STATE OF ARKANSAS

Revisions to the Arkansas State Implementation Plan

Regional Haze SIP Revision for 2008–2018 Planning Period

Prepared by the
Arkansas Department of Environmental Quality
Office of Air Quality
Policy and Planning Branch

October 2017

Public Review Draft

Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, Arkansas 72118-5317

Revisions to the Arkansas State Implementation Plan

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State Implementation Plan

Request for Parallel Processing

STATE OF ARKANSAS
ASA HUTCHINSON
GOVERNOR

October 27, 2017

Samuel Coleman
Acting Regional Administrator
United States EPA Region VI
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

Re: Arkansas State Implementation Plan (SIP)

Dear Acting Regional Administrator Coleman:

The Arkansas Department of Environmental Quality (ADEQ) hereby respectfully submits to the United States Environmental Protection Agency (EPA) revisions to the Arkansas State Implementation Plan (SIP) for approval.

In the most recent SIP, Arkansas has included revisions to address disapproved portions of the Arkansas Regional Haze State Implementation Plan (AR RH SIP), submitted to the EPA in 2008. Enforceable emissions limitations and compliance schedules determined necessary to meet regional haze program requirements under the 40 CFR 51.308 and Clean Air Act §169 have been implemented through consent administrative orders with each of the subject facilities. Arkansas asks that the EPA withdraw from the SIP Regulation No. 19, Regulations of the Arkansas Plan of Implementation for Air Pollution Control, and approve these administrative orders into the SIP. No changes are needed to EPA's determinations with respect to previously approved Best Available Retrofit Technology (BART) limits included in Regulation No. 19, because these limits have been included in the administrative orders.

The SIP package accompanying this letter consists of one hard copy and one electronic copy (on compact disc), summarized as follows:

- Tab A State Implementation Submittal Letter
- Tab B Introduction
- Tab C Administrative Orders
- Tab D Legal Authority to Adopt and Implement the Plan
- Tab E Public Participation

We are requesting parallel processing of this submittal in accordance with the October 31, 2011 Memo "Options and Efficiency Tools for EPA Action on State Implementation Plans." Arkansas will hold a public hearing regarding the SIP revision on January 2, 2018. Arkansas has enclosed a copy of notice of public hearing and opportunity to comment on the proposed SIP revision as required by 40 C.F.R. § 51.102. Notice of the proposal and public hearing is to be published on October 31, 2017 in the Arkansas Democrat Gazette, a newspaper in circulation statewide, and is also posted on ADEQ's website. Information on the public notice, the proposed revision, and related documents are posted to ADEQ's Regional Haze web page (https://www.adeq.state.ar.us/air/planning/sip/regional-haze.aspx). The Federal Land Manager Consultation, Consultation with States, and Public Review sections of the proposed Regional Haze SIP revision describe Arkansas's plans for consultation with federal land managers (FLMs) and for receiving, posting, and responding to comments from the FLMs as well as the public.

Arkansas has provided electronic access to the proposed SIP revision, notification of consultation opportunity to the designated FLMs in accordance with consultation provisions of 40 CFR § 51.308(i)(2), and notification to clean air agency staff for bordering/potentially affected states in accordance with 40 CFR § 51.308(d)(3)(i). Upon conclusion of the public comment period, Arkansas will evaluate and respond to all comments received from the FLMs and the public, finalize the Regional Haze SIP revision, and submit the revision to EPA.

Arkansas requests that EPA review and approve this SIP revision as expeditiously as possible. Arkansas also requests that EPA withdraw "Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Final Rule."

I certify that all documents submitted to the Regional Office in electronic form are exact duplicates of the hard copy documents. Should questions arise, please do not hesitate to contact the ADEQ Associate Director of the Office of Air Quality, Stuart Spencer, at (501) 682-0750, or by email at spencer@adeq.state.ar.us. Thank you for your consideration of Arkansas's submission.

Sincerely,

Asa Hutchinson

Enclosures

Tab B:

Introduction—

Revisions to the 2008 Regional Haze State Implementation Plan

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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, 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.

A. Arkansas State Implementation Plan Revision

Arkansas has made significant improvements in air quality in recent years. Arkansas is now in attainment for all of the national ambient air quality standards and is well below both the State and the EPA's 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.

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 United States Environmental Protection Agency (EPA) in 2008. In 2012, EPA partially approved and partially

[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.

I. <u>Introduction</u>

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disapproved the 2008 AR RH SIP.[3] Specifically, the following elements are being submitted for EPA approval:

- BART compliance dates;
- Best available retrofit technology (BART) eligible sources and subject-to-BART Sources;
- BART determinations:
  - Sulfur dioxide (SO_2), nitrogen oxides (NOx), and particulate matter (PM) BART determinations for Arkansas Electric Cooperative Corporation (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 Southwest Power Company (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 Arkansas, Inc. (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;
- Reasonable progress goals (RPGs); and
- Long-term strategy.

Revisions to disapproved BART requirements for Domtar Ashdown Mill are not included in this SIP revision. The remaining provisions of the 2008 AR RH SIP were approved. Arkansas is not revising portions of 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. [To be assigned upon finalization] between Entergy and ADEQ
- LIS No. [To be assigned upon finalization] between SWEPCO and ADEQ
- LIS No. [To be assigned upon finalization] 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.

Sampling, monitoring, and reporting requirements that are generally applicable to stationary sources, including sources for which emissions limitations are established in this SIP, are 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.

[3] 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)

II. Background

In 1977, Congress added § 169 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 § 169(B) 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 § 169(B)(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).[4]

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 was located in the CENRAP RPO. Figure 1 is a map depicting the five RPO regions designated by EPA.

[4] *Regional Haze Rule* (64 FR 35714, July 1, 1999)

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.[5] The Court had remanded the BART provisions of the 1999 RHR to EPA and denied industry's challenge to the RHR goals of natural 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.

[5] American Corn Growers Assn. v. EPA, 291 F.3d.1 (D.C. Cir. 2002)

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.[6] EPA has also amended regulatory requirements for state regional haze plans for the second planning period and beyond.[7]

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.[8] 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.

EPA disapproved the following elements of the 2008 AR RH SIP:

- BART compliance dates;
- BART-eligible sources and subject-to-BART sources;

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[6] 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).
[7] Protection of Visibility: Amendments to Requirements for State Plans (82 FR 3078, January 10, 2017)
[8] 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)

- 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).[9] This FIP established new BART requirements for those sources whose BART determinations in the 2008 AR RH FIP 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 the use of low sulfur coal (LSC) as 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.

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

[9] 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)

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 (82 FR 18994). Specifically, EPA stayed from April 25, 2017 until July 24, 2017 (ninety days) the compliance dates for the NOx emissions limitations at AECC 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 demonstrates 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.[10]

On July 13, 2017, EPA proposed revisions to the AR RH FIP that would extend the compliance dates for the NOx emissions limitations at AECC Flint Creek Unit 1, White Bluff Units 1 and 2, and Independence Units 1 and 2.[11] 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 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.

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. On October 2, 2017, the Court subsequently issued an order that continued the abeyance until October 31, 2017, as requested by the parties' joint status report.

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[10] Approval and Promulgation of Implementation Plans; Arkansas; Approval of Regional Haze State Implementation Plan Revision and Withdrawal of Federal Implementation Plan (82 FR 42627, September 11, 2017)

[11] 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)

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 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 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

BART Source Category Number and Name	Facility Name	Arkansas Facility Identification Number	Unit ID	Unit Description
	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 SN-22	6A Boiler 9A Boiler
	Green Bay Packaging, Inc. Arkansas Kraft Division	15-00001	SN-05A	Recovery Boiler
	Potlatch Forest Products Corporation – Cypress Bend Mill	21-00036	SN-04	Power Boiler
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	West Nitric Acid Plant

BART Source Category Number and Name	Facility Name	Arkansas Facility Identification Number	Unit ID	Unit Description
			SN-09	East Nitric Acid Plant
			SN-10	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.[12] 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 dv 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.[13][14] 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.

[12] 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.
[13] April 1, 2013 letter from Georgia-Pacific-Crossett to ADEQ and associated supporting attachments.
[14] ADEQ Operating Permit 0597-AOP-R-18

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 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

IV. Revisions to BART Determinations

Among the provisions disapproved in EPA's 2012 action on the 2008 AR RH SIP, were several BART determinations. Specifically, EPA disapproved the:

- 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.

EPA did approve the following 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.

In this SIP revision, ADEQ is addressing disapproved emissions limitations and compliance schedules for AECC Bailey Unit 1; AECC McClellan Plant Unit 1; SWEPCO Flint Creek Plant Boiler No. 1; Entergy Lake Catherine Plant Unit 4; and Entergy White Bluff Units 1 and 2 and Auxiliary Boiler. All emissions limitations, including those previously approved SIP provisions in Regulation No. 19 Chapter 15, will be rendered enforceable through AOs with each subject-to-BART source. ADEQ requests that EPA withdraw previously SIP-approved BART determinations contained in APC&EC Regulation No. 19 Chapter 15 and approve these AOs into the SIP.

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 national ambient air quality standards 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 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.

Ark. Code Ann. § 8-4-312 Factor	Consideration of the Factor
(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 sources;	The volume of air contaminants emitted from subject-to-BART sources for which controls 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	Costs of control may be passed on to customers of the sources for which ADEQ is

Ark. Code Ann. § 8-4-312 Factor	Consideration of the Factor
of the air contamination sources;	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 provided 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 dv 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 dv, 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 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. [To be assigned upon finalization] includes enforceable limitations and compliance dates consistent with ADEQ's BART determination.

2. Summary of BART Analysis 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 SO2 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.

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 provided 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 dv 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 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 determined 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. [To be assigned upon finalization] includes enforceable limitations and compliance dates consistent with ADEQ's BART determination.

2. Summary of BART Analysis 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.

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 provided 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 is capable of burning No. 6 fuel oil as a secondary fuel, although 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, NO_X, 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 dv 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. BART 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 because this limitation has been rendered enforceable through an AO included with this SIP revision.

2. BART 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 because the limitation has been rendered enforceable through an AO included with this SIP revision.

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 provides new information in light of an updated remaining useful life for White Bluff and evaluates three new control scenarios. Entergy also provided to ADEQ supplemental information on April 5, 2017 detailing cost-effectiveness for Dry FGD with various remaining useful life assumptions. ADEQ makes its BART determination included in this SIP based on the updated BART five-factor analysis for SO_2 and previous BART analyses and supplemental information provided by Entergy, and analyses from other stakeholders of interest. These analyses are incorporated by reference and provided in Appendix D of this SIP.

Entergy White Bluff Units 1 and 2 are identical tangentially-fired 850 megawatt boilers, which were installed 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 dv, 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 dv 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 for SO_2

The available SO_2 retrofit control technology options for White Bluff Units 1 and 2 include: fuel switching to lower sulfur coal, 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 coal 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 1.2 lb SO_2/MMBtu based on the new source performance standard for fossil-fuel fired steam generators. Entergy White Bluff is currently using lower sulfur content coal to minimize costs of compliance with the Acid Rain Program. Entergy White Bluff has been able to achieve monthly average emissions rates below 0.69 SO_2/MMBtu.[15] The average monthly emissions rate between 2014 and 2016 was 0.55 lb SO_2/MMBTU for Unit 1 and 0.58 lb SO_2/MMbtu for Unit 2. Consequently, Entergy White Bluff has already lowered its visibility impact on potentially impacted federal Class I areas during this planning period beyond what would be expected due to emissions at its permitted emissions rate.

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.

[15] Calculated using 2014–2016 monthly SO_2 emissions and heat rate (MMBtu) obtained from the Air Markets Program Database https://ampd.epa.gov/ampd/

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. Thus, the cost-effectiveness for LSC is approximately $1,150 per ton of SO_2 reduced.

In Entergy's August 18, 2017 revised BART analysis, Entergy redacted certain information held to be a trade secret, including capital costs, remaining useful life, and average cost-effectiveness for DSI, Enhanced DSI, and Dry FGD. They did provide baseline and controlled emission rates, annual cost-effectiveness for LSC, and incremental cost-effectiveness values of control technologies versus LSC without redaction. Using these data provided without redaction by Entergy, ADEQ was able to calculate the average cost-effectiveness of each technology. The average cost-effectiveness of DSI is approximately $6,239 per ton and the average cost-effectiveness of "enhanced" DSI is approximately $6,405 per ton. Average cost-effectiveness of Dry FGD systems is approximately $5,403 per ton. 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 dv 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.

The cost-effectiveness estimates for all control options evaluated, with the exception of LSC, are greater than what is typically considered cost-effective. Each of the add-on control options DSI and Dry FGD also have a high dollar-per-deciview cost. Average dollar-per-deciview cost for LSC, DSI and Dry FGD are included in Table 4.

Table 4 Average Dollar-Per-Deciview Reduction for Control Options at White Bluff Units 1 and 2[16]

Control Option	Caney Creek	Upper Buffalo	Hercules Glades	Mingo
LSC	$14,500,519	$11,932,988	$10,666,332	$13,554,882
DSI	$133,339,191	$105,415,609	$120,510,530	$116,123,315
Enhanced DSI	$158,836,782	$139,148,713	$168,877,211	$173,411,916
SDA	$131,451,261	$121,376,462	$153,169,879	$153,856,146

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.

[16] Total annualized cost, as calculated by ADEQ using information from Entergy's August 18, 2017 revised BART analysis for White Bluff regarding annualized cost for LSC and the incremental cost-effectiveness of the other control options over LSC, 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.

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, the cost-effectiveness for Dry FGD included in the August 18, 2017 analysis corresponds to Dry FGD cost-effectiveness estimates provided in Entergy's April 21, 2017 letter based on a seven-year to eight-year remaining useful life scenario.[17] In comments on the AR RH FIP, Entergy also proposed dates as part of a "multi-unit plan to improve visibility and to better manage generation assets for reliability and costs."[18] In those comments, Entergy proposed to "take an enforceable limit" regarding their planned changes in coal-fired operations.[19]

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."[20] Based on the controls evaluated, the compliance date for controls would be as expeditiously as practicable, but in no event later than five years after approval of the SIP.[21] The guidelines further specify that the permanent operations cessation date should be "assured by a federally- or State-enforceable restriction preventing further operation."[22] 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 date.

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. Based on remaining useful life, DSI, Dry FGD, and Wet FGD were eliminated as BART for SO_2. The remaining evaluated option, switching to LSC, would result in a 0.129 dv improvement at Caney Creek and a 0.143 dv improvement at Upper Buffalo.

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[17] In the April 21, 2017 letter included in Appendix D, Entergy estimates that "for a seven- to eight-year [remaining useful life], 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 partial costs."

[18] Entergy Arkansas Inc. Comments on the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas, at 5 (Aug. 7, 2015) (Docket ID No. EPA-R06-OAR-2015-0189-0153) (hereinafter "EAI Comments").

[19] Id.

[20] Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations (70 FR 39104,July 6, 2005)

[21] 40 CFR 51.308(e)(iv) requires that "each source subject to BART be required to install and operate BART as expeditiously as practicable, but in no event later than five years after approval of the implementation plan revision." Appendix Y to Part 51, Guidelines for BART Determinations Under the Regional Haze Rule V. Enforceable Limits/Compliance Date also specifies that in developing a compliance date for BART, a "you must require compliance with the BART emission limitations no later than 5 years after EPA approves your regional haze SIP." Therefore beginning calculation of remaining useful life based on a compliance date five years after approval of the SIP is consistent with the requirements of the Regional Haze Rule.

[22] Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations (70 FR 39104,July 6, 2005)

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 was LSC with a required emissions rate of 0.6 lb/MMBtu calculated as a 30-day rolling average over each boiler operating day. ADEQ concurs with this determination. 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. Therefore, ADEQ finds that it is reasonable to require Entergy to comply with the requirement to meet an emission rate of 0.6 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. [To be assigned upon finalization] includes enforceable limitations and compliance dates consistent with ADEQ's determination.

2. BART 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 because these limitations have been rendered enforceable through an AO included with this SIP revision.

E. Southwest 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 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 dv 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 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 dv 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. [To be assigned upon finalization] includes enforceable limitations and compliance dates consistent with ADEQ's BART determination.

2. BART 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. ADEQ proposes that no changes are needed to EPA's determination with respect to the previously approved PM BART limit included in Regulation No. 19 because this limitation has been rendered enforceable through an AO included with this SIP revision.

V. <u>Reasonable Progress Analysis for Arkansas Class I Areas</u>

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."[23] 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.[24]

[23] Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program
[24] Id.

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. In justifying its disapproval of Arkansas's RPGs, EPA asserted that the URP does not establish a "safe harbor" for the State in setting its RPGs and that Arkansas should have performed a four factor analysis and determined whether additional progress would be reasonable.[25] 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 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.

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 Central Regional Air Planning Association (CENRAP) in support of SIP development in the central states region.[26] 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.[27] 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 5 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,

[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: Proposed Rule (76 FR 64186 at 64195, October 17, 2011)

[26] The central states region includes Texas, Oklahoma, Louisiana, Arkansas, Kansas, Missouri, Nebraska, Iowa, Minnesota; and tribal governments included in these states.

[27] August 27, 2007 CENRAP PSAT tool: W20% Projected Bext;

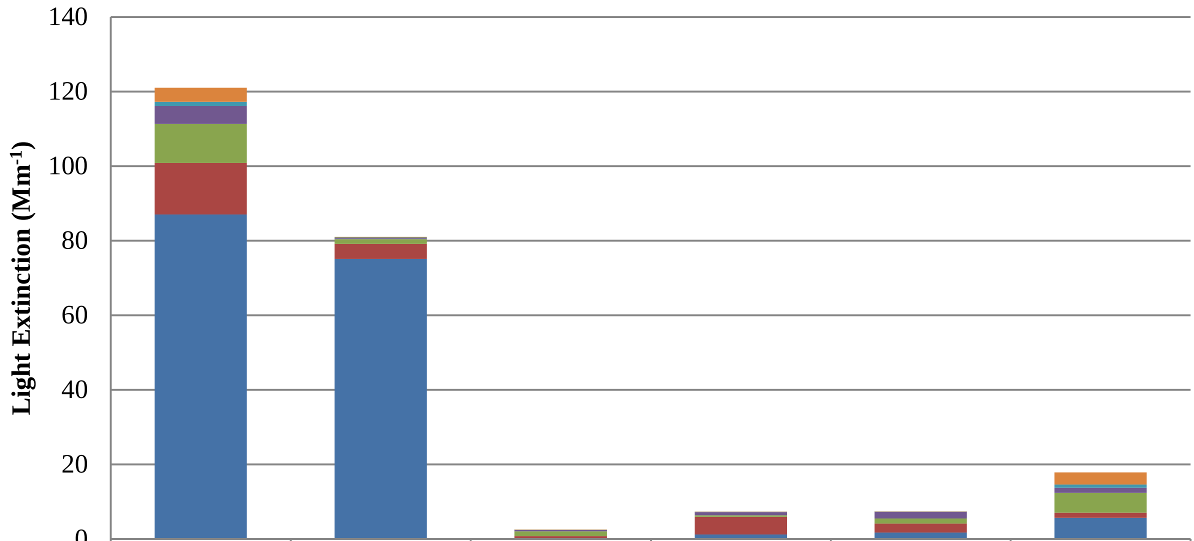
area sources only contribute thirteen percent and sixteen percent of total light extinction at Caney Creek and Upper Buffalo, respectively. The other source categories each contribute between two percent and six percent of total light extinction at Arkansas Class I areas.

Table 5 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

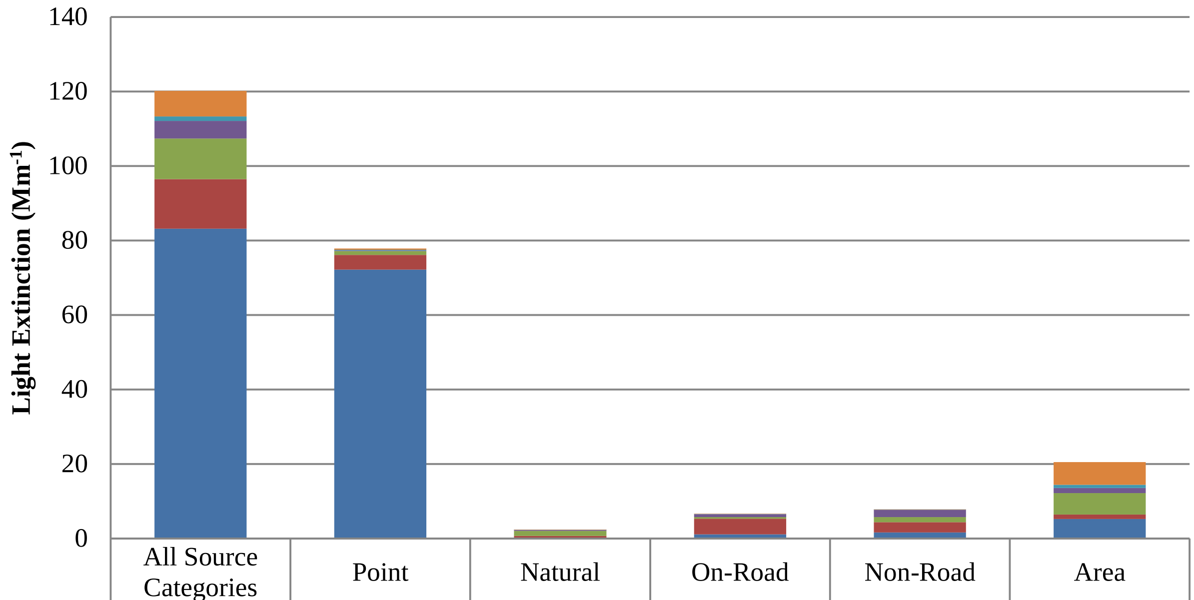
Figure 2 and Figure 3 show the modeled relative contributions to light extinction for each species and source category at Caney Creek and Upper Buffalo on the twenty percent worst days in 2002. According to the 2002 PSAT results, SO_4 contributed approximately sixty-five percent and sixty-three percent 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

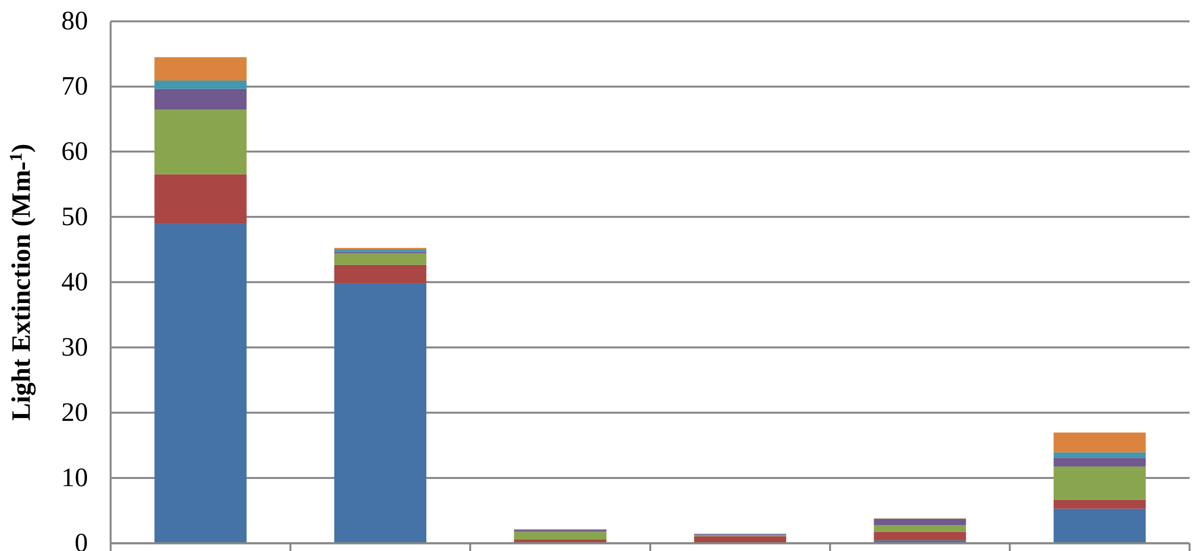
Table 6 shows the modeled relative contributions to light extinction for each source category at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days in 2018. Point sources are projected to remain the primary contributor to light extinction at Arkansas Class I areas. Point sources 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 a very small portion of total light extinction at Arkansas Class I areas on the twenty percent worst days in 2018.

Table 6 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

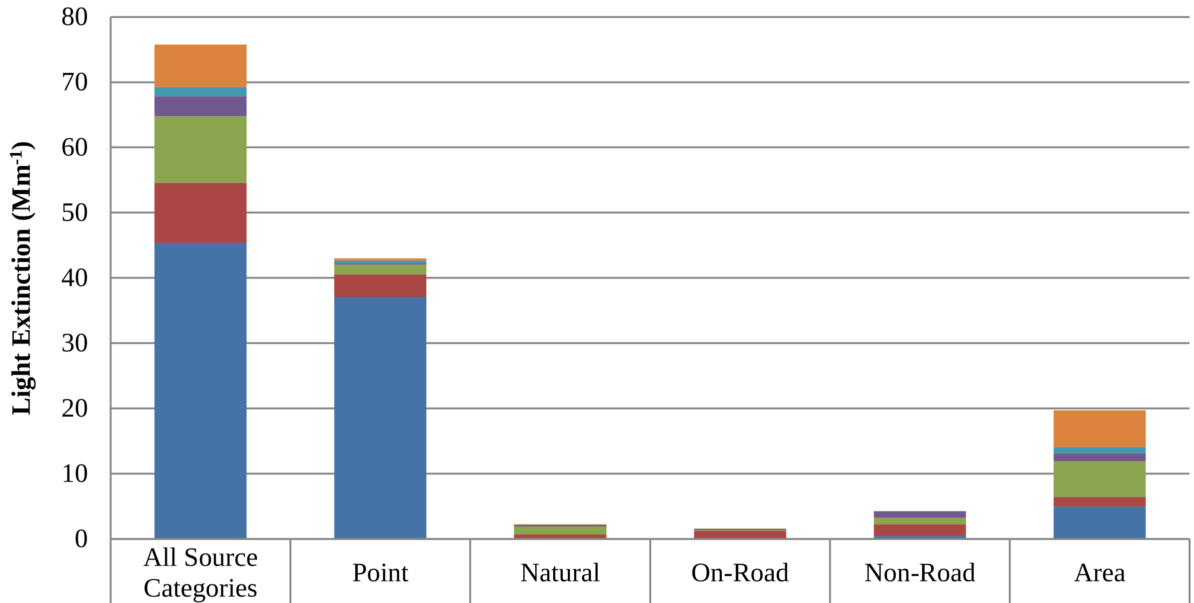
Figure 4 and Figure 5 show the modeled relative contributions to light extinction for each species and source category at Caney Creek and Upper Buffalo on the twenty percent worst days in 2018. According to the regional PSAT data, light extinction attributed to SO_4 is projected to decrease on the twenty 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.

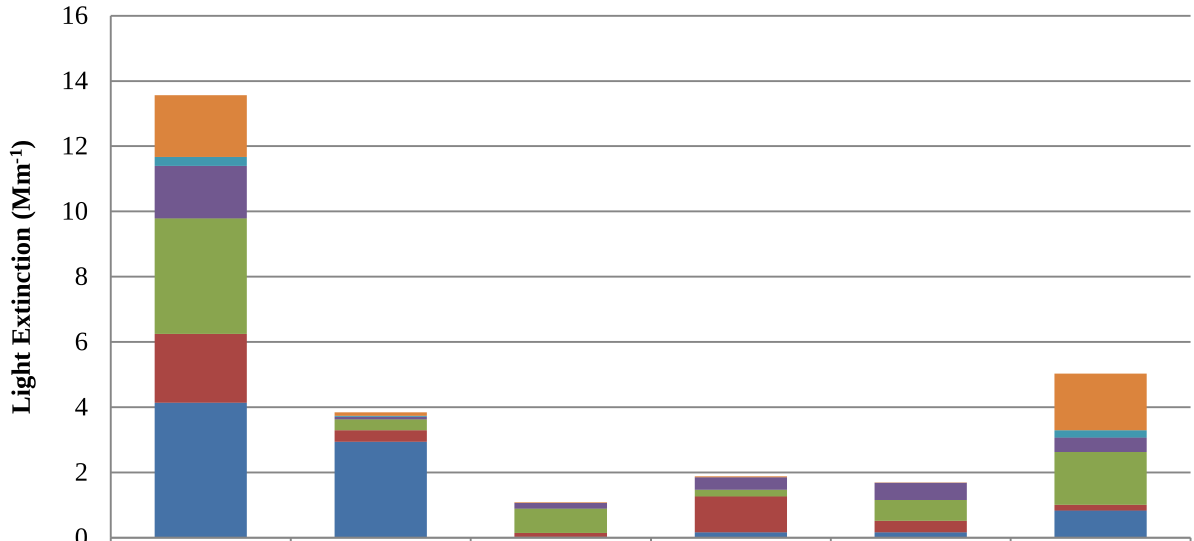
Table 7 shows the relative contributions of sources within Arkansas to light extinction for each source category at Caney Creek and Upper Buffalo on the twenty percent worst days in 2002. Area sources had a larger impact on light extinction than did point sources when only sources within Arkansas were 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 7 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

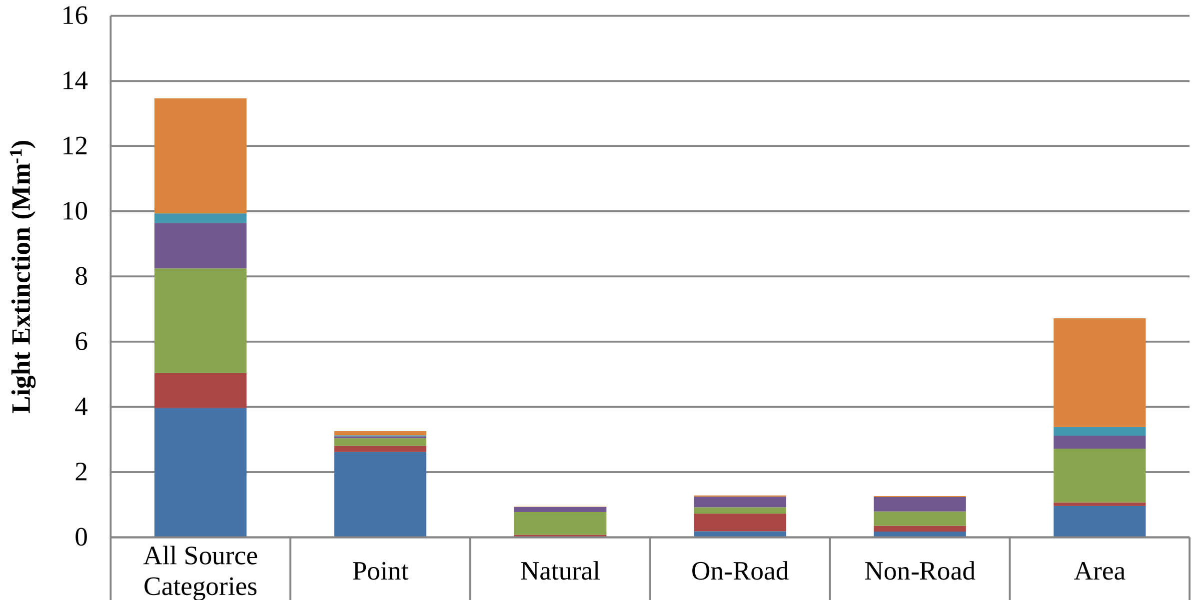
Figure 6 and Figure 7 show the relative contributions of sources within Arkansas to light extinction for each source category and species at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days in 2002. SO_4 from Arkansas sources contributed approximately three percent of total 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



	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

Figure 7 Modeled Light Extinction due to Arkansas Sources for the 20% Worst Days at Upper Buffalo in 2002



	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

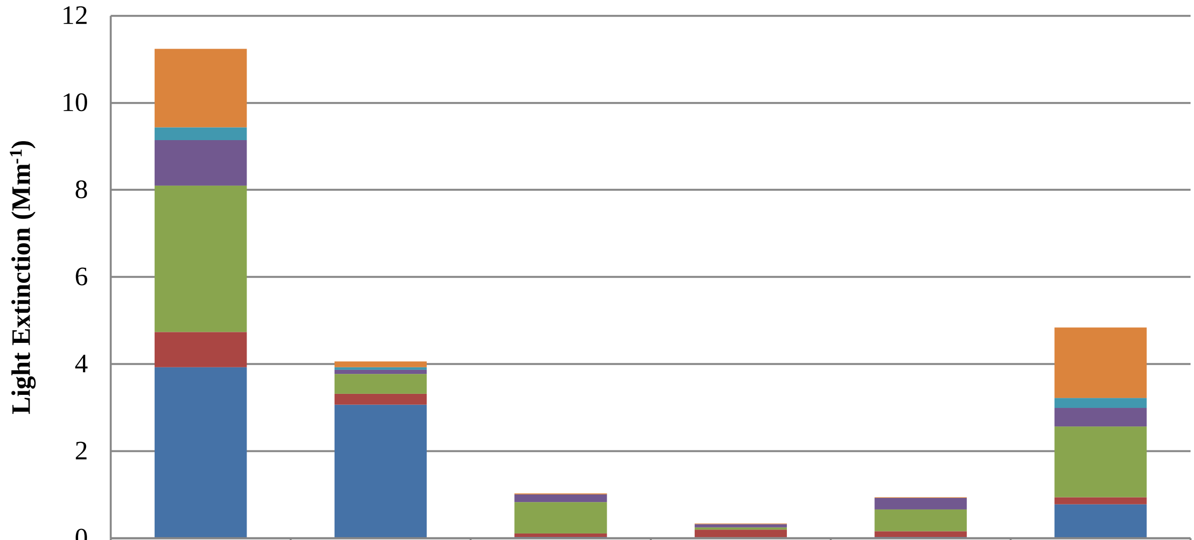
Table 8 shows the relative contributions of sources within Arkansas to light extinction for each source category at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days in 2018. Area sources are projected to continue to have a larger impact on light extinction than do point sources 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.

Table 8 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

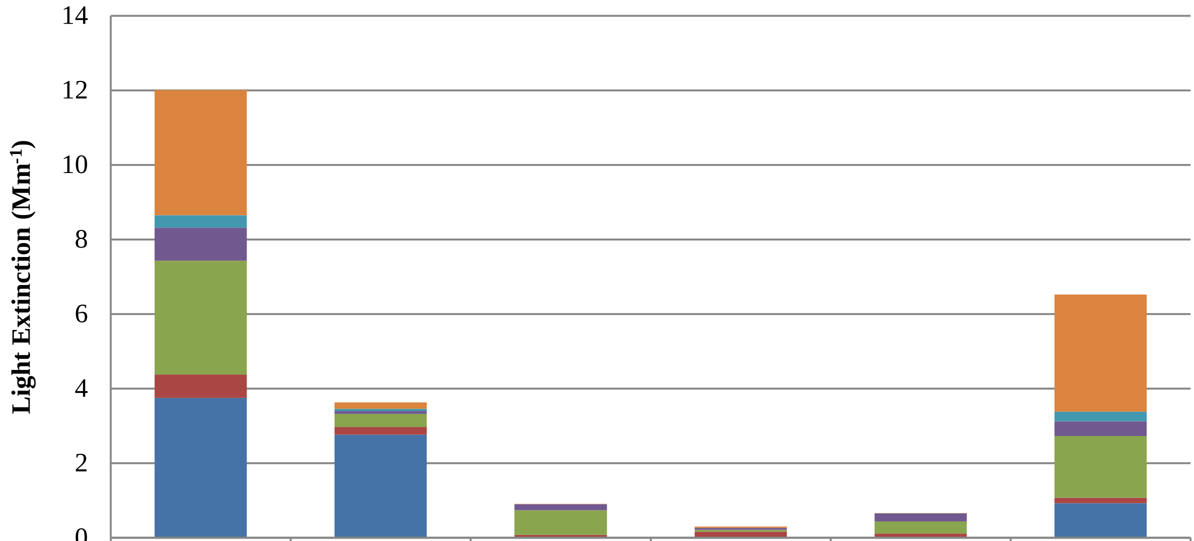
Figure 8 and Figure 9 show the relative contributions of sources within Arkansas to light extinction for each species and source category at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days in 2018. According to the PSAT data for Arkansas sources, light extinction attributed 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



	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

Figure 9 Modeled Light Extinction due to Arkansas Sources for the 20% Worst Days at Upper Buffalo in 2018



	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 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. Identification of Potential Reasonable Progress Sources for the First Planning Period

As a starting point to identifying which sources to evaluate for controls in ADEQ's reasonable progress analysis, ADEQ compiled a list of all 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.[28] For those sources that participate in the Acid Rain Program, ADEQ obtained 2015 sulfur dioxide emissions from the Air Markets Program Data tool.[29] 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 9 below.

Table 9 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.

[28] 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.
[29] https://ampd.epa.gov/ampd/

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 9, 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.[30] Table 10 lists the Q/D values for these sources.

Table 10 Q/D Values for Large SO_2 Point Sources[31]

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
Ash Grove Cement Company/Foreman Cement Plant	1	5
Nucor-Yamato Steel Company	1	1

Three sources identified in Table 10 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 and modeling performed in the development of the 2008 AR RH SIP demonstrated that FutureFuel Chemical Company had less than a 0.5 dv impact on Class I areas. John W. Turk Jr. Power Plant began operation in 2012 and has implemented best available control technology, which is more stringent than BART. As such, ADEQ determined that it was appropriate to defer consideration of these sources under reasonable progress to future regional haze planning periods. Deferring consideration of these two facilities is consistent with EPA's determination in the final AR RH FIP. ADEQ will focus its evaluation of the four

[30] 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)
[31] Class I Areas_Q Over D Calculations.xls in Appendix F.

reasonable progress factors on Entergy Independence because it is the second highest emitter of SO_2 in Arkansas, has high Q/D values, and is not subject to BART.

C. 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. 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. Our analysis below evaluates the statutory factors using the data provided by EPA in support of the AR RH FIP as supplemented by Entergy.

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, units at Independence were installed in 1983, nine years after installation of units at Entergy White Bluff, and are not subject to BART. Because Entergy White Bluff and Entergy Independence are sister facilities, costs for different control technologies examined in the BART analysis for Entergy White Bluff should provide reasonably accurate cost and control efficiency estimates for Entergy Independence. This method of assessing cost of compliance for Entergy Independence is supported by documentation provided in the docket for the AR RH FIP.[32]

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 2014–2016 levels.[33] 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

Emissions of SO_2 from Entergy Independence units are currently controlled by the use of lower sulfur coals than required under current regulations. The new source performance standard for sulfur dioxide is 1.2 lb/MMBtu; however, a more stringent prevention of significant deterioration (PSD) emissions limitation of 0.93 lb/MMBtu is in effect for these units. Entergy Independence

[32] EIA Consolidated Data_WB and Ind_Y2012.xlsx in Appendix F

[33] 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.

has been able to achieve 30-boiler-operating-day average emissions rates in the range of 0.48–0.63 lb SO_2/MMBtu.[34] The 30-boiler-operating-day average monthly emissions rate between 2014 and 2016 was 0.57 lb SO_2/MMBtu at Unit 1 and 0.56 lb SO_2/MMBtu at Unit 2. 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.[35] 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.[36] 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.[37] Annual emissions from Entergy Independence increased to 22,569 SO_2 in 2016, but are lower than any annual emissions rate from 2008–2014.[38]

Market trends for coal and natural gas have resulted in decreased dispatch of Entergy Independence. 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 2008–2018 planning period and beyond.[39] Figure 10 shows energy consumption trends from the electricity sector by fuel from 1980–2016 and projects trends out to 2040. Taken together, the decrease in dispatch and the use of lower sulfur coals have resulted in reduced emissions from Entergy Independence.

[34] Air Markets Program Data: Monthly Heat Input and SO_2 Data for Entergy Independence for 2014-2016 <https://ampd.epa.gov/ampd/>

[35] Entergy Arkansas, Inc. – Independence, Permit No. 0449-AOP-R10 AFIN: 32-00042

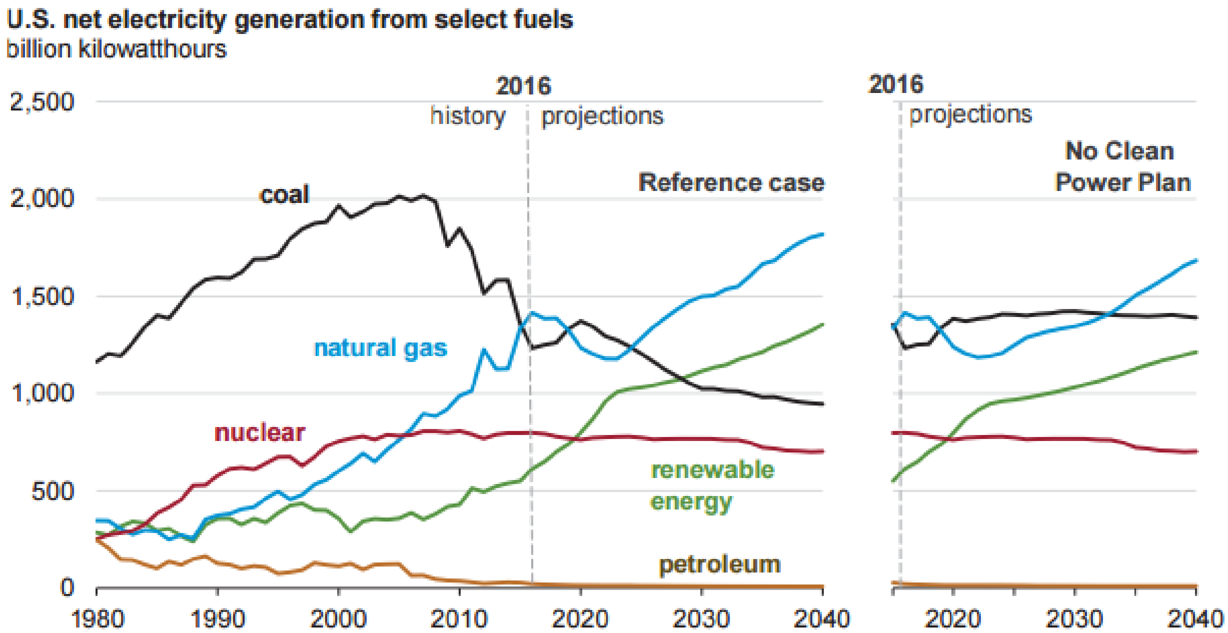
[36] 2009 Arkansas Department of Environmental Quality Emissions Inventory, 2010 Arkansas Department of Environmental Quality Emissions Inventory, 2011 National Emissions Inventory Version 2, 2012 Arkansas Department of Environmental Quality Emissions Inventory, 2013 Arkansas Department of Environmental Quality Emissions Inventory, 2014 National Emissions Inventory Version 1 <https://eis.epa.gov/eis-system-web>

[37] Air Markets Program Data: Air Markets Program Data: Annual SO_2 Data for Entergy Independence for 2015 <https://ampd.epa.gov/ampd/>

[38] Air Markets Program Data: Air Markets Program Data: Quarterly SO_2 Data for Entergy Independence for 2015 and 2016 <https://ampd.epa.gov/ampd/>

[39] *Annual Energy Outlook 2017*. U.S. Energy Information Administration

Figure 10 United States Electricity Sector Energy Consumption by Fuel[40]



2. 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 for Dry FGD estimates in their comments on the AR RH FIP. ADEQ calculated cost information using information provided by Entergy regarding LSC 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.[41] ADEQ estimated annualized operation and maintenance costs of switching to LSC at $1.5 million and $1.6 million for Entergy Independence Unit 1 and Unit 2, respectively.[42] Controlled annual emission rates for the LSC scenario were calculated based on these annualized costs and the anticipated emission reductions from switching to LSC.[43] ADEQ estimated that the average cost-effectiveness for fuel

[40] U.S. Energy Information Administration. (2017). Annual Energy Outlook 2017 at70. <http://www.eia.gov/outlooks/aeo/pdf/0383(2017).pdf>

[41] The Entergy August 18, 2017 revised BART analysis for White Bluff estimated this cost premium at $0.50/ton.

[42] 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.

[43] 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.

switching to LSC is approximately $2,284/ton of SO_2 reduced at Entergy Independence Unit 1 and $2,173/ton of SO_2 reduced at Entergy Independence Unit 2.

Installation of Wet FGD requires a large capital investment. 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.

Installation of Dry FGD also requires a large capital investment. EPA estimated total annualized costs of Dry FGD at $36,842,543 for each Entergy Independence unit based on a thirty-year amortization period.[44] EPA estimated that the average cost-effectiveness for Dry FGD was $2,853 per ton of SO_2 reduced at Entergy Independence Unit 1 and $2,634 per ton of SO_2 reduced at Entergy Independence Unit 2. In comments on the AR RH FIP, Entergy provided different cost-effectiveness estimates for Dry FGD, assuming that the costs at Entergy Independence match the cost of installation and operation at Entergy White Bluff. Entergy's estimates were $4,234/ton of SO_2 removed at Entergy Independence Unit 1 and $3,909 per ton of SO_2 removed at Entergy Independence Unit 2.[45] Table 11 lists ADEQ's estimates of cost-per-deciview for Dry FGD controls at Independence Units 1 and 2 for each Class I area

Table 11 Average Dollar-Per-Deciview Reduction for Control Options at Independence Units 1 and 2[46]

	Caney Creek	Upper Buffalo	Hercules Glades	Mingo
SDA	$67,230,917	$62,551,006	$69,777,543	$70,512,043

3. 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.

[44] EPA calculated cost-effectiveness based on allowed costs and alternative cost-effectiveness values including disallowed costs proposed by Entergy. The costs included in this SIP exclude disallowed costs. Calculations of these costs can be found in the Independence SDA Costs spreadsheet included in Appendix F.

[45] 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

[46] Total Annualized Cost of Dry FGD for Independence from the AR RH FIP divided by the deciview impact of Dry FGD as revised on May 1, 2015. Calculations of dollars-per-deciview can be found in the Independence SDA Costs spreadsheet included in Appendix F.

4. 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.

5. 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, given market trend for coal and the age of Entergy Independence, Entergy may choose to change operations at Entergy Independence thus not realizing a full thirty-year amortization period for Dry and Wet FGD.

6. Degree of Improvement in Visibility

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. In the AR RH FIP, EPA estimated that installation of Dry FGD at Entergy Independence Unit 1 and Unit 1 would achieve a 1.096 dv improvement at Caney Creek and a 1.178 dv improvement at Upper Buffalo. 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 CAMx, a photochemical model, instead of the CALPUFF model used by EPA, Entergy estimated that installation of Dry FGD at Independence would only result in a 0.08 dv improvement at Caney Creek and a 0.07 dv improvement at Upper Buffalo on the twenty percent worst days.[47] A value of one dv is considered perceptible. Because Entergy Independence frequently achieves the less than or equal to the 0.6 lb/MMBtu emission rate associated with LSC, ADEQ has not modeled visibility impacts for the LSC scenario.

D. Additional Controls Necessary for Reasonable Progress at Arkansas Class I Areas

Based on this analysis, ADEQ has determined that no add-on controls for SO_2 or PM beyond BART are necessary for reasonable progress during the 2008–2018 planning period. The Arkansas NOx Regional Haze SIP submitted to EPA required compliance with the CSAPR trading program for ozone season NOx for all Arkansas EGUs participating in that program to address control of NOx for reasonable progress.

Through an evaluation of emissions and distance from wilderness areas, ADEQ determined that only Entergy Independence need be considered in a four factor analysis; however, ADEQ has determined that installation of add-on control technologies, as was finalized in the AR RH FIP, is

[47] 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

neither reasonable nor necessary to achieve reasonable progress for the 2008–2018 planning period. Both Entergy's and EPA's cost-effectiveness estimates for Dry FGD at Entergy Independence exceed screening thresholds used for cost-effectiveness in other approved reasonable progress analyses.[48] Furthermore, the significant capital investment costs of Dry FGD would lock Entergy into continued operation of the aging Entergy Independence for thirty years in order to avoid stranded costs associated with the installation of Dry FGD. Although fuel switching to LSC has a similar cost-effectiveness in terms of emission reductions as does Dry FGD, fuel switching to LSC requires no capital costs and locks in visibility improvements already observed at Arkansas and Missouri Class I areas due to Entergy's choice to burn lower sulfur content coals than required by permit at Entergy Independence Unit 1 and Unit 2. Requiring a technology that does not involve a significant capital investment that must be amortized over a long period also provides Entergy with the flexibility to determine the continued viability of Entergy Independence based on market conditions rather than extending the possible life of the units based on the need to recover the capital costs of Dry FGD. Entergy has also proposed their willingness to commit to using only LSC at Entergy Independence in comments on the AR RH FIP.[49] Therefore, it is reasonable and consistent with EPA guidance to defer more expensive controls to later planning periods in order to maintain a consistent glidepath toward the long-term goal. [50] As such, ADEQ has determined that it is appropriate to require Entergy Independence to meet a 0.6 lb SO_2/MMBtu limit based on LSC to ensure that the visibility progress achieved during this planning period continues.

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 Independence to ensure that the units can operate in the event of a fuel supply disruption. Therefore, ADEQ finds that it is reasonable to require Entergy to comply with the requirement to meet an emission rate of 0.6 lb SO_2/MMBtu at Entergy Independence Unit 1 and Unit 2 no later than three years after approval of this SIP revision.

AO LIS No. [To be assigned upon finalization] includes enforceable limitations and compliance dates consistent with ADEQ's determination.

E. 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 revision proposed in July 2017 that are required to be in effect by the end of the first planning 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

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[48] Approval and Promulgation of Air Quality Implementation Plans; Common Wealth of Kentucky; Regional Haze State Implementation Plan: Proposed Rule (2011). 76 FR 78194
EPA approved RPGs in Kentucky SIP based on CAIR, which had a \$2000/ton SO_2 cost-effectiveness screening threshold.

[49] Entergy Arkansas Inc. Supplemental Comments on the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas (August 8, 2016)

[50] Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program at page 1-4

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.[51] The results of our analysis for the twenty percent worst days for 2018 for Caney Creek and Upper Buffalo are included in Table 12.[52]

Table 12 Reasonable Progress Goals for 2018 for Caney Creek and Upper Buffalo

Class I Area	2018 RPG 20% Worst Days (dv)
Caney Creek	22.47
Upper Buffalo	22.51

Figure 11 and Figure 12 demonstrate that Arkansas is already achieving greater visibility improvements than the RPGs listed in Table 12.

[51] 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

[52] See RPG Calculation Data Sheet provided at https://www.adeq.state.ar.us/air/planning/sip/regional-haze.aspx.

Figure 11 Caney Creek Reasonable Progress Assessment – 20% Worst Days

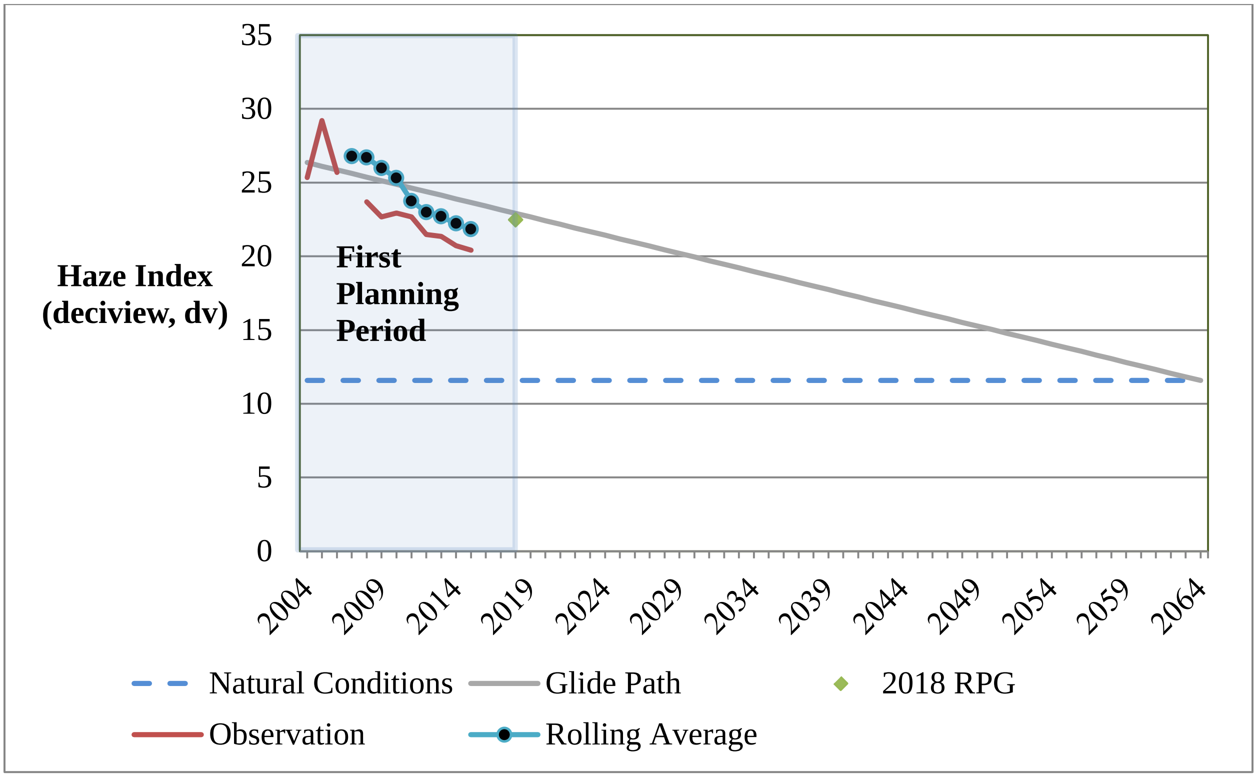
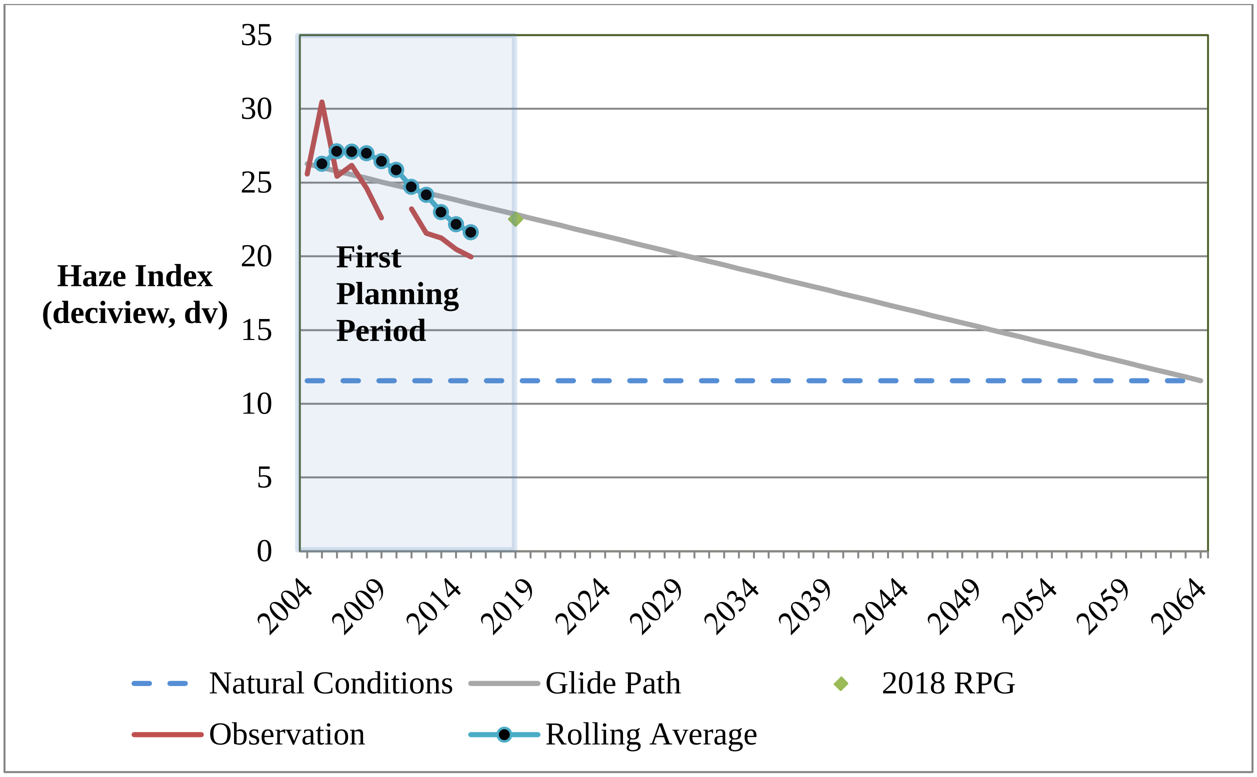


Figure 12 Upper Buffalo Reasonable Progress Assessment – 20% Worst Days



F. 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 impact of Arkansas sources 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.

Figure 13 and Figure 14 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 dv for Mingo and 23.06 for Hercules Glades. The most recent calculations for the twenty percent haziest days and twenty percent best days for Class I areas were performed for 2015.[53] For both Mingo and Hercules Glades, visibility impairment on the twenty percent haziest 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 haziest 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 haziest days at Mingo is on track to beat

[53] http://vista.cira.colostate.edu/DataWarehouse/IMPROVE/Data/SummaryData/RHR_2015/SIA_group_means_7_16.csv

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. Therefore, no additional controls on sources within Arkansas are necessary to ensure that other states' visibility goals for their Class I areas are met. The control measures contained in the 2008 AR RH SIP, the NOx Regional Haze SIP revision, and this SIP revision satisfy the interstate transport visibility requirement of CAA 110(a)(2)(D)(i)(II) for the 2008 eight-hour ozone and 2012 annual $PM_{2.5}$ NAAQS.

Figure 13 Hercules Glades Reasonable Progress Assessment – 20% Worst Days

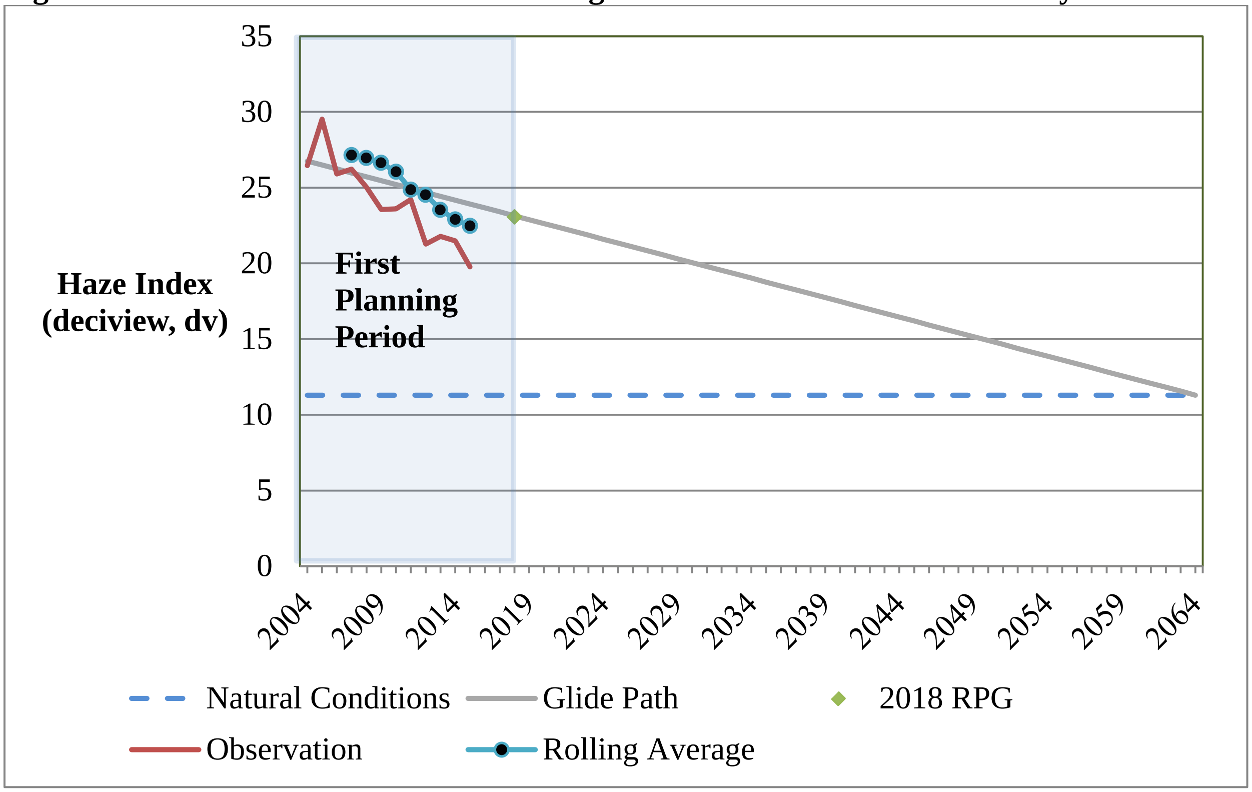
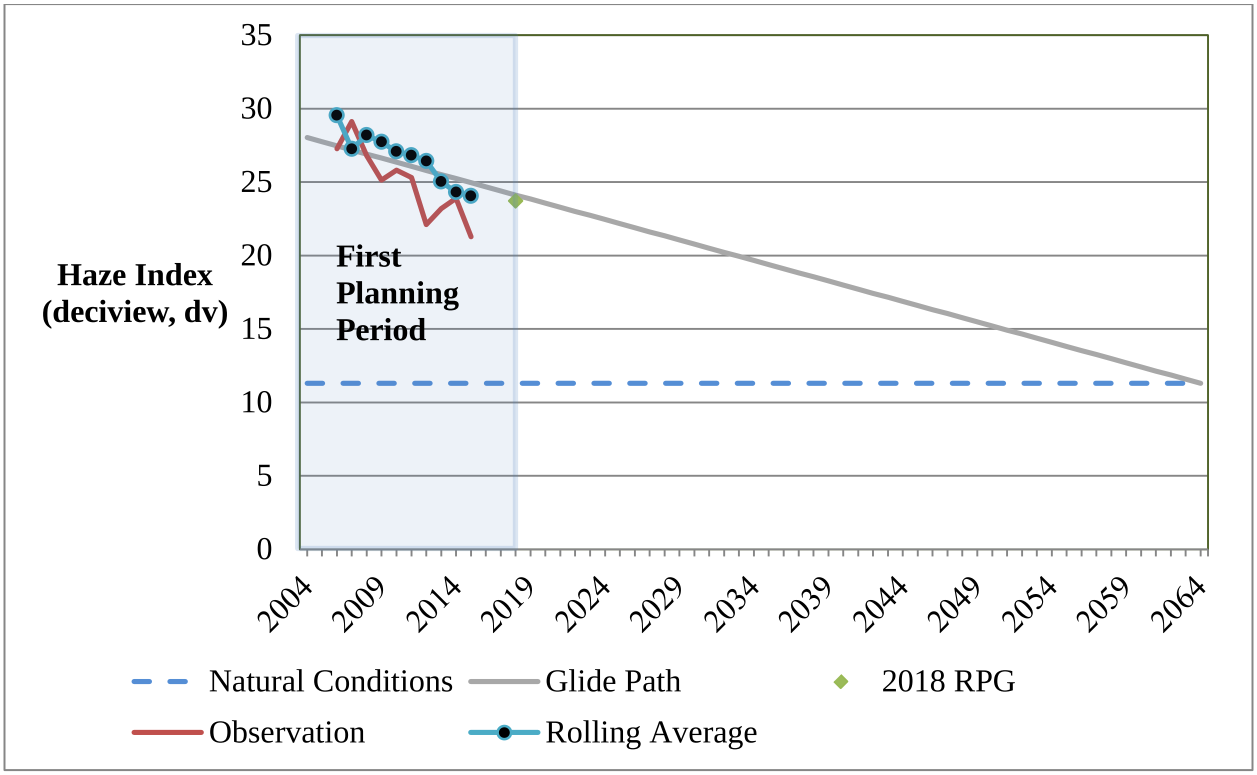


Figure 14 Mingo Reasonable Progress Assessment – 20% Worst Days



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)

ADEQ also acknowledges planned changes in operations at large stationary sources 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. In October 2017, Luminant announced retirement in 2018 of three large power plants in Texas: Big Brown Plant, Sandow Plant, and Monticello Plant.[54] Both Big Brown Plant and Monticello Plant impact visibility at Caney Creek.[55] The baseline maximum visibility impact from Big Brown at Caney Creek is 3.775 dv and the baseline maximum visibility impact from Monticello at Caney Creek is 10.498 dv. [56]

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. Review, Consultations, and Comments

A. EPA Review with Parallel Processing

The State of Arkansas plans to submit this proposed SIP revision, along with a request for parallel processing and a draft notice of public hearing and opportunity for comment, to EPA. Arkansas also requested that EPA stay the NOx emissions limitations for EGUs contained in the AR RH FIP during EPA's review of this SIP revision and withdraw such limitations upon

[54] https://www.luminant.com/luminant-announces-decision-retire-monticello-power-plant/; https://www.luminant.com/luminant-close-two-texas-power-plants/

[55] 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)

[56] Id. Table 15 at 931

approval of this SIP revision. The request for parallel processing has been included in Tab A of this proposed SIP package.

B. Federal Land Manager Consultation

In accordance with the provisions of 40 C.F.R. § 51.308(i)(2), ADEQ will consult with the designated FLM staff personnel. This consultation will give 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. Any comments received from the FLMs will be 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 and notification letters are included in Tab E of this proposed SIP package. Comments from FLMs and responses will be included in the final SIP package

C. 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. Any comments received from Missouri DNR will be considered and posted to ADEQ's Regional Haze webpage. The notification letter is included in Tab E of this proposed SIP package. Comments from Missouri DNR and responses will be included in the final SIP package.

D. Public Review

ADEQ will provide notice of a public hearing to receive public comments on this proposed SIP revision. The notice of the proposal and public hearing will be published in the Arkansas Democrat Gazette, which is a newspaper in circulation statewide, at least thirty days prior to the public hearing and will be posted on ADEQ's website concurrently with newspaper publication of the public notice. The notice will provide logistical information regarding the public hearing and the length of the public comment period. The public comment period for this SIP revision will be at least thirty days in accordance with notice requirements under 40 C.F.R. §51.102.

The notice contains information on the availability of the proposed SIP revision for public inspection at ADEQ information depositories, ADEQ headquarters, and ADEQ's Regional Haze webpage.

Both oral and written comments received by ADEQ during the public comment period will be posted on the ADEQ Regional Haze web page. Copies of written comments, a summary of ADEQ's response to comments, and records from the public hearing will be included in the final SIP package.

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, no BART emission limits are necessary 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, the NOx Regional Haze 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

Contents

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
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

Table of Contents

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** Ammonia** Ozone Sulfuric Acid (SAM)**	10.2 14.0 2.3 38.5	35.0 53.0 9.5 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* Tetrachloroethylene Toluene* Xylene*	0.02 0.01 0.02 0.01	0.07 0.01 0.06 0.02
60	Line 1 Decker	Routed to the Incinerator (SN-83)		
61	Line 2 Decker	VOC TRS Acetaldehyde* Acetone** Acrolein* Benzene* Carbon Tetrachloride* Chloroform* Cresol* Formaldehyde* Methanol* Propionaldehyde* Styrene* Tetrachloroethylene Toluene* 1,2,4-Trichlorobenzene* Xylene*	4.5 2.1 0.33 0.5 0.01 0.01 0.02 0.13 1.56 0.09 2.02 0.10 0.02 0.04 0.01 0.11 0.02	16.9 7.7 1.23 1.8 0.02 0.01 0.07 0.49 5.90 0.33 7.65 0.35 0.06 0.15 0.02 0.40 0.05
62	Fine Paper Machine No. 1	VOC Acetaldehyde* Acetone** Acrolein* Formaldehyde* Methanol* Methylene Chloride Tetrachloroethylene 1,2,4-Trichlorobenezene* Xylene*	18.6 1.20 0.8 0.05 0.24 1.20 0.10 0.09 0.05 0.03	81.3 5.23 3.6 0.20 1.05 5.23 0.41 0.37 0.22 0.11
63	Fine Paper Machine No. 2	VOC Acetaldehyde* Acetone** Acrolein* Formaldehyde* Methanol* Methylene Chloride	11.3 1.20 0.8 0.05 0.24 1.20 0.10	49.3 5.23 3.6 0.20 1.05 5.23 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	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 PM_{10}	0.4	1.5
			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]

SN	Description	Pollutant	lb/hr	ton/yr
70	Tissue Machine No. 7	PM_{10}	0.7	2.9
		PM	0.0646 lb/ ADTFP*	
		VOC	17.7	77.4
			1.78 lb/ ADTFP* Annual Average	

*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	VOC	1.8	7.8
112			
113			

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

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_X does 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_2 emissions, NO_X emissions, 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_2 emissions 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_X may 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_2 concentration, 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_2 concentration 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

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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:

$E=c_s Q_{sd}/BLS$

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 ™

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

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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:

$$Cl_2 Moles = 1/8000\,(5\,T_N - T_A) \times N_{Thio}$$

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:

$$Cl_2 ppmv = \frac{3005(5\,T_N - T_A) \times N_{Thio}}{S_C \times t_S}$$

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:

$$\overline{C} = \sum_{i=1}^{n} C_i / fm_i$$

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 3 0 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

RECEIVED AUG 0 4 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 ›ssett, 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:

$$C_{corr} = C_{meas} \times \frac{(21-X)}{(21-Y)} \qquad (Eq.\ 7)$$

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:

$$ER_{SCCU} = \frac{(THC_{meas})}{BLS} \qquad (Eq.\ 11)$$

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 24 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

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:

$$H_a = 0.20\left[\sum_{i=1}^{p} M_i G_i C_{si}\right] + 0.04\left[\sum_{i=1}^{p} M_i (1 - G_i) + \sum_{j=1}^{q} M_{L_j}\right] \qquad \text{Eq. 13a}$$

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:

$$H_a = 0.08\left[\sum_{i=1}^{p} M_i G_i C_{si}\right] + 0.016\left[\sum_{i=1}^{p} M_i (1 - G_i) + \sum_{j=1}^{q} M_{L_j}\right] \qquad \text{Eq. 13b}$$

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

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_Xor PM at the control device inlet,

C_o= concentration of NO_Xor PM at the control device outlet, and

R = percent reduction of NO_Xor PM emissions.

(2) You must normalize the NO_Xor 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:

$$F_o = \frac{0.209 F_d}{F_c} \qquad \text{(Eq. 4)}$$

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:

$$X_{CO_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 5)}$$

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:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \qquad \text{(Eq. 6)}$$

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:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 7)}$$

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:

$$ER = \frac{C_{adj} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 8)}$$

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_Xconcentration.
		iv. Measure NO_Xat 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_Xconcentration 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_Xin 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_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 measurement for NO_Xconcentration.
		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_Xconcentration.

		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_2concentration is measured in lieu of oxygen concentration measurement, a CO_2correction factor is needed. Calculate the CO_2correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_0value 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_2volume 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_2produced to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

(ii) Calculate the CO_2correction 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_2correction factor, percent.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2correction value, percent.

(iii) Calculate the $NO_X$and SO_2gas concentrations adjusted to 15 percent O_2using CO_2as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \qquad \text{(Eq. 4)}$$

Where:

$\%CO_2$= Measured CO_2concentration 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_2at 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_2at the inlet and outlet of the control device; and	(1) Portable CO and O_2analyzer	(a) Using ASTM D6522–00 (2005)[a] (incorporated by reference, see §63.14). Measurements to determine O_2must 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_2analyzer	(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.

			03	

[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_2or CO_2at 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_2or CO_2at 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

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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 Gas Mcf	6A Boiler Oil Bbls	PM	SO_2	NOx	*	9A Boiler Gas Mcf	9A Boiler TDF Tons	9A Boiler 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				
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

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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			*			
	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

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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
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

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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
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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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
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

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
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

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
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

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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				
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

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
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

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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
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 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				
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 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				
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

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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	PM	SO_2	NOx	*	Gas Mcf	TDF Tons	Bark Tons	*	PM	SO_2	NOx
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					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

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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
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

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GEORGIA-PACIFIC CORPORATION
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				*	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-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 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
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
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
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	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
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	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
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

DATE	Gas Mcf	Oil Bbls	PM	SO_2	NOx	*	Gas Mcf	TDF Tons	Bark Tons	*	PM	SO_2	NOx
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 Mcf	Oil Bbls		Calculated lbs/hr		*	Gas Mcf	TDF Tons	Bark Tons	*		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	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

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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
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		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
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

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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	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
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

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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	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
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

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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	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
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

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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	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				
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

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	Gas	Oil				*	Gas	Rubber	Bark	*			
	Mcf	Bbls				*	Mcf	Tons	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
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

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	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

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				*	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-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

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 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
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

PAPER MILL UTILITY REPORT

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				
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				*	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
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.

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	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
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

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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	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-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

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

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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
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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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							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
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

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							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

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				
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

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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				
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

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							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
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

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	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

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							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
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

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

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							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
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

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
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

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

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				
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

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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

	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
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

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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	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-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

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

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
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

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
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

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				
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

	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
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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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
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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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				
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

GEORGIA-PACIFIC CORPORATION
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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
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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

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
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

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				
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

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
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

DATE	6A Boiler S/B MLbs	6A Boiler Steam MLbs	6A Boiler Gas Mcf	6A Boiler Oil Bbls				*	9A Boiler S/B MLbs	9A Boiler Steam MLbs	9A Boiler Gas Mcf	9A Boiler Rubber Tons	9A Boiler 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

$$\frac{7772\ \text{MCF}}{\text{day}} \cdot \frac{1\ \text{MMCF}}{1000\ \text{MCF}} \cdot \frac{7.6\ \text{lb PM}}{\text{MMCF}} \cdot \frac{1\ \text{day}}{24\ \text{hr}}$$

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 tl 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 emis 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/MMB 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 Techni 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

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.

<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

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

APPENDIX B
BART Five-Factor Analysis for Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations

BART FIVE FACTOR ANALYSIS

ARKANSAS ELECTRIC COOPERATIVE CORPORATION

BAILEY AND MCCLELLAN GENERATING STATIONS

Prepared By:

TRINITY CONSULTANTS, INC.
120 East Sheridan, Suite 205
Oklahoma City, Oklahoma 73104
(405) 228-3292

TRINITY CONSULTANTS, INC.
977 Ridge Drive, Suite 380
Lenexa, Kansas 66219
(913) 894-4500

In conjunction with:

ARKANSAS ELECTRIC COOPERATIVE CORPORATION
PO Box 194208
Little Rock, Arkansas
(501) 570-2420

Trinity Project No. 123701.0036

March 2014
Version 4

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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:

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

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:

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

Visibility impairment predictions 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

4. EXISTING EMISSIONS AND VISIBILITY IMPAIRMENT

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 $\Delta dv \geq 0.5$	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek Wilderness							
2001	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 $\Delta dv \geq 0.5$	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek Wilderness							
2001	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

<u>Control Costs</u>

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.

<u>Annual Tons Reduced</u>

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

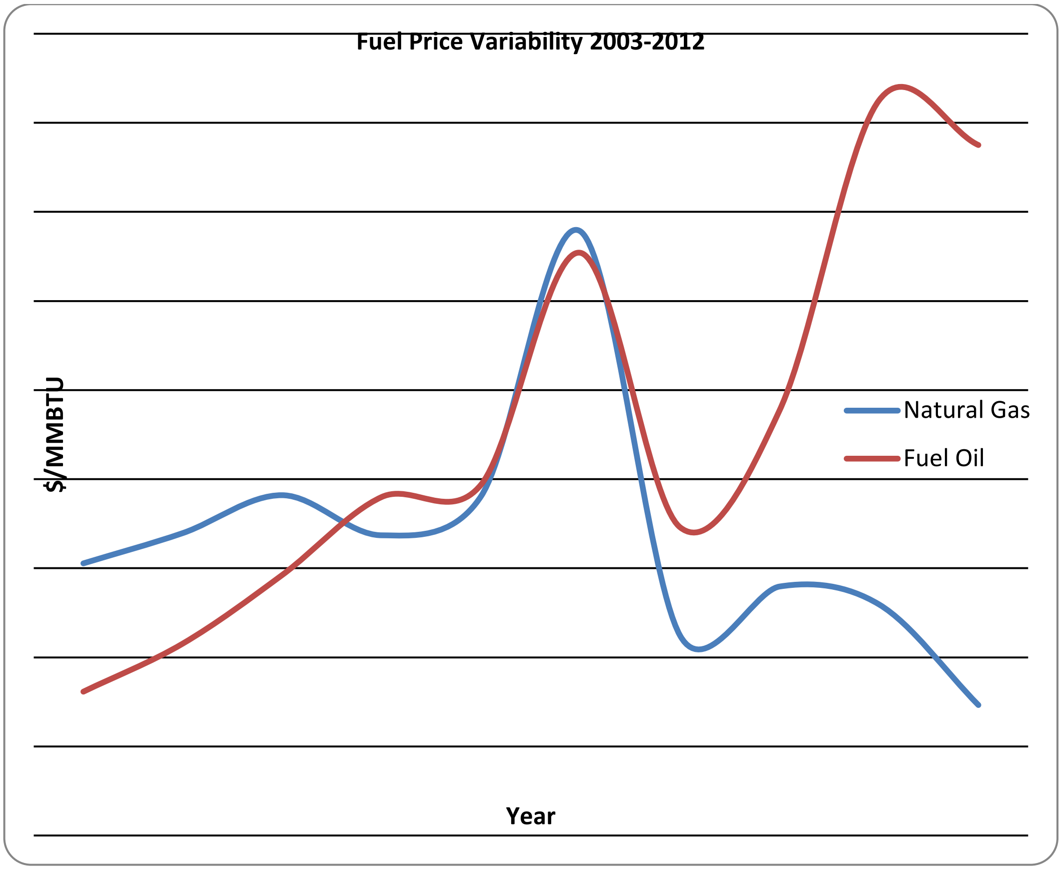

TABLE 5-9. SUMMARY OF COST EFFECTIVENESS FOR FUEL SWITCHING FOR CURRENT NO. 6 FUEL OIL AT BAILEY UNIT 1

	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]

[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

[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.

[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 98^{th} 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

APPENDIX B

MODELING PROTOCOL

CALMET DATA PROCESSING PROTOCOL ▲ BART DETERMINATION
OKLAHOMA GAS & ELECTRIC

MUSKOGEE GENERATING STATION
SEMINOLE GENERATING STATION
SOONER GENERATING STATION

Prepared by:

Vern Choquette ▲ Principal Consultant
Eugene Chen, PE ▲ Senior Consultant
Jeremy Townley ▲ Consultant

TRINITY CONSULTANTS
120 East Sheridan
Suite 205
Oklahoma City, OK 73104
(405) 228-3292

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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

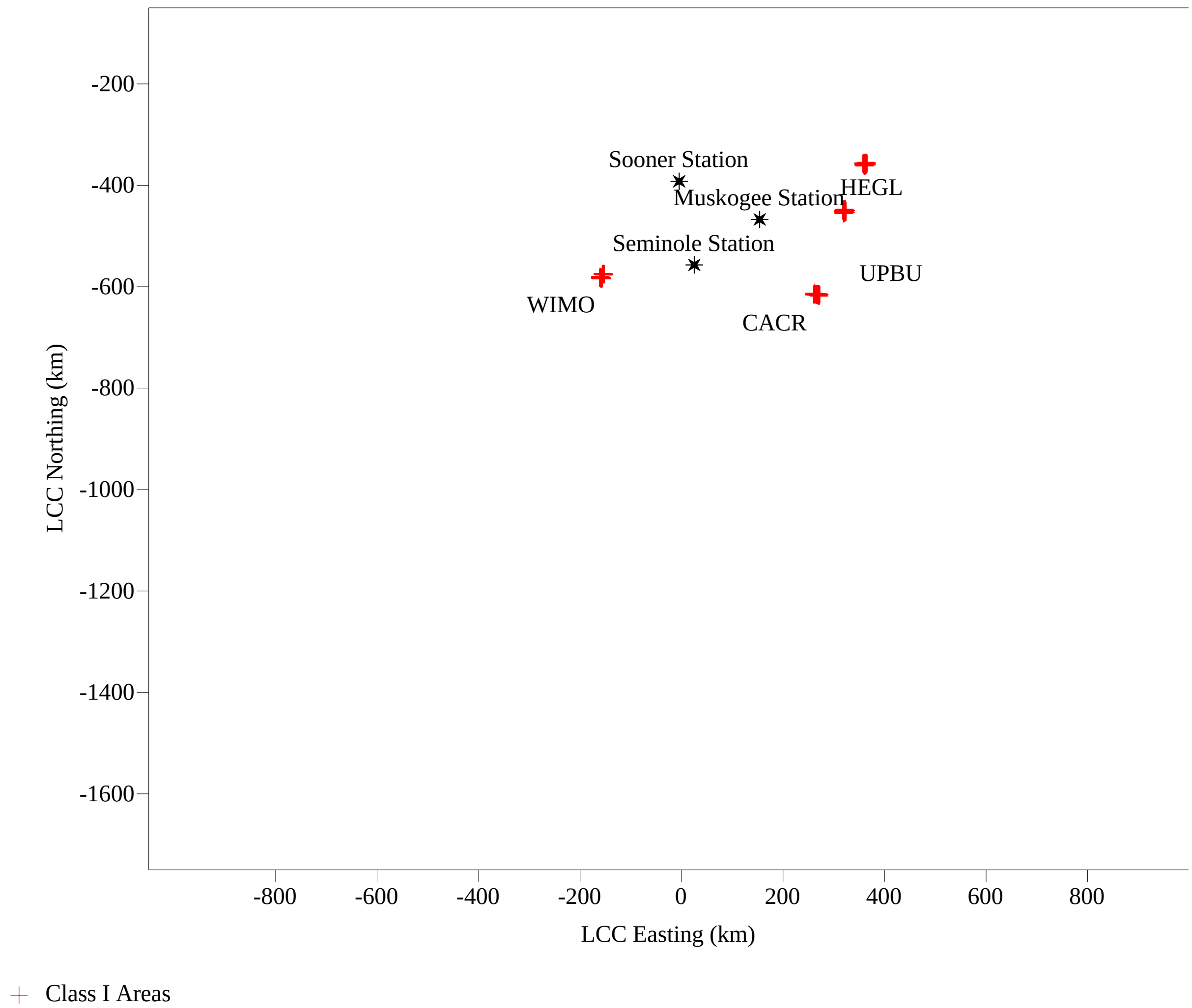
As required in CENRAP's BART Modeling Guidelines, Class I areas within 300 km of each station will be included in each analysis. The following table summarizes the distances of the four closest Class I areas to each station. As seen from this summary, some Class I areas are more than 300 km from the 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

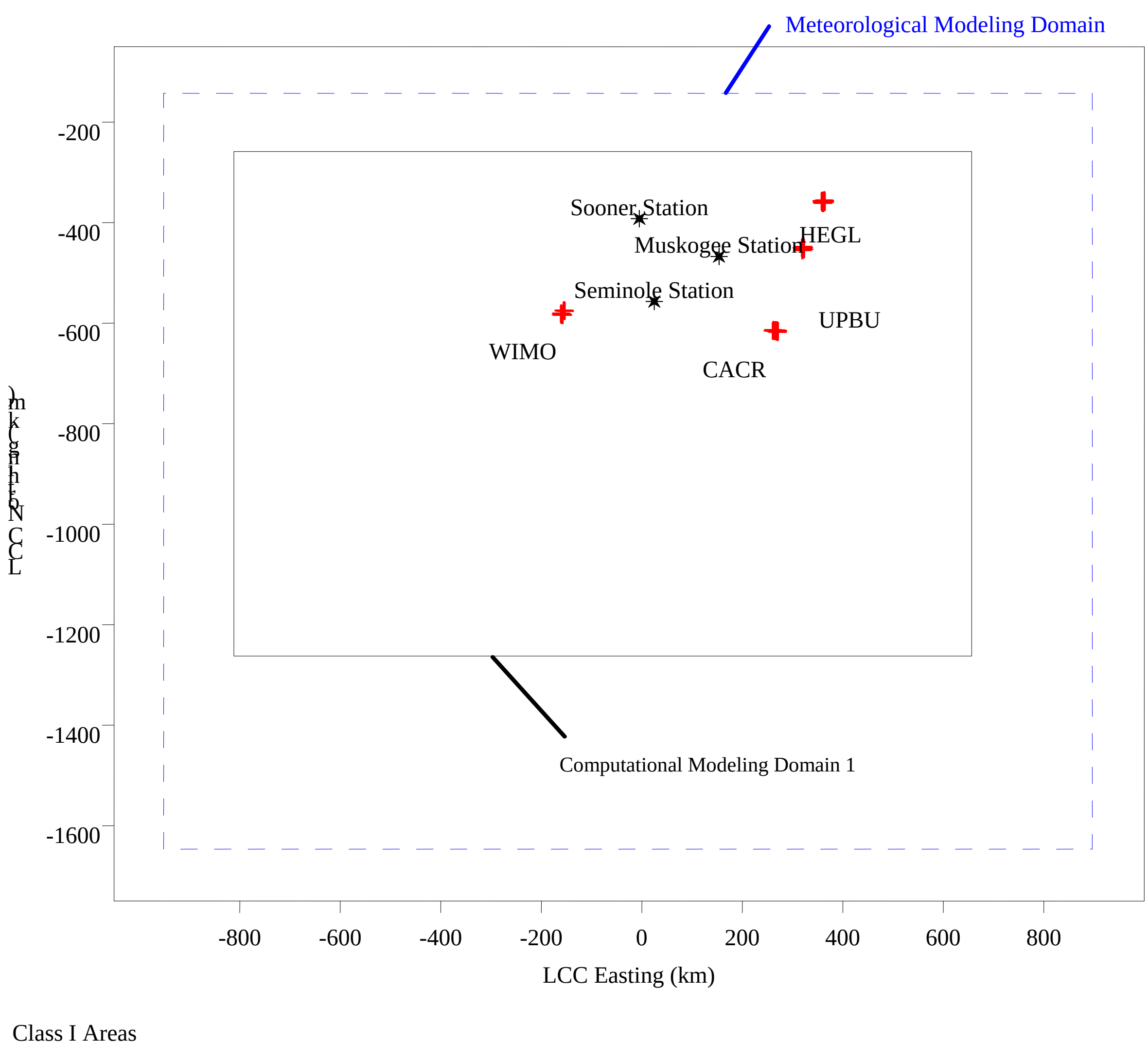
Processor	Version	Level
TERREL	3.3	030402
CTGCOMP	2.21	030402
CTGPROC	2.63	050128
MAKEGEO	2.2	030402
CALMET	5.53a	040716
CALPUFF	5.8	070623
POSTUTIL	1.3	030402
CALPOST	5.51	030709

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.

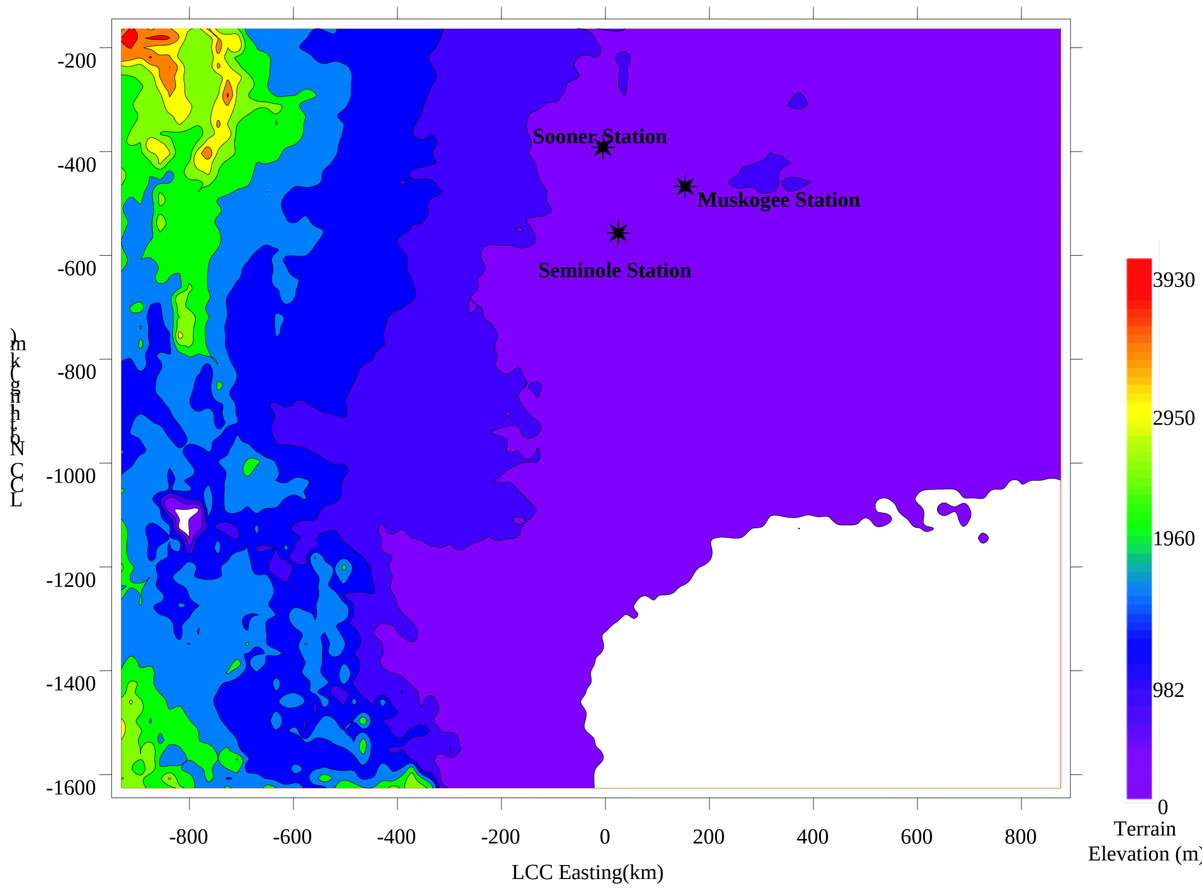
3.1 GEOPHYSICAL DATA

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.

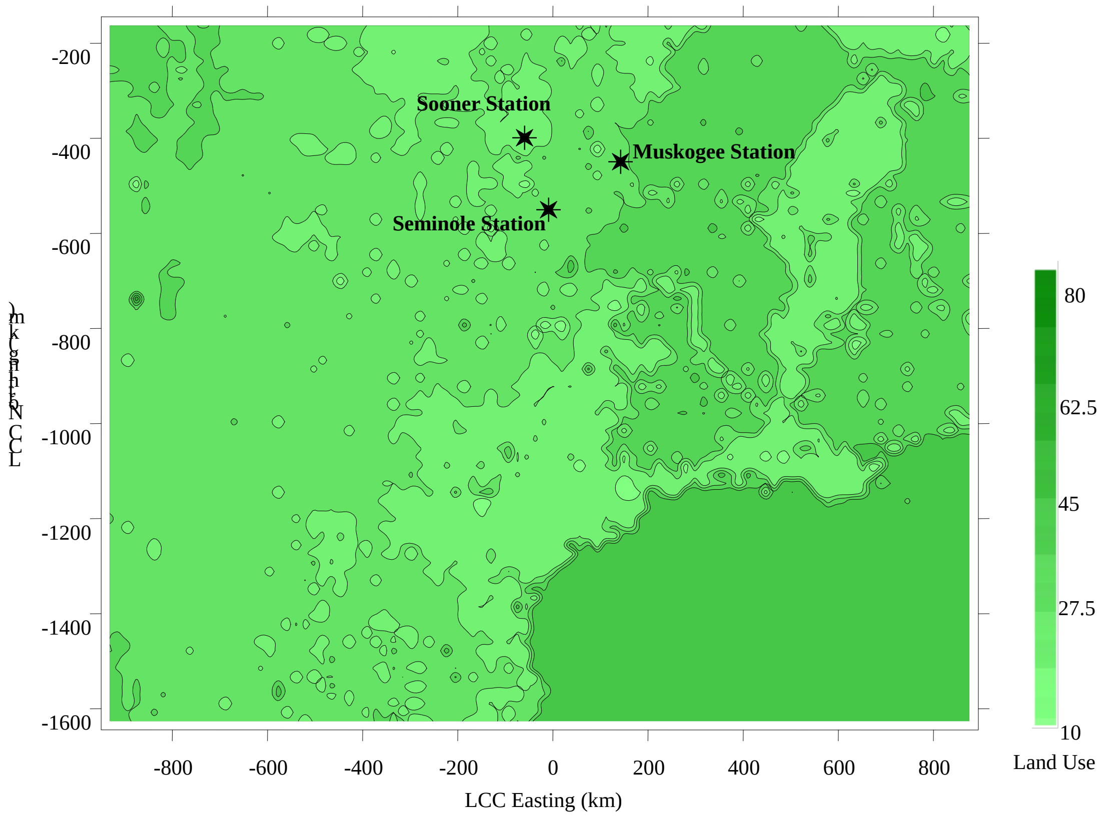
FIGURE 3-1. PLOT OF LAND ELEVATION USING USGS TERRAIN DATA



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.

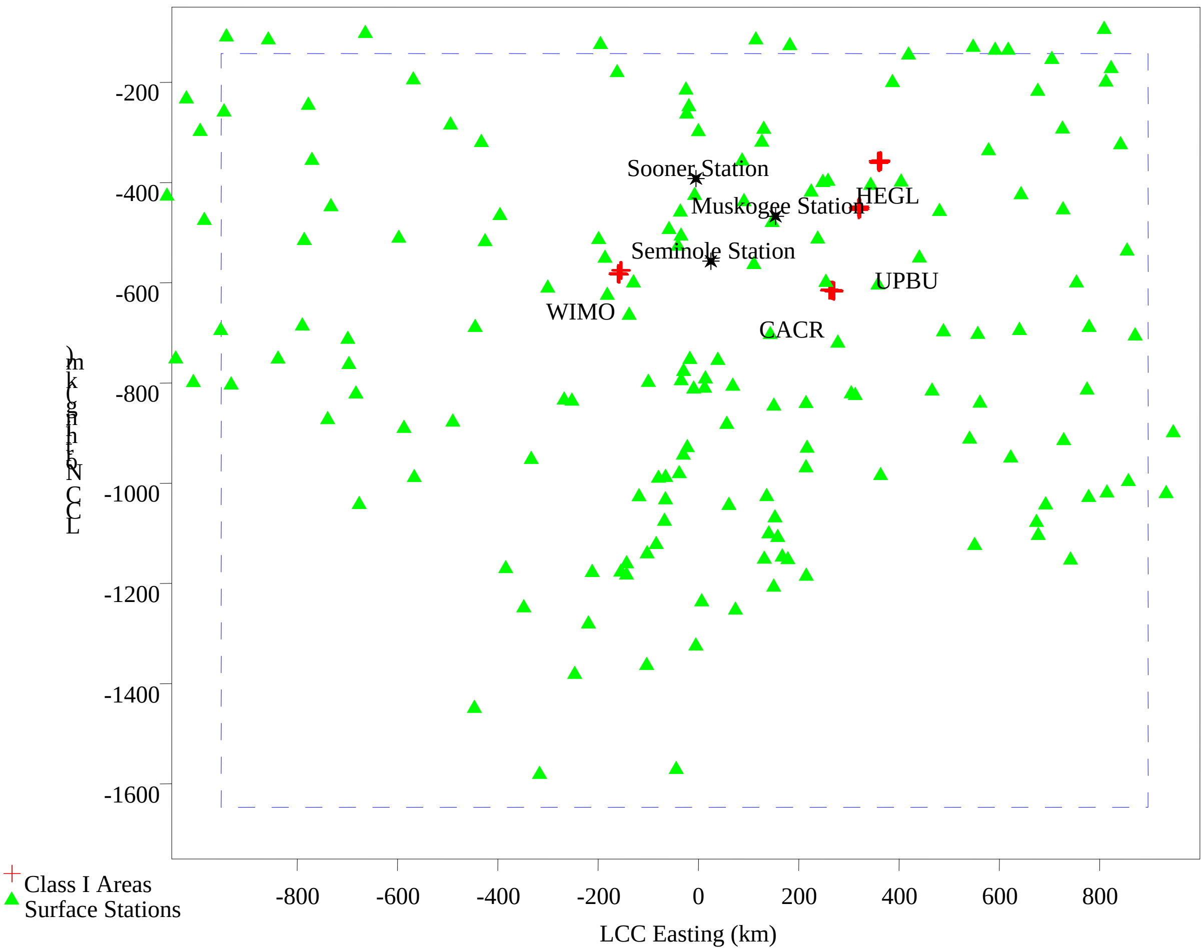
The time periods covered by the data in each of the MM5 files extracted by Alpine Geophysics include a specific number of calendar days, where the data starts at Hour 0 in GMT for the first calendar day and ends at Hour 23 in GMT on the last calendar day. In order to run CALMET in the local standard 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.

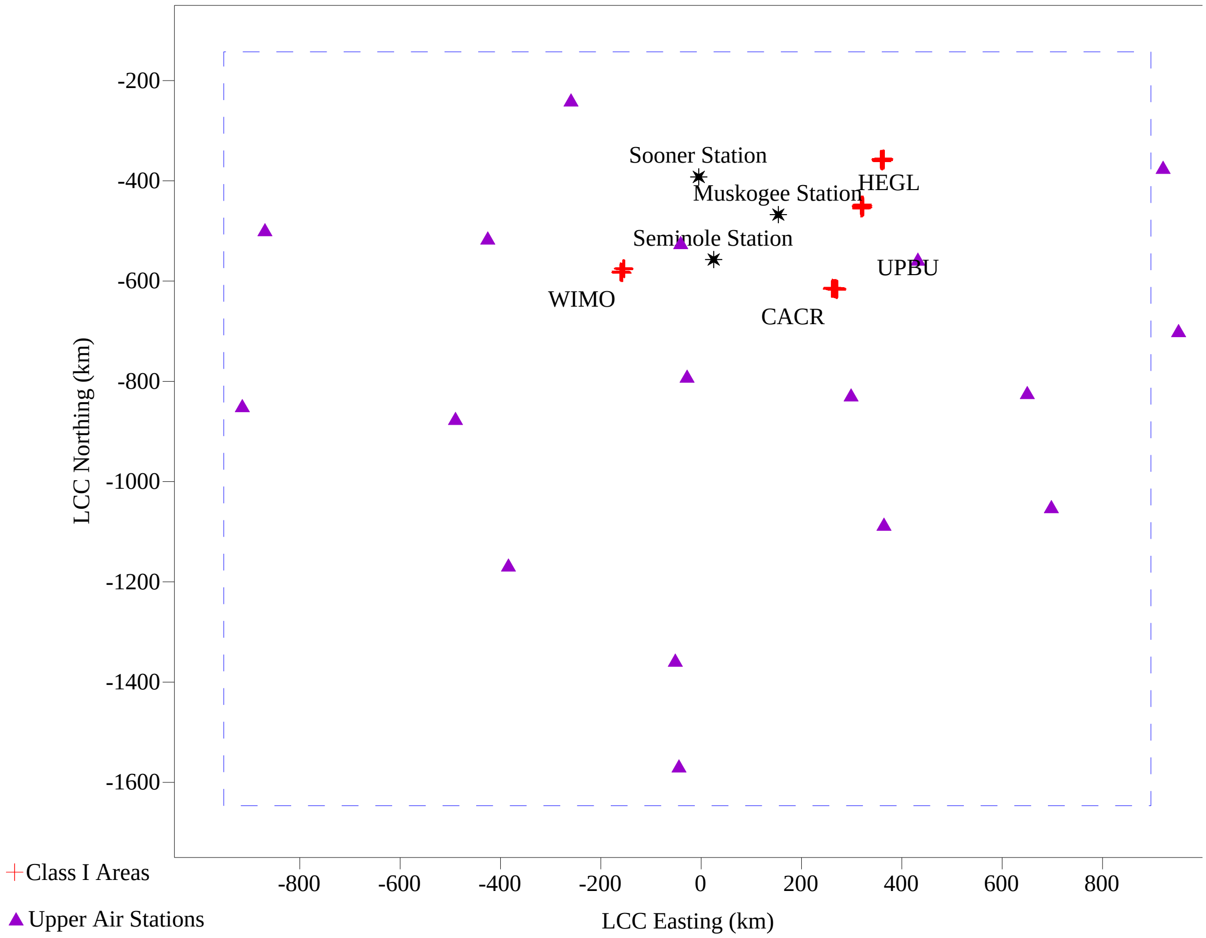
FIGURE 3-3. PLOT OF SURFACE STATION LOCATIONS



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.

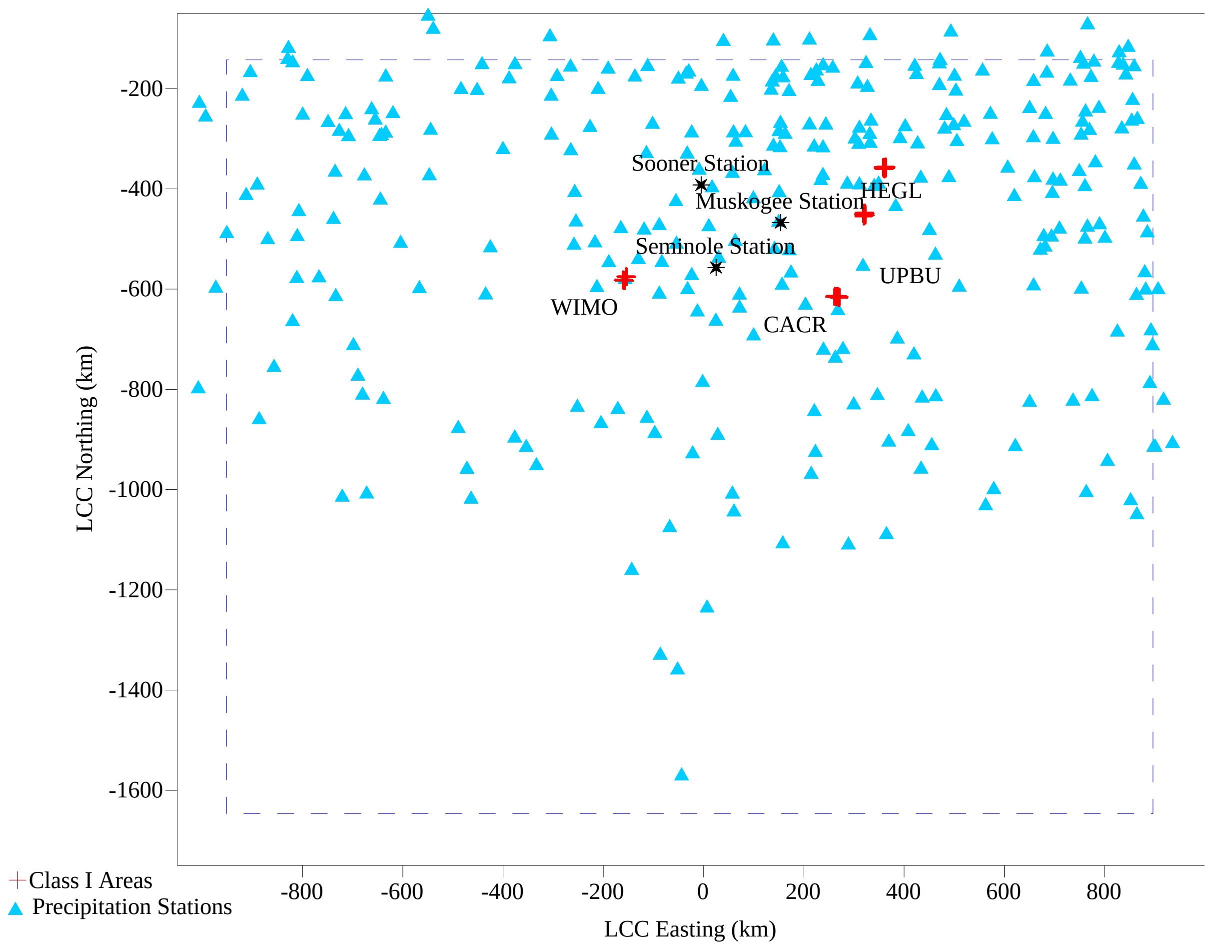
FIGURE 3-4. PLOT OF UPPER AIR STATIONS LOCATIONS



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.

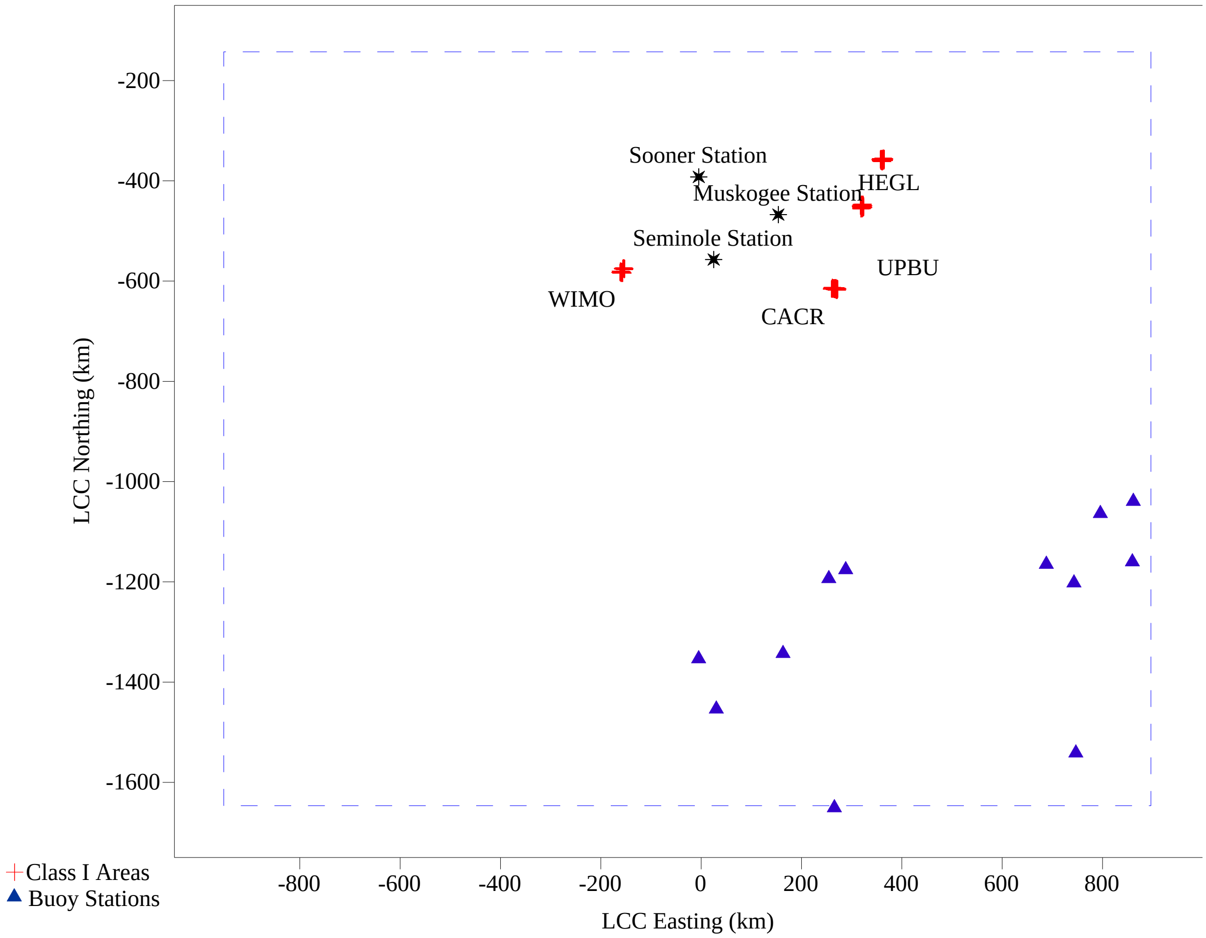
FIGURE 3-5. PLOT OF PRECIPITATION METEOROLOGICAL STATIONS



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 C
BART Five-Factor Analysis for Entergy Arkansas, Inc. Lake Catherine Plant

REVISED BART FIVE FACTOR ANALYSIS

LAKE CATHERINE STEAM ELECTRIC STATION

MALVERN, ARKANSAS (AFIN 30-00011)

Prepared By:

TRINITY CONSULTANTS, INC.
201 NW 63rd St., Suite 220
Oklahoma City, Oklahoma 73116
(405) 848-3724

TRINITY CONSULTANTS, INC.
977 Ridge Drive, Suite 380
Lenexa, Kansas 66219
(913) 894-4500

In conjunction with:

ENTERGY SERVICES, INC.
425 West Capitol Avenue
Little Rock, Arkansas 77203
(501) 377-4000

Trinity Project No. 123701.0053

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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:

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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:

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

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:

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

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/m³)	NH_4NO_3 (μg/m³)	OM (μg/m³)	EC (μg/m³)	Soil (μg/m³)	CM (μg/m³)	Sea Salt (μg/m³)	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

[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.

[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, 98^{th} 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

Prepared by:

Vern Choquette ▲ Principal Consultant
Eugene Chen, PE ▲ Senior Consultant
Jeremy Townley ▲ Consultant

TRINITY CONSULTANTS
120 East Sheridan
Suite 205
Oklahoma City, OK 73104
(405) 228-3292

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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

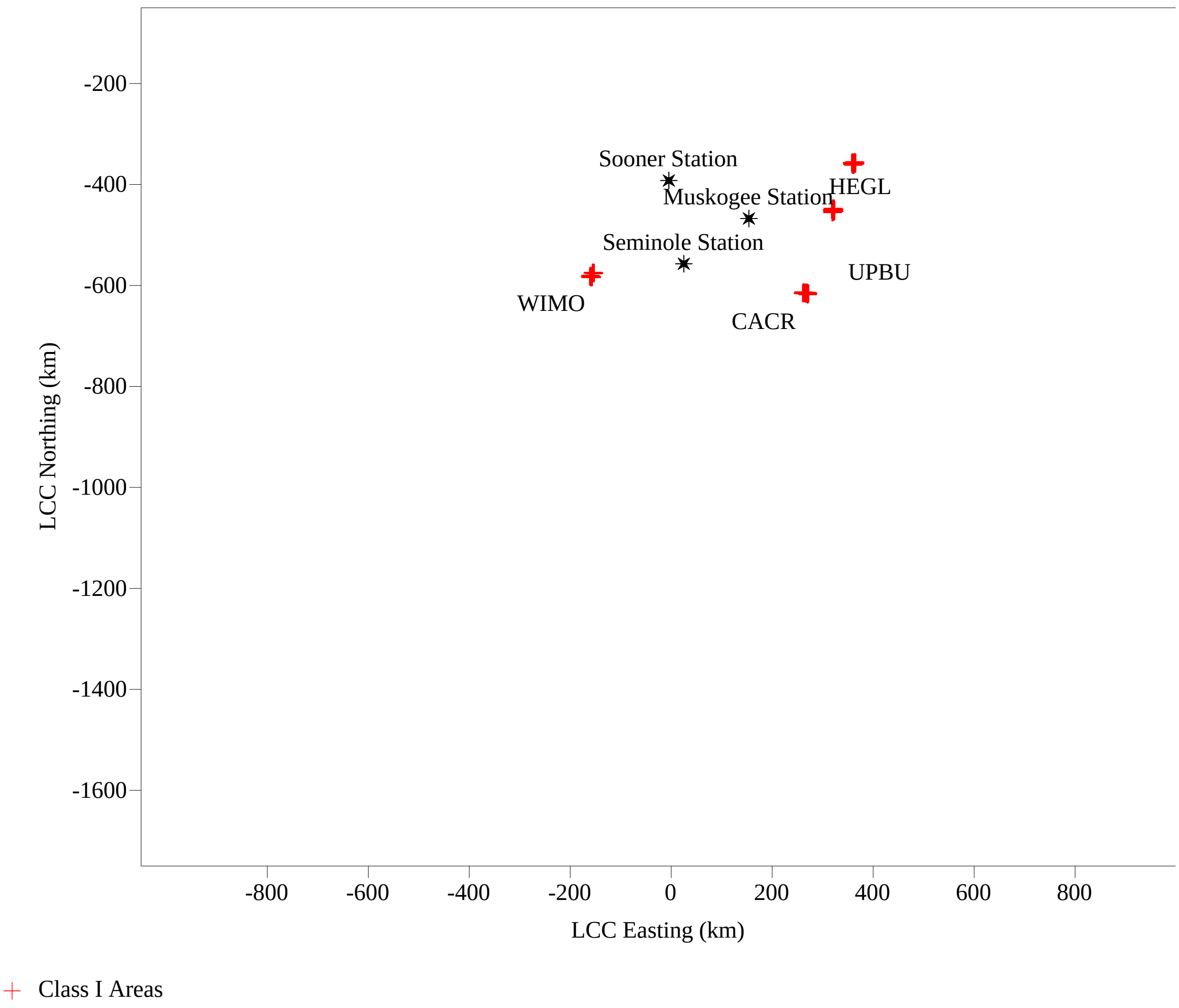
As required in CENRAP's BART Modeling Guidelines, Class I areas within 300 km of each station will be included in each analysis. The following table summarizes the distances of the four closest Class I areas to each station. As seen from this summary, some Class I areas are more than 300 km from the 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

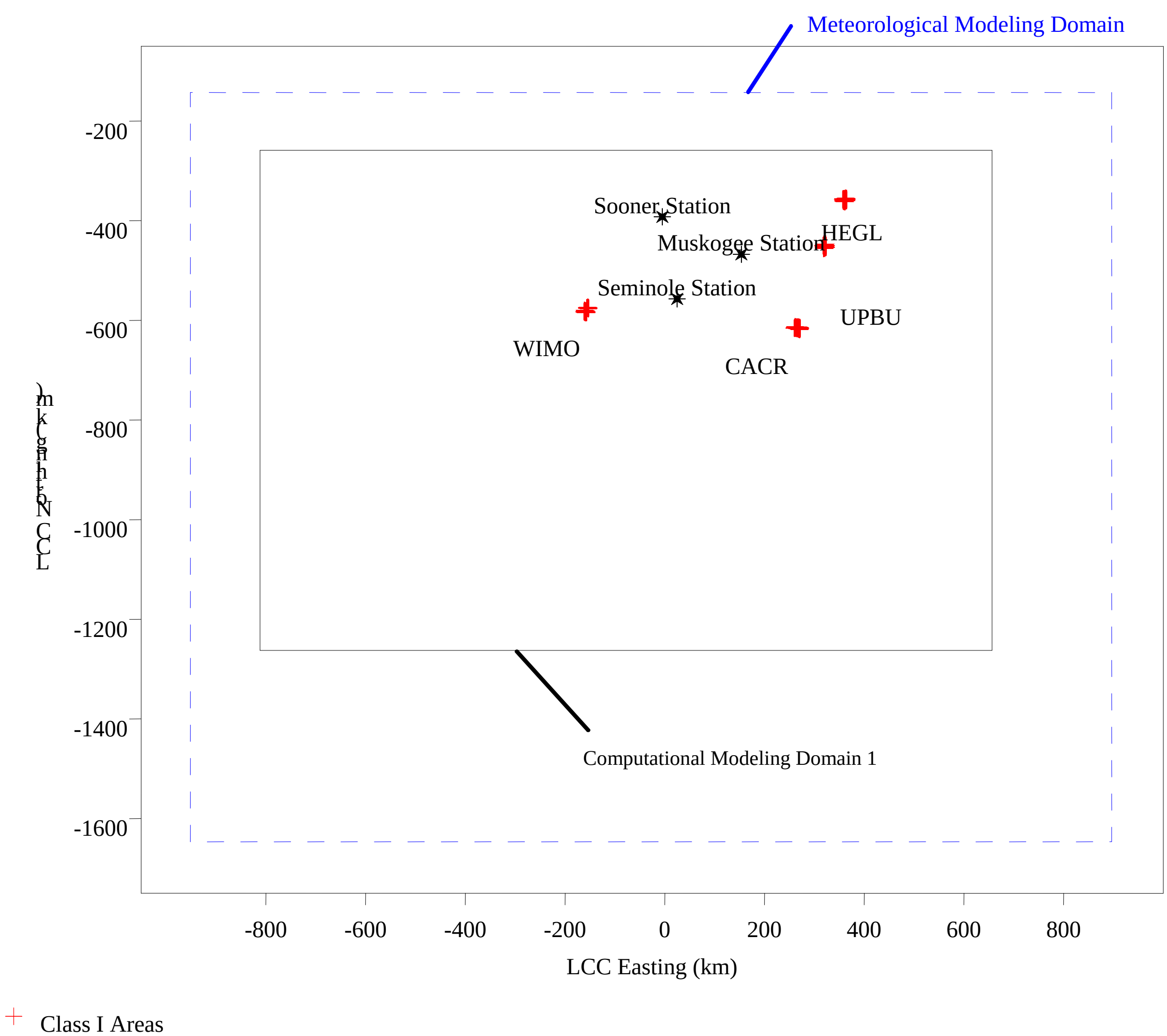
Processor	Version	Level
TERREL	3.3	030402
CTGCOMP	2.21	030402
CTGPROC	2.63	050128
MAKEGEO	2.2	030402
CALMET	5.53a	040716
CALPUFF	5.8	070623
POSTUTIL	1.3	030402
CALPOST	5.51	030709

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.

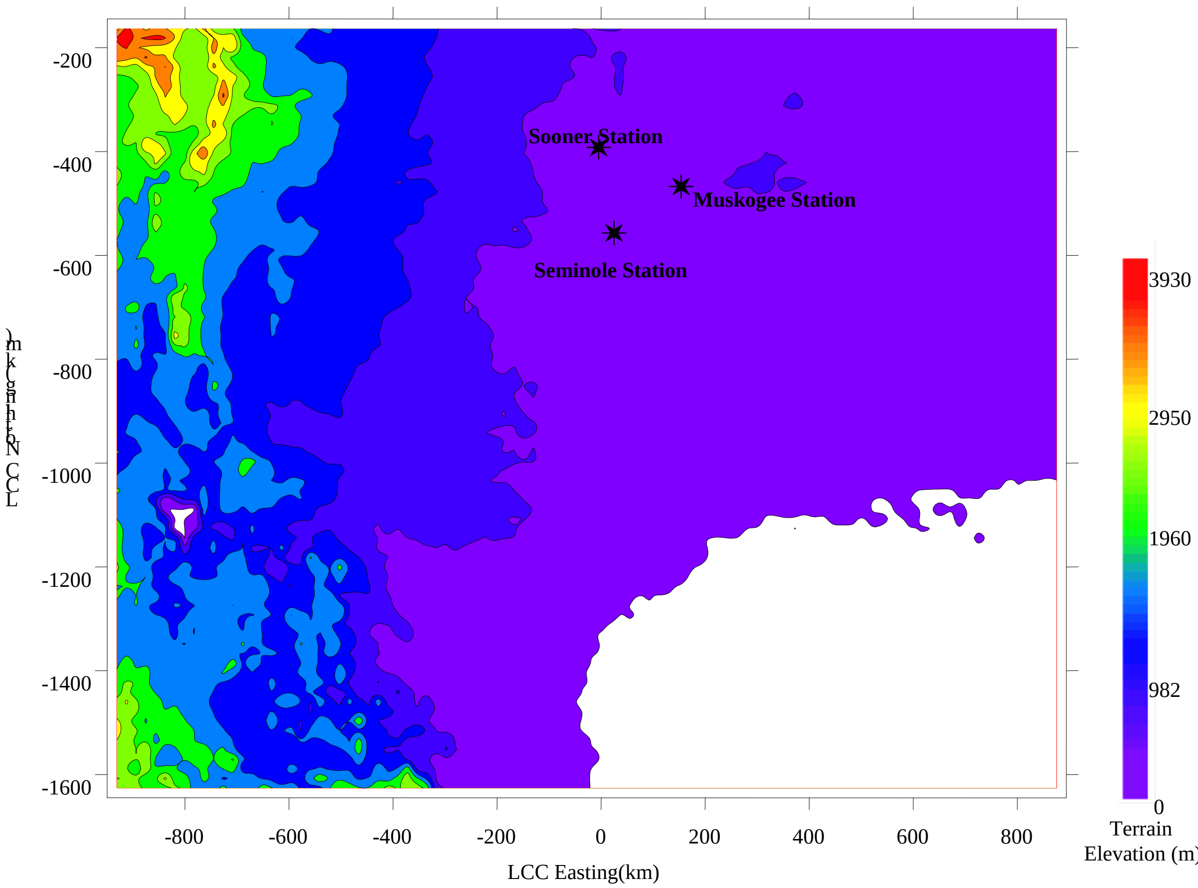
3.1 GEOPHYSICAL DATA

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.

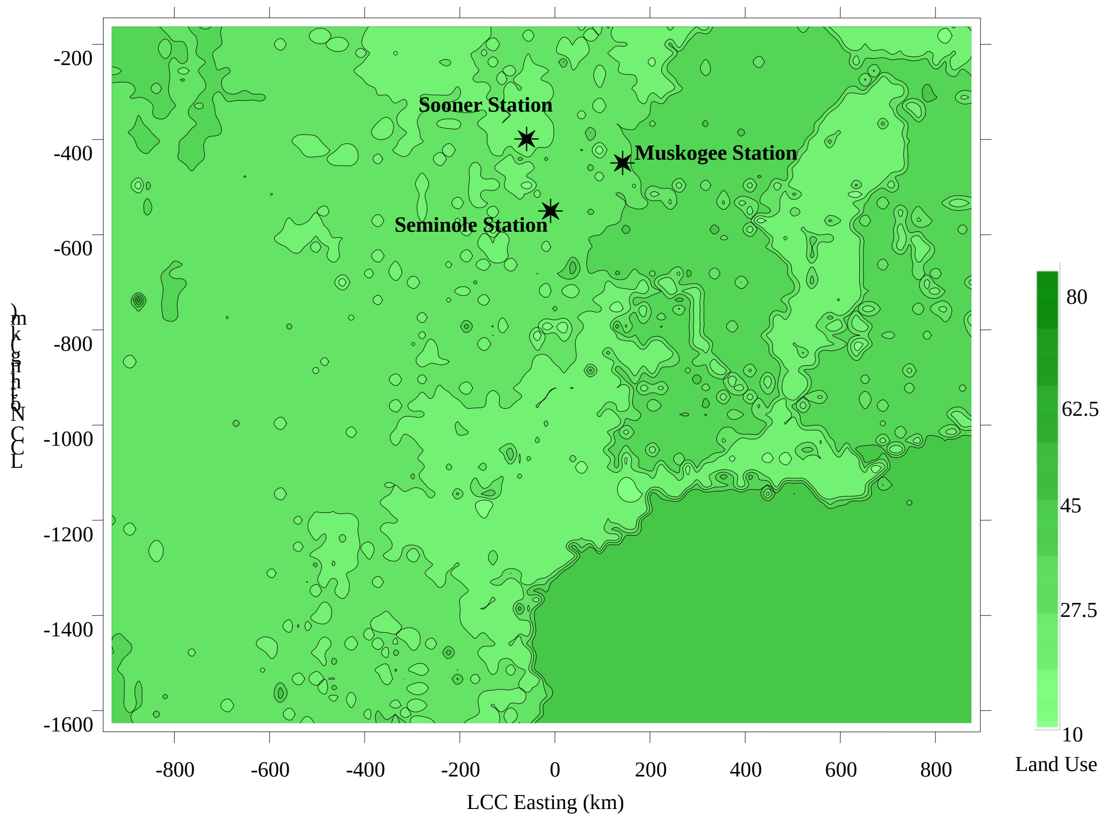
FIGURE 3-1. PLOT OF LAND ELEVATION USING USGS TERRAIN DATA



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.

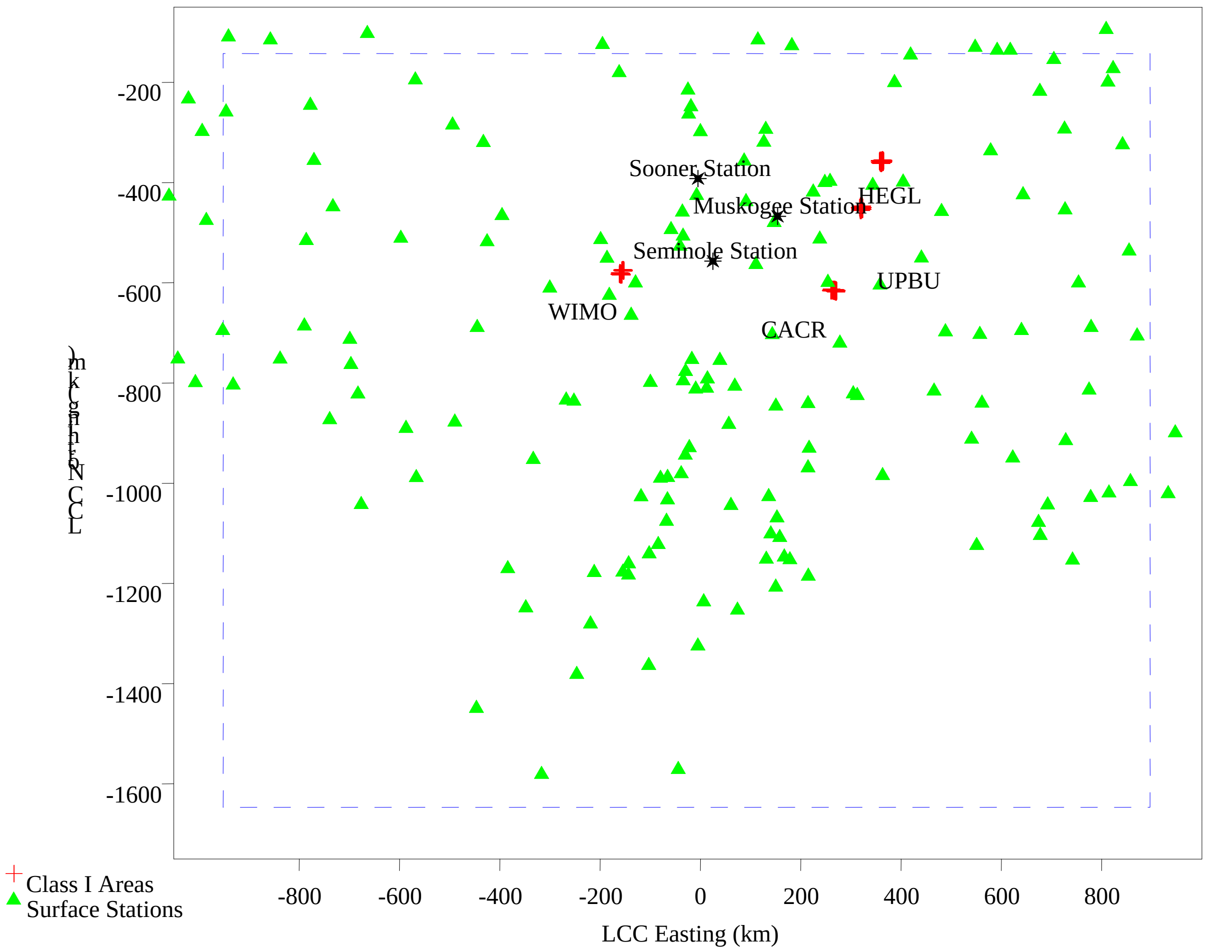
The time periods covered by the data in each of the MM5 files extracted by Alpine Geophysics include a specific number of calendar days, where the data starts at Hour 0 in GMT for the first calendar day and ends at Hour 23 in GMT on the last calendar day. In order to run CALMET in the local standard 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.

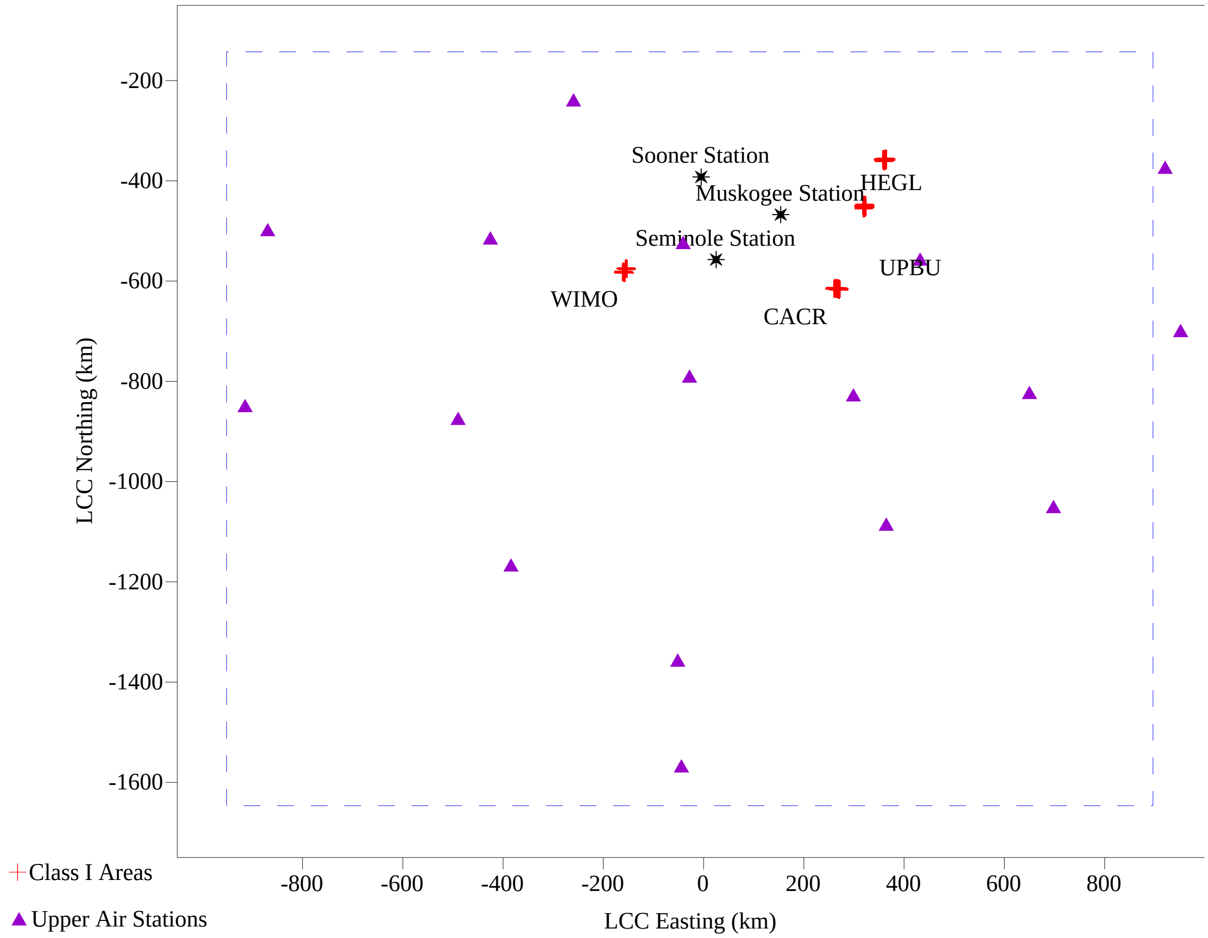
FIGURE 3-3. PLOT OF SURFACE STATION LOCATIONS



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.

