Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in North Dakota

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Revised Draft Report

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Scope of Document

This document provides an initial analysis of the four factors which must be considered in establishing a reasonable progress goal toward achieving natural visibility conditions in mandatory Class I areas. These factors were examined for several candidate control measures for priority pollutants and emission sources. The results of this report are intended to inform policymakers in setting reasonable progress goals for the Class I areas in the Western Regional Air Partnership (WRAP) region.

This document does not address policy issues, set reasonable progress goals, or recommend a long-term strategy for regional haze. Separate documents will be prepared by the States which address the reasonable progress goals, each state's share of emission reductions, and coordinated emission control strategies.

Disclaimer

The analysis described in this document has been funded by the Western Governors' Association. It has been subject to review by the WGA and the WRAP. However, the report does not necessarily reflect the views of the sponsoring and participating organizations, and no official endorsement should be inferred.

Contents

Abbreviations

ACT	Alternative Control Techniques
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CBA	Cold Bed Adsorption
CO_2	Carbon Dioxide
DSI	Duct Sorbent Injection
EC	Elemental Carbon
EDMS	Emissions Data Management System
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
FGD	Flue Gas Desulfurization
FF	Fabric Filters
ICAC	Institute of Clean Air Companies
LAER	Lowest Achievable Emission Rate
LEC	Low-Emission Combustion
LNB	Low-NOx Burners
MRPO	Midwest Regional Planning Organization
MW	Megawatt
NACAA	National Association of Clean Air Agencies
NEI	National Emissions Inventory
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standards
OC	Organic Carbon
OFA	Overfire Air
PM	Particulate Matter
PM_{10}	Particulate Matter Particles of 10 Micrometers or Less
$PM_{2.5}$	Particulate Matter Particles of 2.5 Micrometers or Less
RACT	Reasonably Available Control Technology
SCR	Selective Catalytic Reduction
SNCR	Selective Noncatalytic Reduction
SO_2	Sulfur Dioxide
SRU	Sulfur Recovery Unit
TGTU	Tail Gas Treatment Units
WRAP	Western Regional Air Partnership

Units

acfm	Actual Cubic Feet per Minute
cfm	Cubic Feet per Minute
kWh	Kilowatt Hour
MM-BTU/hr	Million British Thermal Units per Hour
MW	Megawatt
ppmv	Parts per Million by Volume
scfm	Standard Cubic Feet per Minute

1. Introduction

The Regional Haze Rule requires States to set reasonable progress goals toward meeting a national goal of natural visibility conditions in Class I areas by the year 2064. The first reasonable progress goals will be established for the planning period 2008 to 2018. The Western Regional Air Partnership (WRAP), along with its member states, tribal governments, and federal agencies, are working to address visibility impairment due to regional haze in Class I areas. The Regional Haze Rule identifies four factors which should be considered in evaluating potential emission control measures to meet visibility goals. These are as follows:

1. Cost of compliance
2. Time necessary for compliance
3. Energy and non-air quality environmental impacts of compliance
4. Remaining useful life of any existing source subject to such requirements

This report has been prepared as part of a project to evaluate the above factors for possible control strategies intended to improve visibility in the WRAP region. We have identified control measures for emissions of nitrogen oxides (NO_X) and sulfur dioxide (SO_2), which can react in the atmosphere to produce visibility-obscuring particulate matter on a regional scale, and also for direct emissions of particulate matter. For direct particulate matter emissions (PM), we have evaluated the impacts of control measures on various particulate matter components, including $PM_{2.5}$, PM_{10}, elemental carbon (EC) particulate matter, and organic carbon (OC) particulate matter. A number of emission source categories have been addressed, including:

1. Reciprocating internal combustion engines and turbines
2. Oil and natural gas exploration and production field operations
3. Natural gas processing plants
4. Industrial boilers
5. Cement manufacturing plants
6. Sulfuric acid manufacturing plants
7. Pulp and paper plant lime kilns
8. Petroleum refinery process heaters

The four-factor analyses for these emission categories are documented in a separate report, entitled “Assessing Reasonable Progress for Regional Haze in the WRAP Region – Source Category Analysis.”

The current report presents the results of a four-factor analysis of potential control measures for selected emission sources in North Dakota. The emission sources addressed in this current report were selected by the North Dakota Department of Health, and include two electric generating units, three industrial boilers at a coal gasification facility, a sulfur recovery unit and several compressor engines at a natural gas processing facility, and a sulfur recovery unit at another gas processing facility. This report is organized in 4 sections, including this introduction. Section 2 presents the methodology employed to conduct the following analyses and Section 3 results of the four-factor analysis for boilers, including the electric generating units and the industrial boiler at the coal gasification facility. Section 4 gives the results of the four-factor analysis for the natural gas processing facilities.

2. Methodology

The first step in the technical evaluation of control measures for a source category was to identify the major sources of emissions from the category. Emissions assessments were initially based on 2002 emissions inventory in the WRAP Emissions Data Management System (EDMS),[1] which consists of data submitted by the WRAP states in 2004. The states then reviewed the emissions data and parameters from the EDMS used for this analysis and provided updated data when applicable. In some cases, detailed data on PM_{10} and $PM_{2.5}$ emissions were not available from the WRAP inventory. Therefore, PM_{10} and $PM_{2.5}$ data from the U.S. Environmental Protection Agency's (EPA) 2002 National Emissions Inventory (NEI) were used to supplement the WRAP inventory where necessary.

