**STATE OF ARKANSAS**
ASA HUTCHINSON
GOVERNOR

August 13, 2019

Ken McQueen
Regional Administrator
United States EPA Region VI

Submitted via SPeCS for SIPs

Re: Regional Haze State Implementation Plan Revision; Federal Implementation Plan Withdrawal Request

Dear Mr. McQueen:

The State of Arkansas hereby respectfully submits to the United States Environmental Protection Agency (EPA) Revisions to the Arkansas State Implementation Plan (SIP) for approval. Arkansas requests that EPA review and approve this SIP revision. We request, based on this approval, that EPA fully withdraw the 2016 rule "Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Final Rule."

The enclosed SIP revision is intended to address approved and disapproved SIP provisions pertaining to the Domtar Ashdown Mill (Ashdown Mill) in the Arkansas Regional Haze SIP, which was submitted to the EPA in 2008. Enforceable emissions limitations and compliance schedules determined necessary to meet regional haze program requirements under 40 CFR § 51.308 and Clean Air Act § 169 have been implemented through the permit for Ashdown Mill.

This SIP package is being submitted electronically through the State Planning Electronic Collaboration System (SPeCS) for SIPs web-based system in accordance with 40 CFR 51.103(a). Should questions arise, please contact the Arkansas Division of Environmental Quality 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 this submission.

Sincerely,

Asa Hutchinson,

Enclosures

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STATE OF ARKANSAS

# Revisions to the Arkansas State Implementation Plan

## Phase III Regional Haze SIP Revision for 2008–2018 Planning Period

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

August 2019

Arkansas Division of Environmental Quality
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## I. Introduction

### A. Arkansas State Implementation Plan Revision

Arkansas has included in this state implementation plan (SIP) submission revisions to address approved and disapproved SIP provisions pertaining to Domtar Ashdown Mill (Ashdown Mill) in the Arkansas Regional Haze State Implementation Plan (AR RH SIP), which was submitted to the United States Environmental Protection Agency (EPA) in 2008. In 2012, EPA partially approved and partially disapproved the 2008 AR RH SIP, including the following provisions pertaining to Ashdown Mill:[1]

- PM best available retrofit technology (BART) determination for Ashdown Mill Power Boiler No. 1 was approved;
- $SO_2$ and NOx BART determinations for Ashdown Mill Power Boiler No. 1 were disapproved; and
- $SO_2$, NOx, and PM BART determinations for Ashdown Mill Power Boiler No. 2 were disapproved.
- Long-term strategy as it applies to the disapproved BART determinations for the Ashdown Mill

In this SIP, Arkansas is revising all of the prior determinations for Ashdown Mill Power Boiler No. 1 and Power Boiler No. 2 included in the 2008 AR RH SIP.

### B. Arkansas SIP Components Included in this Revision

The Arkansas Division of Environmental Quality (ADEQ), formerly the Arkansas Department of Environmental Quality, is submitting the following conditions from the Ashdown Mill Permit as of the permit effective date, August 1, 2019, of the permit revision 0287-AOP-R22 in this SIP revision:

- Plantwide Condition # 32
- Plantwide Condition # 33
- Plantwide Condition # 34
- Plantwide Condition # 35
- Plantwide Condition # 36
- Plantwide Condition # 37
- Plantwide Condition # 38
- Plantwide Condition # 39
- Plantwide Condition # 40
- Plantwide Condition # 41

[1] *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)

- Plantwide Condition # 42
- Plantwide Condition # 43

ADEQ requests that EPA (i) approve these conditions into the SIP, (ii) withdraw from the SIP the previously approved PM limit for Ashdown Mill Power Boiler No. 1, and (iii) withdraw the AR RH FIP requirements for Ashdown Mill.

Inclusion of permanently enforceable emissions limitations and compliance schedules in the included permit 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 are necessary for this SIP revision.

## 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.

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.

**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, which 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.[2] 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.

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 for electric generating units.[3] In 2017, EPA has also finalized amendments to regulatory requirements for state regional haze plans for the second planning period and beyond.[4] EPA has also announced it will be revising certain aspects of the 2017 amendments.

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.[5] 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);
- BART-eligible sources and subject-to-BART sources other than Georgia Pacific Crossett Mill;
- 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

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

[3] *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).

[4] *Protection of Visibility: Amendments to Requirements for State Plans* (82 FR 3078, January 10, 2017)

[5] *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)

    - PM determination for 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;
- Determination that Georgia Pacific Crossett Mill units were not subject-to-BART;
- 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 Ashdown Mill Power Boiler No. 1; and
    - $SO_2$, NOx, and PM BART determinations for 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).[6] This FIP established new BART requirements for those sources whose BART determinations in the 2008 AR RH SIP were disapproved. The FIP also required the installation of controls at Entergy Independence Units 1 and 2. Despite the previous disapproval of ADEQ's determination in the 2008 AR RH SIP that Georgia Pacific Crossett Mill Boiler 6A and 9A did not cause or contribute to visibility impairment in a Class I area, EPA reversed its decision and concurred with ADEQ that Georgia Pacific Crossett Mill Boiler 6A and 9A are not subject to BART.

On November 22, 2016, the State of Arkansas filed a Petition for Reconsideration and Administrative Stay of the AR RH FIP. In the petition, the State of Arkansas requested that EPA

[6] *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)

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 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 November 22, 2016, Domtar filed a Petition for Reconsideration of the AR RH FIP provisions relevant to Ashdown Mill. The petition was based on an analysis performed by Domtar demonstrating that the FIP controls were not reasonably anticipated to achieve improvements in visibility.

Domtar also filed a Petition for Review with the United States Court of Appeals for the Eighth Circuit. Similar to the Arkansas petition described below, the Domtar petition is being held in abeyance by the Court pending the current efforts to develop a SIP replacement to the 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 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.[7] ADEQ finalized the NOx Regional Haze SIP on October 31, 2017. EPA finalized approval of the NOx Regional Haze SIP on February 12, 2018.[8]

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. Subsequent abeyance Orders were issued by the Court.

On October 31, 2017, ADEQ proposed a second SIP revision (Phase II Regional Haze SIP) to address the remaining disapproved SIP elements, with the exception of requirements for Ashdown Mill. ADEQ submitted the final Phase II SIP to EPA on August 9, 2018.

This Phase III SIP revision is intended to only address requirements for Ashdown Mill and to replace requirements for Ashdown Mill in the AR RH FIP and the 2008 AR RH SIP with the requirements included in this SIP revision. ADEQ is not revising to either the NOx Regional Haze SIP or Phase II Regional Haze SIP with this SIP revision.

## III. Domtar Industries, Inc. Ashdown Mill Analyses and Requirements

Two power boilers at Ashdown Mill were determined to be subject to BART in the 2008 AR RH SIP: Power Boiler No. 1 and Power Boiler No. 2. Power Boiler No. 1 was installed in 1967–68 and has a design heat input rate of 580 MMBtu/hr. Power Boiler No. 1 was previously capable of burning a variety of fuels including bark, wood waste, tire-derived fuel, municipal yard waste, pelletized paper fuel, fuel oil, reprocessed fuel oil and natural gas; however, Power Boiler No. 1 is currently restricted by permit to burning natural gas. Power Boiler No. 2 was installed in 1975 and has a design heat input rate of 820 MMBtu/hr. Power Boiler No. 2 is capable of burning a

[7] *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)
[8] *Air Quality State Implementation Plans; Approvals and Promulgations: Arkansas; Approval of Regional Haze State Implementation Plan Revision for Nitrogen Oxide for Electric Generating Units in Arkansas* (83 FR 5927, February 12, 2018)

variety of fuels including clean cellulosic biomass, coal, tire-derived fuel, natural gas, wood chips used to absorb oil for energy recovery and petroleum coke.

Ashdown Mill Power Boiler No. 1 and Power Boiler No. 2 were determined to be subject to BART in the 2008 AR RH SIP based on modeling performed using a 2001–2003 emissions baseline. Therefore, the five BART statutory factors were evaluated for each boiler. A summary of the BART analyses performed and emission limit determinations, both the EPA-approved emission limit from the 2008 AR RH SIP and those emission limits established in the AR RH FIP, are included in Section III.A. On March 20, 2018, Domtar provided information to ADEQ regarding an alternative to BART that would achieve greater visibility improvements than the BART controls included in the AR RH FIP. On September, 5, 2018, Domtar provided to ADEQ a revised proposed BART Alternative for consideration by ADEQ to accommodate potential further changes in operation at the Ashdown Mill. Section III.B of this SIP summarizes the revised BART Alternative submission.

### A. Summary of BART Determinations for Ashdown Mill

Based on BART analyses (dated October 2006 and March 2007), ADEQ determined in the 2008 AR RH SIP emission limits for Ashdown Mill Power Boiler No. 1 and Power Boiler No. 2. The PM BART limit for Ashdown Mill Power Boiler No. 1 was approved by EPA; however, EPA disapproved the other emission limits for Ashdown Mill included in the 2008 AR RH SIP.[9] In the AR RH FIP, EPA promulgated $SO_2$ and NOx emission limits for Power Boiler No. 1 and $SO_2$, NOx, and PM emission limits for Power Boiler No. 2 based on the 2006 and 2007 analyses, and a revised BART analysis (dated May 2014).[10] The BART limits for Ashdown Mill included in the AR RH FIP and the approved PM BART limit for Power Boiler No. 1 included in the 2008 AR RH SIP are listed in the table below.

**Table 1 EPA-Approved SIP and FIP BART Emission Limits for Ashdown Mill**

| Unit | $SO_2$ Emission Limit | NOx Emission Limit | Final PM emission limit |
|---|---|---|---|
| Ashdown Mill Power Boiler No. 1 | 504 lb/day | 207.4 lb/hr | 0.07 lb/MMBtu |

[9] *Approval and Promulgation of Implementation Plans; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan to Address Pollution Affecting Visibility and Regional Haze.* (77 FR 14604, March 12, 2012). See Docket No. EPA–R06–OAR–2008–0727 for the approved PM BART analysis for Power Boiler No.1.

[10] *Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Final Rule* (81 FR 66332, September 27, 2016). See "AR020.0002-00 TSD for EPA's Proposed Action on the AR RH FIP" in Docket No. EPA-R06-OAR-2015-0189 for the FIP BART analysis for SO2 and NOx BART for Power Boiler No. 1 and SO2, NOx, and PM BART for Power Boiler No. 2.

| | | | |
|---|---|---|---|
| Ashdown Mill Power Boiler No. 2 | 91.5 lb/hr | 345 lb/hr | Satisfied by reliance on applicable PM standard under 40 CFR part 63, subpart DDDDD |

Table 2 provides the cumulative visibility improvement predicted for each Class I area impacted by Arkansas sources—Caney Creek Wilderness Area (CACR), Upper Buffalo Wilderness Area (UPBU), Mingo Wildlife Refuge (MING), and Hercules Glades (HEGL)—based on CALPUFF modeling of the control scenario contained in Table 1 following method 2 as described below.

**Table 2 Method 2 Cumulative Visibility Improvement Due to BART SIP and FIP Controls for Ashdown Mill**

| Description | BART 98th Percentile Visibility Impacts – Max of Three Modeled Years (Δdv) | | | |
|---|---|---|---|---|
| | CACR | UPBU | HEGL | MING |
| Baseline | 1.137 | 0.163 | 0.118 | 0.072 |
| Control Scenario | 0.776 | 0.103 | 0.057 | 0.038 |
| Calculated Improvement | 0.361 | 0.060 | 0.061 | 0.034 |
| Cumulative Improvement | 0.516 | | | |

ADEQ has determined that visibility benefits contained in Table 2 associated with 2008 AR RH SIP and AR RH FIP BART control scenario for Ashdown Mill contained in Table 1 form an appropriate BART benchmark for the purposes of the evaluation of Domtar's BART alternative proposal.

**B. Ashdown Mill BART Alternative**

On March 20, 2018, Domtar provided to ADEQ a proposed BART alternative based on boiler operational changes, fuel switching and repurposing of Ashdown Mill to produce fluff paper. On September 5, 2018, Domtar proposed to ADEQ a revised BART alternative responsive with new emission limits and modeling that would accommodate potential further changes in operation at the Ashdown Mill. Domtar's revised BART Alternative Analysis is included with this SIP revision. Table 3 contains the modeled emission rates for the alternative to BART. Domtar's revised BART Alternative Analysis for Domtar is included with this SIP revision. The BART alternative emissions reductions are based on operational changes for Domtar and are surplus to reductions required to meet other Clean Air Act requirements as of the 2000–2004 baseline of 2008 AR RH SIP, as revised by Arkansas.

**Table 3 BART Alternative Emission Rates**

| Unit | Modeled Emission Rates | | |
|---|---|---|---|
| | $SO_2$ (lb/hr) | NOx (lb/hr) | PM (lb/hr) |
| Power Boiler No. 1 on natural gas only | 0.5 | 191.10 | 5.2 |

| | | | |
|---|---|---|---|
| Power Boiler No. 2 at adjusted emission rates for $SO_2$ and NOx | 435 | 293 | 81.6 |

Domtar provided two methods for evaluation of the revised BART Alternative. Method 1 assesses visibility impairment on a per source per pollutant basis and does not account for the full chemical interactions of emissions from the two units. Method 1 was performed to create a direct comparison with the approach EPA used in the AR RH FIP. In Method 2, all sources and pollutants are combined into a single modeling run per year. In Method 2, the baseline and control scenarios for BART from the AR RH FIP were remodeled. Comparisons of the cumulative and average visibility improvement across affected Class I areas anticipated from the revised proposed BART Alternative to the cumulative visibility improvement anticipated from the FIP BART limits are included in Table 4 for Method 1 and Table 5 for Method 2.

**Table 4 Method 1 Comparison of Cumulative Visibility Improvement**

| Description | BART 98th Percentile Visibility Impacts – Max of Three Modeled Years (Δdv) | | | | | | BART Alternative 98th Percentile Visibility Impacts – Max of Three Modeled Years (Δdv) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Unit | Pollutant | CACR | UPBU | HEGL | MING | Unit | Pollutant | CACR | UPBU | HEGL | MING |
| Baseline | 1 | Both | 0.335 | 0.038 | 0.020 | 0.014 | 1 | Both | 0.335 | 0.038 | 0.020 | 0.014 |
| | 2 | Both | 0.844 | 0.146 | 0.105 | 0.065 | 2 | Both | 0.844 | 0.146 | 0.105 | 0.065 |
| | Both | Both | 1.179 | 0.184 | 0.125 | 0.079 | Both | Both | 1.179 | 0.184 | 0.125 | 0.079 |
| Control Scenario | 2 | $SO_2$ | 0.524 | 0.082 | 0.046 | 0.035 | 1 | Both | 0.286 | 0.033 | 0.017 | 0.011 |
| | 2 | $NO_X$ | | | | | 2 | Both | 0.493 | 0.082 | 0.059 | 0.037 |
| | 2 | Both | 0.524 | 0.082 | 0.046 | 0.035 | Both | Both | 0.779 | 0.115 | 0.076 | 0.048 |
| Calculated Improvement | 2 | $SO_2$ | 0.139 | 0.050 | 0.048 | 0.025 | 1 | Both | 0.049 | 0.005 | 0.003 | 0.003 |
| | 2 | $NO_X$ | 0.181 | 0.014 | 0.011 | 0.005 | 2 | Both | 0.351 | 0.064 | 0.046 | 0.028 |
| | 2 | Both | 0.320 | 0.064 | 0.059 | 0.030 | Both | Both | 0.400 | 0.069 | 0.049 | 0.031 |
| Cumulative Improvement | Both | Both | 0.473 | | | | Both | Both | 0.549 | | | |
| Average Improvement | Both | Both | 0.118 | | | | Both | Both | 0.137 | | | |

**Table 5 Method 2 Comparison of Cumulative Visibility Improvement**

| Description | BART 98th Percentile Visibility Impacts – Max of Three Modeled Years (Δdv) | | | | BART Alternative 98th Percentile Visibility Impacts – Max of Three Modeled Years (Δdv) | | | |
|---|---|---|---|---|---|---|---|---|
| | CACR | UPBU | HEGL | MING | CACR | UPBU | HEGL | MING |
| Baseline | 1.137 | 0.163 | 0.118 | 0.072 | 1.137 | 0.163 | 0.118 | 0.072 |
| Control Scenario | 0.776 | 0.103 | 0.057 | 0.038 | 0.753 | 0.104 | 0.069 | 0.044 |
| Calculated Improvement | 0.361 | 0.060 | 0.061 | 0.034 | 0.384 | 0.059 | 0.049 | 0.028 |
| Cumulative Improvement | 0.516 | | | | 0.520 | | | |
| Average Improvement | 0.129 | | | | 0.130 | | | |

**C. ADEQ's Evaluation of the Ashdown Mill BART Alternative**

Under 40 C.F.R. § 51.308(e)(2), a state "may opt to implement or require participation in an emissions trading program *or other alternative measure* rather than to require sources subject to BART to install, operate, and maintain BART."

The RHR requires the following three elements for any alternative to BART:

(1) A demonstration that the emissions trading program or other alternative measure will achieve greater reasonable progress than would have resulted from the installation and operation of BART at all sources subject to BART in the State and covered by the alternative program.[11]

(2) A requirement that all necessary emissions reductions take place during the period of the first long-term strategy for regional haze.[12]

(3) A demonstration that the emissions reductions resulting from the alternative measure will be surplus to those reductions resulting from measures adopted to meet requirements of the CAA as of the baseline date of the SIP.[13]

ADEQ has evaluated the Ashdown Mill BART Alternative with respect to each of the three alternative to BART elements listed in 40 CFR 51.308(e)(2) and has determined that the proposed BART Alternative described in Section III.B. is an acceptable alternative to the BART limitations described in Section III.A. An explanation of how each of the elements is satisfied by the Ashdown Mill BART Alternative is provided below.

[11] 40 CFR 51.308(e)(2)(i)
[12] 40 CFR 51.308(e)(2)(iii)
[13] 40 CFR 51.308(e)(2)(iv)

1. Demonstration that the Alternative Measure will Achieve Greater Reasonable Progress

Pursuant to 40 CFR 51.308(e)(2)(i), an alternative to BART must achieve greater progress than would have resulted from installation and operation of BART at all sources subject to BART in the State and covered by the alternative program. This demonstration must be based on five criteria, which are addressed below.

a. A list of all BART-eligible sources within the State

A list of all BART-eligible sources within the State was submitted to EPA in the 2008 AR RH SIP. This list was corrected in the SIP narrative of the 2018 Phase II Regional Haze SIP revision. No changes to the list of BART-eligible sources within Arkansas are necessary for this SIP revision.

b. A list of all BART-eligible sources and all BART source categories covered by the alternative program

Ashdown Mill is the sole source covered by the BART alternative proposed by Domtar. All other BART-eligible sources and units in the State have been addressed in separate submissions.[14]

c. Analysis of BART and associated emission reductions

The 2008 AR RH SIP, the PM BART emission limit for Power Boiler No. 1 and the AR RH FIP BART emission limits for Power Boiler No. 1 and Power Boiler No. 2 were based on BART five-factor analyses that are summarized in Section III.A. of this SIP and included with this SIP revision.[15] Table 6 compares annual emissions based on maximum baseline emissions rates to the emission limits for BART included in Table 1.

[14] 2008 AR RH SIP, 2017 NOx Regional Haze SIP, 2018 Phase II Regional Haze SIP

[15] ADEQ considers BART as specified in Table 1 of page 8 and 9 to be appropriate for the purposes of the alternative to BART evaluation specific in 40 CFR §51.308(e)(2)(i)(C)-(D). The BART analyses underlying these limits are included with this SIP revision.

**Table 6 Comparison of Baseline[16] and BART[17] Emission Reductions Based on Baseline Maximum Actual 24-Hour Emissions (Power Boiler No. 1 and Power Boiler No. 2 Total)**

| | NOx (tpy) | PM (tpy) | $SO_2$ (tpy) |
|---|---|---|---|
| Baseline | 3216 | 491 | 3544 |
| BART | 2420 | 537[18] | 493 |
| Emission Reduction | 796 | -46 | 3052 |

d. Analysis of projected emission reductions achievable through the BART Alternative

ADEQ has calculated emissions reductions achievable through the BART Alternative by comparing estimated annual emissions under the BART Alternative scenario with baseline emissions based on maximum baseline emission rates.[19] Table 7 compares the annual emissions based on maximum baseline emissions rates to the estimated annual emissions under the BART Alternative.

**Table 7 Comparison of Baseline[19] and BART Alternative Emission Reductions (Power Boiler No. 1 and Power Boiler No. 2 Total for BART Alternative Operating Scenario)**

| | NOx (tpy) | PM (tpy) | $SO_2$ (tpy) |
|---|---|---|---|
| Baseline | 3216 | 491 | 3544 |
| BART Alternative | 2120 | 380 | 1907 |
| Emission Reduction | 1096 | 111 | 1637 |

e. Determination that the alternative achieves greater reasonable progress than would be achieved through the installation and operation of BART

Pursuant to 40 CFR 51.308(e)(2)(i)(E), ADEQ must determine whether an alternative to BART achieves greater reasonable progress based on the requirements set forth in 40 C.F.R. § 51.308(e)(3) or otherwise based on a clear weight of evidence that the alternative measure achieves greater reasonable progress than would be achieved through installation and operation

[16] 2009-2011 for Power Boiler No. 1 and 2001-2003 for Power Boiler No. 2, per TSD for EPA's Proposed Action on the Arkansas Regional Haze Federal Implementation Plan (February 2015)

[17] Annual emissions estimates for BART are based on the sum of hourly emission rates for Power Boiler No. 1 and Power Boiler No. 2 multiplied by 8760 hours. These rates are based on the PM BART limit for Power Boiler No. 1 from the 2008 AR RH SIP and the BART limits from the 2016 AR RH FIP (See Spreadsheet Domtar_Comparison TPY Emission Calculations included with this SIP revision)

[18] This value is based on a permit limit of 0.1 lb/MMBtu for Power Boiler No. 2, which is more stringent than the EPA FIP limit of 0.44 lb/MMBtu.

[19] Annual emissions estimates under the BART Alternative Scenarios are based on the sum of hourly emission rates for Power Boiler No. 1 and Power Boiler No. 2 multiplied by 8760 hours.

of BART at the covered sources. 40 C.F.R. § 51.308(e)(3) provides two tests for determining whether an alternative achieves greater visibility progress than BART:

> (1) If the distribution of emissions is not substantially different than under BART, and the alternative measure results in greater emission reductions, then the alternative measure may be deemed to achieve greater reasonable progress.
>
> (2) If the distribution of emissions is significantly different, the State must conduct dispersion modeling to determine differences in visibility between BART and the trading program or alternative measure for each impacted Class I area, for the worst and best twenty percent of days. The modeling would demonstrate "greater reasonable progress" if both of the following two criteria are met: visibility does not decline in any Class I area, and there is an overall improvement in visibility, determined by comparing the average differences between BART and the alternative over all affected Class I areas.

Based on the data provided by Domtar in their Ashdown Mill BART Alternative Analysis, ADEQ has performed a weight-of-evidence (WOE) analysis to determine whether the Ashdown Mill satisfies the requirements of 51.308(e)(2)(i)(E). This WOE analysis is based on a comparison of emissions under the BART control scenario and the BART Alternative scenario as well as a modified modeling analysis based on 98th percentile impacts of the BART benchmark versus the BART alternative on affected Class I areas.

The distribution of emissions is substantially different in the BART Alternative scenario than under BART scenario for Ashdown Mill. As indicated in Tables 6 and 7, The NOx reduction under the BART Alternative is greater than would be achieved under the BART scenario. The $SO_2$ emission reduction for the BART Alternative would be less than would be achieved under the BART scenario. The PM emission reduction for the BART Alternative would be greater than would be achieved by the BART scenario.

In the revised BART Alternative Technical Support Document, Domtar provided CALPUFF dispersion modeling based on the 98th percentile visibility impacts. This modeling approach differs from the modeling contemplated under 40 CFR 51.308(e)(3); however, the approach is consistent with the BART Guidelines recommendations for comparing control alternatives at a single source and is appropriate for the comparison of the proposed BART alternative to BART for Ashdown Mill. Domtar provided two methods for the modeling evaluation of the revised BART Alternative. Method 1 assesses visibility impairment on a per source per pollutant basis and does not account for the full chemical interactions of emissions from the two units. Method 1 was performed to create a direct comparison with the approach EPA used in the AR RH FIP. In Method 2, all sources and pollutants are combined into a single modeling run per year. In Method 2, the baseline and control scenarios for BART from the AR RH FIP were remodeled.

The modeling results for both methods demonstrate that the Ashdown Mill BART Alternative would result in greater cumulative visibility improvement for the 98th percentile visibility impacts at Class I areas impacted by Arkansas sources than the AR RH FIP BART emission limits. Table 4 and Table 5 in Section III.B. compare the cumulative visibility improvement anticipated from the BART Alternative to the cumulative visibility improvement anticipated from AR RH FIP BART controls. ADEQ notes that the Class I area where Ashdown Mill has historically had the greatest impact on visibility, CACR, would also experience greater visibility improvement under the BART Alternative scenario than under the BART scenario. Ashdown Mill's baseline, BART scenario, and BART Alternative scenario 98th percentile visibility impacts on the other three affected Class I areas—UPBU, MING, and HEGL—are all smaller than ADEQ's screening threshold of 0.5 dv used for determining whether a source is subject to BART.

The modeling results for both methods also demonstrate that visibility would not decline from the baseline at any of the affected Class I areas as a result of the Ashdown Mill BART Alternative and that the cumulative visibility improvement under the BART Alternative is greater than would be achieved under the BART scenario for Ashdown Mill. The average visibility improvement across affected areas would also be greater under the BART Alternative than under the FIP emission limits for Ashdown Mill based on both methods. Because Method 2 provides a more accurate account of the chemical interaction of emissions from Ashdown Mill Power Boiler No. 1 and 2; ADEQ places more weight on the Method 2 results. Nevertheless, ADEQ finds that Method 1, which also shows greater cumulative and average visibility improvements across affected Class I areas, is also a valid method for comparison of the visibility impacts between the BART Alternative and BART limits for Ashdown Mill consistent with the methodology used in the AR RH FIP. Therefore, ADEQ concludes based on the weight of evidence that the BART Alternative would achieve greater reasonable progress than would be achieved through the installation and operation of BART.

In addition, the BART analysis performed for Ashdown Mill is based, in part, on an assessment of the same factors that must be assessed under reasonable progress requirements set forth at 40 CFR 51.308(f)(2)(i). EPA's 2007 Reasonable Progress Guidance instructs state that "it is reasonable to conclude that any control requirements imposed in the BART determination also satisfy [reasonable progress goals]-related requirements for source review in the first [reasonable progress goals] planning period." Because the requirements under the Ashdown Mill BART Alternative result in greater visibility progress than the BART emission limits determined by EPA and the EPA-approved BART PM limit for Ashdown Mill, ADEQ concludes that no further analysis of controls for reasonable progress beyond the Ashdown Mill BART Alternative is necessary.

2. Requirement that Emission Reductions Take Place during the Period of the First Long-Term Strategy

Pursuant to 40 CFR 51.308(e)(2)(iii), all necessary emission reductions for a BART alternative must take place during the period of the first long-term strategy for the Regional Haze Program.

On December 20, 2018, Domtar submitted a letter[20] to ADEQ demonstrating that Ashdown Mill has been in compliance with the emission limits proposed in the October 5, 2018 draft SIP revision since December of 2016. Domtar has subsequently submitted records[21] demonstrating compliance with the emission limits on a monthly basis until the limits became state enforceable through issuance of a minor modification letter[22] from ADEQ to Domtar on February 28, 2019.[23] The minor modification letter was sent to Domtar pursuant to a minor modification application that Domtar submitted to ADEQ on January 30, 2019. Domtar's minor modification application included proposed conditions that would incorporate the emission limits proposed in the Phase III SIP Revision, along with monitoring, recordkeeping, and reporting requirements, into the permit for Ashdown Mill.

The final permit revision incorporating these limits, 0287-AOP-R22 was effective August 1, 2019.

3. Demonstration that Emissions Reductions from the BART Alternative will be Surplus

Pursuant to 40 CFR 51.308(e)(2)(iv), the emissions reductions resulting from the BART alternative must be surplus to those reductions resulting from measures adopted to meet requirements of the Clean Air Act as of the baseline date of the SIP. The BART alternative emissions reductions are based on changes in operational scenarios for Domtar and are surplus to reductions required to meet other Clean Air Act requirements as of the 2000–2004 baseline of 2008 AR RH SIP, as revised by Arkansas.

## IV. Long-Term Strategy

ADEQ did not propose changes to elements of the long-term strategy in this SIP revision with the exception of the inclusion of enforceable limitations and compliance schedules for Domtar Ashdown Mill. ADEQ finds that the BART Alternative for Domtar has a negligible impact on the reasonable progress goals previously established in the 2018 Regional Haze Phase II SIP; therefore, ADEQ is not changing these goals in this SIP revision.[24]

### A. Enforceable Limitations and Compliance Schedules for Ashdown Mill

The plantwide conditions of Domtar's permit for Ashdown Mill included with this SIP revision requires compliance by Domtar with the emission limits contained in Table 8.

[20] See Documentation of Compliance with Phase III SIP Emission Limits included with this SIP revision.
[21] See Documentation of Compliance with Phase III SIP Emission Limits included with this SIP revision.
[22] See Minor Modification Letter included with this SIP revision.
[23] Under APC&EC Reg. 26.1007, "a source may make the change proposed in its minor permit modification application upon receipt of written notification from the Department." After the source makes the proposed change and until the Department takes action on the minor modification application, the source "must comply with both the applicable requirements governing the change and the proposed permit terms and conditions."
[24] See Phase III SIP Rev RPG Spreadsheet included with this SIP revision.

**Table 8 Emission Limitations for Ashdown Mill**

| Unit | $SO_2$ (lb/hr) | NOx (lb/hr) | PM (lb/hr) |
|---|---|---|---|
| Power Boiler No. 1 | 0.5 | 191.10 | 5.2 |
| Power Boiler No. 2 | 435 | 293 | 81.6 |

Ashdown Mill Power Boilers No. 1 and 2 have been complying with the emission limits contained since at least December 2016. These limits became state enforceable immediately upon issuance of a minor modification letter sent to Domtar on February 28, 2019.[25]

The specific monitoring, recordkeeping, and reporting requirements for compliance with the alternative to BART are specified in the following conditions of permit 0287-AOP-R22, which have been included with this SIP submission:

- Plantwide Condition # 32
- Plantwide Condition # 33
- Plantwide Condition # 34
- Plantwide Condition # 35
- Plantwide Condition # 36
- Plantwide Condition # 37
- Plantwide Condition # 38
- Plantwide Condition # 39
- Plantwide Condition # 40
- Plantwide Condition # 41
- Plantwide Condition # 42
- Plantwide Condition # 43

**B. Federal Land Manager Consultation**

In accordance with the provisions of 40 C.F.R. § 51.308(i)(2), ADEQ gave FLMs the opportunity to discuss their assessment of the impact of the proposed SIP revisions on Arkansas Class I areas——Upper Buffalo Wilderness Area and Caney Creek Wilderness Area—and other Class I areas.

On August 9, 2018 ADEQ submitted letters to notify the FLM staff of this proposed SIP revision and to provide them with electronic access to the revision and related documents. No comments were received from the FLMs.

[25] See Minor Modification Letter included with this SIP revision.

## 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 August 9, 2018 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. No comments were received from Missouri DNR.

## D. Public Review

On October 5, 2018, ADEQ proposed this Phase III SIP revision. The Phase III SIP proposal sought comment on including the alternative emission limits—as well as monitoring, recordkeeping, and reporting requirements—in an Administrative Order. Notice of this proposal was published in the Arkansas Democrat Gazette, which is a newspaper in circulation statewide, and was posted on ADEQ's website concurrent with newspaper publication. The notice provided information on how to access a copy of the Phase III SIP revision, submit comments, and request a public hearing. The public hearing, if requested, was to be held on November 5, 2018 and the public comment period ended on November 5, 2018. No public hearing was requested by the date specified in the notice (October 19, 2018); therefore, no hearing was held.

During the public comment period for the Phase III SIP proposal, ADEQ received comments from Domtar Ashdown Mill requesting that the State not finalize the proposal or the associated administrative order. On a December 17, 2018 conference call with ADEQ, EPA Headquarters, EPA Region 6, and Domtar; Domtar indicated that the BART alternative could be an agreeable approach for Ashdown Mill if the SIP revision submitted specific permit conditions instead of an administrative order. On December 20, 2018, Domtar submitted a letter to ADEQ demonstrating that Ashdown Mill has been in compliance with the emission limits proposed in the October 5, 2018 draft SIP revision since December of 2016 and has subsequently submitted records demonstrating compliance with the emission limits on a monthly basis. On January 30, 2019, Domtar submitted a minor modification application that included proposed conditions that would incorporate the emission limits proposed in the Phase III SIP Revision, along with monitoring, recordkeeping, and reporting requirements, into the permit for Ashdown Mill. On February 28, 2019. ADEQ issued a minor modification letter to Domtar to allow Domtar to begin implementing the proposed changes included in the minor modification application. On April 2, 2019, ADEQ sent Domtar a draft permit for public notice. Public notice of the draft permit was published in Democrat Gazette on April 7, 2019.

ADEQ issued a supplemental proposal to seek comment on changing the type of enforcement mechanism for the alternative emission limits to be submitted for inclusion in the SIP. ADEQ did not reopen or seek comment on any other aspect of the Phase III SIP proposal. Notice of the supplemental proposal was published in the Arkansas Democrat Gazette and posted on ADEQ's website concurrent with newspaper publication. The notice provided information on how to access a copy of the Phase III SIP revision and supplemental proposal, how to submit comments, and logistical information for the public hearing. The public hearing was held at ADEQ headquarters in North Little Rock on May 21, 2019 and the public comment period ended on May 21, 2019.

Both oral and written comments received by ADEQ during the public comment periods were 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 have been included in this final SIP package.

## V. <u>Conclusion</u>

ADEQ requests that EPA review and approve this SIP revision as expeditiously as possible and withdraw emission limitations for Domtar Ashdown Mill Power Boiler Nos. 1 and 2 from the AR RH FIP. In addition, ADEQ requests that EPA replace the previously-approved BART emission limits for Domtar Power Boiler No. 1 included in the 2008 AR RH SIP with the emission limitations included in this SIP revision.

With the NOx Regional Haze SIP submission, the Phase II SIP submission, and this Phase III SIP submission, ADEQ has addressed all disapproved elements of the 2008 AR RH SIP. Therefore, ADEQ requests that EPA fully withdraw the AR RH FIP upon approval of this Phase III SIP submission.

# ADEQ
# OPERATING
# AIR PERMIT

Pursuant to the Regulations of the Arkansas Operating Air Permit Program, Regulation 26:

Permit No. : 0287-AOP-R22

IS ISSUED TO:

Domtar A.W. LLC - Ashdown Mill
285 Highway 71 South
Ashdown, AR 71822
Little River County
AFIN: 41-00002

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:

October 18, 2016 AND October 17, 2021

THE PERMITTEE IS SUBJECT TO ALL LIMITS AND CONDITIONS CONTAINED HEREIN.

Signed:

AUG - 1 2019

Stuart Spencer
Associate Director, Office of Air Quality

Date

## Regional Haze Program (BART Alternative) Specific Conditions

### No. 1 Power Boiler (SN-03)
### Source Description

For compliance with the Clean Air Act Regional Haze Program's requirements for the first planning period, the No. 1 Power Boiler (SN-03)  is subject to a best available retrofit technology (BART) Alternative measures consistent with 40 C.F.R. § 51.308. The following terms and conditions of the BART Alternative measures are to be submitted to EPA for approval as part of the Arkansas State Implementation Plan (SIP). Upon initial EPA approval of this section of the permit into the SIP, the permittee shall continue to be subject to the conditions as approved into the SIP even if the conditions below are revised as part of a permit amendment until such time as EPA approves any revised conditions into the SIP. The permittee shall remain subject to both the initial SIP-approved conditions and the revised conditions, until EPA approves the revised conditions.

### Source Conditions

32. The permittee shall not exceed the emission rates set forth in the following table. The limits are based on a 30 boiler operating day rolling average. 30 boiler operating day rolling average is defined as the arithmetic average of 30 consecutive daily values in which there is any hour of operation, and where each daily value is generated by summing the pounds of pollutant for that day and dividing the total by the sum of the hours the boiler was operating that day. A day is from 6 am one calendar day to 6 am the following calendar day.

[Reg.19.304, 40 C.F.R. §51.308(e)(2), and 40 C.F.R. §52.173]

| SN | Source Name | Pollutant | Lb/hr* |
|---|---|---|---|
| 03 | No. 1 Power Boiler (580 MMBtu/hr) | $PM_{10}$ | 5.2 |
| | | $SO_2$ | 0.5 |
| | | $NO_X$ | 191.1 |

*- These limits are for a 30 boiler operating day rolling average as defined in PW condition 32.

33. For SN-03. compliance with the $PM_{10}$, $SO_2$, and $NO_X$ emission limits shall be demonstrated based on natural gas fuel usage records and the following emission factors:

    a) 7.6 lb-$PM_{10}$/mmscf

    b) 0.6 lb-$SO_2$/mmscf

    c) 280 lb-$NO_X$/mmscf

    [Reg.19.304, 40 C.F.R. §51.308(e)(2), and 40 C.F.R. §52.173]

34. In the event SN-03 (No. 1 Power Boiler) is permanently retired, the BART Alternative limits and conditions applicable to SN-03 shall be satisfied by the permanent retirement of SN-03 and ADEQ receipt of a disconnection notice for SN-03. [Reg.19.304 , 40 C.F.R. §51.308(e)(2), and 40 C.F.R. §52.173]

35. The permittee may request that the Department approve an alternative sampling or monitoring method to the methods specified in plantwide conditions 32 through 34. The Department, with the concurrence of EPA, may approve, at its discretion an alternative method if the alternative sampling or monitoring method is equivalent to the methods specified in plantwide conditions 32 through 34. [Reg 19.304, 40 C.F.R. §51.173 and 40 C.F.R. §51.308(e)(2)]

36. The permittee shall keep records showing compliance with plantwide conditions 32 through 35. All records showing compliance with plantwide conditions 32 through 35 shall be retained for at least 5 years and shall be made available to any agent of ADEQ or EPA upon request. [Reg.19.304, 40 C.F.R. §51.308(e)(2), and 40 C.F.R. §52.173]

**No. 2 Power Boiler (SN-05)**
**Source Description**

For compliance with the Clean Air Act Regional Haze Program's requirements for the first planning period No. 2 Power Boiler (SN-05) is subject to a best available retrofit technology (BART) Alternative measures consistent with 40 C.F.R. § 51.308. The following terms and conditions of the BART Alternative measures are to be submitted to EPA for approval as part of the Arkansas State Implementation Plan (SIP). Upon initial EPA approval of this section of the permit into the SIP, the permittee shall continue to be subject to the conditions as approved into the SIP even if the conditions below are revised as part of a permit amendment until such time as EPA approves any revised conditions into the SIP. The permittee shall remain subject to both the initial SIP-approved conditions and the revised conditions, until EPA approves the revised conditions."

**Source Conditions**

37. The permittee shall not exceed the emission rates set forth in the following table. The limits are based on a 30-day boiler operating day rolling average. 30 boiler operating day rolling average is defined as the arithmetic average of 30 consecutive daily values in which there is any hour of operation, and where each daily value is generated by summing the pounds of pollutant for that day and dividing the total by the sum of the hours the boiler was operating that day. A day is from 6 am one calendar day to 6 am the following calendar day. [Reg.19.304, 40 C.F.R. §51.308(e)(2), and 40 C.F.R. §52.173]

| SN | Source Name | Pollutant | Lb/hr* |
|---|---|---|---|
| 05 | No. 2 Power Boiler (820 MMBtu/hr) | $PM_{10}$ | 81.6 |
| | | $SO_2$ | 435 |
| | | $NO_X$ | 293 |

*- These limits are for a 30 boiler operating day rolling average as defined in PW condition 37.

38. For SN-05, the permittee shall demonstrate compliance with the 30 boiler operating day rolling average $SO_2$ and $NO_X$ limits utilizing a continuous emissions monitor (CEMS) subject to 40 CFR Part 60, as amended. [Reg.19.304, 40 C.F.R. §51.308(e)(2), and 40 C.F.R. §52.173]

39. In the event SN-05 (No. 2 Power Boiler) is permanently retired, the BART Alternative limits and conditions applicable to SN-05 shall be satisfied by the permanent retirement of SN-05 and ADEQ receipt of a disconnection notice for SN-05. [Reg.19.304, 40 C.F.R. §51.308(e)(2), and 40 C.F.R. §52.173]

40. If SN-05 (No. 2 Power Boiler) only combusts natural gas, the applicable natural gas AP-42 emission factors shall be used to demonstrate compliance, in conjunction with natural gas fuel usage records. [Reg.19.304, 40 C.F.R. §51.308(e)(2), and 40 C.F.R. §52.173]

41. While SN-05 (No. 2 Power Boiler) is subject to 40 CFR Part 63 subpart DDDDD (5D), the applicable $PM_{10}$ compliance demonstration requirements from 5D shall be utilized to demonstrate compliance for $PM_{10}$ emissions. [Reg.19.304, 40 C.F.R. §51.308(e)(2), and 40 C.F.R. §52.173]

42. The permittee may request that the Department approve an alternative sampling or monitoring method to the methods specified in plantwide conditions 37 through 41. The

Department, with the concurrence of EPA, may approve, at its discretion an alternative method if the alternative sampling or monitoring method is equivalent to the methods specified in plantwide conditions 37 through 41. [Reg 19.304, 40 C.F.R. §51.173 and 40 C.F.R. §51.308(e)(2)]

43. The permittee shall keep records showing compliance with plantwide conditions 37 through 42. All records showing compliance with plantwide conditions 37 through 42 shall be retained for at least 5 years and shall be made available to any agent of ADEQ or EPA upon request. [Reg.19.304, 40 C.F.R. §51.308(e)(2), and 40 C.F.R. §52.173]

## 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.

**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 replace emission limits applicable to Domtar Ashdown Mill included in the 2008 Arkansas Regional Haze State Implementation Plan (AR RH SIP) and in EPA's 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).

ADEQ will accept written and electronic comments received by no later than 4:30 p.m. on Monday, November 5, 2018. 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: airplancomments@adeq.state.ar.us.

A member of the public may request a hearing. If a hearing request is received by 4:30 p.m. on October 15, 2018, ADEQ will hold a public hearing at 10:00 am on Monday, November 5, 2018 to receive public comments on the SIP revision. The public hearing, if held, will be located in the Commission Room at the Arkansas Department of Environmental Quality headquarters building, 5301 Northshore Drive, North Little Rock, AR 72118.

If no request is received by the deadline, ADEQ will not hold the public hearing and ADEQ will announce the cancellation of the hearing on its website at https://www.adeq.state.ar.us/air/planning/sip/regional-haze.aspx by 4:30 pm on October 19, 2018. If a public hearing is requested, but inclement weather or unforeseen circumstances require ADEQ to postpone the hearing, ADEQ will post this decision on the same web page. To request a public hearing or to find out whether the public hearing has been cancelled, please contact Tricia Treece by email at treecep@adeq.state.ar.us or by phone at 501-682-0084

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.

# Arkansas Democrat Gazette

STATEMENT OF LEGAL ADVERTISING

ADEQ/FISCAL DIVISION
5301 NORTHSHORE DR
NORTH LITTLE ROCK AR 72118

ATTN: Jake Harper
DATE : 10/05/18 INVOICE #: 3195406
ACCT #: L6016734 P.O. #:

REMIT TO:
ARKANSAS DEMOCRAT-GAZETTE, INC.
P.O. BOX 2221
LITTLE ROCK, AR 72203

BILLING QUESTIONS CALL 378-3873

ADCOPY

STATE OF ARKANSAS, )
COUNTY OF PULASKI, ) ss.

I, SuAnn Scales, do solemnly swear that I am the Legal Billing Clerk of the Arkansas Democrat - Gazette, a daily newspaper printed and published in said County, State of Arkansas; that I was so related to this publication at and during the publication of the annexed legal advertisement in the matter of:
notice
pending in the Court, in said County, and at the dates of the several publications of said advertisement stated below, and that during said periods and at said dates, said newspaper was printed and had a bona fide circulation in said County; that said newspaper had been regularly printed and published in said County, and had a bona fide circulation therein for the period of one month before the date of the first publication of said advertisement; and that said advertisement was published in the regular daily issues of said newspaper as stated below.

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Doc 1004518816
Amount - $ 178.20
Date - 10/5/18

TOTAL COST ---------------------- 178.20
Billing Ad #: 74699405

SuAnn Scales

Subscribe and sworn to me this 5th day of October, 20 18
Charles A McNeice Jr
Notary Public

OFFICIAL SEAL - #12696773
CHARLES A. McNEICE, JR.
NOTARY PUBLIC-ARKANSAS
PULASKI COUNTY
MY COMMISSION EXPIRES: 02-02-26

# Arkansas Democrat Gazette

## STATEMENT OF LEGAL ADVERTISING

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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 replace emission limits applicable to Domtar Ashdown Mill included in the 2008 Arkansas Regional Haze State Implementation Plan (AR RH SIP) and in EPA's 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).

ADEQ will accept written and electronic comments received by no later than 4:30 p.m. on Monday, November 5, 2018. 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: airplancomments@adeq.state.ar.us.

A member of the public may request a hearing. If a hearing request is received by 4:30 p.m. on October 15, 2018, ADEQ will hold a public hearing at 10:00 am on Monday, November 5, 2018 to receive public comments on the SIP revision. The public hearing, if held, will be located in the Commission Room at the Arkansas Department of Environmental Quality headquarters building, 5301 Northshore Drive, North Little Rock, AR 72118.

If no request is received by the deadline, ADEQ will not hold the public hearing and ADEQ will announce the cancellation of the hearing on its website at https://www.adeq.state.ar.us/air/planning/sip/regional-haze.aspx by 4:30 pm on October 19, 2018. If a public hearing is requested, but inclement weather or unforeseen circumstances require ADEQ to postpone the hearing, ADEQ will post this decision on the same web page. To request a public hearing or to find out whether the public hearing has been cancelled, please contact Tricia Treece by email at treecep@adeq.state.ar.us or by phone at 501-682-0084

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.

74699405f

**Arkansas Department of Environmental Quality**

**Comment Period Extension**

The Arkansas Department of Environmental Quality (ADEQ) is extending the public comment period on ADEQ's state implementation plan (SIP) revision proposed on October 5, 2018. This SIP proposal addresses emission limits applicable to Domtar Ashdown Mill under the Regional Haze program. The public comment period was originally scheduled to conclude on November 5, 2018; however, ADEQ is extending the public comment period on the proposed SIP to November 9, 2018 to provide the public with thirty days of access to the SIP documents on our website at https://www.adeq.state.ar.us/air/planning/sip/regional-haze.aspx before the close of the comment period.

ADEQ will accept written and electronic comments received by no later than 4:30 p.m. on Friday, November 9, 2018. 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: airplancomments@adeq.state.ar.us.

**Arkansas Democrat Gazette**

## STATEMENT OF LEGAL ADVERTISING

ADEQ/FISCAL DIVISION
5301 NORTHSHORE DR
NORTH LITTLE ROCK AR 72118

ATTN: Jake Harper

DATE : 10/10/18 INVOICE #: 3195592
ACCT #: L6016734 P.O. #:

REMIT TO:
ARKANSAS DEMOCRAT-GAZETTE, INC.
P.O. BOX 2221
LITTLE ROCK, AR 72203

BILLING QUESTIONS CALL 378-3873

STATE OF ARKANSAS, }
COUNTY OF PULASKI, } ss.

I, Yvette Hines, do solemnly swear that I am the Legal Billing Clerk of the Arkansas Democrat - Gazette, a daily newspaper printed and published in said County, State of Arkansas; that I was so related to this publication at and during the publication of the annexed legal advertisement in the matter of:

notice

pending in the Court, in said County, and at the dates of the several publications of said advertisement stated below, and that during said periods and at said dates, said newspaper was printed and had a bona fide circulation in said County; that said newspaper had been regularly printed and published in said County, and had a bona fide circulation therein for the period of one month before the date of the first publication of said advertisement; and that said advertisement was published in the regular daily issues of said newspaper as stated below.

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Subscribe and sworn to me this 10th day of Oct, 20 18

Notary Public

OFFICIAL SEAL - #12347408
DEANNA GRIFFIN
NOTARY PUBLIC-ARKANSAS
PULASKI COUNTY
MY COMMISSION EXPIRES: 03-30-28

## ADCOPY

Arkansas Department of Environmental Quality
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The Arkansas Department of Environmental Quality (ADEQ) is extending the public comment period on ADEQ's state implementation plan (SIP) revision proposed on October 5, 2018. This SIP proposal addresses emission limits applicable to Domtar Ashdown Mill under the Regional Haze program. The public comment period was originally scheduled to conclude on November 5, 2018; however, ADEQ is extending the public comment period on the proposed SIP to November 9, 2018 to provide the public with thirty (30) days of access to the SIP documents on our website at https://www.adeq.state.ar.us/air/planning/sip/regional-haze.aspx before the close of the comment period.

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Published October 10, 2018

Stuart Spencer, Associate Director of the Office of Air Quality
Arkansas Department of Environmental Quality
74705888f

**Arkansas Department of Environmental Quality**

**Public Notice**

The Arkansas Department of Environmental Quality (ADEQ) is publishing notice of supplemental proposal to seek comment on a narrow change to a proposed state implementation plan (SIP) to replace requirements for Domtar Ashdown Mill that was public noticed on October 5, 2018, hereinafter referred to as the "Phase III SIP proposal." This supplemental proposal seeks comment on changing the type of enforcement mechanism for the emission limits included in the Phase III SIP proposal. Specifically, ADEQ proposes to submit specific conditions in a revised Ashdown Mill permit, once finalized, to the United States Environmental Protection Agency instead of entering into an administrative order with Domtar to render emission limits determinations in the Phase III SIP proposal federally enforceable. ADEQ is not reopening or seeking comment on any other aspect of the Phase III SIP proposal.

ADEQ will hold a public hearing on May 21, 2019 to receive public comments on the supplemental proposal. 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 May 21, 2019. 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: airplancomments@adeq.state.ar.us.

A copy of the supplemental proposal and the Phase III SIP proposal are available for public inspection during normal business hours at the ADEQ headquarters building in North Little Rock and online at: https://www.adeq.state.ar.us/air/planning/sip/regional-haze.aspx.

# Arkansas Democrat Gazette

## STATEMENT OF LEGAL ADVERTISING

ADEQ/FISCAL DIVISION
5301 NORTHSHORE DR
NORTH LITTLE ROCK AR 72118

ATTN: jake harper
DATE : 04/21/19 INVOICE #: 3208422
ACCT #: L6016734 P.O. #:

REMIT TO:
ARKANSAS DEMOCRAT-GAZETTE, INC.
P.O. BOX 2221
LITTLE ROCK, AR 72203

BILLING QUESTIONS CALL 378-3873

ADCOPY

STATE OF ARKANSAS, }
COUNTY OF PULASKI, } ss.

I, Charles A McNeice Jr, do solemnly swear that I am the Business Manager of the Arkansas Democrat-Gazette, a daily newspaper printed and published in said County, State of Arkansas; that I was so related to this publication at and during the publication of the annexed legal advertisement the matter of:
ADEQ
pending in the Court, in said County, and at the dates of the several publications of said advertisement stated below, and that during said periods and at said dates, said newspaper was printed and had a bona fide circulation in said County; that said newspaper had been regularly printed and published in said County, and had a bona fide circulation therein for the period of one month before the date of the first publication of said advertisement; and that said advertisement was published in the regular daily issues of said newspaper as stated below.

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Charles A McNeice Jr

Subscribe and sworn to me this 22
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Deanna Griffin
Notary Public

OFFICIAL SEAL - #12347408
DEANNA GRIFFIN
NOTARY PUBLIC-ARKANSAS
PULASKI COUNTY
MY COMMISSION EXPIRES: 03-30-26

Arkansas Democrat Gazette

# STATEMENT OF LEGAL ADVERTISING

## THIS PAGE USED FOR ADDITIONAL AD COPY SPACE AS NEEDED. PAGE MAY BE BLANK

Arkansas Department of
Environmental Quality
Public Notice

The Arkansas Department of Environmental Quality (ADEQ) is publishing notice of supplemental proposal to seek comment on a narrow change to a proposed state implementation plan (SIP) to replace requirements for Domtar Ashdown Mill that was public noticed on October 5, 2018, hereinafter referred to as the "Phase III SIP proposal." This supplemental proposal seeks comment on changing the type of enforcement mechanism for the emission limits included in the Phase III SIP proposal. Specifically, ADEQ proposes to submit specific conditions in a revised Ashdown Mill permit, once finalized, to the United States Environmental Protection Agency instead of entering into an administrative order with Domtar to render emission limits determinations in the Phase III SIP proposal federally enforceable. ADEQ is not re-opening or seeking comment on any other aspect of the Phase III SIP proposal.

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ADEQ will accept written and electronic comments received by no later than 4:30 p.m. Central Time on May 21, 2019. 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: airplancomments@adeq.state.ar.us.

A copy of the supplemental proposal and the Phase III SIP proposal are available for public inspection during normal business hours at the ADEQ headquarters building in North Little Rock and online at: https://www.adeq.state.ar.us/air/planning/sip/regional-haze.aspx.

74916698f

Domtar Phase III
Supplemental Proposal

# ARKANSAS DEPARTMENT OF ENVIORNMENTAL QUALITY

5/21/19 2:00pm

HEARING/MEETING REGISTRATION

| **Name** *Please Print Legibly* | **Address** *Street* | *City* | *State* | *Zip* | Organization Represented |
|---|---|---|---|---|---|
| Jeremy Jewell | | | | | Trinity |
| Kelley Crouch | | | | | Domtar |

**Public hearing/meeting on:** ______ **Date:** ______
**Location:** ______ **Page** ____ **of** ____

Domtar

301 Point Basse Avenue
Nekoosa, Wisconsin 54457-1422
Tel (715) 886-7785
Annabeth.Reitter@Domtar.com

*Submitted electronically to: airplancomments@adeq.state.ar.us*

November 7, 2018

Ms. Tricia Treece
Office of Air Quality
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118

Re: Proposed Revisions to the Arkansas State Implementation Plan – Regional Haze SIP Phase III Revisions

Dear Ms. Treece:

Domtar appreciates the opportunity to provide comment on the Arkansas Department of Environmental Quality (ADEQ) proposed revisions to the Arkansas State Implementation Plan (SIP) addressing Regional Haze SIP Phase III revisions.

Domtar is a leading provider of a wide variety of wood fiber-based products, including communication, specialty and packaging papers, market pulp and absorbent hygiene products. The foundation of our business is a network of fiber converting assets that produce papergrade, fluff and specialty pulps. While most of our pulp production is consumed internally to manufacture paper and consumer products, we are also a large volume pulp vendor, with significant amounts of both market pulp and fluff pulp sold to customers around the globe. Domtar is the largest integrated marketer of uncoated freesheet paper in North America. With approximately 9,700 employees serving more than 50 countries around the world, Domtar is driven by a commitment to turn sustainable wood fiber into useful products that people rely on every day. Domtar operates pulp and paper mills and personal care facilities in the U.S., Canada, Spain, and Sweden. In the U.S. we operate pulp and paper mills in the following states: Arkansas, Illinois, Kentucky, Georgia, Michigan, Missouri, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas and Wisconsin.

Our Ashdown Mill, located in Ashdown, Arkansas, is one of the largest of Domtar's thirteen pulp and paper operations in North America. We are the largest employer in the Ashdown region providing about 800 local jobs and providing significant economic support for the local community. Ashdown's pulp and paper products are sold into global markets competing with low cost producers from other jurisdictions. With the digital revolution and continued year-over-year decline in demand for paper markets, in 2016 the Ashdown Mill undertook a major manufacturing process change with the conversion of a paper machine to manufacture fluff pulp.

The proposed Phase III SIP revision addresses the Domtar A.W. LLC - Ashdown Mill and involves a SIP revision applicable to the Mill's Power Boiler No. 1 and No. 2. In the proposal, Arkansas has included revisions to replace Ashdown Mill emission limits for the two power boilers included in the 2008 Arkansas Regional Haze State Implementation Plan (AR RH SIP) and in EPA's 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). Arkansas is proposing to replace emissions for Power Boiler No. 1 and No. 2 in the existing SIP and FIP with a BART Alternative approach.

After our thorough review of the proposal, and based on that review, we do not support the proposal and request the Department not proceed further with the BART Alternative approach for the Ashdown Mill for the following reasons:

1. Domtar has repeatedly expressed concerns to Arkansas with the approach of "locking in" the BART Alternative requirements in the SIP so that these requirements can only be changed through a long SIP revision process. This approach runs counter to the flexibility required by the Mill to remain competitive in a dynamic and fast-changing global marketplace. Only through flexible, responsive regulatory processes can the Mill quickly implement changes. Locking in the requirements of the proposed BART Alternative into the SIP does not meet this essential requirement.

2. The proposed BART Alternative requires an Administrative Order that contains requirements restricting the ability for Domtar to quickly act on business decisions involving the Ashdown Mill. We will not be signing the Administrative Order included in the proposal.

3. The BART Alternative approach is premised on certain permit limits for NOx and $SO_2$. For unrelated business reasons, the Mill is voluntarily moving to further limit the emissions. Once the voluntary, unrelated emission reductions would become effective, there would be no reasonable anticipation that the emissions from Power Boilers No. 1 and No. 2 would cause/contribute to visibility in the Class 1 areas. The BART Alternative in that case would be moot, and proceeding with that approach would be a waste of the state's limited resources.

4. The Administrative Order process is uncertain, given a recent challenge. This challenge presents a business risk to the Mill and provides another significant business reason for not proceeding with the BART Alternative.

We will be exploring with Arkansas alternate approaches to address the Regional Haze matter for Power Boilers No.1 and No.2 at the Ashdown Mill.

Thank you for the opportunity to comment on the proposed rule. Please contact me at (715) 886-7785 or via email at annabeth.reitter@domtar.com if you have any questions or would like to further discuss.

Sincerely,

Annabeth Reitter

Annabeth Reitter
Corporate Manager, Environmental Regulations

November 9, 2018

Ms. Tricia Treece
Office of Air Quality
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118
airplancomments@adeq.state.ar.us

**RE: ADEQ Proposed Regional Haze State Implementation Plan Revision for Domtar Ashdown Mill**

Dear Ms. Treece,

Please accept the following comments on behalf of the National Parks Conservation Association, the Sierra Club, and Earthjustice concerning the proposed Arkansas Regional Haze State Implementation Plan ("SIP") Revision regarding the proposed Domtar Ashdown Mill best available retrofit technology ("BART") determination. Exempting Domtar from BART is entirely without support and the BART alternative demonstration is deficient. Thus, the Arkansas Department of Environmental Quality ("ADEQ") must withdraw its proposal.

Our comments address the statement that ADEQ makes on page 17 of its SIP revision:[1] "Domtar is pursuing an exemption by EPA for Ashdown Mill from BART requirements pursuant to 40 C.F.R. § 51.303 ("§ 303 exemption"). ADEQ solicits comment on whether and how to consider Domtar's application to EPA for a §303 exemption in this SIP revision and/or the accompanying [Administrative Order]."

We object to any consideration by ADEQ of Domtar's pursuit of a BART exemption for Power Boilers 1 and 2 under § 51.303. To our knowledge, this exemption has never been granted in the history of the Regional Haze program, and for good reason. Once a source has been deemed to be subject to BART, it has already been determined to cause or contribute to visibility impairment. EPA identified these units as being subject to BART specifically because they do significantly impact visibility, most notably at the Caney Creek Wilderness, a designated Class I area. For instance, ADEQ itself notes in Tables 4 and 5 of its proposed SIP that the baseline impacts of these boilers exceed 1.0 deciview at Caney Creek using either its

[1] Revisions to the Arkansas State Implementation Plan, Phase III 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 2018, Public Review Draft. Retrieved from https://www.adeq.state.ar.us/air/planning/sip/regional-haze.aspx on November 8, 2018.

Method 1 or Method 2 analysis. This level of impact far exceeds the minimum level EPA established in its BART Rule, indeed this level of impact is considered to *cause* visibility impairment.[2]

Even after the installation of BART controls, these units are still projected to impact the visibility at the Caney Creek Class I Area in excess of 0.5 deciviews, thereby exceeding even the contribution threshold. Section 51.303(a)(2) specifically rules out any consideration of EPA granting a BART exemption to any source which causes visibility impairment. Indeed, this prohibition applies even under the lesser standard of a source merely contributing to visibility impairment.[3]

We further note that in order to find that Domtar does not cause visibility impairment, ADEQ would have to modify the 1.0 deciview and 0.5 deciview thresholds it has used to determine whether a source causes or contributes to visibility impairment in a future revised SIP. However, it cannot do this, because as we state above, this would violate the Regional Haze Rule's "cause" and "contribute" visibility impairment thresholds.

The process for granting a BART exemption is intentionally deliberative and requires a number of steps. It appears that ADEQ has put the cart before the horse by assuming that it satisfies its SIP obligation for a Domtar BART exemption under § 51.303 by merely soliciting comments on the possibility of such an exemption. Section 51.303 requires that a BART exemption be initiated by Domtar through an application to EPA. There is no record in ADEQ's SIP that Domtar has submitted such an application to EPA. Should that application (which includes a number of requirements that we enumerate below) be granted, ADEQ must then include it in a SIP revision which undergoes public notice and comment.[4] That SIP revision must contain a number of required elements.

Section 51.303(c) requires that any such exemption application to EPA be accompanied by a written concurrence from ADEQ. We are unaware that ADEQ has formally concurred with a BART exemption for Domtar and there is no such concurrence by ADEQ in its proposal. ADEQ merely solicits comment on such an action. Should ADEQ determine that it wishes to concur with Domtar's BART exemption, despite the obvious violation of the Regional Haze Rule such a concurrence would require, it must be included in its proposed SIP that is submitted for public comment. Here, this would necessitate a new or additional SIP revision and the re-opening of the public comment period.

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[2] *See* 70 Fed. Reg. 39,104, 39,120 (July 6, 2005) ("we are clarifying that for purposes of determining which sources are subject to BART, States should consider a 1.0 deciview change or more from an individual source to 'cause' visibility impairment, and a change of 0.5 deciviews to 'contribute' to impairment").

[3] *See* 40 C.F.R. § 51.303(a)(2) ("An application under this section must include all available documentation relevant to the impact of the source's emissions on visibility in any mandatory Class I Federal area and a demonstration by the existing stationary facility that it does not or will not, by itself or in combination with other sources, emit any air pollutant which may be reasonably anticipated to cause or contribute to a significant impairment of visibility in any mandatory Class I Federal area.").

[4] *See id.* § 51.303(g) ("For purposes of judicial review, final EPA action on an application for an exemption under this § 51.303 will not occur until EPA approves or disapproves the State Implementation Plan revision.").

Section 51.303(d) requires that Domtar itself give written notice to any affected Federal Land Managers of any application it intends to submit to EPA for a BART exemption.[5] We see no such notice in the public record for this proposal. Relatedly, Section 51.303(e) requires that any Federal Land Manager recommendation or comments become a part of the application Domtar would submit to EPA. Again, the mere solicitation of comments by ADEQ on such an exemption does not satisfy these requirements.

Under § 51.303(f), after evaluating Domtar's complete application (again containing ADEQ's concurrence, proof of Federal Land Manager Notice and any Federal Land Manager comments and/or recommendations), EPA must publish its findings. Following this, under § 51.303(g), it must then approve or disapprove ADEQ's SIP revision, which must include Domtar's full application.[6]

Again, we urge ADEQ to reject consideration of any BART exemption of the Domtar Ashdown Mill facility. Every technical evaluation EPA or ADEQ has presented, including its present proposed SIP revision, has demonstrated that the Domtar Power Boilers 1 and 2 cause visibility impairment. Should ADEQ disagree and pursue such a misguided course of action, it must follow the requirements of § 51.303.

In addition, ADEQ has failed to adequately demonstrate that the BART alternative would achieve greater reasonable progress than BART. First, the BART alternative results in an overall (Power Boilers units 1 + 2) increase of 323 lbs/hr $SO_2$ and a decrease of 68.3 lbs/hr NOx. ADEQ claims that the NOx decrease mitigates the $SO_2$ increase. The modeling results are not fully presented in Table 4 (which considers the Method 1 approach); results are shown only for Unit 2, not Unit 1. Moreover, the cumulative modeled improvement for the BART alternative is questionable. For a BART alternative to serve as an appropriate option, it must achieve greater reasonable progress than BART, a result that is not made clear through the modeling results or technical support data.

For the above reasons, we request that ADEQ withdraw its proposal to exempt Domtar from BART.

Sincerely,

Stephanie Kodish
Senior Director & Counsel, Clean Air Program
National Parks Conservation Association

Josh Smith
Senior Staff Attorney
Sierra Club

Charles McPhedran
Staff Attorney
Earthjustice

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[5] Note that § 51.303(d) states, "[t]he *existing stationary facility* must give prior written notice to all affected Federal Land Managers of any application for exemption under this § 51.303" (emphasis added).

[6] Thus, the process would begin with Domtar submitting an application to EPA (§ 51.303(a)(1)). That application must include ADEQ's concurrence (§ 51.303(c)), Land Manager notice, and potentially comments (§ 51.303(d-e)). Following this, EPA would provide for notice and comment (§ 51.303(f)), followed by an ADEQ revised SIP submission containing the BART exemption. Finally, Federal Land Managers must submit written concurrence (§ 51.303(h)).

Domtar
Ashdown Mill
285 Hwy 71 South
Ashdown, AR 71822
Tel.: (870) 898-2711
kelley.crouch@domtar.com

Domtar

May 21, 2019

VIA E-MAIL: airplancomments@adeq.state.ar.us

Arkansas Department of Environmental Quality
Office of Air Quality, Policy & Planning Branch
Attn: Tricia Treece
5301 Northshore Drive
North Little Rock, AR 72118-5317

RE: *Comments on Supplemental Proposal for Phase III SIP*

Dear Ms. Treece:

Domtar A.W. LLC (Domtar) submits the following comments on the Arkansas Department of Environmental Quality's (ADEQ's) April 2019 *Revisions to the Arkansas State Implementation Plan, Phase III Regional Haze SIP Revision for 2008–2018 Planning Period Supplemental Proposal* ("the Supplemental Proposal").

1. Except for one administrative issue noted below, Domtar supports the ADEQ's Supplemental Proposal. Domtar agrees that the supplemental proposal and the SIP in total fully satisfies the U.S. EPA SIP requirements set out in the Clean Air Act. The U.S. EPA requires SIPs to meet only "applicable" requirements of Clean Air Act § 110(a)(2) (see detailed discussion regarding the Tennessee SIP – 77 Fed. Reg. 34306, 34310). Applying the U.S EPA's SIP requirements to the Ashdown Mill's BART SIP, only the emission limits and emission limit-specific monitoring are required to be part of the SIP. Monitoring methods, recordkeeping and reporting are not part of Ashdown Mill BART Alternative SIP as the Arkansas SIP already includes approved requirements, and these requirements are part of the Ashdown Mill Title V permit.

   This simplified BART Alternative approach is important and necessary for the Ashdown Mill to remain viable and competitive in the fast-changing, cost-sensitive international markets in which it operates. Detailed and unnecessary SIP requirements would "kill" business innovation and the ability for the mill to change quickly to meet customer demands. SIP revisions just take too long as noted in the recent BP Cherry Point Refinery situation where it took a year to amend a simple BART requirement.

2. Domtar requests that ADEQ renumber the permit 0287-AOP-R22 ("the permit") specific conditions listed in Section II (page 2) of the Supplemental Proposal. It is Domtar's understanding that all regional haze-related conditions will be moved from the specific conditions section of the permit to the end of the plant wide conditions section of the permit in accordance with Domtar's comments on the draft permit. Not only will the approach provided in Domtar's comment mitigate unnecessary burden, it will also provide for greater flexibility to address any potential future Regional Haze requirements. For convenience, the referenced Domtar comment for the draft permit is provided below.

   (Comment No. 1 submitted on the draft permit copied here for reference)
   As written, the draft permit's specific conditions are re-numbered for all sources following SN-05. For example, in the current permit 0287-AOP-R21 ("the current permit") the first specific condition for SN-06 is #67, and it is #75 in the draft permit. This seemingly harmless change would result in hours of administrative work to revise compliance reporting templates (e.g., Annual Compliance Certifications). To avoid this unnecessary burden, Domtar requests that all the regional haze-related conditions (i.e., all the new conditions) be moved to the end of the plant wide conditions section. This option not only avoids unnecessary burden described above, it also provides the greatest flexibility for potential future regional haze-related conditions that may become effective in later regional haze planning periods.

3. Domtar supports ADEQ's proposal for EPA to (1) approve the referenced (as amended; see comment 2, above) specific conditions into the SIP, (ii) withdraw from the SIP the previously approved PM limit for Ashdown Mill Power Boiler No. 1, and (iii) withdraw the AR RH FIP requirements for Ashdown Mill.

4. Domtar agrees with the Supplemental Proposal's statement about the applicability of APC&EC Reg. 19.407(b) regarding permit transfers.

Thank you for your consideration of these comments.

Sincerely,

Kelley L. Crouch

Kelley Crouch
Environmental Manager

cc: Annabeth Reitter, Domtar
Mark Thimke, Foley & Lardner
Jeremy Jewell, Trinity Consultants

**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**
REGION 6
1445 ROSS AVENUE, SUITE 1200
DALLAS TX 75202-2733

May 9, 2019

Ms. Tricia Treece
Office of Air Quality
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118-5317

RE: Regional Haze Phase III SIP Revision
Public Review Draft Supplemental Proposal

Dear Ms. Treece:

Thank you for the opportunity to review the Regional Haze Phase III SIP Revision Draft Supplemental Proposal for the Domtar Ashdown Mill, for which the state published a public notice on April 21, 2019.

For any subject-to-BART source that elects to comply with its regional haze requirements through a BART alternative, 40 CFR § 51.308(e)(2)(iii) requires that all necessary emission reductions take place during the period of the first long-term strategy for regional haze. Based on the Draft Supplemental SIP Narrative and our discussions with ADEQ, it is our understanding that the Domtar Ashdown Mill No. 1 and No. 2 Power Boilers have been complying with the emission limits contained under Specific Conditions 50 and 70 of the Draft Permit for the Domtar Ashdown Mill (Permit No. 0287-AOP-R22) since December 2016. The Draft Supplemental SIP Narrative notes that on February 28, 2019, ADEQ issued a minor modification letter to Domtar to allow Domtar to begin implementing the proposed changes included in the minor modification application submitted by Domtar on January 30, 2019. The proposed changes included in the minor modification application would incorporate the emission limits, and monitoring, recordkeeping, and reporting requirements proposed in the Phase III SIP Revision into the permit for the Domtar Ashdown Mill. Based on discussions with ADEQ, we understand that the minor modification letter issued by ADEQ made the emission limits listed under Specific Conditions No. 50 and 70 of the Draft Permit effective immediately at the state level prior to the issuance of the final permit revision. If and when EPA takes final action to approve the SIP Revision, these emision limits would become federally enforceable as well. For clarity, please provide additional explanation in the SIP Narrative that the minor modification letter ADEQ issued to Domtar rendered the emission limits listed under Specific Conditions No. 50 and 70 of the Draft Permit effective immediately upon issuance of that letter. This will ensure that the public is aware that those emission limits, which ADEQ intends to submit to EPA as part of the Phase III SIP Revision, became effective and enforceable at the state level on February 28, 2019, at the time ADEQ issued the minor modification letter to Domtar.

For your reference, we are also enclosing our submitted comments on the Regional Haze Program Specific Conditions of the Draft Permit for the Domtar Ashdown Mill (Permit No. 0287-AOP-R22), which we submitted to ADEQ on May 9, 2019.

If you have any questions or comments regarding this letter, please contact me at (214) 665-9793 or Dayana Medina of my staff at (214) 665-7241.

Sincerely,

Michael Feldman

Michael Feldman, Ph.D.
Chief, $SO_2$ and Regional Haze Section
State Planning Implementation Branch

Enclosure

**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**
REGION 6
1445 ROSS AVENUE, SUITE 1200
DALLAS TX 75202-2733

May 9, 2019

Mr. Thomas Rheaume
Senior Operations Manager, Office of Air Quality
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118-5317

RE: Draft Permit: Domtar A.W. LLC - Ashdown Mill
Permit No.: 0287-AOP-R22
AFIN: 4100002

Dear Mr. Rheaume:

Thank you for the opportunity to review Draft Permit No. 0287-AOP-R22 for the Domtar Ashdown Mill. We have reviewed the portions of the Draft Permit relating to the new sections on "Regional Haze Program (BART Alternative) Specific Conditions." Please find enclosed our comments on the portions of the Draft Permit relating to the Regional Haze Program Specific Conditions.

If you have any questions or comments, please contact me at (214) 665-9793 or Dayana Medina of my staff at (214) 665-7241.

Sincerely,

Michael Feldman

Michael Feldman, Ph.D.
Chief, $SO_2$ and Regional Haze Section
State Planning Implementation Branch

Enclosure

cc: William Montgomery
Air Quality Planning, Arkansas Department of Environmental Quality

1. The addition of better than best available retrofit technology (BART) requirements to the permit as part of the Regional Haze application is a change to the permitted hourly emissions, but the last sentence under the section titled "Summary of Permitted Activity" (pg. 7) could be interpreted to contradict this. In the "Summary of Permit Activity," please amend the last sentence ("There are no permitted emissions changes for either of these applications.") to clarify that this statement refers to no changes to the tons/year permitted emissions at the facility, and that this is not taking into account the change to the permitted lb/hour emissions limits under the "Regional Haze Program (BART Alternative) Specific Conditions.

2. In the section titled "Regulations" (pg. 14), the regulations table needs to include the Regional Haze requirements for Domtar. Specifically, please revise the table to include BART eligible and subject-to-BART determinations for Domtar under 40 CFR § 52.173 and subject-to-BART alternative measures for Domtar under 40 CFR § 51.308(e)(2).

3. Under the section titled "Regional Haze Program (BART Alternative) Specific Conditions" (pg. 69 and pg. 95) for Power Boiler No. 1 and Power Boiler No. 2, citation to 40 CFR § 52.173 (Finding that Domtar is BART-eligible and subject to BART) and 40 CFR § 51.308(e)(2) (BART Alternative requirements) is required.

4. Under the section titled "Regional Haze Program (BART Alternative) Specific Conditions," revise reference to § 51.308(e)(2) instead of § 51.308 in paragraphs 50-53 for Power Boiler No. 1 (pg. 69) and paragraphs 70-74 for Power Boiler No. 2 (pg. 95). Section 51.308(e)(2) is the BART alternative requirements. Section 51.308 is the general regional haze requirements including reasonable progress, long term strategy, and BART.

5. Under the sections titled "Regional Haze Program (BART Alternative) Specific Conditions" for Power Boiler No. 1 (pg. 69) and Power Boiler No. 2 (pg. 95), please amend the sentence "The following terms and conditions of the BART Alternative measures are to be submitted to EPA for inclusion in the Arkansas State Implementation Plan (SIP)" to read as follows: "The following terms and conditions of the BART Alternative measures are to be submitted to EPA for approval as part of the Arkansas State Implementation Plan (SIP)."

6. The BART Alternative sections of the permit, if approved by EPA, will be part of the Arkansas SIP and become enforceable under federal law. The permit needs to be clear that any future revisions to the "Regional Haze Program (BART Alternative) Specific Conditions" sections of the permit will not be effective until submitted to EPA as a SIP revision and approved by EPA. Under the "Regional Haze Program (BART Alternative) Specific Conditions" sections for Power Boiler No. 1 and No. 2, please add a sentence at the end of the first paragraph (on pg. 69 and pg. 95): "Once this section of the permit is initially approved into the SIP, any future revisions to this section of the permit will not be effective until approved by EPA through approval of a SIP revision."

7. Under the "Regional Haze Program (BART Alternative) Specific Conditions" sections for Power Boilers No. 1 and No. 2, paragraphs 52 and 72 (pg. 70 and pg. 95), need to be amended to reflect that the Power Boiler will meet the BART alternative limits if it chooses to permanently retire. Emission requirements remain even when a unit is retired. Please amend paragraph 52 to state that "In the event SN-03 (No. 1 Power Boiler) is permanently retired, the BART Alternative limits and conditions will be met through the retirement of the source." The same amendment needs to be made to paragraph 72 (pg. 95) with respect to Power Boiler No. 2.

8. ADEQ is opting to comply with the Clean Air Act's regional haze requirements for the first implementation period for the Domtar Ashdown Mill No.1 and No. 2 Power Boilers through a BART alternative under 40 CFR § 51.308(e)(2). ADEQ must ensure that Domtar Power Boilers No. 1 and 2 meet all the general recordkeeping and reporting requirements that apply to all subject-to-BART sources under 40 CFR § 51.308(e). In addition, any source-specific SIP revision, including a permit, must contain enforceable procedures such as monitoring, reporting, recordkeeping, and methodologies for determining compliance. Therefore, specific recordkeeping and reporting requirements similar to those contained in ADEQ's proposed Administrative Order for the Domtar Ashdown Mill, which was part of the Regional Haze Phase III SIP Revision proposed by ADEQ on October 5, 2018, must be added to the "Regional Haze Program (BART Alternative) Specific Conditions" sections of the permit for Power Boilers No. 1 and No. 2.

9. Specific Condition No. 74 of the Draft Permit provides that the No. 2 Power Boiler, which is subject to the Boiler MACT Rule at 40 CFR Part 63 subpart DDDDD—hybrid suspension grate units designed to burn wet biomass/bio-based solid subcategory, will utilize the applicable $PM_{10}$ compliance demonstration requirements from subpart DDDDD to demonstrate compliance with the PM10 emission limit under regional haze. We note that Provision No. 7 of the proposed Administrative Order for the Domtar Ashdown Mill contained in the Phase III SIP Revision proposed by ADEQ on October 5, 2018, states that the owner/operator shall keep records of PM compliance testing under Boiler MACT for No. 2 Power Boiler for five (5) years, and that if testing requirements under Boiler MACT are no longer required under federal law, the owner/operator shall demonstrate compliance for regional haze purposes by keeping records of compliance testing using EPA Reference Method 5 every five years. For this source-specific SIP revision to continuously meet all the applicable enforcement requirements, the alternate compliance demonstration provision must be added to the Specific Conditions for the No. 2 Power Boiler to ensure that the boiler continues to demonstrate compliance with the regional haze provisions in the event it is no longer subject to the Boiler MACT requirements.

RESPONSIVE SUMMARY FOR STATE IMPLEMENTATION PLAN REVISION:

Phase III Regional Haze SIP Revision

Pursuant to Arkansas Code Annotated (Ark. Code Ann.) § 8-4-317(b)(2)(B)(i), the Arkansas Division of Environmental Quality (ADEQ) must prepare a record of the public process in the form of a written response to each issue raised during the public comment period. A responsive summary groups public comments into similar categories and explains why ADEQ accepts or rejects the rationale for each category.

On October 5, 2018, ADEQ proposed a state implementation plan (SIP) revision to replace requirements for Domtar Ashdown Mill (Ashdown Mill) included in Arkansas's 2008 Regional Haze State SIP (2008 AR RH SIP) and the 2016 United States Environmental Protection Agency (EPA) Arkansas Regional Haze federal implementation plan (AR RH FIP). The proposed SIP revision is hereinafter referred to as the Phase III SIP revision.

The public comment period on the Phase III SIP revision closed on November 9, 2018. The public was offered an opportunity to request a public hearing. No hearing was requested; therefore, no hearing was held.

During the public comment period, ADEQ received comments from Domtar requesting that the State not finalize the proposal or an associated administrative order. Subsequent to receipt of these comments, Domtar indicated that the emission limits and associated recordkeeping and reporting requirements in the Phase III SIP could be an agreeable approach if ADEQ submitted specific permit conditions for inclusion in the SIP rather than relying upon an administrative order. Therefore, ADEQ issued a supplemental proposal after receipt of a permit application incorporating the proposed Phase III SIP requirements into Ashdown Mills permit and after publication of the public notice for said permitting action. This supplemental proposal sought comment on changing the type of enforcement mechanism for the proposed Phase III SIP requirements but did not reopen or seek comment on any other aspect of the Phase III SIP proposal.

Notice of the supplemental proposal was published on April 21, 2019. The public comment period on the supplemental proposal closed on May 21, 2019. A public hearing on the supplemental proposal was held on May 21, 2019.

Comments received during the public comment period for the Phase III SIP revision and the supplemental proposal are summarized and a response for each is provided below. Comments received on the draft permit discussed in the supplemental proposal have been summarized and are responded to in another document. ADEQ received comments from Domtar; EPA Region 6; and Sierra Club, National Parks Association, and Earthjustice.

**Comment 1:**

Domtar has expressed concerns with "locking in" the BART Alternative requirements in the SIP so that these requirements can only be changed through a long SIP revision process. Domtar asserts that this approach runs counter to the Mill's need for flexibility to remain competitive.

**Response 1:**

ADEQ acknowledges Domtar's concerns; however, any control measure included in a Regional Haze SIP must be permanent and enforceable. "Locking in" the BART Alternative requirements is necessary for the approvability of the SIP. If ADEQ were to submit a SIP revision based on the BART Alternative that did not render these requirements permanently enforceable, that SIP revision would be disapproved by the EPA, and the AR RH FIP limits would remain in place. No changes to the proposed Phase III SIP are necessary in response to this comment.

**Comment 2:**

Domtar asserts that the BART Alternative requires an administrative order and that the draft administrative order included with the Phase III SIP proposal contains requirements that would restrict the ability for Domtar to act quickly on business decisions involving Ashdown Mill. Domtar indicate that they were unwilling to sign the order included in the proposal.

**Response 2:**

ADEQ disagrees that the BART Alternative specifically requires an administrative order. It does require some mechanism to render enforceable the associated emission limits, recordkeeping, and reporting requirements. That enforceability mechanism could be rulemaking, administrative order, or specific permit conditions. ADEQ acknowledges Domtar's unwillingness to sign the administrative order. On April 21, 2019, ADEQ issued a supplemental proposal seeking comment on changing the enforceability mechanism of the BART Alternative to be based on specific permit conditions rather than on an agreed administrative order. ADEQ is finalizing this revised approach.

**Comment 3:**

Domtar indicated that Ashdown Mill is moving toward further emission reductions than those upon which the BART Alternative approach is premised. Upon realization of the voluntary emission reductions, Domtar asserts that there is no reasonable anticipation that emissions from Power Boilers No. 1 and No. 2 would cause/contribute to visibility in the Class I areas. Domtar asserts that in that case, the BART Alternative would be a waste of the State's resources.

**Response 3:**

Domtar was determined to be subject-to-BART based on baseline emissions for the Regional Haze Program. This determination was adopted into Arkansas Pollution Control and Ecology

Commission Regulation No. 19 and EPA approved this determination. Any effort to unwind such a determination would be unprecedented and would still require imposition of emission limitations, recordkeeping, and reporting requirements based on the more stringent emission reductions necessary to reduce emissions from Power Boilers No. 1 and No. 2 to below the original 0.5 deciview threshold that ADEQ used to determine whether a BART-eligible source causes or contributes to visibility impairment. Furthermore, such an attempt would require more of the State's resources than the BART Alternative. The effort, if approvable by EPA, would require rulemaking by the Arkansas Pollution Control and Ecology Commission in addition to another SIP revision. No changes to the proposed Phase III SIP are necessary in response to this comment.

**Comment 5:**

Sierra Club, National Parks Association, and Earthjustice object to ADEQ’s consideration of Domtar’s pursuit of a BART exemption for Power Boilers 1 and 2 under 40 CFR § 51.303. Specifically, these commenters object based on the lack of precedence for a § 51.303 exemption, Ashdown Mill’s baseline visibility impacts and subject-to-BART determination, failure to satisfy the technical and procedural requirements for a § 51.303 exemption.

The commenters noted that a BART exemption pursuant to 40 CFR §51.303 has never been granted. They assert that “once a source has been deemed to be subject to BART, it has already been determined to cause or contribute to visibility impairment.”

The commenters state that EPA identified Ashdown Mill Power Boilers 1 and 2 as subject to BART because they impact visibility at Caney Creek Wilderness. The commenters point out that the proposed SIP includes baseline impact data for these boilers in excess of 1.0 deciview at Caney Creek. The commenters also note that, even after installation of BART controls, the units are projected to continue to have visibility impacts in excess of 0.5 deciviews at Caney Creek.

The commenters state that 40 CFR 51.303(a)(2) prohibits EPA from granting a BART exemption to any source that causes or contributes to visibility impairment. The commenters state that ADEQ would have to modify its thresholds for determining whether a source causes or contributes to visibility impairment in a revised SIP to find that Domtar does not cause visibility impairment.

The commenters elaborate on the process for granting a BART exemption according to § 51.303 and the fact that the steps required for such a grant have not occurred. The commenters purport that ADEQ is making an assumption that, by soliciting comments on the possibility of an exemption, the state has satisfied its SIP obligation for a Domtar BAR exemption. In particular, the commenters mention that ADEQ must include in a SIP revision a number of required elements that would undergo public comment. The commenters also note that they are unaware of any formal concurrence by ADEQ on a BART exemption for Domtar. The commenters assert that such a formal concurrence must be included in a proposed SIP that is submitted for public comment. The commenters also noted the lack of evidence of written notice to affected federal land managers of Domtar's intent to submit an application to EPA for a BART exemption.

**Response 5:**

Sierra Club, National Parks Association, and Earthjustice misunderstand ADEQ's intention for soliciting comment on Domtar's potential application to EPA for an exemption from BART requirements pursuant to 40 CFR § 51.303. ADEQ did not claim that the requirements of 40 CFR 51.303 were satisfied by the Phase III SIP proposal. Rather, ADEQ sought comments on how Domtar's pursuit of a separate process for an exemption from EPA pursuant to § 51.303 should be considered in final SIP submission for the BART Alternative. Upon further discussions with EPA and Domtar, it is ADEQ's understanding that Domtar is no longer pursuing the § 51.303 exemption. Therefore, the final SIP does not discuss how a § 51.303 exemption would impact the BART Alternative.

**Comment 6:**

Sierra Club, National Parks Association, and Earthjustice assert that ADEQ has failed to adequately demonstrate that the BART alternative would achieve greater reasonable progress than BART. The commenters assert that modeling results are not fully presented in Table 4; results shown do not include Unit 1. The commenters also question the cumulative visibility improvement for BART. The commenters argue that the modeling results and technical supporting data do not make clear that the BART alternative would achieve greater reasonable progress than BART.

**Response 6:**

The proposed SIP has adequately demonstrated that the BART alternative would achieve greater reasonable progress. The results in Table 4 do include Unit 1; however, the proposed SIP included a labeling error in this table. Table 4 represents a combination of Tables 5 and 6 in Domtar's modeling results TSD.[1] This TSD was included in the record for the proposed Phase III SIP throughout the public comment period. The boiler, unit, and pollutant columns in the two tables do not match in the TSD and therefore the Table 4 in the Phase III SIP narrative is partially mislabeled. ADEQ will correct the table in the final SIP. Although the commenters object to the cumulative visibility metric, ADEQ demonstrates in Section III.C.1.e. of the SIP narrative how the modeling results for both methods for Ashdown Mill satisfies the requirements under 40 CFR § 51.308(e)(2)(i)(E) for a determination that an alternative achieves greater reasonable progress than would be achieved through the installation and operation of BART. ADEQ disagrees with the commenters and asserts that the SIP narrative, modeling results, and technical support data included in the record for public review are adequate to support ADEQ's

[1] Exhibit A

determination that the BART alternative achieves greater reasonable progress than BART for Ashdown Mill.

## Supplemental Proposal Comments

**Comment 7:**

EPA states that 40 CFR § 51.308(e)(2)(iii) requires that all necessary emission reductions under a BART alternative take place during the first planning period. EPA states that it is their understanding that Ashdown Mill Power Boilers No. 1 and 2 have been complying with the emission limits contained under Specific Conditions No. 50 and 70 of the Draft Permit since December 2016 and that those limits have been enforceable at the state level since February 28, 2019 when ADEQ issued a minor modification letter to Domtar that included those limits. EPA notes that if and when it takes final action to approve the Phase III SIP revision, these emission limits would become federally enforceable as well. EPA requests that ADEQ provide additional explanation in the SIP Narrative that the minor modification letter ADEQ issued to Domtar rendered the emission limits listed under Specific Conditions No. 50 and 70 of the Draft Permit effective immediately upon issuance of that letter. EPA states that this will ensure that the public is aware that those emission limits that ADEQ intends to submit to EPA as part of the Phase III SIP Revision, became effective and enforceable at the state level on February 28, 2019, at the time ADEQ issued the minor modification letter to Domtar.

**Response 7:**

ADEQ confirms EPA's understanding that Ashdown Mill Power Boilers No. 1 and 2 have been complying with the emission limits contained under Specific Conditions No. 50 and 70 of the Draft Permit since at least December 2016. ADEQ further confirms that the Specific Conditions No. 50 and 70 of the Draft Permit became state enforceable immediately upon issuance of the minor modification letter sent to Domtar on February 28, 2019. ADEQ include this additional information in the final Phase III SIP narrative.

**Comment 8:**

Domtar generally supports the Supplemental Proposal with one exception and agrees that the Phase III SIP and supplemental proposal fully satisfies the U.S. EPA SIP requirements. Domtar asserts that only the emission limits and emission limit-specific monitoring are required to be part of the SIP. Domtar asserts that monitoring methods, recordkeeping and reporting are not a part of the Ashdown Mill BART Alternative SIP as the Arkansas SIP already has approved requirements and these requirements are part of the Ashdown Mill Title V permit. Domtar asserts that detailed and unnecessary SIP requirements would impair innovation and the ability for Ashdown Mill to change quickly to meet customer demands. Domtar points out that the SIP revision process can be lengthy.

**Response 8:**

ADEQ appreciates Domtar's general support. ADEQ disagrees with Domtar that the SIP should not include monitoring methods, recordkeeping, and reporting requirements; however, the requirements can be written in such a way as to offer flexibility without compromising the achievement and enforceability of the required emission reductions. See the response to comments for the permit.

**Comment 9:**

Domtar requests that ADEQ renumber the specific conditions in Section II of the Supplemental Proposal based on Domtar's understanding that regional haze-related conditions will be moved to a different section of the permit.

**Response 9:**

ADEQ will include in the final submission the appropriate references to the specific conditions in the final issued permit.

**Comment 10:**

Domtar supports ADEQ's proposal for EPA to (1) approve the referenced (as amended) specific conditions into the SIP, (2) withdraw from the SIP the previously approved PM limit for Ashdown Mill Power Boiler No. 1, and (3) withdraw the AR RH FIP requirements for Ashdown Mill.

**Response 10:**

ADEQ appreciates and acknowledges this comment. No changes to the proposed Phase III SIP are necessary in response to this comment.

**Comment 11:**

Domtar agrees with the Supplemental Proposal's statement about the applicability of APC&EC Reg. 19.407(b) regarding permit transfers.

**Response 11:**

ADEQ appreciates and acknowledges this comment. No changes to the proposed Phase III SIP are necessary in response to this comment.

EXHIBIT
A

# ASHDOWN MILL
# BART ALTERNATIVE – TECHNICAL SUPPORT DOCUMENT

**September 4, 2018**

## Introduction

With the continued decline in demand for printing and writing paper, the Ashdown Mill looks for opportunities to produce new products or move into new markets so it can remain competitive in dynamic and global markets. In order to maintain flexibility and competitiveness for the Mill, Domtar is slightly revising the BART Alternative. This revised Alternative is based on the January 4, 2018 telephone discussion with the Arkansas Department of Environmental Quality (ADEQ) and the United States Environmental Protection Agency-Region 6 (EPA) staffs. The approach meets the requirements of 40 C.F.R. § 51.308 while allowing the Mill the flexibility of a future voluntary retirement of No.1 Power Boiler based on the continuing reassessment of steam needs under the changing Mill configuration.

In summary, Domtar is proposing the following revised BART Alternative:

- Power Boiler No. 1 on natural gas only (as authorized in Domtar's air operating permit); and

- Power Boiler No. 2 at adjusted emission rates for $SO_2$ and $NO_X$ (and the same emission rate for PM set in the FIP). Compared to the final BART FIP emission rates (*i.e.*, 345 lb/hr for $NO_X$ and 91.5 lb/hr for $SO_2$), this scenario decreases $NO_X$ emissions while allowing increased $SO_2$ emissions.

The specific emission rates associated with BART Alternative are summarized in Table 1 below.

**Table 1. BART Alternative Scenario Emission Rates**

| | Modeled Emission Rates | | |
|---|---|---|---|
| **Unit** | **$SO_2$ (lb/hr)** | **$NO_X$ (lb/hr)** | **PM (lb/hr)** |
| Power Boiler No. 1 on natural gas only | 0.5 | 191.10 | 5.2 |
| Power Boiler No. 2 at adjusted emission rates for $SO_2$ and $NO_X$ | 435.0 | 293.0 | 81.6 |

Modeling of the BART Alternative scenario results in better predicted visibility improvement than the values presented in EPA's FIP across the four affected Class I areas: Caney Creek (CACR), Upper Buffalo (UPBU), Hercules Glades (HEGL), and Mingo (MING). Two CALPUFF-based modeling methodologies were utilized as summarized below. These methodologies were discussed with Mr. Michael Feldman, EPA-Region 6 Air Planning Section.[1] Method 1 follows the approach EPA used in the BART FIP where predicted impacts from

[1] Conference call between Mr. Michael Feldman, (EPA-Region 6, Air Planning Section), Mr. Jeremy Jewell (Trinity), and Ms. Christine Chambers (Trinity) on January 10, 2018.

separate models for each source and pollutant are combined together to arrive at an estimate of cumulative visibility improvement. Method 2 is a full-chemistry method that more accurately accounts for the chemical interaction of emissions through the combination of the sources into a single modeling file. Details on each method as well as the resulting visibility improvement are summarized below.

## **Background**

EPA estimated visibility improvement for the BART FIP Controls by comparing the visibility impairment from a baseline scenario to the impairment for a control scenario. The modeling was conducted per source and per pollutant in separate modeling files, which does not account for the full chemical interaction of all emissions (*i.e.*, "Method 1"). Per discussion with EPA-Region 6, a combined assessment is an acceptable alternate method of calculating a cumulative visibility improvement for a control scenario at a site.[2] With this method ("Method 2"), all sources and pollutants are combined into a single modeling run per scenario per year. This method allows for interaction of the pollutants from the two boiler using the available chemical transformation mechanism of the CALPUFF model. Domtar completed the BART Alternative analysis using both methods to document that the proposed BART Alternative results in greater visibility improvement than EPA's BART FIP.

## **Conclusion**

The proposed Domtar BART Alternative results in a greater visibility improvement than EPA's FIP utilizing either modeling methodology. As such, the BART Alternative results in greater visibility improvement than the EPA's FIP approach.

[2] *Ibid*.

## TRINITY MODELING ASSESSMENT – BART FIP ALTERNATIVE ASHDOWN MILL

### CALPUFF BART FIP Alternative Assessment

Modeling of the BART Alternative results in better predicted visibility improvement than the improvement presented in EPA's FIP across the four affected Class I areas: Caney Creek (CACR), Upper Buffalo (UPBU), Hercules Glades (HEGL), and Mingo (MING). This CALPUFF modeling for the alternative BART assessment relies on key aspects of the original ADEQ and Central States Regional Air Planning Association (CENRAP) CALPUFF modeling protocol, along with a second modeling methodology to reflect full chemistry of the CALPUFF Modeling System as discussed with EPA-Region 6.[3] The following sections describe the modeling methodology, the selected emission rates and stack parameters, and the visibility improvement results at each of the Class I areas.

***CALPUFF Modeling Methodology***

The CALPUFF model is capable of modeling linear chemical transformation effects by using pseudo-first-order chemical reaction mechanisms for the conversion of $SO_2$ to sulfate and $NO_X$ to nitrate using the available background ammonia concentrations included in the model. The preferential scavenging of ammonia is by sulfate; therefore, the total nitrate is estimated using the remaining available ammonia concentration. If the ratio of $SO_2$ to $NO_X$ emissions in the model changes, this chemical interplay is affected.

EPA estimated visibility improvement for the BART FIP Controls by comparing the visibility impairment from a baseline scenario to the impairment for a control scenario. The modeling was conducted per source and per pollutant in separate modeling files, which does not account for the full chemical interaction of emissions. This approach was also utilized by Domtar to determine the visibility improvement from Domtar's BART Alternative and is outlined below in the *Method 1 – EPA's Assessment* section of this document.

Per discussion with EPA-Region 6, a combined assessment is an acceptable alternate method of calculating cumulative visibility effects, and therefore, visibility improvement for a multi-source control scenario at a site.[4] With this method, all sources and pollutants are combined into a single modeling run per scenario per year. This method allows for interaction of pollutants from both boilers using the available chemical transformation mechanism of the CALPUFF model. Domtar completed this assessment using CALPUFF as outlined below in the *Method 2 – Full Chemistry Assessment* section of this document.

[3] Conference call between Michael Feldman, (EPA-Region 6, Air Planning Section), Jeremy Jewell (Trinity), and Christine Chambers (Trinity) on January 10, 2018.

[4] *Ibid*.

### *Modeled Ashdown Mill Emissions*

Table 2a and Table 2b provides a summary of the modeled emission rates.

- Baseline Emissions: Emissions for Power Boiler No. 1 and Power Boiler No. 2 are based on Table 43 of the April 8, 2015 Proposed FIP, 80 FR 18979.
- EPA FIP Proposed Controls: Emissions for Power Boiler No. 2 are based on the Final FIP, 81 FR 66339. No change from baseline for Power Boiler No. 1.
- Domtar BART Alternative: Emissions for Power Boiler No. 1 are based on natural gas only (*i.e.*, the current limits in Domtar's air operating permit), and emissions for Power Boiler No. 2 are at adjusted emission rates for $SO_2$ and $NO_X$. (The same emission rate for PM presented in the FIP.)

**Table 2a. Baseline and EPA FIP Proposed Control Emission Rates**

| | Baseline | | | EPA FIP Proposed Controls | | |
|---|---|---|---|---|---|---|
| **Unit** | **$SO_2$ (lb/hr)** | **$NO_X$ (lb/hr)** | **PM (lb/hr)** | **$SO_2$ (lb/hr)** | **$NO_X$ (lb/hr)** | **PM (lb/hr)** |
| Power Boiler No. 1 | 21.0 | 207.4 | 30.4 | 21.0 | 207.4 | 30.4 |
| Power Boiler No. 2 | 788.2 | 526.8 | 81.6 | 91.5 | 345 | 81.6 |

**Table 2b. Domtar BART Alternative Emission Rates**

| | Domtar BART Alternative PB1 Natural Gas Only, PB2 Reduced $NO_X/SO_2$ | | |
|---|---|---|---|
| **Unit** | **$SO_2$ (lb/hr)** | **$NO_X$ (lb/hr)** | **PM (lb/hr)** |
| Power Boiler No. 1 | 0.5 | 191.10 | 5.2 |
| Power Boiler No. 2 | 435 | 293 | 81.6 |

*Modeled Ashdown Mill Stack Parameters*

Domtar's BART FIP Alternative assessment used actual stack parameters representative of each BART unit. Table 3 summarizes these parameters. These stack parameters are consistent with the FIP modeling.

**Table 3. Modeled Stack Parameters**

| Unit | LCC East (km) | LCC North (km) | Base Elevation (m) | Stack Height (m) | Stack Diameter (m) | Exhaust Temperature (K) | Exhaust Velocity (m/s) |
|---|---|---|---|---|---|---|---|
| No. 1 Power Boiler - A | 267.49713 | -698.63952 | 99.58 | 66.14 | 2.1 | 342.04 | 11.06 |
| No. 1 Power Boiler - B | 267.49891 | -698.63445 | 99.51 | 66.14 | 2.1 | 342.04 | 11.07 |
| No. 2 Power Boiler | 267.45242 | -698.64643 | 99.95 | 71.63 | 3.66 | 324.82 | 11.92 |

*Modeled Class I Areas*

Table 4 below presents the Class I areas included in Domtar's BART Alternative Assessment, the responsible Federal Land Manager (FLM) and approximate distance between the Ashdown Mill and each area. Class I area receptor data from the National Park Service (NPS) Air Resources Division (ARD) is the same as that used in prior modeling analyses.

**Table 4. Modeled Class I Areas**

| Class I Area | FLM | Approximate Distance from Ashdown Mill (km) |
|---|---|---|
| Caney Creek Wilderness (CACR) | Forest Service | 85 |
| Upper Buffalo Wilderness (UPBU) | Forest Service | 250 |
| Hercules Glades Wilderness (HEGL) | Forest Service | 350 |
| Mingo Wildlife Refuge (MING) | Fish and Wildlife Service | 500 |

*BART Alternate Modeling Steps and Modeling Results*

**Method 1 – EPA FIP Assessment Method**

EPA estimated visibility improvement for the BART FIP Controls by comparing the visibility impairment from a baseline scenario to the impairment for a control scenario. The modeling was conducted per source and per pollutant in separate modeling files, which does not account for the full chemical interaction of emissions. For the purposes of direct comparison with the FIP, this approach was also utilized by Domtar to determine the visibility improvement from Domtar's BART Alternative.

EPA's proposed improvement due to the controls outlined in the FIP are predicted to result in a cumulative modeled improvement of **0.473 Δdv** (*see* Table 5 below). Domtar's proposed BART Alternative results in a cumulative modeled improvement of **0.549 Δdv** (*see* Table 6). Detailed steps on the calculation methodology are provided below.

**Table 5. Method 1 - Cumulative Visibility Improvement Due to BART-FIP Controls**

| Description | Boiler | Pollutant | 98th Percentile Visibility Impacts – Max. of Three Modeled Years (Δdv) | | | |
|---|---|---|---|---|---|---|
| | | | CACR | UPBU | HEGL | MING |
| FIP Baseline | 1 | Both | 0.335 | 0.038 | 0.020 | 0.014 |
| | 2 | Both | 0.844 | 0.146 | 0.105 | 0.065 |
| | Both | Both | 1.179 | 0.184 | 0.125 | 0.079 |
| FIP Controls | 2 | $SO_2$ | 0.524 | 0.082 | 0.046 | 0.035 |
| | 2 | $NO_X$ | | | | |
| | 2 | Both | 0.524 | 0.082 | 0.046 | 0.035 |
| Calculated Improvement | 2 | $SO_2$ | 0.139 | 0.050 | 0.048 | 0.025 |
| | 2 | $NO_X$ | 0.181 | 0.014 | 0.011 | 0.005 |
| | 2 | Both | 0.320 | 0.064 | 0.059 | 0.030 |
| **Cumulative Improvement** | **Both** | **Both** | **0.473** | | | |

**Table 6. Method 1 - Cumulative Visibility Improvement Due to Proposed BART Alternative**

| Description | Boiler | Pollutant | 98th Percentile Visibility Impacts – Max. of Three Modeled Years (Δdv) | | | |
|---|---|---|---|---|---|---|
| | | | CACR | UPBU | HEGL | MING |
| FIP Baseline | 1 | Both | 0.335 | 0.038 | 0.020 | 0.014 |
| | 2 | Both | 0.844 | 0.146 | 0.105 | 0.065 |
| | Both | Both | 1.179 | 0.184 | 0.125 | 0.079 |
| BART Alternative | 1 | Both | 0.286 | 0.033 | 0.017 | 0.011 |
| | 2 | Both | 0.493 | 0.082 | 0.059 | 0.037 |
| | Both | Both | 0.779 | 0.115 | 0.076 | 0.048 |
| Calculated Improvement | 1 | Both | 0.049 | 0.005 | 0.003 | 0.003 |
| | 2 | Both | 0.351 | 0.064 | 0.046 | 0.028 |
| | Both | Both | 0.400 | 0.069 | 0.049 | 0.031 |
| **Cumulative Improvement** | **Both** | **Both** | **0.549** | | | |

EPA's estimated visibility effect from the FIP baseline as well as the calculated visibility improvement per Class I area from the FIP Controls is presented in Table 5. This data was extracted from the BART FIP. The cumulative visibility improvement from Domtar's proposed BART Alternative using Method 1, as outlined in Table 6, was calculated using the following steps:

**Determine the maximum 98th percentile visibility impact per Class I area for the BART Alternative:**

1. Run CALPUFF for Boiler No. 1 at emission rates currently listed in the operating permit with no limitation, extract the maximum 98th percentile of the 3-years modeled per Class I area (*see* the BART Alternative, Boiler 1 line item in Table 6 above).

2. Run CALPUFF for Boiler No. 2 with the emission rates listed in Table 1 and extract the maximum 98th percentile of the 3-years modeled per Class I area (*see* the BART Alternative, Boiler 2 line item in Table 6 above).

3. Sum BART Alternative maximum 98th percentile results for Boiler No. 1 and Boiler No. 2 to obtain the total 98th percentile effects (*see* the BART Alternative, Both line item in Table 6 above).

**Determine the visibility improvement between the baseline and Domtar's BART Alternative per Class I area:**

1. Determine the delta between the EPA predicted impacts using baseline conditions and the impacts resulting after Domtar's BART Alternative for Boiler No. 1 by subtracting the BART Alternative impacts from the baseline impacts for Boiler No. 1. (*See* the Calculated Improvement, Boiler No. 1 line item in Table 6 above).

2. Determine the delta between the EPA predicted impacts at the baseline and the impacts resulting after Domtar's BART Alternative for Boiler No. 2 by subtracting the BART Alternative impacts from the baseline impacts for Boiler No 2. (*See* the Calculated Improvement, Boiler No. 2 line item in Table 6 above).

3. Sum the delta from Boiler No. 1 and Boiler No. 2 (*see* the Calculated Improvement, Both line item in Table 6 above).

**Determine the cumulative visibility improvement between the baseline and Domtar's BART Alternative:**

1. Sum the improvement for each Class I area (*see* the Cumulative Improvement line item in Table 6 above).

### Method 2 – Full Chemistry Assessment

With the Full Chemistry method, all sources and pollutants are combined into a single modeling run per year.

When combining sources and pollutants, EPA's proposed improvement due to the FIP controls is predicted to result in a cumulative modeled improvement of **0.516 $\Delta$dv**, as documented in Table 7 below; whereas, Domtar's BART Alternative results in a cumulative modeled improvement of **0.520 $\Delta$dv**, as documented in Table 8. Detailed steps on the calculation methodology are provided below.

**Table 7. Method 2 - Cumulative Visibility Improvement Due to BART FIP Controls**

| Description | Boiler | Pollutant | 98th Percentile Visibility Impacts – Max. of Three Modeled Years ($\Delta$dv) | | | |
|---|---|---|---|---|---|---|
| | | | **CACR** | **UPBU** | **HEGL** | **MING** |
| FIP Baseline | Both | Both | 1.137 | 0.163 | 0.118 | 0.072 |
| FIP Controls | Both | Both | 0.776 | 0.103 | 0.057 | 0.038 |
| Calculated Improvement | Both | Both | 0.361 | 0.060 | 0.061 | 0.034 |
| **Cumulative Improvement** | **Both** | **Both** | **0.516** | | | |

**Table 8. Method 2 - Cumulative Visibility Improvement Due to Proposed BART Alternative**

| Description | Boiler | Pollutant | 98th Percentile Visibility Impacts – Max. of Three Modeled Years (Δdv) | | | |
|---|---|---|---|---|---|---|
| | | | CACR | UPBU | HEGL | MING |
| FIP Baseline | Both | Both | 1.137 | 0.163 | 0.118 | 0.072 |
| BART Alternative | Both | Both | 0.753 | 0.104 | 0.069 | 0.044 |
| Calculated Improvement | Both | Both | 0.384 | 0.059 | 0.049 | 0.028 |
| **Cumulative Improvement** | **Both** | **Both** | **0.520** | | | |

The cumulative visibility improvement from Domtar's proposed BART Alternative using Method 2 was calculated following the below steps.

**<u>EPA's Proposed FIP Controls</u>**

**Determine the maximum 98th percentile visibility impact per Class I area for the BART FIP Baseline:** [5]

1. Run CALPUFF with Boiler No. 1 and Boiler No. 2 with the baseline emission rates for $SO_2$, $NO_X$, and $PM_{10}$ listed in Table 1 and extract the maximum 98th percentile of the 3-years modeled per Class I area (*see* the FIP Baseline, Both Boilers, Both Pollutants, line item in Table 7 and Table 8 above).

**Determine the maximum 98th percentile visibility impact per Class I area for the Proposed BART Controls:**[6]

1. Run CALPUFF for Boiler No. 1 and Boiler No. 2 with the emission rates listed in Table 1 for the EPA FIP Proposed Controls and extract the maximum 98th percentile of the 3-years modeled per Class I area (*see* the FIP Controls, Both Boilers, Both Pollutants line item in Table 7 above).

**Determine the visibility improvement between the FIP Baseline and EPA's Proposed Controls per Class I area:**

1. Determine the delta between the estimated BART FIP impacts at the baseline and the estimated impacts resulting after EPA's Proposed Controls for Both Boilers by subtracting EPA's Proposed Control impacts from the baseline impacts for both boilers.

[5] Because Method 2 combines both boilers and all pollutants into a single modeling file, the FIP baseline scenario was run using the combined source and pollutant methodology. Because EPA modeled the baseline per boiler and summed the visibility impairment from each unit to calculate the FIP baseline visibility impairment, when the emissions from Boiler 1 and Boiler 2 are combined into one modeling file, the predicted baseline visibility impairment will be different than presented in the AR FIP due to the chemical interaction of the pollutants.

[6] Because Method 2 combines both boilers and all pollutants into a single modeling file, the FIP baseline scenario was run using the combined source and pollutant methodology. Because EPA modeled the baseline per boiler and summed the visibility impairment from each unit to calculate the FIP baseline visibility impairment, when the emissions from Boiler 1 and Boiler 2 are combined into one modeling file, the predicted baseline visibility impairment will be different than presented in the FIP due to the chemical interaction of the pollutants.

(*See* the Calculated Improvement, Both Boilers, Both Pollutant line item in Table 7 above).

**Determine the cumulative visibility improvement between the Baseline and EPA's Proposed FIP Controls:**

1. Sum the improvement for each Class I area (*see* the Cumulative Improvement line item in Table 7 above).

**<u>BART Alternative</u>**

**Determine the maximum 98$^{th}$ percentile visibility impact per Class I area for Domtar's BART Alternative:**

1. Run CALPUFF for Boiler No. 1 and Boiler No. 2 with the Domtar BART Alternative emission rates Operating Scenario A listed in Table 1 and extract the maximum 98$^{th}$ percentile of the 3-years modeled per Class I area (*see* the BART Alternative, Both Boilers, Both Pollutants line item in Table 8 above).

**Determine the visibility improvement between the baseline and Domtar's BART Alternative per Class I area:**

1. Determine the delta between the estimated BART FIP predicted impacts at the baseline and the impacts resulting after Domtar's BART Alternative for both boilers by subtracting the BART Alternative impacts from the baseline impacts from both boilers. (*See* the Calculated Improvement, Both Boilers, Both Pollutant line item in Table 8 above).

**Determine the cumulative visibility improvement between the baseline and Domtar's BART Alternative for Operating Scenario A:**

1. Sum the improvement for each Class I area (*see* the Cumulative Improvement line item in Table 8 above).

| | |
|---|---|
| **From:** | Treece, Tricia |
| **To:** | Logan, Judy -FS (jlogan@fs.fed.us); Anderson, Bret A -FS (baanderson02@fs.fed.us); "nwagoner@fs.fed.us"; "sschwenke@fs.fed.us"; "cehamilton@fs.fed.us"; "tim_allen@fws.gov"; "patricia_f_brewer@nps.gov"; kyra.moore@dnr.mo.gov; Wilbur, Emily (emily.wilbur@dnr.mo.gov) |
| **Cc:** | Montgomery, William; Spencer, Stuart; Clark, David |
| **Subject:** | Regional Haze SIP Revision Notification |
| **Date:** | Thursday, August 09, 2018 3:27:00 PM |
| **Attachments:** | Domtar SIP Narrative Redrafted-8_8_2018_Clean.docx<br>Administrative Order 20180731 clean 8_8_2018.docx<br>3_26_2007_BART_Domtar.pdf<br>5_16_14_Supplemental_BART_Deter.pdf<br>BART Alternative Modeling Report 2018-0320_(FINAL COMPILED).pdf<br>Phase III SIP Rev RPG Data Sheet.xlsx |

This email serves to notify you that ADEQ has prepared a SIP revision to the Arkansas Regional Haze State Implementation Plan to address 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 narrative, including supporting technical documents, and a pre-proposal draft administrative order have been attached to this email. 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 me William Montgomery at 501-692-0885 (Montgomery@adeq.state.ar.us) or myself at 501-682-0055 (treecep@adeq.state.ar.us).

Thanks,

*Tricia Jackson Treece*
SIP/Planning Section Supervisor, Policy and Planning Branch
Office of Air Quality
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118
501-682-0055 (office)

| | |
|---|---|
| **From:** | Treece, Tricia |
| **To:** | "Alsharafi, Adel" |
| **Subject:** | RE: Regional Haze SIP Revision Notification |
| **Date:** | Tuesday, August 14, 2018 10:57:00 AM |
| **Attachments:** | 3_26_2007_BART_Domtar.pdf<br>Phase III SIP Rev RPG Data Sheet.xlsx |

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**From:** Alsharafi, Adel [mailto:adel.alsharafi@dnr.mo.gov]
**Sent:** Tuesday, August 14, 2018 10:56 AM
**To:** Treece, Tricia
**Subject:** RE: Regional Haze SIP Revision Notification

Tricia,

I think you can send them via email since they are not large files. But to make sure the get through our email size allowance, would you please send the first and fourth files together in an email and the second and the third in two separate emails.

Thanks,

Adel

---

**From:** Treece, Tricia [mailto:treecep@adeq.state.ar.us]
**Sent:** Tuesday, August 14, 2018 10:47 AM
**To:** Alsharafi, Adel
**Cc:** Leath, Mark; Wilbur, Emily
**Subject:** RE: Regional Haze SIP Revision Notification

One is 5MB
One is 10 MB
One is 11 MB
One is 164 KB

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**From:** Alsharafi, Adel [mailto:adel.alsharafi@dnr.mo.gov]
**Sent:** Tuesday, August 14, 2018 10:46 AM
**To:** Treece, Tricia
**Cc:** Leath, Mark; Wilbur, Emily
**Subject:** RE: Regional Haze SIP Revision Notification

Tricia,

What is the size on those files? I need to know to give you enough file upload allowance.

Thanks,

Adel

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**From:** Treece, Tricia [mailto:treecep@adeq.state.ar.us]

**Sent:** Tuesday, August 14, 2018 10:02 AM
**To:** Wilbur, Emily
**Cc:** Alsharafi, Adel; Leath, Mark
**Subject:** RE: Regional Haze SIP Revision Notification

Sure.

Adel,
Let me know how I can send files to the FTP site.

---

**From:** Wilbur, Emily [mailto:emily.wilbur@dnr.mo.gov]
**Sent:** Tuesday, August 14, 2018 10:00 AM
**To:** Treece, Tricia
**Cc:** Alsharafi, Adel; Leath, Mark
**Subject:** RE: Regional Haze SIP Revision Notification

Hi Tricia,

Hope things are going well in AR!

At your earliest convenience, we would like a copy of the technical support documents. We have an ftp site that you could probably use to transfer the documents. Please work with Adel (copied on this email) to make arrangements. If you have any questions, please let me know.

Thanks!

Emily

---

**From:** Treece, Tricia <treecep@adeq.state.ar.us>
**Sent:** Thursday, August 9, 2018 3:41 PM
**To:** Wilbur, Emily <emily.wilbur@dnr.mo.gov>; Moore, Kyra <kyra.moore@dnr.mo.gov>
**Subject:** FW: Regional Haze SIP Revision Notification

I sent the email below to you, but I got a kick back from your email server, likely due to attachment size. I have removed the attachments other than the pre-proposal SIP narrative for the purposes of consultation. If you would like a copy of the technical supporting documents, I can figure out a way to send those to you since they are large files.

---

**From:** Treece, Tricia
**Sent:** Thursday, August 09, 2018 3:28 PM
**To:** Logan, Judy -FS (jlogan@fs.fed.us); Anderson, Bret A -FS (baanderson02@fs.fed.us); 'nwagoner@fs.fed.us'; 'sschwenke@fs.fed.us'; 'cehamilton@fs.fed.us'; 'tim_allen@fws.gov'; 'patricia_f_brewer@nps.gov'; kyra.moore@dnr.mo.gov; Wilbur, Emily (emily.wilbur@dnr.mo.gov)
**Cc:** Montgomery, William; Spencer, Stuart; Clark, David
**Subject:** Regional Haze SIP Revision Notification

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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 me William Montgomery at 501-692-0885 (Montgomery@adeq.state.ar.us) or myself at 501-682-0055 (treecep@adeq.state.ar.us).

Thanks,

*Tricia Jackson Treece*
SIP/Planning Section Supervisor, Policy and Planning Branch
Office of Air Quality
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118
501-682-0055 (office)

| | |
|---|---|
| **From:** | Treece, Tricia |
| **To:** | "Alsharafi, Adel" |
| **Subject:** | RE: Regional Haze SIP Revision Notification |
| **Date:** | Tuesday, August 14, 2018 10:57:00 AM |
| **Attachments:** | BART Alternative Modeling Report 2018-0320 (FINAL COMPILED).pdf |

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**From:** Treece, Tricia
**Sent:** Tuesday, August 14, 2018 10:57 AM
**To:** 'Alsharafi, Adel'
**Subject:** RE: Regional Haze SIP Revision Notification

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**From:** Alsharafi, Adel [mailto:adel.alsharafi@dnr.mo.gov]
**Sent:** Tuesday, August 14, 2018 10:56 AM
**To:** Treece, Tricia
**Subject:** RE: Regional Haze SIP Revision Notification

Tricia,

I think you can send them via email since they are not large files. But to make sure the get through our email size allowance, would you please send the first and fourth files together in an email and the second and the third in two separate emails.

Thanks,

Adel

---

**From:** Treece, Tricia [mailto:treecep@adeq.state.ar.us]
**Sent:** Tuesday, August 14, 2018 10:47 AM
**To:** Alsharafi, Adel
**Cc:** Leath, Mark; Wilbur, Emily
**Subject:** RE: Regional Haze SIP Revision Notification

One is 5MB
One is 10 MB
One is 11 MB
One is 164 KB

---

**From:** Alsharafi, Adel [mailto:adel.alsharafi@dnr.mo.gov]
**Sent:** Tuesday, August 14, 2018 10:46 AM
**To:** Treece, Tricia
**Cc:** Leath, Mark; Wilbur, Emily
**Subject:** RE: Regional Haze SIP Revision Notification

Tricia,

What is the size on those files? I need to know to give you enough file upload allowance.

| | |
|---|---|
| **From:** | Treece, Tricia |
| **To:** | "Alsharafi, Adel" |
| **Subject:** | RE: Regional Haze SIP Revision Notification |
| **Date:** | Tuesday, August 14, 2018 10:58:00 AM |
| **Attachments:** | 5_16_14_Supplemental_BART_Deter.pdf |

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**From:** Treece, Tricia
**Sent:** Tuesday, August 14, 2018 10:57 AM
**To:** 'Alsharafi, Adel'
**Subject:** RE: Regional Haze SIP Revision Notification

---

**From:** Alsharafi, Adel [mailto:adel.alsharafi@dnr.mo.gov]
**Sent:** Tuesday, August 14, 2018 10:56 AM
**To:** Treece, Tricia
**Subject:** RE: Regional Haze SIP Revision Notification

Tricia,

I think you can send them via email since they are not large files. But to make sure the get through our email size allowance, would you please send the first and fourth files together in an email and the second and the third in two separate emails.

Thanks,

Adel

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**From:** Treece, Tricia [mailto:treecep@adeq.state.ar.us]
**Sent:** Tuesday, August 14, 2018 10:47 AM
**To:** Alsharafi, Adel
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**Subject:** RE: Regional Haze SIP Revision Notification

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One is 10 MB
One is 11 MB
One is 164 KB

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**Sent:** Tuesday, August 14, 2018 10:46 AM
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**Cc:** Leath, Mark; Wilbur, Emily
**Subject:** RE: Regional Haze SIP Revision Notification

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What is the size on those files? I need to know to give you enough file upload allowance.

**From:** Treece, Tricia
**To:** "Alsharafi, Adel"
**Cc:** Leath, Mark; Wilbur, Emily
**Subject:** RE: Regional Haze SIP Revision Notification
**Date:** Tuesday, August 14, 2018 11:03:00 AM

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Great!

---

**From:** Alsharafi, Adel [mailto:adel.alsharafi@dnr.mo.gov]
**Sent:** Tuesday, August 14, 2018 11:01 AM
**To:** Treece, Tricia
**Cc:** Leath, Mark; Wilbur, Emily
**Subject:** RE: Regional Haze SIP Revision Notification

I received all files.

Thanks,

Adel

---

**From:** Treece, Tricia [mailto:treecep@adeq.state.ar.us]
**Sent:** Tuesday, August 14, 2018 10:59 AM
**To:** Alsharafi, Adel
**Subject:** RE: Regional Haze SIP Revision Notification

Done. Let me know if there are any issues. I didn't get an automatic kick back so that's a good sign.

---

**From:** Alsharafi, Adel [mailto:adel.alsharafi@dnr.mo.gov]
**Sent:** Tuesday, August 14, 2018 10:56 AM
**To:** Treece, Tricia
**Subject:** RE: Regional Haze SIP Revision Notification

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**To:** Alsharafi, Adel
**Cc:** Leath, Mark; Wilbur, Emily
**Subject:** RE: Regional Haze SIP Revision Notification

One is 5MB

Domtar

| Invoice No | Reference No | Date | Gross Amount | Deductions | For Inquiry |
|---|---|---|---|---|---|
| Payment is made on behalf of Domtar A.W. LLC | | | | | |
| 3207529 | | 2019-04-10 | 161.71 | 0.00 | 870-898-2711 |
| Total | | | 161.71 | 0.00 | Net $ : 161.71 |

****DIRECT DEPOSIT AVAILABLE****
Avoid postage delay and switch to Direct Deposit payments
Email us at:Genesis-payments@domtar.com to switch.

| Payment Document | Cheque Number | Date | Vendor | Currency | Payment Amount |
|---|---|---|---|---|---|
| 2000664638 | AR-8851437769 | 2019-04-11 | 1103537 | USD | ***********161.71* |

R14US

Domtar

**Domtar Industries LLC**
C.P. 11633 Succ. Centre-Ville
Montréal, QC Canada H3C 5Y8
514-848-5555

**JPMorgan Chase Bank, N.A.**
Syracuse, NY USA

50-937
213

8851437769

2019-04-11

DATE A/Y M/M J/D

PAYEZ / PAY *** ONE HUNDRED SIXTY-ONE and 71/100 $ ********161.71

À / TO

ARKANSAS DEMOCRAT GAZETTE
PO Box 2221
LITTLE ROCK AR 72203-2221

USD FUNDS

SIGNATURES AUTORISÉES / AUTHORIZED SIGNATURES

[redacted]

# Arkansas Democrat Gazette

## STATEMENT OF LEGAL ADVERTISING

DOMTAR INDUSTRIES
285 HWY 71 S
ASHDOWN AR 71822

ATTN: Cynthia Hook
DATE : 04/07/19 INVOICE #: 3207529
ACCT #: L4988762 P.O. #:

REMIT TO:
ARKANSAS DEMOCRAT-GAZETTE, INC.
P.O. BOX 2221
LITTLE ROCK, AR 72203

BILLING QUESTIONS CALL 378-3873

ADCOPY

STATE OF ARKANSAS, }
COUNTY OF PULASKI, } ss.

I, Charles A McNeice Jr, do solemnly swear that I am the Accounting Manager of the Arkansas Democrat-Gazette, a daily newspaper printed and published in said County, State of Arkansas; that I was so related to this publication at and during the publication of the annexed legal advertisement the matter of:
ADEQ
pending in the Court, in said County, and at the dates of the several publications of said advertisement stated below, and that during said periods and at said dates, said newspaper was printed and had a bona fide circulation in said County; that said newspaper had been regularly printed and published in said County, and had a bona fide circulation therein for the period of one month before the date of the first publication of said advertisement; and that said advertisement was published in the regular daily issues of said newspaper as stated below.

RECEIVED
APR 10 2019
By______

| DATE | DAY | LINAGE | RATE | DATE | DAY | LINAGE | RATE |
|---|---|---|---|---|---|---|---|
| 04/07 | Sun | 103 | 1.57 | | | | |

TOTAL COST ---------------------------- 161.71
Billing Ad #: 74897177

Charles A McNeice Jr

Subscribe and sworn to me this 8
day of April, 20 19
Deanna Griffin
Notary Public

OFFICIAL SEAL - #12347408
DEANNA GRIFFIN
NOTARY PUBLIC-ARKANSAS
PULASKI COUNTY
MY COMMISSION EXPIRES: 03-30-26

Arkansas Democrat Gazette
STATEMENT OF LEGAL ADVERTISING
THIS PAGE USED FOR ADDITIONAL AD COPY SPACE AS NEEDED.
PAGE MAY BE BLANK

Public Notice

Pursuant to the Arkansas Operating Air Permit Program (Regulation #26) Section 602, the Office of Air Quality of the Arkansas Department of Environmental Quality gives the following notice:

Domtar A.W. LLC - Ashdown Mill (41-00002) operates a facility located at 285 Highway 71 South, Ashdown, AR 71822. Domtar submitted two applications to add specific conditions to SN-03 and SN-05 (Power Boilers #1 and #2, respectively) for the Regional Haze Program and to add a mobile chipper to the Insignificant Activities list. There are no permitted emissions changes for either of these applications.

The application has been reviewed by the staff of the Department and has received the Department's tentative approval subject to the terms of this notice.

Citizens wishing to examine the permit application and staff findings and recommendations may do so by contacting ADEQ Air Permits Branch. Citizens desiring technical information concerning the application or permit should contact, Christopher Riley, Engineer. Both ADEQ Air Permits Branch and Christopher Riley can be reached at the Department's central office, 5301 Northshore Drive, North Little Rock, Arkansas 72118-5317, telephone: (501) 682-0744.

The draft permit and permit application are available for copying at the above address. This information may be reviewed during normal business hours. The draft permit may also be found at http://www.adeq.state.ar.us/air/permits/draft_noi.aspx.

Comments will be accepted in accordance with Section 8.208 of Regulation #8. During the public comment period, any person may submit written comments to the Department at the above address Attention: ADEQ Air Permits Branch or to airpermits@adeq.state.ar.us by email. Any interested person may request a public hearing on the draft permitting decision during the public comment period. The public comment period shall begin on the day this notice is published and shall expire at 4:30 p.m. Central Time on the thirtieth (30th) calendar day after publication of this notice.

The Director shall make a final decision to issue or deny this application or to impose special conditions in accordance with Section 8.211 of the Arkansas Pollution Control and Ecology Commission's Administrative Procedures (Regulation #8) and Regulation #26.

Dated this 7th day of April, 2019.

Becky W. Keogh, Director

74897177f

**Little River News**
614 E Wood St
Ashdown, AR 71822 US
jamie.lrnews@gmail.com

LITTLE RIVER NEWS

# Invoice

**BILL TO**
Domtar- Kelly Crouch
285 Highway 71 South
Ashdown, AR 71822

**INVOICE #** 1082
**DATE** 04/11/2019
**DUE DATE** 05/11/2019
**TERMS** Net 30

| SERVICE | DESCRIPTION | QTY | RATE | AMOUNT |
|---|---|---|---|---|
| **Legals** | Public notice- Domtar Submitted application 348 words @.30c | 1 | 104.40 | 104.40 |

BALANCE DUE **$104.40**

# PUBLISHER'S AFFIDAVIT

I, J. Quinton Bagley, do solemnly swear that I am the editor of the LITTLE RIVER NEWS; that the same is a weekly newspaper published in Ashdown, in the County and State aforesaid; that said paper has a bona fide circulation in said County and has been published regularly therein once a week for more than one month next preceding the first insertion of the Public Notice Domtar submitted applications a copy of which is hereto attached.

That said advertisement and notice has been published in the LITTLE RIVER NEWS weekly for 1 consecutive weeks, the first publication thereof being on the 11 day of April, 2019. and the last insertion being on the 11 day of April, 2019.

J. Quinton Bagley
Editor and Publisher.

VICKY HARRIS
NOTARY PUBLIC-STATE OF ARKANSAS
LITTLE RIVER COUNTY
My Commission Expires 11-15-2021
Commission # 12385708

Sworn and subscribed to before me this the 22nd day of April A.D. 2019

Vicky Harris
Notary Public

My Commission Expires: 11/15/2021,

**PUBLIC NOTICE**

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The Director shall make a final decision to issue or deny this application or to impose special conditions in accordance with Section 8.211 of the Arkansas Pollution Control and Ecology Commission's Administrative Procedures (Regulation #8) and Regulation #26.

Dated this
Becky W. Keogh
Director 1TA11

List Edit Goto Extras Environment Settings System Help

# Vendor Line Item Display

Selections | Dispute Case

Vendor 1102201
Company Code DI21

Name BLOSSOM MEDIA INC
City ASHDOWN

| St | Pstng Date | Doc. Date | DD | Net due dt | Amount in DC | Clearing | Reference | DocumentNo | BusA | Text | PBk | PayT | User name | Tx | PM | PmtM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| * Clearing Document 2000448459 | | | | | 0.00 | 03/14/2019 | | | | | | | | | | |
| | 04/05/2019 | 03/28/2019 | | 03/28/2019 | 912.00- | 04/11/2019 | LRN032819 | 1901070785 | AR01 | March 2019 Billing | | ZN00 | MCKEED | P0 | | AR |
| | 04/11/2019 | 04/11/2019 | | 04/11/2019 | 912.00 | 04/11/2019 | | 2000451196 | AR01 | | | | MORISSEAUS | | C | |
| * Clearing Document 2000451196 | | | | | 0.00 | 04/11/2019 | | | | | | | | | | |
| | 05/02/2019 | 04/11/2019 | | 04/11/2019 | 104.40- | 05/10/2019 | 1082 | 1901074293 | AR01 | Public Notification | | ZN00 | MCKEED | P0 | | AR |
| | 05/10/2019 | 05/10/2019 | | 05/10/2019 | 104.40 | 05/10/2019 | | 2000453794 | AR01 | | | | FORTEF | | E | |
| * Clearing Document 2000453794 | | | | | 0.00 | 05/10/2019 | | | | | | | | | | |
| ** Account 1102201 | | | | | 32,306.13- | | | | | | | | | | | |

Vendor *
Company Code *

Name *
City *

| St | Pstng Date | Doc. Date | DD | Net due dt | Amount in DC | Clearing | Reference | DocumentNo | BusA | Text | PBk | PayT | User name | Tx | PM | PmtM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *** | | | | | 32,306.13- | | | | | | | | | | | |

Prints Window Contents | FBL1N mtl1prap01 INS

**Formatted address**

BLOSSOM MEDIA INC
dba LITTLE RIVER NEWS
614 E WOOD STREET
ASHDOWN AR 71822
USA

Domtar
Ashdown Mill
285 Hwy 71 South
Ashdown, AR 71822
Tel.: (870) 898-2711
kelley.crouch@domtar.com

Domtar

May 9, 2019

VIA E-MAIL: airpermits@adeq.state.ar.us

Arkansas Department of Environmental Quality
Office of Air Quality, Air Permits Branch
5301 Northshore Drive
North Little Rock, AR 72118-5317

RE: *Comments on Draft Permit 0287-AOP-R22*

To Whom It May Concern:

Domtar A.W. LLC (Domtar) submits the following comments on draft permit 0287-AOP-R22 ("the draft permit").

1. As written, the draft permit's specific conditions are re-numbered for all sources following SN-05. For example, in the current permit 0287-AOP-R21 ("the current permit") the first specific condition for SN-06 is #67, and it is #75 in the draft permit. This seemingly harmless change would result in hours of administrative work to revise compliance reporting templates (e.g., Annual Compliance Certifications). To avoid this unnecessary burden, Domtar requests that all the regional haze-related conditions (i.e., all the new conditions) be moved to the end of the plant wide conditions section. This option not only avoids unnecessary burden described above, it also provides the greatest flexibility for potential future regional haze-related conditions that may become effective in later regional haze planning periods.

2. In the draft permit, ADEQ proposes a definition of "30 boiler operating day rolling average" as "the arithmetic mean of the previous 720 hours of operating data…". This definition appears in draft specific condition 50, in a statement just before draft specific condition 50, and in draft specific condition 70. Domtar feels this definition needs to be changed for consistency with other regional haze determinations across the U.S. (in various FIPs, SIPs, consent orders, and state permits) and with how Domtar interprets other limits/compliance demonstrations applicable to the Ashdown Mill. Domtar proposes the following definition:

   "30 boiler operating day rolling average" means the arithmetic average of 30 daily values where each daily value is generated for any day during which there is any hour of operation (and "day" is defined as a 24-hour period beginning at 6 am and ending at 6 am on the following day).

Thank you for your consideration of these comments.

Sincerely,

Kelley L. Crouch

Kelley Crouch
Environmental Manager

cc: Annabeth Reitter, Domtar
Jeremy Jewell, Trinity Consultants

**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**
REGION 6
1445 ROSS AVENUE, SUITE 1200
DALLAS TX 75202-2733

May 9, 2019

Ms. Tricia Treece
Office of Air Quality
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118-5317

RE: Regional Haze Phase III SIP Revision
Public Review Draft Supplemental Proposal

Dear Ms. Treece:

Thank you for the opportunity to review the Regional Haze Phase III SIP Revision Draft Supplemental Proposal for the Domtar Ashdown Mill, for which the state published a public notice on April 21, 2019.

For any subject-to-BART source that elects to comply with its regional haze requirements through a BART alternative, 40 CFR § 51.308(e)(2)(iii) requires that all necessary emission reductions take place during the period of the first long-term strategy for regional haze. Based on the Draft Supplemental SIP Narrative and our discussions with ADEQ, it is our understanding that the Domtar Ashdown Mill No. 1 and No. 2 Power Boilers have been complying with the emission limits contained under Specific Conditions 50 and 70 of the Draft Permit for the Domtar Ashdown Mill (Permit No. 0287-AOP-R22) since December 2016. The Draft Supplemental SIP Narrative notes that on February 28, 2019, ADEQ issued a minor modification letter to Domtar to allow Domtar to begin implementing the proposed changes included in the minor modification application submitted by Domtar on January 30, 2019. The proposed changes included in the minor modification application would incorporate the emission limits, and monitoring, recordkeeping, and reporting requirements proposed in the Phase III SIP Revision into the permit for the Domtar Ashdown Mill. Based on discussions with ADEQ, we understand that the minor modification letter issued by ADEQ made the emission limits listed under Specific Conditions No. 50 and 70 of the Draft Permit effective immediately at the state level prior to the issuance of the final permit revision. If and when EPA takes final action to approve the SIP Revision, these emision limits would become federally enforceable as well. For clarity, please provide additional explanation in the SIP Narrative that the minor modification letter ADEQ issued to Domtar rendered the emission limits listed under Specific Conditions No. 50 and 70 of the Draft Permit effective immediately upon issuance of that letter. This will ensure that the public is aware that those emission limits, which ADEQ intends to submit to EPA as part of the Phase III SIP Revision, became effective and enforceable at the state level on February 28, 2019, at the time ADEQ issued the minor modification letter to Domtar.

For your reference, we are also enclosing our submitted comments on the Regional Haze Program Specific Conditions of the Draft Permit for the Domtar Ashdown Mill (Permit No. 0287-AOP-R22), which we submitted to ADEQ on May 9, 2019.

If you have any questions or comments regarding this letter, please contact me at (214) 665-9793 or Dayana Medina of my staff at (214) 665-7241.

Sincerely,

Michael Feldman

Michael Feldman, Ph.D.
Chief, $SO_2$ and Regional Haze Section
State Planning Implementation Branch

Enclosure

**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**
REGION 6
1445 ROSS AVENUE, SUITE 1200
DALLAS TX 75202-2733

May 9, 2019

Mr. Thomas Rheaume
Senior Operations Manager, Office of Air Quality
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118-5317

RE: Draft Permit: Domtar A.W. LLC - Ashdown Mill
Permit No.: 0287-AOP-R22
AFIN: 4100002

Dear Mr. Rheaume:

Thank you for the opportunity to review Draft Permit No. 0287-AOP-R22 for the Domtar Ashdown Mill. We have reviewed the portions of the Draft Permit relating to the new sections on "Regional Haze Program (BART Alternative) Specific Conditions." Please find enclosed our comments on the portions of the Draft Permit relating to the Regional Haze Program Specific Conditions.

If you have any questions or comments, please contact me at (214) 665-9793 or Dayana Medina of my staff at (214) 665-7241.

Sincerely,

Michael Feldman

Michael Feldman, Ph.D.
Chief, $SO_2$ and Regional Haze Section
State Planning Implementation Branch

Enclosure

cc: William Montgomery
Air Quality Planning, Arkansas Department of Environmental Quality

1. The addition of better than best available retrofit technology (BART) requirements to the permit as part of the Regional Haze application is a change to the permitted hourly emissions, but the last sentence under the section titled "Summary of Permitted Activity" (pg. 7) could be interpreted to contradict this. In the "Summary of Permit Activity," please amend the last sentence ("There are no permitted emissions changes for either of these applications.") to clarify that this statement refers to no changes to the tons/year permitted emissions at the facility, and that this is not taking into account the change to the permitted lb/hour emissions limits under the "Regional Haze Program (BART Alternative) Specific Conditions.

2. In the section titled "Regulations" (pg. 14), the regulations table needs to include the Regional Haze requirements for Domtar. Specifically, please revise the table to include BART eligible and subject-to-BART determinations for Domtar under 40 CFR § 52.173 and subject-to-BART alternative measures for Domtar under 40 CFR § 51.308(e)(2).

3. Under the section titled "Regional Haze Program (BART Alternative) Specific Conditions" (pg. 69 and pg. 95) for Power Boiler No. 1 and Power Boiler No. 2, citation to 40 CFR § 52.173 (Finding that Domtar is BART-eligible and subject to BART) and 40 CFR § 51.308(e)(2) (BART Alternative requirements) is required.

4. Under the section titled "Regional Haze Program (BART Alternative) Specific Conditions," revise reference to § 51.308(e)(2) instead of § 51.308 in paragraphs 50-53 for Power Boiler No. 1 (pg. 69) and paragraphs 70-74 for Power Boiler No. 2 (pg. 95). Section 51.308(e)(2) is the BART alternative requirements. Section 51.308 is the general regional haze requirements including reasonable progress, long term strategy, and BART.

5. Under the sections titled "Regional Haze Program (BART Alternative) Specific Conditions" for Power Boiler No. 1 (pg. 69) and Power Boiler No. 2 (pg. 95), please amend the sentence "The following terms and conditions of the BART Alternative measures are to be submitted to EPA for inclusion in the Arkansas State Implementation Plan (SIP)" to read as follows: "The following terms and conditions of the BART Alternative measures are to be submitted to EPA for approval as part of the Arkansas State Implementation Plan (SIP)."

6. The BART Alternative sections of the permit, if approved by EPA, will be part of the Arkansas SIP and become enforceable under federal law. The permit needs to be clear that any future revisions to the "Regional Haze Program (BART Alternative) Specific Conditions" sections of the permit will not be effective until submitted to EPA as a SIP revision and approved by EPA. Under the "Regional Haze Program (BART Alternative) Specific Conditions" sections for Power Boiler No. 1 and No. 2, please add a sentence at the end of the first paragraph (on pg. 69 and pg. 95): "Once this section of the permit is initially approved into the SIP, any future revisions to this section of the permit will not be effective until approved by EPA through approval of a SIP revision."

7. Under the "Regional Haze Program (BART Alternative) Specific Conditions" sections for Power Boilers No. 1 and No. 2, paragraphs 52 and 72 (pg. 70 and pg. 95), need to be amended to reflect that the Power Boiler will meet the BART alternative limits if it chooses to permanently retire. Emission requirements remain even when a unit is retired. Please amend paragraph 52 to state that "In the event SN-03 (No. 1 Power Boiler) is permanently retired, the BART Alternative limits and conditions will be met through the retirement of the source." The same amendment needs to be made to paragraph 72 (pg. 95) with respect to Power Boiler No. 2.

8. ADEQ is opting to comply with the Clean Air Act's regional haze requirements for the first implementation period for the Domtar Ashdown Mill No.1 and No. 2 Power Boilers through a BART alternative under 40 CFR § 51.308(e)(2). ADEQ must ensure that Domtar Power Boilers No. 1 and 2 meet all the general recordkeeping and reporting requirements that apply to all subject-to-BART sources under 40 CFR § 51.308(e). In addition, any source-specific SIP revision, including a permit, must contain enforceable procedures such as monitoring, reporting, recordkeeping, and methodologies for determining compliance. Therefore, specific recordkeeping and reporting requirements similar to those contained in ADEQ's proposed Administrative Order for the Domtar Ashdown Mill, which was part of the Regional Haze Phase III SIP Revision proposed by ADEQ on October 5, 2018, must be added to the "Regional Haze Program (BART Alternative) Specific Conditions" sections of the permit for Power Boilers No. 1 and No. 2.

9. Specific Condition No. 74 of the Draft Permit provides that the No. 2 Power Boiler, which is subject to the Boiler MACT Rule at 40 CFR Part 63 subpart DDDDD—hybrid suspension grate units designed to burn wet biomass/bio-based solid subcategory, will utilize the applicable $PM_{10}$ compliance demonstration requirements from subpart DDDDD to demonstrate compliance with the PM10 emission limit under regional haze. We note that Provision No. 7 of the proposed Administrative Order for the Domtar Ashdown Mill contained in the Phase III SIP Revision proposed by ADEQ on October 5, 2018, states that the owner/operator shall keep records of PM compliance testing under Boiler MACT for No. 2 Power Boiler for five (5) years, and that if testing requirements under Boiler MACT are no longer required under federal law, the owner/operator shall demonstrate compliance for regional haze purposes by keeping records of compliance testing using EPA Reference Method 5 every five years. For this source-specific SIP revision to continuously meet all the applicable enforcement requirements, the alternate compliance demonstration provision must be added to the Specific Conditions for the No. 2 Power Boiler to ensure that the boiler continues to demonstrate compliance with the regional haze provisions in the event it is no longer subject to the Boiler MACT requirements.

ADEQ

ARKANSAS
Department of Environmental Quality

AUG - 1 2019

Kelley Crouch, Environmental Manager
Domtar A.W. LLC - Ashdown Mill
285 Highway 71 South
Ashdown, AR 71822

Dear Ms. Crouch:

The enclosed Permit No. 0287-AOP-R22 is your authority to construct, operate, and maintain the equipment and/or control apparatus as set forth in your application initially received on 1/30/2019.

After considering the facts and requirements of A.C.A. §8-4-101 et seq. as referenced by §8-4-304, and implementing regulations, I have determined that Permit No. 0287-AOP-R22 for the construction and operation of equipment at Domtar A.W. LLC - Ashdown Mill shall be issued and effective on the date specified in the permit, unless a Commission review has been properly requested under Arkansas Department of Pollution Control & Ecology Commission's Administrative Procedures, Regulation 8, within thirty (30) days after service of this decision.

The applicant or permittee and any other person submitting public comments on the record may request an adjudicatory hearing and Commission review of the final permitting decisions as provided under Chapter Six of Regulation No. 8, Administrative Procedures, Arkansas Pollution Control and Ecology Commission. Such a request shall be in the form and manner required by Regulation 8.603, including filing a written Request for Hearing with the APC&E Commission Secretary at 101 E. Capitol Ave., Suite 205, Little Rock, Arkansas 72201. If you have any questions about filing the request, please call the Commission at 501-682-7890.

Sincerely,

Stuart Spencer
Associate Director, Office of Air Quality

Enclosure: Final Permit

**RESPONSE TO COMMENTS**

**DOMTAR A.W. LLC - ASHDOWN MILL**
**PERMIT #0287-AOP-R22**
**AFIN: 41-00002**

On April 7, 2019 and April 11, 2019, the Director of the Arkansas Department of Environmental Quality gave notice of a draft permitting decision for the above referenced facility. During the comment period, written comments on the draft permitting decision were submitted by both the facility and the EPA. The Department's response to these issues follows.

*Note: The following page numbers and condition numbers refer to the draft permit. These references may have changed in the final permit based on changes made during the comment period.*

**Comment #1:** EPA Region 6 requests a clarification in regards to the Summary of Permit Activity. The Summary currently states that there are no changes to the permitted emissions for this application. The clarification is that there are no changes to the tons of pollutant per year emitted by the facility.

**Response to Comment #1:** ADEQ agrees that this clarification should be included in the permit. This change has been made.

**Comment #2:** EPA Region 6 requests that the table of applicable regulations on page 14 include the BART eligible and subject-to-BART determinations (40 CFR 52.173) as well as the subject-to-BART alternative (40 CFR 51.308(e)(2)).

**Response to Comment #2:** ADEQ agrees that this clarification should be included in the permit. This change has been made.

**Comment #3:** EPA Region 6 requests that the citations for the BART alternative conditions (starting pages 69 and 95 for SN-03 and SN-05 respectively) be made more specific, and read 40 CFR 51.308(e)(2) as well as 40 CFR 52.173.

**Response to Comment #3:** ADEQ agrees that this clarification should be included in the permit. This change has been made.

**Comment #4:** EPA Region 6 requests that the following sentence (found on both page 69 and 95) be amended from "The following terms and conditions of the BART Alternative measures are to be submitted to EPA for inclusion in the Arkansas State Implementation Plan (SIP)" to "The following terms and conditions of the BART Alternative measures are to be submitted to EPA for approval as part of the Arkansas State Implementation Plan (SIP)".

**Response to Comment #4:** ADEQ agrees that this clarification should be included in the permit. This change has been made. These conditions have been moved to Plantwide section of the permit. See Comment/Response #9.

**Comment #5:** EPA Region 6 requests that the BART/Regional Haze description (found on pages 69 and 95) have the following sentence added: "Once this section of the permit is initially approved into the SIP, any future revisions to this section of the permit will not be effective until approved by EPA through approval of a SIP revision."

**Response to Comment #5:** While ADEQ understands that modifying the facility permit does not, by default, modify the SIP, the above wording is too strict in scope. The following wording will be added to the BART/Regional Haze descriptions instead: "Upon initial EPA approval of this section of the permit into the SIP, the permittee shall continue to be subject to the conditions as approved into the SIP even if the conditions below are revised as part of a permit amendment until such time as EPA approves any revised conditions into the SIP. The permittee shall remain subject to both the initial SIP-approved conditions and the revised conditions, until EPA approves the revised conditions." These conditions have been moved to Plantwide section of the permit. See Comment/Response #9.

**Comment #6:** EPA Region 6 requests that specific conditions 52 and 72 be amended to reflect that the BART alternative limits will be met if the respective source is permanently retired.

**Response to Comment #6:** ADEQ agrees that permanent retirement of a source will meet the requirements of said source. The permit will be modified to reflect that permanent retirement of either source will be considered compliance with all Regional Haze conditions affecting that source. These conditions have been moved to Plantwide section of the permit. See Comment/Response #9.

**Comment #7:** EPA Region 6 requests that specific recordkeeping and reporting requirements similar to those contained in the proposed Administrative Order be added.

**Response to Comment #7:** ADEQ agrees that recordkeeping and reporting requirements are necessary in order for a facility to show compliance with other conditions. The following Regional Haze condition will be added to the permit: "The permittee shall keep records showing compliance with specific conditions 50-52 and 70-74. All records showing compliance with specific conditions 50-52 and 70-74 shall be retained for at least 5 years and shall be made available to any agent of ADEQ or EPA upon request." [Reg. 19.304, 40 C.F.R. §51.173 and 40 C.F.R. §51.308(e)(2)]. Note these conditions have been moved to Plantwide section of the permit and the references updated, see Comment/Response #9.

**Comment #8:** EPA Region 6 requests that language be included in the permit such that if Boiler MACT Rule 40 CFR 63, Subpart DDDDD (5D), is no longer applicable that the facility will revert to using EPA Reference Method 5 every five years.

**Response to Comment #8:** ADEQ agrees that an alternative should be in place. The following wording will be added to the permit: "The permittee may request that the Department approve an alternative sampling or monitoring method to the methods specified in specific conditions 50-52 and 70-74. The Department, with the concurrence of EPA, may approve, at its discretion the alternative sampling method." [Reg. 19.304, 40 C.F.R. §51.173 and 40 C.F.R. §51.308(e)(2)].

)]. Note these conditions have been moved to Plantwide section of the permit and the references updated, see Comment/Response #9.

**Comment #9:** Domtar requests that the BART/Regional Haze conditions be moved to the Plantwide Condition section of the permit. This is so that Domtar does not need to perform hours of administrative work to revise compliance forms.

**Response to Comment #9:** Moving the Regional Haze conditions to the Plantwide Conditions has no impact on enforceability of these conditions and will ensure that SIP requirements remain in the permit even if one or both units are retired as contemplated in the draft permit specific conditions 52 and 72. This change has been made.

**Comment #10:** Domtar requests that the proposed definition, in specific conditions 50 and 70, of "30 boiler operating day rolling average" be changed to read "the arithmetic average of 30 consecutive daily values in which there is any hour of operation, and where each daily value is generated by summing the pounds of pollutant for that day and dividing the total by the sum of the hours the boiler was operating that day. A day is from 6 am one calendar day to 6 am the following calendar day."

**Response to Comment #10:** ADEQ agrees that the above definition is more accurate, and a better representation, than what is currently in the permit. This change has been made. Note these conditions have been moved to Plantwide section of the permit and the references updated, see Comment/Response #9.

# BEST AVAILABLE RETROFIT TECHNOLOGY DETERMINATION

## DOMTAR INDUSTRIES INC. ▪ ASHDOWN MILL (AFIN 41-00002)


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October 31, 2006
*Revised on March 26, 2007*

**Project 060401.0081**

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# 1. INTRODUCTION

Domtar Industries Inc. (Domtar) owns and operates a kraft paper mill located at 285 Highway 71 South in Ashdown, Arkansas (the Ashdown Mill). The Ashdown Mill is a major source as defined in Arkansas Pollution Control and Ecology Commission (ADP&E) Regulation 26, *Regulations of the Arkansas Operating Air Permit Program*, and currently operates under the authority of Arkansas Department of Environmental Quality (ADEQ) Operating Air Permit 0287-AOP-R6, which was issued on July 12, 2006.

The ADEQ has determined that the Ashdown Mill operates two emission units – No. 1 and No. 2 Power Boilers – that are eligible to be regulated under the Best Available Retrofit Technology (BART) provisions of the U.S. Environmental Protection Agency's (EPA) Regional Haze Rule in Title 40 of the Code of Federal Regulations (40 CFR) Part 51. BART is the primary mechanism identified for regulating haze-forming pollutants from stationary sources for the first implementation period under the Regional Haze Rule. The ADEQ has also determined, based on air dispersion modeling, that emissions from the Ashdown Mill BART-eligible source contributes to visibility impairment at a federally protected Class I area. Therefore, Domtar has prepared this report to document its BART determination in accordance with *Appendix Y to Part 51 – Guidelines for BART Determinations Under the Regional Haze Rule* (the BART Guidelines).

An overview of the Regional Haze Rule and BART Guidelines is provided in Section 1.1. Descriptions of the Ashdown Mill's BART-eligible emission units are included in Section 2. Section 3 describes the BART applicability analysis completed by the ADEQ for the Ashdown Mill BART-eligible source. Domtar's BART determination analysis is included in Section 4.

## 1.1 OVERVIEW OF REGIONAL HAZE RULE AND BART GUIDELINES

The Regional Haze Rule requires that major sources of visibility-affecting pollutants belonging to one or more of 26 specific industrial source categories evaluate BART if the source was in existence before August 7, 1977 and began operation after August 7, 1962. "Major sources of visibility-affecting pollutants" are sources that have the potential to emit 250 tons per year (tpy) or more of any of the following: oxides of nitrogen ($NO_X$), sulfur dioxide ($SO_2$), or particulate matter (PM).[1] The "BART-eligible source" is the collection of sources at a facility meeting the applicability criteria.

### 1.1.1 BART APPLICABILITY

In the BART applicability analysis, a BART-eligible source is determined to be subject to BART if it causes or contributes to visibility impairment at one or more of the 156 federally protected Class I areas. Per the U.S. EPA's BART Modeling Guidance, "an individual source will be considered to 'cause visibility impairment' if the emissions

[1] As allowed in the BART Guidelines, the ADEQ has determined that volatile organic compounds (VOC) and ammonia are <u>not</u> visibility-affecting pollutants for the purposes of BART analyses.

results in a change (delta $\Delta$) in deciviews (dv)[2] that is greater than or equal to 1.0 deciview on the visibility in a Class I area…if the emissions from a source results in a change in visibility that is greater than or equal to 0.5 dv in a Class I area the source will be considered to 'contribute to visibility impairment.'" To determine whether a BART-eligible facility causes or contributes to visibility impairment, the U.S. EPA guidance requires the use of an air quality model, specifically recommending the CALPUFF modeling system, to quantify the impacts attributable to a single BART-eligible source. Because contribution to visibility impairment is sufficient cause to require a BART determination, 0.5 dv is the critical threshold for assessment of BART applicability.

Regional haze is quantified using the light extinction coefficient ($b_{\text{ext}}$), which is expressed in terms of the haze index (*HI*) expressed in dv. The *HI* is calculated as shown in the following equation.

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

The impact of a BART-eligible source is determined by comparing the *HI* attributable to a source to estimated natural background conditions. That is, a single-source visibility impact is measured as the change in light extinction versus background, and is referred to as $\Delta$dv. The background extinction coefficient is affected by various chemical species and the Rayleigh scattering phenomenon and can be calculated as shown in the following equation.

$$b_{ext,background}\left(\mathrm{Mm}^{-1}\right) = b_{SO_4} + b_{NO_3} + b_{OC} + b_{Soil} + b_{Coarse} + b_{EC} + b_{Ray}$$

where:

| | |
|---|---|
| $b_{SO_4} = 3\left[(\mathrm{NH}_4)_2\mathrm{SO}_4\right] f(RH)$ | $\left[(\mathrm{NH}_4)_2\mathrm{SO}_4\right]$ denotes the ammonium sulfate concentration |
| $b_{NO_3} = 3\left[\mathrm{NH}_4\mathrm{NO}_3\right] f(RH)$ | $\left[\mathrm{NH}_4\mathrm{NO}_3\right]$ denotes the ammonium nitrate concentration |
| $b_{OC} = 4[\mathrm{OC}]$ | $[\mathrm{OC}]$ denotes the concentration of organic carbon |
| $b_{Soil} = 1[\mathrm{Soil}]$ | $[\mathrm{Soil}]$ denotes the concentration of fine soils |
| $b_{Coarse} = 0.6[\mathrm{Coarse\ Mass}]$ | $[\mathrm{Coarse\ Mass}]$ denotes the concentration of coarse dusts |
| $b_{EC} = 10[\mathrm{EC}]$ | $[\mathrm{EC}]$ denotes the concentration of elemental carbon |
| $b_{Ray} = \text{Rayleigh Scattering}\left(10\ \mathrm{Mm}^{-1}\ \text{by default}\right)$ | Rayleigh Scattering is scattering due to air molecules |
| $f(RH) = \text{Relative Humidity Function}$ | |
| $[\ ] = \text{Concentration in } \mu\mathrm{g/m}^3$ | |

Values for the parameters listed above specific to the natural background conditions at each Class I area are provided on an annual-average basis in the U.S. EPA's *Guidance for Estimating Natural Visibility Conditions under the Regional Haze Rule*.[3]

[2] The deciview (dv) is a metric used to represent normalized light extinction attributable to visibility-affecting pollutants.

[3] U.S. EPA, *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*, Table 2-1, Attachment A, September 2003, EPA-454/B-03-005.

Particulate species that affect visibility are emitted from anthropogenic (human-caused) sources and include coarse particulate matter (PMC), fine particulate matter (PMF), and elemental carbon (EC) as well as precursors to secondary organic aerosols (SOA) and fine particulate matter such as $SO_2$ and $NO_X$. The extinction coefficient due to emissions of visibility-affecting pollutants from a single BART-eligible source is calculated according to the following equation.

$$b_{ext,source}\left(\mathrm{Mm}^{-1}\right) = b_{SO_4} + b_{NO_3} + b_{SOA} + b_{PMF} + b_{PMC} + b_{EC}$$

where:

$$b_{SO_4} = 3\left[(\mathrm{NH_4})_2\mathrm{SO_4}\right] f(RH)$$
$$b_{NO_3} = 3\left[\mathrm{NH_4NO_3}\right] f(RH)$$
$$b_{SOA} = 4[\mathrm{SOA}]$$
$$b_{PMF} = 1[\mathrm{PMF}]$$
$$b_{PMC} = 0.6[\mathrm{PMC}]$$
$$b_{EC} = 10[\mathrm{EC}]$$
$f(RH)$ = Relative Humidity Function
$[\;]$ = Concentration in $\mu g/m^3$

$\left[(\mathrm{NH_4})_2\mathrm{SO_4}\right]$ denotes the ammonium sulfate concentration
$\left[\mathrm{NH_4NO_3}\right]$ denotes the ammonium nitrate concentration
$[\mathrm{SOA}]$ denotes the concentration of secondary organic aerosols
$[\mathrm{PMF}]$ denotes the concentration of fine PM
$[\mathrm{PMC}]$ denotes the concentration of coarse PM
$[\mathrm{EC}]$ denotes the concentration of elemental carbon

#### 1.1.1.1 CALPUFF MODELING ANALYSES

As stated above, the BART Guidelines recommend using the CALPUFF modeling system to compute the 24-hour average visibility impairment attributable to a BART-eligible source to assess whether the 0.5 $\Delta$dv contribution threshold is exceeded, and if so, the frequency, duration, and magnitude of any exceedance events. CALPUFF is a refined air quality modeling system that is capable of simulating the dispersion, chemical transformation, and long-range transport of multiple visibility-affecting pollutant emissions and is therefore preferred for BART applicability and determination analyses.