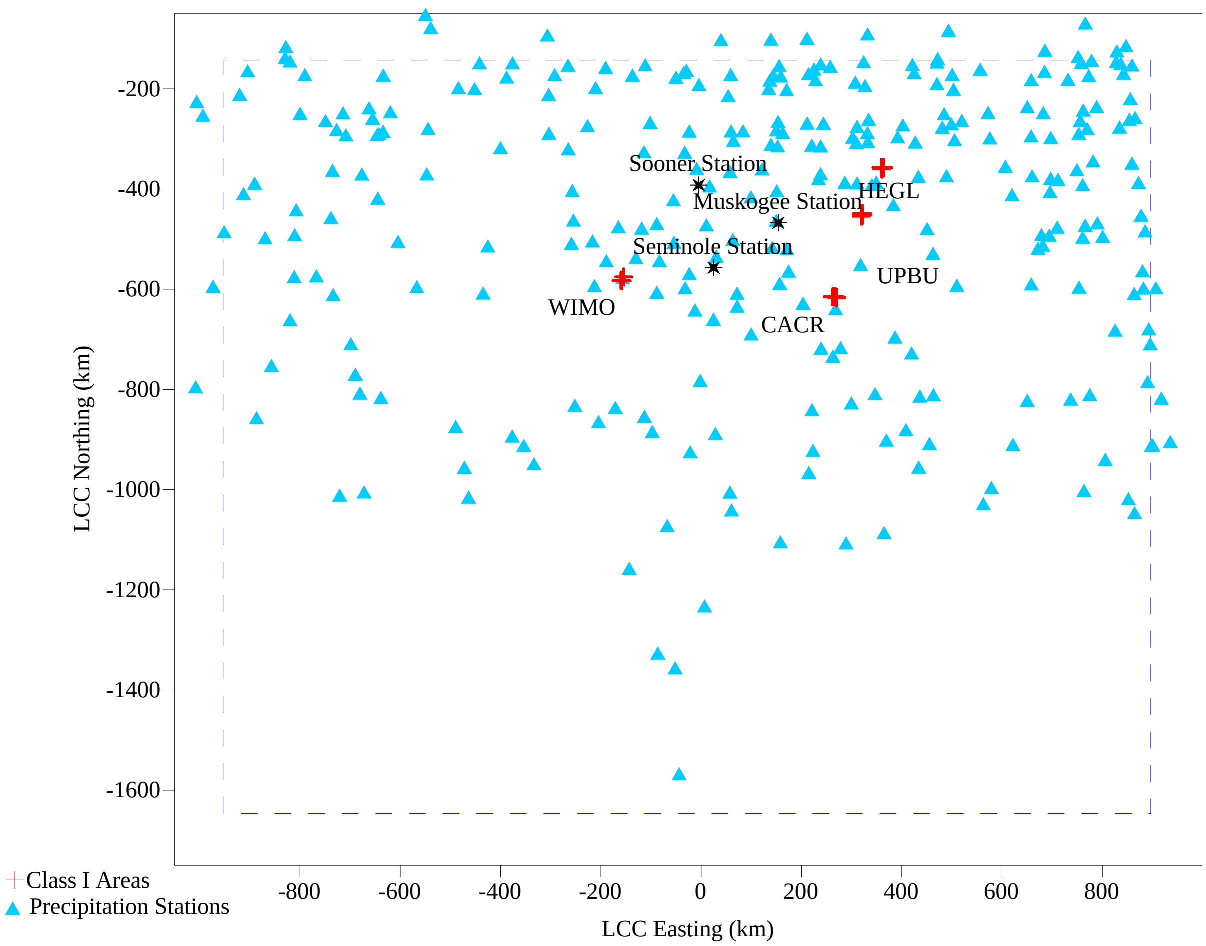
FIGURE 3-4. PLOT OF UPPER AIR STATIONS LOCATIONS



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.

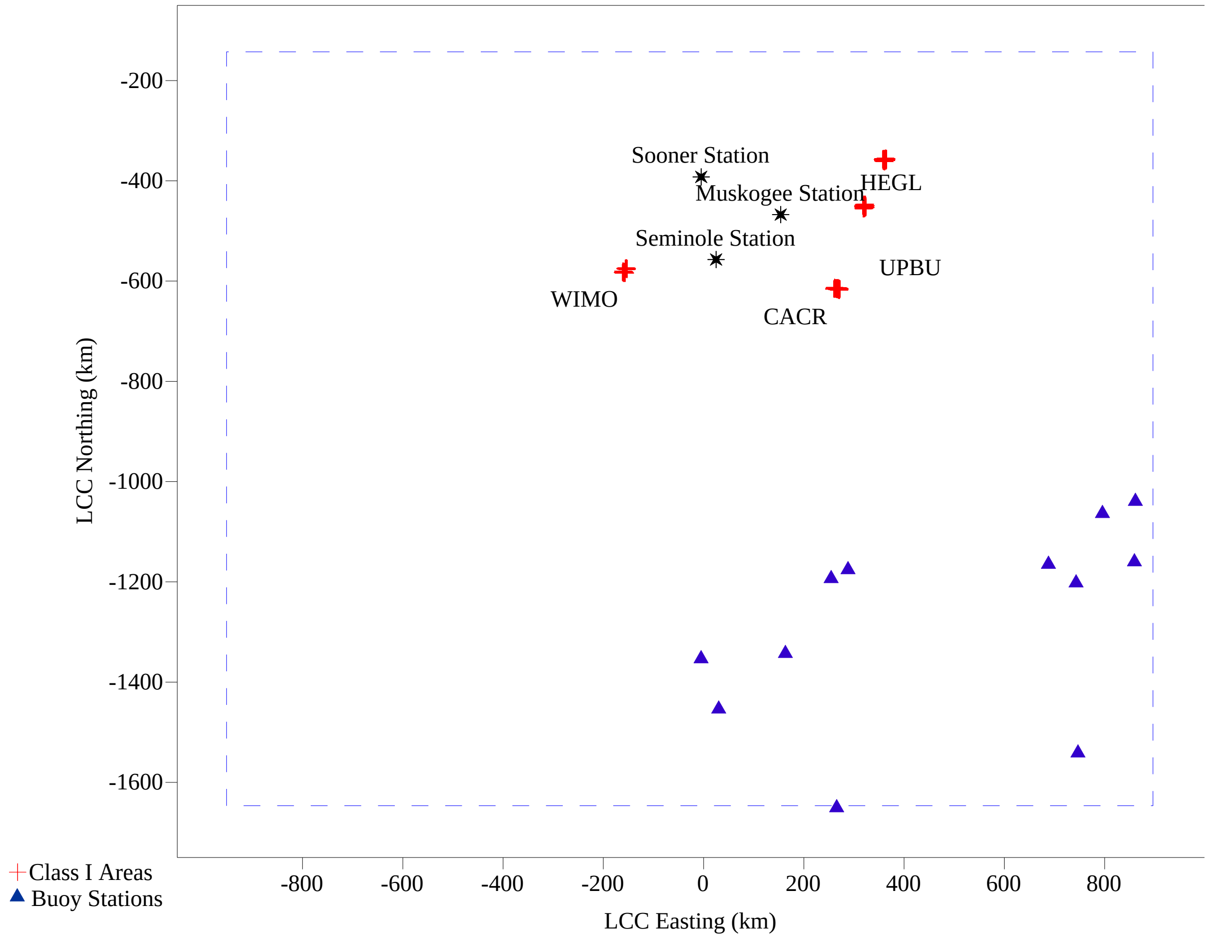
FIGURE 3-5. PLOT OF PRECIPITATION METEOROLOGICAL STATIONS



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

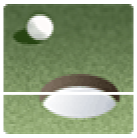
Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
279	NEWB	416270	239.111	-721.818	97.0028	39.9935
280	BPAT	417174	288.962	-1110.65	97.0034	39.9900
281	RANK	417431	-472.048	-959.488	96.9944	39.9913
282	SAAG	417943	-333.338	-952.54	96.9961	39.9914
283	SAAT	417945	-143.322	-1161.27	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

SARGENT & LUNDY NO_X CONTROL TECHNOLOGY STUDY



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

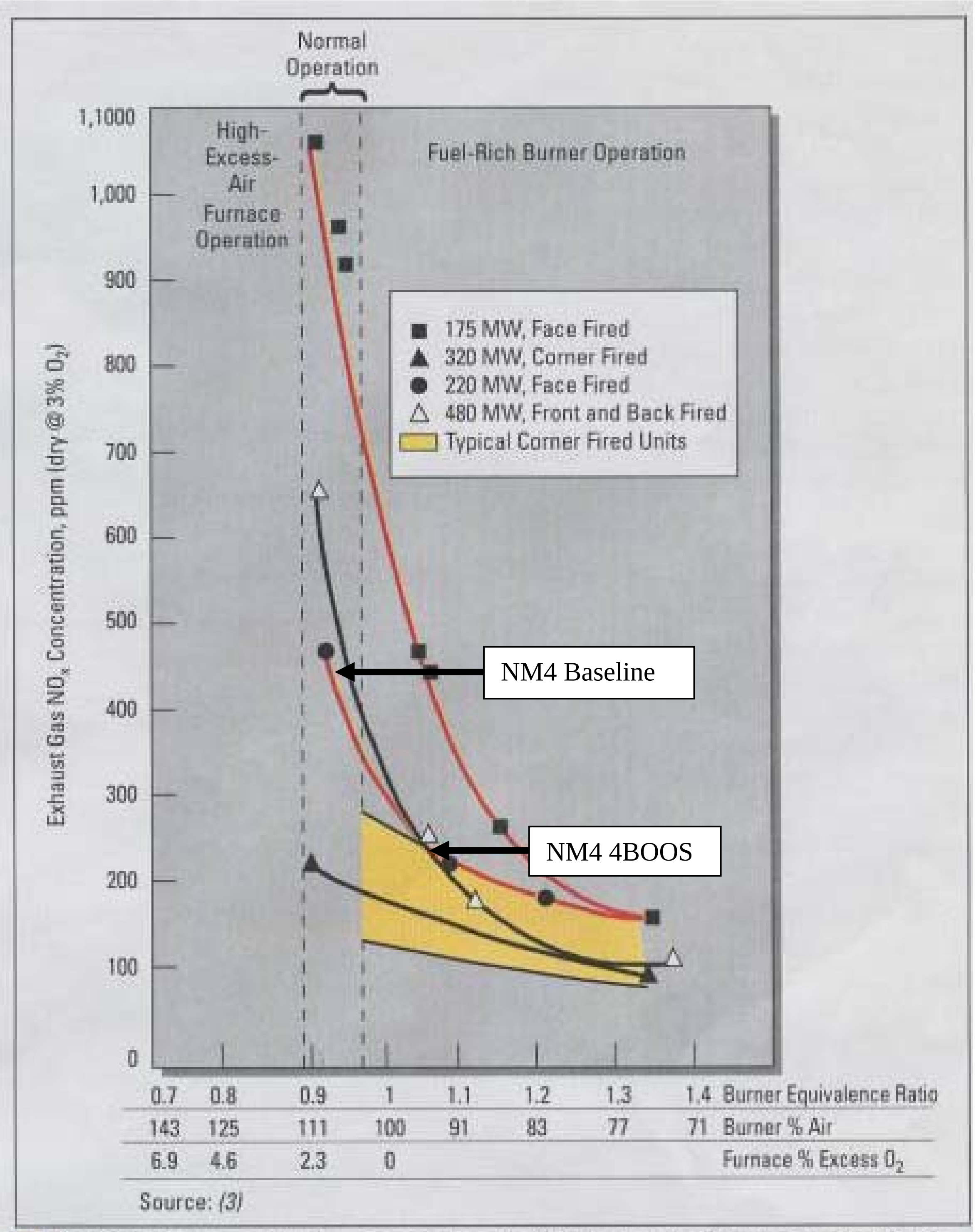


Figure 2. Burners-out-of-service can be an effective combustion staging technique.

Figure 2- Ninemile Units 4 and 5 BOOS Pattern
(Top Elevation Out of Service & Air Registers Open)

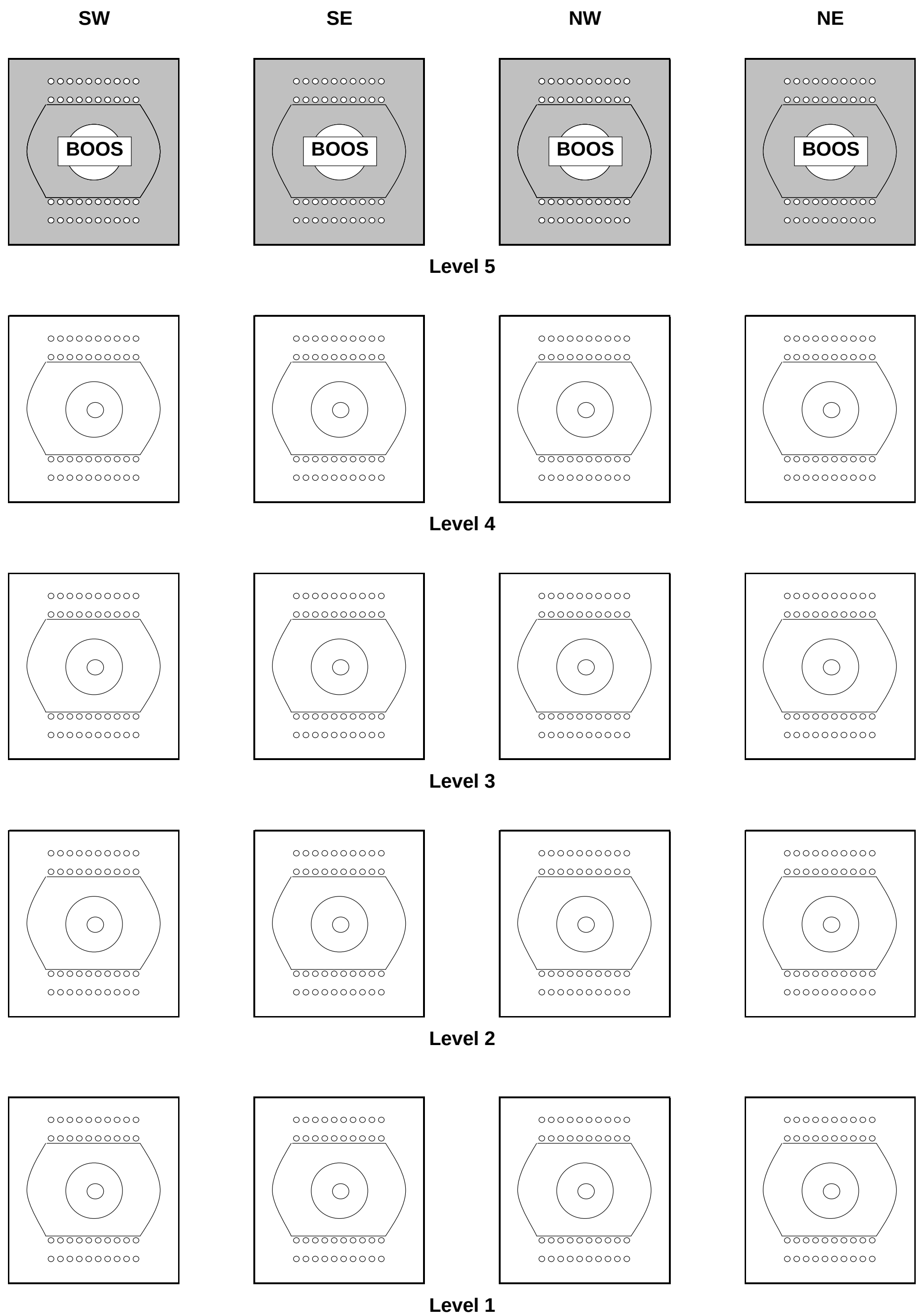


Figure 3- Lake Catherine Unit 4 Burner Header Pressure

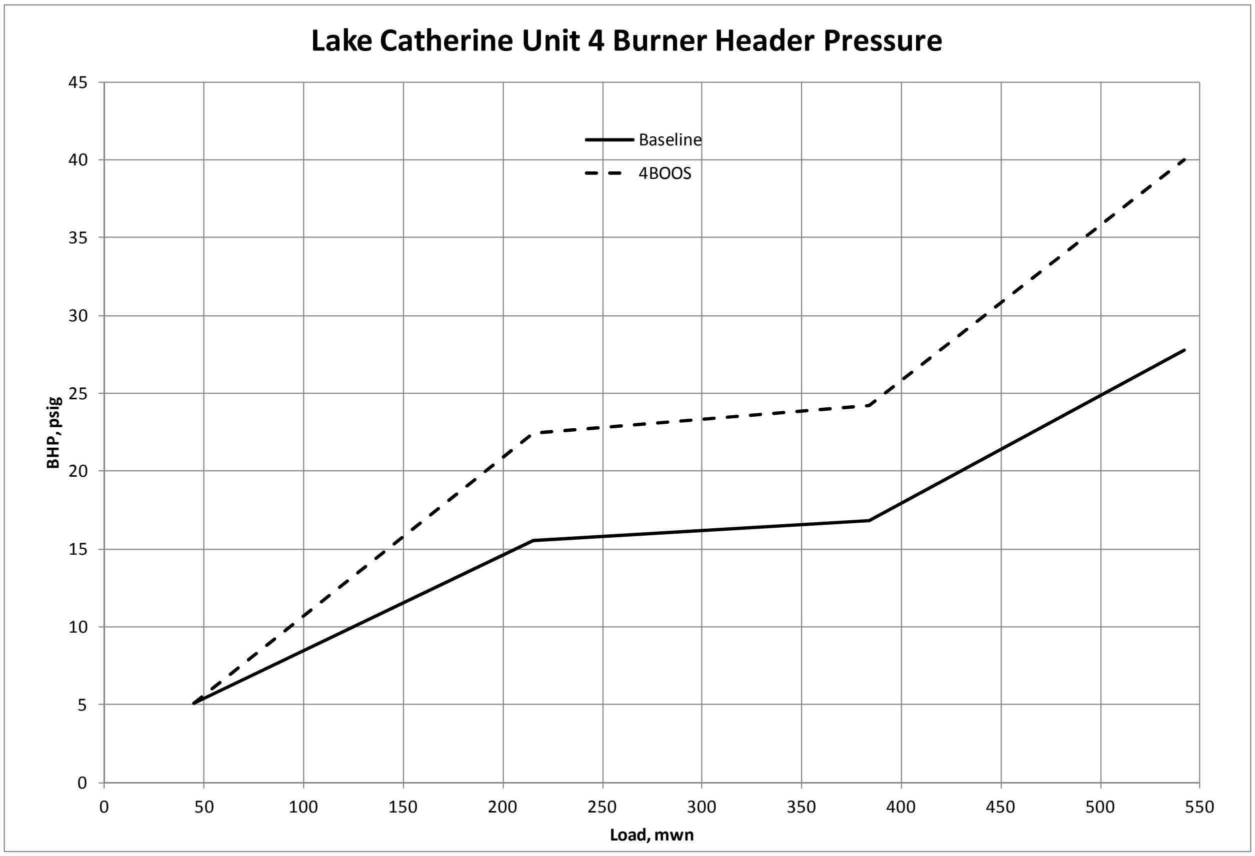
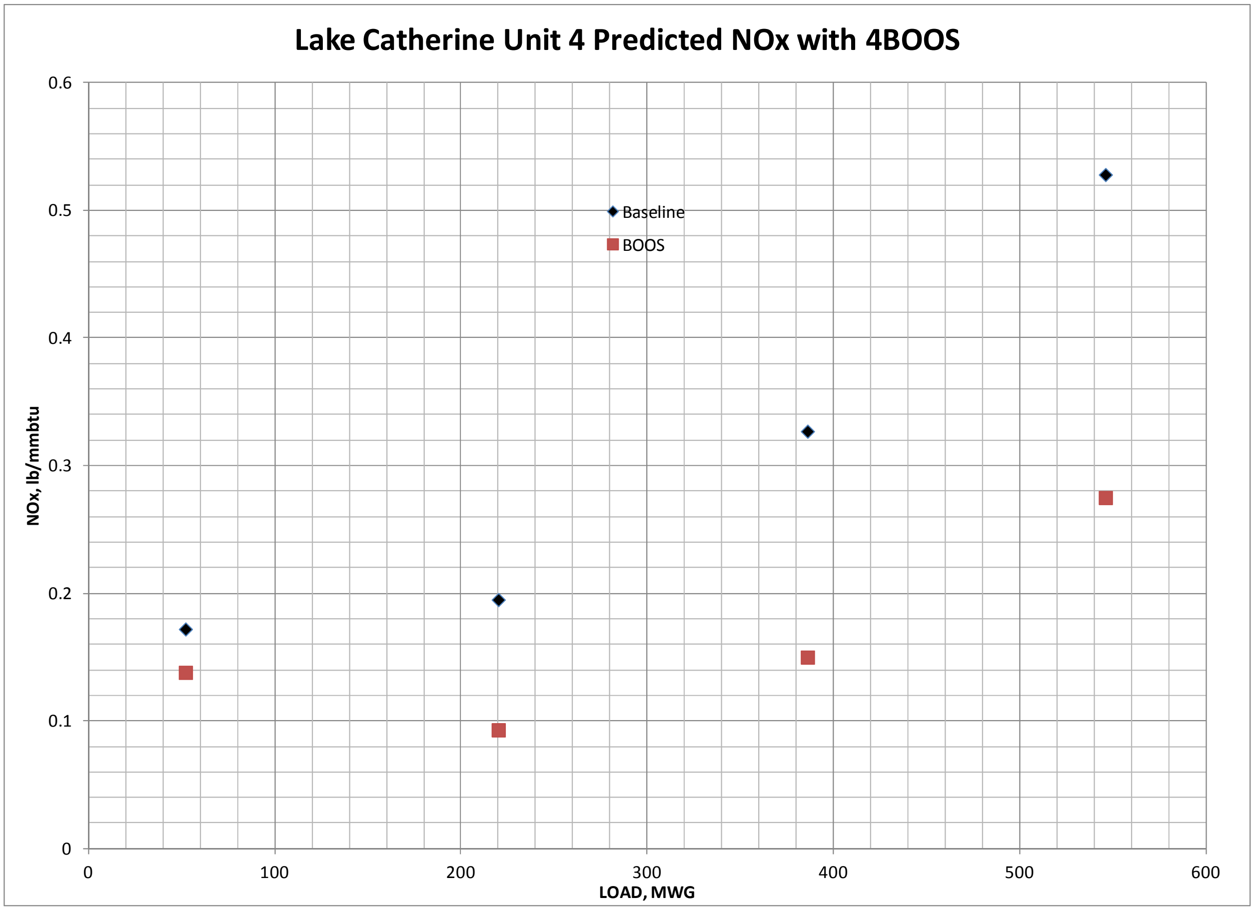
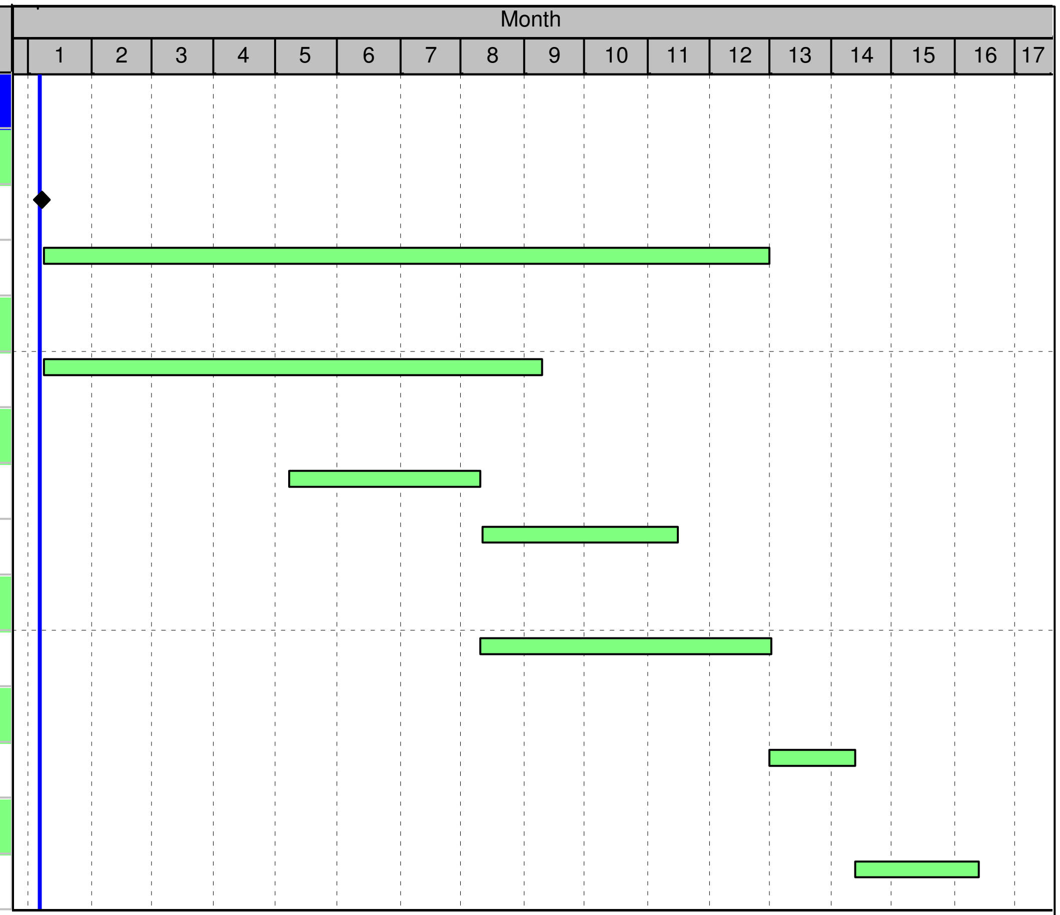


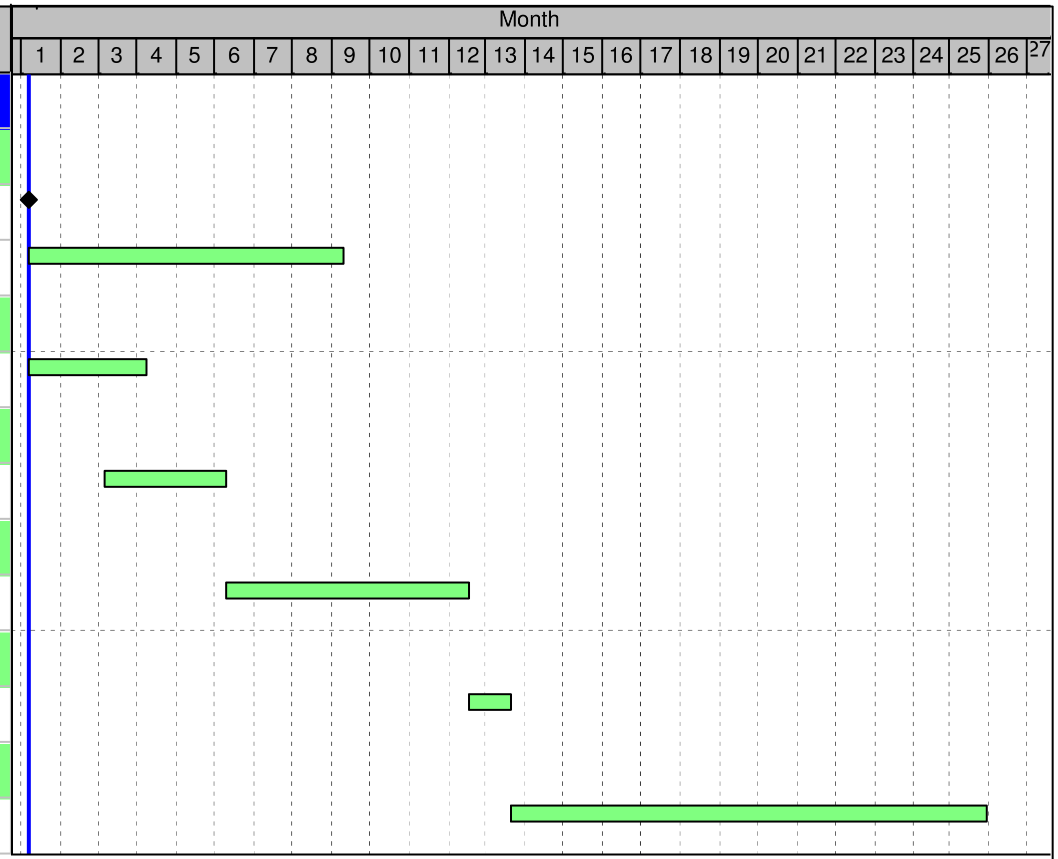
Figure 4- Lake Catherine Unit 4 NOx Emissions Prediction



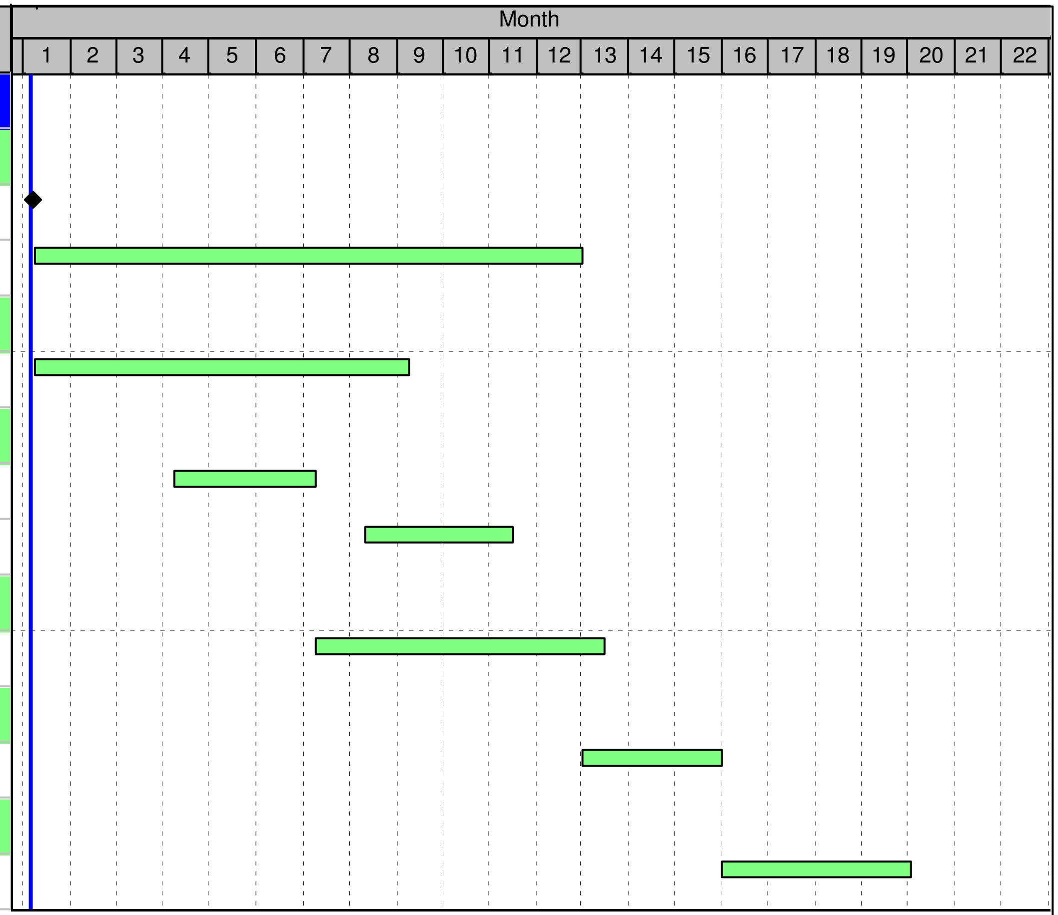
.	Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Aux Boiler (LNB/OFA/F...		15m
	Permitting		12m
	A1000	Project Authorization	0m
	A1010	Air Permit - Prepare/Review/Approve	12m
	Engineering		8m
	A1020	Engineering	8m
	Procurement of Major Equipment		6m
	A1030	LNB/OFA Spec - Prep/Bid/Eval/Award	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



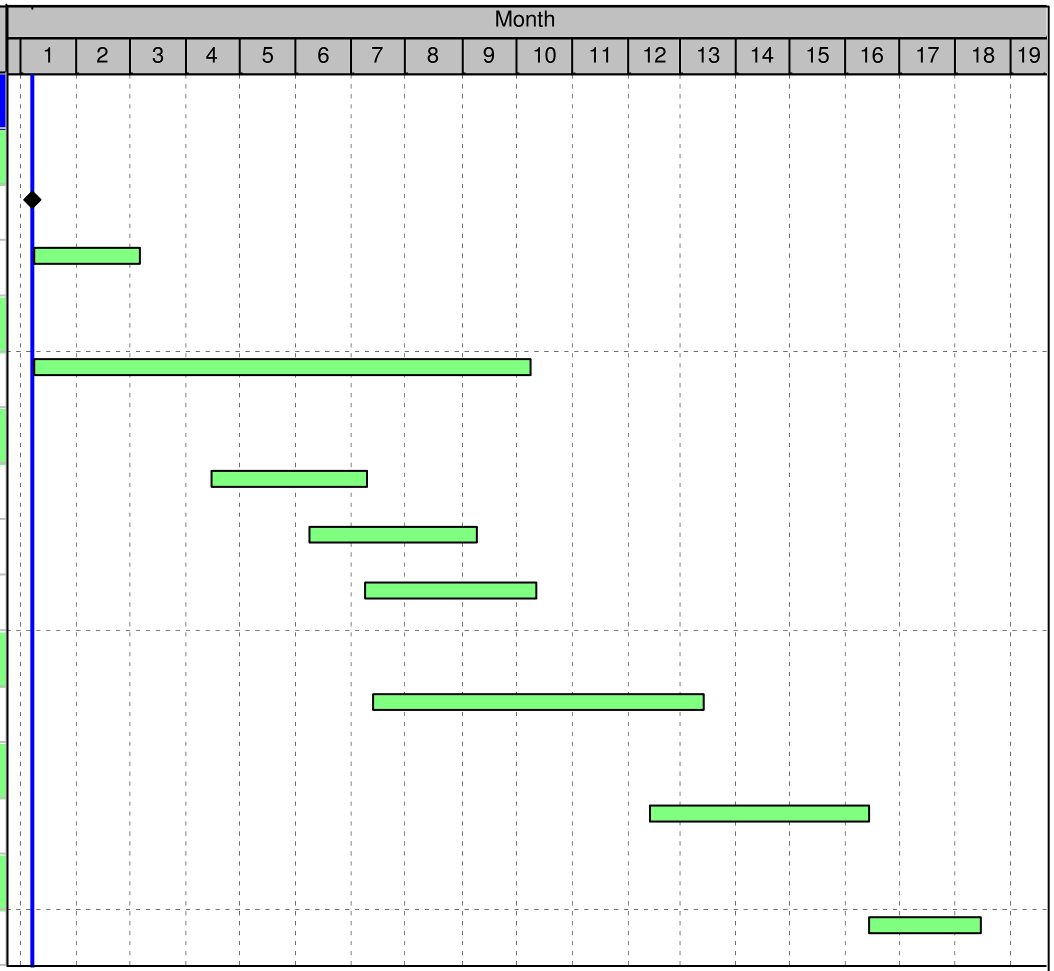
.	Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Neural Network		24m
	Permitting		8m
	A1000	Project Authorization	0m
	A1010	Air Permit - Prepare/Review/Approve	8m
	Engineering		3m
	A1020	Engineering	3m
	Procurement of Major Equipment		3m
	A1030	Neural Network Spec - Prep/Bid/Eval/Award	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



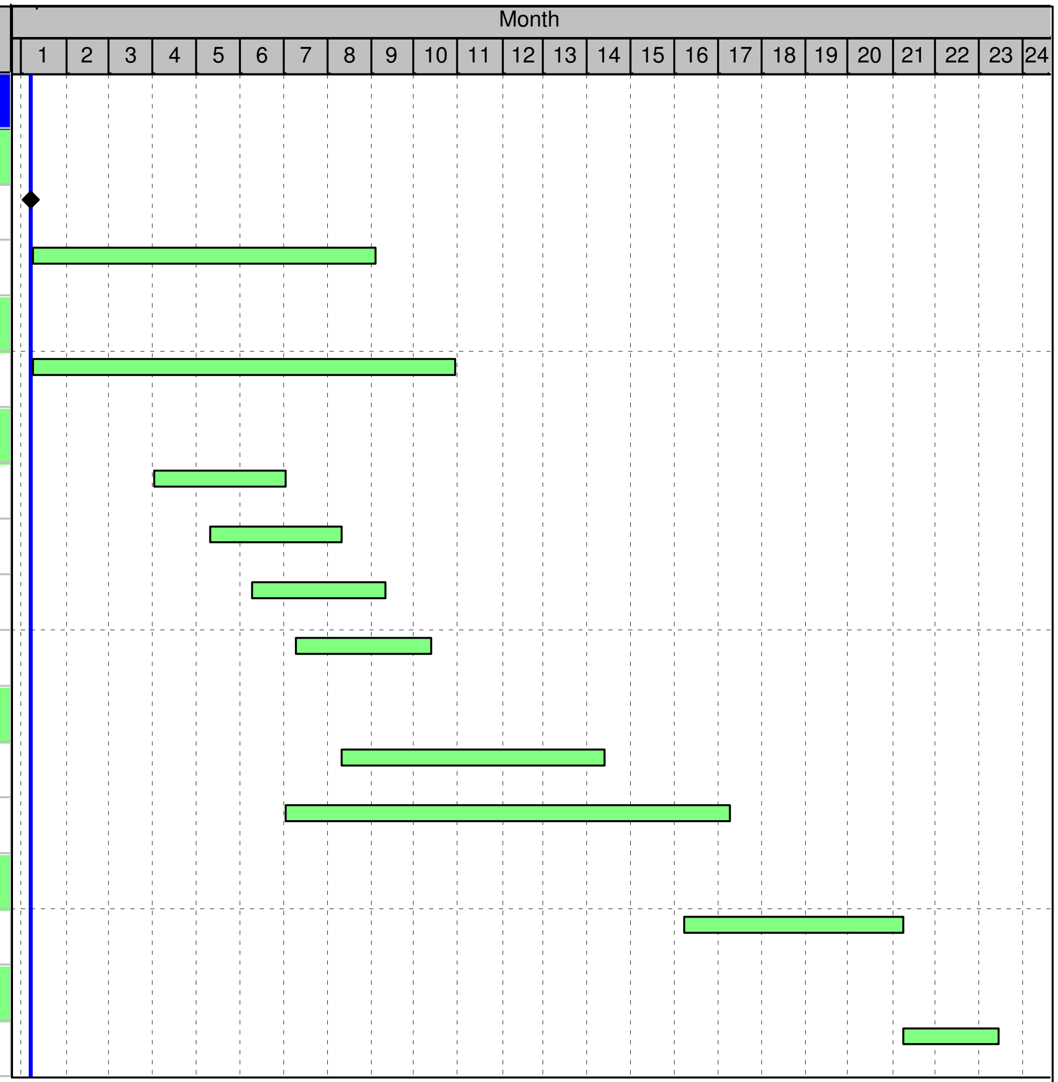
Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Low NOx Burners/Over ...	19m
	Permitting	12m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	12m
	Engineering	8m
A1020	Engineering	8m
	Procurement of Major Equipment	7m
A1030	LNB/OFA Spec - Prep/Bid/Eval/Award	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



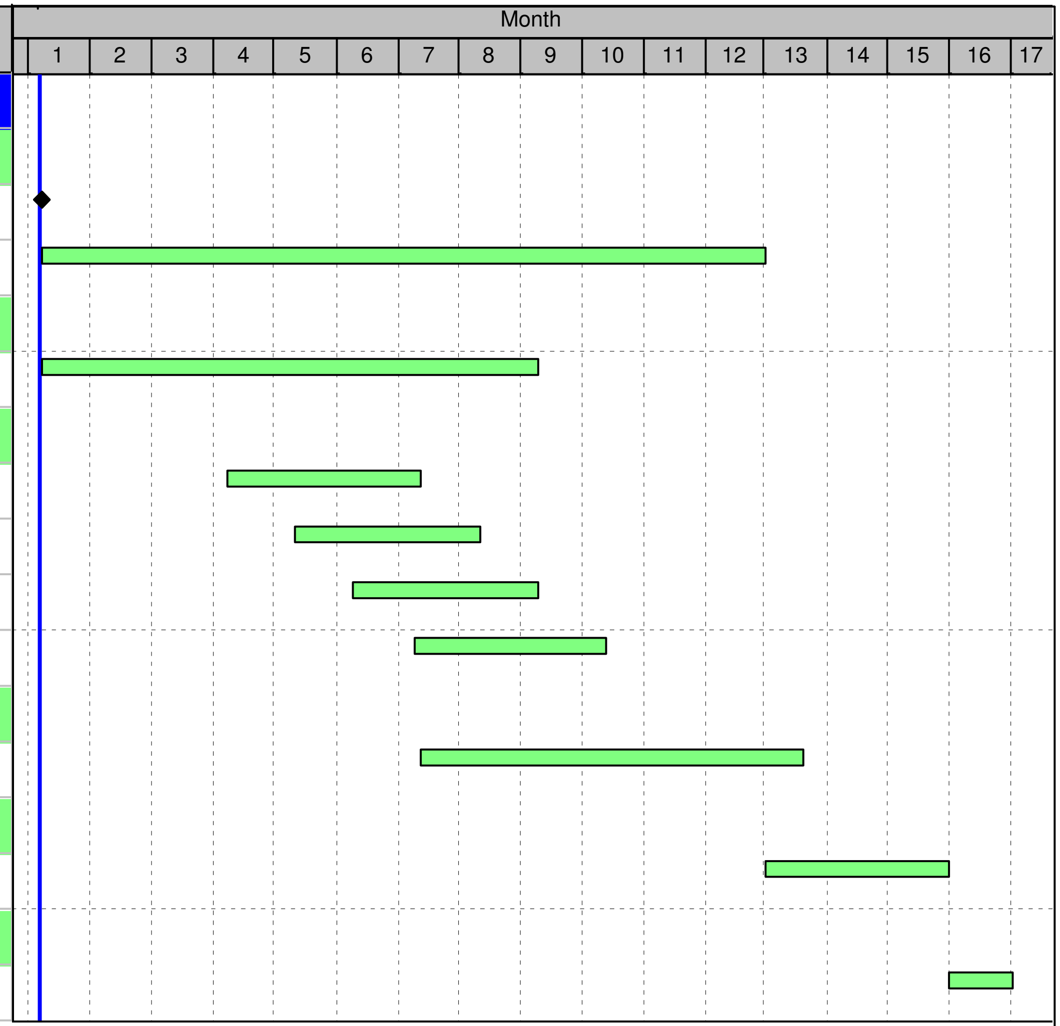
Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Induced Flue Gas Recir...	17m
	Permitting	2m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	2m
	Engineering	9m
A1020	BOP Engineering	9m
	Procurement of Major Equipment	6m
A1140	FGR Duct Procurement Spec - 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

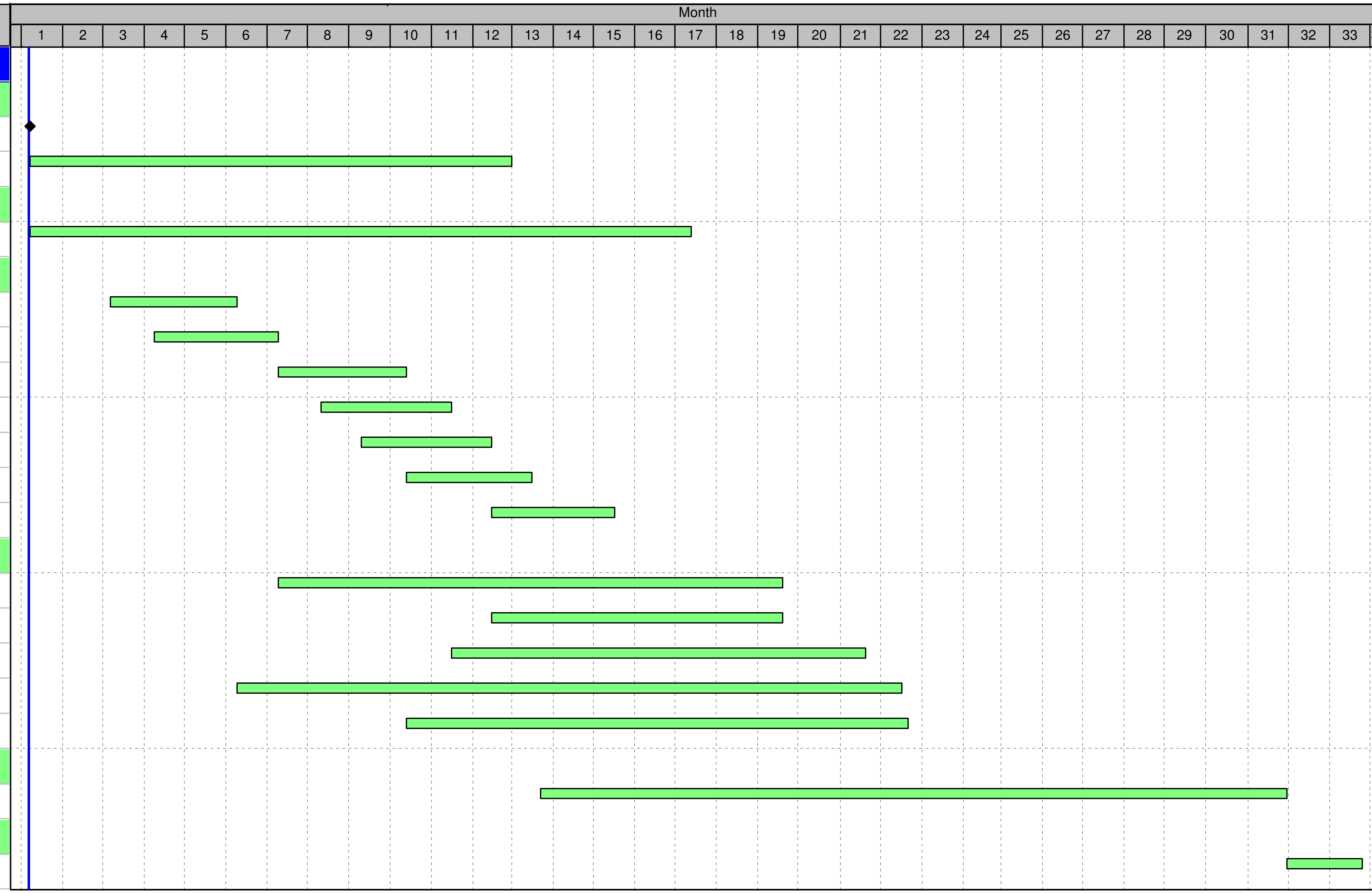


.	Activity ID	Activity Name	Org Dur (months)
		Entergy - NOx Strategy Study - Selective Non-Catalytic ...	16m
		Permitting	12m
	A1000	Project Authorization	0m
	A1010	Air Permit - Prepare/Review/Approve	12m
		Engineering	8m
	A1020	BOP Engineering	8m
		Procurement of Major Equipment	6m
	A1030	SNCR Spec - 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



Run Date: 09-14-12	NOx Control Technology Cost and Performance Study for Entergy Services, Inc. White Bluff and Lake Catherine Selective Non-Catalytic Reduction (SNCR)	Sargent & Lundy LLC

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



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	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 D
BART Five-Factor Analyses for Entergy Arkansas, Inc. White Bluff

Contents

Entergy

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-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:

TRINITY CONSULTANTS, INC.
201 NW 63rd St., Suite 220
Oklahoma City, Oklahoma 73116
(405) 848-3724

TRINITY CONSULTANTS, INC.
977 Ridge Drive, Suite 380
Lenexa, Kansas 66219
(913) 894-4500

In conjunction with:

ENTERGY SERVICES, INC.
425 West Capitol Avenue
Little Rock, Arkansas 77203
(501) 377-4000

Trinity Project No. 123701.0053

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Entergy
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Trinity Consultants

LIST OF TABLES

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

	CACR		UPBU		HERC		MING	
Source	**98th % Δdv**	**Days > 0.5 Δdv**	**98th % Δdv**	**Days > 0.5 Δdv**	**98th % Δdv**	**Days > 0.5 Δdv**	**98th % 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.

10 *See* Table 4-4.

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:

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

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

[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:

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

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:

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

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

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)

[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)	98^{th} Percentile (Δdv)	No. of Day with $\Delta dv \geq 0.5$	98^{th} Percentile Δdv SO_4	98^{th} Percentile Δdv NO_3	98^{th} Percentile Δdv PM_{10}	98^{th} 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 98^{th} percentile impacts from SO_4 are always greater than the 98^{th} 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 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	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 $\Delta dv \geq 0.5$	98th Percentile Δdv SO_4	98th Percentile Δdv NO_3	98th Percentile Δdv PM_{10}	98th Percentile Δdv NO_2
Caney Creek Wilderness							
2001	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.

[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 98th 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 $\Delta dv \geq 0.5$	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek Wilderness							
2001	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

Prepared by:

Vern Choquette ▲ Principal Consultant
Eugene Chen, PE ▲ Senior Consultant
Jeremy Townley ▲ Consultant

Trinity Consultants
120 East Sheridan
Suite 205
Oklahoma City, OK 73104
(405) 228-3292

January 23, 2008

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

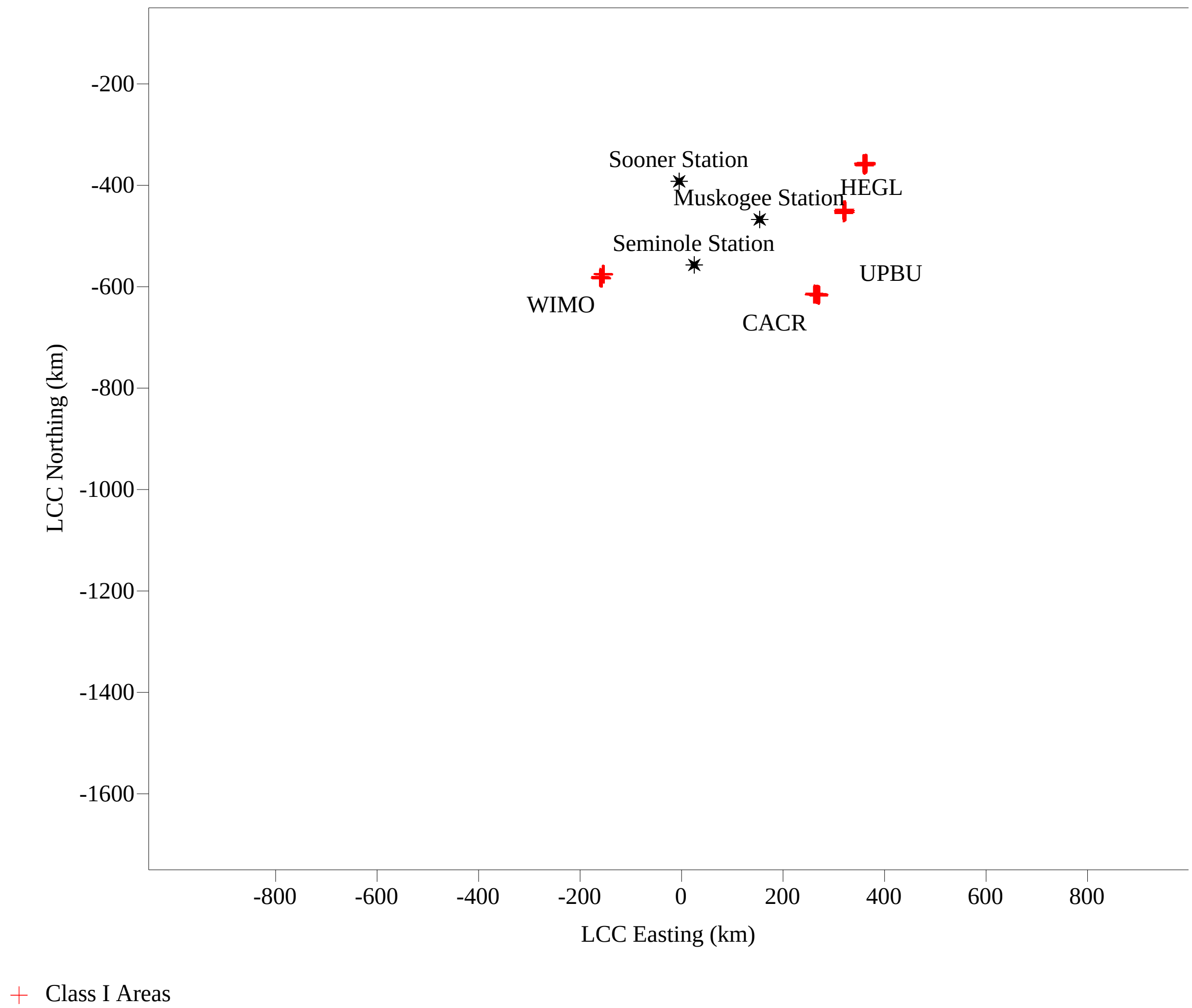
As required in CENRAP's BART Modeling Guidelines, Class I areas within 300 km of each station will be included in each analysis. The following table summarizes the distances of the four closest Class I areas to each station. As seen from this summary, some Class I areas are more than 300 km from the 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.

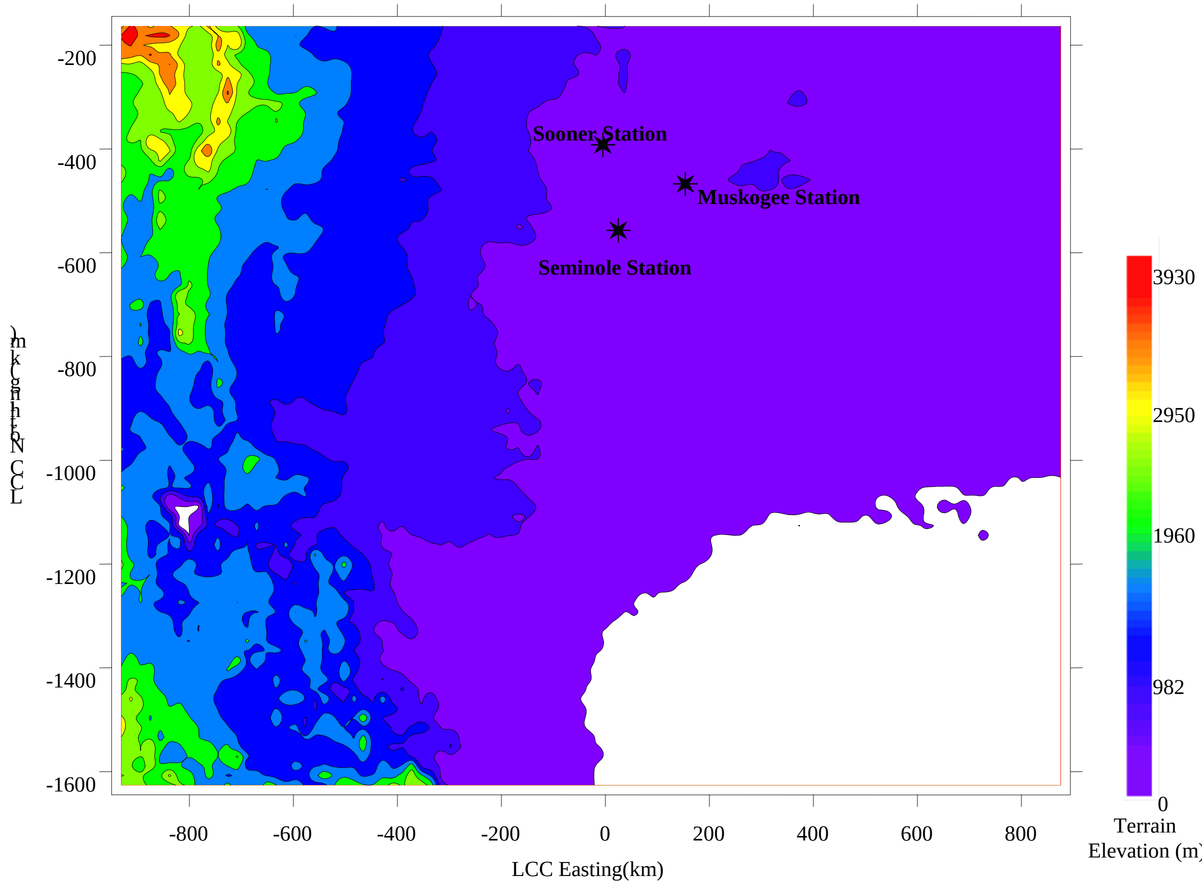
3.1 GEOPHYSICAL DATA

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.

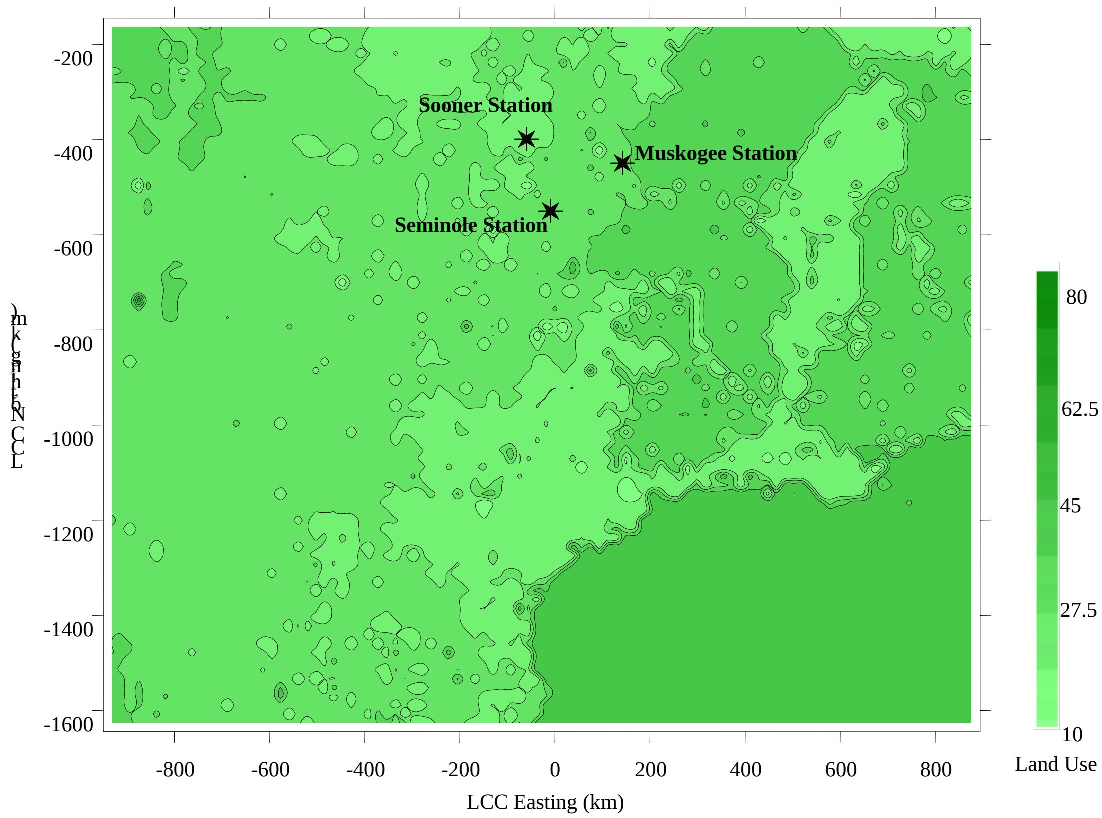
FIGURE 3-1. PLOT OF LAND ELEVATION USING USGS TERRAIN DATA



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.

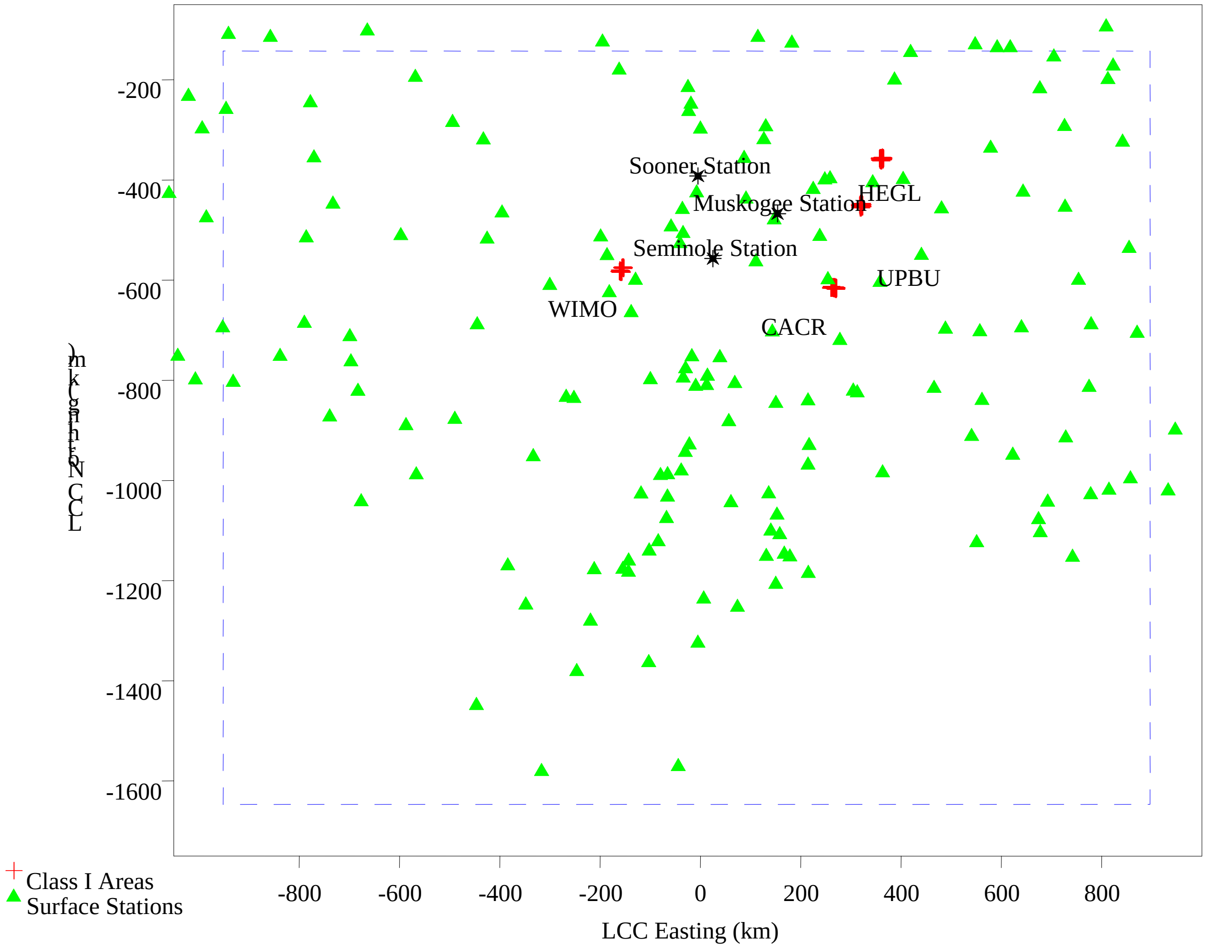
The time periods covered by the data in each of the MM5 files extracted by Alpine Geophysics include a specific number of calendar days, where the data starts at Hour 0 in GMT for the first calendar day and ends at Hour 23 in GMT on the last calendar day. In order to run CALMET in the local standard 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.

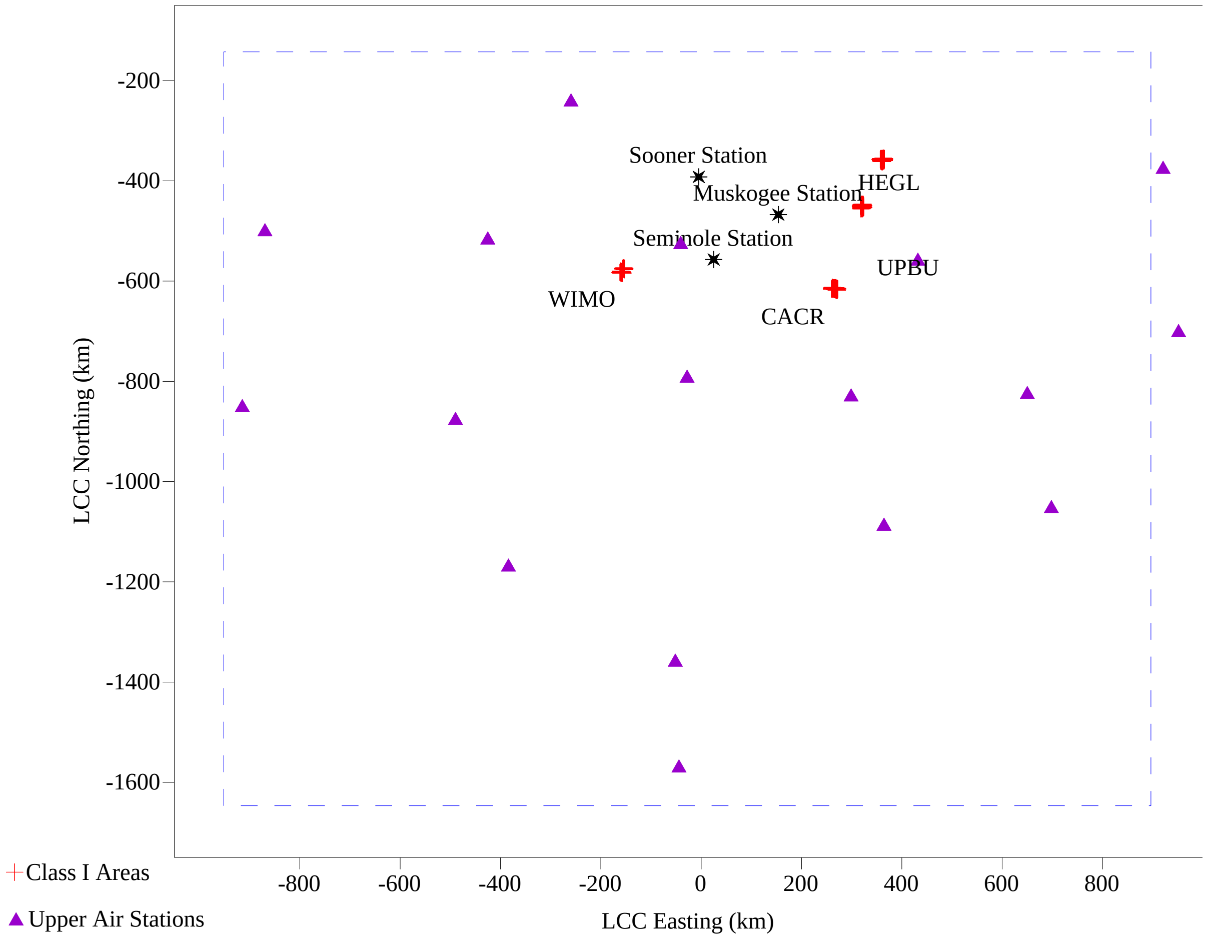
FIGURE 3-3. PLOT OF SURFACE STATION LOCATIONS



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.

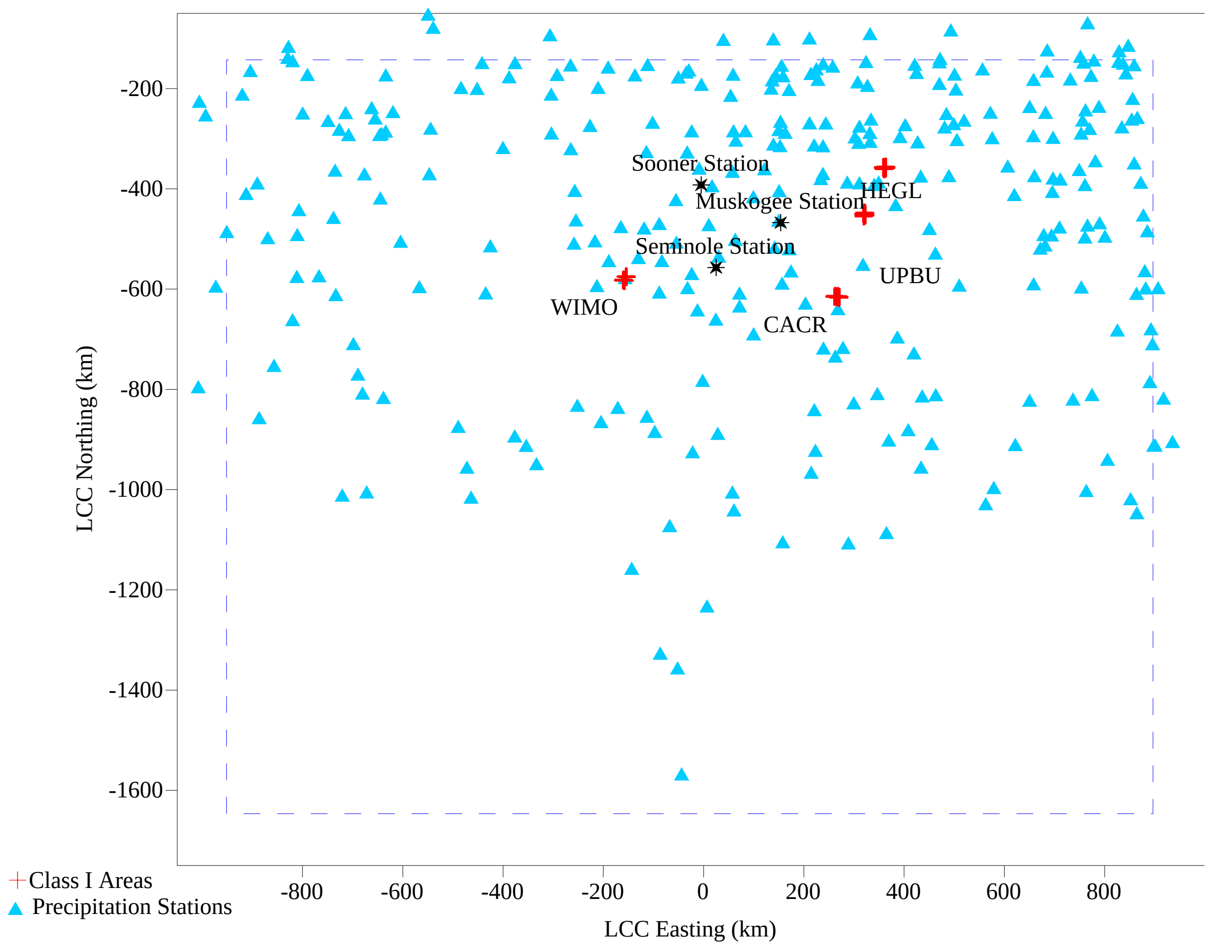
FIGURE 3-4. PLOT OF UPPER AIR STATIONS LOCATIONS



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.

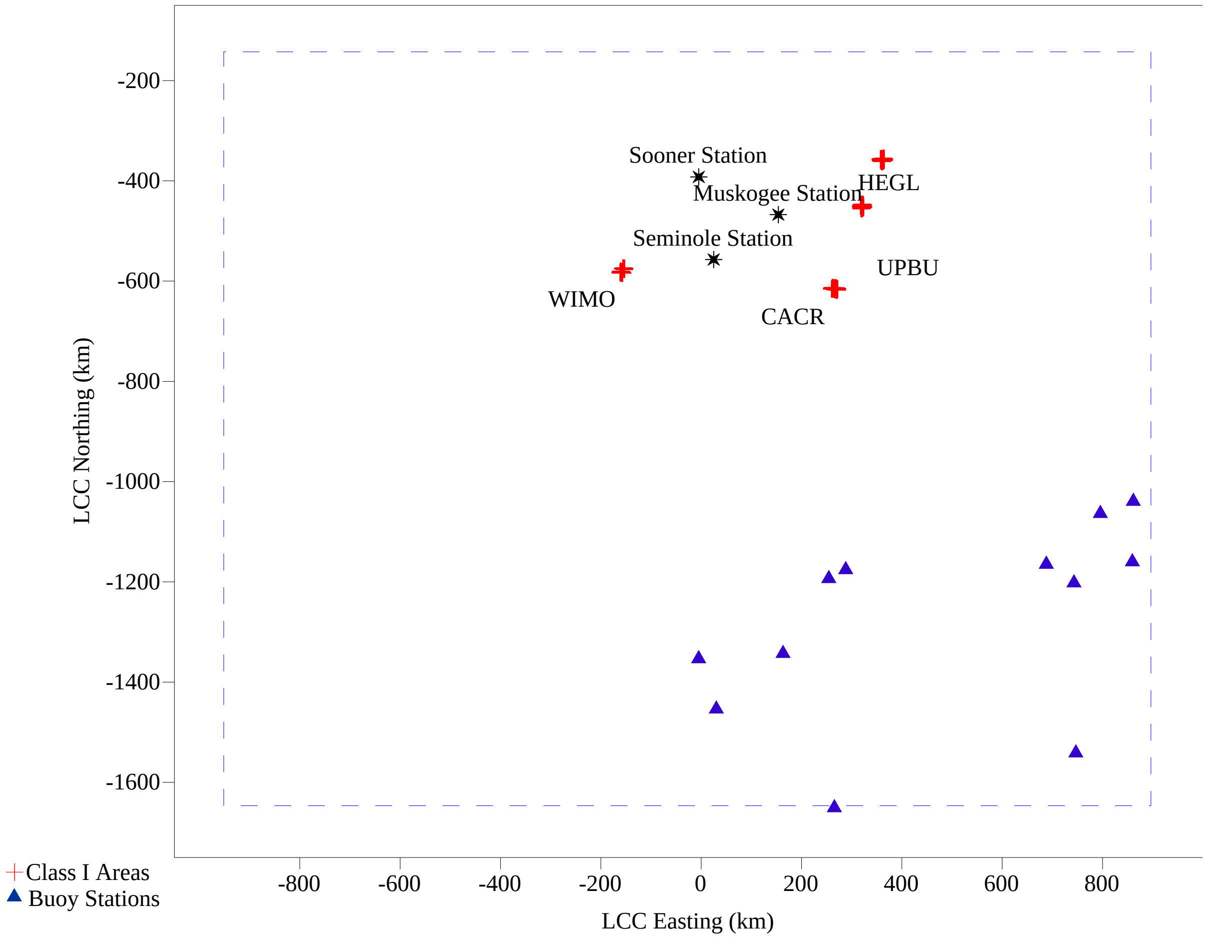
FIGURE 3-5. PLOT OF PRECIPITATION METEOROLOGICAL STATIONS



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

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
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1	5/21/2001	50.906	148,628
1	5/22/2001	52.519	154,556
1	5/23/2001	58.172	170,287
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1	5/25/2001	58.992	169,017
1	5/26/2001	60.789	175,004
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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
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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

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1	6/17/2001	71.396	201,210
1	6/18/2001	75.678	217,184
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1	6/21/2001	69.739	203,174
1	6/22/2001	69.941	208,054
1	6/23/2001	67.056	193,075
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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
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1	7/19/2001	67.091	201,315
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1	7/22/2001	70.121	207,400
1	7/23/2001	58.683	178,725
1	7/24/2001	57.098	206,917
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1	7/26/2001	70.82	217,541
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1	8/7/2001	57.665	191,653
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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
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1	9/25/2001	58.935	173,197
1	9/26/2001	58.448	172,509
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1	1/9/2002	53.326	171,734
1	1/10/2002	63.441	195,374
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1	1/12/2002	68.436	202,097
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1	1/16/2002	73.726	214,133
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1	1/24/2002	50.749	160,297
1	1/25/2002	61.775	193,282
1	1/26/2002	61.535	197,676
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1	1/28/2002	64.414	181,611
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1	3/4/2002	62.583	191,590
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1	3/6/2002	64.212	203,299
1	3/7/2002	70.486	214,514
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1	4/16/2002	53.047	171,720
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1	4/18/2002	43.8	166,016
1	4/19/2002	48.83	175,977
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1	4/22/2002	38.239	113,983
1	4/23/2002	68.634	190,260
1	4/24/2002	63.012	191,729
1	4/25/2002	63.787	197,983
1	4/26/2002	59.158	185,084
1	4/27/2002	69.829	199,244
1	4/28/2002	69.214	186,436
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1	5/9/2002	66.113	182,139
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1	5/15/2002	67.13	216,015
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1	5/19/2002	19.888	74,291
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1	5/24/2002	68	192,062
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1	5/26/2002	65.7	186,889
1	5/27/2002	68.492	186,964
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1	5/29/2002	66.227	185,455
1	5/30/2002	68.742	196,710
1	5/31/2002	64.839	187,781
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1	6/4/2002	70.507	189,222
1	6/5/2002	78.176	213,694
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1	6/7/2002	67.76	201,030
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1	6/9/2002	66.485	191,411
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1	6/16/2002	56.896	167,608
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1	6/18/2002	63.102	186,073
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1	6/20/2002	79.393	189,472
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1	7/3/2002	67.705	216,727
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1	7/8/2002	59.271	194,915
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1	7/17/2002	67.856	189,957
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1	7/21/2002	76.773	205,421
1	7/22/2002	68.664	191,286
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1	8/29/2002	72.557	207,110
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1	10/7/2002	57.704	184,131
1	10/8/2002	70.366	165,991
1	10/9/2002	68.841	174,546
1	10/10/2002	72.823	205,605
1	10/11/2002	62.789	196,835
1	10/12/2002	67.896	219,518
1	10/13/2002	64.469	192,609
1	10/14/2002	76.585	209,355
1	10/15/2002	61.276	184,644
1	10/16/2002	63.876	190,268
1	10/17/2002	63.739	178,031
1	10/18/2002	71.555	196,906
1	10/19/2002	65.951	179,201
1	10/20/2002	69.229	184,225
1	10/21/2002	67.223	172,452
1	10/22/2002	68.757	200,912
1	10/23/2002	66.493	181,742
1	10/24/2002	77.876	197,936
1	10/25/2002	66.975	188,079
1	10/26/2002	72.399	203,780
1	10/27/2002	23.99	74,983
1	10/28/2002	54.183	149,783
1	10/29/2002	62.737	145,898
1	10/30/2002	50.869	128,978
1	10/31/2002	70.349	186,719
1	11/1/2002	67.923	185,442
1	11/2/2002	59.053	158,260
1	11/3/2002	63.912	177,005
1	11/4/2002	67.24	179,065
1	11/5/2002	74.584	200,208
1	11/6/2002	59.928	179,634
1	11/7/2002	72.689	196,407
1	11/8/2002	67.716	178,329
1	11/9/2002	77.283	191,726

1	11/10/2002	63.848	171,424
1	11/11/2002	72.94	193,090
1	11/12/2002	61.283	167,255
1	11/13/2002	69.047	188,017
1	11/14/2002	65.669	178,330
1	11/15/2002	73.693	194,656
1	11/16/2002	66.131	172,077
1	11/17/2002	69.205	194,371
1	11/18/2002	63.507	172,577
1	11/19/2002	71.279	187,306
1	11/20/2002	57.233	149,545
1	11/22/2002	0.285	2,467
1	11/23/2002	43.397	119,570
1	11/24/2002	70.071	193,889
1	11/25/2002	65.963	178,921
1	11/26/2002	65.652	192,450
1	11/27/2002	70.457	162,879
1	11/28/2002	64.064	161,891
1	11/29/2002	46.986	123,508
1	11/30/2002	64.959	169,536
1	12/1/2002	66.605	169,543
1	12/2/2002	73.74	192,490
1	12/3/2002	70.465	178,915
1	12/4/2002	76.84	197,882
1	12/5/2002	66.449	167,574
1	12/6/2002	72.172	176,674
1	12/7/2002	62.203	168,865
1	12/8/2002	65.528	190,748
1	12/9/2002	61.204	179,392
1	12/10/2002	73.699	186,035
1	12/11/2002	67.461	170,849
1	12/12/2002	75.376	194,554
1	12/13/2002	59.989	153,460
1	12/14/2002	68.99	177,279
1	12/15/2002	68.305	160,456
1	12/16/2002	76.191	180,966
1	12/17/2002	73.332	173,618
1	12/18/2002	76.888	195,180
1	12/19/2002	71.893	176,889
1	12/20/2002	67.569	170,932
1	12/21/2002	62.678	166,491
1	12/22/2002	70.113	179,450
1	12/23/2002	71.766	183,176
1	12/24/2002	70.094	183,058
1	12/25/2002	68.993	179,073
1	12/26/2002	72.084	190,734
1	12/27/2002	66.248	171,995

1	12/28/2002	71.41	188,655
1	12/29/2002	60.327	170,084
1	12/30/2002	60.528	169,080
1	12/31/2002	54.642	149,739
1	1/1/2003	73.915	190,490
1	1/2/2003	78.753	194,372
1	1/3/2003	64.163	174,996
1	1/4/2003	74.148	202,634
1	1/5/2003	66.118	176,220
1	1/6/2003	73.507	201,538
1	1/7/2003	61.691	170,119
1	1/8/2003	53.155	190,141
1	1/9/2003	51.59	150,755
1	1/10/2003	54.815	148,813
1	1/11/2003	67.307	178,120
1	1/12/2003	79.089	196,635
1	1/13/2003	60.962	167,295
1	1/14/2003	63.486	199,432
1	1/15/2003	57.585	174,044
1	1/16/2003	62.495	194,099
1	1/17/2003	31.403	95,315
1	1/18/2003	65.728	183,717
1	1/19/2003	60.339	163,905
1	1/20/2003	61.16	165,939
1	1/21/2003	55.715	164,810
1	1/22/2003	59.21	182,170
1	1/23/2003	55.487	186,596
1	1/24/2003	62.545	198,856
1	1/25/2003	62.512	178,918
1	1/26/2003	66.7	191,266
1	1/27/2003	61.967	169,600
1	1/28/2003	67.579	195,026
1	1/29/2003	61.284	173,870
1	1/30/2003	61.872	198,309
1	1/31/2003	58.385	171,516
1	2/1/2003	75.945	197,489
1	2/2/2003	66.362	168,728
1	2/3/2003	65.998	184,364
1	2/4/2003	68.644	176,414
1	2/5/2003	90.467	196,322
1	2/6/2003	58.866	171,981
1	2/7/2003	78.827	199,612
1	2/8/2003	63.091	174,303
1	2/9/2003	63.7	187,172
1	2/10/2003	48.019	168,271
1	2/11/2003	55.823	169,313
1	2/12/2003	62.516	159,288

1	2/13/2003	61.421	174,121
1	2/14/2003	62.005	158,766
1	2/15/2003	78.969	200,801
1	2/16/2003	72.08	184,036
1	2/17/2003	69.689	202,163
1	2/18/2003	62.206	163,617
1	2/19/2003	68.896	180,477
1	2/20/2003	64.623	173,881
1	2/21/2003	67.163	183,845
1	2/22/2003	57.606	157,110
1	2/23/2003	69.672	192,959
1	2/24/2003	57.34	194,459
1	2/25/2003	55.535	183,066
1	2/26/2003	62.888	185,446
1	2/27/2003	47.595	156,992
1	2/28/2003	51.073	147,424
1	3/1/2003	40.516	108,627
1	3/2/2003	52.253	144,424
1	3/3/2003	48.089	173,987
1	3/4/2003	49.411	152,776
1	3/5/2003	48.333	158,937
1	3/6/2003	58.036	202,330
1	3/7/2003	46.863	145,062
1	3/8/2003	49.793	175,267
1	3/9/2003	70.656	170,559
1	3/10/2003	62.434	202,802
1	3/11/2003	57.399	184,481
1	3/12/2003	45.609	164,665
1	3/13/2003	37.658	145,800
1	3/14/2003	58.95	199,236
1	3/15/2003	61.202	187,834
1	3/16/2003	53.613	170,221
1	3/17/2003	59.39	175,018
1	3/18/2003	78.889	209,616
1	3/19/2003	71.377	186,412
1	3/20/2003	86.469	198,170
1	3/21/2003	75.59	185,082
1	3/22/2003	91.133	212,229
1	3/23/2003	89.95	183,040
1	3/24/2003	68.44	199,438
1	3/25/2003	66.328	167,699
1	3/26/2003	87.734	208,448
1	3/27/2003	62.384	171,469
1	4/1/2003	77.815	192,159
1	4/2/2003	75.176	180,236
1	4/3/2003	66.211	194,903
1	4/4/2003	36.75	175,240

1	4/5/2003	62.096	198,466
1	4/6/2003	68.474	174,682
1	4/7/2003	71.167	204,526
1	4/8/2003	73.012	203,697
1	4/9/2003	76.151	202,733
1	4/10/2003	68.052	175,982
1	4/11/2003	75.146	191,851
1	4/12/2003	70.72	186,941
1	4/13/2003	58.355	150,660
1	4/14/2003	69.968	192,204
1	4/15/2003	57.581	162,914
1	4/16/2003	68.308	187,283
1	4/17/2003	69.638	194,059
1	4/18/2003	47.058	137,341
1	4/19/2003	40.801	138,266
1	4/20/2003	69.525	184,518
1	4/21/2003	63.383	195,627
1	4/22/2003	46.951	156,554
1	4/23/2003	53.949	166,751
1	4/24/2003	57.137	173,637
1	4/25/2003	67.083	198,800
1	4/26/2003	65.889	178,524
1	4/27/2003	63.961	184,933
1	4/28/2003	56.091	164,029
1	5/14/2003	0.049	15,011
1	5/15/2003	15.377	77,551
1	5/16/2003	68.357	191,499
1	5/17/2003	64.285	195,408
1	5/18/2003	18.734	103,256
1	5/19/2003	31.395	95,092
1	5/20/2003	22.936	92,627
1	5/21/2003	28.402	89,420
1	5/22/2003	41.112	124,468
1	5/23/2003	59.486	174,644
1	5/24/2003	54.912	160,872
1	5/25/2003	56.33	165,561
1	5/26/2003	58.981	169,606
1	5/27/2003	63.996	182,690
1	5/28/2003	63.645	171,811
1	5/29/2003	60.784	184,084
1	5/30/2003	54.991	184,091
1	5/31/2003	75.624	209,565
1	6/1/2003	60.852	182,601
1	6/2/2003	63.49	206,040
1	6/3/2003	60.287	183,880
1	6/4/2003	67.308	202,062
1	6/5/2003	60.479	181,552

1	6/6/2003	55.256	192,138
1	6/7/2003	60.258	186,045
1	6/8/2003	65.11	194,271
1	6/9/2003	57.75	176,036
1	6/10/2003	62.436	203,259
1	6/11/2003	66.898	189,842
1	6/12/2003	70.574	207,990
1	6/13/2003	56.696	175,684
1	6/14/2003	71.951	215,265
1	6/15/2003	58.017	186,958
1	6/16/2003	59.332	195,251
1	6/17/2003	50.246	162,323
1	6/18/2003	72.322	208,449
1	6/19/2003	64.908	188,054
1	6/20/2003	67.928	206,650
1	6/21/2003	62.11	190,843
1	6/22/2003	66.638	201,823
1	6/23/2003	64.963	195,499
1	6/24/2003	68.687	206,961
1	6/25/2003	60.499	189,095
1	6/26/2003	72.145	210,390
1	6/27/2003	64.627	187,355
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

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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

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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
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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

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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
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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
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2	9/21/2001	56.879	205,070

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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
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2	10/3/2001	62.915	218,269
2	10/4/2001	61.427	207,816
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2	10/7/2001	62.748	204,980
2	10/8/2001	67.948	216,413
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2	10/10/2001	73.355	229,679
2	10/11/2001	62.266	208,230
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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
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2	10/22/2001	66.245	208,530
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2	11/21/2001	55.149	181,063
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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

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2	11/30/2001	57.485	170,671
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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
2	12/23/2001	53.796	190,558
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	1/21/2002	72.29	230,019
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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
2	1/31/2002	63.564	197,722
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2	2/3/2002	54.381	171,970
2	2/4/2002	66.661	210,080
2	2/5/2002	67.477	205,471
2	2/6/2002	70.912	222,089
2	2/7/2002	61.621	194,478
2	2/8/2002	62.479	199,087
2	2/9/2002	55.252	182,193
2	2/10/2002	60.083	189,205
2	2/11/2002	58.505	187,336
2	2/12/2002	61.278	200,113
2	2/13/2002	62.493	200,276
2	2/14/2002	53.959	211,516
2	2/15/2002	51.148	204,465
2	2/16/2002	68.171	218,723
2	2/17/2002	50.575	171,532
2	2/18/2002	59.098	204,245
2	2/19/2002	50.629	166,054
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2	2/23/2002	18.532	70,454
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	3/7/2002	61.224	195,503
2	3/8/2002	67.506	216,459

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2	3/13/2002	56.569	190,646
2	3/14/2002	56.669	230,970
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2	4/4/2002	71.24	213,172
2	4/5/2002	64.366	196,330
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2	4/8/2002	67.72	207,416
2	4/9/2002	64.94	196,108
2	4/10/2002	66.561	211,263
2	4/11/2002	31.135	105,732
2	4/12/2002	66.671	201,828
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2	4/14/2002	62.103	195,979
2	4/15/2002	69.001	209,466
2	4/16/2002	60.639	205,080
2	4/17/2002	61.127	199,518
2	4/18/2002	54.461	206,262
2	4/19/2002	62.814	211,213
2	4/20/2002	67.041	218,172
2	4/21/2002	63.153	206,199
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
2	4/27/2002	67.558	197,847
2	4/28/2002	78.7	217,106
2	4/29/2002	69.386	198,134
2	4/30/2002	68.806	207,862
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2	7/15/2002	12.132	63,796
2	7/16/2002	28.317	102,351

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2	7/20/2002	38.357	117,244
2	7/21/2002	38.988	118,885
2	7/22/2002	40.61	125,594
2	7/23/2002	42.915	131,892
2	7/24/2002	40.241	123,002
2	7/25/2002	37.361	115,289
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2	7/28/2002	26.878	101,064
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2	7/30/2002	42.387	132,270
2	7/31/2002	38.205	119,888
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2	8/3/2002	42.239	132,488
2	8/4/2002	42.95	133,154
2	8/5/2002	43.385	130,753
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2	8/7/2002	43.123	129,834
2	8/8/2002	43.569	128,427
2	8/9/2002	43.707	130,776
2	8/10/2002	43.608	122,620
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2	8/12/2002	45.51	130,658
2	8/13/2002	45.872	130,659
2	8/14/2002	41.298	122,162
2	8/15/2002	42.519	129,385
2	8/16/2002	40.682	131,262
2	8/17/2002	42.923	125,941
2	8/18/2002	35.574	112,584
2	8/19/2002	36.749	117,565
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2	8/23/2002	38.883	123,059
2	8/24/2002	43.506	133,585
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2	8/29/2002	43.262	130,706
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2	9/7/2002	47.637	133,684
2	9/8/2002	43.014	125,865
2	9/9/2002	42.505	134,267
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2	9/11/2002	46.077	134,731
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2	9/15/2002	41.546	133,852
2	9/16/2002	38.665	127,547
2	9/17/2002	40.004	132,831
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2	9/21/2002	42.757	132,226
2	9/22/2002	44.43	131,967
2	9/23/2002	43.747	131,537
2	9/24/2002	39.868	119,834
2	9/25/2002	43.73	129,196
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2	9/27/2002	43.31	132,513
2	9/28/2002	43.877	122,563
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2	9/30/2002	44.132	133,787
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2	10/5/2002	46.533	132,296
2	10/6/2002	37.951	129,378
2	10/7/2002	37.966	134,015
2	10/8/2002	52.868	131,411
2	10/9/2002	48.696	130,423
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2	10/12/2002	40.764	133,441
2	10/13/2002	41.794	131,590
2	10/14/2002	43.046	124,950
2	10/15/2002	42.015	131,725
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2	10/18/2002	42.819	125,107
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2	10/20/2002	41.747	122,107
2	10/21/2002	46.708	127,818
2	10/22/2002	39.902	124,298
2	10/23/2002	46.263	131,562
2	10/24/2002	47.766	131,047
2	10/25/2002	41.849	124,779
2	10/26/2002	41.564	123,656
2	10/27/2002	43.533	129,717
2	10/28/2002	43.741	130,411
2	10/29/2002	51.355	131,682
2	10/30/2002	45.219	125,490
2	10/31/2002	44.394	127,462
2	11/1/2002	44.205	129,628
2	11/2/2002	44.643	129,261
2	11/3/2002	40.96	123,745
2	11/4/2002	44.925	129,527
2	11/5/2002	44.343	129,860
2	11/6/2002	39.085	128,247
2	11/7/2002	39.211	116,214
2	11/8/2002	0.112	713
2	11/9/2002	30.216	89,527
2	11/10/2002	42.778	132,346
2	11/11/2002	45.237	135,241
2	11/12/2002	42.721	133,800
2	11/13/2002	40.472	126,955
2	11/14/2002	43.795	134,896
2	11/15/2002	43.198	131,216
2	11/16/2002	45.042	131,855
2	11/17/2002	38.768	124,964
2	11/18/2002	45.241	134,505
2	11/19/2002	43.17	128,974
2	11/20/2002	44.857	133,926
2	11/21/2002	34.507	124,369
2	11/22/2002	40.563	134,614
2	11/23/2002	41.97	126,004
2	11/24/2002	42.291	130,382
2	11/25/2002	41.495	124,334
2	11/26/2002	37.269	124,510
2	11/27/2002	49.643	130,574
2	11/28/2002	39.346	117,870
2	11/29/2002	36.85	112,104
2	11/30/2002	38.929	116,062
2	12/1/2002	43.494	125,327
2	12/2/2002	43.673	128,968
2	12/3/2002	44.758	128,720
2	12/4/2002	40.619	120,228
2	12/5/2002	44.174	123,841

2	12/6/2002	45.294	122,380
2	12/7/2002	44.022	130,355
2	12/8/2002	39.016	125,323
2	12/9/2002	39.942	128,946
2	12/10/2002	45.545	129,204
2	12/11/2002	46.137	129,573
2	12/12/2002	42.167	122,406
2	12/13/2002	43.991	125,979
2	12/14/2002	42.538	122,758
2	12/15/2002	44.708	118,376
2	12/16/2002	44.316	119,716
2	12/17/2002	50.162	133,839
2	12/18/2002	46.255	134,021
2	12/19/2002	45.517	126,790
2	12/20/2002	40.965	115,263
2	12/21/2002	41.574	121,203
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
2	12/27/2002	42.103	126,936
2	12/28/2002	41.979	125,825
2	12/29/2002	41.407	130,355
2	12/30/2002	39.035	125,098
2	12/31/2002	33.961	106,812
2	1/1/2003	0.341	1,291
2	1/2/2003	24.871	75,015
2	1/3/2003	43.488	131,086
2	1/4/2003	44.772	133,140
2	1/5/2003	43.777	127,572
2	1/6/2003	41.851	127,057
2	1/7/2003	43.265	129,584
2	1/8/2003	33.494	135,839
2	1/9/2003	34.51	117,031
2	1/10/2003	32.859	105,555
2	1/11/2003	45.679	133,252
2	1/12/2003	47.269	131,567
2	1/13/2003	43.467	131,756
2	1/14/2003	34.278	121,976
2	1/15/2003	37.056	126,788
2	1/16/2003	35.639	124,641
2	1/17/2003	40.614	126,291
2	1/18/2003	27.459	85,135
2	1/19/2003	17.771	59,166
2	1/20/2003	35.263	109,848
2	1/21/2003	35.953	123,177

2	1/22/2003	37.714	131,248
2	1/23/2003	35.122	129,180
2	1/24/2003	36.233	127,447
2	1/25/2003	39.378	127,484
2	1/26/2003	40.25	132,336
2	1/27/2003	40.483	128,508
2	1/28/2003	37.561	124,953
2	1/29/2003	38.808	128,100
2	1/30/2003	35.494	130,346
2	1/31/2003	38.757	133,533
2	2/1/2003	41.725	127,852
2	2/2/2003	40.329	120,575
2	2/3/2003	42.013	132,787
2	2/4/2003	43.945	124,794
2	2/5/2003	51.338	123,725
2	2/6/2003	41.152	131,622
2	2/7/2003	45.95	131,172
2	2/8/2003	43.205	130,678
2	2/9/2003	36.771	121,808
2	2/10/2003	33.438	126,701
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
2	2/19/2003	42.955	126,106
2	2/20/2003	43.088	128,814
2	2/21/2003	38.065	117,061
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
2	2/28/2003	38.09	123,264
2	3/1/2003	40.001	116,912
2	3/2/2003	40.728	125,999
2	3/3/2003	33.138	132,172
2	3/4/2003	20.669	79,737
2	3/5/2003	36.366	137,002
2	3/6/2003	34.559	126,821
2	3/7/2003	33.253	114,835
2	4/22/2003	0.024	2,455
2	4/23/2003	0.57	6,409

2	4/24/2003	0.346	4,998
2	4/25/2003	1.653	19,701
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
2	5/4/2003	0.227	2,424
2	5/5/2003	17.06	57,849
2	5/6/2003	30.047	78,658
2	5/7/2003	46.492	142,062
2	5/8/2003	72.41	213,935
2	5/9/2003	68.937	207,975
2	5/10/2003	74.992	230,885
2	5/11/2003	67.38	200,812
2	5/12/2003	70.581	210,656
2	5/13/2003	57.171	171,045
2	5/14/2003	70.563	200,534
2	5/15/2003	70.167	202,730
2	5/16/2003	72.346	205,881
2	5/17/2003	58.061	185,961
2	5/18/2003	19.448	115,299
2	5/19/2003	31.077	101,821
2	5/20/2003	22.744	99,360
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
2	5/25/2003	46.489	143,001
2	5/26/2003	58.979	174,641
2	5/27/2003	55.063	161,496
2	5/28/2003	65.86	179,119
2	5/29/2003	55.553	174,322
2	5/30/2003	60.648	208,039
2	5/31/2003	71.727	198,338
2	6/1/2003	70.761	212,833
2	6/2/2003	61.365	203,050
2	6/3/2003	68.958	210,743
2	6/4/2003	62.461	182,842
2	6/5/2003	62.573	183,088
2	6/6/2003	34.208	115,096
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
2	6/11/2003	72.437	206,864
2	6/12/2003	58.341	175,572
2	6/13/2003	56.284	179,098

2	6/14/2003	61.374	193,446
2	6/15/2003	57.086	189,912
2	6/16/2003	55.164	189,091
2	6/17/2003	62.629	196,250
2	6/18/2003	64.786	189,691
2	6/19/2003	73.637	211,207
2	6/20/2003	63.431	197,470
2	6/21/2003	63.918	197,410
2	6/22/2003	64.29	198,094
2	6/23/2003	75.428	227,341
2	6/24/2003	66.436	202,040
2	6/25/2003	72.313	226,759
2	6/26/2003	66.525	197,524
2	6/27/2003	68.121	197,548
2	6/28/2003	63.802	200,025
2	6/29/2003	77.756	220,554
2	6/30/2003	52.714	170,043
2	7/1/2003	71.656	214,756
2	7/2/2003	63.08	186,501
2	7/3/2003	73.932	215,785
2	7/4/2003	60.631	178,823
2	7/5/2003	68.874	205,836
2	7/6/2003	61.564	178,612
2	7/7/2003	74.013	223,042
2	7/8/2003	67.694	208,792
2	7/9/2003	76.708	221,622
2	7/10/2003	68.181	197,469
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
2	7/15/2003	78.388	230,380
2	7/16/2003	74.257	203,521
2	7/17/2003	75.934	217,919
2	7/18/2003	68.109	191,966
2	7/19/2003	72.846	207,656
2	7/20/2003	61.14	178,396
2	7/21/2003	78.679	230,258
2	7/22/2003	62.621	195,532
2	7/23/2003	65.829	203,912
2	7/24/2003	60.599	178,711
2	7/25/2003	73.576	210,531
2	7/26/2003	70.157	197,491
2	7/27/2003	90.528	215,849
2	7/28/2003	68.841	191,139
2	7/29/2003	70.723	204,797
2	7/30/2003	67.712	197,828

2	7/31/2003	66.125	202,486
2	8/1/2003	71.541	196,492
2	8/2/2003	80.742	214,317
2	8/3/2003	61.329	168,613
2	8/4/2003	68.92	195,435
2	8/5/2003	61.499	178,308
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
Chicago, IL 60603-5780 USA

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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.

CONTRIBUTORS

Prepared by:

Kristen C Bell — 5/16/2013

Kristen Bell — Date
Environmental Associate

Joy Rooney — 5/16/2013

Joy Rooney — Date
Environmental Associate

Reviewed by:

Steve Katzberger — 5/16/2013

Steve Katzberger — Date
Environmental Lead

Approved by:

S. C. McHone — 5/16/2013

Sean McHone — Date
Project Manager

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.
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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

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STATE OF
ARKANSAS
LICENSED
PROFESSIONAL
ENGINEER
No. 15308
SEAN C. McHONE

S. C. McHone
5/16/2013

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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

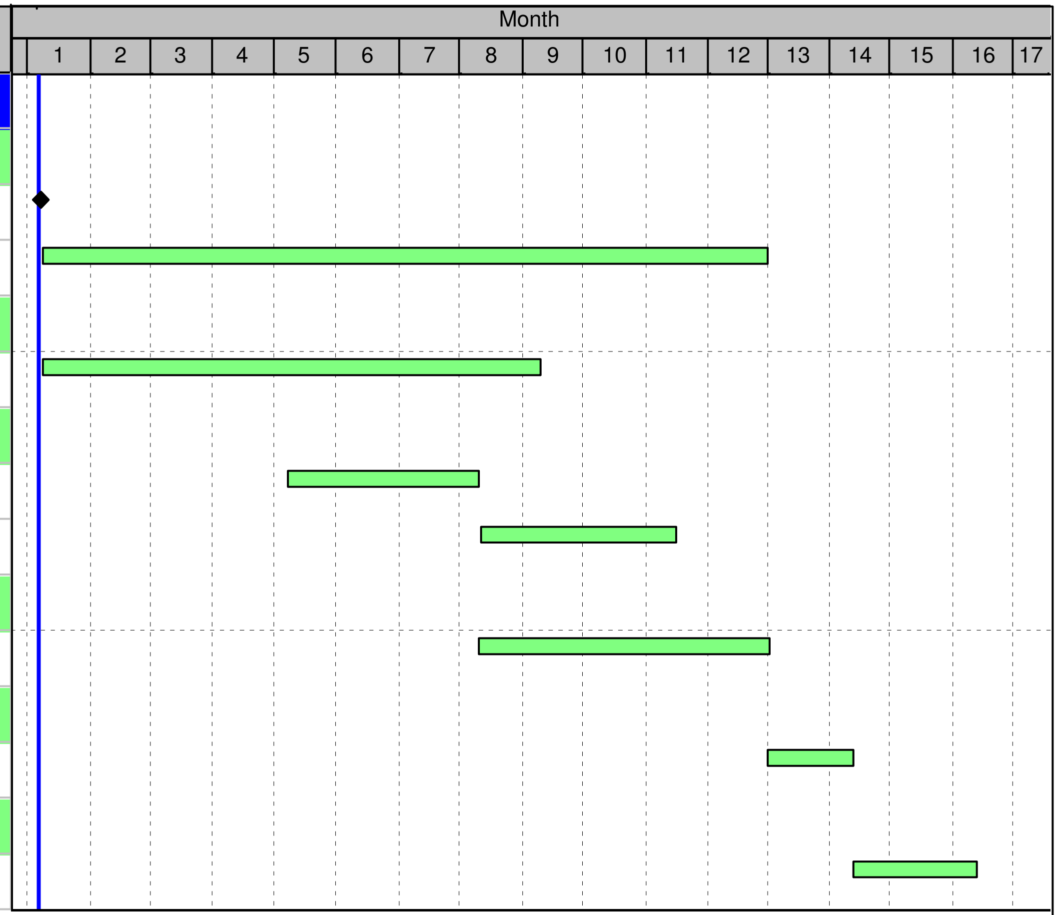
Estimate Totals

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

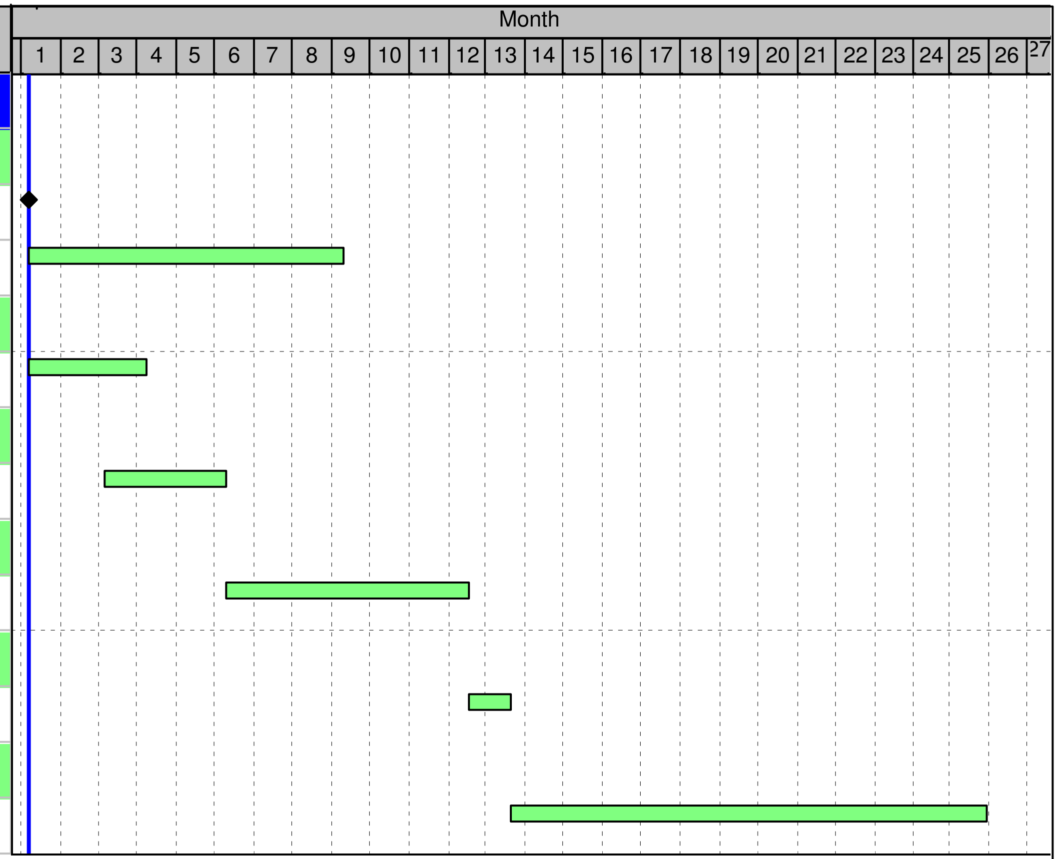
APPENDIX B

1. ESTIMATED PROJECT SCHEDULES

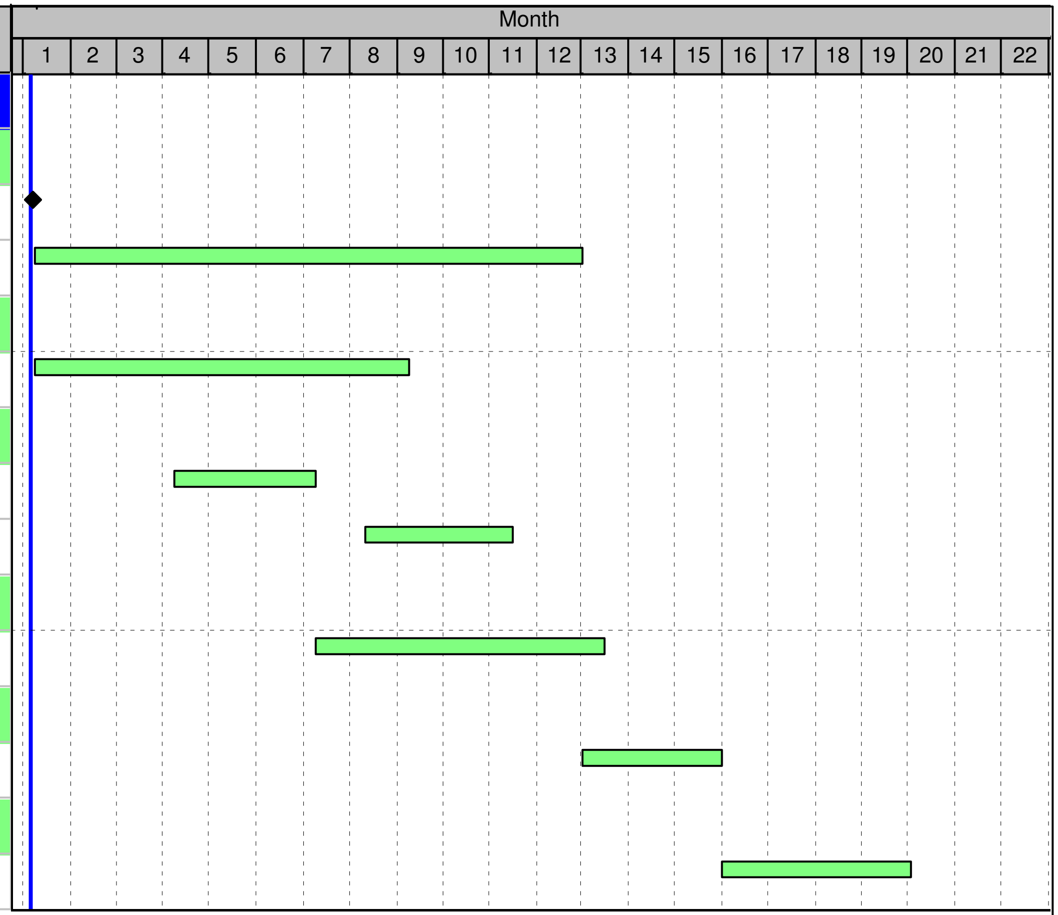
Activity ID	Activity Name	Org Dur (months)
Entergy - NOx Strategy Study - Aux Boiler (LNB/OFA/F...		15m
Permitting		12m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	12m
Engineering		8m
A1020	Engineering	8m
Procurement of Major Equipment		6m
A1030	LNB/OFA Spec - Prep/Bid/Eval/Award	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



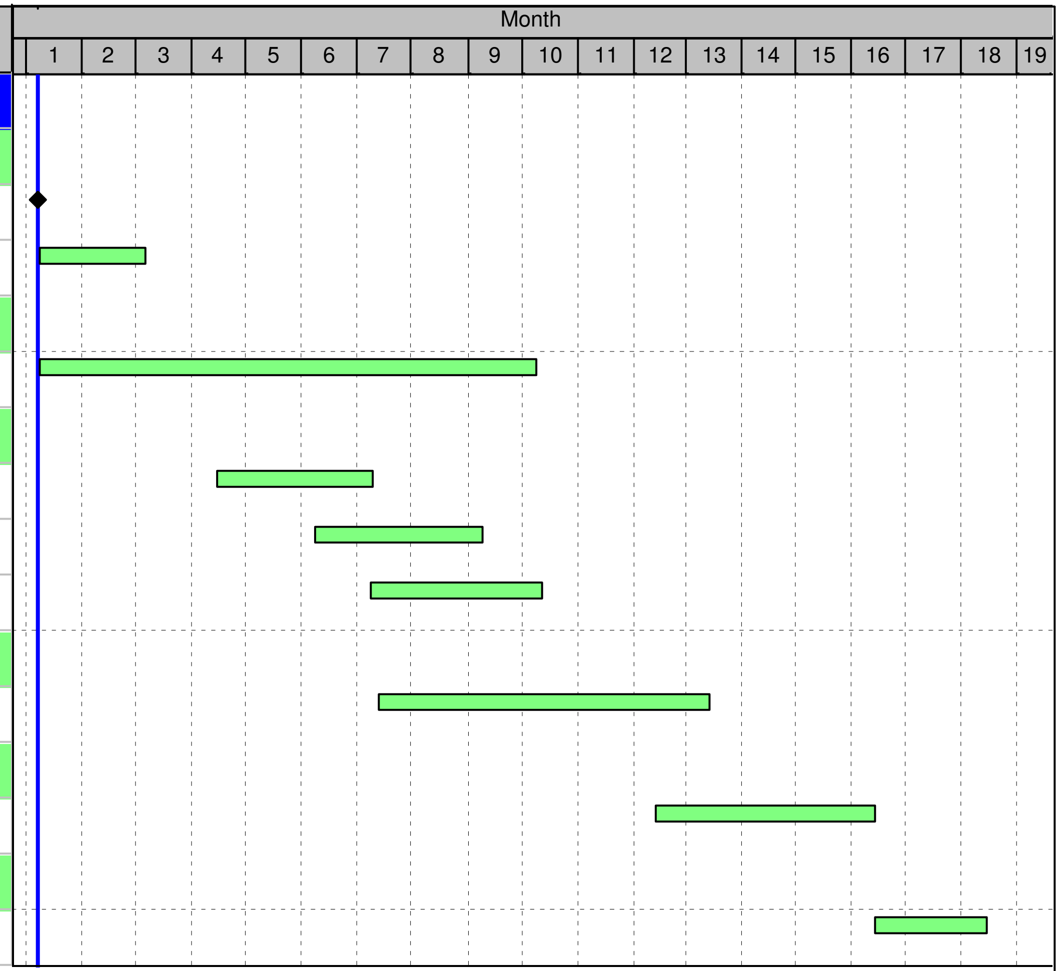
.	Activity ID	Activity Name	Org Dur (months)
		Entergy - NOx Strategy Study - Neural Network	24m
		Permitting	8m
	A1000	Project Authorization	0m
	A1010	Air Permit - Prepare/Review/Approve	8m
		Engineering	3m
	A1020	Engineering	3m
		Procurement of Major Equipment	3m
	A1030	Neural Network Spec - Prep/Bid/Eval/Award	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

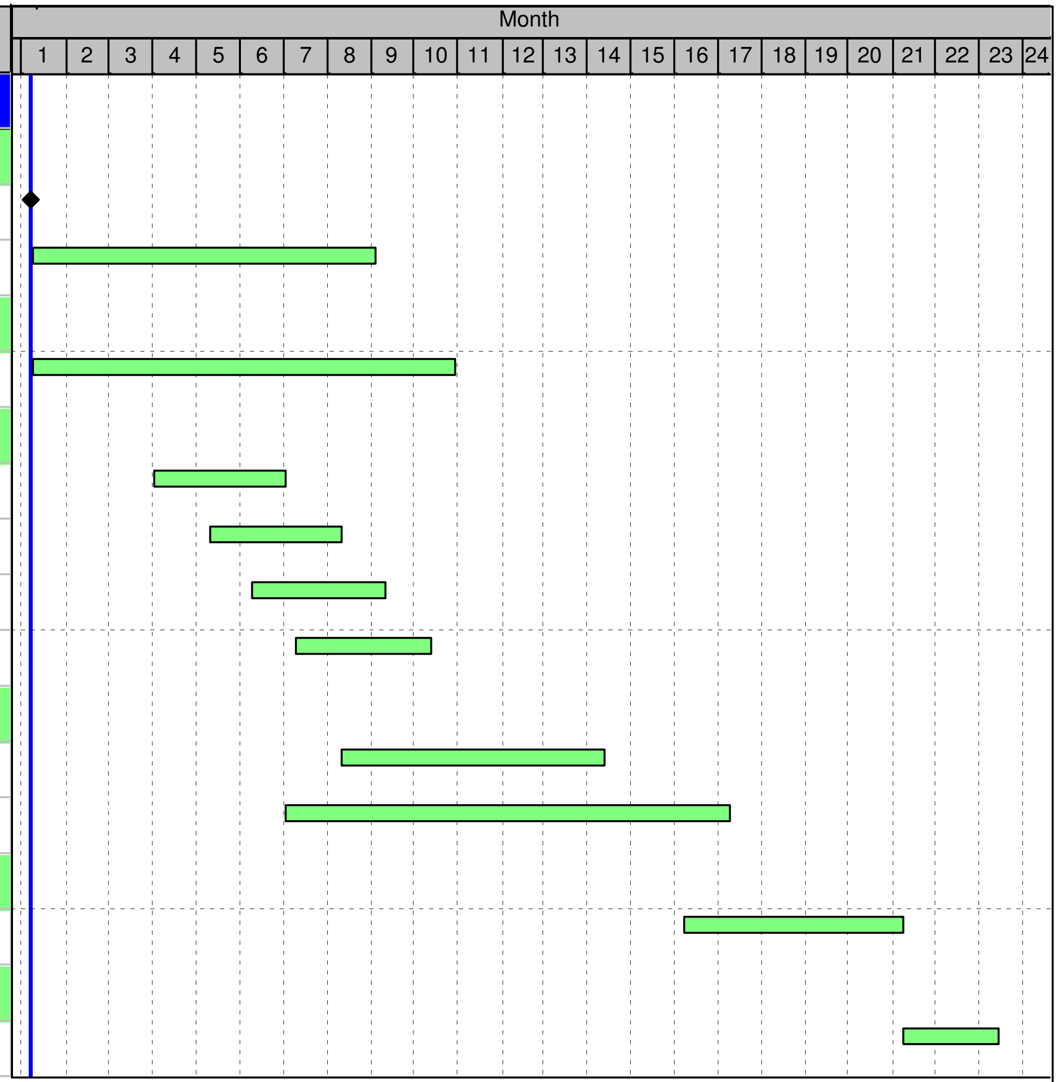


Run Date: 09-17-12

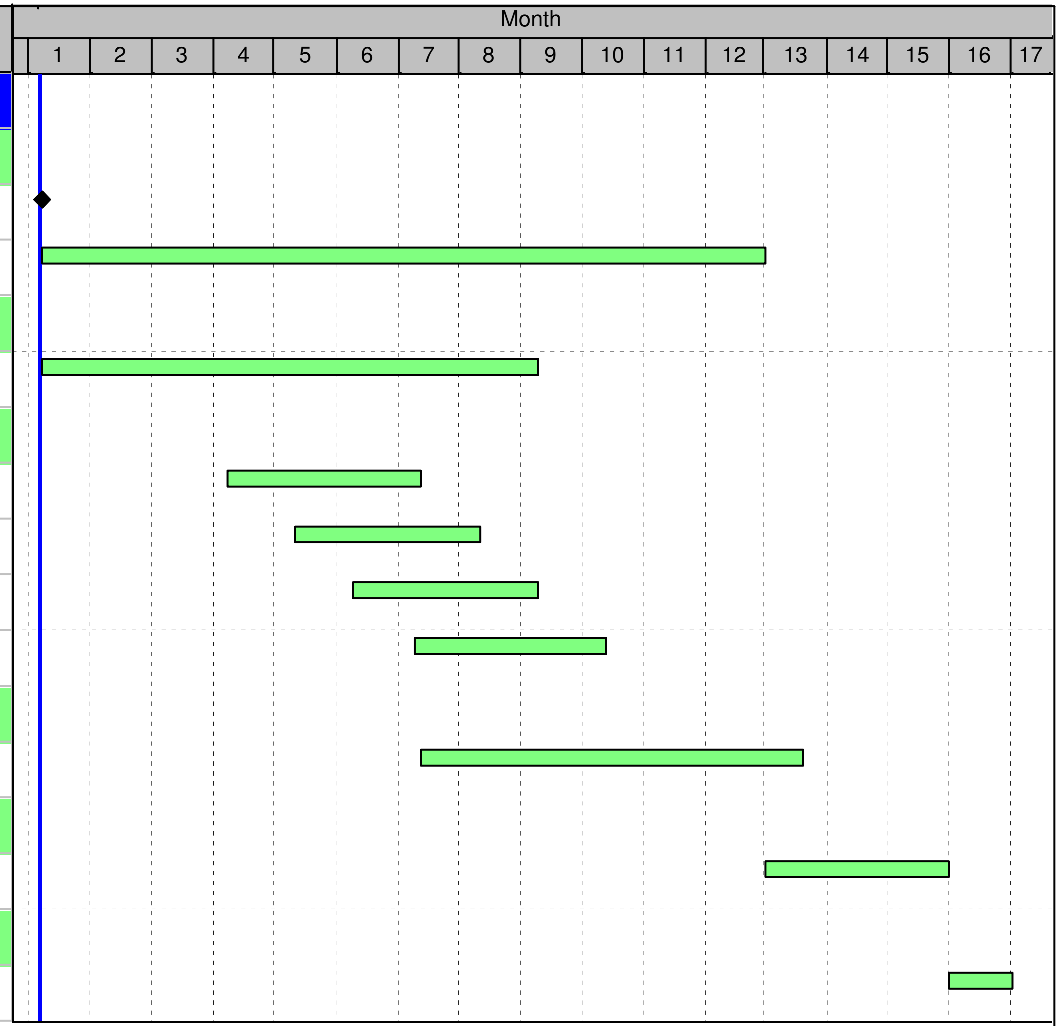
NOx Control Technology Cost and Performance Study for Entergy Services, Inc. White Bluff and Lake Catherine Induced Flue Gas Recirculation (IFGR)

Sargent & Lundy LLC

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

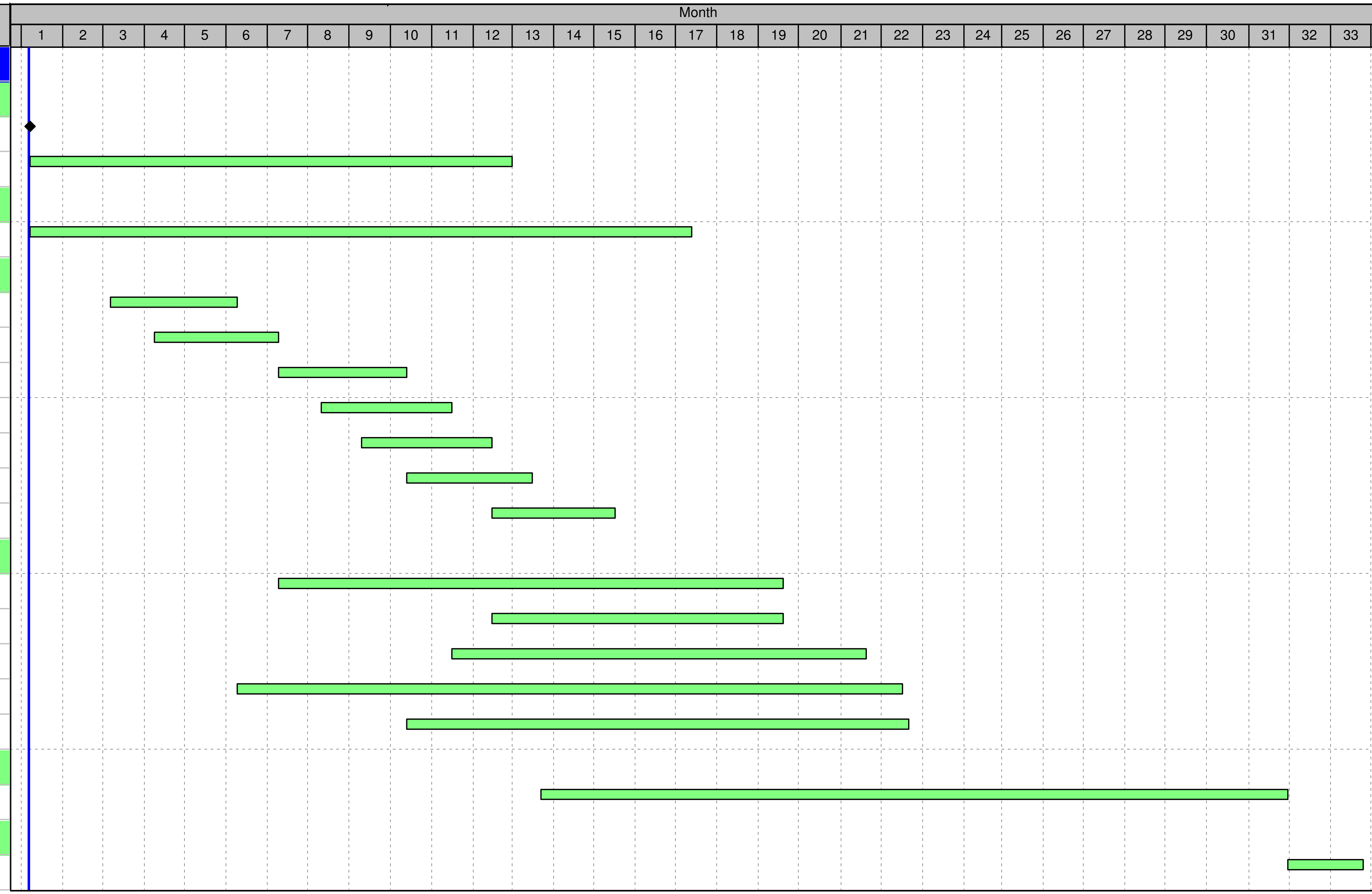


Run Date: 09-14-12

NOx Control Technology Cost and Performance Study for Entergy Services, Inc. White Bluff and Lake Catherine Selective Non-Catalytic Reduction (SNCR)

Sargent & Lundy LLC

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

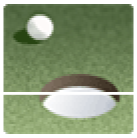
Unit Data		Reagent Costs	
Size (Gross kW)	558,000	Aq.Ammonia $/t	$700
Average NOx Emission Rate (lb/MMBtu)	0.4825	An.Ammonia $/t	$400
Nominal Max. Boiler Heat Input (mmBtu/hr)	5,850.0	Urea $/t	$350
Avg. Heat Rate (Btu/kwh)	10,483.9	N/F-T Urea $/t	$618
Aux. Power (kw)	-	Gas Cost, $/MBtu	4.900
Est. Capacity 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

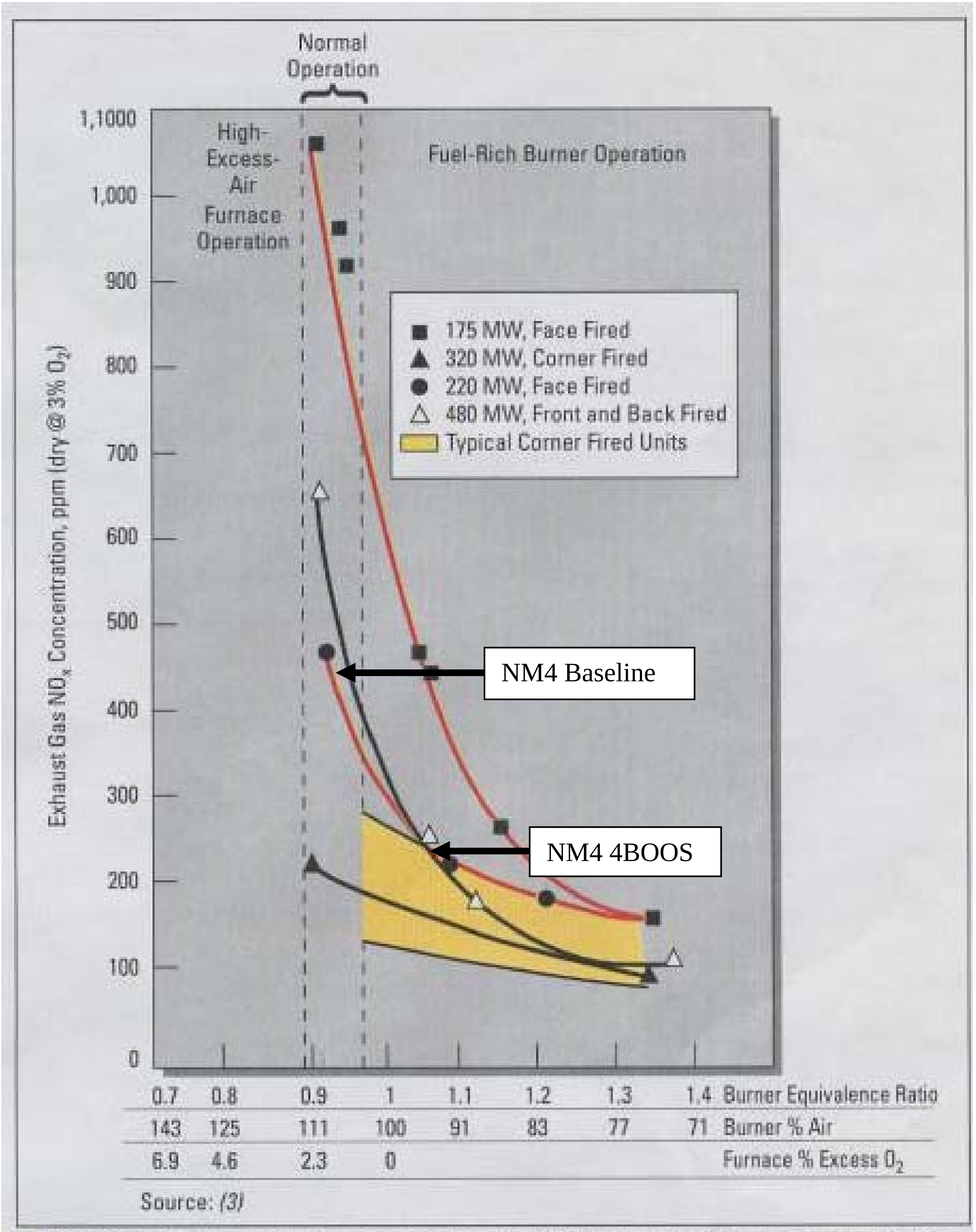


Figure 2. Burners-out-of-service can be an effective combustion staging technique.

