1490001
C-11157
Jerry

Westar Energy.

April 4, 2013

RECEIVED

APR 04 2013

BUREAU OF AIR

Mr. Gerald McIntyre
Bureau of Air & Radiation
Kansas Department of Health & Environment
1000 SW Jackson, Suite 310
Topeka, KS 66612

Re: Westar Energy, Inc. – Jeffrey Energy Center
Source ID - 1490001
Unit 1 and 2 Low NOx Systems – PSD Permit Application

Dear Mr. McIntyre:

Westar Energy, Inc. (Westar) is submitting this air quality permit application for a NOx reduction project at the Jeffrey Energy Center located in St. Mary's, Kansas. The proposed project will result in decreases of NO_X and CO_2 emissions, and an increase of CO emissions.

One copy of the air permit application is attached to this letter. In addition, a copy of the proposed draft permit and modeling files are included on CD for your use. A check in the amount of $5,500 is included as required by K.A.R. 28-19-304(b).

If you have any questions regarding this submittal, please do not hesitate to contact me at (785) 575-1614, or via email at Dan.Wilkus@westarenergy.com.

We look forward to your evaluation of the application.

Sincerely,

WESTAR ENERGY, INC.

Daniel R. Wilkus, P.E.
Director, Air Programs

Westar Energy, Inc.

Westar Energy

Modification of Low NO_X Systems
PSD Construction Air Permit Application
Jeffrey Energy Center
Units 1 and 2

April 2013

Sega

ENGINEERING & TECHNICAL SERVICES

Project No. 12-0256-01

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SECTION 1

INTRODUCTION

INTRODUCTION

Westar Energy, Inc. (Westar) is proposing to undertake an environmentally beneficial project to reduce nitrogen oxide (NO_X) emissions at the Jeffrey Energy Center (JEC) located near St. Mary's, Kansas. Westar proposes to further enhance and/or tune the existing low NO_X systems on Units 1 and 2 to upgrade performance and lower emissions. The facility, which is a major stationary source under the Prevention of Significant Deterioration (PSD) regulation, consists of three pulverized coal-fired boilers. Units 1 and 2's existing low NO_X burners (LNBs) and separated overfire air systems (SOFA) will be enhanced and/or tuned to further reduce emissions of NO_X. As is typical with NO_X reduction projects through combustion controls, a balance must be struck between lowering NO_X and increasing carbon monoxide (CO). As a result of this NO_X reduction project, the annual CO emissions increase may be above the PSD significance levels; therefore, a PSD major modification permit is required.

Westar is applying for a permit to modify its existing low NO_X systems, pursuant to Kansas Administrative Regulation (K.A.R) 28-19-300. This application demonstrates that the requested CO level represents the use of Best Available Control Technology (BACT) and that the associated CO emissions will not have a significant impact on ambient air quality.

The Kansas Department of Health and Environment (KDHE) Notification of Construction or Modification Form can be found in Appendix A. Emission calculations are presented in Appendix B. Potential emissions associated with the project are shown in *Table 1.1 - Summary of Emissions Changes and PSD Significant Emissions Rates* along with the threshold levels for PSD.

Table 1.1 - Summary of Emissions Changes and PSD Significant Emissions Rates

Criteria Pollutant	Baseline Actual Emissions (tpy)	Projected Actual Emissions (tpy)	Emission Change (tpy)	PSD SER (tpy)	Major Modification? (Yes/No)
CO	8,504	23,483	14,979	100	Yes
NO_X	15,118	8,511	-6,607	40	No
CO_2	10,771,528	10,747,993	-23,535	100,000	No

CO is the only pollutant subject to a BACT determination for this project. BACT for CO was determined to be good combustion practices. The associated BACT emission limit has been determined to be 0.4 lb/MMBtu on a 30-day rolling average, excluding periods of startup, shutdown, and malfunction. This BACT analysis can be found in Appendix C.

An air quality analysis was performed for the new Units 1 and 2 CO emission rate. AERMOD was the model used for the analysis. The modeling results show that the CO impacts are well below the CO significant impact level (SIL). As such, it has been determined that the project will not have a significant impact on the ambient air surrounding the JEC plant site. This air quality analysis can be found in Appendix D.

A proposed draft KDHE permit can be found in Appendix E.

SECTION 2

PROJECT DESCRIPTION

PROJECT DESCRIPTION

JEC is an existing coal-fired, electric-generating station located near St. Mary's, Kansas. JEC is located in Pottawatomie County which is currently designated as an attainment/ unclassified area for all criteria pollutants in 40 CFR, Part 81.

The existing low NO_X systems on Units 1 and 2 consist of LNBs, SOFA, and associated equipment and ductwork. Westar proposes to further enhance and/or tune the existing low NO_X systems in order to achieve additional NO_X reductions. Unit 1's modifications include further tuning of existing equipment. Unit 2's low NO_X system modifications include upgrades to the existing LNBs and SOFA, adjustments to existing SOFA, additional SOFA for deeper staging, low NO_X system tuning, and installation of associated equipment. This proposed modification work will be hereinafter referred to as the "Project".

The formation of NO_X during the combustion of fossil fuels is a result of the oxidation of either nitrogen in the combustion air or nitrogen in the fuel. The former is referred to as thermal NO_X, while the latter is typically called fuel NO_X. During the combustion of coal, a majority of the NO_X formed is fuel NO_X. Fuel NO_X is very difficult to prevent as it is not possible to remove nitrogen from the fuel before combustion.

There are two overall approaches to reduce NO_X emissions from a boiler: pre-combustion control and post-combustion reduction. Pre-combustion control reduces NO_X by preventing its formation by manipulating how combustion is carried out. Post-combustion reduction reduces the NO_X formed in the furnace by the addition of a reagent that reacts chemically with the NO_X after it has formed.

LNBs reduce NO_X by lowering the peak flame temperature and limiting the amount of oxygen available at the burner front. LNBs tend to spread the flame out and elongate combustion. Oxygen is required for the formation of NO_X; LNBs limit the availability of oxygen and the NO_X produced is reduced. Lower oxygen levels in the combustion zone create a fuel-rich zone that promotes the formation of CO which is undesirable.

For the Project, the existing Unit 2 LNBs will have their burner tips (auxiliary air tips, oil gun tips, and coal nozzle tips) replaced with new components. The bottom three stationary coal nozzles in each corner will be replaced with new horizontal bias combustion burners.

The addition of overfire air (OFA) and SOFA are methods of staging combustion in the furnace. In OFA and SOFA systems, a portion of the combustion air is redirected from the lower fuel-rich area to a location higher in the furnace. This limits the amount of oxygen available during the phase of combustion when NO_X is formed. For the Project, existing SOFA port sizes will be changed and additional SOFA ports will be added for deeper staging. A substantial amount of new ductwork will also be required to accommodate these SOFA port modifications.

SECTION 3

EMISSIONS CALCULATIONS

EMISSIONS CALCULATIONS

JEC is considered to be a major source with respect to PSD regulations, as the potential emissions of at least one criteria pollutant exceeds the major source threshold of 100 tons per year (tpy). Major modifications at existing major stationary sources occur when the emissions increase resulting from a project exceeding the PSD significant emission rates (SER). The determination of the annual emissions change associated with the project follows the "actual-to-projected-actual" applicability test outlined in the PSD regulations [40 CFR 52.21(a)(2)(iv)(c)] for existing PSD major stationary sources. Thus, the baseline actual and projected actual emissions associated with the proposed Project were calculated. Details of the Project emission calculations are presented in Appendix B.

The following PSD pollutants were evaluated: NO_x, CO, and CO_2. As summarized in *Table 3.1 - Project Emissions*, the calculated Project emissions increase for CO is greater than the PSD SER. Thus, the Project is a major PSD modification for CO emissions. The Project will result in a decrease in NO_x and CO_2 emissions.

Table 3.1 - Project Emissions

Criteria Pollutant	Baseline Actual Emissions (tpy)	Projected Actual Emissions (tpy)	Emission Change (tpy)	PSD SER (tpy)	Major Modification? (Yes/No)
CO	8,504	23,483	14,979	100	Yes
NO_x	15,118	8,511	-6,607	40	No
CO_2	10,771,528	10,747,993	-23,535	100,000	No

According to 40 CFR 52.21(a)(2)(iv)(c), an emissions increase is determined as the sum of the difference between the projected actual emissions and the baseline actual emissions. "Baseline actual emissions" is defined in 40 CFR 52.21(b)(48)(i) as the actual emissions during any consecutive 24-month period selected by the Owner during the five-year period prior to start of project construction. The same 24-month period must be selected for each emission unit. However, different 24-month periods may be selected for each regulated pollutant assessed. The spreadsheet in Appendix B has the historical total monthly emissions from Units 1 and 2 for CO, CO_2, and NO_x.

"Projected actual emissions" is defined in 40 CFR 52.21(b)(41)(i) as "the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that regulated NSR pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source. Projected actual emissions for Units 1 and 2 are calculated as the product of the projected actual emission factors (lb/MMBtu) and projected annual heat input (MMBtu/yr)." The projected actual CO emission factor assumed for this emission change analysis is 0.4 lb/MMBtu. As discussed in Appendix C, this emission level represents the application of BACT for this modification.

