BART FIVE FACTOR ANALYSIS

FLINT CREEK POWER PLANT

GENTRY, ARKANSAS (AFIN 04-00107)

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TABLE OF CONTENTS

LIST OF TABLES

1. EXECUTIVE SUMMARY

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

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

A summary of the existing visibility impairment attributable to SN-01 based on the default natural conditions is provided in Table 1-1. The visibility impairment summarized in Table 1-1 is based on modeling conducted by Trinity Consultants (Trinity) using actual emissions data based on a combination of stack testing and CEMS as further described in Section 4 of this report.

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

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

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

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

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

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

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

- SO_2 – The BART analysis concluded that the installation of a dry scrubber and baghouse (e.g., Novel Integrated Deacidification System [NIDS] technology) constitutes BART. The proposed BART emission rate for SO_2 is 0.06 lb/MMBtu calculated as a 30-day rolling average over each boiler operating day.

- NO_X – EPA recently issued a final rule allowing states that are subject to the Cross-State Air Pollution Rule (CSAPR) trading program for seasonal NO_x to rely on the reductions achieved through that trading program to satisfy the regional haze program requirements for units subject to BART.[3] Subsequently, CSAPR was vacated, and the Clean Air Interstate Rule (CAIR) remains in effect until an acceptable replacement rule is promulgated.[4] If CSAPR is upheld and implemented in Arkansas, SWEPCO will rely on CSAPR to satisfy its regional haze obligations at SN-01. If CSAPR is vacated and CAIR remains in effect, EPA's prior determination that the reductions provided under CAIR's seasonal NO_X trading program provide greater visibility improvements than BART should allow SWEPCO to rely on the seasonal CAIR program to satisfy its NO_X obligations under BART.[5]

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

- PM_{10} – A BART determination for PM_{10} at SN-01 was approved in EPA's March 12, 2012 final rule based on the existing ESP and a BART emission rate of 0.1 lb/MMBtu.[6]

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

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

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

[6] "Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze. Final Rule," 77 Fed. Reg. 14604 (March 12, 2012).

2. INTRODUCTION AND BACKGROUND

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

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

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

A BART-eligible source is subject to BART if the source is "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." EPA has determined that a source is reasonably anticipated to cause or contribute to visibility impairment if the 98th percentile visibility impacts from the source are greater than 0.5 delta deciviews (Δdv) when compared against a natural background[7]. Air quality modeling is the tool that is used to determine a source's visibility impacts.

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

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

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

1. Existing controls
2. Cost of controls

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

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

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

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

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

SN-01 meets the three BART-eligibility criteria described above, and the existing visibility impairment attributable to SN-01 is greater than 0.5 dv in at least one Class I area. Thus, SN-01 is subject to BART. The details of the SN-01 existing/baseline emissions and the contribution of the emissions to visibility impairment can be found in Section 4. The VAPs emitted by SN-01 include NO_X, SO_2, and PM_{10} of various forms (filterable coarse particulate matter [PM_c], filterable fine particle matter [PM_f], elemental carbon [EC], inorganic condensable particulate matter [IOR CPM] as sulfates [SO_4], and organic condensable particulate matter [OR CPM] also referred to as secondary organic aerosols [SOA]). The BART determinations for SO_2, NO_x, and PM_{10} can be found in Sections 5, 6, and 7, respectively.

3. MODELING METHODOLOGIES AND PROCEDURES

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

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

3.1 CALMET AND CALPUFF

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

3.2 CALPOST

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

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

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

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

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

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

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

Visibility impairment predictions for SN-01 relied upon in this BART analysis used the equation shown above. The use of this equation is referred to as "Method 8" in the CALPOST control file. The use of Method 8 requires that one of five different "modes" be selected. The modes specify the approach for addressing the growth of hygroscopic particles due to moisture in the atmosphere. "Mode 5" has been used in this BART analysis. Mode 5 addresses moisture in the atmosphere in a similar way as to "Method 6", where "Method 6" is specified as the preferred approach for use with the old IMPROVE equation in the CENRAP BART modeling protocol.

CALPOST Method 8, Mode 5 requires the following:

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

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

TABLE 3-1. ANNUAL AVERAGE BACKGROUND CONCENTRATION

Class I Area	$(NH_4)_2SO_4$	NH_4NO_3	OM	EC	Soil	CM	Sea Salt	Rayleigh (Mm^{-1})
Caney Creek Wilderness	0.23	0.1	1.8	0.02	0.5	3	0.03	11
Upper Buffalo Wilderness	0.23	0.1	1.8	0.02	0.5	3	0.03	11
Hercules Glades Wilderness	0.23	0.1	1.8	0.02	0.5	3	0.02	11
Mingo Wilderness	0.23	0.1	1.83	0.02	0.51	3.05	0.04	12

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

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Caney Creek Wilderness	2.77	2.53	2.37	2.43	2.68	2.71	2.59	2.6	2.71	2.69	2.67	2.79
Upper Buffalo Wilderness	2.71	2.48	2.31	2.33	2.61	2.64	2.57	2.59	2.71	2.58	2.59	2.72
Hercules Glades Wilderness	2.7	2.48	2.3	2.3	2.57	2.59	2.56	2.6	2.69	2.54	2.57	2.72
Mingo Wilderness	2.73	2.52	2.34	2.28	2.53	2.6	2.64	2.67	2.71	2.56	2.56	2.73

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

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Caney Creek Wilderness	3.85	3.44	3.14	3.24	3.66	3.71	3.49	3.51	3.73	3.72	3.68	3.88
Upper Buffalo Wilderness	3.73	3.33	3.03	3.07	3.54	3.57	3.43	3.5	3.71	3.51	3.52	3.74
Hercules Glades Wilderness	3.7	3.33	3.01	3.01	3.47	3.48	3.41	3.51	3.67	3.43	3.46	3.73
Mingo Wilderness	3.74	3.38	3.07	2.97	3.39	3.52	3.57	3.64	3.72	3.47	3.43	3.74

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

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

This section summarizes the existing (i.e. baseline) visibility impairment attributable to SN-01 based on air quality modeling conducted by Trinity.

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

Table 4-1 summarizes the emission rates that were modeled for SO_2, NO_X, and PM_{10}, including the speciated PM_{10} emissions. The SO_2 and NO_X emission rates are the highest actual 24-hour emission rates based on 2001-2003 continuous emissions monitoring system (CEMS) data. The emission rates for the PM_{10} species reflect the breakdown of the PM_{10} determined from the National Park Service (NPS) "speciation spreadsheet" for *Dry Bottom Boiler Burning Pulverized Coal using only ESP*[8]. Specifically, the NPS workbook shows the following baseline distribution for the PM species:

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

Per EPA's request,[9] an SO_4 emission rate was independently calculated using an EPRI methodology that considers the SO_2 to SO_4 conversion rate and SO_4 reduction factors for various downstream equipment.[10] This SO_4 rate was used in the modeling instead of the rate resulting from the NPS-based breakdown.

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

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

[8] The NPS Workbook, "PC Dry Bottom ESP Example.xls" updated 03/2006, was obtained from the NPS website: http://www.nature.nps.gov/air/Permits/ect/index.cfm. The following parameters were input into the workbook for speciation determination: total PM_{10} emission rate of 192.5 lb/hr, heat value of 8,500 Btu/lb, sulfur content of 0.31%, ash content of 4.9%.

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

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

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

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

4.2 BASELINE VISIBILITY IMPAIRMENT

Trinity conducted modeling to determine the visibility impairment attributable to SN-01 in four Class I Areas: Caney Creek Wilderness (CACR), Upper Buffalo Wilderness (UPBU), Hercules Glades Wilderness (HERC), and Mingo Wilderness (MING) using the CALPUFF dispersion model.

Table 4-2 provides a summary of the modeled visibility impairment attributable to SN-01 at CACR, UPBU, HERC, and MING based on the emission rates shown in Table 4-1. Note that all of the CALMET, CALPUFF, and CALPOST modeling files are included as part of the electronic files submitted with this document.

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

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Day with $\Delta dv \geq 0.5$	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek Wilderness							
2001	1.318	0.609	19	62.49	34.95	1.00	1.55
2002	1.165	0.689	10	60.43	35.25	1.72	2.60
2003	1.298	0.963	19	70.90	27.64	0.62	0.85
Upper Buffalo Wilderness							
2001	1.732	0.955	22	53.01	45.08	1.16	0.74
2002	2.426	0.965	18	96.29	2.75	0.96	0.00
2003	1.394	0.670	23	89.90	5.4	2.74	1.97
Hercules Glades Wilderness							
2001	1.418	0.643	19	76.92	22.4	0.69	0.00
2002	1.364	0.627	15	43.49	51.71	2.08	2.72
2003	2.103	0.657	13	47.91	49.69	1.19	1.21
Mingo Wilderness							
2001	1.28	0.631	11	90.97	8.59	0.42	0.01
2002	0.841	0.424	6	93.66	5.94	0.40	0.00
2003	1.488	0.393	3	38.60	59.69	1.07	0.64

5.1 IDENTIFICATION OF AVAILABLE RETROFIT SO_2 CONTROL TECHNOLOGIES

Sulfur oxides, SO_X, are generated during coal combustion from the oxidation of sulfur contained in the fuel. SO_X emissions are almost entirely dependent on the sulfur content of the fuel and are generally not affected by boiler size or burner design. SO_X emissions from conventional combustion systems are predominantly in the form of SO_2. Since SO_2 is the predominant sulfur compound emitted from SN-01, the BART analysis is specific to emissions of SO_2.

Step 1 of the top-down control review is to identify available retrofit control options for SO_2. The available SO_2 retrofit control technologies for SN-01 are summarized in Table 5-1. The retrofit controls examined are limited to add-on controls that eliminate SO_2 after it is formed, as SN-01 currently uses a low sulfur fuel and would not achieve significant additional reductions through alternative coal supplies.

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

SO_2 Control Technologies
Dry Sorbent Injection
Dry Scrubber
Wet Scrubber

5.2 ELIMINATE TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES

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

5.2.1 DRY SORBENT INJECTION

Dry sorbent injection involves the injection of a sorbent into the exhaust gas stream where SO_2 reacts with and becomes entrained in the sorbent. The stream is then passed through a particulate control device to remove the sorbent and entrained SO_2. The process was developed as a lower cost Flue Gas Desulfurization (FGD) option because the mixing of the SO_2 and sorbent occurs directly in the exhaust gas stream instead of in a separate tower. Depending on the residence time, gas stream temperature, and limitations of the particulate control device, sorbent injection control efficiency can range between 40 and 60 percent.[13] This control is a technically feasible option for the control of SO_2 from SN-01.

[13] "Assessment of Control Technology Options for BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities" Northeast States for Coordinated Air Use Management (NESCAUM), March 2005.

5.2.2 DRY SCRUBBER

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

There are various designs of dry scrubbing systems. In the spray dryer absorber (SDA) design, a fine mist of lime slurry is atomized into an absorption vessel where the SO_2 is absorbed by the slurry droplets. The mixture of reaction products (calcium sulfite/sulfate), unreacted lime, and fly ash is carried out with the exhaust gas and collected with a fabric filter. Circulating dry scrubbing (CDS) is another type of dry scrubbing. In the CDS process, the flue gas is introduced into the bottom of a reactor vessel at high velocity through a venturi nozzle; the exhaust is mixed with water, hydrated lime, recycled flyash and CDS reaction products. The intensive gas-solid mixing that occurs in the reactor promotes the reaction of SO_2 in the flue gas with the dry lime particles. As with SDA, the mixture of reaction products (calcium sulfite/sulfate), unreacted lime, and fly ash is carried out with the exhaust gas and collected with a fabric filter. A large portion of the collected particles is recycled to the reactor to sustain the bed and improve lime utilization.

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

5.2.3 WET SCRUBBER

Wet scrubbing involves scrubbing the exhaust gas stream with a slurry comprised of lime or limestone in suspension. The process takes place in a wet scrubbing tower located downstream of a PM control device such as a fabric filter or an electrostatic precipitator (ESP). The liquid-to-gas ratio is such that the exhaust gas is fully saturated with water and

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

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

5.3 RANK OF TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis is to rank the technically feasible options according to their effectiveness in reducing the visibility affecting pollutants (VAP). Table 5-2 provides a ranking of the control levels for the controls listed in the previous section for SN-01.

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

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

5.4 EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS

A shown in Table 5-2, wet scrubbing can achieve a 95% reduction in SO_2 while dry scrubbing or NID can achieve a 92% reduction in SO_2, and these technologies are the most effective technologies at reducing SO_2. Step four of the BART analysis procedure is the impact analysis. The BART determination guidelines list the four factors to be considered in the impact analysis:

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

[15] Ibid.

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

5.4.1 COST OF COMPLIANCE

Control Costs

The capital and operating costs of WFGD and NID used in the cost effectiveness calculations were estimated based on EPA's Air Pollution Control Cost Manual supplemented with vendor and site-specific information where available. The capital costs were annualized over a 30-year period and then added to the annual operating costs to obtain the total annualized costs. The details of the capital and operating cost estimates are provided in Appendix A of this report.

Annual Tons Reduced

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

Cost Effectiveness

The cost effectiveness in dollars per ton of SO_2 reduced was determined by dividing the annualized cost of control by the annual tons reduced. Table 5-3 indicates that the cost effectiveness of the wet scrubber at an SO_2 rate of 0.04 lb/MMBtu is approximately \$4,900 per ton of SO_2 removed. The cost effectiveness in dollars per deciview of visibility is over \$476 million/dv across the Class I areas, as seen in Table 5-4.

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

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

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

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

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

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

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

5.4.2 ENERGY IMPACTS AND NON-AIR QUALITY IMPACTS

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

5.4.3 REMAINING USEFUL LIFE

The remaining useful life of SN-01 does not impact the annualized capital costs because the useful life of the unit is anticipated to be at least as long as the capital cost recovery period, which is 30 years based on EPA cost estimates.

