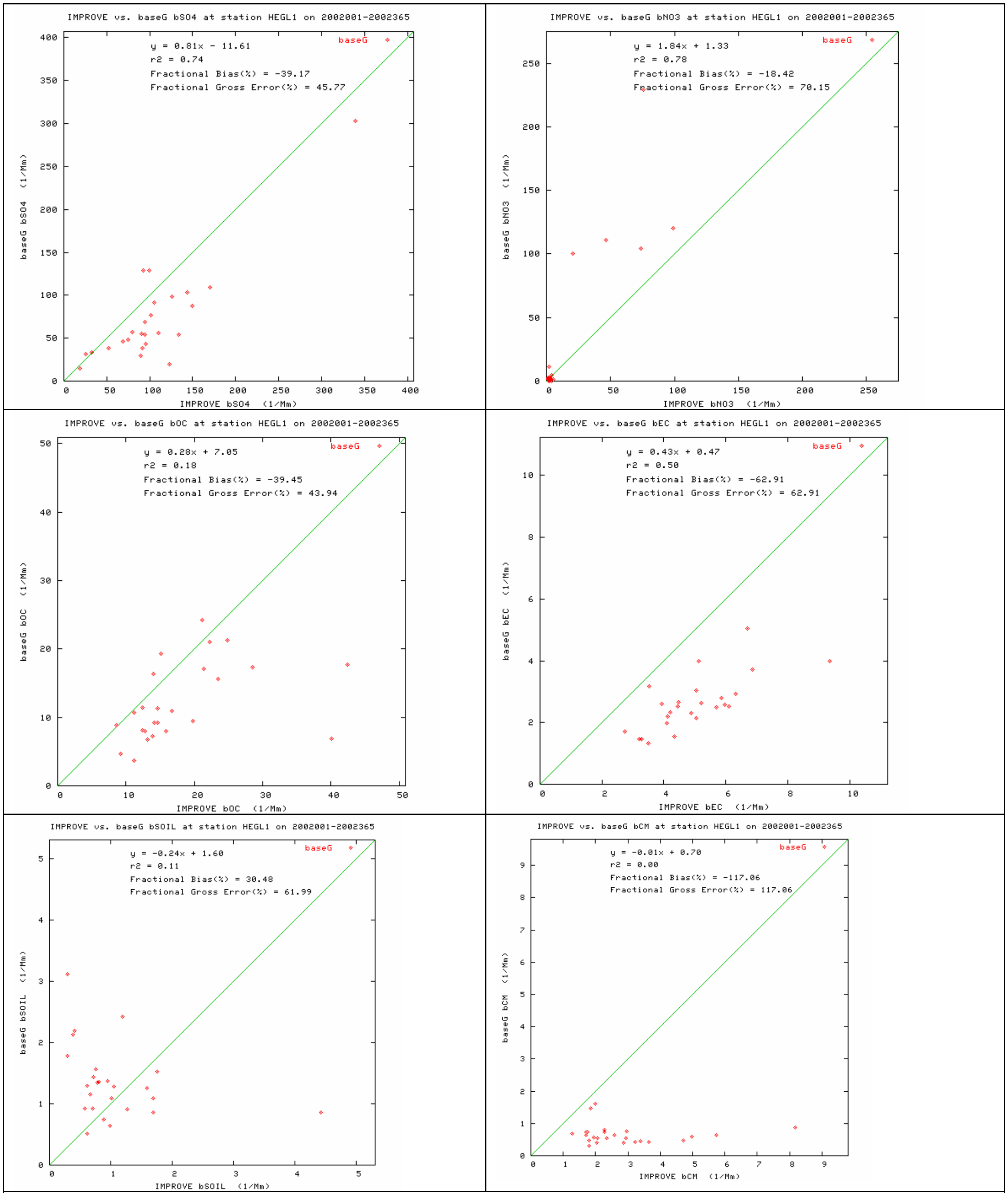


Figure C-53. PM species extinction model performance at Hercules Glade (HEGL) for the worst 20 percent days during 2002.

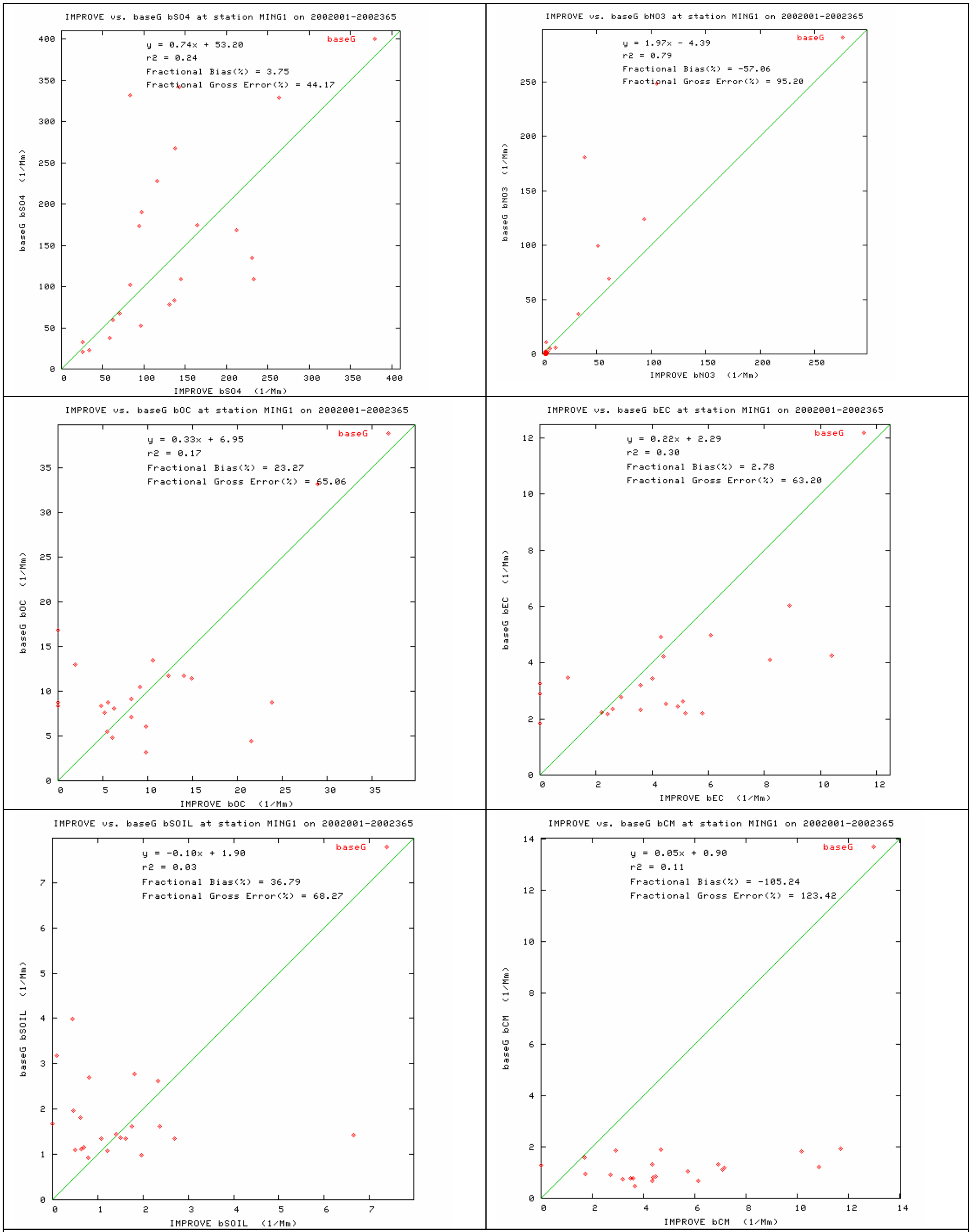


Figure C-54. PM species extinction model performance at Mingo (MING) for the worst 20 percent days during 2002.

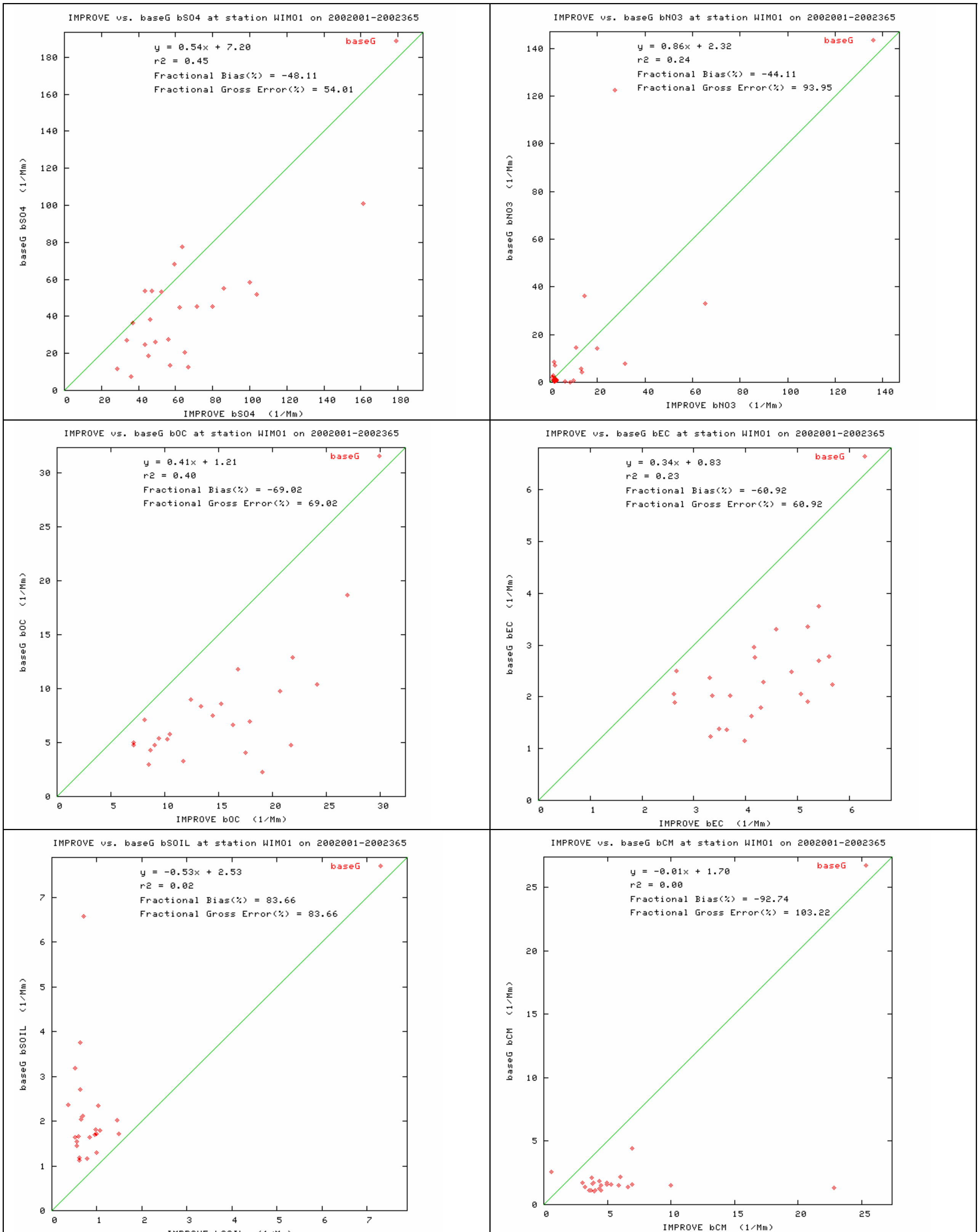


Figure C-55. PM species extinction model performance at Wichita Mountains (WIMO) for the worst 20 percent days during 2002.

C.5.9 Big Bend (BIBE) Texas

The observed extinction on the worst 20 percent days at BIBE is under-predicted on almost every day resulting in a fractional bias value of -72% (Figure 3-17). Every component of extinction is underestimated on average for the worst 20 percent days (Figure C-56) with the underestimation bias ranging from -24% (OMC) to -162% (CM). SO4 extinction, that typically represents the largest component of the total extinction is understated by -94%.

The model does a better job in predicting the total extinction at BIBE for the best 20 percent days with average fractional bias and error values of +13% and 19% (Figure 3-17). With the exception of one day that the observed extinction is overestimated by approximately a factor of 2, the modeled and observed extinction on the best 20 percent days at BIBE are both within 12 to 25 Mm^{-1}. However, there are some mismatches with the components of extinction with the model estimating much lower contributions due to Soil and CM.

C.5.10 Guadalupe Mountains (GUMO) Texas

Most of the worst 30 percent days at GUMO are dust days with high Soil and CM that is not at all captured by the model (Figure 3-18). Extinction due to Soil and CM on the worst 20 percent days is underestimated by -105% and -191%, respectively (Figure C-57). Better performance is seen on the best 20 percent days with bias and error for total extinction of 8% and 21%, but the model still understates Soil and CM.

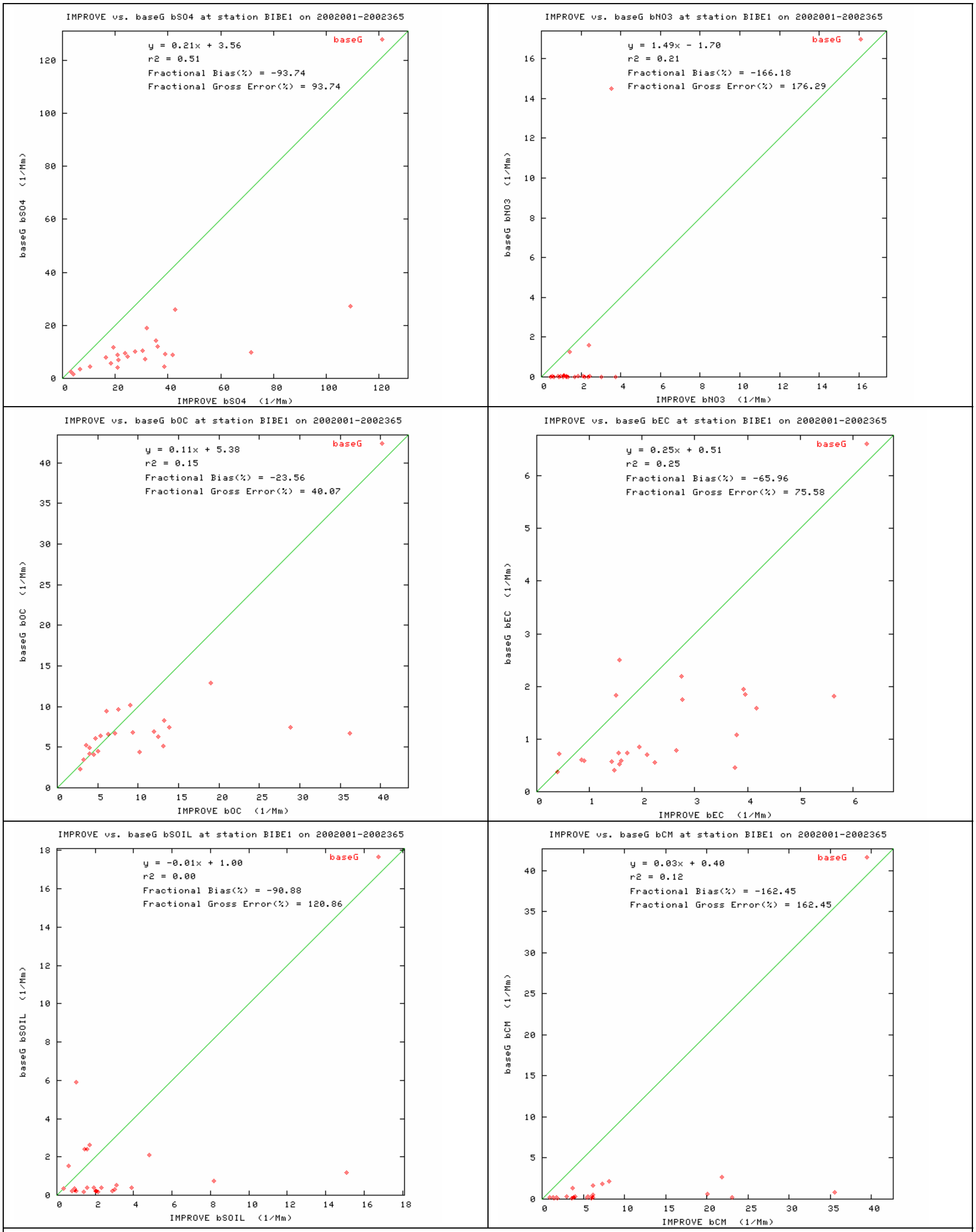


Figure C-56. PM species extinction model performance at Big Bend (BIBE) for the worst 20 percent days during 2002.

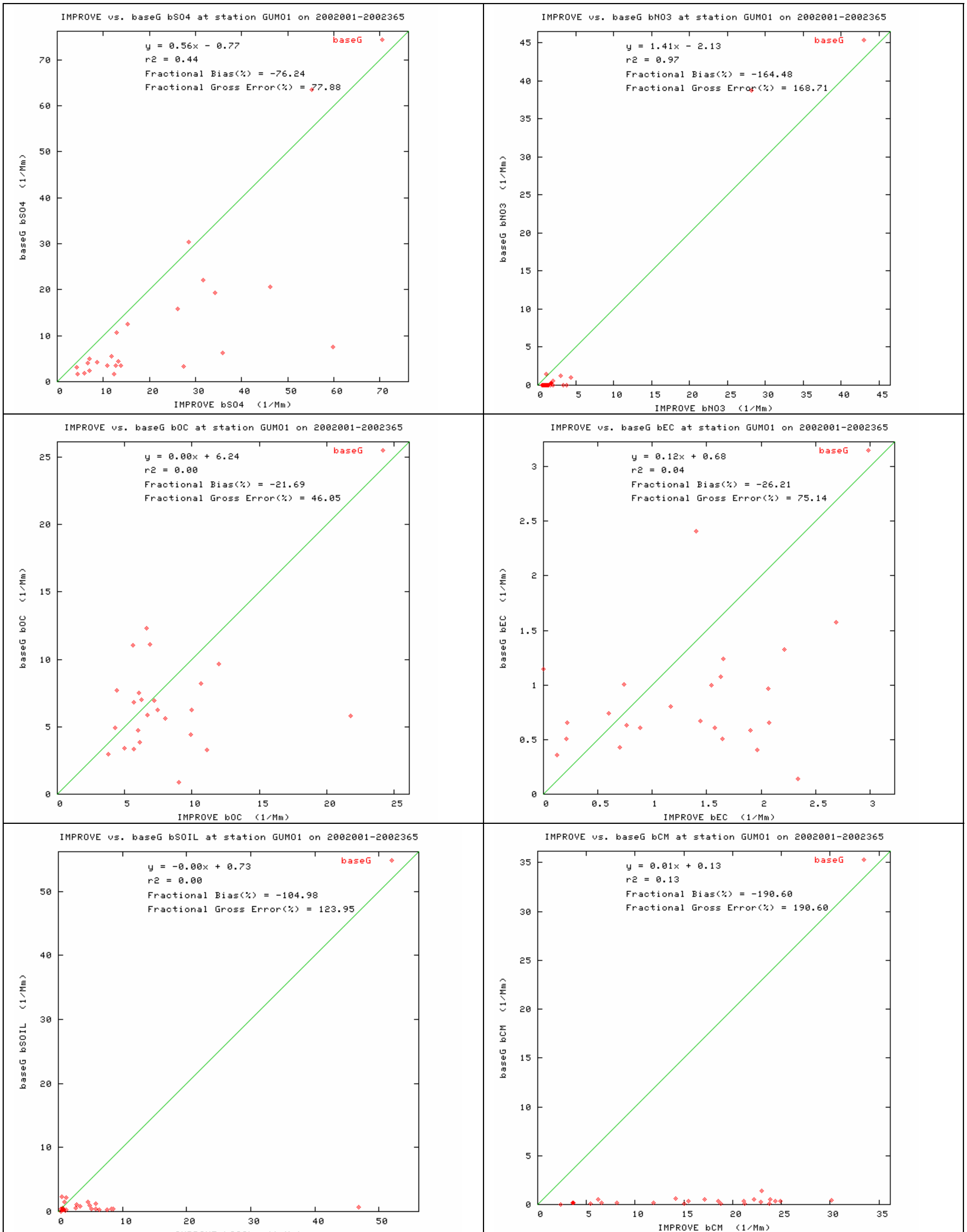


Figure C-57. PM species extinction model performance at Guadalupe Mountains (GUMO) for the worst 20 percent days during 2002.

C.6 Model Performance Evaluation Conclusions

The model performance evaluation reveals that the model is performing best for SO4, OMC and EC. Soil performance is mixed with winter overestimation bias but lower bias but high error in the summer. CM performance is poor year round. The operational evaluation reveals that SO4 performance usually achieves the PM model performance goal and always achieves the model performance criteria, although it does have an underestimation bias that is greatest in the summer. NO3 performance is characterized by a winter overestimation bias with an even greater summer underestimation bias. However, the summer underestimation bias occurs when NO3 is very low and it is not an important component of the observed or predicted PM and visibility impairment. Performance for OMC meets the model performance goal year round at the IMPROVE sites, but is characterized by an underestimation bias at the more urban STN sites. EC exhibits very low bias at the STN sites and a summer underestimation bias at the IMPROVE sites, but meets the model performance goal throughout the year. Soil has a winter overestimation bias that exceeds the model performance goal and criteria raising questions whether the model should be used for this species. Finally, CM performance is extremely poor with an under-prediction bias that exceeds the performance goal and criteria. We suspect that much of the CM concentrations measured at the IMPROVE sites is due to highly localized emissions that can not be simulated with 36 km regional modeling.

Performance for the worst 20 percent days at the CENRAP Class I areas is generally characterized by an underestimation bias. Performance at the BRET, BIBE and GUMO Class I areas for the worst 20 percent days is particularly suspect and care should be taken in the interpretation of the visibility projections at these three Class I areas.

The CMAQ 2002 36 km model appears to be working well enough to reliably make future-year projections for changes in SO4, NO3, EC and OMC at the rural Class I areas. Performance for Soil and especially CM is suspect enough that care should be taken in interpreting these modeling results. The model evaluation focused on the model's ability to predict the components of light extinction mainly at the Class I areas. Additional analysis would have to be undertaken to examine the model's ability to treat ozone and fine particulate to address 8-hour ozone and $PM_{2.5}$ attainment issues.

APPENDIX D

2018 Visibility Projections for CENRAP Class I Areas Using 2002 Typical and 2018 Base Case Base G Emission Scenario CMAQ Results and EPA Default Projection Method and Comparison with 2018 Uniform Rate of Progress (URP) Glidepaths

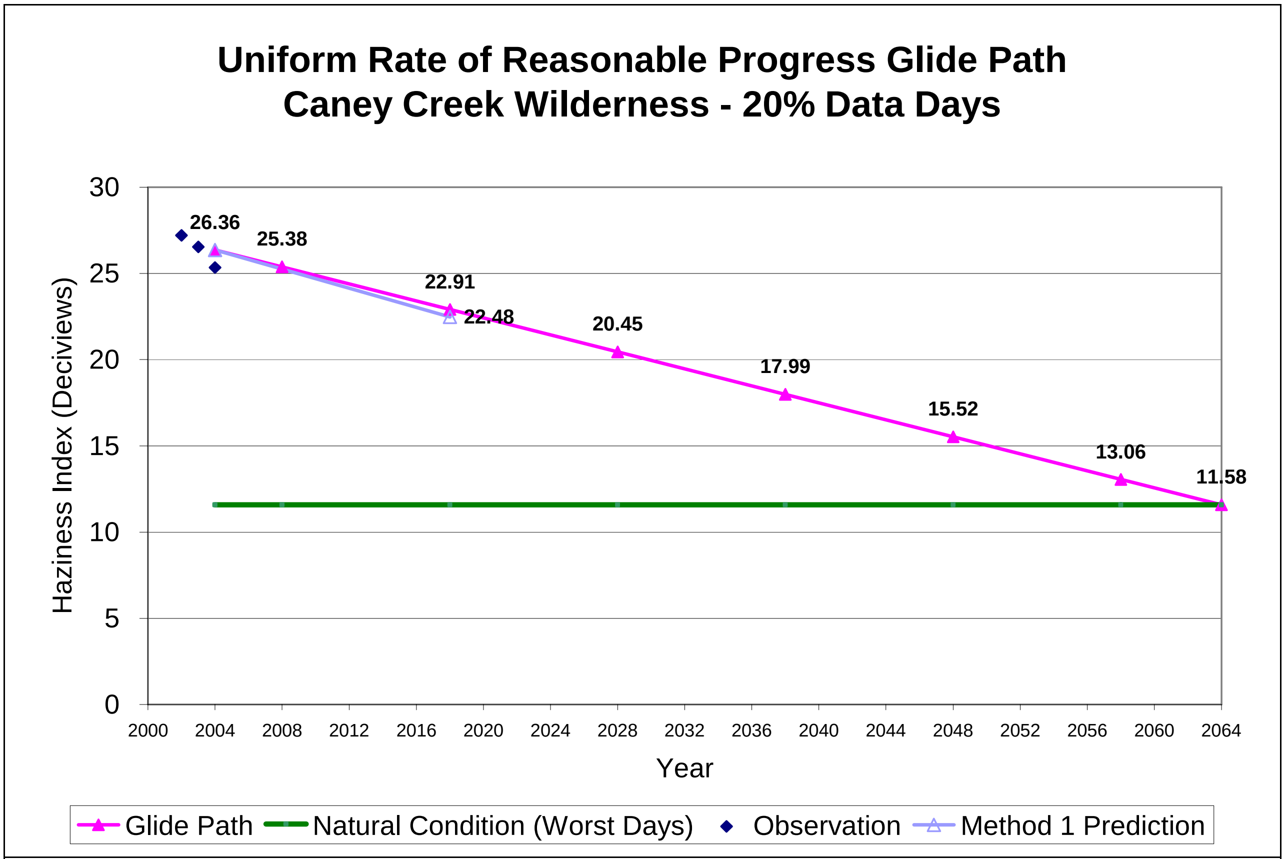


Figure D-1a. 2018 Visibility Projections and 2018 URP Glidepaths in deciview for Caney Creek (CACR), Arkansas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

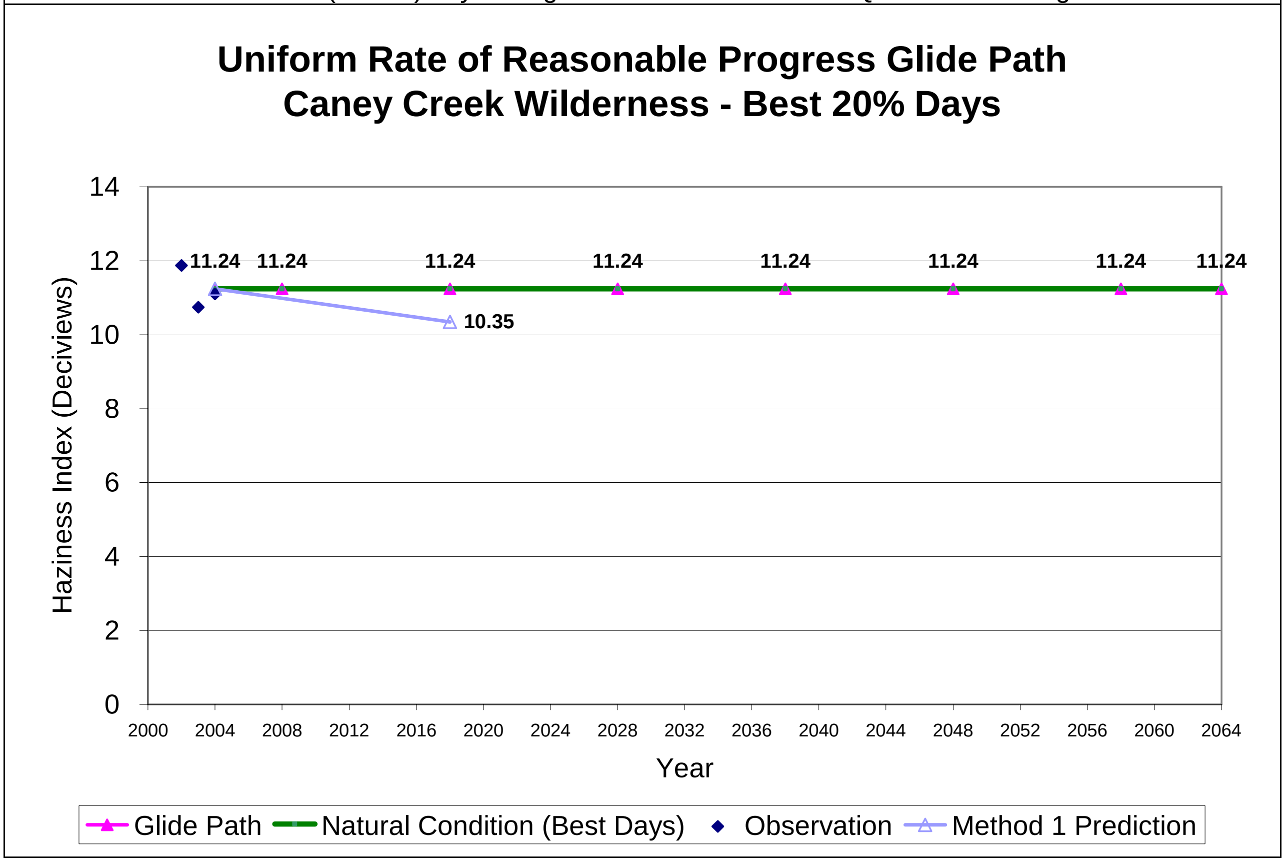


Figure D-1b. 2018 Visibility Projections and 2018 URP Glidepaths in deciview for Caney Creek (CACR), Arkansas and Best 20% (B20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

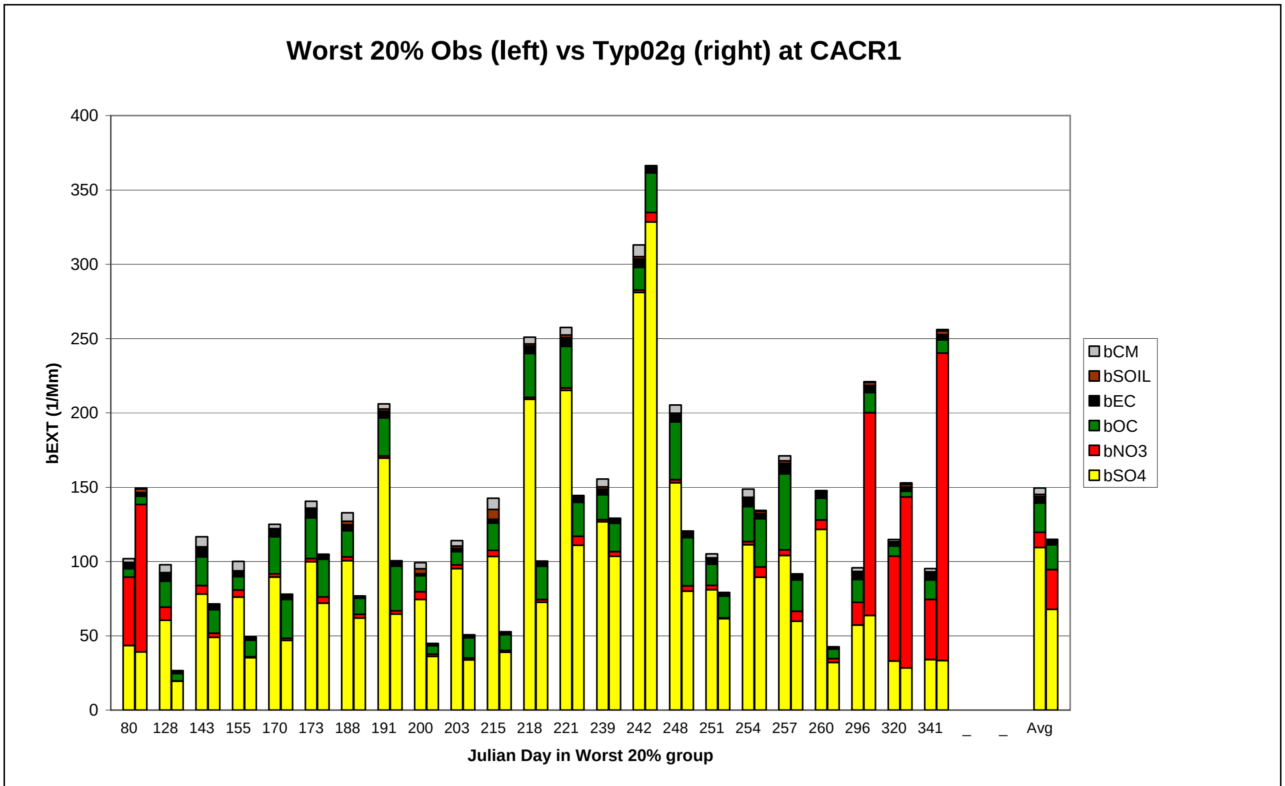


Figure D-1c. Comparison of observed (left) and 2002 Base G modeled (right) daily extinction for Caney Creek (CACR), Arkansas and Worst 20% (W20%) days in 2002.

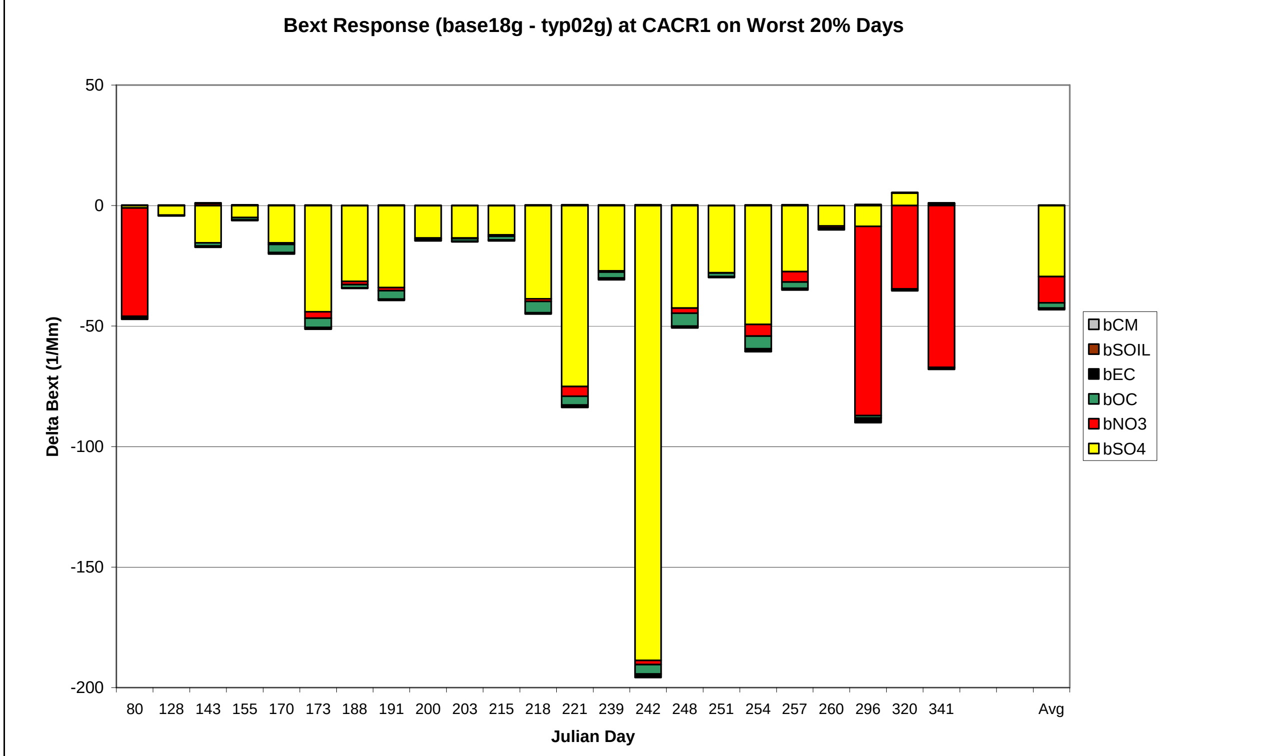


Figure D-1d. Differences in modeled 2002 and 2018 Base G CMAQ results (2018-2002) daily extinction for Caney Creek (CACR), Arkansas and Worst 20% (W20%) days in 2002.

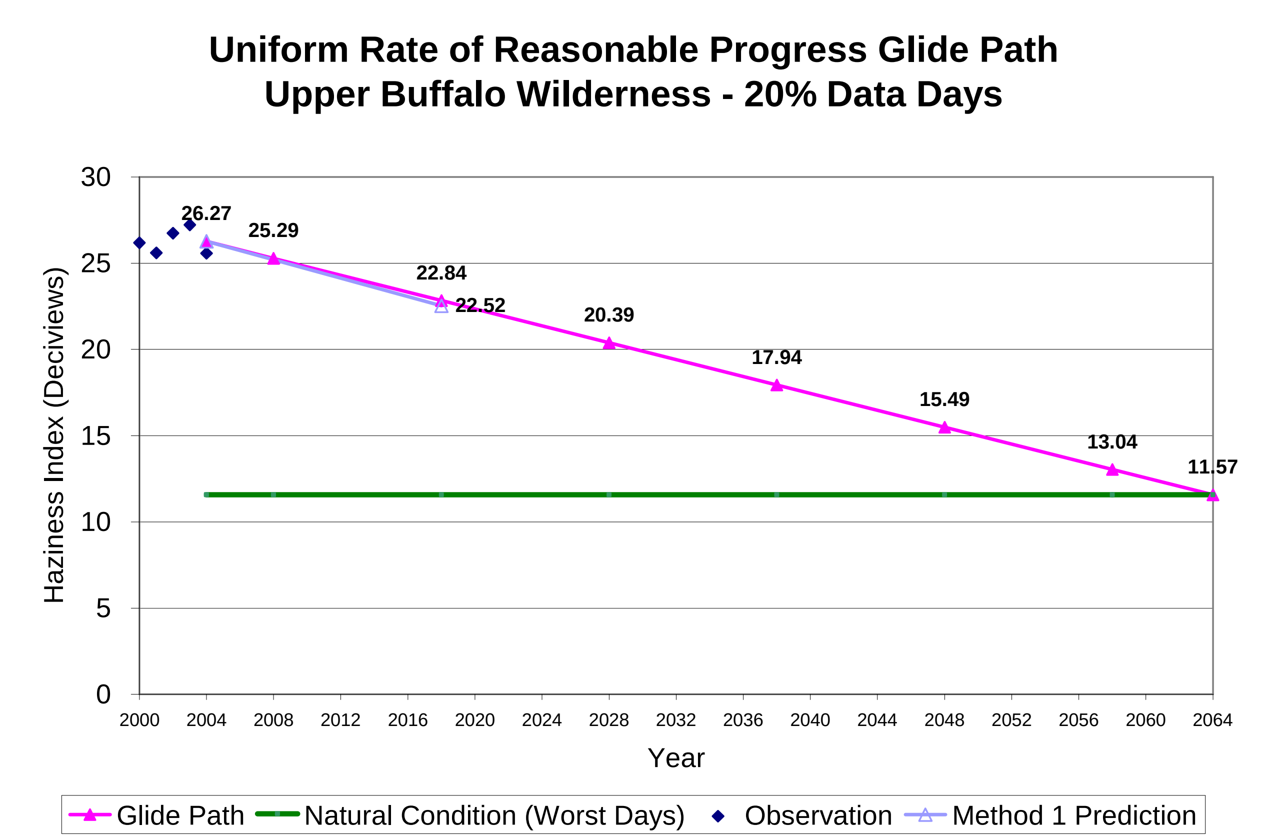


Figure D-2a. 2018 Visibility Projections and 2018 URP Glidepaths in deciview for Upper Buffalo (UPBU), Arkansas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

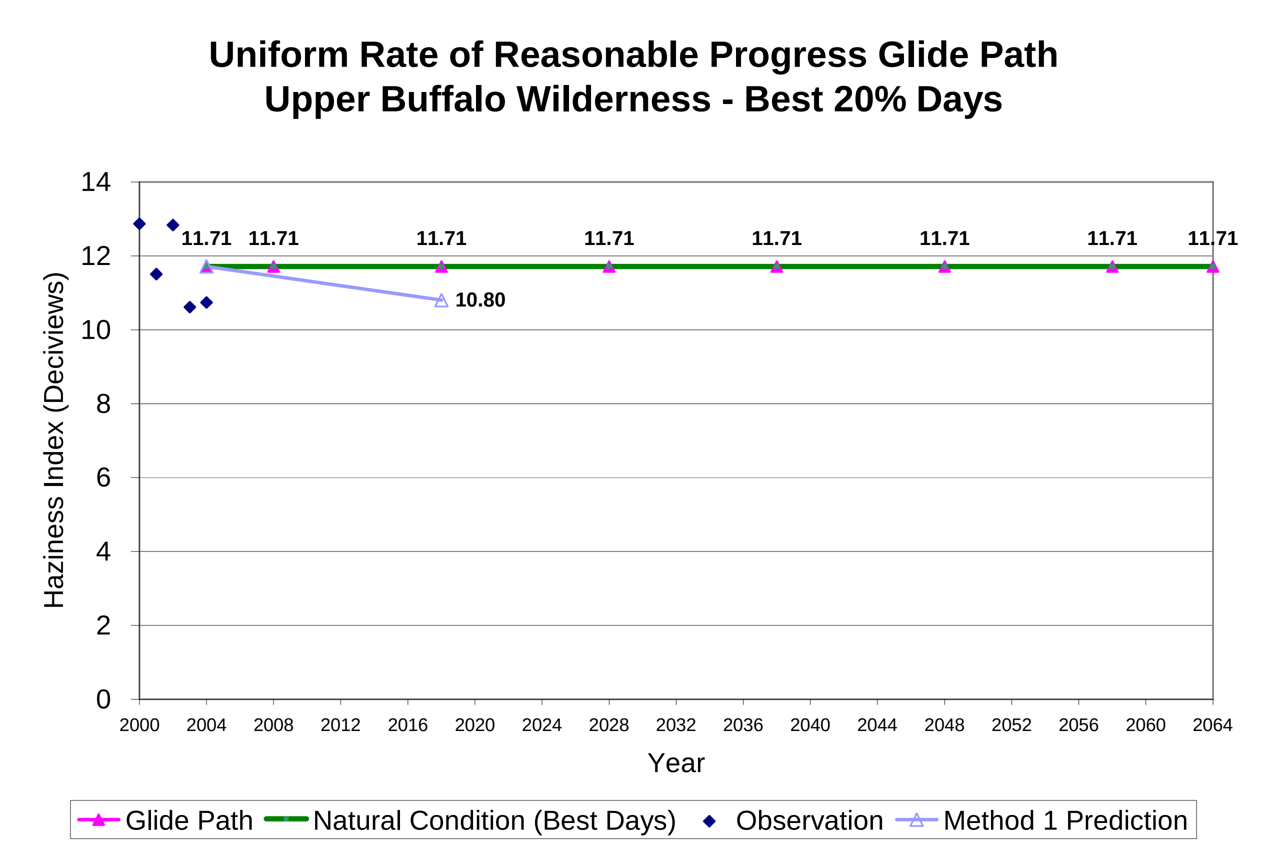


Figure D-2b. 2018 Visibility Projections and 2018 URP Glidepaths in deciview for Upper Buffalo (UPBU), Arkansas and Best 20% (B20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

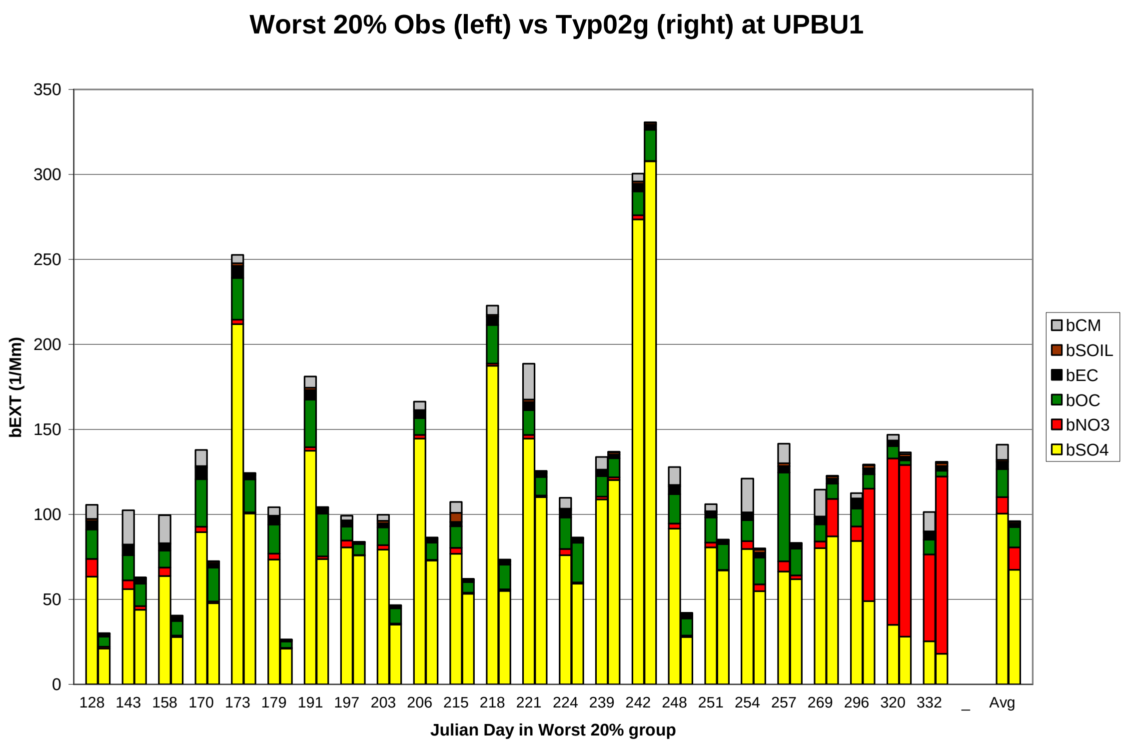


Figure D-2c. Comparison of observed (left) and 2002 Base G modeled (right) daily extinction for Upper Buffalo (UPBU), Arkansas and Worst 20% (W20%) days in 2002.

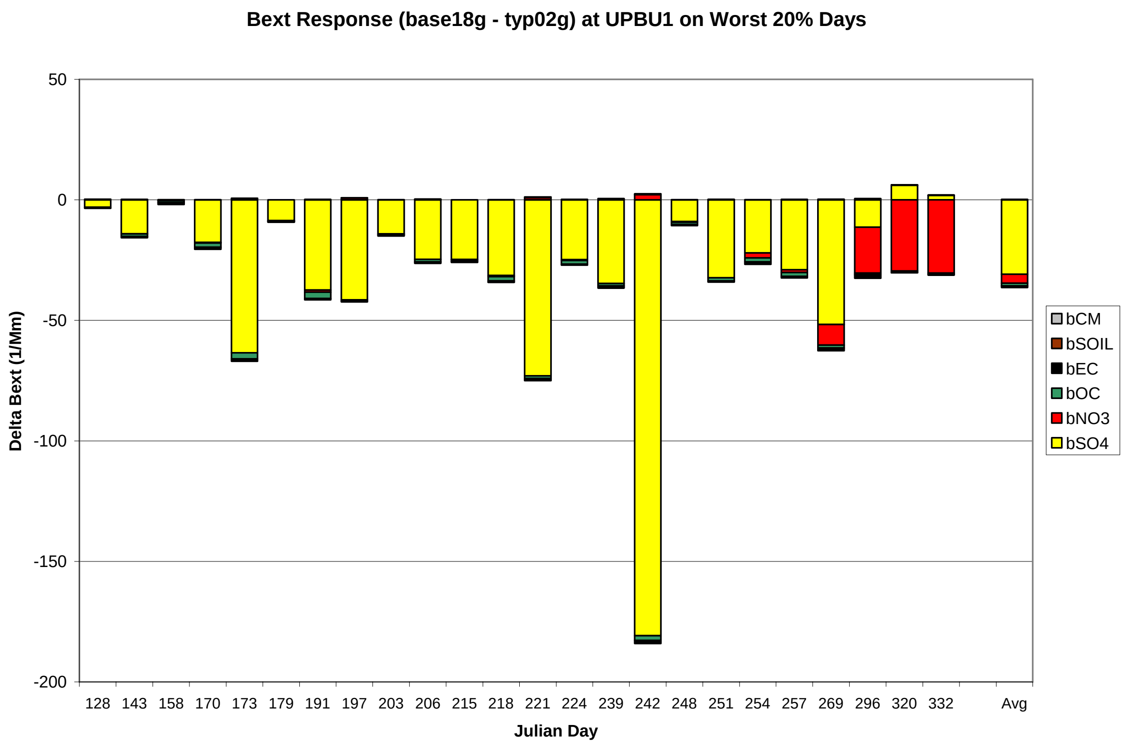


Figure D-2d. Differences in modeled 2002 and 2018 Base G CMAQ results (2018-2002) daily extinction for Upper Buffalo (UPBU), Arkansas and Worst 20% (W20%) days in 2002.

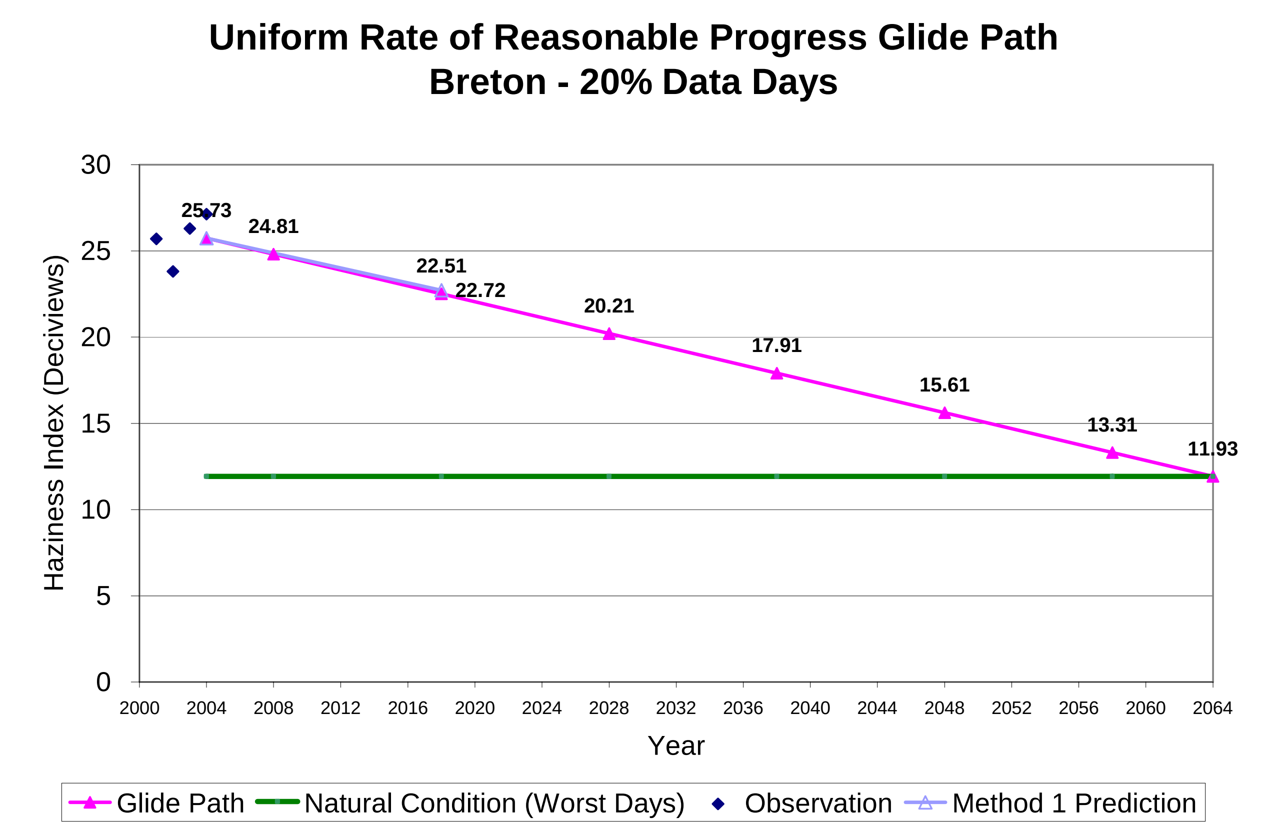


Figure D-3a. 2018 Visibility Projections and 2018 URP Glidepaths in deciview for Breton Island (BRET), Louisiana and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

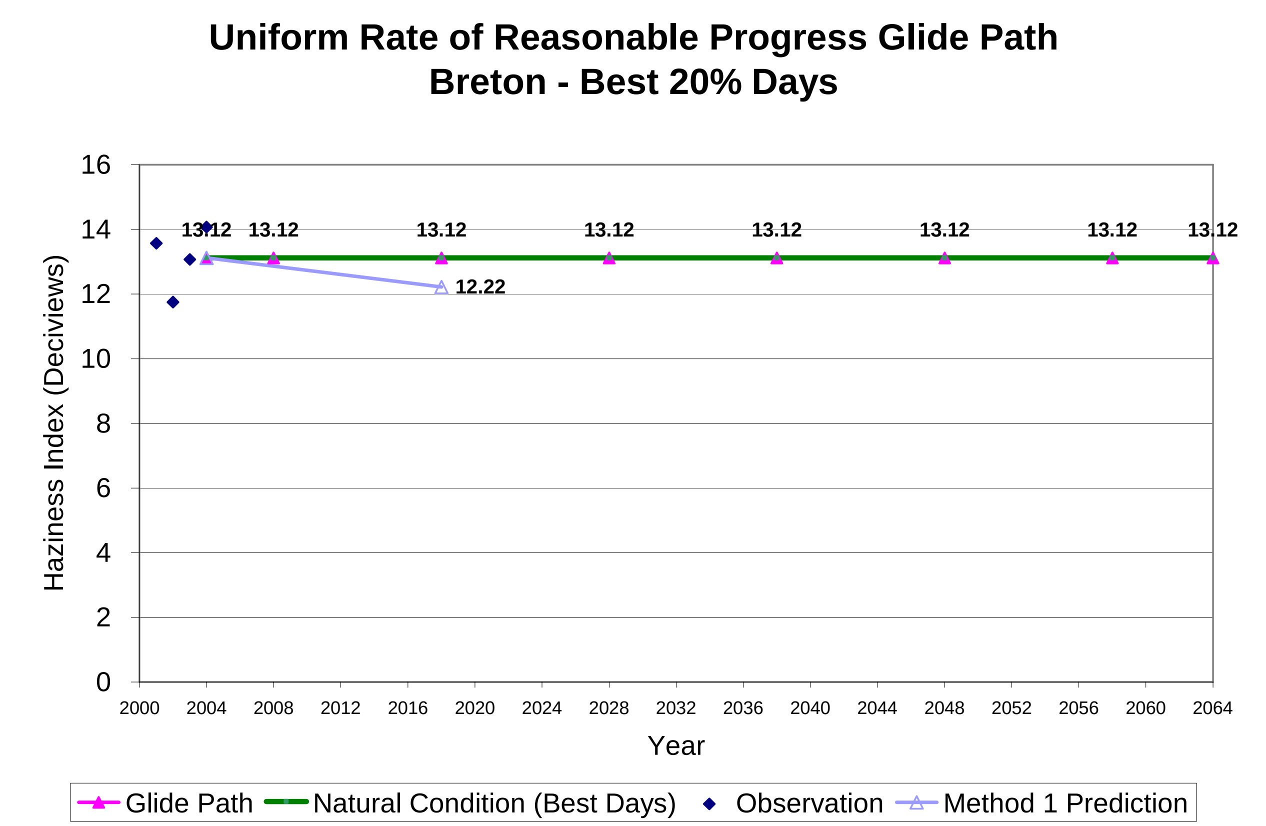


Figure D-3b. 2018 Visibility Projections and 2018 URP Glidepaths in deciview for Breton Island (BRET), Louisiana and Best 20% (B20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

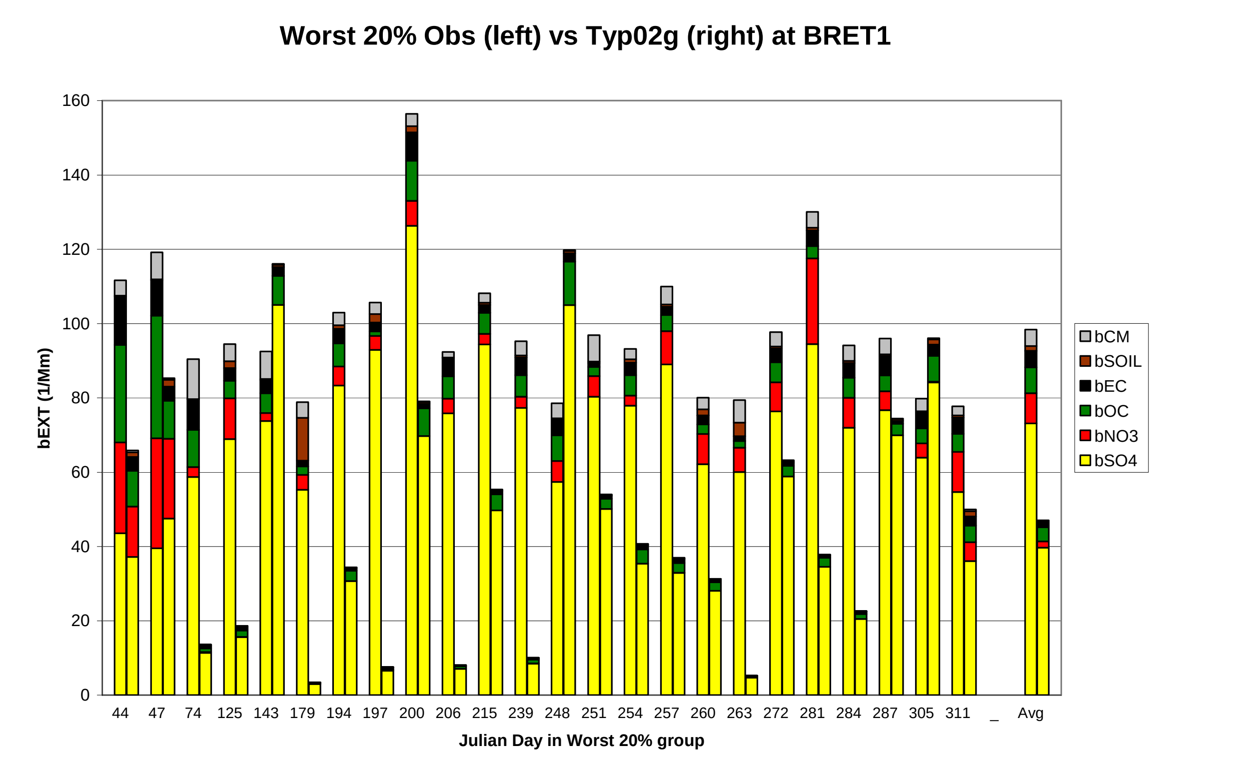


Figure D-3c. Comparison of observed (left) and 2002 Base G modeled (right) daily extinction for Breton Island (BRET), Louisiana and Worst 20% (W20%) days in 2002.

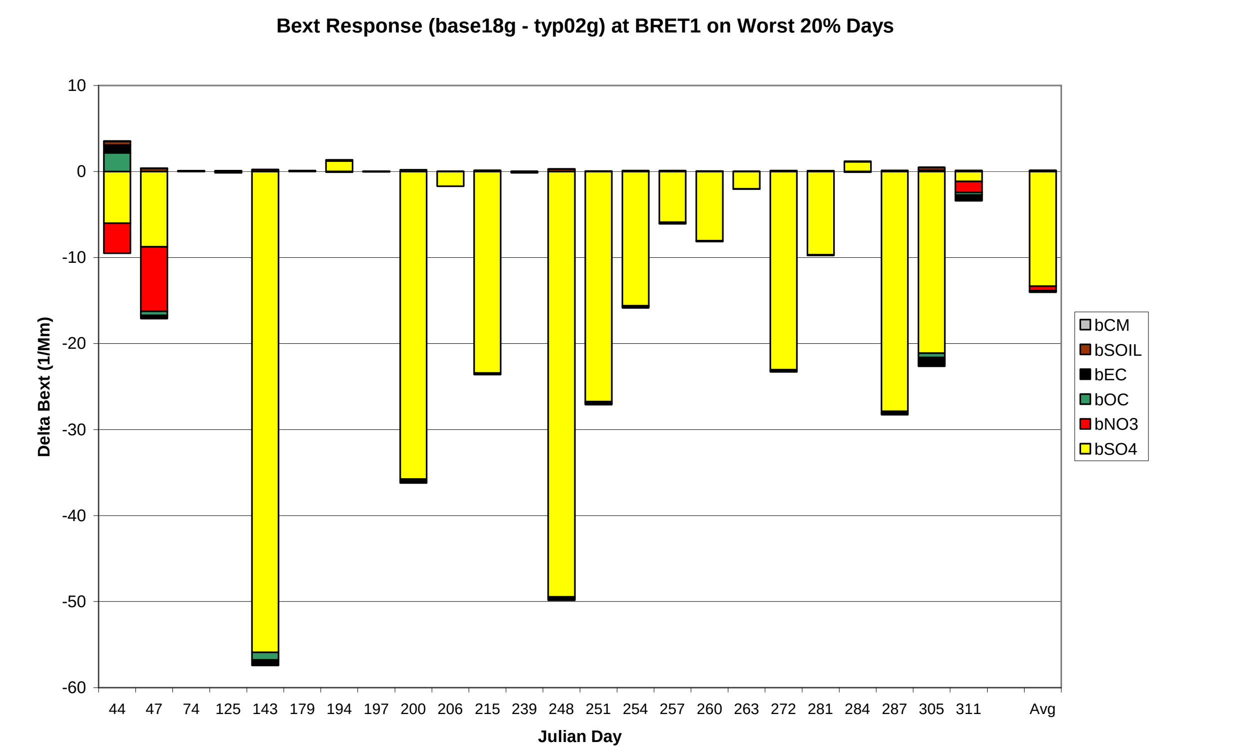


Figure D-3d. Differences in modeled 2002 and 2018 Base G CMAQ results (2018-2002) daily extinction for Breton Island (BRET), Louisiana and Worst 20% (W20%) days in 2002.

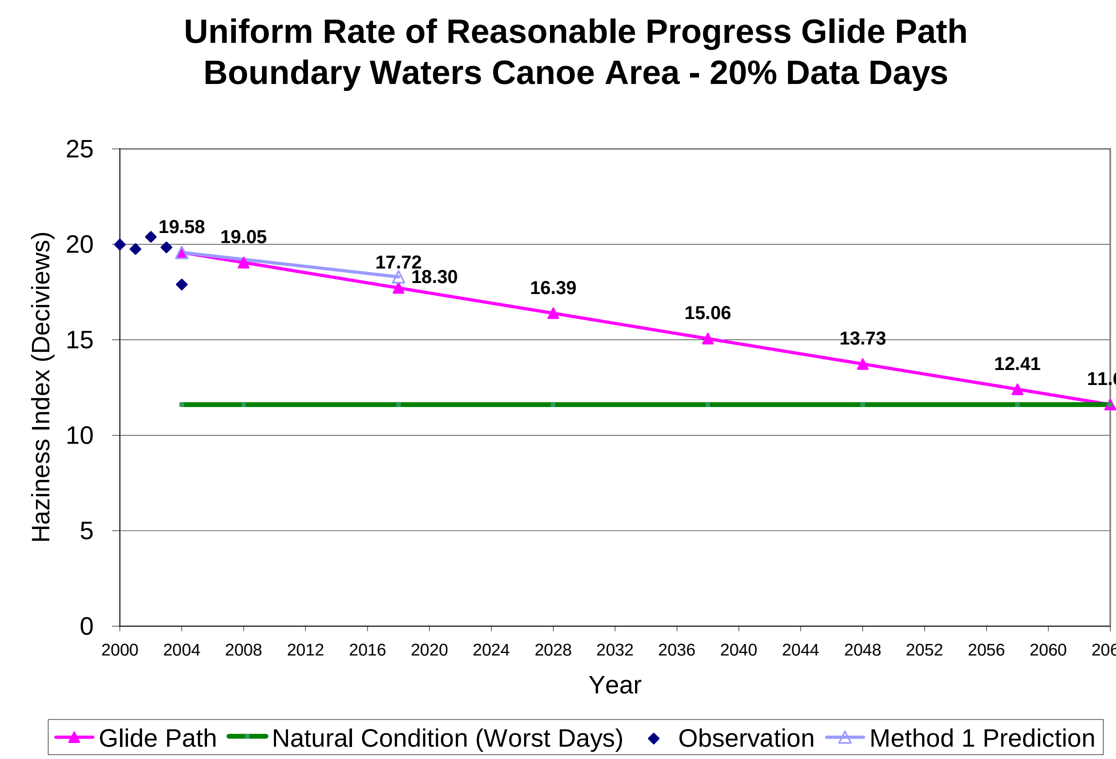


Figure D-4a. 2018 Visibility Projections and 2018 URP Glidepaths in deciview for Boundary Waters (BOWA), Minnesota and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

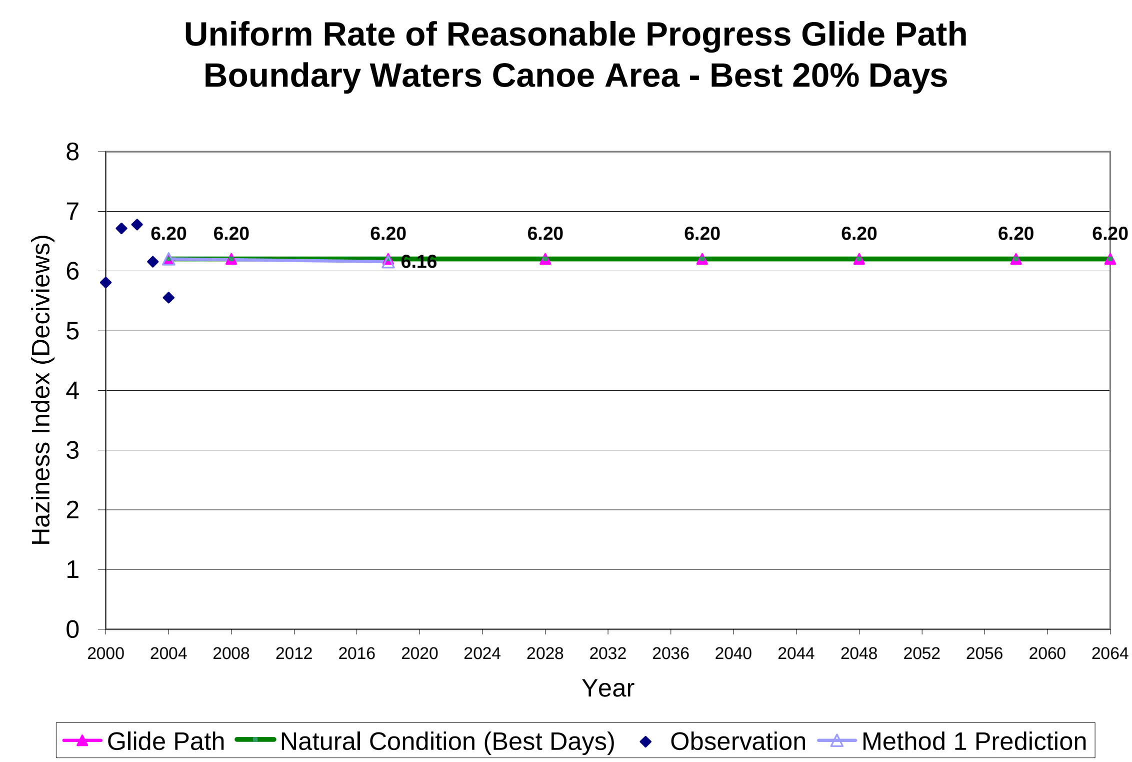


Figure D-4b. 2018 Visibility Projections and 2018 URP Glidepaths in deciview for Boundary Waters (BOWA), Minnesota and Best 20% (B20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

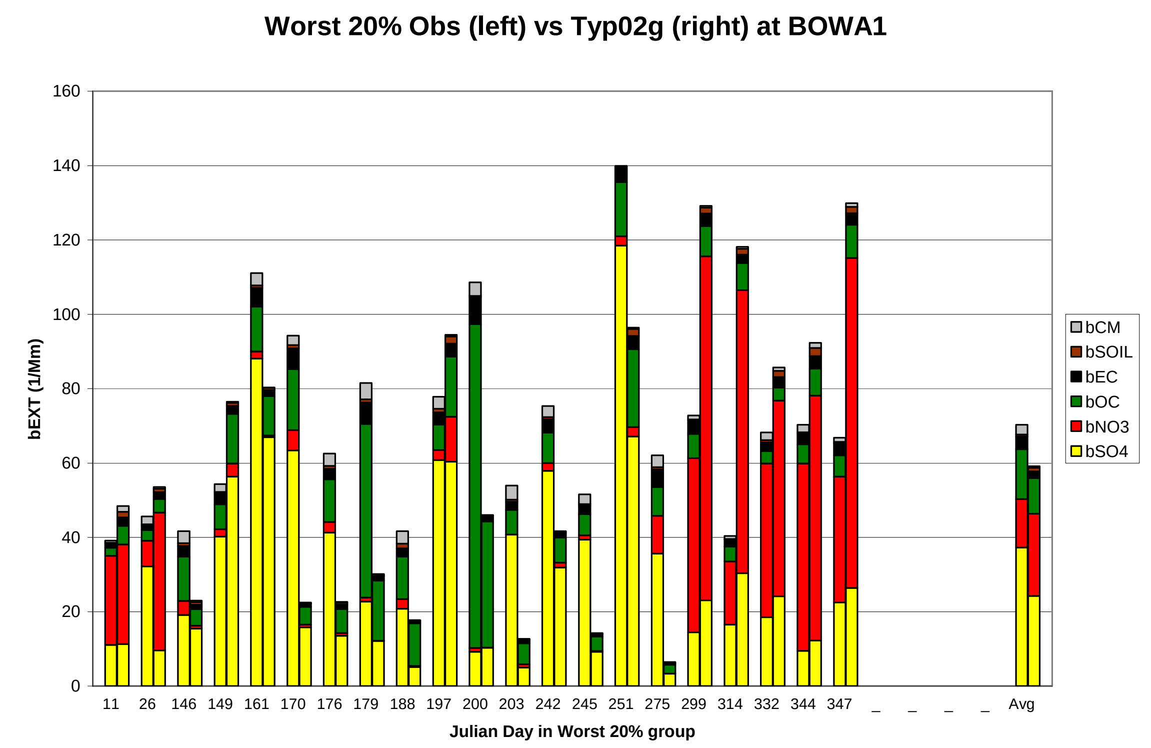


Figure D-4c. Comparison of observed (left) and 2002 Base G modeled (right) daily extinction for Boundary Waters (BOWA), Minnesota and Worst 20% (W20%) days in 2002.

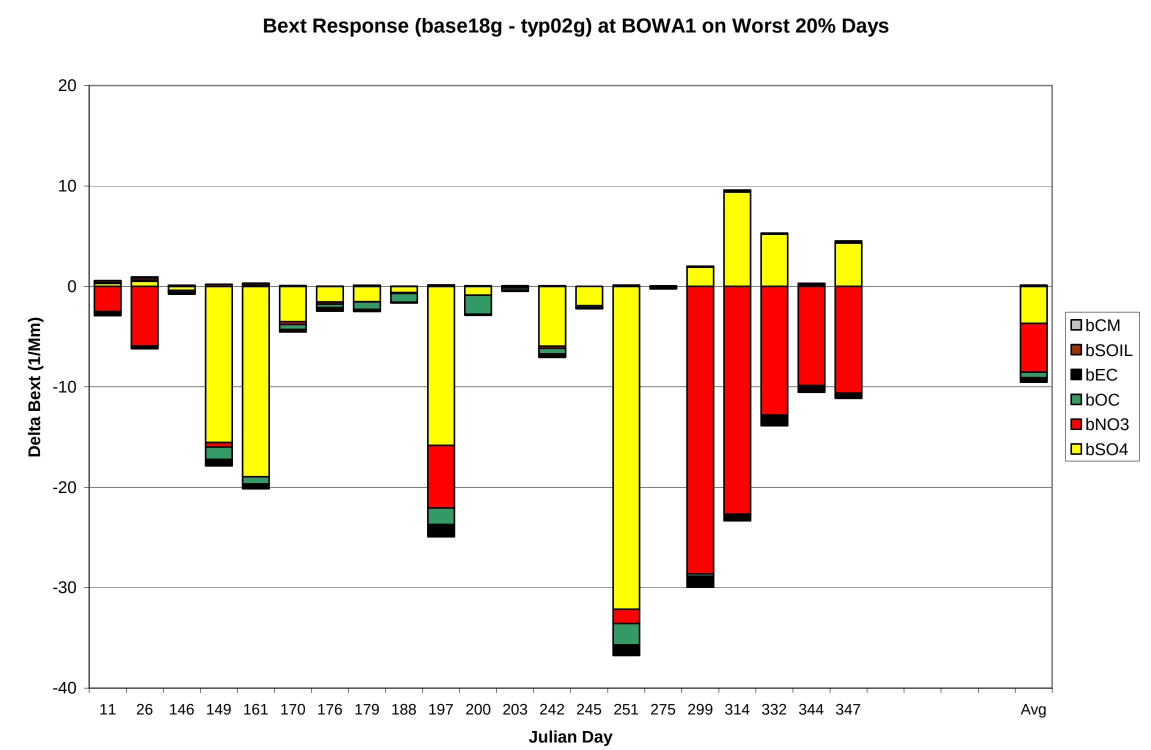


Figure D-4d. Differences in modeled 2002 and 2018 Base G CMAQ results (2018-2002) daily extinction for Boundary Waters (BOWA), Minnesota and Worst 20% (W20%) days in 2002.

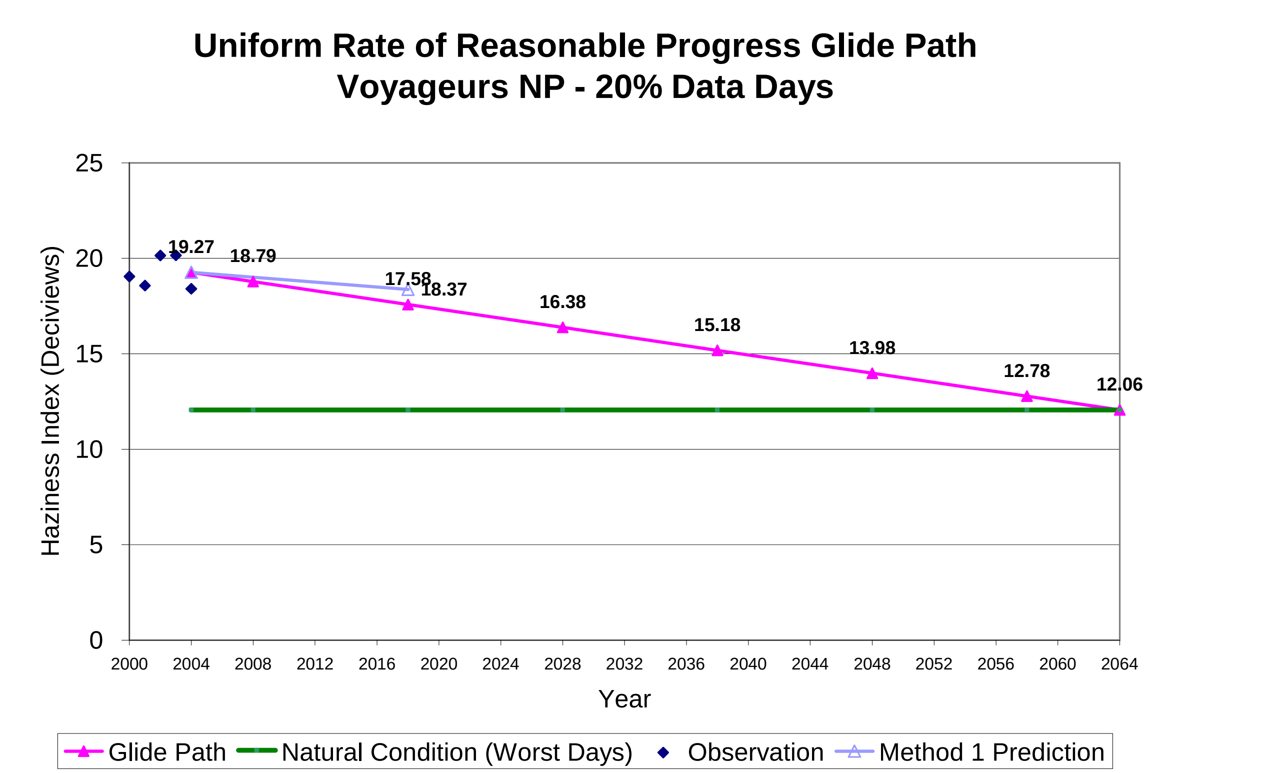


Figure D-5a. 2018 Visibility Projections and 2018 URP Glidepaths in deciview for Voyageurs (VOYA), Minnesota and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

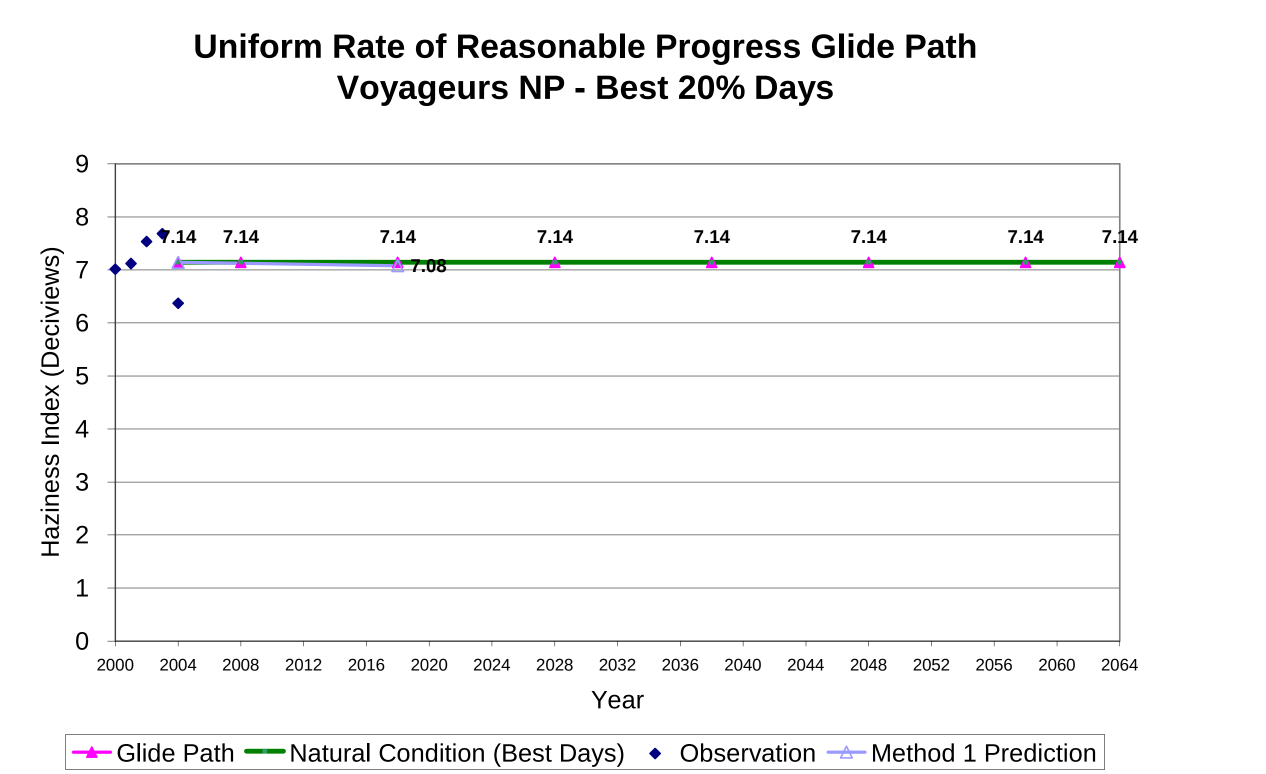


Figure D-5b. 2018 Visibility Projections and 2018 URP Glidepaths in deciview for Voyageurs (VOYA), Minnesota and Best 20% (B20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

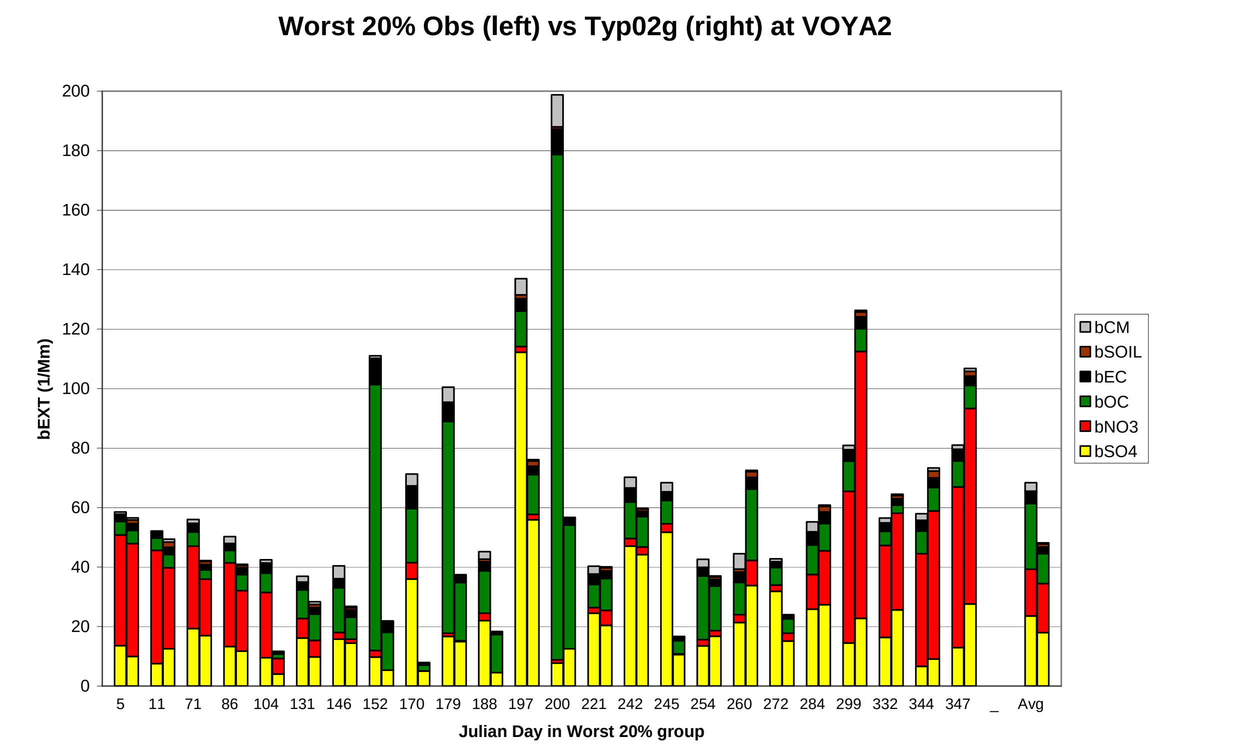


Figure D-5c. Comparison of observed (left) and 2002 Base G modeled (right) daily extinction for Voyageurs (VOYA), Minnesota and Worst 20% (W20%) days in 2002.

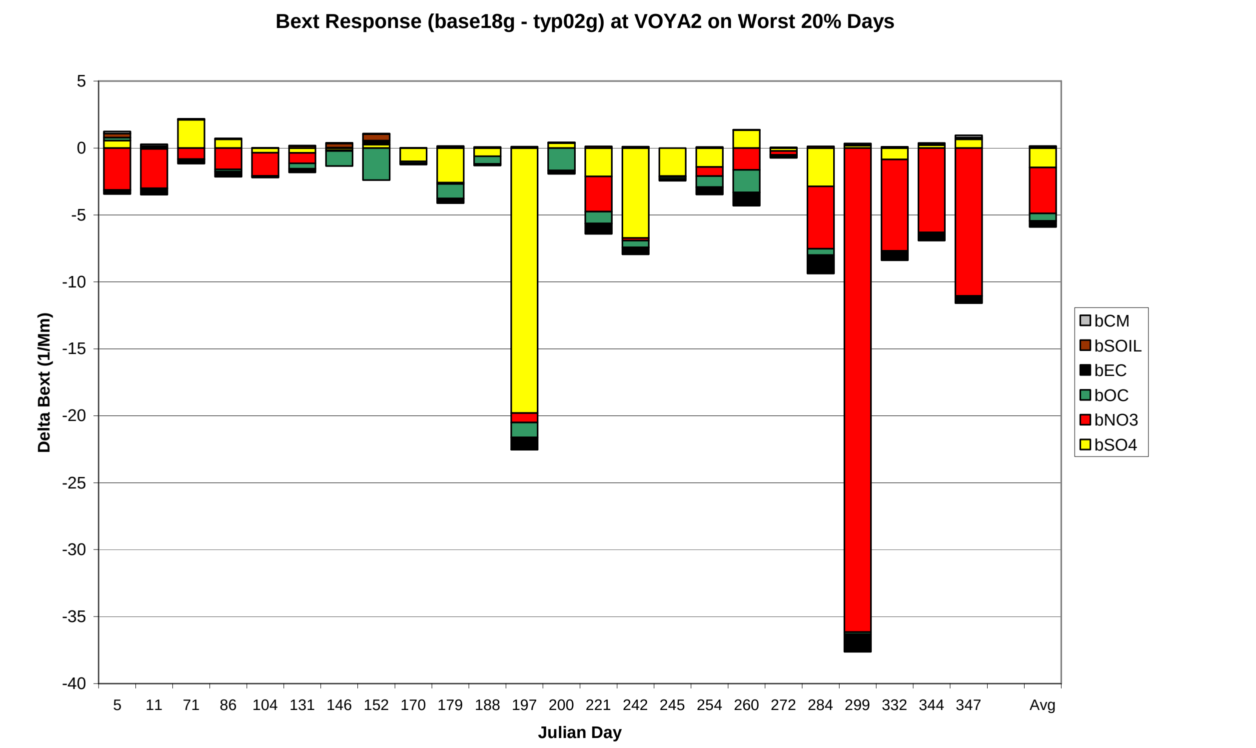


Figure D-5d. Differences in modeled 2002 and 2018 Base G CMAQ results (2018-2002) daily extinction for Voyageurs (VOYA), Minnesota and Worst 20% (W20%) days in 2002.

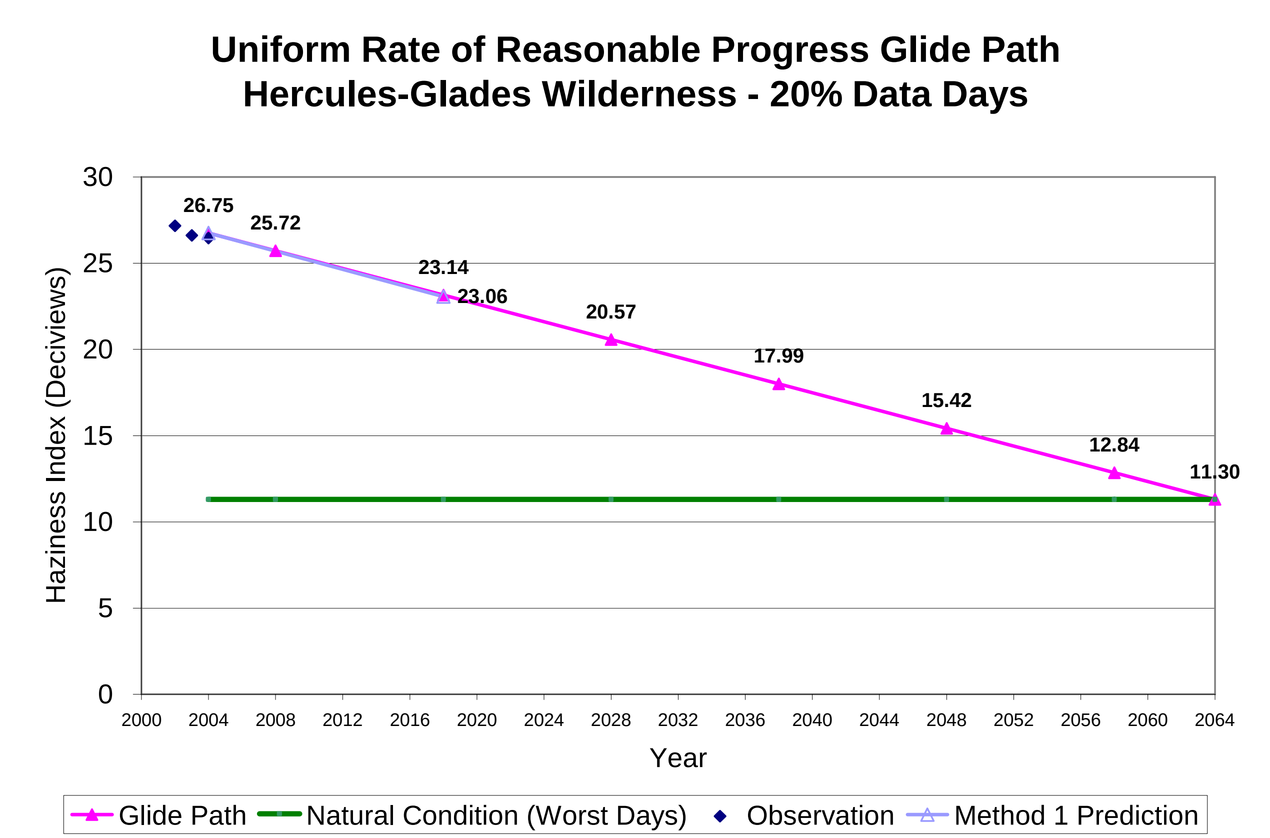


Figure D-6a. 2018 Visibility Projections and 2018 URP Glidepaths in deciview for Hercules-Glade (HEGL), Missouri and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

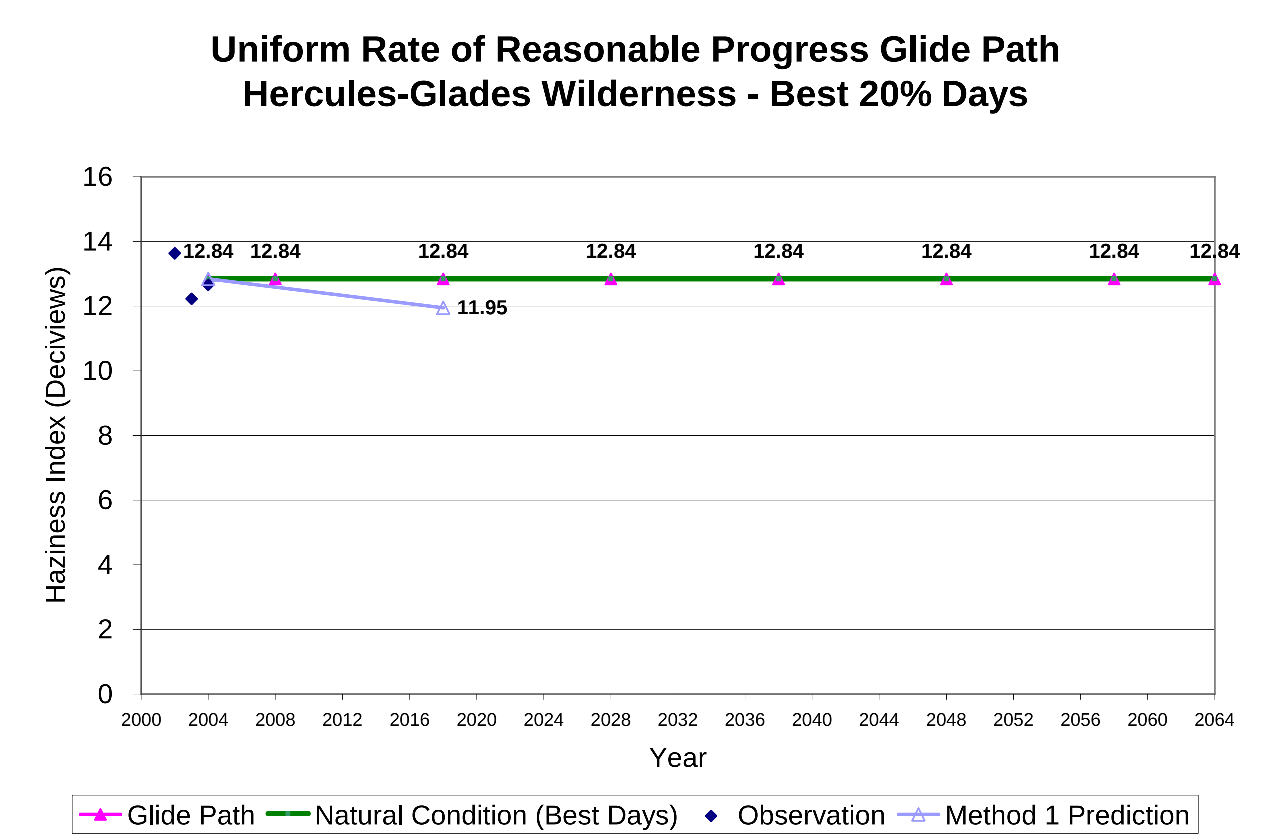


Figure D-6b. 2018 Visibility Projections and 2018 URP Glidepaths in deciview for Hercules-Glade (HEGL), Missouri and Best 20% (B20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

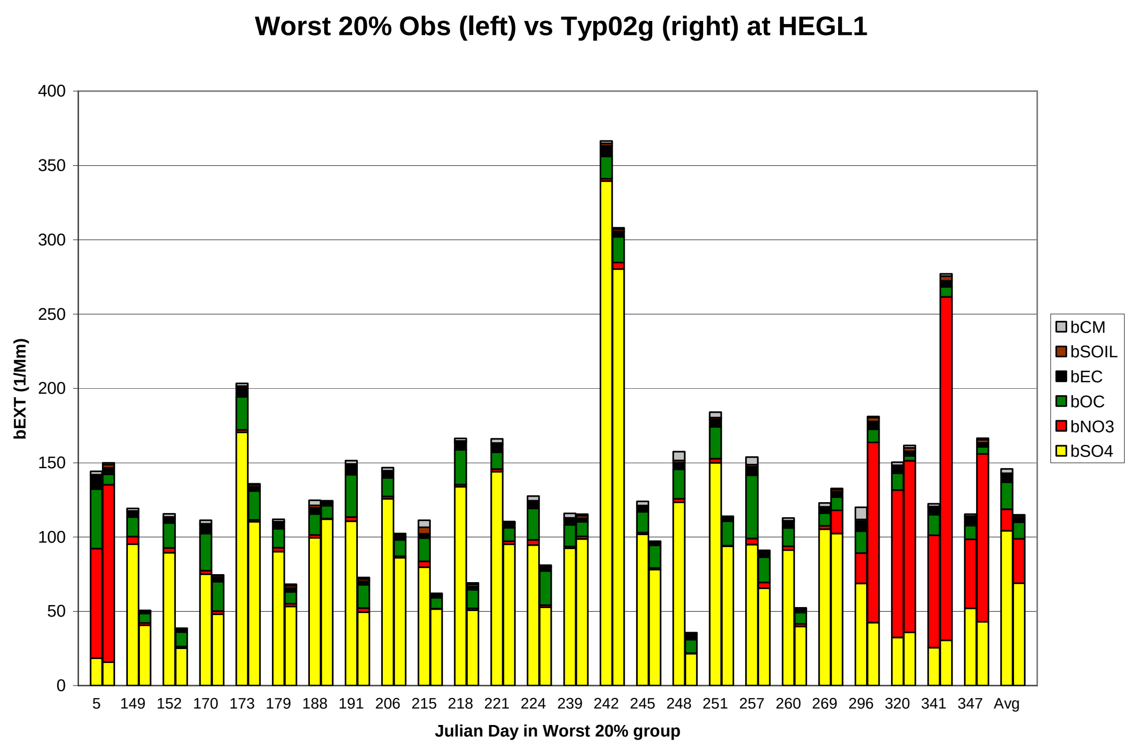


Figure D-6c. Comparison of observed (left) and 2002 Base G modeled (right) daily extinction for Hercules-Glade (HEGL), Missouri and Worst 20% (W20%) days in 2002.

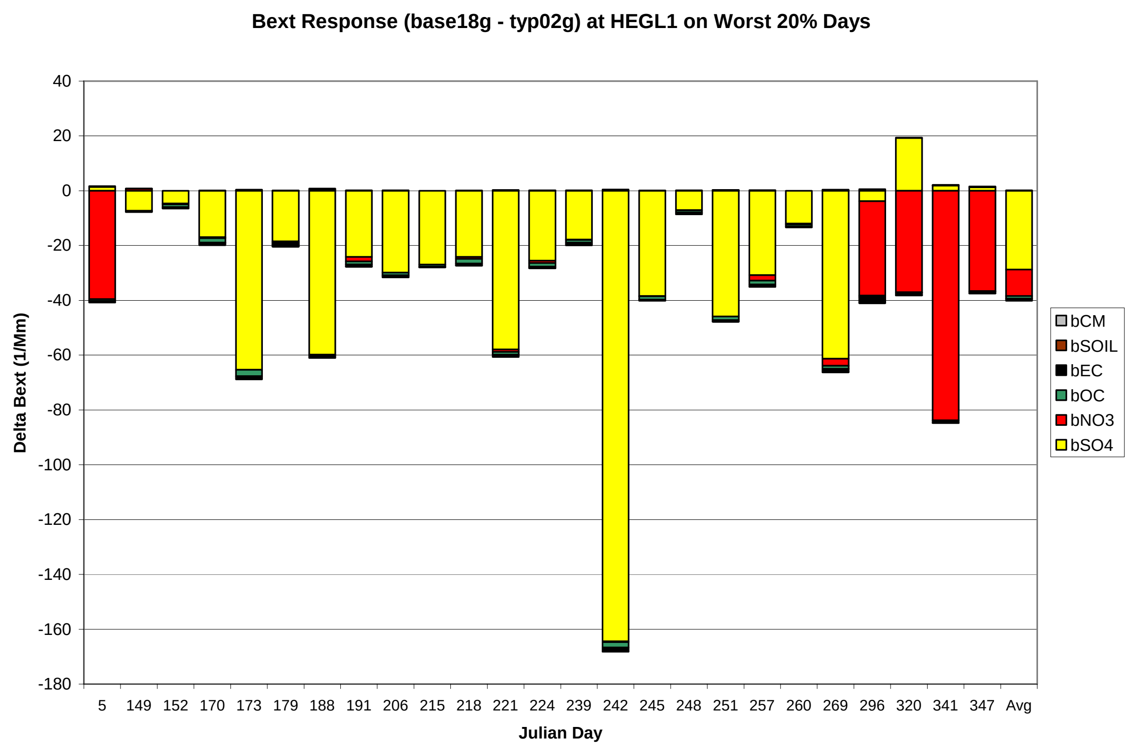


Figure D-6d. Differences in modeled 2002 and 2018 Base G CMAQ results (2018-2002) daily extinction for Hercules-Glade (HEGL), Missouri and Worst 20% (W20%) days in 2002.

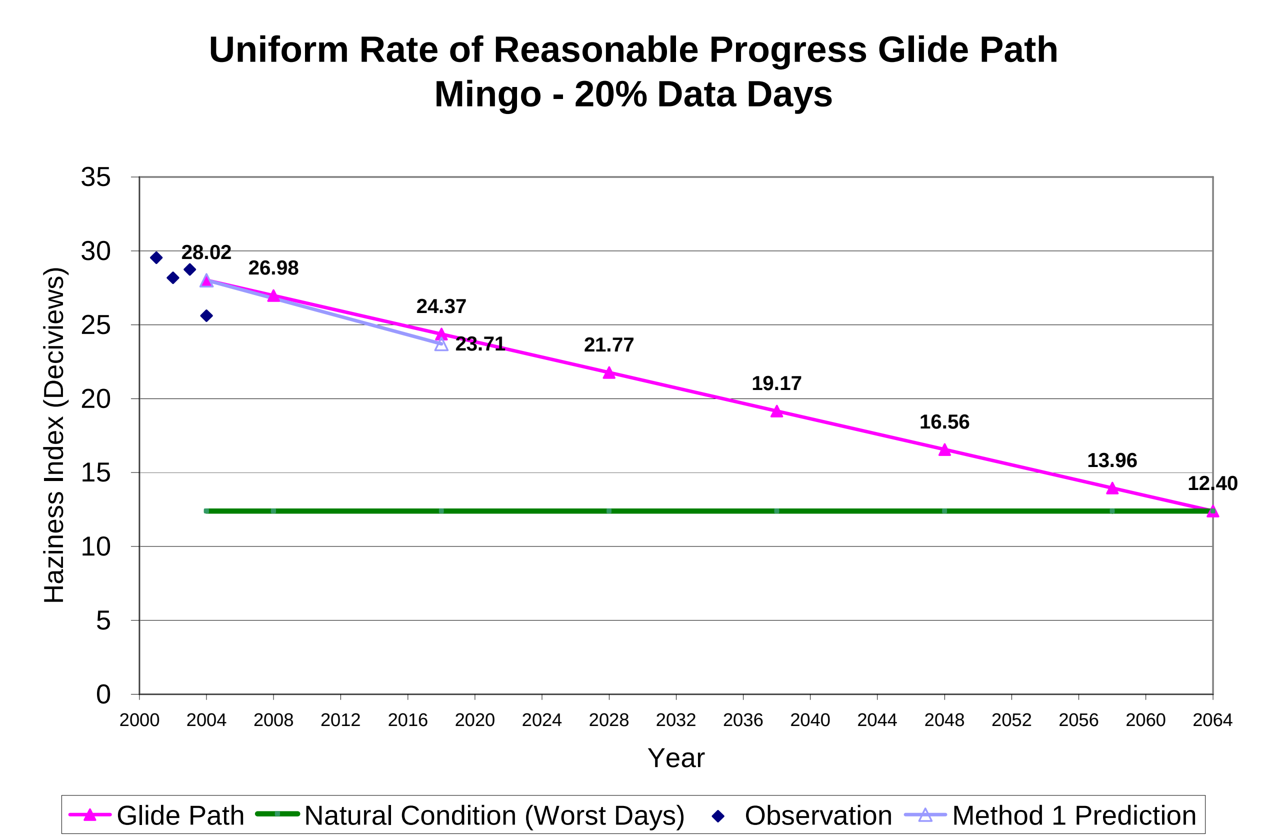


Figure D-7a. 2018 Visibility Projections and 2018 URP Glidepaths in deciview for Mingo (MING), Missouri and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

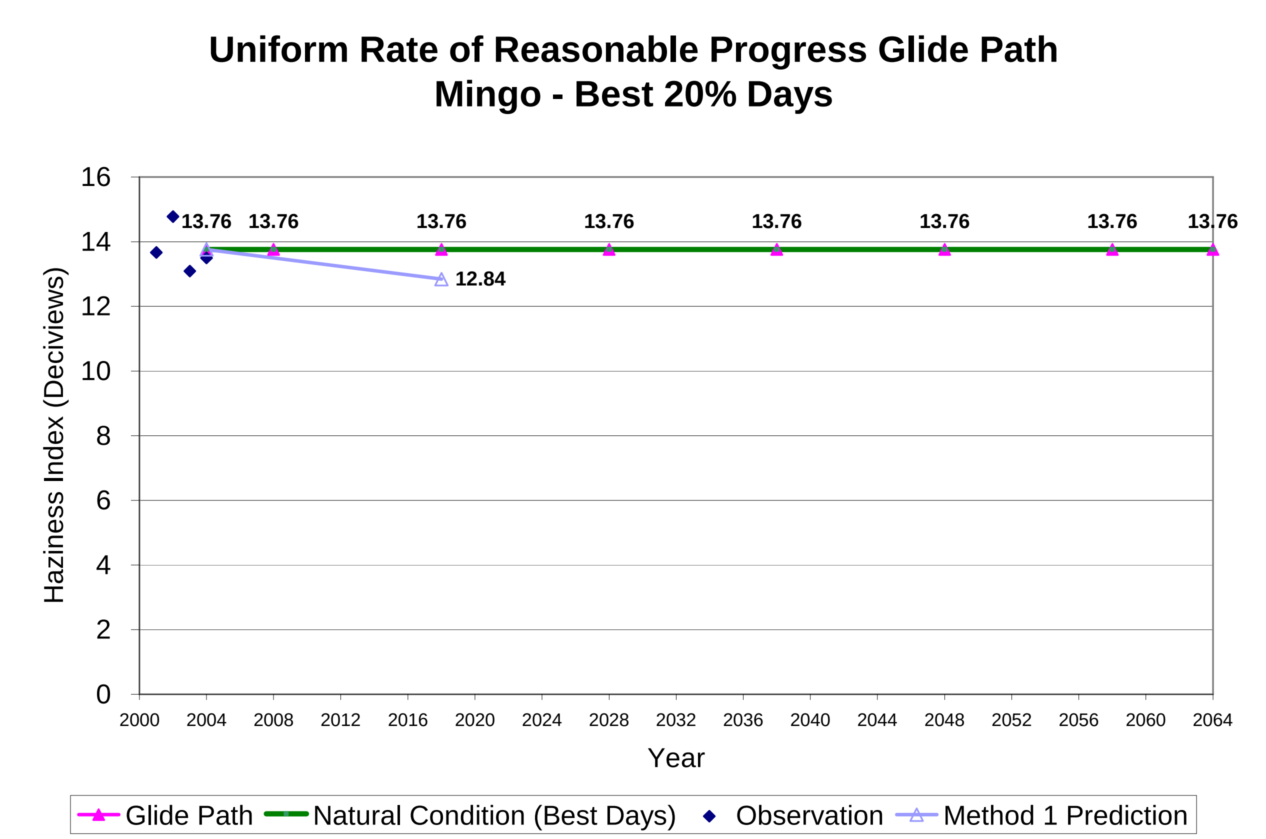


Figure D-7b. 2018 Visibility Projections and 2018 URP Glidepaths in deciview for Mingo (MING), Missouri and Best 20% (B20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

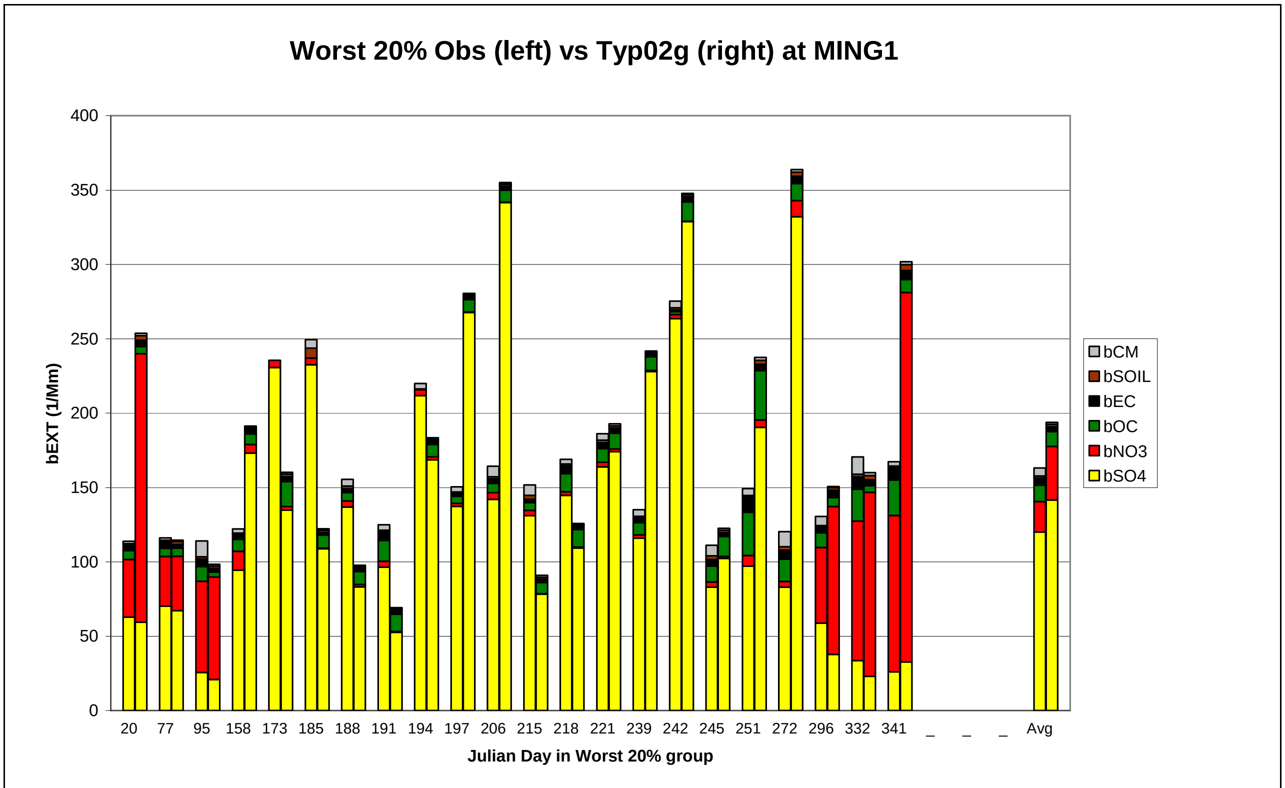


Figure D-7c. Comparison of observed (left) and 2002 Base G modeled (right) daily extinction for Mingo (MING), Missouri and Worst 20% (W20%) days in 2002.

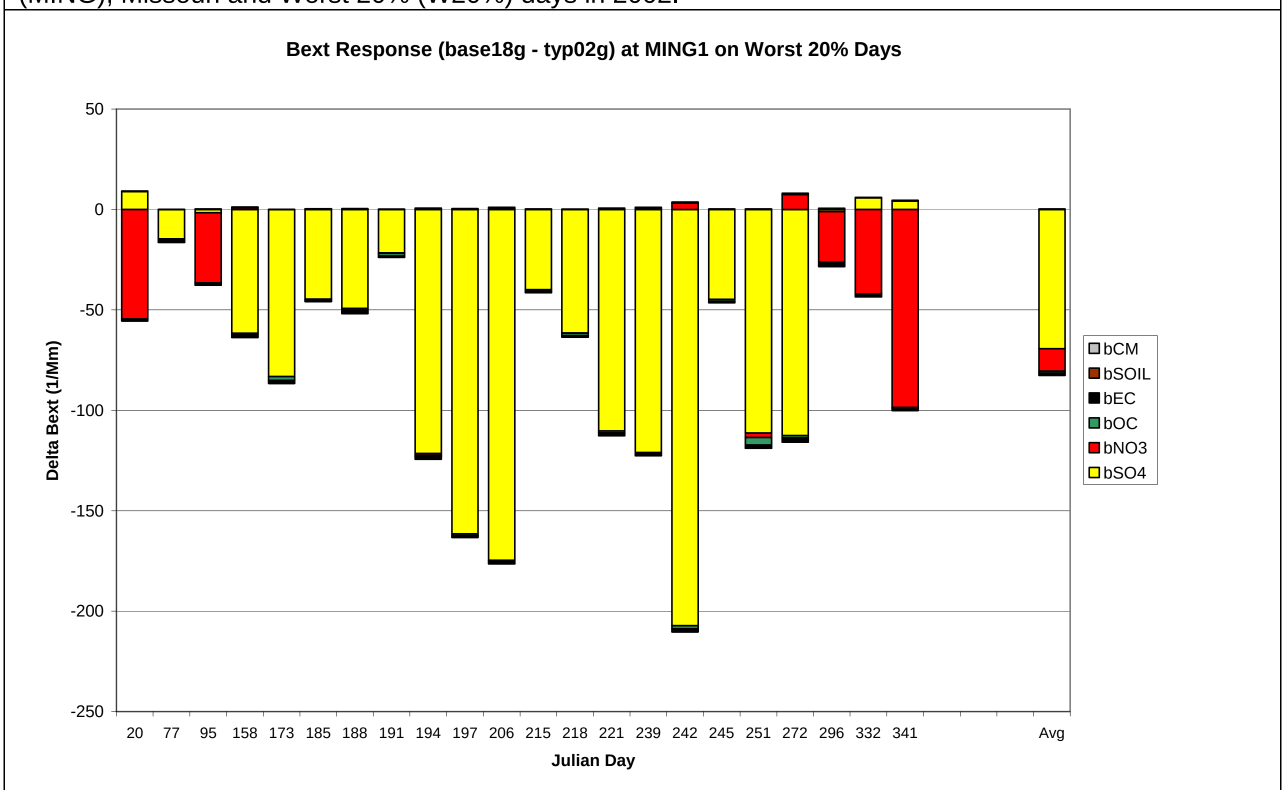


Figure D-7d. Differences in modeled 2002 and 2018 Base G CMAQ results (2018-2002) daily extinction for Mingo (MING), Missouri and Worst 20% (W20%) days in 2002.

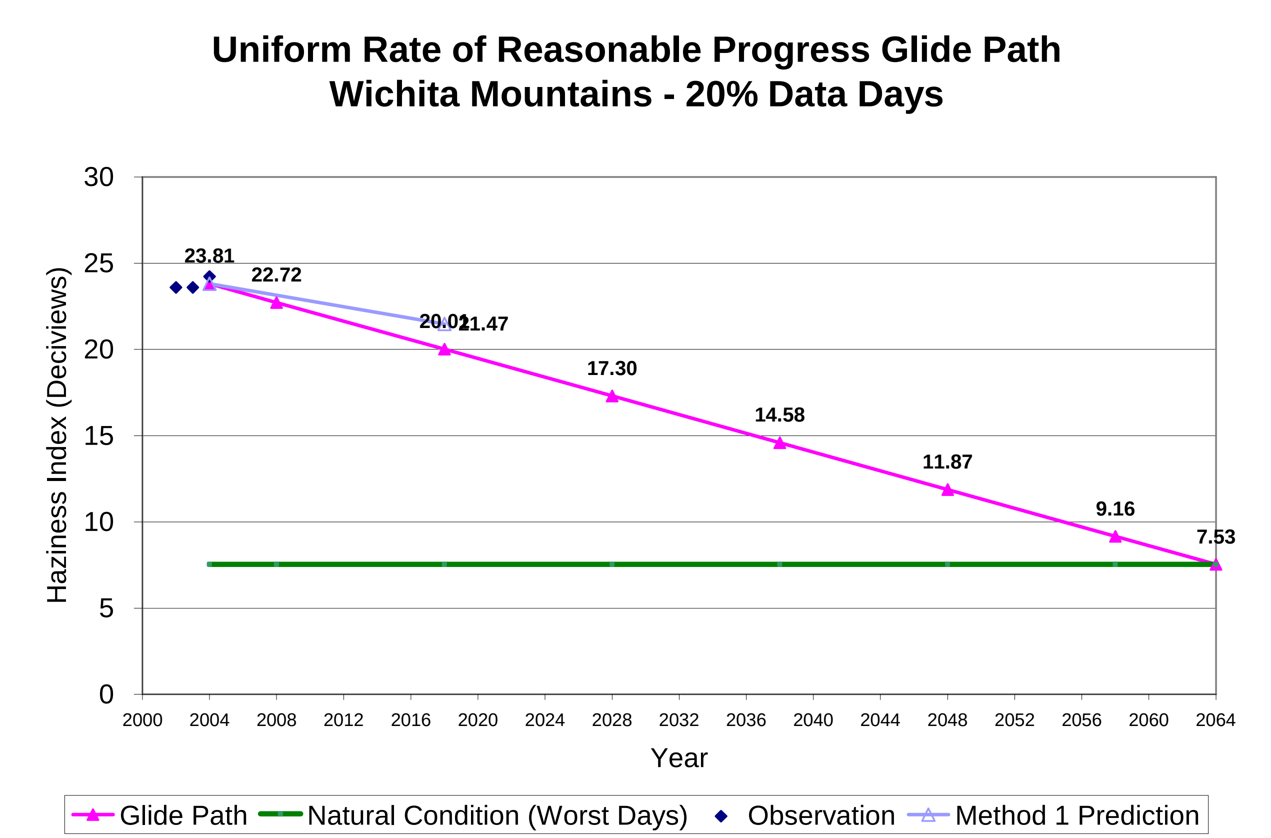


Figure D-8a. 2018 Visibility Projections and 2018 URP Glidepaths in deciview for Wichita Mountains (WIMO), Oklahoma and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

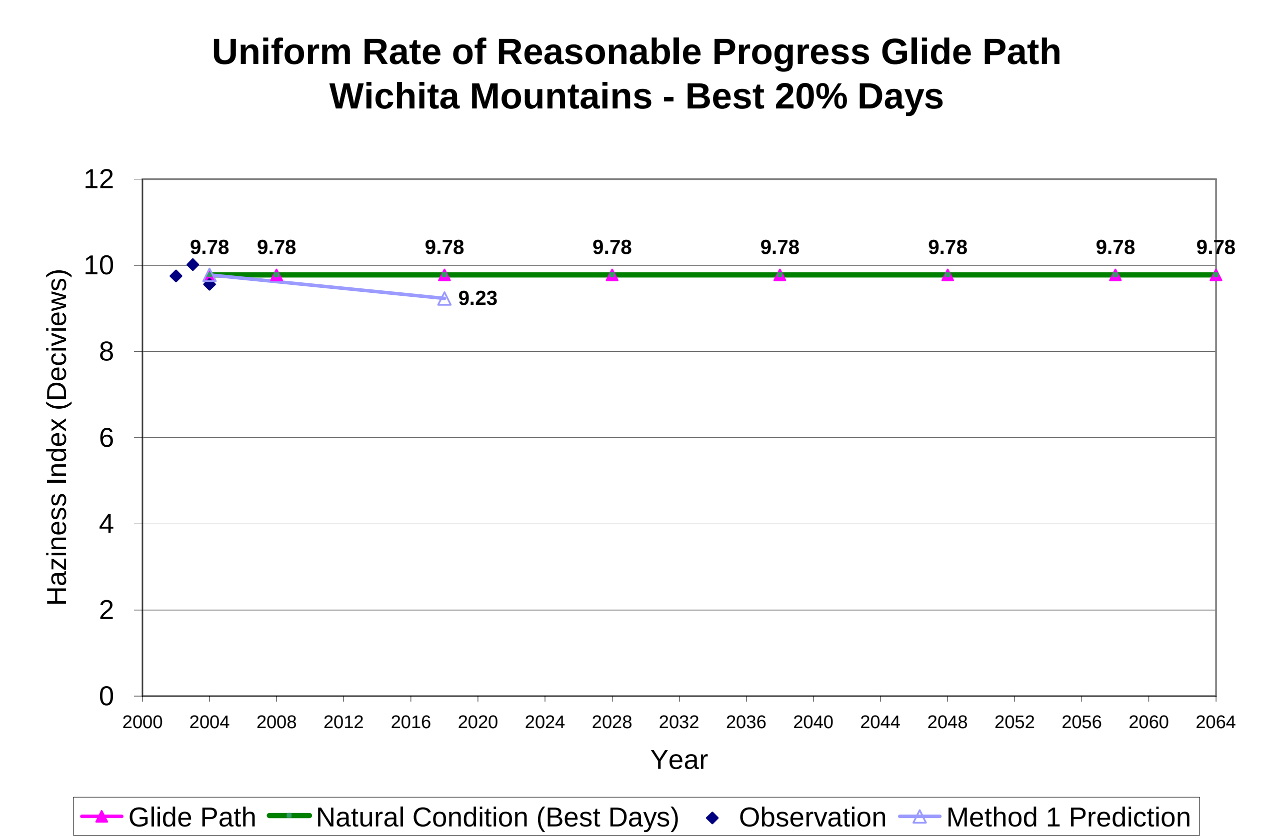


Figure D-8b. 2018 Visibility Projections and 2018 URP Glidepaths in deciview for Wichita Mountains (WIMO), Oklahoma and Best 20% (B20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

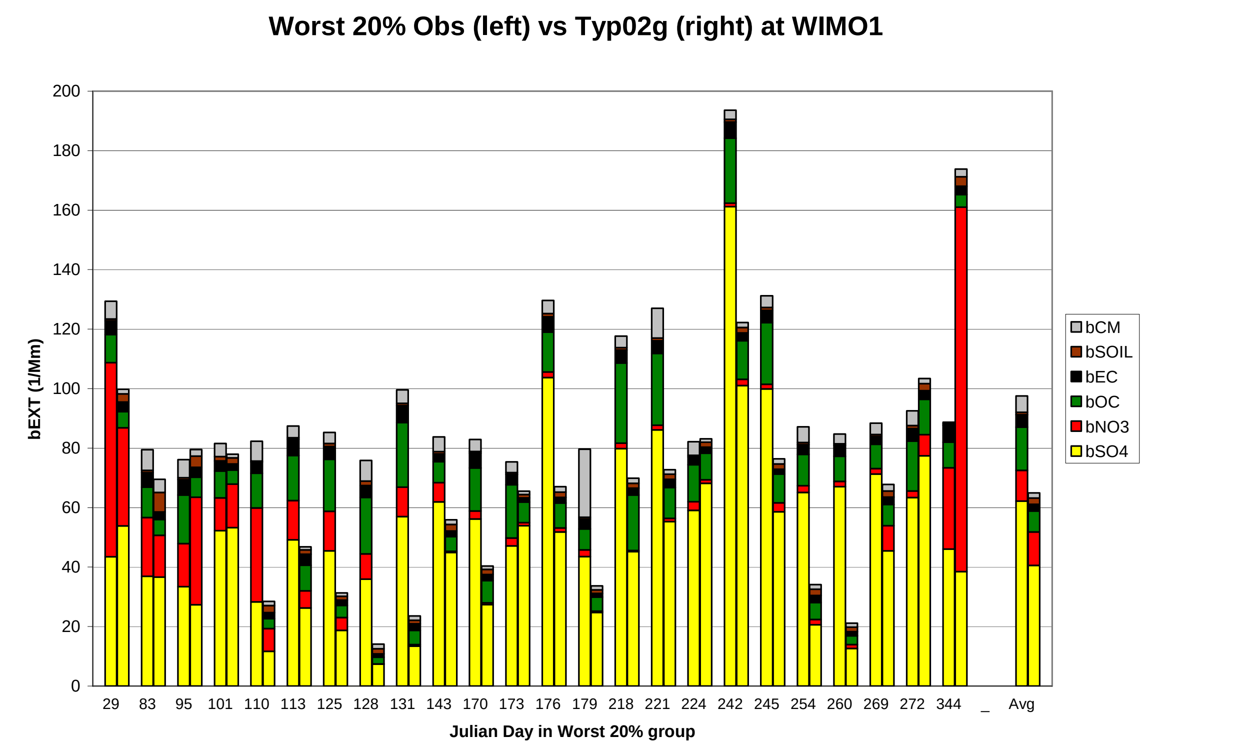


Figure D-8c. Comparison of observed (left) and 2002 Base G modeled (right) daily extinction for Wichita Mountains (WIMO), Oklahoma and Worst 20% (W20%) days in 2002.