SECTION 4

REGULATORY REVIEW

REGULATORY REVIEW

The Project is potentially subject to various Federal and State air regulations. A regulatory review was performed to determine specific applicability of the various regulations. A summary of the review is provided below.

4.1 PREVENTION OF SIGNIFICANT DETERIORATION REGULATIONS

JEC is considered to be a major source with respect to PSD regulations as the potential emissions of at least one criteria pollutant exceeds the major source threshold of 100 tpy. As shown in *Table 4.1 - Summary of Project Emissions and PSD Significant Emission Rates* the total new emissions of CO associated with the Project will be above the PSD significance levels; therefore, a PSD major modification permit is required.

Table 4.1 - Summary of Project Emissions and PSD Significant Emissions Rates

Criteria Pollutant	Baseline Actual Emissions (tpy)	Projected Actual Emissions (tpy)	Emission Change (tpy)	PSD SER (tpy)	Major Modification? (Yes/No)
CO	8,504	23,483	14,979	100	Yes
NO_X	15,118	8,511	-6,607	40	No
CO_2	10,771,528	10,747,993	-23,535	100,000	No

4.1 NEW SOURCE PERFORMANCE STANDARDS, SUBPART Da - ELECTRIC UTILITY STEAM GENERATING UNITS

The New Source Performance Standards (NSPS), Subpart Da applies to each electric utility steam generating unit that fulfills the following criteria:

1. That is capable of combusting more than 250 MMBtu/hr heat input of fossil fuel.

2. For which construction, modification, or reconstruction commenced after September 18, 1978.

The definition of modification provided in 40 CFR 60.2 is:

> Any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emissions of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.

As discussed in Section 3 - Emissions Calculations, the only pollutant that experiences an increase in emissions is CO. However, 40 CFR 60, Subpart Da does not include a standard for CO emissions; therefore, the Project is not considered a modification under NSPS.

4.3 KANSAS AIR REGULATIONS

Several State regulations have been identified as potentially applicable to the Project. A review of each potentially applicable regulation is provided below.

4.3.1 K.A.R. 28-19-300 - Construction Permits and Approvals; Applicability

This regulation requires that anyone who proposes to construct or modify a stationary source or emissions unit shall obtain a construction permit prior to commencing such operations. Westar is applying for a construction permit pursuant to K.A.R. 28-19-300(a)(1) as the increase in CO emissions exceeds 100 tpy.

4.3.2 K.A.R. 28-19-513 - Class I Operating Permits; Permit Amendment, Modification or Re-Opening, and Changes Not Requiring a Permit Action

This regulation outlines the requirements for amending the Class I Operating Permit resulting from changes at the facility. K.A.R. 28-19-513(d) is the provision for Title V revisions that require significant permit modifications. This Project will require a significant modification to the Title V permit as the Project does not qualify for an administrative amendment, off-permit modification, or a minor permit modification.

APPENDICES

APPENDIX A

KANSAS DEPARTMENT OF HEALTH AND ENVIRONMENT NOTIFICATION OF CONSTRUCTION OR MODIFICATION FORM

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: X 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: 1490001

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Jerry Mc

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2) Mailing Information:
Company Name: Westar Energy, Inc.
Address: 818 S. Kansas Avenue, P.O. Box 889
City, State, Zip: Topeka, Kansas 66601

3) Source Location: Westar Energy, Inc.
Street Address: 25905 Jeffrey Road
City, County, State, Zip: St. Mary's, Kansas 66536
Section, Township, Range:
Latitude & Longitude Coordinates:

4) NAICSC/SIC Code (Primary): NAICS: 221112, SIC: 4911

5) Primary Product Produced at the Source: Electrical Generation

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

If no, please explain:

7) Is a permit fee being submitted? : X Yes No

If yes, please include the facility=s federal employee identification number (FEIN #) 480290150

8) Person to Contact at the Site: Kelly Kelsey Phone: (785) 456-6129
Title: Environmental Coordinator

9) Person to Contact Concerning Permit: Mr. Daniel R. Wilkus, P.E. Phone: (785) 575-1614
Title: Director, Air Programs
Email: Dan.Wilkus@westarenergy.com Fax: (785) 575-8039

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 : Daniel R. Wilkus, P.E. – Director, Air Programs

Address: 818 South Kansas Avenue, Topeka, KS 66601

Signature: [signature] Date: 4 / 4 / 2013 Phone: (785) 575-1614

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

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** $16,300,000
Multiply by .05% (.0005)	x .0005
Total	**Line 2** $8,150
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** $ 5,500 Minimum fee is $100

Daniel R. Wilkus, P.E. – Director, Air Programs
(Print)

Certifier of Capital Cost DRWilkus 4/4/2013
(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.

