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AR-13-052

June 25, 2013

Mr. Mike Bates
Chief, Air Division
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118

RE: Entergy Arkansas, Inc. – Lake Catherine Plant
Revised BART Five-Factor Analysis
Permit No. 1717-AOP-R5, AFIN 30-00011

Dear Mr. Bates:

Please find attached a revised and updated Best Available Retrofit Technology (BART) Five-Factor Analysis (FFA) for Unit 4 located at the Entergy Arkansas, Inc – Lake Catherine Plant. This updated FFA was completed in order to incorporate revisions made to the analysis in response to questions received from EPA Region 6 staff regarding the initial FFA which was submitted on March 4, 2013.

In addition to the revised FFA document, we have enclosed a question and answer document in which we directly respond to each specific issue raised in EPA's comments.

We appreciate ADEQ's consideration of this analysis and additional supporting information. Should you or your staff have any questions regarding this submittal, please contact me at (501) 377-4033 or David Triplett at (501) 377-4030.

Sincerely,

G. Tracy Johnson
G. Tracy Johnson
Manager, Arkansas Environmental Support

GTJ/dct

CC: Mary Pettyjohn, ADEQ (via email)

REVISED BART FIVE FACTOR ANALYSIS

LAKE CATHERINE STEAM ELECTRIC STATION

MALVERN, ARKANSAS (AFIN 30-00011)

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June 2013

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1. Executive Summary

This report is a revision to the "BART Five Factor Analysis" submitted to ADEQ on March 4, 2013 and is being submitted to provide a comprehensive document that encompasses the determination of the Best Available Retrofit Technology (BART) for Entergy Arkansas, Inc.'s (Entergy's) BART-affected electric generating unit (EGU), Unit 4 at the Lake Catherine plant including revisions made in response to EPA's comments and suggestions on the previous submittal. The BART determination for each pollutant has not changed.

Unit 4 is a tangentially-fired boiler with a nominal net power rating of 558 MW and a nominal heat input capacity of 5,850 million British thermal units per hour (MMBtu/hr) that is permitted to burn natural gas and No. 6 fuel oil. Entergy does not project to burn fuel oil at Lake Catherine Unit 4 in the foreseeable future, so emissions from fuel oil are not considered in this analysis. If conditions change such that it becomes economic to burn fuel oil, a five factor analysis will be submitted for approval in the State Implementation Plan (SIP). The combustion of fuel oil would not occur until final SIP approval.

BART determinations for SO_2 and PM_{10} based on the use of natural gas were approved in EPA's March 12, 2012 final rule. The determinations result in no SO_2 or PM_{10} controls needed during natural gas combustion.

Based on modeling performed for this analysis, combined emissions of nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter with a mass mean diameter smaller than ten microns (PM_{10}) from Lake Catherine Unit 4 are predicted to cause or contribute greater than 0.5 delta deciviews (Δdv) to visibility impairment in four Class I Areas: Caney Creek Wilderness (CACR), Upper Buffalo Wilderness (UPBU), Hercules Glades Wilderness (HERC), and Mingo Wilderness (MING)[1]. The contributions of the SO_2 and PM_{10} emissions to the visibility impairment are negligible when compared to the contribution of NO_X.

A summary of the existing visibility impairment attributable to the boiler based on the default natural conditions is provided in Table 1-1. The visibility impairment summarized in Table 1-1 is based on recent modeling conducted by Trinity Consultants (Trinity) using emissions data based on a combination of stack testing, Continuous Emission Monitoring System (CEMS) data as reported to EPA's Clean Air Markets Database (CAMD), and AP-42 emission factors as further described in Section 4 of this report.

TABLE 1-1. EXISTING VISIBILITY IMPAIRMENT ATTRIBUTABLE TO UNIT 4

CACR		UPBU		HERC		MING	
98th % Δdv	**Days > 0.5 Δdv**	**98th % Δdv**	**Days > 0.5 Δdv**	**98th % Δdv**	**Days > 0.5 Δdv**	**98th % Δdv**	**Days > 0.5 Δdv**
1.371	80	0.532	21	0.387	8	0.429	7

[1] Sipsey Wilderness was included in the Arkansas Department of Environmental Quality's (ADEQ's) original BART analyses, but is not included in this analysis because the EPA-requested change in meteorological data (to a refined, or "NO OBS = 0", dataset; *see* Section 3 and Appendix B) excludes Sipsey from the modeling domain.

Trinity used the EPA's BART guidelines in 40 CFR Part 51[2] to determine BART for Unit 4. Specifically, Trinity conducted a five-step analysis to determine BART for NO_X that included the following:

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

The BART analysis concludes that for NO_X, the achievement of an emission rate of 0.24 lb/MMBtu through the installation and use of Burners Out of Service (BOOS) represents BART.[3]

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

[3] EPA recently issued a final rule allowing states that are subject to the Cross-State Air Pollution Rule (CSAPR) trading program for seasonal NO_X to rely on the reductions achieved through that trading program to satisfy the regional haze program requirements for units subject to BART. "Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available Technology (BART) Determinations, Limited SIP Disapprovals and Federal Implementation Plans," 77 Fed. Reg. 33651 (June 7, 2012). On August 21, 2012, the D.C. Circuit in a 2-1 decision vacated CSAPR (*EME Homer City Generation v. EPA*, --F. 3d --, No. 11-1302 (D.C. Cir. 2012), and the Clean Air Interstate Rule (CAIR) remains in effect until a replacement rule, if any, is promulgated. If CSAPR ultimately is upheld and implemented in Arkansas, Entergy may rely on CSAPR to satisfy its NO_X regional haze obligations at Unit 4. Alternatively, if CSAPR is vacated and CAIR remains in place, Entergy may rely on CAIR to satisfy its NO_X obligations under BART as EPA has previously determined that the CAIR season NO_X trading program provides greater visibility improvement than BART.

2. INTRODUCTION AND BACKGROUND

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

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the Best Available Retrofit Technology (BART) rule, which included guidance for making source-specific BART determinations.[4] The BART rule defines BART-eligible sources as sources that meet the following criteria:

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

A BART-eligible source is subject to BART if the source is "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." EPA has determined that a source is reasonably anticipated to cause or contribute to visibility impairment if the 98th percentile visibility impacts from the source are modeled to be greater than 0.5 delta deciviews (Δdv) when compared against a natural background.[5] Air quality modeling is the tool that is used to determine a source's visibility impacts.

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

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

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

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4 The BART guidelines were published as amendments to the EPA's RHR in 40 CFR Part 51, Section 308.

5 The original modeling for Arkansas sources relied on screening met data and, as such, reviewed the maximum impact rather than the 98th percentile impact. Use of the 98th percentile impact based on the use of refined met data (such as that used in the modeling conducted as part of this BART analysis) is consistent with both the EPA's 2005 BART rule and the 2005 Central Regional Air Planning Association (CENRAP) BART modeling guidelines.

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

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

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

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

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

3. MODELING METHODOLOGIES AND PROCEDURES

This section summarizes the dispersion modeling methodologies and procedures applied in this BART analysis. All dispersion modeling has been conducted using the CALPUFF modeling system, consisting of the CALPUFF dispersion model, the CALMET meteorological data processor, and the CALPOST post-processing program. These methodologies and procedures are consistent with the ADEQ modeling protocol submitted to EPA in June 2012.

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

3.1 CALMET AND CALPUFF

The CALPUFF data and parameters are based on the 2005 BART modeling guidelines prepared for CENRAP. The CALMET data and parameters are based on the modeling protocol included in Appendix B. Note that the protocol included in Appendix B summarizes modeling methods and procedures that were followed to predict visibility impairment as part of the BART analyses for several BART-eligible sources located in Oklahoma, the first of which was Oklahoma Gas & Electric in 2007. The CALMET dataset developed per this protocol has been used – and approved by EPA – numerous times since its development.

3.2 CALPOST

The CALPOST visibility processing completed for this BART analysis is based on the October 2010 guidance from the Federal Land Managers Air Quality Related Values Workgroup (FLAG)[6].

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

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

The impact of a source is determined by comparing the *HI* attributable to a source relative to estimated natural background conditions. The change in the haze index, in deciviews, also referred to

6 The 2010 FLAG guidance, which was issued in draft form on July 8, 2008, and published as final guidance in December 2010, makes technical revisions to the previous guidance issued in December 2000.

as “delta dv,” or Δdv, based on the source and background light extinction is based on the following equation:

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

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

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

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

CALPOST Method 8, Mode 5 requires the following:

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

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

TABLE 3-1. ANNUAL AVERAGE BACKGROUND CONCENTRATION

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

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

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

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

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

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

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

4. EXISTING EMISSIONS AND VISIBILITY IMPAIRMENT

This section summarizes the existing (i.e., baseline) visibility impairment attributable to Unit 4 based on air quality modeling conducted by Trinity.

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

Table 4-1 summarizes the emission rates that were modeled for SO_2, NO_X, and PM_{10}, including the speciated PM_{10} emissions. The SO_2 and NO_X emission rates are the highest actual 24-hour emission rates based on 2001-2003 continuous emissions monitoring system (CEMS).[7] Please note that CEMS data from these years is representative of burning only natural gas.

The emission rates for the PM_{10} species reflect the breakdown of the filterable and condensable PM_{10} determined from AP-42 Table 1.4-2 *Combustion of Natural Gas.* All filterable PM was assumed to be elemental carbon, as this is the assumption that the National Park Service (NPS) uses for filterable PM_{10} from natural gas fired combustion turbines, and the NPS does not have a speciation analysis specific to gas fired boilers. All of the condensable PM was assumed to be SOA, except for a small fraction of the condensable PM that was estimated to be SO_4. One-third of the estimated SO_2 emissions were separated and adjusted for differences in molecular weight to represent SO_4 emissions. This essentially double counts some of the fuel sulfur based emissions as SO_2 but also as SO_4. Since pipeline natural gas contains very little sulfur, both the SO_2 and SO_4 emission rates are very low.

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

Unit	SO_2[8] (lb/hr)	NO_X[9] (lb/hr)	Total PM_{10} (lb/hr)	SO_4 (lb/hr)	PM_c (lb/hr)	PM_f (lb/hr)	SOA (lb/hr)	EC (lb/hr)
Unit 4	3.1	2,456.4	44.3	1.5	0.0	0.0	31.8	11.0

4.2 BASELINE VISIBILITY IMPAIRMENT

Trinity conducted modeling to determine the visibility impairment attributable to Unit 4 in four Class I Areas: Caney Creek Wilderness (CACR), Upper Buffalo Wilderness (UPBU), Hercules Glades Wilderness (HERC), and Mingo Wilderness (MING) using the CALPUFF dispersion model. Table 4-2 provides a summary of the modeled visibility impairment attributable to Unit 4 at CACR, UPBU, HERC, and MING based on the emission rates shown in Table 4-1. Table 4-2 the maximum

[7] *See* Appendix C

[8] The SO_2 hourly rate was derived from EPA's CAMD. The 2001-2003 max daily rate was 74 lb/day. *See* Appendix C.

[9] The NO_x hourly rate was derived from EPA's CAMD. The 2001-2003 max daily rate was 58,954 lb/day. *See* Appendix C.

impairment in Δdv, the 98th percentile impacts in Δdv, and the number of days with impacts greater than 0.5 Δdv as well as the breakdown by pollutant species for the 98th percentile impact.

As BART is determined on a unit-by-unit basis, this baseline modeling is presented to show how the BART proposed controls will cause improvement, at least on a relative basis.

All of the CALMET, CALPUFF, and CALPOST modeling files used to generate these results are included as part of the electronic files submitted with this document.

TABLE 4-2. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO LAKE CATHERINE, UNIT 4 BY POLLUTANT

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Day with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek Wilderness							
2001	3.480	1.371	31	0.49	85.13	0.00	8.55
2002	3.318	0.909	21	0.31	92.53	0.00	4.18
2003	3.276	1.233	28	0.43	85.66	0.00	7.76
Upper Buffalo Wilderness							
2001	1.478	0.489	7	0.33	89.54	0.00	5.99
2002	0.916	0.532	9	0.22	96.29	0.00	1.26
2003	2.044	0.412	5	0.21	97.36	0.00	0.30
Hercules Glades Wilderness							
2001	0.760	0.387	4	0.30	91.12	0.00	4.92
2002	1.016	0.313	2	0.39	88.73	0.00	6.08
2003	0.881	0.311	2	0.38	93.27	0.00	2.57
Mingo Wilderness							
2001	0.511	0.237	1	0.30	92.55	0.00	3.17
2002	0.763	0.429	5	0.32	96.25	0.00	0.44
2003	0.516	0.214	1	0.18	98.08	0.00	0.10

5. SO_2 BART EVALUATION

A BART determination for SO_2 based on the use of natural gas was approved in EPA's March 12, 2012, final rule. The determination results in no SO_2 controls needed during natural gas combustion.[10]

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

6.1 IDENTIFICATION OF AVAILABLE RETROFIT NO_X CONTROL TECHNOLOGIES

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

Nitrogen oxide (NO) is typically the predominant form of NO_X from fossil fuel combustion. Nitrogen dioxide (NO_2) makes up the remainder of the NO_X. The formation of NO_X compounds in utility boilers is sensitive to the method of firing. In tangentially-fired boilers, such as Unit 4, a single rotating flame is created in the center of the furnace, rather than the discrete flames produced by burners in the wall-fired boilers. Tangentially fired boilers typically have lower uncontrolled NO_X emissions than wall-fired boilers. Therefore baseline NO_X emission rates can vary significantly from plant to plant due to method of firing as well as several other factors.

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

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

TABLE 6-1. AVAILABLE NO_X CONTROL TECHNOLOGIES FOR UNIT 4

NO_X Control Technologies	
Combustion Controls	Burners Out of Service (BOOS) Flue Gas Recirculation (FGR) Separated Overfire Air (SOFA) Low NO_x Burners (LNB)
Post-Combustion Controls	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR)

6.2 ELIMINATE TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES

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

6.2.1 COMBUSTION CONTROLS

6.2.1.1 BURNERS OUT OF SERVICE (BOOS)

BOOS is a staged combustion technique whereby fuel is introduced though operational burners in the lower furnace zone to create fuel-rich conditions, while not introducing fuel to other burners. Additional air is then supplied to the non-operational burners to complete combustion. By removing fuel from certain zones, the temperature is reduced, and the production of thermal NO_X is also reduced. When operated without additional controls, the estimated controlled NO_X level for Unit 4 operating with BOOS is 0.24 lb/MMBtu.[11] This control is a technically feasible option for the control of NO_X from Unit 4.

6.2.1.2 FLUE GAS RECIRCULATION (FGR)

FGR uses flue gas as an inert material to reduce flame temperatures. In a typical flue gas recirculation system, flue gas is collected from the combustion chamber or stack and returned to the burner via a duct and blower. The addition of flue gas reduces the oxygen content of the "combustion air" (air + flue gas) in the burner. The lower oxygen level in the combustion zone reduces flame temperatures; which in turn reduces thermal NO_X formation. When operated without additional controls, the estimated controlled NO_X level for Unit 4 operating with FGR is 0.19 lb/MMBtu.[12] This control is a technically feasible option for the control of NO_X from Unit 4.

6.2.1.3 SEPARATED OVERFIRE AIR (SOFA)

SOFA diverts a portion of the total combustion air from the burners and injects it through separate air ports above the top level of burners. Staging of the combustion air creates an initial fuel-rich combustion zone with a lower peak flame temperature. This reduces the formation of thermal NO_X by lowering combustion temperature and limiting the availability of oxygen in the combustion zone where NO_X is most likely to be formed. When operated without additional controls, SOFA results in estimated NO_X emissions for gas fired boilers of 0.2-0.4 lb/MMBtu.[13] This control is a technically feasible option for the control of NO_X from Unit 4.

6.2.1.4 LOW NO_X BURNERS

LNB technology utilizes advanced burner design to reduce NO_X formation through the restriction of oxygen, lowering of flame temperature, and/or reduced residence time. NO_X creation rates typically peak at oxygen levels of five to seven percent.[14] LNB is a staged combustion process that is designed to split fuel combustion into two zones. In the primary zone, NO_X formation is

[11] Sargent & Lundy May 16, 2013 NOx Control Technology Cost and Performance Study (S&L 2013 Study).

[12] *Id.*

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

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

limited by one of two methods. Under staged fuel-rich conditions, low oxygen levels limit flame temperatures resulting in less NO_X formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel-lean conditions, excess air will reduce flame temperature to reduce NO_X formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NO_X formation.

When operated without additional controls, LNB results in estimated NO_X emissions for gas fired boilers of approximately 0.25 lb/MMBtu.[15] When combined with SOFA, the estimated NO_X control level is 0.19 lb/MMBtu.[16] LNB systems are technically feasible for the control of NO_X from Unit 4.

6.2.2 POST COMBUSTION CONTROLS

6.2.2.1 SELECTIVE CATALYTIC REDUCTION (SCR)

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

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

The SCR process requires a reactor, a catalyst, and an ammonia storage and injection system. The effectiveness of an SCR system is dependent on a variety of factors, including the inlet NO_X concentration, the exhaust temperature, the ammonia injection rate, and the type of catalyst. When combined with SOFA and LNB, the estimated NO_X control level is 0.03 lb/MMBtu.[17] This control is a technically feasible option for the control of NO_X from Unit 4.

6.2.2.2 SELECTIVE NON-CATALYTIC REDUCTION (SNCR)

In SNCR systems, a reagent is injected into the flue gas in the furnace within an appropriate temperature window. The NO_X and reagent (ammonia or urea) react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. The SNCR reagent storage and handling systems are similar to those for SCR systems. However, both ammonia and urea SNCR processes require three or four times as much reagent as SCR systems to achieve similar NO_X reductions. When combined with SOFA and LNB, the estimated NO_X

[15] "Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options." Utility Boiler section. July 1994.
[16] S&L 2013 Study.
[17] *Id.*

control level is 0.14 lb/MMBtu.[18] This control is being evaluated as a technically feasible option for the control of NO_X from Unit 4; however this technology is not adaptable to all gas-fired boilers.

6.3 Rank of Technically feasible NO_X Control Options by Effectiveness

The third step in the BART analysis is to rank the technically feasible options according to effectiveness. Table 6-2 provides a ranking of the control levels for the controls listed in the previous section for Unit 4.

Table 6-2. Control Effectiveness of Technically Feasible NO_X Control Technologies

Control Technology	Estimated Controlled Level for Unit 4 (lb/MMBtu)
SOFA	0.30
LNB	0.25
BOOS	0.24
LNB/SOFA OR FGR	0.19
LNB/SOFA + SNCR	0.14
LNB/SOFA + SCR	0.03

6.4 Evaluation of Impacts for Feasible NO_X Controls

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

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

6.4.1 Cost of Compliance

The capital costs, operating costs, and cost effectiveness of BOOS, LNB/SOFA, LNB/SOFA/SNCR and LNB/SOFA/SCR were estimated for the cost analysis. Since FGR results in the same controlled emission level as LNB/SOFA but at a higher cost[19], FGR is not considered further in the analysis.

[18] S&L 2013 Study.

[19] *Id.*

Control Costs

Control costs were calculated using cost estimates developed by Sargent and Lundy. The capital costs were annualized over a 15-year period and then added to the annual operating costs to obtain the total annualized costs.

The capital and operating cost estimates are provided in Appendix A of this report.

Annual Tons Reduced

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

The baseline annual emission rate was calculated using the baseline emission level of 0.48 lb/MMBtu and an annual heat input reflecting a ten percent capacity factor.[20]

EPA states in the BART guidelines that *"The baseline emission rate should represent a realistic depiction of anticipated annual emissions for the source."* While the average annual capacity factor for Unit 4 from 2001-2003, which are the baseline years from which the peak daily NO_X emission rate was determined as described in Section 4 of this report, was approximately 20 percent, Entergy anticipates that future utilization of Unit 4 will remain in the range of 10 percent, which is consistent with the recent operating history of the unit.

Table 6-3 below illustrates the annual capacity factor values for Unit 4 over the past ten years (2003-2012). Typical utilization of this unit has been less than 5 percent on an annual basis. Utilization in 2012 was slightly higher than 10 percent due to anomalous grid reliability issues which resulted in a need for greater utilization. These issues are not expected to arise in future years and future annual capacity factors are expected to be comparable to those experienced by the unit in 2003-2011. EPA has stated that they agree that the unit has historically operated at less than a 10 percent capacity factor and that a source may calculate baseline emissions based on a continuation of past practice.[21] A 10 percent capacity factor has been used for this analysis as a conservative estimate.

TABLE 6-3. LAKE CATHERINE UNIT 4 CAPACITY FACTORS

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
10.4	3.2	4.2	0.5	0.7	2.7	3.0	3.1	2.3	12.8

The controlled annual emission rates were based on lb/MMBtu levels believed to be achievable from the control technologies multiplied by the annual heat input. The annual heat input used to calculate the annual controlled emission rates was the same heat input that was used to calculate baseline annual emissions.

[20] The annual heat input reflecting a 10% annual capacity factor is 5,124,600 MMBtu/yr (5,850 MMBtu/hr * 8760 hrs/yr * 10% = 5,124,600 MMBtu/yr).

[21] 77 Fed. Reg. 14641.

Cost Effectiveness

The cost effectiveness in dollars per ton of NO_X reduced was determined by dividing the annualized cost of control by the annual tons reduced. An incremental cost analyses was also performed to show the incremental increase in the cost of controls when compared to BOOS. The costs effectiveness analysis is summarized in Table 6-4.

In the BART guidelines, EPA calculated that for all types of boilers other than cyclone boilers, combustion control technology is generally more cost-effective than post-combustion controls. EPA estimates that approximately 75 percent of the BART units (non-cyclone) could meet the presumptive NO_X limits at a cost of $100 to $1,000 per ton of NO_X removed based on the use of combustion control technology.[22] For the units that could not meet the presumptive limits using combustion control technology, EPA estimates that almost all of these sources could meet the presumptive limits using advanced combustion controls. The EPA estimates that the costs of such controls are usually less than $1,500 per ton of NO_X removed.[23]

Table 6-4 indicates that the cost effectiveness of BOOS is approximately $150 per ton of NO_X removed. Further, the incremental cost effectiveness of LNB/SOFA over BOOS is approximately $9,000/ton, while the incremental cost of LNB/SOFA/SNCR over LNB/SOFA is approximately $17,000/ton and the incremental cost LNB/SOFA/SCR over LNB/SOFA is approximately $14,000/ton.

Table 6-4 also summarizes the improvement in the maximum of the 98th percentile visibility impairment results due to each control technology. Details of the post-control modeling results are provided later in Section 6.5, but this summary is presented here for convenience. As Table 6-4 clearly shows, BOOS results in over 0.5 Δdv of visibility improvement when compared the baseline visibility impairment. While LNB/SOFA, LNB/SOFA/SNCR, and LNB/SOFA/SCR offer some additional visibility improvement over BOOS, up to a maximum of 0.672 Δdv of additional improvement for LNB/SOFA/SCR, the very high incremental costs when compared to BOOS cannot be justified.

22 "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART Determinations; Final Rule.) 77 Fed. Reg. 39134-39135 (July 6, 2005).

23 *Id.*

TABLE 6-4. SUMMARY OF COST EFFECTIVENESS FOR UNIT 4 NO_X CONTROLS

	Baseline Emission Rate	Controlled Emission Level	Annual Heat Input[1]	Controlled Emission Rate	NOx Reduced	Capital Cost	Annual Capital Cost	Annual Fixed O&M	Annualized Variable O&M	Total Annual Cost	Cost Effectiveness	Incremental Cost[3]	Incremental Visbility Improvement [2]
	(tpy)	(lb/MMBtu)	(MMBtu/yr)	(tpy)	(ton/yr)	($)	($/yr)	($/yr)	($/yr)	($/yr)	($/ton)	($/ton)	(dv)
BOOS	1,236	0.24	5,124,600	618	618	893,000	71,964	21,000	0	92,964	150	-	0.536
LNB/SOFA	1,236	0.19	5,124,600	495	742	11,845,025	954,548	210,000	19,034	1,183,582	1,596	8,822	0.152
LNB/OFA/SNCR	1,236	0.14	5,124,600	371	865	29,295,494	2,360,819	489,000	462,000	3,311,819	3,827	17,214	0.306
LNB/OFA/SCR	1,236	0.03	5,124,600	77	1159	79,152,952	6,378,652	568,000	268,000	7,214,652	6,223	14,440	0.672

1. The annual heat input reflects a 10% annual capacity factor (5,850 MMBtu/hr * 8760 hrs/yr * 10% = 5,124,600 MMBtu/yr)

2. The incremental visibility improvement for BOOS is the maximum visibility improvement in the 98th percentile impact compared to baseline (See Table 6-9). The incremental visibility improvement for LNB/OFA, LNB/OFA/SNCR, and LNB/SOFA/SCR is the difference between the maximum improvement due to LNB/OFA, LNB/SOFA/SNCR or LNB/SOFA/SCR in the four Class I areas considered in the analysis less the maximum visibility improvement in the four Class I areas from BOOS (See Table 6-9).

3. The incremental cost for LNB/SOFA is calculated in comparison to BOOS while the incremental costs for LNB/SOFA + SNCR and LNB/SOFA + SCR are calculated in comparison to LNB/SOFA alone.

6.4.2 ENERGY IMPACTS & NON-AIR IMPACTS

As noted in Table 6-4, SCR and SNCR systems are capable of achieving additional NO_X reductions when compared to combustion controls such as BOOS, LNB, or SOFA. However, both SCR and SNCR systems create additional energy and/or non-air environmental impacts. SCR and SNCR systems require electricity to operate the ancillary equipment. The need for electricity to help power some of the ancillary equipment creates a demand for energy that currently does not exist.

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

Another environmental impact associated with SCR is the disposal of catalyst waste. To maintain NO_X-removal effectiveness, the catalyst in an SCR system must periodically be cleaned, regenerated, or replaced. Cleaning and regeneration are preferred, but eventually the catalyst reaches the end of its useful life and must be replaced. Ideally the exhausted catalyst can be recycled for reuse, however, if the condition of the spent catalyst does not warrant recycling or a market is unavailable, the old catalyst must be disposed of. Current regulatory interpretations indicate spent SCR catalysts are exempted from hazardous waste regulation via 40 CFR § 261.4(b)(4) (Bevill Exemption) as flue gas emission control wastes. However, ongoing efforts by EPA to increase regulatory oversight of coal combustion residuals could alter that exemption, and create the potential that spent SCR catalysts would be characterized as hazardous wastes, hence increasing the cost of disposal. Regardless of the regulatory treatment of the waste, the disposal creates additional potential financial and environmental impacts associated with an SCR system.

