BART FIVE FACTOR ANALYSIS ▪ WESTAR ENERGY
JEFFREY ENERGY CENTER AND GORDON EVANS ENERGY CENTER

VERSION 0

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1. EXECUTIVE SUMMARY

This report documents the determination of the Best Available Retrofit Technology (BART) as proposed by Westar Energy (Westar) for the Jeffrey Energy Center (JEC) located in St. Mary's, Kansas and the Gordon Evans Energy Center (GEEC) located in Colwich, Kansas. There are two units at JEC and one unit at GEEC that are subject to BART. JEC Unit 1 and Unit 2 are each coal-fired boilers with heat input ratings of 8,110 million British thermal units per hour (MMBtu/hr). GEEC Unit 2 is an oil-fired boiler with a heat input rating of 4,110 MMBtu/hr.

Westar has determined that JEC Unit 1 and Unit 2 and GEEC Unit 2 contribute greater than 0.5 delta deciviews (Δdv) to visibility impairment in a federally protected Class I area when compared to a natural background. Therefore, these three units are subject to BART. A summary of the visibility impairment attributable to the JEC Unit 1 and Unit 2 and GEEC Unit 2 is provided in Table 1-1.

TABLE 1-1. EXISTING VISIBILITY IMPAIRMENT ATTRIBUTABLE TO JEC UNIT 1 AND UNIT 2 AND GEEC UNIT 2 (2001-2003)

	Wichita Mountains		Hercules Glades Wilderness		Caney Creek Wilderness		Mingo NWR		Upper Buffalo Wilderness	
	98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv
JEC Unit 1 and Unit 2	0.99	59	0.90	63	0.73	37	0.49	21	0.85	53
GEEC Unit 2	1.08	85	0.40	16	0.38	14	0.17	4	0.42	16

Westar used the U.S. Environmental Protection Agency's (EPA's) guidelines[1] in 40 CFR Part 51 to determine BART for JEC Unit 1 and Unit 2 and GEEC Unit 2. Specifically, Westar conducted a five-step analysis to determine BART for SO_2, NO_X, and PM_{10} that included the following:

1. Identifying all available retrofit control technologies;
2. Eliminating technically infeasible control technologies;
3. Evaluating the control effectiveness of remaining control technologies;
4. Evaluating impacts and document the results;
5. Evaluating visibility impacts

Based on the five-step analysis, Westar proposes the following as BART:

JEC Unit 1:

- PM_{10} – Westar proposes upgrades to the existing electrostatic precipitator (ESP).
- NO_X – Westar proposes to meet a BART limit of 0.15 lb/MMBtu by installing a low-NO_X burner (LNB) system.
- SO_2 – Westar proposes to meet a BART limit of 0.15 lb/MMBtu by rebuilding the existing wet scrubber.

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[1] 40 CFR 51, Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations

JEC Unit 2:

- PM_{10} – Westar proposes upgrades to the existing ESP.
- NO_X – Westar proposes to meet a BART limit of 0.15 lb/MMBtu by installing a LNB system.
- SO_2 – Westar proposes to meet a BART limit of 0.15 lb/MMBtu by rebuilding the existing wet scrubber.

GEEC Unit 2:

- PM_{10} – Westar proposes that no additional PM_{10} controls, other than the fuel switching from No.6 fuel oil to natural gas proposed as a BART alternative, are required for PM_{10} BART compliance. Additional PM controls for a gas-fired unit would provide little visibility improvement and require significant capital expenditures.
- NO_X and SO_2 – Westar proposes to meet the BART control requirement by switching from combusting No. 6 fuel oil to combusting natural gas, exclusively, except as discussed in Section 9 of this document.

The proposed BART control strategies will result in reductions of the visibility impacts attributable to JEC Unit 1 and Unit 2 and GEEC Unit 2. A summary of the visibility improvement based on the existing emission rates and proposed BART emission rates for JEC Unit 1 and Unit 2 is provided in Table 1-2. A summary of the visibility improvement based on the existing emission rates for GEEC Unit 2 and the BART control strategy for GEEC Unit 2 is provided in Table 1-3.

TABLE 1-2. VISIBILITY IMPAIRMENT IMPROVEMENT FROM JEC UNIT 1 AND UNIT 2 (2001-2003)

	Caney Creek Wilderness			**Hercules Glades Wilderness**			**Mingo NWR**			**Upper Buffalo Wilderness**			**Wichita Mountains**		
	Existing	BART	Improvement	Existing	BART	Improvement	Existing	BART	Improvement	Existing	BART	Improvement	Existing	BART	Improvement
Max Impact (Δdv)	2.74	0.85	69%	2.70	0.75	72%	1.44	0.44	69%	2.73	0.84	69%	3.51	1.19	66%
98% Impact (Δdv)	0.73	0.23	70%	0.90	0.30	67%	0.49	0.16	69%	0.85	0.25	71%	0.99	0.32	68%
Days > 0.5	37	4	89%	63	4	94%	21	0	100%	53	3	94%	59	11	81%

TABLE 1-3. VISIBILITY IMPAIRMENT IMPROVEMENT FROM GEEC UNIT 2 (2001-2003)

	Caney Creek Wilderness			**Hercules Glades Wilderness**			**Mingo NWR**			**Upper Buffalo Wilderness**			**Wichita Mountains**		
	Existing	BART*	Improvement	Existing	BART*	Improvement	Existing	BART*	Improvement	Existing	BART*	Improvement	Existing	BART*	Improvement
Max Impact (Δdv)	1.07	0.49	54%	1.31	0.93	29%	0.71	0.49	31%	2.22	1.62	27%	2.16	1.66	23%
98% Impact (Δdv)	0.38	0.25	34%	0.4	0.21	48%	0.17	0.08	55%	0.42	0.28	33%	1.08	0.69	36%
Days > 0.5	14	0	100%	16	4	75%	4	0	100%	16	11	31%	85	44	48%

* Based on the BART alternative presented in Section 9

2. INTRODUCTION AND BACKGROUND

On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to improve visibility in 156 specific areas across with United States, known as Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence on August 7, 1977.

On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the Best Available Retrofit Technology (BART) rule, which included guidance for making source-specific BART determinations. The BART rule defines BART-eligible sources as sources that meet the following criteria:

(1) Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant,
(2) Began operation between August 7, 1962 and August 7, 1977, and
(3) Are included as one of the 26 listed source categories in the guidance.

A BART-eligible source is subject to BART if the source is "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." EPA has determined that a source is reasonably anticipated to cause or contribute to visibility impairment if the 98th percentile visibility impacts from the source are greater than 0.5 delta deciviews (Δdv) when compared against a natural background. Air quality modeling is the tool that is used to determine a source's visibility impacts.

Once it is determined that a source is subject to BART, a BART determination must address air pollution control measures for the source. The visibility regulations define BART as follows:

> *"…an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by…[a BART-eligible source]. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the cost of compliance, the energy and non air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonable be anticipated to result from the use of such technology.*

Specifically, the BART rule states that a BART determination should address the following five statutory factors:

1. Existing controls
2. Cost of controls
3. Energy and non-air quality environmental impacts
4. Remaining useful life of the source
5. Degree of visibility improvement as a result of controls

Further, the BART rule indicates that the five basic steps in a BART analysis can be summarized as follows:

1. Identify all available retrofit control technologies;
2. Eliminate technically infeasible control technologies;
3. Evaluate the control effectiveness of remaining control technologies;
4. Evaluate impacts and document the results;
5. Evaluate visibility impacts

A BART determination should be made for each visibility affecting pollutant (VAP) by following the five steps listed above for each VAP.

Westar performed a BART applicability analysis for JEC Unit 1 and Unit 2 and GEEC Unit 2 and determined the units are subject to BART. The details of the applicability determination can be found in Section 3. Subsequently, Westar performed an analysis to determine BART for each VAP for JEC Unit 1 and Unit 2 and GEEC Unit 2. The VAPs emitted by JEC Unit 1 and Unit 2 and GEEC Unit 2 include NO_x, SO_2, and particulate matter with a mass mean diameter smaller than ten microns (PM_{10}) of various forms (filterable coarse particulate matter [PM_c], filterable fine particle matter [PM_f], elemental carbon [EC], inorganic condensable particulate matter [IOR CPM] as sulfates [SO_4], and organic condensable particulate matter [OR CPM] also referred to as secondary organic aerosols [SOA]). The BART determinations for SO_2, NO_X, and PM_{10} can be found in Sections 4, 5, and 6, respectively.

EPA established presumptive limits in the BART guidelines for coal-fired electric generating units (EGUs). The presumptive limits were established by reviewing BART-eligible units and determining a level of emissions reductions that would be cost effective. The EPA's BART guidelines state the following with regard to presumptive BART for coal-fired EGU units for SO_2:

> *"You must require 750 MW power plants to meet specific control levels for SO_2 of either 95 percent control or 0.15 lb/MMBtu… For coal fired EGUs with an existing post combustion SO_2 controls achieving less than 50 percent removal efficiencies, we recommend that you evaluate construction a new FGD system to meet the same emission limit as above (95 percent removal or 0.15 lb/MMBtu)"*

For power plants greater than 750 MW, EPA requires that state agencies apply the presumptive BART limit as a floor for SO_2. Thus, the SO_2 presumptive limit for both JEC Unit 1 and Unit 2 is 0.15 lb/MMBtu.

Similarly, the guidelines provide presumptive NO_X limits for coal-fired EGUs. JEC Unit 1 and Unit 2 are tangential-fired units burning sub-bituminous coal; the guidelines state that the NO_X presumptive limit is 0.15 lb/MMBtu for this type of EGU.

The BART guidelines state the following with regard to presumptive BART controls for oil-fired boilers:

"For oil-fired and gas-fired EGUs larger than 200 MW, we believe that installation of current combustion control technology to control NO_X is generally highly cost-effective and should be considered in your determination of BART for these sources."

EPA also established presumptive SO_2 controls for oil-fired EGUs. For oil-fired units, the guidelines state that sources of all sizes should evaluate limiting the sulfur content of the fuel oil to 1 percent or less by weight as BART. Thus, the SO_2 presumptive limit for GEEC Unit 2 is fuel oil sulfur content of 1 percent.

The BART guidelines do not specify presumptive BART limits for PM_{10} emissions.