Figure 2- Ninemile Units 4 and 5 BOOS Pattern
(Top Elevation Out of Service & Air Registers Open)

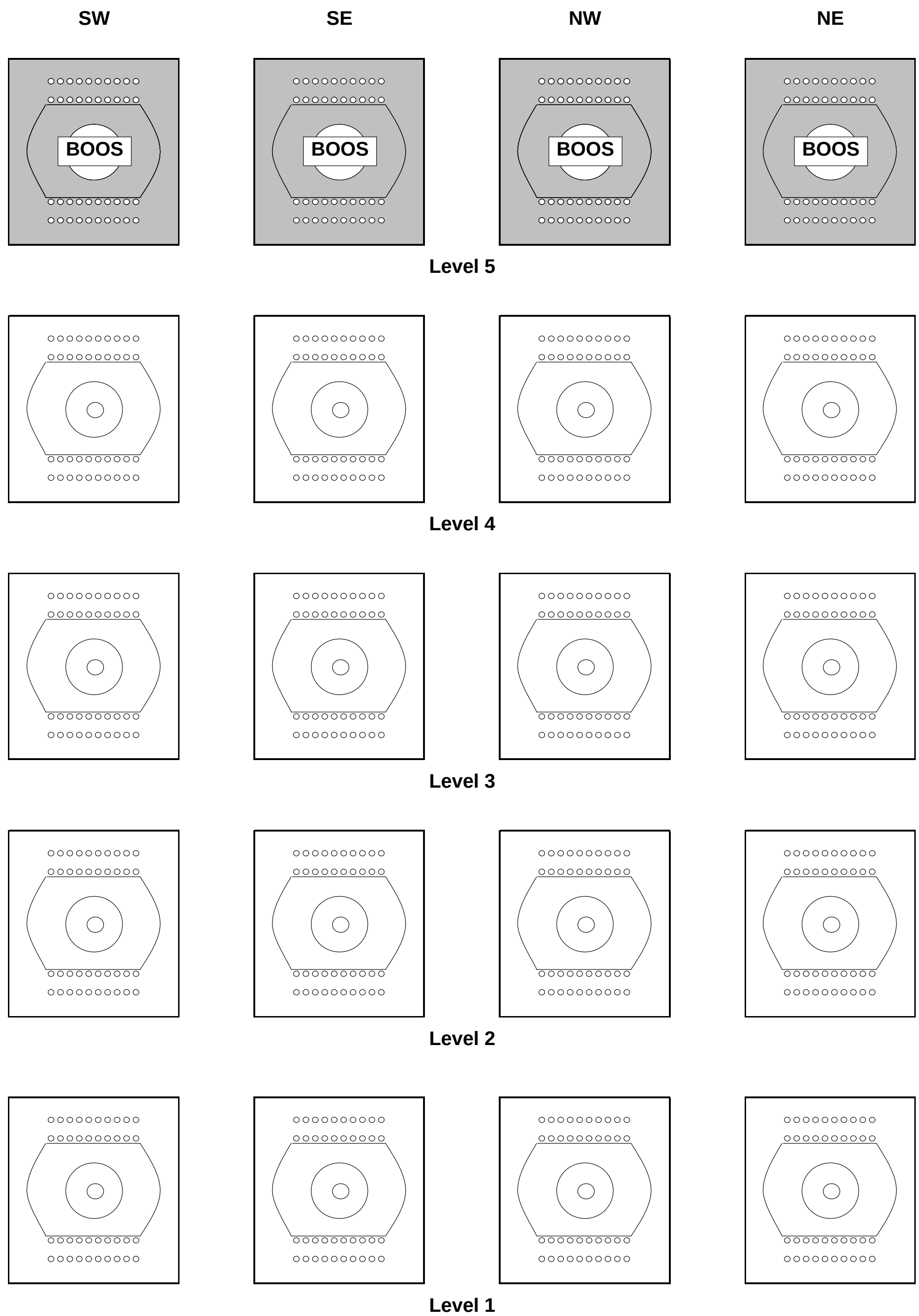


Figure 3- Lake Catherine Unit 4 Burner Header Pressure

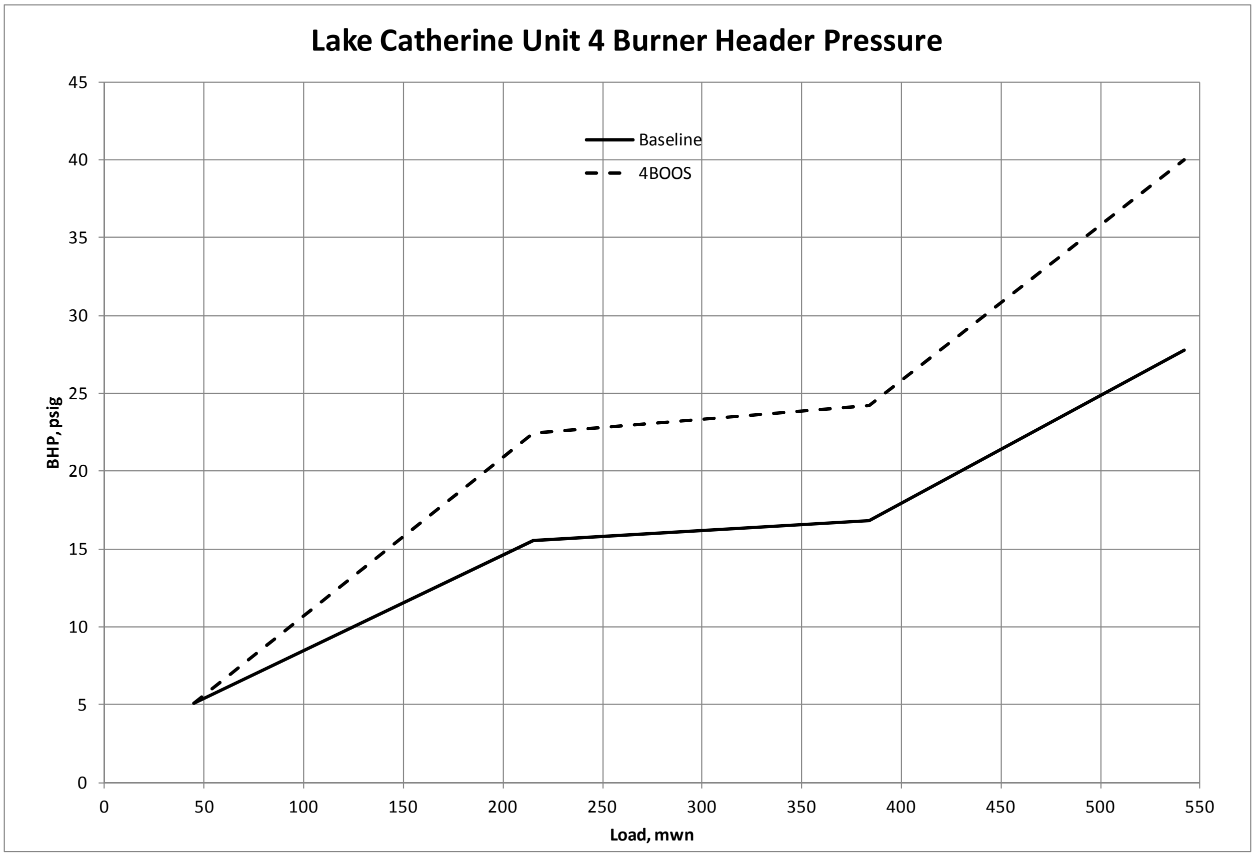
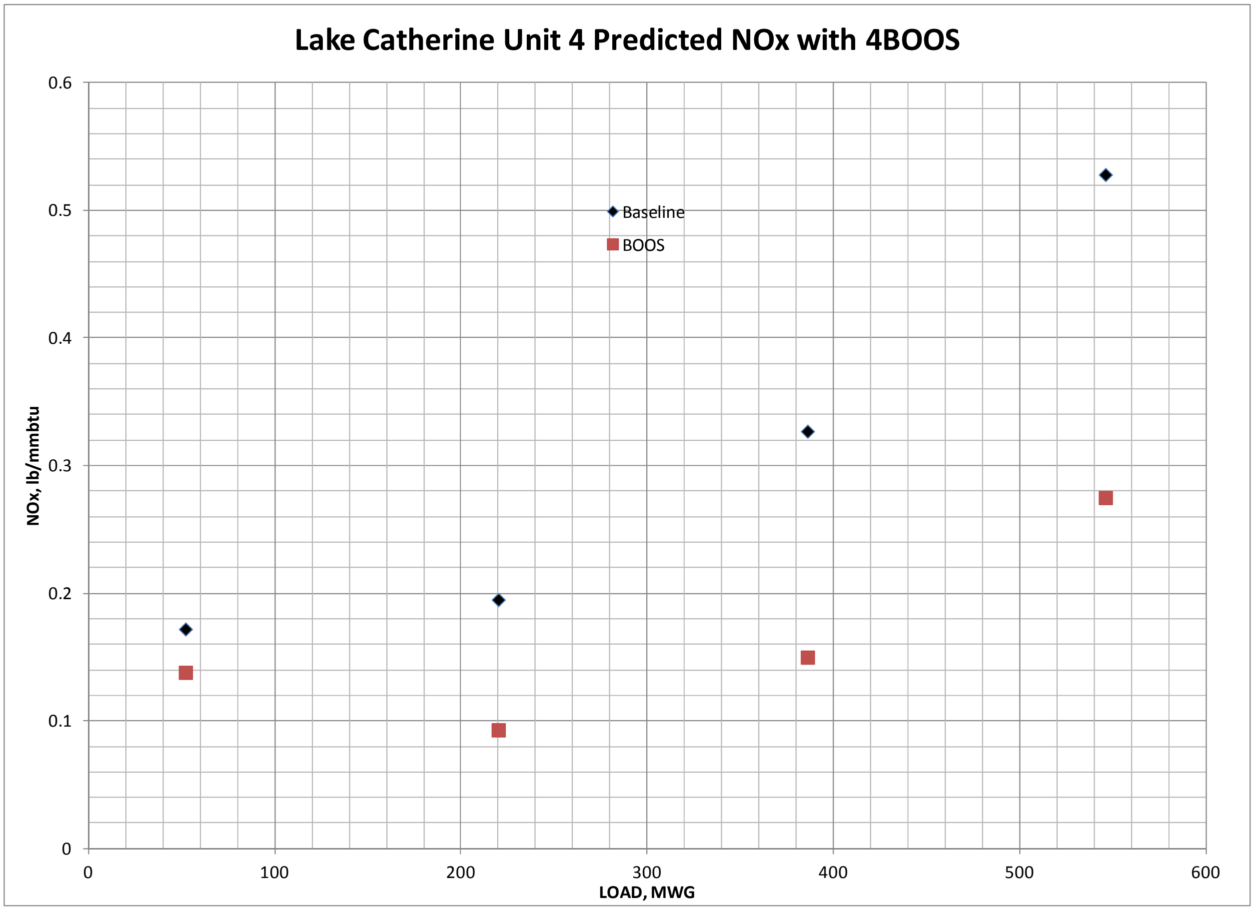


Figure 4- Lake Catherine Unit 4 NOx Emissions Prediction



ADEQ
ARKANSAS
Department of Environmental Quality

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

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[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.

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[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]

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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)	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

ENTERGY ARKANSAS, INC.

WHITE BLUFF DRY FGD

COST ESTIMATE AND TECHNICAL BASIS

SL-012831
Final, Rev. 1
August 3, 2017
Project 13027-002

Prepared by

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000

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. 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

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. <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. 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. 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[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

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

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**

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

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

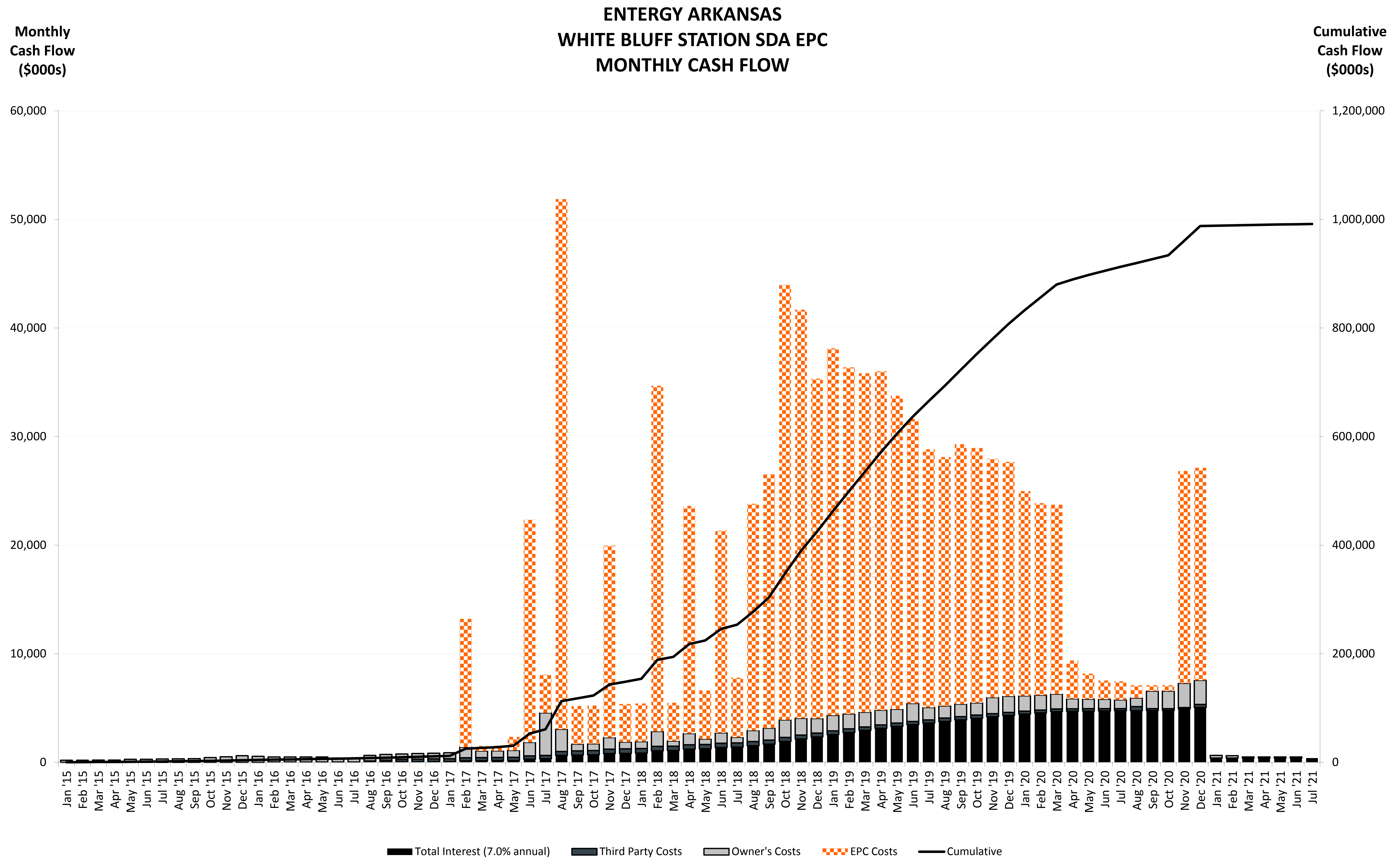
Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		23.99.00	STEEL, MISCELLANEOUS									
			STEEL, MISCELLANEOUS -	BUS DUCT SUPPORTS	167.00 TN	-	-	452,570	3,263	92.62 /MH	302,239	754,809
			STEEL, MISCELLANEOUS -	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				**1,500,000**	**1,083,000**	**10,884**		**841,993**	**3,424,993**
			BOP SYSTEM									

ATTACHMENT 2

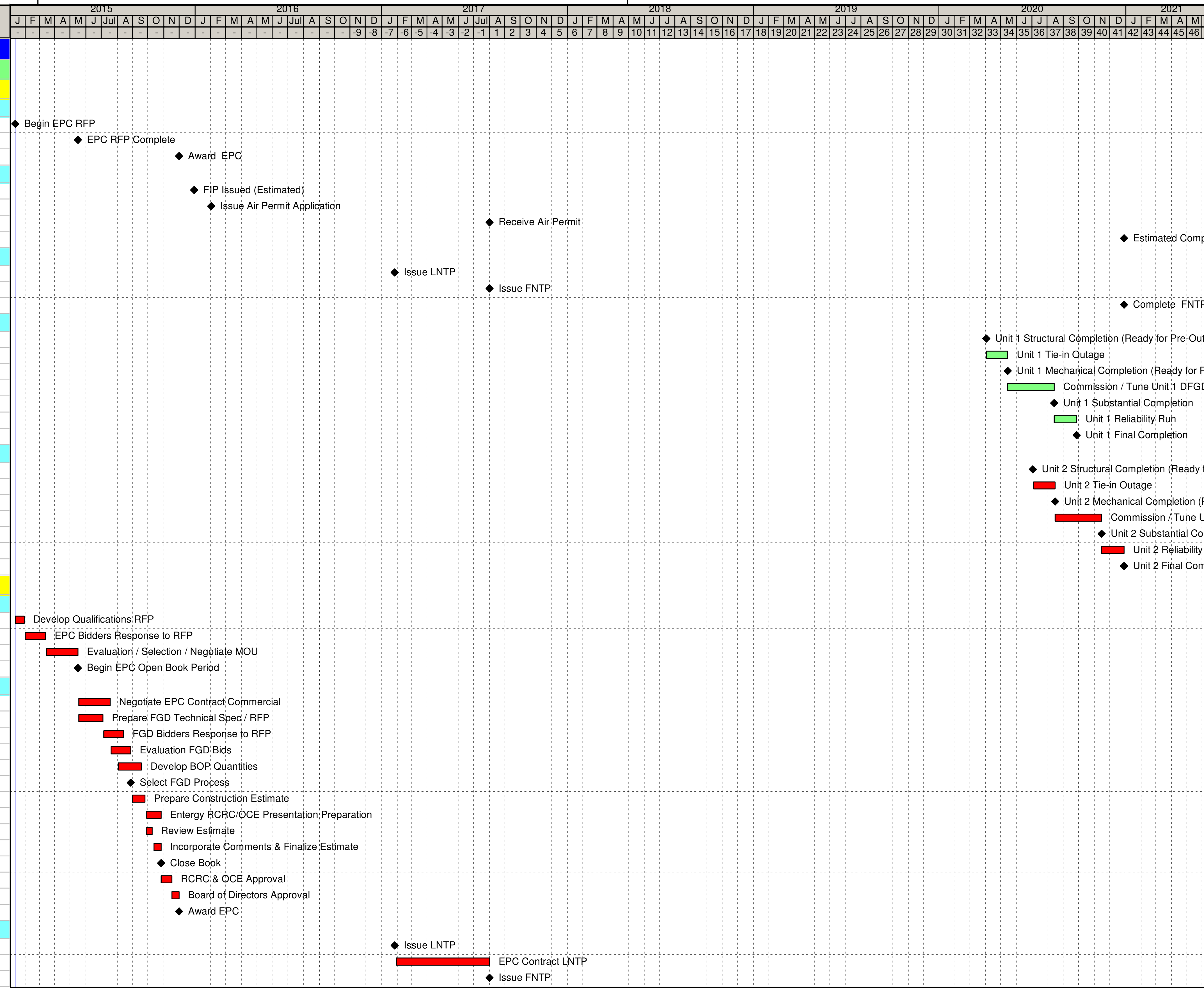
Conceptual Capital Cost Estimate Cash Flow


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

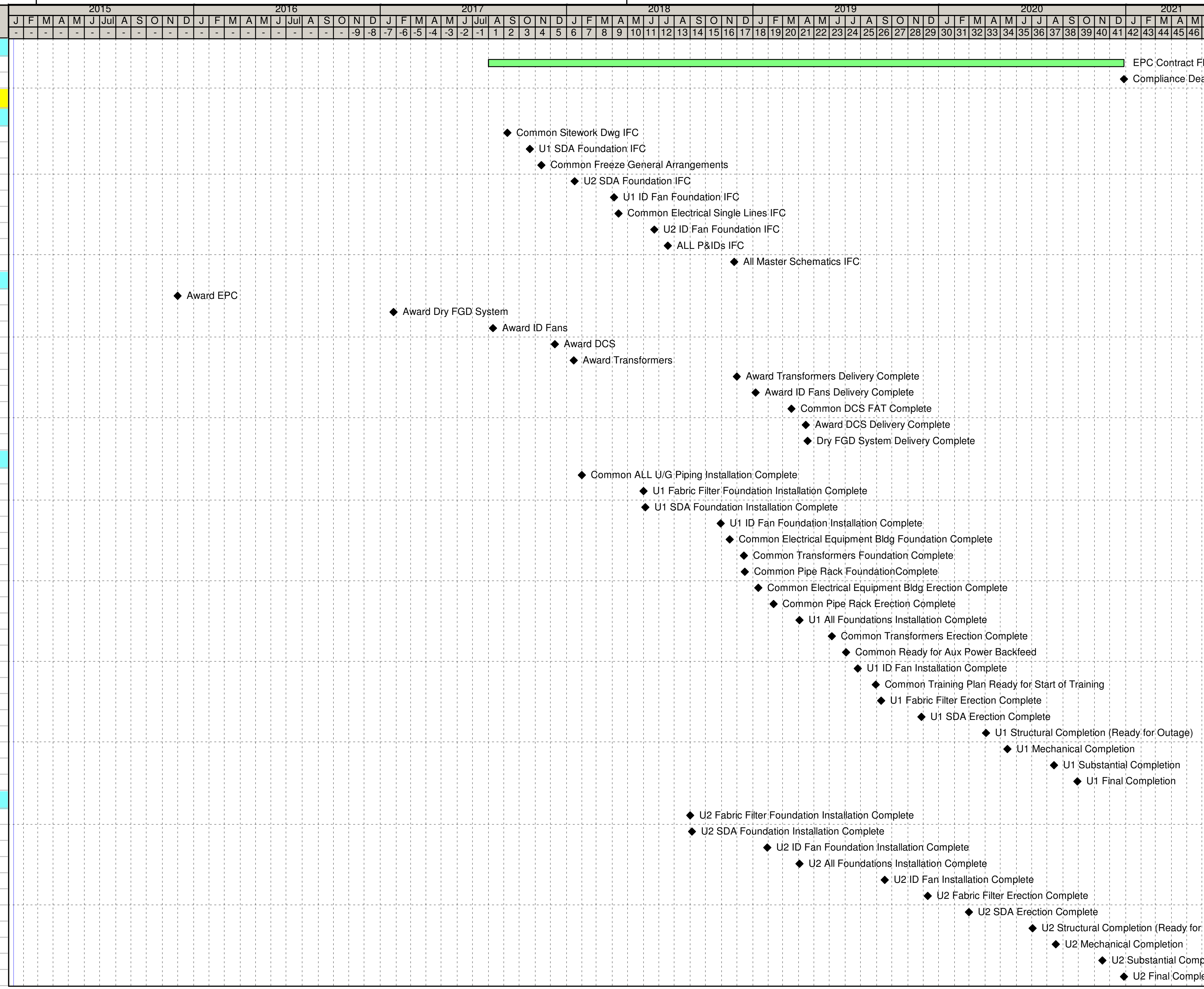
Activity ID	Activity Name	Ori Dur	Start	Finish
WHITE BLUFF FGD SCHEDULE (December 2020)		1556	13-Jan-15	29-Dec-20
Milestones		1556	13-Jan-15	29-Dec-20
Project Milestones		1556	13-Jan-15	29-Dec-20
EPC RFP		225	13-Jan-15	30-Nov-15
MS010	Begin EPC RFP	0	13-Jan-15	
MS100	EPC RFP Complete	0		15-May-15
MS225	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.

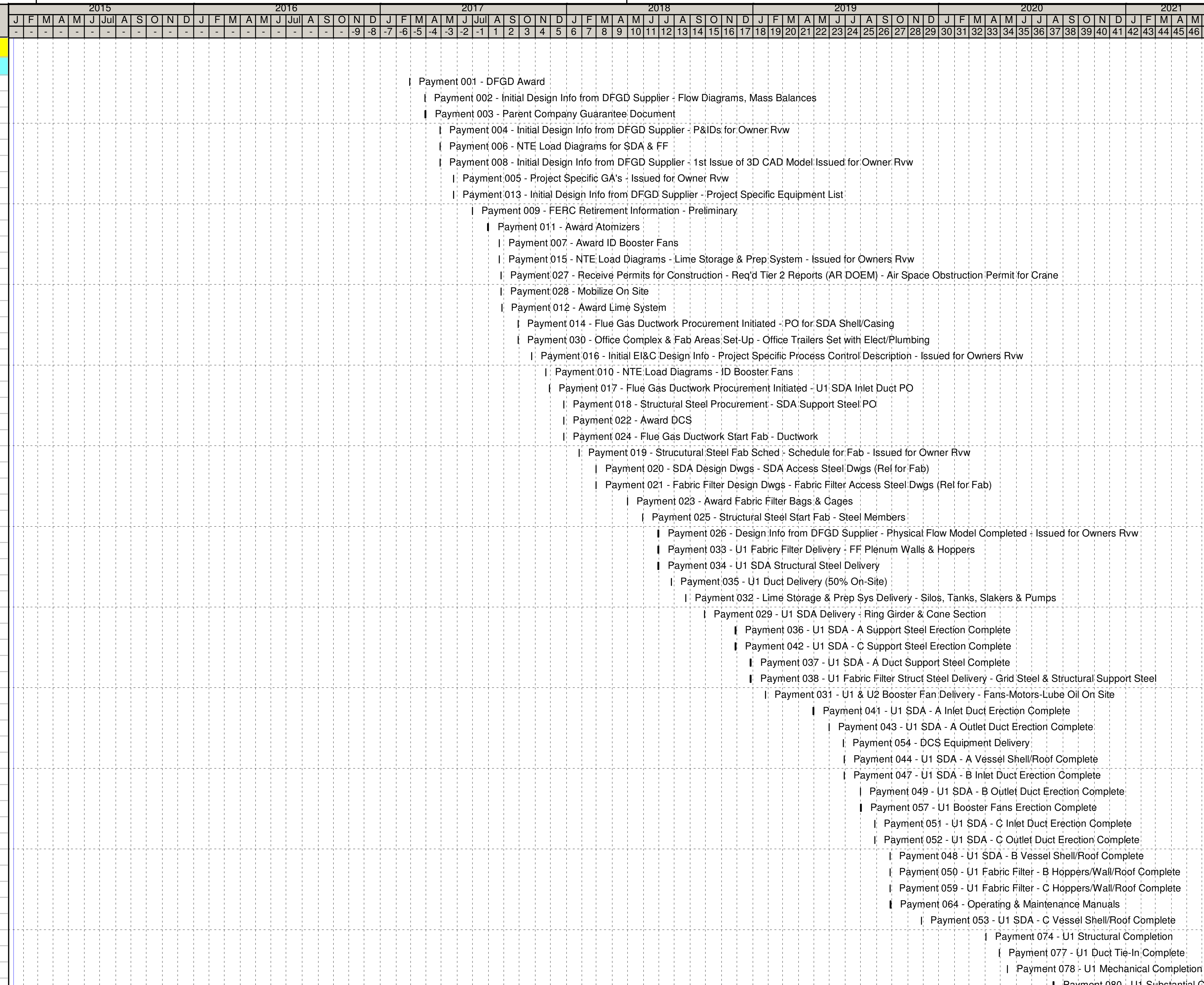
Activity ID	Activity Name	Ori Dur	Start	Finish
FNTP		890	02-Aug-17	29-Dec-20
OV1180	EPC Contract FNTP Period	889	02-Aug-17	28-Dec-20
OV1230	Compliance Deadline	0		29-Dec-20*
EPC Milestones		1292	30-Nov-15	29-Dec-20
Engineering		308	07-Sep-17	26-Nov-18
EPC325	Common Sitework Dwg IFC	0		07-Sep-17
EPC345	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.

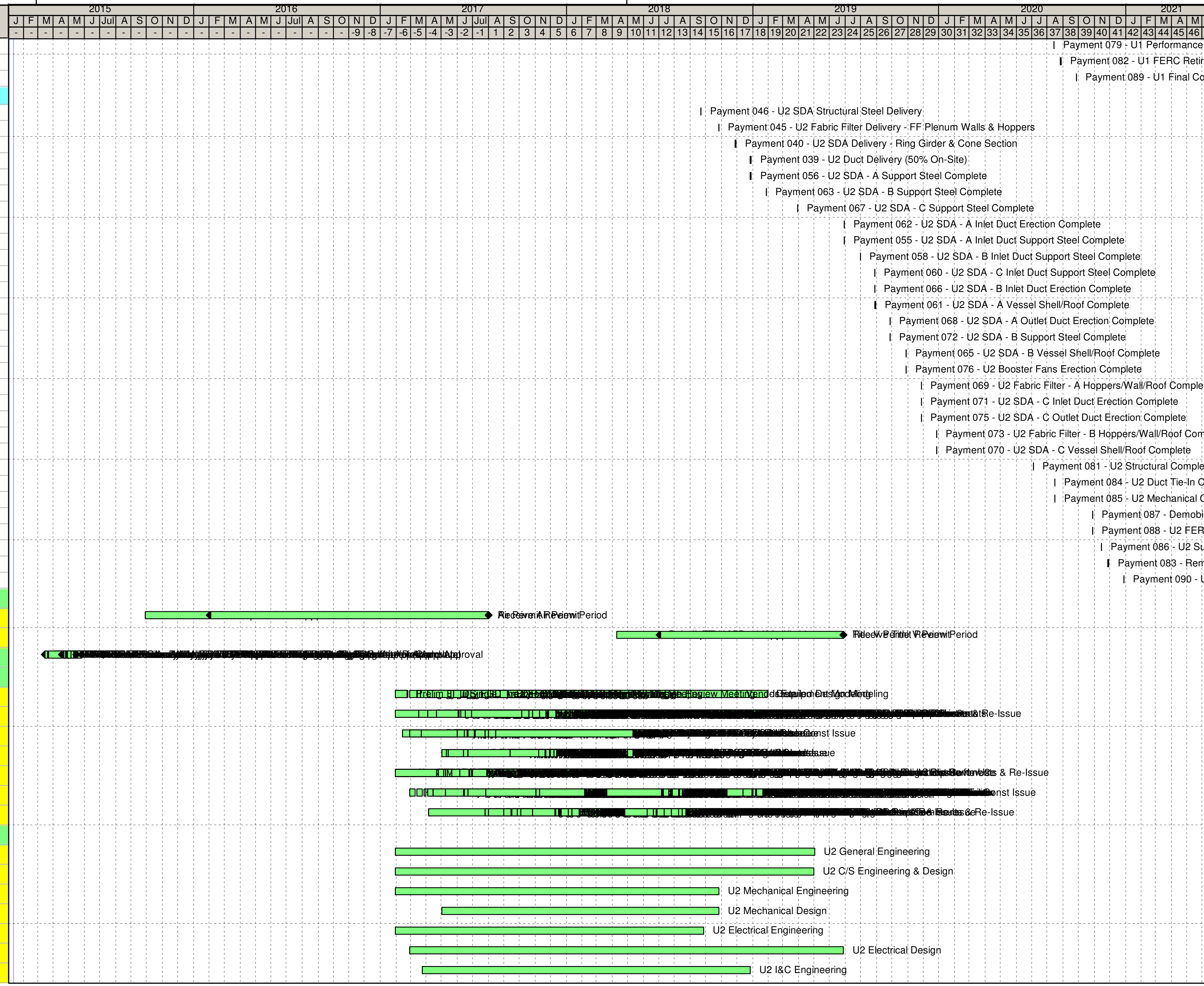
Activity ID	Activity Name	Ori Dur	Start	Finish
Payment Milestones		1401	28-Feb-17	29-Dec-20
Unit 1 & Common		1308	28-Feb-17	27-Sep-20
PAY001	Payment 001 - DFGD Award	1	28-Feb-17	28-Feb-17
PAY002	Payment 002 - Initial Design Info from DFGD Supplier - Flow ...	1	29-Mar-17	29-Mar-17
PAY003	Payment 003 - 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.

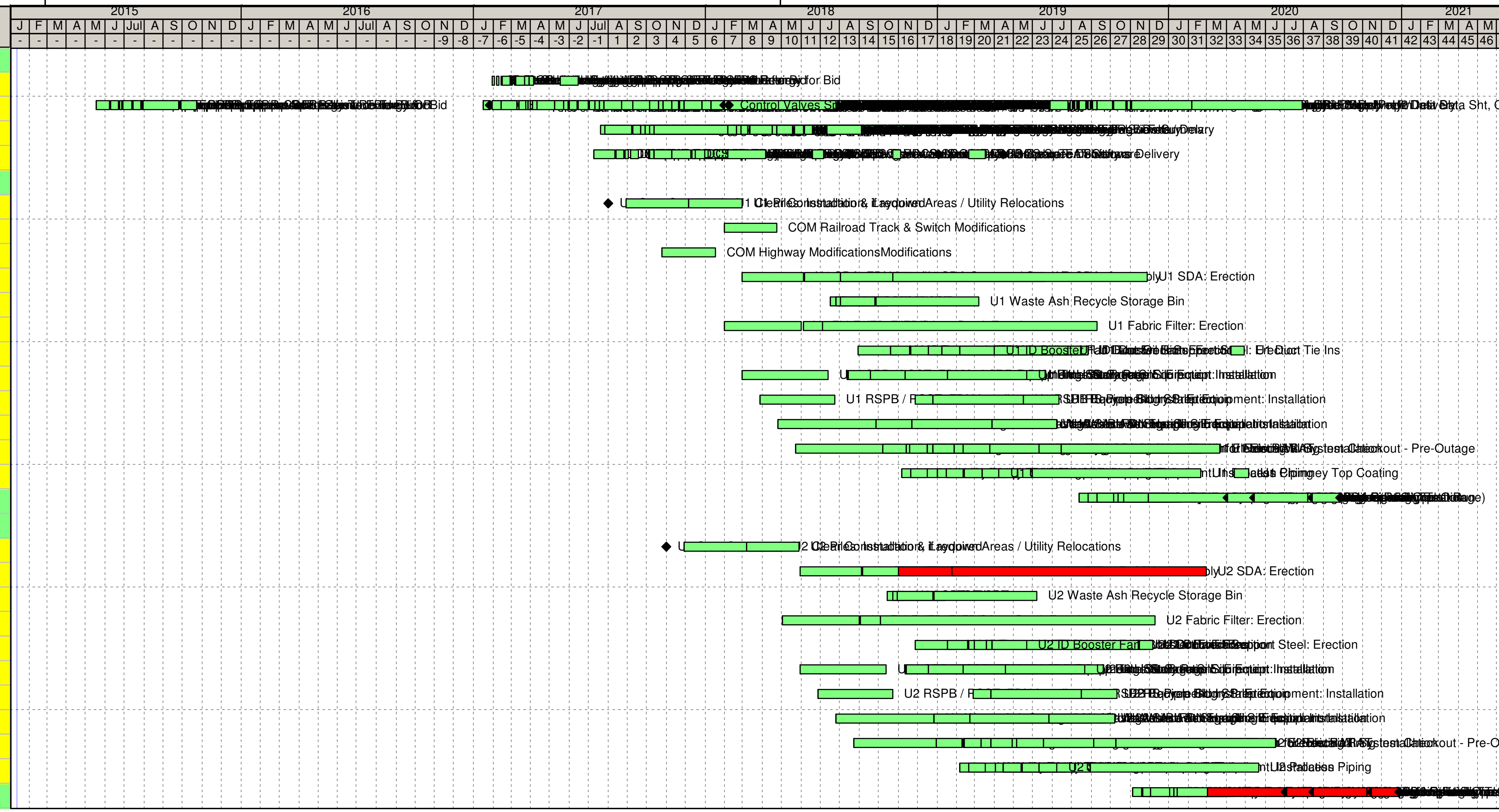
Activity ID	Activity Name	Ori Dur	Start	Finish
PAY079	Payment 079 - U1 Performance Test Report	1	14-Aug-20	14-Aug-20
PAY082	Payment 082 - U1 FERC Retirement Information	1	27-Aug-20	27-Aug-20
PAY089	Payment 089 - U1 Final Completion	1	27-Sep-20	27-Sep-20
Unit 2		830	22-Sep-18	29-Dec-20
PAY046	Payment 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
Critical Remaining Work
Actual Work
Milestone
WBS Summary

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 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%**

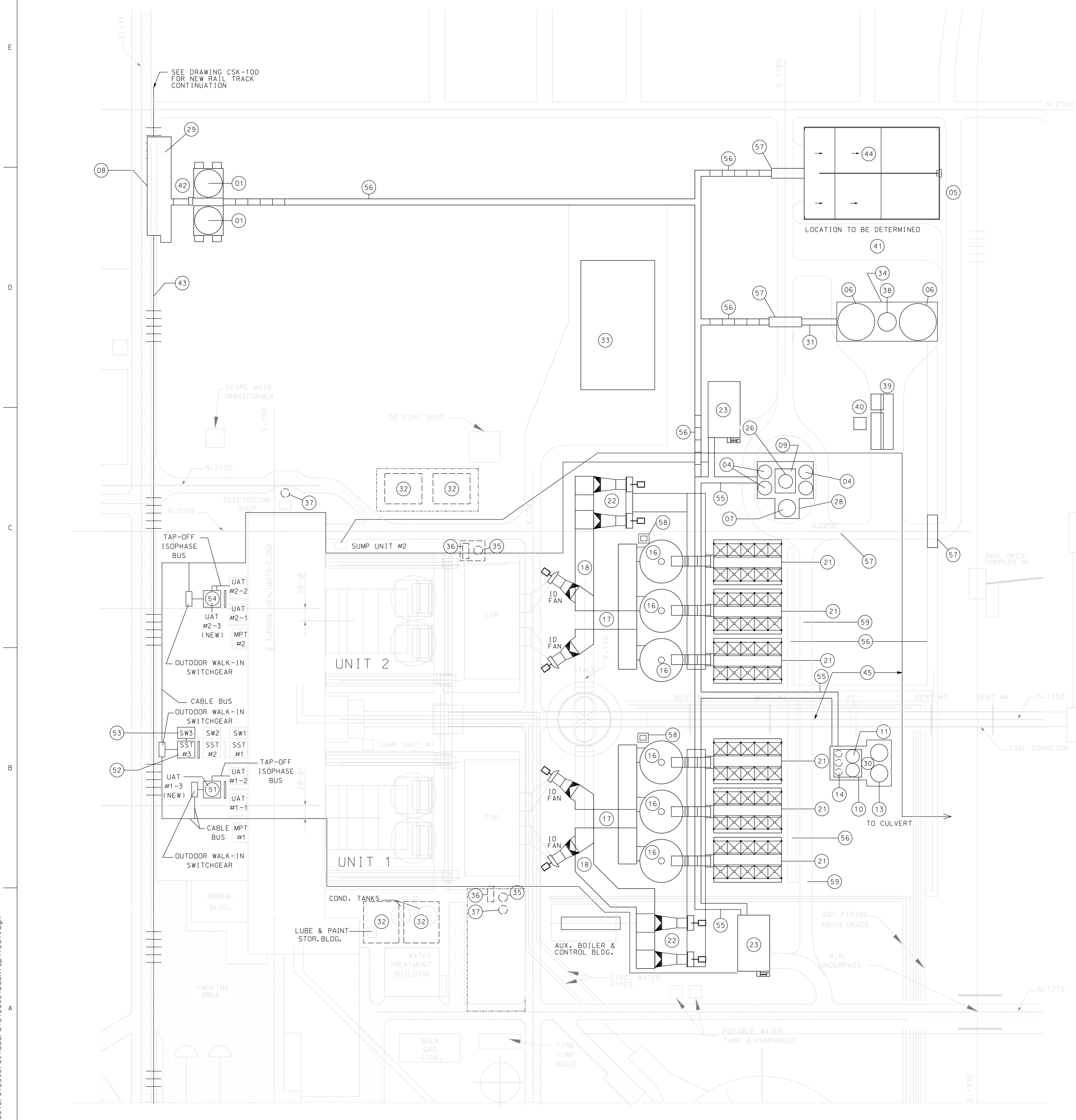
Misc Material and Equipment (Please see Note 1)	% increase in past 3 years	% increase in past 5 years	Projected Potential overall % increase next 5 years.
Construction & Building Index	8%	15%	17.00%
Material Price, Construction Mat.	8%	7%	10.00%
Plant Cost Index	no increase	slightly negative	5.00%
Civil 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



PRELIMINARY NOT FOR CONSTRUCTION

NORTH

60' 0 60' 120' 180'
GRAPHIC SCALE
DRAWING SCALE 1" = 60'-0"

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

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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%

WB FGD Project
Risk Register

ESTIMATE UNCERTAINTY								
		Quantitative Risk Analysis						
Risk Category	Description of Risk	Estimate Total w/out Contingency	Min ($)	Expected	Max ($)	QRA Comments	Status / 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%)	

UNKNOWN RISK

Risk Category	Description of Risk	Quantitative Risk Analysis: 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.	

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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.	

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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.	

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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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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	
2014-059	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

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 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:

27881 Clemens Road
Westlake, Ohio 44145
P: 440.539.8792
www.ftek.com

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.

<u>Fuel Tech, Inc. – Retrofitted ESP Arrangement and Summary:</u>

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

<u>Retrofit ESP Arrangement; Quantities are for one (1) ESP, there are four (4) ESPs total:</u>

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

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***	

Estimate No..: 34019A
Project No.: 13027-004
Estimate Date: 10/20/2016
Prep/Rev/App: A. KOCI/MNO/MNO

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
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									

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	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	0.0256	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	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	0.440	**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	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%	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	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**	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)

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)
= 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)

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)	
	=	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)

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)
	=	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)

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.

PM Speciation Calculations

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**

	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	0.0356	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	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	0.612	**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	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%	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	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**	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	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)
$TSAR_{ALKINJ}$ = $(TSAR_{Comb+SCR+FGC}) * F3_{ALKINJ}$	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.

PM Speciation Calculations

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	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)

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)
		= 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)

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)
	= 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**

	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 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 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
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EXHIBITS

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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.

[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,

[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

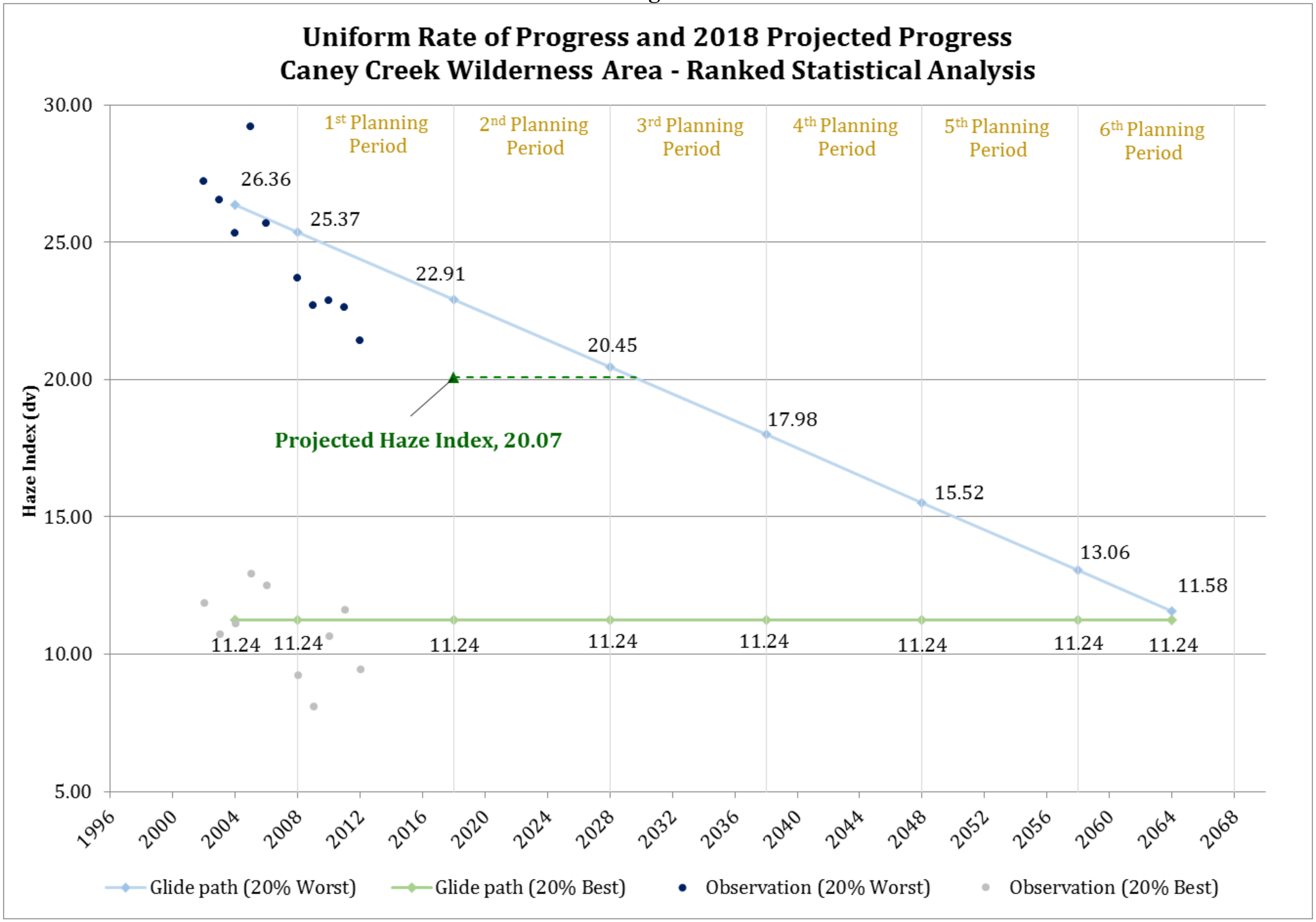
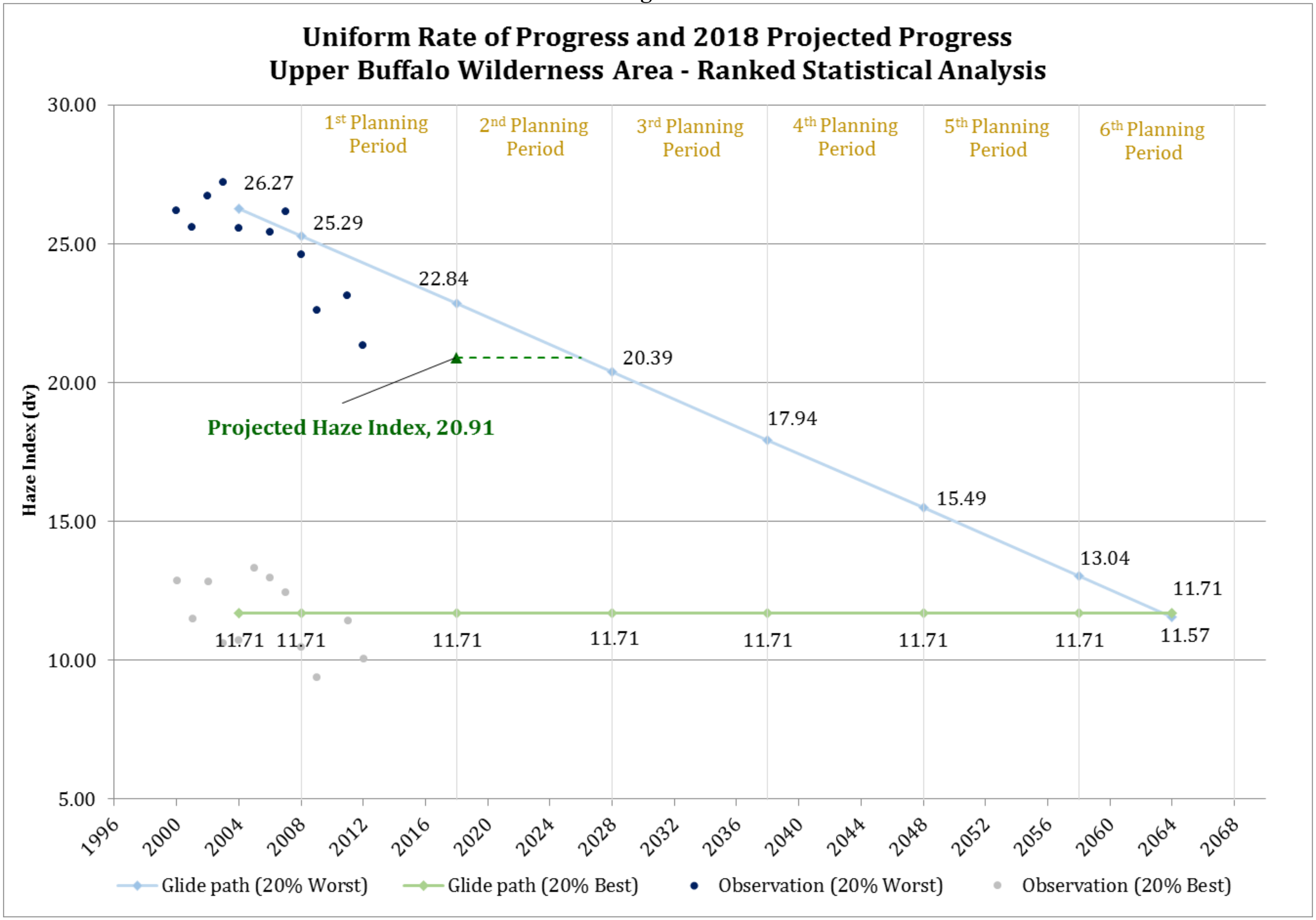

Uniform Rate of Progress and 2018 Projected Progress
Caney Creek Wilderness Area - Ranked Statistical Analysis
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.36
25.37
22.91
20.45
17.98
15.52
13.06
11.58
Projected Haze Index, 20.07
11.24
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 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
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]

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[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

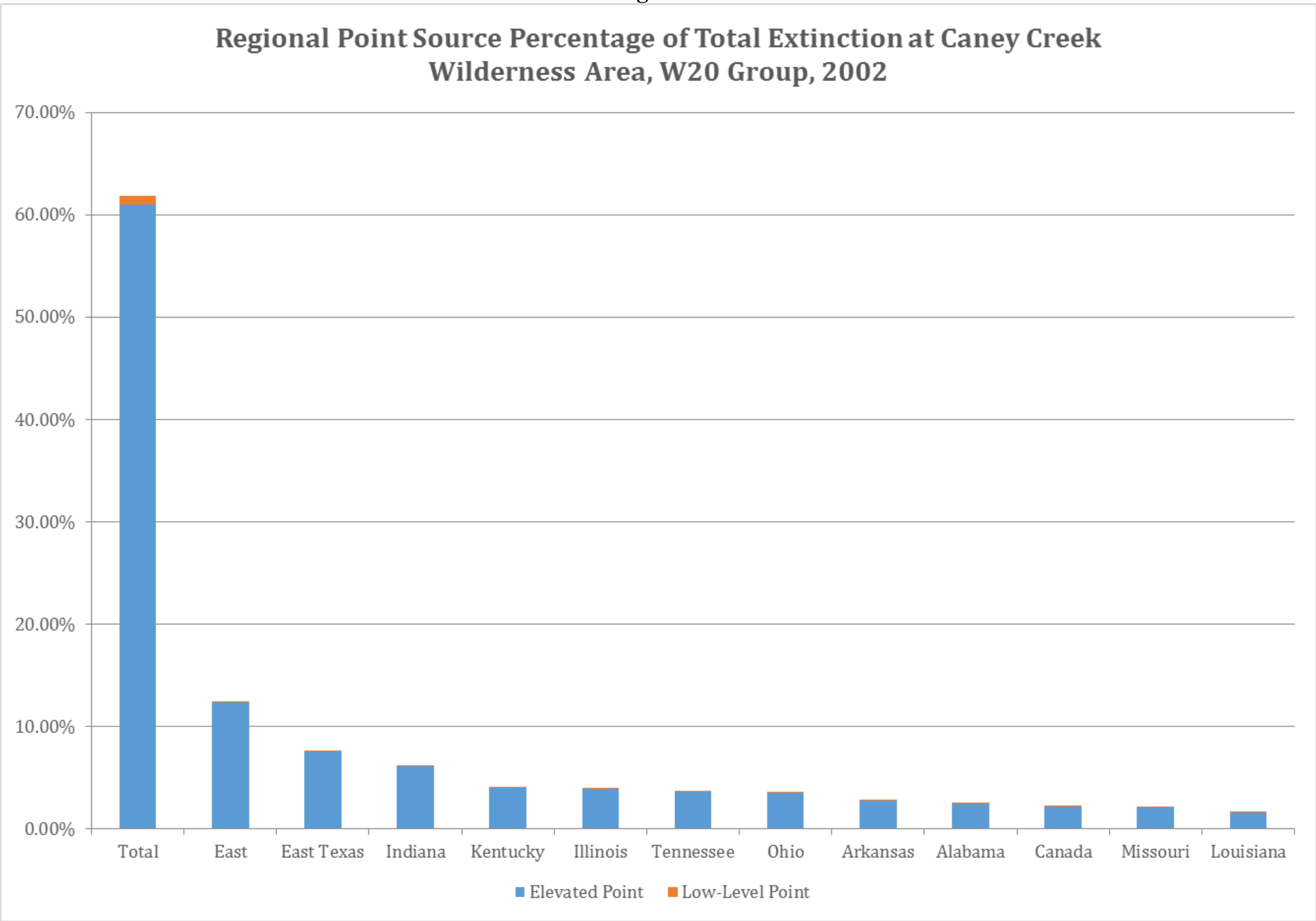
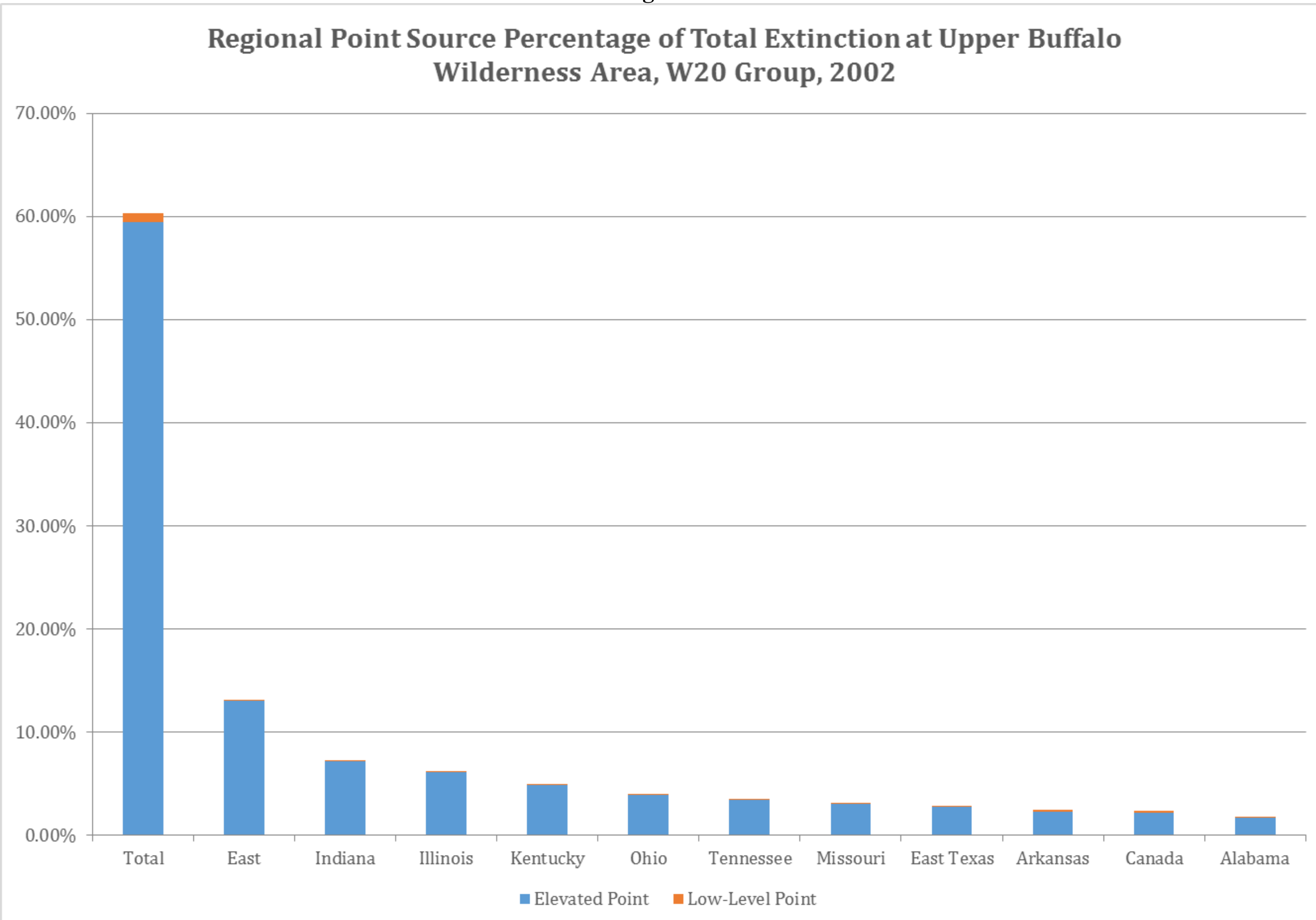

Regional Point Source Percentage of Total Extinction at Caney Creek Wilderness Area, W20 Group, 2002
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
Total
East
East Texas
Indiana
Kentucky
Illinois
Tennessee
Ohio
Arkansas
Alabama
Canada
Missouri
Louisiana
Elevated Point
Low-Level Point

Figure 4

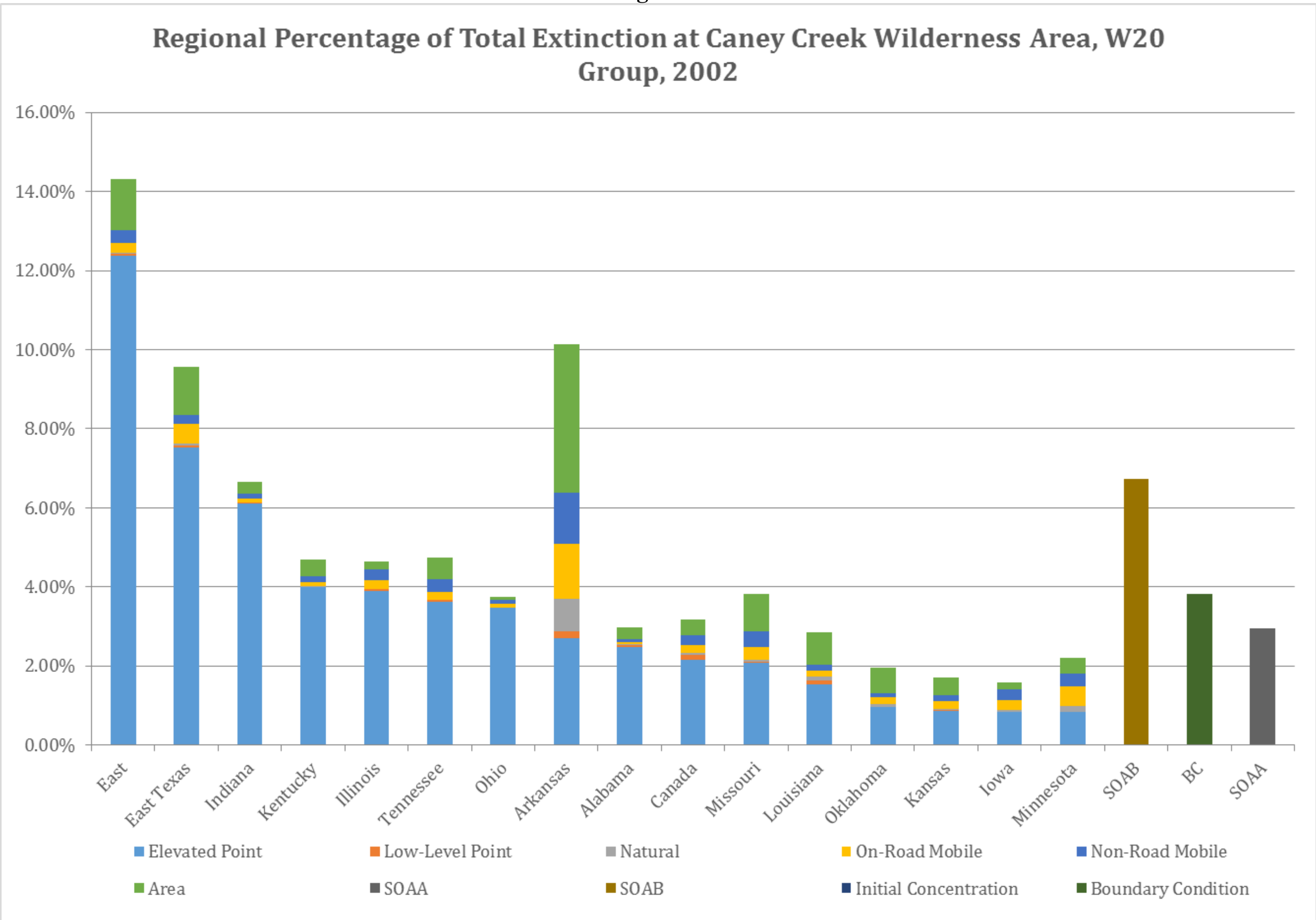


Regional Point Source Percentage of Total Extinction at Upper Buffalo Wilderness Area, W20 Group, 2002
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
Total
East
Indiana
Illinois
Kentucky
Ohio
Tennessee
Missouri
East Texas
Arkansas
Canada
Alabama
Elevated Point
Low-Level Point

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.

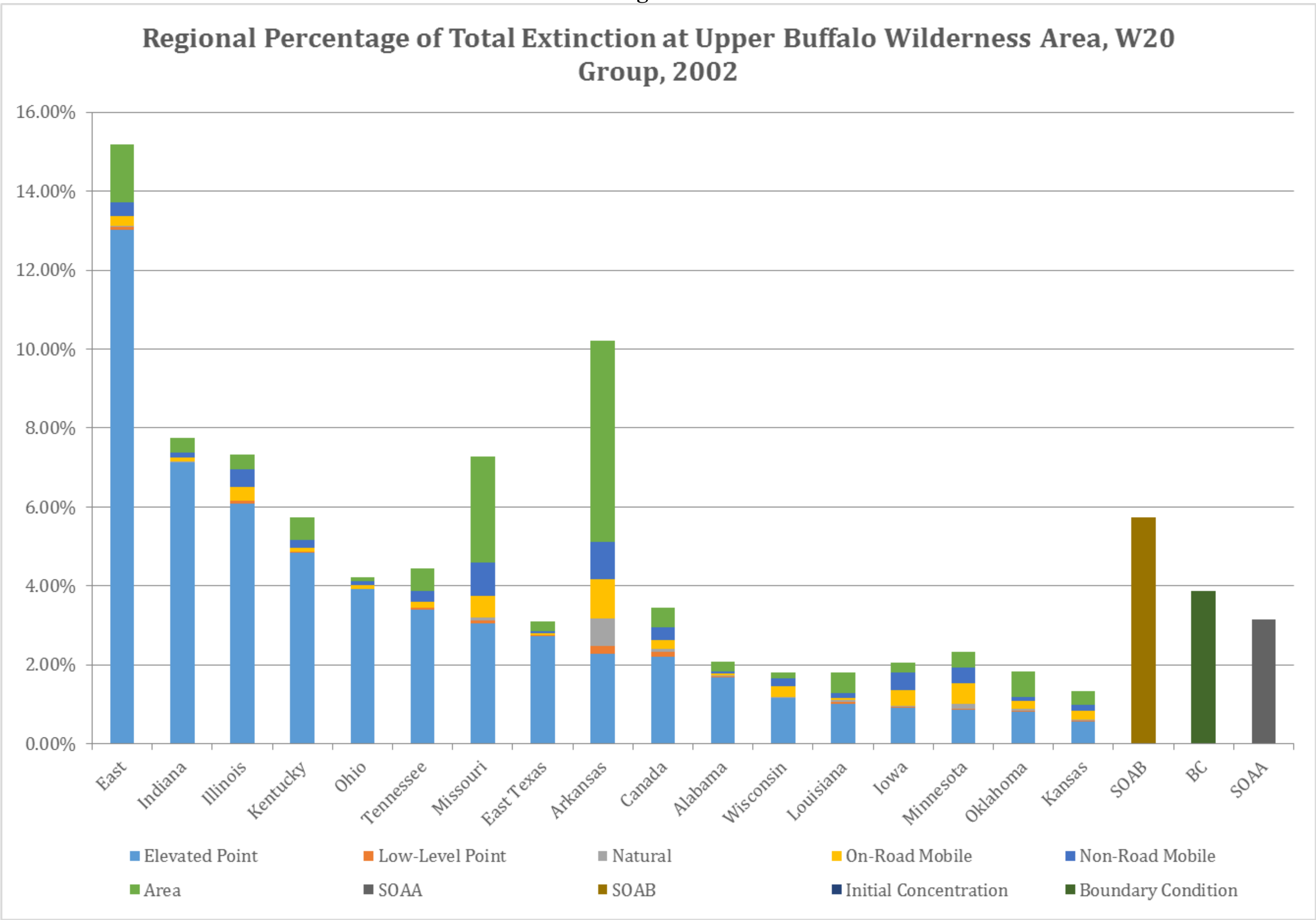
In addition, unlike these other regions, where point sources contribute the majority of visibility impairment to Arkansas' Class I areas, most of Arkansas' share of the contribution to visibility impairment comes from Arkansas area and mobile sources, not point sources. *See* Figures 5 and 6 below.

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

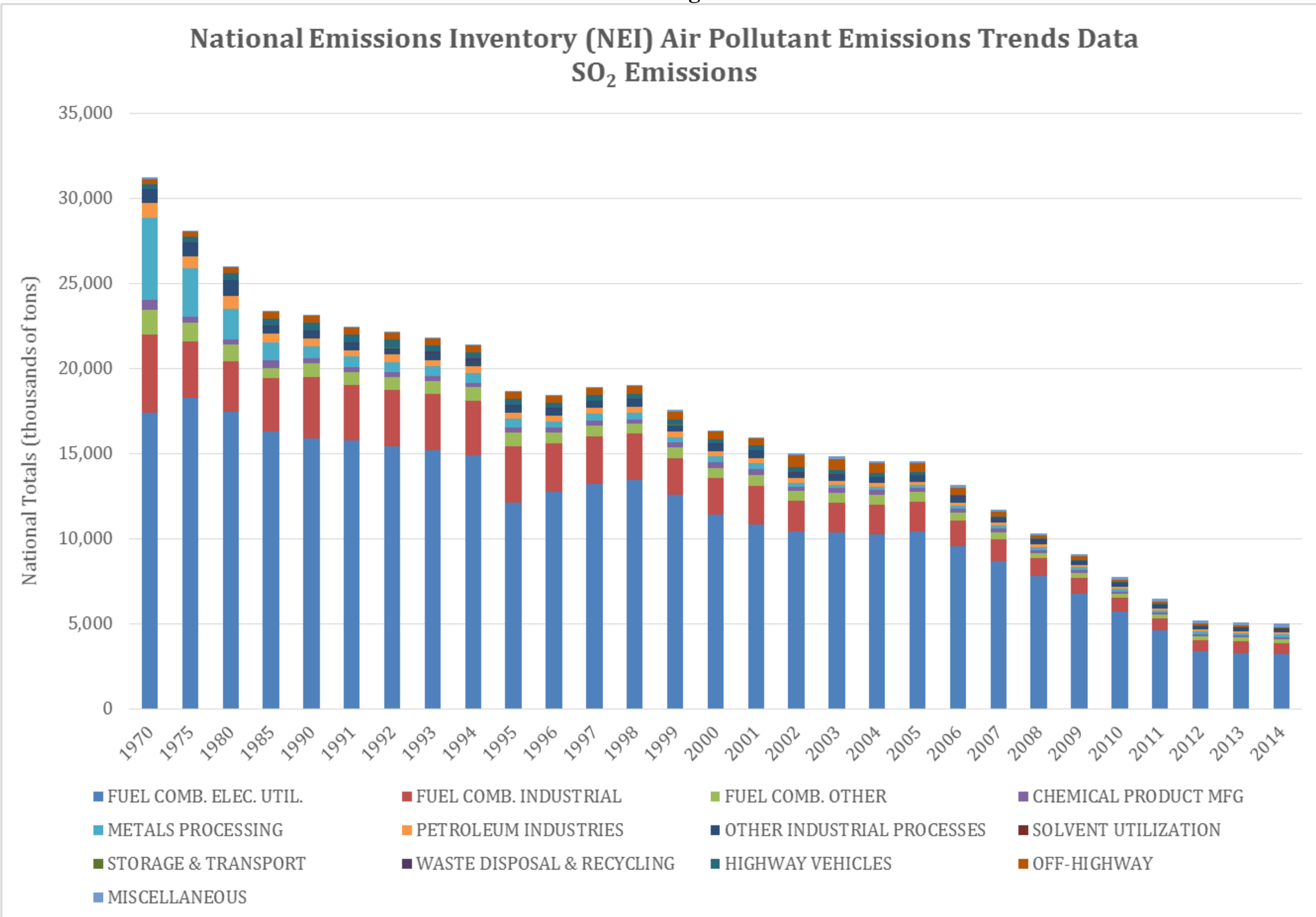
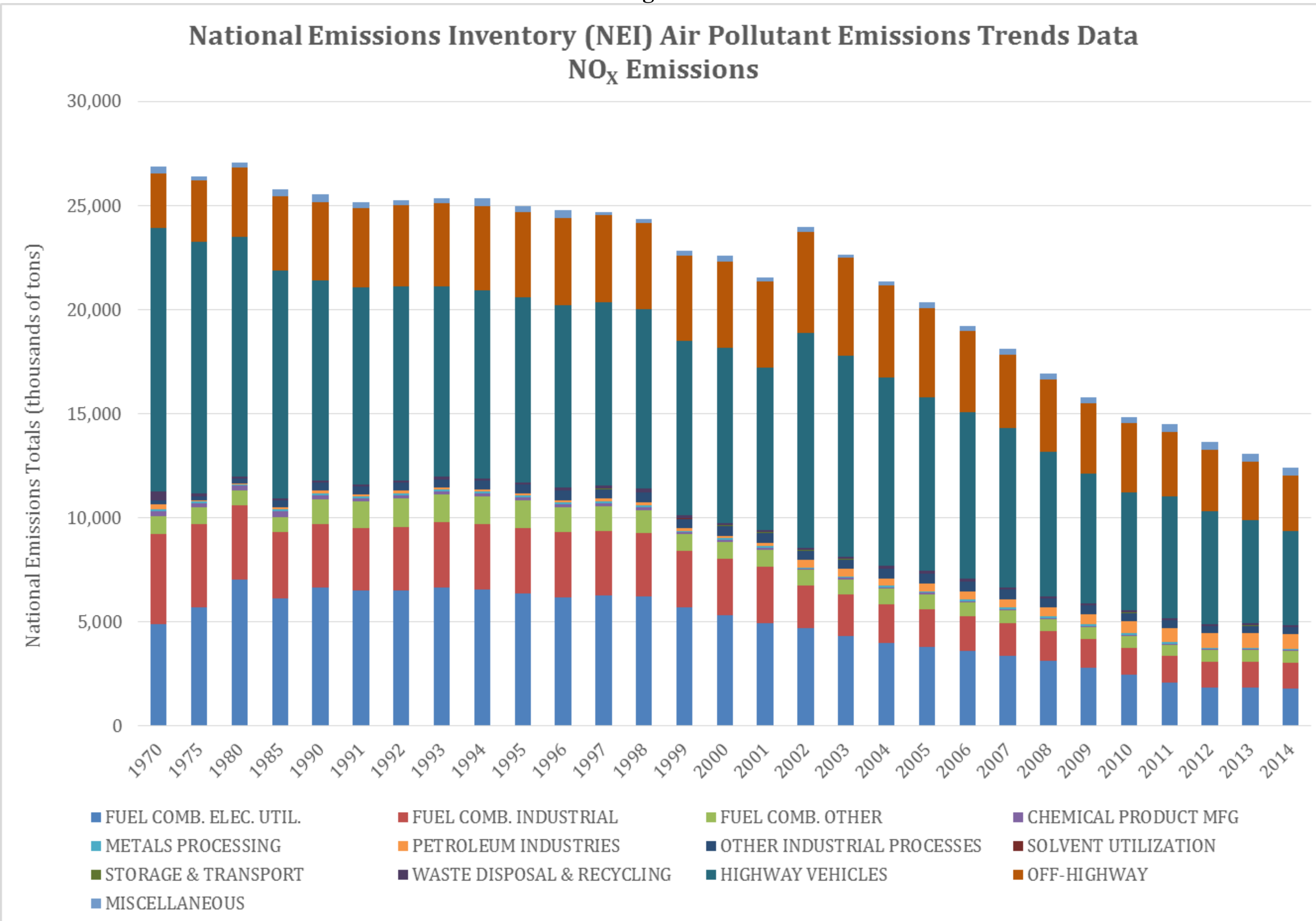

National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data
SO_2 Emissions
National Totals (thousands of tons)
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
1970
1975
1980
1985
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
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

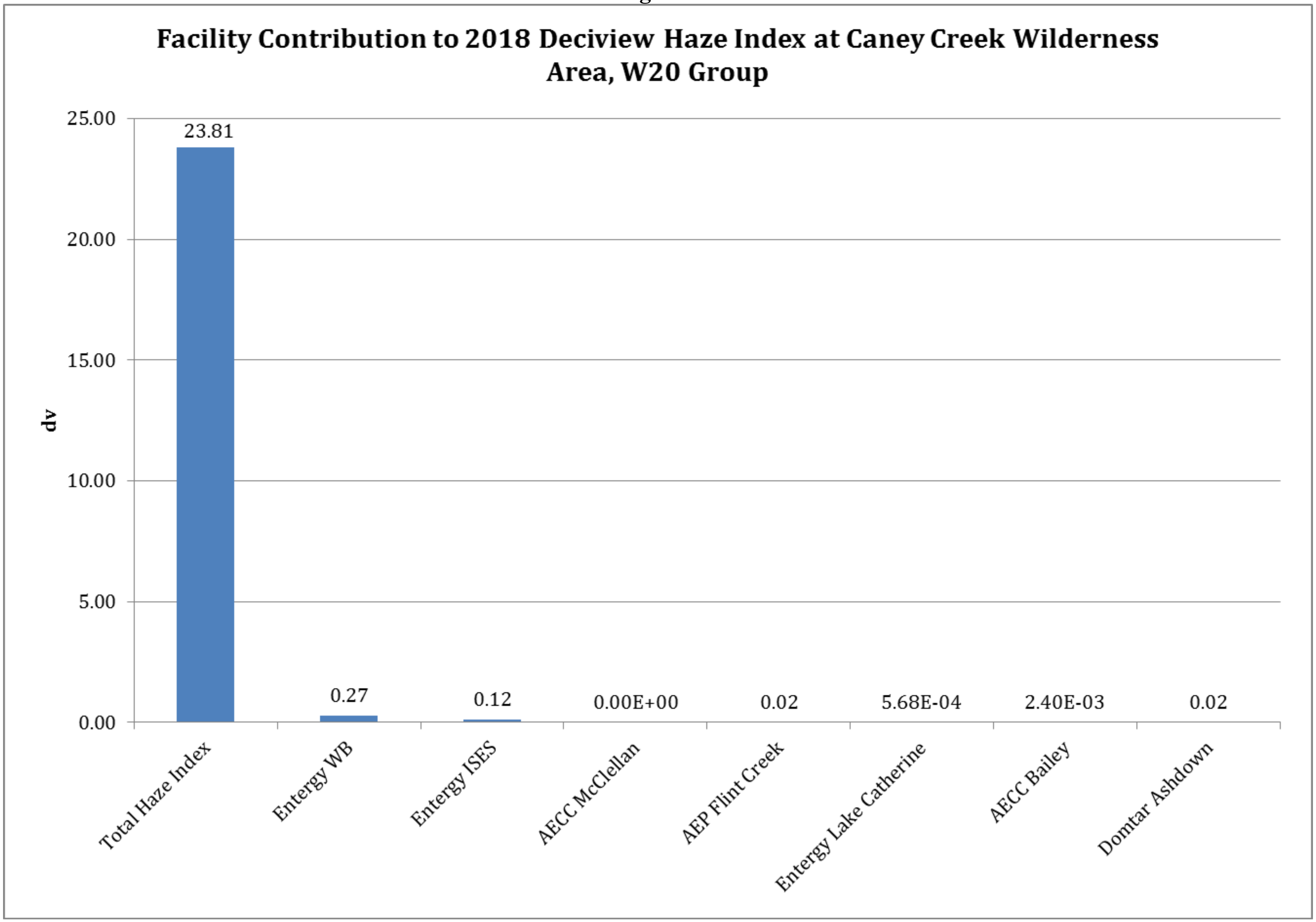
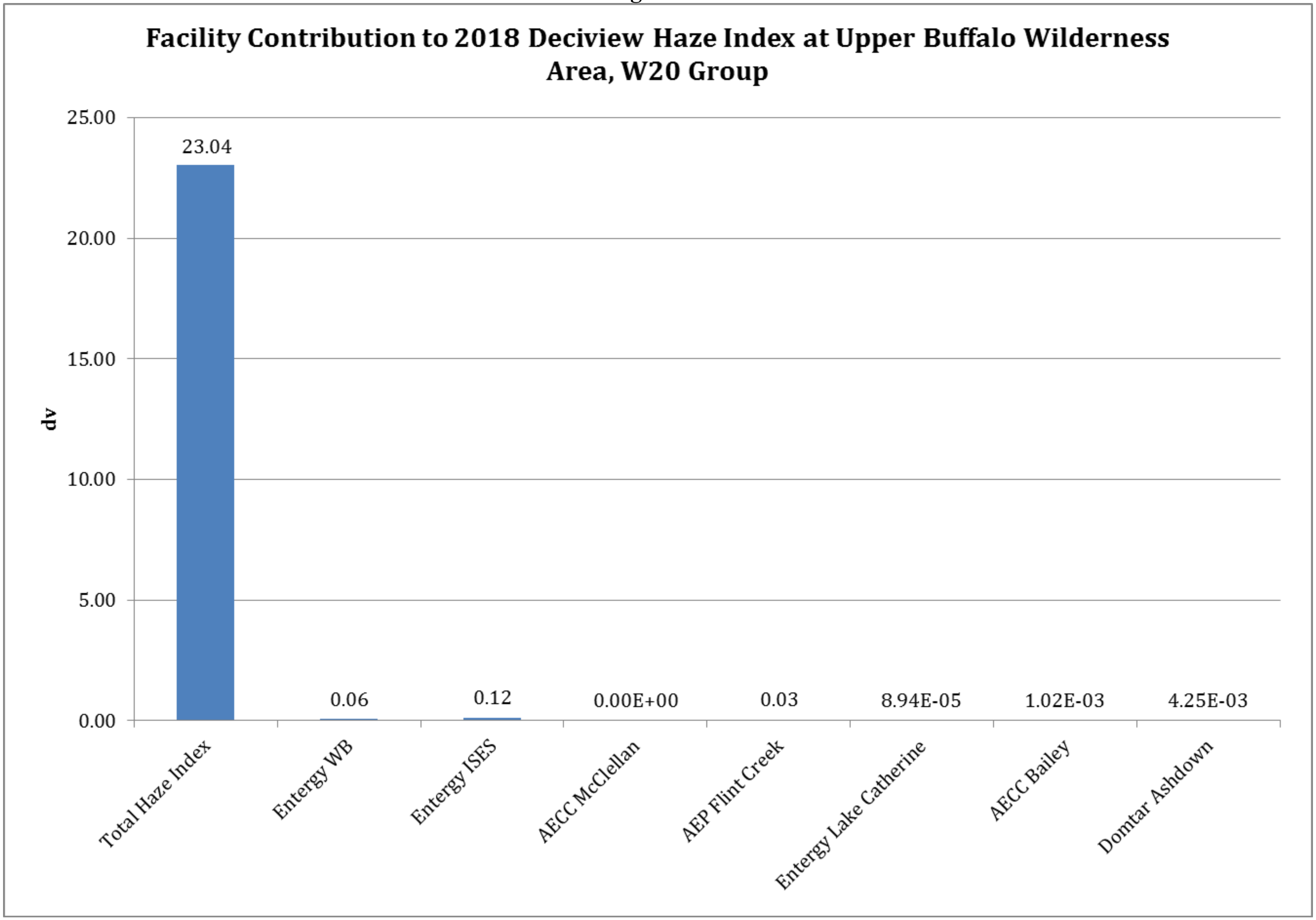

Facility Contribution to 2018 Deciview Haze Index at Caney Creek Wilderness Area, W20 Group
dv
25.00
20.00
15.00
10.00
5.00
0.00
23.81
0.27
0.12
0.00E+00
0.02
5.68E-04
2.40E-03
0.02
Total Haze Index
Entergy WB
Entergy ISES
AECC McClellan
AEP Flint Creek
Entergy Lake Catherine
AECC Bailey
Domtar Ashdown

Figure 10


Facility Contribution to 2018 Deciview Haze Index at Upper Buffalo Wilderness Area, W20 Group
dv
25.00
20.00
15.00
10.00
5.00
0.00
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

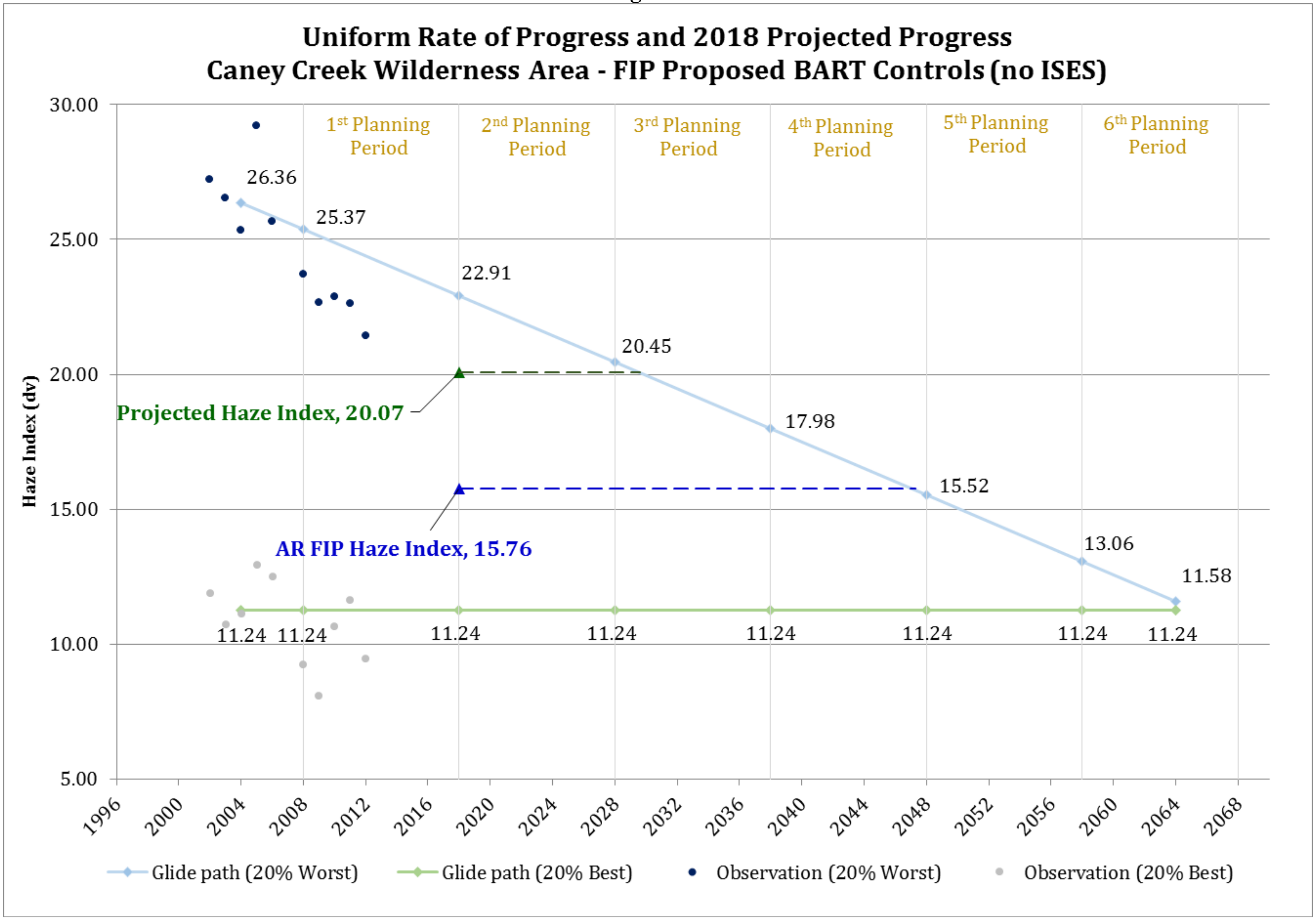
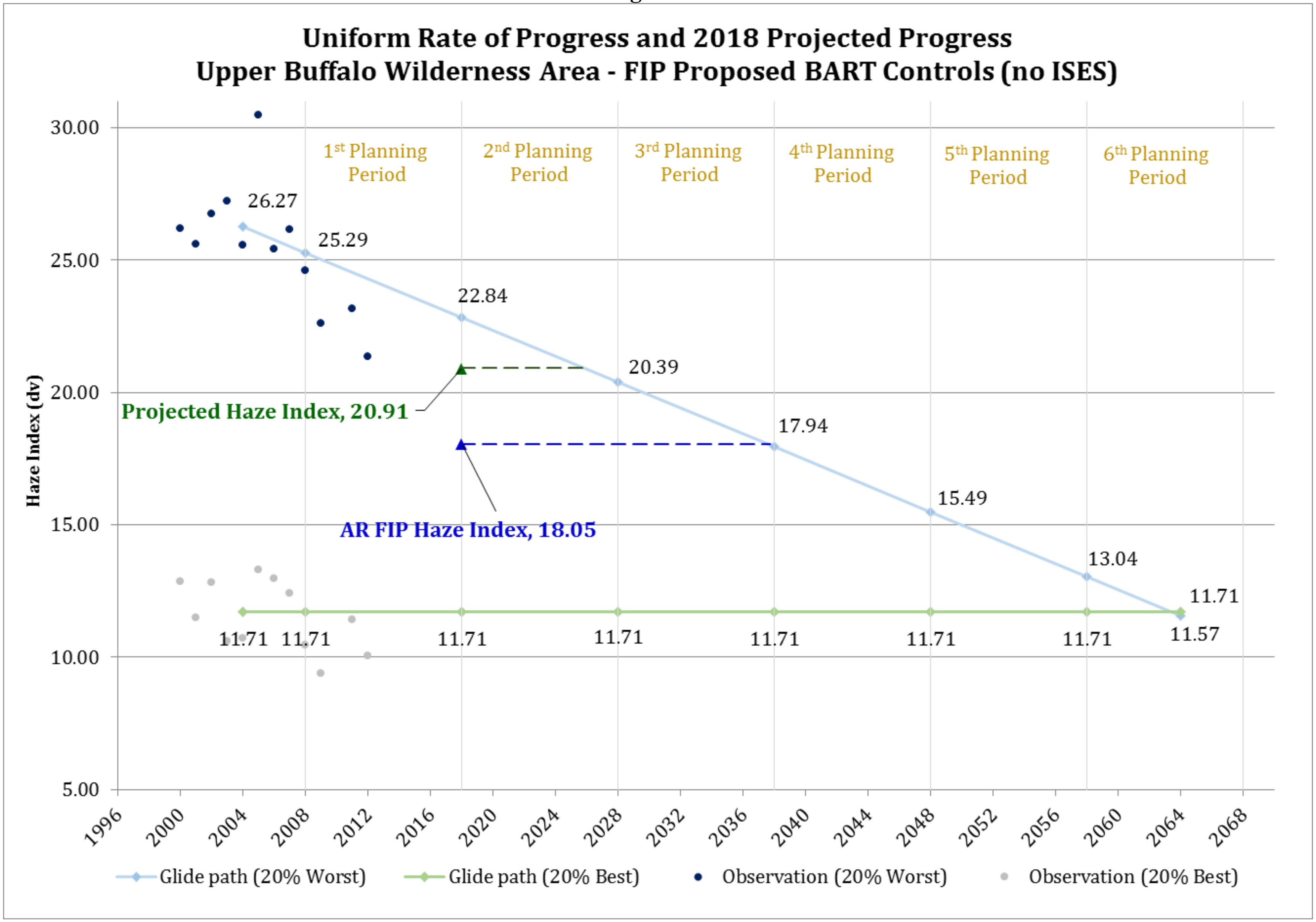

Uniform Rate of Progress and 2018 Projected Progress
Caney Creek Wilderness Area - FIP Proposed BART Controls (no ISES)
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.36
25.37
22.91
20.45
17.98
15.52
13.06
11.58
Projected Haze Index, 20.07
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
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)

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

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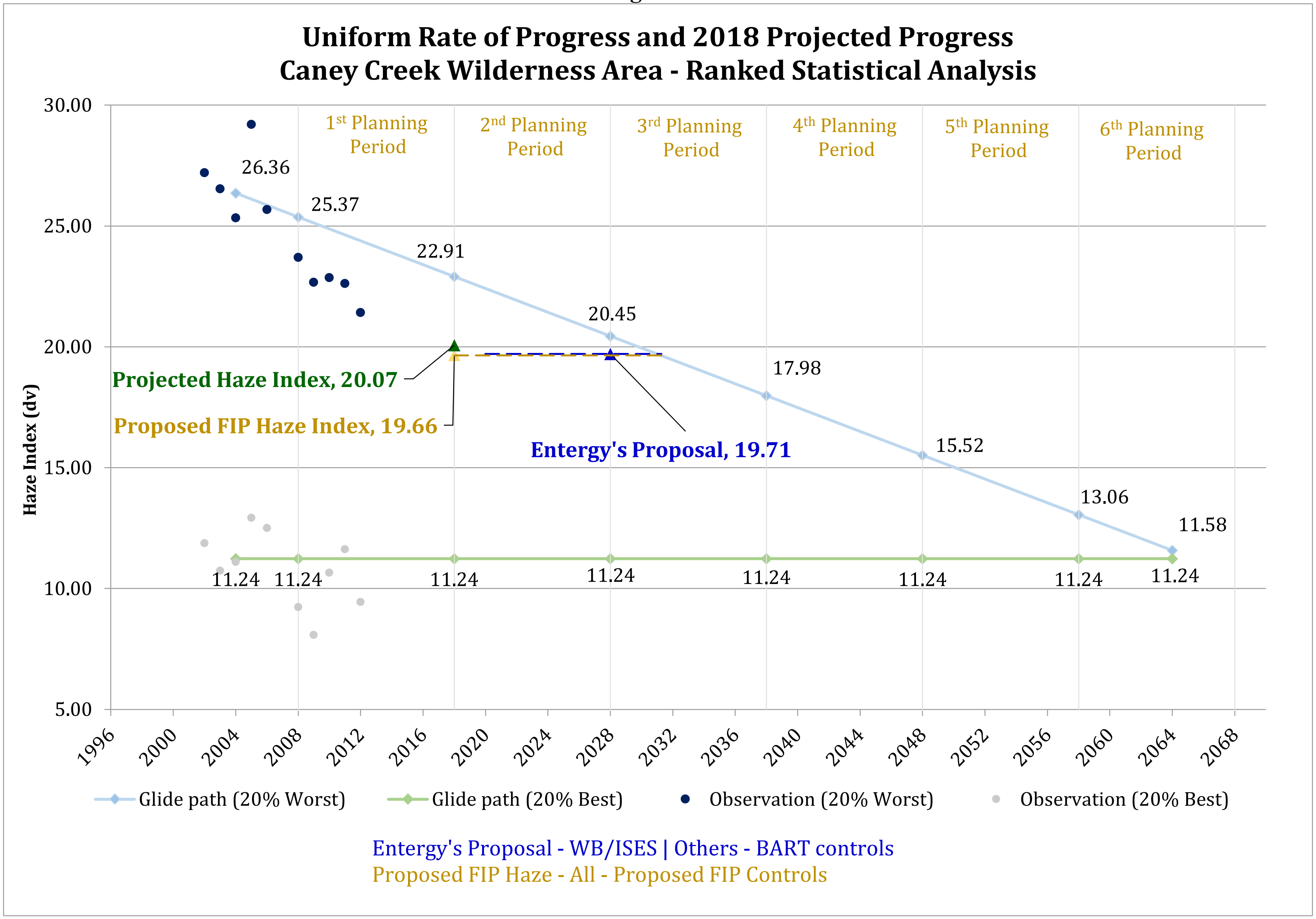
[44] While states that opt to implement an emissions trading program or other alternative measure rather than require sources to install, operate, and maintain BART *are* required to demonstrate that this alternative will achieve greater reasonable progress than would be achieved through the installation 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.

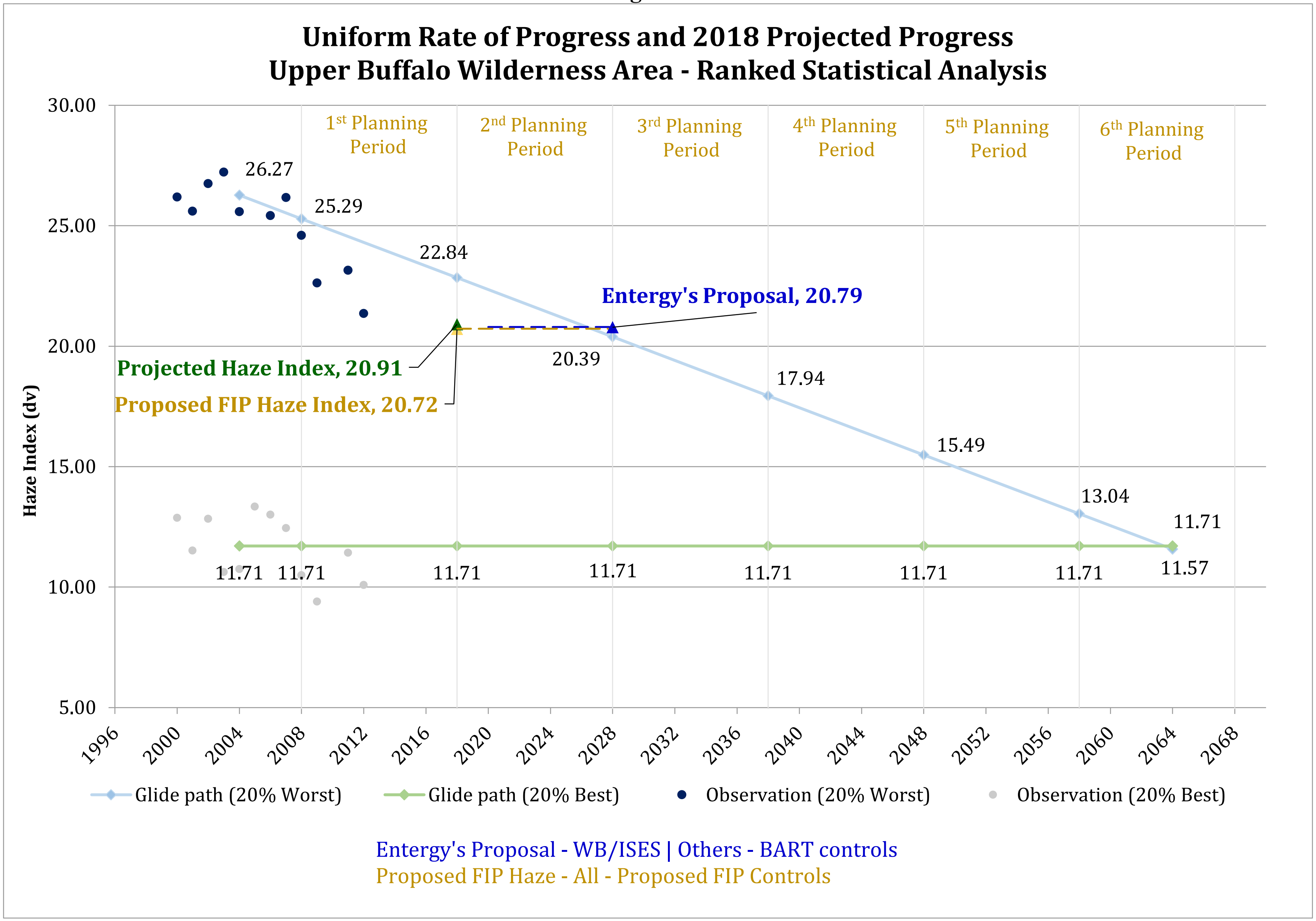
deciview improvements projected for the following scenarios (1) Entergy's proposed controls, based on the cessation of coal-fired operations at White Bluff (referred to as "WB") and the installation of LNB/SOFA and lower SO_2 emission rate at Independence (referred to as "ISES"); and (2) installation 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
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
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
1996
2000
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
2068
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
11.71
Entergy's Proposal, 20.79
Projected Haze Index, 20.91
Proposed FIP Haze Index, 20.72
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.

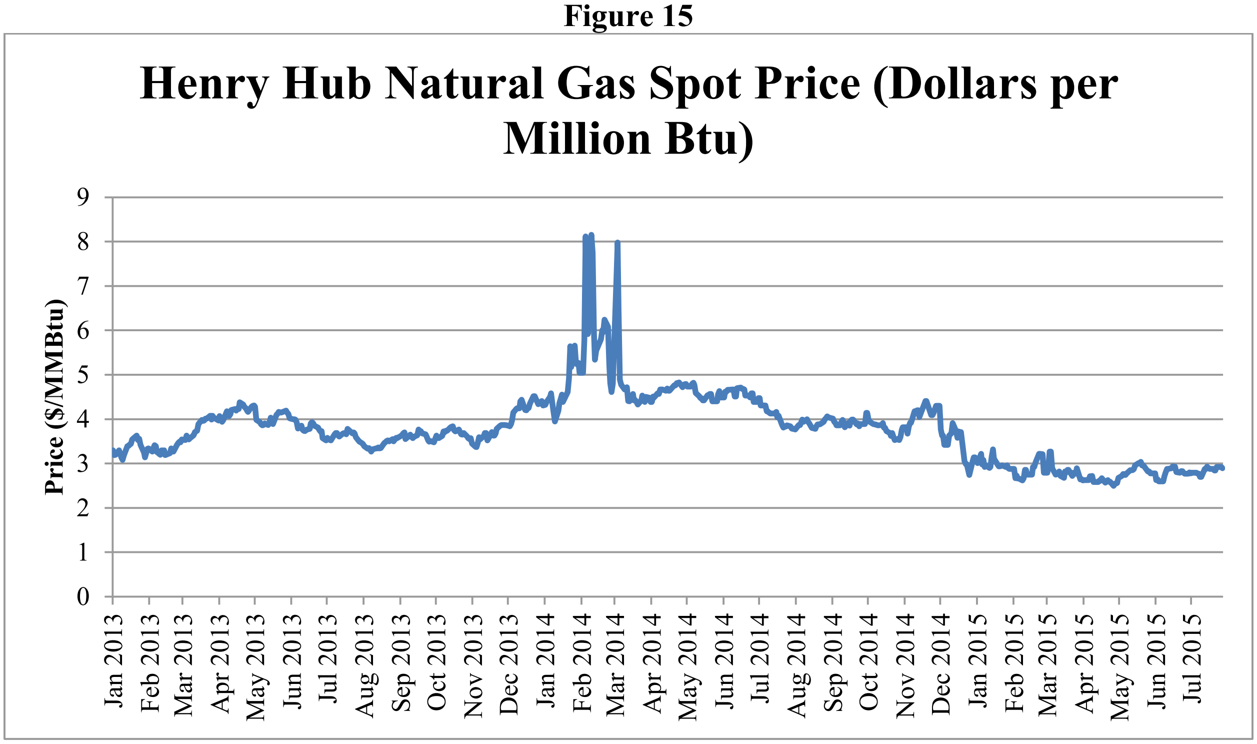
The impact of this change in dispatch of the units can be seen in the following table. The data for 2015 (through June 30) reflects a significant increase in the percentage of time that each unit is dispatched at less than 50% of operating capacity. Three of the four units have spent greater than 40% 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,

Kelly M. McQueen
Assistant General Counsel – Environmental (Lead)
Entergy Services, Inc.

ENTERGY ARKANSAS, INC.

REVIEW OF EPA'S COST ANALYSIS FOR ARKANSAS REGIONAL HAZE PROPOSED FEDERAL IMPLEMENTATION PLAN

SL-012913
Final

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Project No: 13027-002

PREPARED BY

Sargent & Lundy LLC

55 East Monroe Street
Chicago, IL 60603-5780 USA

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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.

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[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;

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[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.

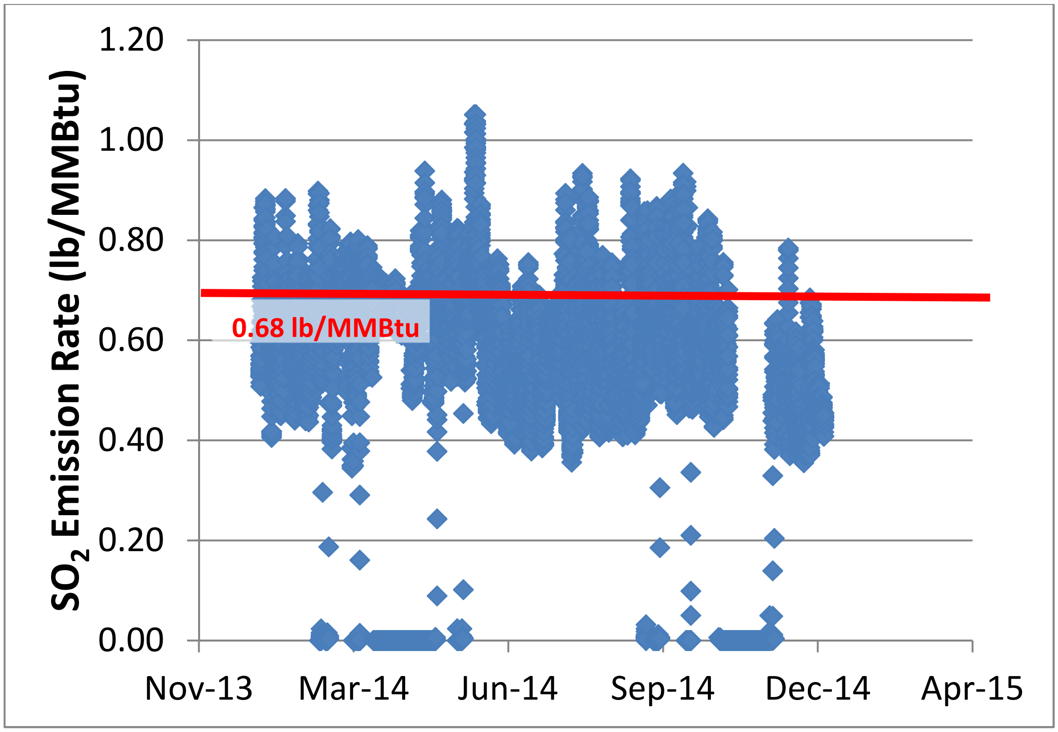

Figure 1: 2014 SO_2 Emissions for White Bluff 1[25]

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

SL-012831
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Prepared by

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000

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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. <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)

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. 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 System, per unit

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. <u>Third Party Services – Construction Management Oversight</u>

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. <u>Third Party Services – Startup and Commissioning Oversight</u>

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***	

Exhibit B to EAI Comments

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

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
			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

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

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
		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

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**									

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
		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

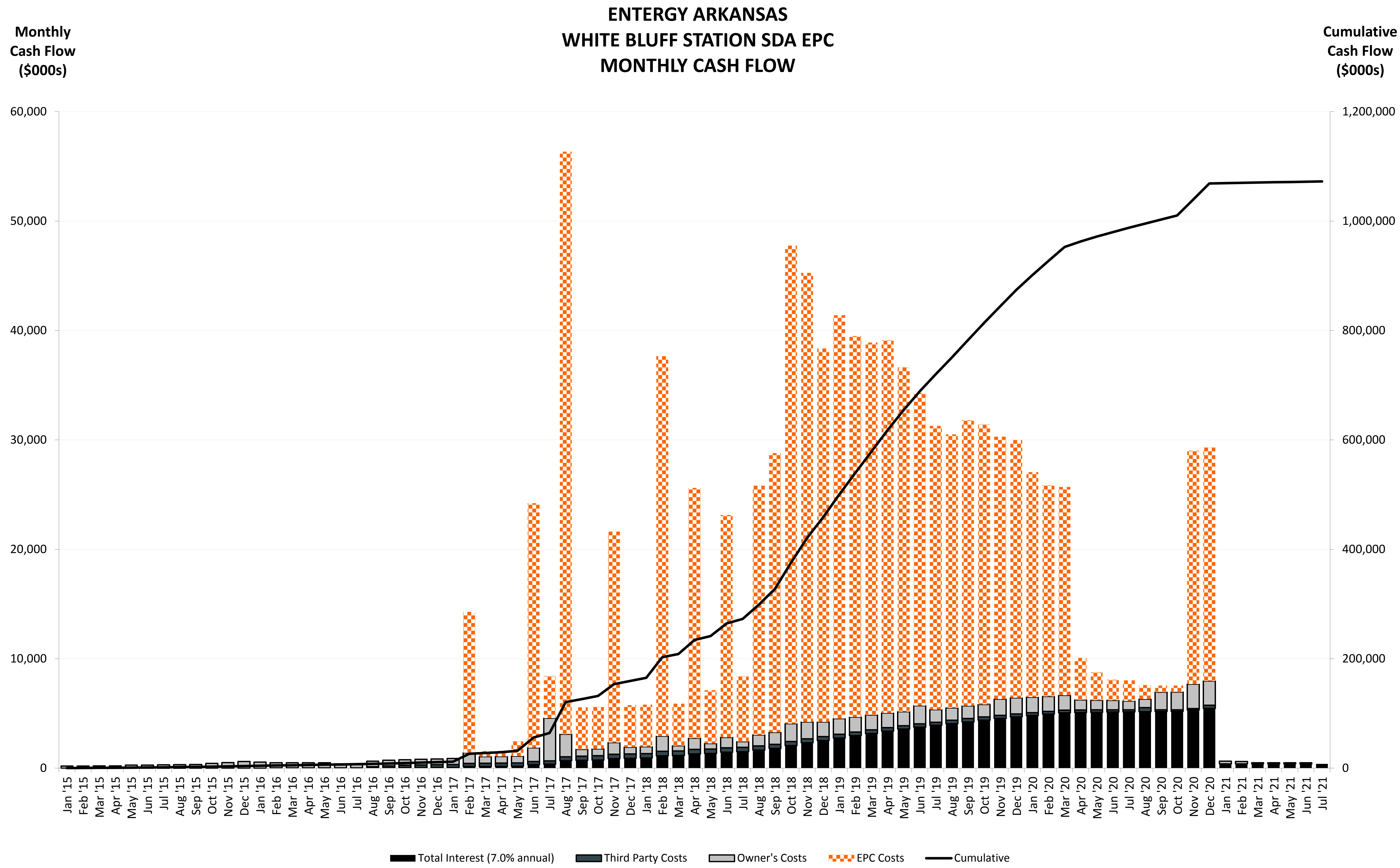


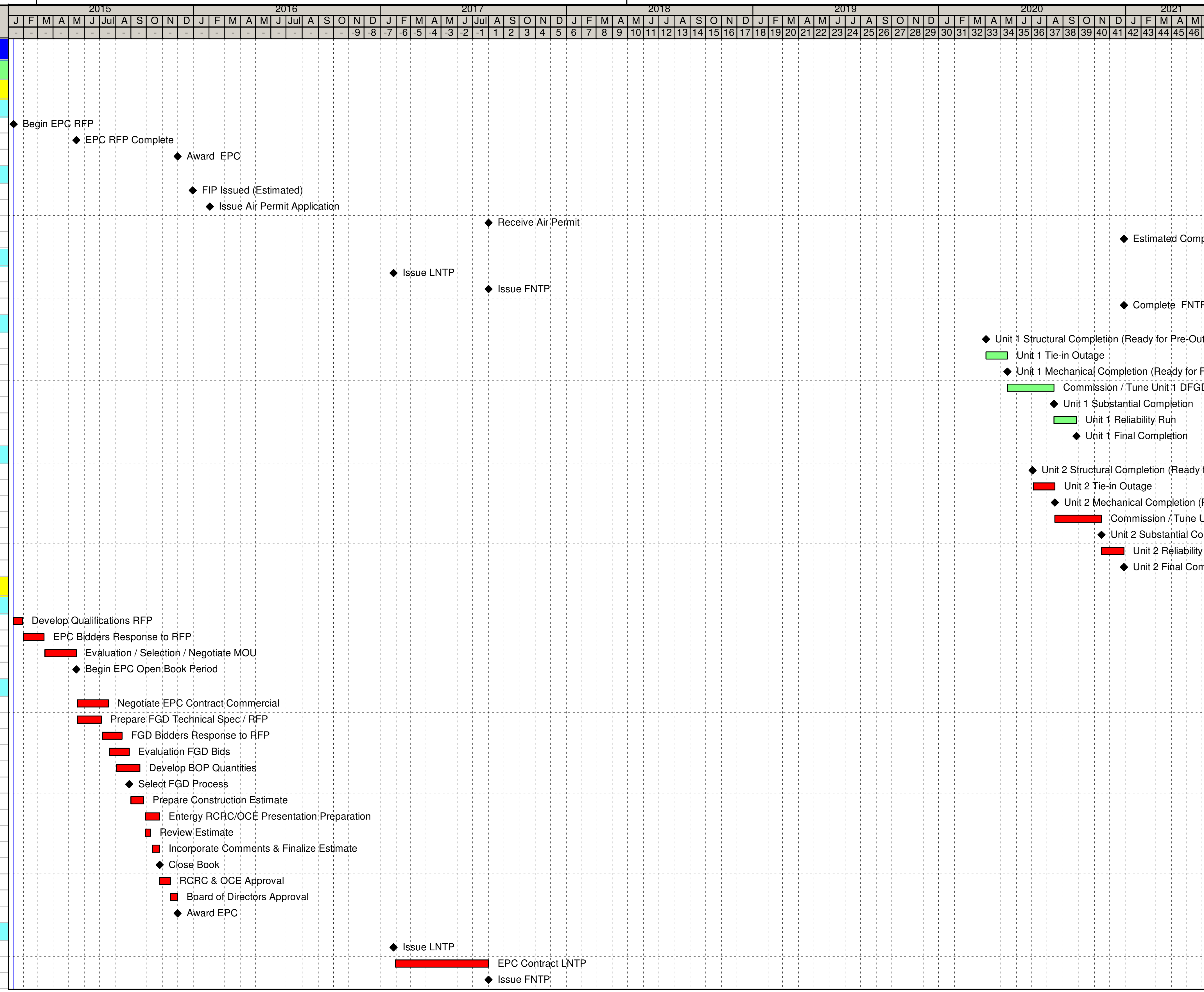
Exhibit B to EAI Comments

ATTACHMENT 3

Level 1 Preliminary Execution Schedule

WHITE BLUFF FGD SCHEDULE (December 2020)

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.

Exhibit B to EAI Comments

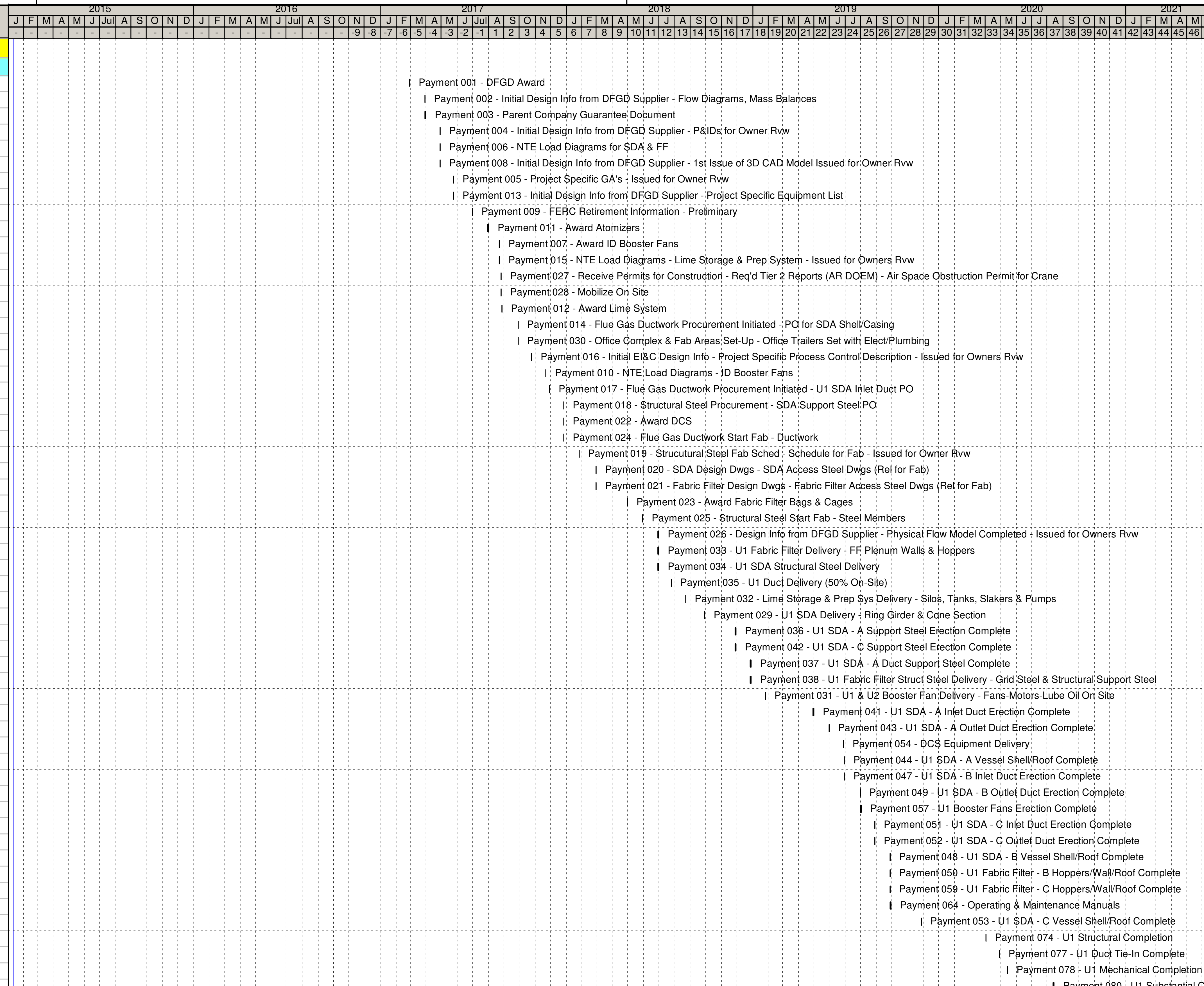
Activity ID	Activity Name	Ori Dur	Start	Finish
FNTP		890	02-Aug-17	29-Dec-20
OV1180	EPC Contract FNTP Period	889	02-Aug-17	28-Dec-20
OV1230	Compliance Deadline	0		29-Dec-20*
EPC Milestones		1292	30-Nov-15	29-Dec-20
Engineering		308	07-Sep-17	26-Nov-18
EPC325	Common Sitework Dwg IFC	0		07-Sep-17
EPC345	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	Ori 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

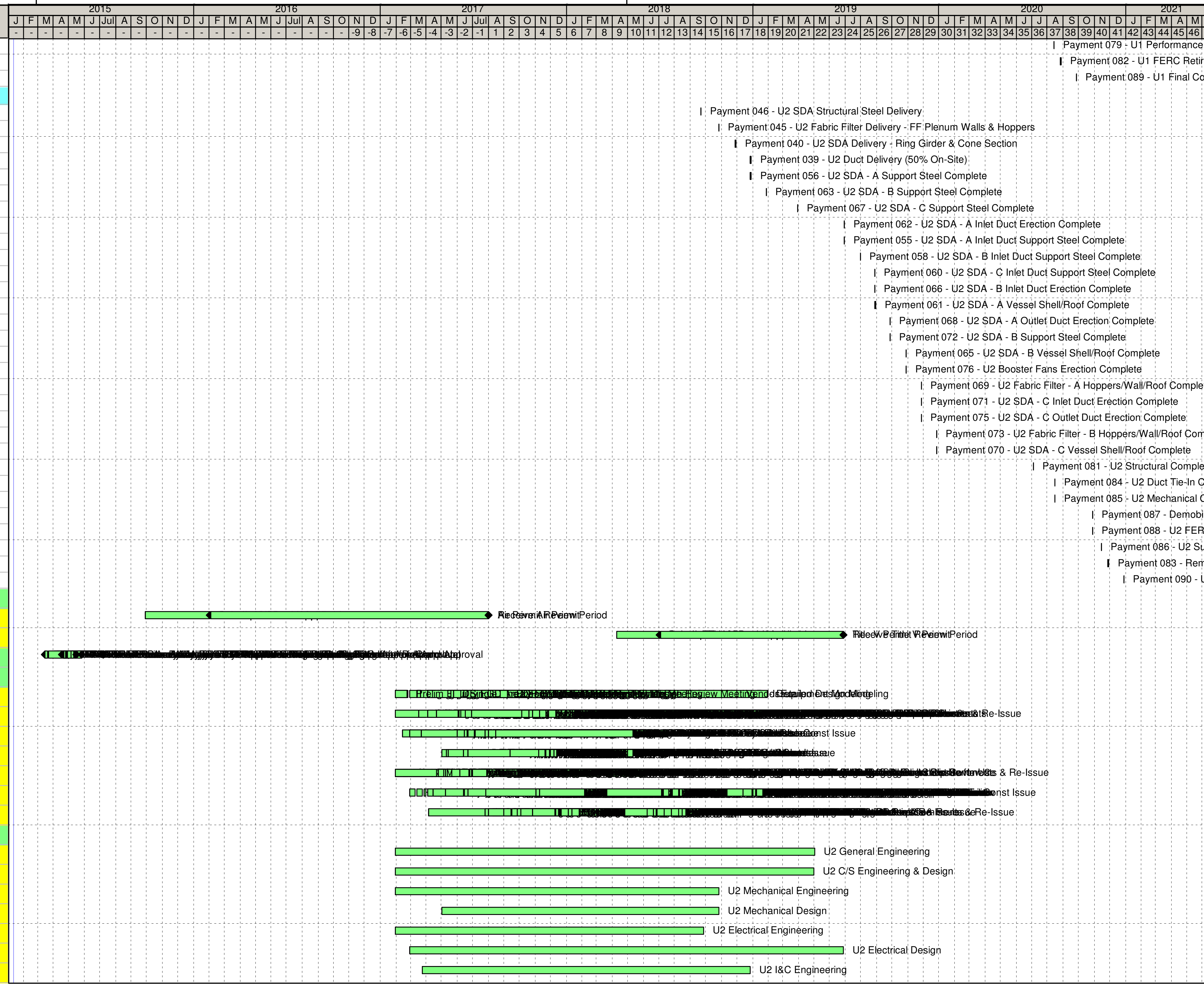


Remaining Work | Actual Work | WBS Summary
Critical Remaining Work | Milestone

TASK filter: Exclude WBS Activities_1.

Exhibit B to EAI Comments

Activity ID	Activity Name	Ori 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

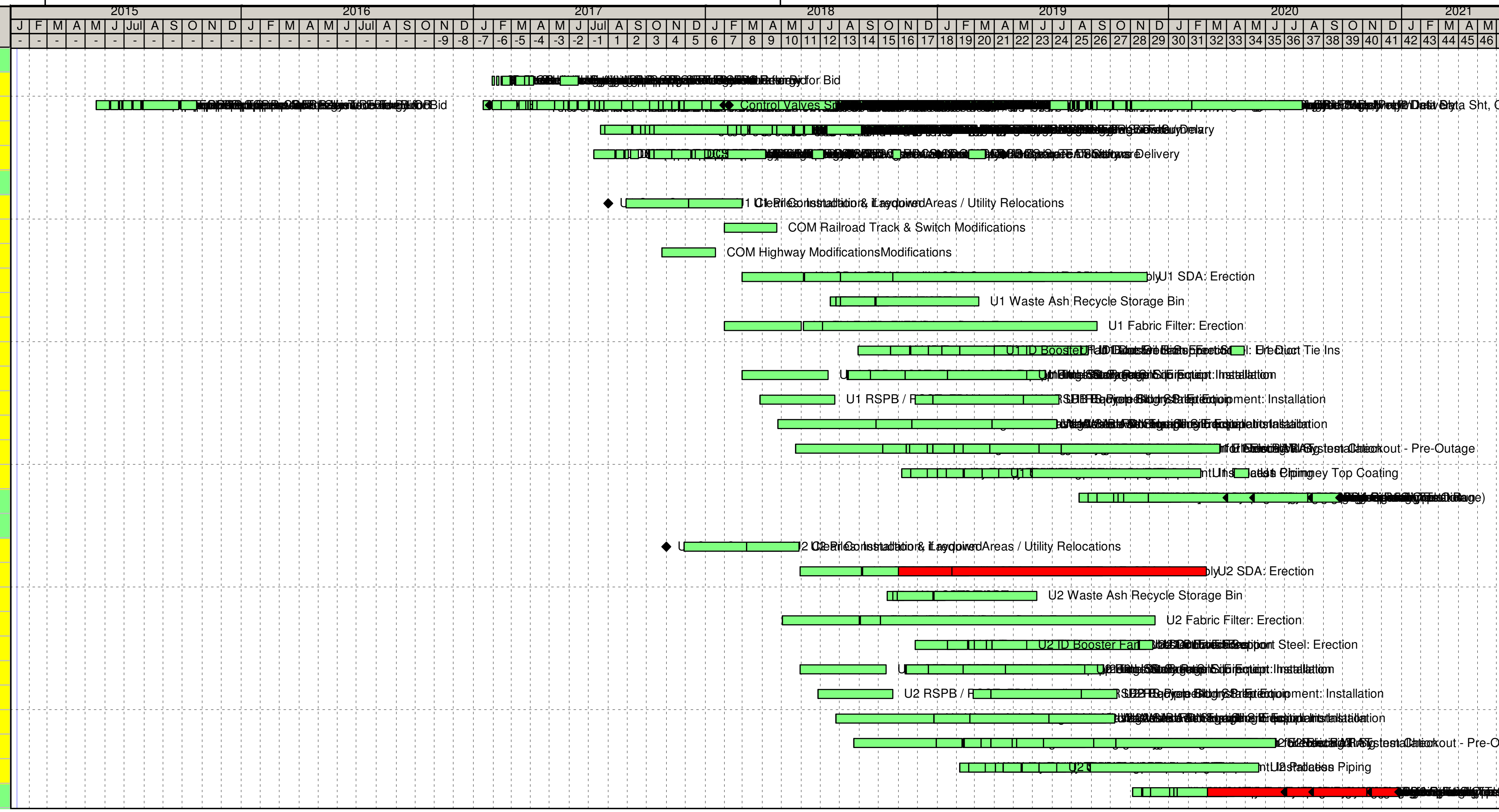


Remaining Work | Actual Work | WBS Summary
Critical Remaining Work | Milestone

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	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

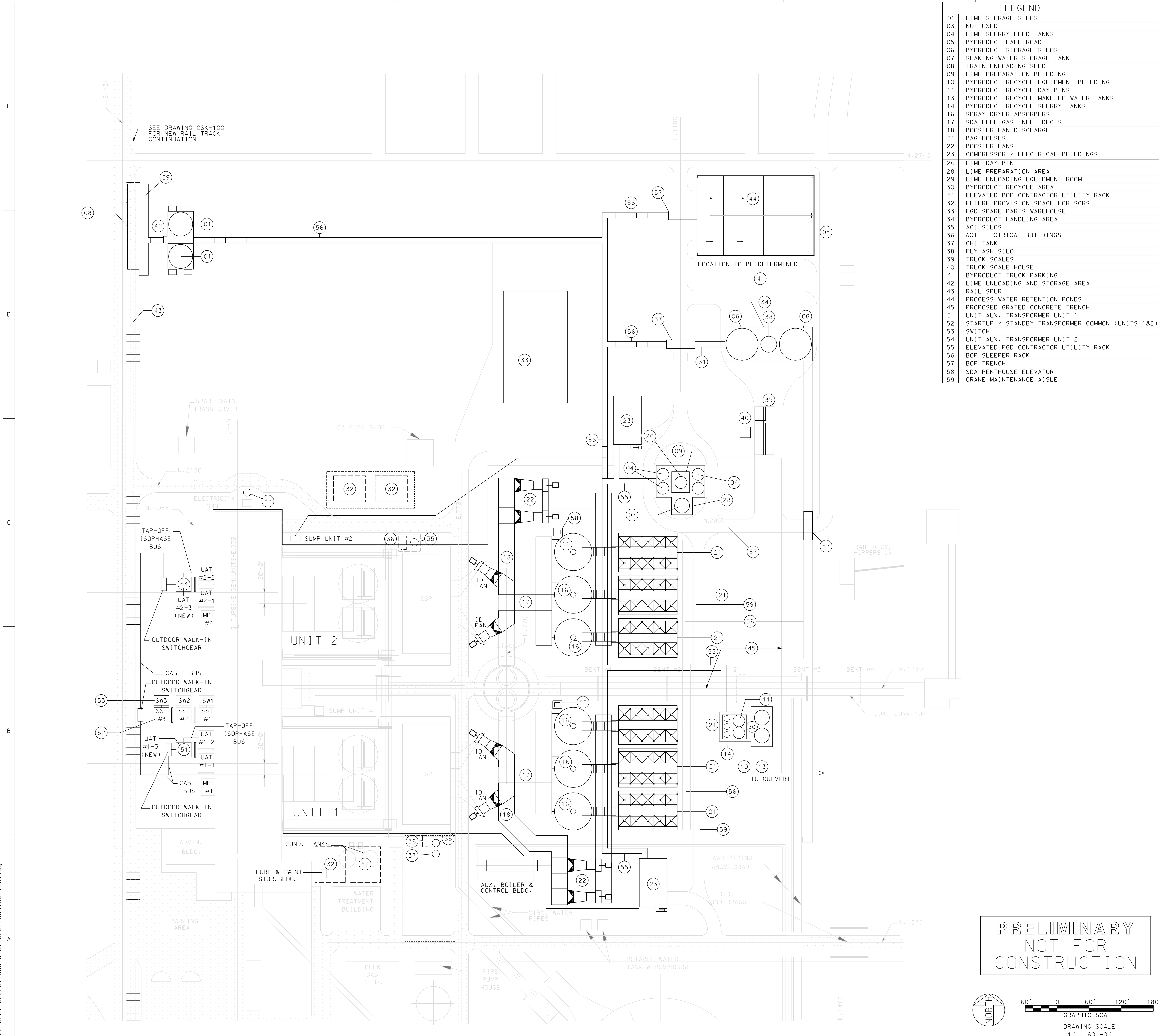
Basis: Pine Bluff Arkansas Labor rates as published in RS Means	Yearly Base Rates + Fringes										
Craft Description	2009	2010	2011	2012	2013	2014	% increase in past 1 year	% increase in past 2 years	% increase in past 3 years	% increase in past 5 years	Projected Potential overall % labor increase 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

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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

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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%

WB FGD Project
Risk Register

ESTIMATE UNCERTAINTY								
		Quantitative Risk Analysis						
Risk Category	Description of Risk	Estimate Total w/out Contingency	Min ($)	Expected	Max ($)	QRA Comments		Status / 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

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							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	
2014-010	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.	

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	

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 $.	

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
2014-034	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							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	
2014-056	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							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	
2014-059	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:

TRINITY CONSULTANTS
12770 Merit Drive
Suite 900
Dallas, TX 75251
(972) 661 -8100
Fax: (972) 385-9203

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.

2. REGIONAL HAZE MODELING METHODOLOGY

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.

