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November 19, 2008

Ms. Anne Jackson
Environmental Analysis and Outcomes - Air Assessment and Environmental Data Management
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194

Re: BART Study – Taconite Harbor Energy Center Unit 3

Dear Ms. Jackson:

As requested in the August 28, 2008 MPCA letter, and as confirmed in our September 12, 2008 letter, Minnesota Power hereby submits for your review and evaluation a BART study for Unit 3 at our Taconite Harbor Energy Center (THEC). This study updates the information we provided in our October 13, 2005 AREA Emissions Reduction Project Proposal.

As was depicted in the 2005 AREA Proposal, the enclosed study evaluates different technologies aimed at reducing NOx, SO_2 and filterable PM emissions from Unit 3. For NOx reduction, we have provided a comparison of three technologies. A Nalco-Mobotec ROFA only system, the Nalco-Mobotec ROFA/RotaMix system, as currently in use on Units 1 & 2 at THEC, and a Selective Catalytic Reduction (SCR) system. We did not include Low NOx Burners in the study as they are very comparable to the ROFA/RotaMix system which has proved successful on Units 1 & 2. Minnesota Power declares that ROFA is BART for Unit 3.

Concerning SO_2 control, the study compares three options. A Nalco-Mobotec boiler alkali injection system with a hot-side to cold-side ESP retrofit (same as already installed on Units 1 & 2), the same Nalco-Mobotec alkali injection system with a baghouse instead of an ESP conversion, and semi-dry spray dryer coupled with a baghouse. A wet FGD system was also considered for SO_2 control, but was dismissed due to high capital cost. Minnesota Power declares that the Nalco-Mobotec alkali injection/baghouse combination is BART for both SO_2 and PM. Minnesota Power would also like to point out that although this BART evaluation focuses on SO_2, NOx and PM control, a baghouse is a good technology for mercury control as well. Recall, mercury reduction units at Taconite Harbor units qualify as supplemental units towards meeting the Minnesota Mercury Reduction Act of 2006.

Related to the controls for SO_2, we are unable to determine with certainty just what the SO_2 removal rate will actually be for the recommended system. We firmly believe that the removal efficiency will be noticeably better than the boiler injections/ESP conversion option due to the "passive" scrubbing that will occur across the baghouse. This passive scrubbing is the result of hydrate coating the baghouse bags providing for additional contact between the SO_2 in the flue gas and the boiler injected hydrate. So SO_2 capture will occur in two steps...in-boiler capture followed by passive scrubbing in the baghouse. Current capture efficiency on Units 1 & 2 is about 40% although given Nalco-Mobotec's continuing efforts, we expect capture efficiency to improve to at least 50%.

With a baghouse however, we estimate the system will readily achieve a capture efficiency of 55+%. Based on this, the cost-effectiveness of the hydrate injection/baghouse combination will be lower than the hydrate injection/ESP conversion option. Following is a table depicting how cost effectiveness varies with improving SO2 capture efficiency.

SO_2 Removal	**Emission Rate (lb/mmBtu)**	**Cost Effectiveness ($/ton)**
40%	0.42	5,300
45%	0.39	4,700
50%	0.35	4,300
55%	0.32	3,900

At this point, Minnesota Power plans to have these BART technologies in operation on Unit 3 no later than the date required under the Regional Haze Rule for BART-affected units.

If you have any questions regarding this information, please contact Brandon Krogh at 218-723-3954.

Sincerely,

Allan S. Rudeck, Jr.
Vice President - Generation

Burns & McDonnell
SINCE 1898

November 19, 2008

Mr. Brandon Krogh
ALLETE, Inc.
30 W. Superior St.
Duluth, MN 55802

Taconite Harbor Energy Center Unit 3
Best Available Retrofit Technology (BART) Analysis
BMcD Project No. 43471

Dear Mr. Krogh:

Minnesota Power has retained Burns & McDonnell (BMcD) to perform a Best Available Retrofit Technology (BART) analysis for the Taconite Harbor Energy Center (THEC) Unit 3. The BART Analysis consists generally of evaluating technologies available for control of emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter (PM) from Taconite Harbor Unit 3. This information will be used by Minnesota Power in selecting BART.

