¶

Mesaba Energy Project

APPLICATION TO THE MINNESOTA POLLUTION CONTROL AGENCY FOR A NEW SOURCE REVIEW CONSTRUCTION AUTHORIZATION PERMIT

MESABA ONE AND MESABA TWO

Prepared by

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GLOSSARY OF TERMS AND ACRONYMS

acfm	Actual Cubic Feet per Minute
AERA	Air Emission Risk Analysis
AGR	Acid Gas Recovery
AP-42	USEPA Compendium of Air Pollutant Emission Factors
AQRV	Air Quality Related Values
ASU	Air Separation Unit
BACT	Best Available Control Technology
BFD	Block Flow Diagram
BFW	Boiler Feed Water
BMP	Best Management Practices
Btu	British Thermal Unit
CAA	Clean Air Act
$CaCO_3$	Calcium Carbonate (Limestone)
CAIR	Clean Air Interstate Rule
CaO	Calcium Oxide (Lime)
CCPI	Clean Coal Power Initiative
CE	Cliffs-Erie, LLC
CEMS	Continuous Emission Monitoring System
C.F.R.	Code of Federal Regulations
CE	Cliffs Erie
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COC	Cycles of Concentration
COS	Carbonyl Sulfide
CR/CRs	Country Road(s)
CTG	Combustion Turbine Generator
DLN	Dry Low NO_x
DOE	Department of Energy
DOT	Department of Transportation
EIS	Environmental Impact Statement
EPA	Environmental Protection Agency
EPC	Engineering, Procurement and Construction
EPRI	Electric Power Research Institute
EU	Emission Unit
FAV	Final Acute Value
FEED	Front End Engineering and Design
FGD	Flue Gas Desulfurization
FSQ	Full Slurry Quench
GCP	Good Combustion Practice

GLG	Great Lakes Gas Transmission Company
GO	Generator Outlet
GPM	Gallons per Minute
gpm	Gallons per Minute
H_2	Hydrogen
H_2O	Water
H_2S	Hydrogen Sulfide
H_2SO_4	Sulfuric Acid
HAP	Hazardous Air Pollutant
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
HVTL	High Voltage Transmission Line
IGCC	Integrated Gasification Combined Cycle
K_2O	Dipotassium Oxide
kW	Kilowatt
LAER	Lowest Achievable Emission Rate
lb/million Btu	Pound per Million British Thermal Unit
lb/MMBtu	Pound per Million British Thermal Unit
LLC	Limited Liability Company
MAAQS	Minnesota Ambient Air Quality Standards
MACT	Maximum Available Control Technology
MDEA	Methyl-Diethanolamine
MDNR	Minnesota Department of Natural Resources
MMBtu	Million British Thermal Units
MMBtu/hr	Million British Thermal Units Per Hour
MOPS	Minnesota Office of Pipeline Safety
MP	Minnesota Power (Company)
MPCA	Minnesota Pollution Control Agency
MW	Megawatt
N_2	Nitrogen
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NETL	National Energy Technology Laboratory (DOE)
NH_3	Ammonia
NiO	Nickel Monoxide
NNG	Northern Natural Gas Co.
NO_X	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NSP	Xcel Energy (Formerly NSP, Northern States Power)
NSPS	New Source Performance Standards

NTP	Notice to Proceed
O&M	Operation and Maintenance
O_2	Oxygen
OSHA	Occupational Safety and Health Administration
PC	Pulverized Coal
PEP	Project Execution Plan
PM	Particulate Matter
PM_{10}	Particulate Matter having an aerodynamic diameter less than 10 Microns
PPA	Power Purchase Agreement
ppmvd	Parts per Million (dry volume)
ppmw	Part per Million (wet basis)
PRB	Powder River Basin
PSD	Preventive of Significant Deterioration
psig	Pounds per Square Inch (gauge)
PSQ	Partial Slurry Quench
PTE	Potential to Emit
RACT	Reasonable Available Control Technology
RCRA	Resource Conservation and Recovery Act
S	Sulfur
SO_3	Sulfur Trioxide
scf	Standard Cubic Feet
SCPC	Supercritical Pulverized Coal
SCR	Selective Catalytic Reduction
SIL	Significant Impact Limits
SNCR	Selective Non Catalytic Reduction
SO_2	Sulfur Dioxide
SRU	Sulfur Recovery Unit
STG	Steam Turbine Generator
SV	Stack Vent
Syngas	Synthetic Gas
TCLP	Toxicity Characteristic Leaching Procedure
TDS	Total Dissolved Solids
TiO_2	Titanium Dioxide
TOC	Total Organic Carbon
TP	Total Phosphorous
TPY	Tons Per Year
TRS	Total Reduced Sulfur
TSP	Total Suspended Particulate Matter
TSS	Total Suspended Solids
TTRA	Taconite Tax Relief Area

VOC	Volatile Organic Compounds
WWTF	Waste Water Treatment Facility
ZLD	Zero Liquid Discharge

1. INTRODUCTION

1.1 Applicant and Air Emission Facility to be Permitted

Excelsior Energy Inc. ("Excelsior"), an energy development company based in Minnetonka, Minnesota has created two wholly-owned project companies, MEP-I LLC and MEP-II LLC (MEP-I LLC and MEP-II LLC, together, the "Applicant" or "Company") to construct, own and operate at a site in Northeastern Minnesota a 1,212 megawatt$_{(net)}$ integrated gasification combined cycle ("IGCC") steam electric power generating station (hereafter, the "IGCC Power Station") fueled by coal and other solid, petroleum-based feedstocks. The Company hereby makes application for a Part 70/New Source Review Construction Authorization for the IGCC Power Station pursuant to the major source provisions of the State of Minnesota's New Source Review ("NSR") program (otherwise referred to as the Prevention of Significant Deterioration ["PSD"] program). Provisions codified at Minn. R. 7007.0200 and 7007.0150, subp.1, and 40 C.F.R. § 52.21 outline the informational requirements for such applications, the assembly of which information is collectively provided herein and hereafter referred to as the "Application").

1.2 Contents of Application

As required, the Application contains relevant applicant information (below in this Section 1), a description of the proposed air emission facility (Section 2), a discussion of regulatory applicability (Section 3), emission estimates (Section 4), determination of Best Available Control Technology (Section 5), a description of the land on which the IGCC Power Station is to be located and the existing meteorology and background air quality characterizing the area (Section 6), an Air Quality Impact Assessment (Section 7), an analysis of impacts to Air Quality Related Values (Section 8), and application forms (Section 9). Table 9.0-1 provided at the beginning of Section 9 provides a summary of the forms included and is intended to facilitate review of the Application.

Calculations used in developing all emission estimates are provided in Appendix A (for criteria pollutants) and Appendix B (for hazardous air pollutants). Appendices C and D contain support for the ambient air quality source impact analysis presented in Section 7 and Section 8. Finally, The Applicant has sponsored preparation of an Air Emission Risk Analysis ("AERA") in accordance with procedures contained in the Minnesota Pollution Control Agency's ("MPCA") AERA Guide (see http://www.pca.state.mn.us/air/aera-guide.html). The report confirming the findings of the AERA is attached as Appendix E.

1.3 Mesaba Energy Project: Phase I and II

The IGCC Power Station described herein consists of Phase I and Phase II of the Mesaba Energy Project (hereafter, "Mesaba One and Mesaba Two," respectively) each phase of which is nominally rated at peak to deliver 606 megawatts ("MW_{net}") of electricity to the bus bar of the high voltage switchyard located within the IGCC Power Station's fenced boundary.

1.4 Terminology

In the following sections of the Application the terms "Project" or "Mesaba One" will be used synonymously with the phrases "Phase I IGCC Power Station" and "Phase I Development." The term "Mesaba Two" will be used synonymously with the phrases "Phase II IGCC Power Station" and "Phase II Development." The combined Phase I and Phase II Developments will be used synonymously with the term "Mesaba One and Mesaba Two" and the phrase "Phase I and II IGCC Power Station." The phrases "IGCC Power Station", "Power Station", or "Station" will be used where the context with respect to Mesaba One, Mesaba Two, or both, is obvious. The term "IGCC Power Station Footprint" or "Station Footprint" means the fenced area within which the IGCC Power Station is located. "Buffer Land" means the land area contiguous with or adjacent to the IGCC Power Station Footprint, extending to the boundary of the property controlled by the Applicant and upon which limited Station-related activity occurs. The term "Associated Facilities" means the buildings, equipment, and other physical structures that are necessary to operate the Station and includes, without limitation: the equipment identified in Sections 1.6.5, 1.6.6, and 1.6.7.

1.5 Applicant Information

The Applicant's offices are located at 11100 Wayzata Boulevard, Suite 305, Minnetonka, Minnesota 55305. The contact for the Application is:

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1.6 Overview of Phase I and II Developments

1.6.1 Location

Mesaba One and Mesaba Two will be located in the Taconite Tax Relief Area ("TTRA") of Northeastern Minnesota in conformance with Minnesota Statutes §216B.1694. Figure 1.6-1 shows the boundary of the TTRA and the location of the IGCC Power Station. A general location map is provided in Figure1.6-2 and shows the IGCC Power Station's proximity to Voyageur's National Park ("VNP"), the Boundary Waters Canoe Area Wilderness ("BWCA"), and Rainbow Lake Wilderness Area, the closest Class 1 areas. A map showing the IGCC Power Station Footprint, Buffer Land, and the Station's immediate proximity to significant receptors is provided in Figure 1.6-3.