### 1.1.2 BART DETERMINATION

BART-eligible sources that are found to cause or contribute to visibility impairment at a Class I area are required to make a BART determination. The BART Guidelines define BART as follows:

> *BART means 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 costs 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. The BART analysis identifies the best system of continuous emission reduction taking into account:*

*(1) The available retrofit control options,*
*(2) Any pollution control equipment in use at the source (which affects the availability of options and their impacts),*
*(3) The costs of compliance with control options,*
*(4) The remaining useful life of the facility,*
*(5) The energy and non-air quality environmental impacts of control options*[*, and*]
*(6) The visibility impacts analysis.*

The BART Guidelines define the following three steps for determining which emission units at a facility are BART-eligible:

1. Identify the emission units in the BART source categories,
2. Identify the start-up dates of those units, and
3. Compare potential emissions to the 250 ton/yr cutoff.

"Fossil-fuel boilers of more than 250 million BTUs per hour heat input" are one of the listed BART source categories. The Ashdown Mill's No. 1 and No. 2 Power Boilers are each greater than 250 million British thermal units per hour (MMBtu/hr), were in existence on August 7, 1977, began operation after August 7, 1962, and each have potential emissions greater than 250 tpy of PM, $NO_X$, or $SO_2$; therefore, these units make up the Ashdown Mill's BART-eligible source. A summary of the BART eligibility criteria for each emission unit is provided in Table 2-1.

**TABLE 2-1. SUMMARY OF BART-ELIGIBLE EMISSION UNITS**

| Emission Unit | Source Number | BART Source Category | Year of Completion of Construction or Reconstruction | Potential $SO_2$ Emissions (tpy) | Potential $NO_X$ Emissions (tpy) | Potential $PM/PM_{10}$ Emissions (tpy) |
|---|---|---|---|---|---|---|
| No. 1 Power Boiler | SN-03 | Boiler [a] | 1968 | 214.0 | 1,084.1 | 1,502.3 |
| No. 2 Power Boiler | SN-05 | Boiler [a] | 1976 | 4,305.5 | 2,514.1 | 359.2 |

[a] Fossil-fuel boilers of more than 250 million BTUs per hour heat input.

Detailed descriptions of each unit are provided in the sub-sections below.

## 2.1 NO. 1 POWER BOILER

The No. 1 Power Boiler (SN-03), also known as the Bark Boiler, was installed in 1968. It has a heat input rating of 580 MMBtu/hr and an average steam generation rate of approximately 120,000 pounds per hour (lb/hr). It combusts primarily bark (approximately 75 percent of the heat input is supplied by bark), but is also permitted to burn bark and wood chips used to absorb oil spills, wood waste, recycled sanitary products composed of cellulose and polypropylene, pelletized paper fuel (PPF), tire-derived fuel (TDF), municipal yard waste, No. 6 fuel oil, reprocessed fuel oil, used oil generated on site, and natural gas. Natural gas is only used to supplement other fuels during high steam demand periods. Fuel oil usage is limited to 2,700,000 gallons per year, and the sulfur content of the fuel oil used is limited to 3.0 percent by weight. TDF usage (total for No.1, No. 2, and No. 3 Power Boilers) is limited to 220 tons per day.

The No. 1 Power Boiler is equipped with a traveling grate, a combustion air system, and multiclones.

The No. 1 Power Boiler is not subject to any New Source Performance Standards (NSPS) in 40 CFR Part 60. It is subject to 40 CFR Part 63, Subpart DDDDD, *National Emissions Standard for Hazardous Air Pollutants* (NESHAP) *for Industrial, Commercial, and Institutional Boilers and Process Heaters*. NESHAP DDDDD establishes Maximum Achievable Control Technology (MACT) limits and is commonly referred to as "the Boiler MACT."

To meet the applicable Boiler MACT PM emission standard of 0.07 lb/Mmbtu, Domtar is preparing to install a wet electrostatic precipitator (WESP) on the No. 1 Power Boiler.

## 2.2 NO. 2 POWER BOILER

The No. 2 Power Boiler (SN-05) started operations in February 1976. It has a heat input rating of 820 MMBtu/hr and an average steam generation rate of approximately 600,000 lb/hr. It combusts primarily bituminous coal (over 80 percent of the heat input is supplied by coal), but is also permitted to burn bark, bark and wood chips used to absorb oil spills, wood waste, petroleum coke (pet coke), recycled sanitary products based on cellulose and polypropylene, PPF, TDF, municipal yard waste, No. 6 fuel oil, reprocessed fuel oil, used oil generated on site, natural gas, and non-condensable gases (NCGs). The NCGs are produced in the pulp area (from the cooking of chips) and evaporator area (where weak black liquor is concentrated) and consist of nitrogen, total reduced sulfur (TRS) compounds, methanol, acetone, $SO_2$, and minor quantities of other compounds such as methyl ethyl ketone (MEK). Under normal operating conditions, natural gas is not combusted.

The No. 2 Power Boiler is equipped with a traveling grate, combustion air system including overfire air, multiclones, and two parallel venturi scrubbers. The $SO_2$ loading to the boiler is significant since the boiler burns coal and NCGs. Therefore, the scrubbing fluid includes water and a source of alkali, such as sodium hydroxide (i.e., caustic) and/or pulp mill extraction stage filtrate.

The No. 2 Power Boiler is subject to 40 CFR 60, Subpart D, *Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971*, 40 CFR 60, Subpart BB, *Standards of Performance for Kraft Pulp and Paper Mills* (since it combusts NCGs), and 40 CFR Part 63, Subpart DDDDD, *National Emissions Standard for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters*.

The No. 2 Power Boiler is equipped with Continuous Emissions Monitoring Systems (CEMS) for $NO_X$, $SO_2$, and carbon monoxide (CO). In accordance with 40 CFR 60, Subpart BB, the No. 2 Power Boiler also has a continuous flame pyrometer to measure the temperature at the point of NCG injection (the temperature at the injection point must remain at or above 1200 ºF for at least 0.5 seconds at all times that NCGs are being burned).

This section summarizes the source-specific inputs and results of the BART applicability analysis conducted by the ADEQ for Domtar's Ashdown Mill BART-eligible source. The screening modeling methodologies and data resources used by the ADEQ in executing the CALPUFF modeling system are described in technical detail in the ADEQ's *Draft BART Modeling Protocol* (the Protocol), dated June 7, 2006, and in the Central Regional Air Planning Association (CENRAP) *BART Modeling Guidelines* (issued on December 22, 2005, and re-issued on February 3, 2006). A copy of the Protocol is included in Appendix A.

## 3.1 MODELED ASHDOWN MILL EMISSIONS

Whereas the BART eligibility determination relies on current potential emissions of visibility-affecting pollutants, the BART applicability modeling analysis is based on maximum 24-hour average actual emission rates of $NO_X$, $SO_2$, and $PM_{10}$ for the modeled three-year period (i.e., 2001, 2002, & 2003).[4] At the ADEQ's request, Domtar estimated the 24-hour average maximum actual emission rates of visibility-affecting pollutants from the No. 1 and No. 2 Power Boilers using a combination of CEMS data, source-specific stack testing results, and emission factors from U.S. EPA's AP-42. These emission rates are summarized in Table 3-1.

**TABLE 3-1. SUMMARY OF 24-HOUR AVERAGE MAXIMUM ACTUAL EMISSION RATES**

| Emission Unit | $NO_X$ Emissions (lb/hr) | $SO_2$ Emissions (lb/hr) | $PM_{10}$/PMF Emissions (lb/hr) |
|---|---|---|---|
| No. 1 Power Boiler | 179.6 | 442.5 | 169.5 |
| No. 2 Power Boiler | 526.8 | 788.2 | 81.6 |

## 3.2 MODELED ASHDOWN MILL STACK PARAMETERS

Actual stack parameters were input to the CALPUFF model to represent each emissions point. The location of each point was represented using the Lambert Conformal Coordinate (LCC) system. According to the Protocol, because the BART modeling focuses on mesoscale transport to Class I areas, effects of building downwash were not considered in the ADEQ's analysis. Table 3-2 summarizes the stack parameters modeled for the BART-eligible emission units at Domtar's Ashdown Mill.

[4] The ADEQ assumed all $PM_{10}$ emissions were PMF for modeling purposes.

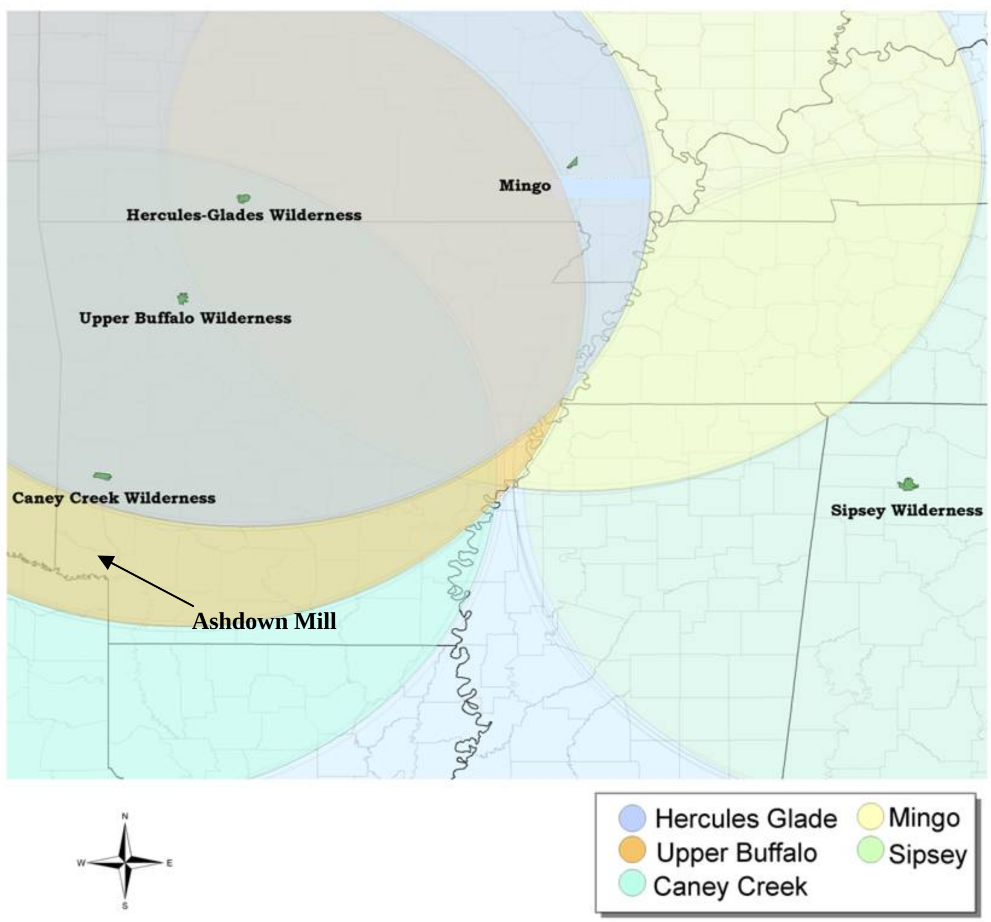
**TABLE 3-2. STACK PARAMETERS**

| Emission Unit | LCC East (km) | LCC North (km) | Base Elevation (m) | Stack Height (m) | Stack Diameter (m) | Exhaust Temperature (K) | Exhaust Velocity (m/s) |
|---|---|---|---|---|---|---|---|
| No. 1 Power Boiler | 267.47491 | -698.66686 | 97.5 | 66.1 | 1.890 | 522 | 26.76 |
| No. 2 Power Boiler | 267.48245 | -698.74355 | 97.5 | 71.6 | 3.659 | 325 | 11.92 |

## 3.3 POTENTIALLY AFFECTED CLASS I AREAS

Regardless of distance from the BART-eligible source, the ADEQ evaluated all Class I areas within 300 km of the Arkansas state boundary in all analyses. Figure 3-1 illustrates the location of the Ashdown Mill relative to each of the modeled Class I areas.

**FIGURE 3-1. LOCATION OF ASHDOWN MILL RELATIVE TO MODELED CLASS I AREAS**




Base map provided by ADEQ.

Table 3-3 presents the Class I areas (and responsible Federal Land Manager [FLM]) included in ADEQ's analyses and the approximate distance from each area to the Ashdown Mill.

**TABLE 3-3. MODELED CLASS I AREAS**

| Class I Area | FLM [a] | Approximate Distance from Ashdown Mill (km) |
|---|---|---|
| Caney Creek Wilderness | FS | 85 |
| Upper Buffalo Wilderness | FS | 250 |
| Hercules-Glades Wilderness | FS | 350 |
| Mingo Refuge | FWS | 510 |
| Sipsey Wilderness | FS | 620 |

[a] FS = Forest Service (Department of Agriculture), FWS = Fish and Wildlife Service (Department of Interior).

## 3.4 BART APPLICABILITY ANALYSIS RESULTS

The ADEQ's BART applicability analysis showed that Domtar's Ashdown Mill contributes to visibility impairment, since the maximum modeled 24-hour average impacts were greater than 0.5 $\Delta$dv, in the Caney Creek, Upper Buffalo, Hercules-Glades, and Mingo Class I areas. The results of the ADEQ's BART applicability analysis for Domtar's Ashdown Mill are summarized in Table 3-4.

**TABLE 3-4. SUMMARY OF BART APPLICABILITY ANALYSIS RESULTS**

| Class I Area | Maximum 24-hour Impact ($\Delta$dv) [a] | Number of Days > 0.5 $\Delta$dv [a] | Number of Days > 1.0 $\Delta$dv [a] |
|---|---|---|---|
| Caney Creek | 2.262 | 159 | 50 |
| Upper Buffalo | 1.181 | 18 | 1 |
| Hercules-Glades | 0.701 | 3 | 0 |
| Mingo | 0.923 | 2 | 0 |
| Sipsey | 0.341 | 0 | 0 |

[a] For total modeled period: years 2001, 2002, and 2003.

Since the ADEQ's BART applicability analysis shows that Domtar's Ashdown Mill BART-eligible source contributes to visibility impairment in at least one Class I area, Domtar must conduct a BART determination analysis for the No. 1 and No. 2 Power Boilers.

# 4. BART DETERMINATION ANALYSIS

In general, BART is determined for each eligible emissions unit using the following five (5) steps from Section IV.D of the BART Guidelines:

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

However, in the preamble to the BART Guidelines, the U.S. EPA clearly encourages the use of streamlined approaches for BART determinations so that states and industry can focus their resources on the main contributors to visibility impairment.[5] Domtar asserts that streamlined BART determinations are appropriate for emissions of PM and $SO_2$ from the Ashdown Mill's No. 1 and No. 2 Power Boilers. The streamlined BART determinations for PM and $SO_2$ are presented in Sections 4.1, 4.2, and 4.3. Steps 1 through 4 of the BART determination analysis for $NO_X$ emissions from the No. 1 and No. 2 Power Boilers are presented in Section 4.3. Section 4.5 presents the visibility impacts evaluation for all pollutants.

## 4.1 BART DETERMINATION FOR PM

Section IV.C of the BART Guidelines describes a streamlined approach for evaluating BART for certain sources that are subject to MACT standards (i.e., NESHAP in 40 CFR 63). The Ashdown Mill's No. 1 and No. 2 Power Boilers are affected sources (in the existing, large, solid fuel subcategory) under the Boiler MACT, and are subject to a PM emissions standard of 0.07 lb/MMBtu. Since the Boiler MACT standard was established recently the technology analysis is up-to-date. The No. 1 and No. 2 Power Boilers must be in compliance with the Boiler MACT standards by September 13, 2007, in advance of the anticipated 2013 BART compliance deadline. Domtar is planning to equip the No. 1 Power Boiler with a WESP to meet the PM standard. The No. 2 Power Boiler is equipped with a wet scrubber and can meet the Boiler MACT PM emission standard. Domtar has not identified any feasible upgrades to the No. 2 Power Boiler's wet scrubber. At ADEQ's request, Domtar evaluated the costs for installing a WESP on the No. 2 Power Boiler. The estimated cost effectiveness, based on the estimates given in the proposal for the WESP on the No. 1 Power Boiler, is at a minimum \$30,000/ton – clearly infeasible. Table 4-1 presents the maximum PM emission rates from each power boiler based on heat input capacity and the Boiler MACT standard.

[5] Federal Register, Vol. 70, No. 128, July 6, 2005, pp 39107 and 39116.

**TABLE 4-1. BART / BOILER MACT-BASED PM EMISSION RATES**

| Emission Unit | PM Emissions (lb/hr) | PM Emissions (tpy) |
|---|---|---|
| No. 1 (Bark) Power Boiler | 40.6 | 177.9 |
| No. 2 (Coal) Power Boiler | 57.4 | 251.5 |

The recent Boiler MACT PM emission standard is presumptively relied upon to meet BART requirements. Accordingly, a comprehensive BART determination analysis is not necessary to determine BART for PM emissions from the Ashdown Mill's No. 1 and No. 2 Power Boilers. The ADEQ agreed to allow this streamlined MACT-equals-BART option in a September 8, 2006, letter, but required that Domtar "consult with the ADEQ Air Division regarding whether the wet electrostatic precipitator (MACT Control) is the best available and cost effective control technology for $PM_{2.5}$."[6] Domtar provides the following evidence that a WESP is the best choice for control of the No. 1 Power Bark Boiler.

Particulate emissions from wood-fired boilers are typically controlled by one of four technologies: baghouse (fabric filter), ESP (wet or dry), wet scrubber, or cyclone. Cyclones provide for the lowest control efficiencies of the options at up to 65 percent, and particulate collection efficiencies of 85 percent or greater have been reported for venturi [wet] scrubbers operating on wood-fired boilers.[7] To achieve control efficiencies of 90 percent or greater, a baghouse or ESP is used. The normal PM control efficiency range for a fabric filter is 95 to 99+ percent, and the normal PM control efficiency range for a WESP is 98 to 99+ percent.[8] Fabric filters are rarely used on wood-fired boilers due to concerns about bag flammability.[9] The principal drawback is a fire danger arising from the collection of combustible carbonaceous fly ash.[10] Both types (i.e., wet and dry) of ESPs are capable of greater than 99 percent removal of particle sizes above 1 micron.[11] An additional benefit of WESPs is that the wash used in WESPs can also have some control effect on other pollutant gases via absorption and can help condense other emissions due to the cooling of the stream.[12] Based on the comparison of control efficiencies and the applicability of each control device, Domtar asserts that the WESP is the best control technology (i.e., BART) for the No. 1 Power Boiler.

[6] Mike Bates (ADEQ), letter to Kelley Crouch (Domtar), September 8, 2006.

[7] U.S. EPA, *Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Source* (AP-42), Fifth Edition, Section 1.6 – Wood Residue Combustion in Boilers, September 2003.

[8] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.

[9] NCASI, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for $NO_X$, $SO_2$ and PM Emissions*, Corporate Correspondence Memo 06-014.

[10] U.S. EPA, *Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Source* (AP-42), Fifth Edition, Section 1.6 – Wood Residue Combustion in Boilers, September 2003.

[11] Northeast States for Coordinated Air Use Management (NESCAUM) and Mid-Atlantic/Northeast Visibility Union (MANE-VU), *Assessment of Control Technology Options for BART-Eligible Sources – Steam Electric Boilers, Industrial Boilers, Cement Plant and Paper and Pulp Facilities*, March 2005.

[12] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.

## 4.2 BART DETERMINATION FOR $SO_2$ – NO. 1 POWER BOILER

Generally, pre-combustion $SO_2$ control strategies involve fuel switching/blending or fuel cleaning so that less fuel-bound sulfur enters the process. However, because wood already contains very little sulfur, pre-combustion $SO_2$ controls are ineffective.

Post-combustion $SO_2$ control is accomplished by reacting the $SO_2$ in the gas with a reagent (usually calcium-based [e.g., lime or limestone] or sodium-based [e.g., caustic]) and removing the resulting product (a sulfate/sulfite) for disposal or commercial use. $SO_2$ reduction technologies are commonly referred to as flue gas desulfurization (FGD) and/or scrubbers and are usually described in terms of the process conditions (wet versus dry), byproduct utilization (throwaway versus saleable) and reagent utilization (once-through versus regenerable).[13] Post-combustion $SO_2$ controls have not been installed on wood-fired boilers because of the relatively low $SO_2$ emissions from wood-combustion (due to the low sulfur content of wood).

Due to the low fuel sulfur input, emissions from wood combustion are inherently low and have a negligible impact on visibility impairment. Therefore, Domtar proposes no additional add-on control, i.e., only the existing fuel restrictions (fuel oil sulfur content and usage limitations) and no additional $SO_2$ removal as BART for $SO_2$ emissions from the No. 1 Power Boiler.

## 4.3 BART DETERMINATION FOR $SO_2$ – NO. 2 POWER BOILER

Section IV.D.1.9 of the BART Guidelines provides an option to skip the comprehensive BART determination analysis for BART-eligible emission units that are already equipped with the most stringent controls available (including any possible improvements to the control device) "as long these most stringent controls available are made federally enforceable for the purpose of implementing BART for that source." The Ashdown Mill's No. 2 Power Boiler is equipped with a wet scrubber for control of $SO_2$ (and particulate) emissions. The existing wet scrubber achieves an $SO_2$ control efficiency of approximately 90 percent, which is within the normal range for the highest efficiency $SO_2$ control strategies and is the BART-based control efficiency presumed by the Central Regional Air Planning Association (CENRAP) and the Midwest Regional Planning Organization (MRPO) for pulp and paper industry power boilers.[14,15]

The No. 2 Power Boiler is equipped with a CEMS for $SO_2$. Thus, Domtar is able to immediately identify needs for both ongoing operational adjustments and periodic maintenance and/or scrubber improvements to maintain high levels of $SO_2$ control. Domtar has not identified any feasible upgrades to the existing wet scrubber. It should be noted that the No. 2 Power Boiler is operated such that $SO_2$ emissions are well below any applicable limits/standards. Since wet scrubbing is the most effective method of controlling $SO_2$ emissions, no additional analysis is needed for $SO_2$ emissions from the No. 2 Power Boiler. Domtar proposes no additional $SO_2$ removal as BART for the No. 2 Power Boiler.

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13 NESCAUM and MANE-VU, *Assessment of Control Technology Options for BART-Eligible Sources – Steam Electric Boilers, Industrial Boilers, Cement Plant and Paper and Pulp Facilities*, March 2005.

14 CENRAP's Control Estimates Spreadsheet dated January 10, 2006.

15 MRPO, *Interim White Paper – Midwest RPO Candidate Control Measures*, March 29, 2005.

## 4.4 BART DETERMINATION ANALYSIS FOR $NO_X$

Each required step of the BART determination analysis for emissions of $NO_X$ from the No. 1 and No. 2 Power Boilers is presented below.

### 4.4.1 STEP 1 - IDENTIFY ALL AVAILABLE RETROFIT CONTROL TECHNOLOGIES

The BART Guidelines require the consideration of all "control technologies with a practical potential for application to the emissions unit and the regulated pollutant under evaluation." The list of available control options should include "the most stringent option and a reasonable set of options for analysis…[, but] it is not necessary to list all permutations of available control levels that exist for a given technology – the list is complete if it includes the maximum level of control each technology is capable of achieving."

Per the BART Guidelines, the BART determination analysis must "take into account technology transfer of controls that have been applied to similar source categories and gas streams [in addition to] existing controls for the source category in question." However, "technologies which have not yet been applied to (or permitted for) full scale operations need not be considered as available; [the U.S. EPA does] not expect the source owner to purchase or construct a process or control device that has not already been demonstrated in practice." The BART Guidelines provides the following additional considerations for preparing the list of potential control options:

- One of the control options should reflect the level of control equivalent to any applicable NSPS,
- Source redesign should not be considered,
- Fuel switching should not be considered, and
- For emission units with existing control measures or devices, one of the control options should involve improvements to the existing controls.

Potential $NO_X$ control technologies and resulting emission control quantities for the Ashdown Mill's No. 1 and No. 2 Power Boilers were identified from the exhaustive review of the U.S. EPA's Clean Air Technology Center, including the RACT/BACT/LAER Clearinghouse (RBLC), control equipment vendor information, publicly-available air permits and applications, and technical literature published by the U.S. EPA, the Regional Planning Organizations (RPOs), and industry groups such as the National Council for Air and Stream Improvement, Inc. (NCASI).[16] In fact, Domtar has largely relied upon the extensive research conducted by NCASI regarding the applicability and effectiveness of each control option for coal- and wood-fired pulp and paper mill power boilers. Each $NO_X$

[16] *NCASI is an independent, non-profit research institute that focuses on environmental topics of interest to the forest products industry. NCASI was established in 1943…In the years since, NCASI has developed technical expertise spanning the spectrum of environmental challenges facing the forest products industry, and is today recognized as the leading source of reliable data on environmental issues affecting this industry.* (http://www.ncasi.org/about/default.aspx)

control option identified as potentially applicable to either power boiler is listed below and explained in detail in the following subsections.

- Selective Non-Catalytic Reduction (SNCR) / $NO_X$OUT
- Selective Catalytic Reduction (SCR)
- Low $NO_X$ Burners (LNB) and Ultra Low $NO_X$ Burners (ULNB)
- Over-fire Air (OFA)
- Reburning / Methane de-$NO_X$ (MdN)
- Flue Gas Recirculation (FGR) (Internal and External)
- Fuel Blending / Boiler Operational Modifications / Tuning / Optimization

For this analysis, utility boiler control technology determinations were generally not considered since utility boilers and pulp and paper mill power boilers are considered too dissimilar.

> *The greatest difference in utility and power boiler operations is the fluctuating steam demand characteristic of pulp and paper mill operations which requires that power boilers continuously adjust fuel firing rates and excess air levels. Even with the most sophisticated combustion controls, it is not practical or safe to maintain excess air continuously at minimum levels. Consequently, power boilers have characteristically and inherently higher $NO_X$ emissions.*
>
> *…$NO_X$ reduction measures are particularly difficult to implement in small, low capacity facilities because a) residence time is limited and often inadequate for applying OFA without excessive loss of thermal efficiency or induced smoking; b) relatively small furnace dimensions limit combustion modifications that increase flame length and tend to cause the flame to impinge on tube wall;, c) peak boiler efficiency and minimized $NO_X$ emissions occur close to minimum flue-gas $O_2$ content, which is at the threshold of smoke or combustible-emissions formation; d) steam is used far more effectively in industrial applications than in conventional electric utility plants and, consequently, emission limits based on boiler heat input or volume of flue gas do not recognize such efficiency.*[17]

Combustion-related $NO_X$ emissions are formed by two mechanisms. $NO_X$ formed from oxidation of molecular nitrogen ($N_2$) in combustion air is referred to as "thermal $NO_X$" and is dependent on high temperatures (approximately 2,800 °F) and an excess of combustion air. $NO_X$ formed by oxidation of nitrogen compounds in fuel is referred to as "fuel $NO_X$." The $NO_X$ formed from coal combustion is primarily fuel $NO_X$.[18] Fuel $NO_X$ is also the dominant $NO_X$ formation mechanism operative during wood combustion because wood combustion in boilers seldom reaches high enough temperatures.[19,20]

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[17] NCASI, *$NO_X$ Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.
[18] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.
[19] NCASI, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for $NO_X$, $SO_2$ and PM Emissions*, Corporate Correspondence Memo 06-014.

The possible $NO_X$ emissions control technologies generally fit into one of two categories: combustion modifications, which are often associated with improving boiler performance, or flue gas treatment (i.e., post-combustion controls). Pre-combustion techniques to reduce fuel $NO_X$ have shown little promise.[21] Combustion modifications are the most common, commercially available means of controlling $NO_X$ emissions from fossil fuel-fired boilers.[22] However, since wood-fired boilers normally burn at lower temperatures (around 1,500 °F), the units have inherently lower $NO_X$ emissions, and, as a result, <u>$NO_X$ combustion control technologies are not applicable to wood-fired boilers</u>.[23] During the past decade, LNB with FGR and LNB alone were the most commonly recommended $NO_X$ control technologies for oil/gas and coal-fired boilers, respectively, while good combustion control was typically the only recommendation for wood waste-fired boilers.[24]

***COMBUSTION MODIFICATIONS***

### 4.4.1.1 FLUE GAS RECIRCULATION

Generally, FGR involves extracting a portion (15 to 30 percent) of the flue gas and readmitting it to the furnace through the burner window. When the flue gas is extracted from the economizer or air heater outlet, a separate fan/blower is needed to withdraw the flue gas. This setup is referred to as external or forced FGR. Internal or induced FGR refers to the setup where the flue gas is extracted from upstream of the stack using the forced draft (FD) fan instead of a separate FGR fan. In either setup, the recirculated flue gas acts as a thermal diluent (i.e., heat sink) to reduce combustion temperatures. It also dilutes the combustion reactants and reduces the excess air requirements thereby reducing the concentration of oxygen in the combustion zone. Thus, thermal $NO_X$ formation is inhibited.[25] The onset of thermal $NO_X$ occurs around 2,800 °F, and $NO_X$ generation increases exponentially with temperatures beyond 2,800 °F. As only thermal $NO_X$ can be controlled by this technique, it is especially effective only in oil and gas-fired units.[26]

### 4.4.1.2 LOW $NO_X$ BURNERS / ULTRA LOW $NO_X$ BURNERS

LNB technology utilizes advanced burner design to reduce $NO_X$ formation through the restriction of oxygen, flame temperature, and/or residence time. A

[20] NCASI, *$NO_X$ Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.
[21] Ibid.
[22] Ibid.
[23] STAPPA and ALAPCO, *Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options*, March 2006.
[24] NCASI, *$NO_X$ Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.
[25] U.S. EPA, Clean Air Technology Center, *Nitrogen Oxides ($NO_X$), Why and How They Are Controlled*. Research Triangle Park, North Carolina, EPA-456/F-99-006R, November 1999.
[26] NCASI, *$NO_X$ Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

LNB is a staged combustion process that is designed to split fuel combustion into two zones, primary combustion and secondary combustion. Two general types of LNB exist: staged fuel and staged air. Lower emission rates can be achieved with a staged fuel burner than with a staged air burner. Staged fuel LNB separate the combustion zone into two regions. The first region is a lean primary combustion region where the total quantity of combustion air is supplied with a fraction of the fuel. Combustion in the primary region (first stage) takes place in the presence of a large excess of oxygen at substantially lower temperatures than a standard burner. In the second region, the remaining fuel is injected and combusted with any oxygen left over from the primary region. The remaining fuel is introduced in the second stage outside of the primary combustion zone so that the fuel/oxygen are mixed diffusively (rather than turbulently), which maximizes the reducing conditions. This technique inhibits the formation of thermal $NO_X$, but has little effect on fuel $NO_X$. By increasing residence times staged air LNB provide reducing conditions, which have a greater impact on fuel $NO_X$ than staged fuel burners. The estimated $NO_X$ control efficiency for LNB in high temperature applications is 25 percent.[27]

The application of LNB is often limited by the longer flames produced as a consequence of improved air distribution control. While there is generally ample room for LNB flames in utility furnaces, their use on smaller power boilers can result in flame impingement on furnace walls, leading to tube wall overheating and mechanical failure. Flame impingement can also result in premature flame quenching and increased soot and CO emissions.[28]

ULNB combine LNB and FGR technologies and may incorporate other techniques such steam injection. The FGR design within ULNB recirculates flue gas from the flame or firebox back into the combustion zone in an effort to reduce oxygen concentrations without significantly reducing flame temperature. Reduced oxygen concentrations in the flame have a strong impact on fuel $NO_X$.[29] ULNB also tend to have large diameters, but shorter flame lengths and may be easier to retrofit.[30]

Combustion modification with LNB is used in both gas/oil-fired and coal-fired units.[31] LNB are not used for wood-fired boilers. The No. 1 Power Boiler burns only a small amount of fuel for which LNB technology exists. Therefore, LNB is not considered further for the No. 1 Power Boiler.

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[27] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.

[28] NCASI, *$NO_X$ Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[29] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.

[30] NCASI, *$NO_X$ Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[31] Ibid.

#### 4.4.1.3 OVERFIRE AIR

In OFA, about 10 to 20 percent of the combustion air flow is directed to separate air ports located downstream of the burners. OFA works by reducing the excess air in the burner zone, thereby enhancing the combustion staging effect and theoretically reducing $NO_X$ emissions. Residual unburned material, such as CO and unburned carbon, which inevitably escapes the main burner zone, is oxidized as the OFA is admixed later.[32]

OFA vendors (e.g., Jansen Combustion and Boiler Technologies, Inc.) have informed Domtar that while OFA often results in decreased $NO_X$ emissions, the primary purpose is combustion optimization, and implementation of OFA can actually increase $NO_X$ emissions in certain circumstances. Domtar has experienced this potential adverse effect. A recent OFA upgrade to the Ashdown Mill's No. 3 Power Boiler (not a BART-eligible unit) is still in startup mode, but so far Domtar has measured a noteworthy increase in $NO_X$ emissions.

Domtar does not consider OFA to be a potential $NO_X$ control technology, and OFA is not considered further in this analysis.

#### 4.4.1.4 REBURNING / METHANE DE-$NO_X$

In reburning, also known as "off-stoichiometric combustion" or "fuel staging," a fraction (5 to 25 percent) of the total fuel heat input is diverted to a second combustion zone downstream of the primary zone. The fuel in the fuel-rich secondary zone acts as a reducing agent, reducing NO, which is formed in the primary zone, to $N_2$. Low nitrogen-containing fuels such as natural gas and distillate oil are typically used for reburning to minimize further $NO_X$ formation. Generally, it is more economical for a facility to use the same fuel for reburning as it does for primary combustion, although there are exceptions. In order to use coal as a reburning fuel, it must be finely ground, which requires additional pulverizing equipment.[33]

MdN utilizes the injection of natural gas together with recirculated flue gases (for enhanced mixing) to create an oxygen-rich zone above the combustion grate. Air is then injected at a higher furnace elevation to burn out the combustibles. This process is claimed to yield between 50 and 70 percent $NO_X$ reduction and to be suitable for all solid fuel-fired stoker boilers. However, as of 2002, MdN had only been demonstrated for a short duration in one pulp mill wood-fired stoker boiler that also burned small amounts of waste treatment plant residuals, with $NO_X$ reductions of 40 to 50 percent reported.[34]

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[32] Ibid.

[33] STAPPA and ALAPCO, *Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options*, March 2006.

[34] NCASI, *$NO_X$ Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

More recently, MdN is being applied to kraft pulp mill stoker boilers by utilizing the VOC content of NCGs to partially replace the natural gas (by up to 25 percent). This technology has been tested for over a year at one pulp mill boiler, and is being tested at several boilers within one forest products industry (FPI) company.[35]

#### 4.4.1.5 FUEL BLENDING

Since wood is inherently low in nitrogen content, fuel blending is not feasible for wood-fired boilers. Therefore, this control strategy is not considered for the Ashdown Mill's No. 1 Power Boiler.

Coal-fired boilers could experience a decrease in $NO_X$ emissions from fuel blending. Preliminary results show that the co-firing of up to 7 percent biomass, on a heat-input basis, with crushed or pulverized coal can lower $NO_X$ emissions by as much as 15 percent.[36] However, fuel biasing on an industrial boiler subject to rapid and excessive load swings could result in too rich or too lean firing conditions, which can lead to flame stability problems and explosive conditions.[37] In addition, unlike utilities, which can specify the nitrogen content of their large oil purchases, most industrial mills cannot.[38]

Domtar historically mixes 10 to 15 percent (heat input basis) wood with coal in the No. 2 Power Boiler. Therefore, fuel blending is considered part of the base case for the No. 2 Power Boiler.

#### 4.4.1.6 BOILER OPERATIONAL MODIFICATIONS / TUNING / OPTIMIZATION

Combustion optimization efforts can lead to improvements in $NO_X$ emissions of 5 to 15 percent. Recent developments of intelligent controls – software-based systems that "learn" to operate a unit and then maintain its performance during normal operation – are expected help in keeping plants well tuned.[39] Domtar has employed, and will continue to employ, the latest boiler optimization and tuning techniques. This control strategy is considered part of the base case for the Ashdown Mill's No. 1 and No. 2 Power Boilers.

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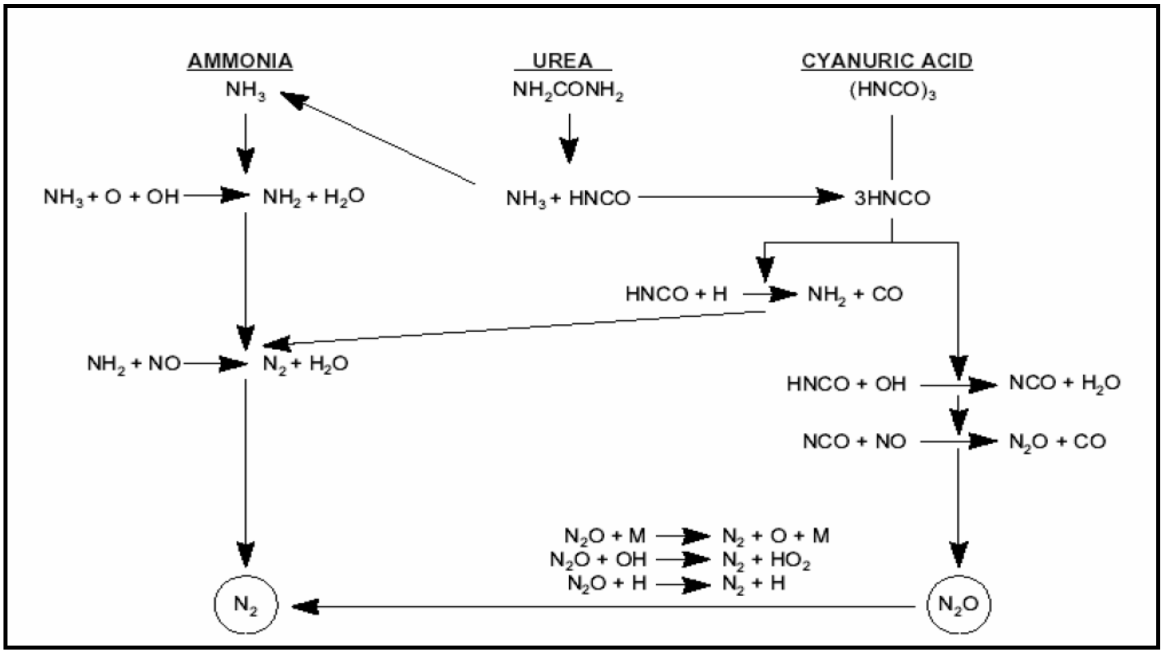
[35] Ibid.
[36] Ibid.
[37] Ibid.
[38] Ibid.
[39] NESCAUM and MANE-VU, *Assessment of Control Technology Options for BART-Eligible Sources – Steam Electric Boilers, Industrial Boilers, Cement Plant and Paper and Pulp Facilities*, March 2005.

### 4.4.1.7 SELECTIVE NON-CATALYTIC REDUCTION

SNCR is a post-combustion $NO_X$ control technology based on the reaction of urea or ammonia ($NH_3$) and $NO_X$. In the SNCR chemical reaction, urea or ammonia-based chemicals are injected into the combustion gas path to reduce the $NO_X$ to nitrogen and water. The primary SNCR reaction sequences are shown in Figure 4-1.[40]

**FIGURE 4-1. PRIMARY SNCR REACTION SEQUENCES**




Typical $NO_X$ removal efficiency for SNCR is 30 to 65 percent. For industrial coal-fired boilers, SNCR can achieve approximately 40 percent $NO_X$ control.[41] An important consideration for implementing SNCR is the operating temperature range. The optimum temperature range is approximately 1,600 to 2,000 °F.[42] Operation at temperatures below this range results in ammonia slip. Operation above this range results in oxidation of ammonia, forming additional $NO_X$. In addition, the urea must have sufficient residence time, about 3 to 5 seconds, at the optimum operating temperatures for efficient $NO_X$ reduction. Therefore, the injection point is typically prior to convective heat recovery.[43]

[40] ABB Power Plant Laboratories, *Engineering development of coal-fired high performance power systems – Phase II topical report*, Selective Non-Catalytic Reduction System Development Subcontract to United Technologies Research Center, Contract No. DE-AC22-95PC95144, February 24, 1997 (reprinted in NCASI's Special Report No. 03-04).

[41] MRPO, *Interim White Paper – Midwest RPO Candidate Control Measures*, March 29, 2005.

[42] U.S. EPA, Clean Air Technology Center, *Nitrogen Oxides ($NO_X$), Why and How They Are Controlled*. Research Triangle Park, North Carolina, EPA-456/F-99-006R, November 1999.

[43] U.S. EPA. *Summary of $NO_X$ Control Technologies and their Availability and Extent of Application*. Research Triangle Park, North Carolina. EPA-450/3-92-004, February 1992.

According to the U.S. EPA, the performance of an SNCR system is affected by six factors.

> *These are a) inlet $NO_X$ level, b) temperature, c) mixing, d) residence time, e) reagent-to- $NO_X$ ratio, and f) fuel sulfur content. Lower inlet $NO_X$ concentrations reduce the reaction kinetics and hence the achievable $NO_X$ emissions reductions. As mentioned above, temperatures below the desired window result in ammonia emissions (slip), and temperatures above the desired window result in $NH_3$ being oxidized to $NO_X$. Mixing becomes an important consideration in regions distant from an injection nozzle where the level of turbulence is reduced and stratification of the reagent and flue gas will probably be a greater problem, especially at low boiler loads. Residence time becomes important to allow the desired reactions to go to completion. Small, packaged, water tube boilers and boilers with varying steam loads are therefore difficult applications for SNCR. As higher than the theoretical $NH_3$ to $NO_X$ ratios are generally required to achieve desired $NO_X$ emission reductions, a trade-off exists between $NO_X$ control and the presence of $NH_3$ in the flue gas. The main disadvantage of SNCR is the low $NO_X$ reduction that is experienced when the allowable ammonia slip is low. Finally, in the case of high sulfur fuels, excess $NH_3$ can react with sulfur trioxide to form ammonium sulfate salt compounds that deposit on downstream equipment leading to plugging and reduced heat transfer efficiencies.*[44]

One concern about the SNCR process is its ability to perform adequately under changing load and fuel conditions.[45] Based on its research regarding this concern, NCASI concludes that SNCR is most widely used for base-loaded boilers, and is not suited for power boilers that experience wide temperature variances, i.e., high load swings. NCASI also points out that the use of SNCR systems on coal-fired boilers is still in the development stage.[46]

The $NO_X$OUT process is an SNCR hybrid based on the following chemical reaction that ideally occurs in the temperature range of 1700 to 2000 °F:

$$2\ NO + NH_2CONH_2 + 1/2\ O_2 \rightarrow 2\ N_2 + CO_2 + 2\ H_2O$$

[44] U.S. EPA, *New source performance standards, subpart Db – technical support for proposed revisions to $NO_X$*, EPA-453-/R-95-012 (republished in NCASI's Special Report 03-04).

[45] NCASI, *$NO_X$ Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[46] Ibid.

The problems with typical SNCR systems (e.g., ammonia slippage and heat transfer surface fouling with byproduct formation) also exist with the $NO_XOUT$ process.

#### 4.4.1.8 SELECTIVE CATALYTIC REDUCTION

SCR is a post-combustion gas treatment process in which $NH_3$ is injected into the exhaust gas in the presence of a catalyst bed usually located between the boiler and air preheater. The catalyst lowers the activation energy required for $NO_X$ decomposition.[47] On the catalyst surface, $NH_3$ and nitric oxide (NO) react to form diatomic nitrogen and water. The overall chemical reaction can be expressed as:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

When operated within the optimum temperature range of approximately 575 to 750 °F, the reaction can result in removal efficiencies between 70 and 90 percent. For coal-fired industrial boilers, SCR can achieve approximately 80 percent $NO_X$ control.[48] The specific temperature ranges are 600 to 750 °F for conventional (vanadium or titanium) catalysts, 470 to 510 °F for platinum catalysts, and 600 to 1000 °F for high-temperature zeolite catalysts.[49] SCR units have the ability to function effectively under fluctuating temperature conditions (usually ± 50 °F), although fluctuation in exhaust gas temperature reduces removal efficiency by disturbing the chemical kinetics (speed) of the $NO_X$ -removal reaction.

According to the U.S. EPA, the performance of an SCR system is affected by six factors.

> *These are a) $NO_X$ level at SCR inlet, b) flue gas temperature, c) $NH_3$-to-$NO_x$ ratio, d) fuel sulfur content, e) gas flow rate, and f) catalyst condition. For SCR, when inlet $NO_X$ concentrations fall below 150 ppm, the reduction efficiencies decrease with decreasing $NO_X$ concentrations. Each type of catalyst has an optimum operating temperature range. Temperatures below this range result in ammonia emissions (slip), and temperatures above the desired range result in $NH_3$ being oxidized to $NO_X$. For up to about 80 percent $NO_X$ reduction efficiencies, a 1:1 $NH_3$:$NO_X$ ratio is sufficient. For higher efficiencies, higher reagent to $NO_X$ ratios are required which may result in higher $NH_3$ slip. In the case of high sulfur fuels, excess $NH_3$ can react with sulfur trioxide to form ammonium sulfate salt compounds that deposit and foul downstream equipment. SCR application experience in the case of*

[47] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.
[48] MRPO, *Interim White Paper – Midwest RPO Candidate Control Measures*, March 29, 2005.
[49] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.

*medium-to-high sulfur fuels is limited. For a given flue gas flow rate, the catalyst structural design should be chosen so that the residence time needed for the reduction reactions to take place on the catalyst surface is achievable.*[50]

### 4.4.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

Per the BART Guidelines, documentation of infeasibility should "explain, based on physical, chemical, or engineering principles, why technical difficulties would preclude the successful use of the control option under review." The BART Guidelines use the two key concepts of "availability" and "applicability" to determine if a control option is technically feasible. These concepts are defined in Section IV.D.2:

*…a technology is considered "available" if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration.*

*The typical stages for bringing a control technology concept to reality as a commercial product are:*

- *concept stage;*
- *research and patenting;*
- *bench scale or laboratory testing;*
- *pilot scale testing;*
- *licensing and commercial demonstration; and*
- *commercial sales.*

*A control technique is considered available, within the context presented above, if it has reached the stage of licensing and commercial availability. Similarly, we do not expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, you would not consider technologies in the pilot scale testing stages of development as "available" for purposes of BART review.*

*In general, a commercially available control option will be presumed applicable if it has been used on the same or a similar source type. Absent a showing of this type, you evaluate technical feasibility by examining the physical and chemical characteristics of the pollutant-bearing gas stream, and comparing them to the gas stream characteristics of the source types to which the technology had been applied previously.*

***COMBUSTION MODIFICATIONS***

[50] U.S. EPA, *New source performance standards, subpart Db – technical support for proposed revisions to $NO_X$*, EPA-453-/R-95-012 (republished in NCASI's Special Report 03-04).

#### 4.4.2.1 FLUE GAS RECIRCULATION

FGR is used to reduce thermal $NO_X$ formation. Emissions due to fuel-bound $NO_X$, which are significant for coal-fired boilers, are not meaningfully affected by FGR. Therefore, FGR is not technically feasible to control $NO_X$ emissions from coal-fired boilers.[51] Similarly, FGR would not be effective in wood combustion since most of the $NO_X$ generated during wood combustion is also from the fuel $NO_X$ pathway.[52] Recent refusals by vendors (e.g., Entropy Technology & Environmental Consultants LP[53]) to provide budgetary estimates for installing FGR are further evidence that FGR is not applicable for the Ashdown Mill's No. 1 and No. 2 Power Boilers.

#### 4.4.2.2 REBURNING / METHANE DE-$NO_X$

Generally, Domtar considers MdN not feasible because (1) it is not fully demonstrated and (2) it incorporates FGR, which is clearly technically infeasible (see Section 4.4.2.1). However, Domtar was able to obtain equipment cost estimates from vendors of MdN. Therefore, MdN is considered further in this analysis.

### *POST-COMBUSTION MODIFICATIONS*

NCASI points out the following issues of concern for post-combustion $NO_X$ controls (i.e., SNCR and SCR) for pulp and paper mill power boilers:[54]

> **Load Swings** - Pulp mill combination and power boilers frequently exhibit wide and rapid load swings that are not consistent with the steady conditions required for effective use of either SNCR or SCR $NO_X$ control technologies. The load swings produce variable temperature conditions in the boiler, causing the temperature zone for $NO_X$ reduction to fluctuate, making it more difficult to know where to inject the reactants.
>
> **Temperature Incompatibility** - Combination and power boilers are affected by temperature profile incompatibility. To obtain the required temperature window, the only location to install this technology is upstream of the particulate matter control device, yet this is where flue gases are dirty and can foul the catalyst rapidly.

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[51] U.S. EPA. *Alternative Control Technologies Document: $NO_X$ Emissions from Utility Boilers.* (EPA-453/R-94-023).

[52] NCASI, *$NO_X$ Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[53] Steve Wood (ETEC), e-mail to Joel Martin (Domtar), September 20, 2006: "Based on the design and operational data provided regarding #2 Coal Boiler, ETEC would decline to bid the application Induced Flue Gas Recirculation for Boiler #2 $NO_X$ control. Flue gas recirculation technology is very effective in reducing natural gas and light oil fuel $NO_X$ emissions, but is not for No.6 fuel oil, coal, bark and other solid fuels. To the best of our knowledge, flue gas recirculation for $NO_X$ control has never been installed on a coal fired boiler."

[54] Ibid.

Downstream of the PM control device, the temperature is too low for the catalyst to be effective.

**Unproven** – SCR or SNCR controls, technologies which, for the most part, are untested and infeasible for pulp and paper mill boilers. These technologies must be operated on a continuous basis within a specified temperature range in order to be effective. The type of fuel burned influences the design of the technology, and FPI facilities' frequent fuel changes and co-firing of multiple fuels would result in design and operational problems.

**Lack of Guarantee for FPI Boilers** – Boiler owners are finding that vendors of SCR and SNCR technologies are unwilling to provide performance guarantees that the controls will meet the level of reduction called for in [NSPS Subpart Db (promulgated on September 16, 1998)].

#### 4.4.2.3 SELECTIVE NON-CATALYTIC REDUCTION

Most boilers in the pulp and paper industry operate in the swing load mode, a consequence of supplying steam as required to the various components of the process. The problem with control of the required flue gas temperature window is an inherent difficulty with use of SNCR for load-following boilers, whether wood or fossil fuel.[55]

Controlling flue gas temperatures over the entire range of operating loads that the boiler is expected to experience will be very difficult to achieve. Boilers in the pulp and paper industry rarely operate under base loaded conditions. Consequently, the location of the desired temperature window is expected to change constantly. Accurate, instantaneous temperature measurement, as well as the ability to accurately adjust the location of the injection nozzle, would be necessary. Ammonia slip would be a recurring problem associated with the application of the SNCR process to industrial boilers with fluctuating loads.[56]

Inadequate reagent dispersion in the region of reagent injection in wood-fired boilers is also a factor mitigating against the use of SNCR technology.[57] Good dispersion of the reagent in the flue gas is needed to get good utilization of the reagent and to avoid excessive ammonia slip from the process. The need for a

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[55] NCASI, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for $NO_X$, $SO_2$ and PM Emissions*, Corporate Correspondence Memo 06-014.

[56] NCASI, *$NO_X$ Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[57] NCASI, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for $NO_X$, $SO_2$ and PM Emissions*, Corporate Correspondence Memo 06-014.

sufficient volume in the boiler at the right temperature window precludes the application of SNCR in all types of industrial boilers.[58]

Additional issues with SNCR include the potential for formation of ammonium sulfate salts (if sulfur oxides are present in the gas stream where they can react with excess ammonia from the SNCR process to form ammonium salts), which cause plugging problems. Ammonia also poses potential water quality issues - ammonia slip released to the atmosphere could contaminate surface waters by deposition.

SNCR has been applied to a few base-loaded wood and combination wood-fired boilers, mainly in the electric generating industry. However, its efficacy on wood-fired boilers with changing loads has not been demonstrated, except when used as a polishing step. Early use of ammonia injection in the case of one pulp mill wood-fired boiler met with significant problems and had to be abandoned (significant ammonia slip, caused by inefficient dispersion of the reagent within the boiler, was to blame). The boiler was unable to meet the manufacturer guarantee unless operated at less than half load. Even then, reducing $NO_X$ to near permitted limits consumed considerably more ammonia than anticipated, leading to the formation of a visible ammonium chloride plume. A similar problem was encountered at a second FPI mill where nearly half the urea (on a molar basis) injected was being emitted as ammonia.[59]

The use of SNCR on stoker type wood-fired boilers that have significant load swings has not been demonstrated. Excessive ammonia slip is a primary concern when adequate dispersion of the SNCR chemical is not achieved in the boiler ductwork within the range of residence times available and temperatures needed for the $NO_X$ reduction reactions to go to completion. Additional concerns include the impact of interference from higher CO levels present in many wood-fired boilers, the possibility of appreciable SNCR chemical being absorbed onto the ash matrix in a wood-fired boiler, and the extent and fate of ammonia in scrubber purge streams.[60]

The MRPO concludes, "if combustion zone temperatures within the boiler do not fall into [the ideal temperature range], then SNCR would be infeasible."[61]

#### 4.4.2.4 SELECTIVE CATALYTIC REDUCTION

The use of SCR on boilers operating in the FPI has also never been successfully demonstrated for wood boilers, and would face the same inherent problem of requiring it to be post PM-control to protect the catalyst, and

[58] NESCAUM and MANE-VU, *Assessment of Control Technology Options for BART-Eligible Sources – Steam Electric Boilers, Industrial Boilers, Cement Plant and Paper and Pulp Facilities*, March 2005.

[59] NCASI, *$NO_X$ Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[60] Ibid.

[61] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.

achieving and maintaining the required temperature window for effective $NO_X$ control.[62] There are numerous other issues with using SCR including catalyst plugging and soluble alkali poisoning as well as increased energy consumption.[63]

The use of SCR technology would be considered technically infeasible based upon the fact that post-particulate removal flue gas temperatures are typically significantly lower than those desired for this application. Many boilers are equipped with wet scrubbers for particulate emission (PM) control. Reheating the scrubbed flue gases from these boilers to bring them within the desired temperature window would involve a significant energy penalty. For pre-particulate removal flue gas application, catalyst deactivation from high particulate loading would be a serious concern, in addition to the impact of fluctuating loads on flue gas temperatures. Deactivation and/or poisoning could result from the size and density of fly ash particulate, and from their unique chemical and physical nature. Water-soluble alkali (such as Mg or Na) in particulate-laden gas streams has been known to poison SCR catalysts. Space considerations for installing a catalyst section in an existing boiler's ductwork are also important. Also note the use of solid fuels can result in catalyst contamination even with efficient PM control system and high moisture levels in exhaust air would result in inefficient SCR operation.[64]

Most boilers feature a flue gas temperature at the economizer exit that is below the ammonium sulfate/bisulfate dew point. Air heater surfaces must withstand corrosion from ammonium sulfates and bisulfates, be easily cleaned with conventional soot blowing, and survive corrosion-inducing water washing. $SO_3$ produced by the catalyst may condense on cooler surfaces, depending on the temperature, during both steady-state and non-steady-state operation. Higher levels of $SO_2$ to $SO_3$ conversion could cause accelerated corrosion or higher $SO_3$-induced plume opacity. Minimizing ammonia levels in the stack (typically <2 to 3 ppm) is required to avoid problems with disposal of scrubber byproduct contaminated by ammonia. The use of a particular catalyst puts restrictions on the fuel flexibility for a boiler. For example, purchasing coal with fly ash containing calcium oxide and arsenic outside the defined range absolves the catalyst supplier from responsibility for arsenic poisoning.[65]

The only "wood-fired" boiler SCR application in service in the U.S. was located at a woodworking facility in Ohio. This SCR was located downstream of a mechanical collector and electrostatic precipitator, operating in flue gas temperatures ranging from 550 to 650 °F. The only problem reported at this

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[62] NCASI, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for $NO_X$, $SO_2$ and PM Emissions*, Corporate Correspondence Memo 06-014.

[63] NCASI, *$NO_X$ Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[64] Ibid.

[65] Ibid.

installation was minor catalyst blinding due to the deposition of fine particulate that escaped the PM collection devices. It was learned the operating temperature for this SCR system allowed the use of conventional catalysts designed to accommodate high dust applications. For these catalysts, the catalyst openings through which the flue gas flows are sized to provide proper surface area contact and sufficient flue gas velocity to minimize fouling. Low temperature catalyst designs are considerably different and would not be recommended for use on any high dust application. Based on this description of the air pollution control system configuration and the operating conditions for this particular wood-fired boiler, it is important to identify several specific differences between this installation and those that operate in the FPI. First, due to the requirement to provide hot air to burn all but the driest of wood fuels, wood-fired boilers are usually equipped with air preheaters. Thus, even when dry particulate control devices like an ESP are utilized, the installation of an SCR catalyst section after a PM control device is not amenable for adaptation to such boilers without, of course, incurring a severe energy penalty. Second, a significant portion of the FPI's wood-fired boilers is controlled for PM emissions by multiclones and wet scrubbers. Therefore the PM emissions from these would be higher than the example situation. Third, it is unclear how the Ohio facility's SCR system would have worked under the fluctuating boiler load characteristics common to many FPI boilers. Finally, sawdust, which was the fuel fired in the Ohio facility's boiler, is a low moisture fuel and the particulate matter present in the flue gases from its combustion is likely to be of different composition than when bark or hog fuel (typically much higher moisture) is burned.[66]

Hence the use of SCR technology has clearly not been demonstrated for industrial wood, biomass or combination fuel-fired boilers in the FPI.[67]

### 4.4.3 STEP 3 – EVALUATE CONTROL EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES

Table 4-2 presents a ranking of the technically feasible control strategies in order of their effectiveness (i.e., potential control efficiency). For controls with a range of performance levels, the BART Guidelines note:

> *It is not [the U.S. EPA's] intent to require analysis of each possible level of efficiency for a control technique as such an analysis would result in a large number of options. It is important, however, that in analyzing the technology you take into account the most stringent emission control level that the technology is capable of achieving.*

[66] Ibid.
[67] Ibid.

**TABLE 4-2. RANKING OF CONTROL STRATEGIES**

| Control Strategy | Applicability | Potential Control Efficiency (%) |
|---|---|---|
| MdN | No. 1 & No. 2 Boilers | 50 [a] |
| LNB | No. 2 Boiler Only | 30 [b,c] |
| Original OFA + Boiler Tuning/Optimization | No. 1 Boiler | Base Case |
| Original OFA + $NO_X$ Air + Fuel Blending + Boiler Tuning/ Optimization | No. 2 Boiler | Base Case |

[a] Based on estimate from Energy System Associates.
[b] NCASI, *$NO_X$ Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.
[c] Based on estimate from B&W.

Note that MdN is included in Table 4-2 despite its questionable technical feasibility.

### 4.4.4 STEP 4 – EVALUATE IMPACTS AND DOCUMENT RESULTS

The technically feasible control technologies are evaluated on the basis of (1) costs of compliance, including consideration of the remaining useful life, (2) energy impacts, and (3) non-air quality environmental impacts.

For the purposes of this analysis, energy and non-air quality environmental impacts are considered minimal for all the technically feasible control options listed in Table 4-2. Per the BART Guidelines, the costs of compliance analysis for each control option consists of comparisons of the average cost effectiveness and the incremental cost effectiveness, which are defined in Section IV.D.4 as follows:

> *Average cost effectiveness means the total annualized costs of control divided by the annual emissions reduction (the difference between baseline annual emissions and the estimate of emissions after controls), using the following formula:*
>
> *Average cost effectiveness (dollars per ton removed) = Control option annualized cost ÷ (Baseline annual emissions – Annual emissions with Control option)*
>
> *…the incremental cost effectiveness calculation compares the costs of performance level of a control option to those of the next most stringent option, as shown in the following formula (with respect to cost per emissions reduction):*
>
> *Incremental Cost Effectiveness (dollars per incremental ton removed) = (Total annualized costs of control option) – (Total annualized costs of next control*

*option) ÷ (Control option annual emissions) – (Next control option annual emissions)*

The average and incremental (where applicable) cost effectiveness for each feasible control option for the Ashdown Mill's No. 1 and No. 2 Power Boilers are summarized in Table 4-3. Detailed control costs calculations are presented in Appendix B.

**TABLE 4-3. CONTROLS COSTS SUMMARY**

| Emission Unit | Control Strategy | Total Annualized Cost (MM$) | $NO_X$ Removed (tpy) | Cost Effectiveness Average ($/ton) | Cost Effectiveness Incremental ($/ton) |
|---|---|---|---|---|---|
| No. 1 Power Boiler | MdN | 3.94 | 542 | 7,262 | 17,354 |
| No. 2 Power Boiler | MdN | 5.35 | 1,257 | 4,259 | 9,571 |
| | LNB | 1.10 | 754 | 1,465 [b] | N/A |

[b] This estimate is consistent with NCASI's Special Report 03-04, which states, "for pulverized coal boilers, a 30 percent $NO_X$ reduction could be achieved with LNB at a cost of <$2,000/ton."

Based on Domtar's analysis, MdN is considered cost prohibitive for both the No. 1 and No. 2 Power Boilers and is ruled out as a BART option. Based on steps 1 through 4 of the BART determination analysis, no retrofit controls are available for the No. 1 Power Boiler and LNB is the best available retrofit control technology for the No. 2 Power Boiler.

### PROPOSED BART DETERMINATIONS FOR $NO_X$

For the No. 1 and No. 2 Power Boilers, Domtar proposes $NO_X$ BART limits of 179.6 lb/hr and 368.7 lb/hr, respectively.

A summary of all proposed BART determinations is provided in Table 4-4. Please note that while example control technologies theoretically capable of achieving the proposed BART limits are listed, Domtar reserves the right to implement other equivalent control strategies between now and the BART effective date (~2013) to meet the same emission limits.

**TABLE 4-4. SUMMARY OF PROPOSED BART DETERMINATIONS**

| **Emission Unit** | **Pollutant** | **BART Limit** | ***Example Control Technology*** |
|---|---|---|---|
| No. 1 Power Boiler | PM | 0.07 lb/MMBtu (Boiler MACT) | *WESP* |
| | $SO_2$ | 442.5 lb/hr | *No additional add-on controls (existing fuel restrictions)* |
| | $NO_X$ | 179.6 lb/hr | *No add-on controls* |
| No. 2 Power Boiler | PM | 0.07 lb/MMBtu (Boiler MACT) | *Wet Scrubber* |
| | $SO_2$ | 788.2 lb/hr | *Wet Scrubber* |
| | $NO_X$ | 368.7 lb/hr (30 Percent Control) | *LNB* |

## 4.5 STEP 5 – EVALUATE VISIBILITY IMPACTS

The degree of visibility improvement is assessed based on the change in modeled impacts for the pre-control (i.e., the BART applicability analysis) and post-control (i.e., the predicted maximum 24-hour emission rate after implementation of BART) emission scenarios. Per the BART Guidelines, this assessment "may consider the frequency, magnitude, and duration components of [visibility] impairment."

The post-control modeling for the visibility improvement analysis was conducted using the CALPUFF modeling system in the same manner as the ADEQ's BART applicability analysis, which is described in Section 3 of this report and in the Protocol (see Appendix A). In fact, the post-control modeling was conducted using the same CALPUFF, POSTUTIL, and CALPOST input files generated by the ADEQ for the applicability analysis. The only changes made to these files for the post-control modeling was to the emissions rates and stack parameter changes associated with implementing the chosen BART controls. Table 4-5 and Table 4-6 summarize the maximum 24-hour average emission rates and the stack parameters, respectively, that were modeled in the post-control analysis.

**TABLE 4-5. SUMMARY OF 24-HOUR AVERAGE MAXIMUM POST-CONTROL EMISSION RATES**

| Emission Unit | $NO_X$ Emissions (lb/hr) | $SO_2$ Emissions (lb/hr) | Total PM Emissions (lb/hr) |
|---|---|---|---|
| No. 1 Power Boiler | 179.6 | 442.5 | 40.6 |
| No. 2 Power Boiler | 368.7 | 788.2 | 57.4 |

**TABLE 4-6. POST-CONTROL STACK PARAMETERS**

| Emission Unit | LCC East (km) | LCC North (km) | Elevation (m) | Stack Height (m) | Stack Diameter (m) | Exhaust Temperature (K) | Exhaust Velocity (m/s) |
|---|---|---|---|---|---|---|---|
| No. 1 Power Boiler | 267.47491 | -698.66686 | 97.5 | 66.1 | 1.890 | 522 | 26.76 |
| No. 2 Power Boiler | 267.48245 | -698.74355 | 97.5 | 71.6 | 3.659 | 325 | 11.92 |

Visibility improvement is quantified and judged in a cumulative matter. That is, to compare to the pre-control modeling analysis executed by the ADEQ, Domtar's post-control modeling analysis simulated all emissions reductions from both emission units. Note that since maximum applicability analysis impacts were less than 0.5 $\Delta$dv for the Sipsey Class I area, this area was not evaluated in the post-control scenario. Table 4-7 summarizes the results of the visibility improvement analysis.

**TABLE 4-7. SUMMARY OF VISIBILITY IMPROVEMENT ANALYSIS RESULTS**

| Class I Area | Maximum 24-hour Impact (Δdv) [a] | Number of Days > 0.5 Δdv [a] | Number of Days > 1.0 Δdv [a] |
|---|---|---|---|
| Caney Creek | 2.039 | 118 | 29 |
| Upper Buffalo | 1.029 | 14 | 1 |
| Mingo | 0.836 | 2 | 0 |
| Hercules-Glades | 0.631 | 2 | 0 |

[a] For total modeled period: years 2001, 2002, and 2003.

As shown in Table 4-7, the application of BART on the Ashdown Mill's No. 1 and No. 2 Power Boilers results in significant visibility impacts improvement in the affected Class I areas. Visibility impairment at Upper Buffalo was reduced by 29 percent while impairment at Caney Creek was reduced by 32 percent (based on total impact and excluding any days with impacts less than 0.50 Δdv). The number of days within the modeled three-year period with impacts greater than 0.50 Δdv decreased from 159 to 118 for the Caney Creek Class I area and from 18 to 14 for the Upper Buffalo Class I area.

In addition to the cumulative analysis, the ADEQ requested emission unit specific and pollutant specific modeling. Since cumulative analysis impacts in the Upper Buffalo and Mingo Class I areas are minimal, the emission unit and pollutant specific modeling was only conducted for the Caney Creek Class I area. The results of these pre- and post-control analyses (each conducted for the entire modeling period: year 2001, 2002, and 2003) are presented in Table 4-8.

**TABLE 4-8. EMISSION UNIT & POLLUTANT SPECIFIC MODELING RESULTS**

| Emission Unit | Pollutant | Pre-Control Scenario | | Post-Control Scenario | |
|---|---|---|---|---|---|
| | | Max. 24-hour Impact (Δdv) | Number of Days > 0.5 Δdv | Max. 24-hour Impact (Δdv) | Number of Days > 0.5 Δdv |
| No. 1 Power Boiler | PM | 0.252 | 0 | 0.065 | 0 |
| | $SO_2$ | 0.575 | 2 | 0.575 | 2 |
| | $NO_X$ | 0.398 | 0 | 0.398 | 0 |
| No. 2 Power Boiler | PM | 0.135 | 0 | 0.095 | 0 |
| | $SO_2$ | 1.036 | 5 | 1.036 | 5 |
| | $NO_X$ | 1.072 | 35 | 0.762 | 14 |
| No. 1 & 2 Power Boilers | PM | 0.391 | 0 | 0.156 | 0 |
| | $SO_2$ | 1.542 | 30 | 1.542 | 30 |
| | $NO_X$ | 1.427 | 54 | 1.129 | 36 |

Additionally, as requested by the ADEQ in its September 8, 2006, letter, Domtar's post-control (and pre-control, where different from the ADEQ's applicability modeling files) CALPUFF, POSTUTIL, and CALPOST input files and CALPOST output files are included with this report on electronic media. The file naming convention is explained below. Note that all filenames contain the "doas" root (characters 4 through 7) to denote Domtar – Ashdown. Note also that path names will need to be modified to represent the user's directory structure when replicating these analyses.

**File Naming Convention:**

**CALPUFF & POSTUTIL** *xx*_doas*yy*(*v**).*fff*

| | | | | | |
|---|---|---|---|---|---|
| *xx* | = | Model: | cp | = | CALPUFF |
| | | | pu | = | POSTUTIL |
| *yy* | = | Year: | 01 | = | 2001 |
| | | | 02 | = | 2002 |
| | | | 03 | = | 2003 |
| *v** | = | Pollutant Run Identifier | A | = | PM Pre-controls |
| | | | B | = | PM Post-controls |
| | | | C | = | $SO_2$ Pre- and Post-controls |
| | | | D | = | $NO_X$ Pre-controls |
| | | | E | = | $NO_X$ Post-controls |
| *fff* | = | File type: | inp | = | Input |

**CALPOST** *xx*_doas*yyz*(*v**).*fff*

| | | | | | |
|---|---|---|---|---|---|
| *xx* | = | Model: | ct | = | CALPOST |
| *yy* | = | Year: | 01 | = | 2001 |
| | | | 02 | = | 2002 |
| | | | 03 | = | 2003 |
| *z* | = | Class I area: | c | = | Caney Creek |
| | | | m | = | Mingo |
| | | | u | = | Upper Buffalo |
| | | | h | = | Hercules-Glades |
| | | | s | = | Sipsey |
| *v** | = | Pollutant Run Identifier | A | = | PM Pre-controls |
| | | | B | = | PM Post-controls |
| | | | C | = | $SO_2$ Pre- and Post-controls |
| | | | D | = | $NO_X$ Pre-controls |
| | | | E | = | $NO_X$ Post-controls |
| *fff* | = | File type: | inp | = | Input |
| | | | lst | = | Output |

The "v" designator is used only for the unit and source specific model runs requested by ADEQ.

# APPENDIX A – ADEQ'S DRAFT BART MODELING PROTOCOL

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**Draft**
**BEST AVAILABLE RETROFIT TECHNOLOGY (BART) MODELING PROTOCOL**

**June 7, 2006**

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# I. Introduction

On 6 July 2005, the U.S. Environmental Protection Agency (EPA) published final amendments to its 1999 Regional Haze Rule in the Federal Register, including Appendix Y, the final guidance for Best Available Retrofit Technology (BART) determinations (70 FR 39104-39172). The BART rule requires the installation of BART on emission sources that fit specific criteria and "may reasonably be anticipated to cause or contribute" to visibility impairment in any Class I area. Air quality modeling is the preferred method for establishing which emission sources cause or contribute to visibility impairment. Arkansas' BART modeling protocol is provided herein.

According to the Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determination; Final Rule (40 CFR Part 51, p 39125), each state is required to develop a BART Modeling Protocol that describes the required methodology to assess the levels of controls needed on sources subject to BART. The aforementioned regulation also requires states to work in partnership with all stakeholders including Tribes, EPA, Federal Land Managers (FLMs), Regional Planning Organizations (RPOs) and the various source operators. Although states are required to work in concert with the previously mentioned stakeholders, EPA has the ultimate authority to approve or disapprove a state's State Implementation Plan (SIP).

The main objective of this protocol is compliance with the RHR visibility improvement goals. To accomplish this goal, the Arkansas Department of Environmental Quality (ADEQ) has set forth three functions of this protocol. First, ADEQ will use the protocol to determine which BART-eligible units are subject-to-BART and must perform a BART-analysis. Second, facilities that ADEQ notifies that are subject-to-BART will use this protocol to conduct post-control modeling required for their BART-analysis. Third, the results from this protocol will be used to conduct cumulative modeling to show the change in visibility impact on Class I areas based on ADEQ's BART determination and the BART emission limits for facilities based on their BART-analysis. The subject-to-BART and final modeling will be submitted to the EPA as part of the BART section of the Arkansas State Implementation Plan (SIP) for Regional Haze.

The AR RH SIP submittal deadline to EPA as set forth in the Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determination; Final Rule (40 CFR Part 51, p 39156) is December 17, 2007. To meet this deadline, ADEQ has developed a schedule for completing BART determinations and implementing the BART strategy in order to meet the mandatory SIP submittal deadline (Appendix A). As shown in Appendix A, the modeling results must be completed no later than March 1, 2007.

The Central States Regional Planning Association (CENRAP) contracted with Alpine Geophysics, LLC to develop a modeling protocol for the states within CENRAP's region of which the state of Arkansas is a member. On December 22, 2005, Alpine Geophysics, LLC delivered the final version of the CENRAP BART Modeling Guidelines (Tesche, et al, 2005). However, comments from EPA Regions VI and VII and the Federal Land Managers (FLMs) were not incorporated into the guidelines; thus, Alpine Geophysics, LLC rewrote the guidelines to reflect the comments from Regions VI and VII and FLMs. These guidelines were re-issued February 3, 2006. Hence, CENRAP's BART Modeling Guidelines (Tesche, et al, 2005) have been approved by Regions VI and VII and the FLMs. Therefore, the Planning and Air Quality Analysis Branch, Air Division, Arkansas Department of Environmental Quality has chosen to adopt the CENRAP BART Modeling Guidelines as ADEQ's BART Modeling Protocol. Additionally, in preparing this draft protocol, ADEQ also consulted the following draft BART modeling protocols:

1. Best Available Retrofit Technology (BART) Modeling Protocol to Determine Sources Subject to BART in the State of Kansas draft version February 24, 2006
2. Best Available Retrofit Technology (BART) Modeling Protocol to Determine Sources Subject to BART in the State of Minnesota draft version February 24, 2006

This draft protocol is most similar to the CENRAP BART Modeling Guidelines. These guidelines were developed to ensure "consistency between states in the development of BART modeling protocols and to harmonize the approaches between adjacent RPOs" (Tesche, et al, 2005).

Soon after the finalization of this modeling protocol, ADEQ will notify sources subject-to-BART. For those facilities subject-to-BART, ADEQ will provide guidance for conducting their BART-analyses.

## II. Background

The Clean Air Act Amendments (CAAA) of 1977 established 156 Class I areas where visibility was determined to be an important value (Figure 1). Areas designated as Class I areas are those national parks exceeding 6000 acres, wilderness areas and national memorial parks exceeding 5000 areas, and all international parks that were in existence on August 7, 1977. While Rainbow Lake Wilderness Area, Wisconsin has been designated as a Class I area, the FLMs have indicated that visibility is not a valuable characteristic and therefore, is not included in BART or other RH analyses.

The state of Arkansas has within her boundary two mandatory Class I federal areas (Class I area), Upper Buffalo Wilderness Area and Caney Creek Wilderness Area which are managed by the United States Forest Service (Figure 2). However, there are two Class I areas in southern Missouri that are located downwind of facilities operating in Arkansas. The Missouri Class I areas are Hercules-Glade Wilderness Area (US Forest Service) and Mingo National Wildlife Refuge (US Fish and Wildlife). While EPA has not listed the maximum distance from a Class I area to model, this criteria has been set by CENRAP as 300 km. As shown in Figure 3, the eastern portion of Arkansas is within the 300 km radius of Sipsey Wilderness Area (US Forest Service), Alabama. Therefore, there are five Class I areas Arkansas will be performing BART determination/exemption modeling (Table 1).


Figure 1 Mandatory Class I federal areas in the United States of America

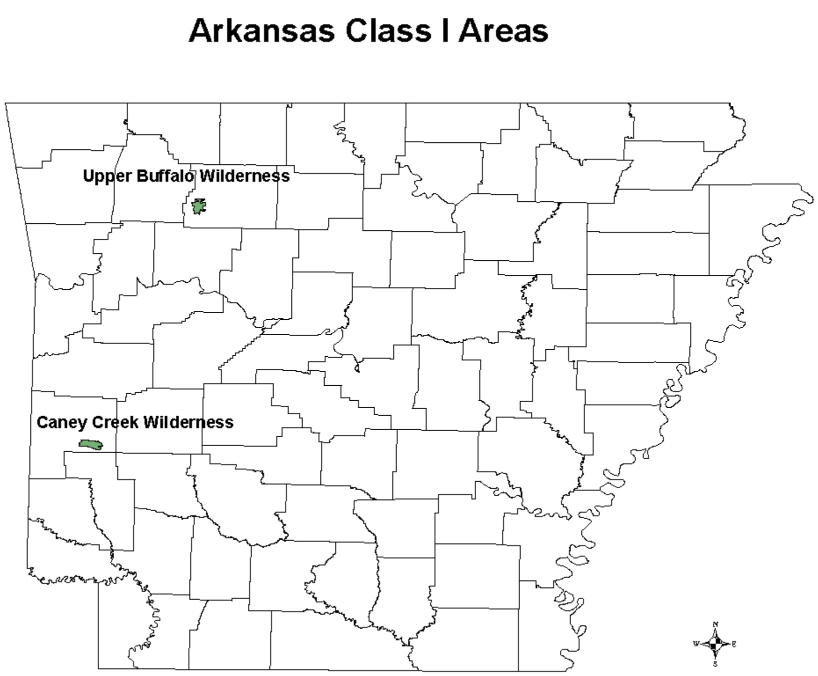


Figure 2 Arkansas's Class I areas

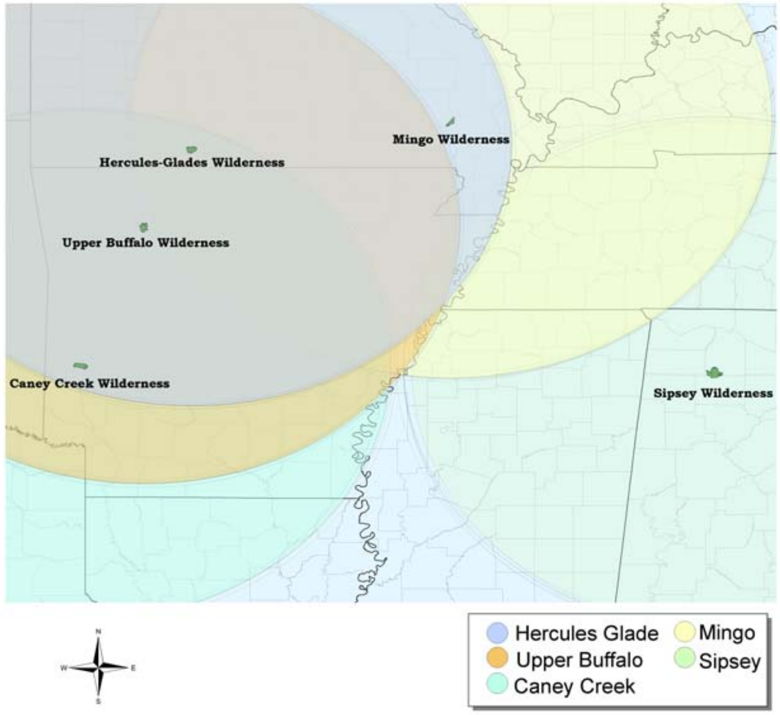


Figure 3 Map showing the 300 km radius buffer zones around five separate receptors (north, south, east, west, and center) located in the following Class I areas: Upper Buffalo, Caney Creek, Hercules Glade, Mingo, and Sipsey. This map was developed to determine which Class I areas will be assessed during the BART determination modeling

Table 1 Class I areas and the State they are located in as well as the supervising agencies ADEQ will evaluate during the BART determination/exemption modeling

| Class I Area | State | Supervising Agency |
|---|---|---|
| Upper Buffalo Wilderness Area | AR | U.S. Forest Service |
| Caney Creek Wilderness | AR | U.S. Forest Service |
| Hercules Glade Wilderness Area | MO | U.S. Forest Service |
| Mingo NWS | MO | U.S. Fish and Wildlife |
| Sipsey Wilderness Area | AL | U.S. Forest Service |

# III. BART-Eligible Sources

The BART requirements in the RHR are intended to reduce emissions specifically from large emission units that, due to age, were exempted from other control requirements of the CAAA. For an emissions unit to be considered eligible for BART, it must fall into one of 26 specified categories, must have the potential to emit at least 250 tons per year of certain haze-forming pollutants, and must have been in existence on August 7, 1977, but not in operation before August 7, 1962.

ADEQ staff determined Arkansas' BART-eligible sources by first identifying which of Arkansas' stationary sources fit the first criteria of being listed in the BART 26 specific categories. After identifying the sources which fit the first criteria, a database search of these facilities was performed to determine whether or not these emitting units' potential to emit were at least 250 tons per year of sulfur dioxide ($SO_2$), nitrogen oxides ($NO_x$), and particulate matter (PM). The next stage of determining BART-eligibility was to research the permit applications for the year the point source was placed into operation. The final step in the process was to contact facilities for the exact date of operation especially for sources that were placed into operation in the years 1977 and 1962. Tables 2 and 3 contain the list of BART-eligible facilities (18) by BART source category and the number of BART-eligible emitting units (27) within each facility. Figure 4 is a map of Arkansas which shows the location of the 18 BART-eligible facilities located in Arkansas. Figure 5 depicts the five Class I areas Arkansas will be assessing and the BART-eligible sources in Arkansas. Appendix B contains maps showing the receptors at each Class I area ADEQ will be assessing.

Table 2 Fossil fuel-fired steam electric plants > 250 MMBtu/hr and Kraft pulp mills facilities with BART-eligible emission units

| BART Source Category Number and Name | Facility Name/Location | Facility ID | AFIN | Unit ID | Unit Description |
|---|---|---|---|---|---|
| 1. Fossil fuel-fired Electric Plants > 250 MMbtu/hour – Electric Generating Units (EGUs) | American Electric Power (SWEPCO)/Gentry | 05-007-00107 | 04-0017 | SN-01 | Boiler |
| | AR Electric Cooperative/Augusta | 05-147-00024 | 74-00024 | SN-01 | Boiler 1350mm |
| | AR Electric Cooperative/Camden | 05-103-00055 | 52-00055 | SN-01 | Boiler |
| | Entergy – Lake Catherine/Jones Mill | 05-059-00011 | 30-00011 | SN-03 | Unit 4 Boiler |
| | Entergy – Ritchie Plant/Helena | 05-107-00017 | 54-00017 | SN-02 | Unit 2 |
| | Entergy – White Bluff/ Redfield | 05-069-00110 | 35-00110 | SN-01 | Unit 1 |
| | Entergy – White Bluff/Redfield | 05-069-00110 | 35-00110 | SN-02 | Unit 2 |
| | Entergy – White Bluff/Redfield | 05-069-00110 | 35-00110 | SN-05 | Auxiliary Boiler |
| 3. Kraft Pulp Mills | Domtar, Inc./Ashdown | 05-081-00002 | 41-00002 | SN-03 | #1 Power Boiler |
| | Domtar, Inc./Ashdown | 05-081-00002 | 41-00002 | SN-05 | #2 Power Boiler |
| | Delta Natural Kraft/Pine Bluff | 05-069-00017 | 35-00017 | SN-02 | Recovery Boiler |
| | Georgia – Pacific Paper/Crossett | 05-003-00013 | 02-00013 | SN-22 | 9A Boiler |
| | Green Bay Packing/ Morrilton | 05-029-00001 | 15-00001 | SN-05A | Recover Boiler |
| | Potlatch/McGehee | 05-041-00036 | 21-00036 | SN-04 | Power Boiler |

Table 3 Petroleum refineries, sintering plants and chemical processing plant facilities with BART-eligible emissions units

| BART Source Category Number and Name | Facility Name/Location | Facility ID | AFIN | Unit ID | Unit Description |
|---|---|---|---|---|---|
| 11. Petroleum Refineries | Lion Oil/El Dorado | 05-139-00016 | 70-00016 | SN-809 | #7 Catalyst Regenerator |
| 19. Sintering Plants | Big River Industries /West Memphis | 05-035-00082 | 198-00082 | SN-01 | Kiln A |
| 21. Chemical Processing Plants | Albermarle – South Plant/Magnolia | 05-027-00028 | 14-00028 | SR-01 | Tail Gas Incinerator |
| | Albermarle – South Plant/Magnolia | 05-027-00028 | 14-00028 | BH-01 | Boiler #1 |
| | Albermarle – South Plant/Magnolia | 05-027-00028 | 14-00028 | BH-02 | Boiler #2 |
| | Eastman Chemical/Batesville | 05-063-00036 | 32-00036 | 6M01-01 | 3 Coal Boilers |
| | El Dorado Chemical/El Dorado | 05-139-00040 | 70-00040 | SN-08 | West Nitric Acid Plant |
| | El Dorado Chemical/El Dorado | 05-139-00040 | 70-00040 | SN-09 | East Nitric Acid Plant |
| | El Dorado Chemical/El Dorado | 05-139-00040 | 70-00040 | SN-10 | Nitric Acid Concentrator |

# Arkansas Class I Areas and BART-Eligible Facilities

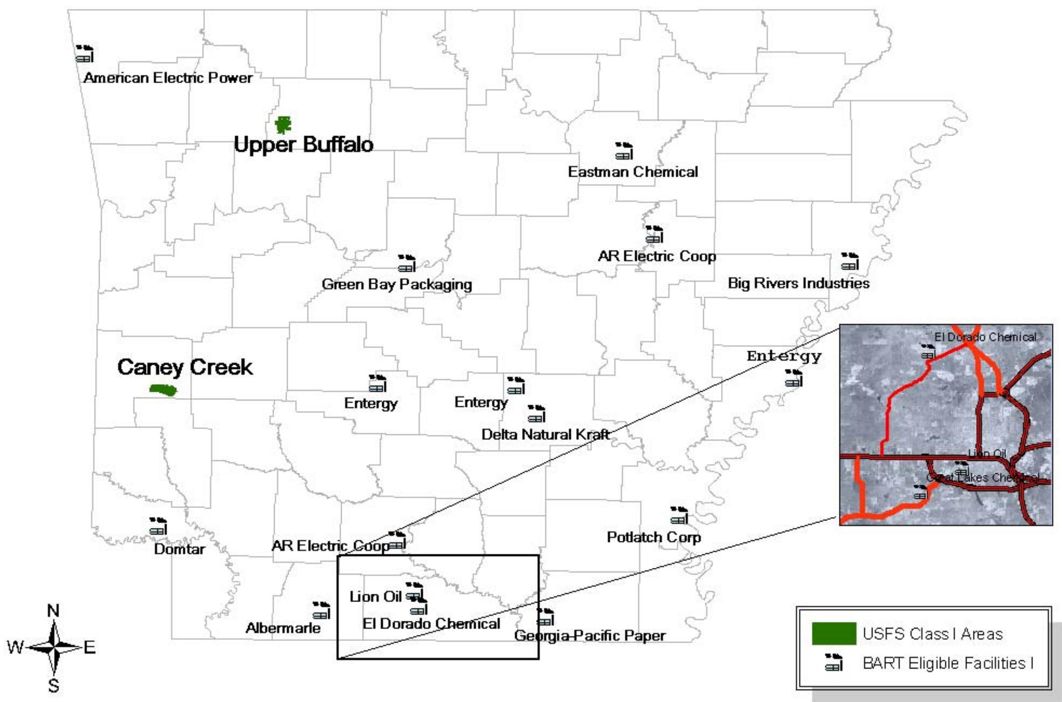


Figure 4 Map indicating the locations of Upper Buffalo, Caney Creek and the eighteen BART-eligible facilities located in Arkansas

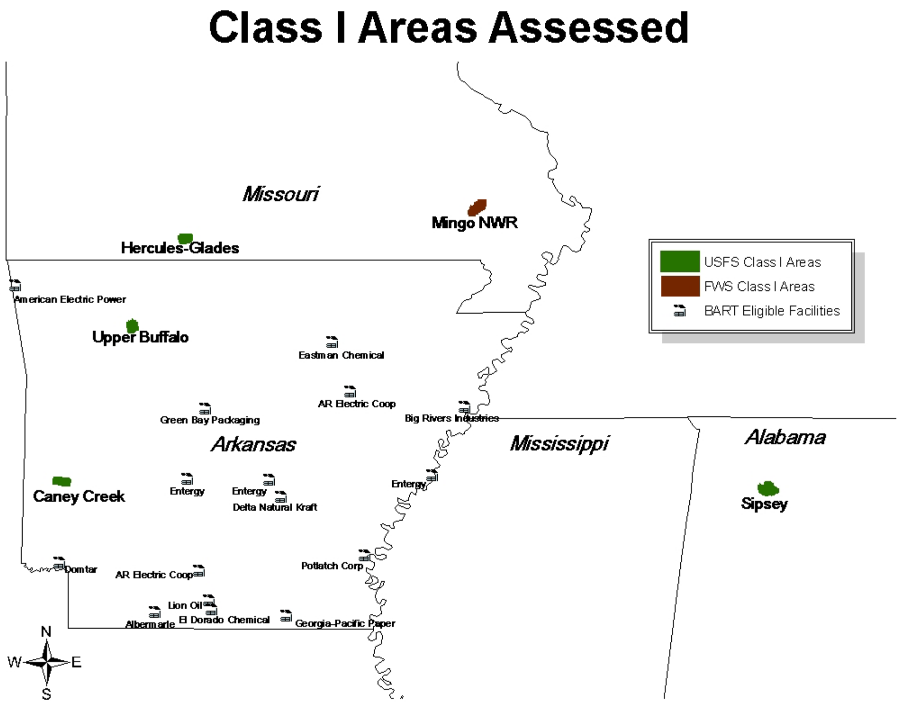


Figure 5 Map indicating the locations of Upper Buffalo, Caney Creek, Hercules Glade, Mingo and the eighteen BART-eligible facilities located in Arkansas

# IV. CAIR and Arkansas

The Clean Air Interstate Rule was finalized in May 2005 by EPA and applies to states in the eastern U.S. Reconsiderations were finalized March 2006. This rule address air pollution transport across state borders. EPA determined which states must reduce which pollutants based on modeling which showed how the travel of pollution affects non-attainment in other states. CAIR requires states to reduce $NO_x$ and/or $SO_2$ emissions. Of the three programs in CAIR, Arkansas is required to participate in only the Ozone-Season $NO_x$ reductions program. Although EPA's BART Modeling Guidance allows CAIR states to participate in the CAIR cap and trade program, the state of Arkansas is not eligible for the aforementioned trading program because Arkansas is in CAIR only for $NO_x$ during the ozone season. Therefore, in Arkansas CAIR **is not better** than BART. Thus BART-eligible EGUs will be modeled for BART determination/exemption by ADEQ.

# V. BART Air Quality Modeling Approach

According to EPA's BART Modeling Guidance, "CALPUFF is the best regulatory modeling application currently available … and is currently the only EPA-approved model…" (p 45); therefore, ADEQ and CENRAP have chosen to use CALPUFF in the

BART determination process as well as in the post-control analysis. One of the air quality modeling approaches suggested by EPA in the BART guidance is an individual source attribution approach. This is the approach ADEQ proposes to take. Specifically, this entails modeling source-specific units and comparing modeled impacts to a particular deciview threshold (described below). ADEQ has decided to conduct the subject-to-BART modeling, rather than have each BART-eligible facility either conduct the modeling or hire a contractor. This plan will eliminate the need for ADEQ to quickly review many air quality modeling analyses conducted using varying approaches. This plan will also satisfy the need to use a consistent approach among the modeling analyses. Once the subject-to-BART modeling is complete, all the modeling inputs will be available to facilities subject to BART for them or their consultants to conduct modeling for making BART analyses.

ADEQ will follow EPA's BART Modeling Guidance (p 42) in sitting a threshold limit in determining whether a BART-eligible source is either subject-to-BART or exempt. According to the aforementioned modeling guidance, an individual source will be considered to "cause visibility impairment" if the emissions results in a change (delta Δ) in deciviews (dv) that is greater than or equal to 1.0 deciview on the visibility in a Class I area. Additionally, if the emissions from a source results in a change in visibility that is greater than or equal to 0.5 dv in a Class I area the source will be considered to "contribute to visibility impairment" (BART Final Rule, 40 CFR 51 p 39113). Thus, ADEQ has set the threshold limit at **0.5 dv**.

The modeling approach discussed here is specifically designed for conducting the subject-to-BART screening analyses. There may be differences between modeling for conducting BART analyses and that for conducting a visibility analysis for a New Source Review permit, which may involve similar emission sources and the same air dispersion model used here.

To **ensure** that no sources pass the screening test when they should fail, the simple approach, by its nature, must be the most conservative of all the conditions likely to be examined for the source in question. For example, many factors influence the contribution of a source to the Class I area other than distance. The frequency of winds transporting the pollutants toward the Class I area may often be important to include for a reliable screening analysis. Also, a more distant Class I area downwind in the predominant wind direction from a source may receive a higher visibility impact than a closer Class I area that is infrequently downwind of the source. Another example of conservatism in the screening process is the use of the latest beta version of the CALMET/CALPUFF modeling system using the no-observation (no-obs) mode (the prognostic meteorological model MM5). Thus, the **maximum** impact instead of the 98$^{th}$ percentile will be used to determine if a source has an impact on visibility in a Class I.

Additionally, the BART analysis process includes several other steps in addition to the modeling described in this protocol (EPA, 2005). These steps, none of which are addressed in this document, include detailed analysis of:

- Costs of compliance among the various retrofit control options
- Energy and non-air quality impacts
- Existing pollution control technologies in use at the BART-eligible unit particularly with respect to their affecting the choice of retrofit options
- Remaining useful life of the units and/or facility
- Improvements in visibility expected from the use of BART controls.

# VI. BART-Eligible Units Physical Parameters

The physical characteristics of the BART-eligible point sources to be used for the screening stage one analysis will be provided by ADEQ staff. For the stage two screening analysis, ADEQ staff will work with the BART-eligible facilities in the development of actual emissions.

## A. Stack Parameters

Stack parameters required for modeling BART-eligible units were extracted from the permit applications. Stack parameters include height of the stack opening from ground in meters, inside diameter in meters, exit velocity in meters per second, exit gas temperature in Kelvin, ground elevation of the stack base in meters, and location coordinates of the stack in Lambert Conformal Conical (LCC). The stack coordinates were taken (in Universal Transverse Mertcator, UTM, and then converted to LCC) by ADEQ staff and then verified using ArcMap. Because the BART modeling focuses on mesoscale transport to Class I areas, other source term parameters (needed to calculate localized impacts) such as building heights and widths for calculating downwash will not be used. Appendix C contains tables indicating the stack parameters and coordinates for each BART-eligible emitting unit.

## B. Emission rates

ADEQ notified by email the BART-eligible facilities to provide the 24-hour average **actual** emission rate with normal operations from the highest emitting day of the year. Excluded from consideration are days where start-up, shutdown or malfunctions occurred unless these activities are regular, frequently occurring components of the source's operation cycle.

ADEQ does not intend to use emissions of VOCs and ammonia from facilities for subject-to-BART analysis. Only specific VOC compounds form secondary organic aerosols that affect visibility. These compounds are a fraction of the total VOCs reported in the emissions inventory, and ADEQ does not have the breakdown of VOC emissions necessary to model those that only impair visibility. Further, the prescribed screening model (CALPUFF) cannot simulate formation of particles from anthropogenic VOCs, nor their visibility impacts. Ammonia from specific sources will not be evaluated in this process, although ammonia is included in the modeling as a background concentration—this will be discussed later in this modeling protocol. The appropriate VOCs and ammonia emission data can, and will be, included in regional scale modeling used for the Regional Haze SIP.

# VII. Air Quality Model and Inputs

As stated in the previous section, CALPUFF is the preferred regulatory air dispersion model for long distance and therefore is the model ADEQ will be using in the BART determination process. ADEQ recognizes that CALPUFF has limited ability to simulate the complex atmospheric chemistry involved in the estimation of secondary particulate formation. However, for purposes of the subject-to-BART analysis, ADEQ intends to use CALPUFF for the following reasons:

1. The increased level of effort required for conducting particulate apportionment in the regional scale, full-chemistry Eulerain model (CAMx) to acquire individual source contributions to Class I areas, relative to the simplicity of the CALPUFF model
2. The lack of a plume-in-grid feature with the particulate apportionment technique currently available in CAMx
3. The desire to be consistent with other CENRAP states, which all (except Texas and Iowa) appear to be using CALPUFF
4. The limited scope of what this modeling is to determine
5. The additional modeling of BART controls that will be conducted as part of the Regional Haze SIP with the CAMx or CMAQ model(s). EPA's BART guidance states that States should follow the EPA's Interagency Workgroup on Air Quality Modeling (IWAQM) guidance, Phase 2 recommendations for long-range transport. The IWAQM guidance was developed to address air quality impacts as assessed through the Prevention of Significant Deterioration (PSD) program at Class I areas, where the source generally is located beyond 50 km of the Class I area. The IWAQM guidance does not specifically address the type of assessment that will occur with the BART analysis.

EPA recommends in their BART modeling guidelines (2005) that States follow the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase II (1998) for long-range transport. The IWAQM guidance was developed to address air quality impact – as assessed through the Prevention of Significant Deterioration (PSD) program – at Class I areas, where the source generally is located beyond 50 km of the Class I area. The IWAQM guidance does not specifically address the type of assessment that will occur with the BART modeling.

## A. CALPUFF Screening Modeling:

CALPUFF modeling will be performed on all Arkansas BART-eligible sources. ADEQ intends to closely follow the CENRAP BART modeling protocol for most of the settings and inputs. Kansas attempted puff splitting and found this method to be computationally prohibitive on the current domain (State of Kansas, 2006). Also, according to Tesche, et al (2005),

> "There is no quantitative evidence that the horizontal and vertical puff-splitting algorithms in CALPUFF yield improved accuracy and precision in model estimates of inert or linearly reactive pollutants although conceptually the methods have appeal in that they attempt to mimic lateral and vertical wind speed and direction shears." (p 6-6)

Therefore, ADEQ will not invoke puff splitting in the no-obs screening analysis nor in the refined screening analysis. However, if a potentially subject-to-BART facility wishes to invoke the puff splitting mode, they will be required to notify ADEQ in writing of their intent and provide a protocol for approval prior to performing the analysis.

### *1. Modeling domain*

The CALPUFF modeling will be conducted on the CENRAP central 6 km grid. The extent of the proposed CALPUFF domain is shown in Figure 2.

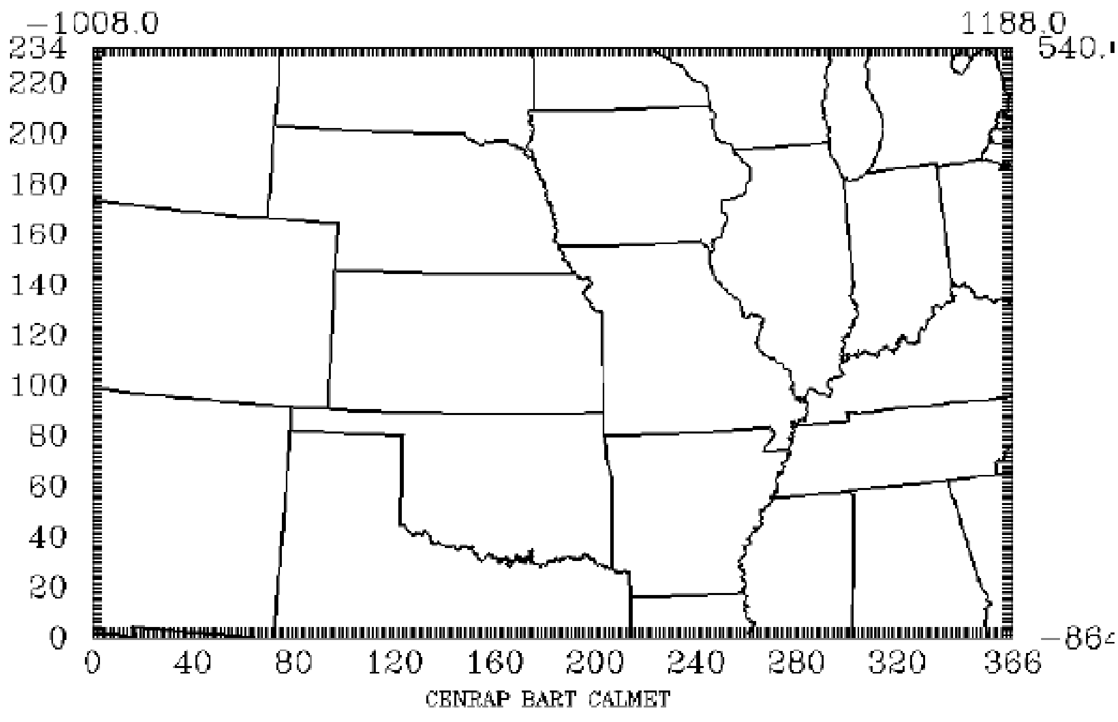


Figure 6 6 km CENRAP Central CALPUFF domain (Tesche, et al, 2005)

CALPUFF will be applied to each source for three annual simulations spanning the years 2001 through 2003. The IWAQM Phase II guidance allows the use of fewer than 5 years of meteorological data if a meteorological model using four-dimensional data assimilation is used to supply data. This is the case in this modeling analysis. See the section on meteorology for more information.

### *2. CALPUFF system implementation*

There are three main components to the CALPUFF model:

1. Meteorological Data Modeling (CALMET);
2. Dispersion Modeling (CALPUFF); and
3. Post-processing (CALPOST)

Versions of the modeling components to use in this BART analysis are shown in Table 4.

Table 4 CALPUFF Modeling Components

| Processor | Version | Level |
|---|---|---|
| TERREL | 3.311 | 030709 |
| CTGCOMP | 2.42 | 030709 |
| CTGPROC | 2.42 | 030709 |
| MAKEGEO | 2.22 | 030709 |
| CALMM5 | 2.4 | 050413 |
| CALMET | 5.53a | 040716 |
| CALPUFF | 5.753 | 051130 |
| POSTUTIL | 1.4 | 040818 |
| CALPOST | 5.6392 | 051130 |

The specific use of each of these components in the BART analysis is described in more detail below.

For screening applications, ADEQ will use the VISTAS version which is the latest 'beta' versions of the CALMET/CALPUFF modeling system. Note that these are **not** the EPA guideline codes but rather an updated version containing recent (as of this writing) science improvements and bug fixes. The current guideline CALPUFF code is version 5.7, level 030402. This substitution results from EPA phasing out the use of the legacy Pasquill-Gifford (P-G) dispersion parameters with the introduction of AERMOD as a new guideline model. CALPUFF employs the AERMOD turbulence-based dispersion coefficients and probability density function (pdf) dispersion methods scheme instead of P-G.

The appropriate model codes may be downloaded from www.src.com or purchased with the latest graphical user interface (GUI) from the model developer. The sequence of model processors listed in Table 4 corresponds to the order in which the programs are typically run.

### *3. Meteorological data modeling (CALMET)*

ADEQ will use the 2001-2003 CENRAP developed no-obs CALMET dataset for the screening analysis.* This decision was based on EPA Regions VI and VII written comments on the CENRAP BART Modeling Guidelines (Tesche, et al, 2005) which state,

> "Normally, in accordance with Section 8.3.1.2 (d) of the Guideline on Air Quality Models, the EPA would require that observations be incorporated in conjunction with prognostic meteorological data. While the idea of use of prognostic data alone holds promise, it is our opinion that this option requires further evaluation to insure that this approach does not bias CALPUFF towards underestimation (Guideline on Air Quality Models, Section 3.2.2 (d)(iv)). While we have significant concern regarding the use of the CALMET fields as they have been developed under the procedures documented in this protocol, we would consider the use of the CALMET meteorological fields provided the screening methodology described in Section 6.1 of the protocol is strictly adhered to. In this case, we feel that the use of the maximum visibility impact rather than the 98th percentile value is conservative in its application, and would overcome concerns of a potential bias towards underprediction [sic] of the "no-observation" mode. Under these circumstances, we would consider the use of the CALMET fields acceptable for the CALPUFF screening procedure." (EPA, 2005)

As stated in Section V. BART Air Quality Modeling Approach, ADEQ will use the **maximum** impact instead of the 98th percentile to determine if a source has an impact on visibility in a Class I.

However, subject-to-BART facilities have the option of using the CENRAP CALMET processed data or incorporating observational meteorological data into the aforementioned CALMET data. If a subject-to-BART facility opts to use the CENRAP CALMET processed data, then the facility will be required to use the maximum impact instead of the 98th percentile (8th day). If a subject-to-BART facility decides they would rather use the 98th percentile, then the facility will be required to incorporate observational data and provide a protocol as well as a performance evaluation which will need to be approved by ADEQ, EPA, and the FLMs.

Appendix F contains the detailed information on all CALMET setting that was used to develop the post-processed no-obs data fields.

***4. Dispersion modeling (CALPUFF)***

The CALMET output is used as input to the CALPUFF model, which simulates the effects of the meteorological conditions on the transport and dispersion of pollutants from an individual source. In general, ADEQ proposes to use the recommended default options in the CALPUFF model. There are some deviations, which are discussed below. Table 5 indicates the species that will be modeled and/or emitted in the no-obs and refined BART analyses.

Table 5 Species modeled in BART screening analyses

| Species | Modeled | Emitted | Dry Deposited |
|---|---|---|---|
| $SO_2$ | Yes | Yes | Computed-gas |
| $SO_4^{-2}$ | Yes | No | Computed-particle |
| $NO_x$ | Yes | Yes | Computed-gas |
| $HNO_3$ | Yes | No | Computed-gas |
| $NO_3^-$ | Yes | No | Computed-particle |
| PM-fine* | Yes | Yes | Computed-particle |
| $PM_{10}$* | Yes | Yes | Computed-particle |

*Please refer to Section VI subsection B for a detailed discussion on PM-fine and $PM_{10}$.

Emissions Speciation: ADEQ does not intend to model sulfate ($SO_4^{-2}$), nitrate ($NO_3^-$), elemental carbon (EC), and secondary organic aerosols (SOA) during the screening analyses. However, ADEQ recognizes the impact EC and SOA have on visibility. For instance, the light extinction ($\beta_{ext}$) coefficient for EC is 10 and for SOA it is 4. Currently, data are quite limited on appropriate speciation of organic/inorganic and filterable/condensable emissions by source category. Although there are speciation profiles available for gas- and oil-fired combustion turbines and coal combustion processes, currently there are no detailed profiles for the full range of BART-eligible sources. Thus, in the case of a subject-to-BART source where the PM profile for SO42-, EC, and SOA are known, ADEQ recommends the aforementioned species be modeled as separate species in CALPUFF in the post-control modeling analysis.

Condensable Emissions: According to Tesche, et al (p 6-5 2005), "condensable emissions are considered primary fine particulate." ADEQ is aware of the inability to measure $PM_{2.5}$ emissions. Thus, BART-eligible facilities will be most likely use AP-42 emission factors to develop the "actual" highest average 24-hr emission rate for this pollutant. In the development of this emission rate, ADEQ will require these facilities to use the AP-42 emission factors for condensable $PM_{2.5}$. For sources where AP-42 factors are not available, assumptions for partitioning need to be resolved with ADEQ.

Size Classification of Primary PM Emissions: Particle size parameters are entered in the CALPUFF input file for dry deposition of particles. There are default values for "aerosol" species (i.e., $SO_4^{-2}$, $NO_3^-$, and $PM_{2.5}$). The default value for each of these species is 0.48 µm geometric mass mean diameter and 2.0 µm geometric standard deviation. The main sources of these particles are fuel combustion. A way to account for this, without including EC and SOA in the modeling, is to use particle speciation in the post-processing step. This is discussed below in the CALPOST section.

As stated in a previous section, all $PM_{10}$ emissions will be modeled as $PM_{2.5}$ for the no-obs model simulations (Tesche, et al, 2005).

Background Ozone concentrations: Ozone ($O_3$) can be input to CALPUFF as hourly or monthly background values. Hourly values of ozone concentrations were obtained from two rural monitoring sites in Arkansas: Deer, Newton County monitoring site and Eagle Mountain, Montgomery County monitoring site. The hourly ozone concentrations were adjusted for the time differences between the post-processed prognostic meteorological file (0 GMT) and the collection time of the ozone (LST). Also, the concentrations were adjusted from parts per million (ppm) to parts per billion (ppb). These hourly ozone values will be used in this modeling.

Background Ammonia concentrations: Background ammonia concentration is assumed to be temporally and spatially invariant and will be fixed at 3 ppb across the entire domain for all months. It may be possible to derive $NH_3$ concentrations from regional modeling outputs that CENRAP is currently developing. At this time these $NH_3$ values are not available in a model ready form.

Receptors: Receptors are locations where model results are calculated and provided in the CALPUFF output files. Receptor locations were derived from the National Park Service's Class I area receptor database at http://www2.nature.nps.gov/air/maps/receptors/index.cfm. Only these discrete NPS receptors will be modeled in CALPUFF. The discrete receptors are necessary for calculating visibility impacts in the nine selected Class I areas that will be evaluated by ADEQ. All the discrete receptors will be placed with enough density that the highest visibility impacts should be evident. The NPS provides receptors in all the Class I areas on a 1 km basis. These receptors will be kept at the 1 km spacing for the BART modeling, and all receptors will be retained. NPS also provides a conversion program to convert the coordinates of the receptors from latitude/longitude (lat/long) to Lambert Conformal Conical (LCC). ADEQ used this conversion program to convert the receptors located in the five Class I areas it is assessing from lat/long to LCC.

Outputs: The CALPUFF modeling results will be displayed in units of micrograms per cubic meter ($\mu g/m^3$). In order to determine visibility impacts, the CALPUFF outputs must be post-processed.

Detailed information on all CALPUFF setting to be used in this screening analysis is located in Appendix G.

### *5. Post-processing (POSTUTIL/CALPOST)*

Hourly concentration outputs from CALPUFF are processed through POSTUTIL and CALPOST to determine visibility conditions. Specifically, POSTUTIL takes the concentration file output from CALPUFF and recalculates the nitric acid and nitrate partition based on total available sulfate and ammonia. The ammonia-limiting method (ALM) in CALPUFF repartitions nitric acid and nitrate on a receptor-by-receptor and hour-by-hour basis to account for the models systematic over-prediction due to overlapping puffs. For both screening applications, the parameter MNIRATE=1 is set in POSTUTIL to implement this approximate correction in its simplest form. The background ammonia concentration that was obtained from CENRAP's regional modeling effort will be used to maintain regional consistency in the CENRAP region. CALPOST uses the concentration file processed through POSTUTIL, along with relative humidity (RH) data, to perform visibility calculations. For the BART analysis, the only modeling results out of the CALPUFF modeling system of interest are the visibility impacts.

Please see Appendix H and I for detailed settings for POSTUTIL and CALPOST.

Light extinction: Light extinction must be computed in order to calculate visibility. CALPOST has seven methods for computing light extinction. This BART screening analysis will use Method 6, which computes extinction from speciated particulate matter with monthly Class I area-specific relative humidity adjustment factors, and is implied by the BART guidance. Relative humidity (RH) is an important factor in determining light extinction (and therefore visibility) because $SO_4^{-2}$ and $NO_3^-$ aerosols, which absorb moisture from the air, have greater extinction efficiencies with greater RH. All BART analyses will apply relative humidity correction factors ($f_{(RH)}$s) to $SO_4^{-2}$ and $NO_3^-$ concentrations outputs from CALPUFF, which were obtained from EPA's "Guidance for Estimating Natural Visibility Conditions under the Regional Haze Rule (EPA, 2003). The $f_{(RH)}$ values for the Class I areas that will be assessed are provided in Table 5.

Table 6 EPA recommended monthly averaged $f(_{RH})$ for the five Class I areas ADEQ is assessing (EPA, 2003)

| Class I Area | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Caney Creek | 3.4 | 3.1 | 2.9 | 3.0 | 3.6 | 3.6 | 3.4 | 3.4 | 3.6 | 3.5 | 3.4 | 3.5 |
| Hercules-Glades | 3.2 | 2.9 | 2.7 | 2.7 | 3.3 | 3.3 | 3.3 | 3.3 | 3.4 | 3.1 | 3.1 | 3.3 |
| Mingo | 3.3 | 3.0 | 2.8 | 2.6 | 3.0 | 3.2 | 3.3 | 3.5 | 3.5 | 3.1 | 3.1 | 3.3 |
| Sipsey | 3.3 | 3.0 | 2.8 | 2.7 | 3.1 | 3.4 | 3.5 | 3.5 | 3.5 | 3.3 | 3.1 | 3.3 |
| Upper Buffalo | 3.3 | 3.0 | 2.7 | 2.8 | 3.4 | 3.4 | 3.4 | 3.4 | 3.6 | 3.3 | 3.2 | 3.3 |

The $PM_{2.5}$ concentrations are considered part of the dry light extinction equation and do not have a humidity adjustment factor. The light extinction equation is the sum of the wet $SO_4^{-2}$ and $NO_3^-$ and dry components $PM_{2.5}$ plus Rayleigh scattering ($\beta_{Ray}$), which is 10 inverse megameters ($Mm^{-1}$).

To account for sources modeled with a known PM speciation profile for EC, SOA, and $SO_4$, an adjustment to the extinction coefficient for the PM components will be made in CALPOST. ADEQ intends to follow the method outlined in the FLM CALPUFF Reviewer's Guide (Gebhart, 2005) which is located in Appendix K.

### *6. Measuring visibility impacts*

The recommended procedure for quantifying visibility impacts can be found in Chapter 3 of the CENRAP BART Modeling Guidelines (Tesche, et al, 2005) which is located in Appendix J. The key point is that the light extinction coefficient ($\beta_{ext}$) can be calculated from the IMPROVE equation as:

$$\beta_{ext} = 3\,f(_{RH})\,[(NH_4)_2SO_4] + 3\,f(_{RH})\,[NH_4NO_3] + 4[OC] + 1[Soil] +$$

$$+ 0.6[Coarse\ Mass] + 10[EC] + \beta_{Ray}$$

The monthly site-specific $f(RH)$ values were obtained for the five Class I Area ADEQ is assessing from Table A-3 in the EPA (2003) guidance document. Then, the haze index (HI), in dv, is calculated in terms of the extinction coefficient via:

$$HI = 10 \ln (\beta_{ext}/10)$$

The change in visibility (measured in terms of Δ dv) is then compared against background conditions. The Δ dv value is calculated from the source's contribution to extinction, $\beta_{source}$, and background extinction, $\beta_{background}$, as follows:

$$\Delta\ dv = 10 \ln (\{\beta_{background} + \beta_{source}\} / \beta_{background})$$

If the Δ dv value is greater than or equal to 0.5 dv, the source is said to contribute to visibility impairment and is thus subject-to-BART controls. If not, it is BART-exempt.

The annual average natural levels of aerosol components at each Class I area being evaluated by ADEQ are shown in Table 7. Natural conditions by component in Table 6 are based on whether the Class I area is in the eastern or the western part of the United States. In this BART analysis, all Class I areas are located in the East. The source of this data is from EPA's Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule (EPA, 2003).

Table 7 Average annual natural levels of aerosol components ($\mu g/m^3$) (EPA, 2003)

| Class I Area | Region | $SO_4$ | $NO_3$ | OC | EC | Soil | Coarse Mass |
|---|---|---|---|---|---|---|---|
| Caney Creek | East | 0.23 | 0.10 | 1.40 | 0.02 | 0.50 | 3.00 |
| Hercules-Glades | East | 0.23 | 0.10 | 1.40 | 0.02 | 0.50 | 3.00 |
| Mingo | East | 0.23 | 0.10 | 1.40 | 0.02 | 0.50 | 3.00 |
| Sipsey | East | 0.12 | 0.10 | 0.47 | 0.02 | 0.50 | 3.00 |
| Upper Buffalo | East | 0.23 | 0.10 | 1.40 | 0.02 | 0.50 | 3.00 |

As stated in section V, in a cooperative agreement with EPA Regions VI and VII and FLMs, CENRAP guidance deviates from use of the 98th percentile impact. The CALMET datasets as described in this protocol were processed with the no-obs options (i.e., surface observations were not used in the CALMET wind field interpolation). Aware that exercising CALMET with no-obs may lead in some applications to potentially less conservatism in the CALPUFF visibility results compared with the use of CALMET with observations, CENRAP has agreed to EPA's recommendation that the **maximum** visibility impact, rather than the 98th percentile value, should be used for the no-obs screening analysis using the CENRAP-developed CALMET datasets.

If the no-obs screening analysis results indicate a BART-eligible facility's maximum Δ dv on a Class I area is less that 0.5 dv, then they will be considered exempt from BART and will be notified by ADEQ of their status. However, if the maximum Δ dv is equal to or greater than 0.5 dv, the source will be considered to be subject-to-BART. ADEQ will notify these subject-to-BART facilities.

# VIII. Change in Visibility Due to BART Controls

Once a facility is determined to be subject-to-BART, this facility must perform an engineering analysis and a post-control modeling analysis using CALPUFF. This modeling analysis must be compared to the pre-control modeling results. Please note that this will be a source specific (i.e. emitting unit specific) and pollutant specific modeling analysis using CALPUFF. If a subject-to-BART facility opts to use the 98$^{th}$ percentile rather than the maximum impact, the subject-to-BART facility will be required to be incorporate observational data with the post processed CALMET prognostic meteorological data. Also these facilities will be required to submit their meteorological modeling protocol, model performance evaluation, and CALPUFF modeling protocol to ADEQ, EPA Region VI, and FLMs for approval. However, if the subject-to-BART facility opts to use the maximum impact rather than the 98$^{th}$ percentile, these facilities may use the post-processed CALMET MM5 data.

Additionally, one control measure that a source may opt to use is to revise their Title V permit to provide for synthetic minor limits so that it falls under the BART emission cap. That permit modification must be done prior to the State going to public hearing on its RH SIP. The limits must be in place for as long as the RH SIP is applicable or for as long as the source is operational. However, the source will still need to do a post-control CALPUFF modeling analysis to determine the amount of emissions it needs to reduce for visibility improvement. (Note: ADEQ **strongly** recommends that all subject-to-BART facilities work closely with ADEQ in their engineering analyses.) Also, after all of the post-control results are submitted to and approved by ADEQ, these results will then be inputted into either CAMx or CMAQ for a cumulative model run. If the control measures proposed by the BART facilities still impact a Class I area, the BART facilities will need to implement additional control. Please note that all post-modeling results are due to ADEQ no later than October 23, 2006.

# IX. References


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U.S. EPA, Regions VI & VII (2005). BART Protocol Comments.

U.S. EPA, Region VI (2006). Personal communication.

# Appendix A. Proposed Time-line

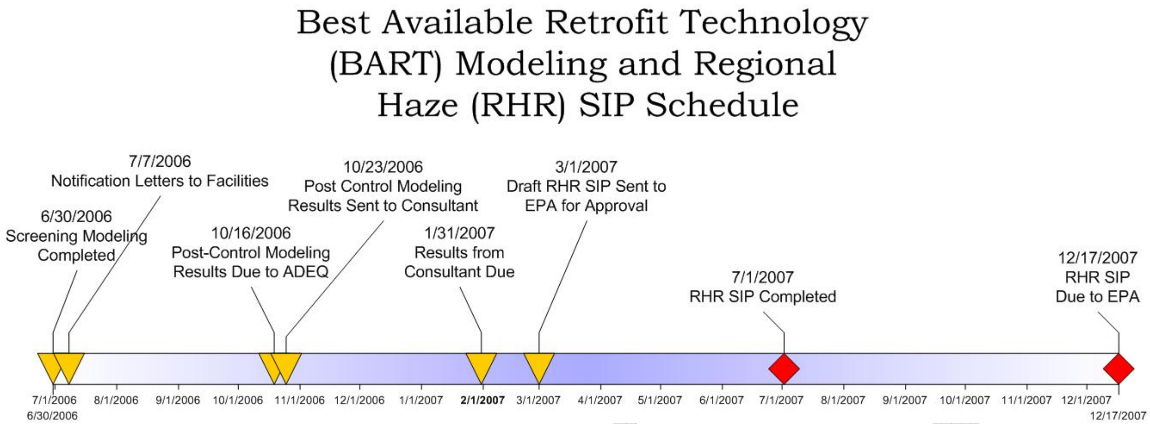



Figure A-1 ADEQ's proposed time-line to meet the RH SIP deadline of December 17, 2007 as set forth by EPA in its Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determination (40 CFR Part 51, p 39156)

# Appendix B. Map of receptors

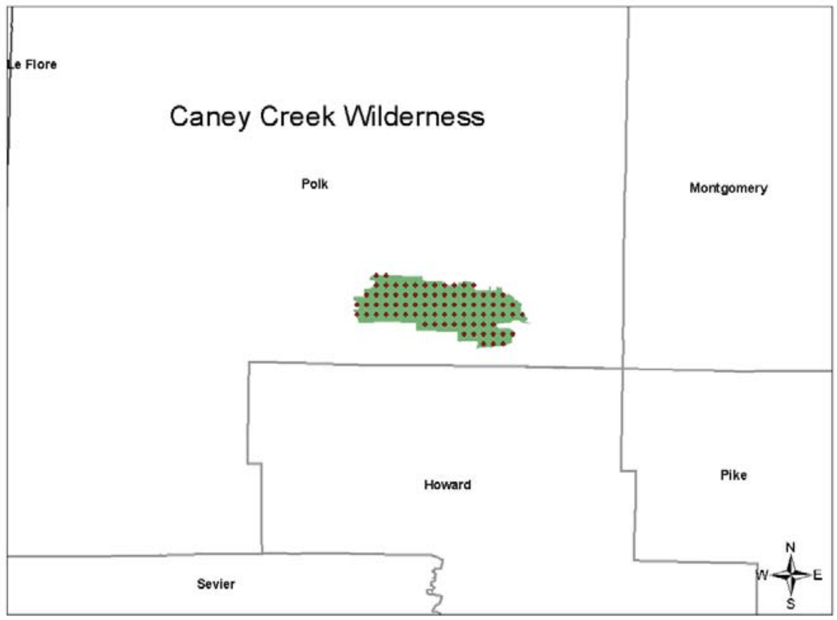



Figure B-1 Receptors located in Caney Creek Wilderness Area, Arkansas

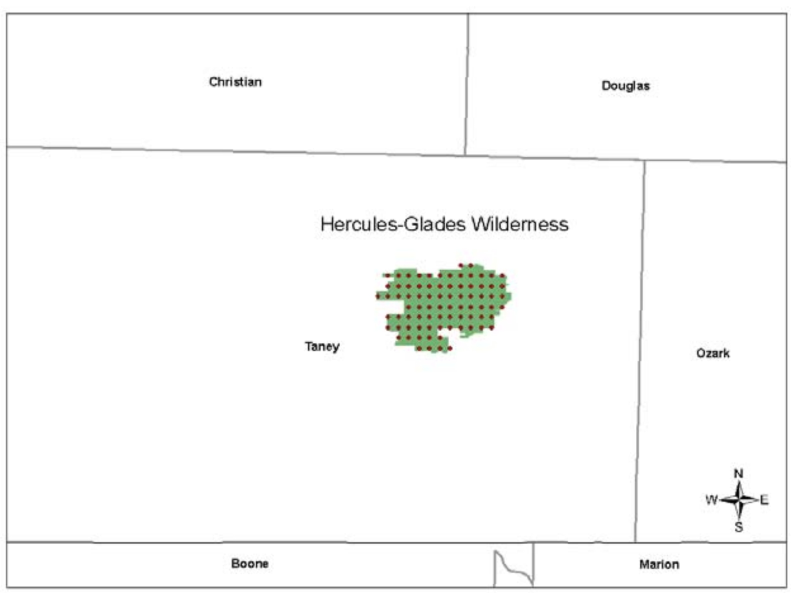



Figure B-2 Receptors located in Hercules-Glade Wilderness Area, Missouri

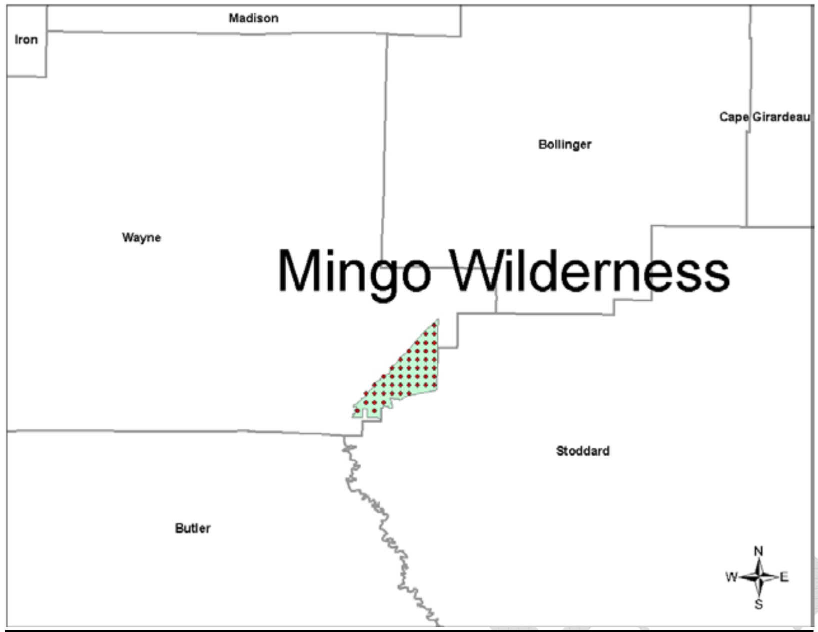


Figure B-3 Receptors located in Mingo Wilderness Area, Missouri

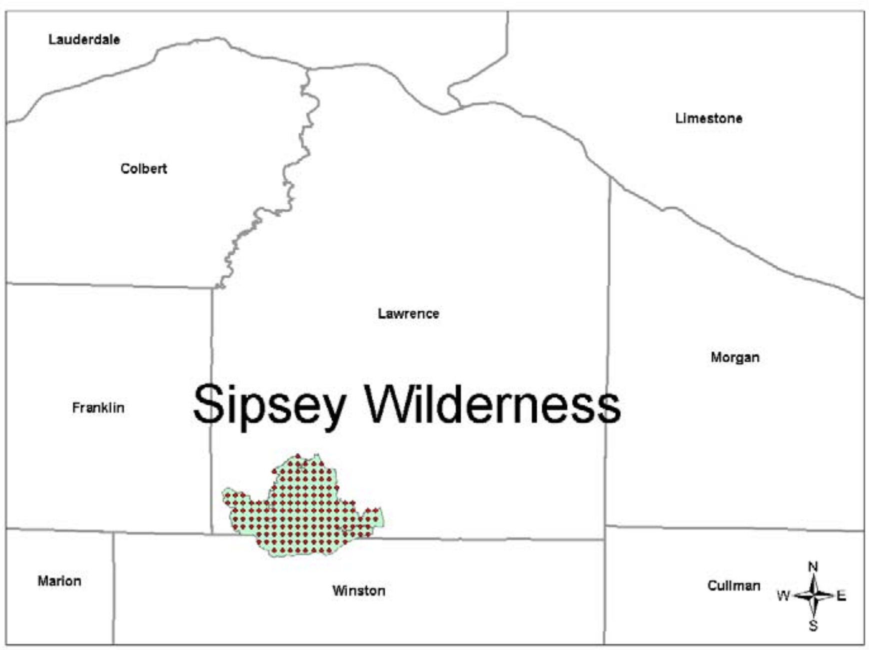


Figure B-4 Receptors located in Sipsey Wilderness, Alabama

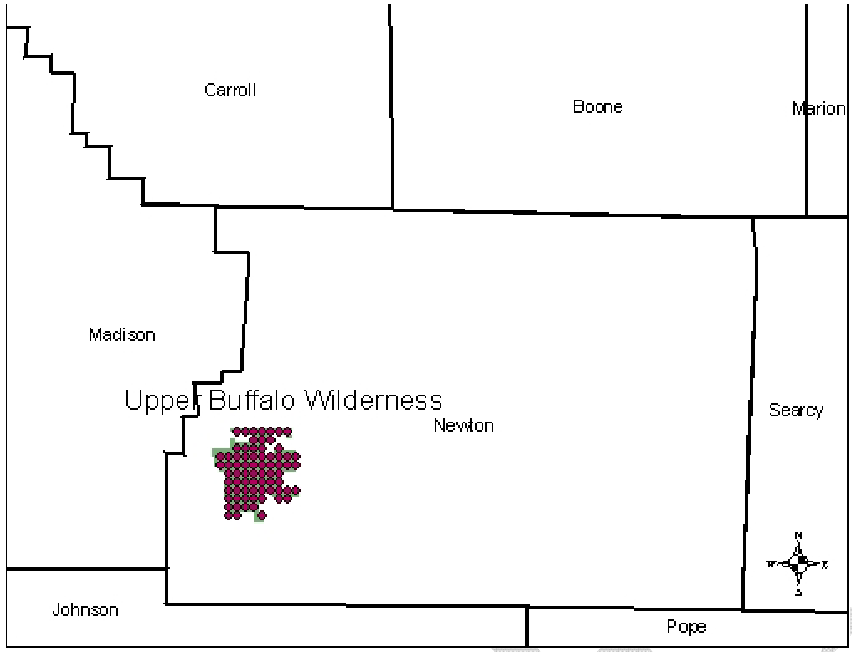


Figure B-4 Receptors located in Upper Buffalo Wilderness Area, Arkansas

# Appendix C. BART-Eligible Sources' Stack Parameters, Base Elevation at Ground Level, and Stack Coordinates

Table C-1 BART-eligible sources' stack parameters

| STATIONARY SOURCE NAME/LOCATION | Emission Unit ID | Stack Height Meters | Stack Diameter Meters | Exit Velocity m/sec | Temperature $^oK$ |
|---|---|---|---|---|---|
| Albermarle-South Plant / Magnolia | SR-01 | 57.9 | 0.814 | 15.24 | 922 |
| Albermarle-South Plant / Magnolia | BH-01 | 6.4 | 2.591 | 9.14 | 505 |
| Albermarle-South Plant / Magnolia | BH-02 | 6.4 | 2.591 | 9.14 | 505 |
| American Elect. Power (SWEPCO) / Gentry | SN-01 | 164.6 | 6.096 | 34.14 | 408 |
| AR Elect. Coop - Bailey Plant / Augusta | SN-01 | 50.9 | 3.000 | 28.04 | 444 |
| AR Elect. Coop - McClellan Plant / Camden | SN-01 | 48.8 | 3.301 | 28.04 | 444 |
| Big River Industries / W. Memphis | SN-01 | 30.5 | 1.524 | 21.88 | 330 |
| Delta Natural Kraft / Pine Bluff | SN-02 | 50.3 | 2.134 | 13.29 | 348 |
| Domtar, Inc. / Ashdown | SN-03 | 66.1 | 1.890 | 26.76 | 522 |
| Domtar, Inc. / Ashdown | SN-05 | 71.6 | 3.659 | 11.92 | 325 |
| Eastman Chemical / Batesville | 6M01-01 | 61.0 | 2.743 | 9.45 | 422 |
| El Dorado Chemical / El Dorado | SN-08 | 22.9 | 1.219 | 33.53 | 505 |
| El Dorado Chemical / El Dorado | SN-09 | 22.9 | 1.219 | 32.00 | 500 |
| El Dorado Chemical / El Dorado | SN-10 | 23.8 | 0.152 | 23.77 | 313 |
| Entergy - Lake Catherine / Jones Mill | SN-03 | 59.4 | 5.182 | 3.08 | 396 |
| Entergy - Ritchie Plant / Helena | SN-02 | 71.9 | 3.658 | 28.62 | 390 |
| Entergy - White Bluff / Redfield | SN-01 | 304.8 | 7.833 | 27.43 | 434 |
| Entergy - White Bluff / Redfield | SN-02 | 304.8 | 7.833 | 27.43 | 434 |
| Entergy - White Bluff / Redfield | SN-05 | 4.6 | 0.914 | 19.81 | 519 |
| Georgia-Pacific Paper / Crossett | SN-22 | 53.3 | 3.658 | 10.45 | 341 |
| Great Lakes Chemical / El Dorado | SN-302A | 9.1 | 0.762 | 40.54 | 555 |
| Green Bay Packaging / Morrilton | SN-05A | 30.8 | 1.798 | 25.60 | 456 |
| Lion Oil / El Dorado | SN-809 | 61.0 | 1.753 | 9.75 | 533 |
| Potlatch Corp. / McGehee | SN-04 | 89.6 | 2.743 | 14.78 | 444 |

Table C-2 BART-Eligible Emission Units' Base Elevation and Lambert Conformal Conical (LCC) Coordinates

| STATIONARY SOURCE NAME/LOCATION (BART File Name) | Emission UNIT ID | Base Elevation, meters (m) | X Easting LCC x | Y Northing LCC y |
|---|---|---|---|---|
| Albermarle-South Plant / Magnolia | SR-01 | 86.9 | 352.81836 | -747.03381 |
| Albermarle-South Plant / Magnolia | BH-01 | 88.4 | 352.67618 | -746.98114 |
| Albermarle-South Plant / Magnolia | BH-02 | 88.4 | 352.65801 | -746.98190 |
| American Elect. Power (SWEPCO) / Gentry | SN-01 | 349.9 | 221.58128 | -410.39077 |
| Ark. Elect. Coop - Bailey Plant / Augusta | SN-01 | 61.3 | 510.86643 | -507.71488 |
| Ark. Elect. Coop - McClellan Plant / Camden | SN-01 | 33.5 | 390.21870 | -702.15534 |
| Big River Industries (General Shale)/ W. Memphis | SN-01 | 60.0 | 609.12652 | -517.70639 |
| Delta Natural Kraft / Pine Bluff | SN-02 | 66.4 | 457.00824 | -621.20692 |
| Domtar, Inc. / Ashdown | SN-03 | 97.5 | 267.47491 | -698.66686 |
| Domtar, Inc. / Ashdown | SN-05 | 97.5 | 267.48245 | -698.74355 |
| Eastman Chemical / Batesville | 6M01-01 | 82.3 | 493.14724 | -458.02938 |
| El Dorado Chemical / El Dorado | SN-08 | 63.1 | 401.11728 | -734.65321 |
| El Dorado Chemical / El Dorado | SN-09 | 63.1 | 401.13533 | -734.65236 |
| El Dorado Chemical / El Dorado | SN-10 | 62.2 | 401.19594 | -734.67412 |
| Entergy - Lake Catherine / Jones Mill | SN-03 | 100.0 | 375.45658 | -606.40861 |
| Entergy - Ritchie Plant / Helena | SN-02 | 54.9 | 586.25363 | -591.07129 |
| Entergy - White Bluff / Redfield | SN-01 | 94.2 | 446.73457 | -625.11197 |
| Entergy - White Bluff / Redfield | SN-02 | 94.2 | 445.61252 | -604.15523 |
| Entergy - White Bluff / Redfield | SN-05 | 94.2 | 445.61539 | -604.25671 |
| Georgia-Pacific Paper / Crossett | SN-22 | 46.0 | 469.03486 | -745.02133 |
| Green Bay Packaging / Morrilton | SN-05A | 98.5 | 387.29077 | -532.44265 |
| Lion Oil / El Dorado | SN-809 | 75.6 | 403.01817 | -741.82948 |
| Potlatch Corp. / McGehee | SN-04 | 43.9 | 533.13136 | -678.59798 |

# Appendix D. BART-Eligible Emission Rates used for the No-Obs Modeling Run

Table D-1 BART-eligible units' highest 24-hour actual emission rates for $SO_2$, $NO_x$, $PM_{10}$* and $PM_{2.5}$ in grams per second (g/sec)

| BART-Eligible Facilities/ Locations | Emission Unit ID Number | Highest 24-Hour Actual Emission Rates (g/sec) | | | |
|---|---|---|---|---|---|
| | | $SO_2$ | $NO_x$ | $PM_{10}$ | $PM_{2.5}$ |
| Albermarle-South Plant / Magnolia | SR-01 | 48.126 | 0.076 | 0.000 | 0.009 |
| Albermarle-South Plant / Magnolia | BH-01 | 0.353 | 2.075 | 0.000 | 0.136 |
| Albermarle-South Plant / Magnolia | BH-02 | 0.535 | 2.578 | 0.000 | 0.128 |
| American Elect. Power (SWEPCO) / Gentry | SN-01 | 595.781 | 245.066 | 21.725 | 5.531 |
| AR Elect. Coop - Bailey Plant / Augusta | SN-01 | 299.344 | 36.933 | 21.729 | 21.729 |
| AR Elect. Coop - McClellan Plant / Camden | SN-01 | 346.189 | 47.124 | 28.764 | 28.764 |
| Big River Industries/ W. Memphis | SN-01 | 0.000 | 8.589 | 0.000 | 7.076 |
| Delta Natural Kraft / Pine Bluff | SN-02 | 0.239 | 1.701 | 1.058 | 0.529 |
| Domtar, Inc. / Ashdown | SN-03 | 0.774 | 22.632 | 0.000 | 21.354 |
| Domtar, Inc. / Ashdown | SN-05 | 70.175 | 52.008 | 0.000 | 7.881 |
| Eastman Chemical / Batesville | 6M01-01 | 54.046 | 11.045 | 0.290 | 0.217 |
| El Dorado Chemical / El Dorado | SN-08 | 0.000 | 20.060 | 0.000 | 0.000 |
| El Dorado Chemical / El Dorado | SN-09 | 0.000 | 15.645 | 0.000 | 0.000 |
| El Dorado Chemical / El Dorado | SN-10 | 0.000 | 0.415 | 0.000 | 0.000 |
| Entergy - Lake Catherine / Jones Mill | SN-03 | 0.420 | 309.535 | 0.365 | 0.246 |
| Entergy - Ritchie Plant / Helena | SN-02 | 0.105 | 17.640 | 0.997 | 0.997 |
| Entergy - White Bluff / Redfield | SN-01 | 978.164 | 550.821 | 15.592 | 11.802 |
| Entergy - White Bluff / Redfield | SN-02 | 985.933 | 596.075 | 16.653 | 12.915 |
| Entergy - White Bluff / Redfield | SN-05 | 4.095 | 3.811 | 0.365 | 0.246 |
| Georgia-Pacific Paper / Crossett | SN-22 | 77.275 | 182.677 | 0.000 | 9.310 |
| Green Bay Packaging / Morrilton | SN-05A | 4.934 | 8.771 | 0.000 | 1.165 |
| Lion Oil / El Dorado | SN-809 | 23.142 | 5.980 | 0.000 | 7.696 |
| Potlatch Corp. / McGehee | SN-04 | 6.942 | 10.533` | 2.752 | 2.752 |

# Appendix E. Chapter 5 of the CENRAP BART Modeling Guidelines (Tesche, et al, 2005)

## 5.0 DATA BASES FOR CALPUFF MODELING

To support BART modeling by the states and source operators, both meteorological and aerometric data sets are required. Regional meteorological data sets generated by the CALMET model suitable for direct input to the CALPUFF modeling system have been developed and archived. These data sets cover calendar years 2001, 2002, and 2003 for three sub-regional grid domains shown in Figures 5-1 through 5-4. The procedures used in developing the CALMET data sets generally follow the IWAQM recommendations (EPA, 1998), except for a few notable refinements. *The processed CALMET files, in CALPUFF-ready input format, are available from CENRAP on hard disk drives to interested states and stakeholders.*

This chapter describes how these meteorological modeling sets were developed and evaluated. The basic CALMET model configuration used to generate the three years of CALPUFF-ready meteorology is described in detail so that users of this information have a clear understanding of the data sets and their applicability. In addition, for those states or source operators who elect to conduct more source-specific CALMET/CALPUFF modeling, the information in this chapter may be helpful in guiding specification of revised CALMET model inputs and generation of revised CALMET data sets.

Also included in Section 5 .2 is a discussion of routinely available air quality monitoring data sets available to the states and source operators in support of screening and source-specific BART modeling exercises.

## 5.1 Development of CALMET Meteorological Files

### 5.1.1 MM5 Data Sets

Alpine Geophysics developed a consistent set of CALMET regional meteorological modeling data sets for use by the CENRAP States, BART eligible sources within the region and others. These meteorological modeling data sets were constructed through the joint use of the CALMET processor and results from existing annual three-dimensional MM5 meteorological simulations. The specific annual prognostic model simulations available for CENRAP BART modeling included:

> 2001 MM5 data set at 36/12 km resolution developed for EPA by Alpine Geophysics (McNally and Tesche, 2002; McNally 2003);

> 2002 MM5 data set at 36 km resolution developed for CENRAP by Iowa DNR (Johnson, 2003a,b),

> 2003 MM5 data set at 36 km resolution developed for the Midwest RPO (Baker, 2005; Baker et al., 2004; Kembell-Cook et al., 2005)

Each of these studies included a performance evaluation of the MM5 generated data sets against surface meteorological observations and the results of these evaluations are contained in the reports or presentations cited above. While there exists a set of annual 12 km MM5 meteorology for 2002, this data set was developed by four independent CENRAP modeling centers and these data sets have not been concatenated into one master data base. More importantly, there has been no systematic, rigorous model performance evaluation performed on the CENRAP 2002 12 km MM5 data yet. Accordingly, until such time as the 2002 12 km data set has been evaluated and shown to be of comparable reliability as the aforementioned MM5 data sets, it's use is contraindicated.

### 5.1.2 CALMET Model Configuration

The CALMET modeling procedures used to construct meteorological inputs to CALPUFF for visibility screening of BART eligible sources generally follows the IWAQM recommendations (EPA, 1998), except as noted below.

*CALMET Model Options*. The CALMET model has a number of user-selected options, parameter settings, and 'switches' that must be defined prior to exercising the processing system. These options and settings are well-described in the CALMET User's Guide (Scire et al., 2000a) and in the CALMET input file to the executable code. Appendix A of this protocol summarizes the CALMET configurations used in developing the processed 6 km meteorological fields over the three CENRAP BART modeling domains. Also included in the tables in Appendix A are the default CALMET options and parameter settings recommended in the IWAQM Phase 2 Report (EPA, 1998).

*CALMET Domain.* Three slightly overlapping modeling domains were defined by CENRAP to support BART modeling. These domains are shown in Figures 5-1 through 5-4 and Table 5-1. The processors used to generate the domain, land use, and elevation data for the CALMET/CALPUFF system include TERREL, CTGPROC, and MAKEGEO, as described below.

> TERREL is the terrain pre-processor that averages terrain features to the modeling grid resolution; TERREL constructs the basic properties of the gridded domain and defines the coordinates upon which meteorological data are stored. Key parameters include specification of grid type, location, resolution and terrain elevation.

> CTGPROC computes the fractional land use for the modeling grid resolution. Land use characteristics for each grid cell are assigned using CTGPROC. The primary variable adjustment associated with CTGRPOC is selection of an appropriate land use database. Version 2.0 of the North American Land Cover Characteristics database is used.

> MAKEGEO is the final pre-processor that combines the terrain and land use data for input to CALMET. Generating the appropriate MAKEGEO.INP control file requires only minimal alteration of the default assignments. Key modifications include specifying domain attributes and ensuring input files are correctly referenced.

Terrain. CALMET requires both terrain height and land use/land cover for the application region. These are generated using the CALMET CTGPROC, TERREL and MAKEGEO processors. The terrain data were created using the TERREL (version 3.311, level 030709) processor and the Shuttle Radar Topography Mission (SRTM)-GTOPO 30 second (~1 km) resolution dataset.

Land Use. The landuse data set was created using the Composite Theme Grid CTGROC processor (version 2.42, level 030709) and the United States Geological Survey (USGS) Global Land Cover Characterization (GLCC) version 2.0 database. The GLCC database is available at 30 second (~1km) resolution. References for these and other modeling datasets can be found at www.src.com.

Vertical Layer Structure. The vertical layer structure for the CALMET/CALPUFF screening applications is more refined than the general suggestions of IWAQM. The CENRAP vertical structure was designed to reduce the need for vertical interpolation while simultaneously improving vertical resolution within the planetary boundary layer (PBL). Table 5-2 identifies the 11 layer interfaces required to define the 10 layer vertical CALMET grid structure. The top interface in the CALMET simulation is 4000 meters.

Use of Observations**.** Based on considerable discussions with State and Federal managers and agency personnel, CENRAP has elected to use the No-Obs mode in CALMET for constructing the 6 km meteorological fields for CALPUFF screening exercises. The three annual MM5 simulations (2001, 2002, and 2003) will be used as the sole source for meteorological data within CALMET. Blending observational data with the MM5 data within CALMET (i.e., use of the "OBS" option is essentially a redundant use of the same data. Substantial improvement in the MM5 initialization data and in the use of four dimensional data assimilation (FDDA) has been achieved in recent years using observational data. The ETA analysis data used in initial and boundary conditions estimates as well as within the FDDA fields derive from 3-hourly, 40 km objective analysis fields computed using an extensive supply of observational data (National Weather Service surface and upper air data, GOES satellite precipitable water; VAD wind profiles from NEXRAD; ACARS aircraft temperature data; SSM/I oceanic surface winds; daily NESDIS snow cover and sea-ice analysis data; RAOB balloon drift; GOES and TOVS-1B radiance data; 2D-VAR SST from NCEP Ocean Modeling Branch; radar estimated rainfall; and surface rainfall). The complexity, resolution, and accuracy of the ETA data that is used to initialize and 'nudge' the MM5 forecasts is extensive indeed. Particularly at the 12-36 km horizontal grid scales over the flat to modestly rolling topography of the CENRAP domain, there is no need to introduce local meteorological observations in order to retrieve local terrain effects, for example. Thus, mesoscale wind patterns are likely to be adequately characterized by the MM5 simulations.

Many observations, especially surface observations, reflect local conditions on a scale smaller than the 6 km CENRAP CALMET fields. The introduction of the local observations into the regional modeling domain may extend the influence of the observational data beyond its true representativeness and result in internally inconsistent flow features. In particular the time interpolation of the 12-hourly upper air sounding data may wash out structure in the MM5 fields that are appropriate to retain. Given that the CENRAP domain as a whole includes areas of moderately rolling terrain, coastal regions and relatively flat terrain, a single set of representative weights[1] that allows significant influence of the observations where appropriate, will involve a considerable effort and substantial testing. The internally consistent MM5 fields are considered likely to be appropriate for the regional simulations, and the incremental benefit of adding the observational data into the regional CALMET simulations is not considered worthwhile.

However, on the smaller domains likely to be considered in source-specific modeling (e.g., 1-4 km in scale) with the higher CALMET grid resolution and the smaller domain size, more control over the region of influence of the meteorological observations can be achieved. It is easier for the diagnostic model to allow the local flow observations to have appropriate influence in the vicinity of the observation, but allow terrain-adjusted flow to dominate away from the observations. Given that the fine scale source-specific domains will be used especially in irregular and/or meteorologically complex settings, the relatively coarser-scale MM5 simulations are less likely to be fully adequate, and the introduction observational data into CALMET is more likely to achieve improvements in the resulting meteorological fields.

*Diagnostic Model Settings*

A number of diagnostic model settings must be selected for CALMET to properly process representative diagnostic meteorological data sets. These are summarized in Appendix A, compared to the default CALMET settings, and discussed in the following:

[1] Weights are assigned in CALMET to control the 'blending' of observations and MM5 predictions.

> CALMET options dealing with radius of influence parameters (R1, R2, RMAX1, RMAX2, RMAX3), BIAS, ICALM parameters are not used in No-Observations mode;

> Gridded cloud data were inferred from the MM5 relative humidity fields (ICLOUD=3);

> Given that all state variables are MM5-derived (IPROG=14; ITPROG=2), surface layer winds were not extrapolated to the upper layers (IEXTRP = -1);

> The IWAQM recommendation for disabling the computation of kinematic effects in the wind field options and parameters was selected. This was selected in light of the very modest elevated terrain in the CENRAP domain, relative to the mountainous regions in the U.S. and Alps where the kinematic parameterizations were originally developed. Thus, the option for computing kinematic effects was disabled (IKINE = 0).

> The BIAS array was set to 0. in the CALMET control file because surface and upper air data were not used (NOOBS = 2);

> Because the MM5 wind fields supply CALMET with the initial guess fields to the diagnostic wind model (IWFCOD =1, IPROG = 14) and observational data are not reintroduced, the following variables were set to nominal values:

- The minimum distance for which extrapolation of surface winds should occur was set to -1 (RMIN2 = -1.).
- RMIN was left at the IWAQM recommendation of 0.1 km.
- RMAX1 and RMAX2 were each assigned a value of 30 km. RMAX3 was assigned a value of 50 km.
- R1 and R2 were each assigned the value of 1.0.
- ISURFT and IUPT were assigned placeholder values of 4 and 2, respectively.

> The radius of influence regarding terrain features is comparable to the resolution of the processed terrain data: 12 km.

> The radius of influence for temperature interpolation is set to 36 km (TRADKM), a value considered appropriate given the 6 km CALMET domain and 36/12 km MM5 domain.

> The beginning/ending land use categories for temperature interpolation over water are assigned category 55: (JWAT1 = JWAT2 = 55).

> SIGMAP was set to 50 km, while the IWAQM recommendation is 100 km, but with no supporting documentation. Because precipitation rates are explicitly incorporated from the MM5 data, a lower radius of influence was deemed appropriate.

> Diagnostic options: IWAQM default values were used (see Appendix A);

> TERRAD (terrain scale) is required for runs with diagnostic terrain adjustments (i.e., the 2003 simulations). Values of ~10-20 km were tested, and an appropriate value determined.

> Land use defining water: JWAT1 = 55, JWAT2 = 55 (large bodies of water). This feature allows the temperature field over large bodies of water such as the Gulf of Mexico and the Great lakes to be properly characterized by buoy observations.

> Mixing height averaging parameter (MNMDAV) were determined sensitivity tests. The purpose of the testing is to optimize the variable to allow spatial variability in the mixing height field, but without excessive noise.

Obviously, there are some instances where more advanced and/or recently developed procedures for constructing the CALMET fields have been used compared with the IWAQM (1998) guidance. For example, one agency expressed concern about the choice to employ prognostic model-derived gridded cloud cover data in CALMET (ICLOUD = 3). While this is admittedly a 'non-guideline' option, in our view it represents the best science option currently available. In particular, the EPA CAIR and CAMR rulemaking modeling and the CAMx/CMAQ modeling being performed by the RPOs for regional haze all utilize the gridded moisture fields in the MM5 model as a basis for estimating cloud. Presumably, if the method is suitable for such advanced visibility modeling, it is adequate for CALPUFF modeling. Of course, in the protocol negotiation, the States, source operators, and regulatory agencies have an opportunity to re-examine the CALMET diagnostic model settings used in creating the CENRAP gridded fields and modify them if warranted.

In summary, the development of the regional CALMET meteorological fields from MM5 data was conducted in No-Observations ("No-Obs") mode. CALMET's boundary layer modules were used to compute mixing heights, turbulence coefficients and other meteorological parameters required as input to CALPUFF.

### 5.1.3 MM5/CALMET Processing

Construction of the CALPUFF-ready meteorological fields entails a two-step process. First, the MM5 prognostic model output fields are extracted and processed for input to CALMET. This step entails running various extraction software routines followed by the CALMM5 code. Then, CALMET is exercised for the full three year period over each sub-regional CENRAP domain.

*CALMM5.* Previous applications of the prognostic Mesoscale Meteorological model version 5 (MM5) served as the source of the gridded meteorological fields for calendar years 2001, 2002, and 2003. The actual CALMM5 configuration entailed modification of a few user-specified variables. However, two setting are of primary importance:

> All vertical layers from MM5 were extracted, providing CALMET configuration flexibility, and

> Vertical velocity, relative humidity, cloud/rain fields, and ice/snow fields were extracted. (Graupel was extracted for 2001, the only year where the data were available in the MM5 datasets.)

*CALMET.* CALMET (v5.53a, lev 040716) was applied consistent with CENRAP's recommendation that the 6 km be generated using the 'No-Obs' option. The specific options used have been discussed above and are summarized in Appendix A.

### 5.1.4 Evaluation of the CALPUFF-Ready Meteorological Data Sets

In typical applications the adequacy of the CALMET fields is seldom evaluated using independent measurements. Often, only cursory visual examination of wind vector plots or time series is considered. This evaluation is important because the CALMET performance analysis gives direct insight into the adequacy of the model-processed fields on a subregional basis. It also serves as an independent quality assurance tool. Alpine's MAPS evaluation software to perform an independent evaluation of the processed CALMET data bases. MAPS was used in conjunction with the NCAR DS472 TDL data sets to evaluate the surface winds and temperatures for 2001-2003 across all three domains. Since only a small portion of the meteorological content of these data were ingested in the MM5 data assimilation routines (see Johnson, 2003a), these data sets are essentially an independent, quantitative means for evaluating the adequacy of the meteorological fields input to CALPUFF.

*CALMET Evaluation Methodology*

Several statistical measures were calculated as part of the CALMET meteorological evaluation using established procedures (e.g., Tesche et al., 1990; Emery et al., 2001). Additional plots and graphs are used to present these statistics on both hourly and daily time frames over the full annual cycle. For this study, evaluation measures were calculated for wind, temperature, and relative humidity because these parameters are the principal meteorological inputs to CALPUFF. The full set of CALMET evaluation statistics and graphical displays generated with the AG-MAPS software (McNally and Tesche,1994) are contained on a DVD available from CENRAP.

The statistics used to evaluate the meteorological fields for 2001-2003 are generated in both absolute terms (e.g., wind speed error in m/s), and relative terms (percent error) as is commonly done for air quality assessments. Obviously, a very different significance is associated with a given relative error for different meteorological parameters. For example, a 10% error for wind speed measured at 10 m/s is an absolute error of 1 m/s, a minor error. Yet a 10% error for temperature at 300 K is an absolute error of 30 K, a ridiculously large error. On the other hand, pollutant concentration errors of 10% at 1 ppb or 10 ppm carry practically the same significance.

Three key meteorological metrics include the bias, error, and index of agreement (IOA) for wind speed, temperature and relative humidity. These measures are defined as follows:

Bias (B): Calculated as the mean difference in prediction-observation pairings with valid data within a given analysis region and for a given time period (hourly or daily):

$$B = \frac{1}{IJ}\sum_{j=1}^{J}\sum_{i=1}^{I}\left(P_j^i - O_j^i\right)$$

Error (E): Calculated as the mean *absolute* difference in prediction-observation pairings with valid data within a given analysis region and for a given time period

$$E = \frac{1}{IJ}\sum_{j=1}^{J}\sum_{i=1}^{I}\left|P_j^i - O_j^i\right|$$

(hourly or daily).

Note that the bias and gross error for winds are calculated from the predicted-observed residuals in speed and direction (not from vector components *u* and *v*). The direction error for a given prediction-observation pairing is limited to range from 0 to ±180°.

Index of Agreement (IOA): calculated following the approach of Willmont (1981). This metric condenses all the differences between model estimates and observations within a given analysis region and for a given time period (hourly and daily) into one statistical quantity. It is the ratio of the total RMSE to the sum of two differences – between each prediction and the observed mean, and each observation and the observed mean:

$$IOA = 1 - \left[\frac{IJ \cdot RMSE^2}{\sum_{j=1}^{J}\sum_{i=1}^{I}\left|P_j^i - M_o\right| + \left|O_j^i - M_o\right|}\right]$$

Viewed from another perspective, the index of agreement is a measure of the match between the departure of each prediction from the observed mean and the departure of each observation from the observed mean. Thus, the correspondence between predicted and observed values across the domain at a given time may be quantified in a single metric and displayed as a time series. The index of agreement has a theoretical range of 0 to 1, the latter score suggesting perfect agreement.

*<u>CALMET Evaluation Results</u>*

Table 5-5 summarizes the statistical measures, averaged over the month, for temperature, wind speed, and relative humidity for all three years. The CALMET evaluation DVD contains a full compilation of the statistical and graphical results. Figures 5-7 through 5-31 present a variety of graphical displays of processed and observed surface temperature, relative humidity, and wind across the three CENRAP subdomains for the three-year period 2001-2003. Figures 5-28 through 5-31 provide convenient summaries of the bias and error in the relative humidity, temperature, and wind speed fields across the continuous 36 month period by subdomain.

Thorough discussion of the performance findings is beyond the scope of these guidelines. However, a few key findings of the evaluation are worth noting here. From Table 5-5, the wind speed index of agreement, a general measure of correlation between measured and observed winds, is systematically greater than a value of 0.8 for virtually every month. These values are typically better than those generally achieved in urban- and regional-scale model applications for ozone SIPs. For example, the statistical benchmark for IOA suggested by Emery et al., (2001) is IOA > 0.6. Thus, the wind speed agreement for all three domains and all three years appears quite good relative to other MM5/RAMS model applications. From Figure 5-11, the wind speed root mean square error for the Central domain for 2002 is generally below 2.0 m/s, the performance goal for this parameter. From Figure 5-29 (as well as in Table 5-5), the temperature bias results for the 36 month are generally quite close to the $\pm$ 0.5 deg C performance goal. As shown in Figure 5-30 the temperature error results are slightly poorer than the 2 deg C performance goal for 2001 and 2003, but are below the 2.0 deg C threshold for 2002. Note that the benchmarks were developed not to provide a pass/fail standard to which all modeling results should be held, but rather to put the results into an historical context.

In summary, we find that:

- Relative Humidity
    - Bias over three-year period near zero all domains
    - For some months over- and under-prediction (up to 10% or more) is evident – no discernable trend
    - Errors typically diminish from 2001 through 2003, and are generally < 12% after 1st quarter of 2001.

- Surface Temperatures

- Monthly averaged temperatures are systematically biased low (cooler) by 0.25 to 1.25 deg C.
- The errors in monthly averaged temperatures typically range between 1.8 and 2.6 deg C
- Average error over all months is about 2.2 deg C.