On July 11, 2008, the D.C. Circuit Court of Appeals vacated the EPA's Clean Air Interstate Rule (CAIR) in its entirety. Many states that were included in the CAIR program (including Minnesota) were allowed to avoid including electric generating units (EGUs) in their Regional Haze Rule State Implementation Plans (SIPs) on the basis that "CAIR is better than BART." Because the CAIR has been vacated, the Minnesota Pollution Control Agency (MPCA) has requested that Minnesota Power submit a BART Analysis for THEC Unit 3.

The following report presents the results of the BART Analysis performed by BMcD.

Note that the cost estimates provided in this evaluation are study-grade cost estimates. These are very rough screening-level cost estimates to be used for comparison of technologies, and do not include all project costs. Because of the short timeframe available for completing this BART analysis, site specific impacts and constraints could not be fully identified or evaluated. However, the costs presented are adequate for comparative purposes. The cost estimates developed as part of this analysis are described in Appendix A.

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EXECUTIVE SUMMARY

A BART Analysis was performed for THEC Unit 3 based on guidelines set by the EPA and MPCA. The following technologies were evaluated for control of NO_x, SO_2, and PM emissions:

- NO_x Control
  - Selective Catalytic Reduction (SCR)
  - Mobotec's Rotating Opposed Fired Air (ROFA) and Rotamix technologies
  - Mobotec's ROFA technology alone
- SO_2 Control
  - Wet Flue Gas Desulfurization (FGD) system using dry ground pulverized limestone delivered to site
  - Semi-Dry FGD system (lime spray dryer) using lime or hydrated lime
  - Mobotec's Furnace Sorbent Injection (FSI) technology using hydrated lime
- PM Control
  - Existing hot-side electrostatic precipitator (ESP) in conjunction with a wet FGD
  - Conversion of the hot-side ESP to a cold-side ESP in conjunction with the Mobotec technology for SO_2 and NO_x control
  - Fabric filter baghouse in conjunction with a semi-dry FGD system or Mobotec's FSI system

INTRODUCTION

THEC is located north of Duluth in Schroeder, Minnesota and consists of three identical 75 MW (net), 79 MW (gross) coal-fired units. Units 1 and 2 were placed in service in 1957 and Unit 3 in 1967. The units have Combustion Engineering tangentially-fired boilers burning low sulfur sub-bituminous coal from the Powder River Basin (PRB).

Each unit was originally equipped with a UOP hot-side ESP for particulate emission control. In 2007, Minnesota Power retrofitted air pollution control technology supplied by Mobotec on THEC Unit 2. The existing hot-side ESP on THEC Unit 2 was converted to a cold-side ESP as part of this project. The same modifications made to THEC Unit 2 are currently being installed on THEC Unit 1. THEC Unit 3 currently uses the original hot-side ESP for particulate control.

The THEC Unit 3 boiler (EU 003) is a BART-eligible unit as it meets the following criteria:

- It falls within one of 26 specifically listed source categories defined under the Regional Haze Rule definition of BART.

- Its startup date was between August 7, 1962 and August 7, 1977.
- It has the potential to emit more than 250 tons per year of a visibility impairing pollutant (SO_2, NO_X, or PM).

The U.S. EPA finalized guidelines for the determination of BART for facilities subject to the Regional Haze Rule in the Federal Register on July 6, 2005 (70 FR 39104). These guidelines, as well as the BART Analysis Guidelines for Facilities provided by the MPCA, were used in developing this analysis.

BART-ELIGIBLE EMISSION UNITS SUBJECT TO MACT STANDARD

THEC Unit 3 is not subject to any currently-existing Maximum Achievable Control Technology (MACT) standard.

BASELINE CONDITIONS FOR BART-ELIGIBLE UNITS

Table 1 lists the current emissions from THEC Unit 3 based on information provided by Minnesota Power. Baseline emissions are estimated based on current emission rates, plant output, and plant heat rate. A capacity factor of 85% is assumed.

Table 1. Current Emission Levels at THEC Unit 3.

		Baseline Emissions	
Pollutant	**Pollution Control Technology Used**	**(lb/mmBtu)**	**(tons/yr)**
NO_x	None	0.40	1,250
SO_2	Low-sulfur coal	0.70	2,190
PM	Hot-side ESP	0.03	90

BART ANALYSIS FOR BART-ELIGIBLE EMISSION UNITS

The following discussion is the BART Analysis for the THEC Unit 3 boiler (EU 003) based on the following five-step process recommended in the EPA and MPCA BART Guidelines:

Step 1 – Identify All Available Retrofit Control Technologies
Step 2 – Eliminate Technically Infeasible Options
Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies
Step 4 – Evaluate Impacts and Document the Results
Step 5 – Propose BART (to be done by Minnesota Power)

Step 4 includes evaluating the cost of compliance, the energy impacts, and the non-air quality environmental impacts of each technology. The remaining useful life of the unit is also considered in this step.