Figure 1.6-1 Minnesota Taconite Tax Relief Area

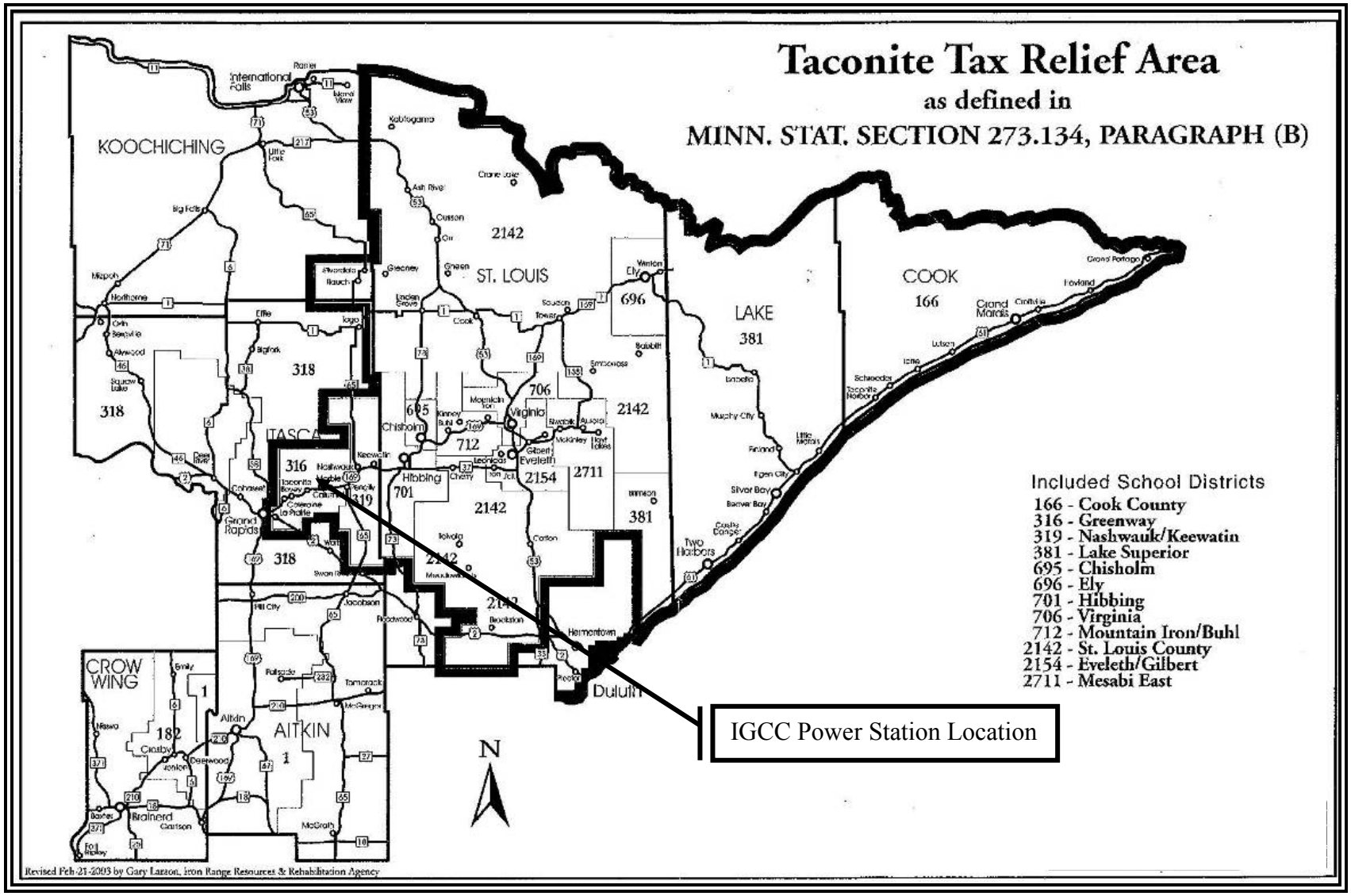


Figure 1.6-2 IGCC Power Station Regional Vicinity Map

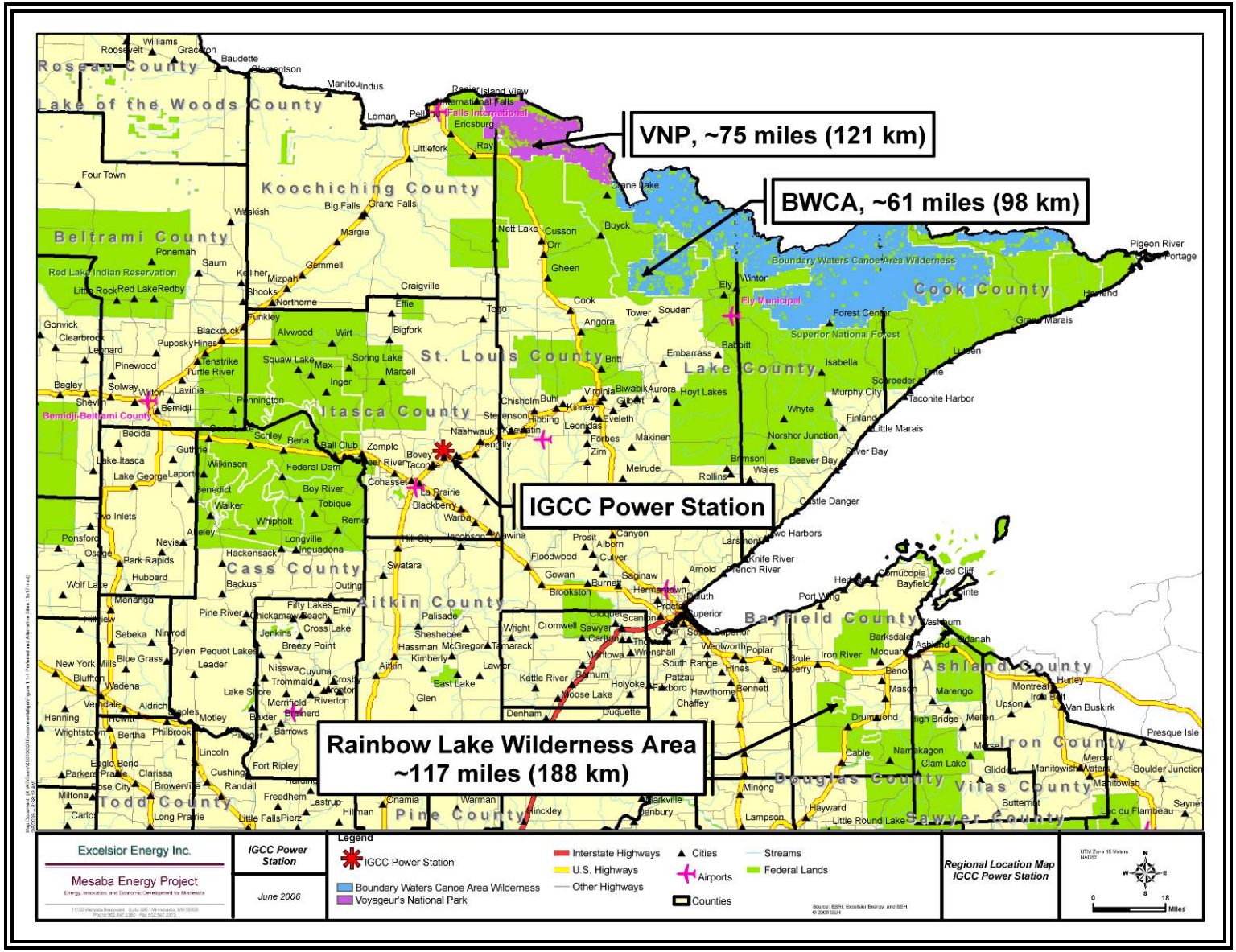
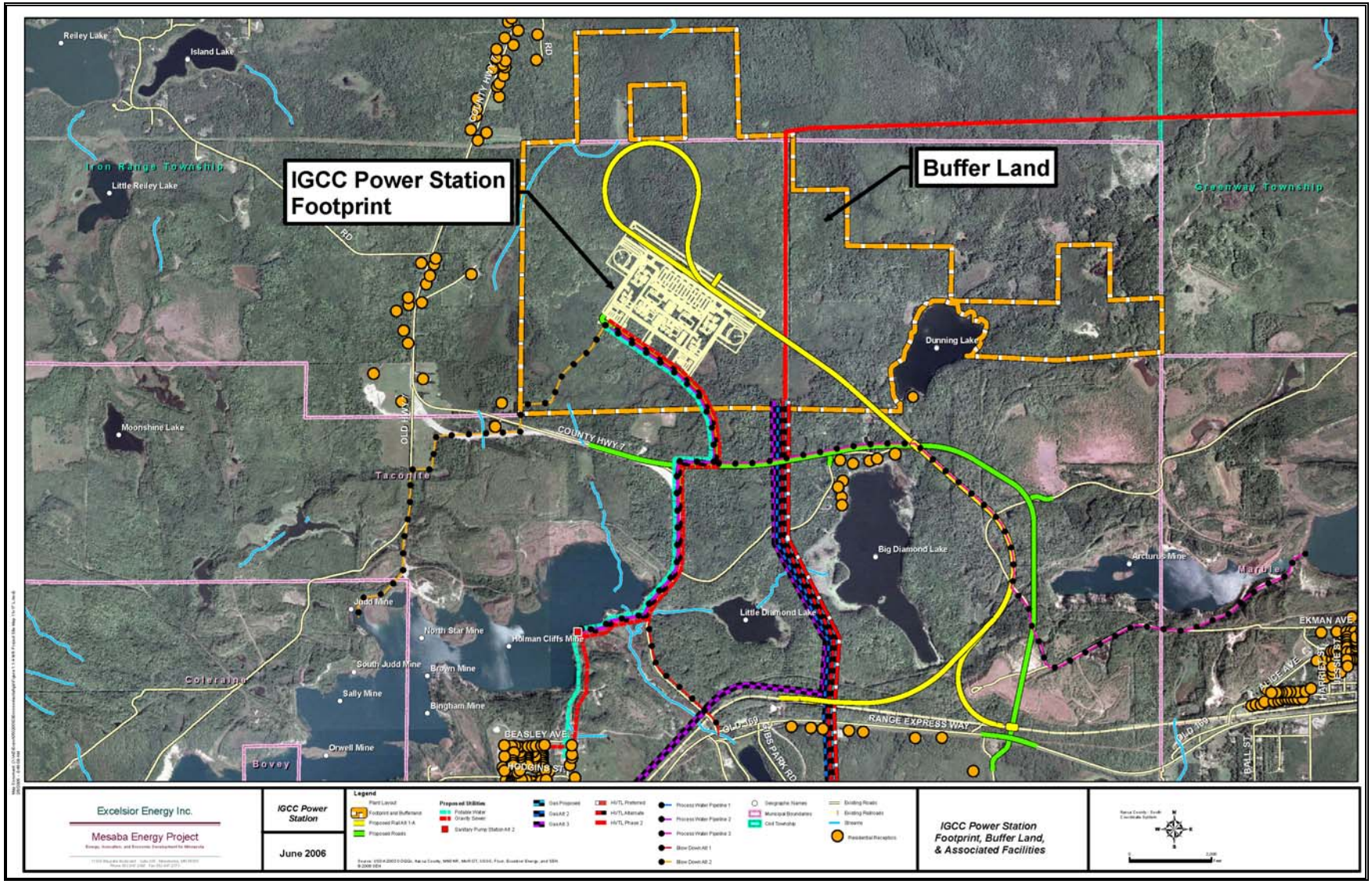


