Westar Energy.

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BUREAU OF AIR

October 19, 2011

Gerald McIntyre
Kansas Department of Health and Environment
Bureau of Air and Radiation
1000 SW Jackson, Suite 310
Topeka, KS 66612-1366

Re: Westar Energy, Inc. Jeffrey Energy Center Unit 3 - NO_x Reduction Project Air Permit Application

Dear Mr. McIntyre:

Westar Energy, Inc. is submitting this air quality permit application for modifications to the existing Low NOx combustion systems on Unit 3 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 Kansas Administrative Rules (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,

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

Enclosures

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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. The project will consist of an upgrade to the existing low NO_X system on Unit 3 (JEC3). The facility, which is a major stationary source under the Prevention of Significant Deterioration (PSD) regulation, consists of three pulverized coal-fired boilers. JEC3 existing low NO_X burners (LNBs) and overfire air system (OFA) will be upgraded and enhanced to further reduce emissions of NO_X. The goal of the project is to further reduce JEC3 NO_X emissions, with final achievable NO_X levels dependant on the effectiveness of tuning the upgraded equipment. 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 carbon monoxide emissions increase may be above the PSD significance levels; therefore, a PSD major modification permit is required. Westar is applying for a permit to upgrade its existing low NO_X system, 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 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 low NO_X project are shown in Table 1 along with the threshold levels for PSD.

Table 1
Summary of Emissions Changes and PSD Significant Emissions Rates (SER)

Criteria Pollutant	Baseline Actual Emissions (tpy)	Future Projected Actual Emissions (tpy)	Emission Change (tpy)	PSD SER (tpy)	Major Modification? (Yes/No)
CO	4,213	10,634	6,421	100	Yes
NO_X	4,521	3,722	-799	40	No
CO_2	5,502,851	5,492,763	-10,088	75,000	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 0.40 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, JEC3 CO emission rate. AERSCREEN 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. 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

Jeffrey Energy Center (JEC) is an existing coal-fired, electric-generating station located in 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 JEC3 low NO_X system consists of low NO_X burners (LNB), separated overfire air (SOFA), and associated equipment and ductwork. Westar proposes to upgrade and further enhance the existing JEC3 low NO_X system in order to achieve additional NO_X reduction. The low NO_X system modifications include upgrades to the existing LNBs, adjustments to existing SOFA, and additional SOFA for deeper staging, boiler tuning, and installation of associated equipment. This proposed modification work will henceforth be titled 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 the 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.

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 LNBs will have their burner tips (auxiliary air tips, oil gun tips, and coal nozzle tips) replaced with brand 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 is another method of staging combustion in the furnace. In an overfire air system, 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, adjustments will be made to the existing SOFA with additional SOFA for deeper staging. A substantial amount of new ductwork will also be required to accommodate these overfire air 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 exceed 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 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, 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
Project Emissions

Criteria Pollutant	Baseline Actual Emissions (tpy)	Future Projected Actual Emissions (tpy)	Emission Change (tpy)	PSD SER (tpy)	Major Modification? (Yes/No)
CO	4,213	10,634	6,421	100	Yes
NO_X	4,521	3,722	-799	40	No
CO_2	5,502,851	5,492,763	-10,088	75,000	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 emissions. "Baseline actual emissions" is defined in 40 CFR 52.21(b)(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 JEC3 for CO, CO_2, and NO_x. The monthly emissions are based on the actual values measured by the continuous emission monitoring (CEM) system on JEC3.

Project actual emissions for JEC3 are calculated as the product of the future (post-project) emission factors (lb/MMBtu) and projected annual heat input (MMBtu/yr). The post project CO emission factor assumed for this emission change analysis is 0.40 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.

PSD 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. Kansas has adopted the Federal PSD regulations (40 CFR 52.21) as in effect July 1, 2007 (K.A.R. 28-19-350). 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
Summary of Project Emissions and PSD Significant Emissions Rates

Criteria Pollutant	Baseline Actual Emissions (tpy)	Future Projected Actual Emissions (tpy)	Emission Change (tpy)	PSD SER (tpy)	Major Modification? (Yes/No)
CO	4,213	10,634	6,421	100	Yes
NO_x	4,521	3,722	-799	40	No
CO_2	5,502,851	5,492,763	-10,088	75,000	No

NSPS SUBPART Da - ELECTRIC UTILITY STEAM GENERATING UNITS

The NSPS Subpart Da applies to each electric utility steam generating unit:

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

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, 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.

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.

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 as 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 modfication, or a minor permit modification.

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.

