BASIN ELECTRIC POWER COOPERATIVE

1717 EAST INTERSTATE AVENUE
BISMARCK, NORTH DAKOTA 58503-0564
PHONE 701-223-0441
FAX: 701/224-5336

May 29, 2009

Received
Air Quality
MAY 2009

Mr. Terry L. O'Clair, P.E.
Division of Air Quality
North Dakota Department of Health
918 E. Divide Avenue, 2nd Floor
Bismarck, ND 58501-1947

Dear Terry:

Per your request, Basin Electric Power Cooperative (Basin Electric) has developed a hypothetical cost effectiveness determination to supplement our previously submitted BART Determination Study for Leland Olds Unit's 1 and 2. This specific work product is a continuation of information surrounding the discussion of the applicability of selective catalytic reduction (SCR) and specifically the tail-end selective catalytic reduction (TE-SCR) to Leland Olds Unit 2.

As Sargent & Lundy has explained both in its March 11, 2009 presentation and in earlier communications with the Department, cyclone boilers burning North Dakota lignite coal have unique challenges that may make SCRs unfeasible because of the high alkalis (mainly sodium and potassium) levels combined with the high temperature and other properties that are uniquely found in cyclone boilers which vaporizes the alkalis into the flue gas stream. This high level of vaporized alkali products in the flue gas stream is known to cause deactivation and poisoning of the catalyst. The design issues for North Dakota lignite have not been addressed by Powder River Basin (PRB), Texas lignite, or other brown coals that do not have the same high alkali content and other chemical properties of North Dakota lignite. Extensive pilot testing is needed to resolve catalyst deactivation and other issues.

Sargent & Lundy developed the first application of SCRs on PRB coal. As they noted in their March 11 presentation to you, the following problems would have arisen for PRB if extensive pilot testing had not been done prior to the first commercial application of SCRs on facilities using PRB coal (slide 59):

- ✓ Catalyst would not have performed
- ✓ Reactors would have been too small
- ✓ Operation would have been problematic

TE-SCRs are a higher cost and much less applied technology than other SCRs. Based on the factors discussed in the March 11th presentation, Sargent & Lundy concluded (slide 68):

> There are attributes of this fuel [ND Lignite] in a tail-end SCR environment that are not well understood today and need more investigation to predict it's performance to make it commercially available technology.

Because of these uncertainties, and the huge potential consequences to our company and the North Dakota lignite resource if an SCR were installed and did not work, Basin Electric committed to completing pilot testing for the SCR technology on cyclone boilers using ND lignite before the next review period for Regional Haze. We ask that you allow us that opportunity, and emphasize that these highly hypothetical estimates are nothing more than an educated guess based on hypothetical performance levels (with a very high probability of being wrong) until pilot testing is completed. We emphasize that point, because there is a risk that these estimates will be cited as if they have the same degree of accuracy as estimates of costs for commercially available technologies. The law is clear that when pilot testing is needed, a technology is not considered "available." One of the reasons for doing this is to avoid putting on extremely expensive technologies such as SCRs, with no assurance that they will work.

Thus, we are supplying you with these cost estimates with the caveats and commitments just described, and ask that the estimates not be misused.

The hypothetical cost effectiveness determination for TE-SCR was performed by Sargent & Lundy, who as you know has significant technical expertise for all application of SCRs. This study indicates that the TE-SCR has numerous unknowns as to its applicability to a North Dakota lignite-fired cyclone boiler for NOx control. Specifically, unknown is the reactivity loss of the catalyst, design factors of the SCR (catalyst volume and surface area), reagent injection rates, reagent slip and economic volatility of the re-heat fuel. These areas need to be more defined prior to placing a pollution control technology on such an unlike flue gas stream that a North Dakota lignite-fired cyclone boiler represents.

Basin Electric's BART Determination submittal included the visibility impairment at the Class I areas in North Dakota using the Departments modeling Calpuff protocol. With the addition of a wet scrubber for SO_2 control and selective non-catalytic reduction (SNCR) technology for NOx control on both Leland Olds units there was significant visibility improvement on the Class I areas. It is expected that the ammonia slip from the TE-SCR may be greater than a SNCR control since it will be located beyond the wet scrubber. This increased ammonia slip in the presence of SO_3 may require additional controls such as a wet electrostatic precipitator (WESP) or other technologies such as sorbent injection in order to minimize potential plume blight issues and PSD requirements.

Based on this hypothetical economic analysis, the Department should consider both the high initial cost and large risk of failure of installing an unproven control technology.

Should you have questions or require additional information, please contact me at (701) 355-5635.

Sincerely,

Cris Miller

Cris Miller
Senior Environmental Project Administrator

/gmj
Enclosure
cc: Lyle Witham

William DePriest
Senior Vice President
312-269-6678
312-269-2499 (fax)

Sargent & Lundy LLC

May 27, 2009

Mr. Cris Miller
Senior Environmental Project Administrator
Basin Electric Power Cooperative
1717 E. Interstate Avenue
Bismark, ND 58503-0564

Project: Basin Electric Power Cooperative – Leland Olds Station
Subject: BART Evaluation Update – Tail End SCR

Dear Mr. Miller:

Per your request as a follow-up to our presentation to the North Dakota Department of Health (NDDH/Department) on March 11, 2009, this letter report has been prepared to provide supplemental information in support of Basin Electric Power Cooperative's (BEPC's) BART Determination Study for Leland Olds Station Units 1 and 2, which was submitted to the NDDH in August 2006 (the "BART Determination Study").

