Emissions Control Analysis for Lewis & Clark Station Unit 1

Response to November 2010 US EPA Request for Additional Reasonable Progress Information

Prepared for
Montana-Dakota Utilities Co.

February 2011
Revised June 2011

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February 2011

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1.0 Executive Summary

This report presents the background and methods for the analysis of a Reasonable Progress (RP) emissions control strategy for the Montana-Dakota Utilities Co. (Montana-Dakota) Lewis & Clark Station Unit 1 located in Sidney, MT (L&C Station). Unit 1 is a dry-bottom, tangentially-fired boiler that started operation in 1958. The boiler is currently permitted to burn lignite coal, which can be supplemented as needed with subbituminous coal and natural gas. L&C Station has one steam turbine with a capacity of up to 56 megawatts.

Pursuant to Section 114 of the Clean Air Act, the Environmental Protection Agency (EPA) has issued two requests to Montana-Dakota to provide information for Unit 1 to assist with the development of a Regional Haze Federal implementation plan (RH FIP). In an initial Section 114 request from January 2009, EPA requested general information about Unit 1 and its associated air emissions control equipment. Montana-Dakota provided responses to the initial request in February 2009. A second request was sent by EPA and received by Montana-Dakota in November 2010 (Appendix A). It requests an analysis of RP control options for Unit 1. This report provides information responsive to EPA's November 2010 request.

Per the EPA recommendations in the November 2010 request, the guidelines included in 40 CFR 51 Appendix Y are used to evaluate costs associated with potential emission controls at Unit 1 for the Regional Haze program. The existing pollution control equipment includes a multi-cyclone dust collector and wet scrubber for particulate matter control along with low NOx burners (LNB) and close-coupled overfire air (CCOFA) for NOx control. The particulate scrubber also achieves nominal SO_2 removal.

Based on the results of technical feasibility reviews, economic impact analyses and consideration of other non-air quality energy and environmental factors, Montana-Dakota proposes the following emission reductions for RP purposes:

- For particulate matter (PM), the existing emission limit of 0.17 lb/MMBtu will be maintained using the existing multi-cyclone and scrubber systems. This limit includes both filterable and condensable particulate contributions. Based on evaluations completed at other utilities, additional/replacement PM controls would provide negligible visibility improvement and would require significant capital expenditures. Pending the findings of planned scrubber optimization studies, the impacts of the proposed SO_2 control strategy may: (a) require that the existing PM emission limit include only filterable particulate contributions; or (b) require a permit modification to accommodate any increases in condensable particulate emissions.

- Separated Overfire Air (SOFA) and Low NOx Burners (LNB) are proposed for RP NOx control with a proposed emission rate of 0.25 lb/MMBtu on a 12-month rolling basis under normal operational conditions. The current burner system is proposed to be completely replaced with an upgraded SOFA/LNB system.

- SO_2 emissions will be reduced by optimizing the existing particulate scrubber and lime injection system to achieve a total SO_2 emissions reduction of approximately 70% on an annual basis. The scrubber lime injection system is proposed to be upgraded to achieve additional removal with a proposed limit of 0.45 lb/MMBtu on a 12-month rolling basis. An optimization study will be conducted to more accurately determine the lb/MMBtu limit and to develop an understanding of operational constraints, if any, posed by continuous lime addition.

2.0 Introduction

On July 15, 2005, the U.S. Environmental Protection Agency (EPA) published the final rules for regional haze and best available retrofit technology (BART). The BART rules, originally promulgated in September 1999, were in effect as of September 6, 2005.

The rules require that each state develop a Regional-Haze State Implementation Plan (RH SIP) to improve visibility in federally-protected national parks and wilderness areas (Class I areas). The SIP must require BART on all BART-subject sources and mandate a plan to achieve natural background visibility by 2064. Each state must submit an RH SIP that includes milestones for establishing reasonable progress (RP) towards the visibility improvement goals, and plans for the first five-year progress period. Upon submission of the SIP, the requirements for BART sources are made enforceable through rules, administrative orders or revisions to existing Title V operating permits. The State of Montana declined to address RH SIP requirements and, as such, EPA is administering RH implementation, including RP, as part of the Montana RH FIP. As the next phase in achieving RH reductions, EPA is therefore, evaluating additional controls from non-BART eligible units that may assist in meeting RP goals.

2.1 Overview of Emissions Control Analysis Approach

Information provided through this RP emissions control evaluation for Unit 1 at L&C Station is expected to be used by EPA in the RH FIP for Montana. The evaluation is specific to Unit 1. Other emission units at L&C Station are not included in the analysis pursuant to the EPA request for information. Although L&C Station was not subject to BART, emission controls and limitations may be evaluated under the auspices of “reasonable progress goals” (RPGs) under the Regional Haze Rule (RHR) [40 CFR 51.308(d)(1)]. In contrast to the requirements for BART evaluations [40 CFR 51.308(e)], RP evaluations focus on the analysis of the four factors set forth in 40 CFR 51.308(d)(1)(i)(A), as described in Section 3.0 below. While the four factors do not require an evaluation of visibility related impacts, Section 2.0 notes that RP by definition is a measure of visibility improvement. L&C Station Unit 1 is a relatively small power facility and it is unclear whether the current facility’s emissions have an impact on visibility in Class I areas. Although a visibility impact evaluation is not included in this report, Montana-Dakota reserves the right to provide additional information regarding such impacts as it relates to the findings in this report.

Based on summaries developed by the National Park Service (NPS) of evaluations conducted for other utilities and boilers that are subject to BART, Montana-Dakota was able to streamline the RP evaluation for Unit 1. Technologies that were covered in certain BART evaluations have been screened out due to inapplicability with Unit 1's small size and firing style along with commercial availability for this application. This analysis, therefore, focuses on cost effective and realistic options that have been considered BART, instead of an all-inclusive review of technologies that, while available, would simply not fit with Unit 1.

2.2 Unit Description and Current Permit Limits

Unit 1 is a dry-bottom, tangentially-fired boiler which began operation in 1958. Unit 1 is fired with lignite coal, but can be supplemented with Powder River Basin (PRB) coal and natural gas on a limited basis. The maximum sustainable capacity of the unit is dependent on the type of fuel fired and is in the range of 48 MW for lignite fuel only (normal operating scenario) and can be as high as 56 MW when fired with natural gas only. A summary of the existing controls and permit limits for visibility impairing pollutants is provided below. The Title V air operating permit for L&C Station (OP0691-05) can be found in Appendix B.

Particulate Matter (PM): Permit limits of 0.08 gr/dscf and 0.17 lb/MMBtu

Unit 1 was constructed with a multi-cyclone dust collector for particulate control, with a design control efficiency of 75%-80%. A flooded-disc wet scrubber with a design control of 98% was installed in 1975. The permit limit includes both filterable and condensable particulate contributions.

Sulfur Dioxide (SO_2): Permit limit of 2.0 lb SO_2/MMBtu

The flooded-disc wet scrubber is designed for particulate control with a nominal SO_2 control efficiency of approximately 15%. In practice, up to 60% SO_2 control has been achieved during certain operating conditions, mainly by the presence of calcium in the coal, but also by adding lime to the existing scrubber system when the coal has lower calcium and higher sulfur content.

Oxides of Nitrogen (NOx): Permit limit of 0.40 lb NOx/MMBtu

NOx controls currently consist of low NOx burners (LNB) and close-coupled overfire air (CCOFA) system installed in 1996.

Other Relevant Emission Controls: Mercury control limit of 1.5 lb/TBtu on a 12-month rolling basis

Montana-Dakota recently installed a mercury control system at Unit 1 to comply with requirements under the Administrative Rules of Montana (ARM 17.8.771). An oxidizing agent and activated carbon injection (OA/ACI) system has been installed for mercury control. The injection of additional particulate into the system has increased PM/PM_{10} loading to the scrubber system. With respect to RP controls, it is noted that compliance with the existing PM limits could be jeopardized by certain additional control options that introduce additional particulate. The oxidizing agent used for mercury control is calcium bromide (CaBr) which is used to treat the coal prior to, and during, combustion.

3.0 Basis for Analysis of Control Options

3.1 Four Factor Analysis

In accordance with the requirements of 40 CFR §51.308(d)(1)(i)(A) and pursuant to the EPA request for information dated November 5, 2010, a four factor analysis is employed to evaluate technically feasible emission control options at Unit 1.

1. **Costs of compliance** – The costing methodology used to evaluate the capital and operating costs for evaluated control options is from EPA's Control Cost Manual[1]. In lieu of site specific cost evaluations, proposed BART control summaries developed by the Federal Land Managers (FLMs) were used to estimate certain inputs to EPA's calculation methodology. Inputs from FLM data summaries were normalized to account for the size of Unit 1 and related economies of scale. In addition to average cost effectiveness (cost per ton of pollutant removed), an evaluation of incremental cost effectiveness is also considered. Incremental dollar per ton cost analyses are used to illustrate the economic effectiveness of one technology in relation to the others. In determining the economic reasonability of evaluated controls, Montana-Dakota has considered, and used as a guide, thresholds for justifiable costs presented for control technologies under other regulatory programs (i.e., Standards of Performance in 40 CFR 60) and cost thresholds used in other BART and RP evaluations (including Montana-Dakota's R.M. Heskett Station).

2. **Time necessary for compliance** –To effectuate emission reductions in the near-term, it is important to give consideration to the timeline necessary for implementation of proposed RP controls. New add-on controls or complete replacement of existing controls require significantly longer timeframes for implementation as compared to retrofit and optimization options for existing controls. Preference is therefore given to retrofit options in this step of the evaluation.

3. **Energy and non-air quality environmental impacts of compliance** – Impacts related to water quality, criteria pollutants not considered to be visibility impairing, energy impacts and other environmental issues raised by the proposed control technologies are included as part of the RP evaluation.

4. **Remaining useful life of the source** –The remaining useful life of the source is considered as part of the overall cost. The methods for calculating annualized cost of control technologies are included in EPA's Control Cost Manual, which incorporates assumptions related to the remaining useful life of the source. No additional discussion of this factor is included in the RP evaluation as the remaining useful life of Unit 1 is not expected to significantly impact estimated costs.

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[1] *EPA Air Pollution Control Cost Manual – Sixth Edition.* US EPA Office of Air Quality Planning and Standards (EPA/452/B-02-001), January 2002.

The determination of technical feasibility for the evaluated controls is based on physical, chemical and engineering principles. To be considered technically feasible, a control must have been previously installed and operated successfully on a similar source under similar physical and operating conditions. Novel controls that have not been demonstrated on full-scale, coal-fired utilities have not been considered. Instead, this evaluation focuses on commercially demonstrated control options. Consideration has also been giving to characteristics specific to Unit 1, which, by definition, preclude the application of certain control technologies.

The degree of control for each evaluated technology is expressed on a 12-month rolling average basis and represents the annual tons of pollutant removed to account for expected variability in emissions and provide a comparable basis for each of the control options.

3.2 Particulate Matter Considerations

The intent of RP goals is to reduce visibility impacts in Class I areas. As such, this RP evaluation focuses on SO_2 and NOx, which are the two key regulated pollutants known to contribute to visibility impairment at Class I areas. By comparison, PM accounts for a relatively small amount of visibility impairment. Additionally, the existing PM controls and permit conditions provide effective emissions reductions. As such, augmenting or adjusting existing PM controls will not provide any appreciable incremental visibility improvement. Based on BART evaluations of particulate controls for coal-fired utilities, it is evident that achieving additional levels of PM reductions requires large capital expenditures with negligible returns in terms of emission reductions and corresponding visibility improvement.

4.0 Long-Term Coal Variability and Impact on Control Effectiveness

For the purpose of establishing representative emission rate predictions, it is important to give consideration to variability in coal characteristics and corresponding boiler operating performance. To this end, Montana-Dakota provides a summary of past coal analyses for consideration in the RP evaluation. The analyzed data set includes 567 weekly readings covering the time period from January 2000 through November 2010, which illustrates the variability between shorter-term vs. annual achievable limits.

L&C Station's lignite coal is supplied by the Savage Mine. Because L&C Station is essentially the primary consumer for the Savage Mine, a range of coal qualities must be accepted. As illustrated by the variability in energy represented in British thermal units (Btu) and in sulfur content in **Error! Reference source not found.** and Figure 2 respectively, significant changes in quality occur on both a short and long term basis. Figures 1 and 2 show weekly sampling data presented as analyzed at L&C Station. Monthly and annual block average data are also summarized. Additional data on coal characteristics are presented in Appendix D. In order to include at least 98% of expected scenarios and appropriately determine a consistently achievable emission limit, a high level of fuel variability must be assessed. This provides a degree of comfort with the operational limit and expected variability determined from past operational data.

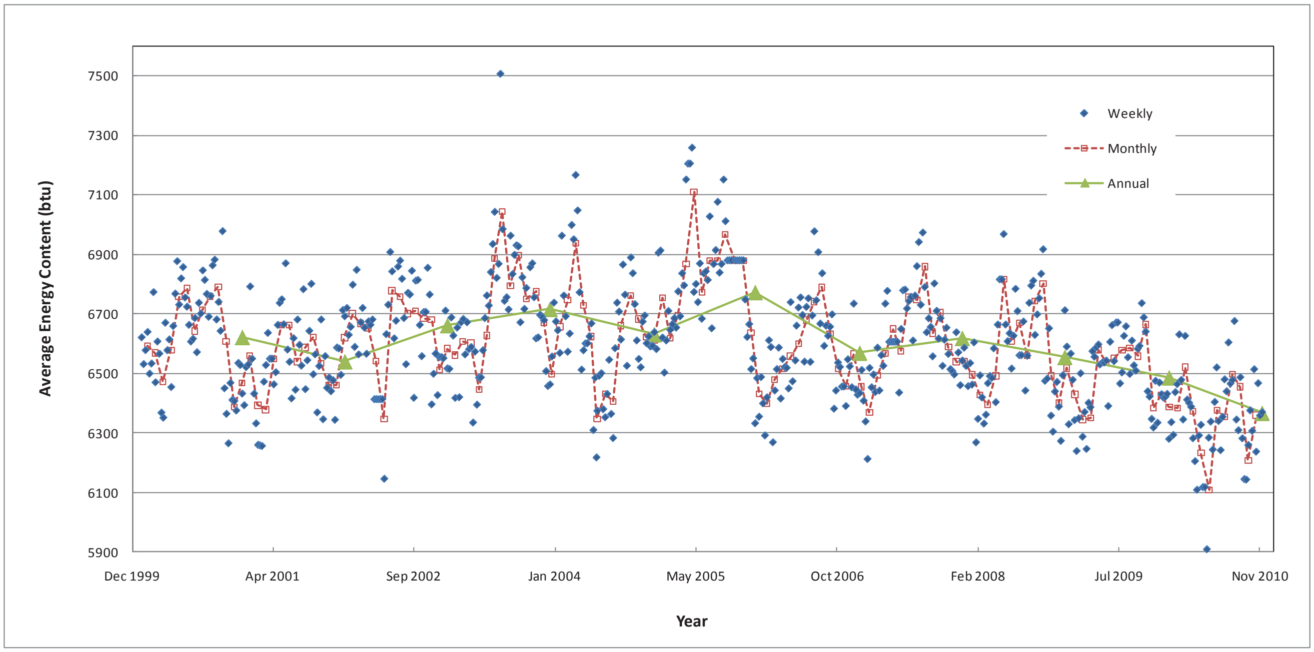

Figure 1. Historical Coal Energy Content (Btu)

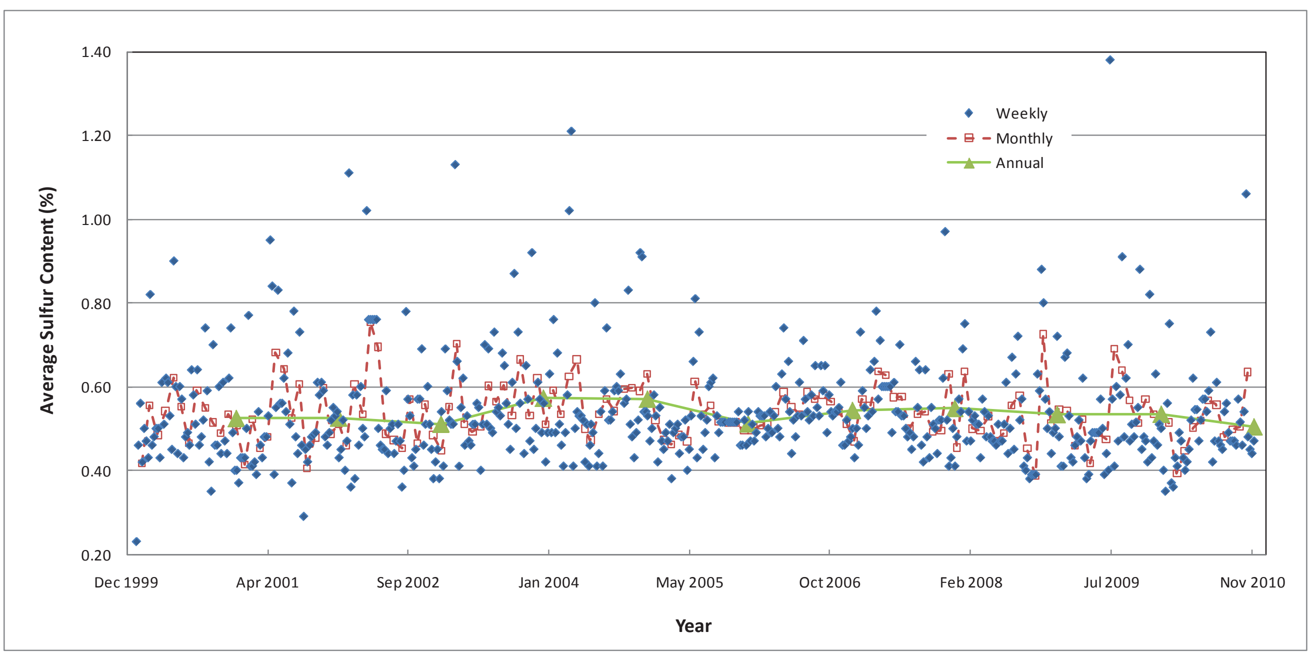

Figure 2. Historical Coal Sulfur Content (%)

Savage Mine is currently in negotiations to obtain rights to mine additional sections of the existing coal deposit. Therefore, a mine plan with core samples to predict future coal quality is not available. Mine plans are variable in nature, and in lieu of predicted coal composition data, historical actual data serves as the best currently available guide for future coal quality expectations. The coal trends presented show a general decrease in quality[2] over time, and indicate the need to consider a poorer coal quality in estimating future emissions performance. Based on statistical analysis of the data presented in Figures 1 and 2, representative coal characteristics for the purpose of evaluating control options are assumed to be approximately 0.5% sulfur and 6,600 Btu/lb.

In instances where relatively poor quality lignite coal is provided to the plant, some blending of subbituminous coal is employed. There is no appreciable difference in the sulfur content (weight percent) of the subbituminous coal supplement, and the as-fired sampling data presented include some blending of subbituminous and lignite coals. Reduced calcium/magnesium concentrations present in the subbituminous coal also result in less inherent SO_2 control. Finally, the on-site coal inventory is fairly limited (generally 2-3 days' supply of lignite) due primarily to the lack of property to safely store additional inventory. Since the need for blending coal is not easily predicted, and its on-hand supply is limited, it is not considered a viable option for emission reductions.

To ensure consistently achievable reductions given the variability and lack of predictability in the given fuel, Montana-Dakota proposes that long term (12-month rolling average) limits be given preference in the emissions limit determination for Unit 1. Based on the data presented above, caution should be used when attempting to derive short term emission rates from calculated annual emission reductions based on general control design values. The proposed long term averaging period is also consistent with other permits issued for proposed RP controls reviewed in preparation of this report.

4.1 Fuel Switching Considerations

For some utilities, switching to coals with lower sulfur content and higher Btu content represents a viable pre-combustion method of reducing SO_2 emissions. Although Unit 1 is currently permitted to blend PRB coal with the primary lignite fuel, there are limitations to achievable blending. In addition to physical limitations of the boiler, the supply and on-site storage of PRB that would be necessary for switching is not, respectively, readily proximate to or physically possible at L&C Station.

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[2] In general, poor coal quality is indicated by low Btu content and calcium content and high sulfur content, ash content, and moisture content.

Based on Unit 1’s design and the limitations of the existing boiler operation, L&C Station is not a candidate for fuel switching. Switching to any fuel with an appreciably different composition and energy content would require boiler surface and other design changes. Previous test burns of PRB at Unit 1 confirm that the high flue gas temperatures, resulting from the use of PBR, cause significant fouling to boiler walls and other boiler surfaces. Due to the physical properties of PRB, coal mills and coal piping to the boiler would also need to be replaced, along with the addition of a railcar unloading system. Re-design of the existing Unit 1 does not constitute a feasible retrofit control option and is not considered further in this evaluation.

5.0 SO_2 Control Evaluation

Unit 1 currently controls SO_2 emissions through calcium concentrations present in the incoming coal. In addition, lime can be added to the wet particulate scrubber to enhance SO_2 removal when the coal has lower calcium content and higher sulfur content. Per EPA's request[3], a list of SO_2 flue gas desulfurization (FGD) control options considered in the RH evaluation is presented below:

- Lime Spray Dryer Absorber (SDA) and Baghouse
- Dry Sorbent Injection (DSI) and Baghouse
- Optimizations of Existing Wet PM Scrubber[3]

Descriptions for each of the evaluated controls along with discussion of feasibility concerns related to each control are presented in the following sections. Additional details regarding the evaluated controls are included in Appendix C.1.

5.1 SO_2 Control Technology Descriptions

The FGD systems commonly used to control SO_2 emissions can be classified as either wet or dry systems. Both systems rely on creating turbulence in the gas stream to increase contact with the absorbing medium. Wet systems are commonly capable of achieving higher removal efficiencies than dry systems. FGD requires the use of an alkali reagent. Lime (or limestone) is the most widely used compound for acid gas absorption. Sodium based reagents are also available, and in some circumstances they provide better SO_2 control, however, they are significantly more expensive. Generally, it takes one molecule of reagent to capture one SO_2 molecule; a stoichiometric ratio of 1. Wet FGD systems generally operate at a stoichiometric ratio of 1.1:1 (reagent: SO_{2} - i.e. 10% extra reagent). Dry FGD systems require stoichiometric ratios of 1.3:1 or higher to achieve optimal SO_2 control.

Wet systems generally require more extensive networks of pumps and piping than dry systems to recirculate, collect, and treat the scrubbing liquid. As implied by the name, dry scrubbers require less water than wet systems, but also require higher temperatures to ensure that all moisture has been evaporated before leaving the scrubber. Based on site specific space constrains, installation of dry

[3] This technology is technically equivalent to "Lime Spray Forced Oxidation (LSFO)". Evaluation of LSFO type controls was specifically requested in the December 9, 2010 call with Ms. Vanessa Hinkle of EPA regarding the scope of technology evaluations encompassed by the November 2010 request for information.

scrubbing technologies would require that the existing particulate scrubber be abandoned in place and replaced with a baghouse to accommodate design control efficiencies.

5.1.1 Lime Spray Dryer Absorber (SDA) with Baghouse

Lime spray dry absorption is a dry scrubbing system that sprays a fine mist of lime slurry into an absorption tower where the SO_2 is absorbed by the droplets. Once absorbed, the SO_2 reacts with lime to form calcium sulfite ($CaSO_3$•$2H_2O$) and calcium sulfate ($CaSO_4$) within the droplets. The SDA temperature must be hot enough to ensure 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 baghouse. Spray dryer absorption control efficiency is typically in the 70% to 90% range. A spray dry scrubber is a technically feasible control option for Unit 1.

5.1.2 Dry Sorbent Injection (DSI) with Baghouse

Dry sorbent injection involves the injection of a lime or limestone powder into the exhaust gas duct work. The stream is then passed through a baghouse or electrostatic precipitator (ESP) to remove the sorbent and entrained SO_2. The process was developed as a lower cost FGD option because the mixing occurs directly in the exhaust gas stream instead of in a separate tower. Depending on the residence time allowed in the system and gas duct temperature, sorbent injection control efficiency is typically between 50% and 70%.

Based on the particulate loading of the existing control system, DSI is expected to achieve removal efficiencies of less than the design range in combination with existing controls. A DSI is a technically feasible control option for Unit 1.

5.1.3 Wet Lime Scrubbing

Wet lime scrubbing involves scrubbing the exhaust gas stream with slurry comprised of lime (CaO) in suspension. The process takes place in a wet scrubbing tower located downstream of a PM control device to prevent the plugging of spray nozzles and other problems caused by the presence of particulates in the scrubber. The SO_2 in the gas stream reacts with the lime to form calcium sulfite ($CaSO_3$•$2H_2O$) and calcium sulfate ($CaSO_4$).

This control option is functionally equivalent to “Lime Spray Forced Oxidation (LSFO)” in terms of concept and control efficiency. Forced oxidation is used in wet scrubbing systems to convert calcium sulfite to calcium sulfate (gypsum). Air is blown through spent lime reagent to accomplish this reaction. This often takes place in the bottom of the wet scrubber. Calcium sulfite is a watery compound and cannot be de-watered. It is typically disposed in ash ponds. Calcium sulfate is a solid and wet scrubber blowdown can be run through a filter press for calcium sulfate recovery. After filtration, calcium sulfate can be disposed of as a solid waste or it can be sold as a raw material for drywall production. The use of forced oxidation has an impact on the method of scrubber waste disposal, but does not appreciably impact SO_2 removal.

Modifications to the existing PM wet scrubber to increase SO_2 removal efficiency is a feasible control option for Unit 1. It would primarily involve upgrades and optimization of the lime injection system.

5.2 Summary of Evaluated Factors

A summary of control effectiveness for each of the evaluated controls is presented in Table 1. The following sections describe considerations consistent with the four factor analysis requirements described in Section 3.1.

Table 1. Control Effectiveness of Technically Feasible SO_2 Control Options

Control Technology	Design Control Efficiency	Controlled Emissions (lb/MMBtu)	Controlled Emissions (ton/year)	Emission Reduction (ton/year)
SDA with Baghouse	95%	0.08	151.8	850.3
Existing Scrubber Mod.	70%	0.45	901.9	100.2
DSI with Baghouse	70%	0.45	901.9	100.2
Baseline Emissions	NA	0.50	1,002.1	NA

Design control efficiencies are based on industry standard control assumptions in combination with sites specific baseline conditions and coal characteristics. Baseline emissions reflect average control provided by the alkaline materials present in lignite coal. Appendix C.1 contains additional references for each evaluated control technology.

5.2.1 Control Cost Evaluation

Table 2 includes the expected installed and operated costs associated with each technology based on reductions from the existing permitted emissions, the EPA cost model and available site specific information. The detailed cost analysis for each technology is provided in Appendix C.1.

Table 2. SO_2 Control Cost Summary

Control Technology	Installed Capital Cost (MM$)	Annualized Operating Cost (MM$/yr)	Pollution Control Cost ($/ton)	Incremental Control Cost ($/ton)
SDA with Baghouse	$66.34	$10.05	$11,825	$13,220
Existing Scrubber Mod.	$0.27	$0.14	$1,383	NA
DSI with Baghouse	$15.75	$2.84	$28,347	NA

The incremental control costs listed in Table 2 represent the incremental value of each technology as compared to the technology with the next highest level of control. Both SDA and DSI technologies represent significant capital investments that are not justified on either an average cost per ton or incremental cost basis.

5.2.2 Other Considerations

For the dry scrubbing control options, the existing particulate scrubber would be abandoned in place and replaced with a baghouse to accommodate either SDA or DSI control. To ensure the required system residence time for either of the dry control options, the existing scrubber would need to be demolished, or the achievable control efficiencies for the dry scrubbing technologies would be significantly decreased. Additionally, physical space limitations at the site would require the demolition and relocation of the existing continuous emissions monitoring systems (CEMS) shelter along with demolition of the old Unit 1 stack to accommodate the baghouse installation. A general arrangement drafting for L&C Station is included in Appendix E to illustrate space limitation and existing equipment layouts. While capital expenditures for the demolition of existing equipment have not been included in the cost evaluation presented above, such costs would be in addition to and increase those costs reported. A more detailed evaluation of site constraints related to installing dry SO_2 control options would be needed to fully determine costs and logistics.

Both dry scrubber additives and additional lime injection may impact particulate emissions control. The existing particulate control system is currently being optimized as a result of adding the OA/ACI mercury control system as described in Section 2.2. Additional optimization tests for particulate loading may be needed if additional lime is introduced into the scrubber for SO_2 control. Increased lime use in the existing scrubber will also necessitate the evaluation of increased lime storage capacity, either through expansion or replacement of the existing storage silo. Further environmental considerations for the evaluated controls are presented in Table 3 below.

Table 3. SO_2 Control Technology Impacts Summary

Control Option	Energy Impacts	Other Impacts	Economic Impacts
SDA Baghouse	Blower requires increased energy use and associated indirect CO_2 emissions increase.	• Requires process downtime and replacement power during installation. • Due to space constraints, the existing equipment must be abandoned/relocated.	Economically infeasible on both an average ($11,825) and incremental ($13,220) cost per ton basis.
Existing Scrubber Modification	No appreciable impacts.	• Potential for particulate emissions increase. • Potential for additional water consumption and wastewater generation. • Potential for stack buildup related lime addition. Consideration for stacking liner materials to be included in scrubber optimization study.	Economically feasible on both an average ($1,383) cost per ton basis.
DSI Baghouse	Blower requires increased energy use and associated indirect CO_2 emissions increase.	• Requires process downtime and replacement power during installation. • Due to space constraints, the existing equipment must be abandoned/relocated.	Economically infeasible on an average ($28,347) cost per ton basis.

5.3 Proposed SO_2 Control Strategy

Based on the analyses provided above, Montana-Dakota believes that modifying the existing scrubber represents the most reasonable control strategy. As compared to DSI and SDA technologies, the pollution control cost along with time for compliance is much more favorable. Additionally, physical facility space constraints support modifying the existing scrubber in lieu of DSI or SDA.

The installation of a continuous lime injection system is also proposed for L&C Station Unit 1. The SO_2 control is currently achieved through the batch addition of lime to the scrubber on an as-needed basis to meet the current permit limit. The addition of a continuous lime injection system would lead to more consistent SO_2 control for purposes of achieving RP reductions. Sizing a hydrated lime storage silo is under consideration. It would be designed and installed to alleviate current onsite lime storage and inventory constraints.