6.4.3 REMAINING USEFUL LIFE

The remaining useful life of Unit 4 is sufficiently long such that it does not affect the BART analysis.

6.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE NO_X CONTROLS

A final impact analysis was conducted to assess the visibility improvement for existing emission rates when compared to the emission rates associated with BOOS, LNB/SOFA, LNB/SOFA/SNCR, and

LNB/SOFA/SCR. Section 4 of this report documented the existing visibility impairment attributable to Unit 4. In order to assess the visibility improvement associated with BOOS, LNB/SOFA, SCR and SNCR systems, the NO_X emission rates associated with the control systems were modeled using CALPUFF. The controlled emission level associated with BOOS is 0.24 lb/MMBtu; the controlled emission level associated with an LNB/SOFA system is 0.19 lb/MMBtu; the controlled emission level associated with an LNB/SOFA/SNCR system is 0.14 lb/MMBtu, and the controlled emission level associated with an LNB/SOFA/SCR system is 0.03 lb/MMBtu. These levels were multiplied by the maximum heat input (5,850 MMBtu/hr) to derive hourly the hourly emission rates used in the modeling.

Tables 6-5 through 6-8 summarize the NO_X emission rates that were modeled to reflect the BOOS, LNB/SOFA, LNB/SOFA/SNCR and LNB/SOFA/SCR control options. The emission rates for the other pollutants shown in Tables 6-5 through 6-8 are the same as in the baseline modeling.

TABLE 6-5. SUMMARY OF EMISSION RATES MODELED TO REFLECT BOOS FOR NO_X CONTROL

	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
Unit 4	3.1	1.5	1,404.0	0.0	0.0	31.8	11.0	44.3

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

	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
Unit 4	3.1	1.5	1,111.5	0.0	0.0	31.8	11.0	44.3

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

	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
Unit 4	3.1	1.5	819.0	0.0	0.0	31.8	11.0	44.3

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

	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
Unit 4	3.1	1.5	175.5	0.0	0.0	31.8	11.0	44.3

Table 6-9 provides a comparison of the existing visibility impairment and the visibility impairment associated with the addition of NO_X controls on Unit 4 in all affected Class I areas, including the maximum modeled visibility impact, 98th percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv.

TABLE 6-9. SUMMARY OF VISIBILITY IMPROVEMENT ASSOCIATED WITH NO_X CONTROL SYSTEM ON UNIT 4 (2001-2003)

	Caney Creek Wilderness			**Upper Buffalo Wilderness**			**Hercules Glades Wilderness**			**Mingo NWR**		
	Maximum Impact (Δdv)	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**
Existing Emission Rate	3.480	1.371	80	2.044	0.532	21	1.016	0.387	8	0.763	0.429	7
BOOS	2.154	0.835	37	1.232	0.307	11	0.6	0.229	2	0.447	0.253	0
Post Control Improvement	*1.326*	*0.536*	*43*	*0.812*	*0.225*	*10*	*0.416*	*0.158*	*6*	*0.316*	*0.176*	*7*
LNB/SOFA	1.759	0.683	28	0.996	0.25	9	0.482	0.185	0	0.358	0.204	0
Incremental Post Control Improvement over BOOS	*0.395*	*0.152*	*9*	*0.236*	*0.057*	*2*	*0.118*	*0.044*	*2*	*0.089*	*0.049*	*0*
LNB/SOFA/SNCR	1.349	0.529	16	0.755	0.193	4	0.362	0.141	0	0.268	0.154	0
Incremental Post Control Improvement over BOOS	*0.805*	*0.306*	*21*	*0.477*	*0.114*	*7*	*0.238*	*0.088*	*2*	*0.179*	*0.099*	*0*
LNB/SOFA/SCR	0.452	0.163	0	0.211	0.057	0	0.101	0.043	0	0.082	0.042	0
Incremental Post Control Improvement over BOOS	*1.702*	*0.672*	*37*	*1.021*	*0.25*	*11*	*0.499*	*0.186*	*2*	*0.365*	*0.211*	*0*

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

As shown in Table 6-9, based on visibility predictions from the CALPUFF modeling system, the operation of a BOOS will result in up to a 0.536 Δdv improvement (depending on the Class I area) to the existing visibility impairment attributable to Unit 4. This visibility improvement increases by 0.152 Δdv for LNB/SOFA (0.835-0.683 = 0.152), 0.306 Δdv for LNB/SOFA/SNCR (0.835-0.529 = 0.306), and 0.672 Δdv for LNB/SOFA/SCR (.835-0.163 = 0.672).

For convenience, Table 6-10 provides a condensed summary of these predicted improvements alongside the estimated control costs. The incremental visibility benefit of going from BOOS to either LNB/SOFA, LNB/SOFA/SCNR or LNB/SOFA/SCR is clearly not justified by the high incremental cost difference. The control technologies are very expensive from an initial capital investment and prohibitively more expensive from an incremental cost effectiveness standpoint than BOOS.

TABLE 6-10. INCREMENTAL COST EFFECTIVENESS FOR UNIT 4 WITH CLASS I AREA IMPROVEMENT (2001-2003)

Control Description	NOx Emissions (lb/MMBtu)	Control Eff. From Baseline (%)	Emission Reduction from Baseline (tons/yr)	Installed Cost ($)	Total Annual Control Cost ($)	Pollution Control Cost ($/ton)	Incremental Cost[1] ($/ton)	Class I Area	Baseline 98th Percentile Δdv	Controlled 98th Percentile Δdv	Improvement in 98th Percentile Δdv	Baseline # Days > 0.5 Δdv	Controlled # Days > 0.5 Δdv
BOOS	0.24	50%	618	893,000	92,964	150	-	Caney Creek	1.371	0.835	0.536	80	37
								Hercules-Glades	0.387	0.229	0.158	8	2
								Mingo	0.429	0.253	0.176	7	0
								Upper Buffalo	0.532	0.307	0.225	21	11
LNB/SOFA	0.19	60%	742	11,845,025	1,183,582	1,596	8,822	Caney Creek	1.371	0.683	0.688	80	28
								Hercules-Glades	0.387	0.185	0.202	8	0
								Mingo	0.429	0.204	0.225	7	0
								Upper Buffalo	0.532	0.250	0.282	21	9
LNB/SOFA + SNCR	0.14	70%	865	29,295,494	3,311,819	3,827	17,214	Caney Creek	1.371	0.529	0.842	80	16
								Hercules-Glades	0.387	0.141	0.246	8	0
								Mingo	0.429	0.154	0.275	7	0
								Upper Buffalo	0.532	0.193	0.339	21	4
LNB/SOFA + SCR	0.03	94%	1,159	79,152,952	7,214,652	6,223	14,440	Caney Creek	1.371	0.163	1.208	80	0
								Hercules-Glades	0.387	0.043	0.344	8	0
								Mingo	0.429	0.042	0.387	7	0
								Upper Buffalo	0.532	0.057	0.475	21	0

1. The incremental cost for LNB/SOFA is calculated in comparison to BOOS while the incremental costs for LNB/SOFA + SNCR and LNB/SOFA + SCR are calculated in comparison to LNB/SOFA alone.

6.6 PROPOSED BART FOR NO_X

Entergy proposes a BART emission rate of 0.24 lb/MMBtu on a 30-day rolling average basis, achievable through use of BOOS at Unit 4.[24]

[24] If CSAPR is upheld and implemented in Arkansas, Entergy will rely on CSAPR to satisfy its regional haze obligations at Lake Catherine. If CSAPR is vacated and CAIR remains in effect, EPA's prior determination that the reductions provided under CAIR's seasonal NO_X trading program provide greater visibility improvements than BART should allow Entergy to rely on the seasonal CAIR program to satisfy its NO_X obligations under BART.

7. PM_{10} BART EVALUATION

A BART determination for PM_{10} based on the use of natural gas was approved in EPA's March 12, 2012, final rule. The determination results in no PM_{10} controls needed during natural gas combustion.[25]

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

APPENDIX A

CONTROL COST CALCULATIONS

BOOS Capital and O&M Cost Estimate	
Operational Data	
N/A	
Capital Cost	
Implementation Cost[1]	893,000
Capital Recovery Factor (CRF)[2]	0.08
Annual Costs	
Fixed O&M Costs[3]	21,000
Variable O&M Costs[4]	0
Annualized Implementation Cost	71,964
Total Annual Costs	92,964

1: It is anticipated that BOOS can be implemented on the unit without any capital expenditures. The one-time costs associated with BOOS implementation would instead be incorporated into the facility's O&M budget for the fiscal year. In order to provide an apples-to-apples comparison with the other NOx control options, these one-time additional O&M costs were treated as if the cost were a capital expenditure. This cost is is based the Sargent & Lundy 5/16/2013 NOx Control Technology Cost and Performance Study.

2: CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life
Equipment CRF, 30-yr actual service life, 7% interest

3: The fixed O&M cost estimate for BOOS is based on the fixed O&M cost estimate for BOOS as provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study

4: The variable O&M cost estimate for BOOS is based on the variable O&M cost estimate for BOOS as provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study

LNB-SOFA Capital and O&M Cost Estimate

Operational Data	
Maximum HI (MMBtu/hr)	5850
Average Annual Operating Hours, 2009-2011	1205
Capital Cost	
Installed Capital Cost[1]	11,845,025
Capital Recovery Factor (CRF)[2]	0.08
Annual Costs	
Fixed O&M Costs[3]	210,000
Variable O&M Costs[4]	19,034
Annualized Capital Cost	954,548
Total Annual Costs	1,183,582

1: The installed capital cost estimate for LNB/OFA + SNCR is based on the installed capital cost estimate provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study ($8,762,000) plus additional cost not accounted for in the S&L cost estimate, including cost for permitting and legal/regulatory support (estimated by Entergy to be $112,500), cost for Entergy employee labor and loaders (estimated by Entergy to be $1,634,363), cost for capital suspense (estimated by Entergy to be $751,978), and cost for AFUDC (estimated by Entergy to be $584,184) .

2: CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life

Equipment CRF, 30-yr actual service life, 7% interest

3: The fixed O&M cost estimate for LNB/OFA is based on the fixed O&M cost estimate for LNB/OFA as provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study

4: The variable O&M cost estimate for LNB/OFA is based on an equation documented in the Eastern Research Group report "Analysis of Combustion Controls for Reducing NOx Emissions from Coal-fired EGUs in the WRAP Region" September 6, 2005. Section 4.3.1 and Appendix D as shown below.

Variable O&M = (0.027 mills/kW-hr/1000) x (1 kW-hr/10,000 Btu) x H x C x 10^6 Btu/mmBtu

Where:
H = Annual operating hours
C = Boiler design capacity (mmBtu/hr)
Note: The variable rate used for variable O&M costs was 0.027 mills/kW-hr. This is the rate listed in Appedix D

LNB-OFA + SNCR Capital and O&M Cost Estimate

Operational Data	
Maximum HI (MMBtu/hr)	5850
Average Annual Operating Hours, 2009-2011	1205
Capital Cost	
Installed Capital Cost[1]	29,295,494
Capital Recovery Factor (CRF)[2]	0.08
Annual Costs[3]	
Fixed O&M Costs	489,000
Variable O&M Costs	462,000
Annualized Capital Cost	2,360,819
Total Annual Costs	3,311,819

1: The installed capital cost estimate for LNB/OFA + SNCR is based on the installed capital cost estimate provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study ($24,269,000) plus additional cost not accounted for in the S&L cost estimate, including cost for permitting and legal/regulatory support (estimated by Entergy to be $112,500), cost for Entergy employee labor and loaders (estimated by Entergy to be $1,634,363), cost for capital suspense (estimated by Entergy to be $1,821,939), and cost for AFUDC (estimated by Entergy to be $1,457,962 for each unit) .

2: CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life
Equipment CRF, 30-yr actual service life, 7% interest

3: The fixed O&M cost estimate for LNB/OFA + SNCR is based on the fixed O&M cost estimate for LNB/OFA + SNCR as provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study

4: The variable O&M cost estimates are based on the cost estimates provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study. Adding LNB/OFA to SNCR makes the variable O&M costs less than that of SNCR alone due to a lower NOx concentration and resulting less reagent usage.

LNB-OFA + SCR Capital and O&M Cost Estimate

Operational Data	
Maximum HI (MMBtu/hr)	5850
Annual Operating Hours, 2009-2011	1205
Capital Costs[1]	
Installed Capital Cost	79,152,952
Capital Recovery Factor (CRF)[2]	0.08
Annual Costs[3]	
Fixed O&M Costs	568,000
Variable O&M Costs	268,000
Annualized Capital Cost	6,378,652
Total Annual Costs	7,214,652

1: The installed capital cost estimate for LNB/OFA + SCR is based on the installed capital cost estimate provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study ($68,349,000) plus additional cost not accounted for in the S&L cost estimate, including cost for permitting and legal/regulatory support (estimated by Entergy to be $387,500), cost for Entergy employee labor and loaders (estimated by Entergy to be $1,634,363), cost for capital suspense (estimated by Entergy to be $4,888,377), and cost for AFUDC (estimated by Entergy to be $3,956,212) .

2: CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life

Equipment CRF, 30-yr actual service life, 7% interest

3: All O&M cost estimateswere provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study

4: The variable O&M cost estimates are based on the cost estimates provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study. Adding LNB/OFA to SCR makes the variable O&M costs less than that of SCR alone due to a lower NOx concentration and resulting less reagent usage.

APPENDIX B

MODELING PROTOCOL

As stated in Section 3.1, the meteorological data used in the analyses presented in this report was originally developed in 2007 and was first used in a BART determination for Oklahoma Gas & Electric. Because the development of a set of CALMET/CALPUFF meteorological data is so intensive, this same dataset has been used numerous times since 2007 for various other BART projects in EPA Region 6. The protocol that accompanied the original development has followed the dataset in each case and is doing so here again.

APPENDIX C

CEMS DATA FROM CAMD FOR 2001 TO 2003

CALMET DATA PROCESSING PROTOCOL ▲ BART DETERMINATION
OKLAHOMA GAS & ELECTRIC

MUSKOGEE GENERATING STATION
SEMINOLE GENERATING STATION
SOONER GENERATING STATION

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OG+E

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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

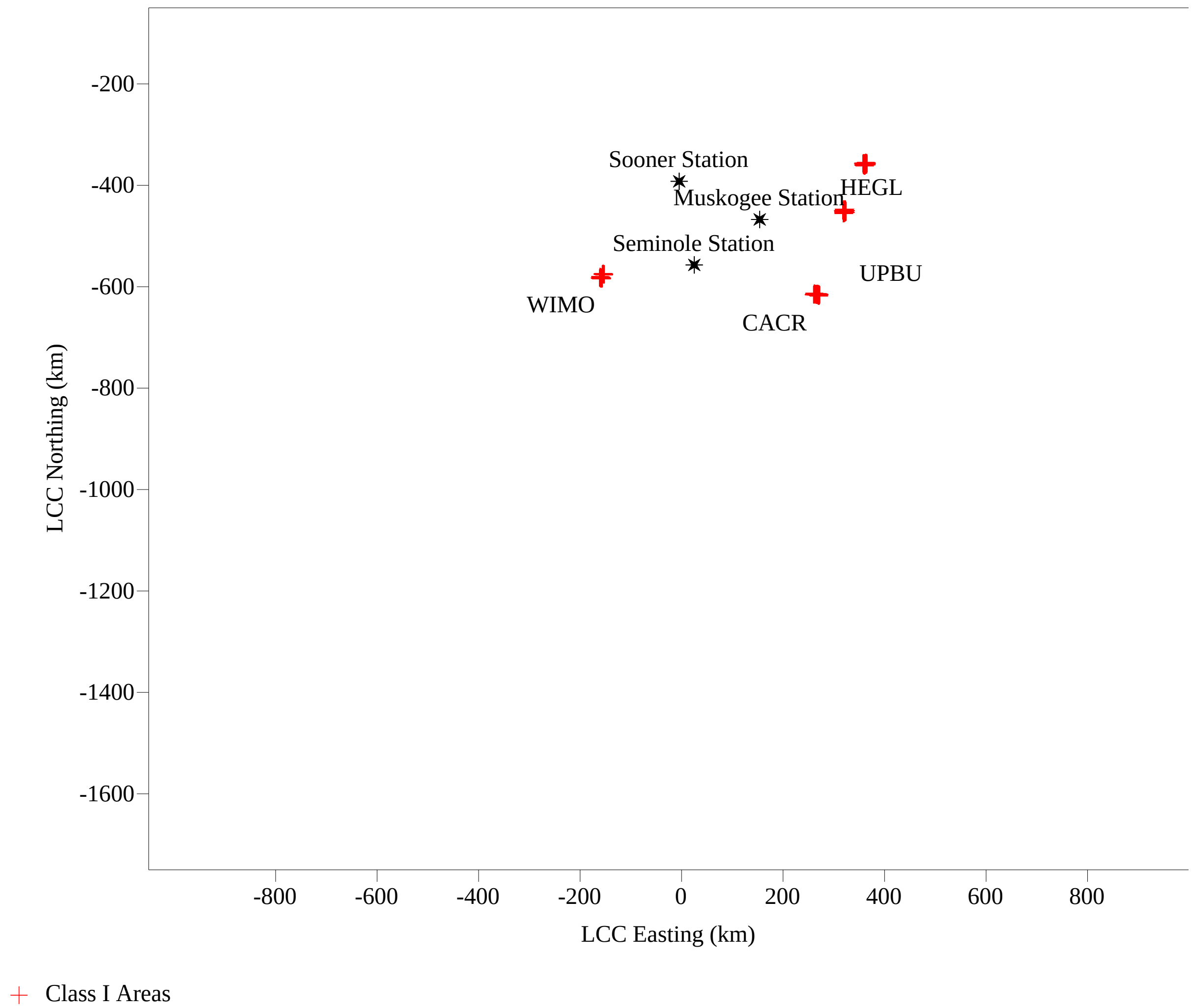
As required in CENRAP's BART Modeling Guidelines, Class I areas within 300 km of each station will be included in each analysis. The following table summarizes the distances of the four closest Class I areas to each station. As seen from this summary, some Class I areas are more than 300 km from the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

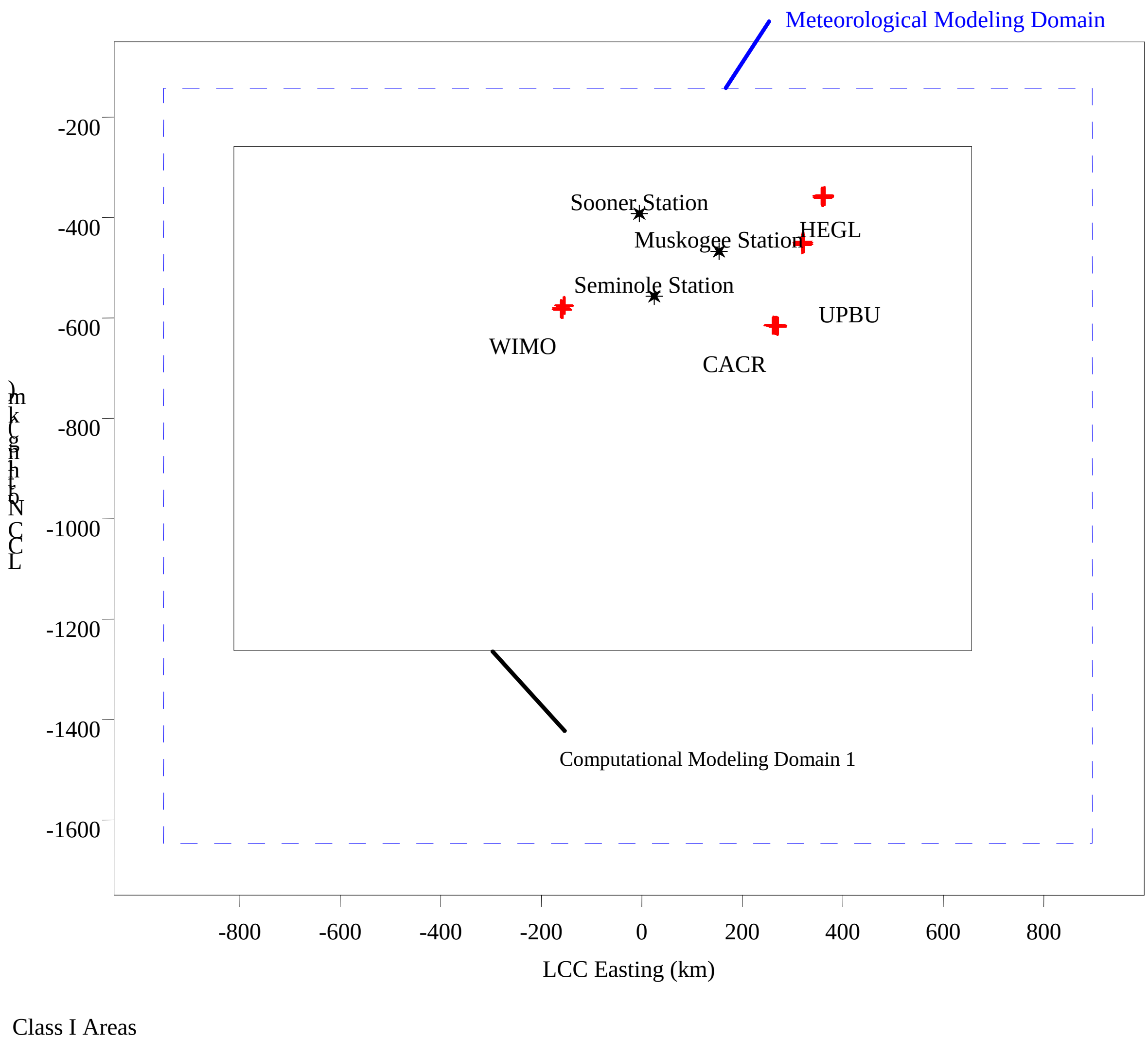
Processor	Version	Level
TERREL	3.3	030402
CTGCOMP	2.21	030402
CTGPROC	2.63	050128
MAKEGEO	2.2	030402
CALMET	5.53a	040716
CALPUFF	5.8	070623
POSTUTIL	1.3	030402
CALPOST	5.51	030709

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.

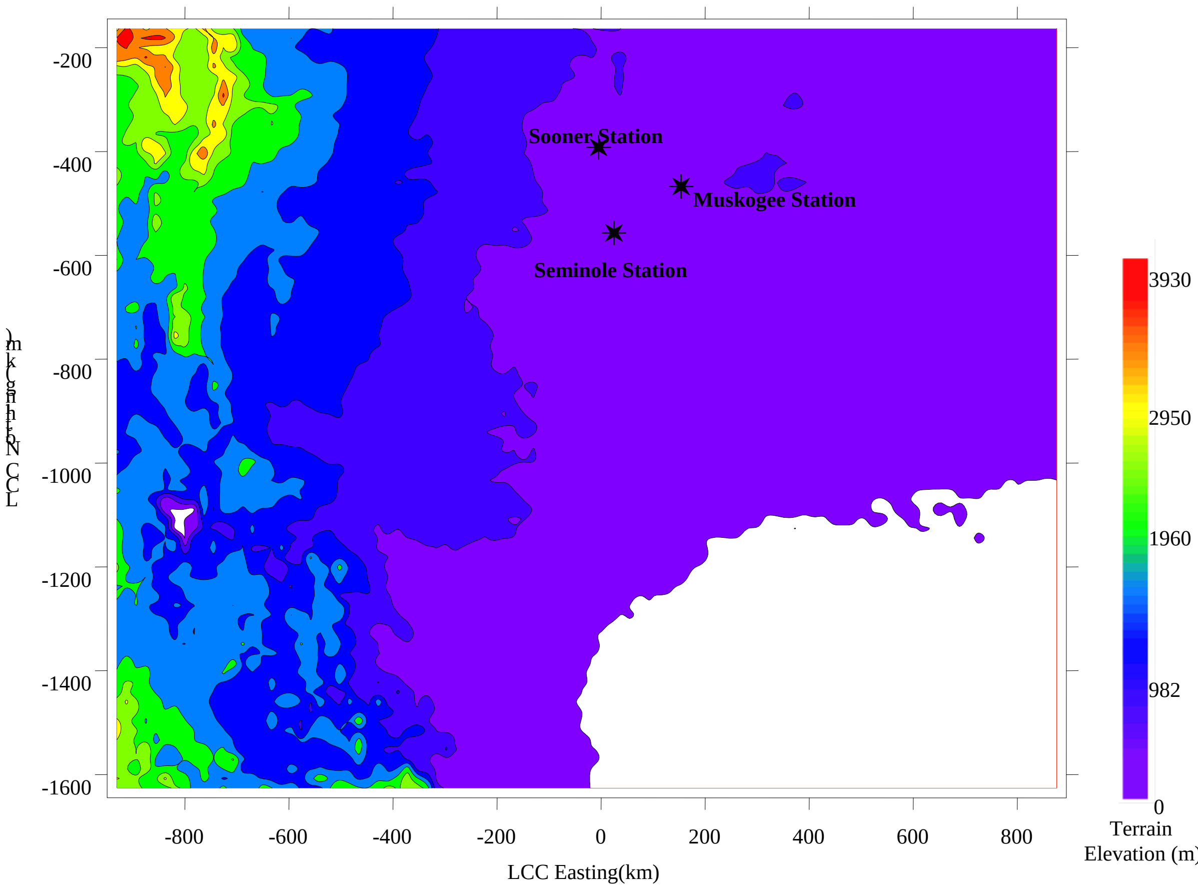
3.1 GEOPHYSICAL DATA

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.