5.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE SO_2 CONTROLS

A final impact analysis was conducted to assess the visibility improvement achieved by comparing the impacts associated with the baseline emission rates to the impacts associated with the controlled emission rates. Section 4 of this report documents the existing visibility impairment attributable to SN-01. In order to assess the visibility improvement associated with the considered control options, the controlled SO_2 emission rates were modeled using CALPUFF.

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

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

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

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

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

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

Control Technology	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_x (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)
NIDS	379.4	0.004	1,945.0	35.2	33.9	24.4	1.3
Wet Scrubber	253.0	0.11	1,945.0	35.2	33.9	24.4	1.3

Comparisons of the existing visibility impacts and the visibility impacts based on the NIDS, including the maximum modeled visibility impact, 98th percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv, for each Class I area are provided in Table 5-7.

TABLE 5-7. SUMMARY OF MODELED IMPACTS FROM SO_2 CONTROL VISIBILITY IMPACT ANALYSIS FOR SN-01 (2001-2003)

	Caney Creek Wilderness			Upper Buffalo Wilderness			Hercules Glades Wilderness			Mingo NWR		
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv
Existing Emission Rate	1.318	0.963	48	2.426	0.965	63	2.103	0.657	47	1.488	0.631	20
NIDS	0.753	0.348	6	1.474	0.501	13	0.882	0.312	5	0.694	0.217	4
Post Control Improvement	*0.565*	*0.615*	*42*	*0.952*	*0.464*	*50*	*1.221*	*0.345*	*42*	*0.794*	*0.414*	*15*
Wet Scrubber	0.746	0.334	5	1.446	0.488	11	0.845	0.305	5	0.677	0.208	4
Post Control Improvement over NIDS	*0.007*	*0.014*	*1*	*0.028*	*0.013*	*2*	*0.037*	*0.007*	*0*	*0.017*	*0.009*	*0*

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

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

5.6 PROPOSED BART FOR SO_2

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

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

5.6.1 COMPARATIVE SO_2 BART DETERMINATIONS

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

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

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

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

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

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

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

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

In other determinations, such as Illinois[22], the control technology was not stated in the BART determination but the SO_2 rate determined to be BART was in the range of 0.11 – 0.23 lb/MMBtu, dependent upon boiler type and averaging considerations. SO_2 BART in Kansas[23] was achieved through "scrubbing" with an emission limitation of 0.10 lb/MMBtu for one boiler and through wet scrubbing with an emission limitation of 0.15 lb/MMBtu for another. An EGU in Montana[24] similar to AEP's SN-01 has a BART emission rate of 0.08 lb/MMBtu.

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

[21] 77 Fed. Reg. 18052 (March 26, 2012).
[22] 77 Fed. Reg. 3966 (Jan. 26, 2012).
[23] 77 Fed. Reg. 52604 (Aug. 23, 2011).
[24] 77 Fed. Reg. 23988 (April 20, 2012).

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

On June 7, 2012 EPA published a final rule allowing states participating in the Cross-State Air Pollution Rule (CSAPR) trading program to use CSAPR to satisfy BART. Arkansas is one of the states with units subject to CSAPR that will participate in a NO_X trading program during the ozone season. EPA commented that "NO_X control in the five ozone season-only states is achieved predominantly by combustion controls."[25] Due to the nature of combustion controls, plants typically keep combustion controls in place and running year-round, even if emission limitations are seasonal. Although Arkansas is an ozone season-only state, combustion controls would run anytime the unit is in operation. However, on August 21, 2012, the D. C. Circuit Court of Appeal issued a decision vacating CSAPR and ordering EPA to continue to implement the Clean Air Interstate Rule (CAIR) until a new rule is adopted to replace it. The Court's decision will not be effective until the time for filing rehearing petitions has passed, or any filed petitions for rehearing have been considered by the Court.[26] If CSAPR is upheld and implemented in Arkansas, SWEPCO proposes rely on CSAPR to satisfy its regional haze obligations at SN-01.

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

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

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

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

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

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

6.2 IDENTIFICATION OF AVAILABLE RETROFIT NO_X CONTROL TECHNOLOGIES

Nitrogen oxides, NO_X, are produced during fuel combustion when nitrogen contained in both the fuel and the combustion air is exposed to high temperatures. The origin of the nitrogen (i.e. fuel vs. combustion air) has led to the use of the terms "thermal" NO_X and "fuel" NO_X when describing NO_X emissions. Thermal NO_X emissions are produced when elemental nitrogen in the combustion air is exposed to a high temperature zone and oxidized. Fuel NO_X emissions are created during the rapid oxidation of nitrogen compounds contained in the fuel.

Nitrogen oxide (NO) is typically the predominant form of NO_X from fossil fuel combustion. Nitrogen dioxide (NO_2) makes up the remainder of the NO_X. The formation of NO_X compounds in utility boilers is sensitive to the method of firing. In a wall-fired boiler, such as SN-01, burners are mounted in the boiler walls, producing discrete flames in the furnace. In tangentially-fired boilers, a single rotating flame is created in the center of the furnace, rather than the discrete flames produced by burners in the wall-fired boilers. Tangentially fired boilers typically have lower uncontrolled NO_X emissions than wall-fired boilers. Therefore baseline NO_X emission rates can vary significantly from plant to plant due to method of firing and also several other factors.

Step 1 of the BART determination is the identification of all available retrofit NO_X control technologies. The available retrofit NO_X control technologies are summarized in Table 6-1 for SN-01.

NO_X emissions controls, as listed in Table 6-1, can be categorized as combustion or post-combustion controls. Combustion controls, including flue gas recirculation (FGR), overfire air (OFA), and Low NO_X Burners (LNB), reduce the peak flame temperature and excess air in the furnace which minimizes NO_X formation. Post-combustion controls, such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) convert NO_X in the flue gas to molecular nitrogen and water.

TABLE 6-1. AVAILABLE NO_X CONTROL TECHNOLOGIES FOR SN-01

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

6.3 ELIMINATE TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES

Step 2 of the BART determination is to eliminate technically infeasible NO_X control technologies that were identified in Step 1. Control ranges were developed using a combination of literature control ranges and efficiencies. Because many controlled emission levels from literature were higher than the baseline NO_X rate at SN-01, vendor estimates were also used to assist in developing the expected emission rates from the known relationships between the control options.

6.3.1 COMBUSTION CONTROLS

6.3.1.1 FLUE GAS RECIRCULATION (FGR)

FGR uses flue gas as an inert material to reduce flame temperatures. In a typical flue gas recirculation system, flue gas is collected from the combustion chamber or stack and returned to the burner via a duct and blower. The addition of flue gas reduces the oxygen content of the "combustion air" (air + flue gas) in the burner. The lower oxygen level in the combustion zone reduces flame temperatures; which in turn reduces thermal NO_X formation. When operated without additional controls, the NO_X control range for coal fired boilers with FGR is approximately 5-25% for coal fired boilers, or 0.23-0.29 lb/MMBtu from SN-01.[29] This control is a technically feasible option for the control of NO_X from SN-01.

6.3.1.2 OVERFIRE AIR (OFA)

OFA diverts a portion of the total combustion air from the burners and injects it through separate air ports above the top level of burners. Staging of the combustion air creates an initial fuel-rich combustion zone with a lower peak flame temperature. This reduces the formation of thermal NO_X by lowering combustion temperature and limiting the availability of oxygen in the combustion zone where NO_X is most likely to be formed. OFA as a single NO_X control technique results in estimated NO_X emissions for coal fired boilers of approximately 10%, or 0.28-0.29 lb/MMBtu from SN-01.[30] This control is a technically feasible option for the control of NO_X from SN-01.

6.3.1.3 LOW NO_X BURNERS

LNB technology utilizes advanced burner design to reduce NO_X formation through the restriction of oxygen, lowering of flame temperature, and/or reduced residence time. NO_X creation rates typically peak at oxygen levels of five to seven percent.[31] LNB is a staged combustion process that is designed to split fuel combustion into two zones. In the primary zone, NO_X formation is limited by one of two methods. Under staged fuel-rich conditions, low oxygen levels limit flame temperatures resulting in less NO_X formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel-lean conditions, excess air will reduce flame temperature to reduce NO_x formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NO_x formation.

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

[30] Ibid.

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

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

6.3.2 POST COM BUSTION CONTROLS

6.3.2.1 SELECTIVE CATALYTIC REDUCTION

SCR refers to the process in which NO_X is reduced by ammonia over a heterogeneous catalyst in the presence of oxygen. The process is termed selective because the ammonia preferentially reacts with NO_X rather than oxygen, although the oxygen enhances the reaction and is a necessary component of the process. The overall reactions are:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

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

6.3.2.2 SELECTIVE NON-CATALYTIC REDUCTION

In SNCR systems, a reagent is injected into the flue gas in the furnace within an appropriate temperature window. The NO_X and reagent (ammonia or urea) react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. The SNCR reagent storage and handling systems are similar to those for SCR systems. However, both ammonia and urea SNCR processes require three to four times as much reagent as SCR systems to achieve similar NO_X reductions. The estimated NO_X control range for SNCR for coal fired boilers is 0.18-0.27 lb/MMBtu.[35] This control is a technically feasible option for the control of NO_X from SN-01.

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

33 Ibid.

34 Ibid.

35 Ibid.

6.4 RANK OF TECHNICALLY FEASIBLE NO_X CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis is to rank the technically feasible options according to effectiveness. Table 6-2 provides a ranking of the control levels for the controls listed in the previous section for SN-01.

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

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

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

6.5 EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS

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

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[36] Ibid.

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

[38] Ibid.

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

6.5.1 COST OF COMPLIANCE

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

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

Annual Tons Reduced
The annual tons reduced that were used in the cost effectiveness calculations were determined by subtracting the estimated controlled annual emission rate from the baseline annual emission rate.

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

Cost Effectiveness
The cost effectiveness in dollars per ton of NO_X reduced was determined by dividing the annualized cost of control by the annual tons reduced. An incremental cost analyses was also performed to show the incremental increase in costs between SCR and an LNB/OFA system, as well as between LNB/OFA + SNCR and LNB/OFA. The costs effectiveness analysis is summarized in Table 6-3.

In the BART guidelines, EPA calculated that for all types of boilers other than cyclone boilers, combustion control technology is generally more cost-effective than post-combustion controls. EPA estimates that approximately 75 percent of the BART units (non-cyclone) could meet the presumptive NO_X limits at a cost of \$100 to \$1,000 per ton of

NO_X removed based on the use of combustion control technology.[39] For the units that could not meet the presumptive limits using combustion control technology, EPA estimates that almost all of these sources could meet the presumptive limits using advanced combustion controls. The EPA estimates that the costs of such controls are usually less than $1,500 per ton of NO_X removed.[40]

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

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

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

[40] Ibid.

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

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

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

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

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

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

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

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

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

6.5.2 Energy Impacts & Non-Air Impacts

SCR systems require electricity to operate the ancillary equipment. The need for electricity to help power some of the ancillary equipment creates a demand for energy that currently does not exist.

SCR and SNCR can potentially cause significant environmental impacts related to the storage of ammonia. The storage of aqueous ammonia above 10,000 lbs is regulated by a risk management program (RMP), since the accidental release of ammonia has the potential to cause serious injury and death to persons in the vicinity of the release. SCR and SNCR will likely also cause the release of unreacted ammonia to the atmosphere. This is referred to as ammonia slip. Ammonia slip from SCR and SNCR systems occurs either from ammonia injection at temperatures too low for effective reaction with NO_x, leading to an excess of unreacted ammonia, or from over-injection of reagent leading to uneven distribution; which also leads to an excess of unreacted ammonia. Ammonia released from SCR and SNCR systems will react with sulfates and nitrates in the atmosphere to form ammonium sulfate and ammonium nitrate. Together, ammonium sulfate and ammonium nitrate are the predominant sources of regional haze.

6.5.3 Remaining Useful Life

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

6.6 Evaluation of Visibility Impact of Feasible NO_X Controls

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

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

TABLE 6-7. SUMMARY OF EMISSION RATES MODELED TO REFLECT LNB/OFA FOR NO_X CONTROL

SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)
4,728.4	3.1	1,454.5	65.1	50.1	15.1	1.9

TABLE 6-8. SUMMARY OF EMISSION RATES MODELED TO REFLECT SCR FOR NO_X CONTROL

SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)
4,728.4	3.1	423.7	65.1	50.1	15.1	1.9

TABLE 6-9. SUMMARY OF EMISSION RATES MODELED TO REFLECT LNB/OFA + SNCR FOR NO_X CONTROL

SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)
4,728.4	3.1	1,277.74	65.1	50.1	15.1	1.9

Table 6-10 provides a comparison of the existing visibility impairment and the visibility impairment associated with the addition of NO_X controls on SN-01 in all affected Class I areas, including the maximum modeled visibility impact, 98^{th} percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv.

TABLE 6-10. SUMMARY OF VISIBILITY IMPROVEMENT ASSOCIATED WITH NO_X CONTROL SYSTEM ON SN-01 (2001-2003)

	Caney Creek Wilderness			**Upper Buffalo Wilderness**			**Hercules Glades Wilderness**			**Mingo NWR**		
	Maximum Impact (Δdv)	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**
Existing Emission Rate	1.318	0.963	48	2.426	0.965	63	2.103	0.657	47	1.488	0.631	20
LNB/OFA	1.232	0.849	39	2.130	0.939	56	1.938	0.633	43	1.361	0.617	17
Post Control Improvement	*0.086*	*0.114*	*9*	*0.296*	*0.026*	*7*	*0.165*	*0.024*	*4*	*0.127*	*0.014*	*3*
SCR	0.986	0.718	22	1.569	0.895	41	1.589	0.573	33	1.099	0.588	14
Improvement over LNB/OFA	*0.246*	*0.131*	*17*	*0.561*	*0.044*	*15*	*0.349*	*0.060*	*10*	*0.262*	*0.029*	*3*
LNB/OFA+ SNCR	1.201	0.849	36	2.022	0.932	54	1.878	0.623	42	1.316	0.612	17
Improvement over LNB/OFA	*0.031*	*0.000*	*3*	*0.108*	*0.007*	*2*	*0.06*	*0.010*	*1*	*0.045*	*0.005*	*0*

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

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

6.7 PROPOSED BART FOR NO_X

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

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

7. PM_{10} BART EVALUATION

EPA's Approval and Promulgation of Implementation Plans published March 12, 2012, determined that the currently installed ESP is BART for PM_{10} for SN-01. As such, no further PM_{10} analysis has been conducted.

