Oklahoma Department of Environmental Quality
Air Quality Division

BART Application Analysis — September 28, 2009

COMPANY:	**Oklahoma Gas and Electric**
FACILITY:	**Seminole Generating Station**
FACILITY LOCATION:	**Konawa, Seminole County, Oklahoma**
TYPE OF OPERATION:	**(3) 567 MW Steam Electric Generating Units**
REVIEWER:	**Phillip Fielder, Senior Engineering Manager** **Lee Warden, Engineering Manager**

I. PURPOSE OF APPLICATION

On July 6, 2005, the U.S. Environmental Protection Agency (EPA) published the final "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations" (the "Regional Haze Rule" 70 FR 39104). The Regional Haze Rule requires certain States, including Oklahoma, to develop programs to assure reasonable progress toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in Class I Areas. The Regional Haze Rule requires states to submit a plan to implement the regional haze requirements (the Regional Haze SIP). The Regional Haze SIP must provide for a Best Available Retrofit Technology (BART) analysis of any existing stationary facility that might cause or contribute to impairment of visibility in a Class I Area.

II. BART ELIGIBILITY DETERMINATION

BART-eligible sources include those sources that:

(1) have the potential to emit 250 tons or more of a visibility-impairing air pollutant;
(2) were in existence on August 7, 1977 but not in operation prior to August 7, 1962; and
(3) whose operations fall within one or more of the specifically listed source categories in 40 CFR 51.301 (including fossil-fuel fired steam electric plants of more than 250 mmBtu/hr heat input and fossil-fuel boilers of more than 250 mmBtu/hr heat input).

Seminole Units 1, 2 and 3 are fossil-fuel fired boilers with heat inputs greater than 250-mmBtu/hr. All three units were in existence prior to August 7, 1977, but not in operation prior to August 7, 1962. Based on a review of existing emissions data, all three units have the potential to emit more than 250 tons per year of NO_X, a visibility impairing pollutant. Therefore, Seminole Units 1, 2 and 3 meet the definition of a BART-eligible source.

BART is required for any BART-eligible source that emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I Area.

DEQ has determined that an individual source will be considered to "contribute to visibility impairment" if emissions from the source result in a change in visibility, measured as a change in deciviews (Δ-dv), that is greater than or equal to 0.5 dv in a Class I area. Visibility impact modeling conducted by OG&E determined that the maximum predicted visibility impacts from Seminole Units 1, 2 and 3 exceeded the 0.5 Δ-dv threshold at the Wichita Mountains Class I Area. Therefore, Seminole Units 1, 2 and 3 were determined to be BART applicable sources, subject to the BART determination requirements.

III. DESCRIPTION OF BART SOURCES

Baseline emissions from Seminole Units 1, 2 and 3 were developed based on an evaluation of actual emissions data submitted by the facility pursuant to the federal Acid Rain Program. In accordance with EPA guidelines in 40 CFR 51 Appendix Y Part III, emission estimates used in the modeling analysis to determine visibility impairment impacts should reflect steady-state operating conditions during periods of high capacity utilization. Therefore, baseline emissions (lb/hr) represent the highest 24-hour block emissions reported during the baseline period. Baseline emission rates (lb/mmBtu) were calculated by dividing the maximum hourly mass emission rates for each boiler by the boiler's full load heat input.

Table 1: Seminole Generating Station- Plant Operating Parameters for BART Evaluation

Parameter	Seminole Unit 1		Seminole Unit 2		Seminole Unit 3	
Plant Configuration	Natural Gas-Fired Boiler		Natural Gas-Fired Boiler		Natural Gas-Fired Boiler	
Firing Configuration	Wall-fired		Wall-fired		Wall-fired	
Gross Output (nominal)	567 MW		567 MW		567 MW	
Maximum Input to Boiler	5,480 mmBtu/hr		5,480 mmBtu/hr		5,496 mmBtu/hr	
Primary Fuel	Natural gas		Natural gas		Natural gas	
Existing NO_X Controls	None		None		Flue gas recirculation	
Existing PM_{10} Controls	NA		NA		NA	
Existing SO_2 Controls	NA		NA		NA	
Baseline Emissions Pollutant	**Baseline Actual Emissions**		**Baseline Actual Emissions**		**Baseline Actual Emissions**	
	lb/hr	**lb/mmBtu**	**lb/hr**	**lb/mmBtu**	**lb/hr**	**lb/mmBtu**
NO_X	**1,859**	**0.339**	**1,940**	**0.354**	**1,204**	**0.219**

IV. BEST AVAILABLE RETROFIT TECHNOLOGY (BART)

Guidelines for making BART determinations are included in Appendix Y of 40 CFR Part 51 (Guidelines for BART Determinations under the Regional Haze Rule). States are required to use the Appendix Y guidelines to make BART determinations for fossil-fuel-fired generating plants having a total generating capacity in excess of 750 MW. The BART determination process described in Appendix Y includes the following steps:

Step 1. Identify All Available Retrofit Control Technologies.
Step 2. Eliminate Technically Infeasible Options.
Step 3. Evaluate Control Effectiveness of Remaining Control Technologies.
Step 4. Evaluate Impacts and Document the Results.
Step 5. Evaluate Visibility Impacts.

Because the units fire natural gas, emissions of sulfur dioxide (SO_2) and particulate matter (PM) are minimal. There are no SO_2 or PM post-combustion control technologies with a practical application to natural gas-fired boilers. BART is good combustion practices. A full BART analysis was conducted for NO_X.

Table 2: Proposed BART Controls and Limits

Unit	NO_X BART Emission Limit	BART Technology
Seminole Unit 1	0.203 lb/mmBtu (30-day average)	Combustion controls including LNB/OFA and FGR
Seminole Unit 2	0.212 lb/mmBtu (30-day average)	Combustion controls including LNB/OFA and FGR
Seminole Unit 3	0.164 lb/mmBtu (30-day average)	Combustion controls including LNB/OFA and FGR

A. NO_X

IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES

Potentially available control options were identified based on a comprehensive review of available information. NO_X control technologies with potential application to Seminole Units 1, 2 and 3 are listed in Table 3.