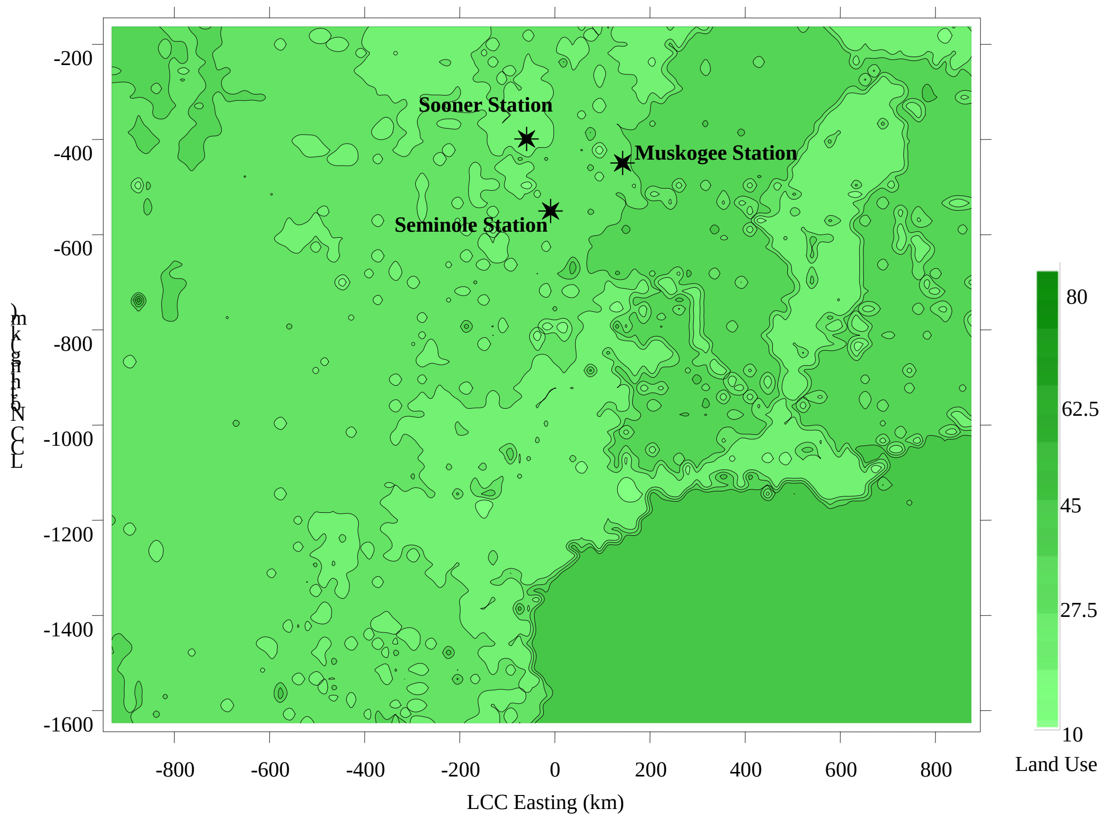
FIGURE 3-1. PLOT OF LAND ELEVATION USING USGS TERRAIN DATA



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.

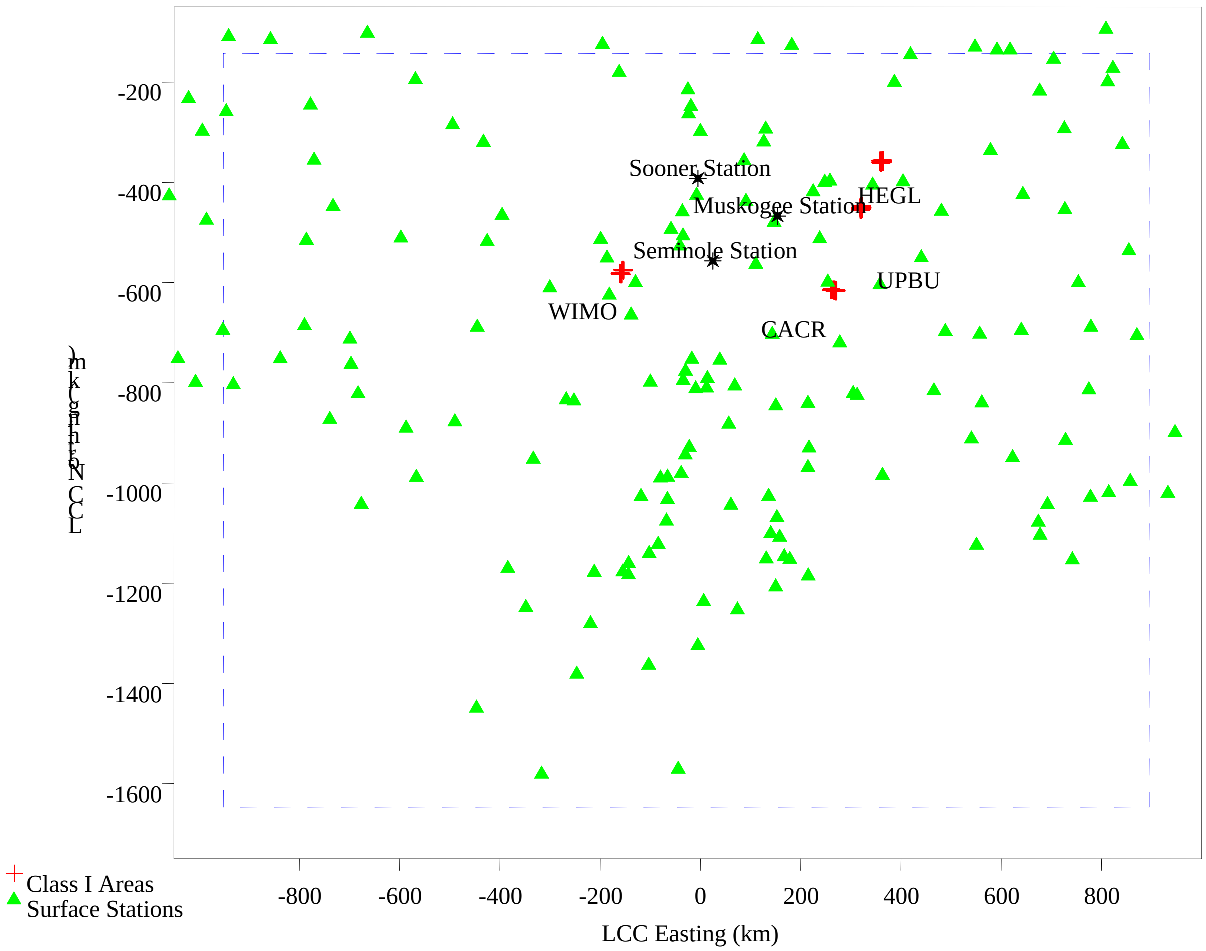
The time periods covered by the data in each of the MM5 files extracted by Alpine Geophysics include a specific number of calendar days, where the data starts at Hour 0 in GMT for the first calendar day and ends at Hour 23 in GMT on the last calendar day. In order to run CALMET in the local standard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

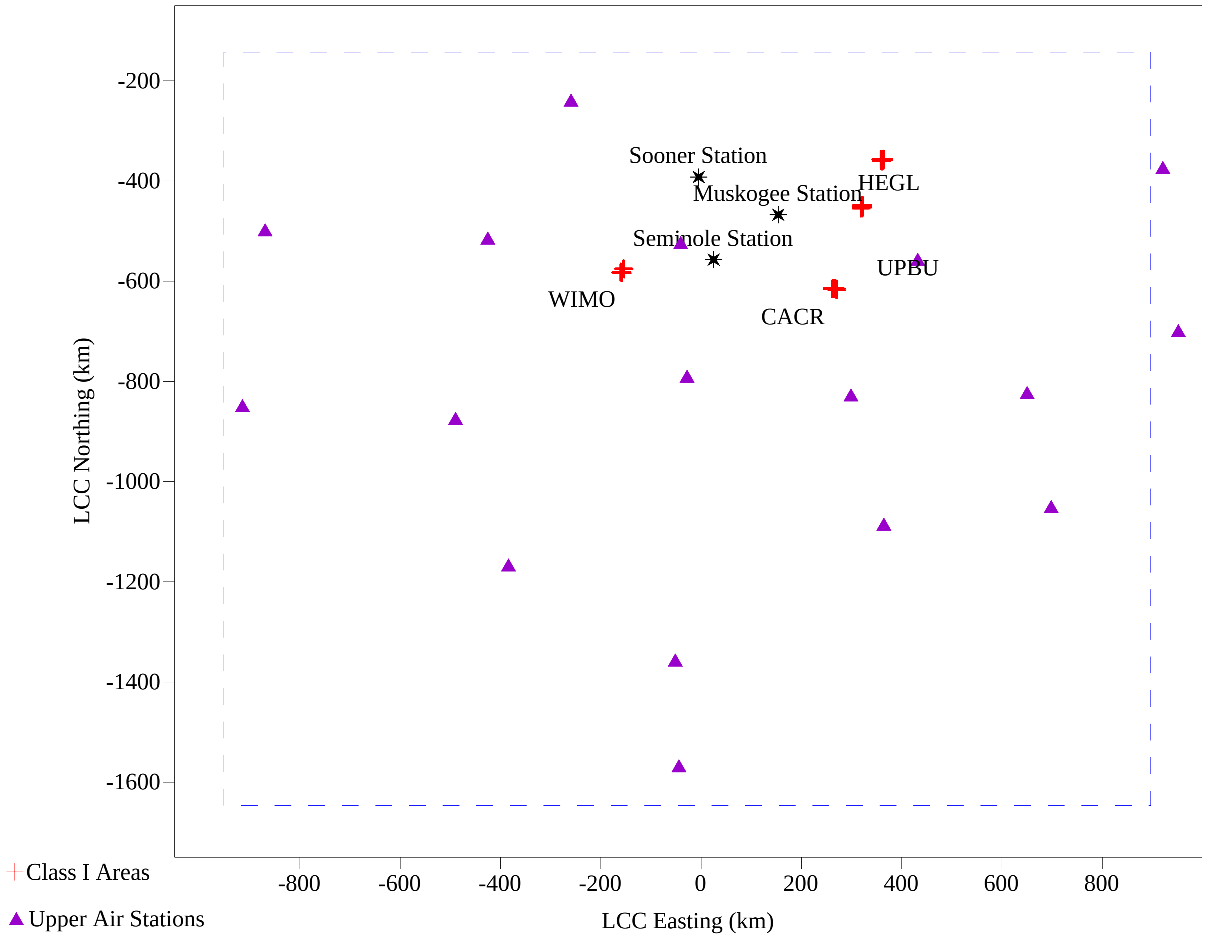
FIGURE 3-3. PLOT OF SURFACE STATION LOCATIONS



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.

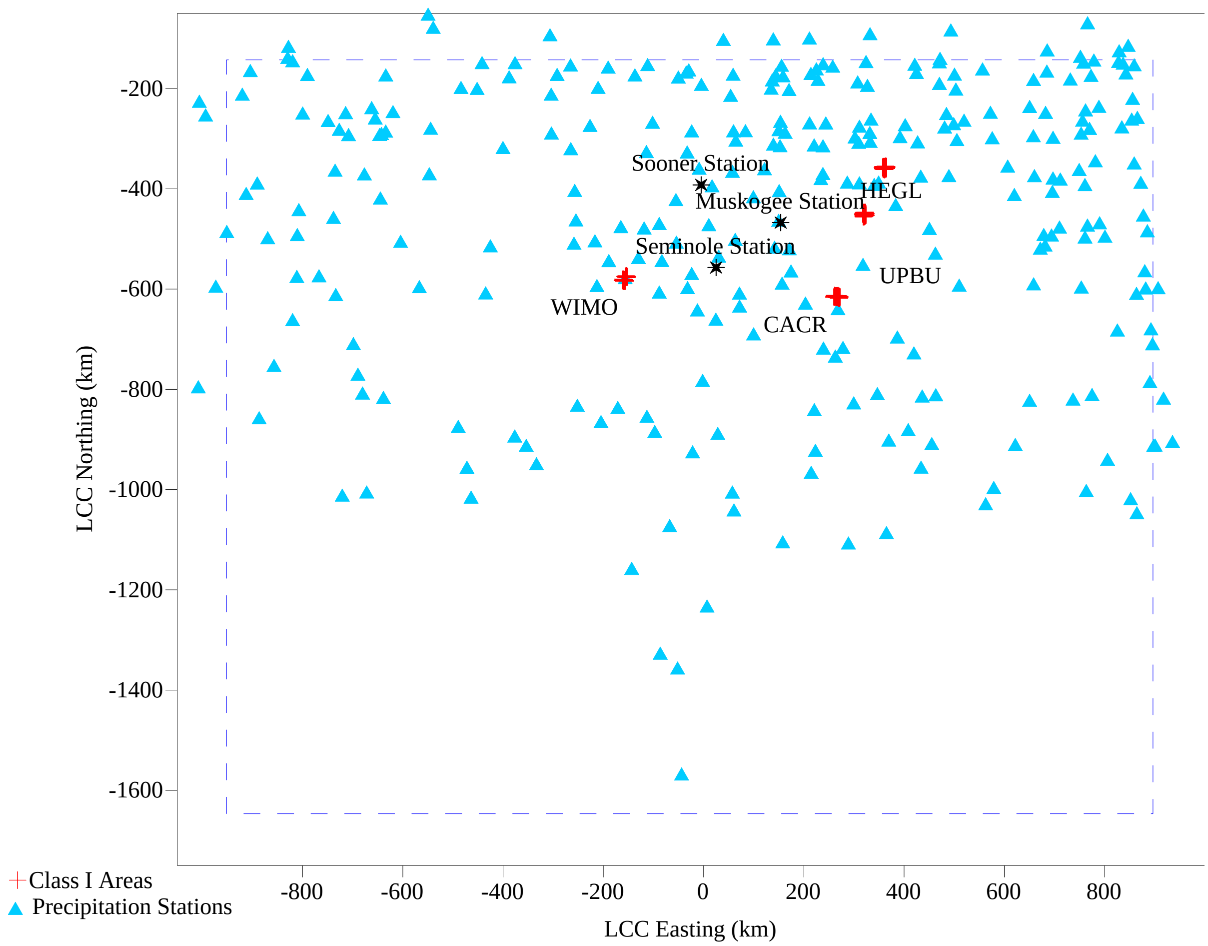
FIGURE 3-4. PLOT OF UPPER AIR STATIONS LOCATIONS



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.

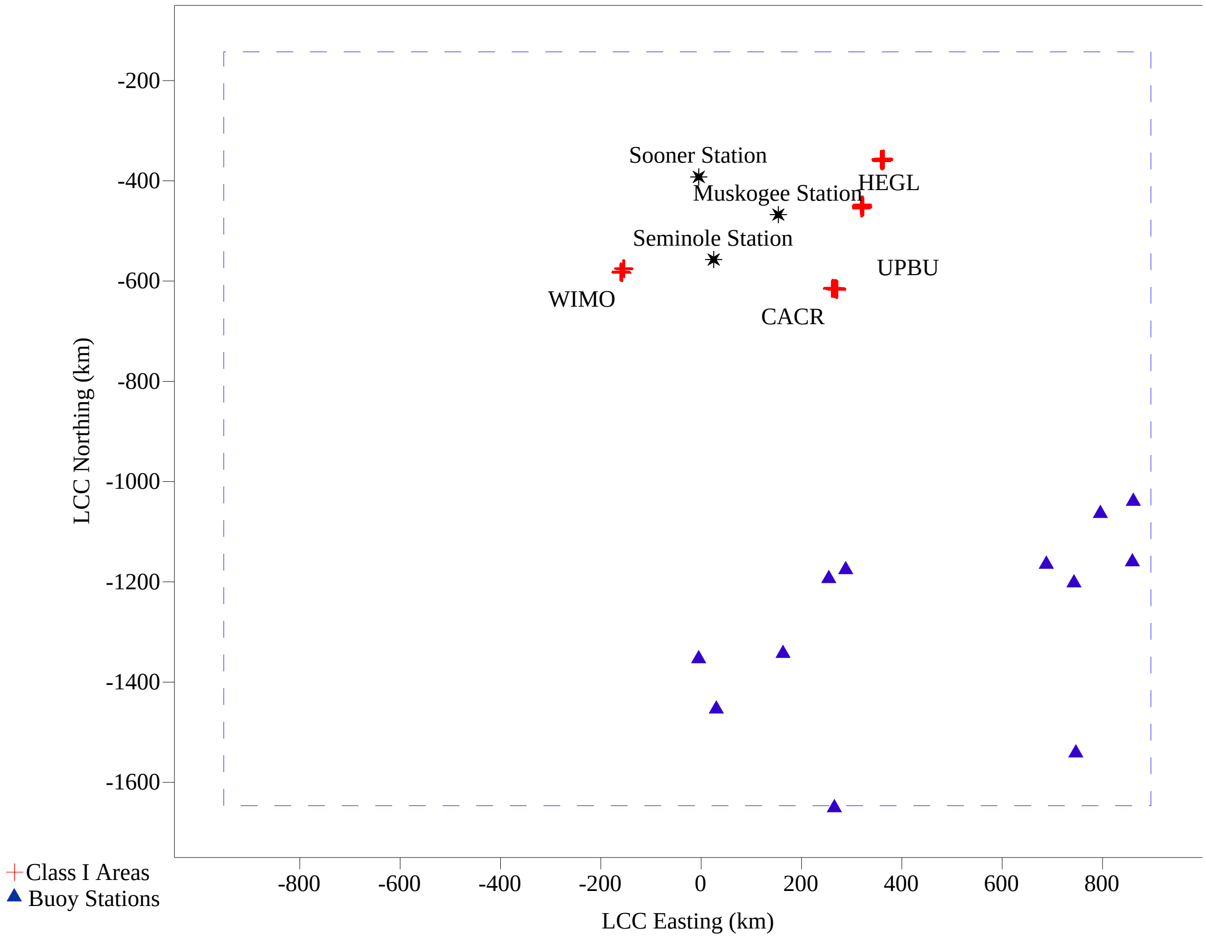
FIGURE 3-5. PLOT OF PRECIPITATION METEOROLOGICAL STATIONS



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

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Date	SO2 (tons)	Avg. NOx Rate (lb/MMBtu)	NOx (tons)	Heat Input (MMBtu)
1/1/2001	0.014	0.202	4.787	46,087
1/2/2001	0.015	0.2243	5.535	48,831
1/3/2001	0.016	0.2324	6.465	54,856
1/4/2001	0.015	0.2472	6.835	51,150
1/5/2001	0.015	0.2295	5.827	48,783
1/6/2001	0.014	0.2258	5.828	48,253
1/7/2001	0.01	0.161	2.72	32,070
1/8/2001	0.013	0.1819	4.203	41,767
1/9/2001	0.014	0.207	5.35	45,700
1/10/2001	0.013	0.1957	4.699	43,529
1/11/2001	0.012	0.1942	4.459	41,573
1/12/2001	0.015	0.2103	6.049	50,330
1/13/2001	0.013	0.1802	4.325	42,266
1/14/2001	0.009	0.148	2.24	30,269
1/15/2001	0.01	0.1638	2.999	34,364
1/16/2001	0.012	0.1739	3.935	41,489
1/17/2001	0.013	0.1896	4.397	41,694
1/18/2001	0.015	0.2143	5.91	51,559
1/19/2001	0.012	0.1832	3.987	40,093
1/20/2001	0.01	0.1459	2.602	32,991
1/21/2001	0.012	0.1796	4.014	41,428
1/22/2001	0.013	0.1769	4.102	42,797
1/23/2001	0.013	0.185	4.93	42,499
1/24/2001	0.01	0.145	2.436	32,177
1/25/2001	0.011	0.1736	3.66	37,899
1/26/2001	0.013	0.1962	5.122	43,715
1/27/2001	0.009	0.1487	2.3	29,992
1/28/2001	0.008	0.1265	1.786	28,231
1/29/2001	0.012	0.1878	4.319	39,764
1/30/2001	0.01	0.1594	2.883	33,206
1/31/2001	0.01	0.1529	2.646	32,017
2/5/2001	0.006	0.086	1.466	20,118
2/6/2001	0.016	0.2086	6.165	53,744
2/7/2001	0.009	0.1866	3.213	31,084
2/18/2001	0.001	0.0188	0.038	3,928
2/19/2001	0.007	0.0982	1.368	24,718
2/20/2001	0.009	0.1274	1.913	29,778
2/21/2001	0.01	0.1512	2.869	34,778
2/22/2001	0.017	0.2335	7.695	56,681
2/23/2001	0.012	0.1743	3.807	39,905
2/24/2001	0.009	0.1102	1.623	29,044

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2/25/2001	0.009	0.13	1.917	29,477
2/26/2001	0.009	0.1329	2.099	30,616
2/27/2001	0.003	0.1306	0.7	10,554
3/4/2001	0.001	0.0184	0.034	3,433
3/5/2001	0.002	0.0515	0.267	7,045
3/6/2001	0.014	0.221	6.083	48,166
3/7/2001	0.015	0.1927	5.478	48,645
3/8/2001	0.012	0.1555	3.269	38,946
3/9/2001	0.015	0.1743	4.568	50,545
3/10/2001	0.011	0.1549	2.964	35,761
3/11/2001	0.01	0.1379	2.435	33,295
3/12/2001	0.012	0.158	3.691	39,661
3/13/2001	0.012	0.1647	3.496	39,647
3/14/2001	0.009	0.1211	1.73	28,569
3/15/2001	0.01	0.141	2.735	33,742
3/16/2001	0.009	0.1279	1.961	30,403
3/17/2001	0.011	0.1602	3.19	36,852
3/18/2001	0.009	0.119	1.786	29,585
3/19/2001	0.014	0.207	5.529	47,177
3/20/2001	0.018	0.2443	8.471	59,677
3/21/2001	0.012	0.1685	3.87	39,580
3/22/2001	0.01	0.142	2.625	33,865
3/23/2001	0.012	0.1767	4.124	40,557
3/24/2001	0.012	0.1817	4.169	40,503
3/25/2001	0.011	0.1617	3.538	37,819
3/26/2001	0.021	0.2919	11.813	68,929
3/27/2001	0.018	0.2611	8.918	60,896
3/28/2001	0.02	0.2639	10.097	67,036
3/29/2001	0.014	0.1788	4.609	45,838
3/30/2001	0.016	0.2006	5.744	52,185
3/31/2001	0.011	0.159	3.131	37,184
4/1/2001	0.013	0.1752	4.115	42,033
4/2/2001	0.02	0.2338	8.676	66,851
4/3/2001	0.02	0.2369	8.8	66,241
4/4/2001	0.017	0.2038	6.068	55,481
4/5/2001	0.018	0.2004	6.511	60,051
4/6/2001	0.016	0.1907	5.821	52,912
4/7/2001	0.018	0.2262	7.664	59,423
4/8/2001	0.018	0.2364	8.721	58,721
4/9/2001	0.023	0.2954	12.863	76,082
4/10/2001	0.019	0.2176	7.726	64,086
4/11/2001	0.018	0.2098	6.773	58,358
4/12/2001	0.016	0.2128	6.479	54,940
4/13/2001	0.013	0.1945	4.508	42,639

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4/14/2001	0.013	0.1562	3.497	42,801
4/15/2001	0.012	0.1644	3.577	40,030
4/16/2001	0.018	0.251	9.291	61,371
4/17/2001	0.014	0.167	4.133	45,200
4/18/2001	0.016	0.2087	6.585	52,319
4/19/2001	0.016	0.1903	5.171	51,766
4/20/2001	0.015	0.1854	4.984	49,224
4/21/2001	0.018	0.217	7.923	60,062
4/22/2001	0.014	0.1674	4.429	45,026
4/23/2001	0.022	0.3043	13.43	74,361
4/24/2001	0.016	0.2062	5.866	52,154
4/25/2001	0.011	0.1527	3.108	37,695
4/26/2001	0.017	0.2286	7.555	56,092
4/27/2001	0.016	0.2169	7.077	51,677
4/28/2001	0.015	0.1953	5.461	48,962
4/29/2001	0.014	0.1772	4.859	47,124
4/30/2001	0.017	0.2	6.797	56,452
5/1/2001	0.023	0.3154	14.69	78,193
5/2/2001	0.022	0.2717	11.62	71,844
5/3/2001	0.018	0.2036	7.091	61,269
5/4/2001	0.016	0.2144	7.245	54,351
5/6/2001	0.002	0.0339	0.123	5,083
5/7/2001	0.015	0.1868	5.25	50,120
5/8/2001	0.011	0.1553	3.234	37,663
5/9/2001	0.017	0.2099	7.313	57,056
5/10/2001	0.021	0.2753	11.622	69,100
5/11/2001	0.015	0.2005	5.819	51,008
5/12/2001	0.014	0.1828	4.776	45,391
5/13/2001	0.012	0.189	4.196	39,970
5/14/2001	0.015	0.1792	5.128	50,519
5/15/2001	0.02	0.2335	9.346	65,047
5/16/2001	0.019	0.2378	9.333	63,118
5/17/2001	0.02	0.2367	8.716	66,585
5/18/2001	0.016	0.184	5.893	52,147
5/19/2001	0.014	0.167	4.463	45,811
5/20/2001	0.013	0.1558	3.867	44,248
5/21/2001	0.011	0.1592	3.108	37,242
5/22/2001	0.008	0.153	2.12	27,721
5/23/2001	0.012	0.1763	3.876	39,538
5/24/2001	0.01	0.1579	3.086	34,319
5/25/2001	0.009	0.1198	1.699	28,368
5/26/2001	0.013	0.1813	4.857	43,433
5/27/2001	0.013	0.1806	4.355	42,547
5/28/2001	0.011	0.1718	3.231	35,115