Montana-Dakota proposes to modify the existing scrubber's lime injection system to achieve emission reductions at L&C Station Unit 1. It is anticipated that the SO_2 emissions will thereby be reduced by 100.2 tpy from baseline. Also, a project is currently underway to optimize the PM removal of the scrubber through improved overspray. The increased fluid contact in the scrubber may also lead to additional SO_2 reductions.

Based on the above, a limit of 0.45 lb/MMBtu is proposed on a 12-month rolling average. Montana-Dakota will use its existing CEMS to demonstrate compliance with the proposed RP limits. Montana-Dakota proposes to conduct an optimization study to determine a sustainable SO_2 removal efficiency through the enhancement of the wet scrubber. The study will take into account technical, operational and reliability concerns, as well as other pollutant emission increases, environmental impacts and cost effectiveness.

For the purpose of the optimization study, Montana-Dakota believes that a long-term (6 to 12 months) evaluation of scrubber capabilities is warranted to identify operational constraints. As this effort is an upgrade to an existing system, rebalancing operation after requiring the installation of new equipment is expected to pose complex considerations. Increasing lime addition can impact scrubber performance, including the potential for pH constraints and water balance issues, which must be accounted for along with variability in coal quality. The optimization study will evaluate these parameters, and provide Montana-Dakota with information regarding the long-term ability for the scrubber to accommodate the proposed changes. Recognizing that EPA is working under certain regulatory time constraints, Montana-Dakota intends to conduct the study and implement the proposed emission reductions as expeditiously as possible. Montana-Dakota will work with EPA to determine a protocol and timeline for the optimization study as necessary.

6.0 NOx Control Evaluation

There are three mechanisms by which NOx production occurs: thermal, fuel and prompt NOx. Fuel bound NOx is a primary concern with solid and liquid fuel combustion sources; it is formed as nitrogen compounds in the fuel are oxidized in the combustion process. The secondary mechanism of NOx production is through thermal NOx formation. This mechanism arises from the thermal dissociation of nitrogen and oxygen molecules in combustion air. The thermal oxidation reaction is as follows:

$$N_2 + O_2 \rightarrow 2NO \qquad (1)$$

Downstream of the flame, significant amounts of NO_2 can be formed when NO is mixed with air. The reaction is as follows:

$$2NO + O_2 \rightarrow 2NO_2 \qquad (2)$$

Thermal oxidation is a function of the residence time, free oxygen, and peak reaction temperature. Prompt NOx is a form of thermal NOx which is generated at the flame boundary. It is the result of reactions between nitrogen and carbon radicals generated during combustion. Only minor amounts of NOx are emitted as prompt NOx.

NOx is currently controlled at Unit 1 with the use of low NOx burners (LNB) and a close-coupled overfire air (CCOFA) system. Per EPA's request[4], a list of NOx control options considered in this RP evaluation is presented below:

- Combustion Controls
  - Separated Overfire Air (SOFA)
  - Low NOx Burners
- Post-Combustion Controls
  - Selective Catalytic Reduction (SCR)
  - Selective Non- Catalytic Reduction (SNCR)

6.1 NOx Control Technology Descriptions

Descriptions for each of the evaluated controls along with discussion of feasibility concerns related to each control are presented in the following sections.

[4] Evaluated controls requested in the December 9, 2010 call with Ms. Vanessa Hinkle of EPA regarding the scope of technology evaluations encompassed by the November 2010 request for information.

6.1.1 Combustion Controls

Various combustion controls exist for Unit 1 NOx reduction. However, as discussed in this section, the only feasible controls for Unit 1 are the addition of separated overfire air (SOFA) and new low NOx burners (LNB).

Separated Overfire Air (SOFA)

SOFA diverts a portion of the total combustion air from the burners and injects it through separate air ports above the top level of burners. SOFA is the typical NOx control technology used in coal-fired boilers and is primarily geared to reduce thermal NOx. Staging of the combustion air creates an initial fuel-rich combustion zone for a cooler fuel-rich combustion zone. This reduces the production of thermal NOx by lowering combustion temperature and limiting the availability of oxygen in the combustion zone where NOx is most likely to be formed.

SOFA technology is compatible with the existing LNB. Replacing the existing CCOFA system with SOFA is a technically feasible option for further NOx reduction. With modifications to combustion controls, there is a potential for increased carbon monoxide (CO) emissions from Unit 1. During normal operation at L&C Station, CO levels are currently on the order of 20 ppm. Generally, CO performance guarantees in the 100 ppm to 200 ppm range for low NOx burners. Although CO is not a visibility impairing pollutant, an increase of as much as a 400 tpy may result, which would require a Prevention of Significant Deterioration (PSD) permitting effort prior to commencing construction.

Low NOx Burners (LNB)

LNB technology utilizes advanced burner design to reduce NOx formation through the restriction of oxygen, flame temperature, and/or residence time. LNB is a staged combustion process that is designed to split fuel combustion into two zones. In the primary zone, NOx formation is limited by either one of two methods. Under staged air rich (high fuel) condition, low oxygen levels limit flame temperatures resulting in less NOx 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 (low fuel) conditions, excess air will reduce flame temperature to reduce NOx formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NOx formation. Low NOx burners typically achieve NOx emission reductions of 25% to 50% as compared to uncontrolled emissions.

LNB are currently used to control NOx emissions from Unit 1. Alone or in combination with additional controls, installing new LNB is a technically feasible option to further reduce emissions.

Based on the currently achieved emission rates, a combined reduction in the range of 30% to 40% would be expected with the addition of SOFA and new LNB.

6.1.2 Post Combustion Controls

For post combustion controls, NOx can be reduced to molecular nitrogen (N_2) in add-on systems located downstream of the furnace area of the combustion process. The two main techniques in commercial service include the selective non-catalytic reduction (SNCR) process and the selective catalytic reduction (SCR) process.

Selective Catalytic Reduction (SCR)

SCR is a post combustion NOx control technology in which ammonia (NH_3) is injected into the flue gas stream in the presence of a catalyst. SCR control efficiency is typically 70% to 90%. NOx is removed through the following chemical reaction:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_20 \qquad (1)$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_20 \qquad (2)$$

The catalyst bed lowers the activation energy required for NOx decomposition. The catalyst contains an active phase such as vanadium pentoxide on a carrier such as titanium dioxide. These are used for their ability to lower the activation energy required for NOx decomposition. SCR requires an optimum temperature range of 650-800°F. The addition of NH_3 is typically at a stoichiometric ratio of 1:1 with NOx molecules. In the presence of the SCR catalyst, this ratio is optimal for NOx reduction while minimizing the amount of ammonia slip which can result when un-reacted NH_3 is present in the system. Depending on SCR installation in relation to existing controls, ammonia slip can generally cause additional NH_3 to be emitted to air or water. As NH_3 is both a visibility impairing air pollutant and a wastewater regulated pollutant, air emissions and water discharges can be impacted.

Typical SCR applications require soot blowers for catalyst cleaning. Firing lignite coal results in an exhaust stream heavily laden with particulate matter, which can contain catalyst poisons such as alkali earth metals. These materials cause the ash to adhere to the catalyst surface and block reaction sites in the catalyst pores. The catalyst plugging observed at the lignite-fired boiler at Coyote Station[5] was caused by materials that could not be cleaned by a soot blower system. Because of Coyote's

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[5] *SCR catalyst Performance in Flue Gases Derived from Subbituminous and Lignite Coals.* Steven A. Benson; Jason D. Laumb; Charlene R. Crocker; John H. Pavlish. 7/1/2004 (Appendix F)

experience and the potential for comparable catalyst surface plugging at L&C Station Unit 1, installation of an SCR system on Unit 1 will likely be technically infeasible. Issues with SCR on lignite boilers are discussed in additional detail in a 2009 study completed by the North Dakota Department of Health (NDDH) which supports the limited feasibility of SCR.[6] For reference, a cost analysis for potential SCR installation at Unit 1 has been developed, but Montana-Dakota would like to note that the feasibility of installing SCR at similar sources remains limited. Additionally, physical space constraints at L&C Station limit the opportunity for SCR system tie-ins as illustrated by the plot plan in Appendix E.

Selective Non-Catalytic Reduction (SNCR)

In the SNCR process, urea or ammonia-based chemicals are injected into the flue gas stream to convert NO to molecular nitrogen, N_2, and water. SNCR control efficiency is typically 25% to 50%. Without a catalyst, the reaction requires a high temperature range to obtain activation energy. The relevant reactions are as follows:

$$NO + NH_3 + \tfrac{1}{4}O_2 \rightarrow N_2 + 3/2H_2O \qquad (1)$$

$$NH_3 + \tfrac{1}{4}O_2 \rightarrow NO + 3/2H_2O \qquad (2)$$

At temperature ranges of 1470 to 1830°F reaction (1) dominates. Similarly, SNCR requires much higher reagent use than SCR because it does not rely on a catalyst. Reagent is typically added at a stoichiometric ratio from between 1.5:1 and 2:1 to achieve desired control while also minimizing ammonia slip.

L&C Station is a member of Midwest Independent Transmission System Operator (MISO) and, as such, is operated as called upon based on energy demand and price. Generally, combustion systems on boilers are not optimized for low load operation, including associated NOx emissions. This is important because the efficiency of many air emission controls cannot be guaranteed at low load operating conditions. This is especially true for SNCR. Therefore, to reflect actual emission reductions on cost per ton basis, an SNCR scenario at low load operation is also presented.

Based on a preliminary SNCR engineering assessment that included the temperature, residence time and the current level of NOx control, an emissions reduction of approximately 15% to 30% would be expected. Based on the timeline for completing the RP evaluation, a detailed assessment could not be conducted; therefore the percent reductions are estimates. For L&C Station, the control expectations

[6] *Best Available Retrofit Technology – Selective Catalytic Reduction Technical Feasibility Analysis for North Dakota Lignite.* North Dakota Department of Health, Division of Air Quality. 7/1/2009

for SNCR are at the same level as could be achieved by the addition of SOFA and new LNB. It is also important to note that the economic analysis does not include unplanned outages to clean the ammonium bisulfate from the air heaters which would impact the cost per ton values presented below.

6.2 Summary of Evaluated Factors

Based on the current utilization[7] and design degree of control being achieved on Unit 1, Table 4 describes the expected annual emissions from each of the remaining feasible control options. A complete evaluation of NOx controls at low load operation is included in Appendix C.2

Table 4. Control Effectiveness of Technically Feasible NOx Control Options

Control Technology	Expected Control Efficiency	Controlled Emissions (lb/MMBtu)	Controlled Emissions (ton/year)	Emission Reduction (ton/year)
SCR	90%	0.04	80.2	721.5
SNCR with SOFA/LNB	50%	0.20	400.9	400.9
SOFA/LNB	38%	0.25	501.1	300.6
SNCR	38%	0.25	501.1	300.6
Current OFA/LNB Configuration	NA	0.40	801.7	NA
SNCR (low load[8])	16%	0.31	297.7	57.6
Current OFA/LNB Configuration (low load)	NA	0.37	355.3	NA

Based on an SNCR designed for a low concentration of ammonia slip, the control efficiency for SNCR is equivalent to the addition of SOFA and new LNB (identified as SOFA/LNB in Tables 4, 5 and 6).

6.2.1 Control Cost Evaluation

Table 5 includes the expected installed and operated costs associated with each technology based on reductions from the existing permitted emissions, the EPA cost model and site specific information as available. The detailed cost analyses for each technology are provided in Appendix C.1 and Appendix C.2.

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[7] Unit 1 load/utilization has a significant impact on burner operation and degree of control achievable on a lb/MMBtu basis.

[8] Low load operational case presented for SNCR reflects operation at 23 MW capacity. Control efficiency and emission reductions are shown in relation to the current NOx control configuration operated at 23 MW.

Table 5. NOx Control Cost Summary

Control Technology	Installed Capital Cost (MM$)	Annualized Operating Cost (MM$/yr)	Pollution Control Cost ($/ton)	Incremental Control Cost ($/ton)
SCR	$38.98	$6.98	$9,680	$18,368
SNCR with SOFA/LNB	$4.53	$1.09	$2,729	$7,279
SOFA/LNB	$2.20	$0.36	$1,213	NA
SNCR	$2.43	$0.76	$2,533	NA
SNCR (low load)	$2.43	$0.56	$9,817	NA

The cost summary presented for SCR is a based on a screening level evaluation, and Montana-Dakota reserves the right to develop a site specific estimate as necessary. Additional constraints such as an extended need for shutdown, rerouting of piping to allow necessary residence time, potential redesign of backend heat recovery and associated costs have not been included in this evaluation.

The incremental control costs listed in Table 5 represent the incremental value of each technology as compared to the technology with the next highest level of control. SCR represent significant capital investments that are not justified on a cost per ton or incremental cost basis. Similarly, SNCR is not justified on an incremental cost basis as associated decreases in emissions are not significantly higher than those achieved by SOFA/LNB.

6.2.2 Other Considerations

Ammonia slip generated as a result of post-combustion controls (SCR and SNCR) will cause increased ammonia concentrations in the scrubber discharge. This in turn will lead to a higher concentration of ammonia in the wastewater discharge, thus the installation of post-combustion controls could also require the installation of wastewater treatment controls. Costs associated with additional wastewater controls have not been quantified as part of this evaluation. Montana-Dakota understands that the EPA will soon be updating the effluent limits for coal-fired facilities, and limits may be established that will significantly impact the cost of SNCR and SCR controls.

As listed in the Montana Department of Environmental Quality's (MT DEQ) water quality standards, the ammonia standard is currently no detectable concentration, with a trigger concentration of 10 mg/L[9]. As illustrated in Appendix D, an ammonia slip range of 5 ppm to 10 ppm (the standard design

[9] *Circular DEQ-7 Montana Numerical Water Quality Standards.* MDEQ Planning, Prevention, and Assistance Division - Water Quality Standards Section. August 2010.

parameters for post-combustion systems) will result in a discharged ammonia concentration range of 8 to 17 mg/L. Therefore, as indicated, the installation of post-combustion controls may trigger stringent wastewater treatment controls for ammonia and other nitrogen constituents.

Post-combustion controls also increase emission risk regarding compliance with particulate emission limits. Increases in condensable particulate emissions potentially associated with sulfuric acid mist generated by SCR would jeopardize compliance with the existing permitted particulate limit of 0.17 lb/MMBtu. As referenced in the Title V operation permit for L&C Station Unit 1, included in Appendix B, this limit includes both filterable and condensable particulate contributions, and therefore, represents a high level of total particulate control.

As described in the control technology summaries above, combustion modifications (SOFA/LNB) are likely to result in a significant increase in CO emissions. Time for compliance for these controls will be dependent on the issuance of permits associated with a CO increase. Combustion modifications generally do not require additional steam or generate solid waste or wastewater.

The energy and non-air quality environmental impacts for the feasible NOx control options are described in Table 6.

Table 6. NOx Control Technology Impacts Summary

Control Option	Energy Impacts	Other Impacts	Economic Impacts
SCR	Reheat potentially required to make SCR technically feasible will result in high energy use and associated costs along with increased CO_2 emissions.	1. Spent catalyst produces an increase in solid waste 2. Ammonia slip concerns, which contributes to water quality impacts. 3. Additional safety and regulatory concerns associated with ammonia storage on site. 4. Oxidant may impact mercury removal efficiency	Economically infeasible on an average ($9.680) and incremental ($18,368) cost per ton basis.
SOFA/LNB	Minimal energy impacts.	1. Increase in CO emissions. Any CO increase may require permitting actions and approval from MT DEQ.	Economically feasible on an average ($1,213) cost per ton basis.

SNCR (or SNCR with SOFA/LNB)	Minimal additional energy impacts.	1. Ammonia slip concerns, which contributes to water quality impacts. 2. Variably operating conditions caused by unit swinging will necessitate extensive O&M requirements. 3. Potential increase in CO emissions. Any CO increase may require permitting actions and approval from MT DEQ (due to SOFA/LNB).	Economically infeasible on an incremental ($7,279) basis and marginally feasible on an average ($2,533) cost per ton basis. Economically infeasible at low load operation on an average basis ($9,817).

6.3 Proposed NOx Control Strategy

Based on the above analysis, Montana-Dakota proposes the addition of SOFA with new LNB for NOx reduction at Unit 1.

From a top down analysis, SCR is determined to be economically infeasible and has significant technical and other concerns on a commercial scale for a lignite fired boiler.

The SNCR with SOFA/LNB combined technology option is not a viable retrofit technology for several reasons, including: 1) cost ineffectiveness (incremental $/ton cost compared to SOFA/LNB control option and average $/ton at low load operation), 2) negative energy and environmental impacts, and 3) relatively insignificant incremental emissions improvement beyond the SOFA/LNB control option.

SOFA/LNB retrofit option represents the most cost effective retrofit technology for further controlling NOx emissions from L&C Station Unit 1.

The proposed NOx RP emissions limit for Unit 1 is 0.25 lb/MMBtu on a 12-month rolling average. This limit will allow the station to maintain compliance while accommodating Unit 1 variability in emissions related to different load operating conditions. For example, low load conditions will generally show an increase in NOx emissions on a lb/MMBtu basis, but will still be consistent with expected actual reduction of mass emissions (tpy) on an annual basis. Montana-Dakota will use its existing CEMS to demonstrate compliance with the proposed RP-based limit.

7.0 Proposed Emissions Control Strategy

Montana-Dakota proposes the following control strategy for L&C Station Unit 1 in consideration of the four-factor test specified at 40 CFR 51.308(d)(1)(i)(A). Montana-Dakota acknowledges that all factors must be weighed in making an emissions control determination for RP goals. That stated, it is important to precede any control determination with the understanding that L&C Station Unit 1 is a non-BART unit, and is less than the presumptive unit threshold of 200 MW. As such, economies of scale for pollution control costs are not realized at L&C Station and any resulting emission reductions are expected to provide little in the way of visibility improvement in Class I areas.

- **PM** – Montana-Dakota proposes to comply with its existing permit limit of 0.17 lb/MMBtu using its existing particulate control system. This report confirms that a change in PM emission limits is not warranted. The PM emission limit will be reviewed and may need to be increased if the SO_2 and NOx controls other than those recommended in this report are required since particulate emission from other evaluated controls would increase. Pending the findings of planned existing wet scrubber optimization studies, the impacts of the proposed SO_2 control strategy may: (a) require that the existing PM emission limit include only filterable particulate contributions; or (b) require a permit modification to accommodate any increases in condensable particulate emissions.

- **SO_2** – Optimization of the existing PM wet scrubber to further reduce SO_2 emissions is proposed. Continuous lime injection system configuration is being developed, and upon installation, an optimization study will be conducted to determine sustainable SO_2 control efficiency.

- **NOx** – The addition of SOFA with new LNB will be installed for NOx control. CO increases and associated permitting requirements related to the shift in combustion balance will be evaluated. Furnace penetration is required for the installation of SOFA/LNB and as such will need to align with a major outage. The next planned outages are scheduled for spring of 2012, which is too soon to accommodate this retrofit, and spring of 2018.

If a state construction permit is required to implement the proposed emissions control strategy, then that permitting schedule may impact the timing of the proposed emission reductions. Montana-Dakota emphasizes that the SO_2 reduction estimate may need to be modified to address findings of the proposed optimization study. The study is intended to identify and balance operational constraints related to increased lime injection rates. The SO_2 control optimization may potentially provide additional reductions and in a shorter timeframe, with less cost than the installation of NOx controls resulting in the same visibility improvements.

If a PSD permit is required as a result of CO increases from implementing the NOx emissions reduction controls at Unit 1, the timeline for implementation will be dependent on expeditious issuance of a PSD permit and any other permits required by the MT DEQ to meet any specific state compliance requirements. Montana-Dakota will make all good faith efforts to secure any such permits in the event that they are required. In the event the issuance of any required permits for the project is not possible, for any reason, Montana-Dakota reserves the right to reevaluate the proposed RP control strategy and schedule with EPA.

Table 7. Proposed Regional Haze Emission Limits

Pollutant	Current Permit Limit	Proposed RH Limit (12-month Rolling Average)	Estimated Pollutant Reduction from Current Emissions
PM	0.17 lb/MMBtu	0.17 lb/MMBtu	N/A
SO_2	2.0 lb/MMBtu	0.45 lb/MMBtu	100.2 tpy
NOx	0.40 lb/MMBtu	0.25 lb/MMBtu	300.6 tpy

Appendix A

EPA 114 Request Letter

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

NOV 0 5 2010

Ref: 8P-AR

CERTIFIED MAIL – RETURN RECEIPT REQUESTED

Abbie Krebsbach
Environmental Manager
Montana-Dakota Utilities Company
400 North Fourth Street
Bismarck, North Dakota 58501

RE: Request for Additional Reasonable Progress Information for the Montana-Dakota Utilities Company, Lewis and Clark Generating Station, Pursuant to Section 114(a) of the Clean Air Act (42 U.S.C. Section 7414(a))

Dear Ms. Krebsbach:

As you know, on July 19, 2006, the Environmental Protection Agency (EPA) received a letter from the Montana Department of Environmental Quality (MDEQ) that stated it was withdrawing its efforts to adopt a state implementation plan (SIP) for regional haze under EPA's Regional Haze Rule (RHR), found at 40 CFR 51.308. Due to Montana's announcement that it would not be addressing the requirements under 40 CFR 51.308, EPA Region 8 is moving forward with the technical and policy work needed to implement the requirements of the RHR under a Federal implementation plan (FIP). See Section 110(c)(1) of the Clean Air Act (CAA), 42 U.S.C. §7410(c)(1).

As part of our effort to address requirements under the RHR for reasonable progress (RP) goals and strategies (see 40 CFR 51.308(d)(1) and 51.308(d)(3)), we previously requested information regarding the Montana-Dakota Utilities Company, Lewis and Clark Generating Station. We have reviewed the information that you submitted dated March 17, 2009 in response to our January 29, 2009 CAA Section 114 information request on the emission unit at your facility. Based on the emissions and current control technology information you submitted, emissions unit 1 (a tangential coal/natural gas boiler) is a source that warrants further analysis in considering and developing strategies for achieving the RP goal for Montana.

Please submit an analysis of control options for this unit postmarked within 60 days of the date of this letter. The analysis must address the four factors included in 40 CFR § 51.308(d)(1)(i)(A) - the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of the potentially affected sources. We suggest that the Best Available Retrofit Technology (BART) Guidelines (see 40 CFR Part 51 Appendix Y) provide additional guidance on how to perform the cost of compliance portion of this analysis. Your analysis must consider the full range of available control technologies and for each technology, you must consider the full range of emission standards including the most stringent.

We understand this is a complicated endeavor, and we are available to answer any questions that you may have on the RHR or the RP analysis. We will assist you in any way we can and look forward to working with you.

Pursuant to Section 114 of the Clean Air Act, 42 U.S.C. §7414, and under authority duly delegated to the undersigned, you are required to provide us with the information specified in this letter. This information will be used by EPA in developing a regional haze FIP, or in the event MDEQ resumes development of a regional haze SIP, in assisting MDEQ in that effort and/or reviewing a regional haze SIP for Montana. Furthermore, information requests pursuant to Section 114 of the CAA are not limited to sources that are regulated by the particular rule EPA is implementing. For example, Section 114(a)(1) says that EPA may gather information from "any person who owns or operates any emission source" or "who the Administrator believes may have information necessary for the purposes set forth in this subsection."

A duly authorized officer or agent of the facility must certify as true, accurate, and complete the response to this information by signing the enclosed Statement of Certification and returning it with the response. Such officer or agent must have sufficient knowledge and authority to make such representations on behalf of Montana-Dakota Utilities Company.

Please submit your response to:

U.S. Environmental Protection Agency Region VIII
1595 Wynkoop Street
Denver, CO 80202-1129
Attention: Vanessa Hinkle, 8P-AR

Pursuant to Section 114(c) of the CAA, 42 U.S.C. §7414(c), and 40 C.F.R. Part 2, Subpart B, Montana-Dakota Utilities Company is entitled to assert a business confidentiality claim covering any part of the submitted information. Attachment B specified the assertion and substantiation requirements for business confidentiality claims. Failure to assert such a claim makes the submitted information subject to public disclosure upon request and without further notice to you, pursuant to the Freedom of Information Act, 5 U.S.C. Section 552. Information subject to a business confidentiality claim may only be made available to the public in accordance with 40 C.F.R. Part 2, Subpart B.

A knowing submittal of false information in response to this request may be actionable under Section 113(c)(2) of the CAA, as well as 18 U.S.C. §§1001 and 1341. Failure to comply with the terms of this request may subject Montana-Dakota Utilities Company to enforcement action under Section 113 of the CAA, 42 U.S.C. §7413.

Also enclosed with this Request for Information is a Small Business Regulatory Enforcement and Fairness Act (SBREFA) information sheet.

The requirements of this letter are not subject to the Paperwork Reduction Act of 1980, 44 U.S.C. §3501 *et seq*.

We appreciate your cooperation in this matter. If you have any questions please call Vanessa Hinkle of my staff at 303-312-6561.

Sincerely,

Stephen S. Tuber
Assistant Regional Administrator
Office of Partnerships and Regulatory Assistance

Enclosures

cc: John Bunyak, NPS
Sandra Silva, USFWS
Thomas Dzomba, USFS

Appendix B

L&C Station Title V Permit

Montana Department of
ENVIRONMENTAL QUALITY

Brian Schweitzer, Governor

P. O. Box 200901 Helena, MT 59620-0901 (406) 444-2544 Website: www.deq.mt.gov

December 6, 2010

Andrea L. Stomberg
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismark, ND 58501

RE: Final Title V Operating Permit #OP0691-05

Dear Ms. Stromberg:

The Department of Environmental Quality has prepared the enclosed Final Operating Permit #OP0691-05, for Montana-Dakota Utilities, Inc. Lewis and Clark Station, located in the Southwest ¼ of Section 9, Township 22 North, Range 59 East, in Richland County, Montana. Please review the cover page of the attached permit for information pertaining to the action taking place on Permit #OP0691-05.

If you have any questions, please contact Shawn Juers, the permit writer, at (406) 444-2049 or by email at sjuers@mt.gov.

Sincerely,

Vickie Walsh

Vickie Walsh
Air Permitting Program Supervisor
Air Resources Management Bureau
(406) 444-9741

Shawn Juers
Environmental Engineer
Air Resources Management Bureau
(406) 444-2049

VW:SJ
Enclosure

cc: Christopher Ajayi, US EPA Region VIII 8P-AR
Carson Coate, US EPA Region VIII, Montana Office

STATE OF MONTANA
Department of Environmental Quality
Helena, Montana 59620

AIR QUALITY OPERATING PERMIT OP0691-05

Issued to: Montana-Dakota Utilities Co.
Lewis and Clark Station
400 North Fourth Street
Bismark, ND 58501

Final Date: December 4, 2010
Expiration Date: August 24, 2014

Effective Date: December 4, 2010
Date of Decision: November 3, 2010

Request Deemed Technically Complete: June 21, 2010 and August 31, 2010
Request Deemed Administratively Complete: June 21, 2010 and August 31, 2010
Administrative Amendment Request Received: May 24, 2010 and August 31, 2010
AFS Number: 030-053-0002A

Permit Issuance and Appeal Processes: In accordance with Montana Code Annotated (MCA) Sections 75-2-217 and 218 and the Administrative Rules of Montana (ARM), ARM Title 17, Chapter 8, Subchapter 12, Operating Permit Program, this operating permit is hereby issued by the Department of Environmental Quality (Department) as effective and final on December 4, 2010. This cover sheet must be attached to the Date of Decision issued on November 3, 2010, and the permit must be kept on-site at the above named facility.

Montana Air Quality Operating Permit
Department of Environmental Quality

Terms not otherwise defined in this permit or in the Definitions and Abbreviations Appendix of this permit have the meaning assigned to them in the referenced regulations.

SECTION I. GENERAL INFORMATION

The following general information is provided pursuant to ARM 17.8.1210(1).

Company Name: Montana Dakota Utilities Co., Lewis & Clark Station

Mailing Address: 400 North Fourth Street

City: Bismarck State: North Dakota Zip: 58501

Plant Location: Southwest ¼, Section 9, Township 22 North, Range 59 East, Richland County, Montana

Responsible Official: Andrea Stomberg Phone: (701) 222-7752

Facility Contact Person: Abbie Kresbach Phone: (701) 222-7844

Primary SIC Code: 4911

Nature of Business: Electric Services

Description of Process: MDU operates a tangential coal-fired boiler capable of burning coal or natural gas and associated equipment for generation of electricity.

SECTION II. SUMMARY OF EMISSION UNITS

The emission units regulated by this permit are the following (ARM 17.8.1211):

Emissions Unit ID	Description	Pollution Control Device/Practice
EU01	Tangential Coal and Natural Gas Fired Boiler	Multi-Cyclone and Flooded Disc Wet Scrubber
EU06	Fuel (gasoline) Storage Tank	None
EU07	Coal Storage Piles	None
EU08	Fugitive Coal, Ash, and Lime Handling	None

SECTION III. PERMIT CONDITIONS

The following requirements and conditions are applicable to the facility or to specific emissions units located at the facility (ARM 17.8.1211, 1212, and 1213).

A. Facility-Wide

Conditions	Rule Citation	Rule Description	Pollutant/Parameter	Limit
A.1	ARM 17.8.105	Testing Requirements	Testing Requirements	-------
A.2	ARM 17.8.304(1)	Visible Air Contaminants	Opacity	40%
A.3	ARM 17.8.304(2)	Visible Air Contaminants	Opacity	20%
A.4	ARM 17.8.308(1)	Particulate Matter, Airborne	Fugitive Opacity	20%
A.5	ARM 17.8.308(2)	Particulate Matter, Airborne	Reasonable Precautions	-------
A.6	ARM 17.8.308	Particulate Matter, Airborne	Reasonable Precaution, Construction	20%
A.7	ARM 17.8.309	Particulate Matter, Fuel Burning Equipment	Particulate Matter	$E= 0.882 * H^{-0.1664}$ Or $E= 1.026 * H^{-0.233}$
A.8	ARM 17.8.310	Particulate Matter, Industrial Processes	Particulate Matter	$E= 4.10 * P^{0.67}$ or $E= 55 * P^{0.11} - 40$
A.9	ARM 17.8.322(4)	Sulfur Oxide Emissions, Sulfur in Fuel	Sulfur in Fuel (liquid or solid fuels)	1 lb/MMBtu fired
A.10	ARM 17.8.322(5)	Sulfur Oxide Emissions, Sulfur in Fuel	Sulfur in Fuel (gaseous)	50 gr/100 CF
A.11	ARM 17.8.324(3)	Hydrocarbon Emissions, Petroleum Products	Gasoline Storage Tanks	-------
A.12	ARM 17.8.324	Hydrocarbon Emissions, Petroleum Products	65,000 Gallon Capacity	-------
A.13	ARM 17.8.324	Hydrocarbon Emissions, Petroleum Products	Oil-effluent Water Separator	-------
A.14	ARM 17.8.342	NESHAPs General Provisions	SSM Plans	Submittal
A.15	ARM 17.8.1212	Reporting Requirements	Prompt Deviation Reporting	-------
A.16	ARM 17.8.1212	Reporting Requirements	Compliance Monitoring	-------
A.17	ARM 17.8.1207	Reporting Requirements	Annual Certification	-------

Conditions

A.1. Pursuant to ARM 17.8.105, any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of the Department, provide the facilities and necessary equipment (including instruments and sensing devices) and shall conduct tests, emission or ambient, for such periods of time as may be necessary using methods approved by the Department.