3. BART APPLICABILITY DETERMINATION

As stated in Section 2, a BART-eligible source is subject-to-BART if the source is “reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area.” EPA has determined that a source is reasonably anticipated to cause or contribute to visibility impairment if the 98th percentile of the visibility impacts from the source is greater than 0.5 Δdv when compared against a natural background. Westar conducted air quality modeling to predict the existing visibility impairment attributable to JEC Unit 1 and Unit 2 and GEEC Unit 2 in the following Class I areas:

- Wichita Mountains
- Hercules Glades Wilderness
- Upper Buffalo Wilderness
- Caney Creek Wilderness
- Mingo National Wildlife Refuge (NWR)

The modeling methods and procedures that were followed were provided to the Kansas Department of Health and Environment (KDHE) in a modeling protocol in September 2006. Table 3-1 summarizes the emission rates that were modeled for SO_2, NO_X, and PM_{10}, including the speciated PM_{10} emissions. The SO_2 and NO_x emission rates are the highest actual 24-hour emission rates based on 2002-2004 continuous emissions monitoring system (CEMS) data. The PM_{10} emission rates are the calculated highest emission rates based on fuel data from 2002-2004 and AP-42 emission factors. The total PM_{10} emission rates include both the filterable and condensable fractions and are speciated into the following:

- Coarse particulate matter (PM_C)
- Fine particulate matter (PM_f)
- Sulfates (SO_4)
- Secondary organic aerosols (SOA)
- Elemental carbon (EC)

TABLE 3-1. EXISTING MAXIMUM 24-HOUR SO_2, NO_X, AND PM_{10} EMISSIONS (AS HOURLY EQUIVALENTS)

	SO_2 (lb/hr)	NO_X (lb/hr)	Total PM_{10} (lb/hr)	SO_4 (lb/hr)	PM_c (lb/hr)	PM_f (lb/hr)	SOA (lb/hr)	EC (lb/hr)
JEC Unit 1	6,938.9	3,972.3	327.4	181.9	55.6	42.8	45.5	1.6
JEC Unit 2	7,128.2	3,924.0	303.9	168.8	51.6	39.8	42.2	1.5
GEEC Unit 2	5,766.7	4,818.3	431.5	38.7	104.7	260.5	6.8	20.8

Table 3-2 summarizes the stack parameters that were used to model JEC Unit 1 and Unit 2 and GEEC Unit 2 (two stacks). It should be noted that the good engineering practice (GEP) stack heights were modeled instead of the actual stack heights for JEC Unit 1 and Unit 2 since the GEP stack heights are less than the actual stack heights.

TABLE 3-2. SUMMARY OF EXISTING STACK PARAMETERS

	JEC Unit 1	JEC Unit 2	GEEC Unit 2 (Stack 2A)	GEEC Unit 2 (Stack 2B)
Latitude (degrees)	39.287	39.287	37.793	37.793
Longitude (degrees)	96.116	96.116	97.518	97.518
Actual Stack height (ft)	600	600	197	197
GEP Stack height (ft)	574	574	381	381
Stack Diameter (ft)	26	26	13	13
Exhaust Velocity (ft/s)	91.3	91.3	69	69
Exhaust Temperature (F)	300	300	290	290

The results of the modeling are summarized in Table 3-3. The results of the modeling indicate that the 98th percentile of the visibility impacts attributable to JEC Unit 1 and Unit 2 and GEEC Unit 2 are greater than 0.5 Δdv when compared against a natural background. Since the visibility impacts are greater than 0.5 Δdv, JEC Unit 1 and Unit 2 and GEEC Unit 2 are subject to BART.

TABLE 3-3. EXISTING VISIBILITY IMPAIRMENT ATTRIBUTABLE TO JEC UNIT 1 AND UNIT 2 AND GEEC UNIT 2 (2001-2003)

Class I Area	Wichita Mountains		Hercules Glades Wilderness		Caney Creek Wilderness		Mingo NWR		Upper Buffalo Wilderness	
	98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv
JEC Unit 1 and Unit 2	0.99	59	0.90	63	0.73	37	0.49	21	0.85	53
GEEC Unit 2	1.08	85	0.40	16	0.38	14	0.17	4	0.42	16

Tables 3-4 and 3-5 provide a breakdown of the visibility impacts listed in Table 3-3 by each VAP for JEC and GEEC, respectively.

TABLE 3-4. BREAKDOWN OF POLLUTANT SPECIFIC CONTRIBUTIONS TO EXISTING VISIBILITY IMPAIRMENT FOR JEC UNIT 1 AND UNIT 2 (2001-2003)

Class I Area	Visibility Impairment Attributable to SO_4 (%)	Visibility Impairment Attributable to NO_3 (%)	Visibility Impairment Attributable to SOA (%)	Visibility Impairment Attributable to EC (%)	Visibility Impairment Attributable to PM_c (%)	Visibility Impairment Attributable to PM_f (%)	Total Visibility Impairment 98% (Δdv)
Wichita Mountains Wilderness	51.13	48.28	0.44	0.04	0.01	0.1	0.99
Hercules Glades Wilderness	38.21	60.92	0.63	0.06	0.03	0.15	0.90
Caney Creek Wilderness	40.79	57.87	0.98	0.09	0.05	0.23	0.73
Mingo Wildlife	43.81	55.53	0.49	0.04	0.01	0.11	0.49
Upper Buffalo Wilderness	39.6	59.22	0.85	0.08	0.05	0.2	0.85

TABLE 3-5. BREAKDOWN OF POLLUTANT SPECIFIC CONTRIBUTIONS TO EXISTING VISIBILITY IMPAIRMENT FOR GEEC UNIT 2 (2001-2003)

Class I Area	Visibility Impairment Attributable to SO_4 (%)	Visibility Impairment Attributable to NO_3 (%)	Visibility Impairment Attributable to SOA (%)	Visibility Impairment Attributable to EC (%)	Visibility Impairment Attributable to PM_c (%)	Visibility Impairment Attributable to PM_f (%)	Total Visibility Impairment 98% (Δdv)
Wichita Mountains Wilderness	29.29	67.54	0.16	1.25	0.19	1.57	1.08
Hercules Glades Wilderness	41.15	57.14	0.09	0.7	0.04	0.88	0.40
Caney Creek Wilderness	26.11	71.72	0.12	0.89	0.04	1.11	0.38
Mingo Wildlife	63.14	34.96	0.1	0.78	0.03	0.98	0.17
Upper Buffalo Wilderness	35.67	62.6	0.09	0.71	0.02	0.89	0.42

As shown in Tables 3-4 and 3-5, the most significant contributors to the visibility impairment are sulfates (SO_4) and nitrates (NO_3). The SO_4 contribution is primarily from the chemical conversion of SO_2 emitted by JEC Unit 1 and Unit 2 and GEEC Unit 2 to SO_4; a very small fraction is from SO_4 emitted as condensable particulate. The NO_3 contribution is entirely from the chemical conversion of NO_X emitted from JEC Unit 1 and Unit 2 and GEEC Unit 2. The contribution of PM_{10} to the total visibility impairment can be estimated as the sum of the contributions from SOA, EC, PM_c, and PM_f. The PM_{10} contribution is less than the contribution from SO_2 and NO_X.

4. JEC SO_2 BART EVALUATION

The existing maximum 24-hour SO_2 emission rates that were modeled for the BART applicability determination are summarized in Table 4-1.

TABLE 4-1. EXISTING MAXIMUM 24-HOUR SO_2 EMISSION RATES FOR JEC UNIT 1 AND UNIT 2

	Heat Input (MMBtu/hr)	SO_2 24-Hour Emission Rate (ton/24-hr)	SO_2 Hourly Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)
JEC Unit 1	8,110	83.3	6,938.9	0.86
JEC Unit 2	8,110	85.5	7,128.2	0.88

4.1 IDENTIFICATION OF AVAILABLE RETROFIT SO_2 CONTROL TECHNOLOGIES

Step 1 of the BART determination is the identification of all available retrofit SO_2 control technologies. A list of control technologies was obtained by reviewing the U.S. EPA's Clean Air Technology Center, control equipment vendor information, publicly-available air permits, applications, and technical literature published by the U.S. EPA and Regional Planning Organizations (RPOs).

The available retrofit SO_2 control technologies are summarized in Table 4-2 for JEC Unit 1 and 2.

TABLE 4-2. AVAILABLE SO_2 CONTROL TECHNOLOGIES FOR JEC UNIT 1 AND UNIT 2

SO_2 Control Technologies
Dry Sorbent Injection Spray Dryer Absorber (SDA) i.e., Semi-Dry Scrubber Wet Scrubber Circulating Dry Scrubber (CDS)

All of the technologies listed in Table 4-2 involve removing the SO_2 in the exhaust gas, which is known as flue gas desulfurization (FGD).

4.2 ELIMINATE TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES

Step 2 of the BART determination is to eliminate technically infeasible SO_2 control technologies that were identified in Step 1.

4.2.1 DRY SORBENT INJECTION

Dry sorbent injection involves the injection of a lime or limestone powder into the exhaust gas stream where SO_2 becomes entrained in the lime. The stream is then passed through a fabric filter to remove the sorbent and entrained SO_2. The process was developed as a lower cost FGD option because the mixing of the SO_2 and lime occurs directly in the exhaust gas stream instead of in a separate tower. Depending on the residence time and gas stream temperature, sorbent injection control efficiency is typically between 40 and 60 percent.[2] This control is a technically feasible option for the control of SO_2 from JEC Unit 1 and Unit 2.

4.2.2 SPRAY DRYER ABSORPTION (SDA)

Spray dryer absorption is a semi-dry scrubbing system that sprays a fine mist of lime slurry into an absorption tower where the SO_2 is absorbed by the slurry droplets. The absorption of the SO_2 leads to the formation of calcium sulfite and calcium sulfate within the droplets. The liquid-to-gas ratio is such that the heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the tower. This leads to the formation of a dry powder which is carried out with the gas and collected with a fabric filter. Existing spray dryer absorption control efficiencies range from 60 to 95 percent.[3] This control is a technically feasible option for the control of SO_2 from JEC Unit 1 and Unit 2.

4.2.3 WET SCRUBBER

Wet scrubbing involves scrubbing the exhaust gas stream with a slurry comprised of lime or limestone in suspension. The process takes place in a wet scrubbing tower located downstream of a PM control device such as a fabric filter or an ESP to prevent the plugging of spray nozzles and other problems caused by the presence of particulates in the scrubber. Similarly to the chemistry illustrated above for spray dryer absorption, the SO_2 in the gas stream reacts with the lime or limestone slurry to form calcium sulfite and calcium sulfate. Wet lime scrubbing is capable of achieving 80-95 percent control.[4] This control is a technically feasible option for the control of SO_2 from JEC Unit 1 and Unit 2.