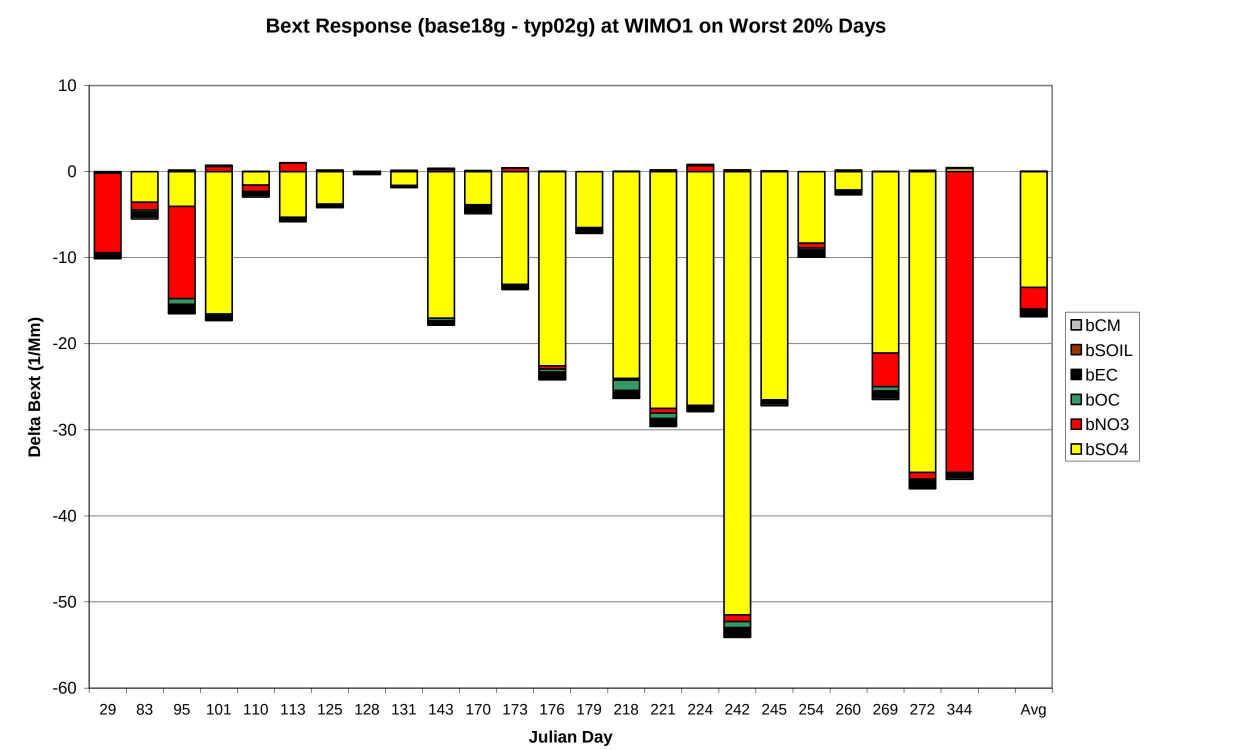


Figure D-8d. Differences in modeled 2002 and 2018 Base G CMAQ results (2018-2002) daily extinction for Wichita Mountains (WIMO), Oklahoma and Worst 20% (W20%) days in 2002.

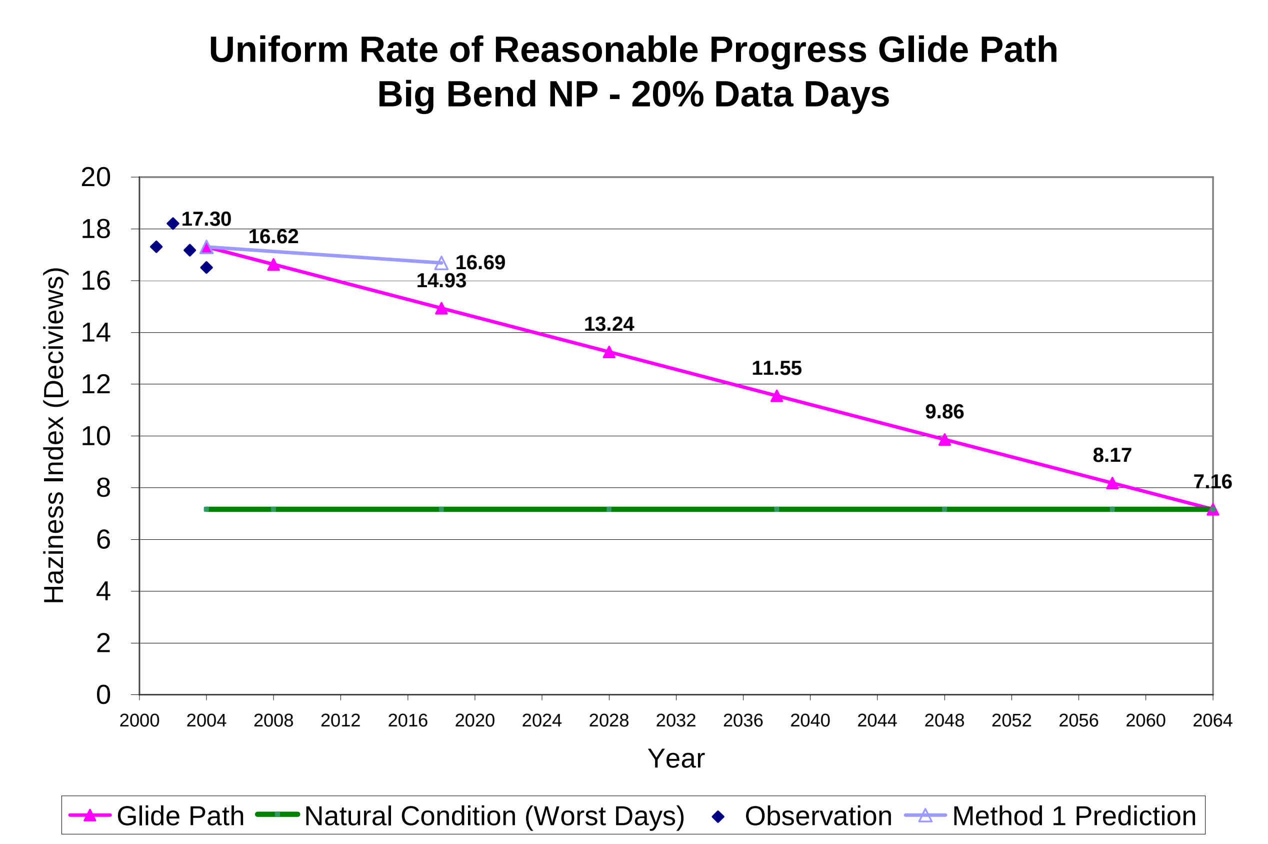


Figure D-9a. 2018 Visibility Projections and 2018 URP Glidepaths in deciview for Big Bend (BIBE), Texas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

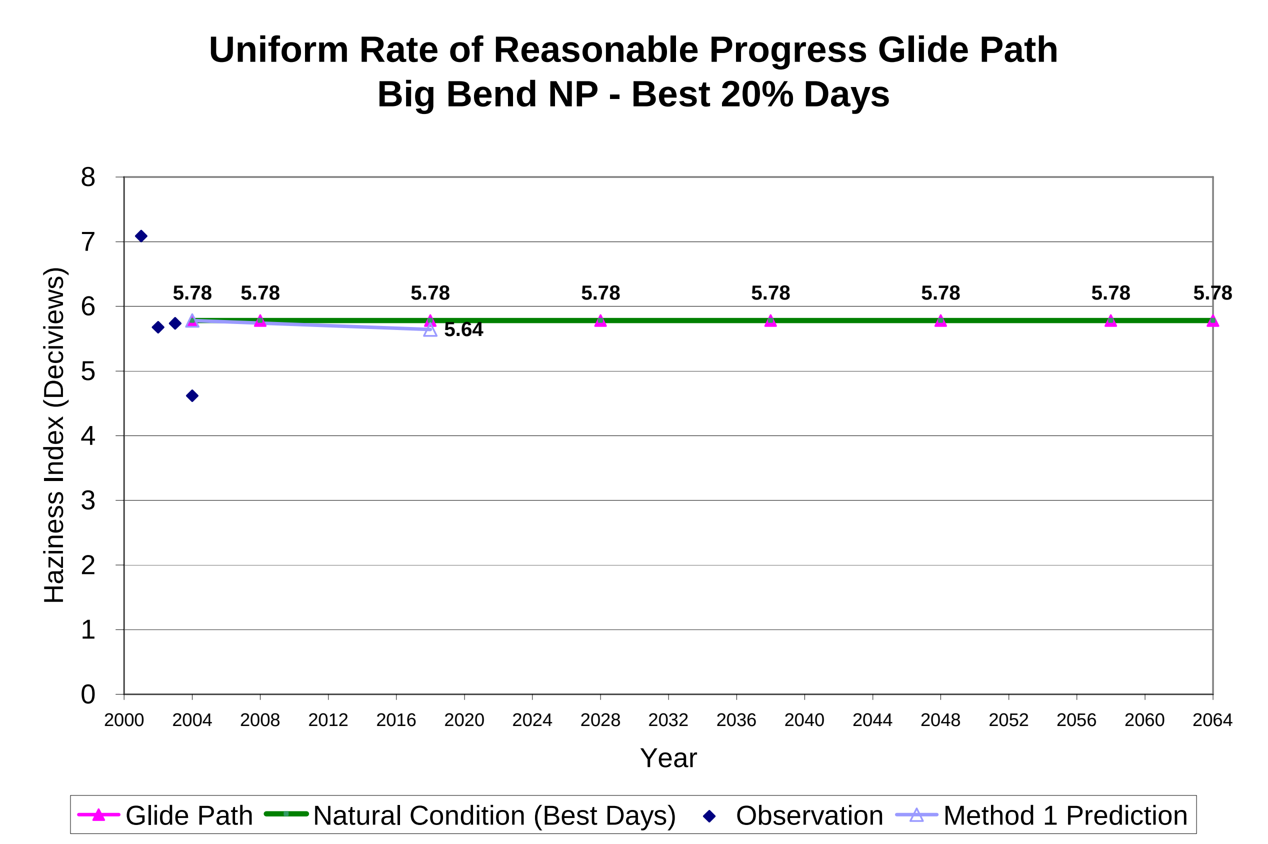


Figure D-9b. 2018 Visibility Projections and 2018 URP Glidepaths in deciview for Big Bend (BIBE), Texas and Best 20% (B20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

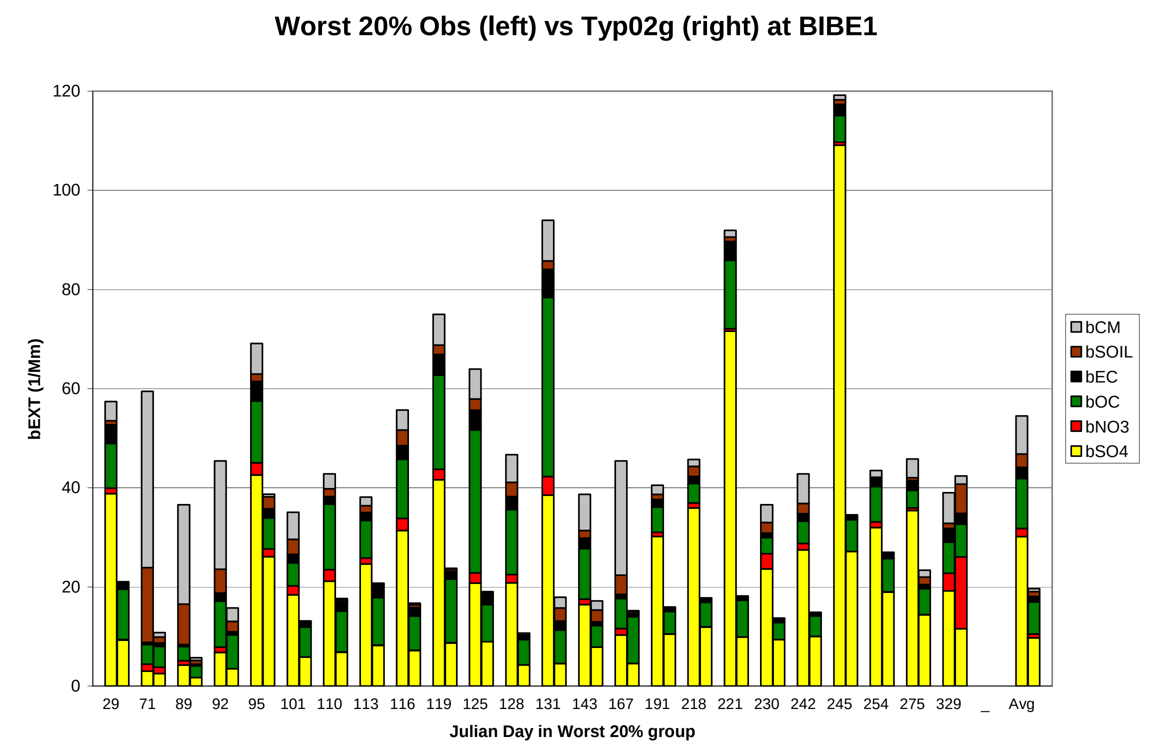


Figure D-9c. Comparison of observed (left) and 2002 Base G modeled (right) daily extinction for Big Bend (BIBE), Texas and Worst 20% (W20%) days in 2002.

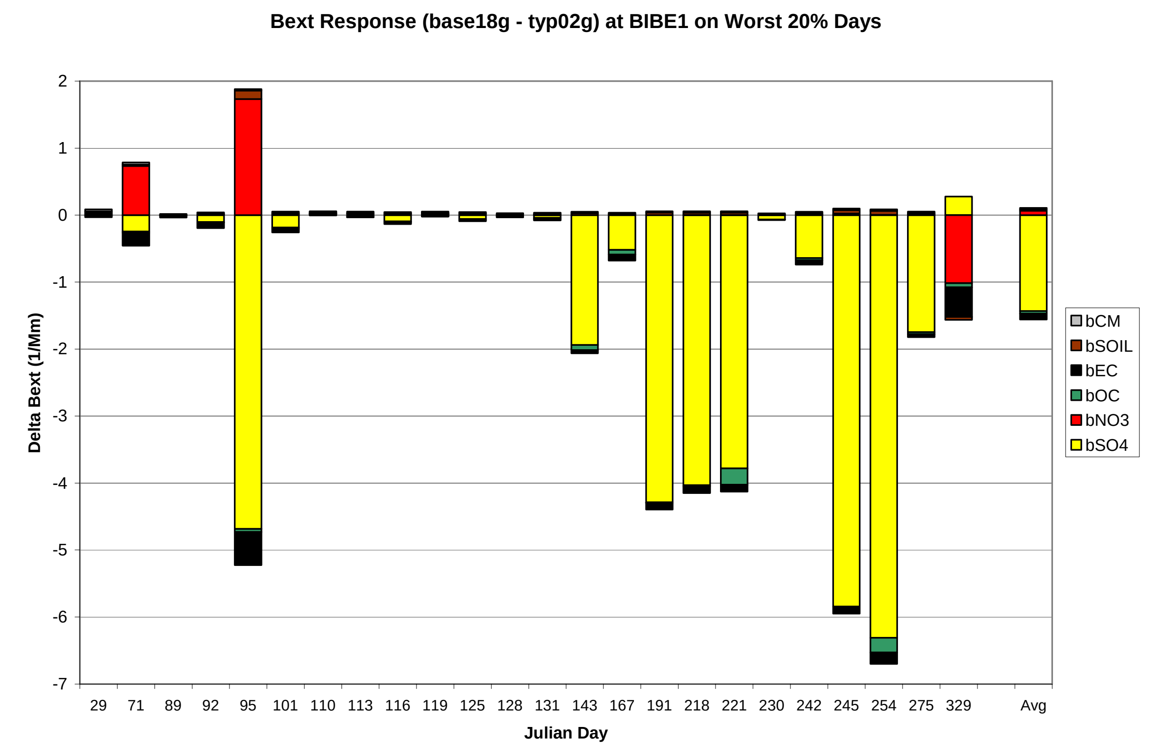


Figure D-9d. Differences in modeled 2002 and 2018 Base G CMAQ results (2018-2002) daily extinction for Big Bend (BIBE), Texas and Worst 20% (W20%) days in 2002.

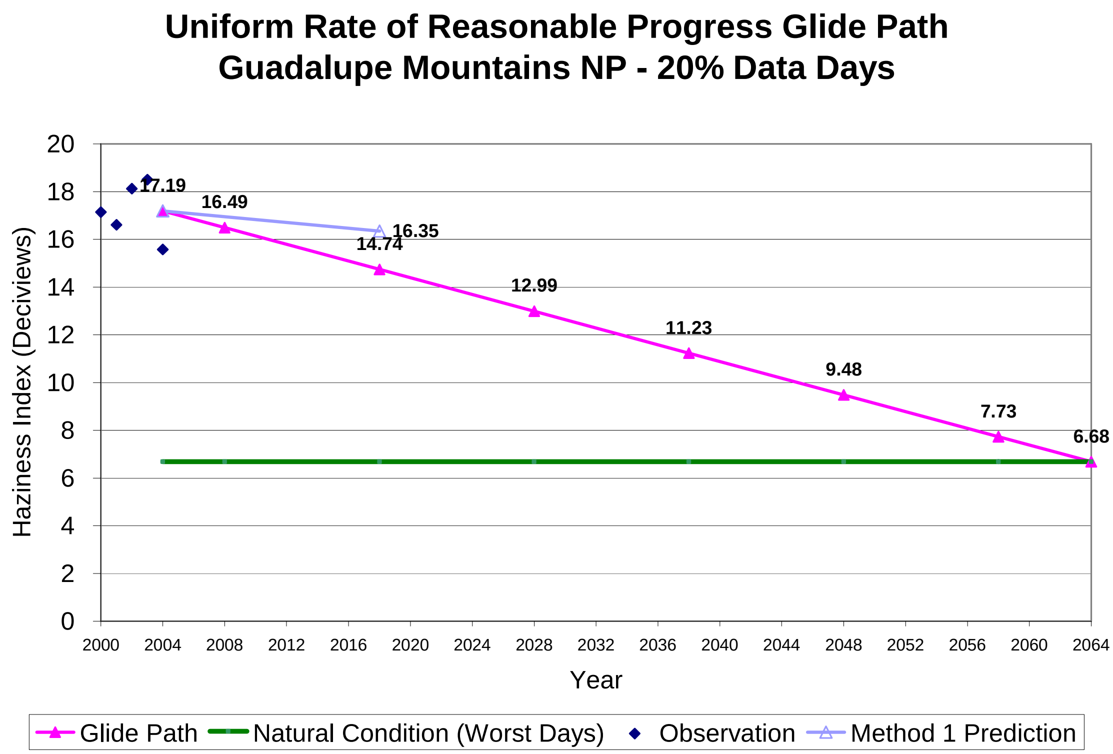


Figure D-10a. 2018 Visibility Projections and 2018 URP Glidepaths in deciview for Guadalupe Mountains (GUMO), Texas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

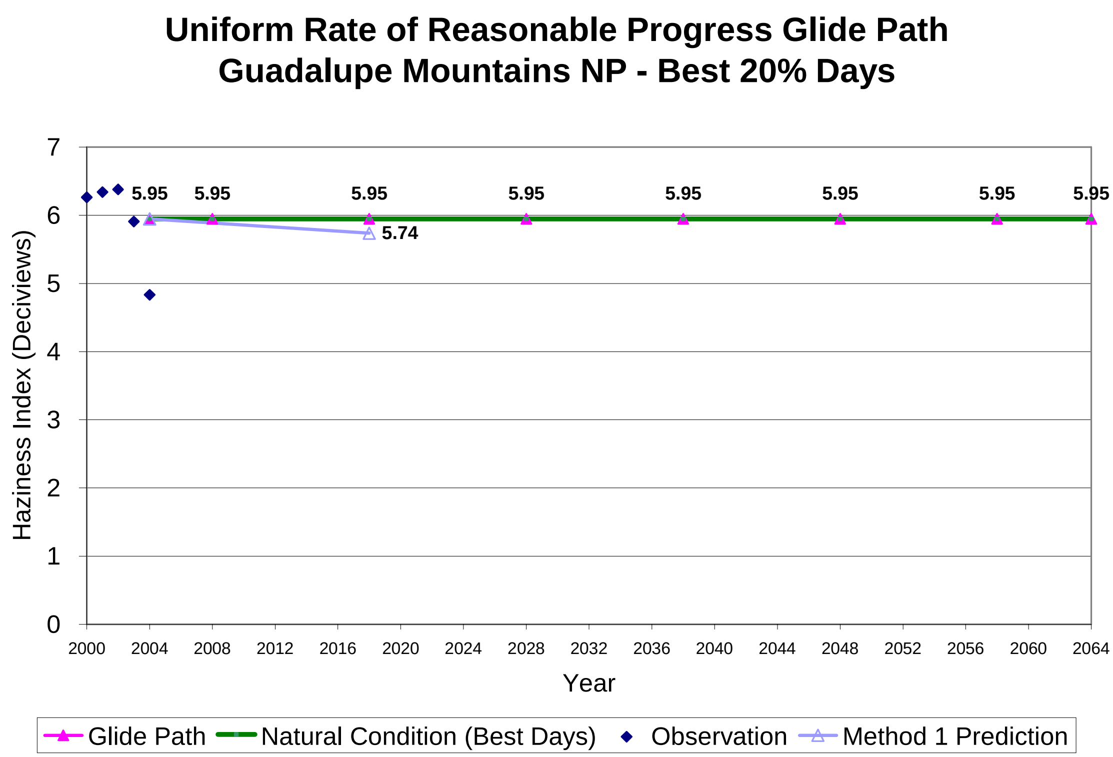


Figure D-10b. 2018 Visibility Projections and 2018 URP Glidepaths in deciview for Guadalupe Mountains (GUMO), Texas and Best 20% (B20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

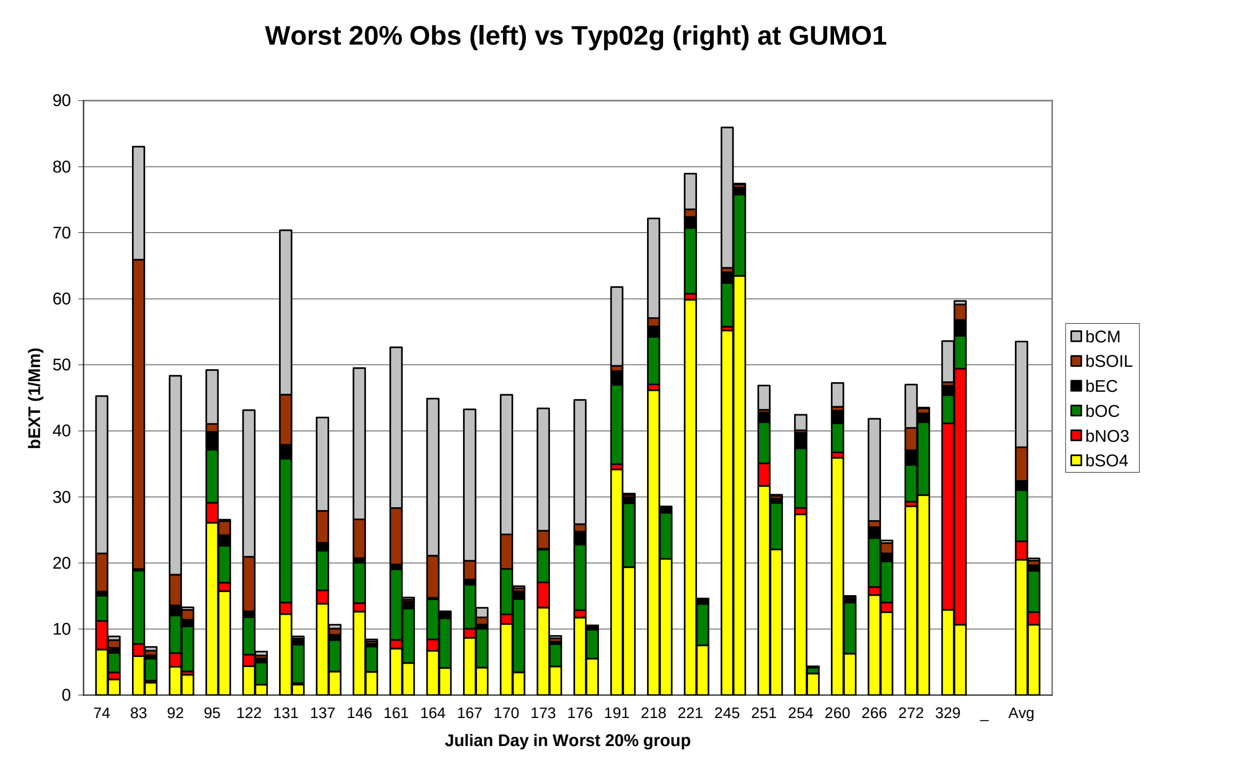


Figure D-10c. Comparison of observed (left) and 2002 Base G modeled (right) daily extinction for Guadalupe Mountains (GUMO), Texas and Worst 20% (W20%) days in 2002.

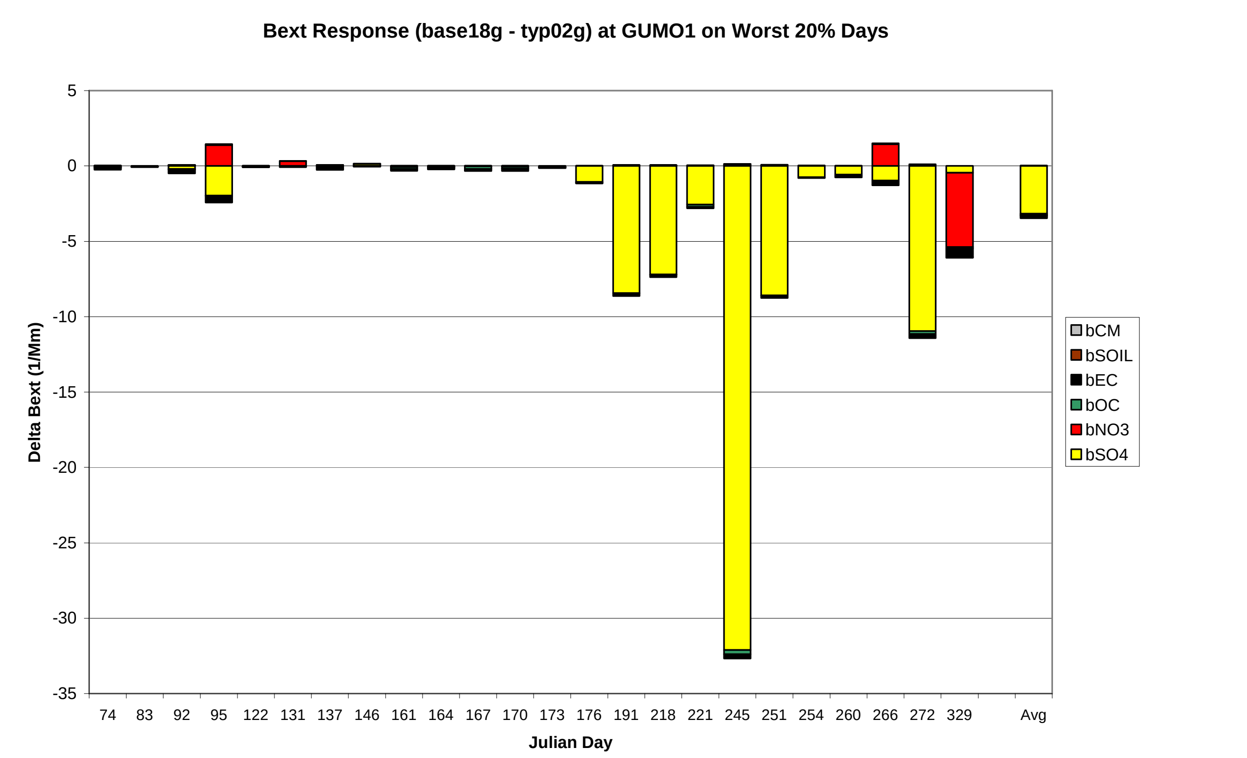


Figure D-10d. Differences in modeled 2002 and 2018 Base G CMAQ results (2018-2002) daily extinction for Guadalupe Mountains (GUMO), Texas and Worst 20% (W20%) days in 2002.

APPENDIX E

CAMx PM Source Apportionment Technology (PSAT) Extinction (Mm^{-1}) Contributions for the 2002 Worst and Best 20 Percent Days at CENRAP Class I Areas

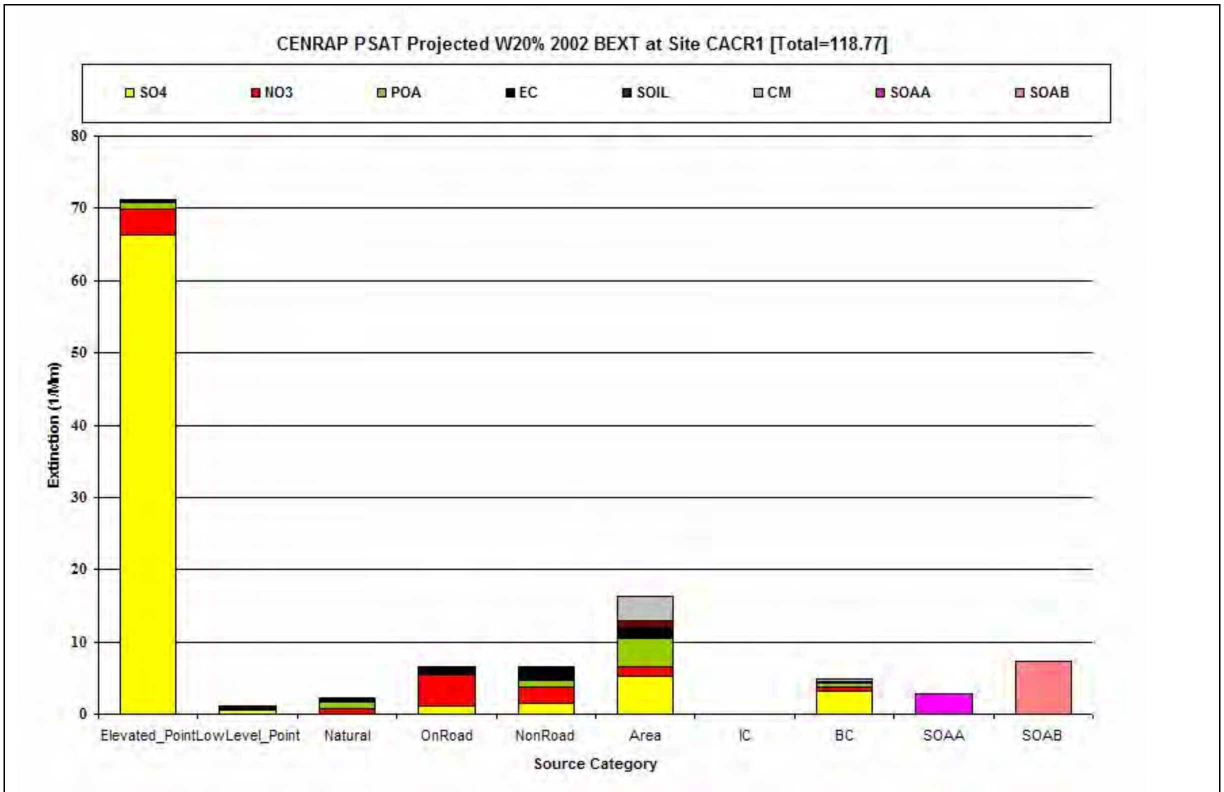


Figure E-1a. PSAT source categories by PM species contributions to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Worst 20% visibility days at Caney Creek (CACR), Arkansas.

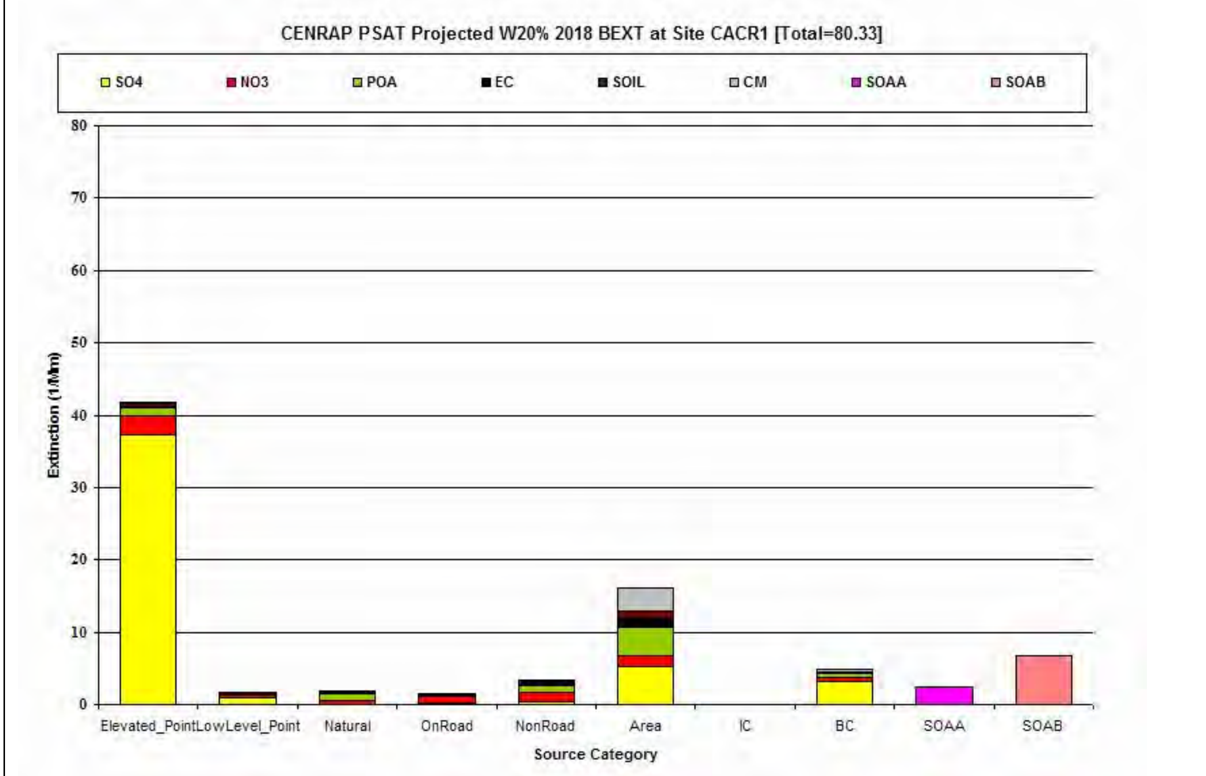


Figure E-1b. PSAT source category by PM species contributions to the average 2018 projected extinction (Mm^{-1}) for the Worst 20% visibility days at Caney Creek (CACR), Arkansas.

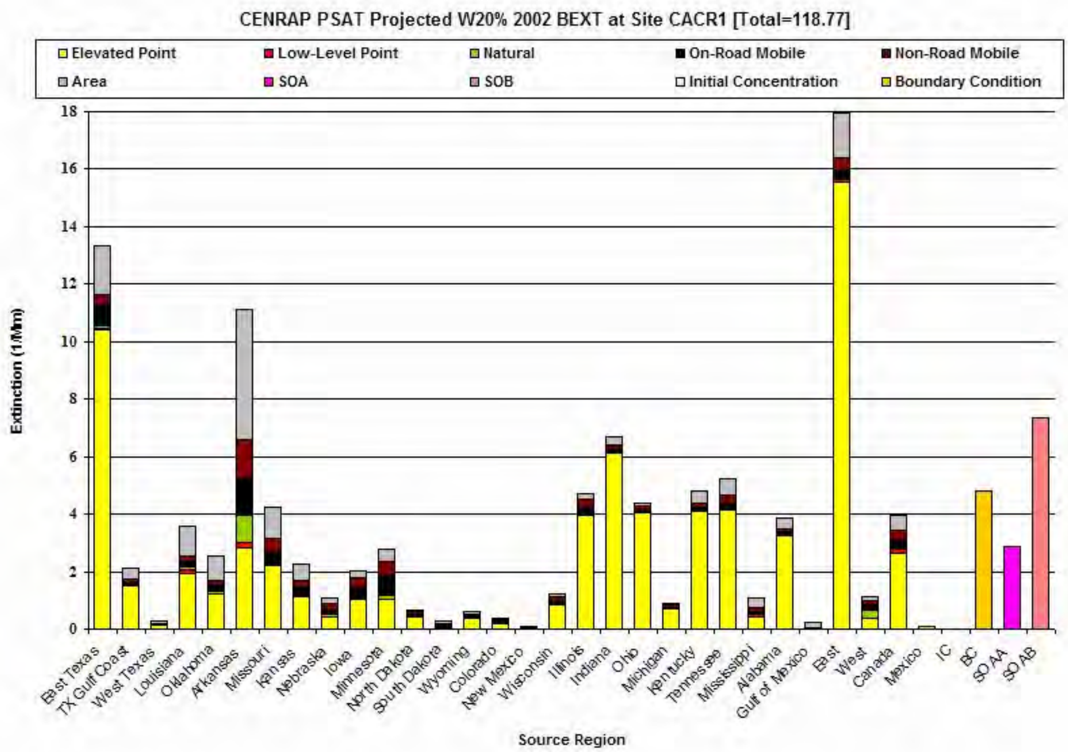


Figure E-1c. PSAT source region by source category contributions to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Worst 20% visibility days at Caney Creek (CACR), Arkansas.

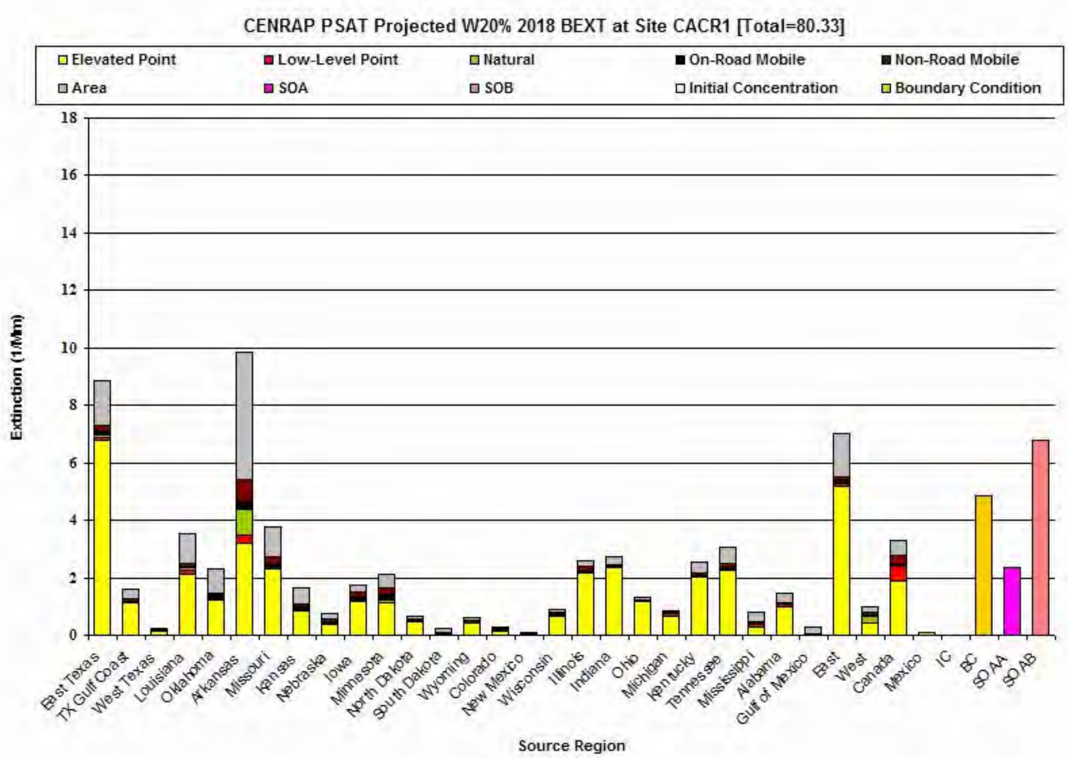


Figure E-1d. PSAT source region by source category contributions to the average 2018 extinction

(Mm^{-1}) for the Worst 20% visibility days at Caney Creek (CACR), Arkansas.

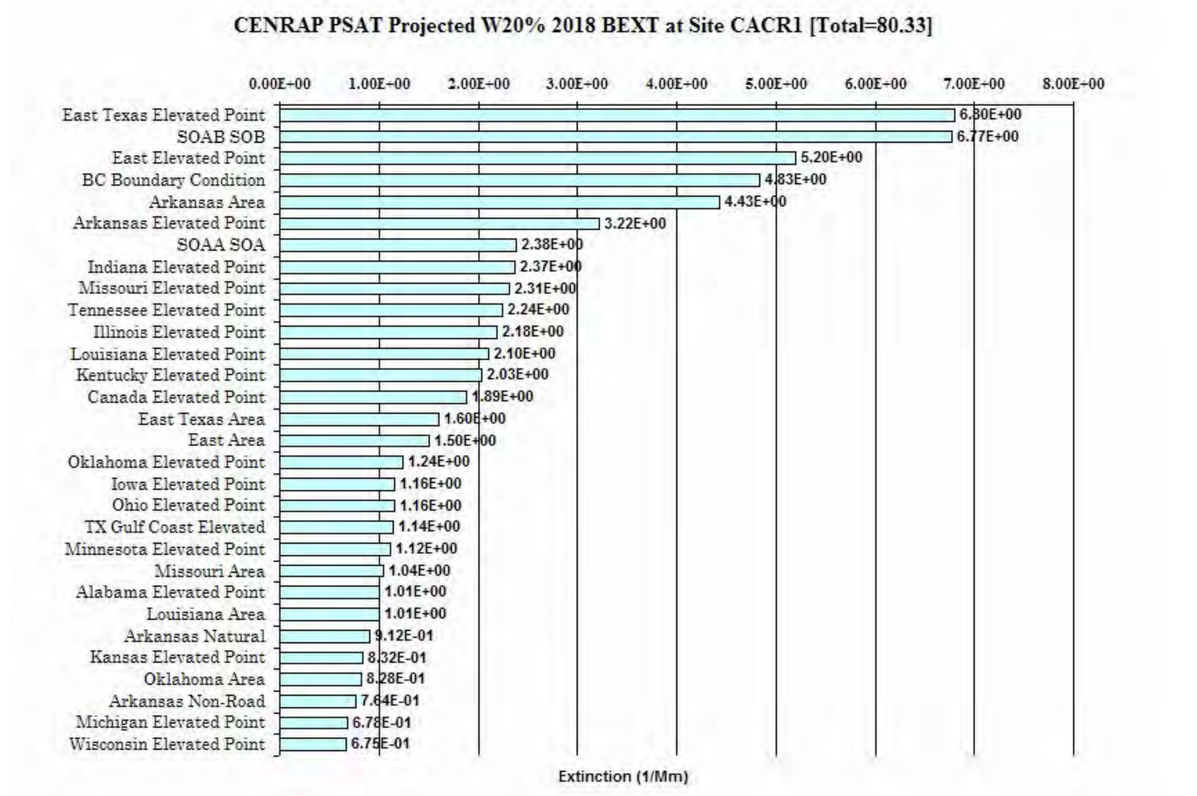
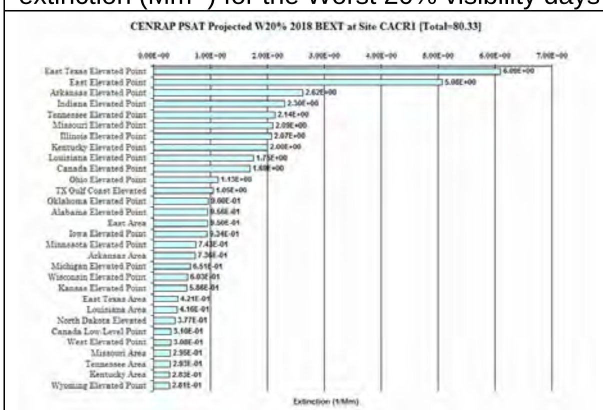


Figure E-1e. Ranked PSAT source region by source category contributions to the average 2018 extinction (Mm^{-1}) for the Worst 20% visibility days at Caney Creek (CACR), Arkansas



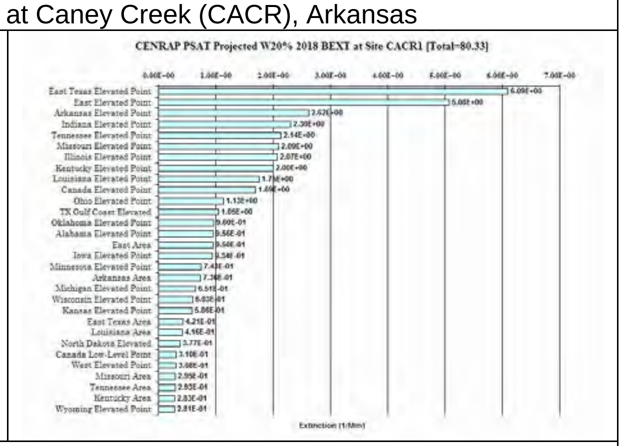


Figure E-1f. Ranked PSAT source region by source category contributions to the average 2018 SO4 (left) and NO3 (right) extinction (Mm^{-1}) for the Worst 20% visibility days at Caney Creek (CACR), Arkansas

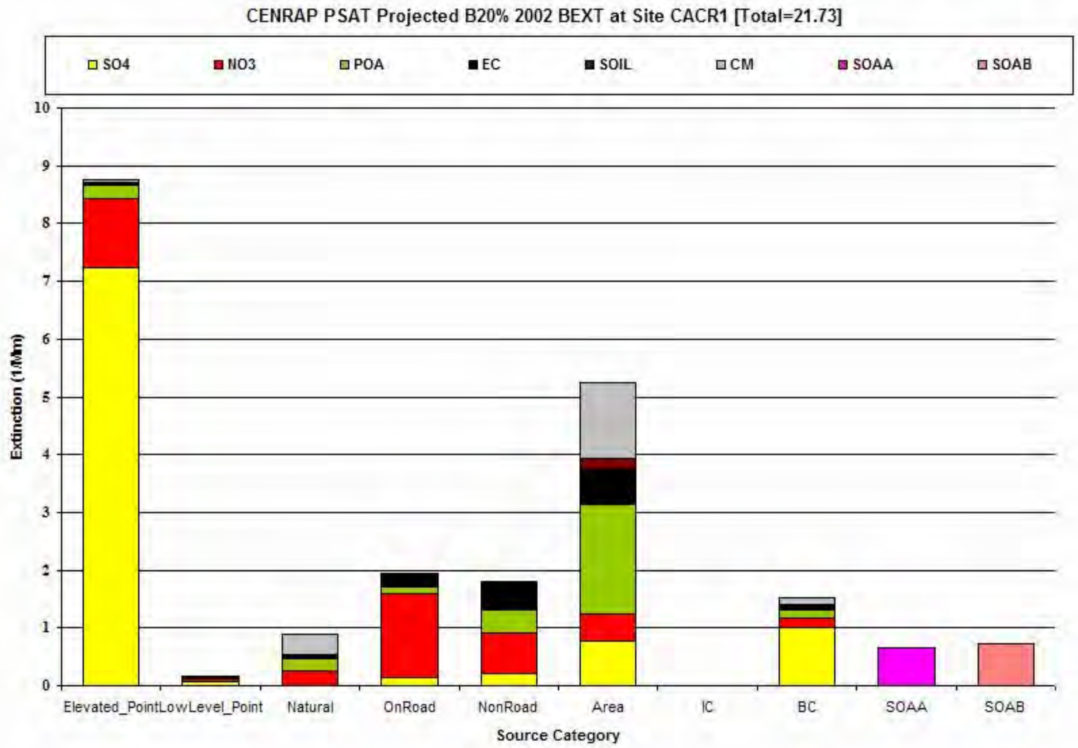


Figure E-1g. PSAT contributions by source category and PM species to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Best 20% visibility days at Caney Creek (CACR), Arkansas.

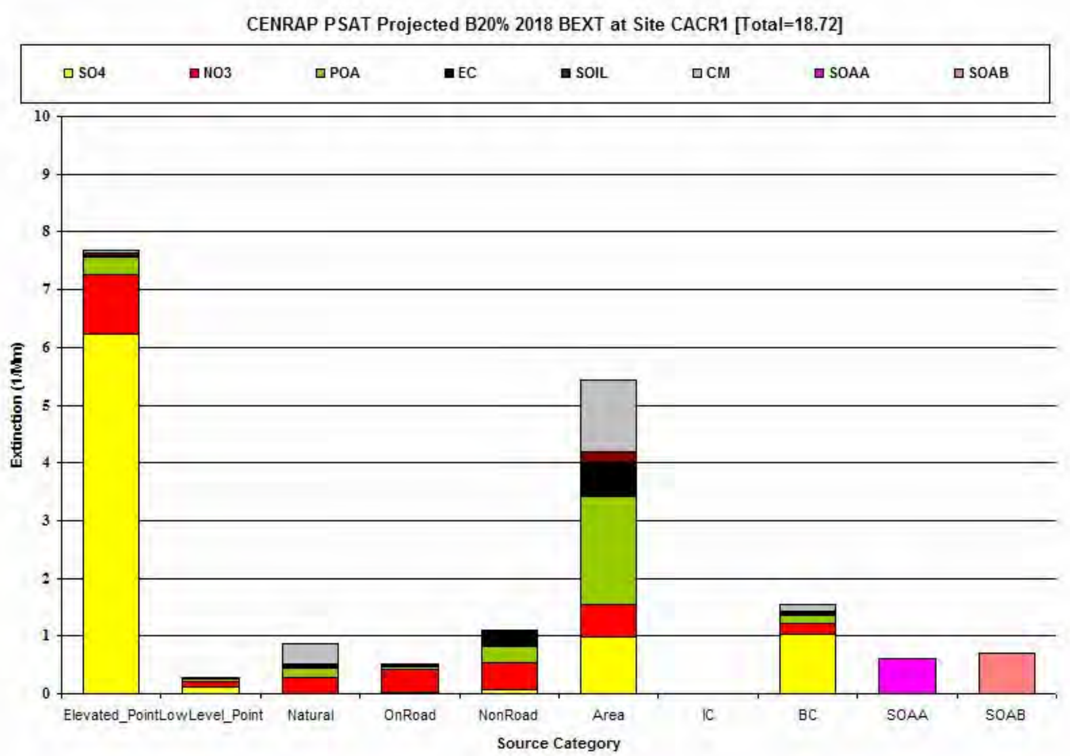


Figure E-1h. PSAT contributions by source category and PM species to the average 2018 extinction (Mm^{-1}) for the Best 20% visibility days at Caney Creek (CACR), Arkansas.

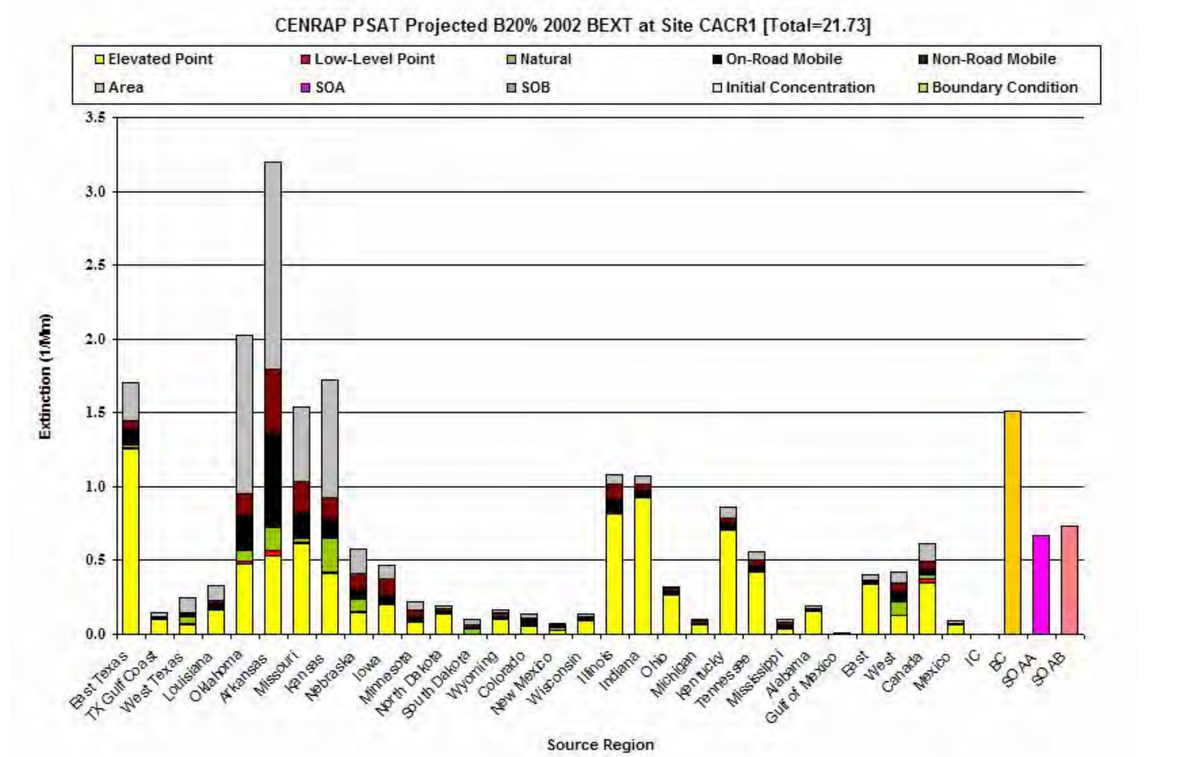


Figure E-1i. PSAT contributions by source region and source category to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Best 20% visibility days at Caney Creek (CACR), Arkansas.

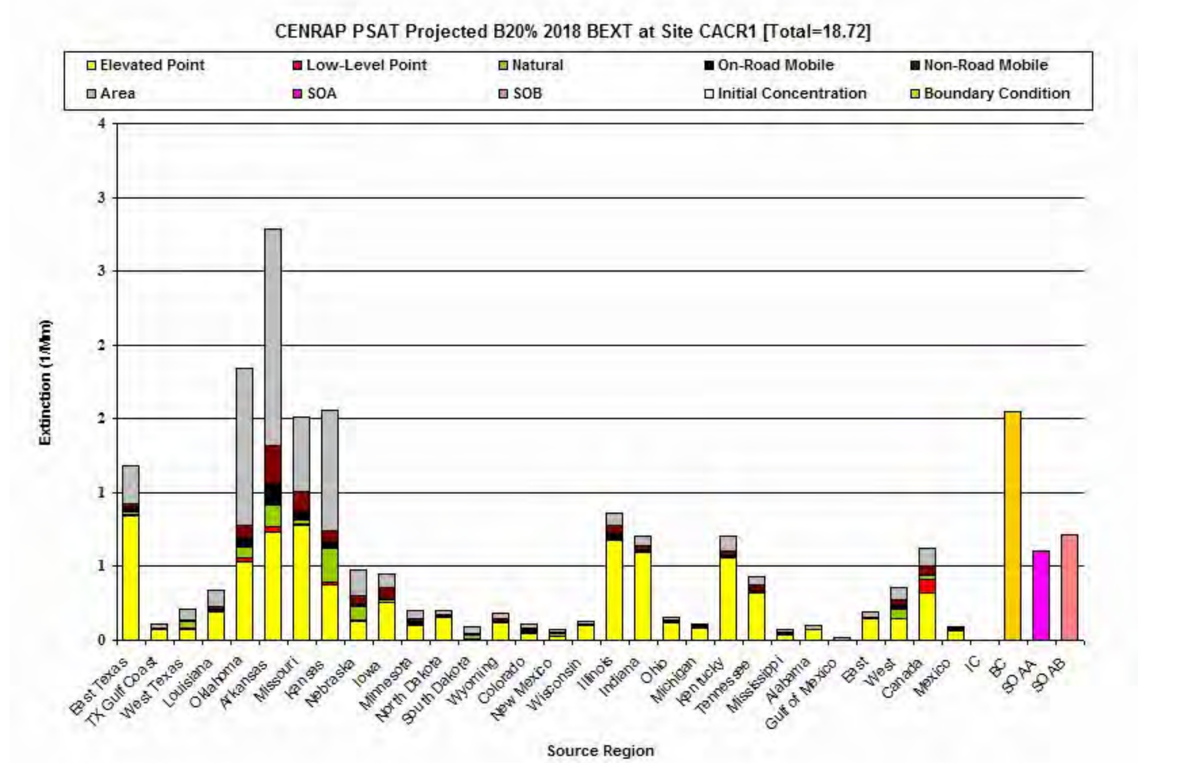


Figure E-1j. PSAT contributions by source region and source category to the average 2018 extinction (Mm^{-1}) for the Best 20% visibility days at Caney Creek (CACR), Arkansas.

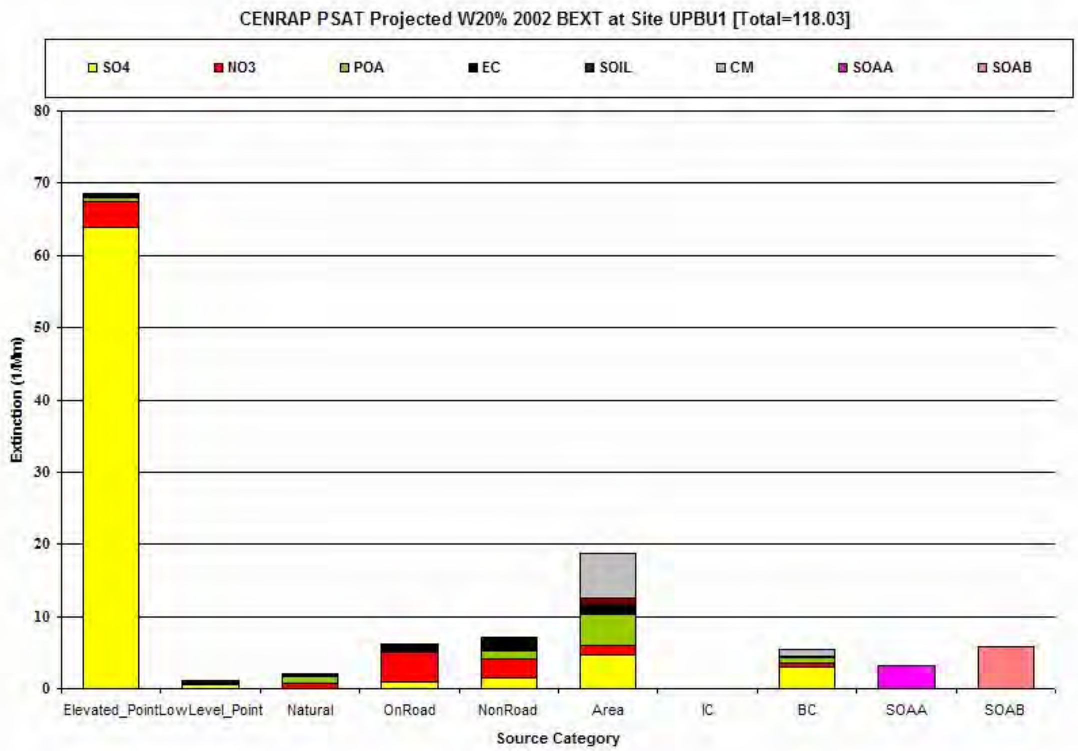


Figure E-2a. PSAT source categories by PM species contributions to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Worst 20% visibility days at Upper Buffalo (UPBU), Arkansas.

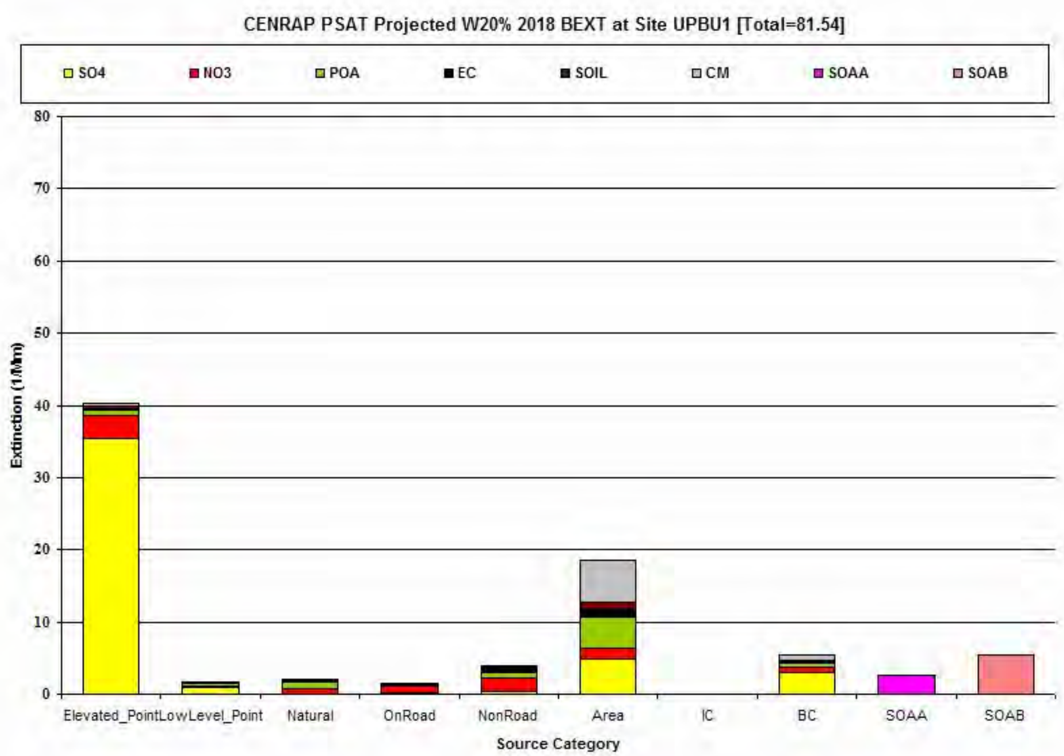


Figure E-2b. PSAT source category by PM species contributions to the average 2018 projected extinction (Mm^{-1}) for the Worst 20% visibility days at Upper Buffalo (UPBU), Arkansas.

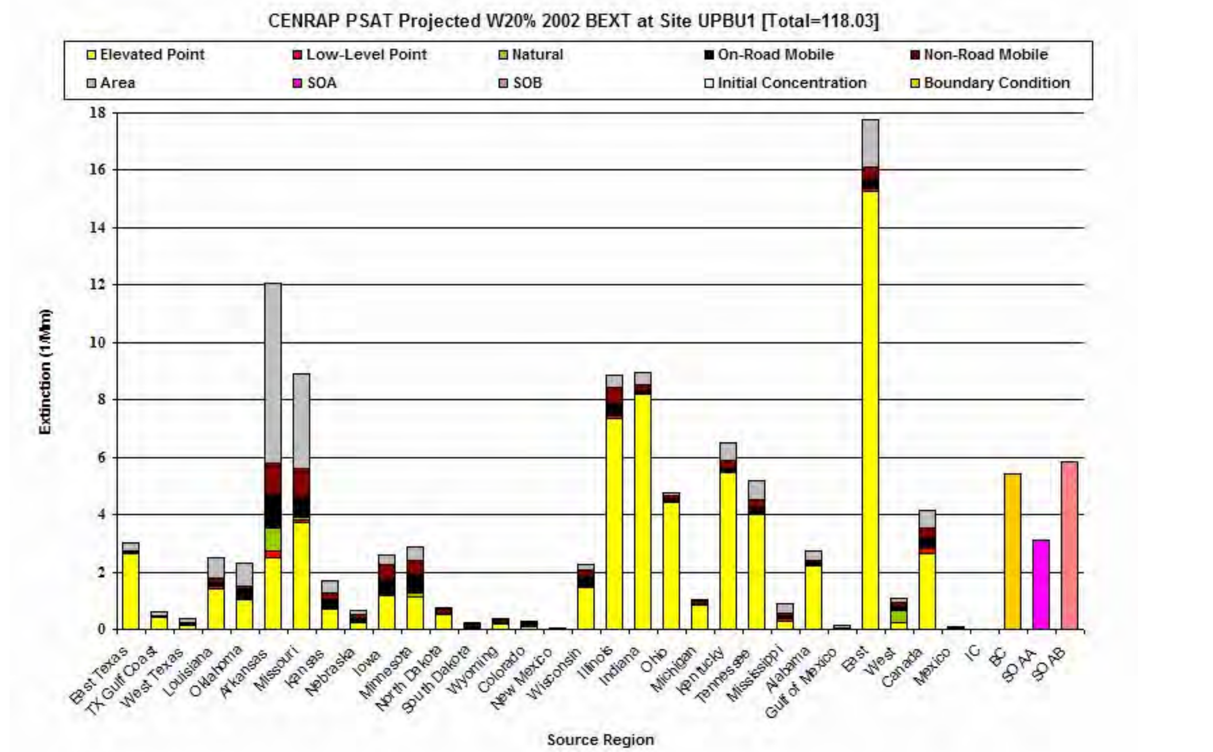


Figure E-2c. PSAT source region by source category contributions to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Worst 20% visibility days at Upper Buffalo (UPBU), Arkansas.

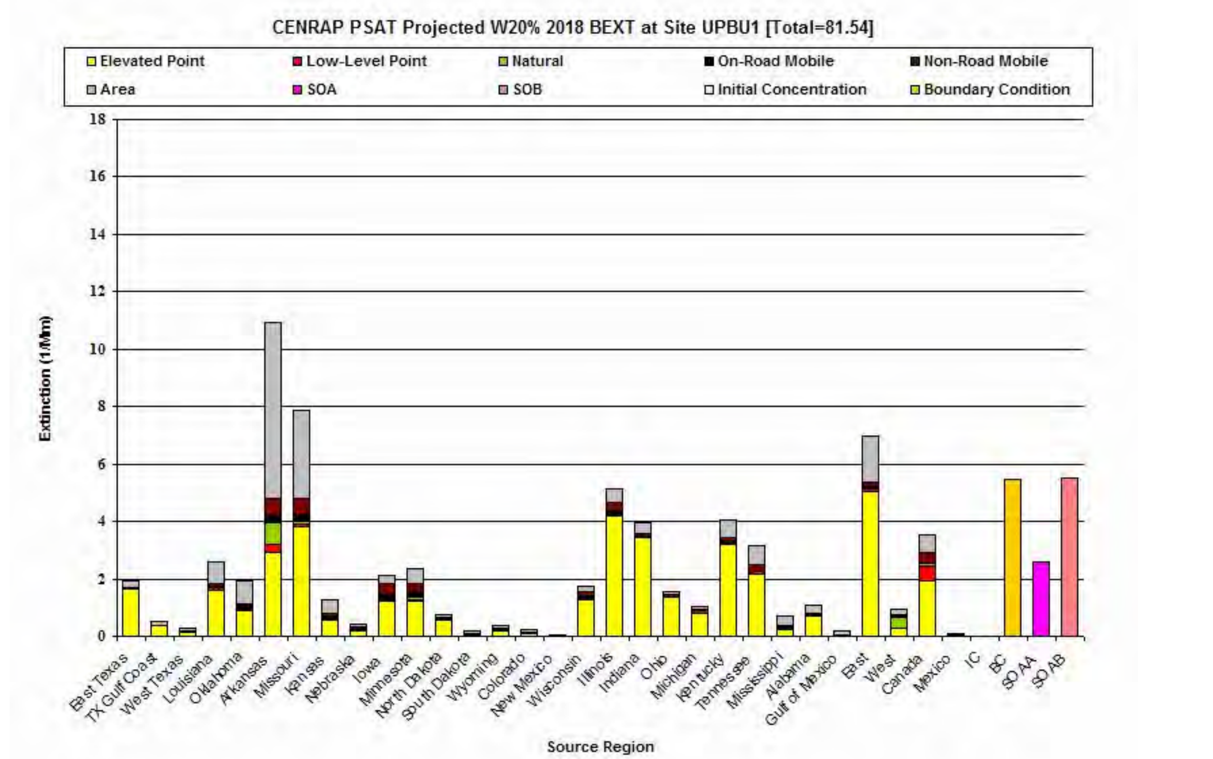


Figure E-2d. PSAT source region by source category contributions to the average 2018 extinction (Mm^{-1}) for the Worst 20% visibility days at Upper Buffalo (UPBU), Arkansas.

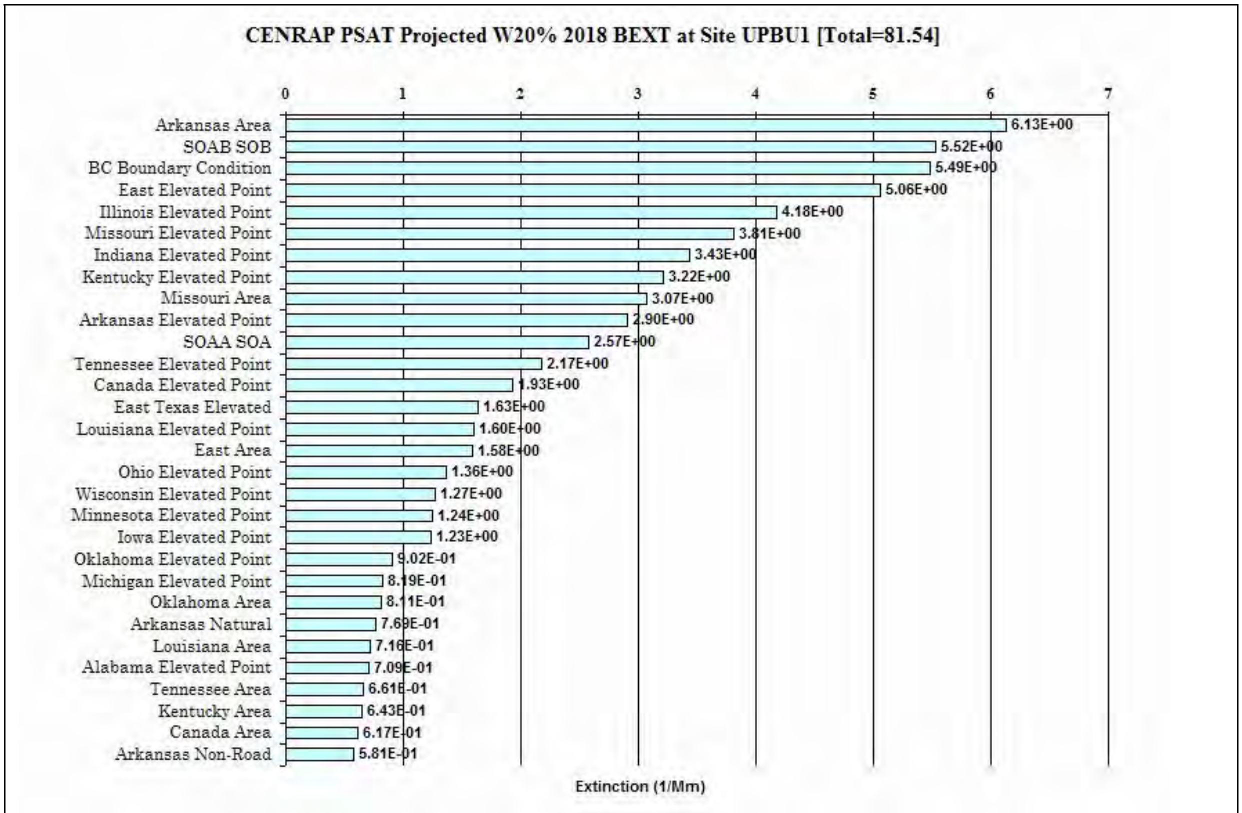
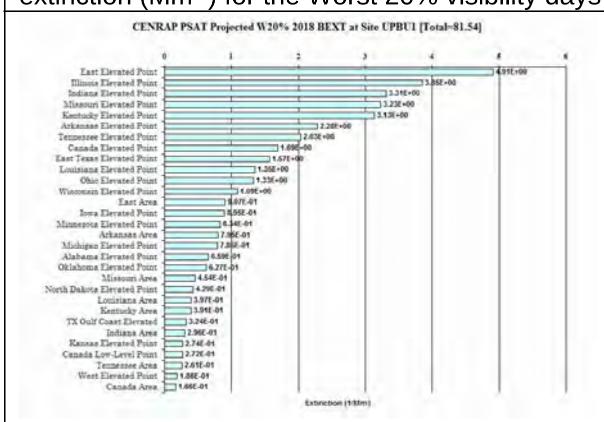


Figure E-2e. Ranked PSAT source region by source category contributions to the average 2018 extinction (Mm^{-1}) for the Worst 20% visibility days at Upper Buffalo (UPBU), Arkansas.



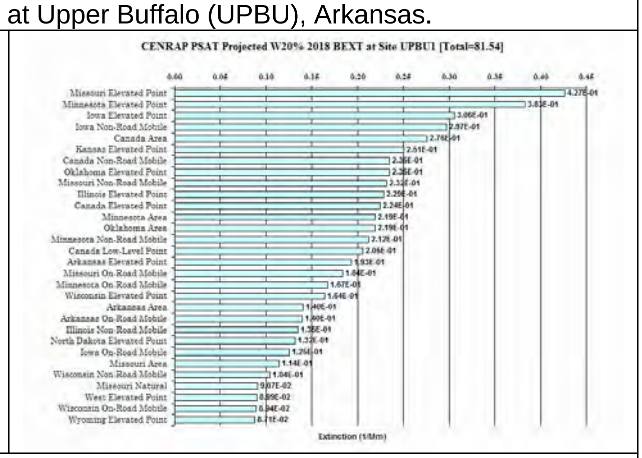


Figure E-2f. Ranked PSAT source region by source category contributions to the average 2018 SO4 (left) and NO3 (right) extinction (Mm^{-1}) for the Worst 20% visibility days at Upper Buffalo (UPBU), Arkansas.

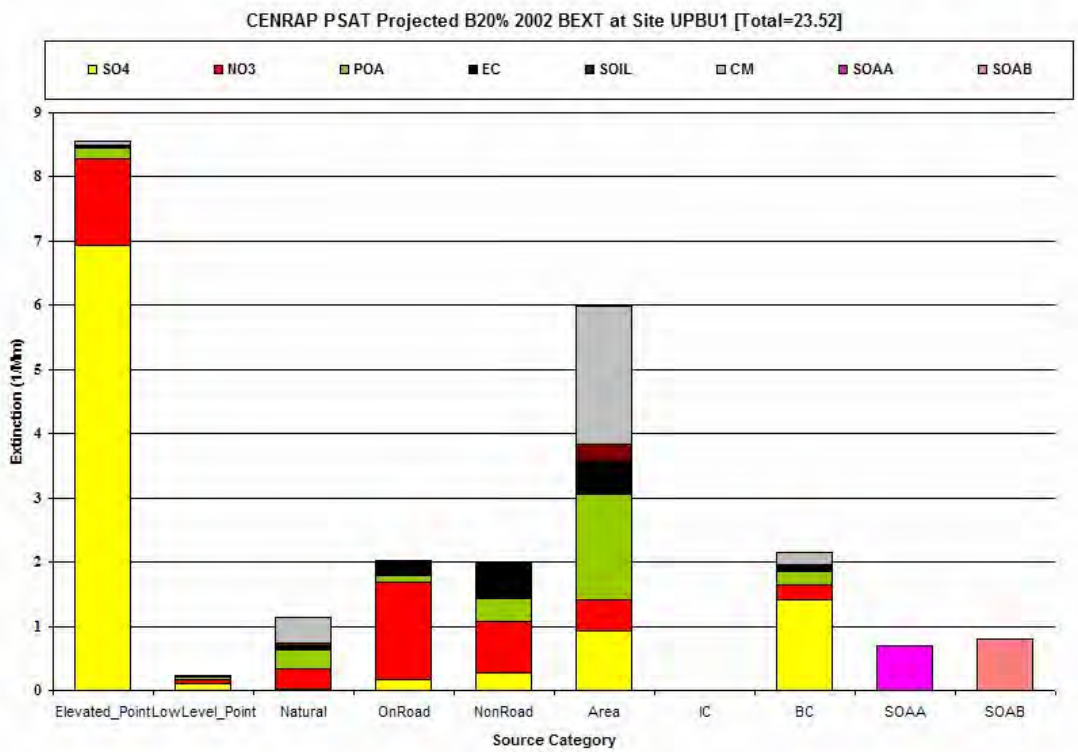


Figure E-2g. PSAT contributions by source category and PM species to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Best 20% visibility days at Upper Buffalo (UPBU), Arkansas.

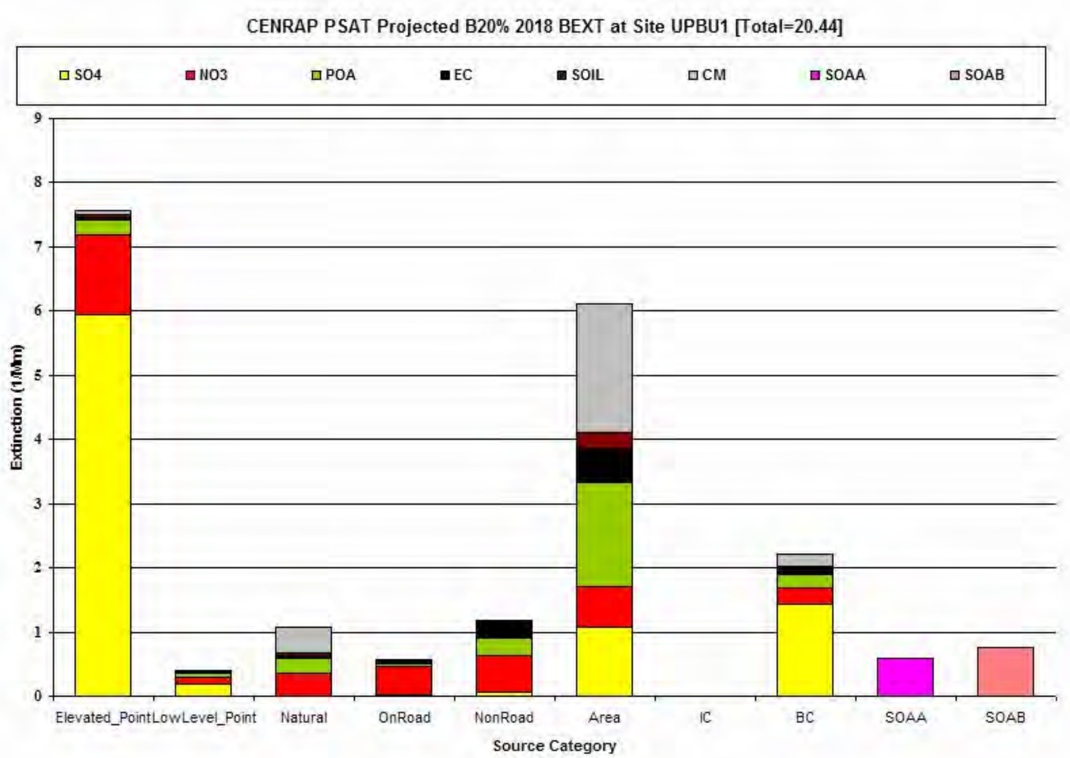


Figure E-2h. PSAT contributions by source category and PM species to the average 2018 extinction (Mm^{-1}) for the Best 20% visibility days at Upper Buffalo (UPBU), Arkansas.

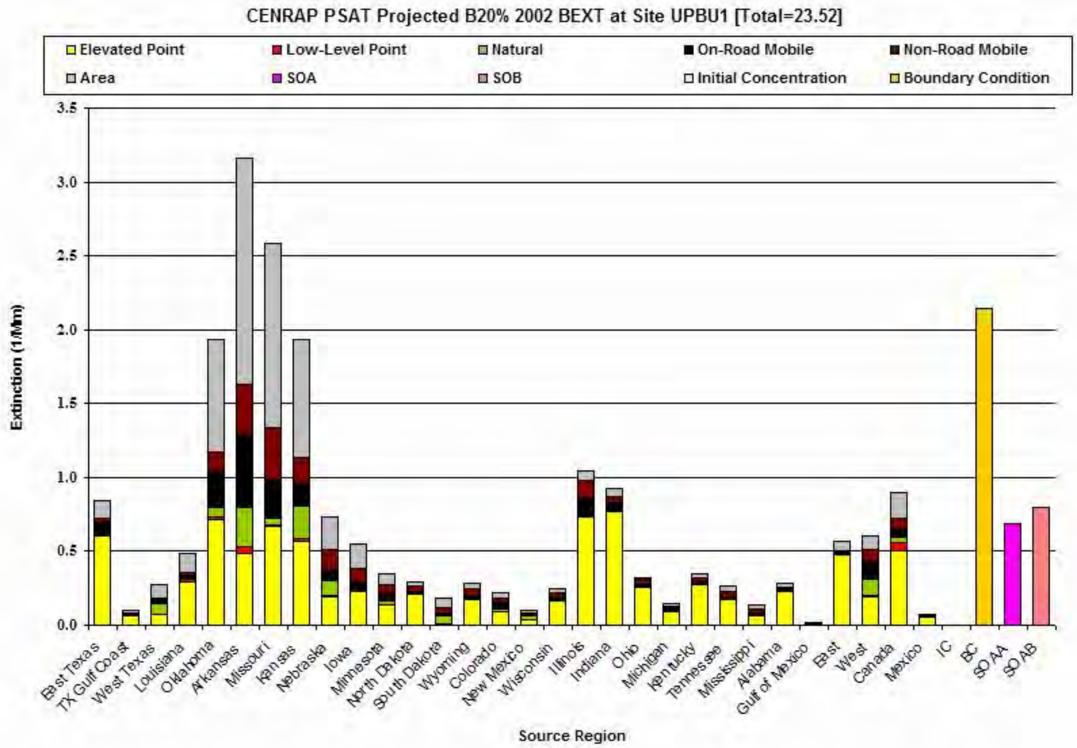


Figure E-2i. PSAT contributions by source region and source category to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Best 20% visibility days at Upper Buffalo (UPBU), Arkansas.

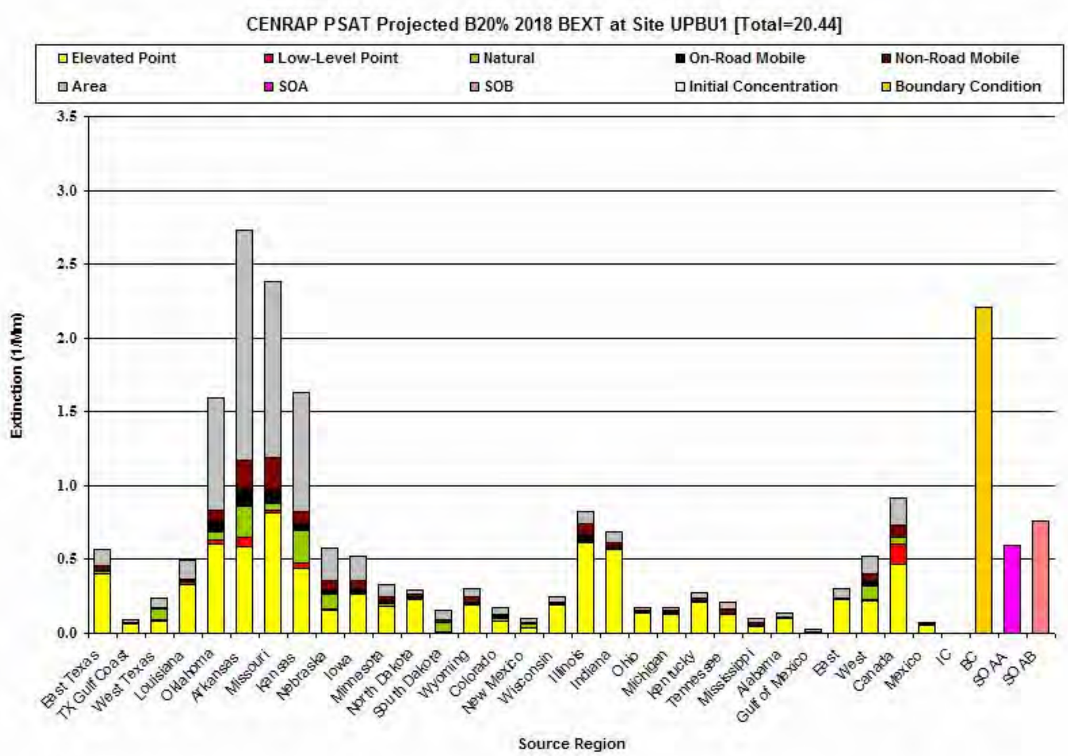


Figure E-2j. PSAT contributions by source region and source category to the average 2018 extinction (Mm^{-1}) for the Best 20% visibility days at Upper Buffalo (UPBU), Arkansas.

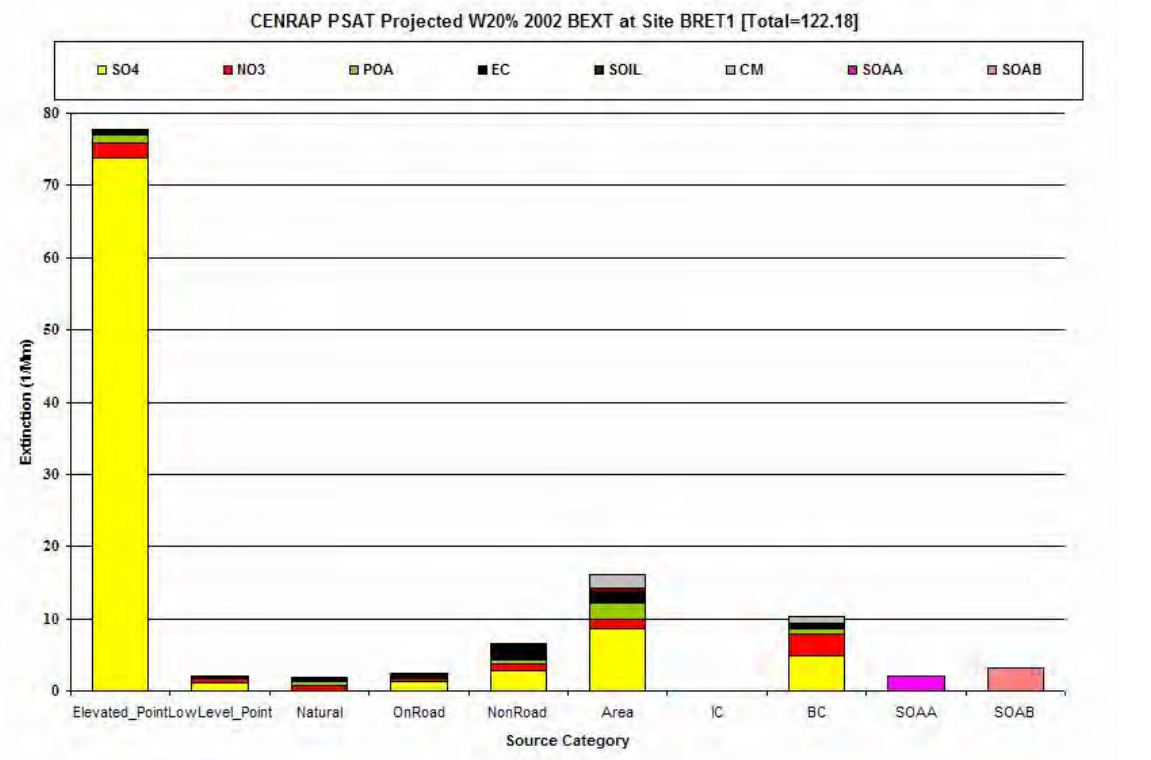


Figure E-3a. PSAT source categories by PM species contributions to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Worst 20% visibility days at Breton Island (BRET), Louisiana.

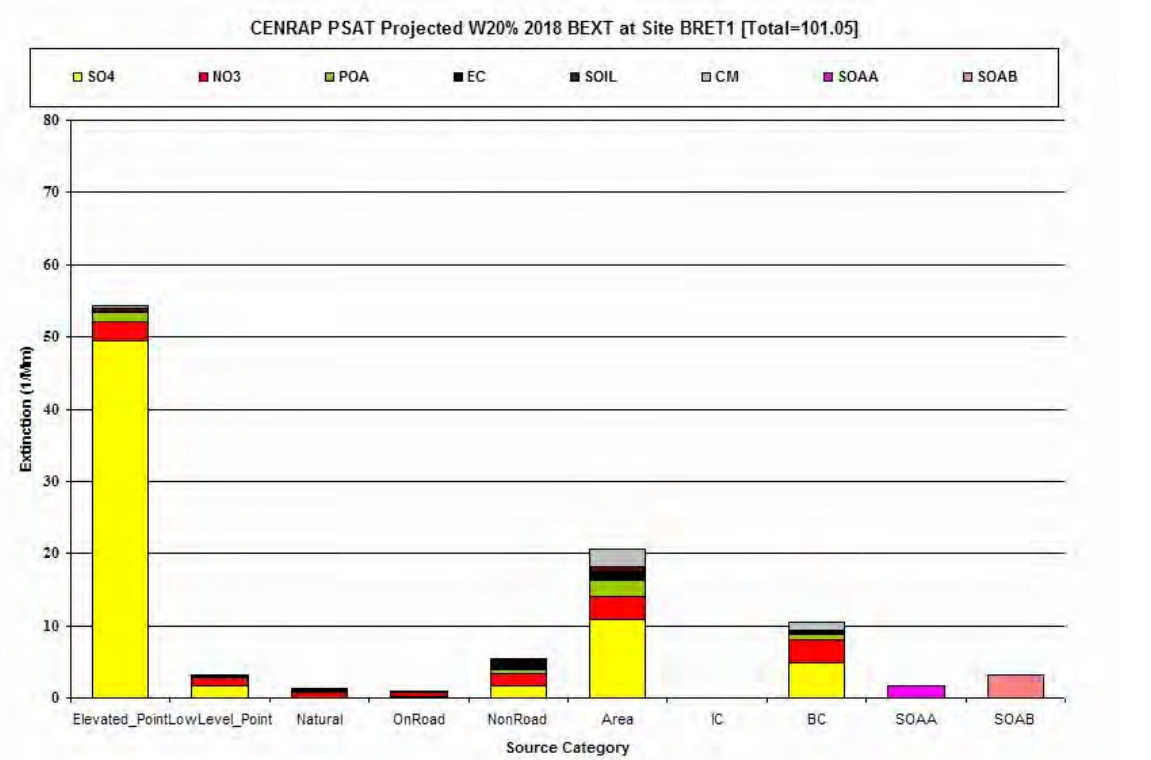


Figure E-3b. PSAT source category by PM species contributions to the average 2018 projected extinction (Mm^{-1}) for the Worst 20% visibility days at Breton Island (BRET), Louisiana.

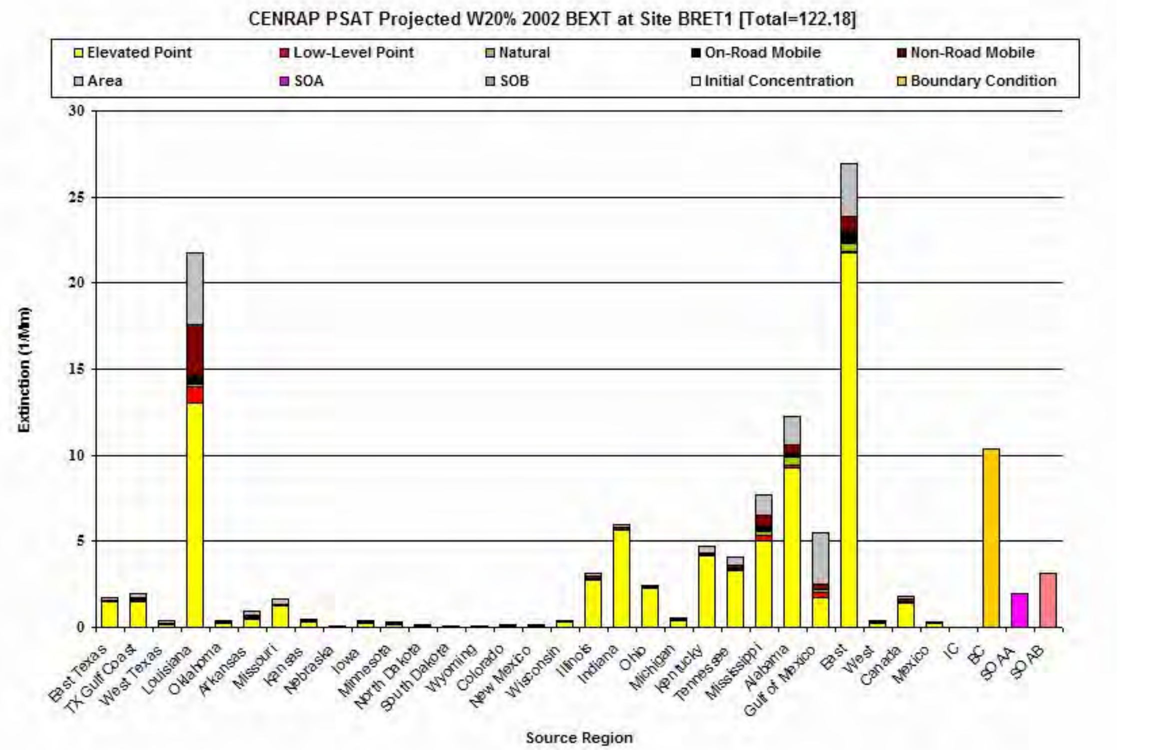


Figure E-3c. PSAT source region by source category contributions to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Worst 20% visibility days at Breton Island (BRET), Louisiana.

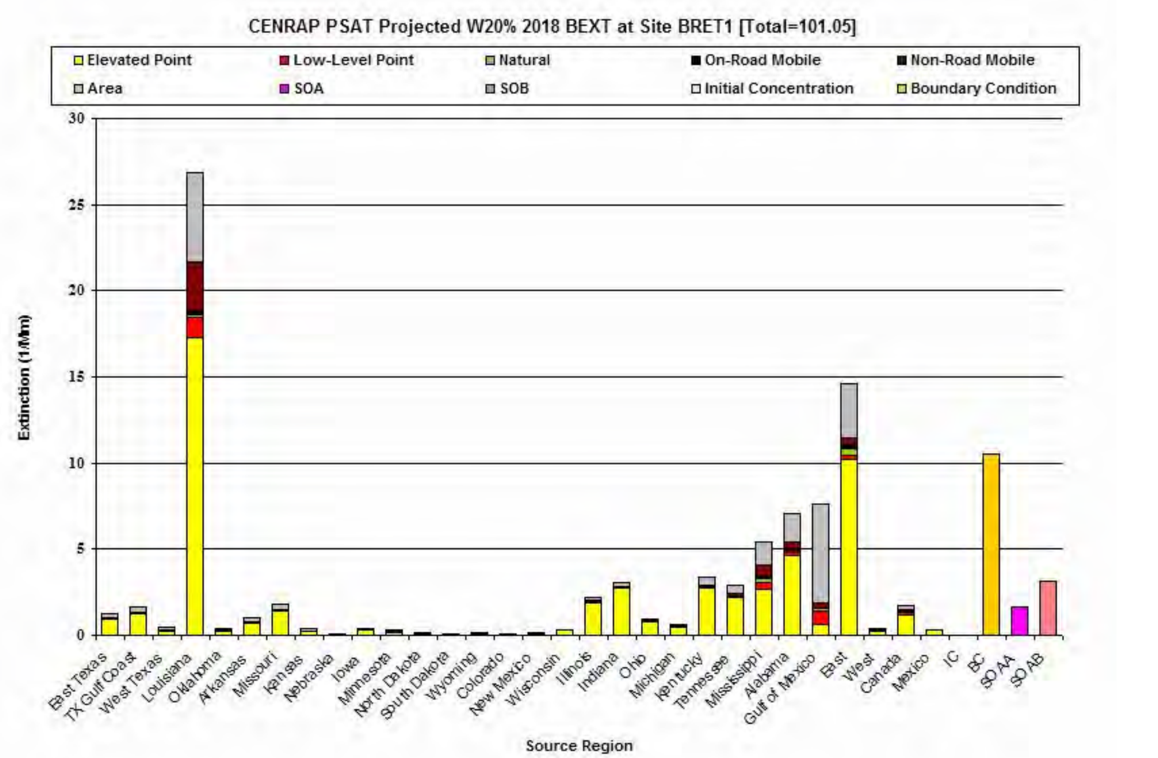


Figure E-3d. PSAT source region by source category contributions to the average 2018 extinction (Mm^{-1}) for the Worst 20% visibility days at Breton Island (BRET), Louisiana.

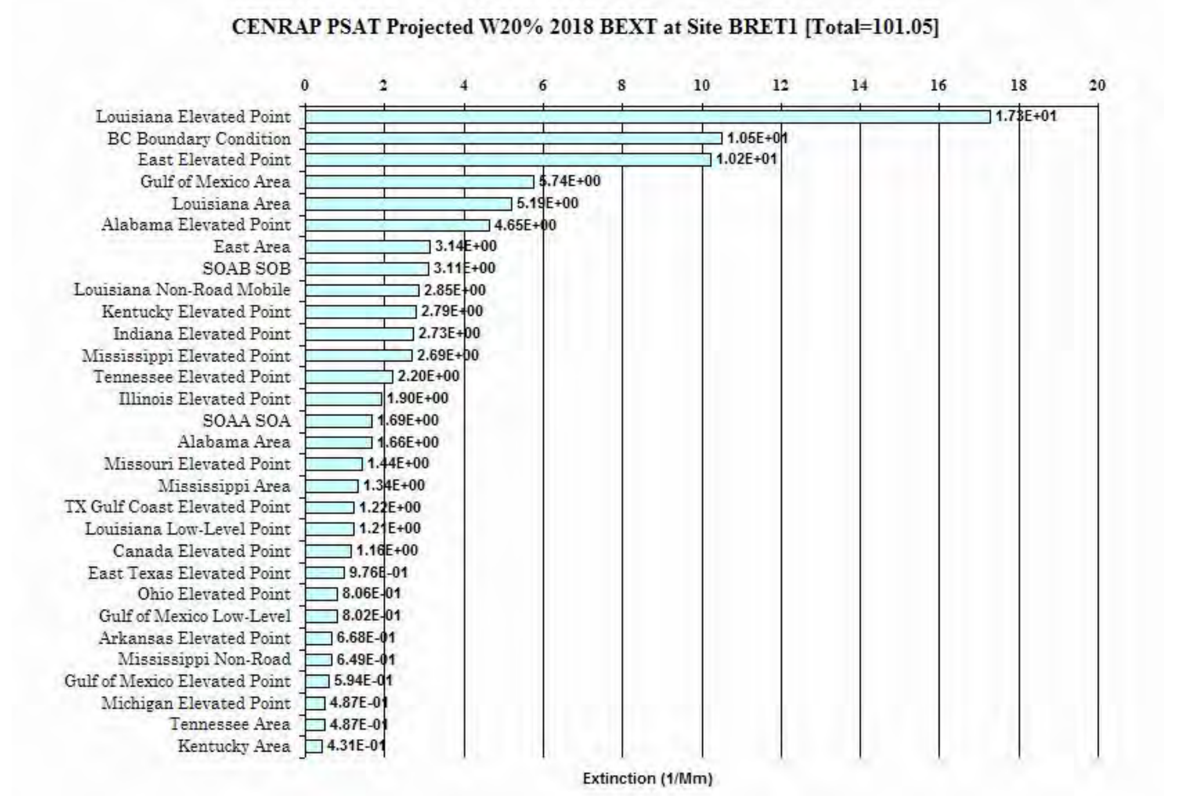
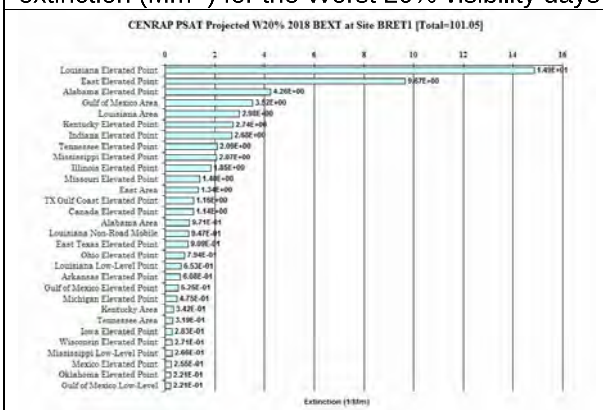


Figure E-3e. Ranked PSAT source region by source category contributions to the average 2018 extinction (Mm^{-1}) for the Worst 20% visibility days at Breton Island (BRET), Louisiana.



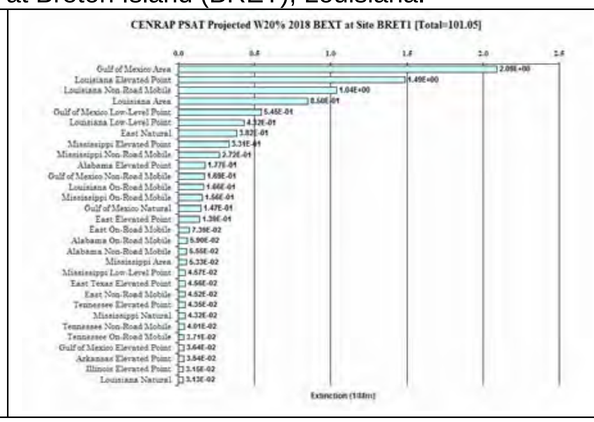


Figure E-3f. Ranked PSAT source region by source category contributions to the average 2018 SO4 (left) and NO3 (right) extinction (Mm^{-1}) for the Worst 20% visibility days at Breton Island (BRET), Louisiana.

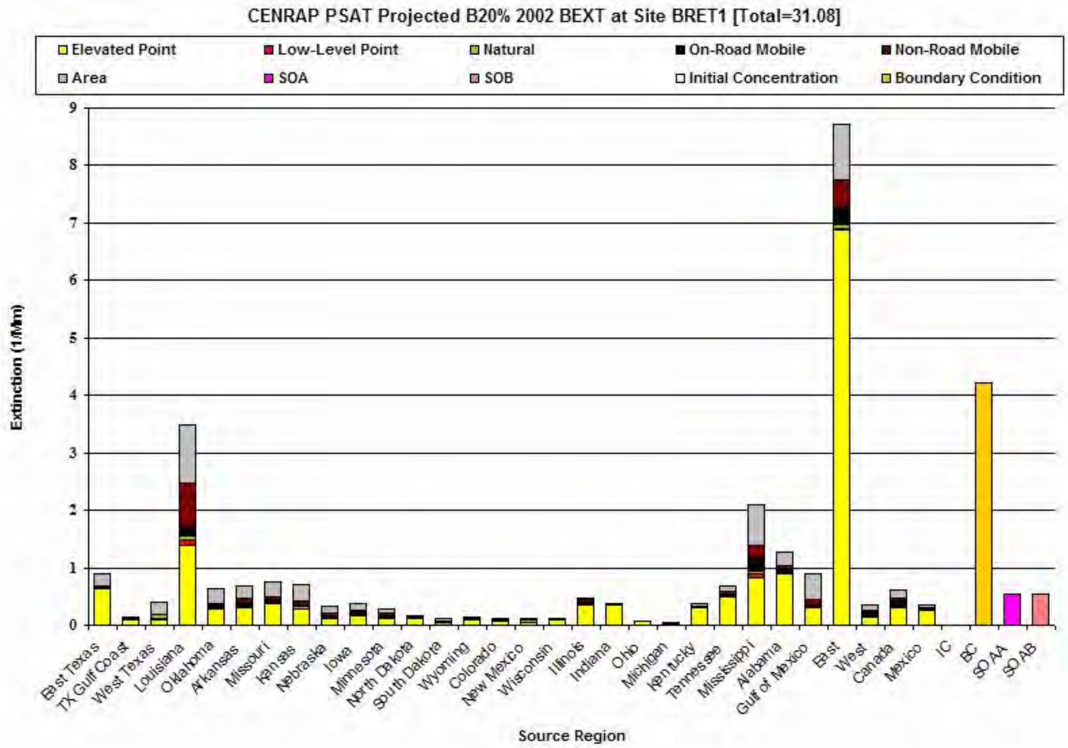


Figure E-3g. PSAT contributions by source category and PM species to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Best 20% visibility days at Breton Island (BRET), Louisiana.

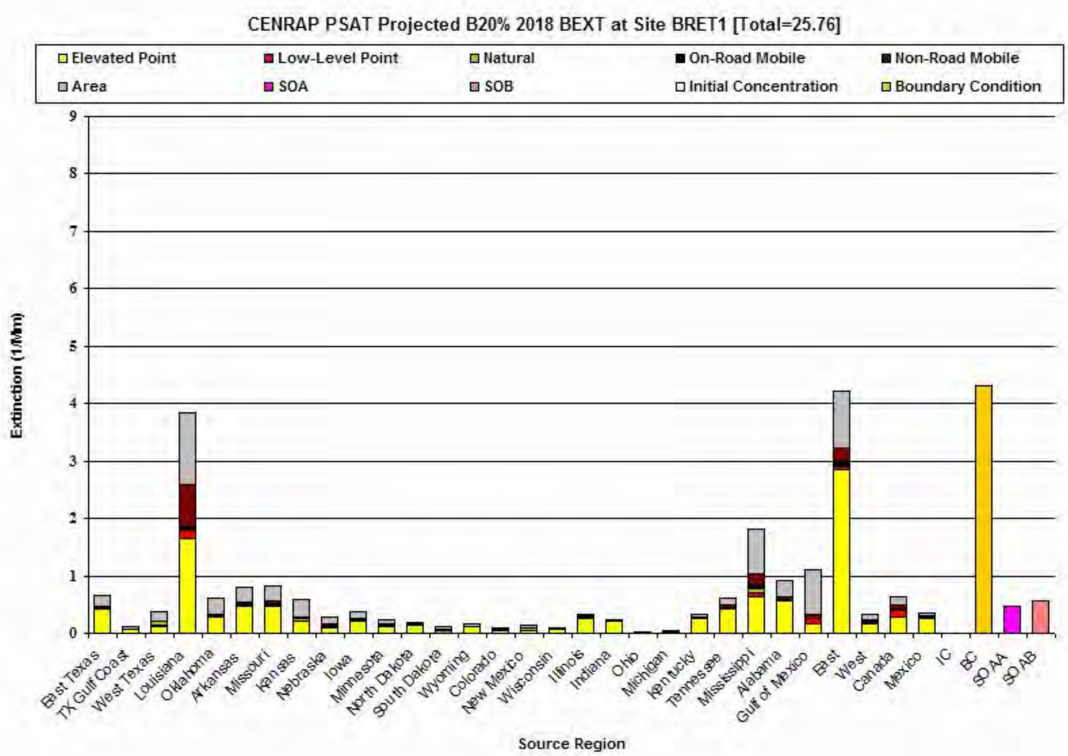


Figure E-3h. PSAT contributions by source category and PM species to the average 2018 extinction (Mm^{-1}) for the Best 20% visibility days at Breton Island (BRET), Louisiana.

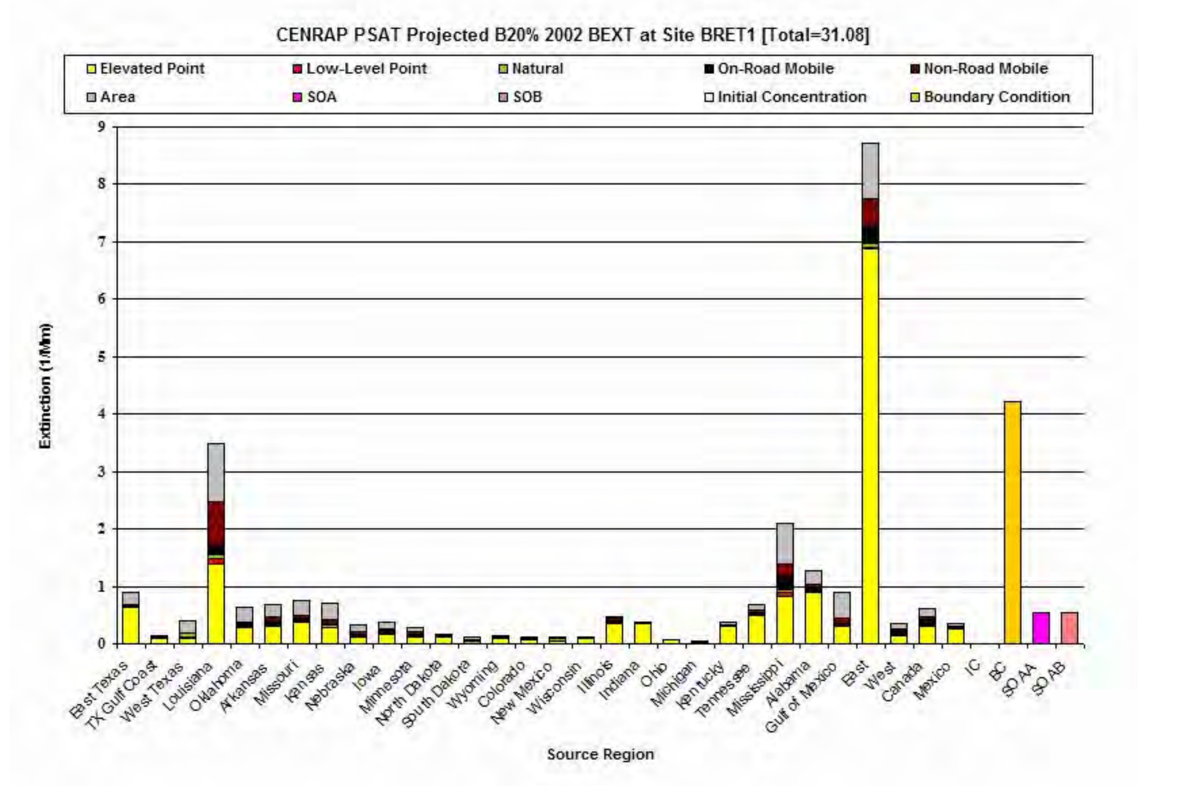


Figure E-3i. PSAT contributions by source region and source category to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Best 20% visibility days at Breton Island (BRET), Louisiana.

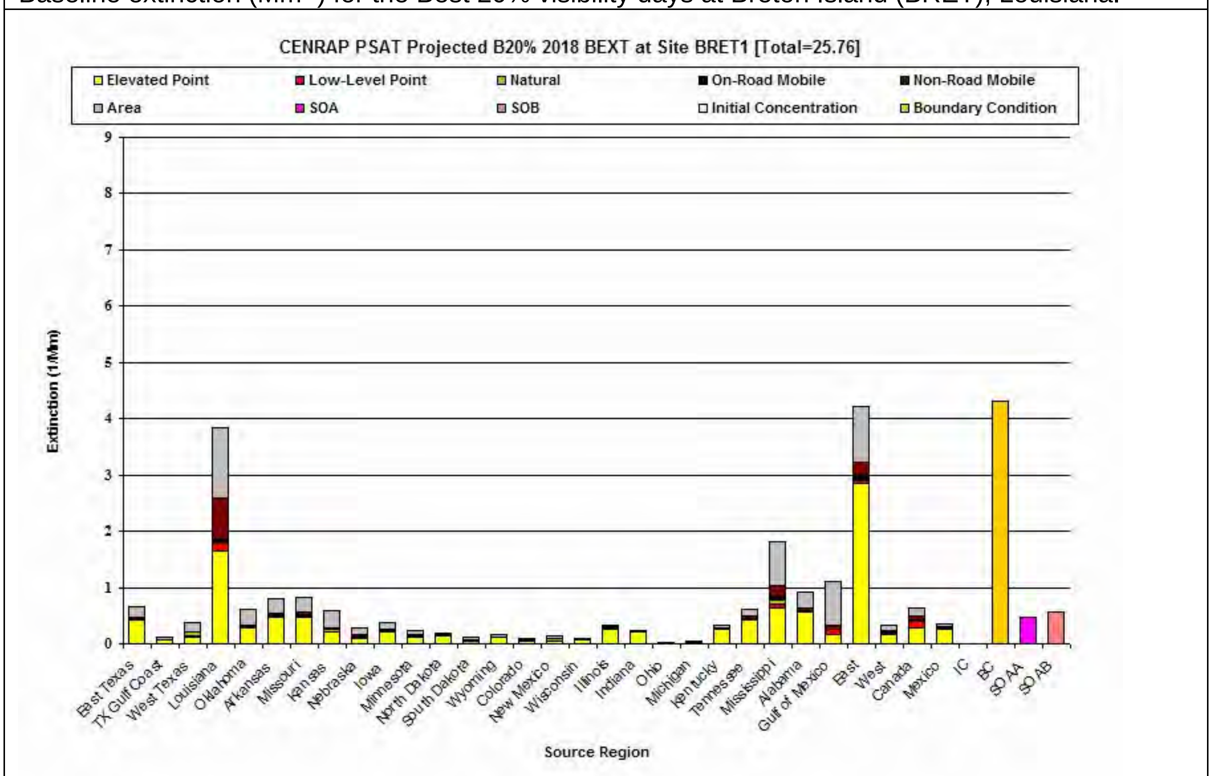


Figure E-3j. PSAT contributions by source region and source category to the average 2018 extinction (Mm^{-1}) for the Best 20% visibility days at Breton Island (BRET), Louisiana.

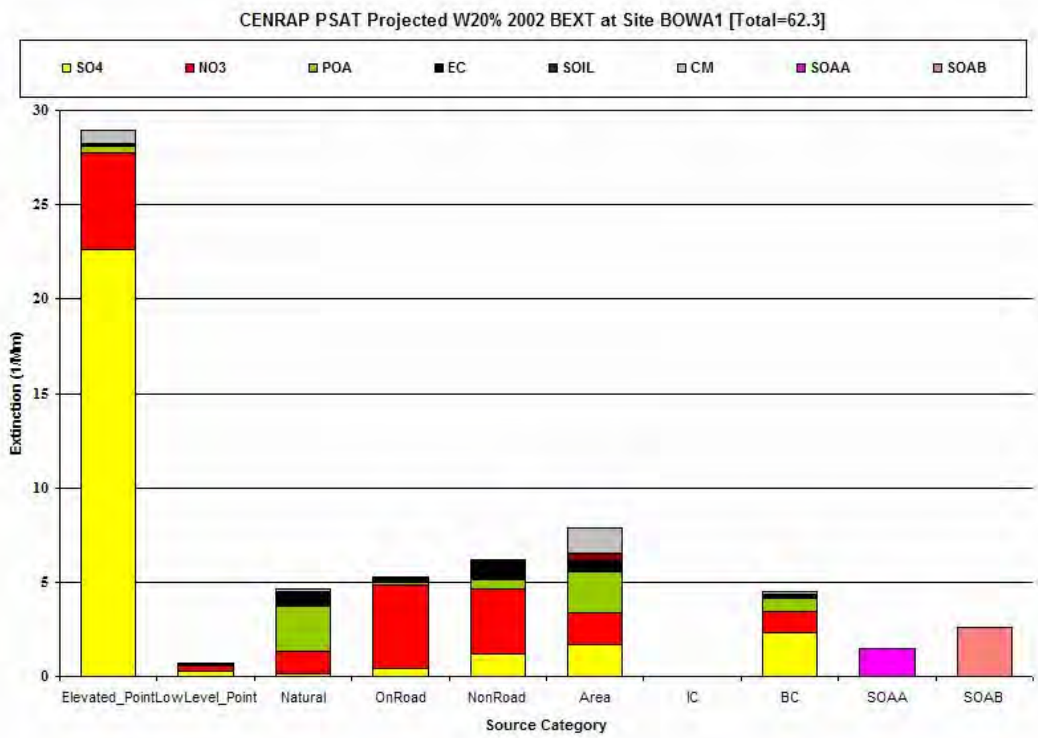


Figure E-4a. PSAT source categories by PM species contributions to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Worst 20% visibility days at Boundary Waters (BOWA), Minnesota.

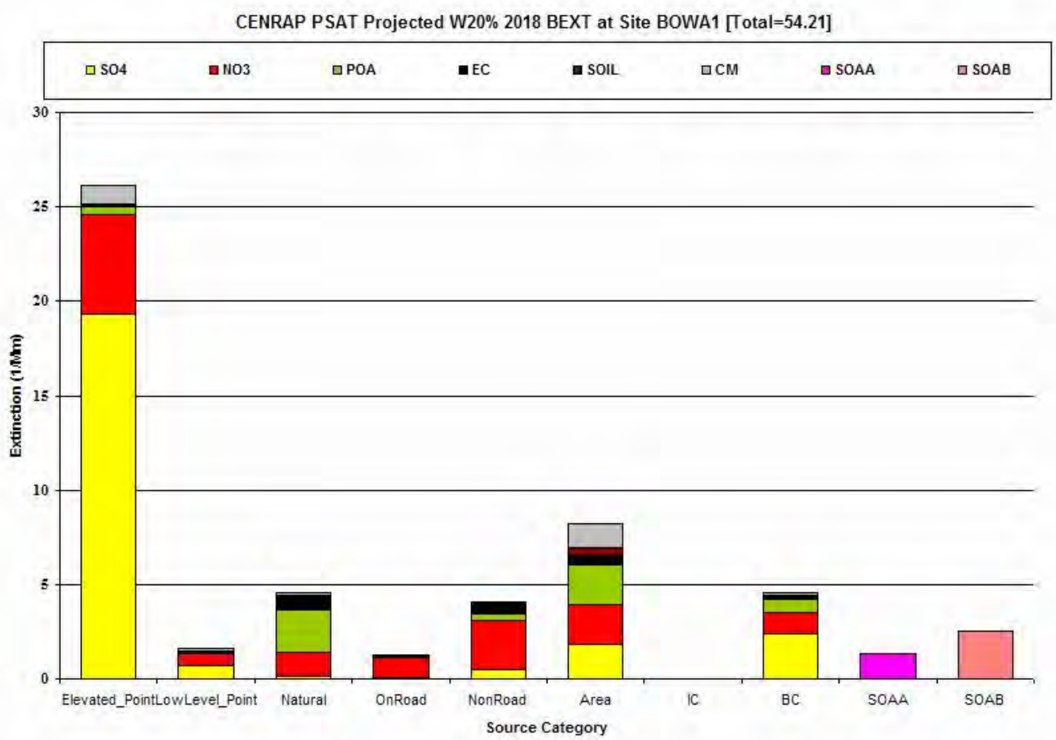


Figure E-4b. PSAT source category by PM species contributions to the average 2018 projected extinction (Mm^{-1}) for the Worst 20% visibility days at Boundary Waters (BOWA), Minnesota.

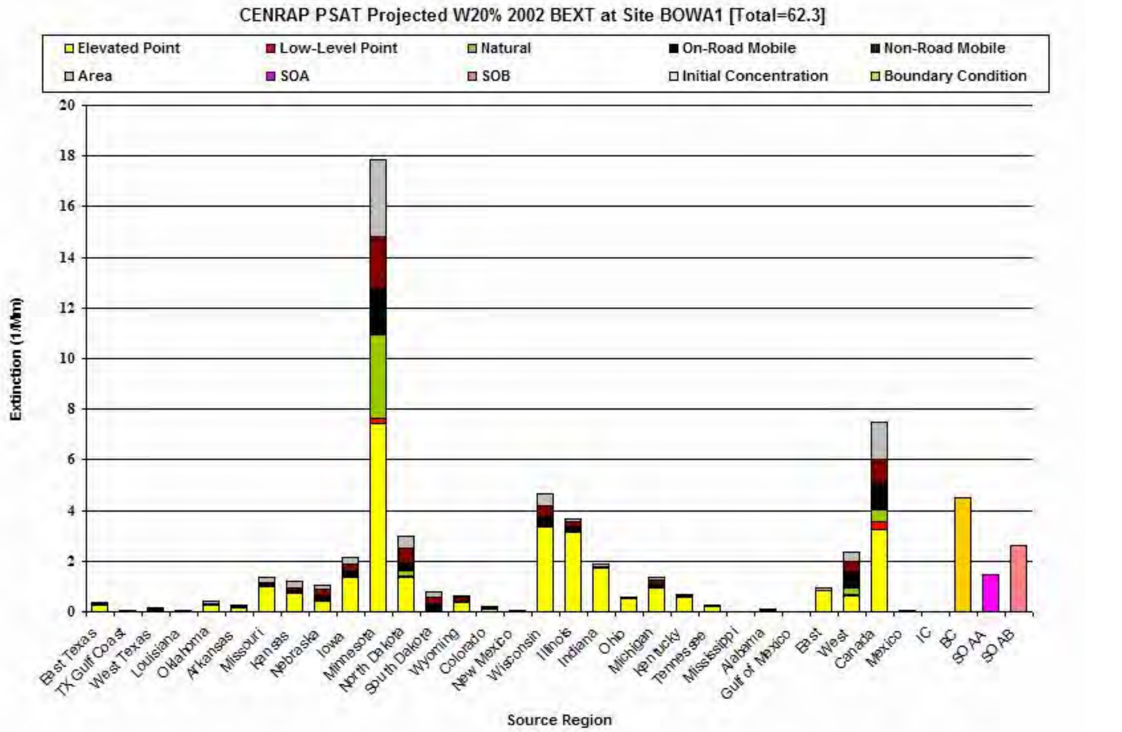


Figure E-4c. PSAT source region by source category contributions to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Worst 20% visibility days at Boundary Waters (BOWA), Minnesota.