Compliance demonstration frequencies that list "as required by the Department" refer to ARM 17.8.105. In addition, for such sources, compliance with limits and conditions listing "as required by the Department" as the frequency, is verified annually using emission factors and engineering calculations by the Department's compliance inspectors during the annual emission inventory review; in the case of Method 9 tests, compliance is monitored during the regular inspection by the compliance inspector.

A.2. Pursuant to ARM 17.8.304(1), MDU shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed on or before November 23, 1968, that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes, unless otherwise specified by rule or in this permit.

A.3. Pursuant to ARM 17.8.304(2), MDU shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes, unless otherwise specified by rule or in this permit.

A.4. Pursuant to ARM 17.8.308(1), MDU shall not cause or authorize the production, handling, transportation, or storage of any material unless reasonable precautions to control emissions of particulate matter are taken. Such emissions of airborne particulate matter from any stationary source shall not exhibit an opacity of 20% or greater averaged over 6 consecutive minutes, unless otherwise specified by rule or in this permit.

A.5. Pursuant to ARM 17.8.308(2), MDU shall not cause or authorize the use of any street, road or parking lot without taking reasonable precautions to control emissions of airborne particulate matter, unless otherwise specified by rule or in this permit.

A.6. Pursuant to ARM 17.8.308, MDU shall not operate a construction site or demolition project unless reasonable precautions are taken to control emissions of airborne particulate matter. Such emissions of airborne particulate matter from any stationary source shall not exhibit an opacity of 20% or greater averaged over 6 consecutive minutes, unless otherwise specified by rule or in this permit.

A.7. Pursuant to ARM 17.8.309, unless otherwise specified by rule or in this permit, MDU shall not cause or authorize particulate matter caused by the combustion of fuel to be discharged from any stack or chimney into the outdoor atmosphere in excess of the maximum allowable emissions of particulate matter for existing fuel burning equipment and new fuel burning equipment calculated using the following equations:

For existing fuel burning equipment (installed before November 23, 1968):
$E = 0.882 * H^{-0.1664}$

For new fuel burning equipment (installed on or after November 23, 1968):
$E = 1.026 * H^{-0.233}$

Where H is the heat input capacity in million BTU (MMBtu) per hour and E is the maximum allowable particulate emissions rate in pounds per MMBtu.

A.8. Pursuant to ARM 17.8.310, unless otherwise specified by rule or in this permit, MDU shall not cause or authorize particulate matter to be discharged from any operation, process, or activity into the outdoor atmosphere in excess of the maximum hourly allowable emissions of particulate matter calculated using the following equations:

For process weight rates up to 30 tons per hour: $E = 4.10 * P^{0.67}$
For process weight rates in excess of 30 tons per hour: $E = 55.0 * P^{0.11} - 40$

Where E = rate of emissions in pounds per hour and P = process weight rate in tons per hour.

A.9. Pursuant to ARM 17.8.322(4), MDU shall not burn liquid or solid fuels containing sulfur in excess of 1 pound per million BTU fired, unless otherwise specified by rule or in this permit.

A.10. Pursuant to ARM 17.8.322(5), MDU shall not burn any gaseous fuel containing sulfur compounds in excess of 50 grains per 100 cubic feet of gaseous fuel, calculated as hydrogen sulfide at standard conditions, unless otherwise specified by rule or in this permit.

A.11. Pursuant to ARM 17.8.324(3), MDU shall not load or permit the loading of gasoline into any stationary tank with a capacity of 250 gallons or more from any tank truck or trailer, except through a permanent submerged fill pipe, unless such tank is equipped with a vapor loss control device or is a pressure tank as described in ARM 17.8.324(1), unless otherwise specified by rule or in this permit.

A.12. Pursuant to ARM 17.8.324, unless otherwise specified by rule or in this permit, MDU shall not place, store or hold in any stationary tank, reservoir or other container of more than 65,000 gallon capacity any crude oil, gasoline or petroleum distillate having a vapor pressure of 2.5 pounds per square inch absolute or greater under actual storage conditions, unless such tank, reservoir or other container is a pressure tank maintaining working pressure sufficient at all times to prevent hydrocarbon vapor or gas loss to the atmosphere, or is designed and equipped with a vapor loss control device, properly installed, in good working order and in operation.

A.13. Pursuant to ARM 17.8.324, unless otherwise specified by rule or in this permit, MDU shall not use any compartment of any single or multiple-compartment oil-effluent water separator, which compartment receives effluent water containing 200 gallons a day or more of any petroleum product from any equipment processing, refining, treating, storing or handling kerosene or other petroleum product of equal or greater volatility than kerosene, unless such compartment is equipped with a vapor loss control device, constructed so as to prevent emission of hydrocarbon vapors to the atmosphere, properly installed, in good working order and in operation.

A.14. Pursuant to ARM 17.8.342 and 40 CFR 63.6, MDU shall submit to the Department a copy of any startup, shutdown, and malfunction (SSM) plan required under 40 CFR 63.6(e)(3) within 30 days of the effective date of this operating permit (if not previously submitted), within 30 days of the compliance date of any new National Emission Standard for Hazardous Air Pollutants (NESHAPs) or Maximum Achievable Control Technology (MACT) standard, and within 30 days of the revision of any such SSM plan, when applicable. The Department requests submittal of such plans in electronic form, when possible.

A.15. MDU shall promptly report deviations from permit requirements including those attributable to upset conditions, as upset is defined in the permit. To be considered prompt, deviations shall be reported to the Department using the schedule and content as described in Section V.E (unless otherwise specified in an applicable requirement) (ARM 17.8.1212).

A.16. On or before February 15 and August 15 of each year, MDU shall submit to the Department the compliance monitoring reports required by Section V.D. These reports must contain all information required by Section V.D, as well as the information required by each individual emissions unit. For the reports due by February 15 of each year, MDU may submit a single report, provided that it contains all the information required by Section V.B & V.D. Per ARM 17.8.1207,

> *any application form, report, or compliance certification submitted pursuant to ARM Title 17, Chapter 8, Subchapter 12 (including semiannual monitoring reports), shall contain certification by a responsible official of truth, accuracy and completeness. This certification and any other certification required under ARM Title 17, Chapter 8, Subchapter 12, shall state that,* ***"based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete."***

A.17. By February 15 of each year, MDU shall submit to the Department the compliance certification required by Section V.B. The annual certification required by Section V.B must include a statement of compliance based on the information available which identifies any observed, documented or otherwise known instance of noncompliance for each applicable requirement. Per ARM 17.8.1207,

> *any application form, report, or compliance certification submitted pursuant to ARM Title 17, Chapter 8, Subchapter 12 (including annual certifications), shall contain certification by a responsible official of truth, accuracy and completeness. This certification and any other certification required under ARM Title 17, Chapter 8, Subchapter 12, shall state that,* ***"based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete."***

B. EU01: Tangential Coal-Fired Boiler (Coal and Natural Gas)

Condition(s)	Pollutant/Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
B.1, B.11, B.12, B.23, B.24, B.26, B.34, .B35, B.36	Opacity	40%	Method 9	As Required by the Department	Semiannual
			Predictive Opacity	Ongoing	Quarterly
B.2, B.13, B.23, B.24, B.34, .B35, B.36	Particulate Matter Fuel Burning	0.17 lb/MMBtu	Method 5	Annual	Semiannual
		0.08 gr/dscf			
B.3, B.4, B.14, B.15, B.16, B.25, B.27, B.28, B.35, B.36	SO_2 Emissions	1.0 lb sulfur/MMBtu fuel or 2.0 lb SO_2/MMBtu	Continuous Scrubber Operations and CEMS	Ongoing	Semiannual
		50 gr sulfur/100 CF fuel	Record Keeping	Ongoing	Semiannual
B.5, B.17, B.28, .B35, B.36	NO_x Emissions/Acid Rain Provisions	0.40 lb/MMBtu	CEMS	Ongoing	Semiannual
B.6, B.18, B.29, .B35, B.36	Acid Rain Provisions	40 CFR 72-78	40 CFR 72-78	40 CFR 72-78	Semiannual
B.7, B.19, B.30, .B35, B.36	PM CAM Plan	ARM 17.8.1506	Provisions from CAM Plan, Appendix I	Ongoing	Semiannual
B.8, B.20, B.31, .B35, B.36	Mercury Emissions	1.5 lb/TBtu	MEMS	Ongoing	Semiannual
B.9, B.21, B.32, .B35, B.36	Mercury Emission Control Equipment	OAI and ACI Systems	Log	Ongoing	Semiannual
B.10, B.22, B.33, .B35, B.36	40 CFR Part 75	40 CFR Part 75	40 CFR Part 75	Ongoing	Semiannual

Conditions

B.1. MDU may not cause or authorize emissions from the Tangential Coal-Fired Boiler (boiler) to be discharged into the outdoor atmosphere that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes (ARM 17.8.304 (2)).

B.2. Particulate matter emissions from the boiler shall not exceed 0.17 lb/MMBtu or 0.08 gr/dscf (ARM 17.8.309).

B.3. MDU shall not fire in the boiler liquid or solid fuels containing sulfur in excess of 1.0 lb of sulfur/MMBtu fuel or 2.0 lb SO_2/MMBtu (ARM 17.8.322(4)).

B.4. MDU shall not fire in the boiler any fuels in excess of 50 grains of sulfur/100 cubic feet of gaseous fuel (ARM 17.8.322).

B.5. NO_X emissions from the boiler shall not exceed 0.40 lb/MMBtu (40 CFR 76.7).

B.6. MDU shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements of the Acid Rain Program contained in 40 CFR 72-78 (40 CFR 72-78).

B.7. MDU shall provide a reasonable assurance of compliance with emission limitations or standards for the anticipated range of operations at the Tangential Coal-fired Boiler for PM (ARM 17.8.1504).

B.8. Beginning January 1, 2010, MDU shall limit mercury emissions from Unit 1 to an emission rate equal to or less than 1.5 pounds mercury per trillion British thermal units (lb/TBtu), calculated as a rolling 12-month average (ARM 17.8.771).

B.9. MDU shall install an oxidizing agent injection (OAI) system and an activated carbon injection (ACI) system. MDU shall implement the operation and maintenance of the OAI and ACI systems on or before January 1, 2010 (ARM 17.8.771).

B.10. MDU shall comply with all applicable standards and limitations, and the applicable operating, reporting, recordkeeping, and notification requirements contained in 40 CFR Part 75 (ARM 17.8.771).

Compliance Demonstration

B.11. MDU shall perform a Method 9 opacity test on the boiler annually or as required by the Department while the boiler is being fired exclusively on coal to monitor compliance with the opacity limitation in Section III.B.1 (ARM 17.8.749 and ARM 17.8.106).

B.12. MDU shall operate and maintain the predictive opacity monitoring system to monitor compliance with the opacity limitation in Section III.B.1. The monitoring system operation shall be performed in accordance with the Predictive Opacity Appendix E of this permit (40 CFR Part 51, Appendix P, §3.9 and ARM 17.8.749).

B.13. MDU shall perform a Method 5 or Method 5B particulate matter test, or another method approved by the Department, on the boiler annually to monitor compliance with the particulate matter fuel burning limit in Section III.B.2. The testing shall be performed in accordance with the Montana Source Test Protocol and Procedures Manual while the boiler is being fired exclusively on coal (ARM 17.8.749 and ARM 17.8.106).

B.14. MDU shall operate the scrubber when the boiler is operating to monitor compliance with the emission limit in III.B.3 (ARM 17.8.322(6)(c)).

B.15. MDU shall monitor compliance with emission limits in III.B.3 pursuant to the requirements in 40 CFR Part 75, and the SO_2 CEMS Appendix F in this permit (ARM 17.8.1212).

B.16. MDU shall burn only pipeline quality natural gas in the emissions unit when burning gaseous fuel to monitor compliance with the emission limit of 50 grains of sulfur/100 cf of gaseous fuel (ARM 17.8.1213).

B.17. MDU shall monitor compliance with emission limits in III.B.5 pursuant to the requirements in 40 CFR Part 75, 40 CFR Part 76 and the NO_X CEMS Appendix G in this permit (ARM 17.8.1212).

B.18. Compliance monitoring for the applicable requirements contained in 40 CFR 72-78 shall be accomplished as described in 40 CFR 72-78 (40 CFR 72-78 and ARM 17.8.1213).

B.19. MDU shall monitor compliance by following the Compliance Assurance Monitoring (CAM) Plan (Appendix I). The CAM Plan, written by MDU in accordance with ARM 17.8.1504 is summarized in Appendix I and is available in full upon request by the Department or the facility (ARM 17.8.1503 and ARM 17.8.1213).

B.20. In order to monitor compliance with the mercury emission limit in III.B.8, a mercury emissions monitoring system (MEMS) shall be installed, certified, and operating on the Unit 1 stack outlet on or before January 1, 2010. Said monitor shall comply with the applicable provisions of 40 CFR Part 75. The MEMS shall also conform to requirements included in Appendix J (ARM 17.8.1213).

B.21. Monitoring compliance with the requirements for the installation and operation of OAI and ACI systems shall be accomplished through recordkeeping (ARM 17.8.1213).

B.22. Compliance monitoring for the operating, reporting, recordkeeping, and notification requirements contained in 40 CFR Part 75 shall be accomplished as described in 40 CFR 75 (ARM 17.8.340 and 40 CFR 75).

Recordkeeping

B.23. MDU shall maintain, on site, an operations and maintenance log which includes the type of fuel fired in the boiler on a daily basis (ARM 17.8.1212).

B.24. All source testing recordkeeping shall be performed in accordance with the Source Test Protocol and Procedures Manual, and shall be maintained on site. Method 9 source test reports for opacity need not be submitted unless requested by the Department (ARM 17.8.106).

B.25. MDU shall maintain, on site, a log of scrubber downtime and maintenance with respect to boiler operations (ARM 17.8.1212).

B.26. MDU shall perform recordkeeping in accordance with the Predictive Opacity Monitoring System Appendix E of this permit (ARM 17.8.1212).

B.27. MDU shall verify that only pipeline quality natural gas is being burned in the boiler by maintaining a log of the Federal Energy Regulatory Commission (FERC) certifications (ARM 17.8.1212).

B.28. MDU shall perform recordkeeping as required in Appendix F and Appendix G of this permit as well as in accordance with 40 CFR Parts 75 and 76, as applicable (ARM 17.8.1212 and 40 CFR Parts 75 and 76).

B.29. MDU shall perform recordkeeping in accordance with 40 CFR 72-78, as applicable and as required by Appendices G and H of this permit (40 CFR 72-78 and ARM 17.8.1212).

B.30. Records shall be prepared and data kept in accordance with 40 CFR Part 64 and the CAM Appendix I of this permit (ARM 17.8.1212 and 40 CFR 64).

B.31. Records shall be prepared and data kept in accordance with 40 CFR Part 75 and the MEMS Appendix J of this permit (ARM 17.8.1212 and 40 CFR 75).

B.32. For any time after January 1, 2010, MDU shall record in a log the date, time, and duration of any incident where the OAI and ACI systems are not maintained or operational (ARM 17.8.1212).

B.33. MDU shall perform recordkeeping in accordance with 40 CFR Part 75 (ARM 17.8.1212 and 40 CFR Part75).

Reporting

B.34. Any compliance source tests shall be submitted in accordance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

B.35. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements (ARM 17.8.1212).

B.36. The semiannual reporting shall provide (ARM 17.8.1212):

a. A summary of results of any source test that was performed during the reporting period;

b. A summary of the log of fuel type used to fire the boiler;

c. A summary of any downtime and maintenance work performed on the wet scrubber;

d. Certification of submittal of the quarterly reports required in Appendices E, F, G, and J ;

e. A summary of compliance with 40 CFR Part 64 and Appendix I of this permit;

f. A summary of the log when the OAI and ACI systems were not maintained or operational: and

g. A summary of compliance with the requirements of 40 CFR 72-78, as applicable.

C. EU06: Fuel (gasoline) Storage Tank

Condition(s)	Pollutant/Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirement
C.1, C.2, C.3, C.4, C.5	40 CFR 63, Subpart CCCCCC	40 CFR 63, Subpart CCCCCC	40 CFR 63, Subpart CCCCCC	Ongoing	Semiannual

Conditions

C.1. MDU shall comply with all applicable standards and limitations, and the applicable operating, reporting, recordkeeping, and notification requirements contained in 40 CFR 63, Subpart CCCCCC (ARM 17.8.340 and 40 CFR 63, Subpart CCCCCC).

Compliance Demonstration

C.2. Compliance monitoring for the operating, reporting, recordkeeping, and notification requirements contained in 40 CFR 63, Subpart CCCCCC shall be accomplished as described in 40 CFR 63, Subpart CCCCCC (ARM 17.8.340 and 40 CFR 63, Subpart CCCCCC).

Recordkeeping

C.3. MDU shall perform recordkeeping in accordance with 40 CFR 63, Subpart CCCCCC (ARM 17.8.1212 and 40 CFR 63, Subpart CCCCCC).

Reporting

C.4. The annual compliance certification required by Section V.B must contain a certification statement for the above applicable requirements (ARM 17.8.1212).

C.5. The semiannual reporting shall provide a summary of compliance with 40 CFR 63, Subpart CCCCCC.

D. EU07: Coal Storage Piles

Condition(s)	Pollutant/Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirement
D.1, D.2, D.3, D.4, D.5, D.6, D.7, D.8	Opacity	40% and Reasonable Precautions	Method 9	Semiannual	Semiannual
			Visual Surveys	Once per Calendar Week	Semiannual

Conditions

D.1. MDU may not cause or authorize emissions from the Coal Storage Piles to be discharged into the outdoor atmosphere that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes (ARM 17.8.304(1)).

D.2. MDU shall not cause or authorize the production, handling, transportation, or storage of any material unless reasonable precautions to control emissions of particulate matter are taken. Such emissions of airborne particulate from any stationary source shall not exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.308(1)).

Compliance Demonstration

D.3 MDU shall conduct either a semiannual Method 9 source test or a weekly visual survey of visible emissions on Coal Storage Piles. Under the visual survey option, once per calendar week, during daylight hours, MDU shall visually survey Coal Storage Piles for any visible emissions. If visible emissions are observed during the visual survey, MDU must take corrective action to contain or minimize the source of emissions. Following the corrective action, MDU shall again visually survey the Coal Storage Piles for any visible emissions. If visible emissions remain, MDU shall conduct a Method 9 source test. The Method 9 source test must begin within one hour of any observation of visible emissions following the corrective action. The person conducting the visual survey shall record the results of the survey (including any corrective action taken and the results of any Method 9 source test performed) in a log, Conducting a visual survey does not relieve MDU of the liability for a violation determined using Method 9 (ARM 17.8.101(27)).

If the visual surveys are not performed once per calendar week as specified above during the reporting period, then MDU shall perform the Method 9 source tests on Coal Storage Piles for that reporting period.

Method 9 source tests must be performed in accordance with the Montana Source Test Protocol and Procedures Manual, except that prior notification of the test is not required. Each observation period must be a minimum of 6 minutes unless any one reading is 20% or greater, then the observation period must be a minimum of 20 minutes or until a violation of the standard has been documented, whichever is a shorter period of time (ARM 17.8.1213).

Recordkeeping

D.4. All source test recordkeeping shall be performed in accordance with the test method used and the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

D.5 If visual surveys are performed, MDU shall maintain a log to verify that the visual surveys were performed as specified in Section III.D.3. Each log entry must include the date, time, results of survey (and results of subsequent Method 9, if applicable), and observer’s initials If any corrective action is required, the time, date, observer’s initials, and any preventive or corrective action taken must be recorded in the log (ARM 17.8.1212).

Reporting

D.6. All source test reports must be submitted to the Department in accordance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

D.7. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements (ARM 17.8.1212).

D.8. The semiannual reporting shall provide (ARM 17.8.1212):

a. A summary of the visual survey log as required by Section III.D.3 or Method 9 source test results, and

b. A summary of the log of corrective actions maintained as required by Section III.D.5.

E. EU08: Fugitive Coal, Ash, and Lime Handling

Condition(s)	Pollutant/Parameter	Permit Limit	Compliance Demonstration Method	Frequency	Reporting Requirement
E.1, E.2, E.3, E.4, E.5, E.6, E.7, E.8	Opacity	40% and Reasonable Precautions	Method 9	Semiannual	Semiannual
			Visual Surveys	Once per Calendar Week	Semiannual

Conditions

E.1. MDU may not cause or authorize emissions from the fugitive coal, ash, and lime handling to be discharged into the outdoor atmosphere that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes (ARM 17.8.304(1)).

E.2. MDU shall not cause or authorize the production, handling, transportation, or storage of any material unless reasonable precautions to control emissions of particulate matter are taken. Such emissions of airborne particulate from any stationary source shall not exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.308(1)).

Compliance Demonstration

E.3 MDU shall conduct either a semiannual Method 9 source test or a weekly visual survey of visible emissions on the coal, ash, and lime handling. Under the visual survey option, once per calendar week, during daylight hours, MDU shall visually survey the coal, ash, and lime handling for any visible emissions. If visible emissions are observed during the visual survey, MDU must take corrective action to contain or minimize the source of emissions. Following the corrective action, MDU shall again visually survey the coal, ash, and lime handling for any visible emissions. If visible emissions remain, MDU shall conduct a Method 9 source test. The Method 9 source test must begin within one hour of any observation of visible emissions following the corrective action. The person conducting the visual survey shall record the results of the survey (including any corrective action taken and the results of any Method 9 source test performed) in a log, Conducting a visual survey does not relieve MDU of the liability for a violation determined using Method 9 (ARM 17.8.101(27)).

If the visual surveys are not performed once per calendar week as specified above during the reporting period, then MDU shall perform the Method 9 source tests on the coal, ash, and lime handling for that reporting period.

Method 9 source tests must be performed in accordance with the Montana Source Test Protocol and Procedures Manual, except that prior notification of the test is not required. Each observation period must be a minimum of 6 minutes unless any one reading is 20% or greater, then the observation period must be a minimum of 20 minutes or until a violation of the standard has been documented, whichever is a shorter period of time (ARM 17.8.1213).

Recordkeeping

E.4. All source test recordkeeping shall be performed in accordance with the test method used and the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

E.5. If visual surveys are performed, MDU shall maintain a log to verify that the visual surveys were performed as specified in Section III.E.3. Each log entry must include the date, time, results of survey (and results of subsequent Method 9, if applicable), and observer's initials If any corrective action is required, the time, date, observer's initials, and any preventive or corrective action taken must be recorded in the log (ARM 17.8.1212).

Reporting

E.6. All source test reports must be submitted to the Department in accordance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

E.7. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements (ARM 17.8.1212).

E.8. The semiannual reporting shall provide (ARM 17.8.1212):

a. A summary of the visual survey log as required by Section III.E.3 or Method 9 source test results; and

b. A summary of the log of corrective actions maintained as specified by Section III.E.5.

SECTION IV. NON-APPLICABLE REQUIREMENTS

Air Quality Administrative Rules of Montana (ARM) and Federal Regulations identified as not applicable to the facility or to a specific emissions unit at the time of the permit issuance are listed below (ARM 17.8.1214). The following list does not preclude the need to comply with any new requirements that may become applicable during the permit term.

A. Facility-Wide

The following table contains non-applicable requirements which are administrated by the Air Resources Management Bureau of the Department of Environmental Quality.

Rule Citation		Reason
State	**Federal**	
ARM 17.8.321, ARM 17.8.323, ARM 17.8.610		These rules are not applicable because the facility is not listed in the source category cited in the rules.
ARM 17.8.320		These rules are not applicable because the facility does not have the specific emissions unit cited in the rules.
	40 CFR 60, Subparts C, Ca, Cb 40 CFR 60, Subparts D, Da, Db, Dc 40 CFR 60, Subparts E-J 40 CFR 60, Subparts K, Ka, Kb 40 CFR 60, Subparts L-Z 40 CFR 60, Subparts AA-EE 40 CFR 60, Subparts GG-HH 40 CFR 60, Subparts KK-NN 40 CFR 60, Subparts PP-XX 40 CFR 60, Subparts AAA-BBB 40 CFR 60, Subpart DDD 40 CFR 60, Subparts FFF-LLL 40 CFR 60, Subparts NNN-VVV 40 CFR 60, Subpart WWW 40 CFR 60, Subparts AAAA-FFFF 40 CFR 60, Subparts IIII-KKKK 40 CFR 61, Subparts B-F 40 CFR 61, Subparts H-L 40 CFR 61, Subparts N-R 40 CFR 61, Subpart T 40 CFR 61, Subparts V-W 40 CFR 61, Subpart Y 40 CFR 61, Subpart BB 40 CFR 61, Subpart FF	These requirements are not applicable because the facility is not an affected source as defined in these regulations.
	40 CFR 63, Subparts F-I 40 CFR 63, Subpart J 40 CFR 63, Subparts L-Q 40 CFR 63, Subparts Q-U 40 CFR 63, Subparts W-Y 40 CFR 63, Subparts AA-EE 40 CFR 63, Subparts GG-MM 40 CFR 63, Subparts OO-YY 40 CFR 63, Subparts CCC-EEE 40 CFR 63, Subparts GGG-JJJ 40 CFR 63, Subparts LLL-RRR	These requirements are not applicable because the facility is not an affected source as defined in these regulations.

Rule Citation		Reason
State	**Federal**	
	40 CFR 63, Subparts TTT-VVV 40 CFR 63, Subpart XXX 40 CFR 63, Subpart AAAA 40 CFR 63, Subparts CCCC-KKKK 40 CFR 63, Subparts MMMM-NNNNN 40 CFR 63, Subparts PPPPP-TTTTT 40 CFR 63, Subpart WWWWW 40 CFR 63, Subparts YYYYY-ZZZZZ 40 CFR 63, Subpart BBBBBB 40 CFR 63, Subparts DDDDDD-HHHHHH 40 CFR 63, Subparts LLLLLL-TTTTTT 40 CFR 63, Subparts WWWWWW-XXXXXX 40 CFR 82, Subparts A-E 40 CFR 82, Subparts G-H	

B. Emission Units

The Operating Permit #OP0691-04 renewal application identified applicable and non-applicable requirements. After review of the application, the Department listed all non-applicable requirements in Section IV.A. These requirements relate to each specific unit, as well as facility wide.

SECTION V. GENERAL PERMIT CONDITIONS

A. Compliance Requirements
ARM 17.8, Subchapter 12, Operating Permit Program §1210(2)(a)-(c)&(e), §1206(6)(c)&(b)

1. The permittee must comply with all conditions of the permit. Any noncompliance with the terms or conditions of the permit constitutes a violation of the Montana Clean Air Act, and may result in enforcement action, permit modification, revocation and reissuance, or termination, or denial of a permit renewal application under ARM Title 17, Chapter 8, Subchapter 12.

2. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

3. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. If appropriate, this factor may be considered as a mitigating factor in assessing a penalty for noncompliance with an applicable requirement if the source demonstrates that both the health, safety or environmental impacts of halting or reducing operations would be more serious than the impacts of continuing operations, and that such health, safety or environmental impacts were unforeseeable and could not have otherwise been avoided.

4. The permittee shall furnish to the Department, within a reasonable time set by the Department (not to be less than 15 days), any information that the Department may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit, or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Department copies of those records that are required to be kept pursuant to the terms of the permit. This subsection does not impair or otherwise limit the right of the permittee to assert the confidentiality of the information requested by the Department, as provided in 75-2-105, MCA.

5. Any schedule of compliance for applicable requirements with which the source is not in compliance with at the time of permit issuance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it was based.

6. For applicable requirements that will become effective during the permit term, the source shall meet such requirements on a timely basis unless a more detailed plan or schedule is required by the applicable requirement or the Department.

B. Certification Requirements
ARM 17.8, Subchapter 12, Operating Permit Program §1207 and §1213(7)(a)&(c)-(d)

1. Any application form, report, or compliance certification submitted pursuant to ARM Title 17, Chapter 8, Subchapter 12, shall contain certification by a responsible official of truth, accuracy and completeness. This certification and any other certification required under ARM Title 17, Chapter 8, Subchapter 12, shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

2. Compliance certifications shall be submitted by February 15 of each year, or more frequently if otherwise specified in an applicable requirement or elsewhere in the permit. Each certification must include the required information for the previous calendar year (i.e., January 1 – December 31).

3. Compliance certifications shall include the following:

   a. The identification of each term or condition of the permit that is the basis of the certification;

   b. The identification of the method(s) or other means used by the owner or operator for determining the status of compliance with each term and condition during the certification period, consistent with ARM 17.8.1212;

   c. The status of compliance with each term and condition for the period covered by the certification, *including whether compliance during the period was continuous or intermittent* (based on the method or means identified in ARM 17.8.1213(7)(c)(ii), as described above); and

   d. Such other facts as the Department may require to determine the compliance status of the source.

4. All compliance certifications must be submitted to the Environmental Protection Agency, as well as to the Department, at the addresses listed in the Notification Addresses Appendix of this permit.

C. Permit Shield

ARM 17.8, Subchapter 12, Operating Permit Program §1214(1)-(4)

1. The applicable requirements and non-federally enforceable requirements are included and specifically identified in this permit and the permit includes a precise summary of the requirements not applicable to the source. Compliance with the conditions of the permit shall be deemed compliance with any applicable requirements and any non-federally enforceable requirements as of the date of permit issuance.

2. The permit shield described in 1 above shall remain in effect during the appeal of any permit action (renewal, revision, reopening, or revocation and reissuance) to the Board of Environmental Review (Board), until such time as the Board renders its final decision.