Once the important emission sources were identified within a given emission source category, a list of potential additional control technologies was compiled from a variety of sources, including control techniques guidelines published by the EPA, emission control cost models such as AirControlNET[2] and CUECost,[3] Best Available Retrofit Technology (BART) analyses, White Papers prepared by the Midwest Regional Planning Organization (MRPO),[4] and a menu of control options developed by the National Association of Clean Air Agencies (NACAA).[5] The options for each source category were then narrowed to a set of technologies that would achieve the emission reduction target under consideration. The following sections discuss the methodology used to analyze each of the regional haze factors for the selected technologies.

2.1 Factor 1 – Costs

Control costs include both the capital costs associated with the purchase and installation of retrofit and new control systems, and the net annual costs (which are the annual reoccurring costs) associated with system operation. The basic components of total capital costs are direct capital costs, which includes purchased equipment and installation costs, and indirect capital expenses. Direct capital costs consist of such items as purchased equipment cost, instrumentation and process controls, ductwork and piping, electrical components, and structural and foundation costs. Labor costs associated with construction and installation are also included in this category. Indirect capital expenses are comprised of engineering and design costs, contractor fees, supervisory expenses, and startup and performance testing. Contingency costs, which represent such costs as construction delays, increased labor and equipment costs, and design modification, are an additional component of indirect capital expenses. Capital costs also include the cost of process modifications. Annual costs include amortized costs of capital investment, as well as costs of operating labor, utilities, and waste disposal. For fuel switching options, annual costs include the cost differential between the current fuel and the alternate fuel.

The U.S. EPA's *Guidance for Setting Reasonable Progress Goals under the Regional Haze Program*[6] indicates that the four-factor analyses should conform to the methodologies given in the *EPA Air Pollution Control Cost Manual*.[7] This study draws on cost analyses which have followed the protocols set forth in the Cost Manual. Where possible, we have used the primary references for cost data. Cost estimates have been updated to 2007 dollars using the Marshall & Swift Equipment Cost Index or the Chemical Engineering Plant Cost Index, both of which are published in the journal, *Chemical Engineering.*

For Factor 1, results of the cost analysis are expressed in terms of total cost-effectiveness, in dollars per ton of emissions reduced. A relevant consideration in a cost-effectiveness calculation is the economic condition of the industry (or individual facility if the analysis is performed on that basis). Even though a given cost-effectiveness value may, in general, be considered "acceptable," certain industries may find such a cost to be overly burdensome. This is particularly true for well-established industries with low profit margins. Industries with a poor economic condition may not be able to install controls to the same extent as more robust industries. A thorough economic review of the source categories selected for the factor analysis is beyond the scope of this project.

2.2 Factor 2 – Time Necessary for Compliance

For Factor 2, we evaluated the amount of time needed for full implementation of the different control strategies. The time for compliance was defined to include the time needed to develop and implement the regulations, as well as the time needed to install the necessary control equipment. The time required to install a retrofit control device includes time for capital procurement, device design, fabrication, and installation. The Factor 2 analysis also included the time required for staging the installation of multiple control devices at a given facility.

2.3 Factor 3 – Energy and Other Impacts

Table 2-1 summarizes the energy and environmental impacts analyzed under Factor 3. We evaluated the direct energy consumption of the emission control device, solid waste generated, wastewater discharged, acid deposition, nitrogen deposition, and climate impacts (e.g., generation and mitigation of greenhouse gas emissions).

In general, the data needed to estimate these energy and other non-air pollution impacts were obtained from the cost studies which were evaluated under Factor 1. These analyses generally quantify electricity requirements, steam requirements, increased fuel requirements, and other impacts as part of the analysis of annual operation and maintenance costs.

Costs of disposal of solid waste or otherwise complying with regulations associated with waste streams were included under the cost estimates developed under Factor 1, and were evaluated as to whether they could be cost-prohibitive or otherwise negatively affect the facility. Energy needs and non-air quality impacts of identified control technologies were aggregated to estimate the energy impacts for the specified industry sectors. However, indirect energy impacts were not considered, such as the different energy requirements to produce a given amount of coal versus the energy required to produce an equivalent amount of natural gas.

Table 2-1 Summary of Energy and Environmental Impacts Evaluated Under Factor 3

Energy Impacts
Electricity requirement for control equipment and associated fans
Steam required
Fuel required
Environmental Impacts
Waste generated
Wastewater generated
Additional carbon dioxide (CO_2) produced
Reduced acid deposition
Reduced nitrogen deposition
Benefits from reductions in $PM_{2.5}$ and ozone, where available
Impacts Not Included
Impacts of control measures on boiler efficiency
Energy required to produce lower sulfate fuels
Secondary environmental impacts to produce additional energy (except CO_2) produced

2.4 Factor 4 – Remaining Equipment Life

Factor 4 accounts for the impact of the remaining equipment life on the cost of control. Such an impact will occur when the remaining expected life of a particular emission source is less than the lifetime of the pollution control device (such as a scrubber) that is being considered. In this case, the capital cost of the pollution control device can only be amortized for the remaining lifetime of the emission source. Thus, if a scrubber with a service life of 15 years is being evaluated for a boiler with an expected remaining life of 10 years, the shortened amortization schedule will increase the annual cost of the scrubber.

The ages of major pieces of equipment were determined where possible, and compared with the service life of pollution control equipment. The impact of a limited useful life on the amortization period for control equipment was then evaluated, along with the impact on annualized cost-effectiveness.

2.5 References for Section 2

1. WRAP (2008), *Emissions Data Management System*, Western Regional Air Partnership, Denver, CO, http://www.wrapedms.org/app_main_dashboard.asp.

2. E.H. Pechan & Associates (2005), *AirControlNET*, *Version 4.1 - Documentation Report*, U.S. EPA, RTP, NC, http://www.epa.gov/ttnecas1/AirControlNET.htm.