Table 3: List of Potential Control Options

Control Technology
Combustion Controls
Low NO_X Burners and Overfire Air (LNB/OFA)
Flue Gas Recirculation (FGR)
Post Combustion Controls
Selective Noncatalytic Reduction (SNCR)
Selective Catalytic Reduction (SCR)
Innovative Control Technologies
Rotating Overfire Air (ROFA)
ROFA + SNCR (Rotamix)
Pahlman Process
Wet NO_X Scrubbing

In support of the Regional Haze Rule, EPA also prepared a cost-effectiveness analysis for retrofit control technologies on oil- and gas-fired units. EPA's analysis concluded that, although a number of oil- and gas-fired units could make significant cost-effective reductions in NO_X emissions using currently available combustion control technologies, for a number of units the use of combustion controls did not appear to be cost effective. As a result, EPA determined that it would be inappropriate to establish a general presumption regarding likely BART limits for oil- and natural gas fired units.

ELIMINATE TECHICALLY INFEASIBLE OPTIONS (NO_X)
Combustion Controls:
Low NO_X burners (LNB)/ Over Fire Air (OFA)
Low NO_X burners (LNB) limit NO_X formation by controlling both the stoichiometric and temperature profiles of the combustion flame in each burner flame envelope. Over Fire Air (OFA) allows for staged combustion. Staging combustion reduces NO_X formation with a cooler flame in the initial stage and less oxygen in the second stage.

LNB/OFA emission control systems have been installed as retrofit control technologies on existing natural gas-fired boilers. Boilers of the size and age of the Seminole Units would be expected to achieve an average emission reduction in the range of 25% to 40% from baseline depending on the baseline emission rate and boiler operating conditions. Seminole units 1, 2, and 3 do not operate as base load units. The units have historically operated as "peaking units" responding to increased demand for electricity. While technically feasible, LNB/OFA may not be as effective under all boiler operating conditions, especially during load changes and at low and high operating loads. Based on information available from burner control vendors and engineering judgment, it is expected that LNB/OFA on the wall-fired boilers can be designed to achieve an average efficiency of 25% from baseline emissions under all normal operating conditions.

Flue Gas Recirculation
Flue gas recirculation (FGR) controls NO_X by recycling a portion of the flue gas back into the primary combustion zone. The recycled air lowers NO_X emissions by two mechanisms: (1) the recycled gas, consisting of products which are inert during combustion, lowers the combustion temperatures; and (2) the recycled gas will reduce the oxygen content in the primary flame zone. The amount of recirculation is based on flame stability. Seminole Unit 3 is currently designed with FGR control.

FGR may be applied in one of two techniques. Both designs are technically feasible retrofit options for gas-boilers. Either system would be expected to achieve an additional 15% reduction above LNB/OFA or approximately 40% overall reduction from baseline.

Post Combustion Controls:
Selective Non-Catalytic Reduction
Selective non-catalytic reduction (SNCR) involves the direct injection of ammonia or urea at high flue gas temperatures. The ammonia or urea reacts with NO_X in the flue gas to produce N_2 and water. At temperatures below the desired operating range, the NO_X reduction reactions diminish and NH_3 emissions increase. Above the desired temperature range, NH_3 is oxidized to

NO_X resulting in low NO_X reduction efficiencies. Mixing of the reactant and flue gas within the reaction zone is also an important factor in SNCR performance. In large boilers, the physical distance over which the 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, reducing overall efficiency. Performance is further influenced by residence time, reagent-to-NO_X ratio, and fuel sulfur content.

The size of the Seminole Units would represent several design problems making it difficult to ensure that the reagent would be injected at the optimum flue gas temperature, and that there would be adequate mixing and residence time. The physical size of the Seminole boilers makes it technically infeasible to locate and install ammonia injection points capable of achieving adequate mixing within the required temperature zone. Higher reagent injection rates would be required to achieve adequate mixing. This design would tend to result in relatively high levels of ammonia slip. Further, because the Seminole boilers are typically used as peaking units, boiler load is continually changing. Boiler load changes affect flue gas flow rates and temperatures, which would make it particularly difficult to inject the needed quantity of reactant.

Installation of SNCR on large boilers, such as those at Seminole, has not been demonstrated in practice. Assuming that SNCR could be installed on the Seminole Units, given the issues addressed above, control effectiveness would be marginal, and depending on boiler exit temperatures, could actually result in additional NO_X formation. SNCR is not a technically feasible retrofit control for the Seminole Boilers.

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) involves injecting ammonia into boiler flue gas in the presence of a catalyst to reduce NO_X to N2 and water. Anhydrous ammonia injection systems may be used, or ammonia may be generated on-site from a urea feedstock.

SCR has been installed as NO_X control technology on existing gas-fired boilers. Based on emissions data available from the EPA Electronic Reporting website, large gas-fired boilers (with heat inputs above approximately 1,000 mmBtu/hr) have achieved actual long-term average NO_X emission rates in the range of approximately 0.02 to 0.05 lb/mmBtu. Several design and operating variables will influence the performance of the SCR system, including the volume, age and surface area of the catalyst (e.g., catalyst layers), uncontrolled NO_X emission rate, flue gas temperature, and catalyst activity.

Based on emission rates achieved in practice at existing gas-fired units, and taking into consideration long-term operation of an SCR control system (including catalyst plugging and deactivation) and the fact that the Seminole boilers typically operate as peaking units, it is anticipated that SCR could achieve a controlled NO_X emission rate of 0.04 lb/mmBtu (30-day rolling average) on Seminole Units 1, 2 and 3.

