BART Five Factor Analysis

Arkansas Electric Cooperative Corporation

Bailey and McClellan Generating Stations

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1. EXECUTIVE SUMMARY

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

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

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

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

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

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

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

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

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

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

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

2. INTRODUCTION AND BACKGROUND

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

3. MODELING METHODOLOGIES AND PROCEDURES

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

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

3.1 CALMET AND CALPUFF

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

3.2 CALPOST

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

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

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

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

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

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

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

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

CALPOST Method 8, Mode 5 requires the following:

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

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

TABLE 3-1. ANNUAL AVERAGE BACKGROUND CONCENTRATION

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

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

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

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

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

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

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

4. EXISTING EMISSIONS AND VISIBILITY IMPAIRMENT

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

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

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

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

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

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

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

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

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

4.2 BASELINE VISIBILITY IMPAIRMENT

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

5.2 ELIMINATE TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES

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

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

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

5.2.2 FUEL SWITCHING

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

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

5.3 RANK OF TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS BY EFFECTIVENESS

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

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

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

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

5.4 EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS

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

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

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

5.4.1 COST OF COMPLIANCE

Control Costs

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

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

Annual Tons Reduced

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Cost Effectiveness

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

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

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

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

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

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

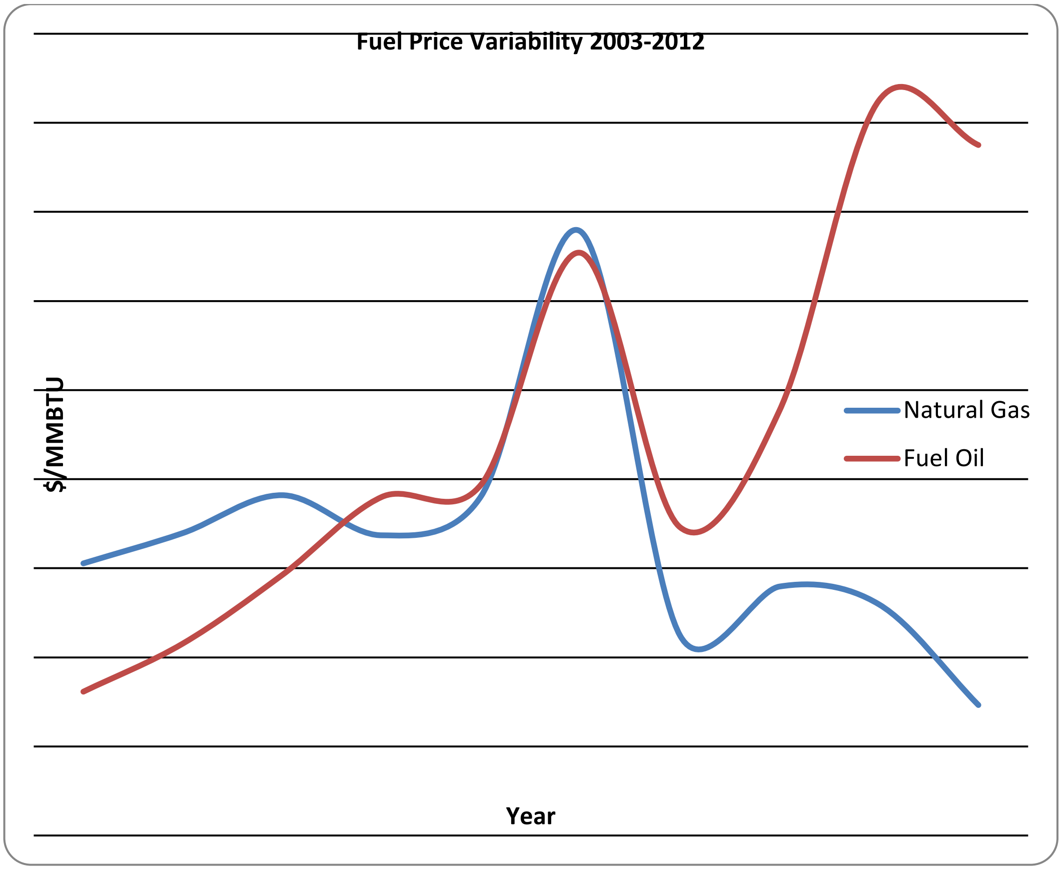

TABLE 5-9. SUMMARY OF COST EFFECTIVENESS FOR FUEL SWITCHING FOR CURRENT NO. 6 FUEL OIL AT BAILEY UNIT 1

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

TABLE 5-10. SUMMARY OF COST EFFECTIVENESS FOR FUEL SWITCHING FOR CURRENT NO. 6 FUEL OIL AT MCCLELLAN UNIT 1

	Average Sulfur Content[A]	Baseline SO_2 Emission Rate[B]	Controlled SO_2 Emission Rate	SO_2 Reduced	Baseline PM10 Emission Rate[B]	Controlled PM10 Emission Rate[F]	PM10 Reduced	Annual Heat Input	Fuel Heating Value (HHV)[C]	Annual Fuel Usage	Fuel Cost	Differential Cost of Fuel Switching	SO_2 Cost Effectiveness	PM10 Cost Effectiveness
	(%)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(MMBtu/yr)	(MMBtu/Mgal) or (MMBtu/Mscf)	(Mgal/yr)	($/MMBtu)	($/yr)	($/ton)	($/ton)
Base Case	1.38	209.43	-	-	136.08	-	-	291,733	155.00	1882.15	16.00	-	-	-
No. 6 - 1%	1.00	-	153.61	55.81	-	76.70	59.38	291,733	155.00	1882.15	16.50	145,866	2,613	2,457
No. 6 - 0.5%	0.50	-	75.88	133.55	-	23.94	112.14	291,733	155.00	1882.15	17.75	510,532	3,823	4,553
Diesel[A]	0.05	-	7.31	202.11	-	1.10	134.98	291,733	136.15	2142.73	20.95	1,444,077	7,145	10,698
Natural Gas	0.04	-	0.07	209.35	-	1.36	134.72	291,733	1,011.00	288.56	5.97	-2,926,874	-13,980	-21,726

[A] Sulfur content of base case No. 6 fuel oil based on average of fuel burned in 2009- 2011. Sulfur content of diesel based on average sulfur in diesel burned at AECC Fitzhugh plant during the same timeframe since diesel is not burned at Bailey or McClellan.

[B] The baseline SO2 emission rates were calcauted using the average fuel usage from 2007 to 2011, the average heat content of the No. 6 fuel oil during that same time, and the average sulfur content of the fuel during that time. The baseline PM10 emission rates are the sum of the filterable PM species as predicted by the NPS workbook (based on total PM10 rates input to the workbook).

[C] Higher heating value of residual oil based on data from supplier. Higher heating value of diesel is the average from Fitzhugh plant. Higher heating value of natural gas from 6.23.11 Bailey gas analysis and 7.12.11 gas analysis.

[F] Reductions in PM Species are based on default NPS profile.

5.4.2 ENERGY IMPACTS AND NON-AIR QUALITY IMPACTS

There are no energy or non-air quality impacts associated with fuel switching to 1% sulfur No. 6 fuel oil, 0.5% sulfur No. 6 fuel oil, or diesel. Switching to natural gas may have an impact during periods of natural gas curtailments. However, temporary permitted use of fuel oil would provide for electric grid reliability. The ability to burn fuel oil at both Bailey and McClellan is important – even if fuel oil is more expensive and difficult to burn than natural gas. During natural gas curtailments, natural gas infrastructure maintenance, and other emergencies, AECC relies on the fuel oil stored at the plants to maintain electrical reliability.

5.4.3 REMAINING USEFUL LIFE

The remaining useful lives of Bailey Unit 1 and McClellan Unit 1 do not impact the annualized capital costs since it is assumed that fuel switching will not require any significant capital costs, and thus for the purpose of this analysis there is nothing to capitalize that would require a review of the life of the equipment.

5.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE SO_2 CONTROLS

A final impact analysis was conducted to assess the visibility improvement associated with switching fuels. Tables 5-11 and 5-12 summarize the lb/hr emission rates that were modeled to reflect fuel switching as a control at Bailey and McClellan, respectively. The SO_2 emission rate in lb/MMBtu associated with the combustion of a particular fuel was calculated by scaling the existing rolling 30-day average emission rate from 2001 to 2003 by the ratio of the sulfur content of the new fuel and the current maximum annual average sulfur content from 2009 to 2011.

The controlled 30-day lb/MMBtu was converted to lb/hr by multiplying by the boiler design heat input. The calculation of the SO_2 emission rate for the one percent sulfur fuel oil for Bailey Unit 1 is provided for an example:

$$1.592 lb/MMBtu * \frac{(1.81\% - 1\%) Sulfur}{1.81\% Sulfur} = 0.880 \text{ lb/MMBtu}$$

$$0.880 lb/MMBtu * 1{,}350 MMBtu/hr = 1{,}187.62 \text{ lb/hr}$$

The SO_4 emission rate was determined assuming the reduction in SO_4 is proportional to the reduction in SO_2 from the baseline case to the controlled case. Once the SO4 emission rate was determined, this rate was assumed to be IOR CPM and the emission rate was divided by the percentage of the total PM that NPS workbook indicates is IOR CPM to get the total PM rate. The total PM rate was then entered into the NPS workbook to get the emission rates for all of the PM species. The NO_x emission rate was modeled at the baseline rate.