Figure 1.6-3 Phase I and II IGCC Power Station Footprint, Buffer Land and Proximity to Significant Receptors



In general, the Site is currently undeveloped and unoccupied but is located in the immediate vicinity of former iron ore mining operations and in immediate proximity to critical infrastructure, including water resources, transportation corridors, mine access roads, transmission corridors, major substations, and community resources. The IGCC Power Station Footprint and Buffer Land is located completely within Iron Range Township (4th Principal Meridian, T56N, R24W) and is generally bounded by County Road 7 to the west and south, a high voltage transmission line corridor to the north, and the Township boundary to the east. As shown in Figure 1.6-3, all but about 200 acres of the property identified as Buffer Land is located within the city limits of Taconite, Minnesota.

1.6.2 Description of IGCC Technology

The gasification process the Applicant will use to supply fuel to its combined cycle power station is ConocoPhillips E-Gas™ technology. In the E-Gas™ process, coal, petroleum coke, or blends of coal and petroleum coke are crushed, slurried with water, and pumped into a pressurized vessel (the gasifier) along with sub-stoichiometric amounts of purified oxygen. In the gasifier, controlled reactions take place, thermally converting feedstock materials into a gaseous fuel known as synthesis gas, or syngas. The syngas is cooled, cleaned of contaminants, and then combusted in a combustion turbine, which is directly connected to an electric generator. The assembly of the combustion turbine and generator is known as a combustion turbine generator ("CTG"). The expansion of hot combustion gases inside the combustion turbine creates rotational energy that spins the generator and produces electricity. The hot exhaust gases exiting the CTG pass through a heat recovery steam generator ("HRSG"), a type of boiler, where steam is produced. The resulting steam is piped to a steam turbine that is connected to an electric generator. The expansion of steam inside the steam turbine spins the generator to produce an additional source of electricity. When a CTG and a steam turbine generator ("STG") are operated in tandem at one location to produce electricity in a highly efficient manner the combination of equipment is referred to as a combined cycle electric power plant. Integration of the gasification process with the combined cycle power plant is known as integrated gasification combined cycle technology, or IGCC, an inherently lower polluting technology to produce electricity from solid feedstocks.

1.6.3 Maximum Emission/Discharge Scenarios Quantified

During the environmental review and permitting process, the Applicant is required to identify operating scenarios producing maximum emissions/discharges associated with construction and operation of the IGCC Power Station. Such scenarios are primarily defined by the operating characteristics of Station equipment and the amounts and characteristics of feedstock to be transported, handled and consumed. Maximum quantities of feedstock consumed and feedstock characteristics are further discussed in Section 2.

For development of its "worst case" scenario, the Applicant focused on identifying operating parameters yielding maximum emissions. In general, these scenarios reflect the highest heat input rates and a cautious approach regarding the design optimizations expected to occur (during the Front End Engineering and Design ["FEED"] process, the preliminary equipment designs used to estimate environmental releases will be refined and uncertainties that now require

conservatively high assumptions to be used will be better understood allowing such conservative assumptions to be refined). In employing such an approach, the Applicant is confident that environmental releases and their associated impacts are conservatively analyzed and presented.

Operating conditions producing maximum emissions/discharges from the IGCC Power Station are identified in Section 2 and assume operation of the gasifiers under partial slurry quench ("PSQ") conditions and consider known seasonal influences and the range of potential feedstocks for which the IGCC Power Station will be designed to utilize. Information is also presented to describe the gasifier operating in full slurry quench ("FSQ") mode. FSQ is achieved by increasing the slurry feed to the second stage of the gasifier to the point where only slurry is used to quench the syngas, thereby eliminating the thermal loss associated with water used to cool the syngas and increasing the overall efficiency of the IGCC Power Station. These efficiency gains will translate into reduced feedstock use and, consequently, reduced pollutant emissions/discharges. However, FSQ is an IGCC Power Station design improvement that is subject to further engineering and verification. Therefore, FSQ's expected benefits are shown, but not reflected in either the maximum resource requirements or maximum pollutant emissions/discharges quantified in the Application.

1.6.4 Feedstock Flexible

The Applicant is proposing to construct and operate Mesaba One and Mesaba Two as feedstock flexible Power Stations that can interchangeably use the following feedstocks:

- 100% bituminous coal (including, but not limited to, Illinois No. 6 bituminous coal)
- 100% subbituminous coal (including, but not limited to, Powder River Basin coal)
- Up to a 50:50 coal/petroleum coke blend
- Other blends of these feedstocks

Natural gas will be used to start up the IGCC Power Station and as a backup fuel when syngas is unavailable. The maximum natural gas flow is expected to be about 105 million standard cubic feet of gas per day per phase of the IGCC Power Station.

1.6.5 IGCC Power Station Footprint and Buffer Land

The Applicant has secured an option on 1260 acres of property within the boundary of the Buffer Land shown in Figure.1.6-3. The actual physical space required for the Mesaba One Footprint encompasses approximately 100 acres. An additional 80 acres of land is required for a temporary construction laydown area for Mesaba One and five acres for a concrete batch plant. Figure 1.6-4 shows the layout plan for Mesaba One and many of its Associated Facilities. The equipment layout for Mesaba Two and its Associated Facilities will be similar to Mesaba One. Therefore, about 200 acres will be required for Mesaba One and Mesaba Two, excluding construction and laydown areas. The remainder of the Buffer Land is required for security, isolation and unspecified future requirements.

The detailed site layout plan for Mesaba One and Mesaba Two is shown in Figure 1.6-5. The location of the most significant point sources of air pollutant emissions are identified in Figure 1.6-5 with the symbol "". The dimensions of significant buildings/structures inside the battery

limits ("ISBL") of the IGCC Power Station have been tabulated and placed adjacent to the left margin in Figure 1.6-5.

Figure 1.6-6 provides a preliminary site grading plan designed to minimize impacts on wetlands and an outline of the earth work required to accommodate the Phase I and II Developments. Ambient air quality modeling studies detailed later in Sections 7.0 and 8.0 take into account the base elevations shown in this figure. The reference lines provided in Figure 1.6-6 correspond to the cross-sections illustrated in Figure 1.6-7.

Visualizations of the Phase I and Phase I and II Developments are shown in Figures 1.6-8 and 1.6-9, respectively.

1.7 Implementation Schedule

The proposed IGCC Power Station would be constructed in two phases. Electric power for each project phase would be produced in two CTGs (about 220 $MW_{(gross)}$ each) and in a STG (up to 300 $MW_{(gross)}$). Power generated from the project would be interconnected to the regional electrical grid by a high voltage transmission line ("HVTL") system. The Project milestone schedule is provided in Figure 1.7-1. The Applicant proposes to commence construction of Mesaba One in the first quarter of 2008 and begin commercial service in the fourth quarter of 2011. The commercial in service date for Phase II is scheduled for 2013 with construction commencing in 2010.

Figure 1.6-4. Preliminary Equipment Layout Plan for Mesaba One

Figure 1.6-5. Preliminary Layout Plan for Mesaba One and Mesaba Two Showing Point Sources of Air Emissions and Building Heights