Innovative NOX Control Technologies:

Rotating Opposed Fire Air and Rotomix

Rotating opposed fired air (ROFA) is a boosted over fire air system that includes a patented rotation process which includes asymmetrically placed air nozzles. Like other OFA systems, ROFA stages the primary combustion zone to burn overall rich, with excess air added higher in the furnace to burn out products of incomplete combustion.

As discussed in for OFA, over fire air control systems are a technically feasible retrofit control technology, and, based on engineering judgment, the ROFA design could also be applied on Seminole Units 1, 2 and 3. However, there is no technical basis to conclude that the ROFA design would provide additional NO_X reduction beyond that achieved with other OFA designs. Therefore, ROFA control systems are not evaluated as a specific control system, but are included in the overall evaluation of combustion controls (e.g., LNB/OFA).

ROFA + SNCR (Rotamix)

The Rotamix system is a SNCR control system (i.e., ammonia injection system) coupled with the ROFA rotating injection nozzle design. The technical limitations discussed in the SNCR section, including the physical size of the boiler, inadequate NH3/NO_X contact, and flue gas temperatures, would apply equally to the Rotamix control system. There is no technical basis to conclude that the Rotamix design addresses these unresolved technical difficulties. Therefore, like other SNCR control systems, the Rotamix system is not a technically feasible retrofit control for the Seminole Boilers.

Pahlman Multi-Pollutant Control Process

The Pahlman™ Process is a patented dry-mode multi-pollutant control system. The process uses a sorbent composed of oxides of manganese (the Pahlmanite™ sorbent) to remove NO_X and SO_2 from the flue gas.

To date, bench- and pilot-scale testing have been conducted to evaluate the technology on utility-sized boilers.9 The New & Emerging Environmental Technologies (NEET) Database identifies the development status of the Pahlman Process as full-scale development and testing. 10 The process is an emerging multi-pollutant control, and there is limited information available to evaluate its technically feasibility and long-term effectiveness on a large natural gas-fired boiler. It is likely that OG&E would be required to conduct extensive design engineering and testing to evaluate the technical feasibility and long-term effectiveness of the control system on Seminole Units 1, 2 and 3. BART does not require applicants to experience extended time delays or resource penalties to allow research to be conducted on an emerging control technique. Therefore, at this time the Pahlman Process is not a technically feasible retrofit control for the Seminole Boilers

Wet NO_X Scrubbing Systems

Wet scrubbing systems have been used to remove NO_X emissions from fluid catalytic cracking units (FCCUs) at petroleum refineries. An example of a wet scrubbing system is Balco Technologies' LoTOx™ system. The LoTOx system is a patented process, wherein ozone is injected into the flue gas stream to oxidize NO and NO_2 to N_2O_5. This highly oxidized species of NO_X is very soluble and rapidly reacts with water to form nitric acid. The conversion of NO_X to nitric acid occurs as the N_2O_5 contacts liquid sprays in the scrubber.

Wet scrubbing systems have been installed at chemical processing plants and smaller coal-fired boilers. The NEET Database classifies wet scrubbing systems as commercially established for petroleum refining and oil/natural gas production. However the technology has not been demonstrated on large utility boilers and it is likely that OG&E would incur substantial engineering and testing to evaluate the scale-up potential and long-term effectiveness of the system. Therefore, at this time wet NO_X scrubbing systems are not technically feasible retrofit controls for the Seminole Boilers

EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES (NO_X)

Table 4: Technically Feasible NO_X Control Technologies- Seminole Station

Control Technology	Seminole Unit 1 Approximate NO_X Emission Rate (lb/mmBtu)	Seminole Unit 2 Approximate NO_X Emission Rate (lb/mmBtu)	Seminole Unit 3 Approximate NO_X Emission Rate (lb/mmBtu)
LNB/OFA + SCR	0.04	0.04	0.04
LNB/OFA + FGR	0.203	0.212	0.164
LNB/OFA	0.254	0.266	NA
Baseline	0.339	0.354	0.219

EVALUATE IMPACTS AND DOCUMENT RESULTS (NO_X)

OG&E evaluated the economic, environmental, and energy impacts associated with the three proposed control options. In general, the cost estimating methodology followed guidance provided in the EPA Air Pollution Cost Control Manual. Major equipment costs were developed based on publicly available cost data and equipment costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit Seminole Units 1, 2 and 3 with the control technologies. Fixed and variable O&M costs were developed for each control system. Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent (e.g., ammonia), byproduct management, water consumption, and auxiliary power requirements. Auxiliary power requirements reflect the additional power requirements associated with operation of the new control technology, including operation of any new fans as well as the power requirements for pumps, reagent handling, and by-product handling. The capital recovery factor used to estimate the annual cost of control was based on a 7% interest rate and a control life of 25 years. OG&E provided a summary of historical capacity factors which typically ranged between approximately 25% to 30%. Annual operating costs and annual emission reductions were calculated assuming a capacity factor of 50%.

Table 5: Economic Cost Per Boiler

Cost	Unit	Option 1: LNB/OFA	Option 2: LNB/OFA w/FGR	Option 3: LNB/OFA +SCR
Control Equipment Capital Cost ($)	Unit 1	$9,432,200	$16,977,200	$104,230,200
	Unit 2	$9,432,200	$16,977,200	$104,230,200
	Unit 3	$9,468,600	$9,468,600	$104,834,200
Capital Recover Factor ($/Yr)	Unit 1	$809,300	$1,456,700	$8,943,000
	Unit 2	$809,300	$1,456,700	$8,943,000
	Unit 3	$812,400	$812,400	$8,994,800
Annual O&M Costs ($/Yr)	Unit 1	$588,600	$1,190,900	$8,152,800
	Unit 2	$588,600	$1,190,900	$8,175,600
	Unit 3	$590,800	$590,800	$8,023,800
Annual Cost of Control ($)	Unit 1	$1,397,900	$2,647,600	$17,095,800
	Unit 2	$1,397,900	$2,647,600	$17,118,600
	Unit 3	$1,403,200	$1,403,200	$17,018,600