TABLE 5-11. SUMMARY OF EMISSION RATES MODELED TO REFLECT FUEL SWITCHING FOR SO_2 CONTROL AT BAILEY UNIT 1

Bailey Unit 1	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_x (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
1% sulfur fuel oil No. 6	1,187.6	2.5	408.8	4.7	11.7	0.4	0.9	20.3
0.5% sulfur fuel oil No. 6	593.8	1.3	408.8	1.5	3.7	0.2	0.3	6.9
Diesel	59.4	0.1	408.8	0.1	0.2	0.0	0.0	0.4
Natural gas	0.5	0.3	443.8	0.0	0.0	7.4	2.6	10.3

TABLE 5-12. SUMMARY OF EMISSION RATES MODELED TO REFLECT FUEL SWITCHING FOR SO_2 CONTROL AT MCCLELLAN UNIT 1

McClellan Unit 1	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_x (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
1% sulfur fuel oil No. 6	2,317.1	4.3	579.8	8.0	19.9	0.8	1.6	34.6
0.5% sulfur fuel oil No. 6	1,158.5	2.1	579.8	2.5	6.2	0.4	0.5	11.7
Diesel	115.9	0.2	579.8	0.1	0.3	0.0	0.0	0.7
Natural gas	0.6	0.3	423.9	0.0	0.0	7.9	2.7	10.9

Visibility improvement was evaluated by comparing the visibility impairment from the baseline scenario to the impairment for a control scenario. The baseline rate used to establish the baseline visibility impairment reflects a peak 24-hour emission rate. Thus, it would make sense that the emission rates used in control scenarios would represent the peak emission rates associated with the controls. That being said, control effectiveness is typically not evaluated on a 24-hour basis. Typically, control effectiveness for EGUs for NO_X/SO_X is based on a longer term performance, with 30-day being standard. While using rolling 30-day average emissions rates gives a lower emission rate than using peak rates, this methodology of comparing the peak to average is consistent with other accepted BART methodologies.

Comparisons of the existing visibility impacts and the visibility impacts based on fuel switching, including the maximum modeled visibility impact, 98th percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv, for each Class I area are provided in Tables 5-13 and 5-14. The visibility improvement associated with fuel switching was calculated as the difference between the existing visibility impairment and the visibility impairment for the various fuels as measured by the 98th percentile modeled visibility impact.

TABLE 5-13. SUMMARY OF MODELED IMPACTS FROM SO_2 CONTROL VISIBILITY IMPACT ANALYSIS FOR BAILEY UNIT 1 (2001-2003)

	Caney Creek Wilderness				**Upper Buffalo Wilderness**				**Hercules Glades Wilderness**				**Mingo NWR**			
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*
Baseline Emission Rate – (fuel oil)	0.970	0.330	8	-	0.696	0.348	7	-	0.687	0.368	6	-	1.592	0.379	12	-
1% sulfur fuel oil No. 6	0.544	0.193	1	41.52%	0.377	0.194	0	44.25%	0.408	0.206	0	44.02%	1.008	0.206	2	45.65%
0.5% sulfur fuel oil No. 6	0.333	0.142	0	56.97%	0.227	0.127	0	63.51%	0.279	0.135	0	63.32%	0.706	0.170	1	55.15%
Diesel	0.208	0.084	0	74.55%	0.156	0.069	0	80.17%	0.215	0.069	0	81.25%	0.429	0.095	0	74.93%
Natural gas	0.219	0.083	0	74.85%	0.170	0.072	0	79.31%	0.238	0.073	0	80.16%	0.443	0.102	0	73.09%

*Improvement is based on the 98th percentile impact (Δdv) for the control scenario compared to the 98th percentile impact (Δdv) baseline impact (Δdv).

†The visibility improvement shown in the table has been calculated from 98th percentile baseline and controlled impacts that include more decimal places than what is shown in the table. Due to rounding of the baseline and controlled 98th percentile impacts shown in the table, the visibility improvement calculated from the baseline and controlled 98th percentile impacts shown in the table may be slightly different than the visibility improvement reflected in the table.

TABLE 5-14. SUMMARY OF MODELED IMPACTS FROM SO_2 CONTROL VISIBILITY IMPACT ANALYSIS FOR MCCLELLAN UNIT 1 (2001-2003)

	Caney Creek Wilderness				Upper Buffalo Wilderness				Hercules Glades Wilderness				Mingo NWR			
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*
Baseline Emission Rate	3.015	0.622	24	-	1.323	0.266	5	-	0.662	0.231	2	-	0.547	0.228	2	-
1% sulfur fuel oil No. 6	2.671	0.537	18	13.67%	1.170	0.231	4	13.16%	0.562	0.202	1	12.55%	0.478	0.193	0	15.35%
0.5% sulfur fuel oil No. 6	1.722	0.322	8	48.23%	0.761	0.146	1	45.11%	0.294	0.115	0	50.22%	0.324	0.136	0	40.35%
Diesel	0.909	0.174	4	72.03%	0.382	0.073	0	72.56%	0.136	0.062	0	73.16%	0.190	0.080	0	64.91%
Natural gas	0.670	0.125	3	79.90%	0.258	0.052	0	80.45%	0.092	0.040	0	82.68%	0.132	0.058	0	74.56%

*Improvement is based on the 98th percentile impact (Δdv) for the control scenario compared to the 98th percentile impact (Δdv) baseline impact (Δdv)

†The visibility improvement shown in the table has been calculated from 98th percentile baseline and controlled impacts that include more decimal places than what is shown in the table. Due to rounding of the baseline and controlled 98th percentile impacts shown in the table, the visibility improvement calculated from the baseline and controlled 98th percentile impacts shown in the table may be slightly different than the visibility improvement reflected in the table.

As shown in Table 5-13, based on visibility predictions from the CALPUFF modeling system, fuel switching at Bailey Unit 1 will result in up to a 45.65, 63.51, 81.25 or 80.16 percent improvement (depending on the Class I area) to the existing visibility impairment attributable to this unit for fuel switching to 1% sulfur fuel oil, 0.5% sulfur fuel oil, diesel and natural gas, respectively. Please note that despite the varying levels of percent visibility improvement, the number of days of visibility impairment $>\Delta 0.5$ dv is 0 in many of the control cases. For example, at Hercules Glades Wilderness there are 0 days of visibility impairment greater than $>\Delta 0.5$ dv for the 1% sulfur fuel oil and also for the natural gas control although the visibility improvement varies from 44.02% to 81.25%.

As shown in Table 5-14, based on visibility predictions from the CALPUFF modeling system, fuel switching at McClellan Unit 1 will result in up to a 15.35, 50.22, 73.16, or 82.68 percent improvement (depending on the Class I area) to the existing visibility impairment attributable to this unit for fuel switching to 1% sulfur fuel oil, 0.5% sulfur fuel oil, diesel and natural gas, respectively.

5.6 PROPOSED BART FOR SO_2

AECC has determined that BART for Bailey Unit 1 and McClellan Unit 1 is fuel switching to using fuels with 0.5% sulfur or less (including natural gas). As mentioned in the Section 5.5 of this report, fuel with a sulfur content of 0.5% or less will have visibility improvements in Class I areas of up to 63.51% for Bailey and 50.22% for McClellan.

When the BART limits become effective, Bailey and McClellan would burn the existing supply of No. 6 fuel oil as the normal course of business dictates and in accordance with any operating restrictions enforced by ADEQ. Future fuel purchases will be fuels of 0.5% sulfur content or less.

While EPA might have some hesitation comparing the visibility impairment from the baseline scenario on a peak 24-hour basis to visibility impairment due to control effectiveness on a 30-day rolling average basis, the increased visibility improvement did not have a significant bearing on AECC selecting to burn 0.5% sulfur fuel oil going forward. Because burning fuel oil is necessary in addition to using natural gas from a grid reliability perspective, AECC had to select a lower sulfur fuel oil than currently received fuel oil. And because the cost/ton of the 0.5% sulfur is lower than for 1% sulfur, 0.5% sulfur is the appropriate option.

6. NO_X BART EVALUATION

On June 7, 2012 EPA published a final rule allowing states participating in the Cross-State Air Pollution Rule (CSAPR) trading program to use CSAPR to satisfy BART. Arkansas is one of the states with units subject to CSAPR that will participate in a NO_x trading program during the ozone season. EPA commented that "NO_x control in the five ozone season-only states is achieved predominantly by combustion controls."[11] Due to the nature of combustion controls, plants typically keep combustion controls in place and running year-round, even if emission limitations are seasonal. Although Arkansas is an ozone season-only state, units with combustion controls would run anytime the unit is in operation.

An email dated June 28, 2012 from ADEQ stated, "ADEQ agrees CSAPR is better than BART and the subject-to-BART sources do not need to include NOx in their five-factor analysis."[12] Therefore, AECC is not including NOx analyses in the Bailey and McClellan five-factor analyses.

On July 6, 2012 EPA published a final rule of the Nebraska Regional Haze Federal Implementation Plan (FIP).[13] Nebraska is subject to CSAPR for annual SO_2 and NO_x. The FIP reviewed the Nebraska suggest BART for NO_x, but ultimately stated that because CSAPR satisfies BART, CSAPR controls will equate with BART in the state.[14]

AECC is proposing to satisfy BART for NO_x by complying with CSAPR at Bailey Unit 1 and McClellan Unit 1.[15]

[11] "Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available Retrofit Technology (BART) Determination, Limited SIP Disapprovals, and Federal Implementation Plans." CFR Vol. 77, No. 110. Thursday, June 7, 2012, Rules and Regulations. Page 33651.

[12] Email from Mary Pettyjohn of ADEQ to subject-to-BART unit operators dated June 28, 2012.

[13] "Approval, Disapproval and Promulgation of Implementation Plans; State of Nebraska; Regional Haze State Implementation Plan; Federal Implementation Plan for Best Available Retrofit Technology Determination." CFR Vol. 77, No. 130. Friday, July 6, 2012. Page 40150.

[14] Ibid, 40151.

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

7.1 IDENTIFICATION OF AVAILABLE RETROFIT PM_{10} CONTROL TECHNOLOGIES

PM_{10} emissions are either "filterable" or "condensable". Filterable PM_{10} is generally considered to be particles less than or equal to 10 microns in diameter that are trapped by a filter during testing of exhaust gas. Condensable PM is material that is emitted in the vapor state but that condenses in the atmosphere to form particles. Filterable PM_{10} emissions from fuel oil combustion depend predominantly on the grade of fuel oil fired. Combustion of lighter distillate oils results in significantly lower PM_{10} formation than does combustion of heavier residual oils. Among residual oils, firing of No. 4 or No. 5 oil usually produces less PM_{10} than does the firing of heavier residual oil. This is due to the higher ash and sulfur contents of residual oil compared to lighter oils.

Step 1 of the BART determination is the identification of all available retrofit PM_{10} control technologies. The available retrofit PM_{10} control technologies are summarized in Table 6-2 for Bailey Unit 1 and McClellan Unit 1.