3. *Coal Utility Environmental Cost (CUECost) Model Version 1.0*, U.S. EPA, RTP, NC, http://www.epa.gov/ttn/catc/products.html.

4. MRPO (2006), *Interim White Papers-- Midwest RPO Candidate Control Measures*, Midwest Regional Planning Organization and Lake Michigan Air Directors Consortium, Des Plaines, IL, www.ladco.org/reports/control/white_papers/.

5. NACAA (formerly STAPPA and ALAPCO) (2006), *Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options*, National Association of Clean Air Agencies, www.4cleanair.org/ PM25Menu-Final.pdf.

6 EPA (2007), *Guidance for Setting Reasonable Progress Goals under the Regional Haze Program*, http://www.epa.gov/ttncaaa1/t1/memoranda/reasonable_progress_guid071307.pdf.

7. EPA (2002), *EPA Air Pollution Control Cost Manual*, *6th ed.*, EPA/452/B-02-001, U.S. EPA, Office of Air Quality Planning and Standards, RTP, NC, Section 5 - SO_2 and Acid Gas Controls, pp 1-30 through 1-42, http://www.epa.gov/ttncatc1/products.html#cccinfo.

3. Boilers

A four factor analysis was performed on three coal-fired boilers; two units at Antelope Valley Station (Units B1 & B2), and one unit at Coyote Station, and three waste gas/liquid boilers at the Dakota Gasification Company. The boilers at Antelope Valley and Coyote are used to produce steam from the combustion of lignite coal to generate electricity in a steam turbine. The units at the Antelope Valley Station are rated at 450 megawatts (MW), and the unit at Coyote Station is rated at 427 MW. Pollutant emissions from the boilers include: nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). The boilers at Dakota Gasification are used to combust off-gas and waste liquids to provide process steam for the facility. Each of the boilers is rated at 763 MMBtu/hr and is vented to a common exhaust stack. In addition to the emissions from the three boilers, two superheaters rated at 169 MMBtu/hr are also vented to this common exhaust stack.

Table 2-1 summarizes the NO_X and SO_2 emissions from each of the boilers, as well as the control measures used to reduce these pollutant emissions.[1] The pollutant emission rates shown in Table 2-1 were obtained from the North Dakota Department of Health, Division of Air Quality.[2] The pollutant emissions are the based on the average of the two highest annual emission rates from the last five years. For the Dakota Gasification facility, the annual emissions were presented for the common exhaust stack, which includes the pollutant emissions from the three boilers and two superheaters. To estimate the emissions from each boiler, the total emission for each pollutant was divided by the total heat input and hours of operation of the boilers and superheaters to develop emission factors for each pollutant. The emission factors were used to estimate the pollutant emissions for each of the boilers based on the heat input to the boiler and the average hours of operation. Emissions of EC and OC can be estimated using speciation factors from EPA's SPECIATE database.[3] The EC and OC components are estimated to comprise 0.021% and 0.012% of PM_{10} emissions from the coal-fired boilers, respectively. There is not enough information to determine the speciation weight percentages for the Dakota Gasification facility, because the facility combusts waste liquid and gas streams from the facility processes.

Table 3-1. Emissions from Selected Boilers - North Dakota

Source Name	Facility Name	Unit ID	Unit Type	Boiler Size (MMBtu/hr)	NO_X Annual Emissions (tons/yr)	SO_2 Annual Emissions (tons/yr)	PM Annual Emissions (tons/yr)
Basin Electric Power	Antelope Valley Station	Unit B1	Lignite coal-fired boiler equipped with OFA, dry scrubber, FF	6,275	7,625	8,117	397
		Unit B2	Lignite coal-fired boiler equipped with OFA, dry scrubber, FF	6,275	6,764	7,298	390
Otter Tail Power Company	Coyote Station	Unit 1	Lignite coal-fired cyclone boiler equipped with dry scrubber, FF	5,800	13,058	14,864	273
Dakota Gasification Co.	Great Plains Synfuels Plant	Unit A[1]	Waste gas/liquid boiler equipped with wet ESP, and wet FGD	763	935	723	65
		Unit B[1]	Waste gas/liquid boiler equipped with wet ESP, and wet FGD	763	935	723	65
		Unit S[1]	Waste gas/liquid boiler equipped with wet ESP, and wet FGD	763	935	723	65

[1] The available pollutant emissions included the emissions for all three boilers rated at 763 MMBtu/hr and two superheaters rated at 169 MMBtu/hr. To estimate the pollutant emissions for each of the boilers the heat inputs and annual operation of the boilers and superheaters were used to develop emission factors. The emission factors were then used to estimate the individual boiler pollutant emissions.

Currently, the Antelope Valley units are equipped with overfire air, dry scrubber and fabric filter to reduce pollutant emissions. The dry scrubber is used to reduce emissions of SO_2 from the exhaust gas and the FF is used to reduce PM, EC, and OC emissions. The units at Antelope Valley are also equipped with OFA to reduce emission of NO_X from the boilers. The Coyote Station boiler is a cyclone unit equipped with a dry scrubber (DSI) and fabric filter (FF). The Dakota Gasification facility is equipped with wet flue gas desulfurization (FGD) and wet electrostatic precipitator (ESP). A list of potential NO_X and SO_2 control strategies are presented in Table 2-2. The table provides the potential emission reductions for each of the control options.[4,5] For NO_X, the emissions reductions assumes the control option is used in conjunction with the current NO_X control technology. For SO_2, the potential emission reduction is calculated assuming a Wet FGD replaces the current SO_2 control technology. These control options have been applied to many electrical generating unit boilers in the U.S. to reduce emissions of NO_X and SO_2. In Table 2-2, the baseline emissions for NO_X are presented as the average of the two highest annual emission rates over the past five years. The uncontrolled emissions for SO_2 are estimated using an AP-42 emission factor of 30S, and assuming a heat rate of 10,400 Btu/Kw-hr for Antelope Valley and 11,400 Btu/Kw-hr for Coyote Station, a coal sulfur content of 0.6%, and operating 8760 hr/yr. The SO_2 emissions at Dakota Gasification are presented as controlled. The boilers are already equipped with wet FGD which achieves the highest potential SO_2 reduction of any of the control options.