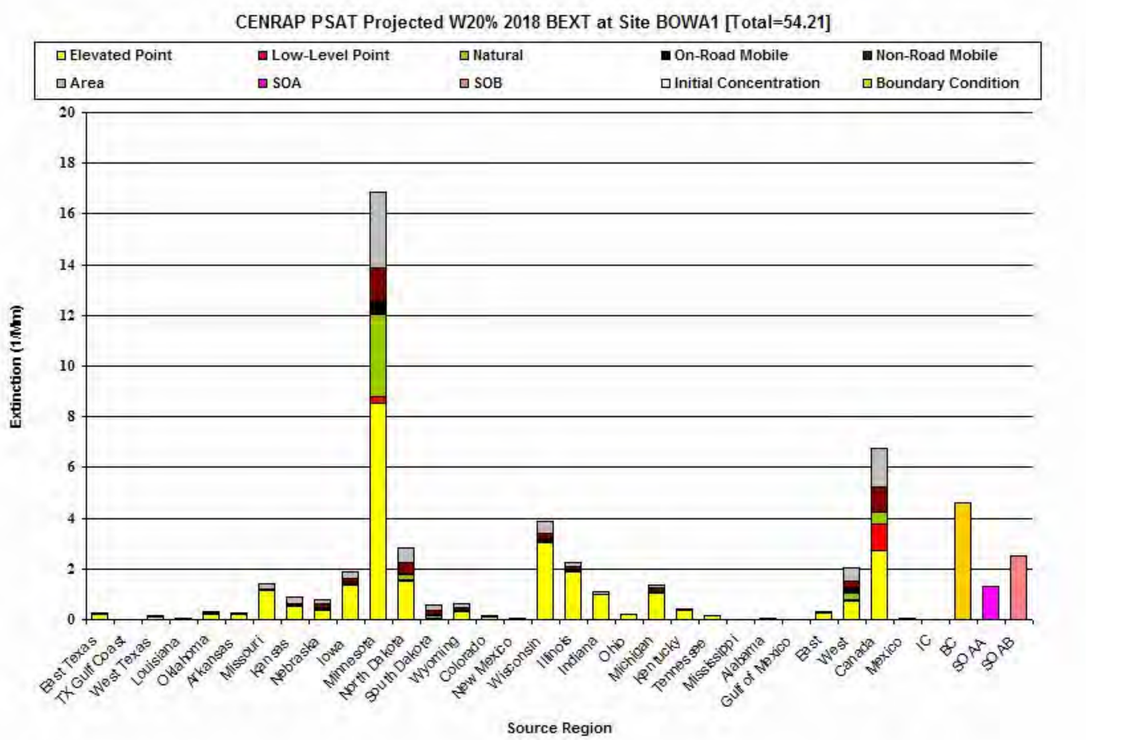


Figure E-4d. PSAT source region by source category contributions to the average 2018 extinction (Mm^{-1}) for the Worst 20% visibility days at Boundary Waters (BOWA), Minnesota.

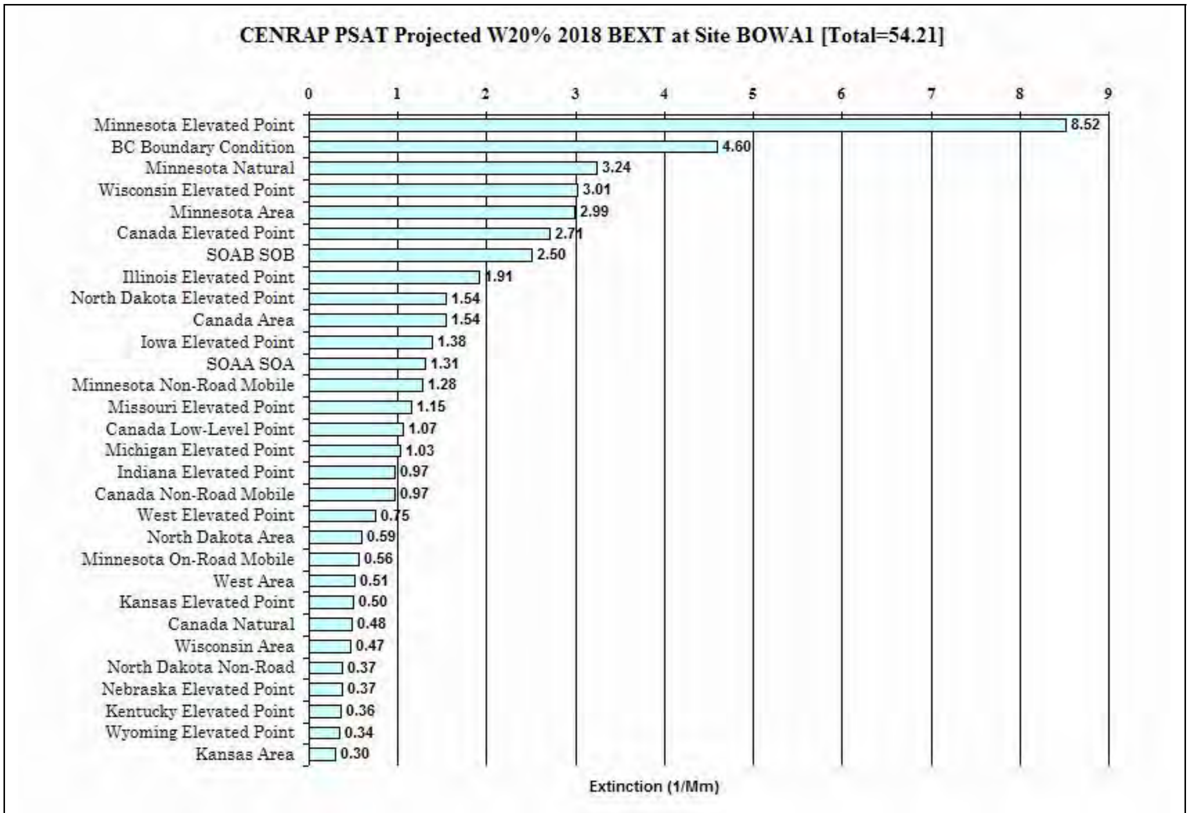


Figure E-4e. Ranked PSAT source region by source category contributions to the average 2018 extinction (Mm^{-1}) for the Worst 20% visibility days at Boundary Waters (BOWA), Minnesota.

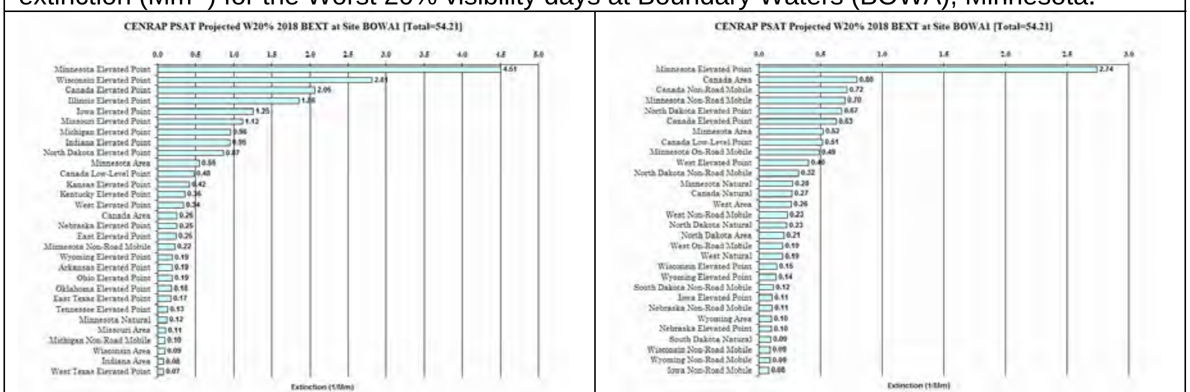


Figure E-4f. Ranked PSAT source region by source category contributions to the average 2018 SO4 (left) and NO3 (right) extinction (Mm^{-1}) for the Worst 20% visibility days at Boundary Waters (BOWA), Minnesota.

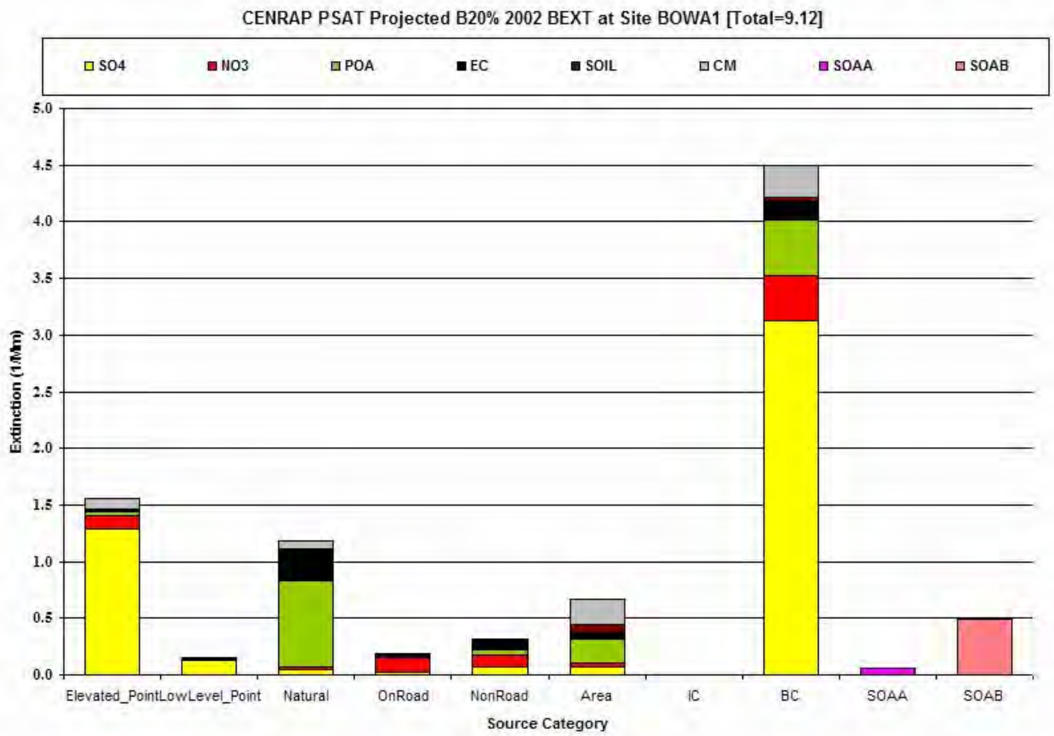


Figure E-4g. PSAT contributions by source category and PM species to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Best 20% visibility days at Boundary Waters (BOWA), Minnesota.

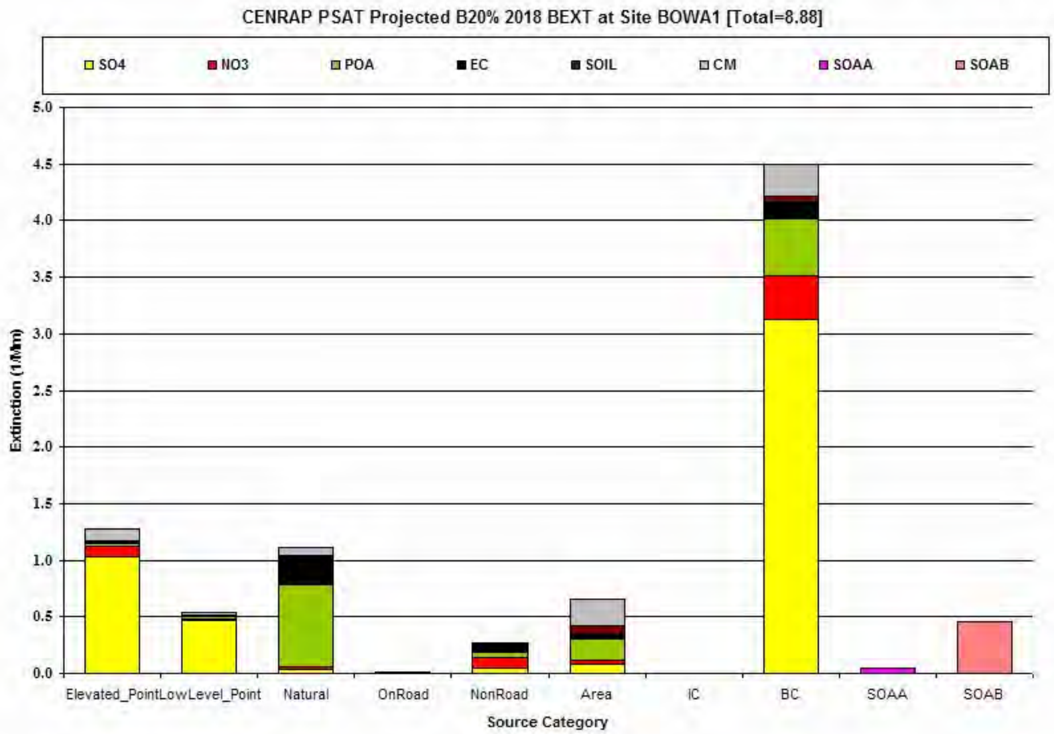


Figure E-4h. PSAT contributions by source category and PM species to the average 2018 extinction (Mm^{-1}) for the Best 20% visibility days at Boundary Waters (BOWA), Minnesota.

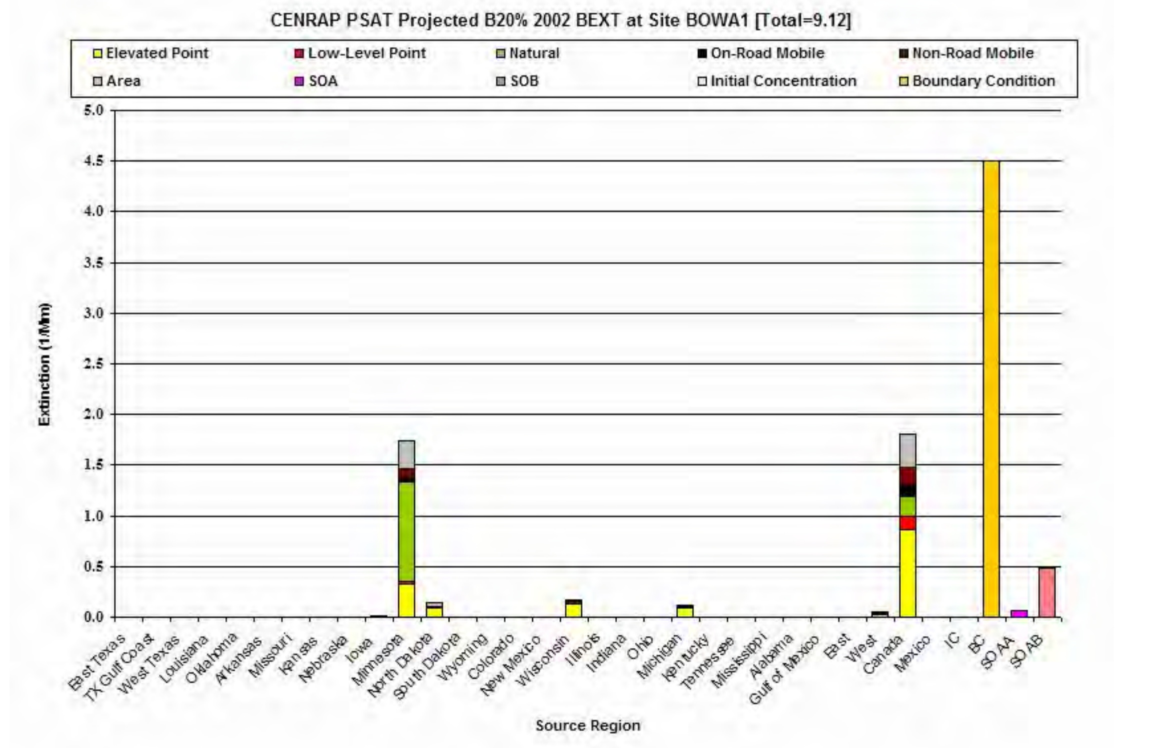


Figure E-4i. PSAT contributions by source region and source category to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Best 20% visibility days at Boundary Waters (BOWA), Minnesota.

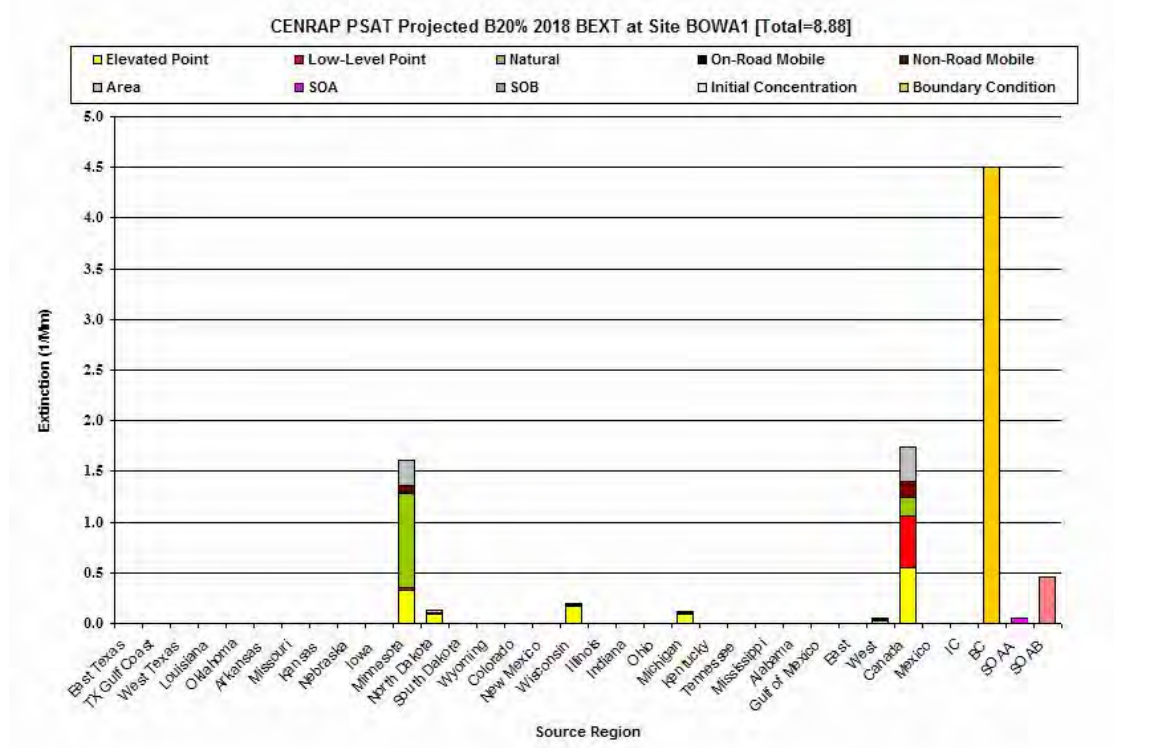


Figure E-4j. PSAT contributions by source region and source category to the average 2018 extinction (Mm^{-1}) for the Best 20% visibility days at Boundary Waters (BOWA), Minnesota.

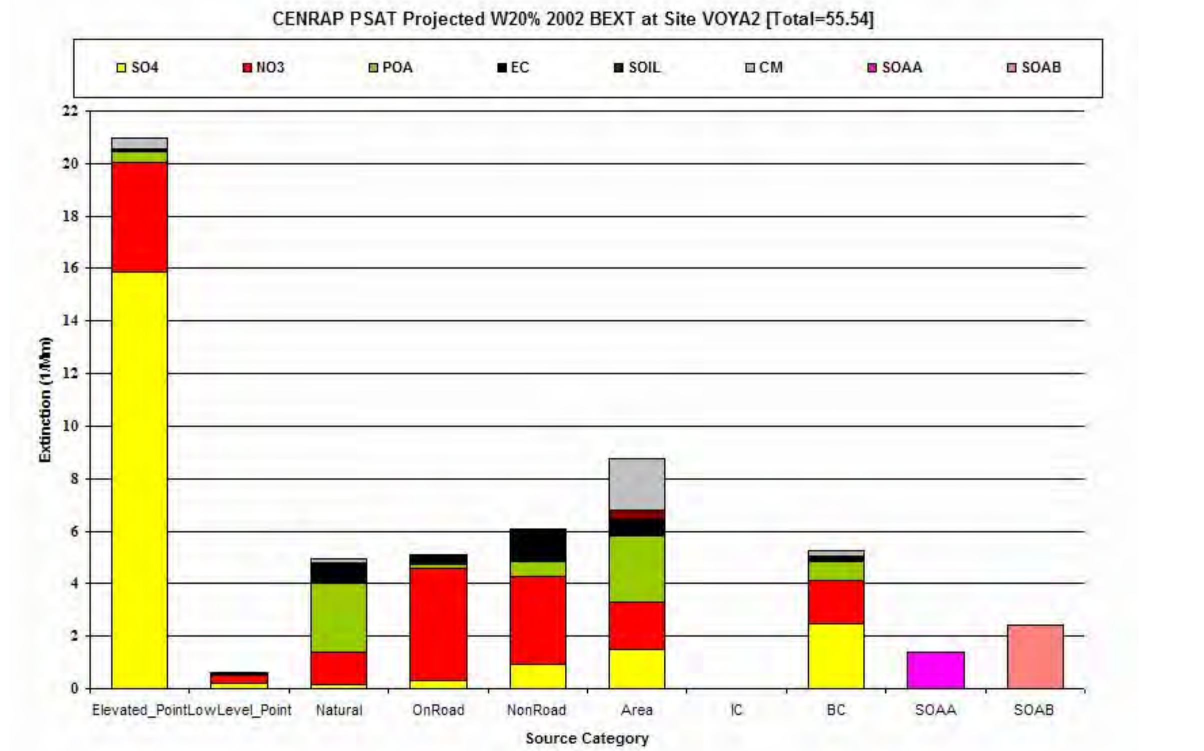


Figure E-5a. PSAT source categories by PM species contributions to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Worst 20% visibility days at Voyageurs (VOYA), Minnesota.

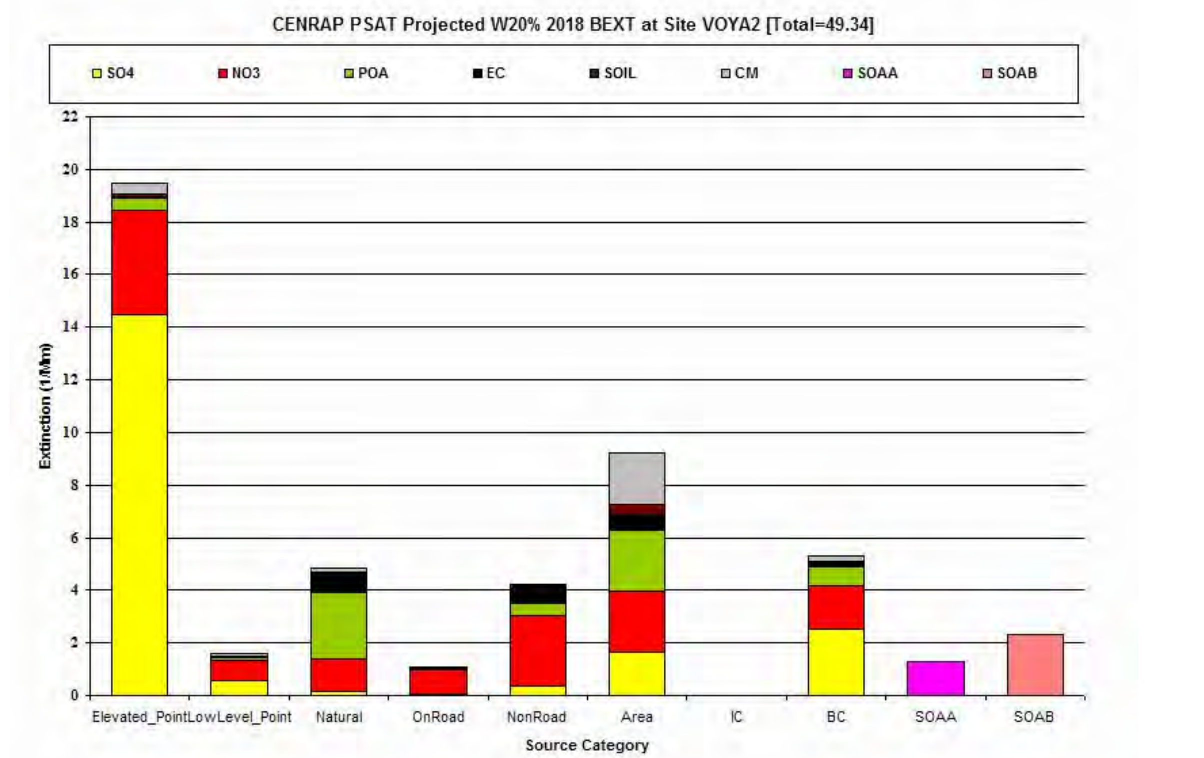


Figure E-5b. PSAT source category by PM species contributions to the average 2018 projected extinction (Mm^{-1}) for the Worst 20% visibility days at Voyageurs (VOYA), Minnesota.

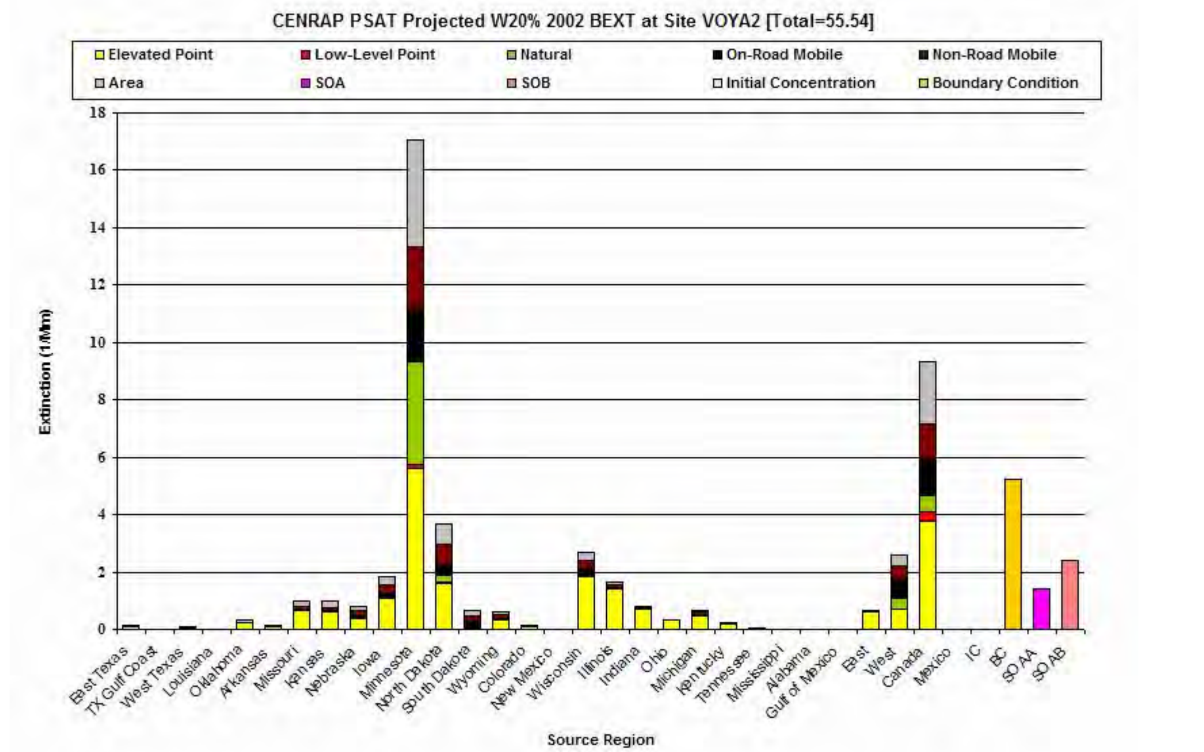


Figure E-5c. PSAT source region by source category contributions to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Worst 20% visibility days at Voyageurs (VOYA), Minnesota.

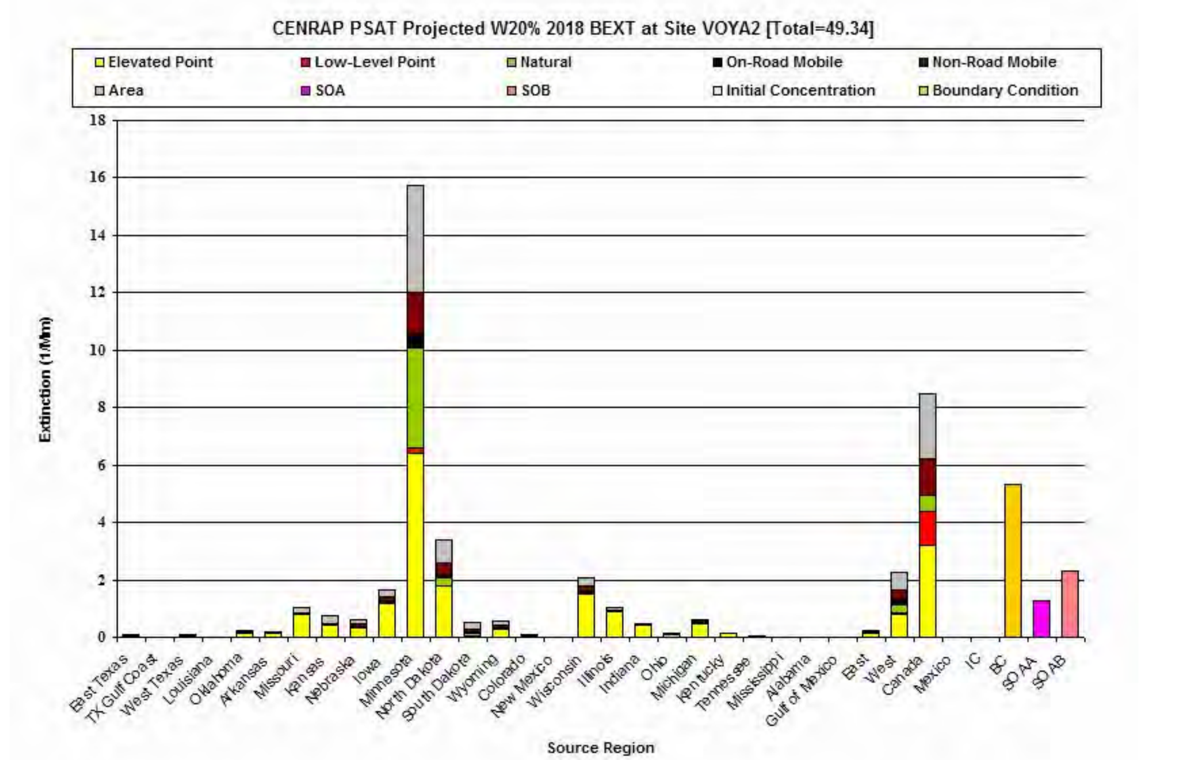


Figure E-5d. PSAT source region by source category contributions to the average 2018 extinction (Mm^{-1}) for the Worst 20% visibility days at Voyageurs (VOYA), Minnesota.

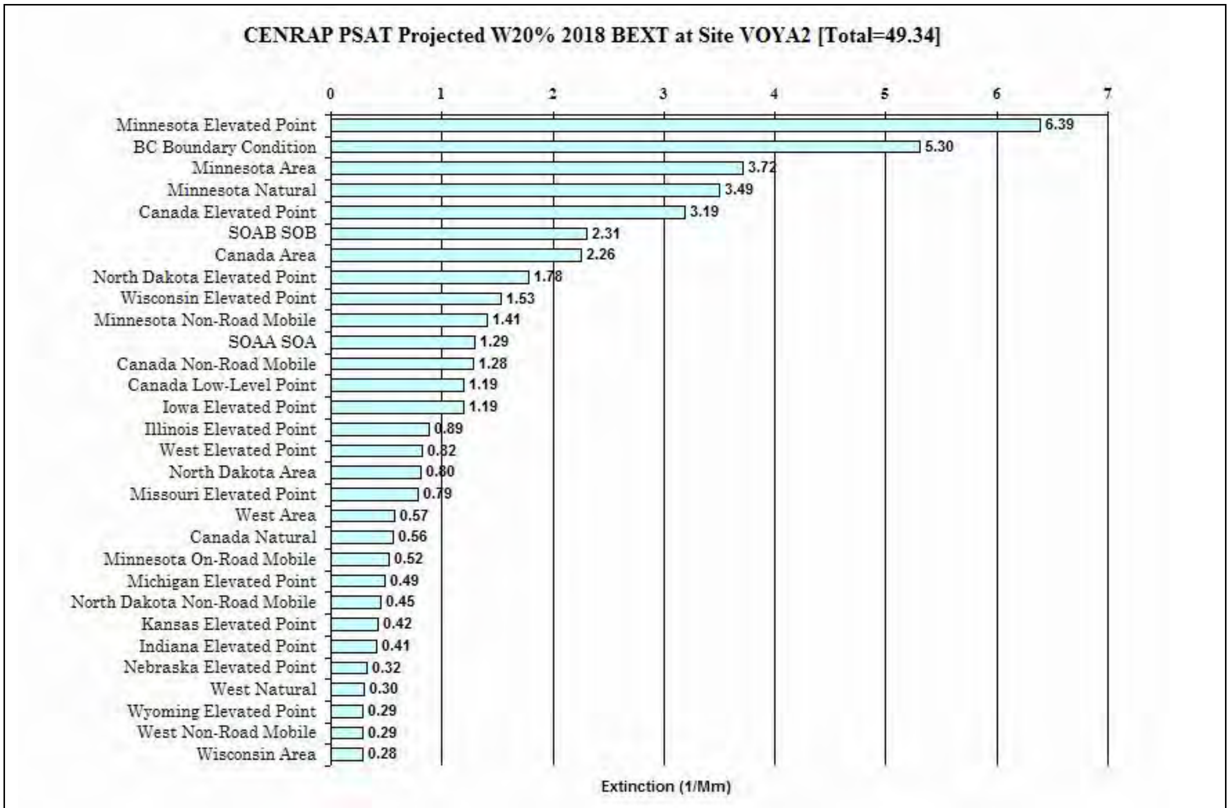


Figure E-5e. Ranked PSAT source region by source category contributions to the average 2018 extinction (Mm^{-1}) for the Worst 20% visibility days at Voyageurs (VOYA), Minnesota.

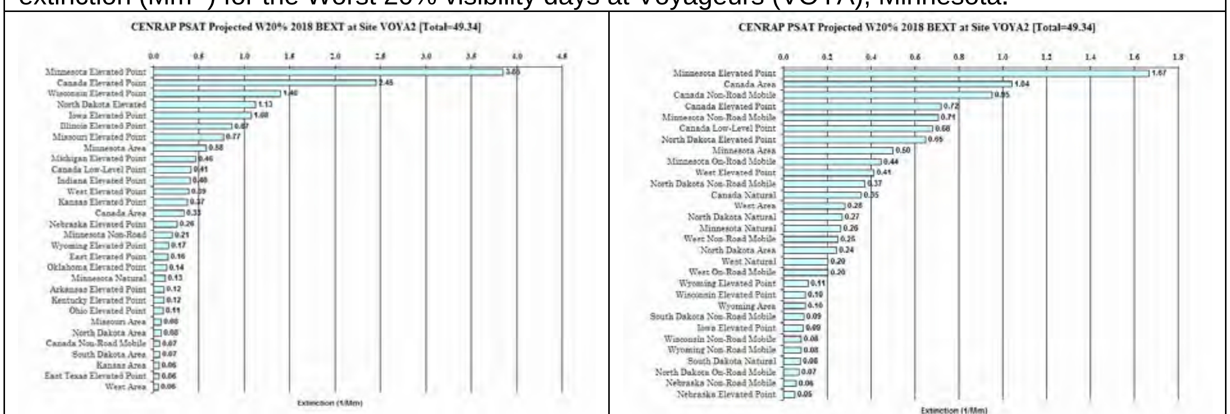


Figure E-5f. Ranked PSAT source region by source category contributions to the average 2018 SO4 (left) and NO3 (right) extinction (Mm^{-1}) for the Worst 20% visibility days at Voyageurs (VOYA), Minnesota.

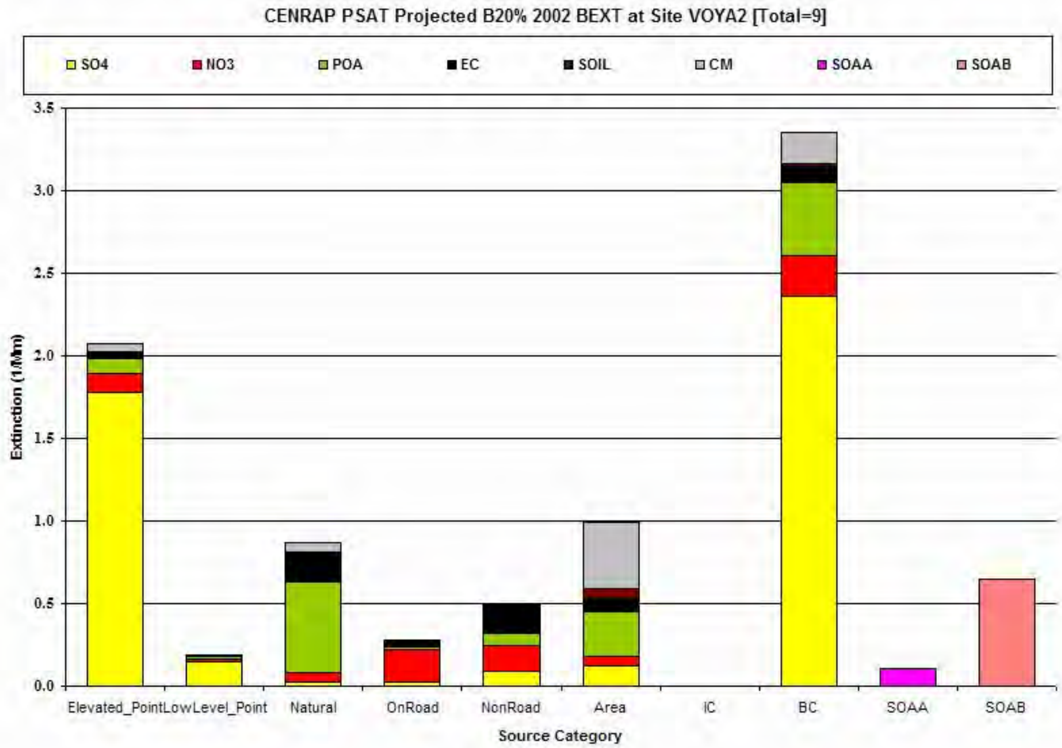


Figure E-5g. PSAT contributions by source category and PM species to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Best 20% visibility days at Voyageurs (VOYA), Minnesota.

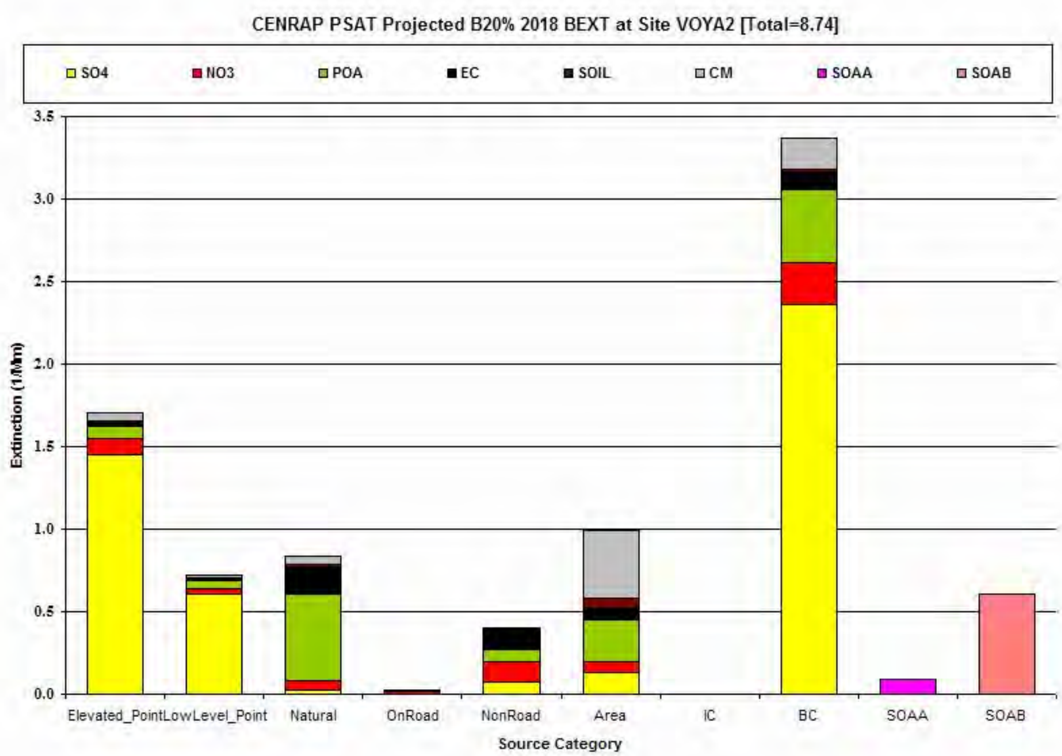


Figure E-5h. PSAT contributions by source category and PM species to the average 2018 extinction (Mm^{-1}) for the Best 20% visibility days at Voyageurs (VOYA), Minnesota.

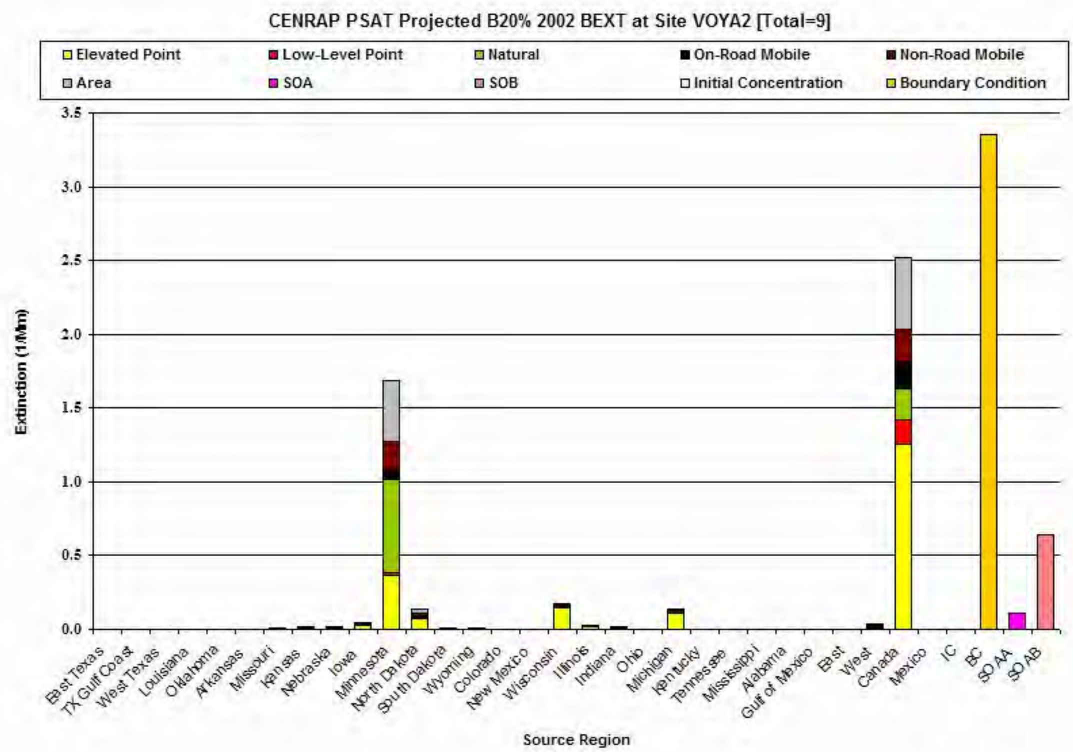


Figure E-5i. PSAT contributions by source region and source category to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Best 20% visibility days at Voyageurs (VOYA), Minnesota.

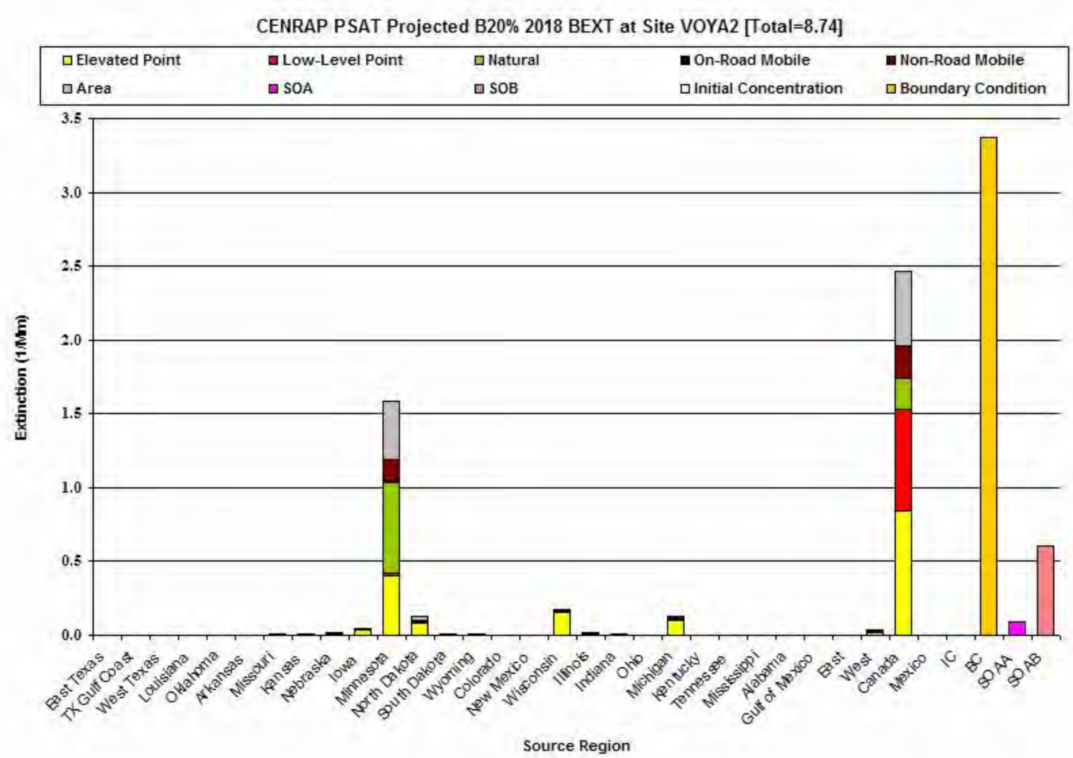


Figure E-5j. PSAT contributions by source region and source category to the average 2018 extinction (Mm^{-1}) for the Best 20% visibility days at Voyageurs (VOYA), Minnesota.

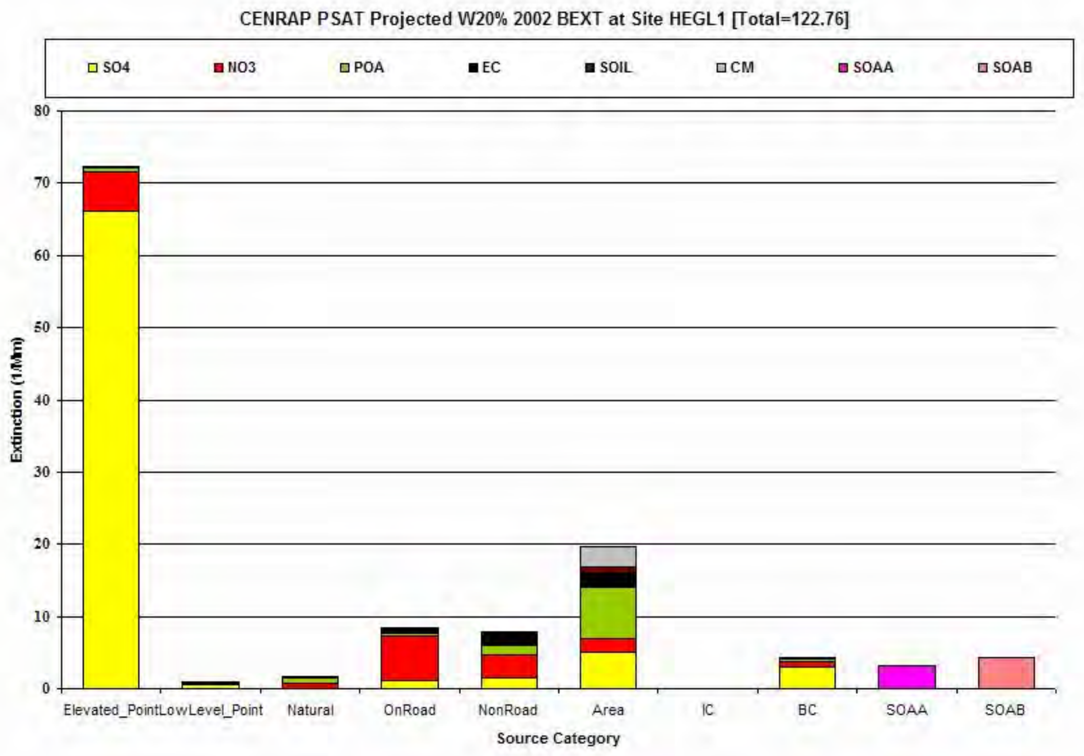


Figure E-6a. PSAT source categories by PM species contributions to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Worst 20% visibility days at Hercules Glade (HEGL), Missouri.

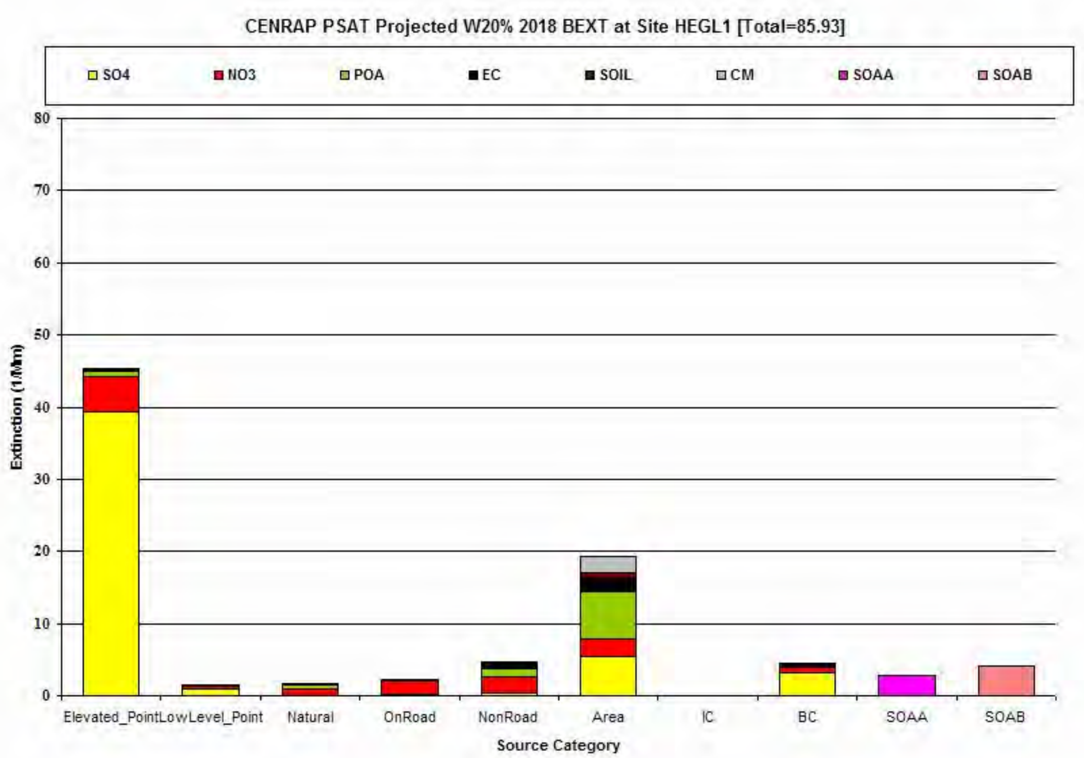


Figure E-6b. PSAT source category by PM species contributions to the average 2018 projected extinction (Mm^{-1}) for the Worst 20% visibility days at Hercules Glade (HEGL), Missouri.

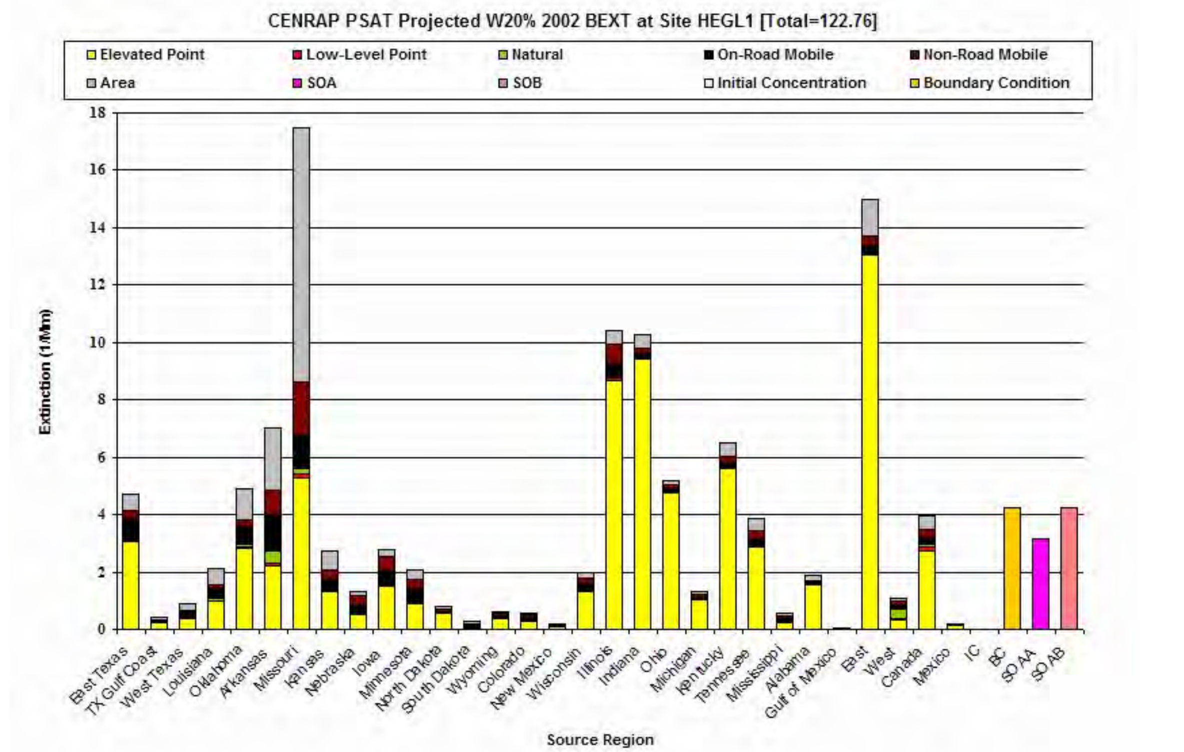


Figure E-6c. PSAT source region by source category contributions to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Worst 20% visibility days at Hercules Glade (HEGL), Missouri.

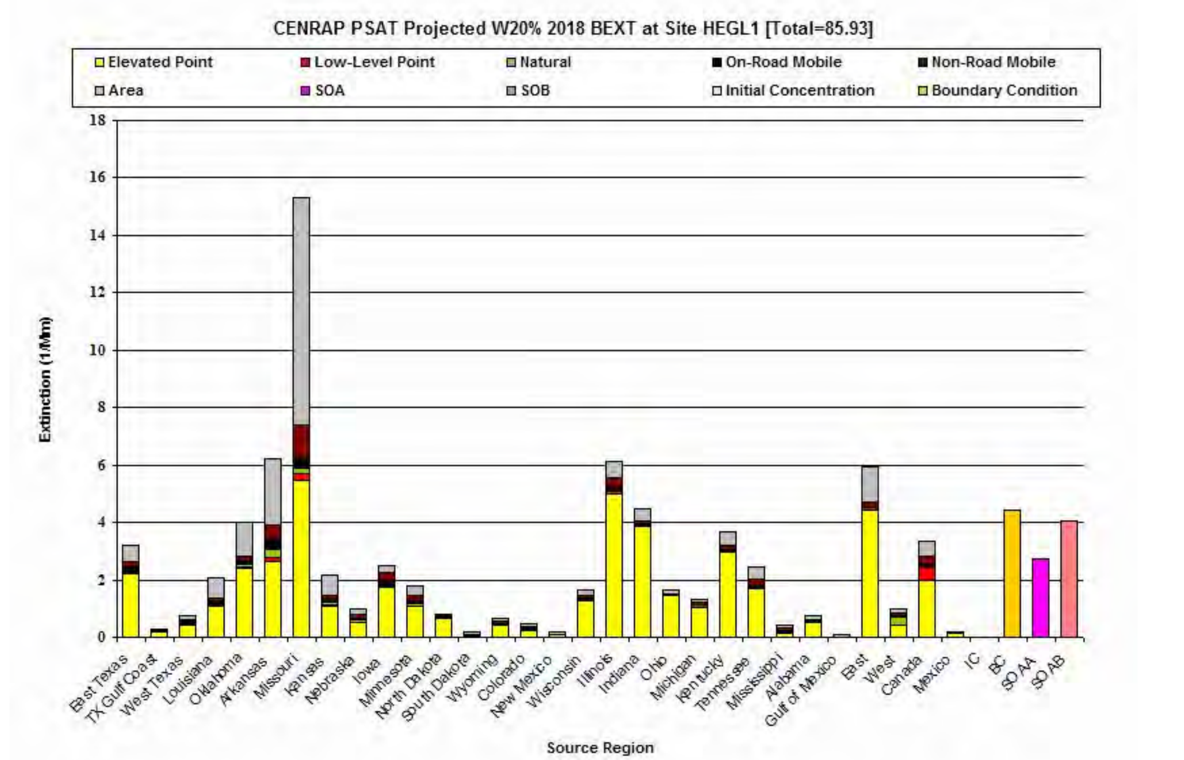


Figure E-6d. PSAT source region by source category contributions to the average 2018 extinction (Mm^{-1}) for the Worst 20% visibility days at Hercules Glade (HEGL), Missouri.

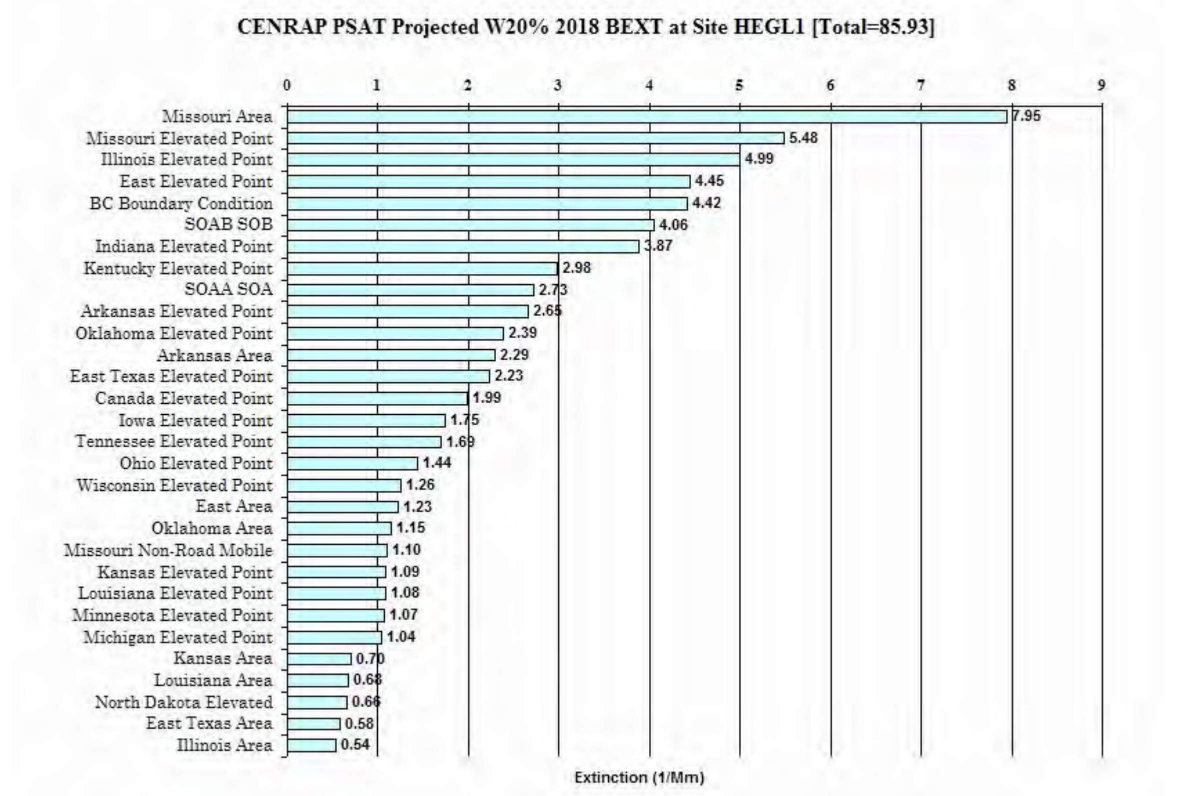
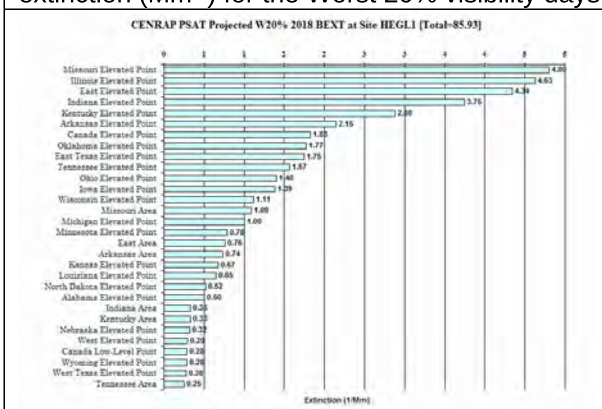


Figure E-6e. Ranked PSAT source region by source category contributions to the average 2018 extinction (Mm^{-1}) for the Worst 20% visibility days at Hercules Glade (HEGL), Missouri.



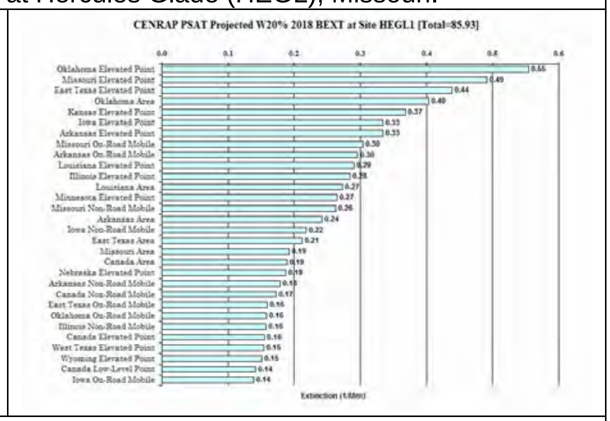


Figure E-6f. Ranked PSAT source region by source category contributions to the average 2018 SO4 (left) and NO3 (right) extinction (Mm^{-1}) for the Worst 20% visibility days at Hercules Glade (HEGL), Missouri.

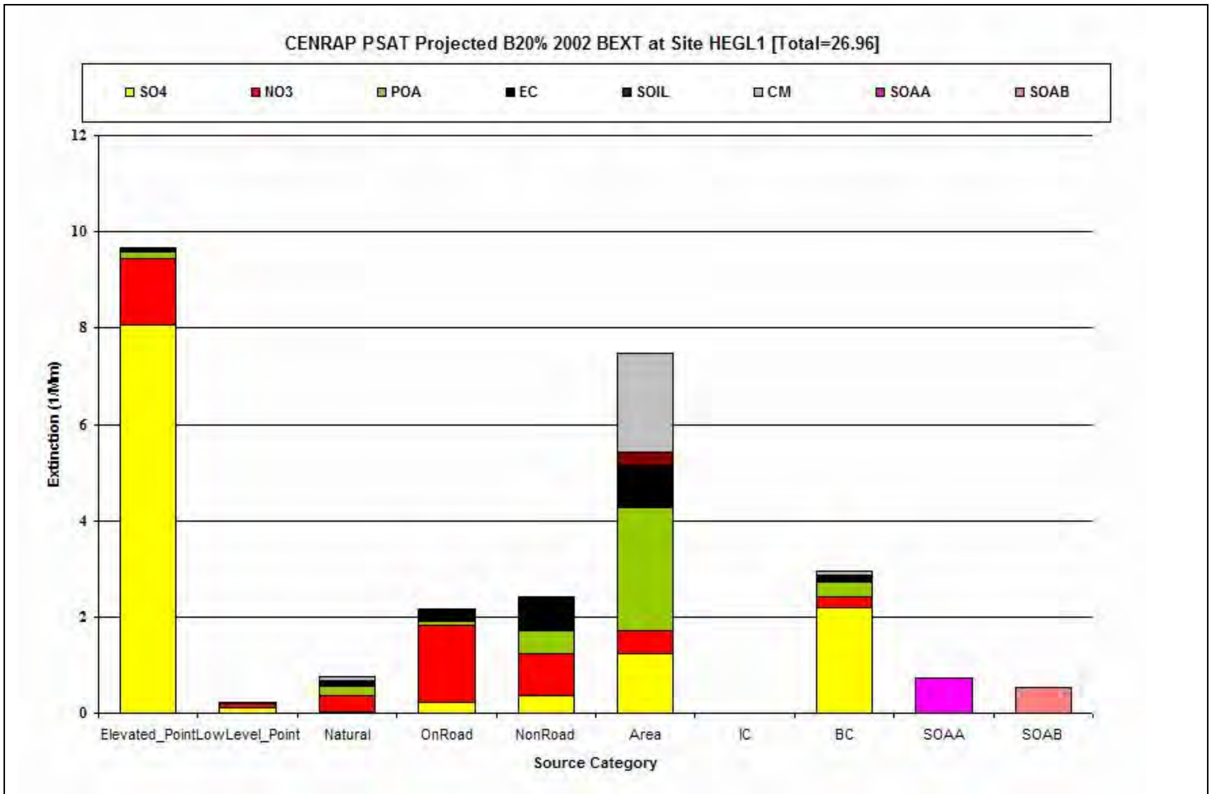


Figure E-6g. PSAT contributions by source category and PM species to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Best 20% visibility days at Hercules Glade (HEGL), Missouri.

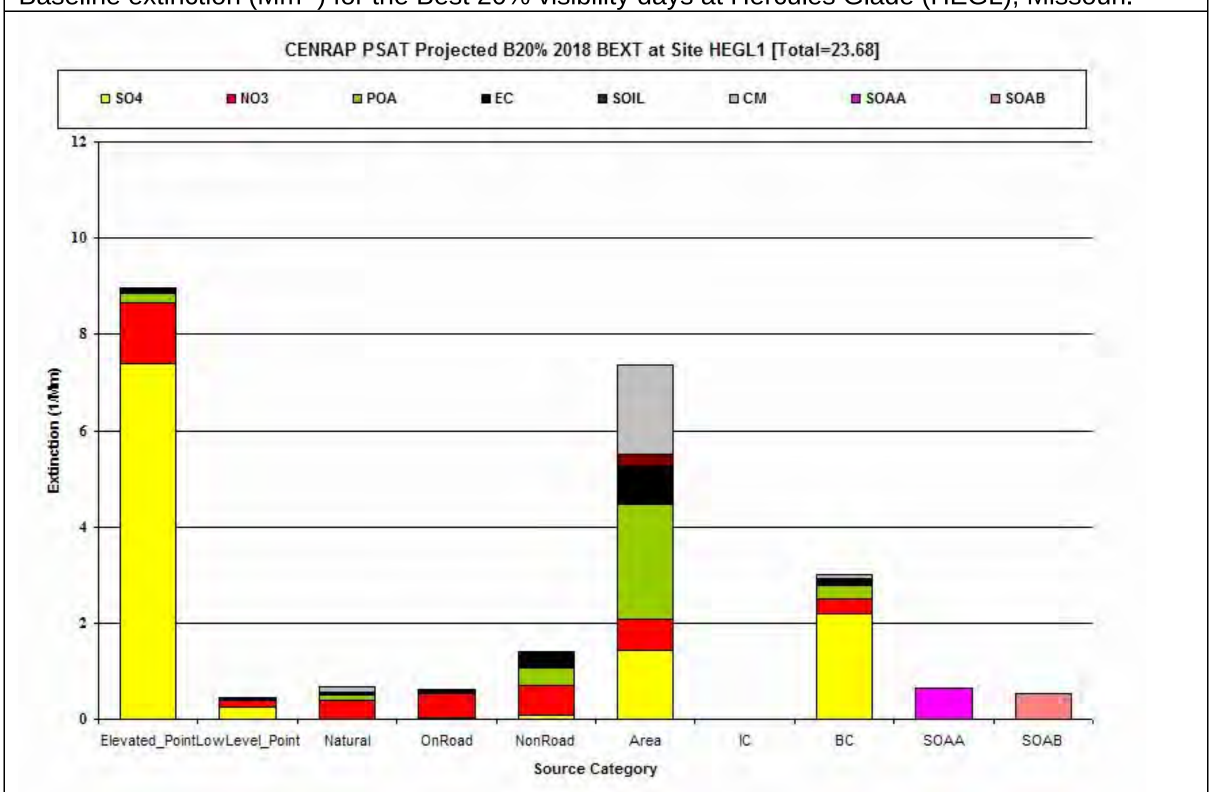


Figure E-6h. PSAT contributions by source category and PM species to the average 2018 extinction (Mm^{-1}) for the Best 20% visibility days at Hercules Glade (HEGL), Missouri.

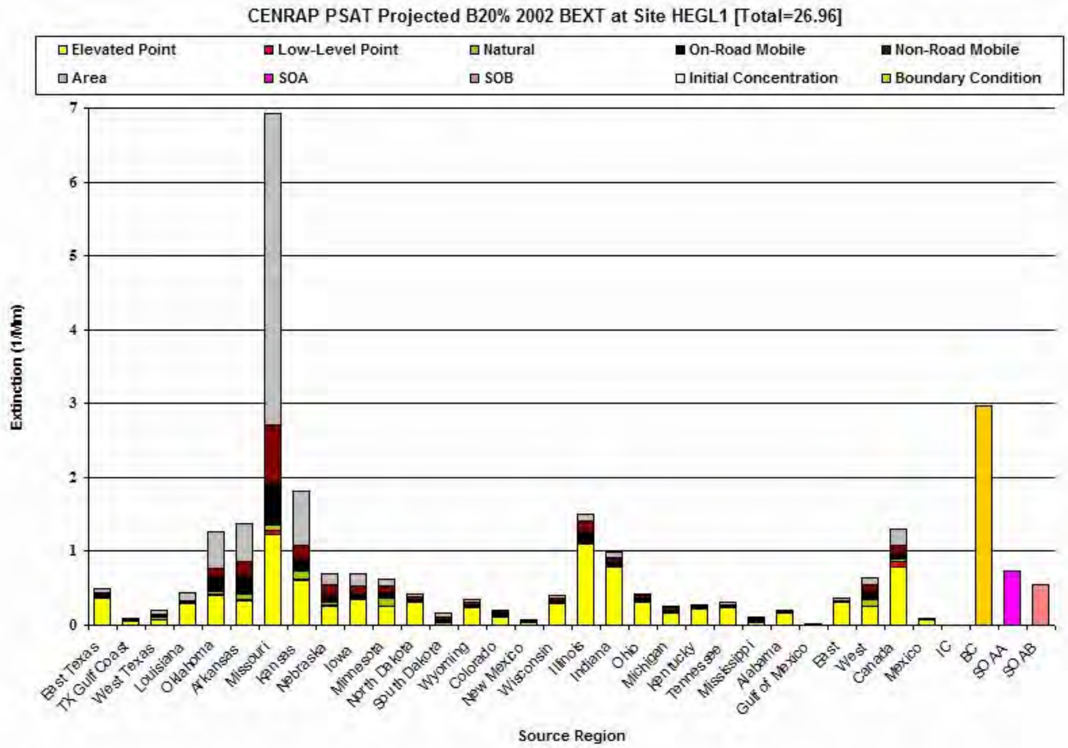


Figure E-6i. PSAT contributions by source region and source category to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Best 20% visibility days at Hercules Glade (HEGL), Missouri.

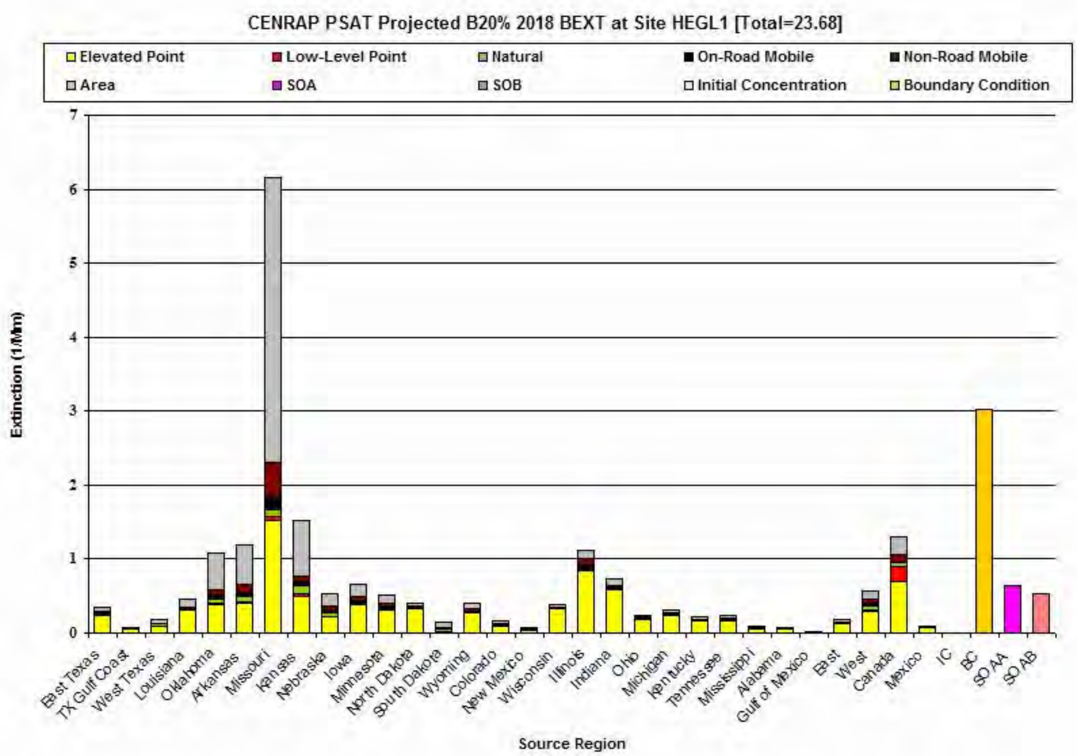


Figure E-6j. PSAT contributions by source region and source category to the average 2018 extinction (Mm^{-1}) for the Best 20% visibility days at Voyageurs Hercules Glade (HEGL), Missouri.

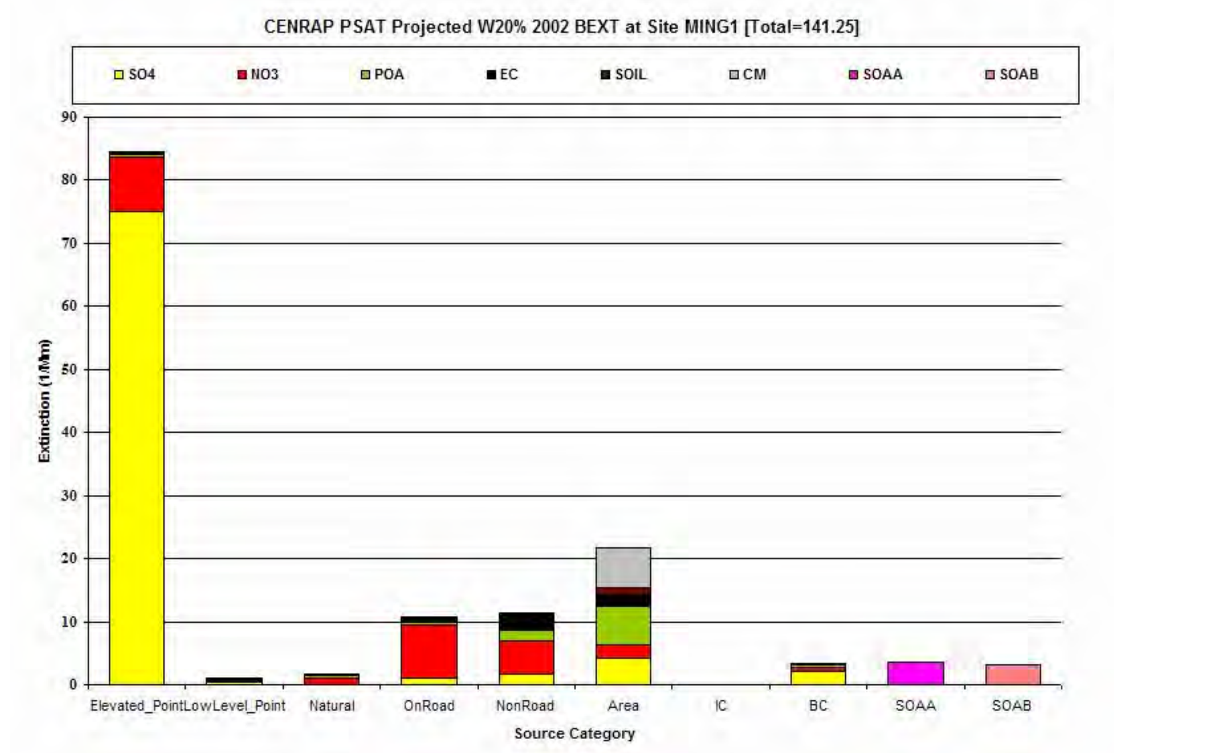


Figure E-7a. PSAT source categories by PM species contributions to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Worst 20% visibility days at Mingo (MING), Missouri.

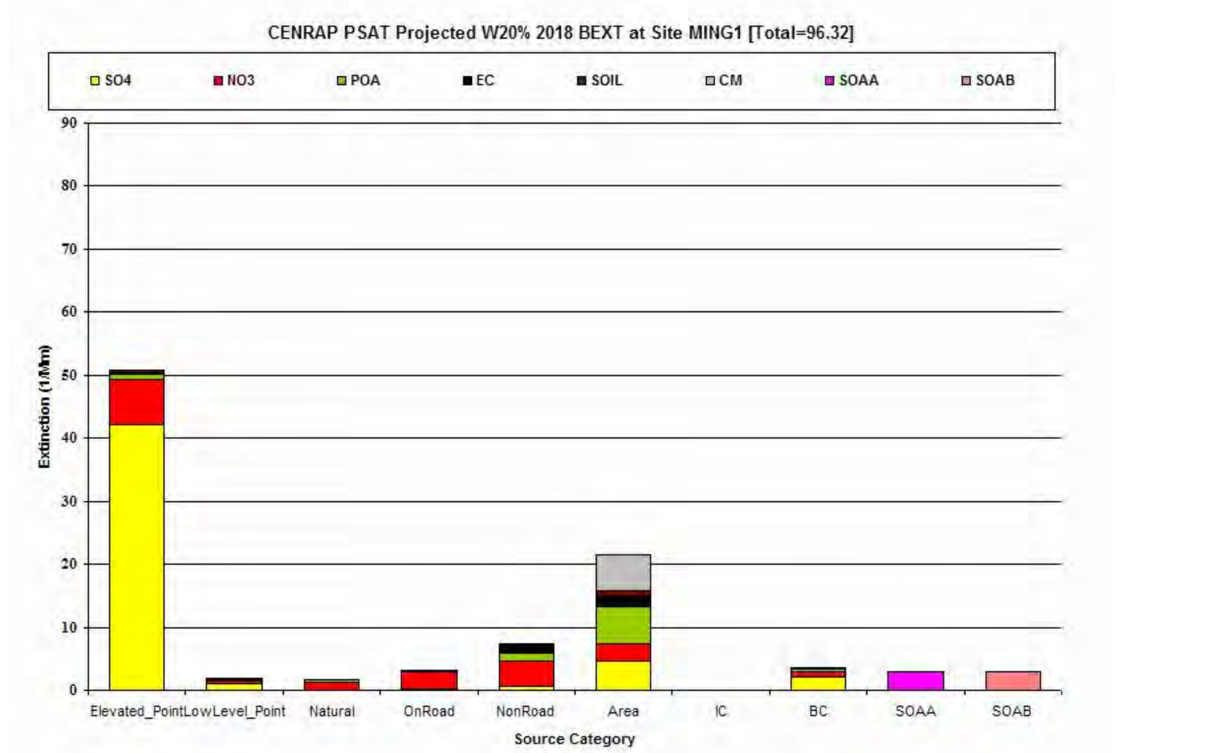


Figure E-7b. PSAT source category by PM species contributions to the average 2018 projected extinction (Mm^{-1}) for the Worst 20% visibility days at Mingo (MING), Missouri.

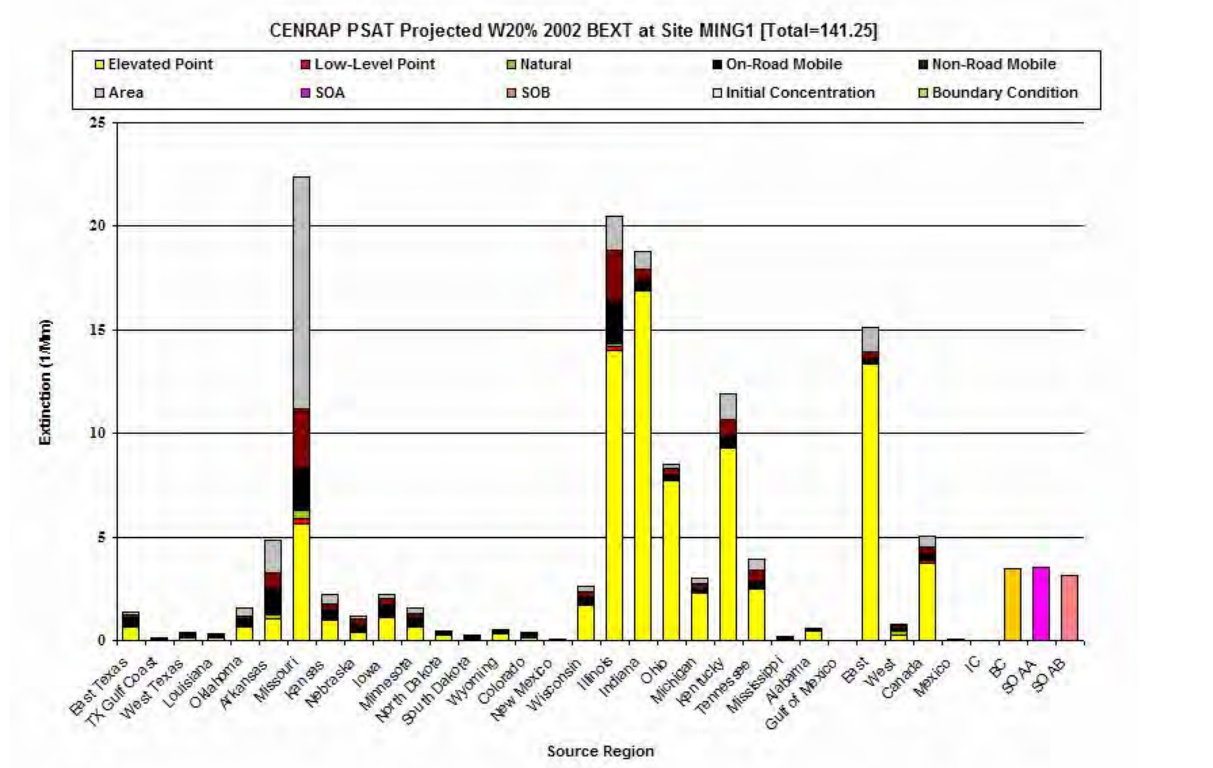


Figure E-7c. PSAT source region by source category contributions to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Worst 20% visibility days at Mingo (MING), Missouri.

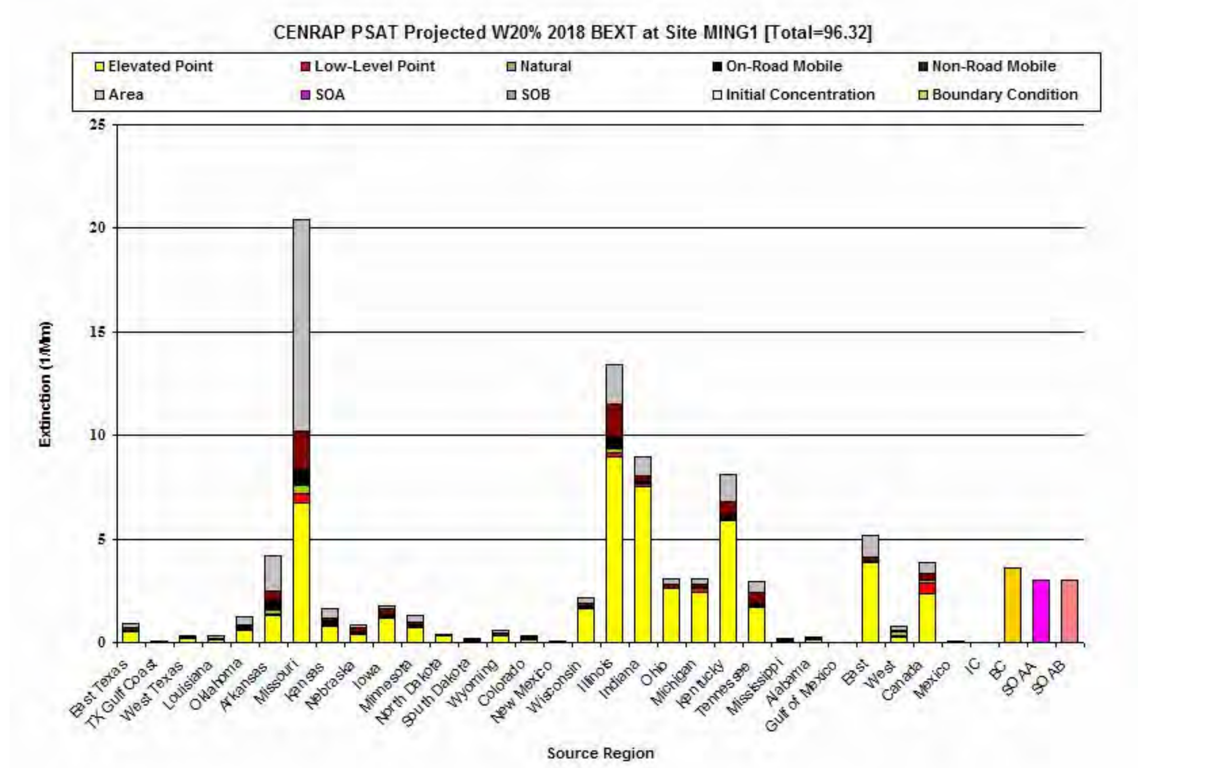


Figure E-7d. PSAT source region by source category contributions to the average 2018 extinction (Mm^{-1}) for the Worst 20% visibility days at Mingo (MING), Missouri.

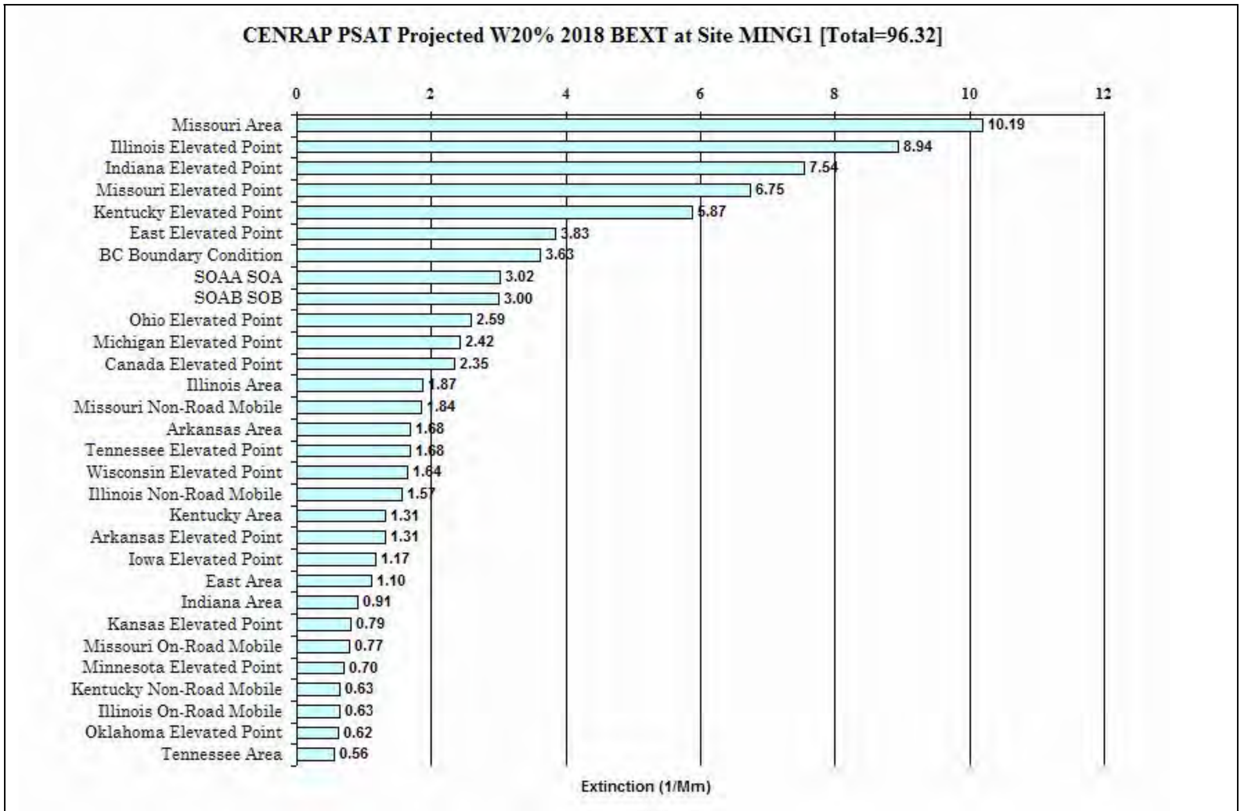
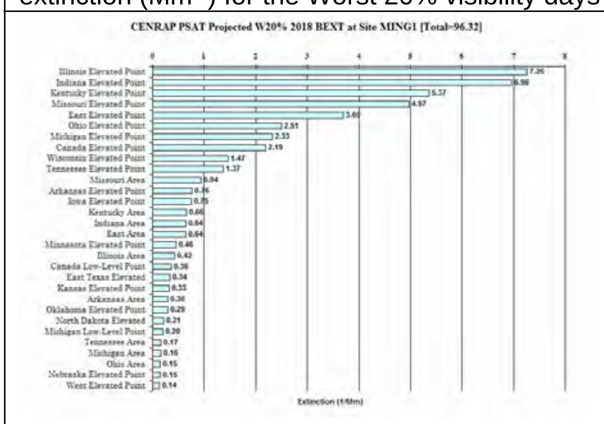


Figure E-7e. Ranked PSAT source region by source category contributions to the average 2018 extinction (Mm^{-1}) for the Worst 20% visibility days at Mingo (MING), Missouri.



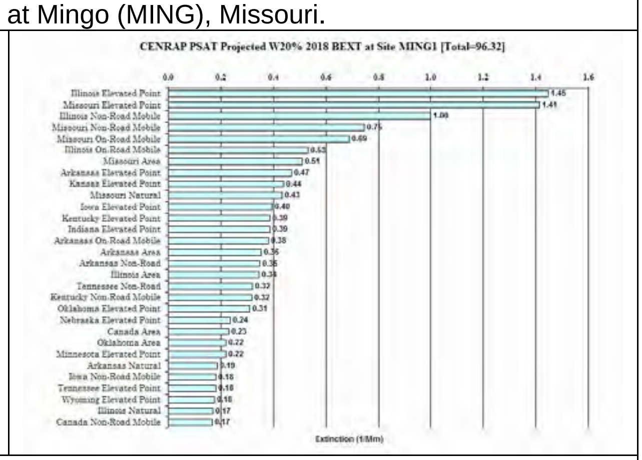


Figure E-7f. Ranked PSAT source region by source category contributions to the average 2018 SO4 (left) and NO3 (right) extinction (Mm^{-1}) for the Worst 20% visibility days at Mingo (MING), Missouri.

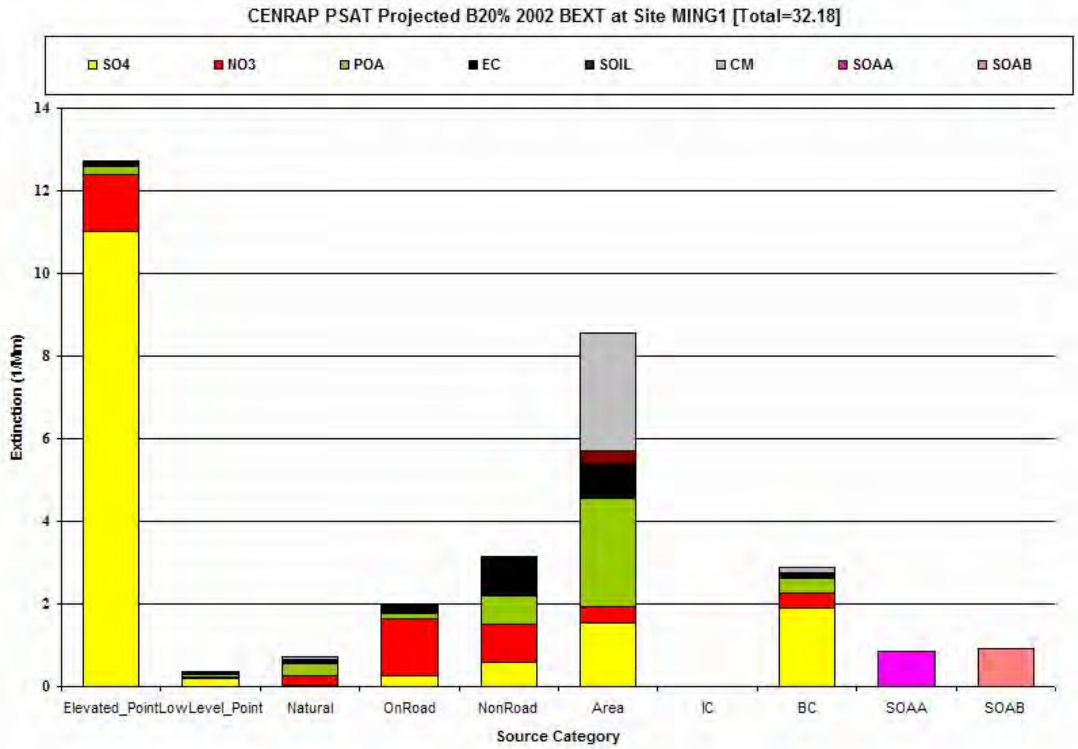


Figure E-7g. PSAT contributions by source category and PM species to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Best 20% visibility days at Mingo (MING), Missouri.

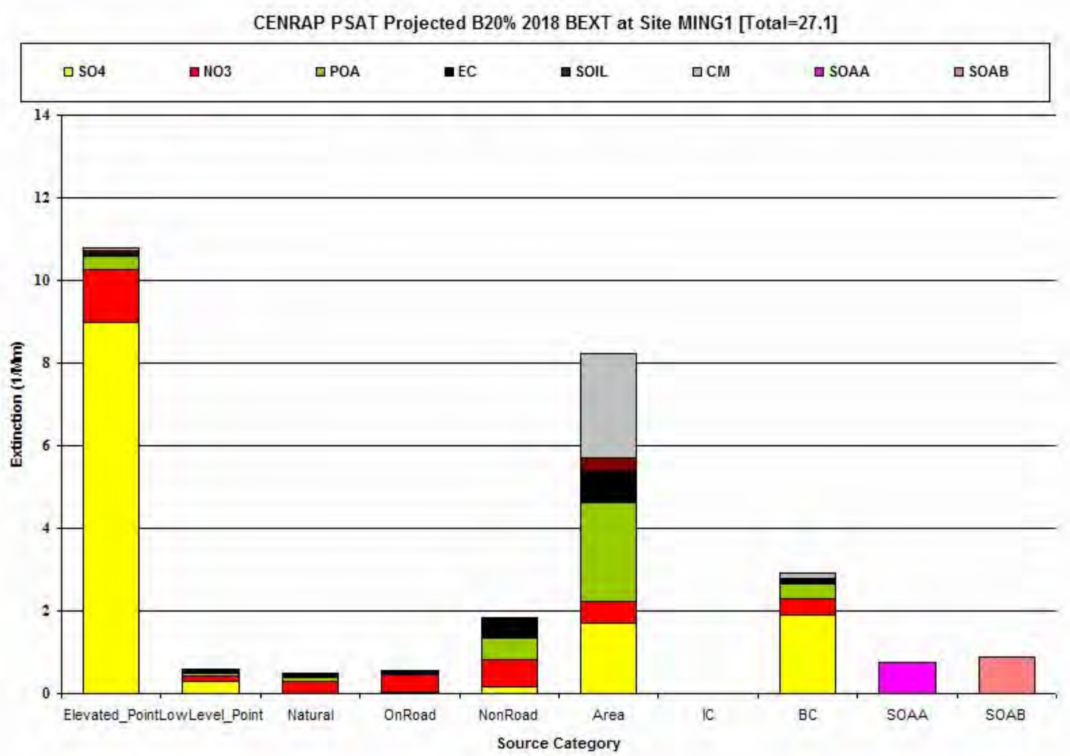


Figure E-7h. PSAT contributions by source category and PM species to the average 2018 extinction (Mm^{-1}) for the Best 20% visibility days at Mingo (MING), Missouri.

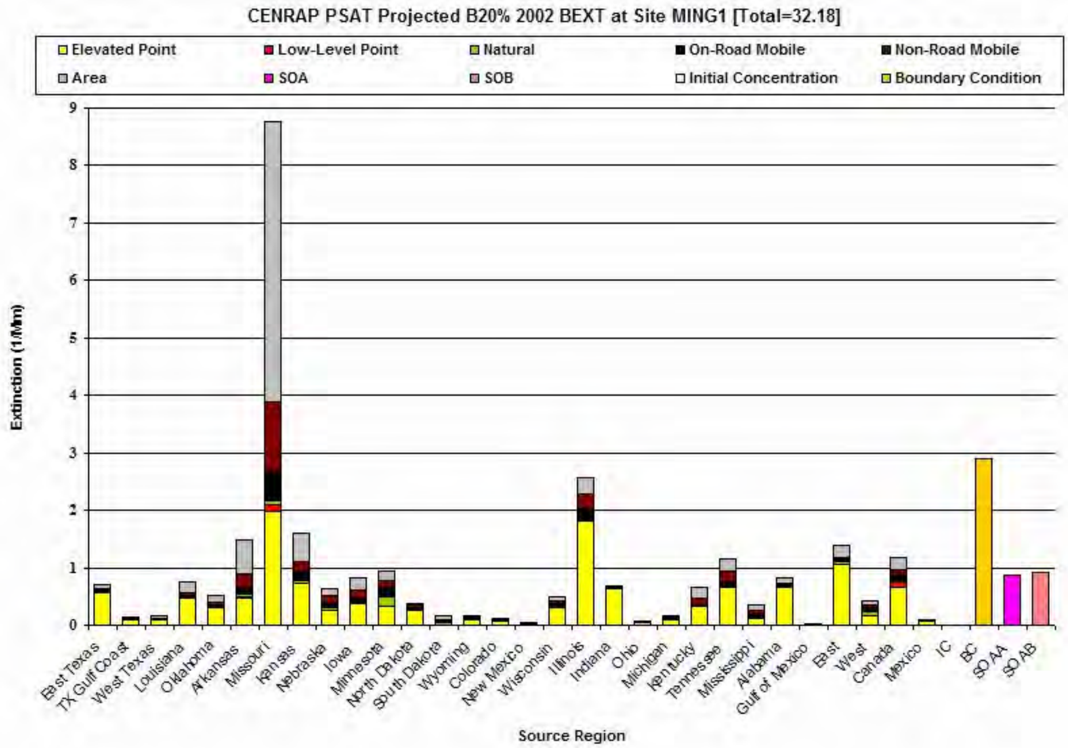


Figure E-7i. PSAT contributions by source region and source category to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Best 20% visibility days at Mingo (MING), Missouri.

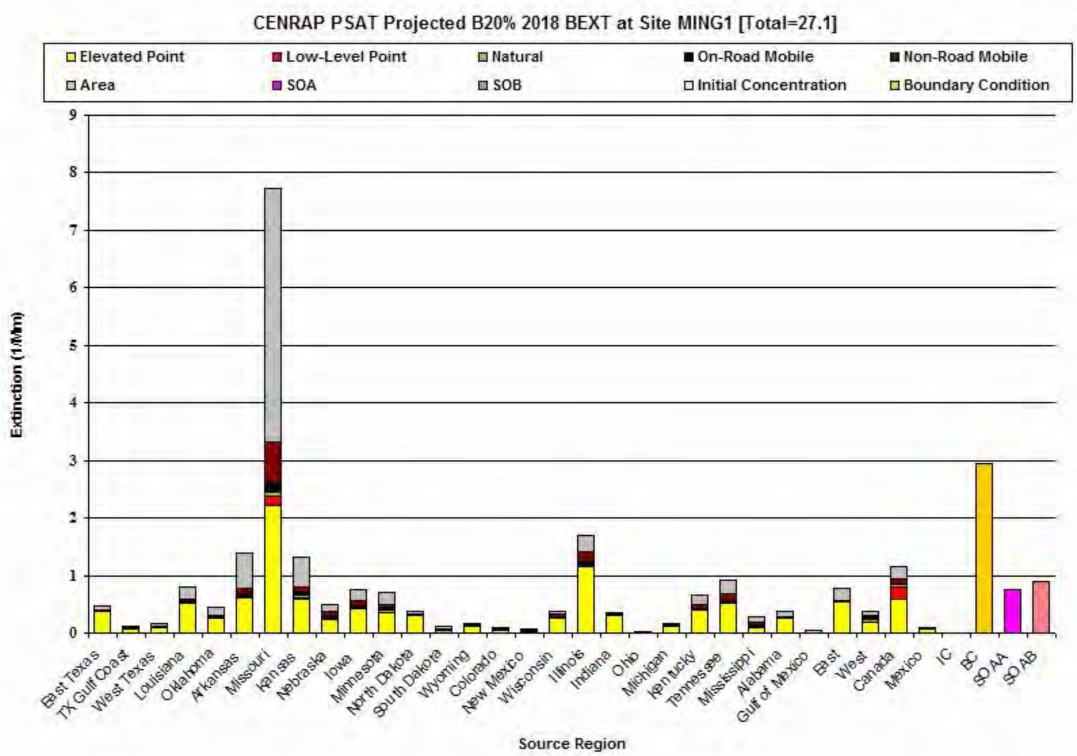


Figure E-7j. PSAT contributions by source region and source category to the average 2018 extinction (Mm^{-1}) for the Best 20% visibility days at Mingo (MING), Missouri.

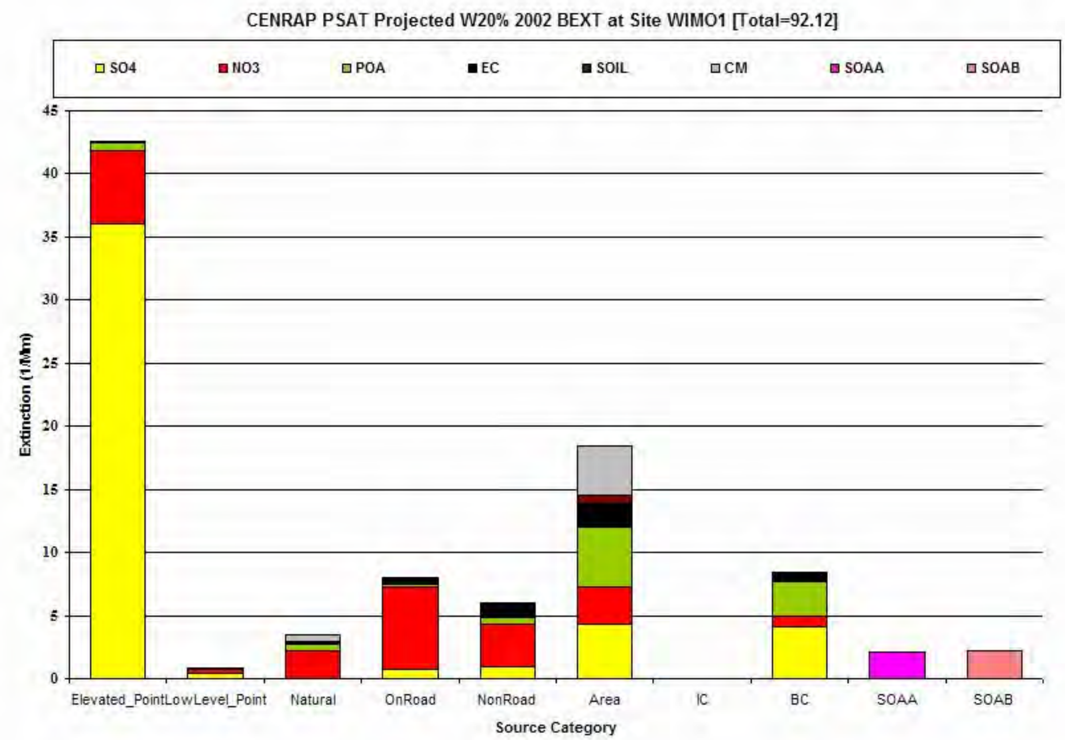


Figure E-8a. PSAT source categories by PM species contributions to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Worst 20% visibility days at Wichita Mountains (WIMO), Oklahoma.

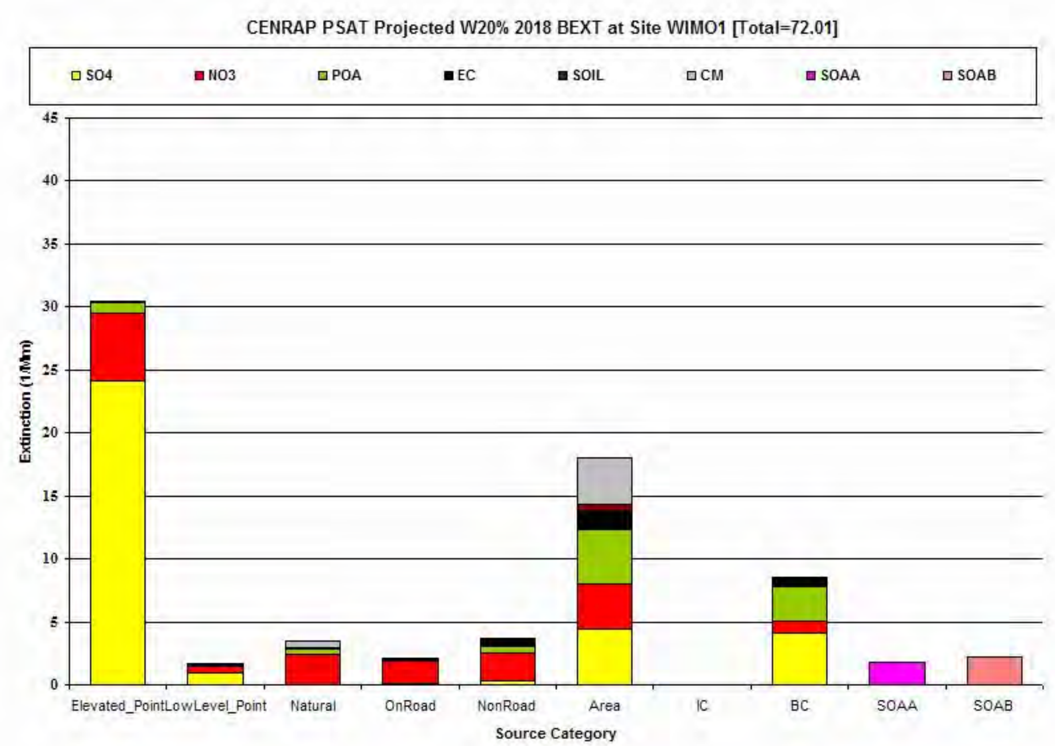


Figure E-8b. PSAT source category by PM species contributions to the average 2018 projected extinction (Mm^{-1}) for the Worst 20% visibility days at Wichita Mountains (WIMO), Oklahoma.

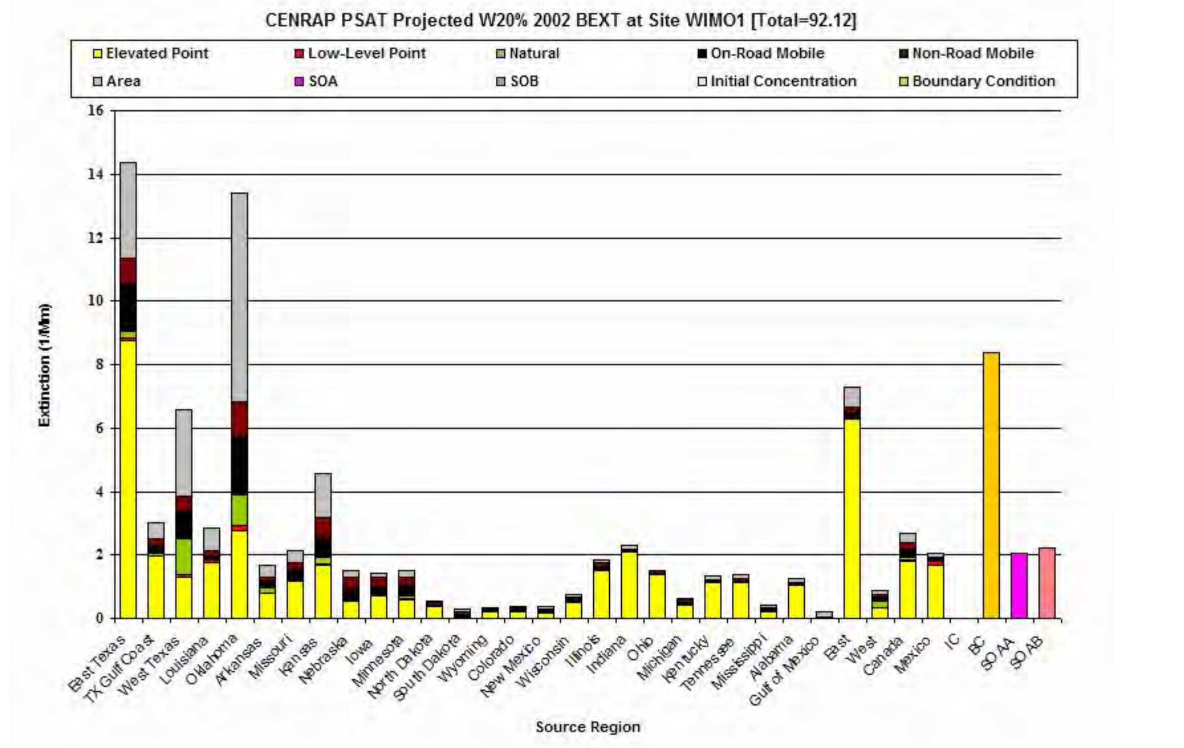


Figure E-8c. PSAT source region by source category contributions to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Worst 20% visibility days at Wichita Mountains (WIMO), Oklahoma.

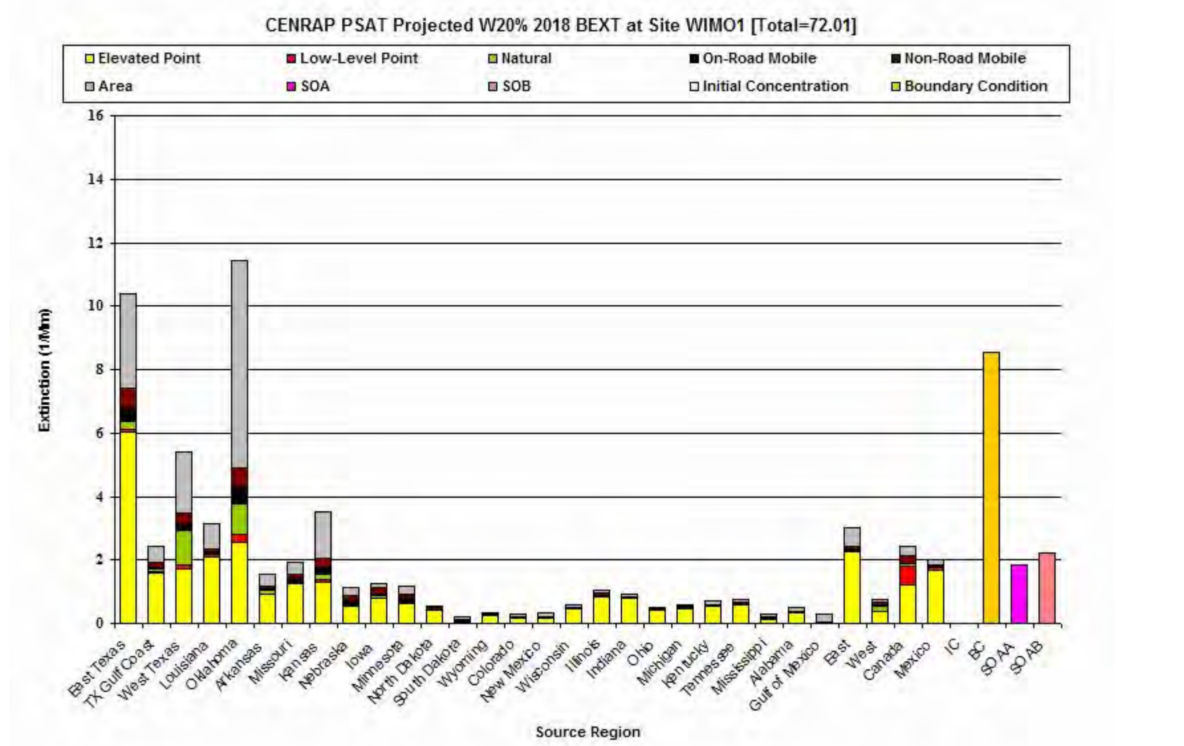


Figure E-8d. PSAT source region by source category contributions to the average 2018 extinction (Mm^{-1}) for the Worst 20% visibility days at Wichita Mountains (WIMO), Oklahoma.

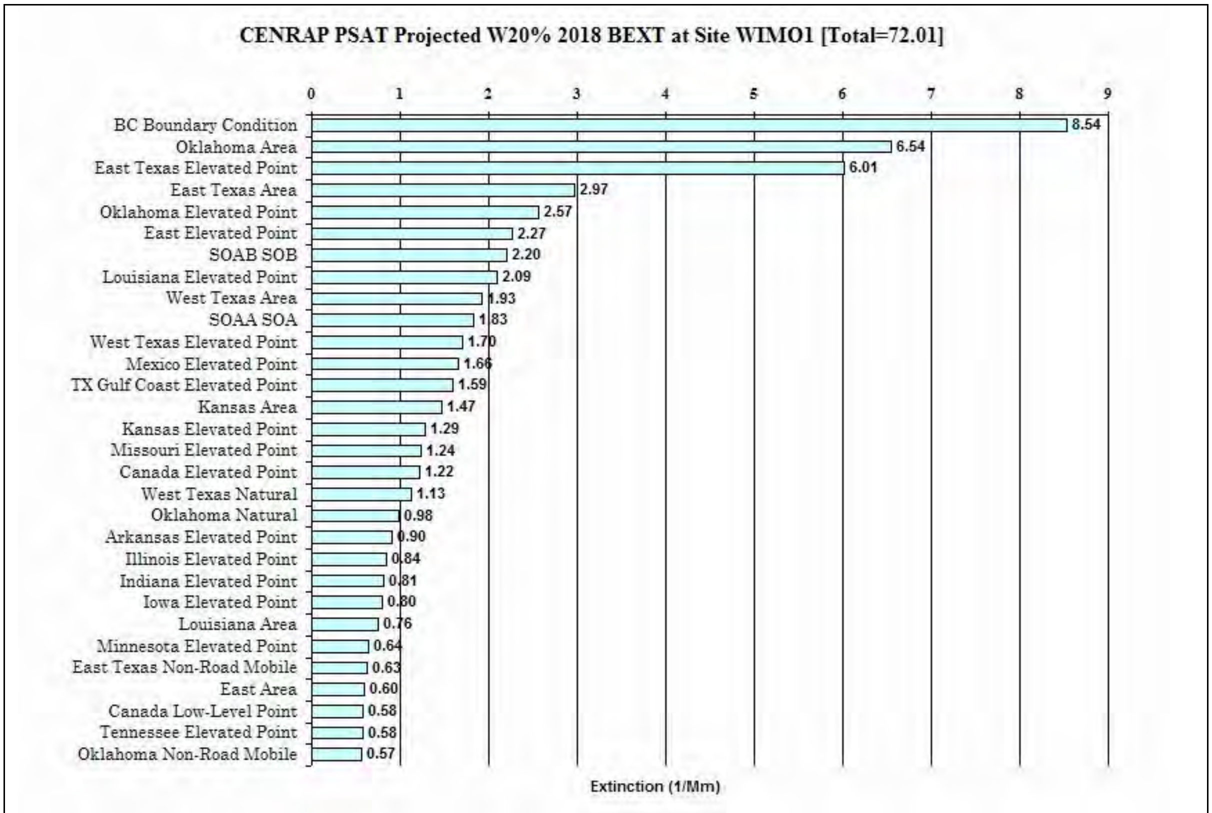


Figure E-8e. Ranked PSAT source region by source category contributions to the average 2018 extinction (Mm^{-1}) for the Worst 20% visibility days at Wichita Mountains (WIMO), Oklahoma.

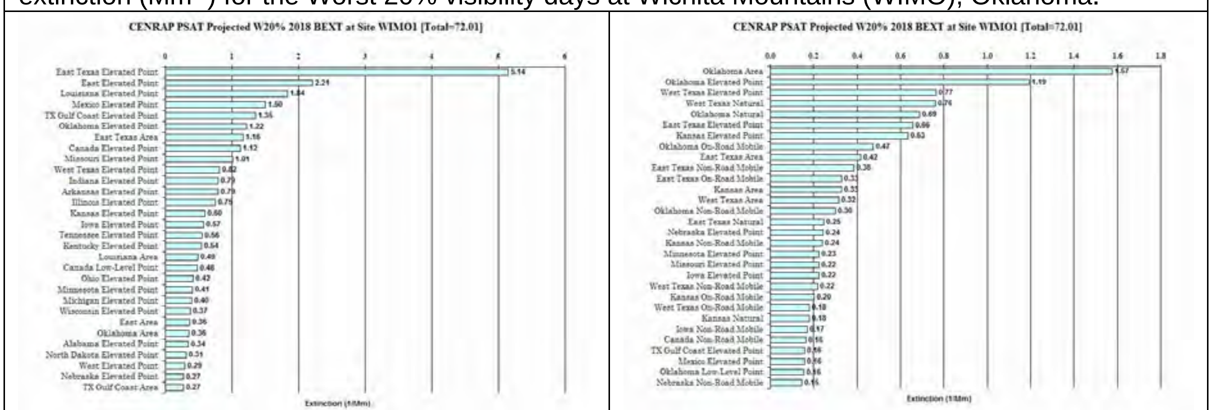


Figure E-8f. Ranked PSAT source region by source category contributions to the average 2018 SO4 (left) and NO3 (right) extinction (Mm^{-1}) for the Worst 20% visibility days at Wichita Mountains (WIMO), Oklahoma.

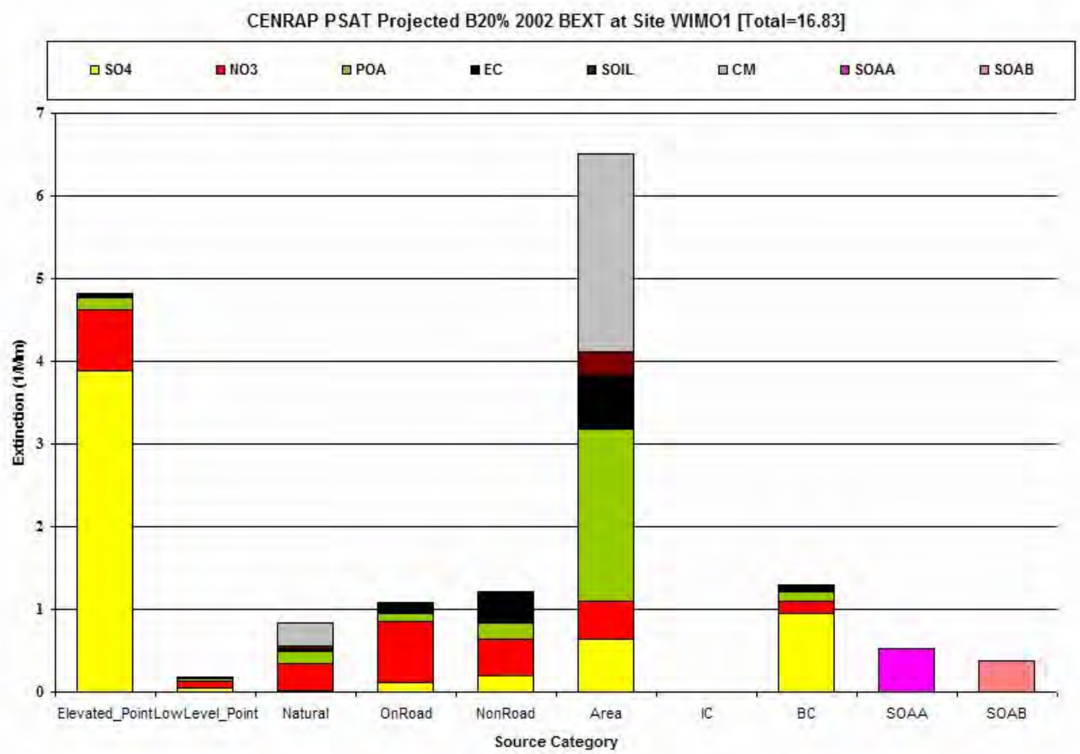


Figure E-8g. PSAT contributions by source category and PM species to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Best 20% visibility days at Wichita Mountains (WIMO), Oklahoma.

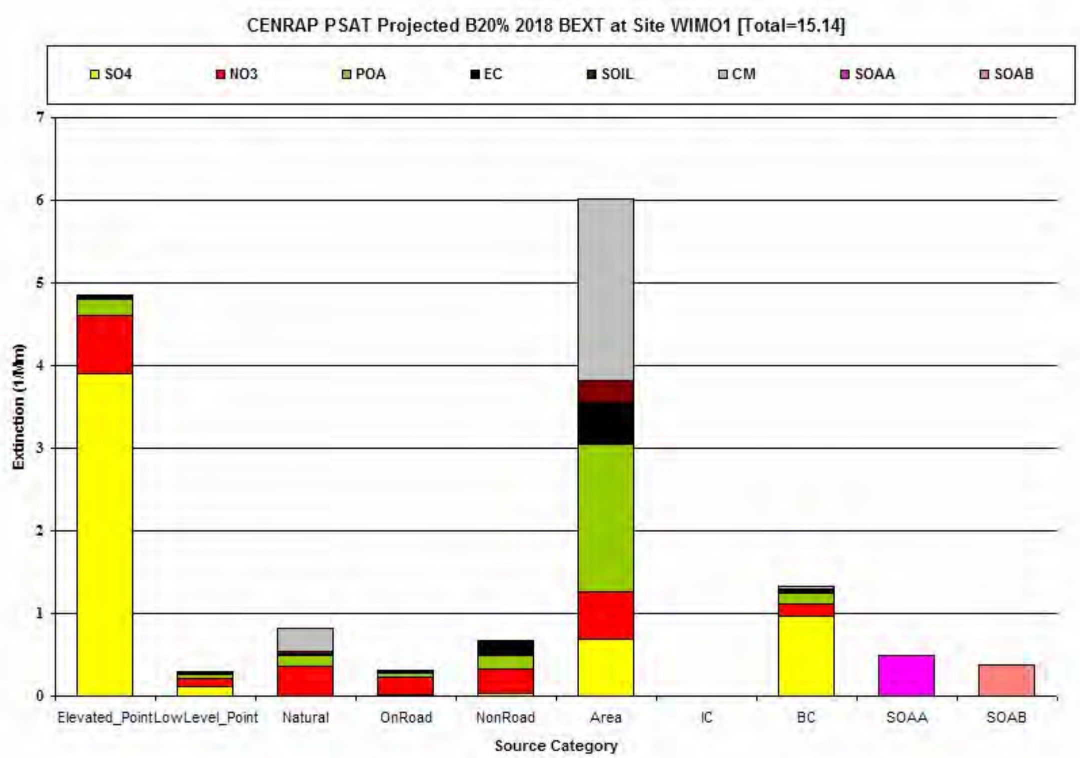


Figure E-8h. PSAT contributions by source category and PM species to the average 2018 extinction (Mm^{-1}) for the Best 20% visibility days at Wichita Mountains (WIMO), Oklahoma.