4.2.4 CIRCULATING DRY SCRUBBER (CDS)

In the circulating dry scrubbing process, the flue gas is introduced into the bottom of a reactor vessel at high velocity through a venturi nozzle; the exhaust is mixed with water, hydrated lime, recycled flyash and CDS reaction products. The intensive gas-solid mixing that occurs in the reactor promotes the reaction of sulfur oxides in the flue gas with the dry lime particles. The mixture of reaction products (calcium sulfite/sulfate), unreacted lime, and fly ash is carried out with the exhaust and collected in an ESP or fabric filter. A large portion of the collected particles is recycled to the reactor to sustain the bed and improve lime utilization. CDS absorbers have been installed with both fabric filters and ESPs for particulate control. The control efficiency of a CDS is similar to that of an SDA. This control is a technically feasible option for the control of SO_2 from JEC Unit 1 and Unit 2.

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[2] "Assessment of Control Technology Options for BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities" Northeast States for Coordinated Air Use Management (NESCAUM), March 2005.

[3] EPA Basic Concepts in Environmental Sciences, Module 6: Air Pollutants and Control Techniques http://www.epa.gov/eogapti1/module6/sulfur/control/control.htm

[4] EPA Basic Concepts in Environmental Sciences, Module 6: Air Pollutants and Control Techniques http://www.epa.gov/eogapti1/module6/sulfur/control/control.htm

4.3 RANK OF TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis is to rank the technically feasible options according to effectiveness. Table 4-3 provides a ranking of the control efficiencies for the controls listed in the previous section for JEC Unit 1 and 2.

TABLE 4-3. CONTROL EFFECTIVENESS OF TECHNICALLY FEASIBLE SO_2 CONTROL TECHNOLOGIES FOR JEC UNIT 1 AND UNIT 2

Control Technology	Estimated Control Efficiency
Wet Scrubber	~80-95%
Spray Dryer Absorber (SDA)	~60-95%
Circulating Dry Scrubber (CDS)	~60-95%
Dry Sorbent Injection	~40-60%

Since dry sorbent injection has the lowest control level of the controls listed in Table 4-3, this control will no longer be evaluated.

4.4 EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS

Step four for the BART analysis procedure is the impact analysis. The BART determination guidelines list the four factors to be considered in the impact analysis:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

4.4.1 COST OF COMPLIANCE

The three remaining SO_2 control options (wet scrubbers, SDA, CDS) for JEC Unit 1 and Unit 2 are FGD systems capable of achieving similar maximum levels of SO_2 reductions. Westar will only evaluate wet scrubbers for BART. Since this control option achieves an equally high level of control as the other control options, cost analyses are not necessary.

4.4.2 ENERGY IMPACTS AND NON-AIR QUALITY IMPACTS

FGD systems require electricity to operate the ancillary equipment. Additionally, wet FGD systems generate wastewater and sludge that must be treated. This places additional burdens on the wastewater treatment and solid waste management capabilities. If wet scrubbing produces calcium sulfite sludge, the sludge will be water-laden, and it must be stabilized for landfilling. If wet scrubbing produces calcium sulfate sludge, it is stable and easy to dewater. However, control costs will be higher because additional equipment is required.

4.4.3 REMAINING USEFUL LIFE

The remaining useful life of JEC Unit 1 and Unit 2 does not impact the annualized capital costs because the useful lives of the units are anticipated to be at least as long as the capital cost recovery period, which is 20 years.

4.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE SO_2 CONTROLS

A final impact analysis was conducted to assess the visibility improvement for existing emission rates when compared to the emission rates of associated with a wet scrubber. The existing emission rates and emission rates associated with a wet scrubber were modeled using CALPUFF. The existing emission rates are the same rates that were modeled for the BART applicability analysis. The emission rate associated with the wet scrubber is 0.15 lb/MMBtu multiplied by the maximum hourly heat inputs for JEC Unit 1 and Unit 2. A sample calculation of the SO_2 emission rate associated with a wet scrubber for JEC Unit 1 is provided as follows:

$$P * HI = 1{,}216.5 \text{ lb/hr}$$

Where:
P (emission rate of wet scrubber) = 0.15 lb/MMBtu
HI (hourly heat input) = 8,110 MMBtu/hr

The existing hourly equivalent of the maximum 24-hour emission rates and the hourly equivalent of the 24-hour emission rates associated with the wet scrubber that were utilized in the visibility impact modeling are summarized in Table 4-4.

TABLE 4-4. SUMMARY OF EMISSION RATES MODELED IN SO_2 CONTROL VISIBILITY IMPACT ANALYSIS FOR JEC UNIT 1 AND UNIT 2

Unit	Emission Rate Scenario	Emission Rate		
		SO_2 (lb/hr)	NO_X (lb/hr)	PM_{10}* (lb/hr)
JEC Unit 1	Existing Emission Rate	6,938.9	3,972.3	327.4
	Wet Scrubber	1,216.5	3,972.3	327.4
JEC Unit 2	Existing Emission Rate	7,128.2	3,924.0	303.9
	Wet Scrubber	1,216.5	3,924.0	303.9

*PM_{10} emissions are calculated based on AP-42 emission factors.

Comparisons of the existing visibility impacts and the visibility impacts based on the wet scrubber, including the maximum modeled visibility impact, 98th percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv, for each Class I area are provided in Tables 4-5 and 4-6 for JEC Unit 1 and JEC Unit 2, respectfully. The visibility improvement associated with the wet scrubber is also shown in Tables 4-5 and 4-6; this value was calculated as the difference between the existing visibility impairment and the visibility impairment for the wet scrubber as measured by the 98th percentile modeled visibility impact.

TABLE 4-5. SUMMARY OF MODELED IMPACTS FROM SO_2 CONTROL VISIBILITY IMPACT ANALYSIS FOR JEC UNIT 1 (2001-2003)

	Wichita Mountains				**Hercules Glades Wilderness**				**Caney Creek Wilderness**				**Mingo NWR**				**Upper Buffalo Wilderness**			
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*
Existing Emission Rate	1.91	0.51	24	-	1.44	0.47	19	-	1.46	0.37	11	-	0.75	0.25	5	-	1.45	0.43	17	-
Wet Scrubber	1.22	0.34	10	33%	0.78	0.30	6	36%	0.95	0.22	5	42%	0.48	0.16	0	34%	0.88	0.27	6	39%

*Improvement is based on the 98th percentile visibility impact (Δdv) of the wet scrubber over the existing emission rate.

TABLE 4-6. SUMMARY OF MODELED IMPACTS FROM SO_2 CONTROL VISIBILITY IMPACT ANALYSIS FOR JEC UNIT 2 (2001-2003)

	Wichita Mountains				Hercules Glades Wilderness				Caney Creek Wilderness				Mingo NWR				Upper Buffalo Wilderness			
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*
Existing Emission Rate	1.91	0.51	24	-	1.45	0.46	20	-	1.47	0.37	11	-	0.75	0.25	5	-	1.47	0.43	17	-
Wet Scrubber	1.20	0.33	10	34%	0.77	0.30	4	36%	0.93	0.21	5	43%	0.47	0.16	0	36%	0.87	0.26	6	40%

*Improvement is based on the 98th percentile visibility impact (Δdv) of a wet scrubber over the existing emission rate.

As shown in Table 4-5, the operation of a wet scrubber on JEC Unit 1 results in a 33 to 42 percent improvement (depending on the Class I area) to the existing visibility impairment attributable to this unit. Similarly, as shown in Table 4-6, the operation of wet scrubbers on JEC Unit 2 results in a 34 to 43 percent improvement (depending on the Class I area) to the existing visibility impairment attributable to this unit.

4.6 PROPOSED BART FOR SO_2

Westar has determined that the SO_2 BART emission rate for JEC Unit 1 and Unit 2 is 0.15 lb/MMBtu based on the operation of wet scrubbers. Westar is proposing to meet this limit for each unit on a 30-day rolling average, excluding periods of startup, shutdown and malfunction. Compliance will be demonstrated using data from the existing continuous emissions monitoring systems (CEMS).

The existing maximum daily NO_X emission rates that were modeled for the BART applicability determination are summarized in Table 5-1.

TABLE 5-1. EXISTING MAXIMUM 24-HOUR NO_X EMISSION RATE FOR JEC UNIT 1 AND UNIT 2

	Heat Input (MMBtu/hr)	NO_X 24-Hour Emission Rate (ton/24-hr)	NO_X Hourly Emission Rate (lb/hr)	NO_X Emission Rate (lb/MMBtu)
JEC Unit 1	8,110	47.7	3,972.3	0.49
JEC Unit 2	8,110	47.1	3,924.0	0.48

5.1 IDENTIFICATION OF AVAILABLE RETROFIT NO_X CONTROL TECHNOLOGIES

Step 1 of the BART determination is the identification of all available retrofit NO_X control technologies. A list of control technologies was obtained by reviewing the U.S. EPA's Clean Air Technology Center, control equipment vendor information, publicly-available air permits, applications, and technical literature published by the U.S. EPA and the RPOs.

The available retrofit NO_X control technologies are summarized in Table 5-2 for JEC Unit 1 and 2.

TABLE 5-2. AVAILABLE NO_X CONTROL TECHNOLOGIES FOR JEC UNIT 1 AND UNIT 2

NO_X Control Technologies	
Combustion Controls	Flue Gas Recirculation (FGR) Overfire Air (OFA) Low NO_X Burners (LNB) and Ultra Low NO_X Burners (ULNB)
Post-Combustion Controls	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR)

NO_X emissions controls, as listed in Table 5-2, can be categorized as combustion or post-combustion controls. Combustion controls, including flue gas recirculation (FGR), overfire air (OFA), and Low NO_X Burners (LNB), reduce the peak flame temperature and excess air in the furnace which minimizes NO_X formation. Post-combustion controls, such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) convert NO_X in the flue gas to molecular nitrogen and water.

5.2 ELIMINATE TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES

Step 2 of the BART determination is to eliminate technically infeasible NO_X control technologies that were identified in Step 1.

