FACT SHEET

BART & PSD Analysis

For the

Omaha Public Power District

Nebraska City Station Unit #1

Located at
7264 L Road
Nebraska City, Otoe County, Nebraska 68410

February 26, 2009

Table of Contents

Executive Summary 3
1.0 Introduction and Purpose 3
1.1 Nebraska Regional Haze Program 3
1.2 Source Description and Permitting Background 4
1.3 Nebraska City Station BART Eligibility Analysis 5
1.4 BART Analysis Methodology 6
1.5 Consideration of Presumptive BART Limitations 7
2.0 BART Analysis for Particulate Matter (both fine and coarse fractions) 7
2.1 Particulate Matter (PM) Formation 7
2.2 BART for PM 8
3.0 BART Analysis for SO_2 9
3.1 SO_2 Formation 9
3.2 Identification of SO_2 Control Technologies and Technical Feasibility 9
3.2.1 Sulfur Removal from Fuel 9
3.2.2 Flue Gas Desulfurization (FGD) 9
3.3 Ranking of Technologically Feasible SO_2 Controls based on Effectiveness 10
3.4 Evaluation of Effective SO_2 Controls 11
3.5 Visibility Impacts 11
4.0 BART Analysis for NO_x 13
4.1 NO_x Formation 13
4.2 Identification of NO_x Control Technologies and Technical Feasibility 13
4.2.1 Combustion Controls 13
4.2.2 Post Combustion Control Technologies 13
4.3 Ranking of Technologically Feasible NO_x Controls based on Effectiveness 14
4.4 Evaluation of Effective NO_x Controls 14
4.5 Visibility Impacts 15
4.6 BART Conclusion for SO_2 and NO_x 15
5.0 Prevention of Significant Deterioration (PSD) 16
5.1 Summary 16
5.2 Best Available Control Technology (BACT) Analysis Methodology 17
5.3 BACT Analysis for Carbon Monoxide (CO) 17
5.4 Ranking of Technologically Feasible CO Controls based on Effectiveness 19
5.5 BACT for CO 19
6.0 Air Dispersion Modeling Analysis 19
6.1 Model Information 19
6.1.1 Facility Location and Site Description 19
6.1.2 Model Selection 20
6.1.3 Source Parameters 20
6.2 Preliminary Modeling Analysis 20
6.3 Additional Impacts Analysis 21
6.3.1 Pollutant Effects on Soil and Vegetation 21
7.0 Type and Quantity of Air Contaminant Emissions Anticipated 21
8.0 Applicable Requirements, Variances or Alternatives to Required Standards: 22
8.1 Nebraska State Construction Permit Requirements 22
8.2 New Source Performance Standards (NSPS) 22
8.3 Particulate Matter Emissions 23
8.4 Sulfur Compound Emissions 23
8.5 Acid Rain 24
8.6 Hazardous Air Pollutants 24
8.7 Visibility Protection 24
9.0 Discussion of Specific Permit Conditions 24

Executive Summary

The Nebraska Department of Environmental Quality (NDEQ) identified the Omaha Public Power District (OPPD) Nebraska City Station Unit #1 as a Best Available Retrofit Technology (BART) eligible and subject source under the U.S. EPA Regional Haze Program. In August 2007, OPPD submitted a BART analysis and permit application to NDEQ. Furthermore, since controls were going to result in the increase in other pollutants above the Prevention of Significant Deterioration (PSD) thresholds, a PSD application was submitted. This fact sheet is a summary of the NDEQ's evaluation and proposed decision on both BART and Best Available Control Technology (BACT).

This analysis concludes that BART should be the installation and optimization of low-NOx burners with over-fired air technology as necessary to meet a limit of 0.23 lb NOx/MMBtu on a 30-day rolling average. This analysis also concludes that BART is existing control equipment along with existing limits for particulates and that no additional SO2 controls are warranted due to the low benefit to cost ratio.

1.0 Introduction and Purpose

The Clean Air Act of 1990 (Title I, Sections 169A and 169B) declared it a national goal to prevent any future, and to remedy any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution. In 1999, the United States Environmental Protection Agency (EPA) issued regulations for the protection of visibility in Class I National Parks and Wilderness Areas. Revisions to the regional haze rules were promulgated on July 6, 2005 and October 13, 2006. These regulations require states to establish goals for improving visibility by developing long-term strategies for reducing emissions of air pollutants that cause visibility impairment. These pollutants include particulate matter (PM, both fine and coarse fractions), sulfur dioxide (SO_2), nitrogen oxides (NO_x), volatile organic compounds (VOC), and ammonia (NH_3). The overall goal of the regional haze regulations is to achieve natural background visibility conditions in all Class I areas by the year 2064.

1.1 Nebraska Regional Haze Program

Nebraska does not have any Class I National Parks or Scenic areas. However, in accordance with the Regional Haze rule, Nebraska has an obligation to address visibility protection through the application of Best Available Retrofit Technology (BART) on BART subject sources and reasonable further progress if Nebraska source emissions are identified in another State's Regional Haze State Implementation Plan (SIP). Additionally, Nebraska belongs to and participates in a regional planning organization, CENRAP. Nebraska participated in a central-states consultation process for Missouri and Oklahoma.[1] No states have identified a need for reasonable further progress reductions from Nebraska sources at this time. Therefore, the application of BART is the primary element of the Nebraska Regional Haze program. In the future, additional requirements on sources through the application of reasonable further progress may be required for Class I areas to achieve natural background conditions by 2064.

On February 16, 2008, Title 129-Nebraska Air Quality Regulations, of the Nebraska Administrative Code, were revised in order to incorporate numerous changes, including the establishment of Chapter 43: Visibility Protection. This chapter incorporated portions of the federal Regional Haze Rule, including 40 CFR 51.301 and 40 CFR 51 Appendix Y by reference. It also requires owners or operators of stationary sources subject to BART to prepare and submit a BART determination in accordance with the Regional Haze Rule. The rules also require the issuance of a construction permit to the source in accordance with Title 129, Chapter 17. Since the

[1] See Missouri's regional haze plan at http://www.dnr.mo.gov/env/apcp/sips.htm. Missouri named Missouri, Arkansas, Kentucky, Illinois, Indiana, Ohio, Oklahoma, Tennessee and Texas as contributing to visibility impairment. Missouri's analysis indicates that reductions from these states are sufficient to meet reasonable progress goals. Oklahoma's plan is still under development, but their consultation plan which includes expected reductions may be found at http://www.deq.state.ok.us/aQDnew/RulesAndPlanning/Regional_Haze/index.htm.

application of BART is required, the BART decisions (i.e. the BART permits) will explicitly be included in Nebraska's Regional Haze SIP.

On August 8, 2007, the Department received a BART analysis for Omaha Public Power District (OPPD) Nebraska City Station (NCS), Unit 1. Additional information was received on December 4, 2007. The purpose of this permitting action is to require emission controls in accordance with NDEQ and BART regulations and to permit the increase in other pollutant emissions that are expected to result from the installation of the BART controls. To make the BART emission limitations enforceable, the NDEQ incorporated the BART requirements in a construction permit. The NDEQ will be evaluating the following visibility impairing pollutants for purposes of BART: PM (both fine and coarse fractions), SO_2, and NO_x.

1.2 Source Description and Permitting Background

In accordance with state law, Nebraska's utility structure is currently 100% consumer-owned, also known as "public power." OPPD is one of the largest publicly owned electric utilities in the United States, serving more than 340,000 customers in 13 southeast Nebraska counties. It was organized as a political subdivision of the State of Nebraska in 1946. Policies and rates are set by an eight-member Board of Directors elected by the people in the areas served. The map below shows OPPD's service area:

OPPD owns and operates Nebraska City Station (NCS) which is located approximately five (5) miles southeast of Nebraska City, Nebraska. The station currently consists of one existing nominal 650 megawatt (MW, net) pulverized coal-fired, dry-bottom boiler referred to as Unit 1. Unit 1 combusts sub-bituminous coal with a typical heat content of 8,400 British thermal units per pound (Btu/lb). Its Standard Industrial Classification (SIC) code is 4911 and North American Industry Classification System (NAICS) code is 221112 for fossil fueled electric generators.

On February 23, 2004 the Department received a PSD construction permit application for "NCS Unit 2" which consisted of a new 6,478 million British thermal units per hour (MMBtu/hr)(660 MW, net) pulverized coal-fired dry-bottom boiler, a new 125 MMBtu/hr auxiliary boiler (Aux Boiler 2), and other associated equipment. A PSD construction permit was issued for Unit 2 on March 9, 2005.

On October 26, 2006, the NDEQ issued a permit revision which superseded Condition XIV.(B)(1), Table 2 to increase the limit of the auxiliary boiler to the fuel equivalent of 876 hours per year until NCS Unit 2 comes on-line and becomes operational (expected to occur in spring 2009).

On September 26, 2007 a permit revision request for the permits issued for NCS Unit 2 was received by the Department. A revised PSD construction permit that superseded the permits issued on March 9, 2005 and October 26, 2006 was issued for NCS Unit 2 on March 6, 2008.

NCS is operating under a Class I operating permit (OP) issued on April 28, 2004 and a Phase II Acid Rain permit effective March 9, 2007.

1.3 Nebraska City Station BART Eligibility Analysis

Nebraska City Station Unit 1 was determined to be subject to BART using the criteria outlined in the Clean Air Act and the Regional Haze Rules. The applicability criteria for determining if a unit is eligible for being required to install BART controls are:

1) The facility in which the unit is located contains emissions units in one or more of 26 source categories. One of the listed source categories is fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour (MMBtu/hr) heat input.
    - ✓ Unit 1 is a fossil-fuel fired steam electric plant with a capacity of approximately 6,835 MMBtu/hr.
2) BART eligible units were in existence on August 7, 1977 ***and*** began operating after August 7, 1962.
    - ✓ OPPD began construction of Unit 1 in 1975 and brought it on-line in May 1979.
3) The total potential emissions of visibility impairing pollutant(s) summed across all units that meet the date criteria in item 2 is greater than or equal to 250 tons/year.
    - ✓ Unit 1 has potential emissions of greater than 250 tons/year for: particulate matter (coarse and fine), SO_2, and NO_x (all visibility impairing pollutants).

Since all of the three criteria presented above were met, the Unit 1 is considered to be BART eligible. In order to determine if Unit 1 is subject to BART requirements, it must be demonstrated that emissions are anticipated to cause or contribute to visibility impairment in one or more Class I areas. This was done by conducting long range transport air dispersion modeling using CALPUFF. If emissions from the BART eligible units at a source will impair visibility in any Class I area more than 0.5 deciviews (a measurement of visibility impairment based on extinction of light), then the unit becomes subject to BART.

OPPD conducted air dispersion modeling in accordance with a modeling protocol approved by the Department. The modeling was based on maximum 24-hour emissions for each pollutant, as summarized in the table below. Note that the annual emissions listed are values equivalent to the 24-hour maximum emissions, and do not necessarily represent "potential to emit" values.

Table 1: NCS Unit 1 Emissions Used for Modeling (Baseline Scenario)

PM – Fine		PM – Coarse		SO_2		NO_x	
Lb/day	Tons/year	Lb/day	Tons/year	Lb/day	Tons/year	Lb/day	Tons/year
4,004	731.23	2,262	413.10	132,518	24,201.10	93,195	17,019.74

The modeling protocol and the modeling results may be obtained from the Department's website: www.deq.state.ne.us, under the "Regional Haze Program" under the "Focus on Air" link. The refined CALPUFF modeling analysis concluded that the emissions from NCS Unit 1, before requiring BART controls, cause or contribute to visibility impairment (NCS contributions exceed 0.5 deciview) on eight or more days (98^{th} percentile) in a year, at one or more Class I areas, in one or more of the three years (2001-2003) of meteorology evaluated. (See Table 2.) Therefore, NCS Unit 1 was determined to be subject to BART requirements.

Table 2: NCS Unit 1 Visibility Impact (Baseline Scenario)

	2001		2002		2003	
	Days > 0.5 dV	98th Percentile dV	Days > 0.5 dV	98th Percentile dV	Days > 0.5 dV	98th Percentile dV
Badlands (SD)	7	0.332	2	0.126	2	0.225
Great Sand Dunes (CO)	0	0.009	0	0.019	0	0.036
Hercules Glades (MO)	14	0.933	9	0.556	6	0.473
Mingo (MO)	4	0.374	5	0.371	2	0.305
Rocky Mountain (CO)	0	0.01	0	0.043	2	0.047
Wichita Mountains (OK)	4	0.306	5	0.381	10	0.686
Wind Cave (SD)	4	0.095	1	0.050	1	0.111

1.4 BART Analysis Methodology

BART is defined as *"…an emissions limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction of each pollutant which is emitted by an existing stationary source. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology*" (40 CFR Part 51.301).

On July 6, 2005, the US EPA issued guidelines on conducting a BART determination, which are contained in Appendix Y of 40 CFR Part 51. States must follow these guidelines in making BART determinations on a source-by-source basis for 750 megawatt (MW) and larger power plants but are not required to use the process in the guidelines when making BART determinations for other types of BART sources, including those with a total plant capacity less than 750 MW. When an early draft of the BART proposal was shared with the Federal Land Managers, a question was raised as to the status of the total plant capacity at NCS. At issue was whether NCS Unit 2 should now be considered part of the total plant capacity at NCS for purposes of determining BART applicability. Since the CAA and the BART regulations did not speak to the specific issue of a source becoming a 750 MW facility after the BART rules were promulgated, the NDEQ raised the question with the US EPA and received a response on November 10, 2008. The response read *"we believe that it is a reasonable interpretation to assume that if the plant is greater than 750 megawatts at the time the BART determination is made by the state (i.e. at the time the state places the BART determination on public notice) then any unit at the plant greater then [sic] 200 megawatts is subject to presumptive BART."* US EPA Region 7's response is still vague in that it does not speak to whether it is sufficient to have commenced or begun actual construction on Unit 2, or whether Unit 2 must be operational. The NDEQ's evaluation of the US EPA's intent is that the plant's commercial operational capacity must be 750 MW or more. Since Unit 2 is not yet commercially operational, NDEQ has determined that NCS, for purposes of BART has a plant capacity of less than 750 MW. Therefore, it is not mandatory for NDEQ to follow 40 CFR 51 Appendix Y for federal purposes.

However, Nebraska Title 129, Chapter 43, Section 002 states that "the owner or operator [of the facility subject to BART] shall prepare the BART determination in accordance with Appendix Y of 40 CFR 51, as directed by the Director." Therefore we have utilized 40 CFR 51 Appendix Y when making this BART determination.

A BART analysis is comprised of the following basic steps:

Step 1: Identify all retrofit control technologies:
All control technologies for similar processes, as well as Best Available Control Technology (BACT) and Lowest Achievable Emission Rate (LAER) technologies must be considered. Control technologies should include pollution prevention, use of add-on controls, and combinations of the two. The owner/operator is not

expected to purchase or construct a process or control device that has not already been demonstrated in practice.

Step 2: Eliminate technically infeasible options:
Technologies demonstrated to be technically infeasible based on physical, chemical, and engineering principles are excluded from further consideration. Physical modifications needed to resolve technical obstacles do not, by themselves, provide justification to eliminate a technology.

Step 3: Rank remaining technologies by control effectiveness:
Technically feasible control technologies are ranked in the order of highest expected emission reduction to lowest expected emission reduction. The ranking also includes expected emission rate, control effectiveness, energy impacts, environmental impacts (including toxic and hazardous air emissions), economic impacts, and visibility impacts.

Step 4: Evaluate most effective controls and document results:
The technology ranking is evaluated and case-by-case consideration is given to costs of compliance, energy impacts, non-air quality and other environmental impacts, and remaining useful life of the unit.

Step 5: Evaluate Visibility Impacts:
Modeling analyses are performed on the pre- and post-control emissions to determine actual impact on visibility. The NDEQ has evaluated visibility improvement balanced with the cost of compliance in determining the best, most appropriate option for BART as allowed under Appendix Y. This was done through a cost per deciview of visibility improvement factor, which is similar to the cost per ton of pollutant removed from the atmosphere that is used in the BACT process.

1.5 Consideration of Presumptive BART Limitations

Appendix Y also gives consideration to presumptive limitations for SO_2 and NO_x established by EPA. When discussing the presumptive sulfur dioxide limits for utility boilers, Appendix Y states "You [the state] must require 750 MW power plants to meet specific control levels for SO_2 of either 95 percent control or 0.15 lbs/MMBtu, for each EGU [Electric Generating Unit] greater than 200 MW that is currently uncontrolled unless you determine that an alternative control level is justified based on a careful consideration of the statutory factors…For a currently uncontrolled EGU greater than 200 MW in size, but located at a power plant smaller than 750 MW in size, such controls are generally cost-effective and could be used in your BART determination considering the five factors…" EPA has provided guidance to NDEQ indicating that the five factors must be evaluated in all cases.

It is clear in 40 CFR 51 Appendix Y that States are afforded the discretion to set limits different than the presumptive levels for NOx and SO2, if careful consideration is given to the statutory factors. The NDEQ has given careful consideration to the statutory factors and the presumptive levels, even though Unit 1 is not located at a 750 MW power plant.

2.0 BART Analysis for Particulate Matter (both fine and coarse fractions)

The objective of this analysis is to determine BART for PM emissions from the NCS Unit 1.

2.1 Particulate Matter (PM) Formation

PM emissions from utility boilers are a function of the boiler burner configuration, operation practices, coal properties, and pollution control equipment. Uncontrolled PM emissions include ash from the non-combustibles in coal as well as unburned carbon resulting from incomplete combustion. When combusting pulverized coal, PM emissions are primarily composed on inorganic ash residue because combustion is nearly complete, resulting in minimal unburned carbon.

PM emissions are classified as filterable and condensable. Filterable PM is the portion of total PM present in the exhaust stream as a solid or liquid, which is typically measured on an EPA Method 5 filter (40 CFR Part 60, Appendix A). Condensable PM is the portion of PM that is initially present as a gas in the exhaust stream, but condenses to a liquid or solid state when cooled to ambient temperatures.

For purposes of BART, coarse PM (PMC) and fine PM (PMF) are analyzed in the visibility impact modeling. PMF is defined as having an aerodynamic diameter of less than or equal to 2.5 microns ($PM_{2.5}$). PMC has an aerodynamic diameter greater than $PM_{2.5}$ but less than or equal to 10 microns.

2.2 BART for PM

Step 1: Identify all retrofit control technologies:
Control of PM emissions can be achieved by application of good combustion practices (i.e. complete combustion) or by treatment of the flue gas after combustion. NCS Unit 1 currently utilizes an electrostatic precipitator to control PM emissions. Add-on control technology would include a fabric filter (baghouse).

Step 2: Eliminate technically infeasible options:
No technologies can be eliminated as being technically infeasible.

Step 3 through 5: Rank remaining technologies by control effectiveness; Evaluate most effective controls and document results; and Evaluate Visibility Impacts:
Step 5, Evaluate Visibility Impacts was done first to see at what level PM was contributing to visibility. If PM was found to be a significant portion of the contribution, then further ranking of technologies would be warranted. If PM was found to be a very small or insignificant portion of the overall visibility contribution from NCS Unit 1, then further evaluation of control technology would not be warranted at this time.

The maximum 24-hour emission rates of PMF and PMC from NCS Unit 1 are presented below. These emission rates were utilized in the visibility modeling conducted.

Table 3: Particulate Matter Emissions

PM – Fine		**PM – Coarse**	
Lb/day	Tons/year	Lb/day	Tons/year
4,004	731.2	2,262	413.1

The baseline case model indicated that the direct particulate emissions were generally responsible for well under 1% of the total predicted change in deciview impact from NCS Unit 1 (See Table 4). In fact, PM only accounted for 0.32% of the greatest deciview impairment Unit 1 had (0.933 in 2001 at Hercules Glades in Missouri). This would indicate that the predicted deciview impact is from a pollutant or pollutants other than PM. The results for each year, by Class I area, are presented below. The 98% percentile value is presented for each year. The results below confirm that the direct particulate matter emissions from NCS Unit 1 do not significantly contribute to visibility impairment in the Class I areas analyzed.

Table 4: Particulate Matter Contribution of the NCS Unit 1 Predicted Visibility Impairment

	2001		2002		2003	
	ΔdV	% PM	ΔdV	% PM	ΔdV	% PM
Badlands (SD)	0.332	0.56%	0.126	0.23%	0.225	0.30%
Great Sand Dunes (CO)	0.009	0.39%	0.019	0.15%	0.036	0.63%
Hercules Glades (MO)	0.933	0.32%	0.556	0.42%	0.473	0.46%
Mingo (MO)	0.374	0.63%	0.371	0.86%	0.305	0.81%
Rocky Mountain (CO)	0.010	0.43%	0.043	0.51%	0.047	0.60%
Wichita Mountains (OK)	0.306	0.43%	0.381	0.56%	0.686	0.51%
Wind Cave (SD)	0.095	0.27%	0.050	0.27%	0.111	0.68%

Based on the fact that NCS Unit 1 appears to be currently adequately controlled by an electrostatic precipitator (ESP), is subject to an emissions limitation of 0.1 lb/MMBtu (Title V OP), and the modeling results revealed that direct particulate emissions do not significantly contribute to visibility impairment in Class I areas, the NDEQ has determined that BART for PM shall be existing controls and requirements.

3.0 BART Analysis for SO_2

The objective of this analysis is to determine BART for SO_2 emissions from the NCS Unit 1. Generally there are two approaches to controlling SO_2 emissions: removal of elemental sulfur from the fuel prior to combustion and flue gas desulfurization (FGD). FGD consists of removal of SO_2 from the flue gases after combustion.

3.1 SO_2 Formation

SO_2 emissions are formed from the oxidation of organic and pyretic sulfur in the coal during the combustion process. The majority of sulfur is oxidized to SO_2; however a small quantity is further oxidized to form sulfur trioxide (SO_3). Approximately 90% of the sulfur present in the subbituminous coal will be emitted as SO_x compounds. Alkaline ash from some coals (including Powder River Basin coals) may cause some of the sulfur to react in the furnace to form various sulfate salts that are then retained in the fly ash. Sulfuric acid mist (H_2SO_4) forms when SO_3 emissions combine with combustion-related moisture, or when SO_2 is oxidized to SO_3 in the atmosphere. This SO_3 will also combine with water in the atmosphere to form H_2SO_4, which typically reacts further with ammonia in the air to form fine particulate matter in the form of ammonium sulfates.

3.2 Identification of SO_2 Control Technologies and Technical Feasibility

3.2.1 Sulfur Removal from Fuel

A significant fraction of the sulfur in coal is in the form of pyrite (FeS_2) or some other mineral sulfates. Mineral sulfates can be removed through washing or other physical cleaning; however organic sulfur cannot be removed by physical cleaning. Sulfur removal from low-sulfur Powder River Basin (PRB) coal has not been demonstrated. NCS uses PRB coal. Since this technology has not been demonstrated and it would not be cost effective to attempt a form of physical cleaning or chemical desulfurization, this technology is infeasible at this time.

3.2.2 Flue Gas Desulfurization (FGD)

FGD consists of removal of SO_2 from the flue gases after combustion. FGD technologies can be divided into two main categories, regenerative and throwaway processes. Regenerative processes recover sulfur in a usable form that can be sold as a reusable sulfur product. Throwaway processes remove sulfur from the flue gas and the byproducts are discarded. The FGD technologies considered may be able to achieve SO_2 removal efficiencies up to 90 to 95%, depending on the amount of sulfur in the coal. For relatively high sulfur coals (such as eastern bituminous coal), removal efficiencies of 95% can be reached, while for lower sulfur coals (such as PRB), the achievable removal efficiency is typically less than 95%.

3.2.2.1 Regenerative Processes

Regenerative processes, by nature, contain a regeneration step in the FGD process that results in higher costs than throwaway processes due to equipment and operational expenses. However, in instances where disposal options are limited and markets for recovered sulfur products are readily available, regenerative processes may be used. Potential regenerative processes include the Wellman-Lord (W-L) process, magnesium oxide process, citrate scrubbing process, Flakt-Boliden process, aqueous carbonate process, Sulf-X process, Conosox process, Westvaco process, and adsorption of SO_2 by a bed of copper oxide.

A new regenerative process that was developed as an indirect result of collaborative research with the former U.S. Bureau of Mines and the University of Minnesota is the Pahlman process. The Pahlman process is a dry removal technology that can remove multiple pollutants (NO_x and SO_2) at efficiencies greater than 99%. As a regenerative process, the Pahlman process purportedly reduces problems associated with waste disposal and creates a commercially valuable byproduct. In the closed-loop process, the Pahlmanite sorbent repeatedly captures NO_x and SO_2, which upon regeneration, yields raw sulfates and nitrates. The Pahlman process is new technology that has been pilot tested at several industrial sites, including smaller coal-fired electrical generating plants.

None of the regenerative processes identified above have been demonstrated on large coal-fired boilers and it would not be cost effective to attempt to utilize a regenerative process of FGD at this time. Therefore all regenerative technologies have been determined to be infeasible at this time.

3.2.2.2 Throwaway Processes-Wet and Dry FGD

Throwaway process have become widely accepted by the coal-fired power industry for FGD because they have lower overall costs and are simpler to operate than regenerative processes. Throwaway processes can achieve the same removal efficiencies as regenerative processes and cost less. Throwaway processes can be divided into two categories, wet or dry. Wet or dry refers to the state of the waste by-products. Both wet and dry technologies have advantages and disadvantages with respect to initial capital and operational expenses.

Wet FGD

Wet scrubbing systems used for SO_2 reduction typically consist of the following operations: scrubbing or absorption, lime handling and slurry preparation, sludge processing, and flue gas handling. Wet FGD technology is a well established process for removing SO_2 from flue gas. Many utilities can also offset operating costs of wet FGD by selling one of the by-products, calcium sulfate (gypsum), to wallboard manufacturing facilities. Although gypsum can be sold, there is little local demand for it near NCS, so OPPD could not take advantage of the cost offset. However, wet scrubbing is a feasible technology for SO_2 control from NCS Unit 1.

Dry FGD

Dry FGD is a well established process for removing SO_2 from flue gas. Many modern dry FGD systems include a loop to recycle a portion of the baghouse-collected material for re-use in the FGD module because this material contains a relatively high amount of unreacted lime. The exhaust from a dry FGD system contains very fine particulate, which would not be effectively controlled by the existing ESP. Therefore if OPPD would be required to install dry FGD, a baghouse would need to be installed also. However, dry scrubbing is a feasible technology for SO_2 control from NCS Unit 1.

3.3 Ranking of Technologically Feasible SO_2 Controls based on Effectiveness

Wet and dry scrubbing are feasible technologies for SO_2 control. Effectiveness is measured by the amount of SO_2 removed by each control technology based on a comparison of the controlled emission rates to the uncontrolled baseline emission rate of NCS Unit 1. In this case, it is anticipated that the same level of SO_2 control can be achieved by the use of either wet or dry FGD. The presumptive BART limit in 40 CFR Appendix Y for electrical generation units above 200 MW at plants greater than 750 MW in capacity is 0.15 lb/MMBtu. However, the NDEQ estimated that both technologies could achieve a lower emissions rate of 0.1 lb/MMBtu.

Based on the maximum actual 24-hr SO_2 emissions over a three year baseline period (2001-2003) of 0.815 lb/MMBtu, together with assumed continuous operation, the maximum annual emissions would be equal to 24,191 tons/year. At the presumptive BART level (0.15 lb/MMBtu) it is estimated that 19,739 tons/year would be removed from the flue gas and not emitted into the atmosphere if either dry or wet scrubbing was employed. At an emissions rate of 0.1 lb/MMBtu, it is estimated a total of 21,223 tons/year would be removed from the flue gas and not emitted into the atmosphere if wet or dry scrubbing was employed.

3.4 Evaluation of Effective SO_2 Controls

The equivalency in anticipated SO_2 emission rates using wet or dry FGD technology makes economics the primary selection factor. Typically dry FGD technology has lower capital and operating costs than wet FGD and will result in a more cost-effective and conservative BART approach. Furthermore, wet FGD to control SO_2 emissions from NCS Unit 1 would result in higher energy penalties to facility operation and the generation of more waste byproducts than would dry FGD. Therefore dry FGD was selected for further evaluation. It is important to note that when final detailed design and vendor commitments incorporating site-specific complexities related to equipment sizing, location, etc. are known, it is possible that detailed cost estimates for dry FGD could vary from those used in this analysis.

OPPD provided cost information associated with the installation of a dry FGD system. The capital cost estimate for the Spray Dryer Absorber (SDA) system included site work, demolition for the installation of the system, SDA lime preparation equipment and building, SDA/Fabric Filter (SDA/FF) system, ID Booster fan equipment, ash handling equipment, and electrical modifications. Operating costs were also considered, including labor, maintenance, lime costs, bag filter replacement, and additional electrical energy consumption. The total annualized cost associated with the installation of an SDA is $34,720,000. The cost effectiveness of this control technology is $1,635.96 per ton SO_2 removed ($34,720,000 / 21,223 tons SO_2 removed). Additional impacts to the source and the surrounding areas include the usage of 1% (6 MW) of the unit's generating capacity to operate the SDA system, disposal of the solid waste byproduct from the spent reagent and ash mixture. The spent reagent and ash mixture must be landfilled, as it cannot be used for beneficial purposes based on its characteristics and current markets. If wet FGD is employed, use of additional land would be needed for scrubber water disposal and settling ponds.

3.5 Visibility Impacts

Air dispersion modeling using CALPUFF was conducted to determine the improvement in visibility at several Class I areas (those areas included in the modeling domain utilized) if an SDA system was installed on NCS Unit 1. The other visibility impairing pollutant levels remained unchanged.

Table 5: Incremental Visibility Effectiveness (SO2 Controls) at Presumptive Level of 0.15 lb/MMBtu

Control Option	Class I Areas – Maximum Impacts (Year)	Badlands (2001)	Great Sand Dunes (2003)	Hercules Glades (2001)	Rocky Mtn (2007)	Wichita Mtn (2003)	Wind Cave (2003)	Mingo (2001)
(0.815 lb SO2/MM	Modeled 98th Percentile (ΔdV)	0.332	0.036	0.933	0.047	0.686	0.111	0.374

Control Option	Class I Areas – Maximum Impacts (Year)	Badlands (2001)	Great Sand Dunes (2003)	Hercules Glades (2001)	Rocky Mtn (2007)	Wichita Mtn (2003)	Wind Cave (2003)	Mingo (2001)
	Incremental Visibility Impairment Improvement	-	-	-	-	-	-	-
SDA/FF Control Added (0.15 lb SO2/MMBtu)	Modeled 98th Percentile (ΔdV)	0.16	0.014	0.496	0.021	0.334	0.05	0.2
	Incremental Visibility Impairment Improvement (ΔdV)	0.172	0.022	0.437	0.026	0.352	0.061	0.174
	Incremental Impairment Improvement Cost ($/yr/ΔdV)[1]	$201,860,465	$1,578,181,818	$79,450,801	$1,335,384,615	$98,636,364	$569,180,328	$199,540,230

[1]Total annualized cost / Incremental visibility impairment improvement

OPPD was asked to conduct further analysis at 0.1 lb/MMBtu for Hercules Glades and Wichita Mountains to determine whether there was a significant improvement in visibility and/or a significant change in the incremental visibility impairment improvement costs. This analysis was received on November 14, 2008. These two Class I areas were selected because of the greatest impact from NCS. Table 6 details the findings:

Table 6: Incremental Visibility Effectiveness (SO2 Controls) at 0.1 lb/MMBtu

	Class I Areas – Maximum Impacts (Year)	Hercules Glades (2001)	Wichita Mtn (2003)
Baseline (no control) (0.815 lb SO2/MMBTu)	Modeled 98th Percentile (ΔdV)	0.933	0.686
	Incremental Visibility Impairment Improvement	-	-
SDA/FF Control Added (0.1 lb SO2/MMBtu)	Modeled 98th Percentile (ΔdV)	0.493	0.311
	Incremental Visibility Impairment Improvement (ΔdV)	0.44	0.375
	Incremental Impairment Improvement Cost ($/yr/ΔdV)[1]	$78,909,091	$92,586,667

[1]Total annualized cost / Incremental visibility impairment improvement

The baseline conditions for Hercules Glade and Wichita Mountains Class I areas, based on the 20% worst visibility days, and the goal of natural background conditions is found in Table 7.

Table 7: Baseline Conditions (20% Worst Days) and Natural Background Goal

Class I Area	Hercules Glades dV	Wichita Mtn dV
Baseline 20% Worst Days	26.75	23.81
Natural Background By 2064	11.3	7.58

4.0 BART Analysis for NO_x

The objective of this analysis is to determine BART for NO_x emissions from the NCS Unit 1. Generally there are two approaches to controlling NO_x emissions: combustion controls and/or flue gas treatment (post-combustion) technologies. Combustion control processes can reduce the quantity of NO_x formed during the combustion process. Post-combustion technologies reduce the NO_x concentrations in the flue gas stream after the NO_x has been formed in the combustion process. These methods may be used alone or in combination to achieve various degrees of NO_x emission reductions.

4.1 NO_x Formation

There are two primary mechanisms of NO_x formation in coal-fired utility boilers: thermal production of NO_x from atmospheric nitrogen and oxygen and oxidation of nitrogen bound in the fuel. High combustion temperatures cause the nitrogen (N_2) and oxygen (O_2) molecules in the combustion air to react and form NO_x. Because the thermal NO_x production is primarily a function of combustion temperature and residence time, NO_x emission rates vary greatly with burner design. Experimental measurements of thermal NO_x formation have shown that the NO_x concentration is exponentially dependent on temperature and is proportional to nitrogen concentration in the flame, the square root of oxygen concentration in the flame, and the gas residence time. The formation of fuel NO_x from reactions of fuel bound nitrogen and air, can account for up to 80% of the total NO_x from coal combustion. Subbituminous coals contain from 0.5% -2% percent by weight fuel-bound nitrogen.

4.2 Identification of NO_x Control Technologies and Technical Feasibility

4.2.1 Combustion Controls

Combustion controls such as flue gas recirculation (FGR), reducing air preheat temperature (RAP), oxygen trim (OT), low excess air (LEA), over-fire air (OFA), staged combustion air (SCA), and low NO_x burners (LNB), can be used to reduce NO_x emissions depending on the type of boiler, characteristics of fuel, and method of firing. New developments in LNB technologies have demonstrated substantial reductions in NO_x formation. Combustion controls are able to be used on industrial and utility boilers and are considered to be feasible technologies for NO_x control from NCS Unit 1.

4.2.2 Post Combustion Control Technologies

<u>4.2.2.1 Selective Catalytic Reduction</u>

Selective Catalytic Reduction (SCR) systems are an add-on flue gas treatment to control NO_x emissions. The SCR process involves the injection of a nitrogen-based reducing agent such as ammonia (NH_3) or urea (CON_2H_4) to reduce the NO_x in the flue gas to N_2 and H_2O. The reagent is injected into the flue gas prior to passage through a catalyst bed which accelerates the NO_x reduction reaction rate. Use of SCR results in small levels of NH_3 emissions, and as the catalyst degrades, the NH_3 emissions will increase. This phenomenon is known as the NH_3 slip. SCR is a proven technology and is a feasible NO_x control technology for NCS Unit 1. Although SCR is a feasible control technology, it would be most practical to install SCR in combination with combustion controls. This is because if NO_x formation was not reduced upstream of the SCR system, the catalyst would degrade more rapidly, making it necessary to replace the catalyst more often. Therefore, the cost associated with installing LNB/OFA is linked to this control technology throughout the analysis.

<u>4.2.2.2 Selective Non-Catalytic Reduction</u>

The selective non-catalytic reduction (SNCR) process involves the injection of a nitrogen-based reducing agent such as NH_3 or urea to reduce the NO_x in the flue gas; however a catalyst is not used. Instead the SNCR process occurs within the upper reaches of a combustion unit, which acts as the reaction chamber. Flue gas temperatures in the range of 1,500 to 1,900 degrees Fahrenheit, along with adequate reaction time within this temperature range, are required for this technology. SNCR is a proven technology and is in commercial use on utility boilers, and therefore, is generally considered a feasible NO_x control technology for these types of emissions sources. However, there are situations where SNCR has limited applicability, such as in the case of NCS Unit 1. Due to the high temperatures experienced at the furnace exit, ammonia injection would have to occur far down stream in the convection section when combustion gases have cooled more. In addition, the location of the appropriate temperature zone would fluctuate with levels of fouling, unit load, and other conditions, requiring multiple injection points with a dynamic determination of the appropriate injection point. This would mean significantly lower residence time in the appropriate temperature window, high ammonia "slip," and non-sufficient NO_x control by this method. Due to the reasons discussed above, SNCR has been determined to be infeasible at this time.