Table 3-2. Control Options for Selected Boilers - North Dakota

Facility Name	Source Type	Pollutant controlled	Control Technology	Uncontrolled emissions[1] (tons/yr)	Annual Emissions (tons/yr)	Estimated control efficiency (%)	Potential emissions reductions[2] (tons/yr)
Antelope Valley Station - Unit B1	Lignite coal-fired boiler equipped with OFA, dry scrubber, FF	NO_X	LNB	12,093	7,625	30 - 75	5,719
			SNCR			30 - 75	5,719
			SCR			40 - 90	6,863
		SO_2	Wet FGD	31,057	8,117	90	5,011
Antelope Valley Station - Unit B2	Lignite coal-fired boiler equipped with OFA, dry scrubber, FF	NO_X	LNB	12,093	6,764	30 - 75	9,070
			SNCR			30 - 75	9,070
			SCR			40 - 90	10,884
		SO_2	Wet FGD	31,057	7,298	90	4,192
Coyote Station - Unit 1	Lignite coal-fired cyclone boiler equipped with dry scrubber, FF	NO_X	SNCR	13,058	13,058	30 - 75	9,794
			SCR			40 - 90	11,752
		SO_2	Wet FGD	28,707	14,864	90	11,993
Great Plains Synfuels Plant - Unit A	Waste gas/liquid boiler equipped with wet ESP, and wet FGD	NO_X	SNCR	935	935	30 - 75	701
			SCR			40 - 90	842
Great Plains Synfuels Plant - Unit B	Waste gas/liquid boiler equipped with wet ESP, and wet FGD	NO_X	SNCR	935	935	30 - 75	701
			SCR			40 - 90	842
Great Plains Synfuels Plant - Unit S	Waste gas/liquid boiler equipped with wet ESP, and wet FGD	NO_X	SNCR	935	935	30 - 75	701
			SCR			40 - 90	842

[1] NO_X uncontrolled emissions calculated using AP-42 emission factors for lignite combustion. SO_2 uncontrolled emissions were calculated using an AP-42 SO_2 emission factor of 30S and assuming 0.6% Sulfur coal.

[2] Potential NO_X emission reductions were calculated assuming the addition of the control options with the existing control technology and assuming the highest percent reduction in the estimated control efficiency range. Potential SO_2 emission reductions were calculated assuming the replacement of the current SO_2 control system with a more effective SO_2 control system.

3.1 Factor 1 – Costs

Table 2-3 provides cost estimates for the emission control options which have been identified for each of the electrical generating unit boilers. Each of the boilers are already equipped with effective PM control, therefore additional PM options were not explored for these boilers. For the NO_X and SO_2 options, the table gives an estimate of the capital cost to install the necessary equipment, and the total annual cost of control, including the amortized cost associated with the capital equipment cost. The capital cost values are expressed in terms of the cost per MW size of the boiler using EPA cost information.[6,7] The capital cost data was extrapolated to determine the capital cost for the larger sized boilers. The annual cost was calculated by amortizing the capital cost over 30 years at an interest rate of 7% and multiplying that value by an O&M factor. Table 2-3 also estimates the cost effectiveness for each control measure, in terms of the cost per ton of emission reduction. Table 2-3 also estimates the cost effectiveness for each control measure, in terms of the cost per ton of emission reduction. Recent literature[8] has indicated that the cost of SCR for electric generating units can vary from $150 to $300 per kilowatt, therefore due to this variability, the capital and annual costs for SCR are presented as a range.

Emissions used to estimate the cost effectiveness of the control options were obtained from Table 3-2. For NO_X, the emissions used for the cost effectiveness calculations were the controlled emission rates. The NO_X controlled emission rates were used because the currently installed NO_X controls can be used in conjunction with the listed control options to reduce NO_X emissions from the current levels. For SO_2, uncontrolled emission levels were estimated for the coal-fired boilers to compare the current SO_2 emission levels with potential SO_2 emission reductions using the listed control technologies.

It should be noted that the application of high dust SCR may not be technically feasible for use on the lignite coal-fired boilers. The lignite coal contains a higher ash content which causes catalyst deactivation and air heater corrosion/blockage. In addition, the higher organically associated sodium in the lignite coal also deactivates the catalyst rapidly. Therefore, each boiler should be evaluated to determine the technical feasibility of applying high dust SCR to control emissions of NO_X.

3.2 Factor 2 – Time Necessary for Compliance

Once a State decides to adopt a particular control strategy, up to 2 years will be needed to develop the necessary rules to implement the strategy. We have estimated that sources may then require up to a year to procure the necessary capital to purchase control equipment. The Institute of Clean Air Companies (ICAC) has estimated that approximately 18 months is required to design, fabricate, and install SCR or SNCR technology for NO_X control, and approximately 30 months to design, build, and install SO_2 scrubbing technology.[9] Additional time of up to 12 months may be required for staging the installation process if multiple boilers are to be controlled at a single facility. Based on these figures, the total time required to achieve emission reductions for industrial boilers is estimated at a total of 5½ years for NO_X strategies, and 6½ years for SO_2 strategies.