APPENDICES

APPENDIX A

KDHE 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: I 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

Jessica
C-9842

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 #)

8) Person to Contact at the Site: Mr. Tom Brown Phone: (785) 456-6129

Title: Manager, JEC Environmental Program

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: 10/18/2011 Phone: (785) 575-1614

Procedures For Requesting Information To Be Held Confidential

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**	$14,300,000
Multiply by .05% (.0005)		x .0005
Total	**Line 2**	$7,150
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 Program
(Print)

Certifier of Capital Cost [signature] 10/18/2011
(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	UNITID	OP_YEAR	OP_MONTH	NOx (tons)	CO2 (tons)	HEAT_INPUT	NOx 24-Month Rolling Avg. (tpy)	CO2 24-Month Rolling Avg. (tpy)	Heat Input 24-Month Rolling Avg. (MMBtu/yr)
KS	Jeffrey Energy Center	3	2006	1	332	441,415	4,302,281			
KS	Jeffrey Energy Center	3	2006	2	310	443,771	4,325,239			
KS	Jeffrey Energy Center	3	2006	3	290	422,205	4,115,809			
KS	Jeffrey Energy Center	3	2006	4	329	456,427	4,448,695			
KS	Jeffrey Energy Center	3	2006	5	293	395,538	3,855,152			
KS	Jeffrey Energy Center	3	2006	6	399	510,084	4,971,592			
KS	Jeffrey Energy Center	3	2006	7	420	556,663	5,425,561			
KS	Jeffrey Energy Center	3	2006	8	408	565,984	5,516,424			
KS	Jeffrey Energy Center	3	2006	9	382	516,105	5,030,267			
KS	Jeffrey Energy Center	3	2006	10	360	468,480	4,566,745			
KS	Jeffrey Energy Center	3	2006	11	444	565,470	5,511,402			
KS	Jeffrey Energy Center	3	2006	12	382	502,541	4,898,418			
KS	Jeffrey Energy Center	3	2007	1	394	505,516	4,927,054			
KS	Jeffrey Energy Center	3	2007	2	274	332,651	3,243,009			
KS	Jeffrey Energy Center	3	2007	3	225	290,373	2,831,580			
KS	Jeffrey Energy Center	3	2007	4	333	422,782	4,120,686			
KS	Jeffrey Energy Center	3	2007	5	126	144,811	1,411,413			
KS	Jeffrey Energy Center	3	2007	6	331	440,265	4,291,079			
KS	Jeffrey Energy Center	3	2007	7	372	501,314	4,886,107			
KS	Jeffrey Energy Center	3	2007	8	373	513,117	5,001,143			
KS	Jeffrey Energy Center	3	2007	9	331	431,002	4,201,154			
KS	Jeffrey Energy Center	3	2007	10	384	487,324	4,750,224			
KS	Jeffrey Energy Center	3	2007	11	346	439,295	4,281,862			
KS	Jeffrey Energy Center	3	2007	12	448	532,465	5,190,273			
KS	Jeffrey Energy Center	3	2008	1	445	534,407	5,095,416			
KS	Jeffrey Energy Center	3	2008	2	454	516,295	4,922,721			
KS	Jeffrey Energy Center	3	2008	3	510	562,114	5,359,582			
KS	Jeffrey Energy Center	3	2008	4	469	546,252	5,208,356			
KS	Jeffrey Energy Center	3	2008	5	409	520,375	4,961,618			
KS	Jeffrey Energy Center	3	2008	6	380	436,539	4,162,623			
KS	Jeffrey Energy Center	3	2008	7	422	486,164	4,635,639			
KS	Jeffrey Energy Center	3	2008	8	539	507,932	4,842,974			
KS	Jeffrey Energy Center	3	2008	9	289	318,221	3,035,041	**4,521**	**5,502,851**	**53,168,059**
KS	Jeffrey Energy Center	3	2008	10				4,341	5,268,611	50,884,687
KS	Jeffrey Energy Center	3	2008	11	71	83,880	821,525	4,154	5,027,817	48,539,748
KS	Jeffrey Energy Center	3	2008	12	265	324,344	3,097,997	4,096	4,938,719	47,639,538
KS	Jeffrey Energy Center	3	2009	1	537	550,377	5,247,687	4,167	4,961,149	47,799,854
KS	Jeffrey Energy Center	3	2009	2	349	428,784	4,088,780	4,204	5,009,215	48,222,740
KS	Jeffrey Energy Center	3	2009	3	438	513,661	4,897,602	4,311	5,120,859	49,255,751
KS	Jeffrey Energy Center	3	2009	4	364	463,690	4,421,143	4,326	5,141,313	49,405,979
KS	Jeffrey Energy Center	3	2009	5	378	483,416	4,609,226	4,452	5,310,615	51,004,886
KS	Jeffrey Energy Center	3	2009	6	306	353,221	3,369,718	4,440	5,267,094	50,544,205
KS	Jeffrey Energy Center	3	2009	7	363	442,974	4,224,851	4,435	5,237,924	50,213,577
KS	Jeffrey Energy Center	3	2009	8	229	296,482	2,828,103	4,363	5,129,606	49,127,057
KS	Jeffrey Energy Center	3	2009	9	348	444,077	4,234,625	4,371	5,136,144	49,143,792
KS	Jeffrey Energy Center	3	2009	10	298	406,068	3,872,859	4,328	5,095,516	48,705,110
KS	Jeffrey Energy Center	3	2009	11	359	468,243	4,464,563	4,335	5,109,990	48,796,461
KS	Jeffrey Energy Center	3	2009	12	448	481,950	4,595,244	4,334	5,084,733	48,498,946
KS	Jeffrey Energy Center	3	2010	1	169	229,974	2,194,050	4,196	4,932,516	47,048,263
KS	Jeffrey Energy Center	3	2010	2	345	447,134	4,263,295	4,142	4,897,936	46,718,550
KS	Jeffrey Energy Center	3	2010	3	387	511,307	4,875,152	4,081	4,872,532	46,476,334
KS	Jeffrey Energy Center	3	2010	4	351	469,807	4,479,472	4,022	4,834,310	46,111,892
KS	Jeffrey Energy Center	3	2010	5	261	351,898	3,356,855	3,948	4,750,071	45,309,511
KS	Jeffrey Energy Center	3	2010	6	368	454,935	4,337,680	3,943	4,759,270	45,397,040
KS	Jeffrey Energy Center	3	2010	7	476	512,437	4,885,943	3,969	4,772,406	45,522,192
KS	Jeffrey Energy Center	3	2010	8	484	478,990	4,567,341	3,942	4,757,935	45,384,376
KS	Jeffrey Energy Center	3	2010	9	404	456,901	4,356,416	3,999	4,827,275	46,045,063
KS	Jeffrey Energy Center	3	2010	10	341	366,046	3,490,142	4,170	5,010,298	47,790,134
KS	Jeffrey Energy Center	3	2010	11	244	100,829	961,999	4,256	5,018,773	47,860,371
KS	Jeffrey Energy Center	3	2010	12	491	477,823	4,556,254	4,369	5,095,512	48,589,499
KS	Jeffrey Energy Center	3	2011	1	530	553,004	5,272,739	4,366	5,096,826	48,602,025
KS	Jeffrey Energy Center	3	2011	2	402	454,978	4,338,085	4,392	5,109,923	48,726,678
KS	Jeffrey Energy Center	3	2011	3	428	501,327	4,780,279	4,387	5,103,756	48,668,016
KS	Jeffrey Energy Center	3	2011	4	416	517,198	4,931,326	4,413	5,130,510	48,923,108
KS	Jeffrey Energy Center	3	2011	5	366	480,201	4,579,271	4,407	5,128,902	48,908,131
KS	Jeffrey Energy Center	3	2011	6	331	456,697	4,355,161	4,419	5,180,640	49,400,852
KS	Jeffrey Energy Center	3	2011	7	427	541,315	5,445,150	4,452	5,229,811	50,011,001
KS	Jeffrey Energy Center	3	2011	8	357	447,941	4,794,989	4,516	5,305,540	50,994,444
KS	Jeffrey Energy Center	3	2011	9	277	390,473	3,935,136	4,481	5,278,738	50,844,700