TABLE 7-1. AVAILABLE PM CONTROL TECHNOLOGIES FOR BAILEY UNIT 1 AND MCCLELLAN UNIT 1

PM_{10} Control Technologies
Dry Electrostatic Precipitator (ESP)
Wet Electrostatic Precipitator (ESP)
Fabric Filter
Wet Scrubber
Cyclone
Fuel Switching

7.2 ELIMINATE TECHNICALLY INFEASIBLE PM CONTROL TECHNOLOGIES

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

7.2.1 DRY ELECTROSTATIC PRECIPITATORS (ESP)

A dry ESP operates by first placing a charge on the particles through a series of electrodes, and then capturing the charged particles on collection plates. Particles from oil-fired boilers tend to be sticky and small. Because of these properties and a general lack of existence in practice, a dry ESP is not a good technological match for either Bailey Unit 1 or McClellan Unit 1.

7.2.2 WET ELECTROSTATIC PRECIPITATORS (ESP)

A wet ESP operates similarly to a dry ESP but is a better technological match for oil-fired boilers because it is not sensitive to small and sticky particulates. A wet ESP utilizes water to collect and remove the particles, and will produce a waste-water product. Flue gas leaving wet ESPs will be saturated and may result in a visual steam plume exiting the stack. The estimated PM control efficiency is up to 90% for a wet ESP.[16] Wet ESP is a technically feasible option for control of PM_{10} for Bailey Unit 1 and McClellan Unit 1.

7.2.3 MECHANICAL COLLECTORS (CYCLONES)

Mechanical collectors, or cyclones, control particulates generated during soot blowing, during upset conditions, or when a heavy oil is fired. For these situations, high-efficiency cyclonic collectors can achieve up to 85% control of particulate.[17] This control is designed for the larger PM size fractions, and thus, when firing residual oil, the control will not be as effective at controlling the smaller particles that are the primary source of visibility impairment. Further, when a clean oil is combusted, cyclonic collectors are not nearly so effective because of the high percentage of small particles (less than 3 micrometers in diameter) emitted.

7.2.4 FABRIC FILTER

Fabric filters work by filtering the PM in flue gas through filter bags. The collected particles are periodically removed from the bag through a pulse jet or reverse flow mechanism. Due to the sticky nature of particles from oil-fired boilers and the associated hazard from flammability of their use, fabric filters are not used to control PM from boilers firing residual oil. Thus, fabric filters are not technically feasible for Bailey Unit 1 and McClellan Unit 1.

7.2.5 WET SCRUBBER

Wet scrubbers remove PM from flue gas by contacting it with a scrubbing liquid using one of several approaches: spraying the gas stream with the liquid, forcing the gas stream through a pool of liquid, or by some other contact method. PM in the gas stream is captured in the scrubbing liquid. The PM-laden scrubbing liquid is separated from the gas stream, and the resultant scrubbing liquid is treated prior to discharge or reuse in the plant. Problems associated with scrubbers include corrosion issues, high power requirements, and water-disposal challenges. However, the use of wet scrubbers for Bailey Unit 1 and McClellan Unit 1 is considered a technically feasible option. The estimated PM_{10} removal efficiency for a wet scrubber is 50-60%.[18]

While wet scrubbers are considered technically feasible, it is worth noting the wet scrubbers are not very efficient at controlling submicron size particles. When drops of water are suspended in a stream of air containing particles, such as they are in wet scrubbers, the air must go around the drops to pass through the scrubber. This creates streamlines of higher velocity air near each drop. For particles to be captured, they must push through these streamlines to the surface of the drop. Particles that are smaller than 1 micron are hardest to control because they follow the streamlines and avoid contact with

[16] Ibid.
[17] AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.3.4.1
[18] AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.3.4.1

the drop. As particle size decreases, more energy is needed to force contact with the drops. This makes conventional scrubbers ineffective for particles smaller than a few microns.[19] While the majority of the PM emissions for Bailey Unit 1 and McClellan Unit 1 are not less than a few microns, particles of this size have the highest ability to impair visibility; thus, a wet scrubber may not be effective at controlling the particles that have the greatest ability to impair visibility.

7.2.6 FUEL SWITCHING

Residual oil has inherent ash that contributes to the emissions of filterable PM. Lower grades of fuel oil have less ash and ultimately lower filterable PM emissions. Filterable PM emissions could be reduced by switching to a lower grade fuel oil or natural gas. Section 5 discussed the option of fuel switching with respect to reducing SO_2 emissions.

Distillate fuel oil has only trace amounts of ash.[20] It is estimated that filterable PM_{10} emissions would be reduced in proportion to the reduction in ash content. Based on the reduction in ash content, reductions of filterable PM_{10} would be expected to be greater than 99%. Reductions in filterable PM_{10} in No. 6 fuel oil are directly related to the sulfur content of the fuel, as seen in AP-42, 1.3-1. The percent reduction in filterable PM_{10} from fuel switching to natural gas is estimated from the reduced ash content in natural gas (trace amount) as compared to current No. 6 fuel, 0.035% ash content, for 99% control efficiency.

7.3 RANK OF TECHNICALLY FEASIBLE PM_{10} CONTROL OPTIONS BY EFFECTIVENESS

Step 3 of the top-down control review is to rank the technically feasible options according to effectiveness. Table 7-3 provides a ranking of the control levels for the controls listed in the previous section.

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[19] http://www.tri-mer.com/q&a/comparing-electrostatic-precipitator.htm

[20] *Combustion-Fossil Power Systems*, J.G. Singer published by Combustion Engineer, Inc.[21]AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.3.4.1, 9.19(S)+3.22. For Bailey, the average sulfur content of fuel delivered in 2009-2011 was 1.81%, and the average fuel usage was 252,855 gal. For McClellan these values were 1.38% sulfur and 1,882,146 gal. Bailey: $(9.19*(1.81)+3.22)*(252,855*10^3/200) = 2.51$ tpy. McClellan: $(9.19*(1.38)+3.22)*(1,882,146*10^3/200) = 14.97$ tpy

TABLE 7-3. CONTROL EFFECTIVENESS OF TECHNICALLY FEASIBLE PM CONTROL TECHNOLOGIES

Control Technology	Control Efficiency[21] (%)
Fuel Switching	≤99%
Wet ESP	≤90
Cyclone	85%
Wet Scrubber	55%

7.4 EVALUATION OF IMPACTS FOR FEASIBLE PM_{10} CONTROLS

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

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

7.4.1 COST OF COMPLIANCE

The capital costs, operating costs, and cost effectiveness of wet ESPs, cyclones and wet scrubbers have been estimated for Bailey Unit 1 and McClellan Unit 1. The cost effectiveness of fuel switching to 1% sulfur fuel oil, 0.5% sulfur fuel oil, diesel and natural gas has also been estimated.

<u>Control Costs</u>

The capital and operating costs of the wet ESP and wet scrubber were prepared by AECC using Electric Power Research Institute's (EPRI) IECCOST Software, and cyclone estimates were derived from EPA estimates. The capital costs were annualized over a 15-year period and then added to the annual operating costs to obtain the total annualized costs. The details of the capital and operating cost estimates are provided in Appendix B of this report.

<u>Annual Tons Reduced</u>

The annual tons reduced that were used in the cost effectiveness calculations were determined by subtracting the estimated controlled annual emission rates from the baseline annual emission rates, as calculated from AP-42: 1.3-1. The controlled annual emission rates were estimated by reducing the existing annual emission rate by the control percentages shown in Table 7-3.

[21] AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.3.4.1, 9.19(S)+3.22. For Bailey, the average sulfur content of fuel delivered in 2009-2011 was 1.81%, and the average fuel usage was 252,855 gal. For McClellan these values were 1.38% sulfur and 1,882,146 gal. Bailey: $(9.19*(1.81)+3.22)*(252,855*10^3/200) = 2.51$ tpy. McClellan: $(9.19*(1.38)+3.22)*(1,882,146*10^3/200) = 14.97$ tpy

Cost Effectiveness

The cost effectiveness was determined by dividing the annualized cost by the annual tons reduced. The costs effectiveness analysis is summarized in Tables 7-4 and 7-5.

Table 7-4 indicates that the cost effectiveness of switching to natural gas is over $5,000/ton for each boiler. Further, Tables 7-4 and 7-5 indicate that the cost effectiveness for all other controls is excessively expensive at $300,217/ton for fuel switching to diesel at McClellan Unit 1 to $36,326,871/ton for a wet scrubber at Bailey Unit 1.

7.4.1.1 ENERGY IMPACTS AND NON-AIR QUALITY IMPACTS

There are no energy or non-air quality impacts associated with fuel switching, but there are impacts associated with wet ESPs and wet scrubbers. ESPs by design apply energy to the particles they are collecting. This energy usage can be significant, especially if the wet ESP is designed to control submicron size particles where more energy is applied to collect more of the particles. Wet scrubbers also require a substantial amount of energy to force exhaust gases through the scrubber.

Both wet ESPs and wet scrubber generate wastewater streams that must either be treated on-site or sent to a waste water treatment plant.   Further, the wastewater treatment process will generate a filter cake that would likely require land-filling.

7.4.1.2 REMAINING USEFUL LIFE

The remaining useful lives of Bailey Unit 1 and McClellan Unit 1 do not impact the annualized capital costs of the wet ESP, wet scrubber, or cyclone because the useful life of the boilers is anticipated to be at least as long as the capital cost recovery period, which is 15 years. Further, the remaining useful lives of Bailey Unit 1 and McClellan Unit 1 do not impact the annualized fuel cost, since it is assumed that fuel switching will not require any capital costs, and thus there is nothing to capitalize that would require a review of the life of the equipment.