The EPA and MPCA BART Guidelines also recommend that visibility impacts be evaluated in a BART Analysis. Note that no visibility impact assessment was performed as part of this BART analysis as BMcD was advised that this was to be performed by the MPCA.

NO_x Emission Controls

STEP 1 – Identify All Available Retrofit Control Technologies

Currently, THEC Unit 3 does not use any controls for NO_x emission reduction other than good combustion practices. Available retrofit technologies for NO_x emissions control include the following:

- Selective Catalytic Reduction (SCR)
- Mobotec's Rotating Opposed Fired Air (ROFA) and Rotamix technology
- Mobotec's Rotating Opposed Fired Air (ROFA) technology

The use of low NO_x burners and overfire air are also available retrofit technologies for NO_x emissions control at THEC Unit 3. However, Minnesota Power asked that this technology not be included in this evaluation due to the performance of Mobotec's ROFA technology at THEC Units 1 and 2.

SCR technology involves the chemical reduction of NO_x to nitrogen by the injection of ammonia reagent into the flue gas upstream of a catalyst bed housed in a reactor. The optimum temperature for the reaction generally is in the range of 650 °F to 850 °F, which corresponds to the flue gas temperatures typically found between the economizer and the air preheater.

Mobotec's ROFA system consists of an air booster fan installed adjacent to the boiler and associated ductwork to deliver secondary combustion air in a controlled, optimized manner to the five or six ROFA boxes installed in the furnace. A reduction in NO_x emissions is achieved through an increase in turbulent mixing in the combustion furnace. Mobotec's ROFA system is generically equivalent to overfire air (OFA), in which a portion of the combustion air is withheld from the primary combustion zone and transferred to a higher elevation in the furnace. The reduced availability of oxygen in the primary combustion zone leads to the reduction of NO_x. Combustion is then completed in the OFA zone where temperatures are lower.

In Mobotec's Rotamix system, urea or ammonia is injected into the furnace, further reducing NO_x formation. Six to eight chemical injection ports are installed on the furnace to deliver a metered quantity of regent. An ammonia or urea storage tank is required, as well as an injection system. Mobotec's Rotamix system is generically equivalent to Selective Non-Catalytic Reduction (SNCR), in which a nitrogen-based reagent chemically reduces NO_x to nitrogen when injected into the furnace at a location where the flue gas temperature ranges between 1,600 °F and 2,100 °F.

STEP 2 – Eliminate Technically Infeasible Options

Both SCR and Mobotec's ROFA and Rotamix technologies are considered technically feasible for application to THEC Unit 3. No technologies considered are eliminated in this step.

STEP 3 – Evaluate Control Effectiveness of Remaining Control Technologies

Mobotec's ROFA and Rotamix technologies have been installed on THEC Unit 2. At this unit, a NO_x emission rate of 0.16 lb/mmBtu was achieved with the use of ROFA alone, and the combination of ROFA and Rotamix achieved a NO_x emission of 0.13 lb/mmBtu. As THEC Unit 2 and Unit 3 are identical units, the performance of the Mobotec technologies on THEC Unit 2 is representative of the performance to be expected on THEC Unit 3.

The use of an SCR is expected to achieve a NO_x emission rate of 0.05 lb/mmBtu based on recent emission guarantees offered by SCR system suppliers.

Table 2 lists the NO_x control technologies considered for THEC Unit 3.

Table 2. NO_x Control Technologies Considered.

NO_x Control Technology	Current Emission Rate (lb/mmBtu)	Post-BART Control Emission Rate (lb/mmBtu)	Percent Reduction (%)
SCR	0.40	0.05	88%
ROFA/Rotamix	0.40	0.13	68%
ROFA	0.40	0.16	60%

STEP 4 – Evaluate Impacts and Document the Results

The capital and operating and maintenance (O&M) costs associated with the NO_x control technologies considered for THEC Unit 3 are summarized in Table 3. The development of these cost estimates is described further in Appendix A.

Table 3. NO_x Control Technology Costs[1].