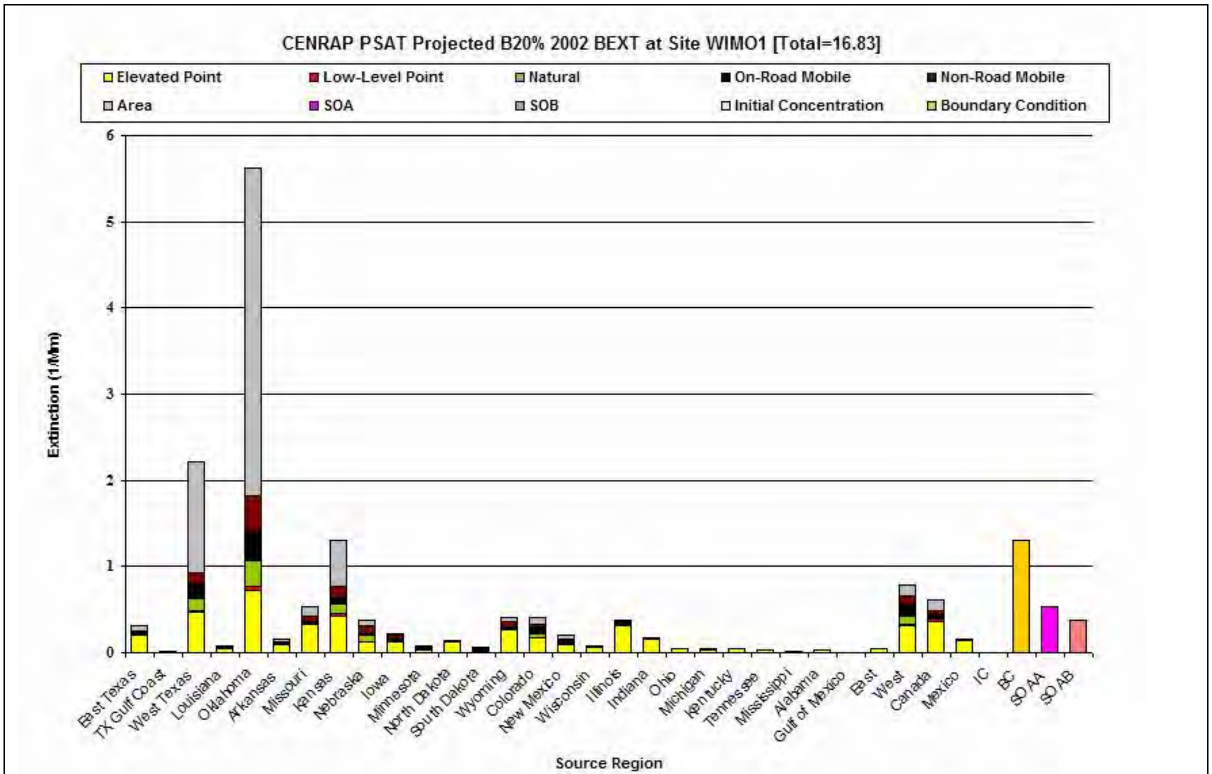


Figure E-8i. PSAT contributions by source region and source category to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Best 20% visibility days at Wichita Mountains (WIMO), Oklahoma.

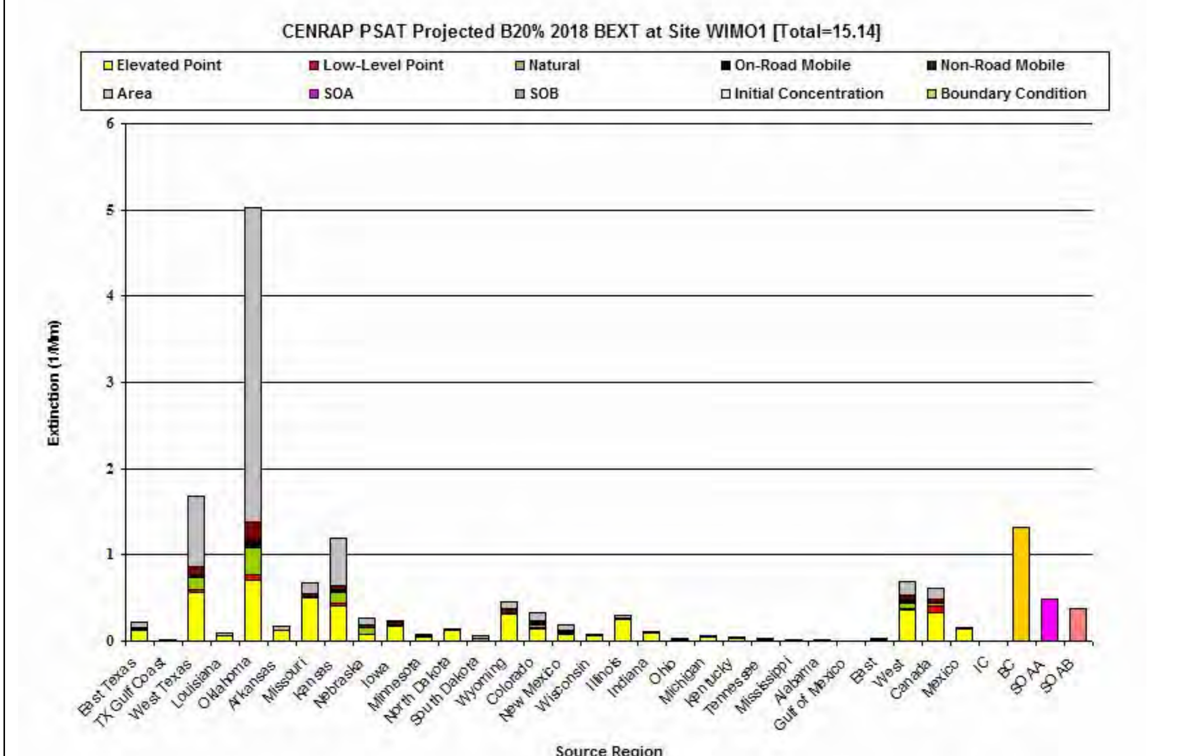


Figure E-8j. PSAT contributions by source region and source category to the average 2018 extinction (Mm^{-1}) for the Best 20% visibility days at Wichita Mountains (WIMO), Oklahoma.

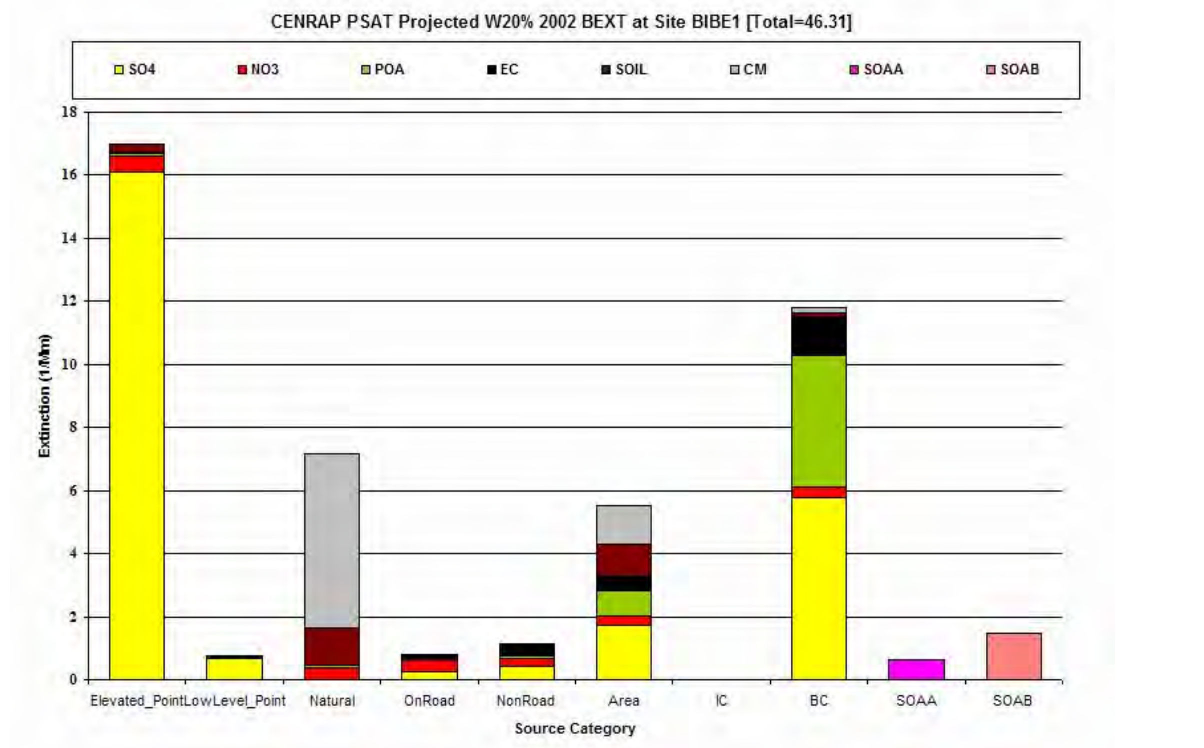


Figure E-9a. PSAT source categories by PM species contributions to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Worst 20% visibility days at Big Bend (BIBE), Texas.

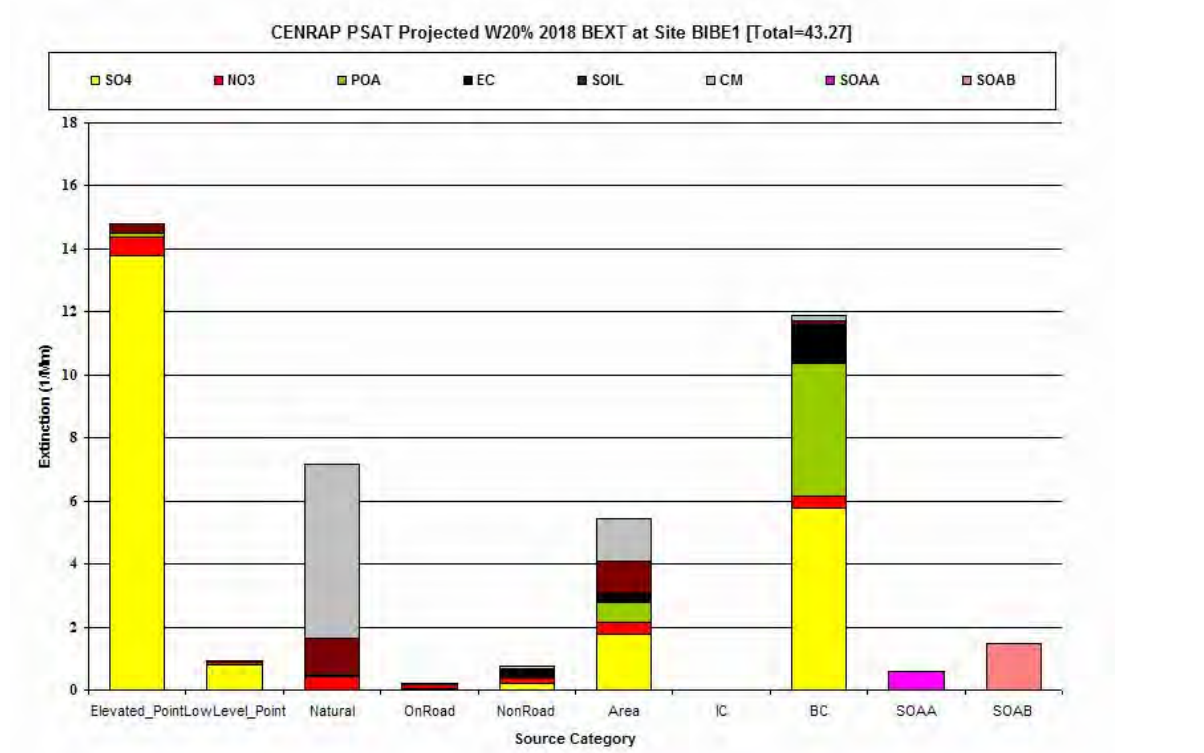


Figure E-9b. PSAT source category by PM species contributions to the average 2018 projected extinction (Mm^{-1}) for the Worst 20% visibility days at Big Bend (BIBE), Texas.

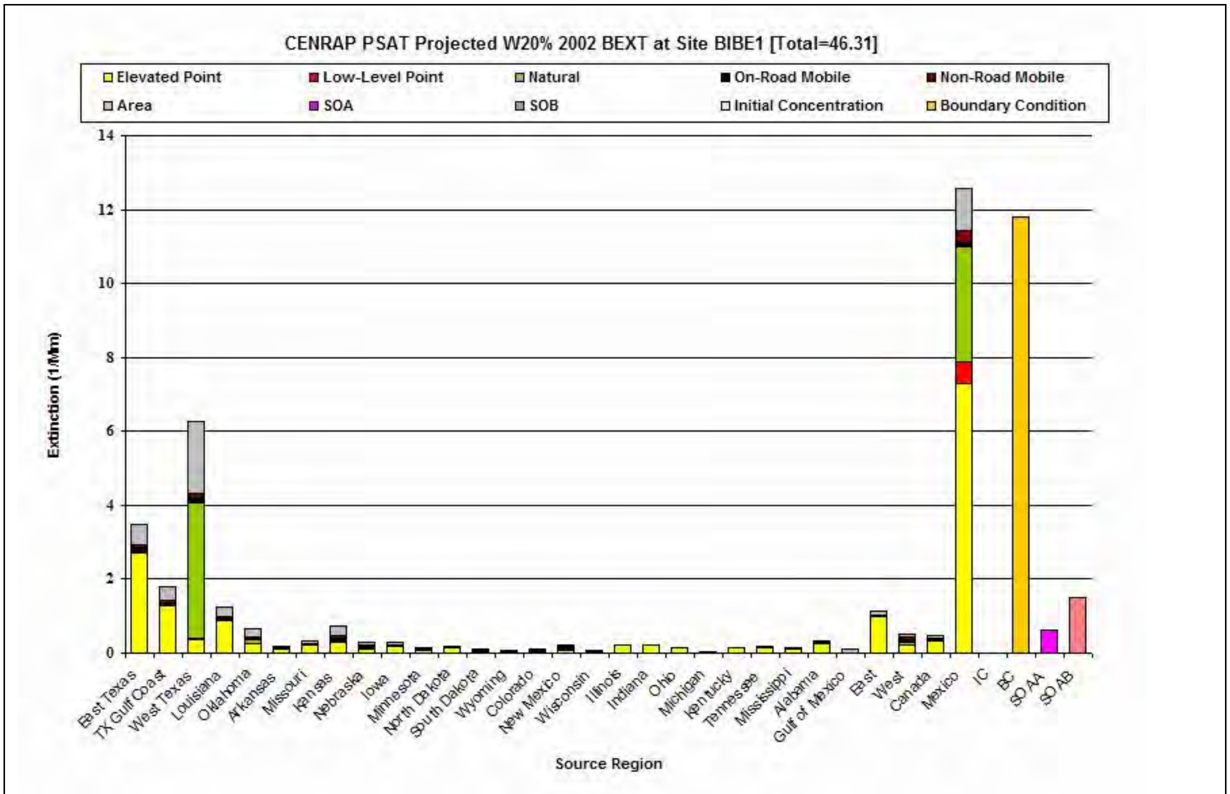


Figure E-9c. PSAT source region by source category contributions to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Worst 20% visibility days at Big Bend (BIBE), Texas.

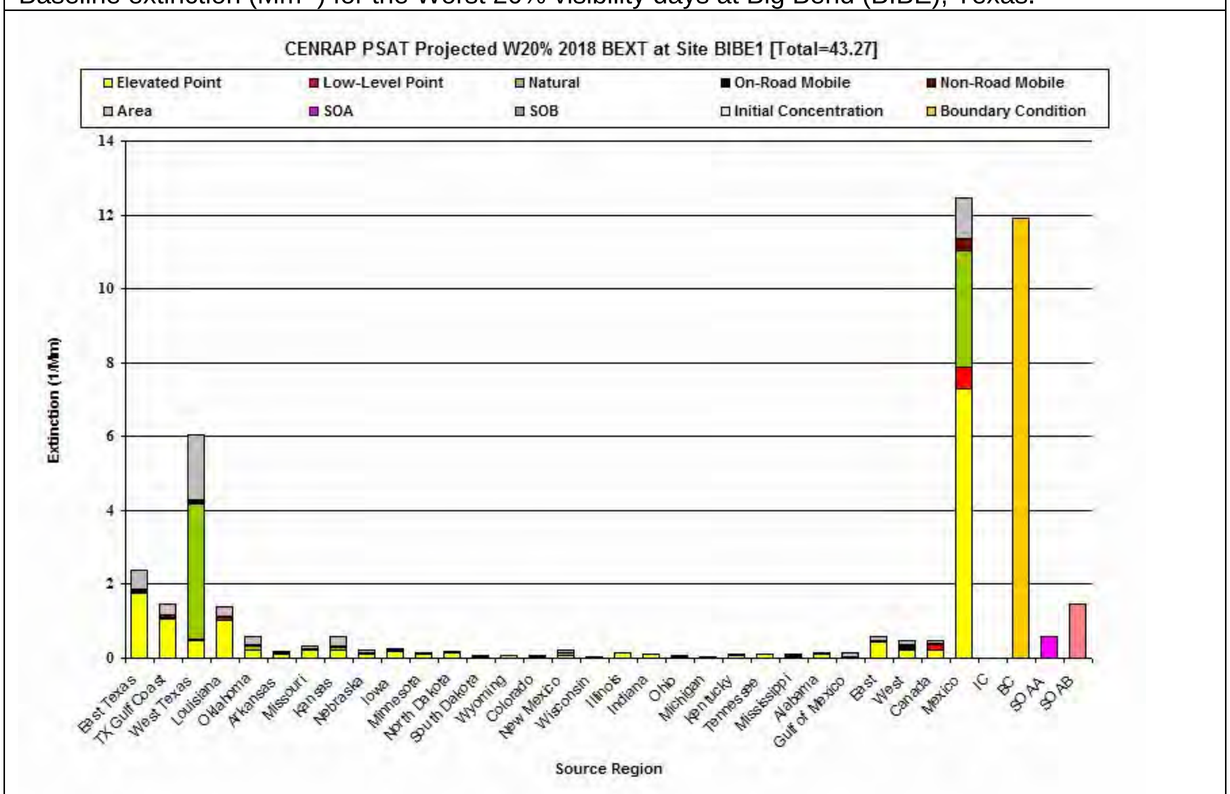


Figure E-9d. PSAT source region by source category contributions to the average 2018 extinction (Mm^{-1}) for the Worst 20% visibility days at Big Bend (BIBE), Texas.

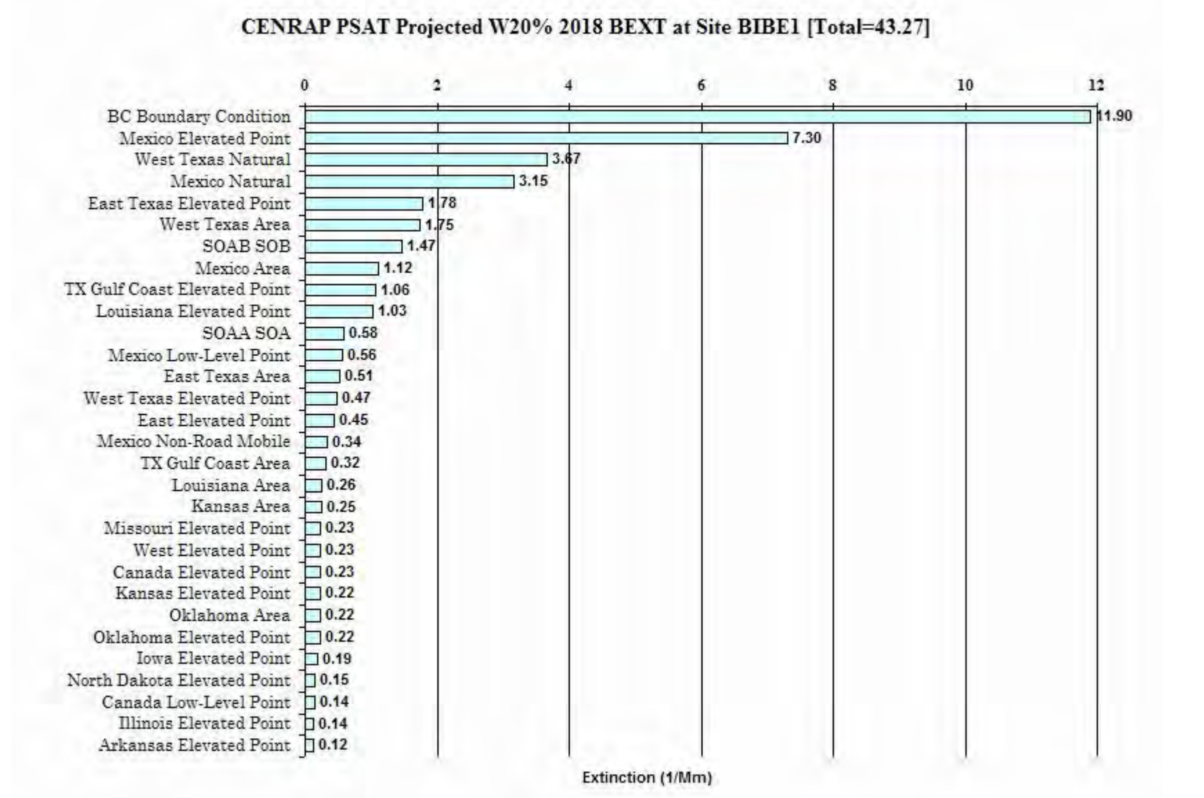
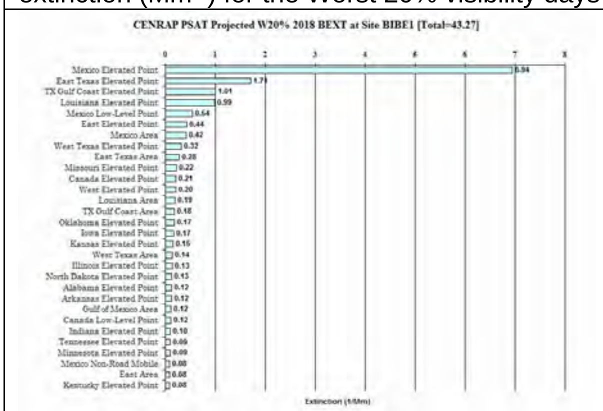


Figure E-9e. Ranked PSAT source region by source category contributions to the average 2018 extinction (Mm^{-1}) for the Worst 20% visibility days at Big Bend (BIBE), Texas.



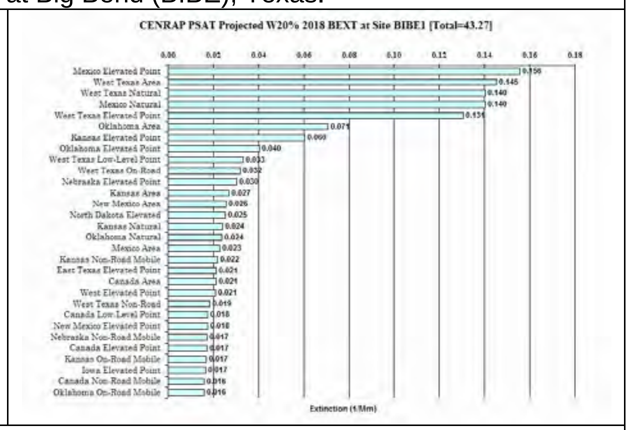


Figure E-9f. Ranked PSAT source region by source category contributions to the average 2018 SO4 (left) and NO3 (right) extinction (Mm^{-1}) for the Worst 20% visibility days at Big Bend (BIBE), Texas.

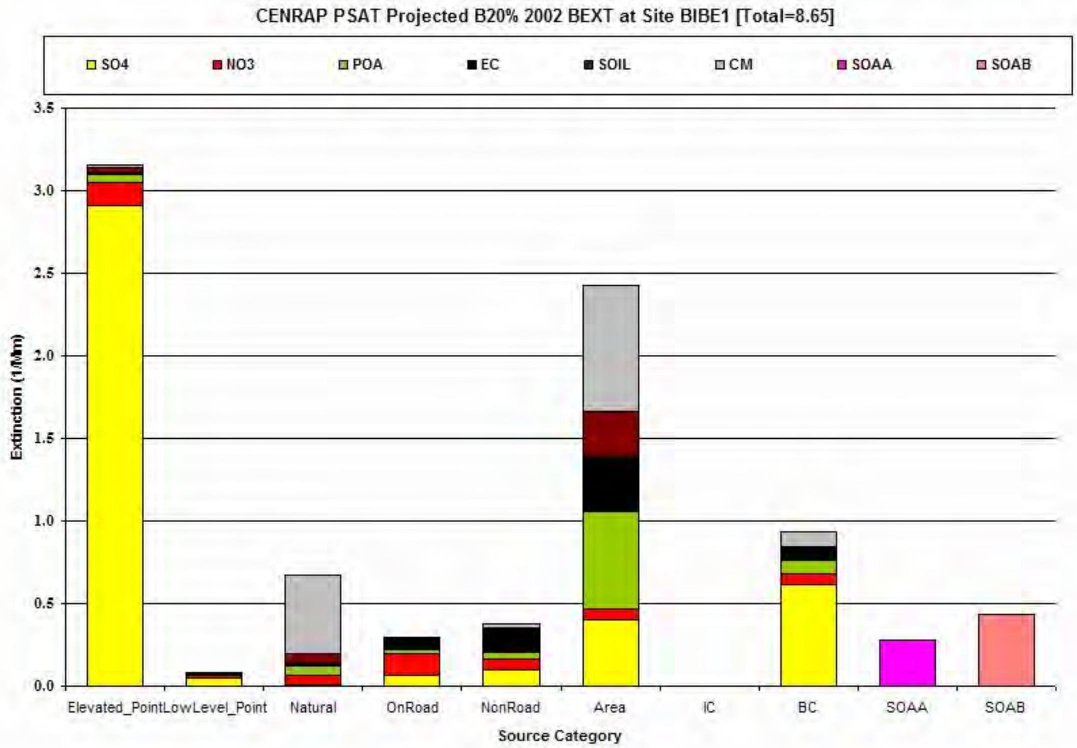


Figure E-9g. PSAT contributions by source category and PM species to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Best 20% visibility days at Big Bend (BIBE), Texas.

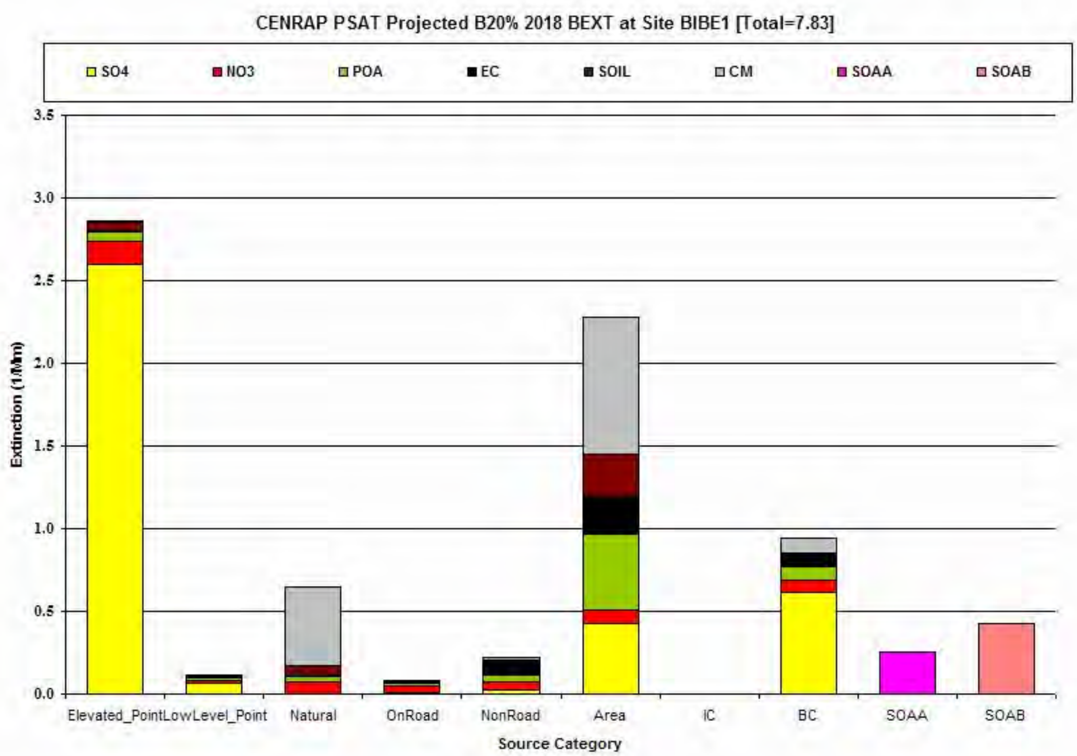


Figure E-9h. PSAT contributions by source category and PM species to the average 2018 extinction (Mm^{-1}) for the Best 20% visibility days at Big Bend (BIBE), Texas.

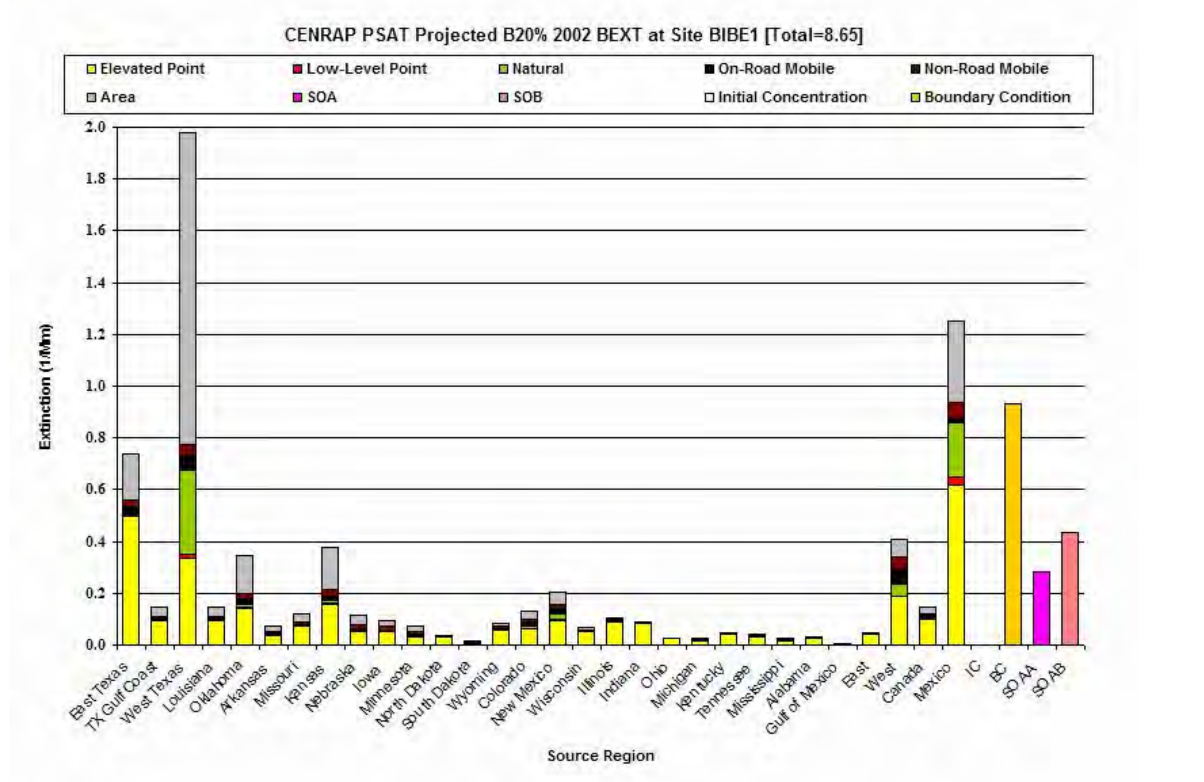


Figure E-9i. PSAT contributions by source region and source category to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Best 20% visibility days Big Bend (BIBE), Texas.

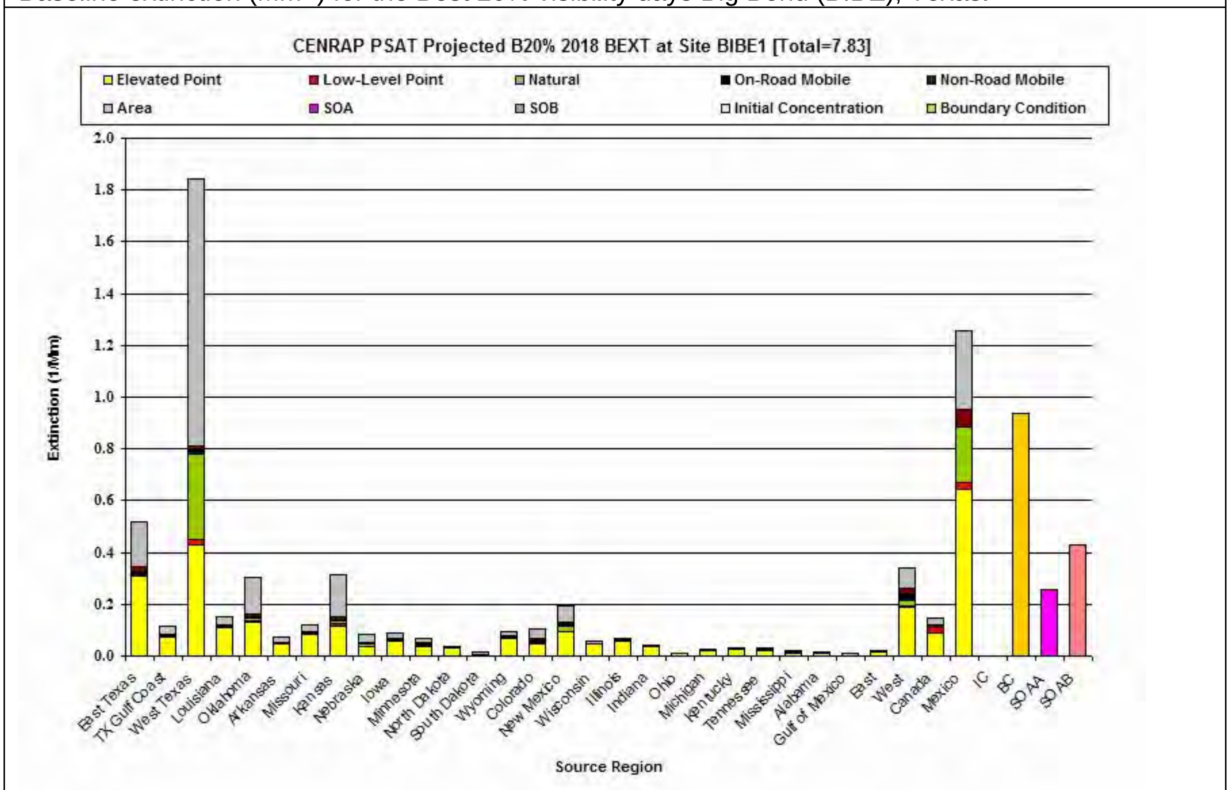


Figure E-9j. PSAT contributions by source region and source category to the average 2018 extinction (Mm^{-1}) for the Best 20% visibility days at Big Bend (BIBE), Texas.

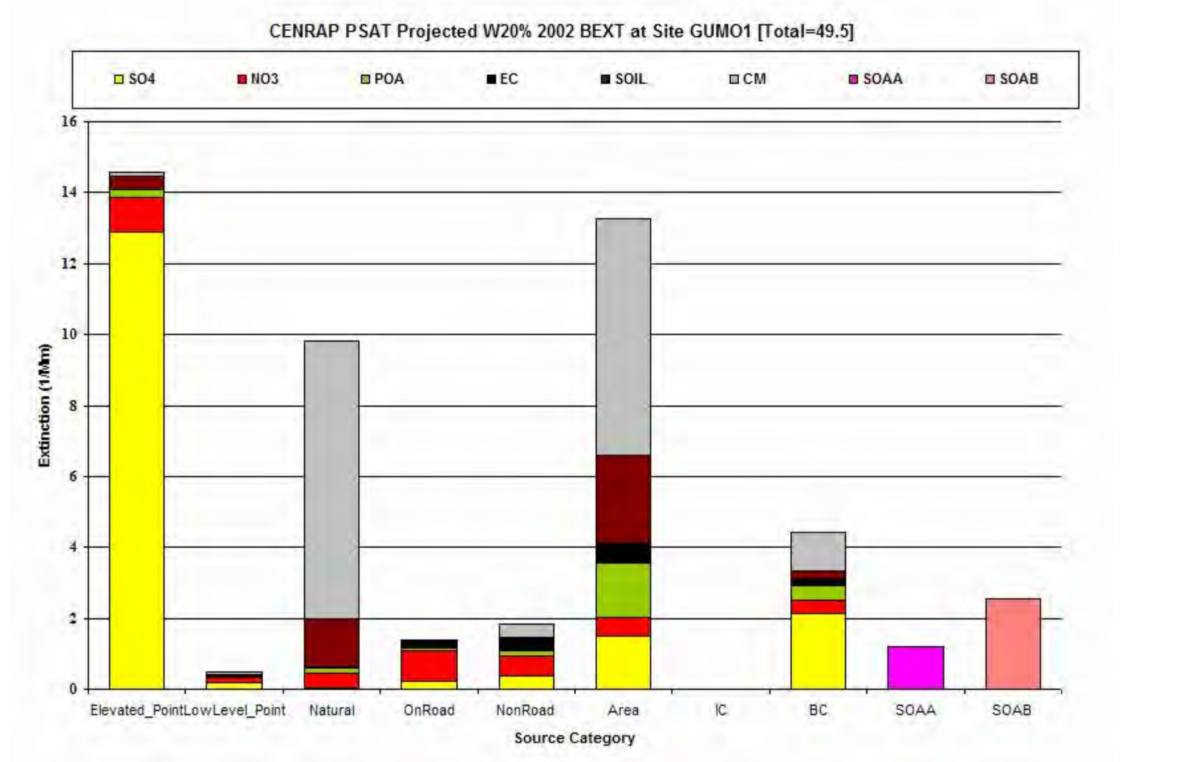


Figure E-10a. PSAT source categories by PM species contributions to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Worst 20% visibility days at Big Bend (BIBE), Texas.

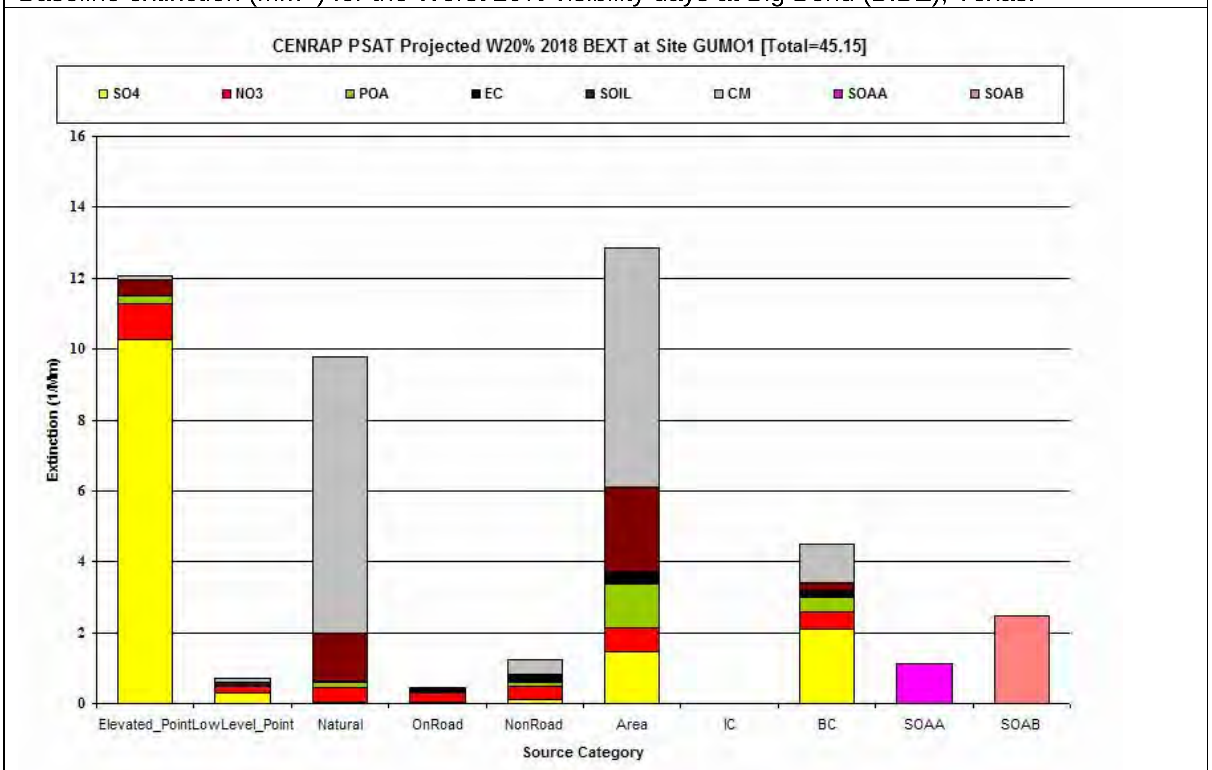


Figure E-10b. PSAT source category by PM species contributions to the average 2018 projected extinction (Mm^{-1}) for the Worst 20% visibility days at Big Bend (BIBE), Texas.

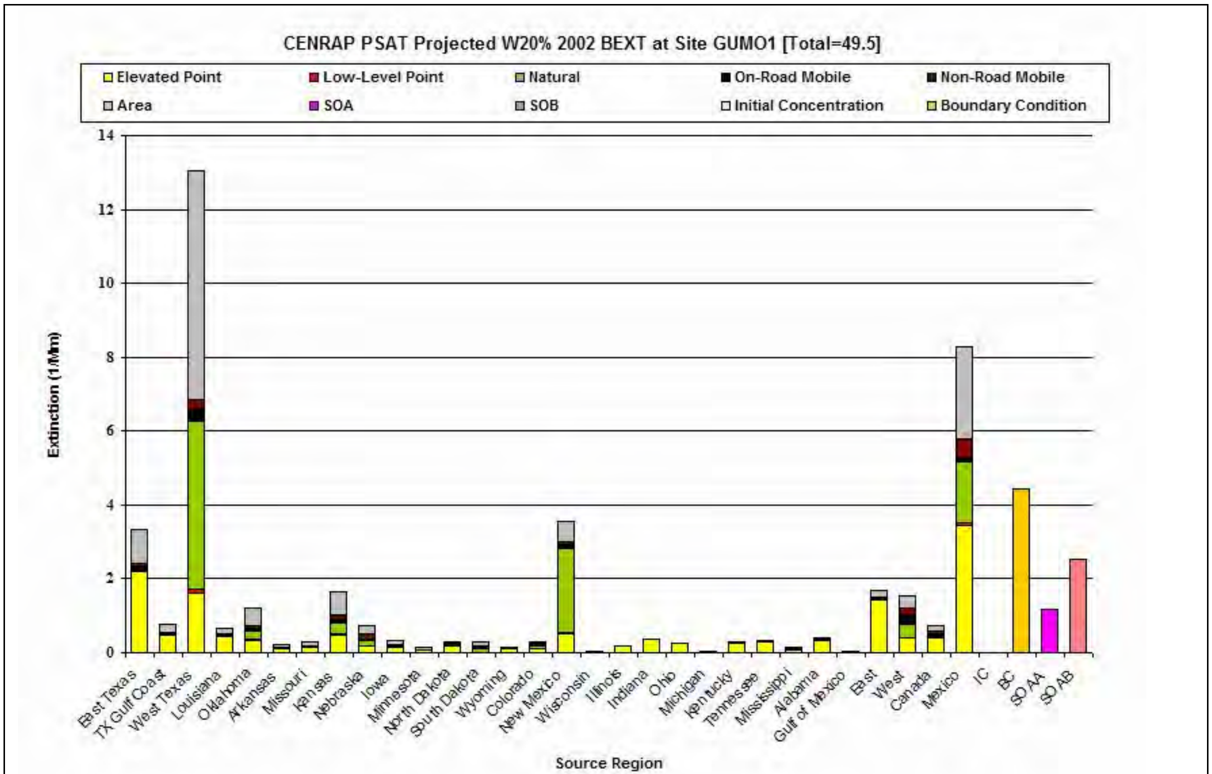


Figure E-10c. PSAT source region by source category contributions to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Worst 20% visibility days at Big Bend (BIBE), Texas.

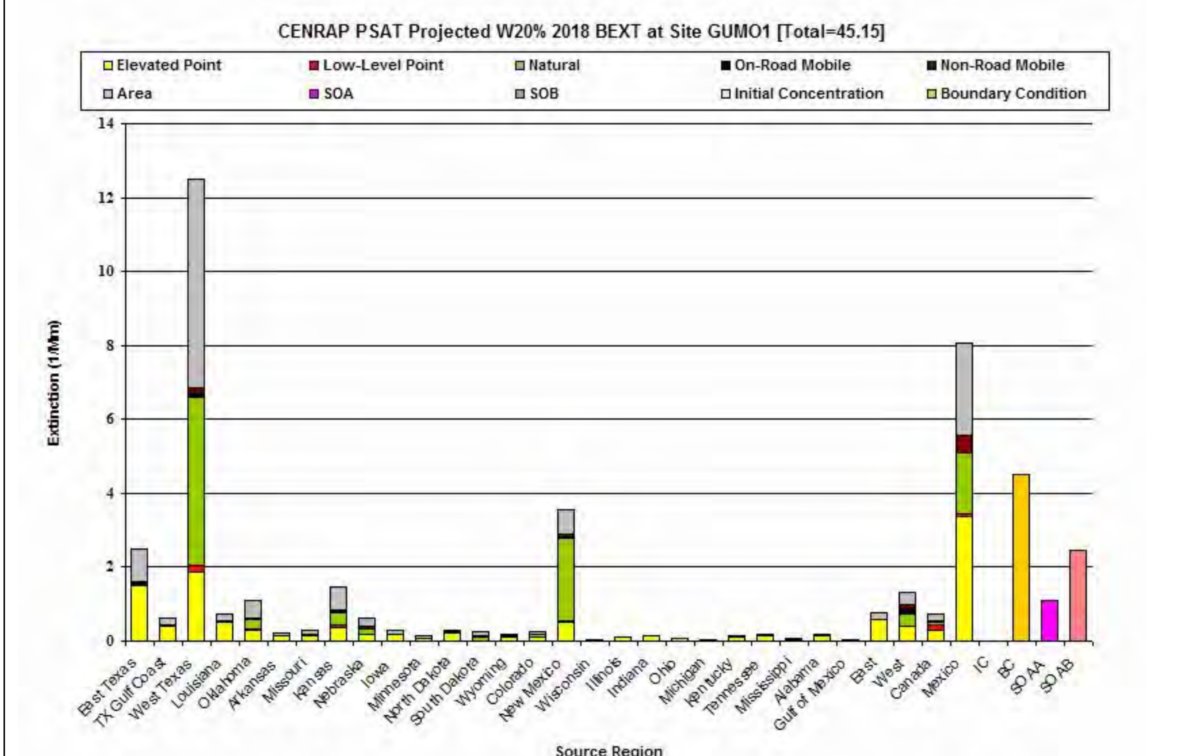


Figure E-10d. PSAT source region by source category contributions to the average 2018 extinction (Mm^{-1}) for the Worst 20% visibility days at Big Bend (BIBE), Texas.

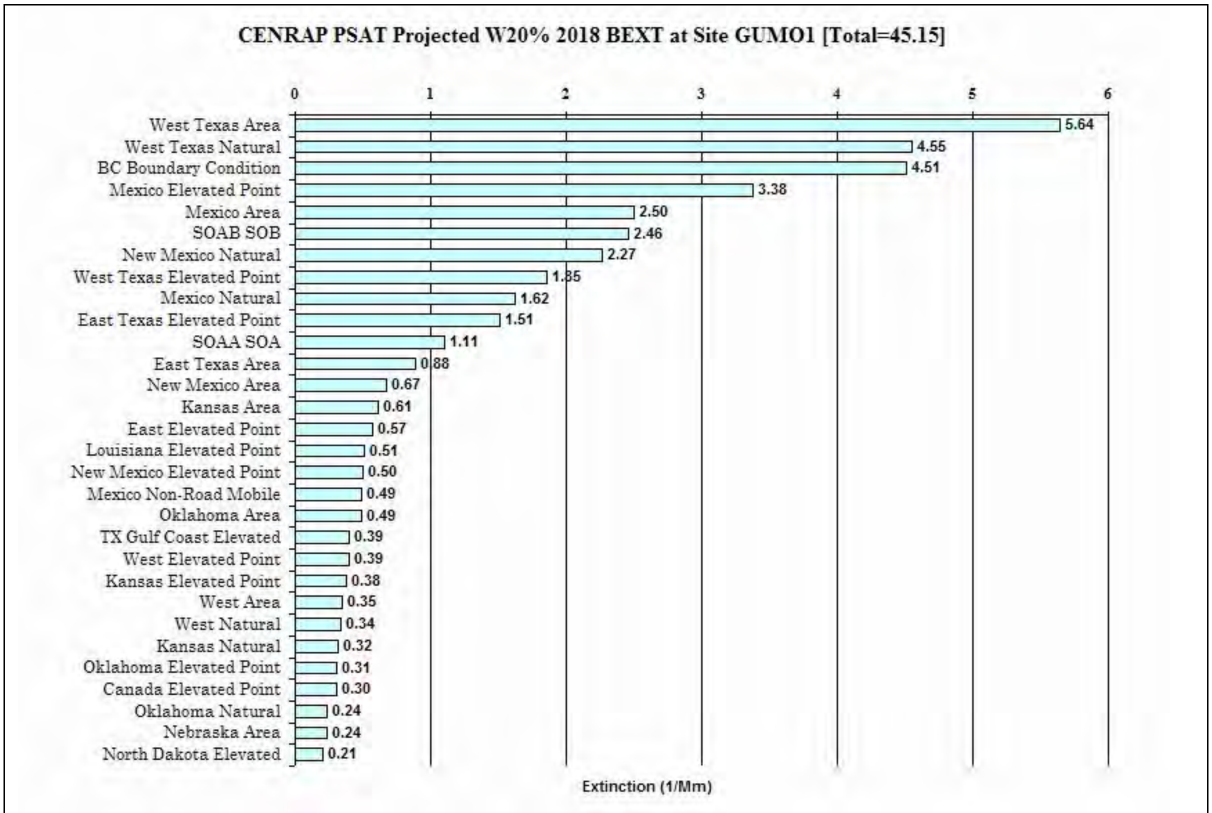
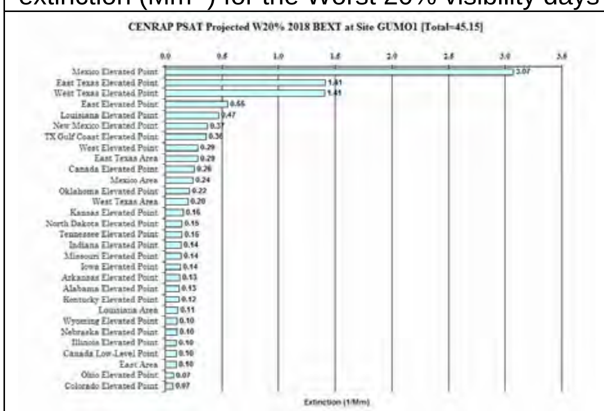


Figure E-10e. Ranked PSAT source region by source category contributions to the average 2018 extinction (Mm^{-1}) for the Worst 20% visibility days at Big Bend (BIBE), Texas.



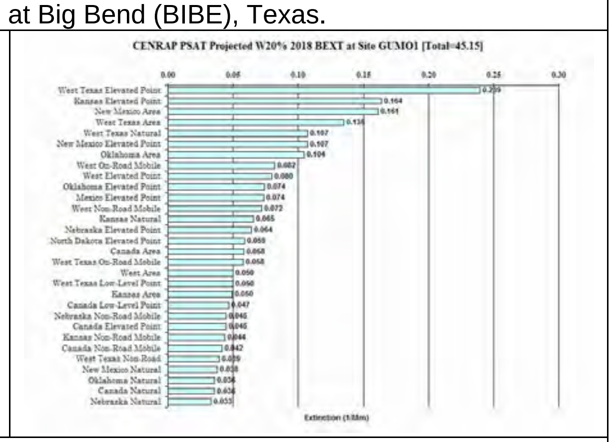


Figure E-10f. Ranked PSAT source region by source category contributions to the average 2018 SO4 (left) and NO3 (right) extinction (Mm^{-1}) for the Worst 20% visibility days at Big Bend (BIBE), Texas.

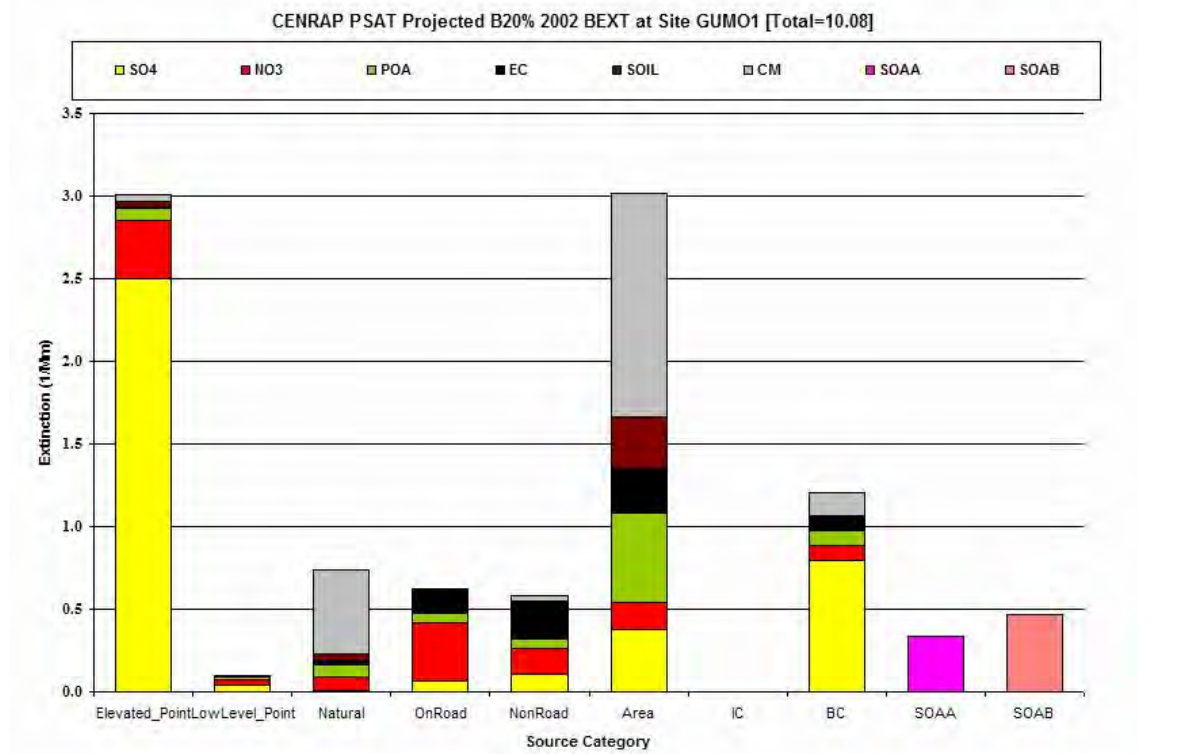


Figure E-10g. PSAT contributions by source category and PM species to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Best 20% visibility days at Big Bend (BIBE), Texas.

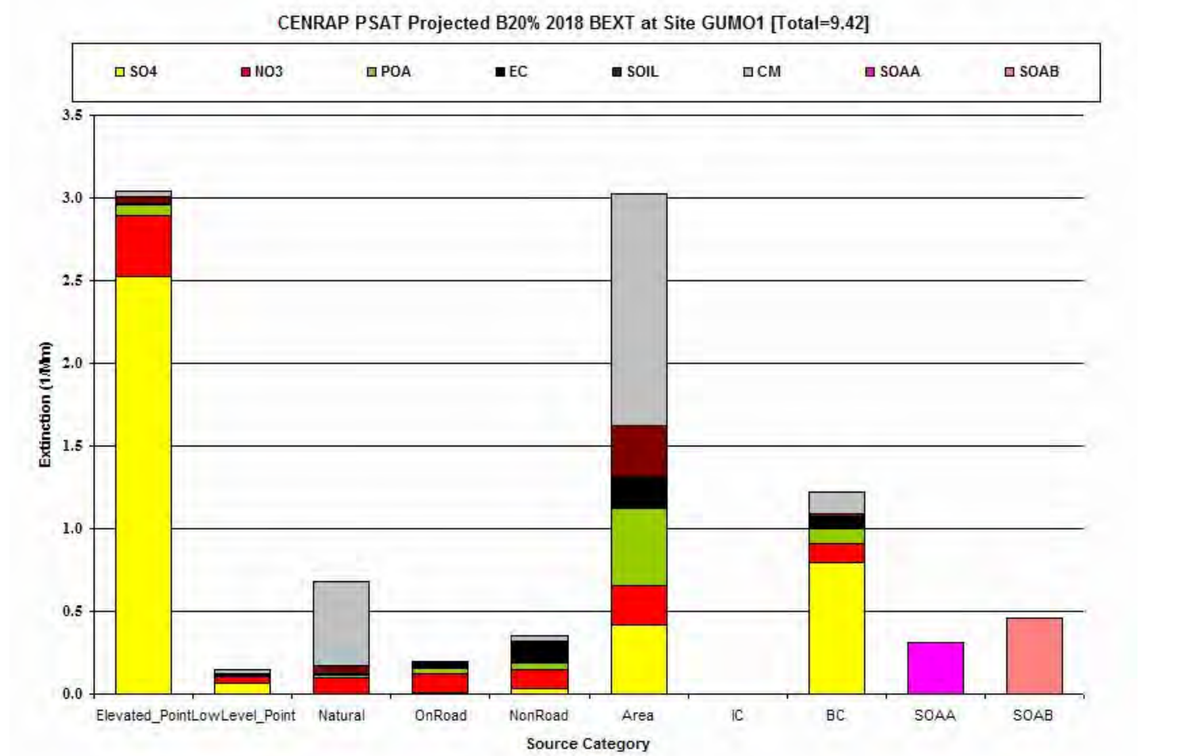


Figure E-10h. PSAT contributions by source category and PM species to the average 2018 extinction (Mm^{-1}) for the Best 20% visibility days at Big Bend (BIBE), Texas.

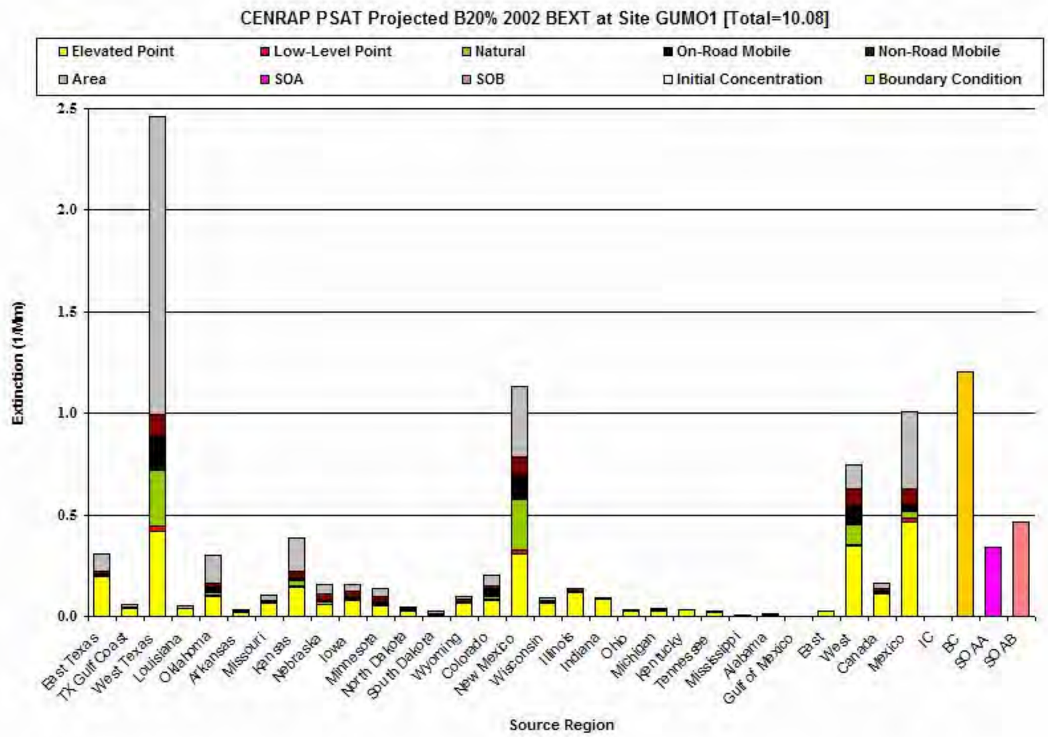


Figure E-10i. PSAT contributions by source region and source category to the average 2000-2004 Baseline extinction (Mm^{-1}) for the Best 20% visibility days Big Bend (BIBE), Texas.

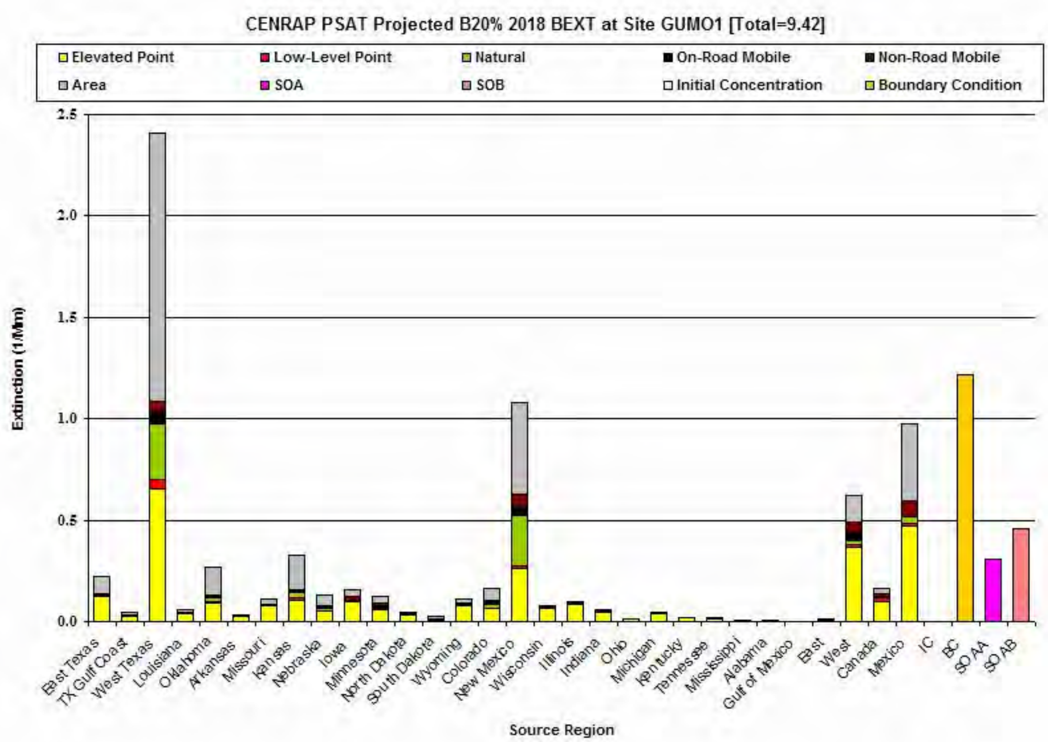


Figure E-10j. PSAT contributions by source region and source category to the average 2018 extinction (Mm^{-1}) for the Best 20% visibility days at Big Bend (BIBE), Texas.

APPENDIX F

Extinction and PM Species-Specific 2018 Visibility Projections and Comparisons with 2018 URP Points

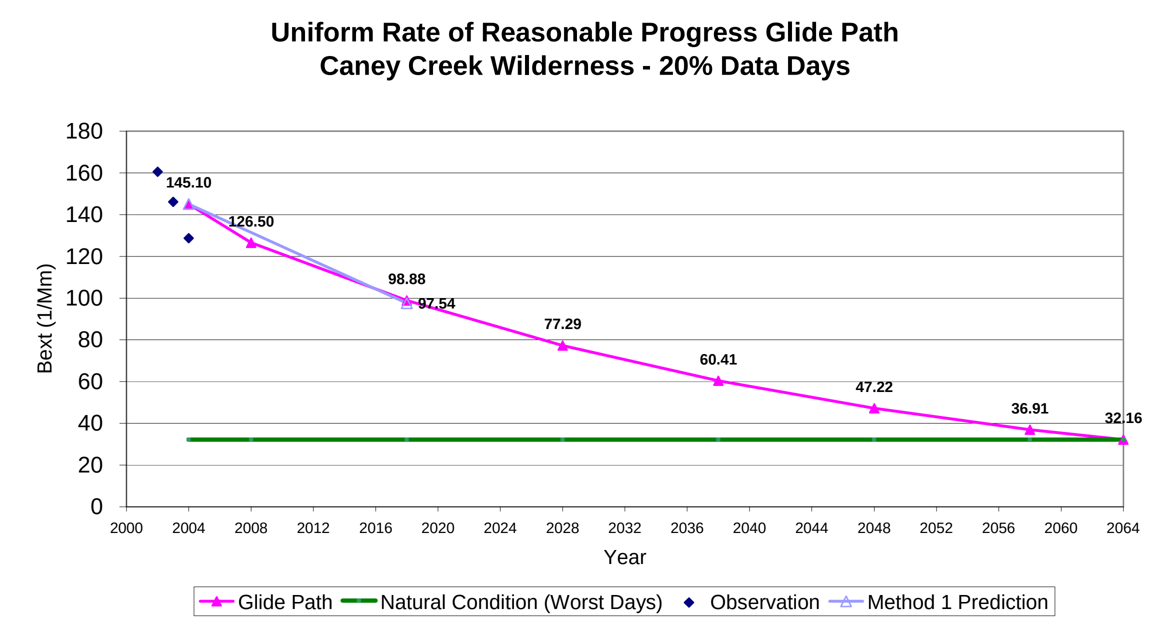


Figure F-1a. 2018 Visibility Projections and 2018 URP Glidepaths in extinction (Mm^{-1}) for Caney Creek (CACR), Arkansas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

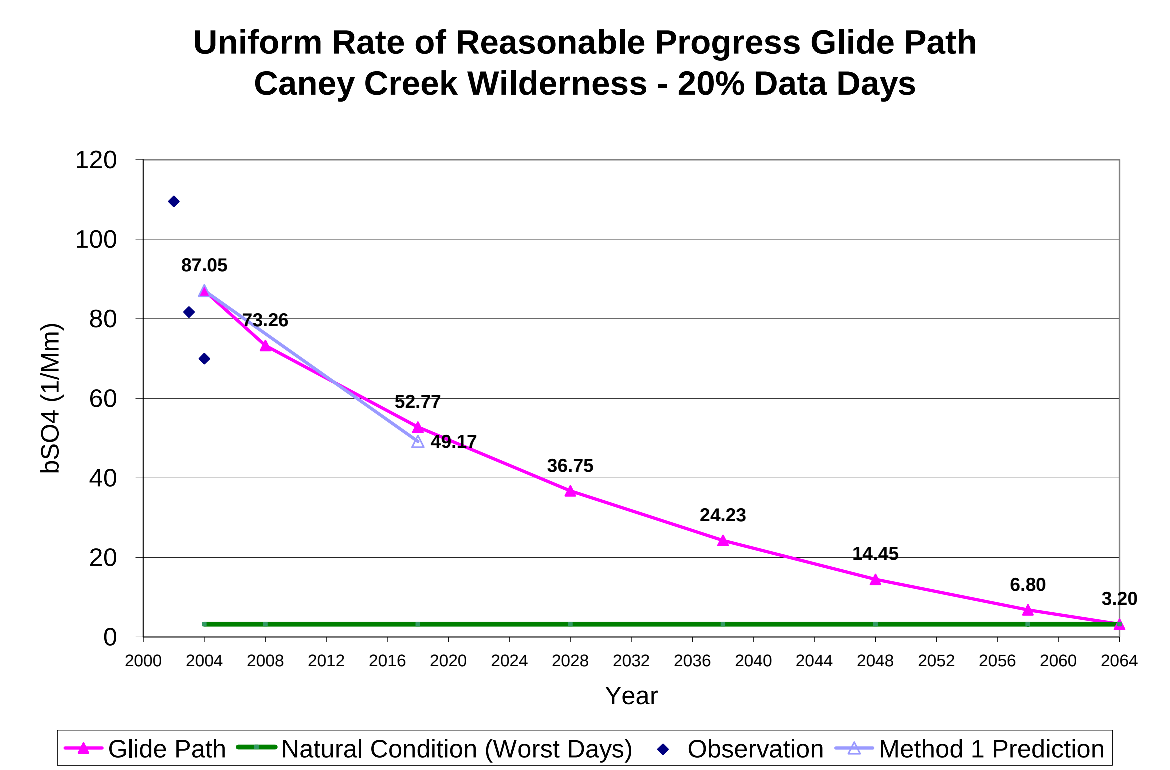


Figure F-1b. 2018 Visibility Projections and 2018 URP Glidepaths for Sulfate (SO4) in extinction (Mm^{-1}) for Caney Creek (CACR), Arkansas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

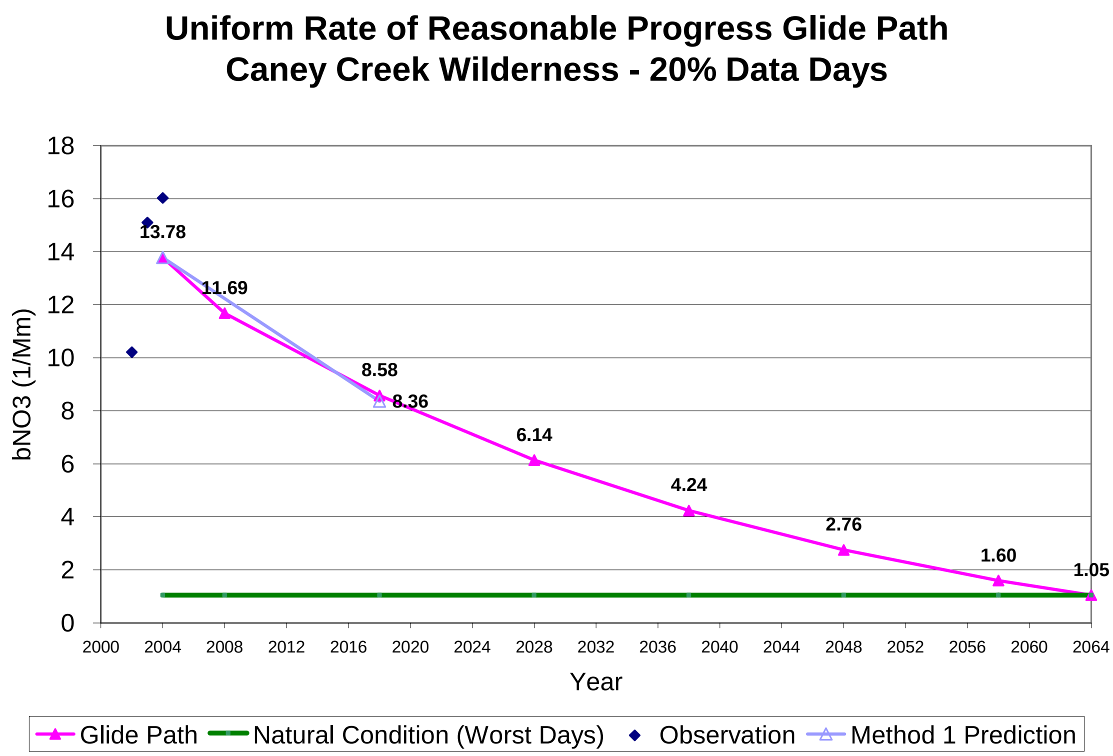


Figure F-1c. 2018 Visibility Projections and 2018 URP Glidepaths for Nitrate (NO3) in extinction (Mm^{-1}) for Caney Creek (CACR), Arkansas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

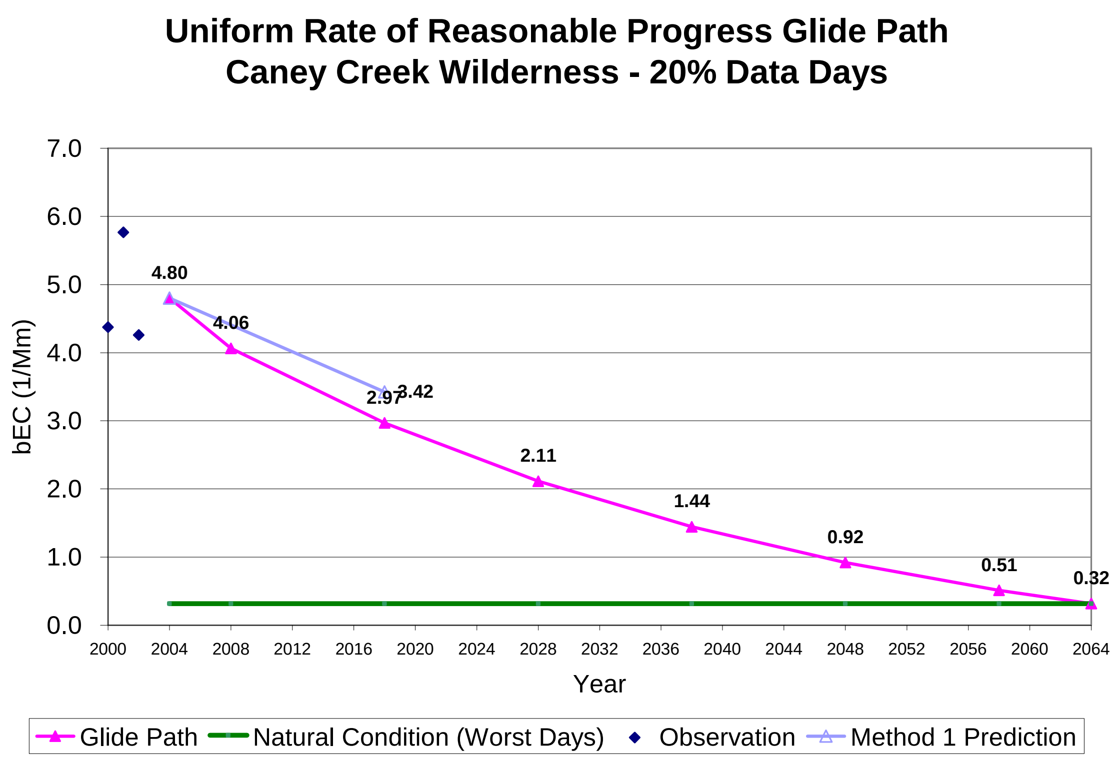


Figure F-1d. 2018 Visibility Projections and 2018 URP Glidepaths for Elemental Carbon (EC) in extinction (Mm^{-1}) for Caney Creek (CACR), Arkansas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

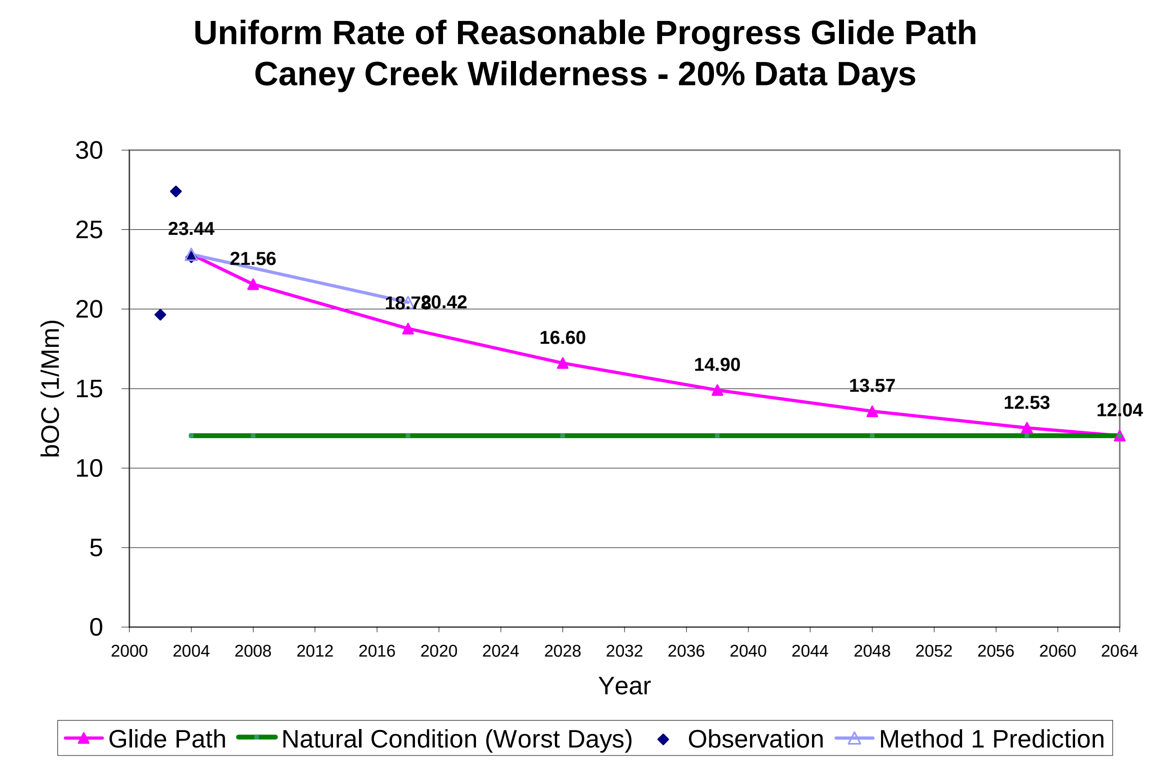


Figure F-1e. 2018 Visibility Projections and 2018 URP Glidepaths for Organic Mass Carbon (OMC) in extinction (Mm^{-1}) for Caney Creek (CACR), Arkansas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

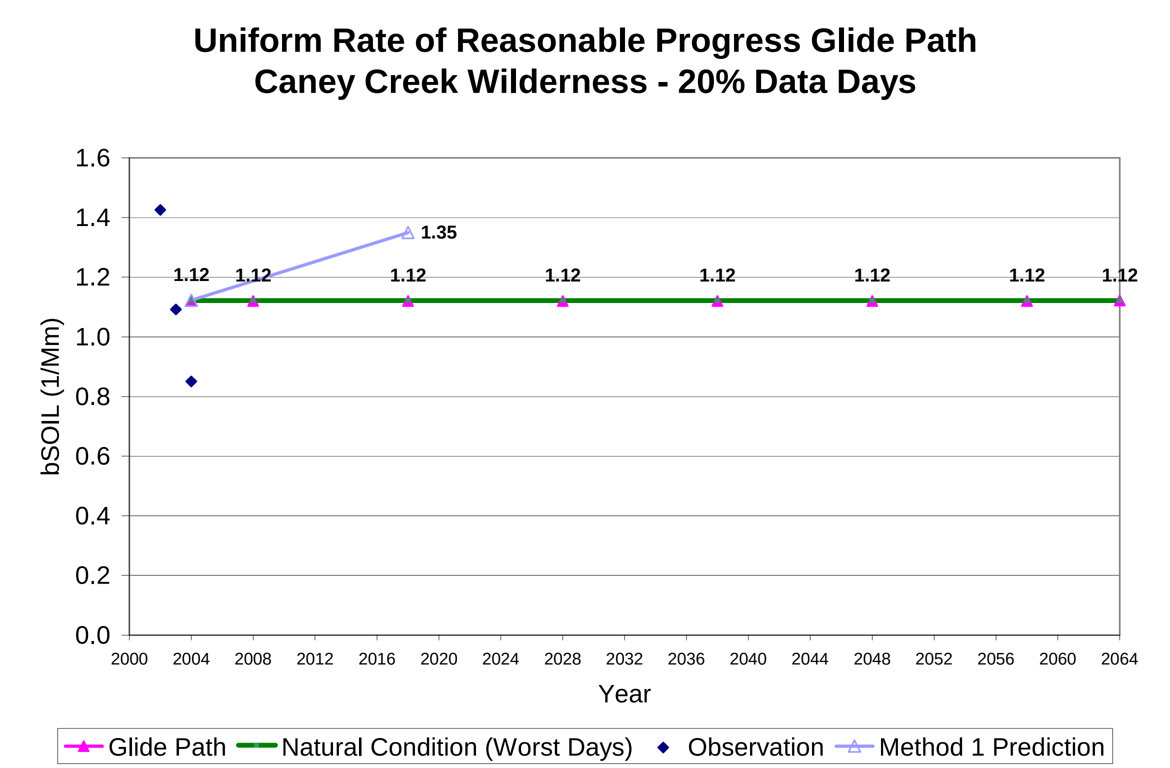


Figure F-1f. 2018 Visibility Projections and 2018 URP Glidepaths for Other Fine Particulate (SOIL) in extinction (Mm^{-1}) for Caney Creek (CACR), Arkansas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

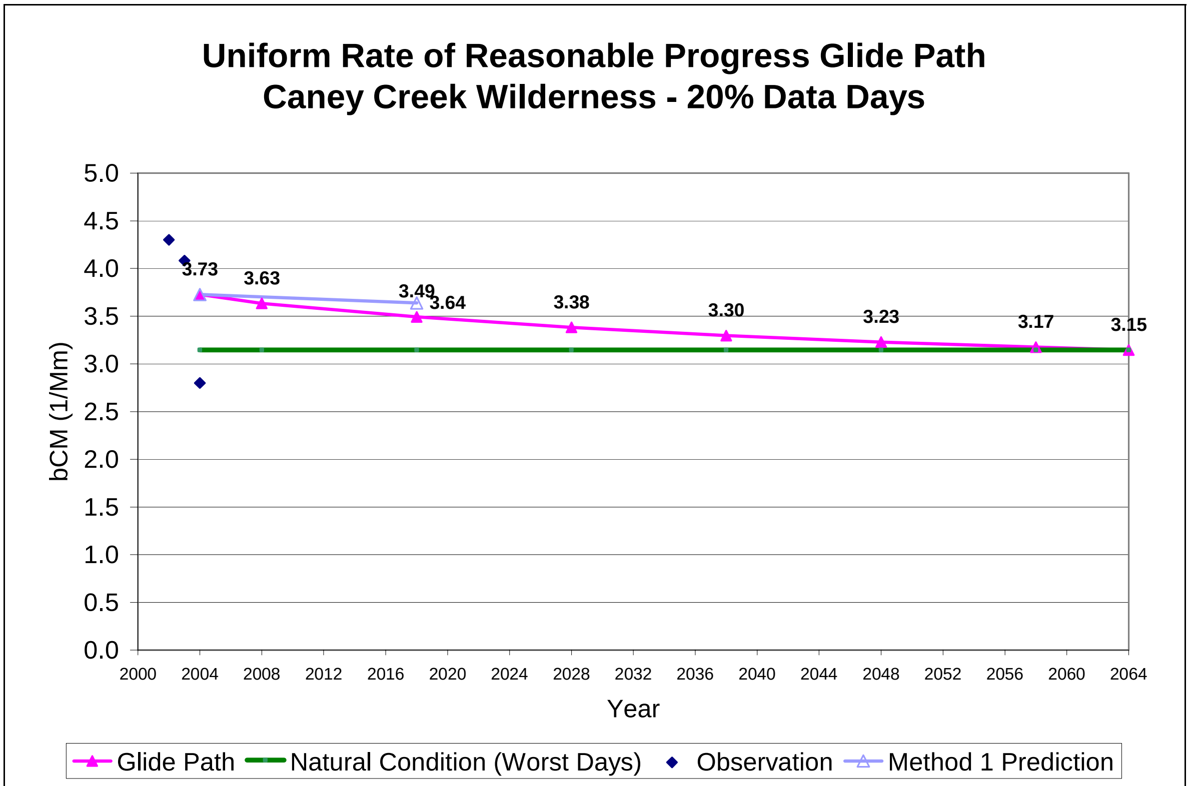


Figure F-1g. 2018 Visibility Projections and 2018 URP Glidepaths for Coarse Mass (CM) in extinction (Mm^{-1}) for Caney Creek (CACR), Arkansas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

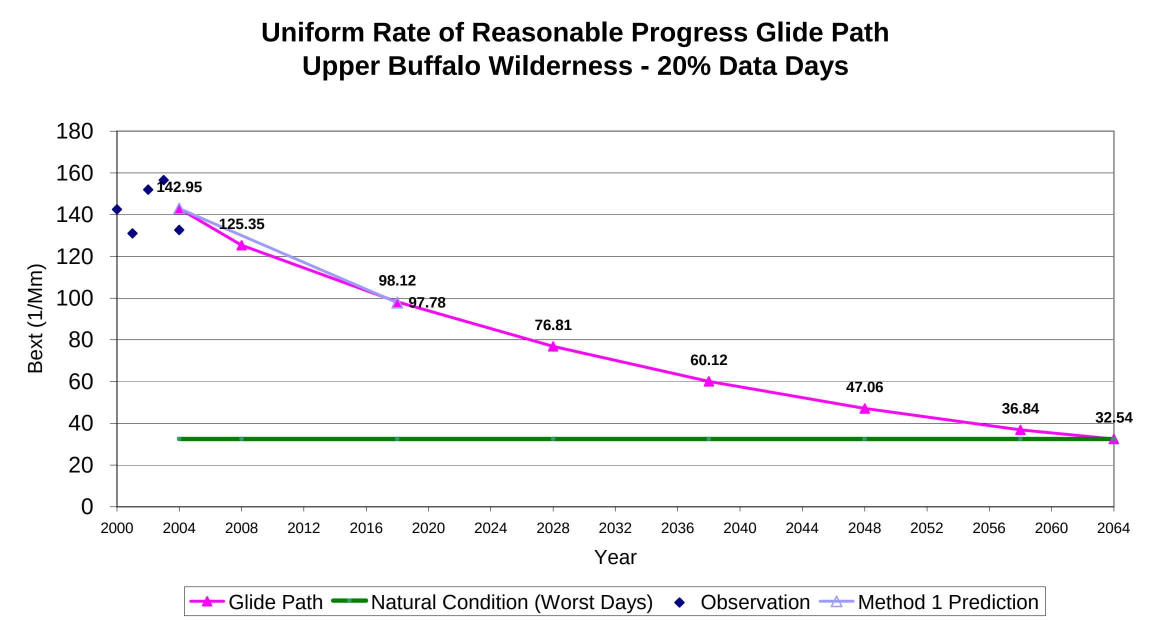


Figure F-2a. 2018 Visibility Projections and 2018 URP Glidepaths in extinction (Mm^{-1}) for Upper Buffalo (UPBU), Arkansas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

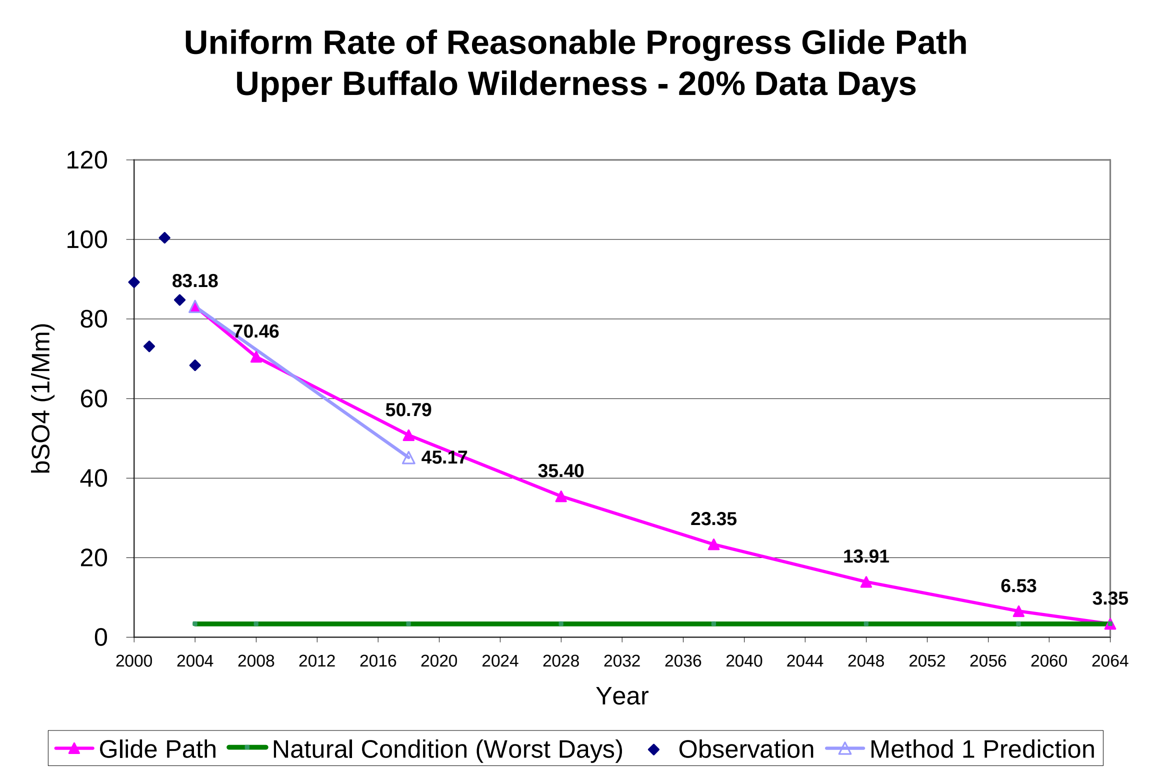


Figure F-2b. 2018 Visibility Projections and 2018 URP Glidepaths for Sulfate (SO4) in extinction (Mm^{-1}) for Upper Buffalo (UPBU), Arkansas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

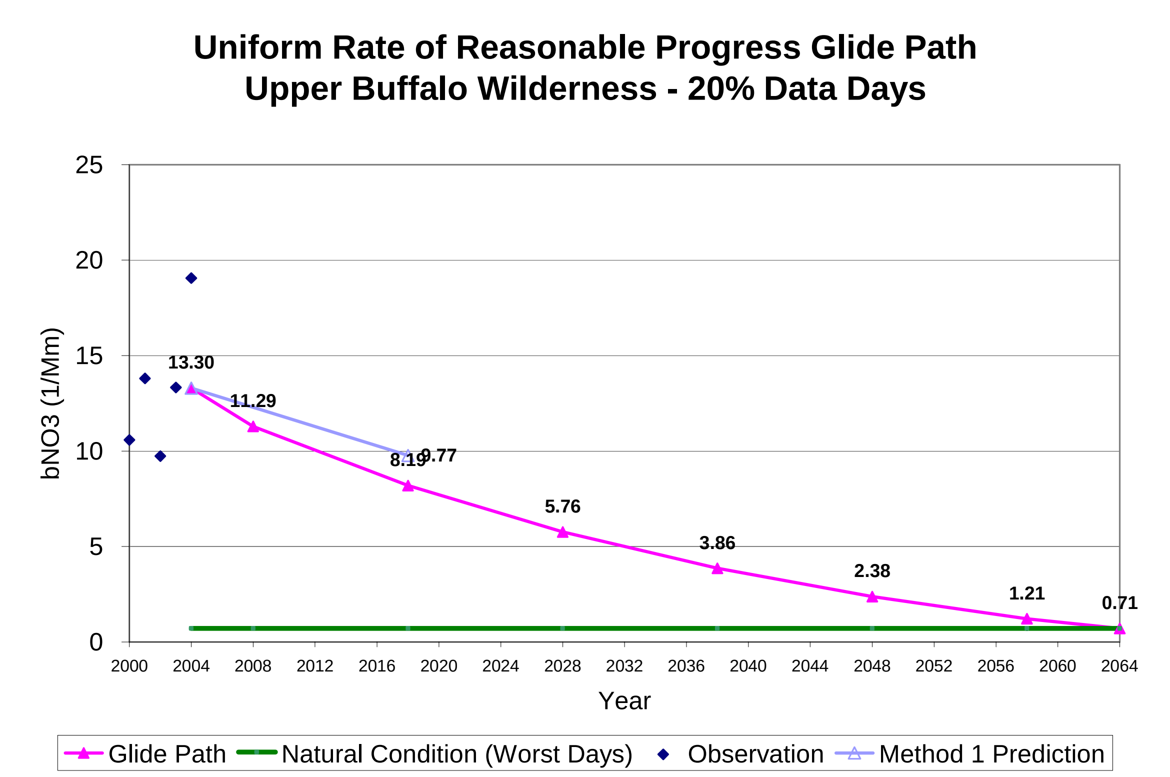


Figure F-2c. 2018 Visibility Projections and 2018 URP Glidepaths for Nitrate (NO3) in extinction (Mm^{-1}) for Upper Buffalo (UPBU), Arkansas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

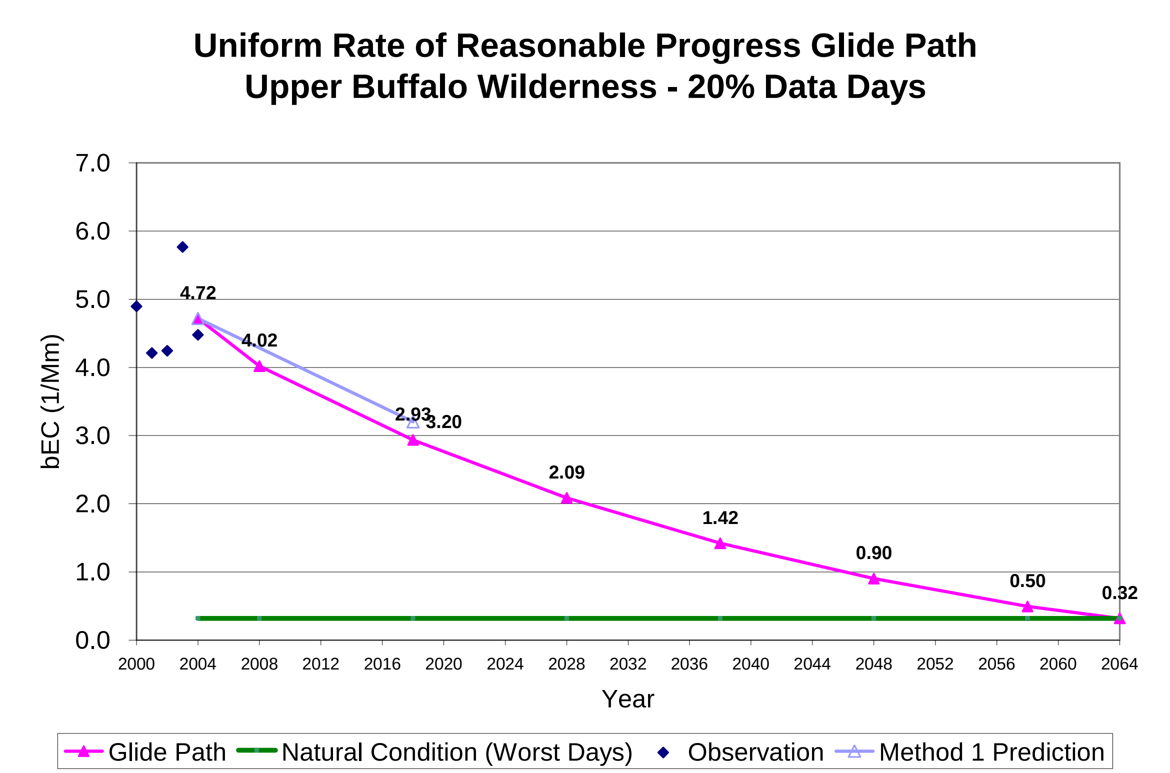


Figure F-2d. 2018 Visibility Projections and 2018 URP Glidepaths for Elemental Carbon (EC) in extinction (Mm^{-1}) for Upper Buffalo (UPBU), Arkansas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

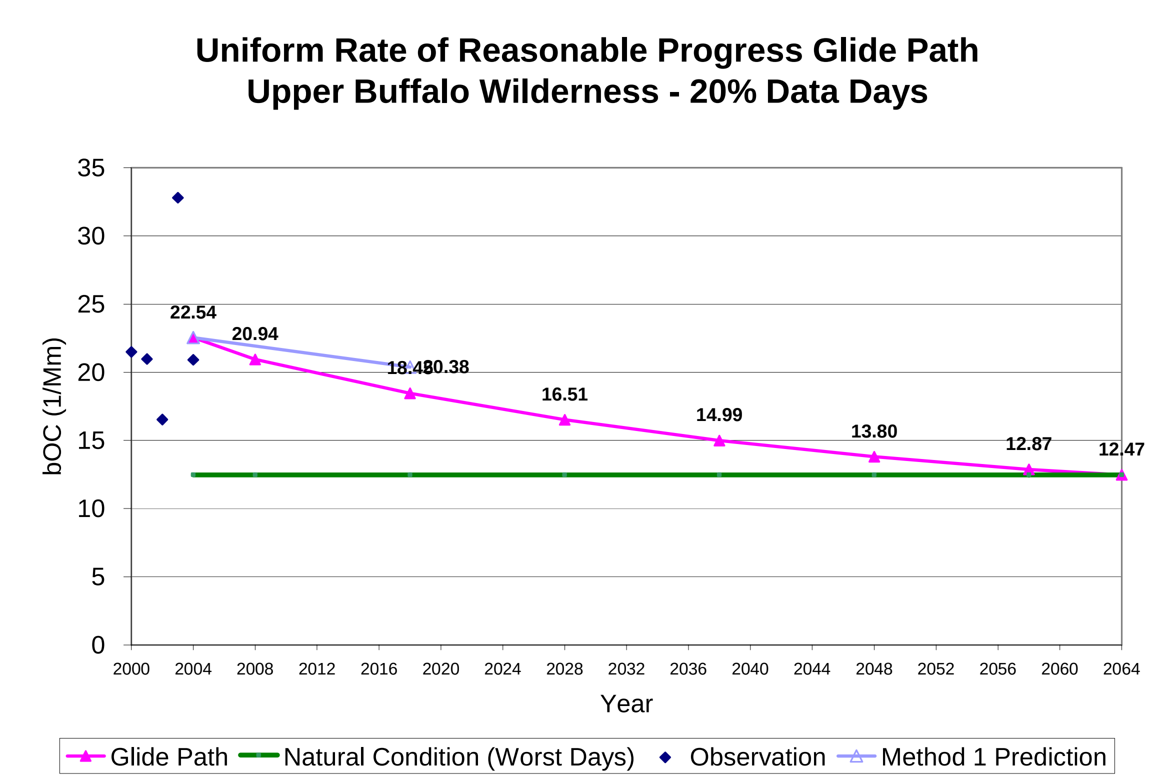


Figure F-2e. 2018 Visibility Projections and 2018 URP Glidepaths for Organic Mass Carbon (OMC) in extinction (Mm^{-1}) for Upper Buffalo (UPBU), Arkansas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

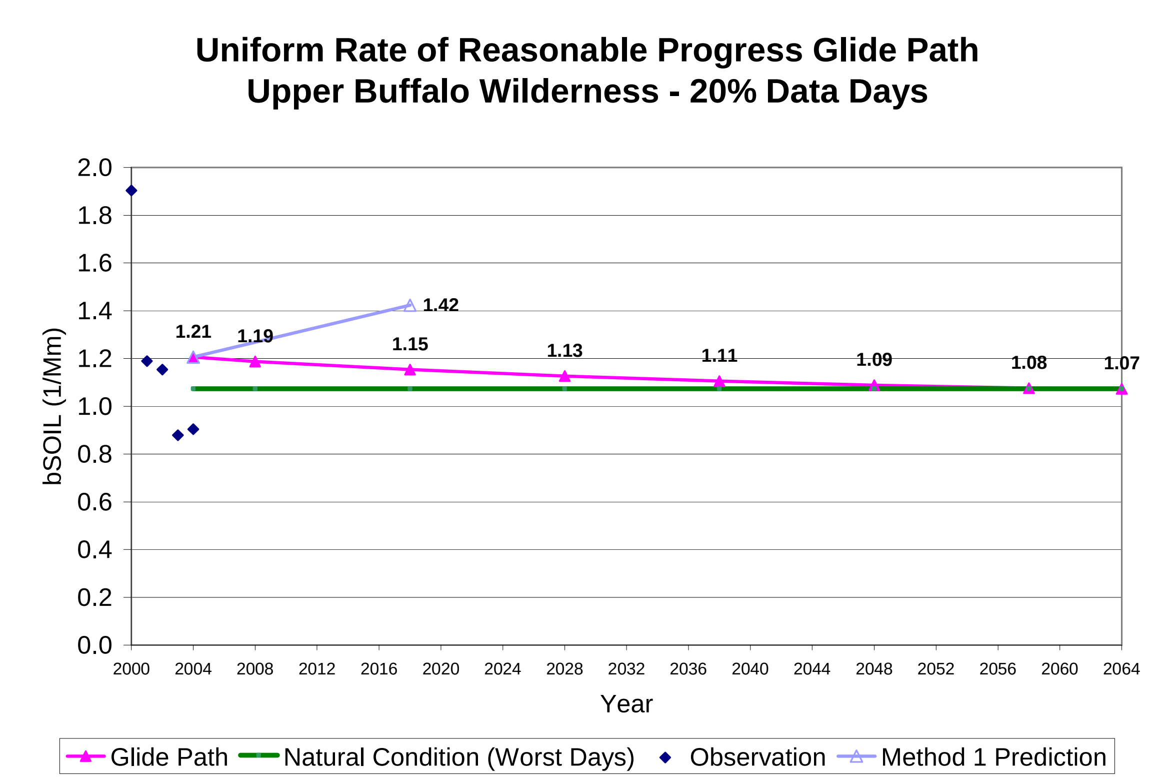


Figure F-2f. 2018 Visibility Projections and 2018 URP Glidepaths for Other Fine Particulate (SOIL) in extinction (Mm^{-1}) for Upper Buffalo (UPBU), Arkansas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

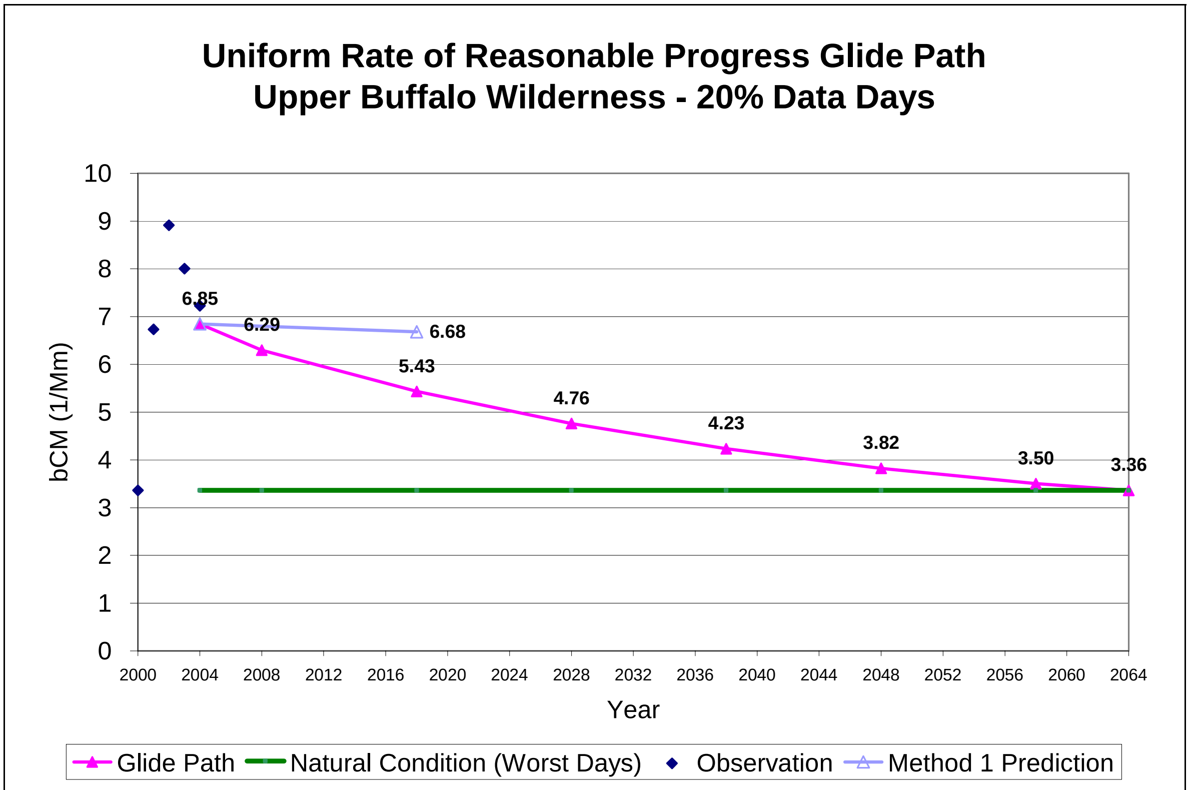


Figure F-2g. 2018 Visibility Projections and 2018 URP Glidepaths for Coarse Mass (CM) in extinction (Mm^{-1}) for Upper Buffalo (UPBU), Arkansas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

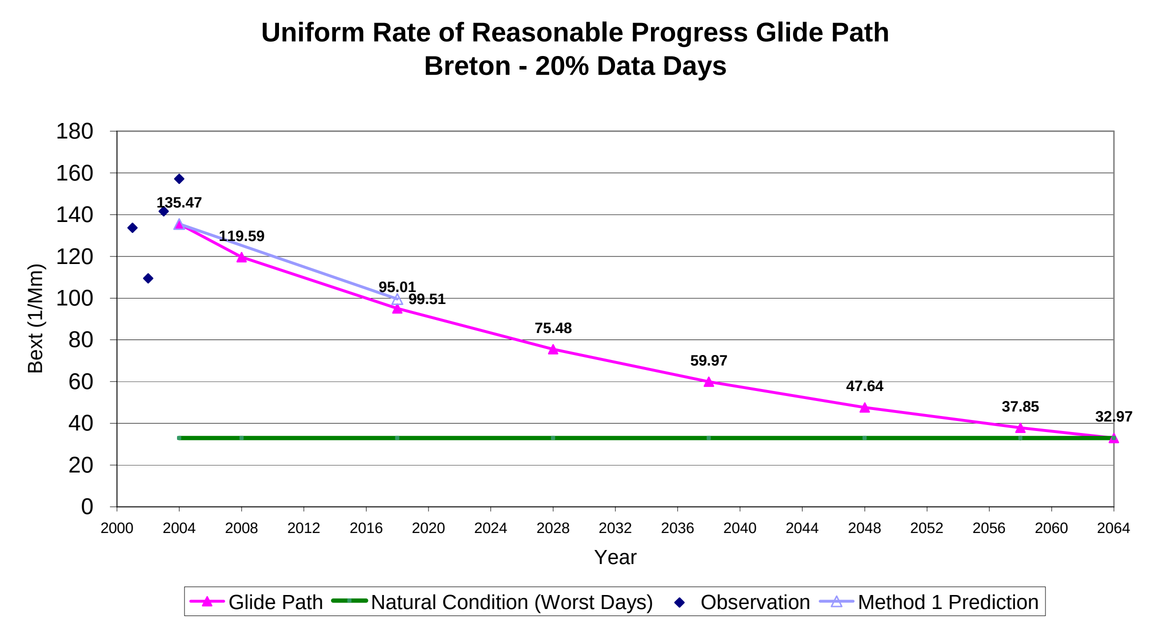


Figure F-3a. 2018 Visibility Projections and 2018 URP Glidepaths in extinction (Mm^{-1}) for Breton Island (BRET), Louisiana and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

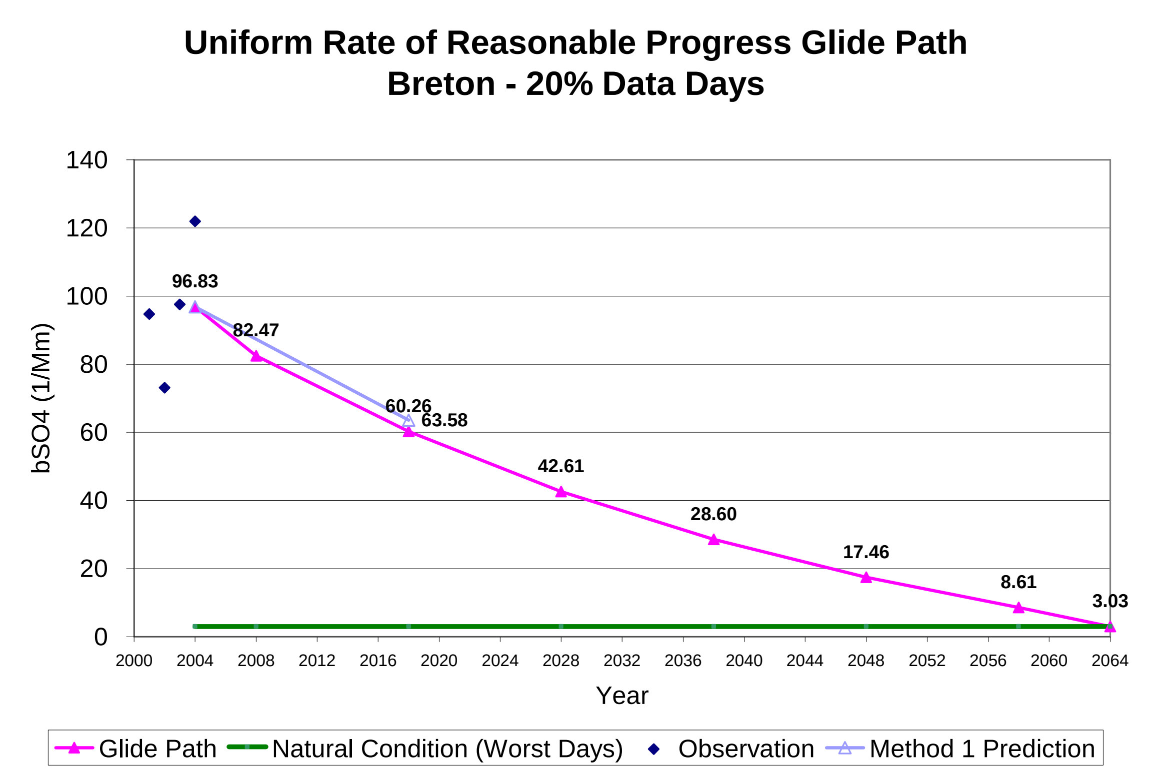


Figure F-3b. 2018 Visibility Projections and 2018 URP Glidepaths for Sulfate (SO4) in extinction (Mm^{-1}) for Breton Island (BRET), Louisiana and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

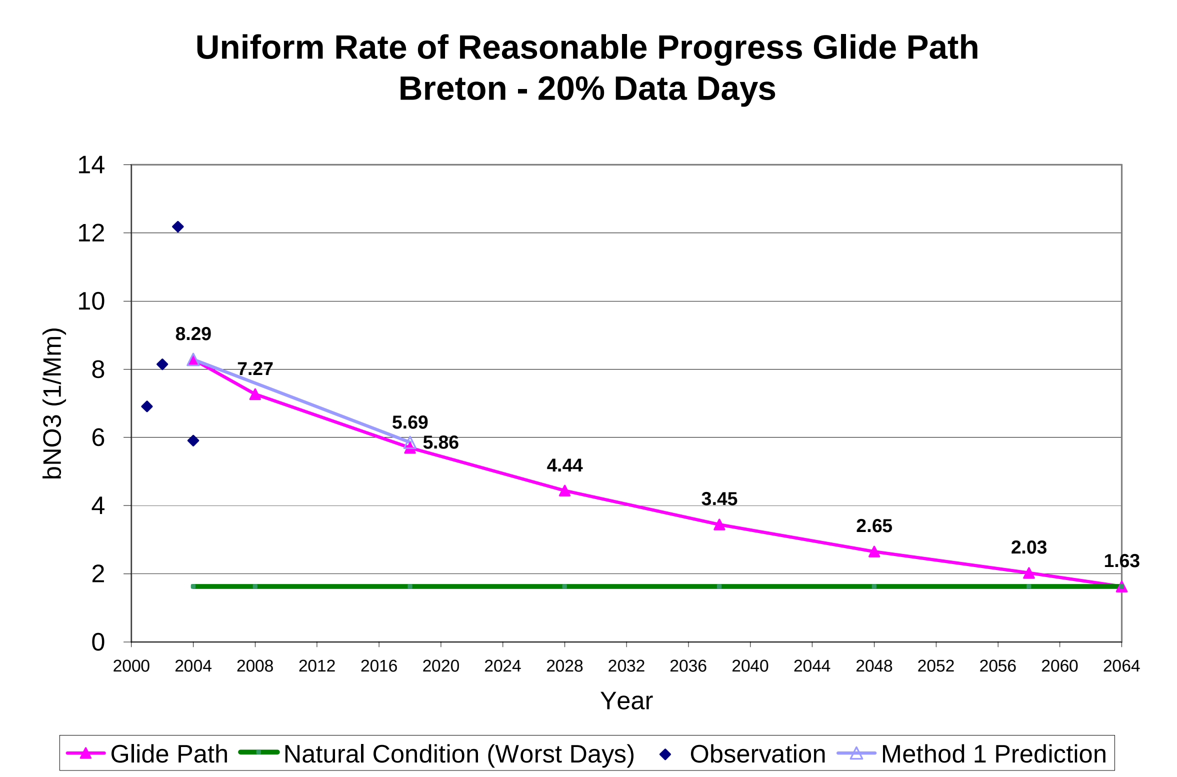


Figure F-3c. 2018 Visibility Projections and 2018 URP Glidepaths for Nitrate (NO3) in extinction (Mm^{-1}) for Breton Island (BRET), Louisiana and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

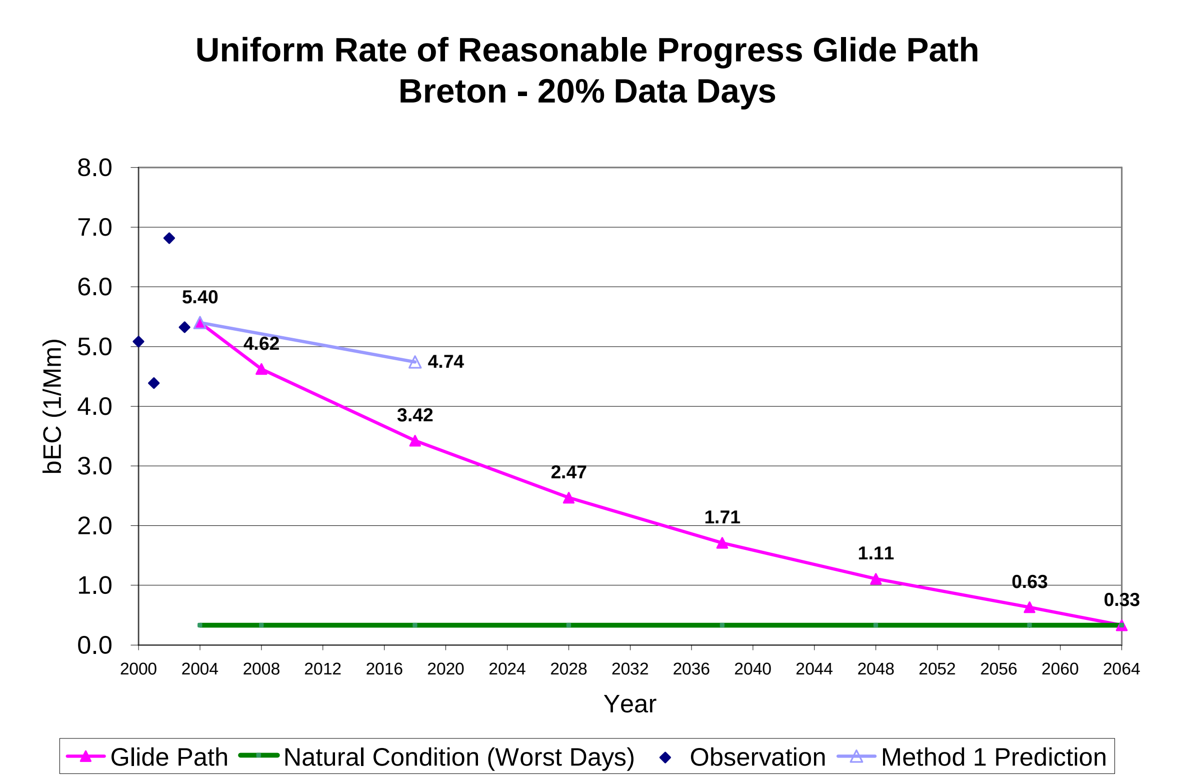


Figure F-3d. 2018 Visibility Projections and 2018 URP Glidepaths for Elemental Carbon (EC) in extinction (Mm^{-1}) for Breton Island (BRET), Louisiana and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

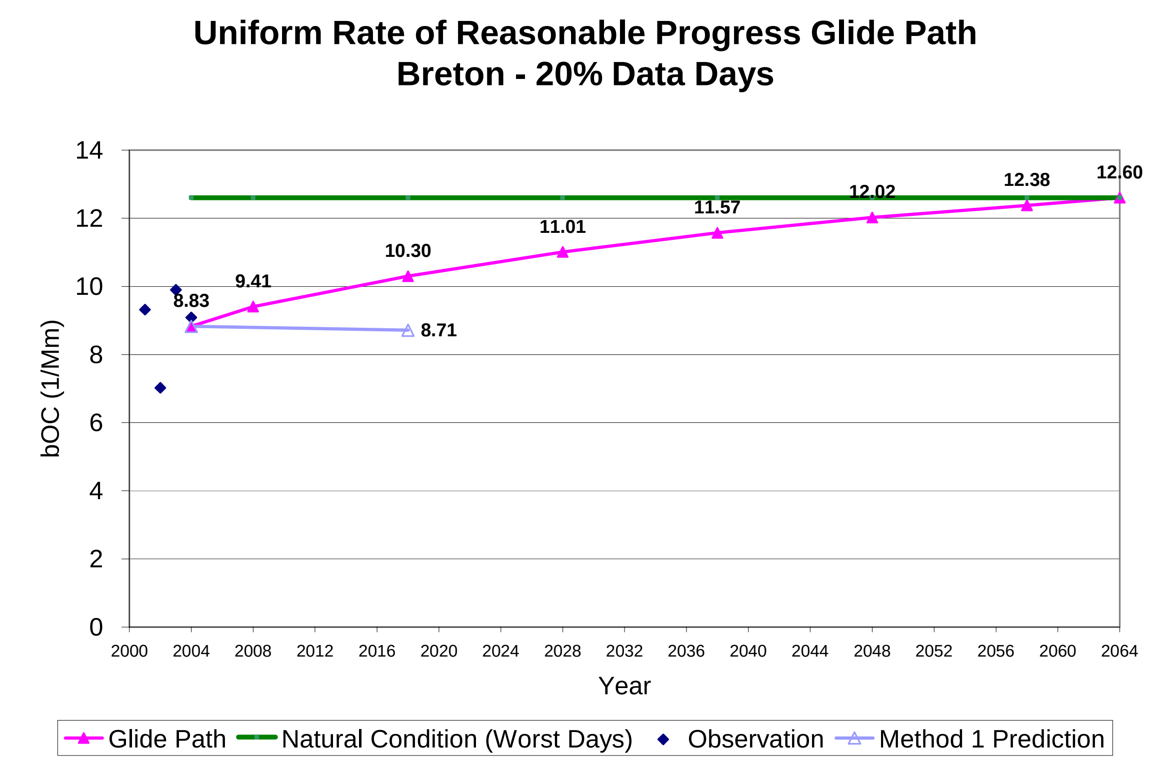


Figure F-3e. 2018 Visibility Projections and 2018 URP Glidepaths for Organic Mass Carbon (OMC) in extinction (Mm^{-1}) for Breton Island (BRET), Louisiana and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

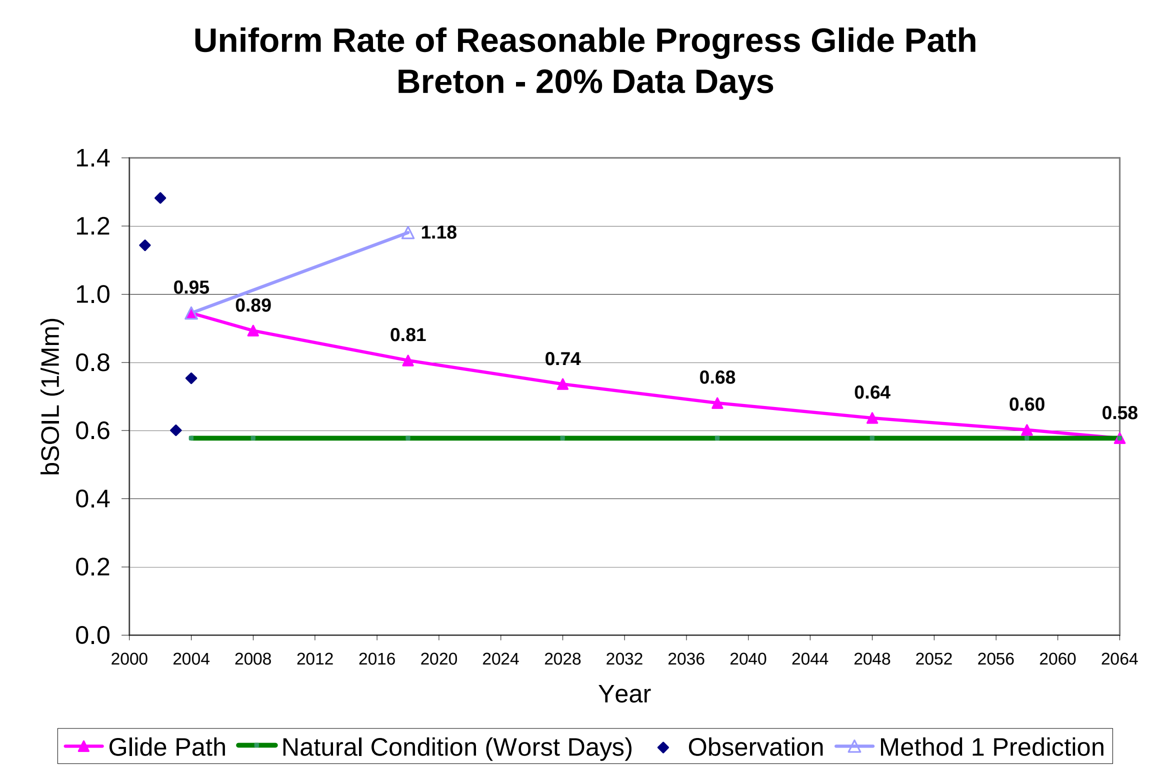


Figure F-3f. 2018 Visibility Projections and 2018 URP Glidepaths for Other Fine Particulate (SOIL) in extinction (Mm^{-1}) for Breton Island (BRET), Louisiana and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