TABLE 7-4. SUMMARY OF COST EFFECTIVENESS FOR BAILEY UNIT 1 PM_{10} CONTROLS

	Baseline Emission Rate	Control Efficiency	Annual Heat Input[A]	Controlled Emission Rate	PM_{10} Reduced	Capital Cost	Total Annual Cost	Cost Effectiveness
	(tpy)	%	(MMBtu/yr)	(tpy)	(ton/yr)	($)	($/yr)	($/ton)
Wet ESP	25.63	90.00	39,193	2.56	23.06	105,141,431	22,638,340	981,583
Wet Scrubber	25.63	55.00	39,193	11.53	14.09	140,957,713	50,150,862	3,558,286
Cyclone	25.63	85.00	39,193	3.84	21.78	989,479	1,188,630	54,570
No. 6 Fuel Oil - 1%	25.63	-	39,193	8.80	16.83	-	463,185	27,528
No 6. Fuel Oil - 0.5%	25.63	-	39,193	2.75	22.88	-	512,175	22,386
Diesel	25.63	-	39,193	0.13	25.50	-	637,592	25,004
Natural Gas	25.63	-	39,193	0.26	25.37	-	59,038	2,327

[A] Annual Heat Input derived for 2007-2011 average fuel usage times the heat content of No. 6 fuel oil

TABLE 7-5. SUMMARY OF COST EFFECTIVENESS FOR MCCLELLAN UNIT 1 PM_{10} CONTROLS

	Baseline Emission Rate	Control Efficiency	Annual Heat Input[A]	Controlled Emission Rate	PM_{10} Reduced	Capital Cost	Total Annual Cost	Cost Effectiveness
	(tpy)	%	(MMBtu/yr)	(tpy)	(ton/yr)	($)	($/yr)	($/ton)
Wet ESP	136.08	90.00	291,733	13.61	122.47	151,509,333	32,605,907	266,237
Wet Scrubber	136.08	55.00	291,733	61.23	74.84	146,303,011	52,056,542	695,549
Cyclone	136.08	85.00	291,733	20.41	115.67	1,432,971	1,721,384	14,882
No. 6 Fuel Oil - 1%	136.08	-	291,733	76.70	59.38	-	3,149,652	53,044
No 6. Fuel Oil - 0.5%	136.08	-	291,733	23.94	112.14	-	3,514,317	31,338
Diesel	136.08	-	291,733	1.10	134.98	-	4,447,862	32,952
Natural Gas	136.08	-	291,733	1.36	134.72	-	76,911	571

[A] Annual Heat Input derived for 2007-2011 average fuel usage times the heat content of No. 6 fuel oil

7.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE PM_{10} CONTROLS

A final impact analysis was conducted to assess the visibility improvement associated with wet ESPs, wet scrubbers, and cyclones. Note that fuel switching has impacts on both SO_2 and PM, as shown in Section 5 of this report. Section 4 of this report documented the existing visibility impairment attributable to Bailey Unit 1 and McClellan Unit 1.

In order to assess the visibility improvement associated with wet ESPs, scrubbers, and cyclones the maximum short-term PM_{10} emission rates associated with these controls were modeled using CALPUFF. The maximum short-term PM_{10} emission rates associated with wet ESPs, scrubbers, and cyclones were calculated by reducing the uncontrolled yearly PM_{10} emission rates, in Table 7-4, by the control percentages shown in Table 7-3. Tables 7-5 through 7-7 summarize the emission rates that were modeled to reflect the wet ESPs, wet scrubbers, and cyclones, respectively. The emission rates for the pollutants shown in Tables 7-5 through 7-7 for NO_X and SO_2 that are not PM are the same as in the baseline modeling.

TABLE 7-5. SUMMARY OF EMISSION RATES MODELED TO REFLECT WET ESP FOR PM_{10} CONTROL

Unit	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
Bailey Unit 1	2,375.8	0.4	408.8	1.2	3.0	0.1	0.2	4.9
McClellan Unit 1	2,747.5	0.5	579.8	1.2	2.9	0.1	0.2	4.8

TABLE 7-6. SUMMARY OF EMISSION RATES MODELED TO REFLECT WET SCRUBBER FOR PM_{10} CONTROL

Unit	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
Bailey Unit 1	2,375.8	1.8	408.8	5.5	13.6	0.3	1.1	22.2
McClellan Unit 1	2,747.5	2.2	579.8	5.2	12.9	0.4	1.0	21.7

TABLE 7-7. SUMMARY OF EMISSION RATES MODELED TO REFLECT CYCLONE FOR PM_{10} CONTROL

Unit	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
Bailey Unit 1	2,375.8	4.0	408.8	1.8	4.5	0.7	0.4	7.4
McClellan Unit 1	2,747.5	4.8	579.8	1.7	4.3	0.8	0.3	7.2

Comparisons of the existing visibility impacts and the visibility impacts for PM-specific controls, excluding fuels switching which are included in Section 5, including the maximum modeled visibility impact, 98^{th} percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv, for each Class I area are provided in Tables 7-8 and 7-9. The visibility improvement associated with PM controls was calculated as the difference between the existing visibility impairment and the visibility impairment for the control as measured by the 98th percentile modeled visibility impact.

TABLE 7-8. SUMMARY OF MODELED IMPACTS FROM PM_{10} CONTROL VISIBILITY IMPACT ANALYSIS FOR BAILEY UNIT 1 (2001-2003)

	Caney Creek Wilderness				Upper Buffalo Wilderness				Hercules Glades Wilderness				Mingo NWR			
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*
Baseline Emission Rate	0.969	0.330	8	-	0.695	0.347	7	-	0.686	0.367	6	-	1.589	0.378	12	-
Wet ESP	0.961	0.327	8	0.91%	0.687	0.343	6	1.15%	0.677	0.356	5	3.00%	1.572	0.371	12	1.85%
Wet Scrubber	0.964	0.328	8	0.61%	0.690	0.345	6	0.58%	0.681	0.360	5	1.91%	1.579	0.374	12	1.06%
Cyclone	0.965	0.328	8	0.61%	0.691	0.345	7	0.58%	0.682	0.361	5	1.63%	1.580	0.374	12	1.06%

*Improvement is based on the 98th percentile impact (Δdv) for the control scenario compared to the 98th percentile impact (Δdv) baseline impact (Δdv)
†The visibility improvement shown in the table has been calculated from 98th percentile baseline and controlled impacts that include more decimal places than what is shown in the table. Due to rounding of the baseline and controlled 98th percentile impacts shown in the table, the visibility improvement calculated from the baseline and controlled 98th percentile impacts shown in the table may be slightly different than the visibility improvement reflected in the table.

TABLE 7-9. SUMMARY OF MODELED IMPACTS FROM PM_{10} CONTROL VISIBILITY IMPACT ANALYSIS FOR MCCLELLAN UNIT 1 (2001-2003)

	Caney Creek Wilderness				Upper Buffalo Wilderness				Hercules Glades Wilderness				Mingo NWR			
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*
Baseline Emission Rate	3.007	0.621	22	-	1.319	0.266	5	-	0.660	0.230	2	-	0.546	0.227	2	-
Wet ESP	2.977	0.617	21	0.64%	1.305	0.263	5	1.13%	0.656	0.227	2	1.30%	0.540	0.223	2	1.76%
Wet Scrubber	2.989	0.619	21	0.32%	1.311	0.264	5	0.75%	0.657	0.228	2	0.87%	0.542	0.224	2	1.32%
Cyclone	2.993	0.619	21	0.32%	1.313	0.265	5	0.38%	0.658	0.229	2	0.43%	0.543	0.225	2	0.88%

*Improvement is based on the 98th percentile impact (Δdv) for the control scenario compared to the 98th percentile impact (Δdv) baseline impact (Δdv)

†The visibility improvement shown in the table has been calculated from 98th percentile baseline and controlled impacts that include more decimal places than what is shown in the table. Due to rounding of the baseline and controlled 98th percentile impacts shown in the table, the visibility improvement calculated from the baseline and controlled 98th percentile impacts shown in the table may be slightly different than the visibility improvement reflected in the table.

As shown in Table 7-8, the operation of wet ESPs results in an estimated 0.003 to 0.004 Δdv improvement (0.64 to 1.76 percent) of the 98th percentile visibility impairment attributable to Bailey Unit 1 at the applicable Class I areas. Further, as shown in Table 7-8, the operation of wet scrubbers results in an estimated 0.002 to 0.003 Δdv improvement (0.32 to 1.32 percent) of the 98th percentile visibility impairment attributable to Bailey Unit 1, and the operation of cyclones results in an estimated 0.001 to 0.002 Δdv improvement (0.32 to 0.88 percent) of the 98th percentile visibility impairment attributable to Bailey Unit 1.

As shown in Table 7-9, the operation of wet ESPs results in an estimated 0.003 to 0.011 Δdv improvement (0.91 to 3.00 percent) of the 98th percentile visibility impairment attributable to McClellan Unit 1 at the applicable Class I areas. Further, as shown in Table 7-9, the operation of wet scrubbers results in an estimated 0.002 to 0.007 Δdv improvement (0.58 to 1.91 percent) of the 98th percentile visibility impairment attributable to McClellan Unit 1, and the operation of cyclones results in an estimated 0.002 to 0.006 Δdv improvement (0.58 to 1.63 percent) of the 98th percentile visibility impairment attributable to McClellan Unit 1.

7.6 PROPOSED BART FOR PM_{10}

The cost effectiveness of all the PM controls evaluated for both the boilers is greater than $5,000/ton, and for most controls is much greater than $5,000/ton. Based on the low PM_{10} emission from the boilers (less than 15 tpy for either Bailey Unit 1 or McClellan Unit 1) and the related low improvement to the visibility impairment attributable to the boilers based on the application of the controls (only up to 0.011 Δdv), none of the controls are determined to satisfy BART. Thus, there are no fuel changes or add-on controls proposed as BART for PM_{10} for Bailey Unit 1 or McClellan Unit 1.[22]

[22] However, AECC is proposing fuel switching to 0.5% sulfur fuel oil as BART for SO_2.