5/29/2001	0.013	0.1931	5.097	43,171
5/30/2001	0.012	0.1745	3.803	40,685
5/31/2001	0.01	0.1417	2.62	33,567
6/1/2001	0.012	0.1624	3.551	39,572
6/2/2001	0.015	0.1946	5.796	49,384
6/3/2001	0.013	0.1658	4.242	44,794
6/4/2001	0.015	0.1862	5.395	50,776
6/5/2001	0.014	0.1903	5.198	46,681
6/6/2001	0.01	0.1415	2.706	34,818
6/7/2001	0.01	0.147	2.676	34,163
6/8/2001	0.013	0.1805	4.463	44,347
6/9/2001	0.01	0.1477	2.744	33,898
6/10/2001	0.012	0.1572	3.357	38,638
6/11/2001	0.017	0.2095	7.511	57,735
6/12/2001	0.019	0.2257	8.151	62,453
6/13/2001	0.019	0.2262	8.396	63,287
6/14/2001	0.019	0.218	7.851	62,402
6/15/2001	0.017	0.2161	7.572	57,158
6/16/2001	0.017	0.2303	7.86	57,767
6/17/2001	0.015	0.1928	5.518	50,985
6/18/2001	0.011	0.154	3.944	37,549
6/19/2001	0.003	0.0882	0.39	8,841
7/4/2001	0	0.012	0.002	340
7/5/2001	0.007	0.0781	1.602	24,168
7/6/2001	0.017	0.2128	7.052	56,775
7/7/2001	0.018	0.2179	7.562	60,597
7/8/2001	0.012	0.1569	3.968	39,226
7/9/2001	0.006	0.0961	1.025	21,338
7/10/2001	0.012	0.1546	4.264	41,608
7/11/2001	0.019	0.2223	8.412	63,578
7/12/2001	0.013	0.1621	4.021	43,458
7/13/2001	0.011	0.157	3.255	37,270
7/14/2001	0.013	0.1955	4.735	42,380
7/15/2001	0.013	0.1699	4.156	41,999
7/16/2001	0.019	0.2452	9.083	61,972
7/17/2001	0.019	0.2417	9.109	64,826
7/18/2001	0.016	0.2237	8.871	53,151
7/19/2001	0.007	0.1258	2.653	23,336
7/20/2001	0.019	0.249	9.25	64,264
7/21/2001	0.02	0.2328	8.491	65,463
7/22/2001	0.02	0.2443	9.321	68,224
7/23/2001	0.02	0.224	8.157	65,909
7/24/2001	0.02	0.2445	9.159	67,299
7/25/2001	0.019	0.2355	8.694	64,989

7/26/2001	0.013	0.1794	4.211	43,236
7/27/2001	0.013	0.1774	4.508	44,375
7/28/2001	0.019	0.2528	10.205	63,064
7/29/2001	0.019	0.2475	9.877	63,148
7/30/2001	0.022	0.2758	12.376	71,671
7/31/2001	0.022	0.2781	12.547	72,866
8/1/2001	0.019	0.2373	9.073	62,425
8/2/2001	0.021	0.2795	12.222	69,430
8/4/2001	0.016	0.1885	7.963	54,373
8/5/2001	0.021	0.2535	11.118	69,392
8/6/2001	0.025	0.2972	15.248	84,978
8/7/2001	0.025	0.2612	12.576	82,822
8/8/2001	0.025	0.3036	14.997	82,983
8/9/2001	0.025	0.3064	14.974	82,680
8/10/2001	0.019	0.2215	8.202	63,423
8/12/2001	0.013	0.1633	5.452	44,824
8/13/2001	0.006	0.1483	1.688	19,487
8/14/2001	0.002	0.0623	0.246	5,337
8/15/2001	0.008	0.1385	2.604	25,423
8/16/2001	0.018	0.2429	8.743	60,910
8/17/2001	0.018	0.2434	9.046	60,599
8/18/2001	0.015	0.1771	4.996	50,262
8/19/2001	0.014	0.1915	5.261	48,081
8/20/2001	0.018	0.2217	8.411	61,514
8/21/2001	0.021	0.2575	11.024	69,191
8/22/2001	0.017	0.2267	7.102	55,132
8/23/2001	0.016	0.1806	5.129	51,909
8/24/2001	0.022	0.2213	8.506	72,974
8/25/2001	0.022	0.2256	8.811	72,126
8/26/2001	0.02	0.2177	7.642	65,753
8/27/2001	0.02	0.2303	7.848	66,030
8/28/2001	0.021	0.2293	8.581	70,504
8/29/2001	0.021	0.2264	8.509	71,148
8/30/2001	0.022	0.2056	7.903	72,119
8/31/2001	0.015	0.1776	4.423	48,572
9/4/2001	0.017	0.1992	8.364	57,635
9/5/2001	0.02	0.2337	9.682	65,332
9/6/2001	0.024	0.2887	13.929	80,508
9/7/2001	0.026	0.3046	15.043	87,673
9/8/2001	0.019	0.2353	8.989	64,371
9/9/2001	0.012	0.1626	3.702	40,954
9/10/2001	0.019	0.2765	11.064	64,465
9/11/2001	0.015	0.2078	5.686	49,648
9/12/2001	0.02	0.2698	11.86	67,987

9/13/2001	0.023	0.287	13.566	75,247
9/14/2001	0.015	0.2122	6.49	50,987
9/15/2001	0.012	0.1745	4.057	41,586
9/16/2001	0.01	0.1532	2.834	34,143
9/17/2001	0.018	0.2053	7.027	59,845
9/18/2001	0.017	0.1845	5.837	55,340
9/19/2001	0.02	0.29	12.096	67,446
9/20/2001	0.014	0.1873	5.165	48,024
9/21/2001	0.015	0.1985	5.829	50,294
9/22/2001	0.017	0.2183	7.653	56,805
9/23/2001	0.009	0.1337	2.095	30,464
9/24/2001	0.011	0.153	3.113	36,686
9/25/2001	0.009	0.1394	2.293	31,182
9/26/2001	0.009	0.1375	2.009	29,212
9/27/2001	0.013	0.1991	4.898	43,804
9/28/2001	0.011	0.1601	3.348	38,249
9/29/2001	0.009	0.1273	1.879	29,507
9/30/2001	0.009	0.1299	1.915	29,494
10/1/2001	0.016	0.2279	7.078	54,478
10/2/2001	0.02	0.2719	10.453	67,704
10/3/2001	0.021	0.2808	11.517	70,491
10/4/2001	0.018	0.217	7.058	59,238
10/5/2001	0.017	0.2193	6.911	58,101
10/6/2001	0.011	0.1701	3.541	37,099
10/7/2001	0.012	0.173	4.088	40,906
10/8/2001	0.018	0.2333	7.922	60,878
10/9/2001	0.021	0.2618	10.653	71,124
10/10/2001	0.025	0.3041	14.046	84,843
10/11/2001	0.022	0.2695	10.787	72,705
10/12/2001	0.014	0.1858	4.721	46,018
10/13/2001	0.009	0.1202	1.806	30,005
10/14/2001	0.009	0.1397	2.083	29,826
10/15/2001	0.014	0.1868	4.97	46,963
10/16/2001	0.015	0.1948	5.346	50,101
10/17/2001	0.014	0.1865	5.001	46,094
10/18/2001	0.015	0.2042	5.707	49,980
10/19/2001	0.016	0.1879	5.568	54,454
10/20/2001	0.011	0.1695	3.665	38,306
10/21/2001	0.014	0.2021	5.378	46,550
10/22/2001	0.017	0.2118	7.204	57,917
10/23/2001	0.019	0.2224	8.303	64,766
10/24/2001	0.02	0.2506	9.924	68,044
10/25/2001	0.014	0.1916	4.787	46,344
10/26/2001	0.012	0.1569	3.256	39,305

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10/27/2001	0.014	0.1796	4.434	45,299
10/28/2001	0.012	0.1632	3.641	40,671
10/29/2001	0.019	0.2607	9.652	64,118
10/30/2001	0.012	0.1614	3.716	41,285
10/31/2001	0.007	0.1413	1.716	22,574
11/2/2001	0.001	0.005	0.006	2,211
11/3/2001	0.012	0.1404	3.282	38,466
11/4/2001	0.009	0.1343	2.105	30,533
11/5/2001	0.017	0.2186	6.839	55,453
11/6/2001	0.019	0.2791	9.677	62,493
11/7/2001	0.022	0.3063	13.163	74,177
11/8/2001	0.016	0.226	6.573	53,905
11/9/2001	0.017	0.2095	6.302	56,263
11/10/2001	0.011	0.1513	2.83	35,031
11/11/2001	0.009	0.1295	1.881	29,044
11/12/2001	0.023	0.3233	14.175	76,017
11/13/2001	0.018	0.2403	8.093	59,969
11/14/2001	0.022	0.32	13.545	73,986
11/15/2001	0.019	0.2603	9.307	64,252
11/16/2001	0.02	0.2591	9.545	66,804
11/17/2001	0.015	0.2233	6.084	49,215
11/18/2001	0.01	0.1308	2.387	33,118
11/19/2001	0.015	0.1822	4.938	50,936
11/20/2001	0.014	0.181	4.702	46,801
11/21/2001	0.013	0.1629	3.929	42,621
11/28/2001	0.002	0.0235	0.15	7,641
11/29/2001	0.014	0.1843	4.9	47,614
11/30/2001	0.013	0.154	3.552	42,054
12/1/2001	0.013	0.1705	3.903	41,932
12/2/2001	0.011	0.1418	2.96	36,214
12/3/2001	0.012	0.1432	3.148	40,199
12/4/2001	0.009	0.1379	2.27	31,592
12/24/2001	0.002	0.0137	0.043	6,050
12/25/2001	0.01	0.1203	2.38	34,423
12/26/2001	0.013	0.1618	4.148	43,510
12/27/2001	0.014	0.1483	3.732	45,410
12/28/2001	0.011	0.1311	2.488	35,588
12/29/2001	0.011	0.1445	3.136	37,497
12/30/2001	0.015	0.1716	4.954	48,976
12/31/2001	0.012	0.1348	2.943	39,026
1/1/2002	0.011	0.1289	2.741	37,107
1/2/2002	0.019	0.2159	7.77	62,305
1/3/2002	0.014	0.1767	4.509	47,734
1/4/2002	0.013	0.1619	3.518	42,761

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1/5/2002	0.015	0.1869	4.642	49,164
1/6/2002	0.011	0.1285	2.462	35,085
1/7/2002	0.014	0.1835	4.424	46,324
1/8/2002	0.012	0.1583	3.56	41,383
1/9/2002	0.009	0.1222	1.888	28,489
2/9/2002	0.016	0.011	0.296	52,507
2/10/2002	0.02	0.0207	0.606	66,669
2/11/2002	0.011	0.1331	2.365	36,624
2/12/2002	0.011	0.1611	3.084	36,846
2/13/2002	0.01	0.1785	3.229	34,397
2/14/2002	0.013	0.2097	4.987	43,360
2/15/2002	0.014	0.2086	5.029	45,459
2/16/2002	0.012	0.2087	4.505	41,526
2/17/2002	0.01	0.1814	2.984	31,880
2/18/2002	0.011	0.1988	3.921	37,465
2/19/2002	0.014	0.1981	4.872	45,380
2/20/2002	0.014	0.2173	5.256	45,213
2/21/2002	0.017	0.2381	6.925	55,851
2/22/2002	0.014	0.2127	5.232	46,535
2/23/2002	0.014	0.2037	4.945	46,575
2/24/2002	0.01	0.1896	3.281	32,913
2/25/2002	0.009	0.1759	2.747	30,582
2/26/2002	0.012	0.1834	3.845	41,052
2/27/2002	0.013	0.1826	3.942	42,493
2/28/2002	0.01	0.1566	2.711	34,015
3/1/2002	0.006	0.2166	2.028	18,483
3/15/2002	0.002	0.0235	0.123	7,253
3/16/2002	0.015	0.2207	5.787	49,573
3/17/2002	0.013	0.2006	4.429	42,117
3/18/2002	0.015	0.2198	5.663	49,072
3/19/2002	0.013	0.2061	4.707	42,893
3/20/2002	0.014	0.2145	5.842	47,868
3/21/2002	0.018	0.2544	8.371	59,345
3/22/2002	0.018	0.2707	9.128	58,545
3/23/2002	0.011	0.192	3.909	37,607
3/24/2002	0.011	0.1744	3.501	37,051
3/25/2002	0.019	0.2433	8.382	62,097
3/26/2002	0.018	0.2377	7.865	60,967
3/27/2002	0.014	0.2157	5.6	47,319
3/31/2002	0.001	0.0128	0.016	2,498
4/1/2002	0.012	0.1843	4.136	40,687
4/2/2002	0.014	0.2243	5.561	46,508
4/3/2002	0.015	0.2472	6.462	49,758
4/4/2002	0.014	0.2277	6.031	48,076

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4/5/2002	0.012	0.2001	4.283	40,215
4/6/2002	0.011	0.191	3.747	37,023
4/7/2002	0.011	0.1853	3.678	36,988
4/8/2002	0.009	0.1468	2.22	30,245
4/9/2002	0.01	0.172	2.907	32,815
4/10/2002	0.013	0.2167	4.962	43,831
4/11/2002	0.016	0.2274	6.512	54,319
4/12/2002	0.016	0.2247	6.09	51,709
4/13/2002	0.017	0.2069	6.17	55,381
4/14/2002	0.013	0.1926	4.747	44,077
4/15/2002	0.018	0.2423	7.569	59,682
4/16/2002	0.019	0.2365	7.739	63,103
4/17/2002	0.02	0.2336	8.481	67,506
4/18/2002	0.018	0.224	7.316	61,168
4/19/2002	0.02	0.2517	8.836	65,022
5/2/2002	0.001	0.0148	0.017	2,211
5/3/2002	0.007	0.0993	1.714	24,898
5/4/2002	0.012	0.1863	3.914	40,781
5/5/2002	0.011	0.1728	3.337	37,451
5/6/2002	0.018	0.2097	6.908	59,594
5/7/2002	0.019	0.2303	8.425	64,152
5/8/2002	0.023	0.2361	9.35	75,224
5/9/2002	0.016	0.2122	5.898	52,439
5/10/2002	0.013	0.1986	4.614	44,164
5/11/2002	0.014	0.1765	4.683	47,444
5/12/2002	0.017	0.191	5.519	55,482
5/13/2002	0.009	0.1702	2.581	30,206
5/14/2002	0.009	0.161	2.348	29,134
5/15/2002	0.011	0.173	3.44	37,392
5/16/2002	0.021	0.2479	9.731	69,029
5/17/2002	0.012	0.2209	5.043	41,299
5/18/2002	0.01	0.188	3.206	33,448
5/19/2002	0.009	0.1645	2.379	28,929
5/20/2002	0.004	0.1594	1.021	12,647
6/1/2002	0.002	0.0113	0.034	5,847
6/2/2002	0.019	0.2273	9.398	63,706
6/3/2002	0.024	0.2836	13.792	81,176
6/4/2002	0.022	0.2306	9.943	73,180
6/5/2002	0.018	0.2241	7.916	61,459
6/6/2002	0.015	0.1971	5.382	48,636
6/7/2002	0.013	0.1934	4.553	43,848
6/8/2002	0.015	0.186	4.854	49,505
6/9/2002	0.013	0.1597	3.658	44,556
6/10/2002	0.017	0.1751	5.207	55,339

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6/11/2002	0.016	0.1805	5.309	53,865
6/12/2002	0.017	0.1882	5.673	55,975
6/13/2002	0.017	0.1988	6.108	56,375
6/14/2002	0.011	0.1794	3.37	36,087
6/15/2002	0.013	0.1893	4.432	44,130
6/16/2002	0.011	0.169	3.104	35,720
6/17/2002	0.014	0.2101	5.291	47,773
6/18/2002	0.014	0.2049	5.253	47,076
6/19/2002	0.016	0.1944	5.498	52,049
6/20/2002	0.016	0.1911	5.7	54,348
6/21/2002	0.016	0.1905	5.506	53,336
6/22/2002	0.016	0.1816	5.251	54,099
6/23/2002	0.018	0.2016	6.77	59,249
6/24/2002	0.022	0.2445	10.128	72,397
6/25/2002	0.022	0.2426	10.262	72,043
6/26/2002	0.018	0.1814	5.963	60,244
6/27/2002	0.015	0.1849	4.94	50,555
6/28/2002	0.015	0.1851	5.1	51,646
6/29/2002	0.021	0.2412	9.898	69,078
6/30/2002	0.021	0.2355	9.247	68,381
7/1/2002	0.019	0.2164	7.691	64,385
7/2/2002	0.018	0.197	6.338	59,640
7/3/2002	0.017	0.1985	6.01	55,029
7/4/2002	0.019	0.2203	7.709	62,456
7/5/2002	0.021	0.2533	10.409	70,091
7/6/2002	0.021	0.2369	9.529	69,859
7/7/2002	0.02	0.2567	10.354	68,153
7/8/2002	0.024	0.2977	13.867	78,883
7/9/2002	0.022	0.2421	10.008	73,374
7/10/2002	0.019	0.2155	7.915	64,969
7/11/2002	0.006	0.1143	1.23	18,875
7/12/2002	0.013	0.168	3.94	43,917
7/13/2002	0.013	0.1685	3.834	43,460
7/14/2002	0.013	0.1713	3.981	42,789
7/15/2002	0.018	0.2131	7.348	59,142
7/16/2002	0.016	0.1863	5.406	53,142
7/17/2002	0.015	0.1769	4.941	51,354
7/18/2002	0.013	0.1603	3.517	42,566
7/19/2002	0.015	0.1703	4.591	50,001
7/20/2002	0.019	0.2103	7.674	63,309
7/21/2002	0.02	0.211	8.165	66,038
7/22/2002	0.018	0.1994	6.706	59,449
7/23/2002	0.017	0.1995	6.439	56,379
7/24/2002	0.014	0.1683	4.345	47,462

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7/25/2002	0.018	0.2057	7.026	59,366
7/26/2002	0.019	0.2195	7.913	61,670
7/27/2002	0.02	0.2344	9.085	65,785
7/28/2002	0.02	0.2329	9.219	66,319
7/29/2002	0.018	0.2211	7.091	60,135
7/30/2002	0.019	0.1987	7.016	62,413
7/31/2002	0.02	0.2116	8.065	67,140
8/1/2002	0.02	0.2348	9.19	67,723
8/2/2002	0.02	0.2204	8.544	65,919
8/3/2002	0.021	0.233	9.727	71,119
8/4/2002	0.022	0.2389	10.048	72,709
8/5/2002	0.023	0.2528	11.034	76,430
8/6/2002	0.022	0.2487	10.381	72,419
8/7/2002	0.02	0.2277	8.971	66,020
8/8/2002	0.016	0.1953	5.712	54,134
8/9/2002	0.02	0.2207	8.389	66,924
8/10/2002	0.019	0.2229	8.173	63,200
8/11/2002	0.019	0.2428	9.007	64,645
8/12/2002	0.019	0.2223	8.197	63,315
8/13/2002	0.015	0.177	4.992	51,591
8/14/2002	0.013	0.1615	3.639	44,028
8/15/2002	0.014	0.1525	3.574	45,965
8/16/2002	0.014	0.178	4.527	47,668
8/17/2002	0.02	0.2145	8.039	66,775
8/18/2002	0.021	0.2241	9.121	71,329
8/19/2002	0.022	0.2147	8.779	72,190
8/20/2002	0.019	0.2123	8	64,039
8/21/2002	0.021	0.2276	9.215	69,432
8/22/2002	0.021	0.2321	9.377	71,456
8/23/2002	0.023	0.235	9.958	75,098
8/24/2002	0.023	0.2532	10.574	78,007
8/25/2002	0.003	0.1184	0.839	9,352
8/26/2002	0.016	0.1796	6.672	54,640
8/27/2002	0.018	0.2074	7.099	59,167
8/28/2002	0.017	0.2014	7.045	57,669
8/29/2002	0.015	0.1921	5.529	51,098
8/30/2002	0.017	0.2171	7.671	57,804
8/31/2002	0.015	0.1841	5.165	51,198
9/1/2002	0.014	0.1783	4.742	48,187
9/2/2002	0.02	0.2379	9.75	67,051
9/3/2002	0.022	0.2633	11.663	74,026
9/4/2002	0.022	0.2336	10.178	73,496
9/5/2002	0.021	0.2239	9.081	69,350
9/6/2002	0.019	0.2164	8.132	63,607

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9/7/2002	0	0.142	0.077	1,086
9/8/2002	0.002	0.0866	0.477	7,847
9/9/2002	0.02	0.2438	9.69	68,073
9/10/2002	0.022	0.2685	12.292	74,588
9/11/2002	0.02	0.2608	10.642	66,892
9/12/2002	0.017	0.227	7.805	55,975
9/13/2002	0.016	0.2185	6.919	54,441
9/14/2002	0.017	0.201	6.647	58,026
9/15/2002	0.015	0.1733	4.41	48,560
9/16/2002	0.015	0.1741	4.554	49,299
9/17/2002	0.014	0.1813	4.473	46,893
9/18/2002	0.019	0.2025	7.282	62,050
9/19/2002	0.015	0.1645	4.117	48,986
9/20/2002	0.016	0.1949	5.813	54,811
9/21/2002	0.017	0.2213	7.779	57,523
9/22/2002	0.015	0.1887	4.946	48,475
9/23/2002	0.017	0.2053	6.094	57,656
9/24/2002	0.009	0.1612	2.532	31,042
9/25/2002	0.009	0.1522	2.184	28,696
9/26/2002	0.009	0.1447	2.192	30,380
9/27/2002	0.016	0.1781	5.067	53,614
9/28/2002	0.02	0.2236	9.112	65,596
9/29/2002	0.018	0.2112	7.366	58,893
9/30/2002	0.024	0.2666	12.481	79,285
10/1/2002	0.02	0.22	8.269	65,225
10/2/2002	0.017	0.1763	5.171	55,756
10/3/2002	0.01	0.148	2.42	32,066
10/4/2002	0.024	0.2682	12.474	81,557
10/5/2002	0.02	0.2543	9.726	68,123
10/6/2002	0.021	0.2488	10.73	70,725
10/7/2002	0.017	0.2079	6.327	55,178
10/8/2002	0.009	0.1534	2.324	30,329
10/9/2002	0.011	0.1682	3.296	37,760
10/10/2002	0.011	0.1739	3.359	37,865
10/11/2002	0.013	0.1826	3.949	42,777
10/12/2002	0.016	0.1726	4.821	52,701
10/13/2002	0.012	0.1787	3.52	38,416
10/14/2002	0.014	0.1891	4.577	45,296
10/15/2002	0.011	0.1567	2.851	35,609
10/16/2002	0.012	0.1799	3.735	39,422
10/17/2002	0.009	0.1603	2.453	28,618
10/20/2002	0.002	0.0122	0.036	5,771
10/21/2002	0.018	0.2094	7.817	62,036
10/22/2002	0.02	0.2096	7.478	65,071

Entergy Arkansas, Inc.
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10/23/2002	0.013	0.1826	4.527	44,437
10/24/2002	0.015	0.1721	4.372	49,483
10/25/2002	0.014	0.1658	4.185	47,824
10/26/2002	0.011	0.1546	2.944	35,938
10/27/2002	0.013	0.1601	3.608	43,240
10/28/2002	0.02	0.2088	7.729	65,115
10/29/2002	0.016	0.194	5.532	54,367
10/30/2002	0.015	0.188	4.794	48,862
10/31/2002	0.011	0.1581	2.904	35,231
11/1/2002	0.011	0.1485	2.819	36,574
11/2/2002	0.01	0.145	2.383	31,903
11/3/2002	0.011	0.1482	2.848	35,811
11/4/2002	0.023	0.2648	12.133	78,254
11/5/2002	0.021	0.2342	9.378	68,889
11/6/2002	0.015	0.1738	4.608	49,173
11/7/2002	0.02	0.2313	8.749	65,161
11/8/2002	0.017	0.1781	5.178	56,524
11/9/2002	0.009	0.136	2.161	31,346
11/10/2002	0.01	0.1448	2.362	31,887
11/11/2002	0.013	0.1856	4.725	44,136
2/14/2003	0.001	0.015	0.013	1,699
2/16/2003	0.001	0.008	0.018	4,605
2/17/2003	0.017	0.007	0.196	55,932
2/18/2003	0.012	0.1238	2.05	41,073
2/19/2003	0.003	0.1366	0.708	9,395
3/28/2003	0.002	0.0242	0.107	7,599
3/29/2003	0.013	0.1843	4.455	44,910
3/30/2003	0.011	0.1648	3.195	37,684
3/31/2003	0.011	0.1599	3.049	37,123
4/1/2003	0.009	0.1645	2.533	30,638
4/2/2003	0.009	0.1578	2.455	30,591
4/3/2003	0.006	0.1202	1.32	19,515
4/4/2003	0.005	0.102	0.967	15,489
4/5/2003	0.009	0.1568	2.442	30,236
4/6/2003	0.009	0.1436	2.17	29,975
4/7/2003	0.011	0.15	3.071	37,476
4/8/2003	0.012	0.1548	3.05	38,738
4/9/2003	0.015	0.1841	5.177	50,011
4/10/2003	0.01	0.141	2.445	34,069
4/11/2003	0.009	0.1414	2.113	29,972
4/12/2003	0.009	0.1431	2.162	30,296
4/13/2003	0.008	0.1405	1.976	28,127
4/14/2003	0.01	0.1486	2.56	33,621
4/15/2003	0.007	0.1452	1.758	24,188

Entergy Arkansas, Inc.
Lake Catherine - Unit 4
CEMS Data from CAMD

4/25/2003	0.003	0.0553	0.492	11,035
4/26/2003	0.01	0.1436	2.364	32,877
4/27/2003	0.01	0.1418	2.309	31,985
4/28/2003	0.008	0.1336	1.711	25,610
5/9/2003	0.004	0.0611	0.614	12,647
5/10/2003	0.017	0.2021	6.54	57,405
5/11/2003	0.01	0.1643	2.778	32,877
5/12/2003	0.01	0.17	3.027	34,463
5/13/2003	0.01	0.1454	2.497	33,067
5/14/2003	0.008	0.1238	1.727	27,904
5/15/2003	0.009	0.1203	1.765	28,349
5/16/2003	0.009	0.129	2.082	31,551
5/17/2003	0.008	0.1178	1.644	27,919
5/18/2003	0.01	0.1452	2.588	34,093
5/19/2003	0.016	0.1815	4.992	51,799
5/20/2003	0.004	0.1189	0.738	11,975
6/1/2003	0.002	0.0204	0.091	7,884
6/2/2003	0.01	0.125	2.122	33,776
6/3/2003	0.009	0.1308	1.946	29,693
6/4/2003	0.01	0.1464	2.454	32,222
6/5/2003	0.007	0.1192	1.338	21,933
6/6/2003	0.007	0.1182	1.317	21,747
6/7/2003	0.006	0.1135	1.1	19,380
6/8/2003	0.006	0.1165	1.136	19,497
6/9/2003	0.002	0.1092	0.387	6,865
6/30/2003	0.002	0.0148	0.051	6,666
7/1/2003	0.01	0.1128	1.846	32,090
7/2/2003	0.01	0.1271	2.185	32,181
7/3/2003	0.01	0.136	2.453	33,123
7/4/2003	0.006	0.0813	1.036	21,649
7/5/2003	0.007	0.1085	1.225	21,943
7/6/2003	0.009	0.1127	1.813	29,175
7/7/2003	0.012	0.138	3.41	40,692
7/8/2003	0.011	0.1252	2.581	36,435
7/9/2003	0.01	0.1078	2.01	34,360
7/10/2003	0.007	0.1007	1.228	23,077
7/11/2003	0.01	0.1343	2.455	33,518
7/12/2003	0.01	0.1307	2.379	32,929
7/13/2003	0.009	0.1247	1.94	29,003
7/14/2003	0.013	0.1405	3.51	43,006
7/15/2003	0.015	0.185	4.892	50,793
7/16/2003	0.014	0.1793	5.3	47,457
7/17/2003	0.013	0.1686	3.913	42,782
7/18/2003	0.013	0.165	4.07	43,826