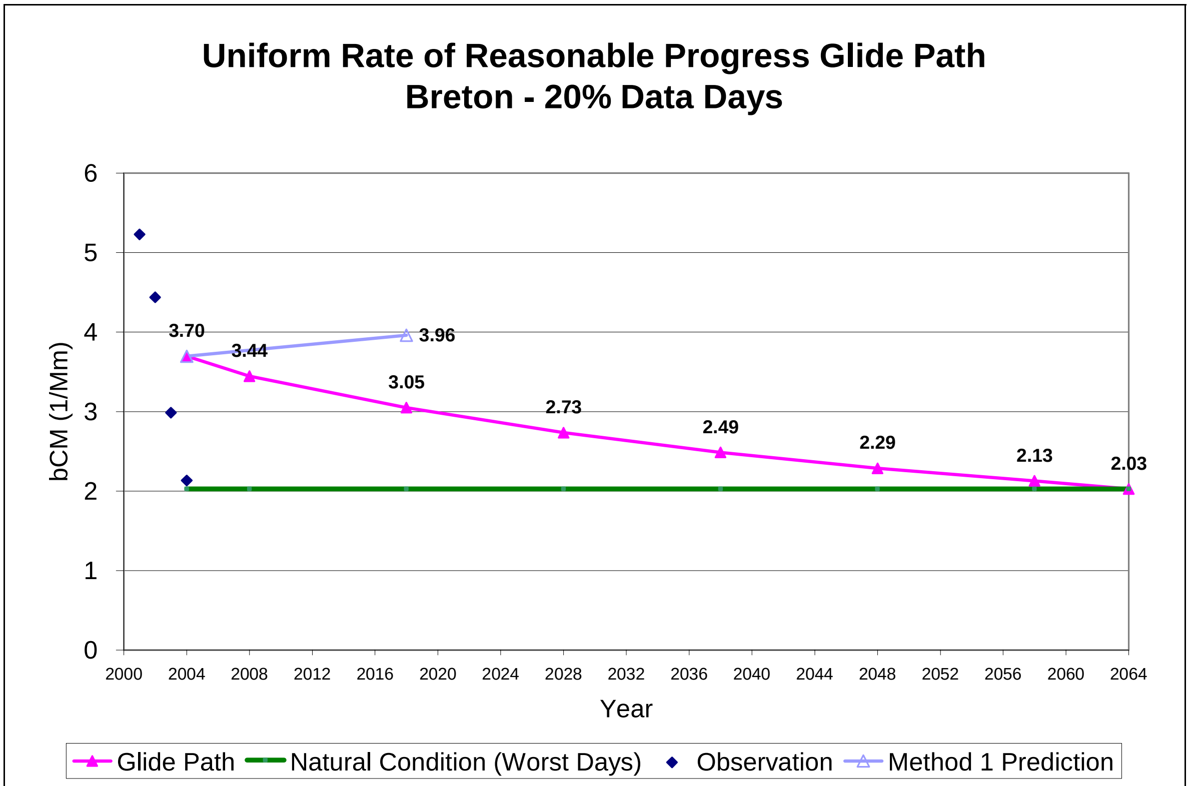


Figure F-3g. 2018 Visibility Projections and 2018 URP Glidepaths for Coarse Mass (CM) in extinction (Mm^{-1}) for Breton Island (BRET), Louisiana and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

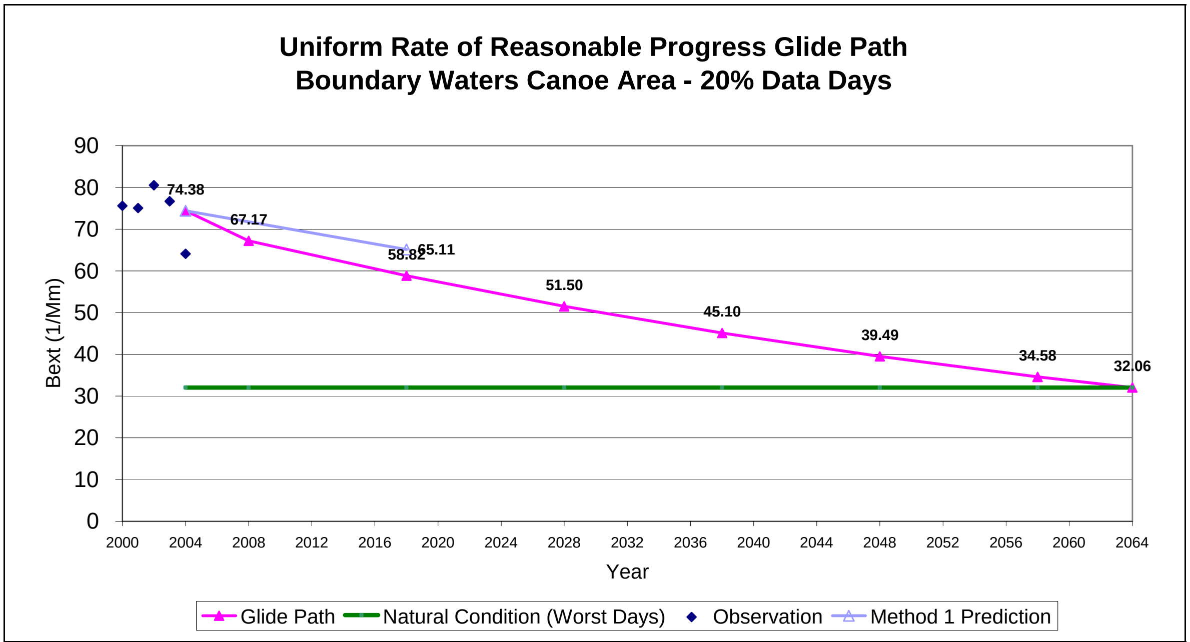


Figure F-4a. 2018 Visibility Projections and 2018 URP Glidepaths in extinction (Mm^{-1}) for Boundary Waters (BOWA), Minnesota and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

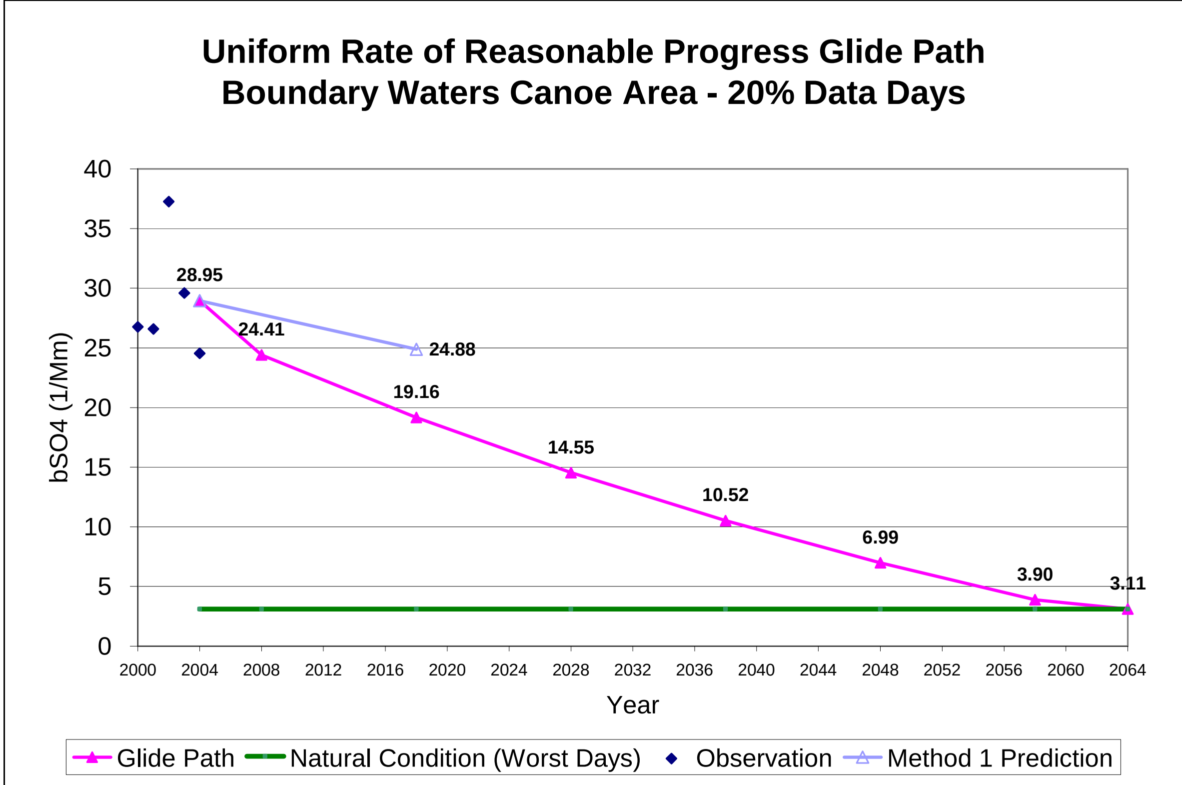


Figure F-4b. 2018 Visibility Projections and 2018 URP Glidepaths for Sulfate (SO4) in extinction (Mm^{-1}) for Boundary Waters (BOWA), Minnesota and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

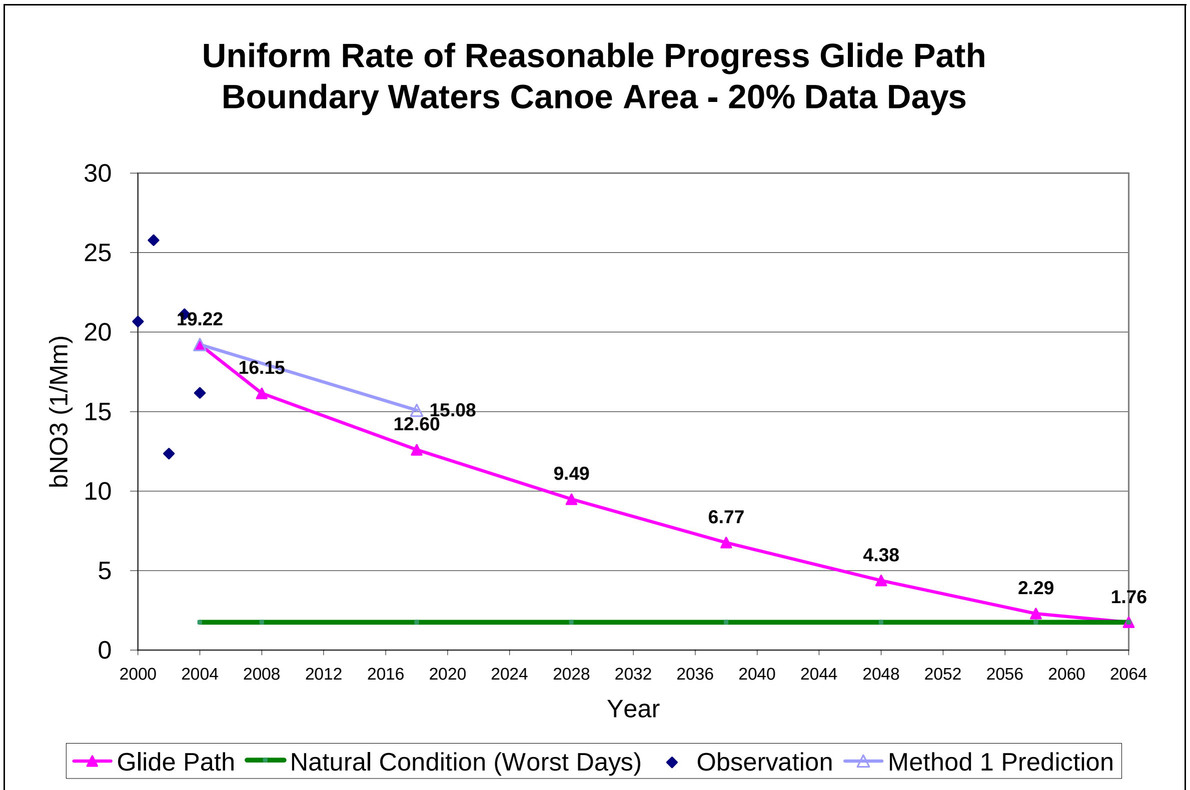


Figure F-4c. 2018 Visibility Projections and 2018 URP Glidepaths for Nitrate (NO3) in extinction (Mm^{-1}) for Boundary Waters (BOWA), Minnesota and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

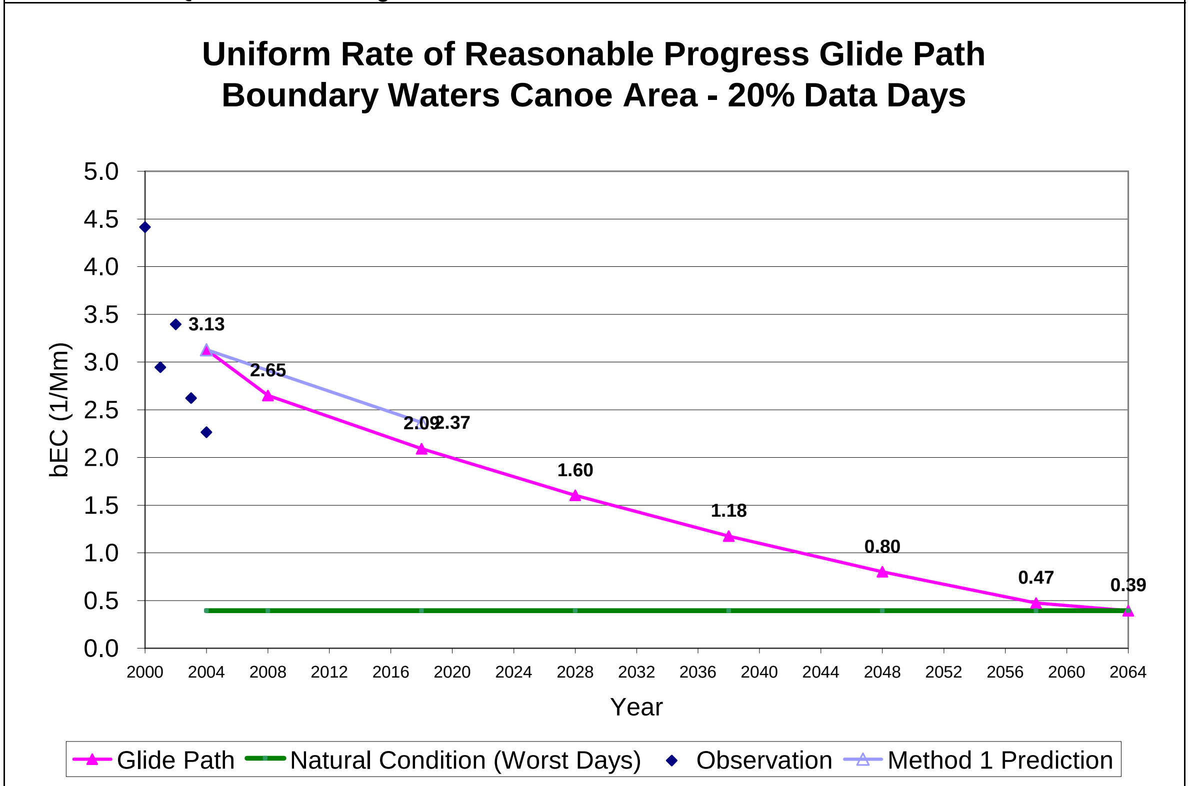


Figure F-4d. 2018 Visibility Projections and 2018 URP Glidepaths for Elemental Carbon (EC) in extinction (Mm^{-1}) for Boundary Waters (BOWA), Minnesota and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

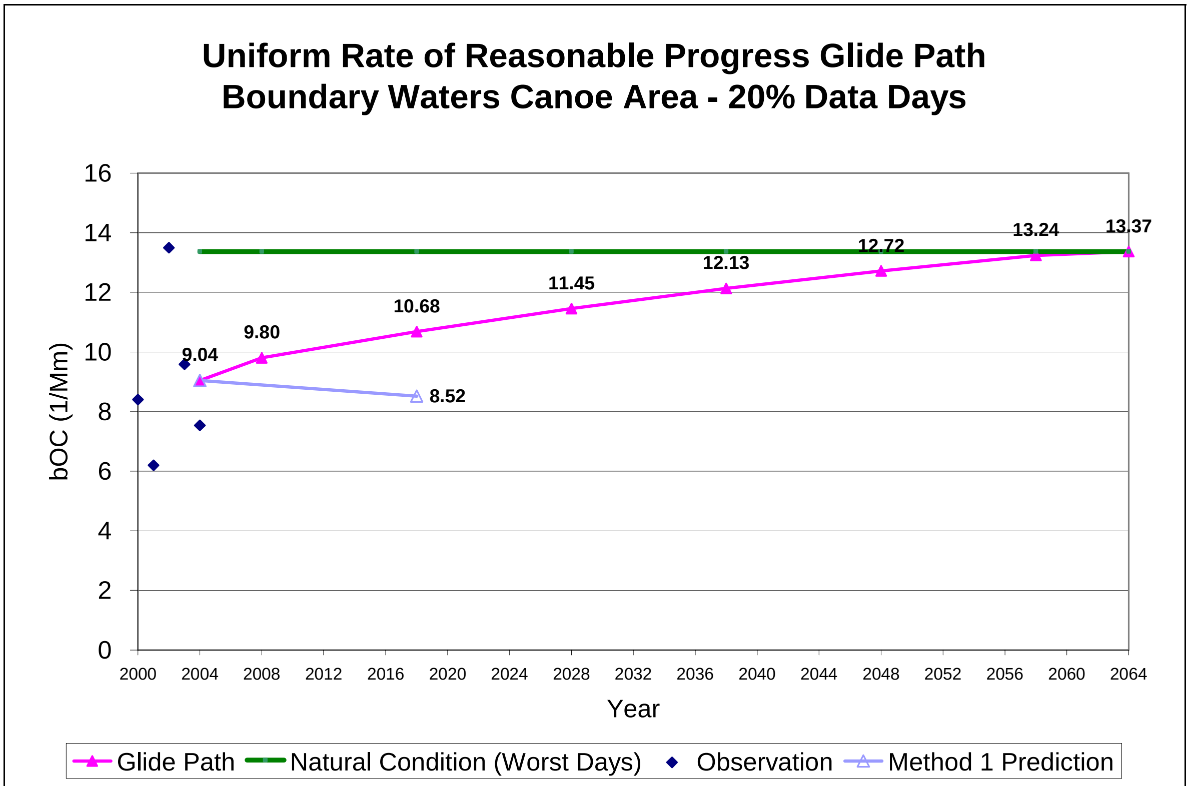


Figure F-4e. 2018 Visibility Projections and 2018 URP Glidepaths for Organic Mass Carbon (OMC) in extinction (Mm^{-1}) for Boundary Waters (BOWA), Minnesota and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

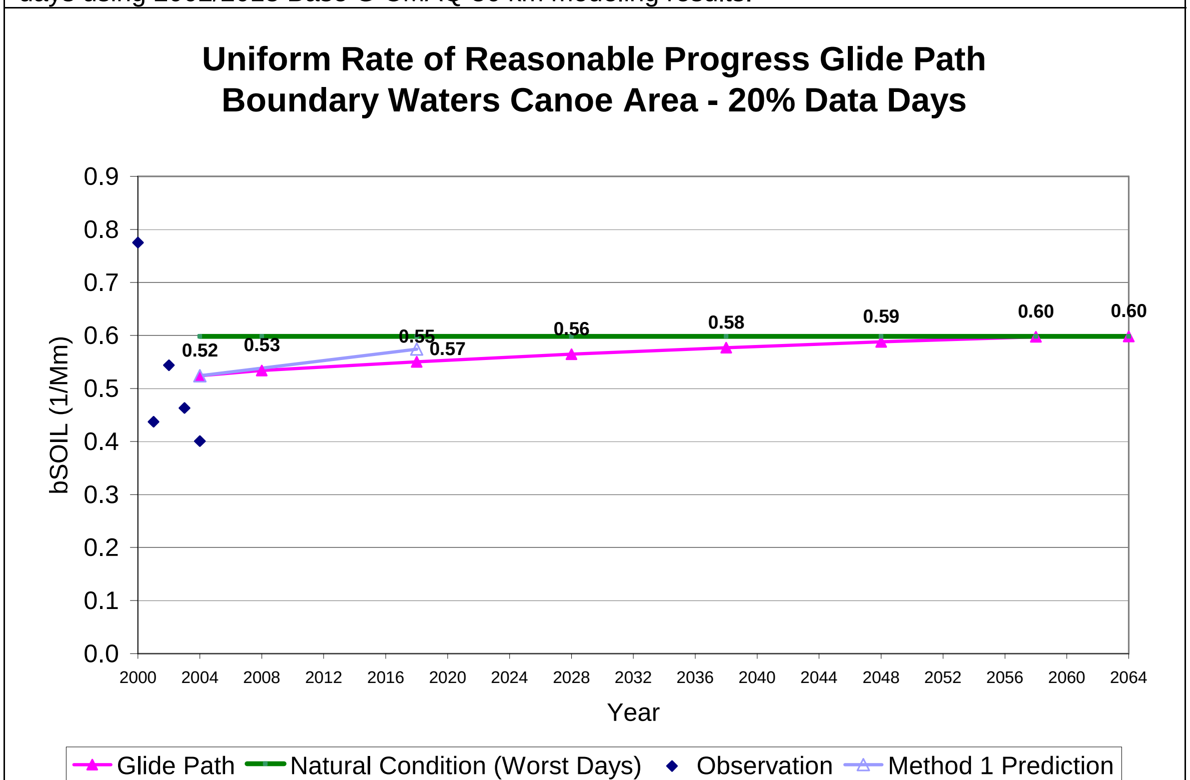


Figure F-4f. 2018 Visibility Projections and 2018 URP Glidepaths for Other Fine Particulate (SOIL) in extinction (Mm^{-1}) for Boundary Waters (BOWA), Minnesota and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

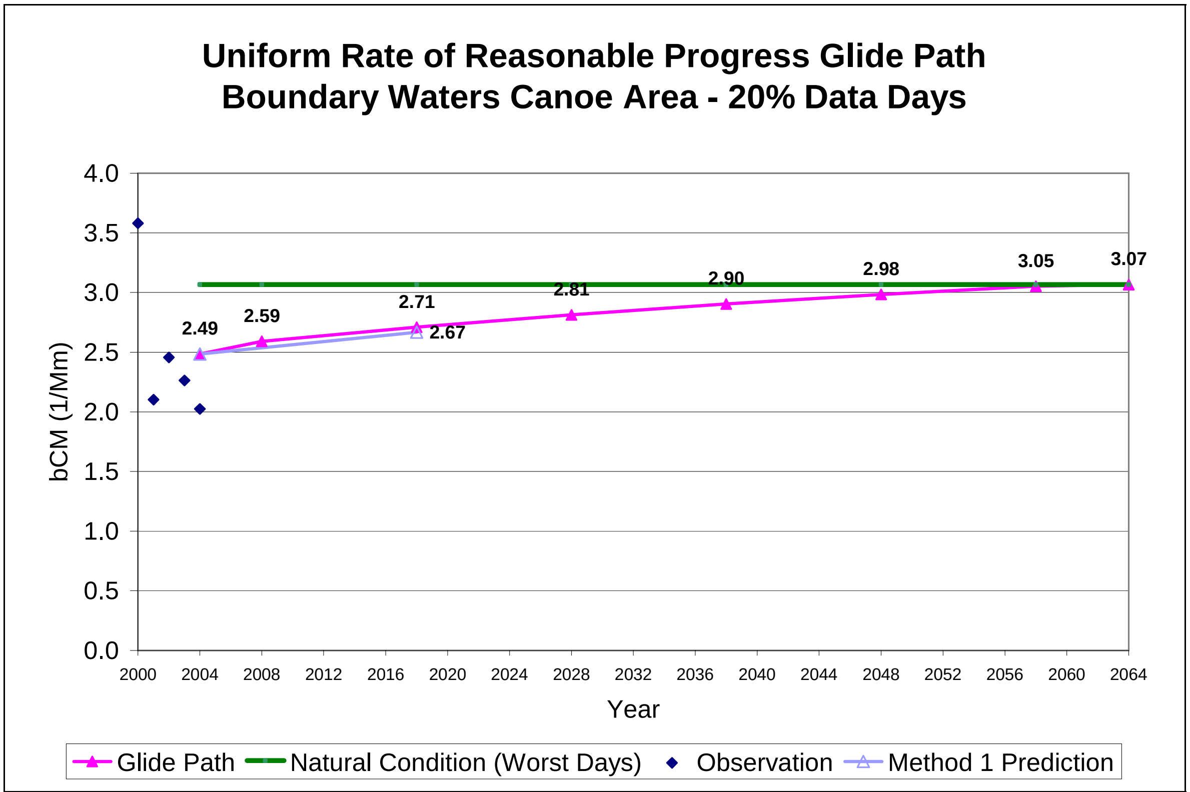


Figure F-4g. 2018 Visibility Projections and 2018 URP Glidepaths for Coarse Mass (CM) in extinction (Mm^{-1}) for Boundary Waters (BOWA), Minnesota and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

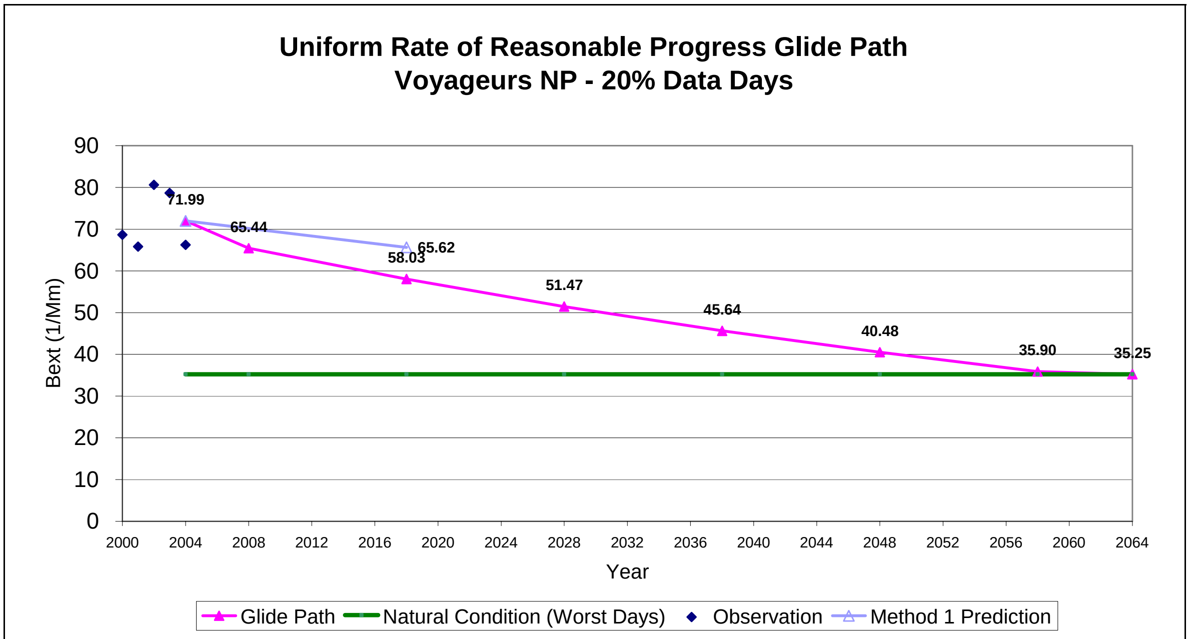


Figure F-5a. 2018 Visibility Projections and 2018 URP Glidepaths in extinction (Mm^{-1}) for Voyageurs (VOYA), Minnesota and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

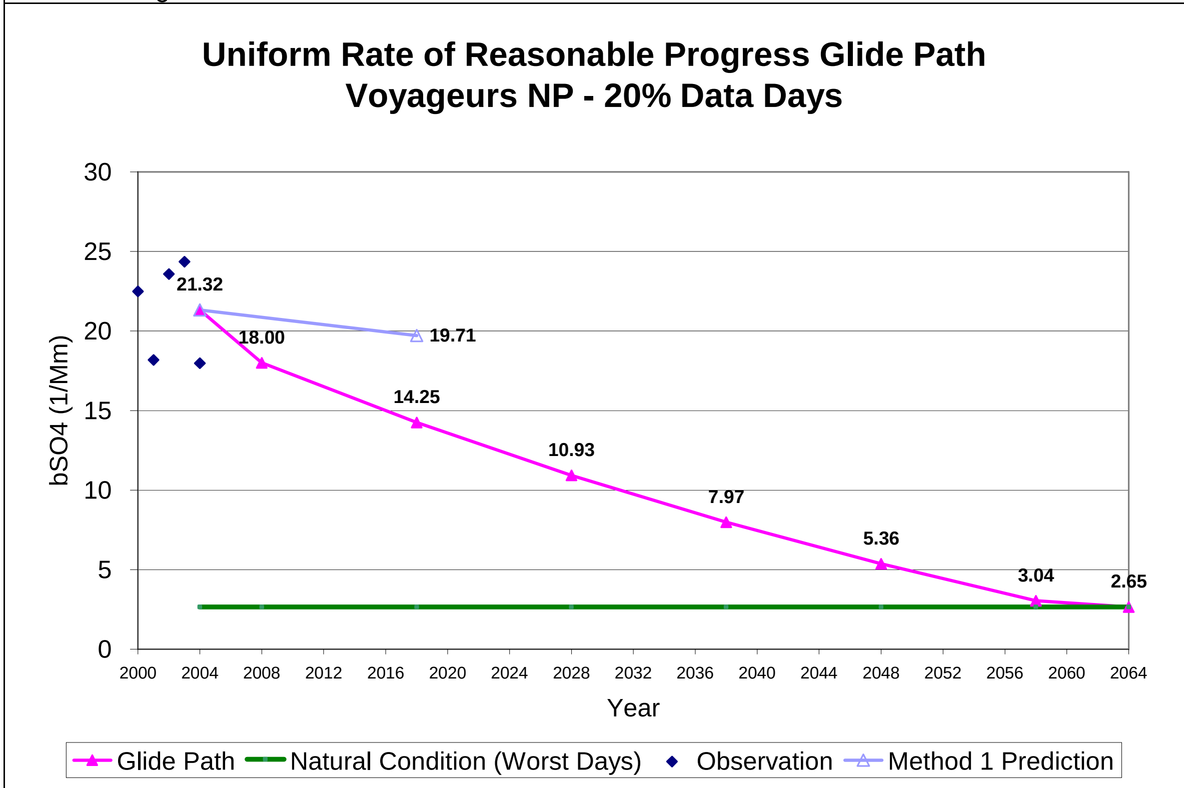


Figure F-5b. 2018 Visibility Projections and 2018 URP Glidepaths for Sulfate (SO4) in extinction (Mm^{-1}) for Voyageurs (VOYA), Minnesota and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

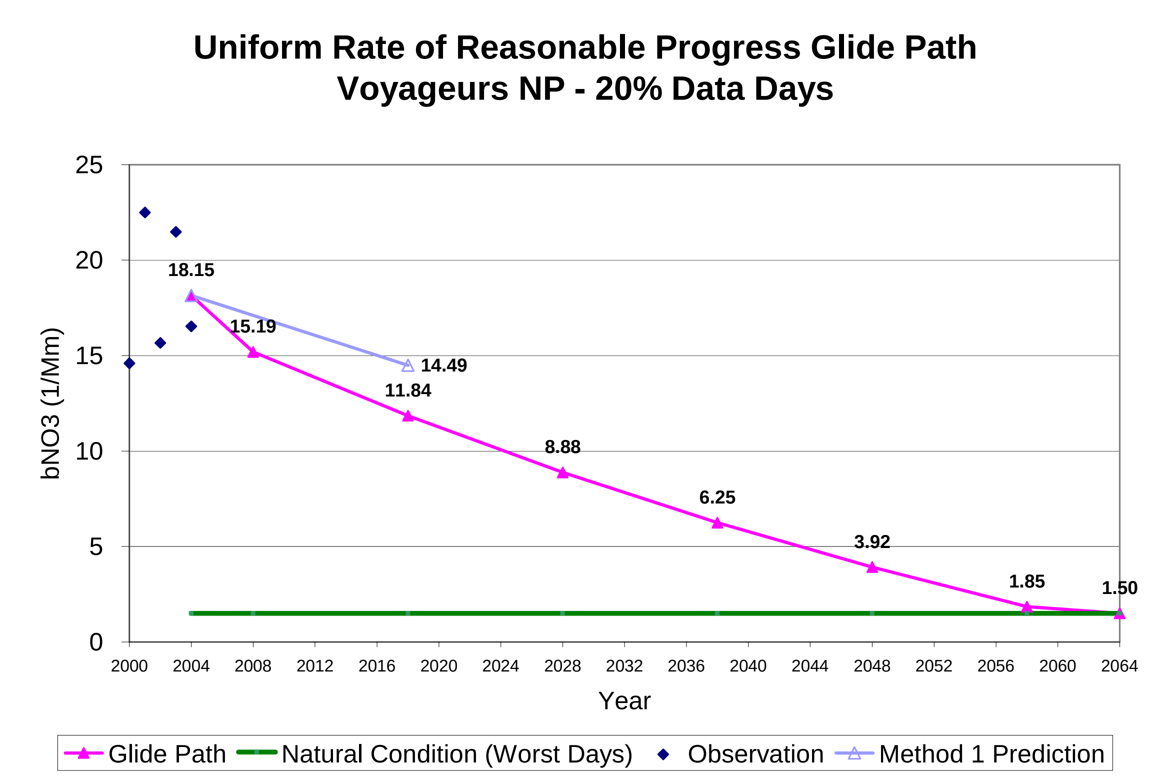


Figure F-5c. 2018 Visibility Projections and 2018 URP Glidepaths for Nitrate (NO3) in extinction (Mm^{-1}) for Voyageurs (VOYA), Minnesota and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

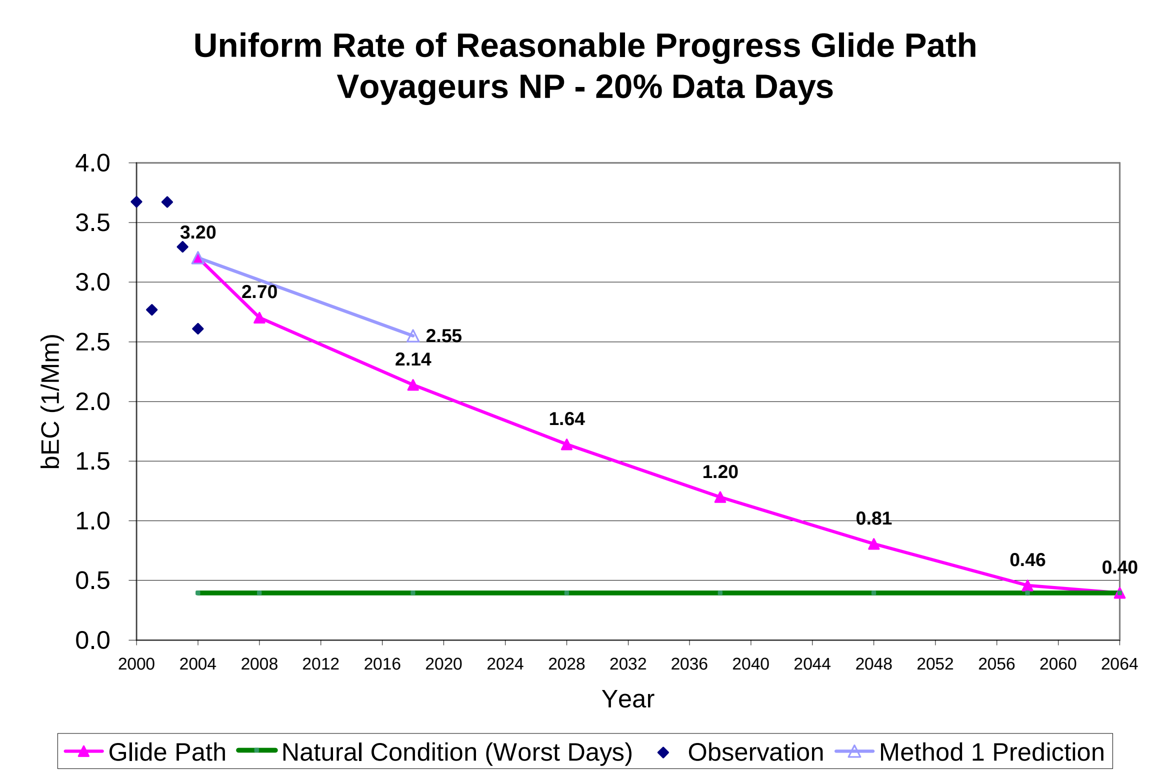


Figure F-5d. 2018 Visibility Projections and 2018 URP Glidepaths for Elemental Carbon (EC) in extinction (Mm^{-1}) for Voyageurs (VOYA), Minnesota and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

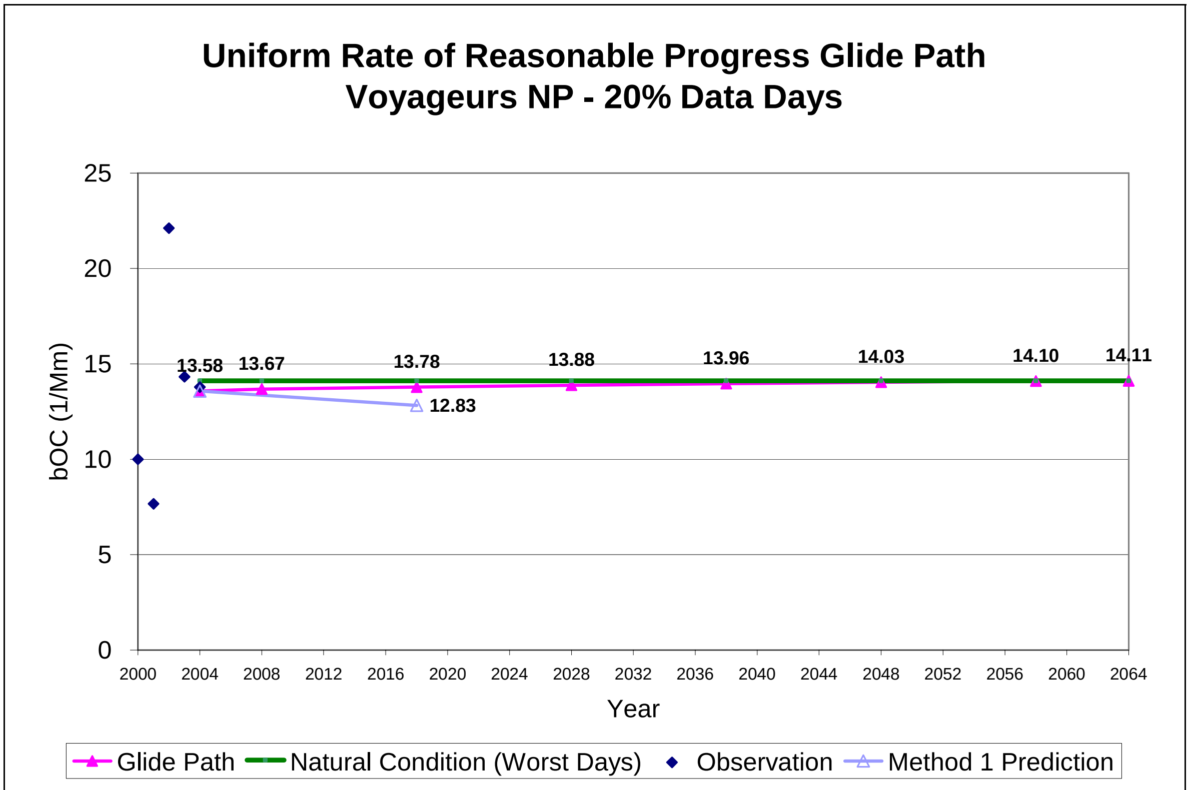


Figure F-5e. 2018 Visibility Projections and 2018 URP Glidepaths for Organic Mass Carbon (OMC) in extinction (Mm^{-1}) for Voyageurs (VOYA), Minnesota and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

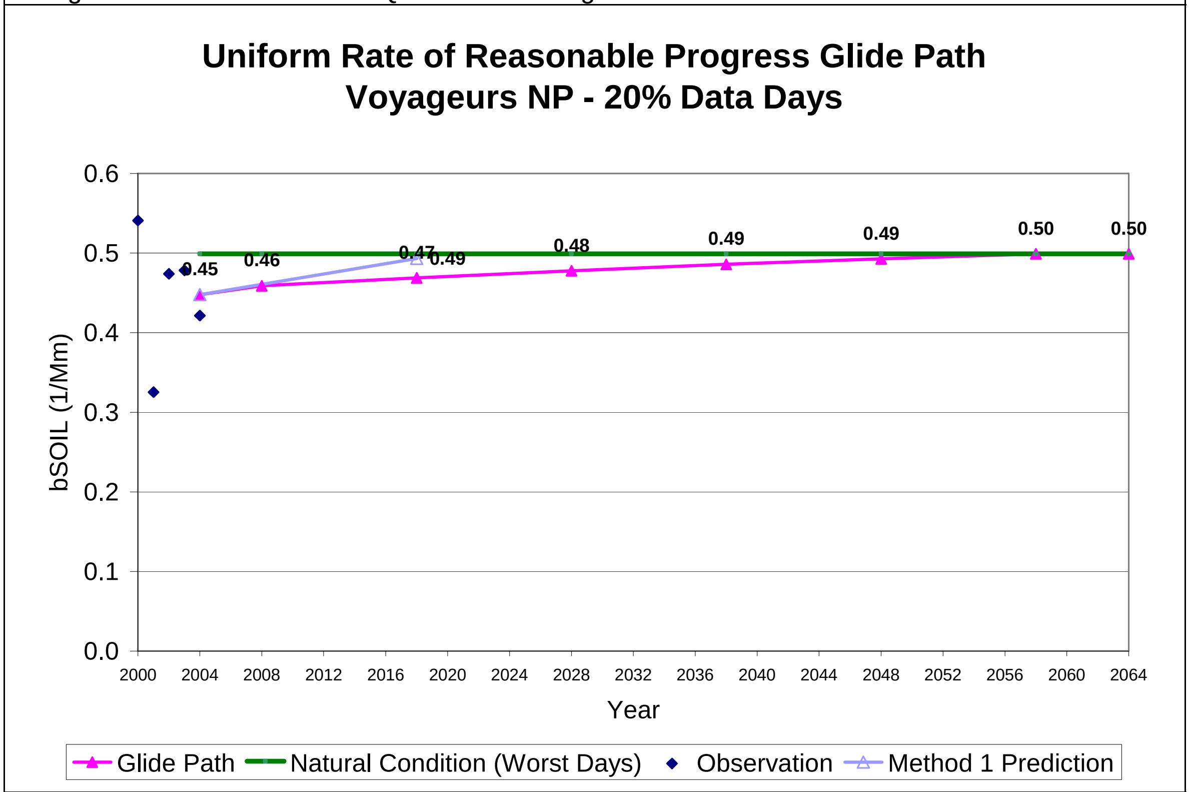


Figure F-5f. 2018 Visibility Projections and 2018 URP Glidepaths for Other Fine Particulate (SOIL) in extinction (Mm^{-1}) for Voyageurs (VOYA), Minnesota and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

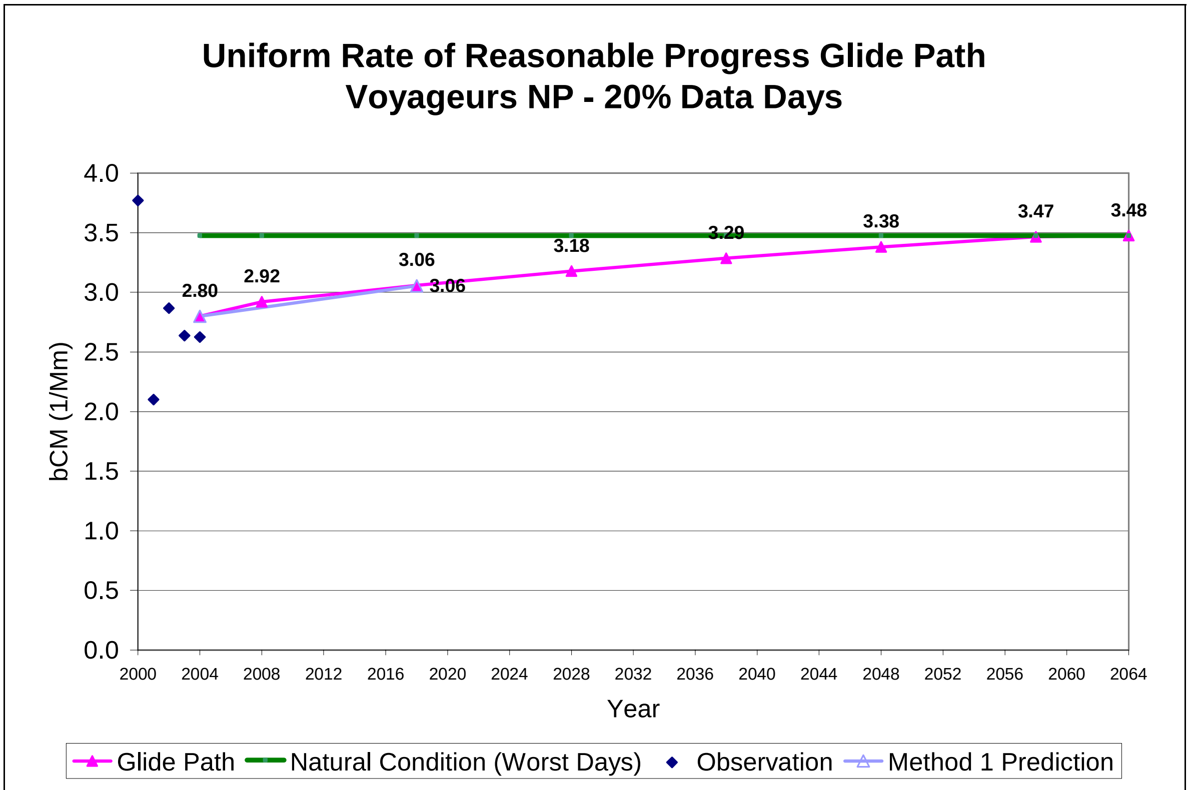


Figure F-5g. 2018 Visibility Projections and 2018 URP Glidepaths for Coarse Mass (CM) in extinction (Mm^{-1}) for Voyageurs (VOYA), Minnesota and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

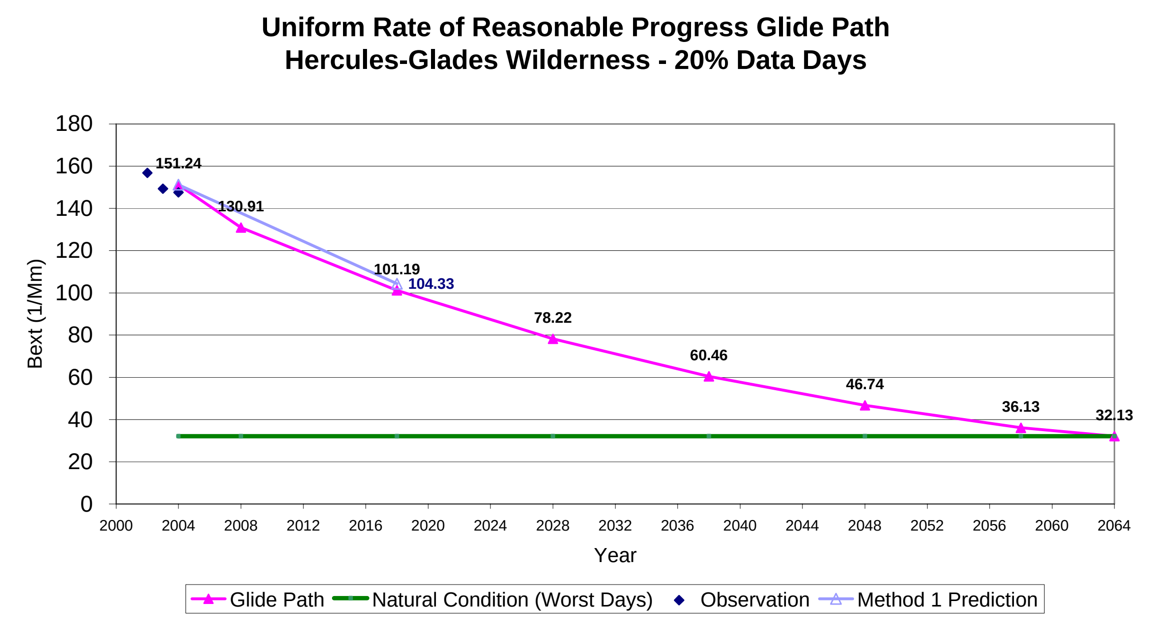


Figure F-6a. 2018 Visibility Projections and 2018 URP Glidepaths in extinction (Mm^{-1}) for Hercules-Glade (HEGL), Missouri and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

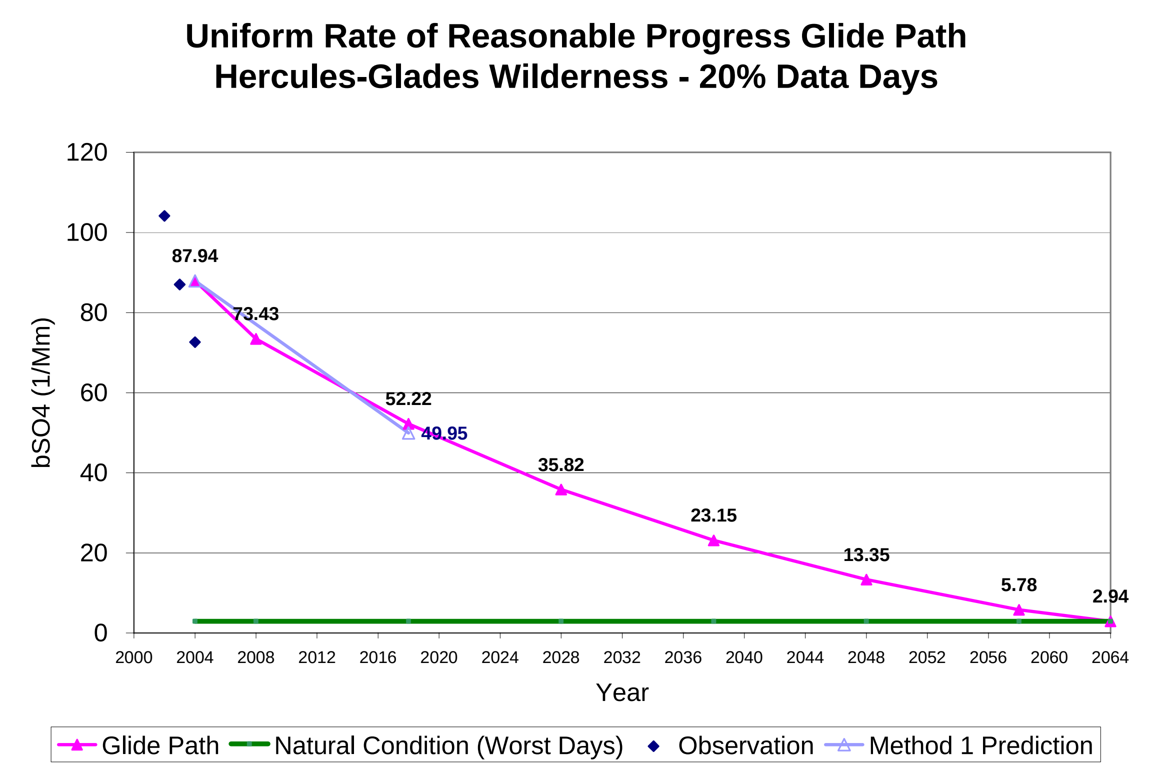


Figure F-6b. 2018 Visibility Projections and 2018 URP Glidepaths for Sulfate (SO4) in extinction (Mm^{-1}) for Hercules-Glade (HEGL), Missouri and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

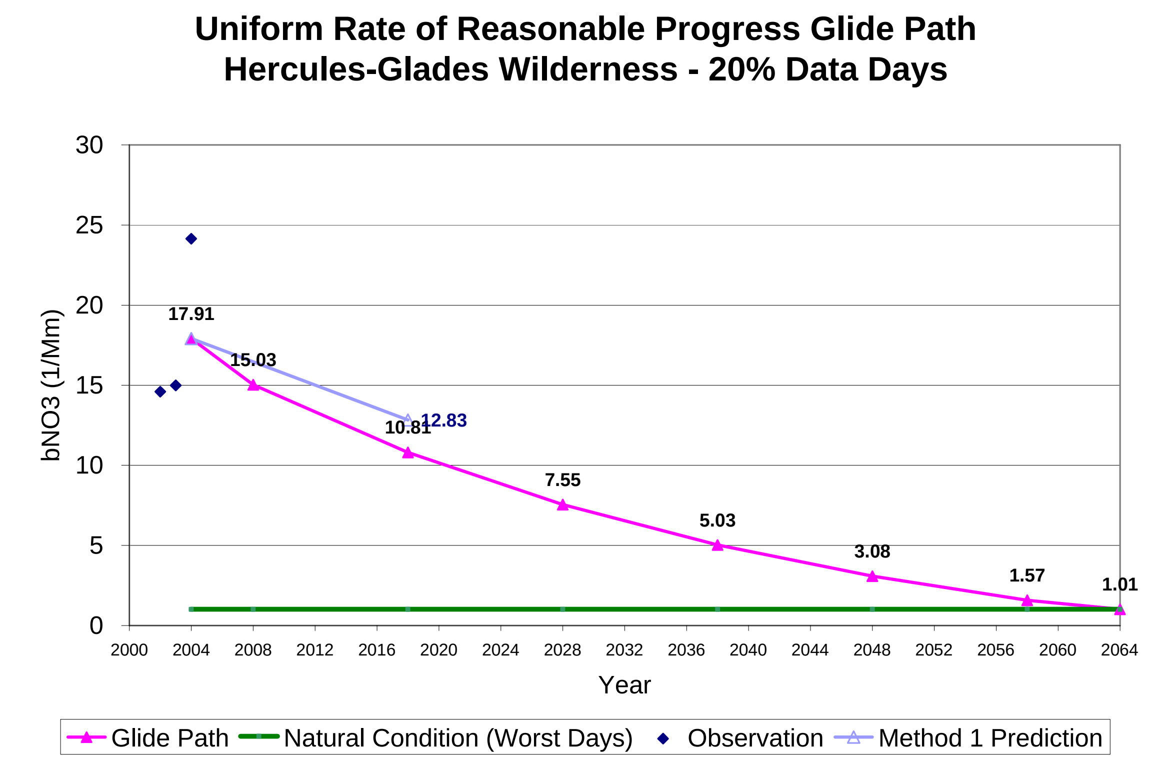


Figure F-6c. 2018 Visibility Projections and 2018 URP Glidepaths for Nitrate (NO3) in extinction (Mm^{-1}) for Hercules-Glade (HEGL), Missouri and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

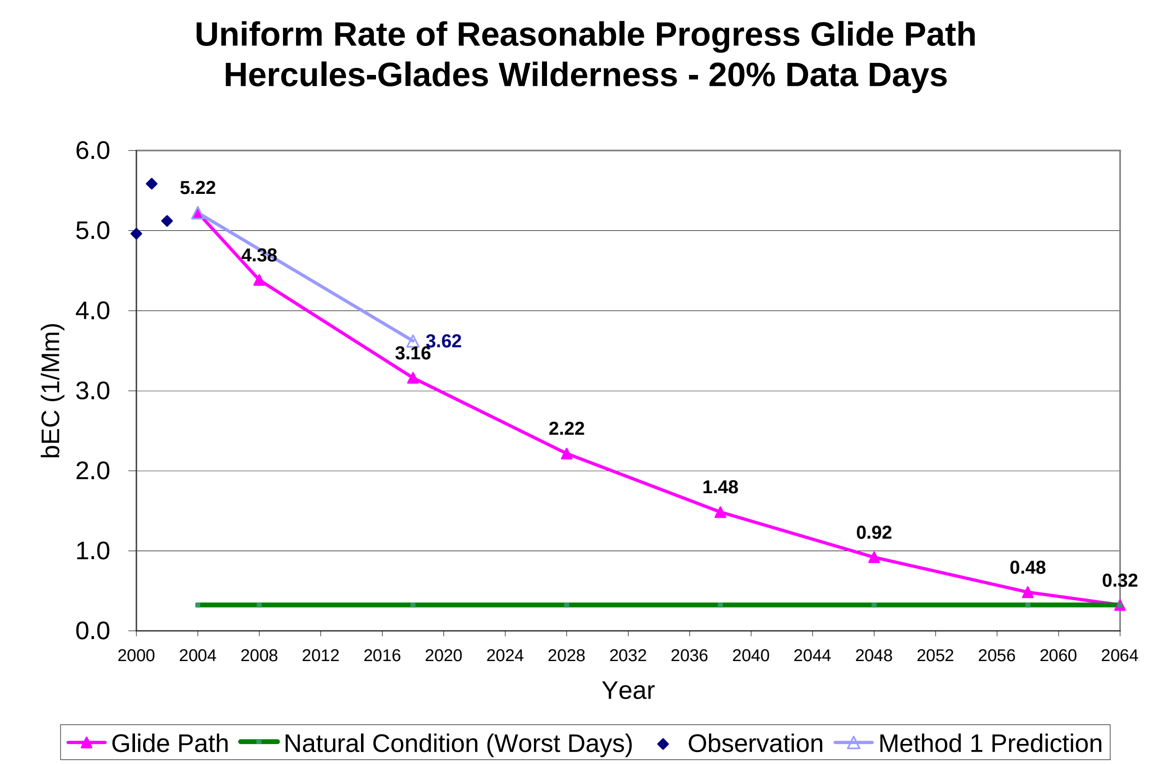


Figure F-6d. 2018 Visibility Projections and 2018 URP Glidepaths for Elemental Carbon (EC) in extinction (Mm^{-1}) for Hercules-Glade (HEGL), Missouri and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

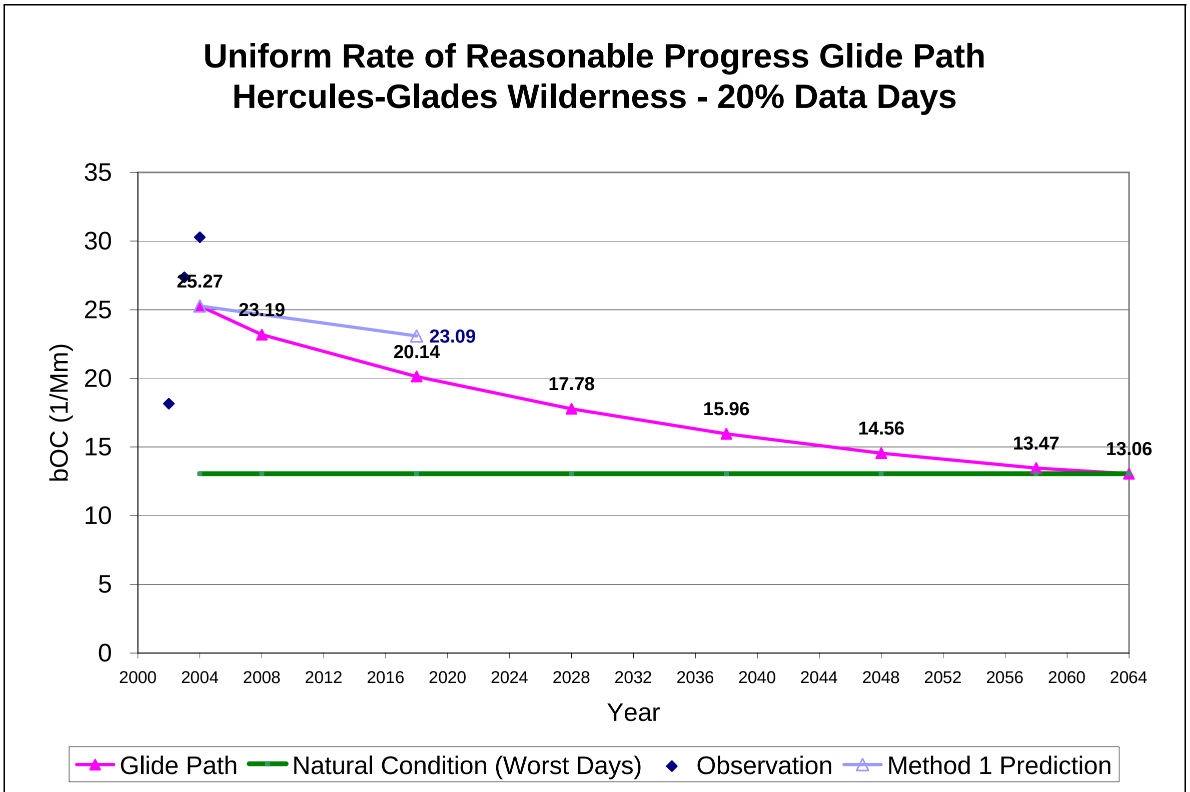


Figure F-6e. 2018 Visibility Projections and 2018 URP Glidepaths for Organic Mass Carbon (OMC) in extinction (Mm^{-1}) for Hercules-Glade (HEGL), Missouri and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

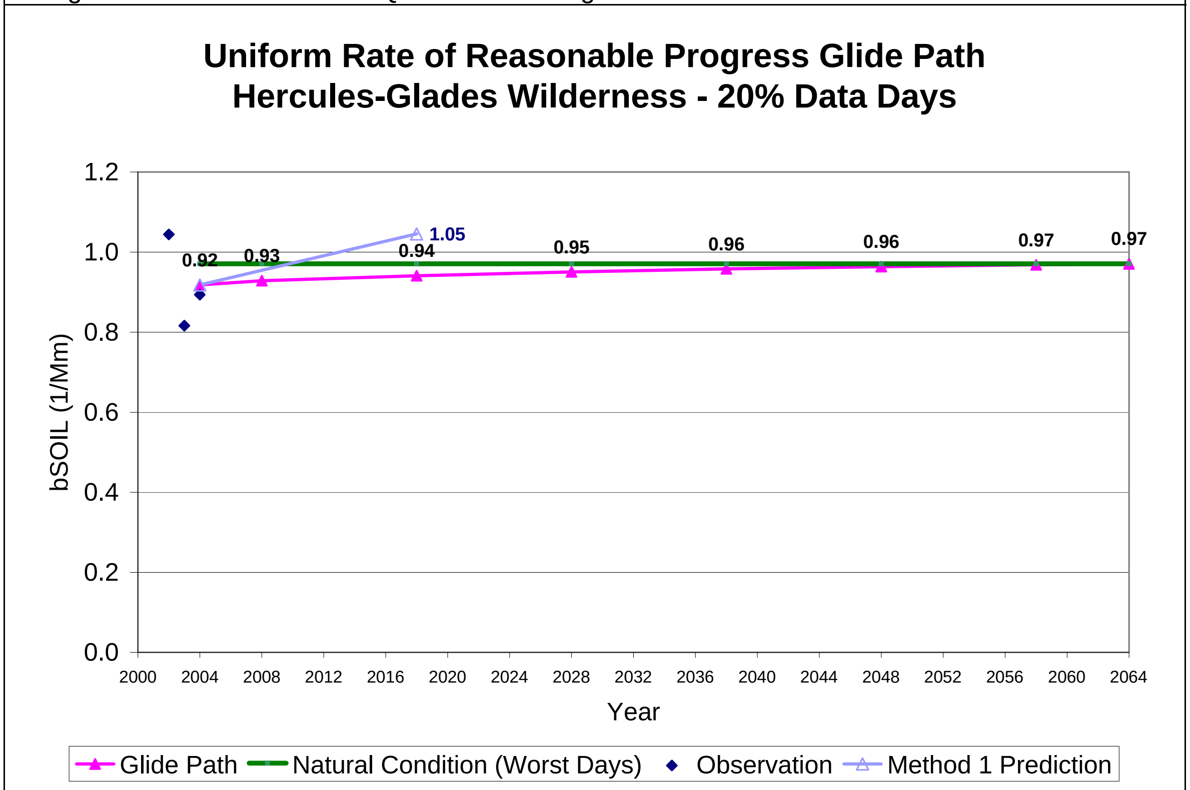


Figure F-6f. 2018 Visibility Projections and 2018 URP Glidepaths for Other Fine Particulate (SOIL) in extinction (Mm^{-1}) for Hercules-Glade (HEGL), Missouri and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

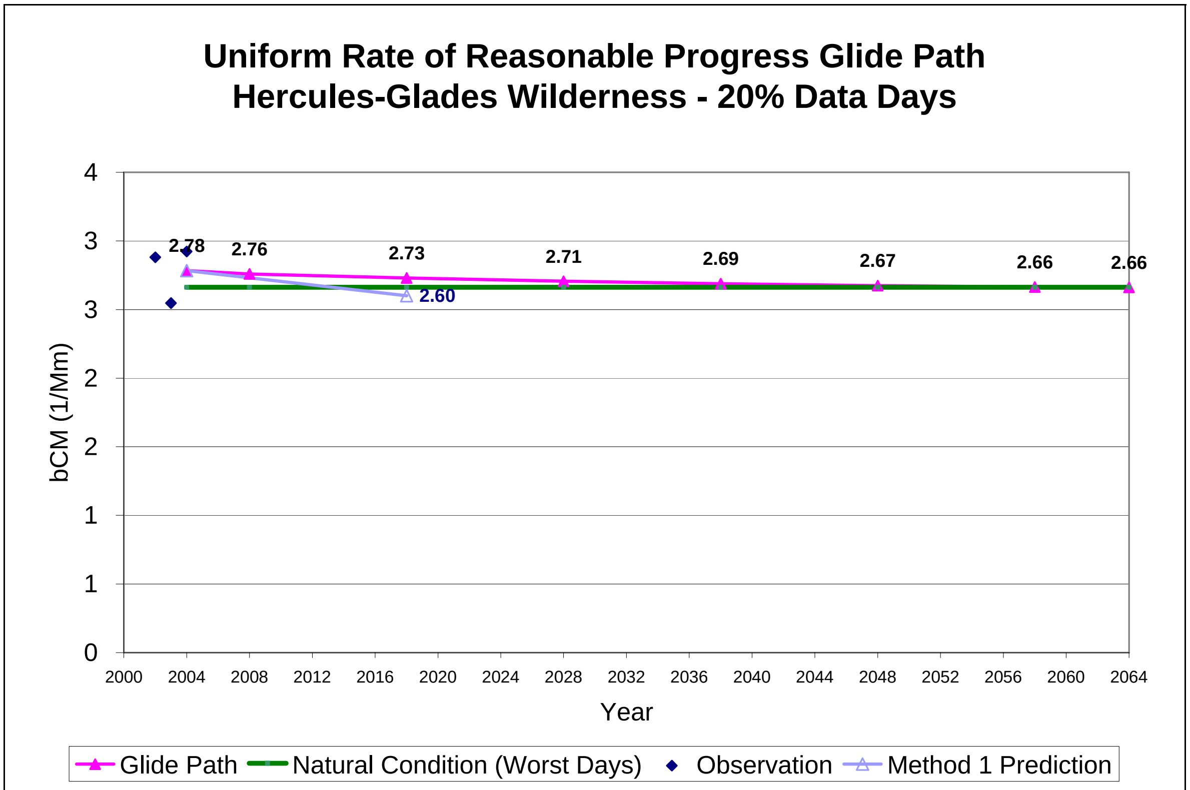


Figure F-6g. 2018 Visibility Projections and 2018 URP Glidepaths for Coarse Mass (CM) in extinction (Mm^{-1}) for Hercules-Glade (HEGL), Missouri and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

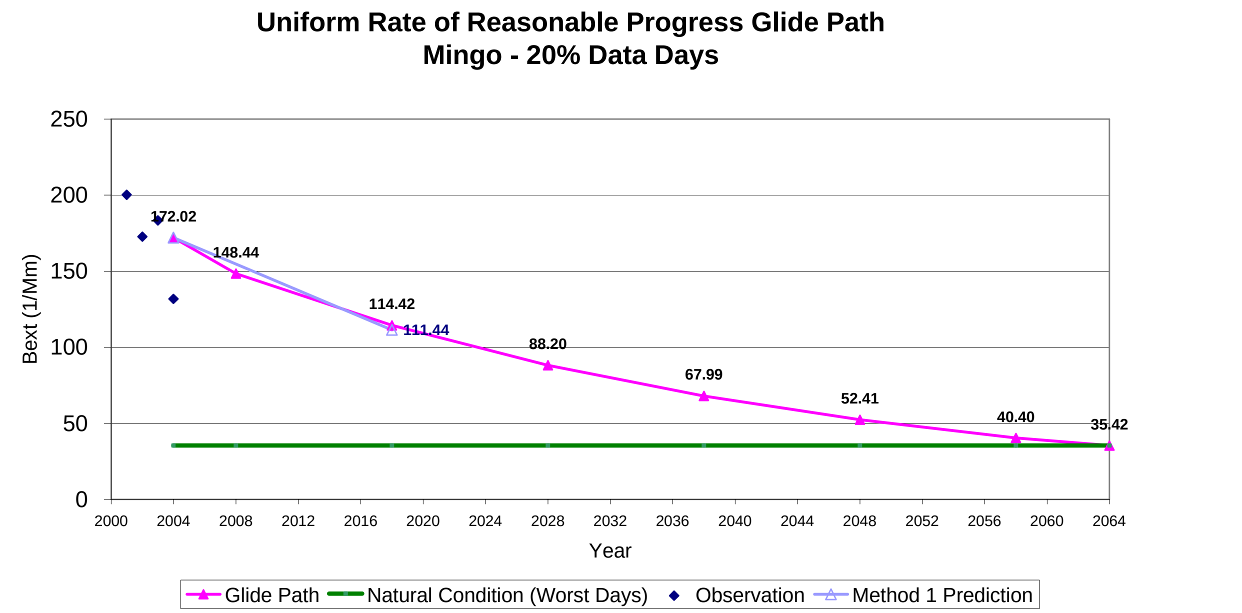


Figure F-7a. 2018 Visibility Projections and 2018 URP Glidepaths in extinction (Mm^{-1}) for Mingo (MING), Missouri and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

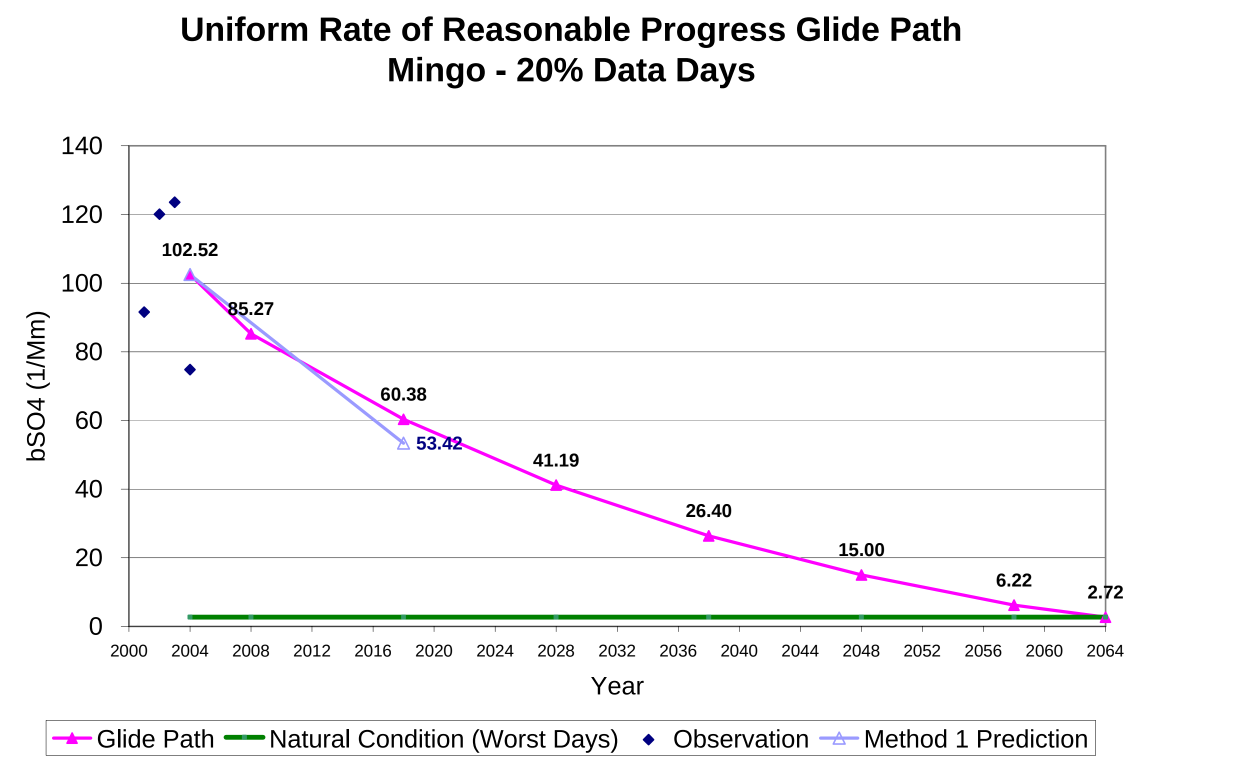


Figure F-7b. 2018 Visibility Projections and 2018 URP Glidepaths for Sulfate (SO4) in extinction (Mm^{-1}) for Mingo (MING), Missouri and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

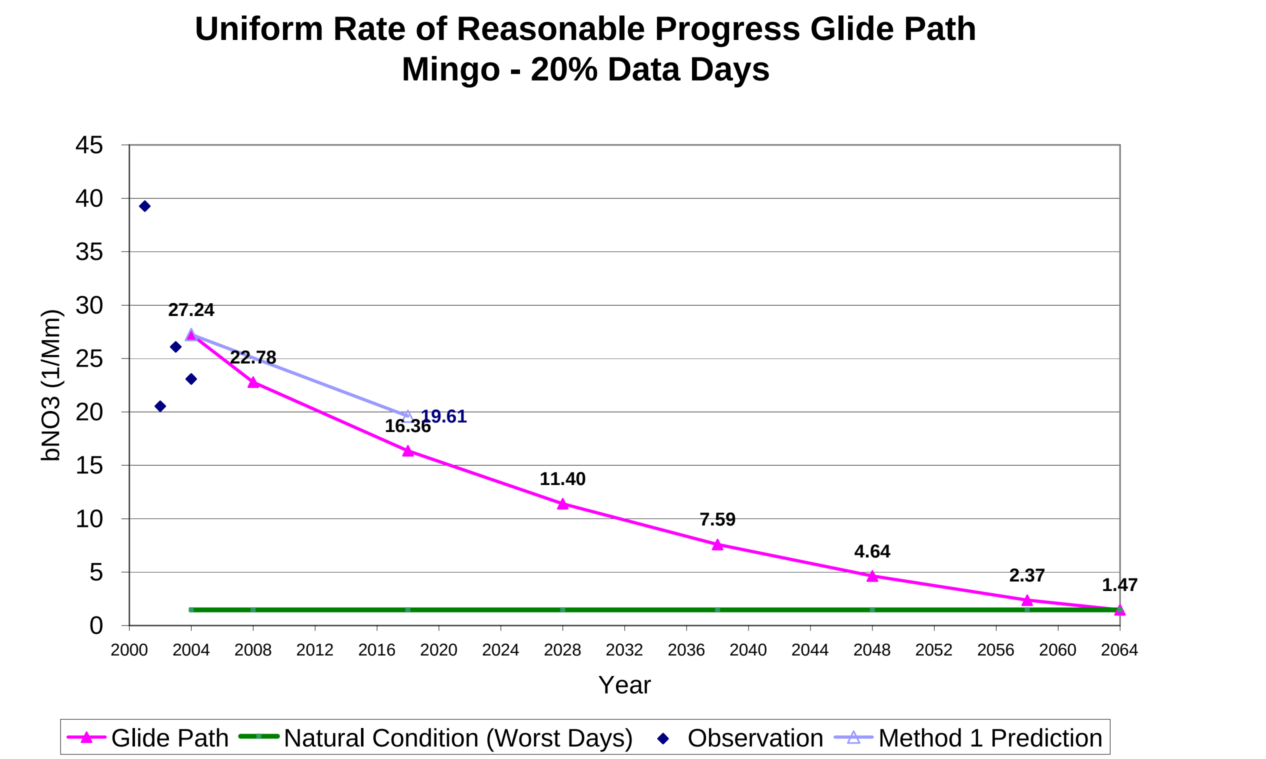


Figure F-7c. 2018 Visibility Projections and 2018 URP Glidepaths for Nitrate (NO3) in extinction (Mm^{-1}) for Mingo (MING), Missouri and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

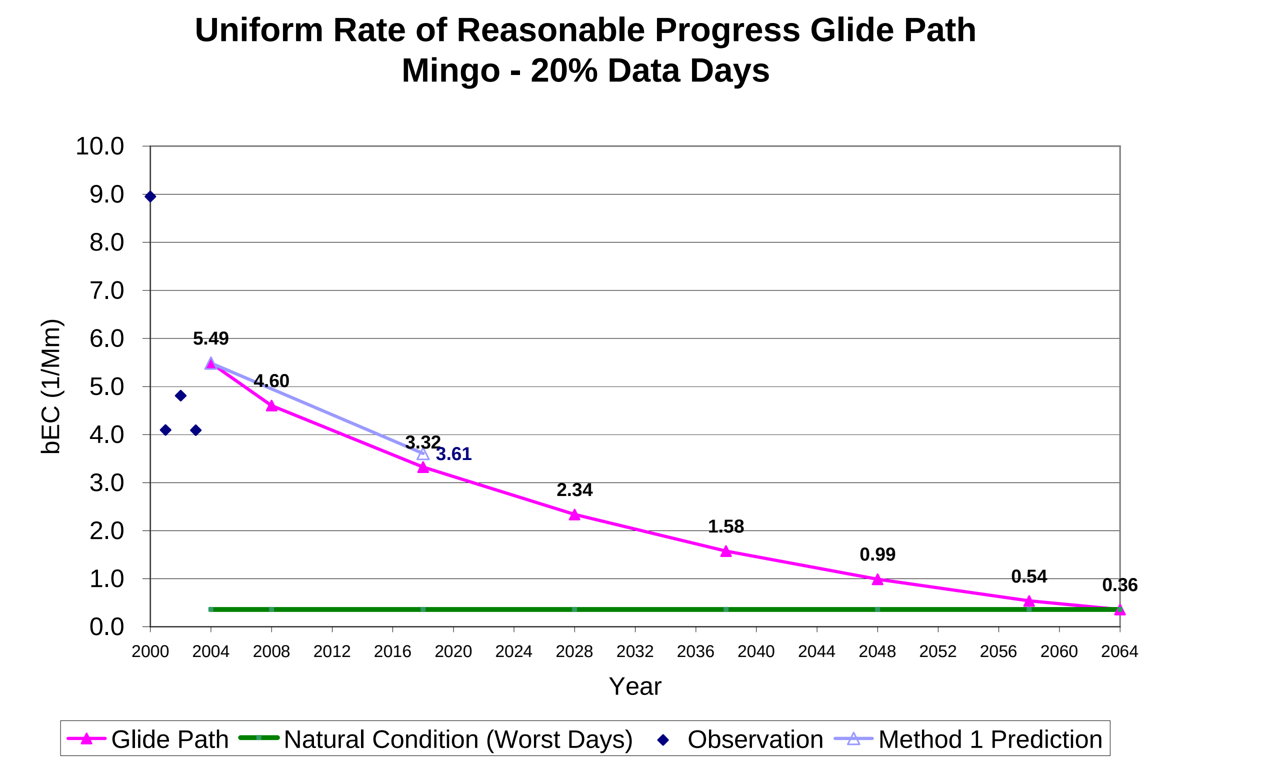


Figure F-7d. 2018 Visibility Projections and 2018 URP Glidepaths for Elemental Carbon (EC) in extinction (Mm^{-1}) for Mingo (MING), Missouri and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

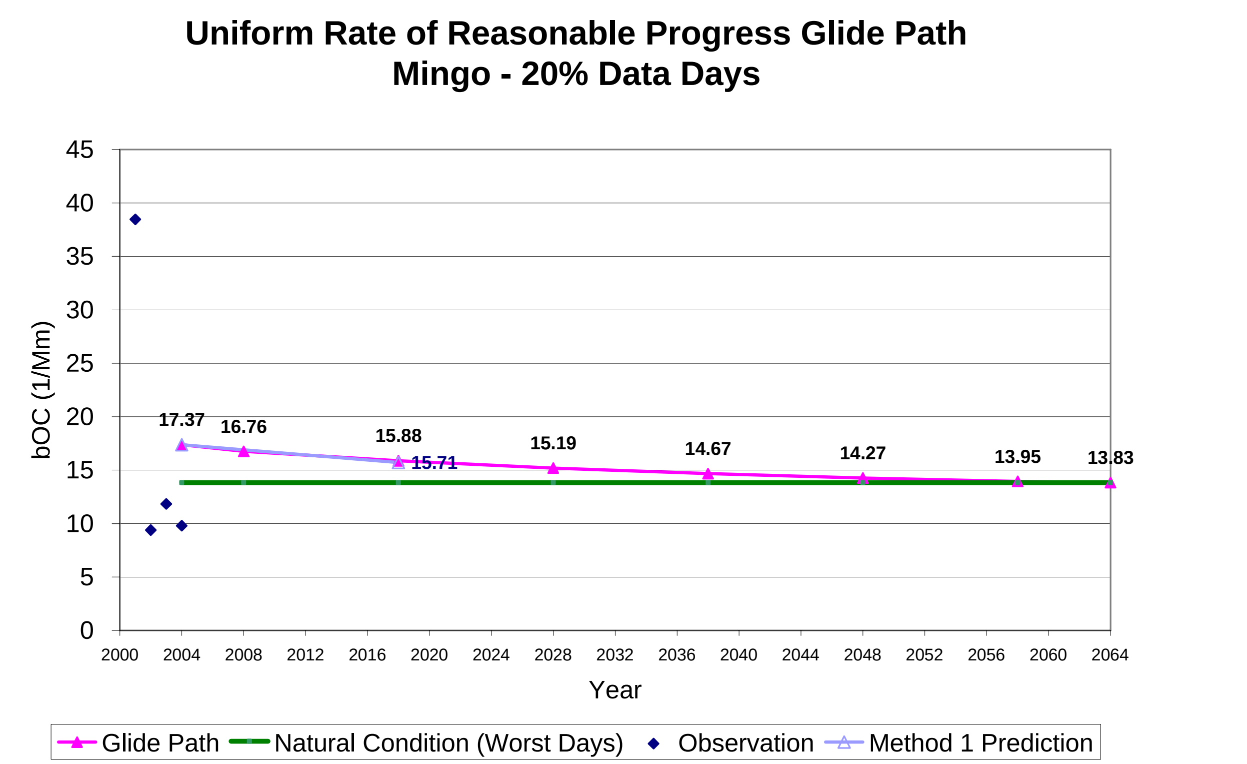


Figure F-7e. 2018 Visibility Projections and 2018 URP Glidepaths for Organic Mass Carbon (OMC) in extinction (Mm^{-1}) for Mingo (MING), Missouri and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

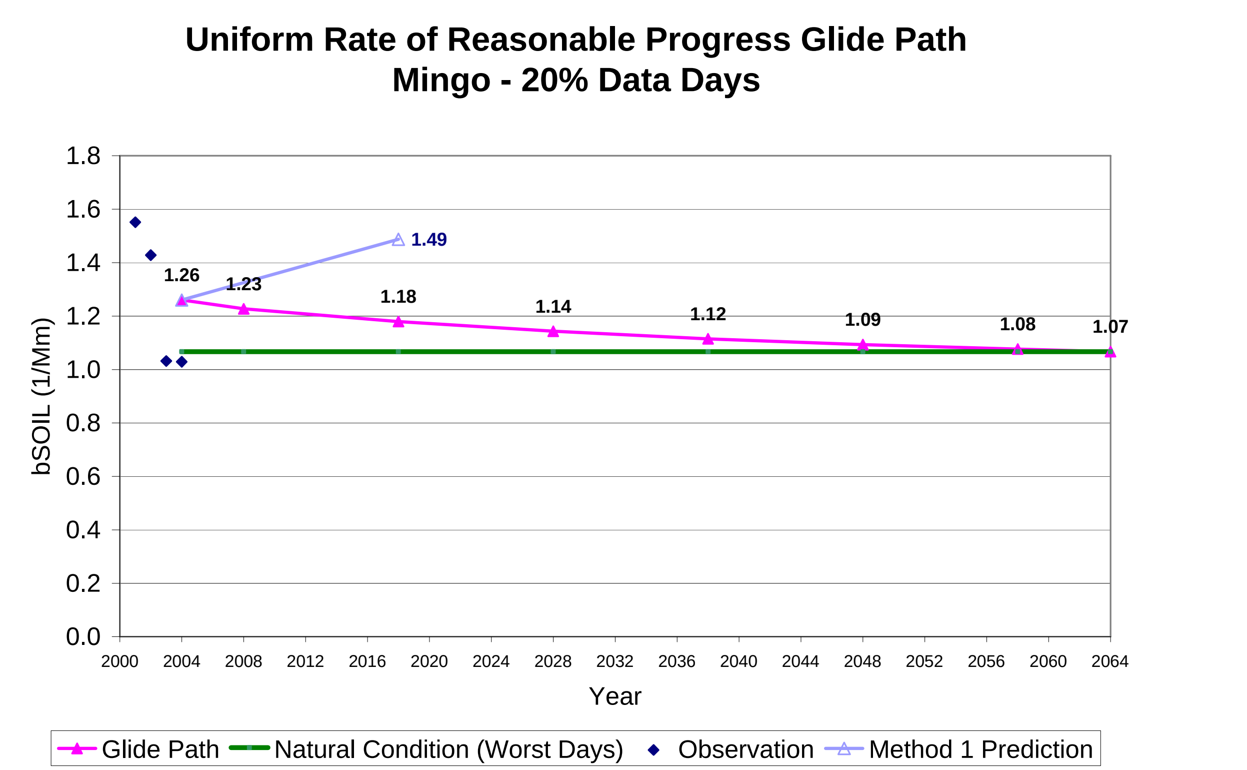


Figure F-7f. 2018 Visibility Projections and 2018 URP Glidepaths for Other Fine Particulate (SOIL) in extinction (Mm^{-1}) for Mingo (MING), Missouri and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

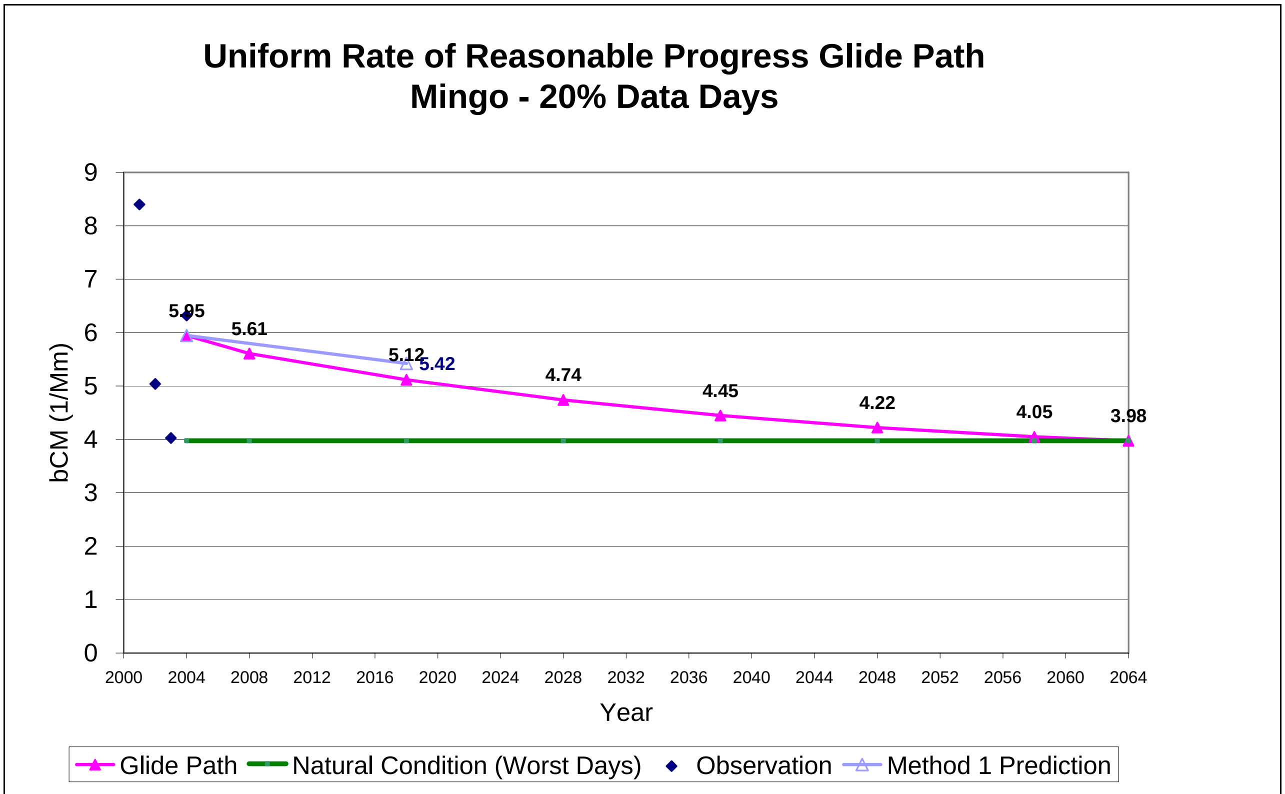


Figure F-7g. 2018 Visibility Projections and 2018 URP Glidepaths for Coarse Mass (CM) in extinction (Mm^{-1}) for Mingo (MING), Missouri and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

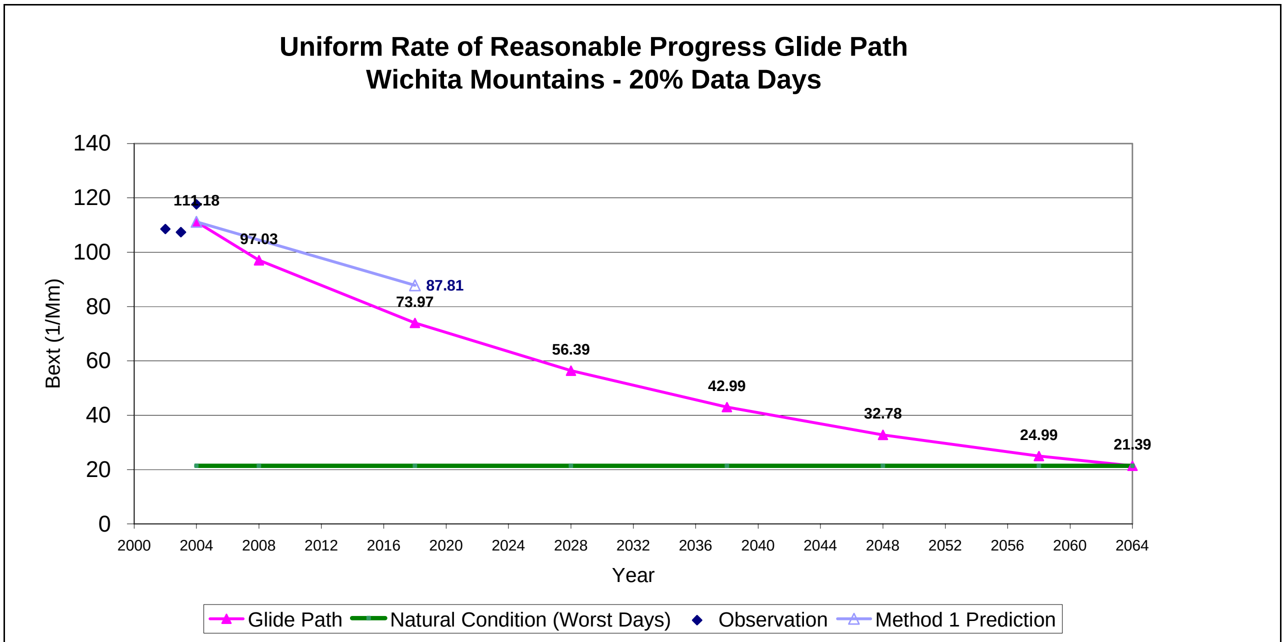


Figure F-8a. 2018 Visibility Projections and 2018 URP Glidepaths in extinction (Mm^{-1}) for Wichita Mountains (WIMO), Oklahoma and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

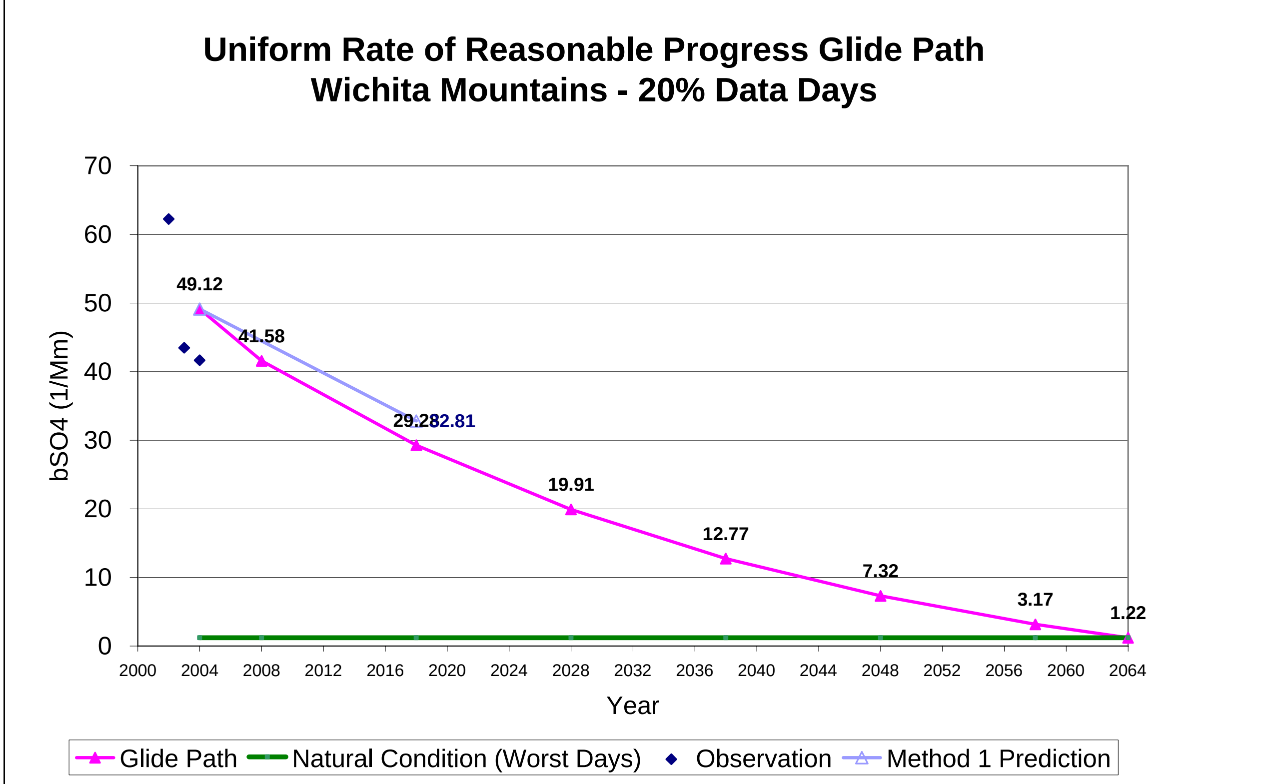


Figure F-8b. 2018 Visibility Projections and 2018 URP Glidepaths for Sulfate (SO4) in extinction (Mm^{-1}) for Wichita Mountains (WIMO), Oklahoma and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

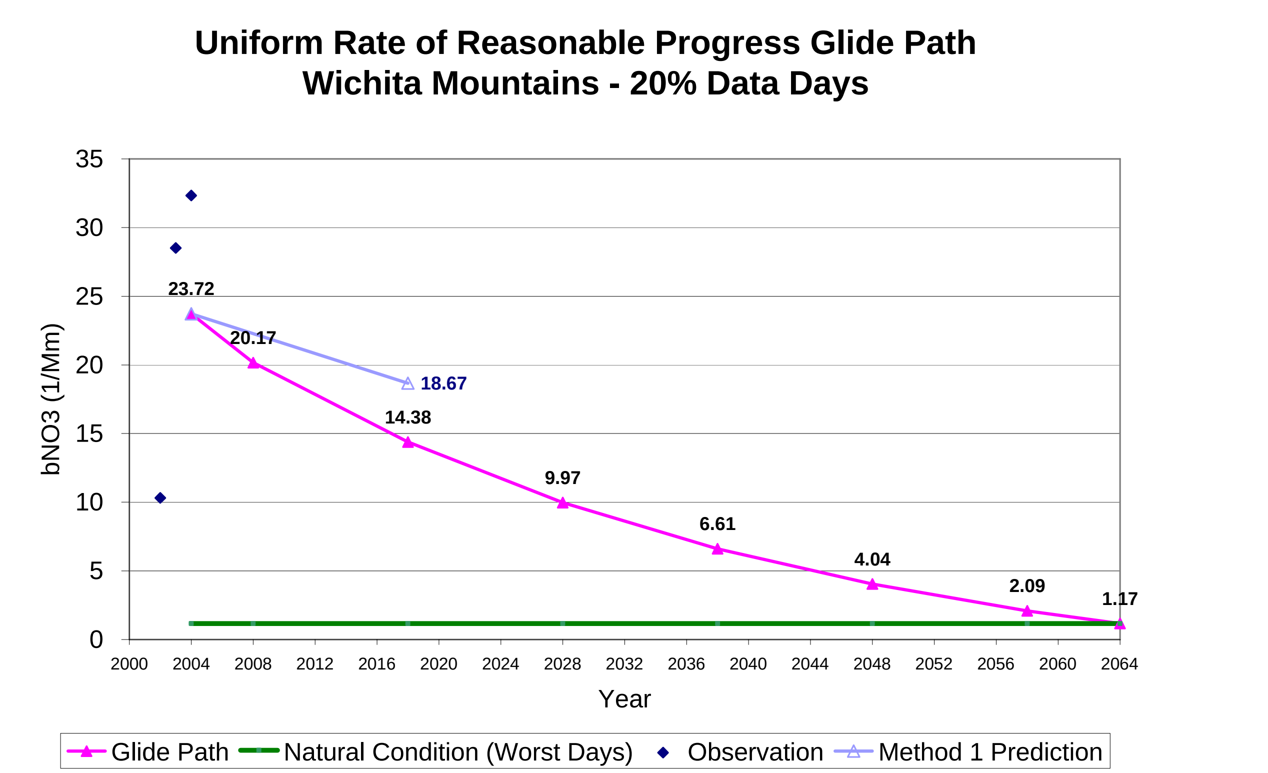


Figure F-8c. 2018 Visibility Projections and 2018 URP Glidepaths for Nitrate (NO3) in extinction (Mm^{-1}) for Wichita Mountains (WIMO), Oklahoma and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

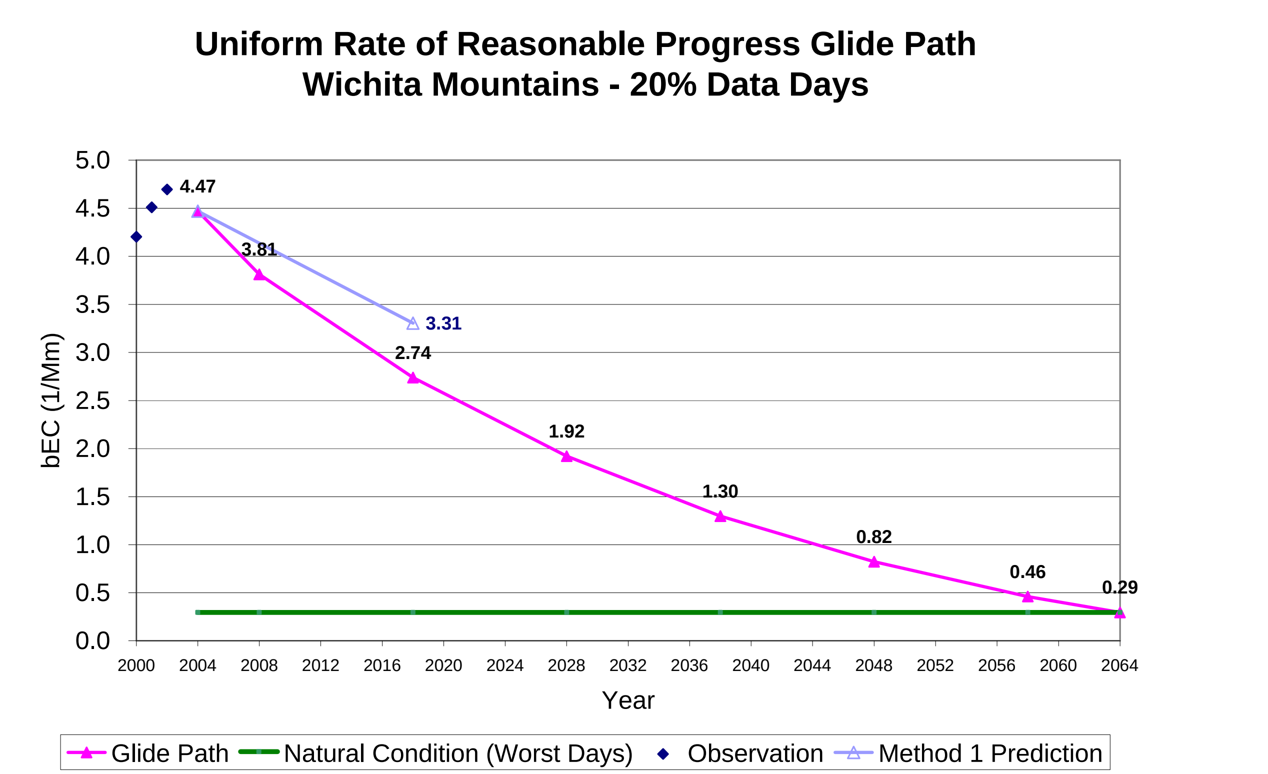


Figure F-8d. 2018 Visibility Projections and 2018 URP Glidepaths for Elemental Carbon (EC) in extinction (Mm^{-1}) for Wichita Mountains (WIMO), Oklahoma and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

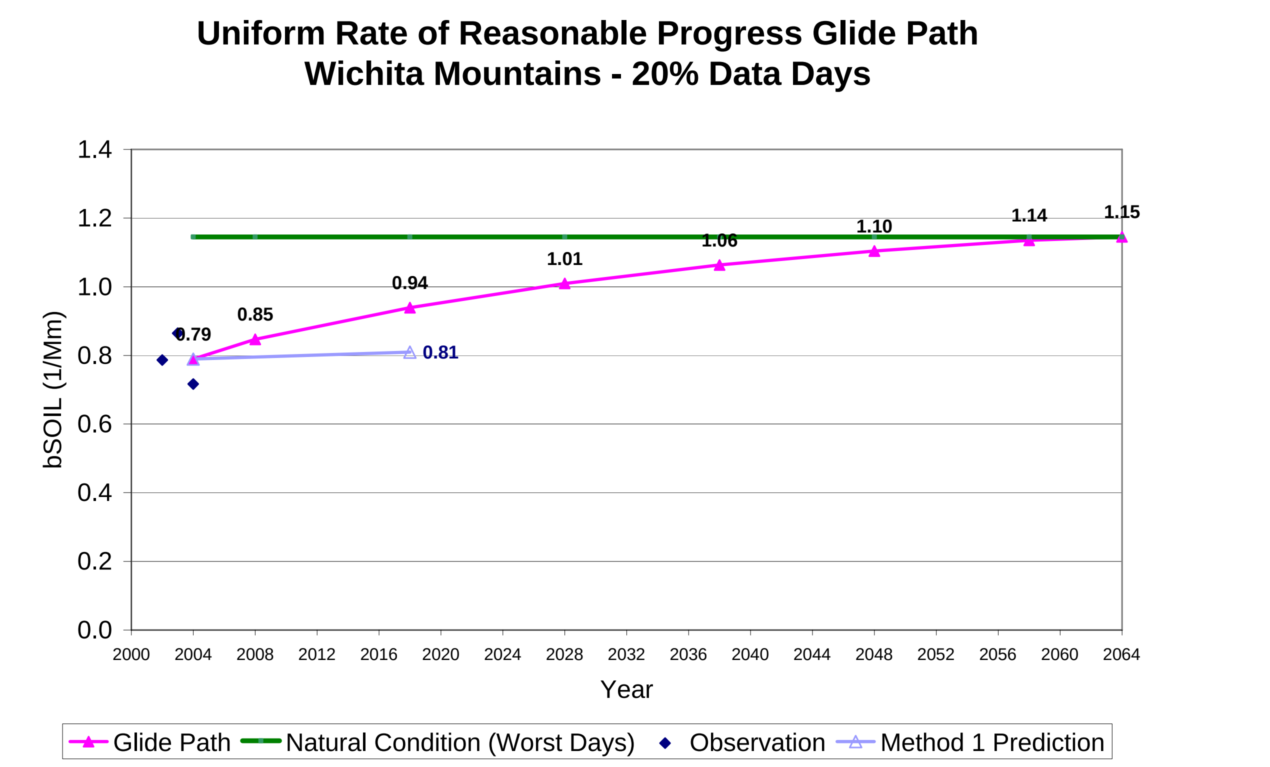


Figure F-8e. 2018 Visibility Projections and 2018 URP Glidepaths for Organic Mass Carbon (OMC) in extinction (Mm^{-1}) for Wichita Mountains (WIMO), Oklahoma and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

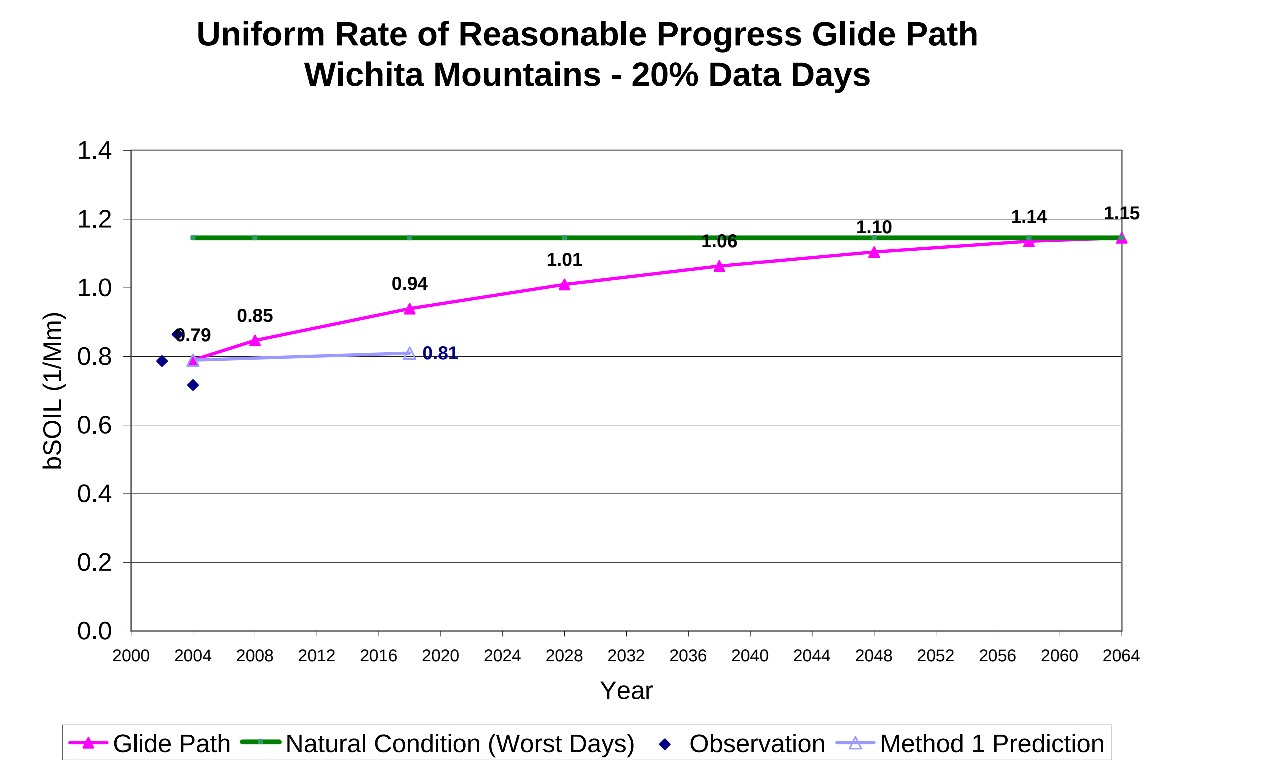


Figure F-8f. 2018 Visibility Projections and 2018 URP Glidepaths for Other Fine Particulate (SOIL) in extinction (Mm^{-1}) for Wichita Mountains (WIMO), Oklahoma and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

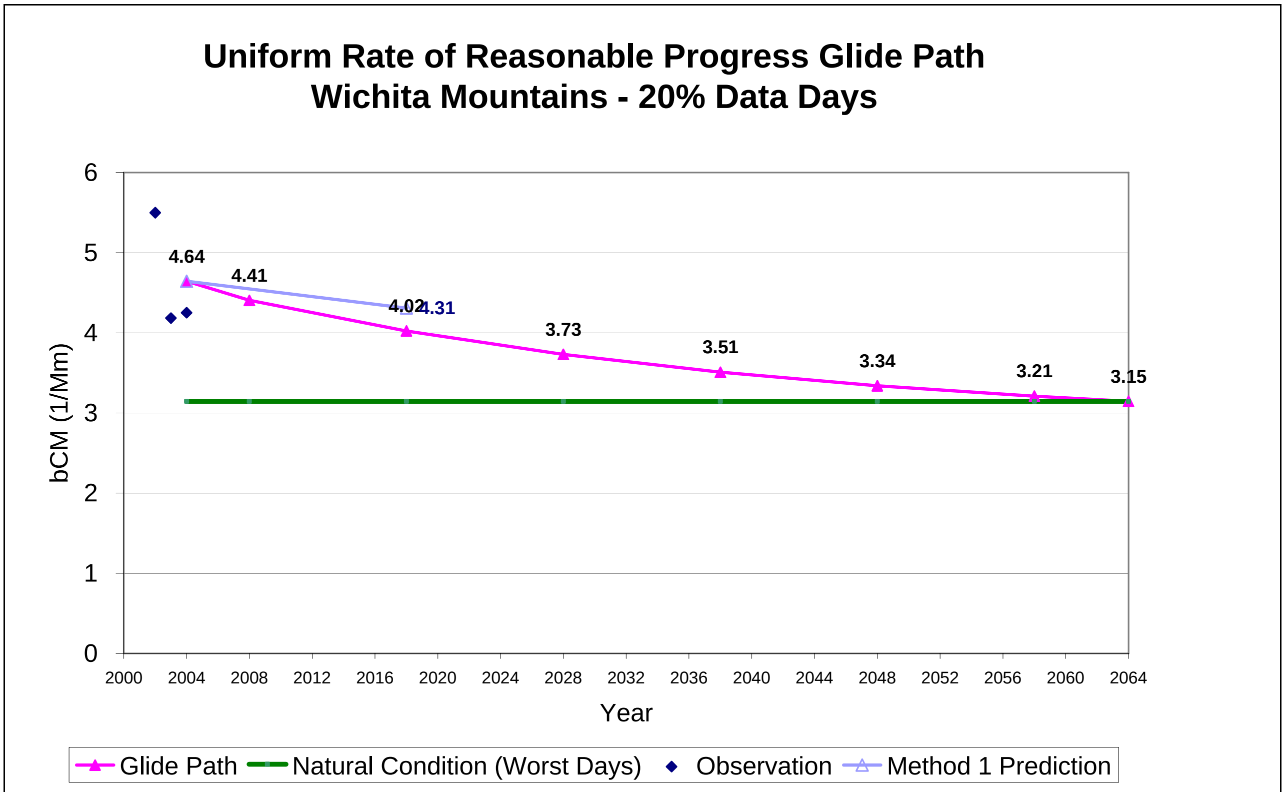


Figure F-8g. 2018 Visibility Projections and 2018 URP Glidepaths for Coarse Mass (CM) in extinction (Mm^{-1}) for Wichita Mountains (WIMO), Oklahoma and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

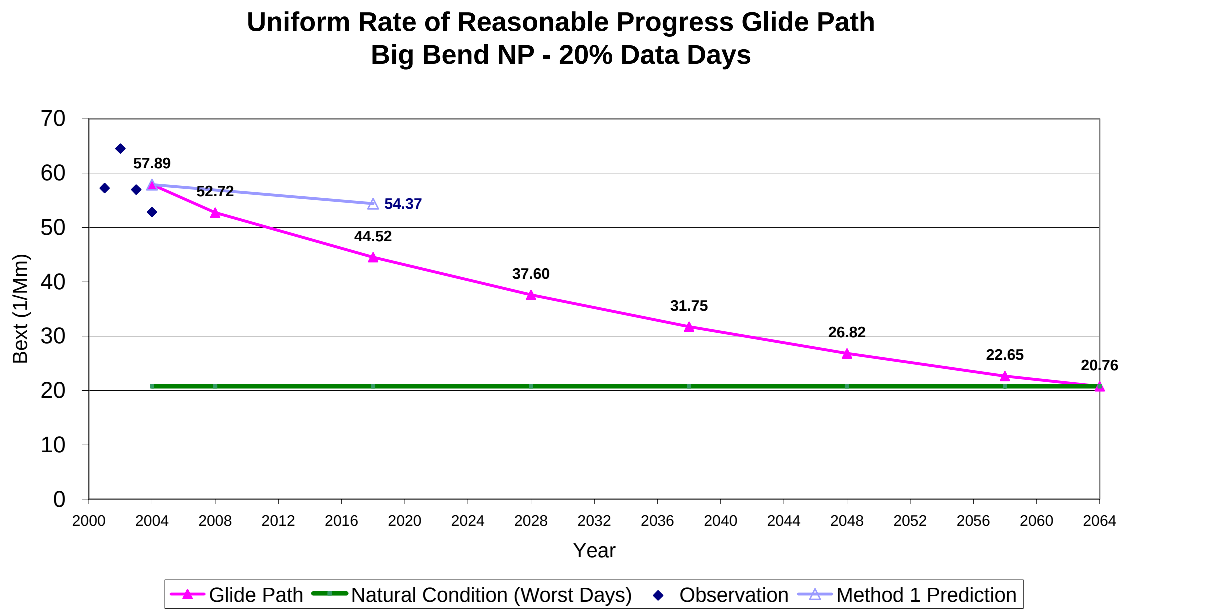


Figure F-9a. 2018 Visibility Projections and 2018 URP Glidepaths in extinction (Mm^{-1}) for Big Bend (BIBE), Texas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

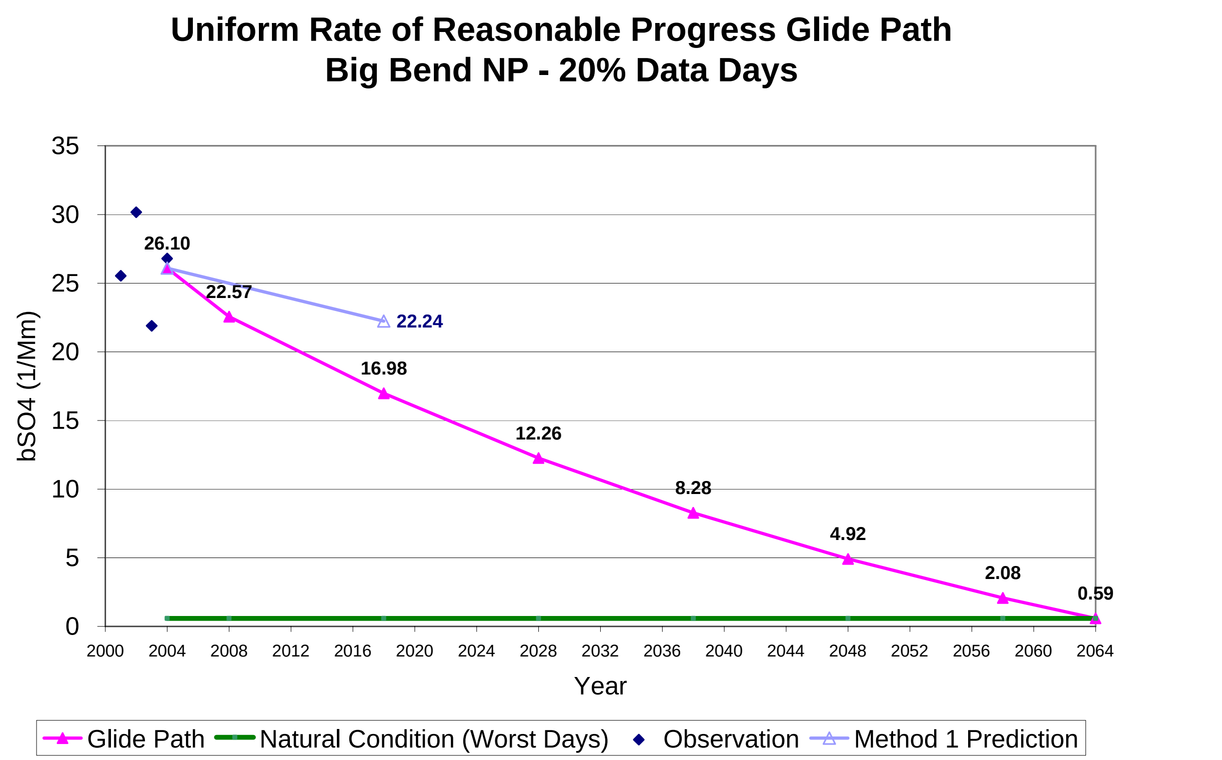


Figure F-9b. 2018 Visibility Projections and 2018 URP Glidepaths for Sulfate (SO4) in extinction (Mm^{-1}) for Big Bend (BIBE), Texas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

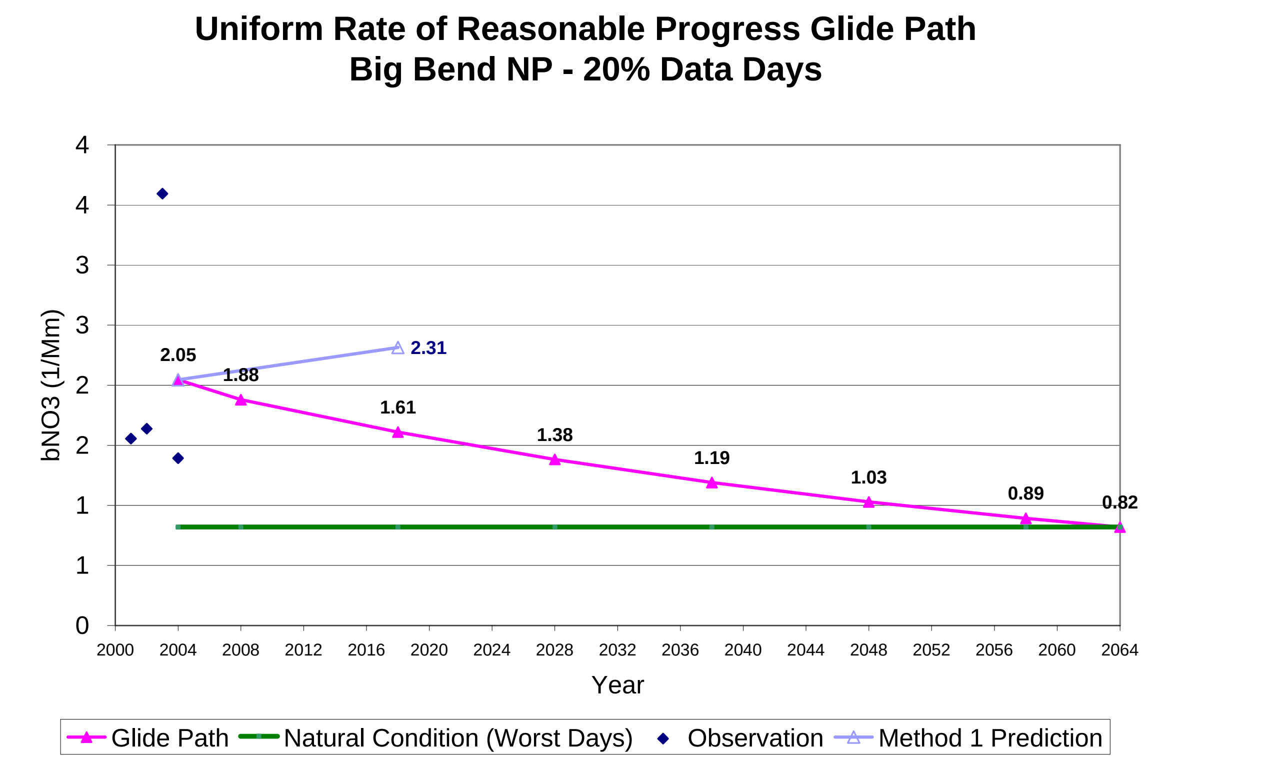


Figure F-9c. 2018 Visibility Projections and 2018 URP Glidepaths for Nitrate (NO3) in extinction (Mm^{-1}) for Big Bend (BIBE), Texas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