APPENDIX A

PM_{10} CONTROL COST CALCULATIONS

Capital Costs		Total Direct Capital	
Technology Wet ESP		Bailey	McClellan
Average High Exhaust Flow Rate (ACFM)[1]		342,529	493,587
Electricity Cost ($Cost_{elect}$, $/kwh)[2]		$0.05	$0.05
Water Cost ($Cost_{water}$, $/gal)[3]		$0.00362	$0.00362
Annual Operating Time (hrs, θ')		8,760	8,760
ESP efficiency (from white paper)		90%	90%
ESP Plate Area (ft^2)[4]	$ESCA = -\ln(p)/w_e \times 5.080 \times Q$	12,760	18,387
Purchased Equipment Cost (Based on 90% Control Efficiency, 2nd Quarter 1987 dollars) - Table 3.14	$33.9/acfm	$11,611,748	$16,732,588
Basic Equipment Costs -Table 3.12	0.45 × Equipment Cost	$5,225,287	$7,529,665
Direct Costs - Table 3.16			
Purchased equipment costs			
ESP + auxiliary equipment (A)	As estimated, A	$16,837,035	$24,262,253
Instrumentation	0.10 A	$1,683,704	$2,426,225
Sales taxes	0.03 A	$505,111	$727,868
Freight	0.05 A	$841,852	$1,213,113
Purchased Equipment cost, PEC	B = 1.18 A	$19,867,701	$28,629,458
Direct Installation Costs Table 3.16			
Foundation & supports	0.04 B	$794,708	$1,145,178
Handling & erection	0.50 B	$9,933,851	$14,314,729
Electrical	0.08 B	$1,589,416	$2,290,357
Piping	0.01 B	$198,677	$286,295
Insulation for ductwork	0.02B	$397,354	$572,589
Painting	0.02B	$397,354	$572,589
Direct Installation Costs	**0.67 B**	**$13,311,360**	**$19,181,737**
Indirect Costs (installation) Table 3.16			
Engineering	0.20B	$3,973,540	$5,725,892
Construction & field expenses	0.20B	$3,973,540	$5,725,892
Contractor fees	0.10B	$1,986,770	$2,862,946
Start-up	0.01B	$198,677	$286,295
Performance test	0.01B	$198,677	$286,295
Model study	0.02B	$397,354	$572,589
Contingencies	0.03B	$596,031	$858,884
Total Indirect Costs, IC	**0.57B**	**$11,324,590**	**$16,318,791**
Cost Index[5]			
a. 2011	585		
b. 1987 Second Quarter (June)	321.9		
Capital recovery factor (CRF)	CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life a. Equipment CRF, 15-yr life, 7% interest	0.11	0.11
TOTAL CAPITAL INVESTMENT (2012$)	**(DC + IC) * (Retrofit factor of 1.4)*(CI_{2012}/CI_{1987}) (Retrofit factor based on average provided for ESP on Page 3-41). No specific factor provided for scrubber, so factor for ESP was relied on.**	**$105,141,431**	**$151,509,333**

Annual Costs			
Direct Annual Costs - Table 2.9			
Operating Labor			
Operator	3hr/shift*2shifts/day*360 days/yr * $12/hr (Assumed operator hrs/day consistent with example on Page 2-57, will adjust pay for 2012 dollars)	$25,920	$25,920
Supervisor	15% of operator	$3,888	$3,888
Maintenance			
Labor	For ESP plate area < 50,000 ft^2 = $4125	$4,125	$4,125
Material	= 0.01 × B	$198,677	$286,295
Utilities			
Fan[6]	= 0.000181× Q × ΔP × θ' × $Cost_{elect}$	$121,655	$175,305
ESP operating power[7]	= $1.94 \times 10^{-3} \times A \times \theta'$	$216,847	$312,478
Pump[8]	= 0.746 × Q_l × Z × S_g × θ' / 3,960η × Costelect	$11,776	$16,970
Water Use (gal/yr)	5 gpm/1000 acfm × air flow × minutes operated per year	900,167,392	1,297,145,760
Water Cost	= Water use × water cost	$3,258,606	$4,695,668
Wastewater treatment	$3.25/1000 gal × Annual water use (based on EPA Manual, 2012 dollars)	$2,925,544	$4,215,724
Total Direct Annual Cost		**$6,767,038**	**$9,736,371**
Indirect Costs, IC			
Administrative charges	2% of Total Capital Investment	$2,102,829	$3,030,187
Property tax	1% of Total Capital Investment	$1,051,414	$1,515,093
Insurance	1% of Total Capital Investment	$1,051,414	$1,515,093
Overhead	60% of total labor and material costs	$121,681	$174,252
Annualized Capital Cost	Capital Recovery Factor * Total Capital Investment	$11,543,964	$16,634,910
Total Indirect Annual Costs		**$15,871,302**	**$22,869,535**
TOTAL ANNUAL COST		**$22,638,340**	**$32,605,907**

Cost estimates made using the EPA Air Pollution Control Cost Manual (APCCM), 6th Edition (January 2002). Section 6, Chapter 3 - Electrostatic Precipitators

Notes:

[1] From RATA data, see 'Exhaust Flowrates' tab for source of system flowrate

[2] Electricity cost form Arkansas Industrial Energy Clearinghouse, http://www.arkansasiec.org/newsmanager/templates/?a=71&z=1

[3] Water cost estimate from Bentonville, AK commercial rate of $0.00362/gal, http://www.bentonvillear.com/utbc_rates.html

[4] For ESP Plate Area:

p = 1 - (Eff/100)

w_e = effective migration velocity (m/s), assume w_e = 31.4 cm/s for Bituminous coal fly ash for a design efficiency of 95% from Table 3.3 (no listings for 90% efficiency or fuel oil)

Q = system flow rate (kacfm)

[5] From Chemical Engineering Plant Cost Index (CEPCI)

[6] For fan power cost:

Q = system flow rate (acfm)

ΔP = system pressure drop (in. H_2O)

Assuming ΔP = 0.38 in. H2O for inlet diffuser plate, inlet and outlet transitions, baffles and plates from Table 3.11, assume ductwork contributres 4.1 in. H_2O (based on EPA Manual). Total pressure drop is 4.48 in. H_2O

θ' = annual operating time (h/yr)

[7] For ESP power cost

A = ESP plate area (ft^2)

θ' = annual operating time (h/yr)

[8] For pump power cost:

Q_l = water flow rate (gal/min)

Z = Fluid head (ft), assume maximum fluid heat is 50 ft

S_g = specific gravity of water being pumped compared to water at 70 °F and 29.92 in. Hg, assume 1

θ' = annual operating time (h/yr)

η = pump motor efficiency (fractional), assume efficiency of 60%

Capital Costs		Total Direct Capital	
Technology WFGD		Bailey	McClellan
Installed Capital Cost (TCI)[1]		$140,957,713	$146,303,011
Annual Costs			
	Equation	Bailey	McClellan
Annualized Fixed O&M		$6,952,216	$7,184,611
Annualized Fixed Charges		$27,120,264	$28,148,699
Annualized Fixed O&M + Fixed Charges		$34,072,480	$35,333,310
Annualized Variable O&M		$601,983	$659,948
Capital Recovery Factor (CRF)	CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life a. Equipment CRF, 15-yr life, 7% interest	0.11	0.11
Annualized Installed Capital Cost	= TCI × CRF	$15,476,399	$16,063,284
Total Annual Costs ($/yr)		$50,150,862	$52,056,542

Notes:

Cost estimates were prepared by AECC using Electric Power Research Institute (EPRI) IECCOST Software.

[1] Includes equipment and installation costs

Capital Costs			
Technology Cyclone		Bailey	McClellan
Average High Exhaust Flow Rate[1] (DSCFM)		234,781	340,011
Cost Index[2] a. 2011 b. 2002	 585 395.6		
Capital Cost[3]	\$2.85/scfm [4]	\$989,479	\$1,432,971
O&M Cost (annual)	\$4.6/scfm [4]	\$1,079,991	\$1,564,051
Capital recovery factor (CRF)	CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life a. Equipment CRF, 15-yr life, 7% interest	0.11	0.11
Annualized Installed Capital Cost	= TCI × CRF	\$108,639	\$157,333
Total Annual Costs (\$/yr)		\$1,188,630	\$1,721,384

Notes:

[1] Average WSCFM flow rate determined from 2011 RATA

[2] From Chemical Engineering Plant Cost Index (CEPCI)

[3] Capital cost adjusted to 2011 cost index using CEPCI cost index

[4] Capital and O&M costs are averaged from the cost ranges given in the EPA Cyclones Air Pollution Control Technology Fact Sheet, document # EPA-452/F-03-005. These costs are expressed in 2002 dollars. Costing was performed for one cyclone. The EPA Cyclone fact sheet states that these costs are based on air flow rates up to 106,000 scfm. Both Bailey and McClellan have air flow rates above this guideline, so it may be necessary to treat the air flow with two cyclones operating in parallel (as stated by the fact sheet)