APPENDIX A

SO_2 CONTROL COST CALCULATIONS

Capital and O&M Cost Estimates

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

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

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

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

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

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

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

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

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

[i] No landfill construction costs are included.

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

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

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

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

[n] Labor rates based on engineering estimates.

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

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

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

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

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

APPENDIX B

NO_X CONTROL COST CALCULATIONS

LNB/OFA Capital and O&M Cost Estimate

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

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

[2] Annual cost calculation methods for variable costs and fixed costs from Eastern Research Group "Analysis of Combustion Controls for Reducing NOx Emissions from Coal-fired EGUs in the WRAP Region" September 6, 2005. Section 4.3.1 and Appendix D.
Note: The variable rate used for variable O&M costs was 0.027 mills/kW-hr. This is the rate listed in Appendix D

SCR Capital and O&M Cost Estimate

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

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

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

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

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

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

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

APPENDIX C

CALMET PROTOCOL

The meteorological data used in the analyses presented in this report was originally developed in 2007 and was first used in a BART determination for Oklahoma Gas & Electric. Because the development of a set of CALMET/CALPUFF meteorological data is so intensive, this same dataset has been used numerous times since 2007 for various other BART projects in EPA Region 6. The protocol that accompanied the original development has followed the dataset in each case and is doing so here again.

CALMET DATA PROCESSING PROTOCOL ▲ BART DETERMINATION
OKLAHOMA GAS & ELECTRIC

MUSKOGEE GENERATING STATION
SEMINOLE GENERATING STATION
SOONER GENERATING STATION

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January 23, 2008

Project 083701.0004

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1. INTRODUCTION

Oklahoma Gas & Electric (OG&E) owns and operates three electric generating stations near Muskogee, Oklahoma (Muskogee Generating Station), Seminole, Oklahoma (Seminole Generating Station), and Stillwater, Oklahoma (Sooner Generating Station). These generating stations are considered eligible to be regulated under the U.S. Environmental Protection Agency's (EPA) Best Available Retrofit Technology (BART) provisions of the Regional Haze Rule. This protocol describes the proposed methodology for conducting the CALMET data processing for the refined CALPUFF BART modeling analysis for OG&E's Muskogee, Seminole, and Sooner Generating Stations. A detailed CALPUFF BART modeling protocol will be submitted in the near future and will include a discussion of the CALPUFF parameters as well as the post processing methodologies to be used in the refined modeling analysis for each station.

1.1 BEST AVAILABLE RETROFIT TECHNOLOGY RULE BACKGROUND

On July 1, 1999, the U.S. Environmental EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to improve visibility in 156 specific areas across with United States, known as Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence on August 7, 1977.

On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the BART rule, which included guidance for making source-specific Best Available Retrofit Technology (BART) determinations. The BART rule defines BART-eligible sources as sources that meet the following criteria:

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

A BART-eligible source is not automatically subject to BART. Rather, BART-eligible sources are subject-to-BART if the sources are "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." EPA has determined that sources are reasonably anticipated to cause or contribute to visibility impairment if the visibility impacts from a source are greater than 0.5 deciviews (dv) when compared against a natural background.

Air quality modeling is the tool that is used to determine a source's visibility impacts. States have the authority to exempt certain BART-eligible sources from installing BART controls if the results of the dispersion modeling demonstrate that the source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I area. Further, states also have the authority to define the modeling procedures for conducting modeling related to making BART determinations.

1.2 OBJECTIVE

The objective of this document is to provide a protocol summarizing the modeling methods and procedures that will be followed to conduct the CALMET data processing necessary to complete a refined CALPUFF modeling analysis for the OG&E generating stations discussed above. The modeling methods and procedures contained in this protocol and the CALPUFF protocol yet to be submitted will be used to determine appropriate controls for OG&E's BART-eligible sources that can reasonably be anticipated to reduce the sources' effects on or contribution to visibility impairment in the surrounding Class I areas. It is OG&E's intent to determine a combination of emissions controls that will reduce the impact of each generating station to a degree that the 98th percentile of the visibility impact predicted by the model due to all the BART eligible sources at each station collectively is below EPA's recommended visibility contribution threshold of 0.5 Δdv.

1.3 LOCATION OF SOURCES AND RELEVANT CLASS I AREAS

The sources listed in Table 1-1 are the sources that have been identified by OG&E as sources that meet the three criteria for BART-eligible sources.

TABLE 1-1. BART-ELIGIBLE SOURCES

EPN	Description
	Muskogee Sources
Unit 4	5,480 MMBtu/hr Coal Fired Boiler
Unit 5	5,480 MMBtu/hr Coal Fired Boiler
	Seminole Sources
SM1	5,480 MMBtu/hr Natural Gas Fired Boiler
SM2	5,480 MMBtu/hr Natural Gas Fired Boiler
SM3	5,496 MMBtu/hr Natural Gas Fired Boiler
	Sooner Sources
Unit 1	5,116 MMBtu/hr Coal Fired Boiler
Unit 2	5,116 MMBtu/hr Coal Fired Boiler

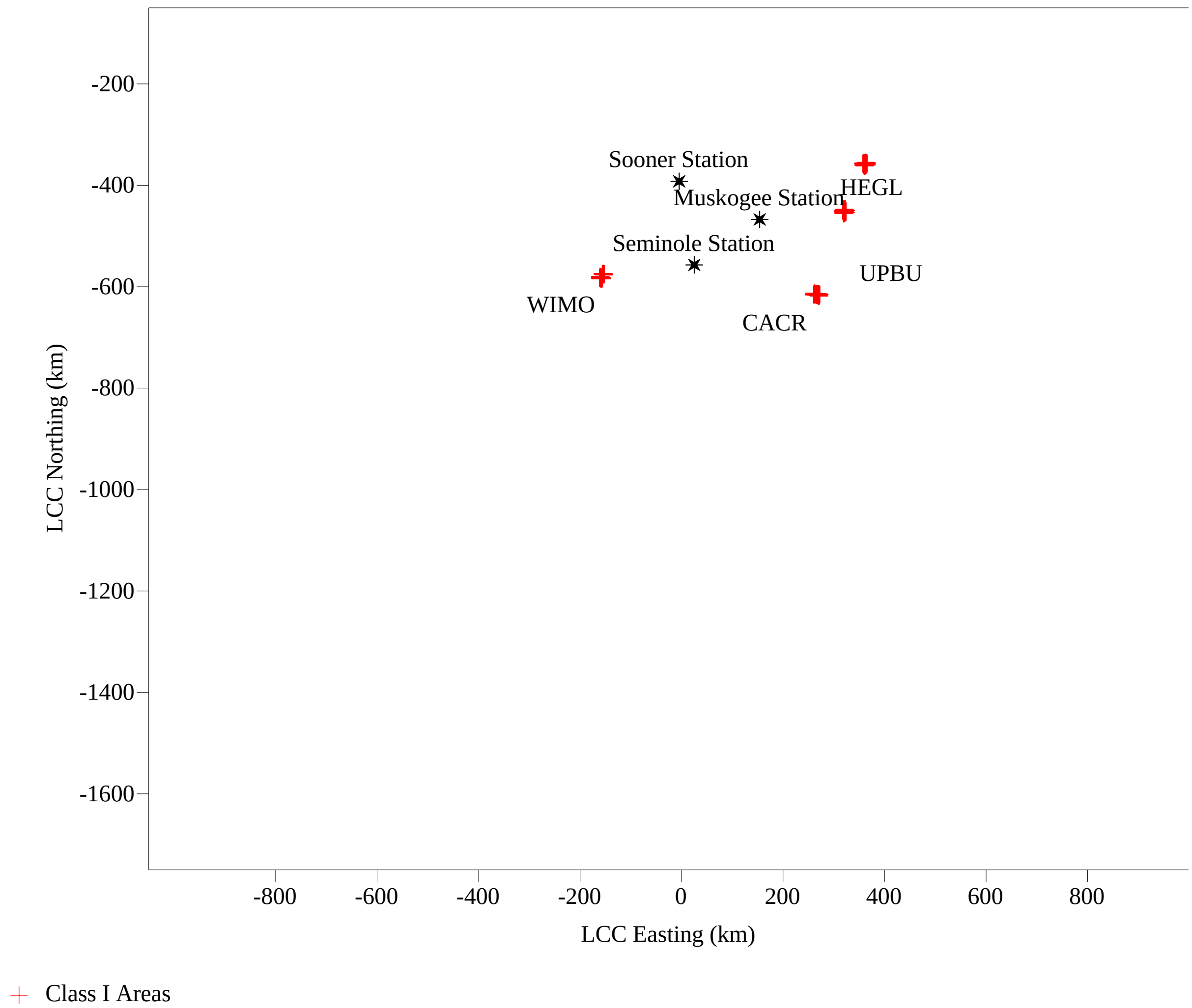
As required in CENRAP's BART Modeling Guidelines, Class I areas within 300 km of each station will be included in each analysis. The following table summarizes the distances of the four closest Class I areas to each station. As seen from this summary, some Class I areas are more than 300 km from the certain stations. However, in order to demonstrate that each station will not have an adverse effect on the visibility at any of the four nearest Class I areas, OG&E has opted to include those Class I areas more than 300 km away in this analysis. Note that the distances listed in the table below are the distances between the stations and the closest border of the Class I areas.

TABLE 1-2. DISTANCE FROM STATION TO SURROUNDING CLASS I AREAS

	CACR	HEGL	UPBU	WIMO
Muskogee	180	230	164	324
Seminole	242	386	310	178
Sooner	345	363	327	234

A plot of the Class I areas with respect to the each station is provided in Figure 1-1.

FIGURE 1-1. PLOT OF SOURCES AND NEAREST CLASS I AREAS



The main components of the CALPUFF modeling system are CALMET, CALPUFF, and CALPOST. CALMET is the meteorological model that generates hourly three-dimensional meteorological fields such as wind and temperature. CALPUFF simulates the non-steady state transport, dispersion, and chemical transformation of air pollutants emitted from a source in "puffs". CALPUFF calculates hourly concentrations of visibility affecting pollutants at each specified receptor in a modeling domain. CALPOST is the post-processor for CALPUFF that computes visibility impacts from a source based on the visibility affecting pollutant concentrations that were output by CALPUFF.

2.1 MODEL VERSIONS

The versions of the CALPUFF modeling system programs that are proposed for conducting OG&E's BART modeling are listed in Table 2-1. A detailed refined CALPUFF BART modeling protocol will be submitted in the near future.

TABLE 2-1. CALPUFF MODELING SYSTEM VERSIONS

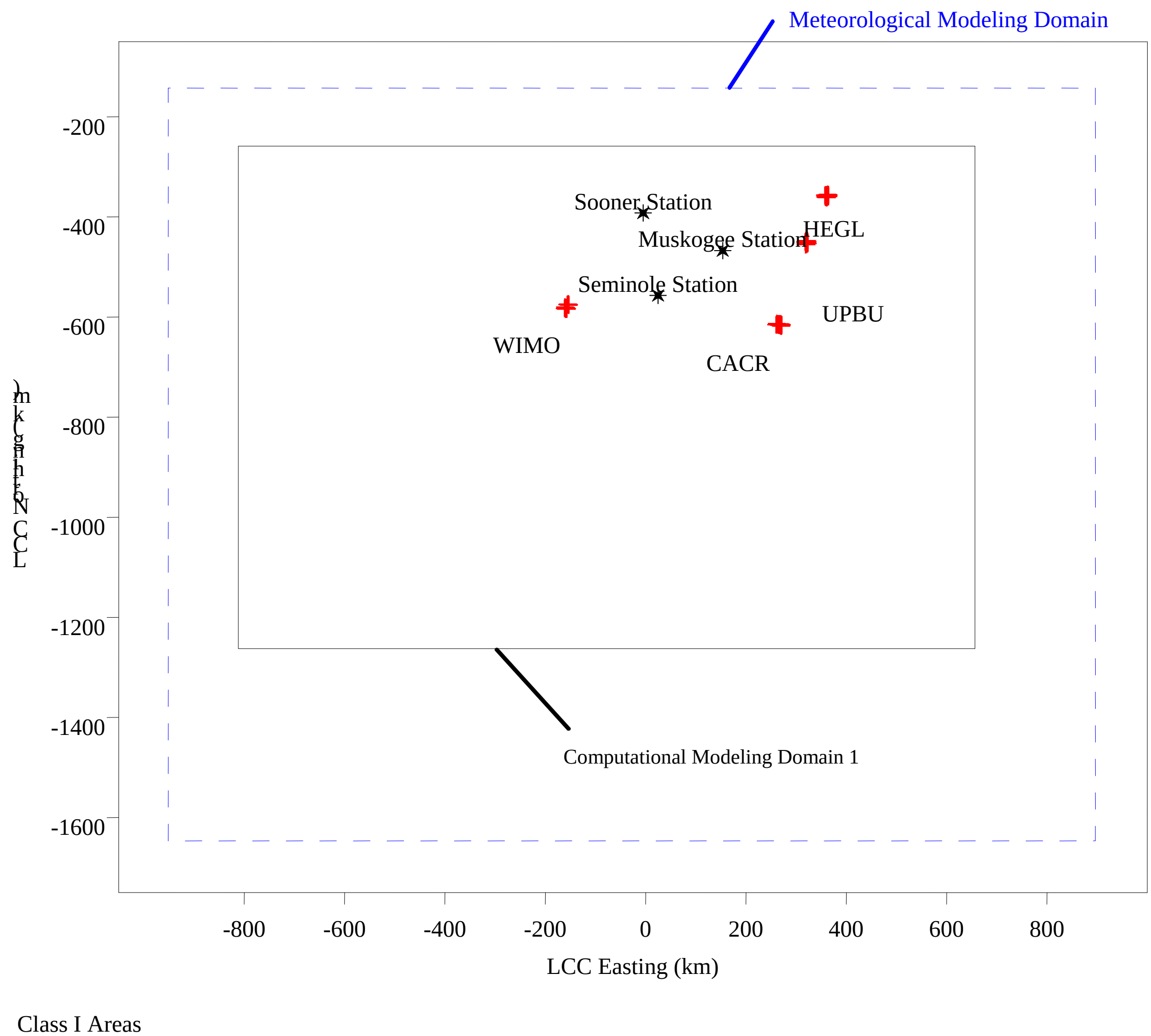
Processor	Version	Level
TERREL	3.3	030402
CTGCOMP	2.21	030402
CTGPROC	2.63	050128
MAKEGEO	2.2	030402
CALMET	5.53a	040716
CALPUFF	5.8	070623
POSTUTIL	1.3	030402
CALPOST	5.51	030709