Monthly				24-Month Rolling	
Month	Average lb/MMBtu	CO (lbs)	Heat Input (MMBtu)	CO 24-Month Rolling Avg. (tpy)	Heat Input 24-Month Rolling Avg. (MMBtu/yr)
Aug-06	0.136	784,332	5,516,424		
Sep-06	0.102	541,267	5,030,267		
Oct-06	0.115	527,078	4,569,592		
Nov-06	0.138	772,961	5,512,496		
Dec-06	0.069	367,491	4,903,306		
Jan-07	0.069	339,170	4,927,054		
Feb-07	0.053	175,657	3,242,020		
Mar-07	0.044	203,529	2,866,157		
Apr-07	0.083	387,578	4,145,186		
May-07	0.007	10,747	1,412,818		
Jun-07	0.118	522,100	4,291,412		
Jul-07	0.139	684,709	4,886,107		
Aug-07	0.131	638,440	5,001,561		
Sep-07	0.152	652,306	4,201,215		
Oct-07	0.153	739,316	4,750,806		
Nov-07	0.111	509,146	4,299,422		
Dec-07	0.047	247,429	5,191,785		
Jan-08	0.047	247,429	5,191,785		
Feb-08	0.068	322,623	4,922,721		
Mar-08	0.119	633,498	5,359,582		
Apr-08	0.153	798,144	5,208,356		
May-08	0.174	884,568	4,961,618		
Jun-08	0.204	813,619	4,181,614		
Jul-08	0.201	993,630	4,634,173		
Aug-08	0.137	706,625	4,842,974		
Sep-08	0.073	237,245	3,037,243	3,104	53,168,059
Oct-08		0	0	2,972	50,884,687
Nov-08	0.138	119,498	828,481	2,809	48,539,748
Dec-08	0.100	315,545	3,102,354	2,796	47,639,538
Jan-09	0.088	461,067	5,247,687	2,826	47,799,854
Feb-09	0.057	218,313	4,089,411	2,837	48,222,740
Mar-09	0.048	233,372	4,897,602	2,844	49,255,751
Apr-09	0.061	272,757	4,421,143	2,816	49,405,979
May-09	0.081	377,324	4,609,226	2,907	51,004,886
Jun-09	0.068	221,625	3,376,500	2,832	50,544,205
Jul-09	0.074	326,632	4,227,113	2,743	50,213,577
Aug-09	0.104	304,082	2,830,026	2,659	49,127,057
Sep-09	0.103	453,850	4,234,625	2,609	49,143,792
Oct-09	0.175	629,908	3,879,868	2,582	48,705,110
Nov-09	0.154	682,527	4,464,563	2,625	48,796,461
Dec-09	0.193	904,123	4,597,316	2,790	48,498,946
Jan-10	0.206	497,951	2,195,743	2,852	47,048,263
Feb-10	0.124	489,157	4,263,212	2,894	46,718,550
Mar-10	0.171	848,369	4,875,021	2,947	46,476,334
Apr-10	0.142	633,347	4,479,468	2,906	46,111,892
May-10	0.151	597,366	3,355,526	2,834	45,309,511
Jun-10	0.183	861,125	4,336,096	2,846	45,397,040
Jul-10	0.176	889,376	4,885,980	2,820	45,522,192
Aug-10	0.130	633,158	4,550,926	2,802	45,384,376
Sep-10	0.090	432,460	4,356,488	2,851	46,045,063
Oct-10	0.104	379,998	3,491,070	2,946	47,790,134
Nov-10	0.137	141,082	963,187	2,951	47,860,371
Dec-10	0.126	552,819	4,556,586	3,010	48,589,499
Jan-11	0.208	1,026,940	5,289,109	3,152	48,602,025
Feb-11	0.141	623,631	4,339,758	3,253	48,726,678
Mar-11	0.192	928,260	4,786,429	3,427	48,668,016
Apr-11	0.168	847,506	4,902,685	3,571	48,923,108
May-11	0.192	950,783	4,581,254	3,714	48,908,131
Jun-11	0.221	999,558	4,350,936	3,909	49,400,852
Jul-11	0.133	695,733	5,445,150	4,001	50,005,510
Aug-11	0.136	666,222	4,794,989	4,091	50,987,991
Sep-11	0.224	940,723	3,935,136	**4,213**	**50,838,247**