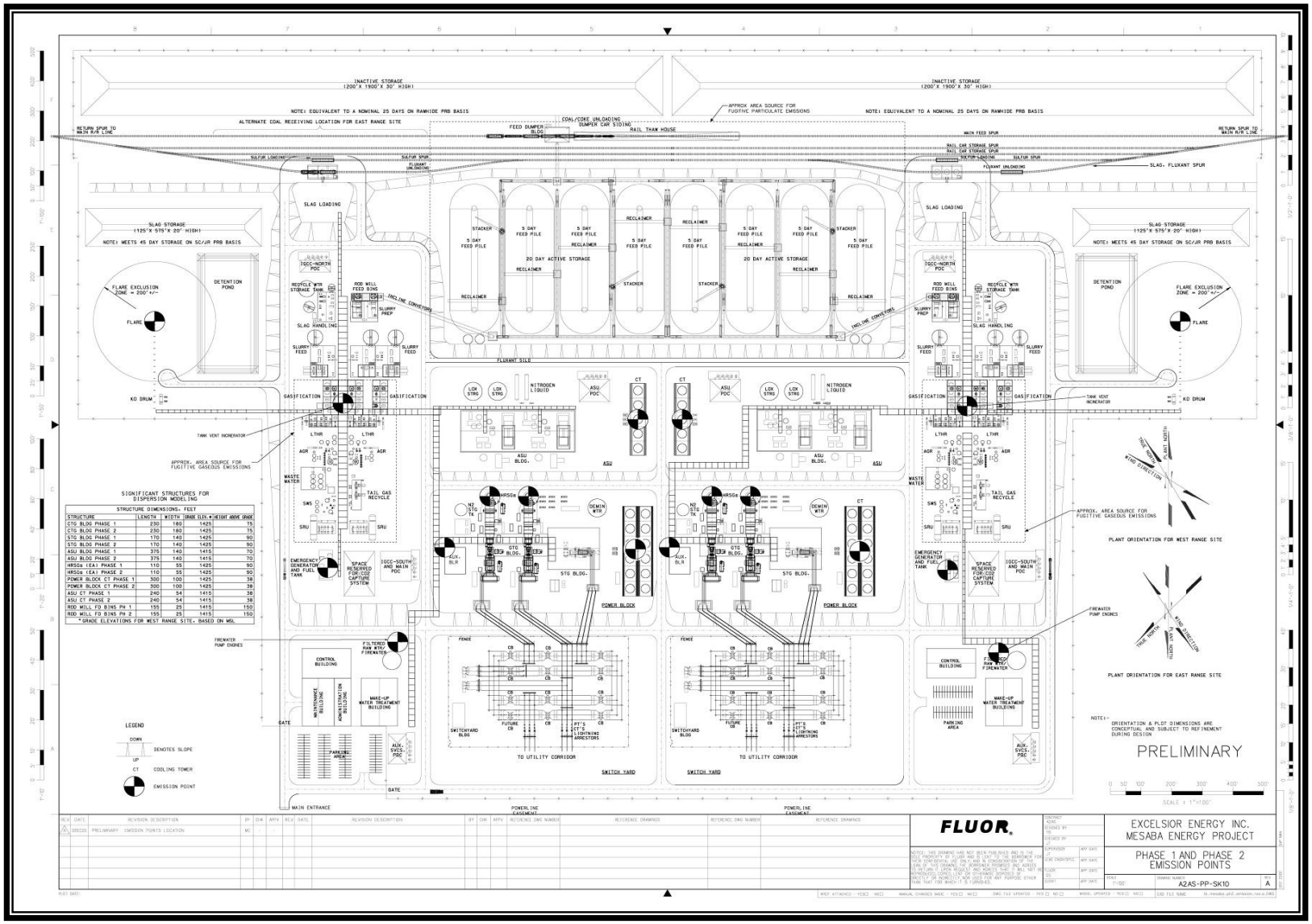


Figure 1.6-6. Preliminary Grading Plan for Mesaba One and Mesaba Two

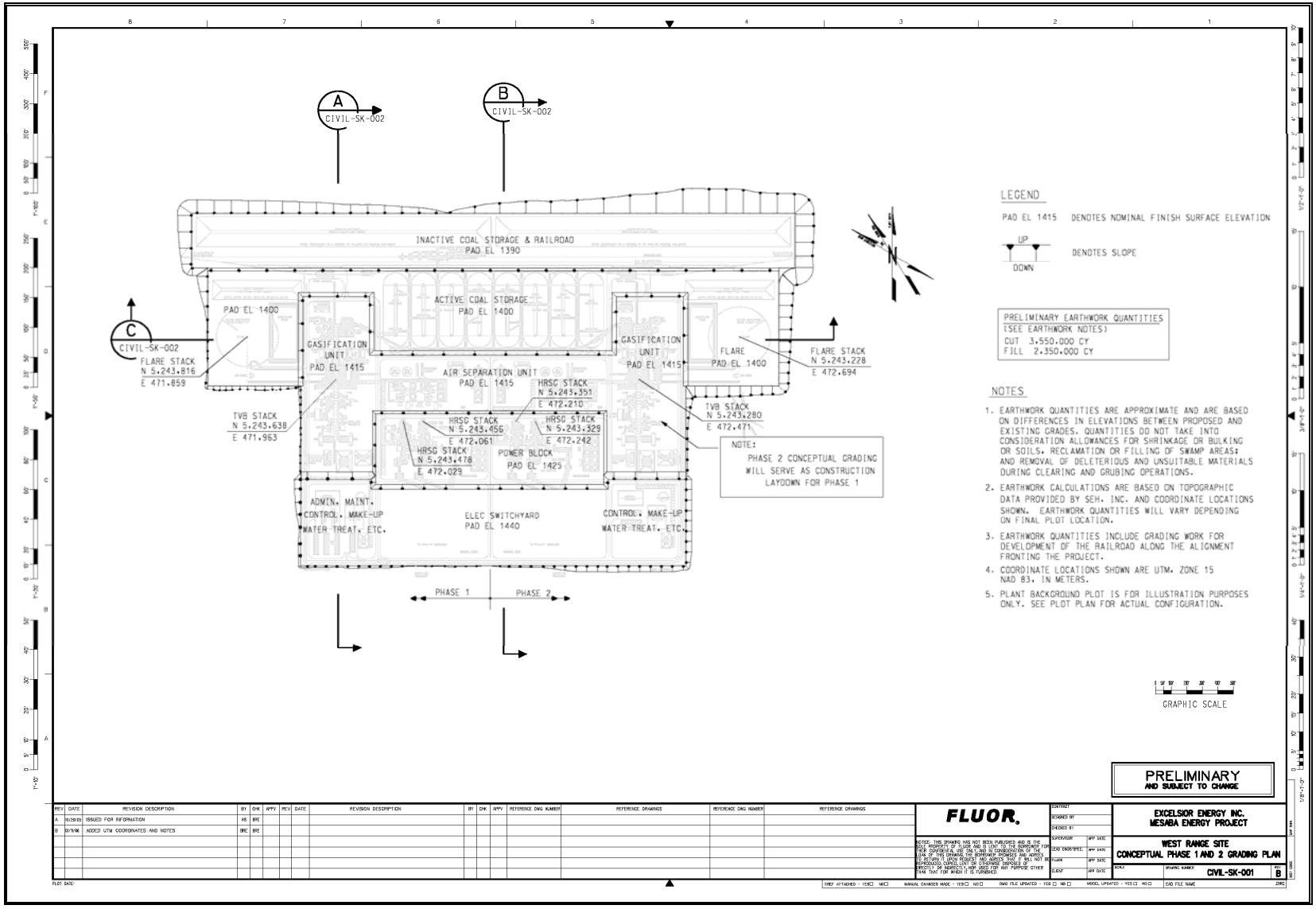


Figure 1.6-7 Cross Sections of Phase I and II IGCC Power Station Footprint

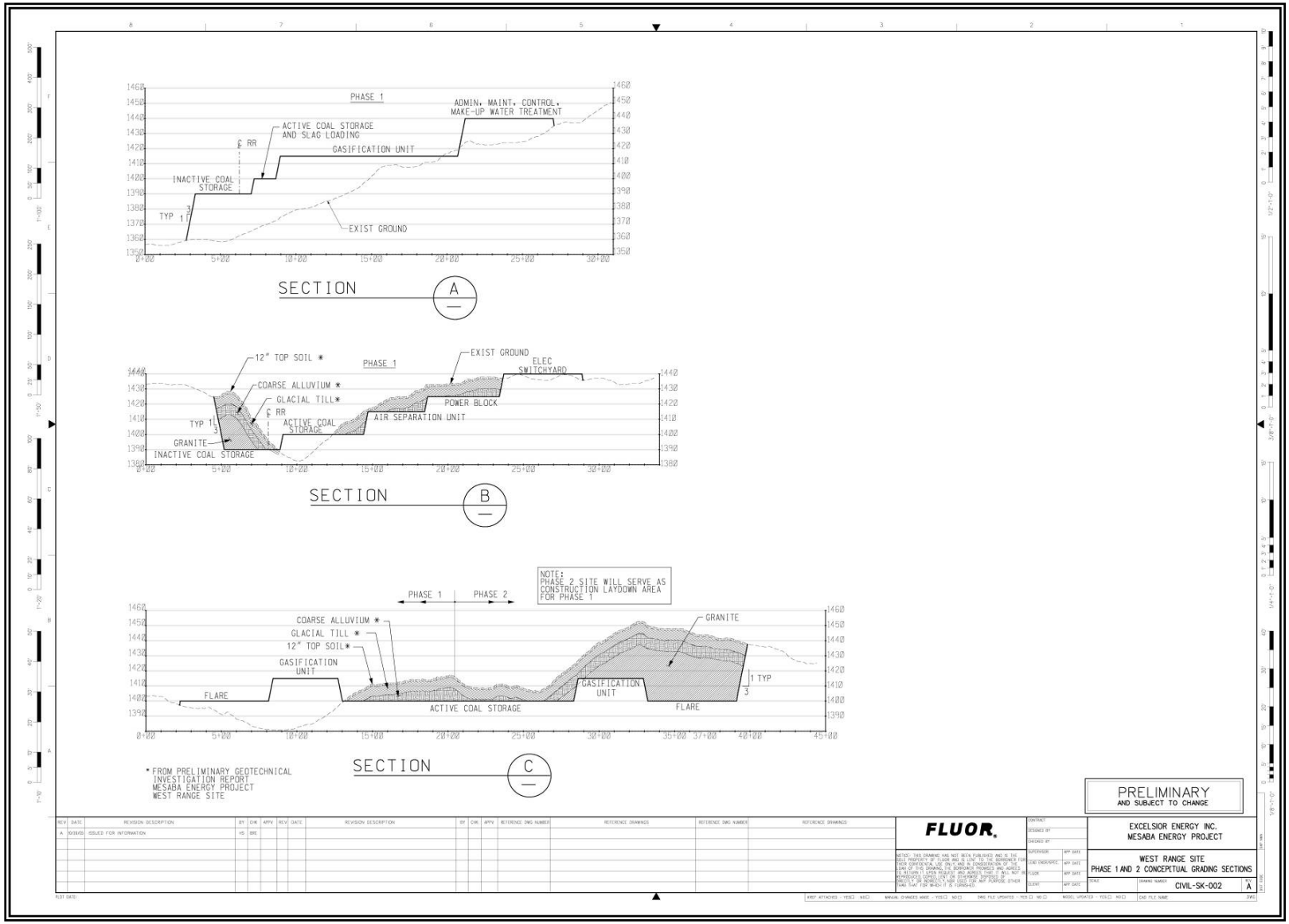


Figure 1.6-8. Visual Rendering of Mesaba One