APPENDIX B

MODELING PROTOCOL

CALMET DATA PROCESSING PROTOCOL ▲ BART DETERMINATION
OKLAHOMA GAS & ELECTRIC

MUSKOGEE GENERATING STATION
SEMINOLE GENERATING STATION
SOONER GENERATING STATION

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Project 083701.0004

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1. INTRODUCTION

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

1.1 BEST AVAILABLE RETROFIT TECHNOLOGY RULE BACKGROUND

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

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

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

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

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

1.2 OBJECTIVE

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

1.3 LOCATION OF SOURCES AND RELEVANT CLASS I AREAS

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

TABLE 1-1. BART-ELIGIBLE SOURCES

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

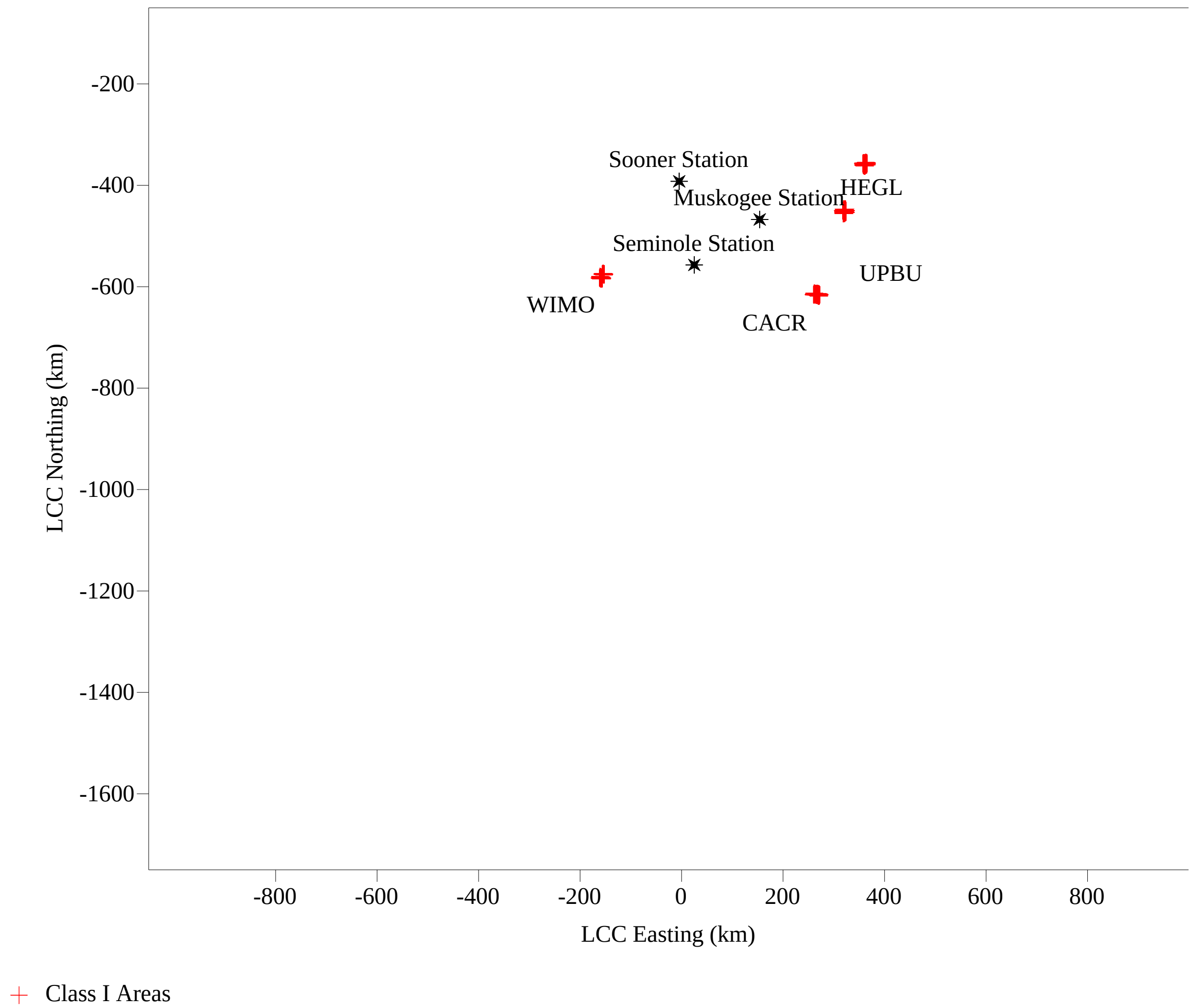
As required in CENRAP's BART Modeling Guidelines, Class I areas within 300 km of each station will be included in each analysis. The following table summarizes the distances of the four closest Class I areas to each station. As seen from this summary, some Class I areas are more than 300 km from the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

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

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

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

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



2. CALPUFF MODEL SYSTEM

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

2.1 MODEL VERSIONS

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

TABLE 2-1. CALPUFF MODELING SYSTEM VERSIONS

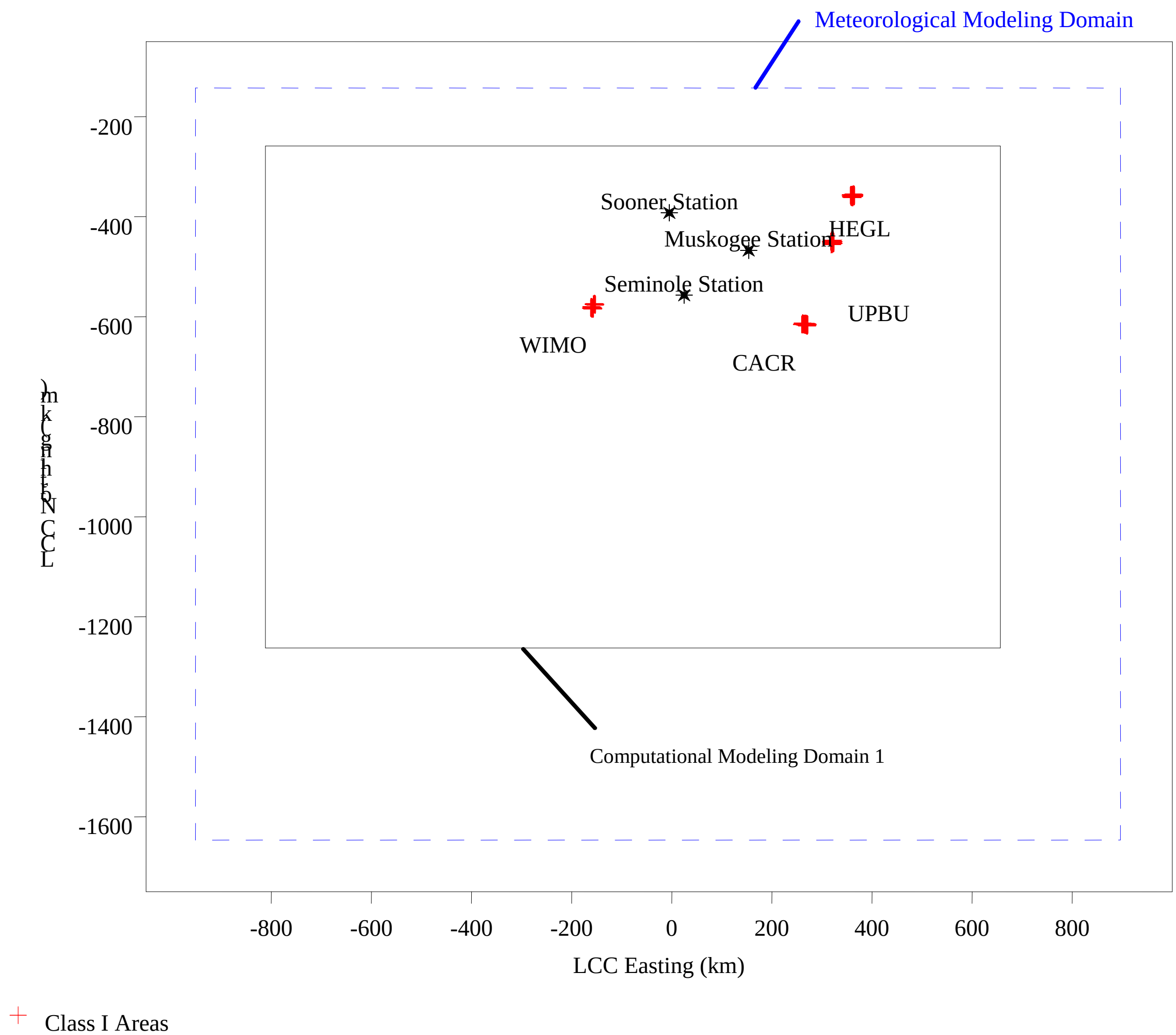
Processor	Version	Level
TERREL	3.3	030402
CTGCOMP	2.21	030402
CTGPROC	2.63	050128
MAKEGEO	2.2	030402
CALMET	5.53a	040716
CALPUFF	5.8	070623
POSTUTIL	1.3	030402
CALPOST	5.51	030709