2.2 MODELING DOMAIN

The CALPUFF modeling system utilizes three modeling grids: the meteorological grid, the computational grid, and the sampling grid. The meteorological grid is the system of grid points at which meteorological fields are developed with CALMET. The computational grid determines the computational area for a CALPUFF run. Puffs are advected and tracked only while within the computational grid. The meteorological grid is defined so that it covers the areas of concern and gives enough marginal buffer area for puff transport and dispersion. A plot of the proposed meteorological modeling domain with respect to the Class I areas being modeled is also provided in

Figure 2-1. The computational domain will be set to extend at least 50 km in all directions beyond the Muskogee, Seminole, and Sooner Generating Stations and the Class I areas of interest. Note that the map projection for the modeling domain will be Lambert Conformal Conic (LCC) and the datum will be the World Geodetic System 84 (WGS-84). The reference point for the modeling domain is Latitude 40ºN, Longitude 97ºW. The southwest corner will be set to -951.547 km LCC, -1646.637 km LCC corresponding to Latitude 24.813 ºN and Longitude 87.778ºW. The meteorological grid spacing will be 4 km, resulting in 462 grid points in the X direction and 376 grid points in the Y direction.

FIGURE 2-1. REFINED METEOROLOGICAL MODELING DOMAIN



3. CALMET

The EPA Approved Version of the CALMET meteorological processor will be used to generate the meteorological data for CALPUFF. CALMET is the meteorological processor that compiles meteorological data from raw observations of surface and upper air conditions, precipitation measurements, mesoscale model output, and geophysical parameters into a single hourly, gridded data set for input into CALPUFF. CALMET will be used to assimilate data for 2001- 2003 using National Weather Service (NWS) surface station observations, upper air station observations, precipitation station observations, buoy station observations (for overwater areas), and mesoscale model output to develop the meteorological field.

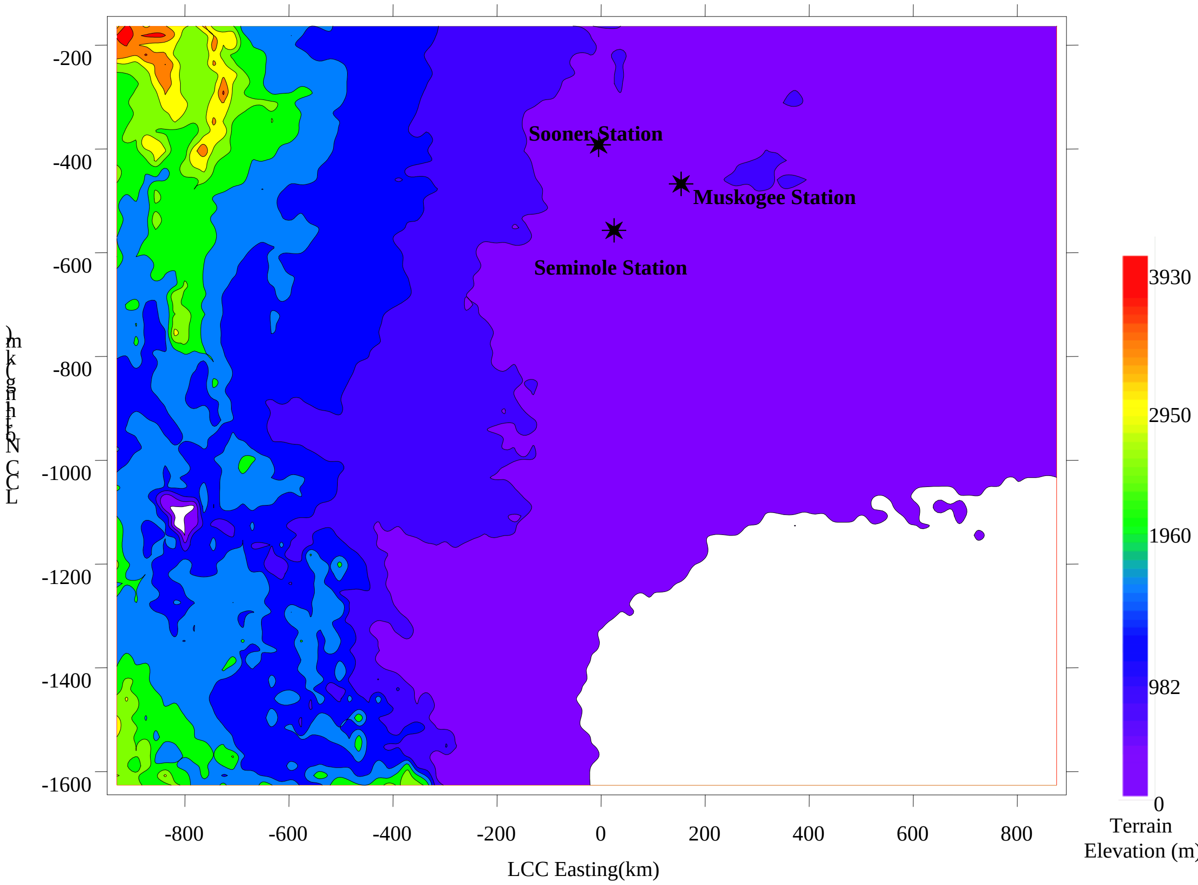
3.1 GEOPHYSICAL DATA

CALMET requires geophysical data to characterize the terrain and land use parameters that potentially affect dispersion. Terrain features affect flows and create turbulence in the atmosphere and are potentially subjected to higher concentrations of elevated puffs. Different land uses exhibit variable characteristics such as surface roughness, albedo, Bowen ratio, and leaf-area index that also effect turbulence and dispersion.

3.1.1 TERRAIN DATA

Terrain data will be obtained from the United States Geological Survey (USGS) in 1-degree (1:250,000 scale or approximately 90 meter resolution) digital format. The USGS terrain data will then be processed by the TERREL program to generate grid-cell elevation averages across the modeling domain. A plot of the land elevations based on the USGS data for the modeling domain is provided in Figure 3-1.

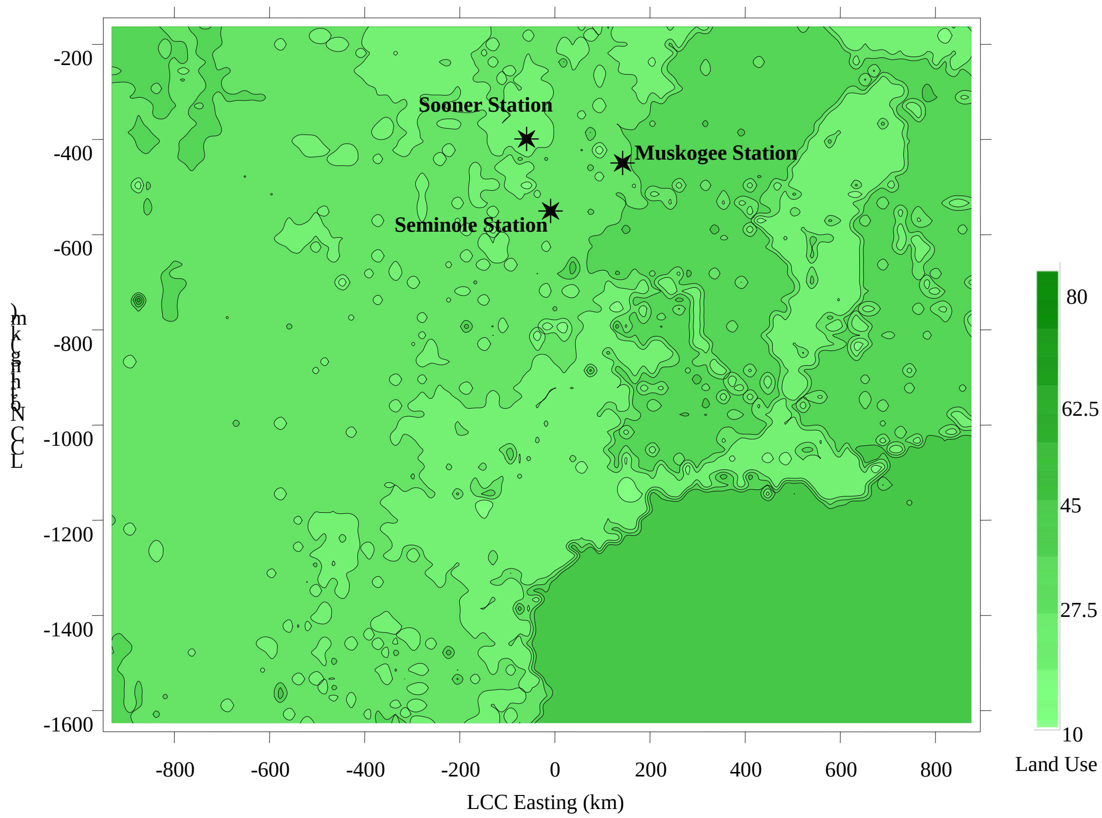
FIGURE 3-1. PLOT OF LAND ELEVATION USING USGS TERRAIN DATA



3.1.2 LAND USE DATA

The land use land cover (LULC) data from the USGS North American land cover characteristics data base in the Lambert Azimuthal equal area map projection will be used in order to determine the land use within the modeling domain. The LULC data will be processed by the CTGPROC program which will generate land use for each grid cell across the modeling domain. A plot of the land use based on the USGS data for the modeling domain is provided in Figure 3-2.

FIGURE 3-2. PLOT OF LAND USE USING USGS LULC DATA



3.1.3 COMPILING TERRAIN AND LAND USE DATA

The terrain data files output by the TERELL program and the LULC files output by the CTGPROC program will be uploaded into the MAKEGEO program to create a geophysical data file that will be input into CALMET.

3.2 METEOROLOGICAL DATA

CALMET will be used to assimilate data for 2001, 2002, and 2003 using mesoscale model output and National Weather Service (NWS) surface station observations, upper air station observations, precipitation station observations, and National Oceanic and Atmosphere Administrations (NOAA) buoy station observations to develop the meteorological field.

3.2.1 MESOSCALE MODEL METEOROLOGICAL DATA

Hourly mesoscale data will also be used as the initial guess field in developing the CALMET meteorological data. It is OG&E's intent to use the following 5th generation mesoscale model meteorological data sets (or MM5 data) in the analysis:

- 2001 MM5 data at 12 km resolution generated by the U.S. EPA
- 2002 MM5 data at 36 km resolution generated by the Iowa DNR

- 2003 MM5 data set at 36 km resolution generated by the Midwest RPO

The specific MM5 data that will be used are subsets of the data listed above. As the contractor to CENRAP for developing the meteorological data sets for the BART modeling, Alpine Geophysics extracted three subsets of MM5 data for each year from 2001 to 2003 from the data sets listed above using the CALMM5 extraction program. The three subsets covered the northern, central, and southern portions of CENRAP. TXI is proposing to use the southern set of the extracted MM5 data.

The 2001 southern subset of the extracted MM5 data includes 30 files that are broken into 10 to 11 day increments (3 files per month). The 2002 and 2003 southern subsets of extracted MM5 data include 12 files each of which are broken into 30 to 31 day increment files (1 file per month). Note that the 2001 to 2003 MM5 data extracted by Alpine Geophysics will not be able to be used directly in the modeling analysis. To run the Alpine Geophysics extracted MM data in the EPA approved CALMET program, each of the MM5 files will need to be adjusted by appending an additional six (6) hours, at a minimum, to the end of each file to account for the shift in time zones from the Greenwich Mean Time (GMT) prepared Alpine Geophysics data to Time Zone 6 for this analysis. No change to the data will occur.