EMISSION FACTORS

		CO lb/MMBtu	NOx lb/MMBtu
JEC3	Post Project Emissions	0.400	0.140

	MAXIMUM ANNUAL HEAT INPUT PAST 5 YEARS		**MAXIMUM HOURLY HEAT INPUT PAST 5 YEARS**	**PAST ANNUAL CAPACITY FACTOR**
	MMBtu/yr	hours/yr*	MMBtu/hr	%
JEC3	53,168,059	6,435	8,262	73

*equivalent to full load

FUTURE PROJECTED HEAT INPUT, WITHOUT DEMAND GROWTH

	MMBtu/hr	hours/yr	MMBtu/yr
JEC3	8,262	6,435	53,168,059

	FUTURE PROJECTED HEAT INPUT	**MAXIMUM ANNUAL HEAT INPUT PAST 5 YEARS**
	MMBtu/yr	MMBtu/yr
JEC3	53,168,059	53,168,059

FUTURE PROJECTED EMISSIONS WITHOUT DEMAND GROWTH, TPY

		CO	NOx
JEC3	Stack Emissions	10,634	3,722

EMISSION CHANGE CALCULATION (TPY)

	CO	NOx	CO2
Total Projected Actual	10,634	3,722	5,492,763
Total Baseline Emission	4,213	4,521	5,502,851
Emission Increase	6,421	(799)	(10,088)
PSD Significant Emission Level	**100**	**40**	**75000**
Major Modification?	**Yes**	**No**	**No**

Jeffrey Energy Center
NOx Reduction Project
CO_2 Calculations

Jeffrey Energy Center is proposing to install low NOx system on Units 3. Combusted carbon in the boiler will either become carbon monoxide (CO) or carbon dioxide (CO_2). As a resu of this project CO emissions will increase therefore CO_2 emissions will decrease. The CO emission increase is 6,421 tons/yr. Based on the following calculations the corresponding decrease in CO_2 is 10,088 tons/yr:

	Molecular Weight
C	12.011
O	15.999
CO	28.01
CO_2	44.009

Increase in CO = 6,421 tons/yr

$$\frac{-6421\ \text{tons(CO)}}{\text{yr}} \times \frac{1\ \text{ton*mol(CO)}}{28.01\ \text{tons(CO)}} \times \frac{1\ \text{ton*mol(CO2)}}{1\ \text{ton*mol(CO)}} \times \frac{44.009\ \text{tons(CO2)}}{1\ \text{ton*mol(CO2)}} = \frac{-10{,}088\ \text{tons(CO2)}}{\text{yr}}$$

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

Baseline CO_2 Emissions		5,502,851 tons/yr
CO_2 emissions from the decrease in CO	+	-10,088 tons/yr
Future Projected CO_2 Emissions	=	5,492,763 tons/yr

Emissions Change	-10,088 tons/yr
PSD Significant Emission Level	75,000 tons/yr
Major Modification?	No

APPENDIX C

BACT ANALYSIS

APPENDIX C - BACT ANALYSIS

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, the Project at JEC warrants a BACT analysis for CO.