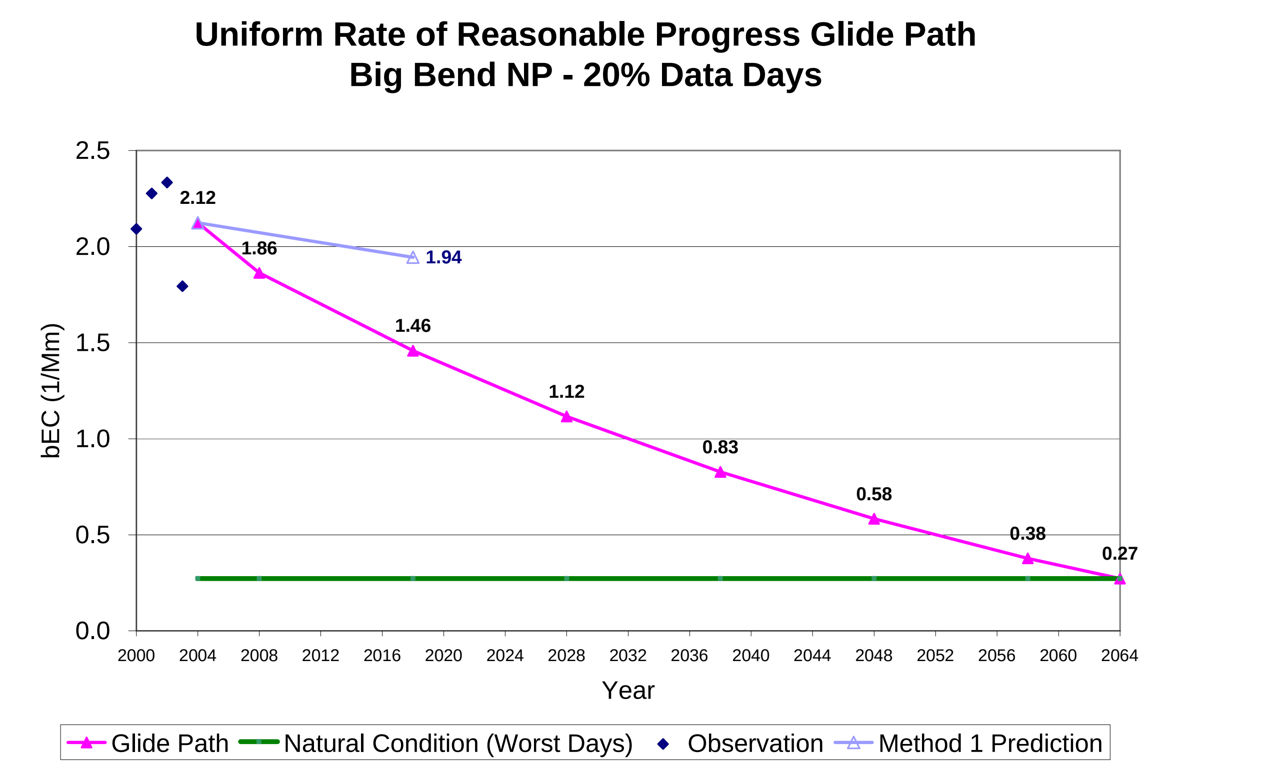


Figure F-9d. 2018 Visibility Projections and 2018 URP Glidepaths for Elemental Carbon (EC) in extinction (Mm^{-1}) for Big Bend (BIBE), Texas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

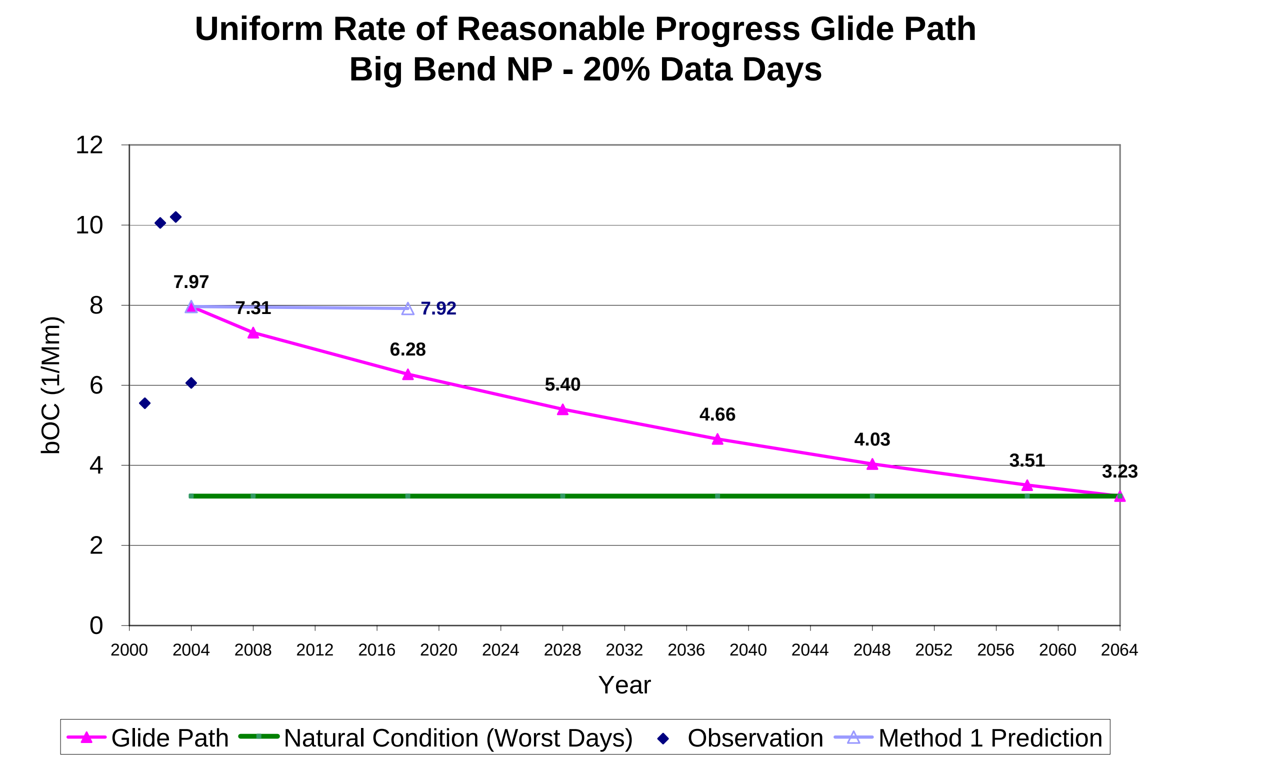


Figure F-9e. 2018 Visibility Projections and 2018 URP Glidepaths for Organic Mass Carbon (OMC) in extinction (Mm^{-1}) for Big Bend (BIBE), Texas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

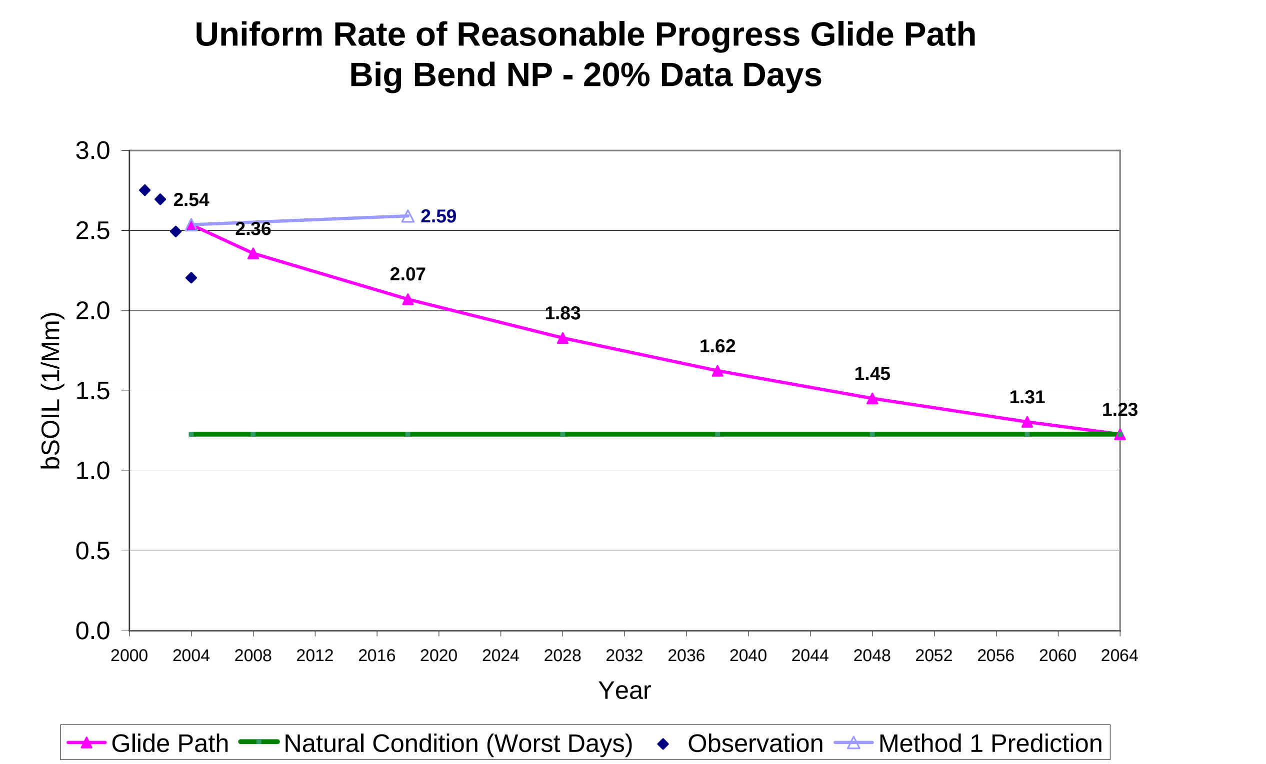


Figure F-9f. 2018 Visibility Projections and 2018 URP Glidepaths for Other Fine Particulate (SOIL) in extinction (Mm^{-1}) for Big Bend (BIBE), Texas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

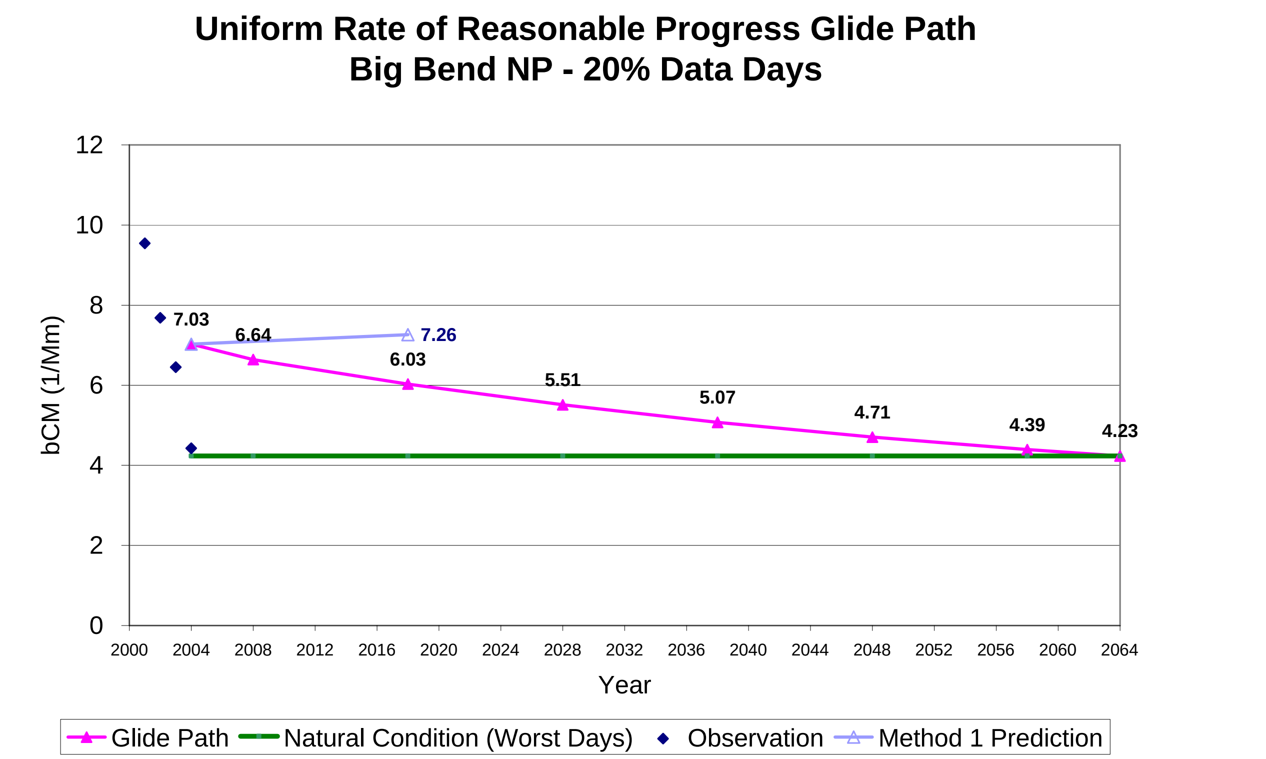


Figure F-9g. 2018 Visibility Projections and 2018 URP Glidepaths for Coarse Mass (CM) in extinction (Mm^{-1}) for Big Bend (BIBE), Texas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

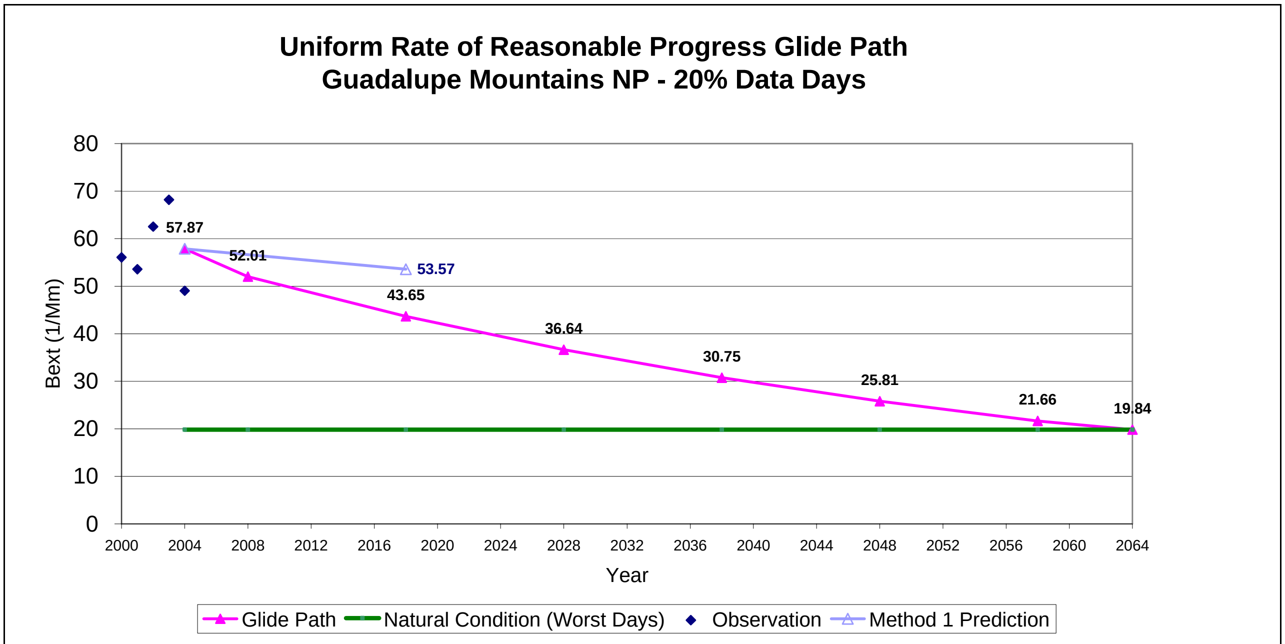


Figure F-10a. 2018 Visibility Projections and 2018 URP Glidepaths in extinction (Mm^{-1}) for Guadalupe Mountains (GUMO), Texas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

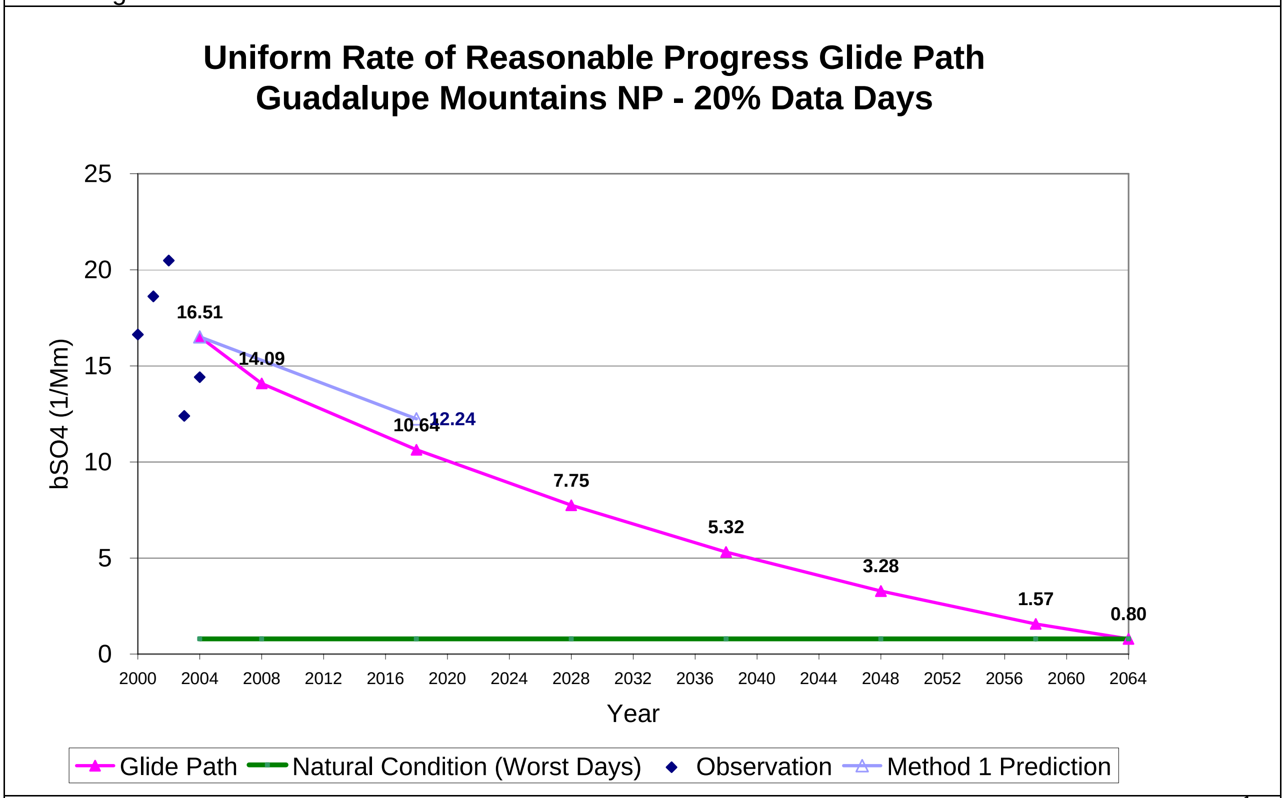


Figure F-10b. 2018 Visibility Projections and 2018 URP Glidepaths for Sulfate (SO4) in extinction (Mm^{-1}) for Guadalupe Mountains (GUMO), Texas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

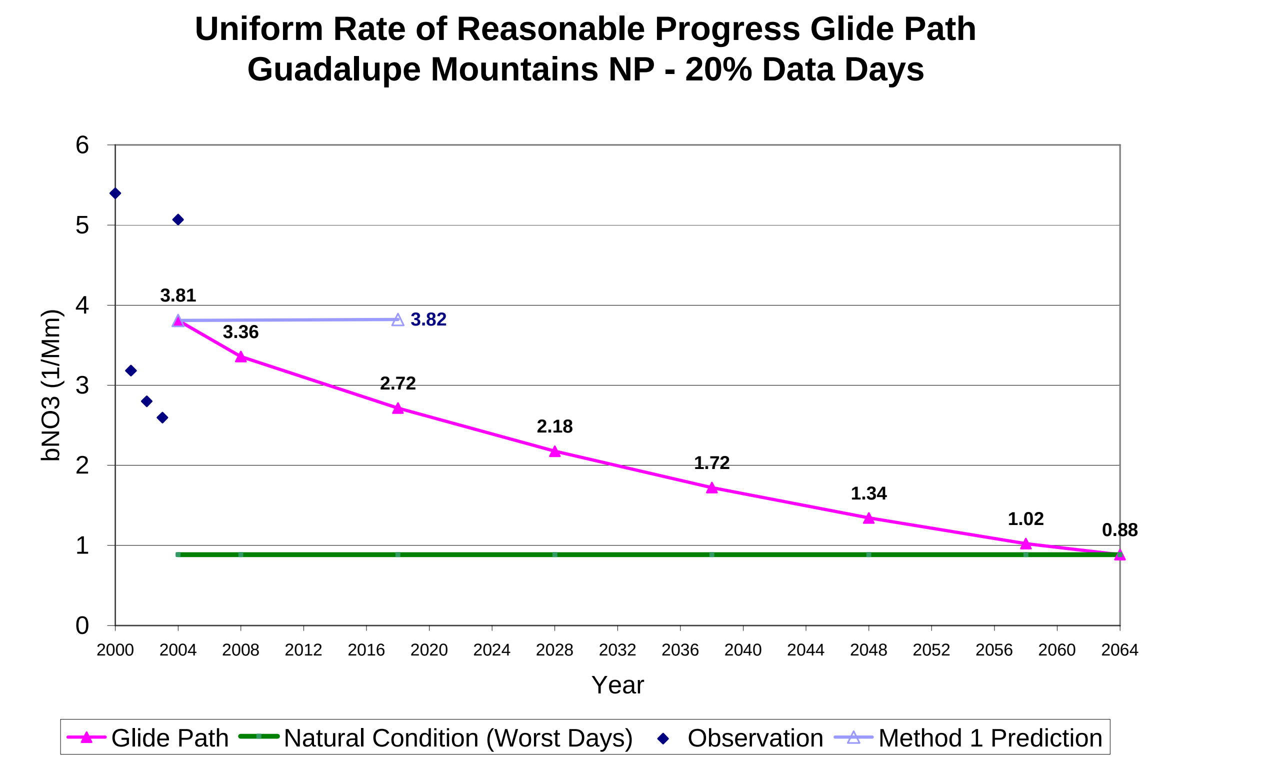


Figure F-10c. 2018 Visibility Projections and 2018 URP Glidepaths for Nitrate (NO3) in extinction (Mm^{-1}) for Guadalupe Mountains (GUMO), Texas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

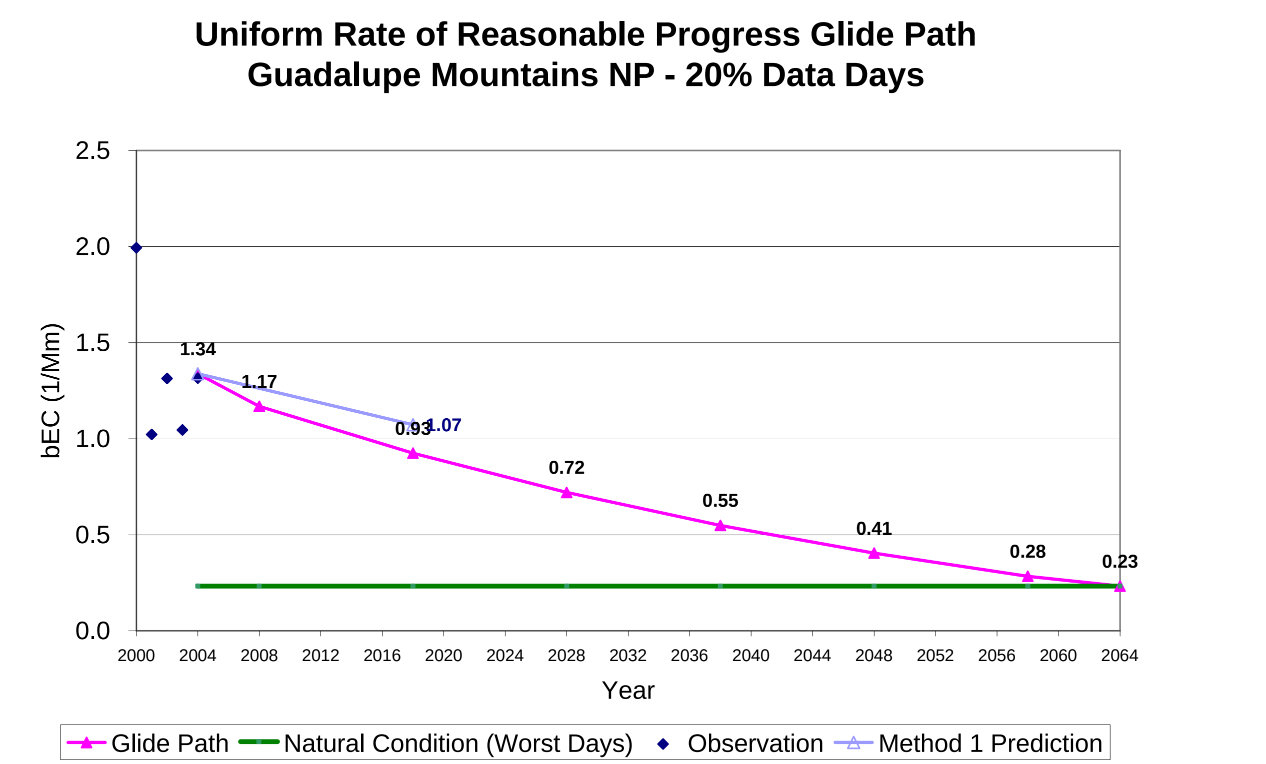


Figure F-10d. 2018 Visibility Projections and 2018 URP Glidepaths for Elemental Carbon (EC) in extinction (Mm^{-1}) for Guadalupe Mountains (GUMO), Texas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

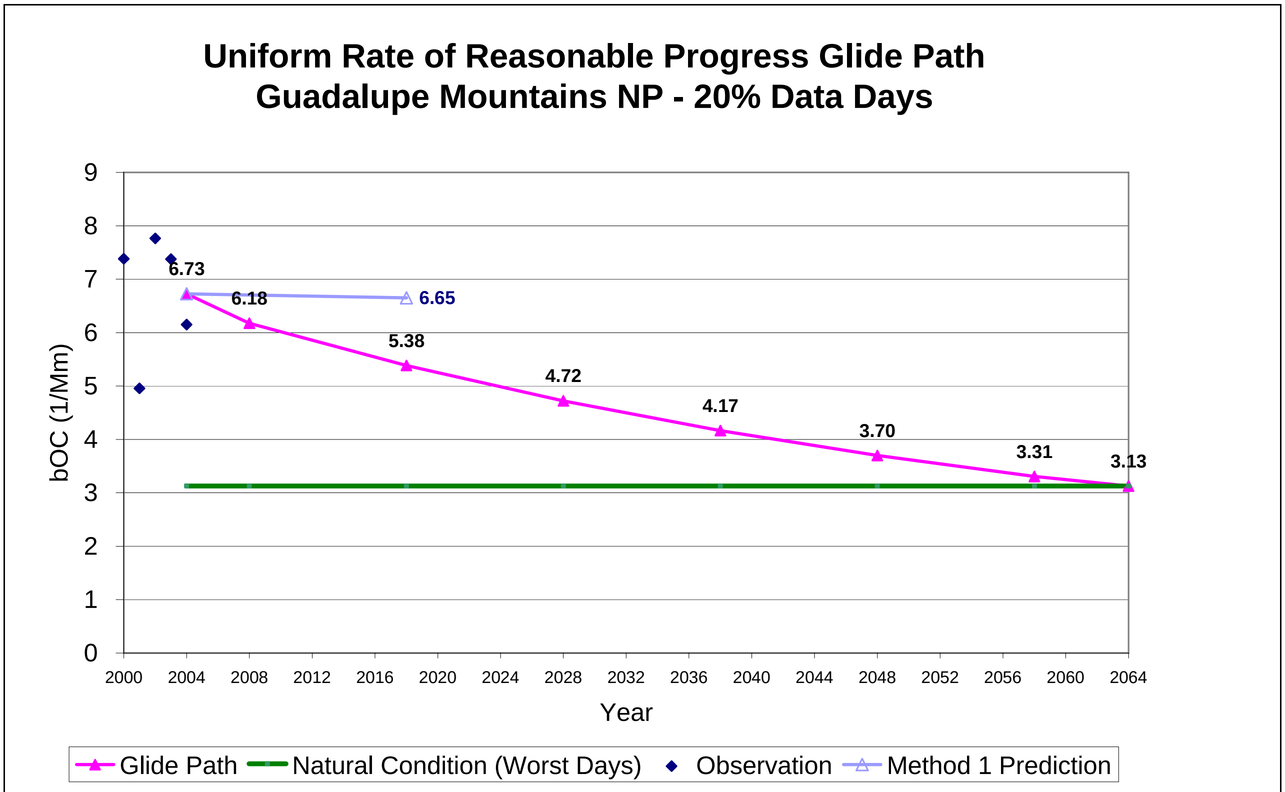


Figure F-10e. 2018 Visibility Projections and 2018 URP Glidepaths for Organic Mass Carbon (OMC) in extinction (Mm^{-1}) for Guadalupe Mountains (GUMO), Texas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

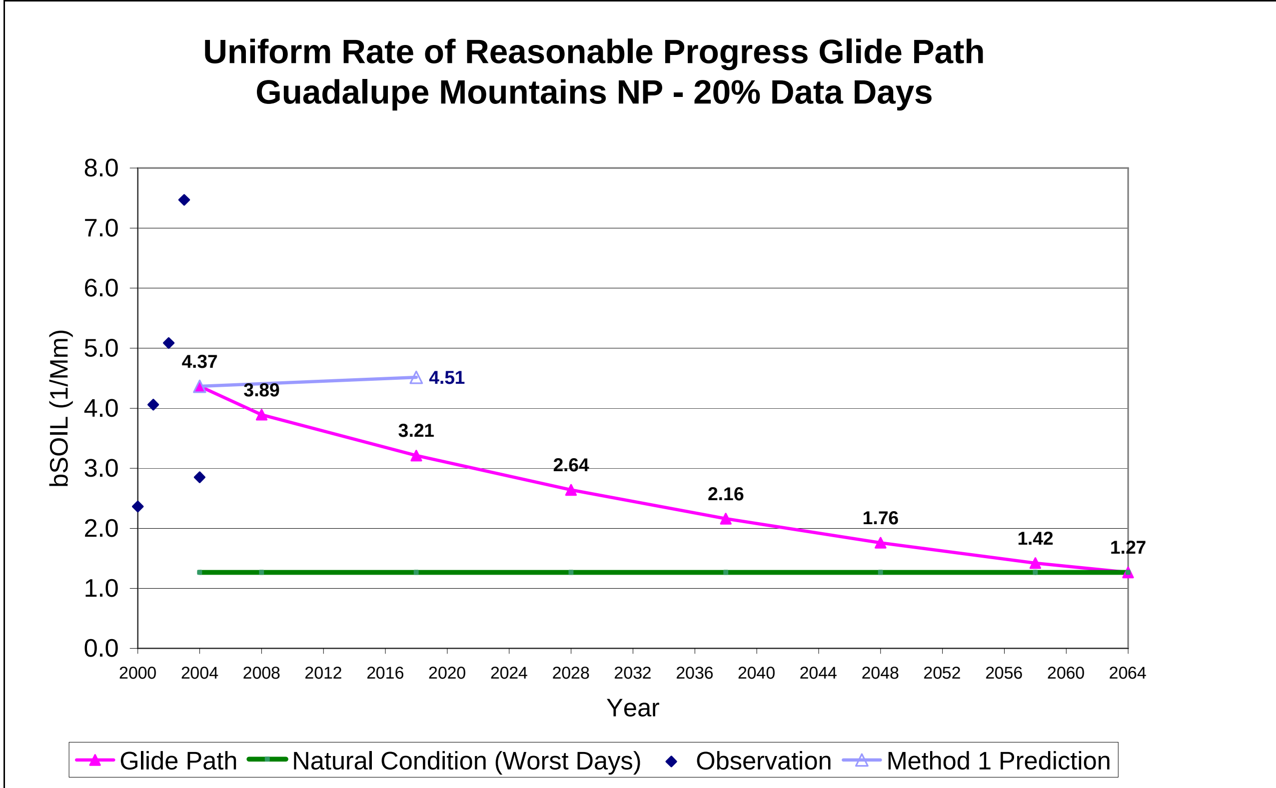


Figure F-10f. 2018 Visibility Projections and 2018 URP Glidepaths for Other Fine Particulate (SOIL) in extinction (Mm^{-1}) for Guadalupe Mountains (GUMO), Texas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

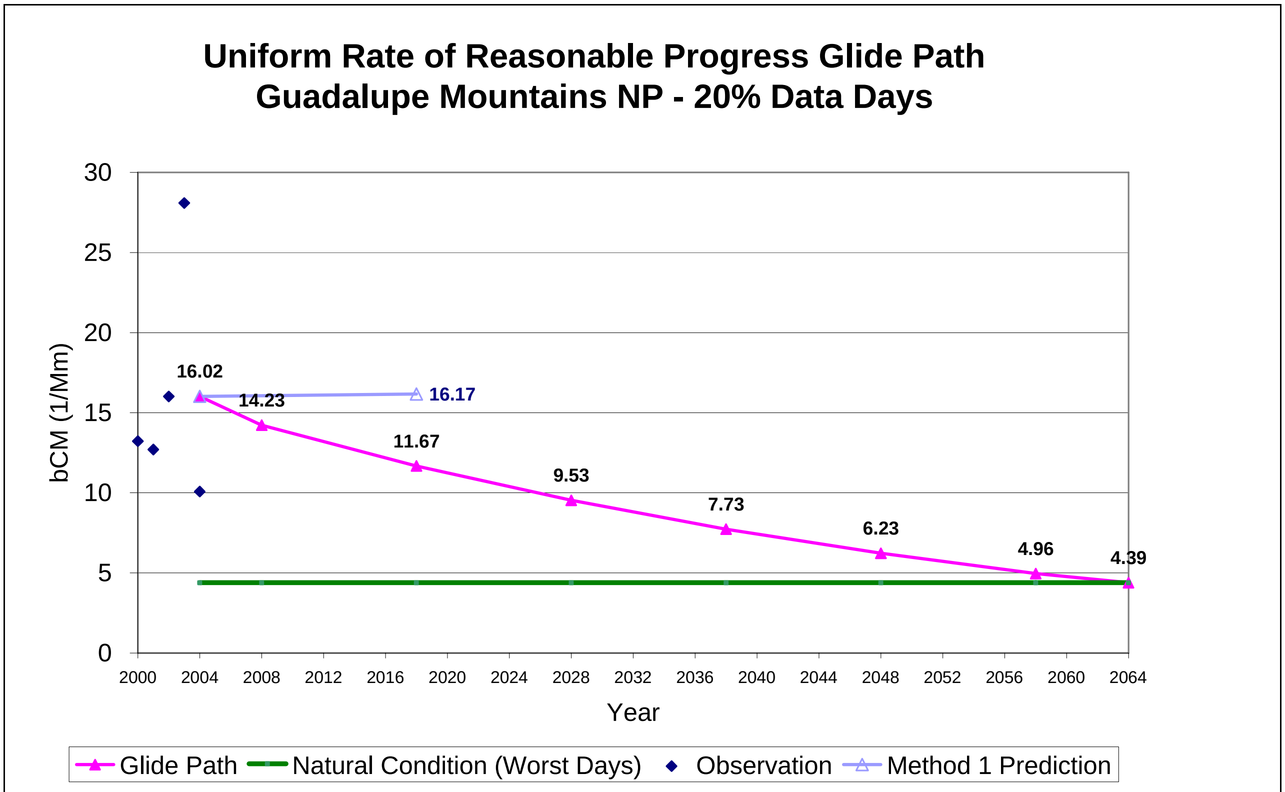


Figure F-10g. 2018 Visibility Projections and 2018 URP Glidepaths for Coarse Mass (CM) in extinction (Mm^{-1}) for Guadalupe Mountains (GUMO), Texas and Worst 20% (W20%) days using 2002/2018 Base G CMAQ 36 km modeling results.

Appendix W

CENRAP Regional Haze Control Strategy Analysis Plan

Jeff Peltola

From: Gregory Stella [gms@alpinegeophysics.com]
Sent: Tuesday, May 09, 2006 3:53 PM
To: Jeff Peltola
Cc: 'Seltz, John'; mac@adeq.state.ar.us; 'T. W. Tesche'; 'Wilkinson, Jim'
Subject: Final CENRAP Regional Haze Control Strategy Analysis Plan

Attachments: Alpine Geophysics Final Report (9 May '06).pdf

Alpine Geophysics Final Report...

VIA E-MAIL

9 May 2006

Mr. Jeff Peltola
CENRAP Technical Director
10005 S. Pennsylvania, Ste C
Oklahoma City, OK 73159

Dear Jeff:

The scientists at Alpine Geophysics are pleased to submit the attached document titled "Final CENRAP Regional Haze Control Strategy Analysis Plan" as outlined in Task 6 of our previously submitted quotation and work plan.

This document and associated materials are the product of our development and application of a quantitative procedure to identify and prioritize potential regional haze control strategies for Class I areas failing to meet visibility goal objectives. Additionally, we have addressed as many of the comments on the draft control strategy analysis plan as submitted to Alpine (April 25 and later) as we have determined to be within the scope of our original proposal to CENRAP.

To facilitate subsequent use of this methodology by CENRAP or others, this Final Report describes the various analytical steps and provides examples of this procedure (both in the body of the report and in supporting in appendixes). Document appendices and relevant technical support information have archived on the Alpine Geophysics project website facilitating easy access by interested parties. The login and password to access these data is provided below.

```
ftp> ftp.alpinegeophysics.com
login> cenrap
pass> pass4ftp
```

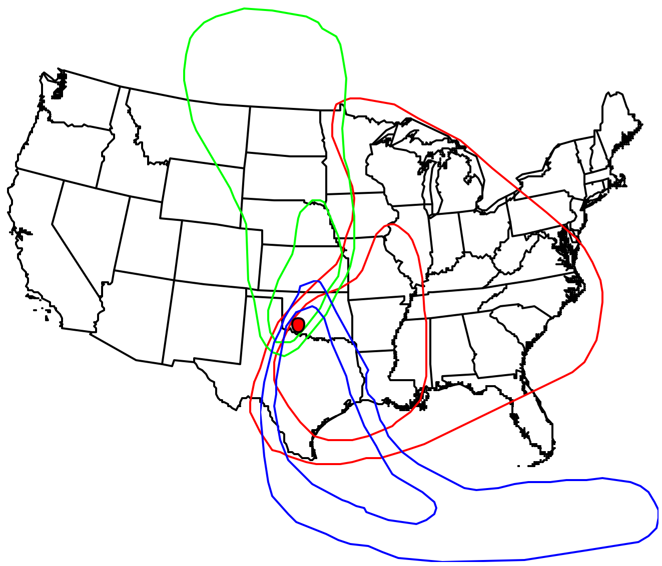
Should you have any questions or problems accessing these files and supporting materials, please contact me at your convenience.

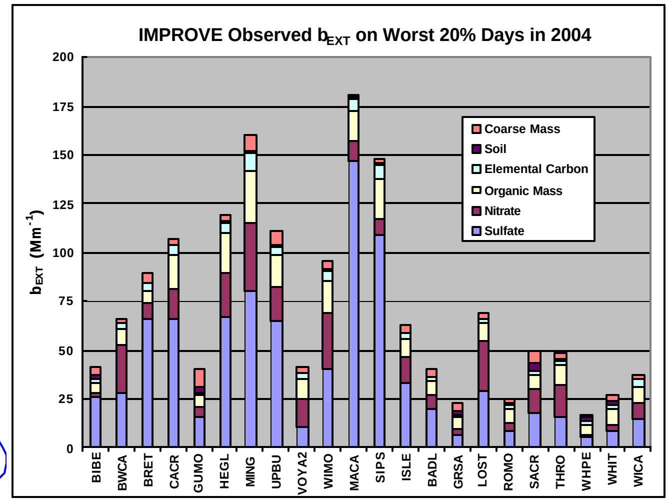
Respectfully yours,

Gregory Stella
Senior Scientist
Alpine Geophysics, LLC
Burnsville, NC 28714

Final Report

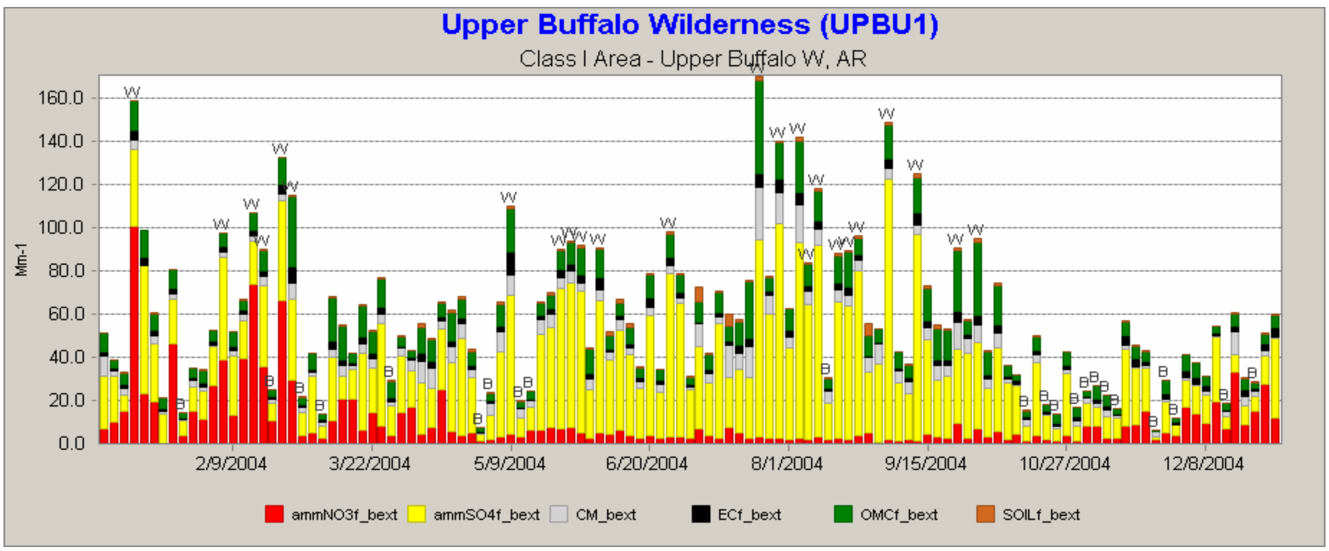
CENRAP REGIONAL HAZE CONTROL STRATEGY ANALYSIS PLAN





Wichita Mountains Areas of Influence (AOIs)

b_{ext} on CENRAP Worst 20% Days in 2004



Daily Variation in $PM_{2.5}$ Components at Upper Buffalo Wilderness

Prepared by

Mr. Gregory M. Stella
Dr. Jim Wilkinson
Dr. T. W. Tesche
Alpine Geophysics, LLC

Prepared for

CENRAP/CENSARA
10005 S. Pennsylvania, Ste C
Oklahoma City, OK 73159

9 May 2006

ALPINE GEOPHYSICS

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EXECUTIVE SUMMARY

The Implementation and Control Strategies (ICS) Workgroup of the Central Regional Air Planning Association (CENRAP), together with other workgroups and state, tribal and federal agencies, have been working for more than four years gathering information for developing regional haze (RH) control strategies for pertinent Class I areas within and adjacent to the CENRAP states and tribes. In late February 2006, under the direction of the CENRAP Technical Director, Alpine Geophysics, LLC was contracted to assist the ICS in this effort. Building upon information developed by the ICS and others, Alpine was charged with developing a quantitative procedure to identify and prioritize potential RH control strategies to be tested by CENRAP modelers. Alpine formulated a methodology for constructing control strategy recommendations based on presently available information and submitted a Work Plan detailing this approach to the ICS/CENRAP leadership for review and approval.

Using the results of preliminary and more recent CENRAP visibility projection modeling together with current information on the composition of visibility-impairing fine particulate aerosols at 22 Class I monitors, Alpine identified residual visibility progress 'increments' that potentially require additional regional and/or subregional emission reductions to achieve visibility goals[1]. We synthesized pertinent 'attribution of haze' documents, CENRAP CAMx/CMAQ visibility modeling results, our own fine particulate modeling in the central U.S, and other technical reports, papers, and analyses bearing directly on the quantification of emissions-source/visibility-receptor impacts at the ten CENRAP Class I and twelve adjoining areas.

Complementing this task, we synthesized a number of recent regional modeling studies helpful in relating emissions reductions of visibility precursors (e.g. SO_2, NO_X) in upwind source regions (Areas of Influence or AOIs) to the improvement in visibility (in deciviews or Mm^{-1}) at downwind Class I areas. Figures ES-1 and ES-2 present ‘level 1’ AOI plots for sulfate and nitrate impacts at the Big Bend, Guadalupe, Wichita Mountains, Breton Island, Voyageurs, and Boundary Waters Class I Areas, respectively. Three distinct levels of AOI have been estimated for each visibility precursor and Class I areas, but the controls most likely to be considered for modeling will be drawn from the closest (i.e., AOI level 1 or AOI-1) area of influence for each Class I area/visibility precursor pair.

[1] We use the term ‘increment’ to denote the difference between the modeled visibility at a Class I area in 2018 compared to the value based on the Reasonable Progress Goal (RPG) glide path, evaluated at the same time period. A positive increment means that the modeled visibility at the Class I area is ‘poorer’ than the level associated with the linear FPG glide path. Accordingly, CENRAP may wish to consider recommending additional precursor controls to ameliorate such a positive visibility increment. In contrast, a negative increment suggests that the modeled growth and emissions controls by 2018 may produce better visibility conditions at the monitor when compared to the linear glide path.

We then deduced from available regional modeling studies 'rules of thumb' relating percentage or tonnage reductions in visibility reducing precursors (e.g., SO_2, NO_X, ammonia, and VOCs) on the expected impact on visibility downwind. These 'rules of thumb', i.e., source-receptor relationships, were essential in estimating the amounts of incremental precursor emissions reductions in regions upwind of each of the various Class I areas that CENRAP modelers should consider in the prescription of initial RH control strategy simulations.

Once an emissions reduction target was determined for each Class I area showing visibility projections above the uniform rate of progress line (i.e., a positive visibility increment), we applied a master list of controls on sources within the Class I AOIs to formulate the CENRAP Control Strategy plan, including cost-effectiveness as a key element.

Alpine's analysis of the most recent CENRAP visibility projection data identified six Class I areas within the CENRAP domain whose projected visibility falls above the uniform rate of progress line (i.e., a projected positive visibility increment). On this basis, we quantified their associated AOIs, emission reduction estimates for reaching 2018 reasonable progress objectives, and potential incremental emission reductions worthy of annual CMAQ/CAMx modeling. For each area, sulfate and to a lesser extent, nitrate reductions were shown to be most beneficial during the 20 percent worst visibility days in 2002.

As each of these areas (and all of the other Class I AOIs in the CENRAP domain) are dominated by EGU SO_2 and NO_X emissions and many of the Class I area AOIs intersect with States currently excluded by the EPA CAIR rule, a region-wide strategy for additional EGU emission reductions at CAIR levels for the non-CAIR EGUs may be beneficial to each Class I area in the CENRAP domain projected below the uniform rate of progress line. An alternate intra-state trading permutation of this regional approach is also recommended for review by CENRAP.

In lieu of a single regional control option applied consistently across the entire CENRAP domain, individual subregional control applications are proposed to reduce emissions within certain Class I area AOIs. Based on the single precursor emission reduction target calculations defined by the ICS, subregional control strategies can be defined for three of the Class I areas projected to be above the reasonable progress glide path[2]. In each case, the marginal cost curves (based on the application of all available control options on all controllable industries and source types) allow the selection of control technologies which attains the ICS defined, AOI-1 specific emission reduction targets.

However, the application of incremental control on all controllable point and area sources within certain AOIs still fails to meet the visibility objectives of three Class I areas modeled to be above the reasonable progress glide slope. In fact, as a result of the implementation of the exhaustive list of additional controls in each primary AOI, Alpine has determined that these three Class I areas[3] will be unable to achieve a level of emissions reduction necessary to bring these areas under the reasonable progress line. Influences such as incrementally uncontrollable source categories, cost-effectiveness limitations and international and inter-RPO emissions transport are barriers that prevent strategies from being configured for these Class I areas within the confines of the CENRAP domain.

[2] These areas include Boundary Waters, Wichita Mountains, and Voyageurs.

[3] These areas include Big Bend, Breton Island, and Guadalupe Mountains.

Although application of the exhaustive list of available control technologies to sources within the AOIs for each of the Class I areas failing to achieve ICS identified emission reduction targets, emission reductions beyond the base case should not be forsaken as a result. Indeed, *significant emission reductions may be warranted* in order to prepare impacted States and tribes for future attainment demonstrations where these measures may set the basis for defining and meeting future progress goals.

It should be noted that although this report and associated material includes controls for particular sources or source categories as options to consider for further photochemical modeling, it does not necessarily indicate that they will be modeled, and does not imply that these strategies ultimately will be implemented.

Finally, while the this methodology was developed and tested for regional haze control programs, with very minor adaptation, the same methods can be used effectively to aid in the design of regional 8-hr ozone and annual $PM_{2.5}$ NAAQS attainment strategies.

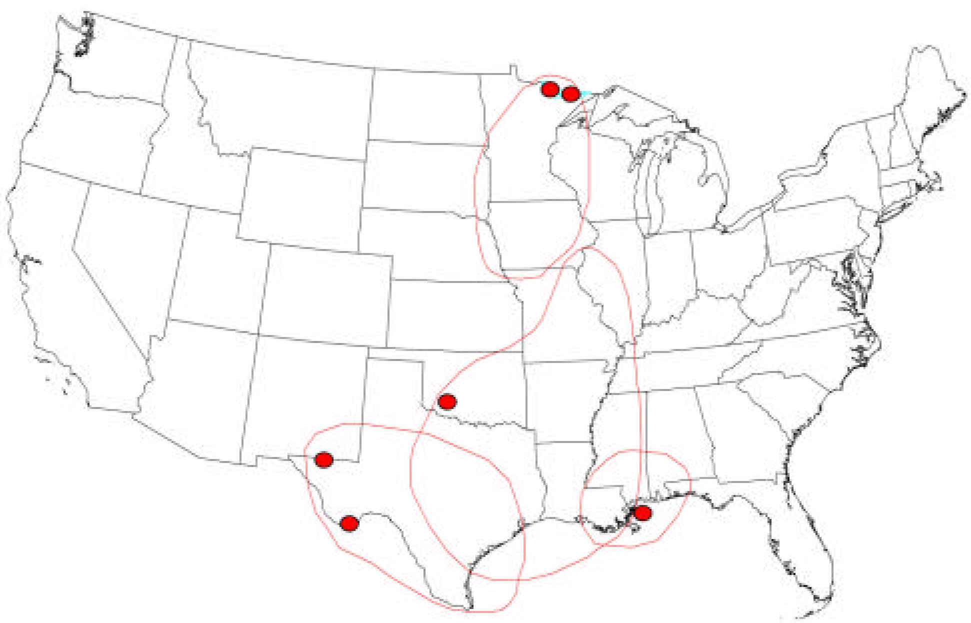


Figure ES-1. Level I Areas of Influence (AOI-1) for Sulfate associated with the Big Bend, Guadalupe, Wichita Mountains, Breton Island, Voyageur, and Boundary Waters Class I Areas.

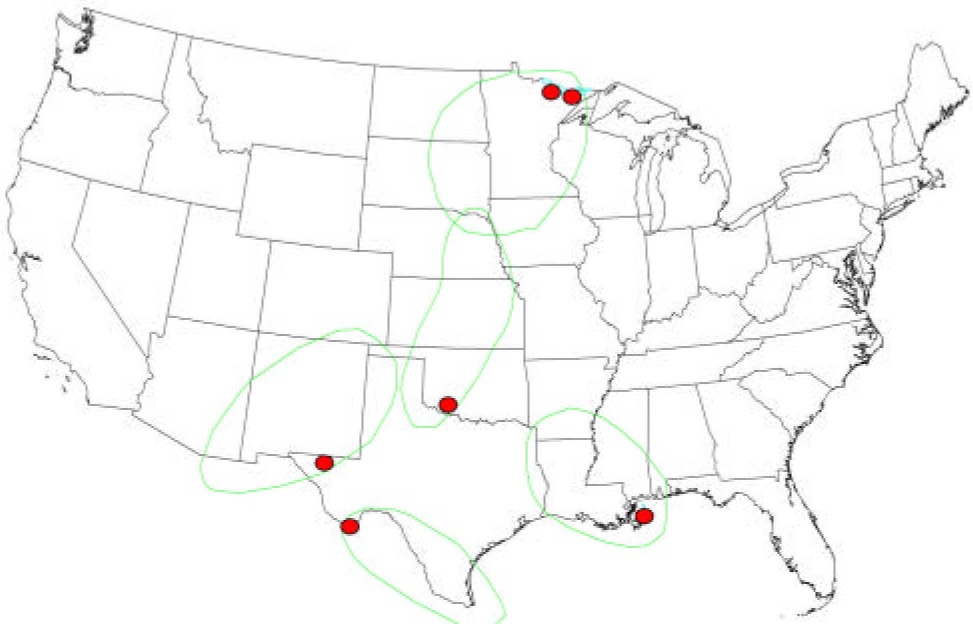


Figure ES-2. Level I Areas of Influence (AOI-1) for Nitrate Associated with the Big Bend, Guadalupe, Wichita Mountains, Breton Island, Voyageur, and Boundary Waters Class I Areas.

1.0 INTRODUCTION

The Implementation and Control Strategies (ICS) Workgroup of the Central Regional Air Planning Association (CENRAP), together with other workgroups and state, tribal and federal agencies, have worked for more than four years in developing the foundation for constructing regional haze (RH) control strategies for pertinent Class I areas (Table 1-1) within and adjacent to the CENRAP states and tribes (Seltz, 2006a,b; Anderson; 2005; Sharp and Anderson, 2005). In late February 2006, Alpine Geophysics, LLC (AG) was contracted to assist the ICS in these ongoing efforts. Specifically, using information developed by the ICS and others, AG was charged with developing a quantitative procedure to identify and prioritize potential RH control strategies to be tested by CENRAP modelers. Alpine formulated a methodology for constructing control strategy recommendations based on presently available information and submitted a Work Plan detailing this approach to the ICS/CENRAP leadership for review (Tesche and Stella, 2006).

Table 1-1. Class I Areas Addressed in this Study.

RPO	Class I Area	ST	Name
CENRAP	Big Bend Nat'l Park	TX	BIBE
CENRAP	Boundary Waters	MN	BWCA
CENRAP	Breton Island	LA	BRET
CENRAP	Caney Creek	AR	CACR
CENRAP	Guadalupe Mountains	TX	GUMO
CENRAP	Hercules-Glades	MO	HEGL
CENRAP	Mingo	MO	MING
CENRAP	Upper Buffalo	AR	UPBU
CENRAP	Voyageurs	MN	VOYA2
CENRAP	Wichita Mountains	OK	WIMO
VISTAS	Mammoth Cave	KY	MACA
VISTAS	Sipsey Wilderness	AL	SIPS
MRPO	Isle Royale	MI	ISLE
WRAP	Badlands	SD	BADL
WRAP	Great Sand Dunes	CO	GRSA
WRAP	Lostwood Wilderness	ND	LOST
WRAP	Rocky Mtn Nat'l Park	CO	ROMO
WRAP	Salt Creek	NM	SACR
WRAP	Theodore Roosevlt	ND	THRO
WRAP	Wheeler Peak	NM	WHPE
WRAP	White Mountain	NM	WHIT
WRAP	Wind Cave	SD	WICA

Based on comments received, the approved Work Plan was implemented, culminating in the quantitative methodology for identifying potentially viable regional haze control strategies for the CENRAP states and tribes. Using the most pertinent aerometric, emissions and air quality modeling data available, we implemented this methodology and, in this report, present a set of recommendations for regional haze precursor emissions reduction strategies. These recommendations, once reviewed and refined by the ICS and Modeling workgroup, will be passed on to the CENRAP Emissions and Air Quality Modeling contractors (ENVIRON International Corporation and the University of California, Riverside) for quantitative testing with the SMOKE/CMAQ/CAMx regional modeling systems.

To facilitate subsequent use of this methodology, this report describes the various analytical steps and provides examples (both in the body of the report and in supporting appendixes). In addition, relevant technical support information, data sets, and analysis software have been supplied to CENRAP for posting on their project website for access by interested parties.

1.1 Study Overview

Preliminary (Typ02a) and more recent (Typ02b) modeling projections from the CMAQ Base18b/Typ02 scenarios (Morris et al., 2006b) have indicated that some Class I areas within or near the CENRAP domain may achieve the 2018 Reasonable Progress Goals (RPG) under current 'on-the-books' and 'on-the-way' controls while others may not unless additional emissions reductions are implemented (see Figures 1-1 and 1-2). As shown in Figure 1-1, six CENRAP Class I Areas (Big Bend, Guadalupe, Wichita Mountains, Breton Island, Voyageur, and Boundary Waters) are projected, by the latest CMAQ modeling, to have somewhat higher visibility metrics (deciviews) when compared to the 2018 RPG glide paths. While Boundary Waters does not explicitly appear in Figure 1-1 due to data base insufficiencies, recent modeling by various RPOs suggests that Boundary Waters responds similarly to Voyageurs. Accordingly, it is thus included as one of the six projected Class I areas where additional precursor controls might be considered by CENRAP/ICS.

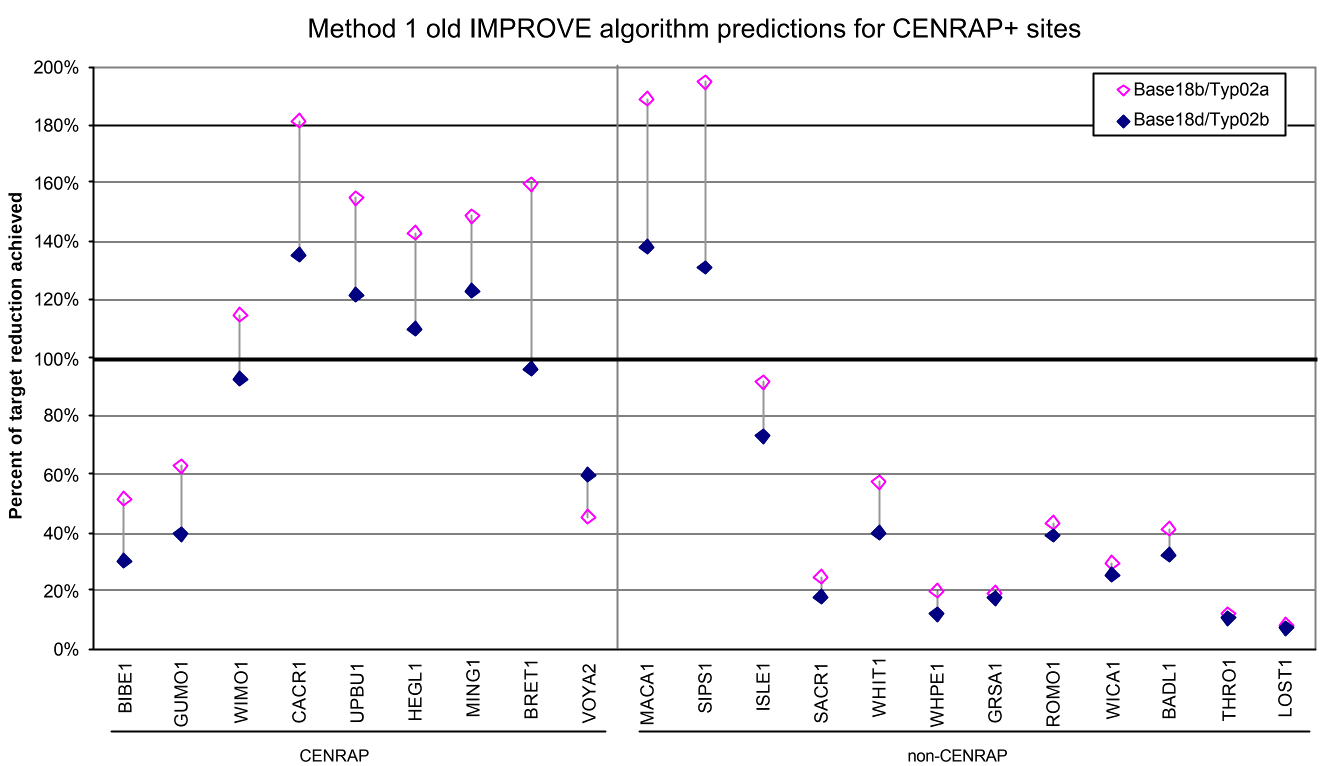


Figure 1-1. Current Visibility Projections (Base 18d/Typ02b) at CENRAP and Other Class I Sites (Source: Morris et al., 2006b).

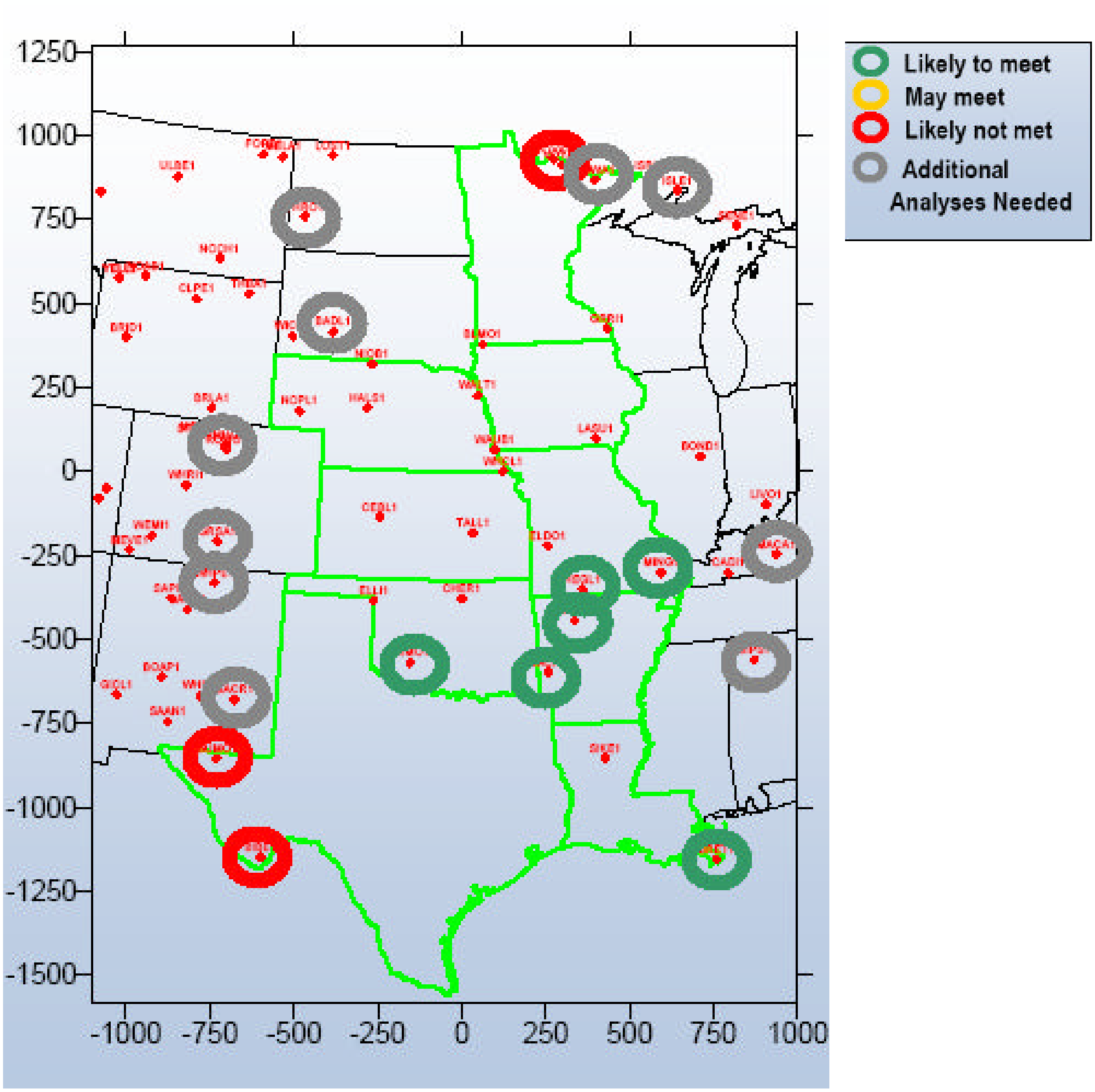


Figure 1-2. Preliminary Visibility Projections by State (Source: Morris et al., 2006b)

To prepare for the modeling of potential additional control strategies, an intensified effort has been undertaken by the ICS work group over the past two years to 'set the stage' for this activity (see for example ICS, 2005, Seltz, 2006). Consonant with these plans and on behalf of CENRAP, the ICS workgroup seeks to integrate focused contractor support with ongoing workgroup activities to accomplish the following objectives:

- Analyze existing regional haze modeling inventories developed by CENRAP, the States, tribes, and other RPOs;
- Synthesize available and pertinent air quality and meteorological data and recent 'attribution of haze studies' by CENRAP and the other RPOs;
- Review preliminary 2018 RPG modeling by CENRAP and other RPOs to identify the key Class I areas for which additional emissions reductions may be needed;
- Develop a prioritized set of regional and subregional precursor emissions control scenarios aimed at achieving the RPG at the CENRAP Class I areas; and
- Monitor the initial 2018 control strategy modeling performed by the CENRAP modeling team to ascertain whether subsequent strategies need to be refined or new strategies developed.

The project Work Plan (Tesche and Stella, 2006) describes in detail how these objectives have been addressed in cooperation with ICS and CENRAP.

1.2 Approach, Assumptions, and Constraints

Development of recommendations for potential CENRAP regional haze control strategy simulations was a three-step process. First, we assembled available information useful in quantifying the reductions in fine particulate aerosol concentrations needed to satisfy CENRAP's preliminary regional haze visibility projections. Naturally, the principal focus was on the Class I areas within the CENRAP region that were estimated to not meet the 2018 Reasonable Further Progress (RFP) glide paths. Based on preliminary and more recent modeling (Morris et al., 2006b), some Class I areas did meet the 2018 RFP glide paths while others did not. As new visibility projections for the Class I areas become available, the ICS may wish to re-examine this study's strategy recommendations in order to account for more up-to-date estimates.

The second step involved developing Areas of Influence (AOIs) upwind of each Class I area within which common 'visibility precursor-Class I receptor' impacts could be aggregated into similar groupings. We used results of numerous statistical and pattern recognition studies, as well as pertinent regional photochemical aerosol modeling by Alpine and ENVIRON scientists as well as other groups (including the RPOs). These analyses culminated in quantitative 'rules of thumb' relating emissions reductions of visibility-impairing precursors (in tons/day) to ambient aerosol concentrations at each of the ten (10) CENRAP Class I monitors. We also developed these quantitative source-receptor relationships for a dozen Class I areas in adjoining RPOs to the extent possible give available data, project resources and schedule. As of this writing, CENRAP Modeling contractors are still performing focused particulate source apportionment modeling (CAMx PSAT) over the region. Once this work is completed, the ICS may wish to re-examine our methodology and strategy recommendations to determine if refined source-receptor relationships alter in any way our present findings and conclusions.

The third step synthesized the results of the first two, together with information on the estimated 2018 CENRAP emissions inventory and the cost-effectiveness of various controls, to deduce a prioritized set of RH control strategies containing elements of both regional emissions reductions and targeted reductions within the AOIs closest to those six CENRAP Class I areas for which positive visibility increments were estimated (Morris et al., 2006b). We used the most up-to-date modeling inventory supplied by the CENRAP Modeling contractor; however, the current round of inventory corrections and refinements will undoubtedly lead to refined emissions data sets in coming months. Thus, another constraint limiting the 'shelf-life' of this study's recommendations is the accuracy and representativeness of the draft 2018 emissions data used in developing this plan's precursor emissions control recommendations.

While project work scope precluded re-running the strategy development process described in this report with updated CAMx/PSAT and CMAQ visibility projections expected in late May or early June 2006, the methodological tools are cataloged and archived should the ICS wish to undertake this activity at a later time.

1.3 Structure of Report

This report is organized as follows. Section 2 provides a brief background on the Regional Haze Rule (RHR) and the role that CENRAP and the other RPOs are playing in developing strategies that will show progress in meeting Reasonable Progress Goals by 2018. We also discuss key considerations that influence the design of regional and subregional control strategies in the context of the RHR. Our technical approach is summarized in Section 3. Details of our methodology are given in the Work Plan (Tesche and Stella, 2006a). In Section 4 we describe the information available to characterize the daily and annul composition of $PM_{2.5}$ constituents (sulfate, nitrate, elemental carbon, etc) at the various IMPROVE monitors in the CENRAP and adjoining Class I Areas. We also describe the method to relate the modeled deciview (dv) or extinction coefficient (Mm^{-1}) – derived from the most recent CENRAP visibility projection modeling – to the fine particulate component concentrations at each Class I area expressed in units of mass per unit volume (i.e., $\mu g/m^3$).

Section 5 presents the quantitative methods for converting these concentration increments (whose reductions will likely achieve the individual Class I areas visibility goals by 2108) to mass emissions rate reductions for the primary particulate aerosol precursors, NO_X and SO_2. In addition, the section describes the methods used to construct Area of Influence (AOI) domains surrounding each Class I area based on historical data analysis, statistical pattern recognition studies, and various photochemical and aerosol modeling studies performed throughout the eastern U.S. by Alpine, ENVIRON, state, tribal and federal regulatory agencies, the Southern

Appalachian Mountains Initiative (SAMI), the RPOs, and university scientists[4]. In Section 6, the information developed in the two preceding chapters is used, together with original analyses of the 2018 regional haze inventories and control technology cost-effectiveness information, to construct a series of curves from which quantitative estimates of suggested precursor emissions controls (within specific AOIs) are developed for each Class I Area in CENRAP projected above the reasonable progress glide path in 2018. Our summary and recommendations are presented in Section 7.

1.4 Technical Support Resources

Several technical appendixes and support documents are provided to accommodate the extensive tabular and graphical information underpinning our methodology. Some appendixes constitute simple tabular data or emissions summaries (in Excel format) while other appendixes contain information in PowerPoint or Adobe Acrobat formats. Finally, the study's Work Plan, Final Report, Technical Support Documents (i.e., the appendixes and other materials), and a compilation of science reports, professional papers and journal articles have been transferred to CENRAP for uploading to their project ftp site.

[4] The AOI methodology was carried out by Dr. Jim Wilkinson of Alpine whose recent Ph.D. original research and Dissertation from Georgia Tech focused on the development of the AOI methodology for regional haze, ozone, and $PM_{2.5}$ control strategy modeling in the eastern U.S.

2.0 CONTEXT FOR REGIONAL HAZE STRATEGY DEVELOPMENT

Section 169A of the Clean Air Act (CCA) sets forth a national goal for visibility which is the "prevention of any future, and the remedying of any existing, impairment of visibility in Class I areas which impairment results from manmade air pollution." In 1999, EPA published a final rule to address a type of visibility impairment known as regional haze (64 FR 35714). The Regional Haze Rule (RHR) requires States to submit implementation plans (SIPs) to address regional haze visibility impairment in federally-protected parks and wilderness areas (i.e., the Class I scenic areas identified in the Clean Air Act). The 1999 rule was issued to fulfill a long-standing EPA commitment to address regional haze under the authority and requirements of sections 169A and 169B of the CAA. In essence, the RHR prescribes that states are to make efforts to improve visibility in 156 Class I areas at such rates that "natural conditions" would be achieved in each area by 2064. A 'reasonable rate of progress' corresponds to linear improvement in visibility, as characterized in units of deciview (dv), between current conditions during the base period of 2000-2004 and natural conditions at the end point of 2064. It is important to note that a modeled 2018 visibility condition at a Class I monitor – numerically equaling the monitor's RPG goal – is not meant to imply 'attainment' of any standard nor is lesser modeled progress in reaching a particular RPG indicative of 'nonattainment'. Indeed, as will be discussed later, progress in attaining visibility improvements at some CENRAP monitors (in Texas and Minnesota) may be thwarted by substantial contributions of visibility precursors from Mexico and Canada over which the States and Tribes have no direct control.

2.1 Role of CENRAP and the Other Regional Planning Organizations (RPOs)

CENRAP is one of five Regional Planning Organizations (RPOs) that have responsibility for coordinating development of State Implementation Plans (SIPs) and Tribal Implementation Plans (TIPs) in selected areas of the U.S. to address the requirements of the Regional Haze Rule (RHR). The RHR visibility SIPs/TIPs are due in 2007/2008. CENRAP modeling results may also form the regional component for 8-hour ozone and fine particulate ($PM_{2.5}$) SIPs/TIPs that are also expected to be due in 2007/2008. CENRAP is a regional partnership of states, tribes, federal agencies, stakeholders and citizen groups established to initiate and coordinate activities associated with the management of regional haze and other air quality issues within the CENRAP states. The CENRAP region includes states and tribal lands located within the boundaries of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Nebraska, Oklahoma and Texas.

The regional emissions and fine particulate/visibility modeling for CENRAP is being performed by the Emissions and Air Quality Modeling Contractor that is comprised of staff from ENVIRON International Corporation (ENVIRON) and the University of California, Riverside (UCR). The ENVIRON/UCR team performs the emissions and air quality modeling simulations for states and tribes within the CENRAP region, providing analytical results used in developing implementation plans under the EPA Regional Haze Rule. Alpine Geophysics serves as the Technical Advisor to CENRAP, working interactively with the emissions and air quality modelers at ENVIRON and UCR.

2.2 Considerations in Designing Regional Haze Control Strategies

Where the year 2018 base case modeling does not show an acceptable regional haze or visibility glide slope for a Class I area within or adjacent to the CENRAP domain, additional (and possibly substantial) emission reductions will most likely be required to show reasonable progress in meeting 2108 visibility goals. Due to the unique location, meteorology, and emission sources within an area of influence to each Class I area, individualized control strategies reducing emissions from the remaining residual sources or source types are most likely to achieve required results. It is highly unlikely that a single cost effective "across-the-board" reduction strategy will achieve the visibility goals for every Class I area.

Although emissions located within areas of direct proximity to Class I area monitors will generally have the greatest influence on attaining visibility goals, these sources may not be the only ones with significant impact on the air quality. Using methods such as localized geography analysis (e.g., within 200km of Class I area boundaries) to initially identify source types and pollutants with the greatest influence will only provide part of the picture. In reality, other methods will also provide information related to transport sources impacting a Class I area. These other methods can include back trajectory analysis, residence time probability, source apportionment modeling (PSAT, OSAT, TSSA), and the cause of haze (COH) studies performed in the past two years by the various RPOs including CENRAP. Other geographic studies, such as identifying sources that have an impact on more than one Class I area are also warranted. These methods can also help to limit or refine geography, pollutants, or source categories of interest for additional reduction potential in each Class I area.

Using these techniques in addition to review of the future year base case emissions inventories and assigned control strategies will allow CENRAP and the ICS Workgroup to further define incremental reduction allowing for the attainment of Class I area air quality or visibility objectives.

2.3 Resources Available to this Study

The reference section of this report and the technical discussions in Sections 4 through 6 identify the major data bases, reports, modeling output files and other resources used in this study. Certain regional modeling and data analysis studies performed by the RPOs and their contractors were particularly useful in developing source-receptor relationships for the various Class I areas. These include: (a) the recent (25 April 2006) visibility projections for the CENRAP and adjoining RPOs recently described by Morris et al. (2006b), (b) monitoring information for the various Class I areas of interest, summarized on the IMPROVE website, and (c) the most recent 2018 SMOKE emissions inventory developed for CENRAP by various state, tribal and federal agencies and contractors.

3.0 TECHNICAL APPROACH

As described in the Work Plan (Tesche and Stella, 2006b), our technical approach consisted of six (6) tasks which are summarized briefly here to provide background for the more detailed technical discussions given in subsequent chapters.

Task 1: Synthesize Relevant Regional Haze Aerometric Analyses: The objective of Task 1 was to synthesize pertinent 'attribution of haze' documents, CENRAP CAMx/CMAQ visibility modeling results, and other technical reports, papers, and analyses bearing directly on the quantification of emissions-source/visibility-receptor impacts at the 10 CENRAP Class I areas and adjoining areas. This Task was aimed at quantifying what is known about source-receptor relationships at the 10 CENRAP Class I areas on the basis of emissions, air chemistry and meteorological statistical analyses and receptor modeling studies.

Task 2: Review Existing Inventories and Control Scenario Strategy Options: This involved a concise summarization of existing regional haze modeling inventories and associated local, State, Tribal and Federal control programs to determine available incremental controls on sources or source types affecting visibility increments (i.e., differences between the modeled 2018 visibility level and the RFP glide slope for the particular Class I Area). In addition, we attempted to confirm future year control plans and reduction scenarios necessary to accomplish incremental reduction analysis. The product of this effort was a set of suggestions for alternate incremental control strategies based on analysis of available emissions, monitoring, and modeled data.

The Task 2 review was conducted in a top down fashion starting with an analysis of the major source categories in the domains of interest (based on results from Tasks 1 and 3) to determine which major categories have the highest residual contribution to the area. Once the highest source types were identified, subcategories within those source types were reviewed. In addition to reviewing the residual emission categories in the future year base, we also identified reductions that have already occurred within each category or at specific units. This allows CENRAP to determine if certain source categories that have yet to be controlled under the base case have the potential for reduction or if source types already reduced have reached the full cost-effective potential. Finally, unit level tables of emission comparisons from 2002 to 2018 were developed that facilitate ICS's review of existing emission reductions and the assignment of new cost-effective controls to units using the best control for the scenario.

Once the list of potential sources available for reduction were identified, we used relevant control strategy information extracted from EPA's AirControlNET (Pechan, 2005) and other sources to further define the most cost-effective strategies for these sources. Since AirConrolNET does not allow for the interactive processing of new inventories (it comes preconfigured with inventories and control strategies applied), this extract was performed outside of the AirConrolNET model to assign incremental control programs. Finally, we ran every accessible control strategy against the identified source list to develop incremental cost curves necessary to design command and control or cost-effectiveness based control strategies by source or domain. This master list of controls was then used in the development of our final control strategy recommendations.

Task 3: Synthesize Relevant Regional Haze Source Attribution Modeling: Complementing Task 1, work under Task 3 was aimed at synthesizing key results from recent regional modeling studies helpful relating emissions reductions of visibility precursors (e.g. SO_2, NO_X) in upwind source regions to the improvement in visibility (in deciviews or, alternatively, in Mm^{-1}) at downwind Class I. More specifically, we attempted to extract from available regional modeling studies useful 'rules of thumb' relating percentage or tonnage reductions in visibility reducing precursors (e.g., SO_2, NO_X, ammonia, and VOCs) on the expected impact on visibility downwind. These 'rules of thumb' or source-receptor relationships were essential in estimating the amounts of precursor emissions to be reduced in regions upwind of each of the various Class I areas.

Task 4: Develop CENRAP Control Strategy Plan: The objective of Task 4 was to assemble the findings and technical work products from Tasks 1 through 3, supplemented with any additional information provided by the ICS Workgroup or CENRAP Modeling contractors, and construct the CENRAP Control Strategy Plan. As described in subsequent chapters, this plan addresses feasible regional haze control strategies with each one including both regional and sub-regional elements.

More specifically, using the results of the most recent CENRAP visibility projection modeling (Morris et al., 2006b), we identified six Class I areas that potentially require additional regional and/or subregional incremental emission reductions to achieve reasonable progress visibility goals. Once an emissions reduction target was determined for each Class I area, we used the master list of controls developed in Task 2 to formulate the CENRAP Control Strategy plan, including cost-effectiveness as a key element. This plan identifies specific source categories (e.g., SIC, SCC, plant ID), and emissions reductions to be implemented. The specificity of the prescribed control scenarios recommended in the plan is sufficient to allow the CENRAP modeling contractors to readily implement the suggested changes through the SMOKE model input stream.

The CENRAP Control Strategy Plan is intended to identify the specific sources and/or source categories where additional control is available with emphasis on known incremental reductions first (e.g., BART). Using this plan as a starting point, CENRAP is equipped to assess the present strategy recommendations and identify any new assumptions (recent or new facility configurations, updated control strategy information from the states and tribes), emergent data sets (e.g., CAMx PSAT modeling; updated 2018 CMAQ visibility projections), corrected modeling inventories, and so on that were unavailable during the three-week time period when this plan was developed.

Task 5: Review Control Strategy Plan With ICS: The project team participated in a teleconference call on 13 April 2006 with the CENRAP ICS Workgroup to discuss the study methodology, findings, and recommendations.

Task 6: Final Report: To the maximum extend feasible within this project's work scope, we incorporated written responses from CENRAP on the 10 April draft report, culminating in this final document.

4.0 ESTIMATION OF RESIDUAL VISIBILITY IMPROVEMENT NEEDS

The estimation of residual visibility improvement needs (i.e., the aerosol species concentration reductions [mass per unit volume] at each Class I monitor) was performed through three activities: (a) literature review and synthesis, (b) analysis of current CMAQ visibility projections and IMPROVE measurements at the Class I sites, and (c) integration of this information into a computational scheme for use in later tasks.

4.1 Literature Review and Synthesis of Pertinent Source-Receptor Information

Our synthesis of *existing* source-receptor information for the CENRAP and adjacent Class I area was guided by the following set of questions for which specific answers were sought in recent reports, papers, RPO and science meeting presentations, as well as recent one-atmosphere modeling studies. These core questions include:

> **What aerosol components are responsible for haze?**

- What are the major components for best, worst and average days visibility days across the CENRAP domain and how do they compare?
- How variable are they episodically, seasonally, inter-annually?
- What site characteristics best group sites with similar patterns of major components?
- How do the relative concentrations of the major components compare with the relative emission rates nearby and regionally?

> **What is meteorology's role in the causes of haze?**

- How do meteorological conditions influencing the CENRAP Class I areas differ for best, worst and typical haze conditions?
- What empirical relationships are their between meteorological conditions and haziness?
- How well can haze conditions be predicted solely using meteorological factors?
- What characteristics best group CENRAP Class I sites with similar relationships between meteorological conditions and haze?
- How well can inter-annual variations in haze be accounted for by variations in meteorological conditions at the CENRAP Class I areas?

> **What are the emission sources responsible for haze?**

- What geographic areas are associated with transported air that arrives at sites on best, typical and worst haze days in the CENRAP region?
- Are the emission characteristics of the transport areas consistent with the aerosol components responsible for haze?
- What do the aerosol characteristics on best, typical and worst days indicate about CENERAP or upwind emissions sources?
- What does the spatial and temporal pattern analysis indicate about the locations and time periods associated with sources responsible for haze?
- What evidence is there for urban impacts on haze at the CENRAP Class I areas and what is the magnitude and frequency when evident?

- What connections can be made between sample periods with unusual species concentrations and activity of highly sporadic sources (e.g. major fires, dust storms)?
- What can be inferred about impacts from sources in other states, other RPOs and other countries, particularly Mexico and Canada?
- What refinements to default natural haze levels can be made using ambient monitoring and emission data?

> **Are there detectable and/or statistically significant multi-year trends in the causes of haze?**
- Are the aerosol components responsible for haze changing?
  Where changes are seen, are they the result of meteorological or emissions changes?
- Where emissions are known to have changed, are there corresponding changes in haze levels?

With these questions in mind, we surveyed the literature relevant to the CENRAP Class I areas in order *to summarize*:

> **Characteristics of Each CENRAP Monitoring Site**
- Their representation of the Class I area and nearby Class I areas;
- Relationship to terrain features, bodies of water, etc;
- Proximity to major point sources, cities, etc.

> **Meteorological Characteristics of Each CENRAP Monitoring Site**
- Expected mesoscale flow patterns of interest (sea/land breeze, mountain/valley winds, convergence zones, nocturnal jets, etc.);
- Orographic precipitation patterns (i.e. favored for precipitation, or in rain-shadow);
- Inversion layers;
- Potential for transport from cities and other significant sources/source areas.

> **Visibility-Aerosol Related Data Analyses**
- Descriptive statistics and interpretation for aerosol data- individual components and reconstructed extinction
- Key aerosol species component spatial and seasonal patterns (e.g., Best 20%, middle 60%, worst 20% reconstructed extinction days and seasonal patterns by site)
- Spatial and seasonal patterns of aerosol components frequency distributions.
- Aerosol component data in light of emissions sources, monitoring site settings, back trajectories
- Results of cluster, CART, and other pattern-recognition analyses to group sites with similar patterns in aerosol component contributions to haze

> **Back Trajectory Analyses**
- Results of back trajectory end point data for each CENRAP Class I area;
- Back trajectory summary statistics residence time by season, best 20% and worst 20% reconstructed extinction and aerosol components for all CENRAP Class I areas;
- Conditional probability maps for high and low extinction and aerosol components.
- Results of emissions density maps giving location information, site setting information, etc., and
- Mesoscale meteorological analyses complementing back trajectories.

Of course, complete answers to all these questions could not be developed in the course of this three week study; however, sufficient information was available that, when distilled into key tabular and graphical summaries, provided a solid foundation for continued efforts in Task 1 and especially Task 2 (discussed in Section 5). Key reports and modeling summaries synthesized during this initial review were supplied to CENRAP for uploading onto the CENSARA project website for easy access by interested CENRAP workgroup members or stakeholders.

4.2 Preliminary Visibility Estimates for Class I Areas

The visibility projection estimates for 2018 available at the time this study was performed (Typ02a) were developed in early 2006 by ENVIRON/UCR and presented at the February CENRAP meetings in Baton Rouge, LA. Appendix B presents these preliminary visibility projections for the ten (10) CENRAP Class I areas and the twelve (12) outlying Class I areas in the WRAP, MRPO, and VISTAS domains. After the draft report had been prepared, Morris et al., (2006b) published an updated set of visibility projections (Typ02b). Given the importance of using the most up to date projections possible, where feasible we repeated our technical work using the updated projections (See Table 1-1 for a visual comparison of the differences). Table 4-1 lists the following information derived from these more recent CENRAP projections of Morris et al., (2006b).

> Visibility (in dv) on the 20% worst days in 2002;

> The 2000-2004 visibility baseline (in dv);

> The 2018 visibility goal (in dv) based on the requirements of the Regional Haze Rule;

> The CMAQ-forecasted 2018 visibility levels on the 20% worst days;

> The 'increment' in visibility, expressed in dv (calculated as the difference between the 2018 goal and the 2018 forecast. Negative values (presented in red in Table 2) denote that additional visibility improvement needed to achieve the desired 2018 progress goal; and

> The 'increment' in visibility, expressed in units of inverse mega-meters (Mm^{-1}).

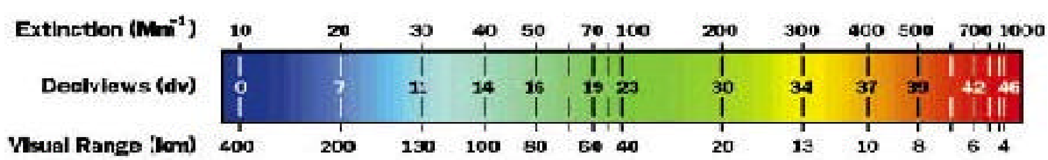
Table 4-1. Reasonable Progress Goal Estimates and 'Increments'.

				W20%	2000/2004	2018	2018	Deciview	Ext	Annual
				Bkgrnd	Baseline	Goal	Forecast	Incre	Incre	f(RH)
RPO	Class I Area	ST	Name	DV	DV	DV	DV	DV	Mm-1	
CENRAP	Big Bend Nat'l Park	TX	BIBE	6.93	17.10	14.73	16.39	1.66	7.9	2.1
CENRAP	Boundary Waters	MN	BWCA	11.21	18.30	16.62	17.54	0.92	5.1	3.3
CENRAP	Breton Island	LA	BRET	11.53	25.59	22.31	22.45	0.14	1.3	3.8
CENRAP	Caney Creek	AR	CACR	11.33	25.34	22.07	20.91	-1.16	-10.0	3.2
CENRAP	Guadalupe Mountains	TX	GUMO	7.02	17.48	15.04	16.53	1.49	7.2	1.8
CENRAP	Hercules-Glades	MO	HEGL	11.27	25.63	22.28	21.94	-0.34	-3.1	3.1
CENRAP	Mingo	MO	MING	11.27	26.49	22.94	22.13	-0.81	-7.7	3.2
CENRAP	Upper Buffalo	AR	UPBU	11.28	25.31	22.03	21.33	-0.70	-6.1	3.1
CENRAP	Voyageurs	MN	VOYA2	11.09	18.46	16.74	17.43	0.69	3.8	3.4
CENRAP	Wichita Mountains	OK	WIMO	11.07	23.06	20.26	20.47	0.21	1.6	2.6
VISTAS	Mammoth Cave	KY	MACA	11.53	29.94	25.65	24.01	-1.64	-19.7	3.2
VISTAS	Sipsey Wilderness	AL	SIPS	11.39	27.71	23.91	22.72	-1.19	-12.3	3.3
MRPO	Isle Royale	MI	ISLE	11.22	20.28	18.16	18.74	0.58	3.7	3.5
WRAP	Badlands	SD	BADL	7.30	17.00	14.74	16.37	1.63	7.7	2.6
WRAP	Great Sand Dunes	CO	GRSA	7.10	13.20	11.78	12.96	1.18	4.1	2.0
WRAP	Lostwood Wilderness	ND	LOST	7.33	19.49	16.66	19.28	2.62	15.8	2.9
WRAP	Rocky Mtn Nat'l Park	CO	ROMO	7.05	14.15	12.49	13.51	1.02	3.7	2.1
WRAP	Salt Creek	NM	SACR	6.99	18.05	15.47	17.59	2.12	11.1	1.8
WRAP	Theodore Roosevlt	ND	THRO	7.31	17.66	15.24	17.40	2.16	11.1	3.7
WRAP	Wheeler Peak	NM	WHPE	7.04	11.26	10.27	11.14	0.87	2.5	1.9
WRAP	White Mountain	NM	WHIT	6.98	14.06	12.41	13.40	0.99	3.6	1.8
WRAP	Wind Cave	SD	WICA	7.24	15.81	13.81	15.30	1.49	6.4	2.5

The relationship between deciviews (dv) and inverse megameters (Mm^{-1}) is described in detail by Malm, (1999). Equation 4-1 defines the Haze Index (HI):

$$HI = 10 \ln(b_{ext}/10) \qquad (4\text{-}1)$$

where HI is the haze index (deciviews [dv]) and b_{ext} is the light extinction coefficient (Mm^{-1}). Thus, one deciview is approximately equal to 11.05 Mm^{-1} and a change of one dv represents a change of approximately ten percent in b_{ext}, "which is a small but perceptible scenic change under many circumstances". Malm (1999) provides the following graphical representation between the extinction (Mm^{-1}), deciviews, and visual range (km):



The measured light extinction at the Class I areas for the 20% worst days each year are available at http://vista.cira.colostate.edu/views/web/AnnualSummaryDev/Composition.aspx, the IMPROVE site. The most recent measured extinction values (in Mm^{-1}) for the various Class I monitors are listed in Table 4-2, presented in Figure 4-1, and also given in Appendix B. For the most part, IMPROVE extinction measurements for the 20% worst days are available for 2004, the most recent year analyzed. These data are presented as extinction totals for the individual visibility-impairing chemical species: sulfate; nitrate; organic mass; elemental carbon; soil; and coarse mass. Table 4-3 lists the fractional extinction for each chemical species. Finally, the IMPROVE data for each species at the 22 Class I monitors are presented as a function of time in the appendices to this document. These time series plots reveal the seasonal and daily variation in the visibility-impairing components throughout the year at teach site. Figures 4-2 and 4-3 present the absolute and fractional extinction values listed in Tables 4-2 and 4-3 in the form of stacked bar charts for ease of comparison.

Table 4-2. Measured Extinction at Class I Areas.

				Measured Extinction (Mm^{-1}) on 20% Worst Days in 2004						
					Amm	Organic	Elem	Soil	Coarse	
RPO	Class I Area	ST	Name	Sulfate	Nitrate	Mass	Carbon	Mass	Mass	Total
CENRAP	Big Bend Nat'l Park	TX	BIBE	25.86	1.57	5.85	1.80	2.21	4.55	41.84
CENRAP	Boundary Waters	MN	BWCA	28.09	24.78	7.76	2.94	0.44	2.10	66.11
CENRAP	Breton Island	LA	BRET	65.60	8.49	6.13	4.26	0.40	4.45	89.33
CENRAP	Caney Creek	AR	CACR	65.68	15.43	17.95	4.27	0.79	2.66	106.78
CENRAP	Guadalupe Mountains	TX	GUMO	15.92	4.98	5.51	1.30	2.83	9.99	40.53
CENRAP	Hercules-Glades	MO	HEGL	67.23	21.92	21.14	5.12	0.88	2.85	119.14
CENRAP	Mingo	MO	MING	80.44	35.11	26.10	8.95	1.55	8.40	160.55
CENRAP	Upper Buffalo	AR	UPBU	64.43	17.39	16.47	4.48	0.90	7.23	110.90
CENRAP	Voyageurs	MN	VOYA2	10.16	15.14	9.94	2.68	0.46	2.84	41.22
CENRAP	Wichita Mountains	OK	WIMO	40.78	28.25	16.64	4.67	0.70	4.06	95.10
VISTAS	Mammoth Cave	KY	MACA	146.48	10.78	15.58	5.33	1.04	1.76	180.97
VISTAS	Sipsey Wilderness	AL	SIPS	109.27	8.09	20.22	7.06	0.95	2.66	148.25
MRPO	Isle Royale	MI	ISLE	33.33	12.64	9.71	2.93	0.48	3.51	62.60
WRAP	Badlands	SD	BADL	20.05	6.58	7.53	1.55	0.75	3.60	40.06
WRAP	Great Sand Dunes	CO	GRSA	6.20	2.78	6.44	1.30	2.11	3.78	22.61
WRAP	Lostwood Wilderness	ND	LOST	28.44	26.00	9.02	2.22	0.41	2.73	68.82
WRAP	Rocky Mtn Nat'l Park	CO	ROMO	8.19	4.73	6.37	2.00	1.11	2.78	25.18
WRAP	Salt Creek	NM	SACR	17.74	12.42	7.04	2.24	4.18	6.08	49.70
WRAP	Theodore Roosevlt	ND	THRO	15.68	16.28	9.95	2.52	0.55	2.99	47.97
WRAP	Wheeler Peak	NM	WHPE	5.69	1.26	4.98	2.05	1.59	1.29	16.86
WRAP	White Mountain	NM	WHIT	8.77	2.49	8.52	2.11	1.58	3.81	27.28
WRAP	Wind Cave	SD	WICA	14.27	8.91	8.35	3.17	0.79	2.08	37.57

4.3 Estimation of Visibility-Impairing Concentration Increments

The information in Tables 4-1 through 4-3 as well as other data provided in the appendices of this document was used to estimate the extent to which additional visibility-impairing precursor emissions reductions might be needed on the basis of current estimates of the projected positive increments and the chemical composition of fine particulate aerosol at the six CENRAP Class I monitors on the worst 20% days. The next step was to transform the visibility increment estimates into concentration increment estimates based on current IMPROVE algorithms. Using the modeled visibility increment (Mm^{-1}) estimates and annual f(RH) values (Table 4-1) together with the measured sulfate, nitrate, OC, EC, soil, and course mass fractions from the IMPROVE Class I monitors (Tables 4-2 and 4-3), we deduced the atmospheric concentrations of the six species groups ($\mu g/m^3$) using the standard IMPROVE equation (EPA, 2003). These concentrations were calculated assuming: (a) the required concentration reductions would be met by each precursor in proportion to the most recent IMPROVE distribution at each Class I monitor (Table 4-4); and (b) the concentration reductions would be met by each precursor individually (Table 4-5).

Table 4-3. Extinction Fraction for 20% Worst Days by Class I Area.

				Extinction Fraction for 20% Worst Days by Class I Area					
				Amm	Amm	Organic	Elem	Soil	Coarse
RPO	Class I Area	ST	Name	Sulfate	Nitrate	Mass	Carbon	Mass	Mass
CENRAP	Big Bend Nat'l Park	TX	BIBE	0.62	0.04	0.14	0.04	0.05	0.11
CENRAP	Boundary Waters	MN	BWCA	0.42	0.37	0.12	0.04	0.01	0.03
CENRAP	Breton Island	LA	BRET	0.73	0.10	0.07	0.05	0.00	0.05
CENRAP	Caney Creek	AR	CACR	0.62	0.14	0.17	0.04	0.01	0.02
CENRAP	Guadalupe Mountains	TX	GUMO	0.39	0.12	0.14	0.03	0.07	0.25
CENRAP	Hercules-Glades	MO	HEGL	0.56	0.18	0.18	0.04	0.01	0.02
CENRAP	Mingo	MO	MING	0.50	0.22	0.16	0.06	0.01	0.05
CENRAP	Upper Buffalo	AR	UPBU	0.58	0.16	0.15	0.04	0.01	0.07
CENRAP	Voyageurs	MN	VOYA2	0.25	0.37	0.24	0.07	0.01	0.07
CENRAP	Wichita Mountains	OK	WIMO	0.43	0.30	0.17	0.05	0.01	0.04
VISTAS	Mammoth Cave	KY	MACA	0.81	0.06	0.09	0.03	0.01	0.01
VISTAS	Sipsey Wilderness	AL	SIPS	0.74	0.05	0.14	0.05	0.01	0.02
MRPO	Isle Royale	MI	ISLE	0.53	0.20	0.16	0.05	0.01	0.06
WRAP	Badlands	SD	BADL	0.50	0.16	0.19	0.04	0.02	0.09
WRAP	Great Sand Dunes	CO	GRSA	0.27	0.12	0.28	0.06	0.09	0.17
WRAP	Lostwood Wilderness	ND	LOST	0.41	0.38	0.13	0.03	0.01	0.04
WRAP	Rocky Mtn Nat'l Park	CO	ROMO	0.33	0.19	0.25	0.08	0.04	0.11
WRAP	Salt Creek	NM	SACR	0.36	0.25	0.14	0.05	0.08	0.12
WRAP	Theodore Roosevlt	ND	THRO	0.33	0.34	0.21	0.05	0.01	0.06
WRAP	Wheeler Peak	NM	WHPE	0.34	0.07	0.30	0.12	0.09	0.08
WRAP	White Mountain	NM	WHIT	0.32	0.09	0.31	0.08	0.06	0.14
WRAP	Wind Cave	SD	WICA	0.38	0.24	0.22	0.08	0.02	0.06

Table 4-4. Required Concentration Reductions: All Species.

				Reduction in All Species (µg/m3) to Eliminate DV Increment					
				Assuming Controls in Proportion of Area-Specific Composition					
RPO	Class I Area	ST	Name	Sulfate	Nitrate	OC	EC	Soil	Coarse
CENRAP	Big Bend Nat'l Park	TX	BIBE	0.77	0.05	0.28	0.03	0.42	1.43
CENRAP	Boundary Waters	MN	BWCA	0.22	0.19	0.15	0.02	0.03	0.27
CENRAP	Breton Island	LA	BRET	0.08	0.01	0.02	0.01	0.01	0.11
CENRAP	Caney Creek	AR	CACR						
CENRAP	Guadalupe Mountains	TX	GUMO	0.53	0.16	0.25	0.02	0.50	2.97
CENRAP	Hercules-Glades	MO	HEGL						
CENRAP	Mingo	MO	MING						
CENRAP	Upper Buffalo	AR	UPBU						
CENRAP	Voyageurs	MN	VOYA2	0.09	0.14	0.23	0.02	0.04	0.44
CENRAP	Wichita Mountains	OK	WIMO	0.09	0.06	0.07	0.01	0.01	0.11
VISTAS	Mammoth Cave	KY	MACA						
VISTAS	Sipsey Wilderness	AL	SIPS						
MRPO	Isle Royale	MI	ISLE	0.19	0.07	0.14	0.02	0.03	0.34
WRAP	Badlands	SD	BADL	0.50	0.16	0.36	0.03	0.14	1.16
WRAP	Great Sand Dunes	CO	GRSA	0.19	0.08	0.29	0.02	0.38	1.13
WRAP	Lostwood Wilderness	ND	LOST	0.75	0.69	0.52	0.05	0.09	1.05
WRAP	Rocky Mtn Nat'l Park	CO	ROMO	0.19	0.11	0.24	0.03	0.17	0.69
WRAP	Salt Creek	NM	SACR	0.73	0.51	0.39	0.05	0.93	2.26
WRAP	Theodore Roosevlt	ND	THRO	0.33	0.34	0.57	0.06	0.13	1.15
WRAP	Wheeler Peak	NM	WHPE	0.15	0.03	0.19	0.03	0.24	0.32
WRAP	White Mountain	NM	WHIT	0.21	0.06	0.28	0.03	0.21	0.84
WRAP	Wind Cave	SD	WICA	0.32	0.20	0.36	0.05	0.13	0.59

Table 4-5. Required Concentration Reductions: One Specie.

				Reduction in One Specie (µg/m3) to Eliminate DV Increment Assuming Controls on Only 1 Specie					
RPO	Class I Area	ST	Name	Sulfate	Nitrate	OC	EC	Soil	Coarse
CENRAP	Big Bend Nat'l Park	TX	BIBE	1.25	1.25	1.97	0.79	7.88	13.13
CENRAP	Boundary Waters	MN	BWCA	0.51	0.51	1.27	0.51	5.08	8.46
CENRAP	Breton Island	LA	BRET	0.12	0.12	0.33	0.13	1.31	2.19
CENRAP	Caney Creek	AR	CACR						
CENRAP	Guadalupe Mountains	TX	GUMO	1.34	1.34	1.81	0.72	7.23	12.05
CENRAP	Hercules-Glades	MO	HEGL						
CENRAP	Mingo	MO	MING						
CENRAP	Upper Buffalo	AR	UPBU						
CENRAP	Voyageurs	MN	VOYA2	0.37	0.37	0.95	0.38	3.81	6.35
CENRAP	Wichita Mountains	OK	WIMO	0.21	0.21	0.40	0.16	1.61	2.68
VISTAS	Mammoth Cave	KY	MACA						
VISTAS	Sipsey Wilderness	AL	SIPS						
MRPO	Isle Royale	MI	ISLE	0.35	0.35	0.92	0.37	3.67	6.12
WRAP	Badlands	SD	BADL	0.99	0.99	1.93	0.77	7.73	12.88
WRAP	Great Sand Dunes	CO	GRSA	0.68	0.68	1.02	0.41	4.07	6.78
WRAP	Lostwood Wilderness	ND	LOST	1.82	1.82	3.96	1.58	15.85	26.41
WRAP	Rocky Mtn Nat'l Park	CO	ROMO	0.59	0.59	0.94	0.37	3.74	6.24
WRAP	Salt Creek	NM	SACR	2.05	2.05	2.77	1.11	11.09	18.49
WRAP	Theodore Roosevlt	ND	THRO	1.00	1.00	2.77	1.11	11.07	18.45
WRAP	Wheeler Peak	NM	WHPE	0.45	0.45	0.63	0.25	2.54	4.23
WRAP	White Mountain	NM	WHIT	0.67	0.67	0.90	0.36	3.60	6.00
WRAP	Wind Cave	SD	WICA	0.85	0.85	1.60	0.64	6.39	10.65

Following the IMPROVE methodology, the relationship between the extinction (Mm^{-1}) of an individual chemical species and the volumetric mass concentration is as follows:

$$b_{Sulfate} = 3 \cdot f(RH) \cdot [SO4]$$

$$b_{Nitrate} = 3 \cdot f(RH) \cdot [NO3]$$

$$b_{EC} = 10 \cdot [EC]$$

$$b_{OM} = 4 \cdot [OM]$$

$$b_{Soil} = 1 \cdot [Soil]$$

$$b_{CM} = 0.6 \cdot [CM]$$

$$b_{Ray} = 10\ Mm^{-1}$$

$$b_{ext} = b_{Ray} + b_{Sulfate} + b_{Nitrate} + b_{EC} + b_{OM} + b_{Soil} + b_{CM}$$

The numeric coefficient at the beginning of each equation is the dry scattering or absorption efficiency. The f(RH) term is a monthly-average relative humidity adjustment factor. The terms in the brackets are the concentrations in micrograms per cubic meter ($\mu g/m^3$) that will need to be reduced on the 20% worst days at the Class I monitor to make up for the projected visibility 'increment'.

Rearranging yields a solution for the aerosol concentrations as a function of the measured or modeled extinction:

$$[SO4] = b_{Sulfate} / [3 \cdot f(RH)]$$

$$[NO3] = b_{Nitrate} / [3 \cdot f(RH)]$$

$$[EC] = b_{EC} / 10$$

$$[OM] = b_{OM} / 4$$

$$[Soil] = b_{Soil}$$

$$[CM] = b_{CM} / 0.6$$

Note that the sulfate (SO_4) and nitrate (NO_3) components are hygroscopic because their extinction coefficients depend upon relative humidity. The concentrations, in square brackets, are in $\mu g/m^3$ and b_{ext} is in units of Mm^{-1}. The Rayleigh scattering term (b_{Ray}) has a default value of 10 Mm^{-1}, as recommended in EPA guidance for tracking reasonable progress (EPA, 2003). The effect of relative humidity variability on the extinction coefficients for SO_4 and NO_3 can be estimated in several ways, but given the scope of this analysis, we calculated annual average Class I areas-specific monthly f(RH) values (last column of Table 4-1) from the seasonal f(RH) data provided by EPA in the BART guidelines.

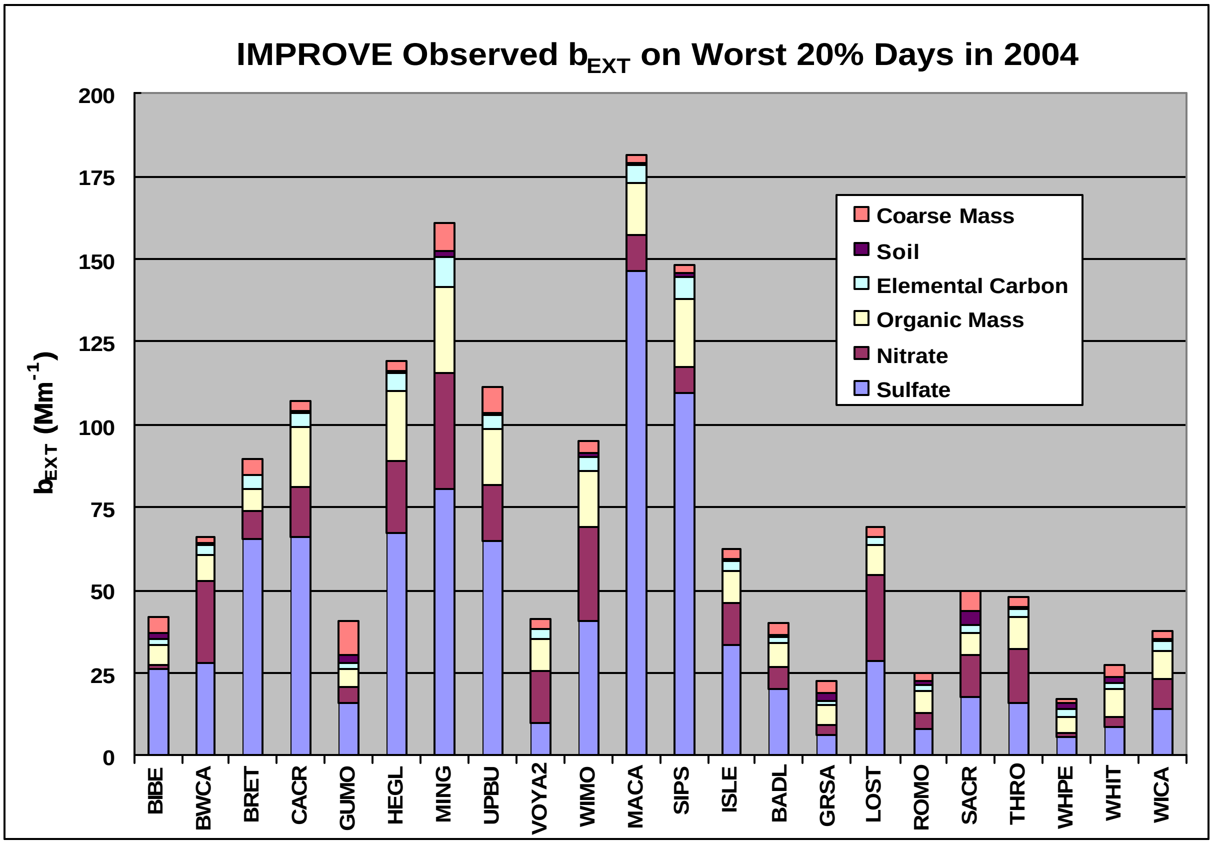


Figure 4-1. Measured Extinction Coefficients at Class I Areas Based on IMPROVE Data.

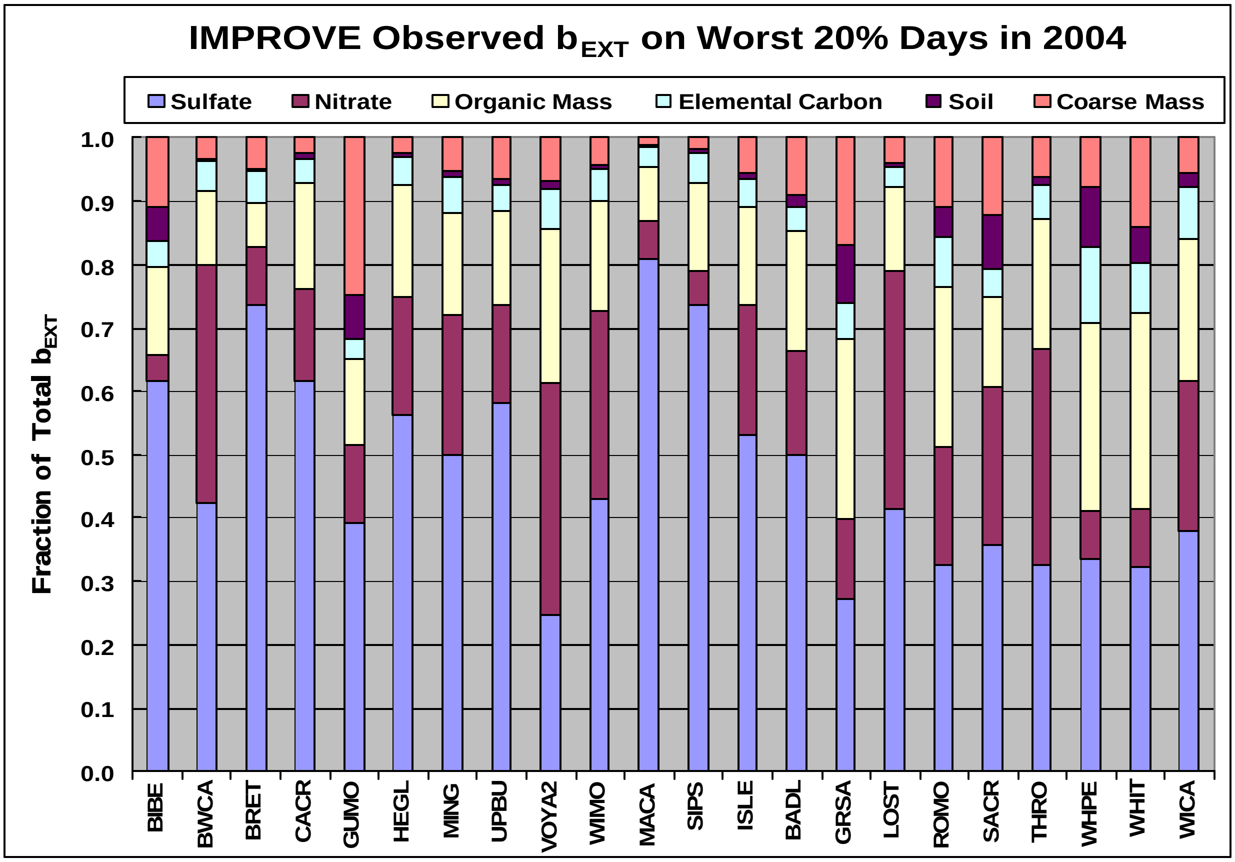


Figure 4-2. Measured Fractional Extinction at Class I Areas Based on IMPROVE Data.

5.0 ESTIMATION OF EMISSIONS REDUCTION NEEDS

5.1 Development of the Areas of Influence (AOI)

To quantify the incremental emissions reductions needed to ameliorate positive visibility increments at Class I areas, it was first necessary to identify those regions that adversely impact visibility at the Class I areas. These Areas of Influence (AOI) directly identify the source regions whose emissions impact a Class I area. Further, an AOI can also be constructed such that it provides a quantitative assessment of the impact of the emissions from a source region on such metrics as $PM_{2.5}$ concentration at a Class I area. This should not be confused with source apportionment where source regions are assigned quantitative culpability to an overall air quality metric such as sulfate concentration or light extinction. Instead, an AOI ideally describes geographically the emissions source regions and magnitude of, say, the impact that a one ton reduction in SO_2 emissions has on sulfate concentration ($\mu g/m^3$) at a Class I area.

An AOI can be constructed based on a variety of data such as: sensitivities derived from the Decoupled Direct Method (DDM) (Yang *et al.*, 1997; Mendoza *et al.*, 2000); brute force sensitivities; various forms of back trajectory analysis which examine air mass residence time (e.g., Schichtel *et al.*, 2006; DRI, 2005c); and methods that combine back trajectory analyses with such information as emissions impact potential (e.g., Raffuse *et al.*, 2005). Over the last two years, one or more of these methods has been used to construct AOIs or AOI-like diagrams for all the Class I areas of interest to this study. Therefore, it was necessary to identify, gather, and synthesize these data from the many sources so that a consistent set of AOIs could be constructed.

Appendix C is a compendium of AOI data for each Class I area of interest that could be extracted from the body of literature that is available. The first six slides of Appendix C provide examples of the data that were available to construct the AOIs – references are provided on each slide. Ultimately, the Residence Time Difference plots (DRI, 2005c), the Probability of Regional Source Contribution to Haze (PORSCH) plots (Raffuse *et al.*, 2005), the Tagged Species Source Apportionment (TSSA) results (Tonnesen and Wang, 2004; UCR, 2006), and a good deal of engineering judgment were used to construct a consistent set of AOIs for each Class I area.

Residence Time Difference (RTD) plots were constructed based on Back Trajectory Residence Time (BTRT) plots. Back trajectory analyses use meteorological fields to estimate the most likely geographical path an air mass traversed to end at a particular receptor. Of note, the meteorological field can be based on interpolation of observations, modeled (e.g., from a prognostic meteorological model such as MM5), or a hybrid field based on combined modeled and observed values. The method essentially reverses the wind field, moving an air mass backward in time. Back trajectories oversimplify actual atmospheric conditions in that dispersion is ignored. Further, the potential emissions source regions that impact a receptor are underestimated given that it is impossible to track every air parcel impacting the receptor.

The BTRT estimates that were developed by DRI (2005b) and used in this study were estimated using HYSPLIT (Draxler and Hess, 1997; NOAA, 2006). HYSPLIT uses archived three dimensional meteorological fields generated from observations and short-term meteorological forecasts. The model produces a series of endpoints representing longitude, latitude, and elevation of the parcel at one-hour intervals. BTRT plots at each site were calculated for all days, by month, and by best and worst twenty percentile days (DRI, 2005c). BTRT plots give the fraction of total hours that an air parcel resided over each specific geographical area. RTD plots were created by subtracting the map for all days at a site from the map for the 20% worst days by pollutant. RTD plots were computed for the twenty percentile worst sulfate, nitrate, organic carbon, elemental carbon, fine soil, and coarse mass days.

The worst twenty percentile sulfate RTD plots, for example, shows the difference in residence time between the worst sulfate days and all days. If the number is positive, then the residence time on the worst sulfate days is greater than on all days. The residence time difference map simply shows the areas that air was more frequently (positive numbers) passing over on worst case days compared to all days.

The PORSCH system is a suite of GIS tools that combines modeled backward wind trajectories, monitored concentrations, meteorological conditions, and emissions estimates to estimate probable regions of influence. PORSCH combines ensemble backward trajectories with chemically speciated emissions data to estimate the trajectory-emissions density-weighted area likely to impact a receptor site. PORSCH can do this for a single day or a suite of days though for purposes of this study, only data relevant to the 20% worst haze days were extracted.

As the name implies Tagged Species Source Apportionment (TSSA) uses “Tagged Chemical Species,” or tracers, to track chemical transformations and transport of each chemical species or precursor species during an air quality model run. Key chemical species are identified for specific emissions source regions or emissions source categories. These tagged chemical species are tracked during all phases of the air quality modeling run (e.g., advection, diffusion, deposition, chemical transformation), and the end results are three dimensional fields in time showing source attribution of the chemical species for any grid cell in model domain. When chemical species are tagged by emissions source region, this provides valuable corroborative evidence for identifying key AOI regions.

Slides 8 through 82 of Appendix C contain the raw data that was extracted from the literature base, which served as the foundation to develop the AOIs for the ten CENRAP Class I areas. Slides 84 through 184 of Appendix C contain the raw data from which AOIs were synthesized for the nine WRAP and two VISTAS Class I areas that border the CENRAP states. Because RTD plots were available for the entire suite of twenty-one Class I areas, they served as the primary basis from which the AOIs were estimated. The RTD plots were manually examined to determine “natural break-points” in residence time difference (only positive values were considered in these plots as positive values indicate air mass residence was greatest in these geographical areas on the 20% worst haze days).

In many cases, these “natural break-points” were difficult to determine given that the scales on the RTD plots were not consistent; hence, engineering judgment was used to place a “break-point.” For virtually all Class I areas, it was possible to determine at least two “break-points” and in some instances, three and four “break-points” were determined. For purposes of this effort, a “break-point” was generally placed where the residence time difference transition was on the order of a factor of ten and over large geographical areas. Little pockets of large RTD transitions, such as might occur over Lake Michigan or the Gulf of Mexico, were merged into a larger "break-point." Once a "break-point" was determined, a hand drawn contour was placed on the plot to indicate the Level 1, 2, or greater "break-point." This was done for each of the chemical species classes: sulfate; nitrate; organic carbon; elemental carbon; fine soils; and coarse material, at each Class I area. For clarification purposes, the Level 1 "break-point" is always the smallest polygon closest to the Class I area, and subsequent Level 2, 3, or greater "break-points" cover progressively larger areas.

Once the RTD "break-points" were determined, the plots were manually compared to the supporting PORSCH and TSSA data in order to determine if a "break-point" needed to expanded, contracted, or moved. The PORSCH data were used primarily to determine if the spatial extent of a "break-point" was adequate and the TSSA data were used to determine if the areas of emissions impact potential were captured within the spatial extent of the RTD "break-points." Based on this reconciliation effort, the Level 1, 2, or greater "break-point" contours were manually adjusted on the plots. Again, a great deal of engineering judgment was used in how these data were combined. This initial effort resulted in the development of 126 plots (six pollutants times twenty-one Class I areas) consisting of one or more "break-point" contours.

Next, each plot was manually compared to the remaining plots to determine if any of the Level 1, 2 or greater "break-point" contours were similar in their geographic placement. If a set of contours from different Class I areas had similar geographic placement, the plots were combined into a single set of contours. In many cases, the "break-point" contours were again manually adjusted so that different plots could be combined into a single set representing multiple Class I areas and multiple pollutants.

This final set of manually created, combined "break-point" contours is what is referred to as the Area of Influence (AOI) for each Class I area. However, these hand drawn AOIs are useless in their current form since it would have been far too time consuming to try to manually extract the counties over which an AOI passed – a step which is necessary if one is to determine the emissions impact potential from a geographic area (i.e., AOI) that impacts a Class I site. Therefore, it is necessary to convert the hand drawn AOIs into a geocoded, electronic file.

Geocoding of the hand drawn AOIs is accomplished by first scanning the image into an electronic file. The scanned image is then registered to a known set of geographical objects. In this case, the geographical objects are the political boundaries of the United States. The function of registering the scanned image, which itself is a political boundaries map of the United States with a set of hand drawn AOIs, is performed using a Geographic Information System (GIS). Secondly, the registered scanned image is rectified so that the image retains its geographic relationship to real world coordinates. Finally, the contours of the rectified image are digitized.

The final set of AOIs is shown in Slides 136 to 143 of Appendix C. These represent the geocoded AOIs that are used to extract a list of counties whose emissions sources have the greatest potential to impact the air quality at a Class I area. Again, ARC/Info was used to extract the counties within each AOI. Figure 5-1 is an example geocoded AOI for the Boundary Waters and Voyageurs Class I areas. Note the distinction between the Level 1 and Level 2 AOIs for both sulfate-to-SO_2 and nitrate-to-NO_X sensitivities.

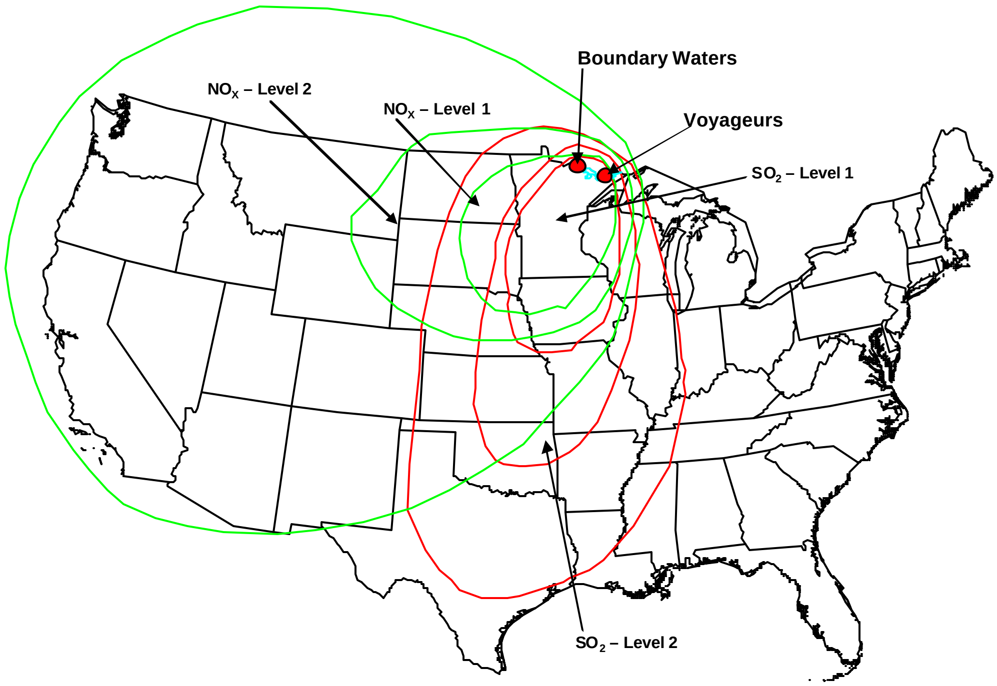


Figure 5-1. Example Geocoded AOI for Boundary Waters and Voyageurs Class I areas. Green contours delineate areas of influence where NO_X emissions impact aerosol nitrate at the Class I areas. Red contours delineate areas of influence where SO_2 emissions impact aerosol sulfate at Class I areas.