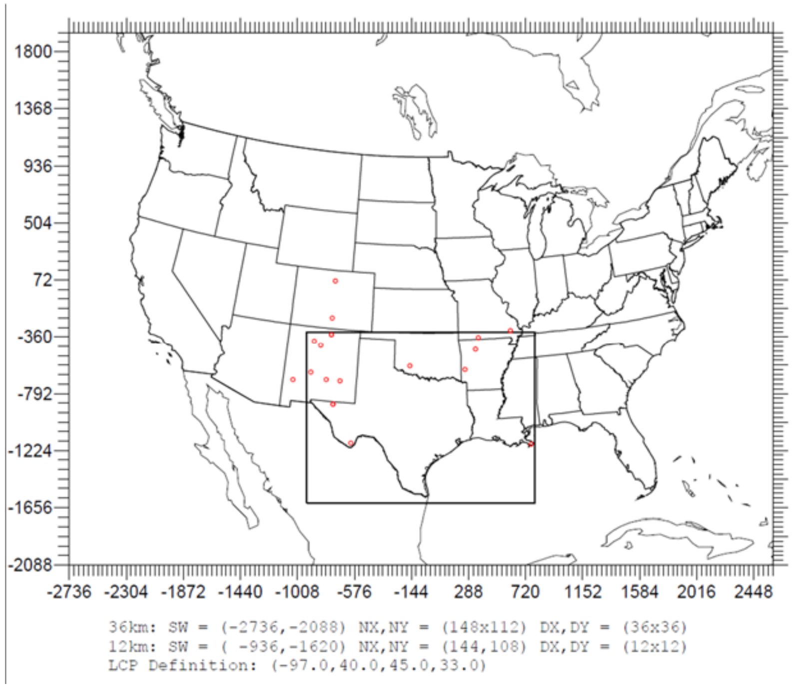
All modeling domain grids are projected in the Lambert Conformal Conic (LCC) map projection. The 36 km grid is also the domain used by the Regional Planning Organizations (RPOs) of which CENRAP is an example. The 12 km grid was developed by ENVIRON to allow for minimizing the effects of the boundary 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

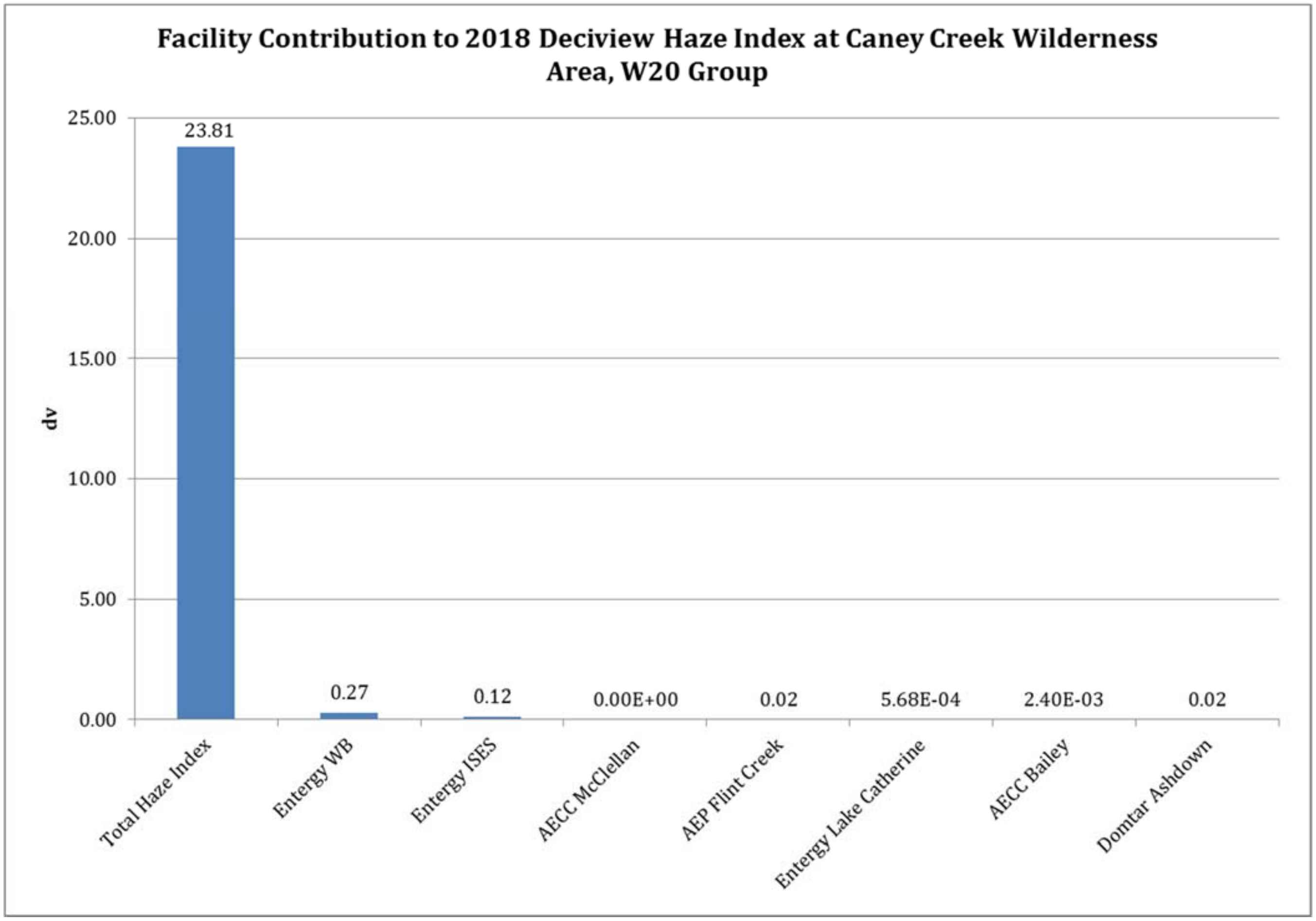
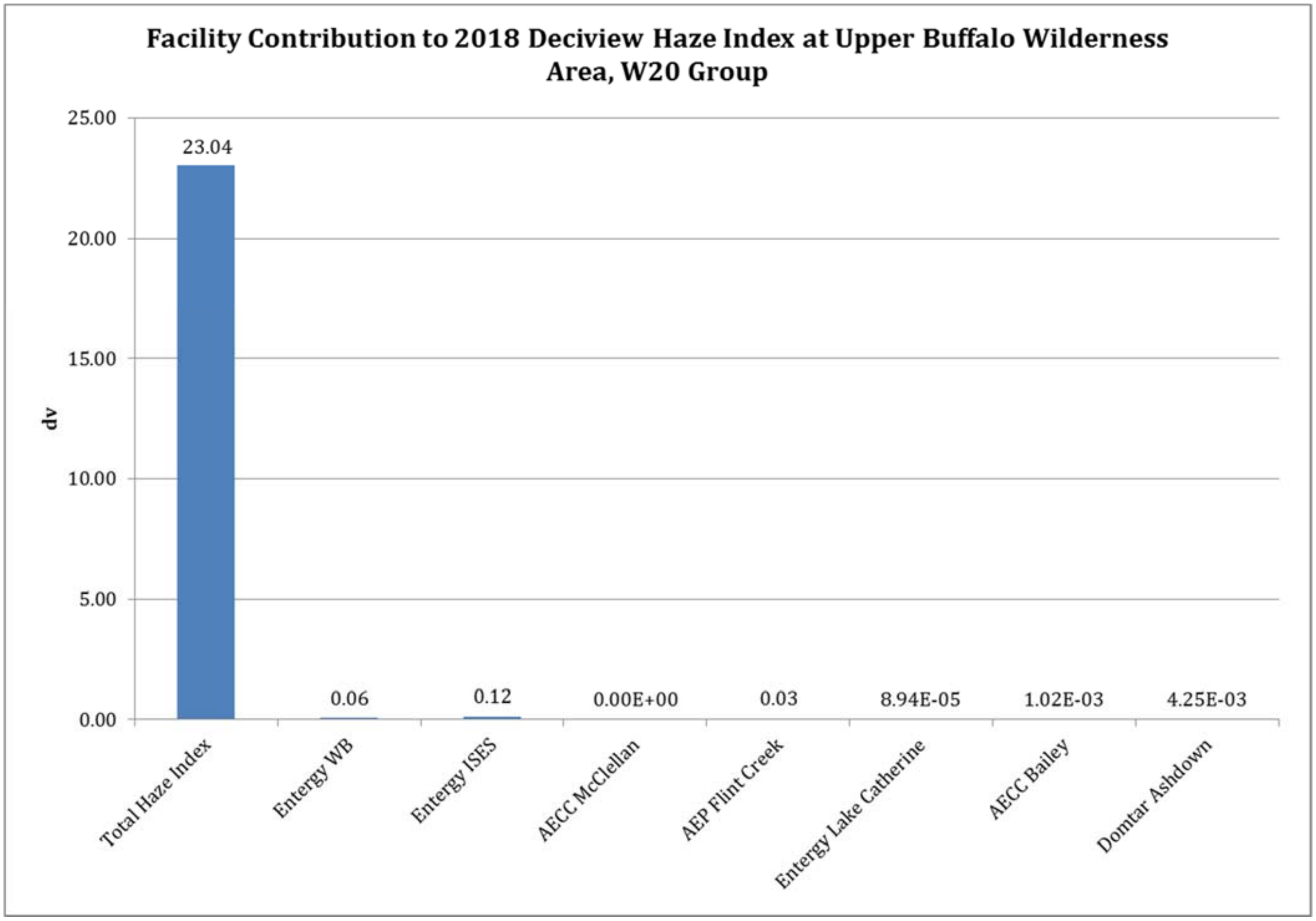


Figure 3-2. Contribution Analysis Results for the Baseline Modeling Scenario at the Upper Buffalo Wilderness Area



3.1.4. Uniform Rate of Progress Curve Analysis

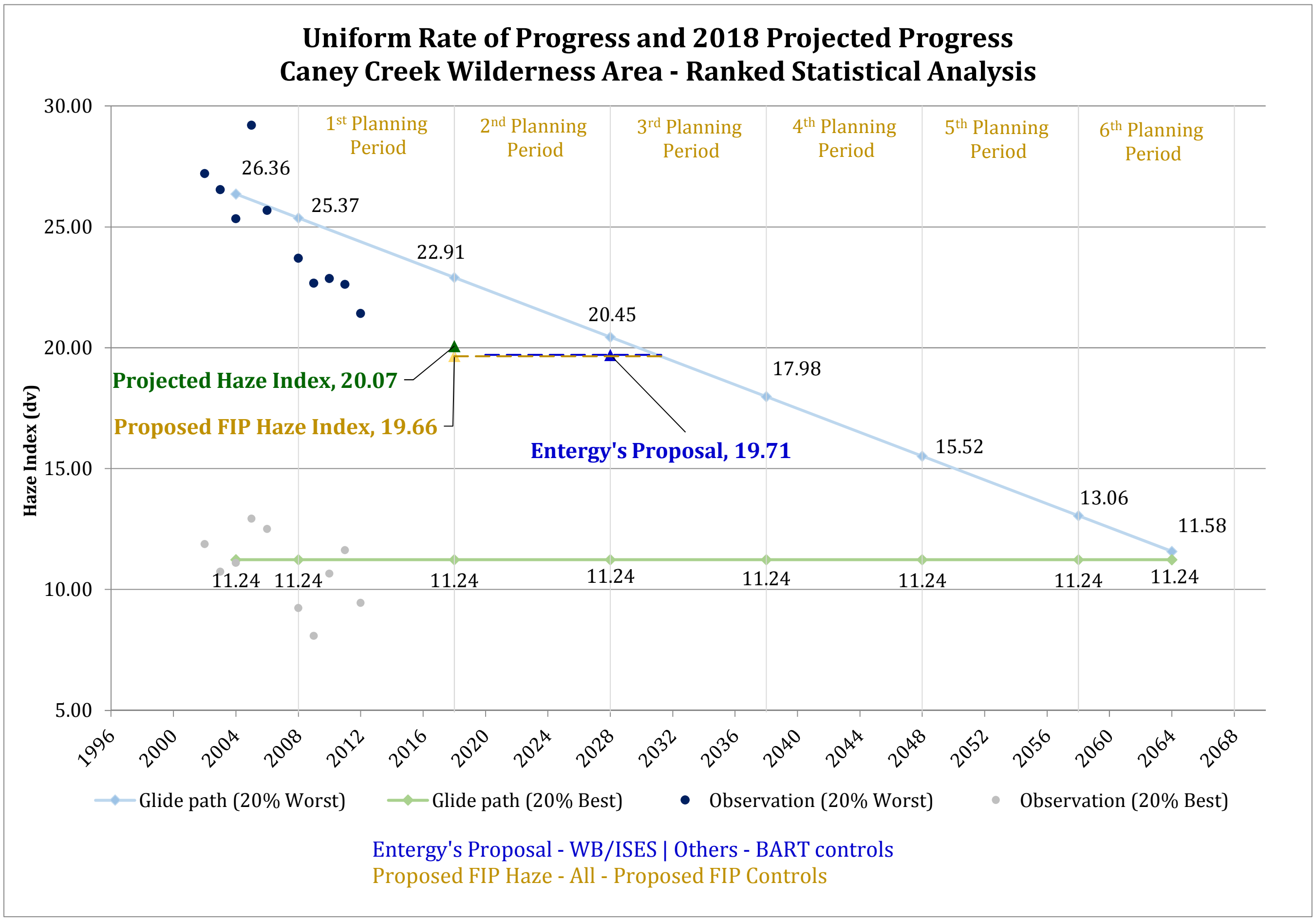
Title 40 of the Code of Federal Regulations (CFR) Part 51 requires that SIPs "analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064."[13] This requirement is demonstrated by creating a URP graph, which shows the rate at which the 20% worst deciview (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).

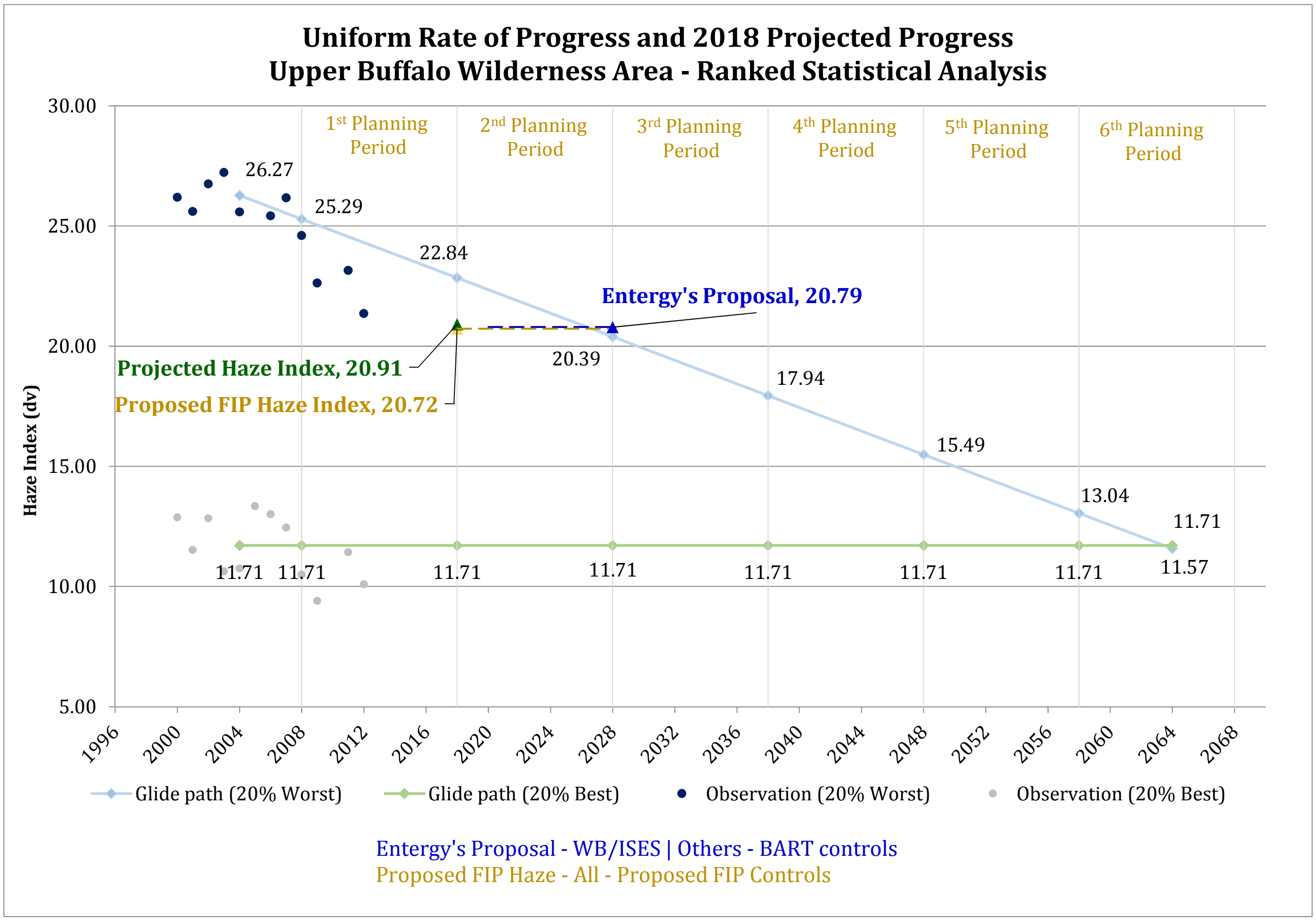
performed using the full set of IMPROVE data for both Caney Creek and Upper Buffalo.[14] The scenario-specific haze index values are calculated by first converting the model-predicted five-year averaged haze index values obtained from MATS into total extinction values in Mm^{-1}. The predicted improvement 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



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Appendix Table A-1. Modeled Emission Rates for the Entergy Independence and White Bluff Units

Unit	Uncontrolled Baseline (tpy)		Entergy's Proposal (tpy)		Arkansas FIP (tpy)	
	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:

TRINITY CONSULTANTS
12770 Merit Drive
Suite 900
Dallas, TX 75251
(972) 661 -8100
Fax: (972) 385-9203

July 2015

Project 154401.0074

Trinity Consultants

Environmental solutions delivered uncommonly well

Exhibit D to EAI Comments

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1. EXECUTIVE SUMMARY

On April 8, 2015, the United States Environmental Protection Agency (EPA) published the proposed Arkansas Regional Haze Federal Implementation Plan (FIP) to address regional haze and visibility transport requirements for the State of Arkansas. Within the Arkansas FIP, the EPA addressed the portions of the Arkansas State Implementation Plan (SIP) which 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) and reasonable progress control requirements. Specifically, the EPA proposed to meet RPGs by presenting options for controlling emissions from the Entergy Arkansas Inc. (Entergy) Independence Plant (ISES), which is not subject to BART.

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.

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.

[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

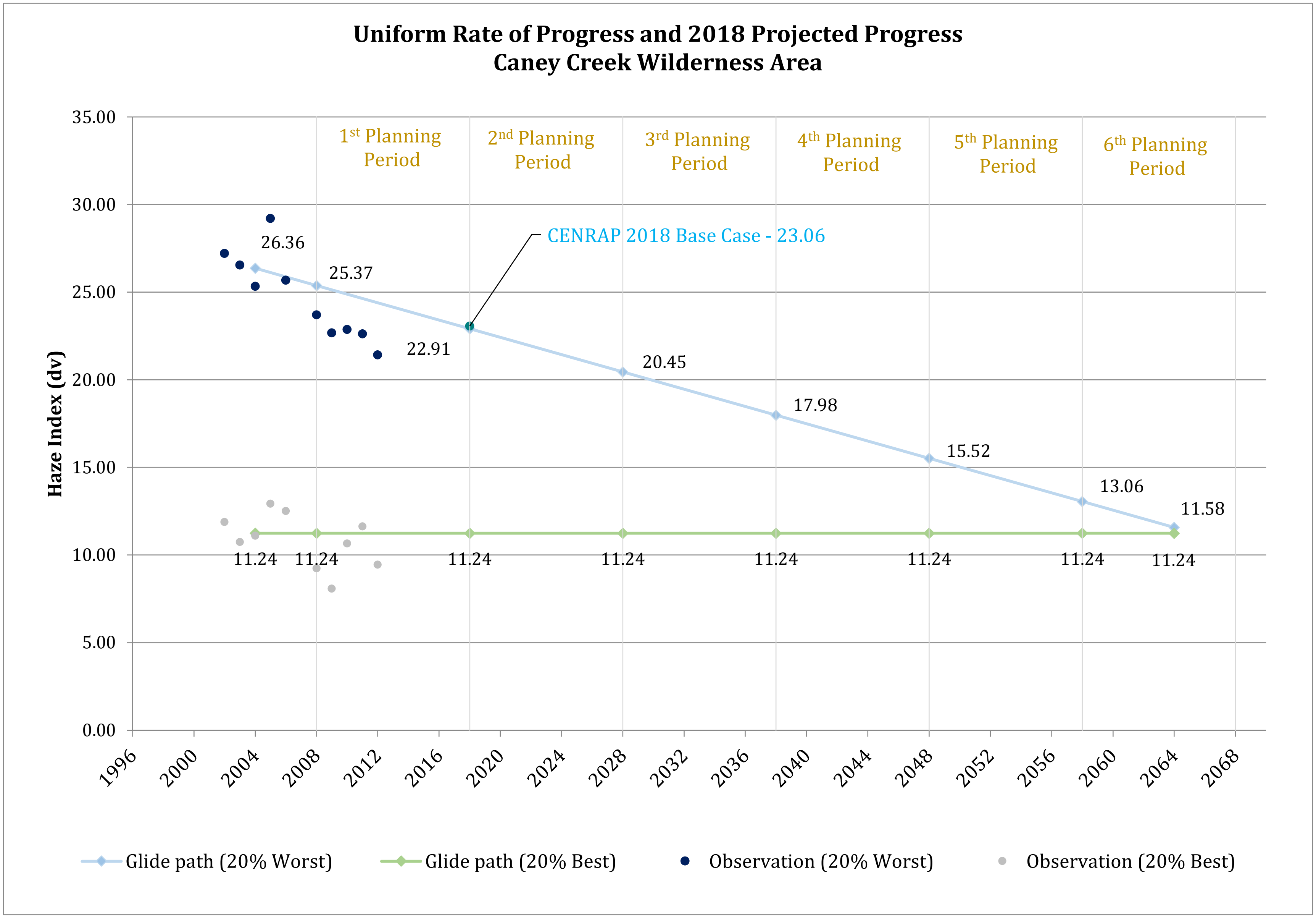


Figure 2-2. Upper Buffalo Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress

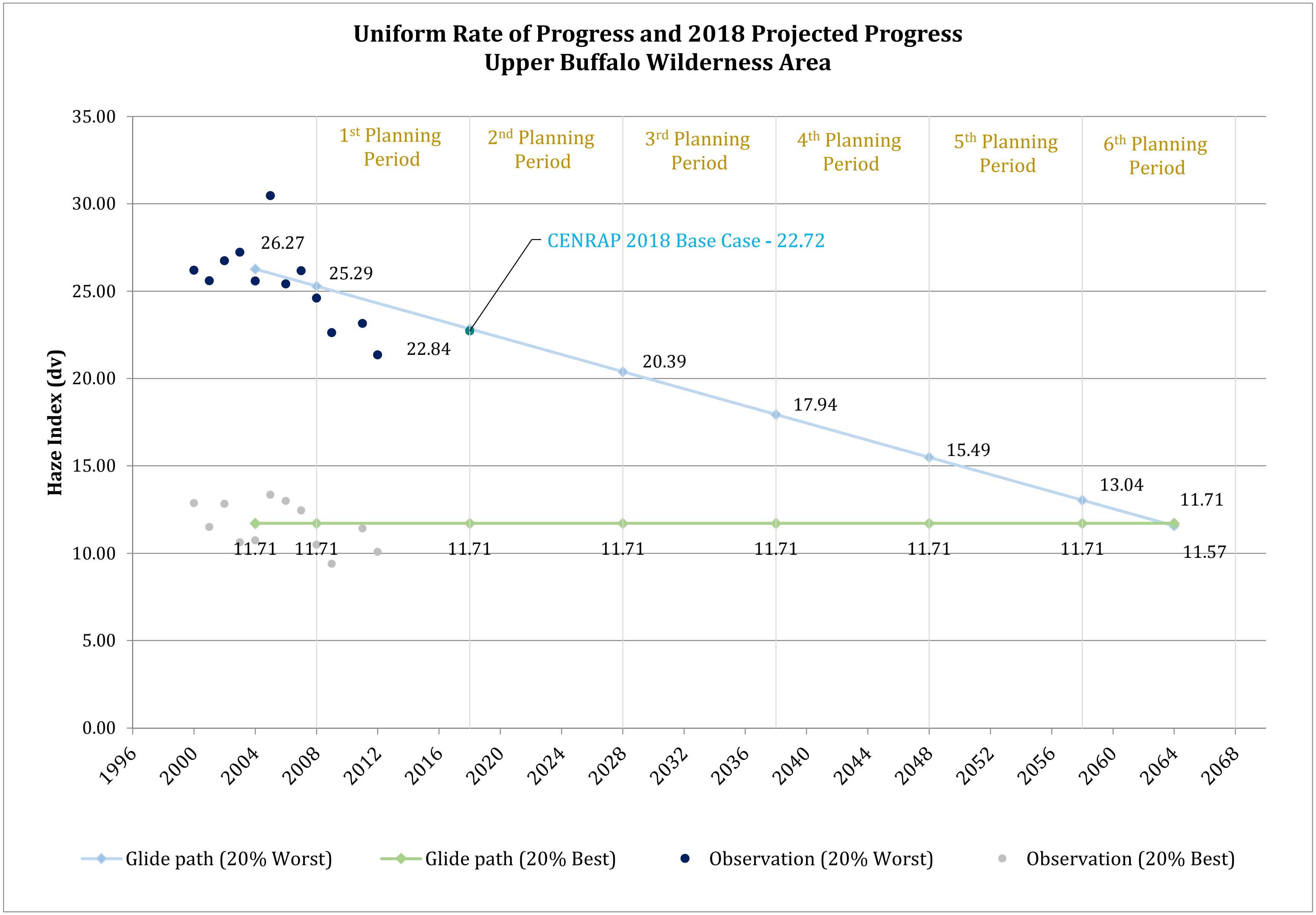
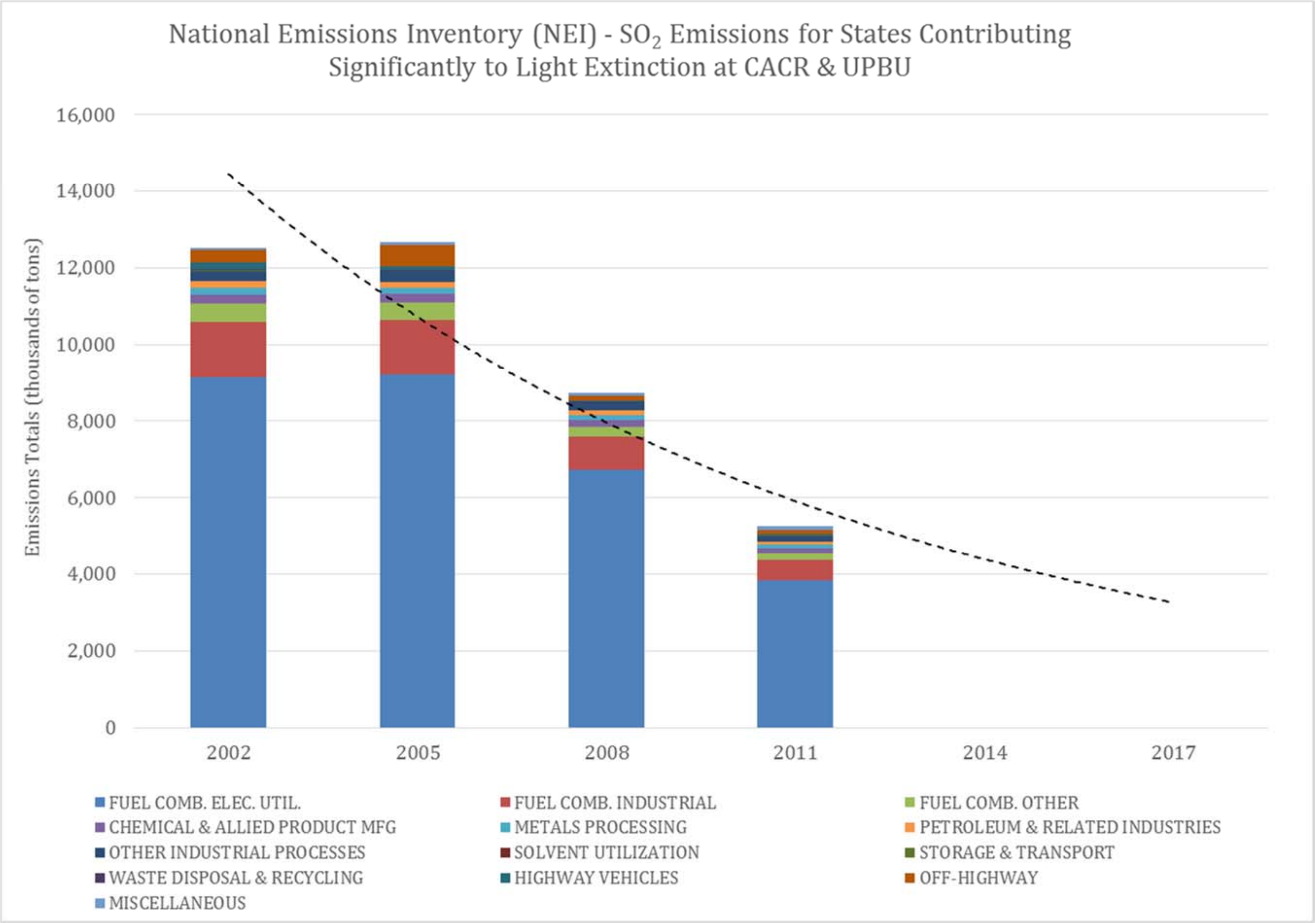


Figure 2-3. National Emissions Inventory (NEI) – SO_2 Emissions for States Contributing Significantly to Light Extinction at Caney Creek and Upper Buffalo



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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.

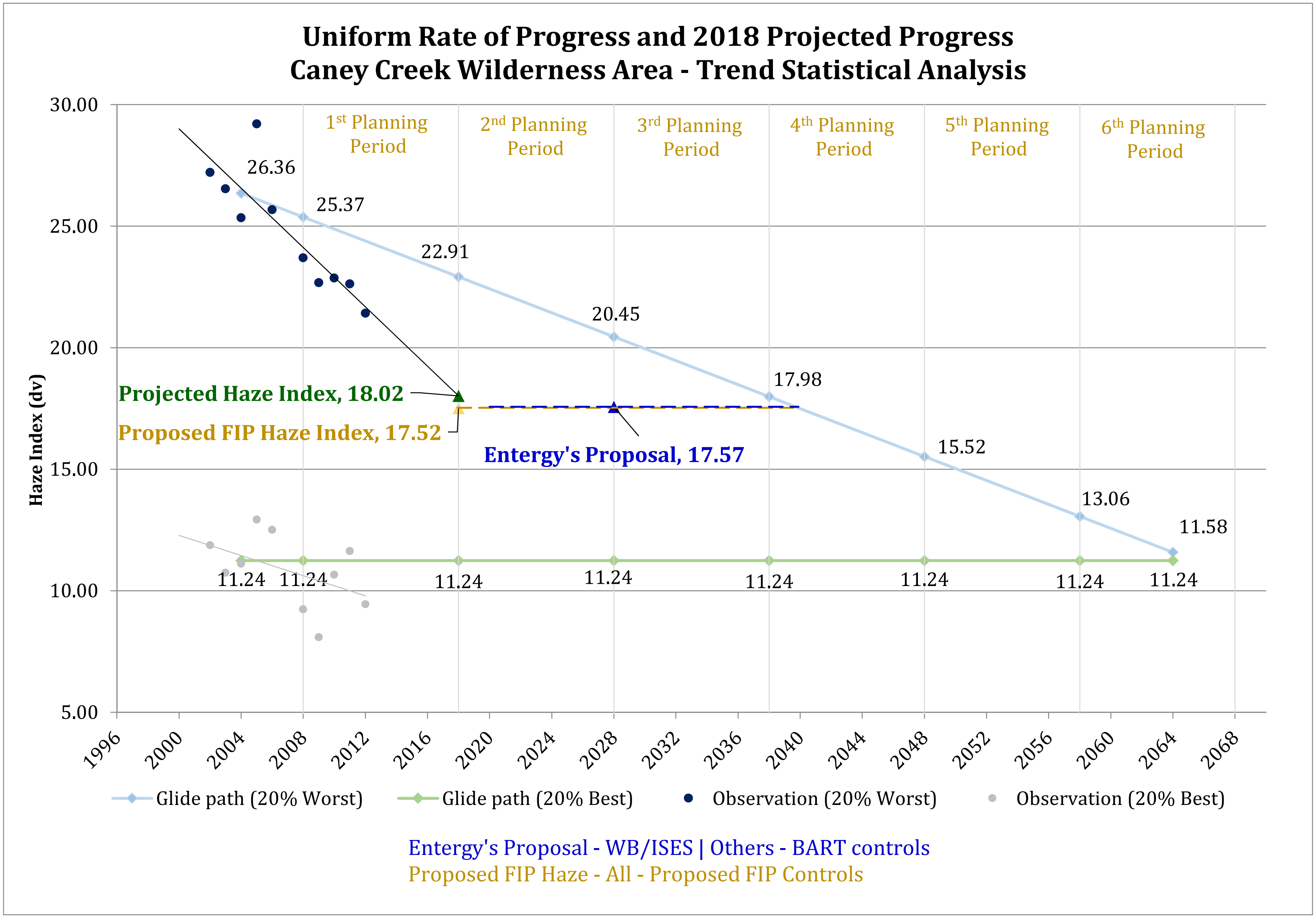


Figure 3-2. Upper Buffalo Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress with Trend Analysis.

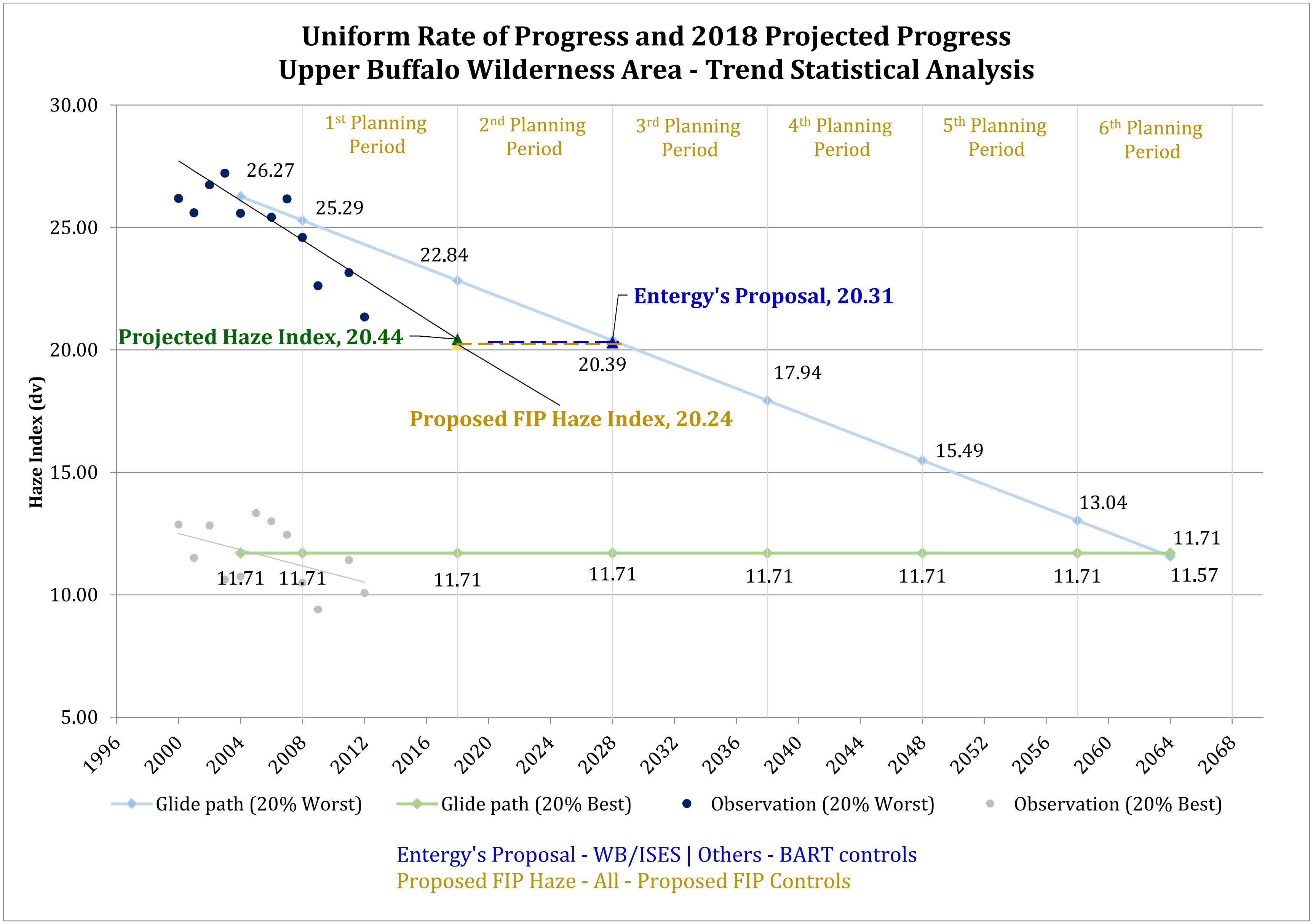
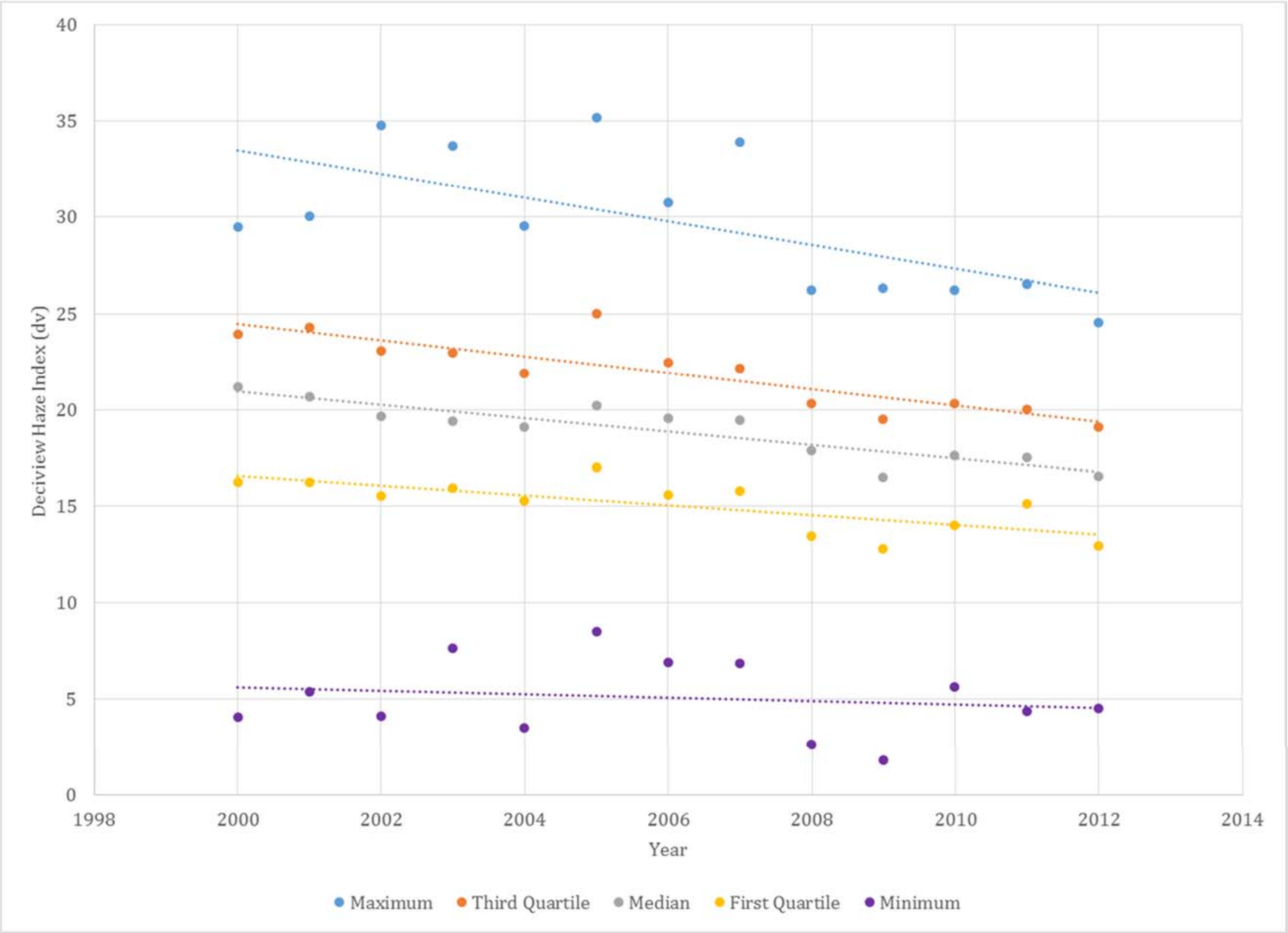


Figure 3-3. Observed Trends in Statistical Values for Caney Creek IMPROVE data.



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

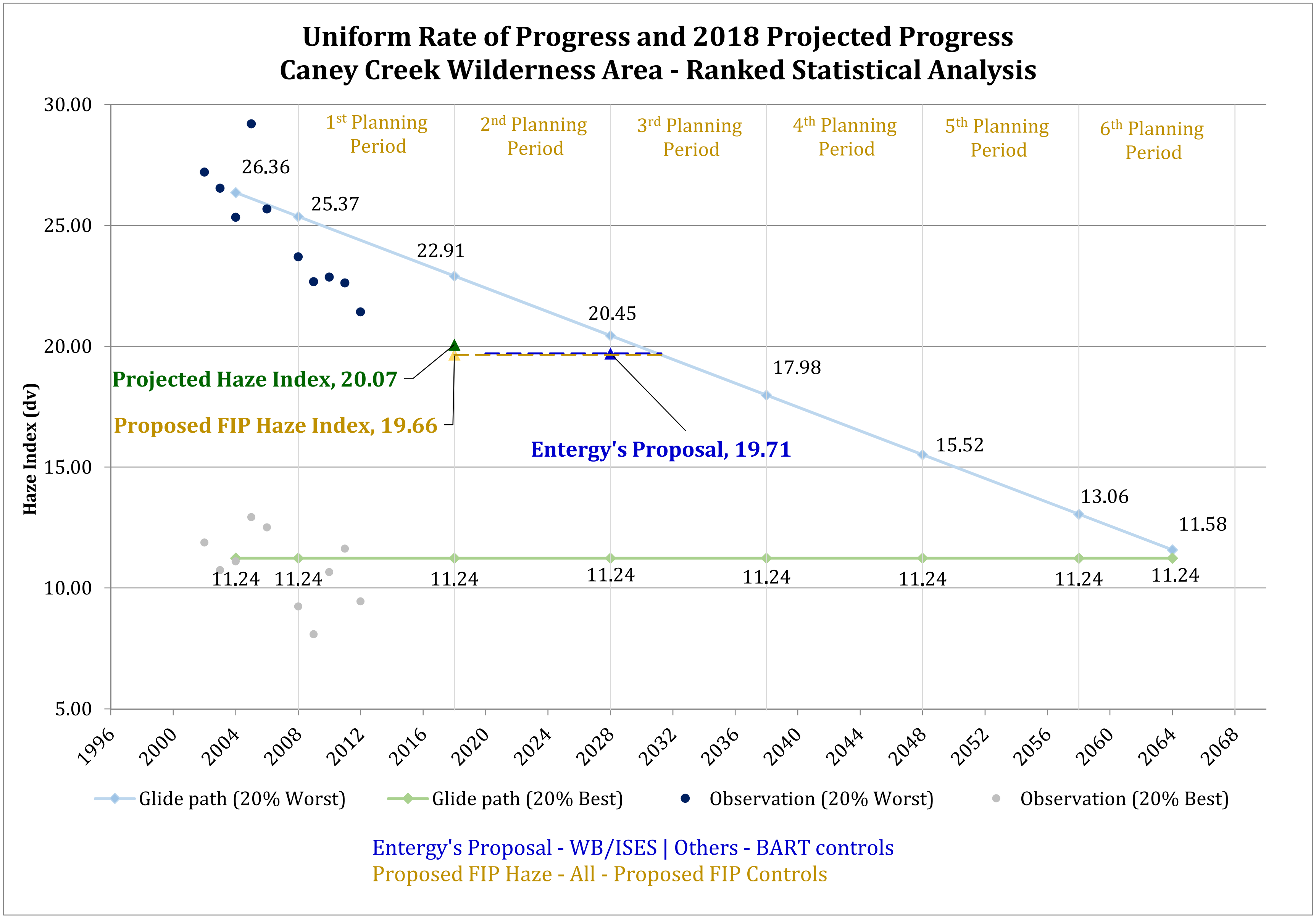
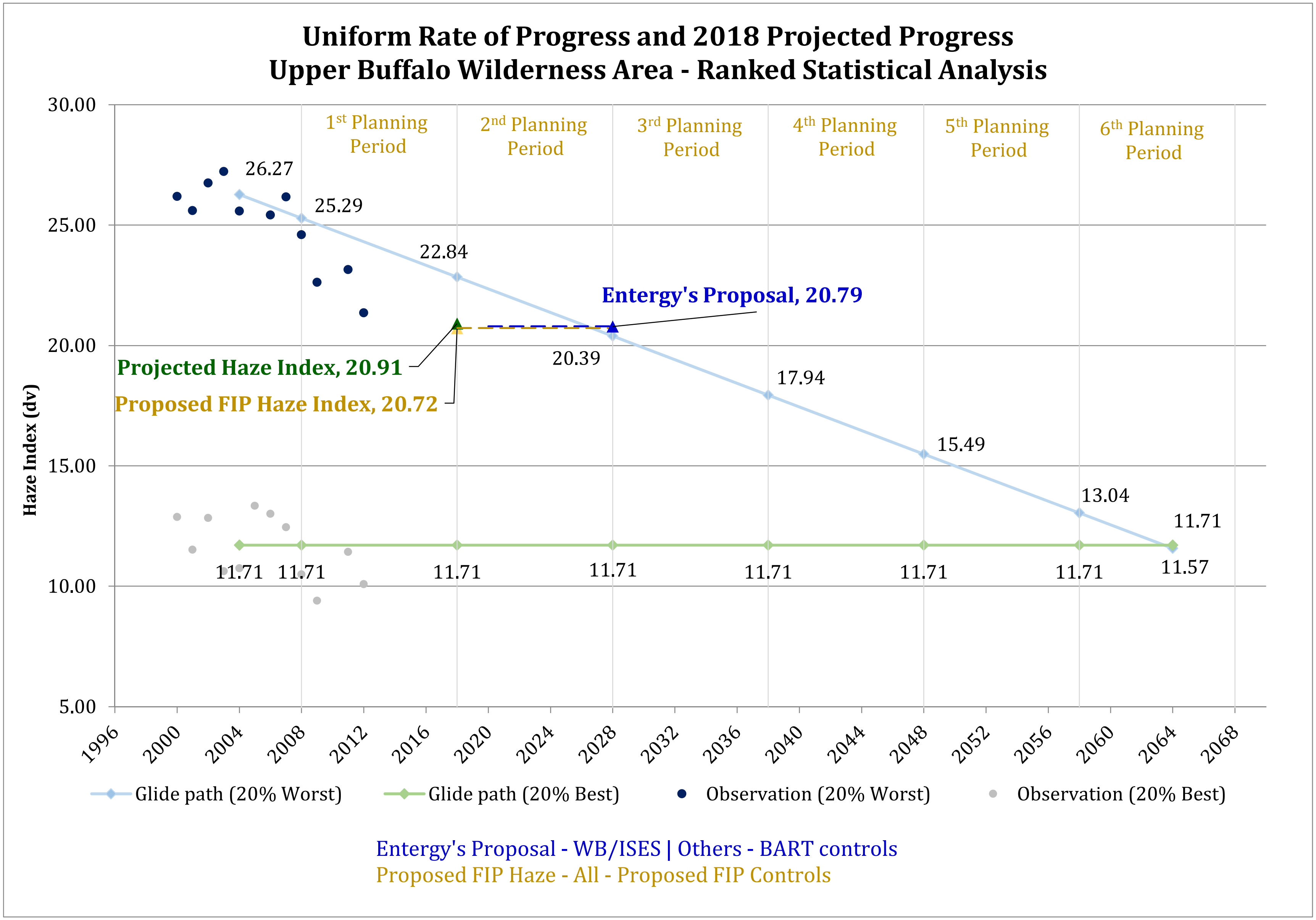


Figure 3-5. Upper Buffalo Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress with Ranked Statistical Analysis



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Just-Noticeable Differences in Atmospheric Haze

Ronald C. Henry
Department of Civil and Environmental Engineering, University of Southern California, Los Angeles

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

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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]

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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):

$$M(\tau) = M_0 \exp(-\tau) \qquad (3)$$

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

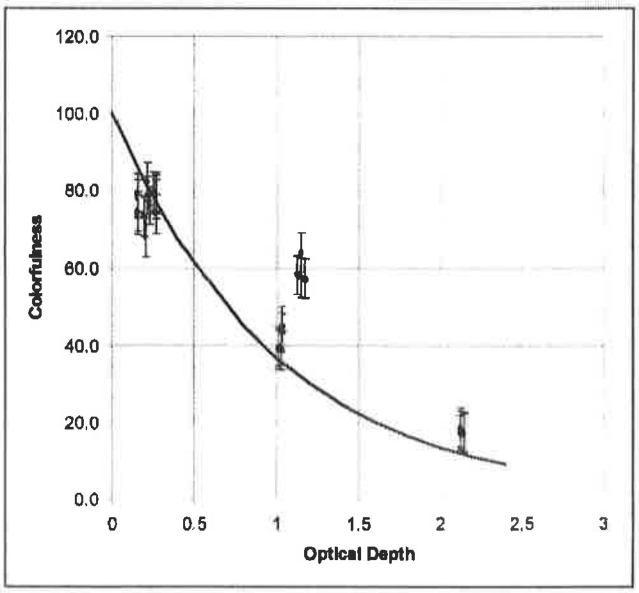

Figure 1. Colorfulness vs. optical depth for observer Urquito for repeated observations of the red barn roof. The line is an exponential fit as in eq 1, and the error bars are two times the standard deviation given in Table 2.

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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.

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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	

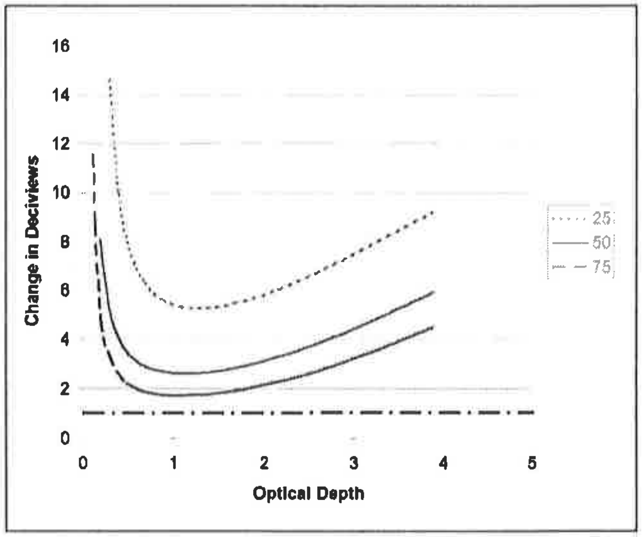

Figure 2. Change in deciviews needed to produce a just-noticeable increase in colorfulness for objects with an inherent colorfulness of 25, 50, and 75. The horizontal dashed dotted line represents what would be expected if a 1-deciview change were actually a uniform measure of haze perception.

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:

$$v = 10\ln\left(-\frac{1}{10x}\ln\left(\frac{M}{M_0}\right)\right) \tag{4}$$

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

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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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About the Author

Dr. Ronald C. Henry is professor of Civil and Environmental Engineering at the University of Southern California, Department of Civil and Environmental Engineering, 3620 South Vermont Ave., Los Angeles, CA 90089-2531; e-mail: *rhenry@usc.edu*.

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FOSTER WHEELER NORTH AMERICA CORP
53 Frontage Road,
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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

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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.**

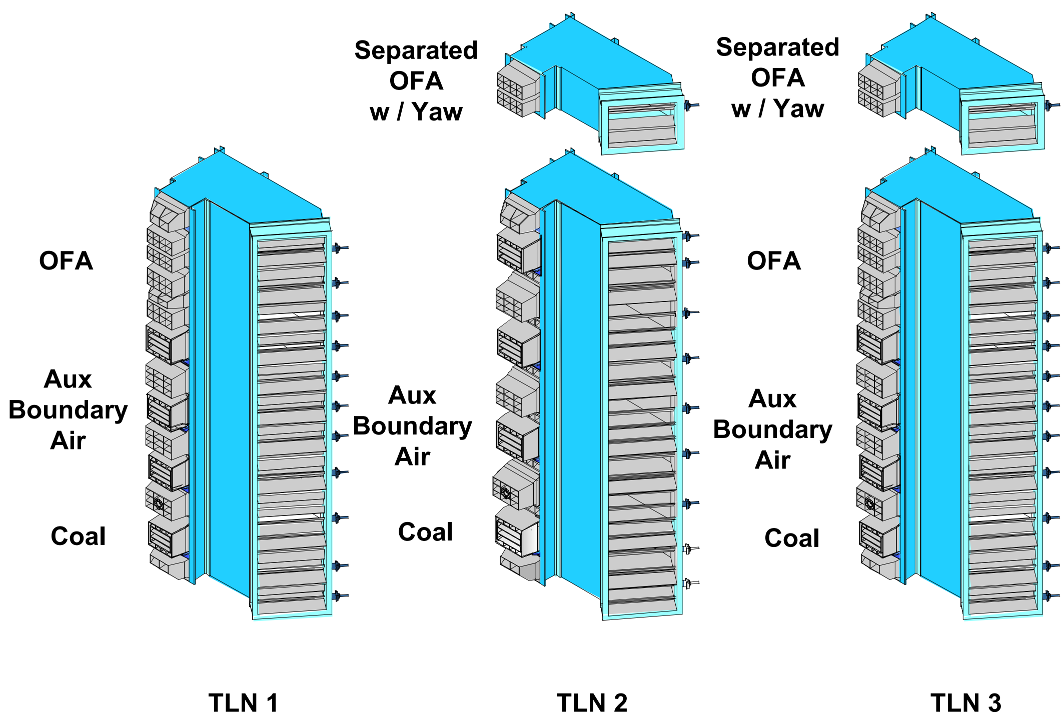

Figure 3 - FWNAC Tangential Low NOx (TLN) Configurations

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.
53 Frontage Road, PO Box 9000
Hampton, NJ 08827-9000

EVALUATION OF THE CALPUFF MODELING SYSTEM MARGIN OF ERROR FOR A BART ANALYSIS

Entergy Arkansas, Inc. > Lake Catherine Plant

Prepared By:

TRINITY CONSULTANTS
12770 Merit Drive
Suite 900
Dallas, TX 75251
(972) 661 -8100
Fax: (972) 385-9203

August 4, 2015

Project 154401.0074

Environmental solutions delivered uncommonly well

Exhibit H to EAI Comments

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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).

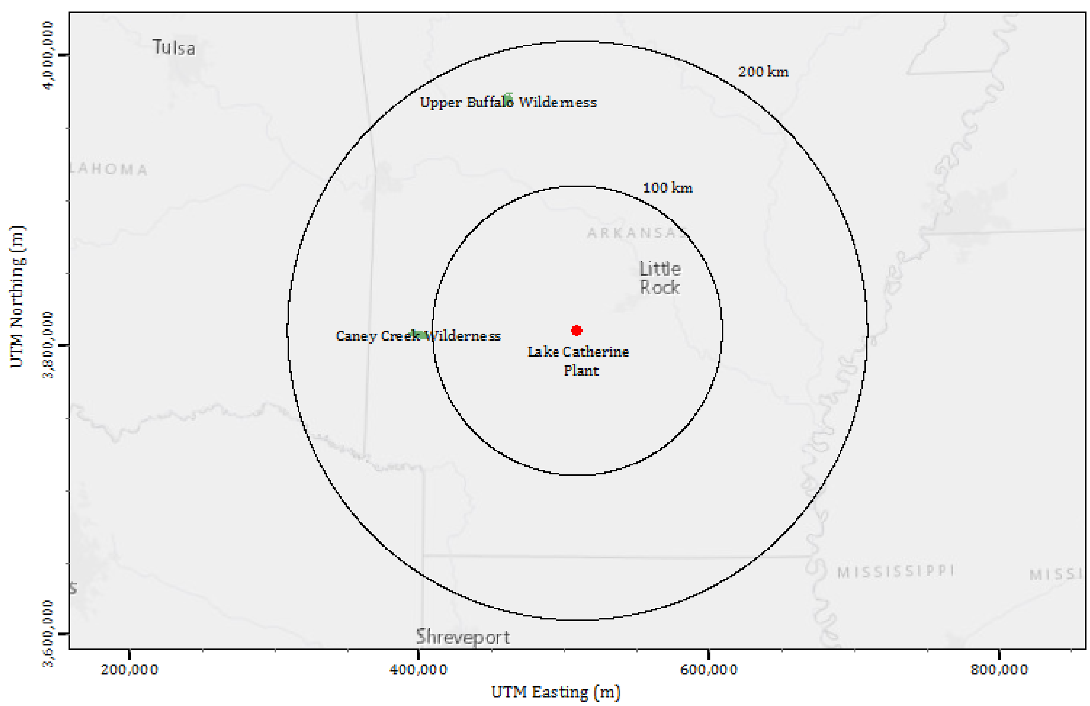
Entergy owns and operates the Lake Catherine Plant located at 141 W. County Line Road in Malvern, Arkansas. The Lake Catherine Plant operates one emission unit – Unit 4 – that is an affected source under the BART provisions of the EPA's Regional Haze Rule, which is codified in Title 40 of the Code of 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."

3. MODELING METHODOLOGY

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

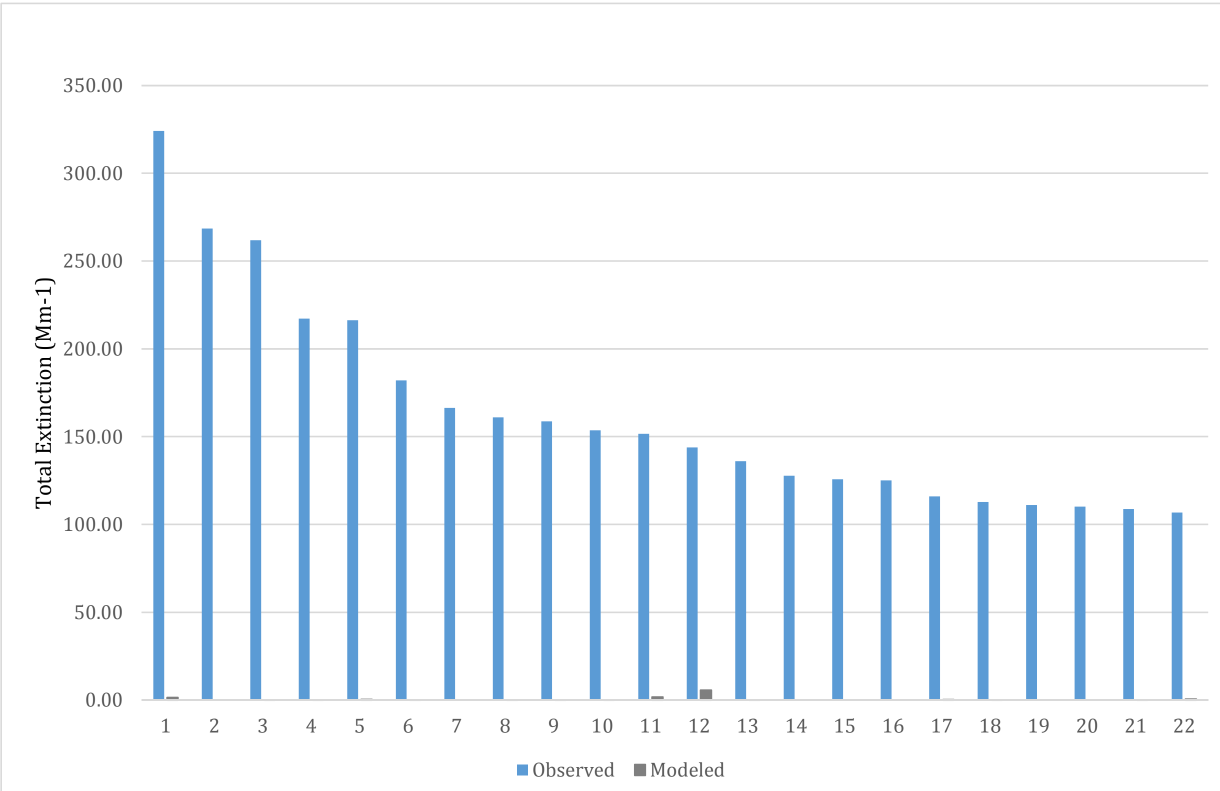


Exhibit H to EAI Comments

Figure 4-2. Measured vs. Modeled Total Extinction on 20% Worst Modeled Days at Caney Creek Wilderness Area in 2002 – Lake Catherine Pre-BART

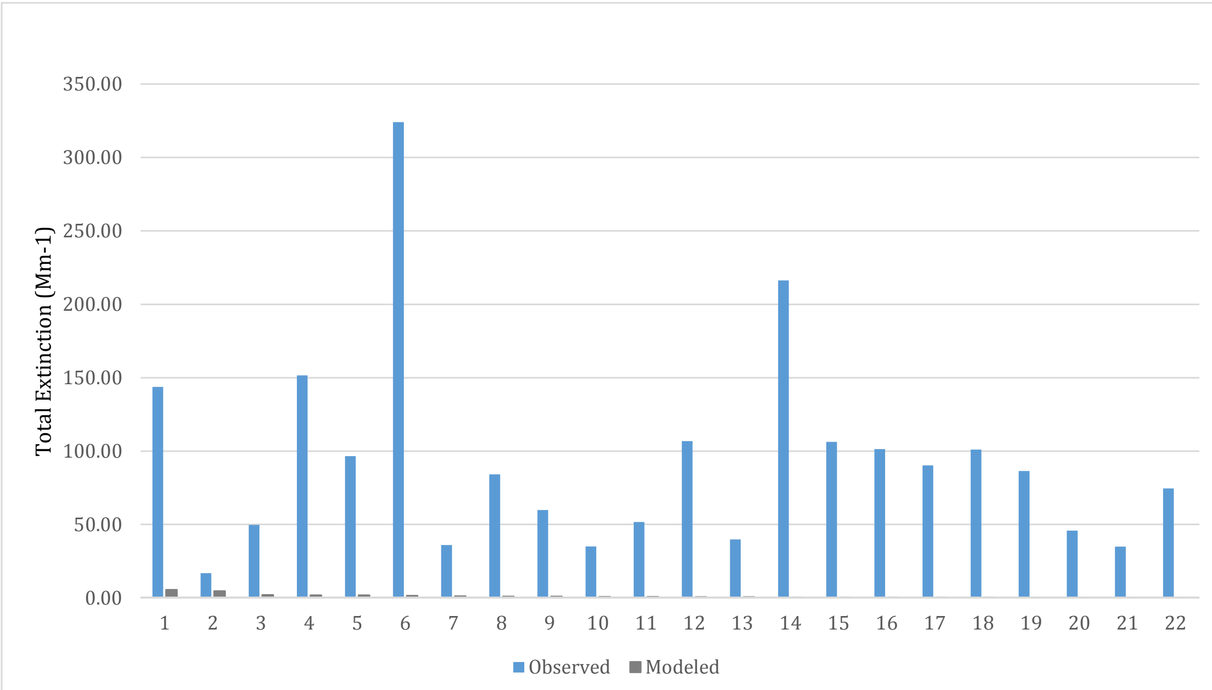
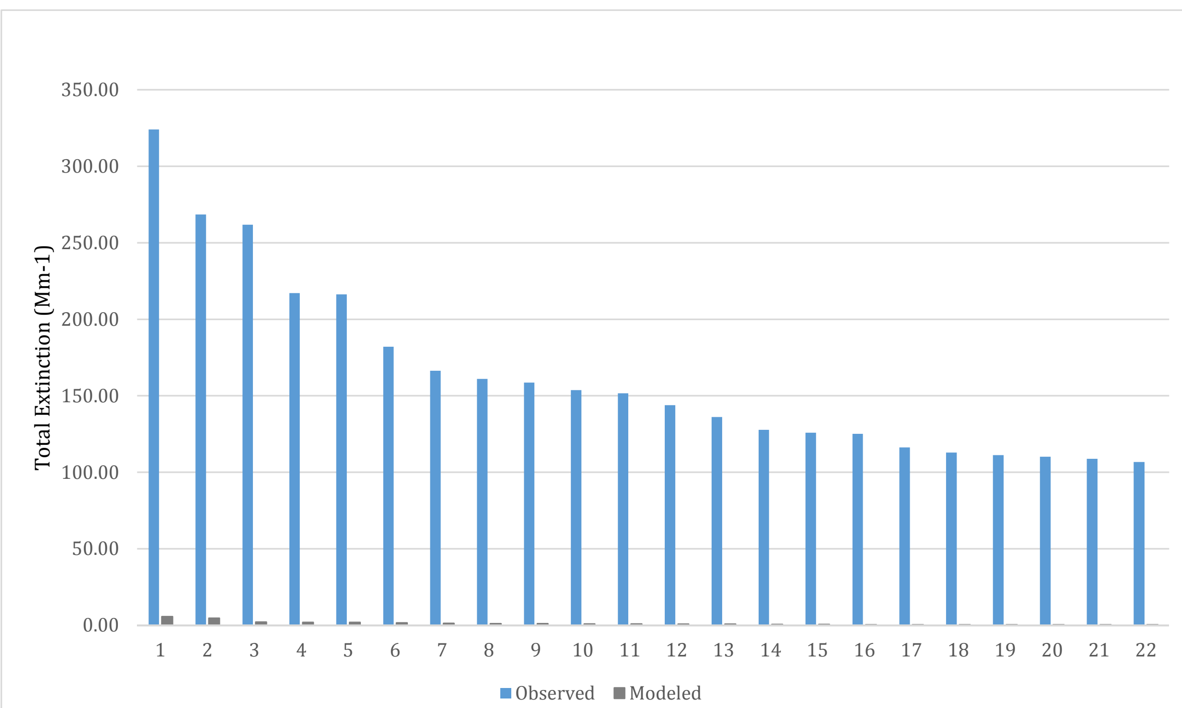


Figure 4-3. Measured and Modeled 20% Worst Days Total Extinction at Caney Creek Wilderness Area in 2002 – Lake Catherine Pre-BART



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

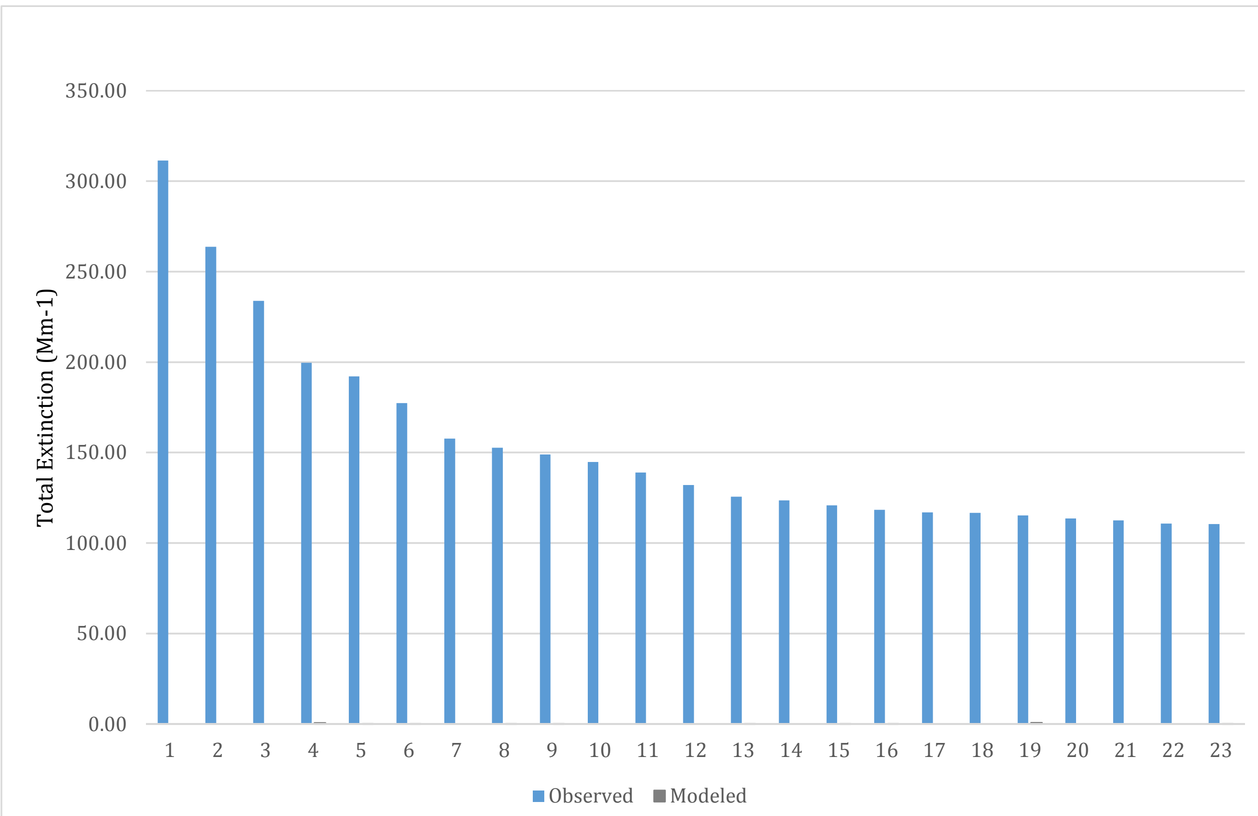


Figure 4-5. Measured vs. Modeled Total Extinction on 20% Worst Modeled Days at Upper Buffalo Wilderness Area in 2002 – Lake Catherine Pre-BART

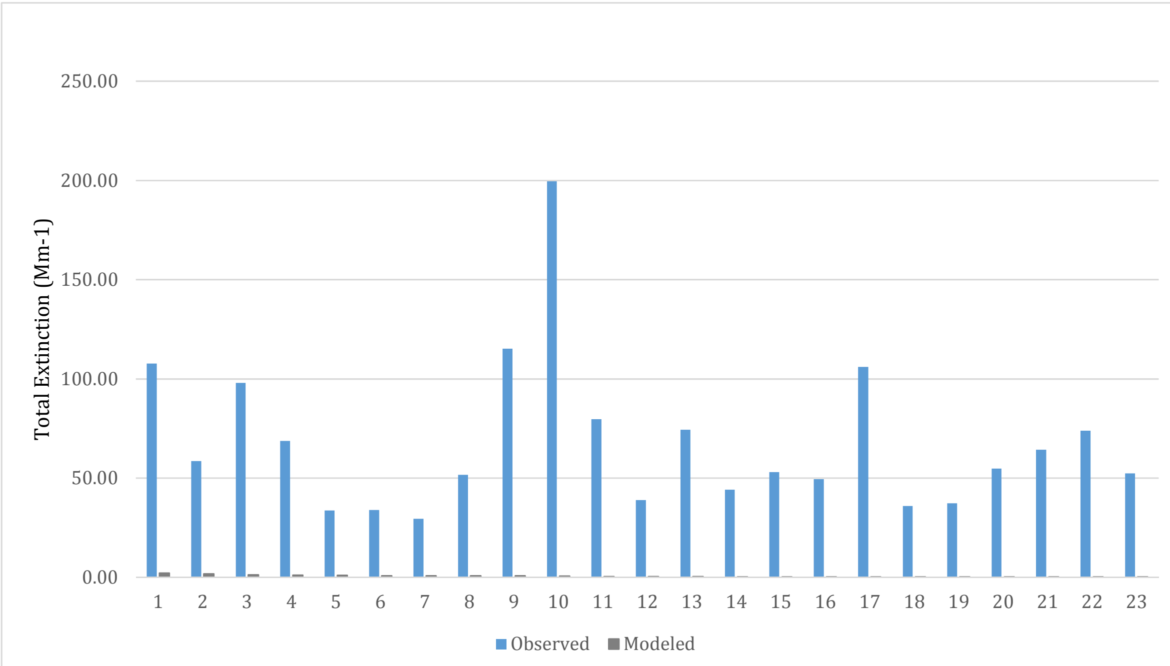
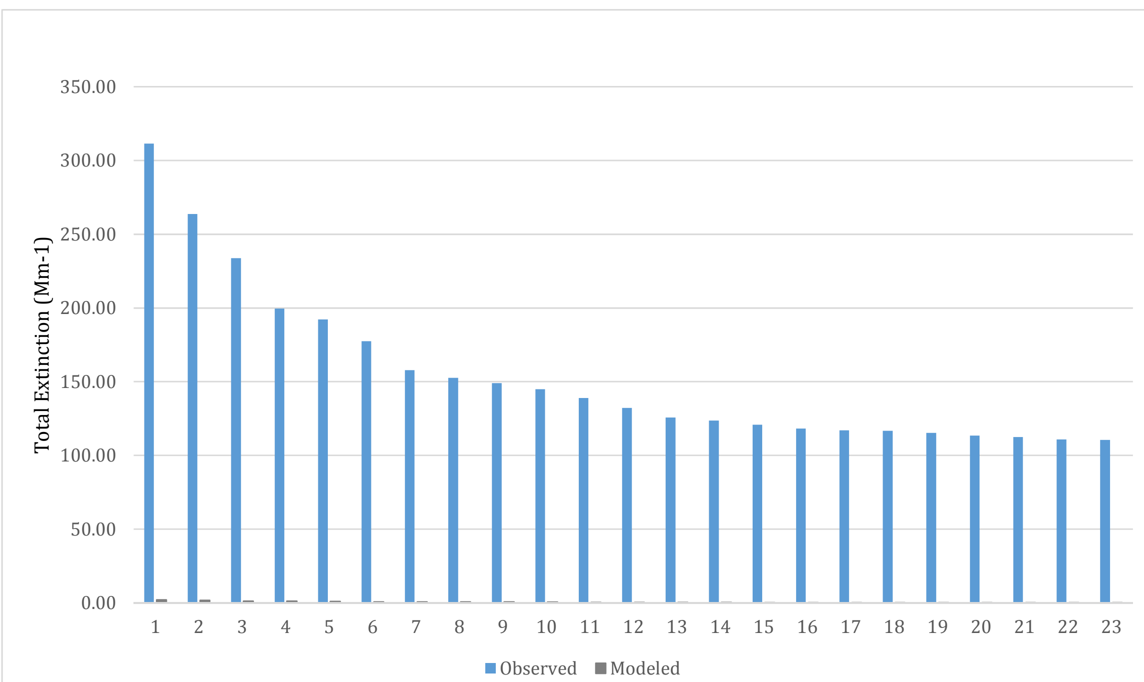


Figure 4-6. Measured and Modeled 20% Worst Days Total Extinction at Upper Buffalo Wilderness Area in 2002 – Lake Catherine Pre-BART



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]

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[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

[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]

[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,

[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.

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 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.

Figure 1. White Bluff Unit 1 Heat Input (MMBtu/yr, 12-month Rolling Values)

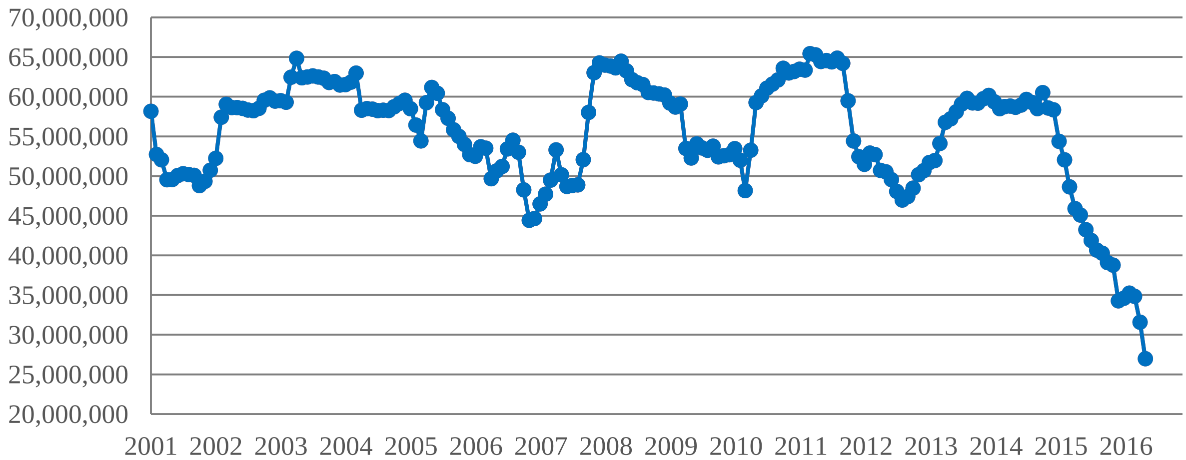
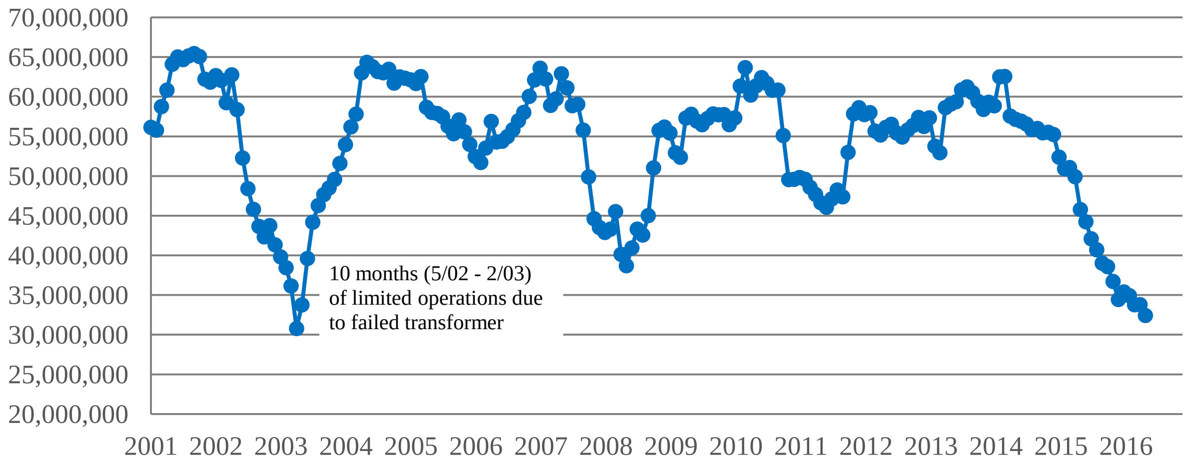


Figure 2. White Bluff Unit 2 Heat Input (MMBtu/yr, 12-month Rolling Values)



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:

TRINITY CONSULTANTS, INC.
5801 E. 41st St., Ste 450
Tulsa, Oklahoma 74135
(918) 622-7111

In conjunction with:

ENTERGY SERVICES, INC.
425 West Capitol Avenue
Little Rock, Arkansas 77201
(501) 377-4000

Trinity Project No. 163701.0067

August 8, 2016

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.

Exhibit 1 to EAI Supplemental Comments

ASSESSMENT OF RECENT CLASS I AREA IMPROVE MONITORING DATA

Prepared By:

TRINITY CONSULTANTS, INC.
5801 E. 41st St. Ste. 450
Tulsa, Oklahoma 74135
(918) 622-7111

In conjunction with:

ENTERGY SERVICES, INC.
425 West Capitol Avenue
Little Rock, Arkansas 77201
(501) 377-4000

Trinity Project No. 163701.0059

August 8, 2016

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

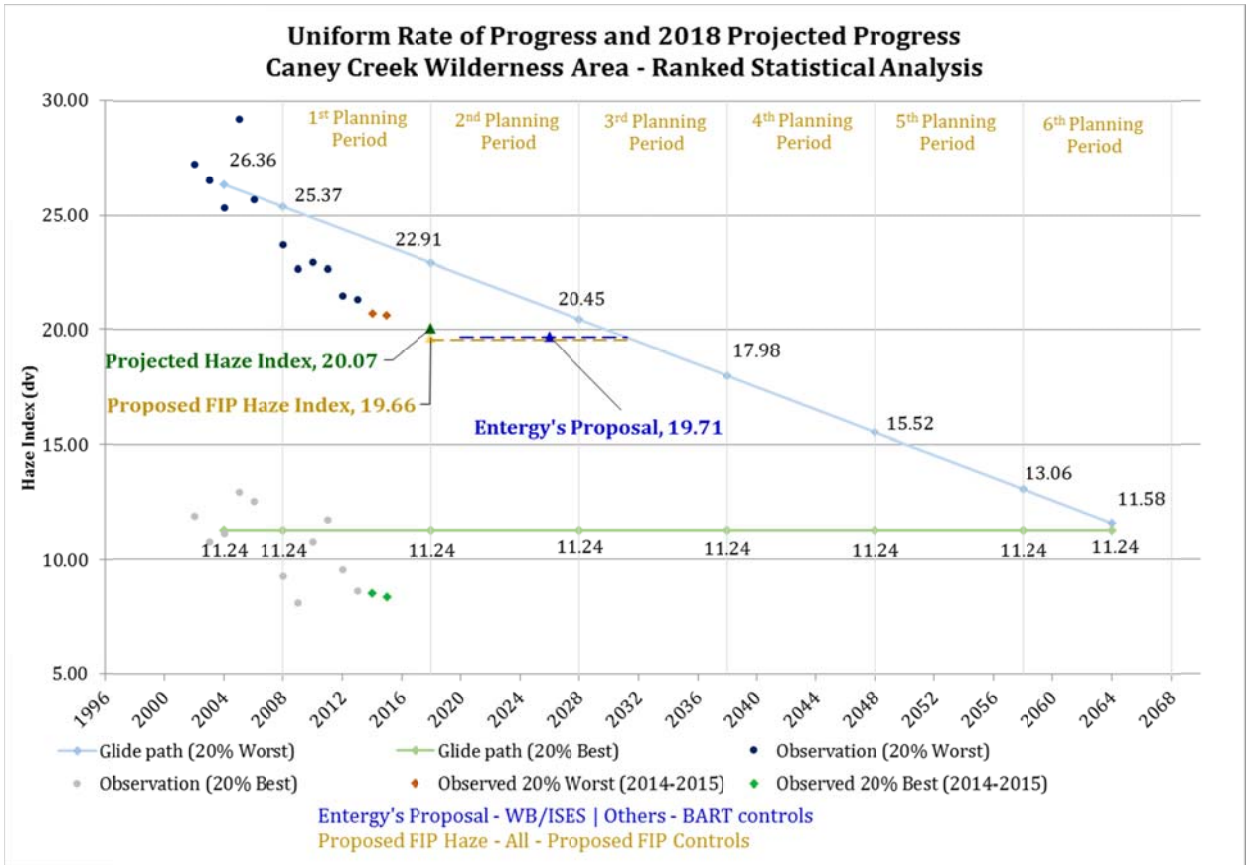
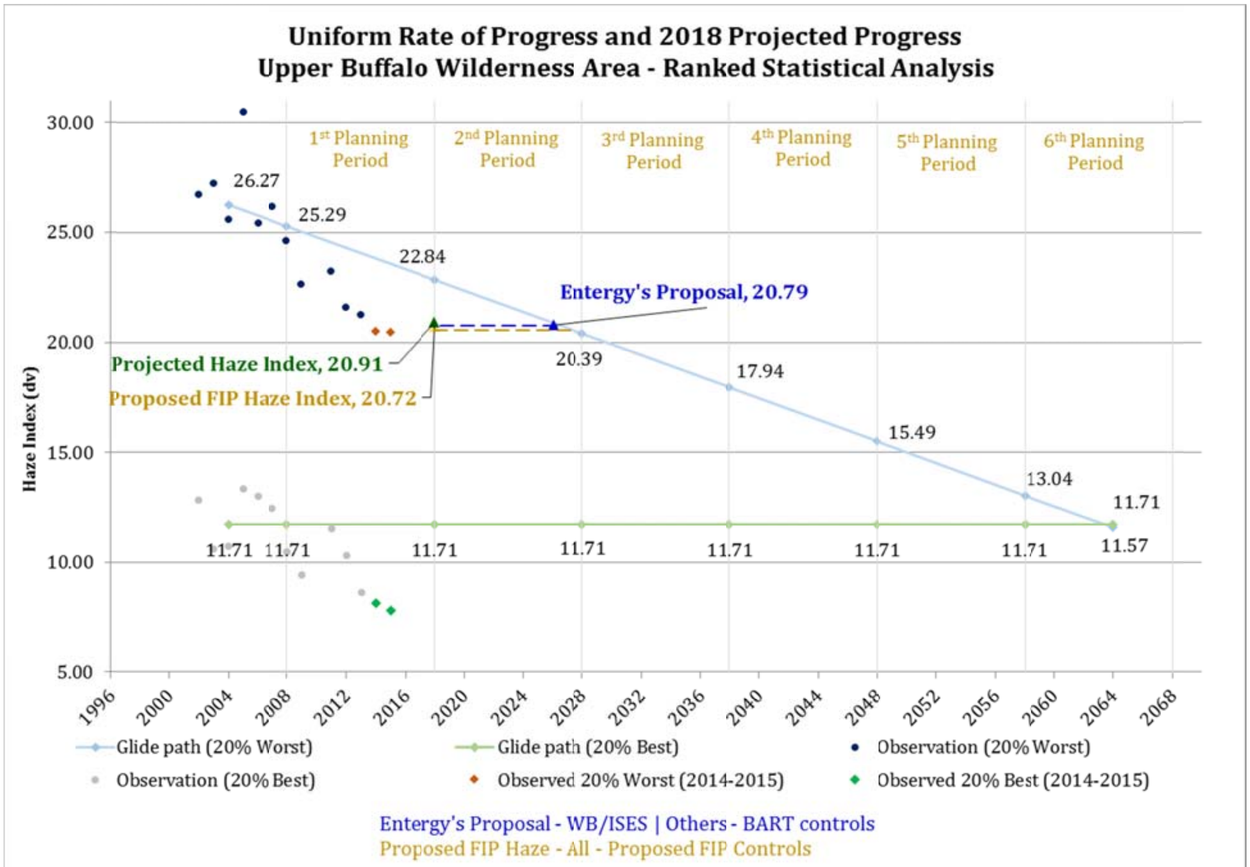


Figure 2. Upper Buffalo Observed Haze Index, Uniform Rate of Progress, and Projected Haze Index



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

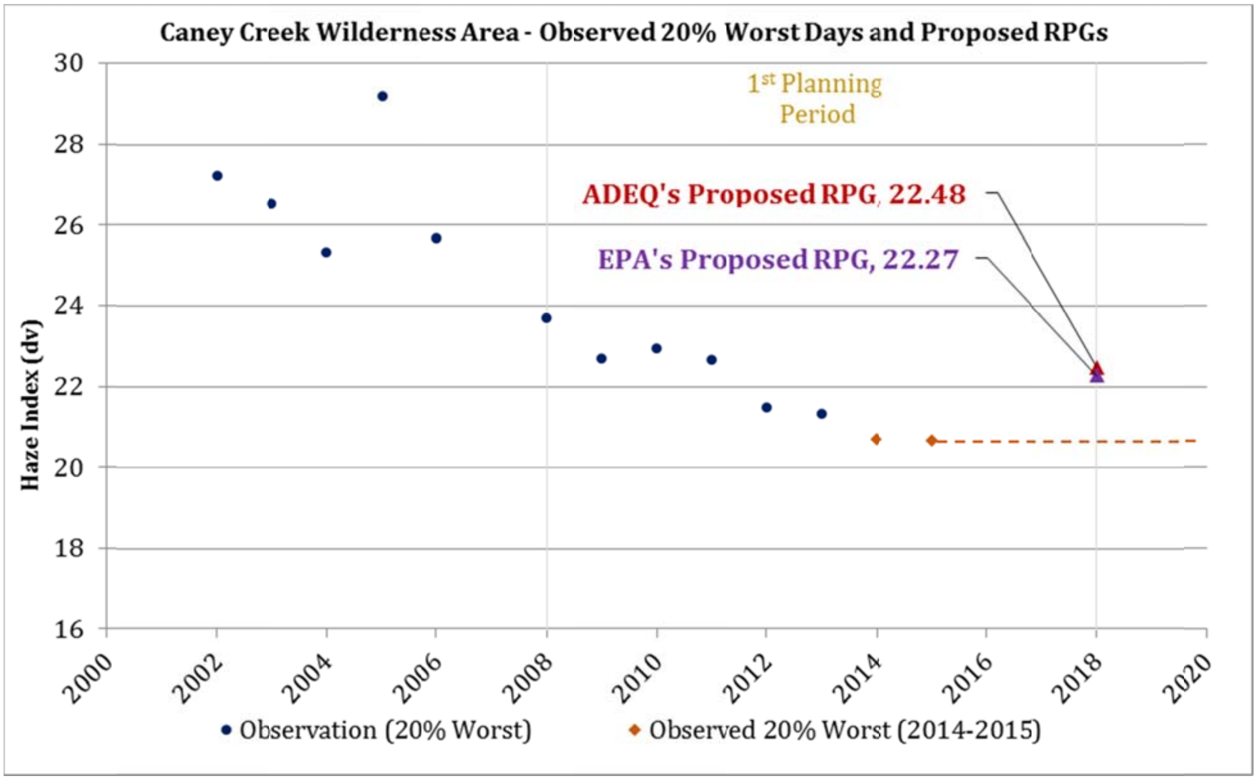
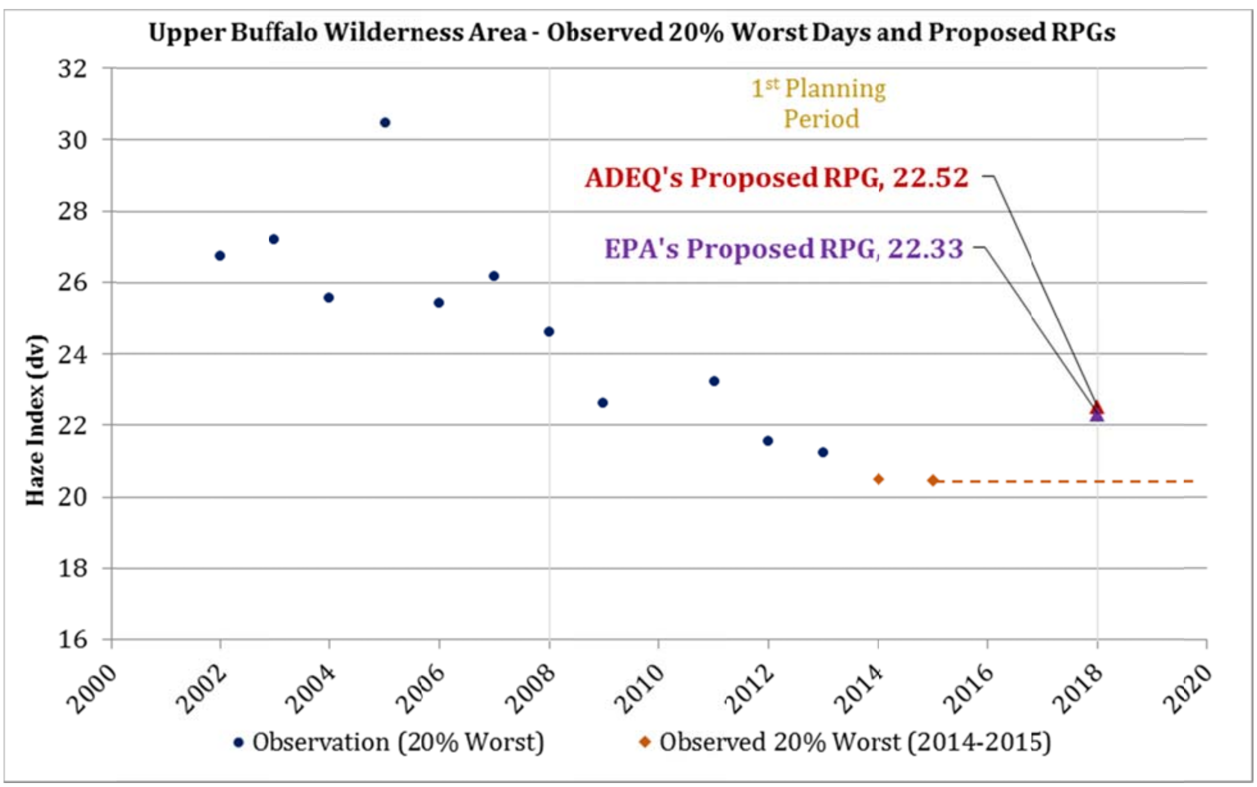


Figure 4. Upper Buffalo Observed Haze Index, 20% Worst Days, and Proposed Reasonable Progress Goals



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	Δ Emission Rate	Incremental reductions	Incremental Annualized Costs	Annualized Costs	Average Cost Effectiveness	Incremental Cost-Effectiveness v. LSC
SN-01 LSC	15939	14,544	1,395			1,600,000.00	1,150	
SN-02 LSC	16034	14,631	1,403			1,610,000.00	1,148	
SN-01 DSI	15939	9,770	6,169	4,774	37065336	38665336	6,268	7764
SN-02 DSI	16034	9,807	6,227	4,824	37062792	38672792	6,211	7683
SN-01 Enhanced DSI	15939	4,187	11,752	10,357	73917909	75517909	6,426	7137
SN-02 Enhanced DSI	16034	4,203	11,831	10,428	73913664	75523664	6,384	7088
SN-01 Dry FGD	15939	1,675	14,264	12,869	75708327	77308327	5,420	5883
SN-02 Dry FGD	16034	1,681	14,353	12,950	75705700	77315700	5,387	5846

	Average Cost Effectiveness
LSC	1149
DSI	6239
Enhanced DSI	6405
Dry FGD	5403

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	12403101	11188811	9580838	13913043
DSI	0.308	0.375	0.341	0.333	125536805	103107563	113388082	116112120
Enhanced DSI	0.492	0.555	0.467	0.436	153491685	136068305	161708585	173206213
SDA	0.603	0.642	0.525	0.504	128206181	120417955	147253956	153389538

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	16597938	12677165	11751825	13196721
DSI	0.274	0.359	0.303	0.333	141141577	107723655	127632977	116134511
Enhanced DSI	0.46	0.531	0.429	0.435	164181878	142229122	176045837	173617618
SDA	0.574	0.632	0.486	0.501	134696341	122334968	159085802	154322754

	Average Cost Per Deciview			
	CACR	UBPU	HERC	MING
LSC	14500519	11932988	10666332	13554882
DSI	133339191	105415609	120510530	116123315
Enhanced DSI	158836782	139148713	168877211	173411916
SDA	131451261	121376462	153169879	153856146

APPENDIX E

BART Five-Factor Analysis for Southwest Power Company Flint Creek

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American Electric Power
1201 Elm Street, Suite 800
Dallas, TX 75270
AEP.com

September 10, 2013

VIA ELECTRONIC SUBMITTAL

Mary Pettyjohn
Arkansas Department of Environmental Quality
5301 Northshore Drive
Little Rock, AR 72118

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

Re: Application for BART Determination for SO_2 and NOx
At the Flint Creek Power Plant, Gentry, Arkansas (AFIN 04-00107)

Dear Ms. Pettyjohn and Ms. Medina:

Below are the responses to each of the questions/requests sent to Southwestern Electric Power Company (SWEPCO) on August 21, 2013, regarding the cost evaluation and proposed emission levels for NO_X control technologies evaluated in the BART five factor analysis for the Flint Creek Power Plant. We also are providing an updated report that incorporates revisions discussed below.

We have summarized and numbered the questions in your August 21, 2013 email to set off the specific responses. If we have misinterpreted your questions, please let us know.

1. *De-escalation of LNB/OFA and SCR Cost Estimates.*

In the enclosed report, we have revised the cost estimates for LNB/OFA and SCR by de-escalating the total annual cost values by three (3) percent per year to present updated costs on a current (2013/2014) basis.

2. *SCR Equipment Life for Capital Recovery*

In the enclosed report, we have revised the cost estimates for SCR to be based on a 30-year life for capital recovery purposes.

3. *LNB/OFA Equipment Life for Capital Recovery*

In the enclosed report, we have revised the cost estimates for LNB/OFA to be based on a 30-year life for capital recovery purposes.

4. *SCR Cost v. Visibility Benefit*

We agree with EPA's assessment that even after the revisions mentioned above, the visibility benefits of SCR do not justify the cost of control.

4. *Emission Level for LNB/OFA*

SWEPCO has requested a 30-day rolling average limitation of 0.23 lb/MMBtu following installation of the LNB/OFA systems at Flint Creek Station, consistent with EPA's determination of the presumptive BART level for this equipment on this type of electric generating unit. SWEPCO submitted information on anticipated levels of controlled NOx emissions from the manufacturer of the LNB/OFA system in support of its request, which ranged from 0.145 – 0.218 lb/MMBtu based on four-hour tests. SWEPCO also submitted actual controlled NO_X emissions data from similar units. EPA agrees that the PacifiCorp Wyodak unit is the most similar to Flint Creek in terms of its uncontrolled emission rate, and agreed that the NO_X emissions for this unit have been as high as 0.21 lb/MMBtu following installation of similar equipment from the same manufacturer. Welsh Unit 2, which is a sister unit to Flint Creek, has also installed equipment from the same manufacturer, and since May of 2005 has measured emissions as high as 0.191 lb/MMBtu.

NO_X emissions are primarily produced as part of the combustion process as a function of the temperature in the combustion zone, and can vary significantly from unit to unit. Pursuing the lowest achievable NO_X emission rates at an electric generating unit can have adverse consequences, including accelerated deterioration of boiler tubes, leading to expensive and time-consuming repairs. In addition, NO_X production is inversely related to the production of CO from the boiler, and pursuing a NO_X rate lower than the requested rate could increase CO production to the point that Flint Creek would need to accept restrictions on its maximum output rating and capacity factor in order to simultaneously achieve both its CO and NO_X limits.

While the requested emission rate is slightly higher than the highest averages achieved at similar units, some margin for compliance is necessary and desirable to accommodate the inherent variability of fuel supply, boiler tune-ups, and attributable to ordinary wear and tear of the equipment. Although the measured performance of Wyodak and Welsh Unit 2 confirms the likely achievability of the requested rate, their current permitted emission limits are as high or higher than the requested rate (0.23 and 0.36 lb/MMBtu, respectively), further confirming that some compliance margin is appropriate. Accordingly, ADEQ should find that the BART emission rate is 0.23 lb/MMBtu, consistent with EPA's determination of presumptive BART and prior BART determinations for similar units.

We hope that this information will satisfactorily address the questions and concerns outlined in the August 21, 2013 email. Please contact me at (214) 777-1113 to provide any additional information you may require.

Sincerely,

KPGaus

Kris Gaus, QEP
Environmental Specialist
Air Quality Services

File:FLC.10.90.50.10.2013

BART Five Factor Analysis

Flint Creek Power Plant

Gentry, Arkansas (AFIN 04-00107)

Prepared By:

Trinity Consultants, Inc.
120 East Sheridan, Suite 205
Oklahoma City, Oklahoma 73104
(405) 228-3292

Trinity Consultants, Inc.
977 Ridge Drive, Suite 380
Lenexa, Kansas 66219
(913) 894-4500

In conjunction with:

American Electric Power Service Corporation
PO Box 660164
Dallas, Texas 72566
(214) 777-1113

for the

Southwestern Electric Power Company
Flint Creek Power Plant
21797 SWEPCO Plant Road
Gentry, Arkansas 72734

Trinity Project Nos. 113701.0022 & 123701.0038

September 2013
Version 4

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1. EXECUTIVE SUMMARY

This report documents the determination of the Best Available Retrofit Technology (BART) for Southwestern Electric Power Company's (SWEPCO's)[1] electric generating unit at the Flint Creek Power Plant (SN-01). SN-01 is a dry bottom wall-fired boiler with a nominal design maximum heat input of 6,324 million British thermal units per hour (MMBtu/hr) that burns primarily low sulfur western coal. The unit has a nominal generating capacity rating of 558 MW and commenced commercial operation in 1978. It is currently equipped with an electrostatic precipitator and low NO_X burners.

Based on modeling performed for this analysis, cumulative emissions of nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter with a mean diameter smaller than ten microns (PM_{10}) from SN-01 are predicted to cause or contribute greater than 0.5 deciviews (Δdv) of visibility impairment in four Class I Areas: Caney Creek Wilderness (CACR), Upper Buffalo Wilderness (UPBU), Hercules Glades Wilderness (HERC), and Mingo Wilderness (MING).

A summary of the existing visibility impairment attributable to SN-01 based on the 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 actual emissions data based on a combination of stack testing and CEMS as further described in Section 4 of this report.

TABLE 1-1. EXISTING VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-01 (2001-2003)

	Caney Creek Wilderness		Upper Buffalo Wilderness		Hercules Glades Wilderness		Mingo Wilderness	
	98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv
AEP Flint Creek SN-01	0.963	48	0.965	63	0.657	47	0.631	20

Trinity used the EPA's BART guidelines in 40 CFR Part 51[2] and other recent EPA guidance to determine BART for SN-01. Trinity conducted a five-step analysis to determine BART 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.

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[1] Southwestern Electric Power Company (SWEPCO) is an owner and the operator of the Flint Creek Power Plant, and a subsidiary of American Electric Power Company, Inc. (AEP). American Electric Power Service Corporation is a subsidiary of AEP that provides legal, accounting, engineering, and other services to the utility operating companies in the AEP system, including SWEPCO. SWEPCO and the Service Corporation are referred to generically as AEP throughout this report.

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

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

- ▲ SO_2 – The BART analysis concluded that the installation of a dry scrubber and baghouse (e.g., Novel Integrated Deacidification System [NIDS] technology) constitutes BART. The proposed BART emission rate for SO_2 is 0.06 lb/MMBtu calculated as a 30-day rolling average over each boiler operating day.
- ▲ NO_X – 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.[3] Subsequently, CSAPR was vacated, and the Clean Air Interstate Rule (CAIR) remains in effect until an acceptable replacement rule is promulgated.[4] If CSAPR is upheld and implemented in Arkansas, SWEPCO will rely on CSAPR to satisfy its regional haze obligations at SN-01. 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 SWEPCO to rely on the seasonal CAIR program to satisfy its NO_X obligations under BART.[5]

  In the alternative, SWEPCO has evaluated the cost-effectiveness and visibility improvement of candidate BART controls at SN-01. The visibility improvements associated with the addition of NO_X controls at SN-01 are minimal, and the cost-effectiveness values for all control options exceed the values previously determined to be reasonable in EPA's presumptive BART analysis. However, visibility improvements consistent with the modeled values used in CENRAP's analysis for the interstate transport portion of Arkansas's Regional Haze SIP obligations can be achieved with the addition of LNB/OFA, and this control option is proposed as BART for SN-01. If ADEQ determines that SWEPCO cannot rely on CAIR or CSAPR as an alternative to BART, the proposed BART emission rate for NO_X at SN-01 is 0.23 lb/MMBtu calculated as a 30-day rolling average over each boiler operating day based on the application of LNB/OFA controls.
- ▲ PM_{10} – A BART determination for PM_{10} at SN-01 was approved in EPA's March 12, 2012 final rule based on the existing ESP and a BART emission rate of 0.1 lb/MMBtu.[6]

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[3] "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).

[4] *EME Homer City Generation, L.P., et al., v. United States Environmental Protection Agency, et al.*,EPA. Case No. 11-1302 (and consolidated cases), *Opinion* (D.C. Cir Aug. 21, 2012).

[5] "Regional Haze Regulations and Best Available Retrofit Technology (BART) Guidelines, 70 Fed. Reg. 39104, 39143 (July 6, 2005).

[6] "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 (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 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[7]. 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:

1. Existing controls
2. Cost of controls

[7] 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

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.

SN-01 meets the three BART-eligibility criteria described above, and the existing visibility impairment attributable to SN-01 is greater than 0.5 dv in at least one Class I area. Thus, SN-01 is subject to BART. The details of the SN-01 existing/baseline emissions and the contribution of the emissions to visibility impairment can be found in Section 4. The VAPs emitted by SN-01 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.

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 protocol included in Appendix C. Note that the protocol included in Appendix C 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:

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

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:

$$b_{ext} = \begin{array}{l} 2.2 f_S(RH)[\text{NH}_4(\text{SO}_4)_2]_{\text{Small}} + 4.8 f_L(RH)[\text{NH}_4(\text{SO}_4)_2]_{\text{Large}} + \\ 2.4 f_S(RH)[\text{NH}_4\text{NO}_3]_{\text{Small}} + 5.1 f_L(RH)[\text{NH}_4\text{NO}_3]_{\text{Large}} + \\ 2.8[\text{OC}]_{\text{Small}} + 6.1[\text{OC}]_{\text{Large}} + 10[\text{EC}] + 1[\text{PMF}] + 0.6[\text{PMC}] + \\ 1.4 f_{SS}(RH)[\text{Sea Salt}] + b_{\text{Site-specific Rayleigh Scattering}} + 0.33[\text{NO}_2] \end{array}$$

Visibility impairment predictions for SN-01 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})
Caney Creek Wilderness	0.23	0.1	1.8	0.02	0.5	3	0.03	11
Upper Buffalo Wilderness	0.23	0.1	1.8	0.02	0.5	3	0.03	11
Hercules Glades Wilderness	0.23	0.1	1.8	0.02	0.5	3	0.02	11
Mingo Wilderness	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
Caney Creek Wilderness	2.77	2.53	2.37	2.43	2.68	2.71	2.59	2.6	2.71	2.69	2.67	2.79
Upper Buffalo Wilderness	2.71	2.48	2.31	2.33	2.61	2.64	2.57	2.59	2.71	2.58	2.59	2.72
Hercules Glades Wilderness	2.7	2.48	2.3	2.3	2.57	2.59	2.56	2.6	2.69	2.54	2.57	2.72
Mingo Wilderness	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
Caney Creek Wilderness	3.85	3.44	3.14	3.24	3.66	3.71	3.49	3.51	3.73	3.72	3.68	3.88
Upper Buffalo Wilderness	3.73	3.33	3.03	3.07	3.54	3.57	3.43	3.5	3.71	3.51	3.52	3.74
Hercules Glades Wilderness	3.7	3.33	3.01	3.01	3.47	3.48	3.41	3.51	3.67	3.43	3.46	3.73
Mingo Wilderness	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
Caney Creek Wilderness	3.9	3.52	3.31	3.41	3.83	3.88	3.69	3.68	3.82	3.76	3.77	3.93
Upper Buffalo Wilderness	3.85	3.47	3.23	3.27	3.72	3.78	3.69	3.7	3.84	3.64	3.67	3.86
Hercules Glades Wilderness	3.86	3.51	3.23	3.22	3.66	3.72	3.69	3.73	3.81	3.57	3.65	3.88
Mingo Wilderness	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 SN-01 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. The emission rates for the PM_{10} species reflect the breakdown of the PM_{10} determined from the National Park Service (NPS) "speciation spreadsheet" for *Dry Bottom Boiler Burning Pulverized Coal using only ESP*[8]. Specifically, the NPS workbook shows the following baseline distribution for the PM species:

- Coarse PM (PM_C) = 33.8 %
- Fine soil (modeled as PM_F) = 26.1 %
- Fine elemental carbon (modeled as EC) = 1.0 %
- Organic condensable PM (modeled as SOA) = 7.8 %
- Inorganic condensable PM (modeled as SO_4) = 31.3 %

Per EPA's request,[9] an SO_4 emission rate was 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.[10] This SO_4 rate was used in the modeling instead of the rate resulting from the NPS-based breakdown.

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

Source	SO_2[11] (lb/hr)	SO_4 (lb/hr)	NO_X[12] (lb/hr)	PM_c (lb/hr)	PM_f (lb/hr)	SOA (lb/hr)	EC (lb/hr)
SN-01	4,728.4	3.1	1,945.0	65.1	50.1	15.1	1.9

[8] 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 192.5 lb/hr, heat value of 8,500 Btu/lb, sulfur content of 0.31%, ash content of 4.9%.

[9] E-mail from Dayana Medina (EPA) to Mary Pettyjohn (ADEQ), February 8, 2013, and phone conversation with Michael Feldman (EPA), February 26, 2013.

[10] Electric Power Research Institute (EPRI) Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: Version 2010a. EPRI, Palo Alto, CA: 2010. 1020636.

[11] Hourly rate was derived from EPA's Clean Air Market Database (CAMD) daily rates of 113,482 lb/day.

[12] Hourly rate was derived from EPA's Clean Air Market Database (CAMD) daily rates of 46,680 lb/day.

4.2 BASELINE VISIBILITY IMPAIRMENT

Trinity conducted modeling to determine the visibility impairment attributable to SN-01 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 SN-01 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.

TABLE 4-2. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-01 BOILER (2001-2003)

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	1.318	0.609	19	62.49	34.95	1.00	1.55
2002	1.165	0.689	10	60.43	35.25	1.72	2.60
2003	1.298	0.963	19	70.90	27.64	0.62	0.85
Upper Buffalo Wilderness							
2001	1.732	0.955	22	53.01	45.08	1.16	0.74
2002	2.426	0.965	18	96.29	2.75	0.96	0.00
2003	1.394	0.670	23	89.90	5.4	2.74	1.97
Hercules Glades Wilderness							
2001	1.418	0.643	19	76.92	22.4	0.69	0.00
2002	1.364	0.627	15	43.49	51.71	2.08	2.72
2003	2.103	0.657	13	47.91	49.69	1.19	1.21
Mingo Wilderness							
2001	1.28	0.631	11	90.97	8.59	0.42	0.01
2002	0.841	0.424	6	93.66	5.94	0.40	0.00
2003	1.488	0.393	3	38.60	59.69	1.07	0.64

5.1 IDENTIFICATION OF AVAILABLE RETROFIT SO_2 CONTROL TECHNOLOGIES

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, 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 SN-01 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 currently uses a low sulfur fuel and would not achieve significant additional reductions through alternative coal supplies.

TABLE 5-1. AVAILABLE SO_2 CONTROL TECHNOLOGIES FOR SN-01

SO_2 Control Technologies
Dry Sorbent Injection
Dry Scrubber
Wet Scrubber

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

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.[13] This control is a technically feasible option for the control of SO_2 from SN-01.

[13] "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.

5.2.2 DRY SCRUBBER

In a dry scrubber, an alkaline reagent (usually lime) and water is introduced into the flue gas stream, where it reacts with SO_2 to form calcium sulfite and calcium sulfate. The liquid-to-gas ratio is such that the heat from the exhaust gas causes the water to evaporate before leaving the scrubber outlet. This leads to the formation of a dry powder which is carried out with the gas and collected with a fabric filter. Existing dry scrubber control efficiencies range from 60 to 95 percent.[14] This is a technically feasible option for the control of SO_2 from SN-01.

There are various designs of dry scrubbing systems. In the spray dryer absorber (SDA) design, a fine mist of lime slurry is atomized into an absorption vessel where the SO_2 is absorbed by the slurry droplets. The mixture of reaction products (calcium sulfite/sulfate), unreacted lime, and fly ash is carried out with the exhaust gas and collected with a fabric filter. Circulating dry scrubbing (CDS) is another type of dry scrubbing. 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 SO_2 in the flue gas with the dry lime particles. As with SDA, the mixture of reaction products (calcium sulfite/sulfate), unreacted lime, and fly ash is carried out with the exhaust gas and collected with a fabric filter. A large portion of the collected particles is recycled to the reactor to sustain the bed and improve lime utilization.

Novel Integrated Deacidification (NID) technology is another particular type of dry scrubber. Hydrated lime is added to recirculated dust in the mixer of the NID system. The solids are sprayed with a thin layer of water in the mixer before being transported to the reactor. The amount of water added is only a few percent which means that the dust remains dry. Hydrated lime reacts with SO_2 in the NID-reactor and leads to the formation of calcium sulfite and calcium sulfate. The flue gas entrained with dry dust material enters the fabric filter where the dust material is captured and clean air is released to atmosphere. Most of the solid material captured is reused in the system. The system has a high recirculation ratio of the dry dust material. Discussions with vendors have indicated that an outlet emission rate of 0.06 lb/MMBtu at Flint Creek will be achievable with the NID technology evaluated. A rate of 0.06 lb/MMBtu represents a 92% control from the baseline 30-day average rate of 0.75 lb/MMBtu. The controlled rate was quoted as an outlet rate rather than a straight percent control.

5.2.3 WET SCRUBBER

Wet scrubbing involves scrubbing the exhaust gas stream with a 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). The liquid-to-gas ratio is such that the exhaust gas is fully saturated with water and

[14] EPA Basic Concepts in Environmental Sciences, Module 6: Air Pollutants and Control Techniques http://www.epa.gov/eogapti1/module6/sulfur/control/control.htm

has a similar appearance to a cooling tower exhaust. Similarly to the chemistry illustrated above for dry scrubbing, the SO_2 in the gas stream is absorbed by water and reacts with the lime or limestone slurry to form calcium sulfite or calcium sulfate. Wet lime scrubbing is capable of achieving 80-95 percent control when used with lower sulfur coals like those burned at SN-01.[15] This control is a technically feasible option for the control of SO_2 from SN-01.

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 their effectiveness in reducing the visibility affecting pollutants (VAP). Table 5-2 provides a ranking of the control levels for the controls listed in the previous section for SN-01.

TABLE 5-2. CONTROL EFFECTIVENESS OF TECHNICALLY FEASIBLE SO_2 CONTROL TECHNOLOGIES

Control Technology	Controlled Emission Rate (lb/MMBtu)	Estimated Control Efficiency
Wet Scrubbing	0.04	95%
Dry Scrubbing, e.g., NID	0.06	92%
Dry Sorbent Injection	0.30	60%

5.4 EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS

A shown in Table 5-2, wet scrubbing can achieve a 95% reduction in SO_2 while dry scrubbing or NID can achieve a 92% reduction in SO_2, and these technologies are the most effective technologies at reducing SO_2. 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:

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

[15] Ibid.

AEP is providing Step 4 and Step 5 evaluations specific to the NID technology as well as WFGD. Also, AEP is providing a discussion of energy and non-air quality impacts of wet scrubbing versus the NID technology.

5.4.1 COST OF COMPLIANCE

Control Costs

The capital and operating costs of WFGD and NID used in the cost effectiveness calculations were estimated based on EPA's Air Pollution Control Cost Manual supplemented with vendor and site-specific information where available. 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.

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 is the average rate from 2001-2003, as reported by AEP in their air emission inventories. The controlled annual emission rates were based on lb/MMBtu levels believed to be achievable for the control technology multiplied by the baseline heat input in MMBtu/yr to the boiler. The baseline heat input is based on the 2001-2003 average daily heat input for SN-01 as determined from the EPA's Clean Air Markets Database (CAMD), divided by 24 hours in a day times an estimated 7,752 hours per year, the average number of operating hours from 2001-2003.

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 the wet scrubber at an SO_2 rate of 0.04 lb/MMBtu is approximately $4,900 per ton of SO_2 removed. The cost effectiveness in dollars per deciview of visibility is over $476 million/dv across the Class I areas, as seen in Table 5-4.

By comparison, Table 5-3 shows the cost effectiveness of a NIDS at an SO_2 rate of 0.06 lb/MMBtu is approximately $3,800 per ton of SO_2 removed. The cost effectiveness in dollars per deciview is approximately $368 million/dv across the Class I areas, as seen in Table 5-5. Table 5-3 shows that the wet scrubber is approximately $35,000/ton incrementally more expensive than the dry scrubber.

TABLE 5-3. SUMMARY OF COST EFFECTIVENESS FOR SN-01 SO_2 CONTROLS

Control Technology	Baseline Emission Rate	Controlled Emission Level	Annual Heat Input	Controlled Emission Rate	SO_2 Reduced	Capital Cost	Capital Recovery + Other Indirect Annual Costs	Annual Fixed O&M	Annual Variable O&M	Total Annual Cost	Cost Effectiveness	Incremental Cost
	(tpy)	(lb/MMBtu)	(MMBtu/yr)	(tpy)	(ton/yr)	($)	($/yr)	($/yr)	($/yr)	($/yr)	($/ton)	($/ton)
NIDS	11,641.00	0.06	37,344,783	1,120.34	10,520.66	281,738,024	30,763,370	205,825	9,478,894	40,448,089	3,845	-
Wet Scrubber	11,641.00	0.04	37,344,783	746.90	10,894.10	374,427,351	40,884,248	205,825	12,502,590	53,592,663	4,919	35,198

TABLE 5-4. DOLLAR PER DECIVIEW COST EFFECTIVENESS FOR SN-01 SO_2 CONTROLS OF WET SCRUBBING

Class I Area	Baseline 98th Percentile Δdv	WFGD Controlled 98th Percentile Δdv	Improvement in 98th Percentile Δdv	Total Annual WFGD Cost	$/dv
Caney Creek	0.963	0.334	0.629	53,592,663	$ 85,202,962
Hercules-Glades	0.657	0.305	0.352	53,592,663	$ 152,251,885
Mingo	0.631	0.208	0.423	53,592,663	$ 126,696,604
Upper Buffalo	0.965	0.488	0.477	53,592,663	$ 112,353,592

TABLE 5-5. DOLLAR PER DECIVIEW COST EFFECTIVENESS FOR SN-01 SO_2 CONTROLS OF NIDS

Class I Area	Baseline 98th Percentile Δdv	NID Controlled 98th Percentile Δdv	Improvement in 98th Percentile Δdv	Total Annual NID Cost	$/dv
Caney Creek	0.963	0.348	0.615	40,448,089	$ 65,769,251
Hercules-Glades	0.657	0.312	0.345	40,448,089	$ 117,240,838
Mingo	0.631	0.217	0.414	40,448,089	$ 97,700,699
Upper Buffalo	0.965	0.501	0.464	40,448,089	$ 87,172,606

5.4.2 Energy Impacts and Non-Air Quality Impacts

Wet scrubbing is expected to achieve a slightly higher level of control of SO_2 emissions compared to the proposed NID technology. However, the negative non-air quality environmental impacts are greater with wet scrubbing systems. Wet scrubbers require increased water use and generate large volumes of wastewater and solid waste/sludge that must be 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 before landfilling. Wet scrubbing systems have increased power requirements and increased reagent usage over dry scrubbers. Wet scrubber-controlled systems also have the potential for increased particulate and sulfuric acid mist releases. Thus, from an overall environmental perspective, dry scrubbing (i.e., NID technology) is superior to wet scrubbing.

5.4.3 Remaining Useful Life

The remaining useful life of SN-01 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, which is 30 years based on EPA cost estimates.

5.5 Evaluation of Visibility Impact of Feasible SO_2 Controls

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. In order to assess the visibility improvement associated with the considered control options, the controlled SO_2 emission rates were modeled using CALPUFF.

The SO_2 emission rate associated with the NID for SN-01 is detailed as follows:

$$P * HI = 379.44 \text{ lb/hr}$$

Where:
P (controlled emission level) = 0.06 lb/MMBtu
HI (hourly heat input) = 6,324 MMBtu/hr

Table 5-6 summarizes the lb/hr emission rates that were modeled to reflect the addition of NIDS as a control at Flint Creek. The SO_2 rate was developed from the controlled rate of 0.06 lb/MMBtu and the boiler heat input of 6,324 MMBtu/hr. The SO_4 emission rate was determined assuming the reduction in SO_4 from the baseline case is proportional to the reduction in SO_2 from the baseline case to the controlled case (92%). The NIDS will have co-effects on some of the acid gases. The control of H_2SO_4 will result in fewer sulfates. The NO_X emission rate was modeled at the baseline rate. The NIDS involves the use of a baghouse. The change from the current ESP to baghouse will result in changes in PM speciation. All other rates that changed from the baseline case were determined using the National Parks Services (NPS) speciation spreadsheets for dry bottom boilers burning pulverized coal using only fabric filter for emissions control.

Table 5-6 also summarizes the emission rates that were modeled to reflect the addition of a wet scrubber on SN-01, at an outlet emission rate of 0.04 lb/MMBtu. The SO_2 rate was developed by multiplying the controlled level of 0.04 lb/MMBtu by the boiler heat input of 6,324 MMBtu/hr. The NO_X emission rates were modeled at the baseline rates. The PM rates that changed from the baseline case were determined using the NPS speciation spreadsheets for dry bottom boilers burning pulverized coal using only fabric filter for emissions control. The SO_4 rates were calculated using the same EPRI methodology used for the baseline case.

TABLE 5-6. SUMMARY OF EMISSION RATES MODELED TO REFLECT SO_2 CONTROLS

Control Technology	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)
NIDS	379.4	0.004	1,945.0	35.2	33.9	24.4	1.3
Wet Scrubber	253.0	0.11	1,945.0	35.2	33.9	24.4	1.3

Comparisons of the existing visibility impacts and the visibility impacts based on the NIDS, 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 5-7.

TABLE 5-7. 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	1.318	0.963	48	2.426	0.965	63	2.103	0.657	47	1.488	0.631	20
NIDS	0.753	0.348	6	1.474	0.501	13	0.882	0.312	5	0.694	0.217	4
Post Control Improvement	*0.565*	*0.615*	*42*	*0.952*	*0.464*	*50*	*1.221*	*0.345*	*42*	*0.794*	*0.414*	*15*
Wet Scrubber	0.746	0.334	5	1.446	0.488	11	0.845	0.305	5	0.677	0.208	4
Post Control Improvement over NIDS	*0.007*	*0.014*	*1*	*0.028*	*0.013*	*2*	*0.037*	*0.007*	*0*	*0.017*	*0.009*	*0*

Note: The visibility improvement shown in the table has been calculated from baseline and controlled impacts that include more decimal places than what is shown in the table. Due to rounding of the baseline and controlled impacts shown in the table, the visibility improvement calculated from the baseline and controlled impacts shown in the table may be slightly different than the visibility improvement reflected in the table.

As shown in Table 5-7, based on visibility predictions from the CALPUFF modeling system, the operation of a dry scrubber will result in up to a 0.647 Δdv improvement (98th percentile basis) (depending on the Class I area) to the existing visibility impairment attributable to SN-01. By comparison, wet scrubbing does not add additional visibility improvement for SN-01 over dry scrubbing. The reason wet scrubbing, despite the lower SO_2 emission rate, does not produce greater visibility improvement is because it results in other visibility impairing emissions.[16]

5.6 PROPOSED BART FOR SO_2

SWEPCO is proposing that the SO_2 BART emission rate for SN-01 be 0.06 lb/MMBtu, based on the installation and operation of the NID technology. AEP is proposing to meet this limit calculated as a 30-day rolling average over each boiler operating day. Compliance will be demonstrated using data from the existing continuous emissions monitoring systems (CEMS).

The visibility improvement attributable to SN-01 through the use of the NIDS ranges from 48.1% to 65.6% across the affected Class I areas (98th percentile basis). This level of improvement is achievable at a cost effectiveness of approximately $3,800 per ton of SO_2 removed. By comparison, wet scrubbing is incrementally more expensive and offers less visibility improvement overall. In addition, the adverse environmental impacts from the use of wet scrubbing, including an increase in particulate and sulfuric acid mist emissions as well as increased water and energy usage and wastewater to be treated, make dry scrubbing a more appealing option.

5.6.1 COMPARATIVE SO_2 BART DETERMINATIONS

The BART emission level proposed for SN-01 is among the most stringent BART emission levels approved for any coal-fired generating unit over the last two years. In Oklahoma, for similar boilers, EPA determined BART to be 0.06 lb/MMBtu achieved through use of dry scrubbers.[17] In Nebraska[18] at the Gerald Gentleman Station, BART for SO_2 was also determined to be 0.06 lb/MMBtu achieved through use of dry scrubbers. These similar units provide a good comparison of emission levels achievable through similar control technology. Levels lower than 0.06 lb/MMBtu have been considered, but rejected based on lack of operating experience on retrofit units, the incremental cost of additional reductions, and the limited incremental visibility improvement associated with those costs. AEP has no data to suggest that lower emission levels are sustainably achievable with the NID technology in a retrofit application, and has not been guaranteed any better performance by equipment vendors. All of these reasons support rejecting any lower emission level for SN-01.

Other BART determinations have resulted in higher emission limitations. For example, in Alabama[19] a smaller EGU was allowed an emission limitation of 0.47 lb/MMBtu through use of flue sorbent injection or comparable technologies. In Arizona[20], SO_2 BART was determined to be in the range of

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[16] Wet scrubbers have less affinity for acid mist than dry scrubbers; thus, sulfate particles that form from sulfuric acid in the stack will be lower for dry scrubbers than wet scrubbers. AEP's best understanding of the reason wet scrubbing does not produce greater visibility improvement that drying scrubbing, despite the lower SO_2 rate, is that the SO_4 rate associated with wet scrubbing is higher.

[17] 77 Fed. Reg. 16168 (March 22, 2011).

[18] 77 Fed. Reg. 40150 (July 6, 2012).

[19] 77 Fed. Reg. 11937 (Feb. 28, 2012).

[20] 77 Fed. Reg. 42834 (July 20, 2012).

0.08 – 0.15 lb/MMBtu from existing wet scrubbers. An EGU in Colorado[21] has a proposed BART emission rate of 0.13 lb/MMBtu through use of dry scrubbing. It is interesting to note that a lower emission rate of 0.09 lb/MMBtu was evaluated and determined not reasonable due to the little visibility improvement as compared to the higher costs between scrubbing at these two rates.

In other determinations, such as Illinois[22], 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[23] 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[24] similar to AEP's SN-01 has a BART emission rate of 0.08 lb/MMBtu.

The proposed SO_2 BART emission rate is equivalent to the most stringent rates previously approved by EPA, is consistent with the design specifications for this equipment, and results in significant visibility improvement in the affected Class I areas. The SO_2 emission rate of 0.06 lb/MMBtu should be adopted as BART for SN-01.

[21] 77 Fed. Reg. 18052 (March 26, 2012).

[22] 77 Fed. Reg. 3966 (Jan. 26, 2012).

[23] 77 Fed. Reg. 52604 (Aug. 23, 2011).

[24] 77 Fed. Reg. 23988 (April 20, 2012).

6. NO_X BART EVALUATION

6.1 CROSS-STATE AIR POLLUTION RULE, CLEAN AIR INTERSTATE RULE, AND BART

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."[25] 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, combustion controls would run anytime the unit is in operation. However, on August 21, 2012, the D. C. Circuit Court of Appeal issued a decision vacating CSAPR and ordering EPA to continue to implement the Clean Air Interstate Rule (CAIR) until a new rule is adopted to replace it. The Court's decision will not be effective until the time for filing rehearing petitions has passed, or any filed petitions for rehearing have been considered by the Court.[26] If CSAPR is upheld and implemented in Arkansas, SWEPCO proposes rely on CSAPR to satisfy its regional haze obligations at SN-01.

Prior to adopting CSAPR, EPA issued a rule confirming that CAIR provides greater reasonable progress toward the national visibility goal than application of BART for NO_X emissions at BART-eligible sources.[27] Since EPA has made the determination that CAIR reductions provide better progress than BART, and Arkansas has adopted the CAIR requirements into the Arkansas SIP,[28] SWEPCO should be entitled to rely upon CAIR to satisfy its obligations for NO_X reductions at SN-01, if CSAPR is vacated in accordance with the D. C. Circuit's opinion.

In the alternative, SWEPCO has evaluated the cost-effectiveness and visibility improvement of candidate BART controls at SN-01. The visibility improvements associated with the addition of NO_X controls at SN-01 are minimal, and the cost-effectiveness values for all control options exceed the values previously determined to be reasonable in EPA's presumptive BART analysis. However, visibility improvements consistent with the modeled values used in CENRAP's analysis for the interstate transport portion of Arkansas's Regional Haze SIP obligations can be achieved with the addition of newer generation LNB/OFA systems, and are proposed as BART for SN-01. If ADEQ determines that SWEPCO cannot rely on CAIR or CSAPR as an alternative to BART, the proposed BART emission rate for NO_X at SN-01 is 0.23 lb/MMBtu calculated as a 30-day rolling average over each boiler operating day based on the application of LNB/OFA controls.

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[25] "Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available Retrofit Technology (BART) Determination, Limited SIP Disapprovals, and Federal Implementation Plans," 77 Fed. Reg. 33651 (June 7, 2012).

[26] *EME Homer City v. EPA,* Case No. 11-1302 and consolidated cases, *Opinion*, (D.C. Cir. Aug. 21, 2012).

[27] 70 Fed. Reg. 39104, 39136-37, and 39143 (July 6, 2005).

[28] APC&EC Reg. 19.1401 *et seq.*; approved at 72 Fed. Reg. 54556 (Sept. 26, 2007).

6.2 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 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 a wall-fired boiler, such as SN-01, burners are mounted in the boiler walls, producing discrete flames in the furnace. In tangentially-fired boilers, 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 and also 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.

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), 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

NO_X Control Technologies	
Combustion Controls	Flue Gas Recirculation (FGR) Overfire Air (OFA) Low NO_X Burners (LNB)
Post-Combustion Controls	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR)

6.3 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 emission levels from literature were higher than the baseline NO_X rate at SN-01, vendor estimates were also used to assist in developing the expected emission rates from the known relationships between the control options.

6.3.1 COMBUSTION CONTROLS

6.3.1.1 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. When operated without additional controls, the NO_X control range for coal fired boilers with FGR is approximately 5-25% for coal fired boilers, or 0.23-0.29 lb/MMBtu from SN-01.[29] This control is a technically feasible option for the control of NO_X from SN-01.

6.3.1.2 OVERFIRE AIR (OFA)

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. OFA as a single NO_X control technique results in estimated NO_X emissions for coal fired boilers of approximately 10%, or 0.28-0.29 lb/MMBtu from SN-01.[30] This control is a technically feasible option for the control of NO_X from SN-01.

6.3.1.3 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.[31] 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.

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[29] "Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options." Utility Boiler section. July 1994.

[30] Ibid.

[31] http://www.energysolutionscenter.org/boilerburner/Workshop/RCTCombustion.htm.

The estimated NO_X control range for LNBs on coal boilers is 0.20-0.26 lb/MMBtu.[32] When combined with OFA, the estimated NO_X control range on is 0.18-0.24 lb/MMBtu.[33] LNB systems are technically feasible for the control of NO_x from SN-01.

6.3.2 POST COMBUSTION CONTROLS

6.3.2.1 SELECTIVE CATALYTIC REDUCTION

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. The estimated NO_X control for SCR on coal fired boilers is 80-90%, and is consistent with vendor estimates of 0.067 lb/MMBtu at SN-01, resulting in an 80% control efficiency.[34] Control efficiencies of 80-90% depend on the design of the boiler as well as the starting baseline emissions. The vendor was able to provide an estimate of control as an outlet emission level of 0.067 lb/MMBtu, a low emission level. A 90% percent reduction would result in an outlet emission rate of 0.03 lb/MMBtu and has not been guaranteed by a vendor. This control is a technically feasible option for the control of NO_X from SN-01.