5.2.1 COMBUSTION CONTROLS

5.2.1.1 FLUE GAS RECIRCULATION (FGR)

FGR uses flue gas as an inert material to reduce flame temperatures. In a typical flue gas recirculation system, flue gas is collected from the heater or stack and returned to the burner via a duct and blower. The addition of flue gas reduces the oxygen content of the “combustion air” (air + flue gas) in the burner. The lower oxygen level in the combustion zone reduces flame temperatures; which in turn reduces thermal NO_X formation. When operated without additional controls, the NO_X control efficiency range for FGR is 30 percent to 50 percent. When coupled with LNB the control efficiency increases to 50-72 percent.[5] This control is a technically feasible option for the control of NO_X from JEC Unit 1 and Unit 2.

5.2.1.2 OVERFIRE AIR (OFA)

OFA diverts a portion of the total combustion air from the burners and injects it through separate air ports above the top level of burners. Staging of the combustion air creates an initial fuel-rich combustion zone with a lower peak flame temperature. This reduces the formation of thermal NO_X by lowering combustion temperature and limiting the availability of oxygen in the combustion zone where NO_X is most likely to be formed.

OFA as a single NO_X control technique may reduce NO_X emissions by 25 to 55 percent. When combined with LNB, reductions of up to 60 percent may result.[6] This control is a technically feasible option for the control of NO_X from JEC Unit 1 and Unit 2.

5.2.1.3 LOW AND ULTRA LOW NO_X BURNERS

LNB technology utilizes advanced burner design to reduce NO_X formation through the restriction of oxygen, lowering of flame temperature, and/or reduced residence time. LNB is a staged combustion process that is designed to split fuel combustion into two zones. In the primary zone, NO_X formation is limited by either one of two methods. Under staged fuel-rich conditions, low oxygen levels limit flame temperatures resulting in less NO_X formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel-lean conditions, excess air will reduce flame temperature to reduce NO_X formation. In the secondary zone, combustion

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[5] "Midwest Regional Planning Organization Boiler Best Available Retrofit Technology (BART) Engineering Analysis" MACTEC, March 30, 2005.

[6] "Assessment of Control Technology Options for BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities" Northeast States for Coordinated Air Use Management (NESCAUM), March 2005

products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NO_X formation. The estimated NO_X control efficiency for LNBs in high temperature applications is 25 percent. However when coupled with FGR or SNCR these efficiencies increase to 50-72 and 50-89 percent, respectively.[7]

ULNBs may incorporate a variety of techniques including induced FGR, steam injection, or a combination of techniques. These burners combine the benefits of flue gas recirculation and LNB control technologies. Rather than a system of fans and blowers (like FGR), the burner is designed to recirculate hot, oxygen depleted flue gas from the flame or firebox back into the combustion zone. This leads to a reduction in the average oxygen concentration in the flame without reducing the flame temperature below temperatures necessary for optimal combustion efficiency.

LNBs may also be coupled with neural net systems to further optimize combustion. Neural net systems are computer automated systems that measure certain operational parameters associated with combustion. Based on these measured parameters, the neural net systems can either automatically adjust operational parameters to achieve optimal operation or provide recommendations to operators of changes to boiler control elements. By accepting the recommendations, NO_X and unit heat rate can be optimized for best overall performance.

The estimated NO_X control efficiency for ULNBs in high temperature applications is 50 percent. Newer designs have yielded efficiencies of between 75-85 percent. When coupled with SCR, efficiencies in the range of 85-97 percent can be obtained.[8]

LNB systems are technically feasible for tangential and wall-fired boilers of various sizes, but are not feasible for other boiler types such as cyclone or stoker. [9] LNB systems are technically feasible for the control of NO_x from JEC Unit 1 and Unit 2.

5.2.2 POST COMBUSTION CONTROLS

5.2.2.1 SELECTIVE CATALYTIC REDUCTION

SCR refers to the process in which NO_X is reduced by ammonia over a heterogeneous catalyst in the presence of oxygen. The process is termed

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[7] "Midwest Regional Planning Organization Boiler Best Available Retrofit Technology (BART) Engineering Analysis" MACTEC, March 30, 2005.

[8] Interim White Paper “Source Category: Electric Generating Units” Midwest RPO Candidate Control Measures, December 9, 2005

[9] AP 42, Fifth Edition, Volume I Chapter 1 Section 1.1.4.3

selective because the ammonia preferentially reacts with NO_X rather than oxygen, although the oxygen enhances the reaction and is a necessary component of the process. The overall reactions can be written:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

The SCR process requires a reactor, a catalyst, and an ammonia storage and injection system. The effectiveness of an SCR system is dependent on a variety of factors, including the inlet NO_X concentration, the exhaust temperature, the ammonia injection rate, and the type of catalyst. The NO_X control efficiency range for SCR is 70 to 90 percent.[10] This control is a technically feasible option for the control of NO_X from JEC Unit 1 and Unit 2.

5.2.2.2 SELECTIVE NON-CATALYTIC REDUCTION

In SNCR systems, a reagent is injected into the flue gas in the furnace within an appropriate temperature window. The NO_X and reagent (ammonia or urea) react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. The SNCR reagent storage and handling systems are similar to those for SCR systems. However, because of higher stoichiometric ratios, both ammonia and urea SNCR processes require three or four times as much reagent as SCR systems to achieve similar NO_X reductions. The NO_X control efficiency range for SNCR is 25 to 50 percent.[11] This control is a technically feasible option for the control of NO_X from JEC Unit 1 and Unit 2.

5.3 RANK OF TECHNICALLY FEASIBLE NO_X CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis is to rank the technically feasible options according to effectiveness. Table 5-3 provides a ranking of the NO_x control efficiencies for JEC Unit 1 and JEC Unit 2.

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[10] Ibid.

[11] Interim White Paper "Source Category: Electric Generating Units" Midwest RPO Candidate Control Measures, December 9, 2005.

TABLE 5-3. CONTROL EFFECTIVENESS OF TECHNICALLY FEASIBLE NO_X CONTROL TECHNOLOGIES

Control Technology	Estimated Control Efficiency (%)
SCR	~70-90
LNB Systems	~30-60
FGR	~30-50
OFA	~25-55
LNB Only	~25-50
SNCR	~25-50

5.4 EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS

Step four for the BART analysis procedure is the impact analysis. The BART determination guidelines list four factors to be considered in the impact analysis:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

5.4.1 COST OF COMPLIANCE

The capital costs, operating costs, and cost effectiveness of LNB systems and SCR were estimated for the cost analysis. LNB systems refer to a control system which includes LNB and possibly OFA or neural net systems. These control options were included in the analysis because they provide the highest levels of control and are commonly used for NO_X control in large utility boilers.

Control Costs

The capital cost of the LNB systems for JEC Unit 1 and Unit 2 was estimated based on Westar's experience with the capital costs for a similar project on JEC Unit 3, and the operating costs were estimated using an EPA cost estimate method.[12] Westar is still experiencing what type of operating costs to expect from a LNB system project, but project specific data from which to base the annual operating costs over the operating life of the system does not yet exist, so an EPA estimate was relied upon.

The capital cost for the SCR was determined from recent SCR installation experience. The operating and maintenance costs for the SCR were estimated using an EPA cost method.[13] The EPA estimates for the operating and maintenance costs are considered to be study grade, which is +/- 30 percent accuracy.

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[12] *Nitrogen Oxides (NO_X), Why and How They Are Controlled.* EPA 456/F-99-006R, November 1999.

[13] *Cost of Selective Catalytic Reduction (SCR) Application for NOx Control on Coal-fired Boiler.* EPA 600/R-01/087, October 2001.

The capital costs were annualized over a 20-year period and then added to the annual operating costs to obtain the total annualized costs for each technology.

Annual Tons Reduced

The annual tons reduced that were used in the cost effectiveness calculations were estimated by subtracting the estimated controlled annual emission rates from the existing annual emission rates. The existing annual emission rates were the highest 365 day rolling totals as determined from CEMS data from 2002-2004.

The controlled annual emission rates were estimated based on NO_X emission rates of 0.15 lb/MMBtu for LNB systems and 0.10 lb/MMBtu for SCR. These emission rates were multiplied by the maximum hourly heat input (8,110 MMBtu/hr) and then multiplied by the annual number of operating hours. The annual number of operating hours was 8,760. The annual operating hours were based on the maximum number of annual operating hours of JEC Unit 1and Unit 2 from 2002-2004. The maximum annual operating time was approximately 94 percent for JEC Unit 1 and 96 percent for JEC Unit 2; therefore, an estimated 100 percent factor was used for both units. A sample of the controlled annual emission rate is shown as follows for a LNB system for JEC Unit 1:

$$0.15 lb/MMBtu * 8{,}110 MMBtu/hr * \frac{8{,}760 hrs}{yr} * \frac{ton}{2{,}000 lb} * 100\% = 5{,}220 \text{ tpy}$$

Cost Effectiveness

The cost effectiveness for the remaining two control options was determined by dividing the annual cost by the annual tons reduced. The incremental cost effectiveness was also calculated for the two control options. In this case, the incremental cost analysis was performed to show the incremental increase in costs between the SCR and the LNB system. The costs are summarized for JEC Unit 1 and JEC Unit 2 in Tables 5-4 and 5-5, respectively.

In the BART guidelines, EPA calculated that for all types of boilers other than cyclone boilers, combustion control technology is generally more cost-effective than post-combustion controls. EPA estimates that approximately 75 percent of the BART units (non-cyclone) could meet the presumptive NO_X limits at a cost of \$100 to \$1,000 per ton of NO_X removed based on the use of combustion control technology. For the units that could not meet the presumptive limits using combustion control technology, EPA estimates that almost all of these sources could meet the presumptive limits using advanced combustion controls; the EPA estimates that the cost of such controls are usually less than \$1,500 per ton removed.

Tables 5-4 and 5-5 indicate that the cost effectiveness of LNB systems for JEC Unit 1 and Unit 2 is less than \$1,500 per ton of NO_X removed. Tables 5-4 and 5-5 also indicate that the costs for SCR for JEC Unit 1 and Unit 2 are over \$1500 per ton of NO_X removed (JEC Unit 1 SCR cost = \$2,211/ton and JEC Unit 2 SCR cost = \$1,738/ton). Additionally, the incremental costs of the SCR over the LNB systems are greater than $6,600 per ton of NO_X removed for JEC Unit 1 and Unit 2. Westar believes that the incremental costs are excessive.