NO_x Control Technology	Capital ($)	Annual O&M ($/yr)	Total Levelized Costs ($/yr)[2]
SCR	$28,920,000	$845,000	$5,085,000
ROFA/Rotamix	$8,113,000	$1,288,000	$2,876,000
ROFA	$5,959,000	$586,000	$1,616,000

[1] All costs are in 2008 dollars.
[2] Assuming a cost of capital of 12.2%, an escalation rate of 3%, and a timeframe of 20 years to amortize the capital cost of new equipment.

At THEC Unit 3, the Mobotec NO_x control technology is expected to have a larger energy impact than the other NO_x control technologies evaluated due to the large ROFA fan. An SCR is estimated to require over 600 kW of power (including booster fans) to operate. The ROFA system at THEC Unit 2 consumes almost 700 kW of power. The Rotamix system at THEC Unit 2 consumes an additional 56 kW of power.

Table 4 lists the control effectiveness (on a cost per ton of pollutant removed basis) for each NO_x control technology considered.

Table 4. NO_x Control Technology Cost Effectiveness[1].

NO_x Control Technology	Tons Removed (tons/yr)	Cost Effectiveness ($/ton)
SCR	1,100	$4,600
ROFA/Rotamix	840	$3,400
ROFA	750	$2,200

[1] All costs are in 2008 dollars.

SO_2 and PM Emission Controls

STEP 1 – Identify All Available Retrofit Control Technologies

THEC Unit 3 does not use any post-combustion controls for SO_2 emission reduction. SO_2 emissions are currently limited by the use of a low-sulfur subbituminous coal. Available retrofit technologies for SO_2 emissions control include the following:

- Wet FGD system using dry ground pulverized limestone delivered to site. In this case, the existing hot-side ESP will continue to be used for control of PM emissions.
- Semi-dry FGD system (lime spray dryer) using lime or hydrated lime. In this case, a new fabric filter baghouse would be used downstream of the spray dryer for control of PM emissions.
- Mobotec's Furnace Sorbent Injection (FSI) technology using hydrated lime. In this case, the existing hot-side ESP will be converted to a cold-side ESP for control of PM emissions.
- Mobotec's FSI technology using hydrated lime. In this case, a new fabric filter baghouse would be used downstream for control of PM emissions. In this case, the existing hot-side ESP would no longer be used.

Mobotec's FSI system injects hydrated lime into the upper furnace to react with the SO_2 that is formed when the sulfur in the coal is burned, delivering in-furnace SO_2 capture. The bound SO_2 reaction products, any unreacted lime, and flyash is then captured by a downstream particulate control device. The FSI system includes injection ports installed in the furnace and a lime storage silo. The lime delivery system includes a positive displacement blower and associated piping, variable speed rotary feeders, and a rotary air lock.

Because of the addition of lime to the boiler, particulate loading to the existing hot-side ESP will increase. The hot-side ESP at THEC Unit 2 was converted to a cold-side ESP in order to handle the increased loading. This evaluation assumes that the hot-side ESP at THEC Unit 3 could be converted to a cold-side ESP in order to handle the increased loading. This analysis will also evaluate the case where a new fabric filter baghouse is installed in order to handle the increased particulate loading. In this case, the existing hot-side ESP would no longer be used.

STEP 2 – Eliminate Technically Infeasible Options

Wet limestone FGD, semi-dry FGD, and Mobotec's FSI technologies are considered technically feasible for application to THEC Unit 3. No technologies considered are eliminated in this step.

STEP 3 – Evaluate Control Effectiveness of Remaining Control Technologies

Mobotec's FSI technology has been installed on THEC Unit 2. The ESP at THEC Unit 2 was converted from hot-side to cold-side in conjunction with the installation of the Mobotec technology. This was done to prevent PM emissions from increasing due to the increased loading on the ESP due to the FSI technology. An SO_2 emission rate of 0.42 lb/mmBtu (40% removal) was achieved with the use of FSI at THEC Unit 2. As THEC

Unit 2 and Unit 3 are identical units, the performance of the Mobotec technology on THEC Unit 2 is representative of the performance to be expected on THEC Unit 3. If a fabric filter baghouse is installed downstream of the existing hot-side ESP at THEC Unit 3, higher SO_2 removal may potentially be achieved. In theory, lime that has not reacted in the boiler could coat the bags in the fabric filter baghouse, allowing for additional SO_2 removal. However, no data is available on the SO_2 removal achieved with this arrangement. Therefore, this analysis will be based on the assumption that the same SO_2 removal (40%) could be achieved with Mobotec's FSI system and a fabric filter baghouse as was observed at THEC Unit 2 with an FSI system and a converted ESP.