APPENDIX B

PROJECT EMISSIONS CALCULATIONS

STATE	FACILITY_NAME	OP_YEAR	OP_MONTH	NOx (tons) Unit 1	NOx (tons) Unit 2	TOTAL NOx (tons)	CO2 (tons) Unit 1	CO2 (tons) Unit 2	TOTAL CO2 (tons)	HEAT_INPUT (MMBtu) Unit 1	HEAT_INPUT (MMBtu) Unit 2	TOTAL HEAT_INPUT (MMBtu)	NOx 24-Month Rolling Avg. (tpy)	CO2 24-Month Rolling Avg. (tpy)	Heat Input 24-Month Rolling Avg. (MMBtu/yr)
KS	Jeffrey Energy Center	2007	10	1,116	173	1,289	538,488	103,753	642,241	5,249,177	1,011,786	6,260,963			
KS	Jeffrey Energy Center	2007	11	1,116	597	1,714	537,975	388,456	926,431	5,243,420	3,788,706	9,032,126			
KS	Jeffrey Energy Center	2007	12	966	792	1,758	478,580	506,533	985,113	4,665,614	4,937,302	9,602,916			
KS	Jeffrey Energy Center	2008	1	997	980	1,977	479,461	545,508	1,024,969	4,571,520	5,201,262	9,772,782			
KS	Jeffrey Energy Center	2008	2	1,189	958	2,148	557,856	520,808	1,078,664	5,319,003	4,965,753	10,284,756			
KS	Jeffrey Energy Center	2008	3	1	1,055	1,055	627	564,614	565,240	5,974	5,383,421	5,389,395			
KS	Jeffrey Energy Center	2008	4	0	988	988	0	527,500	527,500	0	5,029,545	5,029,545			
KS	Jeffrey Energy Center	2008	5	251	855	1,106	277,700	508,108	785,808	2,680,085	4,844,652	7,524,737			
KS	Jeffrey Energy Center	2008	6	343	734	1,076	413,035	427,965	841,001	3,938,647	4,082,993	8,021,641			
KS	Jeffrey Energy Center	2008	7	369	893	1,262	466,442	528,135	994,578	4,447,544	5,036,392	9,483,936			
KS	Jeffrey Energy Center	2008	8	376	782	1,159	506,951	454,638	961,589	4,833,886	4,335,915	9,169,801			
KS	Jeffrey Energy Center	2008	9	326	766	1,092	451,788	448,172	899,960	4,307,675	4,273,615	8,581,291			
KS	Jeffrey Energy Center	2008	10	404	920	1,324	474,986	521,574	996,559	4,529,005	4,973,046	9,502,051			
KS	Jeffrey Energy Center	2008	11	452	719	1,172	496,104	437,033	933,138	4,730,204	4,169,244	8,899,449			
KS	Jeffrey Energy Center	2008	12	453	755	1,208	548,122	410,865	958,988	5,226,174	3,920,414	9,146,588			
KS	Jeffrey Energy Center	2009	1	552	1,019	1,571	470,831	504,793	975,624	4,489,235	4,813,818	9,303,053			
KS	Jeffrey Energy Center	2009	2	502	769	1,271	401,384	431,988	833,371	3,827,551	4,119,405	7,946,956			
KS	Jeffrey Energy Center	2009	3	722	189	911	520,312	101,856	622,169	4,961,029	973,154	5,934,182			
KS	Jeffrey Energy Center	2009	4	488	57	546	465,885	48,243	514,128	4,442,083	511,297	4,953,380			
KS	Jeffrey Energy Center	2009	5	311	739	1,050	373,799	454,107	827,907	3,564,232	4,332,322	7,896,554			
KS	Jeffrey Energy Center	2009	6	383	733	1,116	480,753	447,032	927,785	4,583,814	4,262,341	8,846,155			
KS	Jeffrey Energy Center	2009	7	417	838	1,255	569,251	473,842	1,043,093	5,427,680	4,518,478	9,946,158			
KS	Jeffrey Energy Center	2009	8	434	853	1,287	542,236	506,021	1,048,258	5,170,054	4,824,761	9,994,815			
KS	Jeffrey Energy Center	2009	9	119	782	902	148,257	489,064	637,320	1,413,590	4,663,084	6,076,674	15,118	10,275,716	98,299,952
KS	Jeffrey Energy Center	2009	10	0	898	898	0	528,065	528,065	0	5,034,938	5,034,938	14,923	10,218,628	97,686,940
KS	Jeffrey Energy Center	2009	11	284	590	873	341,425	383,668	725,093	3,256,740	3,658,821	6,915,561	14,503	10,117,959	96,628,657
KS	Jeffrey Energy Center	2009	12	475	637	1,112	573,315	421,313	994,629	5,466,385	4,017,486	9,483,871	14,180	10,122,717	96,569,135
KS	Jeffrey Energy Center	2010	1	508	967	1,475	604,765	555,999	1,160,764	5,766,884	5,301,283	11,068,167	13,929	10,190,614	97,216,827
KS	Jeffrey Energy Center	2010	2	441	987	1,428	547,954	524,043	1,071,997	5,224,582	4,996,604	10,221,186	13,569	10,187,280	97,185,042
KS	Jeffrey Energy Center	2010	3	416	445	861	553,764	262,406	816,170	5,279,996	2,503,166	7,783,161	13,472	10,312,745	98,381,925
KS	Jeffrey Energy Center	2010	4	318	755	1,074	411,156	432,758	843,914	3,920,563	4,126,786	8,047,349	13,514	10,470,952	99,890,827
KS	Jeffrey Energy Center	2010	5	388	725	1,113	489,066	422,142	911,207	4,663,095	4,025,252	8,688,348	13,518	10,533,652	100,472,633
KS	Jeffrey Energy Center	2010	6	366	699	1,065	453,618	398,412	852,030	4,325,736	3,800,449	8,126,185	13,513	10,539,167	100,524,905
KS	Jeffrey Energy Center	2010	7	288	945	1,234	377,084	496,138	873,221	3,596,290	4,730,523	8,326,813	13,499	10,478,488	99,946,343
KS	Jeffrey Energy Center	2010	8	425	913	1,339	556,952	498,752	1,055,703	5,310,374	4,755,443	10,065,816	13,589	10,525,546	100,394,350
KS	Jeffrey Energy Center	2010	9	368	578	946	475,338	366,771	842,109	4,532,211	3,497,468	8,029,679	13,516	10,496,620	100,118,544
KS	Jeffrey Energy Center	2010	10	252	724	976	359,883	439,826	799,709	3,431,892	4,193,618	7,625,510	13,342	10,398,195	99,180,274
KS	Jeffrey Energy Center	2010	11	418	687	1,105	459,384	416,624	876,008	4,380,092	3,972,396	8,352,488	13,308	10,369,631	98,906,794
KS	Jeffrey Energy Center	2010	12	375	1,036	1,410	480,005	522,967	1,002,972	4,577,051	4,986,337	9,563,388	13,410	10,391,623	99,115,194
KS	Jeffrey Energy Center	2011	1	456	578	1,034	545,048	421,071	966,119	5,196,879	4,014,782	9,211,660	13,141	10,386,870	99,069,498
KS	Jeffrey Energy Center	2011	2	452	358	810	481,396	184,854	666,250	4,589,972	1,762,531	6,352,503	12,910	10,303,309	98,272,271
KS	Jeffrey Energy Center	2011	3	381	0	381	503,108	0	503,108	4,796,988	0	4,796,988	12,645	10,243,779	97,703,674
KS	Jeffrey Energy Center	2011	4	232	33	265	335,439	49,092	384,531	3,199,473	469,790	3,669,263	12,505	10,178,981	97,061,615
KS	Jeffrey Energy Center	2011	5	407	295	702	514,030	461,296	975,326	4,901,372	4,398,337	9,299,709	12,331	10,252,690	97,763,193
KS	Jeffrey Energy Center	2011	6	449	397	846	536,741	504,009	1,040,750	5,117,668	4,805,586	9,923,254	12,196	10,309,173	98,301,742
KS	Jeffrey Energy Center	2011	7	412	469	882	527,180	591,489	1,118,670	5,026,940	5,640,764	10,667,704	12,009	10,346,961	98,662,515
KS	Jeffrey Energy Center	2011	8	423	474	897	585,443	577,334	1,162,777	5,582,024	5,504,723	11,086,746	11,814	10,404,221	99,208,481
KS	Jeffrey Energy Center	2011	9	327	318	645	487,682	446,356	934,038	4,649,917	4,256,313	8,906,230	11,686	10,552,580	100,623,258
KS	Jeffrey Energy Center	2011	10	312	292	604	467,437	437,355	904,791	4,457,325	4,171,768	8,629,093	11,538	10,740,943	102,420,336
KS	Jeffrey Energy Center	2011	11	324	198	522	483,186	303,077	786,262	4,607,025	2,890,548	7,497,573	11,362	10,771,528	102,711,342
KS	Jeffrey Energy Center	2011	12	297	313	610	465,154	474,915	940,069	4,435,506	4,528,176	8,963,681	11,111	10,744,248	102,451,247
KS	Jeffrey Energy Center	2012	1	280	235	515	458,154	372,229	830,383	4,368,364	3,549,559	7,917,922	10,631	10,579,058	100,876,125
KS	Jeffrey Energy Center	2012	2	209	262	471	335,105	407,063	742,168	3,195,348	3,881,229	7,076,577	10,153	10,414,143	99,303,820
KS	Jeffrey Energy Center	2012	3	0	266	266	0	420,376	420,376	0	4,008,169	4,008,169	9,855	10,216,246	97,416,325
KS	Jeffrey Energy Center	2012	4	40	217	257	42,908	352,535	395,442	410,560	3,361,321	3,771,881	9,447	9,992,010	95,278,590
KS	Jeffrey Energy Center	2012	5	281	322	603	422,878	453,971	876,849	4,032,684	4,328,468	8,361,152	9,192	9,974,831	95,114,993
KS	Jeffrey Energy Center	2012	6	309	275	583	478,412	404,624	883,036	4,561,523	3,857,965	8,419,488	8,951	9,990,334	95,261,644
KS	Jeffrey Energy Center	2012	7	374	308	682	554,020	446,922	1,000,942	5,282,427	4,261,633	9,544,060	8,675	10,054,195	95,870,268
KS	Jeffrey Energy Center	2012	8	351	293	644	541,747	427,845	969,592	5,165,416	4,081,561	9,246,977	8,327	10,011,140	95,460,848
KS	Jeffrey Energy Center	2012	9	299	299	598	449,293	446,000	895,293	4,285,254	4,252,492	8,537,746	8,153	10,037,731	95,714,882