6.3.2.2 SELECTIVE NON-CATALYTIC REDUCTION

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 to four times as much reagent as SCR systems to achieve similar NO_X reductions. The estimated NO_X control range for SNCR for coal fired boilers is 0.18-0.27 lb/MMBtu.[35] This control is a technically feasible option for the control of NO_X from SN-01.

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32 "Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options." Utility Boiler section. July 1994.

33 Ibid.

34 Ibid.

35 Ibid.

6.4 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 SN-01.

TABLE 6-2. CONTROL EFFECTIVENESS OF TECHNICALLY FEASIBLE NO_X CONTROL TECHNOLOGIES

Control Technology	Estimated Controlled Level for SN-01 (lb/MMBtu) [36]
SCR	0.067
LNB/OFA + SNCR	0.18-0.23 [37]
LNB/OFA	0.18-0.24
SNCR	0.18-0.27
FGR	0.23-0.29
LNB	0.20-0.26
OFA	0.28-0.29

With the exception of the control level for SCR, the control levels in Table 6-2 are presented as ranges. This is due to the fact that the specific level of control that is achievable for SN-01 based on the application of the controls listed in Table 6-2 is unknown. Based on several discussions between AEP Flint Creek and the Babcock and Wilcox Company, it is believed that combustion controls such as LNB in combination with OFA will achieve a NO_X level of approximately 0.23 lb/MMBtu for SN-01. EPA established presumptive SO_2 and NO_X controls for coal-fired EGUs in the BART rule. For dry-bottom wall-fired EGUs, the presumptive NO_X limit is 0.23 lb/MMBtu.[38] The presumptive BART emission rate was modeled for this source by CENRAP. Although 0.23 lb/MMBtu is the presumptive limit for a unit like SN-01, the presumptive limit was not automatically assumed the floor for combustion control on SN-01. Rather, experience with similar boilers and vendor discussions have led the selection of this emission level. Current NO_X emissions from SN-01 are approximately 0.31 lb/MMBtu. Further, it is believed that SCR will achieve a NO_X level of approximately 0.067 lb/MMBtu and LNB/OFA + SNCR will achieve a level of 0.2 lb/MMBtu or 10-20% better control than from LNB/OFA alone. Vendor estimates for LNB/OFA + SNCR were not available at the time of this analysis, and obtaining vendor estimates would add significantly to the timing of this analysis submittal.

6.5 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:

[36] Ibid.

[37] "Preferred and Alternative Methods for Estimating Air Emissions from Boilers." Volume II: Chapter 2. January 2001.

[38] Ibid.

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

6.5.1 COST OF COMPLIANCE

The capital costs, operating costs, and cost effectiveness of LNB/OFA, LNB/OFA + SNCR and SCR were estimated for the cost analysis.

<u>Control Costs</u>
The capital and operating costs of the controls that were used in the cost effectiveness calculations were estimated based on vendor estimates and published calculation methods. The EPA Air Pollution Control Cost Manual was followed to the extent possible and was supplemented with vendor and site-specific information where available. The capital costs were annualized over a 30-year period for LNB/OFA, over a 30-year period for SCR, and over a 20-year period for SNCR, and then added to the annual operating costs to obtain the total annualized costs. All predicted costs were de-escalated to a current (2013) basis assuming three (3) percent per year. The details of the capital and operating cost estimates are provided in Appendix B of this report.

<u>Annual Tons Reduced</u>
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 is the average rate as reported by AEP in the 2001-2003 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 baseline heat input to the boiler in MMBtu/yr. The baseline heat input is based on the 2001-2003 average daily heat input for SN-01 as determined from the EPA's Clean Air Markets Database (CAMD), divided by 24 hours in a day times an estimated 7,752 hours per year, the average number of operating hours from 2001-2003.

<u>Cost Effectiveness</u>
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 costs between SCR and an LNB/OFA system, as well as between LNB/OFA + SNCR and LNB/OFA. 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.[39] 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.[40]

Table 6-3 indicates that the cost effectiveness of LNB/OFA at a NO_X rate of 0.23 lb/MMBtu is $1,762 per ton of NO_X removed. Table 6-3 also indicates that the costs for LNB/OFA/SNCR for SN-01 is approximately $3,100 per ton of NO_X removed and SCR for SN-01 is more than $3,500 per ton of NO_X removed. Additionally, the incremental cost of the LNB/OFA/SNCR over the LNB/OFA system is greater than $5,200 per ton of NO_X removed for SN-01. The incremental cost of SCR over the LNB/OFA system is greater than $4,000 per ton of NO_X removed for SN-01.

The cost effectiveness in dollars per deciview of visibility improvement attributable to the each NO_X control technology was also determined. Additional details on the visibility improvement analysis are provided below. The cost of LNB/OFA is approximately $233 million/dv across the Class I areas, as seen in Table 6-4. The cost of LNB/OFA plus SNCR is approximately $506 million/dv across the Class I areas, as seen in Table 6-5. Table 6-6 shows that control of NO_X from SCR results in a cost of approximately $737 million/dv across the Class I areas. So a review of cost effectiveness on a dollars per deciview basis reveals that both post-combustion control options are prohibitively expensive relative to the LNB/OFA control option.

[39] "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART Determinations; Final Rule." CFR Vol. 77, No. 128. Wednesday, July 6, 2005, Rules and Regulations. Pages 39134-39135.

[40] Ibid.

TABLE 6-3. SUMMARY OF COST EFFECTIVENESS FOR SN-01 NO_X CONTROLS

	Baseline Emission Rate	Controlled Emission Level	Annual Heat Input[4]	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 (v. LNB/OFA)
	(tpy)	(lb/MMBtu)	(MMBtu/yr)	(tpy)	(ton/yr)	($)	($/yr)	($/yr)	($/yr)	($/yr)	($/ton)	($/ton)
LNB/OFA[1]	5,120.27	0.23	37,344,783	4294.65	825.62	16,000,000	1,289,382	240,000	132,364	1,454,621	1,762	-
LNB/OFA/SNCR[2]	5,120.27	0.20	37,344,783	3771.82	1348.45	23,124,235	1,961,860	240,000	2,183,048	4,177,782	3,098	5,209
SCR[3]	5,120.27	0.07	37,344,783	1251.05	3869.22	121,440,000	9,786,413	1,560,000	3,700,000	13,769,599	3,559	4,046

[1] LNB Cost information: Please refer to Appendix B.
[2] SNCR Cost information: Please refer to Appendix B.
[3] SCR Cost information: Please refer to Appendix B.
[4] Baseline heat input was determined from CAMD, 2001-2003, average daily heat inputs times the average number of operating hours from 2001-2003 divided by 24 hours in a day.

TABLE 6-4. DOLLAR PER DECIVIEW COST EFFECTIVENESS FOR SN-01 NO_X CONTROL USING LNB/OFA

Class I Area	Baseline 98th Percentile Δdv	LNB/OFA Controlled 98th Percentile Δdv	Improvement in 98th Percentile Δdv	Total Annual LNB/OFA Cost	$/dv
Caney Creek	0.963	0.849	0.114	1,454,621	$ 12,759,831
Hercules-Glades	0.657	0.633	0.024	1,454,621	$ 60,609,198
Mingo	0.631	0.617	0.014	1,454,621	$ 103,901,483
Upper Buffalo	0.965	0.939	0.026	1,454,621	$ 55,946,952

TABLE 6-5. DOLLAR PER DECIVIEW COST EFFECTIVENESS FOR SN-01 NO_X CONTROL USING LNB/OFA PLUS SNCR

Class I Area	Baseline 98th Percentile Δdv	LNB/OFA/SNCR 98th Percentile Δdv	Improvement in 98th Percentile Δdv	Total Annual LNB/OFA + SNCR Cost	$/dv
Caney Creek	0.963	0.849	0.114	4,177,782	$ 36,647,214
Hercules-Glades	0.657	0.623	0.034	4,177,782	$ 122,875,952
Mingo	0.631	0.612	0.019	4,177,782	$ 219,883,283
Upper Buffalo	0.965	0.932	0.033	4,177,782	$ 126,599,466

TABLE 6-6. DOLLAR PER DECIVIEW COST EFFECTIVENESS FOR SN-01 NO_X CONTROL USING SCR

Class I Area	Baseline 98th Percentile Δdv	SCR Controlled 98th Percentile Δdv	Improvement in 98th Percentile Δdv	Total Annual SCR Cost	$/dv
Caney Creek	0.963	0.718	0.245	13,769,599	$ 56,202,446
Hercules-Glades	0.657	0.573	0.084	13,769,599	$ 163,923,800
Mingo	0.631	0.588	0.043	13,769,599	$ 320,223,238
Upper Buffalo	0.965	0.895	0.07	13,769,599	$ 196,708,560

6.5.2 ENERGY IMPACTS & NON-AIR IMPACTS

SCR 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 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. 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.

6.5.3 REMAINING USEFUL LIFE

The remaining useful life of SN-01 does not impact the annualized capital costs of potential controls because the useful life of the boiler is anticipated to be at least as long as the capital cost recovery period, which is 30 years for LNB/OFA and SCR and 20 years for SNCR.

6.6 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/OFA, LNB/OFA/SNCR and SCR systems. Section 4 of this report documented the existing visibility impairment attributable to SN-01. In order to assess the visibility improvement associated with LNB/OFA, SCR and SNCR systems, the NO_X emission rates associated with both LNB and SCR systems were modeled using CALPUFF. The controlled emission level associated with SCR systems is 0.067 lb/MMBtu for SN-01. The controlled emission level associated with the LNB/OFA system is 0.23 lb/MMBtu, and for LNB/OFA/SNCR is 0.21 lb/MMBtu. These levels were multiplied by the maximum heat input to derive hourly the hourly emission rates used in the modeling.

Tables 6-7 through 6-9 summarize the NO_X emission rates that were modeled to reflect the LNB/OFA SCR and LNB/OFA/SNCR systems, respectively. The emission rates for the other pollutants shown in Tables 6-7 through 6-9 are the same as in the baseline modeling.

TABLE 6-7. SUMMARY OF EMISSION RATES MODELED TO REFLECT LNB/OFA 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)
4,728.4	3.1	1,454.5	65.1	50.1	15.1	1.9

TABLE 6-8. SUMMARY OF EMISSION RATES MODELED TO REFLECT 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)
4,728.4	3.1	423.7	65.1	50.1	15.1	1.9

TABLE 6-9. SUMMARY OF EMISSION RATES MODELED TO REFLECT LNB/OFA + 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)
4,728.4	3.1	1,277.74	65.1	50.1	15.1	1.9

Table 6-10 provides a comparison of the existing visibility impairment and the visibility impairment associated with the addition of NO_X controls on SN-01 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 6-10. SUMMARY OF VISIBILITY IMPROVEMENT ASSOCIATED WITH NO_X CONTROL SYSTEM 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	1.318	0.963	48	2.426	0.965	63	2.103	0.657	47	1.488	0.631	20
LNB/OFA	1.232	0.849	39	2.130	0.939	56	1.938	0.633	43	1.361	0.617	17
Post Control Improvement	*0.086*	*0.114*	*9*	*0.296*	*0.026*	*7*	*0.165*	*0.024*	*4*	*0.127*	*0.014*	*3*
SCR	0.986	0.718	22	1.569	0.895	41	1.589	0.573	33	1.099	0.588	14
Improvement over LNB/OFA	*0.246*	*0.131*	*17*	*0.561*	*0.044*	*15*	*0.349*	*0.060*	*10*	*0.262*	*0.029*	*3*
LNB/OFA+ SNCR	1.201	0.849	36	2.022	0.932	54	1.878	0.623	42	1.316	0.612	17
Improvement over LNB/OFA	*0.031*	*0.000*	*3*	*0.108*	*0.007*	*2*	*0.06*	*0.010*	*1*	*0.045*	*0.005*	*0*

Note: The visibility improvement shown in the table has been calculated from baseline and controlled impacts that include more decimal places than what is shown in the table. Due to rounding of the baseline and controlled impacts shown in the table, the visibility improvement calculated from the baseline and controlled impacts shown in the table may be slightly different than the visibility improvement reflected in the table.

The operation of an LNB/OFA system results in an estimated 0.01 to 0.11 Δdv improvement (2 to 12 percent) (98^{th} percentile basis) of visibility impairment attributable to SN-01 at the modeled Class I areas. Further, the operation of SCR systems results in an estimated 0.02 to 0.13 Δdv incremental improvement over LNB/OFA alone, while LNB/OFA + SNCR results in an estimated 0 to 0.01 Δdv incremental improvement over LNB/OFA alone.

6.7 PROPOSED BART FOR NO_X

If CSAPR is upheld and implemented in Arkansas, SWEPCO will rely on CSAPR to satisfy its regional haze obligations at SN-01. If CSAPR is vacated, SWEPCO should be entitled to rely on EPA's prior determination that CAIR provides greater reductions than BART, and satisfy its obligations by continuing to comply with CAIR.

If a full evaluation of BART is required, the cost-effectiveness of the control options and the limited incremental improvement in visibility in the affected Class I areas do not justify the installation of SCR or SNCR. SWEPCO proposes a BART emission rate of 0.23 lb/MMBtu calculated as a 30-day rolling average for each boiler operating day, achievable through use of LNB/OFA. The visibility improvement attributable to SN-01 through the use of LNB/OFA ranges from 2.2% to 11.8% across the affected Class I areas. This level of improvement is achievable at a cost effectiveness of approximately $1,800 per ton of NO_X removed. Although LNB/OFA plus SNCR adds a slight visibility improvement over LNB/OFA alone, the small improvement does not justify the incremental cost of over $5,200 per ton of NO_X removed. The incremental cost for SCR at SN-01 is greater than $4,000 per ton of NO_X removed, and is an excessive cost to be considered BART. In addition, the adverse environmental impacts from the use of SCR, including an increased demand for electricity and the potential for ammonia slip, which could create haze, outweigh the limited, imperceptible improvements in visibility associated with its use at SN-01.

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. As such, no further PM_{10} analysis has been conducted.

APPENDIX A

SO_2 CONTROL COST CALCULATIONS

Capital and O&M Cost Estimates

Cost Type	Default Estimate Methodology from EPA's Control Cost Manual [a]	NIDS Cost Estimate Based on EPA's Control Cost Manual	WFGD Cost Estimate Based on EPA's Control Cost Manual	*FOR COMPARISON* NIDS Cost Estimate Based on Engineering Study [b]	*FOR COMPARISON* WFGD Cost Estimate Based on Previous Project [b]
CAPITAL COSTS					
Direct Costs					
Purchased Equipment Costs (PEC)					
Equipment Cost (EC)	--	$176,899,430 [d]	$220,921,269 [e]	$176,899,430 [d]	$220,921,269 [e]
Other Purchases					
Boiler Modifications	NA	NA	NA	$985,989	$985,989 [s]
Existing Conditions	NA	NA	NA	$1,259,054 [f]	$1,608,778 [f]
CEMS	NA	NA	NA	$0 [O]	$0 [O]
Rail Improvements	NA	NA	NA	$3,141,629	$10,000,000
Sales Tax	3% of EC [c]	$0 [k]	$0 [k]	$0 [k]	$0 [k]
Freight	5% of EC [c]	$0 [k]	$0 [k]	$0 [k]	$0 [k]
Purchased Equipment Costs (PEC)		*$176,899,430*	*$220,921,269*	*$182,286,102*	*$233,516,035*
Direct Installation Costs					
Foundations and supports	6% of PEC [c]	$0 [k]	$0 [k]	$0 [k]	$0 [k]
Handling and erection	40% of PEC [c]	$0 [k]	$0 [k]	$0 [k]	$0 [k]
Electrical	1% of PEC [c]	$1,768,994	$2,209,213	$27,246,367	$18,538,032
Piping	5% of PEC [c]	$0 [k]	$0 [k]	$0 [k]	$0 [k]
Insulation for ductwork	3% of PEC [c]	$0 [k]	$0 [k]	$0 [k]	$0 [k]
Painting	1% of PEC [c]	$0 [k]	$0 [k]	$0 [k]	$0 [k]
Other Installation Costs	NA	NA	NA	$14,448,208 [l]	$26,661,044 [l]
Direct Installation Costs (DIC)		*$1,768,994*	*$2,209,213*	*$41,694,575*	*$45,199,076*
Other Direct Costs					
Site Preparation Costs (SPC)	--	$19,026,474	$19,026,474	$19,026,474	$19,026,474
Buildings Costs (BC)	--	$22,128,325 [p]	$54,947,952 [p]	$22,128,325 [p]	$54,947,952 [p]
Landfill Construction	--	$0 [i]	$0 [i]	$0 [i]	$0 [i]
Other Direct Costs (ODC)		*$41,154,799*	*$73,974,426*	*$41,154,799*	*$73,974,426*
Total Direct Capital Costs (DC = PEC + DIC + ODC)		*$219,823,223*	*$297,104,907*	*$265,135,476*	*$352,689,537*
Indirect Capital Costs					
Engineering	10% of PEC [c]	$17,689,943	$22,092,127		
Construction and field expenses	10% of PEC [c]	$17,689,943	$22,092,127		
Contractor fees	10% of PEC [c]	$17,689,943	$22,092,127	$77,976,320 [m]	$86,453,748 [m]
Start-up	1% of PEC [c]	$1,768,994	$2,209,213		
Performance test	1% of PEC [c]	$1,768,994	$2,209,213		
Contingency	3% of PEC [c]	$5,306,983	$6,627,638	$0 [q]	$0 [q]
Allocations	NA	NA	NA	$0 [r]	$0 [r]
AFUDC	Assumed zero (0)	$0	$0	$0 [r]	$0 [r]
Total Indirect Capital Costs (IC)		*$61,914,801*	*$77,322,444*	*$77,976,320*	*$86,453,748*
TOTAL CAPITAL INVESTMENT (TCI = DC + IC)		*$281,738,024*	*$374,427,351*	*$343,111,796*	*$439,143,286*
OPERATING COSTS					
Direct Operating Costs					
Fixed O&M Costs (Labor and Materials)					
Operating Labor ($14.24/hour) [n]	8 hr/shift, 3 shifts/day [c]	$124,742	$124,742	$884,000	$1,060,800
Operating Labor Supervision	15% of op. labor [c]	$18,711	$18,711		
Maintenance Labor ($14.24/hour) [n]	2 hr/shift, 3 shifts/day [c]	$31,186	$31,186	$1,331,100	$1,467,950
Maintenance materials	100% of maint. labor [c]	$31,186	$31,186	$1,997,500	$2,201,500
Fixed O&M Costs		*$205,825*	*$205,825*	*$4,212,600*	*$4,730,250*
Other Direct Operating Costs (e.g., utilities)					
Electricity ($0.05588/kW) [g,h]	--	$4,678,363	$8,966,862	$4,678,363	$8,966,862
Sorbent [g]	--	$2,563,783	$828,809	$2,563,783	$828,809
Water	--	$453,050	$992,500	$453,050	$992,500
Waste Disposal	--	$1,300,698	$1,231,419	$1,300,698	$1,231,419
Bag and Cage Replacement	--	$483,000	$483,000	$483,000	$483,000
Other Direct Operating Costs		*$9,478,894*	*$12,502,590*	*$9,478,894*	*$12,502,590*
Total Direct Operating Costs (DOC)		*$9,684,719*	*$12,708,415*	*$13,691,494*	*$17,232,840*
Indirect Operating Costs					
Overhead	60% of O&M [c]	$0 [j]	$0 [j]	NA	NA
Property tax	1% of TCI [c]	$2,394,773 [j]	$3,182,632 [j]	NA	NA
Insurance	1% of TCI [c]	$29,582 [j]	$39,315 [j]	NA	NA
Administration	2% of TCI [c]	$5,634,760	$7,488,547	NA	NA
Capital Recovery (30 years, 7 %)	0.0806 of TCI	$22,704,254	$30,173,754	$27,650,146	$35,388,978
Total Indirect Operating Costs (IOC)		*$30,763,370*	*$40,884,248*	*$27,650,146*	*$35,388,978*
TOTAL ANNUALIZED COSTS (TAC = DOC + IOC)		*$40,448,089*	*$53,592,663*	*$41,341,640*	*$52,621,818*

[a] Default estimates are based on information published in the EPA Cost Control Manual, Sixth Edition. These estimates are used for all cost calculations except as noted.

[b] The NIDS option estimate is based on a site-specific engineering study. The estimate for the WFGD option was generated from the actual costs for the Conesville Unit 4 WFGD project (prorated).
No attempt was made to make the estimate site specific and is deemed to be a Class 5 estimate per AACE International standards. All costs are in 2016 dollars.

[c] EPA Cost Control Manual, Sixth Edition, Table 2-8 and Table 2.9.

[d] Includes lime receiving, handling, and storage equipment, DFGD (J Duct), ID fan, flue gas duct, fabric filter, fly ash / byproduct handling and storage equipment.

[e] Includes reagent receiving equipment, JBR and WFGD system, ID fan, flue gas duct, fabric filter, and stack.

[f] "Existing conditions" includes site specific activities necessary for the construction of the project such as removal of existing equipment and asbestos and lead paint remediation and work at tie-in points of the new e

[g] Based on the average annual operating hours from the 2001 to 2003 baseline period: 7752

[h] Based on engineering estimates, the auxiliary power demand is 10,800 kW for NIDS and 20,700 kW for a WFGD system.

[i] No landfill construction costs are included.

[j] In the OK FIP TSD, EPA used alternative (compared to the Control Cost Manual) estimates for these costs, i.e., zero for Overhead, 0.85 % of TCI
for Property tax, and 0.0105 % of TCI for Insurance. These same estimates are used here for consistency.

[k] The estimated equipment cost (EC) includes sales tax, freight, foundations & support, handling & erection, piping, insulation, and painting.

[l] Includes utility racks, plant and instrument air, various water supplies, sewers, and plant security and communications (i.e., phone and PA systems for employee safety).

[m] Includes construction indirects, outside professional services (e.g., start-up technical support, specialty testing, geophysical engineering services, and surveying), conceptual and detailed design engineering,
project management and controls, AEP services (owners estimated involvement in project management, engineering, project controls, procurement, and construction and start-up supervision), and, for the WFGD
option only, startup management and plant labor (these costs for the NIDS option are included in other categories).

[n] Labor rates based on engineering estimates.

[o] New/revised CEMS and related equipment, including buildings, will be required for each control option, but costs are not included for this assessment.

[p] Included buildings: Process island building, lime (sorbent) building, byproduct exhauster building, control room, and warehouse.

[q] AEP's projects team develops an elaborate risk analysis to estimate contingency and has refined its approach with each project. For example, for the recent Conesville project, the estimated contingency was
$42MM and actual costs were just less than $35MM. However, for the purposes of this assessment, all contingency costs are set equal to zero.

[r] Allocations and AFUDC costs are excluded, i.e., assumed to be zero (0), for the purposes of this assessment.

[s] It is expected that more extensive boiler modifications would be needed for the WFGD option than the NIDS option, but costs are conservatively assumed equal to the NIDS option estimate.

APPENDIX B

NO_X CONTROL COST CALCULATIONS

LNB/OFA Capital and O&M Cost Estimate

Capital Costs		**Total Direct Capital**
Technology LNB-OFA		
Material Capital Costs[1]		
Total Capital Cost Plus Installation		$16,000,000
Annual Costs[2]		
Parameters/Costs	Equation	Unit 1
Boiler design capacity, mmBtu/hr (C)	C	6324
Annual operating hours, hr/yr (H)	H = average from 2001-2003	7752
Capital recovery factor	= [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life a. Equipment CRF, 30-yr life, 7% interest	0.08
Direct Annual Operating Costs $/yr		
Variable O&M Costs	=(0.027 mills/kW-hr/1000) x (1 kW-hr/10,000 Btu) x H x C x 10^6 Btu/mmBtu	$132,364
Indirect Annual Costs, $/yr		
1. Fixed O&M Costs (1.5% of capital cost)	= 0.015 x TCI	$240,000
2. Annualized capital cost	= Equipment CRF x TCI	$1,289,382
Total Annual Costs ($/yr) 2017/2018 Basis		$1,661,746
Total Annual Costs ($/yr) 2013 Basis	Assume 3 % per year for de-escalating 4.5 years	$1,454,621

[1] Public Service Commission Docket 12-008-U.

[2] Annual cost calculation methods for variable costs and fixed costs from Eastern Research Group "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.
Note: The variable rate used for variable O&M costs was 0.027 mills/kW-hr. This is the rate listed in Appendix D

SCR Capital and O&M Cost Estimate

Capital Costs		Total Direct Capital
Technology SCR		
Installed Capital Cost[1]		$121,440,000
Annual Costs		
Variable		
Urea[1]		$2,200,000
Catalyst replacement (per year)[1]		$1,500,000
Total Variable O&M[1]		$3,700,000
Fixed		
Operating Labor Cost[2]	$530,000	
Maintenance Labor[3]	$530,000	
Maintenance Material[1]	$500,000	
Total Fixed O&M[1]		$1,560,000
Capital recovery factor	= [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life a. Equipment CRF, 30-yr life, 7% interest	0.08
Annualized capital cost	= Equipment CRF x TCI	$9,786,413
Total Annual Costs ($/yr) 2016 Basis		$15,046,413
Total Annual Costs ($/yr) 2013 Basis	Assume 3 % per year for de-escalating 3 years	$13,769,599

[1] All capital and O&M cost estimates provided by AEP are based on engineering estimates. The engineering estimates were informed by AEP's experience with SCR installations at other plants owned by AEP

[2] Annual estimates provided by AEP based on 1 person per shift for 5 shifts.

[3] Annual estimates provided by AEP based on 1 person per shift for 5 shifts.

Selective Non-Catalytic Reduction Capital and O&M Cost Estimate [1]

Parameters/Costs	Equation	Unit 1
Capital Costs		
Technology SNCR		
Parameters/Costs	Equation	Unit 1
Boiler design capacity, mmBtu/hr (Q_B)	Q_B	6324
Total operating time (t_{op}, hrs/yr)	$t_{op} = CF_{total} \times 8760$ hrs/yr	7752
Total Capacity Factor (CF_{total})	$CF_{total} = CF_{plant} \times CF_{SNCR}$	0.92
Plant Capacity Factor (CF_{plant})[2]		0.92
SNCR Capacity Factor (CF_{SCNR})[3]	$CF_{SNCR} = t_{SNCR}/365$	1
Assumed NOx removal efficiency (η_{NOx})[4]		35%
Uncontrolled NOx rate (NOx_{in}, lb/MMBtu)[5]		0.33
Electricity Cost ($Cost_{elect}$, \$/kwh)[6]		\$0.05
Water Cost ($Cost_{water}$, \$/gal)[7]		\$0.00362
Coal Cost ($Cost_{coal}$, \$/MMBtu)[8]		\$2.50
Coal HHV (Btu/lb)[9]		9,000
Cost of Ash Disposal (C_{ash}, \$/ton)[10]		\$9.0
Capital recovery factor (CRF)	CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life a. Equipment CRF, 20-yr life, 7% interest	0.09
Cost Index[11] a. 2011 Cost Index b. 1998 Cost Index	 585 389.5	
Capital Costs		
Direct Capital Cost (A)	DC (\$) = (\$950/MMBtu) × Q_B × ((2375 MMBtu/hr/Q_B)^0.577) × (0.66 + 0.85 η_{NOx}) × (CI_{2011}/CI_{1998})	\$5,007,199
Indirect Installation Costs (\$)		
General Facilities	0.05 × A	\$250,360
Engineering and Home Office Fees	0.10 × A	\$500,720
Process Contingency	0.05 × A	\$250,360
Total Indirect Installation Costs (B)	= General Facilities Cost + Engineering and Home Office Fees + Process Contingency	\$1,001,440
Other Installation Costs (\$)		
Project Contingency (C)	C = 0.15 × (A + B)	\$901,296
Total Plant Cost (D)	D = A + B + C	\$6,909,934
Allowance for Funds During Construction (E)	E = 0 (Assumed for SNCR)	\$0
Royalty Allowance (F)	F = 0 (Assumed for SNCR)	\$0
Preproduction Cost (G)	G = 0.02 × (D + E)	\$138,199
Inventory Capital (H)[12]	H = $Vol_{reagent}$ (gal) × $Cost_{reagent}$ (\$/gal)	\$76,102
$Cost_{reag}$, 50% Urea solution (\$/gal)[13]		1.54
Volume of Reagent Tank ($Vol_{reagent}$ (gal))	$Vol_{reagent}$ (gal) = q_{sol} x days of reagent supply × 24 hr/day	49,417
Urea solution volumetric flow rate (q_{sol}, gal/hr)[14]	$q_{sol} = (m_{sol} \times 7.481\ gal/ft^3)/\rho_{reagent}$	147.07
Mass flow rate of urea solution (m_{sol}, lb/hr)[15]	$m_{sol} = m_{reagent}/C_{ureasol}$	1,395.84
Mass flow rate of reagent ($m_{reagent}$, lb/hr)[16]	$m_{reagent} = (NOx_{in} \times Q_B \times \eta_{NOx} \times NSR \times M_{reagent})/(M_{NOx} \times SR_T)$	697.92
Normalized Stoichiometric Ratio (NSR)	$NSR = ([2 \times NOx_{in} + 0.7] \times \eta_{NOx})/NOx_{in}$	1.43
Initial Catalyst and Chemicals (I)	I = 0 (Assumed for SNCR due to no catalyst)	\$0
Total Capital Investment (TCI) (Capital Cost)	**TCI = D + E + F + G + H + I**	**\$7,124,235**
Annual Costs (\$)		
Annual Maintenance Cost (J)	J = 0.015 × TCI	\$106,864
Annual Reagent Cost (K)	$K = q_{sol} \times Cost_{reag} \times t_{op}$	\$1,755,781
Annual Electricity Cost (L)	$L = P \times Cost_{elect} \times t_{op}$	\$58,064
Power (P, kW)	$P = (0.47 \times NOx_{in} \times NSR \times Q_B)/9.5$	149.80
Annual Water Cost (M)	$M = q_{water} \times Cost_{water} \times t_{op}$	\$18,775
Water flowrate for SNCR system (q_{water}, gal/hr)[17]	$q_{water} = (m_{sol}/\rho_{water}) \times [(C_{ureasolstored}/C_{ureasolinj}) - 1]$	669.06
Annual ΔCoal Cost (N)	$N = \Delta Coal \times Cost_{coal} \times t_{op}$	\$109,558
Additional coal required (ΔCoal, MMBtu/hr)[18]	$\Delta Coal = (Hv \times m_{reagent} \times [(1/C_{ureasolinj}) - 1])/10^6$ Btu/MMBtu	5.65
Annual ΔAsh Cost (O)	$O = (\Delta Ash \times Cost_{ash} \times t_{op})/2000$ lb/ton	\$1,643
Additional ash generated (ΔAsh , lb/hr)[19]	$\Delta Ash = (\Delta Coal \times ashproduct \times 10^6$ Btu/MMBtu)/HHV	47.11
Direct Annual Costs (DAC)/Variable O&M	**DAC = J + K + L + M + N + O**	**\$2,050,684**
Indirect Annual Costs (IDAC)/Annualized Capital Cost	**IDAC = CFR × TCI**	**\$672,477**
Total Annualized Costs (TAC)	**TAC = DAC + IDAC**	**\$2,723,162**

[1] All SNCR costing equations from EPA Air Pollution Control Cost Manual (APCCM), 6th Edition (January 2002)
[2] Plant capacity factor from plant data
[3] t_{SCNR} assumed to be 365 days
[4] η_{NOx} (NOx removal efficiency) assumed to be 33% for SNCR alone
[5] 24-hr NOx rate 46,680 lbs/day - from Clean Air Markets Database, with a heat input of 6324 MMBtu/hr
[6] Electricity cost form Arkansas Industrial Energy Clearinghouse, http://www.arkansasiec.org/newsmanager/templates/?a=71&z=1
[7] Water cost estimate from Bentonville, AR commercial rate of $0.00362/gal, http://www.bentonvillear.com/utbc_rates.html
[8] Cost of coal from Lazard's 2009 Levelized Cost of Energy Analysis (LCOE)
[9] Coal used at AEP Flint Creek originates from Powder River Basin near Gillette, WY and is considered to be subbituminous (source: http://www.aecc.com/about/generation-facilities/)
HHV for subbituminous coal ranges from 8,000 - 10,000 Btu/lb (EPA APCCM, 2002).
Using HHV of 9,000 Btu/lb
[10] Cost of ash disposal from BART Analysis for NCS Unit 1, Appendix A
[11] From Chemical Engineering Plant Cost Index (CEPCI)
[12] Cost for urea stored on site, i.e., the first fill of the reagent tanks.
[13] Five-yr average urea cost = $356.11/metric ton, from http://www.indexmundi.com/commodities/?commodity=urea&months=180
Density of 50% urea solution = 9.5 lb/gal (50% urea solution) based on EPA APCCM, 2002
Equates to $1.54/gal
[14] $\rho_{reagent}$ = 71.0 lb/ft^3
[15] $C_{ureasol}$ = urea solution concentration = 50%
[16] $M_{reagent}$ = 60.6 g/mol (molecular weight of urea)
M_{NOx} = 46.01 g/mol (molecular weight of NO_2)
SRT = 2 (ratio of equivalent moles NH_3 per mole of urea)
[17] Concentration of stored urea, $C_{ureasolstored}$ = 50%
Concentration of urea injected into SNCR system, $C_{ureasolinj}$ = 10%
From EPA APCCM, 2002
[18] Approximate heat of vaporization of water at 310°F, Hv = 900 Btu/lb From EPA APCCM, 2002
[19] Ashproduct is the fraction of ash produced as a byproduct of burning a given type of coal. Assumed ashproduct = 0.075 from EPA APCCM, 2002 for subbituminous coal.

APPENDIX C

CALMET PROTOCOL

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

Prepared by:

Vern Choquette ▲ Principal Consultant
Eugene Chen, PE ▲ Senior Consultant
Jeremy Townley ▲ Consultant

TRINITY CONSULTANTS
120 East Sheridan
Suite 205
Oklahoma City, OK 73104
(405) 228-3292

January 23, 2008

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

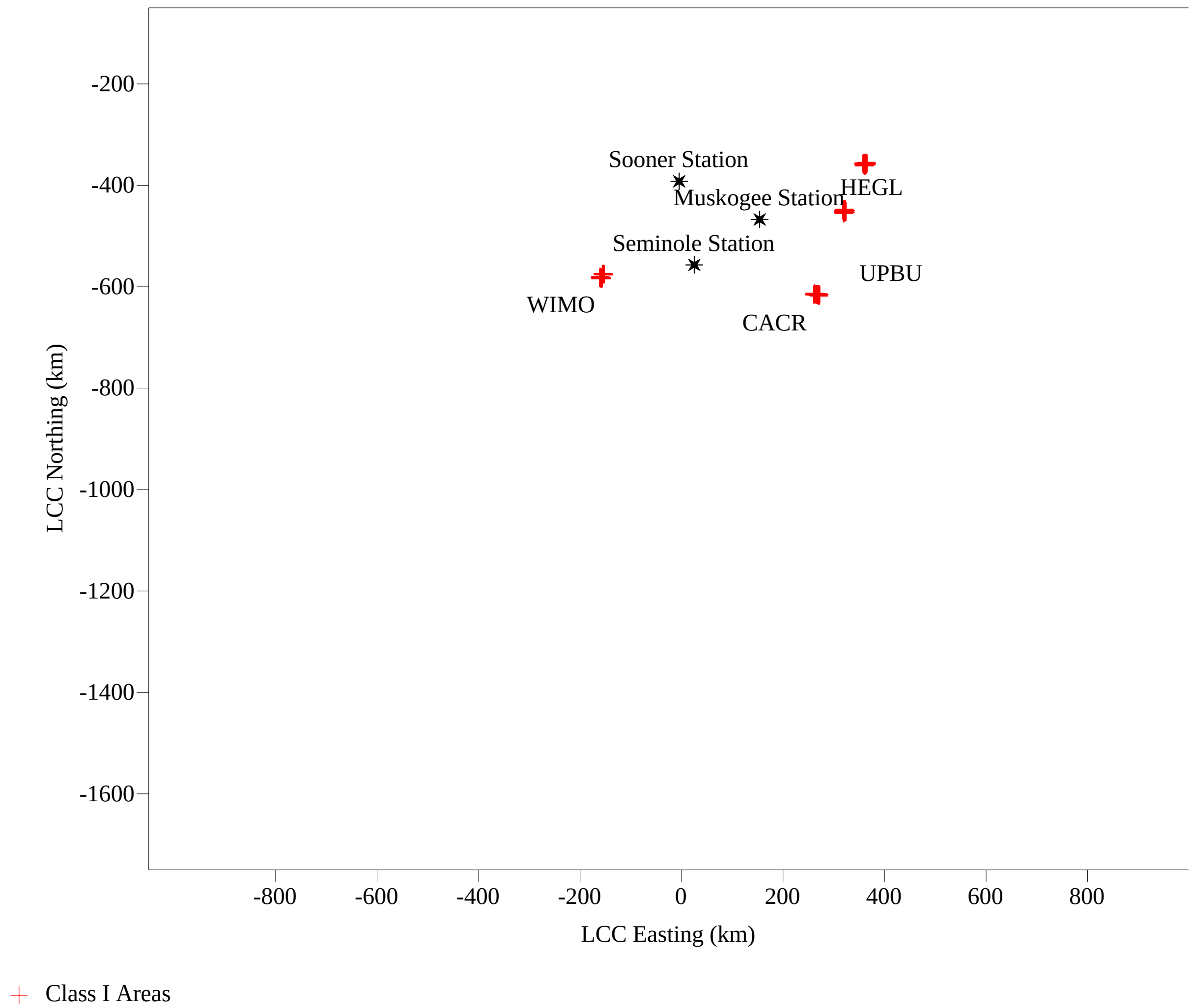
As required in CENRAP's BART Modeling Guidelines, Class I areas within 300 km of each station will be included in each analysis. The following table summarizes the distances of the four closest Class I areas to each station. As seen from this summary, some Class I areas are more than 300 km from the 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

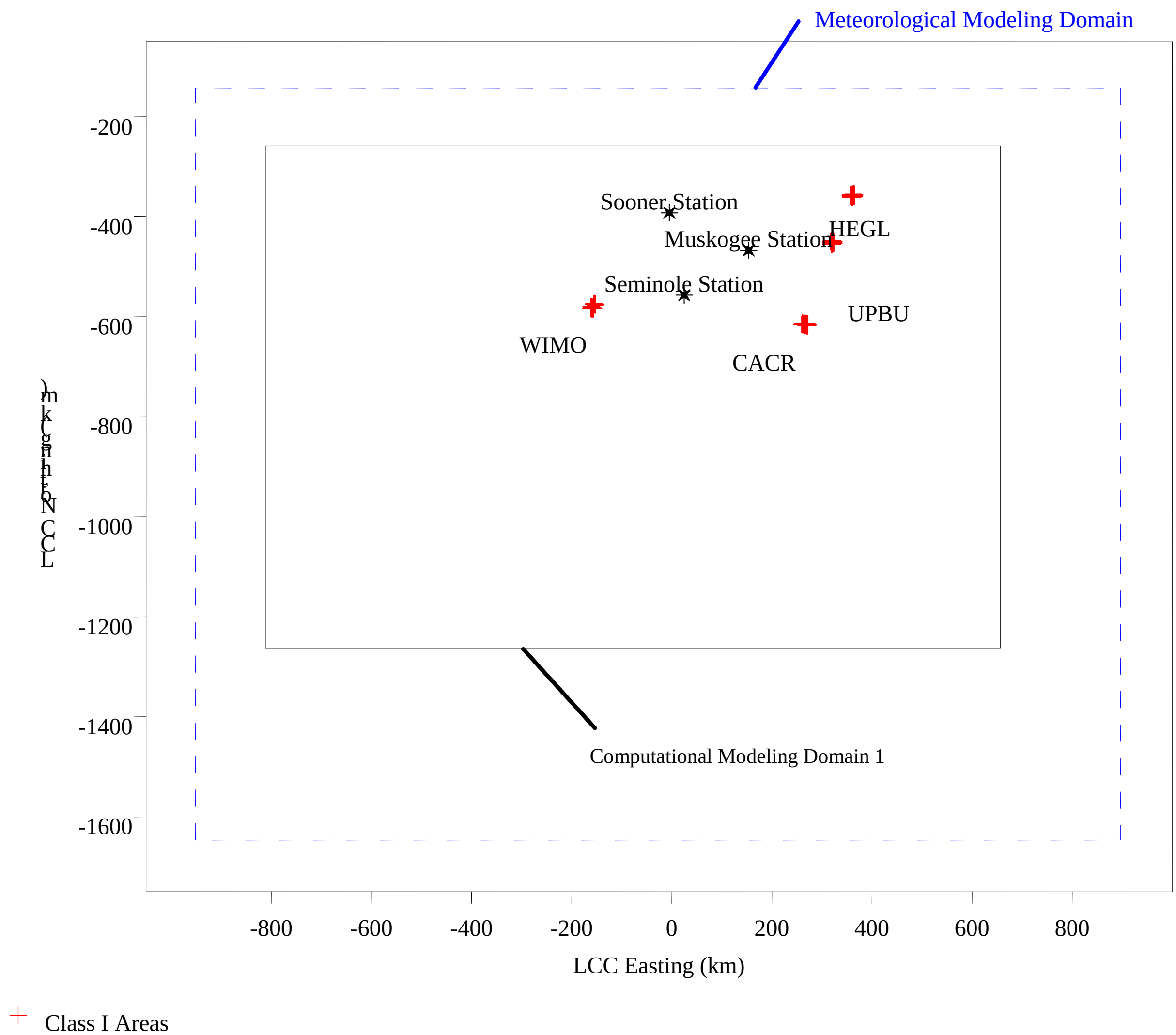
Processor	Version	Level
TERREL	3.3	030402
CTGCOMP	2.21	030402
CTGPROC	2.63	050128
MAKEGEO	2.2	030402
CALMET	5.53a	040716
CALPUFF	5.8	070623
POSTUTIL	1.3	030402
CALPOST	5.51	030709

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.

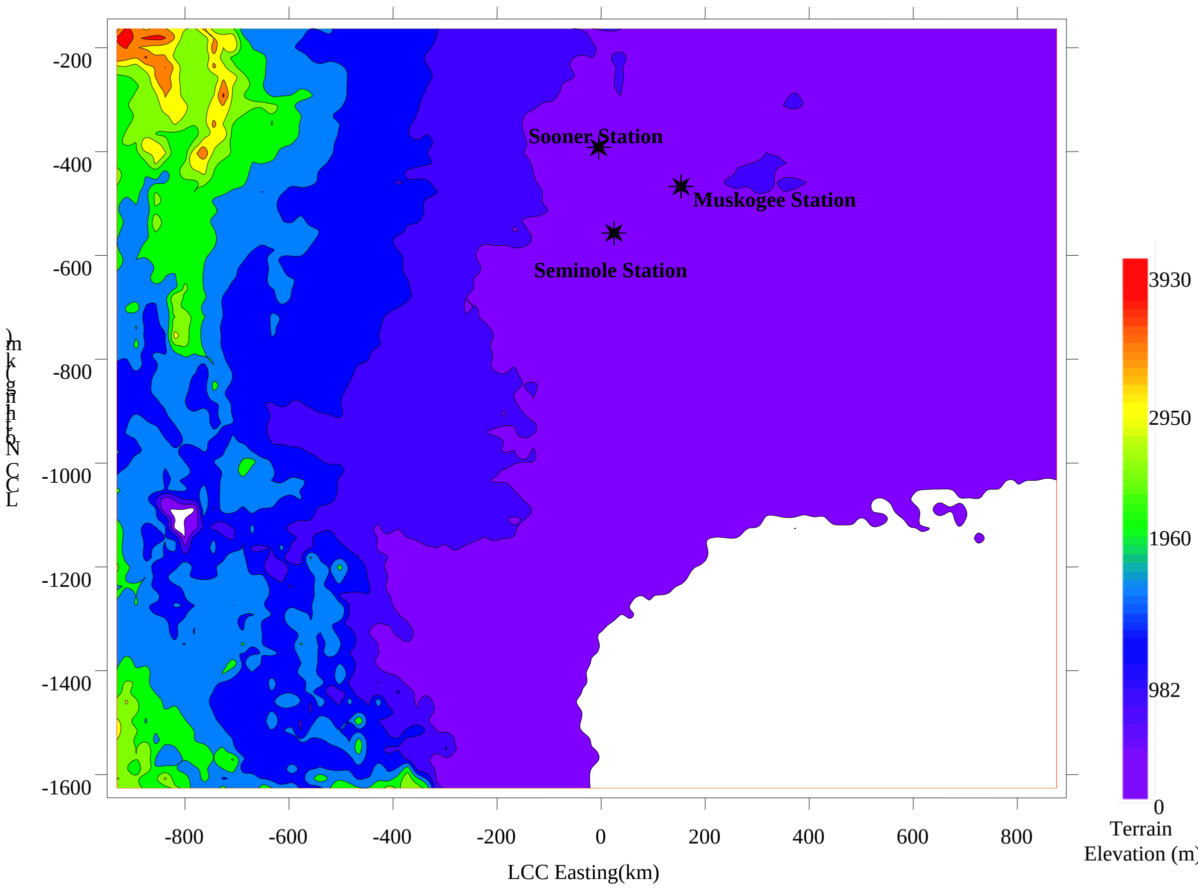
3.1 GEOPHYSICAL DATA

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.

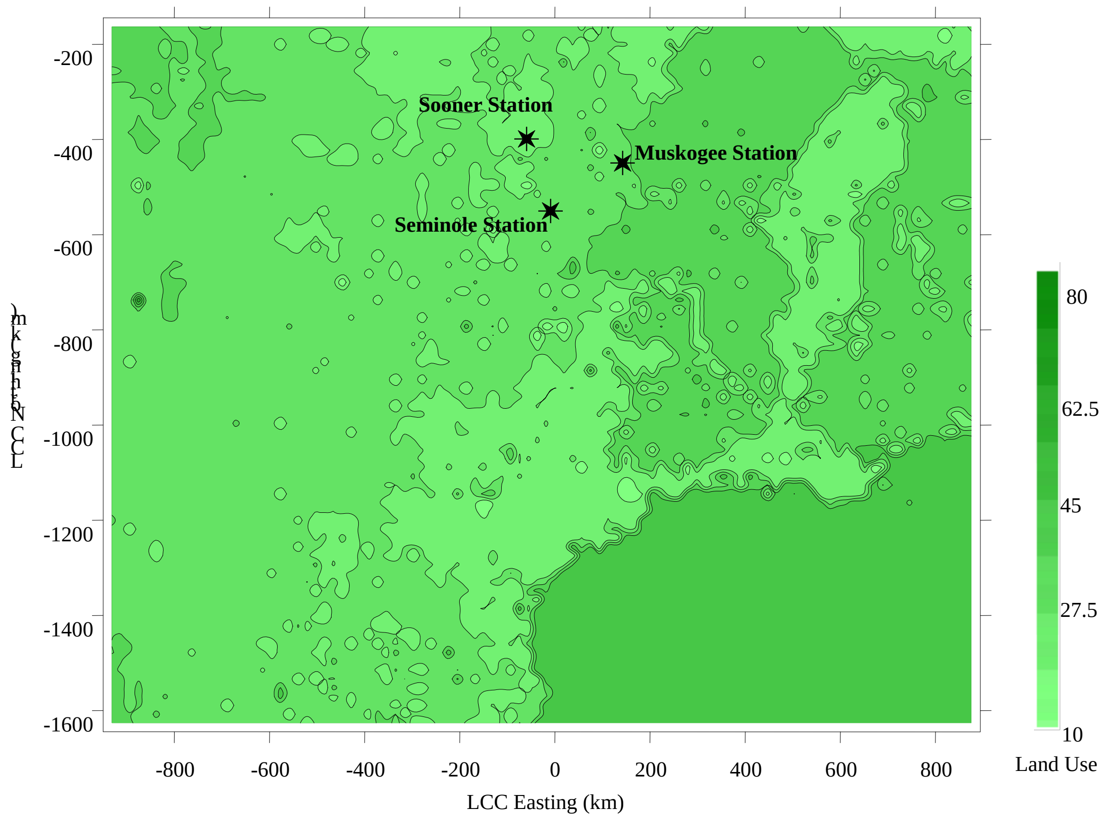
FIGURE 3-1. PLOT OF LAND ELEVATION USING USGS TERRAIN DATA



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.

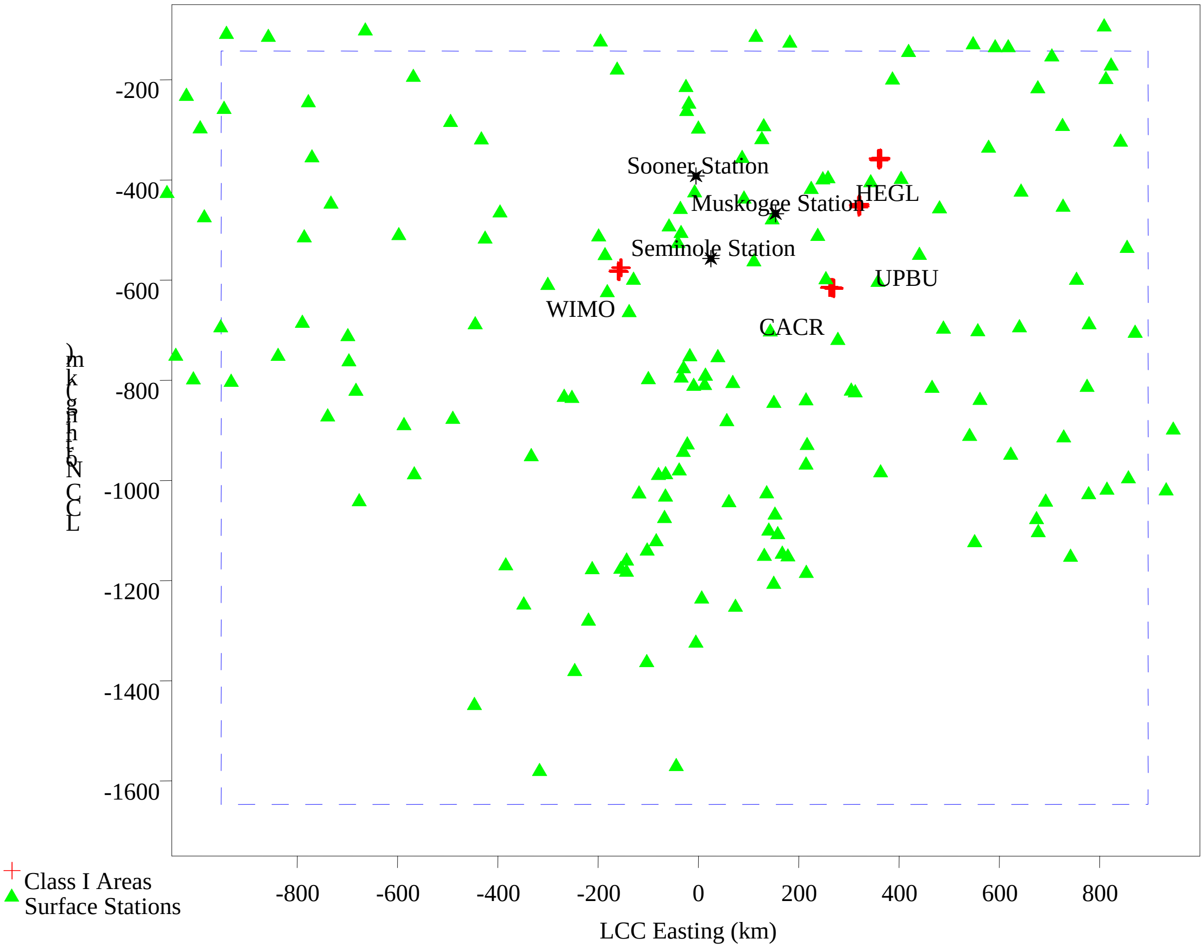
The time periods covered by the data in each of the MM5 files extracted by Alpine Geophysics include a specific number of calendar days, where the data starts at Hour 0 in GMT for the first calendar day and ends at Hour 23 in GMT on the last calendar day. In order to run CALMET in the local standard 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.

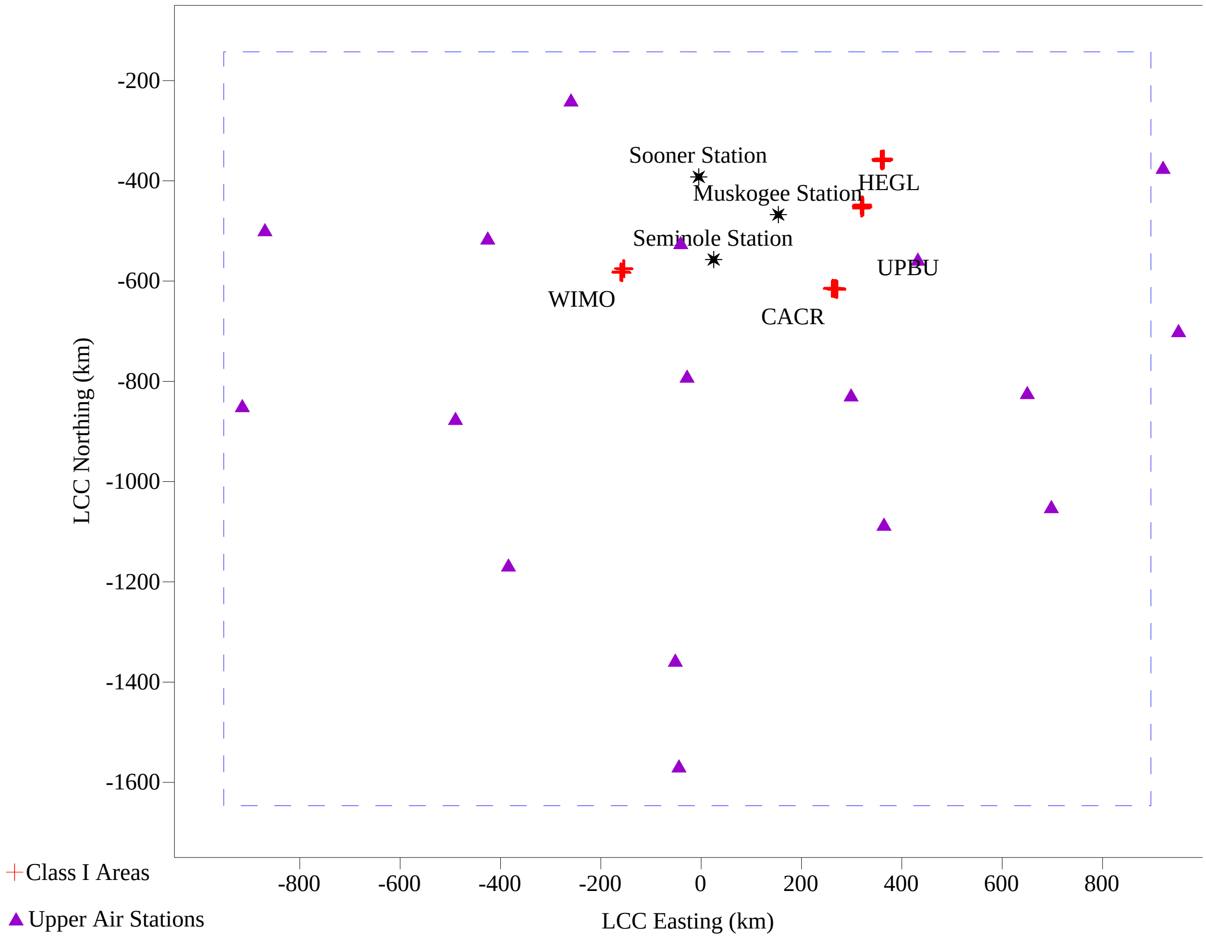
FIGURE 3-3. PLOT OF SURFACE STATION LOCATIONS



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.

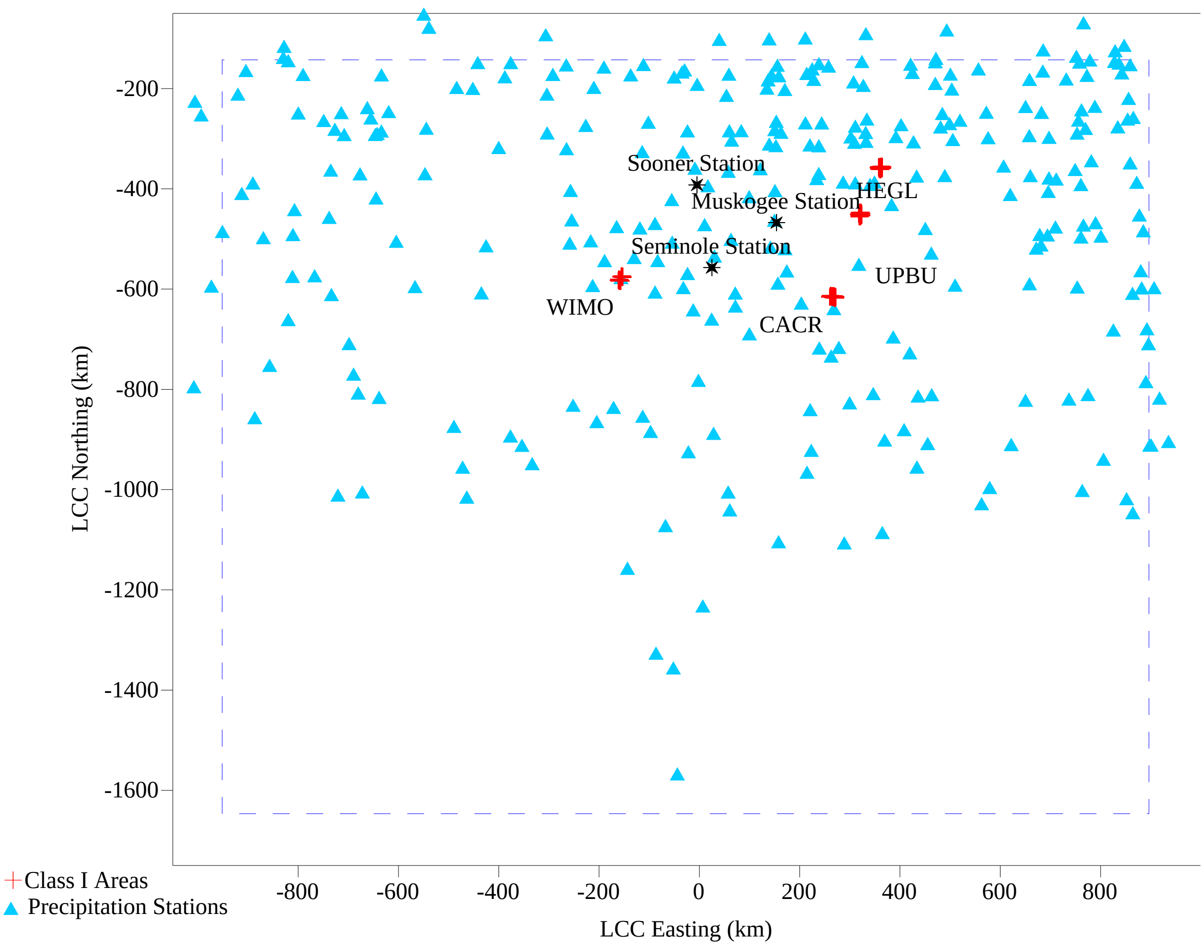
FIGURE 3-4. PLOT OF UPPER AIR STATIONS LOCATIONS



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.

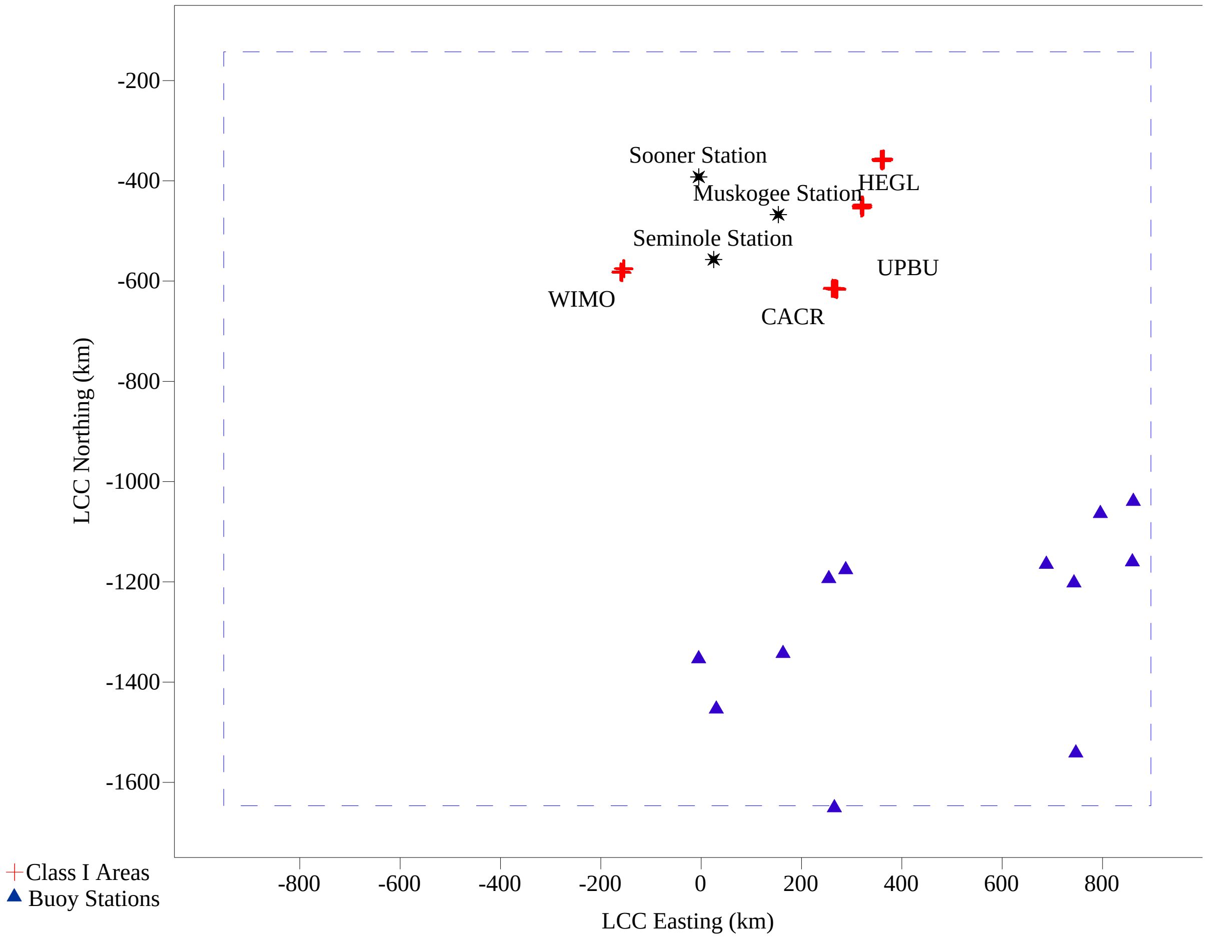
FIGURE 3-5. PLOT OF PRECIPITATION METEOROLOGICAL STATIONS



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

APPENDIX F
Reasonable Progress Analysis Technical Supporting Information and Data Sheets

Contents

Excel files have been converted to PDF and included with the SIP in Appendix F Tabs 2–7. For questions or requesting copies of Excel files, contact Tricia Treece via email at treecep@adeq.state.ar.us or by phone at 501-682-0055.

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

Facility	EIS ID	County	2002 NEI	2005 NEI	2008 NEI v3	2009 ADEQ	2010 ADEQ	2011 NEI V2	2012 ADEQ	2013 ADEQ	2014 NEI v1	2015 ADEQ	2016 CAMD	2013-2015 avg	2014 - 2016 avg
Bonanza Creek Energy - Stamps	1102411	Lafayette	607	6.811										-	
ENTERGY ARK-WHITE BLUFF	893911	Jefferson	34,156	34,890	37,939	33,832	33,832	31,684	31,687	34,196	34,223	20,481	18,336	29,633	24,346
ENTERGY ARKANSAS INC-INDEPENDENCE PLANT	1083411	Independence	24,626	22,367	26,448	27,426	28,675	30,398	32,974	28,854	30,029	14,994	22,570	24,626	22,531
FLINT CREEK POWER PLANT (SWEPCO)	1015511	Benton	10,961	8,227	8,504	6,551	8,134	8,620	8,409	6,699	7,968	6,445	1,637	7,038	5,350
PLUM POINT ENERGY STATION STATION UNIT 1	15259811	Mississippi					2,424	2,830	3,153	2,869	2,549	2,691	3,038	2,703	2,759
FUTUREFUEL CHEMICAL COMPANY	1082811	Independence	6,308		2,881	3,415	3,179	3,421	2,554	2,534	3,174	2,804		2,837	
DOMTAR A.W. LLC, Ashdown Mill	880811	Little River	2,213	2,213	1,534	5,465	1,628	1,603	1,569	2,336	1,489	833		1,553	
EVERGREEN PACKAGING-PINE BLUFF	976711	Jefferson	328	78.97999839	1,252	1,723	1,723	1,755	1,758	1,765	1,077	115		986	
ALBEMARLE CORPORATION-SOUTH PLANT	976011	Columbia	955		1,150	1,184	1,267	1,279	1,270	1,270	1,263	1,611		1,382	
SWEPCO-JOHN W TURK JR POWER PLANT	16584111	Hempstead							49.360516	899	899	876	949	891	908
ASH GROVE CEMENT COMPANY/Foreman Cement Plant	973111	Little River			2,099	2,099	670	440	467	382	321	404		369	
NUCOR-YAMATO STEEL COMPANY	1008911	Mississippi	422	332	411	600	600	607	306	223.2418	393	288		301	
NUCOR CORPORATION-NUCOR STEEL ARKANSAS	1084511	Mississippi	273	355	138.098	71.4383	106.93	136.9782986	135.7048	220.4897	172.258	67.594		153	
SAINT GOBAIN PROPPANTS - FORT SMITH	1101911	Sebastian	0.301000011	8.08	1,039			101.61			162.78			163	
GREEN BAY PACKAGING-AR KRAFT-MORRILTON	991611	Conway	486	55.13999945	167.6852	161.7982	180.8571	141.48	142.55619	145.08177	122.893697	115.677706		128	
EL DORADO CHEMICAL COMPANY-EL DORADO	993511	Union	1,689	1,427	1,174	262	274	223.07001	228.7	3.19	155.27	140.794912		100	
GEORGIA-PACIFIC LLC-CROSSETT PAPER OPER	1091211	Ashley	3,016	2,881	277	271	234.8364	214.825006	64.896655	54.833215	114.504701	120.613955		97	
GREAT LAKES CHEMICAL-EL DORADO	1101811	Union	0.529999996	527	57.6136	89.101475	31.03967	35.003126	35.105451	35.3844	36.0246	31.0247618		34	
LION OIL COMPANY	993611	Union	767	11.5	56.82	59.53	47.37	42.3744999	32.368275	33.349697	35.4867176	36.0965189		35	
JOHN L MCCLELLAN GENERATING STA-CAMDEN	976411	Ouachita	441	461	375	385	385	24.82815	13.740397	20.881011	1.37723444	2.33909	2	8	2
AECC-CARL E BAILEY GENERATING STATION	1050611	Woodruff	380	220.42188	2.05	44.6	46.4969	36.6277	0.182239	10.505727	0.01282626	1.99618231	0	4	1

The data contained in this spreadsheet was obtained from the U.S. Energy Information Administration (EIA) Form EIA-860 and Form EIA-923. Form EIA-860 can be found at *http://www.eia.gov/electricity/data/eia860/* , and collects generator-level specific information about existing and planned generators and associated environmental equipment at electric power plants with 1 megawatt or greater of combined nameplate capacity. Form EIA-923 can be found at *http://www.eia.gov/electricity/data/eia923/* , and collects detailed electric power data on electricity generation, fuel consumption, fossil fuel stocks, and receipts at the power plant and prime mover level.

2012 Form EIA-860 Data - Schedule 6, 'Boiler Data'

Utility ID	Utility Name	Plant Code	Plant Name	State	Boiler ID	Boiler Status	Type of Boiler	New Source Review	Regulation Particulate	Regulation Sulfur	Regulation Nitrogen	Standard Particulate Rate	Standard Sulfur Rate	Standard Nitrgoen Rate	Unit Particualte	Unit Sulfur	Unit Nitrogen	Period Particulate	Period Sulfur	Period Nitrogen	Compliance Year Particulate	Compliance Year Sulfur	Compliance Year Nitrogen	Strategy Particulate 1	Strategy Sulfur 1	Strategy Nitrogen 1	Existing SO2 Strategy Clean Air Act 1	Planned SO2 Strategy Clean Air Act 1	Boiler Manufacturer	Inservice Month	Inservice Year	Max Steam Flow (Thousand Pounds per Hour)	Coal Fire Steam Flow (0.1 Tons per Hour)	Petroleum Fire Steam Flow (0.1 Barresl per Hour)	Gas Fire Steam Flow (0.1 Tons per Hour)	Other Fire Steam Flow	Primary Fuel 1	Fire Primary Fuel 1	Efficiency 100% Load	Efficiency 50% Load	Air Flow 100% Load (Cubic Feet per Minute)	Wet Dry Bottom	Fly Ash Reinjection	Existing NOx Strategy Clean Air Act 1	Planned NOx Strategy Clean Air Act 1
814	Entergy Arkansas Inc	6641	Independence	AR	1	OP	D	N	FD	FD	FD	0.040	0.930	0.700	PB	DP	NP	NV	NV	NV	1983	1983	1983	MS	MS	MS	NC	NC	CE	1	1983	6,023.0	500.0	0.0	0.0	0	SUB	TF	90.0%	90.0%	2,379,146	W	N	NA	NA
814	Entergy Arkansas Inc	6641	Independence	AR	2	OP	D	N	FD	FD	FD	0.040	0.930	0.700	PB	DP	NP	NV	NV	NV	1985	1985	1985	MS	MS	MS	NC	NC	CE	1	1985	6,023.0	500.0	0.0	0.0	0	SUB	TF	90.0%	90.0%	2,379,146	W	N	NA	NA
814	Entergy Arkansas Inc	6009	White Bluff	AR	1	OP	D	N	FD	FD	FD	0.100	1.200	0.450	PB	DP	NP	OH	TH	OT	1980	1980	1980	MS	MS	MS	NC	NC	CE	8	1980	6,023.0	445.0	0.0	0.0	0	SUB	TF	90.0%	90.0%	2,872,984	D	N	NC	NC
814	Entergy Arkansas Inc	6009	White Bluff	AR	2	OP	D	N	FD	FD	FD	0.100	1.200	0.450	PB	DP	NP	OH	TH	OT	1981	1981	1981	MS	MS	MS	NC	NC	CE	7	1981	6,023.0	445.0	0.0	0.0	0	SUB	TF	90.0%	90.0%	2,872,984	D	N	NC	NC

2012 Form EIA-860 Data - Schedule 6, 'Boiler Control Data'

Utility ID	Utility Name	Plant Code	Plant Name	State	Boiler ID	Boiler Status	Type of Boiler	NOx Control Status	Low NOx Process 1	Low NOx Manufacturer	Mercury Emission Control
814	Entergy Arkansas Inc	6641	Independence	AR	1	OP	D	OP	OV	NA	N
814	Entergy Arkansas Inc	6641	Independence	AR	2	OP	D	OP	OV	NA	N
814	Entergy Arkansas Inc	6009	White Bluff	AR	1	OP	D	OP	OV	NA	N
814	Entergy Arkansas Inc	6009	White Bluff	AR	2	OP	D	OP	OV		N

2012 Form EIA-860 Data - Schedule 6, 'Cooling System Data'

Utility ID	Utility Name	Plant Code	Plant Name	State	Cooling ID	Cooling Status	Cooling Type 1	Cooling Water Source	Inservice Month	Inservice Year	Intake Rate at 100% (Cubic Feet per Second)	Chlorine Inservice Month	Chlorine Inservice Year	Tower Inservice Month	Tower Inservice Year	Tower Type 1	Tower Type 2	Tower Water Rate (Cubic Feet per Second)	Power Requirement (MW)	Cost Total (Thousand Dollars)	Cost Towers (Thousand Dollars)	Cost Chlorine Equipment (Thousand Dollars)	Intake Distance Shore (Feet)	Intake Distance Surface (Feet)	Outlet Distance Surface (Feet)	Water Source Code	Water Type Code
814	Entergy Arkansas Inc	6641	Independence	AR	1	OP	RN	White River	1	1983	22	1	1983	1	1983	NW		690	7	10,757	10,269	488		16	1	SW	FR
814	Entergy Arkansas Inc	6641	Independence	AR	2	OP	RN	White River	1	1985	22	1	1985	1	1985	NW		690	7	11,572	11,047	525		16	1	SW	FR
814	Entergy Arkansas Inc	6009	White Bluff	AR	1	OP	RN	Arkansas River	8	1980	45			8	1980	NW		822	7	9,220	9,220		160	48		SW	FR
814	Entergy Arkansas Inc	6009	White Bluff	AR	2	OP	RN	Arkansas River	7	1981	45			7	1981	NW		822	7	9,220	9,220		160	48		SW	FR

2012 Form EIA-860 Data - Schedule 6, 'FGP Data'

Utility ID	Utility Name	Plant Code	Plant Name	State	FGP ID	Inservice Month	Inservice Year	FGP Status	Collector Type 1	Installed Cost (Thousand Dollars)	Fuel Specification Ash Coal (Low)	Fuel Specification Sulfur Coal (Low)	Collection Efficiency	Emission Rate (Pounds per Hour)	Gas Exit Rate (Cubic Feet per Minute)	Gas Exit Temperature (Fahrenheit)
814	Entergy Arkansas Inc	6009	White Bluff	AR	1	8	1980	OP	EK	29,732	10.0%	0.0%	100.0%	381.00	4,675,000	330
814	Entergy Arkansas Inc	6009	White Bluff	AR	2	7	1981	OP	EK	29,732	10.0%	0.0%	100.0%	381.00	4,675,000	330
814	Entergy Arkansas Inc	6641	Independence	AR	1	1	1983	OP	EK	29,732	10.0%	0.0%	100.0%	420.00	2,786,667	350
814	Entergy Arkansas Inc	6641	Independence	AR	2	1	1985	OP	EK	33,080	10.0%	0.0%	100.0%	420.00	2,786,667	350

2012 Form EIA-860 Data - Schedule 6, 'Stack & Flue Data'

Utility ID	Utility Name	Plant Code	Plant Name	State	Flue ID	Stack ID	Inservice Month	Inservice Year	Stack Flue Status	Flue Height (Feet)	Area at Top (Square Feet)	Exit Rate 100% (Cubic Feet per Minute)	Exit Rate 50% (Cubic Feet per Minute)	Exit Temperature 100% (Fahrenheit)	Exit Temperature 50% (Fahrenheit)	Exit Velocity 100% (Feet per Second)	Exit Velocity 100% (Feet per Second)	Exit Temperature Summer (Fahrenheit)	Exit Temperature Winter (Fahrenheit)	Exit Temperature Source
814	Entergy Arkansas Inc	6641	Independence	AR	1	1	1	1983	OP	1,000	552	3,520,000	1,760,000	321	250	114.0	57.0	276	236	M
814	Entergy Arkansas Inc	6641	Independence	AR	2	1	1	1985	OP	1,000	552	3,520,000	1,760,000	321	250	114.0	57.0	287	260	M
814	Entergy Arkansas Inc	6009	White Bluff	AR	1	1	8	1980	OP	1,000	519	2,872,984	1,542,339	262	236	90.0	45.0	261	220	m
814	Entergy Arkansas Inc	6009	White Bluff	AR	2	1	7	1981	OP	1,000	519	2,872,984	1,542,339	262	236	90.0	45.0	238	243	m

2012 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)

Utility ID	Utility Name	Plant Code	Plant Name	State	County	Generator ID	Prime Mover	Status	Nameplate Capacity (MW)
814	Entergy Arkansas Inc	6641	Independence	AR	Independence	1	ST	OP	900.0
814	Entergy Arkansas Inc	6641	Independence	AR	Independence	2	ST	OP	900.0
814	Entergy Arkansas Inc	6009	White Bluff	AR	Jefferson	1	ST	OP	900.0
814	Entergy Arkansas Inc	6009	White Bluff	AR	Jefferson	2	ST	OP	900.0

Summer Capacity (MW)	Winter Capacity (MW)	Unit Code	Operating Month	Operating Year	Energy Source 1	Multiple Fuels	Deliver Power to Transmission Grid	Ownership	Cogenerator
836.0	836.0		1	1983	SUB	N	Y	J	N
842.0	842.0		12	1984	SUB	N	Y	J	N
815.0	815.0		8	1980	SUB	N	Y	J	N
844.0	844.0		8	1981	SUB	N	Y	J	N

Sector Name	Sector	Duct Burners	Planned Modifications	Solid Fuel Gasification System	Pulverized Coal Technology	Subcritical Technology	Startup Source 1
Electric Utility	1	N	N	N	Y		DFO
Electric Utility	1	N	N	N	Y		DFO
Electric Utility	1	N	N	N	Y	Y	DFO
Electric Utility	1	N	N	N	Y	Y	DFO

2012 Form EIA-860 Data - Schedule 4, 'Generator Ownership' (Jointly or Third-Party Owned

Utility ID	Utility Name	Plant Code	Plant Name	State	Generator ID	Status	Ownership ID
814	Entergy Arkansas Inc	6641	Independence	AR	1	OP	807
814	Entergy Arkansas Inc	6641	Independence	AR	1	OP	814
814	Entergy Arkansas Inc	6641	Independence	AR	1	OP	4280
814	Entergy Arkansas Inc	6641	Independence	AR	1	OP	9879
814	Entergy Arkansas Inc	6641	Independence	AR	1	OP	12685
814	Entergy Arkansas Inc	6641	Independence	AR	1	OP	14216
814	Entergy Arkansas Inc	6641	Independence	AR	1	OP	20382
814	Entergy Arkansas Inc	6641	Independence	AR	2	OP	807
814	Entergy Arkansas Inc	6641	Independence	AR	2	OP	4280
814	Entergy Arkansas Inc	6641	Independence	AR	2	OP	9879
814	Entergy Arkansas Inc	6641	Independence	AR	2	OP	12685
814	Entergy Arkansas Inc	6641	Independence	AR	2	OP	14216
814	Entergy Arkansas Inc	6641	Independence	AR	2	OP	20382
814	Entergy Arkansas Inc	6641	Independence	AR	2	OP	25251
814	Entergy Arkansas Inc	6641	Independence	AR	2	OP	39347
814	Entergy Arkansas Inc	6009	White Bluff	AR	1	OP	807
814	Entergy Arkansas Inc	6009	White Bluff	AR	1	OP	814
814	Entergy Arkansas Inc	6009	White Bluff	AR	1	OP	4280
814	Entergy Arkansas Inc	6009	White Bluff	AR	1	OP	9879
814	Entergy Arkansas Inc	6009	White Bluff	AR	1	OP	20382
814	Entergy Arkansas Inc	6009	White Bluff	AR	2	OP	807
814	Entergy Arkansas Inc	6009	White Bluff	AR	2	OP	814
814	Entergy Arkansas Inc	6009	White Bluff	AR	2	OP	4280
814	Entergy Arkansas Inc	6009	White Bluff	AR	2	OP	9879
814	Entergy Arkansas Inc	6009	White Bluff	AR	2	OP	20382

l Only)

Owner Name	Owner State	Percent Owned
Arkansas Electric Coop Corp	AR	35.%
Entergy Arkansas Inc	AR	32.%
Conway Corporation	AR	2.%
City Water and Light Plant	AR	5.%
Entergy Mississippi Inc	MA	25.%
City of Osceola - (AR)	AR	1.%
City of West Memphis - (AR)	AR	1.%
Arkansas Electric Coop Corp	AR	35.%
Conway Corporation	AR	2.%
City Water and Light Plant	AR	15.%
Entergy Mississippi Inc	MA	25.%
City of Osceola - (AR)	AR	1.%
City of West Memphis - (AR)	AR	1.%
Entergy Power, Inc	AR	14.%
East Texas Electric Coop, Inc	TX	7.%
Arkansas Electric Coop Corp	AR	35.%
Entergy Arkansas Inc	AR	57.%
Conway Corporation	AR	2.%
City Water and Light Plant	AR	5.%
City of West Memphis - (AR)	AR	1.%
Arkansas Electric Coop Corp	AR	35.%
Entergy Arkansas Inc	AR	57.%
Conway Corporation	AR	2.%
City Water and Light Plant	AR	5.%
City of West Memphis - (AR)	AR	1.%

2012 Form EIA-860 Data - Schedule 2, 'Plant Data'

Utility ID	Plant Code	Plant Name	Street Address	City	County	State	Zip	Name of Water Source	NERC Region
814	6641	Independence	555 Point Ferry Road	Newark	Independence	AR	72562	White River	SERC
814	6009	White Bluff	1100 White Bluff Road	Redfield	Jefferson	AR	72132	Arkansas River	SERC

Primary Purpose (NAICS Code)	Transmission or Distribution System Owner	Transmission or Distribution System Owner ID	Transmission or Distribution System Owner State	Regulatory Status	Sector Name
22	Entergy Arkansas Inc	814	AR	RE	Electric Utility
22	Entergy Arkansas Inc	814	AR	RE	Electric Utility

Grid Voltage (kV)	Sector	FERC Cogeneration Status	FERC Small Power Producer Status	FERC Exempt Wholesale Generator Status	ISO RTO	Latitude	Longitude
161.00	1	N	N	N	N	35.678442	-91.408761
500.00	1	N	N	N	N	34.422800	-92.140600

The "IPM WB 1 - 0.65 lb" and the "IPM WB 1 - 2 lb" tabs of this spreadsheet are adapted from the Sargent and Lundy cost algorithms documentation for a SDA FGD installation, as incorporated in version 5.13 of the IPM model. These tabs are used to calculate correction factors to the annualized costs to account for Entergy having costed scrubber systems for the White Bluff units assuming coal with a much higher sulfur content than has historically been burned. The "Source" tab lists the origination of these cost algorithms and other information used in this spreadsheet. These tabs include a further correction recommended on page 2 of the Sargent and Lundy documentation, but not included in the actual cost algorithms - an adjustment to the base absorber island and balance of plant costs due to atmospheric pressure changes with elevation.

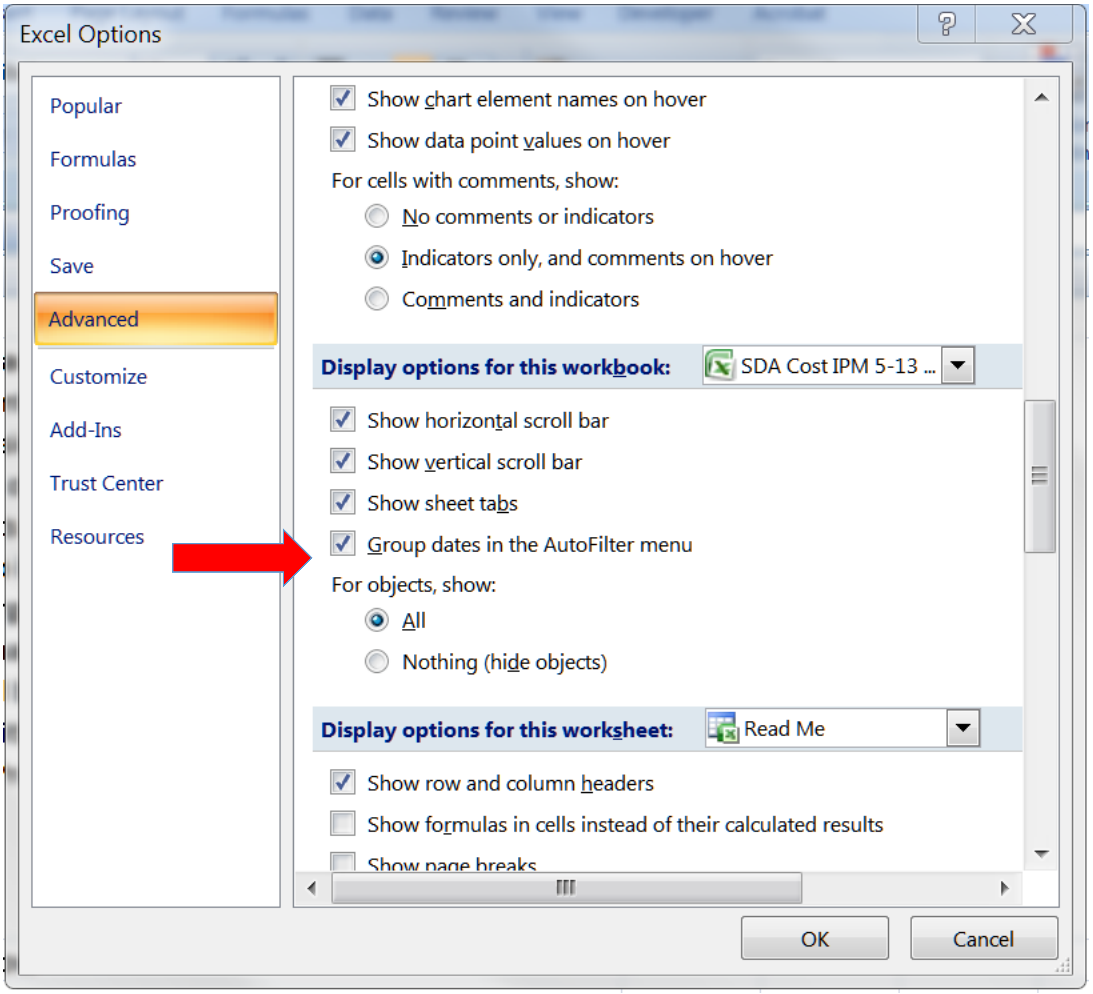
Emissions data downloaded from our Air Markets Program Data are included in the "Annual Emissions" and "Monthly Emissions" tabs as an aid in choosing some input values.

The "Entergy Costs" tabs summarizes those costs we propose are either undocumented or disallowed.

The "Cost Effectiveness" tab first applies corrections to the costs in the "Entergy Costs" tab, generated from the information in the "IPM WB 1 - 0.65 lb" and the "IPM WB 1 - 2 lb" tabs. It then calculates the annualized costs for SDA a the White Bluff Units.

See the "AR Cost TSD" file for details on how the above information has been used.

For the IPM tabs, user must have "show objects" selected in Excel's options for the drop down menus to work:


Excel Options
Popular
Formulas
Proofing
Save
Advanced
Customize
Add-Ins
Trust Center
Resources
Show chart element names on hover
Show data point values on hover
For cells with comments, show:
No comments or indicators
Indicators only, and comments on hover
Comments and indicators
Display options for this workbook:
SDA Cost IPM 5-13 ...
Show horizontal scroll bar
Show vertical scroll bar
Show sheet tabs
Group dates in the AutoFilter menu
For objects, show:
All
Nothing (hide objects)
Display options for this worksheet:
Read Me
Show row and column headers
Show formulas in cells instead of their calculated results
Show page breaks
OK
Cancel

The "IPM WB 1-2 lb" and the "IPM WB - 0.68 lb" tabs of this spreadsheet are adapted from the Sargent and Lundy cost algorithms documentation for a SDA FGD installation, as incorporated in version 5.13 of the IPM model. These tabs include a further correction recommended on page 2 of the Sargent and Lundy documentation, but not included in the actual cost algorithms - an adjustment to the base absorber island and balance of plant costs due to atmospheric pressure changes with elevation. The documentation for these cost algorithms are present in "IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, Final March 2013, Project 12847-002, Systems Research and Applications Corporation, Prepared by Sargent and Lundy."

The elevation adjustment to the base absorber island and balance of plant costs, that is suggested on page 2 of the above documentation, was accomplished by incorporating an atmospheric pressure change with elevation calculation by NASA via http://exploration.grc.nasa.gov/education/rocket/atmosmet.html. It should be noted that in addition to the NASA algorithm, this calculation requires converting the input feet to meters (multiplying elevation*0.3048) and K-Pa to psi (multiplying the calculation by 0.145038).

Emissions data were downloaded from EPA CAMD's website: http://ampd.epa.gov/ampd/

Entergy's SDA costs came from "Revised Bart Five Factor Analysis, White Bluff Steam Electric Station, Redfield, Arkansas (AFIN 35-00110). Appendix A, SDA cost analysis."

The BOP costs are modified based on costs taken from a 2008 S&L quote in the "Entergy Response to EPA Region 6 comments on Entergy White Bluff draft BART Report 06/10/13. Attachment B."

	Excluded BOP Costs			
Acct. No.	Description	Equipment	Material	Labor
106.1	Reagent Prep Enclosure	$0	$195,000	$492,000
107.1	Equipment	$7,012,000	$0	$5,610,000
107.2	4200 Ton Limes Storage Silos	$0	$2,428,000	$5,038,000
107.3	Enclosed Railcar Unloading Shed	$0	$200,000	$200,000
108	Unit 1 NOx Controls	$3,622,000	$1,600,000	$3,073,000
109	Unit 2 NOx Controls	$3,622,000	$1,600,000	$3,073,000
111	Unit 1 Flue Gas System	$0	$364,000	$513,000
111.2	Paint Chimney	$0	$0	$0
112	Unit 2 Flue Gas System	$0	$364,000	$513,000
Totals for Excluded BOP Items		$14,256,000	$6,751,000	$18,512,000
Totals for all BOP Items Excluding Percentage Costs		$45,561,000	$35,120,000	$80,863,000
Percentage BOP Items Reduced (%)		31.29	19.22	22.89

		ENTERGY		
ACCT. NO.	DESCRIPTION	ENTERGY TOTAL EQUIPMENT COST	ENTERGY TOTAL MATERIAL COST	ENTERGY TOTAL LABOR COST
301	MOBILIZE/DEMOBILIZE @ 1% OF LABOR			
301.2	MOBILIZE/DEMOBILIZE @ 1% OF LABOR			$710,000
302	COST DUE TO OVERTIME - 5-10'S			
302.2	COST DUE TO OVERTIME - 5-10'S			$10,363,000
304	PER DIEM - @ $10 PER HOUR			
304.2	PER DIEM - @ $10 PER HOUR			$10,257,000
305	SPARE PARTS @ 1% OF EQUIPMENT			
305.2	SPARE PARTS @ 1% OF EQUIPMENT	$476,000		
306	FREIGHT @ 5% OF MATERIAL			
306.4	FREIGHT @ 5% OF MATERIAL		$1,756,000	
307	GENERAL & ADMINISTRATIVE (G&A) @ 5% OF MATERIAL AND LABOR			
307.5	GENERAL & ADMINISTRATIVE (G&A) @ 5% OF MATERIAL AND LABOR		$1,756,000	$3,143,000
307.6	GENERAL & ADMINISTRATIVE (G&A) @ 5% OF MATERIAL AND LABOR			$1,456,000
308	PROFIT @ 10% OF MATERIAL AND LABOR			
308.5	PROFIT @ 10% OF MATERIAL AND LABOR		$3,512,000	$6,285,000
308.6	PROFIT @ 10% OF MATERIAL AND LABOR			$2,913,000
360	NON CONTRACTOR INDIRECTS			
360.8	ENGINEERING - BOP			$9,855,000
	TOTALS			
	REDUCTION IN BOP COSTS			

* EPA Adjusted BOP costs are calculated by applying the Equipment, Material, and Labor reduction per
Material, and Labor totals, and those totals have changed.

Alternate BOP Adjustm

	Excluded BOP Costs**			
Acct. No.	Description	Equipment	Material	Labor
106.1	Reagent Prep Enclosure	$0	$0	$0
107.1	Equipment	$0	$0	$0
107.2	4200 Ton Limes Storage Silos	$0	$0	$0
107.3	Enclosed Railcar Unloading Shed	$0	$0	$0
108	Unit 1 NOx Controls	$3,622,000	$1,600,000	$3,073,000
109	Unit 2 NOx Controls	$3,622,000	$1,600,000	$3,073,000
111	Unit 1 Flue Gas System	$0	$0	$0
111.2	Paint Chimney	$0	$0	$0
112	Unit 2 Flue Gas System	$0	$0	$0
Totals for Excluded BOP Items		$7,244,000	$3,200,000	$6,146,000
Totals for all BOP Items Excluding Percentage Costs		$45,561,000	$35,120,000	$80,863,000
Percentage BOP Items Reduced (%)		15.90	9.11	7.60

		ENTERGY		
ACCT. NO.	DESCRIPTION	ENTERGY TOTAL EQUIPMENT COST	ENTERGY TOTAL MATERIAL COST	ENTERGY TOTAL LABOR COST
301	MOBILIZE/DEMOBILIZE @ 1% OF LABOR			
301.2	MOBILIZE/DEMOBILIZE @ 1% OF LABOR			$710,000
302	COST DUE TO OVERTIME - 5-10'S			
302.2	COST DUE TO OVERTIME - 5-10'S			$10,363,000
304	PER DIEM - @ $10 PER HOUR			
304.2	PER DIEM - @ $10 PER HOUR			$10,257,000
305	SPARE PARTS @ 1% OF EQUIPMENT			
305.2	SPARE PARTS @ 1% OF EQUIPMENT	$476,000		
306	FREIGHT @ 5% OF MATERIAL			
306.4	FREIGHT @ 5% OF MATERIAL		$1,756,000	
307	GENERAL & ADMINISTRATIVE (G&A) @ 5% OF MATERIAL AND LABOR			
307.5	GENERAL & ADMINISTRATIVE (G&A) @ 5% OF MATERIAL AND LABOR		$1,756,000	$3,143,000
307.6	GENERAL & ADMINISTRATIVE (G&A) @ 5% OF MATERIAL AND LABOR			$1,456,000
308	PROFIT @ 10% OF MATERIAL AND LABOR			
308.5	PROFIT @ 10% OF MATERIAL AND LABOR		$3,512,000	$6,285,000
308.6	PROFIT @ 10% OF MATERIAL AND LABOR			$2,913,000
360	NON CONTRACTOR INDIRECTS			

360.8	ENGINEERING - BOP			$9,855,000
	TOTALS			
	REDUCTION IN BOP COSTS			

**Added back in all disputed BOP costs, regardless of whether these costs are disallowed under the CC

Total
$687,000
$12,622,000
$7,520,000
$400,000
$8,295,000
$8,295,000
$877,000
$0
$877,000
$39,573,000

ADJUSTED BOP COSTS				
	EPA*			
ENTERGY TOTAL COST	EPA TOTAL EQUIPMENT COST	EPA TOTAL MATERIAL COST	EPA TOTAL LABOR COST	EPA TOTAL COST
$710,000			$547,481	$547,481
$10,363,000			$7,990,909	$7,990,909
$10,257,000			$7,909,173	$7,909,173
$476,000	$327,060			$327,060
$1,756,000		$1,418,497		$1,418,497
$4,899,000		$1,418,497	$2,423,567	$3,842,064
$1,456,000			$1,122,722	$1,122,722
$9,797,000		$2,836,994	$4,846,364	$7,683,357
$2,913,000			$2,246,214	$2,246,214
$9,855,000			$7,599,191	$7,599,191
$52,482,000				$40,686,667
				$11,795,333

centages to Entergy's costs, as Entergy's costs are based on Equipment,

ient

Total
$0
$0
$0
$0
$8,295,000
$8,295,000
$0
$0
$0
$16,590,000

ADJUSTED BOP COSTS				
	EPA*			
ENTERGY TOTAL COST	EPA TOTAL EQUIPMENT COST	EPA TOTAL MATERIAL COST	EPA TOTAL LABOR COST	EPA TOTAL COST
$710,000			$656,040	$656,040
$10,363,000			$9,575,412	$9,575,412
$10,257,000			$9,477,468	$9,477,468
$476,000	$400,316			$400,316
$1,756,000		$1,596,028		$1,596,028
$4,899,000		$1,596,028	$2,904,132	$4,500,160
$1,456,000			$1,345,344	$1,345,344
$9,797,000		$3,192,057	$5,807,340	$8,999,397
$2,913,000			$2,691,612	$2,691,612

$9,855,000			$9,106,020	$9,106,020
$52,482,000				$48,347,798
				$4,134,202

M or are undocumented.

Comments

Added "paint chimney" back into BOP costs

changed to calculated totals

The material, and labor reduction percentages changed.

As above, the material, and labor reduction percentages changed so the calculations that depend on them

Entergy does not dispute these costs should be disallowed
Entergy does not dispute these costs should be disallowed

The equipment, material, and labor reduction percentages changed.

n changed.

White Bluff SDA Cost

Item	Entergy	EPA Adjustments	EPA (2013)
Total Contractor Costs (2010)	$156,974,274		$161,676,662
Contingency (2010)	$20,875,711		$21,501,073
Balance of Plant (2008)	$102,085,500	-$25,684,167	$75,325,819
Balance of Plant Indirect Costs (2012)	$8,733,104	-$8,733,104	$0
Misc Contract Labor (2012)	$4,583,719	-$4,583,719	$0
Entergy Internal Costs (2012)	$20,076,644	-$20,076,644	$0
Capital suspense (2012)	$8,348,276	-$8,348,276	$0
Total Capital Investment (TCI)			$258,503,555
Direct Annual Costs (2008)	$7,901,369		$7,790,140
Indirect Annual Costs			
Overhead (2008)	$2,572,707		$2,536,491
Administrative Charges @ 2% of TCI			$5,170,071
Property Tax @ 1% of TCI			$2,585,036
Insurance @ 1% of TCI			$2,585,036
Total Indirect Annual Costs			$12,876,633

*There is less than a 1% difference between how Entergy calculates the SDA cost for Unit 1 and corrections we make and assume the cost for either unit corresponds to Unit 1.

Alternate White Bluff SDA

Item	Entergy	EPA Adjustments	EPA (2013)
Total Contractor Costs (2010)	$156,974,274		$161,676,662
Contingency (2010)	$20,875,711		$21,501,073
Balance of Plant (2008)	$102,085,500	-$10,362,101	$90,432,193
Balance of Plant Indirect Costs (2012)	$8,733,104	$0	$8,474,666
Misc Contract Labor (2012)	$4,583,719	$0	$4,448,074
Entergy Internal Costs (2012)	$20,076,644	$0	$19,482,518
Capital suspense (2012)	$8,348,276	$0	$8,101,226
Total Capital Investment (TCI)			$314,116,413
Direct Annual Costs (2008)	$7,901,369		$7,790,140
Indirect Annual Costs			
Overhead (2008)	$2,572,707		$2,536,491
Administrative Charges @ 2% of TCI			$6,282,328
Property Tax @ 1% of TCI			$3,141,164
Insurance @ 1% of TCI			$3,141,164
Total Indirect Annual Costs			$15,101,147

**Added back in all disputed BOP costs, regardless of whether these costs are disallowed under ts Per Unit*

Comments	Year	CEPCI Annual Composite Index
Entergy 2010 cost escalated to 2013	2008	575.4
EPA escalated to 2013	2009	521.9
S&L 2008 BOP minus EPA adjustments, then escalated to 20	2010	550.8
Disallowed or undocumented - see TSD for details	2011	585.7
Disallowed or undocumented - see TSD for details	2012	584.6
Disallowed or undocumented - see TSD for details	2013	567.3
Disallowed or undocumented - see TSD for details		
EPA escalated to 2013		
EPA escalated to 2013		
2% of TCI		
1% of TCI		
1% of TCI		

Unit 2. We therefore ignore this difference in the

Costs Per Unit**

Comments	Year	CEPCI Annual Composite Index
Entergy 2010 cost escalated to 2013	2008	575.4
EPA escalated to 2013	2009	521.9
S&L 2008 BOP minus just NOx controls, then escalated to 20	2010	550.8
Disallowed costs added back in, then escalated to 2013	2011	585.7
Disallowed costs added back in, then escalated to 2014	2012	584.6
Disallowed costs added back in, then escalated to 2015	2013	567.3
Disallowed costs added back in, then escalated to 2016		
EPA escalated to 2013		
EPA escalated to 2013		
2% of TCI		
1% of TCI		
1% of TCI		

the CCM or are undocumented.

Comments

Updated BOP total from BOP tab, and resulting sums that depend on it.

White Bluff Unit 1

Item	White Bluff Cost at 2.0 lbs/MMBtu	Ratio of 0.68 lb/MMBtu to 2.0 lb/MMBtu[1]	Corrected White Bluff Cost to 0.68 lbs/MMBtu
Annualized Capital Costs	$20,831,872	0.9584	$19,965,416
Total Direct Annual Costs[2]	$7,790,140	0.5823	$4,536,069
Total Indirect Annual Costs	$12,876,633	0.9584	$12,341,058
Total Annualized Cost			$36,842,543
Interest Rate (%)			7
Equipment Lifetime (years)			30
Capital Recovery Factor (CRF)			0.0806
SO2 Emission Rate (lbs/MMBtu)			0.65
Controlled SO2 Emission Rate (%)			90.81
SO2 Emission Baseline (tons)			15,816
SO2 Emission Reduction (tons)			14,363
Cost Effectiveness ($/ton)			$2,565

White Bluff Unit 2

Item	Corrected White Bluff Cost to 0.68 lbs/MMBtu
Total Annualized Cost	$36,842,543
Interest Rate (%)	7
Equipment Lifetime (years)	30
Capital Recovery Factor (CRF)	0.0806
SO2 Emission Rate (lbs/MMBtu)	0.68
Controlled SO2 Emission Rate (%)	91.16
SO2 Emission Baseline (tons)	16,697
SO2 Emission Reduction (tons)	15,221
Cost Effectiveness ($/ton)	$2,421

Independence Unit 1

Item	Corrected White Bluff Cost to 0.68 lbs/MMBtu
Total Annualized Cost	$36,842,543
Interest Rate (%)	7
Equipment Lifetime (years)	30
Capital Recovery Factor (CRF)	0.0806
SO2 Emission Rate (lbs/MMBtu)	0.63
Controlled SO2 Emission Rate (%)	90.49
SO2 Emission Baseline (tons)	14,269
SO2 Emission Reduction (tons)	12,912

Cost Effectiveness ($/ton)	$2,853

Independence Unit 2

Item	Corrected White Bluff Cost to 0.68 lbs/MMBtu
Total Annualized Cost	$36,842,543
Interest Rate (%)	7
Equipment Lifetime (years)	30
Capital Recovery Factor (CRF)	0.0806
SO2 Emission Rate (lbs/MMBtu)	0.61
Controlled SO2 Emission Rate (%)	90.19
SO2 Emission Baseline (tons)	15,511
SO2 Emission Reduction (tons)	13,990
Cost Effectiveness ($/ton)	$2,634

[1] Uses the annualized capital and the sum of the fixed and variable operating costs from the "IPM WB

[2] Entergy also includes annualized capital costs as an indirect annual cost, but we separate it out here,

Alternate White Bluff Unit 1

Item	White Bluff Cost at 2.0 lbs/MMBtu	Ratio of 0.68 lb/MMBtu to 2.0 lb/MMBtu[1]	Corrected White Bluff Cost to 0.68 lbs/MMBtu
Annualized Capital Costs	$25,313,512	0.9584	$24,260,652
Total Direct Annual Costs[2]	$7,790,140	0.5823	$4,536,069
Total Indirect Annual Costs	$15,101,147	0.9584	$14,473,048
Total Annualized Cost			$43,269,770
Interest Rate (%)			7
Equipment Lifetime (years)			30
Capital Recovery Factor (CRF)			0.0806
SO2 Emission Rate (lbs/MMBtu)			0.65
Controlled SO2 Emission Rate (%)			90.81
SO2 Emission Baseline (tons)			15,816
SO2 Emission Reduction (tons)			14,363
Cost Effectiveness ($/ton)			$3,013

Alternate White Bluff Unit 2

Item	Corrected White Bluff Cost to 0.68 lbs/MMBtu
Total Annualized Cost	$43,269,770
Interest Rate (%)	7

Equipment Lifetime (years)	30
Capital Recovery Factor (CRF)	0.0806
SO2 Emission Rate (lbs/MMBtu)	0.68
Controlled SO2 Emission Rate (%)	91.16
SO2 Emission Baseline (tons)	16,697
SO2 Emission Reduction (tons)	15,221
Cost Effectiveness ($/ton)	$2,843

Alternate Independence Unit 1	
Item	Corrected White Bluff Cost to 0.68 lbs/MMBtu
Total Annualized Cost	$43,269,770
Interest Rate (%)	7
Equipment Lifetime (years)	30
Capital Recovery Factor (CRF)	0.0806
SO2 Emission Rate (lbs/MMBtu)	0.63
Controlled SO2 Emission Rate (%)	90.49
SO2 Emission Baseline (tons)	14,269
SO2 Emission Reduction (tons)	12,912
Cost Effectiveness ($/ton)	$3,351

Alternate Independence Unit 2	
Item	Corrected White Bluff Cost to 0.68 lbs/MMBtu
Total Annualized Cost	$43,269,770
Interest Rate (%)	7
Equipment Lifetime (years)	30
Capital Recovery Factor (CRF)	0.0806
SO2 Emission Rate (lbs/MMBtu)	0.61
Controlled SO2 Emission Rate (%)	90.19
SO2 Emission Baseline (tons)	15,511
SO2 Emission Reduction (tons)	13,990
Cost Effectiveness ($/ton)	$3,093

Comments	Comments
Using TCI from Entergy Costs tab	Updated totals due to BOP change
Sum of direct and indirect costs from Entergy Cost tab	
	Updated to multiply the Total indirect annua
Max monthly value from 2009-2013 for Unit 1	
Assume 95%. If outlet < 0.06 lbs/MMBtu, then assume % control for 0.06 lbs/MMBtu.	
3 -yr avg. 2009-2013 for Unit 1, excluding max and min	

Comments
Assumed same as White Bluff Unit 1
Max monthly value from 2009-2013 for Unit 2
Assume 95%. If outlet < 0.06 lbs/MMBtu, then assume % control for 0.06 lbs/MMBtu.
3 -yr avg. 2009-2013 for Unit 2, excluding max and min

Comments
Assumed same as White Bluff Unit 1
Max monthly value from 2009-2013 for Unit 1
Assume 95%. If outlet < 0.06 lbs/MMBtu, then assume % control for 0.06 lbs/MMBtu.
3 -yr avg. 2009-2013 for Unit 1, excluding max and min

Comments
Assumed same as White Bluff Unit 1
Max monthly value from 2009-2013 for Unit 2
Assume 95%. If outlet < 0.06 lbs/MMBtu, then assume % control for 0.06 lbs/MMBtu.
3 -yr avg. 2009-2013 for Unit 2, excluding max and min

1 - 2 lb" and the "IPM WB 1 - 0.68 lb" tabs.

as its correction factor is significantly different.

Comments
Using TCI from Entergy Costs tab
Sum of direct and indirect costs from Entergy Cost tab
Max monthly value from 2009-2013 for Unit 1
Assume 95%. If outlet < 0.06 lbs/MMBtu, then assume % control for 0.06 lbs/MMBtu.
3 -yr avg. 2009-2013 for Unit 1, excluding max and min

Comments
Assumed same as White Bluff Unit 1

Max monthly value from 2009-2013 for Unit 2
Assume 95%. If outlet < 0.06 lbs/MMBtu, then assume % control for 0.06 lbs/MMBtu.
3 -yr avg. 2009-2013 for Unit 2, excluding max and min

Comments
Assumed same as White Bluff Unit 1
Max monthly value from 2009-2013 for Unit 1
Assume 95%. If outlet < 0.06 lbs/MMBtu, then assume % control for 0.06 lbs/MMBtu.
3 -yr avg. 2009-2013 for Unit 1, excluding max and min

Comments
Assumed same as White Bluff Unit 1
Max monthly value from 2009-2013 for Unit 2
Assume 95%. If outlet < 0.06 lbs/MMBtu, then assume % control for 0.06 lbs/MMBtu.
3 -yr avg. 2009-2013 for Unit 2, excluding max and min

l costs by 0.9584

	Annualized Costs
Independence Unit 1	36842542.71
Independence Unit 2	36842542.71
Total Cost	73685085.42

Control Option	Caney Creek	Upper Buffalo	Hercules Glades	Mingo
Δ Deciview	1.096	1.178	1.056	1.045
$/Deciview	$ 67,230,917	$ 62,551,006	$ 69,777,543	$ 70,512,043

Facility	Unit	MW
Independence	1	850
	2	850
White Bluff	1	850
	2	850

Facility	Unit	MW
Independence	1	850
	2	850
White Bluff	1	850
	2	850

Facility Name	Facility ID (ORISPL)	Unit ID	Year	SO2 (tons)		SO2 max 2009-2012 (tons)	SO2 avg. 2009-2012 excluding Max and Min (tons)	Avg. NOx Rate (lb/MMBtu)	NOx (tons)
Independ	6641	1	2009	12,254				0.247	6,610
Independ	6641	1	2010	14,917				0.2449	7,841
Independ	6641	1	2011	15,308				0.2442	7,013
Independ	6641	1	2012	16,233				0.1968	5,364
Independ	6641	1	2013	12,581	14,258	16,233	14,269	0.2075	4,737
Independ	6641	2	2009	15,171				0.2381	7,728
Independ	6641	2	2010	13,758				0.2461	6,778
Independ	6641	2	2011	15,090				0.2269	6,397
Independ	6641	2	2012	16,741				0.2012	5,702
Independ	6641	2	2013	16,273	15,407	16,741	15,511	0.207	5,977
White Blu	6009	1	2009	16,281				0.2464	6,569
White Blu	6009	1	2010	15,936				0.2501	7,927
White Blu	6009	1	2011	15,018				0.2733	7,269
White Blu	6009	1	2012	15,232				0.2705	6,891
White Blu	6009	1	2013	17,227	15,939	17,227	15,816	0.3039	9,244
White Blu	6009	2	2009	17,551				0.2774	7,955
White Blu	6009	2	2010	12,528				0.3099	7,880
White Blu	6009	2	2011	16,666				0.2948	8,743
White Blu	6009	2	2012	16,455				0.2597	7,345
White Blu	6009	2	2013	16,969	16,034	17,551	16,697	0.2934	8,803

Heat Input (MMBtu)	Operating Time	# of Months Reported	Gross Load (MW-h)	Gross Load avg. (MW-h)	Gross Load Max 2009-2012 (MW-h)	Gross Load avg. 2009-2012 excluding Max and Min (MW-h)	Gross Heat Rate (Btu/kWh)
53,166,394	7,334	12	5,395,292				9,854
63,712,504	8,372	12	6,463,750				9,857
57,172,444	7,816	12	5,805,478				9,848
55,348,316	8,482	12	5,513,571				10,039
45,732,632	7,246	12	4,847,543	5,605,127	6,463,750	5,571,447	9,434
64,649,132	8,169	12	6,525,058				9,908
55,125,638	7,585	12	5,953,973				9,259
56,273,140	8,024	12	5,693,302				9,884
57,205,848	7,404	12	5,385,123				10,623
58,742,729	8,437	12	6,041,307	5,919,753	6,525,058	5,896,194	9,724
52,685,717	7,193	12	5,408,276				9,742
63,178,868	8,004	12	6,275,922				10,067
52,436,173	6,887	12	4,888,905				10,726
50,688,512	7,599	12	4,710,116				10,762
60,158,485	7,825	12	5,585,754	5,373,795	6,275,922	5,294,312	10,770
56,474,072	7,610	12	5,841,826				9,667
49,581,773	6,608	12	5,130,420				9,664
58,613,642	7,986	12	5,937,159				9,872
56,244,209	7,596	12	5,210,329				10,795
59,297,615	7,612	12	5,420,970	5,508,141	5,937,159	5,491,041	10,939

Gross Heat Rate 2009-2012 Max (Btu/kWh)	Gross Heat Rate 2009-2012 Avg. (Btu/kWh)	Gross Heat Rate avg. 2009-2012 excluding Max and Min (tons)	County	Operating Status	Unit Type	Fuel Type (Primary)	Fuel Type (Secondary)	SO2 Control(s)	NOx Control(s)
			Independ	Operating	Tangentia	Coal	Residual Oil		Overfire A
			Independ	Operating	Tangentia	Coal	Residual Oil		Overfire A
			Independ	Operating	Tangentia	Coal	Residual Oil		Overfire A
			Independ	Operating	Tangentia	Coal	Residual Oil		Overfire A
10,039	9,806	9,853	Independ	Operating	Tangentia	Coal	Residual Oil		Overfire A
			Independ	Operating	Tangentia	Coal	Residual Oil		Overfire A
			Independ	Operating	Tangentia	Coal	Residual Oil		Overfire A
			Independ	Operating	Tangentia	Coal	Residual Oil		Overfire A
			Independ	Operating	Tangentia	Coal	Residual Oil		Overfire A
10,623	9,879	9,838	Independ	Operating	Tangentia	Coal	Residual Oil		Overfire A
			Jefferson	Operating	Tangentia	Coal	Residual Oil		Overfire A
			Jefferson	Operating	Tangentia	Coal	Residual Oil		Overfire A
			Jefferson	Operating	Tangentia	Coal	Residual Oil		Overfire A
			Jefferson	Operating	Tangentia	Coal	Residual Oil		Overfire A
10,770	10,413	10,518	Jefferson	Operating	Tangentia	Coal	Residual Oil		Overfire A
			Jefferson	Operating	Tangentia	Coal	Residual Oil		Overfire A
			Jefferson	Operating	Tangentia	Coal	Residual Oil		Overfire A
			Jefferson	Operating	Tangentia	Coal	Residual Oil		Overfire A
			Jefferson	Operating	Tangentia	Coal	Residual Oil		Overfire A
10,939	10,187	10,111	Jefferson	Operating	Tangentia	Coal	Residual Oil		Overfire A

PM Control(s)	Facility Latitude	Facility Longitude
Electrosta	35.6733	-91.408
Electrosta	35.6733	-91.408
Electrosta	35.6733	-91.408
Electrosta	35.6733	-91.408
Electrosta	35.6733	-91.408
Electrosta	35.6733	-91.408
Electrosta	35.6733	-91.408
Electrosta	35.6733	-91.408
Electrosta	35.6733	-91.408
Electrosta	35.6733	-91.408
Electrosta	34.4236	-92.139
Electrosta	34.4236	-92.139
Electrosta	34.4236	-92.139
Electrosta	34.4236	-92.139
Electrosta	34.4236	-92.139
Electrosta	34.4236	-92.139
Electrosta	34.4236	-92.139
Electrosta	34.4236	-92.139
Electrosta	34.4236	-92.139
Electrosta	34.4236	-92.139

Facility Name	Facility ID (ORISPL)	Unit ID	Year	Month	SO2 (tons)	SO2 Rate (lbs/MMBtu)	Avg. Annual SO2 (lbs/MMBtu)	Max. Annual SO2 (lbs/MMBtu)
Independ	6641	1	2009	1	1112.15	0.4604736		
Independ	6641	1	2009	2	877.947	0.4307477		
Independ	6641	1	2009	3				
Independ	6641	1	2009	4	449.006	0.4549397		
Independ	6641	1	2009	5	1260.3	0.4951293		
Independ	6641	1	2009	6	1210.71	0.4563594		
Independ	6641	1	2009	7	1290.23	0.4620864		
Independ	6641	1	2009	8	1043.69	0.4541477		
Independ	6641	1	2009	9	1246.37	0.4472149		
Independ	6641	1	2009	10	1372.69	0.4861275		
Independ	6641	1	2009	11	1205.95	0.4587964		
Independ	6641	1	2009	12	1185.06	0.4531908	0.460	0.495
Independ	6641	1	2010	1	1211.49	0.450489		
Independ	6641	1	2010	2	1062.52	0.488712		
Independ	6641	1	2010	3	638.782	0.4297985		
Independ	6641	1	2010	4	1346.07	0.4826621		
Independ	6641	1	2010	5	1505.03	0.5223709		
Independ	6641	1	2010	6	1353.96	0.4644078		
Independ	6641	1	2010	7	1408.7	0.4849137		
Independ	6641	1	2010	8	1423.37	0.4984232		
Independ	6641	1	2010	9	1125.77	0.3946202		
Independ	6641	1	2010	10	1268	0.4434328		
Independ	6641	1	2010	11	1274.4	0.4573997		
Independ	6641	1	2010	12	1298.59	0.4878492	0.467	0.522
Independ	6641	1	2011	1	1400.37	0.5436495		
Independ	6641	1	2011	2	1323.39	0.5160107		
Independ	6641	1	2011	3	1313.28	0.4452915		
Independ	6641	1	2011	4	36.311	0.4485677		
Independ	6641	1	2011	5	866.825	0.5155174		
Independ	6641	1	2011	6	1384.92	0.5444501		
Independ	6641	1	2011	7	1694.42	0.5705155		
Independ	6641	1	2011	8	1519.3	0.566533		
Independ	6641	1	2011	9	1481.51	0.5300026		
Independ	6641	1	2011	10	1440.15	0.5351527		
Independ	6641	1	2011	11	1449.82	0.5674455		
Independ	6641	1	2011	12	1397.57	0.5596489	0.529	0.571
Independ	6641	1	2012	1	1579.63	0.601471		
Independ	6641	1	2012	2	1546.65	0.5990946		
Independ	6641	1	2012	3	1423.81	0.5867701		

Independ	6641	1	2012	4	679.43	0.6221009		
Independ	6641	1	2012	5	1688.27	0.6310765		
Independ	6641	1	2012	6	1550.27	0.5895365		
Independ	6641	1	2012	7	1270.09	0.5800639		
Independ	6641	1	2012	8	1269.23	0.5698796		
Independ	6641	1	2012	9	1304.06	0.5825625		
Independ	6641	1	2012	10	1436.55	0.5965317		
Independ	6641	1	2012	11	1297.03	0.5467498		
Independ	6641	1	2012	12	1187.48	0.5380493	0.587	0.631
Independ	6641	1	2013	1	1171.65	0.5436051		
Independ	6641	1	2013	2	1004.21	0.5084414		
Independ	6641	1	2013	3	1163.73	0.5459182		
Independ	6641	1	2013	4				
Independ	6641	1	2013	5	186.919	0.5572849		
Independ	6641	1	2013	6	1267.08	0.5252809		
Independ	6641	1	2013	7	1240.6	0.5341214		
Independ	6641	1	2013	8	1445.24	0.5541611		
Independ	6641	1	2013	9	1364.34	0.5676353		
Independ	6641	1	2013	10	1169.09	0.544714		
Independ	6641	1	2013	11	1154.9	0.5749294		
Independ	6641	1	2013	12	1413.43	0.597045	0.550	0.597
Independ	6641	2	2009	1	1276.04	0.461954		
Independ	6641	2	2009	2	1050.15	0.4519378		
Independ	6641	2	2009	3	1259.63	0.4710161		
Independ	6641	2	2009	4	1422.48	0.4947402		
Independ	6641	2	2009	5	1279.79	0.4941754		
Independ	6641	2	2009	6	1383.57	0.4601124		
Independ	6641	2	2009	7	1440.84	0.4583515		
Independ	6641	2	2009	8	1475.76	0.4780394		
Independ	6641	2	2009	9	1276.8	0.4608929		
Independ	6641	2	2009	10	759.933	0.4859091		
Independ	6641	2	2009	11	1289.27	0.4647449		
Independ	6641	2	2009	12	1256.92	0.4565007	0.470	0.495
Independ	6641	2	2010	1	1247	0.4462464		
Independ	6641	2	2010	2	1251.07	0.5371917		
Independ	6641	2	2010	3	1268.88	0.4841933		
Independ	6641	2	2010	4	1366.49	0.527994		
Independ	6641	2	2010	5	1547.11	0.5828048		
Independ	6641	2	2010	6	1258.44	0.5178177		
Independ	6641	2	2010	7	1238.53	0.5085562		
Independ	6641	2	2010	8	1576.36	0.5134713		
Independ	6641	2	2010	9	616.404	0.386806		
Independ	6641	2	2010	10	103.895	0.424318		
Independ	6641	2	2010	11	1062.28	0.4609079		

Independ	6641	2	2010	12	1221.49	0.4891148	0.490	0.583
Independ	6641	2	2011	1	1494.15	0.5522822		
Independ	6641	2	2011	2	1211.01	0.509086		
Independ	6641	2	2011	3	853.126	0.4457289		
Independ	6641	2	2011	4	1358.1	0.5252867		
Independ	6641	2	2011	5	1016.42	0.5166005		
Independ	6641	2	2011	6	1232.87	0.5441639		
Independ	6641	2	2011	7	1718.04	0.5591413		
Independ	6641	2	2011	8	1432.63	0.5622682		
Independ	6641	2	2011	9	511.564	0.5077695		
Independ	6641	2	2011	10	1569.1	0.5288457		
Independ	6641	2	2011	11	1515.61	0.5738339		
Independ	6641	2	2011	12	1177.49	0.5651512	0.533	0.574
Independ	6641	2	2012	1	1827.9	0.6063618		
Independ	6641	2	2012	2	1748.74	0.6045646		
Independ	6641	2	2012	3	1719.58	0.5755174		
Independ	6641	2	2012	4	1512.49	0.6083005		
Independ	6641	2	2012	5	1972.43	0.6115068		
Independ	6641	2	2012	6	1806.74	0.5815557		
Independ	6641	2	2012	7	1679.41	0.5883801		
Independ	6641	2	2012	8	1610.54	0.575749		
Independ	6641	2	2012	9	1055.9	0.5635423		
Independ	6641	2	2012	10				
Independ	6641	2	2012	11	547.702	0.5246318		
Independ	6641	2	2012	12	1259.81	0.5430185	0.580	0.612
Independ	6641	2	2013	1	1392.22	0.5430696		
Independ	6641	2	2013	2	1083.62	0.5086952		
Independ	6641	2	2013	3	1366.03	0.5621954		
Independ	6641	2	2013	4	1474.44	0.561091		
Independ	6641	2	2013	5	1591.26	0.591329		
Independ	6641	2	2013	6	1512.97	0.5424321		
Independ	6641	2	2013	7	1551.07	0.5503279		
Independ	6641	2	2013	8	1604.81	0.5640298		
Independ	6641	2	2013	9	1360.3	0.5788117		
Independ	6641	2	2013	10	840.25	0.5256519		
Independ	6641	2	2013	11	1160.29	0.5560632		
Independ	6641	2	2013	12	1335.85	0.5473075	0.553	0.591
White Blu	6009	1	2009	1	1516.25	0.6231833		
White Blu	6009	1	2009	2	1619.07	0.6410627		
White Blu	6009	1	2009	3	1735.47	0.614027		
White Blu	6009	1	2009	4	107.263	0.530905		
White Blu	6009	1	2009	5	29.209	0.4421449		
White Blu	6009	1	2009	6	1450.13	0.6061934		
White Blu	6009	1	2009	7	1579.44	0.6157057		

White Blu	6009	1	2009	8	1685.81	0.6122074		
White Blu	6009	1	2009	9	1656.14	0.6165286		
White Blu	6009	1	2009	10	1426.2	0.6289818		
White Blu	6009	1	2009	11	1796.53	0.6363084		
White Blu	6009	1	2009	12	1679.27	0.599409	0.597	0.641
White Blu	6009	1	2010	1	1509.08	0.5357977		
White Blu	6009	1	2010	2	901.91	0.5022562		
White Blu	6009	1	2010	3	408.786	0.4482279		
White Blu	6009	1	2010	4	1382.85	0.5033332		
White Blu	6009	1	2010	5	1388.49	0.4521856		
White Blu	6009	1	2010	6	1377.96	0.4897129		
White Blu	6009	1	2010	7	1500.65	0.4924952		
White Blu	6009	1	2010	8	1584.48	0.5261722		
White Blu	6009	1	2010	9	1587.79	0.5382955		
White Blu	6009	1	2010	10	1578.06	0.5256973		
White Blu	6009	1	2010	11	1255.06	0.4957317		
White Blu	6009	1	2010	12	1461.15	0.5052743	0.501	0.538
White Blu	6009	1	2011	1	1587.59	0.5366247		
White Blu	6009	1	2011	2	982.144	0.5634057		
White Blu	6009	1	2011	3	1270.08	0.6529243		
White Blu	6009	1	2011	4	1580.22	0.5909492		
White Blu	6009	1	2011	5	1543.28	0.5817336		
White Blu	6009	1	2011	6	1736.65	0.6049289		
White Blu	6009	1	2011	7	1672.26	0.5638458		
White Blu	6009	1	2011	8	1867.67	0.5758514		
White Blu	6009	1	2011	9	1373.9	0.5232034		
White Blu	6009	1	2011	10	335.901	0.5266775		
White Blu	6009	1	2011	11				
White Blu	6009	1	2011	12	1068.33	0.5621128	0.571	0.653
White Blu	6009	1	2012	1	1507.89	0.6081753		
White Blu	6009	1	2012	2	1521.49	0.6206708		
White Blu	6009	1	2012	3	1104.2	0.596224		
White Blu	6009	1	2012	4	957.573	0.5716261		
White Blu	6009	1	2012	5	1548.12	0.6038417		
White Blu	6009	1	2012	6	1509.46	0.634164		
White Blu	6009	1	2012	7	1340.33	0.6032206		
White Blu	6009	1	2012	8	1629.92	0.6038603		
White Blu	6009	1	2012	9	1731.6	0.6085604		
White Blu	6009	1	2012	10	706.755	0.6054709		
White Blu	6009	1	2012	11	465.97	0.5494459		
White Blu	6009	1	2012	12	1208.6	0.5594162	0.597	0.634
White Blu	6009	1	2013	1	1794.41	0.6003996		
White Blu	6009	1	2013	2	1402.39	0.5442306		
White Blu	6009	1	2013	3	1639.01	0.559867		

White Blu	6009	1	2013	4	1633.51	0.5428713		
White Blu	6009	1	2013	5	1546.63	0.5555287		
White Blu	6009	1	2013	6	1449.87	0.5137758		
White Blu	6009	1	2013	7	1560.74	0.5763958		
White Blu	6009	1	2013	8	1855.53	0.6069242		
White Blu	6009	1	2013	9	1491.87	0.5825541		
White Blu	6009	1	2013	10	666.836	0.5790704		
White Blu	6009	1	2013	11	676.484	0.5996412		
White Blu	6009	1	2013	12	1509.79	0.6382544	0.575	0.638
White Blu	6009	2	2009	1	1405.37	0.6388324		
White Blu	6009	2	2009	2	358.88	0.6787513		
White Blu	6009	2	2009	3	1088.61	0.6300497		
White Blu	6009	2	2009	4	1563.71	0.5882022		
White Blu	6009	2	2009	5	1484.16	0.6381304		
White Blu	6009	2	2009	6	1498.11	0.6151241		
White Blu	6009	2	2009	7	1708.73	0.6168551		
White Blu	6009	2	2009	8	1817.63	0.6233566		
White Blu	6009	2	2009	9	1770.9	0.6255764		
White Blu	6009	2	2009	10	1848.03	0.6260922		
White Blu	6009	2	2009	11	1770.2	0.6372881		
White Blu	6009	2	2009	12	1236.69	0.5848061	0.625	0.679
White Blu	6009	2	2010	1	1427.96	0.5440333		
White Blu	6009	2	2010	2	1268.65	0.5011027		
White Blu	6009	2	2010	3	1362.47	0.4706712		
White Blu	6009	2	2010	4	477.879	0.5139129		
White Blu	6009	2	2010	5	1336.23	0.4605269		
White Blu	6009	2	2010	6	1432.36	0.4842052		
White Blu	6009	2	2010	7	1219.22	0.5063863		
White Blu	6009	2	2010	8	1313.26	0.5292348		
White Blu	6009	2	2010	9	1550.08	0.5451226		
White Blu	6009	2	2010	10	49.938	0.5751688		
White Blu	6009	2	2010	11				
White Blu	6009	2	2010	12	1090.05	0.511611	0.513	0.575
White Blu	6009	2	2011	1	1487.8	0.5424193		
White Blu	6009	2	2011	2	1379.83	0.5709102		
White Blu	6009	2	2011	3	1472.37	0.6152169		
White Blu	6009	2	2011	4	246.876	0.5150379		
White Blu	6009	2	2011	5	1386.97	0.5843466		
White Blu	6009	2	2011	6	1600.87	0.598551		
White Blu	6009	2	2011	7	1599.41	0.5446583		
White Blu	6009	2	2011	8	1742.09	0.5726734		
White Blu	6009	2	2011	9	1248.15	0.5176615		
White Blu	6009	2	2011	10	1724.96	0.5967909		
White Blu	6009	2	2011	11	1407.06	0.5792734		

White Blu	6009	2	2011	12	1369.96	0.5442329	0.565	0.615
White Blu	6009	2	2012	1	1346.49	0.583173		
White Blu	6009	2	2012	2	1534.89	0.6042214		
White Blu	6009	2	2012	3	728.632	0.5916919		
White Blu	6009	2	2012	4	124.721	0.5369343		
White Blu	6009	2	2012	5	1686.22	0.5910437		
White Blu	6009	2	2012	6	1759.43	0.6135648		
White Blu	6009	2	2012	7	1424.54	0.5965056		
White Blu	6009	2	2012	8	1655.26	0.5935461		
White Blu	6009	2	2012	9	1684.32	0.590015		
White Blu	6009	2	2012	10	1855.37	0.5843851		
White Blu	6009	2	2012	11	1583.33	0.5393673		
White Blu	6009	2	2012	12	1072.06	0.5507221	0.581	0.614
White Blu	6009	2	2013	1	1659.63	0.5816918		
White Blu	6009	2	2013	2	395.4	0.5267971		
White Blu	6009	2	2013	3	469.29	0.5694223		
White Blu	6009	2	2013	4	1647.99	0.5362469		
White Blu	6009	2	2013	5	1678.17	0.5452371		
White Blu	6009	2	2013	6	1519.07	0.5035324		
White Blu	6009	2	2013	7	1782.52	0.568939		
White Blu	6009	2	2013	8	1778.57	0.5973807		
White Blu	6009	2	2013	9	1409.56	0.5676667		
White Blu	6009	2	2013	10	1531.42	0.5807263		
White Blu	6009	2	2013	11	1558.43	0.6422399		
White Blu	6009	2	2013	12	1539.15	0.6423679	0.572	0.642