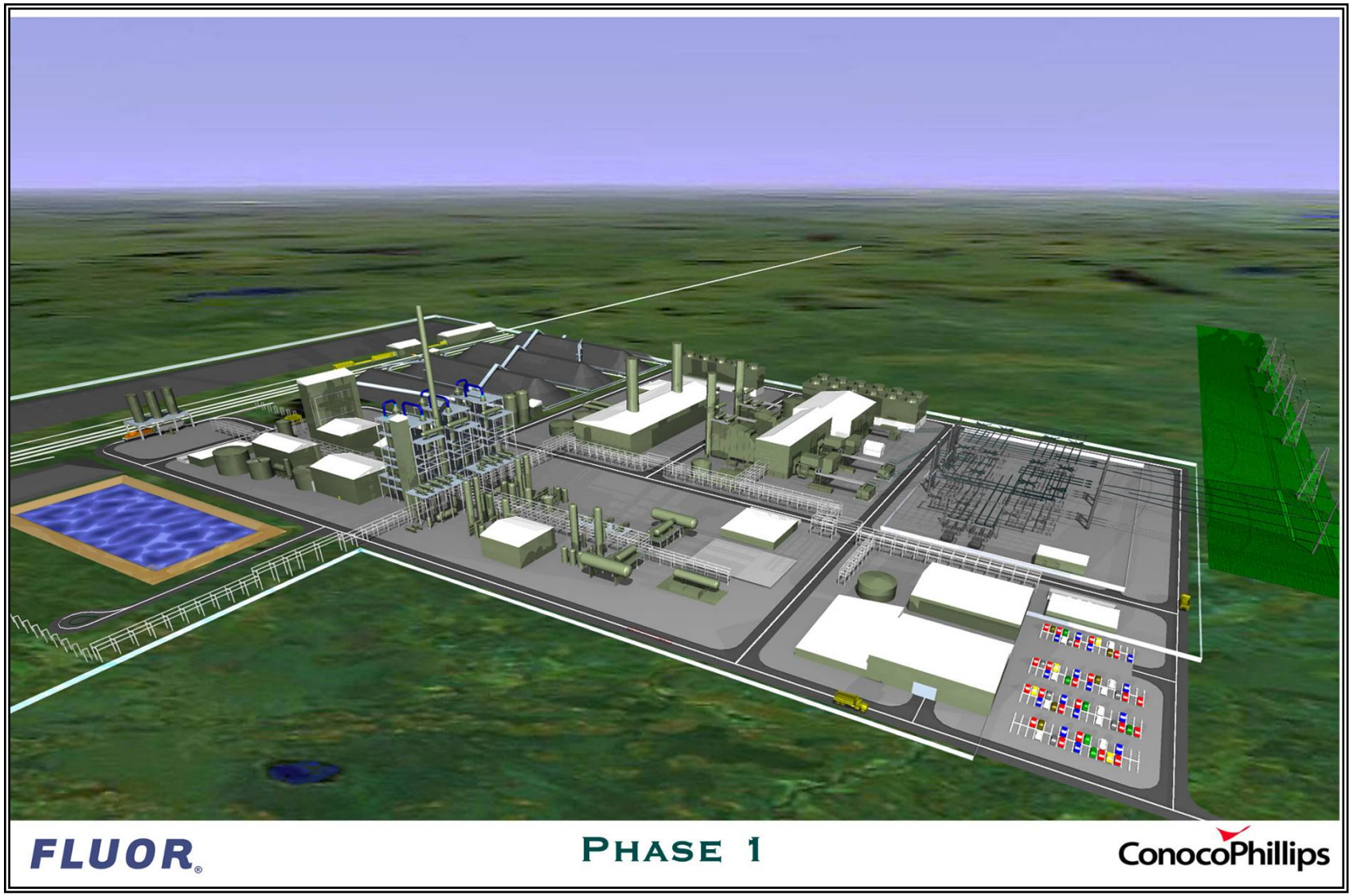


Figure 1.6-9. Artist's Rendering of Mesaba One and Mesaba Two

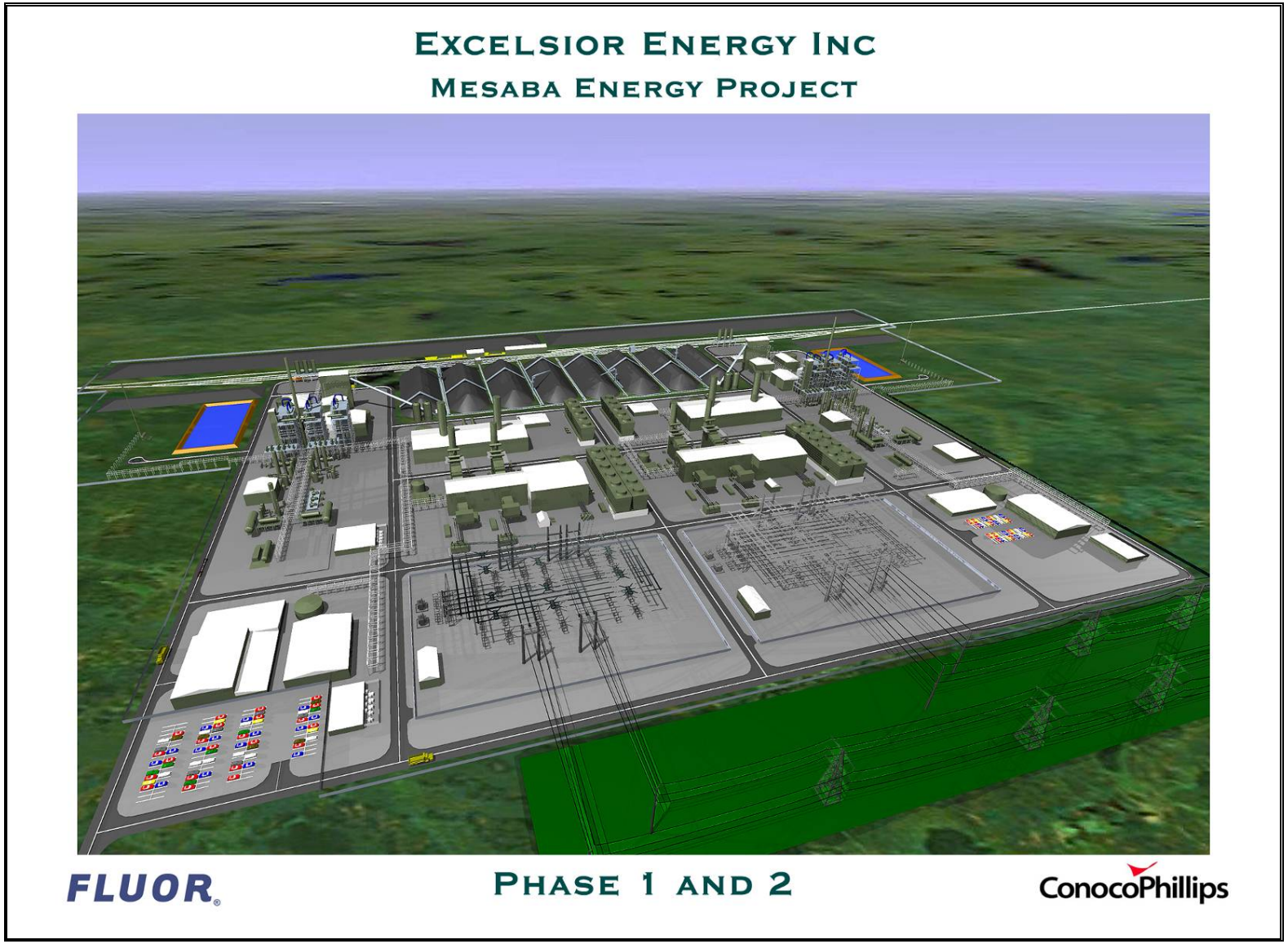


Figure 1.7-1. Mesaba One and Mesaba Two Implementation Schedule

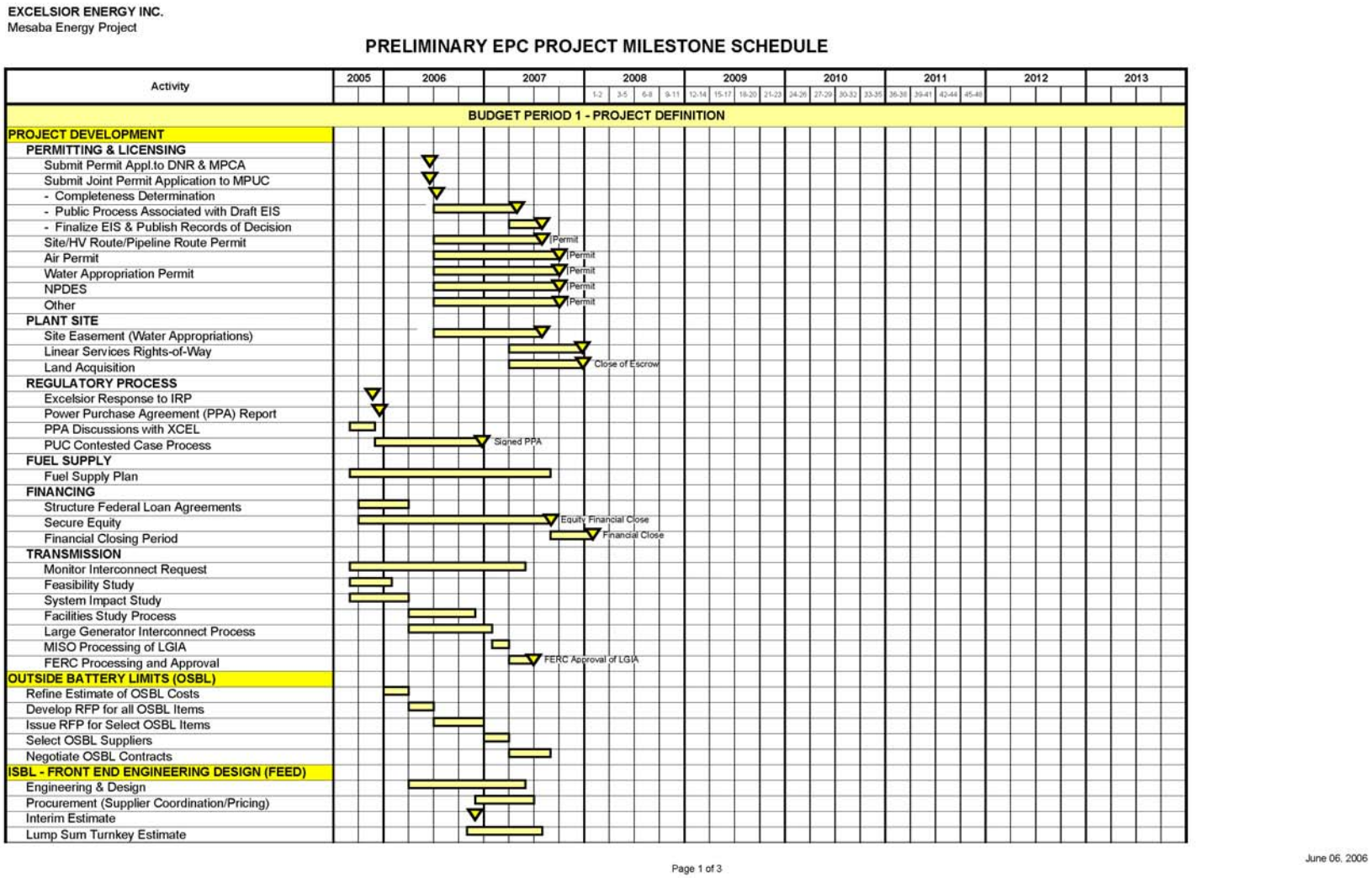


Figure 1.7-1. Mesaba One and Mesaba Two Implementation Schedule (Continued)