Entergy Arkansas, Inc.
Lake Catherine - Unit 4
CEMS Data from CAMD

7/19/2003	0.008	0.1224	1.76	25,804
7/20/2003	0.01	0.1375	2.73	34,139
7/21/2003	0.013	0.1501	3.85	44,737
7/22/2003	0.006	0.103	1.121	21,104
7/23/2003	0.006	0.1008	1.011	19,929
7/24/2003	0.006	0.1075	1.072	19,935
7/25/2003	0.009	0.1438	2.495	31,066
7/26/2003	0.011	0.1486	3.135	35,801
7/27/2003	0.013	0.173	5.431	44,064
7/28/2003	0.017	0.2069	6.998	58,049
7/29/2003	0.011	0.1515	3.021	36,394
7/30/2003	0.007	0.1108	1.516	24,235
7/31/2003	0.009	0.1397	2.345	31,381
8/1/2003	0.01	0.1266	2.392	34,091
8/2/2003	0.006	0.092	0.892	19,398
8/3/2003	0.006	0.0904	0.875	19,360
8/4/2003	0.009	0.1192	2.303	30,760
8/5/2003	0.01	0.1227	2.572	34,455
8/6/2003	0.008	0.1203	1.763	26,244
8/7/2003	0.008	0.1309	1.829	25,444
8/8/2003	0.008	0.1298	2.097	27,401
8/9/2003	0.007	0.1191	1.409	22,463
8/10/2003	0.006	0.1079	1.061	19,660
8/11/2003	0.006	0.1075	1.061	19,738
8/12/2003	0.006	0.1095	1.08	19,725
8/13/2003	0.006	0.1065	1.048	19,690
8/14/2003	0.008	0.1326	2.107	28,151
8/15/2003	0.01	0.1322	2.58	33,848
8/16/2003	0.013	0.1526	3.956	42,216
8/17/2003	0.013	0.1577	4.289	43,090
8/18/2003	0.014	0.1655	4.59	47,382
8/19/2003	0.014	0.1708	5.163	46,902
8/20/2003	0.015	0.1618	5.32	49,507
8/21/2003	0.014	0.1881	5.674	48,299
8/22/2003	0.012	0.166	3.744	41,589
8/23/2003	0.01	0.1376	2.684	32,518
8/24/2003	0.01	0.1334	2.577	33,755
8/25/2003	0.014	0.1732	4.318	45,380
8/26/2003	0.013	0.1547	3.525	42,822
8/27/2003	0.01	0.1459	2.67	33,331
8/28/2003	0.01	0.1498	2.62	32,451
8/29/2003	0.013	0.1693	3.995	43,374
8/30/2003	0.012	0.1627	3.506	40,500
8/31/2003	0.006	0.0985	0.948	19,262

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CEMS Data from CAMD

9/1/2003	0.01	0.1333	2.529	33,302
9/2/2003	0.008	0.1248	1.888	27,757
9/3/2003	0.008	0.1173	1.595	25,074
9/4/2003	0.008	0.1225	1.797	26,458
9/5/2003	0.006	0.105	1.099	20,221
9/6/2003	0.006	0.1046	1.019	19,416
9/7/2003	0.006	0.1108	1.228	21,382
9/8/2003	0.009	0.1403	2.307	29,597
9/9/2003	0.01	0.1442	2.718	32,493
9/10/2003	0.009	0.1393	2.427	30,284
9/11/2003	0.008	0.126	1.829	26,313
9/12/2003	0.006	0.1015	0.992	19,325
9/13/2003	0.009	0.1308	2.093	28,954
9/14/2003	0.007	0.1298	1.696	24,158
9/15/2003	0.007	0.129	1.71	24,800
9/16/2003	0.007	0.1279	1.697	24,474
9/17/2003	0.007	0.1288	1.716	24,273
9/18/2003	0.007	0.1259	1.509	22,736
9/19/2003	0.006	0.1163	1.157	19,547
9/20/2003	0.008	0.1318	1.753	25,392
9/21/2003	0.007	0.1188	1.465	23,212
9/22/2003	0.01	0.1355	2.401	34,680
9/23/2003	0.009	0.1447	2.381	31,309
9/24/2003	0.01	0.1484	2.635	34,458
9/25/2003	0.01	0.1461	2.608	32,192
9/26/2003	0.011	0.1719	3.773	37,670
9/27/2003	0.012	0.1762	4.114	40,712
9/28/2003	0.006	0.1263	1.249	19,773
9/29/2003	0.006	0.1286	1.388	21,146
9/30/2003	0.007	0.1355	1.688	23,273
10/1/2003	0.006	0.1358	1.542	21,627
10/5/2003	0.002	0.0366	0.114	5,808
10/6/2003	0.01	0.1548	2.763	32,216
10/7/2003	0.013	0.1837	4.234	44,450
10/8/2003	0.009	0.156	2.64	30,400
10/18/2003	0	0.0105	0.007	1,196
10/19/2003	0.009	0.1316	2.367	28,415
10/20/2003	0.015	0.1955	5.096	51,193
10/21/2003	0.017	0.2215	7.467	57,794
10/22/2003	0.028	0.3428	16.509	93,036
10/23/2003	0.025	0.2927	12.561	82,673
10/24/2003	0.024	0.2452	9.877	79,990
10/25/2003	0.03	0.3455	17.916	98,845
10/26/2003	0.023	0.2924	12.033	78,223

Entergy Arkansas, Inc.
Lake Catherine - Unit 4
CEMS Data from CAMD

10/27/2003	0.012	0.1688	3.629	38,963
10/28/2003	0.012	0.1751	3.723	38,838
10/29/2003	0.01	0.1726	3.271	34,783
10/30/2003	0.008	0.1362	1.893	25,485
10/31/2003	0.005	0.1143	1.042	17,440
11/9/2003	0.002	0.0359	0.172	7,344
11/10/2003	0.006	0.1283	1.306	20,363
11/11/2003	0.026	0.3002	15.338	85,158
11/12/2003	0.037	0.4825	29.477	122,153
11/13/2003	0.02	0.3162	14.539	67,701
11/14/2003	0.016	0.2494	9.144	53,543
11/15/2003	0.023	0.309	14.475	76,658
11/16/2003	0.014	0.2057	7.065	47,591
11/17/2003	0.011	0.1664	3.785	37,220
11/18/2003	0.004	0.1328	0.842	11,838
12/11/2003	0.001	0.024	0.051	3,992
12/12/2003	0.008	0.1213	1.843	25,998
12/13/2003	0.009	0.137	2.2	28,738
12/14/2003	0.006	0.118	1.209	20,460
12/15/2003	0.009	0.1466	2.348	30,084
Max (tpd) -->	0.037		29.477	
Max (lb/hr) -->	3.1		2456.4	

Note: Dates with no operation/emissions not shown

APPENDIX D

SARGENT & LUNDY NO_X CONTROL TECHNOLOGY STUDY

Prepared for
Gill Elrod Ragon Owen & Sherman, P.A.

NOx Control Technology Cost and Performance Study

Entergy Services, Inc.
White Bluff & Lake Catherine

SL-011439
Final Report
Rev. 4

May 16, 2013
Project No.: 13027-001

Prepared by

Sargent & Lundy LLC

55 East Monroe Street
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White Bluff & Lake Catherine
NOx Control Technology Cost and Performance Study

ISSUE SUMMARY AND APPROVAL PAGE

This is to certify that this report has been prepared, reviewed and approved in accordance with Sargent & Lundy's Standard Operating Procedure SOP-0405, which is based on ANSI/ISO/ASSQC Q9001 Quality Management Systems.

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ENTERGY SERVICES, INC.

WHITE BLUFF AND LAKE CATHERINE

NO_X CONTROL TECHNOLOGY COST AND PERFORMANCE STUDY

CERTIFICATION PAGE

Sargent & Lundy, L.L.C. is registered in the State of Arkansas to practice engineering. The registration number is 620.

I certify that this study was prepared by me or under my supervision and that I am a registered professional engineer under the laws of the State of Arkansas.

Certified By: ______________________ Date: 5/16/2013

Seal:

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

5/16/2013

Issue:	Date:	Certified By:	Pages Certified:

1. INTRODUCTION

1.1. OBJECTIVE

The intent of this study is to provide Gill Elrod Ragon Owen & Sherman, P.A. with a technology evaluation and cost estimates for available methods of NOx control at two Entergy stations including: White Bluff – Units 1 & 2, the White Bluff Auxiliary Boiler, and Lake Catherine – Unit 4. The information developed in this study will be used to create a BART analysis, for compliance with Arkansas DEQ regulations.

1.2. UNIT DESCRIPTIONS

1.2.1. White Bluff - Units 1 & 2

White Bluff - Units 1 & 2 are Alstom-designed, tangentially-fired, pulverized-coal fueled units, rated at 815 MWnet and 844 MWnet respectively. Powder River Basin coal is the primary fuel source for Units 1 & 2. Currently, the units have no NOx controls installed.

1.2.2. White Bluff Auxiliary Boiler

The White Bluff Auxiliary boiler is a small industrial boiler capable of producing 140,000 lb/hr of steam, used for startup of the White Bluff coal units. The auxiliary boiler combusts No. 2 Diesel Oil, and does not have any existing NOx controls.

1.2.3. Lake Catherine - Unit 4

Lake Catherine - Unit 4 is an Alstom-designed, tangentially-fired, natural gas fueled unit, capable of generating 558 MWnet. The unit was originally designed as a dual-fuel unit, able to use natural gas or No. 2 Fuel Oil as fuel. This evaluation will be for natural gas firing only. If No. 2 Fuel Oil is to be combusted in the future, a separate BART analysis will be submitted. The unit currently has no NOx controls.

1.3. ESTIMATE METHODOLOGY

1.3.1. Capital Cost Estimates

S&L's capital cost estimates for retrofit NOx control technologies for White Bluff Units 1&2, White Bluff Auxiliary Boiler and Lake Catherine – Unit 4 encompass the equipment, material, labor, and all other required direct costs. The underlying assumption is that the project will be implemented on a multiple-contracting basis. The capital cost estimates provided herein are "total plant cost," and include the following:

- Equipment and material
- Installation labor
- Indirect field costs and BOP engineering
- Contingency (percentage varies with project size)
- Erection contractor profit (at 10% of material and labor)
- General and administration (at 5% of material and labor)
- Freight on material (at 5% of material)
- Freight on equipment (included with equipment costs)
- Sales/use tax (not included)
- Startup and commissioning (at 1% of construction cost)
- Spare parts (included with equipment costs)
- Consumables (0.5% of material and labor)

Owner's engineering and other Owner's costs were not included. Engineering, Procurement & Project Services and Contingency varied depending on the size of the project. License fees and royalties are not expected for the proposed control strategies. The Basis of Estimate and capital costs are summarized in Appendix A.

Capital cost estimates were calculated in one of three ways. In some cases, vendors were contacted to provide budgetary estimates for equipment and labor. These vendor's costs were used to create Total Installed Cost Estimates. In situations where Sargent & Lundy had performed cost estimates for these units previously, the existing cost estimates were updated to reflect current equipment, labor, and currency values. Remaining cost estimates were developed from similar projects that Sargent & Lundy has completed and adjusted for unit size.

1.3.2. Operating and Maintenance Cost Estimates

Operating and Maintenance Costs for White Bluff - Units 1 & 2 and Lake Catherine – Unit 4 were developed from similar projects Sargent & Lundy has completed. Costs were applied to the units on a $/kW basis, and assuming a 10% capacity factor for Lake Catherine – Unit 4, and 76% for White Bluff—Units 1 & 2. Operating and Maintenance Costs include the following costs:

- Fixed Operating and Maintenance
- Variable Operating and Maintenance
- Fuel Impact Costs

For the White Bluff Auxiliary boiler, costs were developed using Office of Air Quality Planning and Standards (OAQPS) calculations, assuming a 10% capacity factor.

1.4. DESIGN TARGET vs. COMPLIANCE NO_X EMISSION RATES

NOx control systems retrofit onto existing coal or gas-fired boilers are typically designed to achieve varying levels of NOx removal efficiencies from 10%-94%, depending on the control technologies selected. Controlled NOx emissions fluctuate during normal boiler operation in response to a number of design/operating parameters including, but not necessarily limited to: inlet NOx concentrations, boiler load, load changes, particulate matter loading, flue gas temperatures, flue gas velocities and mixing, catalyst volume and surface area, NH_3:NOx stoichiometric ratio, catalyst age and activity, and the quantity of ammonia slip deemed to be acceptable.

The "design target" NOx emission rate is the rate that a NOx control technology vendor would be willing to guarantee. Based on engineering judgment, and taking into consideration emissions data from existing coal- and gas-fired sources, a compliance margin above the design target is recommended for high removal efficiency/low emission rate technologies (such as SCR) to establish an enforceable permit limit based on long-term (e.g., annual average) emissions. Additional compliance margin would be required to establish enforceable permit limits based on shorter-term averaging times. For example, S&L recommends a compliance margin of 0.02 to 0.03 lb/MMBtu for coal units and 0.01 to 0.02 lb/MMBtu for gas units above the design target emission rate for permit limits based on a 30-day rolling average for control strategies including SCR. The NOx control technology emission rates for strategies including SCR in this report have been adjusted to include margin for compliance. The permit level NOx emission rates for SCR are higher by 0.02 to 0.03 lb/MMBtu for coal units and 0.01 to 0.02 lb/MMBtu for gas units.

2. WHITE BLUFF - UNITS 1 & 2

2.1. FUEL SWITCHING OPTIONS

2.1.1. Natural Gas

For White Bluff Units 1 & 2, fuel switching is not a feasible option. Typically, units could be switched from coal to natural gas or propane for NOx reductions. The nearest natural gas pipeline to the White Bluff facility is approximately 20 miles away. Construction of a pipeline is currently estimated at $2M per mile resulting in a cost of $40M to bring natural gas to the site, not including the additional upgrades the boiler would require to burn natural gas instead of coal.

2.1.2. Propane

White Bluff – Units 1 & 2 are each over 800 MWnet. Units of this size require more heat input than can practically be achieved with a propane delivery and storage system. Since a propane pipeline is not available, fuel switching to propane is not a feasible option.

2.2. COMBUSTION CONTROLS

2.2.1. Low NOx Burners and Over-Fire Air

Low NOx burners (LNB) limit NOx formation by controlling both the stoichiometric and temperature profiles of the combustion flame in each burner flame envelope. Control is achieved with design features that regulate the aerodynamic distribution and mixing of the fuel and air, yielding reduced oxygen (O_2) in the primary combustion zone, reduced flame temperature, and reduced residence time at peak combustion temperatures. The combination of these techniques produces lower NOx emissions during the combustion process.

OFA involves injecting combustion air downstream of the fuel-rich primary combustion zone by using over-fire air or side-fired air ports. The fuel-rich mixture that is fed to the burners reduces the flame temperature and oxygen concentration thus reducing the formation of thermal NOx. Generally, OFA is more effective when used with low nitrogen content fuels such as natural gas and propane, since OFA is more effective in controlling thermal NOx rather than fuel NOx.

LNB + OFA is a technically feasible retrofit solution for White Bluff - Units 1 & 2. The combination of LNB + OFA is capable of achieving a NOx emission rate of 0.15 lb/MMBtu. From Unit 1's baseline emissions of 0.33 lb/MMBtu, this is approximately 54.5% NOx removal efficiency. A removal efficiency of 61.5% can be expected for Unit 2, with a baseline NOx of 0.39 lb/MMBtu.

2.2.2. Flue Gas Recirculation (FGR)

NOx reduction efficiency data for coal-fired units with FGR are limited. The amount of NOx reduction achievable with FGR depends primarily on the fuel nitrogen content and amount of FGR used. Generally, FGR is more effective when used with low nitrogen content fuels such as natural gas and propane, since FGR is more effective in controlling thermal NOx rather than fuel NOx. Industry experience with FGR on coal-fired units for steam temperature control has shown very high maintenance on the gas recirculation fans due to erosion and corrosion. Many of the units with FGR for steam temperature control have removed the recirculation fans from service. The NOx control achievable on tangentially fired units like White Bluff – Units 1&2 with LNB+OFA has been comparable to that of FGR at lower capital and O&M cost. Currently, FGR technology is not offered by OEMs for coal-fired units. For these reasons, FGR is not a feasible technology for the White Bluff coal-fired units.

2.2.3. Neural Network

Neural Network (NN) systems are on-line enhancements to digital control systems (DCS) and plant information systems that improve boiler performance parameters such as heat rate, NOx emissions, and CO levels. The Neural Network model is based on historical data and parametric test data. The software applies an optimizing procedure to identify the best set points for the boiler, which are implemented without operator intervention (closed loop), or, at the plant's discretion, conveyed to the plant operators for implementation (open loop).

A Neural Network system is a technically feasible retrofit option for the White Bluff units. A NN is already installed for monitoring and controlling heat rate at White Bluff – Units 1&2. The reprogrammed

NN would be optimized first for minimizing NOx emissions and second for heat rate. It is possible that heat rate may increase as a result. Based on information available from vendors, it is expected that Neural Network technology on a coal-fired boiler can maintain the guaranteed performance of low NOx burners and potentially can achieve approximately 10% NOx reduction over a period of years, resulting in NOx emission rates of 0.30 lb/MMBtu, at max load for Unit 1, and of 0.35 lb/MMBtu for Unit 2. The cost for modifying the existing NNs at White Bluff is estimated to be approximately $250,000 per unit.

2.3. POST COMBUSTION CONTROLS

2.3.1. Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) involves the direct injection of ammonia (NH_3) or urea ($CO(NH_2)_2$) into the furnace at high flue gas temperatures (approximately 1600 ºF – 2000 ºF). The ammonia or urea reacts with NOx in the flue gas to produce N_2 and water as shown in the following equations:

$$(CO(NH_2)_2) + 2NO + \frac{1}{2}O_2 \rightarrow 2H_2O + CO_2 + 2N_2$$

$$2NH_3 + 2NO + \frac{1}{2}O_2 \rightarrow 2N_2 + 3H_2O$$

Flue gas temperature at the point of reactant injection can greatly affect NOx removal efficiencies and the quantity of NH_3 or urea that will pass through the furnace unreacted (referred to as NH_3 slip). In general, SNCR reactions are effective at a temperature range of 1600 ºF – 2000 ºF. At temperatures below the desired operating range, the NOx reduction reactions diminish and unreacted NH_3 emissions increase. Above the desired temperature range, NH_3 is oxidized to NOx resulting in low NOx reduction efficiencies.

Mixing of the reactant and flue gas within the reaction zone is also an important factor to SNCR performance. In large boilers, the physical distance over which reagent must be dispersed increases, and the surface area/volume ratio of the convective pass decreases. Both of these factors make it difficult to achieve good mixing of reagent and flue gas, delivery of reagent in the proper temperature window, and sufficient residence time of the reactant and flue gas in that temperature window.

The temperatures and residence times required for an SNCR system make it a feasible option for NOx reduction for White Bluff - Units 1 & 2. Based on vendor input, a unit with no additional controls and a baseline NOx of 0.33 lb/MMBtu could see a 26.5% NOx reduction, for an outlet rate of 0.24 lb/MMBtu on Unit 1. For Unit 2, with a baseline NOx of 0.39 lb/MMBtu could see a 26.5% reduction to an outlet rate of 0.29 lb/MMBtu.

SNCR systems can also be installed in conjunction with LNB + OFA controls. On these coupled systems, the starting NOx of approximately 0.15 lb/MMBtu can be reduced to 0.13 lb/MMBtu, for a total reduction (LNB + OFA + SNCR) of around 61% for Unit 1 and 67% for Unit 2. In addition to the SNCR equipment, the process requires additional demineralized water at a rate of 170 gpm. An additional water treatment system capable of providing the required flows is included in the capital cost. The cost of the SNCR equipment for the combination technology would be approximately 10% lower based on the lower starting NOx rate with LNB/OFA.

2.3.2. Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) involves injecting ammonia into boiler flue gas in the presence of a catalyst to reduce NOx to N_2 and water. The overall SCR reactions are:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$8NH_3 + 4NO_2 + 2O_2 \rightarrow 6N_2 + 12H_2O$$

The optimal temperature range depends on the type of catalyst used, but is typically between 560 °F and 800 °F to maximize NOx reduction efficiency and minimize ammonium sulfate formation. Below this range, ammonium sulfate is formed resulting in catalyst deactivation. Above the optimum temperature, the catalyst will sinter and thus deactivate rapidly. Another factor affecting SCR performance is the condition of the catalyst material. As the catalyst degrades over time or is damaged, NOx removal decreases which is typically compensated by increased ammonia slip.

SCR has been installed on many large coal-fired and some gas-fired boilers and is considered a feasible technology. Because of the expense of the reagent, SCR systems are usually installed on units with existing LNB + OFA systems, or the upgrades are done simultaneously. At White Bluff, an SCR+LNB/OFA system is capable of removing approximately 90% of NOx emissions on a continuous long-term basis. With a starting NOx of 0.33 lb/MMBtu (Unit 1) to 0.39 lb/MMBtu (Unit 2), an SCR can be expected to achieve permitted emissions compliance at 0.055 lb/MMBtu.

2.4. CAPITAL COSTS

Capital costs for the technically feasible control options for the White Bluff coal units are listed in Table 2.1. The cost of SCR on White Bluff – Unit 1 is higher than for White Bluff – Unit 2 because the ductwork arrangement is different and there is more total ductwork, support steel, and foundations for Unit 1.

Table 2.1: Expected NOx Emissions and Capital Costs, White Bluff Units 1 & 2

Technology	**Controlled NOx (lb/MMBTU)**		**Unit 1 Total Installed Capital Cost (2012$)**	**Unit 2 Total Installed Capital Cost (2012$)**
	Unit 1	Unit 2		
Baseline	0.33	0.39	NA	NA
LNB + OFA	0.15	0.15	7,804,000[1]	11,831,000
Neural Network	0.30	0.35	250,000[2]	250,000[2]
SNCR	0.24	0.29	9,372,000	9,372,000
SNCR (+ LNB/OFA)	0.13	0.13	16,290,000[1]	20,317,000
SCR (+ LNB/OFA)	0.055	0.055	202,601,000	178,240,000

1. LNB/OFA material already purchased for Unit 1. The total cost to Entergy would be the same for Unit 1 as shown for Unit 2.
2. The cost for modifying the existing neural networks on Units 1 & 2.

2.5. OPERATING AND MAINTENANCE COSTS

Annual Operating and Maintenance costs for each of the feasible technologies for White Bluff Units 1 & 2 are shown in Table 2.2. Costs were calculated assuming full load operation, and a capacity factor (C.F.) of 76%.

Table 2.2: Operating and Maintenance Costs, White Bluff – Units 1 & 2 (Based on a C.F. of 76%)

	Unit 1			Unit 2		
Technology	**Variable O&M[1] Costs (2012$)**	**Fixed O&M Costs (2012$)**	**Total O&M Costs (2012$)**	**Variable O&M[1] Costs (2012$)**	**Fixed O&M Costs (2012$)**	**Total O&M Costs (2012$)**
LNB + OFA	--	142,000	142,000	--	142,000	142,000
Neural Network	--	50,000	50,000	--	50,000	50,000
SNCR	5,658,000	169,000	5,827,000	6,671,000	169,000	6,840,000
SNCR (+ LNB/OFA)	4,538,000	311,000	4,849,000	4,542,000	311,000	4,853,000
SCR (+ LNB/OFA)	2,836,000	608,000	3,444,000	2,858,000	608,000	3,466,000

Note 1: Variable O&M includes fuel cost impacts.

Note 2: The current costs of ammonia and urea are highly volatile and may exceed the values used in this report.

3. WHITE BLUFF AUXILIARY BOILER

3.1. FUEL SWITCHING

The White Bluff auxiliary boiler is a B&W, single burner boiler, firing No. 2 diesel oil, rated at 140,000 lb/hr of steam. Fuel switching to natural gas or propane is not practical because the nearest natural gas pipeline is 20 miles from the site. The costs to convert the White Bluff aux boiler to either natural gas or propane would not be justified based on the low capacity factor.

3.2. COMBUSTION CONTROLS

3.2.1. Low NOx Burners + Over-Fire Air

For an auxiliary boiler such as the one at White Bluff, NOx reduction can be achieved with a combination of technologies. LNB + OFA for aux boilers achieve NOx reduction under the same principles as a coal boiler. By modifying temperatures and fuel-rich areas, less NOx is generated. LNB + OFA are feasible technologies for auxiliary boilers, and vendor data indicates that the White Bluff Aux Boiler could achieve 35% reduction with LNB + OFA, for a final emission of 0.11 lb/MMBtu. The baseline NOx emissions from the White Bluff aux boiler are calculated using US EPA's AP-42 emissions factors.

3.2.2. Flue Gas Recirculation

NOx reduction efficiency data for oil-fired units with FGR are limited. The amount of NOx reduction achievable with FGR depends primarily on the fuel nitrogen content and amount of FGR used. Generally, FGR is more effective when used with low nitrogen content fuels such as natural gas and propane, since FGR is more effective in controlling thermal NOx rather than fuel NOx. FGR is a feasible technology for the White Bluff auxiliary boiler. With a recirculation of 15% of the flue gas, the unit could expect to see 13% NOx removal, for an outlet of 0.149 lb/MMBtu.