A semi-dry FGD system is expected to achieve up to 95% SO_2 removal based on information provided by SPE-Amerex, a supplier of the technology. Based on recent supplier guarantees, wet limestone FGD systems are expected to achieve up to 98% SO_2 removal. However, when applied to low-sulfur coal, these technologies are typically guaranteed with a floor on resultant SO_2 emissions, below which the percent removal expectations are not applicable. Recent BACT determinations for units installing a wet limestone FGD system include an SO_2 emission rate no less than 0.06 lb/mmBtu. Recent BACT determinations for units installing a semi-dry FGD system include an SO_2 emission rate no less than 0.08 lb/mmBtu.

Table 5 lists the SO_2 control technologies considered for THEC Unit 3.

Table 5. SO_2 Control Technologies Considered.

SO_2 Control Technology	Current Emission Rate (lb/mmBtu)	Post-BART Control Emission Rate (lb/mmBtu)	Percent Reduction (%)
Wet Limestone FGD and Existing Hot-Side ESP[1]	0.70	0.06	91%
Semi-dry FGD and new FF[2]	0.70	0.08	89%
FSI and ESP Conversion[3]	0.70	0.42	40%
FSI and new FF[2]	0.70	0.42	40%

[1] Assumes the existing hot-side ESP continues to be used.
[2] Includes a new fabric filter baghouse.
[3] Includes the conversion of the existing hot-side ESP to a cold-side ESP.

A budgetary cost estimate was obtained for a wet limestone FGD system. The budgetary cost estimate included the equipment associated with the absorber, reagent (limestone) preparation, and waste handling. However, there are other balance-of-plant costs that are not captured in this high-level analysis. With the use of a wet limestone FGD system, a new stack will be needed to handle the saturated flue gas. This is a significant cost that is not included in this analysis. There is also additional piping, limestone handling equipment, and building costs that are not included. Because a wet limestone FGD system will achieve about the same SO_2 removal as a semi-dry FGD system but will cost significantly more, this technology is not evaluated further.

STEP 4 – Evaluate Impacts and Document the Results

The capital and O&M costs associated with the SO_2 control technologies considered for THEC Unit 3 are summarized in Table 6. The development of these cost estimates is described further in Appendix A. Note that the semi-dry FGD system costs include the cost of a new fabric filter baghouse, as this will be required to handle the increased particulate loading from the spray dryer. Two FSI options are evaluated. One includes the cost of converting the existing hot-side ESP to a cold-side ESP to handle the increased particulate loading from the FSI system, identical to THEC Unit 2. The other includes the cost of a new fabric filter baghouse to handle the increased particulate loading from the FSI system.

Table 6. SO_2 Control Technology Costs[1].

SO_2 Control Technology	Capital ($)	Annual O&M ($/yr)	Total Levelized Costs ($/yr)[2]
Semi-dry FGD and FF[3]	$40,901,000	$3,005,000	$9,689,000
FSI and ESP Conversion[4]	$14,305,000	$1,109,000	$3,468,000
FSI and FF[3]	$15,508,000	$1,868,000	$4,679,000

[1] All costs are in 2008 dollars.

[2] Assuming a cost of capital of 12.2%, an escalation rate of 3%, and a timeframe of 20 years to amortize the capital cost of new equipment.

[3] Includes a fabric filter baghouse.

[4] Includes the conversion of the hot-side ESP to a cold-side ESP.

At THEC Unit 3, the semi-dry FGD system is expected to have a larger energy impact than an FSI system. A semi-dry FGD system is estimated to require almost 900 kW of power (including the fabric filter and booster fans). The FSI system with a hot-side to cold-side ESP conversion at THEC Unit 2 consumes almost 70 kW of power, not including the ROFA fan power requirement discussed in the NO_x Emission Controls section. If a new fabric filter baghouse is used in conjunction with the FSI system, an additional 370 kW are required.

With all of the SO_2 control technologies discussed, there will be a waste product that must be disposed of. Currently, the waste from any SO_2 control technology at THEC is expected to be conditioned and trucked to the existing permitted on-site landfill. Mobotec's FSI technology is estimated to generate the largest quantity of waste product (1,800 lb/hr dry, unconditioned waste compared to almost 1,100 lb/hr dry, unconditioned waste for a semi-dry FGD system). Also, the waste generated from the FSI process contains a significant quantity of unreacted lime, which is hydrophilic and reacts exothermically with water, making the waste challenging to transport.