All Data from EPA Acid Rain Program Database

Monthly										24-Month Rolling	
OP_YEAR	OP_MONTH	AVERAGE CO (lb/MMBtu) Unit 1	AVERAGE CO (lb/MMBtu) Unit 2	CO (lbs) UNIT 1 (CALC)	CO (lbs) UNIT 2 (CALC)	TOTAL CO (lbs) (CALC)	HEAT INPUT (MMBTU) UNIT 1 (Acid Rain)	HEAT INPUT (MMBTU) UNIT 2 (Acid Rain)	TOTAL HEAT INPUT (Acid Rain)	CO 24-Month Rolling Avg. (tpy)	Heat Input 24-Month Rolling Avg. (MMBtu/yr)
2007	10	0.1658	0.1568	870,536	158,676	1,029,212	5,249,177	1,011,786	6,260,963		
2007	11	0.1658	0.1568	869,582	594,174	1,463,756	5,243,420	3,788,706	9,032,126		
2007	12	0.1658	0.1568	773,757	774,306	1,548,063	4,665,614	4,937,302	9,602,916		
2008	1	0.1658	0.1568	758,152	815,702	1,573,854	4,571,520	5,201,262	9,772,782		
2008	2	0.1658	0.1568	882,116	778,768	1,660,884	5,319,003	4,965,753	10,284,756		
2008	3	0.1658	0.1568	991	844,270	845,261	5,974	5,383,421	5,389,395		
2008	4	0.1658	0.1568	0	788,772	788,772	0	5,029,545	5,029,545		
2008	5	0.1658	0.1568	444,472	759,776	1,204,248	2,680,085	4,844,652	7,524,737		
2008	6	0.1658	0.1568	653,195	640,327	1,293,522	3,938,647	4,082,993	8,021,641		
2008	7	0.1658	0.1568	737,592	789,846	1,527,438	4,447,544	5,036,392	9,483,936		
2008	8	0.1658	0.1568	801,663	679,992	1,481,655	4,833,886	4,335,915	9,169,801		
2008	9	0.1658	0.1568	714,395	670,222	1,384,617	4,307,675	4,273,615	8,581,291		
2008	10	0.1658	0.1568	751,101	779,912	1,531,013	4,529,005	4,973,046	9,502,051		
2008	11	0.1375	0.1568	650,445	653,853	1,304,299	4,730,204	4,169,244	8,899,449		
2008	12	0.1446	0.1568	755,946	614,830	1,370,776	5,226,174	3,920,414	9,146,588		
2009	1	0.1561	0.1568	700,594	754,940	1,455,534	4,489,235	4,813,818	9,303,053		
2009	2	0.1440	0.1568	551,248	646,037	1,197,285	3,827,551	4,119,405	7,946,956		
2009	3	0.0657	0.1568	325,715	152,618	478,333	4,961,029	973,154	5,934,182		
2009	4	0.1011	0.1568	449,152	80,186	529,337	4,442,083	511,297	4,953,380		
2009	5	0.1035	0.1568	369,014	679,428	1,048,443	3,564,232	4,332,322	7,896,554		
2009	6	0.1235	0.1568	566,281	668,453	1,234,734	4,583,814	4,262,341	8,846,155		
2009	7	0.1455	0.1568	789,635	708,623	1,498,258	5,427,680	4,518,478	9,946,158		
2009	8	0.2497	0.1568	1,290,747	756,656	2,047,403	5,170,054	4,824,761	9,994,815		
2009	9	0.0750	0.1568	106,002	731,301	837,303	1,413,590	4,663,084	6,076,674	**7,583**	**98,299,952**
2009	10	0	0.1568	0	789,618	789,618	0	5,034,938	5,034,938	**7,524**	**97,686,940**
2009	11	0.1608	0.1568	523,564	573,805	1,097,369	3,256,740	3,658,821	6,915,561	**7,432**	**96,628,657**
2009	12	0.1208	0.1568	660,203	630,053	1,290,256	5,466,385	4,017,486	9,483,871	**7,368**	**96,569,135**
2010	1	0.1271	0.1568	732,745	831,388	1,564,133	5,766,884	5,301,283	11,068,167	**7,365**	**97,216,827**
2010	2	0.25	0.1568	1,306,146	783,606	2,089,752	5,224,582	4,996,604	10,221,186	**7,472**	**97,185,042**
2010	3	0.25	0.1568	1,319,999	392,566	1,712,565	5,279,996	2,503,166	7,783,161	**7,689**	**98,381,925**
2010	4	0.25	0.1568	980,141	647,195	1,627,335	3,920,563	4,126,786	8,047,349	**7,899**	**99,890,827**
2010	5	0.1478	0.1568	689,248	631,271	1,320,519	4,663,095	4,025,252	8,688,348	**7,928**	**100,472,633**
2010	6	0.1648	0.1568	712,818	596,016	1,308,834	4,325,736	3,800,449	8,126,185	**7,932**	**100,524,905**
2010	7	0.1308	0.1568	470,490	741,877	1,212,368	3,596,290	4,730,523	8,326,813	**7,853**	**99,946,343**
2010	8	0.1103	0.1568	585,692	745,785	1,331,477	5,310,374	4,755,443	10,065,816	**7,815**	**100,394,350**
2010	9	0.1175	0.1568	532,678	548,500	1,081,178	4,532,211	3,497,468	8,029,679	**7,740**	**100,118,544**
2010	10	0.2097	0.1568	719,751	657,676	1,377,426	3,431,892	4,193,618	7,625,510	**7,701**	**99,180,274**
2010	11	0.1446	0.1568	633,169	622,982	1,256,151	4,380,092	3,972,396	8,352,488	**7,689**	**98,906,794**
2010	12	0.1878	0.1568	859,474	781,996	1,641,470	4,577,051	4,986,337	9,563,388	**7,757**	**99,115,194**
2011	1	0.2110	0.1568	1,096,332	629,629	1,725,961	5,196,879	4,014,782	9,211,660	**7,824**	**99,069,498**
2011	2	0.1191	0.1568	546,487	276,414	822,901	4,589,972	1,762,531	6,352,503	**7,731**	**98,272,271**
2011	3	0.2137	0.1568	1,025,099	0	1,025,099	4,796,988	0	4,796,988	**7,867**	**97,703,674**
2011	4	0.1586	0.1568	507,336	73,676	581,012	3,199,473	469,790	3,669,263	**7,880**	**97,061,615**
2011	5	0.1665	0.1568	815,930	689,781	1,505,711	4,901,372	4,398,337	9,299,709	**7,995**	**97,763,193**
2011	6	0.1487	0.1568	761,097	753,649	1,514,746	5,117,668	4,805,586	9,923,254	**8,065**	**98,301,742**
2011	7	0.1988	0.1568	999,138	884,628	1,883,767	5,026,940	5,640,764	10,667,704	**8,161**	**98,662,515**
2011	8	0.1612	0.1568	899,919	863,293	1,763,212	5,582,024	5,504,723	11,086,746	**8,090**	**99,208,481**
2011	9	0.1751	0.1211	814,039	515,321	1,329,360	4,649,917	4,256,313	8,906,230	**8,213**	**100,623,258**
2011	10	0.1722	0.1743	767,546	727,110	1,494,657	4,457,325	4,171,768	8,629,093	**8,389**	**102,420,336**
2011	11	0.2072	0.1662	954,479	480,533	1,435,012	4,607,025	2,890,548	7,497,573	**8,474**	**102,711,342**
2011	12	0.1720	0.1433	762,720	648,894	1,411,614	4,435,506	4,528,176	8,963,681	**8,504**	**102,451,247**
2012	1	0.1812	0.1432	791,420	508,145	1,299,566	4,368,364	3,549,559	7,917,922	**8,438**	**100,876,125**
2012	2	0.1543	0.1684	493,033	653,782	1,146,815	3,195,348	3,881,229	7,076,577	**8,202**	**99,303,820**
2012	3	0	0.1453	0	582,265	582,265	0	4,008,169	4,008,169	**7,920**	**97,416,325**
2012	4	0.0242	0.1113	9,922	374,146	384,068	410,560	3,361,321	3,771,881	**7,609**	**95,278,590**
2012	5	0.1592	0.1445	641,878	625,324	1,267,202	4,032,684	4,328,468	8,361,152	**7,595**	**95,114,993**
2012	6	0.1849	0.2081	843,266	802,985	1,646,251	4,561,523	3,857,965	8,419,488	**7,680**	**95,261,644**
2012	7	0.2172	0.1920	1,147,535	818,096	1,965,631	5,282,427	4,261,633	9,544,060	**7,868**	**95,870,268**
2012	8	0.2094	0.1782	1,081,681	727,362	1,809,043	5,165,416	4,081,561	9,246,977	**7,988**	**95,460,848**
2012	9	0.1947	0.1415	834,238	601,564	1,435,802	4,285,254	4,252,492	8,537,746	**8,076**	**95,714,882**

CO Data from CEMS, Heat Input Data from EPA Acid Rain Program Database

JEC1 CEM began operation in 11/2008. Prior data is an average of the CEMs data since 11/2008

JEC2 CEM began operation in 9/2011. Prior data is an average of the CEMs data since 9/2011

EMISSION FACTORS

		CO lb/MMBtu	NOx lb/MMBtu
JEC1	Post Project Emission Factors	0.4	0.15
JEC2	Post Project Emission Factors	0.4	0.14

PROJECTED ACTUAL HEAT INPUT

	MMBtu/yr
JEC1	58,310,323
JEC2	59,106,735

PROJECTED ACTUAL EMISSIONS WITHOUT DEMAND GROWTH, TPY

		CO	NOx
JEC1	Stack Emissions	11,662	4,373
JEC2	Stack Emissions	11,821	4,137

EMISSION CHANGE CALCULATION (TPY)

	CO	NOx	CO2
Total Projected Actual	23,483	8,511	10,747,993
Total Baseline Emission	8,504	15,118	10,771,528
Emission Increase	14,979	(6,607)	(23,535)
PSD Significant Emission Level	**100**	**40**	**75,000**
Major Modification?	**Yes**	**No**	**No**

Jeffrey Energy Center
NOx Reduction Project
CO2 Calculations

Jeffrey Energy Center is proposing to enhance and/or tune the low NOx systems on Units 1 and 2. Combusted carbon in the boiler will either become carbon monoxide (CO) or carbon dioxide (CO_2). As a result of this project CO emissions will increase therefore CO_2 emissions will decrease. The CO emission increase is 14,979 tons/yr. Based on the following calculations the corresponding decrease in CO_2 is 23,535 tons/yr:

	Molecular Weight
C	12.011
O	15.999
CO	28.01
CO2	44.009

Increase in CO = 14,979 tons/yr

$$\frac{-14{,}979\ \text{tons(CO)}}{\text{yr}} \times \frac{1\ \text{ton*mol(CO)}}{28.01\ \text{tons(CO)}} \times \frac{1\ \text{ton*mol(CO2)}}{1\ \text{ton*mol(CO)}} \times \frac{44.009\ \text{tons(CO2)}}{1\ \text{ton*mol(CO2)}} = \frac{-23{,}535\ \text{tons(CO2)}}{\text{yr}}$$

The only change in CO_2 emissions for this project is caused by the increase in CO emissions. So the Projected Actual CO_2 emissions will equal the Baseline CO_2 emissions minus the CO_2 emission decrease due to the increase in CO emissions.

Baseline CO2 Emissions		10,771,528 tons/yr
CO2 emissions from the decrease in CO	+	-23,535 tons/yr
Projected Actual CO2 Emissions	=	10,747,993 tons/yr

Emissions Change	-23,535 tons/yr
PSD Significant Emission Level	75,000 tons/yr
Major Modification?	No

APPENDIX C

BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

C.1 INTRODUCTION

Any major stationary source or major modification subject to PSD must conduct an analysis to ensure the implementation of BACT. The requirement to conduct a BACT analysis can be found in the Clean Air Act itself, in the Federal regulations implementing the PSD program, in the regulations governing Federal approval of State PSD programs, and in the State Implementation Plans (SIP) of the various states. BACT is defined as:

> "...an emission limitation (including a visible emissions standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines 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."[1]

The BACT requirement applies for a given pollutant to each individual new or physically modified emission unit when the project, on a facility-wide basis, has a significant emissions increase for that pollutant. Individual BACT determinations are performed on a unit-by-unit, pollutant-by-pollutant basis. As detailed in *Table C.1 - Project Emissions Increase and PSD SER*, the Project warrants a BACT analysis for CO.