[1]40 CFR §52.21(j).

Table C-1
Project Emissions Increase and PSD Significant Emission Rates

	NO_X	CO	CO_2
Project Emissions Change (tpy)	-799	6,421	-10,088
Significant Emission Rate (tpy)	40	100	75,000
PSD Triggered?	**No**	**Yes**	**No**

On December 1, 1987, the 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 State implementation plans. 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.

BACKGROUND ON CO AND NO_X FORMATION

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 the 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.

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.

The addition of overfire air is another method of staging combustion in the furnace. In an overfire air system, 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.

JEC3 CO AND NO_X EMISSIONS

The existing JEC3 low NO_X system consists of low NO_X burners (LNB), separated overfire air (SOFA), and associated equipment and ductwork. Westar is planning to upgrade and further enhance the existing JEC3 low NO_X system in order to achieve additional NO_X reduction. The low NO_X system modifications include upgrades to the existing LNBs, adjustments to existing SOFA, and additional SOFA for deeper staging, boiler tuning, and installation of associated equipment.

The goal of the Project is to further reduce JEC3 NO_X emissions with final achievable NO_X levels dependant on the effectiveness of tuning the upgraded equipment. 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.

CO BACT ANALYSIS

Carbon Monoxide Control Technology/Feasibility

Catalytic oxidation is the most efficient 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 JEC3 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 JEC3 was previously 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 JEC3 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 previously contacted to discuss the feasibility of adding their systems to a coal-fired utility boiler. The vendors contacted were Engelhard Corporation (Iselin, New Jersey) and Ceram Environmental, Inc. (Overland Park, Kansas). 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. A utility in Indiana experienced excessive sulfur trioxide formation and a significant blue plume problem after retrofitting a selective catalytic reduction (SCR) system to reduce nitrogen oxides. The Ceram representative stated that the conversion rate of sulfur dioxide to sulfur trioxide resulting from a CO oxidation catalyst would be significantly greater than the rate from the SCR catalyst. 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 California (Huntington Beach). 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.

The other CO control technology available is good combustion practices (GCP). 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.

CO 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 similar NO_X combustion control projects (i.e., low-NO_X burners or overfire air) was performed to determine the CO BACT control technologies and emission limits established for other coal-fired boilers. Table C-2 presents a summary of the findings. As shown in Table C-2, past BACT cases which are relevant show CO emission limits of 0.42 lb/MMBtu or greater.