2.2 MODELING DOMAIN

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

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

FIGURE 2-1. REFINED METEOROLOGICAL MODELING DOMAIN



3. CALMET

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

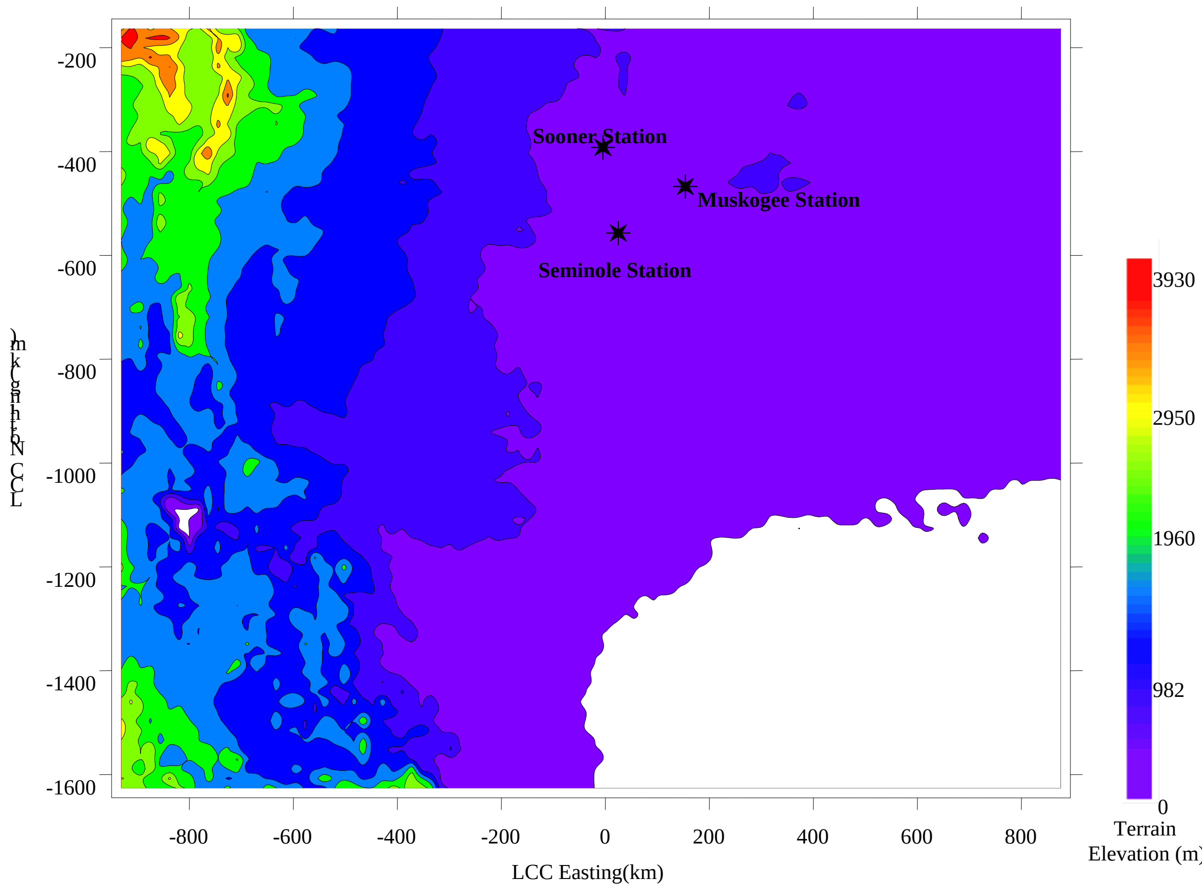
3.1 GEOPHYSICAL DATA

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

3.1.1 TERRAIN DATA

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

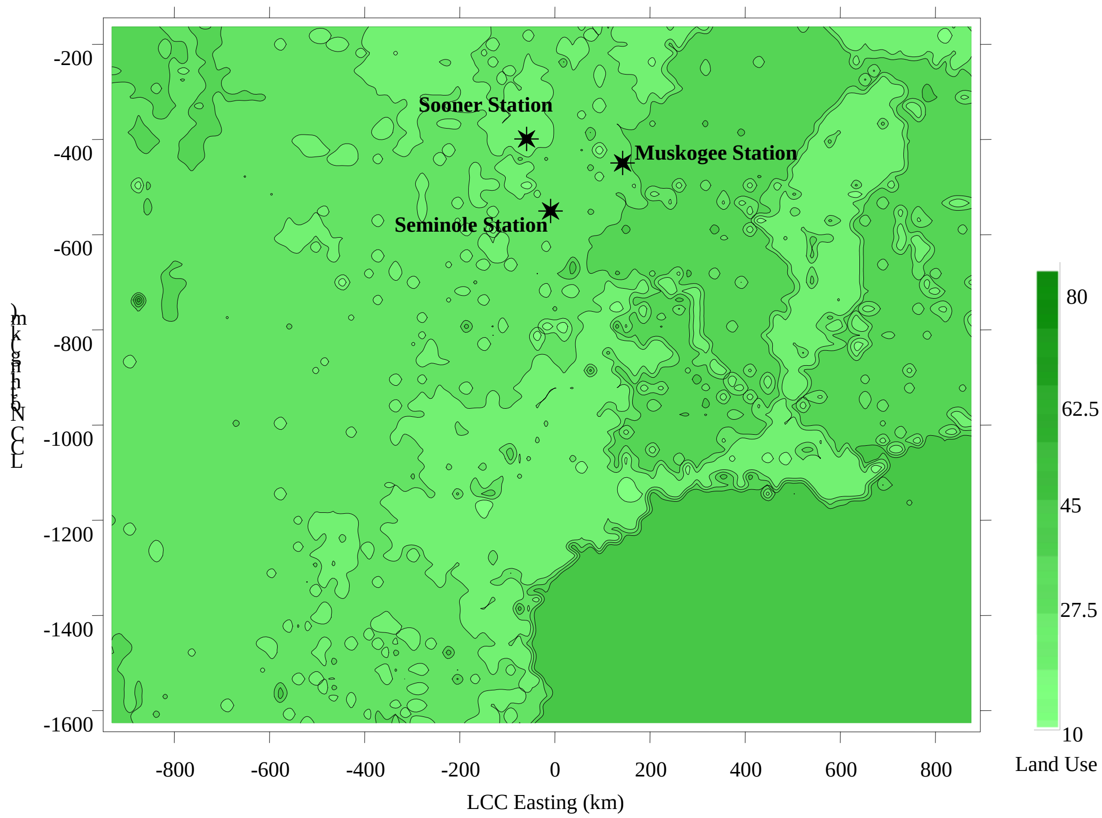
FIGURE 3-1. PLOT OF LAND ELEVATION USING USGS TERRAIN DATA



3.1.2 LAND USE DATA

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

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



3.1.3 COMPILING TERRAIN AND LAND USE DATA

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

3.2 METEOROLOGICAL DATA

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

3.2.1 MESOSCALE MODEL METEOROLOGICAL DATA

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

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

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

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

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

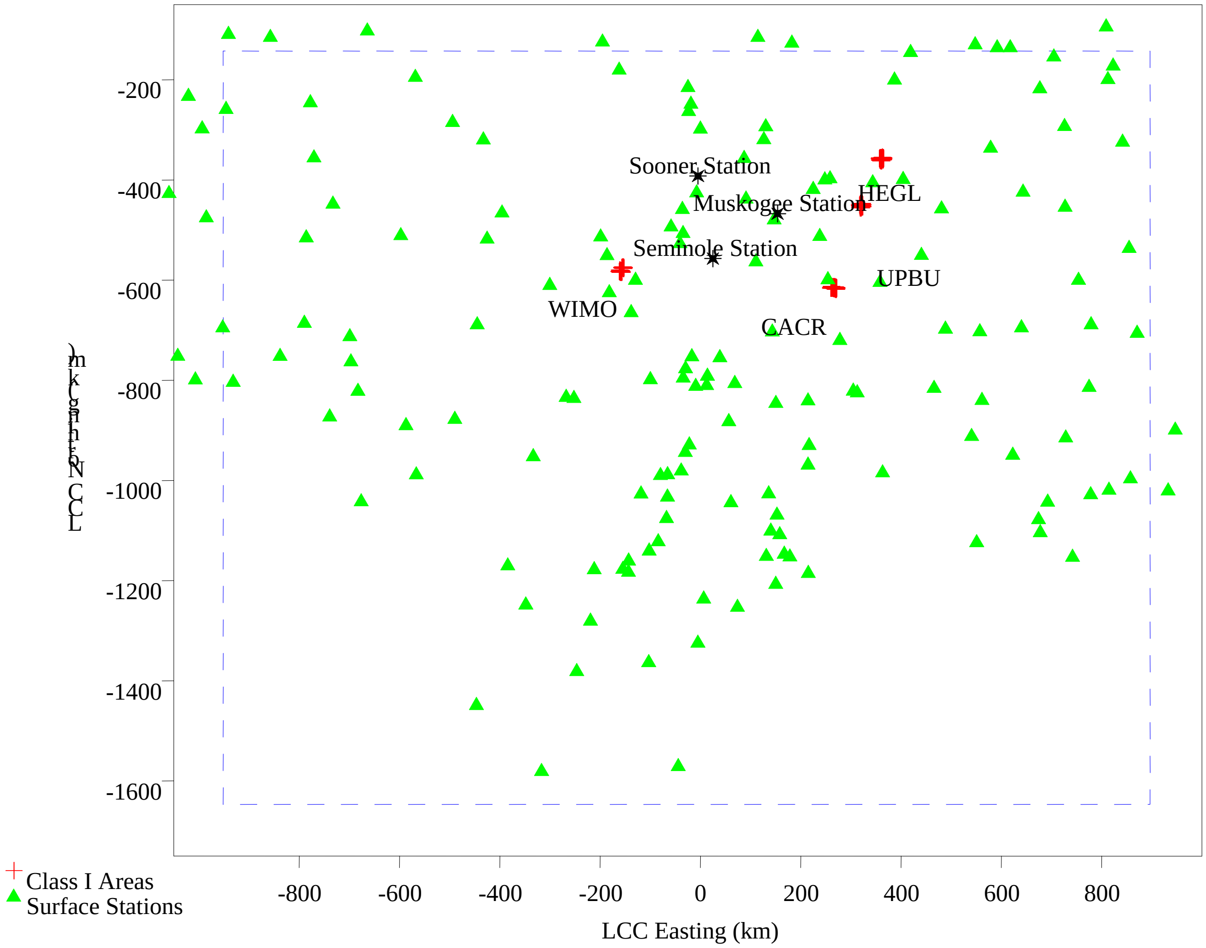
The time periods covered by the data in each of the MM5 files extracted by Alpine Geophysics include a specific number of calendar days, where the data starts at Hour 0 in GMT for the first calendar day and ends at Hour 23 in GMT on the last calendar day. In order to run CALMET in the local standard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

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

3.2.2 SURFACE METEOROLOGICAL DATA

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

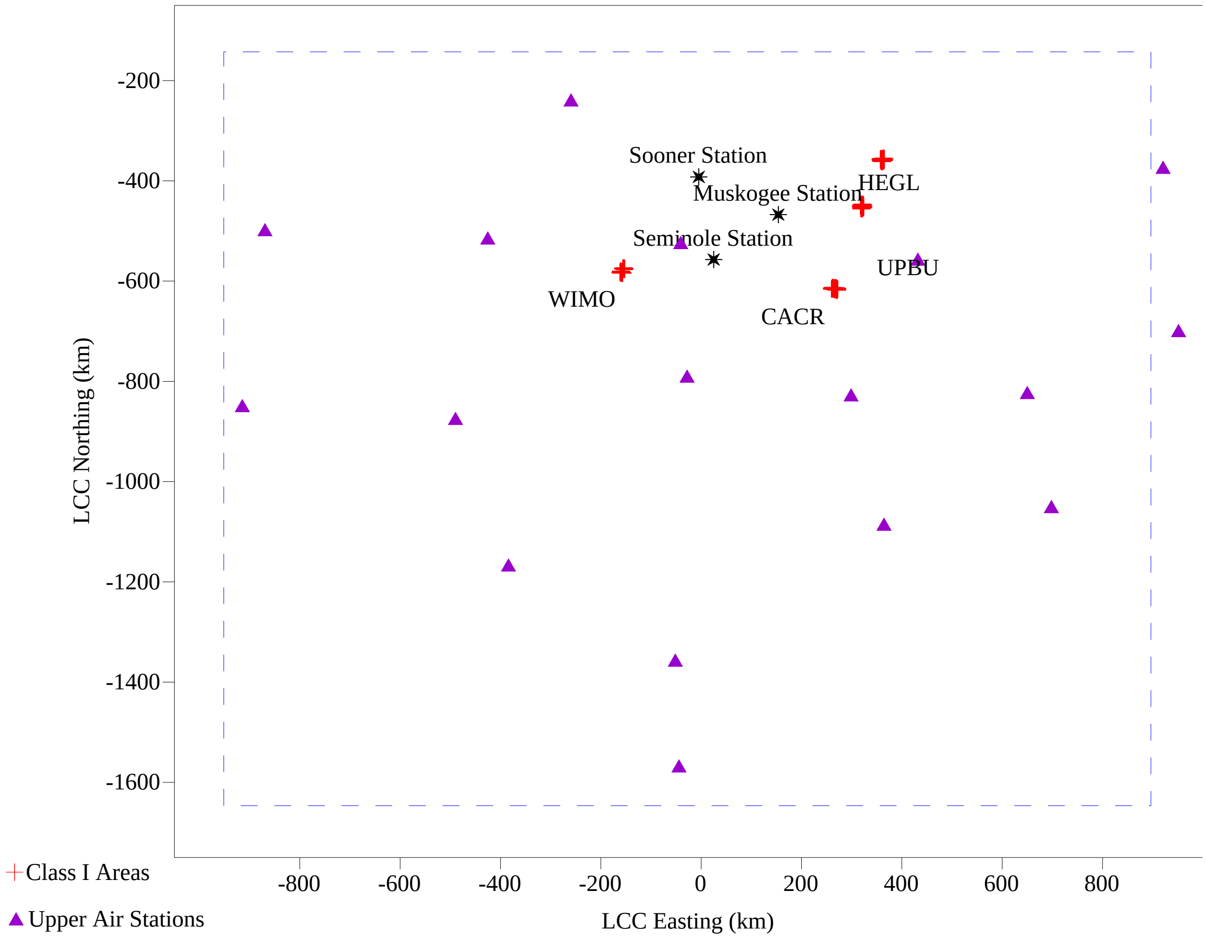
FIGURE 3-3. PLOT OF SURFACE STATION LOCATIONS