Table C.1 - Project Emissions Increase and PSD SER

	NO_X	CO	CO_2
Project Emissions Change (tpy)	-6,607	14,979	-23,535
Significant Emission Rate (tpy)	40	100	75,000
PSD Triggered?	No	Yes	No

[1]40 CFR §52.21(j).

On December 1, 1987, the United States Environmental Protection Agency (U.S. EPA) Assistant Administrator for Air and Radiation issued a memorandum that implemented certain program initiatives to improve the effectiveness of the PSD program within the confines of existing regulations and SIPs. Among the initiatives was a "top-down" approach for determining BACT. In brief, the top-down process requires that all available control technologies be ranked in descending order of control effectiveness. The most stringent or "top" control option is *per se* BACT unless the applicant demonstrates, and the permitting authority in its informed opinion agrees, that the control in question is not technically feasible. For a technology to be considered technically feasible, it must be commercially available and proven effective on a unit of similar size and operating parameters. For the remaining control technologies that are considered technically feasible, energy, environmental, and/or economic impacts may justify the conclusion that the most stringent control option is not achievable in that case. Upon careful and considered elimination of the most stringent control option based upon energy, environmental, and/or economic considerations, the next most stringent alternative is evaluated in the same manner. This process continues until BACT is selected.

The five steps in a BACT evaluation can be summarized as follows:

1. Identify potentially applicable control technologies.
2. Eliminate technically infeasible control technologies.
3. Rank the remaining control technologies based upon emission reduction potential.
4. Evaluate the ranked controls based on energy, environmental, and/or economic considerations.
5. Select BACT.

C.2 BACKGROUND ON CARBON MONOXIDE FORMATION

CO is emitted from the boiler as a result of the incomplete combustion of fuel. This incomplete combustion results in a loss of boiler efficiency. It is desirable to minimize CO emissions as much as possible in order to increase boiler efficiency and reduce fuel use.

Modifications to burner/combustion systems which are designed to minimize NO_X emissions (as is a goal of the Project) typically result in increased CO emissions. Low NO_X combustion systems are designed to limit availability of oxygen in order to limit the NO_X that is produced. When oxygen is limited, the carbon has less available oxygen to bond to, resulting in increased CO emissions and decreased CO_2 emissions. Modern, low-emitting retrofits of the burner and combustion system design are intended to simultaneously minimize formation of CO and NO_X emission. The goal is to strike a balance between the lowest NO_X possible (a goal of this Project) while at the same time keeping CO emissions to a minimum to meet BACT and to maintain acceptable fuel and boiler efficiency.

C.3 UNIT 1 AND 2 CARBON MONOXIDE EMISSIONS

Westar is planning to enhance and/or tune their existing low NO_X systems on Units 1 and 2. The goal of the Project is to further reduce NO_X emissions from Unit 1 and 2. As is typical with NO_X reduction projects using combustion controls, a balance must be struck between lowering NO_X and increasing CO. While the Project will decrease emissions of NO_X, it may cause a subsequent increase in CO emissions. A BACT review for the CO emissions is summarized below.

C.4 CARBON MONOXIDE BACT ANALYSIS

C.4.1 Carbon Monoxide Control Technology/Feasibility

CO can be reduced through pre-combustion approaches and post-combustion approaches as described in the following paragraphs.

CO is emitted from the boiler as a result of incomplete combustion of fuel and loss of boiler efficiency. Therefore, there is a desire by boiler operations to minimize CO emissions as much as possible in order to increase efficiency and reduce fuel use. The most direct approach for reducing CO emissions is to maximize combustion efficiency through good combustion practices (GCP) while at the same time minimizing NO_X formation. This involves parametric monitoring and controlling the operating parameters of the boilers to ensure continual operation as close to optimum (i.e., minimum emission) conditions as possible.

Catalytic oxidation is the most efficient post-combustion CO control technology available. A CO oxidation catalyst system works to reduce CO emissions by allowing the boiler exhaust gases to pass through a reactor containing catalyst material. The catalytic material typically used is a precious metal such as platinum or palladium. The catalyst oxidizes CO to carbon dioxide. The catalyst also oxidizes other gases in the boiler exhaust passing through the reactor such as volatile organic compounds and sulfur dioxide. The exhaust gas temperature must be greater than 500 to 600 degrees F for this CO catalytic reaction to take place with acceptable effectiveness. On a typical coal-fired utility boiler, exhaust gases are above the 500 to 600 degrees F temperature threshold between the exit of the economizer and the inlet to the air heater. The exhaust gas from Units 1 and 2 is in the range of 900 degrees F at this point. Although the capital costs of installing the additional ductwork and relocating major pieces of equipment would be excessive, retrofitting a catalytic reactor is within the range of engineering possibilities. Reheating of the exhaust gas after the air heater is also an engineering possibility, but also at a very high cost. However, as is demonstrated below, use of a CO oxidation catalyst on a coal-fired boiler is not feasible due to high acid gas formation and a lack of catalyst product available for this application.

The technical feasibility of adding a CO oxidation catalyst system to Units 1 and 2 was investigated to confirm the conclusion of the CO BACT analysis that this technology is currently not technically feasible for coal-fired boilers. This investigation included discussions with two separate vendors of catalyst systems and assessing a CO oxidation catalyst installation on a boiler in California. Based on this investigation, a clear conclusion is made that installation and use of a CO oxidation catalyst on coal-fired boilers such as Units 1 or 2 is technically infeasible. The main reason for this infeasibility is the high level of sulfur trioxide and sulfuric acid mist formation resulting from the oxidation of sulfur dioxide found in the boiler exhaust gas. The high level of sulfuric acid would lead to rapid and destructive corrosion of ducts and equipment downstream of the catalyst. The high levels of sulfur trioxide would lead to higher opacity levels and a visible, blue plume from the stack. In addition, current catalyst technology has not been designed for the higher particulate and sulfur dioxide levels found in coal-fired applications. Vendors do not have available catalyst material for coal-fired applications.

Two major vendors of oxidation catalyst were contacted to discuss the feasibility of adding their systems to a coal-fired utility boiler. The vendors contacted were Engelhard Corporation of Iselin, New Jersey (Englehard) and Ceram Environmental, Inc. of Overland Park, Kansas (Ceram). The representative from Engelhard stated that they do not offer a CO oxidation catalyst system for particulate gas streams such as coal-fired applications. One reason cited for this is that the higher particulate levels of the gas stream would quickly plug the catalyst material, rendering it ineffective. The representative indicated that their catalyst material would become plugged in a matter of days, necessitating a unit shutdown for cleaning or replacement. Natural gas-fired applications (such as combustion turbines and gas-fired boilers) do not have this problem because of the near absence of particulate in the boiler exhaust. Note that Engelhard is the vendor that supplied the CO oxidation catalyst for a gas-fired boiler in California with a successfully installed catalyst on a utility boiler. Another reason cited by Engelhard is that there would be a high oxidation conversion rate of sulfur dioxide to sulfur trioxide which would lead to unacceptably high levels of sulfuric acid in the downstream exhaust gas system. Natural gas-fired applications do not have this problem because of the very low amounts of fuel sulfur.

The representative from Ceram stated that application of a CO oxidation catalyst on a coal-fired boiler is technically infeasible due to the high amounts of sulfuric acid that would form downstream of the catalyst. The catalyst would oxidize a relatively high percentage of the sulfur dioxide to sulfur trioxide. These higher levels of sulfur trioxide would lead to opacity problems and a visible, blue plume. This sulfur trioxide would also react with moisture in the exhaust gas to form sulfuric acid. The representative stated that even with a low sulfur coal application, the amounts of sulfuric acid formed would result in rapid and destructive corrosion of most downstream ducts and equipment, making this an infeasible control alternative.

There has been installation of oxidation catalysts to two existing utility boilers in Huntington Beach, California. These boilers are each 225 MW in capacity and are natural gas fired. The oxidation catalyst was installed with an SCR system at a location downstream of the economizer and before the air heater. The design CO emission level is 5 ppmvd (at 3-percent oxygen). The oxidation catalyst application has been operating successfully. Of most important note regarding this application of oxidation catalyst is that these boilers are natural gas fired. The exhaust gas from natural gas-fired boilers contains only very small amounts of particulate and sulfur dioxide which allows the catalyst to be feasible for application to these units. As confirmed by representatives from Engelhard and Ceram, the higher levels of particulate and sulfur dioxide associated with coal firing render the application of oxidation catalyst infeasible.

C.5 CARBON MONOXIDE BACT FOR SIMILAR PROJECTS

A review of the RACT/BACT/LAER Clearinghouse (RBLC) database as well as a review of recent PSD permits that have been issued for coal-fired boiler projects was performed to determine the CO BACT control technologies and emission limits established for other coal-fired boilers. *Table C.2 - Summary of RBLC/Recent Permits* presents a summary of the findings. As shown, the results are organized by the CO emission level (lowest to highest) and data rows for boilers which are not relevant to the Project BACT level are indicated.