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	NOx "Limit" (lb/MMBtu)	CO Control Technology	CO BACT Limit (lb/MMBtu)	Notes on Relevancy of CO BACT Limit to JEC3 BACT Determination
1	Alliant Energy	Ottumwa Generating Station	Chillicothe, IA	Boiler 1	Tangential-fired	78-A-019-P9	1/19/10	Smartburn/ZoloBoss Control System	0.25 (Ann)	GCP	0.163	Not relevant. The NOx levels are higher than what is being targeted by Westar for the Project, thus CO emissions would be expected to be lower
2	Board of Public Utilities	Nearman Creek Station	Kansas City, KS	Unit 1	Wall-fired	None	4/14/11	LNB/OFA	0.26 - Per manufacturer guarantee	GCP	0.17	Not relevant. The NOx levels are higher than what is being targeted by Westar for the Project, thus CO emissions would be expected to be lower
3	Orlando Utilities Commission	Stanton Energy Center	FL	Unit 1	Wall-fired	0950137-015-AC	2/7/08	LNB/OFA	0.28 - Per the manufacturer guarantee	GCP	0.18	Not relevant. The NOx levels are higher than what is being targeted by Westar for the Project, thus CO emissions would be expected to be lower
4	Interstate Power and Light Company	Lansing Station	Lansing, IA	Boiler 3	Unknown	73-A 132P-S2	3/31/08	LNB/OFA	Unknown	GCP	0.25	Not relevant. The NOx levels are unknown there is not enough information to draw a conclusion.
5	Westar Energy, Inc	Tecumseh Energy Center	Tecumseh, KS	Boiler 7/9	Tangential-fired	None	3/18/08	LNB/SOFA	0.15 - Per manufacturer data	GCP	0.25	Not relevant. The NOx levels are higher than what is being targeted by Westar for the Project, thus CO emissions would be expected to be lower
6	Westar Energy, Inc.	Tecumseh Energy Center	Tecumseh, KS	Boiler 8/10	Tangential-fired	None	3/18/08	LNB/SOFA	0.15 - Per manufacturer data	GCP	0.25	Not relevant. The NOx levels are higher than what is being targeted by Westar for the Project, thus CO emissions would be expected to be lower.
7	Westar Energy, Inc.	Jeffrey Energy Center	St. Mary's, KS	Unit 1	Tangential-fired	None	2/29/08	LNB/SOFA	0.15 - Per manufacturer data	GCP	0.25	Not relevant. The NOx levels are higher than what is being targeted by Westar for the Project, thus CO emissions would be expected to be lower
8	Westar Energy, Inc.	Jeffrey Energy Center	St. Mary's, KS	Unit 2	Tangential-fired	None	2/29/08	LNB/SOFA	0.15 - Per manufacturer data	GCP	0.25	Not relevant. The NOx levels are higher than what is being targeted by Westar for the Project, thus CO emissions would be expected to be lower
9	Westar Energy, Inc	Jeffrey Energy Center	St. Mary's, KS	Unit 3	Tangential-fired	None	10/4/05	LNB/SOFA	0.15 - Per manufacturer data	GCP	0.25	Not relevant. The NOx levels are higher than what is being targeted by Westar for the Project, thus CO emissions would be expected to be lower
10	Duke Power Company LLC	Dan River Steam Station	Eden, NC	Unit 1	Tangential-fired	None	7/24/06	LNB/SOFA	0.25 - Expected rate during O3 season	GCP	0.25	Not relevant. The NOx levels are higher than what is being targeted by Westar for the Project, thus CO emissions would be expected to be lower
11	Duke Power Company LLC	Dan River Steam Station	Eden, NC	Unit 2	Tangential-fired	None	7/24/06	LNB/SOFA	0.25 - Expected rate during O3 season	GCP	0.25	Not relevant. The NOx levels are higher than what is being targeted by Westar for the Project, thus CO emissions would be expected to be lower
12	Duke Power Company LLC	Dan River Steam Station	Eden, NC	Unit 3	Tangential-fired	None	7/24/06	LNB/SOFA	0.25 - Expected rate during O3 season	GCP	0.25	Not relevant. The NOx levels are higher than what is being targeted by Westar for the Project, thus CO emissions would be expected to be lower
13	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	0.45 (30-Day)	GCP	0.289	Not relevant. The NOx levels are higher than what is being targeted by Westar for the Project, thus CO emissions would be expected to be lower
14	Portland General Electric	Boardman Power Plant	OR	Unit 1	Wall-fired	Unkown	12/1/10	LNB/OFA	Unknown	GCP	0.35	Not relevant. The NOx levels are unknown there is not enough information to draw a conclusion.
15	MidAmerican Energy Company	George Neal South	Salix, IA	Boiler 4	Wall-fired	05-A-655	9/28/05	LNB/OFA	0.70 (3-hr)	GCP	0.42	Not relevant. The NOx levels are higher than what is being targeted by Westar for the Project, thus CO emissions would be expected to be lower
16	MidAmerican Energy Company	Louisa Generating Station	Muscatine, IA	Louisa Boiler	Wall-fired	05-A-031-P	3/1/05	LNB/OFA	Unknown	GCP	0.42	Not relevant. The NOx levels are unknown there is not enough information to draw a conclusion.
17	MidAmerican Energy Company	Council Bluffs Energy Center	Council Bluffs, IA	Boiler 3	Wall-fired	75-A-357-P4	9/15/06	LNB/OFA	Unknown	GCP	0.42	Not relevant. The NOx levels are unknown there is not enough information to draw a conclusion.
18	Board of Public Utilities	Quindaro Station	Kansas City, KS	Unit 2	Wall-fired	None	4/14/11	LNB/OFA	0.18 (Per manufacturer guarantee)	GCP	0.42	
19	Nebraska Public Power District	Gerald Gentleman Station	Sutherland, NE	Unit 1	Wall fired	CP06-0001	8/18/06	LNB/OFA	0.23 (30-day)	GCP	0.50	
20	Nebraska Public Power District	Gerald Gentleman Station	Sutherland, NE	Unit 2	Wall-fired	Unknown	5/1/10	LNB/OFA	0.23 (30-Day)	GCP	0.50	
21	MidAmerican Energy Company	Council Bluffs Energy Center	Council Bluffs, IA	Boiler 2	Wall-fired	72 A-173-P2	3/7/08	LNB/OFA	Unknown	GCP	0.54	Not relevant. The NOx levels are unknown there is not enough information to draw a conclusion.
22	MidAmerican Energy Company	George Neal North	Sergeant Bluff, IA	Boiler 1	Cyclone	05-A-878-P	12/9/05	OFA	0.30 (30-day)	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.
23	Nebraska Public Power District	Sheldon Station	Sheldon, NE	Unit 2	Cyclone	Unknown	7/11/07	OFA	Unknown	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.
24	MidAmerican Energy Company	George Neal North	Sergeant Bluff, IA	Boiler 2	Wall-fired	07-A-951-P	9/5/07	LNB/OFA	Unknown	GCP	1.63	Not relevant. The NOx levels are unknown there is not enough information to draw a conclusion.