The BART Determination Study identified tail-end selective catalytic reduction (TE-SCR) as a potentially available post-combustion NOx retrofit control technology. However, the study determined that TE-SCR on Leland Olds Station (LOS) Unit 2 would be susceptible to unacceptable catalyst deactivation from soluble alkalis in the lignite (most notably sodium) not removed by the particulate matter and flue gas desulfurization control systems. The study concluded that TE-SCR was not a technically feasible NOx retrofit control technology due to the flue gas characteristics associated with the North Dakota lignite fired in LOS Unit 2.

Although there continue to be significant technical issues associated with the operation of a TE-SCR control system on a unit firing North Dakota lignite, NDDH has requested that BEPC provide a cost effectiveness evaluation for the TE-SCR control system on LOS Unit 2 recognizing the high level of uncertainty in doing so due to the lack of design and operational knowledge surrounding the application of a TE-SCR on a ND lignite–fired cyclone boiler. Cost estimates included in this letter report were prepared in response to the Department's request for a cost effectiveness evaluation. However, as we concluded in our presentation to the Department on March 11, 2009, significant pilot testing will be needed to understand the effect of lignite-derived flue gas on the SCR catalyst and evaluate the technical feasibility and effectiveness of TE-SCR on LOS Unit 2 with any degree of certainty. Without information developed from a testing program, cost estimates included herein should be considered hypothetical case studies based on technical judgment. More accurate estimates cannot be developed without first performing pilot tests, and, without that information, the actual cost effectiveness of the TE-SCR system (assuming it proves to be technically feasible) could be higher or lower than the costs identified below.

In addition, as described below, we still have significant concerns regarding the technically feasibility and effectiveness of a TE-SCR control system on a lignite-fired cyclone boiler. We concur with the conclusions included in the BART Determination Study that, at this point, TE-SCR is not a technically feasible or commercially available Best Available Retrofit Technology (BART) for LOS Unit 2. Again, pilot testing would be required to conclude, with any degree of certainty, that TE-SCR is a technically feasible and economically viable NOx retrofit control technology.

Nevertheless, to support BEPC's response to the Department's request, Sargent & Lundy (S&L) is providing the following supplemental information: (1) a brief technical description of the TE-SCR control system; (2) a hypothetical cost effectiveness evaluation of TE-SCR on LOS Unit 2 accounting for some of the uncertainty associated with the effectiveness and operation of the system; and (3) updated cost effectiveness tables and figures that were originally included in the BART Determination Study.

Tail-E SCR Application at Leland Olds Unit 2

LOS Unit 2 is a Babcock & Wilcox (B&W) cyclone-fired unit with a turbine-generator nameplate rating of 440 MW. LOS Unit 2 is equipped with two parallel electrostatic precipitators (ESPs) for particulate matter control. The unit is not currently equipped with a flue gas desulfurization (FGD) control system, but BEPC is in the process of installing a wet FGD control system for sulfur dioxide (SO_2) control. The wet FGD control system is anticipated to be operational in the fall of 2010. The primary fuel for LOS Unit 2 is North Dakota lignite from the Freedom Coal Mine in Beulah, ND.

Selective catalytic reduction (SCR) was evaluated in the BART Determination Study as a potentially available NOx retrofit control technology. SCR involves injecting ammonia (NH_3) into boiler flue gas in the presence of a catalyst to reduce NOx to nitrogen (N_2) and water. The overall SCR reactions can be shown as follows:

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

The performance of an SCR system is influenced by several factors including flue gas temperature, SCR inlet NOx concentration, catalyst surface area, volume and age of the catalyst, and the amount of ammonia slip that is acceptable. SCR control systems on coal-fired power plants are typically located at the economizer outlet, where the flue gas temperature is most suitable for the NH_3/NOx reactions. However, flue gas characteristics at the economizer outlet can also have detrimental affects on the SCR catalyst. Studies suggest that these flue gas characteristics can be especially troublesome with North Dakota lignite, where the ash chemistry is highly alkaline and contact with the catalyst can lead to significant catalyst deactivation and a shorter catalyst life.

SCR catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is caused by either exposure of the catalyst to excessive temperatures (thermal deactivation) or masking of the catalyst due to entrainment of particulate from the flue gas stream (fouling). Chemical deactivation is caused by either an irreversible reaction of the catalyst with a contaminant in the gas stream (poisoning) or a reversible absorption of a contaminant on the surface of the catalyst (inhibition). Loss of catalyst activity through thermal degradation or poisoning is permanent, and reactivity can only be restored by replacing the catalyst. Recovery of catalyst activity from the reversible phenomenon (i.e., inhibition) is controlled by the economics of new catalyst replacement and is highly dependent on the actual mechanism of deactivation.

In a North Dakota lignite application, SCR catalyst poisoning is expected to result from the presence of trace elements and strong alkaline substances (e.g., Li, Na, K, and Ca) in flue gas. Alkaline metals can chemically attach to active catalyst pore sites and cause deactivation. Sodium (Na) and potassium (K) are of prime concern especially in their water-soluble forms, which are more mobile and can penetrate into the catalyst pores. Earth metals, especially calcium (Ca), can react with SO_3 absorbed within the catalyst to form $CaSO_4$ and blind the catalyst. North Dakota lignite contains relatively high levels of organically associated alkali and alkaline-earth elements, including Na, Ca, K, and magnesium.