Westar has gained significant recent experience with NO_X tuning their other tangentially fired boilers at JEC and Tecumseh Energy Center (TEC) which burn very similar coal. The results of this experience have shown that further NO_X reductions are generally attainable as CO emissions are allowed to rise. Westar's conclusion is that the lowest practical NO_X levels can be achieved while the CO emissions levels are less than 0.4 lb/MMBtu. Given the Project goal of lowest practical NO_X and the importance of achieving these low NO_X emissions while having the flexibility to adjust parameters to achieve this low NO_X, a reasonable CO emission limit which strikes this balance is 0.4 lb/MMBtu. This is similar to the BACT determination approach recently approved for the Westar JEC Unit 3 LNB project.

Table C.2 - Summary of RBLC/Recent Permits

Number	Company Name	Plant Name	City/State	Unit	Boiler Type	Permit No.	Permit Date	NOx Control Technology	CO Control Technology	CO BACT CO Limit	Notes on Relevancy of CO BACT Limit to JEC1 & JEC2 BACT Determination
1	Texas Municipal Power Agency	Gibbons Creek Steam Electric Station	Anderson, TX	Boiler	Tangential-fired	5699 AND PSDTX18M2	10/28/11	TLN3 Separated Over-fire Air	GCP	0.12 (30-day)	
2	Coleto Creek	Coleto Creek Power Station	Fannin, TX	Boiler Unit 2	supercritical, pulverized coal	PSDTX1118	5/3/10	LNB/OFA	GCP	0.12 (30-day)	Not relevant. The boiler type is not the same as Westar's boiler.
3	Consumers Energy	Karn Weadock Generating Complex	Essexville, MI	Boiler	Supercritical	341-07	12/29/09	LNB/OFA SCR	GCP	0.125 (24-hr)	Not relevant. The boiler type is not the same as Westar's boiler.
4	Orlando Utilities Commission	Stanton Energy Center	FL	Unit 2	Wall-fired	0950137-015-AC	2/7/08	LNB/OFA	GCP	0.15 (30-day)	
5	Minnesota Power Division of Allete INC.	Boswell Energy Center	Cohasset, MN	Boiler 4	Tangential-fired	06100004-005	4/28/10	LNB/SOFA	Not technically feasible/CEMS	0.15 (30-day)	
6	Associated Electric Cooperative	Norborne Power Plant	Norborne, MO	Main Boiler	Supercritical	022008-010	2/22/08	LNB/OFA SCR	GTP	0.15 (30-day)	Not relevant. The boiler type is not the same as Westar's boiler.
7	Board of Public Utilities	Nearman Creek Station	Kansas City, KS	Unit 1	Wall-fired	None	4/14/11	LNB/OFA	GCP	0.17	
8	Orlando Utilites Commission	Stanton Energy Center	FL	Unit 1	Wall-fired	0950137-015-AC	2/7/08	LNB/OFA	GCP	0.18	
9	Interstate Power and Light Company	Lansing Station	Lansing, IA	Boiler 3	Unknown	73-A-132P-S2	3/31/08	LNB/OFA	GCP	0.25	Not relevant. The boiler type is unknown there is not enough information to draw a conclusion.
10	Westar Energy, Inc.	Tecumseh Energy Center	Tecumseh, KS	Boiler 7/9	Tangential-fired	None	3/18/08	LNB/SOFA	GCP	0.25	
11	Duke Power Company LLC	Dan River Steam Station	Eden, NC	Unit 1	Tangential-fired	None	7/24/06	LNB/SOFA	GCP	0.25	
12	Duke Power Company LLC	Dan River Steam Station	Eden, NC	Unit 2	Tangential-fired	None	7/24/06	LNB/SOFA	GCP	0.25	
13	Duke Power Company LLC	Dan River Steam Station	Eden, NC	Unit 3	Tangential-fired	None	7/24/06	LNB/SOFA	GCP	0.25	
14	Interstate Power and Light Company	M.L. Kapp Station	Cedar Rapids, IA	Boiler 2	Tangential-fired	78-A-157P-S8	1/11/08	LNB/OFA	GCP	0.289	
15	Consumers Energy	Tes Filer City Station	Filer City, MI	Boiler		264-09	6/25/10	Over-fired air		0.3 (24-hr)	Not relevant. The boiler type is unknown there is not enough information to draw a conclusion.
16	Southwestern Public Service Company	Harrington Station	Amarillo, TX	Unit 1 Boiler	Tangential-fired	PSDTX631M1	1/15/10	LNB/OFA	GCP	0.33 (30-day)	
17	NRG Texas Power LLC	Limestone Electric Generating Station	Jewett, TX	Boiler Units 1 and 2	Tangential-fired	PSDTX371M4	2/1/10	LNB/SOFA	GCP	0.33	
18	Southwestern Public Searvice Company	Tolk Station Power Plant	Sudan, TX	Boiler Unit 1	Tangential-fired	PSDTX50M2	3/23/11		N	0.34	
19	Portland General Electric	Boardman Power Plant	OR	Unit 1	Wall-fired	25-0016-ST-01	12/10/10	LNB/OFA	GCP	0.35 (30-day)	
20	Westar Energy, Inc.	Jeffrey Energy Center	St. Mary's, KS	Unit 3	Tangential-fired	None	3/1/12	LNB/SOFA/Smartburn Control System	GCP	0.4	
21	Westar Energy, Inc.	Tecumseh Energy Center	Tecumseh, KS	Boiler 8/10	Tangential-fired	None	3/1/13	LNB/SOFA	GCP	0.4	
22	MidAmerican Energy Company	George Neal South	Salix, IA	Boiler 4	Wall-fired	05-A-655-P	9/28/05	LNB/OFA	GCP	0.42	
23	MidAmerican Energy Company	Louisa Generating Station	Muscatine, IA	Louisa Boiler	Wall-fired	05-A-031-P	3/1/05	LNB/OFA	GCP	0.42	
24	MidAmerican Energy Company	Council Bluffs Energy Center	Council Bluffs, IA	Boiler 3	Wall-fired	75-A-357-P4	9/15/06	LNB/OFA	GCP	0.42	
25	Board of Public Utilities	Quindaro Station	Kansas City, KS	Unit 2	Wall-fired	None	4/14/11	LNB/OFA	GCP	0.42	
26	City of Grand Island	Platte Generating Station	Grand Island, NE	Boiler	Wall-fired	#CP12-003	8/9/12	LNB/OFA	GCP	0.50 (30-day)	
27	Nebraska Public Power District	Gerald Gentleman Station	Sutherland, NE	Unit 2	Wall-fired	Unknown	5/1/10	LNB/OFA	GCP	0.50	
28	Nebraska Public Power District	Gerald Gentleman Station	Sutherland, NE	Unit 1	Wall-fired	CP06-0001	8/18/06	LNB/OFA	GCP	0.5 (30-day)	
29	MidAmerican Energy Company	Council Bluffs Energy Center	Council Bluffs, IA	Boiler 2	Wall-fired	72-A-173-P2	3/7/08	LNB/OFA	GCP	0.54	
30	Nebraska Public Power District	Sheldon Station	Sheldon, NE	Unit 2	Cyclone	Unknown	7/11/07	OFA	GCP	1.26	Not relevant. Boiler is a cyclone boiler. The design characteristics of cyclone boiler are such that they are not conducive to the same type of low-NOx combustion systems that are applied to wall and tangential-fired boilers.
31	MidAmerican Energy Company	George Neal North	Sergeant Bluff, IA	Boiler 1	Cyclone	05-A-878-P	12/9/05	OFA	GCP	1.26 (3-hr)	Not relevant. Boiler is a cyclone boiler. The design characteristics of cyclone boiler are such that they are not conducive to the same type of low-NOx combustion systems that are applied to wall and tangential-fired boilers.
32	MidAmerican Energy Company	George Neal North	Sergeant Bluff, IA	Boiler 2	Wall-fired	07-A-951-P	9/5/07	LNB/OFA	GCP	1.63 (3-hr)	

C.6 CONCLUSION OF CARBON MONOXIDE BACT

The only control deemed feasible for CO is GCP. Thus, the BACT analysis for CO establishes GCP as BACT for CO. In order to provide the needed flexibility for achieving high levels of NO_X reductions for this project, Westar proposes a CO BACT emissions limit of 0.4 lb/MMBtu on a 30-day rolling average. This BACT limit is in line with other recent and relevant BACT limits such as for Westar JEC Unit 3 and TEC Unit 8/10.

APPENDIX D

AIR QUALITY ANALYSIS

AIR QUALITY ANALYSES

D.1 AIR QUALITY ANALYSIS

An air dispersion modeling analysis was conducted to determine the maximum CO impacts resulting from the Project.

D.1.1 Selection of Model

The United States Environmental Protection Agency's (U.S. EPA) recommended model for evaluating impacts attributable to industrial facilities at source-receptor distances of less than 50 kilometers is AERMOD[1]. Thus, the AERMOD modeling system was used to determine the CO concentrations associated with the Project. The AERMOD modeling system is composed of three modular components: AERMAP, the terrain preprocessor; AERMET, the meteorological preprocessor; and AERMOD, the control module and modeling processor. There are also two additional components associated with AERMET, including AERMINUTE and AERSURFACE. All of the modular components associated with the AEMROD modeling system were relied upon for the modeling described in this report.