- Surface Wind Speeds
  - IOA typically between 0.8 0-0.9
  - Seasonally variable
  - Central subdomain gives best correlation

- Results from MM5/CALMET evaluation provide potentially useful information for diagnosing BART visibility modeling analyses

- MM5/CALMET fields exhibit good statistical agreement with observations, in part because observations figure prominently in the construction of the interpolated CALMET fields.

- MM5/CALMET fields for the three CENRAP subdomains are quite sufficient for use in CALPUFF modeling.

### 5.1.5 Meteorological Data Archive and Distribution

All models, scripts and CALMET data (excepting MM5 outputs) are available from CENRAP on appropriate external combination Firewire/USB drives.

## 5.2 Aerometric Monitoring Networks

Data from ambient monitoring networks for both gas-phase and aerosol species are available for use in CENRAP BART modeling analyses. Table 5-4 summarizes ambient monitoring networks. Data for 2002 have been compiled for all networks covering the CENRAP domain with the exception of the PAMS and PM Supersites. These data sets may be obtained from CENRAP. Figures 5-5 and 5-6 display the locations of monitoring sites in and near the CENRAP States.

**Table 5-1. CENRAP Lambert Conic Conformal Modeling Domain Specifications (40.97 degree projection origin; 33 and 45 degree matching parallels).**

| Domain | Southwest Coordinate (km) | Number of X grid cells | Number of Y grid cells | Horizontal Resolution |
|---|---|---|---|---|
| CALMET | | | | |
| South | -1008, -1620 | 306 | 246 | 6 km |
| Central | -1008, -864 | 388 | 234 | 6 km |
| North | -1008, 0 | 300 | 193 | 6 km |

**Table 5-2. Vertical Layer Structure in CALMET Fields. (Heights are in meters.)**

| Layer number | Layer Height | Layer number | Layer Height |
|---|---|---|---|
| 0 | 0. | 6 | 640. |
| 1 | 20. | 7 | 1200. |
| 2 | 40. | 8 | 2000. |
| 3 | 80. | 9 | 3000. |
| 4 | 160. | 10 | 4000. |
| 5 | 320. | | |

**Table 5-3. Meteorological Model File Sizes for CENRAP BART Modeling.**

| CALMET 6 km File Sizes, (Gbytes) | | | | MM5 File Sizes, (Gbytes) | | |
|---|---|---|---|---|---|---|
| Domain | Monthly | Annual | 3 Years | Domain | Grid | 3 years |
| North | 4.6 | 55.2 | 165.6 | 2001 | 12 km | 1370 |
| Central | 6.6 | 79.2 | 237.6 | 2002 | 36 km | 430 |
| South | 6.0 | 72.0 | 216.0 | 2003 | 36 km | 430 |
| total | 17.2 | 206.4 | 619.2 | total | | 2230 |

## Table 5-4. Statistical Evaluation of the CALMET Meteorological Fields for 2001-2003.

**CALMET Model Evaluation Statistics for 2001.**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Mean |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **RH Bias (%)** | | | | | | | | | | | | | |
| North | 4.54 | 3.19 | 0.17 | -14.55 | -12.09 | -4.35 | -0.62 | 1.17 | -2.07 | -7.98 | -6.62 | -4.22 | -3.62 |
| Central | -2.60 | -7.28 | -11.38 | -10.69 | -8.62 | -2.90 | 0.66 | 1.07 | -1.44 | -5.46 | -6.16 | -7.78 | -5.21 |
| South | -10.23 | -11.53 | -13.78 | -4.24 | -2.08 | 0.99 | 4.12 | 3.16 | -0.12 | -2.12 | -3.44 | -9.76 | -4.09 |
| **RH Error (%)** | | | | | | | | | | | | | |
| North | 10.06 | 10.31 | 14.03 | 18.77 | 16.28 | 12.39 | 11.82 | 11.76 | 13.26 | 15.54 | 13.53 | 12.89 | 13.39 |
| Central | 13.32 | 15.86 | 17.45 | 17.05 | 14.50 | 11.67 | 11.52 | 11.32 | 12.26 | 15.52 | 14.79 | 14.95 | 14.18 |
| South | 16.22 | 18.37 | 18.17 | 13.26 | 12.15 | 11.51 | 12.09 | 12.40 | 11.82 | 14.85 | 14.73 | 16.19 | 14.31 |
| **Temp Bias ($^0$C)** | | | | | | | | | | | | | |
| North | -1.63 | -1.23 | -1.23 | -0.24 | 0.08 | -0.29 | -0.23 | -0.54 | -0.55 | -0.09 | -0.40 | -1.27 | -0.64 |
| Central | -0.99 | -0.65 | -0.54 | -0.16 | 0.13 | -0.23 | -0.43 | -0.54 | -0.36 | -0.34 | -0.30 | -0.74 | -0.43 |
| South | -0.47 | -0.42 | 0.03 | -0.31 | -0.33 | -0.63 | -0.99 | -0.85 | -0.52 | -0.36 | -0.19 | -0.21 | -0.44 |
| **Temp Error ($^0$C)** | | | | | | | | | | | | | |
| North | 3.10 | 2.88 | 2.54 | 2.49 | 2.44 | 2.43 | 2.42 | 2.49 | 2.58 | 2.48 | 2.89 | 2.55 | 2.61 |
| Central | 2.38 | 2.25 | 1.99 | 2.18 | 1.99 | 2.01 | 2.07 | 2.11 | 2.21 | 2.52 | 2.61 | 2.42 | 2.23 |
| South | 2.31 | 2.28 | 1.92 | 2.13 | 2.01 | 2.17 | 2.19 | 2.21 | 2.19 | 2.70 | 2.49 | 2.50 | 2.26 |
| **Wind Speed IOA** | | | | | | | | | | | | | |
| North | 0.79 | 0.83 | 0.83 | 0.87 | 0.86 | 0.85 | 0.81 | 0.84 | 0.84 | 0.82 | 0.81 | 0.79 | 0.83 |
| Central | 0.85 | 0.87 | 0.88 | 0.88 | 0.89 | 0.86 | 0.84 | 0.86 | 0.87 | 0.86 | 0.85 | 0.84 | 0.86 |
| South | 0.81 | 0.80 | 0.85 | 0.79 | 0.83 | 0.83 | 0.78 | 0.80 | 0.82 | 0.82 | 0.80 | 0.82 | 0.81 |

**CALMET Model Evaluation Statistics for 2002.**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Mean |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **RH Bias (%)** | | | | | | | | | | | | | |
| North | 8.33 | 9.52 | 6.63 | 0.95 | -2.42 | 1.25 | 2.43 | 1.60 | 0.57 | 0.47 | 4.47 | 7.73 | 3.46 |
| Central | 7.43 | 5.13 | 4.60 | 1.65 | -1.02 | 1.52 | 2.50 | 1.88 | -0.27 | -1.40 | -0.01 | 4.35 | 2.20 |
| South | 3.08 | -1.19 | 2.53 | 2.32 | 1.26 | 1.98 | 2.51 | 2.62 | -0.80 | -2.42 | -4.45 | -1.03 | 0.53 |
| **RH Error (%)** | | | | | | | | | | | | | |
| North | 11.85 | 13.18 | 11.61 | 11.13 | 11.90 | 10.04 | 9.54 | 9.08 | 10.26 | 10.26 | 11.55 | 11.61 | 11.00 |
| Central | 12.21 | 12.43 | 11.26 | 10.58 | 10.72 | 9.89 | 9.55 | 9.54 | 10.22 | 10.25 | 11.42 | 11.26 | 10.78 |
| South | 11.24 | 11.76 | 10.34 | 8.95 | 9.30 | 9.49 | 9.46 | 9.61 | 9.68 | 9.33 | 11.63 | 10.95 | 10.14 |
| **Temp Bias ($^0$C)** | | | | | | | | | | | | | |
| North | -0.70 | -0.82 | -0.96 | -0.52 | -0.25 | -0.36 | -0.53 | -0.49 | -0.44 | -0.67 | -0.76 | -0.69 | -0.60 |
| Central | -0.57 | -0.65 | -0.79 | -0.62 | -0.41 | -0.68 | -0.81 | -0.74 | -0.49 | -0.54 | -0.55 | -0.52 | -0.61 |
| South | -0.23 | -0.13 | -0.52 | -0.61 | -0.61 | -0.94 | -0.94 | -1.07 | -0.65 | -0.47 | 0.04 | -0.13 | -0.52 |
| **Temp Error ($^0$C)** | | | | | | | | | | | | | |
| North | 2.15 | 2.07 | 2.04 | 1.89 | 1.86 | 1.83 | 1.86 | 1.80 | 1.95 | 1.78 | 1.99 | 2.15 | 1.95 |
| Central | 2.12 | 2.05 | 2.14 | 1.95 | 1.91 | 1.93 | 1.93 | 1.92 | 2.02 | 1.77 | 2.00 | 2.00 | 1.98 |
| South | 2.18 | 2.05 | 2.17 | 1.83 | 1.89 | 1.91 | 1.88 | 2.00 | 1.92 | 1.68 | 2.06 | 1.93 | 1.96 |
| **Wind Speed IOA** | | | | | | | | | | | | | |
| North | 0.82 | 0.84 | 0.86 | 0.88 | 0.86 | 0.85 | 0.85 | 0.83 | 0.85 | 0.85 | 0.81 | 0.78 | 0.84 |
| Central | 0.87 | 0.88 | 0.90 | 0.90 | 0.88 | 0.87 | 0.84 | 0.84 | 0.87 | 0.88 | 0.85 | 0.85 | 0.87 |
| South | 0.86 | 0.86 | 0.85 | 0.85 | 0.84 | 0.82 | 0.79 | 0.80 | 0.83 | 0.83 | 0.83 | 0.82 | 0.83 |

**CALMET Model Evaluation Statistics for 2003.**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Mean |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **RH Bias (%)** | | | | | | | | | | | | | |
| North | 10.15 | 7.40 | 6.01 | 0.93 | -3.76 | -0.38 | 1.38 | 2.04 | -1.66 | -1.99 | 2.96 | 7.68 | 2.56 |
| Central | 6.94 | 4.76 | 4.15 | 0.42 | -2.18 | 0.17 | 2.08 | 2.13 | -2.05 | -4.13 | 0.00 | 5.47 | 1.48 |
| South | 0.00 | 0.00 | 0.47 | -1.10 | -0.37 | 0.54 | 1.77 | 2.89 | -3.31 | -6.01 | -3.66 | -0.33 | -0.76 |
| **RH Error (%)** | | | | | | | | | | | | | |
| North | 13.30 | 11.21 | 12.32 | 11.70 | 11.65 | 10.03 | 9.70 | 9.57 | 11.13 | 12.68 | 11.53 | 11.85 | 11.39 |
| Central | 12.77 | 10.95 | 11.61 | 11.18 | 10.33 | 9.91 | 9.49 | 9.50 | 10.70 | 12.69 | 12.10 | 12.43 | 11.14 |
| South | 11.18 | 10.00 | 9.85 | 10.17 | 9.20 | 9.54 | 8.90 | 9.91 | 10.21 | 12.12 | 12.15 | 12.39 | 10.47 |
| **Temp Bias ($^0$C)** | | | | | | | | | | | | | |
| North | -1.24 | -0.99 | -0.63 | -0.29 | -0.11 | -0.10 | -0.22 | -0.49 | -0.34 | 0.29 | -0.85 | -1.34 | -0.53 |
| Central | -0.84 | -0.80 | -0.64 | -0.47 | -0.27 | -0.36 | -0.60 | -0.66 | -0.32 | 0.30 | -0.54 | -0.89 | -0.51 |
| South | -0.17 | -0.27 | -0.36 | -0.43 | -0.46 | -0.62 | -0.91 | -0.98 | -0.28 | 0.53 | 0.00 | -0.03 | -0.33 |
| **Temp Error ($^0$C)** | | | | | | | | | | | | | |
| North | 2.31 | 2.15 | 2.14 | 2.02 | 1.81 | 1.77 | 1.91 | 1.98 | 2.25 | 2.57 | 2.30 | 2.67 | 2.16 |
| Central | 2.14 | 2.03 | 2.15 | 2.13 | 1.80 | 1.81 | 1.96 | 1.99 | 2.16 | 2.54 | 2.31 | 2.45 | 2.12 |
| South | 2.10 | 1.90 | 2.00 | 2.08 | 1.84 | 1.81 | 1.88 | 2.06 | 1.94 | 2.40 | 2.28 | 2.48 | 2.06 |
| **Wind Speed IOA** | | | | | | | | | | | | | |
| North | 0.79 | 0.81 | 0.83 | 0.86 | 0.87 | 0.85 | 0.86 | 0.87 | 0.84 | 0.82 | 0.80 | 0.82 | 0.83 |
| Central | 0.85 | 0.88 | 0.87 | 0.89 | 0.90 | 0.87 | 0.87 | 0.86 | 0.87 | 0.87 | 0.86 | 0.86 | 0.87 |
| South | 0.83 | 0.83 | 0.85 | 0.83 | 0.85 | 0.81 | 0.83 | 0.82 | 0.85 | 0.84 | 0.82 | 0.82 | 0.83 |

**Table 5-5. Overview of Ambient Data Monitoring Networks Covering the CENRAP Domain.**

| Monitoring Network | Chemical Species Measured | Sampling Period | Data Availability/Source |
|---|---|---|---|
| The Interagency Monitoring of Protected Visual Environments (IMPROVE) | Speciated PM25 and PM10 (see species mappings) | 1 in 3 days; 24 hr average | http://vista.cira.colostate.edu/improve/Data/IMPROVE/improve_data.htm |
| Clean Air Status and Trends Network (CASTNET) | Speciated PM25, Ozone (see species mappings) | Approximately 1-week average | http://www.epa.gov/castnet/data.html |
| National Atmospheric Deposition Program (NADP) | Wet deposition (hydrogen (acidity as pH), sulfate, nitrate, ammonium, chloride, and base cations (such as calcium, magnesium, potassium and sodium)), Mercury | 1-week average | http://nadp.sws.uiuc.edu/ |
| Air Quality System (AQS) Aka Aerometric Information Retrieval System (AIRS) | CO, NO2, O3, SO2, PM25, PM10, Pb | Typically hourly average | http://www.epa.gov/air/data/ |
| Speciation Trends Network (STN) | Speciated PM | 24-hour average | http://www.epa.gov/ttn/amtic/amticpm.html |
| Southeastern Aerosol Research and Characterization (SEARCH) (Southeastern US only) | 24-hr PM25 (FRM Mass, OC, BC, SO4, NO3, NH4, Elem.); 24-hr PM coarse (SO4, NO3, NH4, elements); Hourly PM2.5 (Mass, SO4, NO3, NH4, EC, TC); Hourly gases (O3, NO, NO2, NOy, HNO3, SO2, CO) | Hourly or 24-hour average, depending on parameter. | Electric Power Research Institute (EPRI), Southern Company, and other companies. http://www.atmospheric-research.com |
| EPA Particulate Matter Supersites (Includes St. Louis in the CENRAP region) | Speciated PM25 | | http://www.epa.gov/ttn/amtic/supersites.html |
| Photochemical Assessment Monitoring Stations (PAMS) | Varies for each of 4 station types. | | http://www.epa.gov/ttn/amtic/pamsmain.html |
| National Park Service Gaseous Pollutant Monitoring Network | Acid deposition (Dry; SO4, NO3, HNO3, NH4, SO2), O3, meteorological data | Hourly | http://www2.nature.nps.gov/ard/gas/netdata1.htm |

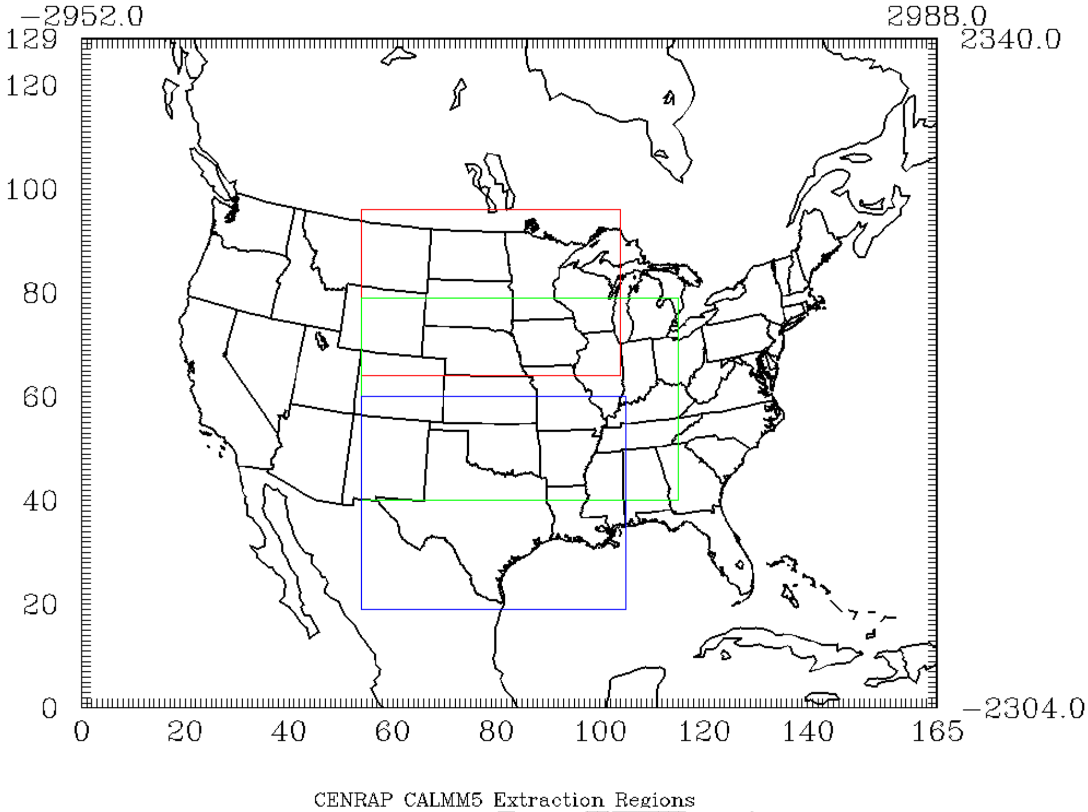


Figure 5-1. CENRAP North, Central, and South 6 km Meteorological Domains.

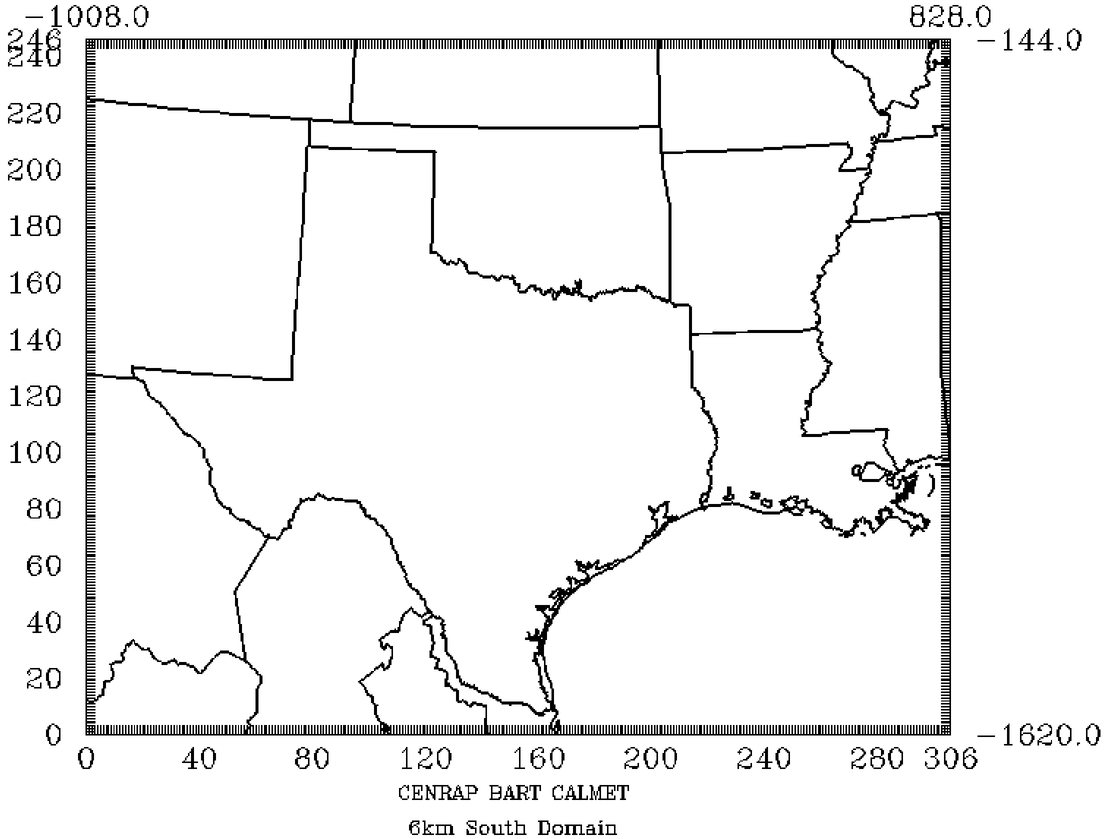



Figure 5-2. CENRAP South Domain.

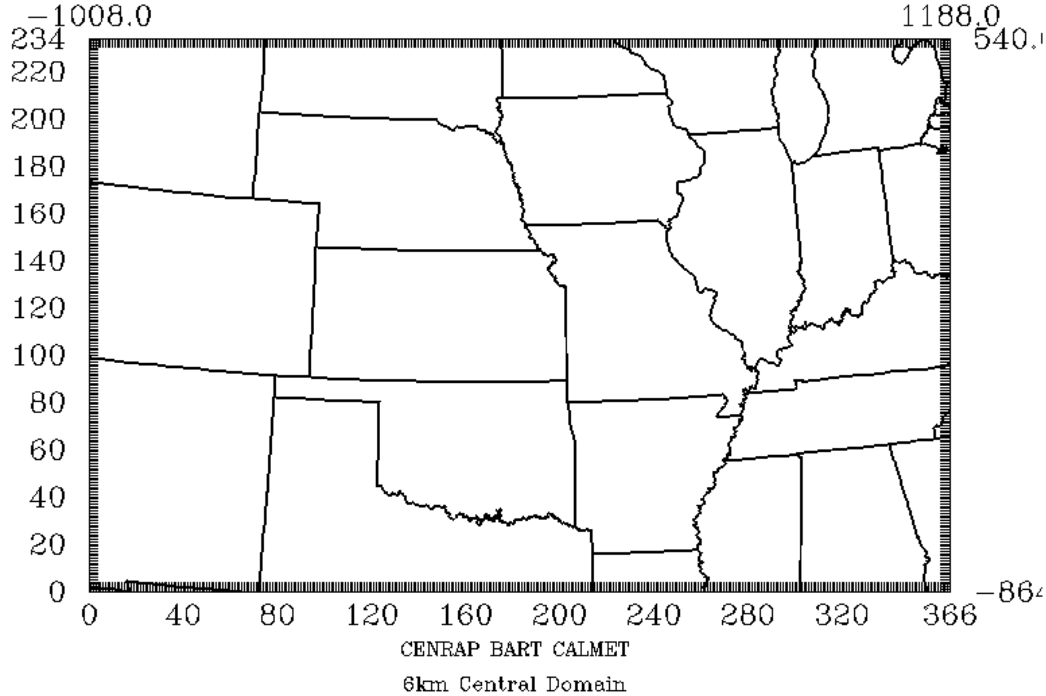



Figure 5-3. CENRAP Central Domain.

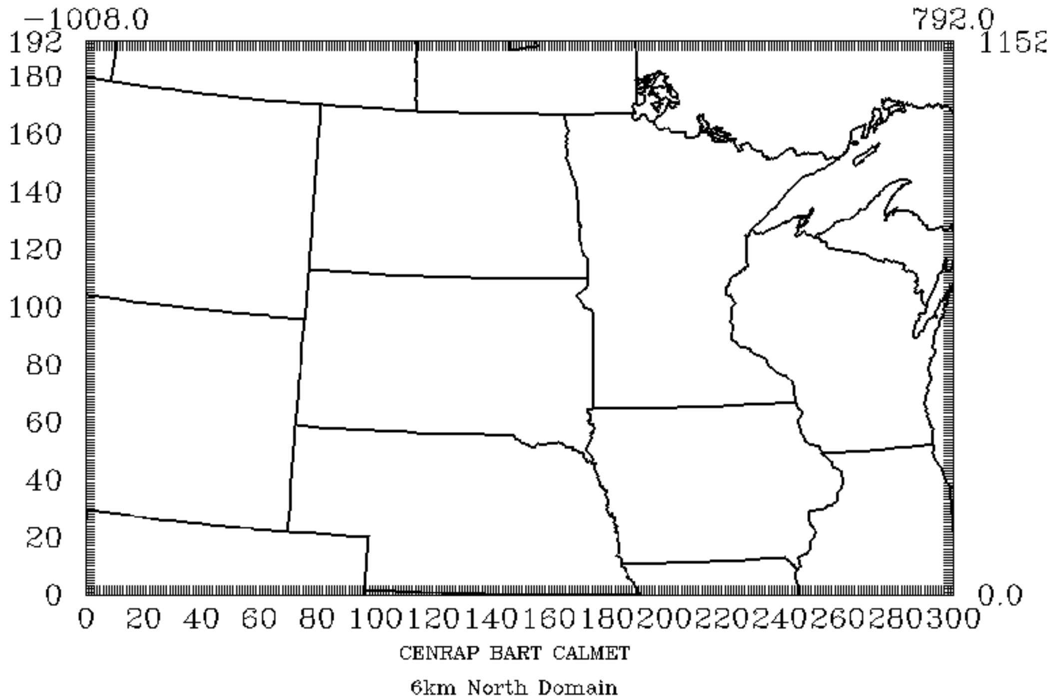



Figure 5-4. CENRAP North Domain.

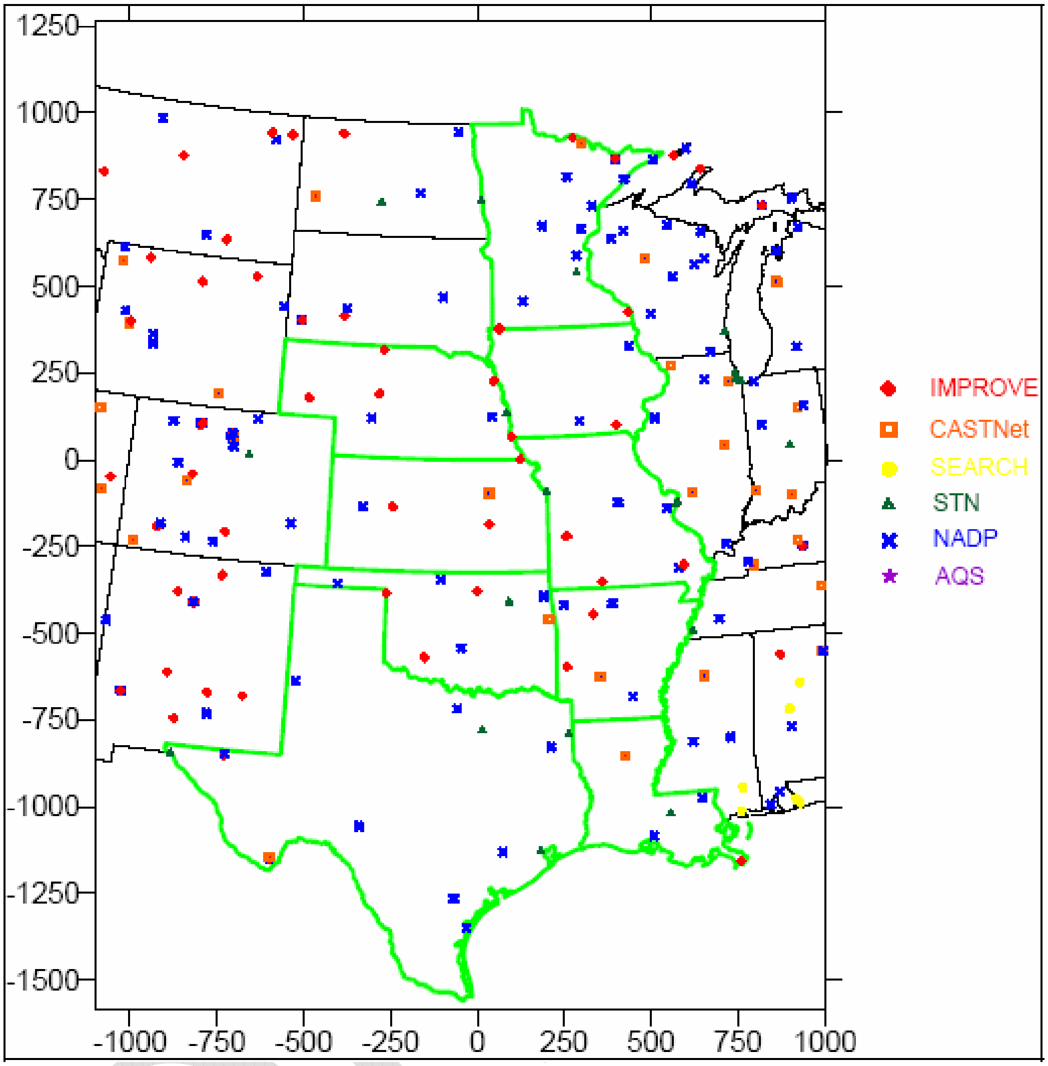


Figure 5-5. Locations of IMPROVE, CASTNet, SEARCH, STN and NADP Monitoring Sites in and Near the CENRAP States.

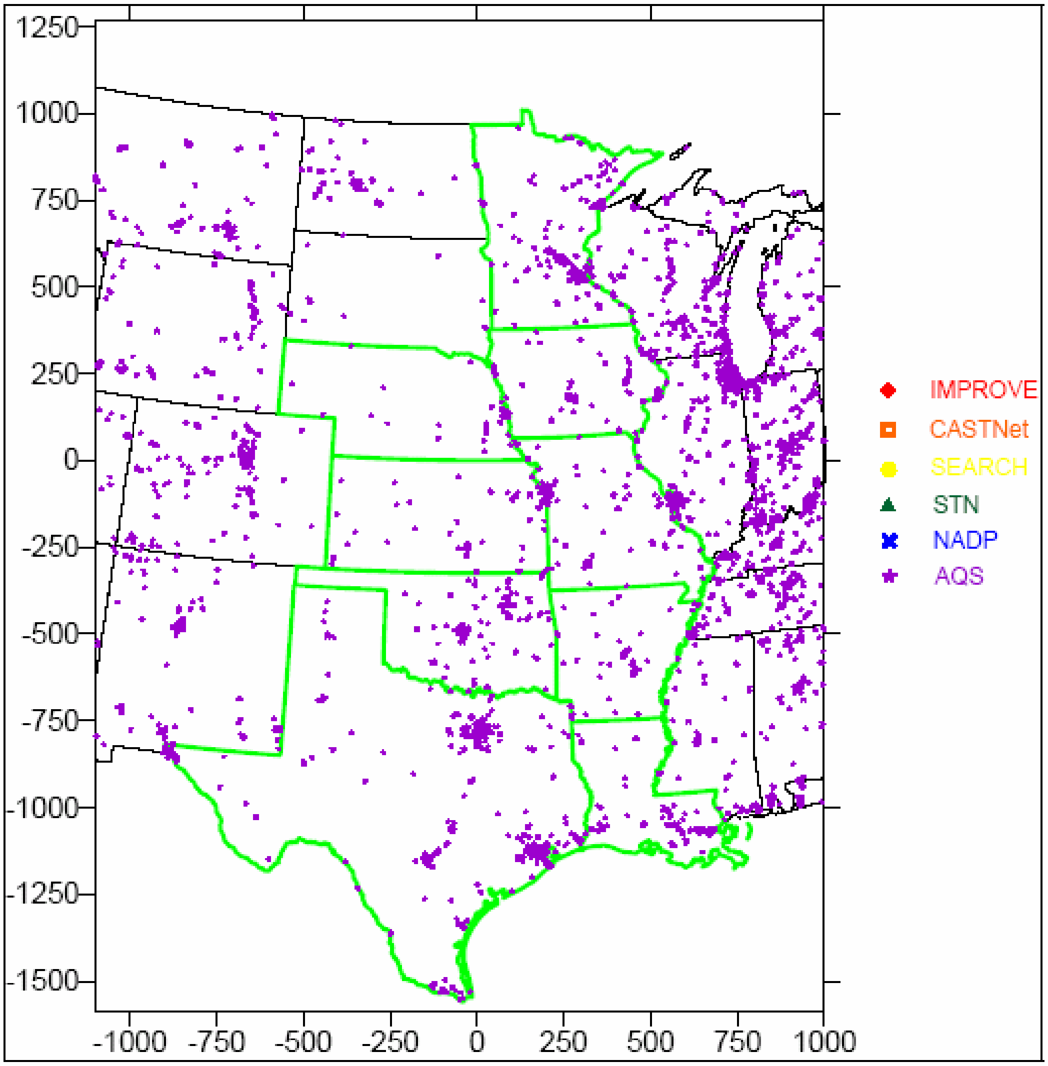


Figure 5-6. Locations of AQS Monitoring Sites in and Near the CENRAP States.

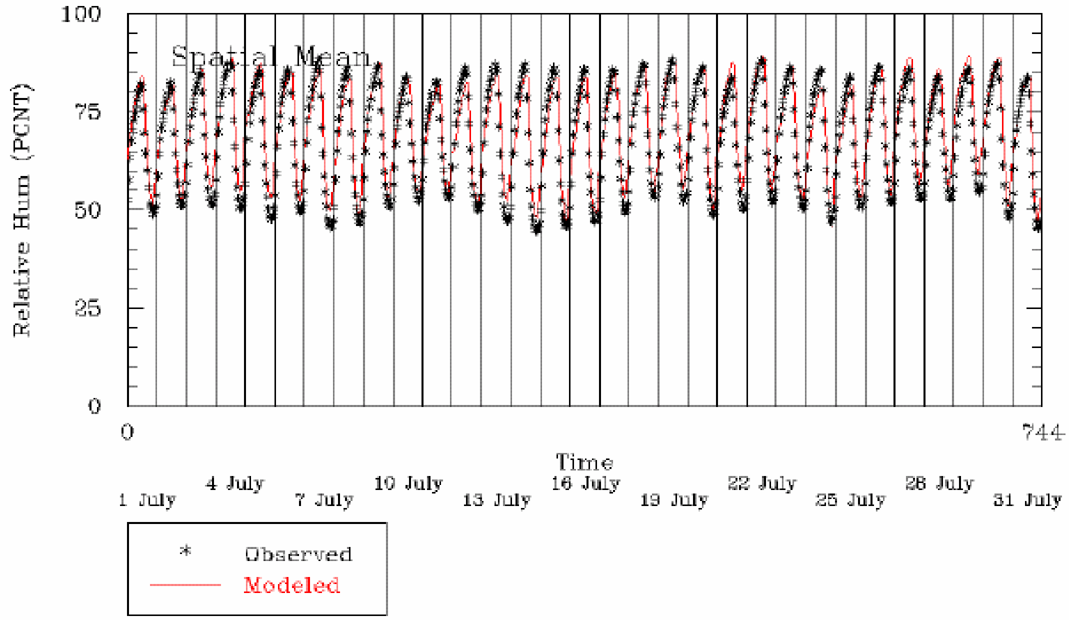



Figure 5-7. Spatial Mean Relative Humidity (%) over the Central Domain: July 2002.

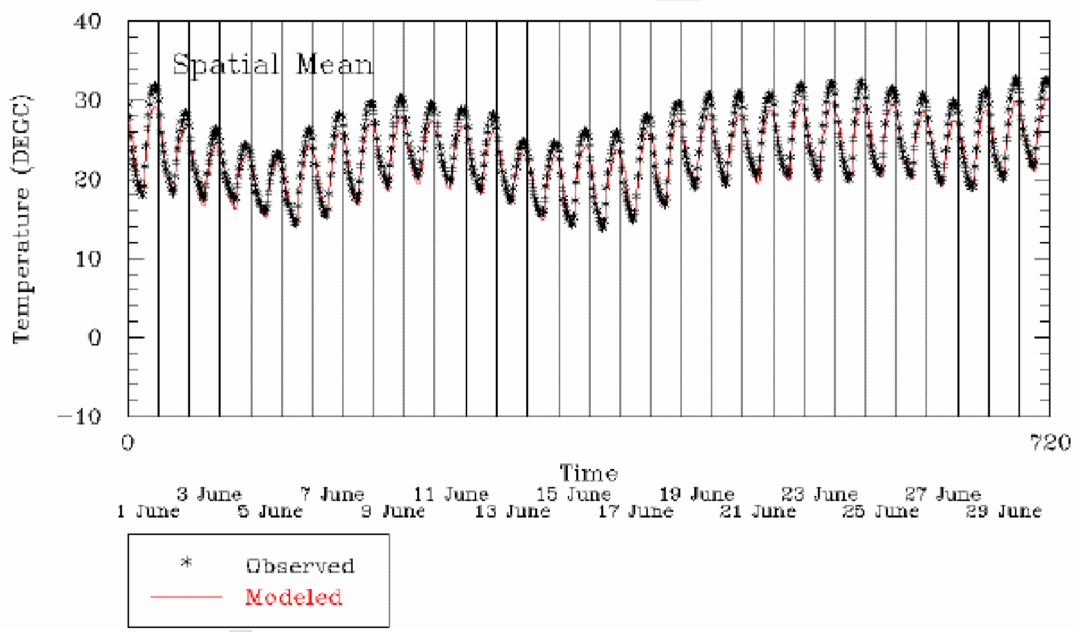



Figure 5-8. Spatial Mean Surface Temperature (deg C) over the Central Domain: July 2002.

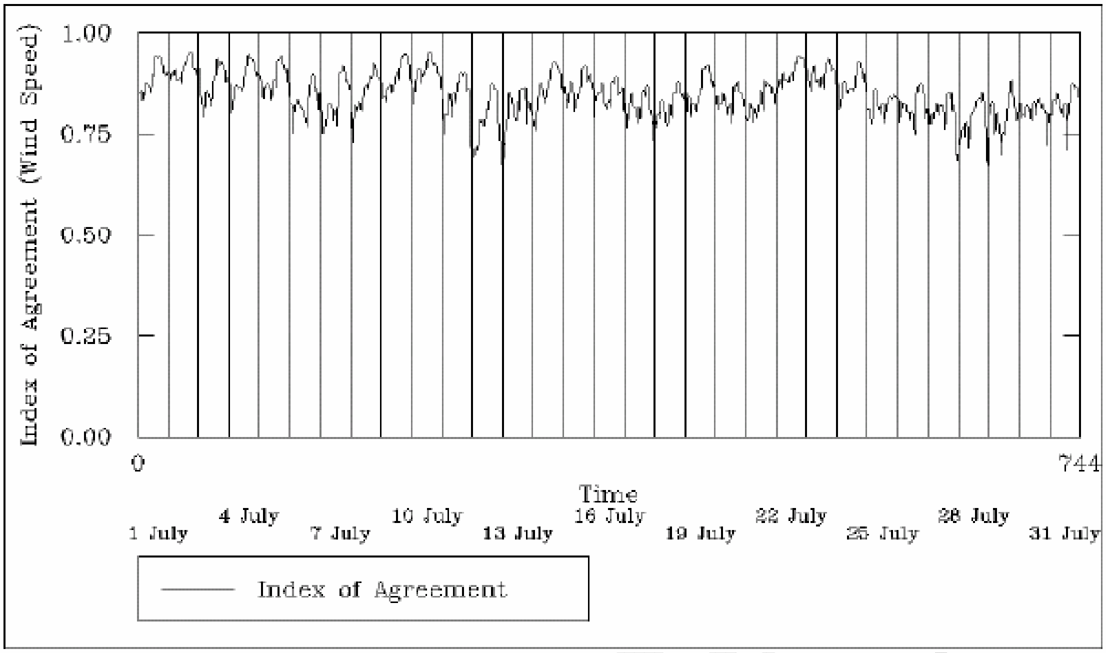



Figure 5-9. Wind Speed Index of Agreement over the Central Domain: July 2002.

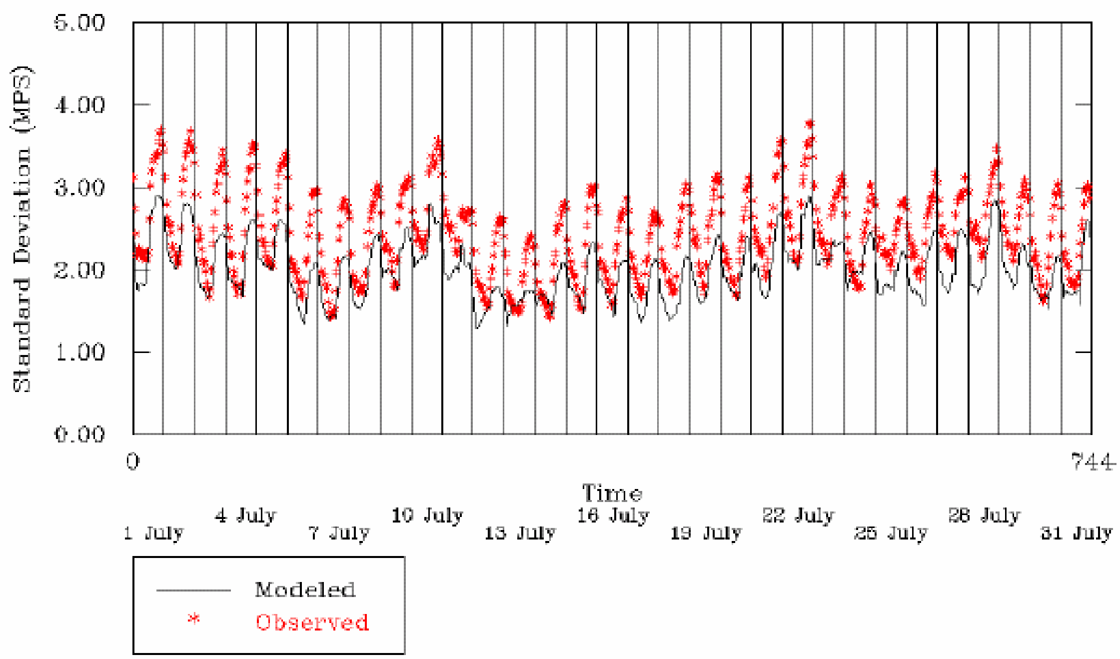



Figure 5-10. Standard Deviation in Wind Speed (m/s) over the Central Domain: July 2002.

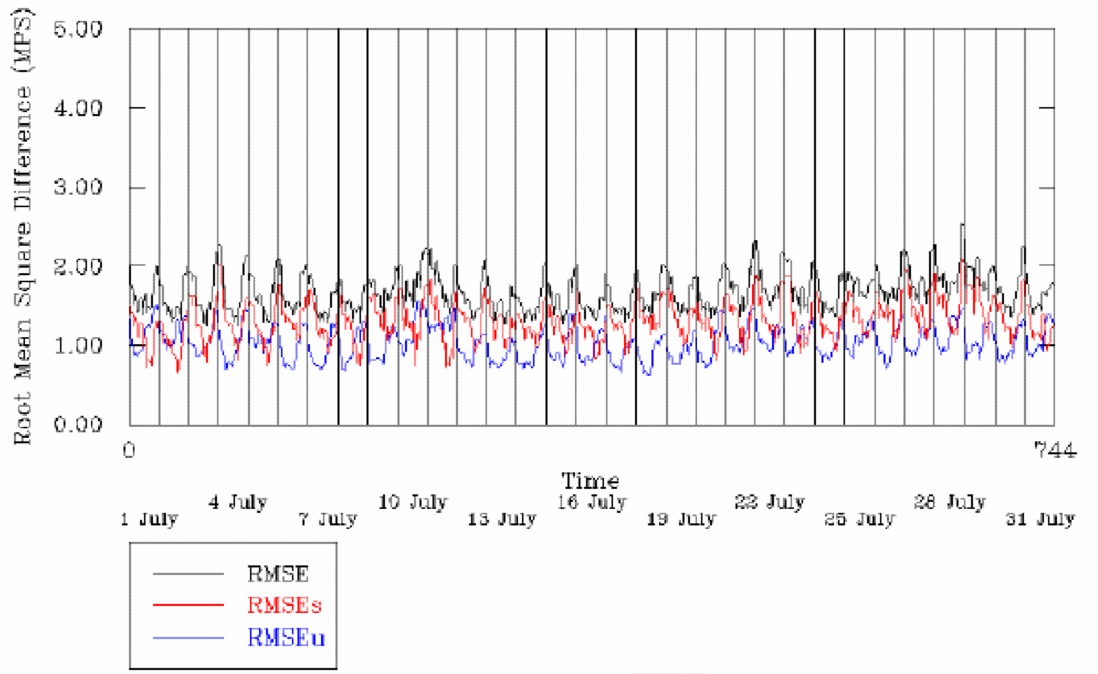



Figure 5-11. Root Mean Square Error in Wind Speed (m/s) over the Central Domain: July 2002.

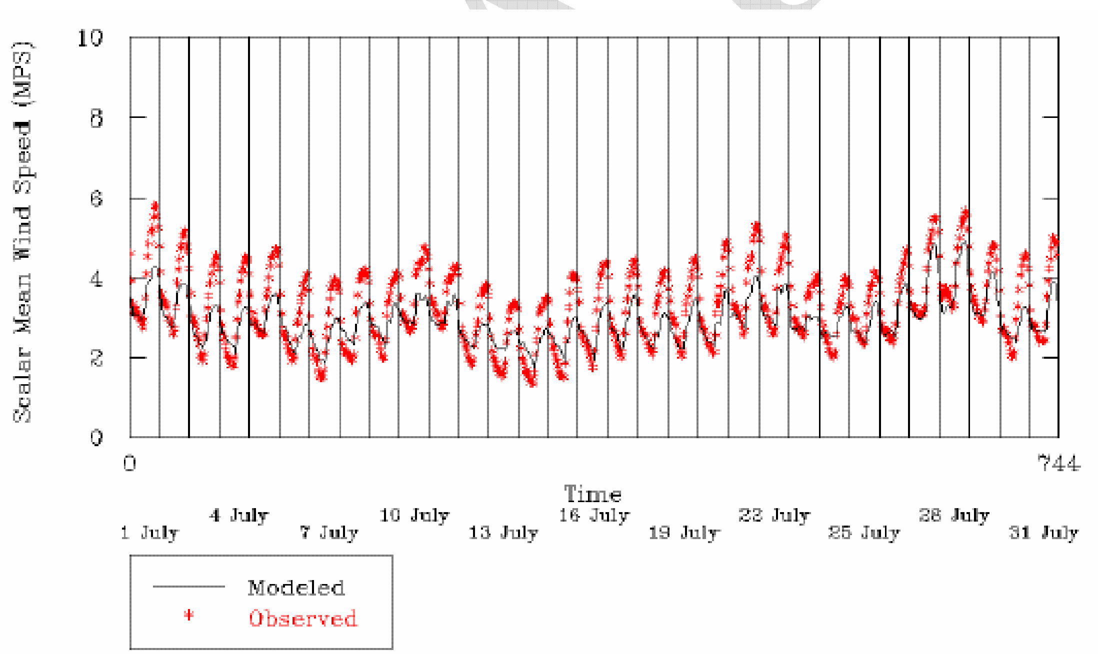



Figure 5-12. Scalar Mean Wind Speed (m/s) over the Central Domain: July 2002.

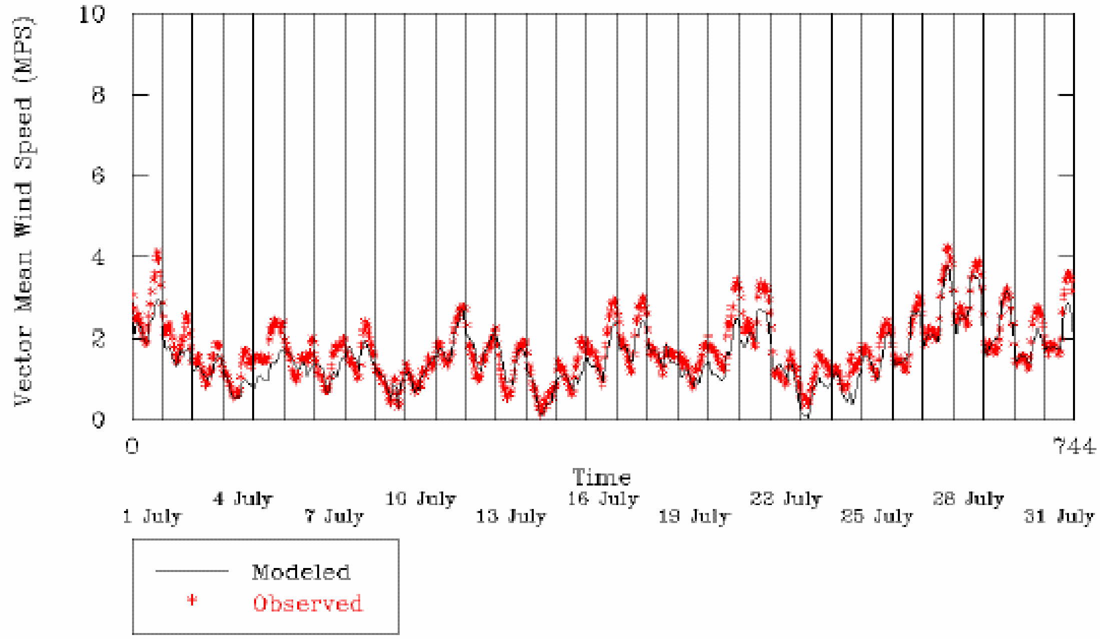



Figure 5-13. Vector Mean Wind Speed (m/s) over the Central Domain: July 2002.

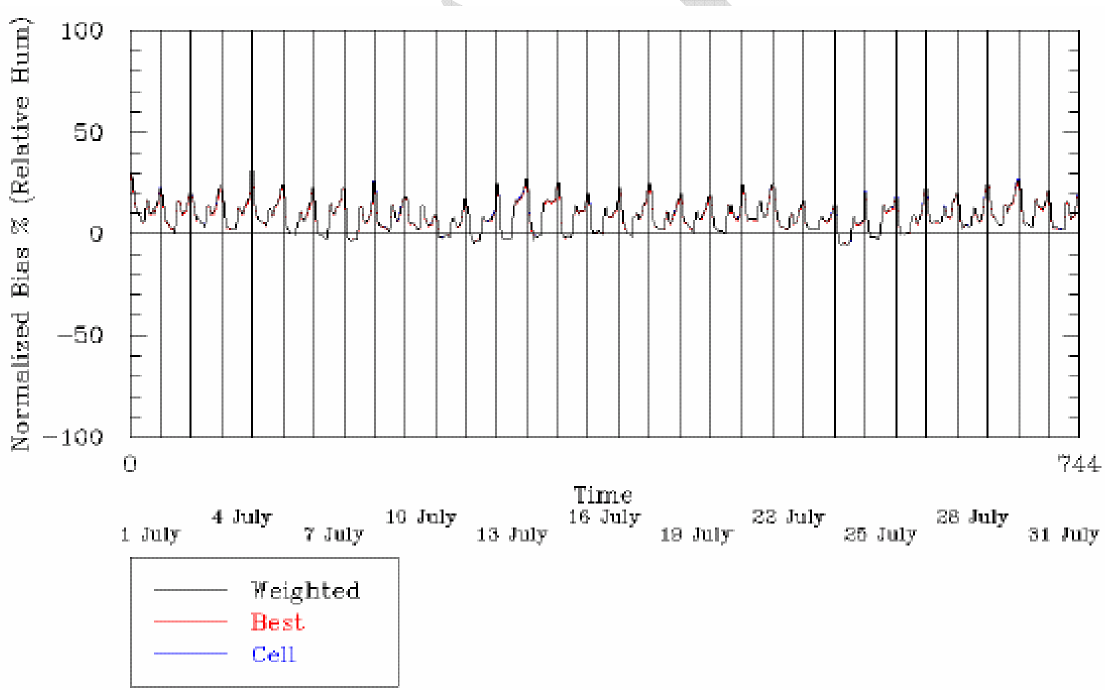



Figure 5-14. Normalized Bias in Relative Humidity (%) over the Central Domain: July 2002.

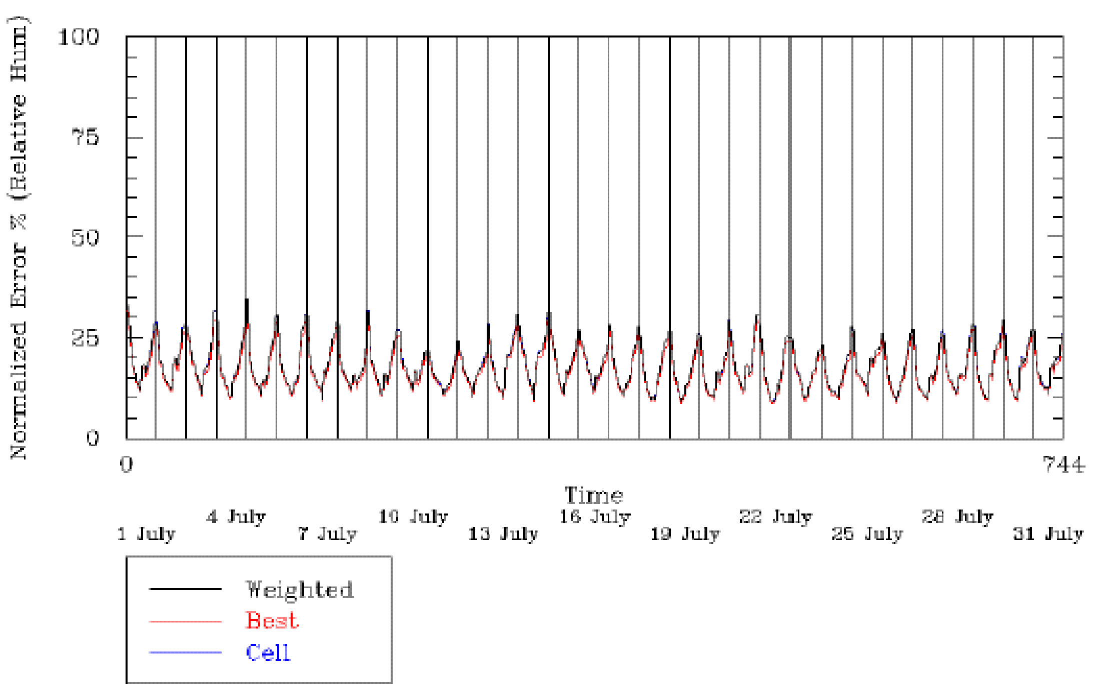



Figure 5-15. Normalized Error in Relative Humidity (%) over the Central Domain: July 2002.

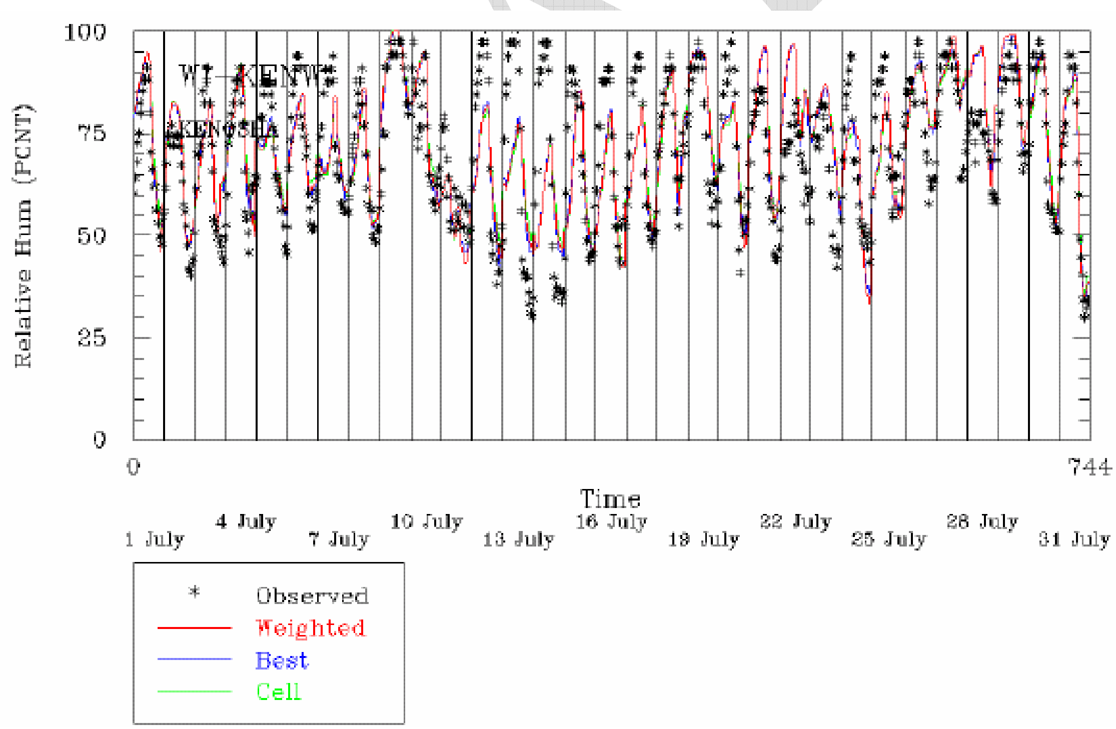



Figure 5-16. Relative Humidity (%) at Kenosha, WI: July 2002.

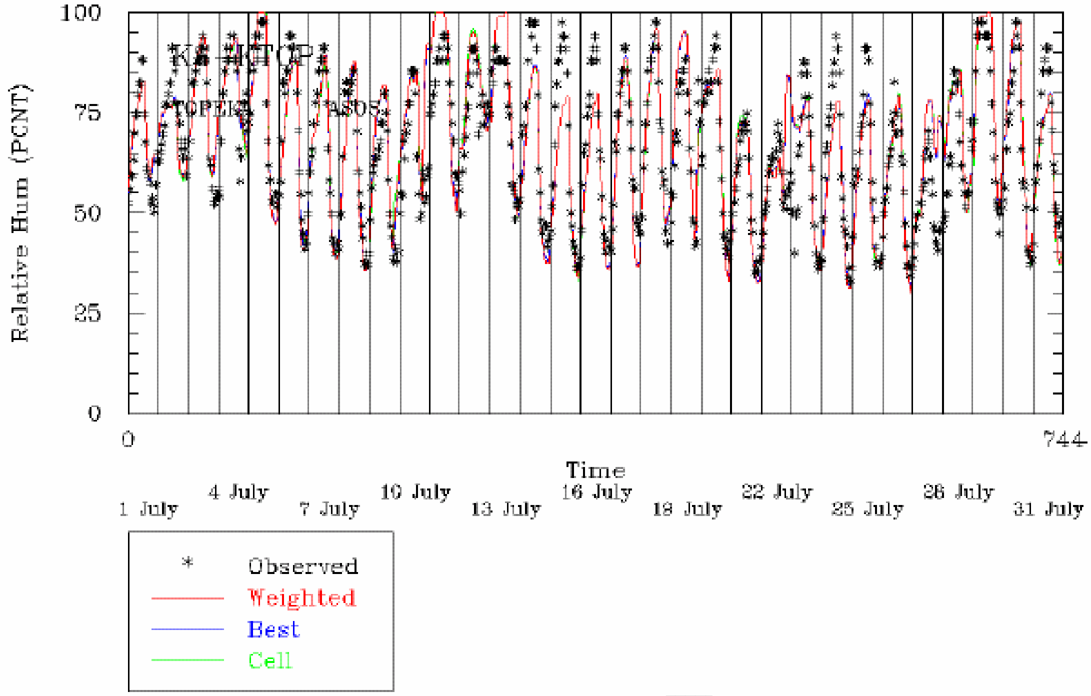



Figure 5-17. Relative Humidity (%) at Topeka, KS: July 2002.

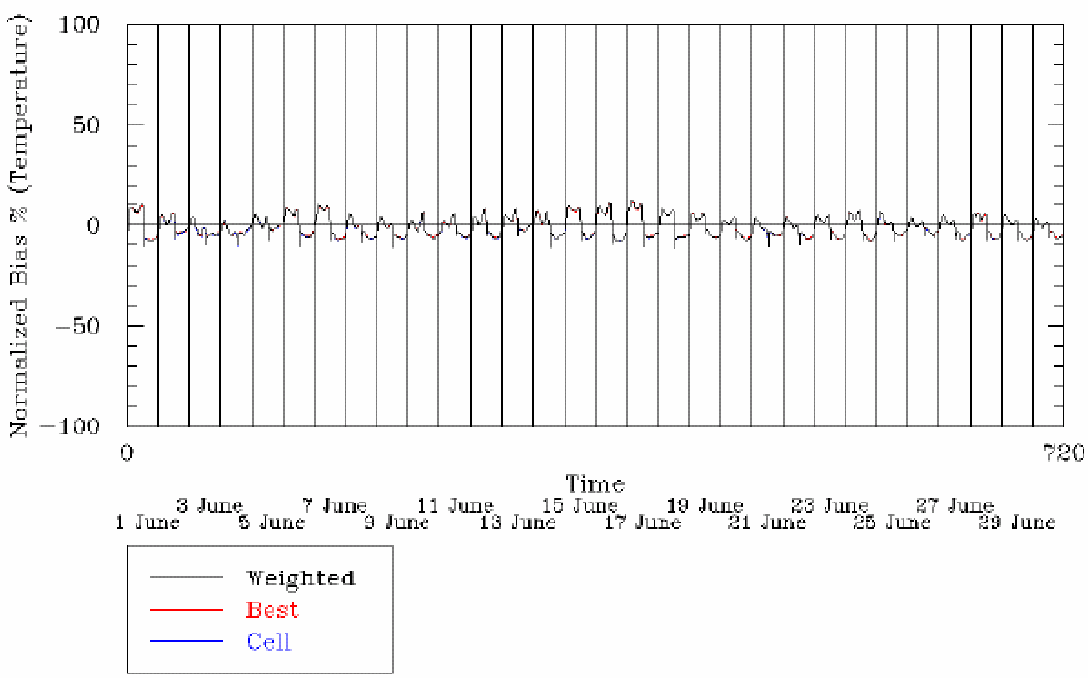



Figure 5-18. Normalized Bias in Surface Temperature (%) over the Central Domain: July 2002.

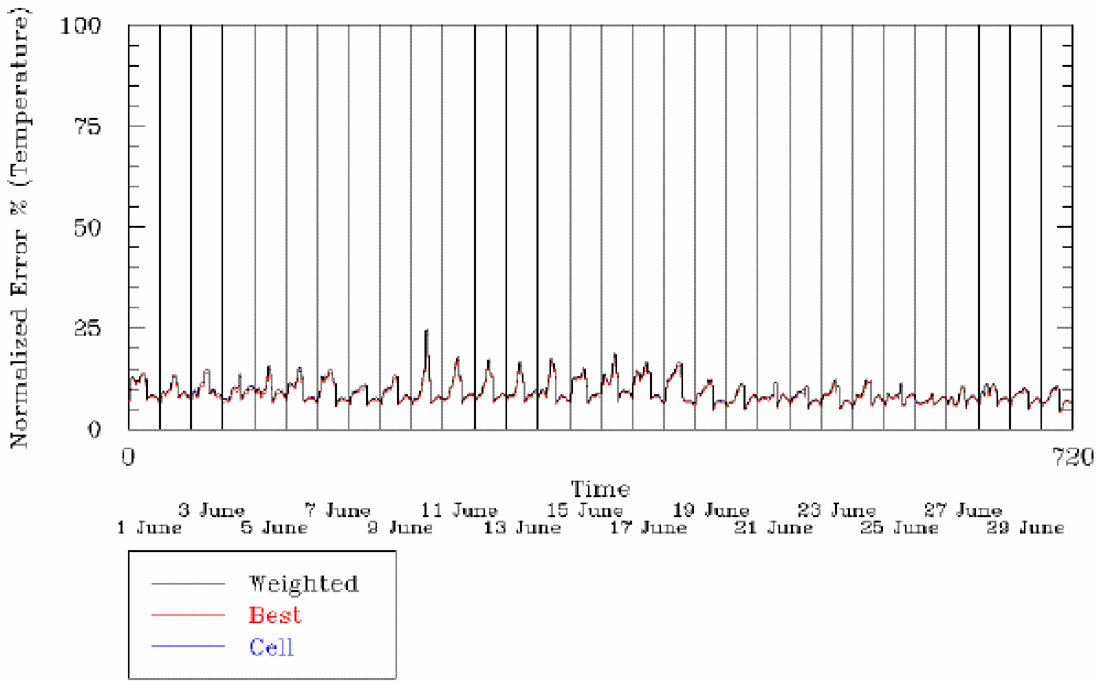



Figure 5-19. Normalized Error in Surface Temperature over the Central Domain: July 2002.

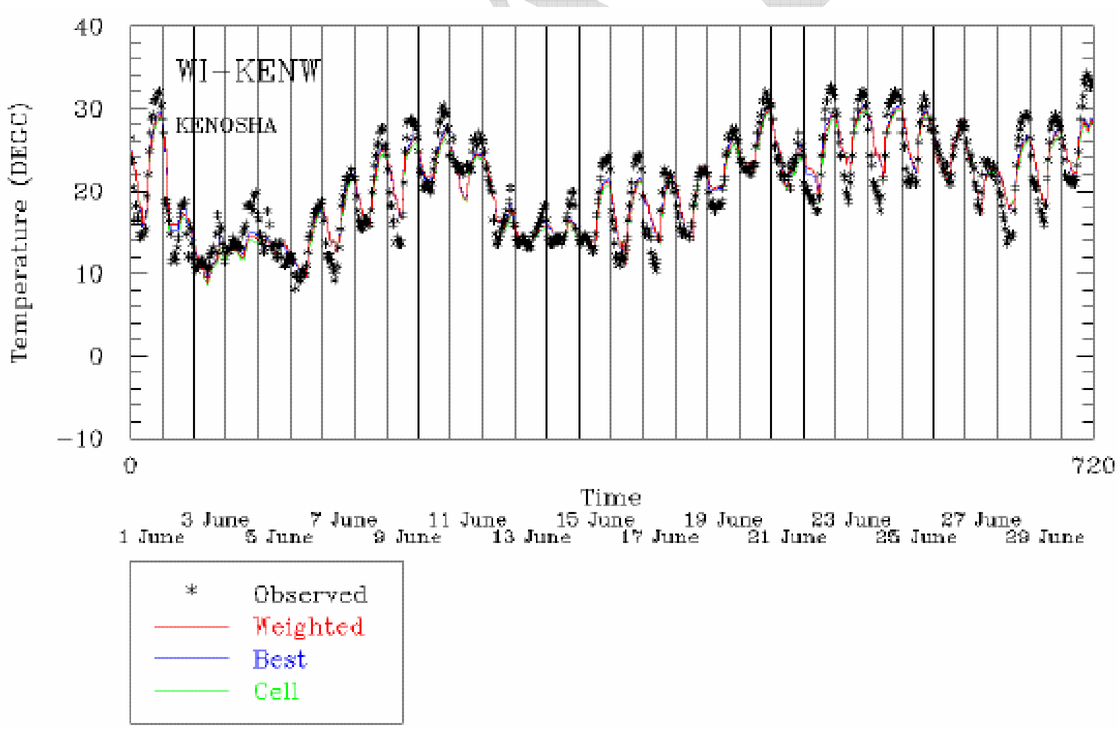



Figure 5-20. Surface Temperature (deg C) at Kenosha, WI: July 2002.

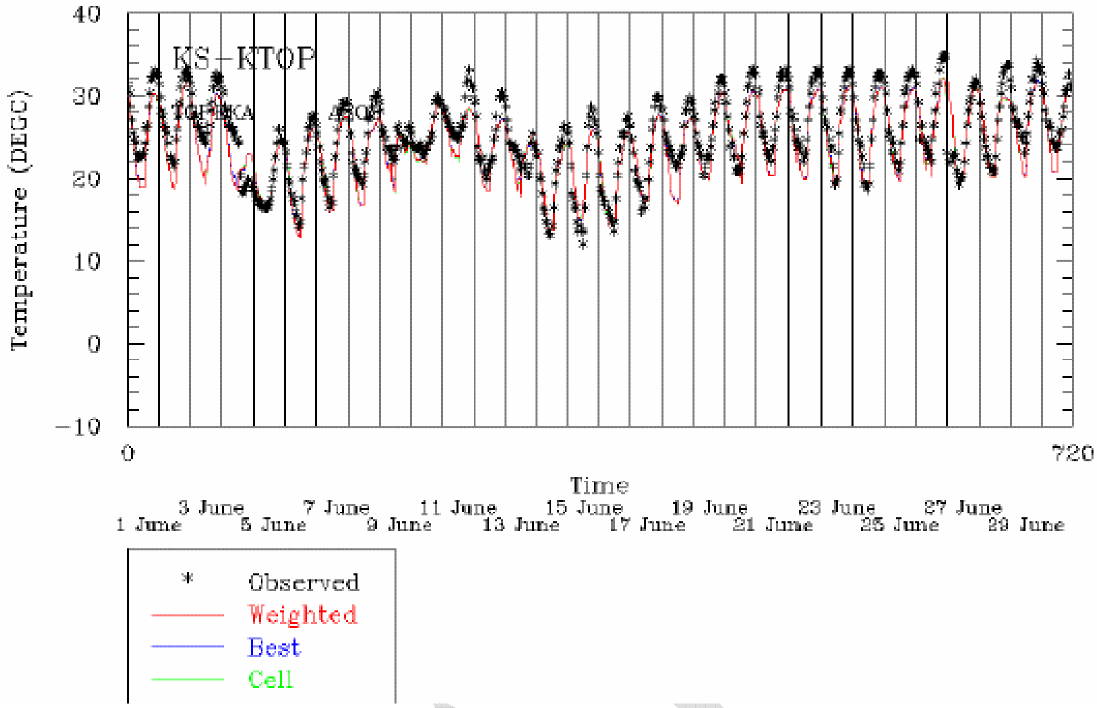
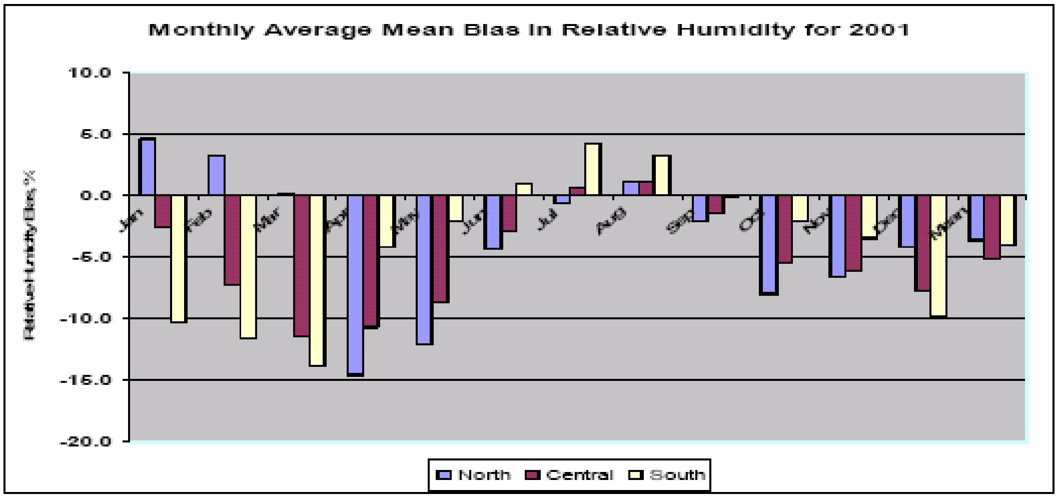
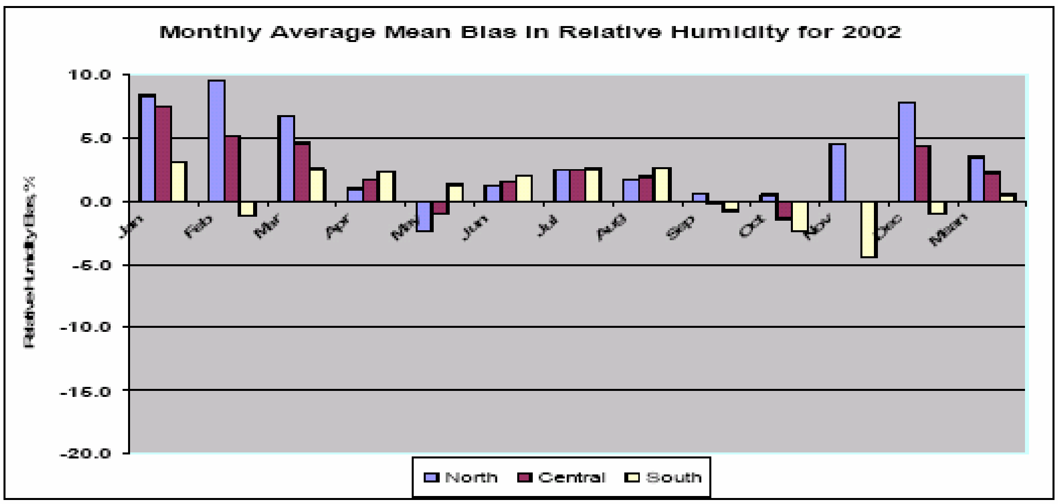



Figure 5-21. Surface Temperature at Topeka, KS: July 2002.



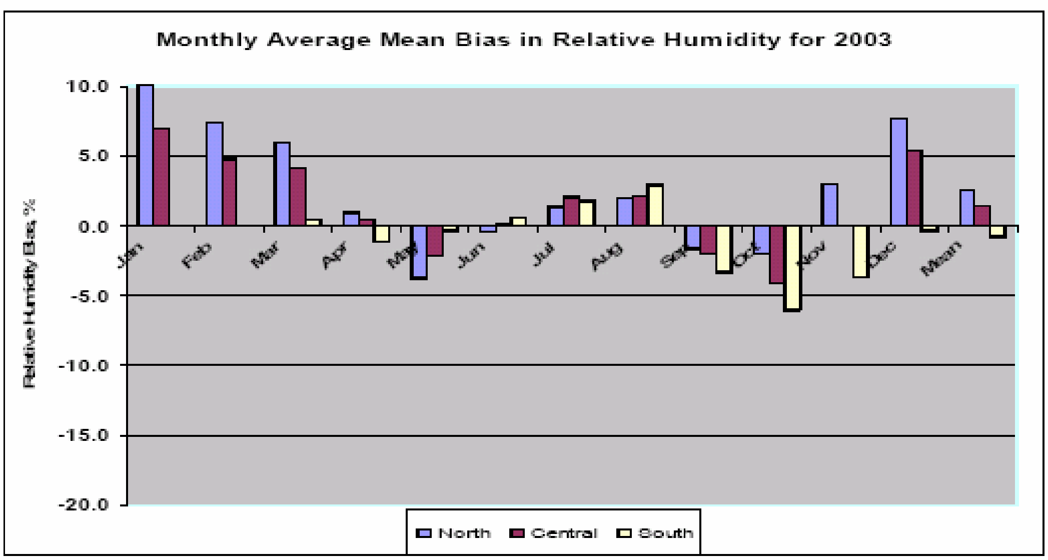




Figure 5-22. MM5/CALMET Relative Humidity Bias (%) by Month for Three BART Modeling Years (2001, 2003, and 2003).

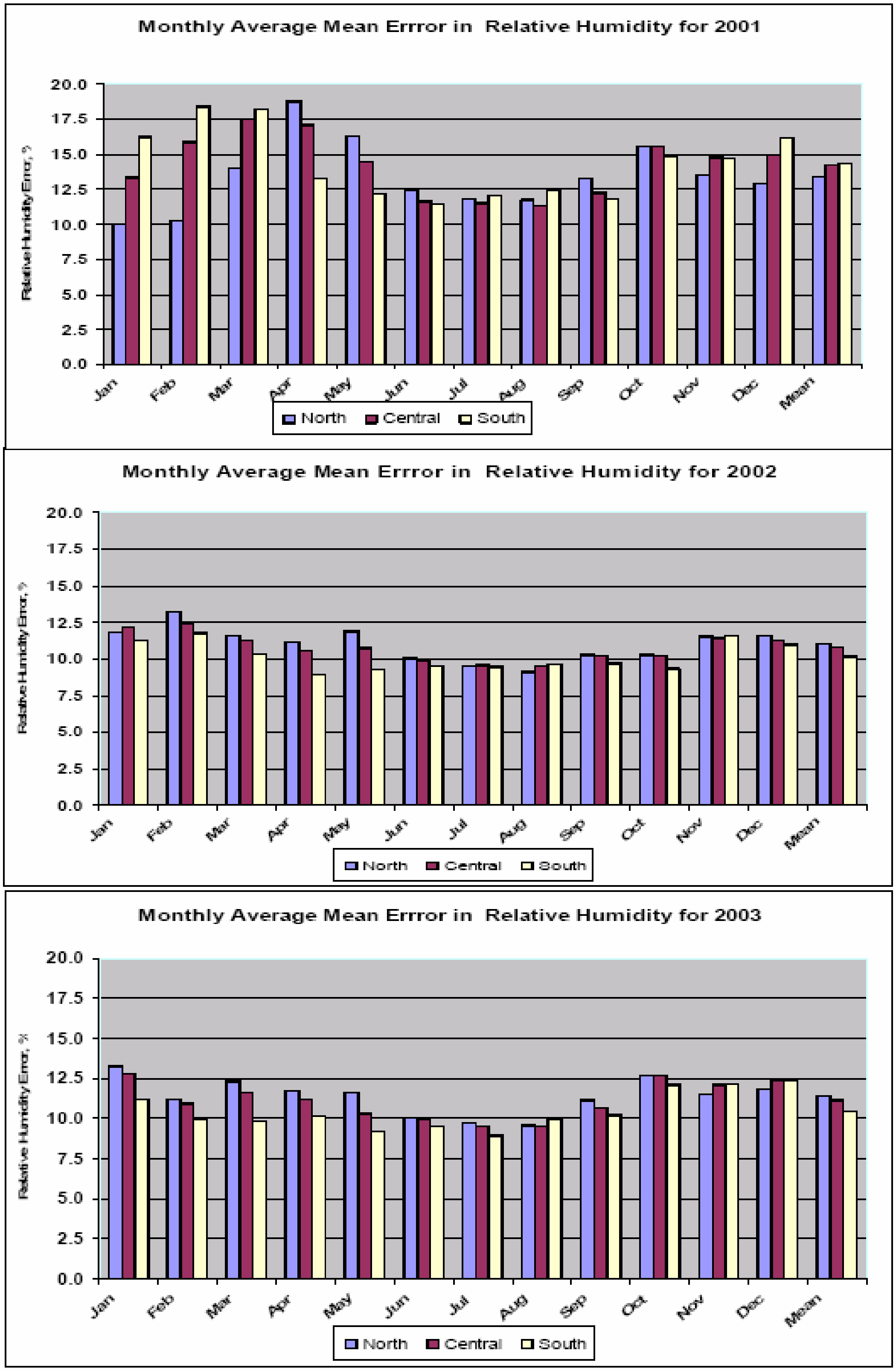



Figure 5-23. MM5/CALMET Relative Humidity Error (%) by Month for Three BART Modeling Years (2001, 2003, and 2003).

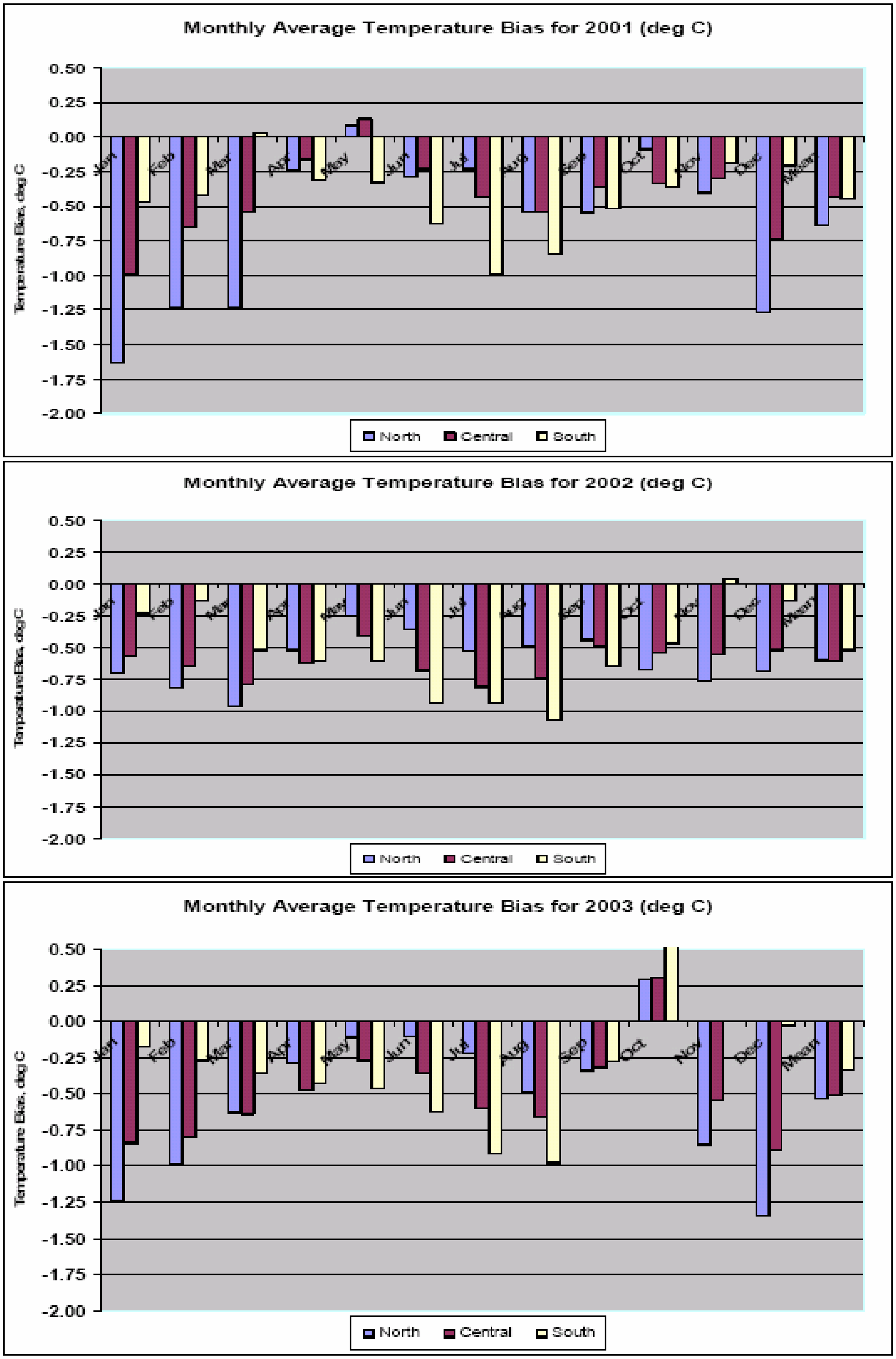



Figure 5-24. MM5/CALMET Temperature Bias (deg C) by Month for Three BART Modeling Years (2001, 2003, and 2003).

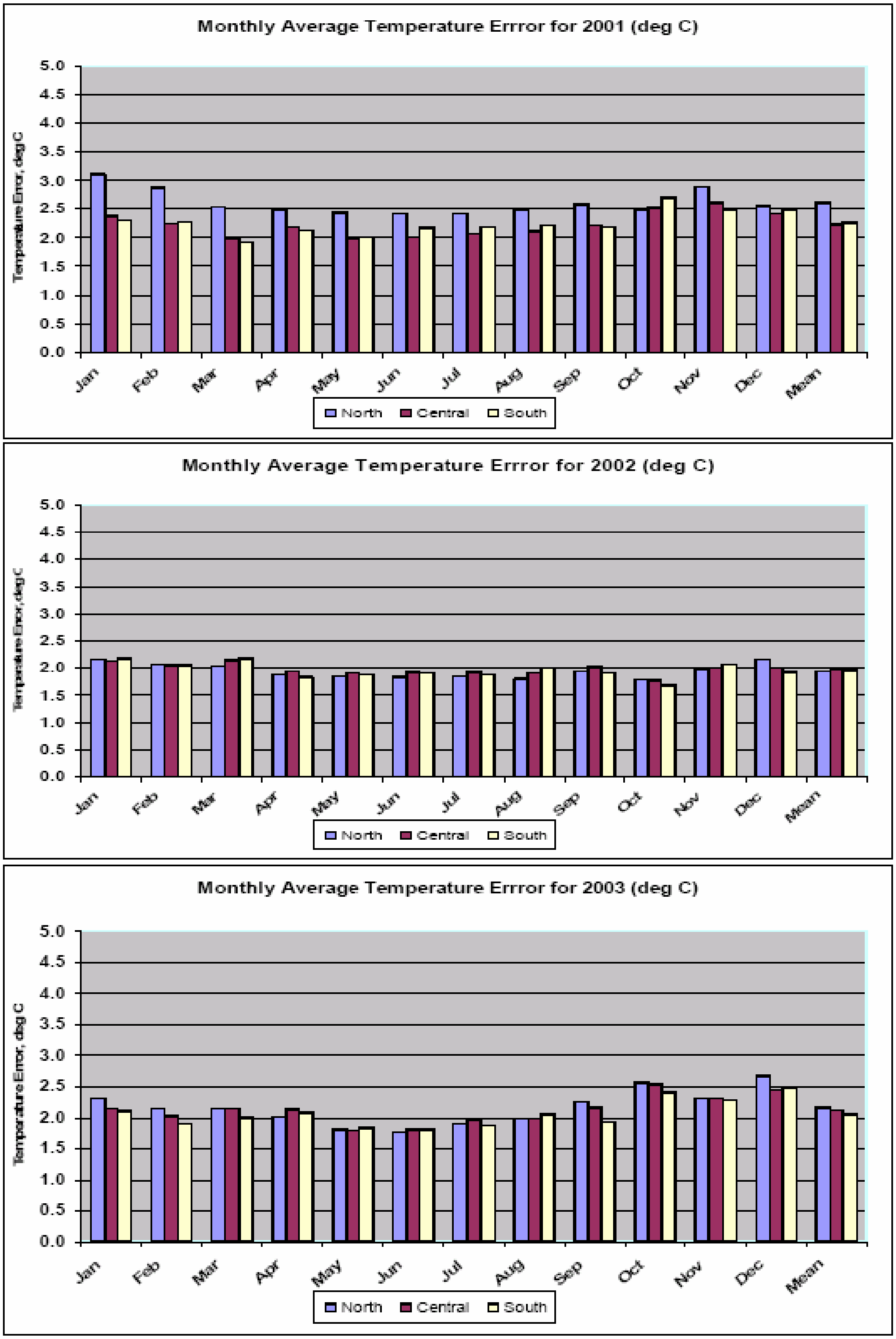



Figure 5-25. MM5/CALMET Temperature Error (deg C) by Month for Three BART Modeling Years (2001, 2003, and 2003).


Figure 5-26. MM5/CALMET Wind Speed Index of Agreement by Month for Three BART Modeling Years (2001, 2003, and 2003).

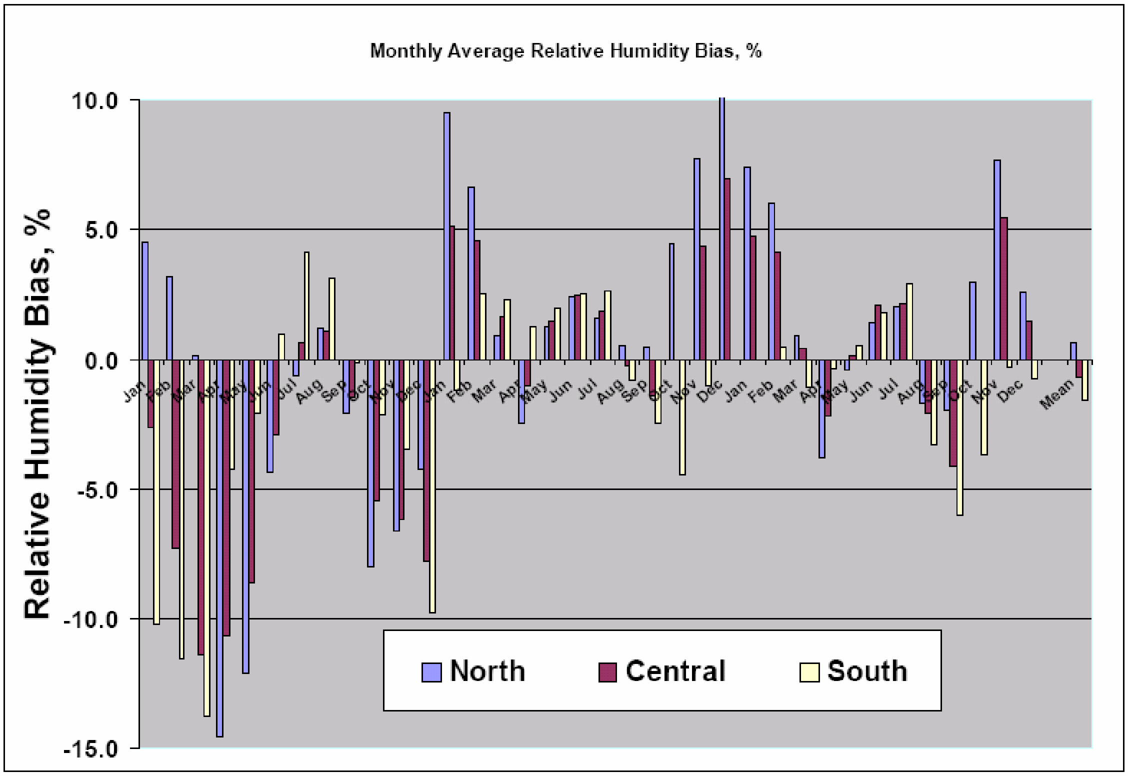



Figure 5-27. MM5/CALMET Relative Humidity Bias (%) over Three Years in All CENRAP Domains.

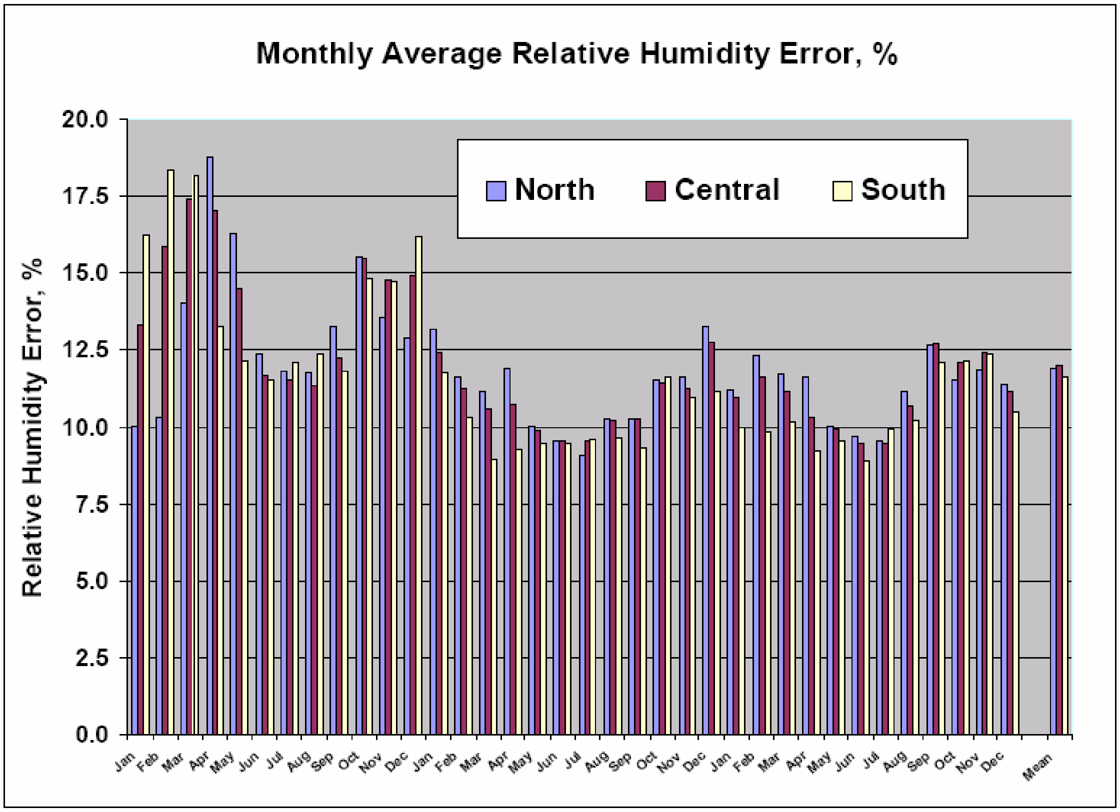



Figure 5-28. MM5/CALMET Relative Humidity Error (%) over Three Years in All CENRAP Domains.

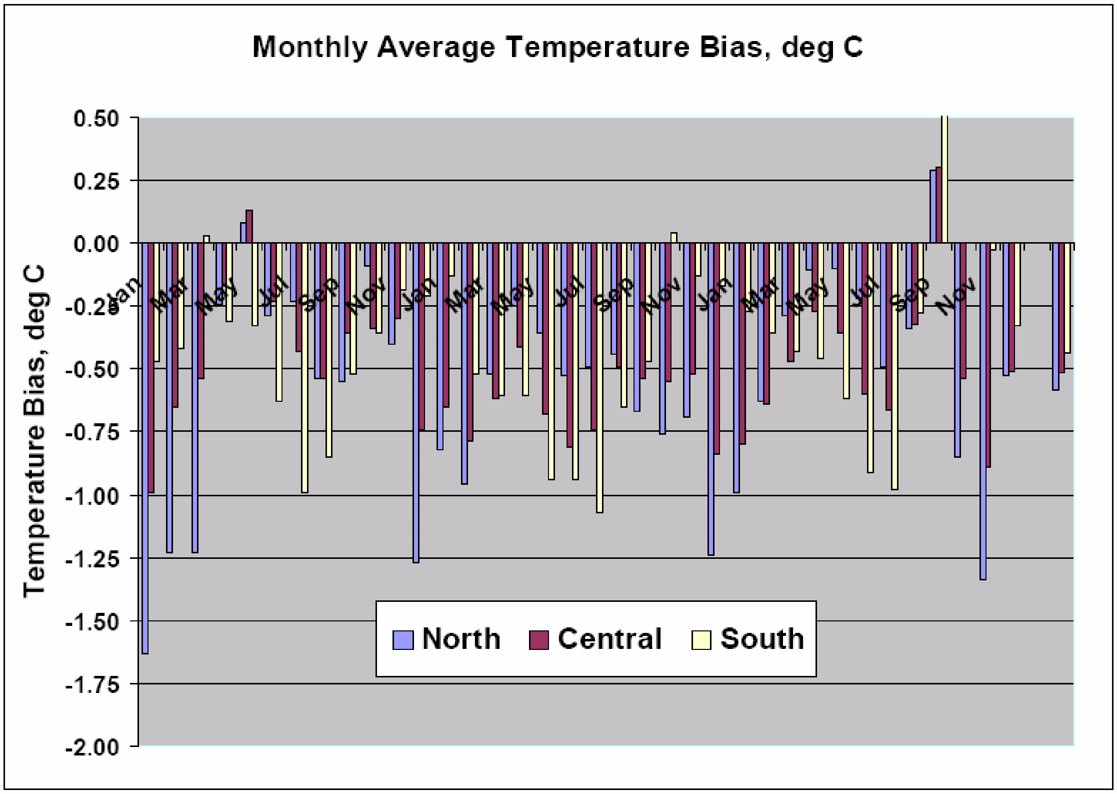



Figure 5-29. MM5/CALMET Surface Temperature Bias (deg C) over Three Years in All CENRAP Domains.

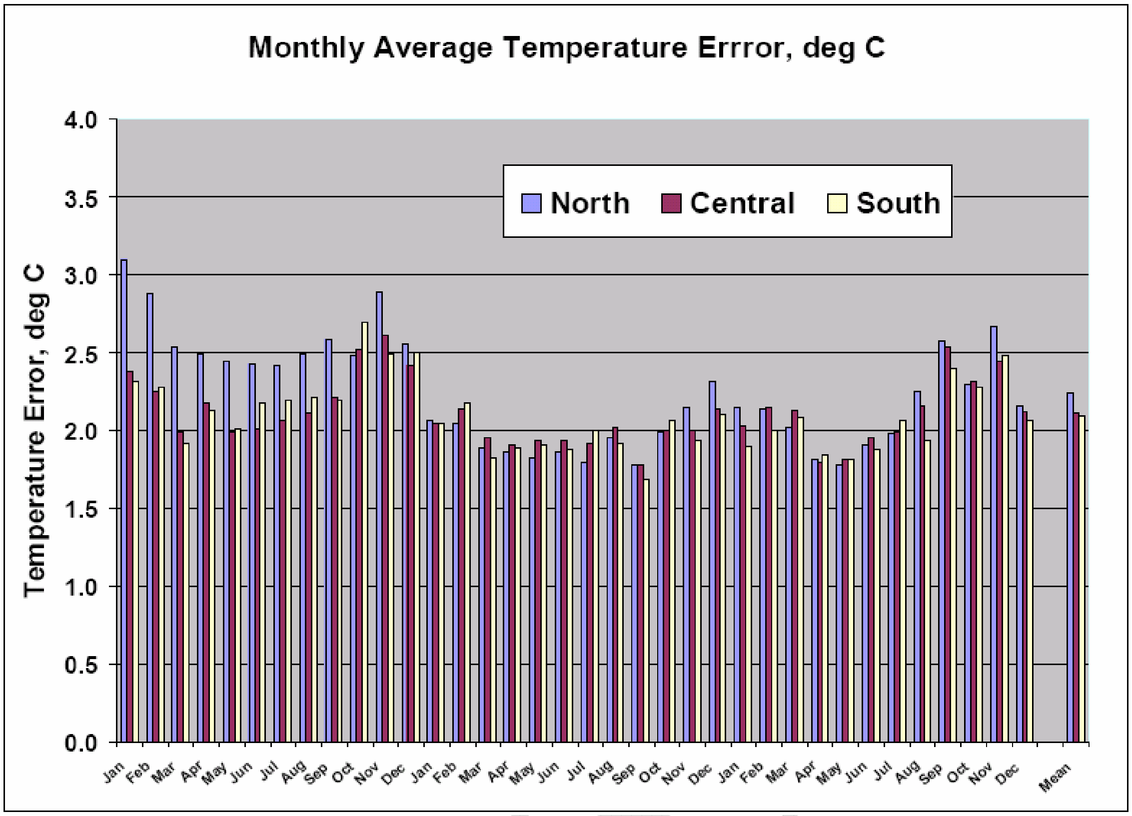


Figure 5-30. MM5/CALMET Surface Temperature Error (deg C) over Three Years in All CENRAP Domains.

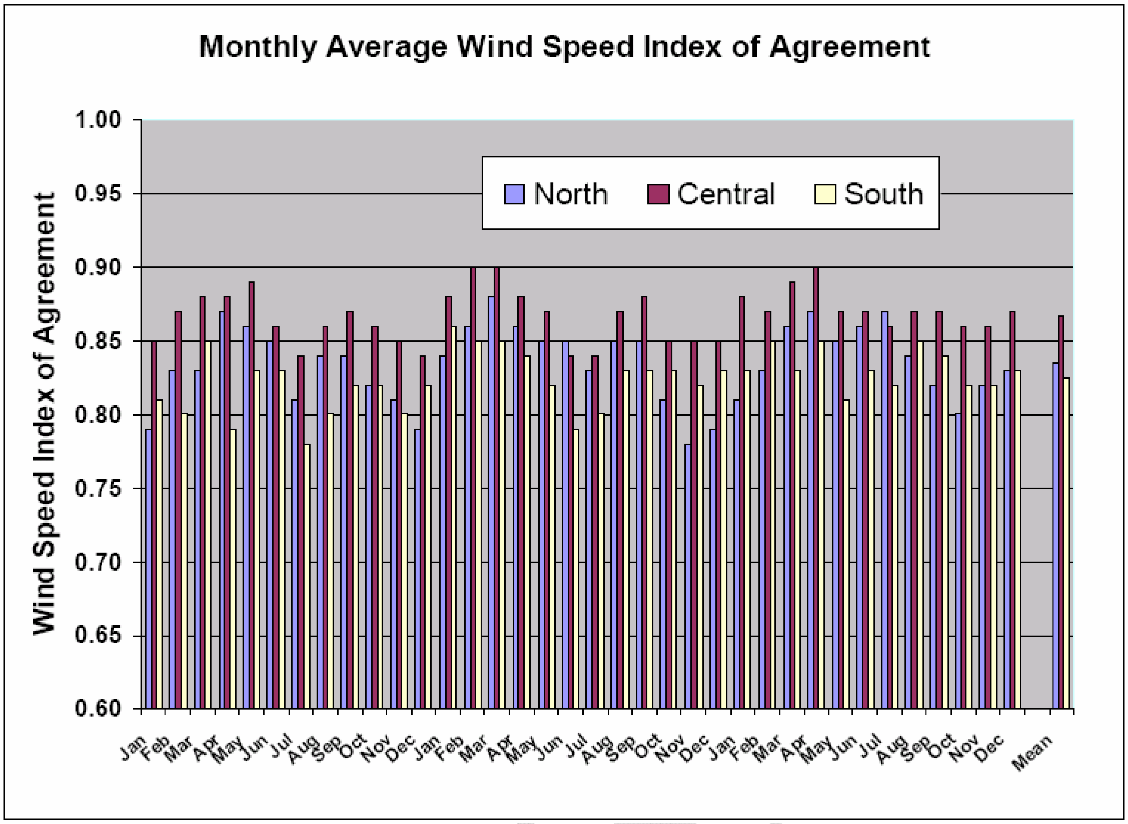


Figure 5-31. MM5/CALMET Wind Speed Index of Agreement over Three Years in All CENRAP Domains.

# Appendix F. CALMET Input Control Parameters

Table F-1 Input Groups in the CALMET Control File.

| Input Group | Description | Applicable |
|---|---|---|
| 0 | Input and output file names | Yes |
| 1 | General run control parameters | Yes |
| 2 | Map Projection and Grid Control Parameters | Yes |
| 3 | Output Options | Yes |
| 4 | Meteorological Data Options | Yes |
| 5 | Wind field Options and Parameters | Yes |
| 6 | Mixing Height, Temperature and Precipitation Parameters | Yes |
| 7 | Surface Meteorological Station Parameters | Yes |
| 8 | Upper Air Meteorological Station Parameters | Yes |
| 9 | Precipitation Station Parameters | Yes |

Table F-2 CALMET Model Input Group 0: Input and Output File Names

| Parameter | Default | Value | Comments |
|---|---|---|---|
| Input | GEO.DAT | GEO.DAT | |
| Input | SURF.DAT | SURF.DAT | |
| Input | CLOUD.DAT | CLOUD.DAT | |
| Input | PRECIP.DAT | PRECIP.DAT | |
| Input | MM4.DAT | MM4.DAT | |
| Input | WT.DAT | WT.DAT | |
| Output | CALMET.LST | CALMET.LST | |
| Output | CALMET.DAT | CALMET.DAT | |
| Output | PACOUT.DAT | PACOUT.DAT | |
| NUSTA | -- | 0 | Number of upper air stations |
| NOWSTA | -- | 0 | Number of over water stations |
| Input | UP1.DAT | UP1.DAT | |
| Input | UP2.DAT | UP2.DAT | |
| Input | UP3.DAT | UP3.DAT | |
| Input | SEA1.DAT | SEA1.DAT | |
| Input | DIAG.DAT | DIAG.DAT | |
| Input | PROG.DAT | PROG.DAT | |
| Output | TEST.PRT | TEST.PRT | |
| Output | TEST.OUT | TEST.OUT | |
| Output | TEST.KIN | TEST.KIN | |
| Output | TEST.FRD | TEST.FRD | |
| Output | TEST.SLP | TEST.SLP | |

Table F-3 CALMET Model Input Group 1: General Run Control Parameters

| Parameter | Default | Value | Comments |
|---|---|---|---|
| IBYR | - | 2001 | Starting year |
| IBMO | - | 1 | Starting month |
| IBDY | - | 1 | Starting day |
| IBHR | - | 1 | Starting hour |
| IBTZ | - | 6 | Base time zone |
| IRLG | - | 8760 | Length of run |
| IRTYPE | 1 | 1 | Run type (must = 1 to run CALPUFF) |
| LCALGRD | T | F | Compute CALGRID data fields |
| ITEST | 2 | 2 | Stop run after SETUP to do input QA |

Table F-4 CALMET Model Input Group 2: Map Projection and Grid Control Parameters

| Parameter | Default | Value | Comments |
|---|---|---|---|
| PMAP | UTM | LCC | Map Projection |
| RLATO | -- | 40N | Latitude (dec. degrees) of projection origin |
| RLONO | -- | 97W | Longitude (dec. degrees) of projection origin |
| XLAT1 | -- | 33N | Matching parallel(s) of latitude for projection |
| XLAT2 | -- | 45N | Matching parallel(s) of latitude for projection |
| DATUM | WGS-G | WGS-G | |
| NX | -- | 300 | Number of X grid cells in meteorological grid |
| NY | -- | 192 | Number of Y grid cells in meteorological grid |
| DGRIDKM | -- | 6.0 | Grid spacing, km |
| XORIGKM | -- | -1008. | Ref. Coordinate of SW corner of grid cell (1,1) |
| YORIGKM | -- | 0.0 | Ref. Coordinate of SW corner of grid cell (1,1) |
| NZ | -- | 10 | No. of vertical layers |
| ZFACE | -- | 0, 20 40, 80, 160, 320, 640, 1200, 2000, 3000, 4000 | Cell face heights in arbitrary vertical grid, m |

Table F-5 CALMET Model Input Group 3: Output Options

| Parameter | Default | Value | Comments |
|---|---|---|---|
| LSAVE | T | T | Disk output option |
| IFORMO | 1 | 1 | Type of unformatted output file |
| LPRINT | F | F | Print met fields |
| IPRINF | 1 | 1 | Print intervals |
| IUVOUT(NZ) | NZ*0 | NZ*0 | Specify layers of u,v wind components to print |
| IWOUT(NZ) | NZ*0 | NZ*0 | Specify layers of w wind component to print |
| ITOUT(NZ) | NZ*0 | NZ*0 | Specify levels of 3-D temperature field to print |
| LDB | F | F | Print input met data and variables |
| NN1 | 1 | 1 | First time step for debug data to be printed |
| NN2 | 1 | 1 | Last time step for debug data to be printed |
| IOUTD | 0 | 0 | Control variable for writing test/debug wind fields |
| NZPRN2 | 1 | 0 | Number of levels starting at surface to print |
| IPR0 | 0 | 0 | Print interpolated wind components |
| IPR1 | 0 | 0 | Print terrain adjusted surface wind components |
| IPR2 | 0 | 0 | Print initial divergence fields |
| IPR3 | 0 | 0 | Print final wind speed and direction |
| IPR4 | 0 | 0 | Print final divergence fields |
| IPR5 | 0 | 0 | Print winds after kinematic effects |
| IPR6 | 0 | 0 | Print winds after Froude number adjustment |
| IPR7 | 0 | 0 | Print winds after slope flows are added |
| IPR8 | 0 | 0 | Print final wind field components |

Table F-6 CALMET Model Input Group 4: Meteorological Data Options

| Parameter | Default | Value | Comments |
|---|---|---|---|
| NOOBS | 0 | 2 | 2 = No surface, over water, or upper air observations; use MM5 for surface, over water, and upper air data |
| NSSTA | -- | 0 | Number of meteorological surface stations |
| NPSTA | -- | 0 | Number of precipitation stations |
| ICLOUD | -- | 3 | Gridded cloud fields |
| IFORMS | 2 | 2 | Formatted surface meteorological data file |
| IFORMP | 2 | 2 | Formatted surface precipitation data file |
| IFORMC | 2 | 2 | Formatted cloud data file |

Table F-7 CALMET Model Input Group 5: Wind field Options and Parameters

| Parameter | Default | CENRAP | Comments |
|---|---|---|---|
| IWFCOD | 1 | 1 | Model selection variable |
| IFRADJ | 1 | 1 | Compute Froude number adjustment effects? |
| IKINE | 0 | 0 | Compute kinematic effects? |
| IOBR | 0 | 0 | Use O'Brien (1970) vertical velocity adjustment? |
| ISLSOPE | 1 | 1 | Compute slope flow effects? |
| IEXTRP | -4 | -1 | Extrapolate surface wind obs to upper levels? |
| ICALM | 0 | 0 | Extrapolate surface winds even if calm? |
| BIAS | NZ*0 | 0, 0, 0, 0, 0, 0, 0, 0, 0, 0 | Layer-dependent biases weighting aloft measurements |
| RMIN2 | 4. | -1.0 | Minimum vertical extrapolation distance |
| IPROG | 0 | 14 | 14 = Yes, use winds from MM5.DAT file as initial guess field [IWFCOD = 1 |
| ISTEPPG | 1 | 1 | MM5 output time step |
| LVARY | F | T | Use varying radius of influence |
| RMAX1 | -- | 30. | Maximum radius of influence over land in sfc layer |
| RMAX2 | -- | 30. | Maximum radius of influence over land aloft |
| RMAX3 | -- | 50. | Maximum radius of influence over water |
| RMIN | 0.1 | 0.1 | Minimum radius of influence used anywhere |
| TERRAD | -- | 12. | Terrain features radius of influence |
| R1 | -- | 1. | Weighting of first guess surface field |
| R2 | -- | 1. | Weighting of first guess aloft field |
| RPROG | -- | 0. | MM5 windfield weighting parameter |
| DIVLIM | 5.E-6 | 5.E-6 | Minimum divergence criterion |
| NITER | 50 | 50 | Number of divergence minimization iterations |
| NSMMTH | 2, 4, 4, 4, 4, 4, 4 | 2, 4, 4, 4, 4, 4, 4 | Number of passes through smoothing filter in each layer of CALMET |
| NITR2 | 99. | 5, 5, 5, 5, 5, 5, 5, 5, 5, 5 | Maximum number of stations used in each layer for the interpolation of data to a grid point |
| CRITFN | 1.0 | 1.0 | Critical Froude number |
| ALPHA | 0.1 | 0.1 | Kinematic effects parameter |
| FEXTR2 | NZ*0.0 | NZ*0.0 | Scaling factor for extrapolating sfc winds aloft |
| NBAR | 0 | 0 | Number of terrain barriers |
| IDIOTP1 | 0 | 0 | Surface temperature computation switch |
| ISURFT | -- | 4 | Number of sfc met stations to use for temp calcs |
| IDIOPT2 | 0 | 0 | Domain-averaged lapse rate switch |
| IUPT | 0 | 2 | Upper air stations to use for lapse rate calculation |
| ZUPT | 200. | 200. | Depth through which lapse rate is calculated |
| IDIOPT3 | 0 | 0 | Domain-averaged wind component switch |

| | | | |
|---|---|---|---|
| IUPWND | -1 | -1 | Number of aloft stations to use for wind calc |
| ZUPWND | 1., 1000. | 1., 1000. | Bottom and top of layer through which the domain-scale winds are computed |
| IDIOPT4 | 0 | 0 | Observed surface wind component switch |
| IDIOPT5 | 0 | 0 | Observed aloft wind component switch |
| LLBREZE | F | F | Use Lake Breeze Module |
| NBOX | 0 | 0 | Number of lake breeze regions |
| NLB | -- | 0 | Number of stations in the region |
| METBXID(NLB) | -- | 0 | Station ID's in the region |

Table F-8 CALMET Model Input Group 6: Mixing Height, Temperature and Precipitation

| Parameter | Default | Value | Comments |
|---|---|---|---|
| CONSTB | 1.41 | 1.41 | Neutral stability mixing height coefficient |
| CONSTE | 0.15 | 0.15 | Convective stability mixing height coefficient |
| CONSTN | 2400. | 2400. | Stable stability maxing height coefficient |
| CONSTW | 0.16 | 0.16 | Over water mixing height coefficient |
| FCORIOL | 1.E-4 | 1.E-4 | Absolute value of Coriolis parameter |
| IAVEZI | 1 | 1 | Conduct spatial averaging? Yes = 1 |
| MNMDAV | 1 | 10 | Maximum search radius in averaging process |
| HAFANG | 30. | 30. | Half-angle of upwind looking cone for averaging |
| ILEVZI | 1 | 1 | Layers of wind use in upwind averaging |
| DPTMIN | 0.001 | 0.001 | Minimum potential temperature lapse rate in the stable layer above the current convective mixing ht |
| DZZI | 200. | 200. | Depth of layer above current conv. mixing height through which lapse rate is computed |
| ZIMIN | 50. | 50. | Minimum overland mixing height |
| ZIMAX | 3000. | 3000. | Maximum overland mixing height |
| ZIMINW | 50. | 50. | Minimum over water mixing height |
| ZIMAXW | 3000. | 3000. | Maximum over water mixing height |
| ITPROG | 0 | 2 | 3D temperature from observations or from MM5? |
| IRAD | 1 | 1 | Type of interpolation; 1 = 1/R |
| TRADKM | 500. | 36. | Temperature interpolation radius of influence |
| NUMTS | 5 | 5 | Max number of stations for temp interpolation |
| IAVET | 1 | 1 | Spatially average temperatures? 1 = yes |
| TGDEFB | -.0098 | -.0098 | Temp gradient below mixing height over water |
| TGDEFA | -.0045 | -.0045 | Temp gradient above mixing height over water |
| JWAT1 | -- | 55 | Beginning land use categories over water |
| JWAT2 | -- | 55 | Ending land use categories for water |
| NFLAGP | 2 | 2 | Precipitation interpolation flag; 2 = 1/R-squared |
| SIGMAP | 100. | 50. | Radius of influence for precipitation interpolation |
| CUTP | 0.01 | 0.01 | Minimum precipitation rate cutoff (mm/hr) |

# Appendix G. CALPUFF Input Control Parameters

Table G-1 Input Groups in the CALPUFF Control File

| Input Group | Description | Applicable |
|---|---|---|
| 0 | Input and output file names | Yes |
| 1 | General run control parameters | Yes |
| 2 | Technical options | Yes |
| 3 | Species list | Yes |
| 4 | Grid control parameters | Yes |
| 5 | Output options | Yes |
| 6 | Sub grid scale complex terrain inputs | Yes |
| 7 | Dry deposition parameters for gases | Yes |
| 8 | Dry deposition parameters for particles | Yes |
| 9 | Miscellaneous dry deposition for parameters | Yes |
| 10 | Wet deposition parameters | Yes |
| 11 | Chemistry parameters | Yes |
| 12 | Diffusion and computational parameters | Yes |
| 13 | Point source parameters | Yes |
| 14 | Area source parameters | No |
| 15 | Line source parameters | No |
| 16 | Volume source parameters | No |
| 17 | Discrete receptor information | Yes |

Table G-2 CALPUFF Model Input Group 0: Input and Output File Names

| Parameter | Default | Value | Comments |
|---|---|---|---|
| METDAT | CALMET.DAT | Not used | Input file name |
| PUFLST | CALPUFF.LST | Varies with facility | CALPUFF output file name |
| CONDAT | CONC.DAT | Varies with facility | Concentration output file name |
| DFDAT | DFLX.DAT | Varies with facility | Dry flux output file name |
| WFDAT | WFLX.DAT | Varies with facility | Wet flux output file name |
| VISDAT | VISB.DAT | Varies with facility | Visibility output file name |
| OZDAT | OZONE.DAT | Varies with year | Ozone input file name |
| LCFILES | - | T | File names converted to lower case |
| NMETDAT | 1 | 12 | Number of CALMET.DAT files for run |
| CALMET.DAT | - | METDAT=/location of CALMET.DAT files | 12 entries one for each month |

Table G-3 CALPUFF Model Input Group 1: General Run Control Parameters

| Parameter | Default | Value | Comments |
|---|---|---|---|
| METRUN | 0 | 0 | All model periods in met file(s) will be run |
| IBYR | - | See note 1 below | Starting year |
| IBMO | - | 1 | Starting month |
| IBDY | - | 1 | Starting day |
| IBHR | - | 1 | Starting hour |
| XBTZ | - | 0 | Time zone for met files (0 = GMT) |
| IRLG | - | See note 2 below | Length of run |
| NSPEC | 5 | 10 | Number of MESOPUFF II chemical species |
| NSE | 3 | See note 3 below | Number of chemical species to be emitted |
| ITEST | 2 | 2 | Program is executed after SETUP phase |
| MRESTART | 0 | 0 | Do not read or write a restart file during run |
| NRESPD | 0 | 0 | File written only at last period |
| METFM | 1 | 1 | CALMET binary file (CALMET.MET) |
| AVET | 60 | 60 | Averaging time in minutes |
| PGTIME | 60 | 60 | PG Averaging time in minutes |

Note 1: Enter the year being modeled (i.e. 2001, 2002, or 2003)
Note 2: Enter 8760 for the years 2001 and 2002 but enter 8748 for the year 2003
Note 3: Enter 6 for the no-obs run and 7 for the refined run

Table G-4 CALPUFF Model Input Group 2: Technical Options

| Parameter | Default | Value | Comments |
|---|---|---|---|
| MGAUSS | 1 | 1 | Gaussian distribution used in near field |
| MCTADJ | 3 | 3 | Partial plume path terrain adjustment |
| MCTSG | 0 | 0 | Sub-grid-scale complex terrain not modeled |
| MSLUG | 0 | 0 | Near-field puffs not modeled as elongated |
| MTRANS | 1 | 1 | Transitional plume rise modeled |
| MTIP | 1 | 1 | Stack tip downwash used |
| MSHEAR | 0 | 0 | (0, 1) Vertical wind shear (not modeled, modeled) |
| MSPLIT | 0 | 0 | Puffs are not split |
| MCHEM | 1 | 1 | MESOPUFF II chemical parameterization scheme |
| MAQCHEM | 0 | 0 | Aqueous phase transformation **not modeled** |
| MWET | 1 | 1 | Wet removal modeled |
| MDRY | 1 | 1 | Dry deposition modeled |
| MDISP | 3 | 2 | AERMOD dispersion coefficients |
| MTURBVW | 3 | 3 | Use both $\sigma_v$ and $\sigma_w$ from PROFILE.DAT to compute $\sigma_y$ and $\sigma_z$ (n/a) |
| MDISP2 | 3 | 2 | AERMOD dispersion coefficients |
| MROUGH | 0 | 0 | PG $\sigma_y$ and $\sigma_z$ **not adjusted** for roughness |
| MPARTL | 1 | 1 | **No partial plume** penetration of elevated inversion |

| | | | |
|---|---|---|---|
| MTINV | 0 | 0 | Strength of temperature inversion computed from default gradients |
| MPDF | 0 | 0 | PDF **not used** for dispersion under convective conditions |
| MSGTIBL | 0 | 0 | Sub-grid TIBL module **not used** for shoreline |
| MBCON | 0 | 0 | Boundary concentration conditions **not modeled** |
| MFOG | 0 | 0 | **Do not** configure for FOG model output |
| MREG | 1 | 1 | Technical options must conform to USEPA Long Range Transport (LRT) guidance |

Table G-5 CALPUFF Model Input Group 3: Species List-Chemistry Options

| CSPEC | Modeled[1] | Emitted [2] | Dry Deposition[3] | Output Group Number |
|---|---|---|---|---|
| $SO_2$ | 1 | 1 | 1 | 0 |
| $SO_4^{-2}$ | 1 | 0 | 2 | 0 |
| NOx | 1 | 1 | 1 | 0 |
| $HNO_3$ | 1 | 0 | 1 | 0 |
| $NO_3^-$ | 1 | 0 | 2 | 0 |
| $NH_3$ | 0 | 0 | 1 | 0 |
| $PM_{10}$[4] | 1 | 1 | 2 | 0 |
| PMF[4] | 1 | 1 | 2 | 0 |
| EC[5] | 1 | 1 | 2 | 0 |
| SOA[5] | 1 | 1 | 2 | 0 |

Note 1: 0 = No, 1 = Yes

Note 2: 0 = No, 1 = Yes (Depends on if species is being modeled or not)

Note 3: 0 = none, 1 = computed gas, 2 = computed particle, 3 = user specified

Note 4: Only PMF will be modeled and emitted in the no-obs run; however, both $PM_{10}$ and PMF will be modeled and emitted in the refined analysis

Note 5: EC and SOA will not be modeled nor will it be emitted during the no-obs and the refined runs

Table G-6 CALPUFF Model Input Group 4: Map Projection and Grid Control Parameters

| Parameter | Default | Value | Comments |
|---|---|---|---|
| PMAP | UTM | LCC | Map Projection |
| FEAST | 0.0 | 0.000 | False Easting |
| FNORTH | 0.0 | 0.000 | False Northing |
| RLATO | None | 40N | Latitude and Longitude of projection origin |
| RLONO | None | 97W | Latitude and Longitude of projection origin |
| XLAT1 | None | 33N | Matching parallel of latitude for map projection |
| XLAT2 | None | 45N | Matching parallel of latitude for map projection |
| DATUM | WGS-84 | WGS-G | Datum region for output coordinates |
| NX | None | 366 | Number of X grid cells in meteorological grid |
| NY | None | 234 | Number of Y grid cells in meteorological grid |
| NZ | None | 10 | Number of vertical layers in meteorological grid |
| DGRIDKM | None | 6 | Grid spacing (km) |
| ZFACE | None | 0, 20 40, 80, 160, 320, 640, 1200, 2000, 3000, 4000 | Cell face heights in meteorological grid (m) |
| XORIGKM | None | -1008 | Reference X coordinate for SW corner of grid cell (1,1) of meteorological grid (km) |
| YORIGKM | None | -864 | Reference Y coordinate for SW corner of grid cell (1,1) of meteorological grid (km) |
| IBCOMP | None | 1 | X index of lower left corner of the computational grid |
| JBCOMP | None | 1 | Y index of lower left corner of the computational grids |
| IECOMP | None | 366 | X index of the upper right corner of the computational grid |
| JECOMP | None | 234 | Y index of the upper right corner of the computational grid |
| LSAMP | T | F | Sampling grid is not used |
| IBSAMP | None | 1 | X index of lower left corner of the sampling grid |
| JBSAMP | None | 1 | Y index of lower left corner of the sampling grid |
| IESAMP | None | 366 | X index of upper right corner of the sampling grid |
| JESAMP | None | 234 | Y index of upper right corner of the sampling grid |
| MESHDN | 1 | 1 | Nesting factor of the sampling grid |

Table G-7 CALPUFF Model Input Group 5: Output Options

| Parameter | Default | Value | Comments |
|---|---|---|---|
| ICON | 1 | 1 | Output file CONC.DAT containing concentrations is created |
| IDRY | 1 | 1 | Output file DFLX.DAT containing dry fluxes is created |
| IWET | 1 | 1 | Output file WFLX.DAT containing wet fluxes is created |
| IVIS | 1 | 1 | Output file containing relative humidity data is created |
| LCOMPRS | T | T | Perform data compression in output file |
| IMFLX | 0 | 0 | Do not calculate mass fluxes across specific boundaries |
| IMBAL | 0 | 0 | Mass balances for each species not reported hourly |
| ICPRT | 0 | 1 | Print concentration fields to the output list file |
| IDPRT | 0 | 0 | Do not print dry flux fields to the output list file |
| IWPRT | 0 | 0 | Do not print wet flux fields to the output list file |
| ICFRQ | 1 | 1 | Concentration fields are printed to output list file every hour (hr) |
| IDFRQ | 1 | 1 | Dry flux fields are printed to output list file every 1 hour |
| IWFRQ | 1 | 1 | Wet flux fields are printed to output list file every 1 hour |
| IPRTU | 1 | 3 | Units for line printer output are in g/m3 for concentration and $g/m^2/s$ for deposition |
| IMESG | 2 | 2 | Messages tracking the progress of run written to screen |
| LDEBUG | F | F | Logical value for debug output |
| IPFDEB | 1 | 1 | First puff to track |
| NPFDEB | 1 | 1 | Number of puffs to track |
| NN1 | 1 | 1 | Meteorological period to start output |
| NN2 | 10 | 10 | Meteorological period to end output |

Table G-8 CALPUFF Model Input Group 6: Sub-Grid Scale Complex Terrain Input

| Parameter | Default | Value | Comments |
|---|---|---|---|
| NHILL | 0 | 0 | Number of terrain features |
| NCTREC | 0 | 0 | Number of special complex terrain receptors |
| MHILL | - | 2 | Input terrain and receptor data for CTSG hills input in CTDM format |
| XHILL2M | 1 | 1 | Conversion factor for changing horizontal dimensions to meters |
| ZHILL2M | 1 | 1 | Conversion factor for changing vertical dimensions to meters |
| XCTDMKM | None | 0.0 E+00 | X origin of CTDM system relative to CALPUFF coordinate system (km) |
| YCTDMKM | None | 0.0 E+00 | Y origin of CTDM system relative to CALPUFF coordinate system (km) |

Table G-9 CALPUFF Model Input Group 7: Dry Deposition Parameters for Gases

| Species | Default | Value | Comments |
|---|---|---|---|
| $SO_2$ | 0.1509 | 0.1509 | Diffusivity |
| | 1000. | 1000. | Alpha star |
| | 8.0 | 8.0 | Reactivity |
| | 0.0 | 0.0 | Mesophyll resistance |
| | 0.04 | 0.04 | Henry's Law coefficient |
| $NO_x$ | 0.1656 | 0.1656 | Diffusivity |
| | 1.0 | 1.0 | Alpha star |
| | 8.0 | 8.0 | Reactivity |
| | 5.0 | 5.0 | Mesophyll resistance |
| | 3.5 | 3.5 | Henry's Law coefficient |
| $HNO_3$ | 0.1628 | 0.1628 | Diffusivity |
| | 1.0 | 1.0 | Alpha star |
| | 18.0 | 18.0 | Reactivity |
| | 0.0 | 0.0 | Mesophyll resistance |
| | 8.0E-8 | 8.0E-8 | Henry's Law coefficient |
| | 0.000359 | 0.000359 | Henry's Law coefficient |

Table G-10 CALPUFF Model Input Group 8: Dry Deposition Parameters for Particles

| Species | Default | Value | Comments |
|---|---|---|---|
| $SO_4^{-2}$ | 0.48 | 0.48 | Geometric mass mean diameter of $SO_4^{-2}$ (μm) |
| $NO_3^-$ | 2.0 | 0.48 | Geometric mass mean diameter of $NO_3^-$ (μm) |
| $PM_{10}$ | 2.0 | 6.0 | Geometric mass mean diameter of PMC (μm) |
| PMF | 2.0 | 0.48 | Geometric mass mean diameter of PMF (μm) |
| EC | 2.0 | 0.48 | Geometric mass mean diameter of EC (μm) |
| SOA | 0.48 | 0.48 | Geometric mass mean diameter of SOA (μm) |

(Geometric Standard Deviation for all species assumed to be 2.0 μm).

Table G-11 CALPUFF Model Input Group 9: Miscellaneous Dry Deposition Parameters

| Parameter | Default | Value | Comments |
|---|---|---|---|
| RCUTR | 30 | 30 | Reference cuticle resistance (s/cm) |
| RGR | 10 | 10 | Reference ground resistance (s/cm) |
| REACTR | 8 | 8 | Reference pollutant reactivity |
| NINT | 9 | 9 | Number of particle size intervals for effective particle deposition velocity |
| IVEG | 1 | 1 | Vegetation in non-irrigated areas is active and unstressed |

Table G-12 CALPUFF Model Input Group 10: Wet Deposition Parameters

| Species | Default | Value | Comments |
|---|---|---|---|
| $SO_2$ | 3.21E-05 | 3.21E-05 | Scavenging coefficient for liquid precipitation ($s^{-1}$) |
| | 0.0 | 0.0 | Scavenging coefficient for frozen precipitation ($s^{-1}$) |
| $SO_4^{-2}$ | 1.0E-04 | 1.0E-04 | Scavenging coefficient for liquid precipitation ($s^{-1}$) |
| | 3.0E-05 | 3.0E-05 | Scavenging coefficient for frozen precipitation ($s^{-1}$) |
| $HNO_3$ | 6.0E-05 | 6.0E-05 | Scavenging coefficient for liquid precipitation ($s^{-1}$) |
| | 0.0 | 0.0 | Scavenging coefficient for frozen precipitation ($s^{-1}$) |
| $NO_3^-$ | 1.0E-04 | 1.0E-04 | Scavenging coefficient for liquid precipitation ($s^{-1}$) |
| | 3.0E-05 | 3.0E-05 | Scavenging coefficient for frozen precipitation ($s^{-1}$) |
| $NH_3$ | 8.0E-05 | 8.0E-05 | Scavenging coefficient for liquid precipitation ($s^{-1}$) |
| | 0.0 | 0.0 | Scavenging coefficient for frozen precipitation ($s^{-1}$) |
| $PM_{10}$ | 1.0E-04 | 1.0E-04 | Scavenging coefficient for liquid precipitation ($s^{-1}$) |
| | 3.0E-05 | 3.0E-05 | Scavenging coefficient for frozen precipitation ($s^{-1}$) |
| PMF | 1.0E-04 | 1.0E-04 | Scavenging coefficient for liquid precipitation ($s^{-1}$) |
| | 3.0E-05 | 3.0E-05 | Scavenging coefficient for frozen precipitation ($s^{-1}$) |
| EC | 1.0E-04 | 1.0E-04 | Scavenging coefficient for liquid precipitation ($s^{-1}$) |
| | 3.0E-05 | 3.0E-05 | Scavenging coefficient for frozen precipitation ($s^{-1}$) |
| OC | 1.0E-04 | 1.0E-04 | Scavenging coefficient for liquid precipitation ($s^{-1}$) |
| | 3.0E-05 | 3.0E-05 | Scavenging coefficient for frozen precipitation ($s^{-1}$) |

Table G-13 CALPUFF Model Input Group 11: Chemistry Parameters

| Parameter | Default | Value | Comments |
|---|---|---|---|
| MOZ | 1 | 1 | Read ozone background concentrations from ozone.dat file (measured values). |
| $BCKO_3$ | 12*80 | 12*40 | Background ozone concentration (ppb) |
| $BCKNH_3$ | 12*10 | 12*3 | Background ammonia concentration (ppb) |
| RNITE1 | 0.2 | 0.2 | Nighttime $NO_2$ loss rate in percent/hour |
| RNITE2 | 2 | 2 | Nighttime $NO_X$ loss rate in percent/hour |
| RNITE3 | 2 | 2 | Nighttime $HNO_3$ loss rate in percent/hour |
| $MH_20_2$ | 1 | 1 | Background $H_2O_2$ concentrations (Aqueous phase transformations **not modeled**) |
| $BCKH_20_2$ | 1 | 1 | Background monthly $H_2O_2$ concentrations (Aqueous phase transformations **not modeled**) |

Table G-14 CALPUFF Model Input Group 12: Dispersion/Computational Parameters

| Parameter | Default | Value | Comments |
|---|---|---|---|
| SYDEP | 550 | 550 | Horizontal size of a puff in meters beyond which the time dependant dispersion equation of Heffter (1965) is used |
| MHFTSZ | 0 | 0 | Do **not use** Heffter formulas for sigma z |
| JSUP | 5 | 5 | Stability class used to determine dispersion rates for puffs above boundary layer |
| CONK1 | 0.01 | 0.01 | Vertical dispersion constant for stable conditions |
| CONK2 | 0.1 | 0.1 | Vertical dispersion constant for neutral/stable conditions |
| TBD | 0.5 | 0.5 | Use ISC transition point for determining the transition point between the Schulman-Scire to Huber-Snyder Building Downwash scheme |
| IURB1 | 10 | 10 | Lower range of land use categories for which urban dispersion is assumed |
| IURB2 | 19 | 19 | Upper range of land use categories for which urban dispersion is assumed |
| ILANDUIN | 20 | * | Land use category for modeling domain |
| XLAIIN | 3.0 | * | Leaf area index for modeling domain |
| ZOIN | -0.25 | * | Roughness length in meters for modeling domain |
| ELEVIN | 0.0 | * | Elevation above sea level |
| XLATIN | -999 | - | North latitude of station in degrees |
| XLONIN | -999 | - | South latitude of station in degrees |
| ANEMHT | 10 | 10 | Anemometer height in meters |
| ISIGMAV | 1 | 1 | Sigma-v is read for lateral turbulence data |
| IMIXCTDM | 0 | 0 | Predicted mixing heights are used |
| XMXLEN | 1 | 1 | Maximum length of emitted slug in meteorological grid units |
| XSAMLEN | 1 | 10 | Maximum travel distance of slug or puff in meteorological grid units during one sampling unit |
| MXNEW | 99 | 60 | Maximum number of puffs or slugs released from one source during one time step |
| MXSAM | 99 | 60 | Maximum number of sampling steps during one time step for a puff or slug |
| NCOUNT | 2 | 2 | Number of iterations used when computing the transport wind for a sampling step that includes transitional plume rise |
| SYMIN | 1 | 1 | Minimum sigma y in meters for a new puff or slug |
| SZMIN | 1 | 1 | Minimum sigma z in meters for a new puff or slug |
| SVMIN | .50 | .50 | Minimum lateral turbulence velocities (m/s) |
| SWMIN | 0.20, 0.12, 0.08, 0.06, | 0.20, 0.12, 0.08, 0.06, | Minimum vertical turbulence velocities (m/s) |

| | | | |
|---|---|---|---|
| | 0.03, 0.016 | 0.03, 0.016 | |
| WSCALM | 0.5 | 0.5 | Minimum non-calm wind speeds (m/s) |
| XMAXZI | 3000. | 3000. | Maximum mixing height (m) |
| XMINZI | 50. | 20. | Minimum mixing height (m) |
| SL2PF | 10. | 10. | Maximum Sy/puff length |
| PLXO | 0.07, 0.07, 0.10, 0.15, 0.35, 0.55 | 0.07, 0.07, 0.10, 0.15, 0.35, 0.55 | Wind speed power-law exponents |
| WSCAT | 1.54, 3.09, 5.14, 8.23, 10.80 | 1.54, 3.09, 5.14, 8.23, 10.80 | Upper bounds of 1st 5 wind speed classes |
| PGGO | 0.020, 0.035 | 0.020, 0.035 | Potential temp gradients PG E & F (deg/km) |
| CDIV | 0.01 | 0.01 | Divergence criterion for dw/dz (1/s) |
| PPC | 0.5, 0.5, 0.5, 0.5, 0.35, 0.35 | 0.5, 0.5, 0.5, 0.5, 0.35, 0.35 | Plume path coefficients (only if MCTADJ=3) |
| NSPLIT | 3 | 3 | Number of puffs when puffs split |
| IRESPLIT | - | 1900 | Hour(s) when puff is eligible to split |
| ZISPLIT | 100 | 100 | Previous hour's minimum mixing height, m |
| ROLDMAX | 0.25 | 0.25 | Previous Max mixing height/current mixing height ratio, must be less than this value to allow puff to split |
| NSPLITH | 5 | 5 | Number of puffs resulting from a split |
| SYSPLITH | 1.0 | 1.0 | Minimum sigma-y of puff before it may split |
| SHSPLITH | 2.0 | 2.0 | Minimum puff elongation rate from wind shear before puff may split |
| CNSPLITH | 1.0E-07 | 1.0E-07 | Minimum species concentration before a puff may split |
| EPSSLUG | 1.0E-04 | 1.0E-04 | Criterion for SLUG sampling |
| EPSAREA | 1.0E-06 | 1.0E-06 | Criterion for area source integration |
| DSRISE | 1.0 | 1.0 | Trajectory step length for numerical rise algorithm |
| Note: Values indicated by an asterisk (*) were allowed to vary spatially across the domain and were obtained from CALMET | | | |

Table G-15 CALPUFF Model Input Group 13: Point Source Parameters

| Parameter | Default | Value | Comments |
|---|---|---|---|
| NPT1 | None | Varies by scenario | Number of point sources with stack parameters |
| IPTU | 1 | 1 | Units for point source emission rates are g/s |
| NSPT1 | 0 | 0 | Number of source-species combinations with variable emissions scaling factors |
| NPT2 | None | 0 | Number of point sources with variable emission parameters provided in external file |
| MISC | None | Point source parameters and emission data | Point source inputs include stack height (H), stack diameter (d), exit temperature (T), exit velocity (v) emissions by species, and coordinate of stack (LCC) |

Table G-16 CALPUFF Model Input Group 17: Discrete Receptor Information

| Parameter | Default | Value | Comments |
|---|---|---|---|
| NREC | None | 427 | Number of discrete receptors |

Please note that ADEQ will not be modeling area, line and volume sources which are input groups 14, 15, and 16 respectively.

# Appendix H. POSTUTIL Input Control Parameters

Table H-1 Input Groups in the POSTUTIL Processor Control File

| Sub Group | Description | Applicable |
|---|---|---|
| 0a | Input and output file names | Yes |
| 1 | NMET – Number of CALMET data files (365) | Yes |
| 2 | NFILES – Number of CALPUFF data files | Yes |

Table H-2 POSTUTIL Processor Input Group 1: General Run Control Parameters

| Parameter | Default | Value | Comments |
|---|---|---|---|
| ISYR | None | See note 1 below | Starting year |
| ISMO | None | 1 | Starting month |
| ISDY | None | 1 | Starting day |
| ISHR | None | 0 | Starting hour |
| NPER | None | See note 2 below | Number of periods to process |
| NSPECINP | None | See note 3 below | Number of CALPUFF species to process |
| NSPECOUT | None | See note 3 below | Number of species to output |
| NSPECCMP | None | 0 | Number of species to derive |
| MDUPLCT | None | 1 | Stop run if duplicate name |
| NSCALED | None | 0 | Number of CALPUFF files to 'scale' |
| MNITRATE | None | 1 | Re-compute the $HNO_3/NO_3$ partition for CALPUFF modeled concentrations? 1 = yes for all sources combined |
| BCKNH3 | 10. | 3. | Default $NH_3$ concentration (ppb) for $HNO_3/NO_3$ partitioning |

Note 1: Enter the modeled year for the CALPUFF run
Note 2: Enter 8760 for years 2001 and 2002, but enter 8748 for the year 2003
Note 3: Enter 6 for the no-obs run and 7 for the refined run

Table H-3 POSTUTIL Processor Input Group 2: Species Processing Information

| Parameter | Default | Value | Comments |
|---|---|---|---|
| ASPECI | None | $SO_2$, $SO_4$, $NO_x$, $HNO_3$, $NO_3$, $PM_{10}$, PMF See Note 1 Below | Species to post-process |
| ASPECO | None | $SO_2$, $SO_4$, $NO_x$, $HNO_3$, $NO_3$, $PM_{10}$, PMF See Note 4 Below | Species to output |
| CSPECCMP | None | CSPECCMP = N<br>$SO_2$ = 0.0<br>$SO_4$ = 0.291667<br>NO = 0.466667<br>$NO_2$ = 0.304348<br>$HNO_3$ = 0.222222<br>$NO_3$ = 0.451613<br>$PM_{10}$ = 0.0 | Nitrogen species to be computed by scaling and summing one or more of the processed input species using the scaling factors for each of the NSPECINP input species |
| CSPECCMP | None | CSPECCMP = S<br>$SO_2$ = 0.50<br>$SO_4$ = 0.333333<br>NO = 0.0<br>$NO_2$ = 0.0<br>$HNO_3$ = 0.0<br>$NO_3$ = 0.0<br>$PM_{10}$ = 0.0 | Sulfur species to be computed by scaling and summing one or more of the processed input species using the scaling factors for each of the NSPECINP input species |
| MODDAT | None | A (Default=1.0)<br>$SO_2$ = 1.1<br>$SO_4$ = 1.5<br>HNO3 = 0.8<br>$NO_3$ = 0.1<br><br>B (Default=0.0)<br>$SO_2$ = 0.0<br>$SO_4$ = 0.0<br>$HNO_3$ = 0.0<br>$NO_3$ = 0.0 | Each species in NSCALED CALPUFF data files may be scaled before processing (e.g., to change the emission rate for all sources modeled in the run that produced a data file). For each scaled species the scaling factors are A and B where x' = Ax + B. |

Note 4: In the no-obs run just enter PMF, but in the refined run enter $PM_{10}$ and PMF

# Appendix I. CALPOST Input Control Parameters

Table I-1Input Groups in the CALPOST Processor Control File

| Group | Description | Applicable |
|---|---|---|
| 0 | Input and output file names | Yes |
| 1 | General Run Control Parameters | Yes |
| 2 | Visibility Parameters | Yes |
| 3 | Output Options | Yes |

Table I-2 CALPOST Processor Input Group 1: General Run Control Parameters

| Parameter | Default | Value | Comments |
|---|---|---|---|
| METRUN | 0 | 1 | 1 = Run all met periods in CALPUFF data file |
| ISYR | None | 2001, 2002, 2003 | Starting year |
| ISMO | None | 1 | Starting month |
| ISDY | None | 1 | Starting day |
| ISHR | None | 0 | Starting hour |
| NPER | None | See note 1 below | Number of periods to process |
| NREP | 1 | 1 | Process every hour of data? Yes = 1 |
| ASPEC | None | VISIB | Process species for visibility |
| ILAYER | 1 | 1 | Layer/deposition code; 1 for CALPUFF concentrations |
| A | 0.0 | 0.0 | Scaling factor, slope |
| B | 0.0 | 0.0 | Scaling factor, intercept |
| LBACK | F | F | Add hourly background concentrations or fluxes |
| MSOURCE | 0 | 0 | Process only total reported contribution |
| LG | F | F | Process gridded receptors |
| LD | F | T | Process discrete receptors |
| LCT | F | F | Process complex terrain receptors |
| LDRING | F | F | Report receptor ring results |
| NDRECP | -1 | See note 2 below | To select the Class I area's receptors enter *1 after the number of receptors otherwise enter *0 |
| IBGRID | -1 | -1 | X index of LL corner of receptor grid |
| JBGRID | -1 | -1 | Y index of LL corner of receptor grid |
| IEGRID | -1 | -1 | X index of UR corner of receptor grid |
| JEGRID | -1 | -1 | X index of UR corner of receptor grid |
| NGONOFF | 0 | 0 | Number of gridded receptor rows |
| NGXRECP | 1 | 0 | Exclude specific gridded receptors, Yes = 0 |

Note 1: Enter 8760 for the years 2001 and 2002, but enter 8748 for the year 2003.

Note 2: CALPOST is to be run for each Class I area assessed.

- The following are the number of receptors for each Class I area being assessed:
  1. Caney Creek = 80
  2. Hercules-Glade = 47
  3. Mingo Wilderness = 80
  4. Sipsey = 148
  5. Upper Buffalo = 72

Table I-3 CALPOST Processor Input Group 2: Species Processing Information

| Parameter | Default | Value | Comments |
|---|---|---|---|
| RHMAX | 98 | 95 | Maximum RH (%) used in particle growth curve |
| LVSO4 | T | T | Compute light extinction for sulfate? |
| LVNO3 | T | T | Compute light extinction for nitrate? |
| LVOC | T | T | Compute light extinction for organic carbon? |
| LVMPC | T | T | Compute light extinction for coarse particles? |
| LVMPF | T | T | Compute light extinction for fine particles? |
| LVEC | T | T | Compute light extinction for elemental carbon? |
| LVBK | T | T | Include background in extinction calculation? |
| SPECPMC | PMC | PMC | Coarse particulate species |
| SPECPMF | PMF | PMF | Fine particulate species |
| EEPMC | 0.6 | 0.6 | Extinction efficiency for coarse particulates |
| EEPMF | 1.0 | 1.0 | Extinction efficiency for fine particulates |
| EEPMCBK | 0.6 | 0.6 | Extinction efficiency for coarse part. background |
| EESO4 | 3.0 | 3.0 | Extinction efficiency for ammonium sulfate |
| EENO3 | 3.0 | 3.0 | Extinction efficiency for ammonium nitrate |
| EEOC | 4.0 | 4.0 | Extinction efficiency for organic carbon |
| EESOIL | 1.0 | 1.0 | Extinction efficiency for soil |
| EEEC | 10.0 | 10.0 | Extinction efficiency for elemental carbon |
| MVISBK | 2 | 6 | Method 6 for background light extinction:<br>Compute extinction from speciated PM measurements. FLAG RH adjustment factor applied to observed & modeled sulfate and nitrate |
| BEXTBTBK | -- | 12 | Background extinction for MVISBK=1 (1/Mm) |
| RHFRAC | -- | 10 | Percentage of particles affected by RH |
| RHFAC | 12*value | Depends on Class I Area | Extinction coefficients for modeled and background hygroscopic species computed using EPA (2003) monthly RH adjustment factors |
| BKSEC | 0.02 | 0.02 | Eastern background elemental carbon $\beta_{ext}$ |
| BKSO4 | 0.23 | 0.23 | Eastern background sulfate $\beta_{ext}$ |
| BKNO3 | 0.10 | 0.10 | Eastern background nitrate $\beta_{ext}$ |
| BKPMC | 3.00 | 3.00 | Eastern background PMC $\beta_{ext}$ |
| BKSOC | 1.40 | 1.40 | Easter background organic carbon $\beta_{ext}$ |
| BKSSOIL | 0.50 | 0.50 | Eastern background soil $\beta_{ext}$ |
| BKSEC | 0.02 | 0.02 | Eastern background elem. $\beta_{ext}$ |
| BEXTRAY | 10.0 | 10.0 | Extinction due to Rayleigh scattering (1/Mm) |

Table I-4 CALPOST Processor Input Group 3: Output Options

| Parameter | Default | Value | Comments |
|---|---|---|---|
| LDOC | F | F | Print documentation image |
| IPRTU | 1 | 3 | Print output units ($\mu g/m^3$) for concentrations and ($\mu g/m^2/sec$) for deposition |
| L1HR | T | F | Report 1 hr averaging times |
| L3HR | T | F | Report 3 hr averaging times |
| L24HR | T | T | Report 24 hr averaging times |
| LRUNL | T | F | Report run-length (annual) averaging times |
| LT50 | T | F | Top 50 table |
| LTOPN | F | F | Top 'N' table |
| NTOP | 4 | 4 | Number of 'Top-N' values at each receptor |
| ITOP | 1,2,3,4 | 1,2,3,4 | Ranks of 'Top-N' values at each receptor |
| LEXCD | F | F | Threshold exceedances counts |
| THRESH1 | -1.0 | -1.0 | Averaging time threshold for 1 hr averages |
| THRESH3 | -1.0 | -1.0 | Averaging time threshold for 3 hr averages |
| THRESH24 | -1.0 | -1.0 | Averaging time threshold for 24 hr averages |
| THRESHN | -1.0 | -1.0 | Averaging time threshold for NAVG-hr averages |
| NDAY | 0 | 0 | Accumulation period, days |
| NCOUNT | 1 | 1 | Number of exceedances allowed |
| LECHO | F | F | Echo option |
| LTIME | F | F | Time series option |
| LPLT | F | F | Plot file option |
| LGRD | F | F | Use grid format instead of DATA format |
| LDEBUG | F | F | Output information for debugging? |

# Appendix J. Chapter 3 of the CENRAP BART Modeling Guidelines (Tesche, et al, 2005)

## 3.0 CALPUFF FORMULATION AND IMPLEMENTATION

The RHR relates visibility attenuation to extinction coefficient ($b_{ext}$) which is a measure of light scattering and absorption due to atmospheric constituents. Values for $b_{ext}$ are estimated using an empirically derived equation which relates the extinction coefficient to relative humidity and the following components of particulate matter mass: (a) sulfates ($SO_4$); (b) nitrates ($NO_3$); (c) organic carbon (OC); (d) elemental carbon (EC); (f) particulate matter (IP) ("crustal material"); and (g) coarse mass (CM) (i.e., $PM_{10} - PM_{2.5}$). The BART guidance requires the use of modeled concentrations of these components, together with a "humidity correction factor", to estimate values for $b_{ext}$ on all days within a three year period. These estimates, when compared with naturally occurring background extinction, are used to determine whether a source is causing or contributing to visibility impairment and also to measure the effectiveness of emissions controls on the source aimed at mitigating such effects. EPA notes that secondary particulate matter constitutes an important fraction of $PM_{2.5}$ and that the modeling requirements for secondary and primary particulate matter differ in their need to consider atmospheric chemistry and in the degree of spatial resolution needed for the modeling (EPA, 2001, pg 22).

This chapter introduces the formulation of the CALPUFF modeling system. We summarize the model capabilities as described in the user's manuals (Scire et al., 2000a,b) and discuss the capabilities and limitations of the model. Equipped with this information, states and source operators can identify those situations for which screening and/or source-specific applications of CALPUFF are appropriate.

In most cases, we expect that application of the CALPUFF system will be sufficient to meet the BART Rule requirements. For that subset of conditions requiring advanced methods, Chapter 5 provides details on full-science alternative models and available data bases for BART modeling. Such conditions might include a situation where the default modeling shows that a source just barely causes or contributes to visibility degradation or in negotiations over the final BART determination that weighs technical and economic feasibility against expected air quality benefits. In both situations, a more accurate estimate of a source's impacts may be very important to source operators.

### 3.1 Original Model Development

The CALPUFF modeling system was originally developed as a component of a three-part modeling system sponsored by the California Air Resources Board (ARB) in the mid-1980s. The ARB sought to develop a new puff-based model, a new grid-based model and an improved meteorological processor that would support application of the two. CALGRID was the urban-scale photochemical grid model resulting from the project (Yamartino et al., 1992) comparable in science and capabilities to the Urban Airshed Model (UAM-IV) (Scheffe and Morris, 1993). The model formulation was aimed at overcoming the deficiencies in EPA's steady-state Gaussian plume models that were routinely used in California for inert and linearly reactive materials (principally $SO_2$) from elevated point sources. Thus, the CALGRID model was designed to treat the complexities of urban-scale photochemical processes while CALPUFF was formulated to treat the non-steady state transport, diffusion, linear reaction, and deposition of primary pollutants from point sources. CALPUFF was not designed to address photochemical oxidants or and secondary aerosol formation production processes in a scientifically rigorous manner.

In recent years, CALPUFF and its meteorological pre-processor (CALMET) have been used in a range of regulatory modeling studies to address point source issues that include complexities posed by complex terrain, large source-receptor distances, parameterized chemical transformation and deposition, and issues related to Class I visibility impacts. These applications are more complex than the California ARB's non-steady-state, linear chemistry formulation of the mid-1980s.

The CALPUFF modeling system has been adopted by the EPA as a guideline model for source-receptor distances greater than 50 km, and for use on a case-by-case basis in complex flow situations for shorter distances. It was recommended for Class I impact assessments by the FLM Workgroup (FLAG, 2000) and the Interagency Workgroup on Air Quality Modeling (IWAQM) (EPA, 1998). As directed in the BART guidance, CALPUFF is the primary modeling system for screening and source-specific BART applications in the CENRAP region. Thus, examination of the model's formulation provides the context for assessing the extent to which it suitable for simulating the various physical processes and gas-phase, aerosol, and aqueous-phase chemical processes that influences visibility.

## 3.2 CALPUFF Model Formulation

The CALPUFF user's guide (Scire et al., 2000a) depicts the modeling system as shown in Figure 3-1. CALMET is a diagnostic/interpolation model that provides meteorological inputs to CALPUFF. These fields include hourly-averaged three-dimensional wind and temperature fields and two-dimensional fields of mixing heights and other meteorological parameters. CALMET uses routine surface and aloft meteorological observations and/or three-dimensional output from prognostic numerical models such as MM5 (Grell et al., 1995) or RUC (Benjamin et al., 2004) to construct the meteorological inputs. Other inputs to the air quality program include emissions information, receptor locations, ancillary geophysical information, and estimated concentrations of ambient pollutants that are entrained by the modeled puffs as each is carried downwind. Tables 3-1 and 3-2 summarize the key features of the CALMET/CALPUFF models as described in the user's guides.

Two post-processor routines are included to facilitate cumulative source impacts (POSTUTIL) and estimates of light extinction and visibility attenuation at Class I receptors of interest (CALPOST). In particular, CALPOST contains several options for computing change in extinction and deciviews for visibility assessments while the POSTUTIL postprocessor includes options for summing contributions of individual sources or groups of sources to assess cumulative impacts. POSTUTIL also contains an empirical nitric acid-nitrate chemical equilibrium module to estimate the cumulative effects of ammonia consumption by background sources once the simulation is completed.

### 3.2.1 Model Concept and Governing Equations

The starting point for the CALPUFF development was the choice of the fundamental reference system of which there are two: Eulerian and Lagrangian. Consistent with the original ARB design criteria, the Lagrangian (moving puff) reference system was chosen for CALPUFF. In the Eulerian approach, the behavior of pollutants is described relative to a fixed coordinate system. The Lagrangian reference frame, in contrast, relates the behavior of pollutants relative to a coordinate system that moves with the average wind. These two approaches yield different mathematical relationships for pollutant concentrations *that are equally valid*. The choice of which approach to adopt depends upon the specific design goals of the modeling system.

The advantages and drawbacks of each approach are thoroughly discussed in the literature (Tesche, 1983; Seinfeld and Pandis, 1998; Jacobson, 1999; Russell and Dennis, 2000). One of the criticisms of early Eulerian grid models was their 'over-dilution' of point source emissions into the fixed grid cells; but for the past twenty years, this limitation has been overcome through with the development of sub-grid-scale, plume-in-grid algorithms (Seigneur, et al., 1981; Godowitch, 2004; Karamchandani et al., 2005; Emery and Yarwood, 2005) and the use of multi-scale nested grids (Russell and Dennis, 2000). While the Lagrangian approach is conceptually simple, flexible, and computationally inexpensive, the governing equations are not directly applicable to situations involving non-linear chemical reactions (Seinfeld and Pandis, (1998) and it is awkward to handle a large number of sources realistically.

### 3.2.2 Transport and Dispersion

Adopting the Lagrangian concept, CALPUFF simulates the transport, dispersion, linear chemical transformation, and deposition of individual puffs carried downwind by the three-dimensional fields generated by CALMET. The model's implementation follows puffs from the near source region (a few tens of meters) to hundreds of kilometers downwind. Its puff-based formulation, in conjunction with three-dimensional hourly meteorological data, allow CALPUFF to simulate the effects of time- and space-varying meteorological conditions on pollutants emitted from a variety of source types. The major features and options of the CALPUFF model are summarized below:

<u>*Building Downwash:*</u> The Huber-Snyder and Schulman-Scire downwash models are both incorporated into CALPUFF. An option is provided to use either model for all stacks, or make the choice on a stack-by-stack and wind sector-by-wind sector basis. Both

algorithms have been implemented in such a way as to allow the use of wind direction specific building dimensions. The PRIME building downwash model (Schulman et al., 2000) is also included in CALPUFF as an option.

Dispersion Coefficients: Turbulent dispersion in CALPUFF is treated with the K-theory (flux-gradient) closure scheme, defined for a Lagrangian frame of reference. Several options are provided in CALPUFF for the computation of dispersion coefficients, including the use of turbulence measurements ($\sigma_v$ and $\sigma_w$), the use of similarity theory to estimate $\sigma_v$ and $\sigma_w$ from modeled surface heat and momentum fluxes, or the use of Pasquill-Gifford (PG) or McElroy-Pooler (MP) dispersion coefficients, or dispersion equations based on the CTDM. Options are provided to apply an averaging time correction or surface roughness length adjustments to the PG coefficients. Recently, the EPA AERMOD dispersion parameters have been included in CALPUFF and are used regularly.

Puff Sampling Functions: Puff sampling routines are included in CALPUFF to address computational difficulties encountered when applying a puff model to near-field releases. For near-field applications during rapidly-varying meteorological conditions, an elongated puff (slug) sampling function may be used. An integrated puff approach may be used during less demanding conditions. Both techniques reproduce continuous plume results under the appropriate steady state conditions.

Wind Shear Effects: A key underpinning of the Lagrangian concept is that the modeled puffs retain their identity over the time- and spatial-scale associated with the effects the model is attempting to predict (i.e., visibility impairment at 200 km or beyond) While discrete puffs emitted from a source retain their physical integrity for a period of time, at some point the action of horizontal and vertical variations in wind speed and direction (i.e. 'wind shear') shred the puff into multiple elements. These new puff parcels, composed of remnants of the old puff, continue to be diffused and dispersed by the wind. The point where significant puff shredding occurs is difficult to define since it depends substantially upon the complexity of the meteorological conditions and the underlying terrain. But when shredding occurs, the Lagrangian concept in CALPUFF breaks down. By ignoring puff shredding (i.e., by keeping puffs intact), the model will systematically over-predict pollutant concentrations.

To deal with this conceptual limitation, CALPUFF contains an optional puff splitting algorithm to simulate vertical wind shear effects across individual puffs. Differential rates of dispersion and transport among the "new" puffs generated from the original, well-mixed puff act to increase the effective rate of horizontal spread of the material as would be expected in the real atmosphere. Puffs may also be split in the horizontal when the puff size becomes large relative to the grid size to account for wind shear across the puffs. Detailed guidance on when and how the puff-splitting algorithm should be used and actual verification studies demonstrating that the technique operates as intended are not discussed in the model documentation or presented in the science literature.

*Complex Terrain:* Effects of complex terrain on puff transport are derived from the CALMET winds. In addition, puff-terrain interactions at gridded and discrete receptor locations are simulated using one of two algorithms that modify the puff-height (either that of ISCST3 or a general "plume path coefficient" adjustment), or an algorithm that simulates enhanced vertical dispersion derived from the weakly-stratified flow and dispersion module of the Complex Terrain Dispersion Model (CTDMPLUS) (Perry et al., 1989). The puff-height adjustment algorithms rely on the receptor elevation (relative to the elevation at the source) and the height of the puff above the surface. The enhanced dispersion adjustment relies on the slope of the gridded terrain in the direction of transport during the time step.