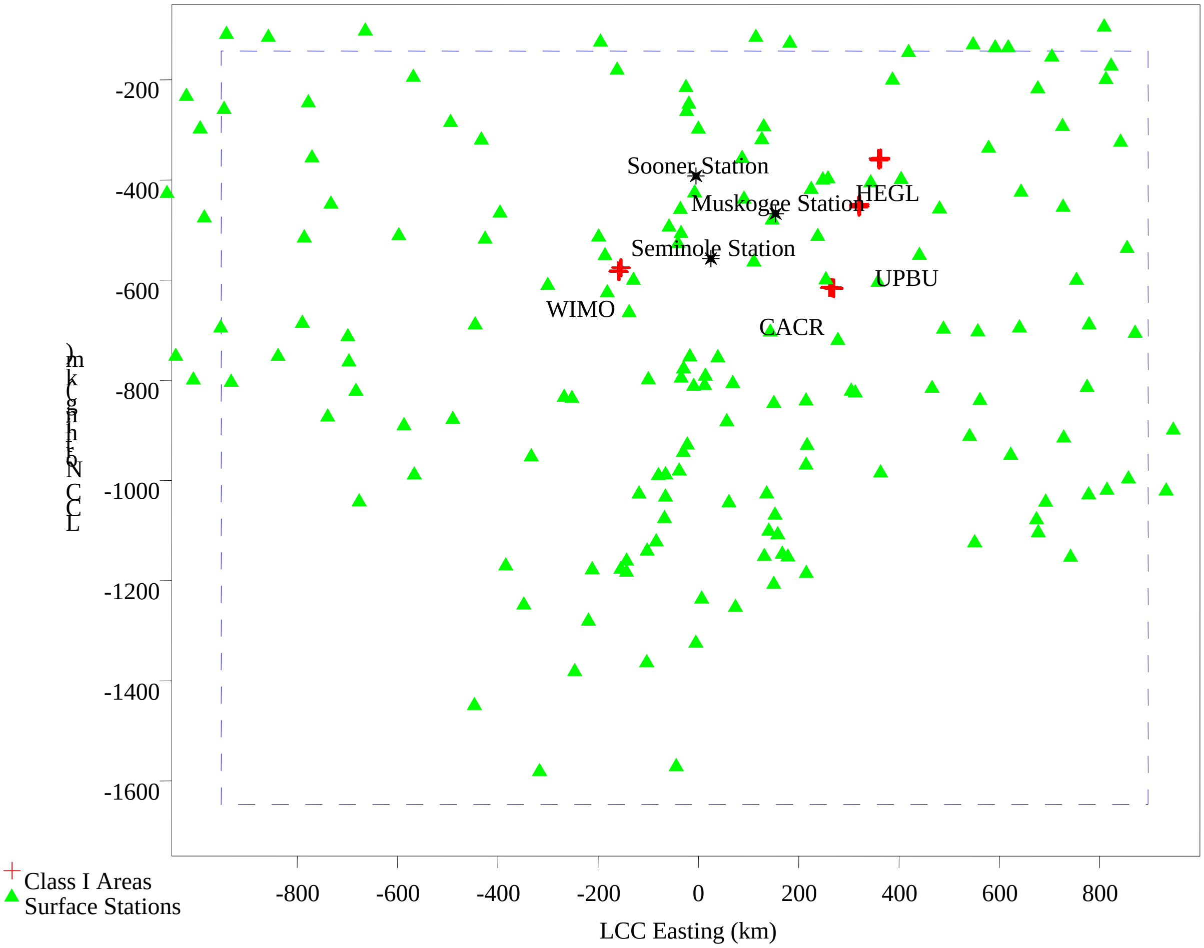
The time periods covered by the data in each of the MM5 files extracted by Alpine Geophysics include a specific number of calendar days, where the data starts at Hour 0 in GMT for the first calendar day and ends at Hour 23 in GMT on the last calendar day. In order to run CALMET in the local standard time (LST), which is necessary since the surface meteorological observations are recorded in LST, there must be hours of MM5 data referenced in a CALMET run that match the LST observation hours. Since the LST hours in Central Standard Time (CST) are 6 hours behind GMT, it is necessary to adjust the data in each MM5 file so that the time periods covered in the files match CST.

Based on the above discussion, the Alpine Geophysics MM5 data will not be used directly. Instead the data files will be modified to add 8 additional hours of data to the end of each file from the beginning of the subsequent file. CALMET will then be run using the appended MM5 data to generate a contiguous set of CALMET output files. The converted MM5 data files occupy approximately 1.2 terabytes (TB) of hard drive space.

3.2.2 SURFACE METEOROLOGICAL DATA

Parameters affecting turbulent dispersion that are observed hourly at surface stations include wind speed and direction, temperature, cloud cover and ceiling, relative humidity, and precipitation type. It is OG&E’s intent to use the surface stations listed in Table A-1 of Appendix A. The locations of the surface stations with respect to the modeling domain are shown in Figure 3-3. The stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA’s SMERGE program.

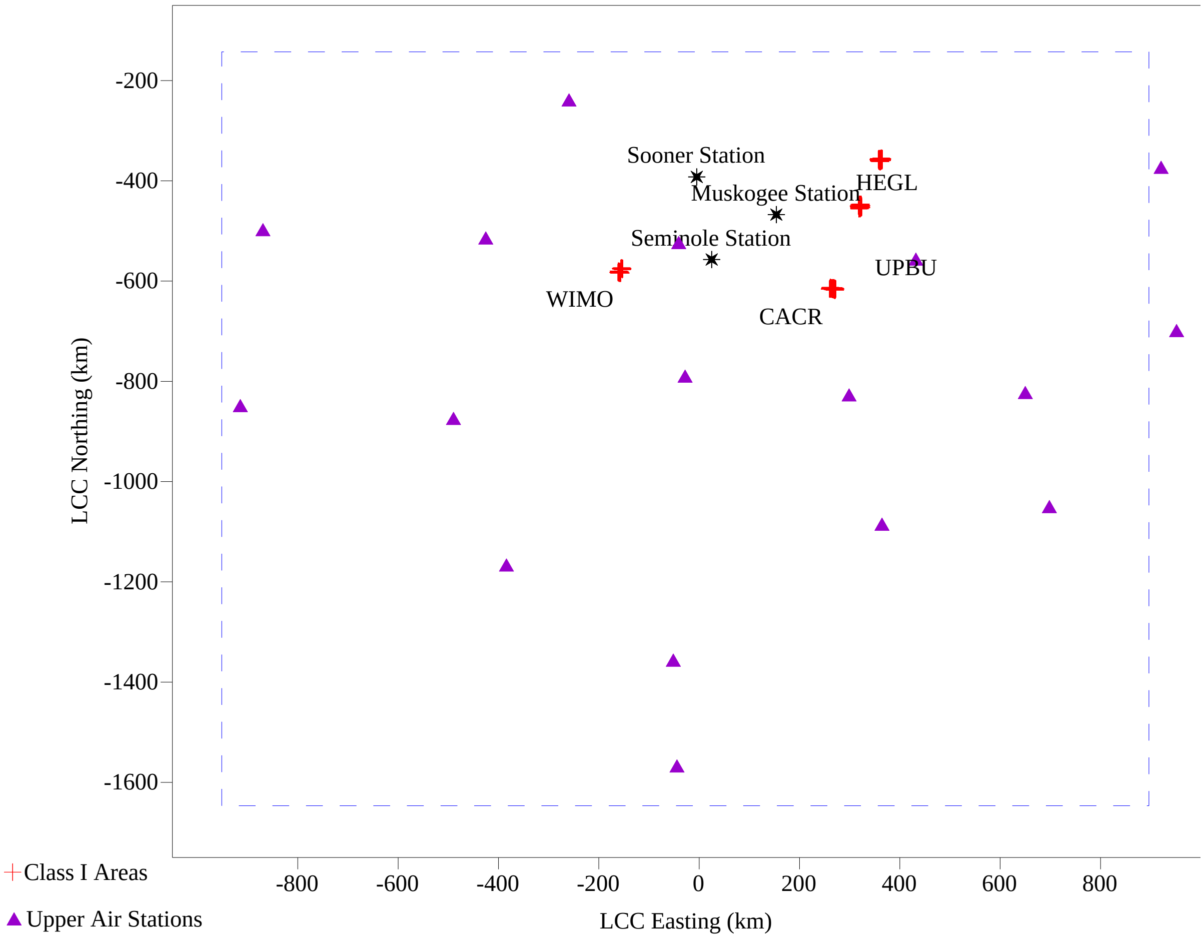
FIGURE 3-3. PLOT OF SURFACE STATION LOCATIONS



3.2.3 UPPER AIR METEOROLOGICAL DATA

Observations of meteorological conditions in the upper atmosphere provide a profile of turbulence from the surface through the depth of the boundary layer in which dispersion occurs. Upper air data are collected by balloons launched simultaneously across the observation network at 0000 Greenwich Mean Time (GMT) (6 o'clock PM in Oklahoma) and 1200 GMT (6 o'clock AM in Oklahoma). Sensors observe pressure, wind speed and direction, and temperature (among other parameters) as the balloon rises through the atmosphere. The upper air observation network is less dense than surface observation points since upper air conditions vary less and are generally not as affected by local effects (e.g., terrain or water bodies). The upper air stations that are proposed for this analysis are listed in Table A-2 of Appendix A. The locations of the upper air stations with respect to the modeling domain are shown in Figure 3-4. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA's READ62 program.

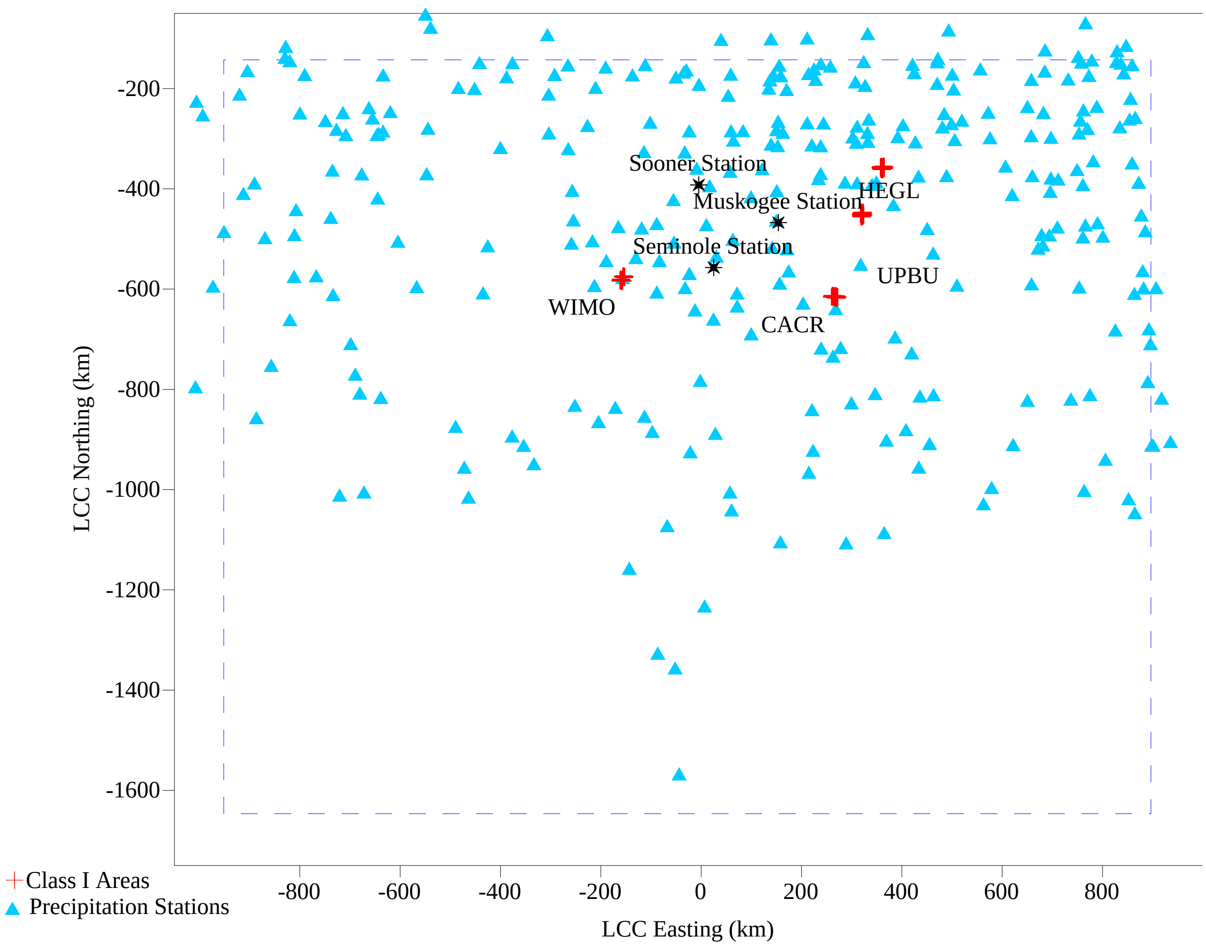
FIGURE 3-4. PLOT OF UPPER AIR STATIONS LOCATIONS



3.2.4 PRECIPITATION METEOROLOGICAL DATA

The effects of chemical transformation and deposition processes on ambient pollutant concentrations will be considered in this analysis. Therefore, it is necessary to include observations of precipitation in the CALMET analysis. The precipitation stations that are proposed for this analysis are listed in Table A-3 of Appendix A. The locations of the precipitation stations with respect to the modeling domain are shown in Figure 3-5. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA's PMERGE program.