Avg. NOx Rate (lb/MMBtu)	NOx (tons)	Heat Input (MMBtu)	Operating Time	Gross Load (MW-h)	County	Facility Latitude	Facility Longitude	Owner
0.2352	571.803	4830466	687.09	490490	Independ	35.6733	-91.408	Arkansas
0.2361	486.431	4076386	600.3	402233	Independ	35.6733	-91.408	Arkansas
			0		Independ	35.6733	-91.408	Arkansas
0.2764	282.576	1973915	338.89	194663	Independ	35.6733	-91.408	Arkansas
0.2883	737.935	5090807	708.13	514443	Independ	35.6733	-91.408	Arkansas
0.2919	767.094	5305949	719.12	545367	Independ	35.6733	-91.408	Arkansas
0.2794	776.893	5584384	744	569295	Independ	35.6733	-91.408	Arkansas
0.2328	567.039	4596249	632.02	457649	Independ	35.6733	-91.408	Arkansas
0.2097	581.38	5573907	720	567102	Independ	35.6733	-91.408	Arkansas
0.2162	615.559	5647456	744	587421	Independ	35.6733	-91.408	Arkansas
0.2122	561.403	5257029	720	533305	Independ	35.6733	-91.408	Arkansas
0.2512	662.294	5229845	720.12	533321	Independ	35.6733	-91.408	Arkansas
0.2445	657.44	5378573	744	552014	Independ	35.6733	-91.408	Arkansas
0.2431	536.409	4348250	598.77	442146	Independ	35.6733	-91.408	Arkansas
0.2372	365.953	2972472	433.87	303056	Independ	35.6733	-91.408	Arkansas
0.2444	682.76	5577691	720	572458	Independ	35.6733	-91.408	Arkansas
0.2312	669.029	5762312	744	583514	Independ	35.6733	-91.408	Arkansas
0.238	697.36	5830896	720	586437	Independ	35.6733	-91.408	Arkansas
0.237	692.54	5810097	744	585833	Independ	35.6733	-91.408	Arkansas
0.2473	711.128	5711492	744	568158	Independ	35.6733	-91.408	Arkansas
0.2506	716.304	5705567	720	568443	Independ	35.6733	-91.408	Arkansas
0.2519	719.545	5719036	744	577999	Independ	35.6733	-91.408	Arkansas
0.2544	708.145	5572378	719.68	568923	Independ	35.6733	-91.408	Arkansas
0.2565	684.068	5323739	739.94	554768	Independ	35.6733	-91.408	Arkansas
0.2675	695.042	5151724	670	533496	Independ	35.6733	-91.408	Arkansas
0.2424	618.974	5129304	672	521526	Independ	35.6733	-91.408	Arkansas
0.2465	728.96	5898527	744	606846	Independ	35.6733	-91.408	Arkansas
0.2237	19.233	161898	22.98	16746	Independ	35.6733	-91.408	Arkansas
0.2657	444.006	3362932	681.15	325950	Independ	35.6733	-91.408	Arkansas
0.2629	677.957	5087408	720	523227	Independ	35.6733	-91.408	Arkansas
0.2621	781.962	5939947	744	612093	Independ	35.6733	-91.408	Arkansas
0.249	678.294	5363511	679.77	552937	Independ	35.6733	-91.408	Arkansas
0.2556	719.867	5590562	720	567726	Independ	35.6733	-91.408	Arkansas
0.2256	611.851	5382188	698.95	538494	Independ	35.6733	-91.408	Arkansas
0.2192	556.556	5109985	719.48	509915	Independ	35.6733	-91.408	Arkansas
0.1935	480.608	4994460	744	496520	Independ	35.6733	-91.408	Arkansas
0.1825	475.724	5252549	744	522407	Independ	35.6733	-91.408	Arkansas
0.1924	496.227	5163302	696	514511	Independ	35.6733	-91.408	Arkansas
0.1663	404.8	4853032	744	477489	Independ	35.6733	-91.408	Arkansas

0.1431	157.508	2184308	417.7	214666	Independ	35.6733	-91.408	Arkansas
0.1756	471.929	5350441	744	517843	Independ	35.6733	-91.408	Arkansas
0.189	496.246	5259298	720	501326	Independ	35.6733	-91.408	Arkansas
0.191	405.449	4379152	744	403042	Independ	35.6733	-91.408	Arkansas
0.2117	450.814	4454380	744	430120	Independ	35.6733	-91.408	Arkansas
0.2143	465.432	4476986	720	462666	Independ	35.6733	-91.408	Arkansas
0.2194	516.44	4816348	744	504190	Independ	35.6733	-91.408	Arkansas
0.2369	553.92	4744503	720	501322	Independ	35.6733	-91.408	Arkansas
0.2177	469.993	4414019	744	463989	Independ	35.6733	-91.408	Arkansas
0.199	426.186	4310666	696.5	450265.35	Independ	35.6733	-91.408	Arkansas
0.1992	392.211	3950166	672	421870	Independ	35.6733	-91.408	Arkansas
0.1936	414.457	4263386	694.48	448250.75	Independ	35.6733	-91.408	Arkansas
			0		Independ	35.6733	-91.408	Arkansas
0.1535	62.701	670820	152	66322	Independ	35.6733	-91.408	Arkansas
0.2135	519.054	4824374	703.37	503191.48	Independ	35.6733	-91.408	Arkansas
0.216	504.39	4645397	677.25	478085.26	Independ	35.6733	-91.408	Arkansas
0.2205	578.618	5215938	744	540419	Independ	35.6733	-91.408	Arkansas
0.1979	477.191	4807090	720	501691	Independ	35.6733	-91.408	Arkansas
0.195	423.152	4292506	722.48	462325.41	Independ	35.6733	-91.408	Arkansas
0.2233	422.369	4017523	720	443499	Independ	35.6733	-91.408	Arkansas
0.2263	517.145	4734765	744	531624	Independ	35.6733	-91.408	Arkansas
0.2702	744.704	5524533	671.78	553203	Independ	35.6733	-91.408	Arkansas
0.2434	573.261	4647312	619.28	472513	Independ	35.6733	-91.408	Arkansas
0.2257	618.477	5348582	674.69	555996	Independ	35.6733	-91.408	Arkansas
0.2649	763.753	5750417	720	595450	Independ	35.6733	-91.408	Arkansas
0.2754	715.907	5179505	654.07	521848	Independ	35.6733	-91.408	Arkansas
0.2548	767.844	6014052	720	595428	Independ	35.6733	-91.408	Arkansas
0.2105	661.555	6287061	744	622058	Independ	35.6733	-91.408	Arkansas
0.2028	630.721	6174198	742.47	599027	Independ	35.6733	-91.408	Arkansas
0.2209	606.026	5540537	720	552423	Independ	35.6733	-91.408	Arkansas
0.2169	356.144	3127881	439.02	319684	Independ	35.6733	-91.408	Arkansas
0.2234	622.424	5548291	720	564625	Independ	35.6733	-91.408	Arkansas
0.2473	666.886	5506765	744	572799	Independ	35.6733	-91.408	Arkansas
0.2367	656.146	5588854	742.97	571670	Independ	35.6733	-91.408	Arkansas
0.266	613.689	4657823	672	535358	Independ	35.6733	-91.408	Arkansas
0.2893	758.129	5241213	744	606610	Independ	35.6733	-91.408	Arkansas
0.2849	733.728	5176173	720	589684	Independ	35.6733	-91.408	Arkansas
0.2613	688.147	5309180	744	602781	Independ	35.6733	-91.408	Arkansas
0.2444	602.166	4860568	639.45	526236	Independ	35.6733	-91.408	Arkansas
0.2172	527.766	4870785	641.36	503568	Independ	35.6733	-91.408	Arkansas
0.227	695.952	6139997	744	625793	Independ	35.6733	-91.408	Arkansas
0.2332	363.548	3187148	405.59	322282	Independ	35.6733	-91.408	Arkansas
0.2012	57.761	489703	142.75	48954	Independ	35.6733	-91.408	Arkansas
0.2247	526.145	4609494	644.8	480932	Independ	35.6733	-91.408	Arkansas

0.2219	554.796	4994700	744	540103	Independ	35.6733	-91.408	Arkansas
0.2272	613.015	5410807	743.73	578969	Independ	35.6733	-91.408	Arkansas
0.2352	557.981	4757570	672	504825	Independ	35.6733	-91.408	Arkansas
0.2282	446.719	3828004	526.73	402324	Independ	35.6733	-91.408	Arkansas
0.2447	634.67	5170890	720	539242	Independ	35.6733	-91.408	Arkansas
0.257	490.648	3935029	744	402603	Independ	35.6733	-91.408	Arkansas
0.2211	509.898	4531256	648.83	462015	Independ	35.6733	-91.408	Arkansas
0.2237	690.843	6145277	744	619454	Independ	35.6733	-91.408	Arkansas
0.2163	560.607	5095896	724.69	510997	Independ	35.6733	-91.408	Arkansas
0.2	210.581	2014946	367.17	198906	Independ	35.6733	-91.408	Arkansas
0.2265	668.77	5934072	744	569538	Independ	35.6733	-91.408	Arkansas
0.2211	584.718	5282393	720	509461	Independ	35.6733	-91.408	Arkansas
0.2066	428.919	4167001	669	394966	Independ	35.6733	-91.408	Arkansas
0.2014	599.385	6029074	744	576879	Independ	35.6733	-91.408	Arkansas
0.2074	599.875	5785122	696	550729	Independ	35.6733	-91.408	Arkansas
0.1913	569.678	5975768	744	547810	Independ	35.6733	-91.408	Arkansas
0.1751	434.374	4972848	720	465121	Independ	35.6733	-91.408	Arkansas
0.182	594.91	6451042	744	575963	Independ	35.6733	-91.408	Arkansas
0.207	647.217	6213478	720	562803	Independ	35.6733	-91.408	Arkansas
0.1997	568.942	5708582	744	525484	Independ	35.6733	-91.408	Arkansas
0.213	574.497	5594580	744	524152	Independ	35.6733	-91.408	Arkansas
0.2345	430.239	3747364	502.73	361863	Independ	35.6733	-91.408	Arkansas
			0		Independ	35.6733	-91.408	Arkansas
0.1929	209.89	2087948	301.65	198343.96	Independ	35.6733	-91.408	Arkansas
0.2143	473.287	4640041	744	495975	Independ	35.6733	-91.408	Arkansas
0.1999	503.327	5127222	744	536713	Independ	35.6733	-91.408	Arkansas
0.2058	424.724	4260390	672	444277	Independ	35.6733	-91.408	Arkansas
0.1981	474.221	4859616	744	519150	Independ	35.6733	-91.408	Arkansas
0.1905	505.183	5255607	720	554264	Independ	35.6733	-91.408	Arkansas
0.2034	544.128	5381979	744	547682	Independ	35.6733	-91.408	Arkansas
0.2206	619.769	5578482	719.61	561801.7	Independ	35.6733	-91.408	Arkansas
0.2132	599.551	5636876	744	560667	Independ	35.6733	-91.408	Arkansas
0.2012	568.884	5690497	744	560760	Independ	35.6733	-91.408	Arkansas
0.2043	474.906	4700303	645	475525	Independ	35.6733	-91.408	Arkansas
0.1956	311.482	3196983	501.36	337871	Independ	35.6733	-91.408	Arkansas
0.2278	438.902	4173245	720	437431	Independ	35.6733	-91.408	Arkansas
0.2206	511.852	4881530	738.9	505164.8	Independ	35.6733	-91.408	Arkansas
0.2558	637.02	4866148	685.9	478205	Jefferson	34.4236	-92.139	Arkansas
0.2605	656.625	5051216	672	516064	Jefferson	34.4236	-92.139	Arkansas
0.2485	698.01	5652755	744	570515	Jefferson	34.4236	-92.139	Arkansas
0.257	51.473	404076	59.27	42221	Jefferson	34.4236	-92.139	Arkansas
0.1093	13.982	132124	78.67	10624	Jefferson	34.4236	-92.139	Arkansas
0.2303	557.277	4784377	690.47	494367	Jefferson	34.4236	-92.139	Arkansas
0.2409	614.384	5130500	719.47	531977	Jefferson	34.4236	-92.139	Arkansas

0.2545	706.241	5507307	739.75	568719	Jefferson	34.4236	-92.139	Arkansas
0.2739	733.549	5372461	720	559457	Jefferson	34.4236	-92.139	Arkansas
0.2389	557.51	4534948	627.31	474908	Jefferson	34.4236	-92.139	Arkansas
0.2461	693.025	5646736	720	585573	Jefferson	34.4236	-92.139	Arkansas
0.2293	649.428	5603069	736.45	575642	Jefferson	34.4236	-92.139	Arkansas
0.2513	709.601	5633014	743.04	590808	Jefferson	34.4236	-92.139	Arkansas
0.2592	471.517	3591434	466	369659	Jefferson	34.4236	-92.139	Arkansas
0.1765	168.179	1824010	254.8	181824	Jefferson	34.4236	-92.139	Arkansas
0.2221	614.441	5494781	710.15	566393	Jefferson	34.4236	-92.139	Arkansas
0.2515	769.323	6141227	744	598077	Jefferson	34.4236	-92.139	Arkansas
0.2618	746.957	5627633	670.28	544114	Jefferson	34.4236	-92.139	Arkansas
0.2605	793.648	6094061	744	599709	Jefferson	34.4236	-92.139	Arkansas
0.2513	758.661	6022656	744	587588	Jefferson	34.4236	-92.139	Arkansas
0.2638	776.03	5899332	720	580151	Jefferson	34.4236	-92.139	Arkansas
0.2496	745.951	6003664	744	588894	Jefferson	34.4236	-92.139	Arkansas
0.2536	636.304	5063472	720	498685	Jefferson	34.4236	-92.139	Arkansas
0.2555	736.086	5783584	744	570018	Jefferson	34.4236	-92.139	Arkansas
0.2709	799.795	5916959	743.98	587140	Jefferson	34.4236	-92.139	Arkansas
0.2775	490.832	3486454	500.65	335389	Jefferson	34.4236	-92.139	Arkansas
0.2687	539.945	3890420	489	355388	Jefferson	34.4236	-92.139	Arkansas
0.2893	782.973	5348057	719.07	499739	Jefferson	34.4236	-92.139	Arkansas
0.2995	792.953	5305803	744	487116	Jefferson	34.4236	-92.139	Arkansas
0.2674	766.605	5741676	720	527565	Jefferson	34.4236	-92.139	Arkansas
0.2612	784.819	5931633	697.57	542143	Jefferson	34.4236	-92.139	Arkansas
0.276	892.239	6486650	744	596147	Jefferson	34.4236	-92.139	Arkansas
0.2721	719.153	5251862	677.47	489482	Jefferson	34.4236	-92.139	Arkansas
0.299	188.215	1275547	165.4	120975	Jefferson	34.4236	-92.139	Arkansas
			0		Jefferson	34.4236	-92.139	Arkansas
0.2415	511.837	3801112	685.7	347818	Jefferson	34.4236	-92.139	Arkansas
0.2607	657.587	4958722	732.13	462786.04	Jefferson	34.4236	-92.139	Arkansas
0.2695	647.012	4902725	696	461945	Jefferson	34.4236	-92.139	Arkansas
0.2636	491.815	3703987	661.44	341946.6	Jefferson	34.4236	-92.139	Arkansas
0.2633	452.301	3350347	659.6	309648.64	Jefferson	34.4236	-92.139	Arkansas
0.2796	714.671	5127576	743.53	481123.03	Jefferson	34.4236	-92.139	Arkansas
0.2705	641.898	4760469	705.73	444149.82	Jefferson	34.4236	-92.139	Arkansas
0.266	580.624	4443900	744	404201	Jefferson	34.4236	-92.139	Arkansas
0.2987	793.188	5398328	744	490920	Jefferson	34.4236	-92.139	Arkansas
0.2733	773.252	5690821	720	526335	Jefferson	34.4236	-92.139	Arkansas
0.2778	325.158	2334563	287.78	219543.52	Jefferson	34.4236	-92.139	Arkansas
0.2384	227.945	1696145	245.01	160024.34	Jefferson	34.4236	-92.139	Arkansas
0.2654	585.341	4320930	659.92	407493.36	Jefferson	34.4236	-92.139	Arkansas
0.2972	883.636	5977386	744	559529	Jefferson	34.4236	-92.139	Arkansas
0.3303	852.766	5153672	672	478900	Jefferson	34.4236	-92.139	Arkansas
0.3497	1026.12	5855005	744	547328	Jefferson	34.4236	-92.139	Arkansas

0.3299	991.426	6018045	719.97	564671.4	Jefferson	34.4236	-92.139	Arkansas
0.347	972.285	5568119	694.2	518674.8	Jefferson	34.4236	-92.139	Arkansas
0.2702	775.208	5643967	703.83	520089.4	Jefferson	34.4236	-92.139	Arkansas
0.2643	725.287	5415518	689.72	496485.4	Jefferson	34.4236	-92.139	Arkansas
0.2949	897.557	6114526	743.21	562640.92	Jefferson	34.4236	-92.139	Arkansas
0.2775	726.119	5121822	681.45	475860.4	Jefferson	34.4236	-92.139	Arkansas
0.3182	374.167	2303126	355.87	211839.36	Jefferson	34.4236	-92.139	Arkansas
0.2751	329.379	2256296	377.79	205658.97	Jefferson	34.4236	-92.139	Arkansas
0.2846	689.974	4731004	699.16	444076.08	Jefferson	34.4236	-92.139	Arkansas
0.2769	644.881	4399799	625.58	448201	Jefferson	34.4236	-92.139	Arkansas
0.2895	153.472	1057471	143.6	108729	Jefferson	34.4236	-92.139	Arkansas
0.2492	461.276	3455642	521.3	349612	Jefferson	34.4236	-92.139	Arkansas
0.2774	730.976	5316896	720	558089	Jefferson	34.4236	-92.139	Arkansas
0.2626	616.881	4651589	646.75	479860	Jefferson	34.4236	-92.139	Arkansas
0.2604	643.913	4870930	665.65	506771	Jefferson	34.4236	-92.139	Arkansas
0.2769	773.208	5540137	744	572172	Jefferson	34.4236	-92.139	Arkansas
0.2606	757.379	5831737	744	604210	Jefferson	34.4236	-92.139	Arkansas
0.3181	903.954	5661671	720	584005	Jefferson	34.4236	-92.139	Arkansas
0.2994	885.313	5903389	743.18	611654	Jefferson	34.4236	-92.139	Arkansas
0.2819	780.241	5555412	720	579398	Jefferson	34.4236	-92.139	Arkansas
0.2752	603.346	4229399	616.39	439122	Jefferson	34.4236	-92.139	Arkansas
0.2762	732.565	5249543	713.08	546835	Jefferson	34.4236	-92.139	Arkansas
0.3112	787.61	5063446	672	535800	Jefferson	34.4236	-92.139	Arkansas
0.3404	989.55	5789464	744	600338	Jefferson	34.4236	-92.139	Arkansas
0.3052	301.585	1859767	268.32	192481	Jefferson	34.4236	-92.139	Arkansas
0.3465	1007.11	5803031	744	595498	Jefferson	34.4236	-92.139	Arkansas
0.3526	1049.93	5916347	720	603783	Jefferson	34.4236	-92.139	Arkansas
0.2887	719.391	4815368	642.14	495804	Jefferson	34.4236	-92.139	Arkansas
0.27	701.983	4962848	694.43	511004	Jefferson	34.4236	-92.139	Arkansas
0.2947	842.231	5687084	720	585294	Jefferson	34.4236	-92.139	Arkansas
0.3061	26.78	173646	22.83	17651	Jefferson	34.4236	-92.139	Arkansas
			0		Jefferson	34.4236	-92.139	Arkansas
0.3043	721.023	4261230	667.41	445930	Jefferson	34.4236	-92.139	Arkansas
0.3311	926.384	5485786	744	588318	Jefferson	34.4236	-92.139	Arkansas
0.3083	752.711	4833804	671.93	495548	Jefferson	34.4236	-92.139	Arkansas
0.3144	754.53	4786514	597.67	474527	Jefferson	34.4236	-92.139	Arkansas
0.2789	150.477	958671	198.45	91973	Jefferson	34.4236	-92.139	Arkansas
0.2838	668.545	4747094	743.97	484023	Jefferson	34.4236	-92.139	Arkansas
0.2733	741.175	5349135	720	540111	Jefferson	34.4236	-92.139	Arkansas
0.3069	916.908	5873058	736.1	584267	Jefferson	34.4236	-92.139	Arkansas
0.259	788.691	6084051	743.9	609690	Jefferson	34.4236	-92.139	Arkansas
0.2755	678.733	4822255	651.9	485682	Jefferson	34.4236	-92.139	Arkansas
0.2967	861.281	5780788	744	585757	Jefferson	34.4236	-92.139	Arkansas
0.3	748.001	4858028	690.31	486549	Jefferson	34.4236	-92.139	Arkansas

0.3005	755.883	5034458	744	510711	Jefferson	34.4236	-92.139	Arkansas
0.2801	672.559	4617810	699.96	458738.44	Jefferson	34.4236	-92.139	Arkansas
0.256	650.566	5080558	696	497879	Jefferson	34.4236	-92.139	Arkansas
0.253	315.014	2462877	380.63	225203.96	Jefferson	34.4236	-92.139	Arkansas
0.1691	46.546	464567	120.34	38376.7	Jefferson	34.4236	-92.139	Arkansas
0.239	681.02	5705889	744	527269	Jefferson	34.4236	-92.139	Arkansas
0.2677	761.941	5735118	720	530441	Jefferson	34.4236	-92.139	Arkansas
0.2443	582.088	4776277	744	422470	Jefferson	34.4236	-92.139	Arkansas
0.2422	673.469	5577534	717.49	497441.91	Jefferson	34.4236	-92.139	Arkansas
0.2361	684.305	5709410	690.66	512090.95	Jefferson	34.4236	-92.139	Arkansas
0.2695	851.985	6349819	744	587676	Jefferson	34.4236	-92.139	Arkansas
0.2746	803.96	5871072	720	547828	Jefferson	34.4236	-92.139	Arkansas
0.3142	621.38	3893277	619.4	364913.62	Jefferson	34.4236	-92.139	Arkansas
0.3423	981.781	5706225	744	529371	Jefferson	34.4236	-92.139	Arkansas
0.3665	279.762	1501147	193.42	137872.92	Jefferson	34.4236	-92.139	Arkansas
0.2688	240.982	1648302	236.55	155712.46	Jefferson	34.4236	-92.139	Arkansas
0.2949	911.384	6146393	720	572664	Jefferson	34.4236	-92.139	Arkansas
0.3074	946.537	6155726	744	563893	Jefferson	34.4236	-92.139	Arkansas
0.291	876.083	6033638	720	540366	Jefferson	34.4236	-92.139	Arkansas
0.28	879.075	6266131	744	558442	Jefferson	34.4236	-92.139	Arkansas
0.2777	849.107	5954564	724.25	533241.48	Jefferson	34.4236	-92.139	Arkansas
0.2543	641.934	4966136	640.43	447076.6	Jefferson	34.4236	-92.139	Arkansas
0.2765	753.29	5274147	721.85	484689.13	Jefferson	34.4236	-92.139	Arkansas
0.3189	776.868	4853096	720	450938	Jefferson	34.4236	-92.139	Arkansas
0.2728	666.124	4792111	703.66	446703.54	Jefferson	34.4236	-92.139	Arkansas

Operating Status	Unit Type	Fuel Type (Primary)	Fuel Type (Secondary)	SO2 Control(s)	NOx Control(s)	PM Control(s)
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator
Operating	Tangentia	Coal	Residual Oil		Overfire A	Electrostatic Precipitator

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		2009-2013 Max 30-boiler operating day emission rate (SO2/MMBtu)	Controlled Rate (SO2/MMBtu)	Control Efficiency
Independence	1	0.635203283	0.6	5.54%
Independence	2	0.623505436	0.6	3.77%

		2009-2013 (drop highest and lowest) avg from EPA FIP	Controlled Rate (SO2/MMBtu)	Average Control Efficiency	Controlled Emission Rate tpy	Quantity of Fuel EI 923 2009-2013 (drop highest and lowest) average	Estimated Annual Cost LSC (based on average fuel quantity and 0.50 cent premium per ton)	Cost-Effectiveness $/ton SO2 reduced
Independence	1	14,269	0.6	4.66%	13,605	3,034,697	$ 1,517,349	$ 2,284
Independence	2	15,511	0.6	4.66%	14,789	3,138,413	$ 1,569,206	$ 2,173

State	Facility Name	Facility ID (ORISPL)	Unit ID	Associated Stacks	Date	Year	SO2 (tons)	Heat Input (MMBtu)	30-operating-day rolling average
AR	Independe	6641	1		1/1/2009	2009	37.51	177017.9	
AR	Independe	6641	1		1/2/2009	2009	33.989	163856.2	
AR	Independe	6641	1		1/3/2009	2009	36.241	170845.8	
AR	Independe	6641	1		1/4/2009	2009	35.839	172093	
AR	Independe	6641	1		1/5/2009	2009	37.011	176066.9	
AR	Independe	6641	1		1/6/2009	2009	37.731	184227.9	
AR	Independe	6641	1		1/7/2009	2009	42.603	184068.4	
AR	Independe	6641	1		1/8/2009	2009	50.523	192033.7	
AR	Independe	6641	1		1/9/2009	2009	54.222	167534.8	
AR	Independe	6641	1		1/10/2009	2009	0.469	2139.5	
AR	Independe	6641	1		1/12/2009	2009	4.052	21738.916	
AR	Independe	6641	1		1/13/2009	2009	35.059	168446.2	
AR	Independe	6641	1		1/14/2009	2009	46.426	205240.2	
AR	Independe	6641	1		1/15/2009	2009	36.166	174680.3	
AR	Independe	6641	1		1/16/2009	2009	31.607	160045.5	
AR	Independe	6641	1		1/17/2009	2009	41.086	193888.7	
AR	Independe	6641	1		1/18/2009	2009	42.546	169892.8	
AR	Independe	6641	1		1/19/2009	2009	49.689	184335.2	
AR	Independe	6641	1		1/20/2009	2009	39.851	177742.1	
AR	Independe	6641	1		1/21/2009	2009	46.075	203397.2	
AR	Independe	6641	1		1/22/2009	2009	49.019	188579	
AR	Independe	6641	1		1/23/2009	2009	37.428	179964.4	
AR	Independe	6641	1		1/24/2009	2009	35.728	175933.1	
AR	Independe	6641	1		1/25/2009	2009	40.542	190626.7	
AR	Independe	6641	1		1/26/2009	2009	40.835	187551.2	
AR	Independe	6641	1		1/27/2009	2009	29.479	137375	
AR	Independe	6641	1		1/28/2009	2009	19.826	94840.1	
AR	Independe	6641	1		1/29/2009	2009	47.422	140688.2	
AR	Independe	6641	1		1/30/2009	2009	34.546	128790.5	
AR	Independe	6641	1		1/31/2009	2009	38.633	156826.4	0.460474431
AR	Independe	6641	1		2/1/2009	2009	35.321	147508.1	0.462392905
AR	Independe	6641	1		2/2/2009	2009	33.831	155585.5	0.463124919
AR	Independe	6641	1		2/3/2009	2009	37.258	165065.8	0.464109034
AR	Independe	6641	1		2/4/2009	2009	36.744	184388	0.463297186
AR	Independe	6641	1		2/5/2009	2009	30.176	158438.3	0.462146368
AR	Independe	6641	1		2/6/2009	2009	33.897	173455.8	0.461582581
AR	Independe	6641	1		2/7/2009	2009	36.156	192876.1	0.458034281
AR	Independe	6641	1		2/8/2009	2009	37.05	195143.1	0.452102462
AR	Independe	6641	1		2/9/2009	2009	33.283	180273.2	0.442168668
AR	Independe	6641	1		2/10/2009	2009	24.26	135811.2	0.439830842
AR	Independe	6641	1		2/11/2009	2009	6.169	34896.572	0.439516586
AR	Independe	6641	1		2/13/2009	2009	4.382	28261.612	0.439570615
AR	Independe	6641	1		2/14/2009	2009	42.97	178779.1	0.440558865
AR	Independe	6641	1		2/15/2009	2009	51.254	199323.9	0.444583428
AR	Independe	6641	1		2/16/2009	2009	34.685	179220.8	0.444091875
AR	Independe	6641	1		2/17/2009	2009	33.143	130437.4	0.44667644
AR	Independe	6641	1		2/18/2009	2009	18.529	90750.1	0.443964618
AR	Independe	6641	1		2/19/2009	2009	33.452	159704.8	0.439334804
AR	Independe	6641	1		2/20/2009	2009	48.356	177988.6	0.442967642
AR	Independe	6641	1		2/21/2009	2009	36.648	155672.9	0.443464155
AR	Independe	6641	1		2/22/2009	2009	38.319	169615.1	0.440631451
AR	Independe	6641	1		2/23/2009	2009	43.307	195468.2	0.441702136
AR	Independe	6641	1		2/24/2009	2009	40.46	189697.4	0.442435448
AR	Independe	6641	1		2/25/2009	2009	37.467	165425.8	0.443524757
AR	Independe	6641	1		2/26/2009	2009	39.21	179453.7	0.443599279

AR	Independe	6641	1	2/27/2009	2009	31.58	152644.8	0.443039858
AR	Independe	6641	1	2/28/2009	2009	0.04	500.505	0.44353383
AR	Independe	6641	1	4/16/2009	2009	0	982.874	0.435997716
AR	Independe	6641	1	4/17/2009	2009	1.793	18625.142	0.431888877
AR	Independe	6641	1	4/18/2009	2009	34.466	155505.8	0.430062781
AR	Independe	6641	1	4/19/2009	2009	38.772	171266.6	0.429287238
AR	Independe	6641	1	4/20/2009	2009	34.033	155394.2	0.429400949
AR	Independe	6641	1	4/21/2009	2009	24.463	114481.5	0.428485084
AR	Independe	6641	1	4/22/2009	2009	22.744	103198.5	0.430123513
AR	Independe	6641	1	4/23/2009	2009	31.08	158403.4	0.430563507
AR	Independe	6641	1	4/24/2009	2009	40.488	187723.2	0.432256576
AR	Independe	6641	1	4/25/2009	2009	36.741	180540.4	0.433825186
AR	Independe	6641	1	4/26/2009	2009	32.15	163544.7	0.434775252
AR	Independe	6641	1	4/27/2009	2009	28.693	153294.8	0.435399128
AR	Independe	6641	1	4/28/2009	2009	32.365	133155.7	0.439651425
AR	Independe	6641	1	4/29/2009	2009	51.432	156692.3	0.448443745
AR	Independe	6641	1	4/30/2009	2009	39.787	121105.4	0.455230792
AR	Independe	6641	1	5/1/2009	2009	35.987	159639.7	0.454003264
AR	Independe	6641	1	5/2/2009	2009	36.615	170430.5	0.450201345
AR	Independe	6641	1	5/3/2009	2009	49.044	190830.7	0.455712899
AR	Independe	6641	1	5/4/2009	2009	65.627	204509.6	0.462910908
AR	Independe	6641	1	5/5/2009	2009	67.438	206858.4	0.472809085
AR	Independe	6641	1	5/6/2009	2009	55.279	208909.6	0.47733852
AR	Independe	6641	1	5/7/2009	2009	39.412	154732.6	0.475822988
AR	Independe	6641	1	5/8/2009	2009	51.021	160824	0.481687882
AR	Independe	6641	1	5/9/2009	2009	52.602	198511.5	0.484933851
AR	Independe	6641	1	5/10/2009	2009	42.022	179795.5	0.486052504
AR	Independe	6641	1	5/11/2009	2009	44.28	160502.7	0.490938958
AR	Independe	6641	1	5/12/2009	2009	35.948	149919.1	0.491966556
AR	Independe	6641	1	5/13/2009	2009	40.278	187152.2	0.491596259
AR	Independe	6641	1	5/14/2009	2009	40.106	171958.3	0.493283594
AR	Independe	6641	1	5/15/2009	2009	34.668	113204.663	0.496258725
AR	Independe	6641	1	5/17/2009	2009	4.209	26807.464	0.495306335
AR	Independe	6641	1	5/18/2009	2009	27.537	138797	0.493610596
AR	Independe	6641	1	5/19/2009	2009	28.908	143067.5	0.492557462
AR	Independe	6641	1	5/20/2009	2009	29.583	143607.1	0.491545432
AR	Independe	6641	1	5/21/2009	2009	40.566	187002.8	0.49102292
AR	Independe	6641	1	5/22/2009	2009	42.059	184911.3	0.491149879
AR	Independe	6641	1	5/23/2009	2009	40.352	184841.9	0.490149495
AR	Independe	6641	1	5/24/2009	2009	50.557	181413.8	0.495792615
AR	Independe	6641	1	5/25/2009	2009	42.456	179237.7	0.497455887
AR	Independe	6641	1	5/26/2009	2009	43.593	183639	0.499938606
AR	Independe	6641	1	5/27/2009	2009	46.357	192255	0.502792042
AR	Independe	6641	1	5/28/2009	2009	50.007	184840.3	0.508189571
AR	Independe	6641	1	5/29/2009	2009	41.581	189433.8	0.506162239
AR	Independe	6641	1	5/30/2009	2009	44.437	171000.5	0.501940893
AR	Independe	6641	1	5/31/2009	2009	37.777	182173.2	0.495130102
AR	Independe	6641	1	6/1/2009	2009	37.656	175497.2	0.494246252
AR	Independe	6641	1	6/2/2009	2009	34.112	163526.24	0.493933768
AR	Independe	6641	1	6/3/2009	2009	41.946	162397.2	0.493903848
AR	Independe	6641	1	6/4/2009	2009	37.322	166526.5	0.486383996
AR	Independe	6641	1	6/5/2009	2009	36.922	170081.8	0.477749178
AR	Independe	6641	1	6/6/2009	2009	36.14	164036	0.474348387
AR	Independe	6641	1	6/7/2009	2009	46.105	172671	0.475329737
AR	Independe	6641	1	6/8/2009	2009	53.901	179964.9	0.474660587
AR	Independe	6641	1	6/9/2009	2009	50.333	189657.7	0.474593226
AR	Independe	6641	1	6/10/2009	2009	39.786	193057.3	0.472437094
AR	Independe	6641	1	6/11/2009	2009	38.113	163748.2	0.469661651

AR	Independe	6641	1	6/12/2009	2009	31.194	156705	0.467124266
AR	Independe	6641	1	6/13/2009	2009	33.383	163555.2	0.466568547
AR	Independe	6641	1	6/14/2009	2009	33.06	156074	0.465222607
AR	Independe	6641	1	6/15/2009	2009	31.51	161040.9	0.459521696
AR	Independe	6641	1	6/16/2009	2009	37.09	171309.7	0.459397588
AR	Independe	6641	1	6/17/2009	2009	43.383	188351.2	0.461112448
AR	Independe	6641	1	6/18/2009	2009	43.914	185684.6	0.463086581
AR	Independe	6641	1	6/19/2009	2009	46.476	193612.7	0.465092731
AR	Independe	6641	1	6/20/2009	2009	46.362	199284.3	0.466199959
AR	Independe	6641	1	6/21/2009	2009	43.294	186944.1	0.466486508
AR	Independe	6641	1	6/22/2009	2009	45.008	190885.3	0.467707286
AR	Independe	6641	1	6/23/2009	2009	45.928	194473.1	0.464825272
AR	Independe	6641	1	6/24/2009	2009	46.331	193160.3	0.465064427
AR	Independe	6641	1	6/25/2009	2009	45.176	189742.8	0.465125592
AR	Independe	6641	1	6/26/2009	2009	41.494	180912.4	0.464292263
AR	Independe	6641	1	6/27/2009	2009	44.308	197569.2	0.461058995
AR	Independe	6641	1	6/28/2009	2009	39.793	193074.2	0.460078089
AR	Independe	6641	1	6/29/2009	2009	33.811	166061.5	0.456531665
AR	Independe	6641	1	6/30/2009	2009	26.859	136344.6	0.456359444
AR	Independe	6641	1	7/1/2009	2009	29.128	135390.8	0.456596241
AR	Independe	6641	1	7/2/2009	2009	32.788	137329	0.458373758
AR	Independe	6641	1	7/3/2009	2009	58.757	181361.1	0.46311445
AR	Independe	6641	1	7/4/2009	2009	37.828	175947.7	0.462478331
AR	Independe	6641	1	7/5/2009	2009	33.207	155354	0.462360555
AR	Independe	6641	1	7/6/2009	2009	36.957	171774.2	0.461991077
AR	Independe	6641	1	7/7/2009	2009	40.407	187229.5	0.458556037
AR	Independe	6641	1	7/8/2009	2009	41.1	188122.5	0.453002656
AR	Independe	6641	1	7/9/2009	2009	57.318	199889.1	0.454766005
AR	Independe	6641	1	7/10/2009	2009	47.064	203659.3	0.456601127
AR	Independe	6641	1	7/11/2009	2009	48.284	195109.9	0.457729738
AR	Independe	6641	1	7/12/2009	2009	39.893	194584.4	0.457740805
AR	Independe	6641	1	7/13/2009	2009	42.94	199043.3	0.458271305
AR	Independe	6641	1	7/14/2009	2009	50.709	184573.9	0.462360686
AR	Independe	6641	1	7/15/2009	2009	43.461	187089.3	0.464530988
AR	Independe	6641	1	7/16/2009	2009	41.605	190888.4	0.46451915
AR	Independe	6641	1	7/17/2009	2009	36.888	173677.9	0.4633902
AR	Independe	6641	1	7/18/2009	2009	32.945	163528.4	0.461247396
AR	Independe	6641	1	7/19/2009	2009	33.518	172132.3	0.458296646
AR	Independe	6641	1	7/20/2009	2009	41.314	183576.2	0.457761094
AR	Independe	6641	1	7/21/2009	2009	36.551	172644.4	0.45647472
AR	Independe	6641	1	7/22/2009	2009	43.548	163704.9	0.458242093
AR	Independe	6641	1	7/23/2009	2009	53.149	196177.8	0.460786174
AR	Independe	6641	1	7/24/2009	2009	40.979	171735.8	0.46063063
AR	Independe	6641	1	7/25/2009	2009	45.388	200040.5	0.459824543
AR	Independe	6641	1	7/26/2009	2009	40.774	183103.7	0.45936796
AR	Independe	6641	1	7/27/2009	2009	47.562	190734.5	0.46116995
AR	Independe	6641	1	7/28/2009	2009	44.538	205002.6	0.461913356
AR	Independe	6641	1	7/29/2009	2009	39.799	177479.8	0.463159674
AR	Independe	6641	1	7/30/2009	2009	32.492	151012.1	0.463989179
AR	Independe	6641	1	7/31/2009	2009	39.346	192486.8	0.462877794
AR	Independe	6641	1	8/1/2009	2009	39.321	180635.6	0.461606985
AR	Independe	6641	1	8/2/2009	2009	38.555	173546.2	0.454897771
AR	Independe	6641	1	8/3/2009	2009	44.981	208257.9	0.454826744
AR	Independe	6641	1	8/4/2009	2009	45.033	209644.2	0.454639952
AR	Independe	6641	1	8/5/2009	2009	49.982	200697.1	0.456943608
AR	Independe	6641	1	8/6/2009	2009	38.97	188624.1	0.456316756
AR	Independe	6641	1	8/7/2009	2009	42.511	195649.8	0.456207496
AR	Independe	6641	1	8/8/2009	2009	49.032	210863.3	0.452367837

AR	Independe	6641	1	8/9/2009	2009	55.859	206920	0.455233655
AR	Independe	6641	1	8/10/2009	2009	53.237	212619.5	0.455576706
AR	Independe	6641	1	8/11/2009	2009	46.257	212344.6	0.456396167
AR	Independe	6641	1	8/12/2009	2009	41.322	195079	0.456143852
AR	Independe	6641	1	8/13/2009	2009	40.794	187059.7	0.452437993
AR	Independe	6641	1	8/14/2009	2009	40.44	201747.3	0.450203385
AR	Independe	6641	1	8/15/2009	2009	35.371	174825.2	0.449277517
AR	Independe	6641	1	8/16/2009	2009	31.756	158918.5	0.44863347
AR	Independe	6641	1	8/17/2009	2009	33.888	171705.4	0.44831793
AR	Independe	6641	1	8/18/2009	2009	38.28	180342.9	0.449350784
AR	Independe	6641	1	8/19/2009	2009	37.683	170691.5	0.449089946
AR	Independe	6641	1	8/20/2009	2009	53.68	184252	0.454225314
AR	Independe	6641	1	8/21/2009	2009	38.24	173379.7	0.451575886
AR	Independe	6641	1	8/22/2009	2009	12.355	63157.107	0.447686353
AR	Independe	6641	1	8/23/2009	2009	12.749	57876.759	0.446673774
AR	Independe	6641	1	8/24/2009	2009	9.197	43515.935	0.446205035
AR	Independe	6641	1	8/28/2009	2009	0.02	4482.57	0.445849702
AR	Independe	6641	1	8/29/2009	2009	17.184	74327.961	0.444066751
AR	Independe	6641	1	8/30/2009	2009	54.764	178897.3	0.450552126
AR	Independe	6641	1	8/31/2009	2009	42.225	176187.9	0.451652196
AR	Independe	6641	1	9/1/2009	2009	49.192	170926	0.456573064
AR	Independe	6641	1	9/2/2009	2009	36.449	174405.8	0.457071143
AR	Independe	6641	1	9/3/2009	2009	36.739	186125.3	0.455520087
AR	Independe	6641	1	9/4/2009	2009	41.371	206341.9	0.453651141
AR	Independe	6641	1	9/5/2009	2009	40.299	194286.6	0.453041804
AR	Independe	6641	1	9/6/2009	2009	39.486	178664.4	0.453637791
AR	Independe	6641	1	9/7/2009	2009	43.038	170177	0.453629038
AR	Independe	6641	1	9/8/2009	2009	38.115	189973.6	0.45315568
AR	Independe	6641	1	9/9/2009	2009	42.427	200032.3	0.452717004
AR	Independe	6641	1	9/10/2009	2009	41.632	203553.9	0.450373268
AR	Independe	6641	1	9/11/2009	2009	42.592	199304.7	0.445653489
AR	Independe	6641	1	9/12/2009	2009	43.658	186581.3	0.444102097
AR	Independe	6641	1	9/13/2009	2009	28.724	159139.6	0.44172717
AR	Independe	6641	1	9/14/2009	2009	45.823	188644.6	0.444189836
AR	Independe	6641	1	9/15/2009	2009	41.334	205946.8	0.442675993
AR	Independe	6641	1	9/16/2009	2009	43.297	194293.1	0.444545703
AR	Independe	6641	1	9/17/2009	2009	41.697	181688.6	0.446534365
AR	Independe	6641	1	9/18/2009	2009	42.475	195486.5	0.447584678
AR	Independe	6641	1	9/19/2009	2009	45.981	196402	0.450270698
AR	Independe	6641	1	9/20/2009	2009	43.23	195761.3	0.450873725
AR	Independe	6641	1	9/21/2009	2009	42.616	198365.5	0.450344247
AR	Independe	6641	1	9/22/2009	2009	33.932	169228.9	0.44368787
AR	Independe	6641	1	9/23/2009	2009	53.28	186858.8	0.448575576
AR	Independe	6641	1	9/24/2009	2009	40.916	190186.8	0.448603174
AR	Independe	6641	1	9/25/2009	2009	38.835	178358.1	0.448240822
AR	Independe	6641	1	9/26/2009	2009	46.101	172822.2	0.451226747
AR	Independe	6641	1	9/27/2009	2009	40.524	173138.7	0.45212261
AR	Independe	6641	1	9/28/2009	2009	39.938	184545.7	0.45134859
AR	Independe	6641	1	9/29/2009	2009	43.792	168540.9	0.448251432
AR	Independe	6641	1	9/30/2009	2009	38.874	174125.6	0.447214893
AR	Independe	6641	1	10/1/2009	2009	44.858	185985.8	0.444458933
AR	Independe	6641	1	10/2/2009	2009	45.896	182194.4	0.447216297
AR	Independe	6641	1	10/3/2009	2009	58.312	199416.5	0.453847607
AR	Independe	6641	1	10/4/2009	2009	46.32	198964.2	0.456211901
AR	Independe	6641	1	10/5/2009	2009	58.078	189283.8	0.462971922
AR	Independe	6641	1	10/6/2009	2009	47.405	199497.6	0.46407414
AR	Independe	6641	1	10/7/2009	2009	45.813	200079.8	0.462599897
AR	Independe	6641	1	10/8/2009	2009	41.728	201225.1	0.462956996

AR	Independe	6641	1	10/9/2009	2009	42.572	192423.8	0.463631515
AR	Independe	6641	1	10/10/2009	2009	50.266	194246.6	0.467456459
AR	Independe	6641	1	10/11/2009	2009	42.955	196880.7	0.467786071
AR	Independe	6641	1	10/12/2009	2009	42.573	200242.2	0.466272025
AR	Independe	6641	1	10/13/2009	2009	55.366	195995	0.472615451
AR	Independe	6641	1	10/14/2009	2009	39.141	182012.1	0.470815834
AR	Independe	6641	1	10/15/2009	2009	45.425	195251.9	0.473145494
AR	Independe	6641	1	10/16/2009	2009	45.467	188802.8	0.474369505
AR	Independe	6641	1	10/17/2009	2009	45.465	187302.3	0.475228397
AR	Independe	6641	1	10/18/2009	2009	35.705	159203.5	0.475885216
AR	Independe	6641	1	10/19/2009	2009	32.986	161472.5	0.474213156
AR	Independe	6641	1	10/20/2009	2009	34.088	144527.9	0.475296089
AR	Independe	6641	1	10/21/2009	2009	37.161	145379.9	0.477892186
AR	Independe	6641	1	10/22/2009	2009	29.563	135759.7	0.479220098
AR	Independe	6641	1	10/23/2009	2009	31.186	144315.1	0.474830683
AR	Independe	6641	1	10/24/2009	2009	39.112	181392.3	0.474935589
AR	Independe	6641	1	10/25/2009	2009	38.506	180623	0.474615465
AR	Independe	6641	1	10/26/2009	2009	36.891	185044.6	0.470153139
AR	Independe	6641	1	10/27/2009	2009	50.682	187520.3	0.472643732
AR	Independe	6641	1	10/28/2009	2009	50.756	166804.6	0.478178093
AR	Independe	6641	1	10/29/2009	2009	65.364	195188.6	0.483755189
AR	Independe	6641	1	10/30/2009	2009	47.124	183865.3	0.485913874
AR	Independe	6641	1	10/31/2009	2009	45.928	186554.3	0.48625513
AR	Independe	6641	1	11/1/2009	2009	41.752	163529.9	0.486399855
AR	Independe	6641	1	11/2/2009	2009	36.826	162157.8	0.481802841
AR	Independe	6641	1	11/3/2009	2009	40.187	183767.9	0.480885576
AR	Independe	6641	1	11/4/2009	2009	39.679	188205.1	0.47415382
AR	Independe	6641	1	11/5/2009	2009	45.631	173214.4	0.475816005
AR	Independe	6641	1	11/6/2009	2009	38.179	181687.2	0.474596735
AR	Independe	6641	1	11/7/2009	2009	42.032	201342.5	0.474700067
AR	Independe	6641	1	11/8/2009	2009	40.031	182357.4	0.474643179
AR	Independe	6641	1	11/9/2009	2009	41.769	188316.6	0.471982245
AR	Independe	6641	1	11/10/2009	2009	39.715	179876.1	0.472273275
AR	Independe	6641	1	11/11/2009	2009	39.417	172776.8	0.473533469
AR	Independe	6641	1	11/12/2009	2009	41.697	183266.7	0.469490853
AR	Independe	6641	1	11/13/2009	2009	47.088	184167.2	0.472312833
AR	Independe	6641	1	11/14/2009	2009	35.679	154289.5	0.472285135
AR	Independe	6641	1	11/15/2009	2009	31.891	146168.6	0.470933228
AR	Independe	6641	1	11/16/2009	2009	27.877	132765.2	0.469084802
AR	Independe	6641	1	11/17/2009	2009	25.025	122051.3	0.468313486
AR	Independe	6641	1	11/18/2009	2009	31.406	144151.3	0.469288036
AR	Independe	6641	1	11/19/2009	2009	41.619	160661.4	0.470757615
AR	Independe	6641	1	11/20/2009	2009	39.327	168310	0.469495437
AR	Independe	6641	1	11/21/2009	2009	40.557	196858.3	0.468202787
AR	Independe	6641	1	11/22/2009	2009	55.325	193142	0.473062603
AR	Independe	6641	1	11/23/2009	2009	44.166	184318.5	0.474729668
AR	Independe	6641	1	11/24/2009	2009	42.353	195180.5	0.474878905
AR	Independe	6641	1	11/25/2009	2009	42.485	201481.5	0.475521473
AR	Independe	6641	1	11/26/2009	2009	37.882	189146	0.470512919
AR	Independe	6641	1	11/27/2009	2009	35.636	173668.9	0.464164895
AR	Independe	6641	1	11/28/2009	2009	46.102	184926.2	0.457749228
AR	Independe	6641	1	11/29/2009	2009	46.222	182219.8	0.457549482
AR	Independe	6641	1	11/30/2009	2009	48.399	183024.6	0.458796767
AR	Independe	6641	1	12/1/2009	2009	42.307	200143	0.455833217
AR	Independe	6641	1	12/2/2009	2009	52.609	190939.7	0.459298979
AR	Independe	6641	1	12/3/2009	2009	39.734	191585.5	0.458455374
AR	Independe	6641	1	12/4/2009	2009	40.726	196447.9	0.45813975
AR	Independe	6641	1	12/5/2009	2009	46.794	201641.8	0.456146477

AR	Independe	6641	1	12/6/2009	2009	52.362	182767.452	0.461338967
AR	Independe	6641	1	12/7/2009	2009	0	702.12	0.46298376
AR	Independe	6641	1	12/8/2009	2009	38.067	129210.1	0.467027075
AR	Independe	6641	1	12/9/2009	2009	39.422	180025.4	0.466866127
AR	Independe	6641	1	12/10/2009	2009	41.259	200196.8	0.465617833
AR	Independe	6641	1	12/11/2009	2009	37.918	182174.8	0.464182007
AR	Independe	6641	1	12/12/2009	2009	37.531	175397	0.463269518
AR	Independe	6641	1	12/13/2009	2009	30.826	136463	0.461217553
AR	Independe	6641	1	12/14/2009	2009	37.896	164959.8	0.461121824
AR	Independe	6641	1	12/15/2009	2009	35.628	179743.7	0.459559034
AR	Independe	6641	1	12/16/2009	2009	37.932	175939.6	0.459611055
AR	Independe	6641	1	12/17/2009	2009	38.989	172325.5	0.460535096
AR	Independe	6641	1	12/18/2009	2009	35.856	151765.5	0.461567253
AR	Independe	6641	1	12/19/2009	2009	33.612	163532.5	0.458250799
AR	Independe	6641	1	12/20/2009	2009	33.452	162117.6	0.456544125
AR	Independe	6641	1	12/21/2009	2009	33.502	162039.3	0.456888512
AR	Independe	6641	1	12/22/2009	2009	35.362	170968.2	0.451119926
AR	Independe	6641	1	12/23/2009	2009	36.312	167748.3	0.449520843
AR	Independe	6641	1	12/24/2009	2009	32.933	148495.9	0.44994142
AR	Independe	6641	1	12/25/2009	2009	41.579	182921.2	0.451227815
AR	Independe	6641	1	12/26/2009	2009	39.56	185095.9	0.452248355
AR	Independe	6641	1	12/27/2009	2009	38.567	182083.7	0.452652558
AR	Independe	6641	1	12/28/2009	2009	43.31	189552	0.451144793
AR	Independe	6641	1	12/29/2009	2009	50.663	191478.5	0.452067071
AR	Independe	6641	1	12/30/2009	2009	42.83	169133.6	0.451112133
AR	Independe	6641	1	12/31/2009	2009	37.522	142249.9	0.454401847
AR	Independe	6641	1	1/1/2010	2010	46.25	161634.3	0.454521523
AR	Independe	6641	1	1/2/2010	2010	42.206	200168.3	0.454729735
AR	Independe	6641	1	1/3/2010	2010	40.262	204401.6	0.453823846
AR	Independe	6641	1	1/4/2010	2010	43.172	204753.5	0.452099526
AR	Independe	6641	1	1/5/2010	2010	40.261	201262.5	0.445636622
AR	Independe	6641	1	1/6/2010	2010	34.927	179203.7	0.443778703
AR	Independe	6641	1	1/7/2010	2010	31.654	165847.9	0.438242569
AR	Independe	6641	1	1/8/2010	2010	44.75	201989.9	0.438437848
AR	Independe	6641	1	1/9/2010	2010	50.572	184575.9	0.443280943
AR	Independe	6641	1	1/10/2010	2010	39.121	186628	0.443362999
AR	Independe	6641	1	1/11/2010	2010	39.12	190675.7	0.442681905
AR	Independe	6641	1	1/12/2010	2010	50.807	185492.2	0.446108139
AR	Independe	6641	1	1/13/2010	2010	39.295	184956.3	0.444963466
AR	Independe	6641	1	1/14/2010	2010	36.809	174757.9	0.445820628
AR	Independe	6641	1	1/15/2010	2010	42.188	185890	0.446581947
AR	Independe	6641	1	1/16/2010	2010	49.967	174817.6	0.450473312
AR	Independe	6641	1	1/17/2010	2010	35.728	151694.7	0.450431471
AR	Independe	6641	1	1/18/2010	2010	35.218	153106.8	0.451910791
AR	Independe	6641	1	1/19/2010	2010	30.996	145730.4	0.452378681
AR	Independe	6641	1	1/20/2010	2010	29.911	142316.7	0.452706404
AR	Independe	6641	1	1/21/2010	2010	48.679	159411.1	0.458721037
AR	Independe	6641	1	1/22/2010	2010	36.761	164130	0.459204144
AR	Independe	6641	1	1/23/2010	2010	38.69	156375.6	0.460693226
AR	Independe	6641	1	1/24/2010	2010	37.081	147692.1	0.462066619
AR	Independe	6641	1	1/25/2010	2010	33.85	177835.9	0.460533229
AR	Independe	6641	1	1/26/2010	2010	35.877	180210.7	0.459674073
AR	Independe	6641	1	1/27/2010	2010	36.483	178307.7	0.45805682
AR	Independe	6641	1	1/28/2010	2010	34.479	166839.1	0.454019785
AR	Independe	6641	1	1/29/2010	2010	35.418	168547	0.451231762
AR	Independe	6641	1	1/30/2010	2010	38.674	179052.1	0.448511813
AR	Independe	6641	1	1/31/2010	2010	32.292	120267.7	0.446717161
AR	Independe	6641	1	2/1/2010	2010	11.175	45676.214	0.448090463

AR	Independe	6641	1	2/4/2010	2010	2.686	17355.969	0.449867006
AR	Independe	6641	1	2/5/2010	2010	42.026	168584	0.452755784
AR	Independe	6641	1	2/6/2010	2010	47.355	197912.5	0.456003327
AR	Independe	6641	1	2/7/2010	2010	42.512	192533.3	0.457878201
AR	Independe	6641	1	2/8/2010	2010	58.493	193931	0.466247465
AR	Independe	6641	1	2/9/2010	2010	39.759	159689.3	0.468262058
AR	Independe	6641	1	2/10/2010	2010	48.39	177082.7	0.468084903
AR	Independe	6641	1	2/11/2010	2010	56.576	174199.7	0.476543239
AR	Independe	6641	1	2/12/2010	2010	44.313	182933	0.479471212
AR	Independe	6641	1	2/13/2010	2010	41.495	174166.4	0.476720254
AR	Independe	6641	1	2/14/2010	2010	40.22	170943.2	0.478504099
AR	Independe	6641	1	2/15/2010	2010	48.977	202516.3	0.480802242
AR	Independe	6641	1	2/16/2010	2010	61.162	193564	0.487913581
AR	Independe	6641	1	2/17/2010	2010	59.63	179753.2	0.491421792
AR	Independe	6641	1	2/18/2010	2010	47.117	174874.8	0.493771747
AR	Independe	6641	1	2/19/2010	2010	40.183	178674	0.493218615
AR	Independe	6641	1	2/20/2010	2010	35.461	178850.2	0.491708631
AR	Independe	6641	1	2/21/2010	2010	39.411	168612.8	0.492939734
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AR	Independe	6641	1	2/25/2010	2010	36.9	177841.4	0.483133998
AR	Independe	6641	1	2/26/2010	2010	35.326	181115.6	0.483408621
AR	Independe	6641	1	2/27/2010	2010	36.172	181654.9	0.483386911
AR	Independe	6641	1	2/28/2010	2010	36.024	180396.4	0.483000062
AR	Independe	6641	1	3/1/2010	2010	36.522	177671.7	0.482770547
AR	Independe	6641	1	3/2/2010	2010	40.595	195486.4	0.482242427
AR	Independe	6641	1	3/3/2010	2010	34.8	171441	0.48142904
AR	Independe	6641	1	3/4/2010	2010	34.174	174311	0.477037228
AR	Independe	6641	1	3/5/2010	2010	31.522	158321.5	0.474519374
AR	Independe	6641	1	3/6/2010	2010	0	17.272	0.47507251
AR	Independe	6641	1	3/18/2010	2010	0	650.04	0.474217337
AR	Independe	6641	1	3/19/2010	2010	8.112	48614.6	0.472630964
AR	Independe	6641	1	3/20/2010	2010	23.536	113393.6	0.472515958
AR	Independe	6641	1	3/21/2010	2010	33.982	145722.2	0.4669536
AR	Independe	6641	1	3/22/2010	2010	32.331	149602	0.464798517
AR	Independe	6641	1	3/23/2010	2010	32.249	154197.7	0.46017835
AR	Independe	6641	1	3/24/2010	2010	38.978	179061.2	0.452196485
AR	Independe	6641	1	3/25/2010	2010	41.763	182330.2	0.451167003
AR	Independe	6641	1	3/26/2010	2010	38.075	186637.1	0.448515512
AR	Independe	6641	1	3/27/2010	2010	43.026	193385	0.44757279
AR	Independe	6641	1	3/28/2010	2010	35.66	174604.8	0.444561494
AR	Independe	6641	1	3/29/2010	2010	44.22	194458.8	0.437262943
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AR	Independe	6641	1	3/31/2010	2010	49.73	186541.4	0.428172898
AR	Independe	6641	1	4/1/2010	2010	44.376	183982.7	0.429467929
AR	Independe	6641	1	4/2/2010	2010	47.769	183774	0.434229887
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AR	Independe	6641	1	4/4/2010	2010	40.512	197033.1	0.432177611
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AR	Independe	6641	1	4/6/2010	2010	54.772	197058.1	0.440156333
AR	Independe	6641	1	4/7/2010	2010	53.005	197385.5	0.44501604
AR	Independe	6641	1	4/8/2010	2010	48.091	183187.9	0.450079494
AR	Independe	6641	1	4/9/2010	2010	47.165	181882.8	0.454582153
AR	Independe	6641	1	4/10/2010	2010	51.253	195928.9	0.459380945
AR	Independe	6641	1	4/11/2010	2010	42.579	176670.5	0.461960402
AR	Independe	6641	1	4/12/2010	2010	45.645	186704.3	0.464869853
AR	Independe	6641	1	4/13/2010	2010	44.239	199414.8	0.466070103

AR	Independeı	6641	1	4/14/2010	2010	45.592	193152.5	0.468930975
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AR	Independeı	6641	1	4/16/2010	2010	48.075	191998.3	0.473661634
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AR	Independeı	6641	1	4/18/2010	2010	36.587	176756.1	0.473050884
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AR	Independeı	6641	1	4/20/2010	2010	42.121	184489	0.472902466
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AR	Independeı	6641	1	4/22/2010	2010	44.002	183371.4	0.475824527
AR	Independeı	6641	1	4/23/2010	2010	49.875	188083	0.478928917
AR	Independeı	6641	1	4/24/2010	2010	44.519	186251.3	0.479573086
AR	Independeı	6641	1	4/25/2010	2010	36.691	161243.5	0.481248643
AR	Independeı	6641	1	4/26/2010	2010	41.838	184416.3	0.481594662
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AR	Independeı	6641	1	5/8/2010	2010	45.843	203622.9	0.481308591
AR	Independeı	6641	1	5/9/2010	2010	45.3	188403	0.480064491
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AR	Independeı	6641	1	5/11/2010	2010	52.422	204912	0.486431942
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AR	Independeı	6641	1	5/13/2010	2010	63.881	204681.5	0.495379031
AR	Independeı	6641	1	5/14/2010	2010	45.39	196803.9	0.494982267
AR	Independeı	6641	1	5/15/2010	2010	50.089	198662.4	0.494966962
AR	Independeı	6641	1	5/16/2010	2010	47.6	195822.4	0.494457965
AR	Independeı	6641	1	5/17/2010	2010	46.488	194313.1	0.494552367
AR	Independeı	6641	1	5/18/2010	2010	39.209	186100.5	0.49466339
AR	Independeı	6641	1	5/19/2010	2010	53.971	187191.2	0.499073694
AR	Independeı	6641	1	5/20/2010	2010	58.612	186733.4	0.504752571
AR	Independeı	6641	1	5/21/2010	2010	38.963	179797.8	0.503413154
AR	Independeı	6641	1	5/22/2010	2010	41.942	173512.5	0.503563898
AR	Independeı	6641	1	5/23/2010	2010	47.24	209330.4	0.500719419
AR	Independeı	6641	1	5/24/2010	2010	46.093	176472.4	0.502154806
AR	Independeı	6641	1	5/25/2010	2010	35.687	177378.8	0.500355971
AR	Independeı	6641	1	5/26/2010	2010	49.78	164393.5	0.504980997
AR	Independeı	6641	1	5/27/2010	2010	64.262	187061.5	0.512151374
AR	Independeı	6641	1	5/28/2010	2010	42.079	180080.6	0.512508074
AR	Independeı	6641	1	5/29/2010	2010	47.675	167901.2	0.5154642
AR	Independeı	6641	1	5/30/2010	2010	45.971	156162.1	0.519419326
AR	Independeı	6641	1	5/31/2010	2010	55.976	182784.9	0.522987066
AR	Independeı	6641	1	6/1/2010	2010	46.523	195446.6	0.523316088
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AR	Independeı	6641	1	6/4/2010	2010	43.864	188057.9	0.517421054
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AR	Independeı	6641	1	6/7/2010	2010	43.619	175620.1	0.519007171
AR	Independeı	6641	1	6/8/2010	2010	57.126	198978.9	0.522226662
AR	Independeı	6641	1	6/9/2010	2010	58.429	193971.6	0.519763201
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AR	Independe	6641	1	6/12/2010	2010	40.221	176657.8	0.509767156
AR	Independe	6641	1	6/13/2010	2010	43.658	194133.8	0.509392138
AR	Independe	6641	1	6/14/2010	2010	41.061	187747.1	0.50715933
AR	Independe	6641	1	6/15/2010	2010	48.492	208284.2	0.506350599
AR	Independe	6641	1	6/16/2010	2010	46.193	205702.4	0.505219527
AR	Independe	6641	1	6/17/2010	2010	45.456	208191	0.505455854
AR	Independe	6641	1	6/18/2010	2010	38.756	198842.3	0.499032306
AR	Independe	6641	1	6/19/2010	2010	39.557	199135.8	0.491214517
AR	Independe	6641	1	6/20/2010	2010	38.85	197111.7	0.489678418
AR	Independe	6641	1	6/21/2010	2010	47.459	201587.5	0.489203314
AR	Independe	6641	1	6/22/2010	2010	41.536	198429.9	0.488137625
AR	Independe	6641	1	6/23/2010	2010	41.959	198446.7	0.484818608
AR	Independe	6641	1	6/24/2010	2010	56.272	199698.5	0.490101064
AR	Independe	6641	1	6/25/2010	2010	44.096	192922.7	0.485710487
AR	Independe	6641	1	6/26/2010	2010	44.471	190852	0.478540841
AR	Independe	6641	1	6/27/2010	2010	41.533	191631.1	0.477397421
AR	Independe	6641	1	6/28/2010	2010	44.376	196950.3	0.473879822
AR	Independe	6641	1	6/29/2010	2010	41.048	179854.2	0.470272542
AR	Independe	6641	1	6/30/2010	2010	36.3	171826.3	0.464407497
AR	Independe	6641	1	7/1/2010	2010	40.804	188269.2	0.463015815
AR	Independe	6641	1	7/2/2010	2010	52.718	195999.7	0.465273669
AR	Independe	6641	1	7/3/2010	2010	45.492	184178	0.465299312
AR	Independe	6641	1	7/4/2010	2010	40.325	191621	0.463799879
AR	Independe	6641	1	7/5/2010	2010	40.153	193180.5	0.46029369
AR	Independe	6641	1	7/6/2010	2010	48.047	190050.7	0.462343802
AR	Independe	6641	1	7/7/2010	2010	43.631	194489	0.460853629
AR	Independe	6641	1	7/8/2010	2010	53.905	202746.5	0.459453704
AR	Independe	6641	1	7/9/2010	2010	50.798	192414.7	0.456963009
AR	Independe	6641	1	7/10/2010	2010	44.49	195317.9	0.456267783
AR	Independe	6641	1	7/11/2010	2010	40.538	188996.8	0.454732165
AR	Independe	6641	1	7/12/2010	2010	43.274	186353	0.455023546
AR	Independe	6641	1	7/13/2010	2010	38.397	159945.2	0.455892966
AR	Independe	6641	1	7/14/2010	2010	43.167	168401.3	0.458150918
AR	Independe	6641	1	7/15/2010	2010	37.036	159984.5	0.458014027
AR	Independe	6641	1	7/16/2010	2010	42.029	173565.3	0.459137072
AR	Independe	6641	1	7/17/2010	2010	44.354	166699.2	0.462119003
AR	Independe	6641	1	7/18/2010	2010	37.307	175568.4	0.463515553
AR	Independe	6641	1	7/19/2010	2010	39.305	184094.8	0.464668204
AR	Independe	6641	1	7/20/2010	2010	47.19	187204.9	0.468467938
AR	Independe	6641	1	7/21/2010	2010	44.543	200647.7	0.467505187
AR	Independe	6641	1	7/22/2010	2010	46.47	207266.5	0.468527948
AR	Independe	6641	1	7/23/2010	2010	55.395	199468.1	0.473232496
AR	Independe	6641	1	7/24/2010	2010	52.736	198800.5	0.472047493
AR	Independe	6641	1	7/25/2010	2010	44.918	183319.7	0.473150601
AR	Independe	6641	1	7/26/2010	2010	45.821	201183.2	0.472760547
AR	Independe	6641	1	7/27/2010	2010	56.524	190205.8	0.478226405
AR	Independe	6641	1	7/28/2010	2010	47.834	191022.9	0.479966759
AR	Independe	6641	1	7/29/2010	2010	41.132	195284.2	0.478678444
AR	Independe	6641	1	7/30/2010	2010	58.122	194092	0.484526621
AR	Independe	6641	1	7/31/2010	2010	42.245	169726.1	0.486637434
AR	Independe	6641	1	8/1/2010	2010	41.301	158953.7	0.485776876
AR	Independe	6641	1	8/2/2010	2010	40.178	181245.8	0.484128031
AR	Independe	6641	1	8/3/2010	2010	45.271	207902.2	0.484487046
AR	Independe	6641	1	8/4/2010	2010	40.759	205147.8	0.483669591
AR	Independe	6641	1	8/5/2010	2010	35.022	170546.1	0.480697417
AR	Independe	6641	1	8/6/2010	2010	40.621	179482.3	0.480911508
AR	Independe	6641	1	8/7/2010	2010	44.908	180654.3	0.479584487

AR	Independe	6641	1	8/8/2010	2010	46.522	161159.1	0.480750264
AR	Independe	6641	1	8/9/2010	2010	45.978	180628	0.482572884
AR	Independe	6641	1	8/10/2010	2010	34.219	155123	0.483250414
AR	Independe	6641	1	8/11/2010	2010	44.467	182311.9	0.484043678
AR	Independe	6641	1	8/12/2010	2010	35.339	159028.7	0.483006438
AR	Independe	6641	1	8/13/2010	2010	43.481	165622.3	0.483366902
AR	Independe	6641	1	8/14/2010	2010	47.098	174446.1	0.485763395
AR	Independe	6641	1	8/15/2010	2010	57.649	198677	0.489222048
AR	Independe	6641	1	8/16/2010	2010	43.438	185998.1	0.487181535
AR	Independe	6641	1	8/17/2010	2010	45.653	174692.1	0.490280579
AR	Independe	6641	1	8/18/2010	2010	52.971	197975.4	0.493987205
AR	Independe	6641	1	8/19/2010	2010	48.118	183587	0.494645511
AR	Independe	6641	1	8/20/2010	2010	49.194	195035.6	0.496830157
AR	Independe	6641	1	8/21/2010	2010	44.343	172991.1	0.499155299
AR	Independe	6641	1	8/22/2010	2010	44.688	165744.8	0.498316408
AR	Independe	6641	1	8/23/2010	2010	39.122	191389.1	0.494000615
AR	Independe	6641	1	8/24/2010	2010	48.517	193898.9	0.494361515
AR	Independe	6641	1	8/25/2010	2010	39.995	187471.9	0.493467272
AR	Independe	6641	1	8/26/2010	2010	57.833	203799.4	0.492718687
AR	Independe	6641	1	8/27/2010	2010	53.912	206806	0.493517927
AR	Independe	6641	1	8/28/2010	2010	58.618	199994.3	0.49947101
AR	Independe	6641	1	8/29/2010	2010	40.264	183606.7	0.49390271
AR	Independe	6641	1	8/30/2010	2010	57.957	200974.2	0.496807486
AR	Independe	6641	1	8/31/2010	2010	55.933	206599.2	0.497814837
AR	Independe	6641	1	9/1/2010	2010	43.993	207337	0.496854281
AR	Independe	6641	1	9/2/2010	2010	40.703	195037	0.49636129
AR	Independe	6641	1	9/3/2010	2010	38.602	194371.2	0.496547625
AR	Independe	6641	1	9/4/2010	2010	36.07	166577.3	0.497280229
AR	Independe	6641	1	9/5/2010	2010	29.82	159458.5	0.495174901
AR	Independe	6641	1	9/6/2010	2010	31.861	179387.8	0.490569456
AR	Independe	6641	1	9/7/2010	2010	34.82	196870.1	0.483216447
AR	Independe	6641	1	9/8/2010	2010	33.937	189370.6	0.478138291
AR	Independe	6641	1	9/9/2010	2010	32.993	191615.4	0.474591407
AR	Independe	6641	1	9/10/2010	2010	36.117	202777.7	0.469900902
AR	Independe	6641	1	9/11/2010	2010	37.858	207582.7	0.46677088
AR	Independe	6641	1	9/12/2010	2010	36.811	188547.4	0.462555139
AR	Independe	6641	1	9/13/2010	2010	34.947	177075.5	0.458082373
AR	Independe	6641	1	9/14/2010	2010	34.736	177742.8	0.451707566
AR	Independe	6641	1	9/15/2010	2010	35.313	188793	0.448628237
AR	Independe	6641	1	9/16/2010	2010	36.099	194820.7	0.443697962
AR	Independe	6641	1	9/17/2010	2010	36.83	196904.8	0.438123822
AR	Independe	6641	1	9/18/2010	2010	37.385	197884.3	0.433276316
AR	Independe	6641	1	9/19/2010	2010	35.287	182903	0.429324683
AR	Independe	6641	1	9/20/2010	2010	37.973	201815.8	0.424947053
AR	Independe	6641	1	9/21/2010	2010	39.903	200604.2	0.420722637
AR	Independe	6641	1	9/22/2010	2010	40.609	204618.9	0.420274587
AR	Independe	6641	1	9/23/2010	2010	39.086	203707.1	0.416308423
AR	Independe	6641	1	9/24/2010	2010	42.176	204432.3	0.415844082
AR	Independe	6641	1	9/25/2010	2010	40.539	202892.6	0.409956924
AR	Independe	6641	1	9/26/2010	2010	32.046	157607.3	0.405867541
AR	Independe	6641	1	9/27/2010	2010	36.656	174019.9	0.400047769
AR	Independe	6641	1	9/28/2010	2010	41.868	186368.6	0.400414247
AR	Independe	6641	1	9/29/2010	2010	47.386	186702	0.397719268
AR	Independe	6641	1	9/30/2010	2010	43.342	187741.7	0.394620188
AR	Independe	6641	1	10/1/2010	2010	42.465	195384.5	0.394911865
AR	Independe	6641	1	10/2/2010	2010	39.489	192852.7	0.394636821
AR	Independe	6641	1	10/3/2010	2010	36.315	175674.9	0.395131159
AR	Independe	6641	1	10/4/2010	2010	37.015	183137.6	0.394313221

AR	Independe	6641	1	10/5/2010	2010	39.269	194849.9	0.395176623
AR	Independe	6641	1	10/6/2010	2010	38.217	188228.7	0.396784408
AR	Independe	6641	1	10/7/2010	2010	40.758	194003.8	0.399055229
AR	Independe	6641	1	10/8/2010	2010	42.797	200891.6	0.401340508
AR	Independe	6641	1	10/9/2010	2010	44.084	184466.9	0.405708571
AR	Independe	6641	1	10/10/2010	2010	48.072	190479.4	0.410758521
AR	Independe	6641	1	10/11/2010	2010	41.244	189424.7	0.413253106
AR	Independe	6641	1	10/12/2010	2010	38.645	190238.4	0.413773444
AR	Independe	6641	1	10/13/2010	2010	42.526	194406.8	0.415168855
AR	Independe	6641	1	10/14/2010	2010	53.089	190000.7	0.420681004
AR	Independe	6641	1	10/15/2010	2010	37.699	178704.7	0.422255633
AR	Independe	6641	1	10/16/2010	2010	39.641	186250.6	0.424127664
AR	Independe	6641	1	10/17/2010	2010	36.555	172402.8	0.425856541
AR	Independe	6641	1	10/18/2010	2010	42.463	198148.9	0.427620706
AR	Independe	6641	1	10/19/2010	2010	42.555	203629.6	0.428613563
AR	Independe	6641	1	10/20/2010	2010	41.955	202877.4	0.429927529
AR	Independe	6641	1	10/21/2010	2010	42.365	205477.9	0.430422083
AR	Independe	6641	1	10/22/2010	2010	43.647	202610.5	0.431635956
AR	Independe	6641	1	10/23/2010	2010	47.514	183479.2	0.436126978
AR	Independe	6641	1	10/24/2010	2010	40.16	173371.1	0.437806131
AR	Independe	6641	1	10/25/2010	2010	40.086	162995.4	0.440749604
AR	Independe	6641	1	10/26/2010	2010	34.594	154018.8	0.441937194
AR	Independe	6641	1	10/27/2010	2010	42.997	168409.6	0.444636283
AR	Independe	6641	1	10/28/2010	2010	37.838	166893.1	0.444743382
AR	Independe	6641	1	10/29/2010	2010	36.471	165016.2	0.442558081
AR	Independe	6641	1	10/30/2010	2010	40.323	168774.4	0.442982067
AR	Independe	6641	1	10/31/2010	2010	37.153	161935.2	0.443741246
AR	Independe	6641	1	11/1/2010	2010	40.34	179355.7	0.445137065
AR	Independe	6641	1	11/2/2010	2010	44.945	198349.1	0.446432401
AR	Independe	6641	1	11/3/2010	2010	43.559	200593.8	0.447386404
AR	Independe	6641	1	11/4/2010	2010	42.429	186673.8	0.449186779
AR	Independe	6641	1	11/5/2010	2010	42.885	182649.4	0.451325691
AR	Independe	6641	1	11/6/2010	2010	46.29	197488.1	0.453038944
AR	Independe	6641	1	11/7/2010	2010	42.046	179894.1	0.454490413
AR	Independe	6641	1	11/8/2010	2010	43.077	185800.1	0.454015819
AR	Independe	6641	1	11/9/2010	2010	44.16	189522.5	0.452676985
AR	Independe	6641	1	11/10/2010	2010	43.81	191087.7	0.453470166
AR	Independe	6641	1	11/11/2010	2010	46.23	190062.4	0.456232373
AR	Independe	6641	1	11/12/2010	2010	54.077	200969	0.459870242
AR	Independe	6641	1	11/13/2010	2010	40.71	186723.4	0.455661304
AR	Independe	6641	1	11/14/2010	2010	40.969	192616.9	0.455697553
AR	Independe	6641	1	11/15/2010	2010	44.321	187434.7	0.457289897
AR	Independe	6641	1	11/16/2010	2010	39.169	181768.2	0.457460263
AR	Independe	6641	1	11/17/2010	2010	44.066	189252.6	0.458773631
AR	Independe	6641	1	11/18/2010	2010	41.166	165377.816	0.461458529
AR	Independe	6641	1	11/19/2010	2010	39.292	172146.8	0.463077119
AR	Independe	6641	1	11/20/2010	2010	40.633	192716.7	0.463525164
AR	Independe	6641	1	11/21/2010	2010	44.981	189020.9	0.4651722
AR	Independe	6641	1	11/22/2010	2010	40.449	184760.9	0.462467999
AR	Independe	6641	1	11/23/2010	2010	41.628	190304	0.461571921
AR	Independe	6641	1	11/24/2010	2010	42.923	191520.5	0.46020747
AR	Independe	6641	1	11/25/2010	2010	37.446	160873.6	0.460671162
AR	Independe	6641	1	11/26/2010	2010	35.951	170180.7	0.457960518
AR	Independe	6641	1	11/27/2010	2010	40.661	182016.2	0.457728458
AR	Independe	6641	1	11/28/2010	2010	41.104	186811.5	0.457600163
AR	Independe	6641	1	11/29/2010	2010	43.555	182092.2	0.457666789
AR	Independe	6641	1	11/30/2010	2010	41.531	184315	0.457400028
AR	Independe	6641	1	12/1/2010	2010	54.449	193650.5	0.461280613

AR	Independe	6641	1	12/2/2010	2010	39.227	172379.6	0.461378303
AR	Independe	6641	1	12/3/2010	2010	48.001	191828.6	0.463706873
AR	Independe	6641	1	12/4/2010	2010	41.935	194014.7	0.462916838
AR	Independe	6641	1	12/5/2010	2010	43.696	182743	0.463200803
AR	Independe	6641	1	12/6/2010	2010	35.073	155048.7	0.462697619
AR	Independe	6641	1	12/7/2010	2010	34.682	161745	0.461546372
AR	Independe	6641	1	12/8/2010	2010	40.401	166756.6	0.462173676
AR	Independe	6641	1	12/9/2010	2010	43.725	171998	0.463497197
AR	Independe	6641	1	12/10/2010	2010	42.212	180736.1	0.46379103
AR	Independe	6641	1	12/11/2010	2010	41.519	176718.1	0.463196561
AR	Independe	6641	1	12/12/2010	2010	39.837	189357.9	0.458939667
AR	Independe	6641	1	12/13/2010	2010	53.391	185215.3	0.463741916
AR	Independe	6641	1	12/14/2010	2010	59.64	184040.3	0.471369877
AR	Independe	6641	1	12/15/2010	2010	42.037	148789.9	0.473907537
AR	Independe	6641	1	12/16/2010	2010	35.746	153328.1	0.47514722
AR	Independe	6641	1	12/17/2010	2010	28.58	124815.7	0.475080055
AR	Independe	6641	1	12/18/2010	2010	31.495	122006	0.475321013
AR	Independe	6641	1	12/19/2010	2010	43.969	187910.2	0.475675032
AR	Independe	6641	1	12/20/2010	2010	21.519	99616.933	0.47684787
AR	Independe	6641	1	12/21/2010	2010	47.653	180991.7	0.478626711
AR	Independe	6641	1	12/22/2010	2010	54.329	182108.7	0.48425921
AR	Independe	6641	1	12/23/2010	2010	46.681	194525.3	0.485822139
AR	Independe	6641	1	12/24/2010	2010	50.353	181484.8	0.489655703
AR	Independe	6641	1	12/25/2010	2010	35.844	172306.1	0.487949736
AR	Independe	6641	1	12/26/2010	2010	39.763	192056.8	0.487361008
AR	Independe	6641	1	12/27/2010	2010	49.954	185477.1	0.490620357
AR	Independe	6641	1	12/28/2010	2010	37.581	183106	0.489611316
AR	Independe	6641	1	12/29/2010	2010	36.332	168151.4	0.488136553
AR	Independe	6641	1	12/30/2010	2010	37.593	172140.6	0.487761536
AR	Independe	6641	1	12/31/2010	2010	41.373	168691.2	0.485036863
AR	Independe	6641	1	1/1/2011	2011	39.293	150747.2	0.487116652
AR	Independe	6641	1	1/2/2011	2011	52.292	188464.2	0.489118743
AR	Independe	6641	1	1/3/2011	2011	45.659	190413.8	0.490923954
AR	Independe	6641	1	1/4/2011	2011	42.076	175501.9	0.490985755
AR	Independe	6641	1	1/5/2011	2011	38.229	164721.3	0.491291968
AR	Independe	6641	1	1/6/2011	2011	53.697	186421.3	0.496343394
AR	Independe	6641	1	1/7/2011	2011	56.617	184156.1	0.500967545
AR	Independe	6641	1	1/8/2011	2011	52.876	193092.8	0.502464361
AR	Independe	6641	1	1/9/2011	2011	62.108	199266.4	0.508342379
AR	Independe	6641	1	1/10/2011	2011	51.534	199906.3	0.509924785
AR	Independe	6641	1	1/11/2011	2011	48.638	189096	0.513329869
AR	Independe	6641	1	1/12/2011	2011	54.362	192242.1	0.513010621
AR	Independe	6641	1	1/13/2011	2011	54.735	183335.5	0.511198796
AR	Independe	6641	1	1/14/2011	2011	47.203	173970.6	0.510714003
AR	Independe	6641	1	1/15/2011	2011	29.152	98590.1	0.513561943
AR	Independe	6641	1	1/18/2011	2011	1.321	9567.5	0.514482856
AR	Independe	6641	1	1/19/2011	2011	46.78	176208.3	0.515006608
AR	Independe	6641	1	1/20/2011	2011	58.438	200439.9	0.519383872
AR	Independe	6641	1	1/21/2011	2011	48.908	200660.3	0.519822546
AR	Independe	6641	1	1/22/2011	2011	49.776	183634.3	0.520370647
AR	Independe	6641	1	1/23/2011	2011	55.736	187530.8	0.520369217
AR	Independe	6641	1	1/24/2011	2011	52.338	187862.3	0.523190469
AR	Independe	6641	1	1/25/2011	2011	53.082	200303.2	0.522356015
AR	Independe	6641	1	1/26/2011	2011	44.692	196895.3	0.523274433
AR	Independe	6641	1	1/27/2011	2011	39.467	180223.1	0.524336939
AR	Independe	6641	1	1/28/2011	2011	52.48	197213.9	0.524128321
AR	Independe	6641	1	1/29/2011	2011	61.106	186212.4	0.532721731
AR	Independe	6641	1	1/30/2011	2011	50.664	181382.7	0.536800962

AR	Independe	6641	1	1/31/2011	2011	57.107	193663.9	0.541964896
AR	Independe	6641	1	2/1/2011	2011	58.576	195132.3	0.545719598
AR	Independe	6641	1	2/2/2011	2011	45.704	190321.1	0.544090643
AR	Independe	6641	1	2/3/2011	2011	46.955	202156	0.5407345
AR	Independe	6641	1	2/4/2011	2011	43.362	200659.5	0.538861392
AR	Independe	6641	1	2/5/2011	2011	36.033	187533.5	0.535436825
AR	Independe	6641	1	2/6/2011	2011	47.508	185234.8	0.536828418
AR	Independe	6641	1	2/7/2011	2011	59.331	197932.2	0.537761353
AR	Independe	6641	1	2/8/2011	2011	63.172	197864.4	0.538810744
AR	Independe	6641	1	2/9/2011	2011	59.198	199128.5	0.54052642
AR	Independe	6641	1	2/10/2011	2011	44.267	189022.4	0.53500935
AR	Independe	6641	1	2/11/2011	2011	56.396	188726.6	0.537889596
AR	Independe	6641	1	2/12/2011	2011	43.434	179777.8	0.536898339
AR	Independe	6641	1	2/13/2011	2011	43.719	165210.5	0.535647916
AR	Independe	6641	1	2/14/2011	2011	51.055	155384.8	0.53706052
AR	Independe	6641	1	2/15/2011	2011	46.189	154214.4	0.5386591
AR	Independe	6641	1	2/16/2011	2011	34.733	140941.1	0.536505955
AR	Independe	6641	1	2/17/2011	2011	34.845	131796.9	0.536771837
AR	Independe	6641	1	2/18/2011	2011	37.557	154507	0.535538548
AR	Independe	6641	1	2/19/2011	2011	42.332	168633.4	0.532768647
AR	Independe	6641	1	2/20/2011	2011	48.54	189914.1	0.533680921
AR	Independe	6641	1	2/21/2011	2011	45.112	184909.8	0.531851271
AR	Independe	6641	1	2/22/2011	2011	34.268	189068	0.523855118
AR	Independe	6641	1	2/23/2011	2011	53.517	198071.4	0.523309683
AR	Independe	6641	1	2/24/2011	2011	44.551	190030	0.521174003
AR	Independe	6641	1	2/25/2011	2011	48.838	198978.8	0.522490469
AR	Independe	6641	1	2/26/2011	2011	49.006	195025.7	0.524557241
AR	Independe	6641	1	2/27/2011	2011	55.327	197187.8	0.525597154
AR	Independe	6641	1	2/28/2011	2011	49.863	201941.5	0.520010089
AR	Independe	6641	1	3/1/2011	2011	57.845	199678.8	0.5208879
AR	Independe	6641	1	3/2/2011	2011	42.761	198646.9	0.515227683
AR	Independe	6641	1	3/3/2011	2011	47.322	200680.6	0.510643223
AR	Independe	6641	1	3/4/2011	2011	38.146	190286.6	0.507914506
AR	Independe	6641	1	3/5/2011	2011	38.24	172224.8	0.507509741
AR	Independe	6641	1	3/6/2011	2011	44.359	173292	0.510410347
AR	Independe	6641	1	3/7/2011	2011	48.304	191942.1	0.514478007
AR	Independe	6641	1	3/8/2011	2011	39.586	193806.5	0.510787973
AR	Independe	6641	1	3/9/2011	2011	38.062	186893.2	0.504051783
AR	Independe	6641	1	3/10/2011	2011	36.341	184565.1	0.495458394
AR	Independe	6641	1	3/11/2011	2011	54.333	199340.3	0.493658672
AR	Independe	6641	1	3/12/2011	2011	39.307	203419.1	0.490551032
AR	Independe	6641	1	3/13/2011	2011	36.866	179021.8	0.484279895
AR	Independe	6641	1	3/14/2011	2011	42.012	192920.5	0.482600243
AR	Independe	6641	1	3/15/2011	2011	40.709	187277.2	0.479571977
AR	Independe	6641	1	3/16/2011	2011	36.097	183914.1	0.471692557
AR	Independe	6641	1	3/17/2011	2011	38.725	172079.2	0.467485258
AR	Independe	6641	1	3/18/2011	2011	43.303	191755.7	0.466304375
AR	Independe	6641	1	3/19/2011	2011	42.794	200865.5	0.463428455
AR	Independe	6641	1	3/20/2011	2011	51.664	196445.3	0.464965105
AR	Independe	6641	1	3/21/2011	2011	41.887	195268.5	0.462652272
AR	Independe	6641	1	3/22/2011	2011	45.407	191210.1	0.461456331
AR	Independe	6641	1	3/23/2011	2011	41.091	198084.5	0.459002083
AR	Independe	6641	1	3/24/2011	2011	48.525	193650.2	0.463588476
AR	Independe	6641	1	3/25/2011	2011	42.032	194848.3	0.45985698
AR	Independe	6641	1	3/26/2011	2011	41.918	198063.9	0.458302242
AR	Independe	6641	1	3/27/2011	2011	41.845	195351.7	0.456162596
AR	Independe	6641	1	3/28/2011	2011	38.749	184078.9	0.453462791
AR	Independe	6641	1	3/29/2011	2011	35.987	174193.7	0.448528407

AR	Independe	6641	1	3/30/2011	2011	40.205	190917.5	0.4460136
AR	Independe	6641	1	3/31/2011	2011	38.86	183804.4	0.440593241
AR	Independe	6641	1	4/1/2011	2011	36.311	161897.532	0.441174567
AR	Independe	6641	1	5/3/2011	2011	0.053	4097.318	0.439745524
AR	Independe	6641	1	5/4/2011	2011	14.488	67386.7	0.44100496
AR	Independe	6641	1	5/5/2011	2011	46.477	185425	0.442993946
AR	Independe	6641	1	5/6/2011	2011	47.064	182825.4	0.443215136
AR	Independe	6641	1	5/7/2011	2011	47.298	182178.6	0.443647457
AR	Independe	6641	1	5/8/2011	2011	47.716	185414.9	0.447384541
AR	Independe	6641	1	5/9/2011	2011	41.832	163185.2	0.450793321
AR	Independe	6641	1	5/10/2011	2011	36.848	146073.1	0.454268431
AR	Independe	6641	1	5/11/2011	2011	34.022	131220.6	0.452413418
AR	Independe	6641	1	5/12/2011	2011	31.391	124662.9	0.45626665
AR	Independe	6641	1	5/13/2011	2011	22.877	91749.1	0.458611133
AR	Independe	6641	1	5/14/2011	2011	29.494	116386.1	0.460634233
AR	Independe	6641	1	5/15/2011	2011	26.094	104831.9	0.462422329
AR	Independe	6641	1	5/16/2011	2011	23.873	84876.9	0.466876695
AR	Independe	6641	1	5/17/2011	2011	24.032	89957.5	0.468777622
AR	Independe	6641	1	5/18/2011	2011	25.775	93578.2	0.471155366
AR	Independe	6641	1	5/19/2011	2011	19.586	85387.8	0.472932516
AR	Independe	6641	1	5/20/2011	2011	20.381	76457.5	0.471602888
AR	Independe	6641	1	5/21/2011	2011	24.307	84640.8	0.475590371
AR	Independe	6641	1	5/22/2011	2011	26.416	96540.7	0.47727835
AR	Independe	6641	1	5/23/2011	2011	25.532	107461.9	0.480251586
AR	Independe	6641	1	5/24/2011	2011	20.251	87049	0.478904864
AR	Independe	6641	1	5/25/2011	2011	22.462	86825.116	0.482161754
AR	Independe	6641	1	5/26/2011	2011	36.346	122796.1	0.488794722
AR	Independe	6641	1	5/27/2011	2011	38.397	121810.8	0.496608778
AR	Independe	6641	1	5/28/2011	2011	28.648	95375.9	0.50318046
AR	Independe	6641	1	5/29/2011	2011	24.874	104702.5	0.50675977
AR	Independe	6641	1	5/30/2011	2011	34.728	152765.6	0.509139486
AR	Independe	6641	1	5/31/2011	2011	45.566	187269	0.512444053
AR	Independe	6641	1	6/1/2011	2011	49.867	180941.5	0.517340681
AR	Independe	6641	1	6/2/2011	2011	51.992	195025.8	0.518707
AR	Independe	6641	1	6/3/2011	2011	59.578	204951.1	0.523568209
AR	Independe	6641	1	6/4/2011	2011	56.773	200423.8	0.526845262
AR	Independe	6641	1	6/5/2011	2011	54.403	180444.1	0.530946329
AR	Independe	6641	1	6/6/2011	2011	44.212	142236.8	0.534856546
AR	Independe	6641	1	6/7/2011	2011	45.528	174778.5	0.535198959
AR	Independe	6641	1	6/8/2011	2011	47.872	181964.3	0.535725652
AR	Independe	6641	1	6/9/2011	2011	48.585	190915.7	0.535584726
AR	Independe	6641	1	6/10/2011	2011	49.169	192337	0.534968681
AR	Independe	6641	1	6/11/2011	2011	43.16	188876.1	0.532280864
AR	Independe	6641	1	6/12/2011	2011	40.159	171833.6	0.530315819
AR	Independe	6641	1	6/13/2011	2011	42.283	188082.4	0.527335394
AR	Independe	6641	1	6/14/2011	2011	48.373	170797.7	0.529639488
AR	Independe	6641	1	6/15/2011	2011	41.835	161824.2	0.528520852
AR	Independe	6641	1	6/16/2011	2011	45.988	174940.7	0.528292965
AR	Independe	6641	1	6/17/2011	2011	55.633	186075.5	0.530706545
AR	Independe	6641	1	6/18/2011	2011	37.908	153802.5	0.530780137
AR	Independe	6641	1	6/19/2011	2011	38.823	133526.6	0.532206849
AR	Independe	6641	1	6/20/2011	2011	35.532	124801.8	0.532437701
AR	Independe	6641	1	6/21/2011	2011	39.144	137800.1	0.533179431
AR	Independe	6641	1	6/22/2011	2011	34.684	104616	0.537397113
AR	Independe	6641	1	6/23/2011	2011	30.045	95571.5	0.54058481
AR	Independe	6641	1	6/24/2011	2011	52.621	179502.8	0.542713178
AR	Independe	6641	1	6/25/2011	2011	35.827	181359	0.535959016
AR	Independe	6641	1	6/26/2011	2011	50.299	187573.3	0.533635821

AR	Independe	6641	1	6/27/2011	2011	53.673	167244.2	0.535976933
AR	Independe	6641	1	6/28/2011	2011	48.226	165029.2	0.53881842
AR	Independe	6641	1	6/29/2011	2011	53.05	178684	0.543279893
AR	Independe	6641	1	6/30/2011	2011	49.678	191448.2	0.54445014
AR	Independe	6641	1	7/1/2011	2011	46.261	191660.8	0.541890745
AR	Independe	6641	1	7/2/2011	2011	53.082	197060.1	0.542102038
AR	Independe	6641	1	7/3/2011	2011	60.556	188981.2	0.544189551
AR	Independe	6641	1	7/4/2011	2011	48.999	163332.4	0.545108248
AR	Independe	6641	1	7/5/2011	2011	47.572	178224.7	0.542639966
AR	Independe	6641	1	7/6/2011	2011	58.477	197604.8	0.542342943
AR	Independe	6641	1	7/7/2011	2011	56.412	197700.9	0.544165291
AR	Independe	6641	1	7/8/2011	2011	59.63	200144.3	0.546814998
AR	Independe	6641	1	7/9/2011	2011	58.28	201262.6	0.549480558
AR	Independe	6641	1	7/10/2011	2011	62.049	206103.9	0.553003059
AR	Independe	6641	1	7/11/2011	2011	64.672	198485.2	0.560289937
AR	Independe	6641	1	7/12/2011	2011	58.872	199132.2	0.564543933
AR	Independe	6641	1	7/13/2011	2011	67.788	199943.6	0.57304256
AR	Independe	6641	1	7/14/2011	2011	50.264	197516.5	0.570842767
AR	Independe	6641	1	7/15/2011	2011	46.654	198160.8	0.568738565
AR	Independe	6641	1	7/16/2011	2011	61.045	196465.3	0.57211142
AR	Independe	6641	1	7/17/2011	2011	59.953	195605.9	0.572711899
AR	Independe	6641	1	7/18/2011	2011	57.245	199115	0.575088404
AR	Independe	6641	1	7/19/2011	2011	61.304	191024	0.577286809
AR	Independe	6641	1	7/20/2011	2011	48.077	198670.6	0.574086552
AR	Independe	6641	1	7/21/2011	2011	54.331	197618.4	0.573371134
AR	Independe	6641	1	7/22/2011	2011	61.105	198790.8	0.573166291
AR	Independe	6641	1	7/23/2011	2011	54.846	198702.2	0.571510283
AR	Independe	6641	1	7/24/2011	2011	47.536	191530.9	0.568548228
AR	Independe	6641	1	7/25/2011	2011	55.185	188955.5	0.574518097
AR	Independe	6641	1	7/26/2011	2011	54.802	193604.9	0.57547873
AR	Independe	6641	1	7/27/2011	2011	57.663	196551.7	0.573945924
AR	Independe	6641	1	7/28/2011	2011	45.149	177768.1	0.571628232
AR	Independe	6641	1	7/29/2011	2011	49.328	180391.3	0.570179405
AR	Independe	6641	1	7/30/2011	2011	47.083	167885.2	0.571603929
AR	Independe	6641	1	7/31/2011	2011	40.196	151953.6	0.57344218
AR	Independe	6641	1	8/1/2011	2011	43.126	168834.1	0.572790785
AR	Independe	6641	1	8/2/2011	2011	50.831	185512	0.569736014
AR	Independe	6641	1	8/3/2011	2011	53.561	197053.7	0.567981633
AR	Independe	6641	1	8/4/2011	2011	50.348	199570.2	0.566842991
AR	Independe	6641	1	8/5/2011	2011	59.364	197831.5	0.56712808
AR	Independe	6641	1	8/6/2011	2011	55.661	199544.2	0.566686877
AR	Independe	6641	1	8/7/2011	2011	51.744	199457.5	0.564022285
AR	Independe	6641	1	8/8/2011	2011	53.139	198312.1	0.562528746
AR	Independe	6641	1	8/9/2011	2011	52.759	196888.5	0.560203393
AR	Independe	6641	1	8/10/2011	2011	55.129	195739.6	0.557155892
AR	Independe	6641	1	8/11/2011	2011	51.564	189281.7	0.555567984
AR	Independe	6641	1	8/12/2011	2011	59.585	193736.6	0.553311379
AR	Independe	6641	1	8/13/2011	2011	52.463	193738.5	0.5544421
AR	Independe	6641	1	8/14/2011	2011	56.26	191867.9	0.558402506
AR	Independe	6641	1	8/15/2011	2011	61.17	179147.1	0.560138477
AR	Independe	6641	1	8/16/2011	2011	57.186	186235.6	0.560088465
AR	Independe	6641	1	8/17/2011	2011	64.075	197301.7	0.562661553
AR	Independe	6641	1	8/18/2011	2011	54.839	174847.608	0.561988448
AR	Independe	6641	1	8/21/2011	2011	0.193	4609.267	0.564408181
AR	Independe	6641	1	8/22/2011	2011	49.328	176979.2	0.564708391
AR	Independe	6641	1	8/23/2011	2011	51.341	198450.1	0.561175019
AR	Independe	6641	1	8/24/2011	2011	56.526	185961.2	0.563100077
AR	Independe	6641	1	8/25/2011	2011	55.446	190371.3	0.566117999

AR	Independe	6641	1	8/26/2011	2011	57.137	188917.1	0.566837217
AR	Independe	6641	1	8/27/2011	2011	52.035	194947.2	0.565684245
AR	Independe	6641	1	8/28/2011	2011	48.686	182441.3	0.563853039
AR	Independe	6641	1	8/29/2011	2011	57.303	194235.9	0.566603399
AR	Independe	6641	1	8/30/2011	2011	51.604	195968.5	0.565823116
AR	Independe	6641	1	8/31/2011	2011	56.901	205729.4	0.565500908
AR	Independe	6641	1	9/1/2011	2011	52.559	206363.9	0.564415951
AR	Independe	6641	1	9/2/2011	2011	54.897	206197.5	0.564853511
AR	Independe	6641	1	9/3/2011	2011	53.617	207854.6	0.5636015
AR	Independe	6641	1	9/4/2011	2011	51.635	201983.5	0.562424744
AR	Independe	6641	1	9/5/2011	2011	46.158	173229	0.563572167
AR	Independe	6641	1	9/6/2011	2011	42.418	163949.6	0.560917639
AR	Independe	6641	1	9/7/2011	2011	46.039	173733.2	0.560058636
AR	Independe	6641	1	9/8/2011	2011	44.735	178532.9	0.55964272
AR	Independe	6641	1	9/9/2011	2011	46.546	175954.7	0.559520319
AR	Independe	6641	1	9/10/2011	2011	47.642	186980.9	0.55866677
AR	Independe	6641	1	9/11/2011	2011	52.326	195188.9	0.557702512
AR	Independe	6641	1	9/12/2011	2011	47.358	180581.5	0.557053614
AR	Independe	6641	1	9/13/2011	2011	43.259	159972.8	0.554514534
AR	Independe	6641	1	9/14/2011	2011	46.257	178844	0.553750787
AR	Independe	6641	1	9/15/2011	2011	49.787	193570.1	0.551197304
AR	Independe	6641	1	9/16/2011	2011	50.388	190955.4	0.546047189
AR	Independe	6641	1	9/17/2011	2011	53.559	203067	0.543039584
AR	Independe	6641	1	9/18/2011	2011	41.462	200180.1	0.534486755
AR	Independe	6641	1	9/19/2011	2011	41.126	201963.9	0.526861895
AR	Independe	6641	1	9/20/2011	2011	45.847	199596.8	0.524855203
AR	Independe	6641	1	9/21/2011	2011	61.311	200768.2	0.526863466
AR	Independe	6641	1	9/22/2011	2011	62.602	204476.7	0.530244287
AR	Independe	6641	1	9/23/2011	2011	67.361	197919.6	0.532917439
AR	Independe	6641	1	9/24/2011	2011	63.879	197363.6	0.535205997
AR	Independe	6641	1	9/25/2011	2011	55.373	186834.1	0.53478554
AR	Independe	6641	1	9/26/2011	2011	31.201	99130.4	0.536481885
AR	Independe	6641	1	9/27/2011	2011	45.946	165852.1	0.537089637
AR	Independe	6641	1	9/28/2011	2011	45.248	199062.7	0.532348276
AR	Independe	6641	1	9/29/2011	2011	52.947	187511	0.533626577
AR	Independe	6641	1	9/30/2011	2011	38.022	172942.9	0.530002209
AR	Independe	6641	1	10/1/2011	2011	47.551	170712.6	0.531600663
AR	Independe	6641	1	10/2/2011	2011	42.585	167533.8	0.530862779
AR	Independe	6641	1	10/3/2011	2011	50.099	183722.6	0.531914247
AR	Independe	6641	1	10/4/2011	2011	12.819	42151.86	0.533299156
AR	Independe	6641	1	10/6/2011	2011	19.729	71856.2	0.533529331
AR	Independe	6641	1	10/7/2011	2011	60.543	199950	0.536765143
AR	Independe	6641	1	10/8/2011	2011	59.608	207905.2	0.538424363
AR	Independe	6641	1	10/9/2011	2011	47.548	186742.7	0.538651445
AR	Independe	6641	1	10/10/2011	2011	56.871	202724.9	0.539819008
AR	Independe	6641	1	10/11/2011	2011	58.314	202861.7	0.54220529
AR	Independe	6641	1	10/12/2011	2011	57.532	195221.7	0.544147416
AR	Independe	6641	1	10/13/2011	2011	64.574	198717.3	0.548721521
AR	Independe	6641	1	10/14/2011	2011	51.34	196484.2	0.548005253
AR	Independe	6641	1	10/15/2011	2011	40.346	175506.1	0.546155857
AR	Independe	6641	1	10/16/2011	2011	56.89	198582.6	0.548276375
AR	Independe	6641	1	10/17/2011	2011	40.526	157891.8	0.547979456
AR	Independe	6641	1	10/18/2011	2011	31.955	152313	0.545087934
AR	Independe	6641	1	10/19/2011	2011	32.025	145462.2	0.547166219
AR	Independe	6641	1	10/20/2011	2011	42.077	158151.2	0.552117439
AR	Independe	6641	1	10/21/2011	2011	42.997	176565.7	0.553465889
AR	Independe	6641	1	10/22/2011	2011	45.146	205856.2	0.546717427
AR	Independe	6641	1	10/23/2011	2011	48.396	200505.8	0.541674986

AR	Independe	6641	1	10/24/2011	2011	50.246	203631.4	0.534510735
AR	Independe	6641	1	10/25/2011	2011	49.105	199941	0.528577558
AR	Independe	6641	1	10/26/2011	2011	47.77	195801.6	0.524757428
AR	Independe	6641	1	10/27/2011	2011	55.661	198133.7	0.5241874
AR	Independe	6641	1	10/28/2011	2011	56.033	201144.1	0.524500041
AR	Independe	6641	1	10/29/2011	2011	60.869	196718.2	0.530565839
AR	Independe	6641	1	10/30/2011	2011	57.015	190835.7	0.531755412
AR	Independe	6641	1	10/31/2011	2011	53.977	198562.5	0.535153034
AR	Independe	6641	1	11/1/2011	2011	54.006	198243.9	0.534815963
AR	Independe	6641	1	11/2/2011	2011	44.934	164129.092	0.536021755
AR	Independe	6641	1	11/3/2011	2011	58.906	176631	0.539988113
AR	Independe	6641	1	11/4/2011	2011	55.107	182381.6	0.541586396
AR	Independe	6641	1	11/5/2011	2011	51.592	177066.8	0.542781395
AR	Independe	6641	1	11/6/2011	2011	55.801	190568.2	0.542002067
AR	Independe	6641	1	11/7/2011	2011	47.013	169513.2	0.541219229
AR	Independe	6641	1	11/8/2011	2011	52.079	174388.8	0.54403919
AR	Independe	6641	1	11/9/2011	2011	45.149	163089.7	0.543699977
AR	Independe	6641	1	11/10/2011	2011	32.427	140645.2	0.5404266
AR	Independe	6641	1	11/11/2011	2011	44.927	149961.4	0.540288643
AR	Independe	6641	1	11/12/2011	2011	38.113	135864.1	0.536760337
AR	Independe	6641	1	11/13/2011	2011	45.923	159201.1	0.538479954
AR	Independe	6641	1	11/14/2011	2011	43.681	159458.9	0.541357309
AR	Independe	6641	1	11/15/2011	2011	39.229	147538.9	0.539898327
AR	Independe	6641	1	11/16/2011	2011	40.536	142366.5	0.541497302
AR	Independe	6641	1	11/17/2011	2011	44.585	185245.9	0.542901893
AR	Independe	6641	1	11/18/2011	2011	51.986	194912.8	0.545351779
AR	Independe	6641	1	11/19/2011	2011	49.427	196330.3	0.544213031
AR	Independe	6641	1	11/20/2011	2011	62.641	205076	0.548612263
AR	Independe	6641	1	11/21/2011	2011	51.405	177166.712	0.553869402
AR	Independe	6641	1	11/22/2011	2011	49.594	182502.5	0.556178037
AR	Independe	6641	1	11/23/2011	2011	51.438	176107.1	0.559497734
AR	Independe	6641	1	11/24/2011	2011	35.068	140169.8	0.560516348
AR	Independe	6641	1	11/25/2011	2011	44.814	156992.2	0.563544731
AR	Independe	6641	1	11/26/2011	2011	50.754	175054.4	0.564157691
AR	Independe	6641	1	11/27/2011	2011	51.447	168468.1	0.565947464
AR	Independe	6641	1	11/28/2011	2011	54.8	184065.7	0.564983336
AR	Independe	6641	1	11/29/2011	2011	52.075	175764.9	0.564718109
AR	Independe	6641	1	11/30/2011	2011	50.362	161080.2	0.567445501
AR	Independe	6641	1	12/1/2011	2011	44.424	147081.6	0.569396116
AR	Independe	6641	1	12/2/2011	2011	32.317	129431.3	0.568305934
AR	Independe	6641	1	12/3/2011	2011	28.787	124252.6	0.562177093
AR	Independe	6641	1	12/4/2011	2011	44.479	131525.7	0.563667478
AR	Independe	6641	1	12/5/2011	2011	38.707	144385.1	0.562164189
AR	Independe	6641	1	12/6/2011	2011	46.971	152941.6	0.56288417
AR	Independe	6641	1	12/7/2011	2011	51.448	167441.2	0.564954145
AR	Independe	6641	1	12/8/2011	2011	37.946	131843.5	0.564074019
AR	Independe	6641	1	12/9/2011	2011	38.867	132333.6	0.56507601
AR	Independe	6641	1	12/10/2011	2011	40.87	175124.6	0.564535958
AR	Independe	6641	1	12/11/2011	2011	46.033	205404.6	0.558557152
AR	Independe	6641	1	12/12/2011	2011	50.798	181732.7	0.558506198
AR	Independe	6641	1	12/13/2011	2011	39.722	140740.1	0.558078727
AR	Independe	6641	1	12/14/2011	2011	36.439	142780	0.557017199
AR	Independe	6641	1	12/15/2011	2011	48.726	166803.6	0.558705253
AR	Independe	6641	1	12/16/2011	2011	52.441	183821.2	0.558836728
AR	Independe	6641	1	12/17/2011	2011	41.227	171790.8	0.558999878
AR	Independe	6641	1	12/18/2011	2011	58.471	184387	0.562837749
AR	Independe	6641	1	12/19/2011	2011	53.932	168160.4	0.567928433
AR	Independe	6641	1	12/20/2011	2011	48.445	171275	0.566032709

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AR	Independe	6641	1	12/22/2011	2011	39.649	171132.5	0.564459454
AR	Independe	6641	1	12/23/2011	2011	37.866	181743.1	0.558187928
AR	Independe	6641	1	12/24/2011	2011	51.085	169122.1	0.561451096
AR	Independe	6641	1	12/25/2011	2011	43.808	134567.4	0.563635855
AR	Independe	6641	1	12/26/2011	2011	47.379	176172.8	0.562111942
AR	Independe	6641	1	12/27/2011	2011	45.58	177931.8	0.558597537
AR	Independe	6641	1	12/28/2011	2011	46.068	180060.8	0.555457003
AR	Independe	6641	1	12/29/2011	2011	53.493	166196.3	0.557141455
AR	Independe	6641	1	12/30/2011	2011	51.667	157992.7	0.558036889
AR	Independe	6641	1	12/31/2011	2011	48.284	158618	0.558301416
AR	Independe	6641	1	1/1/2012	2012	34.008	145203.1	0.557186209
AR	Independe	6641	1	1/2/2012	2012	43.191	183731.3	0.556306047
AR	Independe	6641	1	1/3/2012	2012	40.851	193370.1	0.547948009
AR	Independe	6641	1	1/4/2012	2012	55.705	188212.4	0.549932957
AR	Independe	6641	1	1/5/2012	2012	52.35	173600.2	0.549813558
AR	Independe	6641	1	1/6/2012	2012	60.273	180175.4	0.551917313
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AR	Independe	6641	1	1/10/2012	2012	46.954	182945.2	0.570395726
AR	Independe	6641	1	1/11/2012	2012	40.132	138414.2	0.571057882
AR	Independe	6641	1	1/12/2012	2012	49.16	176433.4	0.57076443
AR	Independe	6641	1	1/13/2012	2012	54.845	182733	0.573471245
AR	Independe	6641	1	1/14/2012	2012	58.547	170096.7	0.576899574
AR	Independe	6641	1	1/15/2012	2012	48.16	159045.5	0.578011609
AR	Independe	6641	1	1/16/2012	2012	42.407	152498.7	0.580643084
AR	Independe	6641	1	1/17/2012	2012	48.203	153388.3	0.580146001
AR	Independe	6641	1	1/18/2012	2012	49.618	164864.5	0.578829186
AR	Independe	6641	1	1/19/2012	2012	47.833	157984.1	0.580100936
AR	Independe	6641	1	1/20/2012	2012	48.381	148175.9	0.581044267
AR	Independe	6641	1	1/21/2012	2012	54.887	184176.6	0.585551181
AR	Independe	6641	1	1/22/2012	2012	51.47	174472.3	0.591753585
AR	Independe	6641	1	1/23/2012	2012	43.708	154944.4	0.590495552
AR	Independe	6641	1	1/24/2012	2012	44.382	143684.4	0.589659815
AR	Independe	6641	1	1/25/2012	2012	53.47	168045.3	0.593014509
AR	Independe	6641	1	1/26/2012	2012	50.246	156680.8	0.597367678
AR	Independe	6641	1	1/27/2012	2012	50.777	152322.3	0.602553964
AR	Independe	6641	1	1/28/2012	2012	52.507	163091.4	0.60253377
AR	Independe	6641	1	1/29/2012	2012	52.281	189674.2	0.598989535
AR	Independe	6641	1	1/30/2012	2012	64.058	194924.7	0.600920394
AR	Independe	6641	1	1/31/2012	2012	54.549	176741.8	0.60525332
AR	Independe	6641	1	2/1/2012	2012	42.462	132794.6	0.611062107
AR	Independe	6641	1	2/2/2012	2012	50.446	168098.3	0.617945767
AR	Independe	6641	1	2/3/2012	2012	59.355	189494	0.619238991
AR	Independe	6641	1	2/4/2012	2012	51.384	173929	0.618814649
AR	Independe	6641	1	2/5/2012	2012	60.359	183424.6	0.618449547
AR	Independe	6641	1	2/6/2012	2012	53.714	181663.8	0.614431576
AR	Independe	6641	1	2/7/2012	2012	43.005	171660.3	0.609976217
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AR	Independe	6641	1	2/10/2012	2012	56.972	179320.1	0.607451752
AR	Independe	6641	1	2/11/2012	2012	58.867	196071.6	0.608929538
AR	Independe	6641	1	2/12/2012	2012	52.337	187539.9	0.607362748
AR	Independe	6641	1	2/13/2012	2012	58.896	191120.5	0.604991531
AR	Independe	6641	1	2/14/2012	2012	51.516	173315.3	0.604615208
AR	Independe	6641	1	2/15/2012	2012	51.191	172108.8	0.605729733
AR	Independe	6641	1	2/16/2012	2012	52.732	170657.8	0.60545694

AR	Independe	6641	1	2/17/2012	2012	50.198	167741.6	0.605343822
AR	Independe	6641	1	2/18/2012	2012	47.834	152167.6	0.606029377
AR	Independe	6641	1	2/19/2012	2012	54.759	171523.5	0.605759467
AR	Independe	6641	1	2/20/2012	2012	60.71	190400.2	0.607283328
AR	Independe	6641	1	2/21/2012	2012	45.871	159295.2	0.606898873
AR	Independe	6641	1	2/22/2012	2012	41.231	168013.5	0.604404724
AR	Independe	6641	1	2/23/2012	2012	59.811	192666.7	0.604644952
AR	Independe	6641	1	2/24/2012	2012	57.476	190793.9	0.603548589
AR	Independe	6641	1	2/25/2012	2012	66.516	201038.1	0.604640552
AR	Independe	6641	1	2/26/2012	2012	56.064	191004.7	0.60223223
AR	Independe	6641	1	2/27/2012	2012	60.896	195170	0.601757603
AR	Independe	6641	1	2/28/2012	2012	51.922	187427.9	0.601876036
AR	Independe	6641	1	2/29/2012	2012	54.959	184025.6	0.599696635
AR	Independe	6641	1	3/1/2012	2012	52.093	180546.4	0.598350488
AR	Independe	6641	1	3/2/2012	2012	56.307	195823.4	0.59649668
AR	Independe	6641	1	3/3/2012	2012	55.332	179013.2	0.597098641
AR	Independe	6641	1	3/4/2012	2012	58.289	183504.6	0.597365513
AR	Independe	6641	1	3/5/2012	2012	47.069	179575.9	0.595149846
AR	Independe	6641	1	3/6/2012	2012	48.682	161625.9	0.593225981
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AR	Independe	6641	1	3/8/2012	2012	59.44	189178.6	0.596318908
AR	Independe	6641	1	3/9/2012	2012	52.143	174049.9	0.597309382
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AR	Independe	6641	1	3/11/2012	2012	43.728	148918.4	0.598106673
AR	Independe	6641	1	3/12/2012	2012	40.239	154121.2	0.595817942
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AR	Independe	6641	1	3/15/2012	2012	42	132757.4	0.593174689
AR	Independe	6641	1	3/16/2012	2012	40.141	133144.9	0.593370322
AR	Independe	6641	1	3/17/2012	2012	37.178	127000.5	0.592356345
AR	Independe	6641	1	3/18/2012	2012	33.224	132914.8	0.589743156
AR	Independe	6641	1	3/19/2012	2012	42.066	161796.9	0.586371756
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AR	Independe	6641	1	3/25/2012	2012	36.739	140600.9	0.584392359
AR	Independe	6641	1	3/26/2012	2012	53.957	161790.7	0.583946182
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AR	Independe	6641	1	3/29/2012	2012	41.415	144000.1	0.585608686
AR	Independe	6641	1	3/30/2012	2012	42.289	140571.5	0.585631396
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AR	Independe	6641	1	4/1/2012	2012	36.067	133861.5	0.586257963
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AR	Independe	6641	1	4/5/2012	2012	39.567	123831.7	0.585598271
AR	Independe	6641	1	4/6/2012	2012	40.815	133397.5	0.587496356
AR	Independe	6641	1	4/7/2012	2012	42.229	133873	0.587045712
AR	Independe	6641	1	4/8/2012	2012	40.418	129613.2	0.587667692
AR	Independe	6641	1	4/9/2012	2012	42.735	140811.4	0.586944196
AR	Independe	6641	1	4/10/2012	2012	39.561	125723.6	0.588197768
AR	Independe	6641	1	4/11/2012	2012	44.154	132741.1	0.593067144
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AR	Independe	6641	1	4/26/2012	2012	0	957.906	0.599916157
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AR	Independe	6641	1	4/28/2012	2012	44.936	132515.4	0.605884958
AR	Independe	6641	1	4/29/2012	2012	47.269	139950.2	0.612082153
AR	Independe	6641	1	4/30/2012	2012	48.851	147519.7	0.616257202
AR	Independe	6641	1	5/1/2012	2012	58.696	185062.7	0.617297914
AR	Independe	6641	1	5/2/2012	2012	51.16	181245.9	0.615523505
AR	Independe	6641	1	5/3/2012	2012	54.981	178995.8	0.615585037
AR	Independe	6641	1	5/4/2012	2012	60.563	180822.1	0.617998123
AR	Independe	6641	1	5/5/2012	2012	64.152	184429.8	0.624973862
AR	Independe	6641	1	5/6/2012	2012	44.074	139097.4	0.623561775
AR	Independe	6641	1	5/7/2012	2012	49.602	172369.4	0.62209424
AR	Independe	6641	1	5/8/2012	2012	49.072	166476.5	0.620028925
AR	Independe	6641	1	5/9/2012	2012	47.492	162235.8	0.620240083
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AR	Independe	6641	1	5/12/2012	2012	49.118	158711.7	0.621650398
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AR	Independe	6641	1	5/17/2012	2012	38.72	134305.1	0.626366312
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AR	Independe	6641	1	5/19/2012	2012	48.819	161718.5	0.625883598
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AR	Independe	6641	1	5/22/2012	2012	61.223	192929.6	0.624868007
AR	Independe	6641	1	5/23/2012	2012	50.265	162210.7	0.623245986
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AR	Independe	6641	1	6/1/2012	2012	46.256	144652.2	0.633550454
AR	Independe	6641	1	6/2/2012	2012	51.287	161682.1	0.634251055
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AR	Independe	6641	1	6/12/2012	2012	37.895	121319.5	0.631993482
AR	Independe	6641	1	6/13/2012	2012	44.153	152097.4	0.629568176
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AR	Independe	6641	1	6/15/2012	2012	50.694	183010.9	0.629152578
AR	Independe	6641	1	6/16/2012	2012	64.701	196383	0.631615505
AR	Independe	6641	1	6/17/2012	2012	57.52	182706.4	0.631366641
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AR	Independe	6641	1	6/23/2012	2012	44.178	186246	0.614458054
AR	Independe	6641	1	6/24/2012	2012	50	186090	0.610973348
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AR	Independe	6641	1	6/30/2012	2012	45.91	175178.6	0.58953615
AR	Independe	6641	1	7/1/2012	2012	45.282	176561.8	0.585612686
AR	Independe	6641	1	7/2/2012	2012	46.904	165859.3	0.583495328
AR	Independe	6641	1	7/3/2012	2012	48.807	179458.9	0.578349519
AR	Independe	6641	1	7/4/2012	2012	40.513	149622.4	0.574908033
AR	Independe	6641	1	7/5/2012	2012	54.073	173963.6	0.577098605
AR	Independe	6641	1	7/6/2012	2012	44.274	154169.8	0.57669585
AR	Independe	6641	1	7/7/2012	2012	35.072	133770.8	0.574594198
AR	Independe	6641	1	7/8/2012	2012	36.885	140240.8	0.572971945
AR	Independe	6641	1	7/9/2012	2012	52.776	179093.2	0.571274967
AR	Independe	6641	1	7/10/2012	2012	41.431	165514.1	0.566950792
AR	Independe	6641	1	7/11/2012	2012	34.84	128723.4	0.564745217
AR	Independe	6641	1	7/12/2012	2012	32.97	111294	0.563936421
AR	Independe	6641	1	7/13/2012	2012	30.189	98853.7	0.564345799
AR	Independe	6641	1	7/14/2012	2012	28.161	94756.4	0.562248496
AR	Independe	6641	1	7/15/2012	2012	33.728	111390.1	0.563522254
AR	Independe	6641	1	7/16/2012	2012	46.372	146704.8	0.561763266
AR	Independe	6641	1	7/17/2012	2012	40.33	130341.6	0.560744668
AR	Independe	6641	1	7/18/2012	2012	50.44	161628.6	0.562014647
AR	Independe	6641	1	7/19/2012	2012	34.636	121781.6	0.562177999
AR	Independe	6641	1	7/20/2012	2012	40.649	131196.9	0.564942756
AR	Independe	6641	1	7/21/2012	2012	47.703	152669.5	0.567542305
AR	Independe	6641	1	7/22/2012	2012	48.485	138755.2	0.572681582
AR	Independe	6641	1	7/23/2012	2012	35.671	109381.8	0.578588997
AR	Independe	6641	1	7/24/2012	2012	41.587	139103.5	0.580878807
AR	Independe	6641	1	7/25/2012	2012	31.981	114508.2	0.579403506
AR	Independe	6641	1	7/26/2012	2012	30.885	119310.5	0.576951054
AR	Independe	6641	1	7/27/2012	2012	27.777	122147	0.573103606
AR	Independe	6641	1	7/28/2012	2012	47.896	174649.3	0.571553611
AR	Independe	6641	1	7/29/2012	2012	55.708	172777.6	0.576558704
AR	Independe	6641	1	7/30/2012	2012	42.171	132714.8	0.580577872
AR	Independe	6641	1	7/31/2012	2012	41.9	148208.6	0.582885316
AR	Independe	6641	1	8/1/2012	2012	40.889	131969.4	0.584738154
AR	Independe	6641	1	8/2/2012	2012	34.274	125320.8	0.585367774
AR	Independe	6641	1	8/3/2012	2012	28.235	119890.4	0.583616944
AR	Independe	6641	1	8/4/2012	2012	43.374	162586.8	0.579993898
AR	Independe	6641	1	8/5/2012	2012	50.981	160805.5	0.582338292
AR	Independe	6641	1	8/6/2012	2012	38.611	119930.7	0.58606104
AR	Independe	6641	1	8/7/2012	2012	27.473	102667.4	0.586854429
AR	Independe	6641	1	8/8/2012	2012	56.861	182695.5	0.588356303
AR	Independe	6641	1	8/9/2012	2012	56.357	191117	0.592000662
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AR	Independe	6641	1	8/11/2012	2012	40.347	137070.8	0.592985858
AR	Independe	6641	1	8/12/2012	2012	45.238	155768.9	0.592099941
AR	Independe	6641	1	8/13/2012	2012	43.594	158628.5	0.590439028
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AR	Independe	6641	1	8/15/2012	2012	44.456	165146.9	0.584468013
AR	Independe	6641	1	8/16/2012	2012	43.521	158017.1	0.58216266
AR	Independe	6641	1	8/17/2012	2012	40.605	143664.5	0.579984976
AR	Independe	6641	1	8/18/2012	2012	35.085	128042.7	0.579339776
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AR	Independe	6641	1	8/20/2012	2012	36.721	141323.6	0.573204811
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AR	Independe	6641	1	9/1/2012	2012	43.453	139619.6	0.57071941
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AR	Independe	6641	1	9/3/2012	2012	49.926	158547.2	0.577441849
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AR	Independe	6641	1	10/9/2012	2012	37.834	165094.7	0.584748205
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AR	Independe	6641	1	10/23/2012	2012	51.312	164777.9	0.583661218
AR	Independe	6641	1	10/24/2012	2012	57.688	157881.3	0.590081776
AR	Independe	6641	1	10/25/2012	2012	60.667	162518.9	0.594683133
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AR	Independe	6641	1	2/16/2013	2013	36.73	157018	0.512329496
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AR	Independe	6641	1	2/18/2013	2013	37.643	144351.6	0.506737331
AR	Independe	6641	1	2/19/2013	2013	33.735	131481.3	0.504223589
AR	Independe	6641	1	2/20/2013	2013	37.992	134154.2	0.50576589
AR	Independe	6641	1	2/21/2013	2013	49.69	147407.4	0.510413559
AR	Independe	6641	1	2/22/2013	2013	34.614	120178.6	0.513089197
AR	Independe	6641	1	2/23/2013	2013	29.065	123081.5	0.514763541
AR	Independe	6641	1	2/24/2013	2013	27.558	117884.1	0.516580939
AR	Independe	6641	1	2/25/2013	2013	34.837	133138.9	0.517169857
AR	Independe	6641	1	2/26/2013	2013	30.202	156462.8	0.508425612
AR	Independe	6641	1	2/27/2013	2013	32.459	124365.2	0.505355204
AR	Independe	6641	1	2/28/2013	2013	40.091	138631.7	0.507838157
AR	Independe	6641	1	3/1/2013	2013	41.842	145885.5	0.511366601
AR	Independe	6641	1	3/2/2013	2013	46.508	155168.8	0.514000602
AR	Independe	6641	1	3/3/2013	2013	31.798	127688	0.514001891
AR	Independe	6641	1	3/4/2013	2013	28.984	131833.2	0.50900876
AR	Independe	6641	1	3/5/2013	2013	44.471	143637.7	0.510506362
AR	Independe	6641	1	3/6/2013	2013	41.801	137942.2	0.513003157
AR	Independe	6641	1	3/7/2013	2013	39.823	130871.5	0.517293431
AR	Independe	6641	1	3/8/2013	2013	34.74	130593.9	0.520309914
AR	Independe	6641	1	3/9/2013	2013	29.51	133069.3	0.516139212
AR	Independe	6641	1	3/10/2013	2013	34.072	136068.1	0.513716609
AR	Independe	6641	1	3/11/2013	2013	43.002	151065	0.516103122
AR	Independe	6641	1	3/12/2013	2013	34.608	128679.9	0.517110474
AR	Independe	6641	1	3/13/2013	2013	40.899	162730	0.516466524
AR	Independe	6641	1	3/14/2013	2013	39.513	164219.1	0.519351418
AR	Independe	6641	1	3/15/2013	2013	41.241	145943.4	0.522915911
AR	Independe	6641	1	3/16/2013	2013	37.564	141043.7	0.524950274
AR	Independe	6641	1	3/17/2013	2013	42.492	152080.4	0.528494377
AR	Independe	6641	1	3/18/2013	2013	46.76	163223.5	0.53250764
AR	Independe	6641	1	3/19/2013	2013	41.986	157313.1	0.536554899
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AR	Independe	6641	1	3/21/2013	2013	44.666	165000.9	0.537561326
AR	Independe	6641	1	3/22/2013	2013	52.012	175330	0.538942586
AR	Independe	6641	1	3/23/2013	2013	46.817	152445.3	0.536965901
AR	Independe	6641	1	3/24/2013	2013	46.204	159966.7	0.537386049
AR	Independe	6641	1	3/25/2013	2013	55.033	182925.2	0.541901203
AR	Independe	6641	1	3/26/2013	2013	44.513	160711.5	0.544320817
AR	Independe	6641	1	3/27/2013	2013	40.574	150277.7	0.544803916
AR	Independe	6641	1	3/28/2013	2013	32.809	137651.2	0.548301256
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AR	Independe	6641	1	5/26/2013	2013	4.689	26730	0.543293687
AR	Independe	6641	1	5/27/2013	2013	7.002	29837.7	0.540578506
AR	Independe	6641	1	5/28/2013	2013	47.748	149580.6	0.545540416
AR	Independe	6641	1	5/29/2013	2013	37.282	152494.3	0.546850415
AR	Independe	6641	1	5/30/2013	2013	47.105	153360.7	0.546838381
AR	Independe	6641	1	5/31/2013	2013	43.067	155735.9	0.545079293
AR	Independe	6641	1	6/1/2013	2013	57.133	179914.4	0.546984039
AR	Independe	6641	1	6/2/2013	2013	49	162122.4	0.549686036
AR	Independe	6641	1	6/3/2013	2013	49.097	175454.4	0.55345246
AR	Independe	6641	1	6/4/2013	2013	44.799	169279.2	0.554175878