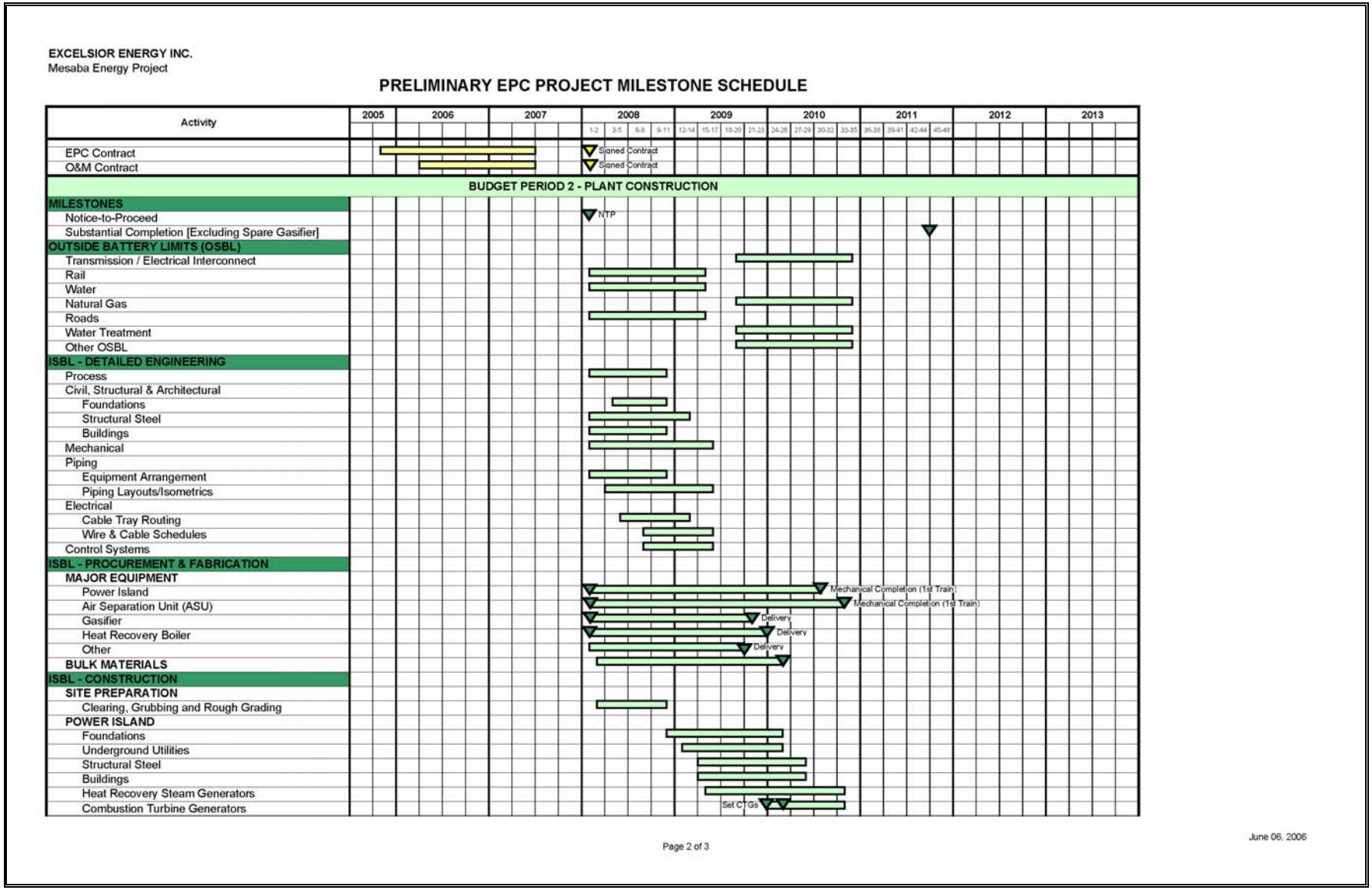
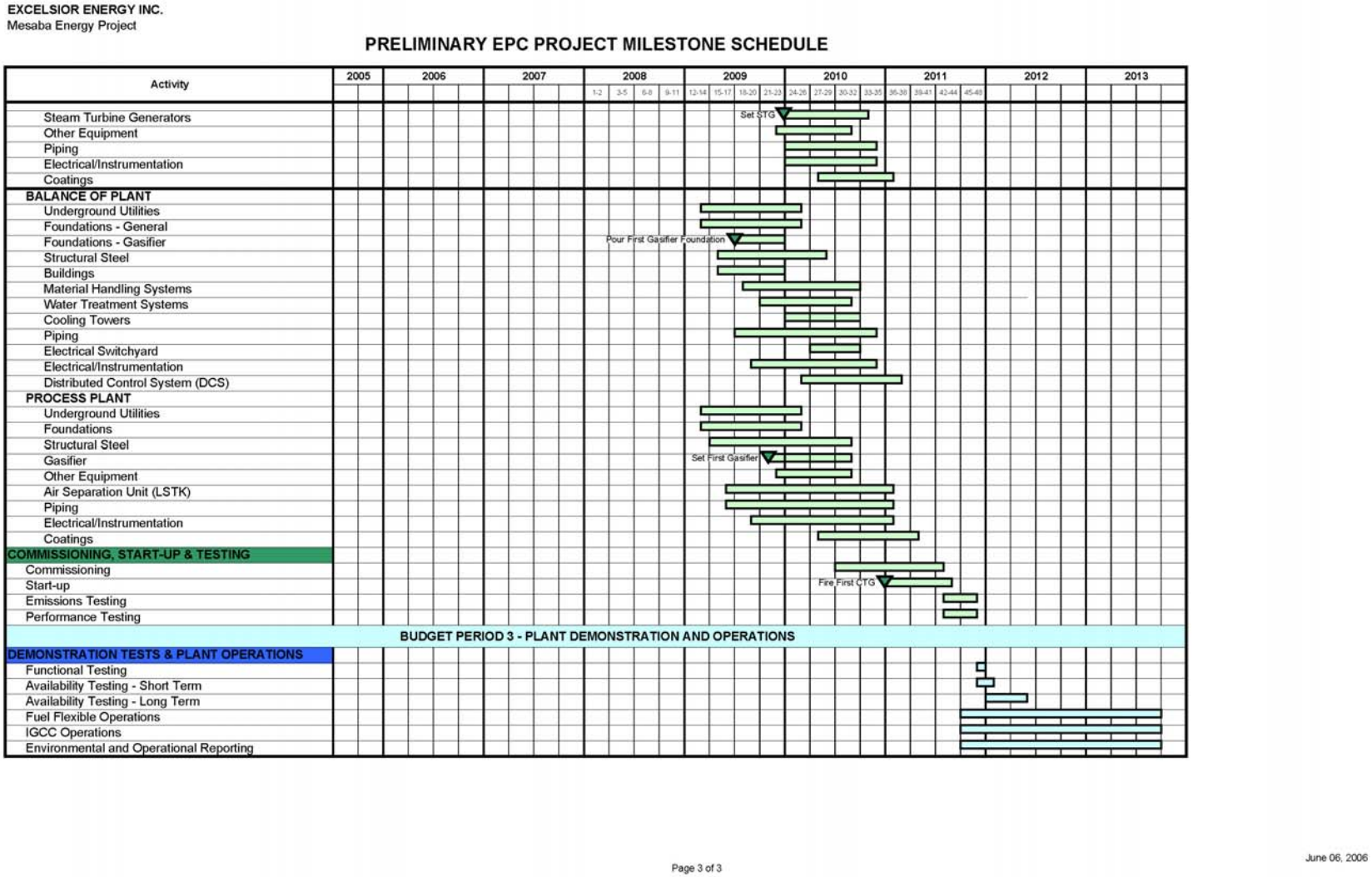


Figure 1.7-1. Mesaba One and Mesaba Two Implementation Schedule (Continued)



2. PROJECT DESCRIPTION

2.1 Resource Inputs

2.1.1 Feedstock Delivery

Coal and petroleum coke feedstocks will normally be received by rail in dedicated unit trains from the mine or refinery. Rail access into the IGCC Power Station Footprint is from existing BNSF Railway ("BNSF") and Canadian National Railway ("CN") tracks. The rail loop will be designed to accommodate unit trains up to 135 cars in length within the Site boundary with the average unit train shipment comprised of 115 cars. Each unit train car will carry on average about 119 tons of feedstock (BNSF, 2005).

Each phase of the IGCC Power Station, under the maximum feedstock input case and assuming the gasifiers are operating in full slurry quench ("FSQ") mode would require a maximum of 8,230 tons of coal per day on an as-received basis. If operating in a partial slurry quench ("PSQ") mode, the daily maximum required fuel tonnage would increase to 8,550 tons on an as-received basis.

One 135-car unit train could deliver 16,100 tons of coal and each 115 car unit train about 13,700 tons. With Mesaba One and Mesaba Two operating at full load with the gasifiers in FSQ mode, a maximum 16,460 tons of coal feedstock per day would be consumed, requiring the delivery of about five 115 car unit trains every four days. With the gasifiers operating in PSQ mode, Mesaba One and Mesaba Two would require under full load operations a maximum of about 17,100 tons of coal per day. Such operating mode would not substantively change the worst case, short term fuel delivery schedule. A maximum of four hours will be typically be required to unload one unit train. The Applicant estimates that a maximum of three unit trains per day (midnight to midnight) could be received and unloaded.