TABLE 5-4. SUMMARY OF COST EFFECTIVENESS FOR JEC UNIT 1 NO$_X$ CONTROLS

	Current Annual Emission Rate	Controlled Annual Emission Rate	Annual Emissions Reduced	Capital Cost	Annualized Capital Cost*	Annualized Fixed O&M*	Annualized Variable O&M*	Total Annualized Cost*	Cost Effectiveness	Incremental Cost
	(tpy)	(tpy)	(ton/yr)	($)	($/yr)	($/yr)	($/yr)	($/yr)	($/ton)	($/ton)
LNB System	9,524	5,220†	4,304	11,500,000	1,350,790	506,709	0	1,857,499	432	-
SCR	9,524	3,480‡	6,044	81,000,000	9,514,260	338,492	3,510,068	13,362,820	2,211	6,613

*The costs are annualized in 2006 dollars.

†The LNB system represents an emission rate of 0.15 lb/MMBtu.

‡The SCR represents an emission rate of 0.1 lb/MMBtu.

TABLE 5-5. SUMMARY OF COST EFFECTIVENESS FOR JEC UNIT 2 NO$_X$ CONTROLS

	Current Annual Emission Rate	Controlled Annual Emission Rate	Reduced Emissions	Capital Cost	Annualized Capital Cost*	Annualized Fixed O&M*	Annualized Variable O&M*	Total Annualized Cost*	Cost Effectiveness	Incremental Cost
	(tpy)	(tpy)	(ton/yr)	($)	($/yr)	($/yr)	($/yr)	($/yr)	($/ton)	($/ton)
LNB System**	11,115	5,156†	5,959	11,500,000	1,350,790	506,709	0	1,857,499	312	-
SCR***	11,115	3,437‡	7,677	81,000,000	9,514,260	338,420	3,493,270	13,345,950	1,738	6,684

*The costs are annualized in 2006 dollars.

†The LNB w/ OFA emission rate represents an emission rate of 0.15 lb/MMBtu.

‡ The SCR represents an emission rate of 0.1 lb/MMBtu.

5.4.2 ENERGY IMPACTS & NON-AIR IMPACTS

SCR systems require electricity to operate the ancillary equipment. Additionally, the SCR can potentially cause significant environmental impacts related to the usage and storage of ammonia. Storage of aqueous ammonia above 10,000 lbs is regulated by a risk management program (RMP), since the accidental release of ammonia has the potential to cause serious injury and death to persons in the vicinity of the release. Ammonia can also be emitted in the exhaust of boilers that operate with SCR or SNCR for NO_X control due to ammonia slip.

Ammonia slip from SCR and SNCR systems occurs either from ammonia injection at temperatures too low for effective reaction with NO_X, leading to an excess of unreacted ammonia, or from over-injection of reagent leading to uneven distribution; which also leads to an excess of unreacted ammonia. Ammonia released from SCR and SNCR systems will react with sulfates and nitrates in the atmosphere to form ammonium sulfate. Together, ammonium sulfate and ammonium nitrate are the predominant sources of regional haze.

5.4.3 REMAINING USEFUL LIFE

The remaining useful life of JEC Unit 1 and Unit 2 do not impact the annualized capital costs of potential controls because the useful lives of the units are anticipated to be at least as long as the capital cost recovery period, which is 20 years.

5.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE NO_X CONTROLS

The final impact analysis was conducted to assess the visibility improvement for existing emission rates when compared to the emission rates associated with SCR and LNB systems. The existing emission rates and emission rates associated with SCR and LNB systems were modeled using CALPUFF. The existing emission rates are the same rates that were modeled for the BART applicability analysis. The emission rates associated with SCR and LNB systems for JEC Unit 1 and Unit 2 are the presumptive limit of 0.15 lb/MMBtu for LNB systems and 0.10 lb/MMBtu for SCR. These rates were multiplied by the maximum hourly heat inputs for JEC Unit 1 and Unit 2 to obtain the modeled hourly emission rate. A sample calculation of the NO_X emission rate associated with a LNB system for JEC Unit 1 is provided as follows:

$$E * HI = 1{,}216.5 \text{ lb/hr}$$

Where:
E (emission rate of LNB system) = 0.15 lb/MMBtu
HI (hourly heat input) = 8,110 MMBtu/hr

TABLE 5-6. SUMMARY OF EMISSION RATES MODELED IN NO_X CONTROL VISIBILITY IMPACT ANALYSIS FOR JEC UNIT 1 AND JEC UNIT 2

Unit	Emission Rate Scenario	Emission Rate		
		SO_2 (lb/hr)	NO_X (lb/hr)	PM_{10} (lb/hr)
JEC Unit 1	Existing Emission Rate	6,938.9	3,972.3	327.4
	LNB System	6,938.9	1,216.5	327.4
	SCR	6,938.9	811.0	327.4
JEC Unit 2	Existing Emission Rate	7,128.2	3,924.0	303.9
	LNB System	7,128.2	1,216.5	303.9
	SCR	7,128.2	811.0	303.9

Comparisons of the existing visibility impacts and the visibility impacts associated with SCR and LNB systems, including the maximum modeled visibility impact, 98th percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv, for each Class I area are provided in Tables 5-8 and 5-9 for JEC Unit 1 and JEC Unit 2, respectively. The visibility improvement associated with SCR and LNB systems are also shown in Tables 5-7 and 5-8; this value was calculated as the difference between the existing visibility impairment and the visibility impairment associated with SCR and LNB systems as measured by the 98th percentile modeled visibility impact.

TABLE 5-7. SUMMARY OF MODELED IMPACTS FROM NO_X CONTROL VISIBILITY IMPACT ANALYSIS FOR JEC UNIT 1 (2001-2003)

	Wichita Mountains				**Hercules Glades Wilderness**				**Caney Creek Wilderness**				**Mingo NWR**				**Upper Buffalo Wilderness**			
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*
Existing Emission Rate	1.91	0.51	24	-	1.44	0.47	19	-	1.46	0.37	11	-	0.75	0.25	5	-	1.45	0.43	17	-
LNB System	1.34	0.34	11	33%	1.08	0.35	4	26%	1.04	0.25	6	33%	0.50	0.18	0	27%	1.23	0.32	4	25%
SCR	1.26	0.31	11	38%	1.03	0.32	4	31%	0.97	0.23	6	39%	0.46	0.18	0	30%	1.20	0.31	3	29%

*Improvement is based on the 98th percentile impact visibility impact (Δdv) of an LNB system and SCR over the existing emission rate.

TABLE 5-8. SUMMARY OF MODELED IMPACTS FROM NO_X CONTROL VISIBILITY IMPACT ANALYSIS FOR JEC UNIT 2 (2001-2003)

	Wichita Mountains				**Hercules Glades Wilderness**				**Caney Creek Wilderness**				**Mingo NWR**				**Upper Buffalo Wilderness**			
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*
Existing Emission Rate	1.91	0.51	24	-	1.45	0.46	20	-	1.47	0.37	11	-	0.75	0.25	5	-	1.47	0.43	17	-
LNB System	1.36	0.34	11	32%	1.10	0.34	4	25%	1.05	0.25	6	32%	0.50	0.19	1	25%	1.24	0.33	4	23%
SCR	1.27	0.32	11	37%	1.04	0.33	4	28%	0.99	0.23	6	38%	0.47	0.18	0	29%	1.21	0.31	3	28%

*Improvement is based on the 98th percentile impact visibility impact (Δdv) of an LNB system and SCR over the existing emission rate.

As shown in Table 5-7, the installation of a LNB system on JEC Unit 1 results in a 25 to 33 percent improvement (depending on the Class I area) to the existing visibility impairment attributable to this unit. The installation of SCR results in 29 to 39 percent visibility improvement. Similarly, as shown in Table 5-8, the installation of a LNB system on JEC Unit 2 results in a 23 to 32 percent improvement (depending on the Class I area) to the existing visibility impairment attributable to this unit. The installation of SCR results in 28 to 38 percent visibility improvement. In short, the visibility improvement based on the installation of LNB systems for JEC Unit 1 and JEC Unit 2 is only slightly better than the visibility improvement based on the installation of SCR for the units. The slight increase in visibility improvement does not offset the large incremental cost of installing SCR over LNB systems.

5.6 PROPOSED BART FOR NO_X

Westar has determined that the NO_X BART emission rate is 0.15 lb/MMBtu for both JEC Unit 1 and Unit 2. Westar proposes to meet this limit for both JEC Unit 1 and Unit 2 by installing LNB systems. Westar has eliminated SCR as BART due to the high incremental cost of SCR over LNB systems and the minimal increase in visibility improvement.

6. GEEC SO_2 BART EVALUATION

The existing maximum 24-hour SO_2 emission rates that were modeled for the BART applicability determination are summarized in Table 6-1.

TABLE 6-1. EXISTING MAXIMUM 24-HOUR SO_2 EMISSION RATES

	Heat Input (MMBtu/hr)	SO_2 24-Hour Emission Rate (ton/24-hr)	SO_2 Hourly Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)
GEEC Unit 2	4,110	69.2	5,766.7	1.40

6.1 IDENTIFICATION OF AVAILABLE RETROFIT SO_2 CONTROL TECHNOLOGIES

Step 1 of the BART determination is the identification of all available retrofit SO_2 control technologies. A list of control technologies was obtained by reviewing the U.S. EPA's Clean Air Technology Center, control equipment vendor information, publicly-available air permits, applications, and technical literature published by the U.S. EPA and Regional Planning Organizations (RPOs).

The available retrofit SO_2 control technologies are summarized in Table 6-2 for GEEC Unit 2.

TABLE 6-2. AVAILABLE SO_2 CONTROL TECHNOLOGIES FOR GEEC UNIT 2

SO_2 Control Technologies
Dry Sorbent Injection
Spray Dryer Absorber (SDA) i.e., Semi-Dry Scrubber
Wet Scrubber
Circulating Dry Scrubber (CDS)
Fuel Switching

6.2 ELIMINATE TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES

Step 2 of the BART determination is to eliminate technically infeasible SO_2 control technologies that were identified in Step 1.

6.2.1 DRY SORBENT INJECTION, SPRAY DRYER ABSORPTION (SDA), WET SCRUBBER, CIRCULATING DRY SCRUBBER (CDS)

These technologies are collectively known as flue gas desulfurization (FGD) systems. FGD applications have not been used historically for SO_2 control in the U.S. electric industry on oil-fired units. As there are no known FGD applications for oil-fired units, the performance of FGDs on oil-fired units is unknown. EPA took this into account when evaluating the presumptive SO_2 emission rate[14] for oil-fired units and determined that the presumptive emission rate should be based on the sulfur content of the fuel oil, rather than on FGD. Therefore, FGDs are considered technically infeasible for the control of SO_2 from GEEC Unit 2 and will no longer be considered for BART.