D.1.2 Meteorological Data

The AERMOD modeling was performed using AERMOD-ready meteorological data for the years 2007 through 2011 as provided by KDHE. The meteorological data incorporates surface data obtained from the Manhattan Municipal Airport surface station (MHK) WBAN No. 03936 and upper air data from the Topeka Philip Billard Municipal Airport upper air station (TOP) WBAN No. 13996.

[1] U.S. EPA, Office of Air Quality Planning and Standards, *Federal Register* Vol. 70 / No. 216, pp. 68,218-68,261, Title 40 of the Code of Federal Regulations, Part 51, Appendix W, *Revision to Guideline on Air Quality Models*, November 9, 2005.

D.1.3 Receptors

Modeled ground-level concentrations were determined using a variable density grid. The grid covers a region extending at least 10 kilometers beyond the JEC fenceline in all directions. The grid density is as follows:

1. Receptors were spaced at 50-meter intervals along the fenceline.
2. Receptors were spaced at 50-meter intervals extending to approximately 1 kilometer from the fenceline.
3. Receptors were spaced at 100-meter intervals from 1 kilometer to 2 kilometers from the fenceline.
4. Receptors were spaced at 250-meter intervals from 2 kilometers to at least 10 kilometers from the fenceline.

D.1.4 Terrain Elevations

The terrain elevation for each modeled building, source, and receptor were determined using data from the U.S. Geological Survey (USGS) National Elevation Dataset (NED). Specifically, the USGS 1/3-arc second (approximately 10-meter resolution) NED was used. The terrain height for each modeled receptor was calculated using the AERMOD terrain processor (AERMAP, Version 11103).

In addition to terrain elevation, an additional parameter called the hill height scale is required for each receptor to feed AERMOD's terrain modeling algorithms. AERMOD computes the impact at a receptor as a weighted interpolation between horizontal and terrain-following states using a critical dividing streamline approach. This scheme assumes that part of the plume mass will have enough energy to ascend and traverse over a terrain feature and the remainder will impinge and traverse around a terrain feature under certain meteorological conditions. The hill height scale is computed by the AERMAP terrain preprocessor for each receptor as a measure of the one terrain feature in the modeling domain that would have the greatest effect on plume behavior at that receptor.

The hill height scale does not represent the critical dividing streamline height itself, but supplies the computational algorithms with an indication of the relative relief within the modeling domain for the determination of the critical dividing streamline height for each hour of meteorological data.

According to Section 2.2.1 of the AERMOD Users Guide[2], the NED array boundary for AERMAP must include all terrain features that exceed a 10-percent elevation slope from any given receptor in order to properly calculate the hill height scale at each receptor. The domain for the hill height analysis in AERMAP was set to the minimum coverage required for proper handling of elevation slope.

D.1.5 Building Downwash and GEP Stack Height Analysis

40 CFR §51, Appendix W - Guideline on Air Quality Models[3] requires an evaluation of the potential for physical structures (e.g. buildings) to affect the dispersion of emissions from stacks due to the downwash effect of structures on plumes released from stacks. Calculations for determining direction-specific downwash parameters were performed using the BREEZE-AERMOD, Version 7.6 software, developed by Trinity. This software incorporates the algorithms of the U.S. EPA-sanctioned Building Profile Input Program with Plume Rise Model Enhancement (BPIP-PRIME). All dominant building structures that are within five times the lesser of the structure height or projected width from Units 1 and 2 stacks were included in the evaluation.

D.1.6 Load Analysis And Modeled Parameters

The AERMOD analysis was completed to confirm that the Project will not result in CO impacts greater than the CO modeling significant levels (MSLs). The modeling analysis was performed for 100-percent, 75-percent, and 50-percent loads. *Tables D.1 - CO Modeled*

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[2] U.S. EPA, Office of Air Quality Planning and Standards, *User's Guide for the AMS/EPA Regulatory Model - AERMOD*, Research Triangle Park, North Carolina, EPA-454/B-03-001, September, 2004.
[3]U.S. EPA, Office of Air Quality Planning and Standards, *Federal Register* Vol. 70/No. 216, pp. 68,218-68,261, 40 CFR 51, Appendix W, *Revision to Guideline on Air Quality Models*, November 9, 2005.

Emission Rates and *D.2 - Modeled Stack Parameters* summarize the emission rates and stack parameters for the various loads. Parameters such as the flow rate, exhaust velocity, and exit temperature are based on the May 2012 Relative Accuracy Test Audits (RATAs) for the boiler's Continuous Emissions Monitoring Systems (CEMS).

Table D.1 - CO Modeled Emission Rates

Unit	Load (%)	Heat Input (MMBtu/hr)	CO BACT Limit (lb/MMBtu)	Potential Emission Rate (lb/hr)	Baseline Actual Emission Rate* (lb/hr)	CO Emission Rate (lb/hr)
1	100	8,262	0.4	3,305	1,113	2,192
	75	6,197	0.4	2,479	1,113	1,366
	50	4,131	0.4	1,652	1,113	540
2	100	8,262	0.4	3,305	829	2,476
	75	6,197	0.4	2,479	829	1,650
	50	4,131	0.4	1,652	829	823

* The baseline rates for Units 1 and 2 are the hourly average of the unit-specific contributions to the baseline actual emissions for the Project (Unit 1 = 4,873 tpy, Unit 2 = 3,631 tpy, Combined = 8,504 tpy).

Table D.2 - Modeled Stack Parameters

Unit	Load (%)	GEP Stack Height (ft)	Stack Diameter (ft)	Exhaust Flow Rate (acfm)	Exhaust Velocity (ft/s)	Exhaust Temperature (F)
1	100	574	25.5	1,982,790	64.71	134
	75			1,512,389	49.36	131
	50			1,131,439	36.92	129
2	100	574	25.5	1,985,037	64.78	134
	75			1,550,967	50.62	132
	50			1,163,602	37.97	129

D.1.7 Summary of AERMOD Results

Table D.3 - CO Modeling Results summarizes the maximum CO concentrations predicted for the Project for 100-percent, 75-percent, and 50-percent loads. All modeling input and output files, building downwash files, and terrain data have been provided electronically as part of this application submittal.

As shown in *Table D.3 - CO Modeling Results,* all of the modeled impacts are less than the CO SILs. As such, the Project will not have a significant impact on the ambient air surrounding JEC.

Table D.3 - CO Modeling Results

Loads	Averaging Period	Maximum Modeled CO Concentrations ug/m^3					Below SIL*?
		2007	2008	2009	2010	2011	
Both Units 1 and 2 at 100% Load	*CO 1-hr*	276	297	378	313	353	Yes
	CO 8-hr	103	94	85	114	105	
Both Units 1 and 2 at 75% Load	*CO 1-hr*	204	224	264	236	266	Yes
	CO 8-hr	75	75	60	86	74	
Both Units 1 and 2 at 50% Load	*CO 1-hr*	116	122	129	122	136	Yes
	CO 8-hr	38	38	34	45	37	
Unit 1 - 100% Load Unit 2 - 75% Load	*CO 1-hr*	233	255	321	275	310	Yes
	CO 8-hr	89	85	72	100	90	
Unit 1 - 100% Load Unit 2 - 50% Load	*CO 1-hr*	185	203	252	218	247	Yes
	CO 8-hr	71	67	57	81	71	
Unit 1 - 75% Load Unit 2 - 100% Load	*CO 1-hr*	232	253	321	273	309	Yes
	CO 8-hr	89	84	72	100	89	
Unit 1 - 50% Load Unit 2 - 100% Load	*CO 1-hr*	182	198	251	214	242	Yes
	CO 8-hr	69	66	57	78	70	
Unit 1 - 75% Load Unit 2 - 50% Load	*CO 1-hr*	162	173	194	178	202	Yes
	CO 8-hr	57	57	49	67	56	
Unit 1 - 50% Load Unit 2 - 75% Load	*CO 1-hr*	156	169	194	176	200	Yes
	CO 8-hr	56	56	46	64	55	

*The Significant Impact Levels (SILs) for CO are 500 ug/m^3 (8-hr average) and 2000 ug/m^3 (1-hr average).

D.2 ADDITIONAL IMPACTS ANALYSIS

In accordance with 40 CFR 52.21(o), the owner or operator of a proposed major source or major modification shall analyze the effects of the project on visibility, soils, and vegetation in the surrounding area and any affected Class I areas. The owner or operator must also evaluate the effects of commercial, residential, industrial, and other growth associated with the new source or modification. In accordance with these requirements, an analysis of additional impacts resulting from the Project follows.

D.2.1 Visibility Impacts

Pollutants that are typically evaluated for their impact on visibility as part of PSD permitting include particulate matter (PM), NO_x, sulfur dioxide (SO_2), and volatile organic compounds (VOCs). Since CO is the only pollutant that will increase as a result of the proposed project, a visibility analysis is not necessary.

D.2.2 Soil and Vegetation Impacts

The primary National Ambient Air Quality Standards (NAAQS) for criteria pollutants were developed to provide adequate protection of human health, while the secondary standards were designed to protect the general welfare, i.e., manmade and natural materials, including soils and vegetation. EPA guidance on new source review supports this by stating:

> For most types of soils and vegetation, ambient concentrations of criteria pollutants below the secondary NAAQS will not result in harmful effects.[4]

CO is not known to harm soils, as there is no deposition of CO onto soil. The Project will actually decrease NO_x emissions, providing a benefit to the surrounding area.