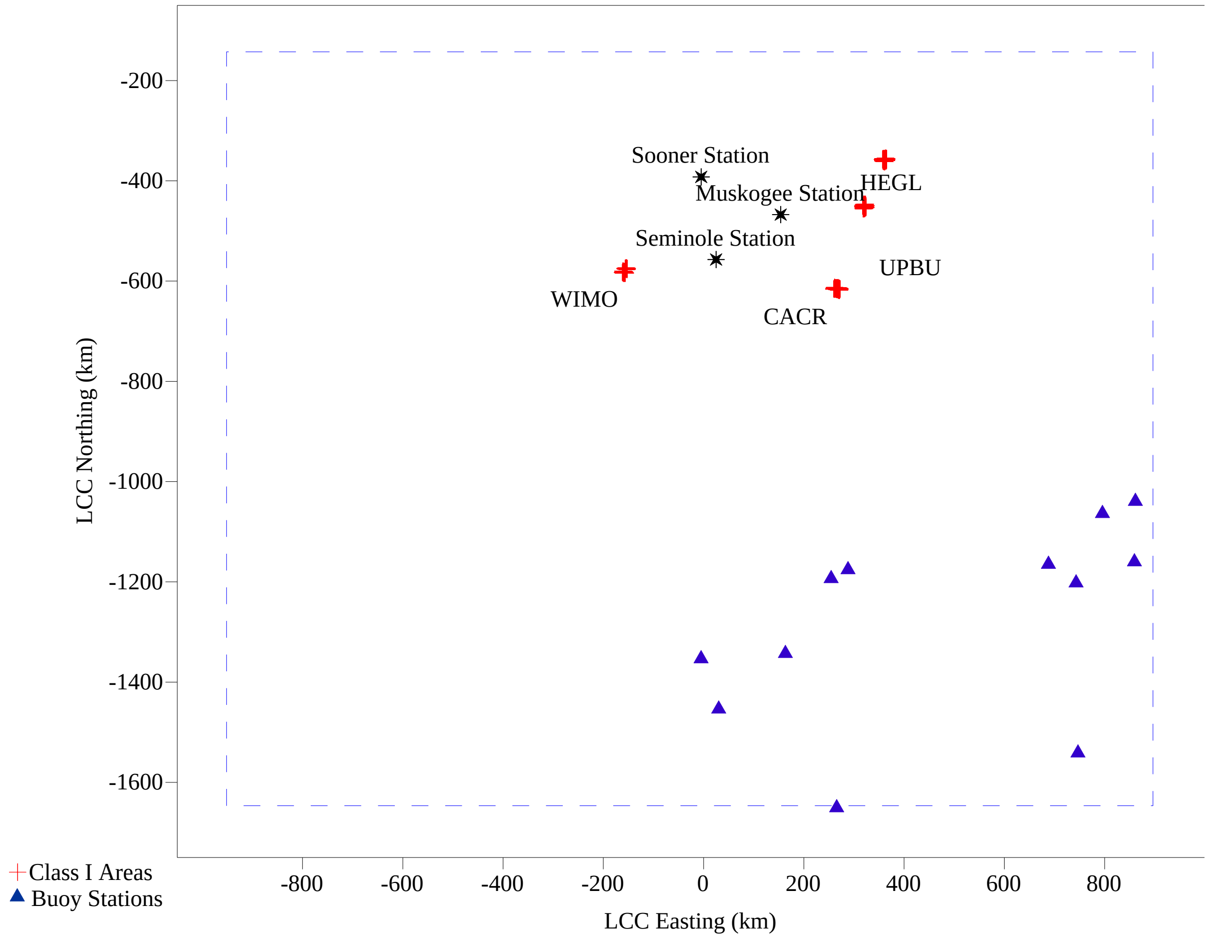
FIGURE 3-5. PLOT OF PRECIPITATION METEOROLOGICAL STATIONS



3.2.5 BUOY METEOROLOGICAL DATA

The effects of land/sea breeze on ambient pollutant concentrations will be considered in this analysis. Therefore, it is necessary to include observations of buoy stations in the CALMET analysis. The buoy stations that are proposed for this analysis are listed in Table A-4 of Appendix A. The locations of the buoy stations with respect to the modeling domain are shown in Figure 3-6. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain along the coastline. Data from the stations will be prepared by filling missing hour records with the CALMET missing parameter value (9999). No adjustments to the data will occur.

FIGURE 3-6. PLOT OF BUOY METEOROLOGICAL STATIONS



3.3 CALMET CONTROL PARAMETERS

Appendix B provides a sample CALMET input file used in OG&E's modeling analysis. A few details of the CALMET model setup for sensitive parameters are also discussed below.

3.3.1 VERTICAL METEOROLOGICAL PROFILE

The height of the top vertical layer will be set to 3,500 meters. This height corresponds to the top sounding pressure level for which upper air observation data will be relied upon. The vertical dimension of the domain will be divided into 12 layers with the maximum elevations for each layer shown in Table 3-1. The vertical dimensions are weighted towards the surface to resolve the mixing layer while using a somewhat coarser resolution for the layers aloft.

TABLE 3-1. VERTICAL LAYERS OF THE CALMET METEOROLOGICAL DOMAIN

Layer	Elevation (m)
1	20
2	40
3	60
4	80
5	100
6	150
7	200
8	250
9	500
10	1000
11	2000
12	3500

CALMET allows for a bias value to be applied to each of the vertical layers. The bias settings for each vertical layer determine the relative weight given to the vertically extrapolated surface and upper air wind and temperature observations. The initial guess fields are computed with an inverse distance weighting ($1/r^2$) of the surface and upper air data. The initial guess fields may be modified by a layer dependent bias factor. Values for the bias factor may range from -1 to +1. A bias of -1 eliminates upper-air observations in the $1/r^2$ interpolations used to initialize the vertical wind fields. Conversely, a bias of +1 eliminates the surface observations in the interpolations for this layer. Normally, bias is set to zero (0) for each vertical layer, such that the upper air and surface observations are given equal weight in the $1/r^2$ interpolations. The biases for each layer of the proposed modeling domain will be set to zero.

CALMET allows for vertical extrapolation of surface wind observations to layers aloft to be skipped if the surface station is close to the upper air station. Alternatively, CALMET allows data from all surface stations to be extrapolated. The CALMET parameter that controls this setting is IEXTRP. Setting IEXTRP to a value less than zero (0) means that layer 1 data from upper air soundings is ignored in any vertical extrapolations. IEXTRP will be set to -4 for this analysis (i.e., the similarity theory is used to extrapolate the surface winds into the layers aloft, which provides more information on observed local effects to the upper layers).

3.3.2 INFLUENCES OF OBSERVATIONS

Step 1 wind fields will be based on an initial guess using MM5 data and refined to reflect terrain affects. Step 2 wind fields will adjust the Step 1 wind field by incorporating the influence of local observations. An inverse distance method is used to determine the influence of observations to the Step 1 wind field. RMAX1 and RMAX2 define the radius of influence for data from surface stations to land in the surface layer and data from upper air stations to land in the layers aloft. In general, RMAX1 and RMAX2 are used to exclude observations from being inappropriately included in the development of the Step 2 wind field if the distance from an observation station to a grid point exceeds the maximum radius of influence.

If the distance from an observation station to a grid point is less than the value set for RMAX, the observation data will be used in the development of the Step 2 wind field. R1 represents the distance from a surface observation station at which the surface observation and the Step 1 wind field are weighted equally. R2 represents the comparable distance for winds aloft. R1 and R2 are used to weight the observation data with respect to the MM5 data that was used to generate the Step 1 wind field. Large values for R1 and R2 give more weight to the observations, where as small values give more weight to the MM5 data.

In this BART modeling analysis, RMAX 1 will be set to 20 km, and R1 will be set to 10 km. This will limit the influence of the surface observation data from all surface stations to 20 km from each station, and will equally weight the MM5 and observation data at 10 km. RMAX2 will be set to 50 km, and R2 will be set to 25 km. This will limit the influence of the upper air observation data from all surface stations to 50 km from each station, and will equally weight the MM5 and observation data at 25 km. These settings of radius of influence will allow for adequate weighting of the MM5 data and the observation data across the modeling domain due to the vast domain to be modeled. RAMX 3 will be set to 500 km.

TABLE A-1. LIST OF SURFACE METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	KDYS	69019	-267.672	-834.095	96.9968	39.9925
2	KNPA	72222	932.565	-1020.909	97.0110	39.9908
3	KBFM	72223	857.471	-996.829	97.0101	39.9910
4	KGZH	72227	946.767	-899.515	97.0112	39.9919
5	KTCL	72228	870.843	-706.104	97.0103	39.9936
6	KNEW	53917	674.172	-1078.342	97.0080	39.9903
7	KNBG	12958	677.719	-1104.227	97.0080	39.9900
8	BVE	12884	741.996	-1153.463	97.0088	39.9896
9	KPTN	72232	550.88	-1124.295	97.0065	39.9898
10	KMEI	13865	774.911	-814.225	97.0092	39.9926
11	KPIB	72234	728.416	-915.165	97.0086	39.9917
12	KGLH	72235	557.072	-703.097	97.0066	39.9936
13	KHEZ	11111	540.777	-912.22	97.0064	39.9918
14	KMCB	11112	622.755	-949.618	97.0074	39.9914
15	KGWO	11113	640.102	-695.286	97.0076	39.9937
16	KASD	72236	692.381	-1043.261	97.0082	39.9906
17	KPOE	72239	363.294	-984.839	97.0043	39.9911
18	KBAZ	72241	-102.133	-1140.886	96.9988	39.9897
19	KGLS	72242	215.108	-1185.604	97.0025	39.9893
20	KDWH	11114	140.413	-1101.174	97.0017	39.9900
21	KIAH	12960	158.266	-1108.37	97.0019	39.9900
22	KHOU	72243	167.147	-1147.402	97.0020	39.9896
23	KEFD	12906	178.551	-1152.782	97.0021	39.9896
24	KCXO	72244	152.739	-1069.309	97.0018	39.9903
25	KCLL	11115	60.898	-1044.381	97.0007	39.9906
26	KLFK	93987	214.643	-969.355	97.0025	39.9912
27	KUTS	11116	136.056	-1026.773	97.0016	39.9907
28	KTYR	11117	150.451	-846.207	97.0018	39.9924
29	KCRS	72246	56.655	-882.642	97.0007	39.9920
30	KGGG	72247	214.572	-841.163	97.0025	39.9924
31	KGKY	11118	-9.365	-812.25	96.9999	39.9927
32	KDTN	72248	304.827	-821.713	97.0036	39.9926
33	KBAD	11119	312.743	-825.101	97.0037	39.9925
34	KMLU	11120	465.834	-816.211	97.0055	39.9926
35	KTVR	11121	561.446	-840.225	97.0066	39.9924
36	KTRL	11122	68.599	-806.417	97.0008	39.9927
37	KOCH	72249	216.81	-930.252	97.0026	39.9916
38	KBRO	12919	-44.167	-1571.387	96.9995	39.9858

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
39	KALI	72251	-103.012	-1363.74	96.9988	39.9877
40	KLRD	12920	-246.548	-1381.603	96.9971	39.9875
41	KSSF	72252	-143.386	-1183.35	96.9983	39.9893
42	KRKP	11123	-4.965	-1324.914	96.9999	39.9880
43	KCOT	11124	-219.097	-1280.964	96.9974	39.9884
44	KLBX	11125	150.245	-1207.466	97.0018	39.9891
45	KSAT	12921	-143.024	-1160.935	96.9983	39.9895
46	KHDO	12962	-211.702	-1178.172	96.9975	39.9894
47	KSKF	72253	-154.625	-1177.555	96.9982	39.9894
48	KHYI	11126	-84.156	-1122.487	96.9990	39.9899
49	KTKI	72254	38.788	-754.791	97.0005	39.9932
50	KBMQ	11127	-118.39	-1027.031	96.9986	39.9907
51	KATT	11128	-67.587	-1075.97	96.9992	39.9903
52	KSGR	11129	131.478	-1151.702	97.0016	39.9896
53	KGTU	11130	-65.624	-1033.173	96.9992	39.9907
54	KVCT	12912	6.587	-1236.788	97.0001	39.9888
55	KPSX	72255	73.878	-1253.33	97.0009	39.9887
56	KACT	13959	-22.12	-929.156	96.9997	39.9916
57	KPWG	72256	-30.147	-944.073	96.9996	39.9915
58	KILE	72257	-65.288	-988.507	96.9992	39.9911
59	KGRK	11131	-79.643	-990.173	96.9991	39.9911
60	KTPL	11132	-38.203	-981.19	96.9996	39.9911
61	KPRX	13960	143.317	-703.663	97.0017	39.9936
62	KDTO	72258	-17.018	-752.974	96.9998	39.9932
63	KAFW	11133	-29.564	-777.061	96.9997	39.9930
64	KFTW	72259	-34.302	-795.502	96.9996	39.9928
65	KMWL	11134	-99.769	-798.767	96.9988	39.9928
66	KRBD	11135	12.453	-810.467	97.0002	39.9927
67	KDRT	11136	-384.069	-1170.59	96.9955	39.9894
68	KFST	22010	-566.418	-988.838	96.9933	39.9911
69	KGDP	72261	-739.127	-873.302	96.9913	39.9921
70	KSJT	72262	-333.338	-952.54	96.9961	39.9914
71	KMRF	23034	-676.265	-1042.616	96.9920	39.9906
72	KMAF	72264	-489.668	-878.107	96.9942	39.9921
73	KINK	23023	-586.882	-890.654	96.9931	39.9920
74	KABI	72265	-252.044	-836.353	96.9970	39.9924
75	KLBB	13962	-445.006	-689.313	96.9948	39.9938
76	KATS	11137	-696.818	-763.258	96.9918	39.9931
77	KCQC	11138	-785.757	-515.724	96.9907	39.9953
78	KROW	23009	-698.822	-712.898	96.9918	39.9936
79	KSRR	72268	-789.593	-686.226	96.9907	39.9938
80	KCNM	11139	-682.79	-822.109	96.9919	39.9926
81	KALM	36870	-838.056	-752.338	96.9901	39.9932
82	KLRU	72269	-931.527	-804.112	96.9890	39.9927
83	KTCS	72271	-952.353	-695.469	96.9888	39.9937