*Subgrid Scale Complex Terrain (CTSG):* An optional module, CTSG treats terrain features that are not resolved by the gridded terrain field, and is based on the CTDMPLUS (Perry et al., 1989). Plume impingement on subgrid-scale hills is evaluated at the CTSG subgroup of receptors using a dividing streamline height ($H_d$) to determine which pollutant material is deflected around the sides of a hill (below $H_d$) and which material is advected over the hill (above $H_d$). The local flow (near the feature) used to define $H_d$ is taken from the gridded CALMET fields. As in CTDMPLUS, each feature is modeled in isolation with its own set of receptors.

*Overwater and Coastal Interaction Effects:* The CALMET processor contains overwater and overland boundary layer parameterizations allowing certain of the effects of water bodies on plume transport, dispersion, and deposition to be estimated. In a sense, CALPUFF operates as a hybrid model, by utilizing gridded fields of meteorology and dispersion conditions as well as grid-based descriptions of underlying land use. This includes the abrupt changes that occur at the coastline of a major body of water.

*Dry Deposition:* A resistance model is used for the computation of dry deposition rates of gases and particulate matter as a function of geophysical parameters, meteorological conditions, and pollutant species. For particles, source-specific mass distributions may be provided for use in the resistance model. Of particular interest for BART analyses is the ability to separately model the deposition of fine particulate matter (< 2.5 µm diameter) from coarse particulate matter (2.5-10 µm diameter).

*Wet Deposition*: An empirical scavenging coefficient approach is used to compute the depletion and wet deposition fluxes due to precipitation scavenging. The scavenging coefficients are specified as a function of the pollutant and precipitation type (i.e., frozen vs. liquid precipitation).

### 3.2.3 Primary Particulates

CALPUFF is designed to simulate $PM_{10}$ or $PM_{2.5}$ or other user defined size distributions of particles. The smaller the particles, the more they disperse like an inert gas. In most cases, the dispersion of inert $PM_{2.5}$ particles will differ only slightly from that of an inert gas. A key primary $PM_{2.5}$ emission from coal-fired electric generating units (EGUs) of relevance to visibility calculations is particulate sulfate. Although primary sulfate emissions account for only a small fraction of the total sulfur emissions from such sources, it is appropriate to include their effect if reasonable estimates of primary sulfate emissions from the source are available. Treating primary sulfate emissions is likely to be most important at short distances from the stack before significant $SO_2$ to secondary sulfate conversion has taken place.

### 3.2.4 Gas-Phase Chemistry

Chemical reactions in the gas-phase play an important role in secondary aerosol formation by generating radical concentrations (e.g., the hydroxyl radical). These radical species oxidize $SO_2$ and NOx, providing the precursors to aqueous–phase chemistry (i.e., chemistry in liquid water droplets) that convert $SO_2$ to sulfate (e.g., $H_2O_2$ and $O_3$), and form condensable gases from some volatile organic compounds (VOCs) that can then condense into particulate secondary organic aerosols (SOA). The levels of NOx, VOC, and $O_3$ concentrations along with the reactivity of the VOCs, sunlight, temperature, and water vapor are all key variables that influence the radical cycle and consequent sulfate and nitrate formation rates.

CALPUFF neglects realistic gas-phase processes entirely. The chemistry in CALPUFF parameterizes chemical transformation effects using five species ($SO_2$, $SO_4^{=}$, $NO_x$, $HNO_3$, and $NO_3^-$) via a set of user-specified, diurnally-varying transformation rates. The model estimates secondary fine particulate matter (sulfate and nitrate) from emissions of gas-phase $SO_2$ and $NO_x$. Rather than simulating important non-linear gas phase oxidant chemistry, the model employs a user-supplied hourly ozone concentration as a surrogate for the hydroxyl radical and other oxidizing radical species. Ambient ammonia concentrations are also a user input along with temperature and relative humidity.

Although simplifications of photochemistry have been attempted in the past, correct representation of the gas-phase photochemistry and the radical cycles are critically important in order to properly characterize sulfate and nitrate formation in the real atmosphere. Seigneur et al., (2000) demonstrated this fact in their evaluation of full-science representations of photochemistry against simplified representations (but more advanced than CALPUFF). They concluded that simplified linearized transformation schemes are inadequate for describing sulfate and nitrate formation processes:

> "These results indicate that the accurate prediction of source-receptor relationships for $PM_{2.5}$ requires a comprehensive treatment of $PM_{2.5}$ formation from gaseous precursors for the secondary components of $PM_{2.5}$ and a spatially resolved treatment of transport processes for primary $PM_{2.5}$. Simplified treatments of either atmospheric chemistry or transport are appropriate only when the secondary or primary components of $PM_{2.5}$, respectively, are not significant. Therefore, the development of source-receptor relationships for $PM_{2.5}$ should be based on air quality models that provide comprehensive descriptions of atmospheric chemistry and transport."

Morris et al., (1998) also compared the sulfate and nitrate particulate estimates from a comprehensive full-science regional model with those from a model incorporating a simplified empirical chemical mechanism developed in a manner similar to the mechanism in CALPUFF. Evaluating the full-science and empirical chemistry models against observed concentrations, Morris and co-workers concluded:

> "Given the importance of the radical cycle for determining secondary PM formation rates, it appears that empirical gas-phase algorithms are inadequate for determining secondary PM formation."

The uncertainty and potential biases introduced into the CALPUFF visibility estimates due to neglect of gas phase oxidant chemistry remain unknown.

### 3.2.5 Aerosol Chemistry

Formation of secondary fine particulate matter (e. g., nitrates, sulfates, organic aerosols) in point source plumes is strongly dependent on the rate of mixing with ambient (background) air and the chemical composition of this background. The rates of oxidation of sulfur dioxide ($SO_2$) and nitrogen dioxide ($NO_2$) to sulfate and nitric acid can be very different within a power plant or industrial plume compared to that in the background air (Gillani and Godowitch, 1999; Karamchandani et al., 2000). Similarly, the formation of secondary organic aerosols from emitted VOCs and those from other anthropogenic and biogenic sources, adds yet another pathway in the formation of visibility-impairing aerosols. The presence of atmospheric ammonia introduces further nonlinearities into the gas phase and aerosol reactions. Accordingly, for a model to realistically simulate the production of secondary particulate sulfate, nitrate, and organic aerosols from a potential BART source, the mixing processes and chemical reactions within and outside of the plume must be treated realistically. If the chemical interactions between these two fundamentally different and interactive chemical environments are overly-simplified or neglected altogether, the ability of the model to correctly calculate plume concentrations, deposition, or visibility impacts is lost.

*Sulfate and Nitrate Formation.* Two $SO_2$ and NOx chemical transformation schemes are available in CALPUFF: the MESOPUFF-II algorithm (Scire et al., 1983; Atkinson et al., 1982) and the RIVAD algorithm (Latimer et al., 1986). These algorithms calculate sulfate and nitrate formation rates based on the puff concentrations, background environmental parameters provided by CALMET, and background ozone and ammonia concentrations provided as input by the user. SOA particulates are not treated by either mechanism. The parameters used are as follows (note that each method does not use all of these parameters).

Puff Average Concentrations (from CALPUFF)

- NOx concentration
- $SO_2$ concentration

Environmental Parameters (from CALMET)

- Temperature
- Surface Relative Humidity (RH)
- Atmospheric Stability
- Solar Radiation

Background Concentrations (User Input)

- Ozone ($O_3$)
- Ammonia ($NH_3$)

The MESOPUFF-II chemical transformation scheme is EPA's recommended approach for Class I area impact assessment (IWAQM, 1998). It entails pathways for five active pollutants ($SO_2$, $SO_4$, NOx, $HNO_3$, and $NO_3$) as follows:

$$SO_2 \xrightarrow{k_1} SO_4$$

$$NOx \xrightarrow{k_2} HNO_3\ (+RNO_3)$$

$$NOx \xrightarrow{k_3} HNO_3$$

$$HNO_3\ (g) \overset{NH_3}{\longleftrightarrow} NO_3\ (PM)$$

where,

$SO_2$ is the puff average sulfur dioxide concentration;
NOx is the puff average oxides of nitrogen concentrations;
$SO_4$ is sulfate concentrations formed from the $SO_2$;
$HNO_3$ is the nitric acid formed from the NOx;
$NO_3$ is the particulate nitrate that is in equilibrium with the nitric acid; and
$NH_3$ is the background ammonia concentration.

Daytime Rates

$k_1 = 36 \times R^{0.55} \times [O_3]^{0.71} \times S^{-1.29} + k_{1(aq)}$

$k_{1(aq)} = 3 \times 10^{-8} \times RH^4$ (added to $k_1$ above during the day)

$k_2 = 1206 \times [O_3]^{1.5} \times S^{-1.41} \times [NOx]^{-0.33}$

$k_3 = 1261 \times [O_3]^{1.45} \times S^{-1.34} \times [NOx]^{-0.12}$

Nighttime Rates

$k_1 = 0.20$ (%/hr)
$k_2 = 0.00$ (%/hr)
$k_3 = 2.00$ (%/hr)

with,

| | |
|---|---|
| $k_1$ | is the $SO_2$ to $SO_4$ gas-phase transformation rate (%/hr) |
| $k_{1(aq)}$ | is the $SO_2$ to $SO_4$ aqueous-phase transformation rate (%/hr) |
| $k_2$ | is the NOx to $HNO_3$+$RNO_3$ transformation rate (%/hr) |
| $k_3$ | is the NOx to $HNO_3$ (only) transformation rate (%/hr) |
| S | is the stability index ranging from 2 to 6 (PGT class A&B=2, C=3, D=4, E=5, F=6) |
| R | is the total solar radiation intensity ($kw/m^2$) |
| RH | is the relative humidity (%) |
| [$O_3$] | is the user provided background ozone concentrations (ppm) |
| [NOx] | is the plume average NOx concentration (ppm) |
| $NH_3$ | is the user provided background ammonia concentrations |

Daytime chemical transformations are based on statistically analyzed hourly transformation rates (Scire et al., 1983) obtained from box model simulations using the Atkinson et al., (1982) photochemical mechanism. In this scheme, gas-phase oxidation of $SO_2$ and NOx depends on the hydroxyl (OH) radical concentrations for which background ozone, solar intensity (R), and stability index are used as surrogates. At night, OH concentrations are much lower and default $SO_2$ and NOx oxidation rates of 0.2 %/hr and 2.0 %/hr are assumed. The $k_{1(aq)}$ sulfate formation rate is added to the $k_1$ rate during the day as a surrogate for aqueous-phase sulfate formation which begins to assume importance above approximately 50% RH (~0.2 %/hr sulfate formation rate) and peaks at 100% RH (3%/hr sulfate formation rate).

The sulfate and nitrate formation rate equations used in the MESOPUFF II scheme were originally generated by developing regression equations for a few key variables on the results of 144 box model simulations that used the 1982 photochemical mechanism of Atkinson et al. These box model simulations varied ambient temperature, ozone concentration, sunlight intensity, VOC concentrations, atmospheric stability, and plume NOx concentrations as shown in Table 3-1. The actual environmental conditions used to generate the sulfate and nitrate transformation equations were extremely limited. For example, the transformation rates did not cover temperatures below 10 deg C (50 deg F) or cleaner rural atmospheric conditions with VOC concentrations less than 50 ppbC.

The CALPUFF MESOPUFF-II chemistry clearly neglects several environmental parameters and chemical processes that are important in simulating sulfate and nitrate formation in $NO_X/SO_2$ emissions source plumes. In many cases these deficiencies lead to an overestimation bias of the source's sulfate and nitrate impacts. Factors that lead such a bias include:

Lack of Temperature Effects: Photochemistry is known to be highly temperature sensitive, as evidenced by the fact that elevated ozone concentrations tend to occur on hot summer days. Lower temperatures produce lower OH and other radical concentrations and consequently lower sulfate and nitrate formation rates. The CALPUFF sulfate and nitrate formation rates, however, do not adequately incorporate temperature effects. The MESOPUFF-II chemical transformation algorithm was developed under conditions with a minimum temperature of only

10° C (50° F). Thus, under conditions colder than 10° C, CALPUFF will overpredict sulfate and nitrate formation rates and impacts. CALPUFF typically estimates maximum sulfate and visibility impacts during the late fall/early spring and winter months; these are the same months when the CALPUFF overestimation bias from not considering temperature effects will be greatest. In addition, under colder temperatures, NOx will be converted to peroxyacetyl nitrate (PAN) so that the NOx is no longer available to be converted to nitrate. Since the CALPUFF chemistry ignores the PAN sink for NOx, it will systematically overpredict nitrate impacts.

<u>Effects of NOx Emissions on Sulfate Chemistry</u>: Downwind of a point source with significant NOx/$SO_2$ emissions, high NOx and $SO_2$ concentrations co-exist. Under high NOx concentrations, radical concentrations are greatly reduced, resulting in very low ozone, sulfate, and nitrate formation rates. This is due to the NOx inhibition effect on photochemistry whereby: (1) the titration of NO with ozone eliminates ozone and its source as a radical generator; and (2) the high $NO_2$ concentrations eliminate the OH radical via the $NO_2$ + OH reaction thereby effectively shutting down photochemistry. Thus, in a NOx/$SO_2$ point source plume near the source, there will be very low OH radical and ozone concentrations and consequently very low sulfate and nitrate formation. Since the simple MESOPUFF-II transformation equations cannot account for the NOx effect on the sulfate formation, CALPUFF will tend to over-predict sulfate formation rate in a NOx/$SO_2$ point source plume near the source, which in turn leads to overstating the sulfate formation rate. Because NOx/$SO_2$ point sources are typically buoyant, they are frequently be emitted aloft in a stable layer where the high NOx concentrations and inhibited sulfate and nitrate formation rates could persist 100 km or more downwind.

*<u>Aqueous-Phase Sulfate Formation Algorithm.</u>* CALPUFF's MESOPUFF-II chemistry treats aqueous-phase sulfate formation solely as a function of relative humidity (RH), which actually has no direct affect on aqueous-phase sulfate formation chemistry. The CALPUFF MESOPUFF-II aqueous-phase sulfate formation rate ranges from values of approximately 0.2 %/hr at 50% RH to 3.0 %/hr at 100% RH. Relative humidity (RH) is a measure of the content of water vapor in the atmosphere. However, in reality aqueous-phase sulfate formation will depend on the amount of atmospheric liquid water content (LWC) in cloud or fog droplets, the pH of the water droplets, and the level of $H_2O_2$, ozone, and $SO_2$ concentrations. Accordingly, in the atmosphere, aqueous-phase sulfate formation chemistry is not affected by RH. Thus, the CALPUFF aqueous-phase chemistry parameterization is incorrect. Although under conditions of clouds and fog there will be high RH, the occurrence of high RH with very little or no clouds or fog can be quite frequent.

In a liquid water droplet, the reaction of $SO_2$ with $H_2O_2$ to form sulfate is essentially instantaneous and is usually limited by the amount of $H_2O_2$ present (i.e., oxidant limited) for a NOx/$SO_2$ point source. Once the $H_2O_2$ is reacted away within the water droplet, sulfate formation via this pathway slows to the rate of $H_2O_2$ formation, which would be extremely slow to nonexistent in a large point source plume due to the scavenging of radicals by the high NOx concentrations. This introduces an inaccurate representation of sulfate formation in CALPUFF that creates uncertainties and bias in modeled visibility impacts. Whether this uncertainty results in an under- or overestimate of sulfate formation is difficult to determine since the approach is scientifically invalid. Under conditions of high RH and little clouds or little plume interaction with clouds, it will clearly overstate sulfate formation. However, under conditions of cloudy conditions with available photochemical oxidants (i.e., $H_2O_2$ and $O_3$) and a dilute NOx/Sox point source plume, it may understate sulfate formation. Near large NOx/$SO_2$ point source where the elevated NOx concentrations scavenge and limit photochemical oxidants, the MESOPUFF-II algorithm will likely overstates sulfate formation.

Thus, the CALPUFF aerosol chemistry fails to account for many environmental parameters that are necessary to simulate sulfate and nitrate formation rates, including VOCs and their reactivity, temperature, liquid water content, and NOx concentrations. In their evaluations against full-science PM models and observations, Seigneur et al., (2000) and Morris et al., (1998) both independently found that the empirical chemistry modules, such as employed by CALPUFF, are inadequate for estimating sulfate and nitrate formation**.** These findings are supported by EPA's $PM_{2.5}$ and Regional Haze SIP modeling guidance (EPA, 2001) that recommends against using Lagrangian models such as CALPUFF for simulating secondary PM.

From the foregoing, it is clear that the CALPUFF chemical transformation algorithms neglect important chemical processes necessary to accurately estimate the sulfate and nitrate impacts due to $SO_2$ and $NO_X$ emissions. Given that EPA recommends the model for BART determinations, a key question is "What is the influence of the simplified chemistry on modeled estimates of visibility impacts from BART sources? In some cases, the inadequacies in the CALPUFF chemistry algorithms may simply introduce broader uncertainties into the calculation of estimated sulfate and nitrate impacts. In many cases, however, the simplifications made in the CALPUFF description of chemical processes result in a systematic bias in the estimated concentrations and visibility impacts due to $SO_2$ and $NO_X$ emissions sources. For large point sources that emit $SO_2$ and NOx emissions, such as EGUs, petrochemical process heaters, cement plant kilns, etc., many of the limitations in the CALPUFF MESOPUFF-II $SO_2$ and NOx transformation algorithms would result in an overestimation bias. While models that are systematically biased high (i.e., over-predict impacts) may be appealing to regulatory decision-makers because they are 'conservative', the overprediction tendency may well lead to unwarranted and excessive control of emissions from some sources. Thus, the tradeoff between simplicity and conservativism on the one hand and technical credibility and unbiased answers on the other is a key element in the negotiation of modeling protocols developed by the states or source operators.

### 3.2.6 Surface Removal

An especially important contributor to particulate concentrations is the rate of deposition to the surface. $PM_{2.5}$ particles, which have a mass median diameter around 0.5

µm, have an average net deposition velocity of about 1 cm/min (or about 14 m/day) and thus the deposition of fine particles is not usually significant except for ground-level emissions. On the other hand, coarse particles (those $PM_{10}$ particles larger than $PM_{2.5}$) have an average deposition velocity of more than 1 m/min (or 1440 m/day), which is significant, even for emissions from elevated stacks.

CALPUFF includes parametric representations of particle and gas deposition in terms of atmospheric, deposition layer, and vegetation layer "resistances" and, for particles, the gravitational settling speed. Gravitational settling, which is of particular importance for the coarse fraction of $PM_{10}$, is accounted for in the calculation of the deposition velocity. Effects of inertial impaction (important for the upper part of the $PM_{10}$ distribution) and Brownian motion (important for small, sub-micron particles) and wet scavenging are also addressed. The BART guidance recommends that fine particulate matter (less than 2.5 µm diameter), which has higher light extinction efficiency than coarse particulate matter (2.5-10 µm diameters), should be treated separately in the model. CALPUFF allows for user-specified size categories to be treated as separate species, which includes calculating size-specific dry deposition velocities for each size category.

## 3.3 CALMET Meteorological Preprocessor

The CALMET meteorological model consists of a diagnostic wind field module and micrometeorological modules for over-water and overland boundary layers. When modeling a large geographical area such as the CENRAP domain, the user has the option to use a Lambert Conformal Projection coordinate system to account for Earth's curvature. The major features and options of the meteorological model are summarized in Table 3-1. The techniques used in the CALMET model are briefly described below.

### 3.3.1 Boundary Layer Modules

The CALMET processor contains two boundary layer modules for application to overland and overwater grid cells.

*Overland Boundary Layer Module:* Over land surfaces, the energy balance method of Holtslag and van Ulden (1983) is used to compute hourly gridded fields of the sensible heat flux, surface friction velocity, Monin-Obukhov length, and convective velocity scale. Mixing heights are determined from the computed hourly surface heat fluxes and observed temperature soundings using a modified Carson (1973) method based on Maul (1980). The module also determines gridded fields of PGT stability class and hourly precipitation rates.

*Overwater Boundary Layer Module:* The aerodynamic and thermal properties of water surfaces suggest that a different method is needed for estimating boundary layer parameters in the marine environment. A profile technique, using air-sea temperature differences, is used in CALMET to compute the micro-meteorological parameters in the marine boundary layer. An upwind-looking spatial averaging scheme is optionally applied to the mixing heights and three-dimensional temperature fields in order to account for important advective effects.

### 3.3.2 CALMET Diagnostic Wind Field Module

The CALMET wind model was constructed from two other meteorological models used in California in the late 1970s. One was the California Institute of Technology (CIT) mass consistent interpolation model described by Goodin et al., (1980). The other was the Complex Terrain Wind Model (CTWM) developed at Systems Applications, Inc. (Tesche and Yocke, 1978; Yocke and Liu, 1978). The CTWM terrain adjustments used to modify the flow fields were assembled in the 1970s as part of research into fire spread and avalanche forecasting in mountainous regions of California. Various heuristic algorithms were developed to approximate down slope drainage flows, terrain blocking and channeling (Geiger, 1965), thermal heat islands (Stern and Malkus, 1953), surface friction retardation, capping by an elevated inversion and so on. These algorithms were based on empirical studies in wind tunnels, numerical modeling experiments, and field studies in the Alps, some dating back to the 1930s (Defant, 1933). Later work by Tesche et al., (1986), Kessler et al., (1987) and Douglas and Kessler (1988) integrated the CIT and CTWM modeling system into a single meteorological model that included algorithms to blend observational data with prognostic meteorological model output. The combined model was used extensively for urban-scale ozone studies throughout the U.S. prior to the switch to MM5 as the preferred meteorological model for SIP studies in the mid-1990s.

The CALMET model development incorporated the main features of the CTWM and CIT wind model and significantly updated the physical parameterizations and improved model input/output (I/O) schemes (Scire et al., 2000a). Today, CALMET uses the CTWM two-step approach to the computation of the wind fields. In the first step, an 'initial-guess' wind field is constructed and then adjusted to approximate the kinematic effects of terrain, slope flows, and terrain blocking. Currently, the gridded MM5 field is used as the initial guess prior to terrain-perturbation. The second step consists of an objective analysis procedure to blend the MM5 field with observational data to produce a final wind field. This introduction of observational data in the second step of the CALMET wind field development is optional. It is also possible to run the model in "no observations" (No-Obs) mode, which involves the use only of MM5 gridded data for the initial guess field followed by fine-scale terrain adjustments on the scale of the CALMET domain.

Normally, the CALMET computational domain is specified to be at smaller grid spacing than the MM5 dataset used to initialize the initial guess field. For example, 36/12 km MM5 data sets available for 2000-2003 over the CENRAP domain have been used to develop the 6 km CALMET grids shown in Figures 5-1 through 5-4.

The current thermal, kinematic, and dynamic effects parameterized in CALMET, used in the first step of the windfield development, are as follows:

*Kinematic Effects of Terrain:* The CTWM algorithms for kinematic effects (Liu and Yocke, 1980) is used to evaluate the influence of the terrain on the wind field. The initial guess field winds are used to compute a terrain-forced vertical velocity, subject to an exponential, stability-dependent decay function. The effects of terrain on the horizontal wind components are evaluated by applying a divergence-minimization scheme to the initial guess wind field. The divergence minimization scheme is applied iteratively until the three-dimensional divergence is less than a threshold value.

*Slope Flows*: The original slope flow algorithm (Defant, 1933) has been upgraded (Scire and Robe, 1997) based on the shooting flow algorithm of Mahrt (1982). This scheme includes both advective-gravity and equilibrium flow regimes. At night, the slope flow model parameterizes the flow down the sides of the valley walls into the floor of the valley, and during the day, upslope flows are parameterized. The magnitude of the slope flow depends on the local surface sensible heat flux and local terrain gradients. The slope flow wind components are added to the wind field adjusted for kinematic effects.

*Blocking Effects:* The thermodynamic blocking effects of terrain on the wind flow are parameterized in terms of the local Froude number (Allwine and Whiteman, 1985). If the Froude number at a particular grid point is less than a critical value and the wind has an uphill component, the wind direction is adjusted to be tangent to the terrain.

### 3.4 Estimation of Regional Haze Contributions

The default procedure for quantifying visibility impacts is described in several documents (IWAQM, 1998; FLAG, 2000). Implementation of these procedures in CALPUFF is described in the user's documentation (Scire et al., 2000b). Generally, 'visibility' may be quantified either by visual range (the greatest distance that a large object can be seen) or by the light extinction coefficient, which is a measure of the light attenuation per unit distance due to scattering and absorption by gases and particles. Visibility is impaired when light is scattered in and out of the line of sight and by light absorbed along the line of sight. The light extinction coefficient ($b_{ext}$) considers light extinction by scattering ($b_{scat}$) and absorption ($b_{abs}$):

$$b_{ext} = b_{scat} + b_{abs}$$

The scattering components of extinction ($b_{scat}$) are represented by light scattering due to air molecules (i.e., Rayleigh scattering, $b_{rayleigh}$) and light scattering due to particles, $b_{sp}$. The absorption components of extinction ($b_{abs}$) include light absorption due to gases ($b_{ag}$) and particles ($b_{ap}$). Furthermore, particle scattering, $b_{sp}$, can be expressed by its components:

$$b_{sp} = b_{SO4} + b_{NO3} + b_{OC} + b_{SOIL} + b_{Coarse}$$

where the chemical species and soot scattering coefficients are given as:

$b_{SO4}$ = 3 [$(NH_4)_2SO_4$] f(RH)

$b_{NO3}$ = 3 [$NH_4NO_3$]f(RH)

$b_{OC}$ = 4 [OC]

$b_{SOIL}$= [Soil]

$b_{Coarse}$= 0.6 [Coarse Mass]

$b_{ap}$ = 10 [EC]

The numeric coefficient at the beginning of each equation is the dry scattering or absorption efficiency in meters-squared per gram. The f(RH) term is a monthly-average relative humidity adjustment factor. The terms in the brackets are the estimated concentrations fro CALPUFF (or other model) in micrograms per cubic meter (μg/$m^3$).

Finally, the total atmospheric extinction is estimated as:

$$b_{ext} = b_{SO4} + b_{NO3} + b_{OC} + b_{SOIL} + b_{Coarse} + b_{ap} + b_{rayleigh}$$

or, substituting in the above terms,

$$b_{ext} = 3\ f(RH)\ [(NH_4)_2SO_4] + 3\ f(RH)\ [NH_4NO_3] + 4[OC] + 1[Soil] + 0.6[Coarse\ Mass] + 10[EC] + b_{Ray} \quad (3\text{-}1)$$

This is the so-called IMPROVE extinction equation currently recommended by EPA (2003). Note that the sulfate ($SO_4$) and nitrate ($NO_3$) components are hygroscopic because their extinction coefficients depend upon relative humidity. The concentrations, in square brackets, are in μg/$m^3$ and $b_{ext}$ is in units of $Mm^{-1}$. The Rayleigh scattering term ($b_{Ray}$) has a default value of 10 $Mm^{-1}$, as recommended in EPA guidance for tracking reasonable progress (EPA, 2003a). The effect of relative humidity variability on the extinction coefficients for $SO_4$ and $NO_3$ can be estimated in several ways, but following the EPA BART guidelines, the Class I area-specific monthly f(RH) values shown in Table 6-1 should be used.

Modeled ground level concentrations of each of the above visibility impairing pollutants are used with the IMPROVE equation to deduce the extinction coefficient. The change in visibility (measured in terms of 'deciviews') is compared against background conditions. The delta-deciview, Δdv, value is calculated from the source's contribution to extinction, $b_{source}$, and background extinction, $b_{background}$, as follows:

$$\Delta dv = 10\ ln((b_{background} + b_{source}) / b_{background})$$

The impact of a source is determined by comparing the Δdv, or haze index (HI), for estimated natural background conditions with the impact of the source and without the impact of the source. *If the Δdv value is greater than the 0.5 dv threshold the source is said to contribute to visibility impairment and is thus subject to BART controls.*

CALPOST uses a previous IMPROVE *f(RH)* curve (FLAG, 2000) which differs slightly from the *f(RH)* now used by IMPROVE and EPA (2003), mainly at high relative humidity. Also, CALPOST sets the maximum *RH* at 98% by default (although the user can change it), while the EPA's guidance now caps it at 95% (easily modified in the CALPUFF input file).

For regional haze light extinction calculations, use of a plume-simulating model such as CALPUFF is appropriate only when the plume is sufficiently diffuse that it is not visually discernible as a plume *per se*, but nevertheless its presence could alter the visibility through the background haze. The IWAQM Phase 2 report states that such conditions occur starting 30 to 50 km from a source. This is consistent with the BART guidance recommendation for using CALPUFF for source-receptor distances greater than 50 km. But, CALPUFF is also recommended by EPA as an option that can be considered for shorter transport distances when the plume may in fact be discernible from the background haze.

Apart from the chemistry issues discussed previously, there do not appear to be any major reasons why CALPUFF cannot be used for even shorter transport distances than 30 km, as long as the scale of the plume is larger than the scale of the output grid so that the maximum concentrations and the width of the plume are adequately represented and so that the sub-grid details of plume structure can be ignored when estimating effects on light extinction. The standard 1-km output grid that has been established for Class I area analyses should serve down to source-receptor distances somewhat under 30 km; how much closer than 30 km will depend on the topography and meteorology of the area and should be evaluated on a case-by-case basis with individual CENRAP State modelers. (For reference, the width of a Gaussian plume, $2\sigma_y$, is roughly 1 km after 10 km of travel distance, assuming Pasquill-Gifford dispersion rates under neutral conditions.)

### 3.4.1 CALPOST Methods

Calculation of the impact of the simulated plume particulate matter component concentrations on light extinction is carried out in the CALPOST postprocessor. For BART applications, this processor is of considerable importance.

CALPOST is used to process the CALPUFF outputs, producing tabulations that summarize the results of the simulations, identifying for example, the highest and second-highest hourly-average concentrations at each receptor. When performing visibility-related modeling, CALPOST uses concentrations from CALPUFF to compute light extinction and related measures of visibility (deciviews), reporting these for a 24-hour averaging time. The CALPOST processor contains several options for evaluating visibility impacts, including the method described in the BART guidance, which uses monthly average relative humidity values. CALPOST contains implementations of the IWAQM-recommended and FLAG-recommended visibility techniques and additional options to evaluate the impact of natural weather events (fog, rain and snow) on background visibility and visibility impacts from modeled sources. CALPOST uses Equation 3-1 to calculate the extinction increment due to the source of interest and provides various methods for estimating the background extinction against which the increment is compared in terms of percent or deciviews.

For background extinction, the CALPOST processor contains seven techniques for computing the change in light extinction due to a source or group of sources (i.e., Methods 1 through 7). These are usually reported as 24-hour average values, consistent with EPA and FLM guidance. In addition, there are two techniques for computing the 24-hour average change in extinction (i.e., as the ratio of 24-hour average extinctions, or as the average of 24-hour ratios). Method 2 is the current default, recommended by both IWAQM (EPA, 1998) and FLAG (2000) for source-specific. Method 6 is recommended by EPA's BART guidance (70 FR 39162).

In Method 2, user-specified, speciated monthly concentration values are used to describe the background. When applied to natural conditions, for which EPA's default natural conditions concentrations are annual averages, the same component concentrations would have to be used throughout the year (unless potential refinements to those default values resulted in concentrations that vary during the year). Hourly background extinction is then calculated using these concentrations and hourly, site-specific *f(RH)* from a 1993 IWAQM curve or, optionally, the EPA regional haze f(RH) curve.[2] Again the *RH* is capped at either 98% (default) or a user-selected value (most commonly at 95%).

Method 6 is similar to Method 2, except monthly f(RH) values (e.g., EPA's monthly climatologically representative values) are used in place of hourly values for calculating both the extinction impact of the source emissions and the background conditions extinction. Hourly source impacts, with the effect on extinction due to sulfates and nitrates calculated using the monthly-average relative humidity in f(RH), are compared against the monthly default natural background concentrations. Thus the monthly-averaged relative humidity is applied to the hygroscopic components (i.e., sulfate and nitrate) of both the source impact and the background extinction with Method 6.

[2] Note that the hourly-varying natural background extinction here is not consistent with that prescribed by the EPA's natural conditions guidance (EPA, 2003b), for which a "climatologically-representative" f(RH) that only varies monthly is to be used. Method 6 uses these monthly average humidity values.

### 3.4.2 POSTUTIL

The POSTUTIL processor allows the cumulative impacts of multiple sources from different simulations to be summed, including computing the difference between two sets of predicted impacts (useful for evaluating the benefits of BART controls). It also contains a chemistry module to evaluate the equilibrium relationship between nitric acid and nitrate aerosols. This capability allows the potential non-linear effects of ammonia scavenging by background sulfate and nitrate sources to be approximated in the formation of nitrate from an individual source. The processor can compute the impacts of individual sources or groups of sources on sulfur and nitrogen deposition into aquatic, forest and coastal ecosystems, thereby allowing changes in deposition fluxes resulting from changes in emissions to be quantified.

The POSTUTIL processor attempts to overcome the bias introduced when CALPUFF assumes that the full background ammonia concentration is entrained into each discrete puff. For a single puff, this may be satisfactory, but the model overestimates the production of ammonium nitrate when multiple puffs co-exist and overlap. The POSTUTIL processor re-partitions the ammonia and nitric acid concentrations to conform to the ammonia-limiting processes influencing nitrate formation. Though based on recognized science, this approximate post-processing method is fundamentally dependent on reliable estimates of ambient $NH_3$ at the Class I receptor of interest.

### 3.4.3 Refined Extinction and Background Visibility Estimates

EPA, the IMPROVE Steering Committee, and the RPOs are evaluating whether refinements are warranted to the methods recommended for calculating extinction and the default estimate of natural background visibility. Whether EPA will approve of any changes to the IMPROVE equation is uncertain at this time. Also, the responsibility for incorporating any changes to the algorithms in CALPUFF (e.g., new f(RH) curves) is unclear. If changes to these methods are recommended by EPA, CENRAP is encouraged to adopt them. However, details of the process for incorporation of any refinements to the IMPROVE equations in the CALPUFF system should be addressed in the State's or source operators modeling protocol.

## 3.5 Model Availability

The EPA-approved version of the CALPUFF modeling system is available from Earth Tech, Inc., (http://www.src.com/calpuff/calpuff1.htm). The main models (CALMET, CALPUFF, and CALPOST), their GUIs, and many of the processors are available to download. One may also register to receive notices of model updates. The most recent update to the system (25 May 2005) is a new version of CALMM5 (MM5 V3) that has been added to the Download BETA-Test page. This version of CALMM5 processes MM5 Version 3 output data directly.

Earth Tech offers CALPUFF training courses that include a description of the technical formulation of the models, overviews of each of the processor programs, and hands-on application of the models to several case study data sets. Attendees of the course receive a training notebook, a workbook of case study problems, exercises, and data sets, updates on recent and future model enhancements, and the latest (proprietary) versions of the models and Graphical User Interfaces (GUIs). Other third-party training courses and materials are also available.

### 3.6 CALPUFF Evaluation Studies

Tesche (2002, 2003) reviewed results of various CALPUFF evaluation studies and reached the following conclusions:

> There is a paucity of model evaluation information for CALPUFF at scales of 50 to 200 km and beyond;

> Based on the limited information available, CALPUFF may be able to give unbiased estimates of short-term (i.e., 3-10 hr) concentrations of *non-reactive contaminants* to within a factor of two (e.g. 200%) out to distances of about 200 km from a source. This level or uncertainty in a 200 km radius around a source is increased if one examines CALPUFF's predictions in a particular modeling cell (e.g., one containing a population center) at a specific hour as opposed to considering the question of bias generally over the entire 200 km region irrespective of location and time of occurrence;

> For time periods of a day or less, CALPUFF is unable to produce reliable predictions of non-reactive concentrations at a specific location and time;

> What limited experimental data do exist suggest that the accuracy and reliability of the model's predictions degrade as the distance scale increases;

> While the IWAQM recommendations on the range of applicability of the CALPUFF model (50 to 200 km) rests on very sparse model evaluation information, EPA's suggestion that the model can be used for scales beyond 200 km, even with case-by-case approval, is not based on model evaluation data; and

> For chemically reactive pollutants such as $SO_2$, $NO_x$, sulfate, nitrate, nitric acid, and other secondary reaction products, the testing of CALPUFF model over extended spatial scales (50 km and beyond) has not been attempted in a rigorous manner.

Scire et al., (2001) report an evaluation of CALPUFF sulfate, nitrate, light extinction, and sulfur and nitrogen deposition at a Class I areas over a range of source-receptor distances. In this study, in which a large number of sources were modeled simultaneously, sulfate and nitrate predictions at the CASTNet monitoring site in Pinedale, Wyoming were evaluated against observations, and light extinction predictions were evaluated using transmissometer measurements. Wet sulfur and nitrogen predictions were compared to observations at several acid deposition monitoring sites. This study is especially relevant because it evaluates the performance of the model to predict variables of direct interest in Class I visibility analyses, such as sulfate and nitrate concentrations and light extinction coefficients

More recently, Chang et al., (2003) reported an intercomparison of CALPUFF with two other transport and dispersion models with high resolution field data. CALPUFF predictions for inert $SF_6$ were compared using two recent mesoscale field datasets: the Dipole Pride 26 (DP26) and the Overland Along-wind Dispersion (OLAD). Both field experiments involved instantaneous releases of sulfur hexafluoride tracer gas in a mesoscale region with desert basins and mountains. Tracer concentrations were observed along lines of samplers at distances up to 20 km. CALPUFF predictions were evaluated using the maximum 3-h dosage (concentration integrated over time) along a sampling line. At the DP26 sampler array, CALPUFF had mean biases within 35% and random scatters of about a factor of 3–4. About 50%–60% of the CALPUFF predictions were within a factor of 2 of the observations. At the OLAD site, the model underpredicted by a factor of 2–3, on average, with random scatters of a factor of 3–7. Only about 25%–30% of the CALPUFF predictions of inert $SF_6$ were within a factor of 2 of observations.

The tracer studies with which CALPUFF transport and diffusion capabilities were evaluated in the IWAQM Phase 2 report were generally over distances greater than 50 km. More recently, model performance has been performed at shorter distances including a power plant in Illinois in simple terrain at source-receptor distances in arcs ranging from 0.5 km to 50 km from the stack (Strimaitis et al., 1998). Another CALPUFF evaluation study over short-distances is reported by Morrison et al. (2003). These studies address model performance over source-receptor distances from a few hundred meters to 50 km.

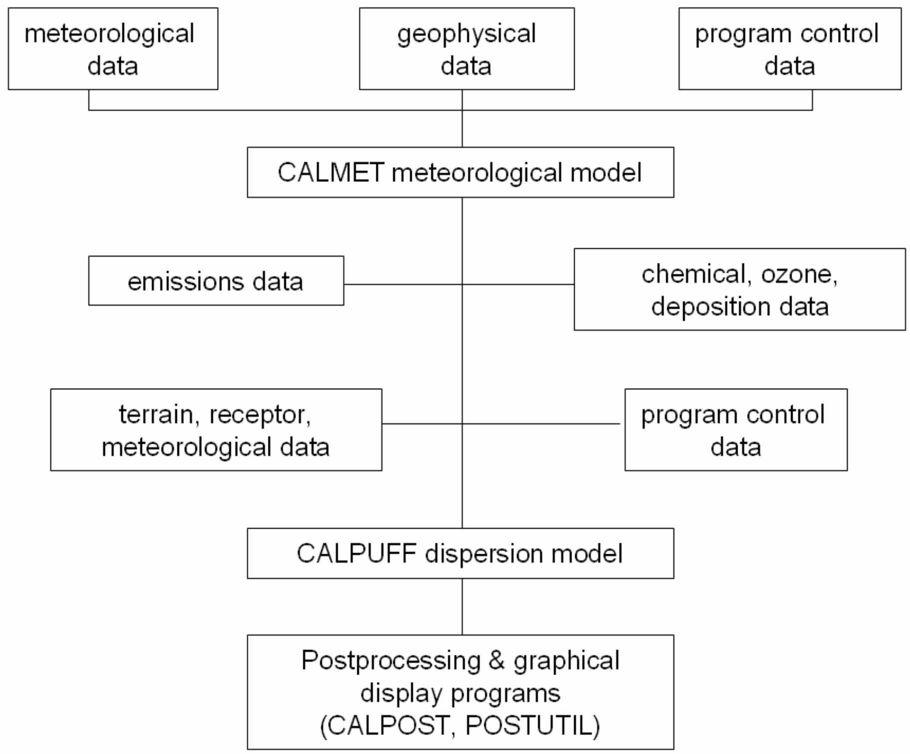



**Figure 3-1. CALPUFF Modeling System Components. (Scire et al., 2000a)**

**Table 3-1. Major Features of the CALMET Meteorological Model. (Scire et al., 2000b)**

- **Boundary Layer Modules of CALMET**
  - Overland Boundary Layer - Energy Balance Method
  - Overwater Boundary Layer - Profile Method
  - Produces Gridded Fields of:
    - -- Surface Friction Velocity
    - -- Convective Velocity Scale
    - -- Monin-Obukhov Length
    - -- Mixing Height
    - -- PGT Stability Class
    - -- Air Temperature (3-D)
    - -- Precipitation Rate

- **Diagnostic Wind Field Module of CALMET**
  - Slope Flows
  - Kinematic Terrain Effects
  - Terrain Blocking Effects
  - Divergence Minimization
  - Produces Gridded Fields of U, V, W Wind Components
  - Inputs Include Domain-Scale Winds, Observations, and (optionally) Coarse-Grid Prognostic Model Winds
  - Lambert Conformal Projection Capability

**Table 3-2. Major Features of the CALPUFF Dispersion Model (Scire et al., 2000a)**

- **Source types**
  - Point sources (constant or variable emissions)
  - Line sources (constant or variable emissions)
  - Volume sources (constant or variable emissions)
  - Area sources (constant or variable emissions)

- **Non-steady-state emissions and meteorological conditions**
  - Gridded 3-D fields of meteorological variables (winds, temperature)
  - Spatially-variable fields of mixing height, friction velocity, convective velocity scale, Monin-Obukhov length, precipitation rate
  - Vertically and horizontally-varying turbulence and dispersion rates
  - Time-dependent source and emissions data for point, area, and volume sources
  - Temporal or wind-dependent scaling factors for emission rates, for all source types

- **Interface to the Emissions Production Model (EPM)**
  - Time-varying heat flux and emissions from controlled burns and wildfires

- **Efficient sampling functions**
  - Integrated puff formulation
  - Elongated puff (slug) formulation

- **Dispersion coefficient ($\sigma_y$, $\sigma_z$) options**
  - Direct measurements of $\sigma_v$ and $\sigma_w$
  - Estimated values of $\sigma_v$ and $\sigma_w$ based on similarity theory
  - Pasquill-Gifford (PG) dispersion coefficients (rural areas)
  - McElroy-Pooler (MP) dispersion coefficients (urban areas)
  - CTDM dispersion coefficients (neutral/stable)

- **Vertical wind shear**
  - Puff splitting
  - Differential advection and dispersion

- **Plume rise**
  - Buoyant and momentum rise
  - Stack tip effects
  - Building downwash effects
  - Partial penetration
  - Vertical wind shear

- **Building downwash**

- Huber-Snyder method
- Schulman-Scire method
- . PRIME method

**Table 3-2. Major Features of the CALPUFF Dispersion Model (Concluded).**

- **Complex terrain**
  - Steering effects in CALMET wind field
  - Optional puff height adjustment: ISC3 or "plume path coefficient"
  - Optional enhanced vertical dispersion (neutral/weakly stable flow in CTDMPLUS)

- **Subgrid scale complex terrain (CTSG option)**
  - Dividing streamline, $H_d$, as in CTDMPLUS:
    - Above $H_d$, material flows over the hill and experiences altered diffusion rates
    - Below $H_d$, material deflects around the hill, splits, and wraps around the hill

- **Dry Deposition**
  - Gases and particulate matter
  - Three options:
    - Full treatment of space and time variations of deposition with a resistance model
    - User-specified diurnal cycles for each pollutant
    - No dry deposition

- **Overwater and coastal interaction effects**
  - Overwater boundary layer parameters
  - Abrupt change in meteorological conditions, plume dispersion at coastal boundary
  - Plume fumigation

- **Chemical transformation options**
  - Pseudo-first-order chemical mechanism for $SO_2$, $SO_4^=$, $NO_x$, $HNO_3$, and $NO_3^-$ (MESOPUFF II method)
  - Pseudo-first-order chemical mechanism for $SO_2$, $SO_4^=$, NO, $NO_2$ $HNO_3$, and $NO_3^-$ (RIVAD/ARM3 method)
  - User-specified diurnal cycles of transformation rates
  - No chemical conversion

- **Wet Removal**
  - Scavenging coefficient approach
  - Removal rate a function of precipitation intensity and precipitation type

Table 3-3. Parameter Variations in Box Model Simulations Used to Develop the CALPUFF Sulfate and Nitrate Formation Algorithms. (Morris et al., 2003).

<table>
<tr><td>Surrogate Parameter</td><td>Number of Variations</td><td>Model Input Parameters And Variations</td></tr>
<tr><td>Season</td><td>3</td><td>Temperatures of 30, 20 and 10 °C were used for the, respectively, summer, fall and winter seasons. Diurnally varying clear skies solar radiation was assumed for each season corresponding to a latitude of 40°.</td></tr>
<tr><td>Background Air Reactivity</td><td>4</td><td>For the summer season the following four levels of background ozone and VOCs were used:
<table>
<tr><td>Ozone (ppb)</td><td>VOC (ppbC)</td></tr>
<tr><td>20</td><td>50</td></tr>
<tr><td>50</td><td>250</td></tr>
<tr><td>80</td><td>500</td></tr>
<tr><td>200</td><td>2,000</td></tr>
</table>
For fall and winter the ozone concentrations were assumed to be 75% and 50% of the summer levels.</td></tr>
<tr><td>Dispersion</td><td>2</td><td>Two different rates of plume dispersion were used: (1) a stable case with a wind speed of 1.5 m/s and; (2) a slightly unstable case with a wind speed of 5.0 m/s.</td></tr>
<tr><td>Release Time</td><td>2</td><td>Photochemical box model simulations were performed with release times of sunrise and noon.</td></tr>
<tr><td>Plume NOx Concentration</td><td>3</td><td>Initial plume NOx concentrations of 7, 350 and 1400 ppb were used.</td></tr>
</table>

**Estimated Average Cost ($/ton) of Methane DeNOx on No. 1 Power Boiler - NOx Control**

| | | |
|---|---|---|
| **CAPITAL COSTS** | | **Costs ($)** |
| Direct Costs | | |
| **Purchased Equipment Cost[a]** | **$** | **1,050,000** |
| Budgetary Qualifier (+/-25%) | | 262,500 |
| | | 1,312,500 |
| **Direct installation costs** | | |
| Foundation and supports | | |
| Handling and erection | | |
| Electrical | | |
| Piping | | |
| Insulation | | |
| Painting | | |
| Direct installation Costs | | 656,250 |
| **Total Direct Capital Cost = Equip Cost + 1.5*Equip Cost[b]** | $ | 1,968,750 |
| **Indirect Capital Costs** | =1.0 x Total Direct Cost | |
| Engineering | | |
| Construction and field expenses | | |
| Contrator fees | | |
| Start-up | | |
| Performance test | | |
| Contingencies | | |
| Structural Modification (4%) | | |
| **Total Indirect Capital Costs[b]** | $ | 1,968,750 |
| **TOTAL CAPITAL INVESTMENT (TCI = DC+IC)** | **$** | **3,937,500** |
| **OPERATING COSTS** | | |
| **Direct Operating Costs** | | |
| Operating Labor[c] | | 9,022 |
| Operating Labor Supervision[d] | | 1,353 |
| Maintenance Labor[e] | | 9,922 |
| Maintenance Materials[f] | | 9,922 |
| Utilities - Electricity[g] | | 112,560 |
| Utilities - Natural Gas[l] | | 3,108,000 |
| Waste Treatment & Disposal | | |
| **Total Direct Operating Costs** | $ | 3,250,779 |
| **Indirect Operating Costs** | | |
| Overhead[h] | | 18,131 |
| Property Tax[i] | | 39,375 |
| Insurance[i] | | 39,375 |
| Administration[j] | | 78,750 |
| Capital Recovery (5% interest, 10 year life)[k] | | 509,924 |
| **Total Indirect Operating** | $ | 685,555 |
| **TOTAL ANNUALIZED COSTS (TAC = DOC + IOC)** | **$** | **3,936,334** |
| Total Annualized Costs | | 3,936,334 |
| Total Uncontrolled NOx Emissions (tpy) | | 1084 |
| Removal Effciency | | 0.5 |
| Pollutant Removed(tpy) | | 542 |
| **Cost/Ton Pollutant Removed** | **$** | **7,262** |

[a]Based on the equipment cost estimate from Energy Systems Associates
[b]Factored estimate based on recent capital project installations
[c]Operating labor = 0.75 hours/day @ $34.37/hr rate for 350 days/year
[d]Supervisor pay = 15% of Operator pay
[e]Maintenance = 240 hours @ $41.34/hr
[f]Maintenance Materials = 100% of Maintenance Labor
[g]Electrical usage (335kW) associated with running fans; from Energy Systems Associates estimate for OFA/FGR combo
[h]Overhead = 60% of Labor & Material
[i] =1% TCI (Total Capital Investment)
[j] =2% TCI (Total Capital Investment)
k =factor of 0.129504575 for 5% interest on 10 year life
[l] = Natural gas usage at $370/hr at $8/MMBTU

**Estimated Average Cost ($/ton) of OFA System Upgrade on No. 1 Power Boiler - NOx Control**

| | | | |
|---|---|---|---|
| **CAPITAL COSTS** | | | **Costs ($)** |
| Direct Costs | | | |
| **Purchased Equipment Cost**[a] | | **$** | **2,980,000** |
| Budgetary Qualifier (+/-25%) | | | 745,000 |
| | | | 3,725,000 |
| **Direct installation costs** | | | |
| Foundation and supports | | | |
| Handling and erection | | | |
| Electrical | | | |
| Piping | | | |
| Insulation | | | |
| Painting | | | |
| Direct installation Costs | | | 1,862,500 |
| **Total Direct Capital Cost = Equip Cost + 1.5*Equip Cost**[b] | | $ | 5,587,500 |
| **Indirect Capital Costs** | | =1.0 x Total Direct Cost | |
| Engineering | | | |
| Construction and field expenses | | | |
| Contrator fees | | | |
| Start-up | | | |
| Performance test | | | |
| Contingencies | | | |
| Structural Modification (4%) | | | |
| **Total Indirect Capital Costs**[b] | | $ | 5,587,500 |
| **TOTAL CAPITAL INVESTMENT (TCI = DC+IC)** | | **$** | **11,175,000** |
| **OPERATING COSTS** | | | |
| **Direct Operating Costs** | | | |
| Operating Labor[c] | | | 9,022 |
| Operating Labor Supervision[d] | | | 1,353 |
| Maintenance Labor[e] | | | 9,922 |
| Maintenance Materials[f] | | | 9,922 |
| Utilities - Electricity[g] | | | 112,560 |
| Utilities - Water | | | |
| Waste Treatment & Disposal | | | |
| **Total Direct Operating Costs** | | $ | 142,779 |
| **Indirect Operating Costs** | | | |
| Overhead[h] | | | 18,131 |
| Property Tax[i] | | | 111,750 |
| Insurance[i] | | | 111,750 |
| Administration[j] | | | 223,500 |
| Capital Recovery (5% interest, 10 year life)[k] | | | 1,447,214 |
| **Total Indirect Operating** | | $ | 1,912,345 |
| **TOTAL ANNUALIZED COSTS (TAC = DOC + IOC)** | | **$** | **2,055,123** |
| Total Annualized Costs | | | 2,055,123 |
| Total Uncontrolled NOx Emissions (tpy) | | | 1084 |
| Removal Effciency | | | 0.4 |
| Pollutant Removed(tpy) | | | 434 |
| **Cost/Ton Pollutant Removed** | | **$** | **4,740** |

[a]Based on the equipment cost estimate provided by Jansen Combustion and Boiler Technologies Inc.
[b]Factored estimate based on recent capital project installations
[c]Operating labor = 0.75 hours/day @ $34.37/hr rate for 350 days/yea
[d]Supervisor pay = 15% of Operator pay
[e]Maintenance = 240 hours @ $41.34/hı
[f]Maintenance Materials = 100% of Maintenance Labo
[g]Electrical usage (335kW) associated with running fans; from Energy Systems Associates estimate for OFA/FGR combc
[h]Overhead = 60% of Labor & Material
[i] =1% TCI (Total Capital Investment)
[j] =2% TCI (Total Capital Investment)
k =factor of 0.129504575 for 5% interest on 10 year life

Estimated Average Cost ($/ton) of Methane DeNOx on No. 2 Power Boiler - NOx Control

| | | | Costs ($) |
|---|---|---|---|
| **CAPITAL COSTS** | | | **Costs ($)** |
| Direct Costs | | | |
| | **Purchased Equipment Cost[a]** | **$** | **1,200,000** |
| | Budgetary Qualifier (+/-25%) | | 300,000 |
| | | | 1,500,000 |
| | **Direct installation costs** | | |
| | Foundation and supports | | |
| | Handling and erection | | |
| | Electrical | | |
| | Piping | | |
| | Insulation | | |
| | Painting | | |
| | Direct installation Costs | | 750,000 |
| **Total Direct Capital Cost = Equip Cost + 1.5*Equip Cost[b]** | | $ | 2,250,000 |
| **Indirect Capital Costs** | | =1.0 x Total Direct Cost | |
| | Engineering | | |
| | Construction and field expenses | | |
| | Contrator fees | | |
| | Start-up | | |
| | Performance test | | |
| | Contingencies | | |
| | Structural Modification (4%) | | |
| **Total Indirect Capital Costs[b]** | | $ | 2,250,000 |
| **TOTAL CAPITAL INVESTMENT (TCI = DC+IC)** | | **$** | **4,500,000** |
| **OPERATING COSTS** | | | |
| **Direct Operating Costs** | | | |
| | Operating Labor[c] | | 9,022 |
| | Operating Labor Supervision[d] | | 1,353 |
| | Maintenance Labor[e] | | 9,922 |
| | Maintenance Materials[f] | | 9,922 |
| | Utilities - Electricity[g] | | 141,120 |
| | Utilities - Natural Gas[l] | | 4,401,600 |
| | Waste Treatment & Disposal | | |
| **Total Direct Operating Costs** | | $ | 4,572,939 |
| **Indirect Operating Costs** | | | |
| | Overhead[h] | | 18,131 |
| | Property Tax[i] | | 45,000 |
| | Insurance[i] | | 45,000 |
| | Administration[j] | | 90,000 |
| | Capital Recovery (5% interest, 10 year life)[k] | | 582,771 |
| **Total Indirect Operating** | | $ | 780,902 |
| **TOTAL ANNUALIZED COSTS (TAC = DOC + IOC)** | | **$** | **5,353,840** |
| Total Annualized Costs | | | 5,353,840 |
| Total Uncontrolled NOx Emissions (tpy) | | | 2514 |
| Removal Effciency | | | 0.5 |
| Pollutant Removed(tpy) | | | 1257 |
| **Cost/Ton Pollutant Removed** | | **$** | **4,259** |

[a]Based on the equipment cost estimate from Energy Systems Associates
[b]Factored estimate based on recent capital project installations
[c]Operating labor = 0.75 hours/day @ $34.37/hr rate for 350 days/year
[d]Supervisor pay = 15% of Operator pay
[e]Maintenance = 240 hours @ $41.34/hr
[f]Maintenance Materials = 100% of Maintenance Labor
[g]Electrical usage (420kW) associated with running fans; from Energy Systems Associates estimate for OFA/FGR combo
[h]Overhead = 60% of Labor & Material
[i] =1% TCI (Total Capital Investment)
[j] =2% TCI (Total Capital Investment)
k =factor of 0.129504575 for 5% interest on 10 year life
[l] = Natural gas usage at $524/hr at $8/MMBTU

**Estimated Average Cost ($/ton) of OFA System Upgrade on No. 2 Power Boiler - NOx Control**

| | | |
|---|---|---|
| **CAPITAL COSTS** | | **Costs ($)** |
| Direct Costs | | |
| **Purchased Equipment Cost**[a] | **$** | **4,338,880** |
| Budgetary Qualifier (+/-25%) | | 1,084,720 |
| | | 5,423,600 |
| **Direct installation costs** | | |
| Foundation and supports | | |
| Handling and erection | | |
| Electrical | | |
| Piping | | |
| Insulation | | |
| Painting | | |
| Direct installation Costs | | 2,711,800 |
| **Total Direct Capital Cost = Equip Cost + 1.5*Equip Cost**[b] | $ | 8,135,400 |
| **Indirect Capital Costs** | =1.0 x Total Direct Cost | |
| Engineering | | |
| Construction and field expenses | | |
| Contrator fees | | |
| Start-up | | |
| Performance test | | |
| Contingencies | | |
| Structural Modification (4%) | | |
| **Total Indirect Capital Costs**[b] | $ | 8,135,400 |
| **TOTAL CAPITAL INVESTMENT (TCI = DC+IC)** | **$** | **16,270,800** |
| **OPERATING COSTS** | | |
| **Direct Operating Costs** | | |
| Operating Labor[c] | | 9,022 |
| Operating Labor Supervision[d] | | 1,353 |
| Maintenance Labor[e] | | 9,922 |
| Maintenance Materials[f] | | 9,922 |
| Utilities - Electricity[g] | | 141,120 |
| Utilities - Water | | |
| Waste Treatment & Disposal | | |
| **Total Direct Operating Costs** | $ | 171,339 |
| **Indirect Operating Costs** | | |
| Overhead[h] | | 18,131 |
| Property Tax[i] | | 162,708 |
| Insurance[i] | | 162,708 |
| Administration[j] | | 325,416 |
| Capital Recovery (5% interest, 10 year life)[k] | | 2,107,143 |
| **Total Indirect Operating** | $ | 2,776,106 |
| **TOTAL ANNUALIZED COSTS (TAC = DOC + IOC)** | **$** | **2,947,445** |
| Total Annualized Costs | | 2,947,445 |
| Total Uncontrolled NOx Emissions (tpy) | | 2514 |
| Removal Effciency | | 0.4 |
| Pollutant Removed(tpy) | | 1006 |
| **Cost/Ton Pollutant Removed** | **$** | **2,931** |

[a]Scaled from quote for #1 PB based on six-tenths factor rule for cost estimation from Peters, Max S. and Timmerhaus, Klaus D., Plant Design and Economics for Chemical Engineers, Fourth Edition, McGraw-Hill, Inc., 1991, p. 169.

[b]Factored estimate based on recent capital project installations

[c]Operating labor = 0.75 hours/day @ $34.37/hr rate for 350 days/year

[d]Supervisor pay = 15% of Operator pay

[e]Maintenance = 240 hours @ $41.34/hr

[f]Maintenance Materials = 100% of Maintenance Labor

[g]Electrical usage assumption (420kW) associated with running auxiliary equipment; from Energy Systems Associates estimate for OFA/FGR combo

[h]Overhead = 60% of Labor & Material

[i] =1% TCI (Total Capital Investment)

[j] =2% TCI (Total Capital Investment)

k =factor of 0.129504575 for 5% interest on 10 year life

**Estimated Average Cost ($/ton) of Low NOx Burners on No. 2 Power Boiler - NOx Control**

| | | |
|---|---|---|
| **CAPITAL COSTS** | | **Costs ($)** |
| Direct Costs | | |
| **Purchased Equipment Cost**[a] | **$** | **1,800,000** |
| **Direct installation costs** | | |
| Foundation and supports | | |
| Handling and erection | | |
| Electrical | | |
| Piping | | |
| Insulation | | |
| Painting | | |
| Direct installation Costs | | 900,000 |
| **Total Direct Capital Cost = Equip Cost + 1.5*Equip Cost**[b] | $ | 2,700,000 |
| **Indirect Capital Costs** | =1.0 x Total Direct Cost | |
| Engineering | | |
| Construction and field expenses | | |
| Contrator fees | | |
| Start-up | | |
| Performance test | | |
| Contingencies | | |
| Structural Modification (4%) | | |
| **Total Indirect Capital Costs**[b] | $ | 2,700,000 |
| **TOTAL CAPITAL INVESTMENT (TCI = DC+IC)** | **$** | **5,400,000** |
| **OPERATING COSTS** | | |
| **Direct Operating Costs** | | |
| Operating Labor[c] | | 9,022 |
| Operating Labor Supervision[d] | | 1,353 |
| Maintenance Labor[e] | | 9,922 |
| Maintenance Materials[f] | | 9,922 |
| Utilities - Electricity[g] | | 141,120 |
| Utilities - Water | | |
| Waste Treatment & Disposal | | |
| **Total Direct Operating Costs** | $ | 171,339 |
| **Indirect Operating Costs** | | |
| Overhead[h] | | 18,131 |
| Property Tax[i] | | 54,000 |
| Insurance[i] | | 54,000 |
| Administration[j] | | 108,000 |
| Capital Recovery (5% interest, 10 year life)[k] | | 699,325 |
| **Total Indirect Operating** | $ | 933,456 |
| **TOTAL ANNUALIZED COSTS (TAC = DOC + IOC)** | **$** | **1,104,795** |
| Total Annualized Costs | | 1,104,795 |
| Total Uncontrolled NOx Emissions (tpy) | | 2514 |
| Removal Effciency | | 0.3 |
| Pollutant Removed(tpy) | | 754 |
| **Cost/Ton Pollutant Removed** | **$** | **1,465** |

Domtar will implement control measures or other options for reducing emissions to comply with the proposed BART limits as expeditiously as possible and before the date five years after EPA approval of ADEQ's BART State Implementation Plan (SIP), as required by Regional Haze Rule and BART Guidelines.

Proposed BART Compliance Timeline

| | |
|---|---|
| May 14-20, 2007 | Installation of WESP on No. 1 Power Boiler complete |
| May 21, 2007 | Tentative startup of WESP on No. 1 Power Boiler |
| September 13, 2007 | Boiler MACT Compliance Deadline |
| March 11, 2008 | Last day to show compliance with Boiler MACT = Date achieve BART Particulate Matter limits |
| Early 2010 | $NO_X$ Reduction Technology Evaluation |
| Late 2011 | $NO_X$ Reduction Technology Selected |
| Late 2012 | Installation of selected $NO_X$ Reduction Technology |
| Early 2013 | BART Compliance Deadline |

# APPENDIX D – REQUESTED DESIGN DETAILS OF NO. 1 POWER BOILER

The No. 1 power boiler, built by Babcock & Wilcox in 1967, is a balanced draft, two drum sterling boiler designed to burn natural gas, fuel oil and bark for the production of steam.

The No. 1 power boiler has a maximum continuous steam rating of 275,000 lbs/hr at 850 psig and 850°F. The boiler discharges steam into the mill's 850# high pressure header system.

The No. 1 power boiler is typically a swing boiler (adjusts its fuel firing rate) to follow the 850 psig header pressure.

The fuel system consists of the three separate subsystems listed below that deliver combustible material into the boiler furnace.

- Bark System - supplies bark, wood waste, pelletized paper fuel, tire-derived fuel and municipal yard waste from the woodyard area and distributes it onto the grate for burning. Bark is the primary fuel source for No. 1 power boiler.

- Natural Gas System - supplies gas from the main mill pipeline to the boiler's six burners and ignitors. Natural gas is used to warm up the boiler during start-up and to supplement bark combustion to maintain load.

- No. 6 Fuel Oil System - prepares and supplies No. 6 fuel oil, used oil generated on site or reprocessed fuel oil to the boiler's burners. Oil serves primarily as a backup to natural gas and is not normally fired.

The combustion air system consists of the three subsystems listed below that provide the oxygen for fuel combustion.

- Air Supply & Preheat System - provides a steady supply of combustion air at the necessary flows and temperatures to ensure efficient combustion.

- Burner Air System - provides air for the combustion of natural gas and/or fuel oil at the burners.

- Bark Air System - provides air for drying and burning of bark system fuels on the grates (undergrate air), combustion of bark system fuels above the grates (overfire air) and distribution of bark system fuels onto the grates (distribution air).

The flue gas system consists of several components listed below that handle the by-products of combustion.

- Tubular Air Heater - transfers heat from the flue gas to the combustion air.

- Mechanical Dust Collector - removes environmentally harmful particulate from the flue gas prior to atmospheric discharge.

- ID Fan - removes the flue gas from the furnace at a controlled rate to maintain a balanced draft.

- Stack - discharges the flue gas to atmosphere.

- Sootblowers - clean the tube surfaces of ash and slag deposited from the flue gas.

The No. 1 Power Boiler will undergo a modification in May 2007 that will entail the installation of a Wet Electrostatic Precipitator to bring the boiler into compliance with the Boiler MACT regulation for particulate matter emissions.

# SUPPLEMENTAL BART DETERMINATION INFORMATION

# DOMTAR A.W. LLC ▪ ASHDOWN MILL (AFIN 41-00002)

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**Original : June 28, 2013**
**Revision : May 16, 2014**

Relevant Previous Submittals:

October 31, 2006
March 26, 2007
June 25, 2007
December 21, 2011

# 1. INTRODUCTION

Domtar A.W. LLC (Domtar) is submitting supplemental information for consideration by the Arkansas Department of Environmental Quality (ADEQ) and the U.S. Environmental Protection Agency (EPA) in the determination of Best Available Retrofit Technology (BART) for Domtar's two BART-affected sources – No. 1 and No. 2 Power Boilers – at its Ashdown, Arkansas kraft paper mill. Previous related analyses and other pertinent information were submitted on October 31, 2006 (original BART report), March 26, 2007 (original BART report, revised), June 25, 2007 (comments on draft Regulation 19 BART requirements), and December 21, 2011 (comments on draft SIP partial approval and partial disapproval).

The supplemental information provided in this report is submitted in response to EPA's final decision to partially disapprove the Arkansas Regional Haze (RH) State Implementation Plan (SIP).[1] Specifically, Domtar is addressing the following five EPA concerns (two regarding $NO_X$, two regarding $SO_2$, and one regarding PM):

- Feasibility of Selective Non-Catalytic Reduction (SNCR) technology for $NO_X$ control for No. 1 and No. 2 Power Boilers;[2]
- Consideration of visibility impacts for the theoretically feasible Methane De-$NO_X$ (MdN) control option for No. 1 and No. 2 Power Boilers;[3]
- Evaluation of the type, frequency, and duration of fuel oil combustion in the No. 1 Power Boiler and the $SO_2$ BART determination of 1.12 lb/MMBtu;[4]
- Assessment of potential upgrades to the existing wet scrubber on No. 2 Power Boiler and the $SO_2$ BART determination of 1.2 lb/MMBtu;[5] and
- Consideration of the same 0.07-lb/MMBtu PM BART limit for No. 2 Power Boiler as approved for the No. 1 Power Boiler.[6]

These five issues are addressed in sections 4 – 6 of this report. The only other changes to the previously submitted information involve (1) updates to the baseline emissions and modeling parameters for No. 1 Power Boiler and (2) updates to the modeling methodology (as requested by EPA and ADEQ). Details of these updates are provided in Section 2 and Section 3, respectively.

A summary of the proposed BART determinations presented in Section 4 – 6 is provided in Table 1-1 below.

[1] 77 FR 14604 – 14677
[2] 77 FR 14634 and 14677
[3] 77 FR 14634 and 14677
[4] 77 FR 14648 and 14677; see also the proposed rule at 76 FR 64208
[5] 77 FR 14649 and 14677
[6] 77 FR 14677; see also the proposed rule at 76 FR 64208

**TABLE 1-1. SUMMARY OF PROPOSED BART DETERMINATIONS**

| Emission Unit | Pollutant | Proposed BART Limit |
|---|---|---|
| No. 1 Power Boiler | PM | 0.07 lb/MMBtu |
| | $SO_2$ | 21.0 lb/hr |
| | $NO_X$ | 207.4 lb/hr |
| No. 2 Power Boiler | PM | 0.44 lb/MMBtu |
| | $SO_2$ | 788.2 lb/hr |
| | $NO_X$ | 345 lb/hr |

# 2. Baseline for No. 1 Power Boiler

Domtar installed a wet electrostatic precipitator (WESP) on the No. 1 Power Boiler in 2007 to meet the then-applicable Boiler MACT emission standard of 0.07 lb/MMBtu. The WESP fundamentally changed the emissions and stack parameters for the No. 1 Power Boiler (e.g., there are now two stacks rather than one), and Domtar proposes to update the BART baseline modeling to reflect these changes (i.e., to reflect current operations). A comparison of the previous baseline modeling parameters and the proposed baseline modeling parameters is provided in Table 2-1.

**Table 2-1. Proposed Changes in Baseline Parameters for No. 1 Power Boiler**

| No. 1 Power Boiler Parameter | Original Baseline (2001 – 2003) | Proposed Baseline (2009 – 2011) |
|---|---|---|
| Number of Stacks | 1 | 2 |
| Max. 24-hour $PM_{10}$/PMF Emissions (lb/hr) | 169.5 | 30.4 |
| Max. 24-hour $SO_2$ Emissions (lb/hr) | 442.5 | 21.0 |
| Max. 24-hour $NO_X$ Emissions (lb/hr) | 179.6 | 207.4 |
| Lambert Conformal Conic (LCC) Projection Coordinates (km) | 267.47491, -698.66686 | 267.49713, -698.63952 & 267.49891, -698.63445 |
| Base Elevation (m) | 97.5 | 99.58 & 99.51 |
| Stack Height (m) | 66.1 | 66.14 ea. |
| Stack Diameter (m) | 1.89 | 2.1 ea. |
| Exhaust Velocity (m/s) | 26.76 | 11.06 ea. |
| Exhaust Temperature (K) | 522 | 342.04 ea. |

**Calculation of Revised/Proposed Baseline Emissions for No. 1 Power Boiler**

The PM emission rate is calculated based on the maximum daily heat input from 2009 – 2011 and an emission factor developed from analysis of past stack testing. Four three-hour tests (12 data points) have been completed since the installation of the WESP in early 2007. They are summarized in Table 2-1a, below.

**Table 2-1a – No. 1 Power Boiler PM Test Results**

| Test Date | Run 1 (lb/MMBtu) | Run 2 (lb/MMBtu) | Run 3 (lb/MMBtu) | Average (lb/MMBtu) |
|---|---|---|---|---|
| 8/7/2007 | 0.0124 | 0.0177 | 0.0113 | 0.0138 |
| 2/26/2008 | 0.0368 | 0.0434 | 0.0468 | 0.0423 |
| 2/28/2008 | 0.0389 | 0.0619 | 0.0475 | 0.0494 |
| 4/22/2010 | 0.0190 | 0.0128 | 0.0098 | 0.0139 |

From the above data, the mean average plus two standard deviations is 0.066 lb/MMBtu. At the maximum daily heat input for the boiler from 2009 – 2011 (11,069.67 MMBtu/day), this emission level is equivalent to 30.4 lb/hr on a maximum day basis.

The NOX emission rate is calculated similarly to the PM rate. For $NO_X$, three three-hour tests (nine data points) have been completed in the last 10 years.[7] They are summarized in Table 2-1b, below.

**TABLE 2-1B – NO. 1 POWER BOILER $NO_X$ TEST RESULTS**

| Test Date | Run 1 (lb/MMBtu) | Run 2 (lb/MMBtu) | Run 3 (lb/MMBtu) | Average (lb/MMBtu) |
|---|---|---|---|---|
| 3/10/2004 | 0.3518 | 0.4048 | 0.3893 | 0.3820 |
| 10/25/2005 | 0.3446 | 0.3706 | 0.3582 | 0.3578 |
| 4/22/2010 | 0.2400 | 0.2641 | 0.2843 | 0.2628 |

From the above data, the mean average plus two standard deviations is 0.4496 lb/MMBtu. At the maximum daily heat input for the boiler from 2009 – 2011 (11,069.67 MMBtu/day), this emission level is equivalent to 207.4 lb/hr on a maximum day basis.

The maximum day $SO_2$ emission rate is calculated based on maximum fuel usage rates in a single day in 2009 – 2011 and sulfur contents (from analysis and/or published values from NCASI) as follows:

Contribution from fuel oil combustion:
50 gal-oil/min * 60 min/hr * 7.88 lb/gal * 0.014 lb-S/lb-oil * 2 lb-$SO_2$/lb-S * (1-97.5/100) = 16.55 lb-$SO_2$/hr

Contribution from TDF & bark combustion:
594 ton-fuel/day * 1 day/24 hr * 0.74 lb-S/ton-fuel * 2 lb-$SO_2$/lb-S * (1-97.5/100) = 0.92 lb-$SO_2$/hr

Total = 16.55 lb/hr + 0.92 lb/hr = 17.47 lb-$SO_2$/hr

Further, monthly $SO_2$ emissions values reported during the baseline period (2009 – 2011) are review to determine variability. These monthly values are shown in Table 2-1c, below.

[7] The 2007 installation of the WESP did not affect $NO_X$ emissions.

**TABLE 2-1C – NO. 1 POWER BOILER MONTHLY $SO_2$ EMISSIONS**

| | No. 1 Power Boiler $SO_2$ Emissions (tons/month) | | |
|---|---|---|---|
| **Month** | **2009** | **2010** | **2011** |
| January | 0.263 * | 0.374 * | 0.27 |
| February | 0.294 * | 0.26 | 0.24 |
| March | 0.04 | 0.30 | 0.27 |
| April | 0.08 | 0.20 | 0.18 |
| May | 0.02 | 0.28 | 0.23 |
| June | 0.00 | 0.08 | 0.21 |
| July | 0.19 | 0.22 | 0.21 |
| August | 0.23 | 0.79 | 0.18 |
| September | 0.13 | 0.20 | 0.21 |
| October | 0.19 | 0.14 | 0.21 |
| November | 0.18 | 0.11 | 0.20 |
| December | 0.13 | 0.13 | 0.21 |

* These values are adjusted from Domtar's official emissions records to include consideration of the 97.5 % control efficiency on $SO_2$ emissions from fuel oil combustion provided by the WESP. The consideration was not applied in the official records until 2011. Only three months are adjusted because those are the only months in 2009 and 2010 during which fuel oil was combusted.

The standard deviation (0.129) of this data is equal to 62 percent of the mean average (0.207) of the data. This means that $SO_2$ emissions, while small, vary a great deal from month-to-month. Considering this information a 20 percent variability factor is applied to the raw maximum day $SO_2$ emission rate (17.47 lb/hr) to arrive at the proposed baseline rate of 21.0 lb/hr.

**A Note about Baseline Emissions for No. 2 Power Boiler**

While comparing No. 1 Power Boiler emission rates from the two baseline periods, Domtar also compared emission rates for the No. 2 Power Boiler. While no definitive changes took place and no enforceable limitations were taken to ensure any decreases, the No. 2 Power Boiler has emitted at lower levels. Most notably the maximum daily $SO_2$ and $NO_X$ emission rates dropped by 16 and 20 percent, respectively. These decreases can be attributed to the mill's ongoing efforts to reduce energy and water consumption. Efficiency increases of 16 to 20 percent are not surprising considering the 2001-2003 baseline period is ten years ago and not truly representative of current operations. However, these decreases are not considered in this report.

For ease of review, the following tables summarize the baseline emission rates and modeling parameters, respectively, for both boilers.

**TABLE 2-2. SUMMARY OF BASELINE 24-HOUR MAXIMUM ACTUAL EMISSION RATES**

| Emission Unit | Baseline Period | $NO_X$ Emissions (lb/hr) | $SO_2$ Emissions (lb/hr) | $PM_{10}$/PMF Emissions (lb/hr) |
|---|---|---|---|---|
| No. 1 Power Boiler | 2009-2011 | 207.4 | 21.0 | 30.4 |
| No. 2 Power Boiler | 2001-2003 | 526.8 | 788.2 | 81.6 |

**TABLE 2-3. SUMMARY OF BASELINE STACK PARAMETERS**

| Emission Unit, Stack | LCC East (km) | LCC North (km) | Base Elevation (m) | Stack Height (m) | Stack Diameter (m) | Exhaust Temperature (K) | Exhaust Velocity (m/s) |
|---|---|---|---|---|---|---|---|
| No. 1 Power Boiler,A | 267.49713 | -698.63952 | 99.58 | 66.14 | 2.1 | 342.04 | 11.06 |
| No. 1 Power Boiler,B | 267.49891 | -698.63445 | 99.51 | 66.14 | 2.1 | 342.04 | 11.06 |
| No. 2 Power Boiler * | 267.45242 | -698.64643 | 99.95 | 71.63 | 3.66 | 324.82 | 11.92 |

* All slight (less than a tenth in most cases) changes in modeling parameters for the No. 2 Power Boiler, compared to the original analysis, are from minor adjustments based on the most up-to-date information and/or rounding conventions.

As a result of the 2007 WESP changes, revised modeling was conducted using the CALPUFF dispersion model to determine the baseline visibility impairment attributable to the No. 1 Power Boiler and No. 2 Power Boiler in four Class I Areas: Caney Creek Wilderness (CACR), Upper Buffalo Wilderness (UPBU), Hercules Glades Wilderness (HERC), and Mingo Wilderness (MING). Table 2-4 and Table 2-5 provide a summary of the modeled visibility impairment attributable to No. 1 Power Boiler and No. 2 Power Boiler, respectively, based on the inputs shown in Table 2-2 and Table 2-3. Note that detailed modeling results are provided in Appendix C and all of the CALMET, CALPUFF, and CALPOST modeling files are included as part of the electronic files submitted with this document.

**TABLE 2-4. BASELINE VISIBILITY IMPAIRMENT**

| Emission Unit | Class I Area | Number of Days ≥ 0.5 Δdv [a] | Maximum (Δdv) [b] | 98th %tile (Δdv) [b] |
|---|---|---|---|---|
| No. 1 Power Boiler | CACR | 0 | 0.476 | 0.335 |
| | UPBU | 0 | 0.090 | 0.038 |
| | HERC | 0 | 0.077 | 0.020 |
| | MING | 0 | 0.060 | 0.014 |
| No. 2 Power Boiler | CACR | 49 | 1.603 | 0.844 |
| | UPBU | 0 | 0.381 | 0.146 |
| | HERC | 0 | 0.329 | 0.105 |
| | MING | 0 | 0.246 | 0.065 |

[a] Sum for all three modeled years.
[b] Maximum value among the three modeled years.

# 3. MODELING METHODOLOGY

The principle changes for the updated modeling compared to the originally submitted modeling are listed below with additional details following:

- Use of refined meteorological data consistent with the met data used for other BART sources in Arkansas.
- Use of $98^{th}$ percentile (or $8^{th}$ high) results rather than daily maximum results for demonstration of baseline and post-control visibility impairment.
- Use of CALPOST version 6.221, Level 080724 based on the October 2010 guidance from the Federal Land Managers Air Quality Related Values Workgroup (FLAG).
- Use of Method 8, Mode 5 as a visibility impairment prediction equation (i.e. the new IMPROVE equation).

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 A. Note that the protocol included in Appendix A 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. Several sources in Texas and Arkansas have also used the CALMET data that was generated in accordance with the protocol.

ADEQ submitted a draft BART Modeling Protocol on June 7, 2006 to EPA. On July 26, 2012 ADEQ updated the protocol including CALPUFF modeling components and the background concentrations in CALPOST. In addition, CALMET is being changed from not having observations (NO OBS = 1) to the hybrid which incorporates observations (NO OBS = 0). This change from NO OBS = 1 to NO OBS = 0 allows for the use of the $8^{th}$ highest – rather than the $1^{st}$ highest – model output. Also, the new IMPROVE Equations is used.

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 ($b_{\text{ext}}$), 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, also referred to as "delta dv," or Δdv, based on the source and background light extinction is based on the following equation:

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

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

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

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

CALPOST Method 8, Mode 5 requires the following:

- Annual average concentrations reflecting natural background for various particles and for sea salt
- Monthly 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 | $(NH_4)_2SO_4$ (μg/m$^3$) | $NH_4NO_3$ (μg/m$^3$) | OM (μg/m$^3$) | EC (μg/m$^3$) | Soil (μg/m$^3$) | CM (μg/m$^3$) | Sea Salt (μg/m$^3$) | Rayleigh (Mm$^{-1}$) |
|---|---|---|---|---|---|---|---|---|
| CACR | 0.23 | 0.1 | 1.8 | 0.02 | 0.5 | 3 | 0.03 | 11 |
| UPBU | 0.23 | 0.1 | 1.8 | 0.02 | 0.5 | 3 | 0.03 | 11 |
| HERC | 0.23 | 0.1 | 1.8 | 0.02 | 0.5 | 3 | 0.02 | 11 |
| MING | 0.23 | 0.1 | 1.83 | 0.02 | 0.51 | 3.05 | 0.04 | 12 |

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

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

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

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

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

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

# 4. SUPPLEMENTAL INFORMATION FOR THE PM BART DETERMINATIONS

For the No. 1 Power Boiler, Domtar originally proposed, ADEQ adopted, and EPA approved a PM BART determination of 0.07 lb/MMBtu. This value was based on the then-final Boiler MACT. The same approach was applied for the No. 2 Power Boiler, but ultimately a limitation of 0.1 lb/MMBtu was adopted. This value was disapproved by EPA. EPA's disapproval is summarized in its proposed rule as follows:

> *Concerning Power Boiler No. 2, Domtar stated that the unit was subject to the Boiler MACT PM emission standard in existence at the time (0.07 lb/MMBtu), and indicated its intent to presumptively rely on such standard to meet BART PM requirements for Power Boiler No. 2. However, instead of adopting 0.07 lb/MMBtu as the BART PM emission limit for Power Boiler No. 2, ADEQ adopted 0.10 lb/MMBtu as the BART PM emission limit. Since ADEQ did not select the Boiler MACT PM emission standard current at the time the BART determination was made as the BART PM emission limit for Power Boiler No. 2, ADEQ cannot elect to take the streamlined approach provided in the BART Guidelines. If ADEQ chooses to take the streamlined approach provided in the BART Guidelines, ADEQ must select the Boiler MACT PM standard if it determines there are no new and cost-effective technologies or available upgrades developed subsequent to the MACT standard.*[8]

To remedy this issue, Domtar proposes as BART the now-applicable Boiler MACT limit of 0.44-lb/MMBtu (for hybrid suspension grate boilers) for the No. 2 Power Boiler.

[8] 76 FR 64208

# 5. SUPPLEMENTAL INFORMATION FOR THE $SO_2$ BART DETERMINATIONS

This section provides the following supplemental information:

- Evaluation of the type, frequency, and duration of fuel oil combustion in the No. 1 Power Boiler and the $SO_2$ BART determination of 1.12 lb/MMBtu.[9]
- Assessment of potential upgrades to the existing wet scrubber on No. 2 Power Boiler and the $SO_2$ BART determination of 1.2 lb/MMBtu.[10]

## 5.1 NO. 1 POWER BOILER: FUEL OIL COMBUSTION AND $SO_2$ BART

In re-evaluating baseline rates (see Section 2), Domtar revised the baseline rates to be reflective of the current WESP technology employed at the No. 1 Power Boiler. As a result, the original baseline rate of 1.12 lb/MMBtu is moot. The new baseline $SO_2$ emission rate is 17.5 lb/hr. Modeling this revised emission rate shows <u>zero days with maximum impacts greater than 0.5 Δdv, and all 98th percentile impacts at all Class I areas are less than 0.5 Δdv</u>. The results are shown in Table 2-4.

Because No. 1 Power Boiler does not contribute to visibility impairment greater than 0.5 Δdv at any of the Class I areas, and moreover does not contribute to visibility impairment on even a single day, Domtar proposes no additional add-on controls and an emission limit of 21 lb/hr (representing a 20 percent compliance margin above the baseline rate of 17.5 lb/hr). Domtar proposes to demonstrate compliance with this limit by calculating emissions on a monthly and rolling 12-month basis, updated within 15 days of the end of each month and submitted in semi-annual reports.

## 5.2 NO. 2 POWER BOILER: POTENTIAL SCRUBBER UPGRADES AND $SO_2$ BART

The existing wet scrubber achieves an $SO_2$ control efficiency of approximately 90 percent, which is within the normal range for the highest efficiency $SO_2$ control strategies and is the BART-based control efficiency presumed by the Central Regional Air Planning Association (CENRAP) and the Midwest Regional Planning Organization (MRPO) for pulp and paper industry power boilers.[11,12] However, as requested, Domtar has considered potential upgrades that could potentially achieve even greater control efficiencies.

Domtar contracted with A.H. Lundberg Associates, Inc. (Lundberg) to evaluate scrubber upgrades and also to provide a quote for a new, add-on spray scrubber system. The upgrades considered included, but were not limited to, those specifically mentioned by EPA, i.e., (1) the elimination of bypass reheat, (2) the installation of liquid distribution rings, (3) the installation of perforated trays, (4) improvements to the auxiliary system requirement, and (5) a redesign of spray header and nozzle configuration. Lundberg determined that any "upgrade" – for the purposes of achieving extra $SO_2$ control – of the existing scrubber would essentially just involve efforts to increase pressure drop.

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[9] 77 FR 14648 and 14677; see also the proposed rule at 76 FR 64208
[10] 77 FR 14649 and 14677
[11] CENRAP's Control Estimates Spreadsheet dated January 10, 2006.
[12] MRPO, *Interim White Paper – Midwest RPO Candidate Control Measures*, March 29, 2005.

Domtar has been unable to quantify the marginal additional control that could possibly be achieved upon implementation of such upgrades. When comparing existing scrubber upgrades with the installation of a new, add-on system to operate downstream of the existing scrubbers, it was decided that the add-on option was more feasible than any upgrade option, and furthermore only with the add-on option is additional control quantifiable. Therefore, the add-on option is considered further in this analysis.

According to the vendor information, which is included in Appendix D, an add-on spray scrubber would utilize sodium hydroxide (NaOH) to absorb $SO_2$ with a control efficiency of approximately 90 percent resulting in a post-control emission rate of 78.8 lb/hr (approximately 0.1 lb/MMBtu at the maximum heat input rate). Note that this represents 99 percent control compared to uncontrolled emissions. Consideration of any further control – beyond 99 percent – is unreasonable.

The total capital cost of the add-on spray scrubber, including purchased equipment cost (according to Lundberg) and the cost to retrofit the system at the Ashdown Mill where there is no existing clear property or adequate structure to support the equipment, is nearly $7.2MM. The total annual cost, including the annualized capital cost plus annual operating costs, is approximately $9.8MM. Using the maximum day baseline emission rate, annualized, this annual cost results in a cost effectiveness of about $3,300/ton based on the removal of 3,016 tpy of $SO_2$. The true cost effectiveness, based on the actual annual-average baseline emission rate (as reported in annual emission inventories) of 2,078 tpy and therefore a removal of 1,870 tpy of $SO_2$, is $5,300/ton. The details of the capital and operating cost estimates for the add-on spray scrubber are provided in Appendix B of this report.

A final impact analysis was conducted to assess the visibility improvement for the control option. The emission rates used in the modeling scenarios are presented in Table 5-2, and the results are summarized in Table 5-3.

**TABLE 5-2. $SO_2$ CONTROL SCENARIOS MODELED EMISSION RATES FOR NO. 2 POWER BOILER**

| Emission Unit | Scenario | $NO_X$ Emissions (lb/hr) | $SO_2$ Emissions (lb/hr) | $PM_{10}$/PMF Emissions (lb/hr) |
|---|---|---|---|---|
| No. 2 Power Boiler | Baseline | 526.8 | 788.2 | 81.6 |
| | Add-on Spray Scrubber | 526.8 | 78.8 | 81.6 |

**TABLE 5-3. VISIBILITY IMPAIRMENT IMPROVEMENT ATTRIBUTABLE TO $SO_2$ CONTROL FOR NO. 2 POWER BOILER**

| Scenario | 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 |
| Baseline | 0.844 | 49 | 0.146 | 0 | 0.105 | 0 | 0.065 | 0 |
| Add-on Spray Scrubber | 0.698 | 31 | 0.093 | 0 | 0.054 | 0 | 0.039 | 0 |
| *Improvement Over Baseline* | *0.146* | *18* | *0.053* | *0* | *0.051* | *0* | *0.026* | *0* |

For CACR, the only Class I area with any impacts greater than 0.5 $\Delta$dv, the addition of a spray scrubber reduces the maximum 98$^{th}$ percentile impact by 17 percent and the number of days with visibility impairment greater than 0.5 $\Delta$dv by 37 percent.  Note that these modest improvement values would be even less if the baseline emission rates were adjusted from a 2001-2003 basis to be more representative of current operations.

Nevertheless, the visibility improvement provided by the add-on spray scrubber is not justified by the cost and the additional energy and water use that it would require (at a time when industries are being pressured to reduce energy and water use).  The capital cost of $7.2MM represents a significant burden to the Ashdown Mill.

Domtar proposes no additional add-on controls and the baseline emission limit of 788.2 lb/hr as BART for the No. 2 Power Boiler.  Domtar proposes to demonstrate compliance with this limit on a 30-day rolling average as measured by the existing continuous emissions monitoring system (CEMS).

# 6. SUPPLEMENTAL INFORMATION FOR THE $NO_X$ BART DETERMINATIONS

This section provides supplemental information regarding the feasibility of Selective Non-Catalytic Reduction (SNCR). An updated evaluation of visibility impacts, including analyses for the theoretically feasible Methane De-$NO_X$ (MdN) technology, is also included.

## 6.1 FEASIBILITY OF SELECTIVE NON-CATALYTIC REDUCTION

From NCASI's 2008 Handbook for Pulp and Paper:

> "SNCR has been applied to several baseloaded wood-fired boilers. However, its efficacy (besides when used as a polishing step) on wood-fired boilers with changing loads has not been demonstrated. The use of ammonia injection (SNCR) on at least one pulp mill wood-fired boiler met with significant problems and had to be abandoned."
>
> "The use of SNCR systems on coal-fired boilers is still in the development stage."

The relevance and timeliness of these statements were confirmed with NCASI on January 17, 2013:

> "Our understanding about the applicability of SNCR systems to control $NO_X$ in industrial boilers has not changed. We agree that for a base loaded pulp mill bark or coal boiler or boiler with steady flue gas flow patterns and temperature distribution across the flue gas pathway, SNCR can be quite effective, resulting typically in about a 50% $NO_X$ reduction. We are not aware of a pulp mill bark boiler with fluctuating loads that has successfully operated an SNCR system and obtained >50% $NO_X$ control consistently. Either the boiler operates at more or less a steady load or the SNCR system is used for polishing (<20 to 30% $NO_X$ reduction) purposes."

Furthermore, Domtar has worked with NCASI to research the operation and effectiveness of the EPA-referenced SNCR in operation at the Temple-Inland paper mill in Orange, TX. NCASI has confirmed that the SNCR, which was installed per a Lowest Achievable Emission Rate (LAER) determination, is in operation and is achieving an overall control efficiency of approximately 20 percent.

Despite the fact that the technical feasibility of SNCR remains highly questionable, Domtar has prepared emission/control and cost estimates for SNCR for both No. 1 and No. 2 Power Boilers. The cost estimates are based on methods/assumptions found in EPA's Control Cost Manual (CCM) supplemented with mill-specific cost information for water, fuels, and ash disposal and urea solution usage estimates from FuelTech Inc. (FTI), the vendor that supplied the SNCR in use at the above-referenced Temple-Inland mill. The information supplied by FTI is shown in Figure 6-1.

**FIGURE 6-1. SNCR OPERATING ESTIMATES PROVIDED BY FUELTECH, INC.**

| Ashdown Mill Power Boilers 1 & 2 - SNCR | | | | | |
|---|---|---|---|---|---|
| Type of Unit | | Power Boiler 1 Stoker Fired Boiler | | Power Boiler 2 Stoker Fired Boiler | |
| Type of Fuel | | Bark & TDF | | Coal | |
| Case *50% – 100% MCR - Unit 1* *50% to 75% MCR - Unit 2* | (Steam) | 250k lb/hr | 250k lb/hr | 170k /b/hr | 170k lb/hr |
| Load | (MMBtu/hr) | 580.0 | 580.0 | 615.0 | 615.0 |
| Baseline NOx | (lb/MMBtu) | 0.594 | 0.594 | 0.416 | 0.416 |
| Expected SNCR NOx Reduction | (%) | 32.5% | 45.0% | 27.5% | 35.0 |
| SNCR Target NOx | (lb/MMBtu) | 0.401 | 0.327 | 0.302 | 0.270 |
| Urea Consumption Rate, 50% by Wt | (gph) | 56.5 | 77.7 | 36.9 | 47.2 |

As shown in Figure 6-1, two cases, differentiated by $NO_X$ reduction rates and urea consumption rates, are considered for each boiler. A third scenario based on 20 percent reduction, consistent with the actual operation of the SNCR at Temple Inland, is considered for No. 1 Power Boiler. Cost estimates for each case are provided in Appendix B, and summary is shown in Table 6-1.

**TABLE 6-1. $NO_X$ CONTROLS COSTS SUMMARY**

| Emission Unit | Scenario | Total Annualized Cost (MM$) | Based on Max. Day Baseline, Annualized: $NO_X$ Removed (tpy) | Based on Max. Day Baseline, Annualized: Cost Effectiveness ($/ton) | Based on Actual Annual Average Emissions: $NO_X$ Removed (tpy) | Based on Actual Annual Average Emissions: Cost Effectiveness ($/ton) |
|---|---|---|---|---|---|---|
| No. 1 Power Boiler | SNCR 20.0% | 1.12 | 169 | 6,632 | 88 | 12,700 |
| | SNCR 32.5% | 1.14 | 274 | 4,176 | 143 | 7,996 |
| | SNCR 45.0% | 1.51 | 379 | 3,990 | 198 | 7,640 |
| No. 2 Power Boiler | SNCR 27.5% | 0.84 | 616 | 1,370 | 422 | 1,998 |
| | SNCR 35.0% | 1.03 | 784 | 1,309 | 537 | 1,909 |

## 6.2 EVALUATION OF VISIBILITY IMPACTS FROM $NO_X$ CONTROLS

A final impact analysis was conducted to assess the visibility improvement for the various SNCR scenarios and, as requested, MdN at each of the boilers. The emission rates used in the modeling scenarios are presented in Table 6-2 and the results are presented in Table 6-3.

**TABLE 6-2. $NO_X$ ANALYSES MODELED EMISSION RATES**

| Emission Unit | Scenario | $NO_X$ Emissions (lb/hr) | $SO_2$ Emissions (lb/hr) | $PM_{10}$/PMF Emissions (lb/hr) |
|---|---|---|---|---|
| No. 1 Power Boiler | Baseline | 207.4 | 21.0 | 30.4 |
| | SNCR 20.0% | 165.9 | 21.0 | 30.4 |
| | SNCR 32.5% | 140.0 | 21.0 | 30.4 |
| | SNCR 45.0% | 114.1 | 21.0 | 30.4 |
| | MdN | 103.7 | 21.0 | 30.4 |
| No. 2 Power Boiler | Baseline | 526.8 | 788.2 | 81.6 |
| | SNCR 27.5% | 381.9 | 788.2 | 81.6 |
| | SNCR 35.0% | 342.4 | 788.2 | 81.6 |
| | MdN | 263.4 | 788.2 | 81.6 |

**TABLE 6-3. VISIBILITY IMPAIRMENT IMPROVEMENT ATTRIBUTED TO $NO_X$ CONTROLS**

| Emission Unit | Scenario | 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 |
| No. 1 Power Boiler | Baseline | 0.335 | 0 | 0.038 | 0 | 0.020 | 0 | 0.014 | 0 |
| | SNCR 20.0% | 0.274 | 0 | 0.031 | 0 | 0.017 | 0 | 0.011 | 0 |
| | *Improvement Over Baseline* | *0.061* | *0* | *0.007* | *0* | *0.003* | *0* | *0.003* | *0* |
| | SNCR 32.5% | 0.237 | 0 | 0.027 | 0 | 0.014 | 0 | 0.009 | 0 |
| | *Improvement Over Baseline* | *0.098* | *0* | *0.011* | *0* | *0.006* | *0* | *0.005* | *0* |
| | SNCR 45.0% | 0.199 | 0 | 0.023 | 0 | 0.012 | 0 | 0.008 | 0 |
| | *Improvement Over Baseline* | *0.136* | *0* | *0.015* | *0* | *0.008* | *0* | *0.006* | *0* |
| | MdN | 0.183 | 0 | 0.021 | 0 | 0.011 | 0 | 0.007 | 0 |
| | *Improvement Over Baseline* | *0.152* | *0* | *0.017* | *0* | *0.009* | *0* | *0.007* | *0* |
| No. 2 Power Boiler | Baseline | 0.844 | 49 | 0.146 | 0 | 0.105 | 0 | 0.065 | 0 |
| | SNCR 27.5% | 0.678 | 35 | 0.134 | 0 | 0.095 | 0 | 0.060 | 0 |
| | *Improvement Over Baseline* | *0.166* | *14* | *0.012* | *0* | *0.010* | *0* | *0.005* | *0* |
| | LNB 30.0% | 0.663 | 32 | 0.132 | 0 | 0.094 | 0 | 0.060 | 0 |
| | *Improvement Over Baseline* | *0.181* | *17* | *0.014* | *0* | *0.011* | *0* | *0.005* | *0* |
| | *Improvement Over SNCR 27.5%* | *0.015* | *3* | *0.002* | *0* | *0.001* | *0* | *0.000* | *0* |
| | SNCR 35.0% | 0.632 | 30 | 0.129 | 0 | 0.092 | 0 | 0.059 | 0 |
| | *Improvement Over Baseline* | *0.212* | *19* | *0.017* | *0* | *0.013* | *0* | *0.006* | *0* |
| | *Improvement Over SNCR 27.5%* | *0.046* | *5* | *0.005* | *0* | *0.003* | *0* | *0.001* | *0* |
| | *Improvement Over LNB 30.0%* | *0.031* | *2* | *0.003* | *0* | *0.002* | *0* | *0.001* | *0* |
| | MdN | 0.548 | 19 | 0.117 | 0 | 0.087 | 0 | 0.057 | 0 |
| | *Improvement Over Baseline* | *0.296* | *30* | *0.029* | *0* | *0.018* | *0* | *0.008* | *0* |

## 6.3 PROPOSED BART FOR $NO_X$

The No. 1 Power Boiler does not contribute to visibility impairment greater than 0.5 Δdv nor any single day of impairment at any of the Class I areas. Therefore, the considered control options provide no improvement in visibility impairment and the costs of the control options are not justified. Domtar proposes no controls with a BART emission determination of 207.4 lb/hr (the baseline rate). Domtar proposes to demonstrate compliance with this limit by calculating emissions on a monthly and rolling 12-month basis, updated within 15 days of the end of each month and submitted in semi-annual reports.

For the No. 2 Power Boiler, Domtar proposes a BART determination of 345 lb/hr (rounded up from 342.4 lb/hr). This proposal represents a six percent decrease – and an accompanying visibility impairment improvement of two fewer days with impacts greater than 0.5 Δdv – compared to the original 2007 BART proposal, which was based on the installation of low-$NO_X$ burners (LNB) and which represented a 30 percent decrease compared to baseline emissions. This level of emissions is potentially achievable through the use of SNCR. Because of the high level of uncertainly around the use and effectiveness of SNCR, Domtar does not feel it is prudent to add the full potential control efficiencies for both LNB and SNCR. Also, Domtar requests that a specific technology not be specified as BART so that it has flexibility to pursue any option that achieves the BART emissions level. Domtar proposes to demonstrate compliance with this limit on a 30-day rolling average as measured by the existing CEMS.

# APPENDIX A – MODELING PROTOCOL

# CALMET DATA PROCESSING PROTOCOL ▲ BART DETERMINATION
# OKLAHOMA GAS & ELECTRIC

**MUSKOGEE GENERATING STATION**
**SEMINOLE GENERATING STATION**
**SOONER GENERATING STATION**


**Prepared by:**

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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 $\Delta$dv.

## 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 |

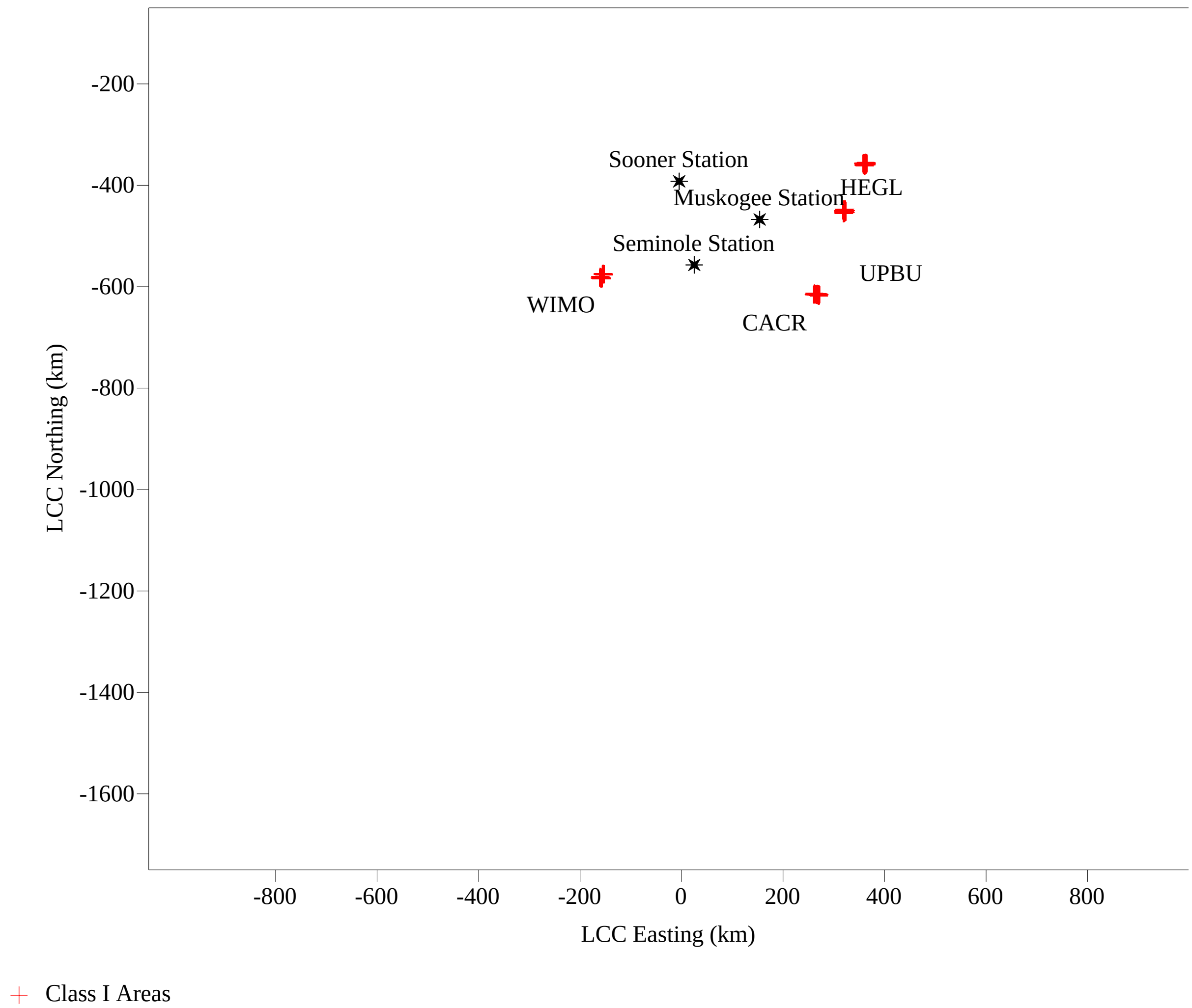
As required in CENRAP's BART Modeling Guidelines, Class I areas within 300 km of each station will be included in each analysis. The following table summarizes the distances of the four closest Class I areas to each station. As seen from this summary, some Class I areas are more than 300 km from the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

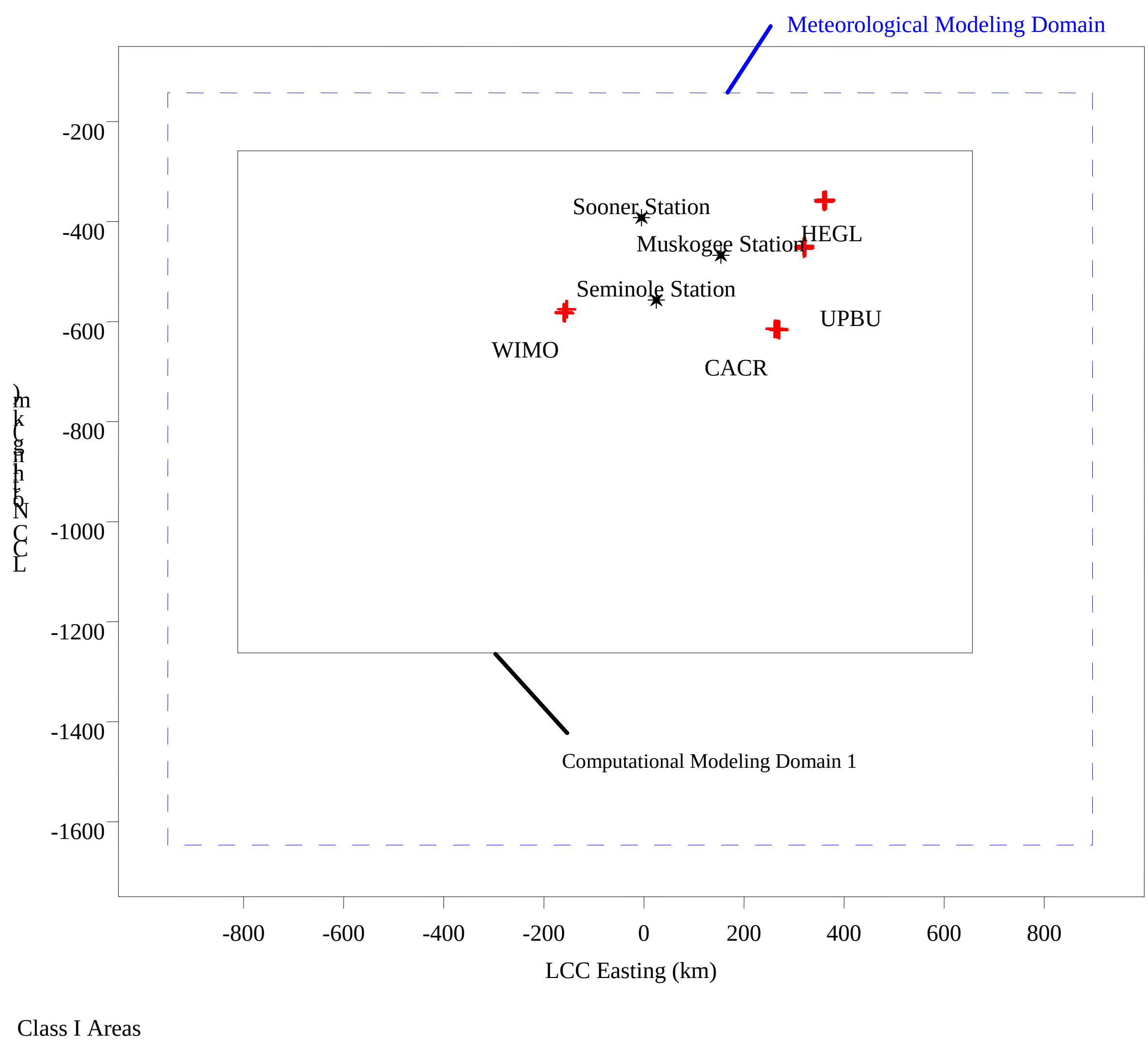
| Processor | Version | Level |
|---|---|---|
| TERREL | 3.3 | 030402 |
| CTGCOMP | 2.21 | 030402 |
| CTGPROC | 2.63 | 050128 |
| MAKEGEO | 2.2 | 030402 |
| CALMET | 5.53a | 040716 |
| CALPUFF | 5.8 | 070623 |
| POSTUTIL | 1.3 | 030402 |
| CALPOST | 5.51 | 030709 |

## 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 40°N, Longitude 97°W. The southwest corner will be set to -951.547 km LCC, -1646.637 km LCC corresponding to Latitude 24.813 °N and Longitude 87.778°W. 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.

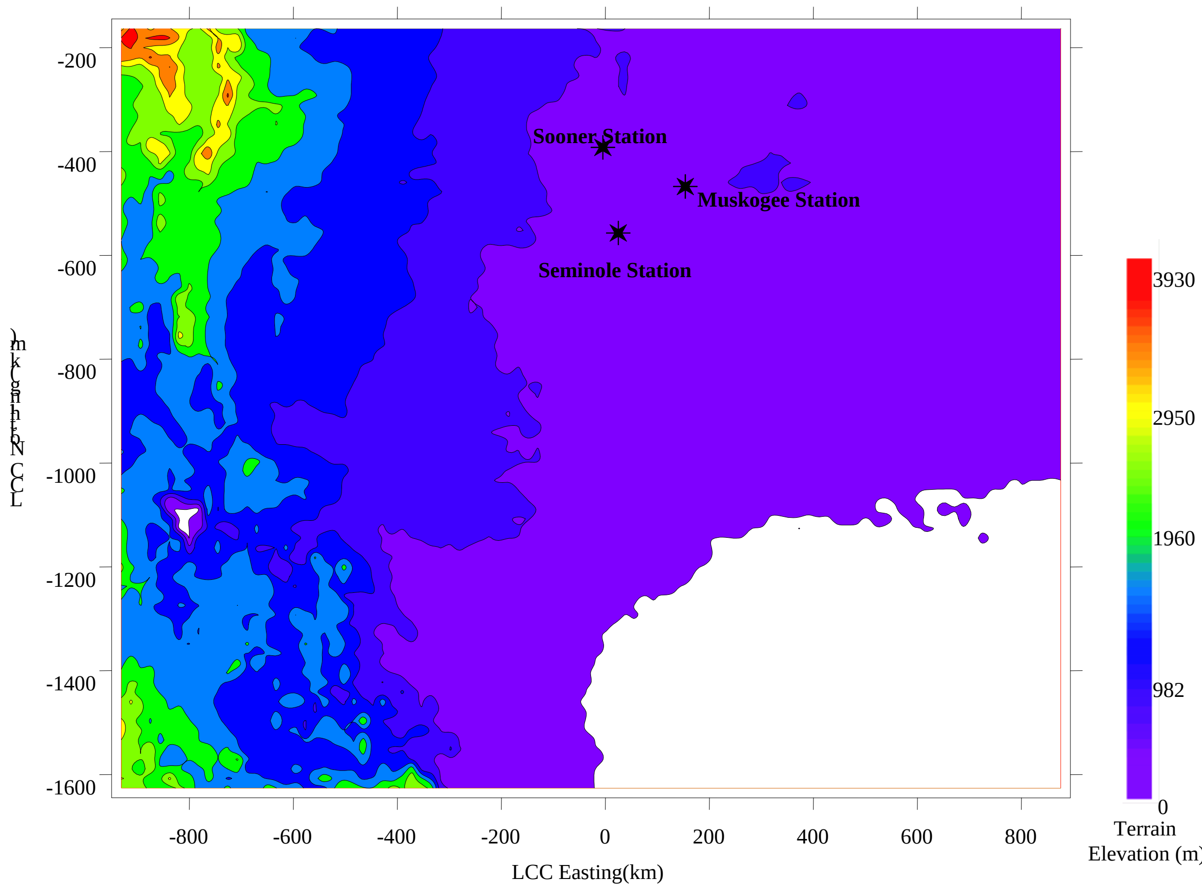
## 3.1 GEOPHYSICAL DATA

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.

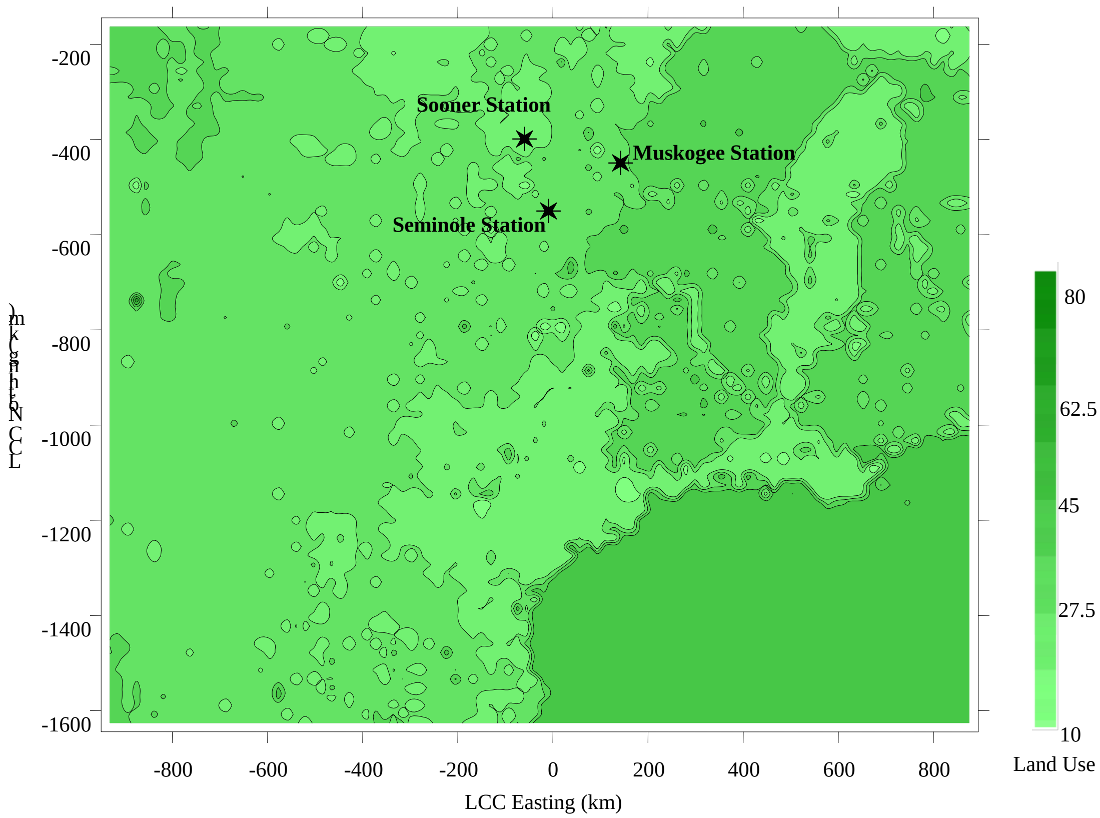
**FIGURE 3-1. PLOT OF LAND ELEVATION USING USGS TERRAIN DATA**




### 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 5$^{th}$ 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.

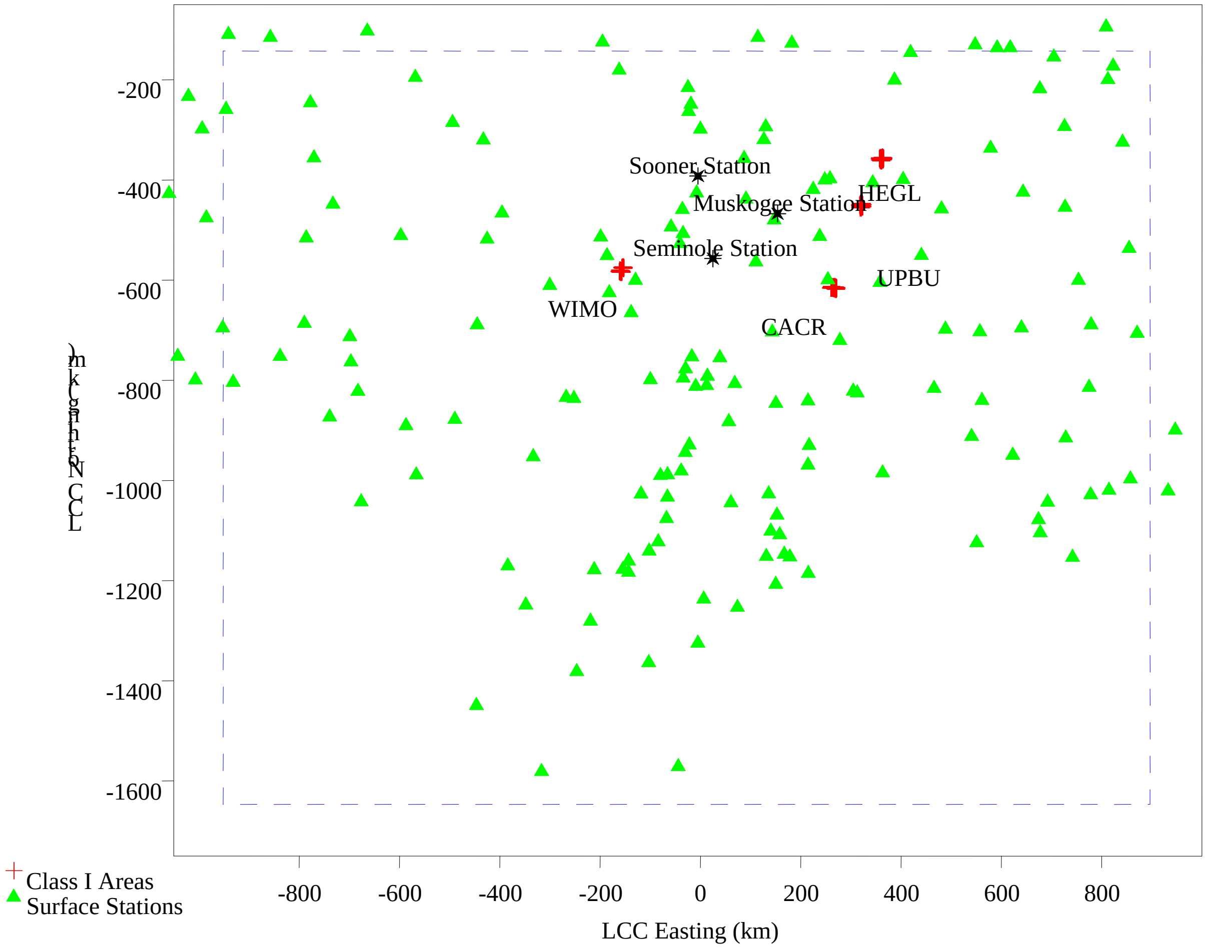
The time periods covered by the data in each of the MM5 files extracted by Alpine Geophysics include a specific number of calendar days, where the data starts at Hour 0 in GMT for the first calendar day and ends at Hour 23 in GMT on the last calendar day. In order to run CALMET in the local standard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

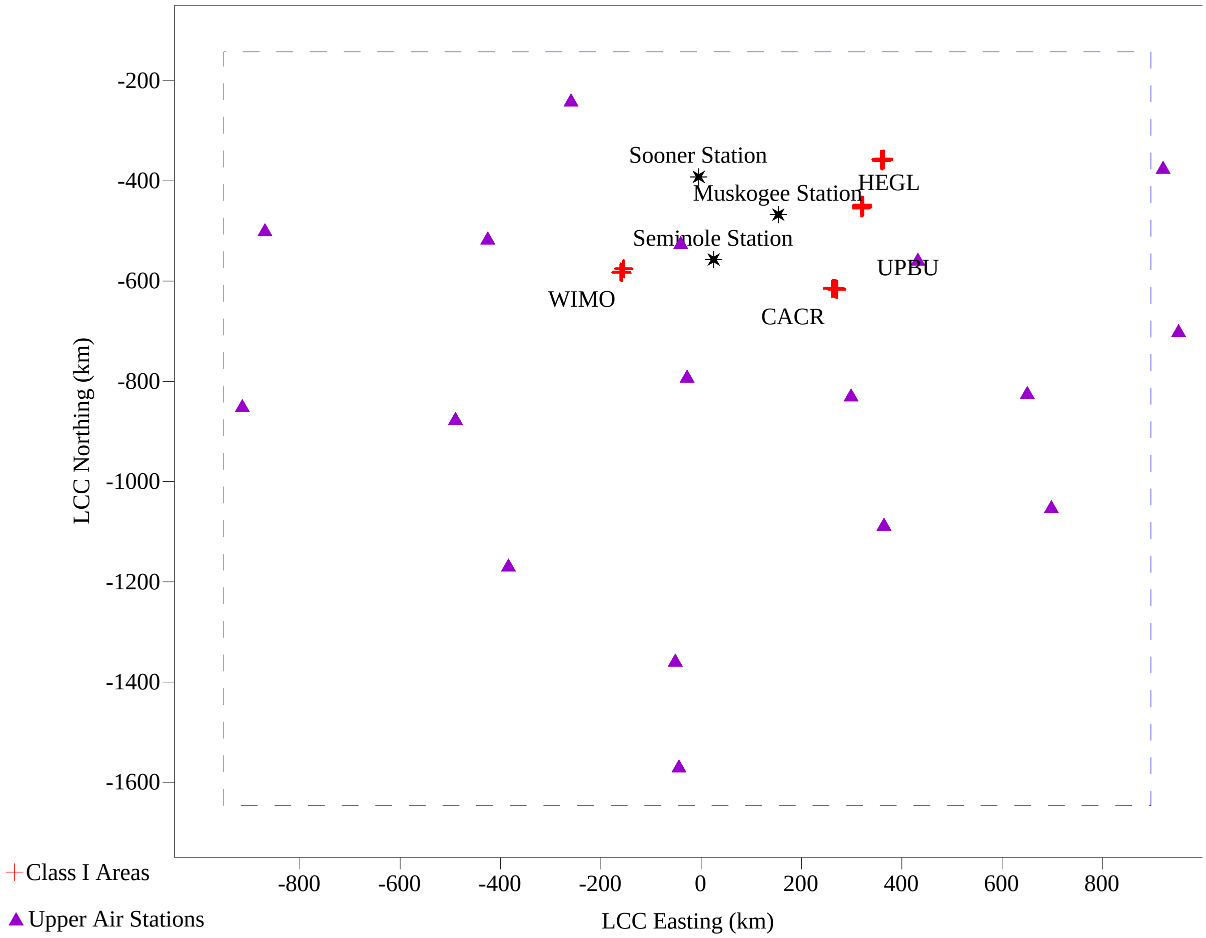
**FIGURE 3-3. PLOT OF SURFACE STATION LOCATIONS**




### 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.

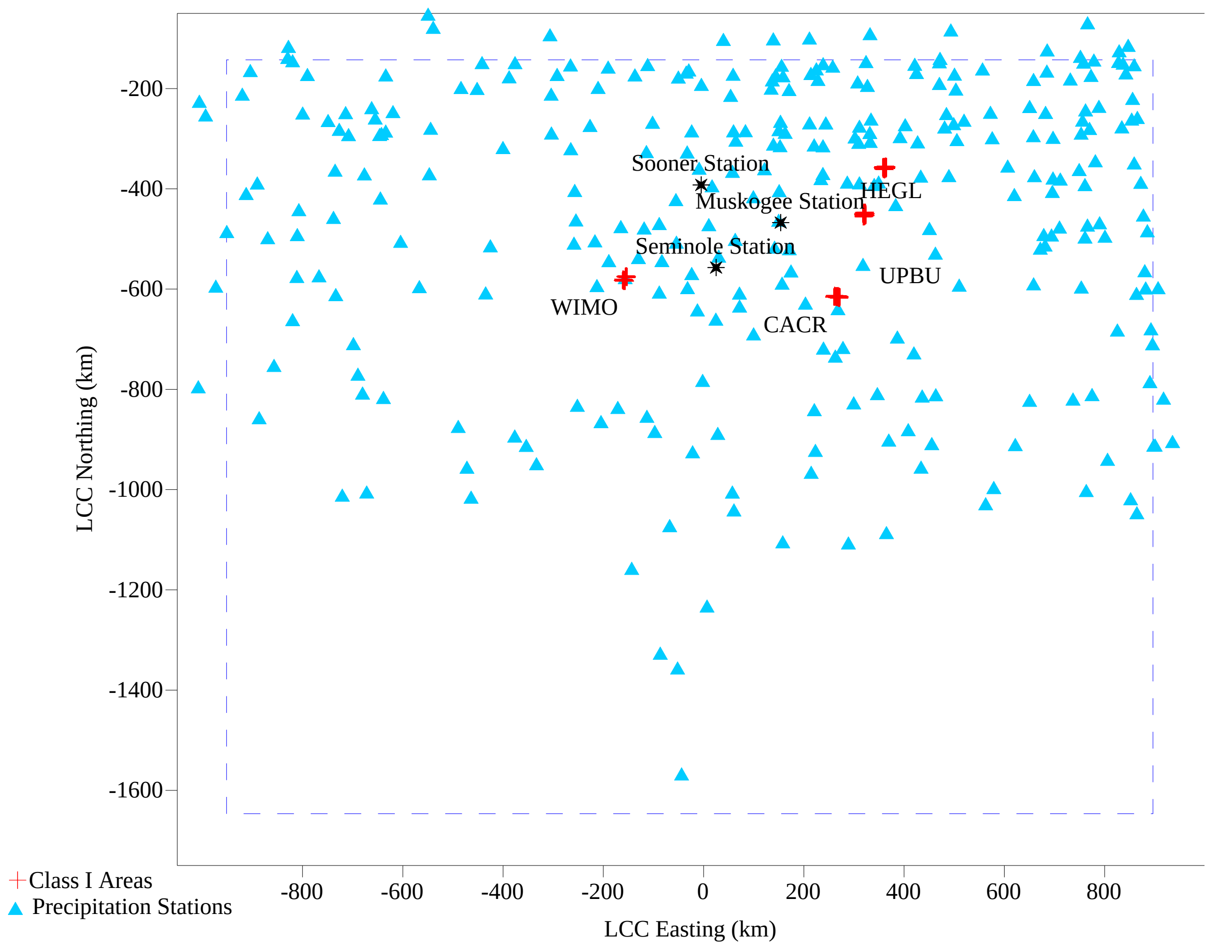
**FIGURE 3-4. PLOT OF UPPER AIR STATIONS LOCATIONS**




## 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.

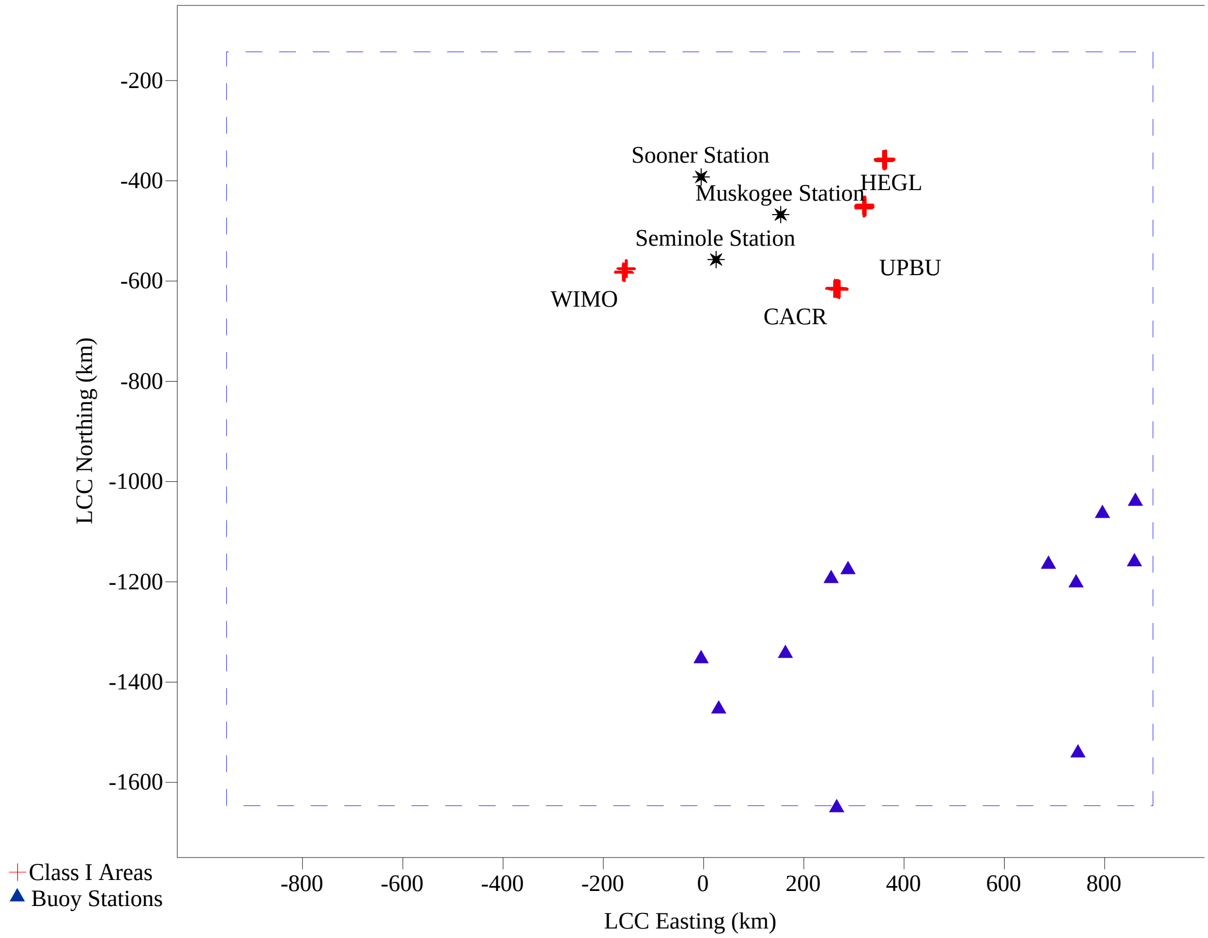
**FIGURE 3-5. PLOT OF PRECIPITATION METEOROLOGICAL STATIONS**




## 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 B – DETAILED CONTROL COST CALCULATIONS

## ADD-ON SPRAY SCRUBBER FOR NO. 2 POWER BOILER $SO_2$ CONTROL

## SNCR for No. 1 Power Boiler $NO_X$ Control

## SNCR for No. 2 Power Boiler $NO_X$ Control

**Add-On Scrubber/~~WESP~~ Capital and O&M Cost Estimate for No. 2 Power Boiler**

| | | |
|---|---|---|
| **Capital Costs** | | |
| Technology<br>Wet Scrubber/~~ESP~~ for No. 2 Power Boiler | | |
| Max Heat Input (MMBtu/hr) | | 820 |
| System Flow Rate (SCFM dry)[1] | | 142,737 |
| Scrubber Exit Gas Temp. (°F)[1] | | 136 |
| Exit Moisture (% wt)[1] | | 12.3 |
| System Flow Rate (ACFM) | | 183,730 |
| Annual Operating Time (θ') , 2001-2003 average | | 8,502 |
| Water Use (gal/yr)[10] | | 1,874,592,263 |
| Electricity Cost ($Cost_{elect}$, $/kwh)[2] | | $0.05 |
| Water Cost ($Cost_{water}$, $/gal)[3] | | $0.00008 |
| $SO_2$ Control Efficiency[1] | | 90% |
| ~~ESP Plate Area (ft²)~~[4] | | NA |
| **Purchased Equipment Cost (PEC)[1]** | | **$2,050,000** |
| **Total Capital Investment (TCI)** | = PEC + Costs to Retrofit[11] | **$7,175,000** |
| Capital recovery factor (CRF) | CRF = [ I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life<br>a. Equipment CRF, 30-yr life, 7% interest[5] | 0.0806 |
| **Annual Costs[6]** | | |
| Variable (Direct) Annual Costs - Table 2.9 | | |
| Operating Labor | | |
| Operator [13] | 3hr/shift*2shifts/day*360 days/yr * $22/hr | $47,520 |
| Supervisor | 15% of operator labor | $7,128 |
| Maintenance | | |
| Labor | Estimated based on past site-specific | $60,000 |
| Material | experience / maintenace costs for other scrubbers | $110,000 |
| Utilities | | |
| Fan[7] | = 108 kW × $Cost_{elect}$ | $45,913 |
| ~~ESP operating power~~[8] | $= 1.94 \times 10^{-3} \times A \times \theta'$ | NA |
| Pump[9] | $= 0.746 \times Q_l \times Z \times S_g \times \theta' / 3{,}960\eta \times$ Costelect | $23,803 |
| Water Cost | = Water use × water cost | $146,593 |
| Wastewater treatment[3] | = $3.25/1000 gal × Annual water use | $6,092,425 |
| Sorbent (caustic) usage[12] | = $0.875/lb × Annual sorbet use (5 lb/min) | $2,300,000 |
| **Total Variable (Direct) Annual Cost** | | **$8,833,382** |
| Fixed (Indirect) Costs, IC | | |
| Administrative charges | 2% of Total Capital Investment | $143,500 |
| Property tax | 1% of Total Capital Investment | $71,750 |
| Insurance | 1% of Total Capital Investment | $71,750 |
| Overhead | 60% of total labor and material costs | $134,789 |
| **Total Fixed (Indirect) Costs** | | **$421,789** |
| **Annualized Capital Cost** | Capital Recovery Factor * Total Capital Investment | **$578,207** |
| **Total Annual Cost** | | **$9,833,378** |

| | |
|---|---|
| **Based on *Modeled Baseline Maximum Daily* Emission Rates:** | |
| Total Uncontrolled NOx Emissions (tpy) | 3351 |
| Pollutant Removed (tpy) | 3016 |
| **Cost Effectiveness ($/ton removed)** | $3,261 |
| **Based on *Actual Annual* Emission Rates:** | |
| Total Uncontrolled NOx Emissions (tpy) | 2078 |
| Pollutant Removed (tpy) | 1870 |
| **Cost Effectiveness ($/ton removed)** | $5,258 |

1: From A.H. Lundberg Associates, Inc. Budget Proposal, June 22, 2012, amended April 17, 2014.
2: Electricity cost form Arkansas Industrial Energy Clearinghouse, http://www.arkansasiec.org/newsmanager/templates/?a=71&z=1
3: Water cost estimate from Ashdown Mill 2013 Budget.

5: Capital recovery interest rate and equipment life from EPA Air Pollution Control Cost Manual (APCCM), 6th Edition (January 2002). Section 6, Chapter 3 - Electrostatic Precipitators, pp. 3-50 and 3-51.
6: Annual Cost estimates made using the EPA Air Pollution Control Cost Manual (APCCM), 6th Edition (January 2002). Section 6, Chapter 3 - Electrostatic Precipitators
7: Fan power demand from A.H. Lundberg Associates, Inc. Budget Proposal, April 17, 2014.

9: For pump power cost:
$Q_l$ = water flow rate (gal/min)
Z = Fluid head (ft), assume maximum fluid heat is 50 ft
$S_g$ = specific gravity of water being pumped compared to water at 70 °F and 29.92 in. Hg, assume 1
θ' = annual operating time (h/yr)
η = pump motor efficiency (fractional), assume efficiency of 60%
10: Liquid to gas ratio: 20 gal/1,000 acf, from A.H. Lundberg Associates, Inc. Budget Proposal, June 22, 2012 - Process description section
11: Domtar's engineers estimate that PEC accounts for only approximately 40 % of the total investment to place a new WESP into service.
This estimate, equivalent to a 2.5 factor, or an even greater factor (up to 3.5) in some cases, is used by Domtar's engineers for all non-Appropriations Request (AR) level sales proposal cost estimates. Additionaly, in this specific case, because there is no room (real estate) at the Ashdown Mill to place a WESP, an additional 1.0 factor is included to account for the need to build a substantial support structure - most likely over a road.
If the extra retrofit factor is not included, then the TCI is $13,175,000 and the cost effectiveness decreases by $200 to $300/ton depending on which baseline averaging period is used.
12: Lundberg estimated a sorbent usage rate of 5 lb/min (2,628,000 lb/yr) is needed to achieve the additional 90 percent (overall 99 percent).
13: Contracted labor rate at the Ashdown Mill.
14: Based on historical annual cost for maintenance and cleaning for the existing WESP on the No. 1 Power Boiler.

**SNCR Capital and O&M Cost Estimate for No. 1 Power Boiler**

| Technology<br>SNCR | | Case 1 | Case 2 | Case 3 |
|---|---|---|---|---|
| Parameters/Costs | Equation[1] | Unit 1 | Unit 1 | Unit 1 |
| Boiler design capacity, mmBtu/hr ($Q_B$) | $Q_B$ | 580 | 580 | 580 |
| Total operating time ($t_{op}$, hrs/yr) | $t_{op} = CF_{total} \times 8760$ hrs/yr | 8130.72 | 8130.72 | 8130.72 |
| Total Capacity Factor ($CF_{total}$) | $CF_{total} = CF_{plant} \times CF_{SNCR}$ | 0.93 | 0.93 | 0.93 |
| Plant Capacity Factor ($CF_{plant}$)[2] | | 0.93 | 0.93 | 0.93 |
| SNCR Capacity Factor ($CF_{SCNR}$)[3] | $CF_{SNCR} = t_{SNCR}/365$ | 1 | 1 | 1 |
| Electricity Cost ($Cost_{elect}$, \$/kwh)[6] | | $0.05 | $0.05 | $0.05 |
| Water Cost ($Cost_{water}$, \$/gal)[7] | | $0.00008 | $0.00008 | $0.00008 |
| Bark Cost ($Cost_{bark}$, \$/MMBtu)[8] | | $5.57 | $5.57 | $5.57 |
| Bark HHV (Btu/lb)[9] | | 2,657 | 2,657 | 2,657 |
| Cost of Ash Disposal ($C_{ash}$, \$/ton)[10] | | $23.06 | $23.06 | $23.06 |
| Capital recovery factor (CRF) | CRF = [ I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life<br>a. Equipment CRF, 30-yr life, 7% interest | 0.0806 | 0.0806 | 0.0806 |
| Cost Index[11]<br>a. 2012 Cost Index<br>b. 1998 Cost Index | <br>584.6<br>389.5 | | | |
| **Capital Costs** | | | | |
| Direct Capital Cost (A) | DC (\$) = (\$950/MMBtu) × $Q_B$ × ((2375 MMBtu/hr/$Q_B$)^0.577) × (0.66 + 0.85$\eta_{NOx}$) × ($CI_{2011}/CI_{1998}$) | $1,890,576 | $1,697,892 | $1,505,207 |
| Indirect Installation Costs (\$) | | | | |
| General Facilities | 0.05 × A | $94,529 | $84,895 | $75,260 |
| Engineering and Home Office Fees | 0.10 × A | $189,058 | $169,789 | $150,521 |
| Process Contingency | 0.05 × A | $94,529 | $84,895 | $75,260 |
| Total Indirect Installation Costs (B) | = General Facilities Cost + Engineering and Home Office Fees + Process Contingency | $378,115 | $339,578 | $301,041 |
| Other Installation Costs (\$) | | | | |
| Project Contingency (C) | C = 0.15 × (A + B) | $340,303.77 | $305,620.53 | $270,937.29 |
| Total Plant Cost (D) | D = A + B + C | $2,608,996 | $2,343,091 | $2,077,186 |
| Allowance for Funds During Construction (E) | E = 0 (Assumed for SNCR) | $0 | $0 | $0 |
| Royalty Allowance (F) | F = 0 (Assumed for SNCR) | $0 | $0 | $0 |
| Preproduction Cost (G) | G = 0.02 × (D + E) | $52,180 | $46,862 | $41,544 |
| Inventory Capital (H)[12] | H = $Vol_{reagent}$ (gal) × $Cost_{reagent}$ (\$/gal) | $46,255 | $33,635 | $33,635 |
| $Cost_{reag}$, 50% Urea solution (\$/gal)[13] | | 1.77 | 1.77 | 1.77 |
| Volume of Reagent Tank ($Vol_{reagent}$ (gal)) | $Vol_{reagent}$ (gal) = $q_{sol}$ x days of reagent supply × 24 hr/day | 26,107 | 18,984 | 18,984 |
| Urea solution volumetric flow rate ($q_{sol}$, gal/hr)[14] | Estimated by SNCR vendor, Fuel Tech | 77.7 | 56.5 | 56.5 |
| Mass flow rate of urea solution ($m_{sol}$, lb/hr)[15] | Estimated by SNCR vendor, Fuel Tech | 738.15 | 536.75 | 536.75 |
| Mass flow rate of reagent ($m_{reagent}$, lb/hr)[15] | Estimated by SNCR vendor, Fuel Tech | 369.08 | 268.38 | 268.38 |
| Normalized Stoichiometric Ratio (NSR) | Not needed since usage estimates were provided | | | |
| Initial Catalyst and Chemicals (I) | I = 0 (Assumed for SNCR due to no catalyst) | $0 | $0 | $0 |
| **Total Capital Investment (TCI) (Capital Cost)** | **TCI = D + E + F + G + H + I** | **$2,707,431** | **$2,423,587** | **$2,152,365** |
| | | | | |
| **Annual Costs (\$)** | | | | |
| Annual Maintenance Cost (J) | J = 0.015 × TCI | $40,611 | $36,354 | $32,285 |
| Annual Reagent Cost (K) | $K = q_{sol} \times Cost_{reag} \times t_{op}$ | $1,119,315 | $813,917 | $813,917 |
| Annual Electricity Cost (L) | Not Estimated | | | |
| Power (P, kW) | Not Estimated | | | |
| Annual Water Cost (M) | $M = q_{water} \times Cost_{water} \times t_{op}$ | $225 | $164 | $164 |
| Water flowrate for SNCR system ($q_{water}$, gal/hr)[17] | $q_{water} = (m_{sol}/\rho_{water}) \times [(C_{ureasolstored}/C_{ureasolinj}) - 1]$ | 353.82 | 257.28 | 257.28 |
| Annual ΔBark Cost (N) | $N = \Delta Bark \times Cost_{bark} \times t_{op}$ | $135,268 | $98,361 | $98,361 |
| Additional bark required (ΔBark, MMBtu/hr)[18] | $\Delta Bark = (Hv \times m_{reagent} \times [(1/C_{ureasolinj}) - 1])/10^6$ Btu/MMBtu | 2.99 | 2.17 | 2.17 |
| Annual ΔAsh Cost (O) | Not Estimated | | | |
| Additional ash generated (ΔAsh , lb/hr) | Not Estimated | | | |
| **Direct Annual Costs (DAC)/Variable O&M** | **DAC = J + K + L + M + N + O** | **$1,295,419** | **$948,795** | **$944,726** |
| **Indirect Annual Costs (IDAC)/Annualized Capital Cost** | **IDAC = CFR × TCI** | **$218,182** | **$195,308** | **$173,451** |
| **Total Annualized Costs (TAC)** | **TAC = DAC + IDAC** | **$1,513,602** | **$1,144,103** | **$1,118,178** |
| Removal Efficiency | | 45% | 32.5% | 20.0% |
| **Based on *Modeled Baseline Maximum Daily* Emission Rates:** | | | | |
| Total Uncontrolled NOx Emissions (tpy) | | 843 | 843 | 843 |
| Pollutant Removed (tpy) | | 379 | 274 | 169 |
| **Cost Effectiveness (\$/ton removed)** | | **$3,990** | **$4,176** | **$6,632** |
| **Based on *Actual Annual* Emission Rates:** | | | | |
| Total Uncontrolled NOx Emissions (tpy) | | 440 | 440 | 440 |
| Pollutant Removed (tpy) | | 198 | 143 | 88 |
| **Cost Effectiveness (\$/ton removed)** | | **$7,640** | **$7,996** | **$12,700** |

[1] All SNCR costing equations from EPA Air Pollution Control Cost Manual (APCCM), 6th Edition (January 2002

[2] Average from 2001 - 2003.

[3] $t_{SCNR}$ assumed to be 365 days

[5] Baseline.

[6] Electricity cost form Arkansas Industrial Energy Clearinghouse, http://www.arkansasiec.org/newsmanager/templates/?a=71&z=

[7] Water cost estimate from Ashdown Mill 2013 Budget.

[8] Bark cost estimate from Ashdown Mill 2013 Budget.

[9] Average from 2001 - 2003.

[10] Ash disposal cost estimate from contracts for ash transport, end use (as soil amendment), and ash pond management.

[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 = $373/metric ton, from http://www.indexmundi.com/commodities/?commodity=urea&months=180. Confirmed as an accurate price with a local supplier, CDI, Inc. (Corporate office: Brea, CA; Local distribution point: Crossett, AR) on January 27, 2014.
Density of 50% urea solution = 9.5 lb/gal (50% urea solution) based on EPA APCCM, 2002.

[14] $\rho_{reagent} = 71.0$ lb/ft$^3$

[15] $C_{ureasol}$ = urea solution concentration = 50%

[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

**SNCR Capital and O&M Cost Estimate for No. 2 Power Boiler**

| Technology<br>SNCR | | *Case 1* | *Case 2* |
|---|---|---|---|
| Parameters/Costs | Equation[1] | Unit 2 | Unit 2 |
| Boiler design capacity, mmBtu/hr ($Q_B$) | $Q_B$ | 820 | 820 |
| Total operating time ($t_{op}$, hrs/yr) | $t_{op} = CF_{total} \times 8760$ hrs/yr | 8502.47 | 8502.47 |
| Total Capacity Factor ($CF_{total}$) | $CF_{total} = CF_{plant} \times CF_{SNCR}$ | 0.97 | 0.97 |
| Plant Capacity Factor ($CF_{plant}$)[2] | | 0.97 | 0.97 |
| SNCR Capacity Factor ($CF_{SCNR}$)[3] | $CF_{SNCR} = t_{SNCR}/365$ | 1 | 1 |
| Electricity Cost ($Cost_{elect}$, \$/kwh)[6] | | \$0.05 | \$0.05 |
| Water Cost ($Cost_{water}$, \$/gal)[7] | | \$0.00008 | \$0.00008 |
| Coal Cost ($Cost_{coal}$, \$/MMBtu)[8] | | \$2.50 | \$2.50 |
| Coal HHV (Btu/lb)[9] | | 9,643 | 9,643 |
| Cost of Ash Disposal ($C_{ash}$, \$/ton)[10] | | \$23.06 | \$23.06 |
| Capital recovery factor (CRF) | CRF = [ I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life<br>a. Equipment CRF, 30-yr life, 7% interest | 0.0806 | 0.0806 |
| Cost Index[11]<br>a. 2012 Cost Index<br>b. 1998 Cost Index | <br>584.6<br>389.5 | | |
| **Capital Costs** | | | |
| Direct Capital Cost (A) | DC (\$) = (\$950/MMBtu) × $Q_B$ × ((2375 MMBtu/hr/$Q_B$)^0.577) × (0.66 + 0.85$\eta_{NOx}$) × ($CI_{2011}/CI_{1998}$) | \$2,024,314 | \$1,889,536 |
| Indirect Installation Costs (\$) | | | |
| General Facilities | 0.05 × A | \$101,216 | \$94,477 |
| Engineering and Home Office Fees | 0.10 × A | \$202,431 | \$188,954 |
| Process Contingency | 0.05 × A | \$101,216 | \$94,477 |
| Total Indirect Installation Costs (B) | = General Facilities Cost + Engineering and Home Office Fees + Process Contingency | \$404,863 | \$377,907 |
| Other Installation Costs (\$) | | | |
| Project Contingency (C) | C = 0.15 × (A + B) | \$364,377 | \$340,116 |
| Total Plant Cost (D) | D = A + B + C | \$2,793,553 | \$2,607,560 |
| Allowance for Funds During Construction (E) | E = 0 (Assumed for SNCR) | \$0 | \$0 |
| Royalty Allowance (F) | F = 0 (Assumed for SNCR) | \$0 | \$0 |
| Preproduction Cost (G) | G = 0.02 × (D + E) | \$55,871 | \$52,151 |
| Inventory Capital (H)[12] | H = $Vol_{reagent}$ (gal) × $Cost_{reagent}$ (\$/gal) | \$28,099 | \$21,967 |
| $Cost_{reag}$, 50% Urea solution (\$/gal)[13] | | 1.77 | 1.77 |
| Volume of Reagent Tank ($Vol_{reagent}$ (gal)) | $Vol_{reagent}$ (gal) = $q_{sol}$ x days of reagent supply × 24 hr/day | 15,859 | 12,398 |
| Urea solution volumetric flow rate ($q_{sol}$, gal/hr)[14] | Estimated by SNCR vendor, Fuel Tech | 47.2 | 36.9 |
| Mass flow rate of urea solution ($m_{sol}$, lb/hr)[15] | Estimated by SNCR vendor, Fuel Tech | 448.40 | 350.55 |
| Mass flow rate of reagent ($m_{reagent}$, lb/hr)[15] | Estimated by SNCR vendor, Fuel Tech | 224.20 | 175.28 |
| Normalized Stoichiometric Ratio (NSR) | Not needed since usage estimates were provided | | |
| Initial Catalyst and Chemicals (I) | I = 0 (Assumed for SNCR due to no catalyst) | \$0 | \$0 |
| **Total Capital Investment (TCI) (Capital Cost)** | **TCI = D + E + F + G + H + I** | **\$2,877,523** | **\$2,681,678** |
| | | | |
| **Annual Costs (\$)** | | | |
| Annual Maintenance Cost (J) | J = 0.015 × TCI | \$43,163 | \$40,225 |
| Annual Reagent Cost (K) | K = $q_{sol} \times Cost_{reag} \times t_{op}$ | \$711,033 | \$555,871 |
| Annual Electricity Cost (L) | Not Estimated | | |
| Power (P, kW) | Not Estimated | | |
| Annual Water Cost (M) | M = $q_{water} \times Cost_{water} \times t_{op}$ | \$143 | \$112 |
| Water flowrate for SNCR system ($q_{water}$, gal/hr)[17] | $q_{water} = (m_{sol}/\rho_{water}) \times [(C_{ureasolstored}/C_{ureasolinj}) - 1]$ | 214.93 | 168.03 |
| Annual ΔCoal Cost (N) | N = ΔCoal × $Cost_{coal} \times t_{op}$ | \$38,602 | \$30,178 |
| Additional coal required (ΔCoal, MMBtu/hr)[18] | ΔCoal = (Hv × $m_{reagent}$ × [(1/$C_{ureasolinj}$) - 1])/$10^6$ Btu/MMBtu | 1.82 | 1.42 |
| Annual ΔAsh Cost (O) | O = (ΔAsh × $Cost_{ash} \times t_{op}$)/2000 lb/ton | \$1,385 | \$1,083 |
| Additional ash generated (ΔAsh , lb/hr)[19] | ΔAsh = (ΔCoal × ashproduct × $10^6$ Btu/MMBtu)/HHV | 14.12 | 11.04 |
| **Direct Annual Costs (DAC)/Variable O&M** | **DAC = J + K + L + M + N + O** | **\$794,325** | **\$627,469** |
| **Indirect Annual Costs (IDAC)/Annualized Capital Cost** | **IDAC = CFR × TCI** | **\$231,889** | **\$216,107** |
| **Total Annualized Costs (TAC)** | **TAC = DAC + IDAC** | **\$1,026,214** | **\$843,575** |
| Removal Effciency | | 35.0% | 27.5% |
| **Based on *Modeled Baseline Maximum Daily* Emission Rates:** | | | |
| Total Uncontrolled NOx Emissions (tpy) | | 2,240 | 2,240 |
| Pollutant Removed (tpy) | | 784 | 616 |
| **Cost Effectiveness (\$/ton removed)** | | **\$1,309** | **\$1,370** |
| **Based on *Actual Annual* Emission Rates:** | | | |
| Total Uncontrolled NOx Emissions (tpy) | | 1,536 | 1,536 |
| Pollutant Removed (tpy) | | 537 | 422 |
| **Cost Effectiveness (\$/ton removed)** | | **\$1,909** | **\$1,998** |

[1] All SNCR costing equations from EPA Air Pollution Control Cost Manual (APCCM), 6th Edition (January 2002)
[2] Average from 2001 - 2003.
[3] $t_{SCNR}$ assumed to be 365 days
[5] Baseline.
[6] Electricity cost form Arkansas Industrial Energy Clearinghouse, http://www.arkansasiec.org/newsmanager/templates/?a=71&z=1
[7] Water cost estimate from Ashdown Mill 2013 Budget.
[8] Cost of coal from Lazard's 2009 Levelized Cost of Energy Analysis (LCOE)
[9] Average from 2001 - 2003.
[10] Ash disposal cost estimate from contracts for ash transport, end use (as soil amendment), and ash pond management.

[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 = $373/metric ton, from http://www.indexmundi.com/commodities/?commodity=urea&months=180. Confirmed as an accurate price with a local supplier, CDI, Inc. (Corporate office: Brea, CA; Local distribution point: Crossett, AR) on January 27, 2014.
Density of 50% urea solution = 9.5 lb/gal (50% urea solution) based on EPA APCCM, 2002.

[14] $\rho_{reagent}$ = 71.0 lb/ft$^3$
[15] $C_{ureasol}$ = urea solution concentration = 50%

[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.

**TABLE C-1. BASELINE VISIBILITY IMPAIRMENT**

| Unit | Class I Area | Year | Number of Days ≥ 0.5 Δdv | Maximum (Δdv) | 98th %tile (Δdv) | Species Contribution to 98th %tile % $SO_4$ | % $NO_3$ | % $PM_{10}$ | % $NO_2$ |
|---|---|---|---|---|---|---|---|---|---|
| No. 1 Power Boiler | CACR | 2001 | 0 | 0.476 | 0.335 | 2.23 | 85.26 | 6.68 | 5.83 |
| | | 2002 | 0 | 0.406 | 0.191 | 2.02 | 84.37 | 7.71 | 5.90 |
| | | 2003 | 0 | 0.308 | 0.171 | 5.47 | 82.28 | 5.88 | 6.37 |
| | UPBU | 2001 | 0 | 0.065 | 0.023 | 11.38 | 82.50 | 6.08 | 0.04 |
| | | 2002 | 0 | 0.090 | 0.038 | 2.75 | 85.89 | 8.03 | 3.32 |
| | | 2003 | 0 | 0.055 | 0.025 | 1.52 | 87.91 | 6.58 | 3.99 |
| | HERC | 2001 | 0 | 0.061 | 0.013 | 6.65 | 89.35 | 3.63 | 0.37 |
| | | 2002 | 0 | 0.077 | 0.020 | 2.70 | 91.82 | 3.94 | 1.55 |
| | | 2003 | 0 | 0.047 | 0.020 | 3.06 | 85.94 | 7.36 | 3.64 |
| | MING | 2001 | 0 | 0.023 | 0.010 | 3.14 | 91.28 | 5.09 | 0.49 |
| | | 2002 | 0 | 0.038 | 0.014 | 4.03 | 90.06 | 5.13 | 0.78 |
| | | 2003 | 0 | 0.060 | 0.011 | 2.11 | 89.98 | 5.84 | 2.06 |
| No. 2 Power Boiler | CACR | 2001 | 28 | 1.340 | 0.844 | 22.04 | 70.68 | 4.58 | 2.69 |
| | | 2002 | 13 | 1.603 | 0.673 | 40.41 | 44.82 | 8.10 | 6.67 |
| | | 2003 | 8 | 0.852 | 0.604 | 25.77 | 60.15 | 7.64 | 6.44 |
| | UPBU | 2001 | 0 | 0.349 | 0.146 | 76.99 | 20.76 | 2.26 | 0.00 |
| | | 2002 | 0 | 0.332 | 0.127 | 30.27 | 57.93 | 7.56 | 4.24 |
| | | 2003 | 0 | 0.381 | 0.117 | 41.02 | 54.57 | 3.58 | 0.83 |
| | HERC | 2001 | 0 | 0.239 | 0.080 | 44.59 | 51.57 | 3.70 | 0.13 |
| | | 2002 | 0 | 0.329 | 0.083 | 38.51 | 55.05 | 5.24 | 1.20 |
| | | 2003 | 0 | 0.196 | 0.105 | 61.17 | 37.68 | 1.06 | 0.09 |
| | MING | 2001 | 0 | 0.139 | 0.065 | 81.46 | 15.47 | 3.07 | 0.00 |
| | | 2002 | 0 | 0.162 | 0.054 | 38.98 | 57.12 | 3.40 | 0.50 |
| | | 2003 | 0 | 0.246 | 0.055 | 93.42 | 3.28 | 3.29 | 0.01 |

**Vendor (“Lundberg”) Information/Sales Proposal for No. 2 Power Boiler $SO_2$ Control**

**Vendor (“Fuel Tech”) Information/Sales Proposal for No. 1 and No. 2 Power Boilers $NO_X$ Control**

LUNDBERG

13201 Bel-Red Road
Bellevue, Washington 98005
tel: 425.283.5070
fax: 425.283.5081

April 17, 2014

Reference: P-125387, Rev.01

Attention: Ms. Kelley Crouch

Subject: $SO_2$ Scrubber for Power Boiler No. 2

Domtar Industries, Inc.
285 Highway 71 S
Ashdown, AR 71822-8356

Dear Ms. Crouch:

In response to your recent request, Lundberg is pleased to submit the following revised budget proposal for the supply of an $SO_2$ scrubbing system No. 2 power boiler at the Ashdown Mill. As you know, the original June, 2012 proposal included an $SO_2$ scrubbing system and a wet ESP for particulate control. In this revision the wet ESP has been eliminated.

As before, the proposal is to supply add-on spray scrubbers downstream of the existing venturi scrubbers. The spray scrubbers will utilize sodium hydroxide to absorb $SO_2$. The design efficiency for the scrubbers will continue to be 90% and all other process considerations addressed in the first proposal will remain the same.

The only significant change in the scrubber design is that we have changed to an upflow configuration. Without a downstream wet ESP operation in the upflow mode will save some cost because the gas can discharge directly out the top of the scrubber.

If you have any questions about the proposal, please feel free to me a call at 425/283-5070.

Thank you for the opportunity to present this proposal. We look forward to working with you on this project.