Table 6: Environmental Costs per Boiler

		Baseline	Option 1: LNB/OFA	Option 2: LNB/OFA w/FGR	Option 3: LNB/OFA +SCR
NO_X Emission Rate (lb/mmBtu)	Unit 1	0.339	0.254	0.203	0.04
	Unit 2	0.354	0.266	0.212	0.04
	Unit 3	0.219	0.164	0.164	0.04
Annual NO_X Emission (TPY)[1]	Unit 1	4,068	3,048	2,436	480
	Unit 2	4,248	3,192	2,544	480
	Unit 3	2,636	1,974	1,974	481
Annual NO_X Reduction (TPY)	Unit 1	--	1020	1632	3588
	Unit 2		1056	1704	3768
	Unit 3		662	662	2155
Annual Cost of Control[2]	Unit 1		$1,397,900	$2,647,600	$17,095,800
	Unit 2		$1,397,900	$2,647,600	$17,118,600
	Unit 3		$1,403,200	$1,403,200	$17,018,600
Cost per Ton of Reduction	Unit 1		$1,370	$1,622	$4,765
	Unit 2		$1,324	$1,554	$4,543
	Unit 3		$2,120	$2,120	$7,897
Incremental Cost per ton of Reduction[3]	Unit 1	N/A	--	$2,042	$7,387
	Unit 2			$1,929	$7,011
	Unit 3			--	$10,459

(1) Emissions for the BART analysis are based on maximum heat inputs of 5,480 mmBtu/hr (Units 1 & 2) and 5,496 mmBtu/hr (Unit 3). Annual emissions were calculated assuming 4,380 hours/year per boiler (50% capacity factor).
(2) Total annual cost for all three units are not additive because Unit 3 is currently equipped with FGR control and Unit 3 has a slightly higher heat input.
(3) Incremental cost effectiveness of the FGR system is compared to costs/emissions associated with LNB/OFA controls. Similarly, incremental cost effectiveness of the SCR system is compared to costs/emissions associated with LNB/OFA+FGR controls.

B. VISIBILITY IMPROVEMENT DETERMINATION

The fifth of five factors that must be considered for a BART determination analysis, as required by a 40 CFR part 51- Appendix Y, is the degree of Class I area visibility improvement that would result from the installation of the various options for control technology. This factor was evaluated for the Seminole Generating Station by using an EPA-approved dispersion modeling system (CALPUFF) to predict the change in Class I area visibility. The Division had previously determined that the Seminole Generating Station was subject to BART based on the results of initial screening modeling that was conducted using current (baseline) emissions from the facility. The screening modeling, as well as more refined modeling conducted by the applicant, is described in detail below.

Wichita Mountain Wildlife Refuge, Caney Creek, Upper Buffalo and Hercules Glade are the closest Class I areas to the Seminole Generating Station, as shown in Figure 1 below.

Only those Class I areas most likely to be impacted by the Seminole Generating Station were modeled, as determined by source/Class I area locations, distances to each Class I area, and professional judgment considering meteorological and terrain factors. It can be reasonably assumed that areas at greater distances and in directions of less frequent plume transport will experience lower impacts than those predicted for the four modeled areas.

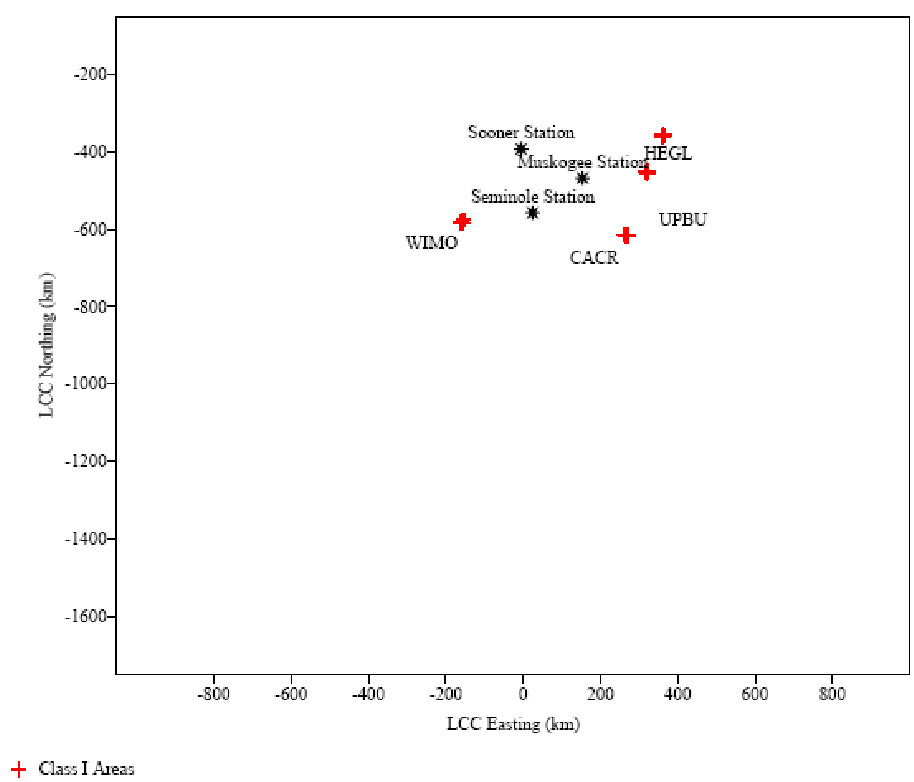

Figure 1: Plot of Facility location in relation to nearest Class I areas

REFINED MODELING:
Because of the results of the applicants screening modeling for the Seminole Generating Station, OG&E was required to conduct a refined BART analysis that included CALPUFF visibility modeling for the facility. The modeling approach followed the requirements described in the Division's BART modeling protocol, *CENRAP BART Modeling Guidelines (Alpine Geophysics, December 2005)* with refinements detailed the applicants CALMET modeling protocol, *CALMET Data Processing Protocol (Trinity Consultants, January 2008)*

CALPUFF System
Predicted visibility impacts from the Seminole Generating Station were determined with the EPA CALPUFF modeling system, which is the EPA-preferred modeling system for long-range transport. As described in the EPA Guideline on Air Quality Models (Appendix W of 40 CFR Part 51), long-range transport is defined as modeling with source-receptor distances greater than 50 km. Because all modeled areas are located more than 50 km from the sources in question, the CALPUFF system was appropriate to use.