3. Nothing in this permit alters or affects the following:

   a. The provisions of Sec. 7603 of the FCAA, including the authority of the administrator under that section;

   b. The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;

   c. The applicable requirements of the Acid Rain Program, consistent with Sec. 7651g(a) of the FCAA;

   d. The ability of the administrator to obtain information from a source pursuant to Sec. 7414 of the FCAA;

e. The ability of the Department to obtain information from a source pursuant to the Montana Clean Air Act, Title 75, Chapter 2, MCA;

f. The emergency powers of the Department under the Montana Clean Air Act, Title 75, Chapter 2, MCA; and

g. The ability of the Department to establish or revise requirements for the use of Reasonably Available Control Technology (RACT) as defined in ARM Title 17, Chapter 8. However, if the inclusion of a RACT into the permit pursuant to ARM Title 17, Chapter 8, Subchapter 12, is appealed to the Board, the permit shield, as it applies to the source's existing permit, shall remain in effect until such time as the Board has rendered its final decision.

4. Nothing in this permit alters or affects the ability of the Department to take enforcement action for a violation of an applicable requirement or permit term demonstrated pursuant to ARM 17.8.106, Source Testing Protocol.

5. Pursuant to ARM 17.8.132, for the purpose of submitting a compliance certification, nothing in these rules shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance. However, when compliance or noncompliance is demonstrated by a test or procedure provided by permit or other applicable requirements, the source shall then be presumed to be in compliance or noncompliance unless that presumption is overcome by other relevant credible evidence.

6. The permit shield will not extend to minor permit modifications or changes not requiring a permit revision (see Sections I & J).

7. The permit shield will extend to significant permit modifications and transfer or assignment of ownership (see Sections K & O).

D. Monitoring, Recordkeeping, and Reporting Requirements
ARM 17.8, Subchapter 12, Operating Permit Program §1212(2)&(3)

1. Unless otherwise provided in this permit, the permittee shall maintain compliance monitoring records that include the following information:

   a. The date, place as defined in the permit, and time of sampling or measurement;

   b. The date(s) analyses were performed;

   c. The company or entity that performed the analyses;

   d. The analytical techniques or methods used;

   e. The results of such analyses; and

   f. The operating conditions at the time of sampling or measurement.

2. The permittee shall retain records of all required monitoring data and support information for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit. All monitoring data, support information, and required reports

and summaries may be maintained in computerized form at the plant site if the information is made available to Department personnel upon request, which may be for either hard copies or computerized format. Strip-charts must be maintained in their original form at the plant site and shall be made available to Department personnel upon request.

3. The permittee shall submit to the Department, at the addresses located in the Notification Addresses Appendix of this permit, reports of any required monitoring by February 15 and August 15 of each year, or more frequently if otherwise specified in an applicable requirement or elsewhere in the permit. The monitoring report submitted on February 15 of each year must include the required monitoring information for the period of July 1 through December 31 of the previous year. The monitoring report submitted on August 15 of each year must include the required monitoring information for the period of January 1 through June 30 of the current year. All instances of deviations from the permit requirements must be clearly identified in such reports. All required reports must be certified by a responsible official, consistent with ARM 17.8.1207.

E. Prompt Deviation Reporting
<u>ARM 17.8, Subchapter 12, Operating Permit Program §1212(3)(c)</u>

The permittee shall promptly report deviations from permit requirements, including those attributable to upset conditions as defined in the permit, the probable cause of such deviations, and any corrective actions or preventive measures taken. To be considered prompt, deviations shall be reported to the Department within the following timeframes (unless otherwise specified in an applicable requirement):

1. For deviations which may result in emissions potentially in violation of permit limitations:

    a. An initial phone notification (or faxed or electronic notification) describing the incident within 24 hours (or the next business day) of discovery; and,

    b. A follow-up written, faxed, or electronic report within 30 days of discovery of the deviation that describes the probable cause of the reported deviation and any corrective actions or preventative measures taken.

2. For deviations attributable to malfunctions, deviations shall be reported to the Department in accordance with the malfunction reporting requirements under ARM 17.8.110; and

3. For all other deviations, deviations shall be reported to the Department via a written, faxed, or electronic report within 90 days of discovery (as determined through routine internal review by the permittee).

Prompt deviation reports do not need to be resubmitted with regular semiannual (or other routine) reports, but may be referenced by the date of submittal.

F. Emergency Provisions
<u>ARM 17.8, Subchapter 12, Operating Permit Program §1201(13) and §1214(5), (6)&(8)</u>

1. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation and causes the source to exceed a technology-based emission limitation under this permit due to the unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of reasonable preventive maintenance, careless or improper operation, or operator error.

2. An emergency constitutes an affirmative defense to an action brought for noncompliance with a technology-based emission limitation if the permittee demonstrates through properly signed, contemporaneous logs, or other relevant evidence, that:

   a. An emergency occurred and the permittee can identify the cause(s) of the emergency;

   b. The permitted facility was at the time being properly operated;

   c. During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in the permit; and

   d. The permittee submitted notice of the emergency to the Department within 2 working days of the time when emission limitations were exceeded due to the emergency. This notice fulfills the requirements of ARM 17.8.1212(3)(c). This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

3. These emergency provisions are in addition to any emergency, malfunction or upset provision contained in any applicable requirement.

G. Inspection and Entry
ARM 17.8, Subchapter 12, Operating Permit Program §1213(3)&(4)

1. Upon presentation of credentials and other requirements as may be required by law, the permittee shall allow the Department, the administrator, or an authorized representative (including an authorized contractor acting as a representative of the Department or the administrator) to perform the following:

   a. Enter the premises where a source required to obtain a permit is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;

   b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;

   c. Inspect at reasonable times any facilities, emission units, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and

   d. As authorized by the Montana Clean Air Act and rules promulgated thereunder, sample or monitor, at reasonable times, any substances or parameters at any location for the purpose of assuring compliance with the permit or applicable requirements.

2. The permittee shall inform the inspector of all workplace safety rules or requirements at the time of inspection. This section shall not limit in any manner the Department's statutory right of entry and inspection as provided for in 75-2-403, MCA.

H. Fee Payment
ARM 17.8, Subchapter 12, Operating Permit Program §1210(2)(f) and ARM 17.8, Subchapter 5, Air Quality Permit Application, Operation, and Open Burning Fees §505(3)-(5) (STATE ONLY)

1. The permittee must pay application and operating fees, pursuant to ARM Title 17, Chapter 8, Subchapter 5.

2. Annually, the Department shall provide the permittee with written notice of the amount of the fee and the basis for the fee assessment. The air quality operation fee is due 30 days after receipt of the notice, unless the fee assessment is appealed pursuant to ARM 17.8.511. If any portion of the fee is not appealed, that portion of the fee that is not appealed is due 30 days after receipt of the notice. Any remaining fee, which may be due after the completion of an appeal, is due immediately upon issuance of the Board's decision or upon completion of any judicial review of the Board's decision.

3. If the permittee fails to pay the required fee (or any required portion of an appealed fee) within 90 days of the due date of the fee, the Department may impose an additional assessment of 15% of the fee (or any required portion of an appealed fee) or $100, whichever is greater, plus interest on the fee (or any required portion of an appealed fee), computed at the interest rate established under 15-31-510(3), MCA.

I. Minor Permit Modifications
ARM 17.8, Subchapter 12, Operating Permit Program §1226(3)&(11)

1. An application for a minor permit modification need only address in detail those portions of the permit application that require revision, updating, supplementation, or deletion, and may reference any required information that has been previously submitted.

2. The permit shield under ARM 17.8.1214 will not extend to any minor modifications processed pursuant to ARM 17.8.1226.

J. Changes Not Requiring Permit Revision
ARM 17.8, Subchapter 12, Operating Permit Program §1224(1)-(3), (5)&(6)

1. The permittee is authorized to make changes within the facility as described below, provided the following conditions are met:

   a. The proposed changes do not require the permittee to obtain a Montana Air Quality Permit under ARM Title 17, Chapter 8, Subchapter 7;

   b. The proposed changes are not modifications under Title I of the FCAA, or as defined in ARM Title 17, Chapter 8, Subchapters 8, 9, or 10;

   c. The emissions resulting from the proposed changes do not exceed the emissions allowable under this permit, whether expressed as a rate of emissions or in total emissions;

   d. The proposed changes do not alter permit terms that are necessary to enforce applicable emission limitations on emission units covered by the permit; and

   e. The facility provides the administrator and the Department with written notification at least 7 days prior to making the proposed changes.

2. The permittee and the Department shall attach each notice provided pursuant to 1.e above to their respective copies of this permit.

3. Pursuant to the conditions above, the permittee is authorized to make Section 502(b)(10) changes, as defined in ARM 17.8.1201(30), without a permit revision. For each such change, the written notification required under 1.e above shall include a description of the change within the source, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change.

4. The permittee may make a change not specifically addressed or prohibited by the permit terms and conditions without requiring a permit revision, provided the following conditions are met:

   a. Each proposed change does not weaken the enforceability of any existing permit conditions;

   b. The Department has not objected to such change;

   c. Each proposed change meets all applicable requirements and does not violate any existing permit term or condition; and

   d. The permittee provides contemporaneous written notice to the Department and the administrator of each change that is above the level for insignificant emission units as defined in ARM 17.8.1201(22) and 17.8.1206(3), and the written notice describes each such change, including the date of the change, any change in emissions, pollutants emitted, and any applicable requirement that would apply as a result of the change.

5. The permit shield authorized by ARM 17.8.1214 shall not apply to changes made pursuant to ARM 17.8.1224(3) and (5), but is applicable to terms and conditions that allow for increases and decreases in emissions pursuant to ARM 17.8.1224(4).

K. Significant Permit Modifications
ARM 17.8, Subchapter 12, Operating Permit Program §1227(1), (3)&(4)

1. The modification procedures set forth in 2 below must be used for any application requesting a significant modification of this permit. Significant modifications include the following:

   a. Any permit modification that does not qualify as either a minor modification or as an administrative permit amendment;

   b. Every significant change in existing permit monitoring terms or conditions;

   c. Every relaxation of permit reporting or recordkeeping terms or conditions that limit the Department's ability to determine compliance with any applicable rule, consistent with the requirements of the rule; or

   d. Any other change determined by the Department to be significant.

2. Significant modifications shall meet all requirements of ARM Title 17, Chapter 8, including those for applications, public participation, and review by affected states and the administrator, as they apply to permit issuance and renewal, except that an application for a significant permit modification need only address in detail those portions of the permit application that require revision, updating, supplementation or deletion.

3. The permit shield provided for in ARM 17.8.1214 shall extend to significant modifications.

L. Reopening for Cause
ARM 17.8, Subchapter 12, Operating Permit Program §1228(1)&(2)

This permit may be reopened and revised under the following circumstances:

1. Additional applicable requirements under the FCAA become applicable to the facility when the permit has a remaining term of 3 or more years. Reopening and revision of the permit shall be completed not later than 18 months after promulgation of the applicable requirement. No reopening is required under ARM 17.8.1228(1)(a) if the effective date of the applicable

requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms or conditions have been extended pursuant to ARM 17.8.1220(12) or 17.8.1221(2);

2. Additional requirements (including excess emission requirements) become applicable to an affected source under the Acid Rain Program. Upon approval by the administrator, excess emission offset plans shall be deemed incorporated into the permit;

3. The Department or the administrator determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emission standards or other terms or conditions of the permit; or

4. The administrator or the Department determines that the permit must be revised or revoked and reissued to ensure compliance with the applicable requirements.

M. Permit Expiration and Renewal

ARM 17.8, Subchapter 12, Operating Permit Program §1210(2)(g), §1220(11)&(12), and §1205(2)(d)

1. This permit is issued for a fixed term of 5 years.

2. Renewal of this permit is subject to the same procedural requirements that apply to permit issuance, including those for application, content, public participation, and affected state and administrator review.

3. Expiration of this permit terminates the permittee's right to operate unless a timely and administratively complete renewal application has been submitted consistent with ARM 17.8.1221 and 17.8.1205(2)(d). If a timely and administratively complete application has been submitted, all terms and conditions of the permit, including the application shield, remain in effect after the permit expires until the permit renewal has been issued or denied.

4. For renewal, the permittee shall submit a complete air quality operating permit application to the Department not later than 6 months prior to the expiration of this permit, unless otherwise specified. If necessary to ensure that the terms of the existing permit will not lapse before renewal, the Department may specify, in writing to the permittee, a longer time period for submission of the renewal application. Such written notification must be provided at least 1 year before the renewal application due date established in the existing permit.

N. Severability Clause

ARM 17.8, Subchapter 12, Operating Permit Program §1210(2)(i)&(l)

1. The administrative appeal or subsequent judicial review of the issuance by the Department of an initial permit under this subchapter shall not impair in any manner the underlying applicability of all applicable requirements, and such requirements continue to apply as if a final permit decision had not been reached by the Department.

2. If any provision of a permit is found to be invalid, all valid parts that are severable from the invalid part remain in effect. If a provision of a permit is invalid in one or more of its applications, the provision remains in effect in all valid applications that are severable from the invalid applications.

O. Transfer or Assignment of Ownership
ARM 17.8, Subchapter 12, Operating Permit Program §1225(2)&(4)

1. If an administrative permit amendment involves a change in ownership or operational control, the applicant must include in its request to the Department a written agreement containing a specific date for the transfer of permit responsibility, coverage and liability between the current and new permittee.

2. The permit shield provided for in ARM17.8.1214 shall not extend to administrative permit amendments.

P. Emissions Trading, Marketable Permits, Economic Incentives
ARM 17.8, Subchapter 12, Operating Permit Program §1226(2)

Notwithstanding ARM 17.8.1226(1) and (7), minor air quality operating permit modification procedures may be used for permit modifications involving the use of economic incentives, marketable permits, emissions trading, and other similar approaches, to the extent that such minor permit modification procedures are explicitly provided for in the Montana State Implementation Plan or in applicable requirements promulgated by the administrator.

Q. No Property Rights Conveyed
ARM 17.8, Subchapter 12, Operating Permit Program §1210(2)(d)

This permit does not convey any property rights of any sort, or any exclusive privilege.

R. Testing Requirements
ARM 17.8, Subchapter 1, General Provisions §105

The permittee shall comply with ARM 17.8.105.

S. Source Testing Protocol
ARM 17.8, Subchapter 1, General Provisions §106

The permittee shall comply with ARM 17.8.106.

T. Malfunctions
ARM 17.8, Subchapter 1, General Provisions §110

The permittee shall comply with ARM 17.8.110.

U. Circumvention
ARM 17.8, Subchapter 1, General Provisions §111

The permittee shall comply with ARM 17.8.111.

V. Motor Vehicles
ARM 17.8, Subchapter 3, Emission Standards §325

The permittee shall comply with ARM 17.8.325.

W. Annual Emissions Inventory

ARM 17.8, Subchapter 5, Air Quality Permit Application, Operation and Open Burning Fees §505 (STATE ONLY)

The permittee shall supply the Department with annual production and other information for all emission units necessary to calculate actual or estimated actual amount of air pollutants emitted during each calendar year. Information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request, unless otherwise specified in this permit. Information shall be in the units required by the Department.

X. Open Burning

ARM 17.8, Subchapter 6, Open Burning §604, 605 and 606

The permittee shall comply with ARM 17.8.604, 605 and 606.

Y. Montana Air Quality Permits

ARM 17.8, Subchapter 7, Permit, Construction and Operation of Air Contaminant Sources §745 and 764 (ARM 17.8.745(1) and 764(1)(b) are STATE ENFORCEABLE ONLY until approval by the EPA as part of the SIP)

1. Except as specified, no person shall construct, install, modify or use any air contaminant source or stack associated with any source without first obtaining a permit from the Department or Board. A permit is not required for those sources or stacks as specified by ARM 17.8.744(1)(a)-(k).

2. The permittee shall comply with ARM 17.8.743, 744, 745, 748, and 764.

3. ARM 17.8.745(1) specifies de minimis changes as construction or changed conditions of operation at a facility holding a Montana Air Quality Permit (MAQP) issued under Chapter 8 that does not increase the facility's potential to emit by more than 15 tons per year of any pollutant, except (STATE ENFORCEABLE ONLY until approved by the EPA as part of the SIP):

    a. Any construction or changed condition that would violate any condition in the facility's existing MAQP or any applicable rule contained in Chapter 8 is prohibited, except as provided in ARM 17.8.745(2);

    b. Any construction or changed conditions of operation that would qualify as a major modification under Subchapters 8, 9 or 10 of Chapter 8;

    c. Any construction or changed condition of operation that would affect the plume rise or dispersion characteristic of emissions that would cause or contribute to a violation of an ambient air quality standard or ambient air increment as defined in ARM 17.8.804;

    d. Any construction or improvement project with a potential to emit more than 15 tons per year may not be artificially split into smaller projects to avoid Montana Air Quality Permitting; or

    e. Emission reductions obtained through offsetting within a facility are not included when determining the potential emission increase from construction or changed conditions of operation, unless such reductions are made federally enforceable.

4. Any facility making a de minimis change pursuant to ARM 17.8.745(1) shall notify the Department if the change would include a change in control equipment, stack height, stack diameter, stack gas temperature, source location or fuel specifications, or would result in an increase in source capacity above its permitted operation or the addition of a new emission unit. The notice must be submitted, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include the information requested in ARM 17.8.745(1) (STATE ENFORCEABLE ONLY until approval by the EPA as part of the SIP).

Z. National Emission Standard for Asbestos
<u>40 CFR, Part 61, Subpart M</u>

The permittee shall not conduct any asbestos abatement activities except in accordance with 40 CFR 61, Subpart M (National Emission Standard for Hazardous Air Pollutants for Asbestos).

AA. Asbestos
<u>ARM 17.74, Subchapter 3, General Provisions and Subchapter 4, Fees</u>

The permittee shall comply with ARM 17.74.301, *et seq.*, and ARM 17.74.401, *et seq*. (State only)

BB. Stratospheric Ozone Protection – Servicing of Motor Vehicle Air Conditioners
<u>40 CFR, Part 82, Subpart B</u>

If the permittee performs a service on motor vehicles and this service involves ozone-depleting substance/refrigerant in the motor vehicle air conditioner (MVAC), the permittee is subject to all the applicable requirements as specified in 40 CFR 82, Subpart B.

CC. Stratospheric Ozone Protection – Recycling and Emission Reductions
<u>40 CFR, Part 82, Subpart F</u>

The permittee shall comply with the standards for recycling and emission reductions in 40 CFR 82, Subpart F, except as provided for MVACs in Subpart B:

1. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to §82.156;

2. Equipment used during the maintenance, service, repair or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to §82.158;

3. Persons performing maintenance, service, repair or disposal of appliances must be certified by an approved technical certification program pursuant to §82.161;

4. Persons disposing of small appliances, MVACs and MVAC-like (as defined at §82.152) appliances must comply with recordkeeping requirements pursuant to §82.166;

5. Persons owning commercial or industrial process refrigeration equipment must comply with the leak repair requirements pursuant to §82.156; and

6. Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to §82.166.

DD. Emergency Episode Plan

The permittee shall comply with the requirements contained in Chapter 9.7 of the State of Montana Air Quality Control Implementation Plan.

Each major source emitting 100 tons per year located in a Priority I Air Quality Control Region, shall submit to the Department a legally enforceable Emergency Episode Action Plan (EEAP) that details how the source will curtail emissions during an air pollutant emergency episode. The industrial EEAP shall be in accordance with the Department's EEAP and shall be submitted according to a timetable developed by the Department, following Priority I reclassification.

EE. Definitions

Terms not otherwise defined in this permit or in the Definitions and Abbreviations Appendix of this permit, shall have the meaning assigned to them in the referenced regulations.

Appendix C.1

Control Cost Worksheets

Appendix C.1 - February 2011 Regional Haze Evaluation for Lewis and Clark Generating Station, Montana Dakota Utilities
Table C.1-1 : Control Cost Summary

SO_2 Control Cost Summary

Control Technology	Controled lb SO_2/MMBtu	Controlled Emissions T/y	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton	Incremental Control Cost $/ton	Air Toxic's & AQRV's?	Energy Impacts?	Non-Air Env Impacts?
Spray Dryer Absorber and Baghouse	0.08	151.8	850.3	$66,336,000	$10,055,057	$11,825	$13,220	None	Medium	Solid Waste
Existing Wet Scrubber	0.45	901.9	100.2	$270,000	$138,637	$1,383	NA	None	Low	Waste-water
Dry Sorbent Injection and Baghouse	0.45	901.9	100.2	$15,746,000	$2,840,734	$28,347	NA	None	Medium	Solid Waste
Baseline	0.50	1002.1								

NO_x Control Cost Summary

Control Technology	Controled lb NOx/MMBtu	Controlled Emissions T/y	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton	Incremental Control Cost $/ton	Air Toxic's & AQRV's?	Energy Impacts?	Non-Air Env Impacts?
Selective Catalytic Reduction	0.04	80.2	721.5	$38,976,000	$6,984,376	$9,680	$18,368	Ammonia Slip	Medium	Ammonia in Wastewater Discharge
SNCR + Low NOx Burners with SOFA	0.20	400.9	400.9	$4,531,000	$1,093,962	$2,729	$7,279	Ammonia Slip, Higher CO Emissions	Low	Ammonia in Wastewater Discharge
Selective Non Catalytic Reduction	0.25	501.1	300.6	$2,433,000	$761,654	$2,533	NA	Ammonia Slip	Low	Ammonia in Wastewater Discharge
Low NOx Burners with SOFA	0.25	501.1	300.6	$2,195,000	$364,546	$1,213	NA	Higher CO Emissions	None	None
Baseline	0.40	801.7								

Appendix C.1 - February 2011 Regional Haze Evaluation for Lewis and Clark Generating Station, Montana Dakota Utilities
Table C.1-2 : Labor, Chemical and Utility Costs

Operating Unit: NA | **Study Year** 2011

Item	Unit Cost	Units	Reference Cost	Year	Data Source	Notes
Operating Labor	33.5	$/hr		2006	Heskett Unit II BART Report	
Maintenance Labor	33.5	$/hr		2006	Heskett Unit II BART Report	
Electricity	0.057	$/kwh	0.049	2006	Heskett Unit II BART Report	http://www.eia.doe.gov/emeu/aer/txt/ptb0810.html
Natural Gas	6.85	$/mscf		2005	Average natural gas spot price July 04 - June 05, Henry La Hub.,	WTRG Economics, WWW.wtrg.com/daily/small/ngspot.gig
Water	1.16	$/mgal	1.00	2006	Heskett Unit II BART Report	cost adjusted for 3% inflation
Cooling Water	0.32	$/mgal	0.23	1999	EPA Air Pollution Control Cost Manual, 6th ed. Section 3.1 Ch 1	Ch 1 Carbon Absorbers, 1999 $0.15 - $0.30 Avg of 22.5 and 7 yrs and 3% inflation
Compressed Air	0.37	$/mscf	0.25	1998	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1	Example problem; Dried & Filtered, Ch 1.6 '98 cost adjusted for 3% inflation
Wastewater Disposal Neutralization	1.96	$/mgal	1.50	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $1- $2/1000 gal. Cost adjusted for 3% inflation Sec 6 Ch 3 lists $1.30 - $2.15/1,000 gal
Wastewater Disposal Bio-Treat	4.96	$/mgal	3.80	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1	Ch 1lists $1.00 - $6.00 for municipal treatment, $3.80 is average. Cost adjusted for 3% inflation
Solid Waste Disposal	32.62	$/ton	25.00	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $20 - $30/ton Used $25/ton. Cost adjusted for 3% inflation
Hazardous Waste Disposal	326.19	$/ton	250.00	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $200 - $300/ton Used $250/ton. Cost adjusted for 3% inflation
Waste Transport	0.65	$/ton-mi	0.50	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 3	Example problem. Cost adjusted for 3% inflation
		$/ton				
Chemicals & Supplies						
Lime	0.00	$/ton		2006		
Caustic	334.33	$/ton	280	2005	Hawkins Chemical	50% solution (50 Deg Be) includes delivery
Ammonia	483.59	$/ton	405	2005	Heskett Unit II BART Report	50% solution of urea in water, includes delivery
Hydrated Lime	290.00	$/ton	290.00	2011	MDU data, Feb 9, 2011 email from George Gasper at Lewis and Clark Station	
Trona	158.45	Mscf	145	2008	Solvay Chemical	cost adjusted for 3% inflation
Urea 50% Solution	637.60	$/ton	550.00	2006	Heskett Unit II BART Report	
Aqua Ammonia	0.70	$/lb	0.70	2011	Barr Engineering Data	$1,400/NH3 neat delivered at 19% aqua ammonia
Limestone	68.96	$/ton	65.00	2009	MDU 2009 Reagent Study	
NA						
Catalyst & Replacement Parts						
SCR Catalyst	214	$/ft^3			Sargent & Lundy, SCR Cost Development Methodology, Aug 2010 and CoaLogix Gas Fired Plants SCR Management Considerations Nov 2009 McIlvaine Webinar	
CO Catalyst	650	$/ft^3			Vendor quote if needed	
Catalyst #3		$/ft^3				
Catalyst #4		$/ft^3	**Gas Flow Calculations for SCR**			
Catalyst #5		$/ft^3	123,200	dscfm @ 68º F		
Filter Bags		$/bag	17.5%	Moisture		
Tower Packing		$/ft^3	850	Deg F		
Replacement Parts			252,207	acfm @ 850º F		
Replacement Parts			0.4	NOx in lb/MMBtu		
N/A						
Other						
Sales Tax	6.5	%				
Interest Rate	7.00%					Standard interest rate specified by the US Office of Management and Budget
Operating Information						
Annual Op. Hrs	8760	Hours				Engineering Estimate
Utilization Rate	80%			2011	MDU data - Telephone Call 12/23/2010	
Equipment Life	20	yrs				Engineering Estimate
Design Capacity	572	MMBtu/hr	48	MW	MDU data - Telephone Call 12/23/2010	Basis firing 100% coal
Standardized Flow Rate	149,961	scfm @ 32º F				
Temperature	145	Deg F			June 9, 2010 Stack Test	
Stack O2 Content	4.0%				June 9, 2010 Stack Test	
Moisture Content	23.3%				June 9, 2010 Stack Test	
Actual Flow Rate	171,830	acfm			acfm basis 145°F scrubber exhaust temperature	
Standardized Flow Rate	160,934	scfm @ 68º F				
Dry Std Flow Rate	123,200	dscfm @ 68º F			June 9, 2010 Stack Test + 10%	

Pollutant	Max Emis Lb/Hr	Uncontrolled Conc		
PM10		0.00	gr/dscf	
Total Particulates		0.00	gr/dscf	
Nitrous Oxides (NOx)	229	259	ppm	Basis 0.4 lb NOx/MMBtu
Sulfur Dioxide (SO_2)	286	233	ppm	Baseline Emissions Basis 0.5 lb SO2/MMBtu
Sulfuric Acid Mist		0.000	ppm	0.50 lb SO2/MMBtu
Fluorides		0.0E+00	gr/dscf	0.0 ppb
Volatile Organic Compounds (VOC)		0.0	ppm	
Carbon Monoxide (CO)	53.8	100.0	ppm	188 t/yr CO
Lead (Pb)		0.0E+00	gr/dscf	0 ppb

Enter this data for each emission unit
Enter data for this study (applies to all units)

Appendix C.1 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities
Table C.1-3 SO2 Control Spray Dry Absorber (SDA) with Baghouse FLM Cost Data

Operating Unit: **NA**

Design Capacity	48	MW	Stack/Vent Number	0		**Chemical Engineering**	
Design Capacity	572.0	MMBtu/hr	Standardized Flow Rate	149,961	scfm @ 32º F	**Chemical Plant Cost Index**	
Expected Utilization Rate	80%		Temperature	145	Deg F	2008	NA
Expected Annual Hours of Operation	8,760	Hours	Moisture Content	4.0%		Jan-10	NA
Annual Interest Rate	7.0%		Actual Flow Rate	171,830	acfm	Inflation Adj	NA
Expected Equipment Life	20	yrs	Standardized Flow Rate	160,934	scfm @ 68º F		
			Dry Std Flow Rate	123,200	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			NA
Purchased Equipment (A)			NA
Purchased Equipment Total (B)	15%	of control device cost (A)	NA
Installation - Standard Costs	74%	of purchased equip cost (B)	NA
Installation - Site Specific Costs			NA
Installation Total			NA
Total Direct Capital Cost, DC			NA
Total Indirect Capital Costs, IC	45%	of purchased equip cost (B)	NA
Total Capital Investment (TCI) = DC + IC			**66,336,000**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,078,971
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	8,976,085
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**10,055,057**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Design Cont Eff	Exit Conc.	Conc. Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10	-	-				0.0	-	NA
Total Particulates	-	-				0.0	-	NA
Nitrous Oxides (NOx)	228.8	801.7				801.7	-	NA
Sulfur Dioxide (SO2)	**286.0**	**1,002.1**	**95%**	**0.08**	**lb/MMBtu**	**151.8**	**850.3**	**11,825**
Sulfuric Acid Mist	-	-				0.00	-	NA
Fluorides	-	-				0.0	-	NA
Volatile Organic Compounds (VOC)	-	-				0.0	-	NA
Carbon Monoxide (CO)	53.8	188.4				188.4	-	NA
Lead (Pb)	-	-				0.00	-	NA

Notes & Assumptions

1. Installed emission control equipment costs from Federal Land Managers summary of cost and perofrmance for proposed BART controls. Average Installed spraydryer absorber system and baghouse cost data adjusted to Lewis and Clark Station capacity
2. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
3. Compressed air for baghouse assumed to be 2 scfm / 1000 acfm EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.5.1.8
4. Bag replacement at 10 min/bag EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4 lists replacement times from 5 - 20 min per bag.
5. Hydrated lime consumption 1.50 lb lime / lb SO_2 removed at 1.3:1 stoichiometric ratio Lime:SO2

Appendix C.1 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities
Table C.1-3 SO2 Control Spray Dry Absorber (SDA) with Baghouse FLM Cost Data