6.2.2 FUEL SWITCHING TO ONE PERCENT SULFUR FUEL OIL

One percent sulfur fuel oil is listed by EPA as the presumptive BART limit for oil-fired units. The one percent sulfur oil is an alternative to the No. 6 fuel oil that is currently combusted by GEEC Unit 2. The lower sulfur content of the one percent sulfur fuel oil should result in approximately a 33 percent reduction in SO_2 emissions from GEEC Unit 2 as compared to the combustion of the current No. 6 fuel oil, which contains approximately 1.5 percent sulfur. Fuel switching to 1 percent sulfur fuel oil is a technically feasible option for the control of SO_2 from GEEC Unit 2.

6.3 RANK OF TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis is to rank the technically feasible options according to effectiveness. Fuel switching is the only remaining technically feasible control option GEEC Unit 2. Westar has estimated that switching to one percent sulfur oil, consistent with the EPA's presumptive BART determination for GEEC Unit 2, would result in approximately a 33% reduction in SO_2 emissions from GEEC Unit 2.

6.4 EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS

Step four for the BART analysis procedure is the impact analysis. The BART determination guidelines list the four factors to be considered in the impact analysis:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

6.4.1 COST OF COMPLIANCE

The cost effectiveness of switching to one percent sulfur fuel oil has been evaluated.

Control Cost

The cost of the fuel switching that was used in the cost effectiveness calculations was determined by calculating the cost of the current No. 6 fuel oil and determining the increased cost of switching to one percent sulfur fuel oil. It was assumed in this analysis that the fuel switch will not require any capital expenses. The fuel costs for 1 percent fuel oil was determined from the most recent fuel costs published by the Energy Information

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[14] *Summary of Comments and Responses on the 2004 and 2001 Proposed Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations* EPA Docket Number OAR-2002-0076.

Administration. The fuel cost for the No. 6 fuel oil is the market price on February 14, 2007.

Annual Tons Reduced

The annual tons reduced that were used in the cost effectiveness calculations were determined by subtracting the estimated controlled annual emission rates from the existing annual emission rates. The existing annual emission rates was the highest 365 day rolling totals as determined from CEMS data from 2002-2004. The controlled annual emission rate was estimated by reducing the existing annual emission rate by 33%.

Cost Effectiveness

In the BART guidelines, EPA calculated that that the majority of BART-eligible units could meet the presumptive limits at a cost of \$400 to \$2,000 per ton of SO_2 removed, based on the use of wet scrubbers and SDA systems. Table 6-3 indicates that the cost of switching to 1% sulfur fuel oil is well above this range.

TABLE 6-3. SUMMARY OF COST EFFECTIVENESS FOR SWITCHING FROM NO. 6 OIL TO 1% SULFUR FUEL OIL

Current/Uncontrolled Annual SO_2 Emission Rate	Controlled Annual SO_2 Emission Rate	Estimated Annual SO_2 Tons Reduced	Estimated SO_2 Control
(tpy)	(tpy)	(tpy)	(%)
4,303	2,869	1,434	33.33

Estimated No. 6 Oil Hourly Usage Rate*	Estimated No. 6 Oil Annual Fuel Usage†	No. 6 Oil Fuel Cost	Estimated Annual No. 6 Oil Fuel Cost	Estimated 1% S Fuel Oil Hourly Usage Rate*	Estimated 1% S Fuel Oil Annual Fuel Usage‡	1% S Fuel Oil Cost	Estimated Annual 1% S Fuel Oil Cost
Mgal/hr	Mgal/yr	Cents/gal	$/yr	Mgal/hr	Mgal/yr	Cents/gal	$/yr
27.40*	108,011†	85	91,809,180	27.96‡	110,215†	117.1	129,061,884

*4110 MMBtu/hr/150 MMBtu/Mgal

†Annual fuel usage is based on the hourly fuel usage rate and 3,942 annual operating hours (Assuming unit operates at an annual 45% capacity factor, 45% * 8,760 hours = 3,942 hours)

‡4110 MMBtu/hr/147 MMBtu/Mgal

Annual Cost of Fuel Switching	SO_2 Cost Effectiveness
($/yr)	($/ton)
37,252,704	25,969

6.4.1.1 ENERGY IMPACTS AND NON-AIR QUALITY IMPACTS

There are no energy or non-air quality impacts associated with fuel switching to one percent sulfur fuel oil.

6.4.1.2 REMAINING USEFUL LIFE

The remaining useful life of GEEC Unit 2 does not impact the annualized cost for this analysis, since it is assumed that fuel switching will not require any capital costs.

6.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE SO_2 CONTROLS

A final impact analysis was conducted to assess the visibility improvement for existing emission rates when compared to the emission rates associated with the combustion of one percent sulfur fuel oil. The existing emission rate and emission rate associated with the combustion of one percent sulfur fuel oil were modeled using CALPUFF. The existing emission rates are the same rates that were modeled for the BART applicability analysis.

The SO_2 emission rate associated with the combustion of one percent sulfur fuel oil was calculated by scaling the hourly equivalent of the maximum 24-hour emission rate for GEEC Unit 2 by the ratio of the one percent sulfur fuel oil content and the current maximum sulfur content (1.5%). The calculation of the SO_2 emission rate for the one percent sulfur fuel oil for GEEC Unit 2 is provided as follows:

$$5{,}676 lb/hr * \frac{1\% Sulfur}{1.5\% Sulfur} = 3{,}845 \text{ lb/hr}$$

The existing hourly equivalent of the maximum 24-hour emission rates and the hourly equivalent of the 24-hour emission rates associated with the remaining control option that was utilized in the visibility impact modeling are summarized in Table 6-4.

TABLE 6-4. SUMMARY OF EMISSION RATES MODELED IN SO_2 CONTROL VISIBILITY IMPACT ANALYSIS

Unit	**Emission Rate Scenario**	**Emission Rate**		
		SO_2 (lb/hr)	NO_X (lb/hr)	PM_{10}* (lb/hr)
GEEC Unit 2	Existing Emission Rate	5,766.7	4,818.3	431.5
	1 Percent Sulfur Fuel Oil	3,844.5	4,818.3	326.3

*PM_{10} emissions are calculated based on AP-42 emission factors.

Comparisons of the existing visibility impacts and the visibility impacts associated with the combustion of one percent sulfur fuel oil, including the maximum modeled visibility impact, 98th percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv, for each Class I area are provided in Table 6-5 for GEEC Unit 2. The visibility improvement associated with the combustion of one percent sulfur fuel oil is also shown in Table 6-5;

this value was calculated as the difference between the existing visibility impairment and the visibility impairment for the remaining control option emission rates as measured by the 98th percentile modeled visibility impact.

TABLE 6-5. SUMMARY OF MODELED IMPACTS FROM SO_2 CONTROL VISIBILITY IMPACT ANALYSIS FOR GEEC UNIT 2 (2001-2003)

	Wichita Mountains				Hercules Glades Wilderness				Caney Creek Wilderness				Mingo NWR				Upper Buffalo Wilderness			
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*
Existing Emission Rate	2.16	1.08	85	-	1.31	0.40	16	-	1.07	0.38	14	-	0.71	0.17	4	-	2.22	0.42	16	-
One Percent Sulfur Fuel Oil	2.02	0.94	71	13%	1.19	0.34	10	13%	0.87	0.34	9	10%	0.65	0.14	2	16%	2.04	0.38	15	10%

*Improvement is based on the 98th percentile impact visibility impact (Δdv) of one percent sulfur fuel oil over the existing emission rate.

As shown in Table 6-5, the combustion of 1 percent sulfur fuel oil results in a 10 to 16 percent improvement (depending on the Class I area) to the existing visibility impairment attributable to GEEC Unit 2.

6.6 PROPOSED BART FOR SO_2

Westar has determined that SO_2 BART for GEEC Unit 2 is fuel switching to 1 percent sulfur fuel oil. However, Westar is proposing an alternative to BART for GEEC Unit 2. The alternative control for GEEC Unit 2 is natural gas combustion; the details of this alternative can be found in Section 9.

The existing maximum daily NO_X emission rates that were modeled for the BART applicability determination are summarized in Table 7-1.

TABLE 7-1. EXISTING MAXIMUM 24-HOUR NO_X EMISSION RATE

	Heat Input (MMBtu/hr)	NO_X 24-Hour Emission Rate (ton/24-hr)	NO_X Hourly Emission Rate (lb/hr)	NO_X Emission Rate (lb/MMBtu)
GEEC Unit 2	4,110	57.8	4,818.3	1.17

7.1 IDENTIFICATION OF AVAILABLE RETROFIT NO_X CONTROL TECHNOLOGIES

Step 1 of the BART determination is the identification of all available retrofit NO_X control technologies. A list of control technologies was obtained by reviewing the U.S. EPA's Clean Air Technology Center, control equipment vendor information, publicly-available air permits, applications, and technical literature published by the U.S. EPA and the RPOs.

The available retrofit NO_X control technologies are summarized in Table 7-2 for GEEC Unit 2.

TABLE 7-2. AVAILABLE NO_X CONTROL TECHNOLOGIES FOR GEEC UNIT 2

NO_X Control Technologies	
Combustion Controls	Flue Gas Recirculation (FGR) Overfire Air (OFA) Low NO_X Burners (LNB) and Ultra Low NO_X Burners (ULNB)
Post-Combustion Controls	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR)

NO_X emissions controls, as listed in Table 5-2, can be categorized as combustion or post-combustion controls. Combustion controls, including flue gas recirculation (FGR), overfire air (OFA), and Low NO_X Burners (LNB), reduce the peak flame temperature and excess air in the furnace which minimizes NO_X formation. Post-combustion controls, such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) convert NO_X in the flue gas to molecular nitrogen and water.

7.2 ELIMINATE TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES

Step 2 of the BART determination is to eliminate technically infeasible NO_X control technologies that were identified in Step 1.