Sodium levels in North Dakota lignite are typically 5 to 20 times higher than sodium levels in bituminous and subbituminous coals, and sodium compounds can represent between 5% and 11% of the ash generated from firing North Dakota lignite. These sodium levels, occurring in both the vapor phase and particulate phase, along with relatively high levels of potassium and calcium, significantly increase the potential for catalyst deactivation, plugging, and erosion. Based on the ash chemistry, a conventional high dust SCR arrangement (i.e., SCR located at the economizer outlet) would experience unacceptable catalyst deactivation rates, and, as concluded in the BART Determination Study, high dust SCR is, therefore, not a technically feasible NOx retrofit control option on units firing North Dakota lignite.

One option that has been studied to address these technical issues is to locate the SCR after the particulate and FGD control systems (if present). SCR control systems located downstream of the particulate and SO_2 controls are generally referred to as tail-gas or tail-end SCRs (TE-SCR). The idea is to remove the alkaline elements that cause unacceptable catalyst deactivation upstream of the SCR. The TE-SCR would still have to be designed to handle vapor phase sodium and fine particulates that are not collected by the ESP and wet FGD.

The TE-SCR configuration requires the flue gas to be re-heated for effective NOx control. Flue gas exiting the wet FGD at approximately 140 °F is directed to a gas-gas heat exchanger (GGHE) to raise its temperature to approximately 550 °F. After the GGHE the flue gas is directed to either an in-duct gas burner or steam heat exchanger to raise its temperature an additional 50 °F. From the duct burner or steam heat exchanger the flue gas would enter the TE-SCR reactor at approximately 600 °F. Ammonia is injected and mixed into the flue gas stream as it enters the SCR reactor, where it reacts with NOx to form nitrogen and water as shown above. Flue gas exiting the TE-SCR is returned to the other side of the GGHE to recover the waste heat before it is exhausted through the stack.

Due to the limited effectiveness of the GGHE, the outlet temperature from the TE-SCR system will be approximately 50 °F to 60 °F higher than the flue gas inlet temperature, resulting in a stack temperature of approximately 190 °F. This stack temperature is about 50 °F higher that the stack gas expected from the wet FGD system currently being installed on LOS Unit 2. The existing stack liner is guaranteed to withstand only 150 °F temperature, thus, the liner may have to be replaced or coated to withstand the higher stack gas temperatures.

TE-SCR has not been demonstrated on a lignite-fired boiler, and there are still significant technical concerns associated with the viability of existing SCR catalysts on a lignite-fired unit. For example, it is not known whether the comparatively high level of soluble sodium and potassium in North Dakota lignite will be effectively removed by the upstream ESP and wet FGD. Furthermore, the potential exists for sodium and potassium compounds remaining in the flue gas as fine particulates to re-vaporize as the flue gas is re-heated in the aforementioned duct burners. The fine particulates remaining in the flue gas would also have tendency to get into the catalyst pores, forming water soluble salts and reducing catalyst activity, as the flue gas passes through the water dew point. SCR catalyst in a TE-SCR will still be vulnerable to alkali poisoning, pore pluggage, and premature catalyst deactivation. In order to understand the effect of lignite-derived flue gas on the SCR catalyst, identify potential design solutions, and evaluate the technical feasibility and effectiveness of TE-SCR on LOS Unit 2 with any degree of certainty, pilot testing will be needed as summarized in the PowerPoint presentation to the Department on March 11, 2009.

TE-SCR Cost Estimate

Notwithstanding the remaining technical issues and uncertainties, S&L prepared a cost estimate to install and operate a TE-SCR on LOS Unit 2. Given the technical uncertainties and limited amount of available cost information, the TE-SCR cost estimate should be considered a hypothetical case study based on technical judgment. This cost estimate is designed to supplement the NOx control cost effectiveness evaluation included in the BART Determination Study. To be consistent with cost estimates included in the BART Determination Study, S&L followed the cost estimating methodologies and assumptions outlined in Section 1.3.5 of the study. S&L did not reevaluate costs for the other potentially feasible NOx retrofit control technologies, but relied on costs included in the BART Determination Study. Capital costs for the other NOx retrofit control technologies were brought up to 2009 dollars using an average annual escalation rate of 4.0%.

Order of magnitude capital costs were developed for the TE-SCR control system. Capital costs include the equipment, material, labor, and all other direct costs needed to retrofit LOS Unit 2 with the control technology. An allowance was included into the capital cost estimate for the Unit 2 stack liner modifications. Fixed and variable O&M costs were also developed for the TE-SCR control system. Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables associated with operating the system, such as reagent usage (e.g., ammonia), auxiliary power requirements, secondary fuel and catalyst replacement.

Accounting for Uncertainty

As discussed above, significant technical issues remain unresolved regarding the effectiveness of a TE-SCR control system on LOS Unit 2. Without pilot scale testing it is not possible to know definitively how the flue gas chemistry will affect the SCR catalyst, and it is very difficult to estimate with any certainty the catalyst deactivation rate (required to estimate annual operating costs of the system). In addition to the catalyst deactivation issues, the cost effectiveness of a TE-SCR control system will be particularly sensitive to the cost of natural gas and ammonia. The TE-SCR control system will require significant quantities of both natural gas and ammonia, and the cost of these consumables will directly affect the cost effectiveness of the system. Finally, installation of the TE-SCR could trigger the necessity to install additional pollution controls to address resulting increases in sulfuric acid mist emissions (another PSD regulated pollutant). Methods used to account for these uncertainties are described below:

Catalyst Replacement Frequency

Based on our engineering judgment, an accelerated catalyst deactivation rate is anticipated with the lignite derived flue gas; therefore, we developed capital and O&M costs for the two most likely scenarios: (1) a catalyst deactivation rate that necessitates catalyst replacement every 12 months; and (2) a catalyst deactivation rate that necessitates catalyst replacement every 6 months. More frequent catalyst replacement requires more frequent shutdown of the unit. Typical catalyst replacement activities require the unit to be shutdown for a two week outage. Because planned major outages are only scheduled every three years, costs associated with the additional catalyst replacement outages were included in the annual O&M estimates.