5.2 Development of Visibility Impairing Pollutant Concentrations to Precursor Emissions Sensitivity Coefficients

Though a list of counties can now be identified whose emissions sources have the greatest potential to impact air quality at a Class I area, this list has limited value until a quantitative value to associate emissions to air quality is estimated. Ideally, these associative values take the form of $\mu g/m^3$ of pollutant reduced per ton per day of precursor emissions reduced. For example, -0.001 $\mu g/m^3$ of sulfate per ton per day SO_2 reduced tells one that for each ton of SO_2 reduced within an AOI, the Class I area will exhibit a decrease of 0.001 $\mu g/m^3$ in sulfate concentration. This value is referred to as a sensitivity value and is very powerful at informing efforts such as those pursued in this study. A great deal of work has been performed to ascertain such sensitivities, and it is from this body of knowledge that sensitivities specific to the current efforts have been derived.

Tesche *et al.* (2003c) conducted a suite of brute force sensitivity runs using the CAMx and CMAQ air quality modeling (AQM) systems over the eastern United States on behalf of VISTAS. By systematically perturbing the global inventory (e.g., reducing global NO_X emissions by 10%) and rerunning the AQM, they developed a suite of metrics that provided the maximum reduction to say the peak, modeled ammonium nitrate. By converting the 10% NO_X reduction to actual tons per day NO_X reduction, which is simply done by taking 10% of the emissions in the AQM-ready emissions files, and dividing that into the peak concentration reduction, the sensitivity that is of most importance is realized. Though this value is a more global sensitivity, its use is still valid for our needs. Indeed, by assuming that such a sensitivity is valid across the domain, this general purpose sensitivity value can be extended to all the AOIs of interest by computing the value of a 10% reduction in each of the AOIs and dividing this number into the general sensitivity value derived from the average of all the sensitivities, by pollutant of course, estimated by Tesche *et al.* (2003c).

Appendix D shows an Excel workbook containing the summary data (i.e., worksheet named "General") from Tesche *et al.* (2003c). The worksheet shows the results of the specific sensitivity analyses conducted, and the results of our efforts to compute a general purpose sensitivity value. Once a general purpose sensitivity value was computed, it was recast in a form specific to the Class I areas of interest. This was done by assuming that the general purpose sensitivity (e.g., $\mu g/m^3$ sulfate reduction per 10% reduction in SO_2 emissions) was valid across the domain and dividing this number by the tons per day value deduced from a 10% reduction of a precursor pollutant in the AOI of interest.

Though a general purpose sensitivity value was estimated for all Class I areas and AOIs of interest, other sensitivity information that was more specific to certain Class I areas was available from work done at the Georgia Institute of Technology (GIT, 2006). Researchers at GIT conducted numerous brute force sensitivity runs of the CMAQ AQM on behalf of VISTAS. One component of these efforts was to conduct specific emissions source region and emissions source category sensitivity experiments to determine light extinction sensitivities to a reduction in one ton of precursor emissions at Mingo Wilderness, Upper Buffalo, Caney Creek, Hercules Glade, Breton Island, Sipsey, and Mammoth Cave. The emissions source regions for the GIT efforts (GIT, 2006) included the individual VISTAS states, the clustered CENRAP states, and the clustered MANE-VU states. The GIT (2006) results were extracted and summaries were prepared for the combined Mingo Wilderness-Upper Buffalo-Caney Creek-Hercules Glade AOIs, the Breton Island AOI, the Sipsey AOI, and the Mammoth Cave AOI. The results of these efforts were summarized in Appendix D, Excel worksheet "Class I Specific."

Finally, the results of the sensitivity summary efforts were combined in order to prepare a consistent set of sensitivity values by AOI. This summary is presented in Appendix D, Excel worksheet "Summary" and in Table 5-1.

Table 5-1. Synthesis of Sensitivity Values for Each Class I Area by AOI level. Units should be interpreted as reduction in nitrate (sulfate) concentration (µg/m^3) per average daily ton reduction in NO_X (SO_2) emissions in the specified AOI Level (see Figure 4-5 for an example of the delineation of the AOI Level).

Abb	Class I	RPO	Level 1 NOX ug/m**3/ton	Level 1 SO2 ug/m**3/ton	Level 2 NOX ug/m**3/ton	Level 2 SO2 ug/m**3/ton
badl	Badlands	WRAP	-0.001	-0.008	-0.003	-0.002
bibe	Big Bend	CENRAP	-0.002	-0.004	-0.001	-0.001
bowa	Boundary Waters	CENRAP	-0.002	-0.006	-0.004	-0.002
bret	Breton Island	CENRAP	-0.00008	-0.002	-0.00005	-0.0007
cacr	Caney Creek	CENRAP	-0.0004	-0.003	-0.002	-0.002
grsa	Great Sand Dunes	WRAP	-0.003	-0.02	--	-0.0005
gumo	Guadalupe Mountains	CENRAP	-0.01	-0.004	-0.002	-0.001
herc	Hercules Glade	CENRAP	-0.0004	-0.003	-0.002	-0.002
lost	Lostwood Wilderness	WRAP	-0.01	-0.008	-0.003	-0.002
maca	Mammoth Cave	VISTAS	-0.001	-0.005	-0.0008	-0.005
ming	Mingo Wilderness	CENRAP	-0.0004	-0.003	-0.002	-0.002
romo	Rocky Mountain	WRAP	-0.007	-0.02	-0.003	-0.0005
sacr	Salt Creek	WRAP	-0.01	-0.08	-0.002	-0.0007
sips	Sipsey Wilderness	VISTAS	-0.001	-0.007	-0.0008	-0.005
thro	Theodore Roosevelt	WRAP	-0.01	-0.008	-0.003	-0.002
upbu	Upper Buffalo	CENRAP	-0.0004	-0.003	-0.002	-0.002
voya	Voyageurs	CENRAP	-0.002	-0.006	-0.004	-0.002
whmo	White Mountain	WRAP	-0.01	-0.08	-0.002	-0.0007
whpe	Wheeler Peak	WRAP	-0.01	-0.08	-0.002	-0.0007
wica	Wind Cave	WRAP	-0.001	-0.008	-0.003	-0.002
wich	Wichita Mountain	CENRAP	-0.005	-0.001	-0.003	-0.0004

5.3 Estimated Emissions Reductions Necessary to Attain 2018 Glide Path

Now that the visibility 'increment' (Table 4-4 [proportional species reduction] and Table 4-5 [single specie reduction]) and the chemical species-to-precursor emissions sensitivity coefficients (Table 5-1) are known by Class I area, it is a simple matter to compute the annualized, incremental emissions reductions that are needed at each Class I area to attain the 2018 glide path. This is accomplished by dividing the visibility 'increment' by the sensitivity coefficient and multiplying by 365.

Table 5-2 shows the required incremental reductions of SO_2 and NO_X emissions that are estimated to be required in order for the Class I areas to meet the glide slope by 2018. The estimated SO_2 and NO_X reductions in Table 5-2 are proportional to chemical species contributions during the 20% worst haze days. In contrast, Table 5-3 shows the estimated SO_2 and NO_X emissions reductions if only one chemical species is reduced. The emissions reductions requirements in Tables 5-2 and 5-3 are reported to two significant figures.

For example, in order for Big Bend to meet the 2018 visibility glide path, approximately 73,000 tons per year of incremental SO_2 emissions reductions (Table 5-2) from SO_2 emissions source residing in the Level 1 AOI (Figure 5-2) are required assuming that incremental emissions reductions are developed based on a proportional reduction in the chemical species. Hence, in addition to the estimated incremental SO_2 emissions reductions of 73,000 tons per year, estimated incremental NO_X emissions reductions of 8,000 tons per year are also expected to be required. Additionally, incremental emissions reductions in coarse material, soil, elemental carbon, and organic compounds are also necessary if, again, emissions reductions are based on proportional reductions in the chemical species, though these reductions were not estimated given that reasonably available emissions control scenarios exist only for NO_X and SO_2.

If only one chemical specie is controlled, for example sulfate, then precursor SO_2 incremental emissions reductions from emissions sources located within the SO_2 Level 1 AOI (Figure 5-2) are estimated to be 120,000 tons per year (Table 5-3). On the other hand, if only nitrate is controlled, precursor NO_X incremental emissions reductions from emissions sources located within the NO_X Level 1 AOI (Figure 5-2) are estimated to be 210,000 tons per year.

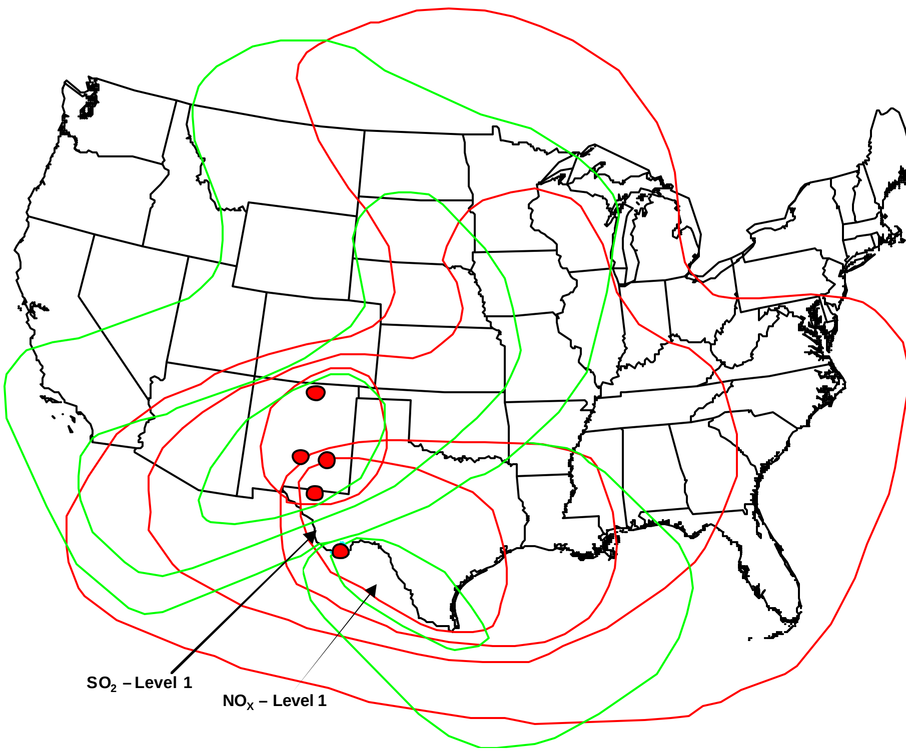


Figure 5-2. Geocoded AOIs for Big Bend, Guadalupe Mountain, Salt Creek, White Mountain, and Wheeler Peak. The Big Bend Level 1 AOI for SO_2 and NO_X are identified.

Table 5-2. SO_2 and NO_X Emissions Reduction Requirements (tons per year) Assuming Proportional Reductions in Sulfate and Nitrate.

Class I Area	ST	Proportional Reduction Requirements (ug/m3) Sulfate	Nitrate	OC	EC	Soil	Coarse	Level 1 AOI sulfate-to-SO2 (ug/m3/ton reduced)	Level 1 AOI nitrate-to-NOX (ug/m3/ton reduced)	Required SO2 Emissions Reductions (tons / year)	Required NOX Emissions Reductions (tons / year)
Big Bend Nat'l Park	TX	0.77	0.05	0.28	0.03	0.42	1.43	-0.004	-0.002	73,000	8,000
Boundary Waters	MN	0.22	0.19	0.15	0.02	0.03	0.27	-0.006	-0.004	13,000	19,000
Breton Island	LA	0.08	0.01	0.02	0.01	0.01	0.11	-0.0001	-0.000007	226,000	572,000
Caney Creek	AR							-0.0002	-0.00001		
Guadalupe Mountains	TX	0.53	0.16	0.25	0.02	0.50	2.97	-0.004	-0.01	50,000	4,000
Hercules-Glades	MO							-0.00019	0.0000		
Mingo	MO							-0.0002	-0.00001		
Upper Buffalo	AR							-0.0002	-0.00001		
Voyageurs	MN	0.09	0.14	0.23	0.02	0.04	0.44	-0.006	-0.004	5,700	14,000
Wichita Mountains	OK	0.09	0.06	0.07	0.01	0.01	0.11	-0.001	-0.005	32,000	4,500
Mammoth Cave	KY							-0.005	-0.001		
Sipsey Wilderness	AL							-0.007	-0.001		
Isle Royale	MI	0.19	0.07	0.14	0.02	0.03	0.34	-0.006	-0.004	11,000	7,000
Badlands	SD	0.50	0.16	0.36	0.03	0.14	1.16	-0.008	-0.001	23,000	45,000
Great Sand Dunes	CO	0.19	0.08	0.29	0.02	0.38	1.13	-0.02	-0.003	3,400	10,000
Lostwood Wilderness	ND	0.75	0.69	0.52	0.05	0.09	1.05	-0.008	-0.01	35,000	19,000
Rocky Mtn Nat'l Park	CO	0.19	0.11	0.24	0.03	0.17	0.69	-0.02	-0.007	3,500	5,800
Salt Creek	NM	0.73	0.51	0.39	0.05	0.93	2.26	-0.004	-0.01	68,800	13,000
Theodore Roosevlt	ND	0.33	0.34	0.57	0.06	0.13	1.15	-0.008	-0.01	15,000	12,000
Wheeler Peak	NM	0.15	0.03	0.19	0.03	0.24	0.32	-0.08	-0.01	690	800
White Mountain	NM	0.21	0.06	0.28	0.03	0.21	0.84	-0.08	-0.01	990	1,500
Wind Cave	SD	0.32	0.20	0.36	0.05	0.13	0.59	-0.008	-0.001	15,000	56,000

Table 5-3. SO_2 and NO_X Emissions Reduction Requirements (tons per year) Assuming a Single Chemical Species is Controlled.

Class I Area	ST	Reduction Requirement Assuming Single Species Control (ug/m3)						Level 1 AOI (ug/m3/ton reduced)		Required SO2 Emissions Reductions (tons / year)	Required NOX Emissions Reductions (tons / year)
		Sulfate	Nitrate	OC	EC	Soil	Coarse	sulfate-to-SO2	nitrate-to-NOX		
Big Bend Nat'l Park	TX	1.25	1.25	1.97	0.79	7.88	13.13	-0.004	-0.002	120,000	210,000
Boundary Waters	MN	0.51	0.51	1.27	0.51	5.08	8.46	-0.006	-0.004	32,000	51,000
Breton Island	LA	0.12	0.12	0.33	0.13	1.31	2.19	-0.0001	-0.000007	308,000	6,010,000
Caney Creek	AR							-0.0002	-0.00001		
Guadalupe Mountains	TX	1.34	1.34	1.81	0.72	7.23	12.05	-0.004	-0.01	130,000	33,000
Hercules-Glades	MO							-0.00019	0.0000		
Mingo	MO							-0.0002	-0.00001		
Upper Buffalo	AR							-0.0002	-0.00001		
Voyageurs	MN	0.37	0.37	0.95	0.38	3.81	6.35	-0.006	-0.004	23,000	37,000
Wichita Mountains	OK	0.21	0.21	0.40	0.16	1.61	2.68	-0.001	-0.005	75,000	15,000
Mammoth Cave	KY							-0.005	-0.001		
Sipsey Wilderness	AL							-0.007	-0.001		
Isle Royale	MI	0.35	0.35	0.92	0.37	3.67	6.12	-0.006	-0.004	22,000	35,000
Badlands	SD	0.99	0.99	1.93	0.77	7.73	12.88	-0.008	-0.001	46,000	280,000
Great Sand Dunes	CO	0.68	0.68	1.02	0.41	4.07	6.78	-0.02	-0.003	12,000	82,000
Lostwood Wilderness	ND	1.82	1.82	3.96	1.58	15.85	26.41	-0.008	-0.01	84,000	52,000
Rocky Mtn Nat'l Park	CO	0.59	0.59	0.94	0.37	3.74	6.24	-0.02	-0.007	11,000	31,000
Salt Creek	NM	2.05	2.05	2.77	1.11	11.09	18.49	-0.004	-0.01	192,800	50,000
Theodore Roosevlt	ND	1.00	1.00	2.77	1.11	11.07	18.45	-0.008	-0.01	45,000	36,000
Wheeler Peak	NM	0.45	0.45	0.63	0.25	2.54	4.23	-0.08	-0.01	2,100	11,000
White Mountain	NM	0.67	0.67	0.90	0.36	3.60	6.00	-0.08	-0.01	3,100	16,000
Wind Cave	SD	0.85	0.85	1.60	0.64	6.39	10.65	-0.008	-0.001	39,000	240,000

6.0 PRIORITIZED CENRAP EMISSIONS REDUCTION SCENARIOS

6.1 Summary of Emission Inventories Used in Control Plan Development

A necessary component of the control strategy design is a thorough review of the emission inventories that are used in the modeling of the future year base case. This inventory can shed light on the residual emissions from sources or source categories defined to be within areas of transport or impact of a Class I area. We obtained and used the current CENRAP future year (2018) base case and 2002 base year emissions to conduct a review of the top emitting categories and pollutants within identified impact areas.

The SMOKE-ready modeling files for both 2002 and 2018 base year and base cases were obtained from CENRAP's emissions modeling contractor (UCR) in addition to a supplementary county level summary of onroad source emissions produced from the gridded, temporalized MOBILE6-based emissions output. Using the annualization methods confirmed with UCR and identified in the SMOKE file headers, each SMOKE input file was converted to annual emissions and summed for the geography and domain of interest.

Tables 6-1 and 6-2 present the major source category breakdown of these emissions for the entire CENRAP domain. AOI-specific breakdowns are presented in Appendix E of this document for those CENRAP Class I areas projected to be above the reasonable progress glide slope. Because the SMOKE-ready files were used in this analysis, the particulate matter transport factor is included in the PM emission summaries. This factor is applied to account for the removal of a substantial portion of fugitive dust emissions near a source by surrounding vegetation and structures when such emissions are used in regional scale modeling analyses.

Table 6-1. CENRAP 2002 Base Year Annual Emissions Summary.

	CENRAP 2002 Base Year Annual Emissions (Tons)						
Source Category	**VOC**	**NOx**	**CO**	**SO2**	**PM-10**	**PM-2.5**	**NH3**
Fuel Comb. Elec. Util.	13,838	1,006,914	290,478	1,545,327	79,429	53,475	4,462
Fuel Comb. Industrial	74,226	907,445	387,579	568,270	118,626	78,412	6,243
Fuel Comb. Other	151,527	98,457	435,320	34,605	67,380	65,556	4,870
Chemical & Allied Product Mfg	56,154	37,002	117,918	140,403	10,946	8,503	13,254
Metals Processing	8,178	16,197	115,827	86,425	14,930	6,486	4
Petroleum & Related Industries	486,785	306,947	274,187	81,950	10,442	7,408	819
Other Industrial Processes	150,388	107,908	119,678	89,127	235,401	74,228	206,676
Solvent Utilization	799,050	392	248	21	1,338	1,110	17
Storage & Transport	200,946	9,023	39,075	2,416	17,321	5,294	220
Waste Disposal & Recycling	58,790	16,836	248,560	5,319	57,500	53,804	9,914
Highway Vehicles	985,527	1,780,289	13,178,713	51,829	100,256	94,514	51,512
Off-highway	660,216	966,296	4,358,200	95,522	83,090	76,924	1,365
Natural Sources	0	0	0	0	0	0	80,213
Miscellaneous	310,871	150,474	4,538,131	47,040	4,325,839	1,062,364	1,440,416
CENRAP Total	**3,956,494**	**5,404,181**	**24,103,914**	**2,748,255**	**5,122,496**	**1,588,078**	**1,819,983**

Table 6-2. 2018 Base Case Annual Emissions Summary.

Source Category	CENRAP 2018 Base Case Annual Emissions (Tons)						
	VOC	NOx	CO	SO2	PM-10	PM-2.5	NH3
Fuel Comb. Elec. Util.	15,963	800,509	231,161	1,397,945	125,999	106,402	12,188
Fuel Comb. Industrial	87,300	985,108	470,053	562,732	134,652	93,244	7,942
Fuel Comb. Other	139,826	93,527	348,628	33,555	57,292	55,498	4,932
Chemical & Allied Product Mfg	91,937	52,915	200,036	229,435	17,361	13,383	23,977
Metals Processing	14,600	24,603	200,166	154,071	23,811	10,838	6
Petroleum & Related Industries	519,225	320,126	287,198	106,536	13,818	9,753	1,077
Other Industrial Processes	215,126	162,931	163,154	133,203	316,220	100,922	285,113
Solvent Utilization	1,095,270	663	426	35	2,563	2,116	19
Storage & Transport	227,269	12,122	69,548	3,325	23,808	7,380	298
Waste Disposal & Recycling	73,117	19,379	296,493	7,704	67,637	63,084	14,019
Highway Vehicles	447,496	445,651	7,466,397	7,335	24,845	12,522	73,128
Off-highway	384,203	263,701	5,067,432	995	43,831	40,311	606
Natural Sources	0	0	0	0	0	0	80,213
Miscellaneous	212,436	107,761	3,200,076	57,923	3,968,055	903,434	1,921,843
CENRAP Total	**3,523,767**	**3,288,994**	**18,000,769**	**2,694,795**	**4,819,893**	**1,418,889**	**2,425,360**

As 2002 pre- and post-modeled emission summaries were provided on the input data files, we were able to verify the emission totals for each State and SCC in the modeling domain (Pechan, 2006). However, as 2018 summaries were not available in time to review the files for this analysis, we have not confirmed that these 2018 emission totals are as expected by the ICS.

Our review was conducted in a top down fashion starting with an analysis of the major source categories in the domains of interest to determine which major categories have the highest residual contribution to the area. Once the highest source types were identified, subcategories within those source types were reviewed. Again, a ranking of the highest residual sub source types was performed and additional analyses on these categories were conducted. Table 6-3 presents a percentage based contribution of residual emissions by major source category for the CENRAP domain. Tables for each CENRAP Class I AOI projected to be above the glide slope for reasonable progress are presented in Appendix E of this document.

In addition to reviewing the residual emission categories in the future year base, it was important to identify reductions that have already occurred within each category or at specific units. This will allow the ICS to determine if certain source categories that have yet to be controlled under the future year base case have the potential for reduction or if source types already reduced have reached the full cost-effective potential. Table 6-4 presents this information in annual tons for all sources in the CENRAP domain, while Table 6-5 presents the same information in terms of percent change from 2002.

Finally, once each subcategory was identified, unit level tables of emission comparisons from 2002 to 2018 were developed allowing the ICS to review existing emission reductions and providing the ability to assign new cost-effective controls to units using the best control for the scenario. These tables present comparisons of 2002 and 2018 emission levels, by pollutant, and future year control technology assignment (by IPM forecasting) for EGU sources. Since unit-specific technology assignments were not identified in the SMOKE control packets nor in documentation obtained for use in this project, these units do not have associated future year technology identification data.

Ultimately, the ICS' final control strategy decisions will include the application of BART applicable source reductions in the future year base case. However, as these sources and their associated reductions were unavailable for this project, they too are not included in this analysis.

Table 6-3. CENRAP 2018 Base Case Annual Residual Emissions Contribution Summary.

	CENRAP 2018 Base Case Annual Emissions (Percent of Total)						
Source Category	**VOC**	**NOx**	**CO**	**SO2**	**PM-10**	**PM-2.5**	**NH3**
Fuel Comb. Elec. Util.	0%	24%	1%	52%	3%	7%	1%
Fuel Comb. Industrial	2%	30%	3%	21%	3%	7%	0%
Fuel Comb. Other	4%	3%	2%	1%	1%	4%	0%
Chemical & Allied Product Mfg	3%	2%	1%	9%	0%	1%	1%
Metals Processing	0%	1%	1%	6%	0%	1%	0%
Petroleum & Related Industries	15%	10%	2%	4%	0%	1%	0%
Other Industrial Processes	6%	5%	1%	5%	7%	7%	12%
Solvent Utilization	31%	0%	0%	0%	0%	0%	0%
Storage & Transport	6%	0%	0%	0%	0%	1%	0%
Waste Disposal & Recycling	2%	1%	2%	0%	1%	4%	1%
Highway Vehicles	13%	14%	41%	0%	1%	1%	3%
Off-highway	11%	8%	28%	0%	1%	3%	0%
Natural Sources	0%	0%	0%	0%	0%	0%	3%
Miscellaneous	6%	3%	18%	2%	82%	64%	79%
CENRAP Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Table 6-4. CENRAP Annual Emissions Change (Tons).

	CENRAP Annual Emissions Change -- 2002 to 2018 (Tons)						
Source Category	**VOC**	**NOx**	**CO**	**SO2**	**PM-10**	**PM-2.5**	**NH3**
Fuel Comb. Elec. Util.	2,125	-206,405	-59,317	-147,382	46,570	52,927	7,727
Fuel Comb. Industrial	13,075	77,663	82,475	-5,538	16,025	14,832	1,699
Fuel Comb. Other	-11,701	-4,930	-86,692	-1,050	-10,087	-10,058	62
Chemical & Allied Product Mfg	35,783	15,913	82,118	89,032	6,416	4,880	10,723
Metals Processing	6,422	8,405	84,338	67,647	8,882	4,352	3
Petroleum & Related Industries	32,441	13,179	13,011	24,587	3,377	2,346	258
Other Industrial Processes	64,738	55,023	43,475	44,076	80,819	26,694	78,437
Solvent Utilization	296,220	271	178	14	1,225	1,006	2
Storage & Transport	26,323	3,099	30,473	909	6,487	2,086	77
Waste Disposal & Recycling	14,328	2,542	47,933	2,385	10,137	9,281	4,105
Highway Vehicles	-538,032	-1,334,638	-5,712,316	-44,495	-75,411	-81,992	21,616
Off-highway	-276,012	-702,595	709,233	-94,527	-39,258	-36,612	-759
Natural Sources	0	0	0	0	0	0	0
Miscellaneous	-98,436	-42,714	-1,338,055	10,883	-357,784	-158,930	481,427
CENRAP Total	**-432,727**	**-2,115,187**	**-6,103,145**	**-53,460**	**-302,603**	**-169,189**	**605,376**

Table 6-5. CENRAP Annual Emissions Change (Percent).

	CENRAP Annual Emissions Change -- 2002 to 2018 (Percent)						
Source Category	**VOC**	**NOx**	**CO**	**SO2**	**PM-10**	**PM-2.5**	**NH3**
Fuel Comb. Elec. Util.	15%	-20%	-20%	-10%	59%	99%	173%
Fuel Comb. Industrial	18%	9%	21%	-1%	14%	19%	27%
Fuel Comb. Other	-8%	-5%	-20%	-3%	-15%	-15%	1%
Chemical & Allied Product Mfg	64%	43%	70%	63%	59%	57%	81%
Metals Processing	79%	52%	73%	78%	59%	67%	67%
Petroleum & Related Industries	7%	4%	5%	30%	32%	32%	31%
Other Industrial Processes	43%	51%	36%	49%	34%	36%	38%
Solvent Utilization	37%	69%	72%	66%	92%	91%	13%
Storage & Transport	13%	34%	78%	38%	37%	39%	35%
Waste Disposal & Recycling	24%	15%	19%	45%	18%	17%	41%
Highway Vehicles	-55%	-75%	-43%	-86%	-75%	-87%	42%
Off-highway	-42%	-73%	16%	-99%	-47%	-48%	-56%
Natural Sources	0%	0%	0%	0%	0%	0%	0%
Miscellaneous	-32%	-28%	-29%	23%	-8%	-15%	33%
CENRAP Total	**-11%**	**-39%**	**-25%**	**-2%**	**-6%**	**-11%**	**33%**

6.2 Process in Preparing Files for Control Plan Modeling

In addition to the SMOKE emission files, the 2018 growth and control packets were obtained from UCR for additional application and verification of future year scenario assignment. Since the CENRAP utilized version of the SMOKE processor does not replace control efficiency, rule effectiveness, and rule penetration values in the output files generated using the growth and control modules of the model, Alpine manually applied these values to the 2018 non-EGU and stationary area source files for which the packets were applied. This step was necessary to duplicate the inventories that went into the results of CENRAP's reasonable progress modeling and to ensure that any incremental assignment of control technologies did not duplicate emission reductions already assumed in the future year base case.

The 2018 IPM file used by CENRAP for EGU sources was also obtained and matched to the 2018 base case inventory of EGU sources. This step was conducted for reasons similar to those identified above for non-EGU and stationary area sources and to ensure that incremental controls assigned to these source types did not duplicate existing base case assumptions. Because IPM does not assign a control efficiency with each control device applied to SO_2 and NO_X, we made some assumptions, based on IPM documentation, as to what pollutant specific level of reduction was applied in the future year base case runs. These assumptions, by primary and secondary control device code combinations for SO_2 and NO_X, are presented in Tables 6-6 and 6-7, respectively.

Since many of the control technology control cost equations within AirControlNET require additional unit-level characteristic data, we also made matches of the SMOKE IDA files to CENRAP NIF, EPA NEI, or EPA CAMD CEM data sets to obtain these variables when missing.

Unit level boiler capacity (MMBtu/hr) or NETDC (MW) values are required for capital and operating and maintenance cost calculations for many of the EGU technologies. In cases where these nameplate capacity values could not be identified, emission weighted (based on the final EPA 2002 NEI) were assigned to boilers using a primary (highest emitting) SCC. Table 6-8 presents these weighted capacities. Additionally, stack flow, sulfur content, and primary SCC assignment were necessary to cross-reference available incremental control technologies to the base case emissions inventory data. These variables were obtained where matches could be found, in priority order of CENRAP, CAMD, and EPA datasets, respectively.

Table 6-6. IPM Post Processing Assigned Device Codes and Applied SO_2 Control Efficiencies.

Primary Device Code	Secondary Device Code	Description	CE	RE
0	0	No Control	0	0
119	0	Dry Scrubber	90	100
141	0	Wet Scrubber	90	100

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Table 6-7. IPM Post Processing Assigned Device Codes and Applied NO_X Control Efficiencies.

Primary Device Code	Secondary Device Code	Description	CE	RE
0	0	UNCONTROLLED	0	0
26	0	FLUE GAS RECIRCULATION	35	100
26	29	FLUE GAS RECIRCULATION + LOW EXCESS AIR FIRING	35	100
26	204	FLUE GAS RECIRCULATION + OVERFIRE AIR	40	100
28	0	STEAM OR WATER INJECTION	65	100
28	32	STEAM OR WATER INJECTION + AMMONIA INJECTION	65	100
28	204	STEAM OR WATER INJECTION + OVERFIRE AIR	90	100
28	205	STEAM OR WATER INJECTION + LOW NOX BURNERS	90	100
29	0	LOW EXCESS AIR FIRING	35	100
32	0	AMMONIA INJECTION	55	100
32	28	AMMONIA INJECTION + STEAM OR WATER INJECTION	65	100
139	0	SCR (SELECTIVE CATALYTIC REDUCTION)	90	100
139	28	SCR (SELECTIVE CATALYTIC REDUCTION) + STEAM OR WATER INJECTION	95	100
139	71	SCR (SELECTIVE CATALYTIC REDUCTION) + FLUID BED DRY SCRUBBER	90	100
139	204	SCR (SELECTIVE CATALYTIC REDUCTION) + OVERFIRE AIR	90	100
139	205	SCR (SELECTIVE CATALYTIC REDUCTION) + LOW NOX BURNERS	94	100
140	0	NSCR (NON-SELECTIVE CATALYTIC REDUCTION)	90	100
140	29	NSCR (NON-SELECTIVE CATALYTIC REDUCTION) + LOW EXCESS AIR FIRING	90	100
140	71	NSCR (NON-SELECTIVE CATALYTIC REDUCTION) + FLUID BED DRY SCRUBBER	90	100
140	204	NSCR (NON-SELECTIVE CATALYTIC REDUCTION) + OVERFIRE AIR	90	100
140	205	NSCR (NON-SELECTIVE CATALYTIC REDUCTION) + LOW NOX BURNERS	90	100
204	0	OVERFIRE AIR	40	100
204	26	OVERFIRE AIR + FLUE GAS RECIRCULATION	40	100
204	205	OVERFIRE AIR + LOW NOX BURNERS	50	100
205	0	LOW NOX BURNERS	50	100
205	26	LOW NOX BURNERS + FLUE GAS RECIRCULATION	60	100
205	28	LOW NOX BURNERS + STEAM OR WATER INJECTION	50	100
205	32	LOW NOX BURNERS + AMMONIA INJECTION	50	100
205	204	LOW NOX BURNERS + OVERFIRE AIR	50	100

6.3 Application of AirControlNET Technologies

AirControlNET is a control technology analysis tool developed to support the U.S. EPA in its analyses of air pollution policies and regulations (Pechan, 2005). The tool provides data on emission sources, potential pollution control measures and emission reductions, and the costs of implementing those controls.

The core of AirControlNET is a relational database system in which control technologies are linked to sources within EPA emissions inventories. The system contains a database of control measure applicability, efficiency, and cost information for reducing the emissions contributing to ambient concentrations of ozone, PM_{10}, $PM_{2.5}$, SO_2, NO_X, as well as visibility impairment (regional haze) from point, area, and mobile sources. PM_{10} and $PM_{2.5}$ as included in AirControlNET represent primary emissions of PM. The control measure data file in AirControlNET includes not only the technology's control efficiency, and calculated emission reductions for that source, but also estimates the costs (annual and capital) for application of the control measure.

Since the existing version of AirControlNET contains the preprocessed application of control technologies to a predetermined set of EPA emission inventories, direct use of the model in this analysis was not possible. However, Alpine received approval from EPA's Innovative Strategies and Economics Group (ISEG) to modify the AirControlNET version 4.1 source code and data tables in order to make it useful to this study (Sorrels, 2006). The results of the application of this modified version of the code still retain the applicability, efficiency, and cost information from the unmodified version of the source code, but were applied to the CENRAP modeling inventories with updated price index scalars to reflect control costs in 2005-dollars.

Using the modified inventories identified in Section 6.2 above, we ran every available control strategy in AirControlNET against the EGU, non-EGU point, and stationary area source inventories to develop a master list of available, *incremental* control strategies for the entire CENRAP 36 km domain necessary for the ICS to design command-and-control or cost-effectiveness based control strategies by source or domain. Mobile source controls were not processed under this assignment as it would have required multiple iterative runs of the EPA NONROAD and MOBILE6 models to generate the appropriate information. This master list of controls was used in the final development of the control strategy plan as described in the following sections.

Since AirControlNET's control cost equations take into consideration the useful remaining life of installed equipment and estimate the costs of compliance with these measures, two of the four reasonable progress goal considerations (see Section 6.6) are directly met through the results of the model's output.

Table 6-8. Emissions Weighted NETDC (MW) Association.

SCC	Description	NETDC (MW)
10100201	External Combustion Boilers; Electric Generation; Bituminous/Subbituminous Coal; Pulverized Coal: Wet Bottom (Bituminous Coal)	200
10100202	External Combustion Boilers; Electric Generation; Bituminous/Subbituminous Coal; Pulverized Coal: Dry Bottom (Bituminous Coal)	500
10100203	External Combustion Boilers; Electric Generation; Bituminous/Subbituminous Coal; Cyclone Furnace (Bituminous Coal)	200
10100212	External Combustion Boilers; Electric Generation; Bituminous/Subbituminous Coal; Pulverized Coal: Dry Bottom (Tangential) (Bituminous Coal)	500
10100215	External Combustion Boilers; Electric Generation; Bituminous/Subbituminous Coal; Cell Burner (Bituminous Coal)	1300
10100218	External Combustion Boilers; Electric Generation; Bituminous/Subbituminous Coal; Atmospheric Fluidized Bed Combustion: Circulating Bed (Bitum. Coal)	200
10100222	External Combustion Boilers; Electric Generation; Bituminous/Subbituminous Coal; Pulverized Coal: Dry Bottom (Subbituminous Coal)	400
10100223	External Combustion Boilers; Electric Generation; Bituminous/Subbituminous Coal; Cyclone Furnace (Subbituminous Coal)	400
10100226	External Combustion Boilers; Electric Generation; Bituminous/Subbituminous Coal; Pulverized Coal: Dry Bottom Tangential (Subbituminous Coal)	500
10100401	External Combustion Boilers; Electric Generation; Residual Oil; Grade 6 Oil: Normal Firing	400
10100404	External Combustion Boilers; Electric Generation; Residual Oil; Grade 6 Oil: Tangential Firing	500
10100501	External Combustion Boilers; Electric Generation; Distillate Oil; Grades 1 and 2 Oil	400
10100601	External Combustion Boilers; Electric Generation; Natural Gas; Boilers > 100 Million Btu/hr except Tangential	400
10100701	External Combustion Boilers; Electric Generation; Process Gas; Boilers > 100 Million Btu/hr	200
10100801	External Combustion Boilers; Electric Generation; Petroleum Coke; All Boiler Sizes	600
10101204	External Combustion Boilers; Electric Generation; Solid Waste; Tire Derived Fuel : Shredded	200
10300811	External Combustion Boilers; Commercial/Institutional; Landfill Gas; Landfill Gas	200
20100101	Internal Combustion Engines; Electric Generation; Distillate Oil (Diesel); Turbine	200
20100109	Internal Combustion Engines; Electric Generation; Distillate Oil (Diesel); Turbine: Exhaust	200
20100201	Internal Combustion Engines; Electric Generation; Natural Gas; Turbine	200
	All other boilers	100

6.4 Development of AOI-Based Cost Curves

Each Class I area in the CENRAP modeling domain has an associated set of AOIs as identified in other areas of this document. In order to best determine where emission reduction has the greatest benefit, this geography was designed to limit the available source type list from including all sources within the entire domain.

Using a geocoded county list from these AOIs, we parsed the master list of incremental control measures from all non-mobile source types and sources located within the boundaries of the AOIs. This parsed list was then sorted on in incremental cost-effectiveness (marginal cost) basis to determine the most cost effective control suite necessary to attain emission reduction targets for specific pollutants within each AOI. Each individual source or source category (unit or county-SCC combination) had its own cost effectiveness curve generated. In aggregate, the results of these applications are cost curves for each visibility impairing pollutant for all EGU, non-EGU point, and stationary area source within the geographic domain of the AOI. Incremental controls on mobile sources were not considered in this analysis. An illustrative example of the steps involved with the cost effectiveness curve design can be found in the Appendix F of this document. Figures 6-1, 6-2 and Appendix G present actual cost curves for AOI-1 areas associated with the six CENRAP Class I areas projected to be above the reasonable progress glide path.

6.5 Application of Cost Curves to Emission Reduction Needs

Two sets of cost curves have been developed for each pollutant-Class I AOI-1 combination identified as of interest to the ICS. The first marginal cost curve includes the application of all available control measures to all applicable source types within the AOI. The second curve is the result of limiting the control measure application to only the top three residual emission subcategories identified in the 2018 base case for each AOI-pollutant combination. These two curves will allow the ICS to determine if limiting the control scenario to only the highest residual categories will attain reasonable glide path emission reduction objectives while presumably minimizing the number and type of controlled sources in each AOI.

Within each AOI, an emissions reduction target has been established based on the review of relevant and available regional haze aerometric analyses and source attribution modeling. Each emissions reduction target sets the “solve point” of the cost curve and allows us to identify the most cost effective sources of reduction for the pollutants of interest within each impacted AOI.

It is noted that each pollutant-based cost curve developed for this analysis is mutually exclusive of each other pollutant’s cost curve and does not consider the feasibility of multiple control technologies being applied to any one source. Additionally, the information provided in these cost curves is representative of the primary pollutant of control and does not reflect any co-control applicability or disbenefit as a result of the application of that control.

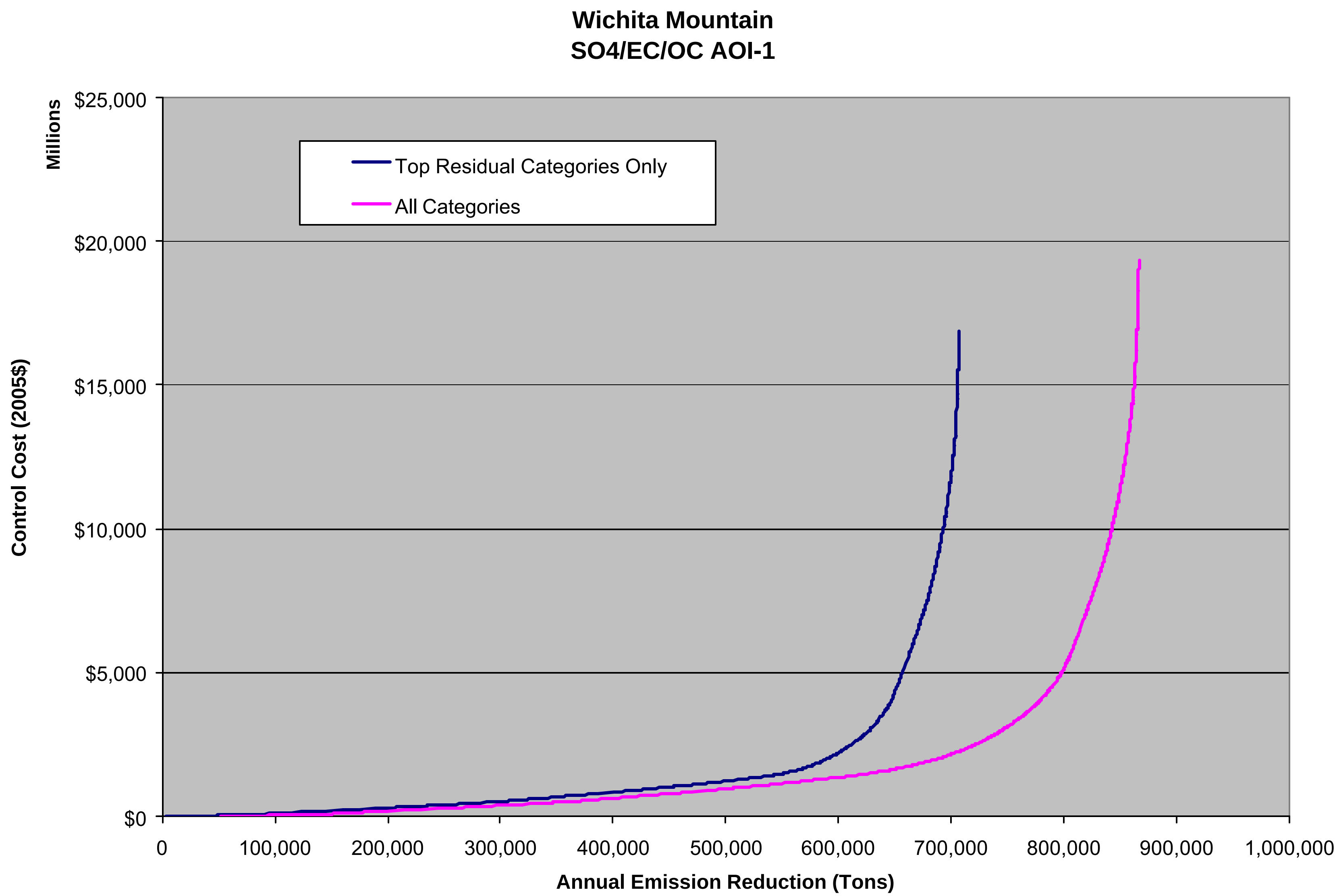

Figure 6-1. Marginal Cost Curve for Wichita Mountain SO4/EC/OC AOI-1.

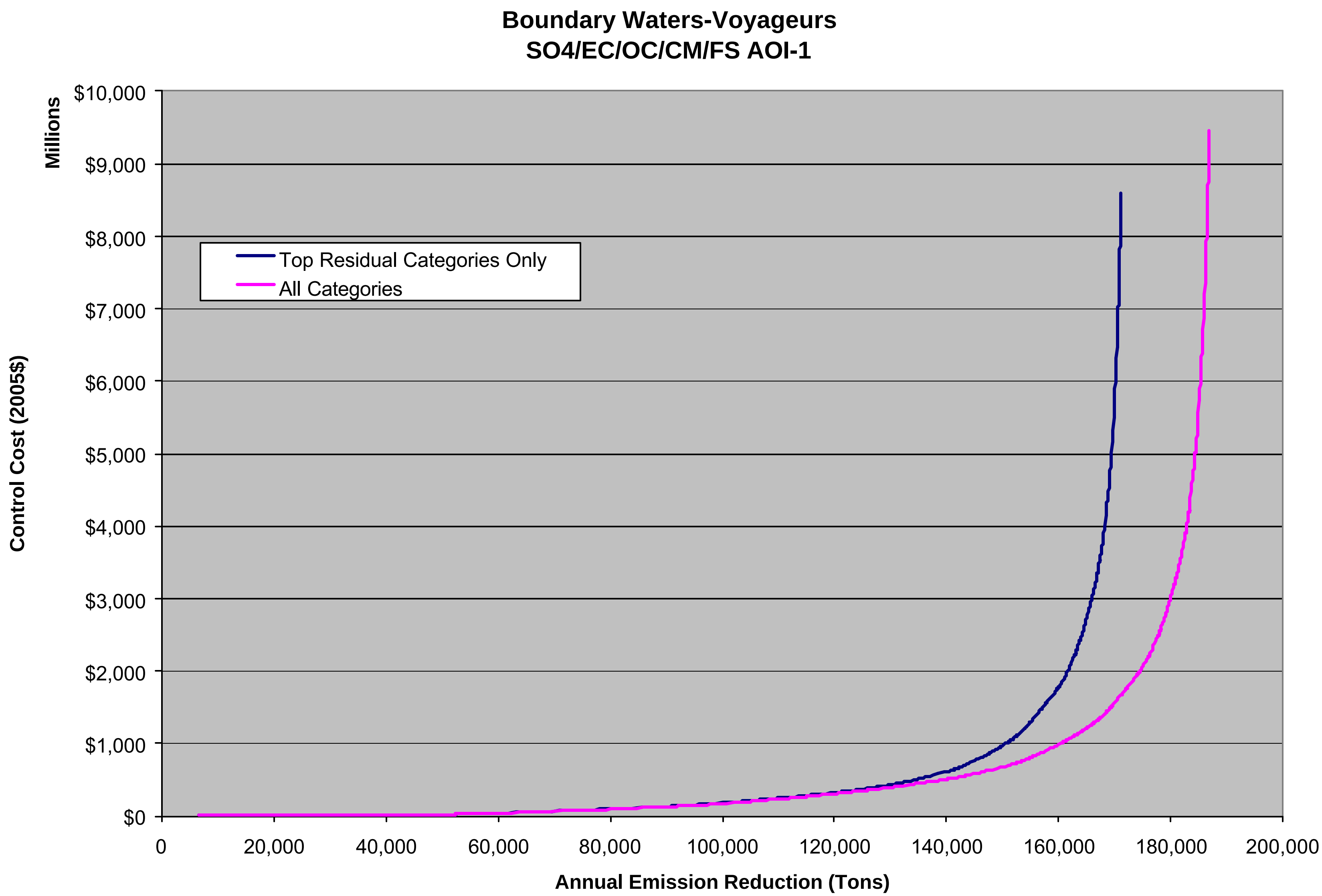

Figure 6-2. Marginal Cost Curve for Boundary Waters – Voyageurs SO4/EC/OC/CM/FS AOI-1.

6.6 Four Factor Analysis for RPG

As part of the regional haze program requirements outlined in 40 CFR 51.308, there are four factors which have been identified as mandatory for purposes of establishing a reasonable progress goal for any mandatory Class I area within a State.

40 CFR 51.308(d)(1)(i)(A) Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal.

6.6.1 Cost of Compliance

The cost of compliance factor is used to determine whether compliance costs for sources are reasonable compared to the emission reductions and visibility improvement they will achieve. Costs should be determined for one-time capital costs and ongoing annual operation, maintenance, and upkeep costs.

Through the application of control technologies using the cost equations from the AirControlNET source code, we have identified individual units for control application, identified the design parameters for emission controls, and developed cost estimates based on those design parameters. An estimation of annualized cost of control, based on a one-time capital cost and continual operating and maintenance costs are included in this estimate, where parameters were available in the AirControlNET equations. This application of control cost analysis as applied to the incremental reduction sources defined in this study meets the application of the cost of compliance statutory factor.

6.6.2 Time Necessary for Compliance

The time necessary for compliance factor may be used to adjust the reasonable progress goals to reflect the degree of improvement achievable within the long term strategy period, as opposed to the improvement expected at full implementation of a control measure, if the time needed for full compliance exceeds the length of the long term strategy period. For example, if vendor availability within the period of the long term strategy could not meet the full requirements of the installation schedule outlined by the control strategy, the reasonable progress goals should reflect the visibility improvement anticipated from installation of controls at the percentage of sources that *could* be controlled within the strategy period.

In this particular analysis, a time necessary for compliance factor could not be determined simply based on the emissions inventory and a list of control measures applicable to controllable sources. An eventual SIP could include control strategies that extend beyond the 2018 milestone and the visibility improvement anticipated from installation of controls at the percentage of sources that *could not* be controlled within the first strategy period would have to be counted in a later SIP. Each of these elements would need to be determined on a unit by unit basis.

6.6.3 Energy and Non-Air Quality Environmental Impacts of Compliance

The energy and non-air impacts factor is meant to consider whether the energy requirements (the amount, type, and availability of energy) of the control technology result in energy penalties or benefits. For example, a particular control may require a fuel, water may be required for a cooling tower, or a landfill may be required for disposal of solid waste byproduct, each which are directly unavailable in the area. Since these impacts are State and site specific, they are not addressed in this analysis. Upon the final configuration of the control strategies by the ICS, each participating State, tribe and affected entity should review the control plan to determine whether significant energy burdens or benefits comes as a direct result of the application of a control technology. If determined to be so, the State should quantify this value and include it in the final submitted SIP.

6.6.4 Remaining Useful Life of Potentially Affected Sources

The statutory factor of the remaining useful life of the source is applicable only to those measures which would require retrofitting of control devices at *existing* sources. The remaining useful life of a source affects the annualized costs of retrofit controls and is included in the methods used for calculating annualized costs in the control cost equations modified from EPA's AirControlNET.

CENRAP's emission projections, as well as the control cost equations applied by Alpine, account for the remaining useful life between the year of the reasonable progress analysis and the date the facility permanently stops operations. Since source specific retirements are taken into consideration with the CENRAP forecasts (units are shut down in the year of their retirement) and average retirement rates are applied to control technologies within the control analysis equations, the statutory factor of the remaining useful life of the source has been considered.

In summary, the basis of our resulting control strategy recommendations provide a demonstration of those reasonable progress goal requirements which could be taken into consideration to meet visibility objectives with the data provided for this analysis. The remaining factors are State, tribal and site dependant and could not be addressed here.

7.0 SUMMARY AND RECOMMENDATIONS

7.1 Summary

Alpine's review of all data discussed in the previous sections of this document have identified six Class I areas (Big Bend National Park, Breton Island, Boundary Waters, Guadalupe Mountains, Wichita Mountain, and Voyageurs) within the CENRAP domain, their particular AOIs, ICS defined emission reduction targets, and potential incremental emission reductions recommended for CENRAP modeling. For each area, sulfate and to a lesser extent, nitrate reductions were shown to be most beneficial during the 20 percent worst visibility days in 2002.

Alpine has configured subregional control strategies based on direction provided by the ICS to use single precursor emission reduction assumptions with a marginal cost per ton cutoff of $5,000 per ton reduced. Emission targets were identified by the ICS for each Class I area AOI to exceed the reasonable progress glide slope. These targets were established as 25 percent more reduction than was identified in Table 5-3 and were to be taken from any available source, not just those identified as having the highest residual emissions contribution to the Class I area AOI. Table 7-1 presents a summary of each of these strategies.

Table 7-1. Subregional control strategy summary for single precursor emission reduction targets.

Class I Area	ST	SO2 Annual Emission Reduction (Tons): ICS Established Reduction Target	SO2 Annual Emission Reduction (Tons): Subregional Control Strategy Reductions	Control Strategy Total Cost ($2005)	Control Strategy Average Cost Per Ton ($/ton reduced)
Breton Island	LA	385,000	119,966	$203,443,093	$1,696
Boundary Waters	MN	40,000	46,301	$107,233,124	$2,316
Voyageurs	MN	28,750			
Wichita Mountains	OK	93,750	99,479	$21,752,713	$219
Guadalupe Mountains	TX	162,500	115,936	$319,001,184	$2,752
Big Bend Nat'l Park	TX	150,000			

For three of the six CENRAP Class I areas projected to be above the reasonable progress glide slope in 2018, control strategies have been prepared which meet the emission reduction targets recommended by the ICS. These areas (Boundary Waters, Wichita Mountains, and Voyageurs) all can meet the ICS defined targets while staying within the single precursor, $5,000 per ton reduced limitations.

We also have determined that as a result of the implementation of the list of additional point and area source controls in each primary AOI the remaining three Class I areas within the CENRAP domain (Big Bend National Park, Breton Island, and Guadalupe Mountains) modeled to be above the reasonable progress glide slope will be unable to achieve a level of emissions reduction necessary to bring these areas under the glide slope by 2018 using the ICS identified control strategy definitions. Influences such as incrementally uncontrollable source categories, marginal cost effectiveness values greater than $5,000 per ton reduced, and international and inter-RPO emission transport prevent strategies from being configured for these Class I areas.

In particular, recent BRAVO research (see, for example Barna et al. 2006) shows that Mexican SO_2 sources account for up to 23% of the observed annual sulfate levels at Big Bend. During the summer months, Mexican SO_2 emissions sources can account for as much as 70% of the sulfate at Big Bend. Barna et al. also show that SO_2 emission sources for the Eastern U.S. are the biggest culprit to high sulfate at Big Bend during the high $PM_{2.5}$ summer days; and SO_2 from the Eastern US and Texas are the biggest contributor to high sulfate at Big Bend during the high $PM_{2.5}$ fall days.

In both of these episode examples, regardless of the emissions reduction achieved by CENRAP with the available source category and technology applications, there still is an emissions component which is directly out of their control. Additional consultation with inter-RPO and international agencies may be required to adequately co-configure strategies to bring these areas into attainment.

7.2 Recommendations

7.2.1 Regional Controls

As each of the six Class I areas projected to be above the reasonable progress glide path (and all of the other Class I AOIs in the CENRAP domain) are dominated by EGU SO_2 and NO_X emissions and many of these area AOIs intersect with States currently excluded by the EPA CAIR rule, *we recommend that CENRAP consider a control scenario which would reduce EGU emissions in non-CAIR States to levels comparable to those promulgated by EPA in the final CAIR regulation.* In addition to this regional strategy proposal, *we further recommend that the ICS consider individual CENRAP States within Class I area AOIs projected above the reasonable progress glide slope to meet CAIR emissions budgets without the interstate trading aspect of the rule*. This nuance may prevent emission reductions from being transferred to areas outside of the influential zones of the affected Class I areas and focus the reductions in those upwind areas with greatest impact on meeting visibility objective goals.

These regional controls could be modeled in multiple ways. Two noted methods being to develop an additional IPM run configured to take into account the CAIR reductions within non-CAIR States with or without the constraint of trading noted above. The second method would be to determine an emission budget (following EPA methods in the CAIR final rule) to determine State level targets for emission reduction. Using these targets, CENRAP could then apply the marginal cost curves developed for this analysis, but limit the solution to only EGU sources identified as "CAIR eligible". This approach would not take into account any trading or participation in the bank and trade system, but would give an estimate of the regional emission reductions associated with the strategy.

7.2.2 Subregional Controls

In lieu of a single regional control option applied consistently across the entire CENRAP domain, individual subregional controls could be applied to reduce emissions within certain Class I area AOIs. Based on the single precursor emission reduction target calculations defined elsewhere in this document, subregional control strategies can be defined for three of the Class I areas projected to be above the reasonable progress glide path. In each case, the marginal cost curves (based on the application of all available control options on all controllable industries and source types) allow the selection of control technologies for sources within an AOI-1 that attains the ICS defined emission reduction targets. Details of these control strategies are presented in Tables 7-2 and 7-3. Note that as Boundary Waters and Voyageurs are associated within the same AOI-1, the larger of the two emission reduction targets was used to configure a control strategy that would meet both areas' needs.

However, as noted in this document, the application of incremental control on all controllable point and area sources within the AOIs still fails to meet the visibility objectives of three Class I areas modeled to be above the reasonable progress glide slope. For this reason, *we additionally recommend that the ICS consider applying the remaining reasonably cost effective control technologies to sources within States and tribal lands contained in the boundaries of the three target Class I area AOIs.* As part of the demonstration of reasonable progress, the application of reasonably cost effective controls to all emission sources and source types through a process as described in this document appears to provide support that the four reasonable progress goal considerations were taken into account where available. As is demonstrated for the Boundary Waters and Voyageurs AOI-1 above, the AOI-1 for Big Bend and Guadalupe Mountains share the same emission reduction target. In this case, however, the target cannot be fully achieved. Tables 7-4 and 7-5 present the details of these strategies.

For those Class I areas outside of CENRAP's domain who based on CENRAP modeling did not forecast below the reasonable progress glide slope, we submit to the ICS our data of incremental control strategy application and cost curves based on existing modeling and inventory assumptions provided by CENRAP to date for purposes of consultation with those States in which the affected Class I areas are located. We have not presented these non-CENRAP data as part of this document but much of the basic information is presented, where appropriate, in the supporting appendixes.

Table 7-2. Subregional control strategy defined for Boundary Waters / Voyageurs SO4 AOI-1.

FIPSST	FIPSCNTY	State	County	Plant ID	Plant Name	Point ID	SIC	Control Measure	BOWA/VOYA SO2 Control Application Ton Reduced	Cost ($2005)	Marginal CPT
27	037	Minnesota	Dakota Co	2703700011	FLINT HILLS RESOURCES LP - PINE BEND	EU111	2911	Sulfur Recovery and/or Tail Gas Treatment	290	$401,526	$1,383
27	037	Minnesota	Dakota Co	2703700011	FLINT HILLS RESOURCES LP - PINE BEND	EU045	2911	Sulfur Recovery and/or Tail Gas Treatment	286	$395,189	$1,383
27	037	Minnesota	Dakota Co	2703700011	FLINT HILLS RESOURCES LP - PINE BEND	EU088	2911	Sulfur Recovery and/or Tail Gas Treatment	62	$86,034	$1,383
27	163	Minnesota	Washington Co	2716300003	MARATHON ASHLAND PETROLEUM LLC	EU019	2911	Sulfur Recovery and/or Tail Gas Treatment	11	$14,854	$1,383
~~55~~	~~123~~	~~Wisconsin~~	~~Vernon Co~~	~~663020930~~	~~DAIRYLAND POWER COOP GENOA STATION-EOP~~	~~B20~~	~~4911~~	~~FGD Wet Scrubber~~	~~16,904~~	~~$28,492,444~~	~~$1,686~~
19	179	Iowa	Wapello Co	90-07-001	IPL - OTTUMWA GENERATING STATION	143977	4911	FGD Wet Scrubber	15,897	$28,492,444	$1,792
19	113	Iowa	Linn Co	57-01-004	0	0	0	FGD	2,042	$4,302,128	$2,107
55	123	Wisconsin	Vernon Co	663020930	DAIRYLAND POWER COOP GENOA STATION-EOP	B20	4911	FGD Wet Scrubber	12,569	$28,492,444	$2,267
31	109	Nebraska	Lancaster Co	0005	NPPD SHELDON STATION	001	4911	FGD Wet Scrubber	6,079	$16,556,061	$2,724
19	193	Iowa	Woodbury Co	97-04-010	MIDAMERICAN ENERGY CO. - GEORGE NEAL NOR	148780	4911	FGD Wet Scrubber	9,065	$28,492,444	$3,143
								Overall Control Strategy	**46,301**	**$107,233,124**	**$2,316**

Duplicate entry in 2018d modeling inventory.

Table 7-3. Subregional control strategy defined for Wichita Mountains SO4 AOI-1.

FIPSST	FIPSCNTY	State	County	Plant ID	Plant Name	Point ID	SIC	Control Measure	WIMO SO2 Control Application Ton Reduced	Cost ($2005)	Marginal CPT
29	093	Missouri	Iron Co	0008	DOE RUN COMPANY-GLOVER SMELTER	8390	3339	FGD	51,834	$4,351,167	$84
48	201	Texas	Harris Co	37	HOUSTON PLANT	000008	2819	Increase % Conversion to Meet NSPS (99.7)	3,486	$670,008	$192
22	033	Louisiana	East Baton Rouge Par	0033	RHODIA INC/BR FAC	02	2869	Increase % Conversion to Meet NSPS (99.7)	7,090	$1,884,093	$266
22	005	Louisiana	Ascension Par	0007	DUPONT CHEMICALS/BURNSIDE PLANT	01	2819	Increase % Conversion to Meet NSPS (99.7)	11,284	$3,896,018	$345
29	099	Missouri	Jefferson Co	0003	DOE RUN COMPANY-HERCULANEUM SMELTER	11722	3339	FGD	10,653	$4,320,204	$406
48	201	Texas	Harris Co	37	HOUSTON PLANT	000011	2819	Increase % Conversion to Meet NSPS (99.7)	5,953	$2,510,908	$422
22	005	Louisiana	Ascension Par	0028	PCS NITROGEN FERTILIZER,L.P./GEISMAR	01	2873	Increase % Conversion to Meet NSPS (99.7)	9,179	$4,120,315	$449
								Overall Control Strategy	**99,479**	**$21,752,713**	**$219**

Table 7-4. Subregional control strategy defined for Breton Island SO4 AOI-1.

									BRET SO2 Control Application		
FIPSST	FIPSCNTY	State	County	Plant ID	Plant Name	Point ID	SIC	Control Measure	Ton Reduced	Cost ($2005)	Marginal CPT
22	033	Louisiana	East Baton Rouge Par	0033	RHODIA INC/BR FAC	02	2869	Increase % Conversion to Meet NSPS (99.7)	7,090	$1,884,093	$266
22	005	Louisiana	Ascension Par	0007	DUPONT CHEMICALS/BURNSIDE PLANT	01	2819	Increase % Conversion to Meet NSPS (99.7)	11,284	$3,896,018	$345
22	005	Louisiana	Ascension Par	0028	PCS NITROGEN FERTILIZER,L.P./GEISMAR	01	2873	Increase % Conversion to Meet NSPS (99.7)	9,179	$4,120,315	$449
22	033	Louisiana	East Baton Rouge Par	0033	RHODIA INC/BR FAC	03	2869	Increase % Conversion to Meet NSPS (99.7)	2,693	$1,884,093	$700
01	097	Alabama	Mobile Co	5009	AKZO NOBEL CHEMICALS INC	004	2819	Increase % Conversion to Meet NSPS (99.7)	2,183	$1,817,521	$832
12	113	Florida	Santa Rosa Co	1130005	EXXONMOBIL PRODUCTION COMPANY	34	1311	Sulfur Recovery and/or Tail Gas Treatment	1,702	$2,354,901	$1,383
22	033	Louisiana	East Baton Rouge Par	0015	EXXONMOBIL REF & SUPPLY CO/B R REFINERY	68	2911	Sulfur Recovery and/or Tail Gas Treatment	64	$88,364	$1,383
22	033	Louisiana	East Baton Rouge Par	0015	EXXONMOBIL REF & SUPPLY CO/B R REFINERY	69	2911	Sulfur Recovery and/or Tail Gas Treatment	64	$88,364	$1,383
22	095	Louisiana	St. John The Baptist	0013	MARATHON ASHLAND PETROLEUM LLC/LA REFINI	14	2911	Sulfur Recovery and/or Tail Gas Treatment	47	$64,441	$1,383
22	095	Louisiana	St. John The Baptist	0013	MARATHON ASHLAND PETROLEUM LLC/LA REFINI	70	2911	Sulfur Recovery and/or Tail Gas Treatment	31	$42,396	$1,383
22	095	Louisiana	St. John The Baptist	0013	MARATHON ASHLAND PETROLEUM LLC/LA REFINI	V2	2911	Sulfur Recovery and/or Tail Gas Treatment	26	$35,613	$1,383
22	077	Louisiana	Pointe Coupee Par	0005	LA GENERATING LLC/BIG CAJUN 2 PWR PLNT	01	4911	FGD Wet Scrubber	16,126	$28,492,444	$1,767
22	077	Louisiana	Pointe Coupee Par	0005	LA GENERATING LLC/BIG CAJUN 2 PWR PLNT	02	4911	FGD Wet Scrubber	15,618	$28,492,444	$1,824
12	033	Florida	Escambia Co	0330045	GULF POWER COMPANY CRIST ELECTRIC GENERA	6	4911	FGD Wet Scrubber	11,179	$20,964,424	$1,875
22	077	Louisiana	Pointe Coupee Par	0005	LA GENERATING LLC/BIG CAJUN 2 PWR PLNT	03	4911	FGD Wet Scrubber	15,022	$28,492,444	$1,897
01	097	Alabama	Mobile Co	1001	ALABAMA POWER COMPANY - BARRY	004	4911	FGD Wet Scrubber	8,396	$18,827,395	$2,242
28	059	Mississippi	Jackson Co	2805900058	CHEVRON PRODUCTS COMPANY, PASCAGOULA REF	051	2911	FGD	1,638	$4,349,179	$2,655
22	051	Louisiana	Jefferson Par	0004	CYTEC INDUSTRIES,INC/FORTIER PLNT	57	2821	Increase % Conversion to Meet NSPS (99.7)	1,087	$3,027,047	$2,784
01	097	Alabama	Mobile Co	1001	ALABAMA POWER COMPANY - BARRY	003	4911	FGD Wet Scrubber	4,712	$13,574,846	$2,881
01	097	Alabama	Mobile Co	1001	ALABAMA POWER COMPANY - BARRY	002	4911	FGD Wet Scrubber	4,631	$13,522,645	$2,920
01	047	Alabama	Dallas Co	0003	INTERNATIONAL PAPER COMPANY	003	2611	FGD	1,971	$7,156,048	$3,630
12	033	Florida	Escambia Co	0330045	GULF POWER COMPANY CRIST ELECTRIC GENERA	4	4911	FGD Wet Scrubber	2,734	$10,069,644	$3,683
12	033	Florida	Escambia Co	0330045	GULF POWER COMPANY CRIST ELECTRIC GENERA	5	4911	FGD Wet Scrubber	2,489	$10,198,414	$4,097
								Overall Control Strategy	**119,966**	**$203,443,093**	**$1,696**

Table 7-5. Subregional control strategy defined for Big Bend / Guadalupe Mountains SO4 AOI-1.

FIPSST	FIPSCNTY	State	County	Plant ID	Plant Name	Point ID	SIC	Control Measure	BIBE/GUMO SO2 Control Application Ton Reduced	Cost ($2005)	Marginal CPT
48	201	Texas	Harris Co	37	HOUSTON PLANT	000008	2819	Increase % Conversion to Meet NSPS (99.7)	3,486	$670,008	$192
48	201	Texas	Harris Co	37	HOUSTON PLANT	000011	2819	Increase % Conversion to Meet NSPS (99.7)	5,953	$2,510,908	$422
48	039	Texas	Brazoria Co	10	SWEENY REFINERY PETROCHEM	000203	2911	FGD	883	$429,763	$487
48	355	Texas	Nueces Co	3	CORPUS CHRISTI REFINERY	000174	2911	Sulfur Recovery and/or Tail Gas Treatment	1,430	$1,978,038	$1,383
48	167	Texas	Galveston Co	1	TEXAS CITY REFINERY	000239	2911	Sulfur Recovery and/or Tail Gas Treatment	478	$660,954	$1,383
48	039	Texas	Brazoria Co	10	SWEENY REFINERY PETROCHEM	000205	2911	Sulfur Recovery and/or Tail Gas Treatment	374	$518,052	$1,383
48	161	Texas	Freestone Co	9	EMBRIDGE ENERGY TEAGUE PL	000004	1311	Sulfur Recovery and/or Tail Gas Treatment	324	$448,705	$1,383
48	355	Texas	Nueces Co	3	CORPUS CHRISTI REFINERY	000174	2911	Sulfur Recovery and/or Tail Gas Treatment	63	$86,977	$1,383
48	201	Texas	Harris Co	39	DEER PARK PLANT	001295	2911	Sulfur Recovery and/or Tail Gas Treatment	56	$77,549	$1,383
48	355	Texas	Nueces Co	3	CORPUS CHRISTI REFINERY	000174	2911	Sulfur Recovery and/or Tail Gas Treatment	49	$67,251	$1,383
48	355	Texas	Nueces Co	20	CORPUS CHRISTI EAST PLANT	000156	2911	Sulfur Recovery and/or Tail Gas Treatment	27	$37,762	$1,383
48	201	Texas	Harris Co	39	DEER PARK PLANT	000208	2911	FGD	4,942	$8,474,217	$1,715
48	175	Texas	Goliad Co	2	COLETO CREEK PLANT	000001	4911	FGD Wet Scrubber	14,490	$28,492,444	$1,966
48	389	Texas	Reeves Co	2	WAHA PLANT	000031	4922	FGD	3,653	$8,153,168	$2,232
48	167	Texas	Galveston Co	5	TEXAS CITY REFINERY	000068	2911	FGD	2,293	$5,993,771	$2,614
48	029	Texas	Bexar Co	63	SOMMERS DEELY SPRUCE PWR	000002	4911	FGD Wet Scrubber	9,755	$28,492,444	$2,921
48	029	Texas	Bexar Co	63	SOMMERS DEELY SPRUCE PWR	000004	4911	FGD Wet Scrubber	9,595	$28,492,444	$2,970
48	029	Texas	Bexar Co	63	SOMMERS DEELY SPRUCE PWR	000004	4911	FGD Wet Scrubber	9,128	$28,492,444	$3,121
48	331	Texas	Milam Co	1	ALCOA SANDOW PLANT	000011	3334	FGD	14,306	$49,048,714	$3,429
48	331	Texas	Milam Co	1	ALCOA SANDOW PLANT	000010	3334	FGD	14,305	$49,048,714	$3,429
48	331	Texas	Milam Co	1	ALCOA SANDOW PLANT	000012	3334	FGD	14,143	$49,048,714	$3,468
48	349	Texas	Navarro Co	11	STREETMAN PLANT	000015	3295	FGD	2,443	$9,903,980	$4,054
48	227	Texas	Howard Co	1	BIG SPRING REFINERY	000267	2911	FGD	2,060	$9,638,812	$4,679
48	135	Texas	Ector Co	22	GOLDSMITH GASOLINE PLANT	000133	1321	FGD	1,700	$8,235,351	$4,844
								Overall Control Strategy	**115,936**	**$319,001,184**	**$2,752**

ALPINE GEOPHYSICS

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I. Introduction

Arkansas' Class I areas, the Caney Creek Wilderness Area ("Caney Creek") and the Upper Buffalo Wilderness Area ("Upper Buffalo"), have seen marked improvement in visibility since the start of regional haze monitoring. Based on the Interagency Monitoring of Protected Visual Environment (IMPROVE) data, which reflects monitored visibility impairment in Class I areas, the haze index for the twenty percent worst days of visibility has been steadily improving as a result of reduced emissions within Arkansas and because of broader industrial and energy trends in other states. According to modeling performed by the Central Regional Air Planning Association (CENRAP)[1], all of Arkansas' elevated point sources (including all power plants and large industrial sources) account for only about 2.7% and 2.3% of total light extinction within Caney Creek and Upper Buffalo, respectively. The overwhelming visibility impact comes from non-Arkansas point sources and mobile sources. Because of the Mercury and Air Toxic Standards (MATS) rule[2], the continuing benefits of the Clean Air Interstate Rule (CAIR), the next phase of the Cross State Air Pollution Rule (CSAPR), and the national ambient air quality standards (NAAQS), along with continuing reductions in emissions from mobile sources, the visibility at Caney Creek and Upper Buffalo will continue to improve. Based on the visibility trends in both Class I areas and the imposition of the State Implementation Plan (SIP) controls, no further action will be necessary to ensure that Arkansas' Class I areas remain below the Uniform Rate of Progress (URP) until at least 2028 and likely even longer as a result of emissions controls that will be required by future regulatory programs and planned retirements of numerous electric generating units.[3]

A. Arkansas State Implementation Plan Revision

Arkansas has made significant improvements in air quality in recent years. Arkansas is currently in attainment for all of the NAAQS and is well below both the State's and the U.S. Environmental Protection Agency's (EPA) 2018 regional haze reasonable progress goals. Arkansas is taking steps to revise its regional haze SIP to return control of the Regional Haze Program to the state.

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[1] CENRAP is a regional planning organization that includes nine states–Nebraska, Kansas, Oklahoma, Texas, Minnesota, Iowa, Missouri, Arkansas, and Louisiana. Five such regional organizations are funded by EPA to address the interstate transport nature of the regional haze pollutants. The primary objective of these organizations is to evaluate technical information to better understand the impact of the affiliated states on national strategy and to develop regional strategies to reduce emissions of particulate matter and other pollutants leading to regional haze.

[2] In spite of the Supreme Court decision in Michigan v. EPA, 135 S. Ct. 2699 (2015), which held that EPA must evaluate costs in determining whether it is appropriate and necessary to regulate hazardous air pollutant emissions from electric generating units (EGUs), several EGUs already have installed controls to comply with MATS or have undertaken other steps to reduce their emissions. Even if the rule is stayed or vacated while EPA undertakes its cost analysis, ADEQ expects that the rule will go forward before the end of this planning period along with the associated emission reductions.

[3] 2016 monitored haze index values for Caney Creek and Upper Buffalo wilderness areas were less than the URP value associated with 2028. Five year average values for these Class I areas from the period 2012–2016 were less than 0.2 deciviews higher than the URP values associated with 2028. See Visibility Progress Update 2016 Datasheet in Appendix F.

Specifically, Arkansas has included in this SIP revisions to address disapproved portions of the Arkansas Regional Haze State Implementation Plan (AR RH SIP), submitted to the EPA in 2008. In 2012, EPA partially approved and partially disapproved the 2008 AR RH SIP.[4] Specifically, the following elements are being submitted to EPA for approval:

- Best available retrofit technology (BART) compliance dates;
- BART eligible sources and subject-to-BART sources;
- Select BART determinations:
    - Sulfur dioxide (SO_2) and particulate matter (PM) BART determinations for Arkansas Electric Cooperative Corporation (AECC) Bailey Plant Unit 1;
    - SO_2 and PM BART determinations for AECC McClellan Plant Unit 1;
    - SO_2 BART determination for Southwestern Power Company (SWEPCO) Flint Creek Plant Boiler No. 1;
    - SO_2 BART determination under both bituminous and sub-bituminous coal firing scenarios for Entergy White Bluff Units 1 and 2;
    - BART determination for Entergy White Bluff Plant Auxiliary Boiler;
- Reasonable progress goals (RPGs); and
- Long-term strategy.

Revisions to disapproved BART requirements for Domtar Ashdown Mill are not included in this SIP revision. Arkansas is not revising determinations included in the 2008 AR RH SIP that were approved.

B. Arkansas SIP Components Included in this Revision

The following Administrative Orders (AOs) are included in this SIP revision:

- LIS No. 18-073 between Entergy and ADEQ
- LIS No. 18-072 between SWEPCO and ADEQ
- LIS No. 18-071 between AECC and ADEQ

Inclusion of permanently enforceable emissions limitations and compliance schedules in the included AOs is consistent with and allowable under federal programs. The AOs contain rescission clauses, which are intended to effect any changes to the AO's provisions by federal court or legislative actions. These clauses would ensure that the effect of any such changes to the AO would be consistent with federal court or legislative action. ADEQ will review any federal guidance and consult with EPA as needed to ensure consistency with federal policy prior taking any actions affecting the AOs or SIP based on federal court or legislative action. Any changes affecting the SIP or AOs would be taken after notice and comment period for any such revisions, which would provide reasonable notice of any change.

Sampling, monitoring, and reporting requirements that are generally applicable to stationary sources, including sources for which emissions limitations are established in this SIP, are

[4] Approval and Promulgation of Implementation Plans; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan to Address Pollution Affecting Visibility and Regional Haze. (77 FR 14604, March 12, 2012)

contained in SIP-approved Arkansas Pollution Control and Ecology Commission (APC&EC) Regulation No. 19 Chapter 7. No revisions to requirements in Regulation No. 19 Chapter 7 were necessary for this SIP revision.

II. Background

In 1977, Congress added § 169A to the Clean Air Act (CAA), which set forth the following goal for restoring pristine conditions in national parks and wilderness areas:

Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from man-made air pollution.

In 1980, EPA issued regulations to address visibility degradation that is "reasonably attributable" to a single source or small group of sources. These regulations primarily addressed "plume blight"—visual impairment of air quality that manifests itself as a coherent plume—rather than overall haze. In 1988, EPA, the states, and federal land managers (FLMs) began monitoring fine particulate matter concentrations and visibility in thirty Class I areas to better understand the species of particulates causing visibility impairment.

When the CAA was amended in 1990, Congress added § 169B which authorized research and regular assessments of progress toward restoring visibility in Class I areas and authorized the creation of visibility transport regions and commissions. Specifically, CAA § 169B(f) mandated the creation of the Grand Canyon Visibility Transport Commission (GCVTC) to make recommendations to EPA for regions affecting the visibility of the Grand Canyon National Park. EPA relied upon the recommendations of GCVTC and research reports to develop the 1999 "Regional Haze Regulations: Final Rule" (RHR).[5]

The 1999 RHR sought to address the combined visibility effects of various pollution sources over a wide geographic region with the goal of achieving natural visibility conditions at designated Class I areas by 2064. This required all states, including those that did not have Class I areas to participate in planning, analysis, and emission control programs under the RHR. States with Class I areas were required to conduct certain analyses to establish goals for each Class I area in the state to 1) improve visibility on the haziest days and 2) ensure no degradation occurs on the clearest days. These goals and long-term strategies to achieve these goals were to be included in SIPs covering each ten-year period leading up to 2064. States were also required to submit progress reports in the form of SIP revisions every five years. The 1999 RHR also expanded the existing Class I visibility monitoring network to 108 Class I areas.

For the purposes of assisting with coordination and cooperation among states to address visibility issues, EPA designated five regional planning organizations (RPOs) to assist with coordination and cooperation among states in addressing visibility issues the states have in common. Arkansas

[5] *Regional Haze Rule* (64 FR 35714, July 1, 1999)

was located in the CENRAP RPO. Figure 1 is a map depicting the five RPO regions designated by EPA.

Figure 1 Regional Planning Organizations

In SIPs covering the first ten-year period, states were also specifically required to evaluate controls for certain sources that were not in operation prior to 1962, were in existence in 1977, and had the potential to emit 250 tons per year or more of any air pollutant. These sources were referred to as "BART-eligible sources." States were required to make BART determinations for all BART-eligible sources or consider exempting some sources from BART requirements because they did not cause or contribute to visibility impairment in a Class I area. BART-eligible sources that were determined to cause or contribute to visibility impairment in a Class I area were subject to BART controls. In determining BART emissions limitations for each subject-to-BART source, states were required to take into account the existing control technology in place at the source, the cost of compliance, energy and nonair environmental impacts of compliance, remaining useful life of the source, and the degree of visibility improvement that was reasonably anticipated from use of each technology considered. States also had the flexibility to choose an alternative to BART—such as an emissions trading program—that would achieve greater reasonable progress in visibility protection than implementation of source-by-source BART controls. SIPs for the first ten-year planning period were due on December 17, 2007.

In 2005, EPA issued a revised BART rule pursuant to a partial remand of the 1999 RHR by the U.S. Court of Appeals of the DC District Court in 2002.[6] The Court had remanded the BART provisions of the 1999 RHR to EPA and denied industry's challenge to the RHR goals of natural

[6] American Corn Growers Assn. v. EPA, 291 F.3d.1 (D.C. Cir. 2002)

visibility and no degradation. The revised BART rule included guidelines for states to use in determining which facilities must install controls and the type of controls the facilities must use.

In addition to revisions to BART, EPA has also issued rulemakings establishing the CAIR and its successor the CSAPR as approvable alternatives to source-by-source BART controls.[7] EPA has also amended regulatory requirements for state regional haze plans for the second planning period and beyond.[8]

On September 9, 2008, Arkansas submitted a SIP for the 2008–2018 planning period to comply with regional haze regulations promulgated as of 2005 codified at 40 C.F.R. Part 51. In a 2012 action on the 2008 AR RH SIP, EPA partially approved and partially disapproved the SIP.[9] This partial approval/partial disapproval of the 2008 AR RH SIP triggered a requirement for EPA to either approve a SIP revision by Arkansas or promulgate a federal implementation plan (FIP) within twenty-four months of the final rule partially approving and partially disapproving the 2008 AR RH SIP.

In the 2012 partial approval/partial disapproval of the 2008 AR RH SIP, EPA approved the following elements of the 2008 AR RH SIP:

- Identification of Class I areas affected by sources in Arkansas;
- Determination of baseline and natural visibility conditions;
- Determination of a uniform rate of progress (URP);
- Select BART determinations:
    - PM determination on SWEPCO Flint Creek Plant Boiler No. 1;
    - SO_2 and PM determinations for the natural gas firing scenario for Entergy Lake Catherine Plant Unit 4;
    - PM determinations for both bituminous and sub-bituminous coal firing scenarios for Entergy White Bluff Plant Units 1 and 2; and
    - PM determination for Domtar Ashdown Mill Power Boiler No. 1;
- Consultation with FLMs and other states regarding RPGs and long-term strategy;
- Coordination of regional haze and reasonably attributable visibility impairment (RAVI);
- Regional haze monitoring strategy and other SIP requirements under 40 C.F.R. 51.308(d)(4);
- A commitment to submit periodic regional haze SIP revisions; and
- A commitment to submit periodic progress reports that include a description of progress toward RPG and a determination of adequacy of the existing SIP.

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[7] Regional Haze Regulations; Revisions to Provisions Governing Alternative to Source-Specific Best Available Retrofit Technology (BART) Determinations (71, FR 60612, October 13, 2006)
Regional Haze Regulations; Revisions to Provisions Governing Alternative to Source-Specific Best Available Retrofit Technology (BART) Determinations, Limited SIP Disapprovals, and Federal Implementation Plans (77 FR 33642, June 7, 2012).
[8] Protection of Visibility: Amendments to Requirements for State Plans (82 FR 3078, January 10, 2017)
[9] Approval and Promulgation of Implementation Plans; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan to Address Pollution Affecting Visibility and Regional Haze. (77 FR 14604, March 12, 2012)

EPA disapproved the following elements of the 2008 AR RH SIP:

- BART compliance dates;
- BART-eligible sources and subject-to-BART sources;
- Select BART determinations:
    - SO_2, NOx, and PM BART determinations for AECC Bailey Plant Unit 1;
    - SO_2, NOx, and PM BART determinations for AECC McClellan Plant Unit 1;
    - SO_2 and NOx BART determinations for SWEPCO Flint Creek Plant Boiler No. 1;
    - SO_2, NOx, and PM BART determinations for the fuel oil firing scenario and NOx BART determination for the natural gas firing scenario at Entergy Lake Catherine Plant Unit 4;
    - SO_2 and NOx BART determinations under both bituminous and sub-bituminous coal firing scenarios for Entergy White Bluff Units 1 and 2;
    - BART determination for Entergy White Bluff Plant Auxiliary Boiler;
    - SO_2 and NOx BART determinations for Domtar Ashdown Mill Power Boiler No. 1; and
    - SO_2, NOx, and PM BART determinations for Domtar Ashdown Mill Power Boiler No. 2;
- RPGs; and
- Long-term strategy.

On September 27, 2016, EPA finalized a regional haze FIP for Arkansas (AR RH FIP).[10] This FIP established new BART requirements for those sources whose BART determinations in the 2008 AR RH SIP were disapproved. The FIP also required the installation of controls at Entergy Independence Units 1 and 2. Despite the previous disapproval of ADEQ's determination in the 2008 AR RH SIP that Georgia Pacific Crossett Mill Boiler 6A and 9A did not cause or contribute to visibility impairment in a Class I area, EPA reversed its decision and concurred with ADEQ that Georgia Pacific Crossett Mill Boiler 6A and 9A are not subject to BART.

On November 22, 2016, the State of Arkansas filed a Petition for Reconsideration and Administrative Stay of the AR RH FIP. In the petition, the State of Arkansas requested that EPA reconsider the AR RH FIP based on new information not raised during the comment period that was of central relevance to the outcome of the FIP. Arkansas asserted that EPA should reconsider controls on Entergy Independence in light of recent data from the IMPROVE monitoring network that shows that Arkansas has already achieved the amount of progress required for the 2008–2018 planning period without having implemented the controls required in the FIP. Arkansas requested that EPA reconsider NOx emissions limitations placed on BART-eligible facilities in light of the recent rulemaking that increased the stringency of the CSAPR. Arkansas also requested reconsideration of BART for SO_2 at Entergy White Bluff during the 2008–2018 planning period. Lastly, Arkansas requested an immediate administrative stay pending completion of EPA's reconsideration of the AR RH FIP.

[10] Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Final Rule (81 FR 66332, September 27, 2016)

On February 3, 2017, the State of Arkansas filed a Petition for Review of the AR RH FIP with the United States Court of Appeals for the Eighth Circuit. On March 8, 2017, the Court held the case in abeyance for ninety days. On April 14, 2017, EPA issued a letter notifying Arkansas that the Agency was convening the reconsideration process for the following:

- Compliance dates for NOx emissions limitations for Flint Creek Unit 1, White Bluff Units 1 and 2, and Independence Units 1 and 2;
- Low-load NOx limitations applicable to White Bluff Units 1 and 2 and Independence Units 1 and 2 during periods of operation at less than fifty percent of the unit's maximum heat input rating;
- SO_2 emissions limitations for White Bluff Units 1 and 2; and
- Compliance dates for SO_2 emissions limitations for Independence Units 1 and 2.

On April 25, 2017, EPA published in the Federal Register a partial stay of the effectiveness of the AR RH FIP.[11] Specifically, EPA stayed from April 25, 2017 until July 24, 2017 (ninety days) the compliance dates for the NOx emissions limitations at Flint Creek Unit 1, White Bluff Units 1 and 2, and Independence Units 1 and 2, as well as the compliance dates for the SO_2 emissions limitations for White Bluff units 1 and 2 and Independence Units 1 and 2. This action did not alter or extend the ultimate compliance dates for these units nor did it stay requirements for other units subject to the FIP.

On July 8, 2017, ADEQ proposed revisions to the State's Regional Haze SIP specifically to address NOx from electric generating units (NOx Regional Haze SIP). The NOx Regional Haze SIP revision sought to replace source-specific NOx BART determinations included in the 2008 AR RH SIP, as well as the NOx limitations promulgated under the AR RH FIP, with reliance on the CSAPR trading program. The NOx Regional Haze SIP revision proposal demonstrated that Arkansas meets all of the current requirements under 40 C.F.R. § 51.308(e)(4) for an alternative to NOx BART. ADEQ submitted the proposed NOx Regional Haze SIP to EPA Region 6 on July 12, 2017 and requested parallel processing. EPA proposed approval of the NOx Regional Haze SIP on September 11, 2017. ADEQ submitted the final NOx Regional Haze SIP on October 31, 2017 and EPA finalized approval on February 12, 2018.[12]

On July 13, 2017, EPA proposed revisions to the AR RH FIP that would extend the compliance dates for the NOx emissions limitations at Flint Creek Unit 1, White Bluff Units 1 and 2, and Independence Units 1 and 2.[13] In the proposal, EPA stated that the Petition for Reconsideration submitted by the State of Arkansas on November 22, 2016, as well as the petitions submitted by the owners of the five units, raised certain arguments regarding the feasibility of eighteen-month

[11] 82 FR 18994

[12] Approval and Promulgation of Implementation Plans; Arkansas; Approval of Regional Haze State Implementation Plan Revision and Withdrawal of Federal Implementation Plan: Proposed Rule (82 FR 42627, September 11, 2017)

Approval and Promulgation of Implementation Plans; Arkansas; Approval of Regional Haze State Implementation Plan Revision for NOx for Electric Generating Units in Arkansas: Final Rule (83 FR 5927, February 12, 2018)

[13] Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Revision of Federal Implementation Plan (82 FR 32284, July 13, 2017)

NOx compliance dates for the five units that have merit and warrant proposal of a revision to the AR RH FIP with respect to those compliance dates. Therefore, EPA proposed extension of the NOx compliance dates by twenty-one months; however, this extension was not finalized due to EPA's September 11, 2017proposal to withdraw NOx emission limits from the AR RH FIP for EGUs in concert with their proposed approval of the NOx Regional Haze SIP revision.[14] The action to withdraw the AR RH FIP EGU NOx emission limits action was finalized on February 12, 2018.[15]

On July 31, 2017, the Eighth Circuit Court of Appeals granted a motion by the parties to hold the case in which the EPA's FIP is at issue in abeyance until September 26, 2017. The Court has continued holding the case in abeyance, as requested by the parties, while ADEQ works on issuing a replacement SIP. On March 7, 2018, the AR RH FIP SO_2 emission limits for Entergy White Bluff and Independence were judicially stayed.

III. Revisions to BART-Eligible and Subject-to-BART Sources

EPA disapproved the list of BART-eligible and subject-to-BART sources included in the 2008 AR RH SIP. The 2008 AR RH SIP inadvertently omitted Georgia Pacific Crossett Mill Boiler 6A and 9A from the list of BART-eligible sources in Table 9.1 on page 45; however, Georgia Pacific Crossett Mill 6A and 9A were included in the list of BART-eligible sources adopted into APC&EC Regulation No. 19 and submitted with the 2008 AR RH SIP.

Table 1 below is a correction to the list of BART-eligible units in Arkansas in the SIP.

Table 1 Facilities with BART-Eligible Units in the State of Arkansas

BART Source Category Number and Name	Facility Name	Arkansas Facility Identification Number	Unit ID	Unit Description
1. Fossil fuel-fired Electric Plants > 250 million British thermal units (MMbtu)/hour – Electric Generating	AECC Carl E. Bailey	74-00024	SN-01	Boiler
	AECC McClellan	52-00055	SN-01	Boiler
	Entergy Lake Catherine	30-00011	SN-03	Unit 4 Boiler

[14] Approval and Promulgation of Implementation Plans; Arkansas; Approval of Regional Haze State Implementation Plan Revision and Withdrawal of Federal Implementation Plan: Proposed Rule (82 FR 42627, September 11, 2017)
[15] Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan Revisions; Withdrawal of Federal Implementing Plan for NOx for Electric Generating Units in Arkansas: Final Rule (83 FR 5915, February 12, 2018)

BART Source Category Number and Name	Facility Name	Arkansas Facility Identification Number	Unit ID	Unit Description
Units (EGUs)	Plant			
	Entergy Ritchie	54-00017	SN-02	Unit 2
	Entergy White Bluff	35-00110	SN-01	Unit 1 Boiler
			SN-02	Unit 2 Boiler
			SN-05	Auxiliary Boiler
	SWEPCO Flint Creek Power Plant	04-00107	SN-01	Boiler
3. Kraft Pulp Mills	Domtar Industries, Inc. Ashdown Mill	41-00002	SN-03	#1 Power Boiler
			SN-05	#2 Power Boiler
	Delta Natural Kraft and Mid America Packaging, LLC.	35-00017	SN-02	Recovery Boiler
	Evergreen Packaging Inc., Pine Bluff Mill	35-00016	SN-04	#4 Recovery Boiler
	Georgia-Pacific Corporation Crossett Paper Operations	02-00013	SN-19	6A Boiler
			SN-22	9A Boiler
	Green Bay Packaging, Inc. Arkansas Kraft Division	15-00001	SN-05A	Recovery Boiler
	Potlatch Forest Products Corporation – Cypress Bend	21-00036	SN-04	Power Boiler

BART Source Category Number and Name	Facility Name	Arkansas Facility Identification Number	Unit ID	Unit Description
	Mill			
11. Petroleum Refineries	Lion Oil Company	70-00016	SN-809	#7 Catalyst Regenerator
15. Sulfur Recovery Plant	Albemarle Corporation South Plant	14-00028	SR-01	Tail Gas Incinerator
19. Sintering Plants	Big River Industries	18-00082	SN-01	Kiln A
21. Chemical Processing Plants	Albemarle Corporation South Plant	14-00028	BH-01 BH-02	Boiler #1 Boiler #2
	FutureFuel Chemical Co.	32-00036	6M01-01	3 Coal Boilers
	El Dorado Chemical Company	70-00040	SN-08 SN-09 SN-10	West Nitric Acid Plant East Nitric Acid Plant Nitric Acid Concentrator

Although EPA initially disapproved ADEQ's determination in the 2008 AR RH SIP that Georgia Pacific-Crossett Mill Boiler 6A and 9A did not cause or contribute to visibility impairment in a Class I area and were not subject to BART, EPA reversed its decision in the 2016 AR RH FIP and concurred with ADEQ that Georgia-Pacific Crossett Mill Boiler 6A and 9A are not subject to BART. This reversal was supported by information provided by Georgia-Pacific regarding revisions to emission limits included in their Title V permit and additional dispersion modeling conducted using those revised limits.[16] The results of this modeling demonstrated that the maximum impact of Georgia-Pacific Crossett's boilers on any Class I area was less than the 0.5 deciview threshold used by ADEQ to determine whether a BART-eligible source should be considered subject-to-BART. Georgia-Pacific provided further information regarding fuel usage during the 2001–2003 baseline and performed calculations using AP-42, Compilation of Air Pollutant Emission Factors, that demonstrated that emission rates during the 2001–2003 baseline were lower than the rates modeled in Georgia Pacific's 2011 BART screening modeling and lower than their currently enforceable Title V permit limits.[17][18] Therefore, EPA concluded that, based upon the additional information provided by Georgia-Pacific, Georgia-Pacific Crossett Mill 6A Boiler and 9A Boiler are not subject to BART. ADEQ concurs that Georgia-Pacific Crossett Mill 6A Boiler and 9A Boiler are not subject to BART; therefore, no revisions are necessary to the list of subject-to-BART sources in Arkansas included in the 2008 AR RH SIP. Documentation in support of the determination that Georgia-Pacific Crossett Mill 6A Boiler and 9A Boiler are not subject to BART can be found in Appendix A. Table 2 lists the subject-to-BART sources in Arkansas.

Table 2 Facilities with Subject-to-BART Units in the State of Arkansas

BART Source Category Number and Name	Facility Name	Arkansas Facility Identification Number	Unit ID	Unit Description
1. Fossil fuel-fired Electric Plants > 250 million British thermal units (MMBtu)/hour – Electric Generating Units (EGUs)	AECC Carl E. Bailey	74-00024	SN-01	Boiler
	AECC McClellan	52-00055	SN-01	Boiler
	Entergy Lake Catherine Plant	30-00011	SN-03	Unit 4 Boiler
	Entergy White Bluff	35-00110	SN-01	Unit 1 Boiler
			SN-02	Unit 2 Boiler
			SN-05	Auxiliary Boiler
	SWEPCO Flint Creek	04-00107	SN-01	Boiler

[16] May 18, 2012 letter from Georgia Pacific Crossett Paper Operations to ADEQ. A copy of this letter is included in Appendix A of this SIP.
[17] April 1, 2013 letter from Georgia-Pacific-Crossett to ADEQ and associated supporting attachments.
[18] ADEQ Operating Permit 0597-AOP-R-18

	Power Plant		
3. Kraft Pulp Mills	Domtar Industries, Inc. Ashdown Mill	41-00002	SN-03 #1 Power Boiler SN-05 #2 Power Boiler

IV. Revisions to BART Determinations

Among the provisions disapproved in EPA's 2012 action on the 2008 AR RH SIP, were several BART determinations, including the following BART determinations that are addressed in this SIP revision:

- SO_2 and PM BART determinations for AECC Bailey Plant Unit 1;
- SO_2 and PM BART determinations for AECC McClellan Plant Unit 1;
- SO_2 BART determinations for SWEPCO Flint Creek Plant Boiler No. 1;
- SO_2 BART determinations under both bituminous and sub-bituminous coal firing scenarios for Entergy White Bluff Units 1 and 2;
- BART determination for Entergy White Bluff Plant Auxiliary Boiler;

In this SIP revision, ADEQ is addressing disapproved emissions limitations and compliance schedules for the subject-to-BART sources listed above. All emissions limitations included in this SIP revision will be rendered enforceable through AOs included with this SIP revision.

The statutory five factors established in U.S.C. § 7491(g)(2) were analyzed for each subject-to-BART unit. These analyses and the emissions limitations determined thereupon are summarized in Sections IV.A–D of this SIP. The analyses are provided in Appendices B–E. Pursuant to Ark. Code Ann. § 8-4-317, ADEQ also considered the factors set forth in Ark. Code Ann. § 8-4-312 for emissions limitations included in this SIP revision to satisfy BART requirements. The emissions limitations included in this SIP are based upon generally accepted scientific knowledge and engineering practices. The need for each measure in attaining or maintaining the NAAQS is not applicable to the Regional Haze Program. Table 3 describes how each factor set forth in Ark. Code Ann. § 8-4-312 was considered.

Table 3 Consideration of Ark. Code Ann. § 8-4-312 for BART Limitations

Ark. Code Ann. § 8-4-312 Factor	Consideration of the Factor
(1) The quantity and characteristics of air contaminants and the duration of their presence in the atmosphere that may cause air pollution in a particular area of the state;	These characteristics were considered in modeling conducted for each source's BART analysis.
(2) Existing physical conditions and topography;	Modeling in support of the emissions limitations established in this SIP utilizes these

Ark. Code Ann. § 8-4-312 Factor	Consideration of the Factor
	factors as inputs.
(3) Prevailing wind directions and velocities;	Modeling in support of the emissions limitations established in this SIP utilizes these factors as inputs.
(4) Temperatures and temperature-inversion periods, humidity, and other atmospheric conditions;	Modeling in support of the emissions limitations established in this SIP utilizes these factors as inputs.
(5) Possible chemical reactions between air contaminants or between such air contaminants and air gases, moisture, or sunlight;	Modeling in support of the emissions limitations established in this SIP utilizes these factors as inputs.
(6) The predominant character of development of the area of the state such as residential, highly developed industrial, commercial, or other characteristics	The predominant character of development of the area of the state impacted by this SIP includes Class I areas—specifically Upper Buffalo and Caney Creek. The Class I areas are protected and remain deliberately undeveloped. Furthermore enhanced visibility in these areas will benefit the primary driver of development around Class I areas: tourism.
(7) Availability of air-cleaning devices;	Availability of air cleaning devices was considered as part of each BART analysis.
(8) Economic feasibility of air-cleaning devices	Economic feasibility of air cleaning devices was considered as part of each BART analysis.
(9) Effect on normal human health of particular air contaminants	This factor is not applicable to the regional haze program, which targets visibility improvements.
(10) Effect on efficiency of industrial operation resulting from use of air-cleaning devices;	Effect on efficiency of air cleaning devices was considered as part of each BART analysis.
(11) The extent of danger to property in the area reasonably to be expected from any particular air contaminant;	This factor is not applicable to the regional haze program, which targets visibility improvements.
(12) Interference with reasonable enjoyment of life by persons in the area and conduct of established enterprises that can reasonably be expected from air contaminants;	Visibility improvements are expected to occur at Arkansas Class I areas in the State as a result of the emissions limitations included in this SIP. Visitors to Caney Creek and Upper Buffalo are expected to enjoy these improvements. Persons that conduct tourism enterprises may also benefit as a result of the BART controls required in this SIP. Costs of control may be passed on to customers of the sources for which ADEQ is establishing emissions limitations; however, these costs are anticipated to be lower in this SIP than in the AR RH FIP that this SIP seeks to replace.
(13) The volume of air contaminants emitted from a particular class of air contamination	The volume of air contaminants emitted from subject-to-BART sources for which controls

Ark. Code Ann. § 8-4-312 Factor	Consideration of the Factor
sources;	are included in this SIP are factored into the BART analysis.
(14) The economic and industrial development of the state and the social and economic value of the air contamination sources;	Costs of control may be passed on to customers of the sources for which ADEQ is establishing emissions limitations. This may have a negative impact on economic and industrial development in the State. However, these costs are anticipated to be lower in this SIP than in the AR RH FIP that this SIP seeks to replace.
(15) The maintenance of public enjoyment of the state's natural resources; and	Visibility improvements are expected to occur at Arkansas Class I areas in the State as a result of the emissions limitations included in this SIP. Visitors to Caney Creek and Upper Buffalo are expected to enjoy these improvements. Persons that conduct tourism enterprises may also benefit as a result of the BART controls required in this SIP.
(16) Other factors that the department or the commission may find applicable.	Other factors considered by the Department in setting BART controls for subject-to-BART sources are contained in the Sections IV.A–D and Appendices B–E of this SIP.

A. Arkansas Electric Cooperative Corporation Carl E. Bailey Generating Station

AECC produced a BART analysis (dated March 2014, Version 4) for the Carl E. Bailey Generating Station. EPA used this analysis in the development of the AR RH FIP and ADEQ has made its BART determination included in this SIP based on the analysis provided by AECC. This analysis is included in Appendix B of this SIP and summarized below.

AECC Bailey Plant Unit 1 is a 122 megawatt wall-fired boiler installed in 1966. Unit 1 has a maximum heat input of 1,350 million British thermal units per hour (MMBtu/hr). AECC Bailey Plant Unit 1 burns pipeline quality natural gas as the primary fuel and No. 6 fuel oil as a secondary fuel. AECC Bailey Plant Unit 1 meets the BART-eligibility criteria. Also, ADEQ determined, based on results of previous air dispersion modeling, that the AECC Bailey Plant Unit 1 contributes greater than 0.5 deciviews to visibility impairment in at least one Class I area. Although, more recent modeling conducted by Trinity Consultants (Trinity) shows impacts for AECC Bailey Unit 1 that are less than 0.5 deciviews, AECC conducted a complete BART analysis and identified the AECC Bailey Plant Unit 1 source as the sole AECC Bailey source subject to BART. Consequently, the five BART statutory factors were considered for AECC Bailey Unit 1.

1. Summary of BART Analysis and Requirements for SO_2

The available control options for AECC Bailey Plant Unit 1 when burning fuel oil are flue gas desulfurization (FGD) systems and fuel switching. No control technologies were evaluated for natural gas burning scenarios due to the intrinsically low sulfur content of natural gas. FGD systems were considered technically infeasible. Fuel switching was the only technically feasible control option.

Fuel oil stored at AECC Bailey since 2006 had an average sulfur content of 1.81% by weight, therefore one percent sulfur No. 6 fuel oil, 0.5% sulfur No. 6 fuel oil, and diesel were considered. Fuel switching to one percent sulfur fuel oil at AECC Bailey Plant Unit 1 would result in up to a forty-five percent control efficiency for SO_2. Switching to 0.5% fuel oil would result in a seventy-two percent control efficiency and switching to 0.05% sulfur diesel would result in a ninety-seven percent control efficiency.

a. Existing Controls in Use at the Source

AECC Bailey does not have existing SO_2 control technology.

b. Cost of Compliance

The fuel switching options evaluated do not require capital investments in equipment; therefore, annual costs are based upon operation and maintenance costs associated with the different fuels. The cost-effectiveness of switching to one percent sulfur No. 6 fuel oil is $1,198/ton of SO_2 reduced. The cost-effectiveness of switching to 0.5% sulfur No. 6 fuel oil is $2,559/ton. The cost-effectiveness of switching to diesel is $5,382/ton, which is out of the range typically identified as cost-effective. Both 0.5% sulfur No. 6 fuel oil and one percent sulfur No. 6 fuel oil were within the range typically considered cost-effective.

c. Energy and Nonair Quality Environmental Impacts

AECC concluded that there are no energy or nonair quality impacts associated with fuel switching.

d. Remaining Useful Life

The remaining useful life of Bailey Unit 1 does not impact the annualized costs of evaluated control technologies since it is assumed that fuel switching will not require any significant capital costs.

e. Degree of Visibility Improvement as a Result of Controls

Visibility improvements that would be anticipated from evaluated technologies are included in Table 5-13 at page 5-12 of AECC's BART analysis. Fuel switching to one percent sulfur No. 6 fuel oil would result in a 41.52% reduction in visibility impairment from AECC Bailey at Caney Creek, a 44.25% reduction at Upper Buffalo, a 44.02% reduction at Hercules Glades Wilderness Area (Hercules Glades), and a 45.65% reduction at Mingo Wilderness Area (Mingo). Fuel switching to 0.5% sulfur No. 6 fuel oil would result in a 56.97% reduction in visibility impairment from AECC Bailey at Caney Creek, a 63.51% reduction at Upper Buffalo, a 63.32% reduction at Hercules Glades, and a 55.15% reduction at Mingo.

f. BART Requirements for SO_2

Based on cost/ton of SO_2 emissions reduced and visibility improvement among low sulfur fuels, AECC determined that SO_2 BART for AECC Bailey Plant Unit 1 is using fuel oil and natural gas with 0.5% sulfur or less. ADEQ concurs with AECC's BART determination for SO_2 at Bailey Plant Unit 1.

AO LIS No. 18-071 includes enforceable limitations and compliance dates consistent with ADEQ's BART determination.

2. Summary of BART Analysis and Requirements for PM

Available PM retrofit control technologies include: dry electrostatic precipitator (Dry ESP), wet electrostatic precipitator (Wet ESP), fabric filter, wet scrubber, a cyclone, and fuel switching. Dry ESP and fabric filters were considered technically infeasible.

A Wet ESP, with an estimated PM control efficiency of up to ninety percent, is a technically feasible option for PM control.

The use of a wet scrubber, with an estimated PM removal efficiency of around fifty-five percent, is a technically feasible option.

A cyclone is a technically feasible option. When clean oil is combusted, a high percentage of small particles are emitted and cyclones are not effective at controlling the smaller particles that are the primary source of visibility impairment, although when including the larger particles an eighty-five percent reduction in PM can be expected.

Fuel switching to lower sulfur content fuel is a technically feasible option. Reductions in filterable PM for No. 6 fuel oil are directly related to the sulfur content of the fuel and greater than a ninety-nine percent reduction of PM is expected solely from a fuel switch to natural gas.

a. Existing Controls in Use at the Source

AECC Bailey does not have existing PM control technology.

b. Cost of Compliance

The cost of compliance differs among the control technologies evaluated. Add-on controls such as Wet ESP, wet scrubber, and cyclone systems involve capital costs for new equipment that were annualized over a fifteen year period for the analysis. Fuel switching options have associated operation and maintenance costs, but no capital costs. The cost-effectiveness values of all evaluated options exceed $22,000/ton of PM removed, which is higher than the range typically considered cost-effective.

c. Energy and Nonair Quality Environmental Impacts

AECC concluded that there are no energy or nonair quality impacts associated with fuel switching; however, there are impacts associated with wet ESPs and wet scrubbers. These impacts were factored into the cost of compliance.

d. Remaining Useful Live

AECC anticipated that the remaining useful life of the AECC Bailey Plant Unit 1 is at least as long as the capital cost recovery period of fifteen years.

e. Degree of Visibility Improvement as a Result of Controls

Visibility improvements that would be anticipated from evaluated add-on technologies are included in Table 7-8 at page 7-9 of AECC's BART analysis and improvements that would be anticipated from fuel switching are included in Table 5-13 at page 5-12. Although no control options were considered cost-effective for PM, AECC determined that switching to 0.5% sulfur No. 6 fuel oil was cost-effective for SO_2. Visibility improvements anticipated from fuel switching to a lower sulfur content fuel oil are discussed in section IV.A.1.e. above.

f. BART Requirements for PM

AECC proposed that no fuel changes or add-on controls constitute PM BART for AECC Bailey Unit 1. In addition, the BART determination for SO_2 of fuel switching to 0.5 % sulfur No. 6 fuel oil will also result in PM reductions. ADEQ concurs with this AECC's BART determination for PM at Bailey Plant Unit 1 that no additional controls are necessary to satisfy PM BART beyond fuel switching to 0.5 % sulfur No. 6 fuel oil consistent with the SO_2 BART determination.

B. Arkansas Electric Cooperative Corporation John L. McClellan Generating Station

AECC produced a BART analysis (dated March 2014, Version 4) for the John L. McClellan Generating Station. EPA used this analysis in the development of the AR RH FIP and ADEQ has made its BART determination included in this SIP based on the analysis provided by AECC. This analysis is included in Appendix B of this SIP and summarized below.

AECC McClellan Plant Unit 1 is a 122 megawatt wall-fired boiler installed in 1971. AECC McClellan Plant Unit 1 has a maximum heat input of 1,436 MMBtu/hr. AECC McClellan Plant Unit 1 burns pipeline quality natural gas as the primary fuel and No. 6 fuel oil as a secondary fuel. AECC McClellan Plant Unit 1 meets the BART-eligibility criteria. Also, ADEQ determined, based on results of previous air dispersion modeling, that the AECC McClellan Plant Unit 1 contributes greater than 0.5 deciview to visibility impairment in at least one Class I area. Therefore, AECC conducted a complete BART analysis and identified the AECC McClellan Plant Unit 1 source as the sole AECC McClellan source subject to BART. Consequently, the five BART statutory factors were considered for AECC McClellan Unit 1.

1. Summary of BART Analysis and Requirements for SO_2

The available control options for AECC McClellan Unit 1 when burning fuel oil are FGD systems and fuel switching. No control technologies were evaluated for natural gas burning scenarios due to the intrinsically low sulfur content of natural gas. FGD systems were considered technically infeasible. Fuel switching was the only technically feasible control option.

Fuel oil stored at AECC McClellan since 2009 had an average sulfur content of 1.38% by weight, therefore one percent sulfur No. 6 fuel oil, 0.5% sulfur No. 6 fuel oil, and diesel were considered. Fuel switching to one percent sulfur fuel oil at AECC McClellan Plant Unit 1 would result in up to a twenty-eight percent control efficiency for SO_2. Switching to 0.5% fuel oil would result in a sixty-four percent control efficiency and switching to 0.05% sulfur diesel would result in a ninety-six percent control efficiency.

a. Existing Controls in Use at the Source

AECC McClellan does not have existing SO_2 control technology.

b. Cost of Compliance

The fuel switching options evaluated do not require capital investments in equipment; therefore, annual costs are based upon operation and maintenance costs associated with the different fuels. The cost-effectiveness of switching to one percent sulfur No. 6 fuel oil is $2,457/ton of SO_2 reduced. The cost-effectiveness of switching to 0.5% sulfur No. 6 fuel oil is $4,553/ton. The cost-effectiveness of switching to diesel is $10,698/ton, which is out of the range typically identified as cost-effective. Both 0.5% sulfur No. 6 fuel oil and one percent sulfur No. 6 fuel oil were within the range typically considered cost-effective.

c. Energy and Nonair Quality Environmental Impacts

AECC concluded that there are no energy or nonair quality impacts associated with fuel switching.

d. Remaining Useful Life

The remaining useful life of McClellan Unit 1 does not impact the annualized costs of evaluated control technologies since it is assumed that fuel switching will not require capital investments in new equipment.

e. Degree of Visibility Improvement as a Result of Controls

Visibility improvements that would be anticipated from evaluated technologies are included in Table 5-13 at page 5-12 of AECC's BART analysis. Fuel switching to one percent sulfur No. 6 fuel oil would result in a 13.67% reduction in visibility impairment from AECC McClellan at Caney Creek, a 13.16% reduction at Upper Buffalo, a 12.55% reduction at Hercules Glades, and a 15.35% reduction at Mingo. Fuel switching to 0.5% sulfur No. 6 fuel oil would result in a 48.23% reduction in visibility impairment from AECC McClellan at Caney Creek, a 45.11% reduction at Upper Buffalo, a 50.22% reduction at Hercules Glades, and a 40.35% reduction at Mingo.

f. BART Requirements for SO_2

Based on cost/ton of SO_2 emissions reduced and visibility improvement among low sulfur fuels, AECC proposed that SO_2 BART for AECC McClellan Plant Unit 1 is using fuel oil and natural gas with 0.5% sulfur or less. ADEQ concurs with AECC's BART determination for SO_2 at McClellan Plant Unit 1.

AO LIS No. 18-071 includes enforceable limitations and compliance dates consistent with ADEQ's BART determination.

2. Summary of BART Analysis and Requirements for PM

Available PM retrofit control technologies include: Dry ESP, Wet ESP, fabric filters, wet scrubber, a Cyclone, and fuel switching. Dry ESP and fabric filters were considered technically infeasible.

A Wet ESP, with an estimated PM control efficiency of up to ninety percent, is a technically feasible option for PM control.

The use of a wet scrubber, with an estimated PM removal efficiency of around fifty-five percent, is a technically feasible option.

A cyclone is a technically feasible option. When clean oil is combusted, a high percentage of small particles are emitted and cyclones are not effective at controlling the smaller particles that are the primary source of visibility impairment, although when including the larger particles an eighty-five percent reduction in PM can be expected.

Fuel switching to lower sulfur content fuel is a technically feasible option. Reductions in filterable PM for No. 6 fuel oil are directly related to the sulfur content of the fuel and greater than a ninety-nine percent reduction of PM is expected solely from a fuel switch to natural gas.

a. Existing Controls in Use at the Source

AECC McClellan does not have existing PM control technology.

b. Cost of Compliance

The cost of compliance differs among the control technologies evaluated. Add-on controls such as Wet ESP, wet scrubber, and cyclone systems involve capital costs for new equipment that were annualized over a fifteen year period for the analysis. Fuel switching options have associated operation and maintenance costs, but no capital costs. The cost-effectiveness of all evaluated options exceeds $14,000/ton of PM removed, which is higher than the range typically considered cost-effective.

c. Energy and Nonair Quality Environmental Impacts

AECC concluded that there are no energy or nonair quality impacts associated with fuel switching; however, there are impacts associated with wet ESPs and wet scrubbers. These impacts were factored into the cost of compliance.

d. Remaining Useful Live

AECC anticipated that the remaining useful life of the AECC McClellan Plant Unit 1 is at least as long as the capital cost recovery period of fifteen years.

e. Degree of Visibility Improvement as a Result of Controls

Visibility improvements that would be anticipated from evaluated add-on technologies are included in Table 7-9 at page 7-10 of AECC BART analysis and improvements that would be anticipated from fuel switching are included in Table 5-14 at page 5-13. Although no control options were considered cost-effective for PM, AECC determined that switching to 0.5% sulfur No. 6 fuel oil was cost-effective for SO_2. Visibility improvements anticipated from fuel switching to a lower sulfur content fuel oil are discussed in section IV.A.1.e. above.

f. BART Requirements for PM

AECC proposed that no fuel changes or add-on controls constitute PM BART for AECC McClellan Unit 1. In addition, the BART determination for SO_2 of fuel switching to 0.5 % sulfur No. 6 fuel oil will result in PM reductions. ADEQ concurs with this AECC's BART determination for PM at McClellan Plant Unit 1 that no additional controls are necessary to satisfy PM BART beyond fuel switching to 0.5 % sulfur No. 6 fuel oil consistent with the SO_2 BART determination.

C. Entergy Arkansas, Inc. Lake Catherine Plant

Entergy provided a BART analysis (dated June 2013) for burning of natural gas at the Entergy Lake Catherine Generating Station. EPA used this analysis in the construction of the AR RH FIP and ADEQ has made its BART determination included in this SIP based on the analysis provided by Entergy. This analysis is included in Appendix C of this SIP and summarized below.

Entergy Lake Catherine Plant Unit 4 is a 558 megawatt tangentially-fired boiler installed in 1970. Entergy Lake Catherine Plant Unit 4 has a maximum heat input of 5,850 MMBtu/hr. Entergy Lake Catherine Plant Unit 4 burns pipeline quality natural gas and was capable of burning No. 6 fuel oil as a secondary fuel at the time the BART analysis was submitted; however, Entergy has committed to not burning fuel oil at this unit. Therefore, emissions from fuel oil were not considered in the BART analysis and the Entergy Lake Catherine Plant Unit 4 must not burn fuel oil until BART determinations are promulgated for this unit for SO_2 and PM for the fuel oil firing scenario through EPA action upon and approval of revised BART determinations submitted by the State as a SIP revision. Entergy Lake Catherine Plant Unit 4 meets the BART-eligibility criteria. Also, ADEQ determined, based on results of previous air dispersion modeling, that the Entergy Lake Catherine Plant Unit 4 contributes an existing visibility impairment of greater than 0.5 deciview in at least one Class I area. Therefore, Entergy conducted a complete BART analysis and identified the Entergy Lake Catherine Plant Unit 4 source as the sole Entergy Lake Catherine unit subject to BART. Consequently, the five BART statutory factors were considered for Entergy Lake Catherine Plant Unit 4.

1. Summary of BART Analysis and Requirements for SO_2

A BART determination for SO_2 based on the use of natural gas was included in the 2008 AR RH SIP and approved in EPA's March 12, 2012, final rule (77 FR 14604). The determination resulted in no SO_2 controls needed during natural gas combustion. Because Entergy has committed to not burning fuel oil, no changes are needed to EPA's determinations with respect to the previously approved SO_2 BART limitations included in APC&EC Regulation No. 19.

2. Summary of BART Analysis and Requirements for PM

A BART determination for PM at Lake Catherine Plant Unit 4 based on the use of natural gas was included in the 2008 AR RH SIP and approved in EPA's March 12, 2012, final rule (77 FR 14604). The determination resulted in no PM controls needed during natural gas combustion. Because Entergy has committed to not burning fuel oil, no changes are needed to EPA's determinations with respect to the previously approved PM BART limitation included in APC&EC Regulation No. 19.

D. Entergy Arkansas, Inc. White Bluff

At the request of ADEQ, Entergy provided an updated BART five-factor analysis for SO_2 for White Bluff (dated August 18, 2017) to supplement previous BART analyses (dated February 2013, October 2013, August 2015, and August 2016) submitted to EPA for their consideration in development of the AR RH FIP. This updated analysis provided new information in light of an updated remaining useful life for White Bluff and evaluated three new control scenarios. At the time of proposal of this SIP revision, certain elements, including the remaining useful life, were held confidential. For this reason ADEQ also relied upon additional supplemental information provided by Entergy on April 5, 2017, which detailed cost-effectiveness for Dry FGD with various remaining useful life assumptions, in the proposed SIP. On December 1, 2017, Entergy released confidentiality claims with respect to the August 18, 2017 updated BART analysis for White Bluff. ADEQ released a notice of data availability to provide the public with the opportunity to take the full updated five-factor analysis into consideration as they prepared their comments on the proposed SIP. ADEQ's final BART determination included in this SIP is based on the updated BART five-factor analysis for SO_2, previous BART analyses, and supplemental information provided by Entergy. These analyses are included in Appendix D of this SIP and our evaluation is provided below.

Entergy White Bluff Units 1 and 2 are identical tangentially-fired 850 megawatt boilers, which were in existence in 1974, and they have a maximum heat input capacity of 8,950 MMBtu/hr each. These units are currently equipped with ESPs to control PM emissions. Entergy White Bluff Units 1 and 2 burn sub-bituminous coal as a primary fuel and burn No. 2 fuel oil or biofuel as a start-up fuel. Entergy White Bluff also has a rarely used 183 MMBtu/hr auxiliary boiler that burns only No. 2 fuel oil or biodiesel. Entergy White Bluff Units 1 and 2 and the auxiliary boiler meet the BART eligibility criteria. Because modeling demonstrates that the auxiliary boiler's greatest impact on visibility at any Class 1 area is only 0.01 deciview, EPA determined that existing emissions limitations for the auxiliary boiler in Entergy's permit satisfy BART for SO_2, NOx, and PM. ADEQ concurs with this determination. Entergy White Bluff Units 1 and 2 contribute greater than 0.5 deciview to at least one Class I area. Consequently, the five BART statutory factors were considered for Entergy White Bluff Units 1 and 2.

1. Summary of BART Analyses and Requirements for SO_2

The available SO_2 retrofit control technology options for White Bluff Units 1 and 2 include: fuel switching to low sulfur coal (LSC), dry sorbent injection (DSI), spray dryer absorber (SDA), circulating dry scrubber (CDS), and Wet FGD. All evaluated options were considered technically feasible.

Fuel switching to LSC with a sulfur content of 0.6 lb/MMBtu would result in an 8.75% reduction in SO_2 emissions from baseline levels.

DSI, which is the injection of sorbent into the exhaust gas stream, has a control efficiency that can range from forty to ninety percent based on sorbent particle size, residence time, temperature, and particulate collection equipment. Entergy evaluated two particulate collection methods for DSI at Entergy White Bluff. The first collection method would require retrofits to the currently installed ESP and would achieve a fifty percent SO_2 removal efficiency. The second "enhanced" collection method would require the installation of a baghouse and would achieve an eighty percent SO_2 removal efficiency. Both evaluated DSI technologies would require landfilling of DSI waste.

SDA and CDS, both Dry FGD systems, have control efficiencies ranging from sixty to ninety-five percent. Both systems utilize a fine mist of lime slurry sprayed into an absorption tower to absorb SO_2. The resulting calcium sulfite and calcium sulfate are then collected with a fabric filter.

Wet FGD, scrubbing the exhaust gas stream with a lime or limestone slurry, is capable of achieving eighty to ninety-five percent control of SO_2 emissions. This option was eliminated in previous analyses and in the AR RH FIP due to the small incremental difference in visibility improvement between Wet FGD and Dry FGD relative to the marginal cost difference.

a. Existing Controls in Use at the Source

The current permitted emissions rate for Units 1 and 2 at Entergy White Bluff is a three-hour average emission rate of 1.2 lb SO_2/MMBtu for each unit based on the new source performance standard for fossil-fuel fired steam generators.

b. Cost of Compliance

The cost of compliance differs among the control technologies evaluated. For some technologies, remaining useful life is a significant factor in determining annual cost. The cost of fuel switching to LSC is not dependent on the remaining useful life of White Bluff Units 1 and 2 or equipment because no capital investments in equipment are required. The other evaluated control technologies require capital investments in new equipment or retrofit of existing equipment. These capital investments are amortized over the remaining useful life of White Bluff Units 1 and 2 to determine the annual cost-effectiveness of SO_2 emissions reductions. The remaining useful life assumptions are discussed in section IV(D)(1)(d) below.

Switching to LSC entails an increased annual cost of operation based on purchase contract terms for the specific sulfur content of the coal. Entergy estimates an increase in operation and maintenance costs based on a $0.50 per ton cost premium to guarantee that the sulfur content of coals is less than 0.6 lb/MMBtu.

In Entergy's August 18, 2017 revised BART analysis, Entergy presented two sets of cost-effectiveness values for add-on control technologies: one set based on claimed "actual costs" and another that comports with EPA's control cost methodology for BART determinations. ADEQ's evaluation of controls is based on the latter of the two. Cost-effectiveness of Wet FGD was not calculated in the updated five factor analysis because EPA already determined in the AR RH FIP that Wet FGD is not BART because Wet FGD is more expensive than Dry FGD technologies with a 0.028 deciview or less incremental impact at Class I areas. The incremental cost of Wet FGD would be even greater considering the updated remaining useful life for Entergy White Bluff Units 1 and 2.