Sincerely,

Steven A. Jaasund, P.E.
Manager—Geoenergy Products
Lundberg

enc: Proposal

cc: Mr. Eric Gardner, Lundberg/ Monroe, LA
Mr. Rudi Miksa, Lundberg/Monroe, LA

P-125387, Rev.01

April 17, 2014

# LUNDBERG

## BUDGET PROPOSAL

### SPRAY SCRUBBER

## DOMTAR INDUSTRIES

### ASHDOWN AR

Our representative in your area:

Mr. Eric Gardner
210 Pinehurst Drive
Monroe, LA 71201
Phone: 318/366-5909

Mr. Rudi Miksa
P.O. Box 7266
Monroe, LA 71211
Phone: 318/361-0165

**PRESENTED BY:** Steven A. Jaasund, P.E.

## TABLE OF CONTENTS

## INTRODUCTION

Lundberg proposes to supply an add-on spray scrubber for the control of $SO_2$ emissions from the No. 2 power boiler at the Domtar Industries Pulp Mill in Ashdown, Arkansas.

The proposal includes two identical gas cleaning trains each including a spray scrubber.

## PROCESS DESCRIPTION

The spray scrubber/wet ESP trains will be installed downstream of the existing venturi scrubbers and will utilize the main boiler fan on a forced draft basis. We anticipate a maximum of 3 inches w.c. will be necessary to overcome the added resistance of the add-on equipment. If this additional pressure is not available from the existing fan, the capacity can be gained by reducing the pressure drop through your existing scrubber an appropriate amount. This pressure drop reduction will not have a significant effect on the size requirements of the new wet ESP.

The spray scrubbers will be an upflow design utilizing downward facing spray headers to maximize liquid to gas contact. The unit will operate at a liquid to gas ratio of 20 gal/1000 acf and will utilize a pH adjusted scrubbing solution to affect a minimum of 90% $SO_2$ absorption. Sodium hydroxide will be used to maintain pH at the required level.

After exiting the spray scrubbers, the gas streams will exit directly out of the top through a stub stack.

A process flow diagram and a general arrangement drawing for the system proposed are included in the appendix of this proposal.

## Design Base

The following process information will be used for the design of the spray scrubber/wet ESP system.

| NO. 2 POWER BOILER DESIGN CONDITIONS | |
|---|---|
| Fuel | Coal, bark, natural gas, TDF, (planning on fuel oil in future) |
| Boiler Type | Stoker |
| Volumetric Gas Flow (scfm dry) | 142,737 |
| Scrubber Exit Gas Temp. (°F) | 136 |
| Exit Moisture (% wt) | 12.3 |
| PM Loading (lb/hr) | 44.6 |
| SO2 Concentration (ppmv) | 235.9 |

The spray scrubber/wet ESP equipment offered will be designed to reduce the $SO_2$ concentration by 90%.

## Energy Requirements

The following table shows the expected energy demands of the wet ESP system described in this proposal.

| SPRAY SCRUBBER ENERGY REQUIREMENTS | |
|---|---|
| Scrubber pumps (kW) | 108 |
| Flange to flange pressure drop (in. w.c.) | 3 |

## PROPOSED SUPPLY

The following list summarizes the major components of the systems offered to treat the emissions from the power boiler.

| ITEM | QUANTITY | DESCRIPTION |
|---|---|---|
| 1 | One (1) lot | System Engineering, including process flow diagrams, process and instrument diagrams, general arrangement drawings, functional narrative of the logic, assembly drawings, instrument specifications, pump specifications, and operation and maintenance manual complete with spare parts lists |
| 2 | Two (2) only | Spray scrubbers; T-316L SS, upflow design with recycle pump, tank and piping |
| 3 | Two (2) only | Discharge stacks; T-316L SS |
| 4 | Two (2) lots | Support and access steel |
| 5 | Two (2) lots | Field instrumentation |
| 6 | One (1) lot | Commissioning, start-up and training |
| 7 | One (1) lot | Local wiring of all electrical elements |
| 8 | One (1) lot | Complete mechanical installation |

## COMMERCIAL TERMS AND CONDITIONS

### CLARIFICATIONS AND WORK BY OTHERS

1. Ducting from the existing scrubber to the inlet flange of the spray scrubbers is not included
2. The cost of a crane to lift the equipment offered to the top of the No. 2 boiler building is not included
3. Structural steel to the bottom of the spray scrubbers is not included. Structural and access steel above this level is included.
4. Civil work or improvements to existing structures is not included. Lundberg will provide foundation-loading information.
5. Performance testing is not included
6. Lundberg will require access to mill drawings and records required to design the proposed system.
7. The client is responsible for obtaining all necessary building/environmental permits, taxes and professional engineering fees.
8. The client is to provide a lay down area close to the work site, as well as field fabrication area for piping, etc.
9. The client is to supply steam and process water as required by the erection crew free of charge. Also parking area, trailer space(s), and access to phone lines. Phone line hookup will be by Lundberg. Lundberg is to supply electrical power for construction.
10. Construction crews may be union or non-union.
11. The client is responsible for the removal, handling, disposal, or replacement of all asbestos materials, lead paint, or contaminated soils that may be encountered.
12. The client is to provide an on-site location for construction debris.
13. Any required demolition work is not included in our bid.

### PRICE

The budget price for the spray scrubber system, Items 1-7, is:

Two million fifty thousand dollars

$2,050,000.00

These prices are FOB mill site. Prices do not include applicable taxes. All prices are in U.S. dollars.

The purchaser assumes liability for payment to the state of any Sales or Use tax if he uses or consumes the property herein purchased in such a way as to render the sale subject to tax.

## TERMS OF PAYMENT

The terms of payment shall be:

- 5% with purchase order.
- 10% with submittal of approval drawings (process flow sheets, equipment drawings and general arrangements.
- 25% with order placed for major equipment (WESP) .
- 10% on delivery of 10" diameter collection electrodes to the shop.
- 5% on construction mobilization.
- 15% on delivery of WESP to the mill; partial shipment allowed.
- 25% on monthly percent completion of construction.
- 5% on satisfaction of performance warranty on each unit, not to exceed six (6) months from shipment. This may be secured by a letter of credit at Lundberg's option, and due at shipment.

Payment will be due thirty (30) days after date of invoice.

## ERECTION ADVISOR

If the Buyer elects to be responsible for the installation of the equipment the services of a qualified erection advisor can be made available at a rate of $1350.00 per man day (man day being ten (10) hours) plus expenses. Charges after ten (10) hours will be $170.00 per hour. Expenses are to include first class food and lodging, economy travel to and from plant site to lodging, and travel to and from project from the normal domicile of the engineer.

## TRAINING SERVICES

Training is included as a part of the equipment package. The additional services of a trainer can be made available at a rate of $1,500.00 per man day (man day being eight (8) hours) plus expenses. Charges after eight (8) hours will be $210.00 per hour. Expenses are to include first class food and lodging, economy travel to and from plant site to lodging, and travel to and from project from the normal domicile of the engineer.

## START-UP SERVICES

Start-up services are included as a part of the equipment package. The additional services of an engineer can be made available at a rate of $1350.00 per man day (man day being ten (10) hours), plus expenses. Charges after ten (10) hours will be $170.00 per hour. Expenses are to include first class food and lodging, economy travel to and from plant site to lodging, and travel to and from project from the normal domicile of the engineer.

## SHIPMENT

Shipment will be made twenty-six (26) weeks after receipt of order. Shipment schedule requires that approval drawings, when submitted, will be returned within two (2) weeks. The time to complete erection is very dependent on site conditions. Normally equipment of this size can be installed in less than 8 weeks.

## CANCELLATION

Should Purchaser place an order for the equipment proposed and later find it necessary to cancel, Purchaser shall pay the full amount for any equipment, portions thereof, or orders for which Vendor is liable, plus charges for engineering work completed at that time, plus fifteen (15) percent of the total costs incurred.

## PERFORMANCE WARRANTY

Lundberg will provide the equipment and process engineering as specified in this proposal for a complete and operable system and guarantee that the inlet $SO_2$ concentration will be reduced by 90% but no lower than 20 ppmv.

This guarantee is in effect when the system is operated in and supplied with the service conditions in general accordance with the Design Base of this proposal.

US EPA Method 1, 2, 3, 4, and 6 shall be used to quantify the $SO_2$ concentration at the outlet of the equipment.

Acceptance tests must be performed within three (3) months after initial start-up of the equipment, not to exceed six (6) months after final shipment. The testing shall be performed by an independent third party that is acceptable to both Buyer and Seller.

The warranty shall be fully satisfied and Lundberg discharged there from upon the earlier of: (a) obtaining guaranteed performance by the testing described above, (b) the expiration of three (3) months from initial start-up with no testing being made, (c) the expiration of six (6) months from final shipment without a test being made.

If the guaranteed performance is not obtained, then Lundberg shall have the right, and if required by the Owners, the obligation, to visit the installation to determine the cause of such failure. It is a condition of this guarantee that the Owner will cooperate with Lundberg in the making of further tests and make available necessary personnel, feed and operating conditions to enable Lundberg to conduct such tests. The tests will be paid for by the purchaser.

If failure to obtain guaranteed performance on the above is due to defect in Lundberg-supplied equipment, design, or engineering, then Lundberg will, at its expense, supply the equipment or process engineering it deems necessary until such performance is met, up to a limit of the contract price. Any remedy includes an equivalent scope of installation as outlined elsewhere in this proposal.

If failure to obtain guaranteed performance is due to the Purchaser's fault in operation, or in not providing proper feed or other specified operating conditions, the Owner shall pay the living and traveling expenses of Lundberg personnel visiting the installation. In addition, the Owner shall pay the sum of $1,300.00 per man-day or fraction thereof for such personnel. Nevertheless, such personnel will, on request, work with the Owner at the Owner's expense in making necessary corrections to accommodate the changed conditions.

## Material and Workmanship

We guarantee every part of the apparatus delivered in accordance with this proposal will be of proper material and workmanship, and agree to repair any part or parts which may prove defective in material or workmanship within twelve months from startup of equipment but not to exceed eighteen months from date of shipment on each unit, it being agreed that such replacement is the full extent of our liability in this connection. Scope of supply of such replacement shall be identical to the scope of supply of the original project. Corrosion or wear from abrasion shall not be considered as defective materials. The best engineering practice will always be followed and materials used will be clearly specified. We shall not be held liable or responsible for work done or expense incurred in connection with repairs, replacements, alterations, or additions made, except on our written authority.

## Vendor's Responsibility

In the course of design of processes and/or equipment where the Vendor provides process flow diagrams, layouts, and installation diagrams, it is anticipated that Vendor furnished design will be followed. Changes in design without written approval of the Vendor will relieve the Vendor of responsibility for performance of the supplied equipment.

## Drawings Limitation

All Vendor drawings supplied to the customer or his engineer under an order resulting from this proposal will remain the property of the Vendor and are conditionally loaned with the understanding that they will not be copied or used except as authorized by us. Reuse of the designs as shown on the drawings for another project is specifically prohibited.

## Confidentiality of Proposal Information

This proposal contains confidential information and remains the property of Lundberg and is conditionally loaned. The information contained herein is not to be shared with any party except those within the Buyer's company who are involved in its evaluation or outside consultants who are assisting the Buyer with this specific project. Specifically prohibited is the distribution of such information to any individual or business deemed to be a competitor by Lundberg.

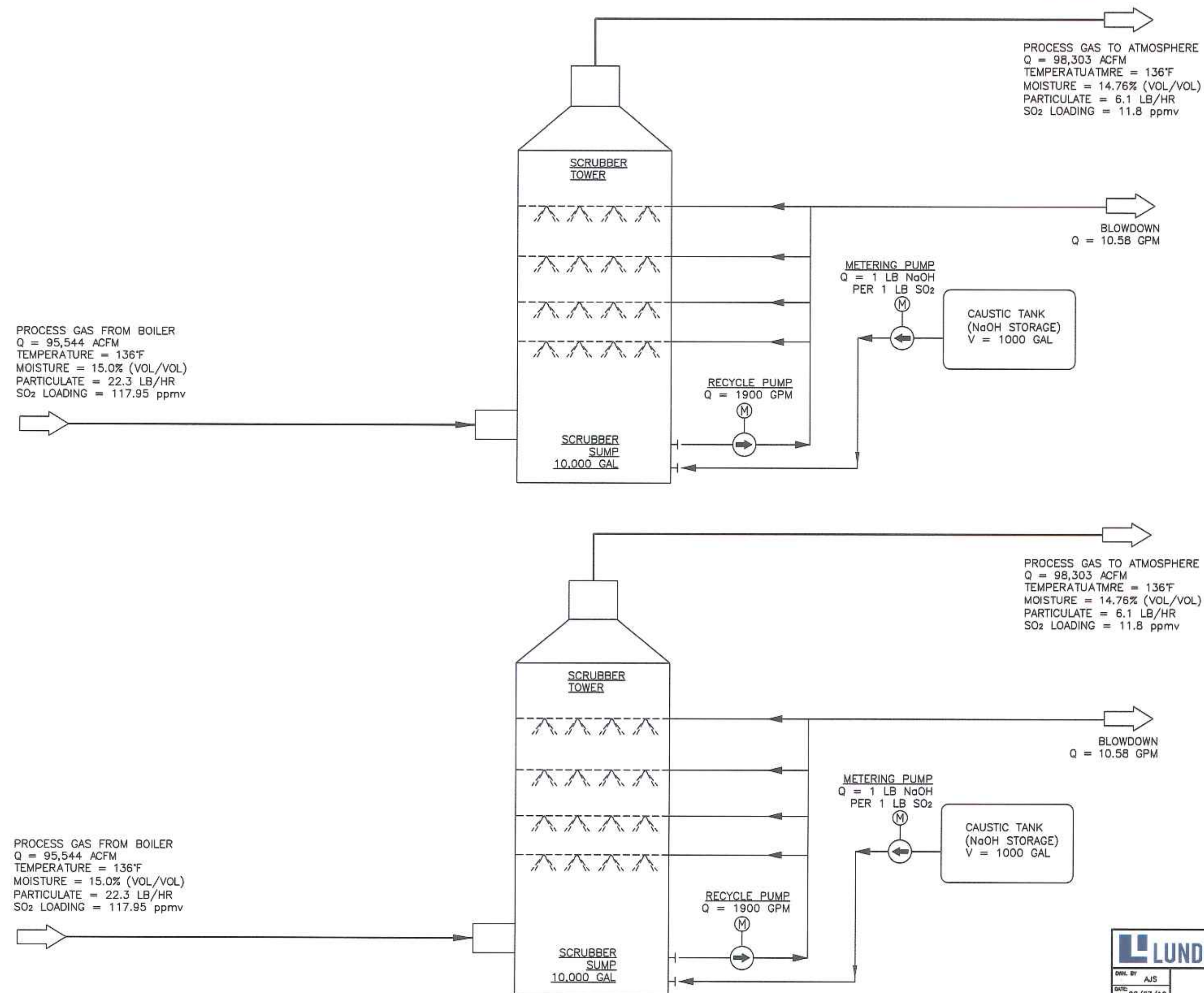
## Security Interest

Lundberg reserves the right to request a security interest in the materials provided as a part of this proposal, and Buyer agrees to provide information needed to assist Lundberg in obtaining a security interest and to execute such documents Lundberg reasonably requests to create a security interest. Security interest language is available on request.

## Enclosures

General Arrangement Drawing

Process Flow Diagram

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DRN. BY AJS | DATE 08/27/12 | CHK. BY | DATE | APP. BY | DATE

DOMTAR
ASHDOWN, ARKANSAS
BOILER #2 EMISSIONS

MODEL 1200 SPRAY TOWER SCRUBBER
PROCESS FLOW DIAGRAM

SCALE: 1/4"=1'-0" | DRAWING NO. AL-125387-P01 | SHT. 1/1 | REV. 01

| REV. | DESCRIPTION | BY | DATE | CHK | DATE | REV. | DESCRIPTION | BY | DATE | CHK | DATE |
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REVISIONS

| DESCRIPTION | DRAWING NO. |
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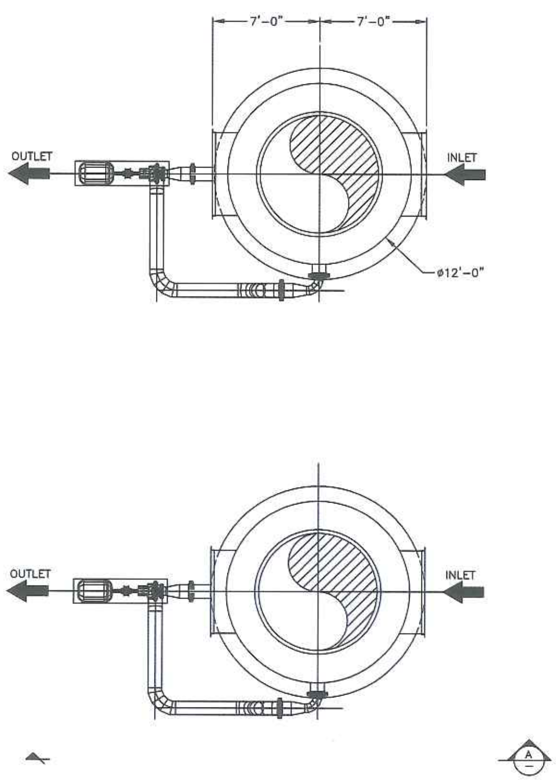
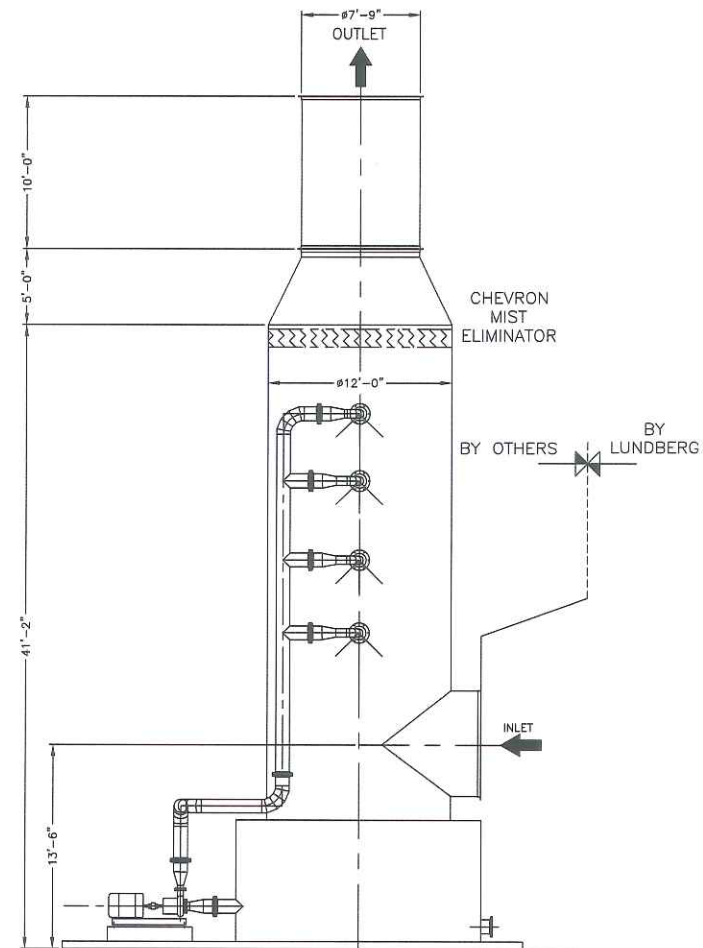
REFERENCE



DWG. NO. AL-125387-P01 SHT. 1/1




MODEL 1200 SPRAY TOWER SCRUBBER
PLAN VIEW
BOILER # 2 EMISSIONS




MODEL 1200 SPRAY TOWER SCRUBBER
ELEVATION VIEW
BOILER # 2 EMISSIONS

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| | REVISIONS | | | | | | REVISIONS | | | | |

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DWN. BY AJS
DATE: 06/27/12
CHK. BY
DATE:
APP. BY
DATE:

DOMTAR
ASHDOWN, ARKANSAS
BOILER #2 EMISSIONS

MODEL 1200 SPRAY TOWER SCRUBBER
GENERAL ARRANGEMENT

| SCALE: | DRAWING NO. | SHT. | REV. |
|---|---|---|---|
| 1/4"=1'-0" | AL-125387-P03 | 1/1 | 01 |

DWG. NO. AL-125387-P03 SHT. 1/1

# Domtar Paper
# Ashdown, Arkansas

# NOx Control Options
# Power Boilers 1 and 2

NOxOUT SNCR® Systems
Power Boilers 1 and 2

NOxOUT SCR System
Power Boiler 2 *(Option)*

Fuel Tech Proposal 12-B-089
June 29, 2012

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TABLE OF CONTENTS

## PROPOSAL SUMMARY

Fuel Tech, Inc. (FTI) is pleased to submit our Proposal 12-B-089 to Domtar Paper covering NOx Control Options for Power Boilers 1 and 2 and the Ashdown Mill. The following proposal provides the technical, performance, and commercial information.

Fuel Tech's Offering has been prepared for two (2) Selective Non-Catalytic Reduction (NOxOUT® SNCR) Systems for Power Boilers 1 and 2 at the Ashdown, Arkansas mill per Domtar's request for proposal dated May 21, 2012. In addition, our proposal includes a catalyst-based Selective Catalytic Reduction, or SCR Option for Power Boiler 2 only, as requested. Both processes would utilize urea as the reagent for the NOx reduction reactions.

## FTI SCOPE OF SUPPLY – SNCR Power Boilers 1&2

The Fuel Tech Equipment Scope of Supply detailed in this proposal provides Unit 1 & 2.

One (1) single-wall FRP reagent storage tank (20,000 gal) with all required appurtenances, which would be common for both boilers.

One (1) urea reagent Circulation Module (with **Optional** Enclosure) to provide a continuous flow of the reagent through the circulation loop piping – the temperature of the concentrated reagent must be maintained at a sufficient level to minimize the potential for crystallization, generally requiring that this loop be heat traced and insulated, also common for both boilers.

Two (2) Metering Modules *(one per boiler)* with Independent Level Control to automatically adjust the reagent and dilution water flow rates and deliver a consistent urea droplet concentration to the distribution modules and injectors.

Six (6) Distribution modules *(three per boiler)* to provide fine, individual control of the diluted and atomized reagent.

Twenty Seven (27) NOxOUT reagent injector assemblies *(15 for PB1 and 12 for PB2).*

Ten (10) NOxOUT Injector automatic retract mechanisms *(for PB1).*

Two (2) Temperature Monitors, *(one per boiler).*

Descriptions of the individual's components identified in the FTI Equipment Scope of Supply summaries, including the module descriptions, estimated module weights and dimensions, are provided later in this Proposal. Expected system utility requirements such as dilution water flow rates, atomizing/cooling air flow rates, and electric power consumption also are provided.

## NOxOUT SNCR® PROCESS DESCRIPTION

The NOxOUT SNCR Process is a post-combustion NOx reduction method that reduces NOx through the controlled injection of reagent into the post-combustion flue gas path. The reagent recommended for this application is a 50% aqueous urea solution, which would be diluted with water having an appropriate quality prior to injection. Depending on the water quality, a stabilized UREA formulation may be recommended to deal with potential issues associated with total water hardness. Whether or not stabilized UREA is required, it is readily available from any of nine (9) licensed UREA suppliers and requires no special safety precautions for handling. Specifically, the chemical makeup of the reagent will not trigger any of the site requirements covered by OSHA standards 1910.119 and 1910.120.

The use of urea for control of oxides of nitrogen was developed under the sponsorship of the Electric Power Research Institute (EPRI) between 1976 and 1981. These early investigations provided fundamental thermodynamic and kinetic information for the NOx-urea reaction chemistry and identified minimal traces of reaction by-products. The predominant reaction is described by:

$$NH_2CONH_2 + 2NO + \frac{1}{2} O_2 \Rightarrow 2N_2 + CO_2 + 2H_2O$$

Urea + Nitrogen Oxide + Oxygen ⇨ Nitrogen + Carbon Dioxide + Water

Through some trace quantities of ammonia and carbon monoxide may form, the level of by-products produced can be minimized through proper application of the process.

The NOx removal efficiency and reagent utilization are related by a variable known as the Normalized Stoichiometric Ratio (NSR). This ratio is defined as shown below. The reagent utilization is equal to the NOx reduction divided by the NSR.

$$NSR = \frac{\text{Actual Molar Ratio of Reagent to Inlet NOx}}{\text{Stoichiometric Molar Ratio of Reagent to Inlet NOx}}$$

Fuel Tech has advanced the original, licensed technology by developing and refining chemical injection hardware, widening the applicable temperature range, and gaining process control expertise as a result of many commercial applications.

## NOxOUT SNCR® PROCESS DESCRIPTION
(Continued…)

Two key parameters that affect the process performance are flue gas temperature and reagent distribution. The NOx reducing reaction is temperature sensitive, typically occurring between 1600°F and 2200°F. By-product emissions (NH3 slip) may become significant at the lower end of this range while chemical utilization and NOx reduction decrease at the higher end of the temperature range. It is important to note that this optimum temperature range is specific to each application. The reagent must be distributed within this optimum temperature zone to achieve the best performance. This particular application, as a result of the isothermal reaction chamber and flue gas temperature, is close to ideal for the SNCR process.

The NOxOUT Process is designed with the aid of computational fluid dynamics (CFD) and our chemical kinetic model (CKM). The CFD model simulates flue gas flows and temperature inside the furnace while the CKM calculates the reaction between urea and NOx based on temperature and flow information from the CFD model. A combination of these two models determines the optimum temperature region and the injection strategy required to effectively distribute the reagent. Recent technology advancements enable Fuel Tech to apply 3D visualization techniques to evaluate rapidly changing operating conditions and their impact on the SNCR process in real time.

Chemical injectors developed by Fuel Tech facilitate the reagent distribution. These injectors use compressed air to atomize and specially designed tips to direct the urea into the post-combustion gas path. The droplet size distribution produced by the injectors promotes efficient contact between the urea and the NOx in the flue gas and service experience.

## SCR PROCESS DESCRIPTION – UNIT 2 Option

Selective Catalytic Reduction (SCR) is a post-combustion NOx control technology that relies on a catalyst bed to host the chemical reduction of nitrous oxides to elemental nitrogen and water using an ammonia reagent. The catalyst bed allows the reaction to occur with high efficacy and at relatively low temperatures.

Application of SCR relies on advanced modeling tools to design the reactor, duct arrangement, flow control devices and ammonia injection grid to achieve mostly uniform conditions of flow, temperature and ammonia-to-NOx distribution to maximize reductions per unit of catalyst with minimal ammonia slip.

Specification of the SCR catalyst is based on determination of pitch and activity suitable for the flue gas conditions and fuel, providing a cross section within design boundaries for space velocity and total volume capable of achieving the minimal performance at end of operating life. SCR catalysts are typically vanadium pentoxide (active ingredient) in a titania base, that are extruded into a ceramic honeycomb substrate or pressed onto an expanded metal substrate. The catalysts are usually assembled in a steel frame (module) of uniform size – approximately 1m x 2m in cross-section and 0.5m to 2.0m in height (catalyst length in direction of flow).

The reagent – ammonia or urea converted to ammonia on site – is injected upstream of the SCR reactor usually via an injection grid. The ammonia is diluted with air (ammonia/air volume ratio is typically 5 to 8% at full load) to help distribution and increase injection velocity. The reagent mixes with the flue gas and enters the SCR reactor housing the catalyst. As the hot flue gas and reagent diffuse through the catalyst and contact activated catalyst sites, the NOx in the flue gas chemically reduces to nitrogen and water. The nitrogen, water vapor, and any other flue gas constituents then flow out of the SCR reactor.

## NOxOUT ULTRA® PROCESS DESCRIPTION – UNIT 2 SCR Option

The NOxOUT ULTRA® process is used in conjunction with a conventional SCR reactor and catalyst, but it relies on the on-site conversion of urea to produce the SCR reagent required to achieve the targeted reduction in NOx. The conversion of urea to ammonia in the NOxOUT ULTRA® process is accomplished through controlled thermal decomposition, which is a highly efficient but much less complicated process than urea hydrolysis.

Fuel Tech has successfully applied the thermal decomposition of urea in NOxOUT® (urea-based) SCR systems that have been in service for many years. NOxOUT ULTRA® is a natural extension of the NOxOUT® SCR process, but rather than decomposing urea in the existing duct system and potentially dealing with distribution, temperature, and residence time issues, urea conversion in the NOxOUT ULTRA® process is completed in an external chamber designed to support the project-specific decomposition reactions and ammonia flow rates.

The NOxOUT ULTRA® system converts concentrated liquid urea to ammonia and delivers a homogeneous air/ammonia mixture to the ammonia injection grid (AIG) at a predetermined flow rate, pressure, and temperature. The reactions of the ULTRA Process are described as:

$NH_2CONH_2 + H_2O \longrightarrow NH_3 + HNCO$
Urea + Water ⟶ Ammonia + Isocyanic Acid
$HCNO + H_2O \longrightarrow NH_3 + CO_2$
Isocyanic Acid + Water ⟶ Ammonia + Carbon Dioxide

Urea, which is unstable at temperatures greater than 300°F, decomposes to NH3 and HNCO when injected in the appropriate temperature environment. HNCO can also convert to NH3 and CO2 by reacting with water. The resultant reagent from this process follows the typical post-combustion SCR process to produce nitrogen and water vapor. The dominant SCR reactions are described as follows:

$4NO + 4NH_3 + O_2 \longrightarrow 4N_2 + 6H_2O$
$NO + NO_2 + 2NH_3 \longrightarrow 2N_2 + 3H_2O$ (dominant)
Nitrogen Oxide(s) + Ammonia + Oxygen ⟶ Nitrogen + Water
$4NO + 4HNCO + O_2 \longrightarrow 4N_2 + 4\,CO_2 + 2H_2O$
Nitrogen Oxide + Isocyanic Acid + Oxygen ⟶ Nitrogen + Carbon Dioxide + Water

The NOxOUT ULTRA® System eliminates all ammonia handling requirements so that the expenses and safety and environmental concerns are removed. The urea solution is readily available for delivery in solution, or in dry form for on-site solutionizing, and requires no special safety precautions for handling which allows the aqueous solution to be stored in tanks vented to atmosphere.

The aqueous urea solution is introduced into the hot air stream of the Decomposition Chamber. The reagent is sprayed through proprietary chemical injectors developed by Fuel Tech to facilitate the reagent distribution and droplet size. Utilizing pressurized air from customer's existing plant compressed air system; these injectors atomize and direct the reagent into the diluted air stream of the NOxOUT ULTRA® System.

**NOxOUT ULTRA® PROCESS DESCRIPTION – UNIT 2 SCR Option…**

The airflow through the Decomposition Chamber including the urea injection will be modeled using a Computational Fluid Dynamics (CFD) model with proprietary droplet trajectory modeling. This will insure proper evaporation, mixing, and decomposition of injected urea reagent within the heated air stream.

The Decomposition Chamber is designed with the appropriate residence time within the temperature window to ensure complete conversion of the urea solution to the SCR reagents. The gas stream containing the SCR reagent is then routed to the AIG. The pressure, flow, and temperature are monitored to conform to the requirements of the SCR system design and to maintain proper ULTRA® operations.

The control of the urea injection will be based on a hardwired reagent demand signal from the Owner's DCS. A short residence time in the decomposition chamber will allow a rapid response time for SCR reagent production, capable of following the 2 – 5 MW per minute load ramping rate. The Decomposition Chamber will require 2 – 4 hours to startup from a "cold start" to allow for heat up and expansion. The system will be able to shutdown almost instantaneously.

The NOxOUT ULTRA® Process thermally decomposes urea and does not involve hydrolysis. Since the NOxOUT ULTRA® process operates at temperatures in the range of 550 to 1,000°F, all of the outlet products are above the 450°F temperature where urea polymers typically start to form. This 400 to 450°F temperature zone appears to be in the range of normal operation of hydrolytic systems, which may contribute unwanted polymerized formaldehyde by-products and frequent maintenance outages.

The features of the NOxOUT ULTRA® system include:

- Safe Reagent Supply
- Skid mounted system for easy installation
- Simplified process and controls compared to other systems (patent pending)
- Designed for maximum system availability and minimum maintenance
- Load following controls for safe operation and easy system shutdown
- Low pressure operation
- Fuel Tech's proven experience with urea based systems and proven system components.

## PROCESS DESIGN TABLE

### Ashdown Mill Power Boilers 1 & 2 - SNCR

| Type of Unit | | Power Boiler 1 Stoker Fired Boiler | | Power Boiler 2 Stoker Fired Boiler | |
|---|---|---|---|---|---|
| Type of Fuel | | Bark & TDF | | Coal | |
| Case ***50% – 100% MCR - Unit 1 50% to 75% MCR - Unit 2*** | (Steam) | 250k lb/hr | 250k lb/hr | 170k /b/hr | 170k lb/hr |
| Load | (MMBtu/hr) | 580.0 | 580.0 | 615.0 | 615.0 |
| Baseline NOx | (lb/MMBtu) | 0.594 | 0.594 | 0.416 | 0.416 |
| Expected SNCR NOx Reduction | (%) | 32.5% | 45.0% | 27.5% | 35.0 |
| SNCR Target NOx | (lb/MMBtu) | 0.401 | 0.327 | 0.302 | 0.270 |
| Urea Consumption Rate, 50% by Wt | (gph) | 56.5 | 77.7 | 36.9 | 47.2 |
| Assumed Avg Temp @ Bullnose EL | (°F) | 2050 | 2050 | 2135 | 2135 |
| Assumed Average CO @ Bullnose EL | (ppm) | 300 | 300 | 200 | 200 |
| Average NH3 Slip (Dry, As Measured) | (ppmd) | 10 | 20 | 10 | 15 |
| Flue Gas Velocity | (ft/sec) | 18.5 | 18.5 | 21.4 | 21.4 |

***Reagent Distribution Strategy***

- Level 1: Ten (10) Standard Flow, Independent Level Control Flow, Retractable Injectors
- Level 2: Five (5) Standard Flow, Fixed Position, Independent Level Control Flow Injectors

***Process Design Comments***

The flue gas flow provided on the CUS for Unit 1 is much lower than what the combustion calculations predict and it has not been used.

Unit 2 runs at 100% MCR, less than 0.3% of the time. The injector locations should be optimized for 75% MCR. The S content for this Unit is expected to be around 0.4% based on the 229 ppm SO2.

Up to 15ppm NH3 may be tolerable, although 10ppm will be more appropriate. The flue gas flow on the CUS is not consistent with the flue gas flow from the combustion calculations and is not used.

Also, the baseline on the CUS is assumed to be lb/MMBtu and not ppm.

## SNCR EQUIPMENT SCOPE OF SUPPLY SUMMARY

| **Power Boilers 1 & 2** | **Ashdown Mill** | |
|---|---|---|
| ***NOxOUT SNCR®*** | ***Unit 1 SNCR*** | ***Unit 2 SNCR*** |
| ***Common Equipment*** | | |
| FRP Urea Storage Tank:20,000 Gal Capacity incl. Tank Heater Control Panel & Tank Valves | 1 | |
| CM-LP Circulation Module w/Control & Drive Starter Panels | 1 | |
| **CM-ENC ***(option)*** Circulation Module Enclosure | 1 | |
| ***Equipment Required per Boiler*** | | |
| | ***Urea & Dilution Water Metering*** | |
| MM-LF-2P Metering Module w/Control & Drive Starter Panels | 1 | 1 |
| | ***Diluted Urea & Atomizing/ Cooling Air Distribution*** | |
| DM-NX-4 Distribution Module | - | 3 |
| DM-NX-5 Distribution Module | 3 | - |
| INJ-NX NOxOUT Injector | 15 | 12 |
| RET-NX | 10 | - |
| CP–RET-5 | 2 | - |
| Temperature Monitor | 1 | 1 |
| ***Additional Equipment and Services*** | | |
| Freight to Jobsite | Included | Included |
| Startup, Optimization, & Training Support Man-days (total) | 30 | |

** **Option:** Circulation Module Enclosure. *SNCR Circulation Module is fabricated to accommodate temperatures ranging from 40° to 104° F. Price for this option can be found in the pricing portion of this proposal.*

## SNCR SCOPE OF SUPPLY EQUIPMENT DESCRIPTIONS

### *FRP UREA STORAGE TANK*

The FRP Urea Storage Tanks are manufactured using Fiberglass Reinforced Plastic (FRP) with a Premium Grade Vinylester Resin. These tanks are fabricated per ASTM D3299, NEC, IEEE, and all applicable OSHA regulations. Site-specific conditions such as low and high ambient temperature, maximum wind load, maximum snow load, and seismic conditions are used to customize the design for a particular geographic location. Each tank is designed to contain a urea-based liquid up to a 1.5 specific gravity. The tank heating package consists of an array of 500 watt, 240 VAC heating pads arranged in multiple levels at a quantity sufficient to maintain an 80°F liquid temperature at the low ambient temperature condition. The pads are covered by polyisocyanurate (PIR or ISO) insulation and the insulation is covered by a second layer of fiberglass and a gel coat for weather protection.

The storage tanks come standard with flanged connections for pump supply, pump return, tank level, tank temperature, and tank fill. A gooseneck vent is included on the top of the tank and a side man-way is installed near the bottom of the tank for maintenance purposes. Other items supplied include a NEC & IEEE-compliant NEMA 4X fiberglass tank heating control panel, a differential pressure level transmitter, multiple isolation valves, tank hold down lugs, brackets to hold the tank to the pad and a J-type Thermocouple. Concrete pad attachment bolts, nuts & washers are not included.
*25,000 Gallon Capacity: 14' Diameter × 21'-9" H; Approximate Empty Weight: 8,500 lb.*
**Reference FTI Drawing C-1**

### *CM-LP CIRCULATION MODULE*

The Low Pressure Circulation Module is designed to continuously circulate the concentrated urea solution and pump the reagent to the Metering Module. The CM-LP module consists of two full flow, single stage centrifugal pumps arranged in a redundant fashion along with an inlet duplex strainer with pressure switch, various pressure gauges, a flow switch, and temperature indication. This module is controlled via an A-B CompactLogix PLC and a PanelView 1500+ operator display with window kit.

The CM-LP Module is constructed on an open frame, stainless steel base in full compliance with ASME B31.1. The pump motors are TEFC and the entire module is rated NEMA 4. The module contains two NEC and IEEE compliant control panels. One control panel houses the 480 VAC, 3 phase equipment including the required disconnects, motor starters, and motor protectors, and the second control panel houses the PLC, all 120 VAC, single phase equipment, and all 24 VDC equipment including a convenience outlet for PLC programming and Ethernet network hub.
*Typical size: 4' W × 8' L × 6' H; Approximate Weight: 1,500 lb.*
**Reference FTI Drawing D-1**

**SNCR SCOPE OF SUPPLY EQUIPMENT DESCRIPTIO**
(Continued…)

### *MM-LF-2P METERING MODULE*

The double pump set, low flow Metering Module provides flow and pressure control and precisely mixes the concentrated urea and dilution water used in the NOxOUT® Process, and pump this mixture to the injectors. The module contains two SS multistage centrifugal water pumps and two SS duplex diaphragm metering pumps arranged in pump sets and all pumps are controlled via separate variable frequency drives. For each pump set, chemical flow is controlled via one magnetic flow meter and water pressure is controlled via one pressure transmitter. Other key components include a cast iron duplex strainer for the water inlet, various pressure gauges, various motor operated valves used for isolation and flushing purposes, individual calibration columns and pulsation dampeners for the chemical pumps, and two inline mixers. This module discharges to two zones of wall injectors.

The Metering Module is constructed on an opened frame, stainless steel base in full compliance with ASME B31.1. The pump motors are TEFC and the entire module is rated NEMA 4. The module contains two NEC and IEEE compliant control panels. One control panel houses the 480 VAC, 3 phase equipment including the required disconnects, electrical distribution equipment and four variable frequency drives. The second control panel contains an Allen-Bradley CompactLogix PLC and a PanelView 1500+ Operator display with window kit. The panel also houses all 120 VAC, single-phase equipment, and all 24 VDC equipment including a convenience outlet for PLC programming and Ethernet network hub.
Typical Size: 4’W x 10’L x 6.5’H, Approximate weight: 2,000 lbs.
**Reference Fuel Tech Drawing: E-5**

### *DM-NX DISTRIBUTION MODULE*

The purpose of the NOxOUT® Distribution Module is to provide mixed chemical and atomizing air to individual NOxOUT Injectors. The module is typically installed near the injectors (usually at the same elevation). Chemical to the module is fed from the Fuel Tech Metering Module. Atomizing Air is typically fed from the plant air system although occasionally, Fuel Tech will supply an Air Compressor. The Distribution Module outputs a pair of feeds to each injector consisting of one atomizing air line and one chemical line. These pairs are grouped together for ease of installation.

The module is constructed in full compliance with ASME B31.1 and includes complete assembly and testing, chemical and air pressure indication, and individual air pressure regulators for each atomizing air line. The pipe-manifold assembly is mounted to a stainless steel frame suitable for wall mounting.
*Typical Size: 2’-4” W × 12” D × 36” H – Approximate Weight: 200 lb.*
**Reference FTI Drawing F-1**

## SNCR SCOPE OF SUPPLY EQUIPMENT DESCRIPTIONS
(Continued…)

### *INJ-NX INJECTOR ASSEMBLY*

The urea injector assemblies are installed at the furnace elevation determined by our process modeling with each appropriately sized and characterized for proper flows and pressures required to achieve the necessary NOx reductions. The injectors are constructed entirely of 316L stainless steel. The nozzle tip is a ceramic-coated 316L stainless steel. The cooling shield is typically 3/4" Inconel tubing or 316 stainless steel with ceramic coating (0.750" OD and 0.065" wall thickness). The inner atomization tube is typically 3/8" tubing with an adapter to accept different injector tips, with a standard length of 2.5 feet.

Each assembly includes Fuel Tech air atomized injector, adapter for insertion adjustment, coupler to attach to boiler support, quick-connects and 6' long steel-braided flex hoses for both the chemical and atomizing air connections.
**Reference FTI Drawing G-1**

### *NOxOUT® INJECTOR AUTOMATIC RETRACT MECHANISM*

The injector automatic retract device is an offset design and mounts on the standard, recommended 1¼" Sch. 40 boiler/furnace penetration. The retract is an air-over-spring mechanism that inserts the $NO_xOUT^®$ injector into the boiler when the zone is required by the NOxOUT system and the injector atomizing/cooling air is on. When the injector is fully inserted into the boiler, a contact arm actuates a spool valve which starts the mixed $NO_x$OUT reagent flow to the injector. When the zone is no longer required to be in service, the injector will automatically retract (using only the compressed spring as the motive force if air is lost) and mixed chemical flow will be shut-off. The advantages of the retract system include complete automation and control room indication of the $NO_x$OUT injection system operation, less man-power requirements, improved wear-life of the injector, and reduced operating costs by eliminating cooling air requirements for unused injectors...
Each retract includes a specially designed 3¼" air-over-spring design, boiler penetration adapter flange (1¼" Sch. 40 MNPT), stainless steel chemical valve and actuator arm, position proximity switch, flex hoses, local control 3-way solenoid, and assembly of $NO_x$OUT injector and associated tubing into the auto-retract device.
**Specifications:**

| | |
|---|---|
| Weight | Approx 100 lbs including injector |
| Dimensions: | Approx 26" |
| Construction: | Carbon steel painted |

**Reference Fuel Tech Drawing: G-2**

**SNCR SCOPE OF SUPPLY EQUIPMENT DESCRIPTIONS**
(Continued…)

**NOxOUT INJECTOR RETRACT CONTROL PANEL**
NOxOUT® Injector Retract Mechanisms are typically controlled directly from the Fuel Tech PLC system or the plant DCS system. In some installations, a local control panel is desired for local indication, maintenance, and for tag out requirements. The Retract Control Panel is a relay based panel which contains Hand-Off-Auto selector switches for each wall retract mechanism and a red pilot light indicating that the injector is inserted.
The panel is constructed in a NEMA 4, gray, Hoffman style enclosure and designed in compliance with NEC and IEEE. The panel can receive the required 120 VAC power either from the Metering Module or from another plant specified source. The panel can be shipped loose and installed per plant requirements, or optionally installed on the Fuel Tech Distribution Modules.
**Specifications:**

| | |
|---|---|
| Weight | Approx 50 lbs |
| Dimensions: | Approx 30" x 30" x 12" |
| Construction: | Carbon steel |

## PROCESS DESIGN TABLE

| *Power Boiler 2 – SCR Option* | | |
|---|---|---|
| Type of Unit | **Stoker Fired Boiler** | |
| Type of Fuel | | Coal |
| Case ***100% MCR*** | (Steam) | 170K lb/hr |
| Gross Heat Input | (MMBtu/hr) | 580 |
| Baseline NOx | (lb/MMBtu) | 0.416 |
| SCR NOx Reduction | (%) | 90 |
| SCR Target NOx | (lb/MMBtu) | 0.042 |
| NH3 Slip ***dry @ Ref 02*** | (ppmd) | 5 |
| Flue Gas Flow wet | (Nm3/hr) | 293,663 |
| Temp at Catalyst Inlet | (°C) | 343 |
| NOx Reducing Catalyst Volume | (m3) | 94.8 |
| NOx Catalyst Pressure Drop | (in. w.g.) | 6.0 |
| Total Catalyst Weight | (Kg) | 63,969.8 |
| Number of Reactors | | 1 |
| Number of Modules per Catalyst Layer | | 15 |
| Number of Layers per Reactor | | 3 |
| Catalyst Layer Depth | (mm) | 1,300 |
| NH3 Consumption | (Kg/hr) | 41.03 |
| Catalyst Lifetime | (Hrs.) | 16,000 |

## SCR SYSTEM SCOPE of SUPPLY – Power Boiler 2 Option

| Description | QTY |
|---|---|
| SCR Reactor - Catalyst Reactor & Ductwork | 1 |
| Straightening & Turning Vanes | 1 lot |
| Expansion Joints for Ductwork | 2 |
| Static Mixer | 1 |
| Graduated Straightening Grid (GSG) | 1 |
| Large Particle Ash Screen (LPA) | 1 |
| Urea Storage Tank – *(10,000 gallons)* | 1 |
| Ultra System Decomposition Chamber | 1 |
| Natural Gas Burner, Management System & Control Module | 1 |
| High Temperature Blower Module | 1 |
| Metering Distribution Module (3 injector) | 1 |
| High Pressure Circulation Module (*including control panel)* | 1 |
| Enclosure for Metering Distribution Module | 1 |
| Ammonia Injection Grid (AIG) | 1 |
| Sonic Horn Acoustic Cleaners w/installation hardware | 6 |
| Instrumentation *(Temperature, Flow, Pressure)* | 1 |
| Analyzing Equipment for Gas Species | 1 |
| Freight for SCR & Ultra Equipment | Included |
| Project and Process Engineering | Included |
| Equipment Check-out – Man-days | 2 |
| Start Up and Optimization Services – Man-days | 12 |

**NOTE:**

1. **Since the location of the SCR Reactor is unknown at this stage, our price does not include ductwork to or from SCR ductwork configuration, routing and size to SCR Reactor is unknown.**
2. **Assumes that the plant has enough compressed air to supply receiver tank for the SCR sonic horns.**
3. **No sonic horn verification system or manufacturer field time is included.**
4. **No SCR duct insulation is included.**

## SCR SCOPE OF SUPPLY EQUIPMENT DESCRIPTIONS – Power Boiler 2 Option

### *ULTRA System Equipment Scope of Supply*

### FRP NOxOUT®A UREA STORAGE TANK

Made of Fiberglass Reinforced Plastic (FRP) with Premium Grade Vinylester Resin. Fabricated per ASTM D3299-88 where applicable, 1.5 Specific Gravity, heating package to maintain 80°F, site specific variables include seismic zone, wind load, snow load, and temperature variance.

Also includes heat trace and insulation with thermostat control, level transmitter, manway, vent, internal downpipe, external fill pipe, thermocouple, ladder, hold down and lifting lugs, FRP flanges for inlet and outlet, and fill and circulation line valves for suction isolation, drain, and return control.
*10,000 Gallon: 10’ Diameter × 17’-1” H; Approximate Empty Weight: 4,200 lb.*
**Reference Attached FTEK Drawing C-1**

### DILUTION AIR AND METERING MODULE

The Dilution Air and Metering Module system provides filtered, pressurized, heated air to the Decomposition Chamber. It also supplies pressure and flow control for atomizing air and properly metered urea solution to the injector mounted at the top of the Decomposition Chamber. The standard module contains two (2) regenerative blowers w/10 HP motor at 300 SCFM @ 75” WC at the connection to the AIG.

Two (2) Dilution Air Heaters are installed downstream of the blower. The electric heaters are sized at 36 KW each @ 480 VAC. The control panel for the heaters utilizes a solid-state relay to modulate the power output to the heater for specific temperature control.

The PLC is used to control the power output of the heater control panel. An over temperature monitor is connected to a type K thermocouple integral to the heater attached to one of the heating elements. A thermocouple at the discharge of the heater is used by the PLC to monitor the outlet temperature of the heater. An additional thermocouple at the outlet of the Decomp is used to control the discharge temperature to a typical setting of 550°F.

To ensure the proper ammonia flow to the AIG, Fuel Tech utilizes a Digital Dosing pump to maintain a precise flow of urea to the injector. A 4-20mA signal from the PLC to the dosing pump is used to control the flow rate of the dosing pump. Manual valves are used to select either urea for Ammonia generation, or water for flushing.

The atomizing air supply is controlled by a solenoid valve. The flow of atomizing air is monitored by a flow meter to ensure that the proper flow of atomizing air is going to the injector when the heater is running.

**SCR SCOPE OF SUPPLY EQUIPMENT DESCRIPTIONS – Power Boiler 2 Option**
(Continued…)

Two (2) control cabinets are mounted on the Air and Metering Module. The main control cabinet utilizes 120 VAC and houses an Allen-Bradley CompactLogix PLC, associated I/O modules, and Panel View 1000 Operator Interface. The PLC monitors the ammonia demand, process variable such as temperature and pressure, and controls the flow of urea and the temperature output of the heater. The PanelView is mounted in the door of the main control panel is used to monitor, control, set up and adjust system operation. The 2nd control cabinet utilizes 480 VAC and houses the heater controls and pump and blower drives.

## DECOMPOSITION CHAMBER AND INJECTOR

The Decomposition Chamber for the NOxOUT ULTRA® process utilizes ambient air from the blowers and heater to fully decompose the urea being delivered to the AIG. The Decomposition Chamber is a reaction vessel where urea is thermally decomposed into Ammonia and Ammonia by products. Heated air from the Air and Metering Skid is used to thermally breakdown the urea into Ammonia and carry the Ammonia to the AIG. Urea at a specific flow rate controlled by the Air and Metering skid is injected into the top of the Chamber.

The chamber is specifically designed with the appropriate flow paths and residence time to achieve a 100% conversion of urea to ammonia. The chamber is constructed of stainless steel and is externally insulated. The thickness and type of insulation may vary depending on ambient temperatures where the chamber is installed. The frame for the chamber is constructed of carbon steel.

The discharge of the Decomposition Chamber flows directly to the ammonia injection grid (AIG). The flow is monitored by a verabar style flow sensor, which generates a differential pressure based upon the flow. This pressure along with the temperature of the gas stream is used to calculate the volumetric flow to the AIG. The level of this flow is also a permissive for the heater to operate to ensure that the heater can only be turned on when adequate airflow is present.

The NOxOUT ULTRA® System Injector will be designed and installed in the Decomposition Chamber. The injector is appropriately sized and characterized for proper flows and pressures that are required to achieve the necessary urea atomization and distribution within the Chamber. The injector fitting will be designed to withstand any hot gas back flow to the atmosphere. The injectors are made completely of 316L stainless steel and the nozzle tip and cooling shield is typically 3/4” tubing (.750” OD & .083” wall thickness).

**SCR SCOPE OF SUPPLY EQUIPMENT DESCRIPTIONS – Power Boiler 2 Option**
(Continued…)

## ULTRA ENCLOSURE

FTEK will provide an Enclosure to house the ULTRA system, to include the metering module and Decomposition Chamber. The enclosure is to be field erected by others. The components of the Enclosure are as follows:

- 16' x 20' x 16' Metal Enclosure
- 26 Gauge Multi-Rib panels on exterior walls and roof
- 26 Gauge Exterior Trim
- 26 Gauge flat stock laminated on 1/2" Plywood on the interior.
- Base angle 3" x 4" x ¼"
- Double Door 6070 Heavy Duty, Level B with door closure and lock
- Wall framing 4"x2" channels, Roof purlins 6"x2 ½" channels
- 3 ½" roof insulation and wall insulation (R11)
- 1 -12 roof slope with gutters and down spout on buildings low side
- (3) Framed openings for intake and exhaust
- Building will be pre-manufactured fully assembled at fabricators' shop and shipped knockdown.
- Building will have eight (8) wall sections and two roof sections to be installed/erected on site.
- HVAC 3 Ton Wall Mount Air Conditioner
- 208/230V, 1 PH, 60 Hz, 5kw Electric Heat.
- With Telecom Controls Package including Low Ambient Cooling.
- Scroll Compressor.
- R-410A Refrigerant

## AMMONIA INJECTION GRID

FTEK will design and fabricate an Ammonia Injection Grid (AIG) specific to the requirements of the unit duct geometry and flow demands of the proposed ULTRA system. In order to achieve uniform ammonia reagent distribution the AIG will utilize multiple control zones, each supplying multiple injection lances permanently installed in the duct. The AIG design will consider the discharge conditions of the ULTRA Chamber and the connecting vapor transport pipe, as well as the sizing and arrangement of the AIG header, valve trains and injection lances.

For the Sinclair refinery package boiler application it is estimated from the conceptual (proposal-basis) design that at total of eight (8) injection lances will be required, each with six (6) nozzles. Four (4) lances will be manifolded into each of two (2) control zones. The control zones will be fed through an adjustable valve with local flow indication (magnehelic-type gauge with orifice plate). FTEK will required detailed boiler dimensions and process data (flows, temperature and pressure) to finalize design.

AIG Piping must be insulated in the field by others. Two (2) thermocouples and temperature transmitters, provided loose by FTEK, will need to be installed and wired in the field by others.

**FUEL TECH ENGINEERING SCOPE OF SUPPLY**
**SNCR AND SCR**

***ENGINEERING***

Fuel Tech will provide Project and Process Engineering and the following drawings and information:

- P&IDs
- Skid Arrangements
- Foundation Loads
- Injector Locations
- Electrical Drawings and Bill of Materials
- Pump Performance Curves

***ENGINEERING SERVICES***

- Project Engineering
- Installation Support, Start-up and Optimization Services
- Operation and Maintenance Manuals (5)

## SCOPE OF SUPPLY BY OTHERS
## SNCR AND SCR

1. Installation of Fuel Tech, Inc. Supplied Equipment.
2. Interconnecting Piping and Wiring of Fuel Tech, Inc. Supplied Equipment.
3. Tank Foundation and Structural Support for System Modules.
4. Estimated SNCR System Utilities. *(To be provided later)*
5. Chemical Supply: Licensed Quality or Industrial Grade urea (50% Solution).
6. Plant service water (NOxOUT reagent) or demineralized water (unstabilized urea).
7. Implement Control Logic Schemes into Plant DCS.
8. NOx, Ammonia, and CO Monitoring Equipment, if Required.
9. Required Penetrations for Injector Wall Sleeves and Mounting.
10. Insulation as required for FTI Equipment
11. Asbestos Abatement, if Required.
12. System Performance Testing.
13. Spare Parts.

## SPECIFICATIONS FOR UREA, DILUTION WATER & SOLUTION MAKE-UP WATER

Depending on the quality of water available for urea dilution at the Metering Module, either a licensed reagent (NOxOUT A or HP identified below) or unstabilized urea may be used. If an unstabilized urea of any concentration is used, the water quality requirements are much more stringent. The urea and dilution water specifications for SNCR operation with stabilized and unstabilized urea are provided below.

| QUALITY SPECIFICATIONS FOR UREA | | | |
|---|---|---|---|
| | NOxOUT® A | NOxOUT® HP | UNSTABILIZED UREA |
| Description | Modified 50% Aqueous Solution of Urea | Modified 50% Aqueous Solution of Urea | 50% Aqueous Solution of Urea |
| Density (g/ml @ 25° C) | 1.13 - 1.15 | 1.13 - 1.15 | 1.13 - 1.15 |
| pH | 7.0 - 10.8 | 7.0 - 10.8 | 7.0 - 10.8 |
| Appearance | Light Yellow, Clear to Slightly Hazy | Light Yellow, Clear to Slightly Hazy | Light Yellow, Clear to Slightly Hazy |
| Salt Out Freeze Point | 64°F (18°C) | 64°F (18°C) | 64°F (18°C) |
| Foam (after bottle is shaken) | Foam Lasts > 15 seconds | Foam Lasts > 15 seconds | Not Applicable |
| Free NH3 | < 5000 ppm | < 5000 ppm | < 5000 ppm |
| Biuret Content | < 5000 ppm | < 5000 ppm | < 5000 ppm |
| Organic Phosphate | 55 - 85 ppm as PO4 | 22 - 40 ppm as PO4 | Not Applicable |
| Orthophosphate | < 6 ppm as PO4 | < 6 ppm as PO4 | < 2 ppm as PO4 |
| Suspended Solids | < 10 ppm | < 10 ppm | < 10 ppm |
| Urea Makeup Water | Total Hardness as CaCO3 ≤ 300 ppm | Total Hardness as CaCO3 ≤ 150 ppm | Total Hardness as CaCO3 ≤ 20 ppm |

| QUALITY SPECIFICATIONS FOR DILUTION WATER | | | |
|---|---|---|---|
| | NOxOUT® A | NOxOUT® HP | UNSTABILIZED UREA |
| | Dilution Water Analysis | Dilution Water Analysis | Dilution Water Analysis |
| Total Hardness as CaCO3 (ppm) | <450 | <150 | <20 |
| "M" Alkalinity as CaCO3 (ppm) | <300 | <100 | <100 |
| Conductivity (µmho) | <2500 | <1000 | <1000 |
| Silica as SiO2 (ppm) | <60 | <60 | <60 |
| Iron as Fe (ppm) | <1.0 | <1.0 | <1.0 |
| Manganese as Mn (ppm) | <0.3 | <0.3 | <0.3 |
| Phosphate as P (ppm) | <1.0 | <1.0 | <1.0 |
| Sulfate as SO4 (ppm) | <200 | <200 | <200 |
| Turbidity (NTU) | < 10 | < 10 | < 10 |
| pH | <8.3 | <8.3 | <8.3 |

## TYPICAL SNCR PROJECT SCHEDULE

### Power Boiler 1 & 2 SNCR

| EVENT | RESPONSIBILITY | WEEKS FROM ORDER DATE |
|---|---|---|
| Receipt of Order | Customer | 0 |
| Begin Project Design | Fuel Tech | 1 |
| Submit Preliminary P&ID Drawings | Fuel Tech | 4 |
| Customer Drawing Comments Received | Customer | 6 |
| Complete Process Modeling | Fuel Tech | 10 |
| Submit Mechanical & Electrical Drawings | Fuel Tech | 10 |
| Customer Drawing Comments Received/Release for Procurement and Fabrication | Customer | 12 |
| Begin Equipment Fabrication | Fuel Tech | 14 |
| Equipment Shipment | Fuel Tech | 32 |
| Equipment Delivery | Fuel Tech | 33 |
| Complete Equipment Installation | Customer | TBD |
| Begin Start-Up & Testing | Fuel Tech | 1-2 weeks after completion of installation |
| Begin Optimization | Fuel Tech | 2-4 weeks |
| Compliance Testing | Customer | TBD |

*Notes*

1. Dates and durations subject to change based on contract release date and turnaround times for drawing approvals.

## TYPICAL PROJECT SCHEDULE – *SCR* SYSTEM

### Power Boiler 2 SCR Option

| EVENT | RESPONSIBILITY | WEEKS FROM ORDER DATE |
|---|---|---|
| Receipt of Order | Customer | 0 |
| Begin Project Design | Fuel Tech | 1 |
| Submit Preliminary P&ID Drawings | Fuel Tech | 4 |
| Preliminary GA Drawings Issued for Review | Fuel Tech | 10 |
| Customer GA Drawing Comments Received | Customer | 12 |
| Complete Process Modeling | Fuel Tech | 10 |
| Submit Electrical Drawings | Fuel Tech | 12 |
| Customer Drawing Comments Received/Release for Procurement and Fabrication | Customer | 14 |
| Begin Equipment Procurement | Fuel Tech | 10 |
| Begin Equipment Fabrication | Fuel Tech | 14 |
| Equipment Shipment | Fuel Tech | 34 |
| Equipment Delivery | Fuel Tech | 36 |
| Complete Equipment Installation | Customer | TBD |
| Begin Start-Up & Testing | Fuel Tech | 1-2 weeks after completion of installation |
| Begin Optimization | Fuel Tech | 2-4 weeks |
| Compliance Testing | Customer | TBD |

Notes

2. Dates and durations subject to change based on contract release date and turnaround times for drawing approvals.
3. An accelerated schedule may be possible depending on project requirements and shop loading at the time of contract.

## PRICING AND PAYMENT TERMS

For the Engineering, Equipment, and Services identified in this proposal, we quote the following budgetary prices, FOB Jobsite:

| | | |
|---|---|---|
| UNIT 1 & 2 SNCR | ONE MILLION THREE HUNDRED FORTY FIVE THOUSAND SIX HUNDRED DOLLARS | **$1,345,600.00** |
| UNIT 1 & 2 OPTION: CIRCULATION MODULE ENCLOSURE | ONE HUNDRED FIFTY SEVEN THOUSAND SIX HUNDRED FORTY DOLLARS | **$157,640.00** |
| UNIT 2 SCR / ULTRA SYSTEM | THREE MILLION THREE HUNDRED SEVENTY THOUSAND TWO HUNDRED SIXTY SEVEN DOLLARS | **$3,370,267.00** |

Price includes the stated number of start-up and optimization services man-days, with travel and living expenses included. Please see our Field Service Pricing Schedule, Exhibit C1, dated January 2012, for per diem service rates.

***PRICE FOR UNIT 2 SCR INCLUDES A DEDUCT FOR THE UNIT 2 SNCR PORTION SHOULD THE SCR OPTION BE PREFERABLE.*

### *TERMS OF PAYMENT*

10% Upon receipt of Letter of Intent, Purchase Order, or Contract

20% Upon submittal of Drawings to the Buyer for Approval

20% Upon Buyer's release for equipment fabrication

10% Upon submittal of Certified Drawings to the Buyer

30% Upon date of shipment of equipment, or thirty days after notification to buyer that equipment is ready to ship, whichever occurs first.

10% After successful completion of acceptance test or six (6) months after receipt of equipment, whichever occurs first.

## EXHIBIT C3 – FUEL TECH, INC. STANDARD TERMS AND CONDITIONS

These terms and conditions shall be part of the attached proposal and shall become part of the contract entered into between FUEL TECH, INC. (Fuel Tech), and the Buyer. Deviations from these terms and conditions must be agreed to in a writing signed by Fuel Tech and the Buyer. Fuel Tech hereby gives notice of its objection to any different or additional terms or conditions unless such different or additional terms or conditions are agreed to in a writing signed by Fuel Tech and Buyer.

1. TERMS OF PAYMENT

All invoices are payable net thirty (30) days from date of invoice. Buyer shall pay interest at the rate of ten percent (10%) per annum on all overdue amounts. Buyer shall pay all sales tax, use tax, excise tax, or other similar taxes.

2. DELAYS

If shipments are delayed by Buyer, payment shall be due on and warranty coverage shall begin to run from thirty days after the original shipment date specified in the contract or thirty (30) days after notification to Buyer that equipment is ready to ship, whichever is earlier. Risk of loss shall pass to Buyer at the time that equipment is identified, and any costs caused by such delay shall be borne by Buyer.

If shipments are delayed by Buyer, Fuel Tech will ship the equipment no later than sixty (60) days after initial notification to the Buyer that the equipment is ready for shipment. Buyer agrees either (1) to provide Fuel Tech an appropriate “ship to” address and to accept delivery or (2) pay reasonable storage charges for the equipment beginning sixty (60) days after initial notification to Buyer that equipment is ready to ship.

3. PERFORMANCE GUARANTEE

Buyer warrants that the operating conditions of the Unit are those specified in the Process Design Table. Buyer is solely responsible for the accuracy of that operating condition information, and all performance guarantees and equipment warranties granted by Fuel Tech shall be void if that operating condition information is inaccurate or is not met. All performance guarantees and equipment warranties are conditioned on Buyer timely providing all of the equipment, materials, chemicals, utilities, and services that it has agreed to provide, on operating the Unit within the operating conditions specified in the Process Design Table, and on using reagent of license grade quality in the operation of the Unit.

## EXHIBIT C3 – FUEL TECH, INC. STANDARD TERMS AND CONDITIONS
(Continued…)

4. EQUIPMENT WARRANTY

Fuel Tech warrants that the equipment it provides shall be free from defects in design, workmanship, and material at the time the equipment is delivered and for a period of twelve (12) months after initial operation, or eighteen (18) months from shipment of equipment, whichever occurs first. Fuel Tech does not warrant wear parts such as injection tips, cooling shields, pump diaphragms, check valves, solenoids, pump impellers, pump wear rings, pump seals, valve packing, and valve seats.

All warranties made by the manufacturer of the equipment (if that manufacturer is any entity other than Fuel Tech) shall be assigned by Fuel Tech to the Buyer, if such assignment is permissible by law and contract. Warranty coverage starts at shipment of equipment or thirty (30) days after notification to Buyer that equipment is ready to ship.

5. DISCLAIMER OF WARRANTIES

Fuel Tech warrants its equipment and the performance of its equipment solely in accordance with the equipment warranty and performance guarantee contained in this proposal and makes no other representations or warranties of any other kind, express or implied, by fact or by law. All warranties other than those specifically set forth in this proposal are expressly disclaimed. **FUEL TECH SPECIFICALLY DISCLAIMS ALL OTHER WARRANTIES, EXPRESS OR IMPLIED, AND DISLCAIMS THE IMPLIED WARRANTY OF MERCHANTABILITY, THE IMPLIED WARRANTY OF FITNESS FOR A PARTICULAR PURPOSE, AND ANY OTHER IMPLIED WARRANTIES OF DESIGN, CAPACITY, OR PERFORMANCE RELATING TO THE EQUIPMENT.**

6. LIMITATION OF LIABILITY

Buyer's sole remedy under the equipment warranty and the performance guarantee shall be to allow Fuel Tech, at Fuel Tech's option, either to repair, replace, or supplement the equipment to meet the performance guarantee, or, in the event that those options are not feasible, to remove the Equipment and refund the contract price to Buyer. NOTWITHSTANDING ANYTHING TO THE CONTRARY, FUEL TECH'S TOTAL LIMIT OF LIABILITY ON ANY CLAIM, WHETHER FOR BREACH OF CONTRACT, BREACH OF WARRANTY, TORT, NEGLIGENCE, STRICT LIABILITY, OR ANY OTHER LEGAL THEORY, FOR ANY LOSS OR DAMAGE ARISING OUT OF, OR CONNECTED TO, OR RESULTING FROM THIS AGREEMENT, INCLUDING WITHOUT LIMITATION AMOUNTS INCURRED BY FUEL TECH OR BUYER IN ATTEMPTING TO REPAIR, REPLACE, OR SUPPLEMENT THE EQUIPMENT OR MEET THE PERFORMANCE GUARANTEE, SHALL BE LIMITED TO THE CONTRACT PRICE TO BE PAID BY BUYER PURSUANT TO THE CONTRACT.

## EXHIBIT C3 – FUEL TECH, INC. STANDARD TERMS AND CONDITIONS
(Continued…)

7. EXCLUSION OF CONSEQUENTIAL DAMAGES

NOTWITHSTANDING ANYTHING TO THE CONTRARY, IN NO EVENT SHALL FUEL TECH BE LIABLE FOR ANY INDIRECT, CONSEQUENTIAL, INCIDENTAL, SPECIAL, OR PUNITIVE DAMAGES, INCLUDING BUT NOT LIMITED TO LOSS OF CAPITAL, LOSS OF REVENUES, LOSS OF PROFITS, LOSS OF ANTICIPATORY PROFITS, LOSS OF BUSINESS OPPORTUNITY, DAMAGE TO EQUIPMENT OR FACILITIES, COST OF SUBSTITUTE NOx REDUCTION SYSTEMS, DOWNTIME COSTS, GOVERNMENT FINES, OR CLAIMS OF CUSTOMERS, EVEN IF ADVISED OF THE POSSIBILITY OF SUCH DAMAGES.

8. RESPONSIBILITY FOR THIRD PARTIES

Buyer shall at all times be responsible for the acts and omissions of its subcontractors and of any other third parties hired or retained or contracted by Buyer to perform work or provide equipment related to the system provided by Fuel Tech, including but not limited to third party design, systems integration, equipment tie-in, or process design changes. Fuel Tech shall have no responsibility for ensuring the accuracy of any such work or the performance of any equipment provided by subcontractors or third parties hired or retained or contracted by Buyer, and Buyer assumes all liability for any such work or equipment and for any failures in Fuel Tech's equipment caused by any such subcontractors or third parties hired or retained or contracted by Buyer. Buyer agrees to indemnify, hold harmless, and defend Fuel Tech from any claims, losses, damages, injuries, or failures caused by any such subcontractors or third parties.

9. CONFIDENTIALITY

Buyer agrees that it shall hold Confidential Information received from Fuel Tech in the strictest confidence, shall not use the Confidential Information for its own benefit except as necessary to fulfill the terms of the agreement between the parties, shall disclose the Confidential Information only to employees, agents, or representatives who have a need to know the Confidential Information, shall not disclose the Confidential Information to any third party, shall not copy the Confidential Information, shall not disassemble, decompile, or otherwise reverse engineer the Confidential Information and any inventions, processes, or products disclosed by Fuel Tech, and, in preventing disclosure of Confidential Information to third parties, shall use the same degree of care as for its own information of similar importance, but no less than reasonable care.

10. LICENSE AGREEMENT AND OTHER TERMS

Sale is subject to agreement on other terms and conditions, including a Sale of Equipment with License Agreement.

## EXHIBIT C3 – FUEL TECH, INC. STANDARD TERMS AND CONDITIONS
(Continued…)

11. INDEMNIFICATION

Each Party shall defend, indemnify, and hold harmless the other Party and its employees, agents, and representatives from any claims, liabilities, lawsuits, costs, losses, or damages that arise out of or result from any negligent or willful acts or omissions of the indemnifying Party's employees, agents, or representatives. Where such claims, liabilities, lawsuits, costs, losses, or damages are the result of the joint or concurrent negligence or willful misconduct of the Parties or their respective agents, employees, representatives, subcontractors, or any third party, each Party's duty of indemnification shall be in the same proportion that the negligence or willful misconduct of such Party, its agents, employees, representatives, or subcontractors contributed thereto. The Party entitled to indemnity under this Agreement shall promptly notify the indemnifying Party of any indemnifiable claim, liability, lawsuit, cost, loss, or damage. The Party responsible for indemnification under this Agreement shall conduct and control the defense of the indemnified claim, liability, lawsuit, cost, loss, or damage. The Parties shall use their best efforts to cooperate in all aspects of the defense of any such claim, liability, lawsuit, cost, loss, or damage. The indemnifying Party shall not be bound by any compromise or settlement made without its prior written consent.

12. FORCE MAJEURE

The Parties shall be excused from liability for delays in manufacture, delivery, or performance due to any events beyond the reasonable control of the Parties, including but not limited to acts of God, war, national defense requirements, riot, sabotage, governmental law, ordinance, rule, or regulation (whether valid or invalid), orders of injunction, explosion, strikes, concerted acts of workers, fire, flood, storm, failure of or accidents involving either Party's plant, or shortage of or inability to obtain necessary labor, raw materials, or transportation ("Force Majeure"). Any delay in the performance by either party under this Agreement shall be excused if and to the extent the delay is caused by the occurrence of a Force Majeure, provided that the affected party shall promptly give written notice to the other party of the occurrence of a Force Majeure, specifying the nature of the delay, and the probable extent of the delay, if determinable.

Following the receipt of any written notice of the occurrence of a Force Majeure, the parties shall immediately attempt to determine what fair and reasonable extension for the time of performance may be necessary. The parties agree to use reasonable commercial efforts to mitigate the effects of events of Force Majeure.

No liabilities of any party that arose before the occurrence of the Force Majeure event shall be excused except to the extent affected by such subsequent Force Majeure.

## EXHIBIT C3 – FUEL TECH, INC. STANDARD TERMS AND CONDITIONS
(Continued…)

13. GOVERNING LAW

This Agreement shall be governed by and interpreted in accordance with the laws of the State of Illinois, excluding its choice of laws rules. The parties shall attempt to settle any disputes, controversies, or claims arising out of this Agreement through consultation and negotiation in good faith and in a spirit of mutual cooperation. If those attempts fail, then any dispute, controversy or claim shall be submitted first to a mutually acceptable neutral advisor for mediation. Neither party may unreasonably withhold acceptance of a neutral advisor. The selection of the neutral advisor must be made within forty-five (45) days after written notice by one party demanding mediation, and the mediation must be held within six months after the initial demand for it. By mutual agreement, however, the parties may postpone mediation until they have each completed some specified but limited discovery about the dispute, controversy, or claim. The cost of mediation shall be equally shared between the parties. Any dispute that the parties cannot resolve through mediation within six (6) months after the initial demand for it may then be submitted to a state or federal court of competent jurisdiction within the State of Illinois for resolution. The use of mediation shall not be construed (under such doctrines as laches, waiver, or estoppel) to have adversely affected any party's ability to pursue its legal remedies, and nothing in this provision shall prevent any party from resorting to judicial proceedings if good faith efforts to resolve a dispute under these procedures have been unsuccessful or interim resort to a court is necessary to prevent serious and irreparable injury to any party or others.

14. ENTIRE AGREEMENT

This Exhibit C3 and the Fuel Tech Proposal attached to it constitute the entire agreement between the parties and can be modified only in writing signed by authorized representatives of each of the parties.

## EXHIBIT C1 – FUEL TECH SERVICE PRICING SCHEDULE

### RATES

Billing will be based on rates in effect at time service is rendered. Rates apply within the USA, but excluding the States of Alaska and Hawaii. The per diem rates listed below are for an 8-hour man-day, during normal working hours. Travel time is working time. Parts and expenses are additional.

| | Daily Rate | Hourly Rate |
|---|---|---|
| Technician | $1,350.00 | $ 170.00 |
| Project Engineer | $1,500.00 | $ 190.00 |
| Process/Test Engineer | $1,600.00 | $ 200.00 |
| Project Manager | $1,600.00 | $ 200.00 |
| Engineering Manager/Director | $2,000.00 | $ 250.00 |
| VP Technology | $2,200.00 | $ 275.00 |

The rates quoted are valid through January 31, 2013. The per diem rate for specialist service and services performed outside the Continental United States will be quoted upon request.

### NORMAL WORKING HOURS AND DAYS

8:00 A.M. to 5:00 P.M., including sufficient time for lunch, Monday through Friday, except legal holidays, at location of customer's plant.

### OVERTIME

Overtime will be billed at 1.5 times the prevailing hourly rate. Overtime is defined as all hours worked under twelve (12) on the employee's first scheduled off day (Saturday), and all hours worked under twelve (12) and over eight (8) hours for a day on the job (Standard hourly rate × 1.5).

### DOUBLE TIME

Double time will be billed at two (2) times the prevailing hourly rate. Double time is defined as all hours worked over twelve (12) on any day, all hours worked on the employee's second scheduled off day (Sunday) and all hours on observed holidays.

**EXHIBIT C1 – FUEL TECH SERVICE PRICING SCHEDULE**
(Continued…)

**EXPENSES**

1) TRAVEL
   a) Automobile travel at the rate of $0.555 per mile.
   b) Travel expenditures will be charged per round-trip from the Fuel Tech personnel's point of origin, plus local travel.
   c) Expenses for travel will be at cost, which will be by airplane, rail or auto, whichever is the most expeditious under given circumstances. Air travel will be at prevailing available rates; Tourist Class within the Continental United States and Business Class for International flights.

2) LIVING
   a) Actual expenses for lodging, meals and incidental costs.
   b) Telephone calls and wires as required in connection with details of the job will be charged at cost.

**GENERAL CONDITIONS**

- Fuel Tech representatives are authorized to act in a consulting capacity only. Operation and control of all equipment shall rest with others. Fuel Tech shall not be held responsible for any damage through any misoperation or misunderstanding.

- Customer shall render all reasonable assistance to Fuel Tech representative. Necessary working and storage space, including field office, if required, shall be furnished by the customer. Customer shall be responsible for ensuring the Fuel Tech representative has full access to the equipment to be serviced and the scheduling of the required Boiler loads.

- It will be the responsibility of the customer to furnish qualified tradesmen when required, to work with our representative.

- In the event of any labor disputes, it shall be left to the judgment of the Fuel Tech representative on the jobsite as to their course of action. Fuel Tech's representative will in no way become involved in labor disputes.

- Terms are Net thirty days (30) from receipt of invoice. Fuel Tech reserves the right to enforce a 1-1/2% carrying charge per month for any invoice in excess of fifteen (15) days overdue.

**EXHIBIT C1 – FUEL TECH SERVICE PRICING SCHEDULE**
(Continued…)

**SPARE PARTS**

Spare parts are available through our Warrenville, IL office. An inventory of critical parts is kept on-site for injectors. Fuel Tech works with key local suppliers to provide quick turnaround for spare parts orders time. Parts and expenses are additional.

**RENTAL EQUIPMENT**

Customer shall, at its own cost and expense, keep the Equipment in good repair, condition, and working order and shall furnish any and all parts, mechanisms, and devices required to keep the Equipment in good working order. Customer hereby assumes and shall bear the entire risk of loss or damage to the Equipment from any and every cause whatsoever. In the event of loss or damage of any kind whatever to the Equipment, Customer shall, at Fuel Tech's option:

a) Place the Equipment in good repair, condition, and working order; or
b) Replace the Equipment with identical Equipment in good repair, condition and working order; or
c) Pay Fuel Tech the replacement cost of the Equipment.

**DISCLAIMER OF WARRANTIES**

**FOR THE PRODUCTS AND SERVICES PROVIDED BY FUEL TECH UNDER THIS AGREEMENT, FUEL TECH SPECIFICALLY DISCLAIMS ALL OTHER WARRANTIES, EXPRESS OR IMPLIED, OR STATUTORY AND DISLCAIMS THE IMPLIED WARRANTY OF MERCHANTABILITY, THE IMPLIED WARRANTY OF FITNESS FOR A PARTICULAR PURPOSE.**

**LIMITATION OF LIABILITY**

To the fullest extent allowed by applicable law whether under the Contract, any contract theory, any warranty theory, strict liability, negligence or other theory: (1) Fuel Tech shall not be liable for any indirect, consequential, incidental, special, or punitive damages, including but not limited to loss of capital, loss of revenues, loss of profits, loss of anticipatory profits, loss of business opportunity, damage to equipment or facilities, cost of substitute programs, downtime costs, government fines, or claims of customers, even if advised of the possibility of such damages, and , (2) in no event shall Fuel Tech's liability exceed the total contract price.

## PRODUCT LITERATURE

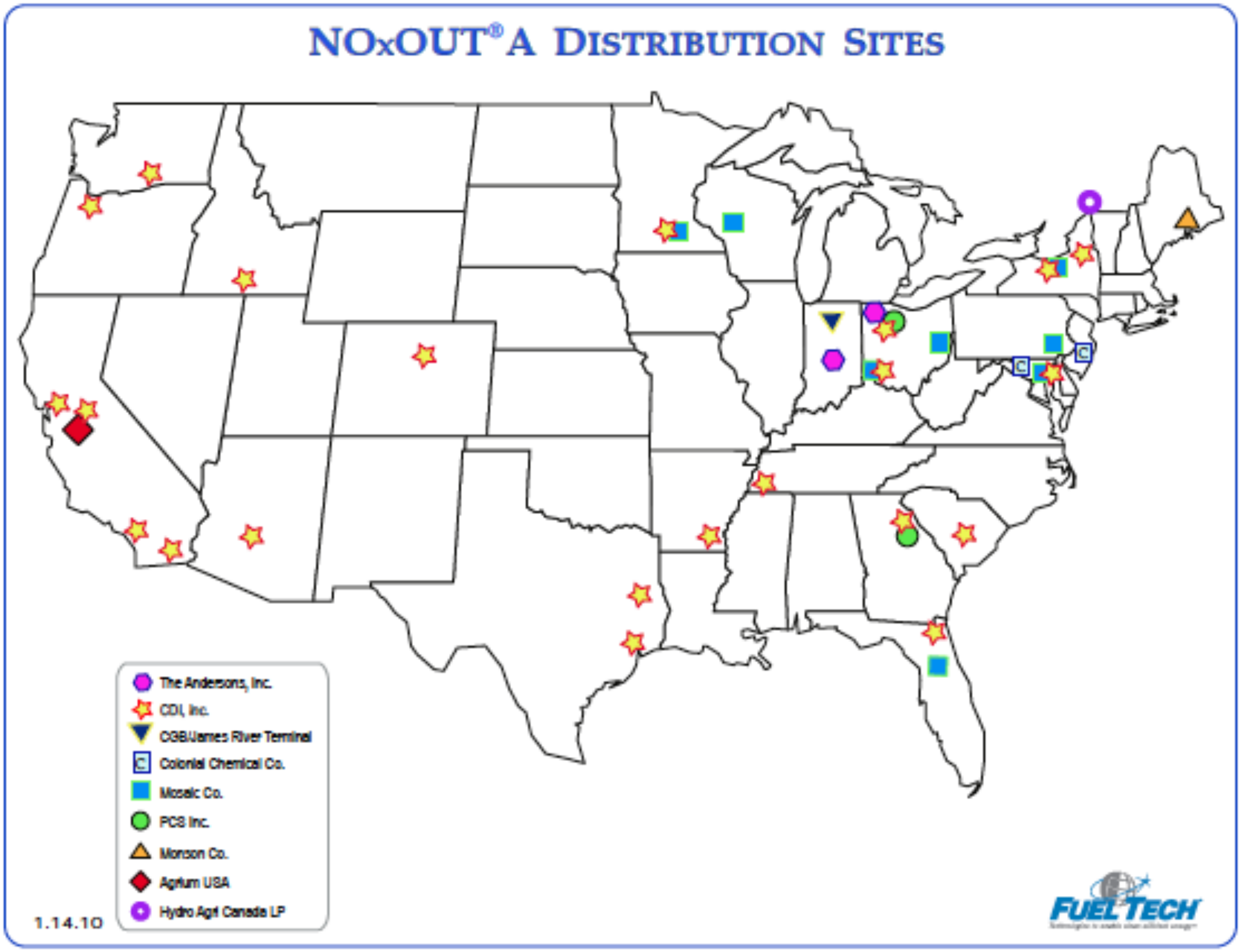
UREA Suppliers and Distribution Sites

Selective Non-Catalytic Reduction (SNCR) NOxOUT® and HERT™ Processes

CFD Modeling Services

SCR Services

GSG – Graduated Straightening Grid


NOxOUT® A Distribution Sites
The Andersons, Inc.
CDI, Inc.
CGB/James River Terminal
Colonial Chemical Co.
Mosaic Co.
PCS Inc.
Morton Co.
Agrium USA
Hydro Agri Canada LP
1.14.10
FUEL TECH

# NOxOUT® Reagent Licensees

| Licensee Corporate Office | Address | Contact Person | Telephone/Fax |
|---|---|---|---|
| **CDI, Inc.** | P.O. Box 9083<br>Brea, CA 92821<br>-or-<br>471 W. Lambert Rd<br>Suite 100<br>Brea, CA 92821 | Luis Cervantes | 714.990.3940<br>714.329.2281 (cell)<br>714.990.4073 (fax) |
| *Distribution Points* | – Crosset, AR – Casa Grande, AZ - City of Industry, CA – Imperial, CA<br>– San Jose, CA – Stockton, CA – Greeley, CO – Jacksonville, FL – Augusta, GA – Kimberly, ID<br>– Baltimore, MD – St. Paul, MN – Albany, NY – Cincinnati, OH – Lima, OH – Deer Island, OR<br>– Russellville, SC – Memphis, TN – Houston, TX – Lufkin, TX – Pasco, WA | | |
| **Mosaic Company**<br>(formerly Cargill, Inc) | 12800 Whitewater Dr<br>MS 190<br>Minnetonka, MN 55343 | Bob Ness | 800.918.8270<br>763.577.2781<br>952.742.7313 (fax) |
| *Distribution Points* | – Brandon, FL – Baltimore, MD – St. Paul, MN – Albany, NY – Cincinnati, OH<br>– Wellsville, OH – Philadelphia, PA – Menomonie, WI | | |
| **PCS Nitrogen, Inc** | 1101 Skokie Blvd<br>Northbrook, IL 60062 | Jennifer A. Zagorski | 847.849.4377<br>847.612.5301<br>847.849.4489 |
| *Distribution Points* | – Augusta, GA - Lima, OH | | |
| **Monson Companies, Inc.** | One Runway Rd<br>P.O. Box 2405<br>South Portland, MD 04116-2406 | Jeff Pellerin | 207.885.5072 x 423<br>207.885.0569 (fax) |
| *Distribution Points* | – South Portland, ME | | |
| **Agrium USA** | 13132 Lake Fraser Dr SE<br>Calgary, AB T2J7E8<br>CANADA | Gerry Kroon | 403.335.7597<br>403.471.6473 (cell) |
| *Distribution Points* | – Stockton, CA | | |
| **The Andersons, Inc.** | 480 W. Dussel Drive<br>P.O. Box 119<br>Maumee, OH 43537 | Charlie Carr | 419.891.6304 |
| *Distribution Points* | – Logansport, IN – Maumee, OH | | |
| **Colonial Chemical Co.** | 78 Carranza Rd<br>Tabernacle, NJ 08088 | Eric Wegelius | 609.268.1200 x 112<br>609.268.2117 (fax) |
| *Distribution Points* | – Frederick, MD – Tabernacle, NJ | | |
| **Hydro Agri Canada LP** | 1130 Sherbrooke St. West<br>Suite 1050<br>Montreal, Quebec H3A2M8<br>CANADA | Mike Drapeau | 514.849.9222 |
| **CGB/James River Terminal** | 5130 Pork Road<br>Jefferson, IN 47130 | Mike Routh | 319.752.2688<br>319.850.8221 (cell) |

**Information Needed by Licensees:**

- Company Name
- Location
- Scheduled Start-Up Date
- If rail delivery- specify railroad
- NOxOUT® Reagent Type Required (A,HP,LT)
- NOxOUT® Reagent Usage Rate
- NOxOUT® Reagent Storage Tank Size

## NOxOUT SNCR® EQUIPMENT MARKETING DRAWINGS

C-1 FRP Urea Storage Tank

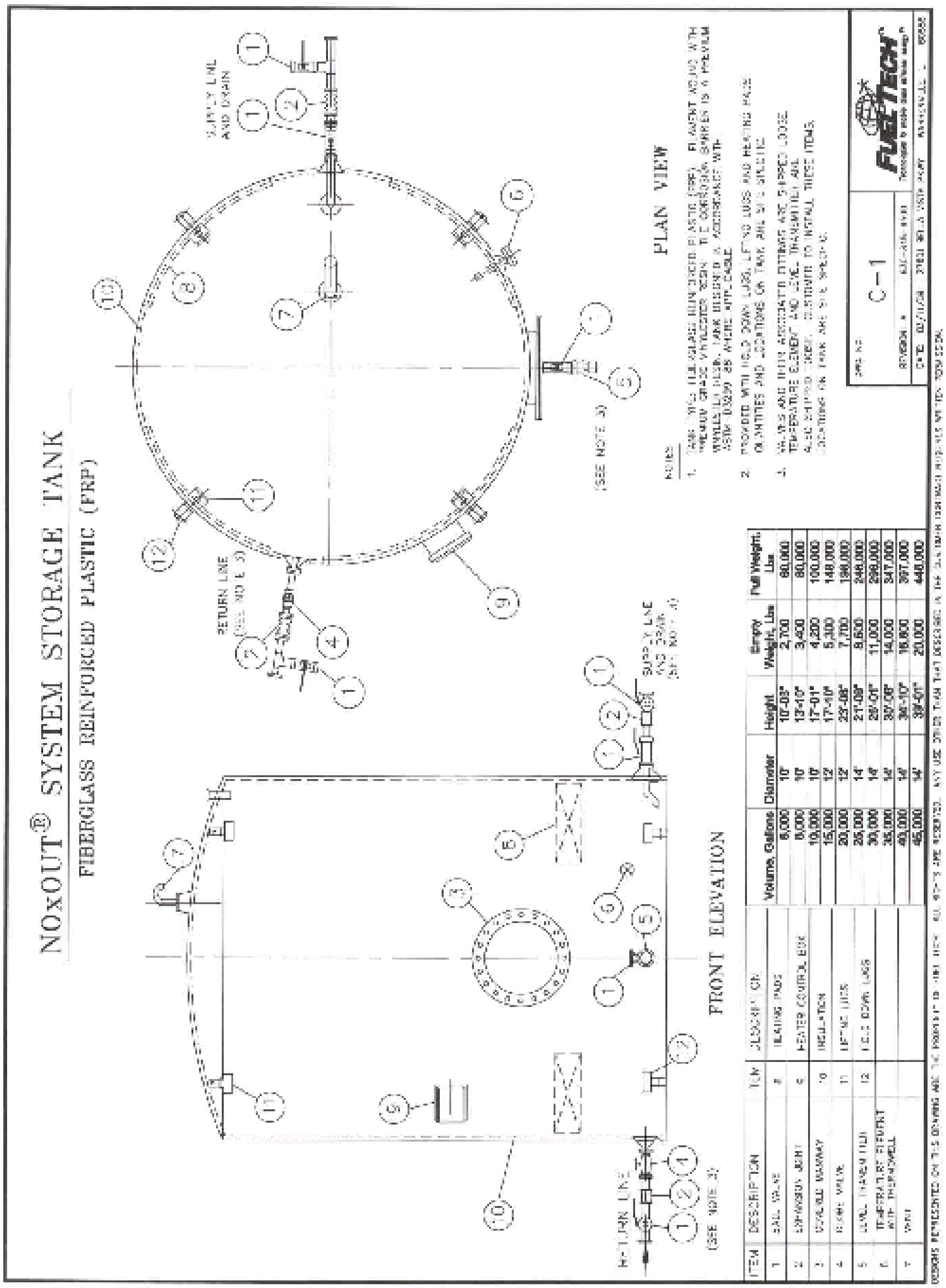
D-1 CM-LP Circulation Module

E-5 MM-LF-2P Metering Module

F-1 DM-NX Distribution Module

G-1 INJ-NX NOxOUT SNCR Injector Assembly

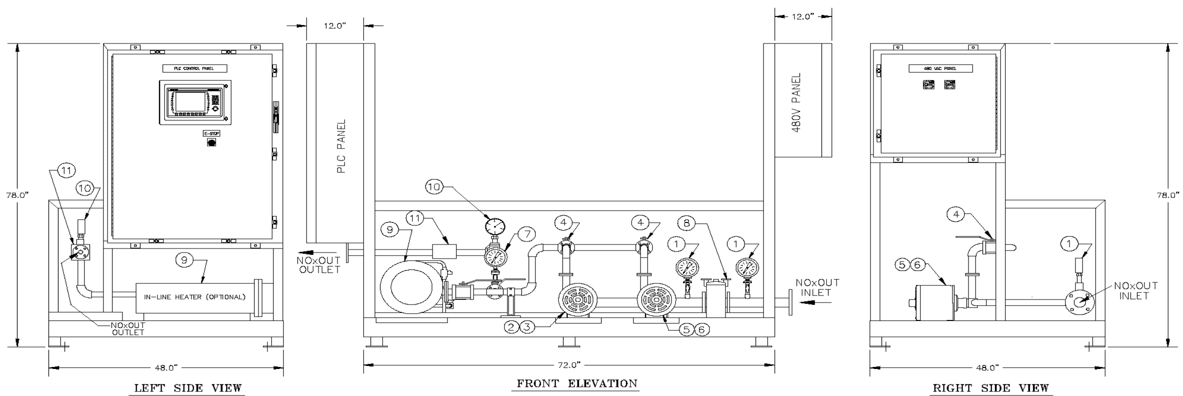
G-2 NOxOUT - Injector Automatic retract Mechanism


NOxOUT® SYSTEM STORAGE TANK
FIBERGLASS REINFORCED PLASTIC (FRP)
PLAN VIEW
FRONT ELEVATION
C-1

# FUEL TECH LOW FLOW CIRCULATION MODULE

## CM–LP

| ITEM | DESCRIPTION | ITEM | DESCRIPTION |
|---|---|---|---|
| 1 | PRESSURE GAUGE | 7 | PRESSURE GAUGE |
| 2 | CIRCULATION PUMP | 8 | DUPLEX STRAINER |
| 3 | MOTOR | 9 | IN–LINE HEATER (OPTIONAL) |
| 4 | BALL VALVE | 10 | TEMPERATURE INDICATOR |
| 5 | CIRCULATION PUMP | 11 | FLOW SWITCH |
| 6 | MOTOR | | |



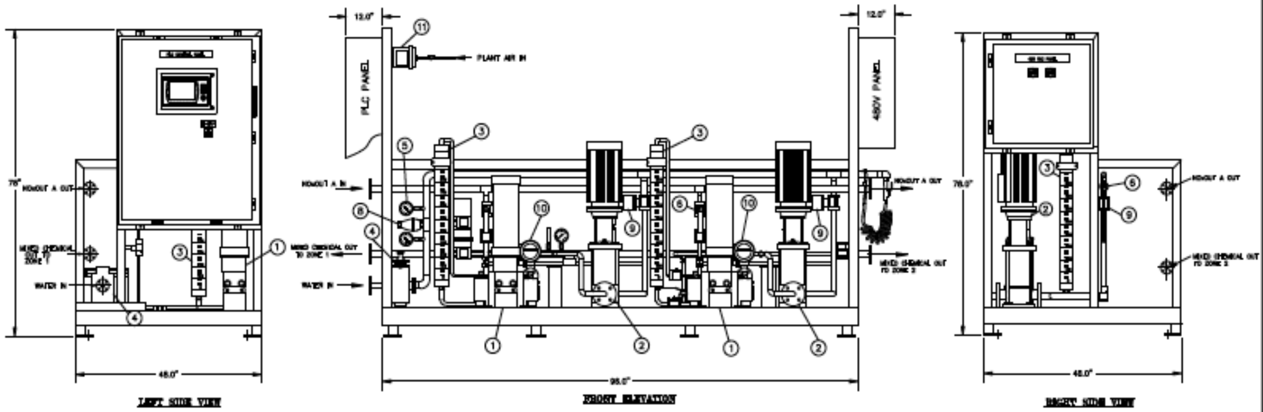

EST. WEIGHT: 1,500 LBS

| | | |
|---|---|---|
| DWG. NO. D–1 | | |
| FUEL TECH, Inc. | 630–845–4500 | |
| DATE: 03/02/09 | 27601 BELLA VISTA PKWY, | WARRENVILLE, IL 60555 |

## DOUBLE PUMP SET METERING MODULE

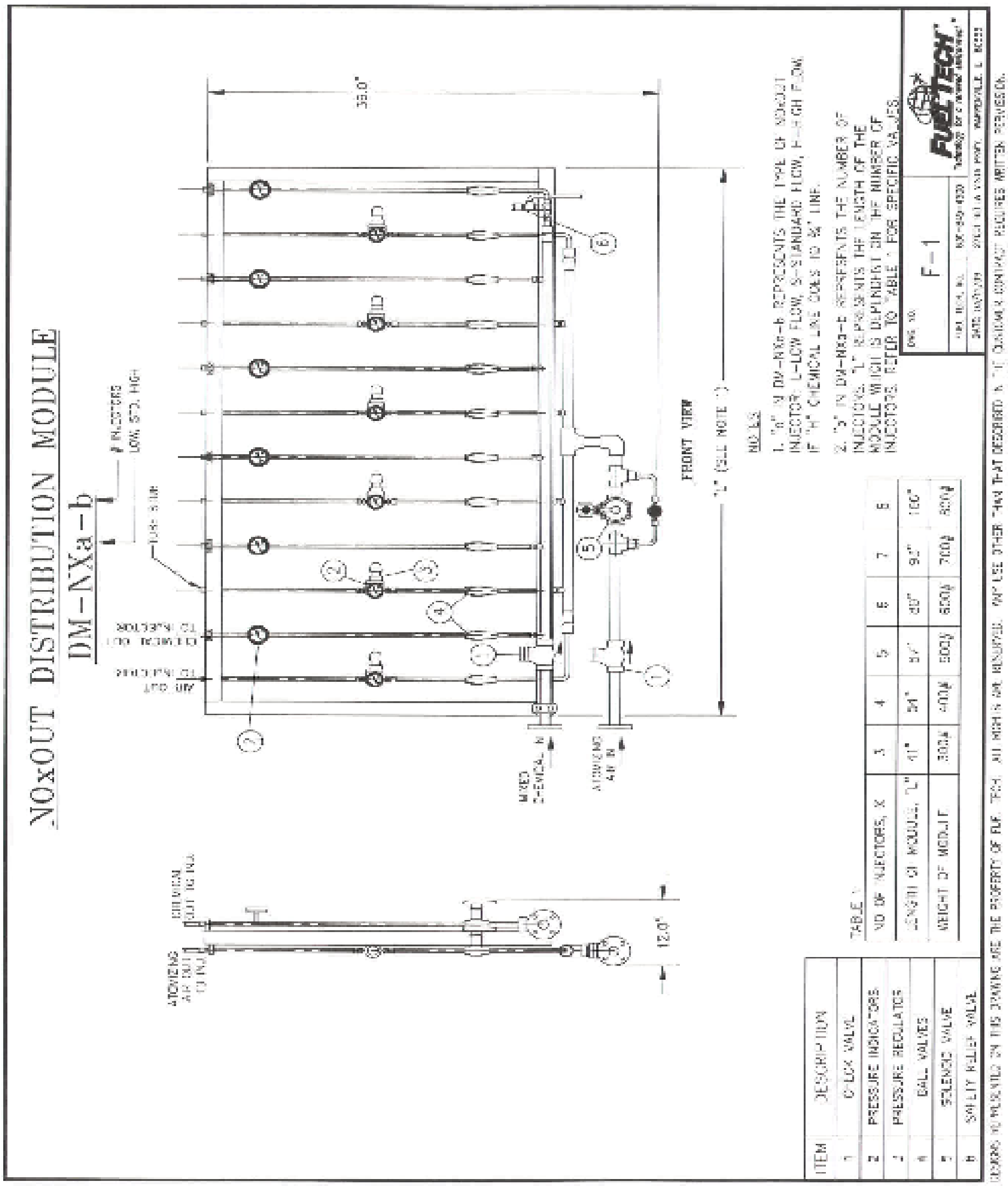
## MM–LF–2P

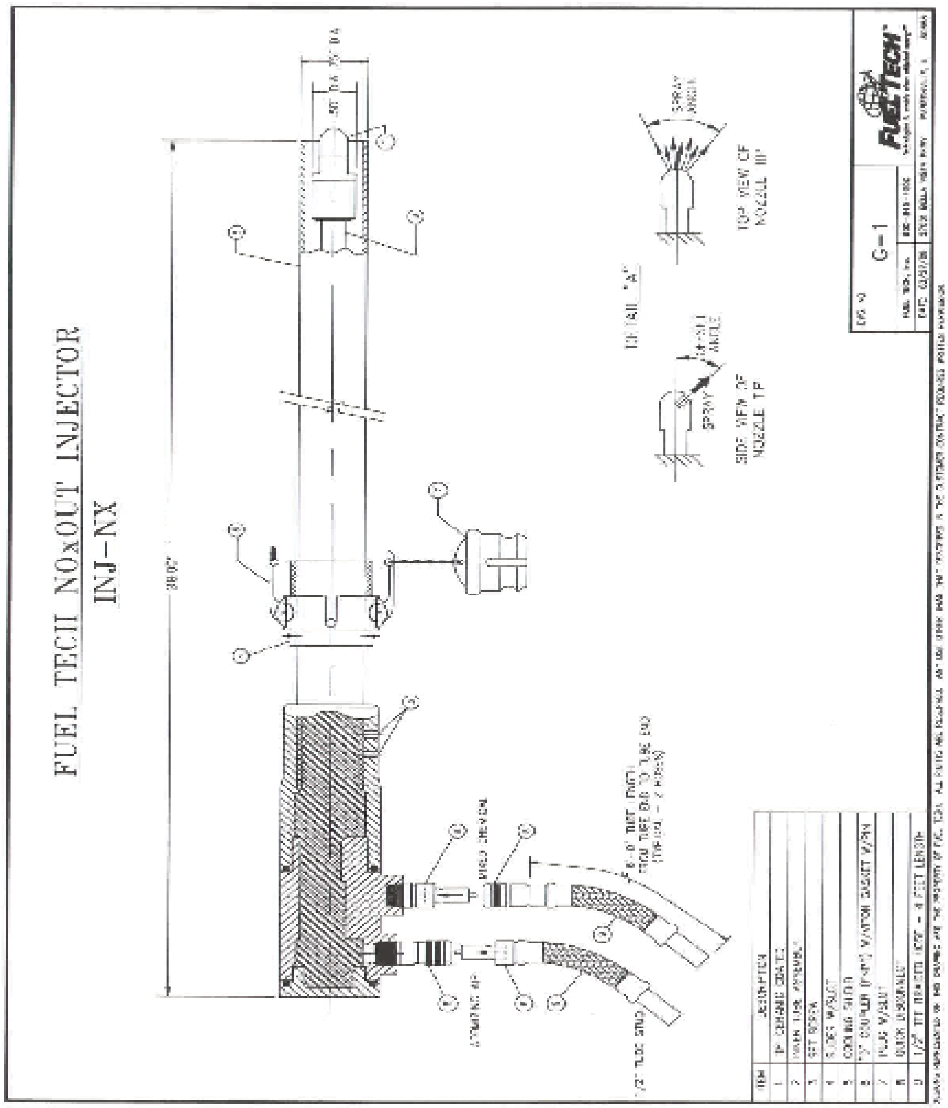
| ITEM | DESCRIPTION | ITEM | DESCRIPTION |
|---|---|---|---|
| 1 | METERING PUMP | 9 | MOTOR OP VALVE |
| 2 | WATER BOOST PUMP | 10 | FLOW INDICATOR |
| 3 | CALIBRATION COLUMN | 11 | AIR PRESSURE SWITCH |
| 4 | STRAINER | 12 | IN LINE STATIC MIXER |
| 5 | PRESSURE INDICATORS | | |
| 6 | BALL VALVE | | |
| 7 | CHECK VALVE | | |
| 8 | PRESSURE REGULATOR | | |

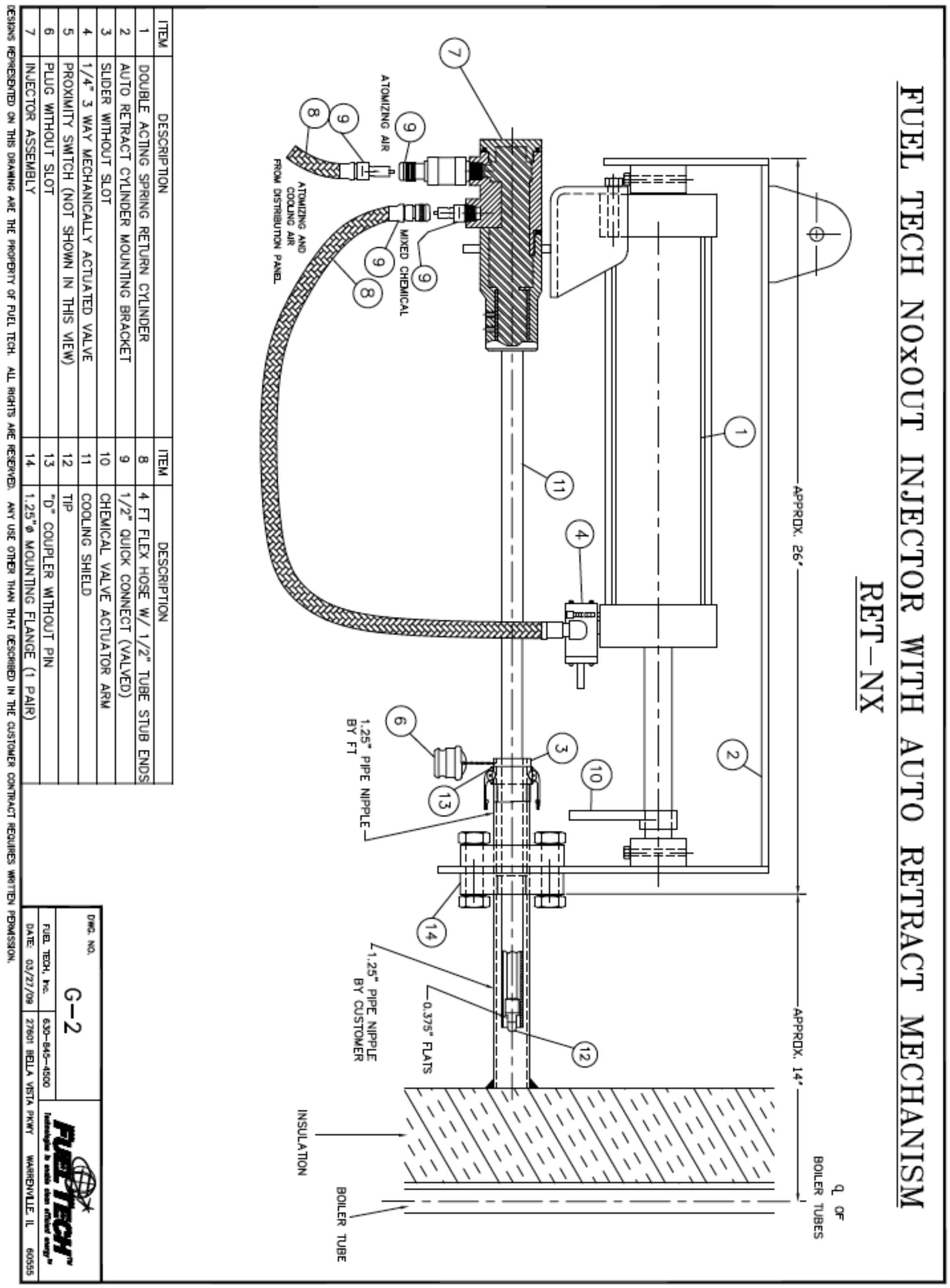



EST. WEIGHT: 2,000 LBS

| | |
|---|---|
| DWG. NO. E–5 | |
| FUEL TECH, Inc. | 630–845–4500 |
| DATE: 03/02/09 | 27601 BELLA VISTA PKWY WARRENVILLE, IL 60555 |


NOxOUT DISTRIBUTION MODULE
DM-NXa-b
FRONT VIEW
33.0"
12.0"
F-1


FUEL TECH NOxOUT INJECTOR
INJ-NX
SPRAY ANGLE
TOP VIEW OF NOZZLE TIP
SIDE VIEW OF NOZZLE TIP
DETAIL "A"
G-1


FUEL TECH NOxOUT INJECTOR WITH AUTO RETRACT MECHANISM
RET–NX
APPROX. 26"
APPROX. 14"
ATOMIZING AIR
ATOMIZING AND COOLING AIR FROM DISTRIBUTION PANEL
MIXED CHEMICAL
1.25" PIPE NIPPLE BY FT
1.25" PIPE NIPPLE BY CUSTOMER
0.375" FLATS
INSULATION
BOILER TUBE
℄ OF BOILER TUBES
ITEM DESCRIPTION
1 DOUBLE ACTING SPRING RETURN CYLINDER
2 AUTO RETRACT CYLINDER MOUNTING BRACKET
3 SLIDER WITHOUT SLOT
4 1/4" 3 WAY MECHANICALLY ACTUATED VALVE
5 PROXIMITY SWITCH (NOT SHOWN IN THIS VIEW)
6 PLUG WITHOUT SLOT
7 INJECTOR ASSEMBLY
8 4 FT FLEX HOSE W/ 1/2" TUBE STUB ENDS
9 1/2" QUICK CONNECT (VALVED)
10 CHEMICAL VALVE ACTUATOR ARM
11 COOLING SHIELD
12 TIP
13 "D" COUPLER WITHOUT PIN
14 1.25"Ø MOUNTING FLANGE (1 PAIR)
DESIGNS REPRESENTED ON THIS DRAWING ARE THE PROPERTY OF FUEL TECH. ALL RIGHTS ARE RESERVED. ANY USE OTHER THAN THAT DESCRIBED IN THE CUSTOMER CONTRACT REQUIRES WRITTEN PERMISSION.
DWG. NO. G–2
FUEL TECH, Inc. 630–845–4500
DATE: 03/27/09 27601 BELLA VISTA PKWY WARRENVILLE, IL 60555

# SNCR

## $NO_xOUT$® and HERT™ Processes

*Proven solutions for flexible, cost-effective $NO_x$ reduction*

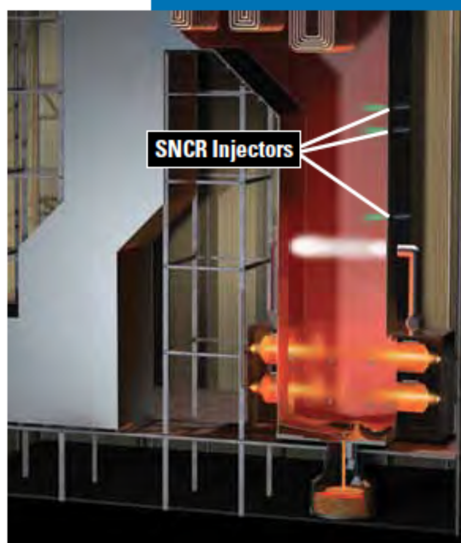
Fuel Tech's urea-based Selective Non-Catalytic Reduction (SNCR) Process is a post-combustion $NO_x$ reduction method that reduces $NO_x$ through a controlled injection of an aqueous urea solution into the combustion gas of utilized industrial sources including: fossil-fired units, waste-fired boilers, furnaces, incinerators, or heaters.

Fuel Tech has enhanced the basic SNCR technology by developing chemical injection hardware, widening the applicable temperature range, and applying process control expertise required for commercial applications.

Fuel Tech has two urea-based SNCR technologies: $NO_xOUT$® systems, which utilize low energy and air atomized injectors, and HERT™ High Energy Reagent Technology, which utilize mechanically atomized injectors and carrier air for injection into the furnace.

The $NO_x$-reducing reaction is temperature sensitive: the optimum temperature range is specific to each application. The reagent needs to be distributed within this optimum temperature zone to obtain the best performance.

The most commonly used reagent consists of a 50% urea solution. This reagent is readily available and requires no special safety precautions for handling.



*SNCR Injection Process*

### SNCR Processes

Fuel Tech's SNCR Processes are designed with the aid of Computational Fluid Dynamics (CFD) and Chemical Kinetic Modeling (CKM) in addition to results from field tests. The CFD model simulates flue gas flows and temperature inside a unit while the CKM calculates the reaction between urea and $NO_x$ based on temperature and flow information from CFD. The combination of these two models determines the optimum temperature region and the optimum injection strategy to distribute the reagent.

| $NO_xOUT$® Process Injection | ← SNCR Technology → | HERT™ High Energy Reagent Technology Injection |
|---|---|---|
| • High momentum injectors<br>• Maximize performance<br>• Adjustable for $NO_x$ reduction downstream of injection point | • CFD/CKM Modeling<br>• Reliable equipment<br>• On-site optimization | • High energy, low momentum injectors<br>• Maximize performance with minimal ammonia slip<br>• Localized $NO_x$ reduction |

### 25-50% $NO_x$ reduction

- Customized solution for each application
- Easy to retrofit – little downtime required
- Low capital cost
- Can be combined with other $NO_x$ reduction technologies
  - 60-70% reduction with Combustion Modification
  - Up to 80% reduction as part of Fuel Tech's ASCR™ Advanced SCR process
- Safe reagent

FUEL TECH
Technologies to enable clean efficient energy™

## Over 580 APC system installations

**worldwide on wide range of fuels and combustion units.**

- Wall-Fired
- Cyclone-Fired
- Tangentially-Fired
- Stokers
- CFB/BFB Boilers
- Municipal Waste
- Coke Ovens
- Cement Kilns
- CO Boilers

**Fuels:**

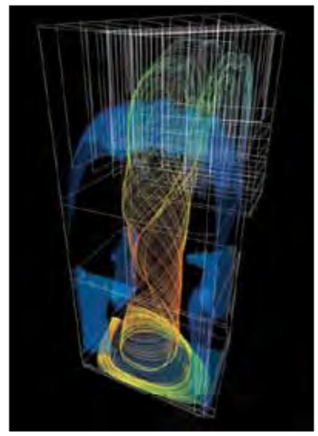
- Coal
- Lignite
- Oil
- Gas
- Sludge
- Wood
- Biomass

Chemical injectors developed by Fuel Tech facilitate the reagent distribution. The $NO_XOUT$® injection system utilizes air-atomized injectors which direct the urea solution into the combustion gas path. The droplet size distribution and spray coverage promote efficient contact between the chemical and the $NO_X$ in the flue gas.

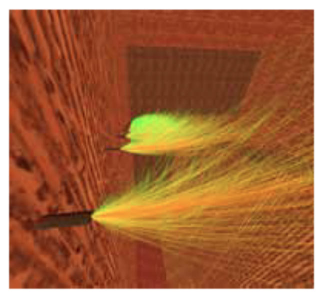
The HERT™ injection system utilizes mechanical atomizers which carry the urea into the furnace using a high energy air stream. Fuel Tech evaluates both for each specific application and offers the best solution for the customer's needs.

Fuel Tech's SNCR Processes provide effective boiler load following capabilities to maximize overall $NO_X$ reduction.

Through computer modeling and proven field experience, an injection strategy is developed that makes use of multilevel injection, control of reagent concentration, droplet size and spray patterns, as well as jet penetration. $NO_XOUT$® and HERT™ systems are applicable on various types of units firing many different fuels, which has been verified by years of field-testing. Since SNCR is a post-combustion process, unit size, boiler type and fuel type can be accommodated in the customized process design.



*CFD Models of $NO_XOUT$® and HERT™ SNCR Processes*



*Independent Zone Metering Module*



FUEL TECH®
*Technologies to enable clean efficient energy™*

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www.ftek.com | (US) 800.666.9688 • (China) 86.10.8487.1742 • (Italy) 39.0331.701110

# Modeling Services

## CFD & Experimental

*Support system performance guarantees through modeling technologies.*

Fuel Tech's experimental (physical) modeling studies combined with Computational Fluid Dynamics (CFD) modeling allow for an insightful understanding of existing flow conditions and effective design of corrective devices such as turning vanes, ash screens, injection systems and static mixers for each unique project.

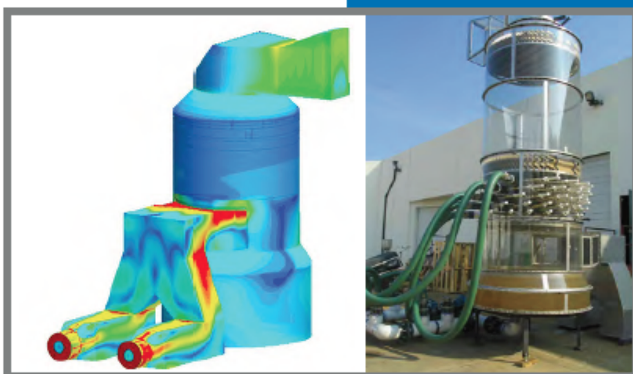
We specialize in fluid dynamics modeling of air pollution control equipment. Scale models of 1:4 to 1:18 have been built for testing for installations in Europe, North America and Asia. Our focus continues to be the delivery of the most accurate and innovative solutions for our customers.

By combining computational and experimental modeling for ESPs, Fuel Tech can predict fluid behavior in new and existing ESP installations, identify flow problems, analyze the process conditions and provide solutions. Corrective flow devices can then be designed, tested and optimized to ensure that flow characteristics meet industry standards.

Innovative techniques are used in physical flow modeling to improve performance in flow critical equipment. Our flow models are constructed quickly and accurately using CNC cut steel as a skeleton, while clear plastic is tested using the latest in flow analysis equipment.

The combination of unique construction techniques, state-of-the-art technology and years of experience enables model studies to be performed in half the time required by our competitors, thereby providing our customers with the confidence and guarantees needed to proceed with construction or retrofitting.

*Physical Models designed to 1/12th scale, combined with CFD modeling.*



Selective Catalytic Reduction (SCR) processes are modeled to ensure that the catalyst is effective and catalyst life is extended for as long as possible. Proper mixing of flue gas and good flow and velocity profile are required to prevent ammonia slip and ensure that $NO_x$ emissions are minimized.

Modeling of Fabric Filters (Baghouses) can be used to predict and solve problem areas of wear and particulate fallout, while reducing overall pressure losses.

Flue Gas Desulphurization (FGD) systems are modeled to prevent poor performance, while solving other problems associated with wet scrubber processes such as:

- Inlet duct liquid pullback
- Mist eliminator performance
- Excessive pressure losses
- Fan inlet flow distribution
- Spray coverage
- Liquid collection

Optimization projects:

- Reduce system pressure losses
- Improve velocity, temperature, gas species and ash distributions
- Prevent in-duct ash and fallout

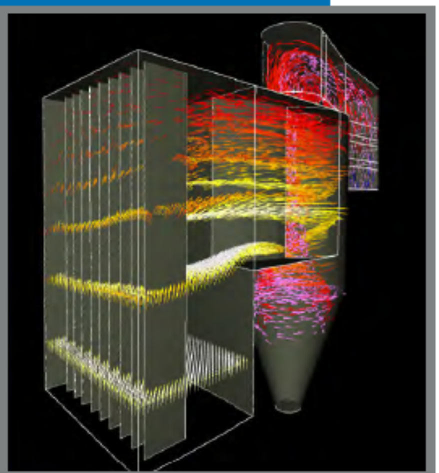
**Fuel Tech has experience modeling and optimizing the following types of equipment:**

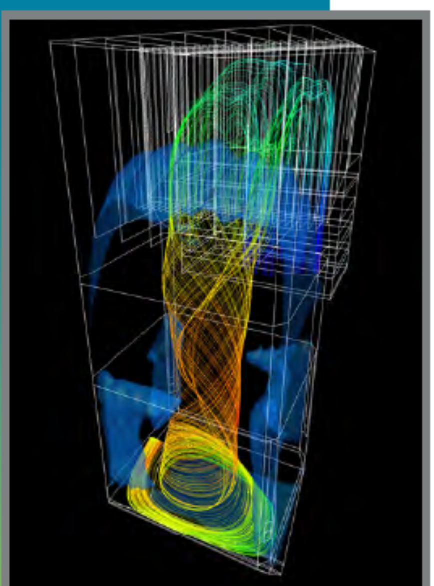
- Boiler Combustion
- Low $NO_x$ Burners
- Over-Fire Air
- Electrostatic Precipitators (ESP)
- Selective Non-Catalytic Reduction Process (SNCR)
- Selective Catalytic Reduction Process (SCR)
- Fabric Filter (Baghouses)
- Flue Gas Desulphurization System (FGD)

Technologies to enable clean efficient energy™

# Modeling Services

*CFD Models designed to accurately predict system performance.*





## Computational Fluid Dynamics (CFD)

Every Fuel Tech product installation has a custom process model supporting it. The model begins with a Computational Fluid Dynamics (CFD) simulation.

CFD models generate predictions of operating temperatures, velocities and other variables from a virtual replication of real-world geometry and operating inputs. Once the base model is generated, we "fly" through the model, using our proprietary visualization software; designed to make explicit to the engineer the complex behaviors of combustion flows. Fuel Tech engineers can explore their models from any perspective with the software and engage the customer in the design stage and tap into the expertise of their plant's experts.

Additional modeling is performed for each unit depending on the type of Fuel Tech application. Once a complete understanding of the process conditions is achieved, a chemical injection strategy is optimized.

Fuel Tech has developed its own chemical spray models specific to boiler and duct conditions, and these models have been validated with both laboratory characterizations of our sprays as well as field performance during 20 years of applications.

Fuel Tech engineers use visualization software to reposition sprays dynamically and gauge the effect on desired performance. CFD simulation of the original model with spray injection provides a more precise mapping of chemical performance.

This proprietary visualization software provides our engineers the ability to show our designs in an immersive, interactive way. Our engineers recognize the information contained in their simulation datasets more rapidly and with greater precision.

Group visualization sessions in our stereovision projection laboratory in Warrenville, IL allow for enhanced design creativity and further risk management. Our designers and sales personnel communicate visually what they have discovered, allowing customers a complete understanding of our recommendations. Customer engagement and feedback on what they see in the virtual environment enriches the design process and further increases quality.

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# SCR Services

*From SCR design to catalyst management services we work with you to **maximize your SCR performance***

Fuel Tech, Inc has a broad range of engineering experience and "real world" operating know-how with SCR systems and related plant operations. We have been involved with SCRs for the control of $NO_x$ and ammonia ($NH_3$) slip emissions on boiler units, simple cycle and combined heat and power systems and incinerators firing coal, gas, oil, and other types of waste fuels.

Our primary focus centers around optimizing process design, catalyst selection, and performance of SCR systems on coal- and natural-gas utility units. Our experience base also spans the full range of SCR applications, including industrial and MSW systems. The design of SCR systems, installation and start up support, ammonia injection grid tuning, performance testing, trouble shooting and operation & maintenance support are among the many services we offer.


*Selective Catalyst Reduction systems help prevent the release of nitrogen oxides from a variety of power and industrial processes. A Simple Cycle Combustion Turbine SCR is shown here.*

We offer our clients unique, experience-based know how focused on the design, operation and maintenance of SCRs, which to date includes more than 55,000 MWs of SCR process design and 20,000 MWs of AIG Tuning services. Fuel Tech's services are targeted to minimize the operating costs of the SCR system, to diagnose operating problems, to enhance overall performance and to assist end users in implementing the most comprehensive catalyst strategies.

After the SCR system has been installed and put into operation, Fuel Tech provides a full range of SCR Management Services. Fuel Tech's comprehensive service program is not simply focused on catalyst management, but encompasses overall SCR system management. As such, our approach does not adhere to traditional catalyst management or owner/catalyst supplier contractual concepts. We partner with owners and operators to ensure that $NO_x$ removal objectives are achieved at the lowest cost without impacting the operating reliability of the units.

- Minimize operating costs of SCR systems
- Optimize SCR process design
- 55,000+ MW experience in SCR process design
- 20,000 MW experience in AIG tuning services

FUEL TECH
Technologies to enable clean efficient energy

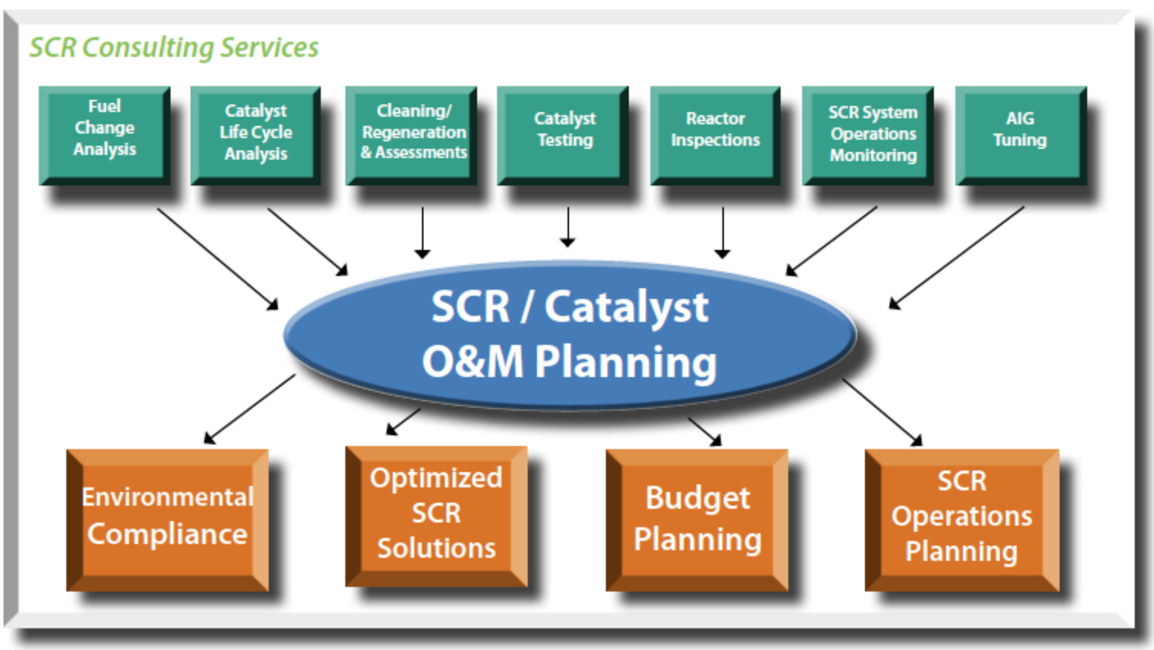
FUEL TECH
Technologies to enable clean efficient energy

Fuel Tech's team of engineers use a combination of field and theoretical studies to solve the SCR industry's most difficult problems.

## SCR Troubleshooting and Optimization

Fuel Tech assists operators in identifying on-going operational issues, while designing and applying improvements to the SCR system in order to enhance overall performance. Our specific services provided in this area include: system audits and inspections, catalyst test sample removal and analysis, field test measurements, catalyst cleaning and regeneration consulting, outage planning and supervision, assessment of fuel planning on SCR behavior, and computational and experimental flow modeling and optimization.

Our comprehensive program of services regarding catalyst management and SCR system performance enhancements is one of a kind in the industry. The program is not simply focused on catalyst management, but encompasses overall SCR system management. Cost effective and reliable operation of the SCR systems for the owner's fleet is of the utmost importance to Fuel Tech. The consulting services associated with Fuel Tech's programs are designed to compliment and supplement the performance guarantees and warranties provided by the SCR and/or Catalyst OEMs.



# Enabling SCR Performance to Exceed Expectations

**Clients include:**

- Electric Utilities
- Independent Power Producers
- A & E Companies
- OEMs
- Component Suppliers

### Requirements for Annual SCR Operation

Fuel Tech can review SCR operational procedures to ensure proper annual operation. This includes all operating sub-systems of a typical SCR. Fuel Tech can also evaluate seasonal catalyst performance and provide a solution for year-round operation. Catalyst management plans can be updated accordingly to coincide with unit outage schedules.

### Specification Review & Preparation

We review turnkey specifications with special attention paid to, design data, guarantees, process design, equipment, catalyst design, and potential impacts on boiler and unit operation. We prepare technical specifications for clients. Where our focus includes catalyst selection, ammonia injection grid design, flow modeling and flow correction requirements, reagent system requirements and performance guarantees.

### Proposal Evaluation

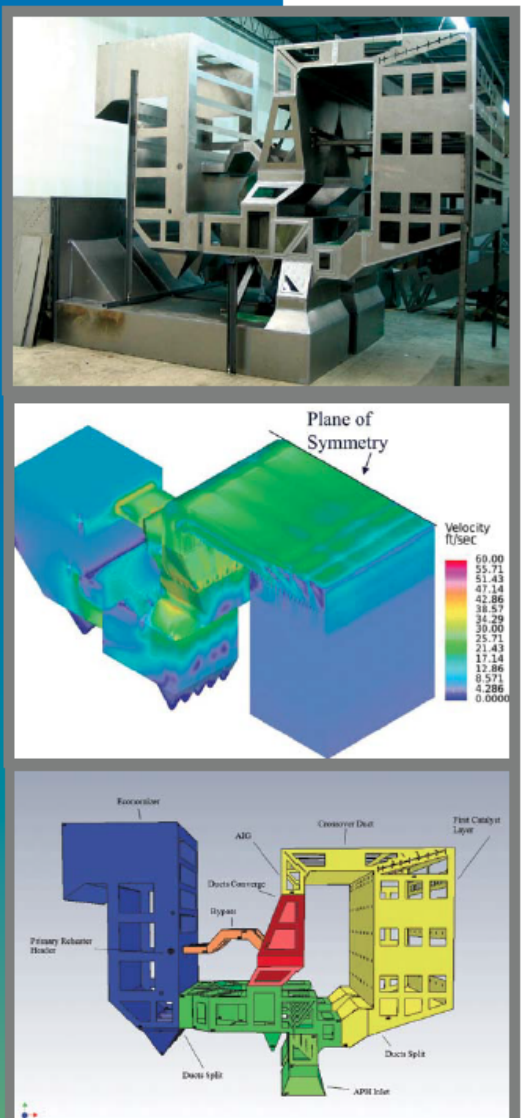
SCR system and catalyst proposal evaluations are critical in determining that the client's or owner's needs are being realized. Fuel Tech's assistance in this area can range from a complete technical assessment of a proposed design and its compliance with the specification to an analysis of a specific technical issue. Fuel Tech will assist in the development of evaluation criteria, preparation of questions to the suppliers, and recommendation of the most qualified and cost competitive supplier.

### SCR Process Arrangement & Component Design

We can assist in defining parameters for SCR design to suite your requirements. Historical boiler operating data will be reviewed and assessed to determine unit process data at full, mid and low loads. Fuel Tech assists clients in selecting SCR catalyst performance requirements so that the client's $NO_x$ emission control strategy is effectively met with minimum negative impact due to $NH_3$ slip and $SO_2$ to $SO_3$ oxidation. We will help define process distribution requirements so that long term performance and operational demands are achieved.

*Ash deposits are a common problem in SCR systems, which can be alleviated through the application of fluid dynamics and utilizing baffling and screening hardware.*

# SCR Services




*Three dimensional computer models allow for the design and testing of computational fluid dynamics and experimental fluid dynamics models. All are used to study the complex relationship between cause and effect in SCR systems.*

## CFD Modeling Services

With the use of Computational Fluid Dynamics (CFD) modeling, we recommend optimal arrangements of duct configuration and flow correction devices in order to maintain appropriate flue gas velocities, temperature distribution, fly ash distribution, and $NH_3$ to $NO_x$ distribution within the SCR system. Fuel Tech provides our clients with the sizing, design, and configuration of the $NH_3$ injection grid, static mixer, large particle ash screen, GSG™ Graduated Straightening Grid, and turning vanes.

## Physical Flow Modeling Services

We also offer physical (or experimental) flow modeling services for SCR systems. The material of construction for the physical model shall be carbon steel based on the suppliers experience with sufficient area to be transparent material to allow inspection of all internal critical areas of the model. Only state-of-the-art measurement devices are used during the modeling, including: hot-wire anemometers, peizo-electric pitot tubes.

Modeling carried out using a three dimensional flow model similar in geometry to the full size SCR system can include the following:

- Boiler backpass from economizer inlet plane
- Boiler backpass economizer and ash hoppers
- Superheat pass and Reheat pass dampers
- SCR inlet ductwork complete
- Flow correction devices including flue gas flow straightening grids at SCR inlet
- LPA screen, ammonia injection grid
- SCR reactor - either single or dual reactors as required
- Catalyst
- Bypass system complete
- SCR outlet ductwork up to, and through, all airheaters
- Dampers and expansion joints
- Ductwork and reactor ash hoppers
- Internal structural members (grating, braces, gusset plates)

## Testing Criteria

- System Pressure Loss Tests
- Fly Ash Dropout Testing
- Flue Gas Velocity Distribution Upstream of $NH_3$ injection
- Flue Gas Velocity Distribution Upstream of the Catalyst
- Velocity Distribution at Large Particle Ash Screen
- Velocity at Floors and Structural Members
- Flue Gas $NO_x$ and $NH_3$ Distribution



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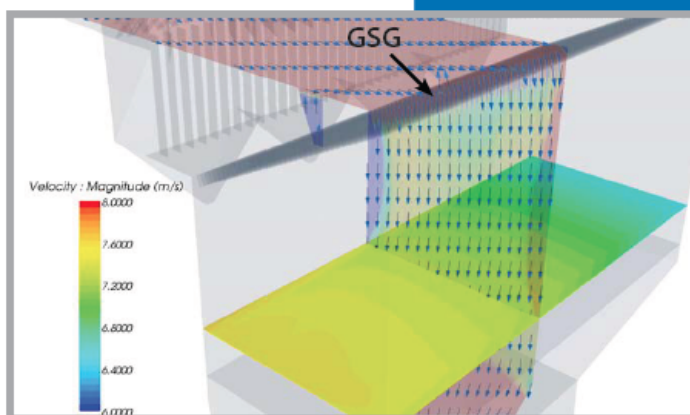
# GSG™
## Graduated Straightening Grid

*Significantly improve SCR performance without increasing cost or complexity.*

Fuel Tech's patent pending GSG™ Graduated Straightening Grid technology is a significant step forward in Selective Catalytic Reduction (SCR) process design.

Until now, improving the velocity distribution and flow direction into the face of the first catalyst layer the traditional solution has been to use many large turning vanes along with a straightening grid placed immediately above the catalyst. The turning vanes were tuned to achieve an even velocity distribution while the straightening grid below straightened the flow direction. This system requires exact spacing and angling of turning vanes during SCR construction to ensure required flow distributions are met. This traditional solution is also extremely sensitive to changes to the upstream flow distribution and any changes to the system require remodeling and retuning of the vanes to maintain the required distributions. After years of research and development using scale and computational modeling, the GSG has been thoroughly tested and successfully installed on a number of units.

The GSG combines the turning vanes and straightening grid into a single sloped grid. The GSG has been shown to be an extremely robust flow corrective solution. It is much less sensitive to upstream flow distributions than traditional solutions which means that the catalyst and catalyst performance are protected even when the unit is not running at optimum design conditions




*Colored planes here depict velocity magnitude.*

(such as economizer bypass) or if boiler or ductwork changes are made in the future.

Finally the simple design of the GSG makes precise spacing and angling of turning vanes unnecessary. Fuel Tech's CFD modeling capabilities combined with our real world expertise provide the basis for all of our technologies and allow us to support guarantees on your system's performance. **The GSG provides flow and velocity distribution towards the first layer of catalyst without turning vanes.**

Prevent problems and downtime associated with:

- Dust accumulation
- Erosion
- Uneven catalyst face
- Shortened catalyst life
- Increased pressure loss

### Traditional Turning Vane Velocity Distribution at Catalyst Face Statistics

- 62% of velocities within 10% of average
- 93.9% of velocities within 20% of average

### GSG Velocity Distribution at Catalyst Face Statistics

- 95% of velocities within 10% of average
- 100% of velocities within 15% of average

# Technical Support Document for EPA's Proposed Action on the Arkansas Regional Haze Federal Implementation Plan

**Prepared and Reviewed by:**

Dayana Medina
Michael Feldman
Barbara Nann

**February 2015**

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# Technical Support Document
# for EPA's
# Proposed Action on the
# Arkansas Regional Haze Federal Implementation Plan

## I. Arkansas Regional Haze

### A. Background on Regional Haze

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

Data from the existing visibility monitoring network, the "Interagency Monitoring of Protected Visual Environments" (IMPROVE) monitoring network, show that visibility impairment caused by air pollution occurs virtually all the time at most national parks (NPs) and wilderness areas (WAs). The average visual range[1] in many Class I areas (*i.e.*, NPs and memorial parks, WAs, and international parks meeting certain size criteria) in the western United States is 100-150 kilometers, or about one-half to two-thirds of the visual range that would exist without anthropogenic air pollution. In most of the eastern Class I areas of the United States, the average visual range is less than 30 kilometers, or about one-fifth of the visual range that would exist under estimated natural conditions. 64 FR 35715 (July 1, 1999).

### B. Regional Haze Requirements

The goal of the Regional Haze Rule (RHR) is to restore natural visibility conditions by 2064 at the 156 Class I areas identified in the 1977 Clean Air Act Amendments.[2] The regional haze state implementation plans (SIPs) must contain measures that make "reasonable progress" toward this goal by reducing anthropogenic emissions that cause haze. The RHR sets out specific requirements for state's initial regional haze SIPs. In particular, each state's plan must establish a

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

[2] 40 CFR 51.301(q) defines natural conditions: "Natural conditions include naturally occurring phenomena that reduce visibility as measured in terms of light extinction, visual range, contrast, or coloration."

long-term strategy that ensures reasonable progress toward achieving natural visibility conditions in each Class I area affected by the emissions from sources within the state. In addition, for each Class I area within the state's boundaries, the plan must establish a reasonable progress goal (RPG) for the first planning period that ends on July 31, 2018. The long-term strategy must include enforceable emission limits and other measures as necessary to achieve the RPG. Regional haze plans must also give specific attention to certain stationary sources that were in existence on August 7, 1977, but were not in operation before August 7, 1962. These sources, where appropriate, are required to install Best Available Retrofit Technology (BART) controls to eliminate or reduce visibility impairment. More details on regional haze plan requirements are summarized in the Federal Register notice for this action.

### C. Relationship of this TSD and Our Proposed FIP Action to Our March 12, 2012 Final Partial Approval and Partial Disapproval of the Arkansas Regional Haze SIP

The Act requires each state to develop plans to meet various air quality requirements, including protection of visibility. (CAA sections 110(a), 169A, and 169B). The plans developed by a state are referred to as State Implementation Plans or SIPs. A state must submit its SIPs and SIP revisions to EPA for approval. Once approved, a SIP is federally enforceable, that is enforceable by EPA and citizens under the Act. If a state fails to make a required SIP submittal or if we find that a state's required submittal is incomplete or unapprovable in whole or in part, then we must promulgate a Federal Implementation Plan (FIP) to fill this regulatory gap within 2 years unless we approve a SIP revision correcting the deficiencies before promulgating a FIP. (CAA section 110(c)(1)).

To address the first implementation period, the State of Arkansas submitted a RH SIP on September 23, 2008, and August 3, 2010, and submitted supplemental information on September 27, 2011. We are hereafter referring to these regional haze submittals collectively as the "2008 Arkansas RH SIP". On March 12, 2012, the EPA partially approved and partially disapproved the RH SIP submitted by Arkansas (77 FR 14604). Under section 110(c) of the Act, whenever we disapprove a SIP submission in whole or in part, within 2 years of the final disapproval action we are required to approve a SIP revision submitted by the State or promulgate a FIP to address the disapproved portions of the SIP unless we first approve a SIP revision correcting the deficiencies before promulgating a FIP. Specifically, section 110(c) provides:

> (1) The Administrator shall promulgate a Federal implementation plan at any time within 2 years after the Administrator—
>
> (A) finds that a state has failed to make a required submission or finds that the plan or plan revision submitted by the state does not satisfy the minimum criteria established under [section 110(k)(1)(A)], or

(B) disapproves a state implementation plan submission in whole or in part, unless the state corrects the deficiency, and the Administrator approves the plan or plan revision, before the Administrator promulgates such Federal implementation plan.

Section 302(y) defines the term "Federal implementation plan" in pertinent part, as:

[A] plan (or portion thereof) promulgated by the Administrator to fill all or a portion of a gap or otherwise correct all or a portion of an inadequacy in a State implementation plan, and which includes enforceable emission limitations or other control measures, means or techniques (including economic incentives, such as marketable permits or auctions or emissions allowances)* * *.

Thus, because we partially disapproved the 2008 Arkansas RH SIP and the SIP submittal addressing the interstate visibility transport requirement, we are required to promulgate a FIP for Arkansas, unless we first approve a SIP revision that corrects the disapproved portions of these SIP submittals. Arkansas has not as yet submitted a revised SIP following our partial disapproval, and more than two years have passed since EPA partially disapproved Arkansas' RH SIP. Thus, EPA is under an obligation to promulgate a Regional Haze FIP to correct the portions of the SIP that we disapproved. We are proposing a FIP to address those portions of the SIP that we disapproved.

**D. Portions of the Arkansas Regional Haze SIP Disapproved by EPA**

In our March 12, 2012, final partial approval and partial disapproval of the 2008 Arkansas RH SIP, we disapproved the following BART determinations made by Arkansas:

- $SO_2$, $NO_X$, and PM BART for the Arkansas Electric Cooperative Corporation (AECC) Carl E. Bailey Generating Station Unit 1;
- $SO_2$, $NO_X$, and PM BART for the AECC John L. McClellan Generating Station Unit 1;
- $SO_2$ and $NO_X$ BART for the American Electric Power (AEP) Flint Creek Power Plant No. 1 Boiler;
- $SO_2$ and $NO_X$ BART for the bituminous and sub-bituminous coal firing scenarios for the Entergy White Bluff Plant Units 1 and 2;
- $SO_2$, $NO_X$, and PM BART for the Entergy White Bluff Plant Auxiliary Boiler;
- $NO_x$ BART for the natural gas firing scenario for the Entergy Lake Catherine Plant Unit 4;
- $SO_2$, $NO_X$, and PM BART for the fuel oil firing scenario for the Entergy Lake Catherine Plant Unit 4;
- $SO_2$ and $NO_X$ BART for the Domtar Ashdown Mill No. 1 Power Boiler; and
- $SO_2$, $NO_X$, and PM BART for the Domtar Ashdown Mill No. 2 Power Boiler.

In our final action we also disapproved Arkansas' determinations that the Georgia-Pacific Crossett Mill 6A Boiler is not BART eligible, and that the 6A and 9A Boilers are not subject to BART. By partially disapproving Arkansas' BART determinations, we also partially disapproved the corresponding Arkansas Pollution Control and Ecology Commission (APCEC) Regulation 19, Chapter 15, which is the State's BART rulemaking that identifies the BART eligible and subject to BART sources in Arkansas and establishes the BART emission limits that sources subject to BART are required to comply with. This rulemaking was submitted by the State of Arkansas on September 23, 2008 as part of the RH SIP, and non-substantive revisions to the rulemaking were submitted as a SIP revision on August 3, 2010. We also disapproved Arkansas' RPGs for its two Class I areas, the Caney Creek Wilderness Area and the Upper Buffalo Wilderness Area, because Arkansas did not meet the requirement under section 169A(g)(1) of the CAA and 40 CFR section 51.308(d)(1)(i)(A) to consider and provide an analysis of the four factors that states are required to consider in establishing their RPGs. We also partially disapproved the State's long-term strategy because it relied on other disapproved portions of the SIP.

The purpose of this TSD and the proposed Federal Register notice associated with this TSD is to correct the disapproved portions of the 2008 Arkansas RH SIP and fulfill the obligation before us under CAA section 110(c) to implement a FIP within two years of our disapproval of the SIP. This TSD contains three appendices that support our proposal: Appendix A to this TSD contains a report detailing our cost analysis for $SO_2$ controls at the Entergy White Bluff and Entergy Independence facilities; Appendix B to this TSD contains a report describing our review of the BART modeling protocol developed by Trinity Consultants on behalf of the BART sources; and Appendix C to this TSD contains a report describing the visibility modeling analysis performed by EPA for the Entergy Independence facility.

This TSD is not meant to be a complete rationale for our decision. It merely provides additional information for some of the technical aspects of the basis for this action when needed. In some of the non-technical areas, our Federal Register notice provides more detail than does this TSD. Also, this TSD treats the requirements of section 51.308 in the order in which they appear in that regulation, whereas our Federal Register notice groups the requirements into related areas so the concepts can be understood more easily. In this regard, the TSD can serve as a checklist of whether the requirements have been addressed.

Throughout this document, we often use language such as, "we find" or other similar phrases that on the surface would suggest a final determination has been made. However, all aspects of our TSD should be considered to be part of our proposal and are subject to change based on comments and other information we may receive during our public comment period.

## II. Best Available Retrofit Technology (BART)

## A. Identification of BART Eligible Sources and Subject to BART Sources

States are required to identify all the BART-eligible sources within their boundaries by utilizing the three eligibility criteria in the BART Guidelines (70 FR 39158) and the Regional Haze regulations (40 CFR 51.301): (1) One or more emission units at the facility fit within one of the 26 categories listed in the BART Guidelines; (2) the emission unit(s) began operation on or after August 6, 1962, and the unit was in existence on August 6, 1977; and (3) the potential emissions of any visibility-impairing pollutant from subject units are 250 tons or more per year. Sources that meet these three criteria are considered BART-eligible. Once a list of the BART-eligible sources within a state has been compiled, states must determine whether to make BART determinations for all of them or to consider exempting some of them from BART because they may not reasonably be anticipated to cause or contribute to any visibility impairment in a Class I area. The BART Guidelines present several options that rely on modeling analyses and/or emissions analysis approaches to determine if a source may reasonably be anticipated to cause or contribute to visibility impairment in a Class I area. A source that may not be reasonably anticipated to cause or contribute to any visibility impairment in a Class I area is not "subject to BART," and for such sources, a state need not apply the five statutory factors to make a BART determination.

### 1. Georgia-Pacific Crossett Mill 6A and 9A Power Boilers

In our March 12, 2012 final action, we approved Arkansas' identification of BART-eligible sources, with the exception of the Georgia-Pacific Crossett Mill 6A Boiler. We also approved the State's determination of which sources are subject to BART, with the exception of the State's determination that the Georgia-Pacific Crossett Mill 6A and 9A Boilers are not subject to BART. Our basis and analyses for our disapproval of Arkansas' determinations that the 6A Boiler is not BART-eligible and that the 6A and 9A Boilers are not subject to BART is found in our October 17, 2011 proposed rulemaking, March 12, 2012 final rulemaking, and the associated TSDs.[3]

A revised Title V permit for the Georgia-Pacific Crossett Mill was issued on August 4, 2011, and again on May 23, 2012. Although no actual pollution controls were installed, the permitted emission limits for $SO_2$ and $PM_{10}$ for the 6A Boiler and $SO_2$, $NO_X$, and $PM_{10}$ for the 9A Boiler were revised so as to be more stringent. In a letter dated May 18, 2012,[4] Georgia-Pacific explained to ADEQ that it had conducted additional dispersion modeling in 2011 based on the currently enforceable Title V permit limits for the 6A and 9A Boilers.[5] The results of the

[3] 76 FR 64186 and 77 FR 14604.

[4] May 18, 2012 letter from James W. Cutbirth, Environmental Services Superintendent at Georgia-Pacific Crossett Paper Operations, to Mary Pettyjohn, ADEQ. A copy of this letter can be found in the docket for this proposed rulemaking.

[5] See ADEQ Operating Air Permit No. 0597-AOP-R14, issued on May 23, 2012. A copy of the air permit can be found in the docket for this proposed rulemaking.

2011 modeling analysis are summarized in the table below. Based on modeling of the current permit limits, the boilers' maximum visibility impact was modeled to be 0.359 Δdv at Caney Creek (2002). In the letter to ADEQ, Georgia-Pacific stated it believes that the 2011 dispersion modeling analysis and the current Title V permit that enforces the modeled limits are sufficient to demonstrate no cause or contribution to visibility impairment by the 6A and 9A Boilers, and that the boilers are therefore not subject to BART.

**Table 1. Maximum Modeled Visibility Impacts from 6A and 9A Boilers (Georgia-Pacific's 2011 Dispersion Modeling Analysis)**

| Class I area | Maximum Visibility Impact (dv) | | |
|---|---|---|---|
| | 2001 meteorology | 2002 meteorology | 2003 meteorology |
| Caney Creek | 0.16 | 0.359 | 0.296 |
| Upper Buffalo | 0.099 | 0.074 | 0.099 |
| Hercules-Glades | 0.08 | 0.288 | 0.125 |
| Mingo | 0.123 | 0.093 | 0.168 |
| Sipsey | 0.171 | 0.184 | 0.119 |

Following discussions with us and ADEQ, Georgia-Pacific provided additional information in support of its contention that the 6A and 9A Boilers are not subject to BART. Georgia-Pacific calculated maximum 24-hour emission rates from the 2001-2003 baseline period using fuel usage data, and then showed that these estimated maximum 24-hour emission rates are below the updated emission rates it modeled in the 2011 BART screening modeling. In a letter dated April 1, 2013, Georgia-Pacific provided spreadsheets with fuel usage data for the 6A and 9A Boilers for each day during the 2001-2003 baseline period.[6] The 6A Boiler burned only natural gas during the 2001-2003 baseline period, while the 9A Boiler burned both natural gas and bark. Georgia-Pacific used emission factors from AP-42, *Compilation of Air Pollutant Emission Factors,*[7] to calculate 24-hour emission rates for $SO_2$, $NO_X$, and $PM_{10}$ (lb/hr) for the 6A and 9A Boilers for each day during the baseline years (see table below). The gas and bark usage

[6] April 1, 2013 letter from James W. Cutbirth, Environmental Services Superintendent at Georgia-Pacific Crossett Paper Operations, to Mary Pettyjohn, ADEQ. A copy of this letter and all attachments can be found in the docket for this proposed rulemaking.

[7] *AP-42, Compilation of Air Pollutant Emission Factors*, has been published since 1972 as the primary compilation of EPA's emission factor information. It contains emission factors and process information for more than 200 air pollution source categories. The emission factors have been developed and compiled from source test data, material balance studies, and engineering estimates. The Fifth Edition of AP-42 was published in January 1995. Since then, EPA has published supplements and updates to the fifteen chapters available in Volume I, Stationary Point and Area Sources. The latest emissions factors are available at http://www.epa.gov/ttnchie1/ap42/.

value for each day was multiplied by the appropriate AP-42 emission factor to calculate the 24-hour emission rate for each day during the baseline period. Example calculations for the 6A and 9A Boilers are shown below.

**Table 2. AP-42 Emission Factors Used to Calculate Pollutant Emission Rates**

| Pollutant | AP-42 Emission Factor | Emission Factor[8] (converted to appropriate units) |
|---|---|---|
| Natural Gas Firing (6A and 9A Boilers) | | |
| $PM_{10}$ | 7.6 lb/MM $ft^3$ | 0.0076 lb/M $ft^3$ |
| $SO_2$ | 0.6 lb/MM $ft^3$ | 0.0006 lb/M $ft^3$ |
| $NO_X$ | 280 lb/MM $ft^3$ | 0.28 lb/M $ft^3$ |
| Bark Firing (9A Boiler) | | |
| $PM_{10}$ | 0.066 lb/MMBtu | 0.594 lb/ton |
| $SO_2$ | 0.025 lb/MMBtu | 0.225 lb/ton |
| $NO_X$ | 0.22 lb/MMBtu | 1.98 lb/ton |

*Example Calculation of 24-hour Pollutant Emission Rates for 6A Boiler:*

Jan 1, 2001 -- Gas usage for 24-hour period = 459 M $ft^3$

$PM_{10}$ (lb/hr) = 459 M $ft^3$ / 24 hr x 0.0076 lb/M $ft^3$ = 0.145 lb/hr

$SO_2$ (lb/hr) = 459 M $ft^3$ / 24 hr x 0.0006 lb/M $ft^3$ = 0.0115 lb/hr

$NO_X$ (lb/hr) = 459 M $ft^3$ / 24 hr x 0.28 lb/M $ft^3$ = 5.355 lb/hr

*Example Calculation of 24-hour Pollutant Emission Rates for 9A Boiler:*

Jan 1, 2001 -- Bark usage for 24-hour period = 814 tons

$PM_{10}$ (lb/hr) = 814 tons/ 24 hr x 0.594 lb/ton bark = 20.15 lb/hr

$SO_2$ (lb/hr) = 814 tons/ 24 hr x 0.225 lb/ton bark = 7.63 lb/hr

$NO_X$ (lb/hr) = 814 tons/ 24 hr x 1.98 lb/ton bark = 67.15 lb/hr

[8] Georgia-Pacific converted the AP-42 emission factors into units of lb/M $ft^3$ to be consistent with the fuel usage units of measure used in the Georgia-Pacific Crossett Mill's Utility Department electronic recording and recordkeeping system. The AP-42 emission factors for bark firing were converted into units of lb/ton by calculating the MM/Btu per ton of bark fired (1 ton bark = 2,000 lb; 2,000 lb x 4,500 Btu/lb = 9,000,000 Btu/ton of bark fired). The AP-42 emission rates were then multiplied by 9.0 MMBtu/ton of bark to obtain units of lb/ton.

Jan 1, 2001 -- Gas usage for 24-hour period = 2,513 M $ft^3$

$PM_{10}$ (lb/hr) = 2,513 M $ft^3$ / 24 hr x 0.0076 lb/M $ft^3$ = 0.8 lb/hr

$SO_2$ (lb/hr) = 2,513 M $ft^3$ / 24 hr x 0.0006 lb/M $ft^3$ = 0.063 lb/hr

$NO_X$ (lb/hr) = 2,513 M $ft^3$ / 24 hr x 0.19 lb/M $ft^3$ = 19.9 lb/hr

Total $PM_{10}$ = 20.15 + 0.8 = 20.95 lb/hr
Total $SO_2$ = 7.63 + 0.063 = 7.69 lb/hr
Total $NO_X$ = 67.15 + 19.9 = 87.0 lb/hr

After calculating the 24-hour pollutant emission rate for each day of the year, Georgia-Pacific determined the maximum 24-hour emission rate by using the "max" function of Excel.[9] For estimating the maximum 24-hour emission rate for $PM_{10}$ for the 9A Boiler, Georgia-Pacific used the results of stack testing it conducted when the boiler was firing bark and gas, since these results yielded higher emission rates than those calculated using AP-42 emission factors. The table below shows the maximum 24-hour emission rates during the baseline period for the 6A and 9A Boilers.

**Table 3. Maximum 24-hour Emission Rates from the 2001 – 2003 Baseline Period**

| | **Maximum 24-hour Emission Rates (lb/hr)** | | |
|---|---|---|---|
| **Unit** | **$SO_2$** | **$NO_X$** | **$PM_{10}$** |
| 6A Boiler | 0.2 | 90.7 | 2.5 |
| 9A Boiler | 17.9 | 174.1 | 72.0 |

Georgia-Pacific then compared the calculated maximum 24-hour emission rates from the baseline period with emission rates modeled in the 2011 BART screening modeling and with the current Title V permit limits (see table below).[10] A comparison of these values shows that the calculated maximum 24-hour emission rates for each pollutant are below the emission rates Georgia-Pacific modeled in the 2011 BART screening modeling, and that the modeled emission rates are approximately equal to the currently enforceable Title V permit limits.

[9] A spreadsheet containing the calculated 24-hour emission rates for each day during the years 2001-2003 for the 6A and 9A Boilers can be found in the docket for this proposed rulemaking.

[10] See ADEQ Operating Air Permit No. 0597-AOP-R14, issued on May 23, 2012. A copy of the air permit can be found in the docket for this proposed rulemaking.

**Table 4. Comparison of Maximum 24-hour Emission Rates with Modeled Emission Rates and Title V Permit Limits**

| **6A Boiler** | | | |
|---|---|---|---|
| | **$SO_2$** | **$NO_X$** | **$PM_{10}$** |
| Calculated Maximum 24-hr Emission Rate (lb/hr) | 0.2 | 90.7 | 2.5 |
| Modeled Emission Rate (lb/hr) | 0.3 | 120.0 | 3.3 |
| Title V permit Limit (lb/hr) | 0.3 | 120.0 | 3.3 |
| **9A Boiler** | | | |
| | **$SO_2$** | **$NO_X$** | **$PM_{10}$** |
| Calculated Maximum 24-hr Emission Rate (lb/hr) | 17.9 | 174.1 | 72.0 |
| Modeled Emission Rate (lb/hr) | 200.0 | 218.0 | 75.8 |
| Title V permit Limit (lb/hr) | 199.8 | 196.0 | 77.4 |

Because the 2011 BART screening modeling showed visibility impacts below 0.5 dv from the boilers and the recently estimated maximum 24-hour emission rates from the 2001-2003 baseline period are below the modeled emission rates, it is reasonable to determine that the boilers had visibility impacts below 0.5 dv during the baseline period. Accordingly, we believe that Georgia-Pacific's newly provided analysis and documentation, as described above, is appropriate to demonstrate that the 6A and 9A boilers are not subject to BART. In comparison to the information available to us when we issued our March 12, 2012, final action on the 2008 Arkansas RH SIP, we believe this newly provided analysis allows 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 are proposing to find that while the 6A Boiler is a BART-eligible source, it is not subject to BART. The 9A Boiler is also BART-eligible (as the State determined in the 2008 Arkansas RH SIP), but we are also proposing to find that the 9A Boiler is not subject to BART. Therefore, it is not necessary to perform a BART five factor analysis and make BART determinations for the Georgia-Pacific Crossett Mill 6A and 9A Boilers.

**2. AECC Carl E. Bailey Generating Station Unit 1**

In our March 12, 2012, final action on the 2008 Arkansas RH SIP, we noted that the original meteorological databases generated by the Central Regional Air Planning Association (CENRAP) and used by Arkansas to conduct its modeling analyses did not include surface and upper air meteorological observations as EPA guidance recommends. Thus, in its evaluation to determine if a source exceeds the 0.5 Δdv contribution threshold at potentially affected Class I areas, Arkansas used the maximum value (*i.e.* 1$^{st}$ high value) of modeled visibility impacts instead of the 98th percentile value (*i.e.* 8th high value). The use of the maximum modeled values in the 2008 Arkansas RH SIP was agreed to by EPA, representatives of the Federal Land Managers, and CENRAP stakeholders. In our March 12, 2012 final action, we approved Arkansas' determination that the AECC Carl E. Bailey Generating Station (AECC Bailey) Unit 1 is subject to BART, based on the maximum value of modeled visibility impacts.