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
84	KSVC	93063	-1042.03	-752.033	96.9877	39.9932
85	KDMN	72272	-1006.77	-799.231	96.9881	39.9928
86	KMSL	72323	854.846	-536.687	97.0101	39.9952
87	KPOF	72330	578.62	-336.733	97.0068	39.9970
88	KGTR	11140	779.065	-689.108	97.0092	39.9938
89	KTUP	93862	753.875	-600.337	97.0089	39.9946
90	KMKL	72334	727.051	-454.383	97.0086	39.9959
91	KLRF	72340	440.654	-550.661	97.0052	39.9950
92	KHKA	11141	643.365	-424.419	97.0076	39.9962
93	KHOT	72341	358.094	-604.603	97.0042	39.9945
94	KTXK	11142	278.022	-720.623	97.0033	39.9935
95	KLLQ	72342	488.655	-698.008	97.0058	39.9937
96	KMWT	72343	254.18	-599.224	97.0030	39.9946
97	KFSM	13964	237.97	-512.87	97.0028	39.9954
98	KSLG	72344	224.881	-419.064	97.0027	39.9962
99	KVBT	11143	248.074	-399.892	97.0029	39.9964
100	KHRO	11144	343.525	-405.601	97.0041	39.9963
101	KFLP	11145	404.239	-399.142	97.0048	39.9964
102	KBVX	11146	480.712	-457.853	97.0057	39.9959
103	KROG	11147	258.44	-397.685	97.0031	39.9964
104	KSPS	13966	-138.053	-664.886	96.9984	39.9940
105	KHBR	72352	-186.121	-551.123	96.9978	39.9950
106	KCSM	11148	-198.844	-513.911	96.9977	39.9954
107	KFDR	11149	-181.653	-625.205	96.9979	39.9944
108	KGOK	72353	-35.905	-458.97	96.9996	39.9959
109	KTIK	72354	-34.581	-506.938	96.9996	39.9954
110	KPWA	11150	-58.596	-493.951	96.9993	39.9955
111	KSWO	11151	-7.42	-425.828	96.9999	39.9962
112	KMKO	72355	146.972	-479.879	97.0017	39.9957
113	KRVS	72356	91.059	-438.276	97.0011	39.9960
114	KBVO	11152	87.136	-357.069	97.0010	39.9968
115	KMLC	11153	110.647	-563.566	97.0013	39.9949
116	KOUN	72357	-40.731	-527.298	96.9995	39.9952
117	KLAW	11154	-129.405	-600.222	96.9985	39.9946
118	KCDS	72360	-300.297	-610.668	96.9965	39.9945
119	KGNT	72362	-985.117	-475.563	96.9884	39.9957
120	KGUP	11155	-1059.48	-427.151	96.9875	39.9961
121	KAMA	23047	-425.319	-518.171	96.9950	39.9953
122	KBGD	72363	-395.603	-466.083	96.9953	39.9958
123	KFMN	72365	-993.449	-297.944	96.9883	39.9973
124	KSKX	72366	-770.464	-355.855	96.9909	39.9968
125	KTCC	23048	-597.271	-511.241	96.9930	39.9954
126	KLVS	23054	-732.565	-448.329	96.9914	39.9960
127	KEHR	72423	812.573	-199.695	97.0096	39.9982
128	KEVV	93817	822.929	-172.715	97.0097	39.9984

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
129	KMVN	72433	704.666	-154.54	97.0083	39.9986
130	KMDH	11156	676.745	-218.041	97.0080	39.9980
131	KBLV	11157	617.659	-136.018	97.0073	39.9988
132	KSUS	3966	547.898	-130.122	97.0065	39.9988
133	KPAH	3816	725.985	-293.319	97.0086	39.9974
134	KJEF	72445	419.01	-145.496	97.0050	39.9987
135	KAIZ	11158	387.096	-200.609	97.0046	39.9982
136	KIXD	72447	182.322	-126.913	97.0022	39.9989
137	KWLD	72450	0	-298.57	97.0000	39.9973
138	KAAO	11159	-18.976	-248.773	96.9998	39.9978
139	KIAB	11160	-23.392	-263.471	96.9997	39.9976
140	KEWK	11161	-24.645	-215.58	96.9997	39.9981
141	KGBD	72451	-161.892	-180.781	96.9981	39.9984
142	KHYS	11162	-195.191	-124.723	96.9977	39.9989
143	KCFV	11163	126.442	-319.698	97.0015	39.9971
144	KFOE	72456	114.618	-115.26	97.0014	39.9990
145	KEHA	72460	-432.761	-320.089	96.9949	39.9971
146	KALS	72462	-777.592	-245.892	96.9908	39.9978
147	KDRO	11164	-945.713	-259.163	96.9888	39.9977
148	KLHX	72463	-568.426	-195.178	96.9933	39.9982
149	KSPD	2128	-494.076	-285.176	96.9942	39.9974
150	KCOS	93037	-664.022	-102.596	96.9922	39.9991
151	KGUC	72467	-857.452	-115.301	96.9899	39.9990
152	KMTJ	93013	-940.981	-109.358	96.9889	39.9990
153	KCEZ	72476	-1020.87	-233.14	96.9880	39.9979
154	KCPS	72531	591.652	-136.14	97.0070	39.9988
155	KLWV	72534	808.939	-94.46	97.0096	39.9992
156	KPPF	74543	130.433	-293.855	97.0015	39.9973
157	KHOP	74671	841.751	-324.569	97.0099	39.9971
158	KBIX	74768	778.252	-1028.514	97.0092	39.9907
159	KPQL	11165	814.599	-1019.583	97.0096	39.9908
160	MMPG	76243	-348.007	-1248.779	96.9959	39.9887
161	MMMV	76342	-446.576	-1449.334	96.9947	39.9869
162	MMMY	76394	-316.664	-1581.176	96.9963	39.9857

TABLE A-2. LIST OF UPPER AIR METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	KABQ	23050	-869.46	-501.713	96.9897	39.9955
2	KAMA	23047	-425.319	-518.171	96.9950	39.9953
3	KBMX	53823	951.609	-702.935	97.0112	39.9936
4	KBNA	13897	920.739	-377.164	97.0109	39.9966
5	KBRO	12919	-44.167	-1571.39	96.9995	39.9858
6	KCRP	12924	-51.535	-1360.35	96.9994	39.9877
7	KDDC	13985	-259.352	-242.681	96.9969	39.9978
8	KDRT	22010	-384.069	-1170.59	96.9955	39.9894
9	KEPZ	3020	-914.558	-852.552	96.9892	39.9923
10	KFWD	3990	-28.034	-793.745	96.9997	39.9928
11	KJAN	3940	650.105	-826.452	97.0077	39.9925
12	KLCH	3937	364.461	-1089.15	97.0043	39.9902
13	KLZK	3952	432.063	-560.441	97.0051	39.9949
14	KMAF	23023	-489.668	-878.107	96.9942	39.9921
15	KOUN	3948	-40.731	-527.298	96.9995	39.9952
16	KSHV	13957	298.869	-831.166	97.0035	39.9925
17	KSIL	53813	698.079	-1054.03	97.0082	39.9905

TABLE A-3. LIST OF PRECIPITATION METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	ADDI	10063	906.825	-601.428	97.0107	39.9946
2	ALBE	10140	917.606	-821.64	97.0108	39.9926
3	BERR	10748	892.454	-683.388	97.0105	39.9938
4	HALE	13620	881.928	-601.878	97.0104	39.9946
5	HAMT	13645	863.663	-612.725	97.0102	39.9945
6	JACK	14193	898.014	-915.623	97.0106	39.9917
7	MBLE	15478	851.953	-1022.41	97.0101	39.9908
8	MUSC	15749	880.113	-567.484	97.0104	39.9949
9	PETE	16370	935.558	-908.259	97.0110	39.9918
10	THOM	18178	900.858	-915.326	97.0106	39.9917
11	TUSC	18385	895.631	-713.223	97.0106	39.9936
12	VERN	18517	825.585	-685.773	97.0098	39.9938
13	BEEB	30530	462.394	-532.485	97.0055	39.9952
14	BRIG	30900	318.015	-554.857	97.0038	39.9950
15	CALI	31140	419.619	-731.44	97.0050	39.9934
16	CAMD	31152	386.546	-699.659	97.0046	39.9937
17	DIER	32020	268.114	-643.184	97.0032	39.9942
18	EURE	32356	286.738	-390.862	97.0034	39.9965
19	GILB	32794	383.362	-435.625	97.0045	39.9961
20	GREE	32978	450.594	-483.201	97.0053	39.9956
21	STUT	36920	509.943	-596.328	97.0060	39.9946
22	TEXA	37048	278.022	-720.623	97.0033	39.9935
23	ALAM	50130	-749.044	-267.856	96.9912	39.9976
24	ARAP	50304	-441.903	-152.324	96.9948	39.9986
25	COCH	51713	-819.794	-148.582	96.9903	39.9987
26	CRES	51959	-828.107	-119.911	96.9902	39.9989
27	GRAN	53477	-451.781	-203.82	96.9947	39.9982
28	GUNN	53662	-829.573	-141.995	96.9902	39.9987
29	HUGO	54172	-539.364	-81.948	96.9936	39.9993
30	JOHN	54388	-483.95	-201.915	96.9943	39.9982
31	KIM	54538	-544.501	-283.337	96.9936	39.9974
32	MESA	55531	-993.391	-256.696	96.9883	39.9977
33	ORDW	56136	-549.552	-55.741	96.9935	39.9995
34	OURA	56203	-904.197	-168.246	96.9893	39.9985
35	PLEA	56591	-1005.94	-229.472	96.9881	39.9979
36	PUEB	56740	-633.961	-176.872	96.9925	39.9984
37	TYE	57320	-662.095	-242.254	96.9922	39.9978
38	SAGU	57337	-790.269	-176.061	96.9907	39.9984

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
39	SANL	57428	-726.777	-285.47	96.9914	39.9974
40	SHEP	57572	-714.046	-252.189	96.9916	39.9977
41	TELL	58204	-920.205	-215.382	96.9891	39.9981
42	TERC	58220	-708.229	-296.023	96.9916	39.9973
43	TRIN	58429	-642.489	-293.805	96.9924	39.9973
44	TRLK	58436	-646.185	-295.727	96.9924	39.9973
45	WALS	58781	-654.989	-262.821	96.9923	39.9976
46	WHIT	58997	-619.615	-250.12	96.9927	39.9977
47	ASHL	110281	684.787	-169.285	97.0081	39.9985
48	CAIR	111166	697.177	-301.436	97.0082	39.9973
49	CARM	111302	772.938	-177.782	97.0091	39.9984
50	CISN	111664	758.146	-151.446	97.0090	39.9986
51	FLOR	113109	751.801	-139.837	97.0089	39.9987
52	HARR	113879	762.044	-246.62	97.0090	39.9978
53	KASK	114629	650.464	-239.886	97.0077	39.9978
54	LAWR	114957	829.038	-128.708	97.0098	39.9988
55	MTCA	115888	827.797	-149.966	97.0098	39.9986
56	MURP	115983	682.261	-251.649	97.0081	39.9977
57	NEWT	116159	766.098	-72.902	97.0090	39.9993
58	REND	117187	731.633	-185.058	97.0086	39.9983
59	SMIT	118020	770.027	-283.638	97.0091	39.9974
60	SPAR	118147	658.275	-185.973	97.0078	39.9983
61	VAND	118781	685.449	-127.048	97.0081	39.9989
62	WEST	119193	778.655	-147.215	97.0092	39.9987
63	EVAN	122738	842.476	-172.871	97.0100	39.9984
64	NEWB	126151	855.854	-223.713	97.0101	39.9980
65	PRIN	127125	836.901	-153.449	97.0099	39.9986
66	STEN	128442	859.099	-156.613	97.0101	39.9986
67	JTML	128967	788.703	-239.572	97.0093	39.9978
68	ARLI	140326	-101.734	-271.373	96.9988	39.9976
69	BAZI	140620	-210.423	-201.758	96.9975	39.9982
70	BEAU	140637	59.762	-288.39	97.0007	39.9974
71	BONN	140957	211.236	-103.29	97.0025	39.9991
72	CALD	141233	-32.689	-330.586	96.9996	39.9970
73	CASS	141351	54.006	-217.645	97.0006	39.9980
74	CENT	141404	170.503	-206.038	97.0020	39.9981
75	CHAN	141427	150.257	-286.094	97.0018	39.9974
76	CLIN	141612	155.623	-157.682	97.0018	39.9986
77	COLL	141730	-265.465	-156.95	96.9969	39.9986
78	COLU	141740	220.541	-316.555	97.0026	39.9971

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
79	CONC	141867	58.918	-175.589	97.0007	39.9984
80	DODG	142164	-226.497	-277.655	96.9973	39.9975
81	ELKH	142432	-400.112	-321.784	96.9953	39.9971
82	ENGL	142560	-264.927	-324.066	96.9969	39.9971
83	ERIE	142582	162.669	-291.383	97.0019	39.9974
84	FALL	142686	83.491	-288.177	97.0010	39.9974
85	GALA	142938	-136.931	-176.83	96.9984	39.9984
86	GARD	142980	-304.059	-215.308	96.9964	39.9981
87	GREN	143248	64.308	-307.161	97.0008	39.9972
88	HAYS	143527	-190.307	-161.342	96.9978	39.9985
89	HEAL	143554	-292.133	-175.921	96.9966	39.9984
90	HILL	143686	214.018	-174.006	97.0025	39.9984
91	INDE	143954	139.335	-315.058	97.0016	39.9972
92	IOLA	143984	153.451	-269.438	97.0018	39.9976
93	JOHR	144104	134.784	-203.41	97.0016	39.9982
94	KANO	144178	-50.289	-181.177	96.9994	39.9984
95	KIOW	144341	-113.967	-329.843	96.9987	39.9970
96	MARI	145039	-4.343	-195.712	97.0000	39.9982
97	MELV	145210	137.104	-186.781	97.0016	39.9983
98	MILF	145306	39.504	-106.05	97.0005	39.9990
99	MOUD	145536	152.624	-318.136	97.0018	39.9971
100	OAKL	145888	-306.378	-96.814	96.9964	39.9991
101	OTTA	146128	158.639	-178.635	97.0019	39.9984
102	POMO	146498	143.864	-176.707	97.0017	39.9984
103	SALI	147160	-29.426	-166.908	96.9997	39.9985
104	SMOL	147551	-34.639	-171.31	96.9996	39.9985
105	STAN	147756	225.026	-164.85	97.0027	39.9985
106	SUBL	147922	-303.514	-292.808	96.9964	39.9974
107	TOPE	148167	139.116	-104.91	97.0016	39.9991
108	TRIB	148235	-387.855	-180.643	96.9954	39.9984
109	UNIO	148293	211.43	-272.537	97.0025	39.9975
110	WALL	148535	-376.076	-152.432	96.9956	39.9986
111	WICH	148830	-23.729	-288.579	96.9997	39.9974
112	WILS	148946	-111.502	-156.22	96.9987	39.9986
113	BENT	150611	781.608	-348.109	97.0092	39.9969
114	CALH	151227	865.268	-261.635	97.0102	39.9976
115	CLTN	151631	749.287	-365.634	97.0088	39.9967
116	HERN	153798	859.01	-352.458	97.0101	39.9968
117	MADI	155067	854.116	-265.064	97.0101	39.9976
118	PADU	156110	753.185	-293.024	97.0089	39.9974