Consumable Costs

The cost effectiveness of the TE-SCR will also be sensitive to the cost of consumables used in the system including natural gas and ammonia. As described above, effective NOx control with a TE-SCR requires re-heating the flue gas from approximately 140 °F to approximately 600 °F. Based on preliminary engineering calculations, re-heating the flue gas will consume approximately 115 mmBtu/hr natural gas. The cost of firing natural gas to re-heat the flue gas will have a significant impact on the cost effectiveness of the system.

Natural gas prices have been subject to significant volatility over the past several years. Volatility in natural gas prices are subject to short-term supply and demand shifts, coupled with the significant lead time required to bring additional natural gas supplies to market and expand pipeline capacity.[2] Natural gas prices are also sensitive to market factors such as weather swings and supply disruptions. Based on information published by the U.S. Energy Information Administration, the price of natural gas for electricity production is currently in the range of $6.60 to $8.00/mmBtu. As recently as 2007 natural gas prices for electricity production reached almost $14/mmBtu. Future swings in natural gas prices will directly affect the cost of operating the TE-SCR control system.

[2] See, e.g., "An Analysis of Price Volatility in Natural Gas Markets," U.S. Energy Information Administration, Office of Oil and Gas, August 2007.

Similarly, the TE-SCR will consume significant quantities of ammonia. Based on preliminary engineering calculations the TE-SCR will consume approximately 873 lb/hr of ammonia. Operating costs of the TE-SCR control system are directly related to the cost of ammonia. Ammonia prices are directly related to the price of natural gas. Approximately 33 mmBtu of natural gas are needed to produce one ton of ammonia, and natural gas accounts for approximately 80% of the ammonia production cost. Anhydrous ammonia costs are currently in the range of approximately $450/ton, but have historically been as high as $700/ton.

To account for potential swings in the cost of natural gas and ammonia, and to envelope potential O&M costs associated with the TE-SCR control system, annual O&M costs were calculated using natural gas prices of $8 and $12/mmBtu and ammonia costs of $450 and $700/ton.

Acid Mist Control

Finally, it is possible that the installation of the TE-SCR will trigger New Source Review (NSR) permitting and additional pollution control requirements for sulfuric acid mist (SAM). In addition to oxidizing NOx to N_2 and water, undesirable reactions can occur in an SCR system including the oxidation of SO_2 and formation of SAM. A fraction of the remaining SO_2 in the flue gas (approximately 1%) will oxidize to SO_3 in the presence of the SCR catalyst. SO_3 can react with water in the flue gas to form SAM. Assuming a controlled SO_2 emission rate of 35 ppmvd @ 15% O_2 and 1% SO_2 to SO_3 conversion across the SCR, SAM emissions from LOS Unit 2 would increase by approximately 24.1 tpy, a quantity in excess of the PSD significant level.

PSD would require increased SAM emissions to be controlled using BACT. Although it is possible that BACT could require the installation of a wet ESP control system after the TE-SCR (which would be very expensive), it is more likely that increased SAM emissions could be addressed using an upstream sorbent injection system. Sorbent injection involves the injection of a powdered absorbent directly into the flue gas exhaust stream upstream of the particulate control device. To address the potential need for SAM control, S&L prepared one cost estimate that includes the capital and O&M costs associated with a sorbent injection system.

The following TE-SCR with advanced separated overfire system (ASOFA) scenarios were developed for direct comparison with the scenarios A-D in the BART Determination Study. Five TE-ASOFA scenarios were developed to account for uncertainty regarding: (1) catalyst deactivation rate; (2) sorbent injection control requirements; and (3) the cost of natural gas and ammonia.

Scenario E: TE-SCR with ASOFA
12-month catalyst replacement frequency
$8/mmBtu natural gas
$450/ton ammonia
No sorbent injection system to address increased acid gas emissions

Scenario F: TE-SCR with ASOFA
6-month catalyst replacement frequency

$8/mmBtu natural gas
$450/ton ammonia
No sorbent injection system to address increased acid gas emissions

Scenario G: TE-SCR with ASOFA
6-month catalyst replacement frequency
$12/mmBtu natural gas
$450/ton ammonia
No sorbent injection system to address increased acid gas emissions

Scenario H: TE-SCR with ASOFA + Sorbent Injection System
6-month catalyst replacement frequency
$12/mmBtu natural gas
$450/ton ammonia
Sorbent injection system installed to address increased acid gas emissions

Scenario I: TE-SCR with ASOFA + Sorbent Injection System
6-month catalyst replacement frequency
$12/mmBtu natural gas
$700/ton ammonia
Sorbent injection system installed to address increased acid gas emissions

Unit costs used to develop annual O&M costs associated with each scenario are summarized below:

Parameter	**Units**	**Scenario E**	**Scenario F**	**Scenario G**	**Scenario H**	**Scenario I**
Inlet NOx Rate	lb/mmBtu	0.48	0.48	0.48	0.48	0.48
NOx Control System		TE-SCR	TE-SCR	TE-SCR	TE-SCR	TE-SCR
SAM Control		na	na	na	Sorbent Injection	Sorbent Injection
Total Initial Catalyst	m^3	530	530	530	530	530
Controlled NOx Rate	lb/mmBtu	0.07	0.07	0.07	0.07	0.07
Catalyst Replacement	frequency	12 months	6 months	6 months	6 months	6 months
Capacity Factor	%	96.2	92.3	92.3	92.3	92.3
Catalyst Cost	$\$/m^3$	7,500	7,500	7,500	7,500	7,500
Power Cost	$/MWh	50	50	50	50	50
Natural Gas Cost	$/mmBtu	8.0	8.0	12.0	12.0	12.0
Ammonia Cost	$/ton	450	450	450	450	700

Updated Cost Evaluation

Provided below are several tables updating the NOx retrofit cost effectiveness evaluation originally included in the Section 2.5.1 of the BART Determination Study. These tables include costs associated with potential NOx control technologies for LOS Unit 2. The control cost estimates included in the 2006 study have been updated to reflect 2009 dollars (costs were originally given as 2005 dollars). The tables also include estimates associated with the installation of TE-SCR and ASOFA on Unit 2. The table numbers included below are intended to match the table numbers used in the BART Determination Study.

Further, the TE-SCR/ASOFA cost effectiveness calculation is consistent with the methods and assumptions used in the BART Determination Study. Consistent with the approach used in the 2006 study, future potential-to-emit (PTE) annual emissions with the TE-SCR/ASOFA system were reduced to account for an annual outage requirement of 2 weeks for Scenario E (catalyst replacement every 12 months) and 4 weeks for Scenarios F thru I (catalyst replacement every 6 months). Levelized total annual costs for Scenarios F thru I vary depending the cost of natural gas and ammonia and the installation/operation of a sorbent injection control system. The following equation was used to calculate the cost effectiveness:

$$\text{Cost Effectiveness (\$/ton)} = \frac{\text{Levelized Total Annual Cost}}{\text{(Historic Pre-Control Annual Baseline Emissions} - \text{Future PTE Annual Emissions)}}$$

The following tables and figures were updated from the BART Determination Study to include the TE-SCR Scenarios:

Table / Figure No.	Description
Table 2.5-1	Unit Capital Cost Factors of Feasible NOx Control Options for LOS Unit 2
Table 2.5-2	Installed and Annualized Capital Costs Estimated for NOx Control Alternatives – LOS Unit 2
Table 2.5-3	Estimated O&M Costs for NOx Control Options (Relative to Historic Pre-Control Annual Emission Baseline) – LOS Unit 2
Table 2.5-5	Estimate Annual Emissions and LTAC for NOx Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 2
Figure 2.5-1	NOx Control Effectiveness – LOS Unit 2 (Historic Pre-Control Annual Emission Baseline)
Table 2.5-7	Estimated Incremental Annual Emissions and LTAC for NOx Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 2
Figure 2.5-3	NOx Control Cost Effectiveness – LOS Unit 2 Dominant Cost Control Curve (Historic Pre-Control Annual Emission Baseline)

TABLE 2.5-1 – Unit Capital Cost Factors of Feasible NO_X Control Options for LOS Unit 2

Alt. No. (1)	NO_X Control Technique	Range(2) ($/kW)	Single Point Unit Capital Cost Factor(3) ($/kW) LOS Unit 2
I	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $700/ton Sorbent Injection Control System	> 300	387
H	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $450/ton Sorbent Injection Control System	> 300	387
G	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	> 300	376
F	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $8/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	> 300	376
E	Tail-End SCR + ASOFA (1 yr catalyst replacement) gas = $8/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	> 300	376
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	20 + ?(4)	53(4),(5),(6)
C	SNCR (using urea) w/ ASOFA	20-35(7)	44(5),(6)
B	Coal Reburn (conventional, pulverized) w/ ASOFA	30-60(7)	178(6),(8)
A	Advanced Separated Overfire Air (ASOFA)	5-10(7)	26(6)

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Unit capital cost factors ($/kW) of these individual technologies combined by simple addition. Actual installed costs may differ due to positive or negative synergistic effects. Range based on published values or vendor proposals.
(3) – Single point cost factor is best estimate for determination of total capital cost for a particular technology or combination, assuming maximum unit capacity is based on existing nameplate rating. Single point cost figures in 2009 dollars.
(4) – No published RRI unit capital cost factor was found in available technical literature. The installed capital costs for RRI are expected to be similar to SNCR. If both RRI and SNCR are installed together, capital cost of the RRI+SNCR portion was assumed to be 1.5x the capital cost of SNCR alone, due to commonality between the two systems sharing certain equipment and systems.
(5) – Estimated capital cost for SNCR point estimate derived from December 2004 budgetary proposal by Fuel Tech. See Appendix A for details.
(6) – The single point unit capital cost factor shown for the "advanced" version of SOFA derived from Burns & McDonnell internal database and cost estimate for North Dakota lignite-fired cyclone boilers.
(7) – NESCAUM 2005 Technical Paper, posted at their website for basic SOFA. See Appendix A for details.
(8) – The single point unit capital cost factor shown for a coal reburn system is highly site-specific, and assumes that new pulverizers and building enclosures are required. The general cost range for pulverized coal-fired boilers is included in the NESCAUM 2005 Technical Paper; for cyclone boilers is included in the 2005 WRAP Draft Report, posted at their website. The single point unit capital cost factor for this alternative for increased PM collection capacity included in coal reburn options is 57.5 $/kW. See Appendix A for details.