Following our March 12, 2012, final action on the Arkansas RH SIP, AECC hired a consultant to conduct revised modeling of AECC Bailey Unit 1.[11] The revised modeling shows visibility impacts from Bailey Unit 1 below 0.5 Δdv, which is the threshold used by Arkansas to determine if a source is subject to BART. However, we already approved the State's determination that the AECC Bailey Unit 1 is subject to BART in our March 12, 2012 final action on the 2008 Arkansas RH SIP. We do not have the discretion to reopen the issue of whether the source is subject to BART because we already approved the portion of the 2008 Arkansas RH SIP in which Arkansas determined AECC Bailey Unit 1 is subject to BART and Arkansas has not provided us a SIP revision to replace the previous determination.[12] We cannot re-consider our approval of that portion of the 2008 Arkansas RH SIP to have been in error because Arkansas did not submit the revised modeling to us with a request to remove the source from BART and the modeling approach used by Arkansas in that SIP is consistent with our regional haze regulations and was agreed to by us, representatives of the Federal Land Managers, and CENRAP stakeholders prior to submittal of the 2008 Arkansas RH SIP. Therefore, our proposed FIP is not reopening the issue of whether the source is subject to BART, and our final approval of Arkansas' determination that the source is subject to BART remains in place and in the subsection that follows we evaluate AECC Bailey Unit 1 under BART.

**B. BART Requirements:** 40 CFR 51.308(e)

In determining BART, the state, or EPA if implementing a FIP, must consider the five statutory factors in section 169A of the CAA: (1) the costs of compliance; (2) the energy and non-air quality environmental impacts of compliance; (3) any existing pollution control technology in use at the source; (4) the remaining useful life of the source; and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. *See also* 40 CFR 51.308(e)(1)(ii)(A).

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[11] See the following BART analyses: "BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations," dated March 2014, Version 4, prepared by Trinity Consultants Inc. in conjunction with Arkansas Electric Cooperative Corporation; and "BART Five Factor Analysis- $NO_X$ Analysis, Addendum to the July 24, 2012 BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations," dated December 2013, Version 3. A copy of these two BART analyses can be found in the docket for our proposed rulemaking.

[12] 77 FR 14604, March 12, 2012.

The BART Guidelines (70 FR 39164, July 6, 2005) describe the BART analysis as consisting of the following five steps:

- Step 1: Identify All Available Retrofit Control Technologies;
- Step 2: Eliminate Technically Infeasible Options;
- Step 3: Evaluate Control Effectiveness of Remaining Control Technologies;
- Step 4: Evaluate Impacts and Document the Results; and
- Step 5: Evaluate Visibility Impacts.

As mentioned previously, Arkansas submitted the 2008 RH SIP to address the first regional haze implementation period on September 23, 2008, and August 3, 2010, and submitted supplemental information on September 27, 2011. On March 12, 2012, the EPA partially approved and partially disapproved the 2008 Arkansas RH SIP (77 FR 14604). This included a disapproval of some of the BART determinations made by Arkansas. Following EPA's partial disapproval action, the Arkansas Department of Environmental Quality (ADEQ) worked closely with the BART facilities and with EPA Region 6 to revise the Regional Haze SIP. Each subject to BART source, through a consultant, performed a BART five-factor analyses to correct the State's BART decisions that were disapproved by us. As part of our proposed FIP, we have reviewed the final version of each BART analysis provided to us by each BART facility and other relevant information provided to us by ADEQ and the facilities. Our analysis of the five factors presented below is largely based on the technical work performed by the BART facilities through their consultant.[13] See Appendix B to this TSD for our review of the BART modeling protocol developed by the BART facilities through their consultant.

## C. BART Determinations and Federally Enforceable Limits

This section addresses the BART requirements for Arkansas sources for which we disapproved the State's BART decision in our March 12, 2012 final rulemaking action.[14]

### 1. AECC Carl E. Bailey Generating Station

The AECC Bailey Unit 1 is subject to BART. In our March 12, 2012 final action we disapproved the State's BART determinations for $SO_2$, $NO_X$, and PM for Bailey Unit 1 (77 FR 14604). AECC, through its consultant, performed a BART five factor analysis (AECC BART

[13] A copy of the final version of each BART analysis performed by a consultant on behalf of each BART sources, upon which our analysis is largely based, can be found in the docket for our proposed rulemaking.

[14] Please see our October 17, 2011 proposed rulemaking (76 FR 64186), March 12, 2012 final rulemaking (77 FR 14604), and the associated TSDs for a complete discussion of the legal rationale for EPA's disapproval of the State's BART decisions and for a discussion of the BART determinations that were approved by EPA.

analysis), and our analysis of the five factors presented below is largely based on the technical work performed by AECC.[15]

The AECC Bailey Unit 1 is a wall-fired boiler with a gross output of 122 MW and a maximum heat input rate of 1350 million British thermal units per hour (MMBtu/hr), and is currently permitted to burn natural gas and fuel oil. The fuel oil burned at the plant is subject to an operating air permit sulfur content limit of 2.3% by weight.

### a. Baseline Emission Rates and Existing Visibility Impairment Attributable to Bailey Unit 1

AECC estimated $SO_2$, $NO_X$, and $PM_{10}$ baseline emission rates and then modeled these emission rates to determine the existing visibility impairment attributable to the boiler based on the default natural conditions. As discussed above, the modeled $NO_X$ and $PM_{10}$ baseline emission rates for the fuel oil firing scenario were updated from what was modeled in the 2008 Arkansas RH SIP. The updated baseline emission rates are shown in the table below.

**Table 5. Baseline Emission Rates for AECC Bailey Unit 1**

| Unit/Fuel Scenario | $SO_2$ (lb/hr) | $NO_X$ (lb/hr) | Total $PM_{10}$[16] (lb/hr) | Inorganic Condensable $SO_4$ (lb/hr) | Coarse Soil PMc (lb/hr) | Fine Soil PMf (lb/hr) | Organic Condensable PM SOA (lb/hr) | Elemental Carbon 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 |

The updated baseline emission rates are based on Continuous Emission Monitoring System (CEMS) data, stack testing, and AP-42 emission factors. The $SO_2$ and $NO_X$ baseline emission rates are the highest actual 24-hour emission rates based on 2001-2003 CEMS data. The revised $NO_X$ emission rate for the fuel oil firing scenario is higher than what was modeled in Arkansas's 2008 RH SIP.

[15] See the following BART analyses: "BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations," dated March 2014, Version 4, prepared by Trinity Consultants Inc. in conjunction with Arkansas Electric Cooperative Corporation; and "BART Five Factor Analysis- $NO_X$ Analysis, Addendum to the July 24, 2012 BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations," dated December 2013, Version 3. A copy of these two BART analyses can be found in the docket for our proposed rulemaking.

[16] The National Park Service PM speciation worksheets are typically used to speciate $PM_{10}$ into $SO_4$, PMc, PMf, SOA, and EC.

The $PM_{10}$ emission rate for natural gas combustion is 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 unit's maximum heat input. The emission rate for the $PM_{10}$ species for natural gas combustion reflects 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 and all condensable PM was assumed to be SOA, except for a small fraction of the condensable PM that was estimated to be sulfate ($SO_4$).

The revised $PM_{10}$ emission rate for fuel oil combustion is lower than what was modeled in Arkansas's 2008 RH SIP. The revised $PM_{10}$ emission rate for fuel oil combustion was based on stack testing of filterable and condensable $PM_{10}$ emissions conducted by the facility on AECC McClellan Unit 1. The results of the stack testing showed that the total $PM_{10}$ emission rate for McClellan Unit 1 was 59.4 lb/hr. The total $PM_{10}$ emission rate for Bailey Unit 1 was determined by scaling the heat input ratio for Bailey vs. McClellan (1350 lb/MMBtu / 1436 lb/MMBtu) to get a total $PM_{10}$ emission rate of 55.8 lb/hr. The emission rate for the $PM_{10}$ species shown in the table above reflects the breakdown of the $PM_{10}$ emissions as determined using the National Park Service (NPS) "speciation spreadsheet" for Uncontrolled Utility Residual Oil Boilers.[17] Our concern with AECC's use of the revised $PM_{10}$ emission rate based on stack testing for the fuel oil firing scenario is that there is no discussion provided on how the stack test results are representative of the maximum 24-hour emissions. However, since the visibility impacts due to $PM_{10}$ emissions from Bailey Unit 1 are so small, we believe a closer inspection of the revised $PM_{10}$ emission rate for fuel oil combustion and any further revision to it would likely not result in significant changes to the modeled visibility impacts and would not affect our proposed BART decision. For Bailey Unit 1, the percentage of the visibility impairment at the four Class I areas attributable to $PM_{10}$ ranges from approximately 3 – 11% for the natural gas firing scenario and 0.5 – 3% for the fuel oil firing scenario. Most of the visibility impairment due to Bailey Unit 1 is attributable to $NO_3$ (approximately 83 – 96%) for the natural gas firing scenario and to $SO_4$ (67 – 99%) for the fuel oil firing scenario (see the table below). Therefore, we did not take further steps to adjust the $PM_{10}$ emission rates or conduct additional modeling.

AECC modeled the baseline emission rates using the CALPUFF dispersion model to determine the baseline visibility impairment attributable to Bailey Unit 1 at the four Class I areas impacted by emissions from BART sources in Arkansas: the Caney Creek Wilderness Area, the Upper Buffalo Wilderness Area, the Hercules-Glades Wilderness Area, and the Mingo National Wildlife Refuge. The baseline (*i.e.*, existing) visibility impairment attributable to Bailey Unit 1 at each Class I area is summarized in the tables below.

**Table 6. Baseline Visibility Impairment Attributable to Bailey Unit 1 (2001-2003)-**

[17] 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: No. 6 fuel oil with a sulfur content of 1.81% and a heat input of 1,350 MMBtu/hr.

## Natural Gas Firing

| Year | Maximum ($\Delta$dv) | 98th Percentile ($\Delta$dv) | No. of Days with $\Delta dv \geq 0.5$ | 98th Percentile $\%SO_4$ | 98th Percentile $\%NO_3$ | 98th Percentile $\%PM_{10}$ | 98th Percentile $\%NO_2$ |
|---|---|---|---|---|---|---|---|
| Caney Creek Wilderness | | | | | | | |
| 2001 | 0.137 | 0.083 | 0 | 0.28 | 93.36 | 3.35 | 0.00 |
| 2002 | 0.219 | 0.075 | 0 | 0.31 | 95.93 | 3.22 | 0.54 |
| 2003 | 0.067 | 0.067 | 0 | 0.4 | 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 National Wildlife Refuge | | | | | | | |
| 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 7. Baseline Visibility Impairment Attributable to Bailey Unit 1 (2001-2003)- Fuel Oil Firing

| Year | Maximum ($\Delta$dv) | 98th Percentile ($\Delta$dv) | No. of Days with $\Delta dv \geq 0.5$ | 98th Percentile $\%SO_4$ | 98th Percentile $\%NO_3$ | 98th Percentile $\%PM_{10}$ | 98th Percentile $\%NO_2$ |
|---|---|---|---|---|---|---|---|
| Caney Creek 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 National Wildlife Refuge | | | | | | | |
|---|---|---|---|---|---|---|---|
| 2001 | 0.52 | 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 |

### b. $SO_2$ BART Evaluation

AECC Bailey Unit 1 currently combusts natural gas and No. 6 fuel oil. Because the $SO_2$ emissions profile and the 98th percentile visibility impact from natural gas combustion attributed to the unit is very small, AECC did not consider additional $SO_2$ controls for combustion of natural gas and instead focused the $SO_2$ evaluation on controlling $SO_2$ emissions from combustion of No. 6 fuel oil. Because of the low $SO_2$ emissions associated with natural gas combustion and the relatively low baseline visibility impacts from AECC Bailey Unit 1 when burning natural gas, we concur with AECC's decision to focus the evaluation on controlling $SO_2$ emissions resulting from the combustion of No. 6 fuel oil. The five factors considered in the analysis are discussed below.

*Step 1- Identify All Available Retrofit Control Technologies*

For $SO_2$ BART, AECC considered flue gas desulfurization (FGD) and fuel switching. The type of FGD technologies considered consisted of Dry Sorbent Injection (DSI), Spray Dryer Absorber (SDA), wet FGD, and dry FGD.

*Step 2- Eliminate Technically Infeasible Options*

AECC found that FGD applications have not been used historically for $SO_2$ control on fuel oil-fired units in the U.S. electric industry and therefore considered it a technically infeasible option for control of Bailey Unit 1. Accordingly, AECC did not further consider FGD for $SO_2$ BART. We concur with AECC's decision to focus the $SO_2$ evaluation on fuel switching.

*Step 3- Evaluate Control Effectiveness of Remaining Control Technologies*:

AECC Bailey Unit 1 currently burns some residual fuel oil. The most recent No. 6 fuel oil shipment for Bailey Unit 1 was in December 2006, and had an average sulfur content of 1.81% by weight. A portion of the fuel oil from this shipment still remains in storage at the facility for future use. The baseline fuel used in the BART analysis is based on the average sulfur content of the fuel oil from this shipment. Switching to a fuel with a lower sulfur content is expected to reduce $SO_2$ emissions in proportion to the reduction in the sulfur content of the fuel, assuming similar heat contents of the fuels. The fuel types with lower sulfur content evaluated by

AECC are lower sulfur No. 6 fuel oil, No. 2 fuel oil (*i.e.*, diesel), and natural gas. These fuel types and the estimated control efficiency of each are shown in the table below.

**Table 8. Control Effectiveness of Technically Feasible $SO_2$ Control Technologies for Bailey Unit 1**

| Fuel Switching to: | Estimated Control Efficiency (%) |
|---|---|
| No. 6 fuel oil (1% sulfur) | 45% |
| No. 6 fuel oil (0.5% sulfur) | 72% |
| Diesel (0.05% sulfur) | 97% |
| Natural gas (0.04% sulfur) | 99.9% |

*Step 4- Evaluate Impacts and Document the Results*

The four factors considered in this step are the costs of compliance, energy and non-air quality environmental impacts of compliance, existing pollution control technology in use at the source, and the remaining useful life of the source.

Bailey Unit 1 currently burns both No. 6 fuel oil and natural gas. AECC estimated the cost of fuel switching by determining the annual cost of the No. 6 fuel oil currently used (*i.e.*, the baseline fuel) and determining the cost of switching to the various lower sulfur content fuels. The supplier of the existing fuels (*i.e.*, No. 6 fuel oil and natural gas) provided AECC with current cost estimates for the existing fuels and for the lower sulfur content No. 6 fuel oil and diesel. As shown in the table below, the supplier's estimate for the cost of No. 6 fuel oil with 0.5% and 1% sulfur content is $17.75/MMBtu and $16.50 /MMBtu (respectively), and for diesel is $20.95/MMBtu. The cost of the base case No. 6 fuel oil with 1.81% sulfur content was estimated to be $16.00/MMBtu.

AECC estimated the $SO_2$ annual emissions reductions as a result of fuel switching by subtracting the estimated controlled annual emission rates from the baseline annual emission rates. AECC estimated the baseline and controlled annual emission rates by conducting a mass balance on the sulfur in the various fuels.[18] The sulfur content of the baseline fuel is 1.81% by weight. The $SO_2$ emissions associated with the base case and the fuel switching scenarios (*i.e.*, 1% sulfur No. 6 fuel oil, 0.5% sulfur No. 6 fuel oil, diesel, and natural gas) were estimated by multiplying the baseline annual fuel usage by the fuel density and by the percent sulfur content of the fuel. This yielded the quantity of sulfur in the fuel. The $SO_2$ emissions were then estimated

[18] See the following BART analyses: "BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations," dated March 2014, Version 4, prepared by Trinity Consultants Inc. in conjunction with Arkansas Electric Cooperative Corporation.

by multiplying the quantity of sulfur available to form $SO_2$ by the ratio of the molecular weight for $SO_2$ vs. sulfur. See the table below for the estimated $SO_2$ emissions associated with the base case and with each fuel switching scenario.

To calculate the average cost-effectiveness of fuel switching, AECC divided the annual cost increase of switching to a lower sulfur fuel by the annual $SO_2$ tons reduced as a result of fuel switching. The table below shows the average cost-effectiveness and incremental cost-effectiveness of fuel switching for Bailey Unit 1.

**Table 9. Summary of Costs Associated with Fuel Switching for Bailey Unit 1**

| Fuel Switching Scenario | Average Sulfur Content (%) | Baseline Emission Rate ($SO_2$ tpy) | Controlled Emission Rate ($SO_2$ tpy) | Annual Emissions Reductions ($SO_2$ tpy) | Annual Heat Input (MMBtu/yr) | Fuel Heating Value (MMBtu/Mgal) or (MMBtu/Mscf) | Annual Fuel Usage (Mgal/yr) | Fuel Cost ($/MMBtu) | Total Annual Differential Cost of Fuel Switching ($/yr) | Average Cost-Effectiveness ($/ton) | Incremental Cost Effectiveness[19] ($/ton) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Base Case** | 1.81 | 37.03 | - | - | 39,193 | 155.00 | 252.86 | 16.00 | - | - | - |
| **No. 6 - 1%** | 1.00 | - | 20.67 | 16.36 | 39,193 | 155.00 | 252.86 | 16.50 | 19,596 | 1,198 | - |
| **No. 6 - 0.5%** | 0.50 | - | 10.23 | 26.80 | 39,193 | 155.00 | 252.86 | 17.75 | 68,587 | 2,559 | 4,693 |
| **Diesel** | 0.05 | - | 0.99 | 36.05 | 39,193 | 136.15 | 287.86 | 20.95 | 194,003 | 5,382 | 13,558 |
| **Natural Gas** | 0.04 | - | 0.01 | 37.02 | 39,193 | 1,011.00 | 38.77 | 6.19 | (384,550) | -10,387 | -596,446 |

AECC's evaluation did not identify any energy or non-air quality impacts associated with switching to 1% sulfur No. 6 fuel oil, 0.5% sulfur No. 6 fuel oil, or diesel. The evaluation indicated that switching to natural gas may have an impact during periods of natural gas curtailment. During periods of natural gas curtailment, natural gas infrastructure maintenance, and other emergencies, the AECC Bailey Generating Station relies on the fuel oil stored at the plant to maintain electrical reliability. AECC's evaluation indicates that because of this, the ability to burn fuel oil at AECC Bailey is important even if fuel oil is currently more expensive than natural gas.

The presence of existing pollution control technology is reflected in the BART analysis in two ways: first, in the consideration of available control technologies, and second, in the

[19] The incremental cost-effectiveness calculation compares the costs and performance level of a control option to those of the next most stringent option, as shown in the following formula (with respect to cost per emissions reduction): Incremental Cost Effectiveness (dollars per incremental ton removed) = (Total annualized costs of control option) – (Total annualized costs of next control option) / (Control option annual emissions) – Next control option annual emissions). See BART Guidelines, 40 CFR Part 51, Appendix Y, section IV.D.4.e.

development of baseline emission rates for use in cost calculations and visibility modeling. Bailey Unit 1 has no existing $SO_2$ pollution control technology.

With regard to consideration of the remaining useful life of the unit, this factor does not impact the $SO_2$ BART analysis in this case since it is assumed that fuel switching will not require any capital cost expenditures.

*Step 5- Evaluate Visibility Impacts*

AECC assessed the visibility improvement associated with fuel switching by comparing the visibility impairment from the baseline scenario to the impairment associated with each control scenario. The $SO_2$ emission rate in lb/MMBtu associated with the combustion of each fuel type was calculated by scaling the existing 30-day rolling average emission rate from 2001-2003 by the ratio of the sulfur content of the new fuel and the current maximum annual average sulfur content from 2009-2011. The controlled 30-day emission rate in lb/MMBtu was converted to units of lb/hr by multiplying by the boiler design heat input. The tables below show the emission rates modeled and a comparison of the baseline (*i.e.*, existing) visibility impacts and the visibility impacts associated with fuel switching, including the maximum modeled visibility impact and the 98$^{th}$ percentile modeled visibility impact. The visibility improvement associated with fuel switching was calculated as the difference between the existing visibility impairment and the visibility impairment for each fuel scenario as measured by the 98$^{th}$ percentile modeled visibility impact.

**Table 10. Summary of Emission Rates Modeled for $SO_2$ Control Scenarios at AECC 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 11. AECC Bailey Unit 1: Summary of 98th Percentile Visibility Impacts and Improvement due to Fuel Switching

| Class I area | Baseline Visibility Impact (Δdv) | No. 6 Fuel Oil- 1% Sulfur | | No. 6 Fuel Oil- 0.5% Sulfur | | | Diesel | | | Natural Gas | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. 1% Sulfur fuel oil | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. 0.5% Sulfur fuel oil | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. Diesel |
| Caney Creek | 0.330 | 0.193 | 0.137 | 0.142 | 0.188 | 0.051 | 0.084 | 0.246 | 0.058 | 0.083 | 0.247 | 0.001 |
| Upper Buffalo | 0.348 | 0.194 | 0.154 | 0.127 | 0.221 | 0.067 | 0.069 | 0.279 | 0.058 | 0.072 | 0.276 | -0.003 |
| Hercules-Glades | 0.368 | 0.206 | 0.162 | 0.135 | 0.233 | 0.071 | 0.069 | 0.299 | 0.066 | 0.073 | 0.295 | -0.004 |
| Mingo | 0.379 | 0.206 | 0.173 | 0.170 | 0.209 | 0.036 | 0.095 | 0.284 | 0.075 | 0.102 | 0.277 | -0.007 |
| Cumulative Visibility Improvement (Δdv) | -- | -- | 0.626 | -- | 0.851 | -- | -- | 1.108 | -- | -- | 1.095 | -- |

The table above shows that switching to No. 6 fuel oil with 1% sulfur content at Bailey Unit 1 is projected to result in 0.173 dv visibility improvement at Mingo (based on the 98th percentile modeled visibility impacts). The visibility improvement at each of the other three affected Class I areas is projected to be slightly less than that amount, while the cumulative visibility improvement at the four Class I areas is projected to be 0.626 dv. Switching to No. 6 fuel oil with 0.5% sulfur content is projected to result in meaningful visibility improvement. It is projected to result in 0.233 dv visibility improvement at Hercules-Glades. The visibility improvement at each of the other three affected Class I areas is projected to be slightly less than that amount, while the cumulative visibility improvement at the four Class I areas is projected to be 0.851 dv. Switching to diesel or natural gas is also projected to result in meaningful visibility improvement. The visibility improvement at Hercules-Glades is projected to be 0.299 dv for switching to diesel and 0.295 dv for switching to natural gas. The cumulative visibility improvement at the four Class I areas is projected to be 1.108 dv for switching to diesel and 1.095 dv for switching to natural gas.

**Our Proposed $SO_2$ BART determination:**

Taking into consideration the five factors, we are proposing to determine that BART for the AECC Bailey Unit 1 is switching to fuels with 0.5% or lower sulfur content by weight. The cost of switching to No. 6 fuel oil with 0.5% sulfur content is within the range of what we consider to be cost-effective for BART and it is projected to result in considerable visibility improvement compared to the baseline at the affected Class I areas. Switching to No. 6 fuel oil with 0.5% sulfur content has an estimated average cost-effectiveness of $2,559/ ton of $SO_2$ removed and is projected to result in visibility improvement ranging from 0.188 to 0.233 dv at each modeled Class I area, and a cumulative visibility improvement of 0.851 dv at the four modeled Class I areas. Switching to natural gas would currently cost less than the baseline fuel oil and is projected to result in even greater visibility improvement than switching to No. 6 fuel oil with 0.5% sulfur content. However, the BART Guidelines provide that it is not our intent to direct subject-to-BART sources to switch fuel forms, such as from coal or fuel oil to gas (40 CFR Part 51, Appendix Y, section IV.D.1). Because natural gas has a sulfur content by weight that is well below 0.5%, the facility may elect to use this type of fuel to comply with BART, but we are not proposing to require a switch to natural gas for Unit 1. Switching to diesel is projected to result in an almost identical level of visibility improvement at each Class I area as switching to natural gas. The incremental visibility improvement of switching to diesel compared to switching to No. 6 fuel oil with a sulfur content of 0.5% is projected to range from 0.058 dv to 0.075 dv at each affected Class I area but the average cost-effectiveness is estimated to be $5,382/ ton of $SO_2$ removed and the incremental cost-effectiveness compared to switching to No. 6 fuel oil with a sulfur content of 0.5% is estimated to be $13,558/ ton of $SO_2$ removed, which we do not consider to be very cost-effective in view of the relatively low incremental visibility improvement. Because diesel also has a sulfur content by weight that is well below 0.5%, the facility may elect to use this type of fuel to comply with BART, but we are not proposing to require a switch to diesel for Unit 1. We are proposing to determine that $SO_2$ BART for Bailey Unit 1 is switching to fuels with 0.5% or lower sulfur content by weight. We propose to require that the facility purchase no fuel after the effective date of the rule that does not meet the sulfur content requirement and that 5 years from the effective date of the rule no fuel be burned that does not meet the requirement. We expect this proposed compliance date would allow the facility sufficient time to burn its existing supply of No. 6 fuel oil (i.e., the baseline fuel), as the normal course of business dictates and in accordance with any operating restrictions enforced by ADEQ. We propose that any higher sulfur fuel oil that remains from the facility's 2006 shipment cannot be burned past this point.

**c. $NO_X$ BART Evaluation**

Nitrogen oxides, or $NO_X$, are produced during fuel combustion when nitrogen contained in both the fuel and the combustion air is exposed to high temperatures. Nitrogen oxide (NO) is typically the predominant form of $NO_X$ from fossil fuel combustion, with nitrogen dioxide ($NO_2$) making up the remainder of the $NO_X$. AECC's evaluation noted that the formation of $NO_X$ compounds in utility boilers is sensitive to the method of firing and combustion flame temperatures. In wall-fired boilers, such as Bailey Unit 1, 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 combustion flame temperatures, among other factors. The baseline $NO_X$ emission rate for Bailey Unit 1 is discussed under section II.C.1.a. of this TSD. The five factors considered in the $NO_X$ BART analysis are discussed below.

*Step 1- Identify All Available Retrofit Control Technologies*

For $NO_X$ BART, AECC evaluated both combustion and post-combustion controls. Combustion controls involve reducing the peak flame temperature and excess air in the furnace to minimize $NO_X$ formation, while post-combustion controls involve converting $NO_X$ in the flue gas to molecular nitrogen and water. The combustion controls evaluated by AECC consisted of flue gas recirculation (FGR), overfire air (OFA), and Low $NO_X$ Burners (LNB). The post-combustion controls evaluated consisted of Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR).

*Step 2- Eliminate Technically Infeasible Options*

AECC found that some boilers may be restricted from installing OFA retrofits due to physical size and space restraints. For purposes of the $NO_X$ BART evaluation, AECC assumed OFA to be a technically feasible option for Bailey Unit 1, but noted that if the five factor BART analysis deemed OFA to be BART, then further analyses would have to be performed to determine if (1) the dimensions of the main boiler has sufficient upper furnace volume for OFA mixing and complete combustion; and (2) if there are physical space requirements for OFA ports and air supply ducts. AECC found the remaining $NO_X$ control options to be technically feasible.

*Step 3- Evaluate Control Effectiveness of Remaining Control Technologies*:

The estimated $NO_X$ controlled emission rate of each control option considered by AECC is shown in the table below. In its evaluation, AECC considered the following control options: a combination of combustion controls (*i.e.*, FGR, OFA, and LNB); a combination of combustion controls and SNCR; and SCR. AECC estimated that when FGR is operated alone, the $NO_X$ control range for oil and gas wall-fired boilers is approximately 0.2 – 0.4 lb/MMBtu, and when OFA is operated alone it results in an estimated $NO_X$ controlled emission rate of 0.2 – 0.3

lb/MMBtu.[20] It also estimated that when LNB is combined with OFA and FGR, a $NO_X$ controlled emission rate of 0.15 – 0.20 lb/MMBtu is achievable.

AECC found that the estimated $NO_X$ control efficiency of SCR is 80-90% on gas fired boilers and 70-80% for oil fired boilers, and estimated that when SCNR is combined with combustion controls, the $NO_X$ level of control is estimated to be 10% greater than with combustion controls alone.[21]

**Table 12. Control Effectiveness of Technically Feasible $NO_X$ Control Technologies for AECC Bailey Unit 1**

| Control Technology | Baseline $NO_X$ Emission Rate (lb/MMBtu) | | Estimated $NO_X$ Controlled Emission Rate (lb/MMBtu) | |
|---|---|---|---|---|
| | Natural Gas | Fuel Oil | Natural Gas | Fuel Oil |
| SCR | 0.29 | 0.30 | 0.04 | 0.08 |
| Combustion Controls + SNCR | | | 0.12 | 0.12 |
| Combustion Controls | | | 0.15 | 0.15 |

*Step 4- Evaluate Impacts and Document the Results*

The four factors considered in this step are the costs of compliance, energy and non-air quality environmental impacts of compliance, the existing pollution control technology in use at the source, and the remaining useful life of the source.

AECC's cost analysis for $NO_X$ controls[22] was based on "budgetary" cost estimates it obtained from the pollution control equipment vendor, Babcock Power Systems. AECC estimated the capital and operating costs of controls based on the vendor's estimates, engineering estimates, and published calculation methods using EPA's Air Pollution Control Cost Manual

[20] "Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options," section II, dated July 1994, State and Territorial Air Pollution Program Administrators (STAPPA) and Association of Local Air Pollution Control Officials (ALAPCO).

[21] "Preferred and Alternative Methods for Estimating Air Emissions from Boilers" Table 2.2-2. January 2001. See http://www.epa.gov/ttn/chief/eiip/techreport/volume02/ii02.pdf.

[22] See "BART Five Factor Analysis- $NO_X$ Analysis, Addendum to the July 24, 2012 BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations," dated December 2013, Version 3.

(EPA Control Cost Manual).[23] We are not aware of any enforceable shutdown date for the AECC Bailey Generating Station, nor did AECC's evaluation indicate any future planned shutdown. This means that the anticipated useful life of the boiler is expected to be at least as long as the capital cost recovery period of controls. Therefore, a 30-year amortization period was assumed in the $NO_X$ BART analysis as the remaining useful life of the unit. The table below summarizes the estimated cost for installation and operation of $NO_X$ controls for Bailey Unit 1.

AECC determined the annual emissions reductions associated with each $NO_X$ control option by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. The baseline annual emission rates are the average rates from 2009-2011, while the controlled annual emission rates are based on the lb/MMBtu levels believed to be achievable from the control technology multiplied by the baseline heat inputs to the boilers in MMBtu/yr. The baseline heat inputs for each unit are the sum of the baseline heat inputs for natural gas and fuel oil. The baseline heat inputs for natural gas are based on the average natural gas usage for each unit from 2007-2011 multiplied by the average heat content of natural gas for the same time period. Similarly, the baseline heat inputs for fuel oil are based on the average fuel oil usage for each unit from 2007-2011 multiplied by the average heat content of fuel oil for the same time period.

To calculate the average cost-effectiveness of $NO_X$ controls, AECC divided the total annual cost of each control option by the estimated annual $NO_X$ tons reduced. The table below shows the average cost effectiveness of $NO_X$ controls for Bailey Unit 1.

**Table 13. Summary of Costs of $NO_X$ Controls for AECC Bailey Unit 1**

| Control Scenario | Baseline Emission Rate ($NO_X$ tpy) | Natural Gas Controlled Emission Level (lb/MMBtu) | Fuel Oil Controlled Emission Level (lb/MMBtu) | Natural Gas Annual Heat Input (MMBtu/yr) | Fuel Oil Annual Heat Input (MMBtu/yr) | Controlled Emission Rate ($NO_X$ tpy) | Annual Emissions Reductions ($NO_X$ tpy) | Capital Cost ($) | Total Annual Cost ($/yr) | Average Cost-Effectiveness ($/ton) | Incremental Cost-Effectiveness ($/ton) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Combustion Controls** | 49.81 | 0.15 | 0.15 | 371,866 | 39,193 | 30.83 | 18.98 | 7,700,000 | 700,477 | 36,905 | -- |
| **Combustion Controls + SNCR** | 49.81 | 0.12 | 0.12 | 371,866 | 39,193 | 24.79 | 25.02 | 11,903,724 | 1,223,157 | 48,884 | 86,536 |
| **SCR** | 49.81 | 0.04 | 0.08 | 371,866 | 39,193 | 9.65 | 40.16 | 11,708,183 | 1,555,718 | 38,738 | 21,996 |

AECC estimated the average cost-effectiveness of installing and operating combustion controls to be $36,905/ton of $NO_X$ removed for Bailey Unit 1. The combination of combustion controls and SNCR was estimated to cost $48,884/ton of $NO_X$ removed, while SCR was

[23] EPA's "Air Pollution Control Cost Manual," Sixth edition, January 2002, is located at www.epa.gov/ttncatc1/products.html#cccinfo.

estimated to cost $38,738/ton of $NO_X$ removed. In its evaluation, AECC also explained that it expects $NO_X$ controls to be less cost-effective (*i.e.*, greater dollars per ton removed) in future years due to projected reduced operation of the unit. Less projected operating time is expected to result in lower annual emissions, which would result in lower cost-effectiveness.

AECC did not identify any energy or non-air quality environmental impacts associated with the use of LNB, OFA, or FGR. As for SCR and SNCR, we are not aware of any unusual circumstances at the facility that could create energy or non-air quality environmental impacts associated with the operation of these controls greater than experienced elsewhere and that may therefore provide a basis for their elimination as BART (40 CFR Part 51, Appendix Y, section IV.D.4.i.2.). Therefore, we do not believe there are any energy or non-air quality environmental impacts associated with $NO_X$ controls at AECC Bailey Unit 1 that would affect our proposed BART determination.

With regard to consideration of any existing pollution control technology in use at the source, Bailey Unit 1 has no existing $NO_X$ pollution control technology. The presence of existing pollution control technology at the source is reflected in the BART analysis in two ways: first, in the consideration of available control technologies, and second, in the development of baseline emission rates for use in cost calculations and visibility modeling.

With regard to consideration of the remaining useful life of the unit, we are not aware of any enforceable shutdown date for the AECC Bailey Generating Station, nor did AECC's evaluation indicate any future planned shutdown. This means that the anticipated useful life of the boiler is expected to be at least as long as the capital cost recovery period of controls. Therefore, a 30-year amortization period was assumed in the $NO_X$ BART analysis as the remaining useful life of the unit.

*Step 5- Evaluate Visibility Impacts*

AECC assessed the visibility improvement associated with $NO_X$ controls by modeling the $NO_X$ emission rates associated with each control option using CALPUFF, and then comparing the visibility impairment associated with the baseline emission rates to the visibility impairment associated with the controlled emission rates. The controlled emission levels associated with combustion controls, combustion controls + SNCR, and SCR systems are shown in the table above. These levels were multiplied by the unit's maximum heat input to derive the hourly emission rates used in the modeling. The tables below show the emission rates modeled and a comparison of the existing (*i.e.*, baseline) visibility impacts and the visibility impacts based on $NO_X$ controls, including the maximum modeled visibility impact and the 98$^{th}$ percentile modeled visibility impact for each Class I area. The visibility improvement associated with $NO_X$ controls was calculated as the difference between the baseline visibility impairment and the visibility impairment for each control scenario as measured by the 98$^{th}$ percentile modeled visibility impact.

**Table 14. Summary of Emission Rates Modeled for $NO_X$ Control Scenarios at AECC Bailey Unit 1**

| Control Scenario | Fuel Scenario | $SO_2$ (lb/hr) | $NO_X$ (lb/hr) | Total $PM_{10}$ (lb/hr) | $SO_4$ (lb/hr) | PMc (lb/hr) | PMf (lb/hr) | SOA (lb/hr) | EC (lb/hr) |
|---|---|---|---|---|---|---|---|---|---|
| Combustion Controls | Natural Gas | 0.5 | 202.5 | 10.2 | 0.3 | 0.0 | 0.0 | 7.4 | 2.5 |
| | Fuel Oil | 2,375.8 | 202.5 | 49.4 | 4.0 | 12.1 | 30.2 | 0.7 | 2.4 |
| SCR | Natural Gas | 0.5 | 59.4 | 10.2 | 0.3 | 0.0 | 0.0 | 7.4 | 2.5 |
| | Fuel Oil | 2,375.8 | 101.5 | 49.4 | 4.0 | 12.1 | 30.2 | 0.7 | 2.4 |
| Combustion Controls + SNCR | Natural Gas | 0.5 | 162.9 | 10.2 | 0.3 | 0.0 | 0.0 | 7.4 | 2.5 |
| | Fuel Oil | 2,375.8 | 161.9 | 49.4 | 4.0 | 12.1 | 30.2 | 0.7 | 2.4 |

**Table 15. AECC Bailey Unit 1: Summary of the 98th Percentile Visibility Impacts and Improvement due to $NO_X$ Controls- Natural Gas Firing**

| Class I area | Baseline Visibility Impact (Δdv) | Combustion Controls | | Combustion Controls + SNCR | | | SCR | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. Combustion Controls (Δdv) | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. Combustion Controls + SNCR (Δdv) |
| Caney Creek | 0.083 | 0.039 | 0.044 | 0.032 | 0.051 | 0.007 | 0.014 | 0.069 | 0.018 |
| Upper Buffalo | 0.072 | 0.034 | 0.038 | 0.028 | 0.044 | 0.006 | 0.013 | 0.059 | 0.015 |
| Hercules-Glades | 0.073 | 0.035 | 0.038 | 0.029 | 0.044 | 0.006 | 0.013 | 0.06 | 0.016 |
| Mingo | 0.102 | 0.051 | 0.051 | 0.043 | 0.059 | 0.008 | 0.021 | 0.081 | 0.022 |
| Cumulative Visibility Improvement (Δdv) | -- | -- | 0.171 | -- | 0.198 | -- | -- | 0.269 | -- |

**Table 16. AECC Bailey Unit 1: Summary of the 98th Percentile Visibility Impacts and Improvement due to $NO_X$ Controls- Fuel Oil Firing**

| Class I area | Baseline Visibility Impact (Δdv) | Combustion Controls | | Combustion Controls + SNCR | | | SCR | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. Combustion Controls (Δdv) | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. Combustion Controls + SNCR (Δdv) |
| Caney Creek | 0.330 | 0.325 | 0.005 | 0.325 | 0.005 | 0.000 | 0.323 | 0.007 | 0.002 |
| Upper Buffalo | 0.347 | 0.332 | 0.015 | 0.329 | 0.018 | 0.003 | 0.325 | 0.022 | 0.004 |
| Hercules-Glades | 0.367 | 0.339 | 0.028 | 0.333 | 0.034 | 0.006 | 0.325 | 0.042 | 0.008 |
| Mingo | 0.378 | 0.369 | 0.009 | 0.367 | 0.011 | 0.002 | 0.364 | 0.014 | 0.003 |
| Cumulative Visibility Improvement (Δdv) | -- | -- | 0.057 | -- | 0.068 | -- | -- | 0.085 | -- |

The table above shows that the installation and operation of $NO_X$ controls is projected to result in very modest visibility improvement from the baseline. Combustion controls at Bailey Unit 1 are projected to result in visibility improvement ranging from 0.038 – 0.051 dv at each Class I area for natural gas firing and 0.005 – 0.028 dv for fuel oil firing (based on the 98th percentile modeled visibility impacts). A combination of combustion controls and SNCR is projected to result in negligible incremental visibility improvement compared to combustion controls alone for both the natural gas and fuel oil firing scenarios. The installation and operation of SCR at Bailey Unit 1 is projected to result in visibility improvement ranging from 0.059 – 0.081 dv at each Class I area for natural gas firing and 0.007 – 0.042 dv for fuel oil firing. SCR is projected to result in negligible incremental visibility improvement compared to a combination of combustion controls and SNCR.

**Our Proposed $NO_X$ BART determination:**

Taking into consideration the five factors, we are proposing to determine that $NO_X$ BART for the AECC Bailey Unit 1 is no additional controls, and are proposing that the existing $NO_X$ emission limit satisfies BART for $NO_X$. We are proposing the existing emission limit of

887 lb/hr for $NO_X$ BART for Bailey Unit 1.[24] As discussed above, the operation of combustion controls at Bailey Unit 1 is projected to result in a maximum visibility improvement of 0.051 Δdv (Mingo), and a smaller amount of visibility improvement at each of the other affected Class I areas. The installation and operation of combustion controls at Bailey Unit 1 has an average cost-effectiveness of $36,905/ton of $NO_X$ removed, which is not cost-effective. We believe the relatively small visibility benefit projected from the operation of combustion controls both when combusting fuel oil and natural gas does not justify the high estimated cost of those controls. The operation of a combination of combustion controls + SNCR is estimated to cost $48,884/ton of $NO_X$ removed, which is also not cost-effective. A combination of combustion controls + SNCR is projected to result in negligible incremental visibility benefit compared to combustion controls alone. The operation of SCR is estimated to cost $38,738/ton of $NO_X$ removed, which is not cost-effective, and is projected to result in negligible incremental visibility benefit compared to a combination of combustion controls + SNCR. We are proposing to find that $NO_X$ BART for Bailey Unit 1 is no additional controls and are proposing the aforementioned existing $NO_X$ emission limit for $NO_X$ BART. We are proposing that this already-existing emission limitation be complied with for BART purposes as of the effective date of the final action.

### d. PM BART Evaluation

The five factors considered in the PM BART analysis for Bailey Unit 1 are discussed below.

*Step 1- Identify All Available Retrofit Control Technologies*

For PM BART, AECC considered the following technologies: dry electrostatic precipitator (ESP), wet ESP, fabric filter, wet scrubber, cyclone (*i.e.*, mechanical collector), and fuel switching.

Residual fuel, such as the No. 6 fuel oil burned at Bailey Unit 1, has inherent ash that contributes to emissions of filterable PM. Filterable PM emissions could be reduced by switching to a lower grade fuel oil or natural gas. For combustion of No. 6 fuel oil, reductions in filterable PM are directly related to the sulfur content of the fuel.[25] Therefore, switching to No. 6 fuel oil with a lower sulfur content is expected to result in lower filterable PM emissions. AECC's evaluation considered switching to No. 6 fuel oil with 1% sulfur content by weight, No. 6 fuel oil with 0.5% sulfur content by weight, diesel, and natural gas. These are the same lower sulfur fuel types evaluated in the $SO_2$ BART analysis for the unit.

*Step 2- Eliminate Technically Infeasible Options*

[24] See ADEQ Operating Air Permit No. 0154-AOP-R4, Section IV, Specific Conditions No. 1 and 7.

[25] See AP-42, section 1.3-1.

AECC's evaluation noted that the particulate matter from oil-fired boilers tends to be sticky and small, affecting the collection efficiency of dry ESPs and fabric filters. Dry ESPs operate by placing a charge on the particles through a series of electrodes, and then capturing the charged particles on collection plates, while fabric filters work by filtering the PM in the flue gas through filter bags. The collected particles are periodically removed from the filter bag through a pulse jet or reverse flow mechanism. Because of the sticky nature of particles from oil-fired boilers, dry ESPs and fabric filters are deemed technically infeasible for use at Bailey Unit 1.

Wet ESPs, cyclones, wet scrubbers, and fuel switching were identified as technically feasible options for Bailey Unit 1. AECC noted that although cyclones and wet scrubbers are considered technically feasible for use at these boiler types, they are not very efficient at controlling particles in the smaller size fraction, particularly particles smaller than a few microns. However, we do not expect this to be an issue for Bailey Unit 1, since the majority of the PM emissions from the unit are greater than a few microns in size.

*Step 3- Evaluate Control Effectiveness of Remaining Control Technologies*:

AECC estimated that switching to a lower sulfur fuel has a PM control efficiency ranging from approximately 44% - 99%, depending on the fuel type. The other technically feasible control technologies are estimated to have the following PM control efficiency: wet ESP- up to 90%, cyclone- 85%, and wet scrubber- 55%.

*Step 4- Evaluate Impacts and Document the Results*

The four factors considered in this step are the costs of compliance, energy and non-air quality environmental impacts of compliance, existing pollution control technology in use at the source, and the remaining useful life of the source.

AECC evaluated the capital costs, operating costs, and average cost-effectiveness of wet ESPs, cyclones, and wet scrubbers.[26] AECC also evaluated the average cost-effectiveness of switching to No. 6 fuel oil with 1% sulfur content, No. 6 fuel oil with 0.5% sulfur content, diesel, and natural gas. AECC developed the capital and operating costs of a wet ESP and wet scrubber using the Electric Power Research Institute's (EPRI) Integrated Emissions Control Cost Estimating Workbook (IECCOST) Software. The capital costs of controls (except for fuel switching) were annualized over a 15-year period and then added to the annual operating costs to obtain the total annualized costs. The table below summarizes the average cost-effectiveness of PM controls. The average cost-effectiveness was determined by dividing the annualized cost of controls by the annual PM emissions reductions. The annual emissions reductions were

[26] See "BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations," dated March 2014, Version 4, prepared by Trinity Consultants Inc. in conjunction with Arkansas Electric Cooperative Corporation.

determined by subtracting the estimated controlled annual emission rates from the baseline annual emission rates, which were derived using emission factors from AP-42, section 1.3-1.

We disagree with two aspects of AECC's cost evaluation for PM controls. First, the total annual cost numbers associated with fuel switching should be the same as the cost numbers used in the $SO_2$ BART cost analysis for Bailey Unit 1 (see Table 9). In earlier draft versions of AECC's analysis, which were provided to us for review, the cost numbers for fuel switching used in the PM and $SO_2$ BART analyses were identical. In response to comments provided by us, the total annual cost and average cost-effectiveness numbers for fuel switching were revised in the final version of AECC's $SO_2$ BART analysis. However, it appears that AECC overlooked updating these cost numbers in the final PM BART analysis.[27] In the table below, we have revised the total annual cost of fuel switching for the PM BART analysis to be consistent with the cost estimates from AECC's $SO_2$ BART analysis, and we have also updated the PM average cost-effectiveness values. The second aspect of AECC's cost evaluation for PM controls that we disagree with is the use of a 15-year capital cost recovery period for calculating the average cost-effectiveness of a wet ESP, wet scrubber, and cyclone. As previously discussed, we are not aware of any enforceable shutdown date for the AECC Bailey Generating Station, nor AECC's evaluation indicate any future planned shutdown. Therefore, we believe that assuming a 30-year equipment life rather than a 15-year equipment life would be more appropriate for these control technologies. Extending the amortization period from 15 to 30 years has the effect of decreasing the total annual cost of each control option, thereby improving the cost-effectiveness of controls (*i.e.*, less dollars per ton removed). However, after considering all five BART factors, we do not believe AECC's assumption of a 15-year amortization period has an impact on our proposed BART decision and therefore we did not revise the amortization period or the average cost-effectiveness calculations for the PM control equipment options. This is discussed in more detail below. The table below summarizes the estimated cost for fuel switching and the installation and operation of PM control equipment for Bailey Unit 1.

**Table 17. Summary of Cost of PM Controls for AECC Bailey Unit 1- Baseline is No. 6 Fuel Oil with 1.81% Sulfur Content by Weight**

| Control Scenario | Baseline Emission Rate (PM tpy) | Control Efficiency (%) | Annual Heat Input (MMBtu/yr) | Controlled Emission Rate (PM tpy) | Annual Emissions Reductions (PM tpy) | Capital Cost ($) | Total Annual Cost ($/yr) | Average Cost-Effectiveness ($/ton) | Incremental Cost-Effectiveness ($/ton) |
|---|---|---|---|---|---|---|---|---|---|
| **Wet Scrubber** | 25.63 | 55.0 | 39,193 | 11.53 | 14.09 | 140,957,713 | 50,150,862 | 3,558,286 | - |

[27] The final version of AECC's BART analysis for $SO_2$ and PM, upon which our analysis is largely based, is titled "BART Five Factor Analysis Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations, March 2014, Version 4." A copy of AECC's analysis can be found in the docket for our proposed rulemaking.

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **No. 6 Fuel oil- 1% S** | 25.63 | 65.7 | 39,193 | 8.80 | 16.83 | -- | 19,596 | 1,164 | -18,296,082 |
| **Cyclone** | 25.63 | 85.0 | 39,193 | 3.84 | 21.78 | 989,479 | 1,188,630 | 54,570 | 236,168 |
| **No. 6 Fuel oil- 0.5% S** | 25.63 | 89.3 | 39,193 | 2.75 | 22.88 | -- | 68,587 | 2,997 | -1,020,948 |
| **Wet ESP** | 25.63 | 90.0 | 39,193 | 2.56 | 23.06 | 105,141,431 | 22,638,340 | 981,583 | 125,387,517 |
| **Natural Gas** | 25.63 | 99.0 | 39,193 | 0.26 | 25.37 | -- | -384,550 | -15,157 | -9,966,619 |
| **Diesel** | 25.63 | 99.5 | 39,193 | 0.13 | 25.50 | -- | 194,003 | 7,608 | 4,450,408 |

The table above shows that the average cost-effectiveness of all add-on PM control technology options evaluated for AECC Bailey Unit 1 ranged from approximately $55,000/ton of PM removed to more than $3.5 million/ton of PM removed. Switching to No. 6 fuel oil with either a 1% or 0.5% sulfur content was found to be within the range of what we generally consider cost-effective for BART. Switching to No. 6 fuel oil with 1% sulfur content is estimated to cost $1,164/ton of PM removed, while switching to No. 6 fuel oil with 0.5% sulfur content is estimated to cost $2,997/ton of PM removed. As discussed in the $SO_2$ BART analysis, the current cost of natural gas is actually lower than the cost of the baseline fuel. Therefore, the average cost-effectiveness of switching from the baseline fuel to natural gas is denoted as a negative value in the table above. As discussed above, AECC also explained that it expects controls to be less cost-effective (*i.e.*, greater dollars per ton removed) in future years due to projected reduced operation of the unit. Less projected operating time is expected to result in lower annual emissions, which in turn would result in lower cost-effectiveness of controls.

AECC did not identify any energy or non-air quality environmental impacts associated with fuel switching, but did identify impacts associated with the use of wet ESPs and wet scrubbers due to their electricity usage. Energy use in and of itself does not disqualify a technology (40 CFR Part 51, Appendix Y, section IV.D.4.h.1.). In addition, the cost of the electricity needed to operate this equipment has already been factored into the cost of controls. AECC also noted that both wet ESPs and wet scrubbers generate wastewater streams that must either be treated on-site or sent to a waste water treatment plant, and the wastewater treatment process will generate a filter cake that would likely require landfilling. The BART Guidelines provide that the fact that a control device creates liquid and solid waste that must be disposed of does not necessarily argue against selection of that technology as BART, particularly if the control device has been applied to similar facilities elsewhere and the solid or liquid waste is similar to those other applications. (40 CFR Part 51, Appendix Y, section IV.D.4.i.2.). We are not aware of any unusual circumstances at the AECC Bailey Generating Station that could potentially create greater problems than experienced elsewhere related to the treatment of wastewater and any necessary landfilling, nor did AECC's evaluation discuss or mention any such unusual circumstances. Therefore, the need to treat wastewater or landfill any filter cake or other waste in and of itself does not provide a basis for disqualification or elimination of a wet ESP or wet scrubber.

With regard to consideration of any existing pollution control technology in use at the source, Bailey Unit 1 has no existing PM pollution control technology. The presence of existing pollution control technology at the source is reflected in the BART analysis in two ways: first, in the consideration of available control technologies, and second, in the development of baseline emission rates for use in cost calculations and visibility modeling.

With regard to consideration of the remaining useful life of the unit, we are not aware of any enforceable shutdown date for the AECC Bailey Generating Station, nor did AECC's evaluation indicate any future planned shutdown. This means that the anticipated useful life of the boiler is expected to be at least as long as the capital cost recovery period of controls. Therefore, we believe it is appropriate to assume a 30-year amortization period in the PM BART analysis as the remaining useful life of the unit. As discussed in more detail below, AECC assumed a 15-year amortization period for control equipment in the BART analysis, but we do not believe this has an impact on our proposed BART decision and therefore we did not revise the amortization period and the average cost-effectiveness calculations for the PM control equipment options. This is discussed in more detail below in the subsection titled "Our Proposed PM BART Determination."

*Step 5- Evaluate Visibility Impacts*

As switching to lower sulfur fuels has impacts on both $SO_2$ and PM emissions, AECC's assessment of the visibility improvement associated with fuel switching is addressed in the $SO_2$ BART analysis for Bailey Unit 1, which is discussed under section II.C.1.b. of this TSD. Table 11 summarizes the visibility improvement associated with controlled emission rates for $SO_2$ and PM as a result of fuel switching.

AECC assessed the visibility improvement associated with wet ESPs, wet scrubbers, and cyclones by modeling the PM emission rates associated with each control option using CALPUFF, and then comparing the visibility impairment associated with the baseline emission rates to the visibility impairment associated with the controlled emission rates as measured by the 98$^{th}$ percentile modeled visibility impact. The controlled $PM_{10}$ emission rates associated with wet ESPs, wet scrubbers, and cyclones were calculated by reducing the uncontrolled annual $PM_{10}$ emission rates by the pollutant removal efficiency of each control technology. The $SO_2$ and $NO_X$ emission rates modeled in the controlled scenarios are the same as those from the baseline scenario, as it is assumed that $SO_2$ and $NO_X$ emissions would remain unchanged. The tables below show a comparison of the emission rates modeled and the existing (*i.e.*, baseline) visibility impacts and the visibility impacts of wet ESPs, wet scrubbers, and cyclones, including the maximum modeled visibility impact and the 98$^{th}$ percentile modeled visibility impact. The visibility improvement associated with each control scenario was calculated as the difference between the existing visibility impairment and the visibility impairment for each control scenario, as measured by the 98th percentile modeled visibility impact.

**Table 18. Summary of Emission Rates Modeled for PM Control Scenarios at AECC Bailey Unit 1**

| 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) |
|---|---|---|---|---|---|---|---|---|
| **Wet ESP** | 2,375.8 | 0.4 | 408.8 | 1.2 | 3.0 | 0.1 | 0.2 | 4.9 |
| **Wet Scrubber** | 2,375.8 | 1.8 | 408.8 | 5.5 | 13.6 | 0.3 | 1.1 | 22.2 |
| **Cyclone** | 2,375.8 | 4.0 | 408.8 | 1.8 | 4.5 | 0.7 | 0.4 | 7.4 |

**Table 19. AECC Bailey Unit 1: Summary of the 98th Percentile Visibility Impacts and Improvement from PM Controls**

| Class I area | Baseline Visibility Impact (Δdv) | Wet Scrubber | | Cyclone | | | Wet ESP | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. Wet Scrubber (Δdv) | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. Cyclone (Δdv) |
| Caney Creek | 0.330 | 0.328 | 0.002 | 0.328 | 0.002 | 0.000 | 0.327 | 0.003 | 0.001 |
| Upper Buffalo | 0.347 | 0.345 | 0.002 | 0.345 | 0.002 | 0.000 | 0.343 | 0.004 | 0.002 |
| Hercules-Glades | 0.367 | 0.360 | 0.007 | 0.361 | 0.006 | -0.001 | 0.356 | 0.011 | 0.005 |
| Mingo | 0.378 | 0.374 | 0.004 | 0.374 | 0.004 | 0.001 | 0.371 | 0.007 | 0.003 |
| Cumulative Visibility Improvement (Δdv) | -- | -- | 0.015 | -- | 0.014 | -- | -- | 0.025 | -- |

The table above shows that the operation of a wet ESP, wet scrubber, and cyclone at Bailey Unit 1 is projected to result in minimal visibility improvement at the four affected Class I areas. The modeled visibility improvement from switching to No. 6 fuel oil with 1% sulfur content, No. 6 fuel oil with 0.5% sulfur content, diesel, and natural gas is summarized in Table 11. These visibility improvement estimates reflect both $SO_2$ and PM emissions reductions as a result of switching to fuels with lower sulfur content. However, the majority of the baseline visibility impact at each Class I area when burning the baseline fuel oil at Bailey Unit 1 is due to $SO_2$ emissions, while $PM_{10}$ emissions contribute only a small portion of the baseline visibility impacts at each Class I area. Table 7 shows that the percentage of the visibility impairment at the four modeled Class I areas attributable to $PM_{10}$ ranges from approximately 0.5 – 3% for the fuel oil firing scenario. Most of the visibility impairment is attributable to $SO_4$ (67 – 99%) for the fuel oil firing scenario. Accordingly, the majority of the visibility improvement associated with switching to lower sulfur fuels can reasonably be expected to be the result of reduced $SO_2$ emissions.

**Our Proposed PM BART determination:**

Taking into consideration the five factors, we propose to determine that PM BART for the AECC Bailey Unit 1 does not require add-on controls. Consistent with our proposed determination for $SO_2$ BART, we are proposing that PM BART is satisfied by Unit 1 switching to fuels with 0.5% or lower sulfur content by weight. As discussed above, we disagree with AECC's use of a 15-year amortization period in the cost analysis for a wet ESP, wet scrubber, and cyclone. We are not aware of any enforceable shutdown date for the AECC Bailey Generating Station, and we believe the expected equipment life of these control technologies, which is at least 30 years, should be assumed to be the amortization period. Assuming a 30-year amortization period, these controls would have lower estimated total annual costs and would therefore have an improved cost-effectiveness (*i.e.*, less dollars per ton removed) than estimated in AECC's evaluation. However, after considering all five BART factors, AECC's assumption of a 15-year amortization period does not have an impact on our proposed BART decision. Even if we revised AECC's cost estimates to reflect a 30-year amortization period, resulting in a lower total annual cost and improved cost-effectiveness, we would still not be able to justify the costs of add-on controls in light of the minimal visibility benefit of these controls (see the table above).

We are proposing to determine that PM BART for Bailey Unit 1 is switching to fuels with 0.5% or lower sulfur content by weight. We propose to require that the facility purchase no fuel after the effective date of the rule that does not meet the sulfur content requirement and that 5 years from the effective date of the rule no fuel be burned that does not meet the requirement. We expect this proposed compliance date would allow the facility sufficient time to burn its existing supply of No. 6 fuel oil (i.e., the baseline fuel), as the normal course of business dictates and in accordance with any operating restrictions enforced by ADEQ. We propose that any higher sulfur fuel oil that remains from the facility's 2006 shipment cannot be burned past this point.

### 2. AECC John L. McClellan Generating Station

The AECC McClellan Unit 1 is subject to BART. In our March 12, 2012 final action we disapproved the State's BART determinations for $SO_2$, $NO_X$, and PM for McClellan Unit 1 (77 FR 14604). AECC, through its consultant, performed a BART five factor analysis (AECC BART analysis), and our analysis of the five factors presented below is largely based on the technical work performed by AECC.[28]

The AECC McClellan Unit 1 is a wall-fired boiler with a gross output of 134 MW and a maximum heat input rate of 1436 MMBtu/hr, and is currently permitted to burn natural gas and fuel oil. The fuel oil burned at the plant is subject to an operating air permit sulfur content limit of 2.8% by weight.

#### a. Baseline Emission Rates and Existing Visibility Impairment Attributable to McClellan Unit 1

AECC estimated $SO_2$, $NO_X$, and $PM_{10}$ baseline emission rates and then modeled these emission rates to determine the existing visibility impairment attributable to the boiler based on the default natural conditions. The modeled $NO_X$ and $PM_{10}$ baseline emission rates for the fuel oil firing scenario were updated from what was modeled in the 2008 Arkansas RH SIP. The updated baseline emission rates are shown in the table below.

**Table 20. Baseline Emission Rates for AECC McClellan Unit 1**

| Unit/Fuel Scenario | $SO_2$ (lb/hr) | $NO_X$ (lb/hr) | Total $PM_{10}$ (lb/hr) | $SO_4$ (lb/hr) | PMc (lb/hr) | PMf (lb/hr) | SOA (lb/hr) | EC (lb/hr) |
|---|---|---|---|---|---|---|---|---|
| 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 | 1.00 | 2.8 |

The updated baseline emission rates are based on CEMS data, stack testing, and AP-42 emission factors. The $SO_2$ and $NO_X$ baseline emission rates are the highest actual 24-hour emission rates based on 2001-2003 CEMS data. The revised $NO_X$ emission rate for the fuel oil

[28] See the following BART analyses: "BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations," dated March 2014, Version 4, prepared by Trinity Consultants Inc. in conjunction with Arkansas Electric Cooperative Corporation; and "BART Five Factor Analysis- $NO_X$ Analysis, Addendum to the July 24, 2012 BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations," dated December 2013, Version 3. A copy of these two BART analyses can be found in the docket for our proposed rulemaking.

firing scenario is higher than what was modeled in Arkansas's 2008 RH SIP, thereby resulting in higher modeled visibility impacts due to $NO_X$.

The $PM_{10}$ emission rate for natural gas combustion is 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 unit's maximum heat input. The emission rate for the $PM_{10}$ species for natural gas combustion reflects 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 and all condensable PM was assumed to be secondary organic aerosol (SOA), except for a small fraction of the condensable PM that was estimated to be sulfate ($SO_4$).

The revised $PM_{10}$ emission rate for fuel oil combustion is lower than what was modeled in Arkansas's 2008 RH SIP. The revised $PM_{10}$ emission rate for fuel oil combustion was based on stack testing of filterable and condensable $PM_{10}$ emissions conducted by the facility on McClellan Unit 1. The results of the stack testing showed that the total $PM_{10}$ emission rate for McClellan Unit 1 was 59.4 lb/hr. The emission rate for the $PM_{10}$ species shown in the table above reflects the breakdown of the $PM_{10}$ emissions as determined using the National Park Service (NPS) "speciation spreadsheet" for Uncontrolled Utility Residual Oil Boilers.[29] As with Bailey Unit 1, our concern with AECC's use of the revised $PM_{10}$ emission rate based on stack testing for the fuel oil firing scenario is that there is no discussion provided on how the stack test results are representative of the maximum 24-hour emissions. However, since the visibility impacts due to $PM_{10}$ emissions from McClellan Unit 1 are so small, we believe a closer inspection of the revised $PM_{10}$ emission rate and any further revisions to it would likely not result in significant changes to the modeled visibility impacts and would not affect our proposed BART decision. For McClellan Unit 1, the percentage of the visibility impairment at the four Class I areas attributable to $PM_{10}$ ranges from approximately 4 – 10% for the natural gas firing scenario and 0.4 – 2.5% for the fuel oil firing scenario (see table below). Most of the visibility impairment due to McClellan Unit 1 is attributable to $NO_3$ (approximately 83 – 95%) for the natural gas firing scenario and to $SO_4$ (60 – 98%) for the fuel oil firing scenario. Therefore, we did not take further steps to adjust the $PM_{10}$ emission rates or conduct additional modeling.

AECC modeled the baseline emission rates using the CALPUFF dispersion model to determine the baseline visibility impairment attributable to McClellan Unit 1 at the four Class I areas impacted by emissions from BART sources in Arkansas: the Caney Creek Wilderness Area, the Upper Buffalo Wilderness Area, the Hercules-Glades Wilderness Area, and the Mingo National Wildlife Refuge. The baseline (*i.e.*, existing) visibility impairment attributable to McClellan Unit 1 at each Class I area is summarized in the tables below.

[29] 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 McClellan Unit 1: No. 6 fuel oil with a sulfur content of 1.38% and a heat input of 1,436 MMBtu/hr.

**Table 21. Baseline Visibility Impairment Attributable to McClellan Unit 1 (2001-2003)- Natural Gas Firing**

| Year | Maximum ($\Delta$dv) | 98th Percentile ($\Delta$dv) | No. of Days with $\Delta dv \geq 0.5$ | 98th Percentile $\%SO_4$ | 98th Percentile $\%NO_3$ | 98th Percentile $\%PM_{10}$ | 98th Percentile $\%NO_2$ |
|---|---|---|---|---|---|---|---|
| Caney Creek 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 National Wildlife Refuge | | | | | | | |
| 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 22. Baseline Visibility Impairment Attributable to McClellan Unit 1 (2001-2003)- Fuel Oil Firing**

| Year | Maximum ($\Delta$dv) | 98th Percentile ($\Delta$dv) | No. of Days with $\Delta dv \geq 0.5$ | 98th Percentile $\%SO_4$ | 98th Percentile $\%NO_3$ | 98th Percentile $\%PM_{10}$ | 98th Percentile $\%NO_2$ |
|---|---|---|---|---|---|---|---|
| Caney Creek Wilderness | | | | | | | |
| 2001 | 1.685 | 0.622 | 10 | 89.86 | 9.62 | 0.53 | 0.000 |
| 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 National Wildlife Refuge | | | | | | | |
|---|---|---|---|---|---|---|---|
| 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 |

### b. $SO_2$ BART Evaluation

AECC McClellan Unit 1 currently combusts natural gas and No. 6 fuel oil. Because the $SO_2$ emissions profile and the 98$^{th}$ percentile visibility impact from natural gas combustion attributed to the unit is very small, AECC did not consider additional $SO_2$ controls for combustion of natural gas and instead focused the $SO_2$ evaluation on controlling $SO_2$ emissions from combustion of No. 6 fuel oil. Because of the low $SO_2$ emissions associated with natural gas combustion and the relatively low baseline visibility impacts from AECC McClellan Unit 1 when burning natural gas, we concur with AECC's decision to focus the evaluation on controlling $SO_2$ emissions resulting from the combustion of No. 6 fuel oil. The five factors considered in the analysis are discussed below.

*Step 1- Identify All Available Retrofit Control Technologies*

For $SO_2$ BART, AECC's evaluation considered FGD and fuel switching. The type of FGD technologies considered consisted of DSI, SDA, wet FGD, and dry FGD.

*Step 2- Eliminate Technically Infeasible Options*

AECC found that FGD applications have not been used historically for $SO_2$ control on fuel oil-fired units in the U.S. electric industry and therefore considered it a technically infeasible option for control of McClellan Unit 1. Therefore, AECC's evaluation did not further consider FGD for $SO_2$ BART. We concur with AECC's decision to focus the $SO_2$ evaluation on fuel switching.

*Step 3- Evaluate Control Effectiveness of Remaining Control Technologies*:

AECC McClellan Unit 1 currently burns some residual fuel oil. The most recent No. 6 fuel oil shipment for McClellan Unit 1 was in April 2009, and had an average sulfur content of 1.38% by weight. A portion of the fuel oil from this shipment still remains in storage at the facility for future use. The baseline fuel used in the BART analysis is based on the average sulfur content of the fuel oil from this shipment. Switching to a fuel with a lower sulfur content is expected to reduce $SO_2$ emissions in proportion to the reduction in the sulfur content of the fuel, assuming similar heat contents of the fuels. The fuel types with lower sulfur content evaluated by

AECC are lower sulfur No. 6 fuel oil, No. 2 fuel oil (*i.e.*, diesel), and natural gas. These fuel types and the estimated control efficiency of each are shown in the table below.

**Table 23. Control Effectiveness of Technically Feasible $SO_2$ Control Technologies for AECC McClellan Unit 1**

| Fuel Switching to: | Estimated Control Efficiency (%) |
|---|---|
| No. 6 fuel oil (1% sulfur) | 28% |
| No. 6 fuel oil (0.5% sulfur) | 64% |
| Diesel (0.05% sulfur) | 96% |
| Natural gas (0.04% sulfur) | 99.9% |

*Step 4- Evaluate Impacts and Document the Results*

The four factors considered in this step are the costs of compliance, energy and non-air quality environmental impacts of compliance, existing pollution control technology in use at the source, and the remaining useful life of the source.

McClellan Unit 1 currently burns both No. 6 fuel oil and natural gas. AECC estimated the cost of fuel switching by determining the annual cost of the No. 6 fuel oil currently used (*i.e.*, the baseline fuel) and determining the cost of switching to the various lower sulfur content fuels. The supplier of the existing fuels (*i.e.*, No. 6 fuel oil and natural gas) provided AECC with current cost estimates for the existing fuels and for the lower sulfur content No. 6 fuel oil and diesel. As shown in the table below, the supplier's estimate for the cost of No. 6 fuel oil with 0.5% and 1% sulfur content is $17.75/MMBtu and $16.50 /MMBtu (respectively), and for diesel is $20.95/MMBtu. The cost of the base case No. 6 fuel oil with 1.38% sulfur content was estimated to be $16.00/MMBtu.

AECC estimated the $SO_2$ annual emissions reductions as a result of fuel switching by subtracting the estimated controlled annual emission rates from the baseline annual emission rates. AECC estimated the baseline and controlled annual emission rates by conducting a mass balance on the sulfur in the various fuels.[30] The sulfur content of the baseline fuel is 1.38% by weight. The $SO_2$ emissions associated with the base case and the fuel switching scenarios (*i.e.*, 1% sulfur No. 6 fuel oil, 0.5% sulfur No. 6 fuel oil, diesel, and natural gas) were estimated by multiplying the baseline annual fuel usage by the fuel density and by the percent sulfur content of the fuel. This yielded the quantity of sulfur in the fuel. The $SO_2$ emissions were then estimated

[30] See the following BART analyses: "BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations," dated March 2014, Version 4, prepared by Trinity Consultants Inc. in conjunction with Arkansas Electric Cooperative Corporation.

by multiplying the quantity of sulfur available to form $SO_2$ by the ratio of the molecular weight for $SO_2$ vs. sulfur. See the table below for the estimated $SO_2$ emissions associated with the base case and with each fuel switching scenario.

To calculate the average cost-effectiveness of fuel switching, AECC divided the annual cost increase of switching to a lower sulfur fuel by the annual $SO_2$ tons reduced as a result of fuel switching. The table below shows the average cost-effectiveness and incremental cost-effectiveness of fuel switching for McClellan Unit 1.

**Table 24. Summary of Costs Associated with Fuel Switching for McClellan Unit 1**

| Fuel Switching Scenario | Average Sulfur Content (%) | Baseline Emission Rate ($SO_2$ tpy) | Controlled Emission Rate ($SO_2$ tpy) | Annual Emissions Reductions (tpy) | Annual Heat Input (MMBtu/yr) | Fuel Heating Value (MMBtu/Mgal) or (MMBtu/Mscf) | Annual Fuel Usage (Mgal/yr) | Fuel Cost ($/MMBtu) | Total Annual Differential Cost of Fuel Switching ($/yr) | Average Cost Effectiveness ($/ton) | Incremental Cost Effectiveness[31] ($/ton) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Base Case** | 1.38 | 209.43 | - | - | 291,733 | 155.00 | 1,882.15 | 16.00 | - | - | - |
| **No. 6 - 1%** | 1.00 | - | 153.61 | 55.81 | 291,733 | 155.00 | 1,882.15 | 16.50 | 145,866 | 2,613 | - |
| **No. 6 - 0.5%** | 0.50 | - | 75.88 | 133.55 | 291,733 | 155.00 | 1,882.15 | 17.75 | 510,532 | 3,823 | 4,691 |
| **Diesel** | 0.05 | - | 7.31 | 202.11 | 291,733 | 136.15 | 2,142.73 | 20.95 | 1,444,077 | 7,145 | 13,616 |
| **Natural Gas** | 0.04 | - | 0.07 | 209.35 | 291,733 | 1,011.00 | 288.56 | 5.97 | -2,926,874 | -13,980 | -603,723 |

AECC did not identify any energy or non-air quality impacts associated with switching to 1% sulfur No. 6 fuel oil, 0.5% sulfur No. 6 fuel oil, or diesel. The evaluation indicated that switching to natural gas may have an impact during periods of natural gas curtailment. During natural gas curtailments, natural gas infrastructure maintenance, and other emergencies, AECC relies on the fuel oil stored at the plant to maintain electrical reliability. The evaluation indicates that because of this, the ability to burn fuel oil at AECC McClellan is important even if fuel oil is currently more expensive than natural gas.

With regard to consideration of any existing pollution control technology in use at the source, McClellan Unit 1 has no existing $SO_2$ pollution control technology. The presence of existing pollution control technology is reflected in the BART analysis in two ways: first, in the

[31] The incremental cost-effectiveness calculation compares the costs and performance level of a control option to those of the next most stringent option, as shown in the following formula (with respect to cost per emissions reduction): Incremental Cost Effectiveness (dollars per incremental ton removed) = (Total annualized costs of control option) – (Total annualized costs of next control option) / (Control option annual emissions) – Next control option annual emissions). See BART Guidelines, 40 CFR Part 51, Appendix Y, section IV.D.4.e.

consideration of available control technologies, and second, in the development of baseline emission rates for use in cost calculations and visibility modeling.

With regard to consideration of the remaining useful life of the unit, this factor does not impact the $SO_2$ BART analysis in this case since it is assumed that fuel switching will not require any capital cost expenditures.

*Step 5- Evaluate Visibility Impacts*

AECC assessed the visibility improvement associated with fuel switching by comparing the visibility impairment from the baseline scenario to the impairment associated with each control scenario. The $SO_2$ emission rate in lb/MMBtu associated with the combustion of each fuel type was calculated by scaling the existing 30-day rolling average emission rate from 2001-2003 by the ratio of the sulfur content of the new fuel and the current maximum annual average sulfur content from 2009-2011. The controlled 30-day emission rate in lb/MMBtu was converted to units of lb/hr by multiplying by the boiler design heat input. The tables below show the emission rates modeled and a comparison of the baseline (*i.e.*, existing) visibility impacts and the visibility impacts associated with fuel switching, including the maximum modeled visibility impact and the 98$^{th}$ percentile modeled visibility impact. The visibility improvement associated with fuel switching was calculated as the difference between the existing visibility impairment and the visibility impairment for each fuel scenario as measured by the 98$^{th}$ percentile modeled visibility impact.

**Table 25. Summary of Emission Rates Modeled for $SO_2$ Control Scenarios at McClellan Unit 1**

| | $SO_2$ (lb/hr) | SO4 (lb/hr) | $NO_X$ (lb/hr) | PMC (lb/hr) | PMF (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 |

**Table 26. AECC McClellan Unit 1: Summary of 98th Percentile Visibility Impacts and Improvement due to Fuel Switching**

| Class I area | Baseline Visibility Impact (Δdv) | No. 6 Fuel Oil- 1% Sulfur | | No. 6 Fuel Oil- 0.5% Sulfur | | | Diesel | | | Natural Gas | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. 1% Sulfur Fuel oil | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. 0.5 % Sulfur Fuel oil | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. Diesel |
| Caney Creek | 0.622 | 0.537 | 0.085 | 0.322 | 0.3 | 0.215 | 0.174 | 0.448 | 0.148 | 0.125 | 0.497 | 0.049 |
| Upper Buffalo | 0.266 | 0.231 | 0.035 | 0.146 | 0.12 | 0.085 | 0.073 | 0.193 | 0.073 | 0.052 | 0.214 | 0.021 |
| Hercules-Glades | 0.231 | 0.202 | 0.029 | 0.115 | 0.116 | 0.087 | 0.062 | 0.169 | 0.053 | 0.040 | 0.191 | 0.022 |
| Mingo | 0.228 | 0.193 | 0.035 | 0.136 | 0.092 | 0.057 | 0.080 | 0.148 | 0.056 | 0.058 | 0.17 | 0.022 |
| Cumulative Visibility Improvement (Δdv) | -- | -- | 0.184 | -- | 0.628 | - | -- | 0.958 | - | -- | 1.072 | - |

The table above shows that switching to No. 6 fuel oil with 1% sulfur content at McClellan Unit 1 is projected to result in 0.085 dv visibility improvement at Caney Creek (based on the 98th percentile modeled visibility impacts). The visibility improvement at each of the other three affected Class I is projected to range from 0.029 – 0.035 dv, while the cumulative visibility improvement at the four Class I areas is projected to be 0.184 dv. Switching to No. 6 fuel oil with 0.5% sulfur content is projected to result in considerable visibility improvement. It is projected to result in 0.3 dv visibility improvement at Caney Creek. The visibility improvement at each of the other three affected Class I areas is projected to range from 0.092 – 0.12 dv, while the cumulative visibility improvement at the four Class I areas is projected to be 0.628 dv. Switching to diesel or natural gas is also projected to result in considerable visibility improvement. The visibility improvement at Caney Creek is projected to be 0.448 dv for switching to diesel and 0.497 dv for switching to natural gas. At each of the three remaining Class I areas, the visibility improvement is projected to range from 0.148 – 0.193 dv for switching to diesel and 0.17 – 0.214 dv for switching to natural gas. The cumulative visibility improvement at the four Class I areas is projected to be 0.958 dv for switching to diesel and 1.072 dv for switching to natural gas.

**Our Proposed $SO_2$ BART determination:**

Taking into consideration the five factors, we are proposing to determine that BART for the AECC McClellan Unit 1 is switching to fuels with 0.5% or lower sulfur content by weight. The cost of switching to No. 6 fuel oil with 0.5% sulfur content is within the range of what we consider to be cost-effective for BART and it is projected to result in considerable visibility improvement compared to the baseline at the affected Class I areas. Switching to No. 6 fuel oil with 0.5% sulfur content has an estimated average cost-effectiveness of $3,823/ton of $SO_2$ removed and is projected to result in visibility improvement ranging from 0.092 to 0.3 dv at each modeled Class I area, and a cumulative visibility improvement of 0.628 dv at the four modeled Class I areas. Switching to natural gas would currently cost less than the baseline fuel oil and is projected to result in even greater visibility improvement than switching to No. 6 fuel oil with 0.5% sulfur content. However, the BART Guidelines provide that it is not our intent to direct subject-to-BART sources to switch fuel forms, such as from coal or fuel oil to gas (40 CFR Part 51, Appendix Y, section IV.D.1). Since natural gas has a sulfur content by weight that is well below 0.5%, the facility may elect to use this type of fuel to comply with BART, but we are not proposing to require a switch to natural gas for Unit 1. Switching to diesel is projected to result in considerable visibility improvement. The visibility improvement of switching to diesel is projected to range from 0.148 to 0.448 dv at each modeled Class I area, and the cumulative visibility improvement is 0.958 dv at the four affected Class I areas. The incremental visibility improvement of switching to diesel compared to switching to No. 6 fuel oil with a sulfur content of 0.5% is projected to range from 0.053 dv to 0.148 dv at each affected Class I area. However, the average cost-effectiveness of switching to diesel is estimated to be $7,145/ ton of $SO_2$ removed and the incremental cost-effectiveness compared to No. 6 fuel oil with a sulfur content of 0.5% is $13,616/ ton of $SO_2$ removed, which we do not consider to be cost-effective in view of the incremental visibility improvement. Since diesel also has a sulfur content by weight that is well below 0.5, the facility may elect to use this type of fuel to comply with BART, but we are not proposing to require a switch to diesel for Unit 1. We are proposing to determine that $SO_2$ BART for McClellan Unit 1 is switching to fuels with 0.5% or lower sulfur content by weight. We propose to require that the facility purchase no fuel after the effective date of the rule that does not meet the sulfur content requirement and that 5 years from the effective date of the rule no fuel be burned that does not meet the requirement We expect this proposed compliance date would allow the facility sufficient time to burn its existing supply of No. 6 fuel oil (i.e., the baseline fuel), as the normal course of business dictates and in accordance with any operating restrictions enforced by ADEQ. We propose that any higher sulfur fuel oil that remains from its 2009 shipment cannot be burned past this point.

### c. $NO_X$ BART Evaluation

Nitrogen oxides, or $NO_X$, are produced during fuel combustion when nitrogen contained in both the fuel and the combustion air is exposed to high temperatures. Nitrogen oxide (NO) is typically the predominant form of $NO_X$ from fossil fuel combustion, with nitrogen dioxide ($NO_2$) making up the remainder of the $NO_X$. AECC noted that the formation of $NO_X$ compounds in utility boilers is sensitive to the method of firing and combustion flame temperatures. In wall-fired boilers, such as McClellan Unit 1, 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 combustion flame temperatures, among other factors. The baseline $NO_X$ emission rate for McClellan Unit 1 is discussed under section II.C.2.a. of this TSD. The five factors considered in the $NO_X$ BART analysis are discussed below.

*Step 1- Identify All Available Retrofit Control Technologies*

For $NO_X$ BART, AECC evaluated both combustion and post-combustion controls. Combustion controls involve reducing the peak flame temperature and excess air in the furnace to minimize $NO_X$ formation, while post-combustion controls involve converting $NO_X$ in the flue gas to molecular nitrogen and water. The combustion controls evaluated by AECC consisted of FGR, OFA, and LNB. The post-combustion controls evaluated consisted of SCR and SNCR.

*Step 2- Eliminate Technically Infeasible Options*

AECC found that some boilers may be restricted from installing OFA retrofits due to physical size and space restraints. For purposes of the $NO_X$ BART evaluation, AECC assumed OFA to be a technically feasible option for McClellan Unit 1, but noted that if the five factor BART analysis deemed OFA to be BART, then further analyses would have to be performed to determine if (1) the dimensions of the main boiler has sufficient upper furnace volume for OFA mixing and complete combustion; and (2) if there are physical space requirements for OFA ports and air supply ducts. AECC found the remaining $NO_X$ control options to be technically feasible.

*Step 3- Evaluate Control Effectiveness of Remaining Control Technologies*:

The estimated $NO_X$ controlled emission rate of each control option considered by AECC is shown in the table below. In its evaluation, AECC considered the following control options: a combination of combustion controls (*i.e.*, FGR, OFA, and LNB); a combination of combustion controls and SNCR; and SCR. AECC estimated that when FGR is operated alone, the $NO_X$

control range for oil and gas wall-fired boilers is approximately 0.2 – 0.4 lb/MMBtu, and when OFA is operated alone it results in an estimated $NO_X$ controlled emission rate of 0.2 – 0.3 lb/MMBtu.[32] It also estimated that when LNB is combined with OFA and FGR, a $NO_X$ controlled emission rate of 0.15 – 0.20 lb/MMBtu is achievable.

AECC found that the estimated $NO_X$ control efficiency of SCR is 80-90% on gas fired boilers and 70-80% for oil fired boilers, and estimated that when SCNR is combined with combustion controls, the $NO_X$ level of control is estimated to be 10% greater than with combustion controls alone.[33]

**Table 27. Control Effectiveness of Technically Feasible $NO_X$ Control Technologies for AECC McClellan Unit 1**

| Control Technology | Baseline $NO_X$ Emission Rate (lb/MMBtu) | | Estimated $NO_X$ Controlled Emission Rate (lb/MMBtu) | |
|---|---|---|---|---|
| | Natural Gas | Fuel Oil | Natural Gas | Fuel Oil |
| SCR | 0.31 | 0.5 | 0.05 | 0.12 |
| Combustion Controls +SNCR | | | 0.12 | 0.10 |
| Combustion Controls | | | 0.15 | 0.15 |

*Step 4- Evaluate Impacts and Document the Results*

The four factors considered in this step are the costs of compliance, energy and non-air quality environmental impacts of compliance, the existing pollution control technology in use at the source, and the remaining useful life of the source.

AECC's cost analysis[34] for $NO_X$ controls was based on "budgetary" cost estimates it obtained from the pollution control equipment vendor, Babcock Power Systems. AECC estimated the capital and operating costs of controls based on the vendor's estimates, engineering estimates, and published calculation methods using the EPA Control Cost Manual. We are not aware of any enforceable shutdown date for the AECC McClellan Generating Station, nor did AECC indicate any future planned shutdown. This means that the anticipated useful life of the boiler is expected to be at least as long as the capital cost recovery period of controls. Therefore,

[32] "Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options," section II, dated July 1994, State and Territorial Air Pollution Program Administrators (STAPPA) and Association of Local Air Pollution Control Officials (ALAPCO).

[33] "Preferred and Alternative Methods for Estimating Air Emissions from Boilers" Table 2.2-2. January 2001. See http://www.epa.gov/ttn/chief/eiip/techreport/volume02/ii02.pdf.

[34] See "BART Five Factor Analysis- $NO_X$ Analysis, Addendum to the July 24, 2012 BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations," dated December 2013, Version 3.

a 30-year amortization period was assumed in the $NO_X$ BART analysis as the remaining useful life of the unit. The table below summarizes the estimated cost for installation and operation of $NO_X$ controls for AECC McClellan Unit 1.

AECC determined the annual emissions reductions associated with each $NO_X$ control option by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. The baseline annual emission rates are the average rates from 2009-2011, while the controlled annual emission rates are based on the lb/MMBtu levels believed to be achievable from the control technology multiplied by the baseline heat inputs to the boilers in MMBtu/yr. The baseline heat inputs for each unit are the sum of the baseline heat inputs for natural gas and fuel oil. The baseline heat inputs for natural gas are based on the average natural gas usage for each unit from 2007-2011 multiplied by the average heat content of natural gas for the same time period. Similarly, the baseline heat inputs for fuel oil are based on the average fuel oil usage for each unit from 2007-2011 multiplied by the average heat content of fuel oil for the same time period.

To calculate the average cost-effectiveness of $NO_X$ controls, AECC divided the total annual cost of each control option by the estimated annual $NO_X$ tons reduced. The table below shows the average cost effectiveness and incremental cost-effectiveness of $NO_X$ controls for AECC McClellan Unit 1.

**Table 28. Summary of Costs of $NO_X$ Controls for AECC McClellan Unit 1**

| Control Scenario | Baseline Emission Rate ($NO_X$ tpy) | Natural Gas Controlled Emission Level (lb/MMBtu) | Fuel Oil Controlled Emission Level (lb/MMBtu) | Natural Gas Annual Heat Input (MMBtu/yr) | Fuel Oil Annual Heat Input (MMBtu/yr) | Controlled Emission Rate ($NO_X$ tpy) | Annual Emissions Reductions ($NO_X$ tpy) | Capital Cost ($) | Total Annual Cost ($/yr) | Average Cost-Effectiveness ($/ton) | Incremental Cost-Effectiveness ($/ton) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Combustion Controls** | 294.04 | 0.15 | 0.15 | 2,040,117 | 291,733 | 174.89 | 119.15 | 7,400,000 | 746,051 | 6,261 | -- |
| **Combustion Controls + SNCR** | 294.04 | 0.12 | 0.10 | 2,040,117 | 291,733 | 136.40 | 157.64 | 11,733,253 | 1,990,988 | 12,630 | 32,344 |
| **SCR** | 294.04 | 0.05 | 0.12 | 2,040,117 | 291,733 | 64.98 | 229.06 | 12,675,562 | 1,732,870 | 7,565 | -3,614 |

AECC estimated the average cost-effectiveness of installing and operating combustion controls to be $6,261/ton of $NO_X$ removed for McClellan Unit 1. The combination of combustion controls and SNCR was estimated to cost $12,630/ton of $NO_X$ removed, while SCR was estimated to cost $7,565/ton of $NO_X$ removed. In its evaluation, AECC also explained that it expects $NO_X$ controls to be less cost-effective (*i.e.*, greater dollars per ton removed) in future years due to projected reduced operation of the unit. Less projected operating time is expected to result in lower annual emissions, which would result in lower cost-effectiveness of controls.

AECC did not identify any energy or non-air quality environmental impacts associated with the use of LNB, OFA, or FGR. As for SCR and SNCR, we are not aware of any unusual circumstances at the facility that could create energy or non-air quality environmental impacts associated with the operation of these controls greater than experienced elsewhere and that may therefore provide a basis for their elimination as BART (40 CFR Part 51, Appendix Y, section IV.D.4.i.2.). Therefore, we do not believe there are any energy or non-air quality environmental impacts associated with $NO_X$ controls at AECC McClellan Unit 1 that would affect our proposed BART determination.

With regard to consideration of any existing pollution control technology in use at the source, McClellan Unit 1 has no existing $NO_X$ pollution control technology. The presence of existing pollution control technology at the source is reflected in the BART analysis in two ways: first, in the consideration of available control technologies, and second, in the development of baseline emission rates for use in cost calculations and visibility modeling.

With regard to consideration of the remaining useful life of the unit, we are not aware of any enforceable shutdown date for the AECC McClellan Generating Station, nor did AECC's evaluation indicate any future planned shutdown. This means that the anticipated useful life of the boiler is expected to be at least as long as the capital cost recovery period of controls. Therefore, a 30-year amortization period was assumed in the $NO_X$ BART analysis as the remaining useful life of Unit 1.

*Step 5- Evaluate Visibility Impacts*

AECC assessed the visibility improvement associated with $NO_X$ controls by modeling the $NO_X$ emission rates associated with each control option using CALPUFF, and then comparing the visibility impairment associated with the baseline emission rates to the visibility impairment associated with the controlled emission rates. The controlled emission levels associated with combustion controls, combustion controls + SNCR, and SCR systems are shown in the table above. These levels were multiplied by each unit's maximum heat input to derive the hourly emission rates used in the modeling. The tables below show a comparison of the emission rates modeled and the existing (*i.e.*, baseline) visibility impacts and the visibility impacts based on $NO_X$ controls, including the maximum modeled visibility impact and the 98$^{th}$ percentile modeled visibility impact. The visibility improvement associated with $NO_X$ controls was calculated as the difference between the baseline visibility impairment and the visibility impairment for each control scenario as measured by the 98$^{th}$ percentile modeled visibility impact.

**Table 29. Summary of Emission Rates Modeled for $NO_X$ Control Scenarios at AECC McClellan Unit 1**

| Control Scenario | Fuel Scenario | $SO_2$ (lb/hr) | NOx (lb/hr) | Total $PM_{10}$ (lb/hr) | $SO_4$ (lb/hr) | PMc (lb/hr) | PMf (lb/hr) | SOA (lb/hr) | EC (lb/hr) |
|---|---|---|---|---|---|---|---|---|---|
| Combustion Controls | Natural Gas | 0.6 | 215.5 | 10.9 | 0.3 | 0.0 | 0.0 | 7.9 | 2.7 |
| | Fuel Oil | 2,747.5 | 215.5 | 48.2 | 4.8 | 11.5 | 28.7 | 0.8 | 2.3 |
| SCR | Natural Gas | 0.6 | 66.0 | 10.9 | 0.3 | 0.0 | 0.0 | 7.9 | 2.7 |
| | Fuel Oil | 2,747.5 | 178.7 | 48.2 | 4.8 | 11.5 | 28.7 | 0.8 | 2.3 |
| Combustion Controls + SNCR | Natural Gas | 0.6 | 171.5 | 10.9 | 0.3 | 0.0 | 0.0 | 7.9 | 2.7 |
| | Fuel Oil | 2,747.5 | 144.0 | 48.2 | 4.8 | 11.5 | 28.7 | 0.8 | 2.3 |

**Table 30. Summary of the 98$^{th}$ Percentile Visibility Impacts and Improvement due to $NO_X$ Controls for AECC McClellan Unit 1- Natural Gas Firing (2001-2003)**

| Class I area | Baseline Visibility Impact (Δdv) | Combustion Controls | | Combustion Controls + SNCR | | | SCR | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. Combustion Controls (Δdv) | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. Combustion Controls + SNCR (Δdv) |
| Caney Creek | 0.125 | 0.068 | 0.057 | 0.056 | 0.069 | 0.012 | 0.027 | 0.098 | 0.029 |
| Upper Buffalo | 0.052 | 0.028 | 0.024 | 0.023 | 0.029 | 0.005 | 0.012 | 0.04 | 0.011 |
| Hercules-Glades | 0.040 | 0.021 | 0.019 | 0.018 | 0.022 | 0.003 | 0.009 | 0.031 | 0.009 |
| Mingo | 0.058 | 0.031 | 0.027 | 0.026 | 0.032 | 0.005 | 0.012 | 0.046 | 0.014 |
| Cumulative Visibility Improvement (Δdv) | -- | -- | 0.127 | -- | 0.152 | -- | -- | 0.215 | -- |

**Table 31. Summary of the 98th Percentile Visibility Impacts and Improvement due to $NO_X$ Controls for AECC McClellan Unit 1- Fuel Oil Firing (2001-2003)**

| Class I area | Baseline Visibility Impact (Δdv) | Combustion Controls | | Combustion Controls + SNCR | | | SCR | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. Combustion Controls (Δdv) | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. Combustion Controls + SNCR (Δdv) |
| Caney Creek | 0.621 | 0.554 | 0.067 | 0.542 | 0.079 | 0.012 | 0.548 | 0.073 | -0.006 |
| Upper Buffalo | 0.266 | 0.264 | 0.002 | 0.264 | 0.002 | 0.000 | 0.264 | 0.002 | 0.000 |
| Hercules-Glades | 0.230 | 0.209 | 0.021 | 0.203 | 0.027 | 0.006 | 0.207 | 0.023 | -0.004 |
| Mingo | 0.227 | 0.203 | 0.024 | 0.200 | 0.027 | 0.003 | 0.201 | 0.026 | -0.001 |
| Cumulative Visibility Improvement (Δdv) | -- | -- | 0.114 | -- | 0.135 | -- | -- | 0.124 | -- |

As shown in the tables above, the installation and operation of $NO_X$ controls is projected to result in very modest visibility improvement from the baseline. Combustion controls at McClellan Unit 1 are projected to result in visibility improvement ranging from 0.019 – 0.057 dv at each Class I area for natural gas firing and 0.002 – 0.067 dv for fuel oil firing (based on the 98th percentile modeled visibility impacts). A combination of combustion controls + SNCR at McClellan Unit 1 is projected to result in only slightly greater visibility improvement than combustion controls alone. For example, the combination of combustion controls + SNCR is projected to result in visibility improvement ranging from 0.022 – 0.069 dv at each Class I area for natural gas firing and 0.002 – 0.079 dv for fuel oil firing. The installation and operation of SCR at McClellan Unit 1 is projected to result in only slightly greater visibility improvement compared to a combination of combustion controls + SNCR. SCR is projected to result in visibility improvement ranging from 0.031 – 0.098 dv at each Class I area for natural gas firing and 0.002 – 0.073 dv for fuel oil firing.

**Our $NO_X$ BART determination:**

Taking into consideration the five factors, we are proposing to determine that $NO_X$ BART for the AECC McClellan Unit 1 is no additional controls, and are proposing that the existing $NO_X$ emission limits satisfy BART for $NO_X$. We are proposing the existing emission limit of 869.1 lb/hr for natural gas firing and 705.8 lb/hr for fuel oil firing for $NO_X$ BART for McClellan Unit 1.[35] As discussed above, the operation of combustion controls at McClellan Unit 1 is projected to result in a maximum visibility improvement of 0.067 dv (Caney Creek), and a smaller amount of visibility improvement at each of the other affected Class I areas. The installation and operation of combustion controls at McClellan Unit 1 has an average cost-effectiveness of $6,261/ton of $NO_X$ removed, which is not within the range of what we generally consider to be cost-effective. We believe the relatively small visibility benefit projected from the operation of combustion controls both when combusting fuel oil and natural gas does not justify the high estimated cost of those controls. The operation of a combination of combustion controls + SNCR is estimated to cost $12,630/ton of $NO_X$ removed, which is also not cost-effective. A combination of combustion controls + SNCR is projected to result in only slight incremental visibility benefit compared to combustion controls alone. The operation of SCR is estimated to cost $7,565/ton of $NO_X$ removed, which is not cost-effective, and is projected to result in only slight incremental visibility benefit compared to a combination of combustion controls + SNCR for the natural gas firing scenario. For the fuel oil firing scenario, SCR is projected to result in slightly lower visibility benefit compared to a combination of combustion controls + SNCR at three of the modeled Class I areas. We are proposing to find that $NO_X$ BART for McClellan Unit 1 is no additional controls and are proposing the aforementioned existing $NO_X$ emission limits for $NO_X$ BART. We are proposing that these already-existing emissions limitations be complied with for BART purposes from the effective date of the final action.

### d. PM BART Evaluation

The five factors considered in the PM BART analysis for McClellan Unit 1 are discussed below.

*Step 1- Identify All Available Retrofit Control Technologies*

For PM BART, AECC considered the following control technologies: dry ESP, wet ESP, fabric filter, wet scrubber, cyclone (*i.e.*, mechanical collector), and fuel switching.

Residual fuel, such as the No. 6 fuel oil burned at McClellan Unit 1, has inherent ash that contributes to emissions of filterable PM. Filterable PM emissions could be reduced by switching to a lower grade fuel oil or natural gas. For combustion of No. 6 fuel oil, reductions in filterable PM are directly related to the sulfur content of the fuel.[36] Therefore, switching to No. 6 fuel oil with a lower sulfur content is expected to result in lower filterable PM emissions. AECC's evaluation considered switching to No. 6 fuel oil with 1% sulfur content by weight, No. 6 fuel oil

[35] See ADEQ Operating Air Permit No. 0181-AOP-R5, Section IV, Specific Condition No. 1, 3, and 13.
[36] See AP-42, section 1.3-1.

with 0.5% sulfur content by weight, diesel, and natural gas. These are the same lower sulfur fuel types evaluated in the $SO_2$ BART analysis for the unit.

*Step 2- Eliminate Technically Infeasible Options*

AECC's evaluation noted that the particulate matter from oil-fired boilers tends to be sticky and small, affecting the collection efficiency of dry ESPs and fabric filters. Dry ESPs operate by placing a charge on the particles through a series of electrodes, and then capturing the charged particles on collection plates, while fabric filters work by filtering the PM in the flue gas through filter bags. The collected particles are periodically removed from the filter bag through a pulse jet or reverse flow mechanism. Because of the sticky nature of particles from oil-fired boilers, dry ESPs and fabric filters are deemed technically infeasible for use at McClellan Unit 1. Wet ESPs, cyclones, wet scrubbers, and fuel switching were identified as technically feasible options for McClellan Unit 1. AECC noted that although cyclones and wet scrubbers are considered technically feasible for use at these boiler types, they are not very efficient at controlling particles in the smaller size fraction, particularly particles smaller than a few microns. However, we do not expect this to be an issue for McClellan Unit 1, since the majority of the PM emissions from the unit are greater than a few microns in size.

*Step 3- Evaluate Control Effectiveness of Remaining Control Technologies*:

AECC estimated that switching to a lower sulfur fuel has a PM control efficiency ranging from approximately 44% - 99%, depending on the fuel type. The other technically feasible control technologies are estimated to have the following PM control efficiency: wet ESP- up to 90%, cyclone- 85%, and wet scrubber- 55%.

*Step 4- Evaluate Impacts and Document the Results*

The four factors considered in this step are the costs of compliance, energy and non-air quality environmental impacts of compliance, existing pollution control technology in use at the source, and the remaining useful life of the source.

AECC evaluated the capital costs, operating costs, and average cost-effectiveness of wet ESPs, cyclones, and wet scrubbers.[37] AECC also evaluated the average cost-effectiveness of switching to No. 6 fuel oil with 1% sulfur content, No. 6 fuel oil with 0.5% sulfur content, diesel, and natural gas. AECC developed the capital and operating costs of a wet ESP and wet scrubber using the Electric Power Research Institute's (EPRI) Integrated Emissions Control Cost

[37] See "BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations," dated March 2014, Version 4, prepared by Trinity Consultants Inc. in conjunction with Arkansas Electric Cooperative Corporation.

Estimating Workbook (IECCOST) Software. The capital costs of controls (except for fuel switching) were annualized over a 15-year period and then added to the annual operating costs to obtain the total annualized costs. The table below summarizes the average cost-effectiveness of PM controls. AECC determined the average cost-effectiveness by dividing the annualized cost of controls by the annual PM emissions reductions. The annual emissions reductions were determined by subtracting the estimated controlled annual emission rates from the baseline annual emission rates, which were derived using emission factors from AP-42, section 1.3-1.

We disagree with two aspects of AECC's cost evaluation for PM controls. First, the total annual cost numbers associated with fuel switching should be the same as the cost numbers used in the $SO_2$ BART cost analysis for McClellan Unit 1 (see Table 24). In earlier draft versions of AECC's analysis, which were provided to us for review, the cost numbers for fuel switching used in the PM and $SO_2$ BART analyses were identical. In response to comments we provided, the total annual cost and average cost-effectiveness numbers for fuel switching were revised in the final version of AECC's $SO_2$ BART analysis. However, it appears that AECC overlooked updating these cost numbers in the final PM BART analysis.[38] In the table below, we have revised the total annual cost of fuel switching for the PM BART analysis to be consistent with the cost estimates from AECC's $SO_2$ BART analysis, and we have also updated the PM average cost-effectiveness values. The second aspect of AECC's cost evaluation for PM controls that we disagree with is the use of a 15-year capital cost recovery period for calculating the average cost-effectiveness of a wet ESP, wet scrubber, and cyclone. As previously discussed, we are not aware of any enforceable shutdown date for the AECC McClellan Generating Station, nor did the AECC's evaluation indicate any future planned shutdown. Therefore, we believe that assuming a 30-year equipment life rather than a 15-year equipment life would be more appropriate for these control technologies. Extending the amortization period from 15 to 30 years has the effect of decreasing the total annual cost of each control option, thereby improving the cost-effectiveness of controls (*i.e.*, less dollars per ton removed). However, after considering all five BART factors, we do not believe AECC's assumption of a 15-year amortization period has an impact on our proposed BART decision and therefore we did not revise the amortization period or the average cost-effectiveness calculations for the PM control equipment options. This is discussed in more detail below. The table below summarizes the estimated cost for fuel switching and the installation and operation of PM control equipment for McClellan Unit 1.

[38] The final version of AECC's BART analysis for $SO_2$ and PM, upon which our analysis is largely based, is titled "BART Five Factor Analysis Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations, March 2014, Version 4." A copy of AECC's analysis can be found in the docket for our proposed rulemaking.

**Table 32. Summary of Cost of PM Controls for AECC McClellan Unit 1- Baseline is No. 6 Fuel Oil with 1.38% Sulfur Content by Weight**

| Control Scenario | Baseline Emission Rate (PM tpy) | Control Efficiency (%) | Annual Heat Input (MMBtu/yr) | Controlled Emission Rate (PM tpy) | Annual Emissions Reduction (PM tpy) | Capital Cost ($) | Total Annual Cost ($/yr) | Average PM Cost Effectiveness ($/ton) | Incremental Cost Effectiveness (S/ton) |
|---|---|---|---|---|---|---|---|---|---|
| **No. 6 Fuel oil- 1% S** | 136.08 | 43.6 | 291,733 | 76.70 | 59.38 | -- | 145,866 | 2,456 | -- |
| **Wet Scrubber** | 136.08 | 55.0 | 291,733 | 61.23 | 74.84 | 146,303,011 | 52,056,542 | 695,549 | 3,357,741 |
| **No. 6 Fuel oil- 0.5% S** | 136.08 | 82.4 | 291,733 | 23.94 | 112.14 | -- | 510,532 | 4,553 | -1,381,931 |
| **Cyclone** | 136.08 | 85.0 | 291,733 | 20.41 | 115.67 | 1,432,971 | 1,721,384 | 14,882 | 343,018 |
| **Wet ESP** | 136.08 | 90.0 | 291,733 | 13.61 | 122.47 | 151,509,333 | 32,605,907 | 266,237 | 4,541,842 |
| **Natural Gas** | 136.08 | 99.0 | 291,733 | 1.36 | 134.72 | -- | -2,926,874 | -21,725 | -2,900,635 |
| **Diesel** | 136.08 | 99.2 | 291,733 | 1.10 | 134.98 | -- | 1,444,077 | 10,698 | 16,811,350 |

The table above shows that the average cost-effectiveness values of all add-on PM control technology options evaluated for AECC McClellan Unit 1 ranged from approximately $15,000/ton of PM removed to more than $266,000/ton of PM removed. Switching to No. 6 fuel oil with either a 1% or 0.5% sulfur content was found to be within the range of what we generally consider cost-effective for BART. Switching to No. 6 fuel oil with 1% sulfur content is estimated to cost $2,456/ton of PM removed, while switching to No. 6 fuel oil with 0.5% sulfur content is estimated to cost $4,553/ton of PM removed. As discussed in the $SO_2$ BART analysis, the current cost of natural gas is actually lower than the cost of the baseline fuel. Therefore, the average cost-effectiveness of switching from the baseline fuel to natural gas is denoted as a negative value in the table above. As discussed above, AECC also explained that it expects controls to be less cost-effective (*i.e.*, greater dollars per ton removed) in future years due to projected reduced operation of the unit. Less projected operating time is expected to result in lower annual emissions, which in turn would result in lower cost-effectiveness of controls.

AECC did not identify any energy or non-air quality environmental impacts associated with fuel switching, but did identify impacts associated with the use of wet ESPs and wet scrubbers due to their electricity usage. Energy use in and of itself does not disqualify a technology (40 CFR Part 51, Appendix Y, section IV.D.4.h.1.). In addition, the cost of the electricity needed to operate this equipment has already been factored into the cost of controls. AECC also noted that both wet ESPs and wet scrubbers generate wastewater streams that must either be treated on-site or sent to a waste water treatment plant, and the wastewater treatment process will generate a filter cake that would likely require landfilling. The BART Guidelines provide that the fact that a control device creates liquid and solid waste that must be disposed of does not necessarily argue against selection of that technology as BART, particularly if the control device has been applied to similar facilities elsewhere and the solid or liquid waste is similar to those other applications (40 CFR Part 51, Appendix Y, section IV.D.4.i.2.). We are not aware of any unusual circumstances at the AECC McClellan Generating Station that could potentially create greater problems than experienced elsewhere related to the treatment of wastewater and any necessary landfilling, nor did the AECC BART evaluation discuss or mention any such unusual circumstances. Therefore, the need to treat wastewater or landfill any filter cake or other waste in and of itself does not provide a basis for disqualification or elimination of a wet ESP or wet scrubber.

With regard to consideration of any existing pollution control technology in use at the source, McClellan Unit 1 has no existing PM pollution control technology. The presence of existing pollution control technology at the source is reflected in the BART analysis in two ways: first, in the consideration of available control technologies, and second, in the development of baseline emission rates for use in cost calculations and visibility modeling.

With regard to consideration of the remaining useful life of the unit, we are not aware of any enforceable shutdown date for the AECC McClellan Generating Station, nor did AECC's evaluation indicate any future planned shutdown. This means that the anticipated useful life of the boiler is expected to be at least as long as the capital cost recovery period of controls. Therefore, we believe it is appropriate to assume a 30-year amortization period in the PM BART analysis as the remaining useful life of the unit. As discussed in more detail below, AECC assumed a 15-year amortization period for control equipment in the BART analysis, but we do not believe this has an impact on our proposed BART decision and therefore we did not revise the amortization period and the average cost-effectiveness calculations for the PM control equipment options. This is discussed in more detail below in the subsection titled "Our Proposed PM BART Determination."

*Step 5- Evaluate Visibility Impacts*

As switching to lower sulfur fuels has impacts on both $SO_2$ and PM emissions, AECC's assessment of the visibility improvement associated with fuel switching is addressed in the $SO_2$ BART analysis for McClellan Unit 1, which is discussed under section II.C.1.b. of this TSD. Table 18 summarizes the visibility improvement associated with controlled emission rates for $SO_2$ and PM as a result of fuel switching.

AECC assessed the visibility improvement associated with wet ESPs, wet scrubbers, and cyclones by modeling the PM emission rates associated with each control option using CALPUFF, and then comparing the visibility impairment associated with the baseline emission rates to the visibility impairment associated with the controlled emission rates as measured by the 98th percentile modeled visibility impact. The controlled $PM_{10}$ emission rates associated with wet ESPs, wet scrubbers, and cyclones were calculated by reducing the uncontrolled annual $PM_{10}$ emission rates by the pollutant removal efficiency of each control technology. The $SO_2$ and $NO_X$ emission rates modeled in the controlled scenarios are the same as those from the baseline scenario, as it is assumed that $SO_2$ and $NO_X$ emissions would remain unchanged. The tables below show the emission rates modeled and a comparison of the existing (*i.e.*, baseline) visibility impacts and the visibility impacts of wet ESPs, wet scrubbers, and cyclones, including the maximum modeled visibility impact and the 98th percentile modeled visibility impact. The visibility improvement associated with each control scenario was calculated as the difference between the existing visibility impairment and the visibility impairment for each control scenario, as measured by the 98th percentile modeled visibility impact.

**Table 33. Summary of Emission Rates Modeled for PM Control Scenarios at McClellan Unit 1**

| Control | $SO_2$ (lb/hr) | $SO_4$ (lb/hr) | $NO_X$ (lb/hr) | $PM_C$ (lb/hr) | PMf (lb/hr) | SOA (lb/hr) | EC (lb/hr) | $PM_{10}$, total (lb/hr) |
|---|---|---|---|---|---|---|---|---|
| **Wet ESP** | 2,747.5 | 0.5 | 579.8 | 1.2 | 2.9 | 0.1 | 0.2 | 4.8 |
| **Wet Scrubber** | 2,747.5 | 2.2 | 579.8 | 5.2 | 12.9 | 0.4 | 1.0 | 21.7 |
| **Cyclone** | 2,747.5 | 4.8 | 579.8 | 1.7 | 4.3 | 0.8 | 0.3 | 7.2 |

**Table 34. AECC McClellan Unit 1: Summary of the 98th Percentile Visibility Impacts and Improvement from PM Controls**

| Class I area | Baseline Visibility Impact (Δdv) | Wet Scrubber | | Cyclone | | | Wet ESP | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. Wet Scrubber (Δdv) | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. Cyclone (Δdv) |
| Caney Creek | 0.621 | 0.619 | 0.002 | 0.619 | 0.002 | 0.000 | 0.617 | 0.004 | 0.002 |
| Upper Buffalo | 0.266 | 0.264 | 0.002 | 0.265 | 0.001 | -0.001 | 0.263 | 0.003 | 0.002 |
| Hercules-Glades | 0.230 | 0.228 | 0.002 | 0.229 | 0.001 | -0.001 | 0.227 | 0.003 | 0.002 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Mingo | 0.227 | 0.224 | 0.003 | | 0.225 | 0.002 | -0.001 | 0.223 | 0.004 | 0.005 |
| Cumulative Visibility Improvement ($\Delta$dv) | -- | -- | 0.009 | | -- | 0.006 | -- | -- | 0.014 | -- |

The table above shows that the operation of a wet ESP, wet scrubber, and cyclone at McClellan Unit 1 is projected to result in minimal visibility improvement at the four affected Class I areas. The modeled visibility improvement from switching to No. 6 fuel oil with 1% sulfur content, No. 6 fuel oil with 0.5% sulfur content, diesel, and natural gas is summarized in Table 18. These visibility improvement estimates reflect both $SO_2$ and PM emissions reductions as a result of switching to fuels with lower sulfur content. However, the majority of the baseline visibility impact at each Class I area when burning the baseline fuel oil at McClellan Unit 1 is due to $SO_2$ emissions, while $PM_{10}$ emissions contribute only a small portion of the baseline visibility impacts at each Class I area. Table 22 shows that the percentage of the visibility impairment at the four modeled Class I areas attributable to $PM_{10}$ ranges from approximately 0.5 – 3% for the fuel oil firing scenario. Most of the visibility impairment is attributable to $SO_4$ (67 – 99%) for the fuel oil firing scenario. Accordingly, the majority of the visibility improvement associated with switching to lower sulfur fuels can reasonably be expected to be the result of reduced $SO_2$ emissions.

**Our Proposed PM BART determination:**

Taking into consideration the five factors, we propose to determine that PM BART for the AECC McClellan Unit 1 does not require add-on controls. Consistent with our proposed determination for $SO_2$ BART, we are proposing that PM BART is satisfied by Unit 1 switching to fuels with 0.5% or lower sulfur content by weight. As discussed above, we disagree with AECC's use of a 15-year amortization period in the cost analysis for a wet ESP, wet scrubber, and cyclone. EPA is not aware of any enforceable shutdown date for the AECC McClellan Generating Station, and we believe the expected equipment life of these control technologies, which is at least 30 years, should be assumed to be the amortization period. Assuming a 30-year amortization period, these controls would have an improved cost-effectiveness (*i.e.*, less dollars per ton removed) than estimated in AECC's evaluation. However, after considering all five BART factors, AECC's assumption of a 15-year amortization period does not have an impact on our proposed BART decision. Even if we revised AECC's cost estimates to reflect a 30-year amortization period, resulting in a lower total annual cost and improved cost-effectiveness, we would still not be able to justify the costs of add-on controls in light of the minimal visibility benefit of these controls (see table above).

We are proposing to determine that PM BART for McClellan Unit 1 is switching to fuels with 0.5% or lower sulfur content by weight. We propose to require that the facility purchase no fuel after the effective date of the rule that does not meet the sulfur content requirement and that 5 years from the effective date of the rule no fuel be burned that does not meet the requirement. We expect this proposed compliance date would allow the facility sufficient time to burn its existing supply of No. 6 fuel oil (*i.e.*, the baseline fuel), as the normal course of business dictates and in accordance with any operating restrictions enforced by ADEQ. We propose that any higher sulfur fuel oil that remains from its 2009 shipment cannot be burned past this point.

### 3. AEP Flint Creek Power Plant

The AEP Flint Creek Power Plant Unit 1 is subject to BART. In our March 12, 2012 final action we disapproved the State's BART determinations for $SO_2$ and $NO_X$ for Flint Creek Unit 1 (77 FR 14604). AEP, through its consultant, performed a BART five factor analysis (AEP BART analysis), and our analysis of the five factors presented below is largely based on the technical work performed by AEP.[39]

Flint Creek Unit 1 is a dry bottom wall-fired boiler with a nominal generating capacity rating of 558 MW and a nominal design maximum heat input rate of 6,324 MMBtu/hr, and burns primarily low sulfur western coal. The unit is currently equipped with an ESP and low $NO_X$ burners.

#### a. Baseline Emission Rates and Existing Visibility Impairment Attributable to AEP Flint Creek Unit 1

AEP estimated $SO_2$, $NO_X$, and $PM_{10}$ baseline emission rates and then modeled these emission rates to determine the existing visibility impairment attributable to Flint Creek Unit 1 based on the default natural conditions. The baseline emission rates are shown in the table below.

**Table 35. AEP Flint Creek Unit 1: Baseline Maximum 24-Hour Emission Rates**

| Source | $SO_2$ (lb/hr) | $SO_4$ (lb/hr) | $NO_X$ (lb/hr) | PMc (lb/hr) | PMf (lb/hr) | SOA (lb/hr) | EC (lb/hr) |
|---|---|---|---|---|---|---|---|
| Unit 1 (SN-01) | 4,728.4 | 3.1 | 1,945.0 | 65.1 | 50.1 | 15.1 | 1.9 |

[39] See "BART Five Factor Analysis Flint Creek Power Plant Gentry, Arkansas (AFIN 04-00107)," dated September 2013, Version 4, prepared by Trinity Consultants Inc. in conjunction with American Electric Power Service Corporation for the Southwestern Electric Power Company Flint Creek Power Plant. A copy of this BART analysis is found in the docket for our proposed rulemaking.

The $SO_2$ and $NO_X$ baseline emission rates are the highest actual 24-hour emission rates based on 2001-2003 CEMS data. The emission rates for the $PM_{10}$ species reflect the breakdown of the filterable and condensable $PM_{10}$ determined from the National Park Service (NPS) "speciation spreadsheet" for *Dry Bottom Boiler Burning Pulverized Coal using only ESP*.[40] The sulfate ($SO_4$) emission rate was calculated using an EPRI methodology that considers the $SO_2$ to $SO_4$ conversion rate and $SO_4$ reduction factors for various downstream equipment.

AEP then modeled the baseline emission rates using the CALPUFF dispersion model to determine the baseline visibility impairment attributable to AEP Flint Creek Unit 1 at the Caney Creek Wilderness Area, Upper Buffalo Wilderness Area, Hercules-Glades Wilderness Area, and Mingo National Wildlife Refuge. The existing visibility impairment attributable to Flint Creek Unit 1 at each Class I area is summarized in the table below.

**Table 36. Baseline Visibility Impairment Attributable to AEP Flint Creek Unit 1 (2001-2003)**

| Year | Maximum ($\Delta$dv) | 98th Percentile ($\Delta$dv) | No. of Days with $\Delta dv \geq 0.5$ | 98th Percentile %$SO_4$ | 98th Percentile %$NO_3$ | 98th Percentile %$PM_{10}$ | 98th Percentile %$NO_2$ |
|---|---|---|---|---|---|---|---|
| Caney Creek 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 National Wildlife Refuge | | | | | | | |
| 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 |

### b. $SO_2$ BART Evaluation

[40] 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. AEP input the following parameters 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%.

Flint Creek Unit 1 primarily combusts low sulfur western coal, but is also permitted to burn fuel oil and tire derived fuels. Fuel oil firing is only allowed during unit startup and shutdown, startup and shutdown of pulverizer mills, for flame stabilization when coal is frozen, fuel oil tank maintenance, to prevent boiler tube failure in extreme cold weather when the unit is offline for maintenance, and malfunction. Sulfur oxides (or $SO_X$) are generated during coal and 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 generally not affected by boiler size or burner design. $SO_X$ emissions from conventional combustion systems are predominantly in the form of $SO_2$. The five factors considered in the $SO_2$ BART analysis are discussed below.

*Step 1- Identify All Available Retrofit Control Technologies*

The $SO_2$ control technologies considered in AEP's $SO_2$ BART analysis are Dry Sorbent Injection (DSI), a dry scrubber, and a wet scrubber.

*Step 2- Eliminate Technically Infeasible Options*

All $SO_2$ control technology options considered in the analysis were determined to be technically feasible options.

*Step 3- Evaluate Control Effectiveness of Remaining Control Technologies*:

DSI involves the injection of a sorbent into the exhaust 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 $SO_2$. In AEP's analysis, it was noted that depending on residence time, gas stream temperature, and limitations of the particulate control device, DSI control efficiency can range between 40 to 60%.[41]

In dry scrubbing systems, an alkaline reagent and water are introduced into the flue gas stream, where they react 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, leading to the formation of a dry powder which is carried out with the gas and collected with a fabric filter. Dry scrubber control efficiency ranges from 60 to 95%. There are various designs of dry scrubbing systems, including Spray Dryer Absorber (SDA), Circulating Dry Scrubbing (CDS), and Novel Integrated Desulfurization (NID) technology. According to AEP's evaluation, discussions with vendors indicated that an outlet emission rate of 0.06 lb/MMBtu at Flint Creek Unit 1 would be achievable with NID technology. In its analysis, AEP noted that it has no data to suggest that lower emission levels are sustainably achievable with the

[41] "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.

NID technology in a retrofit application, and that it was not guaranteed a better performance level by equipment vendors. An emission rate of 0.06 lb/MMBtu represents 92% control from the unit's baseline 30-day average rate of 0.75 lb/MMBtu.

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 ESP. AEP's analysis notes that wet lime scrubbing is capable of achieving 80 to 95% control when used with lower sulfur coals such as those burned at Flint Creek Unit 1.

The table below summarizes the controlled emission rates of $SO_2$ control technologies as evaluated by AEP. The remainder of AEP's analysis focused on the two control options with the highest control efficiency: wet scrubbing and dry scrubbing (NID).

**Table 37. Control Effectiveness of Technically Feasible $SO_2$ Control Technologies for AEP Flint Creek Unit 1**

| Control Technology | $SO_2$ Baseline Emission Rate (lb/MMBtu) | Controlled Emission Rate (lb/MMBtu) | Estimated Control Efficiency |
|---|---|---|---|
| Wet Scrubbing | 0.75 | 0.04 | 95% |
| Dry Scrubbing (NID) | | 0.06 | 92% |
| Dry Sorbent Injection | | 0.30 | 60% |

*Step 4- Evaluate Impacts and Document the Results*

The four factors considered in this step are the costs of compliance, energy and non-air quality environmental impacts of compliance, existing pollution control technology in use at the source, and the remaining useful life of the source.

The capital and operating costs of a wet scrubber and a dry scrubber (NID) estimated in AEP's analysis and used in the calculation of the average cost-effectiveness were based on the EPA Control Cost Manual and supplemented, where available, with vendor and site-specific information obtained by AEP.[42] AEP annualized the capital costs over a 30-year period and then

[42] See "BART Five Factor Analysis Flint Creek Power Plant Gentry, Arkansas (AFIN 04-00107)," dated September 2013, Version 4, prepared by Trinity Consultants Inc. in conjunction with American Electric Power Service Corporation for the Southwestern Electric Power Company Flint Creek Power Plant. AEP's $SO_2$ control cost calculations are found in Appendix A of the BART analysis. An Excel file titled "Consolidated Spreadsheet_2013-09-09" containing spreadsheets with cost information was also provided by AEP Flint Creek in support of the cost analysis. A copy of the BART analysis and the Excel file is found in the docket for our proposed rulemaking.

added these to the annual operating costs to obtain the total annualized costs. The annual emissions reductions 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, and the controlled annual emission rates were based on emission rate levels in lb/MMBtu believed to be achievable for the control technology multiplied by the baseline heat input to the boiler. AEP calculated the average cost-effectiveness in terms of dollars per ton of $SO_2$ reduced by dividing the total annualized cost of controls by the annual emissions reductions. AEP estimated the average cost-effectiveness of a wet scrubber at an $SO_2$ emission rate of 0.04 lb/MMBtu to be $4,919/ton of $SO_2$ removed, while the average cost-effectiveness of NID at an $SO_2$ emission rate of 0.06 lb/MMBtu was estimated to be $3,845/ton of $SO_2$ removed (see the table below).

We disagree with one aspect of AEP's cost analysis.[43] AEP's cost estimates are based on 2016 dollars. AEP escalated costs to a future build date, even though BART should be based on present dollars. The approach in the EPA Control Cost Manual explicitly excludes future escalation, as cost comparisons should be made on a current real dollar basis. Escalation of costs from past to the current year of analysis is permitted, as costs are compared based on the time of estimate, but future escalation is not allowed. We expect that de-escalation to 2014 dollars would result in lower cost numbers and an improved overall cost-effectiveness (*i.e.*, less dollars per ton removed) for all controls evaluated. However, we did not adjust the cost numbers and the cost-effectiveness values because we do not expect this to change our proposed BART decision. This is discussed in more detail below in the subsection titled "Our Proposed $SO_2$ BART Determination."

**Table 38. Summary of Cost of $SO_2$ Controls for AEP Flint Creek Unit 1**

| Control Technology | Baseline Emission Rate ($SO_2$ tpy) | Controlled Emission Rate ($SO_2$ lb/MMBtu) | Controlled Emission Rate ($SO_2$ tpy) | Annual Emissions Reductions ($SO_2$ tpy) | Capital Cost ($) | Capital Recovery & Other Indirect Annual Costs ($/yr) | Annual Fixed O&M ($/yr) | Annual Variable O&M ($/yr) | Total Annual Cost ($/yr) | Average Cost-Effectiveness ($/ton) | Incremental Cost-Effectiveness ($/ton) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| NIDS | 11,641 | 0.06 | 1,120 | 10,521 | 281,738,024 | 30,763,370 | 205,825 | 9,478,894 | 40,448,089 | 3,845 | - |
| Wet Scrubber | 11,641 | 0.04 | 747 | 10,894 | 374,427,351 | 40,884,248 | 205,825 | 12,502,590 | 53,592,663 | 4,919 | 35,240 |

AEP's evaluation noted that the potential negative energy and non-air quality environmental impacts are greater with wet scrubbing systems than dry scrubbing systems. AEP noted that wet scrubbers require increased water use and generate large volumes of wastewater

[43] *Id*.

and solid waste/sludge that must be treated or stabilized before landfilling, placing additional burden on the wastewater treatment and solid waste management capabilities. We do not expect that water availability would affect the feasibility of a wet scrubber at Flint Creek Unit 1 because the facility is not located in an exceptionally arid region. Additionally, the BART Guidelines provide that the fact that a control device creates liquid and solid waste that must be disposed of does not necessarily argue against selection of that technology as BART, particularly if the control device has been applied to similar facilities elsewhere (40 CFR Part 51, Appendix Y, section IV.D.4.i.2.). In cases where the facility can demonstrate that there are unusual circumstances that would create greater problems than experienced elsewhere, this may provide a basis for the elimination of that control option as BART. But in this case, AEP has not indicated that there are any such unusual circumstances. Another potential negative energy and non-air quality environmental impact associated with wet scrubbing systems is the potential for increased power requirements and greater reagent usage compared to dry scrubbers. The costs associated with increased power requirements and greater reagent usage have already been factored into the cost analysis for the wet scrubber.

The presence of existing pollution control technology at the source is reflected in the BART analysis in two ways: first, in the consideration of available control technologies, and second, in the development of baseline emission rates for use in cost calculations and visibility modeling. AEP Flint Creek Unit 1 has no existing $SO_2$ pollution control technology.

With regard to consideration of the remaining useful life of the unit, we are not aware of any enforceable shutdown date for AEP Flint Creek Unit 1, nor did AEP's evaluation indicate any future planned shutdown. This means that the anticipated useful life of the boiler is expected to be at least as long as the capital cost recovery period of controls. Therefore, we believe it is appropriate to assume a 30-year amortization period in the $SO_2$ BART analysis as the remaining useful life of the unit.

*Step 5- Evaluate Visibility Impacts*

AEP assessed the visibility improvement associated with a wet scrubber and NID technology by modeling the $SO_2$ emission rates associated with each control option using CALPUFF, and then comparing the visibility impairment associated with the baseline emission rates to the visibility impairment associated with the controlled emission rates, as measured by the 98$^{th}$ percentile modeled visibility impact. The modeled $SO_2$ emission rates associated with wet scrubbing and NID technology were calculated by multiplying the controlled emission level (*i.e.*, 0.04 lb/MMBtu for wet scrubbing and 0.06 lb/MMBtu for NID technology) by the boiler heat input of 6,324 MMBtu/hr. The $NO_X$ emission rate was modeled at the baseline rate for both the wet scrubbing and NID technology options. NID technology involves the use of a fabric filter, and the change from the existing ESP to a fabric filter will result in changes in PM speciation. AEP estimated this and all other rates that changed from the baseline case using the NPS speciation spreadsheets for dry bottom boilers burning pulverized coal using only fabric filter for emissions control. The tables below show the modeled emission rates and a comparison of the baseline (*i.e.*, existing) visibility impacts and the visibility impacts of a wet scrubber and NID technology, including the maximum modeled visibility impact and the 98th percentile modeled visibility impact for each Class I area. The visibility improvement associated with each control scenario was calculated as the difference between the existing visibility impairment and the visibility impairment for each control scenario as measured by the 98th percentile modeled visibility impact. The table below also shows the incremental visibility improvement of wet scrubbers over NID.

**Table 39. Summary of Emission Rates Modeled for $SO_2$ Control Scenarios at AEP Flint Creek Unit 1**

| Control Technology | $SO_2$ (lb/hr) | $SO_4$ (lb/hr) | $NO_X$ (lb/hr) | $PM_C$ (lb/hr) | PMf (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 |

**Table 40. AEP Flint Creek Unit 1: Summary of the 98th Percentile Visibility Impacts and Improvement Due to $SO_2$ Controls**

| Class I area | Baseline Visibility Impact (Δdv) | NID Technology | | Wet Scrubber | | |
|---|---|---|---|---|---|---|
| | | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. NID (Δdv) |
| Caney Creek | 0.963 | 0.348 | 0.615 | 0.334 | 0.629 | 0.014 |
| Upper Buffalo | 0.965 | 0.501 | 0.464 | 0.488 | 0.477 | 0.013 |
| Hercules-Glades | 0.657 | 0.312 | 0.345 | 0.305 | 0.352 | 0.007 |
| Mingo | 0.631 | 0.217 | 0.414 | 0.208 | 0.423 | 0.009 |
| Cumulative Visibility Improvement (Δdv) | -- | -- | 1.838 | -- | 1.881 | -- |

The table above shows that the installation and operation of $SO_2$ controls at Flint Creek Unit 1 is expected to result in considerable visibility improvement at the four modeled Class I areas. Installation and operation of NID technology is projected to result in visibility improvement of up to 0.615 dv at any single Class I area (based on the 98th percentile modeled visibility impacts), while a wet scrubber is projected to result in visibility improvement of up to 0.629 dv. A wet scrubber is projected to result in very minimal incremental visibility benefit over NID technology, with the projected incremental visibility improvement over NID ranging from 0.007 to 0.014 dv at each Class I area.

**Our Proposed $SO_2$ BART Determination:**

Taking into consideration the five factors, we propose to determine that BART for Flint Creek Unit 1 is an emission limit of 0.06 lb/MMBtu on a 30 boiler-operating-day rolling average based on the installation and operation of NID. The operation of NID is expected to result in visibility improvement ranging from 0.352 to 0.629 dv at each affected Class I area (98th percentile basis), and based on AEP's evaluation, is estimated to have an average cost-effectiveness of $3,845/ton of $SO_2$ removed. By comparison, AEP estimated a wet scrubber to have an average cost-effectiveness of $4,919/ton of $SO_2$ removed and the incremental cost-effectiveness of wet scrubbers compared to NID is estimated to be $35,240 per ton of $SO_2$ removed. As discussed above, we believe that AEP's escalation of the cost of controls to 2016 dollars has likely resulted in the over estimation of the average cost-effectiveness values. Therefore, we believe a wet scrubber and NID are more cost-effective (*i.e.*, less dollars per ton of $SO_2$ removed) than estimated by AEP (see table above). However, we did not adjust the cost numbers and cost-effectiveness values because we do not believe that doing so would change our proposed BART determination. We believe that the average cost-effectiveness of both control options was likely over-estimated and the costs associated with a wet scrubber would continue to be higher than the costs associated with NID if the estimates were adjusted, yet the installation and operation of a wet scrubber is projected to result in minimal incremental visibility improvement over NID. We are proposing to determine that $SO_2$ BART for Flint Creek Unit 1 is an emission limit of 0.06 lb/MMBtu on a 30 boiler-operating-day rolling average based on the installation and operation of NID. We believe that the full compliance time[44] of 5 years is warranted for a new scrubber retrofit and so propose to require compliance with this requirement no later than 5 years from the effective date of the final rule.

### c. $NO_X$ BART Evaluation

Nitrogen oxides, or $NO_X$, are produced during fuel combustion when nitrogen contained in both the fuel and the combustion air is exposed to high temperatures. Nitrogen oxide (NO) is typically the predominant form of $NO_X$ from fossil fuel combustion, with nitrogen dioxide ($NO_2$) making up the remainder of the $NO_X$. AEP's evaluation noted that the formation of $NO_X$ compounds in utility boilers is sensitive to the method of firing and combustion flame

[44] Section 51.308(e)(1)(iv), requires, "each source subject to BART be required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision."

temperatures. In a wall-fired boiler, such as Flint Creek Unit 1, 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 combustion flame temperatures, among other factors. The baseline $NO_X$ emission rate for Flint Creek Unit 1 was discussed under section II.C.2.a. of this TSD. The five factors considered in the $NO_X$ BART analysis are discussed below.

*Step 1- Identify All Available Retrofit Control Technologies*

The NOx control technologies considered in AEP's $NO_X$ BART report include both combustion and post-combustion controls. The combustion controls evaluated consisted of FGR, OFA, and LNB. The post-combustion controls evaluated consisted of SCR and SNCR.

*Step 2- Eliminate Technically Infeasible Options*

All evaluated $NO_X$ control options were found to be technically feasible.

*Step 3- Evaluate Control Effectiveness of Remaining Control Technologies*:

The estimated $NO_X$ controlled emission rate of each control option considered by AEP is shown in the table below. The baseline $NO_X$ emission rate for Flint Creek Unit 1 is approximately 0.31 lb/MMBtu. AEP's evaluation stated that based on experience with similar boilers and discussions with vendors, it is estimated that the installation and operation of new LNB in combination with OFA at Flint Creek Unit 1 would achieve a $NO_X$ control level of approximately 0.23 lb/MMBtu. It also estimated that new LNB/OFA in combination with SNCR would achieve a $NO_X$ control level of approximately 0.2 lb/MMBtu, and SCR would achieve a $NO_X$ control level of approximately 0.067 lb/MMBtu.

**Table 41. Control Effectiveness of Technically Feasible $NO_X$ Control Technologies- AEP Flint Creek Unit 1**

| Control Technology | Estimated Controlled Level for Flint Creek Unit 1 (lb/MMBtu) |
|---|---|
| SCR | 0.067 |
| LNB/OFA + SNCR | 0.18 – 0.23 |
| 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 |

*Step 4- Evaluate Impacts and Document the Results*

The four factors considered in this step are the costs of compliance, energy and non-air quality environmental impacts of compliance, existing pollution control technology in use at the source, and the remaining useful life of the source.

AEP estimated the capital costs, operating costs, and average cost-effectiveness of $NO_X$ controls based on vendor estimates and published calculation methods.[45] AEP noted that the cost analysis followed the EPA Control Cost Manual to the extent possible and estimates were supplemented with vendor and site-specific information where available. The cost analysis assumed a 30-year amortization period for LNB with OFA and for SCR, and a 20-year amortization period for SNCR. The total annual costs were estimated by annualizing the capital cost of controls over either a 30-year or 20-year period and then adding to this value the annual operating cost of controls. AEP determined the annual emissions reductions associated with each $NO_X$ control option 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 Flint Creek in the 2001-2003 air emission inventories, while the controlled annual emission rates are based on the lb/MMBtu levels believed to be achievable from the control technology multiplied by the baseline heat inputs to the boilers in MMBtu/yr. The baseline heat input is based on the 2001-2003 average daily heat input for Flint Creek Unit 1 as determined from the EPA's Clean Air Markets Database (CAMD).

The average cost-effectiveness of $NO_X$ controls was calculated by dividing the total annual cost of each control option by the estimated annual $NO_X$ emissions reductions. The table below summarizes the average-cost effectiveness of $NO_X$ controls for Flint Creek Unit 1.

[45] See "BART Five Factor Analysis Flint Creek Power Plant Gentry, Arkansas (AFIN 04-00107)," dated September 2013, Version 4, prepared by Trinity Consultants Inc. in conjunction with American Electric Power Service Corporation for the Southwestern Electric Power Company Flint Creek Power Plant. AEP's $NO_X$ control cost calculations are found in Appendix B of the BART analysis. An Excel file titled "Consolidated Spreadsheet_2013-09-09" containing spreadsheets with cost information was also provided by AEP Flint Creek in support of the cost analysis. A copy of the BART analysis and the Excel file is found in the docket for our proposed rulemaking.

**Table 42. Summary of $NO_X$ Controls for AEP Flint Creek Unit 1**

| Control Technology | Baseline $NO_X$ Emission Rate (tpy) | Controlled Emission Level (lb/MMBtu) | Controlled Emission Rate ($NO_X$ tpy) | Annual Emissions Reductions ($NO_X$ tpy) | Capital Cost ($) | Annual Capital Cost ($.yr) | Annual Fixed O&M ($/yr) | Annualized Variable O&M ($/yr) | Total Annual Cost ($/yr) | Average Cost-Effectiveness ($/ton) | Incremental Cost-Effectiveness ($/ton) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **LNB/OFA** | 5,120.27 | 0.23 | 4,294.65 | 825.62 | 16,000,000 | 1,289,382 | 240,000 | 132,364 | 1,454,621 | 1,761 | - |
| **LNB/OFA/SNCR** | 5,120.27 | 0.20 | 3,771.82 | 1,348.45 | 23,124,235 | 1,961,860 | 240,000 | 2,183,048 | 4,177,782 | 3.098 | 5,217 |
| **SCR** | 5,120.27 | 0.07 | 1,251.05 | 3,869.22 | 121,440,000 | 9,786,413 | 1,560,000 | 3,700,000 | 13,769,599 | 3,559 | 3,805 |

Based on AEP's cost evaluation for Flint Creek Unit 1, the average cost-effectiveness of installing and operating LNB/OFA is $1,761/ton of $NO_X$ removed. The average cost-effectiveness of LNB/OFA + SNCR is $3,098/ton of $NO_X$ removed, while that of SCR is $3,559/ton of $NO_X$ removed. The incremental cost-effectiveness of LNB/OFA + SNCR compared to LNB/OFA is $5,217/ton of $NO_X$ removed, while that of SCR compared to LNB/OFA + SNCR is $3,805/ton of $NO_X$ removed.

AEP did not identify any energy or non-air quality environmental impacts associated with the use of LNB or OFA. As for SCR and SNCR, we are not aware of any unusual circumstances at the facility that could create energy or non-air quality environmental impacts associated with the operation of these controls greater than experienced elsewhere and that may therefore provide a basis for their elimination as BART (40 CFR Part 51, Appendix Y, section IV.D.4.i.2.). Therefore, we do not believe there are any energy or non-air quality environmental impacts associated with the operation of $NO_X$ controls at AEP Flint Creek Unit 1 that would affect our proposed BART determination.

AEP Flint Creek Unit 1 is currently equipped with early generation low $NO_X$ burners for control of $NO_X$ emissions. The presence of existing pollution control technology at each source is reflected in the BART analysis in two ways: first, in the consideration of available control technologies, and second, in the development of baseline emission rates for use in cost calculations and visibility modeling. The baseline emission rate used in the cost calculations and visibility modeling reflects the operation of these controls. The newer generation low $NO_X$ burners evaluated by AEP are expected to achieve a higher level of $NO_X$ control than the currently installed early generation low $NO_X$ burners.

With regard to consideration of the remaining useful life of the unit, we are not aware of any enforceable shutdown date for the AEP Flint Creek Unit 1, nor did AEP's evaluation indicate any future planned shutdown. This means that the anticipated useful life of the boiler is expected to be at least as long as the capital cost recovery period of controls. AEP assumed a 30-year amortization period in the evaluation of LNB/OFA and SCR and a 20-year amortization period in the evaluation of SNCR. We disagree with AEP's assumption of a 20-year amortization period in the cost analysis of SNCR. Any air pollution controls on the unit are expected to have the same life as the boiler. Therefore, we believe it is appropriate to assume a 30-year amortization period for SNCR, as was done for SCR and combustion controls. Assuming a 30-year amortization period, SNCR would have a lower estimated total annual cost and would therefore be more cost-effective (i.e., less dollars per ton removed) than estimated in AEP's evaluation. However, we did not adjust the amortization period assumed in AEP's evaluation because we do not believe this has an impact on our proposed BART decision. As discussed in the subsection below, the incremental visibility benefit expected from the installation and operation of SNCR is too small to justify the cost of these controls compared to combustion controls alone. Therefore, we did not revise the amortization period and the average cost-effectiveness calculations for SNCR.

*Step 5- Evaluate Visibility Impacts*

AEP assessed the visibility improvement associated with $NO_X$ controls by modeling the $NO_X$ emission rates associated with each control option using CALPUFF, and then comparing the visibility impairment associated with the baseline emission rates to the visibility impairment associated with the controlled emission rates. The controlled emission levels associated with combustion controls, combustion controls + SNCR, and SCR systems are shown in the table above (see third column). These levels were multiplied by the unit's maximum heat input to derive the hourly emission rates used in the modeling. The tables below show the modeled emission rates and a comparison of the existing (*i.e.*, baseline) visibility impacts and the visibility impacts associated with $NO_X$ controls, including the maximum modeled visibility impact and the 98$^{th}$ percentile modeled visibility impact for each Class I area. The visibility improvement over the baseline was calculated as the difference between the baseline visibility impairment and the visibility impairment associated with each control scenario. The incremental visibility improvement of LNB/OFA + SNCR was calculated as the difference in visibility improvement between LNB/OFA + SNCR and LNB/OFA. The incremental visibility improvement of SCR was calculated as the difference in visibility improvement between SCR and LNB/OFA + SNCR.

**Table 43. Summary of Emission Rates Modeled for $NO_X$ Control Scenarios at AEP Flint Creek Unit 1**

| Control Technology | $SO_2$ (lb/hr) | $SO_4$ (lb/hr) | $NO_X$ (lb/hr) | PM (lb/hr) | $PM_F$ (lb/hr) | SOA (lb/hr) | EC (lb/hr) |
|---|---|---|---|---|---|---|---|
| LNB/OFA | 4728.4 | 3.1 | 1454.5 | 65.1 | 50.1 | 15.1 | 1.9 |
| SCR | 4728.4 | 3.1 | 423.7 | 65.1 | 50.1 | 15.1 | 1.9 |
| LNB/OFA + SNCR | 4728.4 | 3.1 | 1277.74 | 65.1 | 50.1 | 15.1 | 1.9 |

**Table 44. AEP Flint Creek Unit 1: Summary of 98th Percentile Visibility Improvement Due to $NO_X$ Controls**

| Class I area | Baseline Visibility Impact (Δdv) | LNB/OFA | | LNB/OFA + SNCR | | | SCR | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. LNB/OFA (Δdv) | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. LNB/OFA + SNCR (Δdv) |
| Caney Creek | 0.963 | 0.882* | 0.081* | 0.849 | 0.114 | 0.033* | 0.718 | 0.245 | 0.131 |
| Upper Buffalo | 0.965 | 0.939 | 0.026 | 0.932 | 0.033 | 0.007 | 0.895 | 0.070 | 0.037 |
| Hercules-Glades | 0.657 | 0.633 | 0.024 | 0.623 | 0.034 | 0.010 | 0.573 | 0.084 | 0.050 |
| Mingo | 0.631 | 0.617 | 0.014 | 0.612 | 0.019 | 0.005 | 0.588 | 0.043 | 0.024 |
| Cumulative Visibility Improvement (Δdv) | -- | -- | 0.145 | -- | 0.2 | 0.055 | -- | 0.442 | 0.242 |

*EPA identified a discrepancy in the results presented by AEP and reran the model for the 2003 model year. These values have been adjusted to reflect the results of the EPA model run.

The table above summarizes the modeled baseline visibility impact and the modeled visibility improvement due to the installation and operation of controls at the four Class I areas within 300 km of the facility. We note that we identified a discrepancy in the results presented by AEP and reran the model for the 2003 model year. The modeled visibility impacts at Caney Creek for the LNB/OFA scenario and the incremental visibility improvement between LNB/OFA and LNB/OFA + SNCR were adjusted to reflect the results of this model run. The table above shows that the installation and operation of LNB/OFA at Flint Creek Unit 1 is projected to result in visibility improvement ranging from 0.014 to 0.081 dv at each modeled Class I area, based on the $98^{th}$ percentile visibility impairment. The installation and operation of LNB/OFA + SNCR is projected to result in visibility improvement of up to 0.114 dv at each modeled Class I area over the baseline. The combination of LNB/OFA + SNCR is projected to result in small incremental visibility benefit over LNB/OFA at Caney Creek and negligible incremental visibility benefit over LNB/OFA at the other three affected Class I areas. The installation and operation of SCR is projected to result in visibility improvement ranging from 0.043 to 0.245 dv at each modeled Class I area. SCR would result in 0.131 dv incremental visibility benefit over LNB /OFA + SNCR at Caney Creek and less than half as much incremental visibility benefit at the other three affected Class I areas.

**Our Proposed $NO_X$ BART determination:**

Taking into consideration the five factors, we propose to determine that BART for Flint Creek Unit 1 is an emission limit of 0.23 lb/MMBtu on a 30 boiler-operating-day rolling average based on the installation and operation of new LNB/OFA. The operation of new LNB/OFA is projected to result in visibility improvement ranging from 0.014 to 0.081 dv at each affected Class I area (98$^{th}$ percentile basis), and a cumulative visibility improvement of 0.145 Δdv across the four affected Class I areas. The installation and operation of LNB/OFA is estimated to have an average cost-effectiveness of $1,762/ton of $NO_X$ removed, which we consider to be very cost-effective. By comparison, the operation of LNB/OFA + SNCR is projected to result in small incremental visibility improvement over LNB/OFA, but is estimated to have an average cost-effectiveness of $3,098/ton of $NO_X$ removed and an incremental cost-effectiveness of $5,217/ton of $NO_X$ removed. We believe that AEP's assumption of a 20-year amortization period for SNCR has likely resulted in the over-estimation of the average cost-effectiveness value. Therefore, we believe LNB/OFA + SNCR is more cost-effective (i.e., less dollars per ton of $NO_X$ removed) than estimated by AEP (see table above). However, we did not adjust the cost numbers and cost-effectiveness values because we do not believe that doing so would change our proposed BART determination, as the installation and operation of LNB/OFA with SNCR is projected to result in minimal incremental visibility improvement over LNB/OFA alone such that the additional cost of SNCR is not justified.

The operation of SCR is projected to result in visibility improvement ranging from 0.043 to 0.245 Δdv at each Class I area, and has an average cost-effectiveness of $3,559/ton of $NO_X$ removed. The incremental visibility benefit of SCR compared to LNB/OFA + SNCR is a maximum of 0.131 dv at any single Class I area, and the incremental cost-effectiveness is estimated to be $3,805/ton of $NO_X$ removed. While we believe the average and incremental cost-effectiveness of SCR, as estimated by AEP, is within the range of what we consider to be cost-effective, we do not believe the 0.131 dv incremental visibility benefit of SCR over LNB/OFA + SCNR warrants the higher costs associated with SCR. We are proposing to determine that $NO_X$ BART for Flint Creek Unit 1 is an emission limit of 0.23 lb/MMBtu on a 30 boiler-operating-day rolling average based on the installation and operation of new LNB/OFA. We consider 3 years to be an adequate time for the installation of $NO_X$ combustion controls and thus propose to require compliance with this requirement no later than 3 years from the effective date of the final rule.

**4. Entergy White Bluff Power Plant**

The Entergy White Bluff Power Plant Units 1 and 2, and the Auxiliary Boiler are subject to BART. In our March 12, 2012 final action we disapproved the State's BART determinations for $SO_2$ and $NO_X$ for Units 1 and 2 and the BART determination for all pollutants for the Auxiliary Boiler (77 FR 14604). Entergy, through its consultant, performed a BART five factor analysis (Entergy BART analysis), and our analysis of the five factors presented below is largely based on the technical work performed by Entergy.[46]

White Bluff Units 1 and 2 are identical tangentially-fired boilers each with a maximum net power rating of 850 MW and a nominal heat input capacity of 8,950 MMBtu/hr. The boilers burn sub-bituminous coal as the primary fuel and No. 2 fuel oil or biofuel as a start-up fuel. Units 1 and 2 are currently equipped with ESPs for control of PM emissions. The Auxiliary Boiler is a 183 MMBtu/hr auxiliary boiler that burns only No. 2 fuel oil or biodiesel, and its purpose is to provide steam for the start-up of the two primary boilers, Units 1 and 2. The Auxiliary Boiler is typically only used in the rare instance when both of the main boilers are not operating.

### a. Baseline Emission Rates and Existing Visibility Impairment Attributable to White Bluff Units 1, 2, and Auxiliary Boiler

Entergy estimated $SO_2$, $NO_X$, and $PM_{10}$ baseline emission rates and then modeled these emission rates to determine the existing visibility impairment attributable to White Bluff Units 1 and 2 and the Auxiliary Boiler based on the default natural conditions. The baseline emission rates are from actual emissions based on CEMS data, stack testing, and annual emissions inventory information. The baseline emission rates are shown in the table below.

**Table 45. Entergy White Bluff: Baseline Maximum 24-Hour Emission Rates**

| Subject to BART Unit | $SO_2$ (lb/hr) | $NO_X$ (lb/hr) | Total $PM_{10}$ (lb/hr) | $SO_4$ (lb/hr) | PMc (lb/hr) | PMf (lb/hr) | SOA (lb/hr) | EC (lb/hr) |
|---|---|---|---|---|---|---|---|---|
| Unit 1 (SN-01) | 7,763.5 | 3,001.4 | 118.6 | 36.8 | 40.4 | 31.1 | 9.2 | 1.2 |
| Unit 2 (SN-02) | 7,825.1 | 3,527.4 | 118.6 | 36.8 | 40.4 | 31.1 | 9.2 | 1.2 |
| Auxiliary Boiler (SN-05) | 5.8 | 31.7 | 2.8 | 0.9 | 0.5 | 1.2 | 0.2 | 0.1 |

The $SO_2$ and $NO_X$ baseline 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 $NO_X$.

The 2001-2003 period was not used as the baseline for $NO_X$ because that period no longer represents actual operation of the boilers. In 2006, Entergy completed the addition of a

[46] See "Revised BART Five Factor Analysis White Bluff Steam Electric Station Redfield, Arkansas (AFIN 35-00110)," dated October 2013, prepared by Trinity Consultants Inc. in conjunction with Entergy Services Inc. A copy of this BART analysis is found in the docket for our proposed rulemaking.

neural network system and conducted extensive boiler tuning that substantially reduced $NO_X$ emissions, resulting in an actual change in operations and emissions between the original baseline period (2001-2003) and current operations. Neural network systems are online enhancements to digital control systems (DCS) and plant information systems that improve boiler performance parameters such as heat rate, $NO_X$ emissions, and carbon monoxide (CO) levels. According to information provided by the facility, the purpose of the neural network system was to monitor and control the heat rate at Units 1 and 2.[47] The neural network system installed at Units 1 and 2 is optimized first for monitoring and controlling the heat rate, and second for minimizing $NO_X$ emissions. We believe the use of 2009-2011 as the new baseline period for $NO_X$ is consistent with the BART Guidelines, which provide that "The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source" (40 CFR Part 51, Appendix Y, Section IV.D.4.c).

The $PM_{10}$ emission rates are based on emission factors from AP-42 for $PM_{10}$ filterable and PM condensable with a 99% 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) "speciation spreadsheet" for Dry Bottom Boiler Burning Pulverized Coal using only ESP.[48] To estimate sulfuric acid emissions to model for the baseline and control cases, Entergy assumed all inorganic PM was $SO_4$. We note that this methodology can overestimate the amount of sulfuric acid emitted from the facility and we recommend that sulfuric acid emissions from power plants be calculated by estimating the amount of $H_2SO_4$ produced and the amount of $H_2SO_4$ removed by control equipment using information from the Electric Power Research Institute (EPRI).[49] Rather than assuming that 100% of inorganic condensable PM is $SO_4$, the EPRI method estimates the amount of $SO_2$ that is oxidized to $SO_3$, assumes that 100% of $SO_3$ is converted to $H_2SO_4$, and then accounts for losses due to downstream equipment. The sulfuric acid emissions for the base and control scenarios may be somewhat overestimated in Entergy's modeling. However, in this specific situation, we do not anticipate that this difference would significantly impact the relative benefits of the $SO_2$ controls examined or impact our BART determination since the overall impacts and benefits of control are large.

[47] See the "S&L $NO_X$ Control Technology Study," which is found in Appendix E to the "Revised BART Five Factor Analysis White Bluff Steam Electric Station Redfield, Arkansas (AFIN 35-00110)," dated October 2013, prepared by Trinity Consultants Inc. in conjunction with Entergy Services Inc. A copy of this BART analysis and its appendices is found in the docket for our proposed rulemaking.

[48] 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. Entergy input the following parameters 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%, ash content of 4.87%.

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

Entergy then modeled the baseline emission rates using the CALPUFF dispersion model to determine the baseline visibility impairment attributable to White Bluff Unit 1, Unit 2, and the Auxiliary Boiler at the Caney Creek Wilderness Area, Upper Buffalo Wilderness Area, Hercules-Glades Wilderness Area, and Mingo National Wildlife Refuge. The existing visibility impairment attributable to White Bluff Units 1 and 2 and the Auxiliary Boiler at each Class I area is summarized in the tables below.

**Table 46. Baseline Visibility Impairment Attributable to White Bluff Unit 1**

| Year | Maximum ($\Delta$dv) | 98th Percentile ($\Delta$dv) | No. of Days with $\Delta dv \geq 0.5$ | 98th Percentile $\%SO_4$ | 98th Percentile $\%NO_3$ | 98th Percentile $\%PM_{10}$ | 98th Percentile $\%NO_2$ |
|---|---|---|---|---|---|---|---|
| Caney Creek 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 National Wildlife Refuge | | | | | | | |
| 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 47. Baseline Visibility Impairment Attributable to White Bluff Unit 2**

| Year | Maximum ($\Delta$dv) | 98th Percentile ($\Delta$dv) | No. of Days with $\Delta dv \geq 0.5$ | 98th Percentile $\%SO_4$ | 98th Percentile $\%NO_3$ | 98th Percentile $\%PM_{10}$ | 98th Percentile $\%NO_2$ |
|---|---|---|---|---|---|---|---|
| Caney Creek 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 National Wildlife Refuge | | | | | | | |
| 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 48. Baseline Visibility Impairment Attributable to White Bluff Auxiliary Boiler**

| Year | Maximum ($\Delta$dv) | 98th Percentile ($\Delta$dv) | No. of Days with $\Delta dv \geq 0.5$ | 98th Percentile $\%SO_4$ | 98th Percentile $\%NO_3$ | 98th Percentile $\%PM_{10}$ | 98th Percentile $\%NO_2$ |
|---|---|---|---|---|---|---|---|
| Caney Creek 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 National Wildlife Refuge | | | | | | | |
| 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 |

### b. $SO_2$ BART Evaluation for Units 1 and 2

White Bluff Units 1 and 2 burn sub-bituminous coal as the primary fuel and No. 2 fuel oil or biofuel as a start-up fuel, while the Auxiliary boiler burns only No. 2 fuel oil or biodiesel. Sulfur oxides, or $SO_X$, are generated during fuel 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 $SO_2$. The five factors considered in the $SO_2$ BART analysis are discussed below.

*Step 1- Identify All Available Retrofit Control Technologies*

The $SO_2$ control technologies considered in Entergy's $SO_2$ BART analysis are DSI, dry FGD, and wet FGD.

*Step 2- Eliminate Technically Infeasible Options*

All $SO_2$ control technology options considered in the analysis were determined to be technically feasible options.

*Step 3- Evaluate Control Effectiveness of Remaining Control Technologies*:

DSI involves the injection of a sorbent into the exhaust 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 sorbet and entrained $SO_2$. Entergy's evaluation noted that depending on residence time, gas stream temperature, and limitations of the particulate control device, the control efficiency of dry sorbent injection can range between 40 – 60%.[50]

There are various designs of dry FGD systems, including SDA and CDS designs. Dry FGD control efficiencies range from 60 to 95%.[51] Wet FGD is generally capable of achieving 80-95% control, but can achieve up to 98% control efficiency.[52] Entergy's analysis noted that engineering evaluations conducted by Sargent & Lundy suggested that a control efficiency of up to 97% may be achievable at Units 1 and 2 through the application of wet FGD when burning higher-sulfur coals, but that Entergy was not able to obtain vendor guarantees for greater than 95% control from wet FGD for the two units.[53] Despite the lack of vendor assurances, Entergy evaluated wet FGD at an outlet $SO_2$ emission rate of 0.04 lb/MMBtu. The remainder of Entergy's analysis focused on the two control options with the highest control efficiency: wet FGD and dry FGD.

*Step 4- Evaluate Impacts and Document the Results*

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[50] "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.

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

[52] *Id.*

[53] See "Revised BART Five Factor Analysis White Bluff Steam Electric Station Redfield, Arkansas (AFIN 35-00110)," dated October 2013, prepared by Trinity Consultants Inc. in conjunction with Entergy Services Inc., Page 5-3.

The four factors considered in this step of the analysis are the costs of compliance, energy and non-air quality environmental impacts of compliance, the existing pollution control technology in use at the source, and the remaining useful life of the source.

**Our Dry Scrubbing Cost Analysis for Entergy White Bluff:**

Entergy's estimates of the capital and direct operating and maintenance costs of a dry scrubber were based on vendor estimates. Estimates of the indirect operating costs were based on calculation methods from our Control Cost Manual. The estimates of the capital and operating and maintenance costs of wet FGD were based on vendor estimates obtained by Entergy for a system estimated to achieve 97% control and calculation methods from our Control Cost Manual.

We have reviewed the cost analysis that is part of Entergy's evaluation and have analyzed it for compliance with the Regional Haze Rule, and disagree with several aspects of the cost analysis and have made adjustments to it as necessary.[54] First, we found that Entergy assumed in its dry FGD cost analysis that it will burn a coal corresponding to an uncontrolled $SO_2$ emission rate of 2.0 lb/MMBtu – far in excess of the sulfur level of the coals it has historically burned, presumably for future fuel flexibility. For the years 2009-2013, the maximum monthly $SO_2$ emission rate for Unit 1 is 0.653 lbs/MMBtu and that for Unit 2 is 0.679 lbs/MMBtu. Thus, Entergy has costed $SO_2$ dry FGD systems for the White Bluff facility that are overdesigned compared to its historical needs. Such a system, being capable of a much higher level of sulfur removal than is currently required, has a correspondingly higher cost. Entergy selected its $SO_2$ emission baseline by using "the average rate from 2001-2003, as reported by Entergy in their air emission inventories,"[55] while selecting its annualized costs based on a 2.0 lb/MMBtu coal. In calculating baseline emissions, the BART Guidelines assume the source in question is otherwise unchanged in the future, except for the addition of BART controls.[56] Thus, we believe it is appropriate to adjust the cost analysis presented in Entergy's report.[57] Additionally, the cost estimate for dry FGD presented in Entergy's report includes line items that have not been documented, appear to be already covered in other cost items, or do not appear to be valid costs under our Control Cost Manual methodology. This includes line items such as

[54] See "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)." A copy of this document is found in the docket for our proposed rulemaking.
[55] Revised Bart Five Factor Analysis, White Bluff Steam Electric Station, Redfield, Arkansas (AFIN 35-00110), dated October 2013, prepared by Trinity Consultants Inc. in conjunction with Entergy Services Inc., Page 5-5.
[56] 70 FR 39167.
[57] See "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)," for a detailed discussion of how Entergy's cost analysis was adjusted.

capital suspense,[58] Entergy internal costs, and certain line items under balance of plant (BOP) costs. Please see our $SO_2$ Cost TSD for more details concerning the adjustments we propose to make to the White Bluff dry FGD cost analysis. A summary of our adjusted cost analysis, which is based on 2013 dollars, is presented in the table below.

**Table 49. Summary of EPA Dry FGD Cost Analysis for White Bluff Units 1 and 2**

| Item | White Bluff Unit 1 | White Bluff Unit 2 |
|---|---|---|
| Total Annualized Cost | $31,981,230 | $31,981,230 |
| Interest Rate (%) | 7 | 7 |
| Equipment Lifetime (years) | 30 | 30 |
| Capital Recovery Factor (CRF) | 0.0806 | 0.0806 |
| $SO_2$ Emission Rate (lbs/MMBtu) | 0.65 | 0.68 |
| Controlled $SO_2$ Emission Rate (%) | 90.81 | 91.16 |
| $SO_2$ Emission Baseline (tons) | 15,816 | 16,697 |
| $SO_2$ Emission Reduction (tons) | 14,363 | 15,221 |
| Cost Effectiveness ($/ton) | $2,227 | $2,101 |

**Our Wet Scrubbing Cost Analysis for Entergy White Bluff:**

Entergy uses a 2012 contractor wet FGD estimate for the White Bluff Units 1 and 2 as the starting point for its cost analysis.[59] It then used multiplier approximations from our Control Cost Manual[60] to calculate the Total Capital Investment (TCI). Entergy then calculated the direct annual costs, using fixed and variable O&M costs from another 2011 contractor cost summary as

[58] Entergy states 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. Function specific capital suspense is dependent upon the personal hours allocated to a specific project for a time period. However, the percent of a total project that is dedicated to capital suspense is not a constant. Rather, it is dependent upon the yearly total capital expense budget and the budgeted capital spending for a specific function." See Entergy Response to EPA Region 6 comments on Entergy White Bluff draft BART Report 06/10/13, Page 9. A copy of this document is found in the docket for this proposed rulemaking.