3.3 Factor 3 – Energy and Other Impacts

Table 2-4 shows the estimated energy and non-air pollution impacts of control measures for industrial boilers. The values were obtained the EPA report listing the performance impacts of each of the control technology options.[10,11] In general, the combustion modification technologies (LNB, OFA) do not require steam or generate solid waste, or wastewater. They also do not require additional fuel to operate, and in some cases may decrease fuel usage because of the optimized combustion of the fuel.

Retrofitting of a SNCR requires energy for compressor power and steam for mixing. This would produce a small increase in CO_2 emissions to generate electricity; however the technology itself does not produce additional CO_2 emissions.

Installation of SCR on an industrial boiler is not expected to increase fuel consumption. However, additional energy is required to operate the SCR, which will produce an increase in CO_2 emissions to generate the electricity. In addition, spent catalyst would have to be changed periodically, producing an increase in solid waste disposal. However, many catalyst companies accept the return of spent catalyst material.

Table 3-3. Estimated Costs of Control for Selected Boilers - North Dakota

Facility Name	Pollutant controlled	Control Technology	Estimated control efficiency (%)	Estimated capital cost ($1000)	Estimated annual cost ($1000/yr)	Cost effectiveness ($/ton)
Antelope Valley Station - Unit B1	NO_X	LNB	51	14,530	2,280	586
		SNCR	40	15,020	8,960	2,938
		SCR	80	67,500 - 135,000	16,966 - 33,932	2,781 - 5,563
	SO_2	Wet FGD	90	170,100	32,170	6,420
Antelope Valley Station - Unit B2	NO_X	LNB	51	14,530	2,280	661
		SNCR	40	15,020	8,960	3,312
		SCR	80	67,500 - 135,000	16,966 - 33,932	3,135 - 6,271
	SO_2	Wet FGD	90	170,100	32,170	7,674
Coyote Station - Unit 1	NO_X	SNCR	40	14,270	8,520	1,631
		SCR	80	64,050 - 128,100	16,099 - 32,198	1,541 - 3,082
	SO_2	Wet FGD	90	161,700	30,580	2,550
Great Plains Synfuels Plant - Unit A	NO_X	SNCR	40	2,840	1,690	4,519
		SCR	80	10,950 - 21,900	2,752 - 5,505	3,680 - 7,359
Great Plains Synfuels Plant - Unit B	NO_X	SNCR	40	2,840	1,690	4,519
		SCR	80	10,950 - 21,900	2,752 - 5,505	3,680 - 7,359
Great Plains Synfuels Plant - Unit S	NO_X	SNCR	40	2,840	1,690	4,519
		SCR	80	10,950 - 21,900	2,752 - 5,505	3,680 - 7,359

[1] The annual cost was calculated using a 30-year equipment life and 7% interest.

[2] NO_X cost effectiveness is calculated from annual emissions using the estimated control efficiency and assumes that the control option is used in conjunction with the current NO_X control. SO_2 cost effectiveness is calculated using the potential emission reductions and reflects the replacement of the current SO_2 control with a Wet FGD.

Retrofitting of the SO_2 control options increase the usage of electricity, and produce both a solid waste and wastewater stream. In addition, increases of CO_2 emission will occur due to the increased energy usage for material preparation (e.g., grinding), materials handling (e.g., pumps/blowers), flue gas pressure loss, and steam requirements. Power consumption is also affected by the reagent utilization of the control technology, which also affects the control efficiency of the control technology.

3.4 Factor 4 – Remaining Equipment Life

Electric generating units do not have a set equipment life. Since many of the strategies are market-based reductions applied to geographic regions, it is assumed that control technologies will not be applied to units that are expected to be retired prior to the amortization period for the specific control equipment. Therefore, the remaining life of an industrial boiler is not expected to affect the cost of control technologies for industrial boilers.

Table 3-4. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Selected Boilers - North Dakota

			Energy and non-air pollution impacts				
Source Type	Control Technology	Pollutant controlled	Electricity requirement (kW)	Steam requirement (lb/hr)	Solid waste produced (ton/hr)	Wastewater produced (gal/min)	Additional CO_2 emitted (tons/yr)
Antelope Valley Station - Unit B1	LNB	NO_X	21.2				0.0212
	SNCR	NO_X	122	1,522			0.122
	SCR	NO_X	3,256	1,826			3.26
	Wet FGD	SO_2	9,423		27.8	585	9.4
Antelope Valley Station - Unit B2	LNB	NO_X	21.2				0.0212
	SNCR	NO_X	122	1,368			0.122
	SCR	NO_X	3,256	1,642			3.26
	Wet FGD	SO_2	9,423		27.8	585	9.4
Coyote Station - Unit 1	SNCR	NO_X	116	3,344			0.1161
	SCR	NO_X	3,089	3,344			3.09
	Wet FGD	SO_2	8,941		26.4	555	8.9
Great Plains Synfuels Plant - Unit A	LNB	NO_X	3.4				0.0034
	LNB w/ OFA	NO_X	3.4				0.0034
	SNCR	NO_X	20	136			0.020
	SCR	NO_X	528	163			0.53
Great Plains Synfuels Plant - Unit B	LNB	NO_X	3.4				0.0034
	LNB w/ OFA	NO_X	3.4				0.0034
	SNCR	NO_X	20	136			0.020
	SCR	NO_X	528	163			0.53
Great Plains Synfuels Plant - Unit S	LNB	NO_X	3.4				0.0034
	LNB w/ OFA	NO_X	3.4				0.0034
	SNCR	NO_X	20	136			0.020
	SCR	NO_X	528	163			0.53

NOTES:
A blank cell indicates no impact is expected.