TABLE 2.5-2 – Installed and Annualized Capital Costs Estimated for NO_X Control Alternatives - LOS Unit 2

Alt. No. (1)	NO_X Control Alternative	Installed Capital Cost(2) ($1,000)	Annualized Capital Cost(3) ($1,000)
I	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $700/ton Sorbent Injection Control System	170,800	14,890
H	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $450/ton Sorbent Injection Control System	170,800	14,890
G	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	165,800	14,450
F	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $8/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	165,800	14,450
E	Tail-End SCR + ASOFA (1 yr catalyst replacement) gas = $8/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	165,800	14,450
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	23,600	2,060
C	SNCR (using urea) w/ ASOFA	19,600	1,710
B	Coal Reburn (conventional, pulverized) w/ ASOFA	78,800(4)	6,870(4)
A	Advanced Separated Overfire Air (ASOFA)	11,800	1,030
	Baseline	0	0

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Installed capital cost is estimated for determination of total capital cost for a control technology, assuming maximum unit output capacity is based on existing nameplate rating of 440,000 kW. Installed capital cost figures in 2009 dollars.
(3) – Annualized capital cost = Installed capital cost x 0.08718 Capital Recovery Factor.
(4) – Costs for increased PM collection capacity included in coal reburn option are $29,500,000 for installed capital cost, and $2,570,000/yr annualized capital cost.

TABLE 2.5-3 – Estimated O&M Costs for NO_X Control Options (Relative to Historic Pre-Control Annual Emission Baseline) – LOS Unit 2

Alt. No. (1)	NO_X Control Alternative	Annual O&M Cost(2) ($1,000)	Levelized Annual O&M Cost(3) ($1,000)
I	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $700/ton Sorbent Injection Control System	40,470	48,280
H	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $450/ton Sorbent Injection Control System	39,590	47,230
G	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	39,210	46,780
F	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $8/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	35,490	42,340
E	Tail-End SCR + ASOFA (1 yr catalyst replacement) gas = $8/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	24,630	29,380
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	12,860	15,340
C	SNCR (using urea) w/ ASOFA	7,680	9,160
B	Coal Reburn (conventional, pulverized) w/ ASOFA	6,700(4)	7,990(4)
A	Advanced Separated Overfire Air (ASOFA)	177	211
	Baseline, based on annual operation at historic 24-mo average pre-control emission rate	0	0

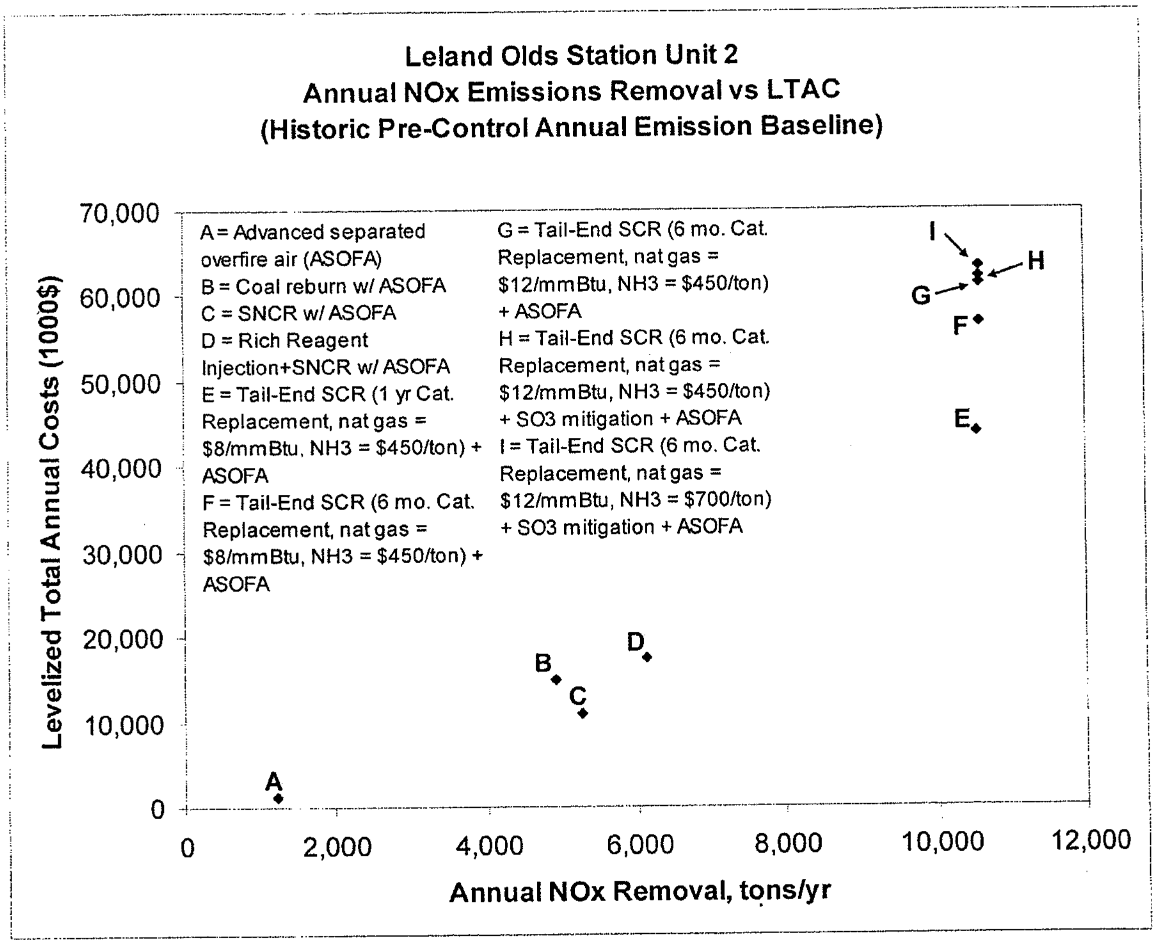
(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Annual O&M cost figures in 2009 dollars.
(3) – Levelized annual O&M cost = Annual O&M cost x 1.19314 Annualized O&M cost factor.
(4) – Costs for increased PM collection capacity included in coal reburn option are $2,030,000 for annual O&M cost, and $2,420,000/yr levelized annual O&M cost.