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A)			**NA**
Purchased Equipment Costs (A)			
Instrumentation	10%	of control device cost (A)	NA
Freight	5%	of control device cost (A)	NA
Purchased Equipment Total (B)	15%		**NA**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	NA
Handling & erection	50%	of purchased equip cost (B)	NA
Electrical	8%	of purchased equip cost (B)	NA
Piping	1%	of purchased equip cost (B)	NA
Insulation	7%	of purchased equip cost (B)	NA
Painting	4%	of purchased equip cost (B)	NA
Installation Subtotal Standard Expenses	74%		**NA**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**NA**
Total Direct Capital Cost, DC			**NA**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	NA
Construction & field expenses	20%	of purchased equip cost (B)	NA
Contractor fees	10%	of purchased equip cost (B)	NA
Start-up	1%	of purchased equip cost (B)	NA
Performance test	1%	of purchased equip cost (B)	NA
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	NA
Total Indirect Capital Costs, IC	45%	of purchased equip cost (B)	**NA**
Total Capital Investment (TCI) (1)	$1,382	per kW installed	**66,336,000**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**65,979,568**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	33.50	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr	73,365
Supervisor	15%	15% of Operator Costs	11,005
Maintenance			
Maintenance Labor	33.50	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr	36,683
Maintenance Materials	100%	of maintenance labor costs	36,683
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.06	$/kwh, 373 kW-hr, 8760 hr/yr, 80% utilization	149,027
NA	NA		-
Water	1.16	$/mgal, 331 gpm, 8760 hr/yr, 80% utilization	161,346
NA	NA		-
Comp Air (3)	0.37	$/mscf, 2 scfm/kacfm, 8760 hr/yr, 80% utilization	53,052
NA	NA		-
NA	NA		-
SW Disposal (CaSO4)	32.62	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization	100,999
NA	NA		-
NA	NA		-
NA	NA		-
Hydrated Lime	290.00	$/ton, 364 lb/hr, 8760 hr/yr, 80% utilization	369,882
NA	NA		-
NA	NA		-
NA	NA		-
Filter Bags	33.71	$/bag, 3,202 bags, 8760 hr/yr, 80% utilization	86,930
Total Annual Direct Operating Costs			**1,078,971**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	94,641
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,326,720
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	663,360
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	663,360
Capital Recovery	0.0944	for a 20- year equipment life and a 7% interest rate	6,228,004
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**8,976,085**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**10,055,057**

See Summary page for notes and assumptions

Appendix C.1 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities
Table C.1-3 SO2 Control Spray Dry Absorber (SDA) with Baghouse FLM Cost Data

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.00%	
Equipment Life	20	years
CRF	0.0944	

Replacement Catalyst:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	214	$/ft^3
Amount Required	0	ft^3
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:	Filter bags &	cages	
Equipment Life	5	years	
CRF	0.2439		
Rep part cost per unit	NA	$/bag	
Amount Required	3202		
Total Rep Parts Cost	326,397	Cost adjusted for freight & sales tax	
Installation Labor (4)	30,035	10 min per bag, Labor + Overhead (68% = $29.65/hr)	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**356,432**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag.
Annualized Cost	**86,930**		

Electrical Use	Flow acfm		D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse (2)	171,830		12			373.2	EPA Cont Cost Manual 6th ed Section 6 Chapter 1 Eq 1.14
Baghouse Shaker	0.0	Gross fabric area ft^2				0	
Other							
Other							
Other							
Other							
Other							
Total						373.2	

Baghouse Filter Cost						
						See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Gross BH Filter Area	42,958	ft^2 ~4:1 air:cloth ratio assumed to determine baghouse area				
Cages	10 ft long	5 in dia	13.42 area/cage ft^2	3202 Cages	11.036	$/cage
Bags	1.69	$/ft2 of fabric			22.68	$/bag
Total					33.711	
Lime Use Rate (5)	1.5	lb lime/lb SO2 removed	364 lb/hr Lime			
	242.7	lb/hr SO2 Reduction				

Operating Cost Calculations — **Annual hours of operation:** **8,760**; **Utilization Rate:** **80.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	33.50	$/Hr	2.0	hr/8 hr shift	2,190	73,365	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr
Supervisor	15%	of Op.			NA	11,005	15% of Operator Costs
Maintenance							
Maint Labor	33.50	$/Hr	1.0	hr/8 hr shift	1,095	36,683	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	36,683	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.057	$/kwh	373.2	kW-hr	2,615,495	149,027	$/kwh, 373 kW-hr, 8760 hr/yr, 80% utilization
Natural Gas	6.85	$/mscf	0	scfm	0	0	$/mscf, 0 scfm, 8760 hr/yr, 80% utilization
Water	1.16	$/mgal	331.0	gpm	139,179	161,346	$/mgal, 331 gpm, 8760 hr/yr, 80% utilization
Cooling Water	0.32	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
Comp Air (3)	0.37	$/mscf	2	scfm/kacfm	144,502	53,052	$/mscf, 2 scfm/kacfm, 8760 hr/yr, 80% utilization
WW Treat Neutralizatior	1.96	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
WW Treat Biotreatemen	4.96	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
SW Disposal (CaSO4)	32.62	$/ton	0.4	ton/hr	3,096	100,999	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
Haz W Disp	326	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
Waste Transport	0.65	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8760 hr/yr, 80% utilization
Waste Recycle	0.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
Hydrated Lime	290.00	$/ton	364	lb/hr	1,275	369,882	$/ton, 364 lb/hr, 8760 hr/yr, 80% utilization
Caustic	334.33	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8760 hr/yr, 80% utilization
Trona	158.45	Mscf	0.0	Mscf/hr	0	0	Mscf, 0 Mscf/hr, 8760 hr/yr, 80% utilization
SCR Catalyst	214.29	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8760 hr/yr, 80% utilization
Filter Bags	33.71	$/bag	3202	bags	NA	86,930	$/bag, 3,202 bags, 8760 hr/yr, 80% utilization

*annual use rate is in same units of measurement as the unit cost factor

Appendix C.1 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities
Table C.1-4 SO2 Control Dry Sorbent Injection (DSI) with Baghouse FLM Cost Data

Operating Unit: **NA**

Design Capacity	48	MW	Stack/Vent Number	0		**Chemical Engineering**	
Design Capacity	572.0	MMBtu/hr	Standardized Flow Rate	149,961	scfm @ 32º F	**Chemical Plant Cost Index**	
Expected Utilization Rate	80%		Temperature	145	Deg F	2004	444.2
Expected Annual Hours of Operation	8,760	Hours	Moisture Content	4.0%		Aug-10	521.9
Annual Interest Rate	7.0%		Actual Flow Rate	171,830	acfm	Inflation Adj	1.17
Expected Equipment Life	20	yrs	Standardized Flow Rate	160,934	scfm @ 68º F		
			Dry Std Flow Rate	123,200	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A) (Baghouse)			3,618,757
Purchased Equipment Total (B)	15%	of control device cost (A)	**4,161,571**
Installation - Standard Costs	74%	of purchased equip cost (B)	3,079,562
Installation - Site Specific Costs			NA
Installation Total			3,079,562
Total Direct Capital Cost, DC			7,241,133
Total Indirect Capital Costs, IC	45%	of purchased equip cost (B)	1,872,707
Total Capital Investment (TCI) = DC + IC			**15,746,000**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	663,587
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	2,177,147
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,840,734**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Design Cont Eff	Exit Conc.	Conc. Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10	-	-				0.0	-	NA
Total Particulates	-	-				0.0	-	NA
Nitrous Oxides (NOx)	228.8	801.7				801.7	-	NA
Sulfur Dioxide (SO2)	**286.0**	**1,002.1**	**70%**	**0.45**	**lb/MMBtu**	**901.9**	**100.2**	**28,347**
Sulfuric Acid Mist	-	-				0.00	-	NA
Fluorides	-	-				0.0	-	NA
Volatile Organic Compounds (VOC)	-	-				0.0	-	NA
Carbon Monoxide (CO)	53.8	188.4				188.4	-	NA
Lead (Pb)	-	-				0.00	-	NA

Notes & Assumptions

1 Installed emission control equipment costs from Federal Land Manager Summary of Cost and perofrmance for proposed BART controls. Installed sorbent injection system cost data Dominion in Kincaid, IL adjusted to Lewis and Clark Station capacity. Installed baghouse cost per 2004 Sargent and Lundy cost estimate

2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

3 Compressed air for baghouse assumed to be 2 scfm / 1000 acfm EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.5.1.8

4 Bag replacement at 10 min/bag EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4 lists replacement times from 5 - 20 min per bag.

5 Hydrated lime consumption 1.50 lb lime / lb SO_2 removed at 1.3:1 stoichiometric ratio Lime:SO2

6

7

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Appendix C.1 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities
Table C.1-4 SO2 Control Dry Sorbent Injection (DSI) with Baghouse FLM Cost Data

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**3,618,757**
Purchased Equipment Costs (A)			
Instrumentation	10%	of control device cost (A)	361,876
Freight	5%	of control device cost (A)	180,938
Purchased Equipment Total (B)	15%		**4,161,571**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	166,463
Handling & erection	50%	of purchased equip cost (B)	2,080,785
Electrical	8%	of purchased equip cost (B)	332,926
Piping	1%	of purchased equip cost (B)	41,616
Insulation	7%	of purchased equip cost (B)	291,310
Painting	4%	of purchased equip cost (B)	166,463
Installation Subtotal Standard Expenses	74%		**3,079,562**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**3,079,562**
Total Direct Capital Cost, DC			**7,241,133**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	416,157
Construction & field expenses	20%	of purchased equip cost (B)	832,314
Contractor fees	10%	of purchased equip cost (B)	416,157
Start-up	1%	of purchased equip cost (B)	41,616
Performance test	1%	of purchased equip cost (B)	41,616
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	124,847
Total Indirect Capital Costs, IC	45%	of purchased equip cost (B)	**1,872,707**
Baghouse Installed Cost (1)			9,113,840
Dry Sorbent Inj Intalled Cost (1)	$123	per kW installed Dry Sorbent Injection	5,904,000
Total Capital Investment (TCI) + Retrofit Factor			**15,746,000**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**15,389,568**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	33.50	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr	73,365
Supervisor	15%	15% of Operator Costs	11,005
Maintenance			
Maintenance Labor	33.50	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr	36,683
Maintenance Materials	100%	of maintenance labor costs	36,683
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.06	$/kwh, 373 kW-hr, 8760 hr/yr, 80% utilization	149,027
NA	NA		-
Water	1.16	$/mgal, 331 gpm, 8760 hr/yr, 80% utilization	161,346
NA	NA		-
Comp Air (3)	0.37	$/mscf, 2 scfm/kacfm, 8760 hr/yr, 80% utilization	53,052
NA	NA		-
NA	NA		-
SW Disposal (CaSO4)	32.62	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization	11,903
NA	NA		-
NA	NA		-
NA	NA		-
Hydrated Lime	290.00	$/ton, 43 lb/hr, 8760 hr/yr, 80% utilization	43,593
NA	NA		-
NA	NA		-
NA	NA		-
Filter Bags	33.71	$/bag, 3,202 bags, 8760 hr/yr, 80% utilization	86,930
Total Annual Direct Operating Costs			**663,587**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	94,641
Administration (2% total capital costs)	2%	of total capital costs (TCI)	314,920
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	157,460
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	157,460
Capital Recovery	0.0944	for a 20- year equipment life and a 7% interest rate	1,452,666
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**2,177,147**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,840,734**

See Summary page for notes and assumptions

Appendix C.1 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities
Table C.1-4 SO2 Control Dry Sorbent Injection (DSI) with Baghouse FLM Cost Data

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.00%	
Equipment Life	20	years
CRF	0.0944	

Replacement Catalyst:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	214	$/ft^3
Amount Required	0	ft^3
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:	**Filter bags & cages**		
Equipment Life	5	years	
CRF	0.2439		
Rep part cost per unit	NA	$/bag	
Amount Required	3202		
Total Rep Parts Cost	326,397	Cost adjusted for freight & sales tax	
Installation Labor (4)	30,035	10 min per bag, Labor + Overhead (68% = $29.65/hr)	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**356,432**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag.
Annualized Cost	**86,930**		

Electrical Use	Flow acfm		D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse (2)	171,830		12			373.2	
Baghouse Shaker	0.0	Gross fabric area ft^2				0	EPA Cont Cost Manual 6th ed Section 6 Chapter 1 Eq 1.14
Other							
Other							
Other							
Other							
Other							
Total						373.2	

Baghouse Filter Cost						
						See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Gross BH Filter Area	42,958	ft^2 - 4:1 air:cloth ratio assumed to determine baghouse area				
Cages	10 ft long	5 in dia	13.42 area/cage ft^2	3202 Cages	11.036	$/cage
Bags	1.69	$/ft2 of fabric			22.68	$/bag
Total					33.711	
Lime Use Rate (5)	1.5	lb lime/lb SO2 removed		43 lb/hr Lime		
	28.6	lb/hr SO2 Reduction				

Operating Cost Calculations — **Annual hours of operation: 8,760** — **Utilization Rate: 80.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	33.50	$/Hr	2.0	hr/8 hr shift	2,190	73,365	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr
Supervisor	15%	of Op.			NA	11,005	15% of Operator Costs
Maintenance							
Maint Labor	33.50	$/Hr	1.0	hr/8 hr shift	1,095	36,683	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	36,683	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.057	$/kwh	373.2	kW-hr	2,615,495	149,027	$/kwh, 373 kW-hr, 8760 hr/yr, 80% utilization
Natural Gas	6.85	$/mscf	0	scfm	0	0	$/mscf, 0 scfm, 8760 hr/yr, 80% utilization
Water	1.16	$/mgal	331.0	gpm	139,179	161,346	$/mgal, 331 gpm, 8760 hr/yr, 80% utilization
Cooling Water	0.32	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
Comp Air (3)	0.37	$/mscf	2	scfm/kacfm	144,502	53,052	$/mscf, 2 scfm/kacfm, 8760 hr/yr, 80% utilization
WW Treat Neutralizatior	1.96	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
WW Treat Biotreatemen	4.96	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
SW Disposal (CaSO4)	32.62	$/ton	0.1	ton/hr	365	11,903	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
Haz W Disp	326	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
Waste Transport	0.65	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8760 hr/yr, 80% utilization
Waste Recycle	0.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
Hydrated Lime	290.00	$/ton	43	lb/hr	150	43,593	$/ton, 43 lb/hr, 8760 hr/yr, 80% utilization
Caustic	334.33	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8760 hr/yr, 80% utilization
Trona	158.45	Mscf	0.0	Mscf/hr	0	0	Mscf, 0 Mscf/hr, 8760 hr/yr, 80% utilization
SCR Catalyst	214.29	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8760 hr/yr, 80% utilization
Filter Bags	33.71	$/bag	3202	bags	NA	86,930	$/bag, 3,202 bags, 8760 hr/yr, 80% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Appendix C.1 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities
Table C.1-5 SO2 Control Increase Existing Wet Scrubber Efficiency

Operating Unit: **NA**

Design Capacity	48	MW	Stack/Vent Number	0	
Design Capacity	572	MMBtu/hr	Standardized Flow Rate	149,961	scfm @ 32º F
Expected Utilization Rate	80%		Temperature	145	Deg F
Expected Annual Hours of Operation	8,760	Hours	Moisture Content	23.3%	
Annual Interest Rate	7.0%		Actual Flow Rate	171,830	0
Expected Equipment Life	20	yrs	Standardized Flow Rate	160,934	acfm
			Dry Std Flow Rate	123,200	scfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs									
Direct Capital Costs									
Purchased Equipment (A)									NA
Purchased Equipment Total (B)	22%	of control device cost (A)							NA
									NA
Installation - Standard Costs	85%	of purchased equip cost (B)							
Installation - Site Specific Costs									NA
Installation Total									NA
Total Direct Capital Cost, DC									NA
Total Indirect Capital Costs, IC	35%	of purchased equip cost (B)							NA
Total Capital Investment (TCI) = DC + IC									270,000
Operating Costs									
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.							77,810
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost							60,827
Total Annual Cost (Annualized Capital Cost + Operating Cost)									**138,637**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Design Cont Eff	Exit Conc.	Conc. Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10	-	-				0.0	-	NA
Total Particulates	-	-				0.0	-	NA
Nitrous Oxides (NOx)	228.8	801.7				801.7	-	NA
Sulfur Dioxide (SO_2)	**286.0**	**1,002.1**	**70%**	**0.45**	**lb/MMBtu**	**901.9**	**100.2**	**1,383**
Sulfuric Acid Mist	-	-				0.0	-	NA
Fluorides	-	-				-	-	NA
Volatile Organic Compounds (VOC)	-	-				0.0	-	NA
Carbon Monoxide (CO)	53.8	188.4				188.4	-	NA
Lead (Pb)	-	-				0.00	-	NA

Notes & Assumptions

1. Sargent and Lundy installed cost estimate for lime silo upgrade needed to increase existing wet scrubber SO_2 control efficiency
2. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1
3. Hydrated lime consumption 1.27 lb lime / lb SO_2 removed at 1.1:1 stoichiometric ratio Lime:SO2

Appendix C.1 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities
Table C.1-5 SO2 Control Increase Existing Wet Scrubber Efficiency

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A)			**NA**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC			
Instrumentation	10%	of control device cost (A)	NA
MN Sales Taxes	6.5%	of control device cost (A)	NA
Freight	5%	of control device cost (A)	**NA**
Purchased Equipment Total (B)	22%		
Installation			NA
Foundations & supports	12%	of purchased equip cost (B)	NA
Handling & erection	40%	of purchased equip cost (B)	NA
Electrical	1%	of purchased equip cost (B)	NA
Piping	30%	of purchased equip cost (B)	NA
Insulation	1%	of purchased equip cost (B)	NA
Painting	1%	of purchased equip cost (B)	**NA**
Installation Subtotal Standard Expenses	85%		
			NA
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			**NA**
Installation Total			**NA**
Total Direct Capital Cost, DC			
Indirect Capital Costs			NA
Engineering, supervision	10%	of purchased equip cost (B)	NA
Construction & field expenses	10%	of purchased equip cost (B)	NA
Contractor fees	10%	of purchased equip cost (B)	NA
Start-up	1%	of purchased equip cost (B)	NA
Performance test	1%	of purchased equip cost (B)	NA
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	NA
Total Indirect Capital Costs, IC	35%	of purchased equip cost (B)	**NA**
Total Capital Investment (TCI) = DC + IC (1)			**270,000**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**270,000**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	33.50	\$/Hr, 0.1 hr/8 hr shift, 8760 hr/yr	3,668
Supervisor	15%	15% of Operator Costs	550
Maintenance			
Maintenance Labor	33.50	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr	18,341
Maintenance Materials	100%	of maintenance labor costs	18,341
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Hydrated Lime	290.00	\$/ton, 36 lb/hr, 8760 hr/yr, 80% utilization	36,909
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**77,810**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	24,541
Administration (2% total capital costs)	2%	of total capital costs (TCI)	5,400
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	2,700
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	2,700
Capital Recovery	0.0944	for a 20- year equipment life and a 7% interest rate	25,486
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**60,827**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**138,637**

See Summary page for notes and assumptions

Appendix C.1 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities
Table C.1-5 SO2 Control Increase Existing Wet Scrubber Efficiency

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.00%	
Equipment Life	20	years
CRF	0.0944	

Replacement Catalyst:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	214	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3811		
Rep part cost per unit	0	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		D P in H2O	**Efficiency**	**Hp**	**kW**	
Blower, Scrubber (2)	171,830		8.55	0.7	-	245.6	EPA Cont Cost Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	**Liquid SPGR**	**D P ft H2O**	**Efficiency**	**Hp**	**kW**	
Circ Pump	1,718 gpm	1	60	0.7	-	27.7	EPA Cont Cost Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	0 gpm	1	60	0.7	-	0.0	EPA Cont Cost Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
Other							
Other							
Other							
Total						0.0	Net power cost 0, no increase in electric use.

Reagent Use & Other Operating Costs					
Overall Control Eff	70%		SO2 Controlled by Lime	29 lb/hr SO2	
Lime Use (3)	1.27	lb Lime/lb SO2	36 lb/hr Lime		
Liquid/Gas ratio	10.0	* L/G = Gal/1,000 acf			
Circulating Water Rate	1,718	gpm			
Water Makeup Rate/WW Disch =		NA	of circulating water rate =	0 gpm	No change in water use assumed

Operating Cost Calculations			**Annual hours of operation:**			**8,760**	
			Utilization Rate:			**80.0%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	33.5	$/Hr	0.10	hr/8 hr shift	110	3,668	$/Hr, 0.1 hr/8 hr shift, 8760 hr/yr
Supervisor	15%	of Op.			NA	550	15% of Operator Costs
Maintenance							
Maint Labor	33.50	$/Hr	0.5	hr/8 hr shift	548	18,341	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	18,341	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.057	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 8760 hr/yr, 80% utilization
Natural Gas	6.85	$/mscf	0	scfm	0	0	$/mscf, 0 scfm, 8760 hr/yr, 80% utilization
Water	1.16	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
Cooling Water	0.32	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
Comp Air	0.37	$/mscf	0	Mscfm	0	0	$/mscf, 0 Mscfm, 8760 hr/yr, 80% utilization
WW Treat Neutralizatior	1.96	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
WW Treat Biotreatemen	4.96	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
SW Disposal	32.62	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
Haz W Disp	326	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
Waste Transport	0.65	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8760 hr/yr, 80% utilization
Waste Recycle	0.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
Hydrated Lime	290.00	$/ton	36.3	lb/hr	127	36,909	$/ton, 36 lb/hr, 8760 hr/yr, 80% utilization
Caustic	334.33	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8760 hr/yr, 80% utilization
Trona	158.45	Mscf	0.0	Mscf/hr	0	0	Mscf, 0 Mscf/hr, 8760 hr/yr, 80% utilization
SCR Catalyst	214.29	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8760 hr/yr, 80% utilization
N/A	0.00	0	0		0	0	0, 0 , 8760 hr/yr, 80% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Appendix C.1 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities
Table C.1-6: Selective Catalytic Reduction (SCR) FLM $/KW Calculation

Operating Unit: **NA**

						Chemical Engineering Chemical Plant Cost Index	
Design Capacity	48	MW	Stack/Vent Number	0			
Design Capacity	572	MMBtu/hr	Standardized Flow Rate	149,961	scfm @ 32° F		
Expected Utilization Rate	80%		Temperature	850	Deg F	1998/1999	390
Expected Annual Hours of Operation	8,760	17.5%	Moisture Content	4.0%	Oxygen	Jul-10	550.7
Annual Interest Rate	7.0%		Actual Flow Rate	252,207	acfm @ 850° F	Inflation Adj	1.41
Expected Equipment Life	20	yrs	Standardized Flow Rate	160,934	scfm @ 68° F		
			Dry Std Flow Rate	123,200	dscfm @ 68° F		

CONTROL EQUIPMENT COSTS

Capital Costs			Duty MMBtu/hr	Control Eff	NOx in lb/MMBtu			
Direct Capital Costs	EPRI Correlation		572	90%	0.40			NA
Purchased Equipment (A)								NA
Purchased Equipment Total (B)	22%	of control device cost (A)						**NA**
Installation - Standard Costs	15%	of purchased equip cost (B)						NA
Installation - Site Specific Costs								0
Installation Total								NA
Total Direct Capital Cost, DC								0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)						0
Total Capital Investment (TCI) = DC + IC								**NA**
Total Capital Investment (TCI) + Retrofit								**38,976,000**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						1,153,201
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						5,831,176
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**6,984,376**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc.**	**Conc. Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	-	-				0.0	-	NA
Total Particulates	-	-				0.0	-	NA
Nitrous Oxides (NOx)	**228.8**	**801.7**	**90%**	**0.04**	**lb/MMBtu**	**80.2**	**721.5**	**9,680**
Sulfur Dioxide (SO2)	286.0	1,002.1				1002.1	-	NA
Sulfuric Acid Mist	-	-				0.0	-	NA
Fluorides	-	-				0.0	-	NA
Volatile Organic Compounds (VOC)	-	-				0.0	-	NA
Carbon Monoxide (CO)	53.8	188.4				188.4	-	NA
Lead (Pb)	-	-				0.0	-	NA

Notes & Assumptions

1 Installed emission control equipment costs from Federal Land Manager Summary of Cost and perofrmance for proposed BART controls. Average installed selective catalytic reduction system cost data adjusted to Lewis and Clark Station capacity. Installed baghouse cost per 2004 Sargent and Lundy cost estimate
2 Reagent Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.32 - 2.35
3 SCR Catalyst Volume per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.18 - 2.24
4 SCR Catalyst Replacement per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.50 - 2.53
5 SCR Electrical Demand per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.48
6 SCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.46

Appendix C.1 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities
Table C.1-6: Selective Catalytic Reduction (SCR) FLM $/KW Calculation

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC			**NA**
Instrumentation	10%	of control device cost (A)	NA
MN Sales Taxes	**7.0%**	**of control device cost (A)**	NA
Freight	5%	of control device cost (A)	NA
Purchased Equipment Total (A)	22%		**NA**
Indirect Installation			
General Facilities	5%	of purchased equip cost (A)	NA
Engineering & Home Office	10%	of purchased equip cost (A)	NA
Process Contingency	5%	of purchased equip cost (A)	NA
Total Indirect Installation Costs (B)	20%	of purchased equip cost (A)	**NA**
Project Contingency (C)	15%	of (A + B)	**NA**
Total Plant Cost D		A + B + C	**NA**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E))	**NA**
Inventory Capital		Reagent Vol * $/gal	**18,823**
Initial Catalyst and Chemicals		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**NA**
Retrofit Factor	30%	of TCI	NA
Installed Cost			
Total Capital Investment (TCI) (1)	$812	per kW installed	**38,976,000**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**NA**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	33.50	$/Hr, 0.2 hr/8 hr shift, 8760 hr/yr	7,337
Supervisor	15%	15% of Operator Costs	1,100
Maintenance			
Maintenance Total (6)	1.50	1.5% of Total Capital Investment	584,640
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.06	$/kwh, 232 kW-hr, 8760 hr/yr, 80% utilization	92,803
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Aqua Ammonia	0.70	$/lb, 80 lb/hr, 8760 hr/yr, 80% utilization	392,593
NA	NA		-
SCR Catalyst	214.29	$/ft3, 0 , 8760 hr/yr, 80% utilization	74,728
NA	NA		-
Total Annual Direct Operating Costs			**1,153,201**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	593,077
Administration (2% total capital costs)	2%	of total capital costs (TCI)	779,520
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	389,760
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	389,760
Capital Recovery	0.0944	for a 20- year equipment life and a 7% interest rate	3,679,059
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**5,831,176**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**6,984,376**

See Summary page for notes and assumptions

Appendix C.1 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities
Table C.1-6: Selective Catalytic Reduction (SCR) FLM $/KW Calculation

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.00%	
Equipment Life	20	yrs
CRF	0.0944	

Replacement Catalyst (4)				
Equipment Life	24,000	hours		
FCW	0.3111			
Rep part cost per unit	214	$/ft^3	# of Layers	3
Replacement Factor	3	Layers replaced per year =		1
Amount Required	1,121	ft^3		
Catalyst Cost	240,242			
Y catalyst life factor	3	Years		
Annualized Cost	**74,728**			

SCR Catalyst Volume (3)								
Duty	572	MMBtu/hr	Catalyst Area	263	ft^2		167	*f* (h SCR)
Q flue gas	252,207	acfm	Rx Area	302			193	*f* (h NH_3)
NOx Cont Eff	90%	(as faction)	Rx Height	17.4	ft		0	*f* (h New) new= -728, Retrofit = 0
NOx in	0.40	lb/MMBtu	n layer	3	layers	Y		Bypass? Y or N
Ammonia Slip	2	ppm	h layer	5.3	ft		127	*f* (h Bypass)
Fuel Sulfur	0.5	wt % (as %)	n total	4	layers		807,212	*f* (vol catalyst)
Temperature	850	Deg F	h SCR	58	ft			*f* (h SCR)
Catalyst Volume	**3,363**	ft^3	New/Retrofit	N	N or R			

Electrical Use (5)					
Duty	572	MMBtu/hr			kW
NOx Cont Eff	90%	(as faction)		Power	232.4
NOx in	0.40	lb/MMBtu			
n catalyst layers	4	layers			
Press drop catalyst	1	in H_2O per layer			
Press drop duct	3	in H_2O			
Total					232.4

Reagent Use & Other Operating Costs (2)			Ammonia Use				
NOx in	0.40	lb/MMBtu		80	lb/hr Neat	1.05	Stoichiometric Ratio
Efficiency	90%			19%	solution	56.0	lb/ft^3 Density
Duty	572	MMBtu/hr		421	lb/hr	56.3	gal/hr
			Volume 14 day inventory	18,906	gal	$18,823	Inventory Cost

Operating Cost Calculations		
	Annual hours of operation:	**8,760**
	Utilization Rate:	**80.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	33.5	$/Hr	0.2	hr/8 hr shift	219	7,337	$/Hr, 0.2 hr/8 hr shift, 8760 hr/yr
Supervisor	15%	of Op.			NA	1,100	15% of Operator Costs
Maintenance							
Maintenance Total (6)	1.5	% of Total Capital Investment				584,640	1.5% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.057	$/kwh	232.4	kW-hr	1,628,748	92,803	$/kwh, 232 kW-hr, 8760 hr/yr, 80% utilization
Natural Gas	6.85	$/mscf	0.0	scfh	0	0	$/mscf, 0 scfh, 8760 hr/yr, 80% utilization
Water	1.16	$/mgal	0.0	gph	0	0	$/mgal, 0 gph, 8760 hr/yr, 80% utilization
Cooling Water	0.32	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
Comp Air	0.37	$/mscf	0.0	scfm/kacfm**	0	0	$/mscf, 0 scfm/kacfm**, 8760 hr/yr, 80% utilization
WW Treat Neutralization	1.96	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
WW Treat Biotreatement	4.96	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
SW Disposal	326.19	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
Haz W Disp	1	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8760 hr/yr, 80% utilization
N/A	0.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
N/A	0.00	0.00	0.0	ton/hr	0	0	0, 0 ton/hr, 8760 hr/yr, 80% utilization
Lime	0.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8760 hr/yr, 80% utilization
Aqua Ammonia	0.70	$/lb	80	lb/hr	560,847	392,593	$/lb, 80 lb/hr, 8760 hr/yr, 80% utilization
Trona	158.45	Mscf	0.0	Mscf/hr	0	0	Mscf, 0 Mscf/hr, 8760 hr/yr, 80% utilization
SCR Catalyst	214.29	$/ft3				74,728	$/ft3, 0 , 8760 hr/yr, 80% utilization
N/A	0	0	0	0	0	0	0, 0 0, 8760 hr/yr, 80% utilization
		** Std Air use is 2 scfm/kacfm			*annual use rate is in same units of measurement as the unit cost factor		

See Summary page for notes and assumptions

Appendix C.1 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities
Table C.1-7 - Level 3 Low NOx Burners with SOFA and Selective Non-Catalytic Reduction