3.5 References for Section 3

1. NEEDS 2006.

2. Email from Tom Bachman, North Dakota Division of Air Quality to Janet Hou, EC/R (3/4/2009), Data for four factors analysis.

3. EPA (2006), *SPECIATE version 4*, U.S. EPA, RTP, NC. http://www.epa.gov/ttn/chief/software/speciate/index.html

4. MRPO (2006), *Interim White Paper - Midwest RPO Candidate Control Measures Source Category: Industrial, Commercial, and Institutional (ICI) Boilers*. http://www.ladco.org/reports/control/white_papers/

5. NESCAUM (2009), *Applicability and Feasibility of NO_X, SO_2, and PM Emission Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers*.

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7. Khan, Sikander (2003), *Methodology, Assumptions, and References: Preliminary SO2 Controls Cost Estimates for Industrial Boilers*.

8. Power Magazine (2006), *Estimating SCR Installation Costs*. http://www.powermag.com/instrumentation_and_controls/Estimating-SCR-installation-costs_506_p3.html

9. Institute of Clean Air Companies (2006), *Typical Installation Timelines for NO_X missions Control Technologies on Industrial Sources*.

10. Reference 6.

11. Reference 7.

4. Natural Gas Processing Facilities

Four-factor analyses have been conducted for selected emission sources at the Hess Corporation Tioga Gas Plant, in Williams County, North Dakota, and the Petro Hunt Little Knife Gas Plant in Billings County, North Dakota. The following emission sources have been evaluated:

- Petro Hunt Little Knife Gas Plant
  - Sulfur recovery unit (SRU) for amine treatment unit #1
- Hess Corporation Tioga Gas Plant
  - SRU for amine treatment unit #1
  - Seven lean-burn natural gas-fired compressor engines – five at 1,920 horsepower (hp) and two at 2,350 hp

Table 4-1 outlines the emission control measures that have already been applied to these sources, the baseline levels of emissions with these current controls, and potential additional control measures that could be adopted to further reduce emissions. The table also gives the estimated control efficiency and annual emission reduction for each potential future control measure.

Information on existing control measures and baseline emission levels for the North Dakota facilities was obtained from the North Dakota Department of Health.[1] The baseline emission level for each source reflects the average of the two highest annual emission rates over the past five years.

The Petro Hunt Little Knife plant has a 3-stage SRU with a cold bed adsorption (CBA) control system. The SRU has a capacity of 120 long tons sulfur per day and an estimated overall recovery efficiency of over 98%. The Hess Tioga plant has a 2-stage Claus SRU, also with a CBA control system. This unit has a capacity of 225 long tons of sulfur per day and an overall recovery efficiency of over 97%.

The New Source Performance Standards (NSPS) for sulfur recovery units at petroleum refineries limit SO2 emissions to 250 ppm, which corresponds to an overall efficiency of 99.98% (from the uncontrolled flow rate of sulfur compounds in the SRU feed stream).[2] This emission rate is generally achieved using tail gas treatment technologies.[3] EPA's RACT/BACT/LAER Clearinghouse indicates that tail gas treatment units (TGTU) installed on sulfur recovery units at petroleum refineries in recent years typically are required to achieve a controlled SO_2 emission concentration of 150 ppm,[4] which corresponds to an overall efficiency of 99.988%. Therefore, it is expected that TGTUs applied to the Petro Hunt and Hess SRUs could achieve an overall sulfur removal efficiency of between 99.98% and 99.988%. This would correspond to a reduction of

Table 4-1. Existing Control Measures and Potential Additional Control Options for Selected Natural Gas Processing Operations in North Dakota

Company	Source	Pollutant	Existing controls	Baseline emissions (tons/yr)	Potential additional control measures	Estimated control efficiency (%)	Potential emission reduction (tons/year)	Refer-ences
Petro Hunt, Little Knife Gas Plant	Sulfur recovery unit, 3-stage, 4-bed, 120 long tons/day sulfur	SO_2	3-stage unit with cold bed adsorbtion, >98% efficient	432	Tail-gas treatment unit - Amine absorption	87 - 92	370 - 400	2,3
Hess Corp., Tioga Gas Plant	Sulfur recovery unit, 2-bed Claus, 225 long tons/day sulfur	SO_2	2-stage Claus unit with cold bed adsorbtion, >97% efficient	1,221	Tail-gas treatment unit - Amine absorption	92 - 95	1,120 - 1,160	2,3
	Natural gas fired reciprocating engines, 1,920 hp, 2-stroke lean burn (Clark Model HLA-8, 5 engines)	NO_X	None	1,566	Air-fuel ratio controllers	10 - 40	160 - 630	5
					Ignition timing retard	15 - 30	230 - 470	5
					Low Emission Combustion (LEC) technology retrofit	80 - 90	1,300 - 1,400	8
					SCR	80 - 90	1,300 - 1,400	5,6,8
					Replacement with electric motors	100	1,600	7
		PM_{10}	None	10	Replacement with electric motors	100	10	7
		$PM_{2.5}$		10			10	
		EC		3.8			3.8	
		OC		2.5			2.5	
	Natural gas fired reciprocating engines, 2,350 hp, 2-stroke lean burn (Clark Model HLA-8, 2 engines)	NO_X	Recently refurbished, NO_X emissions reduced by about 70%	216	SCR	33 - 67	71 - 140	5,6,8
					Replacement with electric motors	100	220	7
		PM_{10}	None	6	Replacement with electric motors	100	6	7
		$PM_{2.5}$		6			6	
		EC		2.3			2.3	
		OC		1.5			1.5	

about 87 to 92% for the Petro Hunt facility (assuming a baseline efficiency of 98.5%), 92 to 95% for the Hess facility (assuming a baseline efficiency of 97.5%).