Table 7 lists the control effectiveness (on a cost per ton of pollutant removed basis) for each SO_2 control technology considered.

Table 7. SO_2 Control Technology Cost Effectiveness[1].

SO_2 Control Technology	**Tons Removed (tons/yr)**	**Cost Effectiveness ($/ton)**
Semi-dry FGD	1,940	$5,000
FSI and ESP Conversion[2]	880	$4,000
FSI and FF[3]	880	$5,300

[1] All costs are in 2008 dollars.
[2] Includes the conversion of the hot-side ESP to a cold-side ESP.
[3] Includes a fabric filter baghouse.

PM Emission Controls

Note that for THEC Unit 3, the PM control technology selected as BART has to be compatible with the SO_2 control technology chosen as BART. PM emissions from THEC Unit 3 are currently controlled by the use of a hot-side ESP. Available retrofit technologies for PM emissions control include the following:

- Conversion of the hot-side ESP to a cold-side ESP in conjunction with the Mobotec FSI technology for SO_2 control
- Fabric filter baghouse in conjunction with the Mobotec FSI technology for SO_2 control
- Fabric filter baghouse in conjunction with semi-dry FGD system

The ESP at THEC Unit 2 was converted from hot-side to cold-side in conjunction with the installation of the Mobotec FSI technology. This was done to prevent PM emissions from increasing due to the increased loading on the ESP due to the FSI technology. Based on information provided by Minnesota Power, the conversion of the hot-side ESP to a cold-side ESP in conjunction with the Mobotec FSI technology resulted in no change in PM emissions from THEC Unit 2. As THEC Unit 2 and Unit 3 are identical units, the performance achieved with the modifications to the ESP at THEC Unit 2 is representative of the performance to be expected on THEC Unit 3.

Note that a fabric filter baghouse can be used in conjunction with a semi-dry FGD absorber to achieve high levels of SO_2 removal. Recent PM guarantees from fabric filter baghouse suppliers have been as low as 0.012 lb/mmBtu. This same fabric filter particulate matter emission guarantee would also be expected downstream of an FSI system or a semi-dry FGD system.

Table 8 lists the PM control technologies considered for THEC Unit 3.

Table 8. PM Control Technologies Considered.

PM Control Technology	Current Emission Rate (lb/mmBtu)	Post-BART Control Emission Rate (lb/mmBtu)	Percent Reduction (%)
Fabric filter baghouse with Semi-Dry FGD	0.03	0.012	60%
Fabric filter baghouse with FSI	0.03	0.012	60%
Convert HS ESP to CS ESP with FSI	0.03	0.03	0%

SUMMARY AND CONCLUSIONS

Table 9 provides a summary of each NO_x, SO_2, and PM control technology evaluated in the BART Analysis for THEC Unit 3. The expected level of emission reduction achieved by each control technology is listed, as well as the total estimated annualized control cost. The estimated average cost effectiveness, on a cost per ton pollution removed basis, is also listed. Any energy impacts or non-air quality environmental impacts are listed, as well as collateral increases in other air pollutants.

Table 9. Summary of the THEC Unit 3 Estimated Impacts Analysis for SO_2, NO_x, and PM Control Scenarios.

Pollutant	Control Technology	Baseline Emissions		Resulting Emissions		Percent Removal (%)	Tons removed (tons/yr)	Total Estimated Levelized Costs ($/yr)	Estimated Cost Effectiveness ($/ton)	Estimated Energy Impacts[3]	Other Air Pollutants	Non-Air Quality Impacts
		(lb/mmBtu)	(tons/yr)	(lb/mmBtu)	(tons/yr)							
NO_x	SCR	0.40	1,250	0.05	160	88%	1,100	$5,085,000	$4,600	<1%	Ammonia Slip	No
NO_x	ROFA/Rotamix	0.40	1,250	0.13	400	68%	840	$2,876,000	$3,400	<1%	Ammonia Slip	No
NO_x	ROFA	0.40	1,250	0.16	500	60%	750	$1,616,000	$2,200	<1%	No	No
SO_2[4]	Semi-dry FGD and FF[1]	0.70	2,190	0.08	250	89%	1,940	$9,689,000	$5,000	≥1%	No	Waste Product
SO_2[4]	FSI and FF[1]	0.70	2,190	0.42	1,310	40%	880	$4,679,000	$5,300	<1%	No	Waste Product
SO_2[4]	FSI and ESP Conversion[2]	0.70	2,190	0.42	1,310	40%	880	$3,468,000	$4,000	<1%	No	Waste Product

[1] Includes a fabric filter baghouse.

[2] Includes the conversion of the hot-side ESP to a cold-side ESP.

[3] This column indicates the estimated auxiliary power requirements of each technology as a percentage of the THEC Unit 3 capacity.

[4] The estimated cost of the PM control device is included in the SO2 cost estimate. Cost efffectiveness is based on tons of SO2 removed only. For more information on the PM control devices evaluated, see the "PM Emissions Control" section of this report.

If you have any questions regarding this report, please contact me at (816) 822-3430 or Dave Hendry at (816) 822-3163.

Sincerely,

BURNS & MCDONNELL

Karen E. Burchardt
Senior Environmental Engineer

cc: Tom Coughlin, Minnesota Power
Dave Hendry, Burns & McDonnell

Attachments: Appendix A

APPENDIX A

THEC UNIT 3 COST ESTIMATES

The following discussion describes the capital and operating and maintenance (O&M) cost estimates that were developed for the Taconite Harbor Energy Center (THEC) Unit 3 Best Available Retrofit Technology (BART) analysis.

Note that the cost estimates provided in this evaluation are study-grade cost estimates (FEP-1: Early Feasibility or Screening Level as described in the attached Appendix A). These are very rough screening-level cost estimates to be used for comparison of technologies, and do not include all project costs. Because of the short timeframe available for completing this BART analysis, site specific impacts and constraints are not fully identified or evaluated.

General Inputs

Capital cost estimates for many of the Air Pollution Control (APC) technologies evaluated in the THEC Unit 3 BART Analysis were based on budgetary cost estimates provided by system suppliers. The capital costs associated with the Mobotec technology and the conversion of the hot-side ESP to cold-side at THEC Unit 2 were provided by Minnesota Power. This study assumes that these costs are similar to the costs expected at THEC Unit 3 as the units are identical.

O&M cost estimates are based on parameters provide by Minnesota Power and system suppliers, as well as Burns & McDonnell's experience on other similar projects. Annual costs were estimated assuming a plant capacity factor of 85%.

The development of the capital and O&M cost estimates for each APC technology are described in more detail below.

SCR System

Budgetary cost estimates for a Selective Catalytic Reduction (SCR) system at THEC Unit 3 were obtained from Alstom Power Inc. (Alstom) and Babcock and Wilcox (B&W). Both quotes were similar and included equipment only. Installation was assumed to be 100% of the equipment costs. Costs for foundations, ductwork, and ductwork support steel were estimated based on the cost estimate developed for the Boswell Energy Center Unit 4. The Boswell Energy Center Unit 4 cost estimates were scaled to represent a unit the size of THEC Unit 3. Owner's costs were estimated to be 30% of the installed cost of the equipment.

The O&M costs associated with the SCR system are based on the following:

- Aqueous ammonia cost of $0.34/lb.
- Catalyst cost of $6,655.00/m^3. It was assumed that one layer of catalyst would be replaced every three years.
- Power costs provided by Minnesota Power.

- Maintenance costs (labor and materials) were assumed to be 1.5% of the total installed cost.
- It was assumed that there is no operating or administrative labor associated with an SCR.

Most of the O&M costs associated with the SCR system can be attributed to the cost of the aqueous ammonia.

Mobotec (ROFA and Rotamix)

The capital cost of the Mobotec NO_x control system (Rotating Opposed Fired Air (ROFA) and Rotamix technology) installed at THEC Unit 2, including equipment, installation and owner's costs, was provided by Minnesota Power. This study assumes that these costs reflect the capital cost of the equipment expected at THEC Unit 3.

The O&M costs associated with the ROFA and Rotamix system are based on the following:

- Urea cost of $0.33/lb.
- Power costs provided by Minnesota Power.
- Labor cost provided by Minnesota Power.
- Maintenance costs (labor and materials) were assumed to be 5% of total installed costs.

The following assumptions were also made when estimating the O&M costs:

- Urea usage is estimated based on information provided by Minnesota Power for THEC Unit 2.
- Power consumption (including associated ROFA and Rotamix fans) is based on information provided by Minnesota Power for THEC Unit 2.
- It was assumed that this equipment would require two operators.