Operating Unit: **NA**

Design Capacity	48	MW	Stack/Vent Number	0		**Chemical Engineering**
Design Capacity	572.0		Standardized Flow Rate	149,961	scfm @ 32º F	**Chemical Plant Cost Index**
Expected Utilization Rate	80%		Temperature	145	Deg F	1998/1999 390
Expected Annual Hours of Operation	8,760	Hours	Moisture Content	4.0%		Jul-10 550.7
Annual Interest Rate	7.0%		Actual Flow Rate	171,830	acfm	Inflation Adj 1.41
Expected Equipment Life	20	yrs	Standardized Flow Rate	160,934	scfm @ 68º F	
			Dry Std Flow Rate	123,200	dscfm @ 68º F	

CONTROL EQUIPMENT COSTS

Capital Costs			Duty MMBtu/hr	Control Eff	NOx in lb/MMBtu		Year	
Direct Capital Costs	EPRI Correlation, 1998 $'s		572	25%	0.40		1998	NA
Purchased Equipment (A)							2010	NA
Purchased Equipment Total (B)	0%	of control device cost (A)						**NA**
Installation - Standard Costs	15%	of purchased equip cost (B)						0
Installation - Site Specific Costs								0
Installation Total								0
Total Direct Capital Cost, DC								0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)						0
Total Capital Investment (TCI) = DC + IC								**4,531,000**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						444,249
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						649,713
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**1,093,962**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Cont Eff %	Exit Conc.	Conc. Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10	-	-				0.0	-	NA
Total Particulates	-	-				0.0	-	NA
Nitrous Oxides (NOx)	**228.8**	**801.7**	**50%**	**0.20**	**lb NOx/MMbtu**	**400.9**	**400.9**	**2,729**
Sulfur Dioxide (SO2)	286.0	1,002.1				1002.1	-	NA
Sulfuric Acid Mist	-	-				0.0	-	NA
Fluorides	-	-				0.0	-	NA
Volatile Organic Compounds (VOC)	-	-				0.0	-	NA
Carbon Monoxide (CO)	53.8	188.4				188.4	-	NA
Lead (Pb)	-	-				0.0	-	NA

Notes & Assumptions

1 "Conceptual Design Study for NOx Reduction Tehcnologies" March, 2011 A site specifice enginieering and cost evaluation prepared by Sargent and Lundy, LLC
2 Reagent Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.22
3 Water use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.25
4 Additional Fuel Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.29
5 SNCR Electrical Demand per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.23
6 SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21

Appendix C.1 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities
Table C.1-7 - Level 3 Low NOx Burners with SOFA and Selective Non-Catalytic Reduction

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A)			
Purchased Equipment Costs (A)			**NA**
Instrumentation	10%	of control device cost (A)	NA
Freight	5%	of control device cost (A)	NA
Purchased Equipment Total (A)			**NA**
Indirect Installation			
General Facilities	5%	of purchased equip cost (A)	**NA**
Engineering & Home Office	10%	of purchased equip cost (A)	**NA**
Process Contingency	5%	of purchased equip cost (A)	**NA**
Total Indirect Installation Costs (B)	20%	of purchased equip cost (A)	**NA**
Project Contingency (C)	15%	of (A + B)	**0**
SNCR Equipment Subtotal			**NA**
Total Plant Cost D		A + B + C	**0**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E))	**0**
Inventory Capital		Reagent Vol * $/gal	**0**
Initial Catalyst and Chemicals		0 for SNCR	**0**
Total Capital Investment (TCI) (1)			**4,531,000**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**4,531,000**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total (5)	1.50	1.5% of Total Capital Investment	67,965
	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.057	$/kwh, 9 kW-hr, 8760 hr/yr, 80% utilization	3,685
Natural Gas	6.85	$/mscf, 1 scfh, 8760 hr/yr, 80% utilization	54,082
Water	1.16	$/mgal, 68 gph, 8760 hr/yr, 80% utilization	552
	NA		
	NA		
	NA		
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	32.62	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization	1,011
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Urea 50% Solution	637.60	$/ton , 0 ton/hr, 8760 hr/yr, 80% utilization	316,954
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**444,249**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	40,779
Administration (2% total capital costs)	2%	of total capital costs (TCI)	90,620
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	45,310
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	45,310
Capital Recovery	0.0944	for a 20- year equipment life and a 7% interest rate	427,694
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**649,713**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,093,962**

See Summary page for notes and assumptions

Appendix C.1 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities
Table C.1-7 - Level 3 Low NOx Burners with SOFA and Selective Non-Catalytic Reduction

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.00%	
Equipment Life	20	years
CRF	0.0944	

Replacement Catalyst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2439	
Rep part cost per unit	214	$/ft^3
Amount Required	12	ft^3
Packing Cost	2,700	Cost adjusted for freight
Installation Labor	405	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	650	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use (5)			
NOx in	0.40	lb/MMBtu	kW
NSR	0.82		
Power			9.2
Total			9.2

Reagent Use & Other Operating Costs			Urea Use (2)			
NOx in	0.40	lb/MMBtu	71	lb/hr Neat	0.04	
Efficiency	25%		50%	solution	71.0	lb/ft^3 Density 50% Solution
Duty	572	MMBtu/hr	142	lb/hr	14.9	gal/hr
		Volume 14 day inventory	5,023	gal	$15,196	Inventory Cost
Water Use (3)	68	gal/hr	Inject at 10% solution			
Fuel Use (4)	1.1	MMBtu/hr	1.1	mscfh natural gas		
Ash Generation	8.8	lb/hr				

Operating Cost Calculations — **Annual hours of operation: 8,760** — **Utilization Rate: 80.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	33.50	$/Hr		hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8760 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total (5)	1.5	% of Total Capital Investment				67,965	1.5% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.057	$/kwh	9.2	kW-hr	64,669	3,685	$/kwh, 9 kW-hr, 8760 hr/yr, 80% utilization
Natural Gas	6.85	$/mscf	1.1	scfh	7,895	54,082	$/mscf, 1 scfh, 8760 hr/yr, 80% utilization
Water	1.16	$/mgal	68.0	gph	477	552	$/mgal, 68 gph, 8760 hr/yr, 80% utilization
Cooling Water	0.32	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
Comp Air	0.37	$/mscf	0.0	scfm/kacfm**	0	0	$/mscf, 0 scfm/kacfm**, 8760 hr/yr, 80% utilization
WW Treat Neutralization	1.96	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
WW Treat Biotreatement	4.96	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
SW Disposal	32.62	$/ton	0.004	ton/hr	31	1,011	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
Haz W Disp	326.19	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
Waste Transport	0.65	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8760 hr/yr, 80% utilization
	0.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
Lime	0.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8760 hr/yr, 80% utilization
Urea 50% Solution	637.60	$/ton	0.0709	ton/hr	497	316,954	$/ton , 0 ton/hr, 8760 hr/yr, 80% utilization
Trona	158.45	Mscf	0.0	Mscf/hr	0	0	Mscf, 0 Mscf/hr, 8760 hr/yr, 80% utilization
SCR Catalyst	214.285714	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8760 hr/yr, 80% utilization
CO Catalyst	650	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8760 hr/yr, 80% utilization
		** Std Air use is 2 scfm/kacfm			*annual use rate is in same units of measurement as the unit cost factor		

See Summary page for notes and assumptions

Appendix C.1 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities
Table C.1-8 - Selective Non-Catalytic Reduction

Operating Unit: **NA**

						Chemical Engineering Chemical Plant Cost Index	
Design Capacity	48	MW	Stack/Vent Number	0			
Design Capacity	572.0		Standardized Flow Rate	149,961	scfm @ 32º F		
Expected Utilization Rate	80%		Temperature	145	Deg F	1998/1999	NA
Expected Annual Hours of Operation	8,760	Hours	Moisture Content	4.0%		Jul-10	NA
Annual Interest Rate	7.0%		Actual Flow Rate	171,830	acfm	Inflation Adj	NA
Expected Equipment Life	20	yrs	Standardized Flow Rate	160,934	scfm @ 68º F		
			Dry Std Flow Rate	123,200	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs			Duty MMBtu/hr	Control Eff	NOx in lb/MMBtu		Year	
Direct Capital Costs	EPRI Correlation, 1998 $'s		572	25%	0.40		1998	NA
Purchased Equipment (A)							2010	NA
Purchased Equipment Total (B)	0%	of control device cost (A)						**NA**
Installation - Standard Costs	15%	of purchased equip cost (B)						0
Installation - Site Specific Costs								0
Installation Total								0
Total Direct Capital Cost, DC								0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)						0
Total Capital Investment (TCI) = DC + IC								**2,433,000**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						412,779
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						348,875
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**761,654**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Cont Eff %	Exit Conc.	Conc. Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10	-	-				0.0	-	NA
Total Particulates	-	-				0.0	-	NA
Nitrous Oxides (NOx)	**228.8**	**801.7**	**38%**	**0.25**	**lb NOx/MMbtu**	**501.1**	**300.6**	**2,533**
Sulfur Dioxide (SO2)	286.0	1,002.1				1002.1	-	NA
Sulfuric Acid Mist	-	-				0.0	-	NA
Fluorides	-	-				0.0	-	NA
Volatile Organic Compounds (VOC)	-	-				0.0	-	NA
Carbon Monoxide (CO)	53.8	188.4				188.4	-	NA
Lead (Pb)	-	-				0.0	-	NA

Notes & Assumptions

1 "Conceptual Design Study for NOx Reduction Tehcnologies" March, 2011 A site specifice enginieering and cost evaluation prepared by Sargent and Lundy, LLC
2 Reagent Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.22
3 Water use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.25
4 Additional Fuel Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.29
5 SNCR Electrical Demand per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.23
6 SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21

Appendix C.1 - February 2011 Regional Haze Evaluation for Lewis and Clark Generating Station, Montana Dakota Utilities

Table C.1-8 - Selective Non-Catalytic Reduction

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A)			
Purchased Equipment Costs (A)			**NA**
Instrumentation	10%	of control device cost (A)	NA
Freight	5%	of control device cost (A)	NA
Purchased Equipment Total (A)			**NA**
Indirect Installation			
General Facilities	5%	of purchased equip cost (A)	**NA**
Engineering & Home Office	10%	of purchased equip cost (A)	**NA**
Process Contingency	5%	of purchased equip cost (A)	**NA**
Total Indirect Installation Costs (B)	20%	of purchased equip cost (A)	**NA**
Project Contingency (C)	15%	of (A + B)	**0**
SNCR Equipment Subtotal			**NA**
Total Plant Cost D		A + B + C	**0**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E))	**0**
Inventory Capital		Reagent Vol * $/gal	**0**
Initial Catalyst and Chemicals		0 for SNCR	**0**
Total Capital Investment (TCI) (1)			**2,433,000**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**2,433,000**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total (6	1.50	1.5% of Total Capital Investment	36,495
	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.057	$/kwh, 9 kW-hr, 8760 hr/yr, 80% utilization	3,685
Natural Gas	6.85	$/mscf, 1 scfh, 8760 hr/yr, 80% utilization	54,082
Water	1.16	$/mgal, 68 gph, 8760 hr/yr, 80% utilization	552
	NA		
	NA		
	NA		
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	32.62	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization	1,011
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Urea 50% Solution	637.60	$/ton , 0 ton/hr, 8760 hr/yr, 80% utilization	316,954
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**412,779**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	21,897
Administration (2% total capital costs)	2%	of total capital costs (TCI)	48,660
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	24,330
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	24,330
Capital Recovery	0.0944	for a 20- year equipment life and a 7% interest rate	229,658
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**348,875**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**761,654**

See Summary page for notes and assumptions

Appendix C.1 - February 2011 Regional Haze Evaluation for Lewis and Clark Generating Station, Montana Dakota Utilities
Table C.1-8 - Selective Non-Catalytic Reduction

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.00%	
Equipment Life	20	years
CRF	0.0944	

Replacement Catalyst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2439	
Rep part cost per unit	214	$/ft^3
Amount Required	12	ft^3
Packing Cost	2,700	Cost adjusted for freight
Installation Labor	405	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	650	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use (5)			
NOx in	0.40	lb/MMBtu	kW
NSR	0.82		
Power			9.2
Total			9.2

Reagent Use & Other Operating Costs			Urea Use (2)			
NOx in	0.40	lb/MMBtu	71	lb/hr Neat	0.04	
Efficiency	25%		50%	solution	71.0	lb/ft^3 Density 50% Solution
Duty	572	MMBtu/hr	142	lb/hr	14.9	gal/hr
		Volume 14 day inventory	5,023	gal	$15,196	Inventory Cost
Water Use (3)	68	gal/hr	Inject at 10% solution			
Fuel Use (4)	1.1	MMBtu/hr	1.1	mscfh natural gas		
Ash Generation	8.8	lb/hr				

Operating Cost Calculations — **Annual hours of operation: 8,760** — **Utilization Rate: 80.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	33.50	$/Hr		hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8760 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total (6	1.5	% of Total Capital Investment				36,495	1.5% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.057	$/kwh	9.2	kW-hr	64,669	3,685	$/kwh, 9 kW-hr, 8760 hr/yr, 80% utilization
Natural Gas	6.85	$/mscf	1.1	scfh	7,895	54,082	$/mscf, 1 scfh, 8760 hr/yr, 80% utilization
Water	1.16	$/mgal	68.0	gph	477	552	$/mgal, 68 gph, 8760 hr/yr, 80% utilization
Cooling Water	0.32	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
Comp Air	0.37	$/mscf	0.0	scfm/kacfm**	0	0	$/mscf, 0 scfm/kacfm**, 8760 hr/yr, 80% utilization
WW Treat Neutralization	1.96	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
WW Treat Biotreatement	4.96	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
SW Disposal	32.62	$/ton	0.004	ton/hr	31	1,011	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
Haz W Disp	326.19	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
Waste Transport	0.65	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8760 hr/yr, 80% utilization
	0.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
Lime	0.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8760 hr/yr, 80% utilization
Urea 50% Solution	637.60	$/ton	0.0709	ton/hr	497	316,954	$/ton , 0 ton/hr, 8760 hr/yr, 80% utilization
Trona	158.45	Mscf	0.0	Mscf/hr	0	0	Mscf, 0 Mscf/hr, 8760 hr/yr, 80% utilization
SCR Catalyst	214.285714	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8760 hr/yr, 80% utilization
CO Catalyst	650	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8760 hr/yr, 80% utilization

** Std Air use is 2 scfm/kacfm *annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Appendix C.1 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities
Table C.1-9 - Level 3 Low NOx Burners with Separated Overfire Air (SOFA)

Operating Unit: **NA**

						Chemical Engineering Chemical Plant Cost Index	
Design Capacity	48	MW	Stack/Vent Number	0			
Design Capacity	572.0		Standardized Flow Rate	149,961	scfm @ 32º F		
Expected Utilization Rate	80%		Temperature	145	Deg F	1998/1999	390
Expected Annual Hours of Operation	8,760	Hours	Moisture Content	4.0%		Jul-10	550.7
Annual Interest Rate	7.0%		Actual Flow Rate	171,830	acfm	Inflation Adj	1.41
Expected Equipment Life	20	yrs	Standardized Flow Rate	160,934	scfm @ 68º F		
			Dry Std Flow Rate	123,200	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs			Duty MMBtu/hr	Control Eff	NOx in lb/MMBtu		Year	
Direct Capital Costs	EPRI Correlation, 1998 $'s		572	25%	0.40		1998	NA
Purchased Equipment (A)							2010	NA
Purchased Equipment Total (B)	0%	of control device cost (A)						**NA**
Installation - Standard Costs	15%	of purchased equip cost (B)						0
Installation - Site Specific Costs								0
Installation Total								0
Total Direct Capital Cost, DC								0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)						0
Total Capital Investment (TCI) = DC + IC								**2,195,000**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						43,471
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						321,075
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**364,546**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc.**	**Conc. Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	-	-				0.0	-	NA
Total Particulates	-	-				0.0	-	NA
Nitrous Oxides (NOx)	**228.8**	**801.7**	**38%**	**0.25**	**lb NOx/MMbtu**	**501.1**	**300.6**	**1,213**
Sulfur Dioxide (SO2)	286.0	1,002.1				1002.1	-	NA
Sulfuric Acid Mist	-	-				0.0	-	NA
Fluorides	-	-				0.0	-	NA
Volatile Organic Compounds (VOC)	-	-				0.0	-	NA
Carbon Monoxide (CO)	53.8	188.4				188.4	-	NA
Lead (Pb)	-	-				0.0	-	NA

Notes & Assumptions

1 "Conceptual Design Study for NOx Reduction Tehcnologies" March, 2011 A site specifice enginieering and cost evaluation prepared by Sargent and Lundy, LLC

Appendix C.1 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities
Table C.1-9 - Level 3 Low NOx Burners with Separated Overfire Air (SOFA)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A)			
Purchased Equipment Costs (A)			**NA**
Instrumentation	10%	of control device cost (A)	NA
Freight	5%	of control device cost (A)	NA
Purchased Equipment Total (A)			**NA**
Indirect Installation			
General Facilities	5%	of purchased equip cost (A)	**NA**
Engineering & Home Office	10%	of purchased equip cost (A)	**NA**
Process Contingency	5%	of purchased equip cost (A)	**NA**
Total Indirect Installation Costs (B)	20%	of purchased equip cost (A)	**NA**
Project Contingency (C)	15%	of (A + B)	**0**
SNCR Equipment Subtotal			**NA**
Total Plant Cost D		A + B + C	**0**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E))	**0**
Inventory Capital		Reagent Vol * $/gal	**0**
Initial Catalyst and Chemicals		0 for SNCR	**0**
Total Capital Investment (TCI) [1]			**2,195,000**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**2,195,000**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	33.50	$/Hr, 0.3 hr/8 hr shift, 8760 hr/yr	9,171
Supervisor	15%	15% of Operator Costs	1,376
Maintenance			
Maintenance Total	1.50	1.5% of Total Capital Investment	32,925
	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
NA	NA		-
	NA		
	NA		
	NA		
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**43,471**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	26,083
Administration (2% total capital costs)	2%	of total capital costs (TCI)	43,900
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	21,950
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	21,950
Capital Recovery	0.0944	for a 20- year equipment life and a 7% interest rate	207,192
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**321,075**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**364,546**

See Summary page for notes and assumptions

Appendix C.1 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities
Table C.1-9 - Level 3 Low NOx Burners with Separated Overfire Air (SOFA)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.00%	
Equipment Life	20	years
CRF	0.0944	

Replacement Catalyst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2439	
Rep part cost per unit	214	$/ft^3
Amount Required	12	ft^3
Packing Cost	2,700	Cost adjusted for freight
Installation Labor	405	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	650	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.40	lb/MMBtu	kW
NSR	0.82		
Power			9.2
Total			9.2

Reagent Use & Other Operating Costs			Urea Use			
NOx in	0.40	lb/MMBtu	NA	lb/hr Neat	NA	
Efficiency	NA		50%	solution	71.0	lb/ft^3 Density 50% Solution
Duty	572	MMBtu/hr	NA	lb/hr	NA	gal/hr
		Volume 14 day inventory	NA	gal	NA	Inventory Cost
Water Use	NA	gal/hr	Inject at 10% solution			
Fuel Use	NA	MMBtu/hr	NA	mscfh natural gas		
Ash Generation	NA	lb/hr				

	Operating Cost Calculations			**Annual hours of operation:**			**8,760**	
				Utilization Rate:			**80.0%**	
	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	33.50	$/Hr	0.3	hr/8 hr shift	274	9,171	$/Hr, 0.3 hr/8 hr shift, 8760 hr/yr
	Supervisor	15%	of Op.			NA	1,376	15% of Operator Costs
	Maintenance							
	Maintenance Total	1.5	% of Total Capital Investment				32,925	1.5% of Total Capital Investment
	Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.057	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 8760 hr/yr, 80% utilization
	Natural Gas	6.85	$/mscf	0.0	scfh	0	0	$/mscf, 0 scfh, 8760 hr/yr, 80% utilization
	Water	1.16	$/mgal	0.0	gph	0	0	$/mgal, 0 gph, 8760 hr/yr, 80% utilization
	Cooling Water	0.32	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
	Comp Air	0.37	$/mscf	0.0	scfm/kacfm**	0	0	$/mscf, 0 scfm/kacfm**, 8760 hr/yr, 80% utilization
	WW Treat Neutralization	1.96	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
	WW Treat Biotreatement	4.96	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
	SW Disposal	32.62	$/ton	0.000	ton/hr	0	0	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
	Haz W Disp	326.19	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
	Waste Transport	0.65	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8760 hr/yr, 80% utilization
		0.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
1	Lime	0.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8760 hr/yr, 80% utilization
6	Urea 50% Solution	637.60	$/ton	0.0000	ton/hr	0	0	$/ton , 0 ton/hr, 8760 hr/yr, 80% utilization
5	Trona	158.45	Mscf	0.0	Mscf/hr	0	0	Mscf, 0 Mscf/hr, 8760 hr/yr, 80% utilization
1	SCR Catalyst	214.285714	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8760 hr/yr, 80% utilization
2	CO Catalyst	650	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8760 hr/yr, 80% utilization
			** Std Air use is 2 scfm/kacfm			*annual use rate is in same units of measurement as the unit cost factor		

See Summary page for notes and assumptions

Appendix C.2

Low Load Operation NOx Control Cost Worksheets

Appendix C.2 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities 23MW Case
Table C.2-1 : Control Cost Summary

NO_x Control Cost Summary

Control Technology	Control lb NOx/MMBtu	Controlled Emissions T/y	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton	Incremental Control Cost $/ton	Air Toxic's & AQRV's?	Energy Impacts?	Non-Air Env Impacts?
Selective Catalytic Reduction	**0.04**	**35.5**	**319.8**	**$38,976,000**	**$6,692,645**	**$20,927**	**$31,263**	**Ammonia Slip**	**Medium**	**Ammonia in Wastewater Discharge**
SNCR + Low NOx Burners with SOFA	**0.23**	**220.9**	**134.5**	**$4,531,000**	**$897,981**	**$6,679**	**$18,515**	**Ammonia Slip, Higher CO Emissions**	**Low**	**Ammonia in Wastewater Discharge**
Selective Non Catalytic Reduction	**0.31**	**297.7**	**57.6**	**$2,433,000**	**$565,673**	**$9,817**	**NA**	**Ammonia Slip**	**Low**	**Ammonia in Wastewater Discharge**
Low NOx Burners with SOFA	**0.26**	**249.7**	**105.6**	**$2,195,000**	**$364,546**	**$3,451**	**NA**	**Higher CO Emissions**	**None**	**None**
Baseline	**0.37**	**355.3**								

Appendix C.2 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities 23MW Case
Table C.2-2 : Labor, Chemical and Utility Costs

Operating Unit: NA **Study Year** 2011

Item	Unit Cost	Units	Reference Cost	Year	Data Source	Notes
Operating Labor	33.5	$/hr		2006	Heskett Unit II BART Report	
Maintenance Labor	33.5	$/hr		2006	Heskett Unit II BART Report	
Electricity	0.057	$/kwh	0.049	2006	Heskett Unit II BART Report	http://www.eia.doe.gov/emeu/aer/txt/ptb0810.html
Natural Gas	6.85	$/mscf		2005	Average natural gas spot price July 04 - June 05, Henry La Hub.,	WTRG Economics, WWW.wtrg.com/daily/small/ngspot.gig
Water	1.16	$/mgal	1.00	2006	Heskett Unit II BART Report	cost adjusted for 3% inflation
Cooling Water	0.32	$/mgal	0.23	1999	EPA Air Pollution Control Cost Manual, 6th ed. Section 3.1 Ch 1	Ch 1 Carbon Absorbers, 1999 $0.15 - $0.30 Avg of 22.5 and 7 yrs and 3% inflation
Compressed Air	0.37	$/mscf	0.25	1998	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1	Example problem; Dried & Filtered, Ch 1.6 '98 cost adjusted for 3% inflation
Wastewater Disposal Neutralization	1.96	$/mgal	1.50	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $1- $2/1000 gal. Cost adjusted for 3% inflation Sec 6 Ch 3 lists $1.30 - $2.15/1,000 gal
Wastewater Disposal Bio-Treat	4.96	$/mgal	3.80	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1	Ch 1lists $1.00 - $6.00 for municipal treatment, $3.80 is average. Cost adjusted for 3% inflation
Solid Waste Disposal	32.62	$/ton	25.00	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $20 - $30/ton Used $25/ton. Cost adjusted for 3% inflation
Hazardous Waste Disposal	326.19	$/ton	250.00	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $200 - $300/ton Used $250/ton. Cost adjusted for 3% inflation
Waste Transport	0.65	$/ton-mi	0.50	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 3	Example problem. Cost adjusted for 3% inflation
		$/ton				
Chemicals & Supplies						
Lime	86.95	$/ton	75.00	2006	Heskett Unit II BART Report	cost adjusted for 3% inflation
Caustic	334.33	$/ton	280	2005	Hawkins Chemical	50% solution (50 Deg Be) includes delivery
Ammonia	483.59	$/ton	405	2005	Heskett Unit II BART Report	50% solution of urea in water, includes delivery
Hydrated Lime	290.00	$/ton	290.00	2011	MDU 2009 Reagent Study	
Trona	158.45	Mscf	145	2008	Solvay Chemical	cost adjusted for 3% inflation
Urea 50% Solution	637.60	$/ton	550.00	2006	Heskett Unit II BART Report	
Aqua Ammonia	0.70	$/lb	0.70	2011	Barr Engineering Data	$1,400/NH3 neat delivered at 19% aqua ammonia
Limestone	68.96	$/ton	65.00	2009	MDU 2009 Reagent Study	
NA						
Catalyst & Replacement Parts						
SCR Catalyst	214	$/ft^3			Sargent & Lundy, SCR Cost Development Methodology, Aug 2010 and CoaLogix Gas Fired Plants SCR Management Considerations Nov 2009 McIlvaine Webinar	
CO Catalyst	650	$/ft^3			Vendor quote if needed	
Catalyst #3		$/ft^3				
Catalyst #4		$/ft^3	**Gas Flow Calculations for SCR**			
Catalyst #5		$/ft^3	59,033	dscfm @ 68º F		
Filter Bags		$/bag	17.5%	Moisture		
Tower Packing		$/ft^3	850	Deg F		
Replacement Parts			120,849	acfm @ 850º F		
Replacement Parts			0.4	NOx in lb/MMBtu		
N/A						
Other						
Sales Tax	6.5	%				
Interest Rate	7.00%					Standard interest rate specified by the US Office of Management and Budget
Operating Information						
Annual Op. Hrs	8760	Hours				Engineering Estimate
Utilization Rate	80%			2011	MDU data - Telephone Call 12/23/2010	
Equipment Life	20	yrs	23	MW	Reduced Capacity Example - Telephone Call 2/9/2011	Engineering Estimate
Design Capacity	274	MMBtu/hr	48	MW	MDU data - Telephone Call 12/23/2010	Basis firing 100% coal
Standardized Flow Rate	71,856	scfm @ 32º F				
Temperature	145	Deg F			June 9, 2010 Stack Test	
Stack O2 Content	4.0%				June 9, 2010 Stack Test	
Moisture Content	23.3%				June 9, 2010 Stack Test	
Actual Flow Rate	82,335	acfm			acfm basis 145°F scrubber exhaust temperature	
Standardized Flow Rate	77,114	scfm @ 68º F				
Dry Std Flow Rate	59,033	dscfm @ 68º F			June 9, 2010 Stack Test + 10%	
Pollutant	**Max Emis Lb/Hr**	**Uncontrolled Conc**				
PM10		0.00	gr/dscf			
Total Particulates		0.00	gr/dscf			
Nitrous Oxides (NOx)	101	240	ppm	Basis 0.37 lb NOx/MMBtu		
Sulfur Dioxide (SO_2)	220	373	ppm	Basis 0.5 %S Coal, 6,600 Btu/lb coal		
Sulfuric Acid Mist		0.000	ppm	0.80	lb SO2/MMBtu	
Fluorides		0.0E+00	gr/dscf	0.0	ppb	
Volatile Organic Compounds (VOC)		0.0	ppm			
Carbon Monoxide (CO)	53.8	208.7	ppm	188	t/yr CO	
Lead (Pb)		0.0E+00	gr/dscf	0	ppb	

Enter this data for each emission unit
Enter data for this study (applies to all units)

Appendix C.2 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities 23MW Case
Table C.2-3: Selective Catalytic Reduction (SCR) FLM $/KW Calculation

Operating Unit: **NA**

Design Capacity	48	MW	Stack/Vent Number	0		**Chemical Engineering**	
Design Capacity	274	MMBtu/hr	Standardized Flow Rate	71,856	scfm @ 32º F	**Chemical Plant Cost Index**	
Expected Utilization Rate	80%		Temperature	850	Deg F	1998/1999	390
Expected Annual Hours of Operation	8,760	17.5%	Moisture Content	4.0%	Oxygen	Jul-10	550.7
Annual Interest Rate	7.0%		Actual Flow Rate	120,849	acfm @ 850º F	Inflation Adj	1.41
Expected Equipment Life	20	yrs	Standardized Flow Rate	77,114	scfm @ 68º F		
			Dry Std Flow Rate	59,033	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs			Duty MMBtu/hr	Control Eff	NOx in lb/MMBtu			
Direct Capital Costs	EPRI Correlation		274	90%	0.40			NA
Purchased Equipment (A)								NA
Purchased Equipment Total (B)	22%	of control device cost (A)						**NA**
Installation - Standard Costs	15%	of purchased equip cost (B)						NA
Installation - Site Specific Costs								0
Installation Total								NA
Total Direct Capital Cost, DC								0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)						0
Total Capital Investment (TCI) = DC + IC								**NA**
Total Capital Investment (TCI) + Retrofit								**38,976,000**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						861,470
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						5,831,176
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**6,692,645**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc.**	**Conc. Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	-	-				0.0	-	NA
Total Particulates	-	-				0.0	-	NA
Nitrous Oxides (NOx)	**101.4**	**355.3**	**90%**	**0.04**	**lb/MMBtu**	**35.5**	**319.8**	**20,927**
Sulfur Dioxide (SO2)	220.1	771.2				771.2	-	NA
Sulfuric Acid Mist	-	-				0.0	-	NA
Fluorides	-	-				0.0	-	NA
Volatile Organic Compounds (VOC)	-	-				0.0	-	NA
Carbon Monoxide (CO)	53.8	188.4				188.4	-	NA
Lead (Pb)	-	-				0.0	-	NA

Notes & Assumptions

1 Installed emission control equipment costs from Federal Land Manager Summary of Cost and perofrmance for proposed BART controls. Average installed selective catalytic reduction system cost data adjusted to Lewis and Clark Station capacity. Installed baghouse cost per 2004 Sargent and Lundy cost estimate
2 Reagent Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.32 - 2.35
3 SCR Catalyst Volume per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.18 - 2.24