Mesaba One would utilize a maximum of 3.12 million tons of feedstock annually assuming operation in PSQ mode at 100 percent capacity factor. The Applicant expects to operate in FSQ mode most of the time and expects to take outages for maintenance each year. Assuming a 90% capacity factor and operation in the FSQ mode, the Applicant would expect to use a maximum of 2.7 million tons of feedstock per year. The Applicant seeks a permit which reflects the maximum fuel consumption case. Because of the plant's fuel flexible capability, it is anticipated that specific fuel utilization will change periodically throughout the lifetime of the IGCC Power Station, with selection based upon the conditions and terms available from various fuel and transportation suppliers.

The location selected for Mesaba One and Mesaba Two offers two major coal transport alternatives, the BNSF and CN, each having direct access to the IGCC Power Station Footprint by construction of short spurs. The availability of multiple rail transportation modes at the site will enhance the long-term benefits of the feedstock-flexible plant design. This capability introduces potential competition into the fuel supply equation and should result in lower fuel costs over the life of the IGCC Power Station.

2.1.2 Feedstock Receiving and Storage

The feedstock handling system will include facilities necessary to unload solid feedstock materials, convey them to storage areas, store until required, reclaim them from storage, blend as necessary, and convey the blended materials to the slurry preparation system. On-site storage facilities will be provided for two feedstock materials, coal and petroleum coke. Storage facilities will also be provided for flux, a feedstock conditioning material. The feedstock storage facilities will include, for each phase of the facility, approximately 20 days of active storage and approximately 25 days of inactive storage. The storage areas will incorporate dust suppression systems (including covered conveyers and other enclosures, dust suppression sprays, and vent filters) and will be paved, lined, or otherwise controlled to enable collection and treatment of storm water runoff and to prevent infiltration to ground water of chemical species leached from feedstock materials and/or flux.

Unloading facilities will include a thawing shed to loosen frozen cargo during the winter season, and a partially enclosed rotary car dumping system. After the locomotive on a unit train positions the first car in the rotary dumper, subsequent cars are placed in the dumping position by an automatic electro-hydraulic positioner. Such rail car positioning systems reduce the run time and fuel consumption of the locomotives or switch engines and the emissions that would otherwise occur if all engines were required to run during the entire unloading process (this normally allows all but one engine to be shut down; the engine remaining is operated at a reduced load to maintain air pressure in the brakes). Feedstock materials fall from the rotated cars into an enclosed pit from which such materials are transferred via a feeder/conveyor system to active storage pile stackers. Four active storage piles for each phase of the facility will provide working feedstock storage. Additional inactive storage will be located on the opposite side of the rail sidings to provide a reserve source of feedstock material in the event normal deliveries of unit trains are interrupted. If needed, feedstock from the inactive pile will be moved by mobile equipment (bulldozers, scrapers, and/or front-end loaders) to the rail unloading pit to access the automated plant feed system. Reclaimers and conveyors will move coal and petroleum coke from the active piles to the slurry feed preparation area.

2.1.3 Feedstock and Feedstock Characteristics

Mesaba One and Mesaba Two are designed to be "feedstock flexible" throughout their economic lifetimes. While conventional pulverized coal ("PC") fired power plants can sometimes use a limited range of fuels, they must be designed for a specific performance fuel. When using other fuels, the performance and output of these PC plants typically deteriorate. Feedstock flexibility will allow the IGCC Power Station to operate at or near maximum capacity using:

- 100% bituminous coal (for example, Illinois No. 6 coal), or
- 100% sub-bituminous coal (for example, Power River Basin coal), or
- Up to a 50:50 coal/petroleum coke blend, or
- Other blends of these fuels.

This feedstock flexibility, made possible by the use of IGCC technology and the design parameters for Mesaba One and Mesaba Two, will provide ongoing future cost benefits because it allows the Station to adapt its feedstock mix over the life of the facility to minimize the cost of

power. Feedstock flexibility provides Mesaba One and Mesaba Two a hedge against physical dependency upon a single feedstock supplier or transportation provider, and against supply disruptions from any mine or carrier. Table 2.1-1 shows the feedstock design specifications being utilized to design the Station's unique feedstock flexibility.

Table 2.1-1
Feedstock Design Specification Basis

FEEDSTOCK	BITUMINOUS COAL		SUB-BITUMINOUS COAL		PETROLEUM COKE	
	DRY BASIS	AS RCVD.	DRY BASIS	AS RCVD.	DRY BASIS	AS RCVD.
HHV, Btu/lb	12,802	11,586	11,942	8,300	15,204	13,699
Ultimate Analysis, Wt %						
Carbon	70.79	64.06	69.9	48.58	87.32	78.71
Hydrogen	4.81	4.35	4.8	3.34	3.67	3.31
Nitrogen	1.51	1.37	0.9	0.63	1.31	1.18
Sulfur	3.32	3.00	0.53	0.37	6.27	5.65
Oxygen	6.92	6.26	16.77	11.66	0.72	0.65
Chlorine	0.14	0.13	<0.01	<0.01	0.01	0.01
Ash	12.51	11.32	7.1	4.93	0.7	0.63
Total	100.00	90.50	100.0	69.50	100.00	90.10
Moisture, %		9.5		30.5		9.9
Ash Mineral Analysis, Wt%						
SiO_2	49.57	NA	31.2	NA	20.55	NA
Al_2O_3	19.32	NA	13.9	NA	9.11	NA
TiO_2	0.96	NA	1.1	NA	0.8	NA
Fe_2O_3	19.32	NA	6.3	NA	5.44	NA
CaO	3.81	NA	24.3	NA	11.77	NA
MgO	1.01	NA	6.1	NA	3.64	NA
Na_2O	0.46	NA	1.7	NA	1.68	NA
K_2O	2.40	NA	0.2	NA	0.66	NA
P_2O_5	0.35	NA	0.5	NA	0.52	NA
SO_3	2.07	NA	13.6	NA	23.75	NA
NiO	NA	NA	NA	NA	4.68	NA
V_20_5	NA	NA	NA	NA	16.11	NA
Other	0.73	NA	1.1	NA	1.29	NA
Total	100.0		100.0		100.0	
Ash Fusion Temp. (Reducing), ^oF						
Initial Deformation	2000	NA	2170	NA	2440	NA
Softening (H=W)	2150	NA	2180	NA	2500	NA
Hemispherical (H=1/2w)	2185	NA	2190	NA	2555	NA
Fluid	2370	NA	2200	NA	2600	NA
Hardgrove Grindability Index	50-65	NA	80	NA	53	NA

Although the primary fuel source for electric power production will be syngas produced from the feedstocks specified above, the IGCC Power Station will also be capable of operating on pipeline natural gas. The power island is a combined-cycle unit, optimized for operation on syngas. The ability to operate on natural gas provides an additional source of available generating capacity

(and reliability for periods when the gasification island is unavailable). The capability of the combined cycle equipment to operate on natural gas offers the option of installing the combined-cycle power island early in the construction process (ahead of the gasification section), thereby allowing for electricity production from natural gas until the gasification section is installed and the IGCC Power Station begins full-time, base load operation on coal-derived syngas. Early operation of the combined cycle power island in this manner is not currently planned. However, in the event of an unforeseen regional contingency, the combined cycle equipment could be started and operated, thereby representing a very useful resource planning option. The Applicant is requesting herein permits for Mesaba One and Mesaba Two to allow for natural gas firing at capacity factors of 30%, 20%, 10% and 5% for years 1, 2, 3, and thereafter, respectively. In addition, the Applicant is requesting a permit to combust natural gas at 100% load in the event of catastrophic occurrence to the gasifiers.

2.1.4 Flux Receiving and Storage

The E-Gas™ gasifier will operate at high temperatures. At such temperatures, ash in feedstock material will melt and drain to the bottom of the gasifier where it is removed. The molten ash – known as slag – will be cooled and solidified in a water bath outside the gasifier.

Mineral matter in the ash determines the temperature at which ash in the gasifier will melt and the slag viscosity at a specific operating temperature. If the slag is too viscous, it will not flow easily from the gasifier, or could plug the bottom. Flux, typically silica/sand, limestone, iron oxide (or iron ore), or a mixture of these, will be blended with the feed as necessary to control the slag melting point and fluidity. A slag that is too fluid could be excessively erosive to the refractory in the gasifier, so the amount and composition of flux, if used, must be carefully monitored and controlled.

Flux will normally be received by truck (or railcar) and pneumatically conveyed to enclosed storage silos equipped with fabric filters for dust control. Flux from storage silos will be automatically blended with feedstock by a weigh belt feeder system. The required quantity of flux will be a small fraction of the total feed, typically less than 250 tons per day per phase.

The feedstock and flux handling/storage facilities and their associated emission controls are further reviewed in Section 4.1.5 in order to predict fugitive particulate matter emissions attending operation of the IGCC Power Station.

2.1.5 Natural Gas Supply Pipeline and Metering Station

Natural gas will be used to start up the facility and as a backup fuel (see Section 4.1.1). When operating on natural gas, the power block of the Phase I IGCC Power Station cannot achieve the nominal 606 MW(net) output attainable as when operating on syngas. This is due, in part, to the lack of nitrogen that would otherwise be available for nitrogen dilution and power augmentation from operation of the ASU system used primarily to supply oxygen to the gasifiers. The maximum natural gas utilization by the IGCC Power Station is predicted to be about 105 million standard cubic feet of gas per day per phase.

Natural gas will be supplied through a direct connection with the Great Lakes Gas Transmission Company ("GLG") pipeline located about 12 miles due south of the IGCC Power Station or from Northern Natural Gas company's ("NNG") tapping point located in La Prairie, Minnesota, about 10 miles west-southwest of the Station. This access to multiple pipeline infrastructure alternatives is beneficial. The Proponent will contract with either or both entities for natural gas transportation capacity for quantities and at pressures sufficient to operate the IGCC Power Station at its limited capability (see above paragraph) when firing its backup fuel. The Applicant will purchase natural gas through a series of contracts with gas suppliers in order to obtain the lowest overall fuel price and best contract conditions for this commodity. The Applicant will install and operate metering equipment to monitor purchases. Typical natural gas composition is shown in Table 2.1-2.