7.2.1 COMBUSTION CONTROLS

7.2.1.1 FLUE GAS RECIRCULATION (FGR)

FGR uses flue gas as an inert material to reduce flame temperatures. In a typical flue gas recirculation system, flue gas is collected from the heater or stack and returned to the burner via a duct and blower. The addition of flue gas reduces the oxygen content of the “combustion air” (air + flue gas) in the burner. The lower oxygen level in the combustion zone reduces flame temperatures; which in turn reduces thermal NO_X formation. When operated without additional controls, the NO_X control efficiency range for FGR is 30 percent to 50 percent. When coupled with LNB the control efficiency increases to 50-72 percent.[15] This control is a technically feasible option for the control of NO_X from GEEC Unit 2.

7.2.1.2 OVERFIRE AIR (OFA)

OFA diverts a portion of the total combustion air from the burners and injects it through separate air ports above the top level of burners. Staging of the combustion air creates an initial fuel-rich combustion zone with a lower peak flame temperature. This reduces the formation of thermal NO_X by lowering combustion temperature and limiting the availability of oxygen in the combustion zone where NO_X is most likely to be formed.

OFA as a single NO_X control technique may reduce NO_X emissions by 25 to 55 percent. When combined with LNB, reductions of up to 60 percent may result.[16] This control is a technically feasible option for the control of NO_X from GEEC Unit 2.

7.2.1.3 LOW AND ULTRA LOW NO_X BURNERS

LNB technology utilizes advanced burner design to reduce NO_X formation through the restriction of oxygen, lowering of flame temperature, and/or reduced residence time. LNB is a staged combustion process that is designed to split fuel combustion into two zones. In the primary zone, NO_X formation is limited by either one of two methods. Under staged fuel-rich conditions, low oxygen levels limit flame temperatures resulting in less NO_X formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel-lean conditions, excess air will reduce flame temperature to reduce NO_X formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NO_X formation. The estimated NO_X control efficiency for LNBs in high temperature applications is 25 percent.

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[15] "Midwest Regional Planning Organization Boiler Best Available Retrofit Technology (BART) Engineering Analysis" MACTEC, March 30, 2005.

[16] "Assessment of Control Technology Options for BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities" Northeast States for Coordinated Air Use Management (NESCAUM), March 2005

However when coupled with FGR or SNCR these efficiencies increase to 50-72 and 50-89 percent, respectively.[17]

ULNBs may incorporate a variety of techniques including induced FGR, steam injection, or a combination of techniques. These burners combine the benefits of flue gas recirculation and LNB control technologies. Rather than a system of fans and blowers (like FGR), the burner is designed to recirculate hot, oxygen depleted flue gas from the flame or firebox back into the combustion zone. This leads to a reduction in the average oxygen concentration in the flame without reducing the flame temperature below temperatures necessary for optimal combustion efficiency.

LNBs may also be coupled with neural net systems to further optimize combustion. Neural net systems are computer automated systems that measure certain operational parameters associated with combustion. Based on these measured parameters, the neural net systems can either automatically adjust operational parameters to achieve optimal operation or provide recommendations to operators of changes to boiler control elements. By accepting the recommendations, NO_X and unit heat rate can be optimized for best overall performance.

The estimated NO_X control efficiency for ULNBs in high temperature applications is 50 percent. Newer designs have yielded efficiencies of between 75-85 percent. When coupled with SCR, efficiencies in the range of 85-97 percent can be obtained.[18]

LNB systems are technically feasible for tangential and wall-fired boilers of various sizes, but are not feasible for other boiler types such as cyclone or stoker. [19] LNB systems are technically feasible for the control of NO_x from GEEC Unit 2.

7.2.2 POST COMBUSTION CONTROLS

7.2.2.1 SELECTIVE CATALYTIC REDUCTION

SCR refers to the process in which NO_X is reduced by ammonia over a heterogeneous catalyst in the presence of oxygen. The process is termed selective because the ammonia preferentially reacts with NO_X rather than oxygen, although the oxygen enhances the reaction and is a necessary component of the process. The overall reactions can be written:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

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[17] "Midwest Regional Planning Organization Boiler Best Available Retrofit Technology (BART) Engineering Analysis" MACTEC, March 30, 2005.

[18] Interim White Paper “Source Category: Electric Generating Units” Midwest RPO Candidate Control Measures, December 9, 2005

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$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

The SCR process requires a reactor, a catalyst, and an ammonia storage and injection system. The effectiveness of an SCR system is dependent on a variety of factors, including the inlet NO_X concentration, the exhaust temperature, the ammonia injection rate, and the type of catalyst. The NO_X control efficiency range for SCR is 70 to 90 percent.[20] This control is a technically feasible option for the control of NO_X from GEEC Unit 2.

7.2.2.2 SELECTIVE NON-CATALYTIC REDUCTION

In SNCR systems, a reagent is injected into the flue gas in the furnace within an appropriate temperature window. The NO_X and reagent (ammonia or urea) react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. The SNCR reagent storage and handling systems are similar to those for SCR systems. However, because of higher stoichiometric ratios, both ammonia and urea SNCR processes require three or four times as much reagent as SCR systems to achieve similar NO_X reductions. The NO_X control efficiency range for SNCR is 25 to 50 percent.[21] This control is a technically feasible option for the control of NO_X from GEEC Unit 2.

7.3 RANK OF TECHNICALLY FEASIBLE NO_X CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis is to rank the technically feasible options according to effectiveness. Table 7-3 provides a ranking of the control efficiencies for the controls listed in the previous section for GEEC 2.

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[20] Ibid.

[21] Interim White Paper "Source Category: Electric Generating Units" Midwest RPO Candidate Control Measures, December 9, 2005.

TABLE 7-3. CONTROL EFFECTIVENESS OF TECHNICALLY FEASIBLE NO_X CONTROL TECHNOLOGIES

Control Technology	Estimated Control Efficiency (%)
SCR	~70-90
LNB Systems	~30-60
FGR	~30-50
OFA	~25-55
LNB Only	~25-50
SNCR	~25-50

7.4 EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS

Step four for the BART analysis procedure is the impact analysis. The BART determination guidelines list four factors to be considered in the impact analysis:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

7.4.1 COST OF COMPLIANCE

As mentioned in Section 2 of this report, EPA has concluded that "for oil-fired and gas-fired EGUs larger than 200 MW, we believe that installation of current combustion control technology to control NO_X is generally highly cost-effective and should be considered in your determination of BART for these sources". Thus, Westar is proposing that BART for GEEC Unit 2 is the operation of LNB.

For purposes of this 5 factor analysis, the capital costs, operating costs, and cost effectiveness of an SCR have been estimated. This control option is the only control option included in the analysis because it provides the highest level of NO_x control and it is the only technology with control efficiency higher than that of LNB systems. Should the analysis conclude that SCR is not BART, the next best control to SCR is LNB, and this will be selected as BART.

Control Costs
The capital cost and operating costs of SCR were estimated based on recent SCR installation experience. The capital costs were annualized over a 20-year period and then added to the annual operating costs to obtain the total annualized costs.

Annual Tons Reduced
The annual tons reduced that were used in the cost effectiveness calculations were estimated by subtracting the estimated controlled annual emission rates from the existing

annual emission rates. The existing annual emission rates were the highest 365 day rolling totals as determined from CEMS data from 2002-2004.

The controlled annual emission rates were estimated by multiplying an estimated control efficiency for the SCR (90 percent) by the existing annual emission rates. A sample of the controlled annual emission rate is shown as follows:

$$2{,}352 tpy * (100\% - 90\%) = 235 \text{ tpy}$$

Cost Effectiveness

The cost effectiveness for the SCR was determined by dividing the annual cost by the annual tons reduced. The cost is summarized in Table 7-4. The cost of the SCR is greater than \$5,300/ton of NO_X removed. Westar believes this cost is excessive.

TABLE 7-4. SUMMARY OF COST EFFECTIVENESS FOR GEEC UNIT 2 NO_X CONTROLS

	Current Annual Emission Rate	Controlled Annual Emission Rate*	Estimated Reduced Emissions	Capital Cost†	Annualized Capital Cost‡	Annualized Fixed O&M‡	Annualized Variable O&M‡	Total Annualized Cost	Cost Effectiveness
	(tpy)	(tpy)	(ton/yr)	($)	($/yr)	($/yr)	($/yr)	($/yr)	($/ton)
SCR	2,352	235	2,117	81,000,000	9,514,260	218,932	1,627,628	11,360,820	5,367

*The annual emission rate represents a control efficiency of 90%.

†The SCR capital cost was determined from recent SCR installation experience

‡The costs are annualized in 2006 dollars.

7.4.2 ENERGY IMPACTS & NON-AIR IMPACTS

SCR systems require electricity to operate the ancillary equipment. Additionally, the SCR can potentially cause significant environmental impacts related to the usage and storage of ammonia. Storage of aqueous ammonia above 10,000 lbs is regulated by a risk management program (RMP), since the accidental release of ammonia has the potential to cause serious injury and death to persons in the vicinity of the release. Ammonia can also be emitted in the exhaust of boilers that operate with SCR or SNCR for NO_X control due to ammonia slip.

Ammonia slip from SCR and SNCR systems occurs either from ammonia injection at temperatures too low for effective reaction with NO_X, leading to an excess of unreacted ammonia, or from over-injection of reagent leading to uneven distribution; which also leads to an excess of unreacted ammonia. Ammonia released from SCR and SNCR systems will react with sulfates and nitrates in the atmosphere to form ammonium sulfate. Together, ammonium sulfate and ammonium nitrate are the predominant sources of regional haze.

7.4.3 REMAINING USEFUL LIFE

The remaining useful life of GEEC Unit 2 does not impact the annualized capital costs of potential controls because the useful life of the unit is anticipated to be at least as long as the capital cost recovery period, which is 20 years.

7.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE NO_X CONTROLS

The final impact analysis was conducted to assess the visibility improvement for existing emission rates when compared to the emission rates associated with SCR. The existing emission rates and emission rates associated with SCR were modeled using CALPUFF. The existing emission rates are the same rates that were modeled for the BART applicability analysis.

The emission rate associated with the SCR for GEEC Unit 2 is 0.12 lb/MMBtu. The emission rate for SCR was determined by reducing the existing hourly equivalent of the maximum 24-hour emission rate by a control efficiency of 90 percent.

The existing hourly equivalent of the maximum 24-hour emission rates and the hourly equivalent of the 24-hour emission rates associated with SCR are summarized in Table 7-5.