The CALPUFF modeling system consists of a meteorological data pre-processor (CALMET), an air dispersion model (CALPUFF), and post-processor programs (POSTUTIL, CALSUM, CALPOST). The CALPUFF model was developed as a non-steady-state air quality modeling system for assessing the effects of time- and space-varying meteorological conditions on pollutant transport, transformation, and removal.

CALMET is a diagnostic wind model that develops hourly wind and temperature fields in a three-dimensional, gridded modeling domain. Meteorological inputs to CALMET can include surface and upper-air observations from multiple meteorological monitoring stations. Additionally, the CALMET model can utilize gridded analysis fields from various mesoscale models such as MM5 to better represent regional wind flows and complex terrain circulations. Associated two-dimensional fields such as mixing height, land use, and surface roughness are included in the input to the CALMET model. The CALMET model allows the user to "weight" various terrain influences parameters in the vertical and horizontal directions by defining the radius of influence for surface and upper-air stations.

CALPUFF is a multi-layer, Lagrangian puff dispersion model. CALPUFF can be driven by the three-dimensional wind fields developed by the CALMET model (refined mode), or by data from a single surface and upper-air station in a format consistent with the meteorological files used to drive steady-state dispersion models. All far-field modeling assessments described here were completed using the CALPUFF model in a refined mode.

CALPOST is a post-processing program that can read the CALPUFF output files, and calculate the impacts to visibility.

All of the refined CALPUFF modeling was conducted with the version of the CALPUFF system that was recognized as the EPA-approved release at the time of the application submittal. Version designations of the key programs are listed in the table below.

Table 7: Key Programs in CALPUFF System

Program	Version	Level
CALMET	5.53a	040716
CALPUFF	5.8	070623
CALPOST	5.51	030709

Meteorological Data Processing (CALMET)
As required by the Division's modeling protocol, the CALMET model was used to construct the initial three-dimensional wind field using data from the MM5 model. Surface and upper-air data were also input to CALMET to adjust the initial wind field.

The following table lists the key user-defined CALMET settings that were selected.

Table 8: CALMET Variables

Variable	Description	Value
PMAP	Map projection	LCC (Lambert Conformal Conic)
DGRIDKM	Grid spacing (km)	4
NZ	Number of layers	12
ZFACE	Cell face heights (m)	0, 20, 40, 60, 80, 100, 150, 200, 250, 500, 1000, 2000, 3500
RMIN2	Minimum distance for extrapolation	-1
IPROG	Use gridded prognostic model outputs	14 km (MM5 data)
RMAX1	Maximum radius of influence (surface layer, km)	20 km
RMAX2	Maximum radius of influence (layers aloft, km)	50 km
TERRAD	Radius of influence for terrain (km)	10 km
R1	Relative weighting of first guess wind field and observation (km)	10 km
R2	Relative weighting aloft (km)	25 km

The locations of the upper air stations with respect to the modeling domain are shown in Figure 2.