The land cover of the area surrounding JEC was analyzed using the 2005 Kansas Land Cover Patterns (available at http://www.kars.ku.edu/maps/klcp2005/). This tool shows the primary land cover in the immediate area around JEC is warm-season grassland. This local area is surrounded by agricultural use, such as corn and soybean farming.

CO has not been found to adversely affect plants at concentrations below 114,500 $\mu g/m^3$ for exposures from one to three weeks (USEPA 1976). There are no reports of measured CO levels producing any adverse effects on plants (EPA 600/P-99/001F). In its most recent review of the CO NAAQS, EPA concluded that "the currently available scientific

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[4]U.S. EPA, Office of Air Quality Planning and Standards. *New Source Review Workshop Manual (Draft)*, Research Triangle Park, NC. October 1990. p. D.5.

information with respect to non-climate welfare effects, including ecological effects and impacts to vegetation, does not support the need for a CO secondary standard" (76 FR 54294).

Since there are no secondary NAAQS standards for CO, the modeled concentrations are compared to the primary NAAQS standards.

The results of the air quality analysis presented in *Table D.3 - CO Modeling Results* demonstrate that the maximum ambient air impacts due to the increase in CO emissions from the Project will be under the applicable SILs, which are lower than the NAAQS. (The one-hour CO NAAQS is 40,000 $\mu g/m^3$, and the eight-hour CO NAAQS is 10,000 $\mu g/m^3$.) Thus, the Project should not result in harmful effects to soils or vegetation.

D.2.3 Growth Impacts

The elements of a growth impact analysis include: a projection of the associated industrial, commercial, and residential source growth that will occur in the area due to the source; and an estimate of the air emissions generated by the above associated industrial, commercial, and residential growth.

There will be no associated growth due to the Project. Project construction will be limited and no commercial or residential growth is projected to occur because of this Project. Given the temporary nature of the construction and the lack of other source growth in the area, the Project is not expected to cause any adverse construction or growth-related air quality impacts.

APPENDIX E

PROPOSED DRAFT KANSAS DEPARTMENT OF HEALTH AND ENVIRONMENT PERMIT

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

Kansas
Department of Health & Environment

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

Robert Moser, MD, Acting Secretary

Sam Brownback, Governor

AIR EMISSIONS SOURCE CONSTRUCTION PERMIT

Source ID No.:	1490001
Effective Date:	
Source Name:	Westar Energy, Inc., Jeffrey Energy Center
NAICS Code:	221112, Fossil Fuel Electric Power Generation
SIC Code:	4911, Electric Services
Source Location:	25905 Jeffrey Road St. Mary's, Kansas 66536
Mailing Address:	818 S. Kansas Avenue, P.O. Box 889 Topeka, Kansas 66601
Contact Person:	Mr. Daniel R. Wilkus, P.E. Director, Air Programs Telephone: (785) 575-1614 Dan.Wilkus@westarenergy.com

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

I. Description of Activity Subject to Air Pollution Control Regulations

Westar Energy, Inc. is proposing to make certain modifications to the existing low nitrogen oxide (NO_X) system on the Unit 1 and 2 boilers at Jeffrey Energy Center (JEC), located near St. Mary's, Kansas. The Unit 1 modifications include further tuning of existing equipment. The Unit 2 modifications include upgrades to the existing low NO_X burners (LNB) and separated overfire air (SOFA), adjustments to existing SOFA, additional SOFA for deeper staging, low NO_X system tuning and installation of associated equipment. This project will result in an overall decrease in NO_X emissions. As a result of lowering NO_X emissions there may be an increase in carbon monoxide (CO) emissions; with the increase in CO emissions a decrease in carbon dioxide (CO_2) emissions is anticipated.

Emissions of NO_X, CO, and CO_2 were evaluated for this permit review. Due to the increase in CO emissions in excess of the major modification thresholds, the proposed modification will be subject to the requirements of 40 CFR 52.21, Prevention of

Significant Deterioration (PSD) as adopted under K.A.R. 28-19-350. JEC Unit 1 and Unit 2 are affected sources 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 K.A.R. 28-19-300 (Construction permits and approvals; applicability) because the potential-to-emit of CO exceeds 100 tons per year.

An air dispersion modeling impact analysis and a Best Available Control Technology (BACT) determination were conducted as part of the construction permit application process.

II. Significant Applicable Air Regulations

The proposed activity is subject to certain Kansas regulations relating to air pollution control. The following air quality regulations were determined to be applicable to this project:

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

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

III. Air Emission Unit Technical Specifications

The following equipment or equivalent is approved:

- Unit 1: Further tuning of the existing low NOx system equipment.
- Unit 2: Upgrades to the existing LNB and SOFA, adjustments to existing SOFA, additional SOFA for deeper staging, low NO_X system tuning and installation of associated equipment.

IV. 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	8,504	23,483	14,979
NO_X	15,118	8,511	-6,607
CO_2	10,771,528	10,747,993	-23,535

V. Air Emission Limitations

The emission limitations established in this permit applies to JEC Units 1 and 2 at all times, including startup, shutdown and malfunction, except as provided in section "VI. Monitoring, Recordkeeping and Reporting, D. Malfunction" of this permit.

Coal Fired Boilers (JEC Unit 1 and JEC Unit 2)

A. The thirty (30) day rolling average emission rate of CO shall not exceed 0.4 lb/mmBtu for JEC Unit 1 or JEC Unit 2. This supercedes all previous CO emission limits.

B. The purpose of the project is to reduce the NO_X emissions from Unit 1 and 2. In the event difficulties are encountered demonstrating compliance with the CO limit while optimizing NO_X 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.

C. During the 60-day shakedown period[1], CO emissions shall be monitored according to the provisions of the Monitoring, Recordkeeping and Reporting Section of this permit. Excesses which occur during the shakedown period will be reported as part of the semi-annual (or more frequent) reporting, but will not be considered deviations for purposes of the Title V semi-annual monitoring reports or Annual Compliance certification.

VI. Monitoring, Recordkeeping and Reporting

A. Compliance with the CO BACT limit shall be demonstrated with the continuous emission monitoring system (CEMS) currently installed on the units. The CO CEMS shall be operated, maintained, and quality assured according to 40 CFR 60, Appendix B, Performance Specification 4A (PS4A) and 40 CFR 60, Appendix F (Quality Assurance/Quality Control).

B. Reports of excess emissions shall be submitted at least semi-annually in accordance with the requirements in 60.7(c). The summary report referenced in 60.7(c) and defined in 60.7(d) applies to the CO CEMS downtime only and is not applicable to an exceedance of the CO limit established in the document.

C. Records shall be kept on site for 2 years in accordance with 60.7(f).

D. Malfunction:

The Owner or Operator must notify KDHE by telephone, facsimile, or electronic mail transmission within two (2) working days following the discovery of any failure of air pollution control equipment, process equipment, or of the failure of any process to operate in a normal manner which results in an increase in emission above the allowable emission limit stated in section "V. Air Emission Limitations" of this permit, a written notification shall be submitted within ten (10) days of the event.

1 The 60-day shakedown period applies to each unit individually and begins when the changes to the low NO_x system are completed and ends 60 days later.

The written notification shall include a description of the malfunctioning equipment or abnormal operation, the date of the initial malfunction, the period of time over which emissions were increased due to the failure, the cause of the failure, the estimated resultant emissions in excess of those allowed in "Air Emission Limitations," and the methods utilized to mitigate emissions and restore normal operations. Compliance with this malfunction notification shall not automatically absolve the owner or operator of liability for the excess emissions resulting from such event.

The following criteria will be used by KDHE to evaluate whether emissions from a malfunction are excluded in determining compliance with the emission rate contained herein:

1. The excess emission were caused by a sudden, unavoidable breakdown of technology, beyond the control of the owner or operator;
2. The excess emissions did not stem from any activity or event that could have been foreseen and avoided, or planned for, and could not have been avoided by better operation and maintenance practices;
3. To the maximum extent practicable, the air pollution control equipment or processes were maintained and operated in a manner consistent with good practices for minimizing emissions;
4. Repairs were made in an expeditious fashion when the operator knew or should have known that applicable emission limitations were being exceeded. Off-shift labor and overtime must have been utilized, the extent practicable, to ensure that such repairs were made as expeditiously as practicable.
5. The amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions;
6. All possible steps were taken to minimize the impact of the excess emissions on ambient air quality;
7. All emission monitoring systems were kept in operation if at all possible;
8. The owner or operator's actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs, or other relevant evidence;
9. The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and
10. The owner or operator properly and promptly notified the appropriate regulatory authority.

VII. Notifications

Notify the Northeast District Office within 30 days after construction is complete so that an evaluation may be conducted.

VIII. General Provisions

A. 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.

B. 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.

C. 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:

1. 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;

2. have access to and copy, at reasonable times, any records that must be kept under conditions of this document;

3. inspect at reasonable times, any facilities, equipment (including monitoring and control equipment) practices or operations regulated or required under this document; and

4. 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.

D. 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.

E. This document is subject to periodic review and amendment as deemed necessary to fulfill the intent and purpose of the Kansas Air Quality Statutes and Regulations.

F. 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.

Permit Engineer

______________________________ ____________________

Date Signed