4 SCR Catalyst Replacement per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.50 - 2.53
5 SCR Electrical Demand per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.48
6 SCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.46

Appendix C.2 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities 23MW Case
Table C.2-3: Selective Catalytic Reduction (SCR) FLM $/KW Calculation

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC			**NA**
Instrumentation	10%	of control device cost (A)	NA
MN Sales Taxes	**7.0%**	**of control device cost (A)**	NA
Freight	5%	of control device cost (A)	NA
Purchased Equipment Total (A)	22%		**NA**
Indirect Installation			
General Facilities	5%	of purchased equip cost (A)	NA
Engineering & Home Office	10%	of purchased equip cost (A)	NA
Process Contingency	5%	of purchased equip cost (A)	NA
Total Indirect Installation Costs (B)	20%	of purchased equip cost (A)	**NA**
Project Contingency (C)	15%	of (A + B)	**NA**
Total Plant Cost D		A + B + C	**NA**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E))	**NA**
Inventory Capital		Reagent Vol * $/gal	**9,019**
Initial Catalyst and Chemicals		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**NA**
Retrofit Factor	30%	of TCI	NA
Installed Cost			
Total Capital Investment (TCI) (1)	$812	per kW installed	**38,976,000**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**NA**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	33.50	$/Hr, 0.2 hr/8 hr shift, 8760 hr/yr	7,337
Supervisor	15%	15% of Operator Costs	1,100
Maintenance			
Maintenance Total (6)	1.50	1.5% of Total Capital Investment	584,640
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.06	$/kwh, 111 kW-hr, 8760 hr/yr, 80% utilization	44,468
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Aqua Ammonia	0.70	$/lb, 38 lb/hr, 8760 hr/yr, 80% utilization	188,117
NA	NA		-
SCR Catalyst	214.29	$/ft3, 0 , 8760 hr/yr, 80% utilization	35,807
NA	NA		-
Total Annual Direct Operating Costs			**861,470**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	593,077
Administration (2% total capital costs)	2%	of total capital costs (TCI)	779,520
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	389,760
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	389,760
Capital Recovery	0.0944	for a 20- year equipment life and a 7% interest rate	3,679,059
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**5,831,176**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**6,692,645**

See Summary page for notes and assumptions

Appendix C.2 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities 23MW Case
Table C.2-3: Selective Catalytic Reduction (SCR) FLM $/KW Calculation

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.00%	
Equipment Life	20	yrs
CRF	0.0944	

Replacement Catalyst (4)				
Equipment Life	24,000	hours		
FCW	0.3111			
Rep part cost per unit	214	$/ft^3	# of Layers	3
Replacement Factor	3	Layers replaced per year =		1
Amount Required	537	ft^3		
Catalyst Cost	115,116			
Y catalyst life factor	3	Years		
Annualized Cost	**35,807**			

SCR Catalyst Volume (3)							
Duty	274	MMBtu/hr	Catalyst Area	126	ft^2	167	f(h SCR)
Q flue gas	120,849	acfm	Rx Area	145		454	f(h NH_3)
NOx Cont Eff	90%	(as faction)	Rx Height	12.0	ft	0	f(h New) new= -728, Retrofit = 0
NOx in	0.40	lb/MMBtu	n layer	3	layers	Y	Bypass? Y or N
Ammonia Slip	2	ppm	h layer	5.3	ft	127	f(h Bypass)
Fuel Sulfur	0.5	wt % (as %)	n total	4	layers	386,789	f(vol catalyst)
Temperature	850	Deg F	h SCR	58	ft		f(h SCR)
Catalyst Volume	**1,612**	ft^3	New/Retrofit	N	N or R		

Electrical Use (5)				
Duty	274	MMBtu/hr		kW
NOx Cont Eff	90%	(as faction)	Power	111.4
NOx in	0.40	lb/MMBtu		
n catalyst layers	4	layers		
Press drop catalyst	1	in H_2O per layer		
Press drop duct	3	in H_2O		
Total				111.4

Reagent Use & Other Operating Costs (2)			Ammonia Use			
NOx in	0.40	lb/MMBtu	38	lb/hr Neat	1.05	Stoichiometric Ratio
Efficiency	90%		19%	solution	56.0	lb/ft^3 Density
Duty	274	MMBtu/hr	202	lb/hr	27.0	gal/hr
		Volume 14 day inventory	9,059	gal	$9,019	Inventory Cost

Operating Cost Calculations	**Annual hours of operation:**	**8,760**
	Utilization Rate:	**80.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	33.5	$/Hr	0.2	hr/8 hr shift	219	7,337	$/Hr, 0.2 hr/8 hr shift, 8760 hr/yr
Supervisor	15%	of Op.			NA	1,100	15% of Operator Costs
Maintenance							
Maintenance Total (6)	1.5	% of Total Capital Investment				584,640	1.5% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.057	$/kwh	111.4	kW-hr	780,442	44,468	$/kwh, 111 kW-hr, 8760 hr/yr, 80% utilization
Natural Gas	6.85	$/mscf	0.0	scfh	0	0	$/mscf, 0 scfh, 8760 hr/yr, 80% utilization
Water	1.16	$/mgal	0.0	gph	0	0	$/mgal, 0 gph, 8760 hr/yr, 80% utilization
Cooling Water	0.32	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
Comp Air	0.37	$/mscf	0.0	scfm/kacfm**	0	0	$/mscf, 0 scfm/kacfm**, 8760 hr/yr, 80% utilization
WW Treat Neutralization	1.96	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
WW Treat Biotreatement	4.96	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
SW Disposal	326.19	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
Haz W Disp	1	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8760 hr/yr, 80% utilization
N/A	0.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
N/A	0.00	0.00	0.0	ton/hr	0	0	0, 0 ton/hr, 8760 hr/yr, 80% utilization
Lime	86.95	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8760 hr/yr, 80% utilization
Aqua Ammonia	0.70	$/lb	38	lb/hr	268,739	188,117	$/lb, 38 lb/hr, 8760 hr/yr, 80% utilization
Trona	158.45	Mscf	0.0	Mscf/hr	0	0	Mscf, 0 Mscf/hr, 8760 hr/yr, 80% utilization
SCR Catalyst	214.29	$/ft3				35,807	$/ft3, 0 , 8760 hr/yr, 80% utilization
N/A	0	0	0	0	0	0	0, 0 0, 8760 hr/yr, 80% utilization
		** Std Air use is 2 scfm/kacfm			*annual use rate is in same units of measurement as the unit cost factor		

See Summary page for notes and assumptions

Appendix C.2 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities 23MW Case
Table C.2-4 - Level 3 Low NOx Burners with SOFA and Selective Non-Catalytic Reduction

Operating Unit: **NA**

Design Capacity	48	MW	Stack/Vent Number	0		**Chemical Engineering**	
Design Capacity	274.1		Standardized Flow Rate	71,856	scfm @ 32º F	**Chemical Plant Cost Index**	
Expected Utilization Rate	80%		Temperature	145	Deg F	1998/1999	390
Expected Annual Hours of Operation	8,760	Hours	Moisture Content	4.0%		Jul-10	550.7
Annual Interest Rate	7.0%		Actual Flow Rate	82,335	acfm	Inflation Adj	1.41
Expected Equipment Life	20	yrs	Standardized Flow Rate	77,114	scfm @ 68º F		
			Dry Std Flow Rate	59,033	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs			Duty MMBtu/hr	Control Eff	NOx in lb/MMBtu		Year	
Direct Capital Costs	EPRI Correlation, 1998 $'s		274	25%	0.40		1998	NA
Purchased Equipment (A)							2010	NA
Purchased Equipment Total (B)	0%	of control device cost (A)						**NA**
Installation - Standard Costs	15%	of purchased equip cost (B)						0
Installation - Site Specific Costs								0
Installation Total								0
Total Direct Capital Cost, DC								0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)						0
Total Capital Investment (TCI) = DC + IC								**4,531,000**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						248,268
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						649,713
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**897,981**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Cont Eff %	Exit Conc.	Conc. Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10	-	-				0.0	-	NA
Total Particulates	-	-				0.0	-	NA
Nitrous Oxides (NOx)	**101.4**	**355.3**	**38%**	**0.23**	**lb NOx/MMbtu**	**220.9**	**134.5**	**6,679**
Sulfur Dioxide (SO2)	220.1	771.2				771.2	-	NA
Sulfuric Acid Mist	-	-				0.0	-	NA
Fluorides	-	-				0.0	-	NA
Volatile Organic Compounds (VOC)	-	-				0.0	-	NA
Carbon Monoxide (CO)	53.8	188.4				188.4	-	NA
Lead (Pb)	-	-				0.0	-	NA

Notes & Assumptions

1 "Conceptual Design Study for NOx Reduction Tehcnologies" March, 2011 A site specifice enginieering and cost evaluation prepared by Sargent and Lundy, LLC
2 Reagent Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.22
3 Water use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.25
4 Additional Fuel Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.29
5 SNCR Electrical Demand per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.23
6 SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21

Appendix C.2 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities 23MW Case
Table C.2-4 - Level 3 Low NOx Burners with SOFA and Selective Non-Catalytic Reduction

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A)			
Purchased Equipment Costs (A)			**NA**
Instrumentation	10%	of control device cost (A)	NA
Freight	5%	of control device cost (A)	NA
Purchased Equipment Total (A)			**NA**
Indirect Installation			
General Facilities	5%	of purchased equip cost (A)	**NA**
Engineering & Home Office	10%	of purchased equip cost (A)	**NA**
Process Contingency	5%	of purchased equip cost (A)	**NA**
Total Indirect Installation Costs (B)	20%	of purchased equip cost (A)	**NA**
Project Contingency (C)	15%	of (A + B)	**0**
SNCR Equipment Subtotal			**NA**
Total Plant Cost D		A + B + C	**0**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E))	**0**
Inventory Capital		Reagent Vol * $/gal	**0**
Initial Catalyst and Chemicals		0 for SNCR	**0**
Total Capital Investment (TCI) (1)			**4,531,000**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**4,531,000**

OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total (5)	1.50	1.5% of Total Capital Investment	67,965
	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.057	$/kwh, 4 kW-hr, 8760 hr/yr, 80% utilization	1,766
Natural Gas	6.85	$/mscf, 1 scfh, 8760 hr/yr, 80% utilization	25,914
Water	1.16	$/mgal, 33 gph, 8760 hr/yr, 80% utilization	265
	NA		
	NA		
	NA		
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	32.62	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization	485
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Urea 50% Solution	637.60	$/ton , 0 ton/hr, 8760 hr/yr, 80% utilization	151,874
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**248,268**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	40,779
Administration (2% total capital costs)	2%	of total capital costs (TCI)	90,620
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	45,310
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	45,310
Capital Recovery	0.0944	for a 20- year equipment life and a 7% interest rate	427,694
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**649,713**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**897,981**

See Summary page for notes and assumptions

Appendix C.2 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities 23MW Case
Table C.2-4 - Level 3 Low NOx Burners with SOFA and Selective Non-Catalytic Reduction

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.00%	
Equipment Life	20	years
CRF	0.0944	

Replacement Catalyst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2439	
Rep part cost per unit	214	$/ft^3
Amount Required	12	ft^3
Packing Cost	2,700	Cost adjusted for freight
Installation Labor	405	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	650	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use (5)			
NOx in	0.40	lb/MMBtu	kW
NSR	0.82		
Power			4.4
Total			4.4

Reagent Use & Other Operating Costs			Urea Use (2)			
NOx in	0.40	lb/MMBtu	34	lb/hr Neat	0.02	
Efficiency	25%		50%	solution	71.0	lb/ft^3 Density 50% Solution
Duty	274	MMBtu/hr	68	lb/hr	7.2	gal/hr
		Volume 14 day inventory	2,407	gal	$7,282	Inventory Cost
Water Use (3)	33	gal/hr	Inject at 10% solution			
Fuel Use (4)	0.6	MMBtu/hr	0.5	mscfh natural gas		
Ash Generation	4.2	lb/hr				

Operating Cost Calculations — **Annual hours of operation: 8,760** — **Utilization Rate: 80.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	33.50	$/Hr		hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8760 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total (5)	1.5	% of Total Capital Investment				67,965	1.5% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.057	$/kwh	4.4	kW-hr	30,987	1,766	$/kwh, 4 kW-hr, 8760 hr/yr, 80% utilization
Natural Gas	6.85	$/mscf	0.5	scfh	3,783	25,914	$/mscf, 1 scfh, 8760 hr/yr, 80% utilization
Water	1.16	$/mgal	32.6	gph	228	265	$/mgal, 33 gph, 8760 hr/yr, 80% utilization
Cooling Water	0.32	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
Comp Air	0.37	$/mscf	0.0	scfm/kacfm**	0	0	$/mscf, 0 scfm/kacfm**, 8760 hr/yr, 80% utilization
WW Treat Neutralization	1.96	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
WW Treat Biotreatement	4.96	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
SW Disposal	32.62	$/ton	0.002	ton/hr	15	485	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
Haz W Disp	326.19	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
Waste Transport	0.65	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8760 hr/yr, 80% utilization
	0.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
Lime	86.95	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8760 hr/yr, 80% utilization
Urea 50% Solution	637.60	$/ton	0.0340	ton/hr	238	151,874	$/ton , 0 ton/hr, 8760 hr/yr, 80% utilization
Trona	158.45	Mscf	0.0	Mscf/hr	0	0	Mscf, 0 Mscf/hr, 8760 hr/yr, 80% utilization
SCR Catalyst	214.285714	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8760 hr/yr, 80% utilization
CO Catalyst	650	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8760 hr/yr, 80% utilization
		** Std Air use is 2 scfm/kacfm			*annual use rate is in same units of measurement as the unit cost factor		

See Summary page for notes and assumptions

Appendix C.2 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities 23MW Case
Table C.2-5 - Selective Non-Catalytic Reduction

Operating Unit: **NA**

						Chemical Engineering Chemical Plant Cost Index	
Design Capacity	48	MW	Stack/Vent Number	0			
Design Capacity	274.1		Standardized Flow Rate	71,856	scfm @ 32º F		
Expected Utilization Rate	80%		Temperature	145	Deg F	1998/1999	NA
Expected Annual Hours of Operation	8,760	Hours	Moisture Content	4.0%		Jul-10	NA
Annual Interest Rate	7.0%		Actual Flow Rate	82,335	acfm	Inflation Adj	NA
Expected Equipment Life	20	yrs	Standardized Flow Rate	77,114	scfm @ 68º F		
			Dry Std Flow Rate	59,033	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs			Duty MMBtu/hr	Control Eff	NOx in lb/MMBtu		Year	
Direct Capital Costs	EPRI Correlation, 1998 $'s		274	25%	0.40		1998	NA
Purchased Equipment (A)							2010	NA
Purchased Equipment Total (B)	0%	of control device cost (A)						**NA**
Installation - Standard Costs	15%	of purchased equip cost (B)						0
Installation - Site Specific Costs								0
Installation Total								0
Total Direct Capital Cost, DC								0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)						0
Total Capital Investment (TCI) = DC + IC								**2,433,000**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						216,798
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						348,875
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**565,673**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc.**	**Conc. Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	-	-				0.0	-	NA
Total Particulates	-	-				0.0	-	NA
Nitrous Oxides (NOx)	**101.4**	**355.3**	**16%**	**0.31**	**lb NOx/MMbtu**	**297.7**	**57.6**	**9,817**
Sulfur Dioxide (SO2)	220.1	771.2				771.2	-	NA
Sulfuric Acid Mist	-	-				0.0	-	NA
Fluorides	-	-				0.0	-	NA
Volatile Organic Compounds (VOC)	-	-				0.0	-	NA
Carbon Monoxide (CO)	53.8	188.4				188.4	-	NA
Lead (Pb)	-	-				0.0	-	NA

Notes & Assumptions

1 "Conceptual Design Study for NOx Reduction Tehcnologies" March, 2011 A site specifice enginieering and cost evaluation prepared by Sargent and Lundy, LLC
2 Reagent Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.22
3 Water use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.25
4 Additional Fuel Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.29
5 SNCR Electrical Demand per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.23
6 SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21

Appendix C.2 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities 23MW Case
Table C.2-5 - Selective Non-Catalytic Reduction

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A)			
Purchased Equipment Costs (A)			**NA**
Instrumentation	10%	of control device cost (A)	NA
Freight	5%	of control device cost (A)	NA
Purchased Equipment Total (A)			**NA**
Indirect Installation			
General Facilities	5%	of purchased equip cost (A)	**NA**
Engineering & Home Office	10%	of purchased equip cost (A)	**NA**
Process Contingency	5%	of purchased equip cost (A)	**NA**
Total Indirect Installation Costs (B)	20%	of purchased equip cost (A)	**NA**
Project Contingency (C)	15%	of (A + B)	**0**
SNCR Equipment Subtotal			**NA**
Total Plant Cost D		A + B + C	**0**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E))	**0**
Inventory Capital		Reagent Vol * $/gal	**0**
Initial Catalyst and Chemicals		0 for SNCR	**0**
Total Capital Investment (TCI) (1)			**2,433,000**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**2,433,000**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total (6	1.50	1.5% of Total Capital Investment	36,495
	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.057	$/kwh, 4 kW-hr, 8760 hr/yr, 80% utilization	1,766
Natural Gas	6.85	$/mscf, 1 scfh, 8760 hr/yr, 80% utilization	25,914
Water	1.16	$/mgal, 33 gph, 8760 hr/yr, 80% utilization	265
	NA		
	NA		
	NA		
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	32.62	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization	485
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Urea 50% Solution	637.60	$/ton , 0 ton/hr, 8760 hr/yr, 80% utilization	151,874
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**216,798**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	21,897
Administration (2% total capital costs)	2%	of total capital costs (TCI)	48,660
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	24,330
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	24,330
Capital Recovery	0.0944	for a 20- year equipment life and a 7% interest rate	229,658
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**348,875**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**565,673**

See Summary page for notes and assumptions

Appendix C.2 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities 23MW Case
Table C.2-5 - Selective Non-Catalytic Reduction

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.00%	
Equipment Life	20	years
CRF	0.0944	

Replacement Catalyst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2439	
Rep part cost per unit	214	$/ft^3
Amount Required	12	ft^3
Packing Cost	2,700	Cost adjusted for freight
Installation Labor	405	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	650	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use (5)			kW
NOx in	0.40	lb/MMBtu	
NSR	0.82		
Power			4.4
Total			4.4

Reagent Use & Other Operating Costs			Urea Use (2)			
NOx in	0.40	lb/MMBtu	34	lb/hr Neat	0.02	
Efficiency	25%		50%	solution	71.0	lb/ft^3 Density 50% Solution
Duty	274	MMBtu/hr	68	lb/hr	7.2	gal/hr
		Volume 14 day inventory	2,407	gal	$7,282	Inventory Cost
Water Use (3)	33	gal/hr	Inject at 10% solution			
Fuel Use (4)	0.6	MMBtu/hr	0.5	mscfh natural gas		
Ash Generation	4.2	lb/hr				

Operating Cost Calculations — **Annual hours of operation: 8,760** — **Utilization Rate: 80.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	33.50	$/Hr		hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8760 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total (6	1.5	% of Total Capital Investment				36,495	1.5% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.057	$/kwh	4.4	kW-hr	30,987	1,766	$/kwh, 4 kW-hr, 8760 hr/yr, 80% utilization
Natural Gas	6.85	$/mscf	0.5	scfh	3,783	25,914	$/mscf, 1 scfh, 8760 hr/yr, 80% utilization
Water	1.16	$/mgal	32.6	gph	228	265	$/mgal, 33 gph, 8760 hr/yr, 80% utilization
Cooling Water	0.32	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
Comp Air	0.37	$/mscf	0.0	scfm/kacfm**	0	0	$/mscf, 0 scfm/kacfm**, 8760 hr/yr, 80% utilization
WW Treat Neutralization	1.96	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
WW Treat Biotreatement	4.96	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
SW Disposal	32.62	$/ton	0.002	ton/hr	15	485	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
Haz W Disp	326.19	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
Waste Transport	0.65	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8760 hr/yr, 80% utilization
	0.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
Lime	86.95	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8760 hr/yr, 80% utilization
Urea 50% Solution	637.60	$/ton	0.0340	ton/hr	238	151,874	$/ton , 0 ton/hr, 8760 hr/yr, 80% utilization
Trona	158.45	Mscf	0.0	Mscf/hr	0	0	Mscf, 0 Mscf/hr, 8760 hr/yr, 80% utilization
SCR Catalyst	214.285714	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8760 hr/yr, 80% utilization
CO Catalyst	650	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8760 hr/yr, 80% utilization
		** Std Air use is 2 scfm/kacfm			*annual use rate is in same units of measurement as the unit cost factor		

See Summary page for notes and assumptions

Appendix C.2 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities 23MW Case
Table C.2-6 - Level 3 Low NOx Burners with Separated Overfire Air (SOFA)

Operating Unit: **NA**

						Chemical Engineering Chemical Plant Cost Index	
Design Capacity	48	MW	Stack/Vent Number	0			
Design Capacity	274.1		Standardized Flow Rate	71,856	scfm @ 32º F		
Expected Utilization Rate	80%		Temperature	145	Deg F	1998/1999	390
Expected Annual Hours of Operation	8,760	Hours	Moisture Content	4.0%		Jul-10	550.7
Annual Interest Rate	7.0%		Actual Flow Rate	82,335	acfm	Inflation Adj	1.41
Expected Equipment Life	20	yrs	Standardized Flow Rate	77,114	scfm @ 68º F		
			Dry Std Flow Rate	59,033	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs			Duty MMBtu/hr	Control Eff	NOx in lb/MMBtu		Year	
Direct Capital Costs	EPRI Correlation, 1998 $'s		274	25%	0.40		1998	NA
Purchased Equipment (A)							2010	NA
Purchased Equipment Total (B)	0%	of control device cost (A)						**NA**
Installation - Standard Costs	15%	of purchased equip cost (B)						0
Installation - Site Specific Costs								0
Installation Total								0
Total Direct Capital Cost, DC								0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)						0
Total Capital Investment (TCI) = DC + IC								**2,195,000**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						43,471
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						321,075
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**364,546**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc.**	**Conc. Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	-	-				0.0	-	NA
Total Particulates	-	-				0.0	-	NA
Nitrous Oxides (NOx)	**101.4**	**355.3**	**30%**	**0.26**	**lb NOx/MMbtu**	**249.7**	**105.6**	**3,451**
Sulfur Dioxide (SO2)	220.1	771.2				771.2	-	NA
Sulfuric Acid Mist	-	-				0.0	-	NA
Fluorides	-	-				0.0	-	NA
Volatile Organic Compounds (VOC)	-	-				0.0	-	NA
Carbon Monoxide (CO)	53.8	188.4				188.4	-	NA
Lead (Pb)	-	-				0.0	-	NA

Notes & Assumptions

1 "Conceptual Design Study for NOx Reduction Tehcnologies" March, 2011 A site specifice enginieering and cost evaluation prepared by Sargent and Lundy, LLC

Appendix C.2 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities 23MW Case
Table C.2-6 - Level 3 Low NOx Burners with Separated Overfire Air (SOFA)

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (A)		
Purchased Equipment Costs (A)		**NA**
Instrumentation	10% of control device cost (A)	NA
Freight	5% of control device cost (A)	NA
Purchased Equipment Total (A)		**NA**
Indirect Installation		
General Facilities	5% of purchased equip cost (A)	**NA**
Engineering & Home Office	10% of purchased equip cost (A)	**NA**
Process Contingency	5% of purchased equip cost (A)	**NA**
Total Indirect Installation Costs (B)	20% of purchased equip cost (A)	**NA**
Project Contingency (C)	15% of (A + B)	**0**
SNCR Equipment Subtotal		**NA**
Total Plant Cost D	A + B + C	**0**
Allowance for Funds During Construction (E)	0 for SNCR	**0**
Royalty Allowance (F)	0 for SNCR	**0**
Pre Production Costs (G)	2% of (D+E))	**0**
Inventory Capital	Reagent Vol * $/gal	**0**
Initial Catalyst and Chemicals	0 for SNCR	**0**
Total Capital Investment (TCI) [1]		**2,195,000**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		**2,195,000**

OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	33.50 $/Hr, 0.3 hr/8 hr shift, 8760 hr/yr	9,171
Supervisor	15% 15% of Operator Costs	1,376
Maintenance		
Maintenance Total	1.50 1.5% of Total Capital Investment	32,925
	NA % of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management		
NA	NA	-
NA	NA	-
NA	NA	-
	NA	
	NA	
	NA	
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
Total Annual Direct Operating Costs		**43,471**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	26,083
Administration (2% total capital costs)	2% of total capital costs (TCI)	43,900
Property tax (1% total capital costs)	1% of total capital costs (TCI)	21,950
Insurance (1% total capital costs)	1% of total capital costs (TCI)	21,950
Capital Recovery	0.0944 for a 20- year equipment life and a 7% interest rate	207,192
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**321,075**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**364,546**

See Summary page for notes and assumptions

Appendix C.2 - February 2011 Regional Haze Evaluation for
Lewis and Clark Generating Station, Montana Dakota Utilities 23MW Case
Table C.2-6 - Level 3 Low NOx Burners with Separated Overfire Air (SOFA)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.00%	
Equipment Life	20	years
CRF	0.0944	

Replacement Catalyst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2439	
Rep part cost per unit	214	$/ft^3
Amount Required	12	ft^3
Packing Cost	2,700	Cost adjusted for freight
Installation Labor	405	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	650	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.40	lb/MMBtu	kW
NSR	0.82		
Power			4.4
Total			4.4

Reagent Use & Other Operating Costs			Urea Use			
NOx in	0.40	lb/MMBtu	NA	lb/hr Neat	NA	
Efficiency	NA		50%	solution	71.0	lb/ft^3 Density 50% Solution
Duty	274	MMBtu/hr	NA	lb/hr	NA	gal/hr
		Volume 14 day inventory	NA	gal	NA	Inventory Cost
Water Use	NA	gal/hr	Inject at 10% solution			
Fuel Use	NA	MMBtu/hr	NA	mscfh natural gas		
Ash Generation	NA	lb/hr				

Operating Cost Calculations — **Annual hours of operation: 8,760** — **Utilization Rate: 80.0%**

	Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
	Operating Labor							
	Op Labor	33.50	$/Hr	0.3	hr/8 hr shift	274	9,171	$/Hr, 0.3 hr/8 hr shift, 8760 hr/yr
	Supervisor	15%	of Op.			NA	1,376	15% of Operator Costs
	Maintenance							
	Maintenance Total	1.5	% of Total Capital Investment				32,925	1.5% of Total Capital Investment
	Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.057	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 8760 hr/yr, 80% utilization
	Natural Gas	6.85	$/mscf	0.0	scfh	0	0	$/mscf, 0 scfh, 8760 hr/yr, 80% utilization
	Water	1.16	$/mgal	0.0	gph	0	0	$/mgal, 0 gph, 8760 hr/yr, 80% utilization
	Cooling Water	0.32	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
	Comp Air	0.37	$/mscf	0.0	scfm/kacfm**	0	0	$/mscf, 0 scfm/kacfm**, 8760 hr/yr, 80% utilization
	WW Treat Neutralization	1.96	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
	WW Treat Biotreatement	4.96	$/mgal	0.0	gpm	0	0	$/mgal, 0 gpm, 8760 hr/yr, 80% utilization
	SW Disposal	32.62	$/ton	0.000	ton/hr	0	0	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
	Haz W Disp	326.19	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
	Waste Transport	0.65	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8760 hr/yr, 80% utilization
		0.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8760 hr/yr, 80% utilization
1	Lime	86.95	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8760 hr/yr, 80% utilization
6	Urea 50% Solution	637.60	$/ton	0.0000	ton/hr	0	0	$/ton , 0 ton/hr, 8760 hr/yr, 80% utilization
5	Trona	158.45	Mscf	0.0	Mscf/hr	0	0	Mscf, 0 Mscf/hr, 8760 hr/yr, 80% utilization
1	SCR Catalyst	214.285714	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8760 hr/yr, 80% utilization
2	CO Catalyst	650	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8760 hr/yr, 80% utilization

** Std Air use is 2 scfm/kacfm *annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Appendix D

Coal Variability Data

Coal Variability

Poor coal quality is indicated by low btu content and calcium content and high sulfur content, ash content, and moisture content. As illustrated in the figures below, trends in past coal characteristics indicate a steady decrease in expected quality for Unit 1's coal supply on an annual basis, with a high degree of variability observed on a short term basis.

Weekly analytical results for various coal properties are presented below. The figures also include monthly and annual averages of the weekly data. A total of 567 samples are included for date ranges from January 2000 through November 2010[1]. Data is presented on an as-received basis and is not moisture corrected.

- **Figure D1**. Coal Energy Content Data
  The data presented illustrates a range in energy content from approximately 5,900 btu to 7,500 btu. From 2005 through present, there is a clear trend toward decreased energy content on an annual basis.

- **Figure D2.** Coal Sulfur Content Data
  The data presented illustrates a range in sulfur content of approximately 0.2% to 1.4%. Coal sulfur content is highly variably on a weekly basis, with average sulfur content maintaining a range of 0.4% to 0.6%.

- **Figure D3.** Coal Calcium Content Data
  The data presented illustrates a range in calcium content of approximately 6% to 27%. Calcium results are highly variable on a weekly basis, and demonstrate a slight decrease in average calcium content on an annual basis.

- **Figure D4.** Coal Ash Content Data
  The data presented illustrates a range in moisture content of approximately 9% to 15%. From 2005 through present, there is a clear trend toward increased ash content on an annual basis.

- **Figure D5.** Coal Moisture Content Data
  The data presented illustrates a range in moisture content of approximately 28% to 40%. From 2005 through present, there is a clear trend toward increased moisture content on an annual basis.

[1] Analytical data for calcium is available from April 2006 through November 2010.