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
119	PCTN	156580	834.464	-280.496	97.0099	39.9975
120	ALEX	160103	433.824	-959.253	97.0051	39.9913
121	BATN	160549	562.794	-1032.4	97.0066	39.9907
122	CALH	161411	436.113	-817.451	97.0052	39.9926
123	CLNT	161899	578.969	-999.986	97.0068	39.9910
124	JENA	164696	455.225	-912.366	97.0054	39.9918
125	LACM	165078	364.784	-1089.92	97.0043	39.9901
126	MIND	166244	346.708	-812.651	97.0041	39.9927
127	MONR	166314	463.225	-814.905	97.0055	39.9926
128	NATC	166582	369.451	-905.316	97.0044	39.9918
129	SHRE	168440	299.526	-831.143	97.0035	39.9925
130	WINN	169803	408.309	-884.596	97.0048	39.9920
131	BROK	221094	621.827	-914.236	97.0073	39.9917
132	CONE	221900	737.007	-823.513	97.0087	39.9926
133	JAKS	224472	650.361	-826.097	97.0077	39.9925
134	LEAK	224966	805.886	-943.78	97.0095	39.9915
135	MERI	225776	774.942	-814.558	97.0092	39.9926
136	SARD	227815	658.33	-593.661	97.0078	39.9946
137	SAUC	227840	763.399	-1005.93	97.0090	39.9909
138	TUPE	229003	753.571	-600.03	97.0089	39.9946
139	ADVA	230022	657.892	-298.102	97.0078	39.9973
140	ALEY	230088	505.348	-305.864	97.0060	39.9972
141	BOLI	230789	331.651	-291.689	97.0039	39.9974
142	CASV	231383	310.855	-392.187	97.0037	39.9965
143	CLER	231674	575.868	-302.209	97.0068	39.9973
144	CLTT	231711	307.465	-190.83	97.0036	39.9983
145	COLU	231791	421.287	-155.672	97.0050	39.9986
146	DREX	232331	228.23	-185.776	97.0027	39.9983
147	ELM	232568	257.758	-159.419	97.0030	39.9986
148	FULT	233079	470.408	-150.668	97.0056	39.9986
149	HOME	233999	619.93	-415.469	97.0073	39.9962
150	JEFF	234271	424.774	-172.095	97.0050	39.9984
151	JOPL	234315	238.245	-318.262	97.0028	39.9971
152	LEBA	234825	402.239	-276.263	97.0048	39.9975
153	LICK	234919	480.849	-280.775	97.0057	39.9975
154	LOCK	235027	302.048	-300.612	97.0036	39.9973
155	MALD	235207	659.982	-377.876	97.0078	39.9966
156	MARS	235298	332.062	-94.655	97.0039	39.9991
157	MAFD	235307	391.968	-300.033	97.0046	39.9973
158	MCES	235415	471.737	-143.942	97.0056	39.9987

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
159	MILL	235594	309.516	-311.398	97.0037	39.9972
160	MTGV	235834	426.937	-310.43	97.0050	39.9972
161	NVAD	235987	243.915	-272.715	97.0029	39.9975
162	OZRK	236460	349.133	-390.626	97.0041	39.9965
163	PDTD	236777	334.055	-265.018	97.0039	39.9976
164	POTO	236826	572.215	-251.455	97.0068	39.9977
165	ROLL	237263	484.503	-253.958	97.0057	39.9977
166	ROSE	237300	500.59	-175.393	97.0059	39.9984
167	SALE	237506	498.94	-274.122	97.0059	39.9975
168	SENE	237656	233.959	-383.703	97.0028	39.9965
169	SPRC	237967	238.112	-373.616	97.0028	39.9966
170	SPVL	237976	332.385	-309.374	97.0039	39.9972
171	STEE	238043	503.354	-205.135	97.0059	39.9981
172	STOK	238082	310.911	-279.239	97.0037	39.9975
173	SWSP	238223	324.053	-150.325	97.0038	39.9986
174	TRKD	238252	340.418	-395.428	97.0040	39.9964
175	TRUM	238466	326.883	-197.796	97.0039	39.9982
176	UNIT	238524	238.567	-154.494	97.0028	39.9986
177	VIBU	238609	519.633	-267.258	97.0061	39.9976
178	VIEN	238620	470.383	-193.872	97.0056	39.9983
179	WAPP	238700	606.68	-358.746	97.0072	39.9968
180	WASG	238746	556.425	-164.993	97.0066	39.9985
181	WEST	238880	489.373	-377.809	97.0058	39.9966
182	ALBU	290234	-869.46	-501.713	96.9897	39.9955
183	ARTE	290600	-689.529	-773.897	96.9919	39.9930
184	AUGU	290640	-973.07	-598.391	96.9885	39.9946
185	CARL	291469	-680.335	-811.474	96.9920	39.9927
186	CARR	291515	-819.836	-665.132	96.9903	39.9940
187	CLAY	291887	-547.124	-374.102	96.9935	39.9966
188	CLOV	291939	-566.973	-599.296	96.9933	39.9946
189	CUBA	292241	-890.304	-392.495	96.9895	39.9965
190	CUBE	292250	-951.142	-489.293	96.9888	39.9956
191	DEMI	292436	-1007.99	-799.087	96.9881	39.9928
192	DURA	292665	-767.148	-577.618	96.9909	39.9948
193	EANT	292700	-735.089	-366.94	96.9913	39.9967
194	LAVG	294862	-738.245	-461.163	96.9913	39.9958
195	PROG	297094	-811.39	-578.971	96.9904	39.9948
196	RAMO	297254	-733.737	-615.175	96.9913	39.9944
197	ROSW	297610	-698.544	-712.921	96.9918	39.9936
198	ROY	297638	-644.735	-422.422	96.9924	39.9962

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
199	SANT	298085	-807.375	-445.708	96.9905	39.9960
200	SPRI	298501	-676.681	-374.272	96.9920	39.9966
201	STAY	298518	-810.491	-495.501	96.9904	39.9955
202	TNMN	299031	-912.488	-413.425	96.9892	39.9963
203	TUCU	299156	-604.359	-508.834	96.9929	39.9954
204	WAST	299569	-638.605	-820.288	96.9925	39.9926
205	WISD	299686	-856.967	-756.366	96.9899	39.9932
206	AIRS	340179	-212.731	-597.062	96.9975	39.9946
207	ARDM	340292	-12.242	-645.633	96.9999	39.9942
208	BENG	340670	174.368	-568.011	97.0021	39.9949
209	CANE	341437	71.857	-637.935	97.0009	39.9942
210	CHRT	341544	203.233	-632.067	97.0024	39.9943
211	CHAN	341684	10.494	-475.655	97.0001	39.9957
212	CHIK	341750	-83.175	-547.26	96.9990	39.9951
213	CCTY	342334	-165	-479.536	96.9981	39.9957
214	DUNC	342654	-88.38	-610.04	96.9990	39.9945
215	ELKC	342849	-216.769	-507.879	96.9974	39.9954
216	FORT	343281	-129.964	-541.113	96.9985	39.9951
217	GEAR	343497	-118.53	-482.187	96.9986	39.9956
218	HENN	344052	-31.964	-601.206	96.9996	39.9946
219	HOBA	344202	-189.062	-547.36	96.9978	39.9951
220	KING	344865	24.538	-664.103	97.0003	39.9940
221	LKEU	344975	141.702	-520.6	97.0017	39.9953
222	LEHI	345108	71.634	-612.05	97.0009	39.9945
223	MACI	345463	-254.63	-466.154	96.9970	39.9958
224	MALL	345589	-55.127	-425.644	96.9994	39.9962
225	MAYF	345648	-258.49	-512.583	96.9970	39.9954
226	MUSK	346130	149.764	-466.905	97.0018	39.9958
227	NOWA	346485	121.551	-364.038	97.0014	39.9967
228	OKAR	346620	-88.424	-473.338	96.9990	39.9957
229	OKEM	346638	63.188	-504.958	97.0008	39.9954
230	OKLA	346661	-54.198	-510.562	96.9994	39.9954
231	PAOL	346859	-23.665	-573.142	96.9997	39.9948
232	PAWH	346935	57.704	-369.174	97.0007	39.9967
233	PAWN	346944	16.927	-398.139	97.0002	39.9964
234	PONC	347196	-8.871	-363.068	96.9999	39.9967
235	PRYO	347309	150.763	-407.824	97.0018	39.9963
236	SHAT	348101	-256.963	-407.368	96.9970	39.9963
237	STIG	348497	171.02	-523.736	97.0020	39.9953
238	TULS	348992	99.361	-419.873	97.0012	39.9962

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
239	TUSK	349023	156.629	-592.395	97.0019	39.9946
240	WMWR	349629	-156.42	-581.308	96.9982	39.9947
241	WOLF	349748	30.212	-538.388	97.0004	39.9951
242	BOLI	400876	760.886	-500.256	97.0090	39.9955
243	BROW	401150	710.048	-480.346	97.0084	39.9957
244	CETR	401587	877.35	-456.294	97.0104	39.9959
245	DICS	402489	872.14	-391.132	97.0103	39.9965
246	DYER	402680	695.792	-409.316	97.0082	39.9963
247	GRNF	403697	760.795	-395.69	97.0090	39.9964
248	JSNN	404561	765.932	-476.414	97.0090	39.9957
249	LWER	405089	885.291	-487.757	97.0105	39.9956
250	LEXI	405210	790.003	-471.897	97.0093	39.9957
251	MASO	405720	694.163	-496.166	97.0082	39.9955
252	MEMP	405954	671.8	-522.492	97.0079	39.9953
253	MWFO	405956	681.292	-516.15	97.0080	39.9953
254	MUNF	406358	678.65	-495.241	97.0080	39.9955
255	SAMB	408065	697.077	-382.536	97.0082	39.9965
256	SAVA	408108	800.788	-498.682	97.0095	39.9955
257	UNCY	409219	711.595	-384.605	97.0084	39.9965
258	ABIL	410016	-251.753	-836.027	96.9970	39.9924
259	AMAR	410211	-425.302	-517.839	96.9950	39.9953
260	AUST	410428	-67.587	-1075.97	96.9992	39.9903
261	BRWN	411136	-43.861	-1571.39	96.9995	39.9858
262	COST	411889	60.611	-1044.72	97.0007	39.9906
263	COCR	412015	-51.832	-1360.01	96.9994	39.9877
264	CROS	412131	-204.599	-868.469	96.9976	39.9922
265	DFWT	412242	-1.867	-786.341	97.0000	39.9929
266	EAST	412715	-171.024	-840.253	96.9980	39.9924
267	ELPA	412797	-886.583	-860.763	96.9895	39.9922
268	HICO	414137	-97.323	-888.181	96.9989	39.9920
269	HUST	414300	157.976	-1108.38	97.0019	39.9900
270	KRES	414880	-434.746	-611.717	96.9949	39.9945
271	LKCK	414975	99.734	-693.521	97.0012	39.9937
272	LNGV	415348	220.962	-844.674	97.0026	39.9924
273	LUFK	415424	214.652	-969.69	97.0025	39.9912
274	MATH	415661	-86.438	-1330.47	96.9990	39.9880
275	MIDR	415890	-489.385	-878.123	96.9942	39.9921
276	MTLK	416104	-672.024	-1008.98	96.9921	39.9909
277	NACO	416177	223.065	-925.966	97.0026	39.9916
278	NAVA	416210	28.358	-892.028	97.0003	39.9919

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
279	NEWB	416270	239.111	-721.818	97.0028	39.9935
280	BPAT	417174	288.962	-1110.65	97.0034	39.9900
281	RANK	417431	-472.048	-959.488	96.9944	39.9913
282	SAAG	417943	-333.338	-952.54	96.9961	39.9914
283	SAAT	417945	-143.322	-1161.27	96.9983	39.9895
284	SHEF	418252	-463.759	-1019.19	96.9945	39.9908
285	STEP	418623	-112.988	-857.918	96.9987	39.9922
286	STER	418630	-376.683	-897.195	96.9956	39.9919
287	VALE	419270	-720.749	-1015.17	96.9915	39.9908
288	VICT	419364	6.882	-1236.45	97.0001	39.9888
289	WACO	419419	-21.834	-928.823	96.9997	39.9916
290	WATR	419499	-353.767	-916.015	96.9958	39.9917
291	WHEE	419665	57.489	-1008.99	97.0007	39.9909
292	WPDM	419916	262.792	-737.786	97.0031	39.9933
293	DORA	232302	433.256	-378.797	97.0051	39.9966
294	DIXN	112353	756.057	-267.193	97.0089	39.9976
295	DAUP	12172	864.408	-1050.41	97.0102	39.9905
296	FREV	123104	847.031	-117.884	97.0100	39.9989
297	WARR	18673	890.447	-788.703	97.0105	39.9929
298	MDTN	235562	493.264	-87.222	97.0058	39.9992

TABLE A-4. LIST OF OVER WATER METEOROLOGICAL STATIONS

Number	Station ID	Input file Name	LCC East (km)	LCC North (km)	Long	Lat
1	42001	42001	746.874	-1541.35	89.67	25.9
2	42002	42002	265.486	-1650.616	94.42	25.19
3	42007	42007	795.674	-1063.667	88.77	30.09
4	42019	42019	163.178	-1342.917	95.36	27.91
5	42020	42020	30.212	-1453.738	96.7	26.94
6	42035	42035	254.465	-1193.539	94.41	29.25
7	42040	42040	859.497	-1160.066	88.21	29.18
8	BURL1	42045	743.116	-1202.117	89.43	28.9
9	DPIA1	42046	861.385	-1039.466	88.07	30.25
10	GDIL1	42047	687.984	-1164.910	89.96	29.27
11	PTAT2	42048	-4.980	-1353.398	97.05	27.83
12	SRST2	42049	288.163	-1175.682	94.05	29.67