Table 4 compares the average and incremental cost-effectiveness versus LSC based on allowed costs of each control technology evaluated in Entergy's updated five factor analysis for White Bluff. Average dollar-per-deciview cost for LSC, DSI and Dry FGD are included in Table 5.

Table 4 Average Cost-Effectiveness and Incremental Cost-Effectiveness for Control Options at White Bluff Units 1 and 2

Control Option	Average Cost Effectiveness ($/ton)	Average Incremental Cost-Effectiveness Relative to LSC ($/ton)
LSC	1,149	
DSI	6,240	7,724
Enhanced DSI	6,406	7,113
Dry FGD	5,404	5,865

Table 5 Average Dollar-Per-Deciview Reduction for Control Options at White Bluff Units 1 and 2[19]

Control Option	Caney Creek	Upper Buffalo	Hercules Glades	Mingo
LSC	14,500,519	11,932,988	10,666,332	13,554,882
DSI	133,341,667	105,417,939	120,512,761	116,126,126
Enhanced DSI	158,855,956	139,165,572	168,897,541	173,433,064
Dry FGD	131,447,683	121,373,255	153,165,608	153,852,117

[19] Total annualized cost, as calculated by ADEQ using information from Entergy's August 18, 2017 revised BART analysis for White Bluff divided by visibility improvements that would be anticipated from evaluated technologies included in Tables 4-6 and 4-7 of Entergy's August 18, 2017 analysis at pages 4-7 and 4-8. Further discussion of those modeled visibility benefits are discussed in Section IV.D.1.e of this SIP.

ADEQ finds that the average cost-effectiveness values for DSI, Enhanced DSI, and Dry FGD at White Bluff exceed what is typically found to be cost-effective for BART based on actions taken in other states.[20] In addition, the dollar-per-deciview values for DSI, Enhanced DSI, and Dry FGD are approximately an order of magnitude greater than for LSC.

c. Energy and Nonair Quality Environmental Impacts

Entergy indicated that there were energy and adverse nonair quality environmental impacts associated with add-on controls under consideration, such as DSI and Dry FGD. These impacts were factored into costs of compliance.

d. Remaining Useful Life

In the August 18, 2017 updated BART analysis for White Bluff, Entergy amortized costs based on their proposal regarding changes in coal-fired operations. The August 18, 2017 analysis redacted Entergy's proposed date to enact these changes; however, Entergy voluntarily released confidentiality claims on those dates on December 1, 2017. On December 18, 2017, ADEQ issued a notice of data availability, including Entergy's unredacted analysis, and extended the public comment period to enable the public to consider this new information as they developed comments on the proposed SIP. In the updated BART analysis, Entergy stated that they anticipate cessation of coal use by White Bluff by the end of the year 2028 and that they are prepared to take an enforceable restriction to that effect.

Under the guidelines for BART determinations, the remaining useful life calculation should begin on "the date that controls will be put in place" (compliance date) and ending on "the date the facility permanently stops operations."[21] The compliance date for BART controls must be be as expeditiously as practicable, but in no event later than five years after approval of the SIP.[22] ADEQ had proposed that the compliance date for Dry FGD at White Bluff would be by 2023 based on five years from the anticipated approval of this SIP in 2018; however, due to comments received during the public comment period and Entergy's use of 2021 in its unredacted analysis , ADEQ is now basing its analysis on a compliance date of October 27, 2021. The shifting of compliance and cessation of coal-fired operations date assumptions by two years results in the same seven year remaining useful life assumption included in the proposed SIP.

The guidelines for BART determinations further specify that the permanent operations cessation date should be "assured by a federally- or State-enforceable restriction preventing further operation."[23] Therefore, ADEQ agrees that Entergy's cost-effectiveness calculations are reasonable based on a remaining useful life of seven years and Entergy's proposal to take an enforceable limit regarding the timing of their planned changes in coal-fired operations.

[20] Cost-effectiveness values included in approved SIPs and FIPs for BART are typically below $5,000/ton. This is illustrated in Exhibit B to the National Parks Conservation Association, Earthjustice, and Sierra Club comments on the Proposed SIP.
[21] Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations (70 FR 39104,July 6, 2005)
[22] 40 CFR 51.308(e)(iv)
[23] Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations (70 FR 39104, July 6, 2005)

e. Degree of Visibility Improvement as a Result of Controls

Visibility improvements that would be anticipated from evaluated technologies are included in Tables 4-6 and 4-7 of Entergy's August 18, 2017 analysis at pages 4-7 and 4-8 and are summarized in Table 6 below. [24]

Table 6 Summary of CALPUFF-Modeled Average Visibility Improvement from Evaluated SO_2 Controls at White Bluff Over Baseline (98th Percentile Impact)

	Average Deciview Improvement over 2001–2003 Baseline (98th Percentile Impact)			
	Caney Creek	Upper Buffalo	Hercules Glades	Mingo
LSC	0.113	0.135	0.152	0.119
DSI	0.291	0.367	0.322	0.333
Enhanced DSI	0.476	0.543	0.448	0.436
SDA	0.589	0.637	0.506	0.503

f. BART Requirements for SO_2

Based on their analysis, Entergy proposed that BART to control SO_2 emissions from Entergy White Bluff Units 1 and 2 is LSC. ADEQ concurs with Entergy's BART determination that LSC is BART for SO_2 at White Bluff Units 1 and 2 given the information presented in their updated five-factor analysis and the remaining useful life of the units. For the remaining useful life assumptions for White Bluff, Dry FGD, DSI, and Enhanced DSI are not within the range typically found to be cost-effective for BART.[25] In addition, the cost-per-deciview improvement for Dry FGD, DSI, and Enhanced DSI are an order of magnitude larger than for LSC. Therefore, ADEQ agrees that BART for White Bluff is LSC based on Entergy's planned cessation of coal-fired operations at White Bluff by the end of 2028. This voluntarily proposed cessation of coal-fired operations date is rendered state-enforceable through an AO.

[24] Entergy's modeled visibility improvement from evaluated SO_2 controls are based on an updated baseline of 2009–2013 emissions rather than the 2001–2003 baseline emissions EPA used in the AR RH FIP to project visibility improvements from Dry FGD and Wet FGD. This change in baseline emissions impacts the modeled visibility benefit from Dry FGD. The modeled visibility benefit of Dry FGD at each unit is 15% to 26% lower in Entergy's updated analysis than estimated in the AR RH FIP. EPA did not evaluate visibility improvements associated with DSI, enhanced DSI, and LSC in the AR RH FIP; however, ADEQ expects that the relative difference in cost-per-deciview among the control options evaluated would be similar across both baseline emissions periods. The difference in visibility impact estimates due to differences in estimated baseline emissions between the AR RH FIP and Entergy's updated five factor analysis does not change ADEQ's ultimate decision for its SO_2 BART determination for White Bluff, which is discussed in Section IV.D.1.e of this SIP and was based on an assessment of all five statutory BART factors.

[25] Cost-effectiveness values included in approved SIPs and FIPs for BART are typically below $5,000/ton. This is illustrated in Exhibit B to the National Parks Conservation Association, Earthjustice, and Sierra Club comments on the Proposed SIP.

In communication with ADEQ, Entergy indicated that it is their practice to project how much coal will be needed in future years and to contract for a portion of their coal supply up to three years in advance. Furthermore, Entergy keeps a reserve supply of coals at White Bluff to ensure that the units can operate in the event of a fuel supply disruption. In response to comments received during the public comment period, ADEQ requested that Entergy provide additional information regarding the time necessary for compliance with an emission limit based on LSC. On April 3, 2018, Entergy submitted a letter to ADEQ providing additional information with regards to current coal contracts, coal blending capabilities at White Bluff.[26] Entergy detailed how site-specific circumstances preclude the ability to guarantee an emission rate of 0.6 lb/MMBTU. Specifically, the sulfur content limits of Entergy's existing coal contracts for the next three years exceed this emission rate. In addition, Entergy cannot accurately calculate expected SO_2 emissions from blending of coals from their stockpile and new deliveries from a train because stockpile coal sulfur content is not tracked. Given the site-specific circumstances for White Bluff, ADEQ finds Entergy's explanation as to why three years is necessary to guarantee compliance with an emission limit of 0.6 lb/MMBTU to be reasonable.

The emission rate for LSC proposed by Entergy was 0.6 lb/MMBtu. During the public comment period, commenters pointed out that the significant digits of this limit, as proposed, could result in smaller reductions than assumed because it is typical to round to the nearest significant digit when demonstrating compliance. For instance, an emission rate as high as 0.64 lb/MMBtu could be rounded down to 0.6 lb SO_2/MMBtu. Based on this comment, ADEQ finds that it is appropriate to revise the number of significant digits associated with the enforceable emission rate for LSC to preclude emission rates higher than evaluated for LSC in Entergy's updated five-factor analysis for White Bluff. Therefore, ADEQ finds that it is reasonable to require Entergy to comply with the requirement to meet an emission rate of 0.60 lb/MMBtu at Entergy White Bluff Unit 1 and Unit 2 no later than three years after approval of this SIP revision.

AO LIS No. 18-073 includes enforceable limitations and compliance dates consistent with ADEQ's determination.

2. Summary of BART Analysis and Requirements for PM

A BART determination for PM for Entergy White Bluff Units 1 and 2 was included in the 2008 AR RH SIP and approved in EPA's March 12, 2012, final rule (77 FR 14604). No changes are needed to EPA's determinations with respect to previously approved PM BART limitations (0.10 lb/MMBtu) included in APC&EC Regulation No. 19.

E. Southwestern Electric Power Company Flint Creek Power Plant

SWEPCO, a subsidiary of AEP, provided a BART analysis (dated September 2013, Version 4) for the Flint Creek Power Plant. EPA used this analysis in the development of the AR RH FIP and ADEQ has made its BART determination included in this SIP based on the analysis

[26] The April 3, 2018 letter from Entergy regarding time necessary for compliance with LSC is included in Appendix D.

provided by SWEPCO. This analysis is provided in Appendix E of this SIP and summarized below.

SWEPCO Flint Creek Plant Boiler No. 1 is a 558 megawatt dry bottom wall-fired boiler that commenced operation in 1978. SWEPCO Flint Creek Plant Boiler No. 1 has a maximum heat input of 6,324 MMBtu/hr. SWEPCO Flint Creek Plant Boiler No. 1 is equipped with Dry FGD with a Pulse Jet Fabric Filter (PJFF) and Activated Carbon Injection (ACI). SWEPCO Flint Creek Plant Boiler No. 1 burns low sulfur western coal as a primary fuel, but can also combust fuel oil and tire-derived fuels. Fuel oil firing is only allowed during unit startup and shutdown, during startup and shutdown of pulverizer mills, for flame stabilization when coal is frozen, for No. 2 fuel oil tank maintenance, to prevent boiler tube failure in extreme cold weather when the unit is offline for maintenance, and during malfunction. SWEPCO Flint Creek Plant Boiler No. 1 meets the BART-eligibility criteria. Also, based on results of air dispersion modeling, the SWEPCO Flint Creek Plant Boiler No. 1 contributes greater than 0.5 deciview to visibility impairment in at least one Class I area. Consequently, the five BART statutory factors were considered for SWEPCO Flint Creek Plant Boiler No. 1.

1. Summary of BART Analysis and Requirements for SO_2

The available SO_2 retrofit control technology options include DSI, Dry FGD, and Wet FGD. DSI, a form of FGD, has a control efficiency of forty to sixty percent and was considered technically feasible in SWEPCO's BART analysis for the SWEPCO Flint Creek Plant Boiler No. 1. A Dry FGD was also deemed a technically feasible option and has a control efficiency of sixty to ninety-five. Novel integrated deacidification (NID), a form of Dry FGD, was predicted to have an achievable ninety-two percent control efficiency on the SWEPCO Flint Creek Plant Boiler No. 1. Wet FGD was also considered a technically feasible option and has an eighty to ninety-five percent control efficiency.

a. Existing Controls in Use at the Source

At the time SWEPCO performed a BART analysis, no SO_2 controls were in place at Flint Creek Plant Boiler No. 1. Since that time, SWEPCO has installed an NID system to comply with SO_2 BART requirements included in the AR RH FIP. Cost-effectiveness and visibility improvement data included in SWEPCO's BART analysis are based on the 2001–2003 baseline, not current SO_2 controls in place at Flint Creek Plant Boiler No. 1.

b. Cost of Compliance

SWEPCO determined the cost effectiveness of a Wet FGD at an SO_2 rate of 0.04 lb/MMBtu (ninety-five percent control of baseline emissions) is $4,919/ton of SO_2 removed, while cost effectiveness of a NID system at an SO_2 rate of 0.06 lb/MMBtu (ninety-two percent control of baseline emissions) is $3,845/ton of SO_2 removed. Because technologies with higher control efficiencies were within the range considered cost-effective, the costs of DSI were not evaluated.

c. Energy and Nonair Quality Environmental Impacts

SWEPCO concluded that although Wet FGD was expected to achieve a slightly higher level of SO_2 control compared to NID technology, a negative energy or nonair quality impact associated with Wet FGD was the generation of large volumes of wastewater and solid waste/sludge that must be treated. Also, Wet FGD systems have increased power requirements and increased reagent usage over Dry FGD, as well as the potential for increased particulate and sulfuric acid mist releases.

d. Remaining Useful Life

The remaining useful life of SWEPCO Flint Creek Plant Boiler No. 1 does not impact the annualized capital costs because the useful life of the unit is anticipated to be at least as long as the capital cost recovery period.

e. Degree of Visibility Improvement as a Result of Controls

Visibility improvements that would be anticipated from evaluated control technologies are included in Table 5-7 on page 5-9 of SWEPCO's 2013 BART analysis. Operation of NID at SWEPCO Flint Creek Plant Boiler No. 1 will result in up to a 0.647 deciview improvement to the existing visibility impairment and Wet FGD does not add additional visibility improvement over Dry FGD because Wet FGD results in other visibility impairing emissions.

f. BART Requirements for SO_2

SWEPCO proposed that BART to control SO_2 emissions from SWEPCO Flint Creek Plant Boiler No. 1 was NID technology with an expected emissions rate of 0.06 lb/MMBtu calculated as a 30-day rolling average over each boiler operating day. ADEQ concurs with this determination.

AO LIS No. 18-072 includes enforceable limitations and compliance dates consistent with ADEQ's BART determination.

2. Summary of BART Analysis and Requirements for PM

A BART determination for PM based on the existing ESP controls was included in the 2008 AR RH SIP and approved in EPA's March 12, 2012, final rule (77 FR 14604). This determination also approved the existing PM emissions rate of 0.10 lb/MMBtu. No changes are needed to EPA's determination with respect to the previously approved PM BART limit included in Regulation No. 19.

V. Reasonable Progress Analysis Framework for Arkansas in the First Planning Period

The 1999 RHR requires states to establish RPGs for each Class I area within the state. These goals must ensure reasonable progress consistent with the URP necessary to achieve natural visibility conditions by 2064 on the twenty percent worst days and no degradation on the twenty percent best days. The URP is also referred to as the "glidepath."

In establishing RPGs, the RHR requires states to consider four factors: (1) cost of compliance, (2) the time necessary for compliance, (3) the energy and nonair quality environmental impacts of compliance, and (4) the remaining useful life of potentially affected sources. If a state determines that additional progress beyond what is necessary to achieve the URP is reasonable, the RHR rule states that "the State should adopt that amount of progress as its goal for the first-long-term strategy." The RHR also requires states to provide a demonstration as part of the SIP if the State determines that the URP needed to reach natural conditions is not reasonable. In its 2007 reasonable progress guidance, EPA states that the "glidepath is not a presumptive limit and states may establish an RPG that provides for greater, lesser, or equivalent visibility improvement as that described by the glidepath."[27] The guidance also instructs the states in the following manner:

> In deciding what amount of emissions reduction is appropriate in setting the RPG, you should take into account the fact that the long-term goal of no manmade impairment encompasses several planning periods. It is reasonable for you to defer reductions to later planning periods in order to maintain a consistent glidepath toward the long-term goal.[28]

In the 2008 AR RH SIP, ADEQ established a URP for Caney Creek and Upper Buffalo based on the progress needed to reach natural conditions by 2064 in each area. The 2008 AR RH SIP established RPGs based on a combination of mandated controls, including BART requirements, and demonstrated that these measures would provide for a rate of progress that improves visibility conditions on the worst days at a rate that surpasses the URP and would prevent degradation on the best days. ADEQ reasoned that no four factor analysis was required because the State determined that no additional controls were necessary to ensure reasonable progress toward natural visibility by 2064 beyond those controls required for sources subject to BART requirements. Therefore, the 2008 AR RH SIP did not include a four-factor analysis.

In 2012, EPA issued a partial approval and a partial disapproval of the 2008 AR RH SIP. In this action, EPA approved the URP, but disapproved the RPGs because Arkansas did not complete a four-factor analysis to demonstrate that additional controls were not reasonable under 40 CFR 51.308(d)(1)(i)(A).[29] EPA's 2016 AR RH FIP included requirements for an additional non-BART facility, Entergy Independence, based on a four factor analysis of this single facility. EPA selected Independence for a four factor analysis due to the magnitude of its SO_2 and NOx emissions.

This submittal addresses EPA's disapproval of the reasonable progress analysis included in the 2008 AR RH SIP by considering key pollutants that contribute to visibility impairment in Arkansas Class I areas and using the four factors, as well as other factors relevant to reasonable progress, to assess whether controls on sources that are not subject to BART are reasonable. Technical supporting information for the reasonable progress analysis can be found in Appendix F.

CAA § 169A requires States to adopt a strategy for making reasonable progress toward improving visibility taking into account the statutory four reasonable progress factors. The 2007

[27] EPA (2007) Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program
[28] *Id.*
[29] Approval and Promulgation of Implementation Plans; Arkansas Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan to Address Pollution Affecting Visibility and Regional Haze: Proposed Rule (76 FR 64186 at 64195, October 17, 2011)

reasonable progress guidance provides that states have “flexibility in how to take into consideration these statutory factors that [the State] has determined to be relevant.”[30] ADEQ has determined that these four statutory factors are appropriately applied broadly to an array of sources state-wide rather than in a source-specific manner. However, due to the circumstances of the 2016 AR RH FIP, which applied the factors to a single facility, Independence, ADEQ has determined that application of the four factors to the specific source analyzed by EPA is also “relevant.” Therefore, ADEQ has performed both a broader analysis using the four factors as well as a more narrow analysis specific to Independence before determining whether any controls are necessary.

A. Identification of Key Pollutants and Source Categories That Contribute to Visibility Impairment in Arkansas Class I Areas

Included with the 2008 AR RH SIP, ADEQ provided emissions and air quality modeling performed by CENRAP in support of SIP development in the central states region.[31] As part of this modeling, the Particulate Source Apportionment Technology Tool (PSAT), included with CAMx Version 4.4, was used to provide source apportionment by geographic regions and major source categories for pollutants that contribute to visibility impairment at each of the Class I areas in the central states region.[32] The PSAT results demonstrate that sulfate (SO_4) from point sources is the principle driver of light extinction at both Arkansas Class I areas on the twenty percent worst days.

1. Regional Particulate Source Apportionment for Caney Creek and Upper Buffalo

Table 7 shows the modeled relative contributions to light extinction for each source category at Caney Creek and Upper Buffalo on the twenty-percent worst days in 2002. Point sources, responsible for approximately sixty percent of total light extinction at each Arkansas Class I area, are the primary contributor to light extinction on the twenty percent worst days. Area sources are the next largest contributor to light extinction at Arkansas Class I areas; however, area sources only contribute thirteen percent and sixteen percent of total light extinction at Caney Creek and Upper Buffalo, respectively. The other source categories each contribute between two percent and seven percent of total light extinction at Arkansas Class I areas.

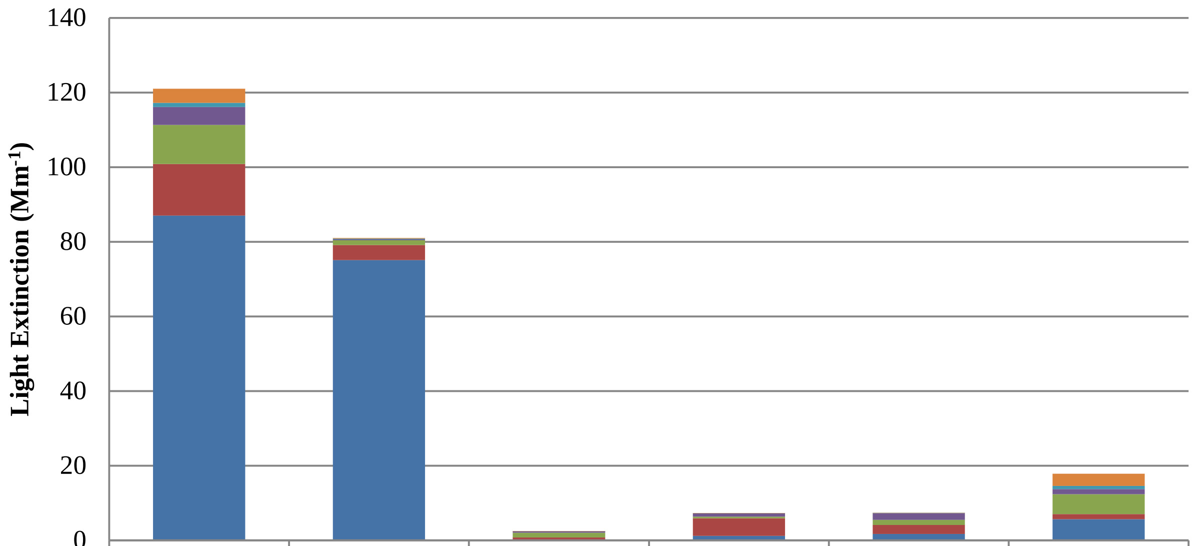
Table 7 Modeled Light Extinction for the 20% Worst Days at Caney Creek and Upper Buffalo in 2002 (Mm^{-1})

	Point	Natural	On-Road	Non-Road	Area
Caney Creek	81.04	2.45	7.26	7.31	17.81
Upper Buffalo	77.8	2.39	6.62	7.72	20.46

[30] EPA (2007) Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program
[31] The central states region includes Texas, Oklahoma, Louisiana, Arkansas, Kansas, Missouri, Nebraska, Iowa, Minnesota; and tribal governments included in these states.
[32] August 27, 2007 CENRAP PSAT tool: W20% Projected Bext;

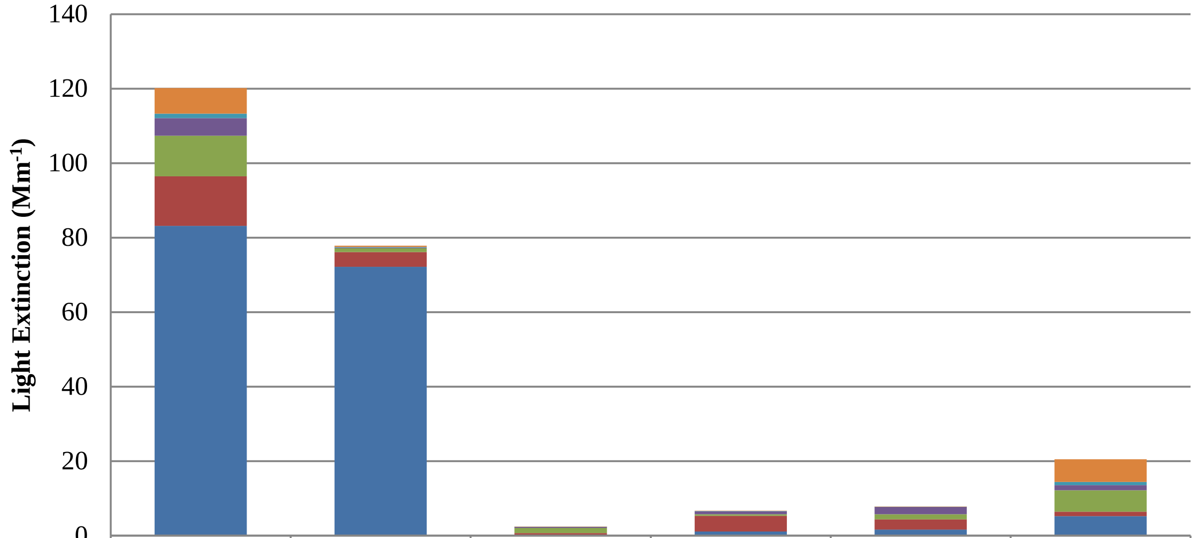
Figure 2 and Figure 3 show the modeled relative contributions to light extinction for each species and source category at Caney Creek and Upper Buffalo on the twenty percent worst days in 2002. According to the 2002 PSAT results, SO_4 contributed approximately sixty-five percent and sixty-three percent of modeled light extinction at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days in 2002. The point source category contributed eighty-six percent and eighty-seven percent of light extinction due to SO_4 at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days. The other source categories contribute much smaller proportions of light extinction due to SO_4. In fact, point sources of SO_4 contributed fifty-five to fifty-six percent of total light extinction at Arkansas Class I areas. By contrast, nitrate (NO_3) contributed approximately ten percent, primary organic aerosols (POA) contributed approximately eight percent, elemental carbon (EC) contributed approximately four percent, and soil contributed approximately one percent of modeled light extinction at both wilderness areas in 2002 on the twenty percent worst days. Crustal material (CM) contributed approximately three percent and five percent of modeled light extinction at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days. Relative contributions from on-road and point sources each represent approximately a third of light extinction attributed to NO_3. Area sources were the primary driver of light extinction attributed to POA, soil, and CM. Light extinction attributed to EC is primarily driven by non-road and area sources.

Figure 2 Modeled Light Extinction for the 20% Worst Days at Caney Creek in 2002



	All Source Categories	Point	Natural	On-Road	Non-Road	Area
CM	3.73	0.21	0.04	0.03	0.02	3.19
SOIL	1.12	0.19	0.01	0.01	0.01	0.87
EC	4.8	0.19	0.33	0.86	1.79	1.4
POA	10.5	1.29	1.33	0.46	1.34	5.32
NO3	13.78	4.06	0.64	4.7	2.45	1.37
SO4	87.05	75.1	0.09	1.19	1.7	5.66

Figure 3 Modeled Light Extinction for the 20% Worst Days at Upper Buffalo in 2002



	All Source Categories	Point	Natural	On-Road	Non-Road	Area
CM	6.85	0.29	0.05	0.05	0.02	6.02
SOIL	1.21	0.2	0.02	0.01	0.01	0.93
EC	4.72	0.16	0.31	0.8	1.93	1.3
POA	10.85	1.06	1.33	0.47	1.38	5.75
NO3	13.3	3.93	0.61	4.14	2.71	1.23
SO4	83.18	72.17	0.08	1.15	1.67	5.24

Table 8 shows the modeled relative contributions to light extinction for each source category at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days in 2018. Point sources are projected to remain the primary contributor to light extinction at Arkansas Class I areas. Point sources are projected to contribute approximately fifty-three percent of total light extinction at Caney Creek and fifty percent of total light extinction at Upper Buffalo on the twenty percent worst days in 2018. Area sources are also projected to continue to be the second largest contributor to light extinction with contributions of twenty percent of total light extinction at Caney Creek and twenty-three percent of total light extinction at Upper Buffalo on the twenty percent worst days in 2018. Natural, on-road, and non-road sources are projected to continue to contribute five percent of total light extinction at Arkansas Class I areas on the twenty percent worst days in 2018.

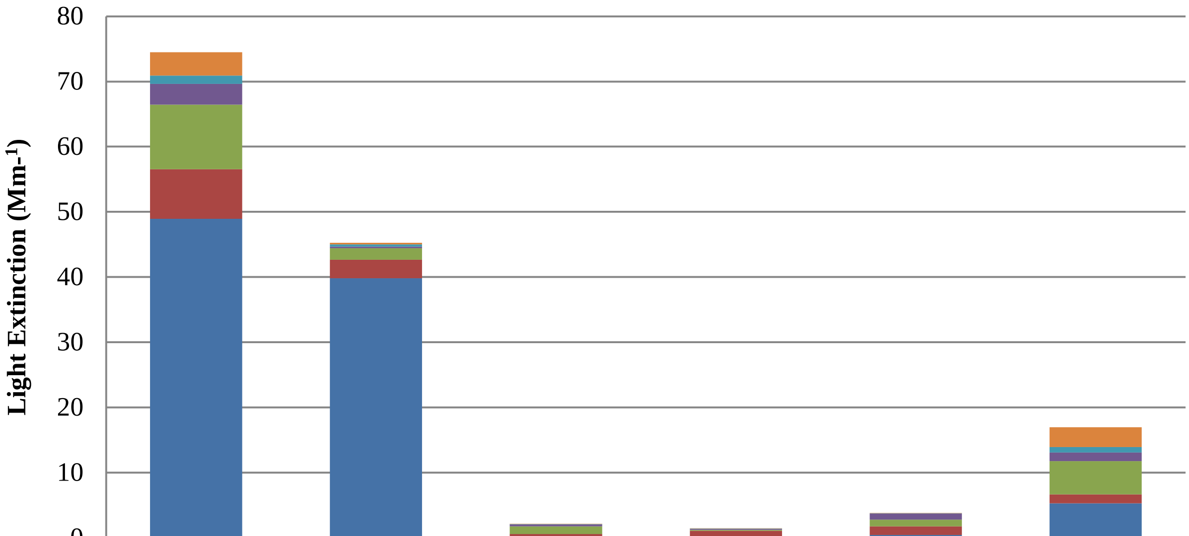
Table 8 Modeled Light Extinction for the 20% Worst Days at Caney Creek and Upper Buffalo in 2018 (Mm^{-1})

	Point	Natural	On-Road	Non-Road	Area
Caney Creek	45.27	2.12	1.44	3.76	16.96
Upper Buffalo	43.02	2.24	1.57	4.25	19.71

Figure 4 and Figure 5 show the modeled relative contributions to light extinction for each species and source category at Caney Creek and Upper Buffalo on the twenty percent worst days in

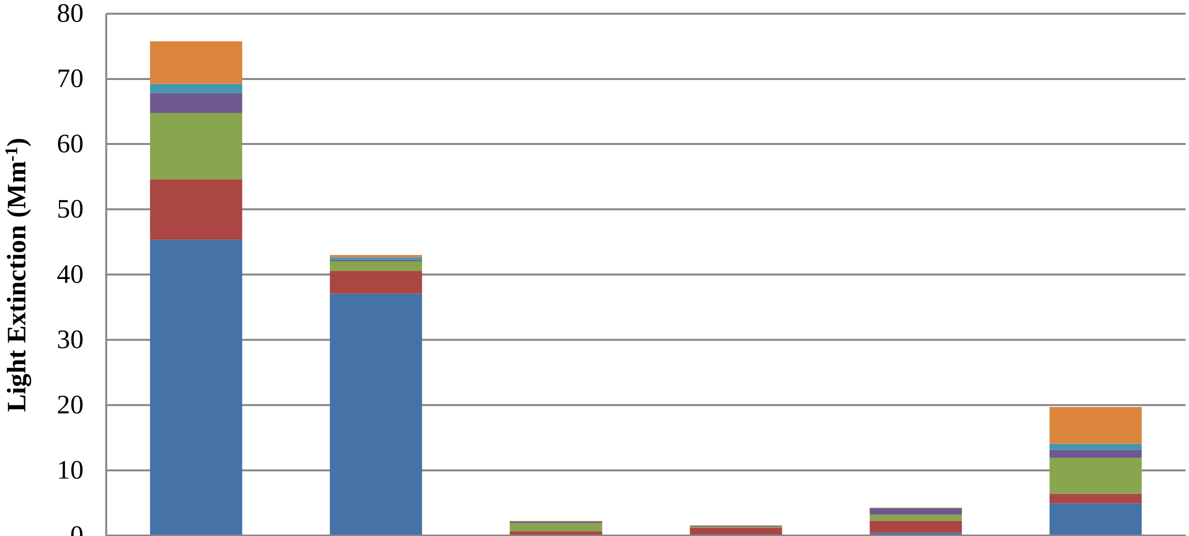
2018. According to the regional PSAT data, light extinction attributed to SO_4 is projected to decrease on the twenty percent worst days by forty-four percent at Caney Creek and by forty-five percent at Upper Buffalo between 2002 and 2018; however, SO_4 is projected to continue to be the primary driver of total light extinction. The 2018 projections show that point sources will continue to be the primary source of light extinction due to SO_4. Point sources of SO_4 are projected to contribute forty-three to forty-six percent of total light extinction on the twenty percent worst days in 2018 in Arkansas Class I areas. The other species are also projected to see reductions in their contribution to total light extinction; however, their relative contributions to total light extinction during 2018 remain much smaller than that of SO_4. Light extinction on the twenty percent worst days attributed to NO_3 from on-road sources is projected to decrease more rapidly than light extinction attributed to NO_3 from point sources; however, point sources of NO_3 will only contribute three to four percent of total light extinction at Arkansas Class I areas on the twenty percent worst days based on 2018 projections.

Figure 4 Modeled Light Extinction for the 20% Worst Days at Caney Creek in 2018



	All Source Categories	Point	Natural	On-Road	Non-Road	Area
CM	3.58	0.24	0.04	0.03	0.01	3.02
SOIL	1.29	0.35	0.01	0.01	0.01	0.87
EC	3.17	0.24	0.3	0.16	0.94	1.31
POA	9.93	1.76	1.18	0.14	1.03	5.09
NO3	7.57	2.84	0.53	0.97	1.33	1.37
SO4	48.95	39.83	0.07	0.12	0.44	5.31

Figure 5 Modeled Light Extinction for the 20% Worst Days at Upper Buffalo in 2018



	All Source Categories	Point	Natural	On-Road	Non-Road	Area
CM	6.53	0.36	0.05	0.04	0.02	5.65
SOIL	1.4	0.4	0.01	0.01	0.01	0.93
EC	3.07	0.21	0.28	0.15	0.99	1.21
POA	10.17	1.48	1.2	0.14	1.01	5.49
NO3	9.22	3.48	0.63	1.1	1.81	1.48
SO4	45.38	37.09	0.06	0.12	0.42	4.95

2. Arkansas Particulate Source Apportionment for Caney Creek and Upper Buffalo

The relative contribution of sources within Arkansas to total light extinction on the twenty percent worst days at both Arkansas Class I areas is small. Species attributed to Arkansas sources contributed approximately ten percent of total light extinction on the twenty percent worst days in Arkansas Class I areas according to 2002 data and are projected to contribute between thirteen and fourteen percent of total light extinction on the twenty percent worst days in Arkansas Class I areas in 2018. Total light extinction is projected to decrease by thirty-five percent on the twenty percent worst days at Arkansas Class I areas between 2002 and 2018. Light extinction on the twenty percent worst days attributed to species from Arkansas sources is projected to decrease by seventeen percent at Caney Creek and to decrease by eleven percent at Upper Buffalo between 2002 and 2018.

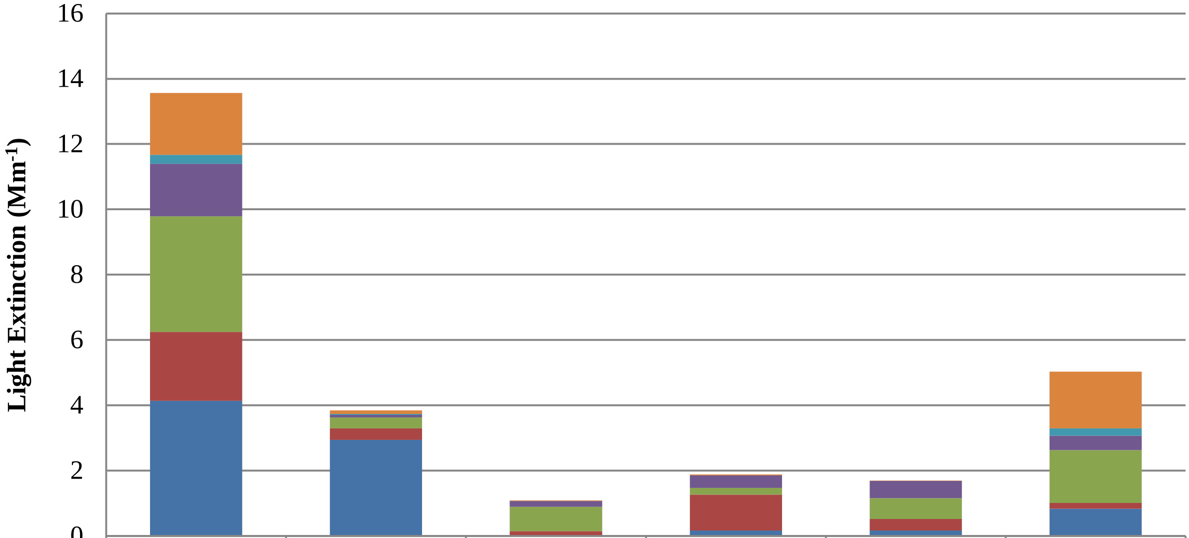
Table 9 shows the relative contributions of sources within Arkansas to light extinction for each source category at Caney Creek and Upper Buffalo on the twenty percent worst days in 2002. Area sources had a larger impact on light extinction than did point sources when only sources within Arkansas were considered. On the twenty percent worst days in 2002, area sources contributed approximately thirty-seven percent of light extinction attributed to Arkansas sources (four percent of total light extinction) at Caney Creek and fifty percent of light extinction attributed to Arkansas sources (five percent of total light extinction) at Upper Buffalo. Point sources contributed approximately twenty-eight percent of light extinction attributed to Arkansas sources (three percent of total light extinction) at Caney Creek and twenty-four percent of light extinction attributed to Arkansas sources (two percent of total light extinction) at Upper Buffalo on the twenty percent worst days. The other sources in Arkansas contributed between seven and fourteen percent each to light extinction attributed to Arkansas sources (approximately one percent each to total light extinction) at Arkansas Class I areas on the twenty percent worst days in 2002.

Table 9 Modeled Light Extinction due to Arkansas Sources for the 20% Worst Days at Caney Creek and Upper Buffalo in 2002 (Mm^{-1})

	Point	Natural	On-Road	Non-Road	Area
Caney Creek	3.85	1.1	1.88	1.72	5.03
Upper Buffalo	3.25	0.94	1.29	1.26	6.72

Figure 6 and Figure 7 show the relative contributions of sources within Arkansas to light extinction for each source category and species at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days in 2002. SO_4 from Arkansas sources contributed approximately three percent of total modeled l extinction at Caney Creek and Upper Buffalo in 2002 on the twenty percent worst days. The point source category contributed approximately two thirds of the light extinction attributed to SO_4 from Arkansas sources at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days in 2002. POA from Arkansas sources contributed approximately three percent and two percent of total light extinction on the twenty percent worst days at Caney Creek and Upper Buffalo, respectively. Area sources were the primary driver of light extinction due to POA. NO_3 from Arkansas sources contributed approximately two percent and one percent to light extinction at Caney Creek and Upper Buffalo on the twenty percent worst days, respectively. On-road sources accounted for approximately fifty percent of the light extinction at Arkansas Class I areas attributed to Arkansas NO_3 sources. EC from Arkansas sources contributed approximately one percent and soil from Arkansas sources contributed approximately 0.2% to total light extinction at both Arkansas Class I areas on the twenty percent worst days. Attribution to light extinction from Arkansas sources of EC was split primarily among on-road, non-road, and area sources. Light extinction from Arkansas sources of soil was primarily attributed to area sources. CM from Arkansas sources, primarily area sources, contributed approximately one and two percent of total light extinction and Caney Creek and Upper Buffalo, respectively.

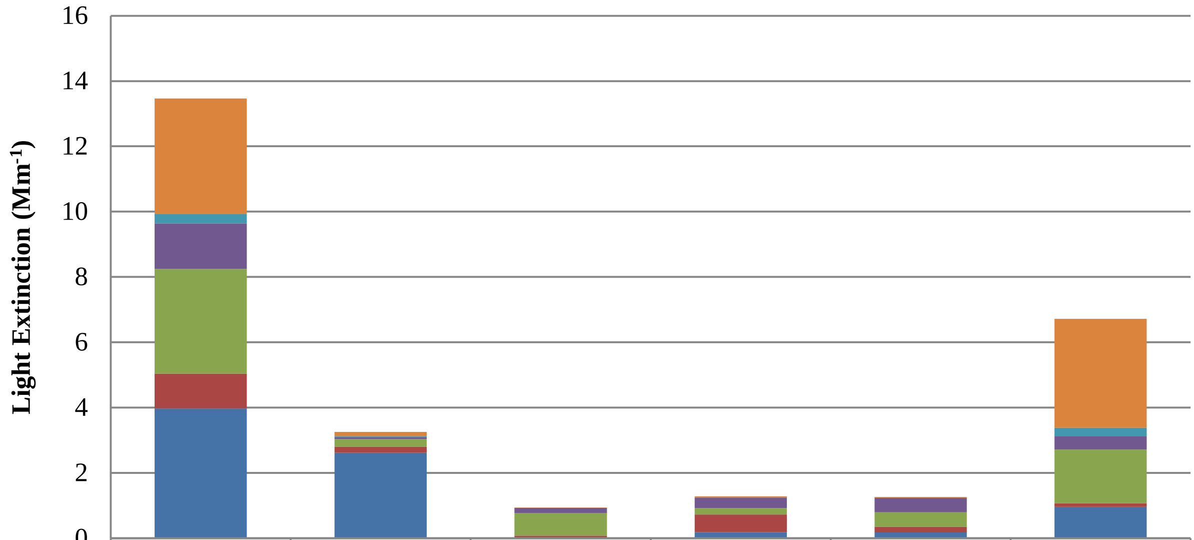
Figure 6 Modeled Light Extinction due to Arkansas Sources for the 20% Worst Days at Caney Creek in 2002[33]



	All Source Categories	Point	Natural	On-Road	Non-Road	Area
CM	1.89	0.1	0.02	0.03	0.01	1.73
SOIL	0.27	0.03	0	0	0	0.23
EC	1.61	0.08	0.18	0.38	0.53	0.44
POA	3.54	0.33	0.74	0.21	0.64	1.62
NO3	2.11	0.36	0.12	1.09	0.35	0.18
SO4	4.14	2.94	0.03	0.17	0.17	0.83

[33] All values have been rounded to the second decimal place. Values less than 0.005 have been rounded down to 0.

Figure 7 Modeled Light Extinction due to Arkansas Sources for the 20% Worst Days at Upper Buffalo in 2002[34]



	All Source Categories	Point	Natural	On-Road	Non-Road	Area
CM	3.53	0.13	0.01	0.03	0.02	3.34
SOIL	0.3	0.03	0	0	0	0.26
EC	1.39	0.06	0.16	0.33	0.45	0.4
POA	3.21	0.24	0.69	0.19	0.44	1.65
NO3	1.07	0.18	0.06	0.54	0.17	0.11
SO4	3.97	2.62	0.02	0.19	0.18	0.96

Table 10 shows the relative contributions of sources within Arkansas to light extinction for each source category at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days in 2018. Area sources are projected to continue to have a larger impact on light extinction than do point sources when only sources located in Arkansas are considered. Area sources are projected to contribute approximately forty-three percent of light extinction attributed to Arkansas sources (six percent of total light extinction) at Caney Creek and fifty-four percent of light extinction attributed to Arkansas sources (eight percent of total light extinction) at Upper Buffalo. Point sources are projected to contribute approximately thirty-six percent of light extinction attributed to Arkansas sources (five percent of total light extinction) at Caney Creek and thirty percent of light extinction attributed to Arkansas sources (four percent of total light extinction) at Upper Buffalo. The other sources in Arkansas are projected to contribute between two percent and nine percent each to light extinction from Arkansas sources (0.3–1.2% of total light extinction) at Arkansas Class I areas on the twenty percent worst days in 2018.

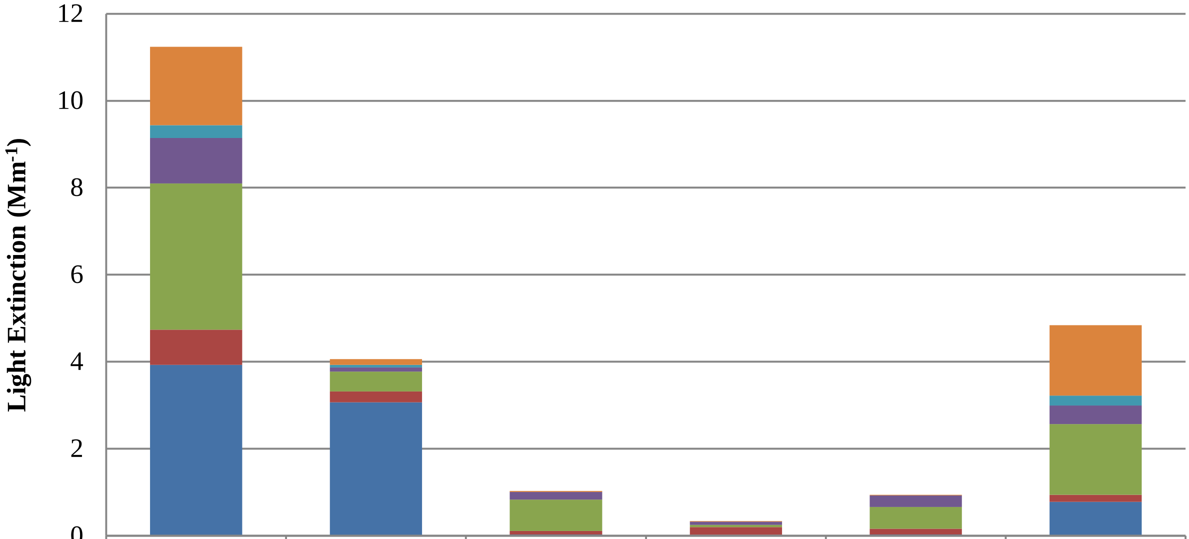
[34] All values have been rounded to the second decimal place. Values less than 0.005 have been rounded down to 0.

Table 10 Modeled Light Extinction due to Arkansas Sources for the 20% Worst Days at Caney Creek and Upper Buffalo in 2018 (Mm^{-1})

	Point	Natural	On-Road	Non-Road	Area
Caney Creek	4.05	1.04	0.35	0.95	4.85
Upper Buffalo	3.63	0.91	0.3	0.66	6.52

Figure 8 and Figure 9 show the relative contributions of sources within Arkansas to light extinction for each species and source category at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days in 2018. According to the PSAT data for Arkansas sources, light extinction attributed to Arkansas NO_3 sources is projected to decrease by sixty-two percent at Caney Creek and by forty-one percent at Upper Buffalo. This projected decrease is largely due to a decrease in light extinction attributed to NO_3 from Arkansas on-road sources. Overall light extinction attributed to Arkansas sources of SO_4 are projected to decrease at Arkansas Class I areas; however, light extinction attributed to point sources of SO_4 located in Arkansas is projected to increase by four percent at Caney Creek and five percent at Upper Buffalo on the twenty percent worst days. Nevertheless, the contribution to total light extinction of SO_4 from Arkansas point sources remains relatively small—three percent of total light extinction at each Arkansas Class I area. Light extinction due to Arkansas sources of POA, EC, and CM are also projected to decrease. Light extinction due to Arkansas sources of soil is projected to increase; but, soil will remain the smallest Arkansas contributor to light extinction at both Arkansas Class I areas.

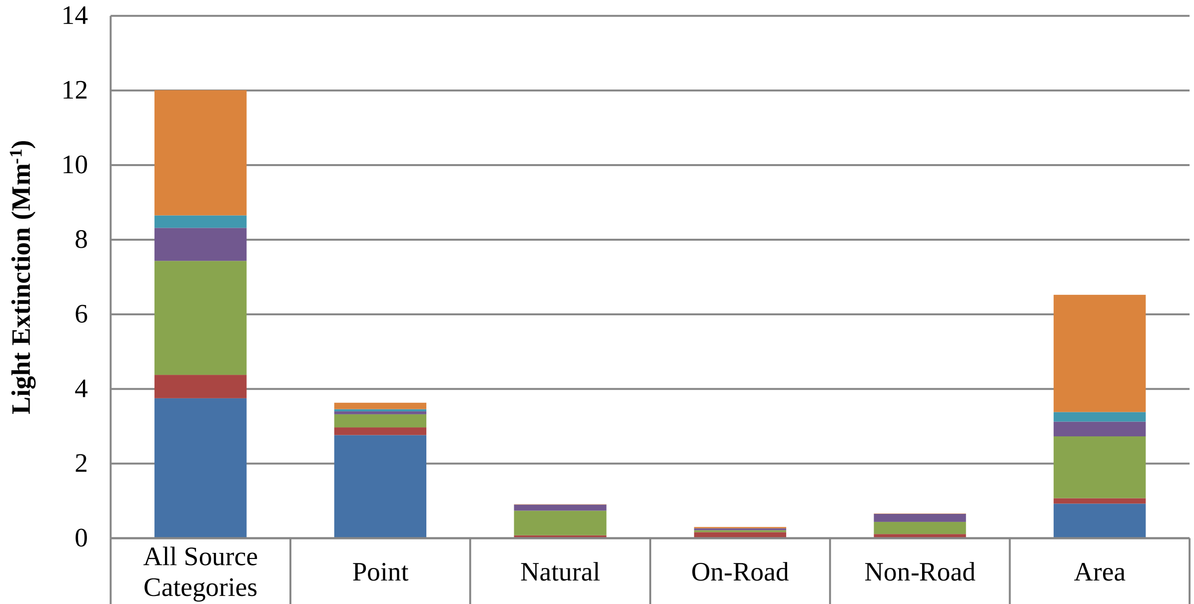
Figure 8 Modeled Light Extinction due to Arkansas Sources for the 20% Worst Days at Caney Creek in 2018[35]



	All Source Categories	Point	Natural	On-Road	Non-Road	Area
CM	1.8	0.13	0.02	0.02	0.01	1.62
SOIL	0.3	0.06	0	0	0	0.23
EC	1.04	0.1	0.18	0.07	0.27	0.42
POA	3.36	0.45	0.72	0.05	0.5	1.63
NO3	0.81	0.25	0.08	0.18	0.13	0.16
SO4	3.93	3.07	0.03	0.02	0.03	0.78

[35] All values have been rounded to the second decimal place. Values less than 0.005 have been rounded down to 0.

Figure 9 Modeled Light Extinction due to Arkansas Sources for the 20% Worst Days at Upper Buffalo in 2018[36]



	All Source Categories	Point	Natural	On-Road	Non-Road	Area
CM	3.36	0.17	0.01	0.03	0.01	3.14
SOIL	0.33	0.06	0	0	0	0.26
EC	0.89	0.08	0.16	0.06	0.21	0.39
POA	3.05	0.35	0.66	0.05	0.33	1.66
NO3	0.63	0.21	0.06	0.14	0.09	0.14
SO4	3.75	2.76	0.02	0.02	0.02	0.93

3. Summary of Key Pollutant and Source Category Findings

The region-wide PSAT data indicate that the relative contribution of SO_4 to light extinction at Arkansas Class I areas is much higher than for other pollutants on the twenty percent worst days. The majority of light extinction due to SO_4 can be attributed to point sources. The PSAT results for Arkansas sources illustrate that the relative contribution to light extinction of the various species from Arkansas sources is not as weighted toward SO_4 as the regional data set showed. Approximately a quarter of light extinction at Arkansas Class I areas resulting from sources located in Arkansas can be attributed to point sources of SO_4. Light extinction from all species associated with the point source category is smaller than for area sources when only sources located in Arkansas are considered. POA and CM are the primary species associated with area source contributions to light extinction.

After examining both region-wide PSAT data and data for Arkansas sources, ADEQ has identified SO_4 as the key species contributing to light extinction at Caney Creek and Upper Buffalo. Area sources do contribute a larger proportion of total light extinction when only sources located in Arkansas are considered; however, the cost-effectiveness for control of POA

[36] All values have been rounded to the second decimal place. Values less than 0.005 have been rounded down to 0.

and CM species from many individual small sources is difficult to quantify. Only a small proportion of total light extinction is due to NO_3 from Arkansas sources and this proportion has historically been driven by onroad sources. NO_3 from Arkansas point sources contributed less than half a percent of total light extinction on the twenty percent worst days at Caney Creek and Upper Buffalo based on 2002 PSAT data and is projected to contribute even less in 2018. Attribution of light extinction to soil and EC for Caney Creek and Upper Buffalo remain in both regional and Arkansas data sets.

The primary driver of SO_4 formation is emissions of SO_2 from point sources both region-wide and in Arkansas. As such, in this SIP ADEQ evaluates sources emitting at least 250 tons per year (tpy) of SO_2. These sources will be evaluated to determine whether their emissions and proximity to Arkansas Class I areas warrant further analysis using the four statutory factors.

B. Reasonable Progress Factors Broadly Applicable to Arkansas Sources

1. Visibility

ADEQ has determined that visibility is a relevant factor for statewide consideration in this reasonable progress analysis. Restoring natural visibility conditions in Class I areas is the central goal of the Regional Haze Program. As stated in 42 U.S.C.A. § 7491, Congress declared “as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution.” As such, ADEQ finds that visibility is the necessary context within which to view whether additional controls are reasonable in the first planning period.

Visibility has improved substantially in Arkansas Class I areas, and the Natural State is approaching natural background conditions more rapidly than the glidepath would indicate is necessary to achieve the goal of natural visibility conditions in Arkansas Class I areas by 2064.[37] Specifically, as reflected in both ADEQ’s Five Year Progress Report and the Regional Haze Modeling Assessment Report, Entergy Arkansas, Inc. – Independence Plant, Trinity Consultants (August 4, 2015) visibility conditions in Caney Creek and the Upper Buffalo for the 20% worst days are improving more rapidly than necessary to achieve the URP, ADEQ’s disapproved Reasonable Progress goals, and EPA’s Reasonable Progress Goals imposed in the Regional Haze FIP.[38] Moreover, according to 2016 IMPROVE monitoring data, visibility improvements at Arkansas Class I areas are already greater than the Reasonable Progress Goals in the AR RH FIP.[39] Figures 10 and 11 demonstrate visibility progress for the twenty percent worst days at Arkansas Class I areas.

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[37] See discussion *infra* Part V.A.1.
[38] ADEQ’s Five Year Progress Report; Regional Haze Modeling Assessment Report, Entergy Arkansas, Inc. – Independence Plant, Trinity Consultants (August 4, 2015).
[39] Visibility Status and Trends Following the Regional Haze Rule Metrics: IMPROVE Aerosol, Regional Haze Rule II (New Equation), with substituted data. Caney Creek, Upper Buffalo, http://views.cira.colostate.edu/fed/SiteBrowser/Default.aspx.

Figure 10 Visibility Progress at Caney Creek – 20% Worst Days

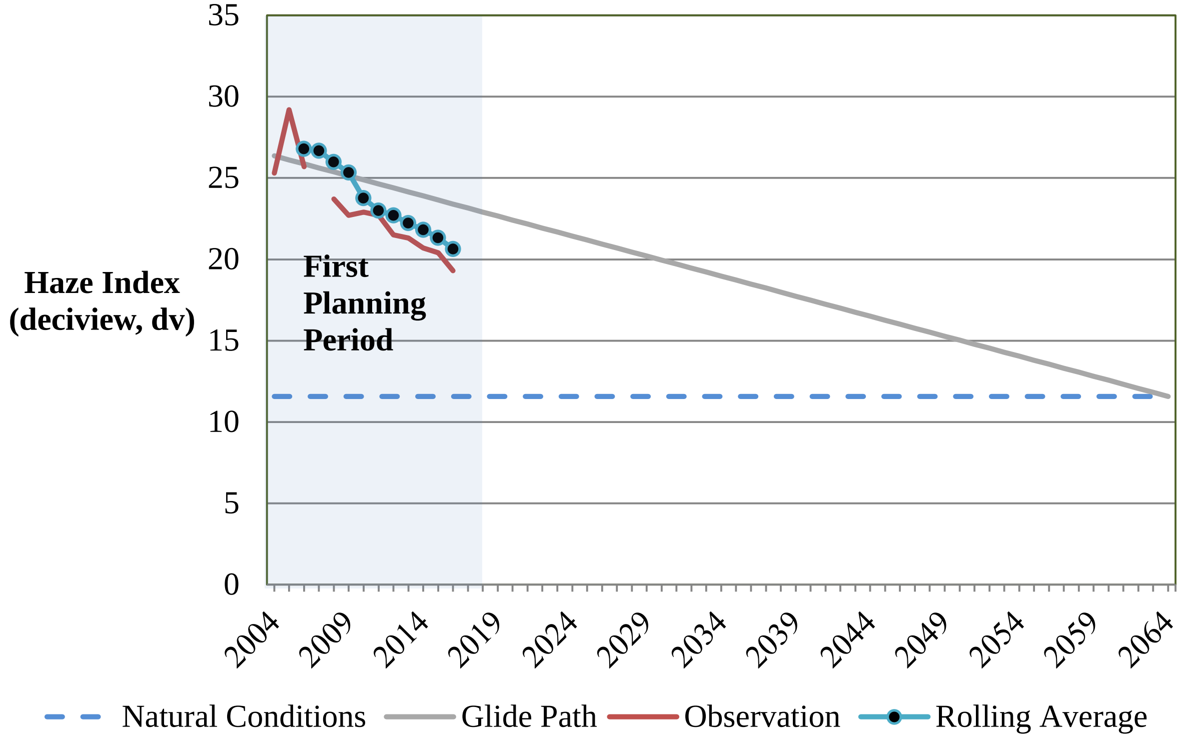
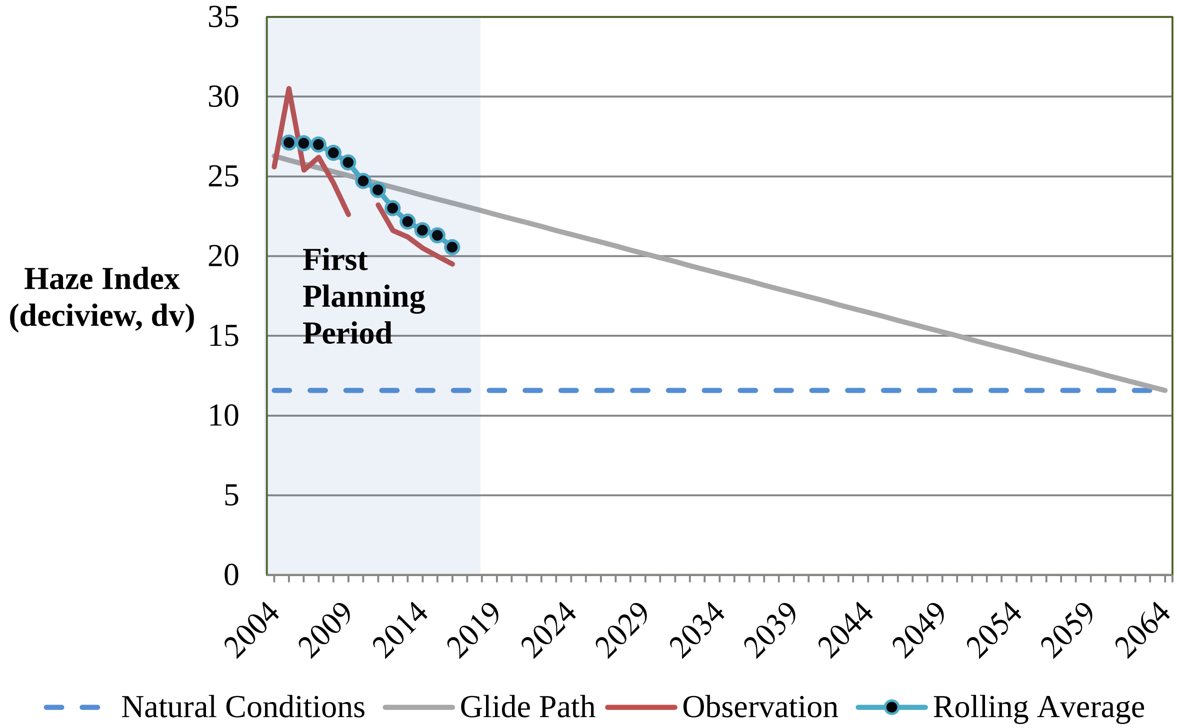


Figure 11 Visibility Progress at Upper Buffalo – 20% Worst Days



As shown by Figures 10 and 11, Arkansas Class I areas are making greater progress toward natural visibility than would result from a URP toward the 2064 goal, even before consideration of the controls included in this SIP. The visibility improvements observed in these Class I areas are a result of reductions from State and federal programs; including new source performance standards for a variety of source types, vehicle emissions standards, changes in NAAQS; innovations in emissions control technologies; retirement or reconstruction of older facilities; and market-driven changes in electricity generation. The BART controls required by this SIP will further keep Arkansas Class I areas on track for achieving natural visibility conditions on or before 2064.

The visibility trajectory in Arkansas's Class I areas is an additional relevant factor for consideration of whether any additional controls are necessary to ensure reasonable progress during this first ten year planning period. If Arkansas Class I areas were making less progress than necessary to achieve the URP during this 2008–2018 planning period, more costly controls could be warranted if found reasonable after consideration of the four statutory factors and other relevant factors. However, Arkansas Class I areas are already below the 2018 point on the URP; therefore, it is reasonable to consider this visibility progress, in addition to the mandatory reasonable progress factors, when evaluating whether additional controls for key pollutants at source categories contributing to visibility impairment are necessary for achieving reasonable progress during the first planning period.

2. Costs of Compliance

The 2007 Reasonable Progress Guidance states that the cost of compliance "can be interpreted to encompass . . . the implication of compliance costs to the health and vitality of industries within a state."[40] In the AR RH FIP, EPA imposed over $2 billion in SO_2 control costs over the next thirty years for the purposes of reasonable progress based solely on cost-effectiveness. By contrast, ADEQ has determined that a broader interpretation, as stated in the guidance, is appropriate for analysis in this context for reasons including the visibility trends identified above.

Additional costs of compliance would create negative impacts on the health and vitality of industries within the State. These additional costs would have even greater negative impacts if additional SO_2 controls were imposed on the electricity sector. ADEQ notes that energy companies are permitted to recover costs related to the installation of emissions control technologies at EGUs required by the final SIP from electricity ratepayers subject to approval by the Arkansas Public Service Commission.[41] Any additional costs to EGUs in the form of required emissions control technologies would be allowed to be passed on to Arkansas ratepayers, including a variety of industries. Energy-intensive industries would be disproportionately impacted by additional costs of controls on the EGUs.

Further discussion of these and other costs related specifically to Independence, the sole facility mandated to control for reasonable progress in the AR RH FIP, is set forth more fully below in Part V.D.4.

[40] EPA (2007) Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program at p. 5-1.
[41] Ark. Code Ann. § 23-4-501

3. Time Necessary for Compliance

The time necessary for compliance varies depending on control technologies considered. The time necessary for compliance for SO_2 control technologies considered for BART in this SIP was typically three to five years, unless progress had already been made toward implementing those control technologies.

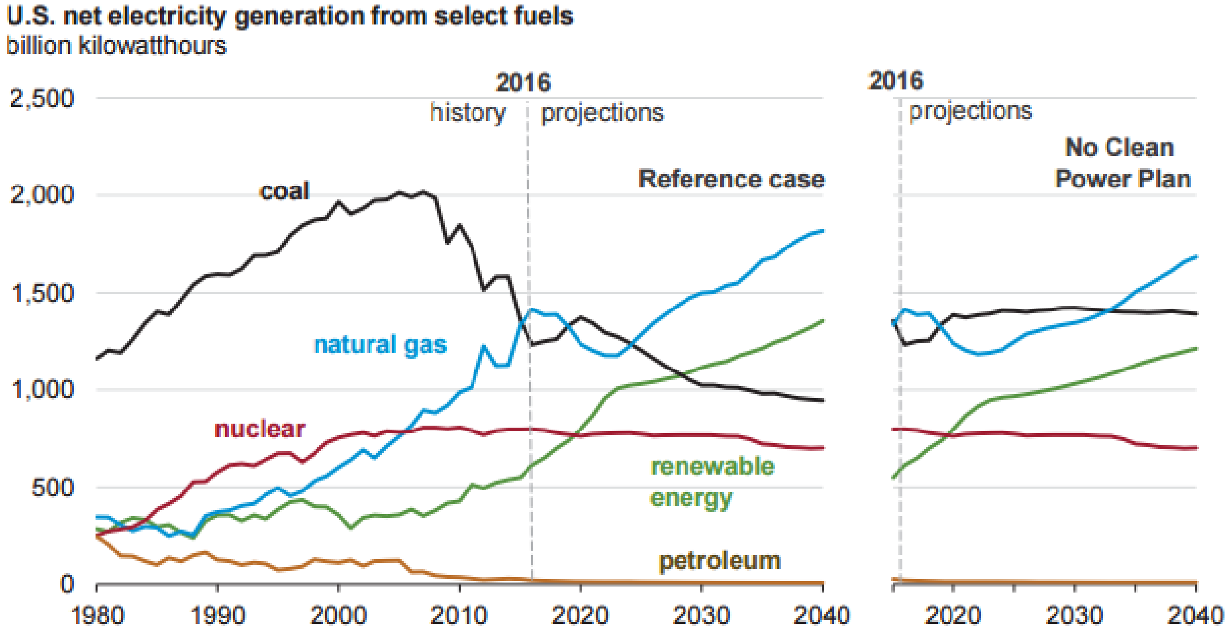
4. Energy & Non-Air Quality Impacts of Compliance

SO_2 control technologies have negative energy and non-air quality impacts including temporary outages required for the installation of such controls, parasitic load, and new waste products. The installation of additional control technologies on Arkansas EGUs including dry and wet scrubbers may have negative impacts including temporary outages required for the installation of such controls, which would temporarily disrupt the supply of electricity to the grid. Similarly, certain control technologies will reduce the generating capacity of particular EGU, which is referred to as a parasitic load.

Energy markets are already producing energy sector trends that are conducive for visibility improvement in Arkansas Class I areas. Market trends for coal and natural gas have resulted in decreased dispatch of coal-fired facilities broadly. This, in turn, decreases the overall amounts of key pollutants that impact visibility: SO_2, NOx, and $PM_{2.5}$. According to data from the Energy Information Administration, the economic pressure on coal units due to low natural gas prices is expected to continue throughout the rest of the first planning period and beyond.[42] Figure 12 shows energy consumption trends from the electricity sector by fuel from 1980–2016 and projects trends out to 2040.

[42] U.S. Energy Information (2017). "Annual Energy Outlook 2017" <https://www.eia.gov/outlooks/aeo/pdf/0383(2017).pdf>

Figure 12 United States Electricity Sector Energy Consumption by Fuel[43]



5. Remaining Useful Life of Potentially Affected Sources

The 2007 Reasonable Progress Guidance states that "this factor is generally best treated as one element of the overall costs analysis." If the remaining useful life for a given facility is less than the typical amortization period for new control equipment, the annualized cost and the controls become less cost-effective. In addition, the cost of controls may result in an economic decision to discontinue operations, thus truncating the remaining useful life of a source.

C. Evaluation of SO_2 Point Sources

In addition to the statewide reasonable progress analysis above, ADEQ has also examined, sources that emitted at least 250 tpy of sulfur dioxide as reported to the EPA Emission Inventory System (EIS) in any given year between 2002 and 2015 in order to determine which sources to evaluate as a rebuttal of the analysis employed by EPA in the AR RH FIP.[44] For those sources that participate in the Acid Rain Program, ADEQ obtained 2015 sulfur dioxide emissions from the Air Markets Program Data tool.[45] ADEQ then narrowed the list of sources to eleven sources that emitted at least 250 tons per year averaged over most recent three-year period for which data is available. These sources are listed in Table 11 below.

[43] U.S. Energy Information (2017). "Annual Energy Outlook 2017" At 70 <https://www.eia.gov/outlooks/aeo/pdf/0383(2017).pdf>

[44] Emissions Inventory datasets: 2002 National Emissions Inventory, 2005 National Emissions Inventory, 2008 National Emissions Inventory V3, 2009 Arkansas Department of Environmental Quality, 2010 Arkansas Department of Environmental Quality, 2011 National Emissions Inventory V2, 2012 Arkansas Department of Environmental Quality, 2013 Arkansas Department of Environmental Quality, 2014 National Emissions Inventory V1, and 2015 Arkansas Department of Environmental Quality.

[45] https://ampd.epa.gov/ampd/

Table 11 Sulfur Dioxide Emissions from Sources Emitting Greater Than 250 Tons per Year

Facility	Most Recent Three-Year Period	Average Sulfur Dioxide Emissions (Tons Per Year)
Entergy White Bluff*	2014–2016	24,346
Entergy Independence	2014–2016	22,531
Flint Creek Power Plant (SWEPCO)*	2014–2016	5,350
Plum Point Energy Station Unit 1	2014–2016	2,759
FutureFuel Chemical Company	2013–2015	2,837
Domtar A.W. LLC, Ashdown Mill*	2013–2015	1,553
Evergreen Packaging-Pine Bluff	2013–2015	986
Albemarle Corporation-South Plant	2013–2015	1,382
SWEPCO- John W. Turk Jr. Power Plant	2014–2016	908
Ash Grove Cement Company/Foreman Cement Plant	2013–2015	369
Nucor-Yamato Steel Company	2013–2015	301

*Facilities are subject to BART requirements which satisfy the four factor analysis requirement for reasonable progress for these sources.

Entergy White Bluff, Flint Creek, and Domtar are all subject to BART. Since the BART analyses conducted to establish BART control requirements are based on an assessment of many of the same factors that must be addressed in establishing the reasonable progress goals, these control requirements satisfy the reasonable progress goal-related requirements for review of these sources during this planning period. No additional emissions controls are necessary for these sources. For the other sources listed in Table 11, ADEQ calculated the total average actual emissions rate (Q) in tons of SO_2 per year over the most recent three-year period and determined the distance (D) in kilometers of each source to its closest Class I area. A Q divided by D value of ten was used as a threshold for further evaluation of reasonable progress controls. This value was selected based on guidance contained in the BART guidelines and is consistent with the approach used in other EPA rulemakings.[46] Table 12 lists the Q/D values for these sources.

Table 12 Q/D Values for Large SO_2 Point Sources[47]

Facility	Upper Buffalo	Caney Creek
Entergy Independence	126	81
Plum Point Energy Station Unit 1	9	7
FutureFuel Chemical Company	17	10
Evergreen Packaging-Pine Bluff	4	5
Albemarle Corporation-South Plant	5	9
SWEPCO- John W. Turk Jr. Power Plant	4	11

[46] 40 CFR part 51, app. Y, § III; Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Proposed Rule (February 18, 2014)
[47] Class I Areas_Q Over D Calculations.xls in Appendix F.

Ash Grove Cement Company/Foreman Cement Plant	1	5
Nucor-Yamato Steel Company	1	1

Three sources identified in Table 12 had a maximum Q/D value greater than or equal to ten: Entergy Independence, FutureFuel Chemical Company, and John W. Turk Jr. Power Plant. Entergy Independence is the second largest point source of SO_2 in Arkansas with average 2014–2016 emissions of 22,531 tpy. By contrast, FutureFuel Chemical Company averaged 2,837 tpy (2013–2015) and John W. Turk Jr. Power Plant averaged 908 tpy (2014–2016). SO_2 emissions from FutureFuel Chemical Company and John W. Turk Jr. Power Plant are approximately an order of magnitude lower than emissions from Entergy Independence. FutureFuel Chemical Company was a BART-eligible source. In the 2008 AR RH SIP, ADEQ determined that FutureFuel Chemical was not subject-to-BART based on modeling conducted for the development of that SIP. Therefore, ADEQ does not find it necessary to further evaluate controls for this facility for this planning period. John W. Turk Jr. Power Plant began operation in 2012 and has implemented best available control technology, which is more stringent than BART; therefore, ADEQ does not anticipate that more stringent controls would be available and/or reasonable for this planning period.

Entergy Independence is not a BART-eligible facility and was required by the AR RH FIP to install controls for the purpose of ensuring reasonable progress. Due to these unique circumstances, ADEQ finds that Independence specifically warrants further consideration under the reasonable progress factors.

D. Consideration of Reasonable Progress Factors for Entergy Independence.

In determining reasonable progress, Clean Air Act section 169(A)(g)(1) requires states to examine the cost of compliance, the time necessary for compliance, energy and nonair impacts, and remaining useful life. In development of the AR RH FIP, EPA performed a reasonable progress analysis that considered two control technologies for Entergy Independence: Wet FGD and Dry FGD.

Entergy provided additional information regarding EPA's analysis in comments on the AR RH FIP, including a proposal to switch to LSC at Independence. Entergy also provided additional information with respect to costs associated with the use of LSC for Entergy White Bluff in an August 18, 2017 submittal. ADEQ's proposed analysis was based on the data provided by EPA in support of the AR RH FIP as supplemented by Entergy. In comments on ADEQ's proposed analysis, Entergy provided additional Independence-specific cost-estimates and modeled benefits anticipated for LSC. ADEQ's final analysis replaces White Bluff data used as a surrogate for Independence with Independence-specific information.

The Entergy Independence Power Plant is a coal-fired electric generating station with two identical 900 megawatt boilers. These boilers burn Wyoming Powder River Basin sub-bituminous coal as their primary fuel and No. 2 fuel oil or bio-diesel as start-up fuel. The layout and boiler units used at this facility are similar to those used at Entergy White Bluff; however, construction at the units at Independence began in 1978 and operation in 1983; therefore, the units are not subject to BART.

The available SO_2 retrofit control technology options for Entergy Independence Units 1 and 2 considered in the AR RH FIP and in this SIP revision are fuel switching to LSC, Dry FGD and Wet FGD. All three options are technically feasible. Fuel switching to coal with a sulfur content of 0.6 lb/MMBtu would result in a four to six percent reduction in SO_2 emissions from 2009–2013 levels.[48] Dry FGD systems have control efficiencies ranging from sixty to ninety-five percent. These systems utilize a fine mist of lime slurry sprayed into an absorption tower to absorb SO_2. The resulting calcium sulfite and calcium sulfate are then collected with a fabric filter. Wet FGD, scrubbing the exhaust stream with a lime or limestone slurry, is capable of achieving eighty-to ninety-five percent control of SO_2 emissions.

1. Existing controls

Each of the Entergy Independence units are subject to a prevention of significant deterioration (PSD) emissions limitation of 0.93 lb/MMBtu is in effect for these units. Entergy Independence Units 1 and 2 are currently permitted to emit 35,438.6 tons per year (tpy) of SO_2 (8,091.0 lb SO_2/hr) each or 70,877.2 tpy of SO_2 (16,182 lb SO_2/hr) combined.[49] Annual emissions for Entergy Independence Units 1 and 2 combined from 2008–2014 ranged from 26,448–32,974 tpy SO_2—less than half of total allowable emissions in their permit.[50] Annual emissions from Entergy Independence dropped to 14,994 tpy SO_2 in 2015—less than a quarter of total allowable emissions in their permit.[51] Annual emissions from Entergy Independence increased to 22,569 SO_2 in 2016, but are lower than any annual emissions rate from 2008–2014.[52]

As previously discussed in Section V.B.4. of this SIP, market trends for coal and natural gas have resulted in decreased dispatch of coal-fired EGUs, which includes Entergy Independence.

2. Degree of Improvement in Visibility Anticipated from Evaluated Controls

Although the degree of visibility improvement is not one of the four statutory factors for a reasonable progress analysis, the ultimate goal of any reasonable progress controls should be achieving visibility improvements.

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[48] Calculated based on a comparison of the maximum 30 boiler operating day SO_2 emission rate during 2009–2013 to a 0.6 lb/MMBtu limit for low sulfur coal. This baseline was selected to match the EPA baseline used to calculate control efficiency and cost-effectiveness values for Dry FGD and Wet FGD.

[49] Entergy Arkansas, Inc. – Independence, Permit No. 0449-AOP-R10 AFIN: 32-00042

[50] 2009 Arkansas Department of Environmental Quality Emissions Inventory, 2010 Arkansas Department of Environmental Quality Emissions Inventory, 2011 National Emissions Inventory Version 2, 2012 Arkansas Department of Environmental Quality Emissions Inventory, 2013 Arkansas Department of Environmental Quality Emissions Inventory, 2014 National Emissions Inventory Version 1 <https://eis.epa.gov/eis-system-web>

[51] Air Markets Program Data: Air Markets Program Data: Annual SO_2 Data for Entergy Independence for 2015 <https://ampd.epa.gov/ampd/>

[52] Air Markets Program Data: Air Markets Program Data: Quarterly SO_2 Data for Entergy Independence for 2015 and 2016 <https://ampd.epa.gov/ampd/>

In the AR RH FIP, EPA estimated, using the CALPUFF model, that installation of Dry FGD at Entergy Independence Unit 1 and Unit 2 would achieve a 1.096 deciview improvement at Caney Creek and a 1.178 deciview improvement at Upper Buffalo.[53] In comments on the AR RH FIP, Entergy disagreed with EPA's estimates of visibility improvements that would be achieved from installation of Dry FGD at Entergy Independence. Using scaled results from CAMx, a photochemical model, instead of the CALPUFF model, Entergy estimated that installation of Dry FGD at Independence would only result in a 0.08 deciview improvement at Caney Creek and a 0.07 deciview improvement at Upper Buffalo on the twenty percent worst days.[54] A value of one deciview is considered perceptible.

In comments on the proposed SIP, Entergy included CALPUFF modeling results for LSC at Entergy Independence Unit 1 and Unit 2 estimating a 0.112 deciview improvement at Caney Creek and a 0.236 deciview improvement at Upper Buffalo based on ninety-eighth percentile values.[55]

3. Remaining Useful Life

There are no State or federally enforceable limitations on continued operations at Entergy Independence; therefore, cost of compliance calculations are based upon a thirty-year amortization period for Dry and Wet FGD. However, Entergy has expressed its intention of ceasing coal-fired operations at Independence by the end of 2030. In addition, market pressures may also impact continued operations at Independence, including changes in dispatch and economic decisions concerning the continued viability of the units. Although the cost of compliance for control technologies evaluated in this SIP are based on a thirty-year amortization period, ADEQ recognizes that Entergy's choices may result in a remaining useful life of less than thirty years and thus higher annual costs associated with controls evaluated.

4. Cost of Compliance

In the AR RH FIP, EPA estimated cost-effectiveness for the Dry FGD and Wet FGD for Entergy Independence based on five-factor BART analysis for White Bluff. Entergy provided different cost-effectiveness values for Dry FGD estimates in their comments on the AR RH FIP and also submitted Independence Dry FGD cost estimates in Exhibit I to their comments on the proposed SIP. ADEQ calculated cost information using information provided by Entergy regarding LSC

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[53] In EPA's supplemental modeling of impacts of Dry FGD and Wet FGD at Independence for the AR RH FIP, EPA evaluated two scenarios lines. The BASE case emission rates for NOx and SO_2 were from the maximum actual 24-hour emissions during the 2001–2003 period. The BASE 2 case emission rates for SO_2 were based on the maximum actual 24-hour emissions during the 2001-2003 period and the NOx emissions were based on the maximum 24-hour emissons during the 2011–2013 period. EPA also modeled the expected visibility impact of controls for each of the BASE case emissions assumptions. The values presented above represent the values included in the Final AR RH FIP.

[54] Entergy Arkansas Inc. (2015). Comments on the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas. Docket ID No. EPA-R06-OAR-2015-0189

[55] Entergy's modeling submitted in comments on the Proposed SIP is based on a 2011–2013 baseline period for modeled emission rates. While Entergy's baseline differs from the two baselines modeled by EPA, we do not expect that the difference would substantially impact the comparison of the visibility benefits among controls evaluated.

cost premiums, U.S. Energy Information Administration fuel consumption data, and EPA Air Markets Program Data.

Fuel switching to LSC has no associated capital costs; however, there is a cost premium associated with guaranteeing that the sulfur content is below 0.6 lb/MMBtu.[56] ADEQ estimated annualized operation and maintenance costs of switching to LSC at $1.6 million and $1.7 million for Entergy Independence Unit 1 and Unit 2, respectively.[57] Controlled annual emission rates for the LSC scenario were calculated based on these annualized costs and the anticipated emission reductions from switching to LSC.[58] ADEQ estimated that the average cost-effectiveness for fuel switching to LSC is approximately \$2,437/ton of SO_2 reduced at Entergy Independence Unit 1 and \$2,345/ton of SO_2 reduced at Entergy Independence Unit 2.

Installation of Wet FGD requires a large capital investment. Entergy did not provide Independence-specific cost-estimates for Wet FGD; however, EPA estimated total annualized costs of Wet FGD at \$49,526,167 for each Entergy Independence unit based on a thirty-year amortization period. EPA estimated that the average cost-effectiveness for Wet FGD was \$3,706 per ton of SO_2 reduced at Entergy Independence Unit 1 and \$3,416 per ton of SO_2 reduced at Entergy Independence Unit 2. In the AR RH FIP, EPA eliminated Wet FGD due to the high incremental cost and the minimal incremental increase in estimated visibility improvement achieved over Dry FGD.[59] Therefore, ADEQ also finds that Wet FGD does not warrant further consideration.

Installation of Dry FGD also requires a large capital investment. In the proposed SIP, ADEQ based its evaluation of costs on the EPA estimated total annualized costs of Dry FGD for each Entergy Independence unit based on a thirty-year amortization period and information available for White Bluff. In comments on the proposed SIP, Entergy submitted control cost estimates specific to Independence. Entergy estimated total capital costs of Dry FGD at Independence to be $491,893,500 per unit based on claimed actual costs and $355,391,500 based on EPA-allowed costs.[60] Entergy annualized the capital cost for both values based on a nine-year amortization period based on their plans for ceasing coal-fired operations at Independence by the end of year in 2030. Entergy's estimates for anticipated emission reductions as a result of Dry FGD also differed from the EPA estimates. Entergy based emissions reduction calculations on a 2009–

[56]The Entergy August 18, 2017 revised BART analysis for White Bluff estimated this cost premium at $0.50/ton.
[57] Annualized capital costs were calculated using average annual fuel consumption in tons multiplied by the $0.50/ton cost premium Entergy quoted for low sulfur coal in their August 18, 2017 revised BART analysis for White Bluff. Annual fuel consumption date was obtained from U.S. Energy Information Administration Form EIA-923 detailed data for 2009–2013.
[58] The control efficiency for low sulfur coal for each unit was calculated based on the difference between the maximum 30-boiler operating day rolling average emission rate during the 2009–2013 baseline period and the controlled emission rate. The controlled annual emissions rate was calculated based on the percent decrease in 30-boiler operating day emission rate from the maximum emission rate achieved by low sulfur coal.
[59] EPA concluded that the minimal amount of incremental visibility improvement projected to result from wet FGD does not justify the higher cost compared to Dry FGD. Based on EPA's supplemental modeling, the incremental visibility improvement of Wet FGD versus Dry FGD would be 0.019 deciviews or less at each of the four Class I areas.
[60] Table 3-1 of Entergy Arkansas Inc. Comments on the Proposed Arkansas Phase II Regional Haze SIP Revision Exhibit I

2013 baseline; whereas, EPA based emission reduction calculations on a baseline over the same period dropping the minimum and maximum year values. ADEQ estimates that, for a thirty-year amortization period, the cost-effectiveness of Dry FGD at Independence would be $2,970/ton for unit 1 and $2,742/ton for unit 2 based on Entergy's Independence-specific capital cost estimates, annual O&M costs, and anticipated emission reductions for Dry FGD.[61]

In addition to the typical cost-effectiveness calculations used to evaluate various control technologies in the context of BART, ADEQ finds other cost-related factors to be of relevance to reasonable progress with regard to specific analysis of Independence including total capital costs, costs to Arkansas communities, and the average dollar-per-deciview reduction in visibility impairment anticipated from assessed control technologies. The total capital costs for Wet FGD and Dry FGD are high even though cost-effectiveness in dollars per ton for these technologies, given a thirty-year remaining useful life assumption, are within the range that other states and EPA have found cost-effective. Cost-effectiveness estimates no longer fall into this range for a nine-year remaining useful life based on Entergy's anticipated cessation of coal-fired operations date at Independence. Therefore, capital costs are a particularly relevant consideration given Entergy's intentions to cease coal-fired operations at Independence in fewer than thirty years. In addition, any costs for control at Independence would be passed on to Arkansas electricity ratepayers. In the proposed SIP, ADEQ presented average cost per deciview reduction values for Dry FGD at Independence, but not for LSC because no modeling of LSC at Independence had been conducted. In comments on the SIP, Entergy provided updated Independence-specific cost-estimates and modeled visibility benefits associated with LSC. Table 13 lists ADEQ's estimates of cost-per-deciview improvement for LSC and Dry FGD at Independence.

Table 13 Average Dollar-Per-Deciview for Control Options at Independence Units 1 and 2[62]

	Caney Creek	Upper Buffalo	Hercules Glades	Mingo
LSC	$29,469,780	$10,929,190	$13,985,658	$12,179,393
Dry FGD	$68,337,085	$63,580,175	$70,925,611	$71,672,197

The cost-per-decivew improvement for Dry FGD is a little over two times higher than for LSC at Caney Creek and between five and six times higher at Upper Buffalo and the two Missouri Class I areas. Evaluation of cost per deciview demonstrates a greater difference in cost to achieve visibility benefits than a cost per ton of pollutant removed metric. Either control evaluated would result in millions of dollars being spent to achieve little visibility benefit.

[61] ADEQ revised the EPA-allowed annualized capital cost for Dry FGD at Independence included in Exhibit I to Entergy's comments based on a thirty-year remaining useful life for the Dry FGD equipment because no enforceable commitment to cease operations by 2030 is in place for Independence. The revised annualized capital cost is based on a capital recovery factor calculated for a thirty-year amortization period in accordance with Chapter 2 of the EPA Control Cost Manual. ADEQ's calculations are included in Appendix F. <https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf>

5. Time Necessary for Compliance

The typical time necessary for compliance for either add-on technology—Dry FGD or Wet FGD—is five years. Entergy estimates that the time necessary to comply with a limit based on LSC is three years due to time left on existing coal supply contracts, the time required to burn through current fuel stocks, and the time needed to build up a stockpile of LSC to assure against possible fuel supply disruptions.

6. Energy and Nonair Quality Environmental Impacts of Compliance

Dry FGD utilizes lime slurry to remove SO_2 from flue gas. In the process, particulate matter is generated that must be controlled through use of a baghouse or electrostatic precipitator. Once collected, the waste material is disposed of through landfilling. Costs associated with control of particulate matter and additional power requirements were factored into the cost estimates calculated by Entergy and EPA. Entergy has not indicated unusual circumstances that would create greater problems than experienced elsewhere that Dry FGD was utilized as BART. Use of LSC is not anticipated to result in any energy or nonair quality environmental impacts.

7. Reasonable Progress Control Determination for Independence

Based on ADEQ's evaluation of the reasonable progress factors for Entergy Independence, ADEQ finds that no additional controls at this source are necessary for reasonable progress during the first planning period. The controls evaluated would result in millions of dollars of costs annually that would be passed on to Arkansas ratepayers for little visibility benefit for visitors to Arkansas's Class I areas. Such costs are not necessary under reasonable progress when Arkansas Class I areas are already making more progress than the URP.

Although ADEQ does not find any of the controls evaluated for Entergy Independence to be necessary for achieving reasonable progress during the first planning period, ADEQ acknowledges Entergy's proposal to switch to LSC at Independence within the next three years. This voluntarily proposed SIP-strengthening measure would result in some visibility benefit at Arkansas Class I areas that, while less than would be anticipated from Dry FGD, would require no capital cost.[63] The lack of substantial capital costs associated with LSC provides flexibility regarding Entergy's planned cessation of coal-fired operations at Independence by the end of 2030 and avoids potential stranded costs associated with controls that require a large capital investment. ADEQ has included Entergy's proposed use of LSC at Independence in the long-term strategy for this SIP and expects that modeled visibility benefits will be realized from use of LSC.

E. Additional Controls Necessary for Reasonable Progress at Arkansas Class I Areas

After consideration of the four statutorily required factors and other relevant factors to reasonable progress, ADEQ has determined that no additional controls beyond BART and other

[63] There is an assumed $0.50/ton cost premium associated with guaranteeing that the sulfur coal content delivered by contract would ensure compliance with an emission rate of 0.60 lb/MMBtu.

Clean Air Act programs are necessary to ensure reasonable progress during the 2008–2018 regional haze planning period. ADEQ evaluated the monitored trajectory of visibility impairment during this planning period, particulate source apportionment data, and SO_2 emissions relative to proximity to Arkansas Class I areas, and the statutory reasonable progress factors.

ADEQ has determined, based on an analysis of the reasonable progress factors both statewide and for Independence, that the cost of additional controls evaluated for the purposes of reasonable progress is unnecessary to ensure reasonable progress during this planning period. Any of the controls evaluated would result in millions of dollars of costs annually for little visibility improvement. If the controls included in the AR RH FIP were imposed, the costs would be passed on to the citizens and businesses of Arkansas through electricity rate increases. Such costs are not warranted under reasonable progress when Arkansas Class I areas are well below their respective URPs during this planning period.

ADEQ's determination that no controls beyond BART and other Clean Air Act programs are necessary to ensure reasonable progress during this planning period is consistent with EPA's rationale for the sixty-year lifespan of the regional haze program. The regional haze program was established as a sixty-year program broken into ten-year planning periods. The program period established in the 1999 Regional Haze Regulations was set in part based on EPA's expectation that continued visibility progress will be possible as "industrial facilities built in the latter half of the 20th century will reach the end of their 'useful lives' and are retired and/or replaced by cleaner, more fuel-efficient facilities."[64] In addition, EPA noted the agency's anticipation that further innovations in control technologies will enable new facilities to achieve lower emissions rates.[65] Entergy's anticipated cessation of coal-fired operations at Independence by the end of 2030 is an example of this principle. The Regional Haze Regulations provide for a fresh look at the changing landscape of visibility impacting sources and potential controls every ten years.

The 2007 reasonable progress guidance states that "[g]iven the significant emissions reductions that we anticipate to result from BART, the CAIR, and the implementation of other CAA, including the ozone and $PM_{2.5}$ NAAQS, for many States this will be an important step in determining your RPG, and may be all that is necessary to achieve reasonable progress in the first planning period."[66]As discussed in greater detail in the long term strategy, more programs with beneficial impacts to visibility in Class I areas have come into effect since this guidance was finalized in 2007.[67] Consistent with these principles, ADEQ is deferring consideration of further measures for the purposes of reasonable progress at Arkansas Class I areas to future planning periods.

F. Reasonable Progress Goals for Arkansas Class I Areas

ADEQ is revising the RPGs established in the 2008 AR RH SIP for the twenty percent worst days at Caney Creek and Upper Buffalo to reflect control measures included in this SIP revision and the NOx Regional Haze SIP that are required to be in effect by the end of the first planning

[64] EPA (1999). "Regional Haze Regulations; Final Rule" (64 FR 35714)
[65] Id. at 35732
[66] EPA (2007) Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program
[67] See discussion *Infra* Part VI.

period. In order to provide RPGs that account for emissions reductions from SIP controls, we have used a method similar to that used by EPA for the AR RH FIP. This method is based on a scaling of light extinction components in proportion to emissions changes anticipated from SIP controls for which compliance is required on or before December 31, 2018. ADEQ is not revising its goal of no degradation on the twenty percent best days included in the 2008 AR RH SIP.

Using the same formulas EPA used to develop its RPGs for the AR RH FIP, ADEQ scaled CENRAP's CAMx 2018 projection of light extinction components for SO_4 and NO_3 in proportion to the SIP revision's emissions reductions for SO_2 and NOx, respectively. ADEQ made updates to reflect the most recent three years of data for emissions and heat input for Arkansas EGUs. The most recent three years of data (2014–2016) were used as opposed to EPA's method of using the five most recent years of data minus the minimum and maximum values (2009–2013) to ensure that recent changes in dispatch of Arkansas EGUs were captured.[68] The results of our analysis for the twenty percent worst days for 2018 for Caney Creek and Upper Buffalo are included in Table 14.[69]

Table 14 Reasonable Progress Goals for 2018 for Caney Creek and Upper Buffalo

Class I Area	2018 RPG 20% Worst Days (deciviews)
Caney Creek	22.47
Upper Buffalo	22.51

Figure 13 and Figure 14 demonstrate that Arkansas is already achieving greater visibility improvements than the RPGs listed in Table 14.[70]

[68] EIA projections show decreased consumption of coal by electric generating units that is expected to continue through 2040. Therefore, ADEQ anticipates that the coal EGU dispatch trends seen in the most recent three years is likely to continue through the first regional haze planning period and the next two planning periods. See Figure 10

[69] See RPG Calculation Data Sheet provided at https://www.adeq.state.ar.us/air/planning/sip/regional-haze.aspx.

[70] Figures 13 and 14 are updates to Figures 11 and 12 in the Proposed SIP. These figures have been updated so that the rolling average is inclusive of the current year and four previous years rather than reflecting the five previous years and to include 2016 data. 2000–2016 visibility data included in Figures 1 and 2 were obtained from: Visibility Status and Trends Following the Regional Haze Rule Metrics: IMPROVE Aerosol, Regional Haze Rule II (New Equation), with substituted data. Caney Creek, Upper Buffalo http://views.cira.colostate.edu/fed/SiteBrowser/Default.aspx.

Figure 13 Caney Creek Reasonable Progress Assessment – 20% Worst Days

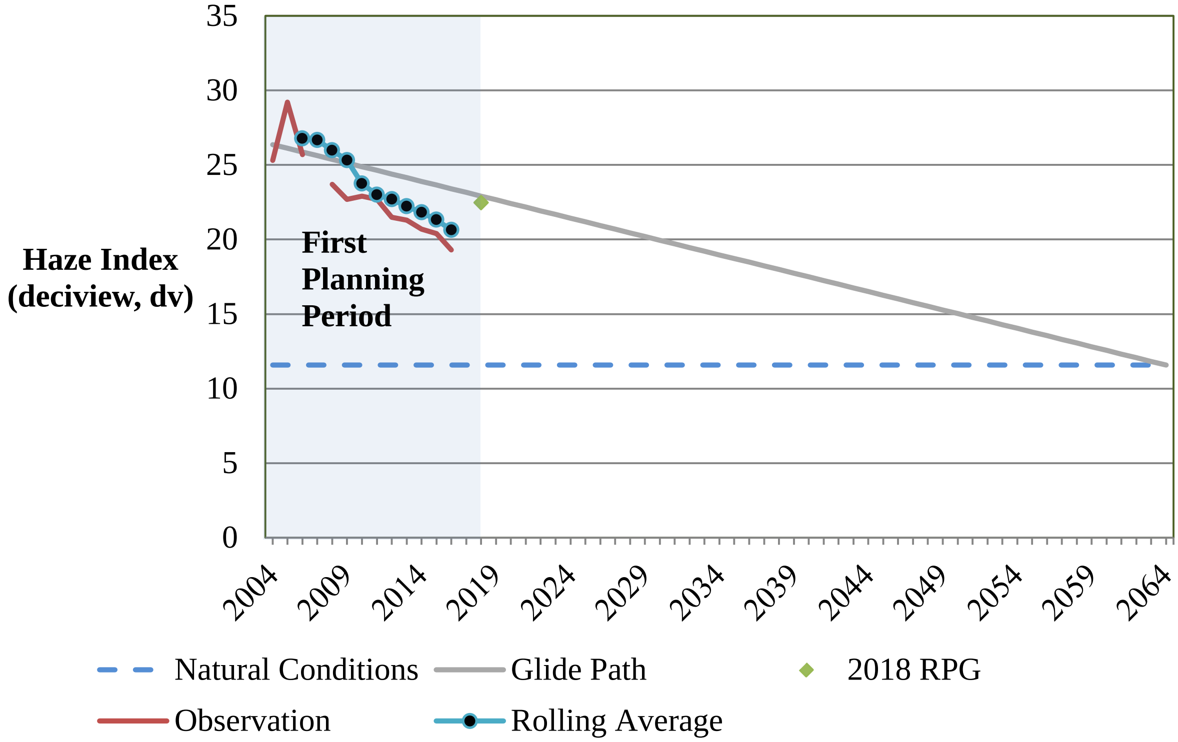
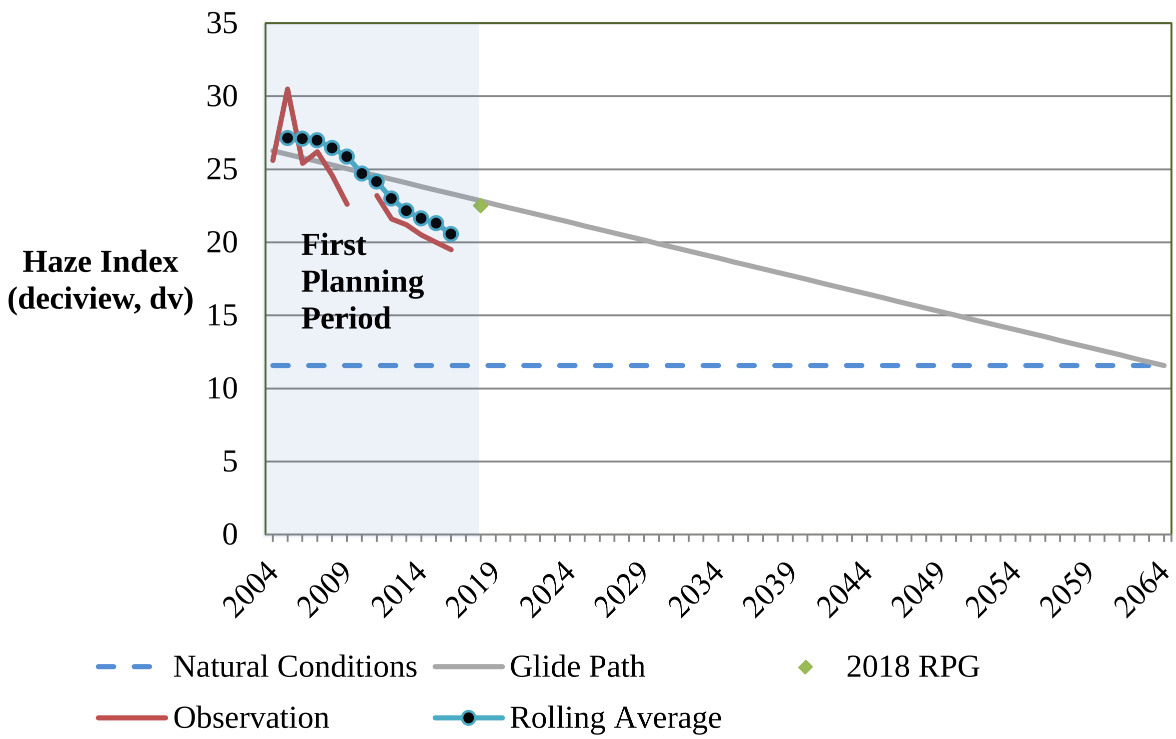


Figure 14 Upper Buffalo Reasonable Progress Assessment – 20% Worst Days



G. Interstate Visibility Transport

Sources in Arkansas impact two Class I areas in Missouri: Hercules Glade and Mingo. CENRAP PSAT data indicates that Arkansas sources contributed approximately seven percent of light extinction at Hercules Glades and four percent of light extinction at Mingo. The relative impact of Arkansas sources compared to sources in other states are projected to increase between 2002 and 2018 to approximately nine percent of total light extinction at Hercules Glades and five percent at Mingo based on the CENRAP PSAT data; however, actual contributions to light extinction attributed to Arkansas sources are projected to decrease by fourteen percent for Hercules Glades and eighteen percent for Mingo See Figures 15 and 16.

Figure 15 Comparison of Projected Light Extinction at Hercules Glades on the Haziest Twenty Percent Days Due to Particulate Species Attributed to Arkansas Sources

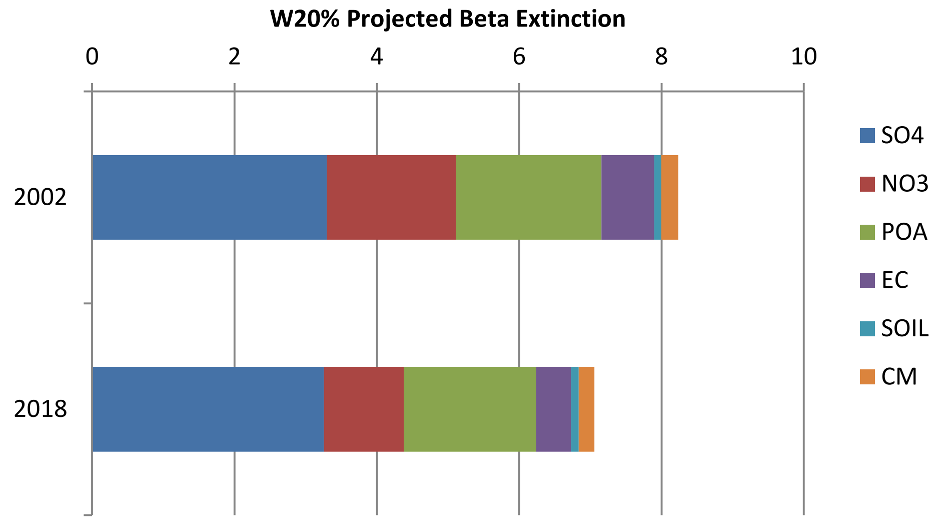


Figure 16 Comparison of Projected Light Extinction at Mingo on the Haziest Twenty Percent Days Due to Particulate Species Attributed to Arkansas Sources

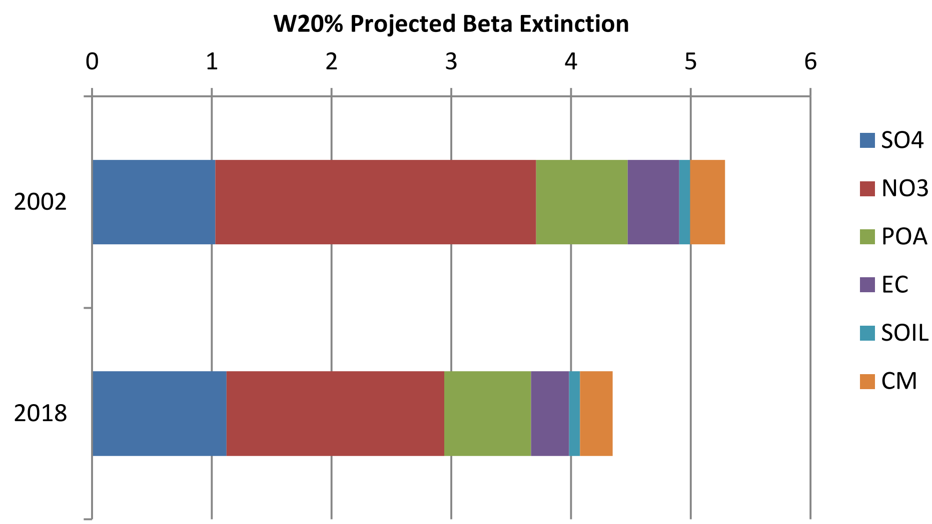
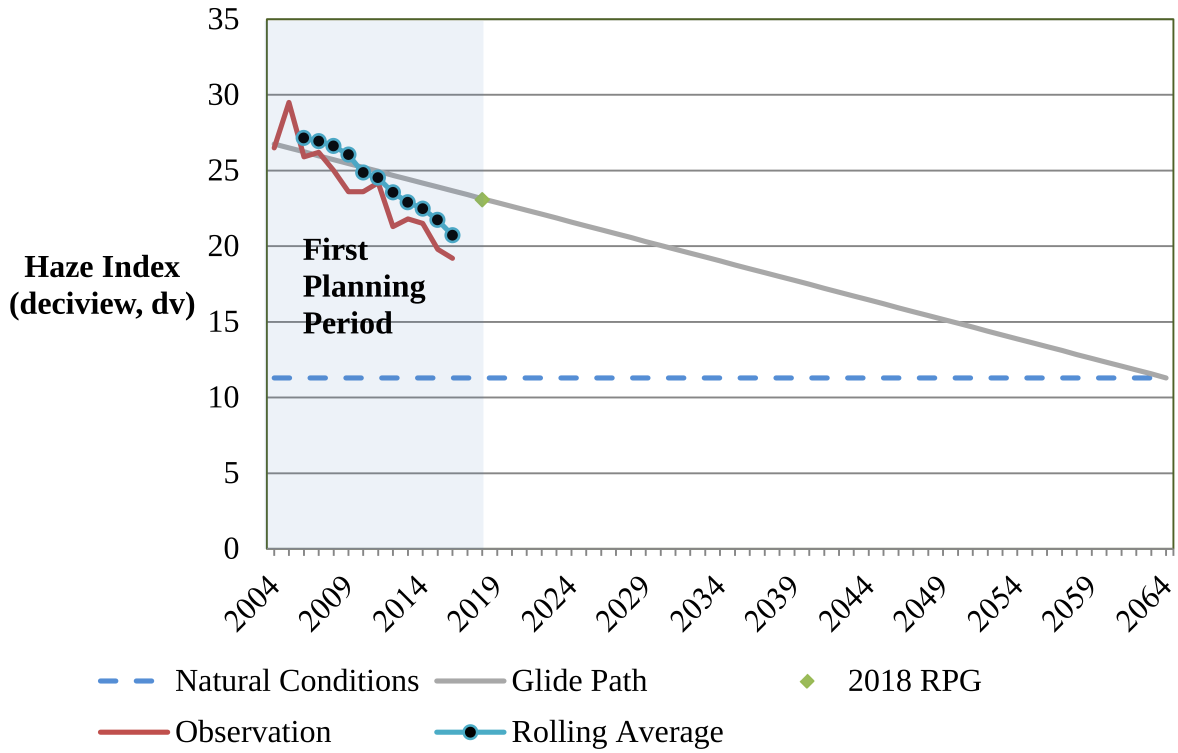


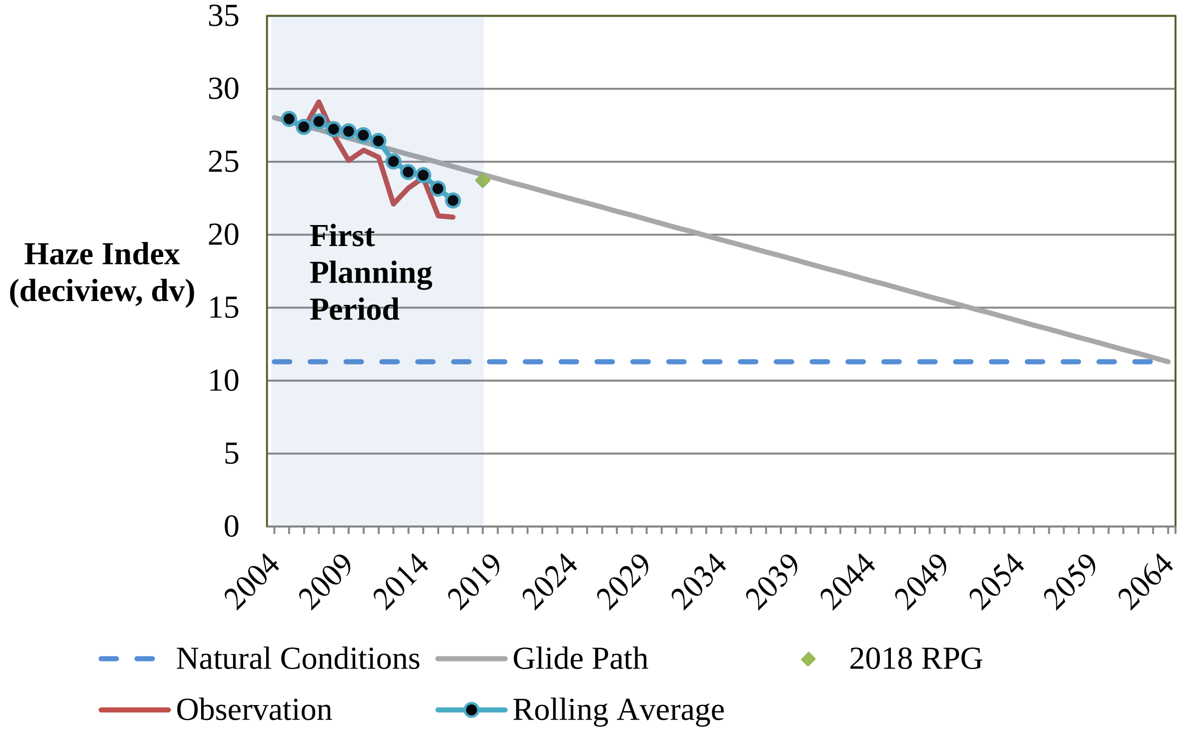
Figure 17 and Figure 18 demonstrate that Missouri is on track to achieve its visibility goals. In Missouri's 2009 Regional Haze SIP, Missouri established 2018 reasonable progress goals of 23.71 deciview for Mingo and 23.06 deciview for Hercules Glades. The most recent calculations for the twenty percent worst days and twenty percent best days for Class I areas were performed for 2015.[71] For both Mingo and Hercules Glades, visibility impairment on the twenty percent worst days in 2015 beat Missouri's 2018 RPGs for both Class I areas. The most recent five-year rolling average of observed visibility impairment on the twenty percent worst days at Hercules Glades beat Missouri's 2018 RPG for that Class I area and the most recent five year-rolling average of observed visibility impairment on the twenty percent worst days at Mingo is on track to beat Missouri's RPG for that Class I area. The visibility progress observed indicates that sources in Arkansas are not interfering with the achievement of Missouri's RPGs for Hercules Glades and Mingo.

Figure 17 Hercules Glades Reasonable Progress Assessment – 20% Worst Days



[71] Figures 17 and 18 are updates to Figures 13 and 14 in the Proposed SIP. These figures have been updated so that the rolling average is inclusive of the current year and four previous years rather than reflecting the five previous years and to include 2016 data. 2000–2016 visibility data were obtained from: Visibility Status and Trends Following the Regional Haze Rule Metrics: IMPROVE Aerosol, Regional Haze Rule II (New Equation), with substituted data. Hercules Glades, Mingo http://views.cira.colostate.edu/fed/SiteBrowser/Default.aspx.
Note: Missouri DNR revised its natural baseline conditions for Mingo on the twenty percent haziest days from 12.4 deciviews to 11.3 deciviews in their 2012 technical supplement to their 2009 Regional Haze SIP. https://dnr.mo.gov/env/apcp/reghaze/regional-haze-jan-30-2012.pdf

Figure 18 Mingo Reasonable Progress Assessment – 20% Worst Days



In the 2008 AR RH SIP, ADEQ relied upon the technical analyses developed by CENRAP and approved by all State participants. CENRAP visibility projections indicated that the emission reductions planned for CENRAP states were sufficient to achieve the reasonable progress goals for Class I areas located in Missouri Class I areas.[72] In addition, CENRAP contracted with Alpine Geophysics to evaluate control strategies for reasonable progress. Alpine Geophysics recommended reasonable progress control strategies for six Class I areas within the CENRAP region: Big Bend National Park, Breton Island, Boundary Waters, Guadalupe Mountains, Wichita Mountain, and Voyageurs.[73] Neither Hercules Glades nor Mingo were included in the list of regions for which additional control strategies were recommended for reasonable progress. In addition, no specific measures were requested by Missouri for achieving reasonable progress in each mandatory Class I Federal area affected by Arkansas.

ADEQ has determined that no additional controls on sources within Arkansas are necessary to ensure that other states' visibility goals for their Class I areas are met.

[72] Technical Support Documentation for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation included in Appendix F
[73] Alpine Geophysics, LLC (2006) "CENRAP Regional Haze Control Strategy Analysis Plan" included in Appendix F

VI. Long-Term Strategy

In 2012, EPA partially approved and partially disapproved Arkansas's long-term strategy included in the 2008 AR RH SIP. 40 CFR 51.308(d)(3)(v) requires the consideration of the following factors in developing a long-term strategy: (1) Emissions reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment; (2) measures to mitigate the impacts of construction activities; (3) emissions limitations and schedules for compliance to achieve the reasonable progress goal; (4) source retirement and replacement schedules; (5) smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the state for these purposes (6) enforceability of emissions limitations and control measures; and (7) the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy. Because EPA disapproved some of ADEQ's BART determinations and RPGs, EPA disapproved the emissions limitations and schedules of compliance element of the long-term strategy included in the 2008 AR RH SIP. EPA approved the other six elements of the long-term strategy.

Because the ongoing air pollution programs element of the Arkansas long-term strategy was previously approved, ADEQ is not proposing changes to that element in this SIP revision. Nevertheless, ADEQ notes that the landscape of ongoing air pollution programs has changed since EPA approved that element of the long-term strategy in the 2008 AR RH SIP. These changes include more stringent vehicle emission standards, renewable fuel standards, fuel efficiency standards, marine and aircraft standards, mercury and air toxics standards, various national emission standards for hazardous air pollution, and a replacement for the clean air interstate rule in the form of CSAPR. These additional air pollution programs are anticipated to achieve even greater emissions reductions that may result in further visibility improvement than the programs described in the 2008 AR RH SIP. A partial list of ongoing air pollution programs that have been implemented since the 2008 AR RH SIP is provided below:

- Tier 3 Vehicle Emissions and Fuel Standards Program (light duty, medium duty, and some heavy duty) (79 FR 23414, 2014)
- 2017 and Later Model Year CAFÉ Standards (77 FR 62624, 2012)
- Renewable Fuel Standard Program: Standards for 2014, 2015, and 2016 and Biomass-Based Diesel Volume for 2017 (80 FR 77420, 2015)
- Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy Duty Engines and Vehicles (76 FR 57106)
- Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles—Phase 2 (81 FR 73478, 2016)
- Ocean-going vessels category 3 marine rule (2010), NOx standards for Aircraft (2012)
- Small Nonroad Engine and Marine Spark-Ignition Engines and Vessels Emission Standards Phase 3 (2008)
- New NAAQS standards: 2006 $PM_{2.5}$, 2008 Ozone, 2010 NO_2, 2010 SO_2, 2012 $PM_{2.5}$
- Mercury and Air Toxics Standards
- CSAPR and CSAPR update
- NESHAP for Primary Aluminum Reduction Plants (80 FR 62390, 2015)
- NESHAP for Secondary Aluminum Production (80 FR 56700, 2015)

- NESHAP for Phosphoric acid manufacturing and phosphate fertilizer production (80 FR 50386, 2015)
- NESHAP for Mineral Wool Production and Wool Fiberglass manufacturing (80 FR 45280, 2015)
- NESHAP for Ferroalloys Production (80 FR 37366, 2015)
- NESHAP for Off-site waste and recovery operations (80 FR 14248, 2015)
- NSPS update for New Residential Wood Heaters, New Residential Hydronic Heaters, and Forced-Air Furnaces (80 FR 13672, 2015)
- NSPS update for Kraft Pulp Mills (79 FR 18952, 2014)
- NESHAP for Group IV Polymers and Resins; Pesticide Active Ingredient Production; and Polyether Polyols production (79 FR 17340, 2014)
- NESHAP and NSPS for Portland cement Manufacturing Industry (78 FR 10006, 2013)
- NESHAP for Hard and Decorative Chromium Electroplating and Chroming Anodizing Tanks and NESHAP for Pickling-HCl Process Facilities and Hydrochloric Acid Regeneration Plants (77 FR 58220, 2012)
- NSPS and NESHAP for Oil and Natural Gas Sector (77 FR 4940, 2012)
- NSPS for Nitric Acid Plants (77 FR 48433, 2012)
- Greenhouse Gas Tailoring Rule Step 3 and Plantwide Applicability Limits (77 FR 41051, 2012)
- NESHAP for Coal- and Oil-Fired Electric Utility Steam Generating Units and NSPS for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small-Industrial-Commercial-Institutional Steam Generating Units (77 FR 9304, 2012)
- NESHAP for Secondary Lead Smelting (77 FR 556, 2012)
- NESHAP for Wood Furniture Manufacturing Operations revision (76 FR 72050, 2011)
- NESHAP for Primary Lead Processing (76 FR 70834, 2011)
- NESHAP for Marine Tank Vessel Loading Operations and NESHAP for Group I Polymers and Resins (76 FR 22566, 2011)
- NESHAP for Major Sources Industrial, Commercial, and Institutional Boiler and Process Heaters (76 FR 15608, 2011)
- Source Determination for Certain Emissions Units in the Oil and Natural Gas Sector (81 FR 35622, 2016)

In addition to the changing regulatory landscape, ADEQ also acknowledges planned changes in operations at Arkansas EGUs. Specifically, ADEQ acknowledges the low NOx burners that are being installed at Entergy Independence and Entergy White Bluff. ADEQ acknowledges receipt of the submittal of documentation by Entergy indicating the planned retirement of Entergy Lake Catherine, the planned cessation of coal-fired operations at Entergy White Bluff by the end of 2028, and the planned cessation of coal-fired operations at Entergy Independence by the end of 2030. In addition, ADEQ appreciates Entergy's commitment, as indicated in their comments on the proposed SIP, to transition to LSC at Independence within the next three years for the rest of that facility's remaining coal-fired life. Per Entergy's request to make this fuel switch an enforceable element of ADEQ's long term strategy, ADEQ has included an emission limit of 0.60 lb SO2/MMBtu on a thirty-boiler operating day rolling average for each of the Entergy Independence units in AO LIS No. 18-073. ADEQ anticipates that these changes will result in emission reductions that provide further progress toward natural visibility at Arkansas and Missouri Class I areas during the second and third planning period.

ADEQ also acknowledges planned changes in operations at large stationary sources outside of Arkansas that have historically impacted Arkansas Class I areas. Specifically, ADEQ anticipates further reductions in visibility impairment due to recent announced closures of power plants in Texas and Tennessee. In October 2017, Luminant announced retirement in 2018 of three large power plants in Texas: Big Brown Plant, Sandow Plant, and Monticello Plant.[74] The Deely plant owned by CPS Energy is also scheduled to close in 2018.[75] Big Brown Plant, Monticello Plant, and Deely impact visibility at Caney Creek.[76] The baseline maximum visibility impact from Big Brown at Caney Creek is 3.775 deciviews, the baseline maximum visibility impact from Monticello at Caney Creek is 10.498 deciviews, and the baseline maximum visibility impact from Deely at Caney Creek is 1.513 deciviews. [77] In addition, the coal-fired units at Tennessee Valley Authority Allen plant in Memphis, Tennessee are scheduled to retire by June 2018 and will be replaced with natural gas generators.[78]

In this SIP revision, ADEQ has addressed the disapproved BART determinations for all subject-to-BART sources in Arkansas, with the exception of Domtar Ashdown Mill, and reasonable progress determinations. BART determinations are summarized in Section IV of this SIP and additional technical supporting data are found in Appendices B–E. Emissions limitations and schedules of compliance are rendered enforceable by AOs. BART requirements and compliance schedules for Domtar Ashdown Mill are included in the AR RH FIP. The long-term strategy and RPGs are reflective of those federally enforceable AR RH FIP controls for Domtar. Therefore, ADEQ requests that EPA fully approve Arkansas's revised long-term strategy.

VII. <u>Review, Consultations, and Comments</u>

A. Federal Land Manager Consultation

In accordance with the provisions of 40 C.F.R. § 51.308(i)(2), ADEQ consulted with designated FLM staff personnel on this SIP. This consultation gave FLMs the opportunity to discuss their assessment of the impact of the proposed SIP revisions on Arkansas Class I areas——Upper Buffalo and Caney Creek—and other Class I areas.

On October 27, 2017, ADEQ submitted letters to notify the federal land manager staff of this proposed SIP revision and to provide them with electronic access to the revision and related documents. ADEQ engaged in telephone communications with the FLMs. In addition, comments

[74] https://www.luminant.com/luminant-announces-decision-retire-monticello-power-plant/; https://www.luminant.com/luminant-close-two-texas-power-plants/
[75] https://www.power-eng.com/articles/2017/10/cps-deely-coal-to-still-close-even-with-clean-power-plan-reversal.html
[76] Promulgation of Air Quality Implementation Plans; State of Texas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan: Proposed Rule (82 FR 912, January 4, 2017)
[77] Id. Table 15 at 931
[78] https://www.tva.gov/Energy/Our-Power-System/Coal/Allen-Fossil-Plant

received from the FLMs were considered and posted to ADEQ's Regional Haze webpage: https://www.adeq.state.ar.us/air/planning/sip/regional-haze.aspx. The FLM contact list, notification letters, and comments received are included in Tab E of this SIP package.

B. Consultation with States

For the 2008 AR RH SIP, ADEQ engaged in extensive interstate consultation with states participating in the CENRAP RPO. Because Missouri has two Class I areas impacted by Arkansas sources, ADEQ submitted a letter on October 27, 2017 to Missouri Department of Natural Resources (DNR) air pollution control program staff to notify them of this proposed SIP revision and to provide them with electronic access to the revision and related documents. Missouri DNR did not have any comments on this SIP revision. The notification letter is included in Tab E of this SIP package.

C. Public Review

ADEQ provided notice of a public hearing to receive public comments on the proposed SIP revision. The notice of the proposal and public hearing was published in the Arkansas Democrat Gazette, which is a newspaper in circulation statewide, on October 31, 2017. The notice contained information on the availability of the proposed SIP revision for public inspection at ADEQ information depositories, ADEQ headquarters, and ADEQ's Regional Haze webpage. On November 3, 2017, a second notice was published to correct typographical errors with respect to dates for the close of the public comment period and the public hearing. On December 18, 2017, a third notice was published extending the public comment period, postponing the public hearing in response requests received, and providing a notice of data availability regarding Entergy's unredacted updated five factor analysis for White Bluff and a reasonable progress analysis performed by Entergy. On January 12, 2018, ADEQ issued a press release providing a second extension of the public comment period. In addition, ADEQ posted this comment period extension to ADEQ's website and notified persons who had already submitted comments via email of the extension.

The public comment period for this SIP revision began on October 31, 2017 and concluded on February 2, 2018 at 11:59 p.m. CST. The public hearing was held on January 19, 2018.

Both oral and written comments received by ADEQ during the public comment period were posted on the ADEQ Regional Haze web page. Copies of written comments, ADEQ's response to comments, and records from the public hearing are included in Tab E.

VIII. Conclusion

With the NOx Regional Haze SIP submission and this SIP submission together, ADEQ has addressed all disapproved elements of the 2008 AR RH SIP, with the exception of requirements for Domtar Ashdown Mill. The compliance obligations for Domtar under the AR RH FIP are currently the subject of litigation and ADEQ supports Domtar's efforts to demonstrate that, due to their changes in operation, alternative emission limits are appropriate as a result of emission reductions achieved from their conversion of the Ashdown Mill to fluff pulp production. ADEQ commits to continuing to work with Domtar to ensure that credit is given for their success in reducing emissions and thereby their impacts on visibility. Arkansas requests that EPA withdraw the elements of the AR RH FIP addressed in this SIP revision and review and approve this SIP revision and Arkansas's "State Implementation Plan Review for the Five-Year Regional Haze Progress Report" submitted in 2015 as expeditiously as possible.

APPENDIX A
Additional Information Regarding BART Screening for Georgia-Pacific Crossett Mill

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