[59] White Bluff Station Unit 1 & 2, Wet FGD - 2.0 lb/MMBtu, Order Of Magnitude Cost Estimate Summary. Attached as Attachment C to the 6/10/13 Entergy Response to EPA comments on the White Bluff draft BART Report. Pdf page 29.

[60] Section 5.2 Post-Combustion Controls, Chapter 1 – Wet Scrubbers for Acid Gas, Table 1.3.

a surrogate for the apparently unavailable direct annual costs from the 2012 estimate.[61] Following this, Entergy calculated the indirect annual costs using additional multiplier approximations from our Control Cost Manual.[62] Lastly, Entergy calculated the annualized capital cost in the usual manner by multiplying the TCI by the capital recovery factor.

As with its dry FGD cost estimates, Entergy designed its wet FGD systems to burn coal corresponding to an uncontrolled $SO_2$ emission rate of 2.0 lb/MMBtu, which are overdesigned compared to its historical needs. Please see our $SO_2$ Cost TSD for more details concerning the adjustments we propose to make to the White Bluff wet FGD cost analysis, which is similar to our dry FGD analysis. A summary of our adjusted cost analysis, which is based on 2013 dollars, is presented in the table below:

**Table 50. Summary of EPA Wet FGD Cost Analysis for White Bluff Units 1 and 2**

| Item | White Bluff Unit 1 | White Bluff Unit 2 |
|---|---|---|
| Total Annualized Cost | $49,526,167 | $49,526,167 |
| Interest Rate (%) | 7 | 7 |
| Equipment Lifetime (years) | 30 | 30 |
| Capital Recovery Factor (CRF) | 0.0806 | 0.0806 |
| $SO_2$ Emission Rate (lbs/MMBtu) | 0.65 | 0.68 |
| Controlled $SO_2$ Emission Rate (%) | 93.87 | 94.11 |
| $SO_2$ Emission Baseline (tons) | 15,816 | 16,697 |
| $SO_2$ Emission Reduction (tons) | 14,847 | 15,713 |
| Cost Effectiveness ($/ton) | $3,336 | $3,152 |

Entergy's evaluation noted that while wet FGD is expected to achieve a slightly higher level of control of $SO_2$ emissions compared to dry FGD, the potential negative energy and non-air quality environmental impacts are greater with wet FGD systems. Entergy noted that wet FGD systems require increased water use and generate large volumes of wastewater and solid waste/sludge that must be treated or stabilized before landfilling, placing additional burden on the wastewater treatment and solid waste management capabilities. However, we do not expect

[61] 6/10/13 Entergy Response to EPA comments on the White Bluff draft BART Report. Pdf page 11. This information was supplemented with a cut sheet from the 2011 S&L report via email from David Triplett on 2-10-15. Entergy declined to provide the full report, citing confidentiality concerns.

[62] Section 5.2 Post-Combustion Controls, Chapter 1 – Wet Scrubbers for Acid Gas, Table 1.4.

that water availability would affect the feasibility of wet FGD since the facility is not located in an exceptionally arid region. Additionally, the BART Guidelines provide that the fact that a control device creates liquid and solid waste that must be disposed of does not necessarily argue against selection of that technology as BART, particularly if the control device has been applied to similar facilities elsewhere (40 CFR Part 51, Appendix Y, section IV.D.4.i.2.). In cases where the facility can demonstrate that there are unusual circumstances there that would create greater problems than experienced elsewhere, this may provide a basis for the elimination of that control option as BART. But in this case, Entergy has not indicated that there are any such unusual circumstances. Entergy's evaluation also pointed out that wet FGD systems have increased power requirements and greater reagent usage compared to dry FGD. The costs associated with increased power requirements and greater reagent usage have already been factored into the cost analysis for wet FGD.

Consideration of the presence of existing pollution control technology at the source is reflected in the BART analysis in two ways: first, in the consideration of available control technologies, and second, in the development of baseline emission rates for use in cost calculations and visibility modeling. White Bluff Units 1 and 2 currently do not operate any $SO_2$ control equipment.

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. This means that the anticipated useful life of the boilers is expected to be at least as long as the capital cost recovery period of controls. Therefore, a 30-year amortization period was assumed in the $SO_2$ BART analysis as the remaining useful life of the units.

*Step 5- Evaluate Visibility Impacts*

Entergy assessed the visibility improvement associated with wet FGD and dry FGD by modeling the $SO_2$ emission rates associated with each control option using CALPUFF, and then comparing the visibility impairment associated with the baseline emission rates to the visibility impairment associated with the controlled emission rates as measured by the 98$^{th}$ percentile modeled visibility impact. Entergy calculated the modeled $SO_2$ emission rates associated with wet FGD and dry FGD were calculated by multiplying the controlled emission level (*i.e.*, 0.04 lb/MMBtu for wet FGD and 0.06 lb/MMBtu for dry FGD) by the boiler heat input of 8,950 MMBtu/hr. The $NO_X$ emission rate was modeled at the baseline rate for both the wet and dry FGD options. For all PM species other than ammonium sulfate, the NPS speciation spreadsheets were relied upon to determine emission rates for PM species. A portion of $SO_2$ is further oxidized to $SO_3$, which is then converted to sulfuric acid. Sulfuric acid can react with ammonia to form ammonium sulfate. The ammonium sulfate emission rates for semi-dry scrubbers were estimated by Entergy by assuming the reduction in ammonium sulfate ($SO_4$) is proportional to the reduction in $SO_2$ from the baseline to the controlled case (95%), while the ammonium sulfate emission rates for wet FGD were estimated by Entergy by assuming 50% reduction in $SO_4$ from the baseline case to the controlled case. This is because wet FGD systems generally have less affinity for $SO_3$, typically capturing between 25-50% of the $SO_3$. Therefore, the estimated ammonium sulfate emission rate for wet FGD is higher than for dry FGD. As discussed above, we recommend that sulfuric acid emissions from power plants be calculated by estimating the amount of $H_2SO_4$ produced and the amount of $H_2SO_4$ removed by control equipment using information from the Electric Power Research Institute (EPRI).[63] However, in this specific situation, we do not anticipate that this difference in methodology would significantly impact the relative benefits of the $SO_2$ controls examined or impact our BART determination since the overall impacts and benefits of control are large. We performed modeling for the sister facility, Independence, as described under the reasonable progress analysis section below. In this modeling, we utilized the EPRI method to estimate sulfuric acid emissions for the baseline and control scenarios. The results of the Independence modeling showed a very small incremental visibility benefit between dry FGD and wet FGD and considerable visibility benefit over the baseline for both control scenarios.

The tables below show the emission rates modeled and a comparison of the baseline (*i.e.*, existing) visibility impacts and the visibility impacts of wet FGD and dry FGD, at each Class I area. The visibility improvement associated with each control scenario was calculated as the difference between the baseline visibility impairment and the visibility impairment for each control scenario as measured by the 98th percentile modeled visibility impact at each Class I area.

**Table 51. Summary of Emission Rates Modeled for $SO_2$ Controls for White Bluff Units 1 and 2**

| Source | $SO_2$ (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 1 - Semi-Dry Scrubbing | 537.0 | 2.7 | 3,001.4 | 1.0 | 1.0 | 0.7 | 0.0 | 5.4 |
| Unit 2 – Semi-Dry Scrubbing | 537.0 | 2.8 | 3,527.4 | 1.0 | 1.0 | 0.7 | 0.0 | 5.6 |
| Unit 1 – Wet Scrubbing | 358.0 | 18.4 | 3,001.4 | 6.7 | 6.5 | 4.6 | 0.2 | 36.4 |
| Unit 2 – Wet Scrubbing | 358.0 | 18.4 | 3,527.4 | 6.7 | 6.5 | 4.6 | 0.2 | 36.4 |

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

**Table 52. Entergy White Bluff Unit 1: Summary of the 98th Percentile Visibility Impacts and Improvement Due to $SO_2$ Controls**

| Class I Area | Visibility Impact (Δdv) | | | Visibility Improvement Over Baseline (dv) | | Incremental Visibility Improvement of Wet FGD vs. Dry FGD (dv) |
|---|---|---|---|---|---|---|
| | Baseline | Dry Scrubber | Wet FGD | Dry Scrubber | Wet FGD | |
| Caney Creek | 1.628 | 0.815 | 0.794 | 0.813 | 0.834 | 0.021 |
| Upper Buffalo | 1.140 | 0.378 | 0.350 | 0.762 | 0.790 | 0.028 |
| Hercules-Glades | 1.041 | 0.358 | 0.360 | 0.683 | 0.681 | -0.002 |
| Mingo | 0.887 | 0.267 | 0.271 | 0.620 | 0.616 | -0.004 |
| Total | 4.696 | 1.818 | 1.775 | 2.878 | 2.921 | 0.043 |

**Table 53. Entergy White Bluff Unit 2: Summary of the 98th Percentile Visibility Impacts and Improvement Due to $SO_2$ Controls**

| Class I Area | Visibility Impact (Δdv) | | | Visibility Improvement Over Baseline (dv) | | Incremental Visibility Improvement of Wet FGD vs. Dry FGD |
|---|---|---|---|---|---|---|
| | Baseline | Dry Scrubber | Wet FGD | Dry Scrubber | Wet FGD | |
| Caney Creek | 1.695 | 0.941 | 0.920 | 0.754 | 0.775 | 0.021 |
| Upper Buffalo | 1.185 | 0.418 | 0.405 | 0.767 | 0.780 | 0.013 |
| Hercules-Glades | 1.061 | 0.415 | 0.416 | 0.645 | 0.644 | -0.001 |
| Mingo | 0.903 | 0.310 | 0.315 | 0.593 | 0.588 | -0.005 |
| Total | 4.844 | 2.084 | 2.056 | 2.759 | 2.787 | 0.028 |

The tables above show that the installation and operation of $SO_2$ controls at White Bluff Units 1 and 2 is expected to result in considerable visibility improvement at the four modeled Class I areas, measured as the difference between the $98^{th}$ percentile visibility impairment associated with the baseline and the $98^{th}$ percentile visibility impairment associated with each control option. The installation and operation of dry FGD is projected to result in visibility improvement of up to 0.813 dv at any single Class I area for Unit 1 and 0.767 dv for Unit 2. The installation and operation of wet FGD is projected to result in visibility improvement of up to 0.834 dv at any single Class I area for Unit 1 and 0.780 dv for Unit 2. The installation and operation of wet FGD is projected to result in very minimal incremental visibility benefit over dry FGD at Caney Creek and Upper Buffalo, while at Hercules-Glades and Mingo, it is projected to result in slight visibility disbenefit.

**Our $SO_2$ BART Determination for Units 1 and 2:**

Taking into consideration the five factors, we propose to determine that BART for White Bluff Units 1 and 2 is an emission limit of 0.06 lb/MMBtu on a 30 boiler-operating-day rolling average basis based on the installation and operation of dry FGD or another control technology that achieves that level of control. The operation of a dry FGD is projected to result in visibility improvement ranging from 0.620 to 0.813 dv at each affected Class I areas ($98^{th}$ percentile basis) for Unit 1 and ranging from 0.593 to 0.767 dv for Unit 2. Based on our adjustments to Entergy's cost analysis, dry FGD is estimated to have an average cost-effectiveness of $2,227/ton of $SO_2$ removed for Unit 1 and $2,101/ton of $SO_2$ removed for Unit 2. Based on our adjustments to Entergy's cost analysis, wet FGD is estimated to have an average cost-effectiveness of $3,336/ton of $SO_2$ removed for Unit 1 and $3,152/ton of $SO_2$ removed for Unit 2. Therefore, considering the five BART factors and the slight visibility benefit at Caney Creek and Upper Buffalo and slight disbenefit at Hercules-Glades and Mingo of wet FGD over dry FGD, we are proposing to determine that $SO_2$ BART for White Bluff Units 1 and 2 is an emission limit of 0.06 lb/MMBtu on a 30 boiler-operating-day rolling average based on the installation and operation of dry FGD or another control technology that achieves that level of control. We are proposing to require compliance with this requirement no later than 5 years from the effective date of the final rule, consistent with the regional haze regulations.[64] Units 1 and 2 each have an existing CEMS, and we are proposing to require that compliance be demonstrated using the unit's existing CEMS. We are proposing to require compliance with this requirement no later than five years from the effective date of the final rule, consistent with the CAA requirements.[65]

[64] 40 CFR section 51.308(e)(1)(iv).

[65] Clean Air Act section 169A (g)(4), 42 U.S.C. 7491(g)(4).

### c. $NO_X$ BART Evaluation for Units 1 and 2

Nitrogen oxides, or $NO_X$, are produced during fuel combustion when nitrogen contained in both the fuel and the combustion air is exposed to high temperatures. Entergy's evaluation noted that the formation of $NO_X$ compounds in utility boilers is sensitive to the method of firing. In tangentially-fired boilers, such as White Bluff Units 1 and 2, 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. The baseline $NO_X$ emission rates for White Bluff Units 1 and 2 were discussed under section II.C.3.a. of this TSD. The five factors considered in the $NO_X$ BART analysis are discussed below.

*Step 1- Identify All Available Retrofit Control Technologies*

The $NO_X$ control technologies considered in Entergy's $NO_X$ BART report include both combustion and post-combustion controls. The combustion controls evaluated consisted of FGR, separated overfire air (SOFA), and LNB. The post-combustion controls evaluated consisted of SCR and SNCR.

*Step 2- Eliminate Technically Infeasible Options*

In its evaluation, Entergy noted that the amount of $NO_X$ reduction achievable with FGR depends primarily on the nitrogen content of the fuel and the amount of FGR used. FGR is more effective in controlling thermal $NO_X$ than fuel $NO_X$, and therefore is generally more effective when used with low nitrogen content fuels such as natural gas and propane. Further, Entergy found that FGR technology is not currently offered by vendors for coal-fired units. Therefore, FGR is not considered to be a technically feasible control technology for the coal-fired White Bluff Units 1 and 2. All other available $NO_X$ control options were identified as technically feasible.

*Step 3- Evaluate Control Effectiveness of Remaining Control Technologies*:

Entergy evaluated three control scenarios: LNB/SOFA; the combination of LNB/SOFA + SNCR; and the combination of LNB/SOFA + SCR. Entergy relied on literature control ranges and efficiencies and vendor estimates in arriving at the expected controlled emission rates for White Bluff Units 1 and 2. The baseline $NO_X$ emission rate Entergy assumed in the BART analysis is 0.31 lb/MMBtu for Unit 1 and 0.36 lb/MMBtu for Unit 2.

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, which reduces the formation of thermal $NO_X$. SOFA refers to a system where 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. Entergy estimates SOFA would achieve a controlled $NO_X$ emission rate of 0.28 – 0.32 lb/MMBtu for Units 1 and 2. LNB technology uses advanced burner design to reduce $NO_X$ formation through the restriction of oxygen, which lowers flame temperature and/or reduces the residence time. When LNB is combined with SOFA, it is expected to achieve a controlled NOx emission rate of 0.15 lb/MMBtu for Units 1 and 2. When SNCR is combined with LNB/SOFA it is expected to achieve a controlled $NO_X$ emission rate of 0.13 lb/MMBtu, and when SCR is combined with LNB/SOFA it is expected to achieve a controlled $NO_X$ emission rate of 0.055 lb/MMBtu for Units 1 and 2.

*Step 4- Evaluate Impacts and Document the Results*

The four factors considered in this step are the costs of compliance, energy and non-air quality environmental impacts of compliance, existing pollution control technology in use at the source, and the remaining useful life of the source.

Entergy estimated the capital costs, operating costs, and average cost-effectiveness of LNB, SOFA, SNCR, and SCR.[66] The capital and operating costs of controls were based on vendor estimates specific to Units 1 and 2. The cost analysis assumed a 30-year amortization period. The total annual costs were estimated by annualizing the capital cost of controls over a 30-year period and then adding to this value the annual operating cost of controls.

The annual emissions reductions associated with each $NO_X$ control option were determined by subtracting the estimated controlled annual emission rates from the baseline annual emission rate. The baseline annual emission rate is the average rate as reported by Entergy in the 2009-2011 air emission inventories, while the controlled annual emission rates are based on the lb/MMBtu levels believed to be achievable from the control technology multiplied by the baseline heat inputs to the boilers in MMBtu/yr. The average cost-effectiveness of $NO_X$ controls was calculated by dividing the total annual cost of each control option by the estimated annual $NO_X$ emissions reductions.

We note that Entergy's cost estimate for each $NO_X$ control option includes capital suspense in the total capital costs.[67] A capital cost suspense of $955,673 for both units for LNB/SOFA; $1,745,429 for both units for LNB/SOFA + SNCR; and $20,552,528 for Unit 1 and

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[66] See "Revised BART Five Factor Analysis White Bluff Steam Electric Station Redfield, Arkansas (AFIN 35-00110)," dated October 2013, prepared by Trinity Consultants Inc. in conjunction with Entergy Services Inc., Page Appendix A to the BART analysis contains Entergy's $NO_X$ control cost calculations and Appendix E contains the "$NO_X$ Control Technology Cost and Performance Study" prepared by Sargent & Lundy on behalf of Entergy. A copy of Entergy's BART analysis and its appendices is found in the docket for our proposed rulemaking.

[67] *Id*.

$21,332,288 for Unit 2 for LNB/SOFA + SCR is included in the capital costs. As discussed above, Entergy described capital suspense as a distribution of overhead costs associated with administrators, engineers, and supervisors that includes function specific rates and corporate accounting rates. However, we do not believe capital suspense should be included in the cost analysis because those costs have not been documented by Entergy and do not appear to be valid costs under the Control Cost Manual methodology. We have adjusted the cost estimate of $NO_X$ controls by subtracting the capital suspense line item from the capital costs.[68] Based on our adjustment to Entergy's cost estimate, the average cost-effectiveness of LNB/SOFA is estimated to be $350/ton of $NO_X$ removed for Unit 1 and $340/ton of $NO_X$ removed for Unit 2, while the average cost-effectiveness of LNB/SOFA + SNCR is estimated to be $1,758/ton of $NO_X$ removed for Unit 1 and $1,449/ton of $NO_X$ removed for Unit 2 (see table below). The average cost-effectiveness of LNB/SOFA + SCR is estimated to be $3,552/ton of $NO_X$ removed for Unit 1 and $2,749/ton of $NO_X$ removed for Unit 2.

**Table 54. Summary of $NO_X$ Control Costs for Entergy White Bluff Units 1 and 2**

| Control Technology | Baseline Emission Rate ($NO_X$ tpy) | Controlled Emission Level (lb/MMBtu) | Controlled Emission Rate (tpy) | Annual Emissions Reduction ($NO_X$ tpy) | Capital Cost ($) | Annual Fixed O&M ($/yr) | Annualized Variable O&M ($/yr) | Total Annual Cost ($/yr) | Average Cost Effectiveness ($/ton) | Incremental Cost-Effectiveness ($/ton) |
|---|---|---|---|---|---|---|---|---|---|---|
| Unit 1 (SN-01) | | | | | | | | | | |
| **LNB/SOFA** | 7,249 | 0.15 | 4,145 | 3,104 | 9,505,533 | 142,000 | 177,887 | 1,085,904 | 350 | - |
| **LNB/SOFA/ SNCR** | 7,249 | 0.13 | 3,593 | 3,657 | 19,625,896 | 311,000 | 4,538,000 | 6,430,580 | 1,758 | 9,665 |
| **LNB/SOFA/ SCR** | 7,249 | 0.055 | 1,520 | 5,729 | 209,776,610 | 608,000 | 2,836,000 | 20,349,142 | 3,552 | 6,717 |
| Unit 2 (SN-02) | | | | | | | | | | |
| **LNB/SOFA** | 8,185 | 0.15 | 4,060 | 4,125 | 13,532,533 | 142,000 | 170,838 | 1,403,376 | 340 | - |
| **LNB/SOFA/ SNCR** | 8,185 | 0.13 | 3,519 | 4,666 | 23,652,896 | 311,000 | 4,542,000 | 6,759,102 | 1,449 | 9,900 |
| **LNB/SOFA/ SCR** | 8,185 | 0.055 | 1,489 | 6,697 | 185,415,610 | 608,000 | 2,858,000 | 20,127,070 | 2,749 | 5,736 |

Entergy did not identify any energy or non-air quality environmental impacts associated with the use of LNB/SOFA. As for SCR and SNCR, we are not aware of any unusual circumstances at the facility that could create energy or non-air quality environmental impacts

[68] See the spreadsheet titled "EPA $NO_X$ Control Cost revisions_White Bluff." A copy of this spreadsheet is found in the docket for our proposed rulemaking.

associated with the operation of these controls greater than experienced elsewhere and that may therefore provide a basis for their elimination as BART (40 CFR Part 51, Appendix Y, section IV.D.4.i.2.). Therefore, we do not believe there are any energy or non-air quality environmental impacts associated with the operation of $NO_X$ controls at Entergy White Bluff Units 1 and 2 that would affect our proposed BART determination.

Consideration of the presence of existing pollution control technology at each unit is reflected in the BART analysis in two ways: first, in the consideration of available control technologies, and second, in the development of baseline emission rates for use in cost calculations and visibility modeling. Other than the installation of a neural net system in 2006 to optimize boiler combustion efficiency, which had the co-benefit of decreasing $NO_X$ emissions compared to the 2001-2003 baseline, White Bluff Units 1 and 2 have no existing $NO_X$ pollution control technology. The lower $NO_X$ emissions achieved as a co-benefit of installing the neural net system is reflected in the analysis by the use of 2009-2011 as the baseline for the $NO_X$ BART analysis.

With regard to consideration of the remaining useful life of the units, we are not aware of any enforceable shutdown date for White Bluff Units 1 and 2, nor did Entergy's evaluation indicate any future planned shutdown. This means that the anticipated useful life of the boilers is expected to be at least as long as the capital cost recovery period of controls. Therefore, a 30-year amortization period was appropriately assumed in the evaluation of $NO_X$ controls as the remaining life of Units 1 and 2.

*Step 5- Evaluate Visibility Impacts*

Entergy assessed the visibility improvement associated with $NO_X$ controls by modeling the $NO_X$ emission rates associated with each control option using CALPUFF, and then comparing the visibility impairment associated with the baseline emission rate to the visibility impairment associated with the controlled emission rates as measured by the $98^{th}$ percentile modeled visibility impact. The controlled emission level associated with LNB/SOFA is 0.15 lb/MMBtu; the controlled emission level associated with LNB/SOFA + SNCR is 0.13 lb/MMBtu; and the controlled emission level associated with LNB/SOFA + SCR is 0.055 lb/MMBtu for each unit. These levels were multiplied by each unit's maximum heat input to derive the hourly emission rates used in the modeling. The tables below show the emission rates modeled and a comparison of the existing (*i.e.*, baseline) visibility impacts and the visibility impacts based on $NO_X$ controls, based on the $98^{th}$ percentile modeled visibility impacts for each Class I area.

## Table 55. Summary of Emission Rates Modeled for $NO_X$ Controls for Entergy White Bluff Units 1 and 2

| | $SO_2$ (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 1 – LNB/SOFA** | 7,763.5 | 36.8 | 1342.5 | 40.4 | 31.1 | 9.2 | 1.2 | 118.6 |
| **Unit 2 – LNB/SOFA** | 7,825.1 | 36.8 | 1342.5 | 40.4 | 31.1 | 9.2 | 1.2 | 118.6 |
| **Unit 1 - LNB/SOFA + SNCR** | 7,763.5 | 36.8 | 1163.5 | 40.4 | 31.1 | 9.2 | 1.2 | 118.6 |
| **Unit 2 - LNB/SOFA + SNCR** | 7,825.1 | 36.8 | 1163.5 | 40.4 | 31.1 | 9.2 | 1.2 | 118.6 |
| **Unit 1 – LNB/SOFA + SCR** | 7,763.5 | 36.8 | 492.3 | 40.4 | 31.1 | 9.2 | 1.2 | 118.6 |
| **Unit 2 - LNB/SOFA + SCR** | 7,825.1 | 36.8 | 492.3 | 40.4 | 31.1 | 9.2 | 1.2 | 118.6 |

## Table 56. Entergy White Bluff Unit 1: Summary of the 98th Percentile Visibility Impacts and Improvement due to $NO_X$ Controls

| Class I area | Baseline Visibility Impact (Δdv) | LNB/SOFA | | LNB/SOFA + SNCR | | | LNB/SOFA + SCR | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. LNB/SOFA (Δdv) | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. LNB/SOFA + SNCR (Δdv) |
| Caney Creek | 1.628 | 1.462 | 0.166 | 1.428 | 0.2 | 0.034 | 1.359 | 0.269 | 0.069 |
| Upper Buffalo | 1.140 | 1.039 | 0.101 | 1.029 | 0.111 | 0.01 | 0.991 | 0.149 | 0.038 |
| Hercules-Glades | 1.041 | 0.865 | 0.176 | 0.844 | 0.197 | 0.021 | 0.832 | 0.209 | 0.012 |
| Mingo | 0.887 | 0.849 | 0.038 | 0.842 | 0.045 | 0.007 | 0.817 | 0.07 | 0.025 |
| Cumulative Visibility Improvement (Δdv) | -- | -- | 0.481 | -- | 0.553 | -- | -- | 0.697 | - |

**Table 57. Entergy White Bluff Unit 2: Summary of the 98th Percentile Visibility Impacts and Improvement due to $NO_X$ Controls**

| Class I area | Baseline Visibility Impact (Δdv) | LNB/SOFA | | LNB/SOFA + SNCR | | | LNB/SOFA + SCR | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. LNB/SOFA (Δdv) | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. LNB/SOFA + SNCR (Δdv) |
| Caney Creek | 1.695 | 1.47 | 0.225 | 1.437 | 0.258 | 0.033 | 1.368 | 0.327 | 0.069 |
| Upper Buffalo | 1.185 | 1.046 | 0.139 | 1.035 | 0.15 | 0.011 | 0.997 | 0.188 | 0.038 |
| Hercules-Glades | 1.060 | 0.870 | 0.190 | 0.849 | 0.211 | 0.021 | 0.838 | 0.222 | 0.011 |
| Mingo | 0.903 | 0.856 | 0.047 | 0.849 | 0.054 | 0.007 | 0.823 | 0.08 | 0.026 |
| Cumulative Visibility Improvement (Δdv) | -- | -- | 0.601 | -- | 0.673 | -- | -- | 0.817 | - |

The tables above show that the installation and operation of LNB/SOFA is projected to result in visibility improvement of up to 0.176 dv at any single Class I area for Unit 1 and 0.225 dv for Unit 2, based on the 98th percentile visibility impairment. The installation and operation of LNB/SOFA + SNCR is projected to result in visibility improvement of up to 0.2 dv in any single Class I area for Unit 1 and 0.258 dv for Unit 2. The installation and operation of LNB/SOFA + SCR is projected to result in visibility improvement of up to 0.269 dv in any single Class I area for Unit 1 and 0.327 dv for Unit 2. The combination of LNB/SOFA + SNCR would result in minimal incremental visibility benefit over LNB/SOFA at all affected Class I areas for both units. The combination of LNB/SOFA + SCR at Unit 1 would result in incremental visibility benefit over LNB/SOFA + SNCR of 0.069 dv at Caney Creek; 0.038 dv at Upper Buffalo; 0.012 dv at Hercules-Glades; and 0.025 dv at Mingo. The combination of LNB/SOFA + SCR at Unit 2 would result in incremental visibility benefit over LNB/SOFA + SNCR of 0.069 dv of at Caney Creek; 0.038 dv at Upper Buffalo; 0.011 dv at Hercules-Glades; and 0.026 dv at Mingo.

**Our $NO_X$ BART determination for Units 1 and 2:**

Taking into consideration the five factors, we propose to determine that BART for White Bluff Units 1 and 2 is an emission limit of 0.15 lb/MMBtu on a 30 boiler-operating-day rolling average based on the installation and operation of LNB/SOFA. The operation of LNB/SOFA is projected to result in visibility improvement ranging from 0.038 to 0.176 dv for Unit 1 and 0.047 to 0.225 dv for Unit 2 at each of the affected Class I areas (98$^{th}$ percentile basis). Based on our adjustments to the cost analysis included in Entergy's evaluation, the operation of LNB/SOFA is estimated to have an average cost-effectiveness of $350/ton of $NO_X$ removed for Unit 1 and $340/ton of $NO_X$ removed for Unit 2, which we consider to be very cost-effective. The operation of LNB/SOFA + SNCR is estimated to have an average cost-effectiveness of $1,758/ton of $NO_X$ removed for Unit 1 and $1,449/ton of $NO_X$ removed for Unit 2. The incremental cost-effectiveness of LNB/SOFA + SNCR compared to LNB/SOFA is $9,665/ton of $NO_X$ removed for Unit 1 and $9,900/ton of $NO_X$ removed for Unit 2.While the average cost-effectiveness of LNB/SOFA + SNCR is still very cost effective, the incremental visibility benefit of LNB/SOFA + SNCR compared to LNB/SOFA is estimated to range from 0.007 to 0.034 dv for Unit 1 and 0.007 to 0.033 dv for Unit 2 at each of the affected Class I areas. We do not believe this small amount of incremental visibility benefit justifies the incremental cost of LNB/SOFA + SNCR.

The operation of LNB/SOFA + SCR at Unit 1 is projected to result in up to 0.269 dv visibility improvement over the baseline at any single Class I area, and based on our adjustments to Entergy's cost analysis, has an average cost-effectiveness of $3,552/ton of $NO_X$ removed. LNB/SOFA + SCR at Unit 1 is projected to result in up to 0.069 dv of incremental visibility improvement over LNB/SOFA + SNCR at any single Class I area, and its incremental cost-effectiveness is estimated to be $6,717/ton of $NO_X$ removed. The operation of LNB/SOFA + SCR at Unit 2 is projected to result in up to 0.327 dv visibility improvement over the baseline at any single Class I area, and has an average cost-effectiveness of $2,749/ton of $NO_X$ removed. LNB/SOFA + SCR at Unit 2 is also projected to result in up to 0.069 dv of incremental visibility improvement over LNB/SOFA + SNCR at any single Class I area, and its incremental cost-effectiveness is estimated to be $5,736/ton of $NO_X$ removed. Although the average and incremental cost-effectiveness of LNB/SOFA + SCR at Units 1 and 2 is still within the range of what we consider to be cost-effective, we believe the incremental visibility benefit over LNB/SOFA + SNCR of up to 0.069 dv at a single Class I area is relatively small considering the incremental cost-effectiveness of $6,717/ton of $NO_X$ removed for Unit 1 and $5,736/ton of $NO_X$ removed for Unit 2. Therefore, we are proposing to determine that $NO_X$ BART for White Bluff Units 1 and 2 is an emission limit of 0.15 lb/MMBtu on a 30 boiler-operating-day rolling average based on the installation and operation of LNB/SOFA. We are proposing to require compliance with this requirement no later than 3 years from the effective date of the final rule, consistent with our regional haze regulations.[69] We are proposing to require that compliance be demonstrated using the unit's existing CEMS.

[69] 40 CFR section 51.308(e)(1)(iv).

### d. BART Evaluation for Auxiliary Boiler

As shown in the table above, the baseline visibility impairment attributable to the Auxiliary Boiler is 0.01 dv at Caney Creek and even lower at the other modeled Class I areas ($98^{th}$ percentile basis). The BART Rule provides that "Consistent with the CAA and the implementing regulations, States can adopt a more streamlined approach to making BART determinations where appropriate. Although BART determinations are based on the totality of circumstances in a given situation, such as the distance of the source from a Class I area, the type and amount of pollutant at issue, and the availability and cost of controls, it is clear that in some situations, one or more factors will clearly suggest an outcome. Thus, for example, a State need not undertake an exhaustive analysis of a source's impact on visibility resulting from relatively minor emissions of a pollutant where it is clear that controls would be costly and any improvements in visibility resulting from reductions in emissions of that pollutant would be negligible." (70 FR 39116).

Given the very small baseline visibility impacts from the Auxiliary Boiler, we believe it is appropriate to take a streamlined approach for determining BART in this case. Because of the very low baseline visibility impacts from the Auxiliary Boiler at each modeled Class I area, we believe that the visibility improvement that could be achieved through the installation and operation of controls would be negligible, such that the cost of those controls could not be justified. Therefore, we are proposing that the existing emission limits satisfy BART for $SO_2$, $NO_X$, and PM. We are proposing that the existing emission limit of 105.2 lb/hr is BART for $SO_2$, the existing emission limit of 32.2 lb/hr is BART for $NO_X$, and the existing emission limit of 4.5 lb/hr is BART for PM for the Auxiliary Boiler.[70] Because we are proposing a BART emission limit that represents current operations and no control equipment installation is necessary, we are proposing that these emissions limitations be complied with for BART purposes from the date of effectiveness of the finalized action.

## 5. Entergy Lake Catherine Plant

Entergy Lake Catherine Unit 4 is subject to BART. In our March 12, 2012 final action we disapproved the State's BART determinations for $NO_X$ for the natural gas firing scenario and for $SO_2$, $NO_X$, and PM for the fuel oil firing scenario (77 FR 14604). Entergy hired a consultant to conduct a BART five-factor analysis for Lake Catherine Unit 4 (Entergy's BART analysis).[71]

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[70] See ADEQ Operating Air Permit No. 0263-AOP-R7, Section IV, Specific Condition No. 32.

[71] See "Revised BART Five Factor Analysis Lake Catherine Steam Electric Station Malvern, Arkansas (AFIN 30-00011)," dated May 2014, prepared by Trinity Consultants Inc. in conjunction with Entergy Services Inc. A copy of this BART analysis is found in the docket for our proposed rulemaking.

Lake Catherine 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 MMBtu/hr. The boiler is permitted to burn natural gas and No. 6 fuel oil. Entergy's analysis states that Lake Catherine Unit 4 has not burned fuel oil since prior to the 2001-2003 baseline period, currently does not burn fuel oil, and that Entergy does not project to burn fuel oil at the unit in the foreseeable future. Therefore, Entergy's analysis[72] addresses BART for the natural gas firing scenario and does not consider emissions from fuel oil firing. Entergy's analysis states that if conditions change such that it becomes economic to burn fuel oil, the facility will submit a BART five factor analysis for the fuel oil firing scenario to the State to be submitted to us as a SIP revision, and that fuel oil combustion will not take place until final EPA approval of BART for the fuel oil firing scenario. We concur with this commitment.[73] Before fuel oil firing is allowed to take place at Lake Catherine Unit 4, revised BART determinations must be promulgated for all pollutants for the fuel oil firing scenario through a FIP and/or through our action upon and approval of revised BART determinations submitted by the State as a SIP revision.

We approved the State's BART determinations for Lake Catherine Unit 4 for $SO_2$ and PM for the natural gas firing scenario in our March 12, 2012 final action (77 FR 14604). Therefore, the only BART determination that remains to be addressed for the natural gas firing scenario is $NO_X$ BART. Our analysis presented below focuses on $NO_X$ BART for the natural gas firing scenario.

### a. Baseline Emission Rates and Existing Visibility Impairment Attributable to Lake Catherine Unit 4

Entergy estimated $SO_2$, $NO_X$, and $PM_{10}$ baseline emission rates and then modeled these emission rates to determine the existing visibility impairment attributable to Lake Catherine Unit 4 based on the default natural conditions. The baseline emission rates are based on a combination of stack testing, CEMS data as reported to EPA's CAMD, and AP-42 emission factors. The baseline emission rates are shown in the table below.

[72] See "Revised BART Five Factor Analysis Lake Catherine Steam Electric Station Malvern, Arkansas (AFIN 30-00011)," dated May 2014, prepared by Trinity Consultants Inc. in conjunction with Entergy Services Inc. A copy of this BART analysis is found in the docket for our proposed rulemaking.

[73] As explained in the regulatory text in the proposed rulemaking associated with this TSD, if Lake Catherine Unit 4 decides to begin burning fuel oil, we will complete a BART analysis for each pollutant for the fuel oil firing scenario after receiving notification that the source will begin burning fuel oil and we will revise the FIP as necessary in accordance with Regional Haze Rule requirements, including the BART provisions in 40 CFR 51.308(e). Alternatively, if the State submits a SIP revision with BART determinations for the fuel oil firing scenario, we will take action on the State's submittal.

**Table 58. Baseline Maximum 24-Hour $SO_2$, $NO_X$, and $PM_{10}$ Emission Rates**

| Source | $SO_2$ (lb/hr) | $NO_X$ (lb/hr) | Total $PM_{10}$ (lb/hr) | $SO_4$ (lb/hr) | PMc (lb/hr) | PMf (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 |

The $SO_2$ and $NO_X$ baseline emission rates are the highest actual 24-hour emission rates based on 2001-2003 CEMS data from natural gas burning. The $PM_{10}$ emission rate reflects the breakdown of the filterable and condensable $PM_{10}$ determined from AP-42 Table 1.4-2 *Combustion of Natural Gas*. Entergy then modeled the baseline emission rates using the CALPUFF dispersion model to determine the baseline visibility impairment attributable to Lake Catherine Unit 4 at the Caney Creek Wilderness Area, Upper Buffalo Wilderness Area, Hercules-Glades Wilderness Area, and Mingo National Wildlife Refuge. The existing visibility impairment attributable to Lake Catherine Unit 4 at each Class I area is summarized in the table below.

**Table 59. Baseline Visibility Impairment Attributable to Entergy Lake Catherine Unit 4**

| Year | Maximum ($\Delta$dv) | 98th Percentile ($\Delta$dv) | No. of Days with $\Delta dv \geq 0.5$ | 98th Percentile %$SO_4$ | 98th Percentile %$NO_3$ | 98th Percentile %$PM_{10}$ | 98th Percentile %$NO_2$ |
|---|---|---|---|---|---|---|---|
| Caney Creek 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 | 97.39 | 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 National Wildlife Refuge | | | | | | | |
| 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 |

### b. $NO_X$ BART Evaluation (Natural Gas Firing)

Nitrogen oxides, or $NO_X$, are produced during fuel combustion when nitrogen contained in both the fuel and the combustion air is exposed to high temperatures. Entergy's evaluation noted that the formation of $NO_X$ compounds in utility boilers is sensitive to the method of firing. In tangentially-fired boilers, such as Lake Catherine 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. Baseline $NO_X$ emission rates can vary significantly from plant to plant due to method of firing as well as several other factors. The baseline $NO_X$ emission rates for Lake Catherine Unit 4 were discussed under section II.C.4.a. of this TSD. The five factors considered in the $NO_X$ BART analysis are discussed below.

*Step 1- Identify All Available Retrofit Control Technologies*

The $NO_X$ control technologies considered in Entergy's $NO_X$ BART analysis include both combustion and post-combustion controls. The combustion controls evaluated by consisted of Burners out of Service (BOOS), FGR, SOFA, and LNB. The post-combustion controls evaluated consisted of SCR and SNCR.

*Step 2- Eliminate Technically Infeasible Options*

Entergy's evaluation stated that SNCR combined with LNB/SOFA was being evaluated as a control option for Lake Catherine Unit 4, but SNCR is not adaptable to all gas-fired boilers. All other $NO_X$ control options evaluated were identified as technically feasible.

*Step 3- Evaluate Control Effectiveness of Remaining Control Technologies*:

Entergy relied on literature control ranges and efficiencies and vendor estimates in arriving at the expected controlled emission rates for Lake Catherine Unit 4. The baseline $NO_X$ emission rate Entergy used in the analysis is 0.48 lb/MMBtu.

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. The removal of fuel from certain zones reduces the temperature and the production of thermal $NO_X$. Additional air is then supplied to the non-operational burners to complete combustion. Based on a $NO_X$ control study developed by Sargent & Lundy on behalf of Entergy (Sargent & Lundy $NO_X$ Control Study), the estimated controlled $NO_X$ level for Unit 4 while operating BOOS at maximum load is 0.24 lb/MMBtu.[74] Based on the level of control expected to be achieved by BOOS and the expected utilization levels at Unit 4, Entergy believes that an emission rate of 0.22 lb/MMBtu is achievable on a 30 boiler-operating-day rolling average basis.

FGR uses flue gas as an inert material to reduce the oxygen level in the combustion zone and thereby reduce flame temperatures and thermal $NO_X$ formation. Entergy estimated the controlled $NO_X$ level for Unit 4 operating with FGR to be 0.19 lb/MMBtu. SOFA refers to a system where the overfire air is injected in a separate wind box mounted above the main wind box in order to achieve greater separation from the combustion zone. Entergy estimated that when operated without additional controls, SOFA results in $NO_X$ emissions for gas fired boilers of 0.2 – 0.4 lb/MMBtu. LNB technology uses advanced burner design to reduce $NO_X$ formation through the restriction of oxygen, which lowers flame temperature and/or reduces the residence time. When operated without additional controls, Entergy estimated the controlled $NO_X$ emission rate for gas fired boilers operating with LNB is approximately 0.25 lb/MMBtu, and when combined with SOFA, the estimated controlled $NO_X$ emission rate is 0.19 lb/MMBtu. When SNCR is combined with LNB/SOFA, Entergy estimated that the controlled $NO_X$ emission rate is 0.14 lb/MMBtu, and when SCR is combined with LNB/OFA it is estimated that the controlled $NO_X$ emission rate is 0.03 lb/MMBtu.

*Step 4- Evaluate Impacts and Document the Results*

The four factors considered in this step are the costs of compliance, energy and non-air quality environmental impacts of compliance, existing pollution control technology in use at the source, and the remaining useful life of the source.

Entergy's evaluation noted that the Sargent & Lundy $NO_X$ Control Study estimated that FGR would result in the same controlled emission level as LNB/SOFA, but at a higher cost.[75] Therefore, Entergy's evaluation did not further consider FGR. Entergy estimated the capital costs, operating costs, and cost effectiveness of BOOS, LNB/SOFA, LNB/SOFA/SNCR, and LNB/SOFA/SCR.[76] Entergy estimated the capital costs, operating costs, and cost-effectiveness of these four control scenarios based on cost estimates provided by Sargent & Lundy. The cost analysis assumed a 30-year amortization period. The capital cost of each $NO_X$ control option was

[74] See "$NO_X$ Control Technology Cost and Performance Study," Final Report, Rev. 4, dated May 16, 2013, prepared by Sargent & Lundy. A copy of this report is included as Appendix D to Entergy's BART Five Factor Analysis for Lake Catherine Unit 4, which can be found in the docket for this proposed rulemaking.

[75] *Id.*

[76] See "Revised BART Five Factor Analysis Lake Catherine Steam Electric Station Malvern, Arkansas (AFIN 30-00011)," dated May 2014, prepared by Trinity Consultants Inc. in conjunction with Entergy Services Inc. Appendix A to Entergy's BART analysis contains the capital and operating cost estimates for each control option evaluated. A copy of this BART analysis and its appendices is found in the docket for our proposed rulemaking.

annualized over a 30-year period and then added to the annual operating costs to obtain the total annualized costs.[77]

The annual emissions reductions associated with each $NO_X$ control option 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 10% capacity factor.[78] The annual tons reduced associated with each $NO_X$ control option 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 10% capacity factor.[79] Entergy's evaluation assumed a 10% capacity factor because the annual capacity factor of the unit during each of the years from 2003-2011 was under 10%, and Entergy anticipates that future annual capacity factors are expected to be comparable to those experienced by the unit in 2003-2011. We agree that assuming a 10% capacity factor is consistent with the BART Guidelines, which provide that the baseline emission rate should represent a realistic depiction of anticipated annual emissions for the source.[80]

The controlled annual emission rates were based on the lb/MMBtu levels believed to be achievable from the control technologies multiplied by the annual heat input. Entergy calculated the average cost-effectiveness of $NO_X$ controls by dividing the total annual cost of each control option by the estimated annual $NO_X$ emissions reductions. The incremental cost-effectiveness of each control option was also calculated.

We disagree with two aspects of Entergy's cost analysis.[81] First, Entergy's cost estimates for LNB/SOFA, LNB/SOFA + SNCR, and LNB/SOFA + SCR include capital suspense as a line item under the capital costs. However, we do not believe capital suspense should be included in the cost analysis because those costs have not been documented by Entergy and do not appear to be valid costs under the Control Cost Manual methodology. Second, Entergy's cost estimates for these controls also include Allowance for Funds Used During Construction (AFUDC). AFUDC is the cost of capital that is incurred to finance a project during the construction period, and is not a valid cost under the methodology in the EPA Control Cost Manual. The exclusion of capital

[77] Based on Entergy's evaluation, it is anticipated that BOOS can be implemented at Unit 4 without any capital expenditures, but there are one-time costs associated with BOOS implementation. To provide an "apples-to-apples" comparison with the other $NO_X$ control options, these one-time additional costs were treated as if they were a capital expenditure in calculating the cost effectiveness.

[78] 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).

[79] 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).

[80] 40 CFR Appendix Y to Part 51- Guidelines for BART Determinations Under the Regional Haze Rule, section IV.D.4.d.

[81] See "Revised BART Five Factor Analysis Lake Catherine Steam Electric Station Malvern, Arkansas (AFIN 30-00011)," dated May 2014, prepared by Trinity Consultants Inc. in conjunction with Entergy Services Inc. Entergy's $NO_X$ control cost estimates are found in Appendices A and D of the BART analysis. A copy of the BART analysis, including the appendices, is found in the docket for our proposed rulemaking.

suspense and AFUDC from the capital cost estimates results in lower total annual costs and improved average cost-effectiveness (*i.e.*, less dollars per $NO_X$ ton removed) for the aforementioned $NO_X$ control options compared to what is estimated in Entergy's evaluation. In the table below, we have revised the capital costs and cost-effectiveness of $NO_X$ controls for Unit 4 to reflect our adjustments to Entergy's cost estimates.[82] Based on our adjustments to Entergy's cost analysis, the average cost-effectiveness of BOOS at a $NO_X$ controlled emission rate of 0.22 lb/MMBtu is estimated to be $138/ton of $NO_X$ removed, while the average cost-effectiveness of LNB/SOFA is estimated to be $1,450/ton of $NO_X$ removed. The average cost-effectiveness of a combination of LNB/SOFA + SNCR is estimated to be $3,523/ton of $NO_X$ removed, while the average cost-effectiveness of the combination of LNB/SOFA + SCR is estimated to be $5,614/ton of $NO_X$ removed.

**Table 60. Summary of $NO_X$ Control Costs for Lake Catherine Unit 4 (Natural Gas Firing)**

| | Baseline Emission Rate ($NO_X$ tpy) | Controlled Emission Level (lb/MMBtu) | Controlled Emission Rate ($NO_X$ tpy) | Annual Emissions Reduction ($NO_X$ tpy) | Capital Cost ($) | Total Annual Cost ($/yr) | Average Cost Effectiveness ($/ton) | Incremental Cost effectiveness ($/ton) |
|---|---|---|---|---|---|---|---|---|
| **BOOS** | 1,236 | 0.22 | 564 | 673 | 893,000 | 92,964 | 138 | - |
| **LNB/SOFA** | 1,236 | 0.19 | 495 | 742 | 10,508,863 | 1,075,905 | 1,450 | 14,246 |
| **LNB/SOFA/SNCR** | 1,236 | 0.14 | 371 | 865 | 26,015,863 | 3,047,525 | 3,523 | 16,029 |
| **LNB/SOFA/SCR** | 1,236 | 0.03 | 77 | 1159 | 70,370,863 | 6,506,935 | 5,614 | 11,767 |

Entergy did not identify any energy or non-air quality environmental impacts associated with the use of BOOS, LNB, or SOFA. As for SCR and SNCR, we are not aware of any unusual circumstances at the facility that could create energy or non-air quality environmental impacts associated with the operation of these controls greater than experienced elsewhere and that may therefore provide a basis for their elimination as BART (40 CFR Part 51, Appendix Y, section IV.D.4.i.2.). Therefore, we do not believe there are any energy or non-air quality environmental impacts associated with the operation of $NO_X$ controls at Entergy Lake Catherine Unit 4 that would affect our proposed BART determination.

The presence of existing pollution control technology at the source is reflected in the BART analysis in two ways: first, in the consideration of available control technologies, and second, in the development of baseline emission rates for use in cost calculations and visibility modeling. Lake Catherine Unit 4 is not currently equipped with any $NO_X$ pollution control

[82] See the spreadsheet titled "EPA $NO_X$ Control Cost revisions_Lake Catherine.xlsx." A copy of this spreadsheet is found in the docket for our proposed rulemaking.

equipment. The baseline emission rates used in the cost calculations and visibility modeling reflects this.

With regard to consideration of the remaining useful life of the unit, we are not aware of any enforceable shutdown date for Lake Catherine Unit 4, nor did Entergy's evaluation indicate any future planned shutdown. This means that the anticipated useful life of the boiler is expected to be at least as long as the capital cost recovery period of controls. Therefore, a 30-year amortization period was assumed in the evaluation of $NO_X$ controls as the remaining life of Unit 4.

*Step 5- Evaluate Visibility Impacts*

Entergy assessed the visibility improvement associated with $NO_X$ controls by modeling the $NO_X$ emission rates associated with each control option using CALPUFF, and then comparing the visibility impairment associated with the baseline emission rate to the visibility impairment associated with the controlled emission rates. The controlled emission level associated with BOOS is 0.22 lb/MMBtu; the controlled emission level associated with LNB/SOFA is 0.19 lb/MMBtu; the controlled emission level associated with LNB/SOFA + SNCR is 0.14 lb/MMBtu; and the controlled emission level associated with LNB/SOFA + SCR is 0.03 lb/MMBtu. These levels were multiplied by the maximum heat input (*i.e.*, 5,850 MMBtu/hr) to derive the hourly emission rates used in the modeling. The tables below show the modeled emission rates and a comparison of the existing (*i.e.*, baseline) visibility impacts and the visibility impacts based on $NO_X$ controls, based on the 98$^{th}$ percentile modeled visibility impact for each Class I area.

**Table 61. Summary of Emission Rates Modeled for $NO_X$ Controls for Entergy Lake Catherine Unit 4**

| 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) |
|---|---|---|---|---|---|---|---|---|
| **BOOS** | 3.1 | 1.5 | 1287.0 | 0.0 | 0.0 | 31.8 | 11.0 | 44.3 |
| **LNB/SOFA** | 3.1 | 1.5 | 1111.5 | 0.0 | 0.0 | 31.8 | 11.0 | 44.3 |
| **LNB/SOFA + SNCR** | 3.1 | 1.5 | 819.0 | 0.0 | 0.0 | 31.8 | 11.0 | 44.3 |
| **LNB/SOFA + SCR** | 3.1 | 1.5 | 175.5 | 0.0 | 0.0 | 31.8 | 11.0 | 44.3 |

**Table 62. Entergy Lake Catherine Unit 4: Summary of 98th Percentile Visibility Impacts and Improvement due to $NO_X$ Controls (Natural Gas Firing)**

| Class I area | Baseline Visibility Impact (Δdv) | BOOS | | LNB/SOFA | | LNB/SOFA + SNCR | | LNB/SOFA + SCR | |
|---|---|---|---|---|---|---|---|---|---|
| | | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) |
| Caney Creek | 1.371 | 0.775 | 0.596 | 0.683 | 0.688 | 0.529 | 0.842 | 0.163 | 1.208 |
| Upper Buffalo | 0.532 | 0.284 | 0.248 | 0.25 | 0.282 | 0.193 | 0.339 | 0.057 | 0.475 |
| Hercules-Glades | 0.387 | 0.212 | 0.175 | 0.185 | 0.202 | 0.141 | 0.246 | 0.043 | 0.344 |
| Mingo | 0.429 | 0.233 | 0.196 | 0.204 | 0.225 | 0.154 | 0.275 | 0.042 | 0.387 |
| Cumulative Visibility Improvement (Δdv) | -- | -- | 1.215 | -- | 1.397 | -- | 1.702 | -- | 2.414 |

The table above shows that the installation and operation of BOOS is projected to result in visibility improvement of up to 0.596 dv at any single Class I area (based on the 98th percentile modeled visibility impacts), while LNB/SOFA is projected to result in visibility improvement of up to 0.688 dv. The installation and operation of the combination of LNB/SOFA + SNCR is projected to result in visibility improvement of up to 0.842 dv at any single Class I area, while the combination of LNB/SOFA + SCR is projected to result in visibility improvement of up to 1.208 dv. The installation and operation of LNB/SOFA is projected to result in 0.092 dv of incremental visibility benefit over BOOS at Caney Creek, and much lower incremental visibility benefit over BOOS at the other Class I areas. The combination of LNB/SOFA + SNCR is projected to result in 0.154 dv of incremental visibility benefit over LNB/SOFA at Caney Creek, and 0.057 dv or less incremental visibility benefit at the other affected Class I areas. The combination of LNB/SOFA + SCR is projected to result in 0.366 dv of incremental visibility benefit over LNB/SOFA + SNCR at Caney Creek, 0.136 dv at Upper Buffalo, 0.098 Δdv at Hercules-Glades, and 0.112 dv at Mingo.

**EPA's Proposed $NO_X$ BART determination (Natural Gas Firing Scenario):**

Taking into consideration the five factors, we are proposing to determine that $NO_X$ BART for Lake Catherine Unit 4 for the natural gas firing scenario is an emission limit of 0.22 lb/MMBtu on a 30 boiler-operating-day rolling average based on the installation and operation of

BOOS. The operation of BOOS is projected to result in visibility improvement ranging from 0.175 to 0.596 dv at each affected Class I area (98th percentile basis). The cumulative visibility improvement across the four affected Class I areas is projected to be 1.215 dv. The operation of BOOS is estimated to have an average cost-effectiveness of $138/ton of $NO_X$ removed, which we consider to be very cost-effective. By comparison, the installation and operation of LNB/SOFA is estimated to have an average cost-effectiveness of $1,450/ton of $NO_X$ removed, which is still very cost-effective. However, the incremental cost-effectiveness of LNB/SOFA over BOOS is $14,246/ton of $NO_X$ ton removed, while the incremental visibility benefits are only 0.027 to 0.092 dv (depending on the Class I area). As discussed in the preceding paragraph, the operation of a combination of LNB/SOFA + SNCR is projected to result in visibility improvement over the baseline ranging from 0.246 to 0.842 dv at each affected Class I area and an incremental visibility improvement over LNB/SOFA ranging from 0.05 to 0.154 dv at each Class I area. However, the combination of LNB/SOFA + SNCR has an average cost-effectiveness of $3,523/ton of $NO_X$ removed and an incremental cost-effectiveness compared to LNB/SOFA of $16,029/ton of $NO_X$ removed. We believe that the high incremental costs of the combination of LNB/SOFA + SNCR when compared to LNB/SOFA do not justify the amount of incremental visibility benefit projected at the affected Class I areas.

The operation of a combination of LNB/SOFA + SCR is projected to result in considerable visibility improvement over the baseline, ranging from 0.344 to 1.208 dv at each affected Class I area. The incremental visibility benefit of the combination of LNB/SOFA + SCR over LNB/SOFA + SNCR ranges from 0.098 to 0.366 dv at each Class I area. However, the combination of LNB/SOFA + SCR has an average cost-effectiveness of $5,614 per ton of $NO_X$ removed and an incremental cost-effectiveness (compared to the combination of LNB/SOFA + SNCR) of $11,767 per ton of $NO_X$ removed. While the incremental visibility benefit is considerable, we do not consider the average and the incremental cost-effectiveness values of the combination of LNB/SOFA + SCR to be cost-effective. Therefore, we are proposing to determine that $NO_X$ BART for Lake Catherine Unit 4 for the natural gas firing scenario is an emission limit of 0.22 lb/MMBtu on a 30 boiler-operating-day rolling average based on the installation and operation of BOOS. We are proposing to require compliance with this requirement no later than 3 years from the effective date of the final rule, consistent with our regional haze regulations.[83] We are proposing to require that compliance be demonstrated using the unit's existing CEMS. We are inviting public comment specifically on whether this proposed $NO_X$ emission limit is appropriate or whether an emission limit based on more stringent $NO_X$ controls would be appropriate.

### 6. Domtar Ashdown Paper Mill

The Domtar Ashdown Paper Mill Power Boilers No. 1 and 2 are subject to BART. We disapproved the State's BART determinations for $SO_2$ and $NO_X$ for Power Boiler No. 1 and the

[83] 40 CFR section 51.308(e)(1)(iv).

BART determination for $SO_2$, $NO_X$, and PM for the No. 2 Power Boiler in our March 12, 2012 final action (77 FR 14604).

The No. 1 Power Boiler has a heat input rating of 580 MMBtu/hr and an average steam generation rate of approximately 120,000 lb/hr. It combusts primarily bark, but is also permitted to burn wood waste, tire-derived fuel (TDF), municipal yard waste, pelletized paper fuel (PPF), fuel oil, reprocessed fuel oil, and natural gas. It is equipped with a traveling grate, a combustion air system, and a wet ESP.

The No. 2 Power Boiler has a heat input rating of 820 MMBtu/hr and an average steam generation rate of approximately 600,000 lb/hr. It combusts primarily pulverized bituminous coal, but is also permitted to burn bark, PPF, TDF, municipal yard waste, fuel oil, used oil, natural gas, petroleum coke, and reprocessed oil. It is equipped with a traveling grate, combustion air system including OFA, multiclones for particulate removal, and two venturi scrubbers in parallel for removal of remaining particulates and $SO_2$.

Domtar hired a consultant to perform a BART five-factor analysis for the Domtar Ashdown Mill Power Boilers No. 1 and 2 (Domtar's 2014 BART analysis).[84] In this proposal, we also refer to certain parts of the Domtar BART evaluation submitted by the State in the 2008 Arkansas RH SIP, which we are hereafter referring to as the "2006/2007 Domtar BART analysis."[85] Although we already took action on that SIP submittal, we reference the 2006/2007 Domtar BART analysis as it contains the best available information we have related to certain $NO_X$ controls for Power Boilers No. 1 and 2.

### a. Baseline Emission Rates and Existing Visibility Impairment Attributable to the Domtar Ashdown Mill Power Boilers No. 1 and 2

The table below summarizes the baseline emission rates for Power Boilers No. 1 and 2. The $SO_2$ baseline emission rate for Power Boiler No. 1 used in Domtar's 2014 BART analysis is the highest actual 24-hour emission rate estimated using maximum 24-hour fuel usage rates during 2009-2011 and sulfur content values for each fuel type.[86] The 2009-2011 period was used as the baseline in Domtar's evaluation for Power Boiler No. 1 because a wet ESP was installed on Power Boiler No. 1 in 2007 to meet the Maximum Achievable Control Technology (MACT)

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[84] See "Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41-00002)," originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC. A copy of this BART analysis is found in the docket for our proposed rulemaking.

[85] See "Best Available Retrofit Technology Determination Domtar Industries Inc., Ashdown Mill (AFIN 41-00002)," originally dated October 31, 2006 and revised on March 26, 2007, prepared by Trinity Consultants Inc. This BART analysis is part of the 2008 Arkansas RH SIP, upon which EPA took final action on March 12, 2012 (77 FR 14604). A copy of this BART analysis is found in the docket for this proposed rulemaking.

[86] In Domtar's 2014 BART analysis, 2009-2011 was used as the baseline period for Power Boiler No. 1 because a wet ESP was installed on Power Boiler No. 1 in 2007. The installation of the wet ESP resulted in a reduction in PM and $SO_2$ emissions from Power Boiler No. 1. Therefore, 2009-2011 is more representative of the boiler's emissions than 2001-2003.

standards under CAA section 112, resulting in a reduction in PM and $SO_2$ emissions from Power Boiler No. 1. Therefore, we believe that the 2009-2011 period is more representative of the boiler's current emissions than 2001-2003. We believe the use of 2009-2011 as the new baseline period for Power Boiler No. 1 is consistent with the BART Guidelines, which provide that the baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source.[87] The $NO_X$ and PM baseline emission rates used for Power Boiler No. 1 are the highest actual 24-hour emission rates estimated using the maximum heat input from 2009-2011 and emission factors developed from the analysis of stack testing the facility had previously conducted. For Power Boiler No. 2, the baseline emission rates are the highest actual 24-hour emission rates based on a combination of 2001-2003 CEMS data, source-specific stack testing results, and emission factors from AP-42.

**Table 63. Domtar Ashdown Mill: Baseline Maximum 24-Hour Emission Rates**

| Subject to BART Unit | $NO_X$ Emissions (lbhr) | $SO_2$ Emissions (lb/hr) | $PM_{10}/PM_f$ Emissions (lb/hr) |
|---|---|---|---|
| Power Boiler No. 1 | 207.4 | 21.0 | 30.4 |
| Power Boiler No. 2 | 526.8 | 788.2 | 81.6 |

Domtar modeled the baseline emission rates using the CALPUFF dispersion model to determine the baseline visibility impairment attributable to the Domtar Ashdown Mill's Power Boilers No. 1 and 2 at the four Class I areas impacted by emissions from BART sources in Arkansas. These Class I areas are the Caney Creek Wilderness Area, Upper Buffalo Wilderness Area, Hercules-Glades Wilderness Area, and Mingo National Wildlife Refuge. The baseline (*i.e.*, existing) visibility impairment attributable to the source at each Class I area is summarized in the table below.

**Table 64. Baseline Visibility Impairment Attributable to the Domtar Ashdown Mill**

| Emission Unit | | Caney Creek | Upper Buffalo | Hercules-Glades | Mingo |
|---|---|---|---|---|---|
| Power Boiler No. 1 | Maximum (Δdv) | 0.476 | 0.090 | 0.077 | 0.060 |
| | 98th Percentile (Δdv) | 0.335 | 0.038 | 0.020 | 0.014 |

[87] 40 CFR Part 51, Appendix Y, section IV.D.4.c.

| | | | | | |
|---|---|---|---|---|---|
| Power Boiler No. 2 | Maximum (Δdv) | 1.603 | 0.381 | 0.329 | 0.246 |
| | 98th Percentile (Δdv) | 0.844 | 0.146 | 0.105 | 0.065 |

### b. $SO_2$ BART Evaluation and Proposed BART Determination for Power Boiler No. 1

The table above shows that the baseline visibility impairment attributable to Power Boiler No. 1 is relatively low based on the 98th percentile visibility impacts, ranging from 0.014 to 0.335 dv at each Class I area. An examination of the species contribution to the 98th percentile visibility impacts shows that $SO_2$ emissions contribute a very small portion of the visibility impairment attributable to Power Boiler No. 1 (see the table below). The $SO_4$ species contributes only 2.23 – 4.03% of the visibility impairment attributable to Power Boiler No. 1 at the modeled Class I areas. We also note that Power Boiler No. 1 combusts primarily bark, which results in very low $SO_2$ emissions due to the low sulfur content of bark.

**Table 65. 98th Percentile Baseline Visibility Impairment and Species Contribution for Domtar Ashdown Mill- Power Boiler No. 1**

| Emissions Unit | Class I area | 98th Percentile Visibility Impacts (dv)[88] | Species Contribution to 98th Percentile Visibility Impacts | | | |
|---|---|---|---|---|---|---|
| | | | 98th Percentile % $SO_4$ | 98th Percentile % $NO_3$ | 98th Percentile % $PM_{10}$ | 98th Percentile % $NO_2$ |
| Power Boiler No. 1 | Caney Creek | 0.335 | 2.23 | 85.26 | 6.68 | 5.83 |
| | Upper Buffalo | 0.038 | 2.75 | 85.89 | 8.03 | 3.32 |
| | Hercules-Glades | 0.020 | 2.70 | 91.82 | 3.94 | 1.55 |
| | Mingo | 0.014 | 4.03 | 90.06 | 5.13 | 0.78 |

The BART Rule provides that states, or EPA in this case, can adopt a more streamlined approach to making BART determinations where appropriate.[89] Considering the very low baseline visibility impairment that is due to $SO_2$ emissions from Power Boiler No. 1 and the fact

[88] The visibility impact shown represents the highest 98th percentile value among the three modeled years.
[89] 70 FR 39116.

that the boiler combusts primarily bark, which has a low sulfur content, we believe that any visibility improvement that could be achieved as a result of emissions reductions associated with the installation and operation of $SO_2$ controls would be negligible, and that the cost of those controls could not be justified. Therefore, we are proposing that the $SO_2$ baseline emission rate of 21.0 lb/hr satisfies $SO_2$ BART for Power Boiler No. 1. We are proposing this $SO_2$ emission rate on a 30 boiler-operating-day averaging basis, where in this particular case boiler-operating-day is defined as a 24-hour period between 12 midnight and the following midnight during which any fuel is fed into and/or combusted at any time in the Power Boiler. Power Boiler No. 1 is not currently equipped with a CEMS. To demonstrate compliance with this $SO_2$ BART emission limit we are proposing to require the facility to use a site-specific curve equation,[90] provided to us by the facility, to calculate the $SO_2$ emissions from Power Boiler No. 1 when combusting bark, and to confirm the curve equation using stack testing.[91] We are also proposing that to calculate the $SO_2$ emissions from fuel oil combustion, the facility must assume that the $SO_2$ inlet is equal to the $SO_2$ being emitted at the stack. We are inviting public comment on whether this method of demonstrating compliance with the proposed BART emission limit is appropriate. Since this proposed BART determination does not require the installation of control equipment, we are proposing that this $SO_2$ emission limit be complied with by the effective date of the final action.

### c. $NO_X$ BART Evaluation for Power Boiler No. 1

*Step 1- Identify All Available Retrofit Control Technologies*

For $NO_X$ BART, Domtar's 2014 BART analysis evaluated SNCR and Methane de-$NO_X$ (MdN). In the 2006/2007 Domtar BART analysis, which was submitted in the 2008 Arkansas RH SIP, other $NO_X$ controls were also evaluated but found by Arkansas to be either already in use or not technically feasible for use at Power Boiler No. 1. Fuel blending, boiler operational modifications, and boiler tuning/optimization are already in use at the source, while FGR, LNB, Ultra Low $NO_X$ Burners (ULNB), OFA, and SCR were determined to be technically infeasible for use at Power Boiler No. 1. Domtar did not further evaluate these $NO_X$ controls in its 2014 BART analysis for Power Boiler No. 1, focusing instead on SNCR and MdN.

*Step 2- Eliminate Technically Infeasible Options*

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[90] The curve equation is Y= 0.4005 * X – 0.2645, where Y= pounds of sulfur emitted per ton dry fuel feed to the boiler and X= pounds of sulfur input per ton of dry bark. The purpose of this equation is to factor in the degree of $SO_2$ scrubbing provided by the combustion of bark.

[91] Background information and an explanation of the site specific curve equation provided by Domtar can be found in the documents titled "Site Specific Curve Equation Background_Domtar PB No1," and "1PB SO2 Emissions from Curve." Copies of these documents can be found in the docket for this proposed rulemaking.

MdN utilizes the injection of natural gas together with recirculated flue gases to create an oxygen-rich zone above the combustion grate. Air is then injected at a higher furnace elevation to burn the combustibles. In response to comments provided by us regarding Domtar's 2014 BART analysis, Domtar stated that discussions regarding the technical infeasibility of MdN in the 2006/2007 Domtar BART analysis, submitted as part of the 2008 Arkansas RH SIP, remain correct.[92] The 2006/2007 Domtar BART analysis submitted in the 2008 Arkansas RH SIP discussed that MdN has not been fully demonstrated for this source type and incorporates FGR, which is technically infeasible for use at Power Boiler No. 1. Domtar also stated it recently completed additional research and found that since the 2006/2007 Domtar BART analysis, MdN has not been placed into operation in power boilers at paper mills or any comparable source types. We are also not aware of any power boilers at paper mills that operate MdN for $NO_X$ control, and agree that this control can be considered technically infeasible for use at Power Boiler No. 1 and do not further consider it in this evaluation. Domtar also questioned the technical feasibility of SNCR for bark fired boilers and boilers with high load swings such as Power Boiler No. 1, but in response to our comments, SNCR was evaluated for Power Boiler No. 1 in Domtar's 2014 BART analysis.

*Step 3- Evaluate Control Effectiveness of Remaining Control Technologies*:

Domtar's 2014 BART analysis evaluated SNCR at removal efficiencies of 20%, 32.5%, and 45% for Power Boiler No. 1. The estimated 32.5% and 45% removal efficiencies were based on equipment vendor estimates that came from the vendor's proposal,[93] which according to the facility, is not an appropriations request level quote and therefore needs further refinement.[94] For example, Domtar's 2014 BART analysis discusses that for a base loaded pulp mill boiler with steady flue gas flow patterns and temperature distribution across the flue gas pathway, SNCR can achieve a 45% removal efficiency. However, Power Boiler No. 1 is not a base loaded boiler. Domtar's 2014 BART analysis states that for pulp mill boilers with fluctuating loads (*i.e.*, high load swing), such as Power Boiler No. 1, SNCR is used primarily for polishing purposes (*i.e.*, < 20 to 30% $NO_X$ reduction) and it is uncertain whether higher removal efficiencies are achievable on a long-term basis. The facility believes that 20% removal efficiency, which has been

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[92] See the document titled "Domtar Responses to ADEQ Regarding Region 6 Comments on Domtar BART Analysis," p. 10. A copy of this document can be found in the docket for our proposed rulemaking.

[93] Fuel Tech Proposal titled "Domtar Paper Ashdown, Arkansas- $NO_X$ Control Options, Power Boilers 1 and 2," dated June 29, 2012. A copy of the vendor proposal is included under Appendix D to the "Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41-00002)," originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC. A copy of this BART analysis and its appendices is found in the docket for our proposed rulemaking.

[94] See the document titled "Domtar Responses to ADEQ Regarding Region 6 Comments on Domtar BART Analysis," p. 9. A copy of this document can be found in the docket for our proposed rulemaking.

demonstrated at a similar bark fired power boiler at another paper mill, is the most reasonable estimate of the removal efficiency of SNCR for Power Boiler No. 1.

*Step 4- Evaluate Impacts and Document the Results*

The four factors considered in this step are the costs of compliance, energy and non-air quality environmental impacts of compliance, existing pollution control technology in use at the source, and the remaining useful life of the source.

In Domtar's 2014 BART analysis, the capital costs, operating costs, and cost-effectiveness of SNCR were calculated based on methods and assumptions found in our Control Cost Manual, and supplemented with mill-specific cost information for water, fuels, and ash disposal and urea solution usage estimates from the equipment vendor.[95] The capital cost was annualized over a 30-year period and then added to the annual operating cost to obtain the total annualized costs. The annual emissions reductions associated with each $NO_X$ control option were determined by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. The baseline annual emissions used in the calculations are the uncontrolled actual emissions from the 2009-2011 baseline period. The average cost-effectiveness was calculated by dividing the total annual cost by the estimated annual $NO_X$ emissions reductions. The table below summarizes the cost of $NO_X$ controls for Power Boiler No. 1.

**Table 66. Summary of Cost of $NO_X$ Controls for Domtar Ashdown Mill Power Boiler No. 1**

| $NO_X$ Control Scenarios | Baseline Emission Rate ($NO_X$ tpy) | $NO_X$ Control Efficiency (%) | Annual Emissions Reduction ($NO_X$ tpy) | Capital Cost ($) | Total Annual Cost ($/yr) | Average Cost Effectiveness ($/ton) | Incremental Cost-Effectiveness ($/ton) |
|---|---|---|---|---|---|---|---|
| **SNCR- 20%** | 440 | 20% | 88 | 2,152,365 | 1,118,178 | 12,700 | - |
| **SNCR- 32.5%** | 440 | 32.5% | 143 | 2,423,587 | 1,144,103 | 7,996 | 471 |
| **SNCR- 45%** | 440 | 45% | 198 | 2,707,431 | 1,513,602 | 7,640 | 6,718 |

Domtar's 2014 BART analysis did not identify any energy or non-air quality environmental impacts associated with the use of SNCR. We are not aware of any unusual

[95] See "Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41-00002)," originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC. A copy of this BART analysis is found in the docket for our proposed rulemaking.

circumstances at the facility that create greater non-air quality environmental impacts than experienced elsewhere that may provide a basis for the elimination of these control options as BART (40 CFR Part 51, Appendix Y, section IV.D.4.i.2.). Therefore, we do not believe there are any energy or non-air quality environmental impacts associated with the operation of $NO_X$ controls at Power Boiler No. 1 that would affect our proposed BART determination.

Consideration of the presence of existing pollution control technology at the source is reflected in the BART analysis in two ways: first, in the consideration of available control technologies, and second, in the development of baseline emission rates for use in cost calculations and visibility modeling. Power Boiler No. 1 is currently equipped with a combustion air system to optimize boiler combustion efficiency, which has the co-benefit of reducing emissions. The baseline emission rate used in the cost calculations and visibility modeling reflects the use of the existing combustion air system.

We are not aware of any enforceable shutdown date for the Domtar Ashdown Mill Power Boiler No. 1, nor did Domtar's 2014 BART analysis indicate any future planned shutdown. This means that the anticipated useful life of the boiler is expected to be at least as long as the capital cost recovery period of controls. Therefore, a 30-year amortization period was assumed in the evaluation of SNCR as the remaining life of the boiler.

*Step 5- Evaluate Visibility Impacts*

In the 2014 BART analysis, Domtar assessed the visibility improvement associated with SNCR by modeling the $NO_X$ emission rates associated with each control option using CALPUFF, and then comparing the visibility impairment associated with the baseline emission rate to the visibility impairment associated with the controlled emission rates as measured by the 98$^{th}$ percentile modeled visibility impact. The tables below show the modeled emission rates and a comparison of the baseline (i.e., existing) visibility impacts and the visibility impacts associated with SNCR for each Class I area.

**Table 67. Summary of Emission Rates Modeled for $NO_X$ Controls for Domtar Ashdown Mill Power Boiler No.1**

| Scenario | $NO_X$ Emissions (lb/hr) | SO2 Emissions (lb/hr) | PM10/PMF Emissions (lb/hr) |
|---|---|---|---|
| **Baseline** | 207.4 | 21.0 | 30.4 |
| **SNCR 20.0%** | 165.9 | 21.0 | 30.4 |
| **SNCR 32.5%** | 140.0 | 21.0 | 30.4 |
| **SNCR 45.0%** | 114.1 | 21.0 | 30.4 |

| MdN | 103.7 | 21.0 | 30.4 |
|---|---|---|---|

**Table 68. Domtar Ashdown Mill Power Boiler No. 1: Summary of the 98th Percentile Visibility Impacts and Improvement due to SNCR**

| Class I area | Baseline Visibility Impact (dv) | SNCR- 20% | | SNCR- 32.5% | | | SNCR- 45% | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. SNCR 20% | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) | Incremental Visibility Improvement vs. SNCR 32.5% |
| Caney Creek | 0.335 | 0.274 | 0.061 | 0.237 | 0.098 | 0.037 | 0.199 | 0.136 | 0.038 |
| Upper Buffalo | 0.038 | 0.031 | 0.007 | 0.027 | 0.011 | 0.004 | 0.023 | 0.015 | 0.004 |
| Hercules-Glades | 0.020 | 0.017 | 0.003 | 0.014 | 0.006 | 0.003 | 0.012 | 0.008 | 0.002 |
| Mingo | 0.014 | 0.011 | 0.003 | 0.009 | 0.005 | 0.002 | 0.008 | 0.006 | 0.001 |
| Cumulative Visibility Improvement (Δdv) | -- | -- | 0.074 | -- | 0.12 | -- | -- | 0.165 | -- |

The table above shows that the installation and operation of SNCR is projected to result in visibility improvements of up to 0.136 dv at any single Class I area when operated at 45% removal efficiency, 0.098 dv when operated at 32.5% removal efficiency, and 0.061 dv when operated at 20% removal efficiency (based on the 98th percentile modeled visibility impacts).

**Our Proposed $NO_X$ BART determination for Power Boiler No. 1:**

Taking into consideration the five factors, we are proposing to determine that $NO_X$ BART for the Domtar Ashdown Mill Power Boiler No. 1 is an emission limit of 207.4 lb/hr on a 30 boiler-operating-day rolling average, where boiler-operating-day is defined as a 24-hour period between 12 midnight and the following midnight during which any fuel is fed into and/or combusted at any time in the Power Boiler. This emission limit is based on the boiler's $NO_X$ baseline emission rate and therefore represents current operating conditions.

MdN was determined to be not technically feasible for use at Power Boiler No. 1

because it has not been fully demonstrated for this source type and incorporates FGR, which is technically infeasible for use at the boiler. The installation and operation of SNCR is projected to result in some visibility improvement at the Class I areas. As discussed in more detail above, we concur with Domtar's position that 20% removal efficiency is the most reasonable estimate of the level of $NO_X$ control SNCR can achieve at Power Boiler No. 1. When operated at 20% removal efficiency, SNCR is projected to result in visibility improvement of up to 0.061 dv at any single Class I area and is estimated to cost $12,700/ton of $NO_X$ removed. We do not believe this high cost justifies the modest visibility improvement projected from the installation and operation of SNCR at 20% removal efficiency. Although there is uncertainty as to whether SNCR can achieve a long term removal efficiency of 45% or even 32.5% at Power Boiler No. 1, we believe that the associated costs are also too high and not justified by the projected visibility benefits. Installation and operation of SNCR at a 45% removal efficiency is projected to result in a visibility improvement of up to 0.136 dv at any single Class I area and is estimated to cost $7,640/ton of $NO_X$ removed. The operation of SNCR at a 32.5% removal efficiency is projected to result in visibility improvement of up to 0.098 dv at any single Class I area and is estimated to cost $7,996/ton of $NO_X$ removed. Therefore, we are proposing to determine that $NO_X$ BART for Power Boiler No. 1 is no additional control and are proposing that an emission limit of 207.4 lb/hr on a 30 boiler-operating-day rolling average satisfies $NO_X$ BART. In this particular case, we are defining boiler-operating-day as a 24-hour period between 12 midnight and the following midnight during which any fuel is fed into and/or combusted at any time in the Power Boiler. Power Boiler No. 1 is not currently equipped with a CEMS. To demonstrate compliance with this $NO_X$ BART emission limit we are proposing to require annual stack testing. We are inviting public comment on the appropriateness of this method for demonstrating compliance with the $NO_X$ BART emission limit for Power Boiler No. 1. Since this proposed BART determination does not require the installation of control equipment, we are proposing that this $NO_X$ emission limit be complied with by the effective date of the final action.

#### d. $SO_2$ BART Evaluation for Power Boiler No. 2

*Step 1- Identify All Available Retrofit Control Technologies*

Power Boiler No. 2 is currently equipped with two venturi wet scrubbers in parallel for removal of particulates and $SO_2$. Domtar's 2014 BART analysis evaluated upgrades to the existing venturi wet scrubbers and new add-on scrubbers for Power Boiler No. 2.[96] Domtar contracted with a vendor to evaluate upgrades to the existing venturi scrubbers and to provide a quote for a new add-on spray scrubber system that would be installed downstream of the existing

[96] See "Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41-00002)," originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC. A copy of this BART analysis is found in the docket for our proposed rulemaking.

venturi scrubbers.[97] Domtar's analysis states that the existing venturi scrubbers achieve an $SO_2$ control efficiency of approximately 90% and notes that this is within the normal range for the highest efficiency achieved by $SO_2$ control technologies. Domtar's analysis also indicates that the upgrades considered for the existing venturi scrubbers include (1) the elimination of bypass reheat, (2) the installation of liquid distribution rings, (3) the installation of perforated trays, (4) improvements to the auxiliary system requirement, and (5) a redesign of spray header and nozzle configuration.

Another option not evaluated in Domtar's 2014 BART analysis is the operation of the existing venturi scrubbers to achieve a higher $SO_2$ control efficiency than what is currently being achieved through the use of additional scrubbing reagent. Following discussions between us and Domtar, the facility provided additional information regarding the existing venturi scrubbers, including a description of the internal structure of the scrubbers, whether any scrubber upgrades have taken place, the type of reagent used, how the facility determines how much reagent to use, and the $SO_2$ control efficiency.[98] Domtar confirmed that no upgrades to the scrubbers have ever been performed and stated that 100% of the flue gas is treated by the scrubber systems. The scrubbing solution used in the venturi scrubbers is made up of three components: 15% caustic solution (*i.e.*, NaOH), bleach plant EO filtrate (typical pH above 9.0), and demineralizer anion rinse water (approximately 2.5% NaOH). The bleach plant EO filtrate and demineralizer anion rinse water are both waste byproducts from the processes at the plant. The 15% caustic solution is added to adjust the pH of the scrubbing solution and maintain it within the required range to ensure that sufficient $SO_2$ is removed from the flue gas in the scrubber to meet the permitted $SO_2$ emission limit of 1.20 lb/MMBtu on a three hour average. Each venturi scrubber has a recirculation tank that is equipped with level control systems to ensure that an adequate supply of the scrubbing solution is maintained. There are pH controllers in place that provide signals for the 15% caustic flow controllers to adjust the flow of the caustic solution to bring the pH into the desired set point range. The pH controllers are overridden in the event that $SO_2$ levels measured at the stack by the CEMS are above the operator set point of 0.86 lb/MMBtu on a two hour average (the $SO_2$ permit limit is 1.20 lb/MMBtu on a three hour average). This allows additional caustic feed to the scrubber solution to increase the pH and reduce the $SO_2$ measured at the stack. According to Domtar, the scrubber systems operate in this manner to maintain continuous compliance with permitted emission limits.

Domtar provided monthly average data for 2011, 2012, and 2013 on monitored $SO_2$ emissions from Power Boiler No. 2, mass of the fuel burned for each fuel type, and the percent

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[97] The information provided by the vendor to Domtar is found in Appendix D to the analysis titled "Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41-00002)," originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC.

[98] See the following: Letters dated July 9, 2014; July 21, 2014; August 15, 2014; August 29, 2014; and September 12, 2014, from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. Copies of these letters and all attachments are found in the docket for our proposed rulemaking.

sulfur content of each fuel type burned.[99] According to the data provided by Domtar, the monthly average $SO_2$ control efficiency of the existing scrubbers for the 2011-2013 period ranged from 57% to 90%. The data indicate that the monthly average control efficiency of the scrubbers is usually below 90%. The information provided also indicates that the facility could add more scrubbing solution to achieve greater $SO_2$ removal than what is necessary to meet permit limits.

Based on our discussions with Domtar and the additional information provided to us, we believe it is technically feasible to increase the current $SO_2$ control efficiency of the existing scrubbers from current levels to 90% on a monthly average basis through the use of additional scrubbing reagent.

*Step 2- Eliminate Technically Infeasible Options*

Domtar's analysis discusses that the vendor determined that any upgrades to the existing venturi scrubbers for purposes of achieving additional $SO_2$ control would involve efforts to increase pressure drop. Additionally, it determined that any additional control that could potentially be achieved from implementation of such upgrades would be marginal, but Domtar was unable to quantify the potential additional control. Therefore, Domtar determined that the installation of new add-on scrubbers to operate downstream of the existing scrubbers was more feasible than any upgrade option. The remainder of Domtar's analysis focused on the add-on scrubber option only.

Additionally, as discussed above, based on our discussions with Domtar and the additional information Domtar provided to us, we determined it would be technically feasible to increase the current control efficiency of the existing scrubbers through the use of additional scrubbing reagent. We evaluate this control option in this TSD.

*Step 3- Evaluate Control Effectiveness of Remaining Control Technologies*:

Based on the information provided to Domtar by the vendor, new add-on spray scrubbers were estimated to achieve 90% control efficiency on top of the $SO_2$ removal currently achieved by the existing venturi scrubbers. In Domtar's analysis, it was estimated that a controlled $SO_2$ emission rate of 78.8 lb/hr would be achieved by the operation of add-on spray scrubbers installed downstream of the existing venturi scrubbers.

To estimate the current control efficiency of the existing venturi scrubbers, we asked Domtar to provide monthly average data for 2011, 2012, and 2013 on monitored $SO_2$ emissions from Power Boiler No. 2, mass of the fuel burned for each fuel type, and the percent sulfur

[99] August 29, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. A copy of this letter and an Excel file attachment titled "Domtar 2PB Monthly SO2 Data," are found in the docket for our proposed rulemaking.

content of each fuel type burned.[100] Based on the information provided by Domtar, the monthly average $SO_2$ control efficiency of the existing scrubbers for the 2011-2013 period ranged from 57% to 90%. The data indicate that the monthly average control efficiency of the scrubbers is usually below 90%. Based on the monthly average $SO_2$ control efficiency data for the 2011-2013 period, we estimated the annual average $SO_2$ control efficiency for the three-year period to be approximately 69%.[101]

To determine the controlled emission rate that corresponds to the operation of the existing venturi scrubbers at a 90% removal efficiency, we first determined the $SO_2$ emission rate that corresponds to the operation of the scrubbers at the current control efficiency of 69%. Based on emissions data we obtained from Domtar, we determined that the No. 2 Power Boiler's annual average $SO_2$ emission rate for the years 2009-2011 was 280.9 lb/hr.[102] This annual average $SO_2$ emission rate corresponds to the operation of the scrubbers at a 69% removal efficiency. We also estimated that 100% uncontrolled emissions would correspond to an emission rate of approximately 915 lb/hr. Application of 90% control efficiency to this results in a controlled emission rate of 91.5 lb/hr, or 0.11 lb/MMBtu based on the boiler's maximum heat input of 820 MMBtu.[103]

*Step 4- Evaluate Impacts and Document the Results*

The four factors considered in this step are the costs of compliance, energy and non-air quality environmental impacts of compliance, existing pollution control technology in use at the source, and the remaining useful life of the source.

Domtar's estimates of the capital and operating and maintenance costs of add-on spray scrubbers for Power Boiler No. 2 were based on the equipment vendor's budget proposal and on calculation methods from our Control Cost Manual. Domtar annualized the capital cost of the add-on spray scrubbers over a 30-year amortization period and then added these to the annual

[100] August 29, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. A copy of this letter and an Excel file attachment titled "Domtar 2PB Monthly SO2 Data," are found in the docket for our proposed rulemaking.

[101] See the spreadsheet titled "Domtar 2PB Monthly SO2 Data." This spreadsheet was included as an attachment to the August 29, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. See also the spreadsheet titled "Domtar PB No2- Cost Effectiveness calculations." Copies of these documents can be found in the docket for this proposed rulemaking.

[102] See the spreadsheet titled "Domtar 2PB Monthly SO2 Data." This spreadsheet was included as an attachment to the August 29, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. See also the spreadsheet titled "No2 Boiler_Monthly Avg SO2 emission rate and calculations." Copies of these documents can be found in the docket for this proposed rulemaking.

[103] See the spreadsheet titled "No2 Boiler_Monthly Avg SO2 emission rate and calculations." A copy of this spreadsheet can be found in the docket for this proposed rulemaking.

operating costs to obtain the total annualized cost.[104] The average cost-effectiveness in dollars per ton removed was calculated by dividing the total annualized cost by the annual $SO_2$ emissions reductions. The average cost-effectiveness of the add-on spray scrubbers for Power Boiler No. 2 was estimated to be $5,258/ton of $SO_2$ removed (see table below). Domtar's analysis notes that because of constricted space, there is no existing property or adequate structure to support the add-on spray scrubber equipment. In our discussions with Domtar, the facility indicated that the installation of add-on spray scrubbers would require construction at the facility to accommodate the equipment, but an estimate of these costs was not available and therefore not factored into the cost estimates presented in Domtar's analysis.

**Table 69. Summary of Costs for Add-On Spray Scrubber for Power Boiler No. 2**

| Control Technology | Baseline Emission Rate ($SO_2$ tpy) | Controlled Emission Level (lb/hr) | Controlled Emission Rate (tpy) | Annual Emissions Reductions ($SO_2$ tpy) | Capital Cost* ($) | Annual Direct O&M Cost ($/yr) | Annual Indirect O&M Cost ($/yr) | Total Annual Cost ($/yr) | Average Cost Effectiveness ($/ton) |
|---|---|---|---|---|---|---|---|---|---|
| Add-on Spray Scrubber | 2,078 | 78.8 | 208 | 1,870 | 7,175,000 | 8,833,382 | 421,789 | 9,833,378 | 5,258 |

* Capital cost does not include new construction to accommodate equipment.

Based on the cost information provided by the facility, increasing the monthly average $SO_2$ control efficiency of the existing venturi scrubbers from current levels to 90% control efficiency would require replacing two scrubber pumps, which involves capital costs of $200,000.[105] It would also require additional scrubbing reagent, treatment of additional wastewater, treatment of additional raw water, and additional energy usage, which involves annual operation and maintenance costs of approximately $1.96 million. We annualized the capital cost of the two scrubber pumps over a 30-year amortization period, assuming a 7% interest rate. We calculated the annualized capital cost to be $16,120, and added this to the annual operating costs to obtain a total annual costs of $1,976,554.[106]

[104] See Appendices B and D to the "Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41-00002)," originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC.

[105] September 30, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. See also the spreadsheet titled "Domtar PB No2- Cost of Using Additional Scrubbing Reagent. Copies of these documents can be found in the docket for this proposed rulemaking.

[106] See the Excel spreadsheet titled "Domtar PB No2- Cost of Using Additional Scrubbing Reagent" for line items of the capital and operation and maintenance costs associated with the use additional scrubbing reagent, and for calculation of the total annual cost. This spreadsheet can be found in the docket for this proposed rulemaking.

We calculated the average cost-effectiveness in dollars per ton removed by dividing the total annual cost by the estimated annual $SO_2$ emissions reductions. To estimate the $SO_2$ annual emissions reductions expected from increasing the control efficiency of the scrubbers through the use of additional scrubbing solution, we calculated the annual average $SO_2$ control efficiency of the existing scrubbers. As discussed above, based on data provided by Domtar for the 2011-2013 period, we estimated the annual average $SO_2$ control efficiency for the three-year period to be approximately 69%.[107] Considering the baseline annual emissions for Power Boiler No. 2 are 2,078 $SO_2$ tpy, and assuming that the scrubbers currently operate at an annual average control efficiency of 69%, we have estimated that the uncontrolled annual emissions would be 6,769 $SO_2$ tpy and that operating the scrubbers at 90% control efficiency would result in controlled annual emissions of 677 $SO_2$ tpy.[108] By subtracting the controlled annual emission rate of 677 $SO_2$ tpy from the baseline annual emission rate of 2,078 $SO_2$ tpy, we estimate that increasing the control efficiency of the existing venturi scrubbers from the current level of 69% to 90% control efficiency would result in annual emissions reductions of 1,401 $SO_2$ tpy.[109] We estimate the average cost-effectiveness of using additional scrubbing reagent to increase the $SO_2$ control efficiency of the existing venturi scrubbers from the current control efficiency (estimated to be 69%) to 90% is $1,411/ton of $SO_2$ removed. The cost information is presented in the table below.

**Table 70. Summary of Cost of Using Additional Scrubbing Reagent to Increase Control Efficiency of Existing Venturi Scrubbers at Domtar Ashdown Mill Power Boiler No. 2**

| Control Option | Baseline Emission Rate ($SO_2$ tpy) | Controlled Emission Rate (tpy) | Annual Emissions Reductions ($SO_2$ tpy) | Capital Costs[110] ($) | Annual Operation & Maintenance Cost[111] ($/yr) | Total Annual Cost ($/yr) | Average Cost Effectiveness ($/ton) |
|---|---|---|---|---|---|---|---|
| Use of Additional Scrubbing Reagent | 2,078 | 677 | 1,401 | 200,000 | 1,960,434 | 1,976,554 | 1,411 |

[107] See the spreadsheet titled "Domtar 2PB Monthly SO2 Data." This spreadsheet was included as an attachment to the August 29, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. See also the spreadsheet titled "Domtar PB No2- Cost Effectiveness calculations." Copies of these documents can be found in the docket for this proposed rulemaking.

[108] See the spreadsheet titled "Domtar PB No2- Cost Effectiveness calculations." A copy of this spreadsheet can be found in the docket for this proposed rulemaking.

[109] *Id.*

[110] The capital costs consist of two new pumps for the existing scrubber system.

[111] The operation and maintenance costs consist of the following costs: additional scrubbing reagent, treatment of additional wastewater, treatment of additional raw water, and additional energy usage.

Domtar's 2014 BART analysis did not identify any energy or non-air quality environmental impacts associated with the use of add-on spray scrubbers. We are not aware of any unusual circumstances at the facility that create energy or non-air quality environmental impacts associated with the use of add-on spray scrubbers greater than experienced elsewhere that may therefore provide a basis for the elimination of this control option as BART (40 CFR Part 51, Appendix Y, section IV.D.4.i.2.). We are also not aware of any unusual circumstances at the facility that create energy or non-air quality environmental impacts associated with the use of additional scrubbing reagent to increase the control efficiency of the existing venturi scrubbers greater than experienced elsewhere that may therefore provide a basis for the elimination of this control option as BART. Therefore, we do not believe there are any energy or non-air quality environmental impacts associated with these control options at Power Boiler No. 2 that would affect our proposed BART determination.

Consideration of the presence of existing pollution control technology at the source is reflected in the BART analysis in two ways: first, in the consideration of available control technologies, and second, in the development of baseline emission rates for use in cost calculations and visibility modeling. Power Boiler No. 2 is equipped with multiclones for particulate removal and two venturi scrubbers in parallel for control of $SO_2$ emissions. It is also equipped with a combustion air system including overfire air to optimize boiler combustion efficiency, which also helps control emissions. The baseline emission rate used in the cost calculations and visibility modeling reflects the use of these existing controls. As discussed above, Domtar's analysis also evaluated upgrades to the existing venturi scrubbers to potentially achieve greater $SO_2$ control efficiency. Another option we have identified and are evaluating in this TSD is to use additional scrubbing reagent to achieve greater $SO_2$ control efficiency of the existing venturi scrubbers,

We are not aware of any enforceable shutdown date for the Domtar Ashdown Mill Power Boiler No. 2, nor did Domtar's 2014 BART analysis indicate any enforceable future planned shutdown. This means that the anticipated useful life of the boiler is expected to be at least as long as the capital cost recovery period of the add-on spray scrubbers. Therefore, a 30-year amortization period was assumed in the evaluation of the add-on spray scrubbers as the remaining useful life of the boiler. A 30-year amortization period was also assumed for the scrubber pump replacements required for using additional scrubbing reagent.

*Step 5- Evaluate Visibility Impacts*

In the 2014 BART analysis, Domtar assessed the visibility improvement associated with the add-on spray scrubbers by modeling the controlled $SO_2$ emission rate using CALPUFF, and then comparing the visibility impairment associated with the controlled emission rate to that of the baseline emission rate as measured by the 98$^{th}$ percentile modeled visibility impact. The tables below show the emission rates modeled and a comparison of the baseline (*i.e.*, existing) visibility impacts and the visibility impacts associated with the add-on spray scrubbers. The installation and operation of add-on spray scrubbers is projected to result in visibility improvement of 0.146 dv at Caney Creek. The visibility improvement is projected to range from 0.026 to 0.053 dv at each of the other Class I areas.

**Table 71. Summary of Emission Rates Modeled for $SO_2$ Controls for Domtar Power Boiler No.2**

| Scenario | $NO_X$ Emissions (lb/hr) | $SO_2$ Emissions (lb/hr) | $PM_{10}$/PMF Emissions (lb/hr) |
|---|---|---|---|
| Baseline | 526.8 | 788.2 | 81.6 |
| Add-on Spray Scrubber | 526.8 | 78.8 | 81.6 |

**Table 72. Domtar Ashdown Mill Power Boiler No. 2: Summary of the 98th Percentile Visibility Impacts and Improvement due to Add-on Spray Scrubbers**

| Class I area | Baseline Visibility Impact[112] (dv) | Add-on Spray Scrubbers | |
|---|---|---|---|
| | | Visibility Impact (Δdv) | Visibility Improvement from Baseline (Δdv) |
| Caney Creek | 0.844 | 0.698 | 0.146 |
| Upper Buffalo | 0.146 | 0.093 | 0.053 |
| Hercules-Glades | 0.105 | 0.054 | 0.051 |
| Mingo | 0.065 | 0.039 | 0.026 |
| Cumulative Visibility Improvement (Δdv) | -- | -- | 0.276 |

Using the visibility modeling analysis of the baseline visibility impacts from Power Boiler No. 2 and the visibility improvement projected from the installation and operation of new add-on spray scrubbers, we have extrapolated the visibility improvement projected as a result of using additional scrubbing reagent to increase the $SO_2$ control efficiency of the existing venturi

[112] The baseline visibility impacts reflect the operation of the existing venturi scrubbers.

scrubbers from the current control efficiency (estimated to be 69%) to 90%, or an outlet emission rate of 0.11 lb/MMBtu. We have assumed that the maximum 24-hour baseline emission rate used in the visibility modeling represents the operation of the existing venturi scrubbers at a 69% control efficiency. We estimate that the visibility improvement of using additional scrubbing reagent to increase the $SO_2$ control efficiency of the existing venturi scrubbers to 90% control efficiency is 0.139 dv at Caney Creek and 0.05 dv or less at each of the other Class I areas (see table below).

**Table 73. Domtar Ashdown Mill Power Boiler No. 2: Summary of the 98$^{th}$ Percentile Visibility Impacts and Improvement from Use of Additional Scrubbing Reagent**

| Class I area | Baseline Visibility Impact (dv) | Add-on Spray Scrubber Impacts (dv) | | Estimated Impacts from Use of Additional Reagent (dv) | |
|---|---|---|---|---|---|
| | | Visibility Impact (dv) | Visibility Improvement from Baseline (dv) | Visibility Impact (dv) | Visibility Improvement from Baseline (dv) |
| Caney Creek | 0.844 | 0.698 | 0.146 | 0.705 | 0.139 |
| Upper Buffalo | 0.146 | 0.093 | 0.053 | 0.096 | 0.05 |
| Hercules-Glades | 0.105 | 0.054 | 0.051 | 0.057 | 0.048 |
| Mingo | 0.065 | 0.039 | 0.026 | 0.04 | 0.025 |
| Cumulative Visibility Improvement (dv) | -- | -- | 0.276 | -- | 0.262 |

**Our Proposed $SO_2$ BART determination Power Boiler No. 2:**

Taking into consideration the five factors, we propose to determine that $SO_2$ BART for Power Boiler No. 2 is an emission limit of 0.11 lb/MMBtu on a 30 boiler-operating-day rolling average, which we estimate is representative of operating the existing scrubbers at 90% control efficiency. In this particular case, we define boiler-operating-day as a 24-hour period between 12 midnight and the following midnight during which any fuel is fed into and/or combusted at any time in the Power Boiler. We are inviting public comment specifically on the appropriateness of this proposed $SO_2$ emission limit. We believe that this emission limit can be achieved by using additional scrubbing reagent in the operation of the existing venturi scrubbers. We estimate that operating the existing scrubbers to achieve this level of control would result in visibility improvement of 0.139 dv at Caney Creek and 0.05 dv or lower at each of the other Class I areas.

We estimate the cumulative visibility improvement at the four Class I areas to be 0.262 dv. Based on the cost information provided by the facility, we have estimated that the use of additional scrubbing reagent to increase the control efficiency of the existing venturi scrubbers is estimated to cost $1,411/ton of $SO_2$ removed. Based on Domtar's BART analysis, new add-on spray scrubbers that would be operated downstream of the existing venturi scrubbers are projected to result in visibility improvement of 0.146 dv at Caney Creek and 0.053 dv or lower at each of the other Class I areas. The cumulative visibility improvement at the four Class I areas is projected to be 0.276 dv. The cost of add-on spray scrubbers is estimated to be $5,258/ton of $SO_2$ removed, not including additional construction costs that would likely be incurred to make space to house the new scrubbers. We do not believe that the amount of visibility improvement that is projected from the installation and operation of new add-on spray scrubbers would justify their high average cost-effectiveness. The incremental visibility improvement of new add-on spray scrubbers compared to using additional scrubbing reagent to increase the control efficiency of the existing venturi scrubbers ranges from 0.001 to 0.007 dv at each Class I area, yet the incremental cost-effectiveness is estimated to be $16,752. We do not believe the incremental visibility benefit warrants the higher cost associated with new add-on spray scrubbers. Therefore, we are proposing to determine that $SO_2$ BART for Power Boiler No. 2 is an emission limit of 0.11 lb/MMBtu on a 30 boiler-operating-day rolling averaging basis, and are inviting comment on the appropriateness of this emission limit. We propose to require the facility to demonstrate compliance with this emission limit using the existing CEMS. Since the $SO_2$ emission limit we are proposing can be achieved with the use of the existing venturi scrubbers but will require scrubber pump upgrades and the use of additional scrubbing reagent, we propose to require compliance with this BART emission limit no later than 3 years from the effective date of the final action, but are inviting public comment on the appropriateness of a compliance date anywhere from 1 – 5 years.

**$NO_X$ BART Evaluation for Power Boiler No. 2**

*Step 1- Identify All Available Retrofit Control Technologies*

For $NO_X$ BART, Domtar's 2014 BART analysis evaluated LNB, SNCR, and Methane de-$NO_X$ (MdN). In the 2006/2007 Domtar BART analysis, which was submitted in the 2008 Arkansas RH SIP, other $NO_X$ controls were also evaluated but found by the State to be either already in use or not technically feasible for use at Power Boiler No. 2. Fuel blending, boiler operational modifications, and boiler tuning/optimization are already in use at the source, while FGR, OFA, and SCR were found to be technically infeasible for use at Power Boiler No. 2. Domtar did not further evaluate these $NO_X$ controls, and instead focused on LNB, SNCR, and MdN in its 2014 BART analysis for Power Boiler No. 2.

*Step 2- Eliminate Technically Infeasible Options*

MdN utilizes the injection of natural gas together with recirculated flue gases to create an oxygen-rich zone above the combustion grate. Air is then injected at a higher furnace elevation to burn the combustibles. In response to comments provided by us regarding Domtar's 2014 BART analysis, Domtar stated that discussions regarding the technical infeasibility of MdN in the 2006/2007 Domtar BART analysis, submitted as part of the 2008 Arkansas RH SIP, remain correct.[113] The 2006/2007 Domtar BART analysis submitted in the 2008 Arkansas RH SIP discussed that MdN has not been fully demonstrated for this type of boiler and incorporates FGR, which is considered technically infeasible for use at Power Boiler No. 2. Domtar also stated it recently completed additional research and found that since the 2006/2007 Domtar BART analysis, MdN has not been placed into operation in power boilers at paper mills or any comparable source types. We are also not aware of any power boilers at paper mills that operate MdN for $NO_X$ control, and agree that this control can be considered technically infeasible for use at Power Boiler No. 2 and do not further consider it in this evaluation. Domtar also questioned the technical feasibility of SNCR for boilers with high load swing such as Power Boiler No. 2, but in response to comments from us, SNCR was evaluated in Domtar's 2014 BART analysis.

*Step 3- Evaluate Control Effectiveness of Remaining Control Technologies*:

Based on vendor estimates, the 2006/2007 Domtar BART analysis estimated the potential control efficiency of LNB to be 30%. In Domtar's 2014 BART analysis, SNCR was evaluated at a control efficiency of 27.5% and 35% for Power Boiler No. 2. These values were based on SNCR control efficiency estimates that came from the equipment vendor's proposal,[114] which according to the facility, is not an appropriations request level quote and therefore requires further refinement.[115] For example, Domtar's 2014 BART analysis discusses that for a base loaded coal boiler with steady flue gas flow patterns and temperature distribution across the flue gas pathway, SNCR is typically capable of achieving 50% $NO_X$ reduction. However, Power Boiler No. 2 is not a base loaded boiler and does not have steady flue gas flow patterns or steady temperature distribution across the flue gas pathway.

To demonstrate the wide range in temperature at Power Boiler No. 2 and its relationship to steam demand, Domtar obtained an analysis of furnace exit gas temperatures for Power Boiler

[113] See the document titled "Domtar Responses to ADEQ Regarding Region 6 Comments on Domtar BART Analysis," p. 10. A copy of this document can be found in the docket for our proposed rulemaking.

[114] Fuel Tech Proposal titled "Domtar Paper Ashdown, Arkansas- $NO_X$ Control Options, Power Boilers 1 and 2," dated June 29, 2012. A copy of the vendor proposal is included under Appendix D to the "Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41-00002)," originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC. A copy of this BART analysis and its appendices is found in the docket for our proposed rulemaking.

[115] See the document titled "Domtar Responses to ADEQ Regarding Region 6 Comments on Domtar BART Analysis," p. 9. A copy of this document can be found in the docket for our proposed rulemaking.

No. 2 from an engineering consultant.[116] The furnace exit gas temperatures were analyzed for a 12-day period that according to Domtar is representative of typical boiler operations. The consultant's report indicated that furnace exit gas temperatures are representative of temperatures in the upper portion of the furnace, which is the optimal location for installation of the SNCR injection nozzles. The consultant estimated that 1700 – 1800°F represents the temperature range at which SNCR can be expected to reach 40% control efficiency at the current boiler operating conditions. It was found that there is wide variability in the furnace exit gas temperatures for Power Boiler No. 2, with temperatures ranging from 1000 – 2000°F. The data also indicate that there is a direct positive relationship between boiler steam demand and furnace exit gas temperatures. It was also found that Power Boiler No. 2 operated in the optimal temperature zone at which SNCR can be expected to reach 40% control efficiency for only a total of 20 hours over the 12-day period analyzed (288 continuous hours), which is approximately 7% of the time.

According to Domtar, the significant temperature swings, which are due to load following and steam demand variability, create a scenario where urea injection will either be too high or too low. When not enough urea is injected, $NO_X$ removal will be less than projected and when too much urea is injected, excess ammonia slip will occur. Domtar stated that the observed significant temperature swings demonstrate that it will be difficult to maintain stable, optimal furnace temperatures at which urea can be injected to effectively reduce $NO_X$ with minimal ammonia slip. We agree that because of the wide variability in steam demand and wide range in furnace temperature observed at Power Boiler No. 2, the $NO_X$ control efficiency of SNCR at the boiler would not reach optimal control levels on a long-term basis. We also believe there is uncertainty as to the level of control efficiency that SNCR would be able to achieve on a long-term basis for Power Boiler No. 2. However, we further consider SNCR in the remainder of the analysis.

*Step 4- Evaluate Impacts and Document the Results*

The four factors considered in this step are the costs of compliance, energy and non-air quality environmental impacts of compliance, existing pollution control technology in use at the source, and the remaining useful life of the source.

In the 2006/2007 Domtar BART analysis, the capital cost, operating cost, and cost-effectiveness of LNB were estimated based on vendor estimates.[117] The analysis was based on a 10-year amortization period, based on the equipment's life expectancy. However, since we believe a 30-year equipment life is a more appropriate estimate for LNB, we have we have

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[116] September 12, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. A copy of this letter and its attachments are found in the docket for our proposed rulemaking

[117] See "Best Available Retrofit Technology Determination Domtar Industries Inc., Ashdown Mill (AFIN 41-00002)," originally dated October 31, 2006 and revised on March 26, 2007, prepared by Trinity Consultants Inc. This BART analysis is part of the 2008 Arkansas RH SIP, upon which EPA took final action on March 12, 2012 (77 FR 14604). A copy of this BART analysis is found in the docket for this proposed rulemaking.

adjusted Domtar's cost estimate for LNB.[118] The annual emissions reductions used in the cost-effectiveness calculations were determined by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. We have also adjusted the average cost-effectiveness calculations presented in the 2006/2007 Domtar BART analysis for LNB by using the boiler's actual annual uncontrolled $NO_X$ emissions rather than the maximum 24-hour emission rate as the baseline annual emissions. The table below summarizes the estimated cost of LNB for Power Boiler No. 2, based on our adjustments to the cost estimates in the 2006/2007 Domtar BART analysis as discussed above.

In Domtar's 2014 BART analysis, the capital costs, operating costs, and cost-effectiveness of SNCR were calculated based on methods and assumptions found in our Control Cost Manual, and supplemented with mill-specific cost information for water, fuels, and ash disposal and urea solution usage estimates from the equipment vendor.[119] The two SNCR control scenarios evaluated were 27.5% and 35% control efficiencies. Domtar annualized the capital cost over a 30-year period and then added to the annual operating cost to obtain the total annualized costs. The annual emissions reductions associated with each $NO_X$ control option were determined by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. The baseline annual emissions used in the calculations are the uncontrolled actual emissions from the 2001-2003 baseline period. The average cost-effectiveness was calculated by dividing the total annual cost by the estimated annual $NO_X$ emissions reductions. The table below summarizes Domtar's estimate of the cost of SNCR for Power Boiler No. 2.

**Table 74. Summary of Cost of $NO_X$ Controls for Power Boiler No. 2**

| $NO_X$ Control Scenario | Baseline Emission Rate ($NO_X$ tpy) | $NO_X$ Removal Efficiency of Controls (%) | Annual Emissions Reduction ($NO_X$ tpy) | Capital Cost ($) | Total Annual Cost ($/yr) | Average Cost Effectiveness ($/ton) | Incremental Cost-Effectiveness ($/ton) |
|---|---|---|---|---|---|---|---|
| **SNCR- 27.5%** | 1,536 | 27.5% | 422 | 2,681,678 | 843,575 | 1,998 | - |
| **LNB** | 1,536 | 30% | 461 | 6,131,745 | 899,605 | 1,951 | 1,437 |
| **SNCR- 35%** | 1,536 | 35% | 537 | 2,877,523 | 1,026,214 | 1,909 | 1,666 |

[118] See the spreadsheet titled "Domtar PB No2 LNB_cost revisions." A copy of this spreadsheet is found in the docket for this proposed rulemaking.

[119] See "Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41-00002)," originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC. A copy of this BART analysis is found in the docket for our proposed rulemaking.

Domtar's 2014 BART analysis did not identify any energy or non-air quality environmental impacts associated with the use of LNB or SNCR. We are not aware of any unusual circumstances at the facility that could create energy or non-air quality environmental impacts associated with the operation of $NO_X$ controls greater than experienced elsewhere and that may therefore provide a basis for the elimination of these control options as BART (40 CFR Part 51, Appendix Y, section IV.D.4.i.2.). Therefore, we do not believe there are any energy or non-air quality environmental impacts associated with $NO_X$ controls at Power Boiler No. 2 that would affect our proposed BART determination.

Consideration of the presence of existing pollution control technology at the source is reflected in the BART analysis in two ways: first, in the consideration of available control technologies, and second, in the development of baseline emission rates for use in cost calculations and visibility modeling. Power Boiler No. 2 is equipped with multiclones for particulate removal and two venturi scrubbers in parallel for control of $SO_2$ emissions. It is also equipped with a combustion air system including overfire air to optimize boiler combustion efficiency, which also helps control emissions. The $NO_X$ baseline emission rate used in the cost calculations and visibility modeling reflects the use of these existing controls.

We are not aware of any enforceable shutdown date for the Domtar Ashdown Mill Power Boiler No. 2, nor did Domtar's 2014 BART analysis indicate any future enforceable planned shutdown. This means that the anticipated useful life of the boiler is expected to be at least as long as the capital cost recovery period of controls. Therefore, a 30-year amortization period was assumed in the evaluation of LNB and SNCR as the remaining life of the boiler.

*Step 5- Evaluate Visibility Impacts*

In the 2014 BART analysis, Domtar assessed the visibility improvement associated with LNB and SNCR by modeling the $NO_X$ emission rates associated with each control option using CALPUFF, and then comparing the visibility impairment associated with the baseline emission rate to the visibility impairment associated with the controlled emission rates as measured by the $98^{th}$ percentile modeled visibility impact. The tables below show the modeled emission rates and a comparison of the baseline (*i.e.*, existing) visibility impacts and the visibility impacts associated with LNB and SNCR for each Class I area.

**Table 75. Summary of Emission Rates Modeled for $SO_2$ Controls for Domtar Power Boiler No. 2**

| Scenario | $NO_X$ Emissions (lb/hr) | $SO_2$ Emissions (lb/hr) | $PM_{10}$/PMF Emissions (lb/hr) |
|---|---|---|---|
| Baseline | 526.8 | 788.2 | 81.6 |
| Add-on Spray Scrubber | 526.8 | 78.8 | 81.6 |

**Table 76. Domtar Ashdown Mill Power Boiler No. 2: Summary of the 98th Percentile Visibility Impacts and Improvement due to $NO_X$ Controls**

| Class I area | Baseline Visibility Impact (dv) | SNCR- 27.5% Control Efficiency | | LNB 30% Control Efficiency | | | SNCR- 35% Control Efficiency | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Visibility Impact (dv) | Visibility Improvement from Baseline (dv) | Visibility Impact (dv) | Visibility Improvement from Baseline (dv) | Incremental Visibility Improvement vs. SNCR 27.5% (dv) | Visibility Impact (dv) | Visibility Improvement from Baseline (dv) | Incremental Visibility Improvement vs. SNCR 35% (dv) |
| Caney Creek | 0.844 | 0.678 | 0.166 | 0.663 | 0.181 | 0.015 | 0.632 | 0.212 | 0.031 |
| Upper Buffalo | 0.146 | 0.134 | 0.012 | 0.132 | 0.014 | 0.002 | 0.129 | 0.017 | 0.003 |
| Hercules-Glades | 0.105 | 0.095 | 0.010 | 0.094 | 0.011 | 0.001 | 0.092 | 0.013 | 0.002 |
| Mingo | 0.065 | 0.060 | 0.005 | 0.060 | 0.005 | 0.000 | 0.059 | 0.006 | 0.001 |
| Cumulative Visibility Improvement (dv) | -- | -- | 0.193 | -- | 0.211 | -- | -- | 0.248 | -- |

The table above shows that the installation and operation of SNCR when operated at 35% control efficiency, if feasible, is projected to result in visibility improvement of 0.212 dv at Caney Creek and 0.017 dv or less at each of the other Class I areas. When operated at 27.5% control efficiency, if feasible, SNCR is projected to result in visibility improvement of 0.166 dv at Caney Creek and 0.012 dv or less at each of the other Class I areas. The installation and operation of LNB is projected to result in visibility improvement of 0.181 dv at Caney Creek and 0.014 dv or less at each of the other Class I areas.

**EPA's Proposed $NO_X$ BART determination for Power Boiler No. 2:**

Taking into consideration the five factors, we are proposing to determine that $NO_X$ BART for the Domtar Ashdown Mill Power Boiler No. 2 is an emission limit of 345 lb/hr on a 30 boiler-operating-day rolling averaging basis, based on the installation and operation of LNB. In this particular case, we define boiler-operating-day as a 24-hour period between 12 midnight and the following midnight during which any fuel is fed into and/or combusted at any time in the Power Boiler. MdN was determined to be not technically feasible for use at Power Boiler No. 2 because it has not been fully demonstrated for this type of boiler and incorporates FGR, which is technically infeasible for use at the boiler. The installation and operation of SNCR is projected to result in some visibility improvement at the Class I areas when operated at 27.5% and 35%

control efficiency. However, based on the information provided by the facility, we believe that because of the wide variability in steam demand and wide range in furnace temperature observed in Power Boiler No. 2, the $NO_X$ control efficiency of SNCR at the boiler would not reach optimal control levels on a long-term basis. There is uncertainty as to the level of control efficiency that SNCR would be able to achieve on a long-term basis for Power Boiler No. 2.

The installation and operation of LNB is projected to result in visibility improvement of 0.181 dv at Caney Creek and 0.005 - 0.014 dv at each of the other Class I areas. The installation and operation of LNB is estimated to cost $1,951/ton of $NO_X$ removed, which we consider to be cost-effective. Therefore, we are proposing to determine that $NO_X$ BART for Power Boiler No. 2 is an emission limit of 345 lb/hr on a 30 boiler-operating-day rolling average basis, based on the installation and operation of LNB. We are proposing to require compliance with this emission limit no later than 3 years from the effective date of the final rule, and are inviting public comment on the appropriateness of this compliance date. We are proposing that the facility demonstrate compliance with this emission limit using the existing CEMS.

**e. PM BART Evaluation for Power Boiler No. 2**

PM BART for Power Boiler No. 2 is addressed in Domtar's 2014 BART analysis. Power Boiler No. 2 is subject to the Boiler MACT standards required under CAA section 112, and found at 40 CFR Part 63, Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. Domtar streamlined the BART analysis for Power Boiler No. 2 by relying on the Boiler MACT standards for PM to satisfy the PM BART requirement. Power Boiler No. 2 was determined to fall under the "biomass hybrid suspension grate" subcategory for the Boiler MACT.[120] As such, Power Boiler No. 2 is subject to the Boiler MACT PM emission limit of 0.44 lb/MMBtu. The BART Guidelines provide that for VOC and PM sources subject to MACT standards, the BART analysis may be streamlined by including a discussion of the MACT controls and whether any major new technologies have been developed subsequent to the MACT standards.[121] The BART Guidelines discuss that there are many VOC and PM sources that are well controlled because they are regulated by the MACT standards, and in many cases it will be unlikely that emission controls more stringent than the MACT standards will be identified without identifying control options that would cost many thousands of dollars per ton. Therefore, the BART Guidelines provide that unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, the MACT standards may be relied on for purposes of BART.

[120] See letter dated October 28, 2013, from Thomas Rheaume, Permits Branch Manager, ADEQ, to Ms. Kelly Crouch, Manager of Environmental, Energy, and Pulp Tech. at Domtar Ashdown Mill. A copy of this letter is found in the docket for this proposed rulemaking.

[121] 40 CFR Part 51, Appendix Y, section IV.C.

Domtar's 2014 BART analysis does not discuss whether any new technologies subsequent to the MACT standards have become available and whether they would lead to cost-effective increases in the level of PM control for Power Boiler No. 2. However, Domtar at one point estimated the cost of installing both an add-on spray scrubber and wet ESP on Power Boiler No. 2. Based on this cost information previously provided by Domtar,[122] we have estimated that a wet ESP alone would have a purchased equipment cost (PEC) of $3.22 million and capital costs of approximately $11.3 million. The total annual cost of a wet ESP alone is estimated to be approximately $1.96 million. The average annual PM emissions from Power Boiler No. 2 for the 2001-2003 baseline period were 183 tpy. Assuming that the wet ESP has a 95% control efficiency for PM emissions, we estimate that it would result in PM emissions reductions of 174 tpy. Based on this, we estimate that the average cost-effectiveness of installing and operating a wet ESP on Power Boiler No. 2 is $11,254/ton PM removed. Additionally, an examination of the species contribution to the 98$^{th}$ percentile visibility impacts shows that PM emissions contribute a very small portion of the visibility impairment attributable to Power Boiler No. 2. As shown in the table below, the baseline visibility impairment attributable to Power Boiler No. 2 is 0.844 dv at Caney Creek and 0.146 dv or less at each of the other Class I areas, based on the 98$^{th}$ percentile visibility impacts. The PM species contribute only 1.06 – 4.58% of the baseline visibility impairment attributable to Power Boiler No. 2 at the modeled Class I areas.

**Table 77. Baseline Visibility Impairment and Species Contribution for Domtar Ashdown Mill- Power Boiler No. 2**

| Emissions Unit | Class I area | 98th Percentile Visibility Impacts (dv)[123] | Species Contribution to 98$^{th}$ Percentile Visibility Impacts | | | |
|---|---|---|---|---|---|---|
| | | | 98$^{th}$ Percentile % $SO_4$ | 98th Percentile % $NO_3$ | 98th Percentile % $PM_{10}$ | 98th Percentile % $NO_2$ |
| Power Boiler No. 2 | Caney Creek | 0.844 | 22.04 | 70.68 | 4.58 | 2.69 |
| | Upper Buffalo | 0.146 | 76.99 | 20.76 | 2.26 | 0.00 |
| | Hercules-Glades | 0.105 | 61.17 | 37.68 | 1.06 | 0.09 |

[122] The cost estimate of new add-on spray scrubbers and a wet ESP for Power Boiler No. 2 is found in Appendix B to the analysis titled "Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41-00002)," dated June 28, 2013, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC. A copy of the BART analysis is found in the docket for our proposed rulemaking

[123] The visibility impact shown represents the highest 98$^{th}$ percentile value among the three modeled years.

| | | | | | | |
|---|---|---|---|---|---|---|
| | Mingo | 0.065 | 81.46 | 15.47 | 3.07 | 0.00 |

**EPA's Proposed PM BART determination for Power Boiler No. 2:**

Because of the very low baseline visibility impacts that are due to PM emissions from Power Boiler No. 2, we believe that there is potential for a very small amount of visibility improvement from the installation and operation of a wet ESP. We conclude that cost of installing and operating PM controls would not be justified in light of the relatively small amount of visibility improvement that could be achieved. Therefore, we are proposing to find that the current Boiler MACT PM standard of 0.44 lb/MMBtu satisfies the PM BART requirement for Power Boiler No. 2. We are also proposing that the same method for demonstrating compliance with the Boiler MACT PM standard is to be used for demonstrating compliance with the PM BART emission limit. Because we are proposing a BART emission limit that represents current/baseline operations and no control equipment installation is necessary, we are proposing that this emission limitation be complied with for BART purposes from the effective date of the final action.

## III. Reasonable Progress Goals

The vehicle for ensuring continuing progress towards achieving the natural visibility goal is the submission of a series of regional haze SIPs from the states that establish two RPGs (*i.e.*, two distinct goals, one for the "best" and one for the "worst" days) for every Class I area for each (approximately) 10-year implementation period.[124] The RHR does not mandate specific milestones or rates of progress, but instead calls for states to establish goals that provide for "reasonable progress" toward achieving natural (*i.e.*, "background") visibility conditions.

The RHR and section 169A of the CAA require the State, or EPA in the case of a FIP, to set RPGs by considering four factors: the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources (collectively "the RP factors").[125] States, or EPA in the case of a FIP, have considerable flexibility in how they take these factors into consideration, as noted in EPA's Reasonable Progress Guidance.[126] The RPGs must provide for an improvement in visibility on the most impaired days, and ensure no degradation in visibility

[124] 40 CFR 51.308(d), (f), and 70 FR 3915

[125] 40 CFR 51.308(d)(1)(i)(A) and CAA section 169A(g)(1).

[126] *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program,* June 1, 2007, memorandum from William L. Wehrum, Acting Assistant Administrator for Air and Radiation, to EPA Regional Administrators, EPA Regions 1-10 (pp. 4-2, 5-1).

on the least impaired days during the planning period.[127] Furthermore, if the projected progress for the worst days is less than the Uniform Rate of Progress (URP), then the state or EPA must demonstrate, based on the factors above, that it is not reasonable to provide for a rate of progress consistent with the URP.[128]

### A. Arkansas' Reasonable Progress Goals – 2018 Visibility Projections

In the 2008 Arkansas RH SIP, which we partially approved and partially disapproved in March 12, 2012, the State adopted the CENRAP modeled 2018 visibility conditions as the RPGs for Caney Creek and Upper Buffalo. ADEQ established a RPG of 22.48 dv for Caney Creek for 2018 for the 20% worst days, which represents a 3.88 dv improvement over a baseline of 26.36 dv. For Upper Buffalo, ADEQ established a RPG of 22.52 dv for 2018 for 20% worst days, which represents a 3.75 dv improvement over a baseline of 26.27 dv.

In our final action on the Arkansas RH SIP published on March 12, 2012, we disapproved the RPGs established by Arkansas for Caney Creek and Upper Buffalo because Arkansas did not establish the RPGs in accordance with the requirements of the CAA and the RHR.[129] Specifically, Arkansas did not take into consideration the four RP factors in establishing its RPGs for Caney Creek and Upper Buffalo, stating that it was an unnecessary exercise. Arkansas believed, incorrectly, that no additional analysis of potential reasonable progress measures was necessary because visibility projections for the Class I areas indicated improvements in visibility consistent with the URP. As discussed in our disapproval action, a state must determine whether additional control measures are reasonable based on a consideration of the four RP factors. Accordingly, in this proposed rule, we are evaluating the four RP factors to determine whether additional controls are reasonable and we are establishing RPGs for Caney Creek and Upper Buffalo after consideration of the RP factors.

### B. Reasonable Progress Analysis

A discussion of the particular pollutants that contribute to visibility impairment at Arkansas' two Class I areas was provided in our October 17, 2011 proposed action on the 2008 Arkansas RH SIP (see 76 FR 64186). In that proposed action, we explained that CENRAP used CAMx with its Particulate Source Apportionment (PSAT) tool to provide source apportionment by geographic region and major source category (i.e., point, natural, on-road, non-road, and area sources).

Sulfate from all the source categories combined contributed 87.05 inverse megameters ($Mm^{-1}$) out of 133.93 $Mm^{-1}$ of light extinction at Caney Creek and 83.18 $Mm^{-1}$ out of 131.79

[127] *Id.*
[128] 40 CFR 51.308(d)(1)(ii).
[129] 77 FR 14604, March 12, 2012.

$Mm^{-1}$ of light extinction at Upper Buffalo on the 20% worst days in 2002, which is approximately 65% and 63% of the total light extinction at each Class I area, respectively. Nitrate from all source categories combined contributed 13.78 $Mm^{-1}$ out of 133.93 $Mm^{-1}$ of light extinction at Caney Creek and 13.30 $Mm^{-1}$ out of 131.79 $Mm^{-1}$ of light extinction at Upper Buffalo, which is approximately 10% of the total light extinction in 2002 on the 20% worst days at each Class I area.

The source category point sources contributed 81.04 $Mm^{-1}$ out of 133.93 $Mm^{-1}$ of light extinction at Caney Creek and 77.80 $Mm^{-1}$ out of 131.79 $Mm^{-1}$ of light extinction at Upper Buffalo on the 20% worst days in 2002 (see the tables below). This represents approximately 60% of the total light extinction at each Class I area. Each of the source categories other than the point source category, contribute a much smaller proportion of the total light extinction at each Class I area. We are therefore focusing only on the point sources category in our reasonable progress analysis for this regional haze planning period.

Sulfate from point sources contributed 75.1 $Mm^{-1}$ out of 133.93 $Mm^{-1}$ of light extinction at Caney Creek and 72.17 $Mm^{-1}$ out of 131.79 $Mm^{-1}$ of light extinction at Upper Buffalo, which is approximately 56% of the total light extinction at Caney Creek and 55% of the total light extinction at Upper Buffalo. Nitrate from point sources contributed 4.06 $Mm^{-1}$ out of 133.93 $Mm^{-1}$ of light extinction at Caney Creek and 3.93 $Mm^{-1}$ out of 131.79 $Mm^{-1}$ of light extinction at Upper Buffalo, which is approximately 3% of the total light extinction at each Class I area. On the 20% worst days in 2002, sulfate from Arkansas point sources contributed 2.20% of the total light extinction at Caney Creek and 1.99% at Upper Buffalo, and nitrate from Arkansas point sources contributed 0.27% of the total light extinction at Caney Creek and 0.14% at Upper Buffalo.[130] For both Caney Creek and Upper Buffalo, $SO_2$ emissions (sulfate precursor) are the principal driver of regional haze on the 20% worst days in Arkansas' Class I areas, as visibility impairment in 2002 on the 20% worst days is largely due to sulfate from point sources.

**Table 78. Modeled baseline light extinction for 20% worst days at Caney Creek Wilderness Area in 2002 ($Mm^{-1}$)**

| | Total[1] | Point | Natural | On-Road | Non-Road | Area |
|---|---|---|---|---|---|---|
| **$SO_4$** | 87.05 | 75.10 | 0.09 | 1.19 | 1.70 | 5.66 |
| **$NO_3$** | 13.78 | 4.06 | 0.64 | 4.70 | 2.45 | 1.37 |
| **POA** | 10.50 | 1.29 | 1.33 | 0.46 | 1.34 | 5.32 |

[130] See the CENRAP TSD and the August 27, 2007 CENRAP PSAT tool (CENRAP_PSAT_Tool_ENVIRON_Aug27_2007.mdb). A copy of the CENRAP TSD and instructions for accessing the August 27, 2007 CENRAP PSAT tool can be found in the docket for this proposed rulemaking.

| | | | | | | |
|---|---|---|---|---|---|---|
| **EC** | 4.80 | 0.19 | 0.33 | 0.86 | 1.79 | 1.40 |
| **SOIL** | 1.12 | 0.19 | 0.01 | 0.01 | 0.01 | 0.87 |
| **CM** | 3.73 | 0.21 | 0.04 | 0.03 | 0.02 | 3.19 |
| **Sum** | 133.93 | 81.04 | 2.45 | 7.26 | 7.31 | 17.81 |

[1]Totals include contributions from boundary conditions. Sums include secondary organic matter.

**Table 79. Modeled baseline light extinction for 20% worst days at Upper Buffalo Wilderness Area in 2002 ($Mm^{-1}$)**

| | **Total[1]** | **Point** | **Natural** | **On-Road** | **Non-Road** | **Area** |
|---|---|---|---|---|---|---|
| **$SO_4$** | 83.18 | 72.17 | 0.08 | 1.15 | 1.67 | 5.24 |
| **$NO_3$** | 13.30 | 3.93 | 0.61 | 4.14 | 2.71 | 1.23 |
| **POA** | 10.85 | 1.06 | 1.33 | 0.47 | 1.38 | 5.75 |
| **EC** | 4.72 | 0.16 | 0.31 | 0.80 | 1.93 | 1.30 |
| **SOIL** | 1.21 | 0.20 | 0.02 | 0.01 | 0.01 | 0.93 |
| **CM** | 6.85 | 0.29 | 0.05 | 0.05 | 0.02 | 6.02 |
| **Sum** | 131.79 | 77.80 | 2.39 | 6.62 | 7.72 | 20.46 |

[1]Totals include contributions from boundary conditions. Sums include secondary organic matter.

The CENRAP's 2018 visibility projections show the total extinction at Caney Creek for the 20% worst days is estimated to be 85.84 Mm-1, which is a reduction of approximately 36% from 2002 levels (see table and figure below). The total extinction at Upper Buffalo for the 20% worst days in 2018 is estimated to be 86.16 $Mm^{-1}$, which is a reduction of approximately 35% from 2002 levels (see the table and figure below). Sulfate from all source categories combined is projected to contribute 48.95 Mm-1 out of 85.84 $Mm^{-1}$ of light extinction at Caney Creek on the 20% worst days in 2018, or approximately 57% of the total light extinction. Nitrate from all source categories combined is projected to contribute 7.57 $Mm^{-1}$ out of 85.84 $Mm^{-1}$ of light extinction at Caney Creek on the 20% worst days in 2018, or approximately 9% of the total light extinction.

The other source categories are each projected to continue contributing a much smaller proportion of the total light extinction at each Class I area. At Upper Buffalo, sulfate from all source categories combined is projected to contribute 45.38 $Mm^{-1}$ out of 86.16 $Mm^{-1}$ of light extinction on the 20% worst days in 2018, which is approximately 53% of the total light extinction. Nitrate from all source categories combined is projected to contribute 9.22 $Mm^{-1}$ out of 86.16 $Mm^{-1}$ of light extinction on the 20% worst days at Upper Buffalo, which is approximately 11% of the total light extinction.

Sulfate from point sources is projected to contribute 39.83 $Mm^{-1}$ out of 85.84 $Mm^{-1}$ of light extinction at Caney Creek on the 20% worst days in 2018, or approximately 46% of the total light extinction. Nitrate from point sources is projected to contribute 2.84 $Mm^{-1}$ out of 85.84 $Mm^{-1}$ of light extinction at Caney Creek on the 20% worst days, which is approximately 3% of the total light extinction. At Upper Buffalo, sulfate from point sources is projected to contribute 37.09 $Mm^{-1}$ out of 86.16 $Mm^{-1}$ of light extinction on the 20% worst days in 2018, which is approximately 43% of the total light extinction. On the 20% worst days in 2018, sulfate from Arkansas point sources is projected to contribute 3.58% of the total light extinction at Caney Creek and 3.20% at Upper Buffalo, and nitrate from Arkansas point sources is projected to contribute 0.29% of the total light extinction at Caney Creek and 0.25% at Upper Buffalo (see Figure 1).[131] Based on the 2018 visibility projections, sulfate from point sources is expected to continue being the principal driver of regional haze on the 20% worst days at Arkansas Class I areas.

**Table 80. Modeled future light extinction for 20% worst days at Caney Creek Wilderness Area in 2018 ($Mm^{-1}$)**

| | Total[1] | Point | Natural | On-Road | Non-Road | Area |
|---|---|---|---|---|---|---|
| **$SO_4$** | 48.95 | 39.83 | 0.07 | 0.12 | 0.44 | 5.31 |
| **$NO_3$** | 7.57 | 2.84 | 0.53 | 0.97 | 1.33 | 1.37 |
| **POA** | 9.93 | 1.76 | 1.18 | 0.14 | 1.03 | 5.09 |
| **EC** | 3.17 | 0.24 | 0.30 | 0.16 | 0.94 | 1.31 |
| **SOIL** | 1.29 | 0.35 | 0.01 | 0.01 | 0.01 | 0.87 |
| **CM** | 3.58 | 0.24 | 0.04 | 0.03 | 0.01 | 3.02 |

[131] See the CENRAP TSD and the August 27, 2007 CENRAP PSAT tool (CENRAP_PSAT_Tool_ENVIRON_Aug27_2007.mdb). A copy of the CENRAP TSD and instructions for accessing the August 27, 2007 CENRAP PSAT tool can be found in the docket for this proposed rulemaking.

| Sum | 85.84 | 45.27 | 2.12 | 1.44 | 3.76 | 16.96 |
|---|---|---|---|---|---|---|

[1]Totals include contributions from boundary conditions and secondary organic matter.

**Figure 1. Extinction for 20% worst days at Caney Creek Wilderness Area in 2018 ($Mm^{-1}$)**

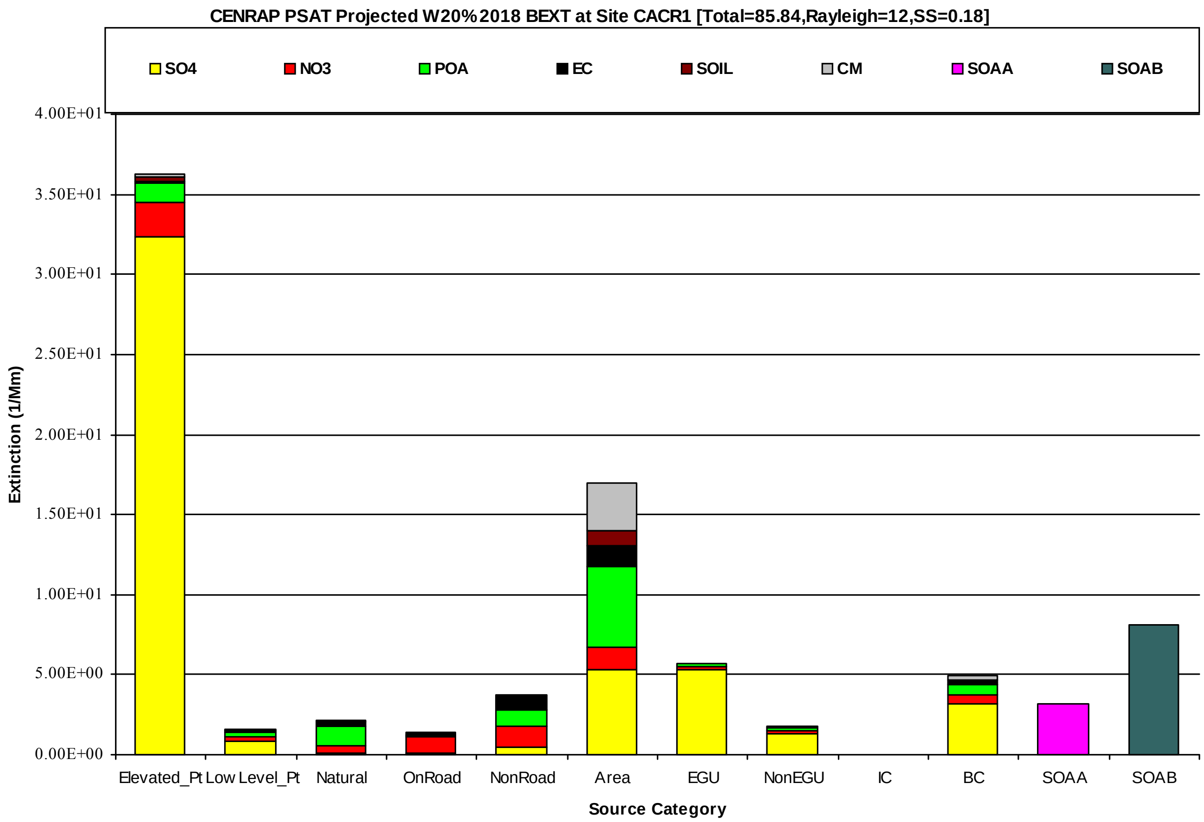


**Table 81. Modeled future light extinction for 20% worst days at Upper Buffalo Wilderness Area in 2018 ($Mm^{-1}$)**

| | Total[1] | Point | Natural | On-Road | Non-Road | Area |
|---|---|---|---|---|---|---|
| $SO_4$ | 45.38 | 37.09 | 0.06 | 0.12 | 0.42 | 4.95 |
| $NO_3$ | 9.22 | 3.48 | 0.63 | 1.10 | 1.81 | 1.48 |
| POA | 10.17 | 1.48 | 1.20 | 0.14 | 1.01 | 5.49 |
| EC | 3.07 | 0.21 | 0.28 | 0.15 | 0.99 | 1.21 |

| | | | | | | |
|---|---|---|---|---|---|---|
| **SOIL** | 1.40 | 0.40 | 0.01 | 0.01 | 0.01 | 0.93 |
| **CM** | 6.53 | 0.36 | 0.05 | 0.04 | 0.02 | 5.65 |
| **Sum** | 86.16 | 43.02 | 2.24 | 1.57 | 4.25 | 19.71 |

[1]Totals include contributions from boundary conditions and secondary organic matter.

**Figure 2. Extinction for 20% worst days at Caney Creek Wilderness Area in 2018 ($Mm^{-1}$)**

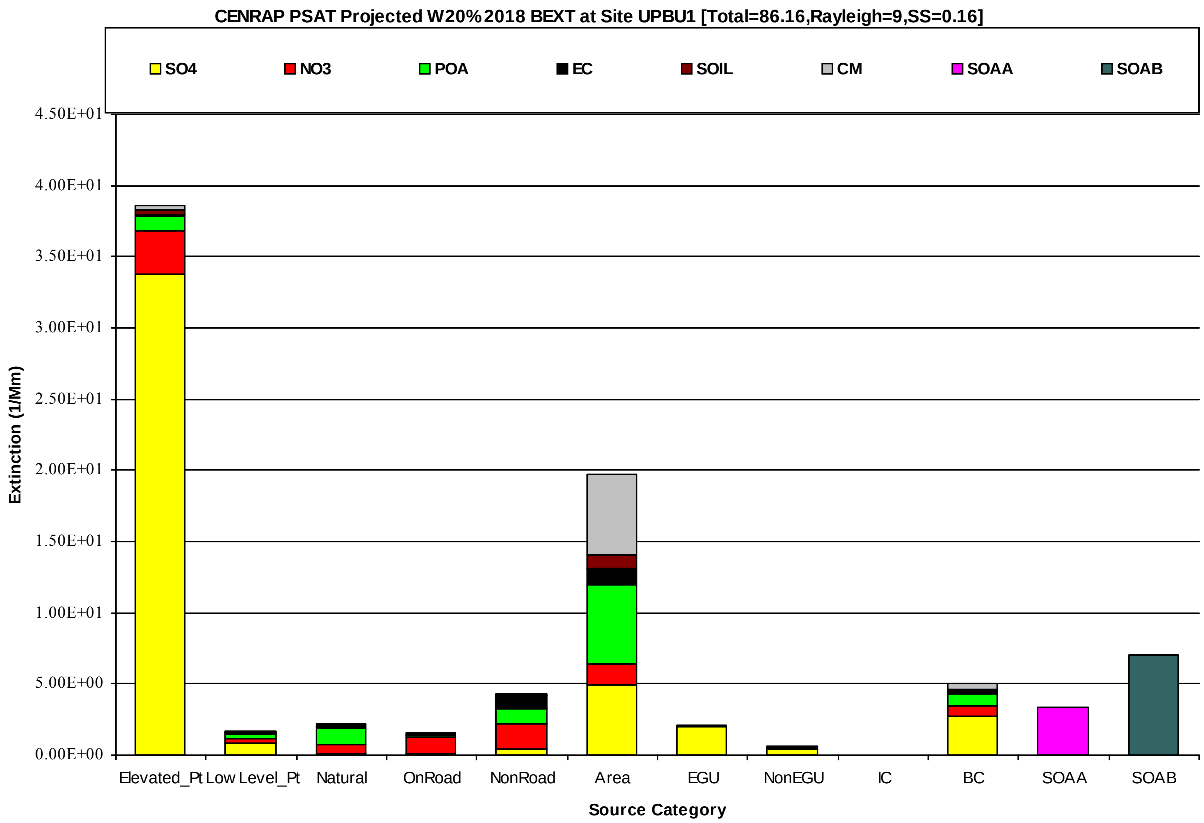

**Table 82. Percentage of Total Extinction due to Arkansas Point Sources**[132]

| | 2002 | | 2018 | |
|---|---|---|---|---|
| | **CACR** | **UPBU** | **CACR** | **UPBU** |
| **Sulfate** | **2.20** | **1.99** | **3.58** | **3.20** |
| **Nitrate** | **0.27** | **0.14** | **0.29** | **0.25** |

As a starting point in our analysis to determine whether additional controls on Arkansas sources are reasonable in the first regional haze planning period, we examined the most recent $SO_2$ and $NO_X$ emissions inventories for point sources in Arkansas. Based on the 2011 National Emissions Inventory (NEI), the Entergy White Bluff Plant, the Entergy Independence Plant, and the AEP Flint Creek Power Plant are the three largest point sources of $SO_2$ and $NO_x$ emissions in Arkansas (see table below).[133] The combined annual emissions from these three sources make up approximately 84% of the statewide $SO_2$ point-source emissions and 55% of the statewide $NO_X$ point-source emissions. We have evaluated White Bluff Units 1 and 2 and Flint Creek Unit 1 for controls under BART and are proposing to require these units to install $SO_2$ and $NO_X$ controls to meet the BART requirements. We believe that our five-factor BART analysis for these three units is adequate for this first planning period to eliminate these sources from further consideration of controls under the reasonable progress requirements for this first regional haze planning period.. Compliance with the BART requirements is anticipated to result in a substantial reduction in $SO_2$ and $NO_X$ emissions from these two facilities. The Entergy Independence Plant is not subject to BART, but its emissions were 30,398 $SO_2$ tpy and 13,411 $NO_X$ tpy based on the 2011 NEI. The Entergy Independence Plant is the second largest source of $SO_2$ and $NO_X$ point-source emissions in Arkansas, accounting for approximately 36% of the $SO_2$ point-source emissions and 21% of the $NO_X$ point-source emissions in the State. Additionally, as we discuss in more detail in the proceeding subsection, the White Bluff and Independence Plants are sister facilities with nearly identical units. Based on this, we expect that the cost-effectiveness of controls will be very similar for the two facilities.

**Table 83. Ten Largest $SO_2$ and $NO_X$ Point Sources in Arkansas (NEI 2011 v1)**

| **Facility Name** | **County** | **NEI 2011 v1 Emissions (tpy)** |
|---|---|---|

[132] See the CENRAP TSD and the August 27, 2007 CENRAP PSAT tool (CENRAP_PSAT_Tool_ENVIRON_Aug27_2007.mdb). A copy of the CENRAP TSD and instructions for accessing the August 27, 2007 CENRAP PSAT tool can be found in the docket for this proposed rulemaking.
[133] See NEI 2011 v1. A spreadsheet containing the emissions inventory is found in the docket for our proposed rulemaking.

| | | $SO_2$ | $NO_X$ |
|---|---|---|---|
| Entergy Arkansas- White Bluff | Jefferson | 31,684* | 16,013* |
| Entergy-Services Inc- Independence Plant | Independence | 30,398 | 13,411 |
| Flint Creek Power Plant (SWEPCO) | Benton | 8,620* | 5,326* |
| FutureFuel Chemical Company | Independence | 3,421 | 385 |
| Plum Point Energy Station Unit 1 | Mississippi | 2,830 | 1,525 |
| Evergreen Packaging- Pine Bluff | Jefferson | 1,755 | 1,010 |
| Domtar A.W. LLC, Ashdown Mill | Little River | 1,603* | 3,152* |
| Albemarle Corporation- South Plant | Columbia | 1,279 | 443 |
| Nucor-Yamato Steel Company | Mississippi | 607 | 263 |
| Ash Grove Cement Company | Little River | 440 | 1,081 |
| Georgia-Pacific LLC- Crossett Paper | Ashley | 215 | 2,402 |
| Marion Intermodal | Crittenden | 12 | 1,328 |
| Natural Gas Pipeline Co of America #308 | Randolph | 0.4 | 3,194 |
| Natural Gas Pipeline Co of America #307 | White | 0.4 | 2,941 |
| Natural Gas Pipeline Co of America #305 | Miller | 0.3 | 1,731 |

*Proposed FIP controls under BART requirements will result in emission reductions

Because in our March 12, 2012 final partial approval and partial disapproval of the 2008 Arkansas RH SIP we made a finding that Arkansas did not complete a reasonable progress analysis and did not properly demonstrate that additional controls were not reasonable under 40 CFR 51.308(d)(1)(i)(A) and we disapproved the RPGs it established for Caney Creek and Upper Buffalo, we are required to complete the reasonable progress analysis and establish revised RPGs, unless we first approve a SIP revision that corrects the disapproved portions of the SIP submittal. As Arkansas has not as yet submitted a revised SIP following our partial disapproval, we must now complete the reasonable progress analysis and establish revised RPGs for Caney Creek and Upper Buffalo. We believe it is appropriate that our evaluation of the reasonable progress factors focuses on the Entergy Independence Power Plant because it is a significant source of $SO_2$ and $NO_X$, as it is the second largest point source for both $NO_X$ and $SO_2$ point source emissions in the State.

We believe it is appropriate to evaluate Entergy Independence even though 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. This is because we believe that in determining whether reasonable progress is being achieved, it would be unreasonable to ignore a source representing more than a third of the State's $SO_2$ emissions and a significant portion of $NO_X$ point source emissions. The preamble to the Regional Haze Rule also states that the URP does not establish a "safe harbor" for the state in setting its progress goals.[134] If the state determines that the amount of progress identified through the URP analysis is reasonable based upon the statutory factors, the state, or us in the case of a FIP, should identify this amount of progress as its reasonable progress goal for the first long-term strategy, unless it determines that additional progress beyond this amount is also reasonable. If the state or we determine that additional progress is reasonable based on the statutory factors, that amount of progress should be adopted as the goal for the first long-term strategy.

In this proposed rulemaking, we are proposing controls for the largest and third largest point sources for both $NO_X$ and $SO_2$ emissions in Arkansas under the BART requirements. As these two BART sources combined with Independence make up a large majority of the $SO_2$ point source emissions (84%) and a large proportion of the $NO_X$ point source emissions (55%) in Arkansas, we believe that a sufficient amount of point source emissions in the State would be addressed in this first regional haze planning period by addressing the Independence facility in our reasonable progress analysis, which as we note above is the second largest source of both $SO_2$ and $NO_X$. We are proposing under Option 1 to control Entergy Independence for the first planning period for both $SO_2$ and $NO_X$. Alternatively, under Option 2, for the first planning period, we are proposing to control Entergy Independence only for $SO_2$.

The fourth largest $SO_2$ and $NO_X$ point sources in Arkansas are the Future Fuel Chemical Company, with emissions of 3,421 $SO_2$ tpy, and the Natural Gas Pipeline Company of America #308, with emissions of 3,194 $NO_X$ tpy (2011 NEI). In comparison to the emissions of the top three sources, emissions from these two facilities are relatively small. Therefore, we are not proposing controls in this first planning period for these two facilities because we believe it is appropriate to defer the consideration of any additional sources besides Independence to future regional haze planning periods. For Independence, however, under Option 1, in combination with the BART sources we would be addressing 84% of the $SO_2$ point source emissions in the State and over 55% of the $NO_X$ point source emissions. Under Option 2, we would be deferring the consideration of additional $NO_X$ controls to future regional haze planning periods. . In the next section, we describe our consideration of the four reasonable progress factors for the Entergy Independence Plant as well as the CALPUFF modeling we conducted to assess the potential visibility benefits of controls.[135]

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[134] See 64 FR 35732.

[135] While visibility is not an explicitly listed factor to consider when determining whether additional controls are reasonable, the purpose of the four-factor analysis is to determine what degree of progress toward natural visibility conditions is reasonable. Therefore, it is appropriate to consider the projected visibility benefit of the controls when determining if the controls are needed to make reasonable progress.

### 1. Entergy Independence Plant Units 1 and 2

#### a. Reasonable Progress Analysis for $SO_2$ Controls

The Entergy Independence Plant is an electric generating station with two nearly identical coal-fired units (Units 1 and 2) with a nameplate capacity of 900 MW each. Units 1 and 2 are tangentially-fired boilers that burn sub-bituminous coal as their primary fuel and No. 2 fuel oil or Bio-diesel as the start-up fuel. To verify that the White Bluff and Independence Plants are sister facilities, we have constructed a master spreadsheet[136] that contains information concerning ownership, location, boiler type, environmental controls and other pertinent information on these facilities. The spreadsheet includes information contained within EIA Forms 860 and 923. According to EIA,[137] the boilers were manufactured by Combustion Engineering with installation dates of 1974 for White Bluff, and 1983 and 1984 for Independence. The two units at White Bluff and the two units at Independence are tangentially firing boilers having nameplate capacities of 900 MW and similar gross ratings. All four units burn coal from the Powder River Basin (PRB) of Wyoming with similar characteristics. All four units employ cold side ESPs for particulate collection. Other pertinent characteristics are similar. The layout of the White Bluff and Independence facilities are also very similar.[138]

*Costs of Compliance*:

Due to the similarity of these facilities, we applied the total annualized dry FGD and wet FGD costs we developed for the White Bluff units to the Independence units. However, we adjusted the cost-effectiveness ($/ton) due to the differing baseline $SO_2$ emissions from the units. Consistent with the cost estimate we developed for White Bluff, we estimated a total annual cost for dry FGD at Independence of approximately $31,981,230 at each unit.[139] We expect dry FGD to achieve a controlled emission level of 0.06 lb/MMBtu, and estimate that the annual emissions reductions at Unit 1 would be 12,912 $SO_2$ tpy, assuming baseline emissions[140] of 14,269 $SO_2$ tpy (see table below). The average cost-effectiveness of dry FGD at Unit 1 is estimated to be $2,477/ton $SO_2$ removed. For Unit 2, we estimate that the annual emissions reductions would be 13,990

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[136] This spreadsheet, entitled "EIA Consolidated Data_WB and Ind_Y2012.xlsx," is located in the docket for our proposed rulemaking.

[137] See "EIA Consolidated Data_WB and IND_Y2012.xlsx."

[138] See "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)," Figures 1 and 2.

[139] See "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)." A copy of this TSD is found in the docket for our proposed rulemaking.

[140] Baseline emissions were determined by examining annual $SO_2$ emissions for the years 2009-2013, eliminating the year with the highest emissions and the year with the lowest emissions, and obtaining the average of the three remaining years.

$SO_2$ tpy, assuming baseline emissions of 15,511 $SO_2$ tpy. The average cost-effectiveness of dry FGD at Unit 2 is estimated to be $2,286/ ton $SO_2$ removed.

**Table 84. Summary of Dry FGD Costs for Entergy Independence Units 1 and 2**

| Unit | Baseline Emission Rate ($SO_2$ tpy) | Controlled Emission Level (lb/MMBtu) | Annual Emissions Reductions ($SO_2$ tpy) | Total Annual Cost ($/yr) | Average Cost Effectiveness ($/ton) |
|---|---|---|---|---|---|
| Unit 1 | 14,269 | 0.06 | 12,912 | $31,981,230 | $2,477 |
| Unit 2 | 15,511 | 0.06 | 13,990 | $31,981,230 | $2,286 |

Because our proposed BART determination for the White Bluff facility is that dry FGD is more cost-effective (lower $/ton) than wet FGD, and that the additional visibility benefits obtained as a result of the greater level of control wet FGD offers over dry FGD are not worth the additional cost of wet FGD, we expect that the same would apply to Independence Units 1 and 2. Therefore, our evaluation of $SO_2$ controls for Independence Units 1 and 2 focuses on dry FGD. Nevertheless, we have calculated the cost-effectiveness of wet FGD for Independence Units 1 and 2 using the total annualized cost estimate provided by Entergy for White Bluff Units 1 and 2, with certain adjustments we made to the cost estimate provided by the facility.[141] Consistent with our estimate for White Bluff, we estimated a total annual cost for wet FGD at Independence of approximately $49,526,167 at each unit.[142] We expect wet FGD to achieve a controlled emission level of 0.04 lb/MMBtu, and estimate that the annual emissions reductions at Unit 1 would be 13,364 $SO_2$ tpy, assuming baseline emissions[143] of 14,269 $SO_2$ tpy (see table below). The average cost-effectiveness of wet FGD at Unit 1 is estimated to be $3,706/ton $SO_2$ ton. For Unit 2, we estimate that the annual emissions reductions would be 14,497 $SO_2$ tpy, assuming baseline emissions of 15,511 $SO_2$ tpy. The average cost-effectiveness of wet FGD at Unit 2 is estimated to be $3,416/ton $SO_2$ removed.

**Table 85. Summary of Wet FGD Costs for Entergy Independence Units 1 and 2**

[141] See our discussion above of the cost analysis for $SO_2$ BART for White Bluff Units 1 and 2.

[142] See our Cost Analysis TSD titled "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)." The TSD is found in the docket for our proposed rulemaking.

[143] Baseline emissions were determined by examining annual $SO_2$ emissions for the years 2009-2013, eliminating the year with the highest emissions and the year with the lowest emissions, and obtaining the average of the three remaining years.

| Unit | Baseline Emission Rate ($SO_2$ tpy) | Controlled Emission Level (lb/MMBtu) | Annual Emissions Reductions ($SO_2$ tpy) | Total Annual Cost ($/yr) | Average Cost Effectiveness ($/ton) |
|---|---|---|---|---|---|
| Unit 1 | 14,269 | 0.04 | 13,463 | $49,526,167 | $3,706 |
| Unit 2 | 15,511 | 0.04 | 14,532 | $49,526,167 | $3,416 |

*Time Necessary for Compliance*:

As is generally the case for installation of scrubber controls on EGUs, we expect that 5 years from the date of our final action would be sufficient time for Independence to install and operate either dry or wet FGD controls at Units 1 and 2 and to comply with the associated emission limits.

*Energy and Non-Air Quality Environmental Impacts of Compliance*:

The installation and operation of wet FGD at Independence Units 1 and 2 would require greater energy usage and reagent usage compared to dry FGD. The cost of this additional energy usage and reagent usage has already been factored into the cost analysis. Non-air quality environmental impacts associated with wet FGD systems include increased water usage and the generation of large volumes of wastewater and solid waste/sludge that must be treated or stabilized before landfilling. Because the facility is not located in an exceptionally arid region, we do not anticipate that there would be water-availability issues that would affect the feasibility of wet FGD. Lastly, wet FGD systems have the potential for increased particulate and sulfuric acid mist releases that contribute to regional haze, which we are taking into consideration through an evaluation of the visibility benefits of each control option.

*Remaining Useful Life*:

Independence Units 1 and 2 were installed in 1983 and 1984. Unit 1 was placed into operation in 1983 and Unit 2 was placed into operation in 1985. As there is no enforceable shut-down date for Units 1 and 2, we assume an equipment life of 30 years.[144]

[144] As we note in our Oklahoma FIP, we typically assume a 30 year equipment life for scrubbers, as we do here. Please see Response to Technical Comments for Sections E. through H. of the Federal Register Notice for the Oklahoma Regional Haze and Visibility Transport Federal Implementation Plan, Docket No. EPA-R06-OAR-2010-0190. Page 35.

*Degree of Improvement in Visibility*:

While visibility is not an explicitly listed factor to consider when determining whether additional controls are reasonable under the reasonable progress requirements, the purpose of the four-factor analysis is to determine what degree of progress toward natural visibility conditions is reasonable. Therefore, it is appropriate to consider the projected visibility benefit of the controls when determining if the controls are needed to make reasonable progress.[145] There are four Class I areas within 300 km of the Entergy Independence Plant. We conducted CALPUFF modeling to determine the visibility improvement of $SO_2$ controls at these Class I areas, based on the 98th percentile visibility impacts. (See Appendix C to this TSD for detailed discussion of the modeling protocol, model inputs and visibility modeling results). As shown in the tables below, both dry FGD and wet FGD are projected to result in considerable visibility improvement from the baseline at each modeled Class I area. For Unit 1, dry FGD is projected to result in almost 0.5 dv of visibility improvement at each modeled Class I area, and for Unit 2 it is projected to result in almost or slightly greater than 0.5 dv of visibility improvement at each Class I area. The incremental visibility improvement of wet FGD over dry FGD is projected to be minimal, ranging from 0.008 – 0.028 dv at each Class I area for Unit 1 and 0.009 – 0.022 dv for Unit 2. Dry FGD at both units is projected to result in visibility improvements ranging from 0.87 to 1.06 dv at each class I area. We also modeled the visibility improvement anticipated from dry FGD at both units using an updated baseline emission level for $NO_X$ based on lower, more recent emissions. This modeled visibility improvement was similar to previous results with visibility improvements ranging from 0.97 to 1.08 dv at each class I area. See Appendix C to this TSD for detailed discussion of the modeling protocol, model inputs and visibility modeling results for each modeled control scenario.