The Hess Tioga facility uses five 1,920 hp reciprocating engines and two 2,350 hp reciprocating engines, all fueled by natural gas in a under lean-burn fueling mode. The two 2,350 hp engines have recently been refurbished, and the reported NO_X emissions from these engines are about 70% lower than the reported emissions from the 1,920 hp engines, or a mass per hp-hour basis.

A number of options have been identified for stationary reciprocating engines in an Alternative Control Techniques (ACT) guidance document written by the U.S. EPA in 1993, and in more recent analyses for New Source Performance Standards.[5,6] In addition, the WRAP sponsored a study of control options for engines used in the oil and gas industry.[7] Reciprocating engines can be designed to operate under rich fuel mixture, or lean fuel mixture conditions. Air-to-fuel-ratio adjustments and ignition retarding technologies can be used to control emissions under either fuel mixture condition. Low-Emission Combustion (LEC) retrofit technology which can also reduce emissions from reciprocating engines by an average of 89%.[8] LEC involves modifying the combustion system to achieve very lean combustion conditions (high air-to-fuel ratios). SCR can also be used either alone or in conjunction with the above technologies to reduce NO_X emissions from reciprocating engines or turbines by 90%. EPA prepared an update to the ACT guidance for reciprocating engines in 2002 which focused on LEC technology and also updated the analysis of SCR.

For the two 2,350 hp engines, we have adjusted the estimated efficiencies of potential future control measures to reflect the emission reduction which appears to have already achieved by the recent refurbishment. We have assumed that air-to-fuel ratio adjustments, ignition timing retarding, and LEC retrofit technology would not achieve further emission reductions, since the estimated emission reductions for these measures are less than the reductions which appear to have already been achieved.

4.1 Factor 1 – Costs

Table 4-2 provides cost estimates for the emission control options which have been identified for the North Dakota gas processing facilities. For each option, the table gives an estimate of the capital cost to install the necessary equipment, and the total annual cost of control, including the amortized cost associated with the capital equipment cost. The table also shows the estimated cost effectiveness for each control measure, in terms of the cost per ton of emission reduction.

Costs for the SRU tail gas treatment units were estimated using data given capital and annual cost data provided a review of the NSPS for Claus SRUs.[2] The NSPS analysis gives costs for three model plant sizes, which were interpolated to estimate costs for plants in the size ranges of the Petro Hunt and Hess SRUs (120 and 225 long tons per day, respectively).

Table 4-2. Estimated Costs of Control for Selected Natural Gas Processing Operations in North Dakota

Company	Source	Control option	Pollutant	Estimated control efficiency (%)	Potential emission reduction (tons/year)	Estimated capital cost ($1000)	Estimated annual cost ($1000/year)	Cost effectiveness ($/ton)	Refer-ences
Petro Hunt, Little Knife Gas Plant	Sulfur recovery unit, 3-stage, 4-bed, 120 long tons/day sulfur	Tail gas treatment unit - amine absorption	SO_2	87 - 92	370 - 400	9,400	3,200	8,060 - 8,560	2,3
Hess Corp., Tioga Gas Plant	Sulfur recovery unit, 2-bed Claus, 225 long tons/day sulfur	Tail gas treatment unit - amine absorption	SO_2	92 - 95	1,120 - 1,160	15,000	5,800	5,000 - 5,180	2,3
	Five natural gas fired reciprocating engines, 1,920 hp each, 2-stroke lean burn (Clark Model HLA-8)	Air-fuel ratio	NO_X	10 - 40	160 - 630	116	260	410 - 1,630	5
		Ignition timing retard	NO_X	15 - 30	230 - 470	116	140	300 - 610	5
		LEC retrofit	NO_X	80 - 90	1,300 - 1,400	2,300	560	400 - 430	8
		SCR	NO_X	80	1,300 - 1,400	450 - 940	380 - 1,600	270 - 1,230	5,6,8
		Replacement with electric motors	NO_X	100	1,600	900	280	180	7
			PM_{10}	100	10			28,000	
			$PM_{2.5}$	100	10			28,000	
			EC	100	4			73,680	
			OC	100	3			112,000	
			Overall	100	1,610			170	
	Two natural gas fired reciprocating engines, 2,350 hp each, 2-stroke lean burn (Clark Model HLA-8, recently refurbished)	SCR	NO_X	33 - 67	71 - 140	180 - 460	190 - 500	1,360 - 7,040	5,6,8
		Replacement with electric motors	NO_X	100	220	400	140	636	7
			PM_{10}	100	6			23,330	
			$PM_{2.5}$	100	6			23,330	
			EC	100	2			60,870	
			OC	100	2			93,330	
			Overall	100	226			619	

Costs for the reciprocating engine controls were estimated using data provided in the EPA ACT document, the ACT update, and the WRAP analysis for oil and gas production.[5,7,8] These sources give equations which relate capital and annual costs of emission controls to engine size in hp. The equations were applied to the engine sizes at the Hess Tioga plant.