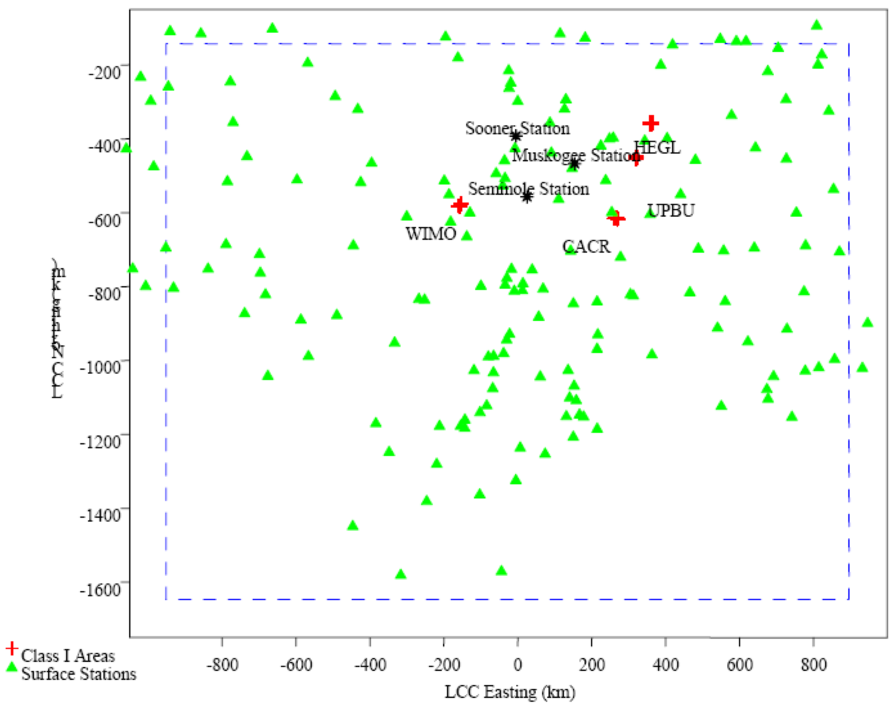

Figure 2: Plot of surface station locations

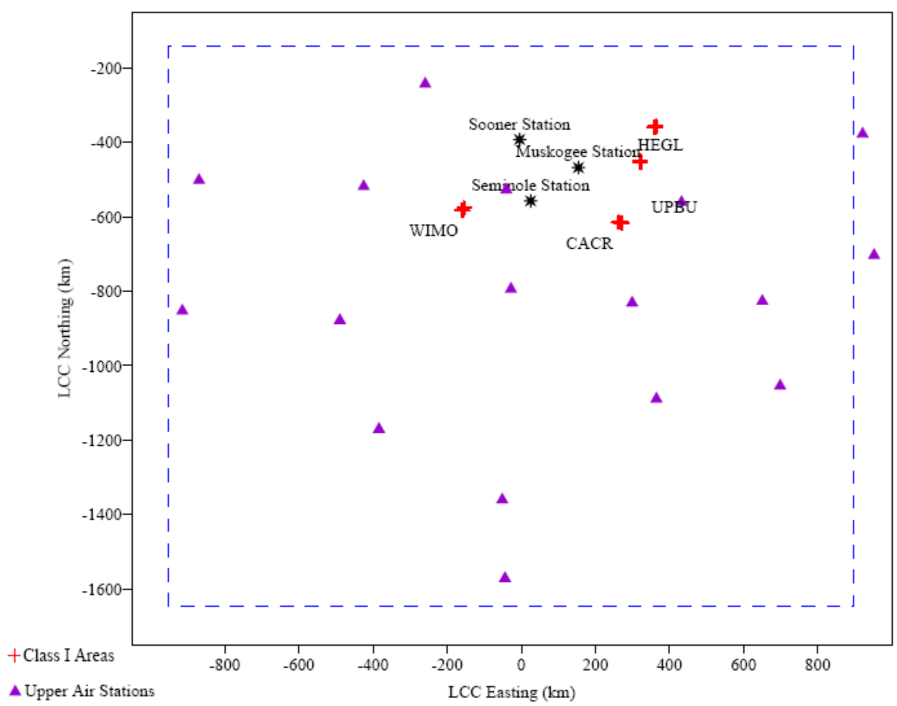

Figure 3: Plot of upper air station locations

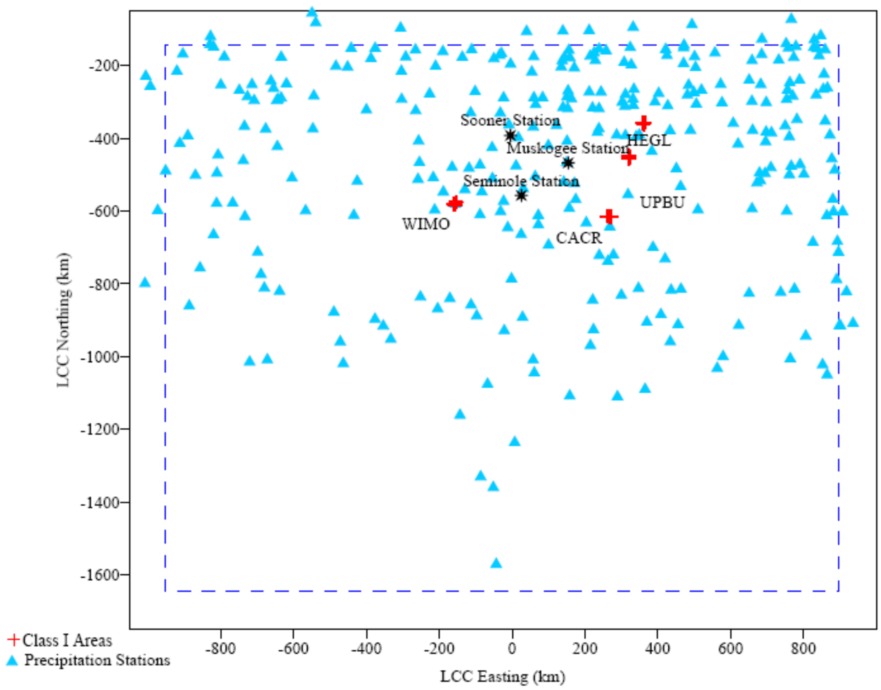

Figure 4. Plot of precipitation observation stations

CALPUFF Modeling Setup

To allow chemical transformations within CALPUFF using the recommended chemistry mechanism (MESOPUFF II), the model required input of background ozone and ammonia. CALPUFF can use either a single background value representative of an area or hourly ozone data from one or more ozone monitoring stations. Hourly ozone data files were used in the CALPUFF simulation. As provided by the Oklahoma DEQ, hourly ozone data from the Oklahoma City, Glenpool, and Lawton monitors over the 2001-2003 time frames were used. Background concentrations for ammonia were assumed to be temporally and spatially invariant and were set to 3 ppb.

Latitude and longitude coordinates for Class I area discrete receptors were taken from the National Park Service (NPS) Class I Receptors database and converted to the appropriate LCC coordinates.

CALPUFF Inputs- Baseline and Control Options

The first step in the refined modeling analysis was to perform visibility modeling for current (baseline) operations at the facility. Emissions of NO_X for the baseline runs were established based on CEM data and maximum 24-hour emissions averages for years 2001 to 2003. All particulate emissions (PM) were based on emission rates of 0.00186 lb/mmBtu (filterable) and were treated as PM_{10} (coarse PM) and 0.00559 lb/mmBtu (condensable) and were treated as $PM_{2.5}$ (fine PM) within CALPUFF and CALPOST. Direct emissions of sulfate were based on the values calculated for the Toxic Release Inventory (TRI) for the years modeled.

Baseline source release parameters and emissions are shown in the table below, followed by tables with data for the various control options. No attempt was made by the applicant to estimate the increase in sulfate emissions that would result from operations of SCR, and as a result the visibility improvement for those scenarios may be overestimated by some undetermined amount.