TABLE 2.5-5 – Estimated Annual Emissions and LTAC for NO_X Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 2

Alt. No. (1)	NO_X Control Alternative	Annual NO_X Emissions(2) (Tons/yr)	Annual NO_X Emissions Reduction(2) (Tons/yr)	Levelized Total Annual Cost(3),(4) ($1,000)	Average Control Cost(4) ($/ton)
I	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $700/ton Sorbent Injection Control System	1,452	10,571	63,170	5,976
H	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $450/ton Sorbent Injection Control System	1,452	10,571	62,12	5,876
G	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	1,452	10,571	61,230	5,792
F	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $8/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	1,452	10,571	56,790	5,372
E	Tail-End SCR + ASOFA (1 yr catalyst replacement) gas = $8/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	1,512	10,511	43,830	4,170
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	5,895	6,128	17,400	2,839
C	SNCR (using urea) w/ ASOFA	6,762	5,261	10,870	2,066
B	Coal Reburn (conventional, pulverized) w/ ASOFA	7,115	4,908	14,860[5]	3,027[5]
A	Advanced Separated Overfire Air (ASOFA)	10,796	1,227	1,241	1,011
	Baseline, based on annual operation at historic 24-mo average pre-control emission rate	12,023	0	0	

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – NO_X emissions and control level reductions relative to the historic pre-control annual baseline for LOS Unit 2.
(3) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See footnote #3 for Tables 2.5-2 and 2.5-3 for annualized cost factors.
(4) – Annualized cost figures in 2009 dollars.
(5) – LTAC for increased PM collection capacity included in coal reburn option are $2,570,000 for annualized capital cost plus $2,420,000 for annualized O&M cost, for a total of $4,990,000/yr. This results in an average control cost of $1,016 per ton of NO_X removed.

Figure 2.5-1 – NO_X Control Cost Effectiveness – LOS Unit 2 (Historic Pre-Control Annual Emission Baseline)[1]



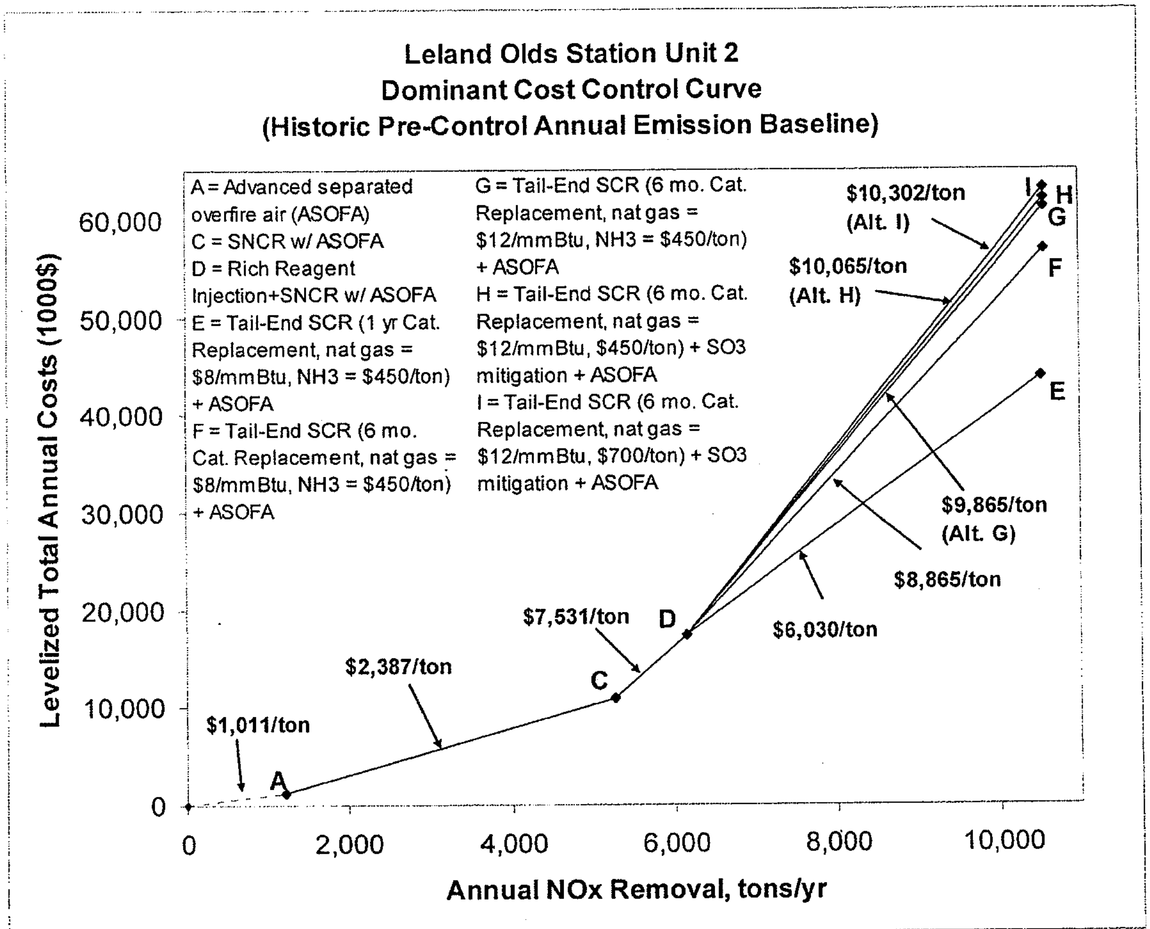
(1) - All cost figures in 2009 dollars. Numbers are listed and qualifiers are noted in Table 2.5-5.

TABLE 2.5-7 – Estimated Incremental Annual Emissions and LTAC for NO_X Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 2

Alt. No.(1)	NO_X Control Technique	Levelized Total Annual Cost(2),(3) ($1,000)	Annual Emission Reduction(4) (Tons/yr)	Incremental Levelized Total Annual Cost(3),(5) ($1,000)	Incremental Annual Emission Reduction(4),(5) (Tons/yr)	Incremental Control Cost Effectiveness ($/ton)(3),(6)
I(7)	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $700/ton Sorbent Injection Control System	63,170	10,571	45,770	4,443	10,302
H(7)	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $450/ton Sorbent Injection Control System	62,120	10,571	44,720	4,443	10,065
G(7)	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	61,230	10,571	43,830	4,443	9,865
F(7)	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $8/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	56,790	10,571	39,390	4,443	8,865
E(7)	Tail-End SCR + ASOFA (1 yr catalyst replacement) gas = $8/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	43,830	10,511	26,430	4,383	6,030
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	17,400	6,128	6,530	867	7,531
C	SNCR (using urea) w/ ASOFA	10,870	5,261	9,629	4,034	2,387
A	Advanced SOFA (ASOFA)	1,241	1,227	1,241	1,227	1,011
	Baseline, based on annual operation at historic 24-month average pre-control emission rate	0	0			

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See footnote #3 for Tables 2.5-2 and 2.5-3 for annualized cost factors. Costs for increased PM collection efficiency are included in coal reburn option.
(3) – Annualized cost figures in 2009 dollars.
(4) – NO_X emissions and control level reductions relative to the historic pre-control annual baseline for LOS Unit 2.
(5) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.
(6) – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).
(7) – Incremental costs for Alternatives E, F, G, H, and I are both relative to Alternative D.

**Figure 2.5-3 – NO_X Control Cost Effectiveness – LOS Unit 2
Dominant Cost Control Curve
(Historic Pre-Control Annual Emission Baseline)[1]**



(1) - All cost figures in 2009 dollars. Numbers are listed and qualifiers are noted in Table 2.5-7.

Conclusions

Significant technical issues remain unresolved regarding the installation of a TE-SCR on a unit firing North Dakota lignite. The flue gas characteristics from firing North Dakota lignite could rapidly accelerate catalyst deactivation due to potentially elevated sodium levels that are not captured in the ESP and wet FGD. Without pilot scale testing it is not possible to know how the flue gas chemistry will affect the SCR catalyst, and it is very difficult to estimate with any certainty the catalyst deactivation rate (required to design the SCR reactor and estimate annual operating costs of the system).

Despite the significant uncertainties surrounding the potential for accelerated catalyst deactivation on Unit 2 TE-SCR, a cost evaluation was performed for a TE-SCR on LOS Unit 2 (a North Dakota lignite fired cyclone furnace). Given the technical uncertainties and limited amount of available cost information, the TE-SCR cost estimate prepared for this evaluation should be considered hypothetical case studies based on technical judgment, and may not be representative of the actual costs associated with the control system. To account for uncertainties in the catalyst deactivation rate, natural gas and ammonia costs, and the need to provide additional acid mist control, S&L prepared costs for several operating scenarios.

The total levelized annual cost for the TE-SCR/ASOFA control systems is estimated to range from approximately $43.8 million per year (based on a 12-month catalyst replacement frequency and lower natural gas and ammonia costs) to approximately $61.2 million per year (based on a 6-month catalyst replacement frequency and assuming higher natural gas and ammonia costs). Levelized annual costs for the control system increases to approximately $63.2 million per year assuming sorbent injection control is needed to address increases in acid gas emissions. Assuming an average controlled NOx emission rate of 0.07 lb/mmBtu, the average annual cost effectiveness of the TE-SCR/ASOFA control system, based on the historic pre-control annual emission baseline, is estimated to range from approximately $4,200 to $6,000/ton, depending on the catalyst replacement frequency and cost of consumables.

The incremental cost effectiveness of the TE-SCR/ASOFA technology over the next lower-cost retrofit control option (RRI/SNCR/ASOFA) ranges from approximately $6,000/ton (assuming a 12-month catalyst replacement frequency and lower consumable costs) to more than $10,000/ton (assuming a 6-month catalyst replacement frequency, higher consumable costs, and the need to address increased SAM emissions).

Again, this economic analysis was based on a hypothetical engineering analysis of what we know today. A more accurate estimate cannot be developed without first performing significant pilot testing as suggested in our March 11, 2009 presentation to the Department. The actual cost effectiveness of the control system could therefore be higher or lower than those identified from this effort.

Should you need additional information, please do not hesitate to contact me.

Sincerely,

Wm. DePriest

William DePriest
Senior Vice President
Environmental Services