CONCLUSION OF CO BACT

The only control deemed feasible for CO is GCP. Thus, the BACT analysis for CO establishes GCP as BACT for CO. Westar proposes a CO BACT emissions limit of 0.4 lb/MMBtu on a 30-day rolling average excluding startup, shutdown, and malfunction based on the use of GCP. This BACT limit is lower than other relevant BACT limits.

APPENDIX D

AIR QUALITY ANALYSIS

APPENDIX D - AIR QUALITY ANALYSIS

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

SELECTION OF MODEL

AERSCREEN is a screening dispersion model approved and recommended by the United States Environmental Protection Agency (U.S. EPA) for evaluating ambient air impacts.[1] AERSCREEN is based on the U.S. EPA preferred/recommended model, AERMOD, which is used for evaluating impacts attributable to emissions from industrial facilities in the near-field (i.e., source receptor distances of less than 50 km). 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.

Per the U.S. EPA's AERSCREEN User's Guide, AERSCREEN is an interactive command-prompt application that interfaces with MAKEMET for generating the meteorological matrix. It also interfaces with AERMAP and BPIPPRM to automate the processing of terrain and building information, and interfaces with the AERMOD model utilizing the SCREEN option to perform the modeling runs.

The BREEZE® AERSCREEN, Version 1.2 software and BREEZE® AERMOD, Version 7.3 developed by Trinity Consultants was used to develop the model data files for AERSCREEN. These software programs incorporate the current regulatory versions of AERSCREEN (11126), AERMOD (11103), AERMAP (11103), BPIPPRM (04274), and MAKEMET (11126).

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[1]Per U.S. EPA Memorandum titled "AERSCREEN released as the EPA Recommended Screening Model", April 11, 2011.

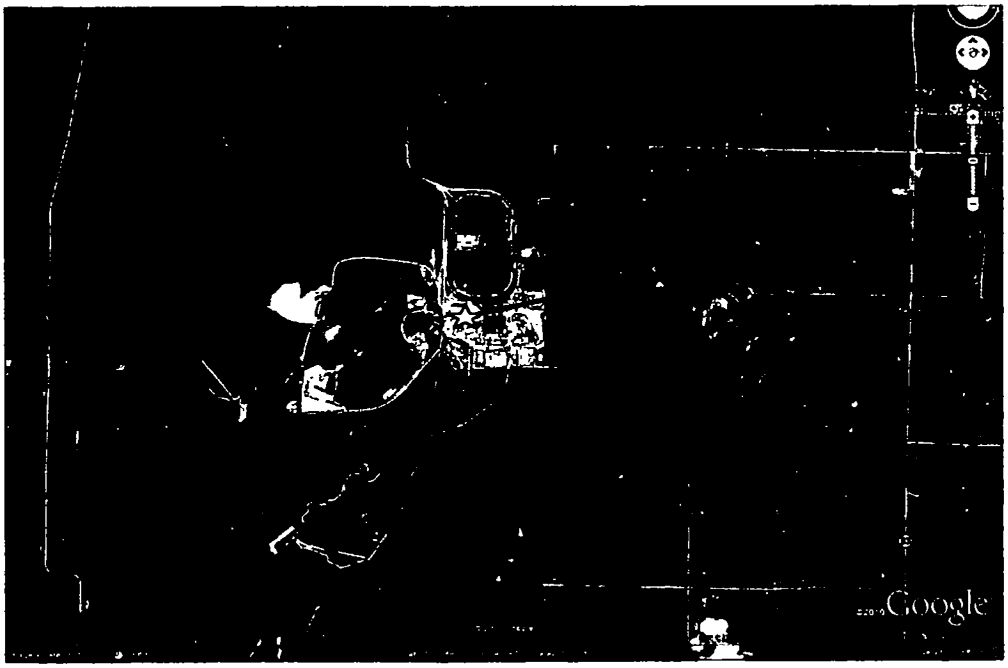
METEOROLOGICAL DATA

The MAKEMET program in AERSCREEN generates meteorological conditions based on user-specified surface characteristics, ambient temperatures, minimum wind speed, and anemometer height. The suggested default values of MAKEMET were used for the minimum temperature (250 K), maximum temperature (310 K), minimum wind speed (0.5 m/s), and the anemometer height (10 meters). The selected surface profile was set to "grassland"; in addition, the climate profile was set to "average" precipitation. The selected surface profile of grassland is based on the aerial image in Figure D-1 below.