Table 9: Baseline Source Parameters

Parameter	Baseline		
	Natural Gas-Fired Unit 1	Natural Gas-Fired Unit 2	Natural Gas-Fired Unit 3 (FGR)
Heat Input (mmBtu/hr)	5,480	5,480	5,496
Base Elevation (m)	290	290	290
Stack Height (m)	54.27	54.27	106.71
Stack Diameter (m)	4.57	4.57	5.49
Stack Temperature (K)	392.44	392.44	411.89
Exit Velocity (m/s)	42.32	42.32	30.95
SO2 Emissions (lb/mmBtu)	0.00055	0.00042	0.00060
SO2 Emissions (TPY)	13.20	10.08	14.44
NOX Emissions[1] (lb/mmBtu)	0.339	0.354	0.219
NOX Emissions TPY	8136.81	8496.85	5271.87
PM_{10} Fine Emissions[2] (lb/mmBtu)	0.00745	0.00745	0.00745
PM_{10} Fine Emissions (TPY)	178.82	178.82	179.34

[1]Baseline NOx emissions were based on the maximum 24-hr average emission rate (lb/hr) reported by each unit during the baseline period 2003-2005. Baseline emissions data were provided by OG&E. Baseline emission rates (lb/mmBtu) were calculated by dividing the maximum 24-hr lb/hr emission rate by the maximum heat input to the boiler.
[2]PM emissions are based on AP-42 emission factors for natural gas combustion (filterable and condensable).

Table 10: Source Parameters and Emissions for BART Control Options

Scenario		Control	Heat Input (mmBtu/hr)	NOX Emissions (lb/mmBtu)	NOX Emissions TPY
Control Option 1		LNB/OFA	5,480	0.254	6,097
	Natural Gas-Fired Unit 2	LNB/OFA	5,480	0.266	6,384
	Natural Gas-Fired Unit 3	LNB/OFA FGR	5,496	0.164	3,948
Control Option 2	Natural Gas-Fired Unit 1	LNB/OFA FGR	5,480	0.203	4,872
	Natural Gas-Fired Unit 2	LNB/OFA FGR	5,480	0.212	5,089
	Natural Gas-Fired Unit 3	LNB/OFA FGR	5,496	0.164	3,948

Scenario		Control	Heat Input (mmBtu/hr)	NOX Emissions (lb/mmBtu)	NOX Emissions TPY
Control Option 3	Natural Gas-Fired Unit 1	LNB/OFA + SCR	5,480	0.040	960
	Natural Gas-Fired Unit 2	LNB/OFA + SCR	5,480	0.040	960
	Natural Gas-Fired Unit 3	LNB/OFA + SCR	5,496	0.040	963

Visibility Post-Processing (CALPOST) Setup

The changes in visibility were calculated using Method 6 with the CALPOST post-processor. Method 6 requires input of monthly relative humidity factors [f(RH)] for each Class I area that is being modeled. Monthly f(RH) factors that were used for this analysis are shown in the table below.

Table 11: Relative Humidity Factors for CALPOST

Month	Wichita Mountains	Caney Creek	Upper Buffalo	Hercules Glade
January	2.7	3.4	3.3	3.2
February	2.6	3.1	3.0	2.9
March	2.4	2.9	2.7	2.7
April	2.4	3.0	2.8	2.7
May	3.0	3.6	3.4	3.3
June	2.7	3.6	3.4	3.3
July	2.3	3.4	3.4	3.3
August	2.5	3.4	3.4	3.3
September	2.9	3.6	3.6	3.4
October	2.6	3.5	3.3	3.1
November	2.7	3.4	3.2	3.1
December	2.8	3.5	3.3	3.3

EPA's default average annual aerosol concentrations for the U.S. that are included in Table 2-1 of EPA's *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program* were to develop natural background estimates for each Class I area.

Visibility Post-Processing Results

Table 12: CALPUFF Visibility Modeling Results for Seminole Units 1, 2 and 3

	2001		2002		2003		3-Year Average	
Class I Area	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv
Baseline								
Wichita Mountains	1.073	20	0.744	12	1.3	25	1.039	19
Caney Creek	1.173	18	0.455	7	0.443	7	0.69	11
Upper Buffalo	0.635	9	0.24	2	0.302	2	0.39	4
Hercules Glade	0.403	5	0.294	3	0.301	3	0.33	4
Scenario 2- Combustion Control- LNB/OFA FGR								
Wichita Mountains	0.707	13	0.476	7	0.832	17	0.67	12
Caney Creek	0.754	12	0.284	1	0.284	2	0.44	5
Upper Buffalo	0.411	4	0.157	2	0.191	1	0.25	2
Hercules Glade	0.255	2	0.186	0	0.188	2	0.21	1

Modeling for SCR controls resulted in an approximately 80% reduction in visibility impairment from scenario two.

C. BART DETERMINATION

After considering: (1) the costs of compliance, (2) the energy and non-air quality environmental impacts of compliance, (3) any pollutant equipment in use or in existence at the source, (4) the remaining useful life of the source, and (5) the degree of improvement in visibility (all five statutory factors) from each proposed control technology, the Division determined BART for the three units at the Seminole Generating Station.

New LNB with OFA is determined to be BART for NOX control for Units 1-3 based, in part, on the following conclusions:

1. Installation of new LNB with OFA and FGR was cost effective, with a capital cost of $16,977,200 per unit for units 1 and 2 and $9,468,600 for unit 3 and an average cost effectiveness of $1,554-$2,120 per ton of NO_X removed for each unit over a twenty year operational life.

2. Combustion control using the LNB/OFA and FGR does not require non-air quality environmental mitigation for the use of chemical reagents (i.e., ammonia or urea) and there is minimal energy impact.

3. After careful consideration of the five statutory factors, especially the costs of compliance and existing controls, NO_X control levels on 30-day rolling averages of 0.203 lb/mmBtu for Unit 1, 0.212 lb/mmBtu for Unit 2 and 0.164 lb/mmBtu for Unit 3 are justified.

4. Annual NO_X emission reductions from new LNB with OFA and FGR on Units 1, 2, and 3 are 662-1,704 tons for a total annual reduction of 3,998 tons.