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AR	Independe	6641	1	6/6/2013	2013	30.012	139317.962	0.548040751
AR	Independe	6641	1	6/7/2013	2013	6.345	24878.9	0.549598376
AR	Independe	6641	1	6/8/2013	2013	36.188	141426	0.551027717
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AR	Independe	6641	1	6/10/2013	2013	45.739	176816.1	0.546294803
AR	Independe	6641	1	6/11/2013	2013	40.266	170110.2	0.54286301
AR	Independe	6641	1	6/12/2013	2013	44.457	163873.3	0.541673298
AR	Independe	6641	1	6/13/2013	2013	40.45	164949	0.539947067
AR	Independe	6641	1	6/14/2013	2013	42.064	151318.7	0.541059514
AR	Independe	6641	1	6/15/2013	2013	39.217	150015.2	0.540391624
AR	Independe	6641	1	6/16/2013	2013	40.157	167986.5	0.535657147
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AR	Independe	6641	1	6/18/2013	2013	44.49	160974.2	0.529542628
AR	Independe	6641	1	6/19/2013	2013	44.665	162076.8	0.527214413
AR	Independe	6641	1	6/20/2013	2013	50.219	173124.6	0.528379775
AR	Independe	6641	1	6/21/2013	2013	47.805	176325.5	0.528546055
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AR	Independe	6641	1	6/23/2013	2013	36.162	158246.6	0.529306134
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AR	Independe	6641	1	6/27/2013	2013	47.253	177354.3	0.52853883
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AR	Independe	6641	1	6/30/2013	2013	47.13	187595.1	0.525282194
AR	Independe	6641	1	7/1/2013	2013	41.698	169738.6	0.519980204
AR	Independe	6641	1	7/2/2013	2013	44.394	170137.4	0.517205619
AR	Independe	6641	1	7/3/2013	2013	46.367	169863.2	0.516672423
AR	Independe	6641	1	7/4/2013	2013	41.653	162317.5	0.516112076
AR	Independe	6641	1	7/5/2013	2013	43.434	172926.3	0.516151733
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AR	Independe	6641	1	7/8/2013	2013	40.104	162832	0.521024397
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AR	Independe	6641	1	7/10/2013	2013	44.193	165111.9	0.527415204
AR	Independe	6641	1	7/11/2013	2013	43.376	149454.5	0.530829754
AR	Independe	6641	1	7/12/2013	2013	45.64	162834.2	0.53141198
AR	Independe	6641	1	7/13/2013	2013	41.191	160115	0.532221139
AR	Independe	6641	1	7/14/2013	2013	32.225	144404.1	0.52902113
AR	Independe	6641	1	7/15/2013	2013	32.601	149379.7	0.526441296
AR	Independe	6641	1	7/16/2013	2013	48.273	176328.6	0.528806042
AR	Independe	6641	1	7/17/2013	2013	42.333	162629.2	0.530239391
AR	Independe	6641	1	7/18/2013	2013	46.459	163306.5	0.53077912
AR	Independe	6641	1	7/19/2013	2013	44.548	175307.7	0.529333044
AR	Independe	6641	1	7/20/2013	2013	49.642	176453.9	0.528752282
AR	Independe	6641	1	7/21/2013	2013	46.608	165316	0.529436304
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AR	Independe	6641	1	7/23/2013	2013	41.525	153004.3	0.5316424
AR	Independe	6641	1	7/24/2013	2013	41.279	140470.8	0.533587434
AR	Independe	6641	1	7/25/2013	2013	45.745	161048.3	0.534056702
AR	Independe	6641	1	7/26/2013	2013	34.813	133099.6	0.533655299
AR	Independe	6641	1	7/29/2013	2013	13.817	50708.87	0.533803811
AR	Independe	6641	1	7/30/2013	2013	45.633	179503.2	0.533066359
AR	Independe	6641	1	7/31/2013	2013	49.147	186918.1	0.532894293
AR	Independe	6641	1	8/1/2013	2013	51.488	183679.7	0.535131262
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AR	Independe	6641	1	8/5/2013	2013	49.69	166894.5	0.537586415
AR	Independe	6641	1	8/6/2013	2013	56.771	187819.7	0.541433547
AR	Independe	6641	1	8/7/2013	2013	58.458	202976.8	0.543675506
AR	Independe	6641	1	8/8/2013	2013	52.615	181133.5	0.542924895
AR	Independe	6641	1	8/9/2013	2013	50.877	183442.5	0.545033957
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AR	Independe	6641	1	8/18/2013	2013	42.35	153534.4	0.548463492
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AR	Independe	6641	1	9/23/2013	2013	47.457	159249.2	0.569300217
AR	Independe	6641	1	9/24/2013	2013	47.866	170165.9	0.570708292
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AR	Independe	6641	1	10/16/2013	2013	34.101	122055.9	0.546369787
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AR	Independe	6641	1	10/26/2013	2013	10.523	36388.915	0.541864292
AR	Independe	6641	1	10/27/2013	2013	24.052	78193.4	0.541609401
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AR	Independe	6641	1	11/5/2013	2013	32.507	122976.7	0.559690394
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AR	Independe	6641	1	11/14/2013	2013	38.958	140811.5	0.555034205
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AR	Independe	6641	1	11/16/2013	2013	35.818	112623.8	0.556512191
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AR	Independe	6641	1	11/21/2013	2013	37.951	126846.3	0.572014085
AR	Independe	6641	1	11/22/2013	2013	42.114	157050.7	0.573185267
AR	Independe	6641	1	11/23/2013	2013	40.422	142478.9	0.574007667
AR	Independe	6641	1	11/24/2013	2013	41.511	164549.8	0.571432336
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AR	Independe	6641	1	11/26/2013	2013	35.875	109965	0.572416138
AR	Independe	6641	1	11/27/2013	2013	38.406	133595.7	0.571078756

AR	Independe	6641	1	11/28/2013	2013	40.999	143535.3	0.571481025
AR	Independe	6641	1	11/29/2013	2013	41.906	146265.9	0.571333812
AR	Independe	6641	1	11/30/2013	2013	45.726	145046.9	0.57492989
AR	Independe	6641	1	12/1/2013	2013	34.621	109430.1	0.577539983
AR	Independe	6641	1	12/2/2013	2013	38.801	123145.4	0.576911555
AR	Independe	6641	1	12/3/2013	2013	39.758	131049.8	0.578093319
AR	Independe	6641	1	12/4/2013	2013	40.1	132729.8	0.579218232
AR	Independe	6641	1	12/5/2013	2013	48.309	161164.6	0.581568982
AR	Independe	6641	1	12/6/2013	2013	43.806	148037.9	0.581666062
AR	Independe	6641	1	12/7/2013	2013	42.617	165438.2	0.579405244
AR	Independe	6641	1	12/8/2013	2013	43.105	143443.4	0.58059263
AR	Independe	6641	1	12/9/2013	2013	55.604	170897.3	0.585927467
AR	Independe	6641	1	12/10/2013	2013	48.927	164351.6	0.584764678
AR	Independe	6641	1	12/11/2013	2013	47.383	180787.3	0.584996391
AR	Independe	6641	1	12/12/2013	2013	48.286	158526.5	0.587590438
AR	Independe	6641	1	12/13/2013	2013	64.807	171253.6	0.596091848
AR	Independe	6641	1	12/14/2013	2013	50.572	159876.3	0.598880439
AR	Independe	6641	1	12/15/2013	2013	45.931	170522.9	0.597298774
AR	Independe	6641	1	12/16/2013	2013	45.054	162018.4	0.594749823
AR	Independe	6641	1	12/17/2013	2013	41.33	138496.1	0.595546934
AR	Independe	6641	1	12/18/2013	2013	39.14	144177.5	0.592949796
AR	Independe	6641	1	12/19/2013	2013	44.122	148912.7	0.591952317
AR	Independe	6641	1	12/20/2013	2013	48.793	155068.9	0.591292071
AR	Independe	6641	1	12/21/2013	2013	39.839	132530.7	0.591385183
AR	Independe	6641	1	12/22/2013	2013	34.702	121561	0.592779772
AR	Independe	6641	1	12/23/2013	2013	39.83	141025.7	0.592706768
AR	Independe	6641	1	12/24/2013	2013	42.637	150912.5	0.595052996
AR	Independe	6641	1	12/25/2013	2013	38.118	141549.1	0.594329201
AR	Independe	6641	1	12/26/2013	2013	45.271	163729.9	0.591377461
AR	Independe	6641	1	12/27/2013	2013	52.675	168027	0.593196996
AR	Independe	6641	1	12/28/2013	2013	57.901	176873.1	0.596295866
AR	Independe	6641	1	12/29/2013	2013	48.641	156755	0.597886091
AR	Independe	6641	1	12/30/2013	2013	50.163	172553.9	0.596227316
AR	Independe	6641	1	12/31/2013	2013	52.592	169919.1	0.596200682
AR	Independe	6641	2	1/1/2009	2009	41.664	200696.2	
AR	Independe	6641	2	1/2/2009	2009	40.824	195780.6	
AR	Independe	6641	2	1/3/2009	2009	41.523	193114.6	
AR	Independe	6641	2	1/4/2009	2009	40.49	190531.3	
AR	Independe	6641	2	1/5/2009	2009	42.291	200733.2	
AR	Independe	6641	2	1/6/2009	2009	41.076	201575.8	
AR	Independe	6641	2	1/7/2009	2009	45.914	196913.6	
AR	Independe	6641	2	1/8/2009	2009	53.892	201741.9	
AR	Independe	6641	2	1/9/2009	2009	64.8	196647.2	
AR	Independe	6641	2	1/10/2009	2009	40.199	189803.4	
AR	Independe	6641	2	1/11/2009	2009	60.44	200956.1	
AR	Independe	6641	2	1/12/2009	2009	61.608	210205.2	
AR	Independe	6641	2	1/13/2009	2009	40.79	197687.6	
AR	Independe	6641	2	1/14/2009	2009	47.432	212742.8	
AR	Independe	6641	2	1/15/2009	2009	39.835	191339.9	
AR	Independe	6641	2	1/16/2009	2009	32.691	165101.5	
AR	Independe	6641	2	1/17/2009	2009	43.173	203428.2	
AR	Independe	6641	2	1/18/2009	2009	46.449	199873.8	
AR	Independe	6641	2	1/19/2009	2009	57.13	210548.3	
AR	Independe	6641	2	1/20/2009	2009	49.134	221041.5	
AR	Independe	6641	2	1/21/2009	2009	50.247	221336.3	
AR	Independe	6641	2	1/22/2009	2009	55.045	213191.4	
AR	Independe	6641	2	1/23/2009	2009	42.829	208311	
AR	Independe	6641	2	1/24/2009	2009	41.004	201737.2	

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AR	Independe	6641	2	1/26/2009	2009	46.263	205307.6	
AR	Independe	6641	2	1/27/2009	2009	38.99	175199.4	
AR	Independe	6641	2	1/28/2009	2009	23.96	111479.022	
AR	Independe	6641	2	2/1/2009	2009	8.139	41081.205	
AR	Independe	6641	2	2/2/2009	2009	42.904	187896.7	0.461313147
AR	Independe	6641	2	2/3/2009	2009	51.256	210500.8	0.463856997
AR	Independe	6641	2	2/4/2009	2009	44.535	207721.4	0.464183073
AR	Independe	6641	2	2/5/2009	2009	41.971	202312.2	0.463599895
AR	Independe	6641	2	2/6/2009	2009	43.407	207040.6	0.463286204
AR	Independe	6641	2	2/7/2009	2009	41.03	210835.5	0.4620468
AR	Independe	6641	2	2/8/2009	2009	41.352	213620	0.461185922
AR	Independe	6641	2	2/9/2009	2009	38.339	203182.1	0.458091091
AR	Independe	6641	2	2/10/2009	2009	20.67	115857.5	0.453372512
AR	Independe	6641	2	2/11/2009	2009	22.369	127625.728	0.443932064
AR	Independe	6641	2	2/13/2009	2009	0.46	5910.852	0.444325064
AR	Independe	6641	2	2/14/2009	2009	46.239	188329.5	0.440164443
AR	Independe	6641	2	2/15/2009	2009	54.138	204364.3	0.437904064
AR	Independe	6641	2	2/16/2009	2009	39.948	200083.6	0.437404801
AR	Independe	6641	2	2/17/2009	2009	45.251	171498.5	0.439922341
AR	Independe	6641	2	2/18/2009	2009	21.415	100488	0.440507803
AR	Independe	6641	2	2/19/2009	2009	36.921	169980	0.441688024
AR	Independe	6641	2	2/20/2009	2009	57.262	200751.7	0.447181438
AR	Independe	6641	2	2/21/2009	2009	43.216	176277.5	0.447949304
AR	Independe	6641	2	2/22/2009	2009	44.252	182313.3	0.445472695
AR	Independe	6641	2	2/23/2009	2009	47.786	196066.5	0.447072921
AR	Independe	6641	2	2/24/2009	2009	46.132	194379.3	0.447802143
AR	Independe	6641	2	2/25/2009	2009	42.179	169949	0.446576972
AR	Independe	6641	2	2/26/2009	2009	42.798	179671.3	0.449039326
AR	Independe	6641	2	2/27/2009	2009	41.547	182934.9	0.450889552
AR	Independe	6641	2	2/28/2009	2009	44.631	196640.5	0.451174416
AR	Independe	6641	2	3/1/2009	2009	45.26	206697.2	0.450662237
AR	Independe	6641	2	3/2/2009	2009	44.182	205938.1	0.449991479
AR	Independe	6641	2	3/3/2009	2009	45.434	206447.5	0.450031923
AR	Independe	6641	2	3/4/2009	2009	29.451	138928.506	0.449768996
AR	Independe	6641	2	3/5/2009	2009	52.441	196407	0.452606709
AR	Independe	6641	2	3/6/2009	2009	0.712	2634.652	0.451250166
AR	Independe	6641	2	3/8/2009	2009	0.011	1933.058	0.452019263
AR	Independe	6641	2	3/9/2009	2009	22.897	97550.225	0.4539158
AR	Independe	6641	2	3/10/2009	2009	45.869	200601.7	0.455534382
AR	Independe	6641	2	3/11/2009	2009	54.177	199013.4	0.462085018
AR	Independe	6641	2	3/12/2009	2009	52.41	196430.6	0.46832276
AR	Independe	6641	2	3/13/2009	2009	61.194	203789.9	0.477748097
AR	Independe	6641	2	3/14/2009	2009	45.163	200040.6	0.479536078
AR	Independe	6641	2	3/15/2009	2009	43.799	199501.6	0.481222911
AR	Independe	6641	2	3/16/2009	2009	44.143	201009.9	0.479961923
AR	Independe	6641	2	3/17/2009	2009	50.496	195648.2	0.480927804
AR	Independe	6641	2	3/18/2009	2009	40.869	204809.2	0.475761751
AR	Independe	6641	2	3/19/2009	2009	40.622	203750.4	0.475685233
AR	Independe	6641	2	3/20/2009	2009	40.393	203238	0.470925958
AR	Independe	6641	2	3/21/2009	2009	42.756	200922.6	0.470057491
AR	Independe	6641	2	3/22/2009	2009	44.105	192953.1	0.47072625
AR	Independe	6641	2	3/23/2009	2009	52.577	194572.9	0.469514204
AR	Independe	6641	2	3/24/2009	2009	60.674	186356.4	0.475165408
AR	Independe	6641	2	3/25/2009	2009	43.192	191075.3	0.473990917
AR	Independe	6641	2	3/26/2009	2009	37.273	183534.9	0.471164401
AR	Independe	6641	2	3/27/2009	2009	42.713	185367.8	0.470677927
AR	Independe	6641	2	3/28/2009	2009	44.01	192126.4	0.469411433

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AR	Independe	6641	2	3/30/2009	2009	46.732	175284.2	0.469714424
AR	Independe	6641	2	3/31/2009	2009	45.633	186068.1	0.471017575
AR	Independe	6641	2	4/1/2009	2009	60.303	195896.4	0.477607086
AR	Independe	6641	2	4/2/2009	2009	43.106	195228.2	0.478163325
AR	Independe	6641	2	4/3/2009	2009	48.412	190358.3	0.480733333
AR	Independe	6641	2	4/4/2009	2009	45.135	200727.7	0.481042124
AR	Independe	6641	2	4/5/2009	2009	39.943	197566.7	0.476286979
AR	Independe	6641	2	4/6/2009	2009	55.378	192774.9	0.479660524
AR	Independe	6641	2	4/7/2009	2009	36.715	183718.7	0.477260991
AR	Independe	6641	2	4/8/2009	2009	45.691	201577.2	0.476566958
AR	Independe	6641	2	4/9/2009	2009	41.714	198942.1	0.475281256
AR	Independe	6641	2	4/10/2009	2009	47.037	201283.8	0.472655999
AR	Independe	6641	2	4/11/2009	2009	48.334	199336.7	0.471028642
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AR	Independe	6641	2	4/13/2009	2009	51.611	203741.6	0.467646173
AR	Independe	6641	2	4/14/2009	2009	46.876	200985.7	0.468578406
AR	Independe	6641	2	4/15/2009	2009	52.694	200455.1	0.471543067
AR	Independe	6641	2	4/16/2009	2009	66.324	207449.2	0.475989357
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AR	Independe	6641	2	4/18/2009	2009	51.464	199409.2	0.487439756
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AR	Independe	6641	2	4/20/2009	2009	42.294	180919.9	0.492025123
AR	Independe	6641	2	4/21/2009	2009	38.762	169397.2	0.4921806
AR	Independe	6641	2	4/22/2009	2009	39.872	164454.8	0.490350572
AR	Independe	6641	2	4/23/2009	2009	38.151	181177.3	0.482996115
AR	Independe	6641	2	4/24/2009	2009	45.085	197024.3	0.48315386
AR	Independe	6641	2	4/25/2009	2009	41.688	191427.4	0.484019777
AR	Independe	6641	2	4/26/2009	2009	34.469	164205.7	0.482937876
AR	Independe	6641	2	4/27/2009	2009	39.266	197198	0.480871687
AR	Independe	6641	2	4/28/2009	2009	45.366	174143.2	0.48440187
AR	Independe	6641	2	4/29/2009	2009	62.174	179330.4	0.489423686
AR	Independe	6641	2	4/30/2009	2009	58.653	176812.4	0.494739816
AR	Independe	6641	2	5/1/2009	2009	41.975	181829.7	0.489562892
AR	Independe	6641	2	5/2/2009	2009	36.185	163741.23	0.489838596
AR	Independe	6641	2	5/6/2009	2009	0.022	4190.708	0.488826051
AR	Independe	6641	2	5/7/2009	2009	41.991	157059.128	0.491576419
AR	Independe	6641	2	5/8/2009	2009	67.77	203830.7	0.501168095
AR	Independe	6641	2	5/9/2009	2009	56.766	205138.9	0.500545478
AR	Independe	6641	2	5/10/2009	2009	47.312	192623.4	0.503587116
AR	Independe	6641	2	5/11/2009	2009	50.202	173783.7	0.507791578
AR	Independe	6641	2	5/12/2009	2009	52.498	201785.6	0.511465461
AR	Independe	6641	2	5/13/2009	2009	45.408	204342.6	0.510585555
AR	Independe	6641	2	5/14/2009	2009	51.741	209006.6	0.510927372
AR	Independe	6641	2	5/15/2009	2009	49.011	167972.5	0.515476899
AR	Independe	6641	2	5/16/2009	2009	43.296	204357.8	0.512371155
AR	Independe	6641	2	5/17/2009	2009	41.658	182893.9	0.512156717
AR	Independe	6641	2	5/18/2009	2009	34.85	160486.4	0.50933799
AR	Independe	6641	2	5/19/2009	2009	37.44	174497.8	0.501699955
AR	Independe	6641	2	5/20/2009	2009	40.771	190091.4	0.494944881
AR	Independe	6641	2	5/21/2009	2009	45.344	204114	0.492220892
AR	Independe	6641	2	5/22/2009	2009	46.363	199482.8	0.491433452
AR	Independe	6641	2	5/23/2009	2009	44.15	197723.7	0.490587556
AR	Independe	6641	2	5/24/2009	2009	57.413	198033.9	0.494891503
AR	Independe	6641	2	5/25/2009	2009	49.343	197260.1	0.495389507
AR	Independe	6641	2	5/26/2009	2009	49.605	202167.8	0.497682076
AR	Independe	6641	2	5/27/2009	2009	52.433	209241.1	0.499257551
AR	Independe	6641	2	5/28/2009	2009	56.485	204928.6	0.503426155

AR	Independe	6641	2	5/29/2009	2009	46.352	204987.2	0.504011976
AR	Independe	6641	2	5/30/2009	2009	51.322	188685.5	0.509162431
AR	Independe	6641	2	5/31/2009	2009	42.085	195247.9	0.506035837
AR	Independe	6641	2	6/1/2009	2009	42.492	190405.8	0.497928609
AR	Independe	6641	2	6/2/2009	2009	44.64	205663.7	0.490325466
AR	Independe	6641	2	6/3/2009	2009	53.117	194451.5	0.493205682
AR	Independe	6641	2	6/4/2009	2009	43.38	187068.6	0.493719768
AR	Independe	6641	2	6/5/2009	2009	43.002	191794.1	0.492570715
AR	Independe	6641	2	6/6/2009	2009	40.281	179252.7	0.490105312
AR	Independe	6641	2	6/7/2009	2009	54.21	195139.8	0.486172402
AR	Independe	6641	2	6/8/2009	2009	60.308	197145.7	0.488062284
AR	Independe	6641	2	6/9/2009	2009	59.212	207702.5	0.490887243
AR	Independe	6641	2	6/10/2009	2009	44.24	207043.1	0.486060533
AR	Independe	6641	2	6/11/2009	2009	46.814	194702.9	0.484704815
AR	Independe	6641	2	6/12/2009	2009	38.124	186847.6	0.483660259
AR	Independe	6641	2	6/13/2009	2009	40.526	193559.4	0.4810869
AR	Independe	6641	2	6/14/2009	2009	36.013	171495.9	0.476326101
AR	Independe	6641	2	6/15/2009	2009	36.678	185442.8	0.475597123
AR	Independe	6641	2	6/16/2009	2009	43.88	198915	0.475050886
AR	Independe	6641	2	6/17/2009	2009	48.141	204016.6	0.476058711
AR	Independe	6641	2	6/18/2009	2009	48.923	207838.1	0.477263044
AR	Independe	6641	2	6/19/2009	2009	50.653	216169.3	0.478499915
AR	Independe	6641	2	6/20/2009	2009	49.696	218347.7	0.478819128
AR	Independe	6641	2	6/21/2009	2009	47.837	210508.1	0.4784268
AR	Independe	6641	2	6/22/2009	2009	48.172	209924	0.478797485
AR	Independe	6641	2	6/23/2009	2009	49.767	218473.1	0.474599887
AR	Independe	6641	2	6/24/2009	2009	50.242	216255.4	0.473395706
AR	Independe	6641	2	6/25/2009	2009	50.05	215184.5	0.472517972
AR	Independe	6641	2	6/26/2009	2009	49.022	212614.7	0.471117581
AR	Independe	6641	2	6/27/2009	2009	44.581	202486.6	0.467345959
AR	Independe	6641	2	6/28/2009	2009	43.52	214034.2	0.465701778
AR	Independe	6641	2	6/29/2009	2009	41.524	201369.9	0.46147177
AR	Independe	6641	2	6/30/2009	2009	34.523	180198.5	0.460111767
AR	Independe	6641	2	7/1/2009	2009	36.793	186865.2	0.45848646
AR	Independe	6641	2	7/2/2009	2009	44.999	197874.9	0.459200979
AR	Independe	6641	2	7/3/2009	2009	65.253	209557.8	0.462081614
AR	Independe	6641	2	7/4/2009	2009	42.946	204475.2	0.460605074
AR	Independe	6641	2	7/5/2009	2009	39.842	190785	0.459634742
AR	Independe	6641	2	7/6/2009	2009	42.437	203618.9	0.458497918
AR	Independe	6641	2	7/7/2009	2009	43.243	210782.4	0.453706187
AR	Independe	6641	2	7/8/2009	2009	43.078	211066.6	0.447008593
AR	Independe	6641	2	7/9/2009	2009	57.864	208497.8	0.446507438
AR	Independe	6641	2	7/10/2009	2009	49.496	210861.3	0.447952946
AR	Independe	6641	2	7/11/2009	2009	51.48	208066.1	0.448500905
AR	Independe	6641	2	7/12/2009	2009	43.618	209550.8	0.448632349
AR	Independe	6641	2	7/13/2009	2009	44.598	207402.9	0.448947091
AR	Independe	6641	2	7/14/2009	2009	56.434	201747.5	0.453363248
AR	Independe	6641	2	7/15/2009	2009	46.638	200264.3	0.455496571
AR	Independe	6641	2	7/16/2009	2009	46.449	204770.1	0.455895534
AR	Independe	6641	2	7/17/2009	2009	43.844	194208.2	0.45522889
AR	Independe	6641	2	7/18/2009	2009	39.438	185039.9	0.453834376
AR	Independe	6641	2	7/19/2009	2009	40.136	185153.4	0.452699313
AR	Independe	6641	2	7/20/2009	2009	45.251	198657.6	0.452703191
AR	Independe	6641	2	7/21/2009	2009	41.407	199776.2	0.451391354
AR	Independe	6641	2	7/22/2009	2009	51.98	195338.5	0.453724932
AR	Independe	6641	2	7/23/2009	2009	55.953	211387.2	0.45628948
AR	Independe	6641	2	7/24/2009	2009	47.704	209485.8	0.455962176
AR	Independe	6641	2	7/25/2009	2009	47.689	215358.4	0.455171358

AR	Independe	6641	2	7/26/2009	2009	44.588	206113.9	0.454197043
AR	Independe	6641	2	7/27/2009	2009	52.206	212602.8	0.455951019
AR	Independe	6641	2	7/28/2009	2009	46.604	215317.7	0.456869816
AR	Independe	6641	2	7/29/2009	2009	44.686	198202.9	0.458149393
AR	Independe	6641	2	7/30/2009	2009	40.438	186410.4	0.459627213
AR	Independe	6641	2	7/31/2009	2009	43.757	207821.5	0.460331439
AR	Independe	6641	2	8/1/2009	2009	42.869	197849.8	0.459634992
AR	Independe	6641	2	8/2/2009	2009	44.908	202545.2	0.453486002
AR	Independe	6641	2	8/3/2009	2009	47.689	219946.8	0.453890323
AR	Independe	6641	2	8/4/2009	2009	48.115	219242.8	0.454481692
AR	Independe	6641	2	8/5/2009	2009	55.568	215186.7	0.457897828
AR	Independe	6641	2	8/6/2009	2009	44.784	207196.3	0.458666586
AR	Independe	6641	2	8/7/2009	2009	47.979	214532.6	0.460002231
AR	Independe	6641	2	8/8/2009	2009	53.168	221283.7	0.457523291
AR	Independe	6641	2	8/9/2009	2009	62.42	220081.5	0.461028582
AR	Independe	6641	2	8/10/2009	2009	56.655	215059.9	0.462182062
AR	Independe	6641	2	8/11/2009	2009	50.283	223166.6	0.463318687
AR	Independe	6641	2	8/12/2009	2009	26.55	121512.914	0.463924466
AR	Independe	6641	2	8/13/2009	2009	45.996	196724.7	0.460884289
AR	Independe	6641	2	8/14/2009	2009	43.038	203514.9	0.459459178
AR	Independe	6641	2	8/15/2009	2009	41.207	190239.2	0.458833842
AR	Independe	6641	2	8/16/2009	2009	39.037	187323.7	0.4577725
AR	Independe	6641	2	8/17/2009	2009	38.644	194579.3	0.456794947
AR	Independe	6641	2	8/18/2009	2009	42.463	194094.5	0.456888341
AR	Independe	6641	2	8/19/2009	2009	42.067	186943.9	0.456721454
AR	Independe	6641	2	8/20/2009	2009	58.96	199782.2	0.462486628
AR	Independe	6641	2	8/21/2009	2009	45.316	197929.4	0.460101927
AR	Independe	6641	2	8/22/2009	2009	61.03	203459.2	0.462370632
AR	Independe	6641	2	8/23/2009	2009	46.436	189631.4	0.463466356
AR	Independe	6641	2	8/24/2009	2009	56.546	196522.5	0.467840979
AR	Independe	6641	2	8/25/2009	2009	44.945	203246.2	0.468181205
AR	Independe	6641	2	8/26/2009	2009	43.842	194245.2	0.466830962
AR	Independe	6641	2	8/27/2009	2009	46.897	187235.2	0.469115301
AR	Independe	6641	2	8/28/2009	2009	45.845	193924.3	0.469837215
AR	Independe	6641	2	8/29/2009	2009	42.974	191848.2	0.470256968
AR	Independe	6641	2	8/30/2009	2009	60.433	189075.3	0.477310843
AR	Independe	6641	2	8/31/2009	2009	49.091	196274.3	0.479518881
AR	Independe	6641	2	9/1/2009	2009	58.17	188540.4	0.485093797
AR	Independe	6641	2	9/2/2009	2009	41.159	186570.1	0.485621854
AR	Independe	6641	2	9/3/2009	2009	38.37	188291	0.484865815
AR	Independe	6641	2	9/4/2009	2009	36.882	180090.3	0.481394002
AR	Independe	6641	2	9/5/2009	2009	38.523	180484.5	0.481451728
AR	Independe	6641	2	9/6/2009	2009	36.146	163776.7	0.48158491
AR	Independe	6641	2	9/7/2009	2009	43.213	157724.2	0.483454798
AR	Independe	6641	2	9/8/2009	2009	32.573	159994.5	0.478042274
AR	Independe	6641	2	9/9/2009	2009	34.631	154098.7	0.475380895
AR	Independe	6641	2	9/10/2009	2009	32.382	156871.4	0.474606391
AR	Independe	6641	2	9/11/2009	2009	36.654	167495.5	0.474316879
AR	Independe	6641	2	9/12/2009	2009	49.786	205982.6	0.474887352
AR	Independe	6641	2	9/13/2009	2009	37.748	195759.8	0.473651745
AR	Independe	6641	2	9/14/2009	2009	53.686	207197.7	0.476674713
AR	Independe	6641	2	9/15/2009	2009	45.549	210127.6	0.477057857
AR	Independe	6641	2	9/16/2009	2009	48.517	209044.8	0.479336871
AR	Independe	6641	2	9/17/2009	2009	48.569	209054.5	0.480228912
AR	Independe	6641	2	9/18/2009	2009	42.716	196500.5	0.47964748
AR	Independe	6641	2	9/19/2009	2009	42.589	183201.5	0.475255517
AR	Independe	6641	2	9/20/2009	2009	35.033	159471	0.474847286
AR	Independe	6641	2	9/21/2009	2009	38.111	175337.6	0.469023199

AR	Independe	6641	2	9/22/2009	2009	36.486	179176.1	0.466329506
AR	Independe	6641	2	9/23/2009	2009	54.158	189667.9	0.46604544
AR	Independe	6641	2	9/24/2009	2009	43.773	201797	0.465745269
AR	Independe	6641	2	9/25/2009	2009	37.752	173485.5	0.465291816
AR	Independe	6641	2	9/26/2009	2009	52.902	192472.4	0.467018786
AR	Independe	6641	2	9/27/2009	2009	44.905	189907	0.467018091
AR	Independe	6641	2	9/28/2009	2009	42.513	197091.3	0.466410176
AR	Independe	6641	2	9/29/2009	2009	51.352	190082.6	0.46305041
AR	Independe	6641	2	9/30/2009	2009	41.951	191241.8	0.460893634
AR	Independe	6641	2	10/1/2009	2009	49.958	204221.9	0.456636871
AR	Independe	6641	2	10/2/2009	2009	44.357	179209.2	0.458395297
AR	Independe	6641	2	10/3/2009	2009	0.331	1813.225	0.460148723
AR	Independe	6641	2	10/15/2009	2009	0.025	4185.23	0.461542443
AR	Independe	6641	2	10/16/2009	2009	4.087	33019.005	0.461381615
AR	Independe	6641	2	10/17/2009	2009	37.759	169881.9	0.461462718
AR	Independe	6641	2	10/18/2009	2009	43.661	190070.6	0.458699396
AR	Independe	6641	2	10/19/2009	2009	35.78	170529.7	0.459010228
AR	Independe	6641	2	10/20/2009	2009	34.728	143663.5	0.459991774
AR	Independe	6641	2	10/21/2009	2009	36.595	144927.7	0.462739713
AR	Independe	6641	2	10/22/2009	2009	29.107	132054.6	0.462999329
AR	Independe	6641	2	10/23/2009	2009	30.766	142714.6	0.461238282
AR	Independe	6641	2	10/24/2009	2009	42.957	199846.4	0.46295486
AR	Independe	6641	2	10/25/2009	2009	42.835	198955.6	0.459350756
AR	Independe	6641	2	10/26/2009	2009	39.943	199936.9	0.458032065
AR	Independe	6641	2	10/27/2009	2009	54.749	202848.3	0.46112569
AR	Independe	6641	2	10/28/2009	2009	60.052	196554.7	0.466948706
AR	Independe	6641	2	10/29/2009	2009	70.199	207598.7	0.477016265
AR	Independe	6641	2	10/30/2009	2009	50.812	199911.5	0.47872437
AR	Independe	6641	2	10/31/2009	2009	51.234	205937.9	0.4807525
AR	Independe	6641	2	11/1/2009	2009	52.507	205756	0.483564471
AR	Independe	6641	2	11/2/2009	2009	45.338	200554.2	0.485020281
AR	Independe	6641	2	11/3/2009	2009	42.2	192478.7	0.480027085
AR	Independe	6641	2	11/4/2009	2009	42.969	201782.4	0.479710854
AR	Independe	6641	2	11/5/2009	2009	50.646	190054.1	0.483223121
AR	Independe	6641	2	11/6/2009	2009	40.724	195235	0.478167901
AR	Independe	6641	2	11/7/2009	2009	43.354	205269.7	0.476118249
AR	Independe	6641	2	11/8/2009	2009	43.687	198654.2	0.476432797
AR	Independe	6641	2	11/9/2009	2009	42.728	191122.6	0.472953701
AR	Independe	6641	2	11/10/2009	2009	42.952	194813.9	0.473014945
AR	Independe	6641	2	11/11/2009	2009	42.619	184227.7	0.471988028
AR	Independe	6641	2	11/12/2009	2009	44.924	194373.4	0.4708067
AR	Independe	6641	2	11/13/2009	2009	44.351	178600.6	0.471717943
AR	Independe	6641	2	11/14/2009	2009	41.19	176286.3	0.471928463
AR	Independe	6641	2	11/15/2009	2009	32.674	151006.9	0.472196563
AR	Independe	6641	2	11/16/2009	2009	28.772	136024.5	0.47183743
AR	Independe	6641	2	11/17/2009	2009	23.865	117144.2	0.470888039
AR	Independe	6641	2	11/18/2009	2009	33.279	151241.5	0.471638205
AR	Independe	6641	2	11/19/2009	2009	43.683	165411.9	0.473039444
AR	Independe	6641	2	11/20/2009	2009	42.947	180752	0.472267716
AR	Independe	6641	2	11/21/2009	2009	38.042	181782	0.471255498
AR	Independe	6641	2	11/22/2009	2009	58.915	201731.7	0.476336912
AR	Independe	6641	2	11/23/2009	2009	45.844	190087.2	0.478199388
AR	Independe	6641	2	11/24/2009	2009	46.094	204286.4	0.47890792
AR	Independe	6641	2	11/25/2009	2009	44.808	205668.5	0.480153657
AR	Independe	6641	2	11/26/2009	2009	38.18	186485.8	0.475631704
AR	Independe	6641	2	11/27/2009	2009	38.336	184105.7	0.468907382
AR	Independe	6641	2	11/28/2009	2009	50.86	199366.8	0.462656566
AR	Independe	6641	2	11/29/2009	2009	50.249	194491.7	0.462904827

AR	Independe	6641	2	11/30/2009	2009	52.532	189495.2	0.464744566
AR	Independe	6641	2	12/1/2009	2009	44.2	204535.8	0.461851702
AR	Independe	6641	2	12/2/2009	2009	56.475	197495.3	0.466124197
AR	Independe	6641	2	12/3/2009	2009	43.992	202668.5	0.465914317
AR	Independe	6641	2	12/4/2009	2009	44.579	206218.7	0.466121754
AR	Independe	6641	2	12/5/2009	2009	47.858	201546.4	0.464158997
AR	Independe	6641	2	12/6/2009	2009	59.852	200872.2	0.470550842
AR	Independe	6641	2	12/7/2009	2009	38.056	181173.9	0.47068455
AR	Independe	6641	2	12/8/2009	2009	51.493	188345.4	0.474377539
AR	Independe	6641	2	12/9/2009	2009	38.627	177493.4	0.474063375
AR	Independe	6641	2	12/10/2009	2009	41.201	201817.9	0.472830735
AR	Independe	6641	2	12/11/2009	2009	30.579	150709.7	0.471334401
AR	Independe	6641	2	12/12/2009	2009	36.961	174113.6	0.470170945
AR	Independe	6641	2	12/13/2009	2009	29.525	133787	0.468592262
AR	Independe	6641	2	12/14/2009	2009	39.097	172874.5	0.468116028
AR	Independe	6641	2	12/15/2009	2009	28.741	163093.3	0.465632229
AR	Independe	6641	2	12/16/2009	2009	35.507	164587.5	0.465663315
AR	Independe	6641	2	12/17/2009	2009	41.113	184601.1	0.466219873
AR	Independe	6641	2	12/18/2009	2009	36.383	156509.7	0.466896358
AR	Independe	6641	2	12/19/2009	2009	24.124	118749.4	0.463744868
AR	Independe	6641	2	12/20/2009	2009	31.82	155428.4	0.461824869
AR	Independe	6641	2	12/21/2009	2009	34.668	170463.8	0.461546446
AR	Independe	6641	2	12/22/2009	2009	37.74	177894.7	0.45578283
AR	Independe	6641	2	12/23/2009	2009	39.448	182109.9	0.454096934
AR	Independe	6641	2	12/24/2009	2009	31.896	144647.7	0.453852257
AR	Independe	6641	2	12/25/2009	2009	41.661	181245.6	0.454748171
AR	Independe	6641	2	12/26/2009	2009	40.909	190403.4	0.455435254
AR	Independe	6641	2	12/27/2009	2009	40.375	189083.4	0.455773387
AR	Independe	6641	2	12/28/2009	2009	43.622	189196.2	0.453932544
AR	Independe	6641	2	12/29/2009	2009	54.913	201021.8	0.455121549
AR	Independe	6641	2	12/30/2009	2009	48.178	187656.8	0.453650372
AR	Independe	6641	2	12/31/2009	2009	43.331	156419.7	0.457439323
AR	Independe	6641	2	1/1/2010	2010	49.257	173022.6	0.456825194
AR	Independe	6641	2	1/2/2010	2010	42.761	202205.6	0.456398738
AR	Independe	6641	2	1/3/2010	2010	40.441	203077.2	0.455101425
AR	Independe	6641	2	1/4/2010	2010	43.737	204190.1	0.453311484
AR	Independe	6641	2	1/5/2010	2010	28.702	146298.512	0.446118929
AR	Independe	6641	2	1/6/2010	2010	28.163	146260.6	0.445307233
AR	Independe	6641	2	1/7/2010	2010	31.419	164382.1	0.439598343
AR	Independe	6641	2	1/8/2010	2010	45.728	203104.4	0.440165595
AR	Independe	6641	2	1/9/2010	2010	53.84	192785.9	0.445813086
AR	Independe	6641	2	1/10/2010	2010	41.98	196014.5	0.446311539
AR	Independe	6641	2	1/11/2010	2010	40.203	195125.5	0.445759933
AR	Independe	6641	2	1/12/2010	2010	49.583	180931.6	0.449368366
AR	Independe	6641	2	1/13/2010	2010	39.666	184762.2	0.448575955
AR	Independe	6641	2	1/14/2010	2010	38.514	183806.9	0.450501303
AR	Independe	6641	2	1/15/2010	2010	44.709	198941	0.451047482
AR	Independe	6641	2	1/16/2010	2010	55.478	194072.6	0.455602186
AR	Independe	6641	2	1/17/2010	2010	40.591	167121.7	0.456267775
AR	Independe	6641	2	1/18/2010	2010	36.845	161064	0.457399161
AR	Independe	6641	2	1/19/2010	2010	32.886	157042.7	0.45765608
AR	Independe	6641	2	1/20/2010	2010	32.032	153638	0.458105163
AR	Independe	6641	2	1/21/2010	2010	48.811	173157.2	0.462605112
AR	Independe	6641	2	1/22/2010	2010	34.776	159485.836	0.462813657
AR	Independe	6641	2	1/23/2010	2010	40.082	169926.6	0.463678078
AR	Independe	6641	2	1/24/2010	2010	38.007	161755.2	0.463999149
AR	Independe	6641	2	1/25/2010	2010	36.912	200171.6	0.461677599
AR	Independe	6641	2	1/26/2010	2010	38.157	199881.3	0.459935046

AR	Independe	6641	2	1/27/2010	2010	37.953	192174.4	0.457585885
AR	Independe	6641	2	1/28/2010	2010	38.452	192253.2	0.452232977
AR	Independe	6641	2	1/29/2010	2010	36.43	179890.3	0.448527457
AR	Independe	6641	2	1/30/2010	2010	39.051	189531.5	0.444212818
AR	Independe	6641	2	1/31/2010	2010	41.839	162779	0.442313634
AR	Independe	6641	2	2/1/2010	2010	40.289	180665.7	0.443163308
AR	Independe	6641	2	2/2/2010	2010	34.579	166052	0.444037674
AR	Independe	6641	2	2/3/2010	2010	42.654	208144	0.443306184
AR	Independe	6641	2	2/4/2010	2010	53.235	223073.8	0.446070261
AR	Independe	6641	2	2/5/2010	2010	43.065	200583.3	0.447084816
AR	Independe	6641	2	2/6/2010	2010	47.685	236086.6	0.447170008
AR	Independe	6641	2	2/7/2010	2010	42.295	225747	0.444128642
AR	Independe	6641	2	2/8/2010	2010	53.679	222406.6	0.441728942
AR	Independe	6641	2	2/9/2010	2010	39.926	162737.3	0.443626038
AR	Independe	6641	2	2/10/2010	2010	53.53	199455.4	0.448052679
AR	Independe	6641	2	2/11/2010	2010	60.145	191485.2	0.450981537
AR	Independe	6641	2	2/12/2010	2010	46.389	199747.6	0.452173058
AR	Independe	6641	2	2/13/2010	2010	42.152	184305.3	0.4534291
AR	Independe	6641	2	2/14/2010	2010	42.774	188527.9	0.453581092
AR	Independe	6641	2	2/15/2010	2010	47.474	207612	0.449637496
AR	Independe	6641	2	2/16/2010	2010	52.645	175713.9	0.45323648
AR	Independe	6641	2	2/17/2010	2010	58.419	188593.8	0.458662365
AR	Independe	6641	2	2/18/2010	2010	47.783	169653.8	0.462900452
AR	Independe	6641	2	2/19/2010	2010	40.858	180408.5	0.463824542
AR	Independe	6641	2	2/20/2010	2010	37.259	185925.5	0.458736479
AR	Independe	6641	2	2/21/2010	2010	43.715	181858.6	0.460066076
AR	Independe	6641	2	2/22/2010	2010	45.659	169075.4	0.46208232
AR	Independe	6641	2	2/23/2010	2010	39.677	172857.3	0.461770317
AR	Independe	6641	2	2/24/2010	2010	37.831	185490.6	0.463276114
AR	Independe	6641	2	2/25/2010	2010	40.235	183519.9	0.465332741
AR	Independe	6641	2	2/26/2010	2010	39.484	191722.5	0.465906232
AR	Independe	6641	2	2/27/2010	2010	39.257	189291.7	0.466430484
AR	Independe	6641	2	2/28/2010	2010	38.379	184455.4	0.466740374
AR	Independe	6641	2	3/1/2010	2010	41.026	191452.5	0.467275172
AR	Independe	6641	2	3/2/2010	2010	42.144	202131.3	0.464182629
AR	Independe	6641	2	3/3/2010	2010	37.107	184159.2	0.462794374
AR	Independe	6641	2	3/4/2010	2010	34.008	175222	0.46185957
AR	Independe	6641	2	3/5/2010	2010	36.999	183669.7	0.46185847
AR	Independe	6641	2	3/6/2010	2010	38.212	190956.5	0.459191906
AR	Independe	6641	2	3/7/2010	2010	46.101	209697.6	0.459522112
AR	Independe	6641	2	3/8/2010	2010	46.01	196996.6	0.462097097
AR	Independe	6641	2	3/9/2010	2010	43.027	196908.3	0.464716682
AR	Independe	6641	2	3/10/2010	2010	45.72	205779.5	0.463261626
AR	Independe	6641	2	3/11/2010	2010	39.215	200739	0.45990441
AR	Independe	6641	2	3/12/2010	2010	40.122	197635.3	0.455319024
AR	Independe	6641	2	3/13/2010	2010	49.417	194352.7	0.451303537
AR	Independe	6641	2	3/14/2010	2010	39.714	198544.4	0.449043715
AR	Independe	6641	2	3/15/2010	2010	39.658	192267.5	0.447534808
AR	Independe	6641	2	3/16/2010	2010	40.966	192690.3	0.446570122
AR	Independe	6641	2	3/17/2010	2010	35.976	202947.7	0.442884817
AR	Independe	6641	2	3/18/2010	2010	39.432	209481.6	0.435635748
AR	Independe	6641	2	3/19/2010	2010	38.917	202667.6	0.427748532
AR	Independe	6641	2	3/20/2010	2010	34.814	172011.8	0.423041629
AR	Independe	6641	2	3/21/2010	2010	45.138	202225.1	0.422925157
AR	Independe	6641	2	3/22/2010	2010	38.24	187475.1	0.423152466
AR	Independe	6641	2	3/23/2010	2010	32.965	164414	0.420688904
AR	Independe	6641	2	3/24/2010	2010	40.607	198522.8	0.416784203
AR	Independe	6641	2	3/25/2010	2010	42.119	195420.1	0.416002612

AR	Independe	6641	2	3/26/2010	2010	40.959	210977.5	0.415254271
AR	Independe	6641	2	3/27/2010	2010	44.064	212638.9	0.41449473
AR	Independe	6641	2	3/28/2010	2010	36.808	190847.9	0.413639865
AR	Independe	6641	2	3/29/2010	2010	45.456	217196.3	0.413785751
AR	Independe	6641	2	3/30/2010	2010	42.643	214332.2	0.413135198
AR	Independe	6641	2	3/31/2010	2010	51.297	207096.6	0.415517408
AR	Independe	6641	2	4/1/2010	2010	41.766	200927.7	0.415474102
AR	Independe	6641	2	4/2/2010	2010	47.385	197564.5	0.418004653
AR	Independe	6641	2	4/3/2010	2010	47.675	202863.6	0.420656768
AR	Independe	6641	2	4/4/2010	2010	40.946	219957.5	0.419425472
AR	Independe	6641	2	4/5/2010	2010	48.03	221963.3	0.420527483
AR	Independe	6641	2	4/6/2010	2010	55.951	219897.4	0.423084282
AR	Independe	6641	2	4/7/2010	2010	48.434	197653.1	0.423842451
AR	Independe	6641	2	4/8/2010	2010	50.106	210585.9	0.425226314
AR	Independe	6641	2	4/9/2010	2010	47.349	201247.3	0.426085199
AR	Independe	6641	2	4/10/2010	2010	52.932	217328.7	0.4294493
AR	Independe	6641	2	4/11/2010	2010	42.433	181885.1	0.431335014
AR	Independe	6641	2	4/12/2010	2010	45.187	191900.8	0.430108542
AR	Independe	6641	2	4/13/2010	2010	46.04	214559.2	0.431061009
AR	Independe	6641	2	4/14/2010	2010	45.4	202017.3	0.432262277
AR	Independe	6641	2	4/15/2010	2010	47.991	198684.4	0.434150925
AR	Independe	6641	2	4/16/2010	2010	47.882	200024	0.438286777
AR	Independe	6641	2	4/17/2010	2010	40.556	180153.5	0.440789183
AR	Independe	6641	2	4/18/2010	2010	35.184	175661.6	0.441527853
AR	Independe	6641	2	4/19/2010	2010	40.288	186699.1	0.442268905
AR	Independe	6641	2	4/20/2010	2010	42.163	189990.4	0.442179233
AR	Independe	6641	2	4/21/2010	2010	42.971	195718.6	0.443145699
AR	Independe	6641	2	4/22/2010	2010	43.837	196870.8	0.444362139
AR	Independe	6641	2	4/23/2010	2010	50.305	209509.7	0.446756303
AR	Independe	6641	2	4/24/2010	2010	53.266	217888.2	0.448770594
AR	Independe	6641	2	4/25/2010	2010	41.567	192822	0.450314099
AR	Independe	6641	2	4/26/2010	2010	44.792	212033.5	0.450599074
AR	Independe	6641	2	4/27/2010	2010	45.457	203761.6	0.452487458
AR	Independe	6641	2	4/28/2010	2010	43.417	197636.4	0.453275117
AR	Independe	6641	2	4/29/2010	2010	40.715	180212.3	0.455202002
AR	Independe	6641	2	4/30/2010	2010	46.667	210235.8	0.453428856
AR	Independe	6641	2	5/1/2010	2010	51.54	211471.2	0.455874256
AR	Independe	6641	2	5/2/2010	2010	48.022	214176.3	0.454834047
AR	Independe	6641	2	5/3/2010	2010	53.494	205230.5	0.456577501
AR	Independe	6641	2	5/4/2010	2010	42.773	184224.9	0.459893436
AR	Independe	6641	2	5/5/2010	2010	47.645	167948.7	0.463926755
AR	Independe	6641	2	5/6/2010	2010	45.272	187184	0.462885297
AR	Independe	6641	2	5/7/2010	2010	49.189	215592.5	0.461744092
AR	Independe	6641	2	5/8/2010	2010	46.572	218776.4	0.459924077
AR	Independe	6641	2	5/9/2010	2010	46.695	202629.5	0.459598107
AR	Independe	6641	2	5/10/2010	2010	67.945	211164.9	0.465114428
AR	Independe	6641	2	5/11/2010	2010	54.042	215894	0.466349677
AR	Independe	6641	2	5/12/2010	2010	57.525	219975.4	0.468274234
AR	Independe	6641	2	5/13/2010	2010	59.172	193794.8	0.474274157
AR	Independe	6641	2	5/14/2010	2010	48.19	219354.7	0.473834832
AR	Independe	6641	2	5/15/2010	2010	50.648	214638.3	0.47346252
AR	Independe	6641	2	5/16/2010	2010	49.218	212988.8	0.472889024
AR	Independe	6641	2	5/17/2010	2010	48.32	206447	0.473398715
AR	Independe	6641	2	5/18/2010	2010	41.301	204882.1	0.473136582
AR	Independe	6641	2	5/19/2010	2010	54.496	196708.6	0.477012369
AR	Independe	6641	2	5/20/2010	2010	59.527	201931.3	0.481754848
AR	Independe	6641	2	5/21/2010	2010	41.523	195336.7	0.481311803
AR	Independe	6641	2	5/22/2010	2010	45.009	192992.3	0.482000125

AR	Independei	6641	2	5/23/2010	2010	47.543	224365.2	0.479931675
AR	Independei	6641	2	5/24/2010	2010	49.681	199083.4	0.480235105
AR	Independei	6641	2	5/25/2010	2010	37.952	195561.8	0.478837881
AR	Independei	6641	2	5/26/2010	2010	50.93	177523.8	0.483573471
AR	Independei	6641	2	5/27/2010	2010	69.423	204656.2	0.49138251
AR	Independei	6641	2	5/28/2010	2010	41.795	185335.9	0.491843812
AR	Independei	6641	2	5/29/2010	2010	44.736	164223.1	0.494471055
AR	Independei	6641	2	5/30/2010	2010	44.64	155643.7	0.498294592
AR	Independei	6641	2	5/31/2010	2010	52.291	183264.9	0.500899795
AR	Independei	6641	2	6/1/2010	2010	45.717	206670.6	0.500757207
AR	Independei	6641	2	6/2/2010	2010	48.351	220771.9	0.497735504
AR	Independei	6641	2	6/3/2010	2010	41.42	195504.7	0.496346659
AR	Independei	6641	2	6/4/2010	2010	42.375	205789.2	0.491482911
AR	Independei	6641	2	6/5/2010	2010	60.466	213730.9	0.494346658
AR	Independei	6641	2	6/6/2010	2010	67.873	223705.6	0.499848128
AR	Independei	6641	2	6/7/2010	2010	50.434	193237.4	0.503241682
AR	Independei	6641	2	6/8/2010	2010	48.802	180017.725	0.505833982
AR	Independei	6641	2	6/9/2010	2010	49.133	174226.6	0.502665942
AR	Independei	6641	2	6/10/2010	2010	49.237	216463	0.501010765
AR	Independei	6641	2	6/11/2010	2010	49.359	215908	0.498618335
AR	Independei	6641	2	6/12/2010	2010	45.577	209973.1	0.492733313
AR	Independei	6641	2	6/13/2010	2010	44.479	202533.3	0.492878349
AR	Independei	6641	2	6/14/2010	2010	12.238	57438.17	0.492991904
AR	Independei	6641	2	6/17/2010	2010	0.211	6411.687	0.49367401
AR	Independei	6641	2	6/18/2010	2010	36.854	200223.4	0.490130262
AR	Independei	6641	2	6/19/2010	2010	42.29	227500.2	0.488511593
AR	Independei	6641	2	6/20/2010	2010	42.898	226340.9	0.481851534
AR	Independei	6641	2	6/21/2010	2010	48.877	222783.4	0.476329882
AR	Independei	6641	2	6/22/2010	2010	46.394	223029.9	0.475725298
AR	Independei	6641	2	6/23/2010	2010	47.41	206640	0.475429671
AR	Independei	6641	2	6/24/2010	2010	61.355	204480.7	0.481936042
AR	Independei	6641	2	6/25/2010	2010	48.562	197078.8	0.48171277
AR	Independei	6641	2	6/26/2010	2010	48.694	193947.3	0.485621727
AR	Independei	6641	2	6/27/2010	2010	44.78	194430.6	0.482030962
AR	Independei	6641	2	6/28/2010	2010	47.743	202041.9	0.474657119
AR	Independei	6641	2	6/29/2010	2010	45.203	188311.9	0.475603043
AR	Independei	6641	2	6/30/2010	2010	41.703	181146.6	0.473139391
AR	Independei	6641	2	7/1/2010	2010	46.576	200257.3	0.470154134
AR	Independei	6641	2	7/2/2010	2010	56.872	198421.7	0.470505829
AR	Independei	6641	2	7/3/2010	2010	47.774	181939	0.473238234
AR	Independei	6641	2	7/4/2010	2010	42.376	189611.2	0.473726002
AR	Independei	6641	2	7/5/2010	2010	43.54	195830.6	0.474438595
AR	Independei	6641	2	7/6/2010	2010	51.227	191429.6	0.478725421
AR	Independei	6641	2	7/7/2010	2010	47.861	199734.8	0.475481003
AR	Independei	6641	2	7/8/2010	2010	57.024	204863.5	0.473240698
AR	Independei	6641	2	7/9/2010	2010	55.055	198264.9	0.47444654
AR	Independei	6641	2	7/10/2010	2010	49.153	198449.2	0.473037931
AR	Independei	6641	2	7/11/2010	2010	43.663	191321.6	0.469715559
AR	Independei	6641	2	7/12/2010	2010	47.717	188398.3	0.471495325
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AR	Independei	6641	2	7/14/2010	2010	51.883	177835.4	0.478314934
AR	Independei	6641	2	7/15/2010	2010	46.333	181877.5	0.480743598
AR	Independei	6641	2	7/16/2010	2010	43.493	174925.5	0.481798986
AR	Independei	6641	2	7/17/2010	2010	33.71	131184.7	0.48297808
AR	Independei	6641	2	7/18/2010	2010	32.981	153689.2	0.485521701
AR	Independei	6641	2	7/19/2010	2010	37.45	170533.4	0.488657363
AR	Independei	6641	2	7/20/2010	2010	46.267	174638.7	0.494289756
AR	Independei	6641	2	7/21/2010	2010	41.288	183640.3	0.495028763

AR	Independe	6641	2	7/22/2010	2010	43.836	188862	0.497132342
AR	Independe	6641	2	7/23/2010	2010	54.118	197098.4	0.500375654
AR	Independe	6641	2	7/24/2010	2010	54.848	188860.3	0.499444695
AR	Independe	6641	2	7/25/2010	2010	31.496	104205.622	0.501676352
AR	Independe	6641	2	7/29/2010	2010	0.014	1409.702	0.501531308
AR	Independe	6641	2	7/30/2010	2010	37.449	131458.2	0.504763497
AR	Independe	6641	2	7/31/2010	2010	51.953	207247.6	0.505868857
AR	Independe	6641	2	8/1/2010	2010	54.914	201311.6	0.508314176
AR	Independe	6641	2	8/2/2010	2010	46.071	203140.8	0.507850886
AR	Independe	6641	2	8/3/2010	2010	46.671	209951.1	0.50695532
AR	Independe	6641	2	8/4/2010	2010	42.73	212693.5	0.500252583
AR	Independe	6641	2	8/5/2010	2010	37.516	183755.1	0.496211
AR	Independe	6641	2	8/6/2010	2010	43.781	188854.3	0.496812023
AR	Independe	6641	2	8/7/2010	2010	51.871	204089.8	0.499177791
AR	Independe	6641	2	8/8/2010	2010	54.613	184941.1	0.501065919
AR	Independe	6641	2	8/9/2010	2010	50.308	188563.2	0.503048906
AR	Independe	6641	2	8/10/2010	2010	45.639	200189.5	0.499186245
AR	Independe	6641	2	8/11/2010	2010	49.178	196161.2	0.497160565
AR	Independe	6641	2	8/12/2010	2010	45.013	196773.5	0.495750809
AR	Independe	6641	2	8/13/2010	2010	52.263	201491.9	0.498048
AR	Independe	6641	2	8/14/2010	2010	52.363	189501.4	0.499699517
AR	Independe	6641	2	8/15/2010	2010	60.005	197804.4	0.50314746
AR	Independe	6641	2	8/16/2010	2010	46.153	194047.9	0.499475807
AR	Independe	6641	2	8/17/2010	2010	46.229	175699.1	0.500015082
AR	Independe	6641	2	8/18/2010	2010	54.305	200225.4	0.501688642
AR	Independe	6641	2	8/19/2010	2010	53.892	200585.4	0.502709821
AR	Independe	6641	2	8/20/2010	2010	54.204	202687.2	0.505960342
AR	Independe	6641	2	8/21/2010	2010	53.626	205311.2	0.508635823
AR	Independe	6641	2	8/22/2010	2010	54.813	196419.7	0.509721867
AR	Independe	6641	2	8/23/2010	2010	40.916	194707.4	0.508570986
AR	Independe	6641	2	8/24/2010	2010	51.399	195273.1	0.510707198
AR	Independe	6641	2	8/25/2010	2010	40.693	187646.1	0.506735581
AR	Independe	6641	2	8/26/2010	2010	60.757	204478.2	0.507437634
AR	Independe	6641	2	8/27/2010	2010	55.904	206924.5	0.506853628
AR	Independe	6641	2	8/28/2010	2010	67.952	205467.7	0.512383924
AR	Independe	6641	2	8/29/2010	2010	44.452	196675.1	0.509112166
AR	Independe	6641	2	8/30/2010	2010	61.351	207340.6	0.512272383
AR	Independe	6641	2	8/31/2010	2010	56.775	207286	0.512383768
AR	Independe	6641	2	9/1/2010	2010	45.316	206926.2	0.511803272
AR	Independe	6641	2	9/2/2010	2010	45.46	208162.2	0.511549693
AR	Independe	6641	2	9/3/2010	2010	40.603	203277	0.511644615
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AR	Independe	6641	2	9/5/2010	2010	27.091	146457.3	0.510896721
AR	Independe	6641	2	9/6/2010	2010	29.27	166547.9	0.506439344
AR	Independe	6641	2	9/7/2010	2010	36.347	202644.9	0.498669441
AR	Independe	6641	2	9/8/2010	2010	35.798	195104.6	0.493162635
AR	Independe	6641	2	9/9/2010	2010	33.45	190056.6	0.489850843
AR	Independe	6641	2	9/10/2010	2010	37.654	210419.6	0.484731371
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AR	Independe	6641	2	9/12/2010	2010	37.246	187924.7	0.477520632
AR	Independe	6641	2	9/13/2010	2010	35.582	178136.5	0.472717013
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AR	Independe	6641	2	9/16/2010	2010	32.961	175960.9	0.458154641
AR	Independe	6641	2	9/17/2010	2010	32.075	168846.876	0.452965948
AR	Independe	6641	2	10/19/2010	2010	0	516.66	0.449900561
AR	Independe	6641	2	10/20/2010	2010	1.088	17619.92	0.445656904
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AR	Independe	6641	2	10/22/2010	2010	7.186	41489.749	0.436557399
AR	Independe	6641	2	10/28/2010	2010	0.027	1779.554	0.437055542
AR	Independe	6641	2	10/29/2010	2010	19.175	89292.5	0.433282217
AR	Independe	6641	2	10/30/2010	2010	39.921	167457	0.434787913
AR	Independe	6641	2	10/31/2010	2010	27.43	120805.9	0.428347321
AR	Independe	6641	2	11/1/2010	2010	5.871	27909.975	0.423175265
AR	Independe	6641	2	11/4/2010	2010	2.752	16473.375	0.411537215
AR	Independe	6641	2	11/5/2010	2010	41.274	172679.8	0.412353955
AR	Independe	6641	2	11/6/2010	2010	40.077	187403.7	0.404349734
AR	Independe	6641	2	11/7/2010	2010	38.613	173195.8	0.399051917
AR	Independe	6641	2	11/8/2010	2010	41.486	184898.2	0.399318974
AR	Independe	6641	2	11/9/2010	2010	38.901	174591.3	0.399387443
AR	Independe	6641	2	11/10/2010	2010	42.168	183304.2	0.402045265
AR	Independe	6641	2	11/11/2010	2010	44.924	184438.5	0.404123305
AR	Independe	6641	2	11/12/2010	2010	52.292	191965.2	0.411675778
AR	Independe	6641	2	11/13/2010	2010	38.909	173389.7	0.415553292
AR	Independe	6641	2	11/14/2010	2010	38.116	174278.4	0.419187597
AR	Independe	6641	2	11/15/2010	2010	42.883	176350.5	0.424435405
AR	Independe	6641	2	11/16/2010	2010	37.822	170272.2	0.428537699
AR	Independe	6641	2	11/17/2010	2010	41.768	179350.5	0.433731898
AR	Independe	6641	2	11/18/2010	2010	42.994	171006.5	0.439868758
AR	Independe	6641	2	11/19/2010	2010	42.43	181038.3	0.443137091
AR	Independe	6641	2	11/20/2010	2010	38.113	178481.8	0.444334577
AR	Independe	6641	2	11/21/2010	2010	41.842	175018.7	0.447903789
AR	Independe	6641	2	11/22/2010	2010	39.211	177542.2	0.45076098
AR	Independe	6641	2	11/23/2010	2010	41.324	187214.2	0.453603733
AR	Independe	6641	2	11/24/2010	2010	42.743	186721.4	0.456816587
AR	Independe	6641	2	11/25/2010	2010	34.574	145449.9	0.457506399
AR	Independe	6641	2	11/26/2010	2010	32.289	152427.5	0.457671665
AR	Independe	6641	2	11/27/2010	2010	39.319	171398	0.458840255
AR	Independe	6641	2	11/28/2010	2010	38.765	172373.5	0.459507838
AR	Independe	6641	2	11/29/2010	2010	42.481	174099.3	0.460695544
AR	Independe	6641	2	11/30/2010	2010	38.334	166221	0.461283034
AR	Independe	6641	2	12/1/2010	2010	49.217	170932.9	0.464749229
AR	Independe	6641	2	12/2/2010	2010	34.254	147072.1	0.465041629
AR	Independe	6641	2	12/3/2010	2010	41.628	165027.8	0.466571558
AR	Independe	6641	2	12/4/2010	2010	39.004	176633.3	0.466146264
AR	Independe	6641	2	12/5/2010	2010	40.014	168067.6	0.466075377
AR	Independe	6641	2	12/6/2010	2010	40.583	172987.3	0.467560492
AR	Independe	6641	2	12/7/2010	2010	32.411	150691.6	0.467197413
AR	Independe	6641	2	12/8/2010	2010	36.658	161361.8	0.467457146
AR	Independe	6641	2	12/9/2010	2010	42.012	168331.7	0.469232286
AR	Independe	6641	2	12/10/2010	2010	38.229	168807.5	0.469022967
AR	Independe	6641	2	12/11/2010	2010	36.758	160975.4	0.467981568
AR	Independe	6641	2	12/12/2010	2010	37.548	182431.4	0.463080161
AR	Independe	6641	2	12/13/2010	2010	49.866	180389.8	0.466732138
AR	Independe	6641	2	12/14/2010	2010	54.486	171657.7	0.473378117
AR	Independe	6641	2	12/15/2010	2010	38.704	137733.7	0.475334525
AR	Independe	6641	2	12/16/2010	2010	33.454	142006.2	0.476266388
AR	Independe	6641	2	12/17/2010	2010	25.328	109517.7	0.476342593
AR	Independe	6641	2	12/18/2010	2010	29.163	109337.4	0.476691461
AR	Independe	6641	2	12/19/2010	2010	41.635	174725.8	0.476980743
AR	Independe	6641	2	12/20/2010	2010	41.649	185167.4	0.477771224
AR	Independe	6641	2	12/21/2010	2010	42.907	165752.3	0.479108598
AR	Independe	6641	2	12/22/2010	2010	50.212	165399.5	0.484796631
AR	Independe	6641	2	12/23/2010	2010	42.708	175878.8	0.48649009
AR	Independe	6641	2	12/24/2010	2010	45.481	161148.1	0.490181302
AR	Independe	6641	2	12/25/2010	2010	35.252	163176.7	0.488676016

AR	Independe	6641	2	12/26/2010	2010	37.067	174154.8	0.488459072
AR	Independe	6641	2	12/27/2010	2010	45.376	164012.3	0.491676709
AR	Independe	6641	2	12/28/2010	2010	33.874	162175.8	0.490698828
AR	Independe	6641	2	12/29/2010	2010	35.69	159764.8	0.489351914
AR	Independe	6641	2	12/30/2010	2010	33.699	150854.3	0.488990747
AR	Independe	6641	2	12/31/2010	2010	36.625	148526.8	0.486041263
AR	Independe	6641	2	1/1/2011	2011	38.731	144413.5	0.48816654
AR	Independe	6641	2	1/2/2011	2011	52.916	181987.1	0.491121652
AR	Independe	6641	2	1/3/2011	2011	45.242	183237.5	0.493027361
AR	Independe	6641	2	1/4/2011	2011	38.467	158424.6	0.493370743
AR	Independe	6641	2	1/5/2011	2011	30.905	135382.8	0.493203354
AR	Independe	6641	2	1/6/2011	2011	47.037	163818.1	0.497938355
AR	Independe	6641	2	1/7/2011	2011	54.79	178477.8	0.503684668
AR	Independe	6641	2	1/8/2011	2011	50.554	182071	0.505784001
AR	Independe	6641	2	1/9/2011	2011	60.416	191600.5	0.512536533
AR	Independe	6641	2	1/10/2011	2011	51.403	194949	0.514961374
AR	Independe	6641	2	1/11/2011	2011	41.888	164369.3	0.518645979
AR	Independe	6641	2	1/12/2011	2011	52.357	183371.8	0.519349508
AR	Independe	6641	2	1/13/2011	2011	49.819	162596.9	0.518399929
AR	Independe	6641	2	1/14/2011	2011	43.409	159238.2	0.518044926
AR	Independe	6641	2	1/15/2011	2011	50.61	178869.4	0.521129673
AR	Independe	6641	2	1/16/2011	2011	55.425	180819.3	0.525733589
AR	Independe	6641	2	1/17/2011	2011	59.995	188954	0.529630036
AR	Independe	6641	2	1/18/2011	2011	49.386	187931.5	0.531299382
AR	Independe	6641	2	1/19/2011	2011	54.394	193327.3	0.535443547
AR	Independe	6641	2	1/20/2011	2011	57.836	196141.9	0.53808929
AR	Independe	6641	2	1/21/2011	2011	47.234	194710.4	0.533882035
AR	Independe	6641	2	1/22/2011	2011	44.769	166645.2	0.535637882
AR	Independe	6641	2	1/23/2011	2011	48.615	165592.8	0.536391284
AR	Independe	6641	2	1/24/2011	2011	50.663	182993.7	0.54028986
AR	Independe	6641	2	1/25/2011	2011	46.135	174498.2	0.543755364
AR	Independe	6641	2	1/26/2011	2011	33.202	148168.479	0.540708674
AR	Independe	6641	2	1/27/2011	2011	34.362	161465.3	0.54097211
AR	Independe	6641	2	1/28/2011	2011	50.202	192595.7	0.543139802
AR	Independe	6641	2	1/29/2011	2011	53.889	165868.1	0.54932386
AR	Independe	6641	2	1/30/2011	2011	45.538	163949.6	0.551113574
AR	Independe	6641	2	1/31/2011	2011	53.957	184337.7	0.552717942
AR	Independe	6641	2	2/1/2011	2011	56.209	185114.7	0.553639718
AR	Independe	6641	2	2/2/2011	2011	40.766	171294.5	0.553194669
AR	Independe	6641	2	2/3/2011	2011	42.435	184272.1	0.551990394
AR	Independe	6641	2	2/4/2011	2011	40.456	189941.6	0.54992708
AR	Independe	6641	2	2/5/2011	2011	32.285	168586.6	0.543914014
AR	Independe	6641	2	2/6/2011	2011	41.294	163962.9	0.540329875
AR	Independe	6641	2	2/7/2011	2011	54.236	185231.5	0.541390814
AR	Independe	6641	2	2/8/2011	2011	51.518	163430.4	0.540910924
AR	Independe	6641	2	2/9/2011	2011	53.981	181344.4	0.543276854
AR	Independe	6641	2	2/10/2011	2011	40.22	168359.6	0.542237141
AR	Independe	6641	2	2/11/2011	2011	53.031	173634.6	0.543491499
AR	Independe	6641	2	2/12/2011	2011	41.471	167406.7	0.539840292
AR	Independe	6641	2	2/13/2011	2011	43.7	157141	0.540164538
AR	Independe	6641	2	2/14/2011	2011	46.715	143414.8	0.542328131
AR	Independe	6641	2	2/15/2011	2011	46.101	155684.8	0.541368151
AR	Independe	6641	2	2/16/2011	2011	31.061	128656.7	0.536484989
AR	Independe	6641	2	2/17/2011	2011	29.358	113023.5	0.536510725
AR	Independe	6641	2	2/18/2011	2011	33.944	141451.4	0.533917307
AR	Independe	6641	2	2/19/2011	2011	40.206	161421.6	0.530575667
AR	Independe	6641	2	2/20/2011	2011	46.169	182077.9	0.531491712
AR	Independe	6641	2	2/21/2011	2011	43.136	176350.4	0.529807293

AR	Independe	6641	2	2/22/2011	2011	31.258	177385.1	0.521636313
AR	Independe	6641	2	2/23/2011	2011	45.89	182499.7	0.519783309
AR	Independe	6641	2	2/24/2011	2011	39.995	183043.4	0.516453042
AR	Independe	6641	2	2/25/2011	2011	43.206	189506.2	0.516188152
AR	Independe	6641	2	2/26/2011	2011	47.059	190267.4	0.518255756
AR	Independe	6641	2	2/27/2011	2011	53.442	193857.5	0.5193998
AR	Independe	6641	2	2/28/2011	2011	41.865	179208.6	0.513332835
AR	Independe	6641	2	3/1/2011	2011	49.38	172092.3	0.51401803
AR	Independe	6641	2	3/2/2011	2011	40.079	191976.5	0.507832025
AR	Independe	6641	2	3/3/2011	2011	40.725	174252.116	0.502852031
AR	Independe	6641	2	3/13/2011	2011	17.053	86323.535	0.50191722
AR	Independe	6641	2	3/14/2011	2011	40.609	191337.5	0.500486974
AR	Independe	6641	2	3/15/2011	2011	36.126	168478.7	0.500902406
AR	Independe	6641	2	3/16/2011	2011	32.964	164612	0.501571189
AR	Independe	6641	2	3/17/2011	2011	34.114	148246.7	0.500273598
AR	Independe	6641	2	3/18/2011	2011	40.05	175806.9	0.495525357
AR	Independe	6641	2	3/19/2011	2011	41.533	196013.3	0.488323652
AR	Independe	6641	2	3/20/2011	2011	49.622	187828.6	0.485956884
AR	Independe	6641	2	3/21/2011	2011	39.873	184798.2	0.484233423
AR	Independe	6641	2	3/22/2011	2011	40.899	169833.1	0.479779072
AR	Independe	6641	2	3/23/2011	2011	39.858	189375.9	0.477056276
AR	Independe	6641	2	3/24/2011	2011	46.445	185377.6	0.47548662
AR	Independe	6641	2	3/25/2011	2011	40.088	186966.4	0.468863407
AR	Independe	6641	2	3/26/2011	2011	41.109	193400.8	0.463507136
AR	Independe	6641	2	3/27/2011	2011	39.696	183347.9	0.461959337
AR	Independe	6641	2	3/28/2011	2011	36.274	172571.6	0.459368891
AR	Independe	6641	2	3/29/2011	2011	32.593	157504.9	0.457466147
AR	Independe	6641	2	3/30/2011	2011	37.289	175912.7	0.455119143
AR	Independe	6641	2	3/31/2011	2011	36.748	171947	0.452434067
AR	Independe	6641	2	4/1/2011	2011	40.321	174201.2	0.451554933
AR	Independe	6641	2	4/2/2011	2011	55.86	174162	0.461122788
AR	Independe	6641	2	4/3/2011	2011	48.917	180787.2	0.462415746
AR	Independe	6641	2	4/4/2011	2011	46.642	177552.5	0.465410155
AR	Independe	6641	2	4/5/2011	2011	31.276	160557.2	0.463434944
AR	Independe	6641	2	4/6/2011	2011	47.796	189130.8	0.463815496
AR	Independe	6641	2	4/7/2011	2011	46.803	189468.6	0.461675347
AR	Independe	6641	2	4/8/2011	2011	54.073	203506.1	0.464176298
AR	Independe	6641	2	4/9/2011	2011	55.21	203140.6	0.463657898
AR	Independe	6641	2	4/10/2011	2011	47.698	194429.6	0.466312942
AR	Independe	6641	2	4/11/2011	2011	30.65	144627.9	0.465113255
AR	Independe	6641	2	4/12/2011	2011	26.57	108424.7	0.466763996
AR	Independe	6641	2	4/13/2011	2011	33.973	156799.4	0.467304753
AR	Independe	6641	2	4/14/2011	2011	60.692	185959.1	0.475053726
AR	Independe	6641	2	4/15/2011	2011	35.998	150823.3	0.477446968
AR	Independe	6641	2	4/16/2011	2011	35.875	145634.5	0.478351956
AR	Independe	6641	2	4/17/2011	2011	35.455	129911.8	0.480795299
AR	Independe	6641	2	4/18/2011	2011	45.021	167480.1	0.484778512
AR	Independe	6641	2	4/19/2011	2011	54.588	161234.5	0.489194228
AR	Independe	6641	2	4/20/2011	2011	47.905	170563.4	0.493661585
AR	Independe	6641	2	4/21/2011	2011	52.438	167440.6	0.498370039
AR	Independe	6641	2	4/22/2011	2011	42.292	180590.8	0.500167708
AR	Independe	6641	2	4/23/2011	2011	53.847	198307.4	0.501784526
AR	Independe	6641	2	4/24/2011	2011	41.317	202224.5	0.500779375
AR	Independe	6641	2	4/25/2011	2011	45.008	171138.8	0.504458721
AR	Independe	6641	2	4/26/2011	2011	54.211	159372.2	0.512482428
AR	Independe	6641	2	4/27/2011	2011	48.873	160647.3	0.518605262
AR	Independe	6641	2	4/28/2011	2011	48.532	189654	0.521560257
AR	Independe	6641	2	4/29/2011	2011	44.2	184214.5	0.523401979

AR	Independe	6641	2	4/30/2011	2011	46.059	188905.5	0.525286739
AR	Independe	6641	2	5/1/2011	2011	49.191	205209.4	0.52556583
AR	Independe	6641	2	5/2/2011	2011	49.04	203504.4	0.520010482
AR	Independe	6641	2	5/3/2011	2011	45.306	186586.4	0.518055629
AR	Independe	6641	2	5/4/2011	2011	47.646	196008.7	0.516618403
AR	Independe	6641	2	5/5/2011	2011	44.796	179286.5	0.519910658
AR	Independe	6641	2	5/6/2011	2011	41.281	160967.8	0.520217983
AR	Independe	6641	2	5/7/2011	2011	33.548	131969.7	0.520873648
AR	Independe	6641	2	5/8/2011	2011	45.354	176921.3	0.520178047
AR	Independe	6641	2	5/9/2011	2011	39.446	154680.7	0.518942064
AR	Independe	6641	2	5/10/2011	2011	35.321	139883	0.519644287
AR	Independe	6641	2	5/11/2011	2011	29.416	113904.6	0.522328559
AR	Independe	6641	2	5/12/2011	2011	29.93	118280.9	0.522640546
AR	Independe	6641	2	5/13/2011	2011	25.617	101538.3	0.525082864
AR	Independe	6641	2	5/14/2011	2011	28.61	111254.8	0.520001906
AR	Independe	6641	2	5/15/2011	2011	25.91	101388.3	0.52114013
AR	Independe	6641	2	5/16/2011	2011	23.118	80515.4	0.522897098
AR	Independe	6641	2	5/17/2011	2011	22.986	82728.3	0.52284108
AR	Independe	6641	2	5/18/2011	2011	21.793	79149.9	0.522782398
AR	Independe	6641	2	5/19/2011	2011	18.63	76021	0.516797546
AR	Independe	6641	2	5/20/2011	2011	18.793	68128.1	0.515615177
AR	Independe	6641	2	5/21/2011	2011	34.222	113333	0.513682956
AR	Independe	6641	2	5/22/2011	2011	36.571	129427	0.517082602
AR	Independe	6641	2	5/23/2011	2011	21.583	87658.2	0.515363665
AR	Independe	6641	2	5/24/2011	2011	32.132	128973.2	0.519998894
AR	Independe	6641	2	5/25/2011	2011	28.589	103133.7	0.520612662
AR	Independe	6641	2	5/26/2011	2011	20.057	70002	0.515199785
AR	Independe	6641	2	5/27/2011	2011	36.854	113788.2	0.515225885
AR	Independe	6641	2	5/28/2011	2011	26.788	90113.5	0.517236946
AR	Independe	6641	2	5/29/2011	2011	24.589	106775.8	0.517455933
AR	Independe	6641	2	5/30/2011	2011	32.843	136707.7	0.517610171
AR	Independe	6641	2	5/31/2011	2011	46.458	187189.4	0.518645432
AR	Independe	6641	2	6/1/2011	2011	54.082	194001.7	0.522680715
AR	Independe	6641	2	6/2/2011	2011	51.153	190029.4	0.525337816
AR	Independe	6641	2	6/3/2011	2011	60.08	203423.9	0.530958704
AR	Independe	6641	2	6/4/2011	2011	57.055	199829.1	0.534586569
AR	Independe	6641	2	6/5/2011	2011	53.467	176101.4	0.538908954
AR	Independe	6641	2	6/6/2011	2011	41.48	133808.9	0.542855374
AR	Independe	6641	2	6/7/2011	2011	43.033	172265.2	0.542293634
AR	Independe	6641	2	6/8/2011	2011	47.541	179788.5	0.542972996
AR	Independe	6641	2	6/9/2011	2011	48.668	187029.7	0.543258327
AR	Independe	6641	2	6/10/2011	2011	48.971	188001	0.542965905
AR	Independe	6641	2	6/11/2011	2011	42.141	178515.2	0.540879789
AR	Independe	6641	2	6/12/2011	2011	38.675	163258.4	0.539077571
AR	Independe	6641	2	6/13/2011	2011	40.7	178967.6	0.536072134
AR	Independe	6641	2	6/14/2011	2011	38.592	136304.3	0.537679523
AR	Independe	6641	2	6/15/2011	2011	19.012	75315.33	0.536368063
AR	Independe	6641	2	6/18/2011	2011	7.121	30077.032	0.535512178
AR	Independe	6641	2	6/19/2011	2011	32.194	117013.6	0.535639889
AR	Independe	6641	2	6/20/2011	2011	30.116	109994.5	0.536790646
AR	Independe	6641	2	6/21/2011	2011	43.836	154727.4	0.537640666
AR	Independe	6641	2	6/22/2011	2011	43.566	135686.5	0.539207128
AR	Independe	6641	2	6/23/2011	2011	35.494	114984.3	0.540534724
AR	Independe	6641	2	6/24/2011	2011	51.291	175702.5	0.543264719
AR	Independe	6641	2	6/25/2011	2011	35.74	185354	0.537928738
AR	Independe	6641	2	6/26/2011	2011	51.698	193297.3	0.537418786
AR	Independe	6641	2	6/27/2011	2011	66.718	210687	0.5412543
AR	Independe	6641	2	6/28/2011	2011	49.558	170901.1	0.540077059

AR	Independe	6641	2	6/29/2011	2011	52.323	182184.2	0.540359096
AR	Independe	6641	2	6/30/2011	2011	48.57	194007.1	0.540529178
AR	Independe	6641	2	7/1/2011	2011	45.49	193434.2	0.53943625
AR	Independe	6641	2	7/2/2011	2011	53.154	201465.6	0.540591492
AR	Independe	6641	2	7/3/2011	2011	58.387	186525.4	0.54316365
AR	Independe	6641	2	7/4/2011	2011	47.079	158337.6	0.545018747
AR	Independe	6641	2	7/5/2011	2011	45.77	174890.1	0.54232889
AR	Independe	6641	2	7/6/2011	2011	57.893	197320.2	0.542954237
AR	Independe	6641	2	7/7/2011	2011	56.013	199501.3	0.541393971
AR	Independe	6641	2	7/8/2011	2011	56.659	203447.1	0.53991009
AR	Independe	6641	2	7/9/2011	2011	59.455	210578.4	0.542347948
AR	Independe	6641	2	7/10/2011	2011	61.617	211200.6	0.544562803
AR	Independe	6641	2	7/11/2011	2011	68.357	212012.2	0.549672842
AR	Independe	6641	2	7/12/2011	2011	60.874	209462.4	0.552043797
AR	Independe	6641	2	7/13/2011	2011	67.567	198731.6	0.559848868
AR	Independe	6641	2	7/14/2011	2011	53.121	204149.7	0.561019127
AR	Independe	6641	2	7/15/2011	2011	44.455	202280.7	0.55993766
AR	Independe	6641	2	7/16/2011	2011	61.075	201433.3	0.561567248
AR	Independe	6641	2	7/17/2011	2011	60.094	199925.9	0.563849712
AR	Independe	6641	2	7/18/2011	2011	57.622	203832.1	0.564399361
AR	Independe	6641	2	7/19/2011	2011	62.381	195691.8	0.567255012
AR	Independe	6641	2	7/20/2011	2011	48.591	203292.9	0.564445186
AR	Independe	6641	2	7/21/2011	2011	54.326	202123.3	0.563438217
AR	Independe	6641	2	7/22/2011	2011	64.953	203408	0.56423425
AR	Independe	6641	2	7/23/2011	2011	55.962	205663	0.562497991
AR	Independe	6641	2	7/24/2011	2011	47.225	194385.1	0.559343603
AR	Independe	6641	2	7/25/2011	2011	54.79	191430.1	0.565209682
AR	Independe	6641	2	7/26/2011	2011	51.825	190509.9	0.565519089
AR	Independe	6641	2	7/27/2011	2011	58.096	196469.1	0.563958801
AR	Independe	6641	2	7/28/2011	2011	47.603	204713.4	0.560085374
AR	Independe	6641	2	7/29/2011	2011	53.853	201510.1	0.558780854
AR	Independe	6641	2	7/30/2011	2011	53.699	192505.3	0.560645853
AR	Independe	6641	2	7/31/2011	2011	50.055	195046.1	0.562027996
AR	Independe	6641	2	8/1/2011	2011	49.086	198548.1	0.560935986
AR	Independe	6641	2	8/2/2011	2011	51.481	197633.7	0.557573078
AR	Independe	6641	2	8/3/2011	2011	56.327	211377.7	0.555730803
AR	Independe	6641	2	8/4/2011	2011	50.629	209871.7	0.554123286
AR	Independe	6641	2	8/5/2011	2011	59.986	203764.4	0.554224883
AR	Independe	6641	2	8/6/2011	2011	56.595	206963.4	0.553734665
AR	Independe	6641	2	8/7/2011	2011	52.316	205806.2	0.552086943
AR	Independe	6641	2	8/8/2011	2011	52.921	202874.8	0.550631519
AR	Independe	6641	2	8/9/2011	2011	52.265	202427.5	0.548337602
AR	Independe	6641	2	8/10/2011	2011	54.547	198673.6	0.544972629
AR	Independe	6641	2	8/11/2011	2011	46.52	179086	0.542948406
AR	Independe	6641	2	8/12/2011	2011	55.313	181749.8	0.540394976
AR	Independe	6641	2	8/13/2011	2011	41.937	154033.7	0.541189049
AR	Independe	6641	2	8/14/2011	2011	46.547	160719.8	0.545713931
AR	Independe	6641	2	8/15/2011	2011	59.168	177050.3	0.547330692
AR	Independe	6641	2	8/16/2011	2011	56.856	186056.6	0.547521071
AR	Independe	6641	2	8/17/2011	2011	65.236	203326.9	0.550168394
AR	Independe	6641	2	8/18/2011	2011	61.903	198301.3	0.549760213
AR	Independe	6641	2	8/19/2011	2011	61.158	191388	0.555177791
AR	Independe	6641	2	8/20/2011	2011	61.927	199225.4	0.558054136
AR	Independe	6641	2	8/21/2011	2011	60.921	198727	0.557120591
AR	Independe	6641	2	8/22/2011	2011	51.909	200572.3	0.556217405
AR	Independe	6641	2	8/23/2011	2011	52.674	198802.9	0.557662944
AR	Independe	6641	2	8/24/2011	2011	25.028	86070.9	0.557528813
AR	Independe	6641	2	8/25/2011	2011	22.758	80190	0.558128535

AR	Independe	6641	2	8/26/2011	2011	18.745	64553.518	0.557204182
AR	Independe	6641	2	8/27/2011	2011	1.996	10412.488	0.560423063
AR	Independe	6641	2	8/28/2011	2011	22.981	87100.3	0.56088109
AR	Independe	6641	2	8/29/2011	2011	29.446	99995.7	0.561545265
AR	Independe	6641	2	8/30/2011	2011	25.781	100036.6	0.562506988
AR	Independe	6641	2	8/31/2011	2011	27.672	100555.3	0.565017252
AR	Independe	6641	2	9/1/2011	2011	25.992	102644.1	0.565577969
AR	Independe	6641	2	9/2/2011	2011	23.468	90431.17	0.566151875
AR	Independe	6641	2	9/4/2011	2011	0	1619.309	0.569872843
AR	Independe	6641	2	9/5/2011	2011	22.129	87249.4	0.567734669
AR	Independe	6641	2	9/6/2011	2011	22.56	90653.2	0.567254361
AR	Independe	6641	2	9/7/2011	2011	23.533	91583.8	0.569005926
AR	Independe	6641	2	9/8/2011	2011	22.794	94540.4	0.569351619
AR	Independe	6641	2	9/9/2011	2011	33.559	130331.5	0.570273126
AR	Independe	6641	2	9/10/2011	2011	46.926	192503.7	0.567297256
AR	Independe	6641	2	9/11/2011	2011	51.59	201227.8	0.566686152
AR	Independe	6641	2	9/12/2011	2011	48.112	186372.3	0.562394593
AR	Independe	6641	2	9/13/2011	2011	46.766	176163.6	0.561695633
AR	Independe	6641	2	9/14/2011	2011	40.923	167096.4	0.557983363
AR	Independe	6641	2	9/15/2011	2011	48.105	189885.3	0.550675351
AR	Independe	6641	2	9/16/2011	2011	34.192	130380.056	0.546963681
AR	Independe	6641	2	9/29/2011	2011	0.037	3478.206	0.541343344
AR	Independe	6641	2	9/30/2011	2011	20.878	78785.6	0.536566852
AR	Independe	6641	2	10/1/2011	2011	51.326	180113.7	0.532807269
AR	Independe	6641	2	10/2/2011	2011	42.451	168996.5	0.526445432
AR	Independe	6641	2	10/3/2011	2011	45.601	166422.7	0.522614458
AR	Independe	6641	2	10/4/2011	2011	52.977	193741.3	0.524220899
AR	Independe	6641	2	10/5/2011	2011	52.481	208770.1	0.522645615
AR	Independe	6641	2	10/6/2011	2011	48.861	210010.7	0.51800337
AR	Independe	6641	2	10/7/2011	2011	61.658	205447.7	0.521392439
AR	Independe	6641	2	10/8/2011	2011	62.662	215002.4	0.523762998
AR	Independe	6641	2	10/9/2011	2011	49.433	192762.8	0.523609918
AR	Independe	6641	2	10/10/2011	2011	59.29	209998.7	0.525547478
AR	Independe	6641	2	10/11/2011	2011	60.717	211387.2	0.526461206
AR	Independe	6641	2	10/12/2011	2011	58.309	200788.3	0.529143566
AR	Independe	6641	2	10/13/2011	2011	67.383	206354.2	0.534256001
AR	Independe	6641	2	10/14/2011	2011	52.235	198919.2	0.534480407
AR	Independe	6641	2	10/15/2011	2011	39.982	172649.4	0.53218868
AR	Independe	6641	2	10/16/2011	2011	57.172	200326.3	0.533920742
AR	Independe	6641	2	10/17/2011	2011	37.886	149307	0.533598321
AR	Independe	6641	2	10/18/2011	2011	28.015	136189.1	0.530957472
AR	Independe	6641	2	10/19/2011	2011	29.912	137667.2	0.528668341
AR	Independe	6641	2	10/20/2011	2011	35.839	136419.4	0.529434196
AR	Independe	6641	2	10/21/2011	2011	39.827	166520.4	0.528158871
AR	Independe	6641	2	10/22/2011	2011	48.082	223063.3	0.52551192
AR	Independe	6641	2	10/23/2011	2011	50.893	211829.1	0.524181393
AR	Independe	6641	2	10/24/2011	2011	52.803	218667.4	0.522748644
AR	Independe	6641	2	10/25/2011	2011	48.603	201223.4	0.520967538
AR	Independe	6641	2	10/26/2011	2011	49.424	205924.7	0.520362349
AR	Independe	6641	2	10/27/2011	2011	58.414	210434.4	0.522216945
AR	Independe	6641	2	10/28/2011	2011	57.896	209166	0.523370577
AR	Independe	6641	2	10/29/2011	2011	60.96	198971	0.526842193
AR	Independe	6641	2	10/30/2011	2011	55.961	190463.5	0.528816798
AR	Independe	6641	2	10/31/2011	2011	52.051	196534.5	0.527559647
AR	Independe	6641	2	11/1/2011	2011	55.561	200506.2	0.529218416
AR	Independe	6641	2	11/2/2011	2011	25.41	95370.8	0.528731923
AR	Independe	6641	2	11/3/2011	2011	50.778	153325.3	0.531722975
AR	Independe	6641	2	11/4/2011	2011	63.4	207771	0.535666081

AR	Independe	6641	2	11/5/2011	2011	59.355	200034.6	0.540315868
AR	Independe	6641	2	11/6/2011	2011	62.201	208592.2	0.540207678
AR	Independe	6641	2	11/7/2011	2011	47.696	174087.2	0.538815866
AR	Independe	6641	2	11/8/2011	2011	40.946	135839.2	0.541275731
AR	Independe	6641	2	11/9/2011	2011	38.176	137531.5	0.540729272
AR	Independe	6641	2	11/10/2011	2011	31.919	133678	0.537854426
AR	Independe	6641	2	11/11/2011	2011	41.472	136994.7	0.537973519
AR	Independe	6641	2	11/12/2011	2011	38.77	136769.5	0.534228559
AR	Independe	6641	2	11/13/2011	2011	40.305	139353.2	0.535752299
AR	Independe	6641	2	11/14/2011	2011	39.509	143000.8	0.538627504
AR	Independe	6641	2	11/15/2011	2011	33.917	128924.3	0.537056335
AR	Independe	6641	2	11/16/2011	2011	48.743	166537.3	0.539479874
AR	Independe	6641	2	11/17/2011	2011	49.106	202135.8	0.540748293
AR	Independe	6641	2	11/18/2011	2011	56.198	205190.5	0.543792714
AR	Independe	6641	2	11/19/2011	2011	52.596	204301.7	0.543156355
AR	Independe	6641	2	11/20/2011	2011	68.48	218832.1	0.548511737
AR	Independe	6641	2	11/21/2011	2011	60.904	204994.6	0.555124159
AR	Independe	6641	2	11/22/2011	2011	55.848	209370.4	0.557221997
AR	Independe	6641	2	11/23/2011	2011	57.867	198146.3	0.561249414
AR	Independe	6641	2	11/24/2011	2011	39.146	158148.1	0.562240198
AR	Independe	6641	2	11/25/2011	2011	56.113	194488.3	0.565977915
AR	Independe	6641	2	11/26/2011	2011	59.448	200964.5	0.567382021
AR	Independe	6641	2	11/27/2011	2011	58.872	184715.8	0.570387317
AR	Independe	6641	2	11/28/2011	2011	62.249	204425.2	0.570286197
AR	Independe	6641	2	11/29/2011	2011	61.342	206654.9	0.570575247
AR	Independe	6641	2	11/30/2011	2011	59.281	191708.8	0.573833888
AR	Independe	6641	2	12/1/2011	2011	45.987	155560.2	0.575102357
AR	Independe	6641	2	12/2/2011	2011	32.768	131423.1	0.573961224
AR	Independe	6641	2	12/3/2011	2011	28.369	124254.9	0.568596919
AR	Independe	6641	2	12/4/2011	2011	42.72	129169.3	0.569242059
AR	Independe	6641	2	12/5/2011	2011	34.719	127718.3	0.56765052
AR	Independe	6641	2	12/6/2011	2011	33.979	112740.62	0.56724357
AR	Independe	6641	2	12/7/2011	2011	0	736.084	0.567853047
AR	Independe	6641	2	12/8/2011	2011	22.02	76009.414	0.567039217
AR	Independe	6641	2	12/9/2011	2011	35.249	118838.8	0.568039156
AR	Independe	6641	2	12/10/2011	2011	28.027	123092.091	0.567665193
AR	Independe	6641	2	12/13/2011	2011	23.668	86765.942	0.566150801
AR	Independe	6641	2	12/14/2011	2011	31.829	127794.8	0.564268642
AR	Independe	6641	2	12/15/2011	2011	40.51	137282.1	0.564606401
AR	Independe	6641	2	12/16/2011	2011	41.039	143531.1	0.56519697
AR	Independe	6641	2	12/17/2011	2011	33.156	138886.5	0.563670077
AR	Independe	6641	2	12/18/2011	2011	45.185	145095.3	0.564735966
AR	Independe	6641	2	12/19/2011	2011	42.529	135195.2	0.570099233
AR	Independe	6641	2	12/20/2011	2011	36.942	133121.2	0.570668347
AR	Independe	6641	2	12/21/2011	2011	43.369	141121.2	0.57461409
AR	Independe	6641	2	12/22/2011	2011	32.691	140385.1	0.568566805
AR	Independe	6641	2	12/23/2011	2011	35.544	167669.8	0.56177779
AR	Independe	6641	2	12/24/2011	2011	64.023	205723.4	0.566015812
AR	Independe	6641	2	12/25/2011	2011	53.984	164354.1	0.568653241
AR	Independe	6641	2	12/26/2011	2011	53.664	197660.7	0.570163915
AR	Independe	6641	2	12/27/2011	2011	53.599	210212.3	0.56695652
AR	Independe	6641	2	12/28/2011	2011	54.642	210341	0.563542195
AR	Independe	6641	2	12/29/2011	2011	65.541	201167.1	0.564468906
AR	Independe	6641	2	12/30/2011	2011	66.067	195829.7	0.567319995
AR	Independe	6641	2	12/31/2011	2011	55.671	185322	0.567494491
AR	Independe	6641	2	1/1/2012	2012	39.777	162071	0.562368979
AR	Independe	6641	2	1/2/2012	2012	48.915	203935.7	0.557491964
AR	Independe	6641	2	1/3/2012	2012	46.147	217176.9	0.552775831

AR	Independe	6641	2	1/4/2012	2012	64.226	213903	0.557642826
AR	Independe	6641	2	1/5/2012	2012	63.296	206657.6	0.557198194
AR	Independe	6641	2	1/6/2012	2012	65.701	195301.3	0.562372158
AR	Independe	6641	2	1/7/2012	2012	73.538	201239.3	0.568503841
AR	Independe	6641	2	1/8/2012	2012	66.225	203922.2	0.57189848
AR	Independe	6641	2	1/9/2012	2012	75.661	207048.5	0.578214275
AR	Independe	6641	2	1/10/2012	2012	52.112	207807	0.574813508
AR	Independe	6641	2	1/11/2012	2012	49.404	169993.9	0.5778182
AR	Independe	6641	2	1/12/2012	2012	52.619	189394.8	0.577557184
AR	Independe	6641	2	1/13/2012	2012	63.734	209782.1	0.580581857
AR	Independe	6641	2	1/14/2012	2012	66.594	197214.5	0.583739853
AR	Independe	6641	2	1/15/2012	2012	56.47	187328.9	0.584694878
AR	Independe	6641	2	1/16/2012	2012	46.575	168112.5	0.586443991
AR	Independe	6641	2	1/17/2012	2012	55.617	176478	0.586882813
AR	Independe	6641	2	1/18/2012	2012	53.716	178515	0.586342937
AR	Independe	6641	2	1/19/2012	2012	60.297	196779.1	0.587985777
AR	Independe	6641	2	1/20/2012	2012	64.094	193882.6	0.589794393
AR	Independe	6641	2	1/21/2012	2012	61.554	202579.6	0.593405612
AR	Independe	6641	2	1/22/2012	2012	62.374	206528.9	0.598622015
AR	Independe	6641	2	1/23/2012	2012	52.78	187752	0.596616656
AR	Independe	6641	2	1/24/2012	2012	50.65	163930.6	0.595519618
AR	Independe	6641	2	1/25/2012	2012	60.344	189265.8	0.598663623
AR	Independe	6641	2	1/26/2012	2012	60.791	189128.5	0.603305131
AR	Independe	6641	2	1/27/2012	2012	62.33	186334.9	0.608458226
AR	Independe	6641	2	1/28/2012	2012	59.523	184438.6	0.608136745
AR	Independe	6641	2	1/29/2012	2012	58.857	212310	0.603918293
AR	Independe	6641	2	1/30/2012	2012	71.561	217021.3	0.60608729
AR	Independe	6641	2	1/31/2012	2012	62.421	203239.8	0.609553474
AR	Independe	6641	2	2/1/2012	2012	64.282	197409.2	0.615476585
AR	Independe	6641	2	2/2/2012	2012	58.981	195994.7	0.62210498
AR	Independe	6641	2	2/3/2012	2012	65.17	205911.7	0.623281291
AR	Independe	6641	2	2/4/2012	2012	58.711	196793	0.622762248
AR	Independe	6641	2	2/5/2012	2012	73.259	212606	0.623505436
AR	Independe	6641	2	2/6/2012	2012	63.293	213227	0.618725794
AR	Independe	6641	2	2/7/2012	2012	52.94	213143.7	0.613217971
AR	Independe	6641	2	2/8/2012	2012	54.825	189018.4	0.607977296
AR	Independe	6641	2	2/9/2012	2012	30.727	117980.6	0.610036095
AR	Independe	6641	2	2/10/2012	2012	57.396	183413.3	0.611388564
AR	Independe	6641	2	2/11/2012	2012	64.77	210358.8	0.613373338
AR	Independe	6641	2	2/12/2012	2012	59.628	206826	0.612266952
AR	Independe	6641	2	2/13/2012	2012	66.415	209710.6	0.61088515
AR	Independe	6641	2	2/14/2012	2012	62.148	204871.5	0.610995149
AR	Independe	6641	2	2/15/2012	2012	61.501	204239.2	0.612324923
AR	Independe	6641	2	2/16/2012	2012	58.85	192256.6	0.611780102
AR	Independe	6641	2	2/17/2012	2012	60.629	202901.5	0.611594499
AR	Independe	6641	2	2/18/2012	2012	50.05	162176.7	0.611708693
AR	Independe	6641	2	2/19/2012	2012	62.281	194413.3	0.611034038
AR	Independe	6641	2	2/20/2012	2012	67.638	210543.7	0.61227926
AR	Independe	6641	2	2/21/2012	2012	55.098	193066.4	0.611200818
AR	Independe	6641	2	2/22/2012	2012	46.521	187793.8	0.609056741
AR	Independe	6641	2	2/23/2012	2012	65.606	210710	0.609297654
AR	Independe	6641	2	2/24/2012	2012	63.097	210115.5	0.608081411
AR	Independe	6641	2	2/25/2012	2012	73.358	217121.5	0.609445698
AR	Independe	6641	2	2/26/2012	2012	63.628	213093.5	0.607149935
AR	Independe	6641	2	2/27/2012	2012	68.307	216794.6	0.60680407
AR	Independe	6641	2	2/28/2012	2012	57.194	205125.1	0.606976435
AR	Independe	6641	2	2/29/2012	2012	62.438	207506.4	0.604893949
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AR	Independe	6641	2	3/2/2012	2012	63.794	221694	0.601150958
AR	Independe	6641	2	3/3/2012	2012	57.727	184971.8	0.601837228
AR	Independe	6641	2	3/4/2012	2012	67.927	210025.9	0.602343103
AR	Independe	6641	2	3/5/2012	2012	53.367	202694.6	0.599973722
AR	Independe	6641	2	3/6/2012	2012	55.511	182798.4	0.597029213
AR	Independe	6641	2	3/7/2012	2012	55.031	197619.5	0.595821345
AR	Independe	6641	2	3/8/2012	2012	63.136	202967	0.60026347
AR	Independe	6641	2	3/9/2012	2012	53.307	177526.7	0.600913197
AR	Independe	6641	2	3/10/2012	2012	56.03	177266.8	0.603408478
AR	Independe	6641	2	3/11/2012	2012	53.554	182499.4	0.602220211
AR	Independe	6641	2	3/12/2012	2012	51.799	200369.9	0.598894966
AR	Independe	6641	2	3/13/2012	2012	49.66	214559.3	0.594800544
AR	Independe	6641	2	3/14/2012	2012	58.258	196265.7	0.593411321
AR	Independe	6641	2	3/15/2012	2012	51.86	173156.1	0.593116492
AR	Independe	6641	2	3/16/2012	2012	49.454	172769	0.59220007
AR	Independe	6641	2	3/17/2012	2012	43.853	157961.4	0.590555666
AR	Independe	6641	2	3/18/2012	2012	40.674	176522.1	0.586405598
AR	Independe	6641	2	3/19/2012	2012	50.464	206065.1	0.582188697
AR	Independe	6641	2	3/20/2012	2012	52.443	195070.4	0.578793235
AR	Independe	6641	2	3/21/2012	2012	59.101	198805.8	0.577049567
AR	Independe	6641	2	3/22/2012	2012	52.838	182328.4	0.57733442
AR	Independe	6641	2	3/23/2012	2012	55.107	186419.4	0.580387901
AR	Independe	6641	2	3/24/2012	2012	60.736	207173.7	0.579080507
AR	Independe	6641	2	3/25/2012	2012	47.016	185342	0.576037768
AR	Independe	6641	2	3/26/2012	2012	64.573	203229.2	0.57439989
AR	Independe	6641	2	3/27/2012	2012	58.184	196401.4	0.574176693
AR	Independe	6641	2	3/28/2012	2012	65.728	207881.4	0.574169773
AR	Independe	6641	2	3/29/2012	2012	56.441	198427.6	0.574572503
AR	Independe	6641	2	3/30/2012	2012	56.272	189740.9	0.574205674
AR	Independe	6641	2	3/31/2012	2012	56.869	184428	0.575340202
AR	Independe	6641	2	4/1/2012	2012	47.257	180317.8	0.573723097
AR	Independe	6641	2	4/2/2012	2012	39.049	137594.6	0.571933125
AR	Independe	6641	2	4/3/2012	2012	33.41	123324.3	0.568459004
AR	Independe	6641	2	4/4/2012	2012	42.303	144628.2	0.570423161
AR	Independe	6641	2	4/5/2012	2012	48.032	151902	0.570907139
AR	Independe	6641	2	4/6/2012	2012	50.18	168159.4	0.572206071
AR	Independe	6641	2	4/7/2012	2012	53.359	170757.1	0.571999843
AR	Independe	6641	2	4/8/2012	2012	50.189	162326.2	0.572452499
AR	Independe	6641	2	4/9/2012	2012	56.415	187450.7	0.571522709
AR	Independe	6641	2	4/10/2012	2012	49.498	157890.5	0.572621519
AR	Independe	6641	2	4/11/2012	2012	54.138	164472.4	0.5773106
AR	Independe	6641	2	4/12/2012	2012	52.004	157124.1	0.584419242
AR	Independe	6641	2	4/13/2012	2012	46.354	156659	0.58429414
AR	Independe	6641	2	4/14/2012	2012	54.781	185233.9	0.584064741
AR	Independe	6641	2	4/15/2012	2012	43.736	139799.2	0.585550557
AR	Independe	6641	2	4/16/2012	2012	46.666	162626.8	0.586099934
AR	Independe	6641	2	4/17/2012	2012	43.297	177773.5	0.586956311
AR	Independe	6641	2	4/18/2012	2012	51.032	153497.5	0.59308861
AR	Independe	6641	2	4/19/2012	2012	51.379	160364.9	0.596650005
AR	Independe	6641	2	4/20/2012	2012	48.414	147606.5	0.598438015
AR	Independe	6641	2	4/21/2012	2012	48.122	150194.5	0.600359692
AR	Independe	6641	2	4/22/2012	2012	41.211	149339.5	0.599267024
AR	Independe	6641	2	4/23/2012	2012	43.558	153394.9	0.598842067
AR	Independe	6641	2	4/24/2012	2012	53.917	177690.2	0.602518737
AR	Independe	6641	2	4/25/2012	2012	54.394	202490	0.598535813
AR	Independe	6641	2	4/26/2012	2012	62.9	199463.2	0.600054916
AR	Independe	6641	2	4/27/2012	2012	64.237	195325.1	0.600967234
AR	Independe	6641	2	4/28/2012	2012	57.373	174118.8	0.604284553

AR	Independe	6641	2	4/29/2012	2012	63.308	189680.7	0.607125757
AR	Independe	6641	2	4/30/2012	2012	61.982	191642.5	0.608301319
AR	Independe	6641	2	5/1/2012	2012	71.68	232685.6	0.611682388
AR	Independe	6641	2	5/2/2012	2012	65.767	242379	0.609604655
AR	Independe	6641	2	5/3/2012	2012	69.335	231179.9	0.610769392
AR	Independe	6641	2	5/4/2012	2012	74.258	229312.1	0.613059213
AR	Independe	6641	2	5/5/2012	2012	80.033	235481.7	0.61542
AR	Independe	6641	2	5/6/2012	2012	71.255	225917.9	0.616628713
AR	Independe	6641	2	5/7/2012	2012	64.162	232504.1	0.613648241
AR	Independe	6641	2	5/8/2012	2012	56.881	197858	0.612134163
AR	Independe	6641	2	5/9/2012	2012	50.735	176934.9	0.611247253
AR	Independe	6641	2	5/10/2012	2012	61.668	199870.7	0.611011177
AR	Independe	6641	2	5/11/2012	2012	42.617	152174.2	0.608228603
AR	Independe	6641	2	5/12/2012	2012	55.27	182647.8	0.606624519
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AR	Independe	6641	2	5/15/2012	2012	35.514	125482.1	0.610416171
AR	Independe	6641	2	5/16/2012	2012	50.115	171538.2	0.610675013
AR	Independe	6641	2	5/17/2012	2012	49.145	173204.5	0.613248269
AR	Independe	6641	2	5/18/2012	2012	65.915	211920.5	0.612182539
AR	Independe	6641	2	5/19/2012	2012	55.647	190109.4	0.610490757
AR	Independe	6641	2	5/20/2012	2012	61.524	206140.2	0.608843608
AR	Independe	6641	2	5/21/2012	2012	63.498	212928.3	0.607568879
AR	Independe	6641	2	5/22/2012	2012	67.969	225761.2	0.608766532
AR	Independe	6641	2	5/23/2012	2012	63.264	212959.2	0.609293943
AR	Independe	6641	2	5/24/2012	2012	67.723	230380.3	0.608548747
AR	Independe	6641	2	5/25/2012	2012	72.971	239171.1	0.610994496
AR	Independe	6641	2	5/26/2012	2012	67.917	225055.6	0.610074478
AR	Independe	6641	2	5/27/2012	2012	69.303	223463.9	0.608924637
AR	Independe	6641	2	5/28/2012	2012	78.054	222153.6	0.610889005
AR	Independe	6641	2	5/29/2012	2012	70.487	225312	0.60969437
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AR	Independe	6641	2	6/1/2012	2012	54.376	173677.1	0.614460181
AR	Independe	6641	2	6/2/2012	2012	59.308	192580.9	0.615059676
AR	Independe	6641	2	6/3/2012	2012	69.342	207442.7	0.615654006
AR	Independe	6641	2	6/4/2012	2012	62.199	197882.6	0.613585133
AR	Independe	6641	2	6/5/2012	2012	59.913	221913.1	0.610240538
AR	Independe	6641	2	6/6/2012	2012	64.604	228006.2	0.610841026
AR	Independe	6641	2	6/7/2012	2012	56.69	193078.3	0.611261283
AR	Independe	6641	2	6/8/2012	2012	57.11	205201	0.610514902
AR	Independe	6641	2	6/9/2012	2012	64.705	211755.7	0.61032045
AR	Independe	6641	2	6/10/2012	2012	61.114	199391.2	0.611655242
AR	Independe	6641	2	6/11/2012	2012	62.132	204634.5	0.611700091
AR	Independe	6641	2	6/12/2012	2012	45.393	148891	0.609153201
AR	Independe	6641	2	6/13/2012	2012	51.313	182212.5	0.606592148
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AR	Independe	6641	2	6/17/2012	2012	59.214	199531	0.606790705
AR	Independe	6641	2	6/18/2012	2012	58.321	209729.2	0.605744331
AR	Independe	6641	2	6/19/2012	2012	64.636	232245.3	0.604220479
AR	Independe	6641	2	6/20/2012	2012	60.632	223110.8	0.602334893
AR	Independe	6641	2	6/21/2012	2012	60.8	212605.6	0.601315133
AR	Independe	6641	2	6/22/2012	2012	53.262	192039.1	0.600130773
AR	Independe	6641	2	6/23/2012	2012	52.022	207700.8	0.597282357
AR	Independe	6641	2	6/24/2012	2012	56.174	202527.3	0.59539694
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AR	Independe	6641	2	6/26/2012	2012	67.78	221085.1	0.595134778
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AR	Independe	6641	2	6/28/2012	2012	67.409	230388	0.590119612
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AR	Independe	6641	2	6/30/2012	2012	61.004	227931.2	0.581555735
AR	Independe	6641	2	7/1/2012	2012	58.42	222387.8	0.578323641
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AR	Independe	6641	2	7/4/2012	2012	59.829	209920.7	0.571467025
AR	Independe	6641	2	7/5/2012	2012	65.039	211610.8	0.574032731
AR	Independe	6641	2	7/6/2012	2012	64.192	221199.5	0.574523413
AR	Independe	6641	2	7/7/2012	2012	54.717	207056.7	0.572621595
AR	Independe	6641	2	7/8/2012	2012	54.55	196811.8	0.572571324
AR	Independe	6641	2	7/9/2012	2012	59.225	200525.3	0.571849789
AR	Independe	6641	2	7/10/2012	2012	49.547	197755.4	0.568312934
AR	Independe	6641	2	7/11/2012	2012	45.502	164411.6	0.566645106
AR	Independe	6641	2	7/12/2012	2012	34.985	115454.7	0.566343707
AR	Independe	6641	2	7/13/2012	2012	35.013	111160.5	0.567589678
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AR	Independe	6641	2	7/16/2012	2012	41.163	134546.6	0.56538315
AR	Independe	6641	2	7/17/2012	2012	63.125	201812.6	0.56650466
AR	Independe	6641	2	7/18/2012	2012	61.544	198554.5	0.568702529
AR	Independe	6641	2	7/19/2012	2012	59.35	202989.2	0.569751309
AR	Independe	6641	2	7/20/2012	2012	60.236	193168.7	0.572578512
AR	Independe	6641	2	7/21/2012	2012	50.894	164209.1	0.573962919
AR	Independe	6641	2	7/22/2012	2012	66.886	188099.7	0.579138493
AR	Independe	6641	2	7/23/2012	2012	53.937	163675.7	0.584322094
AR	Independe	6641	2	7/24/2012	2012	60.179	198872.2	0.586116557
AR	Independe	6641	2	7/25/2012	2012	51.538	182298.9	0.584758499
AR	Independe	6641	2	7/26/2012	2012	62.444	225225.7	0.582429978
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AR	Independe	6641	2	7/31/2012	2012	66.835	215920.4	0.590933479
AR	Independe	6641	2	8/1/2012	2012	56.07	182710.5	0.591957952
AR	Independe	6641	2	8/2/2012	2012	41.014	147841.4	0.592743319
AR	Independe	6641	2	8/3/2012	2012	49.395	209503.3	0.588917456
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AR	Independe	6641	2	8/5/2012	2012	73.445	221341.5	0.591191736
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AR	Independe	6641	2	8/9/2012	2012	63.594	208929.5	0.603955531
AR	Independe	6641	2	8/10/2012	2012	34.998	118455.9	0.605202369
AR	Independe	6641	2	8/11/2012	2012	43.044	147050.7	0.604650477
AR	Independe	6641	2	8/12/2012	2012	50.873	171266.9	0.603810346
AR	Independe	6641	2	8/13/2012	2012	53.766	187352	0.603612071
AR	Independe	6641	2	8/14/2012	2012	40.792	151749.1	0.60273229
AR	Independe	6641	2	8/15/2012	2012	47.531	170971.5	0.60111404
AR	Independe	6641	2	8/16/2012	2012	51.39	182967.2	0.598975546
AR	Independe	6641	2	8/17/2012	2012	51.99	179888.2	0.597574721
AR	Independe	6641	2	8/18/2012	2012	44.301	160425.4	0.596744496
AR	Independe	6641	2	8/19/2012	2012	46.903	170219.7	0.594425514
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AR	Independe	6641	2	8/23/2012	2012	52.242	199022.8	0.579012329
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AR	Independe	6641	2	8/25/2012	2012	46.536	161381.1	0.579738259
AR	Independe	6641	2	8/26/2012	2012	51.737	165196.9	0.584705683
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AR	Independe	6641	2	8/29/2012	2012	45.273	177345	0.579060676
AR	Independe	6641	2	8/30/2012	2012	51.866	194309.7	0.575825104
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AR	Independe	6641	2	9/1/2012	2012	55.563	181928.7	0.576213143
AR	Independe	6641	2	9/2/2012	2012	48.846	175214	0.579661238
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AR	Independe	6641	2	9/8/2012	2012	59.448	208643	0.569984678
AR	Independe	6641	2	9/9/2012	2012	43.193	173452.8	0.567197916
AR	Independe	6641	2	9/10/2012	2012	42.042	173266.6	0.564069419
AR	Independe	6641	2	9/11/2012	2012	53.24	177113.3	0.564335418
AR	Independe	6641	2	9/12/2012	2012	45.717	183812.5	0.561722187
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AR	Independe	6641	2	9/14/2012	2012	52.324	176658.1	0.561826413
AR	Independe	6641	2	9/15/2012	2012	50.892	162968.7	0.56371802
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AR	Independe	6641	2	9/19/2012	2012	35.639	137352.8	0.560331482
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AR	Independe	6641	2	9/21/2012	2012	49.04	157824.466	0.565186847
AR	Independe	6641	2	11/16/2012	2012	0	1473.39	0.566567196
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AR	Independe	6641	2	11/18/2012	2012	14.643	55606.992	0.564416573
AR	Independe	6641	2	11/20/2012	2012	35.239	133772.692	0.561354193
AR	Independe	6641	2	11/21/2012	2012	56.346	195440.3	0.559780541
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AR	Independe	6641	2	11/23/2012	2012	39.501	149457.6	0.558804309
AR	Independe	6641	2	11/24/2012	2012	48.099	180272.9	0.558866967
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AR	Independe	6641	2	11/27/2012	2012	52.655	188665.5	0.547156714
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AR	Independe	6641	2	11/30/2012	2012	52.864	191786.8	0.54504312
AR	Independe	6641	2	12/1/2012	2012	50.791	181497.5	0.541898251
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AR	Independe	6641	2	12/3/2012	2012	46.03	173180	0.535303196
AR	Independe	6641	2	12/4/2012	2012	45.007	154551.4	0.538179386
AR	Independe	6641	2	12/5/2012	2012	42.536	145179.5	0.541568863
AR	Independe	6641	2	12/6/2012	2012	43.277	154203.8	0.539978645
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AR	Independe	6641	2	12/9/2012	2012	38.02	148755	0.53669138
AR	Independe	6641	2	12/10/2012	2012	37.778	143604.9	0.533273769
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AR	Independe	6641	2	12/12/2012	2012	41.62	146993.9	0.534674872
AR	Independe	6641	2	12/13/2012	2012	35.542	141126.7	0.535984075
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AR	Independe	6641	2	12/15/2012	2012	47.601	177013	0.532107623
AR	Independe	6641	2	12/16/2012	2012	47.679	178694	0.529114048
AR	Independe	6641	2	12/17/2012	2012	49.666	178503.1	0.530294875
AR	Independe	6641	2	12/18/2012	2012	39.03	139210	0.532156886
AR	Independe	6641	2	12/19/2012	2012	34.964	140184.2	0.531269219
AR	Independe	6641	2	12/20/2012	2012	30.757	118559.2	0.531089449
AR	Independe	6641	2	12/21/2012	2012	37.551	145137.7	0.528848781
AR	Independe	6641	2	12/22/2012	2012	40.515	149330.8	0.528313257
AR	Independe	6641	2	12/23/2012	2012	34.233	119364.8	0.52943008
AR	Independe	6641	2	12/24/2012	2012	43.304	145930.7	0.531232369
AR	Independe	6641	2	12/25/2012	2012	43.443	150446.7	0.536855994
AR	Independe	6641	2	12/26/2012	2012	31.664	114474.2	0.540824284
AR	Independe	6641	2	12/27/2012	2012	34.988	129605.5	0.540090444
AR	Independe	6641	2	12/28/2012	2012	42.323	157576.1	0.539674132
AR	Independe	6641	2	12/29/2012	2012	45.075	152379.1	0.541099965
AR	Independe	6641	2	12/30/2012	2012	41.953	141915.2	0.54224398
AR	Independe	6641	2	12/31/2012	2012	36.103	126534.1	0.54233988
AR	Independe	6641	2	1/1/2013	2013	44.779	156066.9	0.545137145
AR	Independe	6641	2	1/2/2013	2013	55.868	177320.7	0.549051246
AR	Independe	6641	2	1/3/2013	2013	39.069	127547.6	0.549718283
AR	Independe	6641	2	1/4/2013	2013	37.987	127234.2	0.549892359
AR	Independe	6641	2	1/5/2013	2013	57.868	181441.7	0.553096859
AR	Independe	6641	2	1/6/2013	2013	51.2	173370.7	0.555424894
AR	Independe	6641	2	1/7/2013	2013	47.716	185184.1	0.557297147
AR	Independe	6641	2	1/8/2013	2013	45.998	181298.1	0.556813072
AR	Independe	6641	2	1/9/2013	2013	38.984	139723	0.557829421
AR	Independe	6641	2	1/10/2013	2013	32.246	129964	0.555449523
AR	Independe	6641	2	1/11/2013	2013	32.636	124653.8	0.554207449
AR	Independe	6641	2	1/12/2013	2013	36.913	134111.2	0.555691102
AR	Independe	6641	2	1/13/2013	2013	44.459	188118.4	0.555155536
AR	Independe	6641	2	1/14/2013	2013	56.031	198951.9	0.556192689
AR	Independe	6641	2	1/15/2013	2013	55.408	187661.8	0.558508178
AR	Independe	6641	2	1/16/2013	2013	51.565	170392.3	0.560353221
AR	Independe	6641	2	1/17/2013	2013	35.621	151194	0.557362887
AR	Independe	6641	2	1/18/2013	2013	42.067	154548.1	0.558728535
AR	Independe	6641	2	1/19/2013	2013	51.585	186012.2	0.55958976
AR	Independe	6641	2	1/20/2013	2013	46.061	152781.9	0.56235076
AR	Independe	6641	2	1/21/2013	2013	42.308	165567.2	0.561153587
AR	Independe	6641	2	1/22/2013	2013	50.474	187429.1	0.55993801
AR	Independe	6641	2	1/23/2013	2013	39.318	163358.4	0.556179063
AR	Independe	6641	2	1/24/2013	2013	39.35	179506.5	0.551048669
AR	Independe	6641	2	1/25/2013	2013	40.694	188009.9	0.54638803
AR	Independe	6641	2	1/26/2013	2013	52.056	194194.8	0.546151583
AR	Independe	6641	2	1/27/2013	2013	54.686	172843	0.549496533
AR	Independe	6641	2	1/28/2013	2013	51.43	172302.1	0.549854796
AR	Independe	6641	2	1/29/2013	2013	38.882	158639.7	0.546747387
AR	Independe	6641	2	1/30/2013	2013	34.121	148673.6	0.543506487
AR	Independe	6641	2	1/31/2013	2013	44.838	169120.6	0.542103036
AR	Independe	6641	2	2/1/2013	2013	40.185	151779.4	0.538560506
AR	Independe	6641	2	2/2/2013	2013	50.484	170398.7	0.538510809
AR	Independe	6641	2	2/3/2013	2013	44.586	156940.4	0.537953014
AR	Independe	6641	2	2/4/2013	2013	48.196	183680.7	0.533860026
AR	Independe	6641	2	2/5/2013	2013	35.968	150978.7	0.530156596
AR	Independe	6641	2	2/6/2013	2013	21.289	97060.9	0.528907098
AR	Independe	6641	2	2/7/2013	2013	32.742	116880.7	0.530467073
AR	Independe	6641	2	2/8/2013	2013	45.115	157171.9	0.531085205
AR	Independe	6641	2	2/9/2013	2013	41.919	163594.4	0.53138856
AR	Independe	6641	2	2/10/2013	2013	38.862	149055.4	0.53128396

AR	Independe	6641	2	2/11/2013	2013	44.681	172012.4	0.530356267
AR	Independe	6641	2	2/12/2013	2013	37.48	180100.8	0.528395829
AR	Independe	6641	2	2/13/2013	2013	41.007	170260.2	0.525371251
AR	Independe	6641	2	2/14/2013	2013	34.951	148641.2	0.521190797
AR	Independe	6641	2	2/15/2013	2013	35.822	158514.7	0.515997983
AR	Independe	6641	2	2/16/2013	2013	40.781	170870.8	0.516032089
AR	Independe	6641	2	2/17/2013	2013	28.744	140619.7	0.512042239
AR	Independe	6641	2	2/18/2013	2013	42.398	162619.4	0.510724477
AR	Independe	6641	2	2/19/2013	2013	35.432	143545.9	0.50731001
AR	Independe	6641	2	2/20/2013	2013	42.063	155104.4	0.508306694
AR	Independe	6641	2	2/21/2013	2013	53.89	167570.2	0.511822739
AR	Independe	6641	2	2/22/2013	2013	36.989	139978.7	0.513348259
AR	Independe	6641	2	2/23/2013	2013	33.266	141068.5	0.514939949
AR	Independe	6641	2	2/24/2013	2013	30.205	132557.2	0.516553142
AR	Independe	6641	2	2/25/2013	2013	38.538	150688.3	0.515572632
AR	Independe	6641	2	2/26/2013	2013	33.635	169501.5	0.506888801
AR	Independe	6641	2	2/27/2013	2013	33.091	120761.5	0.504593944
AR	Independe	6641	2	2/28/2013	2013	41.301	138433.3	0.507877785
AR	Independe	6641	2	3/1/2013	2013	46.312	154793.5	0.512518367
AR	Independe	6641	2	3/2/2013	2013	51.057	164546.7	0.515746114
AR	Independe	6641	2	3/3/2013	2013	33.242	128366.8	0.515348634
AR	Independe	6641	2	3/4/2013	2013	33.098	139845.6	0.511144593
AR	Independe	6641	2	3/5/2013	2013	46.425	149631.9	0.512785352
AR	Independe	6641	2	3/6/2013	2013	45.99	153713.3	0.515226005
AR	Independe	6641	2	3/7/2013	2013	43.148	139170.2	0.519792793
AR	Independe	6641	2	3/8/2013	2013	37.825	137991	0.522404091
AR	Independe	6641	2	3/9/2013	2013	33.161	145393	0.519312019
AR	Independe	6641	2	3/10/2013	2013	35.304	139024.3	0.517059856
AR	Independe	6641	2	3/11/2013	2013	46.366	157537.9	0.519719253
AR	Independe	6641	2	3/12/2013	2013	38.726	136911.2	0.521058472
AR	Independe	6641	2	3/13/2013	2013	44.788	168861.6	0.521470255
AR	Independe	6641	2	3/14/2013	2013	43.637	169878.4	0.525394433
AR	Independe	6641	2	3/15/2013	2013	44.892	155431.4	0.528866645
AR	Independe	6641	2	3/16/2013	2013	42.048	150998.1	0.531754183
AR	Independe	6641	2	3/17/2013	2013	47.42	160527	0.53668647
AR	Independe	6641	2	3/18/2013	2013	51.095	173458	0.540972838
AR	Independe	6641	2	3/19/2013	2013	49.902	170484.9	0.546762448
AR	Independe	6641	2	3/20/2013	2013	38.94	143659.3	0.54752936
AR	Independe	6641	2	3/21/2013	2013	48.333	177336.8	0.549139801
AR	Independe	6641	2	3/22/2013	2013	54.275	181787.4	0.551282674
AR	Independe	6641	2	3/23/2013	2013	54.123	175752.1	0.550397284
AR	Independe	6641	2	3/24/2013	2013	47.646	165997.5	0.551919522
AR	Independe	6641	2	3/25/2013	2013	57.391	189557.2	0.556547996
AR	Independe	6641	2	3/26/2013	2013	48.667	175990.5	0.559269123
AR	Independe	6641	2	3/27/2013	2013	45.93	168701.8	0.560270305
AR	Independe	6641	2	3/28/2013	2013	37.207	155395.7	0.563478676
AR	Independe	6641	2	3/29/2013	2013	36.475	144526.9	0.562073561
AR	Independe	6641	2	3/30/2013	2013	41.496	145532.4	0.561310933
AR	Independe	6641	2	3/31/2013	2013	41.109	138813.7	0.561005637
AR	Independe	6641	2	4/1/2013	2013	52.508	177442.3	0.56008729
AR	Independe	6641	2	4/2/2013	2013	48.491	182022.4	0.560180802
AR	Independe	6641	2	4/3/2013	2013	44.2	175277.3	0.560670907
AR	Independe	6641	2	4/4/2013	2013	36.713	136590.3	0.558144301
AR	Independe	6641	2	4/5/2013	2013	40.384	132309.4	0.5582982
AR	Independe	6641	2	4/6/2013	2013	50.448	169852.1	0.557771524
AR	Independe	6641	2	4/7/2013	2013	51.361	164767.7	0.560284397
AR	Independe	6641	2	4/8/2013	2013	56.121	176430.4	0.56615378
AR	Independe	6641	2	4/9/2013	2013	42.614	154228.7	0.567386737