3.2.3 UPPER AIR METEOROLOGICAL DATA

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

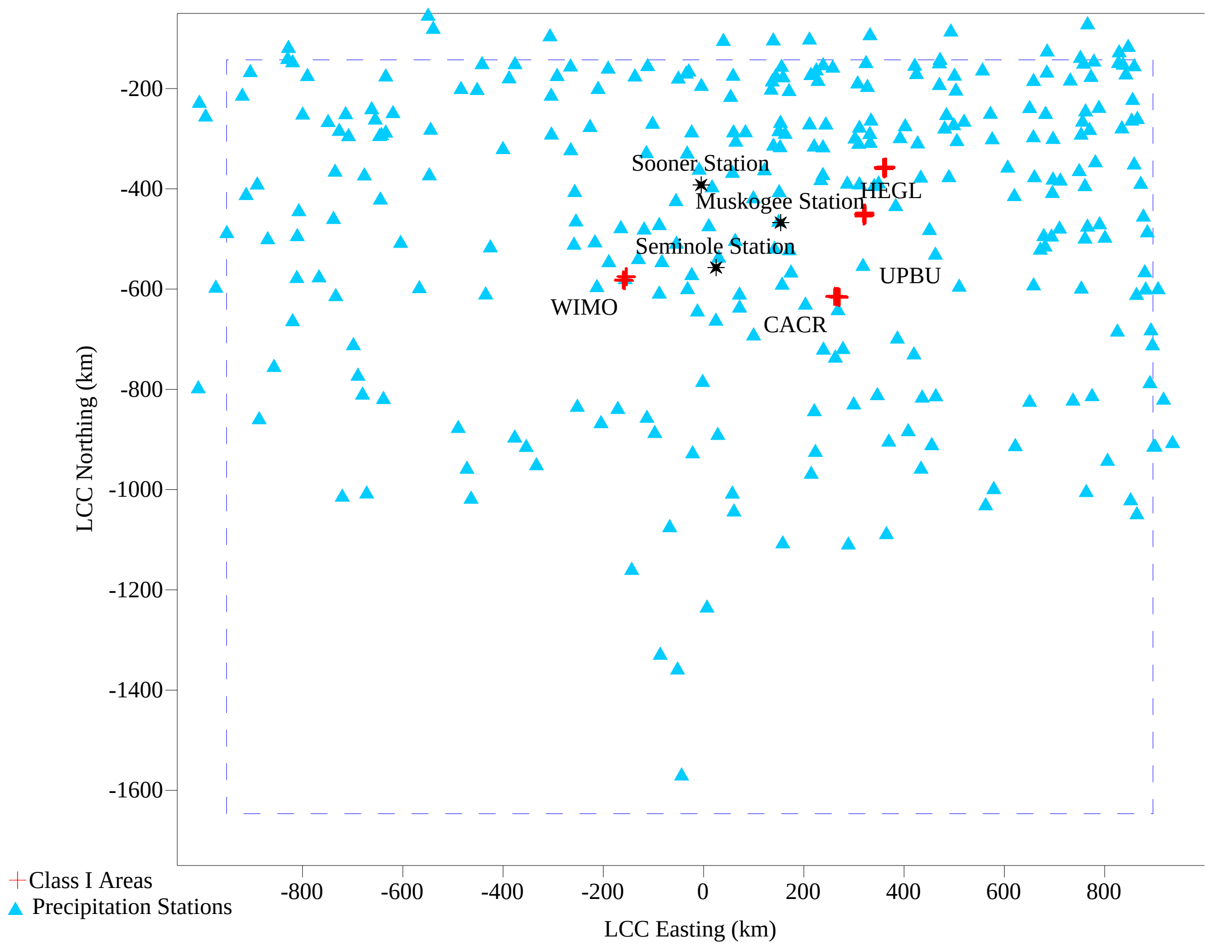
FIGURE 3-4. PLOT OF UPPER AIR STATIONS LOCATIONS



3.2.4 PRECIPITATION METEOROLOGICAL DATA

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

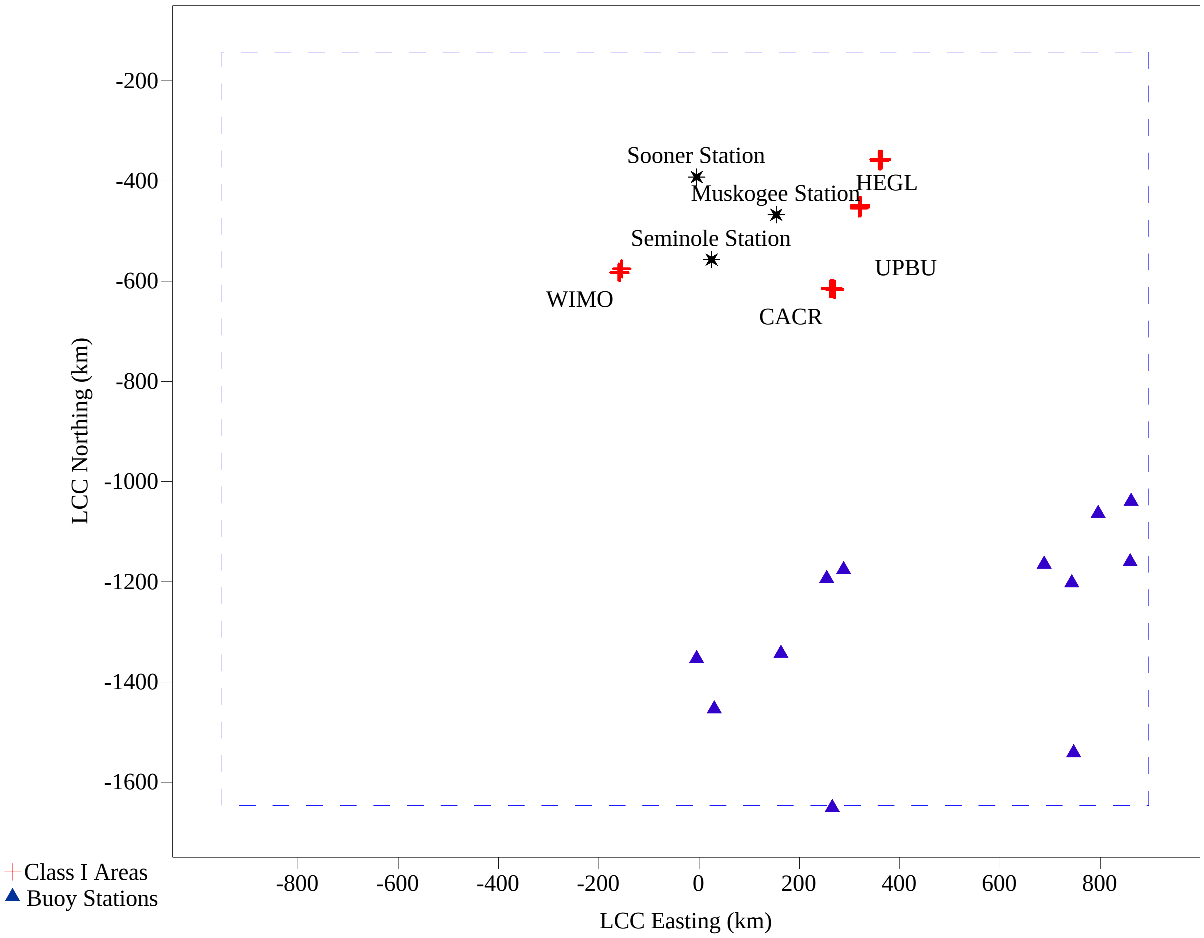
FIGURE 3-5. PLOT OF PRECIPITATION METEOROLOGICAL STATIONS



3.2.5 BUOY METEOROLOGICAL DATA

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

FIGURE 3-6. PLOT OF BUOY METEOROLOGICAL STATIONS



3.3 CALMET CONTROL PARAMETERS

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

3.3.1 VERTICAL METEOROLOGICAL PROFILE

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

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

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

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

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

3.3.2 INFLUENCES OF OBSERVATIONS

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

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

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

TABLE A-1. LIST OF SURFACE METEOROLOGICAL STATIONS

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

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

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

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

TABLE A-2. LIST OF UPPER AIR METEOROLOGICAL STATIONS

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

TABLE A-3. LIST OF PRECIPITATION METEOROLOGICAL STATIONS

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

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

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

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

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

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

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

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

TABLE A-4. LIST OF OVER WATER METEOROLOGICAL STATIONS

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