LNB with OFA and SCR was not determined to be BART for NO_X control for Units 1-3 based, in part, on the following conclusions:

1. The cost of compliance for installing SCR on each unit is significantly higher than the cost for LNB with OFA and FGR. Additional capital costs for SCR on Units 1-3 are on average $89,957,200 per unit. Based on projected actual emissions, SCR could reduce overall NO_X emissions from Seminole Units 1, 2 and 3 by approximately 5,513 tpy (compared to combustion controls and flue gas recirculation); however, the incremental cost associated with this reduction is approximately $44,534,600 per year, or $8,078/ton.

2. Additional non-air quality environmental mitigation is required for the use of chemical reagents.

3. Operation of LNB with OFA and SCR is parasitic and requires power from each unit.

4. SCR control may not be as effective on boilers that operate as peaking units, as NO_X reduction in an SCR is a function of flue gas temperature.

5. The cumulative visibility improvement for SCR, as compared to LNB/OFA and FGR across Wichita Mountains and Caney Creek (based on the 98th percentile modeled results) was 0.56-0.60 Δdv for all three units.

The Division considers the installation and operation of the BART determined NO_X controls, new LNB with OFA and FGR, to meet the statutory requirements of BART.

Unit-by-unit NO_X BART determinations:

Seminole Generating Station Unit 1: New LNB with OFA and FGR and meeting NO_X emission limit of 0.203 lb/mmBtu (30-day rolling average), 1,112 lb/hr (30-day rolling average), and 4,872 tpy (12-month rolling) as BART for NO_X.

Seminole Generating Station Unit 2: New LNB with OFA and FGR and meeting NO_X emission limit of 0.212 lb/mmBtu (30-day rolling average), 1,162 lb/hr (30-day rolling average), and 5,089 tpy (12-month rolling) as BART for NO_X.

Seminole Generating Station Unit 3: New LNB with OFA and FGR and meeting NO_X emission limit of 0.164 lb/mmBtu (30-day rolling average), 901 lb/hr (30-day rolling average), and 3,948 tpy (12-month rolling) as BART for NO_X.

V. CONSTRUCTION PERMIT

Prevention of Significant Deterioration (PSD)
Seminole Generating Station is a major source under OAC 252:100-8 Permits for Part 70 Sources. Oklahoma Gas and Electric should comply with the permitting requirements of Subchapter 8 as they apply to the installation of controls determined to meet BART.

The installation of controls determined to meet BART will not change NSPS or NESHAP/MACT applicability for the gas-fired units at the Seminole Station.

VI. OPERATING PERMIT

The Seminole Generating Station is a major source under OAC 252:100-8 and has submitted an application to modify their existing Title V permit to incorporate the requirement to install controls determined to meet BART. The Permit will contain the following specific conditions:

1. The boilers in EUG 2 are subject to the Best Available Retrofit Technology (BART) requirements of 40 CFR Part 51, Subpart P, and shall comply with all applicable requirements including but not limited to the following: [40 CFR §§ 51.300-309 & Part 51, Appendix Y]

a. Affected facilities. The following sources are affected facilities and are subject to the requirements of this Specific Condition, the Protection of Visibility and Regional Haze Requirements of 40 CFR Part 51, and all applicable SIP requirements:

EU ID#	Point ID#	EU Name	Heat Capacity (MMBTUH)	Construction Date
2-B	01	Unit 1 Boiler	5,480	1968
2-B	02	Unit 2 Boiler	5,480	1968
2-B	03	Unit 3 Boiler	5,496	5/28/70

b. Each existing affected facility shall install and operate the SIP approved BART as expeditiously as practicable but in no later than five years after approval of the SIP incorporating the BART requirements.

c. The permittee shall apply for and obtain a construction permit prior to modification of the boilers. If the modifications will result in a significant emission increase and a significant net emission increase of a regulated NSR pollutant, the applicant shall apply for a PSD construction permit.

d. The affected facilities shall be equipped with the following current combustion control technology, as determined in the submitted BART analysis, to reduce emissions of NOX to below the emission limits below:

i. Low-NOX Burners,

ii. Overfire Air, and

iii. Flue Gas Recirculation.

e. The permittee shall maintain the combustion controls (Low-NOX burners, overfire air, and flue gas recirculation) and establish procedures to ensure the controls are properly operated and maintained.

f. Within 60 days of achieving maximum power output from each affected facility, after modification or installation of BART, not to exceed 180 days from initial start-up of the affected facility the permittee shall comply with the emission limits established in the construction permit. The emission limits established in the construction permit shall be consistent with manufacturer's data and an agreed upon safety factor. The emission limits established in the construction permit shall not exceed the following emission limits:

EU ID#	Point ID#	NOX Emission Limit	Averaging Period
2-B	01	0.203 lb/MMBTU	30-day rolling
2-B	02	0.212 lb/MMBTU	30-day rolling
2-B	03	0.164 lb/MMBTU	30-day rolling

g. Boiler operating day shall have the same meaning as in 40 CFR Part 60, Subpart Da.

h. After installation of the BART, the affected facilities shall only be fired with natural gas.

i. Within 60 days of achieving maximum power output from each boiler, after modification of the boilers, not to exceed 180 days from initial start-up, the permittee shall conduct performance testing as follows and furnish a written report to Air Quality. Such report shall document compliance with BART emission limits for the affected facilities. [OAC 252:100-8-6(a)]

   i. The permittee shall conduct NOX, CO, and VOC testing on the boilers at 60% and 100% of the maximum capacity. NOX and CO testing shall also be conducted at least one additional intermediate point in the operating range.

   ii. Performance testing shall be conducted while the units are operating within 10% of the desired testing rates. A testing protocol describing how the testing will be performed shall be provided to the AQD for review and approval at least 30 days prior to the start of such testing. The permittee shall also provide notice of the actual test date to AQD.

   iii. The following USEPA methods shall be used for testing of emissions, unless otherwise approved by Air Quality:

   Method 1: Sample and Velocity Traverses for Stationary Sources.

   Method 2: Determination of Stack Gas Velocity and Volumetric Flow Rate.

   Method 3: Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight.