Project No. 135938
June 2011

Sunflower Electric Power Corporation Prevention of Significant Deterioration Construction Permit Application

Holcomb Unit 1
Holcomb, Finney County, Kansas

Prepared for:
Sunflower Electric Power Corporation
Holcomb Generating Station
Holcomb, Kansas

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SUNFLOWER ELECTRIC POWER CORPORATION
A Touchstone Energy® Cooperative

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Acronyms and Abbreviations

30-DRA	30 Day Running Average
AERMOD	American Meteorological Society / EPA Regulatory Model
AQRV	Air Quality Related Value
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
Btu	British Thermal Unit
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CEMS	Continuous Emission Monitoring Systems
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
EGU	Electric Generating Unit
FF	Fabric Filter
FGD	Flue Gas Desulfurization
FLM	Federal Land Manager
GEP	Good Engineering Practice
H1	Holcomb Unit 1
H2	Holcomb Unit 2
H_2SO_4	Sulfuric acid mist
HERT	High Energy Reagent Technology
K.A.R.	Kansas Administrative Regulations
KDHE	Kansas Department of Health and Environment
km	Kilometer
LAER	Lowest Achievable Emission Rates
lb/hr	Pounds per hour
lb/MMBtu	pounds per million Btu
LNB	Low NO_X burner
m	Meter
MACT	Maximum Achievable Control Technology
$\mu G/M^3$	Micrograms per Cubic Meter
MMBtu	Million British Thermal Units
MMBtu/hr	Million Btu per hour
MW	Megawatt
NAAQS	National Ambient Air Quality Standard
NO	Nitrogen monoxide
NO_2	Nitrogen dioxide
NO_X	Nitrogen oxides
NSPS	New Source Performance Standard
NSR	New Source Review
OFA	Over Fire Air
PC	Pulverized coal
PM	Particulate Matter
PM_{10}	Particulate Matter less than 10 microns in diameter
$PM_{2.5}$	Particulate Matter less than 2.5 microns in diameter
PRB	Powder River Basin
PSD	Prevention of Significant Deterioration
RACT	Reasonably Achievable Control technology
RBLC	USEPA RACT/BACT/LAER Clearinghouse
ROFA	Rotating Opposed Fire Air
RTO	Regenerative Thermal Oxidizer

SCR	Selective catalytic reduction
SNCR	Selective Non-catalytic reduction
SO_2	Sulfur dioxide
SO_3	Sulfur trioxide
SU/SD	Start Up/Shut Down
TCEQ	Texas Commission on Environmental Quality
TPY	Tons per Year
TXI	TXI Operations, LP
ULBN	Ultra Low-NO_x Burner
USDOI	United States Department of the Interior
USEPA	United States Environmental Protection Agency
USGS	U.S. Geological Survey
VOC	Volatile Organic Compounds

PART 1.0
INTRODUCTION

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1.0 Introduction

Sunflower Electric Power Corporation (Sunflower) owns and operates the 360-MW coal-fired Holcomb 1 (H1) electric utility generating unit (EGU) and associated facilities and equipment at its Holcomb Generating Station (Holcomb Station) located near the City of Holcomb, Finney County, Kansas.[1] Sunflower received a Prevention of Significant Deterioration (PSD) construction permit for H1 from the United States Environmental Protection Agency (USEPA) in 1978. Initial start–up of the EGU was in 1983. In October 1996, Sunflower submitted a Title V permit application for H1, in accordance with 40 CFR, Part 70 and K.A.R. 28-19-500. The H1 Title V permit was issued in December 2003 and renewed in 2009.

1.1 Project Overview

Sunflower is proposing to construct and operate new low nitrogen oxide burners (LNB) and Overfire Air (OFA) system on the existing Holcomb 1 steam generator system (H1). The Pulverized Coal (PC) steam generator is designed to burn low sulfur Powder River Basin (PRB) coal with a nominal net generation capacity of 360 megawatts (MW). LNB and OFA are the two primary forms of combustion control to reduce NO_X emissions from PC fired units. NO_X, primarily in the form of NO and NO_2 is formed during combustion by two primary mechanisms: thermal NO_X and fuel NO_X. Thermal NO_X results from the dissociation and oxidation of nitrogen in the combustion air. The rate and degree of thermal NO_X formation is dependent upon oxygen availability during the combustion process and is exponentially dependent upon the combustion temperature. Fuel NO_X, on the other hand, results from the oxidation of nitrogen organically bound in the fuel. This is the dominant NO_X producing mechanism in the combustion of pulverized coal and typically accounts for 75 to 80 percent of total NO_X.

OFA works by reducing the excess air in the burner zone, thereby enhancing the combustion staging effect of the LNBs and further reducing NO_X emissions. Residual unburned material, such as CO and unburned carbon that inevitably escapes the main burner zone, is subsequently oxidized as the OFA is added.

In addition to LNB/OFA systems Sunflower will also evaluate a more robust form of OFA known as a Rotating Opposed Fire Air (ROFA) System. A ROFA system may be installed with or without LNBs or modifications to the existing burners and may offer the ability to stage the lower furnace much deeper—which allows greater NO_X emission reduction while maintaining good combustion characteristics.

The net result of the staged combustion associated with a LNB is usually lower peak combustion temperatures and longer and/or wider flames, due to the delayed mixing process. The lower combustion

[1] Holcomb Station is located approximately 3.5 miles south of the City of Holcomb and 7.5 miles southwest of Garden City, Kansas.

temperatures and potential for encroachment on cooled boiler surfaces are the main reasons why low NO_X combustion techniques may be associated with the potential for increased carbon in ash and higher CO emissions. The resulting efficiency loss due to increased carbon in ash and increased CO emissions can be somewhat offset, however, by the lower total excess air demand that is part of the low NO_X firing strategy.

Combustion optimization to ensure coal/air balance across all of the coal burners, and maintaining coal fineness minimize efficiency losses. As part of this project, Sunflower will also evaluate instrumentation and software to assist with combustion optimization.

1.1.1 Timeline

Sunflower is proposing to implement the LNB/OFA NO_X emissions control upgrade to align with a planned maintenance outage of H1 scheduled for the spring of 2013. The duration of the outage is currently set for five weeks. However, since the LNB/OFA project is expected to be the critical path, the actual outage duration may be adjusted once a contract is awarded. LNB/OFA projects on similar units have been completed during outages of four to eight weeks in length.

2.0 Process Description

2.1 Pulverized Coal-Fired Steam Generator

The H1 steam generator is designed to fire low-sulfur PRB coal with a design heat input rate of 3,389 million Btu per hour (MMBtu/hr). Low sulfur fuel, back-end controls and steam generator design reduce emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X), particulate matter (PM), carbon monoxide (CO), and volatile organic compound (VOC) when combined with Dry FGD and FF as back-end control technologies.

2.1.1 Steam Generation Process

In a PC-fired steam generator, the fuel is pulverized to the consistency of talcum powder and pneumatically injected through the burners into the furnace. Combustion takes place almost entirely while the coal is suspended in the furnace volume and is started by use of natural gas igniters. When normal steam generator temperature is achieved, the combustion process is self-sustaining and igniters are removed from service.

2.1.2 Air Pollutant Generation and Control – NO_X, CO, and VOC

The furnace geometry is optimized to provide adequate burner spacing, burner zone cooling surface, and burner zone residence time for the required NO_X levels. Peak NO_X formation is reduced by controlling the rate of combustion and optimum stoichiometry. Combustion air gradually mixes with products of combustion further downstream to complete char reactions while minimizing NO_X re-formation. Additional air staging is accomplished by introducing a portion of the combustion air above the uppermost level of burners. This further stages combustion and reduces the formation of NO_X in the immediate burner combustion zone.

During combustion, carbon in the coal reacts with oxygen to produce heat and CO_2. In order to complete this reaction, the coal particles and oxygen must have sufficient time in the combustion zone to complete the reaction, sufficient mixing of fuel and oxygen, and a high enough temperature. These three concepts are generally referred to as the three “Ts” of combustion: time, turbulence, and temperature. Modern steam generator design is keyed to optimize the three Ts and thereby allow the combustion reaction to go to completion to the greatest extent possible. Modern environmental regulations emphasize reducing the emission of NO_X, which is usually accomplished by reducing the oxygen in the combustion zone to just above stoichiometric concentrations and staging the combustion air so as to reduce peak flame temperature. If furnace temperatures are not high enough to allow all of the carbon to react to form CO_2, or if there is a deficiency in combustion air to supply the oxygen, the products of incomplete combustion will remain. CO and VOC emissions are the result of incomplete combustion. Operating with higher flame temperatures and longer furnace residence times can reduce CO and VOC emissions, but these conditions concurrently result in an increased NO_X formation. Balancing lowest levels of CO, VOC, and NO_X emissions is a key consideration in steam generator design and operation.

3.0 Air Emissions

This permit application identifies the changes to the H1 steam generator. Emissions were calculated assuming continuous operations (8,760 hours annually) for the H1 steam generator. No other material handling or other processes are being affected by this change. Emission calculations are shown in Appendix D. The emission calculation methodology for the H1 steam generator criteria pollutants are based on information that is consistent with the Best Available Control Technology (BACT) analysis findings discussed in Part 4.0.

Specific reference and methodologies are detailed in the emission calculation worksheets included in Appendix D.

4.0 Regulatory Applicability

4.1 Federal and State Requirements

H1 is subject to a variety of federal and state air quality regulations. In order to better show these requirements, a compilation of all regulations has been identified in a matrix and tables contained in Part 2.0 of this document. The regulatory matrix is shown as Table 2-1 in Part 2.0.

4.2 New Source Performance Standards (NSPS)

USEPA regulates stationary sources under the NSPS as contained in 40 CFR Part 60 through the development of standards applicable to a specific category of sources. Emission sources within a specific category constructed or modified after a given date must meet the requirements of the NSPS. For the H1 steam generator, NSPS Subpart A and Da apply.

NSPS Subpart A encompasses the general NSPS regulations and includes the conventional monitoring, recordkeeping, and reporting requirements.

NSPS Subpart Da applies to "Electric Steam Generating Units for Which Construction is Commenced After September 18, 1978" and thus impacts the operations of the proposed PC steam generators. Subpart Da establishes limits for PM, NO_X, SO_2, and opacity limits for emissions from the steam generator. Sunflower's proposed operations are designed to meet the regulatory requirements defined in Subpart Da. On February 28, 2005, USEPA published proposed revisions to Subpart Da. These revisions included lower emission limitations for NO_X and SO_2. The emission limitations determined for the H1 steam generator are in compliance with both the existing Subpart Da and the new Subpart Da revisions. This subpart imposes additional monitoring and record-keeping obligations to the source operator.

4.3 Compliance Assurance Monitoring (CAM)

USEPA established the Compliance Assurance Monitoring (CAM) rule under 40 CFR Part 64 to ensure that major source units required to obtain a Part 70 Operating Permit and that utilize a control device to achieve compliance with a Federal regulatory emission standard will maintain compliance during daily operations. The CAM rule requires owners and operators to monitor the operation and maintenance of the subject control equipment, to evaluate the performance of their control device, and to report whether or not the emission limitations are met. A review of available data indicated that no increase in particulate matter emissions would occur as a result of this project. As PM emissions are the only emissions that would be covered by CAM, no CAM requirements are needed as a result of this modification.

4.4 Acid Rain

USEPA was authorized by Congress under Title IV of the CAA to establish the Acid Rain Program. USEPA established the provisions of the Acid Rain Program in 40 CFR, Part 72 through Part 77. The

main goal of the program is to achieve significant environmental benefits through reductions of SO_2 and NO_X emissions, the primary components of acid rain. The H1 steam generator is subject to the Acid Rain provisions, as identified within the regulatory applicability table of Part 2.0. A revised Acid Rain permit application is not required due to this modification.

4.5 Title V Operating Permit

USEPA was authorized by Title V of the CAA to establish an air quality operating permit program that provides as a central point for tracking all applicable air quality requirements for every source required to obtain a permit. USEPA established provisions of the Title V Program in 40 CFR, Part 70. Each state was also required to establish an operating permit program. As required by K.A.R. 28-19-510, Sunflower will submit an application to amend the Holcomb Station Title V operating permit within one year of completion of the modification on H1.

4.6 Prevention of Significant Deterioration (PSD) Regulations

Kansas, in accordance with criteria established by USEPA, has classified the ambient air quality of the different areas of the state as either attainment, non-attainment, or unclassifiable. The designation for the respective areas is based on ambient air concentrations observed or predicted for select compounds for each representative area. The USEPA-promulgated ambient air quality standards (subsequently adopted by the KDHE, see Table 1-1) that were designed to protect the public health (primary standard) and welfare (secondary standard) for criteria pollutants. The designations for Finney County, where the Holcomb Generating Station is located, are identified in Table 1-2.

Table 1-1
National Ambient Air Quality Standards (NAAQS)

Pollutant	Averaging Period [A]	NAAQS [B]	
		Primary ($\mu g/m^3$)	Secondary ($\mu g/m^3$)
CO	8-hour	10,000	10,000
	1-hour	40,000	40,000

Notes:
A. Short term ambient standards may be exceeded once per year.
B. Source: K.A.R. 28-19-200

Table 1-2
Pollutant Ambient Air Quality Classifications

Pollutant	Classification [A]
CO	Unclassifiable/Attainment

Notes:
A. Source: 40 CFR 81.317

The designation of unclassifiable/attainment indicates that there is insufficient monitoring data to prove that the area has attained the federal standard but that the limited data available indicates that the standard has been achieved. Areas with this classification are treated as attainment areas for permitting purposes.

Holcomb Station is located in an area classified as full attainment for all criteria pollutants. Modifications to existing major sources that exceed a defined threshold and that are located in an attainment area are required to obtain a PSD permit prior to initiation of construction of the project. For PSD to apply, the proposed project emissions are compared to the "PSD Pollutant Significance Threshold" significance level (40 CFR 52.21(b)). If the significance level is exceeded, PSD permitting requirements will apply to the respective pollutant. Criteria pollutants that qualify for major modification are identified below in Table 1-3.

Table 1-3
Project PSD Applicability

Pollutant	Baseline Emissions (tpy)	Project Potential Emissions (tpy)[D]	Net Emissions Change (tpy)	PSD Significance Level (tpy)	BACT Required
NO_X	4,687.2[A]	2,671.9	-2,015.3	40	No
CO	509.1[B]	3,711.0	3,201.8	100	Yes
CO_2	--[C]	--[E]	-5030.3[F]	75,000	No

Notes:

A. NO_X baseline emissions based on CEMS data from January 2006 – December 2010. Highest emissions in a 24-month consecutive period determined.
B. CO baseline emissions based on CEMS data from January 2006 – December 2010. Highest emissions in a 24-month consecutive period determined.
C. No baseline emissions for CO_2 were calculated.
D. Potential emissions based on revised emission levels for 8,760 hours annually.
E. Potential emission of CO_2 was not calculated.
F. Net emission change for CO_2 based on the direct molar ratio of CO to CO_2. As no new sources of carbon are being introduced to the system, the increase in CO will lead to a corresponding decrease in CO_2. Hence, baseline and project potential emissions are not relevant for this permit application.

Therefore, this Project does qualify as a PSD source. Once a facility is subject to the PSD permitting requirements, the following items must be considered in the permit application:

- BACT review;
- NAAQS and PSD Increment Air Quality analysis;
- Additional Impact Analysis; and
- Class I Area Impact.

4.6.1 Best Available Control Technology BACT Review

In accordance with PSD requirements listed in K.A.R. 28-19-350, Sunflower conducted an analysis to determine the BACT emission limitation for each pollutant subject to PSD permitting. BACT is defined in 40 CFR 52.21(b)(12):[2]

> "an emission limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under this Part which would be emitted from any proposed major stationary source or major modification which the administrative authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant."

Guidelines for the evaluation of BACT can be found in the NSR Manual. The BACT requirements are intended to ensure that a proposed new facility or major modification will incorporate air pollution control systems and technologies that reflect the latest demonstrated practical control techniques for each particular emission unit. An evaluation of these controls and techniques is required, including a cost-benefit analysis of alternative control techniques capable of achieving a higher degree of emission reduction than the proposed control technology. The cost-benefit analysis requires the documentation of the materials, energy, and economic penalties associated with the proposed action. A final decision on BACT is based on sound engineering judgment balancing environmental benefit with energy, economic, and other impacts. Part 4.0 of this Application documents the BACT process and findings for the Project.

4.6.2 Air Quality Analysis

In accordance with PSD requirements listed in K.A.R. 28-19-350, Sunflower conducted a study to demonstrate that the allowable emissions increase from the proposed project does not cause or contribute to air pollution in violation of any NAAQS. Dispersion modeling was conducted for this project using the USEPA-approved AERSCREEN air dispersion modeling software to compare project net emission increases to the modeling significance levels. The final results of the air dispersion modeling indicate that the LNB/OFA modification to Holcomb 1 will not cause or contribute to an exceedance of the NAAQS. The final modeling results and a detailed description of the process and methodology used to arrive at the results are included in Part 5.0 of this Application.

4.6.3 Additional Impact Analysis

In addition to the standard air quality analysis, K.A.R. 28-19-350 requires an analysis of the impairment to visibility and the effects on soils and vegetation which would occur as a result of the modification of H1. Impacts due to commercial, residential, industrial, and other growth in the vicinity of the project

[2] Incorporated by reference into Kansas regulations in K.A.R. 28-19-350(b).

must also be addressed to the extent they are a result of the proposed action. Results of the "additional impact analysis" demonstrate that the project will not have a negative impact on the surrounding area. Detailed discussion on the "Additional Impact Analysis" is included in Part 7.0 of this Application.

4.6.4 Class I Area Impact

As this project is located more than 100 km from the nearest Class I area,[3] and since the project will result in a net decrease in all visibility impacting pollutants, the Federal Land Manager was not contracted for this project. The only applicable PSD pollutant is CO, which neither impacts visibility nor has PSD Class I Increments. Emissions of SO_2 and PM will be unaffected by this modification, and emissions of NO_X will decrease as a result of the project.

4.7 Permit Shield

Holcomb Station is in compliance with all applicable state and federal air quality regulations. Pursuant to K.A.R. 28-19-512(b), Sunflower requests authorization through the Title V permit program to continue operating all existing emission sources in accordance with the existing Title V permit.

4.8 Compliance Monitoring Devices or Activities

Certain monitoring devices or activities are required by regulations to ascertain compliance with applicable requirements. In accordance with K.A.R. 28-19-500, compliance monitoring devices or activities will be included in the revised Title V operating permit application which will be submitted within one year of completing modifications of H1.

4.9 Test Methods and Procedures

Sunflower will utilize test methods for determining compliance with applicable requirements. In accordance with K.A.R. 28-19-62, a description and reference to applicable test methods are included in the Draft Final Permit included in Appendix F.

4.10 Proposed Specific Conditions

Sunflower has evaluated the proposed operations due to the modifications on H1. Based on an assessment of the proposed modifications and the applicable regulations, Sunflower has proposed specific conditions that will ensure compliance of the facility with permit conditions as well as applicable rules. The proposed specific conditions are included in Appendix F.

[3] The Great Sand Dunes National Monument is the nearest Class I area and is located approximately 400 km west of Holcomb Station in southwestern Colorado

4.11 Compliance with all Current and Future Requirements

Holcomb Station is in compliance with all applicable state and federal requirements. Sunflower will take necessary action to ensure compliance with future regulations, as appropriate.

PART 2.0
RULE OF APPLICABILITY MATRIX

Holcomb 1 LNB/OFA Retrofit
Holcomb, Finney County, Kansas
Table 2.1: Applicable/Potentially Applicable State and Federal Air Quality Requirements

Source ID #	Source Description	State Regulations (K.A.R. 28-19-Section)																											40 CFR 60 NSPS Subparts					40 CFR 61 NESHAP Subparts											
		8	9	11	12	18	19	20	30	31	32	55	56	57	58	80	202	204	212	275	300-304	350	500-502	513	645	650	720	750	A	Da	Db	Y	III	A	M	40 CFR 64	40 CFR 68	40 CFR 72	40 CFR 73	40 CFR 75	40 CFR 76	40 CFR 77	40 CFR 82	40 CFR 98
	Facility Wide	A	A	A	A	A		A				A	A	A	A	A	A	A	A		A	A	A	A	A	A		P2	A					A	A		A							A	A
EU-MAINBOILER	Holcomb 1 Steam Generator				A	A	A	A	A	A	A									A		A				A	A	P2	A	A						A		A	A	A	A	A		

KEY TO MATRIX

A. Current applicable Requirement

- 1) The regulations have applicable requirements which apply to this particulate emission source.
  Example: NSPS Subpart GG - Standards of Performance for Stationary Gas Turbines would apply to a stationary gas turbine with a heat input of greater than 10 MMbtu/hr.
- 2) The emission source may have an exemption from control stated in the regulation. The emission source may not have to be controlled but may have monitoring, recordkeeping, or reporting requirements.
  Example: NSPS Kb for VOC Storage Vessels does not apply to a xylene tank, that has been modified since 7/23/84. The vapor pressure is <0.75 psia and no controls are required but recordkeeping is required.

P. Potentially Applicable Requirement

- 1) The regulations have applicable requirements which apply to this particular emission source, but the source is currently exempt from these requirements due to meeting a specific criteria, such as it has not been constructed, modified, or reconstructed since the regulations have been in place. If the specific criteria changes the source will have to comply at a future date.
  Example: NSPS Kb for VOC Storage Vessels does apply to an aromatics storage vessel if it has not been modified, or reconstructed since 7/23/84. Therefore, NSPS Kb is a potentially applicable requirement for the tank.
- 2) The regulations apply to this type of emission source (i.e., tank) but does not meet the definition for this particular emission source.
  Example: NSPS Kb for Petroleum Liquid Storage Vessels does not apply to an isopropyl alcohol storage vessel because it is not a petroleum liquid.

Blank - Not Applicable

The regulations clearly do not apply to this type of emission source.
Example: NSPS GG for Stationary Gas turbines does not apply to a cooling tower.

PART 3.0
KDHE CONSTRUCTION PERMIT APPLICATION FORMS

Kansas Department of Health and Environment
Bureau of Air and Radiation
Phone (785) 296-1570 Fax (785) 291-3953

Notification of Construction or Modification

(K.A.R. 28-19-300 Construction permits and approvals; applicability)

Check one: ☑ **Applying for a Permit under K.A.R. 28-19-300(a)** ☐ **Applying for an Approval under K.A.R. 28-19-300(b)***

1) Source ID Number: 0550023

2) Mailing Information:
   Company Name: Sunflower Electric Power Corporation
   Address: 301 West 13th Street
   City, State, Zip: Hays Kansas 67601

3) Source Location:
   Street Address: 2440 Holcomb Lane
   City, County, State, Zip: Holcomb, Finney County, Kansas 67851
   Section, Township, Range: Sections 29,30,31,32 Township 24S Range 33W
   Latitude & Longitude Coordinates: North 37° 55' West 100° 58'

4) NAICSC/SIC Code (Primary): 221112, Fossil Fuel Power Generation / SIC 4911

5) Primary Product Produced at the Source: Electricity

6) Would this modification require a change in the current operating permit for your facility? ☑ Yes ☐ No

   If no, please explain:

7) Is a permit fee being submitted? ☑ Yes ☐ No

   If yes, please include the facility's federal employee identification number (FEIN #) 01-0707918

8) Person to Contact at the Site: Paul Reynolds Phone: (620) 277-4522
   Title: Manager, Generation Engineering / Environmental

9) Person to Contact Concerning Permit: Paul Reynolds Phone: (620) 277-4522
   Title: Manager, Generation Engineering & Environment
   Email: preynolds@Sunflower.net Fax: (620) 277-4522

Please read before signing:

Reporting forms provided may not adequately describe some processes. Modify the forms if necessary. Include a written description of the activity being proposed, a description of where the air emissions are generated and exhausted and how they are controlled. A simple diagram showing the proposed activity addressed in this notification which produces air pollutants at the facility (process flow diagrams, plot plan, etc.) with emission points labeled must be submitted with reporting forms. Information that, if made public, would divulge methods or processes entitled to protection as trade secrets may be held confidential. See the reverse side of this page for the procedure to request information be held confidential. A copy of the Kansas Air Quality Statutes and Regulations will be provided upon request.

Name and Title :

Address:

Signature: Paul E. Reynolds Digitally signed by Paul E. Reynolds DN: cn=Paul E. Reynolds, o=Sunflower Electric Power Corporation, ou=Manager, Generation Engineering/ Enviornment, email=preynolds@sunflower.net, c=US Date: 2011.06.03 14:42:01 -05'00' Date: ___/___/_____ Phone: ( )

* If you do not know whether to apply for a permit or an approval, follow approval application procedures.

Procedures For Requesting Information To Be Held Confidential

March 15, 2006
Revision 6

An applicant may request that information submitted to the Department, other than emission data or information in any air quality permit or approval, be treated as confidential if the information would divulge methods or processes entitled to protection as trade secrets.

A request to designate information within the Department's air quality files as confidential must include:

(1) An uncensored copy of the document clearly marked as confidential;

(2) A copy of the document, or copies if more than one is required to be filed with the Department, with the confidential information masked;

(3) Specification of the type of information to be held as confidential (i.e., product formulations, process rates);

(4) Specification and justification of the reason the information is qualified by statute to be treated as confidential (competitive advantage, company developed secret formulation, trade secret); and

(5) A reference at each place in the document or documents where information is masked referring to the specification of the type of information masked and the specification and justification the information is qualified by statute to be treated as confidential.

ONLY THE CONFIDENTIAL INFORMATION ON ANY DOCUMENT MAY BE MASKED. ALL INFORMATION ON ANY DOCUMENT WHICH IS NOT CONFIDENTIAL MUST REMAIN LEGIBLE.

The information will be treated as confidential until the secretary has acted upon the request and the owner or operator has had the opportunity to exhaust any available remedies if the secretary determines the information is not confidential.

Complete this and all reporting forms and submit to:

Kansas Department of Health and Environment
Bureau of Air and Radiation
1000 SW Jackson, Suite 310
Topeka, KS 66612-1366
(785) 296-1570

Sources located in Wyandotte County should obtain forms from, and submit forms to:

Unified Government of Wyandotte County
Department of Air Quality
619 Ann Avenue
Kansas City, KS 66101
(913) 573-6700

CALCULATING THE CONSTRUCTION PERMIT APPLICATION FEE

[These requirements are found at K.A.R. 28-19-304(b).]

Calculate the construction permit application fee as follows:

Estimated capital cost of the proposed activity for which the application is made, including the total cost of equipment and services to be capitalized.	**Line 1** $_____	
Multiply by .05% (.0005)		x_____.0005
Total	**Line 2** $_____	
If Line 2 is less than $100, enter $100 on Line 3. If Line 2 is greater than $4,000, enter $4,000 on Line 3.		
Otherwise, copy Line 2 to Line 3.		
Construction permit application fee.	**Line 3** $ 4,000	Minimum fee is $100

Certifier of Capital Cost

(Print)

Paul E. Reynolds Digitally signed by Paul E. Reynolds DN: cn=Paul E. Reynolds, o=Sunflower Electric Power Corporation, ou=Manager, Generation Engineering/ Environment, email=preynolds@sunflower.net, c=US Date: 2011.06.03 14:42:20 -05'00'

(Signature) Date

K.A.R. 28-19-350 is a complex regulation pertaining to prevention of significant deterioration (PSD). An additional fee of $1,500 will be required if a PSD review is necessary. If you believe the proposed activity in this Notification of Construction or Modification will be subject to the requirements of K.A.R. 28-19-350, contact the Department for further evaluation.

For purposes of construction permit or approval applications, the following are not considered modifications:

1. Routine maintenance or parts replacement.
2. An increase or decrease in operating hours or production rates if:
   a. production rate increases do not exceed the originally approved design capacity of the stationary source or emissions unit; and
   b. the increased potential-to-emit resulting from the change in operating hours or production rates do not exceed any emission or operating limitations imposed as a permit condition.

Kansas Department of Health and Environment
Division of Environment
Bureau of Air and Radiation

INDIRECT HEATING UNIT (BOILER)

1) Source ID Number: 0550023

2) Company/Source Name: Holcomb 1, LLC

3) Emission Unit Identification: Holcomb Unit 1 Main Boiler (EU-MAINBOILER)

4) Manufacturer:_____Model No.:_____

5) Maximum design heat-input rate: 3,389,000,000 BTU/hr
   Heat-release Rate: _____ BTU/hr/cu. ft. of furnace volume
   Annual load factor: _____
   Heater design: Cyclone _____; Underfeed stoker _____; Spreader stoker _____;
   Pulverized (dry-tangential or normal/wet) XX; Other (specify) _____
   Normal Operating Schedule: _____ hours/year
   Date of latest modification: _____

6) Primary Fuel Type:
   Natural Gas ____ Oil ____Coal XX Other (specify) _____
   Secondary Fuel Type:
   Natural Gas ____ Oil ____ Coal ____ Other (specify) _____

7) If other fuel is waste liquid:
   What is the source of the waste? _____
   Will the waste be pretreated to remove any of the contaminants? Yes ____; No ____ If yes, describe method of pretreatment:
   _____
   _____
   If waste liquid is used in combination with fuel oil:
   Specify the volume percent of waste liquid:_____ %
   Specify the anticipated annual operating hours during which the fuel and waste combination will be used: _____ hrs.
   Fill in the data below for the fuel oil.

Include the chemical and physical characteristics of the waste liquid. Also, include any source emissions test data that is available from testing similar facilities that have disposed of this type liquid waste.

INDIRECT HEATING UNIT (BOILER)
(cont.)

8) Fuel Specific Data: (if other is specified, give appropriate data)

Natural Gas:

Heating value: 1,020 BTU/cu. ft.

(If fuel gas is used, also specify %Sulfur: _____)

Coal:

Fuel Parameters: %Sulfur: 0.29 % Ash: 5.06

Heating value: 8,620 BTU/lb.

Fuel Oil:

Fuel Parameters: %Sulfur: ____ Grade: _____

Heating value: _____ BTU/gal.

Density: _____ lb./gal.

9) Air Emissions Control Technology: NOx xx SOx xx CO xx Particulate xx

If yes, breakdown of Control Technology: NOX - Dry Low-NOx Burners, Overfire air; SOX - Dry flue gas desulfurization; CO - Good combustion practices; Particulate - Fabric filter

10) Soot blowing (if applicable): frequency: _____ duration: _____

11) Has boiler been derated because of:

Fuel change _____ Equip. limitations _____ Regulatory compliance _____

12) Emissions discharge to atmosphere 475 ft. above grade through stack or duct 16.33 ft. diameter at 180 ° F temperature, with 1,426,877 cfm flow rate and 113.5 fps velocity.

13) For emission control equipment, use the appropriate CONTROL EQUIPMENT form and duplicate as needed. Be sure to indicate the emission unit that the control equipment is affecting

14) Did construction, modification, or reconstruction commence after August 17, 1971 and on or before September 18, 1978 and does the indirect heating unit have a maximum design heat-input capacity to combust more than 250 million BTU/hour? Yes ☐; No ☑

If yes, this plant may be subject to NSPS, 40 CFR Part 60, Subpart D.

15) Did construction, modification, or reconstruction commence after September 18, 1978 and does the indirect heating unit have a maximum design heat-input capacity to combust more than 250 million BTU/hour? Yes ☑; No ☐

If yes, this plant may be subject to NSPS, 40 CFR Part 60, Subpart Da.

16) Did construction, modification, or reconstruction commence after June 19, 1984 and does the indirect heating unit have a maximum design heat-input capacity to combust more than 100 million BTU/hour but less than 250 million BTU/hour? Yes ☐; No ☑

If yes, this plant may be subject to NSPS, 40 CFR Part 60, Subpart Db.

INDIRECT HEATING UNIT (BOILER)
(cont.)

17) Did construction, modification, or reconstruction commence after June 9, 1989 and does the indirect heating unit have a maximum design heat-input capacity to combust 10 million or more BTU/hour but less than 100 million BTU/hour? Yes _____; No ✔

If yes, this plant may be subject to NSPS, 40 CFR Part 60, Subpart Dc.

PART 4.0
CONTROL TECHNOLOGY ANALYSIS

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1.0 Summary and Introduction

1.1 Summary of Conclusions

As discussed in Part 1.0, Sunflower is submitting a Prevention of Significant Deterioration (PSD) permit application consistent with K.A.R. 28-19-350. Any proposed construction at a major source having the potential to emit regulated pollutants at levels greater than the corresponding PSD significance levels is subject to PSD review, including a BACT analysis for each of these pollutants. The projected controlled net annual emissions change and PSD significance levels for H1 (steam generator) are shown in Table 4-1. The potential emissions for the H1 steam generator are based on continuous operation of the unit for an entire year (8,760 hours). Emissions from the H1 steam generator are at an assumed Maximum Continuous Rating heat input of 3,389 million Btu per hour (MMBtu/hr).

Table 4-1
H1 Project Annual Emissions Change

Pollutant	Baseline Emissions (tpy)	Project Potential Emissions (tpy)[D]	Net Emissions Change (tpy)	PSD Significance Level (tpy)	BACT Required
NO_X	4,687.2[A]	2,671.9	-2,015.3	40	No
CO	509.1[B]	3,711.0	3,201.8	100	Yes
CO_2	--[C]	--[E]	-5030.3[F]	75,000	No

Notes:

A. NO_X baseline emissions based on CEMS data from January 2006 – December 2010. Highest emissions in a 24-month consecutive period determined.
B. CO baseline emissions based on CEMS data from January 2006 – December 2010. Highest emissions in a 24-month consecutive period determined.
C. No baseline emissions for CO_2 were calculated.
D. Potential emissions based on revised emission levels for 8,760 hours annually.
E. Potential emission of CO_2 was not calculated.
F. Net emission change for CO_2 based on the direct molar ratio of CO to CO_2. As no new sources of carbon are being introduced to the system, the increase in CO will lead to a corresponding decrease in CO_2. Hence, baseline and project potential emissions are not relevant for this permit application.

As shown in Table 4-1, the controlled potential to emit for CO is greater than its respective PSD significance levels. This pollutant is subject to BACT review because it exceeds the PSD significance level. Appendix D shows in detail the calculations of this pollutant with respect to BACT significance levels.

A BACT analysis was performed using the "top-down" approach, which is described in USEPA guidance.[1] A summary of the BACT results is shown in Table 4-2. Modeling demonstrates that the 30-day averaging period is protective of the National Ambient Air Quality Standards (NAAQS). The use of

[1] "New Source Review Workshop Manual," Environmental Protection Agency, Office of Air Quality Planning and Standards, October 1990 Draft. (NSR Manual).

natural gas, good work practices, and the use of control technologies in accordance with manufacturer's instructions will minimize emissions during startup, shutdown, and malfunction events.

Table 4-2
H1 Steam Generator BACT Summary

Pollutant	Control Method	Emission Limit (lb/MMBtu)
CO	Good Combustion Practices	0.25

BACT for the Steam Generator

CO: Good combustion practices are the only feasible methods available to control CO emissions for a PC steam generator. Good combustion practices were selected as BACT for CO with a limitation of 0.25 lb/MMBtu. Compliance with CO limitations will be determined with a continuous emission monitor (CEM). For further information on the emission limit determinations, see Section 3.0.

1.2 Approach to BACT Determination

USEPA's NSR Manual identifies the basic steps of a "top-down" BACT analysis to guide the evaluation of control technologies for individual pollutants.

1. Identify and Evaluate Potential Control Options
2. Eliminate Technically Infeasible Options
3. Rank Remaining Technologies by Control Effectiveness (Includes consideration of performance as well as consideration of Energy, Environmental and Economic Impact
4. Evaluate Most Effective Controls and Document Results (case-by-case or site specific consideration of the available technologies)
5. Select BACT

Once the source is defined by the applicant, then the selection of the emission control technology is based on the "top down" BACT process preferred by USEPA. USEPA does not consider the BACT requirement a means to redefine the design of the source when considering available control alternatives. Rather it is a means of identifying appropriate control devices for the generation technology determined to be deployed. For example, applicants proposing to construct a coal-fired EGU have not been required by USEPA as part of a BACT analysis to consider building a natural gas-fired electric turbine even though the turbine may be inherently less polluting per unit product (in this case electricity).[2]

[2] Ibid: Section IV A.3. page B.13 This conclusion was recently restated and confirmed in a letter from USEPA's Office of Air Quality Planning and Standards, which says in part: "As noted in prior USEPA decisions and guidance, USEPA does not consider the BACT requirement as a means to redefine the basic design of the source or change the fundamental scope of the project when considering control alternatives". (Letter from Stephen Page, December 13, 2005 to Mr. Paul Plath of E3 Consulting, LLC).

The BACT determination looks at the available emission control technology for the type of source and completes an evaluation, eliminating those that are not feasible and then ranking those remaining based on control effectiveness and other factors. Feasibility considers the extent to which the technology has actually been found to be effective in similar applications.[3,4] The most effective controls are further evaluated with a project specific assessment of effectiveness, economic, energy and environmental impacts. The determination of BACT for a project, in terms of emission control level, is made utilizing comparisons to similar projects for the appropriate emission level. However, BACT for a proposed project is not necessarily the lowest emission limit recently established for another somewhat similar project. While the most effective level of control must be considered in the BACT analysis, different levels of control for a given control alternative can be considered.[5] Consideration may be given to the ability of users of a particular control technology to consistently achieve a given emission limit or percentage reduction. Technologies or emission limits which are not physically achieved may be excluded.[6] It is necessary, however, for the applicant to demonstrate the differences between the proposed project and the other sources to support the determination if a lower level of effectiveness is selected.

Where a control technology has been successfully applied to similar sources in a source category, an applicant should concentrate on documenting significant cost differences, if any, between the application of the control technology on those other sources and the particular source under review.[7] In some cases, site-specific criteria may drive emission limits to vary. For example, a source whose emissions would affect Class I areas or areas that are non-attainment for a criteria pollutant may be subject to requirements that are different from BACT or to environment/economic tradeoffs different from those applicable to H1. A project located in a non-attainment zone might select a control technology that is considered for BACT, but is required to meet LAER (lowest achievable emission rates). Technologies required under LAER determinations are available and must be included in the BACT analysis as control alternatives and usually represent the top alternative. In the course of the BACT analysis, however, one or more of the options may be eliminated from consideration because they are demonstrated to be technically infeasible or have unacceptable energy, economic, and environmental impacts on a case-by-case (or site-specific) basis.[8]

The ability of a given control alternative to control releases of unregulated toxic or hazardous emissions are evaluated and may, as appropriate, affect the BACT decision. Conversely, hazardous or toxic

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[3] Ibid: Section IV.A.1."DEMONSTRATED AND TRANSFERABLE TECHNOLOGIES: Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice."
[4] Ibid Section IV.B."TECHNICAL FEASIBILITY ANALYSIS (STEP 2): Innovative controls that have not been demonstrated on any source type similar to the proposed source need not be considered in the BACT analysis."
[5] Ibid: Section IV C. page B.23
[6] Ibid Section III.B page B 7. "For example, in cases where the level of control in a permit is not expected to be achieved in practice (e.g., a source has received a permit but the project was cancelled, or every operating source at that permitted level has been physically unable to achieve compliance with the limit),and supporting documentation showing why such limits are not technically feasible is provided, the level of control (but not necessarily the technology) may be eliminated from further consideration."
[7] Ibid: Section IV D.2, page B.31
[8] Ibid: Section III. A page B.5

emissions resulting from a given control technology are also considered and may, as appropriate, also affect the BACT decision.[9]

In the final analysis, the control equipment has to be evaluated as an integrated air pollution control system. The control technologies are interdependent, and reducing emissions for one pollutant may result in adverse impacts and higher emissions of another pollutant. As one example, some technologies that reduce NO_X emissions will unavoidably result in higher CO and VOC emissions due to reaction kinetics. This aspect is especially important to this permit application because the main reason to install the control technology is to reduce NO_X. The best overall air pollution control system utilizes the mix of control technologies that yields the optimal overall performance and lowest overall emission levels.

BACT limits must be practicably enforceable.[10] A key issue to whether numerical emission limits are enforceable as a practical matter during periods of startup, shutdown, or malfunction hinges upon whether emission tests conducted during such periods can be used to determine compliance. For coal-fired units, emission tests cannot be conducted with any degree of reliability during startup and shutdown events. A requirement for good air pollution control practices provides practical enforceability as well as an adequate basis to pursue enforcement for improper operation or maintenance.

The approach to startup, shutdown, and malfunction events generally taken by USEPA for Maximum Achievable Control Technology (MACT) and NSPS regulations, including the NSPS standards that apply to coal-fired boilers, is to address such events with a broad requirement to use good air pollution control practices. This approach is consistent with provisions in the definition of BACT that allow work practices to be set in circumstances where technological or economic limitations on measurement methodology make imposition of an emission standard infeasible. It simply reflects a different approach to addressing startup, shutdown, and malfunction events while retaining the maximum degree of control possible.

[9] Ibid: Section IV.D.3.b page B.50
[10] Ibid, Section V, page B.56

2.0 IDENTIFICATION AND SCREENING OF CONTROL OPTIONS

This section presents the results of control technology identification (USEPA Protocol Step 1); elimination of technically infeasible options (USEPA Protocol Step 2); and ranking of the screened technologies (USEPA Protocol Step 3) for all of the BACT pollutants for H1.

2.1 Identification of Control Technologies

In accordance with USEPA protocol for "top down" BACT determination, all demonstrated and all reasonably potentially applicable control technology alternatives have been identified. "Demonstrated technologies" is understood to mean technologies and/or emission limits for which there is substantial operating experience on similar sources from which to judge, among other factors, the variability and sustainability of performance over time. As noted, the determination of BACT is site-specific and therefore site-specific factors, such as the fuel used, enter into the consideration of demonstrated and applicable technologies. This includes inherently lower emitting processes, if demonstrations of commercial service with identical or similar fuels are documented.

USEPA's BACT protocol also includes evaluation of innovative technologies, and other add-on controls when applicable to the physical and chemical characteristics of the stack emission stream. The "top down" protocol has been in effect for coal power plants in the United States for more than 20 years. BACT development for these projects has resulted in competition between technologies to achieve the lowest, cost effective emission controls and has produced a set of commercially demonstrated, high efficiency technologies that are recognized as appropriate choices for coal-fired power plants. BACT identification for all applicable pollutants from H1 was, thus, based on an extensive examination of recent permits and demonstrations for similar coal-fired PC type power plants. Two main sources were reviewed to determine the control technologies and emission limits that were consistent with BACT:

- USEPA's RACT/BACT/LAER Clearinghouse (RBLC) database (determinations in the last six years (2005-present)).
- A focused study of similar NO_X retrofit projects, including permits, draft permits, and applications filed or issued in the last six years. In most permit applications, the applicant includes a list of similar projects in the BACT analysis. Sunflower reviewed these lists to identify additional NO_X retrofit projects that may be relevant.

In addition to those technologies that have been applied in recent US coal-fired power plants and incorporated in recent permits, other technologies are to be considered as part of a BACT analysis. The initial steps of a BACT analysis include identification of technology and elimination of those that are not feasible. Sunflower performed a review of the applicability of a range of technologies that have appeared in recent literature on emission controls for coal-fired power plants. Appendix D Table D-1 summarizes the results of this review. Those technologies given detailed consideration in this BACT analysis are noted in the Appendix D Table D-1, as well as others that are not appropriate for more detailed consideration.

2.1.1 RBLC Database

The RBLC database is a repository of data maintained by USEPA containing information pertaining to PSD air permits issued in the United States and its territories. The RBLC database was reviewed to identify recent BACT determinations for similar projects. This database is maintained on USEPA's Technology Transfer Network website on the Internet at www.epa.gov/ttn/catc. Advanced queries of the database were conducted to identify control technology determinations previously made for sources similar to the H1 steam generator. These queries were conducted for RBLC permits issued from January 2005 through April 2011.

Facilities similar to H1 were identified from the RBLC query for the comparative analysis. Specifically, prior BACT determinations for solid fuel steam generators burning pulverized coal were identified. Appendix D provides a summary of the CO emission limitations identified in the RBLC as BACT for comparable projects. All of the BACT controls were listed as good combustion practices or a similar phrase. There were nine similar projects identified in the RBLC that have been permitted since January 2005. Refer to Appendix D, Table D-1, for detailed summaries of the power plant units listed in the RBLC and the associated CO emission limits.

2.1.2 Study of Similar Project Permits and Applications

Sunflower conducted a thorough study of other information available on similar NO_X retrofit projects for PC power plants. The study was limited to projects with published applications, draft permits, or permits issued after 2005. The goal of this study was to identify the very latest BACT levels, whether final or proposed, and consider these in this updated and consolidated BACT determination. For CO, summaries of permit limitations for recent projects are presented below. The permit limitation summary tables list information for final permits only.

Sunflower reviewed CO emission limits in air permits for similar LNB/OFA installation projects in order to frame the proposed CO emission limit for the H1 LNB Project relative to installations at other existing coal-fired units. Note that CO limits for new units were not considered. NO_X reduction components are an inherent aspect of the design of new units, whereas, the LNB technology selected by Sunflower for Holcomb 1 was not available when Holcomb 1 was fabricated and thus must be "added on." As is demonstrated below, there have been numerous installation projects at existing units that provide an adequate sample from which to establish past CO emission limit precedents.

2.1.3 Ranking of Screened Emission Control Technologies

Table 4-3 summarizes BACT technologies selected for all projects listed in the permit limitation summary tables presented in the sections below and ranks them from the highest to lowest permitted emission limitation. Appendix D Table D-1 provides a summary of the projects considered in this BACT analysis a comparison to the proposed H1 modifications.

Table 4-3, and the permit limitation summary tables that follow, take into account facilities similar to H1 that Sunflower identified from the RBLC query and Sunflower's research of permits/applications. A brief summary of observations from the results presented in Table 4-3 follows.

The permit limitation summary table upon which the Table 4-3 results are based is limited to existing coal-fired units. No technology other than "good combustion practices" has been identified as BACT for CO emissions from the RBLC query or the permit research.

Table 4-3
Technology Ranking for Pulverized Coal-Fired Steam Generators

Pollutant	Number of Units	Control Technology Description Associated with BACT Emission Limit	Range of Emission Limits (lb/MMBtu) [A]
CO	27	Good Combustion Practices	0.15 – 1.63

Notes:

G. A range of emission limitations for a particular control technology is indicated. Each power plant unit has a unique emission limitation (i.e., the emission limitation is not a range of emissions).

3.0 CARBON MONOXIDE (CO)

CO emissions are a product of incomplete combustion. The formation of CO results when there is insufficient residence time at high temperature or incomplete mixing to complete the final step in fuel carbon oxidation. These emissions are controlled through managed combustion practices including high temperatures, adequate excess air and residence time, and optimal fuel/air mixing during combustion. Note that in the case of CO emissions, it is not possible to minimize these emissions without regard to increases in emissions of other pollutants, particularly NO_X. Control of CO is accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion.

3.1 Selection of Control Technologies

A review of potential control technologies is provided in Appendix D of this application (see Appendix D, Table D-1). Table D-1 identified and eliminated the following CO control technologies:

- Recuperative Thermal Oxidation
- Flares
- Afterburners

In addition, Regenerative Thermal Oxidation (RTO) and catalytic oxidation have been examined below in more depth as a possible CO control option. Both RTO and catalytic oxidation were found to be infeasible as a CO control method for the steam generator due to critical technical problems. As a result, both have been eliminated as an appropriate control technology for the H1 steam generator.

Good combustion practices have been selected as the CO control technology for the H1 steam generator.

3.1.1 Evaluation of Control Technology

The highest level of emissions reduction would be through the use of an oxidation catalyst. Oxidation catalysts have been used with success on combined-cycle combustion turbines when situated at the appropriate location within the heat recovery unit. In these systems, control efficiencies on CO can be 90 percent or greater. However, oxidation catalysts are not available for use on a solid-fuel fired steam generator. Catalytic oxidation for CO is not technically feasible for a number of reasons. First, the oxidation catalyst is not discriminatory and does not distinguish between CO and other molecules. As such, the catalyst has the tendency to oxidize SO_2 to SO_3, thereby increasing the amount of H_2SO_4 in the exhaust stream. Acid gases and metals present in the gas stream, even in minute quantities, have the ability to poison the catalyst and render it inactive. Finally, due to the high amount of PM present in the flue gas stream, the ash acts as a scouring mechanism, plugging and eroding the catalyst after a very brief period of operation, resulting in extremely high operational and maintenance costs to effect more frequent catalyst replacement. Because of these critical technical problems, oxidation catalysts have been eliminated as a control technology option for CO control.

Thermal oxidation is used in many industries to reduce CO and VOC emissions, but thermal oxidizers are not usually used to control combustion emissions. However, an RTO system is used by TXI Operations, LP (TXI) to control emissions from a cement kiln at its Midlothian, Texas facility. TXI's experience using RTO for controlling CO and VOC emissions from its No. 5 Kiln has resulted in various operating issues including high back pressures, high operating costs due to supplemental natural gas firing, and production curtailment for RTO maintenance. It should be noted that RTO was rejected as BACT by the TCEQ as economically unreasonable. However, TXI entered into a settlement agreement with private parties who objected to the kiln to operate it with an RTO system.

Even if this application of thermal oxidation to control combustion emissions had been more successful, there are differences between the design and operation of coal-fired steam generators and the design and operation of kilns at Portland cement plants, which affect the practicality of "technology transfer" of RTO systems. Specifically, the flue gas flow rate from the H1 steam generator will be much higher than from cement kilns and the CO emission concentrations from the H1 steam generator will be much lower than from cement kilns.

The lower flue gas flow rate at cement kilns means that the scale of the RTO equipment is much smaller at a cement kiln than what would be required at a coal-fired steam generator. Even at this smaller scale, the TXI RTO system is one of the largest RTOs in service. The scale-up of the TXI equipment to the size that would be necessary for the H1 steam generator represents a significant and unacceptable technical risk, especially when applied to a new process category.

No instances of a thermal oxidation system being used to control emissions from a gas stream similar in makeup to the H1 coal-fired steam generator have been identified. As such, thermal oxidation has been determined to be technically infeasible and has been eliminated as a potential control option.

In addition to the technical difficulties with installing an RTO system that make it infeasible as a potential BACT candidate, the installation of RTO equipment on the existing coal-fired steam generator would require significant increases in energy requirements due to the higher fan power requirements as well as natural gas consumption for thermal oxidation of CO. Due to the higher auxiliary electrical load, increased coal-firing would be required to maintain the same net electrical output of the new generating unit without an RTO system. This would essentially increase all air emissions from the steam generator, to attain marginal and uncertain reductions in CO. The natural gas burners used in the RTO system could also increase emissions of NO_X.

The only feasible method identified to control CO emissions from a coal-fired steam generator entails the use of appropriate combustion control techniques. The RBLC database identifies no other CO control techniques for pulverized coal units.

CO emissions can be controlled by good combustion practices to minimize CO formation in the steam generator. Recent burner improvements which enable lower NO_X emission levels at the furnace outlet are achieved by designing for rich fuel-air mixtures in the primary combustion zones of the individual burners. Increased CO levels at the furnace outlet are the result. Achieving a CO emission reduction at

the expense of increasing NO_X emission levels is generally not encouraged by regulatory agencies. Simultaneously balancing low CO and NO_X emission levels at the steam generator outlet is an appropriate consideration in the steam generator design and operation.

3.1.2 Environmental Considerations

Environmental impacts are a consideration in the determination of the appropriate control technology for CO. For the technologies that have been determined to be technically feasible as control options, an analysis of the environmental considerations is discussed below.

Operating the steam generator to achieve lower CO emission level results in higher NO_X emissions. Generally, reducing NO_X emissions is considered to be more important than achieving lower CO emissions. There are no environmental issues that would preclude the use of good combustion practices for the steam generator.

3.1.3 Energy Considerations

There are no energy issues that would preclude the use of good combustion practices for the steam generator.

3.1.4 Economic Considerations

There are no economic considerations that would eliminate good combustion practices as a method to control CO from the steam generator.

3.2 CO BACT Emission Limitations Determination

In determining the CO BACT emission limitation, it is necessary to take into account the fact that CO and NO_X emissions are interdependent variables and are affected simultaneously by changes in combustion conditions. Accordingly, selection of the BACT CO emission limitation was approached in a holistic fashion, recognizing the interrelationships in the formation, relative level of concern, and impact of each of the two pollutants.

Sunflower has determined the BACT emission limitation for CO for the steam generator to be 0.25 lb/MMBtu on a 30-day rolling average basis, including periods of startup and shutdown. CO emissions will be verified by a CEMS. Short-term averaging periods are not warranted, because modeling has demonstrated there are no significant impacts (see Part 5.0).

Reducing the CO emission level below that guaranteed by the vendors can result in an increased level of steam generator water-wall tube wastage and thus premature tube failure. This wastage is less significant when fuel sulfur content is low, as it is for H1, but the additional operational and maintenance costs that would result weigh against lower CO emission limitations.

NO_X emissions from coal-fired steam generators are typically of greater concern to regulators. Altering combustion conditions to reduce NO_X emissions will increase the creation of CO. As such, the level to

which CO emissions can be reduced is limited by the need to minimize NO_X emissions and the main purpose of the pollution control project is to reduce NO_X emissions from H1.

Steam generators are designed to meet multiple objectives including thermal efficiency, reliability of operation, and overall flame stability. Combustion conditions are carefully tailored to avoid damage to the steam generator walls and other surfaces to maintain reliability of operations. In addition, thermal efficiency would be degraded significantly if extraordinary amounts of excess combustion air are used to minimize CO emissions. As designing and operating a steam generator to minimize CO emissions at the expense of increased NO_X emissions has not been demonstrated, this approach to determining the BACT emission limitations for CO was not used.

Additionally, there is also a difference in CO formation due to operational differences between steam generators firing western low-sulfur coal and those firing high sulfur bituminous coals. The operators of many high-sulfur bituminous steam generators are more concerned with keeping all regions of the furnace in an oxidizing environment to protect the steam generator from corrosion associated with burning high sulfur coal. Operating the steam generator in this fashion can result in lower furnace CO.

Table 4-4 provides the CO limits established for similar LNB/OFA installation projects and other relevant information such as unit size and permit date. The list includes 21 projects, six of which were located in Kansas with permit dates spanning October 2005 to April 2011.

Some projects were identified from the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC). A search was conducted for all entries with permit issuance dates in the last six years (permit date between January 2005 through April 2011) for all coal units greater than 250 MMBtu/hr (Process Type = 11.110) with a numerical CO emission limit provided. This list was culled down to large coal-fired utility boilers that underwent LNB/OFA installation projects. Nine of the 21 projects listed in Table 4-4 were also included in the RBLC. Some of the projects listed in Table 4-4 involved multiple units, therefore, there are 27 units listed in Table 4-4.

The RBLC list was supplemented with projects identified via an internet permit search and with projects lists provided in LNB/OFA installation project air permit applications. The BACT determinations for all of these projects listed good combustion practices as BACT.

The CO limits in Table 4-4 range from 0.15 lb/MMBtu[11] to 1.63 lb/MMBtu.[12] CO limits for the projects located in Kansas ranged from 0.17 lb/MMBtu[13] to 0.319 lb/MMBtu.[14] In reviewing the information, it is

[11] Item #26 – Boswell Energy Center and Item #27 – Stanton Energy Center Unit 2

[12] Item #1 – Neal Energy Center North Boiler 2

[13] Item #24 – Nearman Creek

[14] Item #14 – LaCygne

important to note which units are installing additional controls for NO_X reductions (i.e., SCR) which results in a lower NO_X emission rate than the LNB/OFA technology installed alone.

Table 4-5 shows that many of the CO emission limitations for similar NO_X retrofit projects are higher than the proposed CO BACT level of 0.25 lb/MMBtu. Of the projects that have lower CO limits, either the project has a lower NO_X level than the anticipated H1 NO_X level of 0.18 lb/MMBtu because the project includes SCR or the project has a NO_X level much higher than 0.18 lb/MMBtu. The only exception to this pattern is that the Jeffrey Energy Center units are limited to 0.25 lb/MMBtu for CO but have a lower NO_X level, that is, 0.15 lb/MMBtu. This lower NO_X level of 0.15 lb/MMBtu is not relevant to the H1 retrofit project because it was established under a Regional Haze Agreement between Westar Energy and KDHE. This NO_X limit is the presumptive BART NO_X level established in the BART Guidelines for tangential-fired units firing subbituminous coal.[15] Also, it should be noted that the JEC units are tangentially fired, which are inherently lower NO_X emitters as compared to wall fired units such as H1. A similar presumptive BART NO_X level for H1 (dry-bottom, wall-fired firing subbituminous coal) is 0.23 lb/MMBtu, which is much higher than the anticipated H1 NO_X level after installation of the retrofit controls.

3.2.1 CO BACT During Startup and Shutdown

Sunflower has determined the BACT emission limitation for CO for the steam generator is 0.25 lb/MMBtu on a 30-day rolling average basis, including periods of startup and shutdown. CO emissions will be verified by a CEMS.

Table 4-4
Similar Project CO Limits

Item	Plant	Unit	Permit Date	Heat Input (MMBtu/hr)	Size (MW)	State	CO Limit (lb/MMBtu)	Averaging Period
1	Neal Energy Center North	Boiler 2	Sept 2007	3,081	349	IA	1.63	3-hr (no SU/SD)
2	Neal Energy Center North	Boiler 1	Dec 2005	1,363	147	IA	1.26	3-hr (no SU/SD)
3	Neal Energy Center North	Boiler 3	Aug 2005	5,021	515	IA	1.26	1-hr (no SU/SD)
4	New Madrid Power Plant	Unit 1	Sept 2006	7,150	615	MO	0.55	30-DRA (no SU/SD)
5	New Madrid Power Plant	Unit 2	Sept 2006	7,150	615	MO	0.55	30-DRA (no SU/SD)
6	Gerald Gentlemen Station	Unit 1	Aug 2006	7,538	681	NE	0.50	30-DRA (no SU/SD)
7	Gerald Gentlemen Station	Unit 2	May 2010	7,538	681	NE	0.50	30-DRA (no SU/SD)

[15] Appendix Y to 40 CFR Part 51—Guidelines for BART Determinations Under the Regional Haze Rule, TABLE 1.—PRESUMPTIVE NOX EMISSION LIMITS FOR BART-ELIGIBLE COAL-FIRED UNITS, Federal Register, July 6, 2005 (70 FR 39172).

Item	Plant	Unit	Permit Date	Heat Input (MMBtu/hr)	Size (MW)	State	CO Limit (lb/MMBtu)	Averaging Period
8	Quindaro Power Station	Unit 2	Apr 2011	--	158	KS	0.42	30-DRA (w SU/SD)
9	Neal Energy Center South	Boiler 4	Sept 2005	6,900	640	IA	0.42	Calendar Day (no SU/SD)
10	James River Power Station	Unit 3	Mar 2007	496	44	MO	0.35	30-DRA (no SU/SD)
11	James River Power Station	Unit 4	Mar 2007	600	60	MO	0.35	30-DRA (no SU/SD)
12	James River Power Station	Unit 5	Mar 2007	1,000	105	MO	0.35	30-DRA (no SU/SD)
13	Boardman Power Plant	Unit 1	Dec 2010	--	584	OR	0.35	30-DRA (no SU/SD)
14	La Cygne Generating Station	Unit 2	Apr 2011	7,700	685	KS	0.319	None (w SU/SD)
15	M.L. Kapp Generating Station	Boiler 2	Jan 2008	1,932	218	IA	0.289	30-DRA (no SU/SD)
16	Tecumseh Energy Center	Unit 7/9	Mar 2008	1,102	82	KS	0.25	30-DRA (no SU/SD)
17	Tecumseh Energy Center	Unit 8/10	Mar 2008	1,911	150	KS	0.25	30-DRA (no SU/SD)
18	Jeffrey Energy Center	Unit 1	Feb 2008	8,262	720	KS	0.25	30-DRA (no SU/SD)
19	Jeffrey Energy Center	Unit 2	Feb 2008	8,262	720	KS	0.25	30-DRA (no SU/SD)
20	Jeffrey Energy Center	Unit 3	Oct 2005	--	720	KS	0.25	30-DRA (no SU/SD)
21	Big Bend Station	Unit 4	Jan 2008	4,330	486	FL	0.2	30-Boiler DRA (w SU/SD)
22	C.D. McIntosh, Jr. Power Plant	Unit 3	Mar 2007	3,640	364	FL	0.20	30-Boiler DRA (w SU/SD)
23	Stanton Energy Center	Unit 1	Feb 2008	4,286	468	FL	0.18	30-DRA (w SU/SD)
24	Nearman Creek Power Station	Unit 1	Apr 2011	--	261	KS	0.17	30-DRA (w SU/SD)
25	Ottumwa Generating Station	Boiler 1 [A]	Jan 2010	6,370	726	IA	0.163	30-DRA (no SU/SD)
26	Boswell Energy Center	Boiler 4	Jul 2010	6400	558	MN	0.15	30-DRA (no SU/SD)
27	Stanton Energy Center	Unit 2	Feb 2008	4,286	468	FL	0.15	30-DRA (w SU/SD)

Notes:

A. Fires wood residue also

Table 4-5
CO / NO_X Limits and Technologies

Item	Plant	Unit	CO Limit (lb/MMBtu)	NO_X Limit (lb/MMBtu)	NO_X Controls
1	Neal Energy Center North	Boiler 2	1.63	3,931 tpy	LNB/OFA
2	Neal Energy Center North	Boiler 1	1.26	2,985 tpy	OFA
3	Neal Energy Center North	Boiler 3	1.26	0.30 (30-DRA)	LNB/OFA
4	New Madrid Power Plant	Unit 1	0.55	--	OFA, SCR
5	New Madrid Power Plant	Unit 2	0.55	--	OFA, SCR
6	Gerald Gentlemen Station	Unit 1	0.50	0.23 (30-DRA)[A]	LNB/OFA
7	Gerald Gentlemen Station	Unit 2	0.50	0.23 (30-DRA)[A]	LNB/OFA
8	Quindaro Power Station	Unit 2	0.42	0.18[E]	LNB/OFA
9	Neal Energy Center South	Boiler 4	0.42	0.70 (3-hr roll)	LNB/OFA
10	James River Power Station	Unit 3	0.35	0.35[B]	ULNB, HERT[D]
11	James River Power Station	Unit 4	0.35	0.35[B]	ULNB, HERT[D]
12	James River Power Station	Unit 5	0.35	0.35[B]	ULNB, HERT[D]
13	Boardman Power Plant	Unit 1	0.35	0.70 (3-hr block)	LNB/OFA
14	LaCygne Generating Station	Unit 2	0.319	0.13[C]	LNB, OFA, SCR
15	M.L. Kapp Generating Station	Boiler 2	0.289	0.45 (30-DRA)	LNB/OFA
16	Tecumseh Energy Center	Unit 7/9	0.25	0.18[C]	LNB/OFA
17	Tecumseh Energy Center	Unit 8/10	0.25	0.18[C]	LNB/OFA
18	Jeffrey Energy Center	Unit 1	0.25	0.15[C]	LNB/OFA
19	Jeffrey Energy Center	Unit 2	0.25	0.15[C]	LNB/OFA
20	Jeffrey Energy Center	Unit 3	0.25	0.15[C]	LNB/OFA
21	Big Bend Station	Unit 4	0.2	0.10 (30-DRA)	LNB/OFA, SCR
22	C.D. McIntosh, Jr. Power Plant	Unit 3	0.20	0.22 (annual)	LNB/OFA, SCR
23	Stanton Energy Center	Unit 1	0.18	0.60 (30-DRA) 0.46 (annual)	LNB/OFA
24	Nearman Creek Power Station	Unit 1	0.17	0.26[E]	LNB/OFA
25	Ottumwa Generating Station	Boiler 1	0.163	0.25 (12-mo roll)	ZoloBoss Control System
26	Boswell Energy Center	Boiler 4	0.15	0.70 (3-hr) 0.40 (annual)	ROTA-Mix SNCR
27	Stanton Energy Center	Unit 2	0.15	0.17 (30-DRA)	LNB/OFA, SCR

Notes

A. Emissions from 1 and 2 averaged together. SU/SD also applies
B. May 1 – September 30 each year
C. Regional haze agreement
D. High Energy Reagent Technology (HERT) system uses urea as the reagent
E. No limit associated with PSD permit. Manufacturer guarantee.

PART 5.0
AIR DISPERSION MODELING ANALYSIS

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1.0 Air Quality Analysis

1.1 Executive Summary

Sunflower is proposing to construct and operate new low nitrogen oxide burners (LNB) and Overfire Air (OFA) system on the existing Holcomb 1 steam generator system (H1). Air dispersion modeling is required to demonstrate that the project will not cause or contribute to an exceedance of the National Ambient Air Quality Standards (NAAQS) or the Prevention of Significant Deterioration (PSD) Increment for any criteria pollutant. The modeling demonstration is included in the following sections and summarized here. The final results of the air dispersion modeling indicate that the emissions increase of CO will not exceed the significance threshold, and therefore the Holcomb 1 LNB.OFA retrofit will not cause or contribute to an exceedance of the NAAQS. The final modeling results and a detailed description of the process and methodology used to arrive at the results are included in this Part.

1.2 Introduction

The proposed project consists of the addition of LNB and OFA on the existing Holcomb 1 steam generator system (H1). Emission source for the proposed project includes the PC steam generator, which operates on PRB coal.

The Holcomb Generating Station is located near Holcomb, Finney County, Kansas; a site location map is provided in Appendix B. Finney County is designated as an attainment area for all criteria pollutants by the KDHE. In an attainment area, any major modification is required to submit a PSD application. As part of a PSD permit application, K.A.R. 28-19-350 requires comparisons of criteria pollutants impacts to the PSD significant impact, PSD increment, and NAAQS levels. Sunflower is submitting this section to address the air quality analysis conducted for H1.

1.3 PSD Air Impact Analysis Applicability

In accordance with the requirements of K.A.R. 28-19-350, PSD permit applications must contain an analysis of ambient impacts associated with the proposed new source or modification. Analysis is conducted for those pollutants that exceed the significant net increase defined by K.A.R. 28-19-16a. The analysis presented assesses project related impacts and follows USEPA and KDHE guidelines for determining compliance with State air quality standards, NAAQS, and PSD increment consumption.

The analysis of ambient air impacts was conducted through air dispersion modeling. Per K.A.R. 28-19-350, analysis through air dispersion modeling is required for PSD applicable pollutants which exceed the significant emission rate defined in K.A.R. 28-19-200(eee).

Figure B-2 in Appendix B shows a conceptual diagram for the Holcomb Generating Station with the addition of the new Holcomb 2 steam generator and associated equipment (H2) to the site.[1] This site layout was the basis for the modeling compliance demonstration. The PSD Significance Determination for the proposed project reveals a significant net emissions increase for CO as shown in Table 5-1.

Table 5-1
Summary of Project Emission Rates (tpy)

Pollutant	Baseline Emissions (tpy)[A]	Project Potential Emissions (tpy)[B]	Net Emissions Change (tpy)	PSD Significance Level (tpy)	Modeling Required
CO	509.1	3,711.0	3,201.8	100	Yes

Notes:
A. CO baseline emissions based on CEMS data from January 2006 – December 2010. Highest emissions in a 24-month consecutive period determined.
B. Potential emissions based on revised emission levels for 8,760 hours annually.

1.4 Significant Impact Modeling

The initial step in modeling for PSD applications is the preliminary analysis of the impact of the increase of criteria pollutants due to the proposed project. The preliminary analysis determines whether the applicant can forego further air quality analyses for a particular pollutant, determines applicability of ambient monitoring requirements, and defines the significant impact area utilized in full impact analysis where applicable. The net increases modeled for each pollutant are then compared to the PSD significance level for each applicable averaging period. Table 5-2 lists the PSD Significance Impact Levels listed in KAR 28-19-350, as well as the NAAQS [40 CFR 50], Significant Monitoring Concentration [40 CFR 52.21(i)(5)(i)], and the PSD Class II Increment [40 CFR 52.21(c)].

Table 5-2
PSD Class II Increment, NAAQS, and Significance Levels (µg/m^3)

Pollutant	Averaging Period	NAAQS	Significant Impact Level	Significant Monitoring Concentration	PSD Class II Increment
CO	8-hour	10,000	500	575	NA
	1-hour	40,000	2000	NA	NA

[1] Discussions with KDHE and USEPA indicated that due to the recently issued PSD permit for H2, all structures and associated equipment with the H2 project should be included in the air dispersion modeling for the H1 modification.

The emissions increase for the project is associated with the addition of LNB/OFA to the PC unit. The emissions increases include the proposed unit's maximum potential to emit hourly emission rates based upon federally enforceable operating limits. Additionally, per 40 CFR 51 Appendix A to Appendix W, should the stack parameters change in association with operating conditions (variations in base load) leading to higher ground level concentrations, the worst-case scenario must be modeled. Sunflower opted to model all feasible operating scenarios and as such, effectively modeled these conditions. If the screening run did not exceed the significance level at any off site receptor, no further modeling was conducted. In all cases, for the preliminary analysis, the maximum impact was used.

1.5 Air Impact Assessment Methodology

Sunflower conducted the modeling in accordance with the Kansas Department of Health and Environment (KDHE) approved modeling procedures. Specifically, the PSD application modeling procedure for screening determination of the proposed project impact for criteria pollutants meeting the significance level was utilized for this modeling exercise. The methodology included analysis for compliance with the NAAQS.

1.5.1 Modeling Program

The emissions were modeled using the latest version (11126) of AERSCREEN. AERSCREEN is the screening version of AERMOD. Unlike AERMOD, AERSCREEN can estimate concentrations without the need for meteorological data. A collaboration between the USEPA and State modelers, AERSCREEN was produced to give the user two options for modeling: either by using the command-prompt interface to give a more automated process for the user or by using the MAKEMET program which gives the user more flexibility for defining receptors. Sunflower utilized the command-prompt interface of the AERSCREEN model for this air quality impact analysis because the MAKEMET approach is more appropriate for an area with a more complex terrain than that surrounding Holcomb.

1.5.2 Urban or Rural Dispersion Option

The USEPA prescribed Auer land use classification procedure was used to determine the appropriate model setting. The procedure requires a land use evaluation of the area surrounding the proposed facility within a three kilometer (km) radius. A United States Geological Survey (USGS) land use and land cover map of the area (Figure B-1 in Appendix B) was used for the evaluation. As shown in Figure B-1, the surrounding area is predominately rural (less than 50 percent of land use is classified as heavy industrial, light-moderate industrial, commercial, or compact residential). Given the facility's predominantly rural setting, the H1 source was modeled as a rural source.

1.5.3 Land Use and Terrain

A review of the land use within a 3 km radius of the proposed facility location was performed using the USGS land use map of the area. In accordance with the Auer land use classification procedure, the dispersion environment within a 3 km radius of the site is rural. The terrain in the vicinity of the facility is relatively flat therefore the terrain was not included in the modeling.

1.5.4 Meteorology

AERSCREEN estimates concentrations without the need for the user to input meteorological data. The "regulator default" settings for minimum and maximum temperature, minimum wind speed, and anemometer height were used to determine the meteorology in this model. The meteorology was calculated using the AERMET seasonal tables. Being in western Kansas, the surface characteristics option had the number six selection of "Grassland." The dominant surface profile is average moisture since western Kansas is not classified as an arid region.

1.5.5 Receptors

Receptors were placed so that the maximum offsite ground-level concentrations could be determined. The only receptor information that AERSCREEN requires in its command-prompt user interface program is the maximum receptor distance, the distance to the fence line, and the height of any flagpole receptor. The closest fence line to H1 is at a distance of approximately 1,300m. That value was used as the minimum distance to ambient air in the AERSCREEN program. For the maximum distance to a receptor, a value of 10 km was used since this was the furthest receptor spacing requested by KDHE (500m apart for distances >10,000m). Flag pole receptors were not input in the model.

1.5.6 Good Engineering Practice Stack Height

Sources included in a PSD permit application are subject to Good Engineering Practice (GEP) stack height requirements outlined in 40 CFR §51.100, 40 CFR §51.118, and KAR 28-19-18a through 18f. A GEP analysis was conducted for the existing H1 stack. The purpose of this evaluation was to determine if the discharge from a stack would become caught in the turbulent wake of a "nearby" building or other structure, resulting in downwash of the plume. Downwash of the plume can result in elevated ground-level concentrations. The procedure is based on EPA's *Guideline for Determination of Good Engineering Practice Stack Height* (EPA 1985), the Stack Height Regulations (40 CFR 51), and current Model Clearinghouse guidance. GEP stack height, for stacks constructed after January 12, 1979, is defined as the greater of

- 65 meters, measured from the base of the stack and
- Stack Height calculated from the following formula:

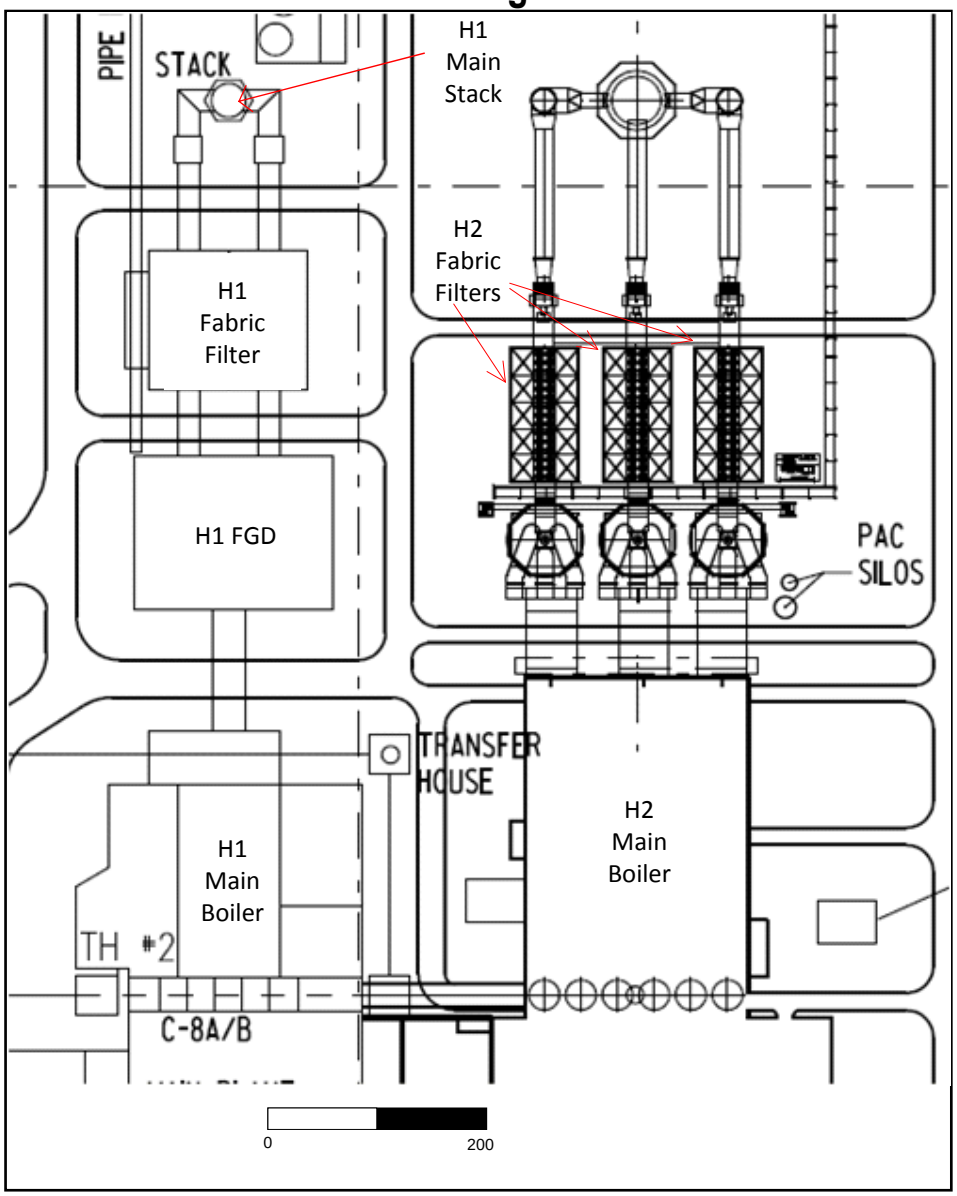
$$H_G = H + 1.5L,$$

Where, H_G = the GEP Stack Height
H = the height of the "nearby" structure
L = the lesser of the building height or the greatest crosswind distance of the building - also known as maximum projected width.

The only stack affected by this project is the existing H1 steam generator stack, which has an actual height above 65 meters. This stack will not be modified for this project.

The term "nearby" is defined as a distance up to 5L (L defined above) from the proposed stacks. As seen in Figure 5-1 there is more than one structure within 5L to the existing H1 steam generator stack; thus the stack height (H_G) based on each of these structures was calculated.

Figure 5-1
H1 Stack and Surrounding Structure Locations



As seen in Table 5-3, there are several structures "nearby" to the H1 stack that can influence the stack height, and this table shows the calculated GEP Stack Heights based upon the structures. The GEP Stack Height for the stack is dependent upon the new steam generator building structures. The calculated GEP Stack Height for the H1 steam generator stack is 206.4 meters (677.2 feet) based on the H2 Boiler

Building. Therefore, the full physical stack height of 475 feet above grade for the H1 steam generator stack is creditable for modeling purposes.

Table 5-3
GEP Stack Height Analysis Data

Structure	Height (m)	Width (m)	Length (m)	Projected Building Width (m)	Region of Influence (m)	Distance to Stack (m)	GEP Stack Height (m)
H1 Boiler	71.0	50.0	53.5	69.4	250.0	177.1	175.1
H1 FGD	40.5	54.9	43.3	54.9	202.5	100.7	101.4
H1 Baghouse	28.4	43.8	39.4	43.8	142.0	41.7	70.9
H2 Boiler	82.3	70.1	56.4	83.0	282.0	213.6	**206.4**
H2 Baghouse	30.5	19.3	38.4	36.5	96.5	104.9	76.8

1.5.7 Sources of Emissions

The H1 steam generator is being modified with the installation of LNB as a part of this permit application. As such, it was the only source included in the significant modeling analysis.

1.6 Load Analysis

Modeling runs were conducted at full load and part loads to confirm that operation of the steam generator would not result in impacts greater than the NAAQS or PSD increments. The H1 steam generator load (and consequently the hourly emission rates) was modeled at four different points (100%, 75%, 50% and 25%) to account for varying loads and process conditions. This methodology accounted for all worst-case conditions that can be experienced at the facility.

In addition, this load analysis accounted for emissions during startup and shutdown operations. During startup, the main boiler is first fired on natural gas until it reaches the appropriate conditions, after which a coal fire is established in the steam generator. The low load conditions (25% and 50%) accounted for these conditions. Similarly, when the unit is shutting down, the load in the boiler is gradually decreased until no fuel is fed to the boiler. The low load conditions (25% and 50%) accounted for these conditions.

Table 5-4
Steam Generator Stack Parameters at Modeled Load Levels

Load	Stack Height (ft)	Stack Diameter (ft)	Flue Gas Exhaust Temperature (°F)	Flue Gas Exit Velocity (ft/sec)
100%	475	16.33	180	113.5
75%	475	16.33	180	85.2
50%	475	16.33	180	56.8
25%	475	16.33	180	28.4

The modeled emission rate was set at 1.0 grams per second (1 g/s) for all load cases. As only one source is being modeled, this was done such that the results of the model are directly scalable to this rate, and multiple emission rates do not need to be considered. The resulting concentration that is predicted by the AERSCREEN model (in micrograms per cubic meter) can be directly multiplied by the proposed emission rate for H1 (in g/s) to arrive at a corresponding concentration.

2.0 Screening Modeling Results

AERSCREEN was run using the parameters and methodology described in Section 1. The results of the initial screening modeling indicates that for CO impacts are below the PSD modeling significance thresholds, and as such, no further modeling was required. Table 5-5 shows the maximum predicted concentration results of the screening modeling for CO, the proposed emission rate for H1, and the scaled concentration result.

Table 5-5
CO Screening Analysis Modeling Results

Load	Averaging Period	Maximum Concentration ($\mu g/m^3$)[A]	Proposed Emission rate (g/s)	Scaled Concentration ($\mu g/m^3$)	Modeling Significance Threshold ($\mu g/m^3$)
100%	1-hour	1.743	92.33	160.9	2,000
100%	8-hour	1.568	92.33	144.8	500
75%	1-hour	1.912	69.25	132.4	2,000
75%	8-hour	1.720	69.25	119.1	500
50%	1-hour	2.287	46.17	105.6	2,000
50%	8-hour	2.059	46.17	95.1	500
25%	1-hour	3.240	23.08	74.8	2,000
25%	8-hour	2.916	23.08	67.3	500

Note:

A. Maximum concentration was indicated at a distance of 2085 meters from H1 at a direction of 10 degrees at 100% load, 1925 meters from H1 at a direction of 10 degrees at 75% load, 1930 meters from H1 at a direction of 10 degrees at 50% load, and 1515 meters from H1 at a direction of 10 degrees at 25% load.

3.0 Conclusion

The results of the modeling analysis indicate that the CO emissions from the H1 steam generator do not exceed the modeling significance threshold, and therefore to not cause or contribute to an exceedance of the NAAQS. All modeling results are included with this application on a thumb drive. This satisfies the air dispersion modeling requirements of the PSD permit and demonstrates compliance with all applicable standards.

PART 6.0
AMBIENT AIR MONITORING SUMMARY

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1.0 AMBIENT AIR MONITORING SUMMARY 6-1

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1.0 Ambient Air Monitoring Summary

In accordance with the requirements of K.A.R. 28-19-350, PSD permit applicants must conduct an analysis of ambient impacts associated with the proposed new source or modification. Analysis is conducted for those pollutants that exceed the significant net increase defined by K.A.R. 28-19-300. As identified in Part 5.0 of this application, Sunflower has conducted an ambient impact analysis for CO. As part of the analysis, air dispersion modeling was conducted in accordance with an approved protocol. Per KDHE air quality modeling procedures and the USEPA New Source Review Workshop Manual (Draft October 1990), any criteria pollutant with significant impact modeling resulting in predicted concentrations above the monitoring *de minimis* concentrations may require pre-construction monitoring. Pre-construction monitoring is conducted to define background levels of the specific pollutants for inclusion in the National Ambient Air Quality Standards (NAAQS) modeling task, which is performed to assess the impacts of the proposed new installation on the existing ambient air quality. In the absence of available monitoring data from an established representative monitoring system, a site-specific air monitoring network may be required for applicable pollutants. As shown in Table 6-1, pre-construction monitoring is not required for CO.

Table 6-1
Pre-Construction Monitoring Thresholds

Pollutant	Maximum Predicted Concentration ($\mu g/m^3$) [A]	PSD Monitoring *De Minimis* Levels ($\mu g/m^3$) [B]
CO	144.8	575

Notes:
A. Concentrations are for the modification to the H1 steam generator only.
B. 8-hour average

PART 7.0
ADDITIONAL IMPACTS ANALYSIS

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1.0 Air Quality Analysis

1.1 Introduction

The PSD regulations (40 CFR 52.21(o)) require the owner or operator of any proposed new major source or major modification of an existing major stationary source to provide an analysis of the impairment to visibility, soils, and vegetation that would occur as a result of the modification and any general commercial, residential, industrial, or other growth associated with the modification. The information provided must also include an analysis of the air quality impact projected for the area as a result of general growth associated with the modification.

Pursuant to these requirements, Sunflower has conducted the analysis identified on the following sections for the H1 project:

- Federal Class I Area impact and visibility impairment analysis
- Growth analysis;
- Vegetation impacts; and
- Soil impacts.

1.2 Federal Class I Area Impact Analysis

Federal Class I areas include such areas as national parks and national wilderness areas and are of special natural, scenic, recreational, or historic value for which the PSD regulations provide special protection. The Federal Bureau of Land Management (FLM) has responsibility and authority to protect the Air Quality Related Values (AQRV) for each Class I area. The AQRV's are Flora and Fauna, Water, Visibility, Cultural-Archeological and Paleontological, and growth impacts. The nearest Class I area to the Holcomb Generating Station is the Great Sand Dunes National Monument, which is located approximately 400 km to the west of the facility. The potential degradation of these attributes have been correlated to the predicted air quality impacts for the Class I area. The predicted air quality impacts are determined by air dispersion modeling and visible emissions modeling. Modeling results are compared to stringent pollutant impact limits. Due to the extreme distance of the Class I area, the fact that no visibility impairing pollutants are increasing as a result of this project, and that the Great Sand Dunes National Monument is located in a generally upwind position, Sunflower did not contact the FLM for this project.

1.3 Class II Analysis

As this project will result in a net decrease in all visibility impacting pollutants, a Class II visibility analysis was not conducted. The only applicable PSD pollutant is CO, which does not impact visibility. Emissions of SO_2 and PM will be unaffected by this modification, and emissions of NO_X will decrease as a result of the project.

1.4 Vegetation Impact Analysis

Air pollutants can affect vegetation through two basic avenues, either direct absorption through the foliage or uptake from the soil of trace elements deposited to the soil. The effects of air pollution on vegetation can include visible damage to foliage and fruit, changes in metabolic function, adverse changes in plant activity, and, in the case of crops, yield reduction. The effects of air pollutants on vegetation fall into three broad categories: acute, chronic, and long-term/evolutionary.

- **Acute Effects**

  Acute effects result from relatively short duration (less than 1 month) exposures to high concentrations of pollutants. Acute effects are generally most easily recognized and have been the focus of the greatest amount of study.

- **Chronic Effects**

  Chronic effects are those occurring from exposure to lower concentrations of pollutants over extended periods of months or even years. Some research has been conducted on chronic effects indicating that concentrations well below those capable of causing acute effects can, with prolonged exposures, have adverse impacts on the overall health of at least some plant species.

- **Long-Term Effects**

  Long-term or evolutionary effects include abnormal changes to ecosystems and subtle physiological alterations in organisms, including selection for more resistant strains. Because the changes can be subtle, occur gradually over very long periods, and may be masked by naturally occurring changes in an ecosystem, little data is currently available regarding these type effects.

The potential effects of air pollutants on vegetation from the facility will focus on CO, as SO_2, PM/PM_{10}/$PM_{2.5}$/trace elements, and VOC/Ozone will not be affected by this project, and NO_X will decrease as a result of this project. The United States Department of the Interior (USDOI) Document entitled *Impacts of Coal-Fired Power Plants on Fish, Wildlife, and their Habitats* (among other publications listed) was consulted for analysis of CO. Beyond the listed pollutants, other environmental (soil moisture, temperature, amount of sunlight, etc.) and life cycle (age, reproductive stages, etc.) variables can effect a given plants response to specific pollutants. While adequate information is available to make generalizations regarding air pollution impacts on various types of vegetation, concrete conclusions as to site-specific vegetation exposure impacts cannot be presently definitively concluded from available research study data.

In general, land use in the vicinity of the Holcomb Generating Station is pasture and crop land (Harner *et al*. 1965). In the immediate area, native pasture is prevalent. Vegetation is dominated by grasses tolerant of sandy soils (Harner *et al*. 1965; Kuchler 1974). They include little bluestem (*Schizachyrium scoparium*), sand dropseed (*Sporobolus cryptandrus*), sand paspalum (*Paspalum setaceum*), sand bluestem (*Andropogon hallii*), switchgrass (*Panicum virgatum*), sideoats grama (*Bouteloua curtipendula*), and big sandreed (*Calmofilva gigantea*).

To the north of the project facility, along the Arkansas River, pasture, meadows, and dry land and irrigated crops are found. Switchgrass, little bluestem, big bluestem (*Andropogon gerardii*), Indian grass (*Sorghastrum nutans*), Canada wild rye (*Elymus canadensis*) are found in pastures and meadows. Wheat, corn, soybeans, and alfalfa are often cropped in the river valley. The same crops are farmed elsewhere outside of the river valley and north of the project site.

Trees are rare in the vicinity of the project site except along hedgerows, creek beds, and the Arkansas River. Species used in hedgerows include Siberian elm (*Ulmus pumila*), mulberry (*Morus* sp.), eastern red cedar (*Juniperus virginiana*), Russian olive (*Elaegnus angustifolia*), cottonwood (*Populus deltoides*), ponderosa pine (*Pinus ponderosa*), and osage orange (*Maclura pomifera*). Cottonwood, salt cedar (*Tamarix* spp.), and willow (*Salix* sp.) also grow in the Arkansas River floodplain.

At the Holcomb Generating Station, land use is industrial. Vegetation in this type of area is typically dominated by disturbance-tolerant weedy species, including lamb's-quarters (*Chenopodium album*), pigweed (*Amaranthus* sp.), and Russian thistle (*Salsola kali*). Turf grasses, such as western wheatgrass (*Agropyron smithii*) and tall fescue (*Festuca arundinacea*) are planted in lawn areas.

The proposed modification and the associated increase of CO are not expected to have significant effects on vegetation. Many pollutants have been shown to have an impact on vegetation at levels well above those expected from this site. The potential effects of the air emissions to vegetation within the immediate vicinity of the Holcomb Generating Station site were compared to scientific research examining the effects of pollution on vegetation. Damage to vegetation most often results from acute exposure to pollution, but may also occur after prolonged or chronic exposures. Acute exposures are typically manifested by internal physical damage to leaf tissues, while chronic exposures are more associated with the inhibition of physiological processes such as photosynthesis, carbon allocation, and stomatal functioning.

1.4.1 Carbon Monoxide

Concentrations of CO, even in polluted atmospheres, are not typically detrimental to vegetation (USEPA 1976). CO has not been found to produce detrimental effects on plants at concentrations below 114,500 $\mu g/m^3$ for exposures from one to three weeks (USEPA 1976). NAAQS are set for 1-hour and 8-hour averaging periods, at rates more stringent than the literature exposure threshold. Therefore, the NAAQS were utilized for comparison with modeled concentrations to predict any CO effects on vegetation. Additionally, the USEPA has stated that "*for most types of soils and vegetation, ambient concentrations of criteria pollutants below the secondary national ambient air quality standards (NAAQS) will not result in harmful effects*" (USEPA, 1990). Modeling results indicate H1 will not exceed the NAAQS for CO.

Table 7-1
Project CO Modeling Results (µg/m³)

Averaging Period	Maximum Allowable NAAQS	Project Maximum Off-Site Concentration	Percentage of Threshold
1-hour	40,000	160.9	0.4%
8-hour	10,000	144.8	1.5%

Through compliance with the CAA and NAAQS for the pollutant, the potential and real adverse vegetation effects of CO emissions from the proposed project have been avoided to the maximum extent possible.

1.5 Soil Impact Analysis

Air contaminants can affect soil through fumigation by gaseous pollutants, accumulation of compounds formed from gaseous pollutants, or by deposition and adsorption of particulate matter. Gaseous fumigation affects on soil are assumed to be minimal compared to affects of vegetation, which is discussed in the previous section. Soils are primarily impacted by PM_{10} emissions through deposition (direct settling of solid/particulate forms); adsorption/absorption at the boundary layer; or precipitation, which scrubs particulate matter and solublize some pollutants (solublize is defined as: to make substances not appreciably soluble under normal conditions soluble in water). The amount of research/study and subsequent reports dealing with the effects of atmospheric contaminates on soils is very limited. A majority of the publications focus on trace elements and their excesses or deficiencies as they relate to agricultural crop yields. The modifications on H1 will not affect PM_{10} emissions from the unit.

For sufficiently small depositions of air contaminates, the overall ecosystem can adapt in the same general manner it adapts to other changes in soil chemistry caused through natural weathering, leaching during wet periods, and erosion. Agricultural and horticultural practices such as liming, fertilization, and application of herbicides and pesticides can significantly modify soil chemistries, making evaluation of effects from the comparatively small amounts of deposited atmospheric contaminants even more difficult. While deposition can result in some modification of soil chemistry, damage to vegetative cover may lead to greater overall soil impacts through mechanisms such as increased solar heating, moisture loss and increased erosion. Where atmospheric contaminates are at levels below those causing harm to vegetation, these secondary impacts to the soil would not be experienced.

Two soil types are mapped at or near the Holcomb Generating Station (Harner *et al.* 1965). They include:

- Tivoli fine sand
- Tivoli-Vona loamy fine sands

Both soil types are deep, noncalcareous, very sandy soils in steep, duny terrain (Harner et al. 1965). The soils are low in fertility and drain very easily. Water is absorbed quickly, and consequently, runoff is very low. Blowout of the soil is prevalent where vegetation is lacking. Erosion often is a problem.

Sulfates and nitrates caused by SO_2 and NO_2 deposition on soil can be beneficial and detrimental to soils depending on its composition. However, the modifications on H1 will not affect SO_2 emissions from the unit, and NO_X emissions will be decreasing as a result of the project, so no adverse effects are anticipated.

2.0 Conclusions

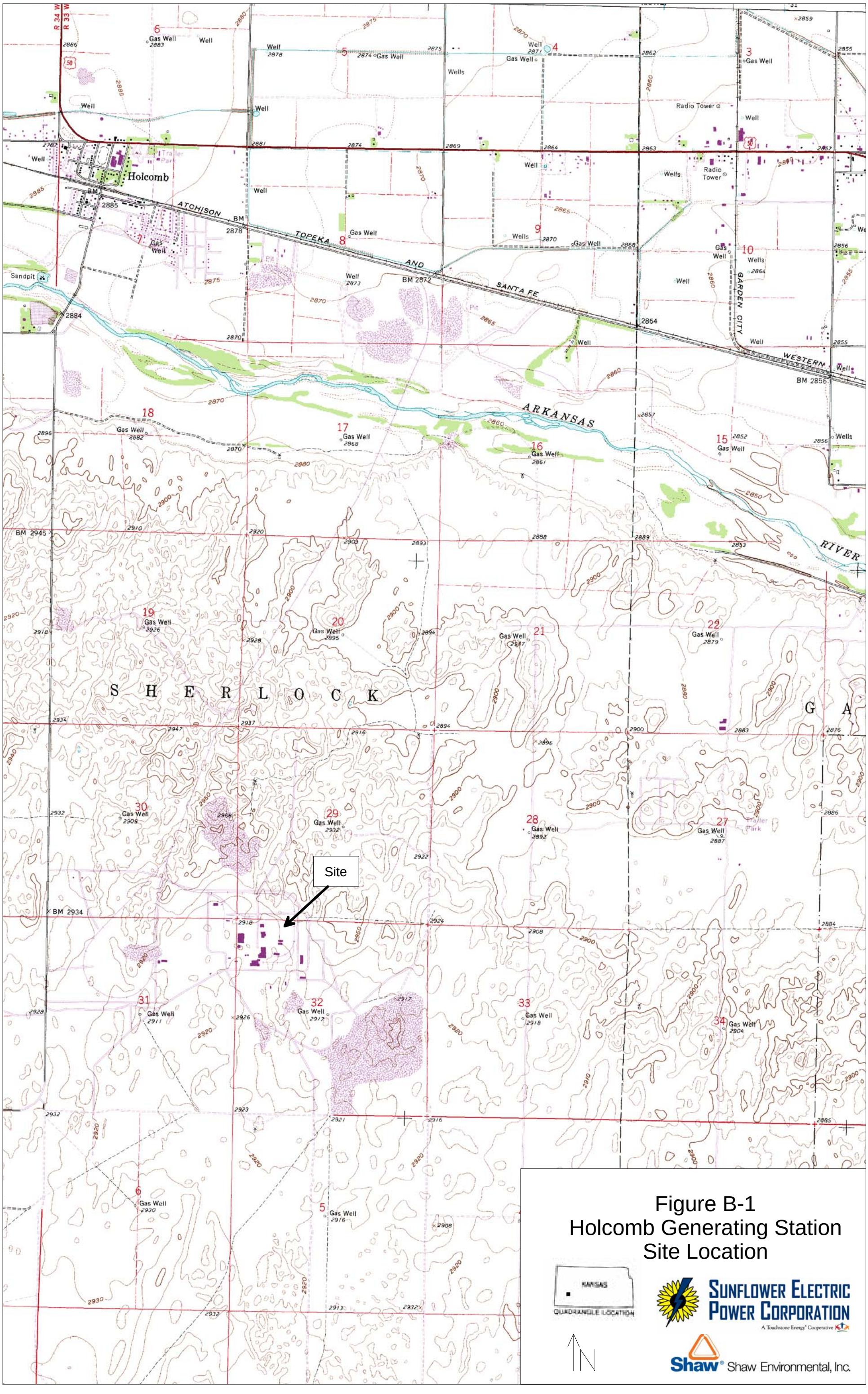
Based on the information presented in the sections above, it is concluded that the modification to H1 can be accomplished with little or no adverse impact on the vegetation, soils or visibility of the area surrounding the facility.

APPENDIX A
COMPLETENESS CHECKLIST

Updated Completeness Checklist

- ☒ Control Technology Analysis – Part 4.0
- ☒ Compliance with PSD Class I/II Increment – Part 5.0
- ☒ Compliance with National Ambient Air Quality Standards – Part 5.0
- ☒ Application Forms – Part 3.0
- ☒ Analysis of Additional Impacts
  - ☒ Soils – Part 7.0
  - ☒ Vegetation – Part 7.0
  - ☒ Visibility – Part 7.0
  - ☒ Regional Growth – Part 7.0

APPENDIX B
SITE LOCATION AND SITE LAYOUT DIAGRAMS


Holcomb
ATCHISON TOPEKA AND SANTA FE
ARKANSAS RIVER
GARDEN CITY WESTERN
S H E R L O C K
Site
Figure B-1
Holcomb Generating Station
Site Location
KANSAS
QUADRANGLE LOCATION
N
SUNFLOWER ELECTRIC POWER CORPORATION
A Touchstone Energy® Cooperative
Shaw® Shaw Environmental, Inc.

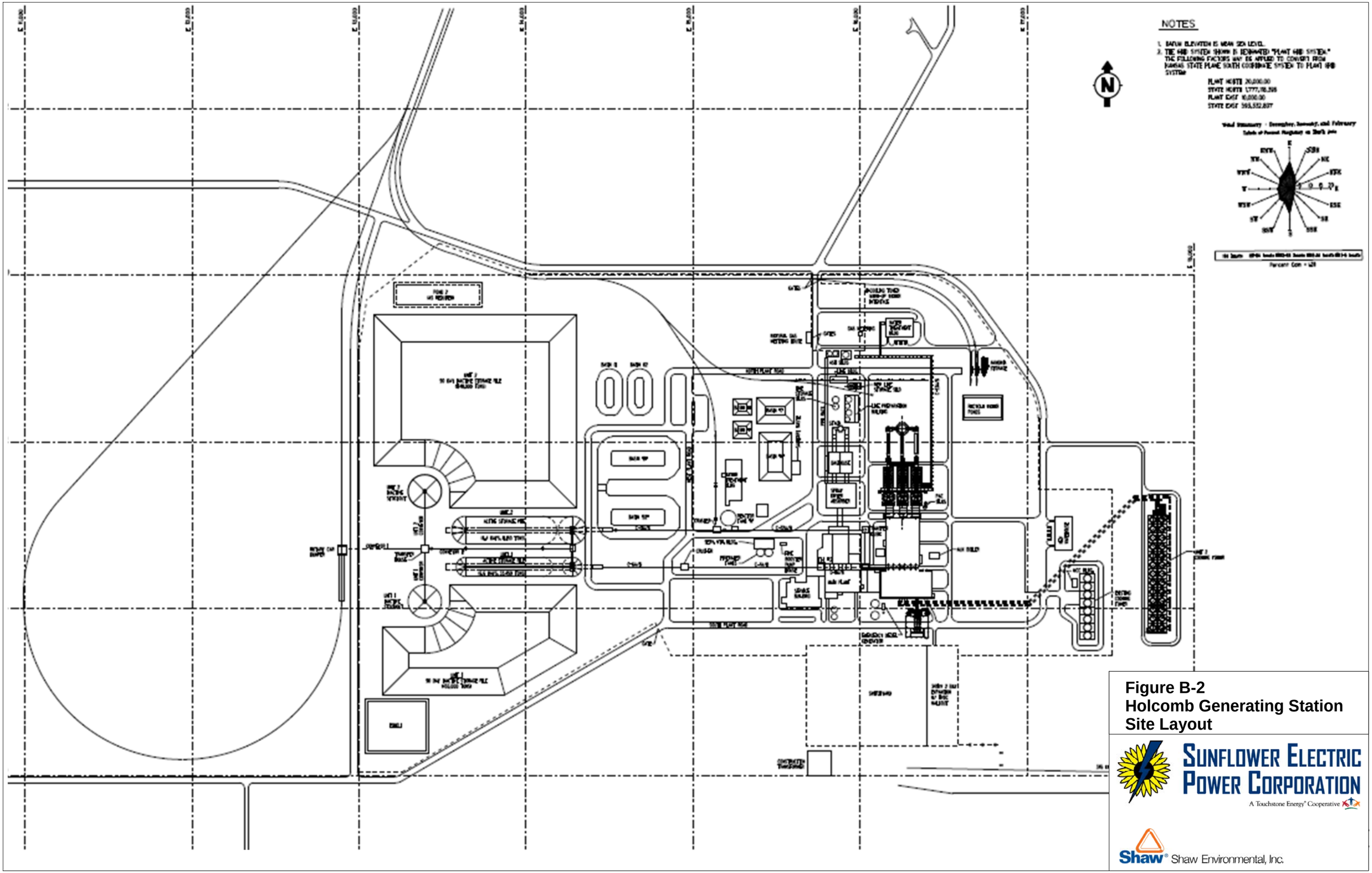


Figure B-2
Holcomb Generating Station
Site Layout

SUNFLOWER ELECTRIC POWER CORPORATION
A Touchstone Energy® Cooperative

Shaw® Shaw Environmental, Inc.

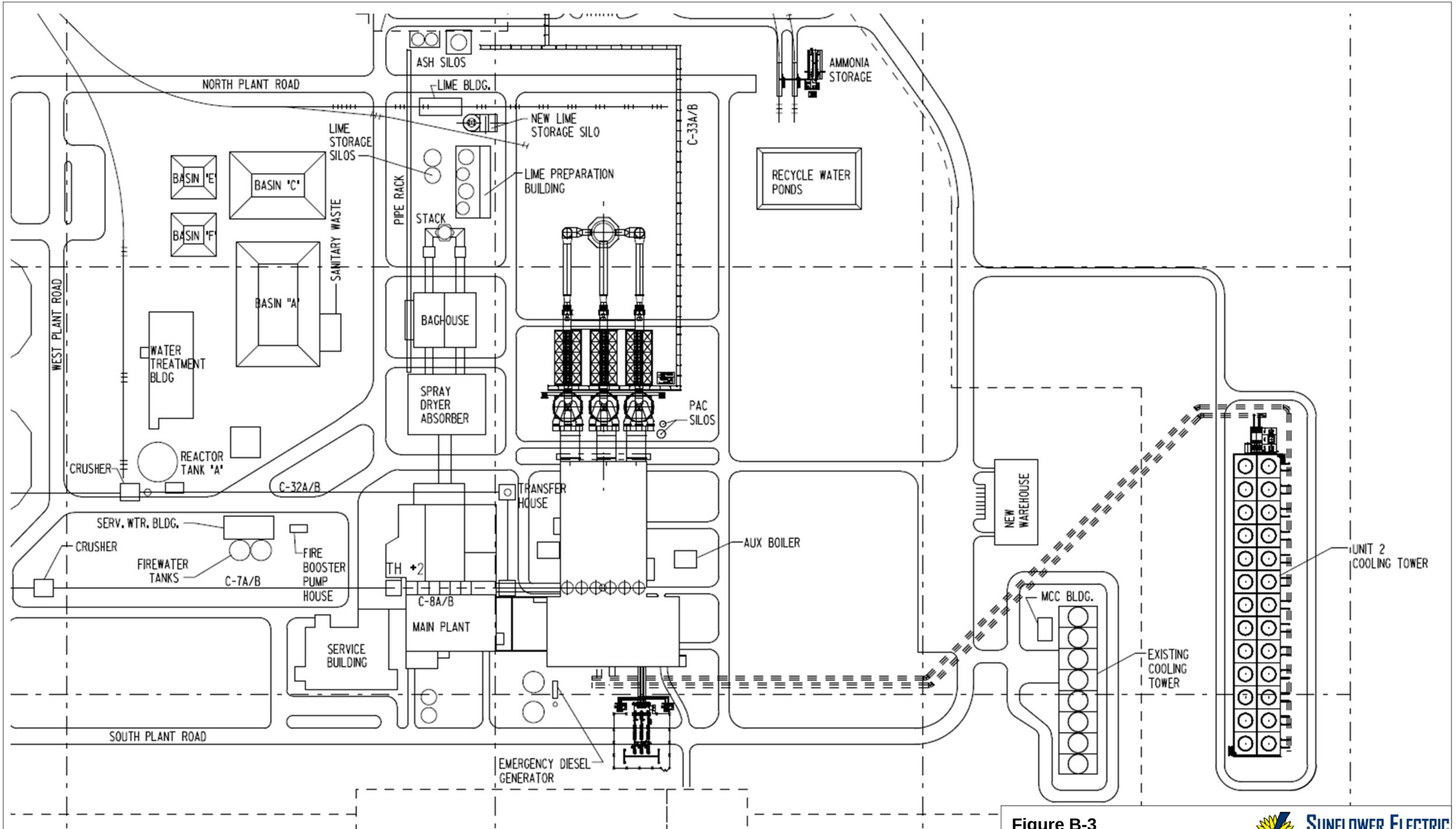


Figure B-3
Holcomb Generating Station
Detailed Site Layout

SUNFLOWER ELECTRIC POWER CORPORATION
A Touchstone Energy® Cooperative

Shaw® Shaw Environmental, Inc.

APPENDIX C
AIR EMISSION CALCULATIONS

Year	Month	CO_2 TONS	HEATIN MMBTU	NO_X TONS	CO TONS	CO LB/MMBTU
2006	January	254,485.0	2,481,738	369.8	34.7	0.028
	February	229,010.0	2,234,312	321.7	29.0	0.026
	March	77,328.3	754,550	103.8	13.2	0.035
	April	119.9	1,901	0.2	0.4	0.434
	May	197,282.5	1,938,583	278.2	34.9	0.036
	June	244,159.5	2,383,050	396.8	35.7	0.030
	July	266,639.1	2,600,636	418.7	31.2	0.024
	August	265,273.6	2,587,011	410.0	31.0	0.024
	September	253,856.3	2,475,051	382.4	18.6	0.015
	October	247,271.8	2,413,015	409.0	20.5	0.017
	November	253,552.2	2,472,502	419.1	19.8	0.016
	December	245,723.3	2,405,025	390.8	12.0	0.010
2007	January	245,889.0	2,399,402	374.3	10.8	0.009
	February	238,402.4	2,325,149	366.2	27.9	0.024
	March	221,223.3	2,163,213	344.0	27.0	0.025
	April	253,292.6	2,470,620	403.9	27.2	0.022
	May	260,801.0	2,544,102	395.6	28.0	0.022
	June	254,817.8	2,489,139	355.9	37.3	0.030
	July	276,674.0	2,698,626	408.8	45.9	0.034
	August	282,686.8	2,756,430	406.6	51.0	0.037
	September	234,298.9	2,288,523	382.2	42.3	0.037
	October	263,736.4	2,572,369	389.7	43.7	0.034
	November	272,878.4	2,659,866	416.3	43.9	0.033
	December	277,015.8	2,700,756	434.8	47.3	0.035
2008	January	263,863.3	2,573,922	404.3	48.9	0.038
	February	261,823.2	2,551,921	402.4	35.7	0.028
	March	282,183.4	2,750,376	432.5	42.6	0.031
	April	170,048.6	1,621,366	251.1	23.5	0.029
	May	215,189.3	2,055,497	301.4	29.8	0.029
	June	266,931.9	2,547,246	377.8	39.5	0.031
	July	278,328.6	2,655,238	403.7	45.1	0.034
	August	253,204.6	2,419,933	366.5	43.6	0.036
	September	270,568.9	2,580,376	382.4	45.2	0.035
	October	281,856.1	2,688,632	398.4	43.0	0.032
	November	255,895.2	2,443,918	374.2	40.3	0.033
	December	282,612.4	2,694,709	447.6	52.5	0.039
2009	January	270,579.0	2,579,893	424.5	43.9	0.034
	February	260,302.5	2,481,910	412.6	44.7	0.036
	March	261,390.5	2,492,278	401.1	47.4	0.038
	April	234,383.8	2,234,789	343.3	42.5	0.038
	May	141,465.0	1,348,832	208.8	25.0	0.037
	June	251,634.0	2,399,258	386.3	45.6	0.038
	July	272,124.3	2,594,626	415.1	49.3	0.038
	August	256,438.4	2,445,060	386.2	48.9	0.040
	September	249,812.7	2,381,885	382.9	46.4	0.039
	October	202,923.0	1,934,821	298.8	37.7	0.039
	November	246,400.4	2,349,347	341.1	42.3	0.036
	December	245,047.6	2,336,466	354.7	35.0	0.030
2010	January	276,211.6	2,633,596	414.9	40.8	0.031
	February	244,512.0	2,331,344	364.3	44.3	0.038
	March	245,572.3	2,341,447	339.8	39.8	0.034
	April	126,175.6	1,203,046	166.6	16.2	0.027
	May	190,618.6	1,817,491	257.8	26.4	0.029
	June	261,036.0	2,488,910	375.0	38.6	0.031
	July	277,992.4	2,650,572	420.1	41.1	0.031
	August	271,375.3	2,587,486	402.5	41.4	0.032
	September	260,814.5	2,486,797	388.8	36.1	0.029
	October	250,494.3	2,388,392	362.6	39.4	0.033
	November	244,444.2	2,330,706	351.9	33.8	0.029
	December	260,189.8	2,480,847	390.1	36.0	0.029

24-Month Consecutive Period	NO_X TONS	CO TONS	HEATIN MMBTU
Jan '06 thru Dec '07	8,578.9	713.5	54,815,567.4
Feb '06 thru Jan '08	8,613.4	727.7	54,907,751.1
Mar '06 thru Feb '08	8,694.1	734.3	55,225,360.5
Apr '06 thru Mar '08	9,022.8	763.8	57,221,186.9
May '06 thru Apr '08	9,273.7	786.9	58,840,652.5
Jun '06 thru May '08	9,296.9	781.8	58,957,566.1
Jul '06 thru Jun '08	9,277.9	785.5	59,121,762.7
Aug '06 thru Jul '08	9,262.9	799.4	59,176,364.4
Sep '06 thru Aug '08	9,219.4	812.0	59,009,285.7
Oct '06 thru Sep '08	9,219.4	838.6	59,114,610.3
Nov '06 thru Oct '08	9,208.8	861.1	59,390,227.7
Dec '06 thru Nov '08	9,163.9	881.6	59,361,644.1
Jan '07 thru Dec '08	9,220.7	922.1	59,651,328.4
Feb '07 thru Jan '09	9,270.9	955.2	59,831,818.9
Mar '07 thru Feb '09	9,317.3	972.0	59,988,579.9
Apr '07 thru Mar '09	9,374.4	992.3	60,317,645.6
May '07 thru Apr '09	9,313.8	1,007.6	60,081,814.7
Jun '07 thru May '09	9,127.0	1,004.5	58,886,544.8
Jul '07 thru Jun '09	9,157.3	1,012.8	58,796,664.1
Aug '07 thru Jul '09	9,163.6	1,016.2	58,692,664.1
Sep '07 thru Aug '09	9,143.2	1,014.1	58,381,293.2
Oct '07 thru Sep '09	9,143.9	1,018.2	58,474,654.9
Nov '07 thru Oct '09	9,053.0	1,012.2	57,837,107.2
Dec '07 thru Nov '09	8,977.8	1,010.6	57,526,587.8
Jan '08 thru Dec '09	8,897.7	998.4	57,162,297.6
Feb '08 thru Jan '10	8,908.3	990.3	57,221,971.8
Mar '08 thru Feb '10	8,870.2	998.9	57,001,394.5
Apr '08 thru Mar '10	8,777.5	996.1	56,592,465.0
May '08 thru Apr '10	8,693.0	988.8	56,174,144.8
Jun '08 thru May '10	8,649.4	985.3	55,936,139.1
Jul '08 thru Jun '10	8,646.6	984.4	55,877,803.1
Aug '08 thru Jul '10	8,663.0	980.4	55,873,137.4
Sep '08 thru Aug '10	8,699.0	978.2	56,040,690.3
Oct '08 thru Sep '10	8,705.4	969.1	55,947,112.0
Nov '08 thru Oct '10	8,669.6	965.5	55,646,871.5
Dec '08 thru Nov '10	8,647.3	959.0	55,533,659.6
Jan '09 thru Dec '10	8,589.8	942.4	55,319,797.5

Maximum (24 mo period)	**9,374.4**	**1,018.2**	**60,317,645.6**
Quantity per Year	**4,687.2**	**509.1**	**30,158,822.8**

24-Month Consecutive Period	NO_X TONS	CO TONS	HEATIN MMBTU
Maximum (24 mo period)	**9,374.4**	**1,018.2**	**60,317,645.6**
Quantity per Year	**4,687.2**	**509.1**	**30,158,822.8**

Max Heatin for H1 from Permit	**3389**	**MMBtu/hr**

	Molecular Mass
C	12.01
O	15.99
CO	28
CO_2	43.99

	CO	NO_X	CO_2
Projected Potential Emissions Rate (lb/MMBtu)*	0.250	0.180	
Baseline Emissions Rate (lb/MMBtu)	0.034	0.311	
Net Emissions Rate Change (lb/MMBtu)	0.216	-0.131	
Projected Potential Emissions (tpy)	3711.0	2671.9	
Net Emissions Change (tpy)	3,201.8	-2015.3	-5030.3
Net Emissions Change (lb/hr)	732.8		
Net Emissions Change (g/s)	92.3		

Load	Exit Velocity (ft/s)	Averaging Period	Max Conc. (ug/m^3)**	Scaled Conc. (ug/m^3)	% of Threshold
100%	113.5	1-hr	1.743	160.9	8.05%
		8-hr	1.568	144.8	28.96%
75%	85.13	1-hr	1.912	132.4	6.62%
		8-hr	1.72	119.1	23.82%
50%	56.75	1-hr	2.287	105.6	5.28%
		8-hr	2.059	95.1	19.01%
25%	28.38	1-hr	3.24	74.8	3.74%
		8-hr	2.916	67.3	13.46%

*From BACT Analysis
**From AERSCREEN Results

APPENDIX D
BACT SUPPORTING DOCUMENTATION

No.	Company	Plant	Unit	State	RBLC ID	CO Limit	CO Limit Units	CO Avg.	Project Description	Permit Date	Permit No.	Comments	Firing	Additional CO Limit	NOx Level	NOx Avg. Period	Additional NOx Control
1	KCP&L	**La Cygne Generating Station**	Unit 2 7,700 MMBtu/hr 685 MW	KS	N/A	0.319	lb/MMBtu	No averaging period specified in amended permit (includes SUSD)	For Unit 2, the project will include the replacement of the existing LNBs, installation of OFA and SCR to reduce NOx emissions; installation of a wet FGD scrubber, and the installation of a new fabric filter.	Effective March 16, 2011 Amended April 20, 2011	Source 1070005	March 16, 2011 final permit amended to read: "The emission rate of carbon monoxide (CO) emissions shall not exceed 0.319 lb/MMBtu as demonstrated with post construction and annual performance testing." From the permit: "The purpose of the OFA/LNB and SCR portion of this project is to reduce the NOx emissions from Unit 2. In the event difficulties are encountered demonstrating compliance with the CO limit while optimizing NOx emissions, the owner or operator may request a revision to the CO limit. The revision will be subject to KDHE approval and may require a public notice and comment period." Under KCP&L Regional Haze Agreement (see List of Aspects document). Because the addition and replacement of the above referenced emission controls will result in an increased pressure drop between the boilers and the stack, the induced draft (ID) fans will also be replaced on Unit 1 and Unit 2. Unit 1 currently has six (6) fans that will be replaced by three (3) fans; Unit 2 currently has four (4) fans that will be replaced by three (3) fans.	Wall-fired, dry bottom		From RH Agreement: 0.13 lb/MMBtu	30-day rolling weighted average of both Units I and 2, excluding periods of startup and shutdown.	SCR included in project.
2	KC, KS Board of Public Utilities	**Nearman Creek Power Station**	Unit 1 (N1) MMBtu/hr N/A 261 MW	KS	N/A	0.17	lb/MMBtu	30-day rolling (includes SUSD)	Low NOx Combustion (LNC) system comprised of LNBs, OFA, undefire air, boundary air, and wing port air combustion control methods.	April 14, 2011	Source 2090008	Project also includes: 1) installation of new igniters, scanners, and cooling skids. The new igniters will be the sized to provide the same heat input as the existing equipment. 2) installation of coal inlet divider heads. 3) installation of additional combustion optimization equipment. Additional instrumentation will be installed to improve the performance of this system.	Wall-fired, dry bottom	N/A	No limit associated with PSD permit Less than or equal to 0.26 lb/MMBtu (Mfg guarantee)	N/A	None
3	KC, KS Board of Public Utilities	**Quindaro Power Station**	Unit 2 MMBtu/hr N/A 158 MW	KS	N/A	0.42	lb/MMBtu	30-day rolling (includes SUSD)	Low NOx Combustion System (LNC) comprised of LNBs and OVA combustion control methods.	April 14, 2011	Source 2090048	Project also includes: 1) installation of new igniters, scanners, and cooling skids. The new igniters will be sized to provide the same heat input as the existing equipment. 2) installation of combustion optimization equipment ... to improve control and unit operation through more automated control resulting in reduced NOx and CO emissions. 3) replacement of mill motors ... to ensure the motors are able to provide the power required to operate the ball mills in a way that improves coal fineness, which will result in lower CO emissions. The new mill motors will not increase the throughput of the coal into the boiler. 4) replacement of coal classifiers to ensure the required coal fineness is provided as required by the new coal burners.	Wall-fired, dry bottom		No limit associated with PSD permit Less than or equal to 0.18 lb/MMBtu (Mfg guarantee)	N/A	None
4	Westar Energy	**Tecumseh Energy Center**	Units 7/9 & 8/10 Units 7/9 - 1,102 MMBtu/hr Units 8/10 - 1,911 MMBtu/hr Unit 7 - 82 MW Unit8 - 150 MW	KS	N/A	0.25	lb/MMBtu	30 day rolling (except SUSD)	Units 7/9 and 8/10 -- On each, addition of LNBs, SOFA, and rebuilding of the ESP	March 18, 2008	Source 1770030	Under Westar Regional Haze Agreement (see List of Aspects document). Tecumseh is not subject to presumptive BART. From permit: "The purpose of this project is to reduce the NOx emissions from TEC7/9 and TEC8/10. In the event difficulties are encountered demonstrating compliance with the CO limit while optimizing NOx emissions, the owner or operator may request a revision to the CO limit." [Same language in JEC 1&2 permit].	Both tangentially fired		Both units - 0.18 lb/MMBtu [Contingent upon EPA Approval of the Regional Haze Kansas State Implementation Plan. The Regional Haze Agreement between Westar Energy, Inc. and KDHE was signed February 29, 2008.]	30-day rolling average (except SUSD)	None
5	Westar Energy	**Jeffrey Energy Center**	Units 1 and 2 Each unit - 8,262 MMBtu/hr Each unit - 720 MW	KS	N/A	0.25	lb/MMBtu	30 day rolling (except SUSD)	Units 1 & 2 Add/rebuild air pollution controls, improve plant efficiency, and supply steam energy to a new, separately-owned, ethanol plant. Specifically the permit was for the addition of LNBs and SOFA to JEC1 and JEC2, and tuning of all three boilers.	February 29, 2008	Source 1490001	Under Westar Regional Haze Agreement (see List of Aspects document). From permit: The purpose of this project is to reduce the NOx emissions from each boiler unit. In the event difficulties are encountered demonstrating compliance with the CO limit while optimizing NOx emissions, the owner or operator may request a revision to the CO limit.	Both tangentially fired		From RH Agreement (presumptive BART): 0.15 Lb/MMBtu	30-day rolling average excluding periods of startup and shutdown.	None
6	Westar Energy	**Jeffrey Energy Center**	Unit 3 MMBtu/hr N/A 720 MW	KS	N/A	0.25	lb/MMBtu	30 day rolling (except SUSD)	Unit 3 The project will include the addition of low-NOx burners, separated overfire air (SOFA), and changes to the pulverizers to improve consistency of coal fineness to allow proper operation of the low-NOx burners.	October 4, 2005	Source 1490001	Under Westar Regional Haze Agreement (see List of Aspects document). From permit: The purpose of this project is to reduce the NOx emissions from JEC3. In the event difficulties are encountered demonstrating compliance with the CO limit while optimizing NOx emissions, the owner or operator may request a revision to the CO limit.	Tangentially fired		From RH Agreement (presumptive BART): 0.15 Lb/MMBtu	30-day rolling average excluding periods of startup and shutdown.	None
7	Minnesota Power/Allete	**Boswell Energy Center**	Boiler 4 6,400 MMBtu/hr 558 MW	MN	MN-0081	0.15	lb/MMBtu	30-day Rolling (except SUSD)	Unit #4 to be retrofitted with an upgraded SOFA system and LNBs	July 16, 2010	06100004-005	Unit #4 was originally constructed in the late 1970s with closecoupled over-fired air (CCOFA) technology. The project will replace the original CCOFA system with an upgraded separated over-fire air (SOFA) system and low NOX burners (LNB).	Tangentially-fired	28,826 lb/hr 1-hour for SUSD (based on ambient air modeling)	7/16/2010 Title V limits (includes SNCR): 0.7 lb/MMBtu 0.40 lb/MMBtu	3-hr annual	ROTA-Mix SNCR
8	Orlando Utilities Commission (OUC)	**Stanton Energy Center**	Units 1 and 2 Each Unit: 4,286 MMBtu/hr 468 MW	FL	FL-0306	Unit 1 -- 0.18 Unit 2 -- 0.15	lb/MMBtu	30 Operating Day Rolling (except SUSD)	LNB and OFA equipment on Units 1 and 2	February 6, 2008	0950137-015-AC	Unit 2 includes low NOx burners (LNB), overfire air (OFA) and a selective catalytic reduction (SCR) system for NOx control. The more stringent requirements for Unit 2 are from a modification of PSD-FL-084 dated December 1991. The value for Unit 1 will be a little greater than the value for Unit 2. This will provide more flexibility to reduce NOx emissions from Unit 1 which does not have an SCR system. The BACT limit for Unit 2 is the same as originally set by EPA in the 1991 PSD permit modification.	Wall-fired, dry bottom (both)	None	1/1/2010 Title V limits: Unit 1 0.60 0.46 Unit 2 (has SCR) 0.17	 30 day rolling annual 30 day rolling	SCR on Unit 2 only
9	Tampa Electric Co.	**Big Bend Station**	Unit 4 4,330 MMBtu/hr 486 MW	FL	FL-0307	0.2	lb/MMBtu	30-boiler operating day rolling average (includes SUSD)	Permit issued after project installed. LNBs, a SOFA system, <u>and SCR (installed in 2007)</u> on Unit 4	January 15, 2008	0570039-027-AC	Reassessment of BACT determination. CO/NOx Optimization Study required. 4/5/2011 Title V permit shows CO remains at the 0.20 lb/MMBtu level.	Tangentially-fired		RBLC comment says down to 0.10 lb/MMBtu since May 2007. Title V permit: 0.10 lb/MMBtu (except SUSD)	 30-day rolling average	SCR included in project.

No.	Company	Plant	Unit	State	RBLC ID	CO Limit	CO Limit Units	CO Avg.	Project Description	Permit Date	Permit No.	Comments	Firing	Additional CO Limit	NOx Level	NOx Avg. Period	Additional NOx Control
10	Lakeland Electric	**C.D. McIntosh, Jr. Power Plant**	Unit 3 3,640 MMBtu/hr 364 MW	FL	FL-0308	0.20	lb/MMBtu	30-operating day rolling average (includes SUSD). This level must also be met on a 3-hr average during test.	LNBs and OFA system	March 22, 2007	1050004-018-AC	Phase 2 of project was the subsequent installation of SCR Permit allows CO limit can be reduced later. Lakeland Electric will install 32 complete Advanced Burner Systems Opti-Flow LNB assemblies that accommodate the existing igniters and flame scanners and a complete OFA system including windboxes on the front and rear walls with interconnecting ductwork to the existing secondary air.	Wall-fired, dry bottom	0.20 lb/MMBtu 3-hour average must be met during initial compliance demonstration.	4/6/2011 Title V limit (with SCR): 0.22 (including SUSD)	calendar year average	SCR installed on Phase 2.
11	IPL	**Ottumwa Generating Station**	Boiler 1 6,370 MMBtu/hr 726 MW Fires wood residue also.	IA	IA-0091	0.163	lb/MMBtu	30-day rolling average (except SUSD) "To allow for a brake-in period of the Smart-burn, this standard becomes effective 01/01/2008."	The permit for Boiler #1 was modified to allow the addition of ZoloBoss control system to reduce NOX emissions. CO limit established under 78-A-019P-S8, Install Smart Burn OFA system and repair tubes	January 19, 2010	78-A-019-P9	The permit for Boiler #1 was modified to allow the addition of ZoloBoss control system to reduce NOX emissions. IPL is unsure what level of NOX reduction will take place but is asking for a reduction in the allowable NOX emissions from 0.3 lb/MMBtu and 8370 ton/yr to 0.25 lb/MMBtu and 6975 ton/yr.	Tangentially-fired	4,548 tons/year 12-month rolling total This standard becomes effective after the installation of the ZoloBoss system.	0.25 lb/MMBtu	12-month rolling average. This standard becomes effective after the installation of the ZoloBoss system.	None
12	IPL	**M.L. Kapp Generating Station**	Boiler 2 1,932 MMBtu/hr 218 MW	IA	N/A	0.289	lb/MMBtu	30-day rolling (except SUSD)	LNBs and OFA	January 11, 2008	78-A-157P-S8		Tangentially-fired	558 lb/hr 2,446 tons/year	0.45 lb/MMBtu	30-day rolling average	None
13	MidAmerican Energy	**Neal Energy Center North**	Boiler 1 1,363 MMBtu/hr 147 MW	IA	IA-0081	1.26	lb/MMBtu	3-hr average (except SUSD)	ESP and OFA	December 9, 2005	05-A-878-P		Cyclone	2,507 tons/year 12-month rolling total	2,985 tons/year "Limit established to make reductions from addition of OFA enforceable."		None
14	MidAmerican Energy	**Neal Energy Center North**	Boiler 2 3,081 MMBtu/hr 349 MW	IA	IA-0090	1.63	lb/MMBtu	3-hr rolling average (except SUSD)	ESP and sixteen (16) radially stratified flame core (RSFC) Low NOx Burners/Over Fire Air	September 5, 2007	07-A-951-P		Wall-fired, dry bottom	7,287 tons/year 12-month rolling total 5,082 lb/hr for NAAQS	3,931 tons/year "Emission rate established to make NOx reductions from original and replacement LNB projects federally enforceable."		None
15	MidAmerican Energy	**Neal Energy Center South**	Boiler 4 6,900 MMBtu/hr 640 MW	IA	IA-0080	0.42	lb/MMBtu	1 calendar day average (except SUSD)	LNB and OFA	September 28, 2005	05-A-655-P		Wall-fired, dry bottom	12,693 tons/year 12-month rolling total 8,694 lb/hr for NAAQS	0.70 lb/MMBtu = 300 ng/J heat input	3-hour rolling average	None
16	MidAmerican Energy	**Neal Energy Center North**	Boiler 3 5,021 MMBtu/hr 515 MW	IA	N/A	1.26	lb/MMBtu	1-hr average (except SUSD)	Amend NOx Limits 95-A-313-S2 established the CO and initial NOx limits for the LNB/OFA project. NOx limit raised by this permitting action (from 0.20 lb/MMBtu to 0.30 lb/MMBtu.	August 31, 2005	95-A-313-S3	"The amount of NOx emissions reduction was overestimated and this proposed permit amendment involves adjusting the NOx emission limits."	Wall-fired, dry bottom	9,236.6 tons/year 12-month rolling total "Emission limit required justifying Pollution Control Project (PCP). Based on average annual emission rate of 0.25 lb/MMBtu (See Section 14 for Operating Limits)."	0.30 lb/MMBtu	30-day rolling average	None
17	Nebraska Public Power District	**Gerald Gentlemen Station**	Unit 1 7,538 MMBtu/hr N/A 681 MW	NE	NE-0045	0.50	lb/MMBtu	30-day rolling average (except SUSD)	BART -- Unit 1 installation of LNBs and OFA	August 18, 2006	CP06-0001	Permit not available	Wall-fired, dry bottom				None
18	Nebraska Public Power District	**Gerald Gentlemen Station**	Unit 2 7,538 MMBtu/hr 681 MW	NE	N/A	0.50	lb/MMBtu	30-day rolling average (except SUSD)	BART -- Unit 2 installation of LNBs and OFA	May 11, 2010	CP07-0050	This construction permit shall supersede the construction permit issued on August 18, 2006 (CP06-0001) in its entirety at the time compliance with the NOx emissions limitation is demonstrated. Until such time as the August 18, 2006, permit is superseded, specific conditions relating to CO remain in effect for Unit 1.	Wall-fired, dry bottom		Emissions from both units (1 and 2) shall be averaged together and shall meet a NOx emissions limitation of 0.23 lb/MMBtu (30-day rolling average). Apply during SUSD.		None
19	City Utilities of Springfield	**James River Power Station**	Unit 3 496 MMBtu/hr 44 MW Unit 4 600 MMBtu/hr 60 MW Unit 5 1000 MMBtu/hr 105 MW	MO	N/A	0.35	lb/MMBtu	30-day rolling average (except SUSD)	Replacement of existing OFA and upgrade burner configuration with ultra low-NOx design on Units 3, 4, and 5. A High Energy Reagent Technology (HERT) system will be installed for additional NOx control. Urea is used as the reagent.	March 8, 2007	032007-003		Wall-fired, dry bottom - All 3 units	3,213 tons/year combined for all 3 units (including SUSD)	The permittee shall limit emissions of NOX to the rate of 0.35 pounds per million Btu NOX of heat input during the control period. The control period is defined as the period between May 1 and September 30 of each calendar year.		None
20	Associated Electric Cooperative	**New Madrid Power Plant**	Unit 1 7,150 MMBtu/hr 615 MW Unit 2 7,150 MMBtu/hr 615 MW	MO	N/A	0.55	lb/MMBtu	30-day rolling average (except SUSD)	Installation of Over-Fire Air (OFA) combustion controls on Units 1 and 2.	September 18, 2006	092006-004		Cyclone	2,911 tons of CO from Boiler #1 (EU0010) and less than 2,702 tons of CO from Boiler #2 (E0020) in any consecutive 12-month period. New Madrid Power Plant shall emit less than 5,513 tons of CO from Boilers #1 and #2 combined (EU0010 & EU0020) in any consecutive 12-month period.	NOX emissions are expected to decrease by at least 50% (a reduction of around 0.66 lb/MMBTU), or by almost 15,000 tons per year.		SCR
21	Portland General Electric Company	**Boardman Power Plant**	Unit 1 MMBtu/hr N/A 584 MW	OR	N/A	0.35	lb/MMBtu	30-day rolling average (includes SUSD)	Installation and operation of new burners and over-fire air system to comply with the BART requirements by July 1, 2011.	December 10, 2010	25-0016-ST-01	CO pre-change = 0.03 lb/MMBtu CO post-change = 0.35 lb/MMBtu NOx pre-change = 0.46 lb/MMBtu NOx post-change = 0.23 lb/MMBtu	Wall-fired, dry bottom		0.70 lb/mmBtu heat input for coal - NSPS	3-hour block	None

APPENDIX E
PROPOSED DRAFT PERMIT

Bureau of Air
Curtis State Office Building
1000 SW Jackson, Suite 310
Topeka, KS 66612-1366

Phone: 785-296-1578
Fax: 785-291-3953
jwebb@kdheks.gov
www.kdheks.gov/bar

Kansas

Robert Moser, MD, Acting Secretary

Department of Health & Environment

Sam Brownback, Governor

AIR EMISSIONS SOURCE CONSTRUCTION PERMIT

Source ID No.: 0550023

Effective Date: Draft

Source Name: Holcomb Station

SIC Code: 4911; Electric Services

NAICS Code: 221112; Fossil Fuel Electric Power Generation

Source Location: 2440 Holcomb Lane
Holcomb, Kansas

Mailing Address: P.O. Box 430
Holcomb, Kansas 67851

Contact Persons: Mr. Paul Reynolds
Manager, Generation Engineering/Environmental
Telephone Number: (620) 227-4522

This permit is issued pursuant to K.S.A. 65-3008 as amended.

Description of Activity Subject to Air Pollution Control Regulations

The Sunflower Electric Power Corporation (Sunflower) is proposing to install emission control technologies at its existing Holcomb Power Station (Holcomb) electric generating facility located in Finney County, Holcomb, Kansas. Sunflower will reduce NO_X emissions on the Holcomb 1 steam generator (H1) through the use of a new Low NO_X Combustion system (LNC) comprised of low NO_X burners (LNB) and overfire air (OFA) combustion control methods.

The project will not result in any increase in fuel consumption, heat input, or steam generation. However, due to the inverse relationship between NO_X and CO emissions, the new LNC equipment will result in an increase in CO emissions, and thus subject the proposed modification to the requirements of 40 CPR 52.21, Prevention of Significant Deterioration (PSD) as adopted under K.A.R. 28-19-350, as a result of being a major modification of a major stationary source for at least one regulated pollutant emitted in excess of the PSD significant emission levels. Holcomb 1 is an affected source subject to Title IV of the Federal Clean Air Act, Acid Deposition Control. The proposed project does not constitute a modification or reconstruction for the purpose of determining applicability of New Source Performance Standard (NSPS)

requirements. This project is subject to the provision of K.A.R. 28-19-300 (Construction permits and approvals; applicability) because the potential-to emit of CO exceeds 100 tons per year.

None of the following emissions will increase as a result of this project: particulate matter (PM), PM with a diameter less than 10 microns (PM_{IO}), PM with a diameter less than 2.5 microns ($PM_{2.5}$), sulfur dioxide (SO_2), volatile organic compounds (VOC), lead, sulfuric acid mist (H_2SO_4), fluorides, hydrogen sulfide (H_2S), total reduced sulfur, and carbon dioxide equivalent (CO_2e). An ambient impact analysis and a Best Available Control Technology (BACT) determination were conducted as a part of the construction permit application process.

Significant Applicable Air Regulations
The proposed activity is subject to Kansas Administrative Regulations (K.A.R.) relating to air pollution control. The following air quality regulations were determined to be applicable to this source:

K.A.R. 28-19-19 Continuous Emission Monitoring

K.A.R. 28-19-30 Indirect Heating Equipment Emission General Provisions

K.A.R. 28-19-31 Indirect Heating Equipment Emission Limitations

K.A.R. 28-19-300 Construction permits and approvals; applicability

K.A.R. 28-19-350 Prevention of significant deterioration of air quality

K.A.R. 28-19-650 Emissions Opacity Limits

Air Emission Unit Technical Specifications

The following equipment or equivalent is approved:

1. Installation of a Low NO_X Combustion System (LNC) comprised of low NO_X burners (LNB) and overfire air (OFA) combustion control methods.

Air Emissions Estimates from the Proposed Activity

Pollutant Type	Baseline Actual (tons per year)	Projected Actual (tons per year)	Change in Emissions (tons per year)
CO	509.1	3,711.0	3,201.8
Nitrogen Oxides (NO_X)	4,687.2	2,671.9	(2,015.3)
CO_2	--	--	(5,030.3)

Air Emission Limitations

Each emission limitation established or referenced in this permit applies to the respective emission source subject to that limitation at all times, including startup, shutdown and malfunction, unless the applicability of that limitation is expressly excluded under certain conditions as to which a different limitation is applicable under a specific provision of this permit. All requirements and conditions included in or referenced in this permit must be met. The exceedance of any emission limitation established by or referenced in this permit will constitute a violation of the permit and may be subject to enforcement action.

1. Holcomb Unit 1
    a. The thirty (30) day rolling average emission rate of carbon monoxide (CO) emissions shall not exceed 0.25 lb/MMBtu.

Monitoring, Recordkeeping and Reporting

1. Compliance with the CO BACT limit on H1 shall be demonstrated with an existing continuous emission monitoring system (CEMS). The CO CEMS was installed, and is certified, operated, maintained, and quality assured according to 40 CFR 60, Appendix B, Performance Specification 4 (PS4) and 40 CFR 60, Appendix F (Quality Assurance/ Quality Control)
2. Reports of excess emissions shall be submitted semi-annually in accordance with the requirements in 40 CFR 60.7(c). Additionally, a summary report, as referenced in 40 CFR 60.7(c) and defined in 40 CFR 60.7(d) should be submitted semi-annually to assure that CO CEMS is properly functioning.
3. The owner or operator shall maintain records of the occurrence and duration of any startup, shut-down, or malfunction in the operation of each unit subject to 40 CFR Part 60; any malfunction of any air pollution control equipment; and all periods during which a continuous monitoring system or monitoring device is inoperative. These requirements are described in 40 CFR 60.7(b).
4. Records shall be kept on site for 2 years in accordance with 60.7(f).

Notification

The following written notifications are to be submitted in accordance with 40 CFR 60.7(a).

1. The date construction starts, postmarked no later than 30 days after such date.
2. 40 CFR 60.7(a)(4) requires that written notification be provided for any physical or operational change which may increase the emission rate of any air pollutant to which a standard applies. Such notice is to be postmarked 60 days, or as soon as practicable, before the change is commenced and is to include the following information:
    a. the precise nature of the change;
    b. present and proposed emission control systems;
    c. the production capacity of Unit 2 before and after the change; and
    d. the expected completion date.

General Provisions

1. This document shall become void if the construction or modification has not commenced within 18 months of the effective date, or if the construction or modification is interrupted for a period of 18 months or longer.
2. A construction permit or approval must be issued by KDHE prior to commencing any construction or modification of equipment or processes which results in an increase of potential-to-emit equal to or greater than the thresholds specified by K.A.R 28-19-300.
3. Upon presentation of credentials and other documents as may be required by law, representatives of KDHE (including authorized contractors of KDHE) shall be allowed to:
    a. enter upon the premises where a regulated facility or activity is located or conducted or where records must be kept under conditions of this document;
    b. have access to and copy, at reasonable times, any records that must be kept under conditions of this document;
    c. inspect at reasonable times, any facilities, equipment (including monitoring and control equipment) practices or operations regulated or required under this document; and
    d. sample or monitor, at reasonable times, for the purposes of assuring compliance with this document or as otherwise authorized by the Secretary of KDHE, any substances or parameters at any location.
4. The emission unit or stationary source which is the subject of this document shall be operated in compliance with all applicable requirements of the Kansas Air Quality Act and the Federal Clean Air Act.
5. This document does not relieve the facility of the obligation to obtain other approvals, permits, licenses or documents of sanction which may be required by other federal, state or local government agencies.

Approval Engineer

_____ _____

Gerald McIntyre
Environmental Scientist
Air Permitting Section

Date Signed

APPENDIX F
AIR MODELING PROTOCOL

AIR DISPERSION MODELING PROTOCOL FOR PREVENTION OF SIGNIFICANT DETERIORATION PERMITTING HOLCOMB GENERATING STATION HOLCOMB 1 LOW-NO_X BURNER AND OVERFIRE AIR RETROFIT

May 5, 2011

Submitted by:

SUNFLOWER ELECTRIC POWER CORPORATION
A Touchstone Energy® Cooperative

2075 West St. John Street
Garden City, Kansas 67846

Shaw™ Shaw Environmental, Inc.

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1.0 Background

Shaw Environmental, Inc (Shaw) has prepared this modeling protocol on behalf of Sunflower Electric Power Corporation (Sunflower). As mandated by the Kansas Administrative Regulations (KAR 28-19-350), Sunflower is planning to submit a Prevention of Significant Deterioration (PSD) air permit application to request authorization to construct and operate new low nitrogen oxide burners (LNB) and Overfire Air (OFA) System on the existing Holcomb 1 steam generator system (H1). The PC steam generator is designed to fire low sulfur Powder River Basin (PRB) coal with a nominal net generation capacity of 389 megawatts (MW). Based on the emissions estimates, this project will exceed the potential to emit thresholds for carbon monoxide (CO) and will therefore require an air dispersion modeling analysis to be performed.

Shaw has prepared this modeling protocol which outlines the procedures to be followed in conducting PSD Class II Increment and National Ambient Air Quality Standards (NAAQS) modeling for the Holcomb Generating Station (Holcomb) LNB/OFA retrofit project located south of the city of Holcomb in Finney County, Kansas. As part of a PSD permit application, KAR 28-19-350(f)(1) requires comparisons of criteria pollutants impacts to the NAAQS, PSD significant impact, and PSD increment levels.

2.0 Modeling Methodology

Shaw proposes to conduct the modeling in accordance with the Kansas Department of Health and Environment (KDHE) approved modeling procedures. Specifically, the PSD application modeling procedure for screening determination of the proposed project impact for criteria pollutants meeting the significance level will be utilized for this modeling exercise.

2.1 Modeling Program

The emissions will be modeled using the latest version (11076) of AERSCREEN. AERSCREEN is the screening version of AERMOD. Unlike AERMOD, AERSCREEN can estimate concentrations without the need for meteorological data. A collaboration between the USEPA and State modelers, AERSCREEN was produced to give the user two options for modeling: either by using the command-prompt interface to give a more automated process for the user or by using the MAKEMET program which gives the user more flexibility for defining receptors. Shaw will be utilizing the command-prompt interface of the AERSCREEN model for this air quality impact analysis because the MAKEMET approach is more appropriate for an area with a more complex terrain than Holcomb. Shaw proposes to utilize all "regulatory default" options in the AERSCREEN model for this air quality impact analysis.

2.2 Meteorology

AERSCREEN will estimate concentrations without the need for the user to input meteorological data. The "regulator default" settings for minimum and maximum temperature, minimum wind speed, and anemometer height will be used to determine the meteorology in this model. The meteorology will be calculated using the AERMET seasonal tables. Being in western Kansas, the surface characteristics option will have the number six selection of "Grassland." The dominant surface profile is average moisture since western Kansas is not classified as an arid region.

2.3 Receptors

Receptors will be placed so that the maximum offsite ground-level concentrations can be determined. The only receptor information that AERSCREEN requires in its command-prompt user interface program is the maximum receptor distance, the distance to the fence line, and the height of any flagpole receptor. The closest fence line to H1 is at a distance of approximately 1300 m. That value will be used as the minimum distance to ambient air in the AERSCREEN program. For the maximum distance to probe, a value of 10 km will be used since this was the furthest receptor spacing requested by KDHE (500m apart for distances >10,000m). Because there is no elevated area of major concern around Holcomb, it is not necessary to model with a flag pole height.

2.4 Land Use and Terrain

A review of the land use within a 3 km radius of the proposed facility location was performed using the USGS land use map of the area. In accordance with the Auer land use classification procedure, the dispersion environment within a 3 km radius of the site is rural. The terrain in the vicinity of the facility is relatively flat therefore the terrain will not be included in the modeling.

2.5 Good Engineering Practice Stack Height

Sources included in a PSD permit application are subject to Good Engineering Practice (GEP) stack height requirements outlined in 40 CFR §51.100, 40 CFR §51.118, and KAR 28-19-18a through 18f. A GEP analysis will be conducted for the existing H1 stack. The purpose of this evaluation is to determine if the discharge from a stack will become caught in the turbulent wake of a "nearby" building or other structure, resulting in downwash of the plume. Downwash of the plume can result in elevated ground-level concentrations. The procedure is based on EPA's *Guideline for Determination of Good Engineering Practice Stack Height* (EPA 1985), the Stack Height Regulations (40 CFR 51), and current Model Clearinghouse guidance. GEP stack height, for stacks constructed after January 12, 1979, is defined as the greater of

- 65 meters, measured from the base of the stack and
- Stack Height calculated from the following formula:

$$H_G = H + 1.5L,$$

Where, H_G = the GEP Stack Height
H = the height of the "nearby" structure
L = the lesser of the building height or the greatest crosswind distance of the building - also known as maximum projected width.

The only stack affected by this project is the existing H1 steam generator stack, which has an actual height above 65 meters. This stack will not be modified for this project.

The term "nearby" is defined as a distance up to 5L (L defined above) from the proposed stack. As there is more than one structure within 5L to the steam generator stack, the stack height (H_G) calculations based on each of these structures will be completed.[1]

Nearby structures which are expected to influence building downwash include the existing equipment associated with Holcomb 1 and the expected equipment of Holcomb 2. The term "nearby" is defined as a distance up to 5L (L defined above) from the proposed stack, H1. H1 has a height below its GEP so it will be modeled with its actual height.

[1] The downwash analysis will be completed using EPA's Building Profile Input Program (BPIP-PRIME) model (Version 04274).

2.6 Emission Estimating and Modeling

The H1 steam generator is being modified with the installation of LNB/OFA system as a part of this permit application. As such, it is being included in the initial significant modeling analysis.

2.7 Load Analysis

Modeling runs will be conducted at full load and part loads to confirm that operation of the steam generator would not result in impacts greater than the NAAQS or PSD increments. The H1 steam generator load (and consequently the hourly emission rates) will be modeled at four different load points (100%, 75%, 50% and 25%) to account for varying loads and process conditions. This methodology will account for all worst-case conditions that can be experienced at the facility.

In addition, this load analysis will account for emissions during startup and shutdown operations. During startup, the main boiler is first fired on natural gas until it reaches the appropriate conditions, after which a coal fire is established in the steam generator. The low load conditions (25% and 50%) will account for these conditions. Similarly, when the unit is shutting down, the load in the boiler is gradually decreased until no fuel is fed to the boiler. The low load conditions (25% and 50%) will account for these conditions.

2.8 Class I Modeling Methodology

Holcomb Generating Station is more than 200 km from the nearest Class I area (Great Sand Dunes National Wildlife Area, approximately 400 km west). The Federal Bureau of Land Management (FLM) will not be contacted by Sunflower or Shaw to determine if any special air dispersion modeling analysis is required with regards to the Great Sand Dunes National Wildlife Area. Should KDHE communication with the FLM result in a request for an analysis of the potential impacts on the Class I area, the FLM will be contacted to determine the appropriate modeling and methodology to employ.

3.0 PSD Modeling Methodology

3.1 Preliminary Analysis

The initial step in modeling for PSD applications is the screening determination of the impact of the contemporaneous net increase of criteria pollutants due to the H1 LNB/OFA retrofit. The net increases for each pollutant will be calculated and tabulated for inclusion in the modeling report.

The modeled results from the contemporaneous emissions increases will be compared to the PSD modeling significance levels listed in KAR 28-19-350. Those values, along with the NAAQS [40 CFR 50], monitoring significance level [40 CFR 52.21(i)(5)(i)], and the PSD Class II Increment [40 CFR 52.21(c)], are reproduced in the following table.

Table 1
NAAQS, Significance Levels and Class II Increments ($\mu g/m^3$)

Pollutant	Averaging Period	NAAQS	Modeling Significance Level	Monitoring Significance Level	PSD Class II Increment
CO	8-hour	10,000	500	575	NA
	1-hour	40,000	2000	NA	NA

The emissions increase for the project is associated with the LNB/OFA retrofit. The emissions increases will include the proposed unit's maximum potential to emit hourly emission rates based upon federally enforceable operating limits. Additionally, per 40 CFR 51 Appendix A to Appendix W, should the stack parameters change in association with operating conditions (variations in base load) leading to higher ground level concentrations, the worst-case scenario will be modeled. Sunflower is opting to model all feasible operating scenarios and as such, will effectively model these conditions. The preliminary analysis using AERSCREEN will be conducted for this project. If the screening run does not exceed the significance level at any off site receptor, no further modeling will be conducted. In all cases, the maximum impact will be used. Should the AERSCREEN results indicate that predicted concentrations exceed the modeling significance level, Sunflower will submit a revised modeling protocol detailing how the modeling analysis will be done utilizing the AERMOD modeling program.

4.0 Data Presentation

The modeling report will be submitted as a supplement to the PSD permit application and will contain all of the information required for a complete PSD application. These elements include the following:

- An overview of the project,
- A list of emissions and stack parameters,
- A plot plan,
- The approved modeling protocol,
- GEP discussion/calculations,
- A summary of modeling results,
- Building downwash files,
- Modeling input and output files on CD-ROM.

APPENDIX G
AIR DISPERSION MODELS ON CD-ROM