3.2.3. Low NOx Burners + Over-fire Air + Flue Gas Recirculation

These three technologies are often installed simultaneously for greater NOx reduction. A vendor has proposed that for the White Bluff aux boiler, a combination of LNB + OFA + FGR will reduce the NOx from 0.171 lb/MMBtu to 0.100 lb/MMBtu when burning No. 2 Fuel Oil. This reduction of 42% will come from a new LNB and OFA system and the recirculation of 15% of the flue gas flow.

3.2.4. Neural Network

The White Bluff Auxiliary Boiler is not a candidate for a neural network (NN) because there are few controllable variables to be optimized. The aux boiler also uses a relatively new PLC control system.

3.3. POST COMBUSTION CONTROLS

3.3.1. Selective Non-Catalytic Reduction

SNCR control has proven to be difficult to apply to industrial boilers because of the temperature and mixing requirements, especially industrial boilers that modulate or cycle frequently. In order to effectively reduce NOx emissions, the reactant (ammonia or urea) must be injected into the flue gas within a specific flue gas temperature window, and must remain within that temperature window for a sufficient residence time. In industrial boilers that cycle frequently, the location of the specific exhaust gas temperature window is constantly changing. Thus, SNCR has not been effective on industrial boilers that have high turndown capabilities and modulate or cycle frequently. Based on the temperature and residence time requirements associated with effective NOx reduction, the planned use of the auxiliary boiler, and the limited availability of SNCR control systems for industrial boilers, it has been determined that SNCR is not technically feasible for the White Bluff auxiliary boiler.

3.3.2. Selective Catalytic Reduction

SCR for NOx control on auxiliary boilers is not common, because of their cycling operation, and the use of fuel oil. SCRs have critical operating temperature ranges, which are difficult to achieve and maintain in short periods of time. Because of the sulfur content of diesel oil, the SCR catalyst can become poisoned, resulting in a lower NOx removal efficiency. With this lower efficiency and high cost, an SCR is not considered a feasible technology.

3.4. CAPITAL COST ESTIMATES

Capital costs for the technically feasible control options for the White Bluff Auxiliary Boiler are listed in Table 3.1.

Table 3.1: Expected NOx Emissions and Capital Costs, White Bluff Units 1 & 2

Technology	Controlled NOx	Total Installed Capital Cost (2012$)
Baseline	0.171	--
LNB	0.111	255,000
OFA	0.137	231,000
FGR	0.149	366,000
LNB + OFA + FGR	0.100	852,000

3.5. OPERATING AND MAINTENANCE COST ESTIMATES

Annual Operating and Maintenance costs for each of the feasible technologies for White Bluff Units 1 & 2 are shown in Table 3.2. Costs were calculated assuming full load operation and a capacity factor (C.F.) of 10%.

Table 3.2: White Bluff Auxiliary Boiler Operating and Maintenance Costs (Based on a C.F. of 10%)

Technology	Variable O&M Costs (2012$)	Fixed O&M Costs (2012$)	Total O&M Costs (2012$)
LNB	4,000	4,000	8,000
OFA	5,000	4,000	9,000
FGR	0	7,000	7,000
LNB + OFA + FGR	9,000	15,000	24,000

4. LAKE CATHERINE - UNIT 4

4.1. FUEL SWITCHING

Lake Catherine - Unit 4 already combusts natural gas, which has the lowest NOx formation of potential fuels. Because fuel switching would not result in a lower NOx emission rate, it is not a feasible option for NOx control.

4.2. COMBUSTION CONTROLS

4.2.1. Burners-Out-Of-Service

Burners-Out-Of-Service (BOOS) allows operators to stop fuel flow to certain burners in the boiler (typically the top level of burners), while air flow is maintained. By removing fuel from the top row of burners, the combustion air becomes over-fire air and the production of thermal NOx is reduced. While the reduction of NOx can be significant, the tradeoff is a reduced generating capacity, if no further modifications to the firing system are made. BOOS is a feasible technology for Lake Catherine - Unit 4. Testing of BOOS at Lake Catherine by Entropy Technology & Environmental Consultants, Inc. (ETEC) with the top levels of burners out resulted in a maximum load of 405 MW, a 28% reduction in capacity, and NOx levels of 0.12 lb/MMBtu, a reduction of 55% from the baseline while using the existing burners.

Recovery of the lost unit capacity is possible by increasing the fuel fired in the three levels of burners that remain in service. The burners remaining in service would have to increase fuel throughput by 25%. The natural gas piping to each burner may also have to be increased in size for the higher fuel flow rates. ETEC, Inc. has experience with several units similar in design to Lake Catherine – Unit 4 that have been able to achieve full capacity by increasing the original "high" burner header pressure (BHP) to increase fuel flow to the burners (See Appendix D). The increase in BHP from 42 to 50 psig at Lake Catherine – Unit 4 would increase fuel flow by 25% and the burners would be operated "fuel rich", lowering NOx formation. Using this approach would reduce NOx emissions at a small capital cost. The costs for BOOS with recovery of full unit capacity were based on vendor cost information for a previous project adjusted on a $/kW basis to Lake Catherine – Unit 4 and escalated to 2012. The cost provided does not include any modifications to the boiler. A boiler OEM or consultant would need to evaluate the existing fuel piping, superheat and reheat attemperation sprays, tube metal temperatures and burner tilt positions for the new operating conditions. The expected NOx reduction would range from 40% at low load to 50% at full load and NOx levels of 0.24 lb/MMBtu.

4.2.2. Low NOx Burners + Over-Fire Air

Low NOx Burners and Over-Fire Air for a gas-fired unit function similarly to coal-fired boilers, as discussed for White Bluff - Units 1 & 2. By controlling the temperature and stoichiometric profiles, the NOx produced as a result of thermal processes is reduced.

LNB + OFA are commonly installed on gas-fired units of this size, and are a feasible retrofit technology for Lake Catherine - Unit 4. With the installation of LNB + OFA, Lake Catherine could expect a 60% reduction in NOx, from 0.4825 lb/MMBtu to 0.19 lb/MMBtu.

4.2.3. Flue Gas Recirculation

Flue Gas Recirculation (FGR) reduces NOx by recirculating flue gas to the furnace. This recirculated gas has lower oxygen content than ambient air usually used for combustion. Lower oxygen and lower flame temperatures reduces thermal NOx formation. FGR can be installed on a unit in two ways. Traditional FGR installations require a new recirculation fan. Induced FGR, or IFGR, installs ductwork from the air preheater outlet to the suction of the existing forced draft fan. IFGR does not require a separate fan, but due to FD fan capacity restrictions, IFGR is not available at higher loads, because the forced draft fans were not designed for the higher air and gas flow rate.

FGR is technically feasible on Lake Catherine - Unit 4 and can result in reductions of 60%. For Unit 4, this would be equivalent to NOx emissions of 0.19 lb/MMBtu.

4.2.4. Water Injection

Water injection operates on similar principles to LNB + OFA and FGR. By injecting water into the furnace, the temperature of the flue gas is reduced, thereby reducing the amount of thermal NOx formed.

Water injection is a feasible technology for Lake Catherine - Unit 4, and can reduce NOx emissions by 9% at full load. Water injection is typically used as a trimming technology at high load. On Unit 4, the emissions would be lowered from the baseline of 0.4825 lb/MMBtu to 0.44 lb/MMBtu.

4.2.5. Neural Network

Lake Catherine – Unit 4 could also install a neural network (NN) but for the low capacity factor and current lack of NOx CEMS, a NN would not be practical. Several of the other technologies would provide greater NOx reductions.

4.3. POST COMBUSTION CONTROLS

4.3.1. Selective Non-Catalytic Reduction

Selective Non-Catalytic Reduction for gas-fired units operates under the same principles as SNCR for coal-fired units, with a few design changes. One of the keys of SNCR design is adequate chemical distribution at the right temperature for the reaction. Lake Catherine - Unit 4 has horizontal superheat platens, which requires multiple-nozzle lances to distribute the urea; the gas pattern does not provide adequate distribution. The reaction and temperature requirements are the same for gas-fired boilers as they are for coal-fired units.

SNCR has been installed on boilers such as Lake Catherine 4 and is considered a feasible technology, although the residence time in the desired temperature zone is lower for a gas-fired unit and the temperature window moves as unit load changes. The unit could expect to see reductions in NOx from the baseline of 0.4825 lb/MMBtu to 0.29 lb/MMBtu, or approximately 40% reduction at full load. In addition to the SNCR equipment, the process requires additional demineralized water at a rate of 85 gpm. An additional water treatment system capable of providing the required flows is included in the capital cost.

SNCR can be combined with LNB/OFA to achieve a combined NOx removal efficiency of 70% for an outlet emission of approximately 0.14 lb/MMBtu,

4.3.2. Selective Catalytic Reduction

Selective Catalytic Reduction units are similar for gas and coal-fired units. Ammonia or urea reagent reacts with NOx to form nitrogen and water, in the presence of a catalyst. Because gas boilers do not have particulate control or sulfur dioxide control, they typically have a shorter distance from the economizer outlet to the stack, which may result in long ductwork runs to and from the SCR.

SCR is a feasible technology for Lake Catherine - Unit 4. Combined with a LNB + OFA installation, which is typical of SCR installations, the unit could achieve a combined NOx removal efficiency of 94%, for a permitted outlet NOx of 0.03 lb/MMBtu at full load. This includes a margin for compliance as discussed in Section 1.4. Without the LNB + OFA installed, the SCR can also be designed to achieve 90% removal efficiency for an outlet emission of approximately 0.05 lb/MMBtu.

4.4. CAPITAL COST ESTIMATES

Capital costs for the technically feasible control options for Lake Catherine - Unit 4 are listed in Table 4.1.

Table 4.1: Expected NOx Emissions and Capital Costs, Lake Catherine Unit 4

Technology	**Controlled NOx (lb/MMBtu)**	**Total Installed Capital Cost (2012$)**
Baseline	0.4825(1)	--
BOOS (at full capacity)	0.24	893,000
LNB / OFA	0.19	8,762,000
IFGR (below 500 MW)	0.39	2,166,000
FGR	0.19	11,489,000
Water Injection	0.44	2,177,000
SNCR	0.29	15,507,000
SNCR (+ LNB/OFA)	0.14	24,269,000
SCR	0.05	59,587,000
SCR (+ LNB/OFA)	0.03	68,349,000

Note 1: The baseline NOx rate is the maximum daily emission rate from the 2001-2003 baseline period.

4.5. OPERATING AND MAINTENANCE COST ESTIMATES

Annual Operating and Maintenance costs for each of the feasible technologies for Lake Catherine - Unit 4 are shown in Table 4.2. Costs were calculated assuming full load operation, and a capacity factor (C.F. of 10%).

Table 4.2: Annual Operating and Maintenance Costs, Lake Catherine Unit 4 (Based on C.F. of 10%)

Technology	**Variable O&M[1,2] Costs (2012$)**	**Fixed O&M Costs (2012$)**	**Total O&M Costs (2012$)**
BOOS	--	21,000	21,000
LNB + OFA	--	210,000	210,000
IFGR	--	52,000	52,000
FGR	142,000	207,000	349,000
Water Injection	486,000	52,000	538,000
SNCR	1,640,000	279,000	1,919,000
SNCR (+ LNB/OFA)	462,000	489,000	951,000
SCR	254,000	358,000	612,000
SCR (+ LNB/OFA)	268,000	568,000	836,000

Note 1: Variable O&M includes fuel cost impacts.

Note 2: The current costs of ammonia and urea are highly volatile and may exceed the values used in this report.

APPENDIX A: CAPITAL COST ESTIMATE

1. BASIS OF ESTIMATES

2. CONCEPTUAL COST ESTIMATE SUMMARY SHEETS

Basis of Estimate

Estimates:
31813A – Lake Catherine, Unit 4 - Low NOx Burners and Over Fired Air
31814A – Lake Catherine, Unit 4 - SCR
31815A – Lake Catherine, Unit 4 - SNCR
31816A – White Bluff, Unit 1 - Low NOx Burners and Over Fired Air
31817A – White Bluff, Unit 1 – SCR
31818A – White Bluff, Unit 2 – SCR
31819A – White Bluff, Units 1 and 2 – SNCR
31820A – White Bluff, Auxiliary Boiler – Low NOx Burners, Over Fired Air, and Flue Gas Recirculation
31832A – White Bluff, Unit 2 - Low NOx Burners and Over Fired Air

General Information

Project Type – Compliance study for Lake Catherine Unit 4 and White Bluff Station Units 1&2.
Type of estimates – Conceptual Cost Estimate for the SCR Case and Order of Magnitude Cost Estimates for all other cases.
Project location – White Bluff: Close to Pine Bluff, Arkansas; Lake Catherine: Close to Mahern, AR
MW rating: White Bluff Unit 1: 815 MW, Unit 2: 844 MW; Lake Catherine Unit 4: 558 MW
Unique site issues – Existing Site.
Contracting strategy – Multiple Lump Sum.

The major components of the capital cost consist of equipment, field materials and supplies, direct labor, indirect field labor, and indirect construction costs. The capital cost was determined through the process of estimating the cost of equipment, components and bulk quantity.

The cost estimates are based largely on Sargent & Lundy LLC experience on similar projects. Detailed engineering has not been performed to firm up the project details, and specific site characteristics have not been fully analyzed. We have attempted to assign allowances where necessary to cover issues that are likely to arise but are not clearly quantified at this time.

Estimate Development

The cost estimates for the Low NOx Burners/Over Fired Air cases were based on a previous estimate prepared in 2011. Equipment costs were escalated to current pricing level. Also, material and labor have been updated to 2012 pricing.
Cost estimates for the SNCR technology (two cases) were based on budgetary quotes received from engineering and on previous estimates.
The cost estimates for the White Bluff SCR was mainly based on similar size and scope cost estimates from other projects and structural takeoffs from engineering. All equipment common to both Units was divided evenly between the two estimates.
The cost estimate for Lake Catherine SCR was adjusted from another cost estimate for a gas fired power station. White Bluff's auxiliary boiler cost estimate for Low NOx Burners/Over Fired Air/Flue Gas Recirculation was also adjusted from a similar project.

Pricing and Quantities

The data used to develop these estimates is based on using material and equipment types and sizes typically used in a power plant.
Equipment and material costs were estimated on the basis of S&L in house data, vendor catalogs, industry publications and other related projects. In most cases, the costs for bulk materials and equipment were derived from recent vendor or manufacturer's quote for similar items on other projects. Where actual or specific information regarding equipment specifications was available, that information was used to size and quantify material and equipment requirements. Where information was not furnished or was not adequate, requirements were assumed and estimated based on information available from project estimates of similar type and size.

Quantities contained herein are intended to be reasonable and representative of projects of this type. All quantity data was developed internally by S&L. Quantities were developed based on project experience of a plant of comparable size and then adjusted based on actual size and capacity differences and also taking into consideration the specific site layout based on the general arrangement drawing. While project specifics will certainly have an impact on these quantities, we feel they are appropriate for a study at this level.

Labor Wage Rates

Labor Profile – Union

Labor wage rate selected for the estimate - 2012 Union rates for Pine Bluff, Arkansas. Base craft rates are as published in RS Means Labor Rates for the Construction Industry, 2012 Edition. The craft rates are then incorporated into work crews appropriate for the activities by adding allowances for small tools, construction equipment, insurance, and site overheads to arrive at crew rates detailed in the cost estimate. A 1.15 regional labor productivity multiplier is included based on the Compass International Global Construction Yearbook.

Labor Work Schedule and Incentives - Assumed 5x10 work week for regular work and 7x10 work week for outage work. 10% of the work is assumed to be outage related.

Project Direct & Construction Indirect Costs

The estimate is constructed in such a manner where most of the direct construction costs are determined directly and several direct construction cost accounts are determined indirectly by taking a percentage of the directly determined costs and are identified as “Variable Accounts”. These percentages are based on our experience with similar type and size projects. Sales tax is specific to location. Listed below are the variable accounts.

- Cost of overtime – 5-10’s Hour Days and Outage Work at a 7-10 Schedule
- Subsistence (per diem) – not included
- Consumables – 0.5% of material and labor
- Freight on Equipment - included with equipment cost
- Freight on Material @ 5% of material
- Spare Parts – included with equipment costs
- Contractors G&A Expense @ 10%
- Contractors Profit @ 5%

Project Indirect Costs

Included are the following:

- Engineering, Procurement & Project Services varied depending on the size of the project estimated.
    - 31813A @ 19% of construction cost
    - 31814A @ 8% of construction cost
    - 31815A @ 8% of construction cost
    - 31816A @ 16% of construction cost
    - 31817A @ 6% of construction cost
    - 31818A @ 6% of construction cost
    - 31819A @ 8% of construction cost
    - 31820A @ 12% of construction cost
    - 31832A @ 16% of construction cost
- Construction Management varied depending on the size of the project estimated.
    - 31813A @ 6% of construction cost
    - 31814A @ 3% of construction cost
    - 31815A @ 2% of construction cost
    - 31816A @ 6% of construction cost
    - 31817A @ 2% of construction cost

  - 31818A @ 2% of construction cost
  - 31819A @ 2% of construction cost
  - 31820A @ 0% of construction cost
  - 31832A @ 6% of construction cost
- Craft start-up and commission support @ 1% of construction cost
- General Owner's Costs, including Owners Engineering & Bond Fees – not included
- EPC Fee – not included

These percentages are based on our experience with similar type and size projects.

Escalation

Not included.

Contingency

The contingency rates vary for each project based on the project's size. The rates are based on past history of similar projects. This rate relates to pricing and quantity variation in the specific scope estimated. The contingency does not cover new scope outside of what has been estimated, only the variation in the defined scope. This is a composite rate and already takes into account the plus and minuses of expected actual costs. The rate does not represent the high range of all costs, nor is it expected that the project will experience all actual costs be realized at the maximum value of their range of variation.

Exclusions

There are items that have been specifically excluded from the estimate. In order to establish the overall project costs, the following items must also be accounted for. This list is for information only and is not intended to be all inclusive.

- Permitting costs
- Rock excavation
- Remediation of soil for hazardous materials
- Power outage cost during construction

Assumptions

- No rock excavation, no dewatering
- Assumed that asbestos removal or lead paint abatement will not be required.
- No obstruction for the ammonia pipe routing. 6" clearing & grubbing of existing terrain is included, no tree removal.
- Directional boring underneath the existing railroad tracks is included, but with no major interferences or obstructions.
- Electrical equipment and wiring installation is based on non-hazardous location.
- Adjustments for plant unit size were made based on good engineering practice. Actual design and quantities may be significantly different than the quantities shown in the estimates.

Estimate Totals

Description	Amount	Totals	
Labor	331,677		
Material	125,263		
Subcontract	2,850,000		
Equipment			
Other	2,000,000		
	5,306,940	5,306,940	USD
91-1 Scaffolding	46,000		
91-2 OT Working 5-10 Hour Days	41,000		
91-3 OT Working 7-10 Hr Days			
91-4 Per Diem			
91-5 Consumables	2,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	6,000		
91-9 Freight on Process Equip.	100,000		
91-10 Sales Tax			
91-11 Contractor's G&A Expense	65,000		
91-12 Contractor's Profit	32,000		
	292,000	5,598,940	USD
93-1 EP&P Services	1,064,000		
93-2 CM Support	168,000		
93-3 Start-Up/Commissioning	56,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	1,288,000	6,886,940	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	50,000		
94-4 Contingency on Labor	145,000		
94-5 Contingency on Sub.	713,000		
94-6 Contingency on Equipment	525,000		
94-7 Contingency on Indirect	386,000		
	1,819,000	8,705,940	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		8,705,940	USD
98 - Interest During Constr			
		8,705,940	USD
Total		8,705,940	USD

Estimate Totals

Description	Amount	Totals	
Labor	19,780,000		
Material	15,815,652		
Subcontract	2,590,000		
Equipment			
Other	8,290,000		
	46,475,652	46,475,652	USD
91-1 Scaffolding			
91-2 OT Working 5-10 Hour Days			
91-3 OT Working 7-10 Hr Days			
91-4 Per Diem			
91-5 Consumables			
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material			
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense			
91-12 Contractor's Profit			
		46,475,652	USD
93-1 EP&P Services	3,718,100		
93-2 CM Support	1,394,300		
93-3 Start-Up/Commissioning	464,800		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	5,577,200	52,052,852	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	2,372,400		
94-4 Contingency on Labor	2,967,000		
94-5 Contingency on Sub.	388,500		
94-6 Contingency on Equipment	1,243,500		
94-7 Contingency on Indirect	836,600		
	7,808,000	59,860,852	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		59,860,852	USD
98 - Interest During Constr			
		59,860,852	USD
Total		59,860,852	USD

Estimate Totals

Description	Amount	Totals	
Labor	2,629,958		
Material	1,083,165		
Subcontract	80,600		
Equipment			
Other	6,193,056		
	9,986,779	9,986,779	USD
91-1 Scaffolding	445,600		
91-2 OT Working 5-10 Hour Days	311,700		
91-3 OT Working 7-10 Hr Days	99,200		
91-4 Per Diem			
91-5 Consumables	18,600		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	54,200		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	458,800		
91-12 Contractor's Profit	229,500		
	1,617,600	11,604,379	USD
93-1 EP&P Services	928,400		
93-2 CM Support	232,100		
93-3 Start-Up/Commissioning	116,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	1,276,500	12,880,879	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	390,000		
94-4 Contingency on Labor	1,209,300		
94-5 Contingency on Sub.	24,200		
94-6 Contingency on Equipment	619,300		
94-7 Contingency on Indirect	383,000		
	2,625,800	15,506,679	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		15,506,679	USD
98 - Interest During Constr			
		15,506,679	USD
Total		15,506,679	USD

Estimate Totals

Description	Amount	Totals	
Labor	653,648		
Material	306,347		
Subcontract	3,700,000		
Equipment			
Other			
	4,659,995	4,659,995	USD
91-1 Scaffolding	48,000		
91-2 OT Working 5-10 Hour Days	77,000		
91-3 OT Working 7-10 Hr Days	24,000		
91-4 Per Diem			
91-5 Consumables	5,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	15,000		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	112,000		
91-12 Contractor's Profit	55,000		
	336,000	4,995,995	USD
93-1 EP&P Services	799,000		
93-2 CM Support	300,000		
93-3 Start-Up/Commissioning	50,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	1,149,000	6,144,995	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	110,000		
94-4 Contingency on Labor	279,000		
94-5 Contingency on Sub.	925,000		
94-6 Contingency on Equipment			
94-7 Contingency on Indirect	345,000		
	1,659,000	7,803,995	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		7,803,995	USD
98 - Interest During Constr			
		7,803,995	USD
Total		7,803,995	USD

Estimate Totals

Description	Amount	Totals	
Labor	2,255,791		
Material	1,089,242		
Subcontract	68,100		
Equipment			
Other	1,948,100		
	5,361,233	5,361,233	USD
91-1 Scaffolding	368,000		
91-2 OT Working 5-10 Hour Days	267,300		
91-3 OT Working 7-10 Hr Days	85,100		
91-4 Per Diem			
91-5 Consumables	16,700		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	54,500		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	408,200		
91-12 Contractor's Profit	204,100		
	1,403,900	6,765,133	USD
93-1 EP&P Services	541,200		
93-2 CM Support	135,300		
93-3 Start-Up/Commissioning	67,700		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	744,200	7,509,333	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	392,100		
94-4 Contingency on Labor	1,032,500		
94-5 Contingency on Sub.	20,400		
94-6 Contingency on Equipment	194,800		
94-7 Contingency on Indirect	223,300		
	1,863,100	9,372,433	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		9,372,433	USD
98 - Interest During Constr			
		9,372,433	USD
Total		9,372,433	USD

Estimate Totals

Description	Amount	Totals	
Labor	56,778,212		
Material	34,013,262		
Subcontract	8,156,000		
Equipment			
Other	21,324,260		
	120,271,734	120,271,734	USD
91-1 Scaffolding	2,270,000		
91-2 OT Working 5-10 Hour Days	6,730,000		
91-3 OT Working 7-10 Hr Days	2,142,000		
91-4 Per Diem			
91-5 Consumables	454,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	1,701,000		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	10,238,000		
91-12 Contractor's Profit	5,120,000		
	28,655,000	148,926,734	USD
93-1 EP&P Services	8,936,000		
93-2 CM Support	2,979,000		
93-3 Start-Up/Commissioning	1,489,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	13,404,000	162,330,734	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	8,163,000		
94-4 Contingency on Labor	15,726,000		
94-5 Contingency on Sub.	1,631,000		
94-6 Contingency on Equipment	4,265,000		
94-7 Contingency on Indirect	2,681,000		
	32,466,000	194,796,734	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		194,796,734	USD
98 - Interest During Constr			
		194,796,734	USD
Total		194,796,734	USD

Estimate Totals

Description	Amount	Totals	
Labor	653,648		
Material	306,347		
Subcontract	3,700,000		
Equipment			
Other	2,600,000		
	7,259,995	7,259,995	USD
91-1 Scaffolding	48,000		
91-2 OT Working 5-10 Hour Days	77,000		
91-3 OT Working 7-10 Hr Days	24,000		
91-4 Per Diem			
91-5 Consumables	5,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	15,000		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	112,000		
91-12 Contractor's Profit	55,000		
	336,000	7,595,995	USD
93-1 EP&P Services	1,215,000		
93-2 CM Support	456,000		
93-3 Start-Up/Commissioning	76,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	1,747,000	9,342,995	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	110,000		
94-4 Contingency on Labor	279,000		
94-5 Contingency on Sub.	925,000		
94-6 Contingency on Equipment	650,000		
94-7 Contingency on Indirect	524,000		
	2,488,000	11,830,995	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		11,830,995	USD
98 - Interest During Constr			
		11,830,995	USD
Total		11,830,995	USD