4.2 Factor 2 – Time Necessary for Compliance

Once the regional haze control strategy is formulated for North Dakota, up to 2 years will be needed for the state to develop the necessary rules to implement the strategy. We have estimated that sources may then require up to a year to procure the necessary capital to purchase control equipment. The ICAC has estimated that approximately 13 months is required to design, fabricate, and install SCR or SNCR technology for NO_X control.[9] However, state regulators' experience indicates that closer to 18 months is required to install this technology.[10] In the Clean Air Interstate Rule (CAIR) analysis, EPA estimated that approximately 30 months is required to design, build, and install SO_2 scrubbing technology for a single emission source.[11] The analysis also estimated that up to an additional 12 months may be required for staging the installation process if multiple sources are to be controlled at a single facility.

Based on these figures, the total time required achieve emission reductions for the Petro Hunt facility would be up to 6½ years. This includes 2 years for regulatory development, 1 year for capital acquisition, and 2½ years for designing, building and installing the TGTU. The time to achieve emission reductions for the Hess facility would also be up to 6½ years. This estimate includes the same components as the estimate for Petro Hunt, with an additional year for staging the installation of controls for multiple emission sources (the SRU and the reciprocating engines.)

4.3 Factor 3 – Energy and Other Impacts

Table 4-3 shows the estimated energy and non-air pollution impacts of control measures for sources at the Petro Hunt and Hess facilities. The table shows the additional fuel, electricity, and steam requirements resulting required to operate the control equipment; and the additional solid waste would be produced. CO_2 emissions associated with the generation of the additional electricity and steam are also estimated in the table.

The electricity and steam requirements for sulfur recovery TGTUs are based operating parameters from the 1982 NSPS review analysis.[2] These energy requirements are high in relation to the SO_2 emission reduction. Operating parameters were not readily available for newer TGTU designs; however, the energy requirement of these systems may be lower than the 1982 design.

Table 4-3. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Selected Natural Gas Processing Operations in North Dakota

Source Type		Control Technology	Pollutant controlled	Potential emission reduction (tons/year)	Additional fuel requirement (%)	Energy and non-air pollution impacts (per ton of emission reduced): Electricity requirement (kW-hr)	Steam requirement (tons steam)	Solid waste produced (tons waste)	Additional CO_2 emitted (tons)
Petro Hunt, Little Knife Gas Plant	Sulfur recovery unit, 3-stage, 4-bed, 120 long tons/day sulfur	Amine absorption	SO_2	370 - 400		2,200	210	0.01	57
Hess Corp., Tioga Gas Plant	Sulfur recovery unit, 2-bed Claus, 225 long tons/day sulfur	Amine absorption	SO_2	1,120 - 1,160		700	120	0.004	32
	Five natural gas fired reciprocating engines, 1,920 hp each, 2-stroke lean burn (Clark Model HLA-8)	Air-fuel ratio	NO_X	160 - 630	2.5				1.9
		Ignition timing	NO_X	230 - 470	2.5				1.9
		LEC retrofit	NO_X	1,300 - 1,400	a				
		SCR	NO_X	1,300 - 1,400	0.5				0.4
		Replacement with electric motors	NO_X	1,600	(100)	66,000			b
			$PM_{2.5}$, PM_{10}, EC, OC	10					b
			Total	1,610					b
	Two natural gas fired reciprocating engines, 2,350 hp each, 2-stroke lean burn (Clark Model HLA-8, recently refurbished)	SCR	NO_X	71 - 140	0.5				0.0
		Replacement with electric motors	NO_X	220	(100)	66,000			b
			$PM_{2.5}$, PM_{10}, EC, OC	6					b
			Total	226					b

NOTES:

a - The measure is expected to improve fuel efficiency.

b - CO_2 from the generation of electricity would be offset by avoided emissions due to replacing the diesel engine

blank indicates no impact is expected.

For gas-fired reciprocating engines and diesel engines, air-to-fuel-ratio adjustments and ignition retarding technologies have been found to increase fuel consumption by up to 5%, with a typical value of about 2.5%.[12,13] This increased fuel consumption would result in increased CO_2 emissions. LEC technology is not expected to increase fuel consumption; and may provide some fuel economy.[12]

Installation of SCR on the reciprocating engines would cause a small increase in fuel consumption, about 0.5%, in order to force the exhaust gas through the catalyst bed.[12] This would produce an increase in CO_2 emissions to generate the electricity. In addition, spent catalyst would have to be changed periodically, producing an increase in solid waste disposal.[14]

4.4 Factor 4 – Remaining Equipment Life

The startup dates for the emission sources at the Petro Hunt and Hess natural gas facilities are as follows:

- Petro Hunt Little Knife Plant
  - SRU – 1983
- Hess Tioga Plant
  - SRU – 1991
  - 1,920 hp engines – 1954
  - 2,350 hp engines – 1954

It is not possible to compute the remaining service lifetimes of these sources since emission sources at industrial facilities are often refurbished. For instance, the 2,300 hp engines at Hess were recently refurbished, although they are over 50 years old. Therefore, the remaining lifetimes of the SRUs and compressors are expected to be longer than 15 year figure which has been used to amortize the capital costs of add-on emission controls or equipment modifications to reduce emissions.

If the remaining life of an emission source is less than the projected lifetime of a pollution control device, then the capital cost of the control device would have to be amortized over a shorter period of time, corresponding to the remaining lifetime of the emission source. This would cause an increase in the amortized capital cost of the pollution control option, and a corresponding increase in the total annual cost of control. This increased cost can be quantified as follows:

$$A_1 = A_0 + C \times \frac{1-(1+r)^{-m}}{1-(1+r)^{-n}}$$

where:

A_1 = the annual cost of control for the shorter equipment lifetime ($)
A_0 = the original annual cost estimate ($)
C = the capital cost of installing the control equipment ($)

r = the interest rate (0.07)
m = the expected remaining life of the emission source (years)
n = the projected lifetime of the pollution control equipment

4.5 References for Section 4

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