TABLE 7-5. SUMMARY OF EMISSION RATES MODELED IN NO_X CONTROL VISIBILITY IMPACT ANALYSIS

Unit	**Emission Rate Scenario**	**Emission Rate**		
		SO_2 (lb/hr)	NO_X (lb/hr)	PM_{10} (lb/hr)
GEEC Unit 2	Existing Emission Rate	5,766.7	4,818.3	431.5
	SCR	5,766.7	481.8	431.5

Comparisons of the existing visibility impacts and the visibility impacts associated with SCR, including the maximum modeled visibility impact, 98th percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv, for each Class I area are provided in Table 7-6 for GEEC Unit 2. The visibility improvement associated with SCR is also shown in Table 7-6; this value was calculated as the difference between the existing visibility impairment and the visibility impairment for the remaining control options as measured by the 98th percentile modeled visibility impact.

TABLE 7-6. SUMMARY OF MODELED IMPACTS FROM NO_X CONTROL VISIBILITY IMPACT ANALYSIS FOR GEEC UNIT 2 (2001-2003)

	Wichita Mountains				**Hercules Glades Wilderness**				**Caney Creek Wilderness**				**Mingo NWR**				**Upper Buffalo Wilderness**			
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*
Existing Emission Rate	2.16	1.08	85	-	1.31	0.40	16	-	1.07	0.38	14	-	0.71	0.17	4	-	2.22	0.42	16	-
SCR	1.34	0.60	28	45%	1.09	0.20	5	51%	0.65	0.21	4	46%	0.34	0.09	0	48%	1.07	0.20	8	51%

*Improvement is based on the 98th percentile impact visibility impact (Δdv) of SCR over the existing emission rate.

As shown in Table 7-6, the installation of SCR results in 45 to 51 percent visibility improvement (depending on the Class I area) to the existing visibility impairment attributable to GEEC Unit 2. However, as documented in Table 7-4, the cost of SCR for this unit is estimated at over $5,300/ton. This large cost does not offset the visibility improvement that would be obtained by controlling NO_x using an SCR. Further, the future visibility impairment attributable to GEEC Unit 2 will be significantly improved from the existing visibility impairment based on the switch from the combustion of No. 6 fuel oil to the combustion of natural gas, and the large corresponding reduction in SO_2 emissions.

7.6 PROPOSED BART FOR NO_X

Since SCR is not cost effective for GEEC Unit 2, Westar has determined that NO_x BART for GEEC Unit 2 is a LNB. However, Westar is proposing an alternative to BART for GEEC Unit 2. The alternative control for GEEC Unit 2 is natural gas combustion; the details of this alternative can be found in Section 9.

8. PM_{10} BART EVALUATION

The primary source of PM from JEC Unit 1 and Unit 2 is the fly ash in the flue gas. Other sources of PM include unburned carbon present in the flue gas, which is the result of incomplete combustion, and reactions of SO_2 and NO_X compounds to form fine PM in the form of nitrates, sulfur trioxide, and sulfates. PM emissions from JEC Unit 1 and Unit 2 are currently controlled by electrostatic precipitators (ESP). Similarly, PM emissions from GEEC Unit 2 are particles generated during the combustion of the No. 6 fuel oil. PM emissions from GEEC Unit 2 are currently uncontrolled.

The maximum daily PM_{10} emission rates that were modeled for the BART applicability determination are summarized in Table 8-1.

TABLE 8-1. EXISTING MAXIMUM 24-HOUR PM_{10} EMISSION RATE

	Heat Input (MMBtu/hr)	PM_{10} 24-Hr Emission Rate (ton/24-hr)	PM_{10} Hourly Emission Rate (lb/hr)	PM_{10} Emission Rate (lb/MMBtu)
JEC Unit 1	8,110	3.93	327.4	0.04
JEC Unit 2	8,110	3.65	303.9	0.04
GEEC Unit 2	4,110	5.2	431.5	0.10

From Table 8-1 it can be seen that the current PM_{10} emission rates for JEC Unit 1 and Unit 2 and GEEC Unit 2 are much less than the current emission rates of SO_2 and NO_X. The low PM_{10} emission rates correspond to low visibility impacts attributable to PM_{10} when compared to the impacts attributable to SO_2 and NO_X, from JEC Unit 1 and Unit 2 and GEEC Unit 2, as shown in Tables 8-2 and 8-3.

TABLE 8-2. VAP VISIBILITY IMPAIRMENT CONTRIBUTIONS FROM JEC UNIT 1 AND UNIT 2 (2001-2003)

	Visibility Impairment Attributable to SO_4[1] (%)	Visibility Impairment Attributable to NO_3[2] (%)	Visibility Impairment Attributable to PM_{10}[2] (%)
Wichita Mountains Wilderness	51.13	48.28	0.59
Hercules Glades Wilderness	38.21	60.92	0.87
Caney Creek Wilderness	40.79	57.87	1.35
Mingo Wildlife	43.81	55.53	0.65
Upper Buffalo Wilderness	39.6	59.22	1.18

1 The visibility impairment attributable to SO_4 is primarily from SO_2 emissions. A very small portion is from SO_4 emitted as condensable particulate.

2 The visibility impairment attributable to NO_3 is entirely from NO_X emissions.
3 The visibility impairment attributable to PM_{10} is the sum of the visibility impairment attributable to all modeled primary PM species (PMc, PMf, EC, and SOA).

TABLE 8-3. VISIBILITY IMPAIRMENT CONTRIBUTIONS FROM GEEC UNIT 2(2001-2003)

	Visibility Impairment Attributable to SO_4[1] (%)	Visibility Impairment Attributable to NO_3[2] (%)	Visibility Impairment Attributable to PM_{10}[2] (%)
Wichita Mountains Wilderness	29.29	67.54	3.17
Hercules Glades Wilderness	41.15	57.14	1.71
Caney Creek Wilderness	26.11	71.72	2.16
Mingo Wildlife	63.14	34.96	1.89
Upper Buffalo Wilderness	35.67	62.6	1.71

1 The visibility impairment attributable to SO_4 is primarily from SO_2 emissions. A very small portion is from SO_4 emitted as condensable particulate.

2 The visibility impairment attributable to NO_3 is entirely from NO_X emissions.

3 The visibility impairment attributable to PM_{10} is the sum of the visibility impairment attributable to all modeled primary PM species (PMc, PMf, EC, and SOA).

Westar proposes to upgrade the existing ESPs on JEC Unit 1 and Unit 2 in order to improve the PM control from these units. The upgrades to the existing ESPs will improve control of PM from JEC Unit 1 and Unit 2, thereby improving the visibility impacts from JEC Unit 1 and Unit 2.

Westar proposes that no additional PM control technologies are required for GEEC Unit 2, which is currently uncontrolled. The fuel switching from fuel oil no. 6 to natural gas proposed as a BART alternative for SO_2 (see Section 9) will significantly reduce the PM emissions from GEEC Unit 2. Given the small PM emission rates from natural gas combustion, Westar believes that the reduced PM emissions from the fuel switching combined with the cost of retrofitting GEEC Unit 2 with a new PM control technology would provide little visibility improvement and require significant capital expenditures.

9. PROPOSED GEEC BART ALTERNATIVE

Based on the GEEC SO_2 and NO_x BART analyses, Westar has determined that BART for SO_2 for GEEC Unit 2 is the combustion of 1 percent sulfur fuel oil and BART for NO_X is a LNB. Westar is proposing an alternative to the controls determined to meet BART for SO_2 and NO_X for GEEC Unit 2. In order for control strategies to be acceptable as an alternative to what is determined to meet BART, the alternatives must show greater visibility improvement than what is determined to meet BART based on the following visibility metrics:

- The maximum visibility impact
- The 98th percentile visibility impact
- The number of days where the visibility impacts are greater than 0.5 Δdv

In other words, the values for the metrics listed above for an alternative BART control strategy must be equal to or better than the values for the BART control strategy for each Class I area.

As an alternative to combusting 1 percent fuel oil to reduce SO_2 and LNB to reduce NO_X for GEEC Unit 2, Westar is proposing to combust natural gas in GEEC Unit 2. The switch to natural gas will provide greater than 95 percent SO_2 control from GEEC Unit 2.

9.1.1.1 COMPLIANCE WITH ALTERNATIVE BART CONTROL STRATEGY

Westar is proposing to demonstrate compliance with the alternative BART control strategy for GEEC Unit 2 that includes switching from No. 6 fuel oil to natural gas by submitting annual certifications of compliance verifying that natural gas was the only fuel combusted in GEEC Unit 2 for the year, except as provided below.

In order to assure electric system reliability, Westar requires the availability of an emergency fuel for backup, as well as the ability to burn a limited amount of the fuel periodically during non-emergencies to assure that the emergency system functions adequately. When the natural gas company implements an Operational Flow Order (OFO) or declares an emergency which could result in an impact to electric system reliability, Westar will combust No. 6 fuel oil for the time period of the emergency. Westar will diminish the existing supply of No. 6 fuel oil, once diminished the emergency fuel will be replaced with a fuel oil containing 1% or less sulfur content.

9.1.2 COMPARISON OF VISIBILITY IMPACTS FOR BART AND PROPOSED ALTERNATIVE BART CONTROL STRATEGIES

The modeled visibility impacts of the BART control strategy and the proposed alternative BART control strategy are summarized in Table 9-1. The visibility improvement associated with the BART and alternative BART control options are also shown in Table 9-1; this value was calculated as the difference between the existing visibility impairment and the visibility impairment for the BART and alternative BART control options as measured by the 98th percentile modeled visibility impact. The visibility impacts for each metric are lower in all five Class I areas for the alternate BART control strategy.

TABLE 9-1. MODELED IMPACTS BASED ON PRESUMPTIVE BART EMISSION RATES AND ALTERNATIVE BART AT GEEC UNIT 2 (2001-2003)

	Wichita Mountains				**Hercules Glades Wilderness**				**Caney Creek Wilderness**				**Mingo NWR**				**Upper Buffalo Wilderness**			
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*
Existing	2.16	1.08	85	-	1.31	0.40	16	-	1.07	0.38	14	-	0.71	0.17	4	-	2.22	0.42	16	-
BART - LNB + 1% sulfur fuel oil	2.02	0.94	71	13%	1.19	0.34	10	13%	0.87	0.34	9	10%	0.65	0.14	2	16%	2.04	0.38	15	10%
Alternative - Natural gas	1.66	0.69	44	36%	0.93	0.21	4	48%	0.49	0.25	0	34%	0.49	0.08	0	55%	1.62	0.28	11	33%