4.3 Ranking of Technologically Feasible NO_x Controls based on Effectiveness

Combustion controls and SCR are feasible technologies for NO_x control. Effectiveness is measured by the amount of NO_x removed by each control technology based on a comparison of the controlled emission rates to the uncontrolled baseline emission rate of NCS Unit 1. It is generally not practical to install higher efficiency NO_x control technologies without first optimizing combustion controls. Reducing the concentration of NO_x to be controlled provides the benefit of longer catalyst life and less reagent usage for add-on NO_x control technologies. NCS Unit 1 currently has overfire air (OFA), which might need to be modified, optimized, or replaced to work along with a new LNB system. Therefore LNB/OFA will be evaluated as the first level of NO_x control, and then SCR with the LNB/OFA system as the second level of NO_x control.

Based on the maximum actual 24-hr NO_x emissions over a three year baseline period (2001-2003), together with assumed continuous operation, the maximum annual emissions would be equal to 17,008 tons/year. If LNB/OFA was employed, the NO_x emissions limitation would be established at 0.23 lb/MMBtu which is the presumptive BART limitation in Appendix Y for this source type. If only LNB/OFA were required for BART, it is estimated that 10,181 tons/year would be removed from the flue gas and not emitted into the atmosphere. If SCR and LNB/OFA were installed, an emissions limitation of 0.08 lb/MMBtu would be established, equating to 14,633 tons/year of NO_x reductions from Unit 1. By installing both an SCR system in conjunction with LNB/OFA, NO_x would be controlled more efficiently than with a stand-alone SCR system.

4.4 Evaluation of Effective NO_x Controls

The cost of compliance, energy impacts, non-air quality impacts, and remaining useful life of the unit were all evaluated for purposes of determining if either, both, or none of the feasible control options should be required for BART.

OPPD provided cost information associated with the installation of LNB/OFA with and without the installation of an SCR system. The capital cost included the costs associated with the burner modification (installation of LNB/OFA and over fire air modification), SCR equipment, ID Booster fan equipment, air heaters, and electrical modifications. Operating costs were also considered. The total annualized cost associated with the installation of LNB/OFA is $1,380,000. The cost effectiveness of LNB/OFA is $135.55 per ton NO_x removed ($1,380,000 / 10,181 tons NO_x removed). The total annualized cost associated with the installation of LNB/OFA and SCR is $39,590,000. The cost effectiveness of LNB/OFA and SCR is $2,705.53 per ton NO_x removed ($39,590,000 / 14,633 tons NO_x removed). The incremental cost analysis of installing LNB/OFA and SCR as opposed to LNB/OFA alone is $8,583 ([$39,590,000 - $1,380,000] / [14,633 – 10,181]). Additional impacts to the source and the surrounding areas include 1) the usage of the unit's generating capacity to operate the SCR system, 2) hazardous spill risk due to transport and storage of ammonia, and 3) ammonia used in the system would cause the ash to be contaminated, thereby jeopardizing the current beneficial reuse of a portion of the ash produced by NCS Unit 1.

4.5 Visibility Impacts

Air dispersion modeling using CALPUFF was conducted to determine the improvement in visibility at several Class I areas (those areas included in the modeling domain utilized) if either LNB/OFA or LNB/OFA with SCR was installed on NCS Unit 1. The other visibility impairing pollutant levels remained unchanged.

Table 8: Incremental Visibility Effectiveness (NOx Controls)

Control Option	Class I Areas – Maximum Impacts (Year)	Badlands (2001)	Great Sand Dunes (2003)	Hercules Glades (2001)	Rocky Mtn (2003)	Wichita Mtn (2003)	Wind Cave (2003)	Mingo (2001)
Baseline (0.573 lb/MMBTU) (no NOx Control)	Modeled 98th Percentile (ΔdV)	0.332	0.036	0.933	0.047	0.686	0.111	0.374
	Incremental Visibility Impairment Improvement	-	-	-	-	-	-	-
LNB/OFA Control Added (0.23 lb/MMBtu)	Modeled 98th Percentile (ΔdV)	.258	0.03	0.633	0.036	0.531	0.105	0.269
	Incremental Visibility Impairment Improvement (ΔdV)	0.074	0.006	0.3	0.011	0.155	0.006	0.105
	Incremental Impairment Improvement Cost ($/yr/ΔdV)[1]	$18,648,649	$230,000,000	$4,600,000	$125,454,545	$8,903,226	$230,000,000	$13,142,857
LNB/OFA & SCR Control Added (0.08 lb/MMBtu)	Modeled 98th Percentile (ΔdV)	0.16	0.014	0.453	0.013	0.447	0.05	0.2
	Incremental Visibility Impairment Improvement (ΔdV)	0.172	0.022	0.48	0.03	0.239	0.061	0.174
	Incremental Impairment Improvement Cost ($/yr/ΔdV)[1]	$230,174,420	$1,799,545,455	$82,479,167	$1,319,666,667	$165,648,536	$649,016,393	$227,528,736

[1]Total annualized cost / Incremental visibility impairment improvement

4.6 BART Conclusion for SO_2 and NO_x

Dry scrubber technology is a technically feasible SO_2 retrofit technology that could be implemented on NCS Unit 1. The cost effectiveness of this control technology is $1,636 per ton SO_2 removed. Over the three years of meteorology modeled, the range of incremental visibility impairment improvement cost is $79,450,801 - $1,578,181,818 per year per change in deciview. As stated in Chapter 8 of the Regulatory Impact Analysis (RIA) the US EPA prepared for the Regional Haze rule, high cost control measures that have only minimal effect on visibility improvement can be avoided. Using scrubbing technology would be expected to result in the number of days where NCS's impact contributed to more than 0.5 dV to decrease from 14 days to 7 days during the worst meteorological year for Hercules Glades and from 10 days to 6 days for Wichita Mountains.

LNB/OFA technology is a feasible NO_x retrofit technology that could be implemented on NCS Unit 1. The cost effectiveness of this control technology is $135.55 per ton NO_x removed ($1,380,000 / 10,181 tons NO_x removed. The lowest incremental visibility impairment improvement cost is $4,600,000 per year per change in deciview. The NDEQ determined that at a minimum, LNB/OFA would be required for BART. Using

LNB/OFA technology would be expected to result in the number of days where NCS's impact contributed to more than 0.5 dV to decrease from 14 days to 9 days during the worst meteorological year for Hercules Glades and from 10 days to 9 days for Wichita Mountains.

Adding SCR to the LNB/OFA system would result in incremental visibility impairment improvement cost of approximately $82,479,167 - $1,799,545,455. As stated in Chapter 8 of the RIA EPA prepared for the Regional Haze rule, high cost control measures that have only minimal effect on visibility improvement can be avoided. Adding SCR to LNB/OFA technology would be expected to result in the number of days where NCS's impact contributed to more than 0.5 dV to decrease from 14 days to 6 days during the worst meteorological year for Hercules Glades and from 10 days to 7 days for Wichita Mountains. Since the incremental visibility impairment improvement cost is so large for the LNB/OFA + SCR compared to LNB/OFA, that NCS 1 can cost effectively achieve presumptive levels using LNB/OFA, the Department has determined that it would not be appropriate to require the installation of SCR at this time. Furthermore, since the incremental visibility impairment improvement cost is so large compared to similar improvements in visibility using LNB/OFA technology and the states with the Class I areas that would benefit the most, Missouri and Oklahoma, have not identified a need for SO_2 emission reductions from Nebraska at this point in time, the Department has determined that it is excessive to require the installation of SO2 scrubbing technology at this time. However, controls may be required in the future for purposes of "reasonable further progress."

Information provided by OPPD in the BART analysis showed that BART proposals in Minnesota and North Dakota would cost between $1,250,000 - $10,100,000 per year per deciview, have a post-BART impact between 0.67 – 2.36 dV, and have a greater than 0.5 dV impact on 13 – 72 days. The BART selected for NCS Unit 1 would achieve a post-BART impact level of 0.621 dV, has only 9 days of greater than 0.5 dV impact on a Class I area, and would still be well within the cost range in Minnesota and North Dakota. To reduce the impacts on a maximum of an additional 3 days, but add up to 20 times the cost per deciview is not cost effective.

Therefore BART for NCS Unit 1 shall be the installation of LNB/OFA with an emission limitation of 0.23 lb NOx/MMBtu.

5.0 Prevention of Significant Deterioration (PSD)

5.1 Summary

BART for NCS Unit 1 has been determined to be the installation of low NO_x burners supported by an existing, modified, or replacement overfire air port system as needed to meet a NO_x limit of 0.23 lb/MMBtu. Although NO_x emissions would decrease, carbon monoxide (CO) emissions are expected to increase in emissions above PSD significance thresholds (100 tons/year for CO). Title 129, Chapter 1, Section 076 defines a "major modification" as any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase of a regulated New Source Review (NSR) pollutant and a significant net emissions increase of that pollutant from the major stationary source. Therefore, the installation of LNB/OFA is a major modification and NSR regulations are applicable. Otoe County is in attainment for all National Ambient Air Quality Standards (NAAQS) so the Prevention of Significant Deterioration (PSD) regulations apply to this source. The PSD regulations state that the application of best available control technology (BACT) is required for each new or modified emission unit and each regulated air pollutant for which the project emissions exceed the established PSD significance thresholds. Since Unit 1 is the only unit required to install BART (i.e. installation of LNB/OFA), Unit 1 is the only unit which needs to apply BACT for the increase in CO. BACT is defined as an emissions limitation established based on the maximum degree of pollutant reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines in achievable. However, BACT cannot be less stringent than emission limits established by an applicable NSPS.

Since it would not be appropriate to require NCS to install LNB/OFA without addressing the increase in CO emissions expected, the Department has decided to address the BART requirements and PSD requirements in a single permitting action. As documented below, it has been determined that BACT for this unit should be a specific 30-day rolling average CO emissions limitation of 0.50 lb/MMBtu, with the control being good combustion practices.

5.2 Best Available Control Technology (BACT) Analysis Methodology

In a memorandum dated December 1, 1987, the EPA stated its preference for a "top-down" analysis regarding BACT determinations. The first step in a top-down BACT analysis is to determine, for the emissions unit and pollutant in question, the most stringent control technology and emissions limit available for a similar or identical source or source category. If it can be shown that this level of control is infeasible on the basis of technical, economic, energy, and environmental impacts for the source in question, then the next most stringent level of control is identified and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any technical, economic, energy or environmental consideration.

A "Top-Down" BACT analysis is comprised of the following five basic steps:

5.2.1 Step 1: Identify all potentially applicable control technologies:
All control technologies for similar processes, as well as Lowest Achievable Emission Rate (LAER) technologies are included.

5.2.2 Step 2: Eliminate technically infeasible options:
Technologies demonstrated to be infeasible based on physical, chemical, and engineering principles are excluded from further consideration.

5.2.3 Step 3: Rank remaining technologies by control effectiveness:
Technically feasible control technologies are ranked in the order of highest expected emission reduction to lowest expected emission reduction. The ranking also includes expected emission rate, control effectiveness, energy impacts, environmental impacts (including toxic and hazardous air emissions), and economic impacts.

5.2.4 Step 4: Evaluate most effective controls and document results:
The technology ranking is evaluated and case-by-case consideration is given to energy, environmental, and economic impacts. The most effective option not rejected is chosen as BACT and is used to express an enforceable emission limitation for the affected emission unit.

5.2.5 Step 5: Propose BACT

5.3 BACT Analysis for Carbon Monoxide (CO)

The objective of this analysis is to determine BACT for CO emissions from the NCS Unit 1 LNB/OFA system. Generally there are two approaches to controlling CO emissions: combustion controls and/or flue gas treatment (post-combustion) technologies. The rate of CO emissions from combustion sources is dependent upon the combustion efficiency of the source. Combustion control processes can reduce the quantity of CO formed during the combustion process. Post-combustion technologies reduce the CO concentrations in the flue gas stream after the CO has been formed in the combustion process. These methods may be used alone or in combination to achieve various degrees of CO emission reductions. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion can minimize CO emissions.

5.3.1 CO Formation
CO formation occurs primarily through incomplete combustion. The oxidation of CO to carbon dioxide (CO_2) is dependent on temperature, residence time during the combustion process, and the amount of excess O_2

present. Since temperature and residence time are critical factors in formation of CO, smaller boilers often emit more CO than larger combustion units, because these units have less high-temperature residence time to achieve complete combustion. Often, measures used to minimize or control emissions of NO_x can result in incomplete combustion and increased CO emissions. Therefore, an acceptable compromise is necessary to achieve the lowest NO_x emission rate possible while still keeping CO emissions as low as possible.

5.3.2 Identification of CO Control Technologies and Technical Feasibility

Combustion Controls

Combustion controls generally include staged combustion to minimize NO_x formation, high temperatures and low oxygen levels in the primary combustion zone, sufficient excess air to complete combustion, sufficient residence times, and good air/fuel mixing. Combustion efficiency is often related to the three "T's" of combustion: time, temperature, and turbulence. These components of combustion efficiency are designed into pulverized coal (PC) boilers in order to maximize fuel efficiency and reduce operating costs in terms of fuel consumption. Therefore, combustion control is accomplished primarily through burner/furnace design and operation. The primary combustion control methods used, once the burner/furnace design is set, are adjustments in the amount of air and the ratio of primary air to secondary air. These adjustments significantly affect combustion efficiency and CO levels in the combustion flue gases.

LNB/OFA systems for PC boilers are designed to burn the coal in a slow, controlled manner, which results in the minimum possible quantity of combustion air in the primary combustion zone. This initial combustion zone helps reduce NO_x formation; however it increases the amount of incomplete combustion that increases CO emissions. CO emissions can be minimized by injecting air through over-fire air ports located in the upper furnace section. The injected air brings the total amount of combustion air up to the level needed to achieve complete combustion, thereby minimizing CO emissions. It is technically feasible and economically desirable to minimize CO emissions; therefore, good combustion practices are considered to be feasible technologies for CO control from NCS Unit 1.

5.3.3 Post Combustion Control Technologies

Oxidation Catalysts

There are a variety of manufacturers who offer oxidation catalysts to control CO emissions. The catalysts are a flue gas treatment technology with a typically honeycomb type of arrangement to allow the maximum surface area exposure to a given gas flow. The typical oxidation catalyst for CO is a rhodium or platinum (noble metal) catalyst on an alumina support material. Acceptable catalyst operating temperatures range from 400 – 1250 ^{o}F, with optimum temperature range being 850 – 1,100 ^{o}F. Below 600 ^{o}F, a greater catalyst volume would be required to achieve the same reduction.

Catalytic oxidation has never been applied to a coal-fired unit due to several problems due to the solid fuel use, temperature requirements, and sulfur dioxide present in the flue gas. Catalyst plugging, fouling and poisoning by fuel sulfur and fly ash cause the catalyst to be ineffective. In order for the ideal temperature to be applied to the catalyst, the catalyst would need to be installed before the boiler economizer, which is ahead of the unit's particulate controls (fabric filters). Installation of the catalyst in this section of the boiler would result in rapid poisoning and deactivation of the catalyst by sulfur and metal compounds, and plugging and fouling of the active catalyst sites with particulates due to the high dust loading. Additionally, significant cost would be incurred for retrofitting this technology to an existing boiler. In addition, because the catalyst would oxidize a high percentage of the flue-gas sulfur dioxide (SO_2) to sulfur trioxide (SO_3), the oxidation catalyst would result in significantly increased sulfuric acid mist formation and condensable particulate. High levels of sulfuric acid would lead to rapid and destructive corrosion of ducts and equipment downstream of the catalyst and higher fine particulate and opacity levels, which would result in a visible plume from the stack. Current oxidation catalyst technology has not been designed for the higher particulate and sulfur dioxide levels found in coal-fired applications. Therefore, catalytic oxidation is not considered technically feasible for PC boilers like NCS Unit 1.

5.4 Ranking of Technologically Feasible CO Controls based on Effectiveness

Based on the CO control technologies presented above, the only feasible BACT technology for this source is good combustion practices (GCP). Catalytic oxidizers have not been proposed or demonstrated for use on a pulverized coal-fired boiler and therefore are technically infeasible for NCS Unit 1.

5.5 BACT for CO

At the time this permit was issued, the highest CO BACT emission limit that has been permitted on a retrofitted unit in US EPA Region 7, is 1.63 lb/MMBtu (3-hr average) for the Mid American Energy Company, Neal – North, Unit 2 Boiler (2007). A search of the RACT/BACT/LAER Clearinghouse (RBLC) database revealed that the lowest such limit for a retrofitted unit was in 2005 at the Mid-American Energy, Neal – South, Unit 4 Boiler (0.42 lb/MMBtu, calendar day average.) OPPD proposed an emissions limit of 0.50 lb/MMBtu (30-day rolling average) for BACT, which is below the most recent permitted emission limit. A longer averaging period is necessary because NCS Unit 1 does not have a neural net system installed. This computer automated system measures certain operating parameters associated with combustion, and based on the parameters, automatically adjusts the system to achieve an optimal operating scenario. Since NCS Unit 1 does not have a neural net system, any "tweaks" in operation must be made by the operators manually. The NDEQ agrees that the 0.5 lb/MMBtu (30-day rolling average) is an acceptable CO BACT limit for NCS Unit 1.

The CO permit limit (30-day rolling average of 0.50 lb/MMBtu) is comparable with other recently issued permits issued in Nebraska and throughout US EPA Region 7. In 2006, Nebraska Public Power District (NPPD) Gerald Gentleman Station (GGS) was issued a PSD construction permit for a LNB replacement project. The CO emissions limits being established in this permitting action for NCS Unit 1 is identical to the emissions limitation established for NPPD GGS Unit1. This is appropriate since NCS Unit1 is almost identical in size and design to GGS Unit 1 and there have been no breakthroughs in CO control technology or GCP since the permit for GGS Unit 1 was issued.

6.0 Air Dispersion Modeling Analysis

All projects that are subject to NSR review are required to be accompanied by an air quality analysis of the ambient impacts associated with the project. This analysis includes an assessment of existing air quality, an air dispersion modeling analysis, an additional impact analysis, and an evaluation of any adverse impacts to Class I areas. The air dispersion modeling analysis is required to demonstrate that new emissions from the source or due to the major modification, in conjunction with applicable emissions from other existing sources, will not cause or contribute to a violation of any applicable National Ambient Air Quality Standards (NAAQS) or PSD increment. Depending on the modeling results, pre-application monitoring or more thorough analyses may be required. Although a significant modeling analysis was conducted in conjunction with the BART analysis, CO is not a visibility impairing pollutant and therefore was not addressed. Below is a summary of the modeling analysis conducted. More information can be obtained in the materials submitted by the source.

6.1 Model Information

<u>6.1.1 Facility Location and Site Description</u>

The OPPD Nebraska City Station is located approximately five (5) miles southeast of Nebraska City, Nebraska in Otoe County. While there is no complex terrain (above the stack height), there is rolling terrain at the edges of the Missouri River Valley in which the facility is located. Otoe County is currently classified as in attainment or unclassifiable for all NAAQS pollutants.

6.1.2 Model Selection

The air quality impact analysis of CO emissions was performed using the EPA SCREEN3 dispersion model. Inputs to SCREEN3 included stack parameters based on calculated Good Engineering Practice (GEP) height of 667.5 feet (the stack of NCS Unit 1 is actually taller, but only the GEP height can be used for modeling demonstrations of compliance when using SCREEN3). Because the GEP stack height was used, no building downwash dimensions were input to the SCREEN3 analysis. The emission rate input into SCREEN3 was equivalent to 3417 lb/hr, which is based on the maximum heat input rate of 6834.3 MMBtu/hr of Unit 1 and the BACT emissions limit of 0.5 lb/MMBtu.

The model was executed for a maximum (100%) load condition, because this load produces higher impacts than when the unit operates at partial loads. The “simple terrain” option was used and the maximum terrain elevation difference of 98.66 meters was input into the model. This is a very conservative procedure in that the model assumes that the terrain rise of 98.66 meters above the stack base occurs at every receptor distance input to the model.

6.1.3 Source Parameters

One emission source, NCS Unit 1, was evaluated for purposes of PSD screening modeling. It is the only unit at the OPPD facility for which a change is proposed. The results of the screening modeling indicated that impacts from the potential emission increases resulting from the changes to NCS are insignificant. The following table presents the source parameters.

Table 9: Modeled Source Parameters

Source Type	Emission Rate (g/sec)	Stack Height (m)	Inside Diameter (m)	Exit Velocity (m/s)	Exit Temperature (K)	Ambient Air Temp. (K)
Point	430.56 (3,417 lb/hr)	203.46	7.193	30.0	415.0	293.0

6.2 Preliminary Modeling Analysis

The preliminary modeling analysis evaluates potential emissions from the PSD project alone. The results of the preliminary analysis determine whether or not a full impact analysis is required. For this project the preliminary modeling analysis was also used to determine whether or not pre-application monitoring needed to be required from the source.

The following table shows the results of the modeling analysis conducted. The results indicate that the modification of Unit 1 will not cause a significant impact in the surrounding area for the 1-hour or 8-hour averaging periods for CO. Therefore no refined modeling analysis needs to be completed and no pre-application monitoring was necessary.

Table 10: Maximum Modeled NCS Unit 1 Concentrations, Significant Impact Levels (SIL), and Pre-application Monitoring Thresholds

Pollutant	Averaging Period	Modeled Concentration (ug/m^3)	SIL (ug/m^3)	Pre-application Monitoring Threshold (ug/m^3)
CO	1-hr	172.3	2,000	N/A
	8-hr	120.6	500	575

6.3 Additional Impacts Analysis

An Additional Impacts Analysis, as required by Title 129, Chapter 19, Section 022, and the PSD regulations 40 CFR 52.21(o), describes air quality and related impacts due to associated growth and construction, as well as potential impacts of atmospheric emissions on soils, vegetation, and visibility impairment. This analysis was provided in the materials submitted by the source.

Visibility analyses were not conducted since the burner modification will not result in an increase of emissions of any visibility impairing pollutant.

6.3.1 Pollutant Effects on Soil and Vegetation

Current literature contains little information on air pollutant effects on soil and no specific studies could be identified where potential pollutant effects on the soils specific to the project area were evaluated. One study was found concerning CO effects on vegetation. The study indicated that natural background concentration of CO has no detrimental effects on green plants, and adverse effects are only seen at extremely high CO concentrations that occur primarily in urban areas due to high traffic density. Since the project is taking place in a rural area, CO emissions are not expected to negatively impact vegetation. NAAQS are not expected to be exceeded as a result of this project. Since NAAQS were designed to protect the public health and welfare from known or anticipated adverse pollutant impacts, it can be assumed that there will not be any adverse effects on the soil or vegetation.

7.0 Type and Quantity of Air Contaminant Emissions Anticipated

As a result of the LNB installation supported by an Overfire Air Port System on NCS Unit 1, NO_x and CO are the only pollutants expected to change. NO_x emissions should decrease, while CO emissions may increase. Since CO is the only pollutant that may increase; it is the only pollutant subject to PSD review.

CO PTE after LNB/OFA Project Emission Calculation

6,834 MMBtu/hr x 0.50 lb CO/MMBtu = 3417.15 lb CO/hr x 8,760 hr/yr / 2,000 lb/ton = <u>14,967 ton CO/yr</u>

The current potential emissions of Unit 1 were calculated by using a CO emission factor of 0.5 lb/ton of coal from AP-42, Chapter 1, Table 1.1-3 (9/1998) and the maximum amount of coal that could be combusted in Unit 1 assuming a Btu content of coal of 8,400 Btu/lb.

CO PTE prior to LNB/OFA Project Emission Calculation

6,834 MMBtu/hr / 0.0084 MMBtu/lb x 8,760 hr/yr / 2,000 lb/ton = 3,563,443 ton coal/year
3,563,443 ton coal/year x 0.5 lb CO/ton coal = 1,781,722 lb CO/yr / 2,000 lb/ton = <u>891 ton CO/yr</u>

Change in PTE Emission Calculation:
(Future Potential minus Current Potential)
14,967 ton CO/yr – 891 ton CO/yr = 14,076 ton CO/yr

This project is also expected to reduce the amount of NO_x emissions currently being emitted by NCS Unit 1. Currently, NCS Unit 1 must comply with a NO_x emissions limit of 0.2 lbs/MMBtu derived from gaseous fuel, 0.3 lbs/MMBtu derived from liquid fuel, 0.7 lbs/MMBtu derived from solid fossil fuel, or the prorated equation contained in 40 CFR 60.44(b) when a combination of fuels is burned, based on an arithmetic average of three contiguous one-hour periods (40 CFR 60.44(a) and (b), and 60.45(g)) in order to be in compliance with the applicable New Source Performance Standard (NSPS), Subpart D, for Fossil-Fuel-Fired Steam Generators. In addition, NCS Unit 1 must comply with a NO_x emission limit of 0.46 lb/MMBtu on an annual basis. The NO_x limit of 0.46 lb/MMBtu for dry bottom wall-fired boilers is found in 40 CFR 76.7(a)(2) and became effective 1/1/2008. NCS Unit 1 has a heat input rating of 6,834 MMBtu/hr and by using the highest possible emission factor of 0.46 lbs/MMBtu, maximum potential NO_x emissions are currently 13,769 tons/year.

6,834 MMBtu/hr x 0.46 lb NO_x/MMBtu = 3,144 lb NO_x /hr x 8,760 hr/yr / 2,000 lb/ton = <u>13,769 ton NO_x /yr</u>

By establishing a NO_x emissions limitation of 0.23 lb/MMBtu for BART, the new potential emissions of NO_x from NCS Unit #1 will be approximately 6,885 tons/year once the LNB/OFA project has been completed.

6,834 MMBtu/hr x 0.23 lb NO_x/MMBtu = 1,572 lb NO_x /hr x 8,760 hr/yr / 2,000 lb/ton = <u>6,885 ton NO_x /yr</u>

Change in PTE Emission Calculation:

(Future Potential minus Current Potential)
6,885 ton NO_x/yr – 13,769 ton NO_x/yr = - 6,884 tons NO_x/yr

Therefore, once the LNB/OFA project has been completed, maximum potential CO emissions would increase by 14,076 tons/year while maximum potential NO_x emissions would decrease by 6,884 tons/year.

8.0 Applicable Requirements, Variances or Alternatives to Required Standards:

8.1 Nebraska State Construction Permit Requirements

A state construction permit is required for this facility because this construction project has a net increase in emissions at the site greater than one or more of the threshold levels identified in Title 129, Chapter 17, Section <u>001.01</u> for PM_{10}, SO_x (SO_2 and/or SO_3), NO_x, CO, VOC and HAPs. Specifically, CO emissions are expected to increase greater than 50 tons/year.

The facility-wide potential emissions from the facility after the issuance of this permit falls into the following category:

100 tons or more per year of any air pollutant; or
10 tons or more per year of any single HAP; or
25 tons or more per year of any combination of HAPs

Therefore, the facility submitted a $3,000.00 fee in order to obtain this Air Quality Construction Permit, in accordance with Title 129, Chapter 17, Section <u>003.01</u>.

Section <u>014.04</u> of this chapter states that a source may request a state construction permit when establishing a Best Available Retrofit Technology (BART) permit or other permit required to reduce visibility impairment in a Class I Federal area pursuant to the provisions of Chapter 43.

8.2 New Source Performance Standards (NSPS)

The proposed project will not trigger the applicability of any new NSPS requirements to NCS Unit 1.

Subpart A – General Provisions*:* NSPS Subpart A, adopted by reference in Title 129, Chapter 18, Section 001.01, applies to those units covered by the specific NSPS as discussed below. The permittee is required to submit notification of the date construction commenced postmarked no later than 30 days after such date (40 CFR 60.7(a)(1)), notification of the anticipated date of initial startup of the equipment postmarked not more than 60 days nor less than 30 days prior to such date (40 CFR 60.7(a)(2)), and notification of the actual date of initial start up of the equipment postmarked within 15 days after such date (40 CFR 60.7(a)(3)). Unit 1 at NCS is currently subject to this subpart and the proposed project does not affect the applicability of this regulation or the compliance status of the unit.

Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators: This subpart, adopted by reference in Title 129, Chapter 18, Section 001.17, is for steam generating units with a design rate greater than 250 MMBtu/hr, installed after August 17, 1971. NCS Unit 1 is currently subject to this subpart and the proposed project does not affect the applicability of this regulation or the compliance status of the unit.

Subpart Da – Standards of Performance for Electric Utility Steam Generating Units**:** This subpart, adopted by reference in Title 129, Chapter 18, Section 001.11, is for steam generating units with a design rate greater than 250 MMBtu/hr, installed after September 18, 1978. The installation of LNB will not constitute a modification or reconstruction of the existing facility as specified in provisions under 40 CFR 60.14 and 40 CFR 60.15. Therefore, Unit 1 will continue to be an existing unit under NSPS Subpart D and will not be subject to any requirements under NSPS Subpart Da.

Subpart HHHH - Emission Guidelines and Compliance Times for Coal-Fired Electric Steam Generating Units: This subpart established a model cap and trade program as a means of reducing national Hg emissions from coal fired electric utilities. NCS Unit 1 would have been subject to Subpart HHHH, however the subpart was vacated in its entirety by the Court of Appeals for the District of Columbia Circuit on February 8, 2008 (State of New Jersey, ET AL.v. EPA).

8.3 Particulate Matter Emissions

Title 129, Chapter 20, Section 002 -Particulate Emissions from Combustion Sources

NCS Unit 1 will continue to comply with the emission limits for fuel combustion located in this chapter. For units with heat input capacities between 10 MMBtu/hr and 10,000 MMBtu/hr, the following formula is used to determine the Maximum Allowable Emissions of Particulate Matter in lb/MMBtu:

$$\text{Lb/MMBtu} = 1.026/I^{0.233} \text{ where I is the total heat input in MMBtu/hr.}$$

$$1.026/(6834.3 \text{ MMBtu/hr})^{0.233} = 0.131 \text{ lb/MMBtu}$$

Title 129, Chapter 20, Section 004 - Opacity

All of the equipment at the facility is subject to the opacity standard (20% opacity limit) specified in Title 129, Chapter 20, Section 004. Although coal is combusted at the facility, control equipment has been installed in the past to control particulate emissions that contribute to opacity.

8.4 Sulfur Compound Emissions

No fossil fuel burning equipment at the facility may emit sulfur oxides greater than two and one half (2.5) pounds per million BTU input. NCS Unit 1 will comply with this emission limit by complying with requirements that are contained within NSPS Subpart D for SO_2 emissions. This limit is currently specified and contained within the facility's Class I Operating Permit issued April 28, 2004.

8.5 Acid Rain

The federal acid rain program requirements (40 CFR Part 72) have been incorporated by reference in this chapter. Unit 1 will continue to be considered an affected unit for purposes of the Acid Rain Rule because it is a utility unit that will generate more than 25 MW of electricity. The Acid Rain Rule requires a facility to monitor opacity, and all sulfur dioxide, nitrogen oxides, and carbon dioxide emissions for each affected unit. The proposed project does not affect any requirements of this rule. NCS is currently operating under an Acid Rain Permit that was issued on March 9, 2007.

8.6 Hazardous Air Pollutants

Title 129, Chapter 27, Section 002 - Best Available Control Technology (BACT)

Title 129, Chapter 27, Section 002 requires a BACT determination for any source with net emissions increase of HAP in excess of 2.5 tons/year of any single HAP, or combined emissions of 10 tons/year of any group of HAPs. The proposed project will not result in net increases in potential emissions of HAPs that equals or exceeds the BACT thresholds. Therefore, requirements of this section do not apply to the proposed project.

Title 129, Chapter 27, Section 003 - Maximum Achievable Control Technology (MACT)

This section requires that MACT be installed on any source with a net emissions increase of HAP in excess of 10 tons/year of any single HAP, or combined emissions of 25 tons/year of any group of HAPs. The proposed project will not result in net increases in potential emissions of HAPs that equal or exceed the MACT thresholds. Therefore, requirements of this section do not apply to the proposed project.

Subpart A – General Provision: This subpart, adopted by reference in Title 129, Chapter 28, Section 001.01, applies to the owner or operator of any stationary source that emits or has the potential to emit any hazardous air pollutant listed in or pursuant to section 112(b) of the Act; and is subject to any standard, limitation, prohibition, or federally enforceable requirement established pursuant to Part 63.

Subpart DDDDD – Industrial, Commercial, and Institutional Boilers and Process Heaters: This subpart, adopted by reference in Title 129, Chapter 28, Section 001.90, applies to certain boilers and process heaters that are located at major HAP sources (≥10 tons/year of individual HAP or ≥ 25 tons/year of combined HAPs).

8.7 Visibility Protection

Title 129, Chapter 43 incorporates 40 CFR 51.301 and Appendix Y of 40 CFR 51 by reference. It requires that BART analyses be submitted by sources determined to be subject to the requirement and establishes the construction permit as the mechanism for making the BART requirements federally enforceable. OPPD submitted a BART analysis for NCS Unit 1 on August 7, 2007.

9.0 Discussion of Specific Permit Conditions

General Condition V.
General condition V. requires the low NO_x Burners supported by an overfire air port system on Unit 1 to be operational and demonstrate compliance with the BART and BACT limitations as expeditiously as practicable, but no later than five years after the approval by EPA of the Regional Haze State Implementation Plan (SIP). Forty CFR Part 51, Section 51.302(c)(4)(iv) states:

"The plan [State Implementation Plan] *must require that each existing stationary facility required to install and operate BART do so as expeditiously as practicable but in no case later than five years after plan approval."*

Although the completion of the LNB/OFA project need not be completed until five years after the SIP approval, construction must commence on the project within 18 months of SIP approval in order for the Department to ensure that the project has undergone some progress in a reasonable timeframe. OPPD submitted additional timeline information regarding the time necessary to install the LNB/OFA to the Department on April 22, 2008. The Department will notify OPPD within 15 days of SIP approval that the approval has occurred.

The requirements for EPA for approving SIP submissions are contained in the Clean Air Act, Section 110(k). Section 110(k)(1)(B) states that within 60 days of receipt of a State's plan or plan revision submission, but no later than 6 months after the date by which a State is required to submit the plan or revision, the Administrator must determine whether the minimum criteria for the plan have been met. If the Administrator does not inform the State of the determination within 6 months of receipt of the submission, the plan or revision is deemed to meet the minimum criteria.

Section 110(k)(2) also states that within 12 months of a determination that a plan submission meets the minimum criteria, the Administrator must act on the plan, making a determination of full and partial approval/disapproval or conditional approval.

No other general conditions have been altered for this permitting action.

Specific Conditions

(A) Establishes a NO_x emissions limit and Department determined BART control, low NO_x Burners supported by an overfire air port system, for NCS Unit 1. The 30-day rolling emissions limit of 0.23 lb/MMBtu must be complied with at all times including times of startup, shutdown, or malfunction. All malfunctions shall be addressed in accordance with Nebraska Title 129, Chapter 35. A discussion of how this limit was chosen can be found under the BART discussion located in this document. The NO_x emissions data is required to be collected in accordance with 40 CFR Part 75 for Acid Rain, which incorporates requirements the source is currently subject to.

(B) Establishes a CO emissions limit and Department determined BACT control, combustion controls, for NCS Unit 1. The 30-day rolling emissions limit of 0.50 lb/MMBtu must be complied with at all times excluding startups and shutdowns. All malfunctions shall be addressed in accordance with Nebraska Title 129, Chapter 35. A discussion of how this limit was chosen can be found under the PSD discussion located in this document.

(C) Requires that records be kept documenting all notifications, reports, test results, and plans submitted to the Department. The owner or operator is also required to maintain appropriate CEMS information, which is required in Conditions XIV.(A)(2)(d) and XIV.(B)(1)(c). These records must be maintained on-site for a minimum period of five (5) years and be clear and readily accessible to Department representatives.

STATUTORY OR REGULATORY PROVISIONS ON WHICH PERMIT REQUIREMENTS ARE BASED:

Applicable regulations: Title 129 - Nebraska Air Quality Regulations as amended August 18, 2008.

PROCEDURES FOR FINAL DETERMINATION WITH RESPECT TO THE PROPOSED CONSTRUCTION PERMIT:

The public notice, as required under Title 129, NAQR Chapter 14, shall be published on December 12, 2008, in the Nebraska City News-Press newspaper. Persons or groups shall have 30 days from that issuance of public notice (January 10, 2009) to provide the NDEQ with any written comments concerning the proposed permit action and/or to request a public hearing, in accordance with NAQR Chapter 14. If a public hearing is granted by the Director, there will be a notice of that meeting published at least 30 days prior to the hearing. Persons having comments or requesting a public hearing may contact:

W. Clark Smith-Permitting Section Supervisor
Air Quality Division
Nebraska Department of Environmental Quality
PO Box 98922
Lincoln, Nebraska 68509-8922

If no public hearing is requested, the permit may be granted at the close of the 30-day comment period. If a public hearing is requested, the Director of the NDEQ may choose to extend the date on which the permit is to be granted until after that public hearing has been held. Additional public information is available on the agency's website and by request at ndeq_records@nebraska.gov. During the 30-day comment period, persons requiring further information should contact:

Beverly Kellison-Program Planning & Development Unit Supervisor
Air Quality Division
Nebraska Department of Environmental Quality
PO Box 98922
Lincoln, Nebraska 68509-8922

Telephone inquiries may be made at:

(402) 471-2189

TDD users please call 711 and ask the relay operator to call us at (402) 471-2186.