Mobotec (ROFA)

The capital cost of the Mobotec NO_x control system (ROFA only) installed at THEC Unit 2, including equipment, installation and owner's costs, was provided by Minnesota Power. This study assumes that these costs reflect the capital cost of the equipment expected at THEC Unit 3.

The O&M costs associated with the ROFA and Rotamix system are based on the following:

- Power costs provided by Minnesota Power.
- Labor cost provided by Minnesota Power.
- Maintenance costs (labor and materials) were assumed to be 5% of total installed costs.

The following assumptions were also made when estimating the O&M costs:

- Power consumption (including associated ROFA fans) is based on information provided by Minnesota Power for THEC Unit 2.
- It was assumed that this equipment would require two operators.

Semi-Dry FGD System

The capital cost for a semi-dry FGD system at THEC Unit 3 was estimated using cost the EPA's Coal Utility Environmental Cost (CUECost) computer model (Version 1.0). This cost estimate includes equipment and installation. Owner's costs were estimated to be 7.5% of the installed cost of the equipment based on information provided by Minnesota Power.

The O&M costs associated with the semi-dry FGD system are based on the following:

- Lime cost of $123.00/ton, delivered.
- Waste disposal cost of $8.00/ton.
- Water costs of $0.40/1000gal.
- Power costs provided by Minnesota Power.
- Labor cost provided by Minnesota Power.
- Maintenance costs (labor and materials) were assumed to be 2% of total installed cost.
- Administrative labor assumed to be 30% of the operating and maintenance labor costs.

The following assumptions were also made when estimating the O&M costs:

- Lime and water usage was based on the quote from SPE-Amerex.
- Power consumption is assumed to be 0.7% of the boiler capacity (excluding the booster fan).
- The waste disposal costs were estimated assuming 95% removal of the uncontrolled SO_2 in the flue gas.
- It was assumed that this equipment would require seven operators.

Mobotec (FSI)

The capital cost of the Mobotec SO_2 control system (Furnace Sorbent Injection (FSI) technology) installed at THEC Unit 2, including equipment, installation and owner's costs, was provided by Minnesota Power. This study assumes that these costs reflect the capital cost of the equipment expected at THEC Unit 3.

The O&M costs associated with the FSI system are based on the following:

- Lime cost of $123.00/ton delivered.

- Waste disposal at $8.00/ton.
- Power costs provided by Minnesota Power.
- Labor cost provided by Minnesota Power.
- Maintenance costs (labor and materials) were assumed to be 5% of total installed costs.

The following assumptions were also made when estimating the O&M costs:

- Lime usage and waste generated are based on information provided by Minnesota Power for THEC Unit 2.
- Power consumption is based on information provided by Minnesota Power for THEC Unit 2.
- It was assumed that this equipment would require two operators.

Fabric Filter Baghouse

The capital cost for a fabric filter baghouse at THEC Unit 3 was estimated using cost the EPA's Coal Utility Environmental Cost (CUECost) computer model (Version 1.0). This cost estimate includes equipment and installation. Owner's costs were estimated to be 7.5% of the installed cost of the equipment based on information provided by Minnesota Power.

The O&M costs associated with the fabric filter baghouse are based on the following:

- Power costs provided by Minnesota Power.
- Bag replacement cost of $108/bag, based on pricing provided by Hamon Research-Cottrell.
- Maintenance costs (labor and materials) were assumed to be 5.0% of total installed cost.

The following assumptions were also made when estimating the O&M costs:

- Estimated power consumption for the fabric filter baghouse was provided by SPE-Amerex.
- The estimated number of bags in the baghouse was provided by SPE-Amerex. The bag life was assumed to be three years, so the bag replacement cost was estimated as one third of the total bag cost per year.
- There is no operating or administrative labor associated with the fabric filter baghouse.

Conversion of the Hot-Side ESP to a Cold-Side ESP

The capital cost of converting the hot-side ESP at THEC Unit 2 to a cold-side ESP, including equipment, installation and owner's costs, was provided by Minnesota Power. This study assumes that these costs reflect the capital cost of the equipment expected at THEC Unit 3.

The O&M costs associated with the ESP conversion are based on the following:

- Power costs provided by Minnesota Power.
- Minnesota Power advised that there was 100-kW increase in ESP power consumption when the THEC Unit 2 ESP was converted to cold-side. This study assumes the same power consumption increase for the THEC Unit 3 ESP.
- Minnesota Power advised that there was no increase in operating or maintenance labor costs associated with the THEC Unit 2 ESP conversion. This study assumes the same for THEC Unit 3.

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