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AR	Independe	6641	2	4/11/2013	2013	57.535	175987.7	0.572488538
AR	Independe	6641	2	4/12/2013	2013	40.71	176000.1	0.570005686
AR	Independe	6641	2	4/13/2013	2013	49.281	171835.9	0.572067818
AR	Independe	6641	2	4/14/2013	2013	49.011	162930.1	0.572866997
AR	Independe	6641	2	4/15/2013	2013	48.205	161898	0.574092908
AR	Independe	6641	2	4/16/2013	2013	56.459	207965	0.572261268
AR	Independe	6641	2	4/17/2013	2013	56.28	206193.8	0.570599032
AR	Independe	6641	2	4/18/2013	2013	46.142	199792.8	0.565808617
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AR	Independe	6641	2	4/22/2013	2013	42.702	179627	0.557488539
AR	Independe	6641	2	4/23/2013	2013	50.677	186860.7	0.556403726
AR	Independe	6641	2	4/24/2013	2013	49.749	180454.4	0.554409546
AR	Independe	6641	2	4/25/2013	2013	43.66	163517.1	0.553803401
AR	Independe	6641	2	4/26/2013	2013	52.214	178696.9	0.55517643
AR	Independe	6641	2	4/27/2013	2013	49.447	184225.5	0.556821668
AR	Independe	6641	2	4/28/2013	2013	46.418	170810.3	0.557835904
AR	Independe	6641	2	4/29/2013	2013	53.404	187817.1	0.557879602
AR	Independe	6641	2	4/30/2013	2013	59.644	175004.2	0.561091421
AR	Independe	6641	2	5/1/2013	2013	63.675	197559.8	0.563185208
AR	Independe	6641	2	5/2/2013	2013	58.017	181347.3	0.566869004
AR	Independe	6641	2	5/3/2013	2013	46.812	161736.2	0.569320778
AR	Independe	6641	2	5/4/2013	2013	43.341	148393.5	0.570560264
AR	Independe	6641	2	5/5/2013	2013	31.508	110551.6	0.569543829
AR	Independe	6641	2	5/6/2013	2013	40.846	158347	0.567129473
AR	Independe	6641	2	5/7/2013	2013	53.812	179016.3	0.566524482
AR	Independe	6641	2	5/8/2013	2013	56.326	179876.6	0.566231133
AR	Independe	6641	2	5/9/2013	2013	46.069	150385.4	0.567960552
AR	Independe	6641	2	5/10/2013	2013	58.819	183827.8	0.568018554
AR	Independe	6641	2	5/11/2013	2013	53.466	184049.6	0.5656098
AR	Independe	6641	2	5/12/2013	2013	50.616	166314.2	0.570408803
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AR	Independe	6641	2	5/17/2013	2013	60.359	196785.5	0.570298011
AR	Independe	6641	2	5/18/2013	2013	59.559	184139.7	0.577110922
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AR	Independe	6641	2	5/22/2013	2013	45.791	160147.4	0.585278582
AR	Independe	6641	2	5/23/2013	2013	50.007	178466	0.585966839
AR	Independe	6641	2	5/24/2013	2013	55.382	179338.2	0.588263309
AR	Independe	6641	2	5/25/2013	2013	51.955	178634.1	0.589741918
AR	Independe	6641	2	5/26/2013	2013	56.621	181504.2	0.591116284
AR	Independe	6641	2	5/27/2013	2013	56.801	175877.4	0.594893597
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AR	Independe	6641	2	5/29/2013	2013	42.227	177503	0.594477163
AR	Independe	6641	2	5/30/2013	2013	55.418	183011	0.59193686
AR	Independe	6641	2	5/31/2013	2013	51.96	181079.6	0.589299195
AR	Independe	6641	2	6/1/2013	2013	64.994	197729.8	0.590125953
AR	Independe	6641	2	6/2/2013	2013	53.877	171985.1	0.591676861
AR	Independe	6641	2	6/3/2013	2013	55.669	187933.7	0.59191702
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AR	Independe	6641	2	6/8/2013	2013	46.429	169323.5	0.584717021
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AR	Independe	6641	2	6/12/2013	2013	50.873	184482.4	0.57204778
AR	Independe	6641	2	6/13/2013	2013	46.651	189299.4	0.567973479
AR	Independe	6641	2	6/14/2013	2013	48.389	176487.9	0.569440219
AR	Independe	6641	2	6/15/2013	2013	45.057	175609.2	0.571111571
AR	Independe	6641	2	6/16/2013	2013	47.413	196244.6	0.56635848
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AR	Independe	6641	2	6/21/2013	2013	55.164	201412	0.559705237
AR	Independe	6641	2	6/22/2013	2013	49.768	184813.1	0.558971202
AR	Independe	6641	2	6/23/2013	2013	41.955	178758.7	0.55413904
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AR	Independe	6641	2	6/26/2013	2013	53.812	198261.7	0.547646834
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AR	Independe	6641	2	6/30/2013	2013	51.914	202288.3	0.542432485
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AR	Independe	6641	2	7/3/2013	2013	51.389	183662.8	0.533886767
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AR	Independe	6641	2	7/7/2013	2013	57.156	186508.7	0.537373043
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AR	Independe	6641	2	7/13/2013	2013	48.881	184841	0.546360653
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AR	Independe	6641	2	7/26/2013	2013	47.086	173627	0.552474271
AR	Independe	6641	2	7/27/2013	2013	52.722	196633.3	0.552533101
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AR	Independe	6641	2	8/1/2013	2013	49.357	170658	0.552535665
AR	Independe	6641	2	8/2/2013	2013	49.369	170710.9	0.553110688
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AR	Independe	6641	2	8/4/2013	2013	47.952	177073.3	0.551799746
AR	Independe	6641	2	8/5/2013	2013	53.496	179060.6	0.552354685
AR	Independe	6641	2	8/6/2013	2013	61.644	200946.3	0.552540189
AR	Independe	6641	2	8/7/2013	2013	58.838	203044	0.555057253
AR	Independe	6641	2	8/8/2013	2013	57.44	193817.8	0.553145148
AR	Independe	6641	2	8/9/2013	2013	54.796	192765.4	0.553280206
AR	Independe	6641	2	8/10/2013	2013	54.056	189534.2	0.552640884
AR	Independe	6641	2	8/11/2013	2013	48.853	178676.1	0.551770263
AR	Independe	6641	2	8/12/2013	2013	51.619	188597.8	0.552391871
AR	Independe	6641	2	8/13/2013	2013	43.308	159613.9	0.554693669
AR	Independe	6641	2	8/14/2013	2013	46.669	168562.1	0.557553764
AR	Independe	6641	2	8/15/2013	2013	51.34	182099.5	0.557403164
AR	Independe	6641	2	8/16/2013	2013	50.055	177671.5	0.557641645
AR	Independe	6641	2	8/17/2013	2013	51.27	185125.8	0.557059324
AR	Independe	6641	2	8/18/2013	2013	46.728	169224.8	0.558013472
AR	Independe	6641	2	8/19/2013	2013	55.65	193629.7	0.557171846
AR	Independe	6641	2	8/20/2013	2013	54.794	189714.8	0.557475117
AR	Independe	6641	2	8/21/2013	2013	56.712	199900.2	0.558701304
AR	Independe	6641	2	8/22/2013	2013	55.394	193382.9	0.55907982
AR	Independe	6641	2	8/23/2013	2013	52.114	194047.2	0.557411595
AR	Independe	6641	2	8/24/2013	2013	51.447	193666.3	0.55557786
AR	Independe	6641	2	8/25/2013	2013	50.643	189307.7	0.555289448
AR	Independe	6641	2	8/26/2013	2013	49.352	185298.4	0.555208806
AR	Independe	6641	2	8/27/2013	2013	49.653	174744	0.558561218
AR	Independe	6641	2	8/28/2013	2013	53.389	188020.1	0.560020818
AR	Independe	6641	2	8/29/2013	2013	48.019	169756.1	0.561022502
AR	Independe	6641	2	8/30/2013	2013	55.879	189833.8	0.562529038
AR	Independe	6641	2	8/31/2013	2013	53.333	174426.1	0.563585651
AR	Independe	6641	2	9/1/2013	2013	50.517	165887.9	0.564494837
AR	Independe	6641	2	9/2/2013	2013	50.247	164371.6	0.567947686
AR	Independe	6641	2	9/3/2013	2013	53.239	175031.2	0.570077327
AR	Independe	6641	2	9/4/2013	2013	51.153	174186.9	0.569730796
AR	Independe	6641	2	9/5/2013	2013	45.611	186134	0.565427214
AR	Independe	6641	2	9/6/2013	2013	52.489	185020.9	0.564969022
AR	Independe	6641	2	9/7/2013	2013	49.603	188484.6	0.562653023
AR	Independe	6641	2	9/8/2013	2013	56.018	193805.2	0.562993007
AR	Independe	6641	2	9/9/2013	2013	62.252	189092.1	0.566036714
AR	Independe	6641	2	9/10/2013	2013	54.171	176185.9	0.568240911
AR	Independe	6641	2	9/11/2013	2013	56.88	195863.8	0.569409233
AR	Independe	6641	2	9/12/2013	2013	48.452	175898.1	0.569594283
AR	Independe	6641	2	9/13/2013	2013	49.441	167898.3	0.57067344
AR	Independe	6641	2	9/14/2013	2013	49.463	161285	0.572159527
AR	Independe	6641	2	9/15/2013	2013	51.048	173826.1	0.572925799
AR	Independe	6641	2	9/16/2013	2013	53.16	172471.5	0.574949501
AR	Independe	6641	2	9/17/2013	2013	51.597	176954.7	0.575919376
AR	Independe	6641	2	9/18/2013	2013	60.873	193941.6	0.577800202
AR	Independe	6641	2	9/19/2013	2013	49.604	195876.9	0.575249152
AR	Independe	6641	2	9/20/2013	2013	51.488	177548.6	0.575691936
AR	Independe	6641	2	9/21/2013	2013	52.792	186132.4	0.575502434
AR	Independe	6641	2	9/22/2013	2013	37.275	155822.4	0.574079447
AR	Independe	6641	2	9/23/2013	2013	50.01	163292.5	0.57679318
AR	Independe	6641	2	9/24/2013	2013	52.722	188725.8	0.577630636
AR	Independe	6641	2	9/25/2013	2013	36.645	130638.1	0.578790358
AR	Independe	6641	2	9/26/2013	2013	41.141	138666.2	0.579521624
AR	Independe	6641	2	9/27/2013	2013	42.403	147260.3	0.579836695
AR	Independe	6641	2	10/11/2013	2013	5.974	30941.824	0.579130114
AR	Independe	6641	2	10/12/2013	2013	43.722	151874	0.57866935
AR	Independe	6641	2	10/13/2013	2013	43.77	154301.9	0.577184315

AR	Independe	6641	2	10/14/2013	2013	25.82	105916.8	0.574214999
AR	Independe	6641	2	10/15/2013	2013	33.057	127383	0.571555208
AR	Independe	6641	2	10/16/2013	2013	46.414	164713	0.569982722
AR	Independe	6641	2	10/17/2013	2013	49.583	171949.1	0.569604368
AR	Independe	6641	2	10/18/2013	2013	38.998	153370.7	0.570714881
AR	Independe	6641	2	10/19/2013	2013	42.89	163096.7	0.569342988
AR	Independe	6641	2	10/20/2013	2013	37.196	169278.4	0.566483686
AR	Independe	6641	2	10/21/2013	2013	44.326	171374.8	0.564273737
AR	Independe	6641	2	10/22/2013	2013	36.458	165484.5	0.556314697
AR	Independe	6641	2	10/23/2013	2013	37.576	153689.6	0.551994338
AR	Independe	6641	2	10/24/2013	2013	42.194	164480.2	0.54946001
AR	Independe	6641	2	10/25/2013	2013	44.296	158942.6	0.54967203
AR	Independe	6641	2	10/26/2013	2013	45.435	167346.4	0.548044563
AR	Independe	6641	2	10/27/2013	2013	34.874	132620.4	0.545183742
AR	Independe	6641	2	10/28/2013	2013	50.595	174114.4	0.544957928
AR	Independe	6641	2	10/29/2013	2013	52.317	185249.7	0.543125773
AR	Independe	6641	2	10/30/2013	2013	46.344	177607.5	0.540825608
AR	Independe	6641	2	10/31/2013	2013	38.412	153247	0.535930589
AR	Independe	6641	2	11/1/2013	2013	39.253	150653.1	0.536693106
AR	Independe	6641	2	11/2/2013	2013	45.388	146488.1	0.537663852
AR	Independe	6641	2	11/3/2013	2013	40.794	150697	0.536581904
AR	Independe	6641	2	11/4/2013	2013	39.885	146771.4	0.538791601
AR	Independe	6641	2	11/5/2013	2013	38.396	149032.7	0.53537206
AR	Independe	6641	2	11/6/2013	2013	45.655	155800.9	0.536146064
AR	Independe	6641	2	11/7/2013	2013	34.624	126774.9	0.535709004
AR	Independe	6641	2	11/8/2013	2013	35.11	126060.4	0.534528322
AR	Independe	6641	2	11/9/2013	2013	23.367	98822.3	0.531789948
AR	Independe	6641	2	11/10/2013	2013	35.534	114683.9	0.535008696
AR	Independe	6641	2	11/11/2013	2013	39.243	153079.7	0.532890233
AR	Independe	6641	2	11/12/2013	2013	40.791	152662.3	0.531768222
AR	Independe	6641	2	11/13/2013	2013	40.105	153757.3	0.53245173
AR	Independe	6641	2	11/14/2013	2013	37.027	139212.1	0.532809289
AR	Independe	6641	2	11/15/2013	2013	41.255	146308.6	0.532697327
AR	Independe	6641	2	11/16/2013	2013	29.371	100478.2	0.532174877
AR	Independe	6641	2	11/17/2013	2013	21.64	83097.6	0.532780075
AR	Independe	6641	2	11/18/2013	2013	32.469	109608.4	0.534528934
AR	Independe	6641	2	11/19/2013	2013	47.518	155415.5	0.540958114
AR	Independe	6641	2	11/20/2013	2013	47.976	149471.8	0.54536855
AR	Independe	6641	2	11/21/2013	2013	42.498	143437.4	0.550948634
AR	Independe	6641	2	11/22/2013	2013	42.98	161368.6	0.552468584
AR	Independe	6641	2	11/23/2013	2013	39.502	142003.1	0.554102544
AR	Independe	6641	2	11/24/2013	2013	43.248	167982	0.552455581
AR	Independe	6641	2	11/25/2013	2013	38.412	137850	0.552980619
AR	Independe	6641	2	11/26/2013	2013	32.479	112129	0.554514755
AR	Independe	6641	2	11/27/2013	2013	37.183	136713.2	0.553075139
AR	Independe	6641	2	11/28/2013	2013	42.15	154598.4	0.55226921
AR	Independe	6641	2	11/29/2013	2013	40.868	153242.4	0.552869504
AR	Independe	6641	2	11/30/2013	2013	45.575	155044.6	0.556064179
AR	Independe	6641	2	12/1/2013	2013	30.377	106187.3	0.557753259
AR	Independe	6641	2	12/2/2013	2013	35.699	117633.2	0.556952248
AR	Independe	6641	2	12/3/2013	2013	35.994	129443.6	0.557500743
AR	Independe	6641	2	12/4/2013	2013	37.686	136910.8	0.557770918
AR	Independe	6641	2	12/5/2013	2013	48.674	169456.9	0.560011918
AR	Independe	6641	2	12/6/2013	2013	43.124	160966.5	0.55806907
AR	Independe	6641	2	12/7/2013	2013	4.684	28771.56	0.556771059
AR	Independe	6641	2	12/8/2013	2013	37.676	140323.6	0.556070591
AR	Independe	6641	2	12/9/2013	2013	55.252	180461.7	0.560560178
AR	Independe	6641	2	12/10/2013	2013	48.585	174702.8	0.558743793

AR	Independe	6641	2	12/11/2013	2013	48.045	197610.8	0.55700976
AR	Independe	6641	2	12/12/2013	2013	47.639	172802.4	0.557597328
AR	Independe	6641	2	12/13/2013	2013	65.875	196489.7	0.564103041
AR	Independe	6641	2	12/14/2013	2013	50.398	176689	0.565406487
AR	Independe	6641	2	12/15/2013	2013	46.442	186617.2	0.562543842
AR	Independe	6641	2	12/16/2013	2013	44.001	174453.2	0.559743382
AR	Independe	6641	2	12/17/2013	2013	38.847	142112.5	0.560052252
AR	Independe	6641	2	12/18/2013	2013	36.312	149351.5	0.556821334
AR	Independe	6641	2	12/19/2013	2013	42.449	158871.6	0.554148928
AR	Independe	6641	2	12/20/2013	2013	46.062	161015.3	0.55188942
AR	Independe	6641	2	12/21/2013	2013	39.009	138967.9	0.550891508
AR	Independe	6641	2	12/22/2013	2013	31.719	122395	0.550656831
AR	Independe	6641	2	12/23/2013	2013	37.559	144346	0.54950251
AR	Independe	6641	2	12/24/2013	2013	42.408	159296.3	0.550193572
AR	Independe	6641	2	12/25/2013	2013	39.717	151155.7	0.549144126
AR	Independe	6641	2	12/26/2013	2013	45.717	178320.8	0.54697663
AR	Independe	6641	2	12/27/2013	2013	51.87	187752.7	0.547292867
AR	Independe	6641	2	12/28/2013	2013	56.218	196709.9	0.548387653
AR	Independe	6641	2	12/29/2013	2013	46.522	169441.1	0.548907524
AR	Independe	6641	2	12/30/2013	2013	49.059	185277	0.546856885
AR	Independe	6641	2	12/31/2013	2013	52.231	186996.9	0.546755681

Data Set	Plant Name	Operator Name	Operator Id	Plant State	Boiler Id	Reported Prime Mover	Reported Fuel Type Code	Physical Unit Label	Quantity Of Fuel Consumed January	Quantity Of Fuel Consumed February	Quantity Of Fuel Consumed March	Quantity Of Fuel Consumed April	Quantity Of Fuel Consumed May	Quantity Of Fuel Consumed June	Quantity Of Fuel Consumed July	Quantity Of Fuel Consumed August	Quantity Of Fuel Consumed September	Quantity Of Fuel Consumed October	Quantity Of Fuel Consumed November	Quantity Of Fuel Consumed December	Quantity of Fuel Annual
2009 EIA 923 Page 3 Boiler Fuel Data	Independence Steam Electric Station	Entergy Arkansas Inc	814	AR	1	ST	SUB	short tons	278,703	232,624	0	113,215	300,145	319,598	329,010	264,863	327,979	338,316	304,430	306,017	3,114,900
2010 EIA 923 Page 3 Boiler Fuel Data	Independence Steam Electric Station	Entergy Arkansas Inc	814	AR	1	ST	SUB	short tons	309,705	244,432	167,428	317,185	328,408	330,428	332,869	325,580	334,047	325,858	323,750	310,006	3,649,696
2011 EIA 923 Page 3 Boiler Fuel Data	Independence Steam Electric Station	Entergy Arkansas Inc	814	AR	1	ST	SUB	short tons	299,461	294,788	338,042	9,775	199,710	304,517	359,304	325,187	337,294	308,516	299,849	292,409	3,368,852
2012 EIA 923 Page 3 Boiler Fuel Data	Independence Steam Electric Station	Entergy Arkansas Inc	814	AR	1	ST	SUB	short tons	306,205	301,585	282,625	127,442	307,815	292,535	245,658	260,436	274,771	298,887	294,644	269,940	3,262,543
2013 EIA 923 Page 3 Boiler Fuel Data	Independence Steam Electric Station	Entergy Arkansas Inc	814	AR	1	ST	SUB	short tons	255,984	240,873	257,684	0	38,218	291,180	276,508	321,905	287,252	263,524	250,316	302,362	2,785,806
2014 EIA 923 Page 3 Boiler Fuel Data	Independence Steam Electric Station	Entergy Arkansas Inc	814	AR	1	ST	SUB	short tons	250,786	294,592	328,485	269,056	244,025	318,876	315,732	284,951	297,908	306,333	311,963	72,966	3,295,673
2015 EIA 923 Page 3 Boiler Fuel Data	Independence Steam Electric Station	Entergy Arkansas Inc	814	AR	1	ST	SUB	short tons	215,944	121,867	7,282	64,220	236,323	123,450	258,233	212,092	166,347	227,577	86,436	32,909	1,752,680
2016 EIA 923 Page 3 Boiler Fuel Data	Independence Steam Electric Station	Entergy Arkansas Inc	814	AR	1	ST	SUB	short tons	174,277	23,131	22,227	194,685	194,090	263,818	282,384	255,762	281,942	291,143	86,180	310,771	2,380,410
2009 EIA 923 Page 3 Boiler Fuel Data	Independence Steam Electric Station	Entergy Arkansas Inc	814	AR	2	ST	SUB	short tons	307,463	263,112	310,621	334,002	298,631	347,756	355,158	337,502	321,276	183,322	321,038	326,202	3,706,083
2010 EIA 923 Page 3 Boiler Fuel Data	Independence Steam Electric Station	Entergy Arkansas Inc	814	AR	2	ST	SUB	short tons	317,374	292,333	330,160	325,030	340,292	295,879	284,240	347,285	181,562	26,747	266,653	293,463	3,301,018
2011 EIA 923 Page 3 Boiler Fuel Data	Independence Steam Electric Station	Entergy Arkansas Inc	814	AR	2	ST	SUB	short tons	318,048	276,485	219,228	301,923	248,792	260,865	351,438	298,606	120,020	323,292	295,312	229,639	3,243,648
2012 EIA 923 Page 3 Boiler Fuel Data	Independence Steam Electric Station	Entergy Arkansas Inc	814	AR	2	ST	SUB	short tons	327,144	312,109	314,837	273,023	334,994	321,549	308,529	306,478	209,779	0	113,934	282,519	3,104,895
2013 EIA 923 Page 3 Boiler Fuel Data	Independence Steam Electric Station	Entergy Arkansas Inc	814	AR	2	ST	SUB	short tons	299,647	251,528	295,729	317,241	315,547	324,274	325,342	336,129	275,364	190,602	249,737	287,573	3,468,713

2014 EIA 923 Page 3 Boiler Fuel Data	Independence Steam Electric Station	Entergy Arkansas Inc	814	AR	2	ST	SUB	short tons	286,421	306,140	295,181	328,527	324,953	322,525	312,104	304,516	193,746	32,098	307,052	261,163	3,274,426
2015 EIA 923 Page 3 Boiler Fuel Data	Independence Steam Electric Station	Entergy Arkansas Inc	814	AR	2	ST	SUB	short tons	84,271	187,621	0	69,537	188,242	215,435	173,821	136,206	207,523	104,255	110,630	58,162	1,535,703
2016 EIA 923 Page 3 Boiler Fuel Data	Independence Steam Electric Station	Entergy Arkansas Inc	814	AR	2	ST	SUB	short tons	133,600	168,157	201,299	199,244	184,554	257,159	276,170	255,301	295,348	64,712	85,798	316,435	2,437,777

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

Facility	2002 CENRAP[1] NOx (tpy)	2002 CENRAP[1] SO2 (tpy)	2018 CENRAP[1] NOx (tpy)	2018 CENRAP[1] SO2 (tpy)	2018 control level	average annual heat input 2014-2016	BART/RP controlled emissions[2] NOx (tpy)	BART/RP controlled emissions[2] SO2 (tpy)	SIP emission reduction SO2 (tpy)	SIP emission reduction NOx (TPY)	
AECC - Carl E Bailey Generating Sta Total	149.36606	380.50435	0	0	SO2 and NOx 2014-2016 annual average		17.60966667	10	-0.694666667	See CSAPR Sheet	2014-2016 emissions
DOMTAR INDUSTRIES INC-ASHDOWN MILL Total	3727.03275	2260.17015	3839.49543	2241.4	NOx reduced 461 tpy, SO2 reduced 1401 tpy		3378.49543	840.39995	1401	461.00	
Entergy Arkansas - Lake Catherine Total	1363.51007	4.10167	0	0	SO2 and NOx 2014-2016 annual average	2279714.683	250.7686151	0	-0.684	See CSAPR Sheet	2014-2016 emissions
ENTERGY ARK-INDEPENDENCE Total	15593.03146	25014.7613	16121.40089	26786.19	CSAPR	80506224.61	6037.966846	2415.186738	0	See CSAPR Sheet	
ENTERGY ARK-WHITE BLUFF Total	17055.5395	34787.11009	9242.0991	45969.64	CSAPR	82145745.11	6160.930883	2464.372353	0	See CSAPR Sheet	
JOHN L MCCLELLAN GENERATING STATION Total	277.87033	451.17586	287.81265	0.11676	SO2 and NOx 2014-2016 annual average		287.81265	75	-2.145906667	See CSAPR Sheet	
SWEPCO-FLINT CREEK POWER PLANT Total	5079.90054	11165.104	4334.51944	2896.149	0.06 lb/MMBtu SO2, CSAPR	30217002.84	3474.955327	906.5100853	1989.638815	See CSAPR Sheet	
Grand Total	*43246.25071*	*74062.92742*	*33825.3275*	*77893.5*			*19608.53942*	*6711.469127*	*3387.808908*	*6075.347*	

[1]Facility annual emissions calculated from daily emission values for Monday, Weekday, Sat, and Sun for each month from Pechan CENRAP EI Summary Project_Final Aug 2007.mdb (see 2002 CENRAP EI, 2018 CENRAP EI and DAYSoftheWK worksheets)

[2]Controlled emissions are calculated from BART/RP control emission level and average heat input for Flint Creek.

	2018 CENRAP Arkansas Point Source Emissions (tpy)[3]	SIP Emission reductions	Scaling factor
NOx	71,107	6,075	0.9146
SO2	106,461	3,388	0.9682

[3] source category emissions from CENRAP-EI-SUMMARY-080107wv_c6e.zip

2018 RPG

SourceName	2018 CENRAP extinction due to Arkansas point source from 2018 CENRAP PSAT[4] CACR1	UPBU1	Scaling Factor	SIP Scaled 2018 extinction due to Arkansas point source CACR1	UPBU1	Reduction in Arkansas point source extinction CACR1	UPBU1
SO4	3.0726339	2.7600939	0.968177935	2.974856	2.672262011	0.097777557	0.087831889
NOx	0.2498123	0.2119485	0.914560493	0.228468	0.193839725	0.02134384	0.018108775
Total	3.3224462	2.9720424		3.203325	2.866101736	0.119121397	0.105940664

[4]CENRAP-PSAT-Tool-ENVIRON-Aug27-2007.mdb

	2018 CENRAP CAMx modeled extinction (1/Mm)		2018 CENRAP CAMx impairment (dv)		Total Reduction in extiction due to FIP controls		Scaled 2018 CAMx modeled extinction (1/Mm)		2018 Scaled impairment (dv)	
	CACR1	UPBU1	CACR1	UPBU1	CACR1	UPBU1	CACR1	UPBU1	CACR1	UPBU1
visibility impairment	85.84	86.16	22.80748	22.52975	0.11912	0.10594	85.72088	86.05406	22.79530	22.51861
rayleigh scattering	12	9					12	9		

Percent Reduction in total extinction from SIP controls (2018 CENRAP CAMx modeled and Scaled extinction)	
0.122%	0.111%

Delta dv from SIP controls (2018 CAMx Modeled and Scaled Impairment (dv))	
0.01218	0.01114

Estimated 2018 RPG Adjusting 2018 CENRAP CMAQ modeled RPG

	CACR1	UPBU1
2018 CENRAP CMAQ modeled RPG (dv)	22.48	22.52
2018 CENRAP CMAQ modeled RPG (extinction, 1/Mm)	94.68779	95.06730
Reduce 2018 CMAQ RPG extinction by same percentage as calculated above for CAMx model results	94.57251	94.96147
Adjusted RPGs	***22.46782***	***22.50886***

Delta dv from SIP controls (2018 CMAQ Modeled and Scaled Impairment (dv))	0.01218	0.01114

Delta dv from SIP controls (2018 CMAQ Modeled and Scaled Impairment (dv))	CACR1	UPBU1
	0.01218	0.01114

Estimated delta dv at natural background due to SIP

	CACR1	UPBU1
NC-II average Natural Conditions (dv)	7.619	7.534
Natural Conditions (1/Mm)	21.42343	21.24210
NC plus extinction from SIP controls (1/Mm)	21.54255	21.34804
NC plus extinction from SIP controls (dv)	7.67445	7.58375
Delta dv	0.05545	0.04975

SO2 (tpy)	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2014-2016 average
Carl Bailey	1560.006	380.279	434.511	1193.956	220.403	149.074	5.459	2.074	44.905	46.428	36.394	0.18	10.513	0.015	2.009	0.06	0.694666667
Flint Creek Power Plant	14531.152	10961.213	9429.045	10098.571	8227.253	8526.449	8722.594	8501.698	6811.486	8506.178	8618.775	8409.396	6699.391	7968.114	6445.245	1636.987	5350.115333
Independence	23015.138	24613.833	22140.18	23588.239	22363.256	26172.297	29538.868	26448.23	27425.294	28674.644	30397.963	32973.75	28854.282	30028.873	14993.656	22569.595	22530.708
Lake Catherine	5.032	4.067	1.754	0.572	0.736	0.088	0.124	0.355	0.425	0.541	0.454	2.216	1.768	0.311	0.597	1.144	0.684
McClellan	2369.913	440.674	1668.734	2089.962	461.214	441.11	433.467	378.96	395.428	55.206	24.603	14.212	20.837	1.863	2.426	2.499	2.262666667
White Bluff	36715.823	34151.42	39303.695	44497.997	34889.863	38122.068	33515.241	37938.569	33831.8	28464.344	31684.363	31687.164	34196.256	34222.588	20480.478	18336.022	24346.36267

NOx (tpy)	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2014-2016 average
Carl Bailey	343.662	147.79	92.563	264.028	138.203	36.815	16.159	16.617	22.587	36.66	92.722	64.648	15.634	3.606	32.249	16.974	17.60966667
Flint Creek Power Plant	5940.657	5095.808	4755.575	4944.856	4627.796	5460.765	5345.459	4919.11	3782.247	4879.983	5323.612	5455.769	4277.576	5126.981	4318.244	3055.824	4167.016333
Independence	18559.994	16314.772	15743.107	15520.502	13171.061	14662.846	17353.184	15123.051	14338.106	14618.656	13410.679	11066.772	10714.403	12301.268	6268.072	9863.663	9477.667667
Lake Catherine	2060.917	1570.033	547.766	140.483	204.357	25.58	89.304	119.088	191.427	152.372	149.156	938.223	855.28	175.596	264.273	528.934	322.9343333
McClellan	545.167	278.436	312.515	444.042	205.248	159.97	235.764	254.114	165.513	316.42	413.142	331.633	292.185	172.654	132.93	95.07	133.5513333
White Bluff	19159.856	17704.706	19016.176	18206.888	16262.701	14155.37	13899.686	16472.099	14523.365	15806.461	16012.686	14235.626	18046.844	17906.084	9459.276	9719.359	12361.573

Heat input (MMBtu/yr)	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2014-2016 average
Carl Bailey	2847752.27	1206487.89	649595.69	2216436.29	1248079.86	305417.91	110986.65	187864.47	213572.96	432444.71	681341.89	599338.83	160257.15	50015.65	382638.09	188489.83	207047.8567
Flint Creek Power Plant	40116045.9	37915334.18	34349825.4	38817679.1	35571749.23	37415630.95	38281500.33	36963054.02	29012386.31	36889221.88	39841329.11	39578106.92	31745694.15	36914098.23	30945760.7	22791149.6	30217002.84
Independence	127286861.1	119314326.1	118365745.6	119463596.1	112147210.1	121705200.3	134907665.8	118966628.4	117815526.1	118838142	113445584.2	112554164	104475361.2	109631987.4	53357587.7	78529098.8	80506224.61
Lake Catherine	16772257.83	13555133.65	5846215.525	1908853.367	2449652.698	291724.076	412125.38	1186846.753	1415814.997	1804235.538	1514550.499	7386910.013	5893812.694	1036286.399	1991064.11	3811793.54	2279714.683
McClellan	3358881.549	1951265.005	2160287.609	2850587.827	1649518.562	1535991.138	2002430.024	2497924.437	1636218.192	2444251.289	2702579.251	2429814.919	2540685.869	1406358.682	1097234.34	774097.058	1092563.359
White Bluff	112561358.4	100773662.7	113065625.7	121879576.1	106686109.6	106763234.5	107764262.1	116381711.9	109159789.2	112760640.9	111049815.6	106932720.2	119456100.3	113580945.8	68706757.3	64149532.3	82145745.11

SO2 Rate (lb/MMBtu)	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2014-2016 average
Carl Bailey	1.095605131	0.630390082	1.337789048	1.077365504	0.353187335	0.976196845	0.098372192	0.022079747	0.420512035	0.214723404	0.106830361	0.000600662	0.131201634	0.000599812	0.01050078	0.00063664	0.003912412
Flint Creek Power Plant	0.724455847	0.578194192	0.549001044	0.52030782	0.462572304	0.455769355	0.455708054	0.460010582	0.469557101	0.461174162	0.432654994	0.424951907	0.422066121	0.431711155	0.41655108	0.14365111	0.330637782
Independence	0.361626295	0.412588057	0.374097758	0.394902544	0.398819658	0.430093323	0.437912372	0.444632757	0.465563325	0.482583176	0.535903856	0.585917905	0.552365298	0.547812253	0.56200652	0.57480846	0.561542408
Lake Catherine	0.000600038	0.000600068	0.000600046	0.000599313	0.000600902	0.00060331	0.000601759	0.000598224	0.000600361	0.0005997	0.000599518	0.00059998	0.000599951	0.00060022	0.00059968	0.00060024	0.000600047
McClellan	1.411132227	0.451680319	1.544918365	1.46633756	0.559210439	0.574365293	0.432940972	0.303419907	0.48334385	0.045172115	0.018207052	0.01169801	0.016402657	0.002649395	0.00442203	0.00645655	0.004509326
White Bluff	0.652369934	0.677784633	0.695236855	0.730196124	0.65406571	0.714142245	0.622010309	0.65196788	0.619858287	0.504863112	0.57063333	0.592656091	0.572532603	0.602611429	0.59617071	0.57166503	0.590149053

NOx rate (lb/MMBtu)	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	
Carl Bailey	0.241356668	0.244992099	0.284986497	0.238245513	0.221464995	0.24107951	0.291188174	0.176904127	0.21151554	0.169547686	0.272174664	0.215731058	0.195111419	0.144194867	0.16856137	0.18010521	
Flint Creek Power Plant	0.296173607	0.268799319	0.276890782	0.254773398	0.26019502	0.291897523	0.279271134	0.266163613	0.260733258	0.264575003	0.267240683	0.275696309	0.269490154	0.277779019	0.27908469	0.26815883	
Independence	0.291624663	0.273475492	0.266007821	0.259836511	0.234888786	0.24095677	0.257260162	0.254240222	0.243399261	0.24602633	0.236424874	0.196647936	0.205108705	0.224410198	0.23494585	0.2512104	
Lake Catherine	0.245753079	0.231651423	0.187391655	0.147190981	0.166845692	0.175371196	0.433382676	0.200679658	0.270412449	0.168904776	0.19696405	0.25402313	0.290229787	0.338894731	0.26545906	0.277525	
McClellan	0.324612221	0.285390246	0.289327216	0.311544163	0.248858067	0.208295473	0.235477892	0.203460118	0.202311649	0.258909549	0.305739045	0.272969762	0.230004822	0.24553338	0.24230011	0.24562811	
White Bluff	0.340433987	0.351375658	0.336374135	0.298768483	0.304870073	0.26517312	0.257964667	0.28307023	0.26609368	0.280354224	0.28838744	0.266253883	0.302150229	0.315300843	0.27535213	0.30302198	

Lake Catherine

NOx (tpy)	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2014-2016 average
unit 1	108.031	43.499		0.387	4.409			3.973		0.026	1.522						
unit 2	125.252	53.1		0.075	2.173			0.568		1.456	0.609	1.542					
unit 3	103.433	52.364	7.649	0.05	1.858			1.259		0.345	1.876	9.137	48.831				
unit 4	1724.201	1421.07	540.117	139.971	195.917	25.58	89.304	113.288	191.427	150.545	145.149	927.544	806.449	175.596	264.273	528.934	322.9343333

Lake Catherine

SO2 (tpy)	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2014-2016 average
unit 1	0.187	0.079		0.001	0.004			0.003		0	0.002						
unit 2	0.182	0.07		0	0.003			0.001		0.001	0	0.001					
unit 3	0.335	0.193	0.023	0	0.005			0.003		0	0.002	0.011	0.061				
unit 4	4.328	3.725	1.731	0.571	0.724	0.088	0.124	0.348	0.425	0.54	0.45	2.204	1.707	0.311	0.597	1.144	0.684

Lake Catherine

HI (MMBtu/yr)	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2014-2016 average
unit 1	621638.325	263536.375		3076.6	11900.875			10939.05		125.2	6822.737						

unit 2	606500.45	232715.775		1028.65	8813.15			3085.7		2703.75	1131.74	2863.214					
unit 3	1116149.425	643331.075	75960.55	647.1	15883.68			11509.847		1431.536	7783.524	37914.437	202620.635				
unit 4	14427969.63	12415550.43	5770254.975	1904101.017	2413054.993	291724.076	412125.38	1161312.156	1415814.997	1799975.052	1498812.498	7346132.362	5691192.059	1036286.399	1991064.11	3811793.54	2279714.683

Lake Catherine

SO2 rate (lb/MMBtu)	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	
unit 1	0.000601636	0.000599538	#DIV/0!	0.000650068	0.000672219	#DIV/0!	#DIV/0!	0.000548494	#DIV/0!	0	0.000586275	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
unit 2	0.000600164	0.000601592	#DIV/0!	0	0.000680801	#DIV/0!	#DIV/0!	0.000648151	#DIV/0!	0.000739713	0	0.000698516	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
unit 3	0.000600278	0.000600002	0.000605578	0	0.000629577	#DIV/0!	#DIV/0!	0.000521293	#DIV/0!	0	0.000513906	0.000580254	0.00060211	#DIV/0!	#DIV/0!	#DIV/0!	
unit 4	0.000599946	0.000600054	0.000599973	0.000599758	0.000600069	0.00060331	0.000601759	0.000599322	0.000600361	0.000600008	0.000600475	0.000600044	0.000599874	0.00060022	0.00059968	0.00060024	

Lake Catherine

NOx rate (lb/MMBtu)	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	
unit 1	0.347568661	0.330117617	#DIV/0!	0.251576416	0.740953921	#DIV/0!	#DIV/0!	0.726388489	#DIV/0!	0.415335463	0.44615526	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
unit 2	0.413031845	0.456350671	#DIV/0!	0.145822194	0.493126748	#DIV/0!	#DIV/0!	0.368149853	#DIV/0!	1.077022654	1.07621892	1.077111246	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
unit 3	0.185338984	0.162790209	0.201394013	0.15453562	0.233950822	#DIV/0!	#DIV/0!	0.218769198	#DIV/0!	0.481999754	0.482043866	0.481979991	0.481994344	#DIV/0!	#DIV/0!	#DIV/0!	
unit 4	0.239008127	0.228917761	0.187207325	0.147020561	0.162380883	0.175371196	0.433382676	0.195103443	0.270412449	0.167274541	0.193685334	0.252525807	0.28340249	0.338894731	0.26545906	0.277525	

DATE	DAY_OF_WK		#ofday type per month
01/04/2002	Friday	1Friday	4
01/05/2002	Saturday	1Saturday	4
01/06/2002	Sunday	1Sunday	6
01/07/2002	Weekday	1Weekday	17
02/02/2002	Saturday	2Saturday	4
02/03/2002	Sunday	2Sunday	4
02/04/2002	Monday	2Monday	4
02/05/2002	Weekday	2Weekday	16
03/02/2002	Saturday	3Saturday	4
03/03/2002	Sunday	3Sunday	7
03/04/2002	Monday	3Monday	4
03/05/2002	Weekday	3Weekday	16
04/02/2002	Weekday	4Weekday	17
04/06/2002	Saturday	4Saturday	4
04/07/2002	Sunday	4Sunday	4
04/08/2002	Monday	4Monday	5
05/04/2002	Saturday	5Saturday	4
05/05/2002	Sunday	5Sunday	6
05/06/2002	Monday	5Monday	3
05/07/2002	Weekday	5Weekday	18
06/03/2002	Monday	6Monday	4
06/04/2002	Weekday	6Weekday	16
06/08/2002	Saturday	6Saturday	5
06/09/2002	Sunday	6Sunday	5
07/03/2002	Weekday	7Weekday	16
07/06/2002	Saturday	7Saturday	4
07/07/2002	Sunday	7Sunday	6
07/08/2002	Monday	7Monday	5
08/03/2002	Saturday	8Saturday	5
08/04/2002	Sunday	8Sunday	4
08/05/2002	Monday	8Monday	4
08/06/2002	Weekday	8Weekday	18
09/07/2002	Saturday	9Saturday	4
09/08/2002	Sunday	9Sunday	7
09/09/2002	Monday	9Monday	4
09/10/2002	Weekday	9Weekday	15
10/05/2002	Saturday	10Saturday	4
10/06/2002	Sunday	10Sunday	4
10/07/2002	Monday	10Monday	4
10/08/2002	Weekday	10Weekday	19
11/02/2002	Saturday	11Saturday	4
11/03/2002	Sunday	11Sunday	7
11/04/2002	Monday	11Monday	4
11/05/2002	Weekday	11Weekday	15
12/07/2002	Saturday	12Saturday	4
12/08/2002	Sunday	12Sunday	8
12/09/2002	Monday	12Monday	5
12/10/2002	Weekday	12Weekday	14

DATE	DAY_OF_WK			note
1/1/2002	Tuesday	Sunday	1Sunday	holiday/Sunday
1/2/2002	Wednesday	sunday	1sunday	holiday/Sunday
1/3/2002	Thursday	Weekday	1Weekday	
1/4/2002	Friday	Friday	1Friday	
1/5/2002	Saturday	Saturday	1Saturday	
1/6/2002	Sunday	Sunday	1Sunday	
1/7/2002	Monday	Weekday	1Weekday	
1/8/2002	Tuesday	Weekday	1Weekday	
1/9/2002	Wednesday	Weekday	1Weekday	
1/10/2002	Thursday	Weekday	1Weekday	
1/11/2002	Friday	Friday	1Friday	
1/12/2002	Saturday	Saturday	1Saturday	
1/13/2002	Sunday	Sunday	1Sunday	
1/14/2002	Monday	Weekday	1Weekday	
1/15/2002	Tuesday	Weekday	1Weekday	
1/16/2002	Wednesday	Weekday	1Weekday	
1/17/2002	Thursday	Weekday	1Weekday	
1/18/2002	Friday	Friday	1Friday	
1/19/2002	Saturday	Saturday	1Saturday	
1/20/2002	Sunday	Sunday	1Sunday	
1/21/2002	Monday	Weekday	1Weekday	
1/22/2002	Tuesday	Weekday	1Weekday	
1/23/2002	Wednesday	Weekday	1Weekday	
1/24/2002	Thursday	Weekday	1Weekday	
1/25/2002	Friday	Friday	1Friday	
1/26/2002	Saturday	Saturday	1Saturday	
1/27/2002	Sunday	Sunday	1Sunday	
1/28/2002	Monday	Weekday	1Weekday	
1/29/2002	Tuesday	Weekday	1Weekday	
1/30/2002	Wednesday	Weekday	1Weekday	
1/31/2002	Thursday	Weekday	1Weekday	
2/1/2002	Friday	Weekday	2Weekday	
2/2/2002	Saturday	Saturday	2Saturday	
2/3/2002	Sunday	Sunday	2Sunday	
2/4/2002	Monday	Monday	2Monday	
2/5/2002	Tuesday	Weekday	2Weekday	
2/6/2002	Wednesday	Weekday	2Weekday	
2/7/2002	Thursday	Weekday	2Weekday	
2/8/2002	Friday	Weekday	2Weekday	
2/9/2002	Saturday	Saturday	2Saturday	
2/10/2002	Sunday	Sunday	2Sunday	
2/11/2002	Monday	Monday	2Monday	
2/12/2002	Tuesday	Weekday	2Weekday	
2/13/2002	Wednesday	Weekday	2Weekday	
2/14/2002	Thursday	Weekday	2Weekday	
2/15/2002	Friday	Weekday	2Weekday	
2/16/2002	Saturday	Saturday	2Saturday	
2/17/2002	Sunday	Sunday	2Sunday	

2/18/2002	Monday	Monday	2Monday	
2/19/2002	Tuesday	Weekday	2Weekday	
2/20/2002	Wednesday	Weekday	2Weekday	
2/21/2002	Thursday	Weekday	2Weekday	
2/22/2002	Friday	Weekday	2Weekday	
2/23/2002	Saturday	Saturday	2Saturday	
2/24/2002	Sunday	Sunday	2Sunday	
2/25/2002	Monday	Monday	2Monday	
2/26/2002	Tuesday	Weekday	2Weekday	
2/27/2002	Wednesday	Weekday	2Weekday	
2/28/2002	Thursday	Weekday	2Weekday	
3/1/2002	Friday	Weekday	3Weekday	
3/2/2002	Saturday	Saturday	3Saturday	
3/3/2002	Sunday	Sunday	3Sunday	
3/4/2002	Monday	Monday	3Monday	
3/5/2002	Tuesday	Weekday	3Weekday	
3/6/2002	Wednesday	Weekday	3Weekday	
3/7/2002	Thursday	Weekday	3Weekday	
3/8/2002	Friday	Weekday	3Weekday	
3/9/2002	Saturday	Saturday	3Saturday	
3/10/2002	Sunday	Sunday	3Sunday	
3/11/2002	Monday	Monday	3Monday	
3/12/2002	Tuesday	Weekday	3Weekday	
3/13/2002	Wednesday	Weekday	3Weekday	
3/14/2002	Thursday	Weekday	3Weekday	
3/15/2002	Friday	Weekday	3Weekday	
3/16/2002	Saturday	Saturday	3Saturday	
3/17/2002	Sunday	Sunday	3Sunday	
3/18/2002	Monday	Monday	3Monday	
3/19/2002	Tuesday	Weekday	3Weekday	
3/20/2002	Wednesday	Weekday	3Weekday	
3/21/2002	Thursday	Weekday	3Weekday	
3/22/2002	Friday	Weekday	3Weekday	
3/23/2002	Saturday	Saturday	3Saturday	
3/24/2002	Sunday	Sunday	3Sunday	
3/25/2002	Monday	Monday	3Monday	
3/26/2002	Tuesday	Weekday	3Weekday	
3/27/2002	Wednesday	Weekday	3Weekday	
3/28/2002	Thursday	Weekday	3Weekday	
3/29/2002	Friday	sunday	3sunday	holiday/Sunday
3/30/2002	Saturday	sunday	3sunday	holiday/Sunday
3/31/2002	Sunday	Sunday	3Sunday	
4/1/2002	Monday	Monday	4Monday	
4/2/2002	Tuesday	Weekday	4Weekday	
4/3/2002	Wednesday	Weekday	4Weekday	
4/4/2002	Thursday	Weekday	4Weekday	
4/5/2002	Friday	Weekday	4Weekday	
4/6/2002	Saturday	Saturday	4Saturday	
4/7/2002	Sunday	Sunday	4Sunday	

4/8/2002	Monday	Monday	4Monday
4/9/2002	Tuesday	Weekday	4Weekday
4/10/2002	Wednesday	Weekday	4Weekday
4/11/2002	Thursday	Weekday	4Weekday
4/12/2002	Friday	Weekday	4Weekday
4/13/2002	Saturday	Saturday	4Saturday
4/14/2002	Sunday	Sunday	4Sunday
4/15/2002	Monday	Monday	4Monday
4/16/2002	Tuesday	Weekday	4Weekday
4/17/2002	Wednesday	Weekday	4Weekday
4/18/2002	Thursday	Weekday	4Weekday
4/19/2002	Friday	Weekday	4Weekday
4/20/2002	Saturday	Saturday	4Saturday
4/21/2002	Sunday	Sunday	4Sunday
4/22/2002	Monday	Monday	4Monday
4/23/2002	Tuesday	Weekday	4Weekday
4/24/2002	Wednesday	Weekday	4Weekday
4/25/2002	Thursday	Weekday	4Weekday
4/26/2002	Friday	Weekday	4Weekday
4/27/2002	Saturday	Saturday	4Saturday
4/28/2002	Sunday	Sunday	4Sunday
4/29/2002	Monday	Monday	4Monday
4/30/2002	Tuesday	Weekday	4Weekday
5/1/2002	Wednesday	Weekday	5Weekday
5/2/2002	Thursday	Weekday	5Weekday
5/3/2002	Friday	Weekday	5Weekday
5/4/2002	Saturday	Saturday	5Saturday
5/5/2002	Sunday	Sunday	5Sunday
5/6/2002	Monday	Monday	5Monday
5/7/2002	Tuesday	Weekday	5Weekday
5/8/2002	Wednesday	Weekday	5Weekday
5/9/2002	Thursday	Weekday	5Weekday
5/10/2002	Friday	Weekday	5Weekday
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5/12/2002	Sunday	Sunday	5Sunday
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5/15/2002	Wednesday	Weekday	5Weekday
5/16/2002	Thursday	Weekday	5Weekday
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5/18/2002	Saturday	Saturday	5Saturday
5/19/2002	Sunday	Sunday	5Sunday
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5/21/2002	Tuesday	Weekday	5Weekday
5/22/2002	Wednesday	Weekday	5Weekday
5/23/2002	Thursday	Weekday	5Weekday
5/24/2002	Friday	Weekday	5Weekday
5/25/2002	Saturday	Saturday	5Saturday
5/26/2002	Sunday	Sunday	5Sunday

5/27/2002	Monday	sunday	5sunday	holiday/Sunday
5/28/2002	Tuesday	sunday	5sunday	holiday/Sunday
5/29/2002	Wednesday	Weekday	5Weekday	
5/30/2002	Thursday	Weekday	5Weekday	
5/31/2002	Friday	Weekday	5Weekday	
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6/2/2002	Sunday	Sunday	6Sunday	
6/3/2002	Monday	Monday	6Monday	
6/4/2002	Tuesday	Weekday	6Weekday	
6/5/2002	Wednesday	Weekday	6Weekday	
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6/10/2002	Monday	Monday	6Monday	
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7/1/2002	Monday	Monday	7Monday	
7/2/2002	Tuesday	Weekday	7Weekday	
7/3/2002	Wednesday	Weekday	7Weekday	
7/4/2002	Thursday	sunday	7sunday	holiday/Sunday
7/5/2002	Friday	sunday	7sunday	holiday/Sunday
7/6/2002	Saturday	Saturday	7Saturday	
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7/31/2002	Wednesday	Weekday	7Weekday
8/1/2002	Thursday	Weekday	8Weekday
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8/30/2002	Friday	Weekday	8Weekday
8/31/2002	Saturday	Saturday	8Saturday
9/1/2002	Sunday	Sunday	9Sunday

9/2/2002	Monday	sunday	9sunday	holiday/Sunday
9/3/2002	Tuesday	sunday	9sunday	holiday/Sunday
9/4/2002	Wednesday	Weekday	9Weekday	
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11/27/2002	Wednesday	Weekday	11Weekday	
11/28/2002	Thursday	sunday	11sunday	holiday/Sunday
11/29/2002	Friday	sunday	11sunday	holiday/Sunday
11/30/2002	Saturday	sunday	11sunday	holiday/Sunday
12/1/2002	Sunday	Sunday	12Sunday	
12/2/2002	Monday	Monday	12Monday	
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12/28/2002	Saturday	Saturday	12Saturday	
12/29/2002	Sunday	Sunday	12Sunday	
12/30/2002	Monday	Monday	12Monday	
12/31/2002	Tuesday	Weekday	12Weekday	

DATE			FIPSST	FIPSCNTY	STATE	PLANT_ID

PLT_NAME	CO_18_TPD	NOX_18_TPD	SO2_18_TPD	VOC_18_TPD	PM25_18_TPD	PM10_18_TPD
DOMTAR INDUSTRIES INC-ASHDOWN MILL Total						
ENTERGY ARK-INDEPENDENCE Total						
ENTERGY ARK-WHITE BLUFF Total						
JOHN L MCCLELLAN GENERATING STATION Total						
SWEPCO-FLINT CREEK POWER PLANT Total						
Grand Total						

PEC_18_TPI	NH3_18_TPI	NOx	SO2
		3839.495	2241.4
		16121.4	26786.19
		9242.099	45969.64
		287.8127	0.11676
		4334.519	2896.149
		33825.33	77893.5

DATE			FIPSST	FIPSCNTY	STATE	PLANT_ID

PLT_NAME	CO_02_TPD	NOX_02_TPD	SO2_02_TPD	VOC_02_TPD	PM25_02_TPD
AECC - Carl E Bailey Generating Sta Total					
DOMTAR INDUSTRIES INC-ASHDOWN MILL Total					
Entergy Arkansas - Lake Catherine Total					
ENTERGY ARK-INDEPENDENCE Total					
ENTERGY ARK-WHITE BLUFF Total					
JOHN L MCCLELLAN GENERATING STATION Total					
SWEPCO-FLINT CREEK POWER PLANT Total					
Grand Total					

PM10_02_TPD	NH3_02_TPD

NOx
149.36606
3727.03275
1363.51007
15593.03146
17055.5395
277.87033
5079.90054
43246.25071

SO2
380.50435
2260.17015
4.10167
25014.7613
34787.11009
451.17586
11165.104
74062.92742

Plant Name	Boiler ID	CSAPR NOx Allocation 2017 (Ozone Season)	CSAPR NOx Allocation 2018 and Beyond (Ozone Season)	AMPD Average 2014-2016 Emissions (Ozone Season)	∆ 2014-2016 emissions and 2017 budget (Ozone Season)	∆ 2014-2016 emissions and 2018 budget (Ozone Season)
Carl Bailey	01	36	26	14.968	21	11
Cecil Lynch	2				0	0
Cecil Lynch	3	118	86		118	86
City Water & Light - City of Jonesboro	SN04	20	14	6.696	13	7
City Water & Light - City of Jonesboro	SN06	24	17	3.913666667	20	13
City Water & Light - City of Jonesboro	SN07	19	15	6.390333333	13	9
Dell Power Plant	1	17	17	6.507666667	10	10
Dell Power Plant	2	18	18	5.145	13	13
Flint Creek Power Plant	1	1,332	965	2008.024	-676	-1,043
Fulton	CT1	14	14	4.439666667	10	10
Hamilton Moses	1				0	0
Hamilton Moses	2				0	0
Harry D. Mattison Power Plant	1	21	21	6.675333333	14	14
Harry D. Mattison Power Plant	2	19	18	7.430333333	12	11
Harry D. Mattison Power Plant	3	12	12	5.508	6	6
Harry D. Mattison Power Plant	4	9	9	5.092333333	4	4
Harvey Couch	1				0	0
Harvey Couch	2	17	12		17	12
Hot Spring Energy Facility	CT-1	28	28	15.89533333	12	12
Hot Spring Energy Facility	CT-2	21	21	15.89766667	5	5
Hot Spring Power Co., LLC	SN-01	37	37	8.527333333	28	28
Hot Spring Power Co., LLC	SN-02	38	38	8.582666667	29	29
Independence	1	1,840	1,333	2362.954333	-523	-1,030
Independence	2	2,017	1,461	2402.146333	-385	-941
John W. Turk Jr. Power Plant	SN-01	322	322	294.5836667	27	27
Lake Catherine	1	0	0		0	0
Lake Catherine	2	0	0		0	0

Lake Catherine	3	1	1		1	1
Lake Catherine	4	256	186	257.2126667	-1	-71
McClellan	01	108	78	96.38233333	12	-18
Oswald Generating Station	G1	26	22	13.44433333	13	9
Oswald Generating Station	G2	19	19	11.95833333	7	7
Oswald Generating Station	G3	24	21	9.873666667	14	11
Oswald Generating Station	G4	14	14	13.04633333	1	1
Oswald Generating Station	G5	19	17	12.00666667	7	5
Oswald Generating Station	G6	18	16	13.553	4	2
Oswald Generating Station	G7	18	18	20.07	-2	-2
Pine Bluff Energy Center	CT-1	108	108	84.32633333	24	24
Plum Point Energy Station	1	690	690	547.0276667	143	143
Robert E Ritchie	2				0	0
Thomas Fitzhugh	2	53	45	21.64266667	31	23
Union Power Station	CTG-1	27	27	21.64966667	5	5
Union Power Station	CTG-2	26	26	19.72733333	6	6
Union Power Station	CTG-3	32	32	27.36233333	5	5
Union Power Station	CTG-4	30	30	26.22966667	4	4
Union Power Station	CTG-5	27	27	22.78666667	4	4
Union Power Station	CTG-6	26	26	24.54366667	1	1
Union Power Station	CTG-7	32	32	28.571	3	3
Union Power Station	CTG-8	29	29	25.52233333	3	3
White Bluff	1	2,116	1,533	3279.700333	-1,164	-1,747
White Bluff	2	2,130	1,544	2873.332333	-743	-1,329
Total		11,808	9,025	14,639	**-2,831**	**-5,614**

All emissions estimates are in tons.

2016 Annual and Ozone Season NOx emissions were obtained from the Air Markets Program Database Query Tool. CSAPR allocations were obtained from the EPA Unit-level Allocations and Underlying Data for the CSAPR Update for the 2008 Ozone NAAQS Spreadsheet.

State	Facility Name	Facility ID (ORISP	Unit ID	Year	NOx (tons)
AR	Carl Bailey	202	1	2014	3.605
AR	Carl Bailey	202	1	2015	29.273
AR	Carl Bailey	202	1	2016	12.026
AR	City Water &	56505	SN04	2014	0.471
AR	City Water &	56505	SN04	2015	12.888
AR	City Water &	56505	SN04	2016	6.729
AR	City Water &	56505	SN06	2014	1.838
AR	City Water &	56505	SN06	2015	8.689
AR	City Water &	56505	SN06	2016	1.214
AR	City Water &	56505	SN07	2014	3.343
AR	City Water &	56505	SN07	2015	3.724
AR	City Water &	56505	SN07	2016	12.104
AR	Dell Power Pl	55340	1	2014	3.349
AR	Dell Power Pl	55340	1	2015	4.743
AR	Dell Power Pl	55340	1	2016	11.431
AR	Dell Power Pl	55340	2	2014	2.287
AR	Dell Power Pl	55340	2	2015	3.212
AR	Dell Power Pl	55340	2	2016	9.936
AR	Flint Creek Po	6138	1	2014	2431.938
AR	Flint Creek Po	6138	1	2015	1969.984
AR	Flint Creek Po	6138	1	2016	1622.15
AR	Fulton	7825	CT1	2014	1.429
AR	Fulton	7825	CT1	2015	2.87
AR	Fulton	7825	CT1	2016	9.02
AR	Harry D. Matt	56328	1	2014	1.746
AR	Harry D. Matt	56328	1	2015	3.627
AR	Harry D. Matt	56328	1	2016	14.653
AR	Harry D. Matt	56328	2	2014	1.629
AR	Harry D. Matt	56328	2	2015	4.55
AR	Harry D. Matt	56328	2	2016	16.112
AR	Harry D. Matt	56328	3	2014	2.549
AR	Harry D. Matt	56328	3	2015	3.437
AR	Harry D. Matt	56328	3	2016	10.538
AR	Harry D. Matt	56328	4	2014	2.969
AR	Harry D. Matt	56328	4	2015	3.498
AR	Harry D. Matt	56328	4	2016	8.81
AR	Hot Spring Er	55418	CT-1	2014	6.398
AR	Hot Spring Er	55418	CT-1	2015	19.256
AR	Hot Spring Er	55418	CT-1	2016	22.032
AR	Hot Spring Er	55418	CT-2	2014	6.908
AR	Hot Spring Er	55418	CT-2	2015	19.151
AR	Hot Spring Er	55418	CT-2	2016	21.634
AR	Independence	6641	1	2014	2631.595
AR	Independence	6641	1	2015	1770.798
AR	Independence	6641	1	2016	2686.47
AR	Independence	6641	2	2014	2925.846

AR	Independence	6641		2	2015	1752.775
AR	Independence	6641		2	2016	2527.818
AR	John W. Turk	56564	SN-01		2014	322.056
AR	John W. Turk	56564	SN-01		2015	274.381
AR	John W. Turk	56564	SN-01		2016	287.314
AR	Lake Catherin	170		4	2014	157.578
AR	Lake Catherin	170		4	2015	244.577
AR	Lake Catherin	170		4	2016	369.483
AR	Magnet Cove	55714	SN-01		2014	3.389
AR	Magnet Cove	55714	SN-01		2015	3.58
AR	Magnet Cove	55714	SN-01		2016	18.613
AR	Magnet Cove	55714	SN-02		2014	3.385
AR	Magnet Cove	55714	SN-02		2015	3.952
AR	Magnet Cove	55714	SN-02		2016	18.411
AR	McClellan	203		1	2014	125.126
AR	McClellan	203		1	2015	86.601
AR	McClellan	203		1	2016	77.42
AR	Oswald Gener	55221	G1		2014	6.819
AR	Oswald Gener	55221	G1		2015	9.385
AR	Oswald Gener	55221	G1		2016	24.129
AR	Oswald Gener	55221	G2		2014	5.372
AR	Oswald Gener	55221	G2		2015	9.89
AR	Oswald Gener	55221	G2		2016	20.613
AR	Oswald Gener	55221	G3		2014	5.209
AR	Oswald Gener	55221	G3		2015	8.615
AR	Oswald Gener	55221	G3		2016	15.797
AR	Oswald Gener	55221	G4		2014	6.216
AR	Oswald Gener	55221	G4		2015	10.731
AR	Oswald Gener	55221	G4		2016	22.192
AR	Oswald Gener	55221	G5		2014	5.77
AR	Oswald Gener	55221	G5		2015	10.504
AR	Oswald Gener	55221	G5		2016	19.746
AR	Oswald Gener	55221	G6		2014	7.483
AR	Oswald Gener	55221	G6		2015	11.11
AR	Oswald Gener	55221	G6		2016	22.066
AR	Oswald Gener	55221	G7		2014	4.447
AR	Oswald Gener	55221	G7		2015	7.551
AR	Oswald Gener	55221	G7		2016	48.212
AR	Pine Bluff Ene	55075	CT-1		2014	69.975
AR	Pine Bluff Ene	55075	CT-1		2015	94.731
AR	Pine Bluff Ene	55075	CT-1		2016	88.273
AR	Plum Point Er	56456		1	2014	364.706
AR	Plum Point Er	56456		1	2015	663.672
AR	Plum Point Er	56456		1	2016	612.705
AR	Thomas Fitzhu	201		2	2014	1.585
AR	Thomas Fitzhu	201		2	2015	18.953
AR	Thomas Fitzhu	201		2	2016	44.39

AR	Union Power	55380	CTG-1	2014	15.38
AR	Union Power	55380	CTG-1	2015	21.919
AR	Union Power	55380	CTG-1	2016	27.65
AR	Union Power	55380	CTG-2	2014	12.968
AR	Union Power	55380	CTG-2	2015	20.645
AR	Union Power	55380	CTG-2	2016	25.569
AR	Union Power	55380	CTG-3	2014	25.812
AR	Union Power	55380	CTG-3	2015	31.955
AR	Union Power	55380	CTG-3	2016	24.32
AR	Union Power	55380	CTG-4	2014	26.794
AR	Union Power	55380	CTG-4	2015	29.626
AR	Union Power	55380	CTG-4	2016	22.269
AR	Union Power	55380	CTG-5	2014	25.382
AR	Union Power	55380	CTG-5	2015	16.974
AR	Union Power	55380	CTG-5	2016	26.004
AR	Union Power	55380	CTG-6	2014	24.433
AR	Union Power	55380	CTG-6	2015	24.146
AR	Union Power	55380	CTG-6	2016	25.052
AR	Union Power	55380	CTG-7	2014	31.709
AR	Union Power	55380	CTG-7	2015	26.135
AR	Union Power	55380	CTG-7	2016	27.869
AR	Union Power	55380	CTG-8	2014	25.866
AR	Union Power	55380	CTG-8	2015	22.137
AR	Union Power	55380	CTG-8	2016	28.564
AR	White Bluff	6009	1	2014	4481.067
AR	White Bluff	6009	1	2015	2897.856
AR	White Bluff	6009	1	2016	2460.178
AR	White Bluff	6009	2	2014	4348.127
AR	White Bluff	6009	2	2015	2397.896
AR	White Bluff	6009	2	2016	1873.974

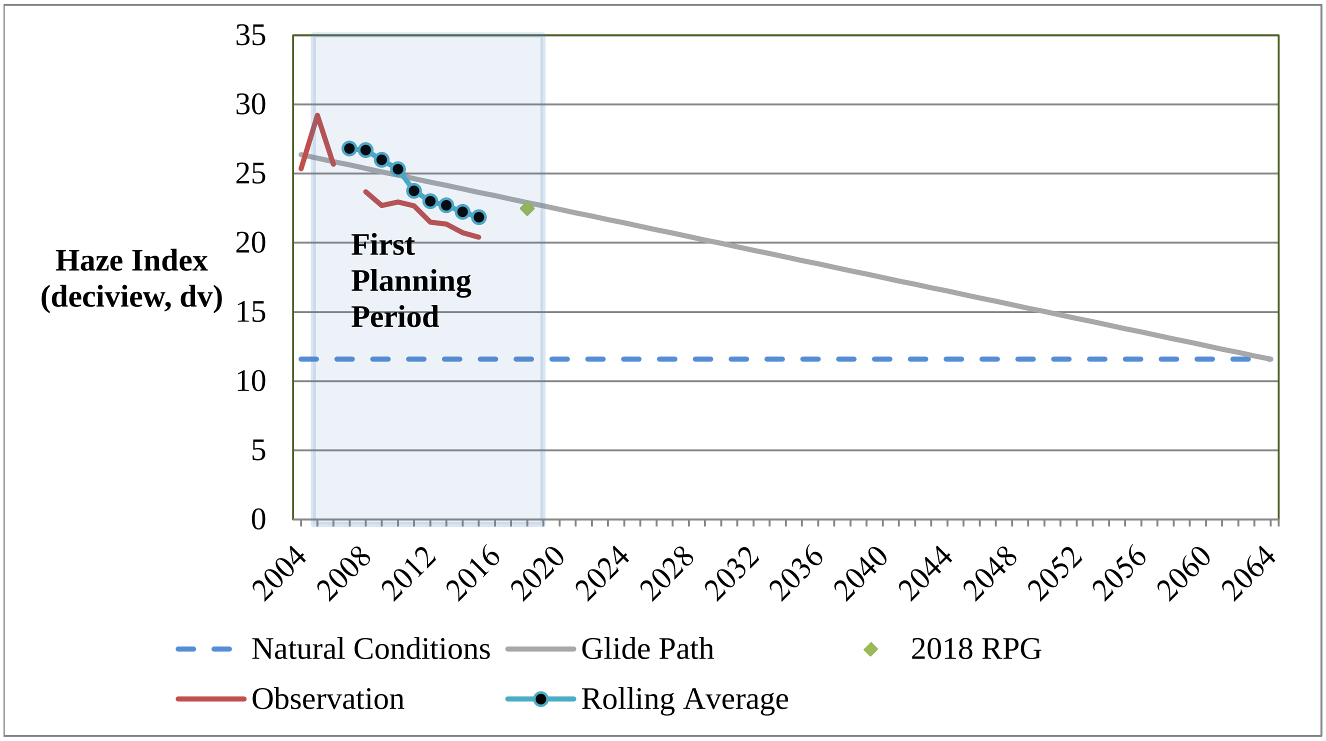
		Observatio	Rolling Ave	2018 RPG	Glide Path	Natural Conditions
CACR1	2002	27.20821				11.58
CACR1	2003	26.53692				11.58
CACR1	2004	25.34289			26.36	11.58
CACR1	2005	29.20991			26.113667	11.58
CACR1	2006	25.68353			25.867333	11.58
CACR1	2007		26.79629		25.621	11.58
CACR1	2008	23.6971	26.69331		25.374667	11.58
CACR1	2009	22.68463	25.98336		25.128333	11.58
CACR1	2010	22.94169	25.31879		24.882	11.58
CACR1	2011	22.6743	23.75174		24.635667	11.58
CACR1	2012	21.48868	22.99943		24.389333	11.58
CACR1	2013	21.34876	22.69728		24.143	11.58
CACR1	2014	20.71672	22.22761		23.896667	11.58
CACR1	2015	20.40995	21.83403		23.650333	11.58
	2016				23.404	11.58
	2017				23.157667	11.58
	2018			22.47	22.911333	11.58
	2019				22.665	11.58
	2020				22.418667	11.58
	2021				22.172333	11.58
	2022				21.926	11.58
	2023				21.679667	11.58
	2024				21.433333	11.58
	2025				21.187	11.58
	2026				20.940667	11.58
	2027				20.694333	11.58
	2028				20.448	11.58
	2029				20.201667	11.58
	2030				19.955333	11.58
	2031				19.709	11.58
	2032				19.462667	11.58
	2033				19.216333	11.58
	2034				18.97	11.58
	2035				18.723667	11.58
	2036				18.477333	11.58
	2037				18.231	11.58
	2038				17.984667	11.58
	2039				17.738333	11.58
	2040				17.492	11.58
	2041				17.245667	11.58
	2042				16.999333	11.58
	2043				16.753	11.58
	2044				16.506667	11.58
	2045				16.260333	11.58
	2046				16.014	11.58
	2047				15.767667	11.58

2048	15.521333	11.58
2049	15.275	11.58
2050	15.028667	11.58
2051	14.782333	11.58
2052	14.536	11.58
2053	14.289667	11.58
2054	14.043333	11.58
2055	13.797	11.58
2056	13.550667	11.58
2057	13.304333	11.58
2058	13.058	11.58
2059	12.811667	11.58
2060	12.565333	11.58
2061	12.319	11.58
2062	12.072667	11.58
2063	11.826333	11.58
2064	11.58	11.58

URP 0.246333

26.36 baseline is from 2008 Arkansas SIP .

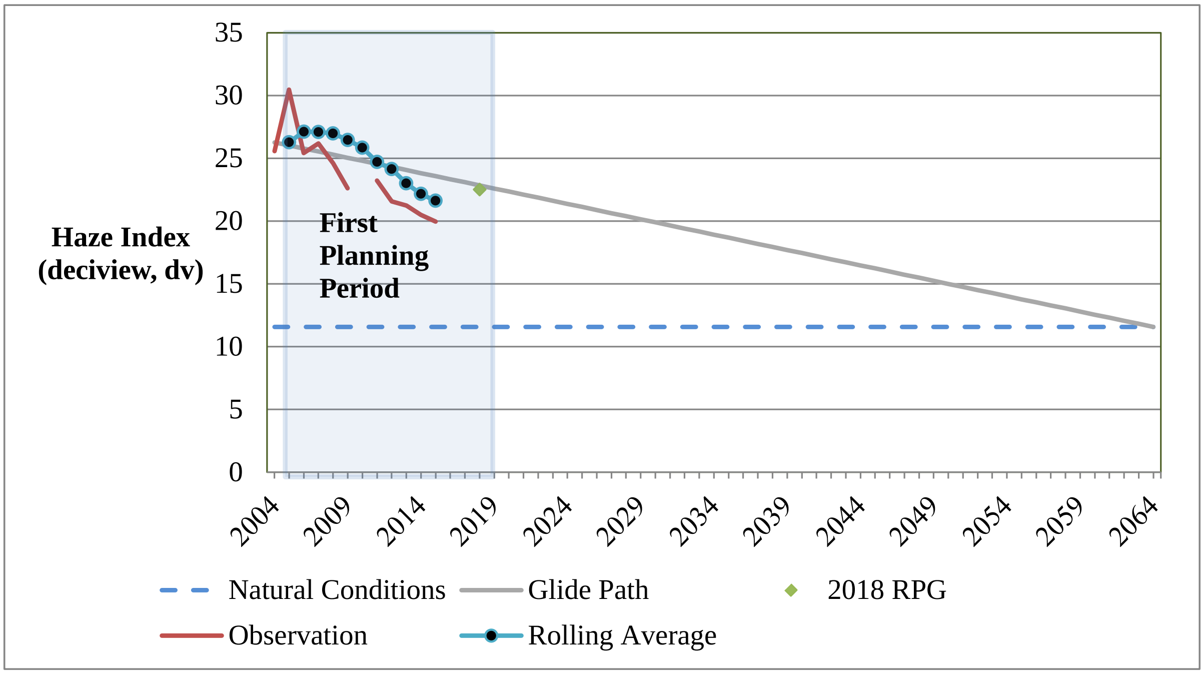
Using RPG from FIP



Site	Year	Observatio	Rolling Ave	2018 RPG	Glide Path	Natural Conditions
UPBU1	2000	26.1878				11.57
UPBU1	2001	25.59995				11.57
UPBU1	2002	26.74401				11.57
UPBU1	2003	27.21901				11.57
UPBU1	2004	25.57924			26.27	11.57
UPBU1	2005	30.46803	26.266		26.025	11.57
UPBU1	2006	25.42405	27.12205		25.78	11.57
UPBU1	2007	26.17466	27.08687		25.535	11.57
UPBU1	2008	24.59907	26.973		25.29	11.57
UPBU1	2009	22.61692	26.44901		25.045	11.57
UPBU1	2010		25.85655		24.8	11.57
UPBU1	2011	23.21347	24.70368		24.555	11.57
UPBU1	2012	21.56255	24.15103		24.31	11.57
UPBU1	2013	21.24529	22.998		24.065	11.57
UPBU1	2014	20.4934	22.15956		23.82	11.57
UPBU1	2015	19.96032	21.62868		23.575	11.57
	2016				23.33	11.57
	2017				23.085	11.57
	2018			22.51	22.84	11.57
	2019				22.595	11.57
	2020				22.35	11.57
	2021				22.105	11.57
	2022				21.86	11.57
	2023				21.615	11.57
	2024				21.37	11.57
	2025				21.125	11.57
	2026				20.88	11.57
	2027				20.635	11.57
	2028				20.39	11.57
	2029				20.145	11.57
	2030				19.9	11.57
	2031				19.655	11.57
	2032				19.41	11.57
	2033				19.165	11.57
	2034				18.92	11.57
	2035				18.675	11.57
	2036				18.43	11.57
	2037				18.185	11.57
	2038				17.94	11.57
	2039				17.695	11.57
	2040				17.45	11.57
	2041				17.205	11.57
	2042				16.96	11.57
	2043				16.715	11.57
	2044				16.47	11.57
	2045				16.225	11.57
	2046				15.98	11.57
	2047				15.735	11.57
	2048				15.49	11.57

2049	15.245	11.57
2050	15	11.57
2051	14.755	11.57
2052	14.51	11.57
2053	14.265	11.57
2054	14.02	11.57
2055	13.775	11.57
2056	13.53	11.57
2057	13.285	11.57
2058	13.04	11.57
2059	12.795	11.57
2060	12.55	11.57
2061	12.305	11.57
2062	12.06	11.57
2063	11.815	11.57
2064	11.57	11.57

URP 0.245
26.27 baseline is from 2008 Arkansas SIP .
Using RPG from FIP

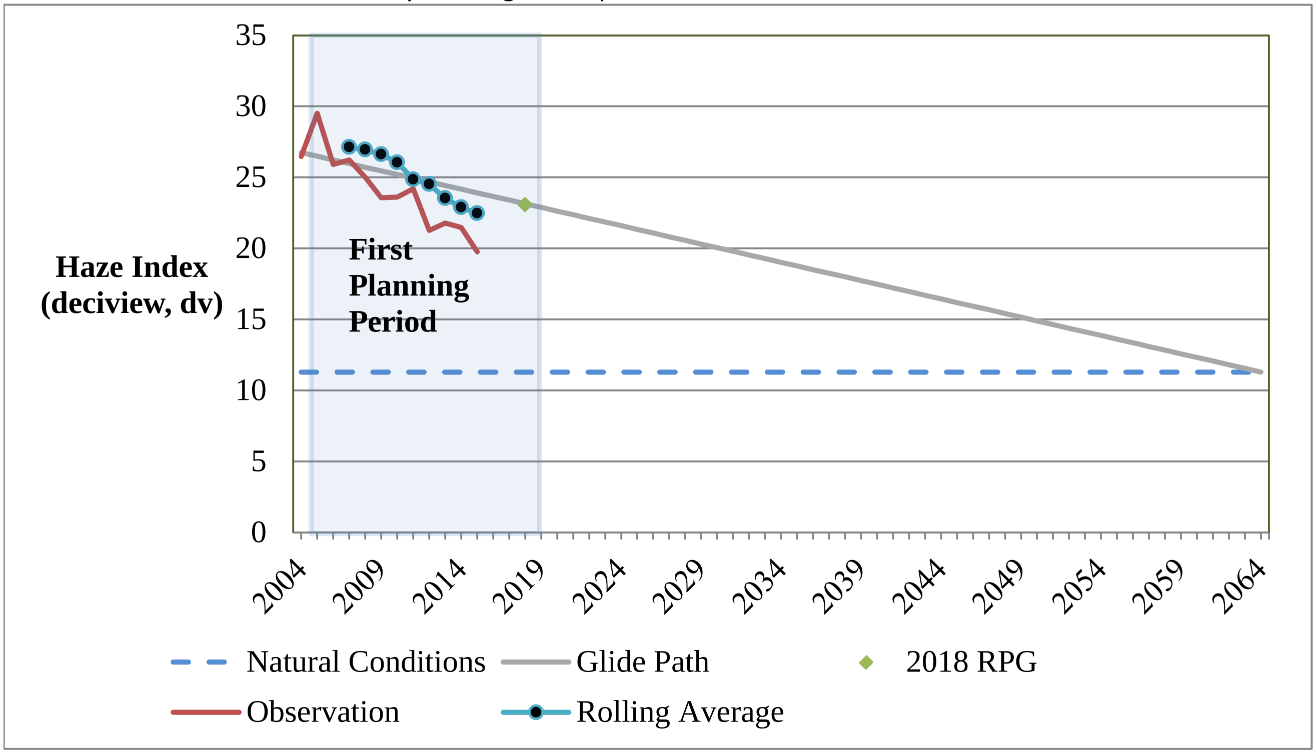


site	year	Observation	Rolling Average	2018 RPG	Glide Path	Natural Conditions
HEGL1	2002	27.16946				11.3
HEGL1	2003	26.61187				11.3
HEGL1	2004	26.46658			26.75	11.3
HEGL1	2005	29.51535			26.4925	11.3
HEGL1	2006	25.90707			26.235	11.3
HEGL1	2007	26.23409	27.13407		25.9775	11.3
HEGL1	2008	25.01096	26.94699		25.72	11.3
HEGL1	2009	23.5667	26.62681		25.4625	11.3
HEGL1	2010	23.61062	26.04684		25.205	11.3
HEGL1	2011	24.20526	24.86589		24.9475	11.3
HEGL1	2012	21.26939	24.52553		24.69	11.3
HEGL1	2013	21.78387	23.53259		24.4325	11.3
HEGL1	2014	21.48251	22.88717		24.175	11.3
HEGL1	2015	19.77021	22.47033		23.9175	11.3
	2016				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.

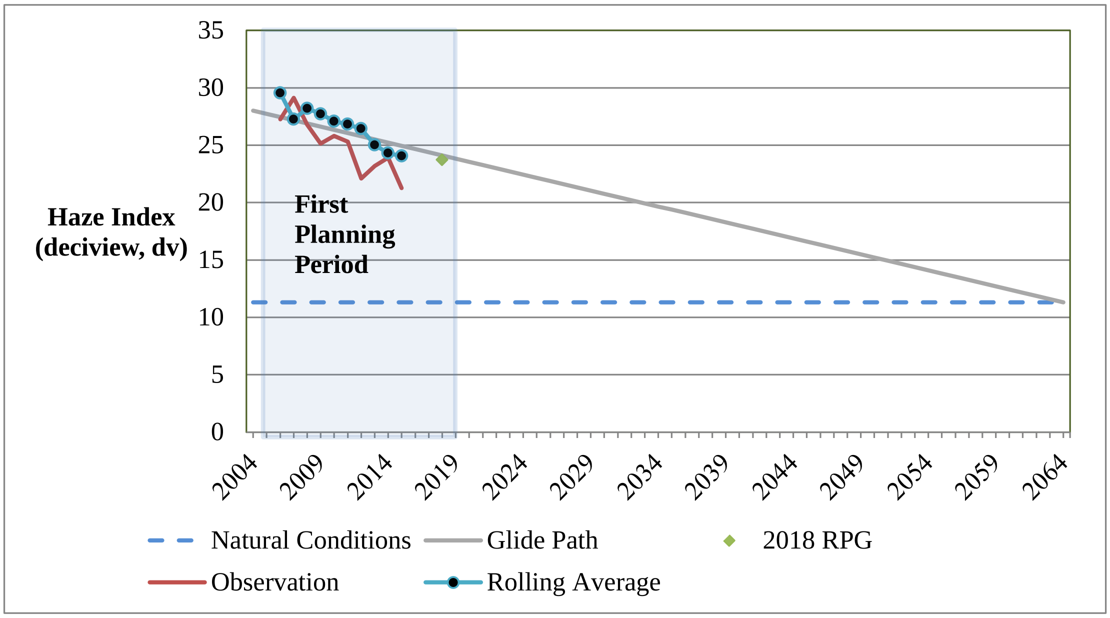


site	year	Observation	Rolling Average	2018 RPG	Glide Path	Natural Conditions
MING1	2001	29.54172959				11.3
MING1	2002					11.3
MING2	2003					11.3
MING3	2004				28.02	11.3
MING4	2005				27.741333	11.3
MING1	2006	27.26314968	29.54172959		27.462667	11.3
MING1	2007	29.12263883	27.26314968		27.184	11.3
MING1	2008	26.79529298	28.19289426		26.905333	11.3
MING1	2009	25.12848879	27.72702716		26.626667	11.3
MING1	2010	25.80093978	27.07739257		26.348	11.3
MING1	2011	25.30045604	26.82210201		26.069333	11.3
MING1	2012	22.11355806	26.42956328		25.790667	11.3
MING1	2013	23.18838845	25.02774713		25.512	11.3
MING1	2014	23.90040011	24.30636622		25.233333	11.3
MING1	2015	21.27608056	24.06074849		24.954667	11.3
	2016				24.676	11.3
	2017				24.397333	11.3
	2018			23.71	24.118667	11.3
	2019				23.84	11.3
	2020				23.561333	11.3
	2021				23.282667	11.3
	2022				23.004	11.3
	2023				22.725333	11.3
	2024				22.446667	11.3
	2025				22.168	11.3
	2026				21.889333	11.3
	2027				21.610667	11.3
	2028				21.332	11.3
	2029				21.053333	11.3
	2030				20.774667	11.3
	2031				20.496	11.3
	2032				20.217333	11.3
	2033				19.938667	11.3
	2034				19.66	11.3
	2035				19.381333	11.3
	2036				19.102667	11.3
	2037				18.824	11.3
	2038				18.545333	11.3
	2039				18.266667	11.3
	2040				17.988	11.3
	2041				17.709333	11.3
	2042				17.430667	11.3
	2043				17.152	11.3
	2044				16.873333	11.3
	2045				16.594667	11.3
	2046				16.316	11.3
	2047				16.037333	11.3
	2048				15.758667	11.3
	2049				15.48	11.3
	2050				15.201333	11.3
	2051				14.922667	11.3
	2052				14.644	11.3
	2053				14.365333	11.3
	2054				14.086667	11.3
	2055				13.808	11.3
	2056				13.529333	11.3

2057	13.250667	11.3
2058	12.972	11.3
2059	12.693333	11.3
2060	12.414667	11.3
2061	12.136	11.3
2062	11.857333	11.3
2063	11.578667	11.3
2064	11.3	11.3

URP 0.278667

28.02 baseline is from Missouri 5-year Progress Report. Improve SIA means spreadsheet did not have data for 2002-2005



Tab C:

Evidence of Adoption of the Plan into Administrative Orders

ARKANSAS
DEPARTMENT OF ENVIRONMENTAL QUALITY

In the Matter of:

LIS No. ________

Southwest Electric Power Company

Flint Creek Power Plant
2197 SWEPCO Plant Road
Gentry, AR 72734
AFIN: 04-00107

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 A.C.A. § 8-4-101 *et seq*. including Ark. Code Ann. § 8-4-311, which provides the Arkansas Department of Environmental Quality with the authority to "[m]ake, issue, modify, revoke, and enforce orders prohibiting, controlling, or abating air pollution[.]"ADEQ hereby enters this AO in order to satisfy the requirements associated with the Regional Haze Rule, 40 C.F.R. Subpart P, and 40 C.F.R. Part 51, Appendix Y.

FINDINGS OF FACT

1. AEP/SWEPCO owns and operates electric generating units in the state of Arkansas including Flint Creek Unit 1 (SN_01). AEP/SWEPCO is a corporation registered to do business in the state of Arkansas with its principal place of business in Columbus, Ohio.

2. On July 1, 1999, EPA published regulations to address visibility impairment in the nation's Class I areas. 64 Fed. Reg. 35714. On July 6, 2005, the EPA published an amendment to BART requirements included in the 1999 regulation. 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 1 areas covered by the Regional Haze Rule—Caney Creek Wilderness Area and the Upper Buffalo Wilderness Area -- exist in Arkansas.

4. In order to meet the requirements of the Regional Haze Rule, States must submit State Implementation Plans (SIP) implementing the requirements of the Regional Haze Rule to the U.S. EPA for approval. See id. The States were required to submit their SIPs prior to December 17, 2007. 40 C.F.R. § 51.308(b). Each regional-haze SIP 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. Arkansas is required under 40 C.F.R. § 51.308(e) to submit a SIP addressing BART requirements. This SIP must contain emission limits representing BART with schedules for compliance with BART or an Alternative to BART for each BART-eligible source that may reasonably be anticipated to cause or contribute to impairment of visibility in a Class 1 area.

7. 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). EPA has determined that an individual source will be considered to “contribute to visibility impairment” if emissions from the source result in a change in visibility, measured in deciviews (dv), that is greater than or equal to 0.5 dv in a Class I area. 40 C.F.R. Part 51, Appendix Y(III)(A)(1); 70 Fed. Reg. 39, 120. Visibility impact modeling indicates that the maximum predicted visibility impacts from the AEP/SWEPCO unit listed in Paragraph 7 above exceed the 0.5 deciview threshold at an Arkansas Class I Area. Therefore the unit listed in Paragraph 7 is subject-to-BART.

8. Current Arkansas Regional Haze regulations are located in APC&EC Regulation 19, Chapter 15. In APC&EC Regulation 19, Chapter 15, ADEQ identified Flint Creek Unit 1 (SN-01) as a BART-eligible and subject-to-BART source, and include the following BART requirements for Flint Creek:

   a. An emission rate for sulfur dioxide (SO_2) of 0.15 pounds per million British thermal unit (lb/mmBtu) on a 30-day rolling average;

   b. An emission rate for nitrogen oxides (NOx) of 0.23 lb/mmBtu on a 30-day rolling average; and

   c. The existing particulate matter (PM) emission rate of 0.1 lb/mmBtu based on emission testing conducted in accordance with EPA Methods 5 and 202.

9. On March 26, 2010, the Arkansas Pollution Control & Ecology Commission enacted a variance under Ark. Code Ann. § 8-4-313, Minute Order No. 10-08, which altered the compliance deadlines specified in APC&EC Reg. 19.1504(B). Minute Order No. 10-08, Docket No. 10-002-MISC. The variance states that the sources subject to BART listed in Regulation 19.1504(A) [are] granted a variance from the October 15, 2013 deadline, imposed by Regulation 19.1504(B), and, instead, the sources subject to BART shall be

required to comply with BART as expeditiously as practicable but in no event later than five (5) years after EPA approval of the Arkansas Regional Haze SIP."

10. On March 12, 2012, EPA finalized a rule partially approving and partially disapproving the Arkansas Regional Haze SIP. *Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze Implementation Plan; Interstate Transport Implementation Plan to Address Pollution Affecting Visibility and Regional Haze; Final Rule*, 77 Fed. Reg. 14,603 (March 12, 2012). With respect to Flint Creek Unit 1, EPA approved the BART determination for PM, but disapproved the BART determinations for SO_2 and NOx.

11. To facilitate preparation of a revised state implementation plan, AEP/SWEPCO prepared and submitted a report to ADEQ and EPA in December of 2012 entitled *Five Factor Analysis - Flint Creek Power Plant*, a copy of which is attached as Exhibit A. The report identifies available technologies for reducing emissions of SO_2 and NOx at Flint Creek Unit 1, examines the feasibility and cost-effectiveness of the available technologies considering the remaining useful life of the unit, evaluates their energy and non-air quality environmental impacts, and models the impacts on visibility at four nearby Class 1 areas. Based on consideration of all of these factors, the report recommends installation of a Novel Integrated Deacidification System (NIDS) to reduce emissions of SO_2 to 0.06 lb/mmBtu on a 30-day average basis, and participation in the ozone season CSAPR NOx budget program as BART for NOx, as provided in EPA's final rule *Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific BART Determinations, Limited SIP Disapprovals and Federal Implementation Plans*, 77 Fed. Reg. 33,651 (June 7, 2012).

12. On July 10, 2013, the Arkansas Public Service Commission determined in Docket No. 12-008-U that the installation of Dry Flue Gas Desulfurization with pulse jet fabric filter, a "dry scrubber", low NOx burners with overfire air, and activated charcoal injection to reduce emissions of sulfur dioxide and particulate matter was in the public interest. Installation of the dry scrubber and activated carbon injection system was completed in May of 2016.

13. On September 27, 2016, EPA finalized a federal implementation plan (FIP) containing BART requirements for Flint Creek Unit 1 and other subject-to-BART units in Arkansas. EPA's final action was the subject of petitions reconsideration and petitions for judicial review filed by ADEQ and the Environmental and Energy Alliance of Arkansas, of which AEP/SWEPCO is a member. Among other matters, the petitions challenged the compliance deadline established in the FIP.

14. On April 25, 2017, EPA issued notice of its intent to convene a proceeding to reconsider the Arkansas FIP.

15. AEP/SWEPCO and ADEQ agree that the deadlines set forth in this AO constitute compliance that is as expeditious as practicable within the meaning of Minute Order No. 10-08. Docket No. 10-002-MISC.

ORDER

WHEREFORE, ADEQ does hereby order as follows.

1. AEP/SWEPCO shall comply with all requirements set forth in this Order.

2. By no later than April 27, 2018, Flint Creek Unit 1 (SN-01) shall comply with BART for sulfur dioxide by meeting an emission limit of 0.06 pounds of sulfur dioxide per million British thermal units (0.06 lb/MMBtu) on a rolling 30-boiler-operating-day average.

3. By no later than effective date of this AO, Flint Creek Unit 1 (SN-01) shall comply with BART for particulate matter by meeting an emission limit of 0.10 pounds of particulate matter per million British thermal units (0.10 lb/MMBtu).

4. Compliance with the emission limits for SO_2 in this Administrative Order shall be determined by using data from a continuous emission monitoring system.

5. 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 the Arkansas Department of Environmental Quality.

6. Consistent with the Regional Haze Rule's "[r]equirements for comprehensive periodic revisions of implementation plans" for regional-haze at 40 CFR § 51.308(f), ADEQ may reopen the requirements of this CAO for consistency with long-term strategy and reasonable progress in future state implementation plan revisions, which are due in 2021, 2028 and every ten years thereafter to address advancement in technological control, changes in visibility conditions, or refinements in the assessment methodology.

7. Prior to the execution of any agreement for the transfer of ownership or operation of Flint Creek, AEP/SWEPCO shall provide notice of and a copy of this AO to the proposed transferee. No transfer of ownership or operation of any portion of Flint Creek shall relieve the AEP/SWEPCO of its obligation to ensure that the terms of the AO are implemented unless, at least 30 days prior to such transfer, AEP/SWEPCO 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 Flint Creek without complying with this Paragraph constitutes a violation of this AO.

8. Nothing contained in this AO shall relieve AEP/SWEPCO 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 AEP/SWEPCO of responsibilities contained in the permit.

9. If any provision or requirement of this Order is held illegal or unenforceable in a judicial proceeding, this provision or requirement shall severed and rendered inoperative, and the remaining provisions of this agreement shall continue to be binding on the parties.

10. This AO is effective upon execution by the Director of ADEQ.

    By virtue of the signature appearing below, the individual represents that he or she is either an Officer or authorized representative of AEP/SWEPCO.

SO ORDERED THIS _____ DAY OF __________, 2017.

____
Becky W. Keogh, Director
Arkansas Department of Environmental Quality

APPROVED AS TO FORM AND CONTENT:

Southwestern Power Company

By _________________________________
Its ___________________________
Date _________________________________

ARKANSAS
DEPARTMENT OF ENVIRONMENTAL QUALITY

In the Matter of:

LIS No. ________

ENTERGY ARKANSAS, INC.

White Bluff Facility
1100 White Bluff Road
Redfield, AR 72132
AFIN: 35-00110

Lake Catherine Facility
141 West County Line Road
Jones Mill, AR 72105
AFIN: 30-00011

Independence Facility
555 Point Ferry Rd.
Newark, AR 72203
AFIN: 31-00042

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, which provides the Arkansas Department of Environmental Quality (ADEQ) with the authority to "[m]ake, issue, modify, revoke, and enforce orders prohibiting, controlling, or abating air pollution[.]" ADEQ hereby enters this AO in order to satisfy the requirements associated with the Regional Haze Rule, 40 C.F.R. Subpart P, and 40 C.F.R. Part 51, Appendix Y.

FINDINGS OF FACT

1. Entergy Arkansas, Inc. (Entergy) 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 regulation. 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 in Arkansas areas are covered by the Regional Haze Rule: Caney Creek Wilderness Area (Caney Creek) and the Upper Buffalo Wilderness Area (Upper Buffalo).

4. In order to meet the requirements of the Regional Haze Rule, States must submit State Implementation Plans (SIP) implementing the requirements of the Regional Haze Rule to the U.S. EPA for approval. *id*. Each Regional Haze SIP 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. Arkansas is required under 40 C.F.R. § 51.308(e) to submit a SIP addressing BART requirements. This SIP must contain emission limits representing BART or an alternative to BART and schedules for compliance with BART for each BART-eligible source that may reasonably be anticipated to cause or contribute to impairment of visibility in a Class 1 area.

7. The following units are fossil fuel-fired steam electric plants with heat inputs greater than 250 MMBtu/hr; units that were in existence prior to August 7, 1977, but in operation after August 7, 1962; and, based on a review of existing emissions data, units that have the potential to emit more than 250 tons per year of a visibility impairing pollutant. Consequently the following four (4) units meet the definition of a BART-eligible source:

    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).

8. 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). U.S. EPA has determined that an individual source will be considered to "contribute to visibility impairment" if emissions from the source result in a change in visibility, measured in deciviews (dv), that is greater than or equal to 0.5 dv in a Class I area. 40 C.F.R. Part 51, Appendix Y(III)(A)(1); 70 Fed. Reg. 39, 120. Visibility impact modeling indicates that the maximum predicted visibility impacts from all four (4) of the Entergy units listed in Paragraph 7 above exceed the 0.5 deciview threshold at an Arkansas Class I Area. Therefore, all four units (4) listed in Paragraph 7 are subject-to-BART.

9. On August 18, 2017 Entergy provided to ADEQ a revised BART analysis emission rate of 0.6 lb/MMBtu based on burning low sulfur coal as BART. Based on information provided in Entergy's analysis, ADEQ determined that low sulfur coal constitutes BART for White Bluff Unit 1 (SN-01), White Bluff Unit 2 (SN-02), and White Bluff Auxiliary Boiler (SN-05).

10. The regional rule requires that each state submit a long-term strategy, which includes "emissions limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals established" by states with Class I Areas. 40 C.F.R. § 51.308(d)(3). The most recent available IMPROVE data has shown that Arkansas has surpassed its 2018 reasonable progress goals for Caney Creek and Upper Buffalo in the first planning period. ADEQ has determined that certain requirements on the following units are necessary to ensure that progress that has allowed Arkansas to exceed the reasonable progress goals for this planning period will continue into future planning periods:

    a. Independence Unit 1 (SN-01)

    b. Independence Unit 2 (SN-02)

11. The regional haze rule provides [r]equirements for comprehensive periodic revisions of implementation plans for regional-haze at 40 CFR § 51.308(f) in which each state, including Arkansas, must revise and submit its regional-haze implementation plan revision to EPA in 2021, 2028, "and every ten years thereafter."

ORDER

WHEREFORE, ADEQ does hereby order as follows.

1. Entergy shall comply with all requirements set forth in this Order.

2. As of the effective date of this AO, White Bluff Unit 1 (SN-01) and White Bluff Unit 2 (SN-02) shall comply with BART for particulate matter by meeting an emission limit of 0.10 pounds of particulate matter per million British thermal units (0.10 lb/MMBtu).

3. White Bluff Unit 1 (SN-01) and White Bluff Unit 2 (SN-02) shall comply with an emission limit of 0.6 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 and with Entergy's execution of its intended changes to operations at the White Bluff facility Units 1 and 2 indicated in their comments to EPA's federal implementation plan of Aug. 7, 2015 cited in their Petition for Reconsideration dated Nov. 23, 2015[1], no later than December 31, 2030.

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[1] Entergy Arkansas Inc. Petition for Reconsideration and Request for Stay of Entergy Arkansas Inc., at 6 (Nov. 23, 2015) (In re: Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan, EPA Docket No. EPA-R06-OAR-2015-0189) at p. 6 ("Entergy explicitly made such a commitment in its comments on the Proposed FIP: . . . 'As part of a multi-unit plan to

4. 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).

5. Independence Unit 1 (SN-01) and Independence Unit 2 (SN-02) shall comply with an emission limit of 0.6 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.

6. As of the effective date of this AO, Lake Catherine Unit 4 (SN-03) shall comply with BART for particulate matter by meeting an emission limit of 44.5 pounds of particulate matter per hour (44.5 lb/hr) on a thirty-boiler-operating-day rolling average.

7. As of the effective date of this AO, Lake Catherine Unit 4 (SN-03) shall burn only natural gas.

8. Compliance with the emission limits for SO_2 and NO_x in this Administrative Order shall be determined by using data from a continuous emission monitoring system.

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 the Arkansas Department of Environmental Quality.

10. Consistent with the Regional Haze Rule's "[r]equirements for comprehensive periodic revisions of implementation plans" for regional-haze at 40 CFR § 51.308(f), ADEQ may reopen the requirements of this CAO for consistency with long-term strategy and reasonable progress in future state implementation plan revisions, which are due in 2021, 2028 and every ten years thereafter to address advancement in technological control, changes in visibility conditions, or refinements in the assessment methodology.

11. Prior to the execution of any agreement for the transfer of ownership or operation of White Bluff, Lake Catherine, or Independence, Entergy shall provide notice of and a copy of this AO to the proposed transferee. No transfer of ownership or operation of any portion of White Bluff, Lake Catherine, or Independence shall relieve the Entergy of its obligation to ensure that the terms of the AO are implemented unless, at least 30 days prior to such transfer, Entergy 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

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*.'")(*citing* Entergy Arkansas Inc. Comments on the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas, at 5 (Aug. 7, 2015) (Docket ID No. EPA-R06-OAR-2015-0189-0153)) 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 White Bluff, Lake Catherine, or Independence without complying with this Paragraph constitutes a violation of this AO.

12. Nothing contained in this AO shall relieve Entergy 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 of responsibilities contained in the permit.

13. If any provision or requirement of this Order is held illegal or unenforceable in a judicial proceeding, the provision or requirement shall be severed and rendered inoperative, and the remaining provisions of this AO shall continue to be binding on the parties.

14. This AO is effective upon execution by the Director of ADEQ.

15. By virtue of the signature appearing below, the individual represents that he or she is either an Officer or authorized representative of Entergy.

SO ORDERED THIS _____ DAY OF __________, 2017.

____
Becky W. Keogh, Director
Arkansas Department of Environmental Quality

APPROVED AS TO FORM AND CONTENT:

Entergy Arkansas, Incorporated

By ________________________________
Its ___________________________
Date ________________________________

ARKANSAS
DEPARTMENT OF ENVIRONMENTAL QUALITY

In the Matter of:

LIS No. ________

Arkansas Electric Cooperative Corporation

Carl E. Bailey Generating Station
Highway 339 South
Augusta, AR 72006
AFIN: 74-00024

John L. McClellan Generating Station
1625 Bradley Ferry Road
Camden, AR 71701
AFIN: 52-00055

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 A.C.A. § 8-4-101 *et seq*. including Ark. Code Ann. § 8-4-311, which provides the Arkansas Department of Environmental Quality with the authority to "[m]ake, issue, modify, revoke, and enforce orders prohibiting, controlling, or abating air pollution[.]"ADEQ hereby enters this AO in order to satisfy the requirements associated with the Regional Haze Rule, 40 C.F.R. Subpart P, and 40 C.F.R. Part 51, Appendix Y.

FINDINGS OF FACT

1. AECC is an Arkansas corporation with its principal place of business in Little Rock, Arkansas.

2. On July 1, 1999, 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 BART requirements included in the 1999 regulation. 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 covered by the Regional Haze Rule—Caney Creek Wilderness Area and the Upper Buffalo Wilderness Area—exist in Arkansas.

4. In order to meet the requirements of the Regional Haze Rule, States must submit State Implementation Plans (SIP) implementing the requirements of the Regional Haze Rule to

the U.S. EPA for approval. See id. The States were required to submit their SIPs prior to December 17, 2007. 40 C.F.R. § 51.308(b). Each regional-haze SIP 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. Arkansas is required under 40 C.F.R. § 51.308(e) to submit a SIP addressing BART requirements. This SIP must contain emission limits representing BART with schedules for compliance with BART or an alternative to BART for each BART-eligible source that may reasonably be anticipated to cause or contribute to impairment of visibility in a Class I area.

7. Current Arkansas regional haze regulations are located in APC&EC Regulation 19, Chapter 15.

8. On March 26, 2010, the Arkansas Pollution Control & Ecology Commission enacted a variance under Ark. Code Ann. § 8-4-313, Minute Order No. 10-08, which altered the compliance deadlines specified in APC&EC Reg. 19.1504(B). Minute Order No. 10-08, Docket No. 10-002-MISC. The variance states that the sources subject to BART listed in Regulation 19.1504(A) [are] granted a variance from the October 15, 2013 deadline, imposed by Regulation 19.1504(B), and, instead, the sources subject to BART shall be required to comply with BART as expeditiously as practicable but in no event later than five (5) years after EPA approval of the Arkansas regional-haze SIP.

9. AECC and ADEQ agree that the deadlines set forth in this AO constitute compliance that is as expeditious as practicable within the meaning of Minute Order No. 10-08. Docket No. 10-002-MISC.

10. The following units are fossil fuel-fired steam electric plants with heat inputs greater than 250 MMBtu/hr; units that were in existence prior to August 7, 1977, but in operation after August 7, 1962; and, based on a review of existing emissions data, units that have the potential to emit more than 250 tons per year of a visibility impairing pollutant. Consequently the following two (2) units meet the definition of a BART-eligible source:

    a. Carl E. Bailey Generating Station Unit 1 and

    b. John L. McClellan Generating Station Unit 1.

11. 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). EPA has determined that an individual source will be considered to “contribute to visibility

impairment" if emissions from the source result in a change in visibility, measured in deciviews (dv), that is greater than or equal to 0.5 dv in a Class I area. 40 C.F.R. Part 51, Appendix Y(III)(A)(1); 70 Fed. Reg. 39, 120. Visibility impact modeling indicates that the maximum predicted visibility impacts from both of the AECC units listed in Paragraph 10 above exceed the 0.5 dv threshold at an Arkansas Class I Area. Therefore both units listed in Paragraph 10 are subject-to-BART.

12. In lieu of installing and operating BART, the federal rules provide that States may allow sources subject to BART to implement an alternative demonstrated to "achieve greater reasonable progress toward natural visibility conditions." 40 C.F.R. § 51.308(e). On June 7, 2012, EPA finalized revisions to the regional-haze program, which determined that the Cross-State Air Pollution Rule (CSAPR) achieved greater reasonable progress toward the national goal of achieving natural visibility conditions in Class I areas than source-specific BART. 77 Fed. Reg. 33642. On September 7, 2016, EPA finalized an update to CSAPR for the 2008 National Ambient Air Quality Standards for ozone. Arkansas EGUs including Carl E. Bailey Generating Station Unit 1 and John L. McClellan Generating Station Unit 1 are currently required by federal law to comply with CSAPR during the ozone season.

13. On July 12, 2017, ADEQ submitted a SIP revision, which addressed nitrogen oxide requirements for Arkansas EGUs including Carl E. Bailey Generating Station Unit 1 and John L. McClellan Generating Station Unit 1. Specifically, the SIP revision allows participation in CSAPR as an Alternative to Source-Specific BART for nitrogen oxides requirements. On September 11, 2017, EPA proposed to approve the CSAPR SIP Revision. 82 Fed. Reg. 42627.

ORDER

WHEREFORE, ADEQ does hereby order as follows:

1. AECC shall comply with all requirements set forth in this Order.

2. No later than October 27, 2021, Carl E. Bailey Generating Station Unit 1 and John L. McClellan Generating Station Unit 1 shall comply with BART for sulfur dioxide and particulate matter by burning only fuel that has 0.5% or less sulfur content by weight.

3. As of the effective date of this AO, AECC shall not purchase fuel for combustion at either Carl E. Bailey Generating Station Unit 1 or John L. McClellan Generating Station Unit 1 that does not meet the sulfur content limit in Paragraph 2.

4. To determine compliance with the sulfur dioxide and particulate matter requirements in paragraph two of the Order, AECC shall sample and analyze each shipment of fuel to determine the sulfur content by weight. All records pertaining to the sampling of each shipment of fuel must be maintained by AECC and made available upon request to ADEQ representatives.

5. 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 the Arkansas Department of Environmental Quality.

6. Consistent with the Regional Haze Rule's "[r]equirements for comprehensive periodic revisions of implementation plans" for regional-haze at 40 CFR § 51.308(f), ADEQ may reopen the requirements of this CAO for consistency with long-term strategy and reasonable progress in future state implementation plan revisions, which are due in 2021, 2028 and every ten years thereafter to address advancement in technological control, changes in visibility conditions, or refinements in the assessment methodology.

7. Prior to the execution of any agreement for the transfer of ownership or operation of the Carl E. Bailey Generating Station Unit 1 or John L. McClellan Generating Station Unit 1, AECC shall provide notice of and a copy of this AO to the proposed transferee. Transfer of ownership or operation of any portion of the Carl E. Bailey Generating Station Unit 1 or John L. McClellan Generating Station Unit 1 shall not relieve AECC of its obligation to ensure that the terms of the AO are implemented unless, at least 30 days prior to such transfer, AECC provides written notice of the prospective transfer to the 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 Carl E. Bailey Generating Station Unit 1 or John L. McClellan Generating Station Unit 1 without complying with this Paragraph constitutes a violation of this AO.

8. Nothing contained in this AO shall relieve AECC 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 AECC of responsibilities contained in the permit.

9. If any provision or requirement of this Order is held illegal or unenforceable in a judicial proceeding, the provision or requirement shall be severed and rendered inoperative, and the remaining provisions of this AO shall continue to be binding on the parties.

10. This AO is effective upon execution by the Director of ADEQ.

11. By virtue of the signature appearing below, the individual represents that he or she is either an Officer or authorized representative of AECC.

SO ORDERED THIS _____ DAY OF __________, 2017.

____

Becky W. Keogh, Director
Arkansas Department of Environmental Quality

APPROVED AS TO FORM AND CONTENT:

Arkansas Electric Cooperative Corporation

By ______________________________________
Its _______________________________
Date ______________________________________

Tab D:

Legal Authority to Adopt and Implement the Plan

State's Legal Authority to Adopt and Implement the Plan

The State's legal authority to adopt and implement this State Implementation Plan revision can be found in Arkansas Code Annotated (Ark. Code Ann.) §§ 8-1-203(b)(1), 8-4-311(a)(1), 8-4-317.

Ark. Code Ann. § 8-1-203

8-1-203. Powers and responsibilities of the Arkansas Pollution Control and Ecology Commission.

(a) The Arkansas Pollution Control and Ecology Commission shall meet regularly in publicly noticed open meetings to discuss and rule upon matters of environmental concern.

(b) The commission's powers and duties shall be as follows:

(1) (A) Promulgation of rules and regulations implementing the substantive statutes charged to the Arkansas Department of Environmental Quality for administration.

(B) In promulgation of such rules and regulations, prior to the submittal to public comment and review of any rule, regulation, or change to any rule or regulation that is more stringent than the federal requirements, the commission shall duly consider the economic impact and the environmental benefit of such rule or regulation on the people of the State of Arkansas, including those entities that will be subject to the regulation.

(C) The commission shall promptly initiate rulemaking proceedings to further implement the analysis required under subdivision (b)(1)(B) of this section.

(D) The extent of the analysis required under subdivision (b)(1)(B) of this section shall be defined in the commission's rulemaking required under subdivision (b)(1)(C) of this section. It will include a written report which shall be available for public review along with the proposed rule in the public comment period.

(E) Upon completion of the public comment period, the commission shall compile a rulemaking record or response to comments demonstrating a reasoned evaluation of the relative impact and benefits of the more stringent regulation;

(2) Promulgation of rules, regulations, and procedures not otherwise governed by applicable law that the commission deems necessary to secure public participation in environmental decision-making processes;

(3) Promulgation of rules and regulations governing administrative procedures for challenging or contesting department actions;

(4) In the case of permitting or grants decisions, providing the right to appeal a permitting or grants decision rendered by the Director of the Arkansas Department of Environmental Quality or his or her delegatee;

(5) In the case of an administrative enforcement or emergency action, providing the right to contest any such action initiated by the director;

(6) Instruct the director to prepare such reports or perform such studies as will advance the cause of environmental protection in the state;

(7) Make recommendations to the director regarding overall policy and administration of the department. However, the director shall always remain within the plenary authority of the Governor; and

(8) Upon a majority vote, initiate review of any director's decision.

(c) (1) In providing for adjudicatory review as contemplated by subdivisions (b)(4) and (5) of this section, the commission may appoint one (1) or more administrative hearing officers. The administrative hearing officers shall at all times serve as agents of the commission.

(2) In hearings upon appeals of permitting or grants decisions by the director or contested administrative enforcement or emergency actions initiated by the director, the administrative hearing officer shall administer the hearing in accordance with procedures adopted by the commission and, after due deliberation, submit his or her recommended decision to the commission.

(3) (A) (i) Commission review of any appealed or contested matter shall be upon the record compiled by the administrative hearing officer and his or her recommended decision.

(ii) Commission review shall be de novo. However, no additional evidence need be received unless the commission so decides in accordance with established administrative procedures.

(B) The commission may afford the opportunity for oral argument to all parties of the adjudicatory hearing.

(C) (i) By the majority vote of a quorum, the commission may affirm, reverse and dismiss, or reverse and remand to the director.

(ii) If the commission votes to affirm or reverse, such decision shall constitute final agency action for purposes of appeal.

(4) Any party aggrieved by the commission decision may appeal as provided by applicable law.

(d) The chair of the Arkansas Pollution Control and Ecology Commission may appoint one (1) or more committees composed of commission members to act in an advisory capacity to the full commission.

HISTORY: Acts 1991, No. 1230, § 1; 1993, No. 163, § 7; 1993, No. 165, § 7; 1993, No. 1264, § 2; 1995, No. 117, § 1.

Ark. Code Ann. § 8-4-311

8-4-311. Powers generally.

(a) The Arkansas Department of Environmental Quality or its successor shall have the power to:

(1) Develop and effectuate a comprehensive program for the prevention and control of all sources of pollution of the air of this state;

(2) Advise, consult, and cooperate with other agencies of the state, political subdivisions, industries, other states, the federal government, and with affected groups in the furtherance of the purposes of this chapter;

(3) Encourage and conduct studies, investigations, and research relating to air pollution and its causes, prevention, control, and abatement as it may deem advisable and necessary;

(4) Collect and disseminate information relative to air pollution and its prevention and control;

(5) Consider complaints and make investigations;

(6) Encourage voluntary cooperation by the people, municipalities, counties, industries, and others in preserving and restoring the purity of the air within the state;

(7) Administer and enforce all laws and regulations relating to pollution of the air;

(8) Represent the state in all matters pertaining to plans, procedures, or negotiations for interstate compacts in relation to air pollution control;

(9) **(A)** Cooperate with and receive moneys from the federal government or any other source for the study and control of air pollution.

(B) The department is designated as the official state air pollution control agency for such purposes;

(10) Make, issue, modify, revoke, and enforce orders prohibiting, controlling, or abating air pollution and requiring the adoption of remedial measures to prevent, control, or abate air pollution;

(11) Institute court proceedings to compel compliance with the provisions of this chapter and rules, regulations, and orders issued pursuant to this chapter;

(12) Exercise all of the powers in the control of air pollution granted to the department for the control of water pollution under §§ 8-4-101 -- 8-4-106 and 8-4-201 -- 8-4-229; and

(13) Develop and implement state implementation plans provided that the commission shall retain all powers and duties regarding promulgation of rules and regulations under this chapter.

(b) The Arkansas Pollution Control and Ecology Commission shall have the power to:

(1) **(A)** Promulgate rules and regulations for implementing the substantive statutes charged to the department for administration.

(B) In promulgation of such rules and regulations, prior to the submittal to public comment and review of any rule, regulation, or change to any rule or regulation that is more stringent than federal requirements, the commission shall duly consider the economic impact and the environmental benefit of such rule or regulation on the people of the State of Arkansas, including those entities that will be subject to the regulation.

(C) The commission shall promptly initiate rulemaking to further implement the analysis required under subdivision (b)(1)(B) of this section.

(D) The extent of the analysis required under subdivision (b)(1)(B) of this section shall be defined in the commission's rulemaking required under subdivision (b)(1)(C) of this section. It will include a written report that shall be available for public review along with the proposed rule in the public comment period.

(E) Upon completion of the public comment period, the commission shall compile a rulemaking record or response to comments demonstrating a reasoned evaluation of the relative impact and benefits of the more stringent regulation;

(2) Promulgate rules, regulations, and procedures not otherwise governed by applicable law that the commission deems necessary to secure public participation in environmental decision-making processes;

(3) Promulgate rules and regulations governing administrative procedures for challenging or contesting department actions;

(4) In the case of permitting or grants decisions, provide the right to appeal a permitting or grants decision rendered by the Director of the Arkansas Department of Environmental Quality or his or her delegatee;

(5) In the case of an administrative enforcement or emergency action, providing the right to contest any such action initiated by the director;

(6) Instruct the director to prepare such reports or perform such studies as will advance the cause of environmental protection in the state;

(7) Make recommendations to the director regarding overall policy and administration of the department, provided, however, that the director shall always remain within the plenary authority of the Governor;

(8) Upon a majority vote, initiate review of any director's decision;

(9) Adopt, after notice and public hearing, reasonable and nondiscriminatory rules and regulations requiring the registration of and the filing of reports by persons engaged in operations that may result in air pollution;

(10) (A) Adopt, after notice and public hearing, reasonable and nondiscriminatory rules and regulations, including requiring a permit or other regulatory authorization from the department, before any equipment causing the issuance of air contaminants may be built, erected, altered, replaced, used, or operated, except in the case of repairs or maintenance of equipment for which a permit has been previously used, and revoke or modify any permit issued under this chapter or deny any permit when it is necessary, in the opinion of the department, to prevent, control, or abate air pollution.

(B) A permit shall be issued for the operation or use of any equipment or any facility in existence upon the effective date of any rule or regulation requiring a permit if proper application is made for the permit.

(C) No such permit shall be modified or revoked without prior notice and hearing as provided in this section.

(D) Any person that is denied a permit by the department or that has such permit revoked or modified shall be afforded an opportunity for a hearing in connection therewith upon written application made within thirty (30) days after service of notice of such denial, revocation, or modification.

(E) The operation of any existing equipment or facility for which a proper permit application has been made shall not be interrupted pending final action thereon.

(F) (i) An applicant or permit holder that has had a complete application for a permit or for a modification of a permit pending longer than the time specified in the state regulations promulgated pursuant to Title V of the Clean Air Act Amendments of 1990, or any person that participated in the public participation process, and any other person that could obtain judicial review of such actions under state laws, may petition the commission for relief from department inaction.

(ii) The commission will either deny or grant the petition within forty-five (45) days of its submittal.

(iii) For the purposes of judicial review, either a commission denial or the failure of the department to render a final decision within thirty (30) days after the commission has granted a petition shall constitute final agency action;

(11) (A) Establish through its rulemaking authority, either alone or in conjunction with the appropriate state or local agencies, a system for the banking and trading of air emissions designed to maintain both the state's attainment status with the national ambient air quality standards mandated by the Clean Air Act and the overall air quality of the state.

(B) The commission may consider differential valuation of emission credits as necessary to achieve primary and secondary national ambient air quality standards, and may consider establishing credits for air pollutants other than those designated as criteria air pollutants by the United States Environmental Protection Agency.

(C) Any regulation proposed pursuant to this authorization shall be reported to the House Interim Committee on Public Health, Welfare, and Labor and the Senate Interim Committee on Public Health, Welfare, and Labor or appropriate subcommittees thereof prior to its final promulgation; and

(12) In the case of a state implementation plan, provide the right to appeal a final decision rendered by the Director of the Arkansas Department of Environmental Quality or his or her delegate under § 8-4-317.

HISTORY: Acts 1949, No. 472, [Part 2], § 5, as added by Acts 1965, No. 183, § 7; A.S.A. 1947, § 82-1935; Acts 1993, No. 994, § 1; 1995, No. 895, § 4; 1997, No. 179, § 1; 1997, No. 1219, § 6; 1999, No. 1164, § 31; 2013, No. 1302, §§ 2, 3.

Ark. Code Ann. § 8-4-317

8-4-317. State implementation plans generally.

(a) In developing and implementing a state implementation plan, the Arkansas Department of Environmental Quality shall consider and take into account the factors specified in § 8-4-312 and the Clean Air Act, 42 U.S.C. § 7401 et seq., as applicable.

(b) (1) (A) Whenever the department proposes to finalize a state implementation plan submittal for review and approval by the United States Environmental Protection Agency, it shall cause notice of its proposed action to be published in a newspaper of general circulation in the state.

(B) The notice required under subdivision (b)(1)(A) of this section shall afford any interested party at least thirty (30) calendar days in which to submit comments on the proposed state implementation plan submittal in its entirety.

(C) (i) In the case of any emission limit, work practice or operational standard, environmental standard, analytical method, air dispersion modeling requirement, or monitoring requirement that is incorporated as an element of the proposed state implementation plan submittal, the record of the proposed action shall include a written explanation of the rationale for the proposal, demonstrating the reasoned consideration of the factors in § 8-4-312 as applicable, the need for each measure in attaining or maintaining the National Ambient Air Quality Standards, and that any requirements or standards are based upon generally accepted scientific knowledge and engineering practices.

(ii) For any standard or requirement that is identical to an applicable federal regulation, the demonstration required under subdivision (b)(1)(C)(i) of this section may be satisfied by reference to the regulation. In all other cases, the department shall provide its own justification with appropriate reference to the scientific and engineering literature considered or the written studies conducted by the department.

(2) (A) At the conclusion of the public comment period and before transmittal to the Governor for submittal to the United States Environmental Protection Agency, the department shall provide written notice of its final decision regarding the state implementation plan submittal to all persons who submitted public comments.

(B) (i) The department's final decision shall include a response to each issue raised in any public comments received during the public comment period. The response shall manifest reasoned consideration of the issues raised by the public comments and shall be supported by appropriate legal, scientific, or practical reasons for accepting or rejecting the substance of the comment in the department's final decision.

(ii) For the purposes of this section, response to comments by the department should serve the roles of both developing the record for possible judicial review of a state implementation plan decision and serving as a record for the public's review of the department's technical and legal interpretations on long-range regulatory issues.

(iii) This section does not limit the department's authority to raise all relevant issues of regulatory concern upon adjudicatory review by the Arkansas Pollution Control and Ecology Commission of a particular state implementation plan decision.

(c) **(1)** Only those persons that submit comments on the record during the public comment period have standing to appeal the final decision of the department to the commission upon written application made within thirty (30) days after service of the notice under subdivision (b)(2)(A) of this section.

(2) An appeal under subdivision (c)(1) of this section shall be processed as a permit appeal under § 8-4-205. However, the decision of the Director of the Arkansas Department of Environmental Quality shall remain in effect during the appeal.

HISTORY: Acts 2013, No. 1302, § 4.

Tab E

Consultations and Public Participation

<u>FLM Consultation:</u>
-Notification of proposed SIP Revision

<u>Consultation with States</u>
-Notification of proposed SIP Revision

<u>Public Participation:</u>
-Public Notice Information and Public Hearing Documentation

ADEQ
ARKANSAS
Department of Environmental Quality

October 27, 2017

Tim Allen, Meteorologist / Modeler
U.S. Fish and Wildlife Service
National Wildlife Refuge System
Branch of Air Quality
7333 W Jefferson Ave., Suite 375
Lakewood, CO 80235-2017

RE: Arkansas Regional Haze State Implementation Plan

Dear Mr. Allen:

This letter serves to notify you that ADEQ has prepared a revision to the Arkansas Regional Haze State Implementation Plan (SIP) to address all remaining disapproved portions of the SIP with the exception of NOx requirements for electric generating units which were addressed in our July 8, 2017 proposal and BART requirements for Domtar Ashdown Mill.

This notification is intended to provide your agency with an opportunity for a sixty-day consultation period on this SIP revision in accordance with 40 C.F.R. § 51.308(i). This consultation will give you the opportunity to discuss—by conference call, in person, and/or in writing— your assessment of the impact of the proposed revisions on Class I areas impacted by Arkansas sources.

Notice of the public hearing and public comment period will be published in the Arkansas Democrat Gazette and posted to the ADEQ Regional Haze webpage (https://www.adeq.state.ar.us/air/planning/sip/regional-haze.aspx) providing, at minimum, a thirty-day public comment period.

A pre-proposal copy of the SIP revision and the draft notice of public hearing have been included with this letter. Should changes be made to the SIP revision prior to proposal, we will send an updated draft. We expect that any such changes would not impact the control strategy included in the SIP and the resulting visibility improvements expected at Class I areas.

Written comments should be mailed to Tricia Treece, Office of Air Quality, Arkansas Department of Environmental Quality, 5301 Northshore Drive, North Little Rock, AR 72118. Electronic comments should be sent to: treecep@adeq.state.ar.us.

Should you have any questions, please contact Will Montgomery at 501-692-0885 (montgomery@adeq.state.ar.us) or Tricia Treece at 501-682-0055 (treecep@adeq.state.ar.us).

Sincerely,

Stuart Spencer
Associate Director
Office of Air Quality

Enclosures

ADEQ
ARKANSAS
Department of Environmental Quality

October 27, 2017

Cherie Hamilton, Forest Supervisor
U.S. Forest Service
Ozark/St. Francis: Upper Buffalo Wilderness Area
605 West Main Street
Russellville, AR 72801

RE: Arkansas Regional Haze State Implementation Plan

Dear Forest Supervisor Hamilton:

This letter serves to notify you that ADEQ has prepared a revision to the Arkansas Regional Haze State Implementation Plan (SIP) to address all remaining disapproved portions of the SIP with the exception of NOx requirements for electric generating units which were addressed in our July 8, 2017 proposal and BART requirements for Domtar Ashdown Mill.

This notification is intended to provide your agency with an opportunity for a sixty-day consultation period on this SIP revision in accordance with 40 C.F.R. § 51.308(i). This consultation will give you the opportunity to discuss—by conference call, in person, and/or in writing— your assessment of the impact of the proposed revisions on Class I areas impacted by Arkansas sources.

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Should you have any questions, please contact Will Montgomery at 501-692-0885 (montgomery@adeq.state.ar.us) or Tricia Treece at 501-682-0055 (treecep@adeq.state.ar.us).

Sincerely,

Stuart Spencer
Associate Director
Office of Air Quality

Enclosures

ADEQ

ARKANSAS

Department of Environmental Quality

October 27, 2017

Pat Brewer
Regulatory, Policy, Smoke Management
NPS Air Resources Division
P.O. Box 25287
Denver, CO 80225-0287

RE: Arkansas Regional Haze State Implementation Plan

Dear Ms. Brewer:

This letter serves to notify you that ADEQ has prepared a revision to the Arkansas Regional Haze State Implementation Plan (SIP) to address all remaining disapproved portions of the SIP with the exception of NOx requirements for electric generating units which were addressed in our July 8, 2017 proposal and BART requirements for Domtar Ashdown Mill.

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Should you have any questions, please contact Will Montgomery at 501-692-0885 (montgomery@adeq.state.ar.us) or Tricia Treece at 501-682-0055 (treecep@adeq.state.ar.us).

Sincerely,

Stuart Spencer
Associate Director
Office of Air Quality

Enclosures

ARKANSAS DEPARTMENT OF ENVIRONMENTAL QUALITY
5301 NORTHSHORE DRIVE / NORTH LITTLE ROCK / ARKANSAS 72118-5317
TELEPHONE 501-682-0744 / FAX 501-682-0880 / www.adeq.state.ar.us

ADEQ
A R K A N S A S
Department of Environmental Quality

October 27, 2017

Sherri Schwenke
U.S. Forest Service
Mark Twain Forest: Hercules Glade Wilderness Area
401 Fairgrounds Road
Rolla, MO 65401

RE: Arkansas Regional Haze State Implementation Plan

Dear Ms. Schwenke:

This letter serves to notify you that ADEQ has prepared a revision to the Arkansas Regional Haze State Implementation Plan (SIP) to address all remaining disapproved portions of the SIP with the exception of NOx requirements for electric generating units which were addressed in our July 8, 2017 proposal and BART requirements for Domtar Ashdown Mill.

This notification is intended to provide your agency with an opportunity for a sixty-day consultation period on this SIP revision in accordance with 40 C.F.R. § 51.308(i). This consultation will give you the opportunity to discuss—by conference call, in person, and/or in writing— your assessment of the impact of the proposed revisions on Class I areas impacted by Arkansas sources.

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Should you have any questions, please contact Will Montgomery at 501-692-0885 (montgomery@adeq.state.ar.us) or Tricia Treece at 501-682-0055 (treecep@adeq.state.ar.us).

Sincerely,

Stuart Spencer
Associate Director
Office of Air Quality

Enclosures

ADEQ
ARKANSAS
Department of Environmental Quality

October 27, 2017

Norm Wagoner, Forest Supervisor
U.S. Forest Service
Ouachita: Caney Creek Wilderness Area
P.O. Box 1270
Hot Springs, AR 71902

RE: Arkansas Regional Haze State Implementation Plan

Dear Forest Supervisor Wagoner:

This letter serves to notify you that ADEQ has prepared a revision to the Arkansas Regional Haze State Implementation Plan (SIP) to address all remaining disapproved portions of the SIP with the exception of NOx requirements for electric generating units which were addressed in our July 8, 2017 proposal and BART requirements for Domtar Ashdown Mill.

This notification is intended to provide your agency with an opportunity for a sixty-day consultation period on this SIP revision in accordance with 40 C.F.R. § 51.308(i). This consultation will give you the opportunity to discuss—by conference call, in person, and/or in writing— your assessment of the impact of the proposed revisions on Class I areas impacted by Arkansas sources.

Notice of the public hearing and public comment period will be published in the Arkansas Democrat Gazette and posted to the ADEQ Regional Haze webpage (https://www.adeq.state.ar.us/air/planning/sip/regional-haze.aspx) providing, at minimum, a thirty-day public comment period.

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Written comments should be mailed to Tricia Treece, Office of Air Quality, Arkansas Department of Environmental Quality, 5301 Northshore Drive, North Little Rock, AR 72118. Electronic comments should be sent to: treecep@adeq.state.ar.us.

Should you have any questions, please contact Will Montgomery at 501-692-0885 (montgomery@adeq.state.ar.us) or Tricia Treece at 501-682-0055 (treecep@adeq.state.ar.us).

Sincerely,

Stuart Spencer
Associate Director
Office of Air Quality

Enclosures

ADEQ
ARKANSAS
Department of Environmental Quality

October 27, 2017

Kyra Moore
Air Pollution Control Program Director
Missouri Department of Natural Resources
P.O. Box 176
Jefferson City, Missouri 65102

RE: Arkansas Regional Haze State Implementation Plan

Dear Director Moore:

This letter serves to notify you that ADEQ has prepared a revision to the Arkansas Regional Haze State Implementation Plan (SIP) to address all remaining disapproved portions of the SIP with the exception of NOx requirements for electric generating units which were addressed in our July 8, 2017 proposal and BART requirements for Domtar Ashdown Mill.

This notification is intended to provide your agency with an opportunity for consultation on this SIP revision in accordance with 40 CFR § 51.308(d)(3)(i). This consultation will give you the opportunity to discuss—by conference call, in person, and/or in writing—your assessment of the impact of the proposed revisions on reasonable progress in Class I areas in your state.

Notice of the public hearing and public comment period will be published in the Arkansas Democrat Gazette and posted to the ADEQ Regional Haze webpage (https://www.adeq.state.ar.us/air/planning/sip/regional-haze.aspx) providing, at minimum, a thirty day public comment period.

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Should you have any questions, please contact Will Montgomery at 501-692-0885 (montgomery@adeq.state.ar.us) or Tricia Treece at 501-682-0055 (treecep@adeq.state.ar.us).

Sincerely,

Stuart Spencer
Associate Director
Office of Air Quality

Enclosures

Arkansas Department of Environmental Quality

Public Notice

The Arkansas Department of Environmental Quality (ADEQ) is publishing this Public Notice to provide interested persons the opportunity to comment on ADEQ's proposed state implementation plan (SIP) revision.

In this SIP proposal, Arkansas has included revisions to address disapproved portions of the Arkansas Regional Haze State Implementation Plan (AR RH SIP), submitted to EPA in 2008 and to replace emission emission limits for Arkansas subject-to-BART power plants and Entergy Independence included in the 2016 rule "Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Final Rule" (AR RH FIP). This SIP revises Arkansas's reasonable progress goals and Arkansas's long-term strategy for the first Regional Haze planning period ending in 2018.

ADEQ will hold a public hearing on Tuesday, January 2, 2017 to receive public comments on the SIP revision. The public hearing will begin at 2:00 p.m. in the Commission Room at the Arkansas Department of Environmental Quality headquarters building, 5301 Northshore Drive, North Little Rock, AR 72118. In the event of inclement weather or other unforeseen circumstances, a decision may be made to postpone the hearing. If the hearing is postponed and rescheduled, a new legal notice will be published to announce the details of the new hearing date and comment period.

ADEQ will accept written and electronic comments received by no later than 4:30 p.m. (Central Time) on Tuesday, January 2, 2017. Written comments should be mailed to Tricia Treece, Office of Air Quality, Arkansas Department of Environmental Quality, 5301 Northshore Drive, North Little Rock, AR 72118. Electronic comments should be sent to: treecep@adeq.state.ar.us.

A copy of Arkansas's proposed SIP revision is available for public inspection during normal business hours at the Office of Communications in the ADEQ headquarters building in North Little Rock. In addition, Arkansas's SIP revision is available for viewing or downloading on ADEQ's website at: https://www.adeq.state.ar.us/air/planning/sip/regional-haze.aspx. Public libraries hosting ADEQ information depositories will also be available to assist interested persons in accessing the SIP from ADEQ's website. These information depositories are located in public libraries at Arkadelphia, Batesville, Blytheville, Camden, Clinton, Crossett, El Dorado, Fayetteville, Forrest City, Fort Smith, Harrison, Helena, Hope, Hot Springs, Jonesboro, Little Rock, Magnolia, Mena, Monticello, Mountain Home, Pocahontas, Russellville, Searcy, Stuttgart, Texarkana, and West Memphis; in campus libraries at the University of Arkansas at Pine Bluff and the University of Central Arkansas at Conway; and in the Arkansas State Library, 900 W. Capitol, Suite 100 in Little Rock.

ADEQ
ARKANSAS
Department of Environmental Quality

October 27, 2017

Dear Information Depository Librarian:

Please assist the Arkansas Department of Environmental Quality by assisting the public with accessing the materials relevant to the enclosed notice via Arkansas Department of Environmental Quality's web page: https://www.adeq.state.ar.us/air/planning/sip/regional-haze.aspx. The information concerns proposed changes to the Arkansas state implementation plan.

The proposed changes are subject to public comment until January 2, 2017. These documents may be removed from the depository after January 2, 2017.

Thank you for your continued service as an information depository for the Arkansas Department of Environmental Quality. If you have any questions, please contact me by telephone at 501-682-0916, or by e-mail at Robinson@adeq.state.ar.us.

Kindest regards,

Kelly Robinson

Public Information Officer

Enclosures