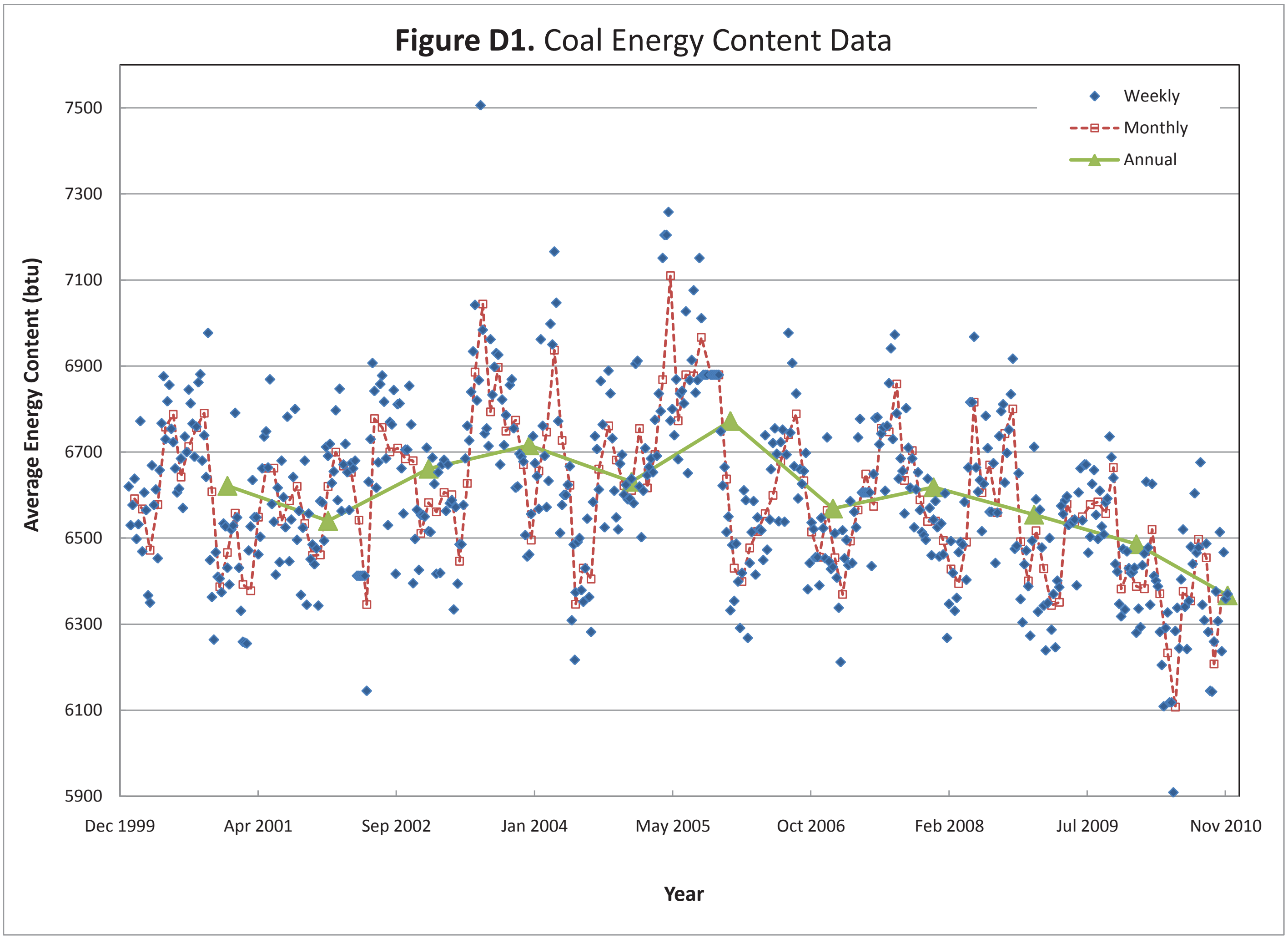


Figure D1. Coal Energy Content Data
Weekly
Monthly
Annual
Average Energy Content (btu)
7500
7300
7100
6900
6700
6500
6300
6100
5900
Dec 1999
Apr 2001
Sep 2002
Jan 2004
May 2005
Oct 2006
Feb 2008
Jul 2009
Nov 2010
Year

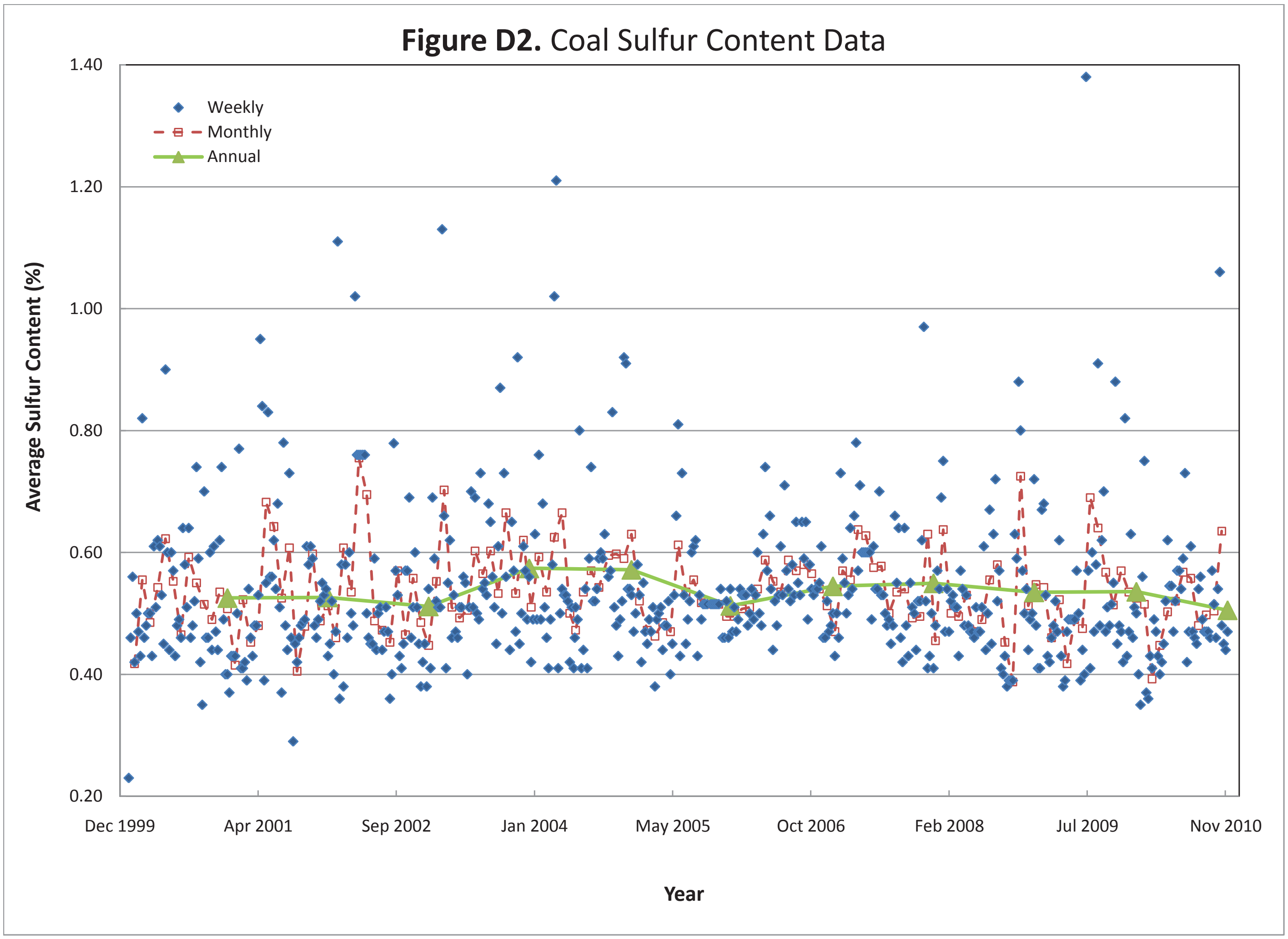


Figure D2. Coal Sulfur Content Data
Weekly
Monthly
Annual
Average Sulfur Content (%)
1.40
1.20
1.00
0.80
0.60
0.40
0.20
Dec 1999
Apr 2001
Sep 2002
Jan 2004
May 2005
Oct 2006
Feb 2008
Jul 2009
Nov 2010
Year

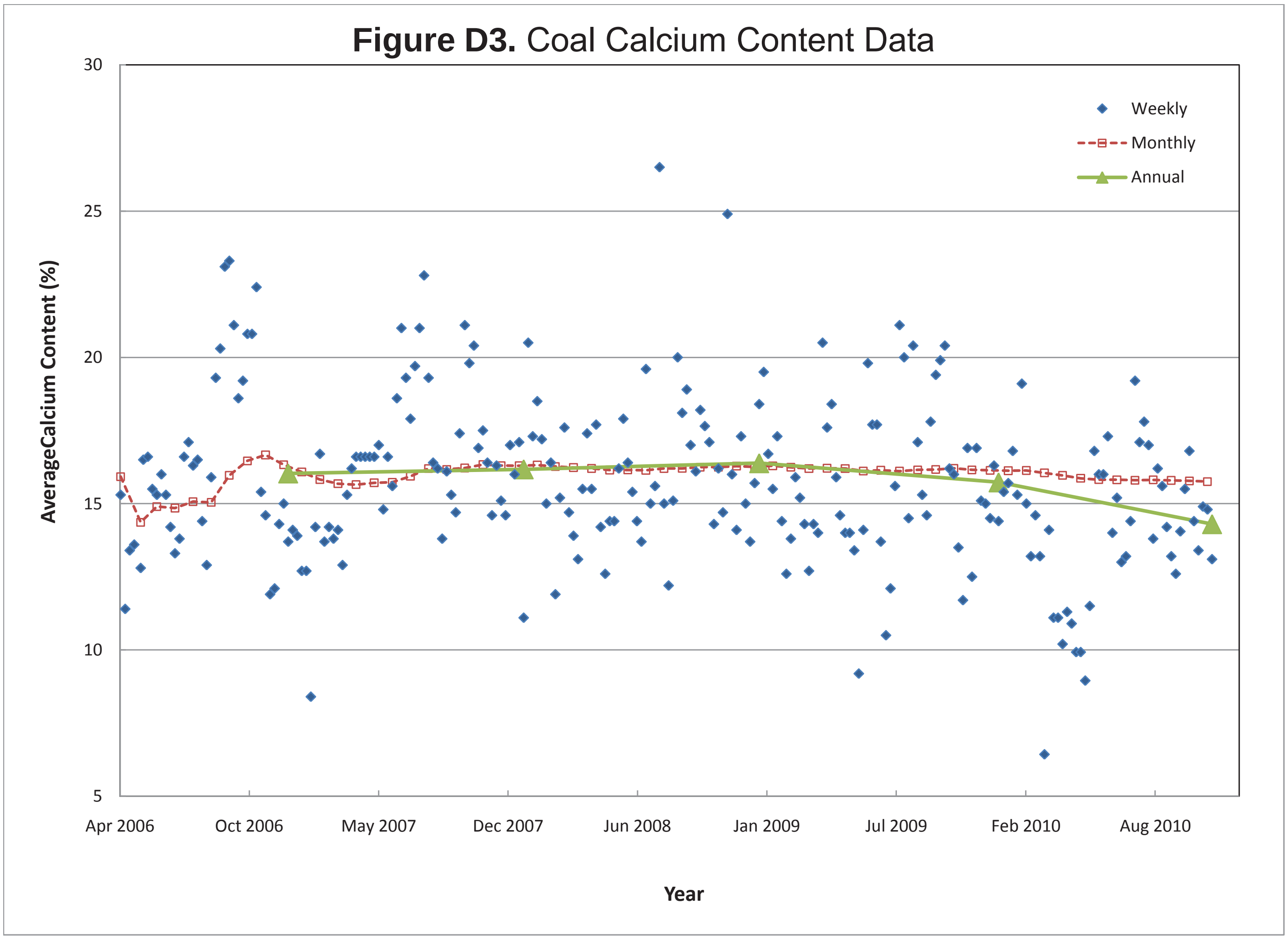


Figure D3. Coal Calcium Content Data
AverageCalcium Content (%)
30
25
20
15
10
5
Weekly
Monthly
Annual
Apr 2006
Oct 2006
May 2007
Dec 2007
Jun 2008
Jan 2009
Jul 2009
Feb 2010
Aug 2010
Year

Figure D4. Coal Ash Content Data

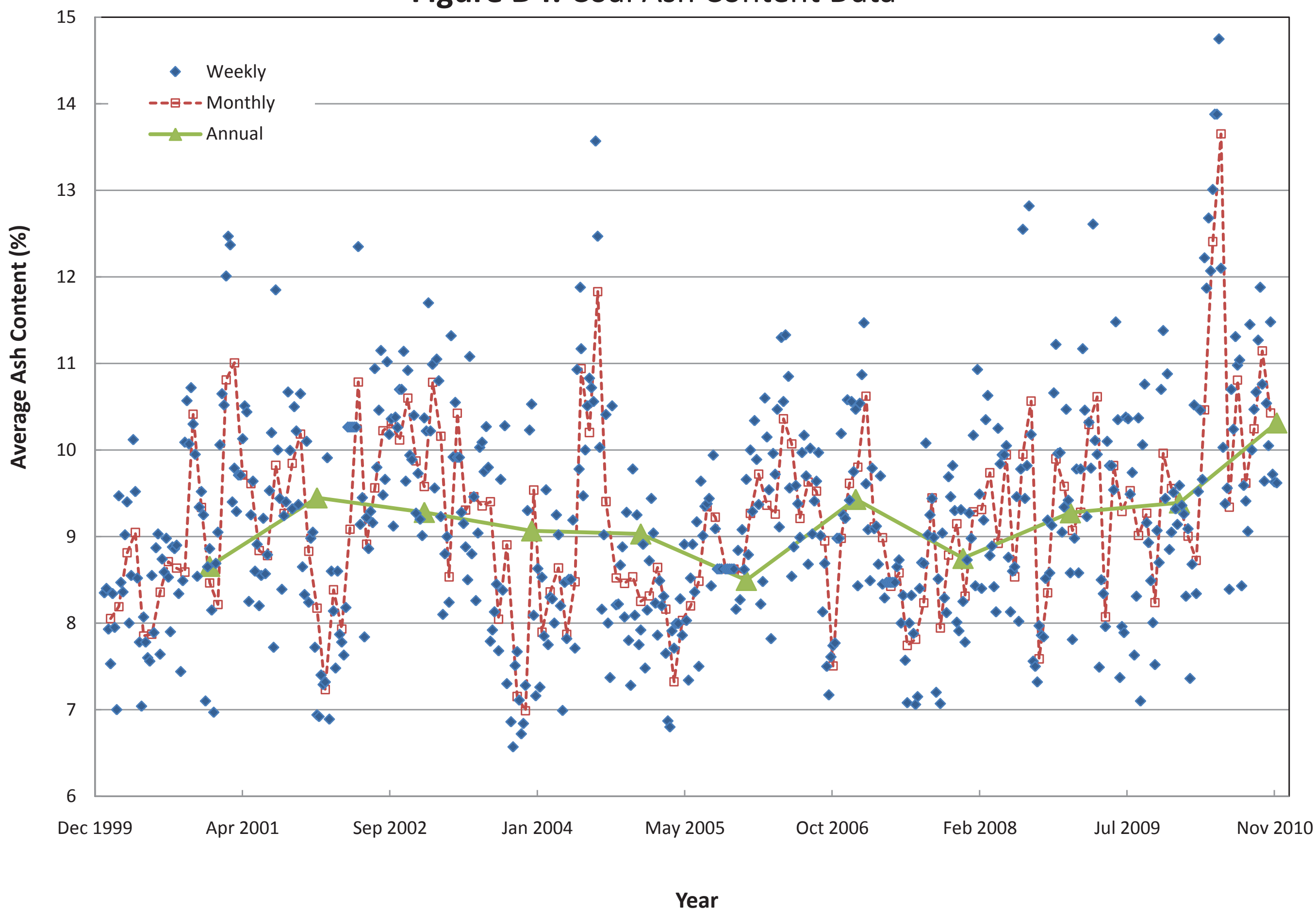
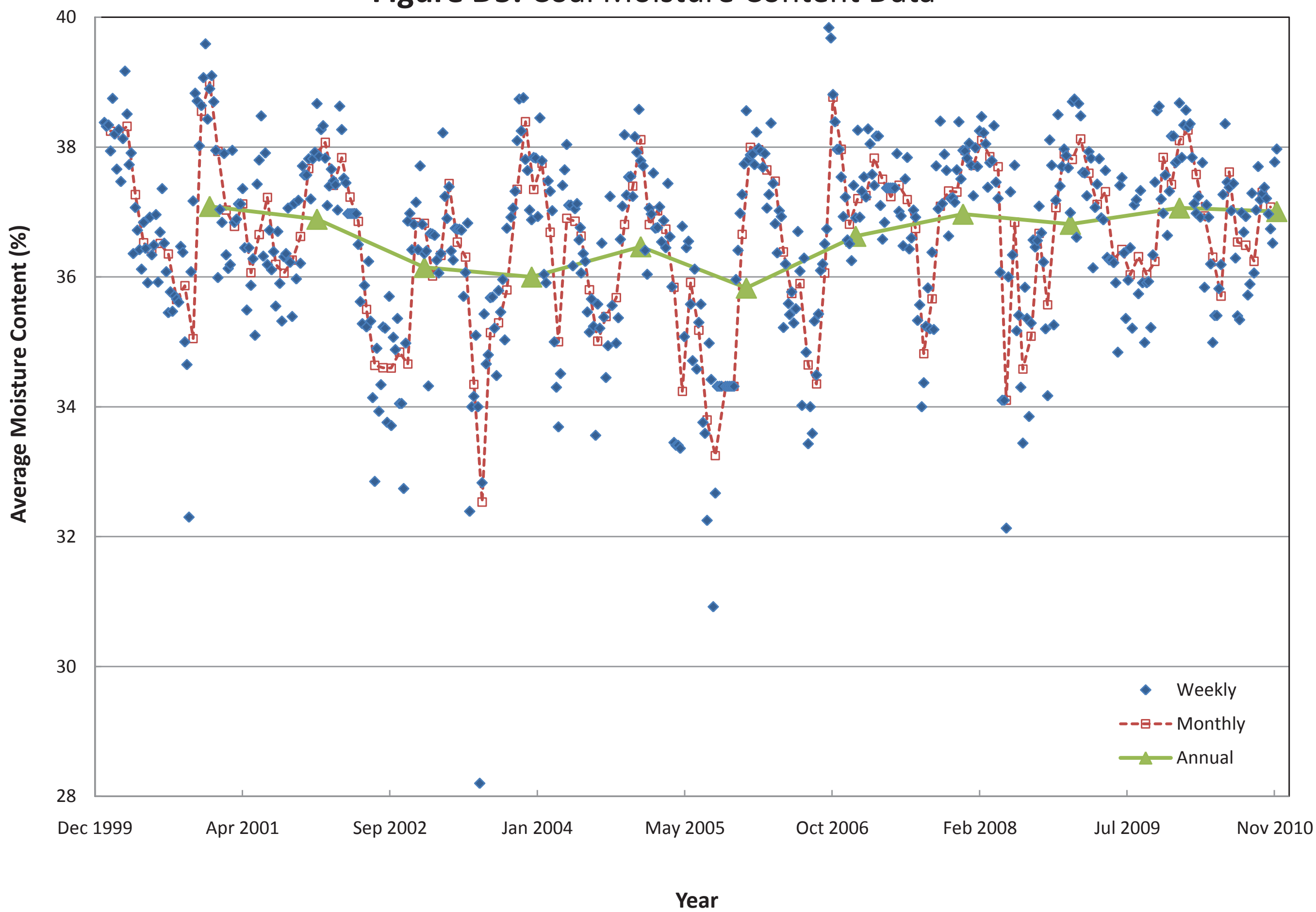
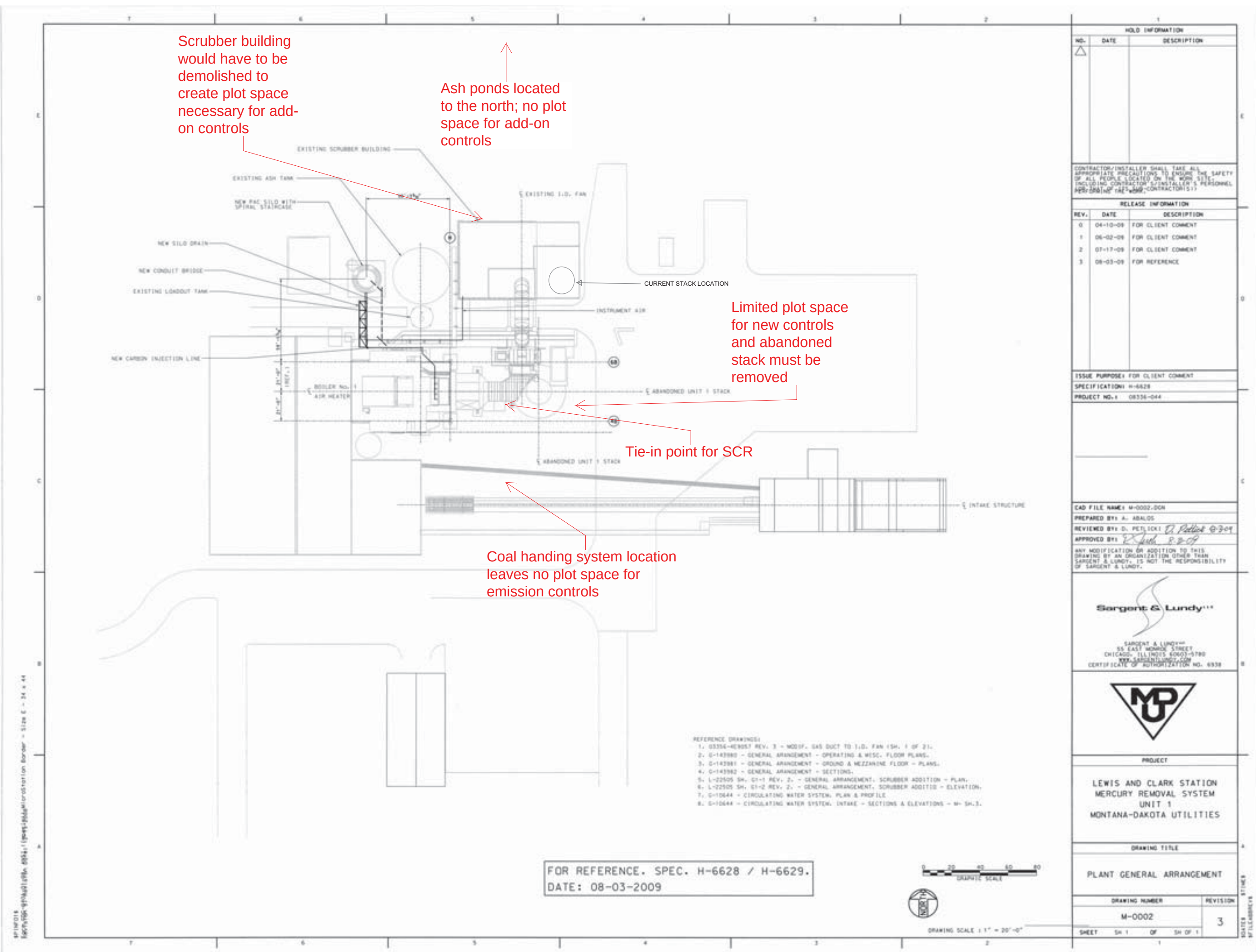


Figure D5. Coal Moisture Content Data

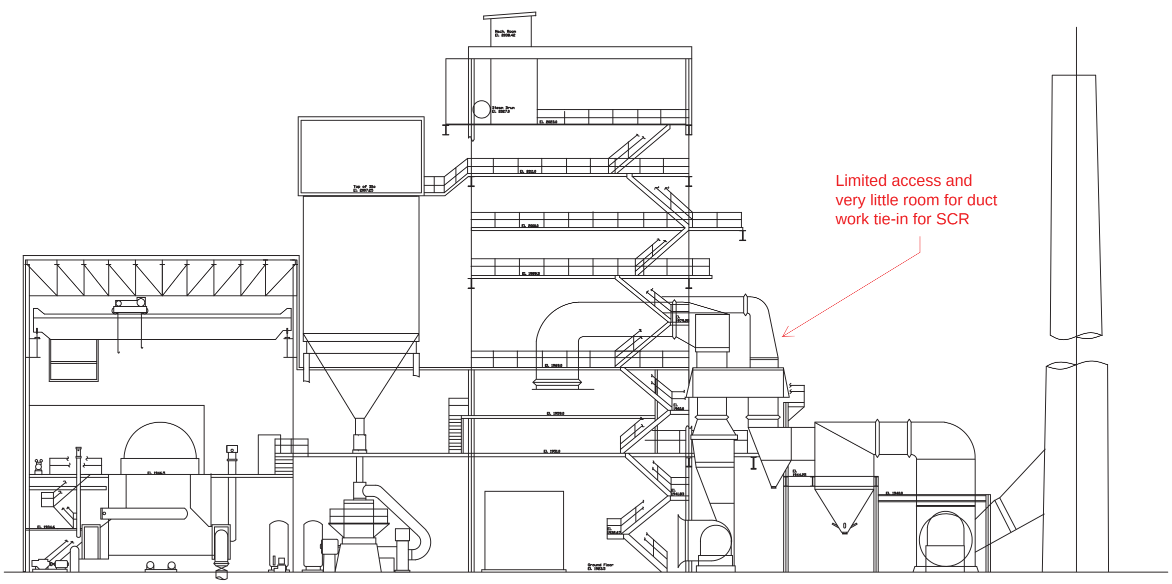


Appendix E

General Arrangement Drawing



Scrubber building would have to be demolished to create plot space necessary for add-on controls
Ash ponds located to the north; no plot space for add-on controls
EXISTING SCRUBBER BUILDING
EXISTING ASH TANK
NEW PAC SILO WITH SPIRAL STAIRCASE
EXISTING I.D. FAN
NEW SILO DRAIN
NEW CONDUIT BRIDGE
EXISTING LOADOUT TANK
CURRENT STACK LOCATION
INSTRUMENT AIR
Limited plot space for new controls and abandoned stack must be removed
NEW CARBON INJECTION LINE
BOILER No. 1 AIR HEATER
ABANDONED UNIT 1 STACK
Tie-in point for SCR
INTAKE STRUCTURE
Coal handing system location leaves no plot space for emission controls
FOR REFERENCE. SPEC. H-6628 / H-6629.
DATE: 08-03-2009
HOLD INFORMATION
RELEASE INFORMATION
0 04-10-09 FOR CLIENT COMMENT
1 06-02-09 FOR CLIENT COMMENT
2 07-17-09 FOR CLIENT COMMENT
3 08-03-09 FOR REFERENCE
ISSUE PURPOSE: FOR CLIENT COMMENT
SPECIFICATION: H-6628
PROJECT NO.: 08336-044
CAD FILE NAME: M-0002.DGN
PREPARED BY: A. ABALOS
REVIEWED BY: D. PETLICKI
Sargent & Lundy
SARGENT & LUNDY
55 EAST MONROE STREET
CHICAGO, ILLINOIS 60603-5780
WWW.SARGENTLUNDY.COM
CERTIFICATE OF AUTHORIZATION NO. 6938
PROJECT
LEWIS AND CLARK STATION
MERCURY REMOVAL SYSTEM
UNIT 1
MONTANA-DAKOTA UTILITIES
DRAWING TITLE
PLANT GENERAL ARRANGEMENT
DRAWING NUMBER
M-0002
REVISION
3
SHEET SH 1 OF SH OF 1



General Notes

1. Drawing is a copy of 1958 Ebasco drawing, Modifications (new stack, scrubber, ductwork, ect.) are not shown.

No.	Revision/Issue	Date

Industrial Contractors, Inc.
701 Channel Drive
P.O. Box 5519
Bismarck, ND 58502

Montana Dakota Utilities
Lewis & Clark Station
General Arrangement

Project

Date 05/22/98

Scale None

Sheet SK-01

Appendix F

Ammonia Slip Water Impacts

Water Impacts of Ammonia Slip Calculation

Water impacts of SNCR are based on a design ammonia slip range of 5 to 10 ppm. Using this range in combination with Equation 1 below, an SNCR ammonia exhaust rate of 2.14 lb/hr to 4.27 lb/hr was calculated.

Equation 1

$$NH_3\ Slip\ (ppm) = NH_3\ Rate\ \left(\frac{lb}{hr}\right) \times \frac{1\ hr}{60\ min} \times \frac{1\ lb-mol}{17.03\ lb} \times \frac{385\ scf}{lb-mol} \times \frac{min}{160{,}934\ scf} \times \frac{10^6 parts}{million}$$

Where:
NH_3 Slip = Design basis ammonia slip range (ppm)
NH_3 Rate = SNCR emitted ammonia rate (lb/hr)
160,934 = Unit 1 exhaust flow rate based on June 9, 2010 stack testing
17.03 = Molecular weight of ammonia
385 = Volumetric flow conversion factor at standard conditions

To determine the final effluent concentrations, the predicted ammonia exhaust rates were combined with facility specific flow data as illustrated in Equation 2. Effluent ammonia concentrations are calculated to be 8.4 mg/L to 16.7 mg/L.

Equation 2

$$NH_3\ \left(\frac{mg}{L}\right) = \left(NH_3\ Rate\ \left(\frac{lb}{hr}\right) \times \frac{453{,}592\ mg}{lb}\right) \div \left(\frac{510\ gal}{min} \times \frac{60\ min}{hr} \times \frac{3.79\ L}{gal}\right)$$

Where:
NH3 = Effluent ammonia concentration (mg/L)
510 = Effluent flow rate from 2006 water quality testing at L&C
453,592 & 510 = standard mass and volume conversions

As stated in the Montana DEQ Water Quality Circular[i], the standard for ammonia is no detectable concentration, with a trigger value of 10 mg/L. As demonstrated in the calculations above, installation of SNCR with standard ammonia slip design parameters has the potential to adversely impact effluent ammonia concentrations.

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[i] Excerpt from Circular DEQ-t (August 2010), Page 11.

CIRCULAR DEQ-7, MONTANA NUMERIC WATER QUALITY STANDARDS(9)

Except where indicated, values are listed as micro-grams-per-liter (µg/L). A '---' indicates that a Standard has not been adopted or information is currently unavailable. A '( )' indicates that a detailed note of explanation is provided.

Pollutant Element / Chemical Compound or Condition §§ - Primary Synonym § - Other Names	CASRN numbers, NIOSH number, SAX Number (25) (26) (27)	Category (1) (2)	Aquatic Life Standards		Bio-concentration Factor (BCF) (5)	Human Health Standards (17) (16)		Trigger Value (22)	Required Reporting Value (19)
			Acute (3)	Chronic (4)		Surface Water	Ground Water		
Ammonia [total ammonia nitrogen (NH3-N plus NH4-N)] as mg/l N §§ --- § Ammonia Anhydrous § Anhydrous Ammonia § Spirit of Hartshorn	7664-41-7 BO 0875000 AMY500	Toxic	(7)(8) NPP	(7)(8) NPP	---	---	---	10	50

Appendix F

Ammonia Slip Water Impacts