Estimate Totals

Description	Amount	Totals	
Labor	2,255,791		
Material	1,089,242		
Subcontract	68,100		
Equipment			
Other	1,948,100		
	5,361,233	5,361,233	USD
91-1 Scaffolding	368,000		
91-2 OT Working 5-10 Hour Days	267,300		
91-3 OT Working 7-10 Hr Days	85,100		
91-4 Per Diem			
91-5 Consumables	16,700		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	54,500		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	408,200		
91-12 Contractor's Profit	204,100		
	1,403,900	6,765,133	USD
93-1 EP&P Services	541,200		
93-2 CM Support	135,300		
93-3 Start-Up/Commissioning	67,700		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	744,200	7,509,333	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	392,100		
94-4 Contingency on Labor	1,032,500		
94-5 Contingency on Sub.	20,400		
94-6 Contingency on Equipment	194,800		
94-7 Contingency on Indirect	223,300		
	1,863,100	9,372,433	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		9,372,433	USD
98 - Interest During Constr			
		9,372,433	USD
Total		9,372,433	USD

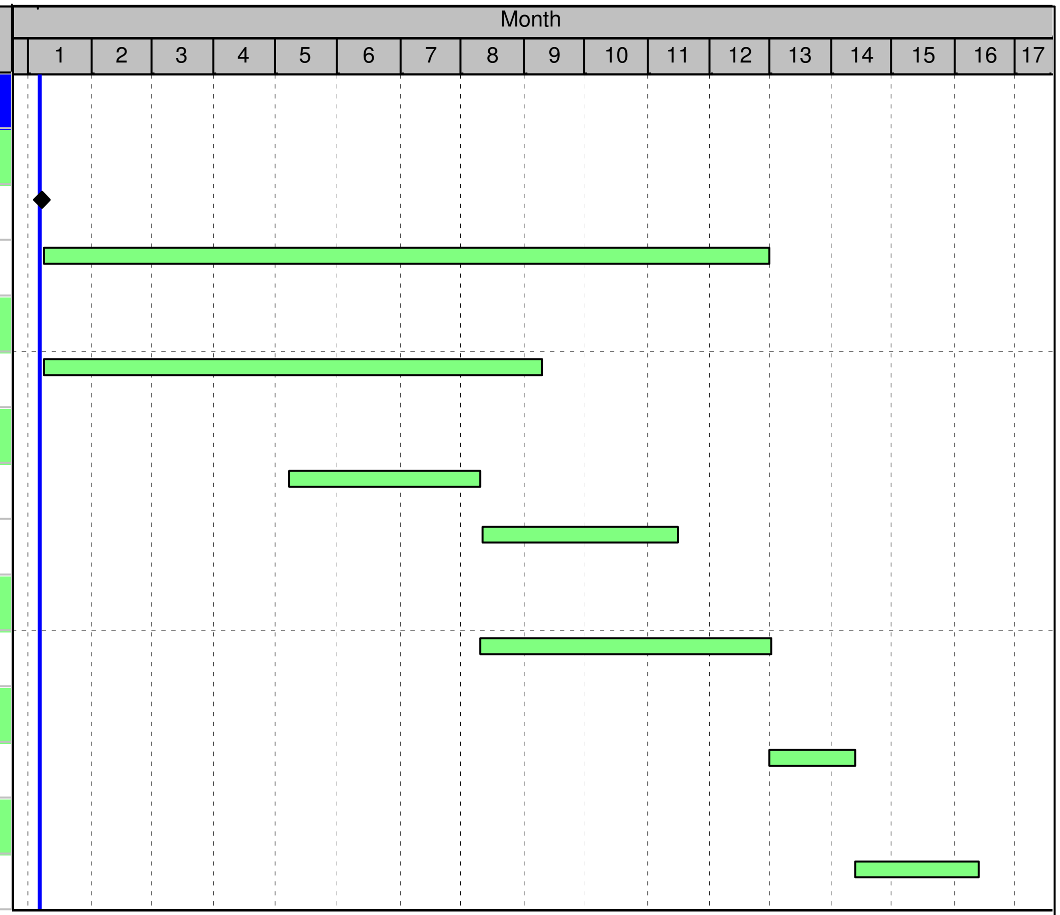
Estimate Totals

Description	Amount	Totals	
Labor	48,597,255		
Material	26,751,692		
Subcontract	6,577,640		
Equipment			
Other	21,324,260		
	103,250,847	103,250,847	USD
91-1 Scaffolding	1,884,000		
91-2 OT Working 5-10 Hour Days	5,759,000		
91-3 OT Working 7-10 Hr Days	1,834,000		
91-4 Per Diem			
91-5 Consumables	377,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	1,338,000		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	8,520,000		
91-12 Contractor's Profit	4,261,000		
	23,973,000	127,223,847	USD
93-1 EP&P Services	7,633,000		
93-2 CM Support	2,544,000		
93-3 Start-Up/Commissioning	1,272,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	11,449,000	138,672,847	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	6,421,000		
94-4 Contingency on Labor	13,444,000		
94-5 Contingency on Sub.	1,316,000		
94-6 Contingency on Equipment	4,265,000		
94-7 Contingency on Indirect	2,290,000		
	27,736,000	166,408,847	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		166,408,847	USD
98 - Interest During Constr			
		166,408,847	USD
Total		166,408,847	USD

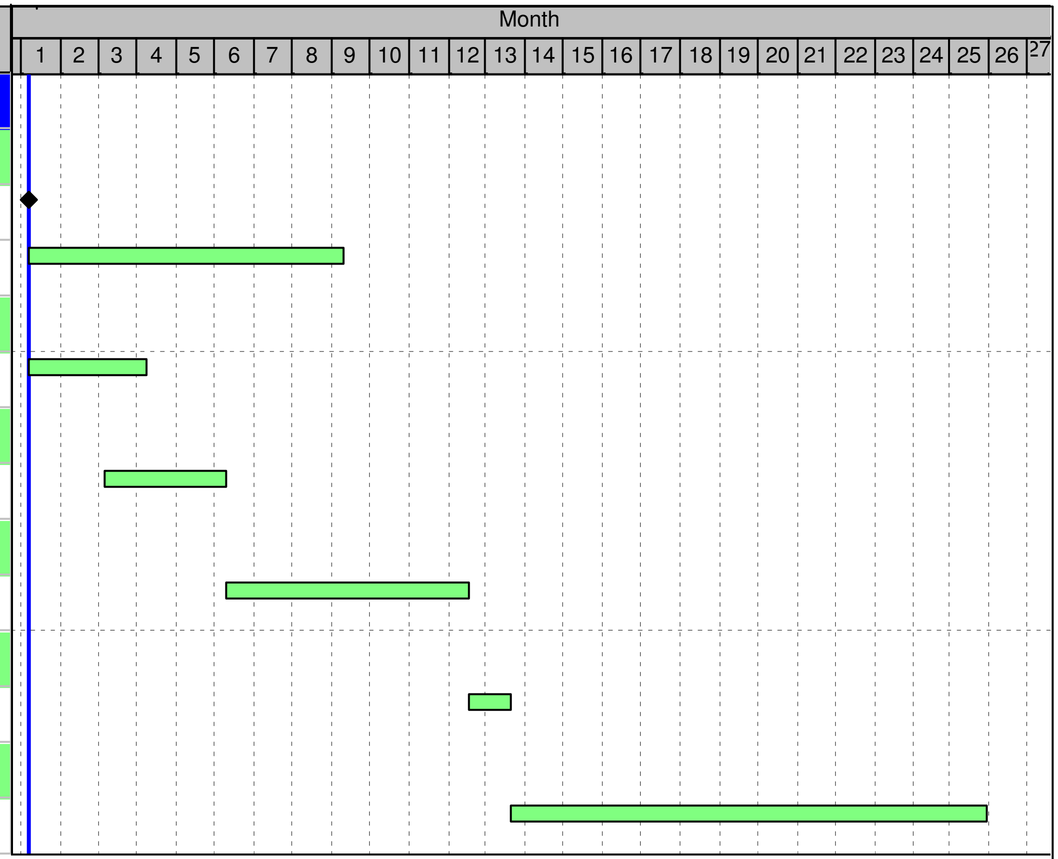
APPENDIX B

1. ESTIMATED PROJECT SCHEDULES

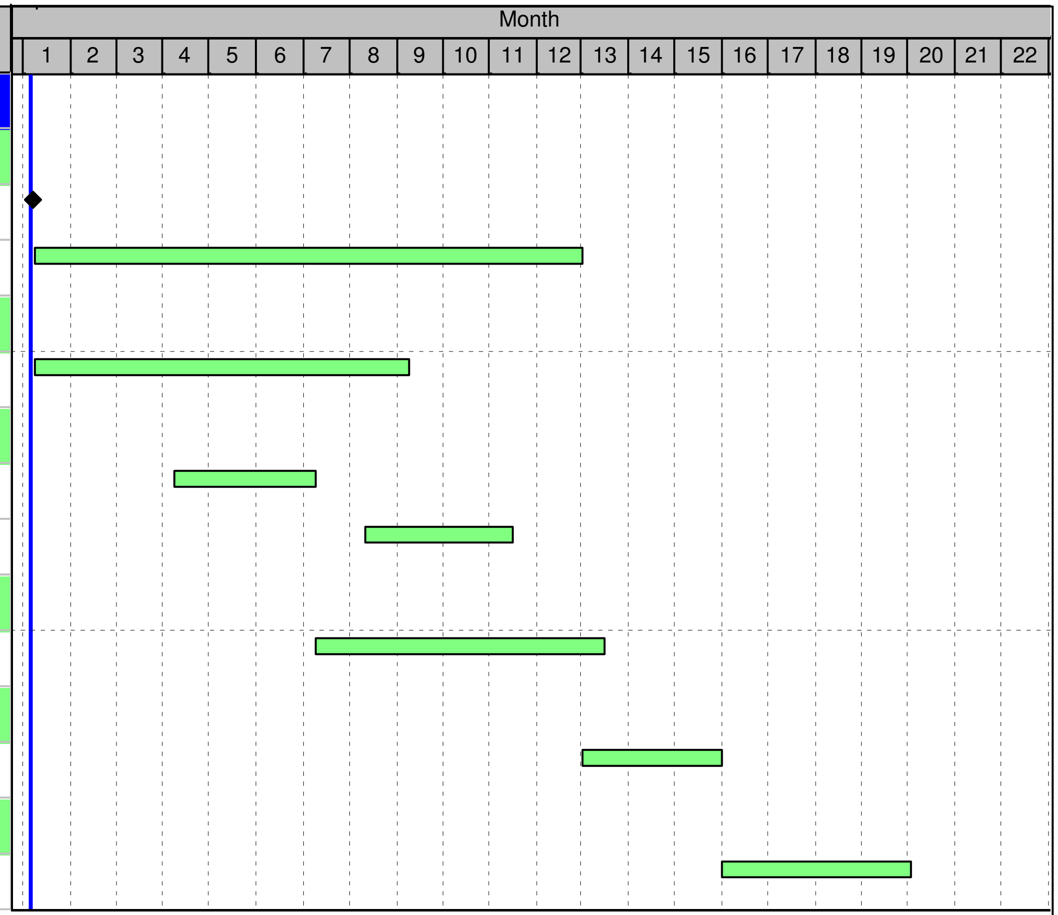
.	Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Aux Boiler (LNB/OFA/F...		15m
	Permitting		12m
	A1000	Project Authorization	0m
	A1010	Air Permit - Prepare/Review/Approve	12m
	Engineering		8m
	A1020	Engineering	8m
	Procurement of Major Equipment		6m
	A1030	LNB/OFA Spec - Prep/Bid/Eval/Award	3m
	A1070	GWC Spec - Prep/Bid/Eval/Award	3m
	Vendor Engineering/Fab/Delivery		5m
	A1040	LNB/OFA Vendor Engineering/Fabrication/Delivery	5m
	Installation		1m
	A1050	Installation	1m
	Commissioning & Start-Up		2m
	A1060	Commissioning & Start-Up	2m



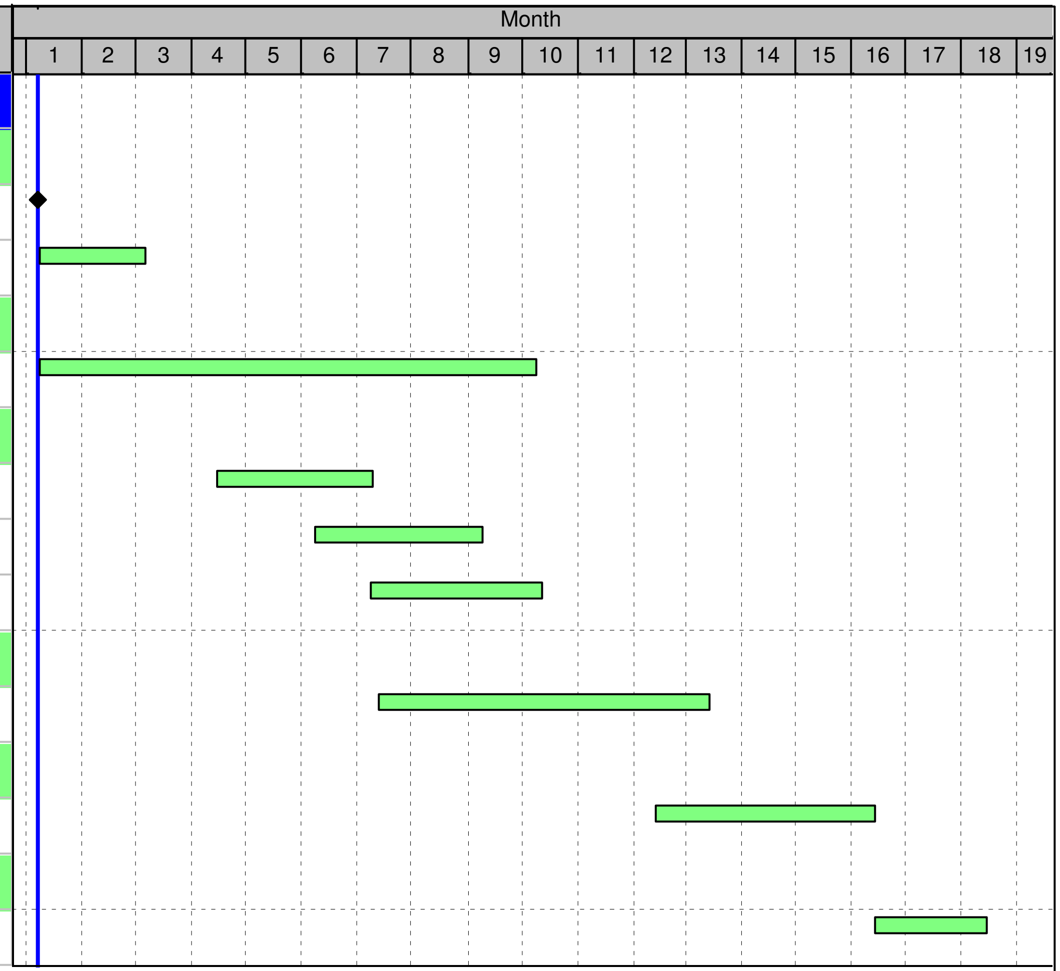
Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Neural Network	24m
	Permitting	8m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	8m
	Engineering	3m
A1020	Engineering	3m
	Procurement of Major Equipment	3m
A1030	Neural Network Spec - Prep/Bid/Eval/Award	3m
	Vendor Engineering/Fab/Delivery	6m
A1040	NN Vendor Engineering/Fabrication/Delivery	6m
	Installation	1m
A1050	Installation	1m
	Commissioning & Start-Up	12m
A1060	Commissioning & Start-Up	12m



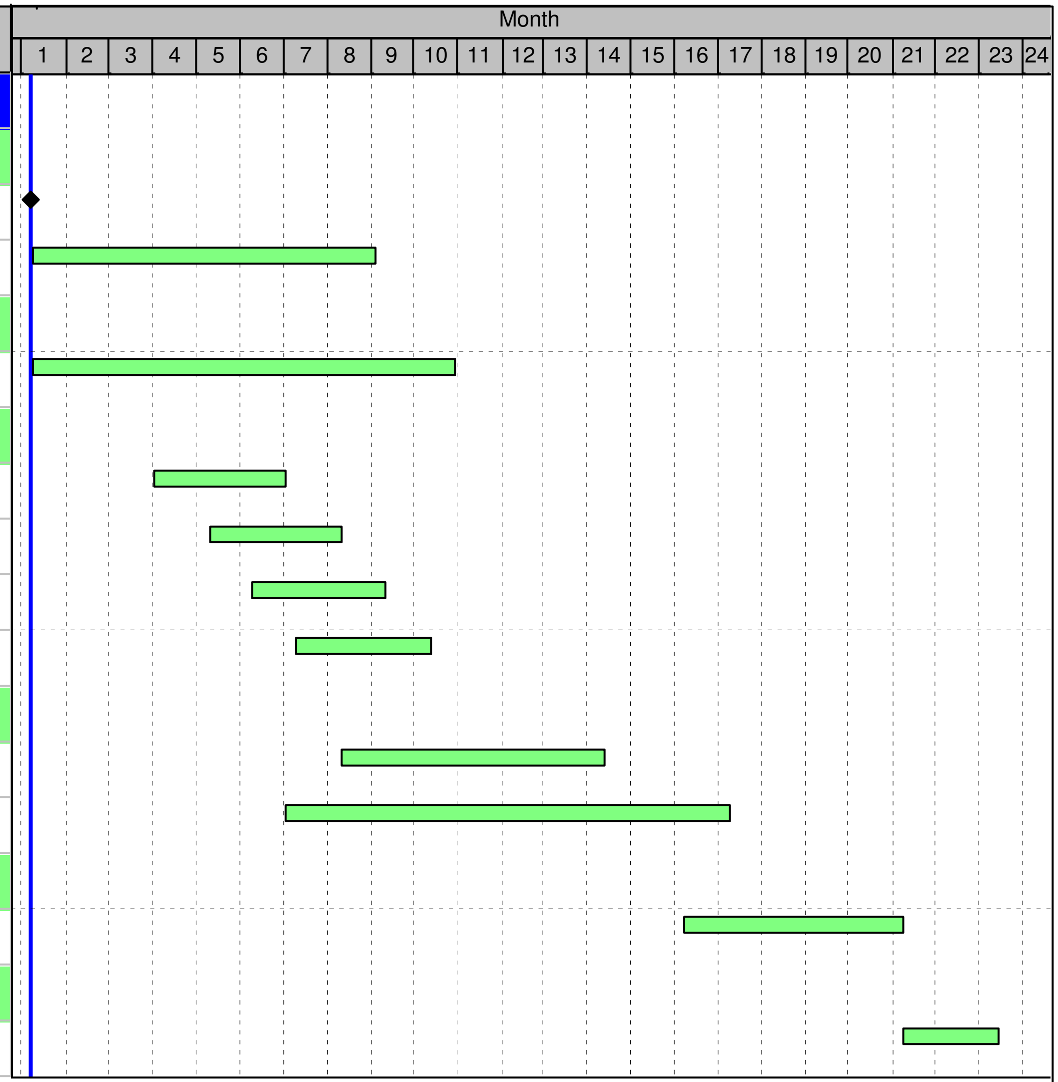
Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Low NOx Burners/Over ...	19m
	Permitting	12m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	12m
	Engineering	8m
A1020	Engineering	8m
	Procurement of Major Equipment	7m
A1030	LNB/OFA Spec - Prep/Bid/Eval/Award	3m
A1070	GWC Spec - Prep/Bid/Eval/Award	3m
	Vendor Engineering/Fab/Delivery	6m
A1040	LNB/OFA Vendor Engineering/Fabrication/Delivery	6m
	Installation	3m
A1050	Installation	3m
	Commissioning & Start-Up	4m
A1060	Commissioning & Start-Up	4m



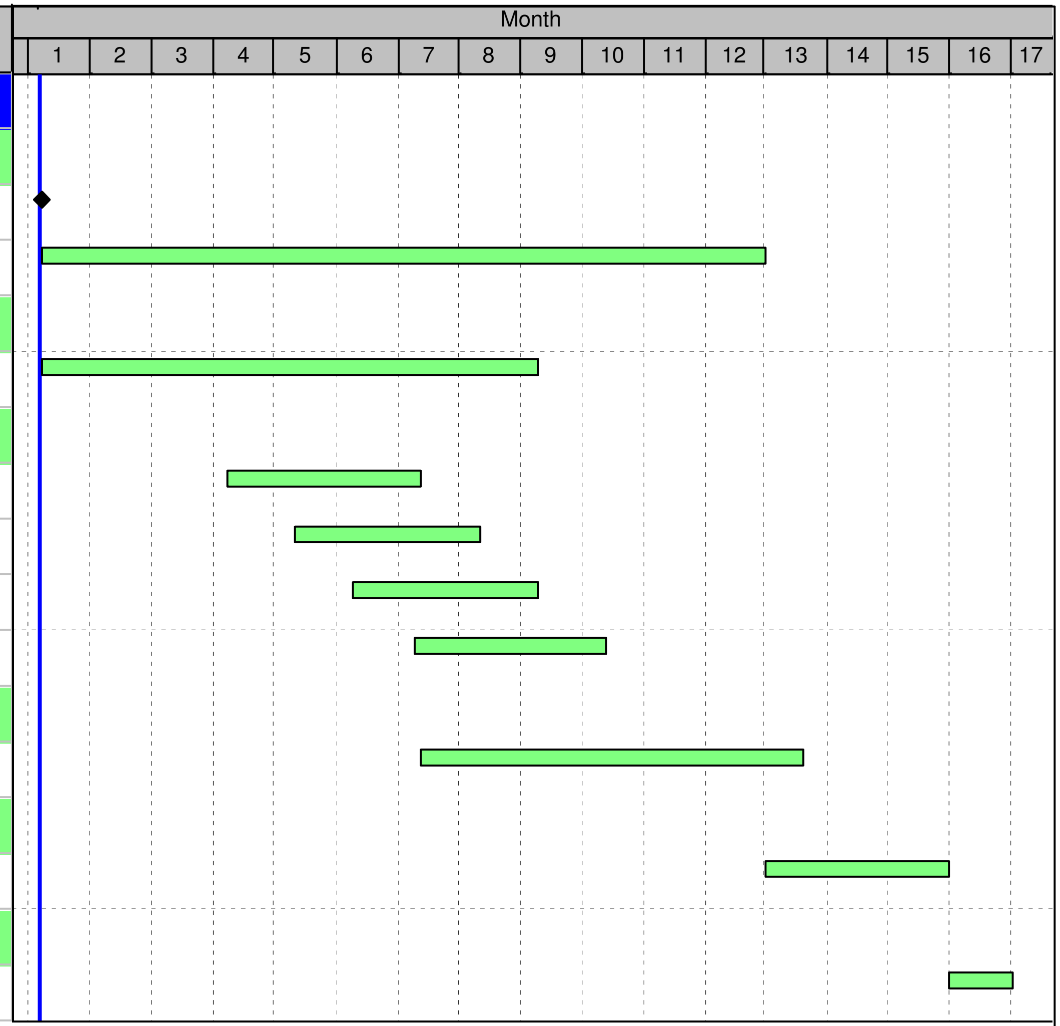
Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Induced Flue Gas Recir...	17m
	Permitting	2m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	2m
	Engineering	9m
A1020	BOP Engineering	9m
	Procurement of Major Equipment	6m
A1140	FGR Duct Procurement Spec - Prep/Bid/Eval/Award	3m
A1030	Mech Install Spec - Prep/Bid/Eval/Award	3m
A1120	Elec Install Spec - Prep/Bid/Eval/Award	3m
	Vendor Engineering/Fab/Delivery	6m
A1040	FGR Duct Vendor Engineering/Fabrication/Delivery	6m
	Installation	4m
A1050	Installation	4m
	Commissioning & Start-Up	2m
A1060	Commissioning & Start-Up	2m



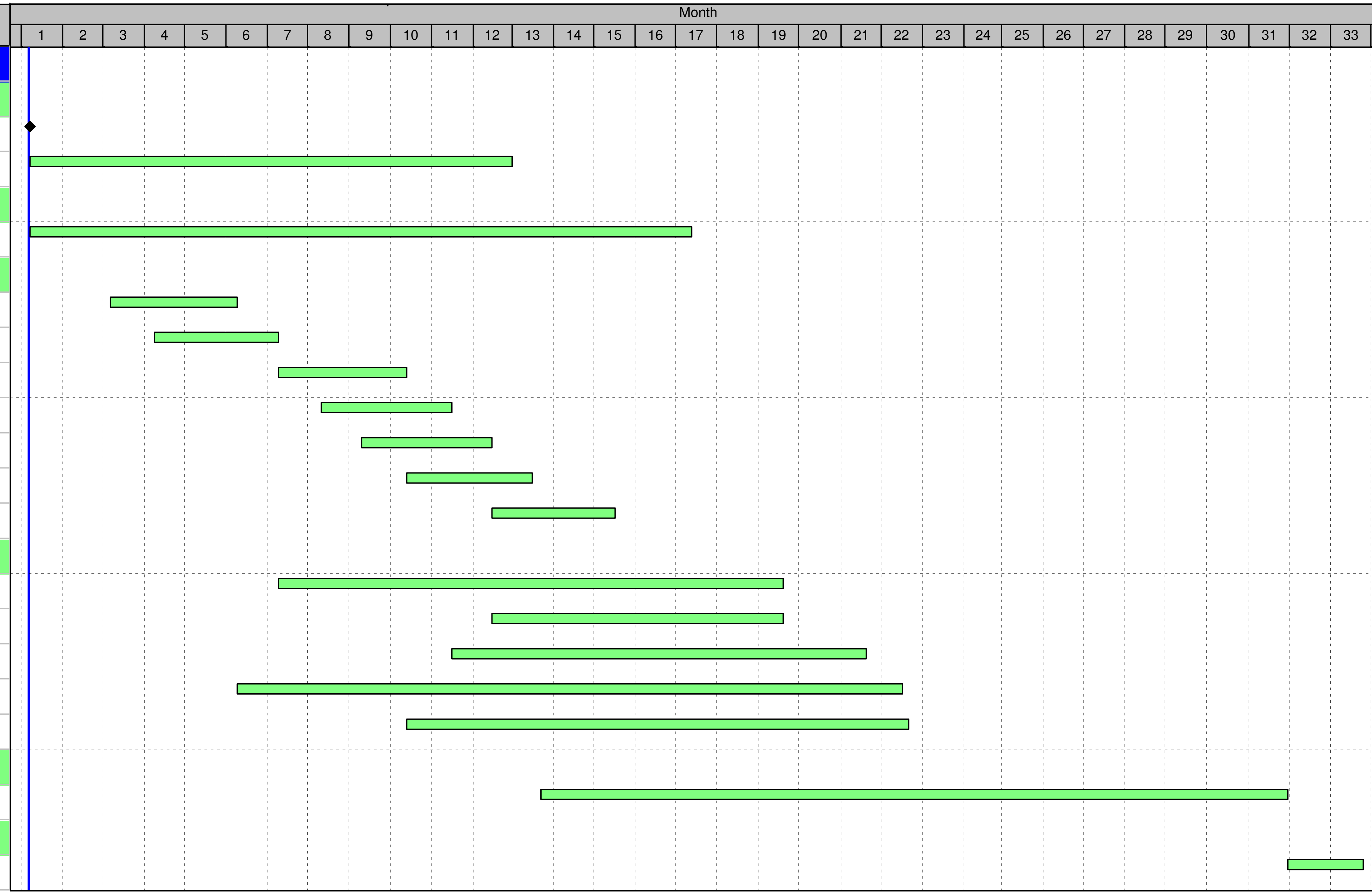
Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Flue Gas Recirculation ...	22m
	Permitting	8m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	8m
	Engineering	10m
A1020	BOP Engineering	10m
	Procurement of Major Equipment	6m
A1150	FGR Fan Procurement Spec - Prep/Bid/Eval/Award	3m
A1140	FGR Duct Procurement Spec - Prep/Bid/Eval/Award	3m
A1030	Mech Install Spec - Prep/Bid/Eval/Award	3m
A1120	Elec Install Spec - Prep/Bid/Eval/Award	3m
	Vendor Engineering/Fab/Delivery	10m
A1040	FGR Duct Vendor Engineering/Fabrication/Delivery	6m
A1160	FGR Fan Vendor Engineering/Fabrication/Delivery	10m
	Installation	5m
A1050	Installation	5m
	Commissioning & Start-Up	2m
A1060	Commissioning & Start-Up	2m



Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Selective Non-Catalytic ...	16m
	Permitting	12m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	12m
	Engineering	8m
A1020	BOP Engineering	8m
	Procurement of Major Equipment	6m
A1030	SNCR Spec - Prep/Bid/Eval/Award	3m
A1070	Civil/Structural Installation Spec - Prep/Bid/Eval/Award	3m
A1080	Mech Installation Spec - Prep/Bid/Eval/Award	3m
A1090	Elec/I&C Installation Spec - Prep/Bid/Eval/Award	3m
	Vendor Engineering/Fab/Delivery	6m
A1040	SNCR Vendor Engineering/Fabrication/Delivery	6m
	Installation	3m
A1050	Installation	3m
	Commissioning & Start-Up	1m
A1060	Commissioning & Start-Up	1m



Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Selective Catalytic Red...	32m
	Permitting	12m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	12m
	Engineering	16m
A1020	BOP Engineering	16m
	Procurement of Major Equipment	12m
A1140	Ammonia Injection System Procurement Spec - Prep/Bid/Eval/Award	3m
A1150	Catalyst Procurement Spec - Prep/Bid/Eval/Award	3m
A1170	Fan Spec - Prep/Bid/Eval/Award	3m
A1190	Ductwork Spec - Prep/Bid/Eval/Award	3m
A1130	Structural Steel Spec - Prep/Bid/Eval/Award	3m
A1030	Mech Install Spec - Prep/Bid/Eval/Award	3m
A1120	Elec Install Spec - Prep/Bid/Eval/Award	3m
	Vendor Engineering/Fab/Delivery	16m
A1160	Catalyst Vendor Engineering/Fabrication/Delivery	12m
A1210	Structural Steel Vendor Engineering/Fabrication/Delivery	7m
A1200	Ductwork Vendor Engineering/Fabrication/Delivery	10m
A1040	Ammonia Injection System Vendor Engineering/Fabrication/Delivery	16m
A1180	Fan Vendor Engineering/Fabrication/Delivery	12m
	Installation	18m
A1050	Installation	18m
	Commissioning & Start-Up	2m
A1060	Commissioning & Start-Up	2m



APPENDIX C

1. OPERATING AND MAINTENANCE COST ESTIMATES

NO_X Compliance Costs

Unit Name White Bluff 1

Unit Data		Reagent Costs	
Size (Gross kW)	815,000	Aq.Ammonia $/t	$700
Average NOx Emission Rate (lb/MMBtu at full load)	**0.33**	An.Ammonia $/t	$400
Nominal Max. Boiler Heat Input (mmBtu/hr)	8,950.0	Urea $/t	$350
Avg. Heat Rate (Btu/kwh)	10,981.6	N/F-T Urea $/t	$618
Aux. Power (kw)	-	Coal Cost, $/Mbtu	2.650
Est. Capacity Factor (%)	76.00		
Boiler Type	T/F	Water Cost, $/1000 gal (3)	2
Boiler Eff. (%)	84	Electricity, $/MWh	41.50
Estimated NOx, tons/day Max	**26.936**		
Emission Limit, tons	-		
NOx Sales/Buy rate, $/ton	-		
Fuel -	PRB		
Seasonal Days	153		
Basis	0		
Analysis - Enter "0" for Annual and 1 for Seasonal			
CF For Variable O&M	76.00		

Technology	Estimated Reduction from Baseline	Emission Rate After Control	Tons of NOx Emission, Seasonal/Annual	Tons of NOx Removed, season/annual	Estimated Capital Cost		Operating & Maintenance Cost: Fixed O&M	Variable O&M, season or yr	Fuel Impact, season or yr
	%	(lb/mmBtu)	tons	tons	$/kW	$/unit	$/yr	$/@CF	$/@CF
LNB + OFA (Note 5)	54.5	0.15	4,469	5,363	9.6	$7,804,000	$142,000	$0	$0
Neural Net	10.0	0.30	8,848	983	0.3	$250,000	$50,000	$0	$0
Full SNCR	26.5	0.24	7,229	2,602	11.5	$9,372,000	$169,000	$5,377,000	$281,000
LNB+OFA+Full SNCR	61.4	0.13	3,799	6,033	20.0	$16,290,000	$311,000	$4,154,000	$384,000
LNB+OFA+Full SCR	83.3	0.055	1,639	8,193	248.6	$202,601,000	$608,000	$2,836,000	$0

(1) Aux. Power cost is calculated based on variation in capacity factor
(2) Assumed water cost of $2/1000 gallons.
(3) Assumed that 15% urea will be used for SNCR technology.
(4) Assumed that initial catalyst life is 12,000 hours
(5) LNB/OFA material already purchased for Unit 1. The total cost to Entergy would be the same for Unit 1 as shown for Unit 2.
(6) For SCR technology, the variable O&M costs are based on operating at NOx outlet emissions marginally below the compliance emission rate.

NO_X Compliance Costs

Unit Name White Bluff 2

Unit Data		Reagent Costs	
Size (Gross kW)	844,000	Aq.Ammonia $/t	$700
Average NOx Emission Rate (lb/MMBtu at full load)	**0.39**	An.Ammonia $/t	$400
Nominal Max. Boiler Heat Input (mmBtu/hr)	8,950.0	Urea $/t	$350
Avg. Heat Rate (Btu/kwh)	10,604.3	N/F-T Urea $/t	$618
Aux. Power (kw)	-	Coal Cost, $/Mbtu	2.650
Est. Capacity Factor (%)	76.00		
Boiler Type	T/F	Water Cost, $/1000 gal (3)	2
Boiler Eff. (%)	84	Electricity, $/MWh	41.50
Estimated NOx, tons/day Max	**31.833**		
Emission Limit, tons	-		
NOx Sales/Buy rate, $/ton	-		
Fuel -	PRB		
Seasonal Days	153		
Basis	0		
Analysis - Enter "0" for Annual and 1 for Seasonal			
CF For Variable O&M	76.00		

Technology	Estimated Reduction from Baseline	Emission Rate After Control	Tons of NOx Emission, Seasonal/Annual	Tons of NOx Removed, season/annual	Estimated Capital Cost		Operating & Maintenance Cost: Fixed O&M	Variable O&M, season or yr	Fuel Impact, season or yr
	%	(lb/mmBtu)	tons	tons	$/kW	$/unit	$/yr	$/@CF	$/@CF
LNB + OFA	61.5	0.15	4,469	7,150	14.0	$11,831,000	$142,000	$0	$0
Neural Net	10.0	0.35	10,457	1,162	0.3	$250,000	$50,000	$0	$0
Full SNCR	26.5	0.29	8,544	3,076	11.1	$9,372,000	$169,000	$6,338,000	$333,000
LNB+OFA+Full SNCR	67.3	0.13	3,799	7,821	24.1	$20,317,000	$311,000	$4,158,000	$384,000
LNB+OFA+Full SCR	85.9	0.055	1,639	9,981	211.2	$178,240,000	$608,000	$2,858,000	$0

(1) Aux. Power cost is calculated based on variation in capacity factor
(2) Assumed water cost of $2/1000 gallons.
(3) Assumed that 15% urea will be used for SNCR technology.
(4) Assumed that initial catalyst life is 12,000 hours
(5) For SCR technology, the variable O&M costs are based on operating at NOx outlet emissions marginally below the compliance emission rate.

NO_X Compliance Costs

Unit name Lake Catherine Unit 4

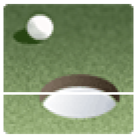
Unit Data		Reagent Costs	
Size (Gross kW)	558,000	Aq.Ammonia $/t	$700
Average NOx Emission Rate (lb/MMBtu)	0.4825	An.Ammonia $/t	$400
Nominal Max. Boiler Heat Input (mmBtu/hr)	5,850.0	Urea $/t	$350
Avg. Heat Rate (Btu/kwh)	10,483.9	N/F-T Urea $/t	$618
Aux. Power (kw)	-	Gas Cost, $/MBtu	4.900
Est. Capacity Factor (%)	10.00	Water Cost, $/1000 gal (3)	2
Boiler Type	T/F	Electricity, $/MWh	41.50
Boiler Eff. (%)	82		
Estimated NOx, tons/day Max	3.387		
Emission Limit, tons	-		
NOx Sales/Buy rate, $/ton	2500.0		
Fuel	Gas		
Seasonal Days	153		
Basis	0		
Analysis - Enter "0" for Annual and 1 for Seasonal			
CF For Variable O&M	10.00		

Technology	Estimated Reduction from Baseline	Emission Rate After Control	Tons of NOx Emission, Seasonal/Annual	Tons of NOx Removed, season/annual	Estimated Capital Cost		Operating & Maintenance Cost: Fixed O&M	Variable O&M, season or yr	Fuel Impact, season or yr
	%	(lb/mmBtu)	tons	tons	$/kW	$/unit	$/yr	$/@CF	$/@CF
Baseline	0	0.4825							
BOOS (at 558 MW)	50.0	0.24	618	618	1.6	$893,000	$21,000	$0	$0
LNB + OFA	60.0	0.19	495	742	15.7	$8,762,000	$210,000	$0	$0
SCR	90.0	0.05	124	1,113	106.8	$59,587,000	$358,000	$254,000	$0
SNCR	40.0	0.29	742	495	27.8	$15,507,000	$279,000	$1,542,000	$98,000
Water Injection	9.1	0.44	1,124	113	3.9	$2,177,000	$52,000	$18,000	$468,000
IFGR (below 500 MW)	19.0	0.39	1,001	235	3.9	$2,166,000	$52,000	$0	$0
FGR	60.0	0.19	495	742	20.6	$11,489,000	$207,000	$142,000	$0
LNB/OFA + SNCR	70.0	0.14	371	865	43.5	$24,269,000	$489,000	$393,000	$69,000
LNB/OFA + SCR	94.0	0.03	74	1,162	122.5	$68,349,000	$568,000	$268,000	$0

(1) Aux. Power cost is calculated based on variation in capacity factor
(2) Assumed water cost of $2/1000 gallons.
(3) Assumed that 15% urea will be used for SNCR technology.
(4) Assumed that initial catalyst life is 40,000 hours.
(5) Water Injection is used only for trimming at high load. Approximately 66% of Hours are affected.
(6) For SCR technology, the variable O&M costs are based on operating at NOx outlet emissions marginally below the compliance emission rate.

APPENDIX D

1. BOOS AT FULL UNIT LOAD



To: DAVID H PARK/Sargentlundy@Sargentlundy,
Cc:
Bcc:
Subject: Fw: BOOS for NOx Control
From: STEVE M KATZBERGER/Sargentlundy - Thursday 03/28/2013 03:32 PM

From: Stephen Wood [mailto:swood@etecinc.net]
Sent: Monday, March 25, 2013 2:20 PM
To: HANTZ, JOSEPH
Subject: BOOS for NOx Control

Joe,

The attached PDF file contains background information on utilizing burners out of service for NOx control, as well as, predicted Lake Catherine Unit 4 burner header pressures and NOx emissions, utilizing the top burner elevation out of service (4BOOS). If you have any questions, please let me know.

Regards,

Steve Wood
Principal Officer
Entropy Technology & Environmental Consultants, Inc. (ETEC Inc.)
12337 Jones Rd. Suite 414
Houston, TX 77070
Ph: 281-807-7007
Cell: 713-253-8230
Fax: 281-807-1414
Website: www.etecinc.net

 BOOS for NOx Control.pdf

Combustion Modification (BOOS) for NOx Control

Implementation of Burner Out Of Service (BOOS) operation is a practical and cost-effective means for achieving staged combustion (i.e., modifying burner stoichoimetry to reduce NOx emissions formation) on an existing gas/oil fired electric utility boiler. Utilizing BOOS operation for NOx control is well documented in the literature, e.g., EPA 456/F-99-006R "Nitrogen Oxides (NOx), Why And How They Are Controlled", November 1999, and EPRI TR-108181 "Retrofit NOx Control Guidelines for Gas- and Oil-Fired Boilers, Version 2.0", June 1997, among numerous others.

The technique of BOOS operation involves terminating the fuel flow to selected burners on the top elevation while leaving the air registers open. The remaining burners operate fuel-rich, thereby limiting oxygen availability, lowering peak flame temperatures, and reducing NOx formation. The un-reacted products combine with the air from the above terminated-fuel burners to complete burnout before exiting the furnace. I have personally been involved with implementing BOOS operation on virtually every gas fired electric utility boiler design across the country since the mid 1970's. In almost every case, the original "high" burner header pressure (BHP) set point had to be increased to accommodate BOOS operation. No adverse operational or maintenance problems corresponding to BOOS implementation have been reported.

BOOS operation can be a very effective NOx reduction technology, depending on the degree of staging, as shown for Ninemile Unit 4 (750 mw CE Tangential Fired) in Figure 1. The corresponding BOOS pattern is shown in Figure 2. The BHP corresponding to 4BOOS operation on Lake Catherine Unit 4 is shown in Figure 3. The "High" BHP set point would need to be increased from 42 to 50 psig. The predicted NOx emissions corresponding to 4BOOS operation are presented in Figure 4.

Figure 1- Stoichiometry Modification (BOOS) NOx Reduction

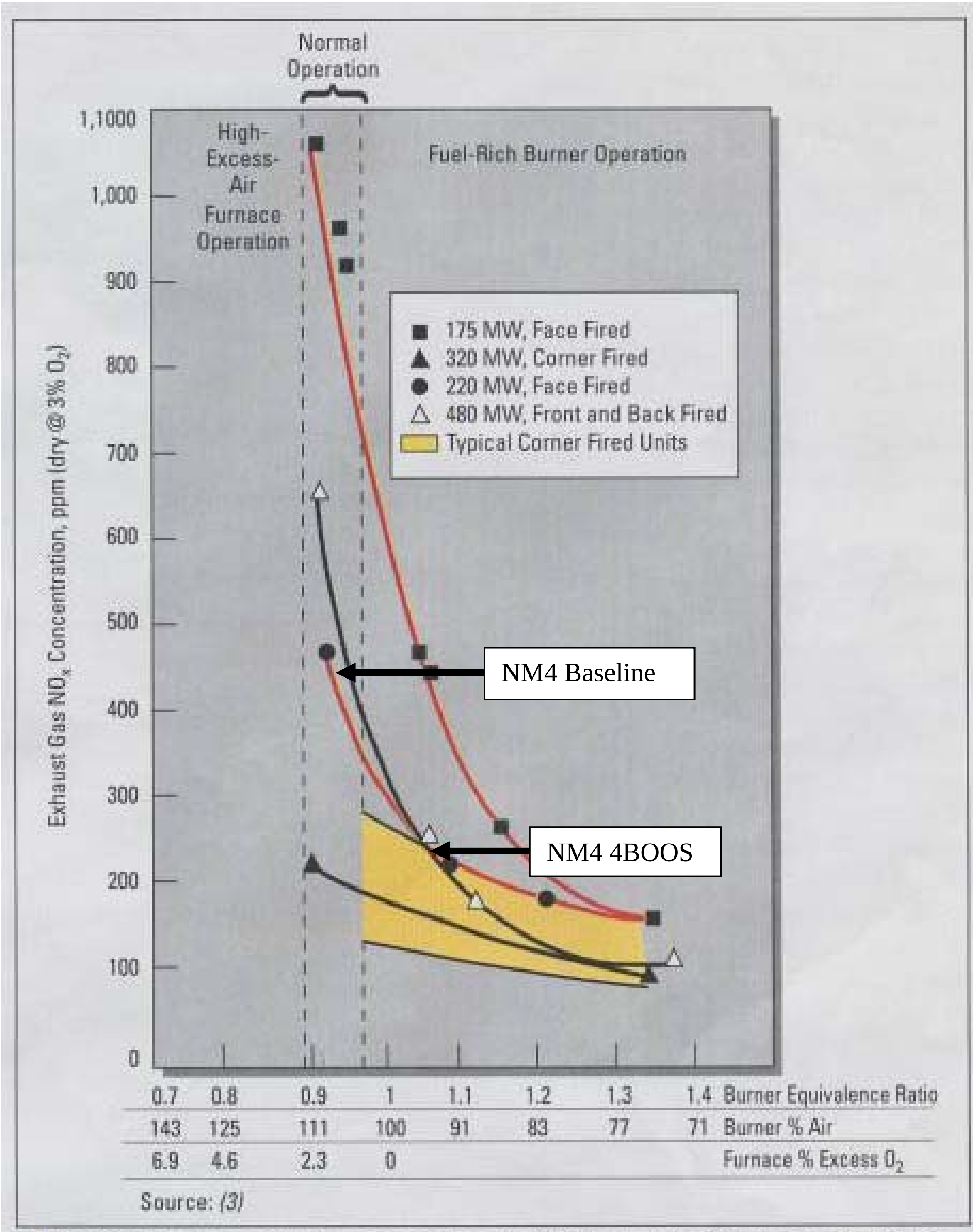


Figure 2. Burners-out-of-service can be an effective combustion staging technique.

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

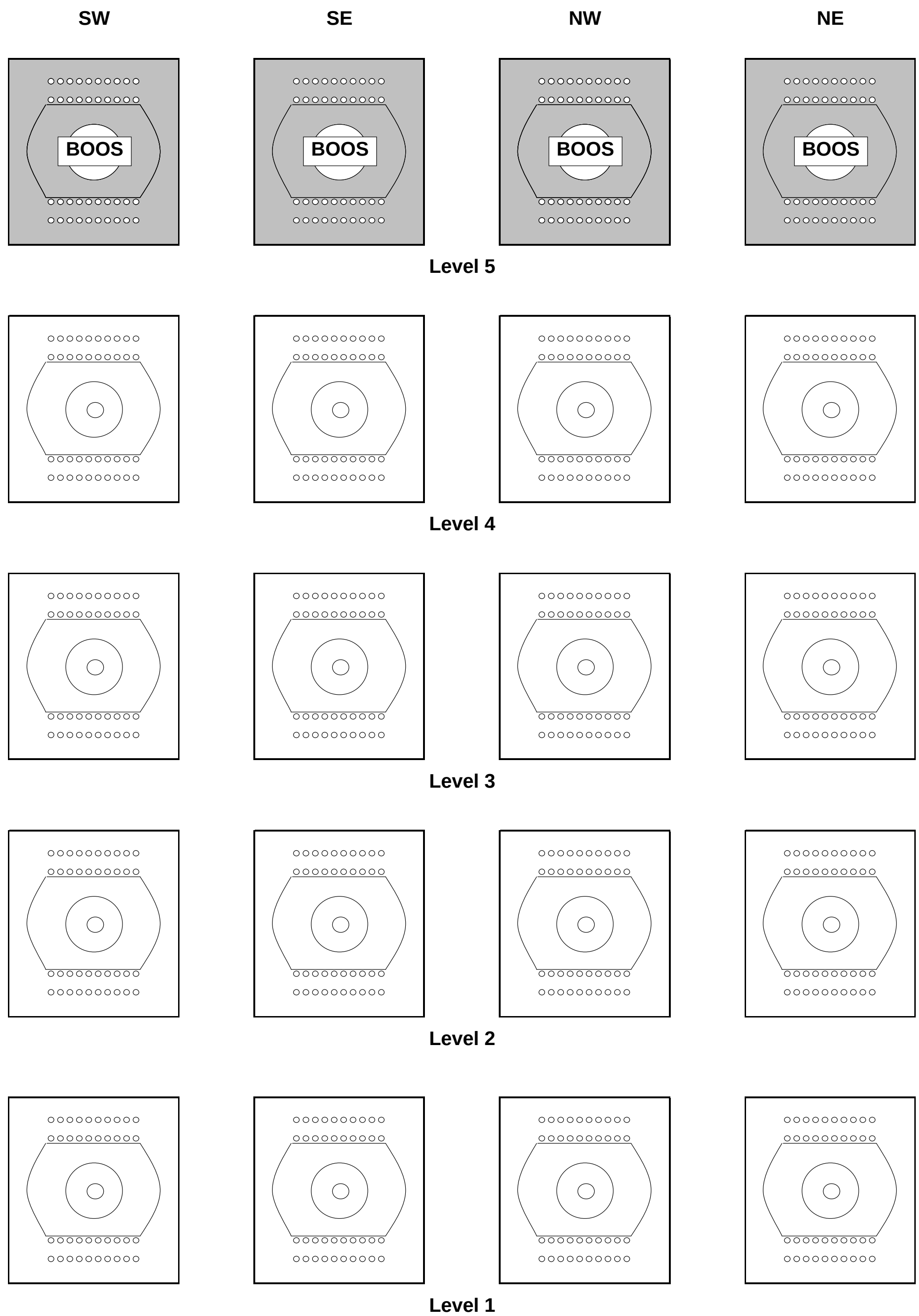


Figure 3- Lake Catherine Unit 4 Burner Header Pressure

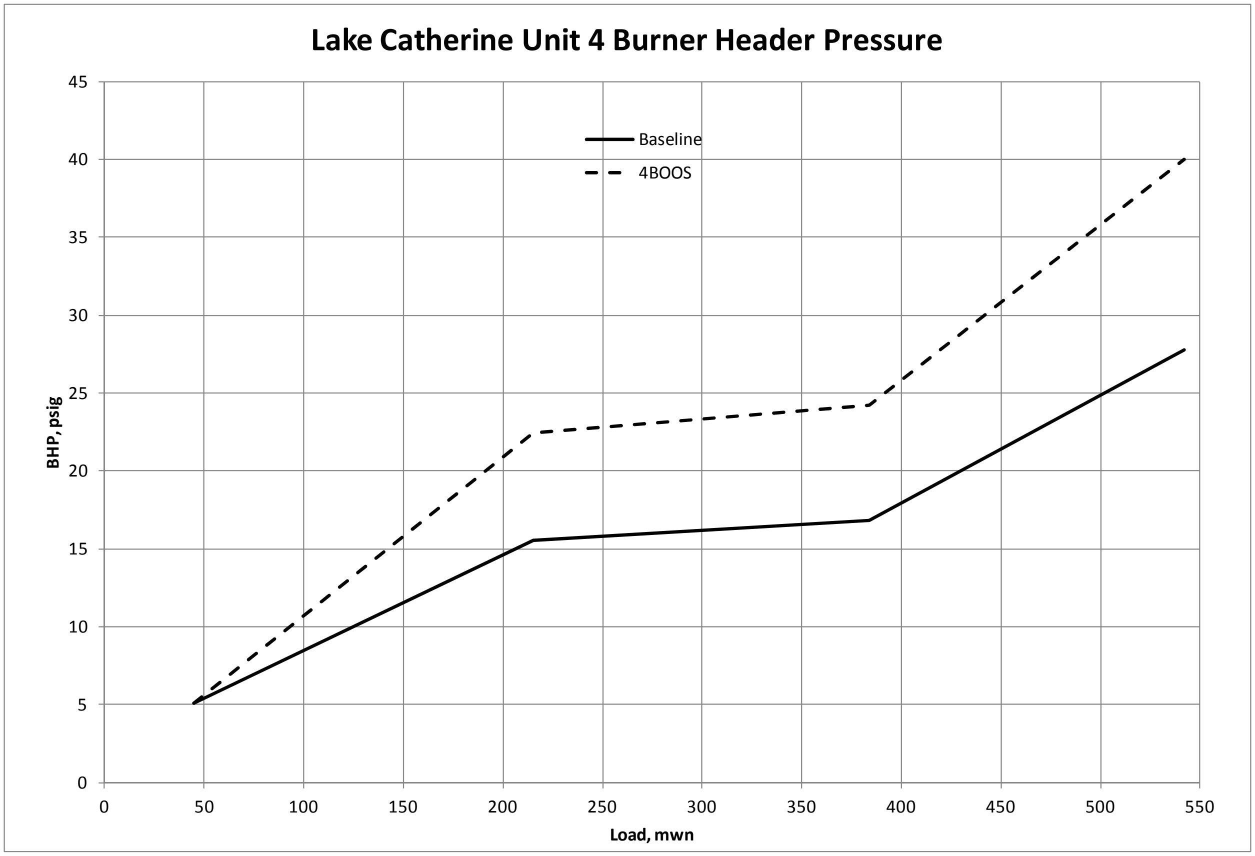


Figure 4- Lake Catherine Unit 4 NOx Emissions Prediction