Dispersion Coefficients

The U.S. EPA's Auer land use classification was used to determine whether rural or urban dispersion coefficients should be used in AERSCREEN. The land use type within a 3 kilometer radius around the facility was evaluated to determine if the area is predominantly rural or urban. If 50 percent or more of the land use is rural then the rural option is selected, otherwise the urban option is selected. The aerial image provided below indicates that the area surrounding the facility is predominately (greater than 50 percent) rural, thus the rural option was selected in AERSCREEN.

Figure D-1
3km Radius Aerial Imagery of Facility



RECEPTORS AND TERRAIN

Receptor Grids

Ground-level concentrations were calculated at 25-meter intervals extending from the minimum distance to ambient air (1,470 meters) out to 5 kilometers, and 50-meter intervals from 5 kilometers to 10 kilometers. A receptor was located in each of the 36 - 10 degree flow sectors.

Terrain Elevations

AERMAP was used to interpolate elevations for each AERSCREEN-generated receptor based on National Elevation Data (NED) data obtained from the United States Geological Survey (USGS). The USGS NED data consisted of arrays of 1/3 arc second (approximately 10 meter) spaced elevations. The source elevation was based on the plant elevation of 1,300 feet (396.24 meters). In order to import elevations using AERMAP, the source location and datum must be provided. JEC3 is located at 748,566 meters east and 4,352,571 meters north in Universal Transverse Mercator (UTM) Zone 14, Datum NAD83.

BUILDING DOWNWASH AND GEP STACK HEIGHT ANALYSIS

40 CFR §51, Appendix W, *Guideline on Air Quality Models*[2] 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 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). The buildings considered include the three boiler buildings, the control equipment structures and ducts for all three units, and the control equipment weather cover.

SUMMARY OF MODELED PARAMETERS FOR THE BOILER

Table D-1 summarizes the emission rate and stack parameters that were modeled for the JEC 3 boiler. The modeling was conducted using the lowest flow rate and lowest exit temperature when considering flow rates and temperatures at approximately 50 percent, 75 percent, and 100 percent loads.

Table D-1
CO Modeled Emission Rate and Stack Parameters

	CO Emission Rate (lb/hr)	GEP Stack Height (ft)	Stack Diameter (ft)	Exhaust Flow Rate (acfm)	Exhaust Velocity (ft/s)	Exhaust Temperature (F)
JEC3	1,466*	574	25.5	1,092,000	35.64	125

*Equivalent to 6,421 tpy

[2]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.

SUMMARY OF MODEL RESULTS

Table D-2 summarizes the maximum CO concentrations predicted for the Project. All modeling input and output files, building downwash files, and terrain data have been provided electronically as part of this application submittal.

Table D-2
Modeling Results

Averaging Period	Maximum Impact (μg/m^3)	Significant Impact Level (μg/m^3)
1-Hour	453.90	2,000
8-Hour	408.50	500

As shown in Table D-2, the changes to the CO one-hour and eight-hour modeled impacts are not significant, as they are well below the CO significant impact levels (SILs). As such, it has been determined that the project will not have a significant impact on the ambient air surrounding the Jeffrey Energy Center and thus no additional modeling is required.

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.

VISIBILITY

Pollutants that are typically evaluated for their impact on visibility as part of PSD permitting include PM, NO_x, SO_2, and VOC. Since CO is the only pollutant that will increase as a result of the proposed project, a visibility analysis is not necessary.

SOIL AND VEGETATION IMPACTS

The primary 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.*[3]

The results of the air quality analysis presented in the beginning of Appendix D of this report 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. Thus, the proposed project should not result in harmful effects to soils or vegetation.

GROWTH IMPACTS

The elements of a growth impact analysis include 1) a projection of the associated industrial, commercial, and residential source growth that will occur in the area due to the source; and 2) an estimate of the air emissions generated by the above associated industrial, commercial, and residential growth.

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[3]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.

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 KDHE PERMIT

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

Kansas

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

Robert Moser, MD, Acting Secretary

Department of Health & Environment

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) combustion system on the Unit 3 boiler at Jeffrey Energy Center (JEC), located near St. Mary's, Kansas. The low NO_X system modifications include upgrades to the existing low NO_X burners (LNB), adjustments to existing separated overfire air (SOFA), additional SOFA for deeper staging, boiler 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. JEC3 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 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:

The low NO_X system modifications include upgrades to the existing low NO_X burners (LNB), adjustments to existing separated overfire air (SOFA), additional SOFA for deeper staging, boiler 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	4,213	10,634	6,421
NO_X	4,521	3,722	-799
CO_2	5,502,851	5,492,763	-10,088

V. Air Emission Limitations

Coal Fired Boiler (JEC Unit 3)

A. The thirty (30) day rolling average emission rate of CO shall not exceed 0.40

lb/mmBtu, excluding periods of startup, shutdown, and malfunction.

B. The purpose of the project is to reduce the NO_X emissions from Unit 3. 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.

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 unit. The CO CEMS shall be 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)

B. Reports of excess emissions shall be submitted 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)

VII. 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