**Table 86. Entergy Independence Unit 1: EPA Modeled Maximum 98th Percentile Visibility Impact and Improvement from $SO_2$ Controls**

| Class I Area | Distance (km) | Visibility Impact ($\Delta$dv) | | | Visibility Improvement Over Baseline (dv) | | Incremental Visibility Improvement of Wet FGD vs. Dry FGD |
|---|---|---|---|---|---|---|---|
| | | Baseline | Dry FGD | Wet FGD | Dry FGD | Wet FGD | |
| Caney Creek | 277 | 1.133 | 0.657 | 0.64 | 0.476 | 0.493 | 0.017 |
| Upper Buffalo | 180 | 0.845 | 0.385 | 0.377 | 0.460 | 0.468 | 0.008 |
| Hercules-Glades | 173 | 0.793 | 0.295 | 0.267 | 0.498 | 0.526 | 0.028 |

[145] See 79 FR at 74838, 74840, and 74874.

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Mingo | 174 | 0.739 | 0.298 | 0.284 | 0.441 | 0.455 | 0.014 |
| | | | | | | | |
| Total | - | 3.51 | 1.635 | 1.568 | 1.875 | 1.942 | 0.067 |

**Table 87. Entergy Independence Unit 2: EPA Modeled Maximum 98th Percentile Visibility Impact and Improvement from $SO_2$ Controls**

| Class I Area | Distance (km) | Visibility Impact ($\Delta$dv) | | | Visibility Improvement Over Baseline (dv) | | Incremental Visibility Improvement of Wet FGD vs. Dry FGD |
|---|---|---|---|---|---|---|---|
| | | Baseline | Dry FGD | Wet FGD | Dry FGD | Wet FGD | |
| Caney Creek | 277 | 1.412 | 0.865 | 0.843 | 0.547 | 0.569 | 0.022 |
| Upper Buffalo | 180 | 0.997 | 0.509 | 0.499 | 0.488 | 0.498 | 0.01 |
| Hercules-Glades | 173 | 0.977 | 0.364 | 0.355 | 0.613 | 0.622 | 0.009 |
| Mingo | 174 | 0.883 | 0.388 | 0.374 | 0.495 | 0.509 | 0.014 |
| | | | | | | | |
| Total | - | 4.269 | 2.126 | 2.071 | 2.143 | 2.198 | 0.055 |

**Table 88. Entergy Independence: EPA Modeled Maximum 98th Percentile Visibility Impact and Improvement of $SO_2$ Controls (Facility-wide)**

| Class I Area | Distance (km) | Visibility Impact ($\Delta$dv) | | | Visibility Improvement Over Baseline (dv) | | Incremental Visibility Improvement of Wet FGD vs. Dry FGD |
|---|---|---|---|---|---|---|---|
| | | Baseline | Dry FGD | Wet FGD | Dry FGD | Wet FGD | |
| Caney Creek | 277 | 2.412 | 1.474 | 1.442 | 0.938 | 0.97 | 0.032 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Upper Buffalo | 180 | 1.764 | 0.876 | 0.86 | 0.888 | 0.904 | 0.016 |
| Hercules-Glades | 173 | 1.704 | 0.648 | 0.608 | 1.056 | 1.096 | 0.04 |
| Mingo | 174 | 1.547 | 0.676 | 0.649 | 0.871 | 0.898 | 0.027 |
| | | | | | | | |
| Total | - | 7.427 | 3.674 | 3.559 | 3.753 | 3.868 | 0.115 |

**Proposed Reasonable Progress Determination for $SO_2$ for the Entergy Independence Plant:**

Based on our analysis of the four RP factors, as well as the considerable projected visibility improvement, we propose to require compliance with an $SO_2$ emission limit of 0.06 lb/MMBtu for Independence Units 1 and 2 based on a 30 boiler-operating-day rolling average basis. We propose to find that this emission limit, which is based on the installation and operation of dry FGD, is cost-effective at $2,477/ ton $SO_2$ removed for Unit 1 and $2,286/ton $SO_2$ removed for Unit 2, and would result in significant visibility benefits at the Caney Creek and Upper Buffalo Wilderness Areas and the two Class I areas in Missouri. Under either Option 1 or 2, we are proposing $SO_2$ controls on Independence Units 1 and 2 for the first planning period. We note that more recent emission data show an overall increase in $SO_2$ emissions from the facility. Therefore anticipated visibility improvement from controls would be anticipated to be larger and the \$/$SO_2$ ton reduced would be smaller had we used a more recent time period for the baseline emissions modeled. We found that in this instance, the cost of wet FGD on a dollars per ton removed basis is higher than that of dry FGD. We found the cost of wet FGD to be $3,706 and $3,416 per ton of $SO_2$ removed at Units 1 and 2, respectively. We found the cost of dry FGD to be $2,477 and $2,286 per ton of $SO_2$ removed for Units 1 and 2, respectively. We do not believe that the minimal amount of incremental visibility improvement projected to result from wet FGD justifies the higher cost compared to dry FGD. We are proposing to require compliance with an emission limit of 0.06 lb/MMBtu based on a 30 boiler-operating-day rolling average basis for Independence Units 1 and 2 no later than 5 years from the effective date of the final rule, based on the installation and operation of dry FGD. We are proposing that the facility demonstrate compliance with this emission limit using the existing CEMS.

### b. Reasonable Progress Analysis for $NO_X$ controls

As noted previously, monitoring data as well as CENRAP's CAMx source apportionment modeling results for 2002 and 2018 show that visibility impairment is not projected to be significantly impacted by nitrate on the 20% worst days at Caney Creek or Upper Buffalo. Point source emissions of $NO_X$ are projected to contribute to less than 5% of the total impairment on the 20% worst days in both 2002 and 2018. The CENRAP CAMx source apportionment modeling does not provide visibility impairment estimates for individual facilities.

As part of our analysis for Independence, we performed modeling using CALPUFF to assess the facility's individual visibility impact and the visibility benefit of controls, as was done for the subject-to-BART units discussed above including the sister facility, White Bluff. CALPUFF is the recommended model[146] for visibility impact analysis for BART determinations and other single source visibility modeling where the Class I areas of interest are within 300 km of the source. This modeling provided information on the total visibility impairment from emissions from the source, including impacts from $SO_2$ and $NO_X$ emissions. The primary goal of this modeling was to assess the potential visibility benefit of $SO_2$ controls, given the relatively large emissions of $SO_2$ from the facility and that $SO_2$ emissions are the primary cause of visibility impairment on the 20% worst days at the Class I areas of interest. The results of this analysis of $SO_2$ controls are discussed in the section above. These CALPUFF results also indicated that impacts from $NO_X$ emissions can be significant on some days, and as discussed further below, $NO_X$ emission controls can be anticipated to result in a sizeable reduction in the maximum impacts from the facility. The analysis of the sister facility, Entergy Independence, revealed similar results.

In evaluating CALPUFF modeling results for BART, the 98th percentile ranked impact (H8H) was used consistent with our guideline techniques in conducting the CALPUFF modeling. CALPUFF modeling provides an assessment of the near maximum (98$^{th}$ percentile) visibility impairment on nearby Class I areas from the source of interest based on the facility's maximum short term emissions modeled over a three year period. It is important to note that a specific facility's maximum impact on a Class I area may not correlate with the same meteorological conditions or days when visibility is most impaired at a particular Class I area since CALPUFF modeling is only for one facility and does not include other facilities and emissions sources. Because of the nature of visibility impairment, we consider it appropriate to assess visibility impacts from a single source against a natural background. Visibility impairment on the 20% worst days may be driven by impacts from other facilities and different meteorological conditions. Identification of the 20% worst days is determined by IMPROVE monitor data during the baseline period at each Class I area. The source apportionment results for the 20% worst days are then based on CAMx modeling using a single year of meteorological data (2002) and using estimates of actual emissions from 2002 and projected to 2018 for all emission sources in the modeling domain (continental U.S.). Due in large part to the difference in metrics between

[146] 70 FR 39104.

the maximum impact as modeled by CALPUFF and the average impact during the 20% worst days, the CALPUFF modeling results discussed below indicate a more significant impact than suggested by the source apportionment CAMx results. We also note that differences in the metrics examined (maximum 98$^{th}$ percentile impact versus average impact during the 20% worst days), emissions modeled (single–source maximum 24-hour actual emissions versus actual emissions from all emission sources[147]), and differences in chemistry models result in CAMx visibility analysis results for a source or group of sources being much lower in magnitude than visibility impacts as modeled by CALPUFF.

The single source CALPUFF modeling shows that sizeable reductions to the maximum 98$^{th}$ percentile visibility impact from the Independence facility may be achieved through $NO_X$ controls.[148] We recognize, however, that at this time, point source $NO_X$ emissions are not the main contributors to visibility impairment on the 20% worst days at Arkansas' Class I areas, as projected by CAMx source apportionment modeling. Also, Arkansas Class I areas are projected to achieve progress greater than that needed to meet the URP. Because our assessment of the Independence facility indicates that it is potentially one of the largest single contributors to visibility impairment at Class I areas in Arkansas, we believe that it is appropriate to evaluate the appropriateness of $NO_X$ controls during this planning period.

*Costs of Compliance:*

As discussed above, due to the similarity of these facilities, we applied the total annualized LNB/SOFA cost developed by Entergy for White Bluff Units 1 and 2, with one line item revision made by us, to Independence Units 1 and 2.[149] However, we adjusted the cost-effectiveness ($/ton) due to the differing $NO_X$ emissions from the units. Since our proposed BART determination for the White Bluff facility is that LNB/SOFA is more cost effective (lower $/ton) than SNCR or SCR, and that the additional visibility benefits obtained as a result of the greater level of control SNCR and SCR offer over combustion controls are not worth the additional cost of SNCR or SCR, we expect that the same would apply to Independence Units 1 and 2. Therefore, our evaluation of $NO_X$ controls for Independence Units 1 and 2 will focus solely on LNB/SOFA.

Consistent with the cost estimate developed for White Bluff, we estimated a total annual cost for LNB/SOFA at Independence of approximately $1,085,904 at Unit 1 and $1,403,376 at

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[147] Emissions used in CALPUFF modeling represented the maximum 24-hour emission rate. Based on evaluation of some sources that had both annual and maximum 24-hour actual data, EPA recommended that sources could use an emission rate that was double the annual emission rate (used in CAMx) to approximate the maximum 24-hour actual emission rates for some sources for CALPUFF modeling when there was not enough data to generate a maximum 24-hr actual emission rate.

[148] See "Degree of Improvement in Visibility" section below and Appendix C to this TSD for detailed discussion of the modeling protocol, model inputs and visibility modeling results.

[149] See our discussion above of the cost analysis for $NO_X$ BART for White Bluff Units 1 and 2, under section III.C.4 of this proposed rulemaking.

Unit 2.[150] We expect LNB/SOFA to achieve a controlled emission level of 0.15 lb/MMBtu, and estimate that the annual emissions reductions at Unit 1 would be 2,710 $NO_X$ tpy, assuming baseline emissions[151] of 6,329 $NO_X$ tpy (see table below). The average cost-effectiveness of LNB/SOFA at Unit 1 is estimated to be $401/ton $NO_X$ removed. For Unit 2, we estimate that the annual emissions reductions would be 3,217 $NO_X$ tpy, assuming baseline emissions of 6,384 $NO_X$ tpy. The average cost-effectiveness of LNB/SOFA at Unit 2 is estimated to be $436/ton $NO_X$ removed.

**Table 89. Summary of LNB/SOFA Costs for Entergy Independence Units 1 and 2**

| Unit | Baseline Emission Rate ($NO_X$ tpy) | Controlled Emission Level (lb/MMBtu) | Annual Emissions Reductions ($NO_X$ tpy) | Total Annual Cost ($/yr) | Average Cost Effectiveness ($/ton) |
|---|---|---|---|---|---|
| Unit 1 | 6,329 | 0.15 | 2,710 | $1,085,904 | $401 |
| Unit 2 | 6,384 | 0.15 | 3,217 | $1,403,376 | $436 |

*Time Necessary for Compliance:*

As is generally the case for installation of $NO_X$ controls on EGUs, we expect that 3 years from the date of our final action would be sufficient time for Independence to install and operate LNB/SOFA controls at Units 1 and 2 and to comply with the associated emission limits.

*Energy and Non-Air Quality Environmental Impacts of Compliance*:

We are not aware of any energy or non-air quality environmental impacts that would preclude LNB/SOFA from consideration at Independence Units 1 and 2.

*Remaining Useful Life*:

Independence Units 1 and 2 were installed in 1983 and 1984. Unit 1 was placed into operation in 1983 and Unit 2 was placed into operation in 1985. As there is no enforceable shut-

[150] See the spreadsheet titled "Independence Cost Spreadsheet_ LNB-SOFA." A copy of this spreadsheet is found in the docket for our proposed rulemaking.

[151] Baseline emissions were determined by examining annual $NO_X$ emissions for the years 2009-2013, eliminating the year with the highest emissions and the year with the lowest emissions, and obtaining the average of the three remaining years.

down date for Units 1 and 2, we presume that the units would continue to operate for greater than 30 years and fully amortize the cost of controls. In our analysis of the cost of controls we have assumed an equipment life of 30 years.

*Degree of Improvement in Visibility*:

While visibility is not an explicitly listed factor to consider when determining whether additional controls are reasonable under the reasonable progress requirements, the purpose of the four-factor analysis is to determine what degree of progress toward natural visibility conditions is reasonable. Therefore, it is appropriate to consider the projected visibility benefit of the controls when determining if the controls are needed to make reasonable progress.[152] There are four Class I areas within 300 km of the Entergy Independence Plant. We conducted CALPUFF modeling to determine the visibility improvement of $NO_X$ controls at these Class I areas, based on the 98th percentile visibility impacts.[153] As shown in the table below, LNB/SOFA is projected to result in a visibility improvement from the baseline at each modeled Class I area.[154] On a facility-wide basis, the installation and operation of LNB/SOFA on Units 1 and 2 is projected to result in 0.461 dv in visibility improvement at Caney Creek, while the projected visibility improvement at each of the other modeled Class I areas ranges from 0.213 – 0.264 dv. We also conducted a modeling run of both LNB/OFA and dry FGD, which shows projected visibility benefits ranging from 1.18 – 1.48 dv at each Class I area.[155] As discussed above, more recent emission data show an overall increase in $SO_2$ emissions from the facility. Therefore anticipated visibility improvement from controls would be anticipated to be larger and there would be an improvement in the cost-effectiveness (i.e., lower dollars per ton removed) of controls had we used a more recent time period for the baseline emissions modeled.

[152] See 79 FR at 74838, 74840, and 74874.
[153] See Appendix C to the TSD, titled "Technical Support Document for Visibility Modeling Analysis for Entergy Independence Generating Station," for a detailed discussion of the visibility modeling protocol and model inputs.
[154] *Id.*
[155] This is discussed in more detail in Appendix C to the TSD, titled "Technical Support Document for Visibility Modeling Analysis for Entergy Independence Generating Station,"

**Table 90. Entergy Independence Units 1 and 2 (Facility-Wide): EPA Modeled Maximum 98th Percentile Visibility Impacts of LNB/SOFA**

| Class I Area | Distance (km) | Visibility Impact ($\Delta$dv) | | Visibility Improvement of LNB/SOFA Over Baseline (dv) |
|---|---|---|---|---|
| | | Baseline[156] | LNB/SOFA | |
| Caney Creek | 277 | 2.054 | 1.593 | 0.461 |
| Upper Buffalo | 180 | 1.724 | 1.476 | 0.248 |
| Hercules-Glades | 173 | 1.482 | 1.218 | 0.264 |
| Mingo | 174 | 1.492 | 1.279 | 0.213 |
| Total | - | 6.752 | 5.566 | 1.186 |

**Proposed Reasonable Progress Determination for $NO_X$ for the Entergy Independence Plant:**

As discussed above, based on the CENRAP's CAMx modeling, sulfate from point sources is the driver of regional haze at Caney Creek and Upper Buffalo on the 20% worst days in both 2002 and 2018. Nitrate from point sources is not considered a driver of regional haze at these Class I areas on the 20% worst days, contributing only approximately 3% of the total light extinction. The Regional Haze Rule requires that the established RPGs provide for an improvement in visibility for the most impaired days (i.e., the 20% worst days) over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period (40 CFR 51.308(d)(1)). Because of the small contribution of nitrate from point sources to the total light extinction at Caney Creek and Upper Buffalo on the most impaired days, we do not expect that $NO_X$ controls under the reasonable progress requirements would offer as much improvement on the most impaired days compared to $SO_2$ controls. However, upon evaluation of the four reasonable progress factors, we found that the installation and operation of LNB/SOFA at Independence Units 1 and 2 is estimated to cost \$401/$NO_X$ ton removed at Unit 1 and \$436/$NO_X$ ton removed at Unit 2, which we consider to be very cost-effective. These $NO_X$ controls are also projected to result in significant visibility improvements at

[156] Baseline $NO_X$ emissions were updated to the maximum 24-hr emissions from 2011-2013 for the evaluation of the anticipated benefit from $NO_X$ controls. See Appendix C to the TSD for additional discussion of baseline emission rates.

Arkansas and Missouri Class I areas, based on CALPUFF modeling using the 98th percentile modeled visibility impacts.

Therefore, under Option 1, for the first planning period, we are proposing both an $SO_2$ emission limit as described above and a $NO_X$ emission limit of 0.15 lb/MMBtu on a 30 boiler-operating-day averaging basis based on the installation and operation of LNB/SOFA, in light of their cost-effectiveness and visibility benefit based on CALPUFF modeling, even though nitrate from point sources is projected to contribute a very small proportion of the total light extinction at Caney Creek and Upper Buffalo on the 20% worst days in 2018. Based on our visibility modeling of both LNB/OFA and dry FGD, proposed Option 1 is projected to have visibility benefits ranging from 1.18 – 1.48 dv at each Class I area.[157] Under Option 2, we are proposing only $SO_2$ controls for Independence Units 1 and 2 under the reasonable progress requirements. Based on our visibility modeling of dry FGD, proposed Option 2 is projected to have visibility benefits ranging from 0.87 – 1.06 dv at each Class I area. We specifically solicit public comment on this proposed alternative approach.

In addition to options 1 and 2, we also solicit public comment on any alternative $SO_2$ and $NO_X$ control measures that would address the regional haze requirements for Entergy White Bluff Units 1 and 2 and Entergy Independence Units 1 and 2 for this planning period. This includes, but is not limited to, a combination of early unit shutdowns and other emissions control measures that would achieve greater reasonable progress than the BART and reasonable progress requirements we have proposed for these four units in this rulemaking.

## C. Proposed Reasonable Progress Goals

We propose RPGs for Caney Creek and Upper Buffalo that are consistent with the combination of control measures from the approved portion of the 2008 Arkansas RH SIP and our proposed Arkansas RH FIP. In total, these final and proposed controls to meet the BART and RP requirements will result in higher emissions reductions and commensurate visibility improvements beyond what was in the 2008 Arkansas RH SIP. Development of refined numerical RPGs for Arkansas' Class I areas would require photochemical grid modeling of a multistate area, involving thousands of emission sources, unlike the comparatively simple single-source CALPUFF modeling used for individual BART assessments. In order to accurately reflect all emissions reductions expected to occur during this planning period, the new photochemical modeling would require an update of the emissions inventory for Arkansas and the surrounding states to include not just the actions under this FIP, but all EPA and state regulatory actions on point, area, and mobile sources. After the inventory is developed and reviewed by the affected

[157] See Appendix C to the TSD, titled "Technical Support Document for Visibility Modeling Analysis for Entergy Independence Generating Station," for a detailed discussion of the visibility modeling protocol and model inputs.

states for accuracy, it must be converted to a model-ready format before air quality modeling can be used to estimate the future visibility levels at the Class I areas. This modeling would require specialized and extensive computing hardware and expertise. Developing all of the necessary input files, running the photochemical model, and post-processing the model outputs would take several months at a minimum. Therefore, we are not conducting new photochemical grid modeling to establish revised numeric RPGs for Caney Creek and Upper Buffalo.

In order to provide RPGs that account for emission reductions from the FIP controls, we have used a method similar to the one used in our Regional Haze FIP for Hawaii[158] and Arizona,[159] which is based on a scaling of visibility extinction components in proportion to emission changes. To determine the new RPGs for Caney Creek and Upper Buffalo, we started with the 2018 projection of extinction components from the CENRAP's CAMx photochemical modeling with source apportionment. The 2018 CAMx emission scenario included some assumptions of state BART determinations and other SIP controls, as well as projected emissions from other point, area, and mobile sources. We scaled the modeled visibility extinction components for sulfate ($SO_4$) and nitrate ($NO_3$) from point sources in Arkansas (Table 92) in proportion to the FIP's emission reductions for $SO_2$ and $NO_X$, respectively. The sulfate scaling factor was the 2018 CENRAP emission inventory for Arkansas point source $SO_2$ emissions with FIP controls for BART and RP sources in place, divided by the original 2018 CENRAP emission inventory for Arkansas point source $SO_2$ emissions (Table 91). We conducted the same scaling exercise with nitrate and $NO_X$. The scaled sulfate and nitrate extinctions were added to the unscaled extinctions for organic mass and other components to get total extinction, and then this was used to calculate post-FIP RPGs in deciviews.[160] Although we recognize that this method is not refined, it allows us to translate the emission reductions contained in this proposed FIP into quantitative RPGs, based on modeling previously performed by the CENRAP.

**Table 91. 2018 CENRAP CAMx modeled extinction due to Arkansas point sources ($Mm^{-1}$)[161]**

| | CACR | UPBU |
|---|---|---|
| **Sulfate** | 3.0726 | 2.7601 |
| **Nitrate** | 0.2498 | 0.2120 |

[158] See 77 FR 31692, 31708.
[159] See 79 FR 52420, 52468.
[160] See "CACR UPBU RPG analysis.xlsx" in the docket for this proposed rulemaking for additional details on these calculations.
[161] See the CENRAP TSD and the August 27, 2007 CENRAP PSAT tool (CENRAP_PSAT_Tool_ENVIRON_Aug27_2007.mdb). A copy of the CENRAP TSD and instructions for accessing the August 27, 2007 CENRAP PSAT tool can be found in the docket for this proposed rulemaking.

**Table 92. Nitrate and Sulfate Scaling Factors for 2018 RPG calculation**

| | 2018 CENRAP Arkansas Point Source Emissions (tpy) | FIP Emission reductions[162] | | Scaling factor | |
|---|---|---|---|---|---|
| | | Option 1 | Option 2 | Option 1 | Option 2 |
| $NO_X$ | 71,107 | 8,745 | 1,219 | 0.8770 | 0.9829 |
| $SO_2$ | 106,461 | 69,128 | 69,128 | 0.3507 | 0.3507 |

These RPGs reflect rates of progress that are faster than the rates projected by Arkansas. The revised RPGs for the first planning period for the 20% worst days are 22.27 dv for Caney Creek and 22.33 dv for Upper Buffalo. The results of our analysis are shown in the table below.[163] The RPG calculation was performed for both our proposed Options 1 and 2. Under Option 1 we are proposing to control Entergy Independence Units 1 and 2 for the first planning period for both $SO_2$ and $NO_X$. Alternatively, under Option 2, we are proposing to control Entergy Independence Units 1 and 2 only for $SO_2$ for the first planning period. Due to the small impact from all Arkansas point source NOx emissions combined on the 20% worst days and the scaling approach utilized to estimate the adjustment to the RPG, the difference between the two proposed options results in a very small difference in the calculated 2018 RPGs for the 20% worst days for Caney Creek and Upper Buffalo (less than 0.003 dv). We note that some FIP controls will not be in place by 2018, however, for the purpose of this calculation, we included reductions from all FIP controls. Arkansas will have to re-evaluate during the next regional haze planning period what BART and reasonable progress controls are in place and re-calculate the RPGs for the next planning period as needed. We also note that RPGs, unlike the emission limits that apply to specific RP sources, are not directly enforceable.[164] Rather, they are an analytical framework considered by us in evaluating whether measures in the implementation plan are sufficient to achieve reasonable progress.[165] Arkansas may choose to use these RPGs for purposes of its progress report, or may develop new RPGs for approval by us along with its progress report, based on new modeling or other appropriate techniques, in accordance with the requirements of 40 CFR 51.308(d)(1).

[162] $NO_X$ FIP emission reductions also include adjustments to AECC Bailey and Lake Catherine units 1,2, and 3 to recent actual emissions (average from 2009-2013, excluding the maximum and minimum year). These gas units were projected for early retirement (see ipmcair2020parsed.xls in the docket for this proposed rulemaking) by 2018 in the CENRAP 2018 emission inventory.

[163] Please see Appendix C to the TSD, titled "Technical Support Document for Visibility Modeling Analysis for Entergy Independence Generating Station," and the RPG calculation spreadsheet for additional details on calculations. These documents are found in the docket for our proposed rulemaking.

[164] 40 CFR 51.308(d)(1)(v).

[165] 64 FR 35733 and 40 CFR 51.308(d)(1)(v).

**Table 93. Proposed Reasonable Progress Goals for 20% Worst Days (In deciviews)**

| Class I area | 2000-2004 baseline | 2064 natural conditions | 2018 URP | 2018 Projection by CENRAP | Estimated FIP effect | Estimated FIP 2018 RPG |
|---|---|---|---|---|---|---|
| Caney Creek | 26.36 | 11.58 | 22.91 | 22.48 | -0.21 | 22.27 |
| Upper Buffalo | 26.27 | 11.57 | 22.84 | 22.52 | -0.19 | 22.33 |

## IV. Our Proposed Long-Term Strategy

Section 169A(b) of the CAA and 40 CFR 51.308(d)(3) require that states include in their SIP a 10 to 15-year strategy, referred to as the long-term strategy, for making reasonable progress for each Class I area within their state. This long-term strategy is the compilation of all control measures a state will use during the implementation period of the specific SIP submittal to meet any applicable RPGs for a particular Class I area. The long-term strategy must include "enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals" for all Class I areas within, or affected by emissions from, the state.[166]

Section 51.308(d)(3)(v) requires that a state consider certain factors (the long-term strategy factors) in developing its long-term strategy for each Class I area. These factors are the following: (1) emission reductions due to ongoing air pollution control programs, including measures to address RAVI; (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. Since states are required to consider emissions limitations and schedules of compliance to achieve the RPGs for each Class I area, the BART emission limits that are in the state's regional haze SIP are an element of the state's long-term strategy (40 CFR 51.308(d)(3)) for each Class I area. In our March 11, 2012 final action on the 2008 Arkansas RH SIP, since we disapproved a portion of Arkansas' BART determinations and both RPGs for Arkansas' two Class I areas, we also disapproved these

[166] 40 CFR 51.308(d)(3).

elements and approved all other elements of Arkansas' long-term strategy. The BART limits and two RPGs for Arkansas' Class I areas that are in this proposed FIP address our March 11, 2011 disapproval of Arkansas' BART limits and two RPGs. We propose to find that the proposed BART limits and two RPGs that are in this proposed FIP also correct the deficiency in Arkansas' long-term strategy for each of its Class I areas.

**ASHDOWN MILL**
**BART ALTERNATIVE – TECHNICAL SUPPORT DOCUMENT**

**September 4, 2018**

## Introduction

With the continued decline in demand for printing and writing paper, the Ashdown Mill looks for opportunities to produce new products or move into new markets so it can remain competitive in dynamic and global markets. In order to maintain flexibility and competitiveness for the Mill, Domtar is slightly revising the BART Alternative. This revised Alternative is based on the January 4, 2018 telephone discussion with the Arkansas Department of Environmental Quality (ADEQ) and the United States Environmental Protection Agency-Region 6 (EPA) staffs. The approach meets the requirements of 40 C.F.R. § 51.308 while allowing the Mill the flexibility of a future voluntary retirement of No.1 Power Boiler based on the continuing reassessment of steam needs under the changing Mill configuration.

In summary, Domtar is proposing the following revised BART Alternative:

- Power Boiler No. 1 on natural gas only (as authorized in Domtar's air operating permit); and

- Power Boiler No. 2 at adjusted emission rates for $SO_2$ and $NO_X$ (and the same emission rate for PM set in the FIP). Compared to the final BART FIP emission rates (*i.e.*, 345 lb/hr for $NO_X$ and 91.5 lb/hr for $SO_2$), this scenario decreases $NO_X$ emissions while allowing increased $SO_2$ emissions.

The specific emission rates associated with BART Alternative are summarized in Table 1 below.

**Table 1. BART Alternative Scenario Emission Rates**

| | Modeled Emission Rates | | |
|---|---|---|---|
| **Unit** | **$SO_2$ (lb/hr)** | **$NO_X$ (lb/hr)** | **PM (lb/hr)** |
| Power Boiler No. 1 on natural gas only | 0.5 | 191.10 | 5.2 |
| Power Boiler No. 2 at adjusted emission rates for $SO_2$ and $NO_X$ | 435.0 | 293.0 | 81.6 |

Modeling of the BART Alternative scenario results in better predicted visibility improvement than the values presented in EPA's FIP across the four affected Class I areas: Caney Creek (CACR), Upper Buffalo (UPBU), Hercules Glades (HEGL), and Mingo (MING). Two CALPUFF-based modeling methodologies were utilized as summarized below. These methodologies were discussed with Mr. Michael Feldman, EPA-Region 6 Air Planning Section.[1] Method 1 follows the approach EPA used in the BART FIP where predicted impacts from

[1] Conference call between Mr. Michael Feldman, (EPA-Region 6, Air Planning Section), Mr. Jeremy Jewell (Trinity), and Ms. Christine Chambers (Trinity) on January 10, 2018.

separate models for each source and pollutant are combined together to arrive at an estimate of cumulative visibility improvement. Method 2 is a full-chemistry method that more accurately accounts for the chemical interaction of emissions through the combination of the sources into a single modeling file. Details on each method as well as the resulting visibility improvement are summarized below.

## **Background**

EPA estimated visibility improvement for the BART FIP Controls by comparing the visibility impairment from a baseline scenario to the impairment for a control scenario. The modeling was conducted per source and per pollutant in separate modeling files, which does not account for the full chemical interaction of all emissions (*i.e.*, "Method 1"). Per discussion with EPA-Region 6, a combined assessment is an acceptable alternate method of calculating a cumulative visibility improvement for a control scenario at a site.[2] With this method ("Method 2"), all sources and pollutants are combined into a single modeling run per scenario per year. This method allows for interaction of the pollutants from the two boiler using the available chemical transformation mechanism of the CALPUFF model. Domtar completed the BART Alternative analysis using both methods to document that the proposed BART Alternative results in greater visibility improvement than EPA's BART FIP.

## **Conclusion**

The proposed Domtar BART Alternative results in a greater visibility improvement than EPA's FIP utilizing either modeling methodology. As such, the BART Alternative results in greater visibility improvement than the EPA's FIP approach.

[2] *Ibid*.

## TRINITY MODELING ASSESSMENT – BART FIP ALTERNATIVE ASHDOWN MILL

### CALPUFF BART FIP Alternative Assessment

Modeling of the BART Alternative results in better predicted visibility improvement than the improvement presented in EPA's FIP across the four affected Class I areas: Caney Creek (CACR), Upper Buffalo (UPBU), Hercules Glades (HEGL), and Mingo (MING). This CALPUFF modeling for the alternative BART assessment relies on key aspects of the original ADEQ and Central States Regional Air Planning Association (CENRAP) CALPUFF modeling protocol, along with a second modeling methodology to reflect full chemistry of the CALPUFF Modeling System as discussed with EPA-Region 6.[3] The following sections describe the modeling methodology, the selected emission rates and stack parameters, and the visibility improvement results at each of the Class I areas.

### *CALPUFF Modeling Methodology*

The CALPUFF model is capable of modeling linear chemical transformation effects by using pseudo-first-order chemical reaction mechanisms for the conversion of $SO_2$ to sulfate and $NO_X$ to nitrate using the available background ammonia concentrations included in the model. The preferential scavenging of ammonia is by sulfate; therefore, the total nitrate is estimated using the remaining available ammonia concentration. If the ratio of $SO_2$ to $NO_X$ emissions in the model changes, this chemical interplay is affected.

EPA estimated visibility improvement for the BART FIP Controls by comparing the visibility impairment from a baseline scenario to the impairment for a control scenario. The modeling was conducted per source and per pollutant in separate modeling files, which does not account for the full chemical interaction of emissions. This approach was also utilized by Domtar to determine the visibility improvement from Domtar's BART Alternative and is outlined below in the *Method 1 – EPA's Assessment* section of this document.

Per discussion with EPA-Region 6, a combined assessment is an acceptable alternate method of calculating cumulative visibility effects, and therefore, visibility improvement for a multi-source control scenario at a site.[4] With this method, all sources and pollutants are combined into a single modeling run per scenario per year. This method allows for interaction of pollutants from both boilers using the available chemical transformation mechanism of the CALPUFF model. Domtar completed this assessment using CALPUFF as outlined below in the *Method 2 – Full Chemistry Assessment* section of this document.

[3] Conference call between Michael Feldman, (EPA-Region 6, Air Planning Section), Jeremy Jewell (Trinity), and Christine Chambers (Trinity) on January 10, 2018.

[4] *Ibid*.

### *Modeled Ashdown Mill Emissions*

Table 2a and Table 2b provides a summary of the modeled emission rates.

- Baseline Emissions: Emissions for Power Boiler No. 1 and Power Boiler No. 2 are based on Table 43 of the April 8, 2015 Proposed FIP, 80 FR 18979.

- EPA FIP Proposed Controls: Emissions for Power Boiler No. 2 are based on the Final FIP, 81 FR 66339. No change from baseline for Power Boiler No. 1.

- Domtar BART Alternative: Emissions for Power Boiler No. 1 are based on natural gas only (*i.e.*, the current limits in Domtar's air operating permit), and emissions for Power Boiler No. 2 are at adjusted emission rates for $SO_2$ and $NO_X$. (The same emission rate for PM presented in the FIP.)

**Table 2a. Baseline and EPA FIP Proposed Control Emission Rates**

| | **Baseline** | | | **EPA FIP Proposed Controls** | | |
|---|---|---|---|---|---|---|
| **Unit** | **$SO_2$ (lb/hr)** | **$NO_X$ (lb/hr)** | **PM (lb/hr)** | **$SO_2$ (lb/hr)** | **$NO_X$ (lb/hr)** | **PM (lb/hr)** |
| Power Boiler No. 1 | 21.0 | 207.4 | 30.4 | 21.0 | 207.4 | 30.4 |
| Power Boiler No. 2 | 788.2 | 526.8 | 81.6 | 91.5 | 345 | 81.6 |

**Table 2b. Domtar BART Alternative Emission Rates**

| | **Domtar BART Alternative PB1 Natural Gas Only, PB2 Reduced $NO_X/SO_2$** | | |
|---|---|---|---|
| **Unit** | **$SO_2$ (lb/hr)** | **$NO_X$ (lb/hr)** | **PM (lb/hr)** |
| Power Boiler No. 1 | 0.5 | 191.10 | 5.2 |
| Power Boiler No. 2 | 435 | 293 | 81.6 |

*Modeled Ashdown Mill Stack Parameters*

Domtar's BART FIP Alternative assessment used actual stack parameters representative of each BART unit. Table 3 summarizes these parameters. These stack parameters are consistent with the FIP modeling.

**Table 3. Modeled Stack Parameters**

| Unit | LCC East (km) | LCC North (km) | Base Elevation (m) | Stack Height (m) | Stack Diameter (m) | Exhaust Temperature (K) | Exhaust Velocity (m/s) |
|---|---|---|---|---|---|---|---|
| No. 1 Power Boiler - A | 267.49713 | -698.63952 | 99.58 | 66.14 | 2.1 | 342.04 | 11.06 |
| No. 1 Power Boiler - B | 267.49891 | -698.63445 | 99.51 | 66.14 | 2.1 | 342.04 | 11.07 |
| No. 2 Power Boiler | 267.45242 | -698.64643 | 99.95 | 71.63 | 3.66 | 324.82 | 11.92 |

*Modeled Class I Areas*

Table 4 below presents the Class I areas included in Domtar's BART Alternative Assessment, the responsible Federal Land Manager (FLM) and approximate distance between the Ashdown Mill and each area. Class I area receptor data from the National Park Service (NPS) Air Resources Division (ARD) is the same as that used in prior modeling analyses.

**Table 4. Modeled Class I Areas**

| Class I Area | FLM | Approximate Distance from Ashdown Mill (km) |
|---|---|---|
| Caney Creek Wilderness (CACR) | Forest Service | 85 |
| Upper Buffalo Wilderness (UPBU) | Forest Service | 250 |
| Hercules Glades Wilderness (HEGL) | Forest Service | 350 |
| Mingo Wildlife Refuge (MING) | Fish and Wildlife Service | 500 |

*BART Alternate Modeling Steps and Modeling Results*

**Method 1 – EPA FIP Assessment Method**

EPA estimated visibility improvement for the BART FIP Controls by comparing the visibility impairment from a baseline scenario to the impairment for a control scenario. The modeling was conducted per source and per pollutant in separate modeling files, which does not account for the full chemical interaction of emissions. For the purposes of direct comparison with the FIP, this approach was also utilized by Domtar to determine the visibility improvement from Domtar's BART Alternative.

EPA's proposed improvement due to the controls outlined in the FIP are predicted to result in a cumulative modeled improvement of **0.473 Δdv** (*see* Table 5 below). Domtar's proposed BART Alternative results in a cumulative modeled improvement of **0.549 Δdv** (*see* Table 6). Detailed steps on the calculation methodology are provided below.

**Table 5. Method 1 - Cumulative Visibility Improvement Due to BART-FIP Controls**

| Description | Boiler | Pollutant | 98th Percentile Visibility Impacts – Max. of Three Modeled Years (Δdv) | | | |
|---|---|---|---|---|---|---|
| | | | CACR | UPBU | HEGL | MING |
| FIP Baseline | 1 | Both | 0.335 | 0.038 | 0.020 | 0.014 |
| | 2 | Both | 0.844 | 0.146 | 0.105 | 0.065 |
| | Both | Both | 1.179 | 0.184 | 0.125 | 0.079 |
| FIP Controls | 2 | $SO_2$ | 0.524 | 0.082 | 0.046 | 0.035 |
| | 2 | $NO_X$ | | | | |
| | 2 | Both | 0.524 | 0.082 | 0.046 | 0.035 |
| Calculated Improvement | 2 | $SO_2$ | 0.139 | 0.050 | 0.048 | 0.025 |
| | 2 | $NO_X$ | 0.181 | 0.014 | 0.011 | 0.005 |
| | 2 | Both | 0.320 | 0.064 | 0.059 | 0.030 |
| **Cumulative Improvement** | **Both** | **Both** | **0.473** | | | |

**Table 6. Method 1 - Cumulative Visibility Improvement Due to Proposed BART Alternative**

| Description | Boiler | Pollutant | 98th Percentile Visibility Impacts – Max. of Three Modeled Years (Δdv) | | | |
|---|---|---|---|---|---|---|
| | | | CACR | UPBU | HEGL | MING |
| FIP Baseline | 1 | Both | 0.335 | 0.038 | 0.020 | 0.014 |
| | 2 | Both | 0.844 | 0.146 | 0.105 | 0.065 |
| | Both | Both | 1.179 | 0.184 | 0.125 | 0.079 |
| BART Alternative | 1 | Both | 0.286 | 0.033 | 0.017 | 0.011 |
| | 2 | Both | 0.493 | 0.082 | 0.059 | 0.037 |
| | Both | Both | 0.779 | 0.115 | 0.076 | 0.048 |
| Calculated Improvement | 1 | Both | 0.049 | 0.005 | 0.003 | 0.003 |
| | 2 | Both | 0.351 | 0.064 | 0.046 | 0.028 |
| | Both | Both | 0.400 | 0.069 | 0.049 | 0.031 |
| **Cumulative Improvement** | **Both** | **Both** | **0.549** | | | |

EPA's estimated visibility effect from the FIP baseline as well as the calculated visibility improvement per Class I area from the FIP Controls is presented in Table 5. This data was extracted from the BART FIP. The cumulative visibility improvement from Domtar's proposed BART Alternative using Method 1, as outlined in Table 6, was calculated using the following steps:

**Determine the maximum 98th percentile visibility impact per Class I area for the BART Alternative:**

1. Run CALPUFF for Boiler No. 1 at emission rates currently listed in the operating permit with no limitation, extract the maximum 98th percentile of the 3-years modeled per Class I area (*see* the BART Alternative, Boiler 1 line item in Table 6 above).

2. Run CALPUFF for Boiler No. 2 with the emission rates listed in Table 1 and extract the maximum 98th percentile of the 3-years modeled per Class I area (*see* the BART Alternative, Boiler 2 line item in Table 6 above).

3. Sum BART Alternative maximum 98th percentile results for Boiler No. 1 and Boiler No. 2 to obtain the total 98th percentile effects (*see* the BART Alternative, Both line item in Table 6 above).

**Determine the visibility improvement between the baseline and Domtar's BART Alternative per Class I area:**

1. Determine the delta between the EPA predicted impacts using baseline conditions and the impacts resulting after Domtar's BART Alternative for Boiler No. 1 by subtracting the BART Alternative impacts from the baseline impacts for Boiler No. 1. (*See* the Calculated Improvement, Boiler No. 1 line item in Table 6 above).

2. Determine the delta between the EPA predicted impacts at the baseline and the impacts resulting after Domtar's BART Alternative for Boiler No. 2 by subtracting the BART Alternative impacts from the baseline impacts for Boiler No 2. (*See* the Calculated Improvement, Boiler No. 2 line item in Table 6 above).

3. Sum the delta from Boiler No. 1 and Boiler No. 2 (*see* the Calculated Improvement, Both line item in Table 6 above).

**Determine the cumulative visibility improvement between the baseline and Domtar's BART Alternative:**

1. Sum the improvement for each Class I area (*see* the Cumulative Improvement line item in Table 6 above).

**Method 2 – Full Chemistry Assessment**

With the Full Chemistry method, all sources and pollutants are combined into a single modeling run per year.

When combining sources and pollutants, EPA's proposed improvement due to the FIP controls is predicted to result in a cumulative modeled improvement of **0.516 $\Delta$dv**, as documented in Table 7 below; whereas, Domtar's BART Alternative results in a cumulative modeled improvement of **0.520 $\Delta$dv**, as documented in Table 8. Detailed steps on the calculation methodology are provided below.

**Table 7. Method 2 - Cumulative Visibility Improvement Due to BART FIP Controls**

| Description | Boiler | Pollutant | 98th Percentile Visibility Impacts – Max. of Three Modeled Years ($\Delta$dv) | | | |
|---|---|---|---|---|---|---|
| | | | **CACR** | **UPBU** | **HEGL** | **MING** |
| FIP Baseline | Both | Both | 1.137 | 0.163 | 0.118 | 0.072 |
| FIP Controls | Both | Both | 0.776 | 0.103 | 0.057 | 0.038 |
| Calculated Improvement | Both | Both | 0.361 | 0.060 | 0.061 | 0.034 |
| **Cumulative Improvement** | **Both** | **Both** | **0.516** | | | |

**Table 8. Method 2 - Cumulative Visibility Improvement Due to Proposed BART Alternative**

| Description | Boiler | Pollutant | 98th Percentile Visibility Impacts – Max. of Three Modeled Years (Δdv) | | | |
|---|---|---|---|---|---|---|
| | | | CACR | UPBU | HEGL | MING |
| FIP Baseline | Both | Both | 1.137 | 0.163 | 0.118 | 0.072 |
| BART Alternative | Both | Both | 0.753 | 0.104 | 0.069 | 0.044 |
| Calculated Improvement | Both | Both | 0.384 | 0.059 | 0.049 | 0.028 |
| **Cumulative Improvement** | **Both** | **Both** | **0.520** | | | |

The cumulative visibility improvement from Domtar's proposed BART Alternative using Method 2 was calculated following the below steps.

**<u>EPA's Proposed FIP Controls</u>**

**Determine the maximum 98$^{th}$ percentile visibility impact per Class I area for the BART FIP Baseline:** [5]

1. Run CALPUFF with Boiler No. 1 and Boiler No. 2 with the baseline emission rates for $SO_2$, $NO_X$, and $PM_{10}$ listed in Table 1 and extract the maximum 98$^{th}$ percentile of the 3-years modeled per Class I area (*see* the FIP Baseline, Both Boilers, Both Pollutants, line item in Table 7 and Table 8 above).

**Determine the maximum 98$^{th}$ percentile visibility impact per Class I area for the Proposed BART Controls:**[6]

1. Run CALPUFF for Boiler No. 1 and Boiler No. 2 with the emission rates listed in Table 1 for the EPA FIP Proposed Controls and extract the maximum 98$^{th}$ percentile of the 3-years modeled per Class I area (*see* the FIP Controls, Both Boilers, Both Pollutants line item in Table 7 above).

**Determine the visibility improvement between the FIP Baseline and EPA's Proposed Controls per Class I area:**

1. Determine the delta between the estimated BART FIP impacts at the baseline and the estimated impacts resulting after EPA's Proposed Controls for Both Boilers by subtracting EPA's Proposed Control impacts from the baseline impacts for both boilers.

[5] Because Method 2 combines both boilers and all pollutants into a single modeling file, the FIP baseline scenario was run using the combined source and pollutant methodology. Because EPA modeled the baseline per boiler and summed the visibility impairment from each unit to calculate the FIP baseline visibility impairment, when the emissions from Boiler 1 and Boiler 2 are combined into one modeling file, the predicted baseline visibility impairment will be different than presented in the AR FIP due to the chemical interaction of the pollutants.

[6] Because Method 2 combines both boilers and all pollutants into a single modeling file, the FIP baseline scenario was run using the combined source and pollutant methodology. Because EPA modeled the baseline per boiler and summed the visibility impairment from each unit to calculate the FIP baseline visibility impairment, when the emissions from Boiler 1 and Boiler 2 are combined into one modeling file, the predicted baseline visibility impairment will be different than presented in the FIP due to the chemical interaction of the pollutants.

(*See* the Calculated Improvement, Both Boilers, Both Pollutant line item in Table 7 above).

**Determine the cumulative visibility improvement between the Baseline and EPA's Proposed FIP Controls:**

1. Sum the improvement for each Class I area (*see* the Cumulative Improvement line item in Table 7 above).

**<u>BART Alternative</u>**

**Determine the maximum 98$^{th}$ percentile visibility impact per Class I area for Domtar's BART Alternative:**

1. Run CALPUFF for Boiler No. 1 and Boiler No. 2 with the Domtar BART Alternative emission rates Operating Scenario A listed in Table 1 and extract the maximum 98$^{th}$ percentile of the 3-years modeled per Class I area (*see* the BART Alternative, Both Boilers, Both Pollutants line item in Table 8 above).

**Determine the visibility improvement between the baseline and Domtar's BART Alternative per Class I area:**

1. Determine the delta between the estimated BART FIP predicted impacts at the baseline and the impacts resulting after Domtar's BART Alternative for both boilers by subtracting the BART Alternative impacts from the baseline impacts from both boilers. (*See* the Calculated Improvement, Both Boilers, Both Pollutant line item in Table 8 above).

**Determine the cumulative visibility improvement between the baseline and Domtar's BART Alternative for Operating Scenario A:**

1. Sum the improvement for each Class I area (*see* the Cumulative Improvement line item in Table 8 above).

ADEQ
ARKANSAS
Department of Environmental Quality

February 28, 2019

Via Email Only to: kelley.crouch@domtar.com

Kelley Crouch
Environmental Manager
Domtar A.W. LLC - Ashdown Mill
285 Highway 71 South
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RE: **Application for Minor Modification**
**Determination of Qualifying Minor Modification**
AFIN: 41-00002 Permit No.: 0287-AOP-R21

Dear Ms. Crouch:

The Department has conducted an initial review of the above referenced air permit application received on January 30, 2019. This application was submitted as a minor modification to Permit No. 0287-AOP-R21:

- Insert BART Alternative conditions for the Regional Haze Program
  There are no permitted emission changes

Based solely upon this administrative review, it has been determined that your request qualifies as a minor modification only upon the permittee's compliance with the following Interim Conditions:

30 boiler operating day rolling average is defined as the arithmetic mean of the previous 720 hours of operating data, excluding times in which the unit is not operating.

Regional Haze – BART alternative Specific Conditions

BART Alternative Description

For compliance with the Clean Air Act Regional Haze Program's requirements for the first planning period, the No. 1 Power Boiler (SN-03) and the No. 2 Power Boiler (SN-05) are subject to a best available retrofit technology (BART) Alternative measures consistent with 40 C.F.R. § 51.308. The following terms and conditions of the BART Alternative measures are to be submitted to EPA for inclusion in the Arkansas State Implementation Plan (SIP).

1) The permittee shall not exceed the emission rates set forth in the following table. The limits are based on a 30 boiler operating day rolling average. 30 boiler operating day

rolling average is defined as the arithmetic mean of the previous 720 hours of operating data, excluding times in which the unit is not operating.
[Reg.19.304 and 40 C.F.R. §51.308]

| SN | Source Name | Pollutant | Lb/hr |
|---|---|---|---|
| 03 | No. 1 Power Boiler (580 MMBtu/hr) | $PM_{10}$ | 5.2 |
| | | $SO_2$ | 0.5 |
| | | $NO_X$ | 191.1 |

2) For SN-03. compliance with the $PM_{10}$, $SO_2$, and $NO_X$ emission limits shall be demonstrated based on natural gas fuel usage records and the following emission factors:

    a) 7.6 lb-$PM_{10}$/mmscf

    b) 0.6 lb-$SO_2$/mmscf

    c) 280 lb-$NO_X$/mmscf

    [Reg.19.304 and 40 C.F.R. §51.308]

3) The permittee shall not exceed the emission rates set forth in the following table. The limits are based on a 30-day boiler operating day rolling average. 30 boiler operating day rolling average is defined as the arithmetic mean of the previous 720 hours of operating data, excluding times in which the unit is not operating. [Reg.19.304 and 40 C.F.R. §51.308]

| SN | Source Name | Pollutant | Lb/hr |
|---|---|---|---|
| 05 | No. 2 Power Boiler (820 MMBtu/hr) | $PM_{10}$ | 81.6 |
| | | $SO_2$ | 435 |
| | | $NO_X$ | 293 |

4) For SN-05, the permittee shall demonstrate compliance with the 30 boiler operating day rolling average $SO_2$ and $NO_X$ limits utilizing a continuous emissions monitor (CEMS) subject to 40 CFR Part 60, as amended. [Reg.19.304 and 40 C.F.R. §51.308]

5) In the event either SN-03 (No. 1 Power Boiler) or SN-05 (No. 2 Power Boiler) is permanently retired, the BART Alternative limits and conditions will not be applicable to the retired source. [Reg.19.304 and 40 C.F.R. §51.308]

6) If SN-05 (No. 2 Power Boiler) only combusts natural gas, the applicable natural gas AP-42 emission factors shall be used to demonstrate compliance, in conjunction with natural gas fuel usage records. [Reg.19.304 and 40 C.F.R. §51.308]

7) While SN-05 (No. 2 Power Boiler) is subject to 40 CFR Part 63 subpart DDDDD (5D), the applicable $PM_{10}$ compliance demonstration requirements from 5D shall be utilized to demonstrate compliance for $PM_{10}$ emissions. [Reg.19.304 and 40 C.F.R. §51.308]

This letter is your authorization to proceed with the proposed minor modification as described within the permit application and the conditions set forth above. The Department will revise Permit No. 0287-AOP-R21 as expeditiously as possible. Until final permit action is taken, you must comply with the terms and conditions listed in the current permit and as modified by this letter. Should you not accept the terms and conditions of this letter, this minor modification determination is withdrawn.

Place this letter and a copy of your application with the permit at the facility.

If you have any questions, please feel free to call Christopher Riley, Engineer, at (501) 682-0742 or riley@adeq.state.ar.us.

Sincerely,

Phillip Murphy

Phillip Murphy, P.E.
Engineer Supervisor
Office of Air Quality

c: Compliance Monitoring

Domtar
Ashdown Mill
285 Hwy 71 South
Ashdown, AR 71822
Tel.: (870) 898-2711
allan.bohn@domtar.com

Domtar

December 20, 2018

William K. Montgomery, Policy & Planning Branch Manager
Arkansas Department of Environmental Quality
Office of Air Quality
5301 Northshore Drive
North Little Rock, AR 72118-5317

RE: *Domtar A.W. LLC*
*Demonstration of Compliance with Proposed BART Alternative Limits*

Dear Mr. Montgomery:

In accordance with the December 17, 2018 conference call with EPA Headquarters, EPA Region VI, and ADEQ, Domtar is providing information with this letter demonstrating that both BART-affected emission units at its Ashdown Mill (Power Boilers No. 1 and No. 2) are in compliance with the BART Alternative Limits in the proposed Arkansas Regional Haze SIP Phase III. Also, existing permit conditions applicable to Power Boilers No. 1 and 2 that require monitoring, recordkeeping and reporting are sufficient to continue demonstrating compliance with the BART Alternative emission rates.

Domtar reviewed the last two years (December 2016 to November 2018) of emissions data for both Power Boiler No. 1 and Power Boiler No. 2. This review confirms that neither unit emitted at levels greater than the BART Alternative limits during this time period. See Tables 1 and 2 below.

**Table 1. BART Alternative Emission Rates (30-day Rolling Averages)**

| Unit | $SO_2$ (lb/hr) | $NO_X$ (lb/hr) | PM (lb/hr) |
|---|---|---|---|
| Power Boiler No. 1 | 0.5 | 191.1 | 5.2 |
| Power Boiler No. 2 | 435 | 293 | 82 [a,b] |

[a] According to the final FIP and proposed SIP, compliance with the BART and BART Alternative PM limits is based on compliance with Boiler MACT in accordance with 40 CFR Part 63 Subpart DDDDD.
[b] Rounded up from 81.6 as presented in the FIP and SIP to be consistent with the proposed $SO_2$ and $NO_X$ limits and the current Title V permit limit.

**Table 2. Emission Rates for 12/2016 – 11/2018**

| Unit | $SO_2$ (lb/hr) Maximum of 30-day Rolling Averages | $NO_X$ (lb/hr) Maximum of 30-day Rolling Averages | PM (lb/hr) |
|---|---|---|---|
| Power Boiler No. 1 | 0 | 0 | 0 |
| Power Boiler No. 2 | 294 | 179 | 34 [a] |

[a] Compliance with the BART Alternative limit is demonstrated via compliance with Boiler MACT. The Boiler MACT standard is 0.44 lb/MMBtu. Based on compliance testing conducted in January 2016, actual emissions from Power Boiler No. 2 are 0.059 lb/MMBtu (13 percent of the standard). The 34 lb/hr value listed in this table is an estimate based on the test result and the heat input to the boiler during testing, 569 MMBtu/hr.

Detailed emissions data for Power Boiler No. 2 – CEMS-based information for $SO_2$ and $NO_X$ and Boiler MACT stack test results for PM – are provided in Attachment 1. Note that Power Boiler No. 1 is in standby mode with zero emissions since early 2016.

For purposes of this interim period, the Mill will utilize the following approach for compliance demonstration:

**Table 3. Compliance Demonstration**

| Unit | $NO_X/SO_2$ | PM |
|---|---|---|
| Power Boiler No. 1 | Fuel usage/emission factor | Stack testing [a] |
| Power Boiler No. 2 | CEMS [b] | Boiler MACT [c] |

[a] Permit requirement.
[b] 30-day rolling average.
[c] Stack test results.

Based on the above demonstration, Power Boilers No. 1 and No. 2 at the Ashdown Mill satisfy the timing requirements of 40 C.F.R. § 51.308(e) as the necessary emission reductions associated with the BART Alternative occurred during the first long-term strategy for regional haze. The improvements to visibility achieved by the BART Alternative are demonstrated in the Department's Proposed Phase III SIP documentation. As shown by the prior emission data, Power Boilers No. 1 and No. 2 are readily able to and will continue to meet the BART Alternative emission rates. This commitment will be verified utilizing monitoring and recordkeeping already required by the Ashdown Mill's air permit.

Also, as we discussed, the next step is developing acceptable SIP components that include (i) the emission rates and (ii) only those additional requirements necessary to demonstrate compliance. A key aspect of this BART Alternative approach is maintaining flexibility for the Ashdown Mill so as to allow it to quickly respond to market conditions and cost/efficiency optimization programs. Doing so is essential to the ability of the Mill to remain competitive and provide high wage/quality jobs to southwestern Arkansas.

Thank you for your consideration of this information. Please contact Mrs. Kelley Crouch at 870-898-2711 (ext. 26168) with any questions and to set up a call or meeting to discuss any additional data needs and next steps.

Sincerely,

Allan M. Bohn

Allan M. Bohn
V.P. General Manager

cc: Kelley Crouch, Domtar
Annabeth Reitter, Domtar
Jeremy Jewell, Trinity Consultants
Mark A. Thimke, Foley & Lardner LLP

# Attachment 1 – Detailed Emissions Data

## Power Boiler No. 2

- **Continuous Emissions Monitoring System Data for $SO_2$ and $NO_X$ (30-day rolling averages for 12/2016 – 11/2018)**
- **Boiler MACT stack test (initial compliance demonstration) results for PM (January 2016)**

| No. 2 PB CEMS Data | Nox lb/hr | Max 30 Day 179.08<br>Nox lb/hr 30-day avg | SO2 lb/hr | Max 30 Day 293.64<br>SO2 lb/hr 30-day avg |
|---|---|---|---|---|
| 12/1/2016 6:00 | 127.85 | | 142.99 | |
| 12/2/2016 6:00 | 120.49 | | 109.15 | |
| 12/3/2016 6:00 | 134.94 | | 259.52 | |
| 12/4/2016 6:00 | 150.54 | | 138.43 | |
| 12/5/2016 6:00 | 206.42 | | 285.05 | |
| 12/6/2016 6:00 | 159.29 | | 228.36 | |
| 12/7/2016 6:00 | 138.19 | | 215.12 | |
| 12/8/2016 6:00 | 125.83 | | 113.51 | |
| 12/9/2016 6:00 | 171.08 | | 242.16 | |
| 12/10/2016 6:00 | 168.91 | | 207.44 | |
| 12/11/2016 6:00 | 120.70 | | 197.42 | |
| 12/12/2016 6:00 | 109.27 | | 216.46 | |
| 12/13/2016 6:00 | 124.21 | | 258.56 | |
| 12/14/2016 6:00 | 67.58 | | 106.44 | |
| 12/15/2016 6:00 | 107.11 | | 182.83 | |
| 12/16/2016 6:00 | 104.43 | | 239.45 | |
| 12/17/2016 6:00 | 102.09 | | 199.70 | |
| 12/18/2016 6:00 | 145.21 | | 293.89 | |
| 12/19/2016 6:00 | 158.30 | | 279.15 | |
| 12/20/2016 6:00 | 186.66 | | 395.07 | |
| 12/21/2016 6:00 | 154.51 | | 244.37 | |
| 12/22/2016 6:00 | 172.87 | | 348.29 | |
| 12/23/2016 6:00 | 148.57 | | 243.65 | |
| 12/24/2016 6:00 | 181.76 | | 342.59 | |
| 12/25/2016 6:00 | 153.09 | | 263.32 | |
| 12/26/2016 6:00 | 174.84 | | 322.77 | |
| 12/27/2016 6:00 | 163.61 | | 265.61 | |
| 12/28/2016 6:00 | 160.47 | | 222.11 | |
| 12/29/2016 6:00 | 154.70 | | 290.95 | |
| 12/30/2016 6:00 | 118.35 | 143.73 | 223.25 | 235.92 |
| 12/31/2016 6:00 | 106.62 | 143.02 | 243.49 | 239.27 |
| 1/1/2017 6:00 | 126.84 | 143.23 | 207.03 | 242.53 |
| 1/2/2017 6:00 | 154.91 | 143.90 | 415.49 | 247.73 |
| 1/3/2017 6:00 | 132.50 | 143.30 | 273.71 | 252.24 |
| 1/4/2017 6:00 | 106.51 | 139.97 | 190.94 | 249.10 |
| 1/5/2017 6:00 | 157.50 | 139.91 | 334.75 | 252.65 |
| 1/6/2017 6:00 | 208.46 | 142.25 | 325.86 | 256.34 |
| 1/7/2017 6:00 | 217.12 | 145.29 | 235.30 | 260.40 |
| 1/8/2017 6:00 | 180.20 | 145.60 | 297.37 | 262.24 |
| 1/9/2017 6:00 | 149.51 | 144.95 | 328.76 | 266.29 |
| 1/10/2017 6:00 | 155.22 | 146.10 | 279.40 | 269.02 |
| 1/11/2017 6:00 | 174.43 | 148.27 | 239.21 | 269.78 |

| No. 2 PB CEMS Data | Nox lb/hr | Nox lb/hr<br>30-day avg | SO2 lb/hr | SO2 lb/hr<br>30-day avg |
|---|---|---|---|---|
| 1/12/2017 6:00 | 126.65 | 148.35 | 280.24 | 270.50 |
| 1/13/2017 6:00 | 131.79 | 150.49 | 241.40 | 275.00 |
| 1/14/2017 6:00 | 159.44 | 152.24 | 266.99 | 277.80 |
| 1/15/2017 6:00 | 153.20 | 153.87 | 223.25 | 277.26 |
| 1/16/2017 6:00 | 160.47 | 155.81 | 311.31 | 280.98 |
| 1/17/2017 6:00 | 134.27 | 155.45 | 236.80 | 279.08 |
| 1/18/2017 6:00 | 152.82 | 155.26 | 291.35 | 279.49 |
| 1/19/2017 6:00 | 96.80 | 152.27 | 200.73 | 273.01 |
| 1/20/2017 6:00 | 106.17 | 150.66 | 162.24 | 270.27 |
| 1/21/2017 6:00 | 130.70 | 149.25 | 283.59 | 268.11 |
| 1/22/2017 6:00 | 142.03 | 149.03 | 251.13 | 268.36 |
| 1/23/2017 6:00 | 126.07 | 147.18 | 229.80 | 264.61 |
| 1/24/2017 6:00 | 168.93 | 147.70 | 279.09 | 265.13 |
| 1/25/2017 6:00 | 97.53 | 145.13 | 112.67 | 258.13 |
| 1/26/2017 6:00 | 140.62 | 144.36 | 181.76 | 255.33 |
| 1/27/2017 6:00 | 109.45 | 142.66 | 158.74 | 253.22 |
| 1/28/2017 6:00 | 115.61 | 141.36 | 217.66 | 250.78 |
| 1/29/2017 6:00 | 114.62 | 141.23 | 192.09 | 249.74 |
| 1/30/2017 6:00 | 121.22 | 141.72 | 244.48 | 249.77 |
| 1/31/2017 6:00 | 107.32 | 141.07 | 279.21 | 252.18 |
| 2/1/2017 6:00 | 149.55 | 140.89 | 273.16 | 247.43 |
| 2/2/2017 6:00 | 124.02 | 140.61 | 242.83 | 246.40 |
| 2/3/2017 6:00 | 112.14 | 140.80 | 245.93 | 248.24 |
| 2/4/2017 6:00 | 101.13 | 138.92 | 189.28 | 243.39 |
| 2/5/2017 6:00 | 85.69 | 134.82 | 184.00 | 238.66 |
| 2/6/2017 6:00 | 110.94 | 131.28 | 189.86 | 237.14 |
| 2/7/2017 6:00 | 97.98 | 128.54 | 188.22 | 233.51 |
| 2/8/2017 6:00 | 141.28 | 128.27 | 294.87 | 232.38 |
| 2/9/2017 6:00 | 138.27 | 127.70 | 230.80 | 230.76 |
| 2/10/2017 6:00 | 100.61 | 125.24 | 178.68 | 228.74 |
| 2/11/2017 6:00 | 103.27 | 124.46 | 194.40 | 225.88 |
| 2/12/2017 6:00 | 130.18 | 124.41 | 209.98 | 224.83 |
| 2/13/2017 6:00 | 140.86 | 123.79 | 349.39 | 227.58 |
| 2/14/2017 6:00 | 107.87 | 122.28 | 209.20 | 227.11 |
| 2/15/2017 6:00 | 99.17 | 120.24 | 202.28 | 223.47 |
| 2/16/2017 6:00 | 112.53 | 119.51 | 256.56 | 224.13 |
| 2/17/2017 6:00 | 108.20 | 118.03 | 195.97 | 220.95 |
| 2/18/2017 6:00 | 151.37 | 119.84 | 290.47 | 223.94 |
| 2/19/2017 6:00 | 134.35 | 120.78 | 229.99 | 226.20 |
| 2/20/2017 6:00 | 127.70 | 120.68 | 220.14 | 224.09 |
| 2/21/2017 6:00 | 195.82 | 122.48 | 294.05 | 225.52 |
| 2/22/2017 6:00 | 181.66 | 124.33 | 230.96 | 225.56 |
| 2/23/2017 6:00 | 192.34 | 125.11 | 228.09 | 223.86 |
| 2/24/2017 6:00 | 182.98 | 127.96 | 186.51 | 226.32 |
| 2/25/2017 6:00 | 209.16 | 130.24 | 203.75 | 227.05 |

| No. 2 PB CEMS Data | Nox lb/hr | Nox lb/hr 30-day avg | SO2 lb/hr | SO2 lb/hr 30-day avg |
|---|---|---|---|---|
| 2/26/2017 6:00 | 182.72 | 132.69 | 125.86 | 225.96 |
| 2/27/2017 6:00 | 175.72 | 134.69 | 225.58 | 226.22 |
| 2/28/2017 6:00 | 158.79 | 136.16 | 202.84 | 226.58 |
| 3/1/2017 6:00 | 137.48 | 136.70 | 95.23 | 221.60 |
| 3/2/2017 6:00 | 174.89 | 138.96 | 94.71 | 215.45 |
| 3/3/2017 6:00 | 159.77 | 139.30 | 80.74 | 209.04 |
| 3/4/2017 6:00 | 186.22 | 141.37 | 91.30 | 203.99 |
| 3/5/2017 6:00 | 125.19 | 141.80 | 74.48 | 198.27 |
| 3/6/2017 6:00 | 105.82 | 141.96 | 41.04 | 193.33 |
| 3/7/2017 6:00 | 125.70 | 143.29 | 82.96 | 189.96 |
| 3/8/2017 6:00 | 160.86 | 144.96 | 38.91 | 184.93 |
| 3/9/2017 6:00 | 124.43 | 145.84 | 75.20 | 181.16 |
| 3/10/2017 6:00 | 98.81 | 144.42 | 109.80 | 175.00 |
| 3/11/2017 6:00 | 117.83 | 143.74 | 66.40 | 169.52 |
| 3/12/2017 6:00 | 157.24 | 145.63 | 117.43 | 167.47 |
| 3/13/2017 6:00 | 158.68 | 147.48 | 102.96 | 164.43 |
| 3/14/2017 6:00 | 171.45 | 148.85 | 145.33 | 162.27 |
| 3/15/2017 6:00 | 182.93 | 150.26 | 116.86 | 154.52 |
| 3/16/2017 6:00 | 190.34 | 153.00 | 209.67 | 154.54 |
| 3/17/2017 6:00 | 172.36 | 155.44 | 145.41 | 152.64 |
| 3/18/2017 6:00 | 134.62 | 156.18 | 180.21 | 150.10 |
| 3/19/2017 6:00 | 151.24 | 157.62 | 173.28 | 149.34 |
| 3/20/2017 6:00 | 162.70 | 157.99 | 290.68 | 149.35 |
| 3/21/2017 6:00 | 115.99 | 157.38 | 113.14 | 145.45 |
| 3/22/2017 6:00 | 140.97 | 157.82 | 176.26 | 143.99 |
| 3/23/2017 6:00 | 111.85 | 155.02 | 113.50 | 137.97 |
| 3/24/2017 6:00 | 176.10 | 154.84 | 323.99 | 141.07 |
| 3/25/2017 6:00 | 135.49 | 152.94 | 195.39 | 139.98 |
| 3/26/2017 6:00 | 166.24 | 152.39 | 210.65 | 140.79 |
| 3/27/2017 6:00 | 126.74 | 149.64 | 159.05 | 139.30 |
| 3/28/2017 6:00 | 121.12 | 147.59 | 139.54 | 139.75 |
| 3/29/2017 6:00 | 164.29 | 147.20 | 174.15 | 138.04 |
| 3/30/2017 6:00 | 112.48 | 145.66 | 113.31 | 135.05 |
| 3/31/2017 6:00 | 97.95 | 144.34 | 117.69 | 135.80 |
| 4/1/2017 6:00 | 98.33 | 141.79 | 145.08 | 137.48 |
| 4/2/2017 6:00 | 93.96 | 139.60 | 147.41 | 139.70 |
| 4/3/2017 6:00 | 110.61 | 137.08 | 236.51 | 144.54 |
| 4/4/2017 6:00 | 101.27 | 136.28 | 168.11 | 147.66 |
| 4/5/2017 6:00 | 114.56 | 136.57 | 156.28 | 151.51 |
| 4/6/2017 6:00 | 108.78 | 136.01 | 244.42 | 156.89 |
| 4/7/2017 6:00 | 107.48 | 134.23 | 167.97 | 161.19 |
| 4/8/2017 6:00 | 101.63 | 133.47 | 166.85 | 164.24 |
| 4/9/2017 6:00 | 122.27 | 134.25 | 228.07 | 168.19 |
| 4/10/2017 6:00 | 129.08 | 134.63 | 180.32 | 171.98 |
| 4/11/2017 6:00 | 166.95 | 134.95 | 270.68 | 177.09 |

| No. 2 PB CEMS Data | Nox lb/hr | Nox lb/hr 30-day avg | SO2 lb/hr | SO2 lb/hr 30-day avg |
|---|---|---|---|---|
| 4/12/2017 6:00 | 132.37 | 134.07 | 249.87 | 181.99 |
| 4/13/2017 6:00 | 107.21 | 131.93 | 205.65 | 184.00 |
| 4/14/2017 6:00 | 109.92 | 129.50 | 171.97 | 185.84 |
| 4/15/2017 6:00 | 121.24 | 127.19 | 190.62 | 185.20 |
| 4/16/2017 6:00 | 112.56 | 125.20 | 176.50 | 186.24 |
| 4/17/2017 6:00 | 123.47 | 124.83 | 219.88 | 187.56 |
| 4/18/2017 6:00 | 104.20 | 123.26 | 149.50 | 186.77 |
| 4/19/2017 6:00 | 113.49 | 121.62 | 138.35 | 181.69 |
| 4/20/2017 6:00 | 141.88 | 122.48 | 256.75 | 186.48 |
| 4/21/2017 6:00 | 110.70 | 121.47 | 211.31 | 187.65 |
| 4/22/2017 6:00 | 101.44 | 121.13 | 175.37 | 189.71 |
| 4/23/2017 6:00 | 119.05 | 119.23 | 159.88 | 184.24 |
| 4/24/2017 6:00 | 153.75 | 119.83 | 152.56 | 182.81 |
| 4/25/2017 6:00 | 147.26 | 119.20 | 310.97 | 186.15 |
| 4/26/2017 6:00 | 108.46 | 118.59 | 233.25 | 188.63 |
| 4/27/2017 6:00 | 108.86 | 118.18 | 171.92 | 189.71 |
| 4/28/2017 6:00 | 109.48 | 116.36 | 188.87 | 190.20 |
| 4/29/2017 6:00 | 98.30 | 115.88 | 199.81 | 193.08 |
| 4/30/2017 6:00 | 98.11 | 115.89 | 182.67 | 195.25 |
| 5/1/2017 6:00 | 103.52 | 116.06 | 199.28 | 197.05 |
| 5/2/2017 6:00 | 101.58 | 116.32 | 209.64 | 199.13 |
| 5/3/2017 6:00 | 107.31 | 116.21 | 228.14 | 198.85 |
| 5/4/2017 6:00 | 117.35 | 116.74 | 263.25 | 202.02 |
| 5/5/2017 6:00 | 91.18 | 115.96 | 116.25 | 200.69 |
| 5/6/2017 6:00 | 107.04 | 115.90 | 189.27 | 198.85 |
| 5/7/2017 6:00 | 109.28 | 115.96 | 232.69 | 201.01 |
| 5/8/2017 6:00 | 96.08 | 115.78 | 184.47 | 201.59 |
| 5/9/2017 6:00 | 92.27 | 114.78 | 187.20 | 200.23 |
| 5/10/2017 6:00 | 115.26 | 114.32 | 232.24 | 201.96 |
| 5/11/2017 6:00 | 102.92 | 112.18 | 155.78 | 198.13 |
| 5/12/2017 6:00 | 132.13 | 112.18 | 263.52 | 198.59 |
| 5/13/2017 6:00 | 123.97 | 112.73 | 279.73 | 201.06 |
| 5/14/2017 6:00 | 105.16 | 112.58 | 202.37 | 202.07 |
| 5/15/2017 6:00 | 99.05 | 111.84 | 165.17 | 201.22 |
| 5/16/2017 6:00 | 115.83 | 111.95 | 195.27 | 201.85 |
| 5/17/2017 6:00 | 34.99 | 109.00 | 42.35 | 195.93 |
| 5/18/2017 6:00 | 191.59 | 111.91 | 349.58 | 202.60 |
| 5/19/2017 6:00 | 155.15 | 113.30 | 275.53 | 207.17 |
| 5/20/2017 6:00 | 118.77 | 112.53 | 223.26 | 206.05 |
| 5/21/2017 6:00 | 115.51 | 112.69 | 174.45 | 204.83 |
| 5/22/2017 6:00 | 113.52 | 113.09 | 196.21 | 205.52 |
| 5/23/2017 6:00 | 134.17 | 113.59 | 237.08 | 208.09 |
| 5/24/2017 6:00 | 77.21 | 111.04 | 116.65 | 206.90 |
| 5/25/2017 6:00 | 30.17 | 107.14 | 48.27 | 198.14 |
| 5/26/2017 6:00 | 106.70 | 107.08 | 200.57 | 197.05 |

| No. 2 PB CEMS Data | Nox lb/hr | Nox lb/hr 30-day avg | SO2 lb/hr | SO2 lb/hr 30-day avg |
|---|---|---|---|---|
| 5/27/2017 6:00 | 117.35 | 107.36 | 194.21 | 197.79 |
| 5/28/2017 6:00 | 113.25 | 107.49 | 235.26 | 199.34 |
| 5/29/2017 6:00 | 106.33 | 107.76 | 163.15 | 198.12 |
| 5/30/2017 6:00 | 124.05 | 108.62 | 245.41 | 200.21 |
| 5/31/2017 6:00 | 136.64 | 109.73 | 353.67 | 205.36 |
| 6/1/2017 6:00 | 115.01 | 110.17 | 195.38 | 204.88 |
| 6/2/2017 6:00 | 93.46 | 109.71 | 145.68 | 202.13 |
| 6/3/2017 6:00 | 90.42 | 108.81 | 146.96 | 198.26 |
| 6/4/2017 6:00 | 104.09 | 109.25 | 203.91 | 201.18 |
| 6/5/2017 6:00 | 108.53 | 109.29 | 190.29 | 201.21 |
| 6/6/2017 6:00 | 166.23 | 111.19 | 306.59 | 203.67 |
| 6/7/2017 6:00 | 93.11 | 111.09 | 166.86 | 203.09 |
| 6/8/2017 6:00 | 97.42 | 111.27 | 199.15 | 203.49 |
| 6/9/2017 6:00 | 114.92 | 111.25 | 258.53 | 204.36 |
| 6/10/2017 6:00 | 117.77 | 111.75 | 218.11 | 206.44 |
| 6/11/2017 6:00 | 119.29 | 111.32 | 178.88 | 203.62 |
| 6/12/2017 6:00 | 139.61 | 111.84 | 268.21 | 203.23 |
| 6/13/2017 6:00 | 161.54 | 113.72 | 247.66 | 204.74 |
| 6/14/2017 6:00 | 93.61 | 113.54 | 215.09 | 206.41 |
| 6/15/2017 6:00 | 91.93 | 112.74 | 155.08 | 205.07 |
| 6/16/2017 6:00 | 89.37 | 114.56 | 225.07 | 211.16 |
| 6/17/2017 6:00 | 100.73 | 111.53 | 237.39 | 207.42 |
| 6/18/2017 6:00 | 103.49 | 109.81 | 280.39 | 207.58 |
| 6/19/2017 6:00 | 99.34 | 109.16 | 185.78 | 206.33 |
| 6/20/2017 6:00 | 153.19 | 110.41 | 220.45 | 207.86 |
| 6/21/2017 6:00 | 160.73 | 111.99 | 247.73 | 209.58 |
| 6/22/2017 6:00 | 126.34 | 111.73 | 194.19 | 208.15 |
| 6/23/2017 6:00 | 113.27 | 112.93 | 255.90 | 212.79 |
| 6/24/2017 6:00 | 121.91 | 115.99 | 197.99 | 217.78 |
| 6/25/2017 6:00 | 107.77 | 116.02 | 178.52 | 217.05 |
| 6/26/2017 6:00 | 104.38 | 115.59 | 170.60 | 216.26 |
| 6/27/2017 6:00 | 95.93 | 115.01 | 140.85 | 213.12 |
| 6/28/2017 6:00 | 110.99 | 115.17 | 159.76 | 213.00 |
| 6/29/2017 6:00 | 158.05 | 116.30 | 219.42 | 212.14 |
| 6/30/2017 6:00 | 99.92 | 115.08 | 157.56 | 205.60 |
| 7/1/2017 6:00 | 127.11 | 115.48 | 165.68 | 204.61 |
| 7/2/2017 6:00 | 149.96 | 117.36 | 265.97 | 208.62 |
| 7/3/2017 6:00 | 99.68 | 117.67 | 162.66 | 209.14 |
| 7/4/2017 6:00 | 104.78 | 117.70 | 235.03 | 210.18 |
| 7/5/2017 6:00 | 108.34 | 117.69 | 103.92 | 207.30 |
| 7/6/2017 6:00 | 125.96 | 116.35 | 280.19 | 206.42 |
| 7/7/2017 6:00 | 119.43 | 117.23 | 203.03 | 207.63 |
| 7/8/2017 6:00 | 119.03 | 117.95 | 244.64 | 209.14 |
| 7/9/2017 6:00 | 132.83 | 118.54 | 190.73 | 206.88 |
| 7/10/2017 6:00 | 107.49 | 118.20 | 171.00 | 205.31 |

| No. 2 PB CEMS Data | Nox lb/hr | Nox lb/hr 30-day avg | SO2 lb/hr | SO2 lb/hr 30-day avg |
|---|---|---|---|---|
| 7/11/2017 6:00 | 111.25 | 117.93 | 174.72 | 205.17 |
| 7/12/2017 6:00 | 141.97 | 118.01 | 259.13 | 204.87 |
| 7/13/2017 6:00 | 101.09 | 116.00 | 138.98 | 201.25 |
| 7/14/2017 6:00 | 99.81 | 116.20 | 179.76 | 200.07 |
| 7/15/2017 6:00 | 145.56 | 117.99 | 218.57 | 202.19 |
| 7/16/2017 6:00 | 69.54 | 117.33 | 115.55 | 198.54 |
| 7/17/2017 6:00 | 22.90 | 114.74 | 33.50 | 191.74 |
| 7/18/2017 6:00 | 144.65 | 116.11 | 242.41 | 190.47 |
| 7/19/2017 6:00 | 162.20 | 118.20 | 266.50 | 193.16 |
| 7/20/2017 6:00 | 139.14 | 117.73 | 255.41 | 194.33 |
| 7/21/2017 6:00 | 155.67 | 117.57 | 281.00 | 195.44 |
| 7/22/2017 6:00 | 139.44 | 118.00 | 291.33 | 198.68 |
| 7/23/2017 6:00 | 100.76 | 117.58 | 188.77 | 196.44 |
| 7/24/2017 6:00 | 98.32 | 116.80 | 190.64 | 196.19 |
| 7/25/2017 6:00 | 131.55 | 117.59 | 187.40 | 196.49 |
| 7/26/2017 6:00 | 147.47 | 119.03 | 233.45 | 198.58 |
| 7/27/2017 6:00 | 107.10 | 119.40 | 204.16 | 200.69 |
| 7/28/2017 6:00 | 111.24 | 119.41 | 209.10 | 202.34 |
| 7/29/2017 6:00 | 129.54 | 118.46 | 148.79 | 199.99 |
| 7/30/2017 6:00 | 112.48 | 118.88 | 221.87 | 202.13 |
| 7/31/2017 6:00 | 136.28 | 119.18 | 307.19 | 206.85 |
| 8/1/2017 6:00 | 162.10 | 119.59 | 385.49 | 210.83 |
| 8/2/2017 6:00 | 84.67 | 119.09 | 191.91 | 211.80 |
| 8/3/2017 6:00 | 110.08 | 119.26 | 210.32 | 210.98 |
| 8/4/2017 6:00 | 119.96 | 119.65 | 228.44 | 215.13 |
| 8/5/2017 6:00 | 114.30 | 119.26 | 211.85 | 212.85 |
| 8/6/2017 6:00 | 113.92 | 119.08 | 234.54 | 213.90 |
| 8/7/2017 6:00 | 92.84 | 118.20 | 163.48 | 211.20 |
| 8/8/2017 6:00 | 121.13 | 117.81 | 247.77 | 213.10 |
| 8/9/2017 6:00 | 108.23 | 117.84 | 110.66 | 211.09 |
| 8/10/2017 6:00 | 106.85 | 117.69 | 220.40 | 212.61 |
| 8/11/2017 6:00 | 140.60 | 117.65 | 271.01 | 213.01 |
| 8/12/2017 6:00 | 71.34 | 116.65 | 167.98 | 213.98 |
| 8/13/2017 6:00 | 111.89 | 117.06 | 102.52 | 211.40 |
| 8/14/2017 6:00 | 131.88 | 116.60 | 234.09 | 211.92 |
| 8/15/2017 6:00 | 121.06 | 118.32 | 209.91 | 215.06 |
| 8/16/2017 6:00 | 112.07 | 121.29 | 205.98 | 220.81 |
| 8/17/2017 6:00 | 135.61 | 120.99 | 259.07 | 221.37 |
| 8/18/2017 6:00 | 111.64 | 119.30 | 201.49 | 219.20 |
| 8/19/2017 6:00 | 92.28 | 117.74 | 166.85 | 216.25 |
| 8/20/2017 6:00 | 93.52 | 115.67 | 190.05 | 213.22 |
| 8/21/2017 6:00 | 213.68 | 118.15 | 407.64 | 217.09 |
| 8/22/2017 6:00 | 148.95 | 119.75 | 193.09 | 217.24 |
| 8/23/2017 6:00 | 115.23 | 120.32 | 222.38 | 218.30 |
| 8/24/2017 6:00 | 170.58 | 121.62 | 259.89 | 220.71 |

| No. 2 PB CEMS Data | Nox lb/hr | Nox lb/hr 30-day avg | SO2 lb/hr | SO2 lb/hr 30-day avg |
|---|---|---|---|---|
| 8/25/2017 6:00 | 112.00 | 120.43 | 180.89 | 218.96 |
| 8/26/2017 6:00 | 103.41 | 120.31 | 170.62 | 217.84 |
| 8/27/2017 6:00 | 129.94 | 120.93 | 229.91 | 218.54 |
| 8/28/2017 6:00 | 139.77 | 121.28 | 215.46 | 220.76 |
| 8/29/2017 6:00 | 114.16 | 121.33 | 215.50 | 220.55 |
| 8/30/2017 6:00 | 68.11 | 119.06 | 112.07 | 214.04 |
| 8/31/2017 6:00 | 120.29 | 117.67 | 178.52 | 207.14 |
| 9/1/2017 6:00 | 104.49 | 118.33 | 182.47 | 206.83 |
| 9/2/2017 6:00 | 138.99 | 119.29 | 197.04 | 206.39 |
| 9/3/2017 6:00 | 105.38 | 118.80 | 164.43 | 204.25 |
| 9/4/2017 6:00 | 170.07 | 120.66 | 339.57 | 208.51 |
| 9/5/2017 6:00 | 115.68 | 120.72 | 189.09 | 206.99 |
| 9/6/2017 6:00 | 85.78 | 120.49 | 149.42 | 206.53 |
| 9/7/2017 6:00 | 94.94 | 119.61 | 248.49 | 206.55 |
| 9/8/2017 6:00 | 104.47 | 119.49 | 276.41 | 212.07 |
| 9/9/2017 6:00 | 98.65 | 119.22 | 221.12 | 212.10 |
| 9/10/2017 6:00 | 110.97 | 118.23 | 198.79 | 209.69 |
| 9/11/2017 6:00 | 15.67 | 116.37 | 29.35 | 205.07 |
| 9/12/2017 6:00 | 0.00 | 112.64 | 0.00 | 201.65 |
| 9/13/2017 6:00 | 0.05 | 108.25 | 9.80 | 194.18 |
| 9/14/2017 6:00 | 0.00 | 104.21 | 0.00 | 187.18 |
| 9/15/2017 6:00 | 0.00 | 100.48 | 0.00 | 180.31 |
| 9/16/2017 6:00 | 0.00 | 95.96 | 0.00 | 171.68 |
| 9/17/2017 6:00 | 0.00 | 92.24 | 0.00 | 164.96 |
| 9/18/2017 6:00 | 0.00 | 89.16 | 0.00 | 159.40 |
| 9/19/2017 6:00 | 0.00 | 86.04 | 0.00 | 153.07 |
| 9/20/2017 6:00 | 0.00 | 78.92 | 0.09 | 139.48 |
| 9/21/2017 6:00 | 19.21 | 74.59 | 35.72 | 134.23 |
| 9/22/2017 6:00 | 90.80 | 73.78 | 168.59 | 132.44 |
| 9/23/2017 6:00 | 93.47 | 71.21 | 190.48 | 130.13 |
| 9/24/2017 6:00 | 91.06 | 70.51 | 187.99 | 130.36 |
| 9/25/2017 6:00 | 78.74 | 69.69 | 183.17 | 130.78 |
| 9/26/2017 6:00 | 112.32 | 69.10 | 270.52 | 132.14 |
| 9/27/2017 6:00 | 140.48 | 69.13 | 280.36 | 134.30 |
| 9/28/2017 6:00 | 115.83 | 69.18 | 252.60 | 135.54 |
| 9/29/2017 6:00 | 114.69 | 70.73 | 257.32 | 140.38 |
| 9/30/2017 6:00 | 98.94 | 70.02 | 210.82 | 141.46 |
| 10/1/2017 6:00 | 95.83 | 69.73 | 170.42 | 141.05 |
| 10/2/2017 6:00 | 99.26 | 68.41 | 223.27 | 141.93 |
| 10/3/2017 6:00 | 112.15 | 68.64 | 232.63 | 144.20 |
| 10/4/2017 6:00 | 157.82 | 68.23 | 374.37 | 145.36 |
| 10/5/2017 6:00 | 142.08 | 69.11 | 261.27 | 147.77 |
| 10/6/2017 6:00 | 121.00 | 70.28 | 294.61 | 152.61 |
| 10/7/2017 6:00 | 106.01 | 70.65 | 219.08 | 151.63 |
| 10/8/2017 6:00 | 102.97 | 70.60 | 209.74 | 149.40 |

| No. 2 PB CEMS Data | Nox lb/hr | Nox lb/hr 30-day avg | SO2 lb/hr | SO2 lb/hr 30-day avg |
|---|---|---|---|---|
| 10/9/2017 6:00 | 98.10 | 70.58 | 178.13 | 147.97 |
| 10/10/2017 6:00 | 103.15 | 70.32 | 221.28 | 148.72 |
| 10/11/2017 6:00 | 103.38 | 73.24 | 205.14 | 154.58 |
| 10/12/2017 6:00 | 112.38 | 76.99 | 244.98 | 162.75 |
| 10/13/2017 6:00 | 99.81 | 80.32 | 210.14 | 169.42 |
| 10/14/2017 6:00 | 111.33 | 84.03 | 272.90 | 178.52 |
| 10/15/2017 6:00 | 107.54 | 87.61 | 198.38 | 185.13 |
| 10/16/2017 6:00 | 101.13 | 90.98 | 216.92 | 192.36 |
| 10/17/2017 6:00 | 95.48 | 94.17 | 159.69 | 197.69 |
| 10/18/2017 6:00 | 137.62 | 98.75 | 251.59 | 206.07 |
| 10/19/2017 6:00 | 159.55 | 104.07 | 289.28 | 215.72 |
| 10/20/2017 6:00 | 135.56 | 108.59 | 228.35 | 223.32 |
| 10/21/2017 6:00 | 99.42 | 111.26 | 198.70 | 228.76 |
| 10/22/2017 6:00 | 99.46 | 111.55 | 223.78 | 230.60 |
| 10/23/2017 6:00 | 116.46 | 112.32 | 268.75 | 233.21 |
| 10/24/2017 6:00 | 110.77 | 112.97 | 204.36 | 233.75 |
| 10/25/2017 6:00 | 164.20 | 115.82 | 294.01 | 237.45 |
| 10/26/2017 6:00 | 102.56 | 115.50 | 225.91 | 235.96 |
| 10/27/2017 6:00 | 136.80 | 115.38 | 281.70 | 236.00 |
| 10/28/2017 6:00 | 140.69 | 116.20 | 314.99 | 238.08 |
| 10/29/2017 6:00 | 116.33 | 116.26 | 180.40 | 235.52 |
| 10/30/2017 6:00 | 152.31 | 118.04 | 211.73 | 235.55 |
| 10/31/2017 6:00 | 177.02 | 120.74 | 296.30 | 239.75 |
| 11/1/2017 6:00 | 186.35 | 123.65 | 245.12 | 240.47 |
| 11/2/2017 6:00 | 157.39 | 125.16 | 308.42 | 243.00 |
| 11/3/2017 6:00 | 170.04 | 125.56 | 294.17 | 240.33 |
| 11/4/2017 6:00 | 149.35 | 125.80 | 209.81 | 238.61 |
| 11/5/2017 6:00 | 190.46 | 128.12 | 332.61 | 239.88 |
| 11/6/2017 6:00 | 213.81 | 131.71 | 242.19 | 240.65 |
| 11/7/2017 6:00 | 291.63 | 138.00 | 361.89 | 245.72 |
| 11/8/2017 6:00 | 15.10 | 135.24 | 0.48 | 239.80 |
| 11/9/2017 6:00 | 116.87 | 135.69 | 230.07 | 240.09 |
| 11/10/2017 6:00 | 177.05 | 138.15 | 444.23 | 248.06 |
| 11/11/2017 6:00 | 139.19 | 139.04 | 276.65 | 249.12 |
| 11/12/2017 6:00 | 110.71 | 139.41 | 256.87 | 250.67 |
| 11/13/2017 6:00 | 130.72 | 140.05 | 265.58 | 250.43 |
| 11/14/2017 6:00 | 170.99 | 142.17 | 251.07 | 252.19 |
| 11/15/2017 6:00 | 124.87 | 142.96 | 200.46 | 251.64 |
| 11/16/2017 6:00 | 113.45 | 143.56 | 243.90 | 254.45 |
| 11/17/2017 6:00 | 111.81 | 142.70 | 240.27 | 254.07 |
| 11/18/2017 6:00 | 109.52 | 141.03 | 267.95 | 253.36 |
| 11/19/2017 6:00 | 104.67 | 140.00 | 211.39 | 252.79 |
| 11/20/2017 6:00 | 100.94 | 140.05 | 178.80 | 252.13 |
| 11/21/2017 6:00 | 140.56 | 141.42 | 334.44 | 255.82 |
| 11/22/2017 6:00 | 102.14 | 140.94 | 216.68 | 254.08 |

| No. 2 PB CEMS Data | Nox lb/hr | Nox lb/hr 30-day avg | SO2 lb/hr | SO2 lb/hr 30-day avg |
|---|---|---|---|---|
| 11/23/2017 6:00 | 111.86 | 140.98 | 259.06 | 255.90 |
| 11/24/2017 6:00 | 113.41 | 139.29 | 189.36 | 252.42 |
| 11/25/2017 6:00 | 162.69 | 141.29 | 347.28 | 256.46 |
| 11/26/2017 6:00 | 123.32 | 140.84 | 232.19 | 254.81 |
| 11/27/2017 6:00 | 112.51 | 139.90 | 235.55 | 252.16 |
| 11/28/2017 6:00 | 126.21 | 140.23 | 286.28 | 255.69 |
| 11/29/2017 6:00 | 114.72 | 138.98 | 251.35 | 257.01 |
| 11/30/2017 6:00 | 119.69 | 137.07 | 280.91 | 256.50 |
| 12/1/2017 6:00 | 125.15 | 135.03 | 211.29 | 255.37 |
| 12/2/2017 6:00 | 116.93 | 133.68 | 242.59 | 253.18 |
| 12/3/2017 6:00 | 114.86 | 131.84 | 179.85 | 249.37 |
| 12/4/2017 6:00 | 144.80 | 131.69 | 309.45 | 252.69 |
| 12/5/2017 6:00 | 129.30 | 129.65 | 215.18 | 248.77 |
| 12/6/2017 6:00 | 115.61 | 126.38 | 203.20 | 247.47 |
| 12/7/2017 6:00 | 124.73 | 120.81 | 190.78 | 241.77 |
| 12/8/2017 6:00 | 154.50 | 125.46 | 221.18 | 249.13 |
| 12/9/2017 6:00 | 194.94 | 128.06 | 266.58 | 250.34 |
| 12/10/2017 6:00 | 179.42 | 128.14 | 225.67 | 243.06 |
| 12/11/2017 6:00 | 194.20 | 129.97 | 255.28 | 242.35 |
| 12/12/2017 6:00 | 161.44 | 131.67 | 239.34 | 241.76 |
| 12/13/2017 6:00 | 151.82 | 132.37 | 173.11 | 238.68 |
| 12/14/2017 6:00 | 176.65 | 132.56 | 223.11 | 237.75 |
| 12/15/2017 6:00 | 212.45 | 135.48 | 318.43 | 241.68 |
| 12/16/2017 6:00 | 224.03 | 139.16 | 348.28 | 245.16 |
| 12/17/2017 6:00 | 196.85 | 142.00 | 276.74 | 246.38 |
| 12/18/2017 6:00 | 178.22 | 144.29 | 385.18 | 250.28 |
| 12/19/2017 6:00 | 144.21 | 145.61 | 378.50 | 255.85 |
| 12/20/2017 6:00 | 146.24 | 147.12 | 284.08 | 259.36 |
| 12/21/2017 6:00 | 168.45 | 148.04 | 366.58 | 260.43 |
| 12/22/2017 6:00 | 144.46 | 149.46 | 293.36 | 262.99 |
| 12/23/2017 6:00 | 142.36 | 150.47 | 297.82 | 264.28 |
| 12/24/2017 6:00 | 155.63 | 151.88 | 283.87 | 267.43 |
| 12/25/2017 6:00 | 154.02 | 151.59 | 338.65 | 267.15 |
| 12/26/2017 6:00 | 194.75 | 153.97 | 383.97 | 272.21 |
| 12/27/2017 6:00 | 146.86 | 155.12 | 352.99 | 276.12 |
| 12/28/2017 6:00 | 144.74 | 155.73 | 151.14 | 271.62 |
| 12/29/2017 6:00 | 155.01 | 157.08 | 301.53 | 273.29 |
| 12/30/2017 6:00 | 159.56 | 158.41 | 268.76 | 272.88 |
| 12/31/2017 6:00 | 142.35 | 158.98 | 294.77 | 275.67 |
| 1/1/2018 6:00 | 152.03 | 160.15 | 295.49 | 277.43 |
| 1/2/2018 6:00 | 165.80 | 161.85 | 260.10 | 280.10 |
| 1/3/2018 6:00 | 148.45 | 161.97 | 299.21 | 279.76 |
| 1/4/2018 6:00 | 162.20 | 163.07 | 276.36 | 281.80 |
| 1/5/2018 6:00 | 166.03 | 164.75 | 201.46 | 281.74 |
| 1/6/2018 6:00 | 182.63 | 166.68 | 251.78 | 283.78 |

| No. 2 PB CEMS Data | Nox lb/hr | Nox lb/hr 30-day avg | SO2 lb/hr | SO2 lb/hr 30-day avg |
|---|---|---|---|---|
| 1/7/2018 6:00 | 160.63 | 166.88 | 274.62 | 285.56 |
| 1/8/2018 6:00 | 226.69 | 167.94 | 419.09 | 290.64 |
| 1/9/2018 6:00 | 188.80 | 168.25 | 315.53 | 293.64 |
| 1/10/2018 6:00 | 179.82 | 167.77 | 187.28 | 291.37 |
| 1/11/2018 6:00 | 145.80 | 167.25 | 172.11 | 289.13 |
| 1/12/2018 6:00 | 207.16 | 169.10 | 268.93 | 292.32 |
| 1/13/2018 6:00 | 211.68 | 170.26 | 254.34 | 293.36 |
| 1/14/2018 6:00 | 256.08 | 171.72 | 262.98 | 291.52 |
| 1/15/2018 6:00 | 187.99 | 170.52 | 318.21 | 290.51 |
| 1/16/2018 6:00 | 225.03 | 171.46 | 289.23 | 290.93 |
| 1/17/2018 6:00 | 215.88 | 172.71 | 344.90 | 289.59 |
| 1/18/2018 6:00 | 242.94 | 176.00 | 289.56 | 286.62 |
| 1/19/2018 6:00 | 191.43 | 177.51 | 148.24 | 282.09 |
| 1/20/2018 6:00 | 177.85 | 177.82 | 229.76 | 277.53 |
| 1/21/2018 6:00 | 151.07 | 178.04 | 225.11 | 275.26 |
| 1/22/2018 6:00 | 164.55 | 178.78 | 283.33 | 274.78 |
| 1/23/2018 6:00 | 156.38 | 178.81 | 198.33 | 271.92 |
| 1/24/2018 6:00 | 153.86 | 178.80 | 116.09 | 264.51 |
| 1/25/2018 6:00 | 193.84 | 178.77 | 332.75 | 262.80 |
| 1/26/2018 6:00 | 133.24 | 178.32 | 220.18 | 258.37 |
| 1/27/2018 6:00 | 167.57 | 179.08 | 233.04 | 261.10 |
| 1/28/2018 6:00 | 144.76 | 178.74 | 115.03 | 254.89 |
| 1/29/2018 6:00 | 130.28 | 177.76 | 219.00 | 253.23 |
| 1/30/2018 6:00 | 133.81 | 177.48 | 218.01 | 250.67 |
| 1/31/2018 6:00 | 155.57 | 177.59 | 245.00 | 248.99 |
| 2/1/2018 6:00 | 134.80 | 176.56 | 291.09 | 250.02 |
| 2/2/2018 6:00 | 96.18 | 174.82 | 216.91 | 247.28 |
| 2/3/2018 6:00 | 93.49 | 172.53 | 235.58 | 245.92 |
| 2/4/2018 6:00 | 130.82 | 171.35 | 290.92 | 248.90 |
| 2/5/2018 6:00 | 121.84 | 169.33 | 270.81 | 249.53 |
| 2/6/2018 6:00 | 117.37 | 167.89 | 156.58 | 245.60 |
| 2/7/2018 6:00 | 152.28 | 165.41 | 269.89 | 240.62 |
| 2/8/2018 6:00 | 125.83 | 163.31 | 291.54 | 239.82 |
| 2/9/2018 6:00 | 110.45 | 160.99 | 214.91 | 240.75 |
| 2/10/2018 6:00 | 146.24 | 161.01 | 297.84 | 244.94 |
| 2/11/2018 6:00 | 138.78 | 158.73 | 283.71 | 245.43 |
| 2/12/2018 6:00 | 156.79 | 156.90 | 374.72 | 249.44 |
| 2/13/2018 6:00 | 167.08 | 153.93 | 266.88 | 249.57 |
| 2/14/2018 6:00 | 131.59 | 152.05 | 156.27 | 244.17 |
| 2/15/2018 6:00 | 114.54 | 148.37 | 235.11 | 242.37 |
| 2/16/2018 6:00 | 98.20 | 144.45 | 192.26 | 237.28 |
| 2/17/2018 6:00 | 99.15 | 139.66 | 197.03 | 234.20 |
| 2/18/2018 6:00 | 97.28 | 136.52 | 207.44 | 236.17 |
| 2/19/2018 6:00 | 90.14 | 133.59 | 224.76 | 236.00 |
| 2/20/2018 6:00 | 136.81 | 133.12 | 241.93 | 236.57 |

| No. 2 PB CEMS Data | Nox lb/hr | Nox lb/hr 30-day avg | SO2 lb/hr | SO2 lb/hr 30-day avg |
|---|---|---|---|---|
| 2/21/2018 6:00 | 97.25 | 130.87 | 196.77 | 233.68 |
| 2/22/2018 6:00 | 117.77 | 129.59 | 234.13 | 234.87 |
| 2/23/2018 6:00 | 86.66 | 127.35 | 200.73 | 237.70 |
| 2/24/2018 6:00 | 77.62 | 123.47 | 154.35 | 231.75 |
| 2/25/2018 6:00 | 97.97 | 122.30 | 174.24 | 230.22 |
| 2/26/2018 6:00 | 96.51 | 119.93 | 190.03 | 228.78 |
| 2/27/2018 6:00 | 113.08 | 118.87 | 190.13 | 231.29 |
| 2/28/2018 6:00 | 118.57 | 118.48 | 218.99 | 231.29 |
| 3/1/2018 6:00 | 118.54 | 117.97 | 168.29 | 229.63 |
| 3/2/2018 6:00 | 79.98 | 115.45 | 135.79 | 225.99 |
| 3/3/2018 6:00 | 128.15 | 115.23 | 282.51 | 225.70 |
| 3/4/2018 6:00 | 91.66 | 115.08 | 163.20 | 223.91 |
| 3/5/2018 6:00 | 122.13 | 116.04 | 182.28 | 222.14 |
| 3/6/2018 6:00 | 124.04 | 115.81 | 170.57 | 218.12 |
| 3/7/2018 6:00 | 25.71 | 112.61 | 34.88 | 210.26 |
| 3/8/2018 6:00 | 119.70 | 112.68 | 205.29 | 211.88 |
| 3/9/2018 6:00 | 101.84 | 111.00 | 150.58 | 207.91 |
| 3/10/2018 6:00 | 106.74 | 110.37 | 186.79 | 204.41 |
| 3/11/2018 6:00 | 109.27 | 110.33 | 176.63 | 203.14 |
| 3/12/2018 6:00 | 107.36 | 109.03 | 181.07 | 199.25 |
| 3/13/2018 6:00 | 106.23 | 107.95 | 176.74 | 195.68 |
| 3/14/2018 6:00 | 110.41 | 106.40 | 118.27 | 187.13 |
| 3/15/2018 6:00 | 90.62 | 103.85 | 119.40 | 182.22 |
| 3/16/2018 6:00 | 166.73 | 105.02 | 311.85 | 187.40 |
| 3/17/2018 6:00 | 163.38 | 106.65 | 324.62 | 190.39 |
| 3/18/2018 6:00 | 160.81 | 108.74 | 302.99 | 194.08 |
| 3/19/2018 6:00 | 177.59 | 111.35 | 179.33 | 193.49 |
| 3/20/2018 6:00 | 220.92 | 115.47 | 328.93 | 197.54 |
| 3/21/2018 6:00 | 201.94 | 119.20 | 287.43 | 199.63 |
| 3/22/2018 6:00 | 212.66 | 121.73 | 259.10 | 200.20 |
| 3/23/2018 6:00 | 191.82 | 124.88 | 417.63 | 207.56 |
| 3/24/2018 6:00 | 151.01 | 125.99 | 241.40 | 207.80 |
| 3/25/2018 6:00 | 128.04 | 127.37 | 212.04 | 208.18 |
| 3/26/2018 6:00 | 162.67 | 130.20 | 233.24 | 210.81 |
| 3/27/2018 6:00 | 134.16 | 131.41 | 217.12 | 212.24 |
| 3/28/2018 6:00 | 170.17 | 133.86 | 270.62 | 214.92 |
| 3/29/2018 6:00 | 161.86 | 135.49 | 241.26 | 216.63 |
| 3/30/2018 6:00 | 99.41 | 134.85 | 129.89 | 213.66 |
| 3/31/2018 6:00 | 111.63 | 134.62 | 165.80 | 213.58 |
| 4/1/2018 6:00 | 110.15 | 135.63 | 205.95 | 215.91 |
| 4/2/2018 6:00 | 127.56 | 135.61 | 209.45 | 213.48 |
| 4/3/2018 6:00 | 122.91 | 136.65 | 180.23 | 214.05 |
| 4/4/2018 6:00 | 110.33 | 136.26 | 192.48 | 214.39 |
| 4/5/2018 6:00 | 114.88 | 135.95 | 199.84 | 215.36 |
| 4/6/2018 6:00 | 156.20 | 140.30 | 262.06 | 222.93 |

| No. 2 PB CEMS Data | Nox lb/hr | Nox lb/hr 30-day avg | SO2 lb/hr | SO2 lb/hr 30-day avg |
|---|---|---|---|---|
| 4/7/2018 6:00 | 139.79 | 140.97 | 266.43 | 224.97 |
| 4/8/2018 6:00 | 150.38 | 142.59 | 273.04 | 229.05 |
| 4/9/2018 6:00 | 155.04 | 144.20 | 206.84 | 229.72 |
| 4/10/2018 6:00 | 148.23 | 145.50 | 194.55 | 230.32 |
| 4/11/2018 6:00 | 145.45 | 146.77 | 142.14 | 229.02 |
| 4/12/2018 6:00 | 150.10 | 148.23 | 190.66 | 229.49 |
| 4/13/2018 6:00 | 163.31 | 149.99 | 188.07 | 231.81 |
| 4/14/2018 6:00 | 113.46 | 150.75 | 196.76 | 234.39 |
| 4/15/2018 6:00 | 103.90 | 148.66 | 204.80 | 230.82 |
| 4/16/2018 6:00 | 106.96 | 146.78 | 153.83 | 225.13 |
| 4/17/2018 6:00 | 123.58 | 145.54 | 143.16 | 219.80 |
| 4/18/2018 6:00 | 8.78 | 139.91 | 13.68 | 214.28 |
| 4/19/2018 6:00 | 157.30 | 137.79 | 232.27 | 211.06 |
| 4/20/2018 6:00 | 148.12 | 136.00 | 255.77 | 210.00 |
| 4/21/2018 6:00 | 177.19 | 134.81 | 248.48 | 209.65 |
| 4/22/2018 6:00 | 158.00 | 133.69 | 239.99 | 203.73 |
| 4/23/2018 6:00 | 121.18 | 132.69 | 176.14 | 201.55 |
| 4/24/2018 6:00 | 81.43 | 131.14 | 165.81 | 200.01 |
| 4/25/2018 6:00 | 37.39 | 126.96 | 58.07 | 194.17 |
| 4/26/2018 6:00 | 100.81 | 125.85 | 215.33 | 194.11 |
| 4/27/2018 6:00 | 131.02 | 124.54 | 239.46 | 193.07 |
| 4/28/2018 6:00 | 144.62 | 123.97 | 261.81 | 193.76 |
| 4/29/2018 6:00 | 120.03 | 124.66 | 218.60 | 196.72 |
| 4/30/2018 6:00 | 120.55 | 124.95 | 231.13 | 198.89 |
| 5/1/2018 6:00 | 123.25 | 125.39 | 168.03 | 197.63 |
| 5/2/2018 6:00 | 133.21 | 125.58 | 147.10 | 195.55 |
| 5/3/2018 6:00 | 108.01 | 125.08 | 97.55 | 192.80 |
| 5/4/2018 6:00 | 128.10 | 125.68 | 163.67 | 191.84 |
| 5/5/2018 6:00 | 151.58 | 126.90 | 247.32 | 193.42 |
| 5/6/2018 6:00 | 109.72 | 125.35 | 170.92 | 190.38 |
| 5/7/2018 6:00 | 158.03 | 125.96 | 189.44 | 187.81 |
| 5/8/2018 6:00 | 130.58 | 125.30 | 233.78 | 186.51 |
| 5/9/2018 6:00 | 127.83 | 124.39 | 185.73 | 185.80 |
| 5/10/2018 6:00 | 128.41 | 123.73 | 187.03 | 185.55 |
| 5/11/2018 6:00 | 134.04 | 123.35 | 118.11 | 184.75 |
| 5/12/2018 6:00 | 149.80 | 123.34 | 236.55 | 186.28 |
| 5/13/2018 6:00 | 118.70 | 121.85 | 196.03 | 186.54 |
| 5/14/2018 6:00 | 121.73 | 122.13 | 138.16 | 184.59 |
| 5/15/2018 6:00 | 113.30 | 122.44 | 162.21 | 183.17 |
| 5/16/2018 6:00 | 161.43 | 124.26 | 220.21 | 185.39 |
| 5/17/2018 6:00 | 137.75 | 124.73 | 202.04 | 187.35 |
| 5/18/2018 6:00 | 182.45 | 130.52 | 208.05 | 193.83 |
| 5/19/2018 6:00 | 171.62 | 131.00 | 131.88 | 190.48 |
| 5/20/2018 6:00 | 140.26 | 130.73 | 145.76 | 186.81 |
| 5/21/2018 6:00 | 122.66 | 128.92 | 173.32 | 184.31 |

| No. 2 PB CEMS Data | Nox lb/hr | Nox lb/hr 30-day avg | SO2 lb/hr | SO2 lb/hr 30-day avg |
|---|---|---|---|---|
| 5/22/2018 6:00 | 107.04 | 127.22 | 103.28 | 179.75 |
| 5/23/2018 6:00 | 148.68 | 128.13 | 152.39 | 178.96 |
| 5/24/2018 6:00 | 123.48 | 129.54 | 199.21 | 180.07 |
| 5/25/2018 6:00 | 113.40 | 132.07 | 140.14 | 182.81 |
| 5/26/2018 6:00 | 117.64 | 132.63 | 186.65 | 181.85 |
| 5/27/2018 6:00 | 96.62 | 131.48 | 99.72 | 177.19 |
| 5/28/2018 6:00 | 112.84 | 130.42 | 174.02 | 174.27 |
| 5/29/2018 6:00 | 108.57 | 130.04 | 157.52 | 172.23 |
| 5/30/2018 6:00 | 116.53 | 129.91 | 152.31 | 169.60 |
| 5/31/2018 6:00 | 143.45 | 130.58 | 216.37 | 171.22 |
| 6/1/2018 6:00 | 199.01 | 132.78 | 56.96 | 168.21 |
| 6/2/2018 6:00 | 162.34 | 134.59 | 77.21 | 167.53 |
| 6/3/2018 6:00 | 104.94 | 133.81 | 53.02 | 163.85 |
| 6/4/2018 6:00 | 142.94 | 133.53 | 80.79 | 158.29 |
| 6/5/2018 6:00 | 162.07 | 135.27 | 15.38 | 153.11 |
| 6/6/2018 6:00 | 134.93 | 134.50 | 77.42 | 149.38 |
| 6/7/2018 6:00 | 102.60 | 133.57 | 65.28 | 143.76 |
| 6/8/2018 6:00 | 104.56 | 132.79 | 118.96 | 141.53 |
| 6/9/2018 6:00 | 118.04 | 132.45 | 183.19 | 141.41 |
| 6/10/2018 6:00 | 100.57 | 131.33 | 95.64 | 140.66 |
| 6/11/2018 6:00 | 100.84 | 129.70 | 107.02 | 136.34 |
| 6/12/2018 6:00 | 166.15 | 131.28 | 134.08 | 134.27 |
| 6/13/2018 6:00 | 98.43 | 130.50 | 145.84 | 134.53 |
| 6/14/2018 6:00 | 91.08 | 129.76 | 58.90 | 131.09 |
| 6/15/2018 6:00 | 122.64 | 128.47 | 175.56 | 129.60 |
| 6/16/2018 6:00 | 115.25 | 127.72 | 121.08 | 126.90 |
| 6/17/2018 6:00 | 109.23 | 125.28 | 158.25 | 125.24 |
| 6/18/2018 6:00 | 115.94 | 123.42 | 123.39 | 124.96 |
| 6/19/2018 6:00 | 131.99 | 123.15 | 150.46 | 125.11 |
| 6/20/2018 6:00 | 101.90 | 122.46 | 145.82 | 124.20 |
| 6/21/2018 6:00 | 81.54 | 121.61 | 91.97 | 123.82 |
| 6/22/2018 6:00 | 117.21 | 120.56 | 109.45 | 122.39 |
| 6/23/2018 6:00 | 114.33 | 120.25 | 112.82 | 119.51 |
| 6/24/2018 6:00 | 110.19 | 120.15 | 78.30 | 117.45 |
| 6/25/2018 6:00 | 106.36 | 119.77 | 94.84 | 114.39 |
| 6/26/2018 6:00 | 105.46 | 120.06 | 110.38 | 114.74 |
| 6/27/2018 6:00 | 148.44 | 121.25 | 106.31 | 112.48 |
| 6/28/2018 6:00 | 142.99 | 122.40 | 158.15 | 112.50 |
| 6/29/2018 6:00 | 116.32 | 122.39 | 140.32 | 112.10 |
| 6/30/2018 6:00 | 110.69 | 121.30 | 134.14 | 109.36 |
| 7/1/2018 6:00 | 106.35 | 118.21 | 120.39 | 111.48 |
| 7/2/2018 6:00 | 127.83 | 117.06 | 141.76 | 113.63 |
| 7/3/2018 6:00 | 111.50 | 117.28 | 89.38 | 114.84 |
| 7/4/2018 6:00 | 100.48 | 115.86 | 116.28 | 116.02 |
| 7/5/2018 6:00 | 110.95 | 114.16 | 122.47 | 119.59 |

| No. 2 PB CEMS Data | Nox lb/hr | Nox lb/hr 30-day avg | SO2 lb/hr | SO2 lb/hr 30-day avg |
|---|---|---|---|---|
| 7/6/2018 6:00 | 102.57 | 113.08 | 71.66 | 119.40 |
| 7/7/2018 6:00 | 110.62 | 113.35 | 62.93 | 119.32 |
| 7/8/2018 6:00 | 135.25 | 114.37 | 125.67 | 119.55 |
| 7/9/2018 6:00 | 119.93 | 114.43 | 136.39 | 117.99 |
| 7/10/2018 6:00 | 161.42 | 116.46 | 171.88 | 120.53 |
| 7/11/2018 6:00 | 117.31 | 117.01 | 120.33 | 120.97 |
| 7/12/2018 6:00 | 122.49 | 115.56 | 157.92 | 121.77 |
| 7/13/2018 6:00 | 118.79 | 116.23 | 160.48 | 122.26 |
| 7/14/2018 6:00 | 118.04 | 117.13 | 106.07 | 123.83 |
| 7/15/2018 6:00 | 101.87 | 116.44 | 114.16 | 121.78 |
| 7/16/2018 6:00 | 111.52 | 116.32 | 110.11 | 121.42 |
| 7/17/2018 6:00 | 92.35 | 115.75 | 133.20 | 120.58 |
| 7/18/2018 6:00 | 157.36 | 117.14 | 193.03 | 122.90 |
| 7/19/2018 6:00 | 128.77 | 117.03 | 163.62 | 123.34 |
| 7/20/2018 6:00 | 109.93 | 117.30 | 151.19 | 123.52 |
| 7/21/2018 6:00 | 104.70 | 118.07 | 110.32 | 124.13 |
| 7/22/2018 6:00 | 114.55 | 117.98 | 139.01 | 125.12 |
| 7/23/2018 6:00 | 160.57 | 119.52 | 141.06 | 126.06 |
| 7/24/2018 6:00 | 150.74 | 120.87 | 236.92 | 131.35 |
| 7/25/2018 6:00 | 166.16 | 122.86 | 214.35 | 135.33 |
| 7/26/2018 6:00 | 114.41 | 123.16 | 157.54 | 136.90 |
| 7/27/2018 6:00 | 112.03 | 121.95 | 178.87 | 139.32 |
| 7/28/2018 6:00 | 105.34 | 120.69 | 173.66 | 139.84 |
| 7/29/2018 6:00 | 107.08 | 120.39 | 141.05 | 139.86 |
| 7/30/2018 6:00 | 138.56 | 121.32 | 167.10 | 140.96 |
| 7/31/2018 6:00 | 107.14 | 121.34 | 143.87 | 141.74 |
| 8/1/2018 6:00 | 112.08 | 120.82 | 165.12 | 142.52 |
| 8/2/2018 6:00 | 112.11 | 120.84 | 177.96 | 145.47 |
| 8/3/2018 6:00 | 108.56 | 121.11 | 123.80 | 145.73 |
| 8/4/2018 6:00 | 84.75 | 120.23 | 109.34 | 145.29 |
| 8/5/2018 6:00 | 89.17 | 119.79 | 125.83 | 147.09 |
| 8/6/2018 6:00 | 29.90 | 117.10 | 26.39 | 145.88 |
| 8/7/2018 6:00 | 0.75 | 112.61 | 0.77 | 141.71 |
| 8/8/2018 6:00 | 0.00 | 108.61 | 0.00 | 137.17 |
| 8/9/2018 6:00 | 0.00 | 103.23 | 0.00 | 131.44 |
| 8/10/2018 6:00 | 15.14 | 99.83 | 21.84 | 128.15 |
| 8/11/2018 6:00 | 110.37 | 99.42 | 156.62 | 128.11 |
| 8/12/2018 6:00 | 126.45 | 99.68 | 158.56 | 128.05 |
| 8/13/2018 6:00 | 131.80 | 100.14 | 163.26 | 129.95 |
| 8/14/2018 6:00 | 132.06 | 101.14 | 158.98 | 131.45 |
| 8/15/2018 6:00 | 115.20 | 101.27 | 140.88 | 132.47 |
| 8/16/2018 6:00 | 136.60 | 102.74 | 141.10 | 132.74 |
| 8/17/2018 6:00 | 144.78 | 102.32 | 172.91 | 132.06 |
| 8/18/2018 6:00 | 111.33 | 101.74 | 190.21 | 132.95 |
| 8/19/2018 6:00 | 110.88 | 101.77 | 129.58 | 132.23 |

| No. 2 PB CEMS Data | Nox lb/hr | Nox lb/hr 30-day avg | SO2 lb/hr | SO2 lb/hr 30-day avg |
|---|---|---|---|---|
| 8/20/2018 6:00 | 122.94 | 102.38 | 126.31 | 132.76 |
| 8/21/2018 6:00 | 113.69 | 102.35 | 122.38 | 132.21 |
| 8/22/2018 6:00 | 128.49 | 101.28 | 165.24 | 133.02 |
| 8/23/2018 6:00 | 139.38 | 100.90 | 214.49 | 132.27 |
| 8/24/2018 6:00 | 138.71 | 99.99 | 147.21 | 130.03 |
| 8/25/2018 6:00 | 93.90 | 99.31 | 105.31 | 128.29 |
| 8/26/2018 6:00 | 109.79 | 99.23 | 158.62 | 127.61 |
| 8/27/2018 6:00 | 116.88 | 99.62 | 161.75 | 127.22 |
| 8/28/2018 6:00 | 108.39 | 99.66 | 139.97 | 127.18 |
| 8/29/2018 6:00 | 90.55 | 98.06 | 98.48 | 124.89 |
| 8/30/2018 6:00 | 95.16 | 97.66 | 102.15 | 123.50 |
| 8/31/2018 6:00 | 104.51 | 97.41 | 126.80 | 122.23 |
| 9/1/2018 6:00 | 101.57 | 97.06 | 79.97 | 118.96 |
| 9/2/2018 6:00 | 114.39 | 97.25 | 149.41 | 119.81 |
| 9/3/2018 6:00 | 129.64 | 98.75 | 145.31 | 121.01 |
| 9/4/2018 6:00 | 136.57 | 100.33 | 127.73 | 121.07 |
| 9/5/2018 6:00 | 144.09 | 104.13 | 129.80 | 124.52 |
| 9/6/2018 6:00 | 122.16 | 108.18 | 117.98 | 128.43 |
| 9/7/2018 6:00 | 122.75 | 112.27 | 108.47 | 132.04 |
| 9/8/2018 6:00 | 117.72 | 116.20 | 88.23 | 134.99 |
| 9/9/2018 6:00 | 122.44 | 119.77 | 65.84 | 136.45 |
| 9/10/2018 6:00 | 113.01 | 119.86 | 39.64 | 132.55 |
| 9/11/2018 6:00 | 72.85 | 118.07 | 36.80 | 128.49 |
| 9/12/2018 6:00 | 0.00 | 113.68 | 0.00 | 123.05 |
| 9/13/2018 6:00 | 0.00 | 109.28 | 0.00 | 117.75 |
| 9/14/2018 6:00 | 20.96 | 106.14 | 4.54 | 113.21 |
| 9/15/2018 6:00 | 130.79 | 105.94 | 132.94 | 112.94 |
| 9/16/2018 6:00 | 143.59 | 105.90 | 205.66 | 114.03 |
| 9/17/2018 6:00 | 109.37 | 105.84 | 87.53 | 110.61 |
| 9/18/2018 6:00 | 191.74 | 108.53 | 147.53 | 111.20 |
| 9/19/2018 6:00 | 146.31 | 109.31 | 27.04 | 107.89 |
| 9/20/2018 6:00 | 89.71 | 108.51 | 12.59 | 104.23 |
| 9/21/2018 6:00 | 81.28 | 106.94 | 52.62 | 100.48 |
| 9/22/2018 6:00 | 95.37 | 105.47 | 62.99 | 95.43 |
| 9/23/2018 6:00 | 116.70 | 104.74 | 44.82 | 92.02 |
| 9/24/2018 6:00 | 146.40 | 106.49 | 119.78 | 92.50 |
| 9/25/2018 6:00 | 118.17 | 106.77 | 105.49 | 90.73 |
| 9/26/2018 6:00 | 179.09 | 108.84 | 169.96 | 91.00 |
| 9/27/2018 6:00 | 204.68 | 112.05 | 134.11 | 90.81 |
| 9/28/2018 6:00 | 88.52 | 111.98 | 93.32 | 90.64 |
| 9/29/2018 6:00 | 106.17 | 112.35 | 114.80 | 91.06 |
| 9/30/2018 6:00 | 111.11 | 112.57 | 156.46 | 92.05 |
| 10/1/2018 6:00 | 149.12 | 114.16 | 75.82 | 91.91 |
| 10/2/2018 6:00 | 111.44 | 114.06 | 173.04 | 92.69 |
| 10/3/2018 6:00 | 132.43 | 114.15 | 256.03 | 96.39 |

| No. 2 PB CEMS Data | Nox lb/hr | Nox lb/hr 30-day avg | SO2 lb/hr | SO2 lb/hr 30-day avg |
|---|---|---|---|---|
| 10/4/2018 6:00 | 101.81 | 112.99 | 129.12 | 96.43 |
| 10/5/2018 6:00 | 102.16 | 111.59 | 103.16 | 95.54 |
| 10/6/2018 6:00 | 87.95 | 110.45 | 133.65 | 96.07 |
| 10/7/2018 6:00 | 91.35 | 109.41 | 124.48 | 96.60 |
| 10/8/2018 6:00 | 107.20 | 109.06 | 201.87 | 100.39 |
| 10/9/2018 6:00 | 106.12 | 108.51 | 190.31 | 104.54 |
| 10/10/2018 6:00 | 103.46 | 108.19 | 156.60 | 108.44 |
| 10/11/2018 6:00 | 98.25 | 109.04 | 155.79 | 112.40 |
| 10/12/2018 6:00 | 122.01 | 113.11 | 218.90 | 119.70 |
| 10/13/2018 6:00 | 90.95 | 116.14 | 149.36 | 124.68 |
| 10/14/2018 6:00 | 88.53 | 118.39 | 116.37 | 128.40 |
| 10/15/2018 6:00 | 96.71 | 117.26 | 199.71 | 130.63 |
| 10/16/2018 6:00 | 96.32 | 115.68 | 125.04 | 127.94 |
| 10/17/2018 6:00 | 135.13 | 116.54 | 169.38 | 130.67 |
| 10/18/2018 6:00 | 113.09 | 113.92 | 92.40 | 128.83 |
| 10/19/2018 6:00 | 107.24 | 112.62 | 159.52 | 133.25 |
| 10/20/2018 6:00 | 96.87 | 112.85 | 141.38 | 137.54 |
| 10/21/2018 6:00 | 119.06 | 114.11 | 156.10 | 140.99 |
| 10/22/2018 6:00 | 114.43 | 114.75 | 158.03 | 144.16 |
| 10/23/2018 6:00 | 94.40 | 114.01 | 165.09 | 148.17 |
| 10/24/2018 6:00 | 99.05 | 112.43 | 210.78 | 151.20 |
| 10/25/2018 6:00 | 113.00 | 112.25 | 251.52 | 156.07 |
| 10/26/2018 6:00 | 97.27 | 109.53 | 178.95 | 156.37 |
| 10/27/2018 6:00 | 89.78 | 105.70 | 161.01 | 157.27 |
| 10/28/2018 6:00 | 93.78 | 105.87 | 201.82 | 160.88 |
| 10/29/2018 6:00 | 95.47 | 105.52 | 199.52 | 163.71 |
| 10/30/2018 6:00 | 96.15 | 105.02 | 170.60 | 164.18 |
| 10/31/2018 6:00 | 113.51 | 103.83 | 226.17 | 169.19 |
| 11/1/2018 6:00 | 139.60 | 104.77 | 237.02 | 171.32 |
| 11/2/2018 6:00 | 84.87 | 103.18 | 107.32 | 166.37 |
| 11/3/2018 6:00 | 100.55 | 103.14 | 147.69 | 166.99 |
| 11/4/2018 6:00 | 118.14 | 103.67 | 204.41 | 170.36 |
| 11/5/2018 6:00 | 135.92 | 105.27 | 260.05 | 174.57 |
| 11/6/2018 6:00 | 98.68 | 105.52 | 154.90 | 175.59 |
| 11/7/2018 6:00 | 82.69 | 104.70 | 88.62 | 171.81 |
| 11/8/2018 6:00 | 91.71 | 104.22 | 181.80 | 171.53 |
| 11/9/2018 6:00 | 125.33 | 104.95 | 192.18 | 172.71 |
| 11/10/2018 6:00 | 146.12 | 106.54 | 151.35 | 172.57 |
| 11/11/2018 6:00 | 123.44 | 106.59 | 210.66 | 172.29 |
| 11/12/2018 6:00 | 161.30 | 108.94 | 329.61 | 178.30 |
| 11/13/2018 6:00 | 149.53 | 110.97 | 261.98 | 183.15 |
| 11/14/2018 6:00 | 140.68 | 112.44 | 237.00 | 184.40 |
| 11/15/2018 6:00 | 136.03 | 113.76 | 285.39 | 189.74 |
| 11/16/2018 6:00 | 110.74 | 112.95 | 194.56 | 190.58 |
| 11/17/2018 6:00 | 100.63 | 112.53 | 174.11 | 193.30 |

| No. 2 PB CEMS Data | Nox lb/hr | Nox lb/hr 30-day avg | SO2 lb/hr | SO2 lb/hr 30-day avg |
|---|---|---|---|---|
| 11/18/2018 6:00 | 136.28 | 113.50 | 280.00 | 197.32 |
| 11/19/2018 6:00 | 126.33 | 114.48 | 277.79 | 201.87 |
| 11/20/2018 6:00 | 184.68 | 116.67 | 301.98 | 206.73 |
| 11/21/2018 6:00 | 144.94 | 117.69 | 246.31 | 209.67 |
| 11/22/2018 6:00 | 159.62 | 119.86 | 274.11 | 213.31 |
| 11/23/2018 6:00 | 122.58 | 120.64 | 201.20 | 212.99 |
| 11/24/2018 6:00 | 167.09 | 122.45 | 285.59 | 214.12 |
| 11/25/2018 6:00 | 108.59 | 122.82 | 158.11 | 213.43 |
| 11/26/2018 6:00 | 126.46 | 124.05 | 232.95 | 215.83 |
| 11/27/2018 6:00 | 141.11 | 125.63 | 311.54 | 219.48 |
| 11/28/2018 6:00 | 157.34 | 127.69 | 208.70 | 219.79 |
| 11/29/2018 6:00 | 177.83 | 130.41 | 303.50 | 224.22 |
| 11/30/2018 6:00 | 136.31 | 131.17 | 220.02 | 224.01 |
| 12/1/2018 6:00 | | | | |

Domtar

January 19, 2017

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

*Re: Domtar A. W. LLC – Ashdown Mill (AFIN 41-00002)*
*BMACT Performance Test Summary per §63.7550*
*Arkansas Operating Air Permit No. 287-AOP-R18*

Dear Air Compliance:

Domtar A. W. LLC owns and operates the Ashdown Mill at 285 Highway 71 South in Ashdown, Arkansas 71822 (Little River County). The facility includes a Kraft pulp mill with associated paper manufacturing operations and produces a variety of paper products. The Ashdown Mill currently operates under the authority of Arkansas Department of Environmental Quality (ADEQ) Operating Air Permit 287-AOP-R18, which expires on October 17, 2021.

Per 40 CFR Part 63, Subpart DDDDD, the facility conducted performance testing on No. 3 Power Boiler (SN-01) and No.2 Power Boiler (SN-05). During the performance tests, operating load and control parameters were established in accordance with § 63.7540 and Table 4. The following tables include a summary of the testing results and applicable operating parameters of each affected unit. See the enclosed test report for details.

Section 1.5 contains testing notes associated with deviations from the test protocol for each source. During the test for #2PB it was identified there was an equipment monitoring issue with the 2PB Scrubber Differential Pressure (DP). Since DP is a parametric monitoring requirement for this source, the first two runs were voided and two additional valid test runs were conducted to make up the 3 test runs. This was identified during the testing and was communicated to ADEQ personnel. In addition, the final test results for #3PB indicated Run1 as an outlier for particulate matter results. The test average is well below the Subpart DDDDD limit. All process data was reviewed and there were no conditions identified that may have contributed to the high PM. Previous stack tests under similar test scenarios were also reviewed and there were no historical results in this range. The operating data and test results were also reviewed by third parties and it was concluded the results for Run1 could have been influenced by contamination. Comparison to the Subpart limit was based on all three runs in an effort to be conservative with the emission data.

## Summary of Performance Testing

| Source | Parameter* | BMACT Limit (lb/MMBtu) | Emission Results (lb/MMBtu) |
|---|---|---|---|
| No. 3 Power Boiler (SN-01) | Particulate Matter | 0.44 | 3.7E-02 |
| | Percent of Limit | | 8% |
| | Hydrogen Chloride | 2.2E-02 | 6.1E-04 |
| | Percent of Limit | | 3% |
| | Mercury | 5.7E-06 | 2.2E-07 |
| | Percent of Limit | | 4% |
| No. 2 Power Boiler (SN-05) | Particulate Matter | 0.44 | 5.9E-02 |
| | Percent of Limit | | 13% |
| | Hydrogen Chloride | 2.2E-02 | 1.2E-03 |
| | Percent of Limit | | 5% |
| | Mercury | 5.7E-06 | 2.8E-07 |
| | Percent of Limit | | 5% |

*CO CEMS used to demonstrate compliance with CO limit; therefore a performance test for Carbon Monoxide is not required.

## Summary of Operating Parameters

| Source | Control Equipment | Monitoring Parameter | BMACT Operating Limit* |
|---|---|---|---|
| No. 3 Power Boiler (SN-01) | NA | Steam Output | < 525 Klbs/hr |
| | Electrostatic Precipitator | Opacity | < 10% |
| No. 2 Power Boiler (SN-05) | NA | Steam Output | < 525 Klbs/hr |
| | Wet Scrubber** | Recirculation Flow | > 1105 gpm |
| | | Differential Pressure | > 11.2"of H20 |
| | | pH | > 4.4 SU |

*BMACT Operating limits are 720-hr rolling average limits with exception of Opacity. Opacity is a daily block average.

**SN-05 is equipped with two scrubbers, the operating limits are for each scrubber unless one scrubber is isolated and the boiler is operating at half maximum load.

Please contact Kelley Crouch at (870) 898-2711 Ext. 26168 or at Kelley.Crouch@domtar.com or Charles Allen at (870) 898-2711 Ext. 26471 if you have any questions.

Based upon the information and belief formed after a reasonable inquiry, I, as a responsible official for the above mentioned facility, certify the information contained in this notification is accurate and true to the best of my knowledge.

Sincerely,

DOMTAR A. W. LLC

Robert C. Grygotis
V.P., General Manager
Ashdown Mill

Domtar
Ashdown Mill
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Domtar

February 21, 2019

William K. Montgomery, Policy & Planning Branch Manager
Arkansas Department of Environmental Quality
Office of Air Quality
5301 Northshore Drive
North Little Rock, AR 72118-5317

RE: *Domtar A.W. LLC*
*Demonstration of Compliance with Proposed BART Alternative Limits*
*Ongoing Compliance – January 2019 Data*

Dear Mr. Montgomery:

In accordance with the December 20, 2018 letter demonstrating that both BART-affected emission units at its Ashdown Mill (Power Boilers No. 1 and No. 2) are in compliance with the BART Alternative Limits in the proposed Arkansas Regional Haze SIP Phase III, Domtar is providing the attached summary of continuous emission monitoring data for the most recent operating month. This data demonstrates continuing compliance with the proposed BART Alternative Limits.

Domtar reviewed the emissions data for both Power Boiler No. 1 and Power Boiler No. 2 for January 2019. This review confirms that neither unit emitted at levels greater than the BART Alternative limits during this time period. See Tables 1 and 2 below.

**Table 1. BART Alternative Emission Rates**

| Unit | $SO_2$ (lb/hr) | $NO_X$ (lb/hr) | PM (lb/hr) |
|---|---|---|---|
| Power Boiler No. 1 | 0.5 | 191.1 | 5.2 |
| Power Boiler No. 2 | 435 | 293 | 82 [a,b] |

[a] According to the final FIP and proposed SIP, compliance with the BART and BART Alternative PM limits is based on compliance with Boiler MACT in accordance with 40 CFR Part 63 Subpart DDDDD.
[b] Rounded up from 81.6 as presented in the FIP and SIP to be consistent with the proposed $SO_2$ and $NO_X$ limits and the current Title V permit limit.

**Table 2. Emission Rates for 1/2019**

| Unit | $SO_2$ (lb/hr) Maximum of 30-day Rolling Averages | $NO_X$ (lb/hr) Maximum of 30-day Rolling Averages | PM (lb/hr) |
|---|---|---|---|
| Power Boiler No. 1 | 0 | 0 | 0 |
| Power Boiler No. 2 | 280 | 170 | 48 [a] |

[a] Compliance with the BART Alternative limit is demonstrated via compliance with Boiler MACT. The Boiler MACT standard is 0.44 lb/MMBtu. Based on compliance testing conducted in January 2016, actual emissions from Power Boiler No. 2 are 0.059 lb/MMBtu (13 percent of the standard). The 48 lb/hr value listed in this table is a conservative estimate based on the test result and the heat input capacity of the boiler, 820 MMBtu/hr.

Detailed emissions data from January 2019 for Power Boiler No. 2 – CEMS-based information for $SO_2$ and $NO_X$ are provided in Attachment 1. Note that Power Boiler No. 1 is in standby mode with zero emissions since early 2016.

Thank you for your consideration of this information. Please contact me with any questions or to discuss any additional data needs.

Sincerely,

Kelley R. Crouch

Kelley Crouch
Environmental Manager

cc: Annabeth Reitter, Domtar
Jeremy Jewell, Trinity Consultants
Mark A. Thimke, Foley & Lardner LLP

# Attachment 1 – Detailed Emissions Data

## Power Boiler No. 2

- **Continuous Emissions Monitoring System Data for $SO_2$ and $NO_X$ (30-day rolling averages for 1/2019)**

| | | Max 30 Day | | Max 30 Day |
|---|---|---|---|---|
| | | 169.74 | | 279.66 |
| No. 2 PB CEMS Data | Nox lb/hr | Nox lb/hr 30-day avg | SO2 lb/hr | SO2 lb/hr 30-day avg |
| 1/1/2019 6:00 | 144.24 | 129.95 | 209.47 | 211.06 |
| 1/2/2019 0:00 | 149.82 | 129.47 | 210.19 | 210.10 |
| 1/3/2019 0:00 | 172.57 | 131.09 | 233.88 | 209.95 |
| 1/4/2019 0:00 | 187.53 | 133.41 | 264.56 | 212.05 |
| 1/5/2019 0:00 | 166.83 | 135.21 | 213.88 | 210.23 |
| 1/6/2019 0:00 | 160.34 | 135.91 | 260.43 | 211.76 |
| 1/7/2019 0:00 | 140.30 | 134.60 | 189.30 | 206.58 |
| 1/8/2019 0:00 | 94.35 | 133.13 | 143.51 | 203.93 |
| 1/9/2019 0:00 | 127.27 | 131.87 | 146.88 | 200.88 |
| 1/10/2019 0:00 | 181.43 | 132.83 | 296.52 | 200.79 |
| 1/11/2019 0:00 | 175.58 | 133.77 | 240.68 | 203.60 |
| 1/12/2019 0:00 | 154.38 | 135.49 | 344.40 | 208.82 |
| 1/13/2019 0:00 | 147.46 | 135.88 | 294.99 | 211.14 |
| 1/14/2019 0:00 | 136.77 | 135.98 | 235.67 | 210.26 |
| 1/15/2019 0:00 | 182.48 | 138.77 | 330.00 | 216.83 |
| 1/16/2019 0:00 | 183.21 | 141.07 | 264.82 | 218.82 |
| 1/17/2019 0:00 | 165.24 | 143.35 | 264.99 | 222.43 |
| 1/18/2019 0:00 | 155.87 | 146.15 | 301.59 | 229.48 |
| 1/19/2019 0:00 | 176.72 | 147.73 | 368.59 | 236.15 |
| 1/20/2019 0:00 | 208.46 | 148.63 | 344.90 | 240.58 |
| 1/21/2019 0:00 | 199.35 | 149.86 | 276.83 | 243.15 |
| 1/22/2019 0:00 | 195.37 | 151.58 | 295.09 | 246.34 |
| 1/23/2019 0:00 | 178.72 | 154.38 | 376.39 | 252.75 |
| 1/24/2019 0:00 | 174.57 | 157.00 | 271.31 | 254.61 |
| 1/25/2019 0:00 | 196.95 | 160.52 | 301.31 | 257.87 |
| 1/26/2019 0:00 | 196.40 | 164.02 | 318.61 | 262.58 |
| 1/27/2019 0:00 | 156.54 | 164.81 | 386.50 | 269.76 |
| 1/28/2019 0:00 | 169.04 | 164.67 | 365.79 | 272.32 |
| 1/29/2019 0:00 | 188.68 | 166.31 | 300.52 | 275.46 |
| 1/30/2019 0:00 | 170.39 | 167.90 | 254.12 | 276.86 |
| 1/31/2019 0:00 | 199.44 | 169.74 | 293.47 | 279.66 |

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Domtar

March 15, 2019

William K. Montgomery, Policy & Planning Branch Manager
Arkansas Department of Environmental Quality
Office of Air Quality
5301 Northshore Drive
North Little Rock, AR 72118-5317

RE: *Domtar A.W. LLC*
*Demonstration of Compliance with Proposed BART Alternative Limits*
*Ongoing Compliance – February 2019 Data*

Dear Mr. Montgomery:

In accordance with the December 20, 2018 letter demonstrating that both BART-affected emission units at its Ashdown Mill (Power Boilers No. 1 and No. 2) are in compliance with the BART Alternative Limits in the proposed Arkansas Regional Haze SIP Phase III, Domtar is providing the attached summary of continuous emission monitoring data for the most recent operating month. This data demonstrates continuing compliance with the proposed BART Alternative Limits.

Domtar reviewed the emissions data for both Power Boiler No. 1 and Power Boiler No. 2 for February 2019. This review confirms that neither unit emitted at levels greater than the BART Alternative limits during this time period. See Tables 1 and 2 below.

**Table 1. BART Alternative Emission Rates**

| Unit | $SO_2$ (lb/hr) | $NO_X$ (lb/hr) | PM (lb/hr) |
|---|---|---|---|
| Power Boiler No. 1 | 0.5 | 191.1 | 5.2 |
| Power Boiler No. 2 | 435 | 293 | 82 [a,b] |

[a] According to the final FIP and proposed SIP, compliance with the BART and BART Alternative PM limits is based on compliance with Boiler MACT in accordance with 40 CFR Part 63 Subpart DDDDD.
[b] Rounded up from 81.6 as presented in the FIP and SIP to be consistent with the proposed $SO_2$ and $NO_X$ limits and the current Title V permit limit.

**Table 2. Emission Rates for 2/2019**

| Unit | $SO_2$ (lb/hr) Maximum of 30-day Rolling Averages | $NO_X$ (lb/hr) Maximum of 30-day Rolling Averages | PM (lb/hr) |
|---|---|---|---|
| Power Boiler No. 1 | 0 | 0 | 0 |
| Power Boiler No. 2 | 305 | 178 | 48 [a] |

[a] Compliance with the BART Alternative limit is demonstrated via compliance with Boiler MACT. The Boiler MACT standard is 0.44 lb/MMBtu. Based on compliance testing conducted in January 2016, actual emissions from Power Boiler No. 2 are 0.059 lb/MMBtu (13 percent of the standard). The 48 lb/hr value listed in this table is a conservative estimate based on the test result and the heat input capacity of the boiler, 820 MMBtu/hr.

Detailed emissions data from February 2019 for Power Boiler No. 2 – CEMS-based information for $SO_2$ and $NO_X$ are provided in Attachment 1. Note that Power Boiler No. 1 is in standby mode with zero emissions since early 2016.

Thank you for your consideration of this information. Please contact me with any questions or to discuss any additional data needs.

Sincerely,

Kelley R. Crouch

Kelley Crouch
Environmental Manager

cc: Annabeth Reitter, Domtar
Jeremy Jewell, Trinity Consultants
Mark A. Thimke, Foley & Lardner LLP

# Attachment 1 – Detailed Emissions Data

## Power Boiler No. 2

- **Continuous Emissions Monitoring System Data for $SO_2$ and $NO_X$ (30-day rolling averages for 2/2019)**

| | | Max 30 Day 178.16 | | Max 30 Day 305.30 |
|---|---|---|---|---|
| No. 2 PB CEMS Data | Nox lb/hr | Nox lb/hr 30-day avg | SO2 lb/hr | SO2 lb/hr 30-day avg |
| 1/30/2019 0:00 | 170.39 | 167.90 | 254.12 | 276.86 |
| 1/31/2019 0:00 | 199.44 | 169.74 | 293.47 | 279.66 |
| 2/1/2019 0:00 | 190.96 | 171.11 | 278.59 | 281.94 |
| 2/2/2019 0:00 | 217.73 | 172.61 | 327.29 | 285.05 |
| 2/3/2019 0:00 | 195.29 | 172.87 | 302.27 | 286.31 |
| 2/4/2019 0:00 | 203.55 | 174.09 | 321.07 | 289.88 |
| 2/5/2019 0:00 | 149.57 | 173.74 | 351.67 | 292.92 |
| 2/6/2019 0:00 | 167.17 | 174.63 | 258.90 | 295.24 |
| 2/7/2019 0:00 | 135.13 | 175.99 | 307.62 | 300.71 |
| 2/8/2019 0:00 | 153.92 | 176.88 | 284.36 | 305.30 |
| 2/9/2019 0:00 | 162.09 | 176.23 | 272.04 | 304.48 |
| 2/10/2019 0:00 | 162.61 | 175.80 | 238.47 | 304.41 |
| 2/11/2019 0:00 | 151.14 | 175.69 | 232.25 | 300.67 |
| 2/12/2019 0:00 | 163.45 | 176.23 | 262.40 | 299.58 |
| 2/13/2019 0:00 | 192.66 | 178.09 | 309.21 | 302.03 |
| 2/14/2019 0:00 | 184.50 | 178.16 | 286.32 | 300.58 |
| 2/15/2019 0:00 | 117.18 | 175.96 | 231.74 | 299.47 |
| 2/16/2019 0:00 | 117.36 | 174.36 | 256.33 | 299.18 |
| 2/17/2019 0:00 | 129.09 | 173.47 | 265.87 | 297.99 |
| 2/18/2019 0:00 | 140.99 | 172.28 | 232.16 | 293.45 |
| 2/19/2019 0:00 | 116.18 | 169.20 | 256.13 | 290.49 |
| 2/20/2019 0:00 | 172.06 | 168.29 | 254.46 | 289.74 |
| 2/21/2019 0:00 | 145.42 | 166.63 | 314.74 | 290.40 |
| 2/22/2019 0:00 | 119.12 | 164.64 | 190.01 | 284.18 |
| 2/23/2019 0:00 | 159.95 | 164.15 | 267.61 | 284.06 |
| 2/24/2019 0:00 | 152.37 | 162.67 | 278.73 | 283.31 |
| 2/25/2019 0:00 | 144.15 | 160.92 | 278.02 | 281.96 |
| 2/26/2019 0:00 | 116.91 | 159.60 | 219.27 | 276.38 |
| 2/27/2019 0:00 | 106.33 | 157.51 | 254.45 | 272.67 |
| 2/28/2019 0:00 | 105.72 | 154.75 | 226.36 | 270.20 |

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Domtar

April 16, 2019

William K. Montgomery, Policy & Planning Branch Manager
Arkansas Department of Environmental Quality
Office of Air Quality
5301 Northshore Drive
North Little Rock, AR 72118-5317

RE: *Domtar A.W. LLC*
*Demonstration of Compliance with Proposed BART Alternative Limits*
*Ongoing Compliance – March 2019 Data*

Dear Mr. Montgomery:

In accordance with the December 20, 2018 letter demonstrating that both BART-affected emission units at its Ashdown Mill (Power Boilers No. 1 and No. 2) are in compliance with the BART Alternative Limits in the proposed Arkansas Regional Haze SIP Phase III, Domtar is providing the attached summary of continuous emission monitoring data for the most recent operating month. This data demonstrates continuing compliance with the proposed BART Alternative Limits.

Domtar reviewed the emissions data for both Power Boiler No. 1 and Power Boiler No. 2 for March 2019. This review confirms that neither unit emitted at levels greater than the BART Alternative limits during this time period. See Tables 1 and 2 below.

**Table 1. BART Alternative Emission Rates**

| Unit | $SO_2$ (lb/hr) | $NO_X$ (lb/hr) | PM (lb/hr) |
|---|---|---|---|
| Power Boiler No. 1 | 0.5 | 191.1 | 5.2 |
| Power Boiler No. 2 | 435 | 293 | 82 [a,b] |

[a] According to the final FIP and proposed SIP, compliance with the BART and BART Alternative PM limits is based on compliance with Boiler MACT in accordance with 40 CFR Part 63 Subpart DDDDD.
[b] Rounded up from 81.6 as presented in the FIP and SIP to be consistent with the proposed $SO_2$ and $NO_X$ limits and the current Title V permit limit.

**Table 2. Emission Rates for 3/2019**

| Unit | $SO_2$ (lb/hr) Maximum of 30-day Rolling Averages | $NO_X$ (lb/hr) Maximum of 30-day Rolling Averages | PM (lb/hr) |
|---|---|---|---|
| Power Boiler No. 1 | 0 | 0 | 0 |
| Power Boiler No. 2 | 270 | 153 | 48 [a] |

[a] Compliance with the BART Alternative limit is demonstrated via compliance with Boiler MACT. The Boiler MACT standard is 0.44 lb/MMBtu. Based on compliance testing conducted in January 2016, actual emissions from Power Boiler No. 2 are 0.059 lb/MMBtu (13 percent of the standard). The 48 lb/hr value listed in this table is a conservative estimate based on the test result and the heat input capacity of the boiler, 820 MMBtu/hr.

Detailed emissions data from March 2019 for Power Boiler No. 2 – CEMS-based information for $SO_2$ and $NO_X$ are provided in Attachment 1. Note that Power Boiler No. 1 is in standby mode with zero emissions since early 2016.

Thank you for your consideration of this information. Please contact me with any questions or to discuss any additional data needs.

Sincerely,

Kelley R. Crouch

Kelley Crouch
Environmental Manager

cc: Annabeth Reitter, Domtar
Jeremy Jewell, Trinity Consultants
Mark A. Thimke, Foley & Lardner LLP

# Attachment 1 – Detailed Emissions Data

## Power Boiler No. 2

- **Continuous Emissions Monitoring System Data for $SO_2$ and $NO_X$ (30-day rolling averages for 3/2019)**

| | | Max 30 Day 152.78 | | Max 30 Day 269.86 |
|---|---|---|---|---|
| No. 2 PB CEMS Data | Nox lb/hr | Nox lb/hr 30-day avg | SO2 lb/hr | SO2 lb/hr 30-day avg |
| 3/1/2019 0:00 | 111.44 | 152.78 | 244.04 | 269.86 |
| 3/2/2019 0:00 | 124.98 | 150.30 | 205.90 | 266.94 |
| 3/3/2019 0:00 | 122.80 | 148.03 | 250.37 | 266.00 |
| 3/4/2019 0:00 | 141.35 | 145.48 | 312.47 | 265.51 |
| 3/5/2019 0:00 | 126.45 | 143.19 | 320.04 | 266.10 |
| 3/6/2019 0:00 | 136.93 | 140.97 | 175.62 | 261.25 |
| 3/7/2019 0:00 | 139.90 | 140.65 | 344.06 | 261.00 |
| 3/8/2019 0:00 | 159.28 | 140.38 | 282.55 | 261.79 |
| 3/9/2019 0:00 | 174.80 | 141.70 | 286.93 | 261.10 |
| 3/10/2019 0:00 | 88.85 | 139.54 | 201.78 | 258.34 |
| 3/11/2019 0:00 | 100.15 | 137.47 | 226.25 | 256.82 |
| 3/12/2019 0:00 | 177.76 | 137.98 | 341.61 | 260.26 |
| 3/13/2019 0:00 | 135.50 | 137.46 | 184.35 | 258.66 |
| 3/14/2019 0:00 | 154.26 | 137.15 | 244.38 | 258.06 |
| 3/15/2019 0:00 | 119.66 | 134.72 | 274.21 | 256.89 |
| 3/16/2019 0:00 | 108.89 | 132.19 | 168.52 | 252.97 |
| 3/17/2019 0:00 | 103.15 | 131.73 | 90.71 | 248.26 |
| 3/18/2019 0:00 | 111.08 | 131.52 | 233.09 | 247.49 |
| 3/19/2019 0:00 | 137.72 | 131.81 | 258.04 | 247.23 |
| 3/20/2019 0:00 | 104.74 | 130.60 | 207.95 | 246.42 |
| 3/21/2019 0:00 | 107.36 | 130.30 | 195.84 | 244.41 |
| 3/22/2019 0:00 | 34.86 | 125.73 | 72.03 | 238.33 |
| 3/23/2019 0:00 | 0.00 | 125.05 | 0.00 | 235.70 |
| 3/24/2019 0:00 | 0.00 | 125.26 | 0.00 | 237.33 |
| 3/25/2019 0:00 | 0.00 | 123.98 | 0.00 | 236.21 |
| 3/26/2019 0:00 | 0.00 | 122.89 | 0.00 | 234.57 |
| 3/27/2019 0:00 | 0.00 | 122.04 | 0.00 | 232.83 |
| 3/28/2019 0:00 | 0.00 | 122.25 | 0.00 | 233.40 |
| 3/29/2019 0:00 | 0.00 | 122.94 | 0.00 | 232.48 |
| 3/30/2019 0:00 | 0.00 | 123.72 | 0.00 | 232.76 |
| 3/31/2019 0:00 | 25.18 | 119.80 | 7.04 | 221.99 |

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Domtar

May 16, 2019

William K. Montgomery, Policy & Planning Branch Manager
Arkansas Department of Environmental Quality
Office of Air Quality
5301 Northshore Drive
North Little Rock, AR 72118-5317

RE: *Domtar A.W. LLC*
*Demonstration of Compliance with Proposed BART Alternative Limits*
*Ongoing Compliance – April 2019 Data*

Dear Mr. Montgomery:

In accordance with the December 20, 2018 letter demonstrating that both BART-affected emission units at its Ashdown Mill (Power Boilers No. 1 and No. 2) are in compliance with the BART Alternative Limits in the proposed Arkansas Regional Haze SIP Phase III, Domtar is providing the attached summary of continuous emission monitoring data for the most recent operating month. This data demonstrates continuing compliance with the proposed BART Alternative Limits.

Domtar reviewed the emissions data for both Power Boiler No. 1 and Power Boiler No. 2 for April 2019. This review confirms that neither unit emitted at levels greater than the BART Alternative limits during this time period. See Tables 1 and 2 below.

**Table 1. BART Alternative Emission Rates**

| Unit | $SO_2$ (lb/hr) | $NO_X$ (lb/hr) | PM (lb/hr) |
|---|---|---|---|
| Power Boiler No. 1 | 0.5 | 191.1 | 5.2 |
| Power Boiler No. 2 | 435 | 293 | 82 [a,b] |

[a] According to the final FIP and proposed SIP, compliance with the BART and BART Alternative PM limits is based on compliance with Boiler MACT in accordance with 40 CFR Part 63 Subpart DDDDD.
[b] Rounded up from 81.6 as presented in the FIP and SIP to be consistent with the proposed $SO_2$ and $NO_X$ limits and the current Title V permit limit.

**Table 2. Emission Rates for 4/2019**

| Unit | $SO_2$ (lb/hr) Maximum of 30-day Rolling Averages | $NO_X$ (lb/hr) Maximum of 30-day Rolling Averages | PM (lb/hr) |
|---|---|---|---|
| Power Boiler No. 1 | 0 | 0 | 0 |
| Power Boiler No. 2 | 250 | 137 | 48 [a] |

[a] Compliance with the BART Alternative limit is demonstrated via compliance with Boiler MACT. The Boiler MACT standard is 0.44 lb/MMBtu. Based on compliance testing conducted in January 2016, actual emissions from Power Boiler No. 2 are 0.059 lb/MMBtu (13 percent of the standard). The 48 lb/hr value listed in this table is a conservative estimate based on the test result and the heat input capacity of the boiler, 820 MMBtu/hr.

Detailed emissions data from April 2019 for Power Boiler No. 2 – CEMS-based information for $SO_2$ and $NO_X$ are provided in Attachment 1. Note that Power Boiler No. 1 is in standby mode with zero emissions since early 2016.

Thank you for your consideration of this information. Please contact me with any questions or to discuss any additional data needs.

Sincerely,

Kelley R. Crouch

Kelley Crouch
Environmental Manager

cc: Annabeth Reitter, Domtar
Jeremy Jewell, Trinity Consultants
Mark A. Thimke, Foley & Lardner LLP

# Attachment 1 – Detailed Emissions Data

## Power Boiler No. 2

- **Continuous Emissions Monitoring System Data for $SO_2$ and $NO_X$ (30-day rolling averages for 4/2019)**

| | | Max 30 Day 137.03 | | Max 30 Day 249.86 |
|---|---|---|---|---|
| No. 2 PB CEMS Data | Nox lb/hr | Nox lb/hr 30-day avg | SO2 lb/hr | SO2 lb/hr 30-day avg |
| 4/1/2019 0:00 | 67.93 | 120.51 | 94.81 | 225.46 |
| 4/2/2019 0:00 | 130.88 | 119.54 | 245.34 | 224.72 |
| 4/3/2019 0:00 | 150.90 | 119.49 | 330.07 | 226.43 |
| 4/4/2019 0:00 | 130.04 | 119.02 | 253.82 | 225.62 |
| 4/5/2019 0:00 | 169.06 | 120.76 | 333.45 | 229.43 |
| 4/6/2019 0:00 | 130.63 | 121.57 | 269.80 | 229.94 |
| 4/7/2019 0:00 | 124.35 | 121.70 | 265.13 | 230.67 |
| 4/8/2019 0:00 | 127.91 | 122.25 | 271.03 | 231.57 |
| 4/9/2019 0:00 | 130.35 | 122.42 | 257.05 | 233.28 |
| 4/10/2019 0:00 | 125.95 | 122.53 | 219.68 | 232.25 |
| 4/11/2019 0:00 | 132.06 | 122.22 | 240.21 | 229.85 |
| 4/12/2019 0:00 | 134.38 | 122.48 | 270.05 | 228.18 |
| 4/13/2019 0:00 | 132.22 | 122.33 | 247.48 | 230.57 |
| 4/14/2019 0:00 | 138.38 | 122.28 | 255.50 | 227.62 |
| 4/15/2019 0:00 | 138.21 | 121.57 | 193.28 | 224.65 |
| 4/16/2019 0:00 | 132.18 | 120.15 | 250.27 | 223.42 |
| 4/17/2019 0:00 | 136.61 | 121.75 | 252.53 | 225.12 |
| 4/18/2019 0:00 | 150.25 | 123.42 | 255.00 | 226.07 |
| 4/19/2019 0:00 | 151.03 | 122.52 | 264.47 | 223.50 |
| 4/20/2019 0:00 | 134.80 | 122.50 | 81.60 | 220.08 |
| 4/21/2019 0:00 | 199.23 | 124.00 | 344.59 | 223.42 |
| 4/22/2019 0:00 | 151.87 | 125.07 | 301.50 | 224.33 |
| 4/23/2019 0:00 | 144.37 | 126.26 | 286.59 | 228.26 |
| 4/24/2019 0:00 | 149.63 | 127.81 | 241.85 | 233.30 |
| 4/25/2019 0:00 | 128.67 | 128.39 | 277.31 | 234.78 |
| 4/26/2019 0:00 | 143.21 | 128.57 | 262.68 | 234.93 |
| 4/27/2019 0:00 | 124.54 | 129.23 | 224.24 | 235.47 |
| 4/28/2019 0:00 | 119.93 | 129.65 | 231.53 | 236.66 |
| 4/29/2019 0:00 | 145.41 | 133.34 | 247.57 | 242.51 |
| 4/30/2019 0:00 | 135.79 | 137.03 | 227.53 | 249.86 |