Table 2.1-2
Typical Natural Gas Constituents

CONSTITUENT	PERCENT BY VOLUME
Methane	96.9
Ethane	2.00
Propane	0.50
n-Butane	0.10
i-Butane	0.10
n-Pentane	0.00
i-Pentane	0.00
Hexane+	0.10
Oxygen	0.00
Carbon dioxide	0.00
Nitrogen	0.30
TOTAL	**100.00**
Sulfur, ppmv	14.8
Specific Gravity (air = 1.00)	0.57-58
Net Heating Value (Btu per scf)	935

Btu = British thermal units.
scf = standard cubic feet.

2.1.6 Cooling Water and Cooling Tower Blowdown (Black & Veatch, 1996)

Heat must be rejected from the IGCC Power Station's condensers in order to maintain proper steam cycle characteristics. A large volume of water is required for this purpose (a 600 MW pulverized coal power plant would require about 300,000 gallons of water per minute for a once-through cooling system). The IGCC Power Station will use cooling towers to reduce relative to a once-through cooling system the amount of water otherwise required to be withdrawn from source waters. In a cooling tower, warmed cooling water from the Power Station's condenser will be cooled by the evaporation of a portion of the water as it passes through the cooling tower. In addition to evaporation, a small amount of entrained water, called drift (water droplets that are entrained in the exhaust air stream carrying heat away from the towers), will be emitted to the external environment. As evaporation continues, salts dissolved in the remaining cooling water become more concentrated. When the concentrations of dissolved salts near their solubility limit, scale formation may occur on the plant's condenser tubes and hinder heat transfer.

Although addition of certain chemicals can inhibit scale formation, a portion of the cooling water, called blowdown, must be discharged. The amount of blowdown is calculated as follows:

$$\text{Blowdown} = \frac{\text{Evaporation}}{\text{Cycles - 1}} - \text{Drift}$$

The cycles, or "cycles of concentration," relate to how much the dissolved solids are allowed to concentrate in the cooling water system. Assuming: i) the Power Station is operating on eight cycles of concentration; ii) the total amount of water recirculated in the power block and gasification/ASU cooling towers is approximately 320,000 gallons per minute; iii) drift constitutes approximately 0.001% of the water being recirculated; iv) the plant operates at a 92% capacity factor; and v) the concentration of mercury in the raw make-up water is 0.9 nanograms per liter; releases of mercury via drift could be expected to be on the order of 0.04 grams per year per phase of the IGCC Power Station. Releases on this order of magnitude are considered to be inconsequential from an environmental perspective.

2.1.7 Contact Process Water

Water is used in numerous enclosed vessels to cool and clean the syngas. This is generally accomplished by routing the syngas through a countercurrent flow of water, with the syngas generally being introduced into the bottom of a tower and water at the top. The water, by virtue of its physical contact with the contaminated syngas, picks up soluble and insoluble contaminants, becomes contaminated itself, and thereafter is treated. In Mesaba One and Mesaba Two, such contact process waters will be segregated from cooling tower blowdown and routed through a ZLD system, thereby ensuring that no trace elements carried over from the feedstock will be discharged to ambient receiving waters. Proprietary systems incorporated into the sour water treatment system remove any mercury from the wastewater stream prior to processing the wastewater stream through the brine concentrator and ZLD system.

2.2 Major Buildings, Infrastructure, Topography, and Access Roadways

The major buildings associated with the IGCC Power Station include the control room, administration building, warehouse/maintenance shop, combustion turbine and steam turbine buildings, weather enclosures for the Air Separation Unit (ASU) compressors, coal slurry preparation, water treatment/lab, railcar thaw shed, switchyard control room, several power distribution centers (prefabricated) and a visitor's center. For purposes of ambient air quality modeling, the dominant structures on site include the following (with approximate dimensions indicated):

- Combustion Turbine Generator Building, 230 ft. x 180 ft. x 75 ft. high.
- Steam Turbine Generator Building, 170 ft. x 140 ft. x 90 ft. high.
- Air Separation Unit (ASU) Building, 375 ft. x 140 ft. x 70 ft. high.
- Heat Recovery Steam Generator (HRSG), 110 ft. x 55 ft. x 90 ft. high.
- Rod Mill Feed Bins, 155 ft. x 25 ft. x 150 ft. high.

These structures and their relative proximities to the IGCC Power Station's point and fugitive emission sources are identified in Figure 1.4-5. A preliminary engineering layout of the IGCC Power Station Footprint and the finished grade elevations currently projected are shown on Figure 1.4-6. The dominant geographic feature on the IGCC Power Station Footprint is a hill that rises approximately 60 feet above the 1,425 foot base elevation at which the IGCC Power Station's HRSGs would be located.

Road access to the IGCC Power Station is currently planned from two directions. Heavy construction traffic, including some construction workers, would access the IGCC Power Station Footprint from U.S. Highway 169, about 1.4 miles east of County Road No. 7. Remaining construction personnel and permanent employees would access the IGCC Power Station Footprint from County Road No. 7. Figure 1.6-3 shows the proposed access roads into the IGCC Power Station Footprint. Current plans call for Itasca County to sponsor construction and operation of this new roadway

2.3 Process Description

Detailed descriptions are provided below for the subsystems within an IGCC Power Station configured to use ConocoPhillips' E-Gas™ technology. The subsystems included are oxygen supply, feedstock slurry preparation, gasification, slag handling, syngas cooling, particulate matter removal, mercury removal, syngas scrubbing, low temperature heat recovery, acid gas removal, sulfur recovery, tank vent collection, sour water treatment and the combined cycle power block. An overall schematic block flow diagram identifying important equipment and processes related to air pollutant emissions from Mesaba One and Mesaba Two are presented in Figures 2.3-1 and 2.3-2. The numbering scheme in Figures 2.3-1 and 2.3-2 is consistent with the numbering scheme provided on the permit application forms in Section 9.

Figure 2.3-1. Block Flow Diagram Showing Air Pollutant Emission Sources for Mesaba One

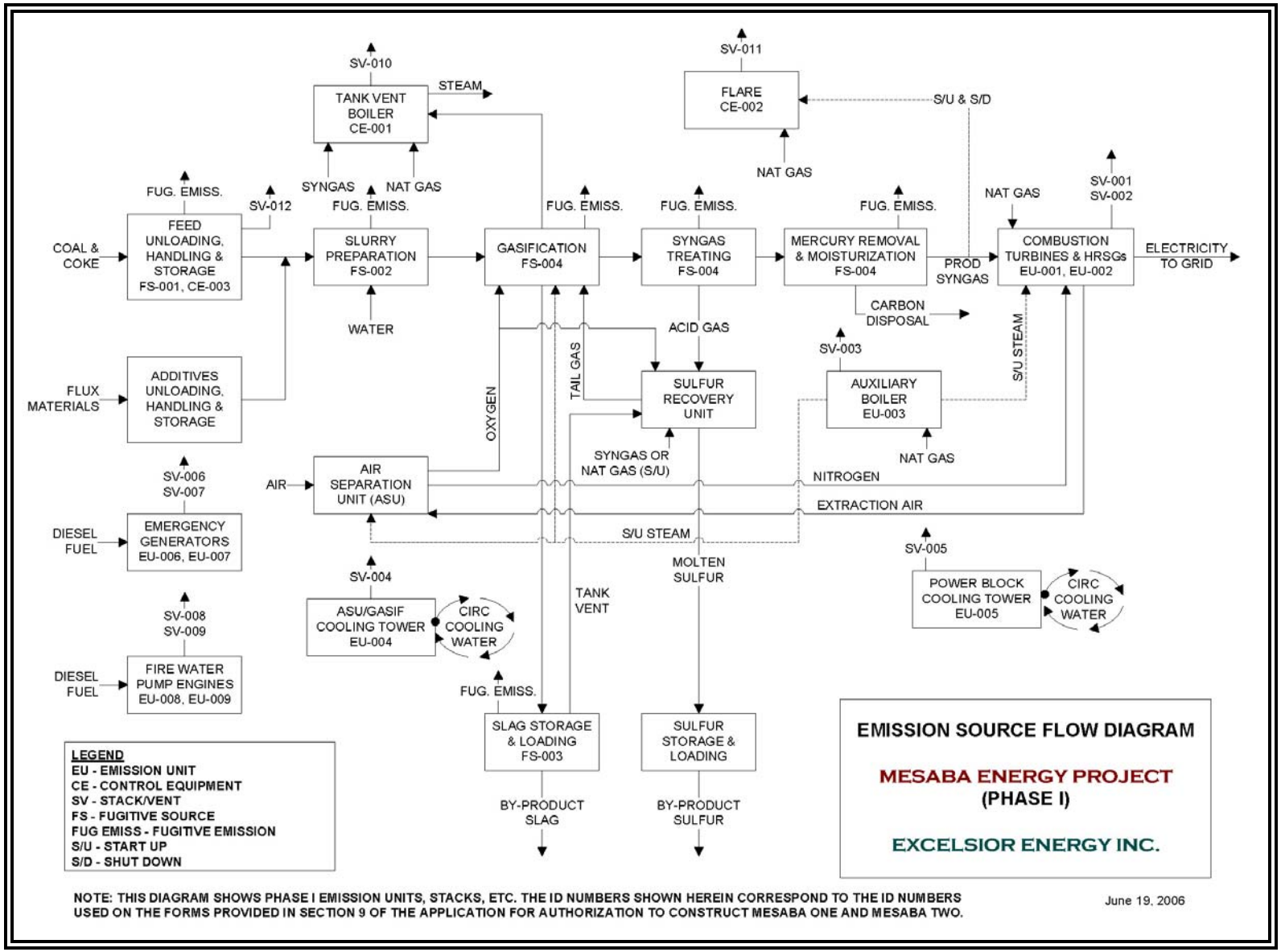
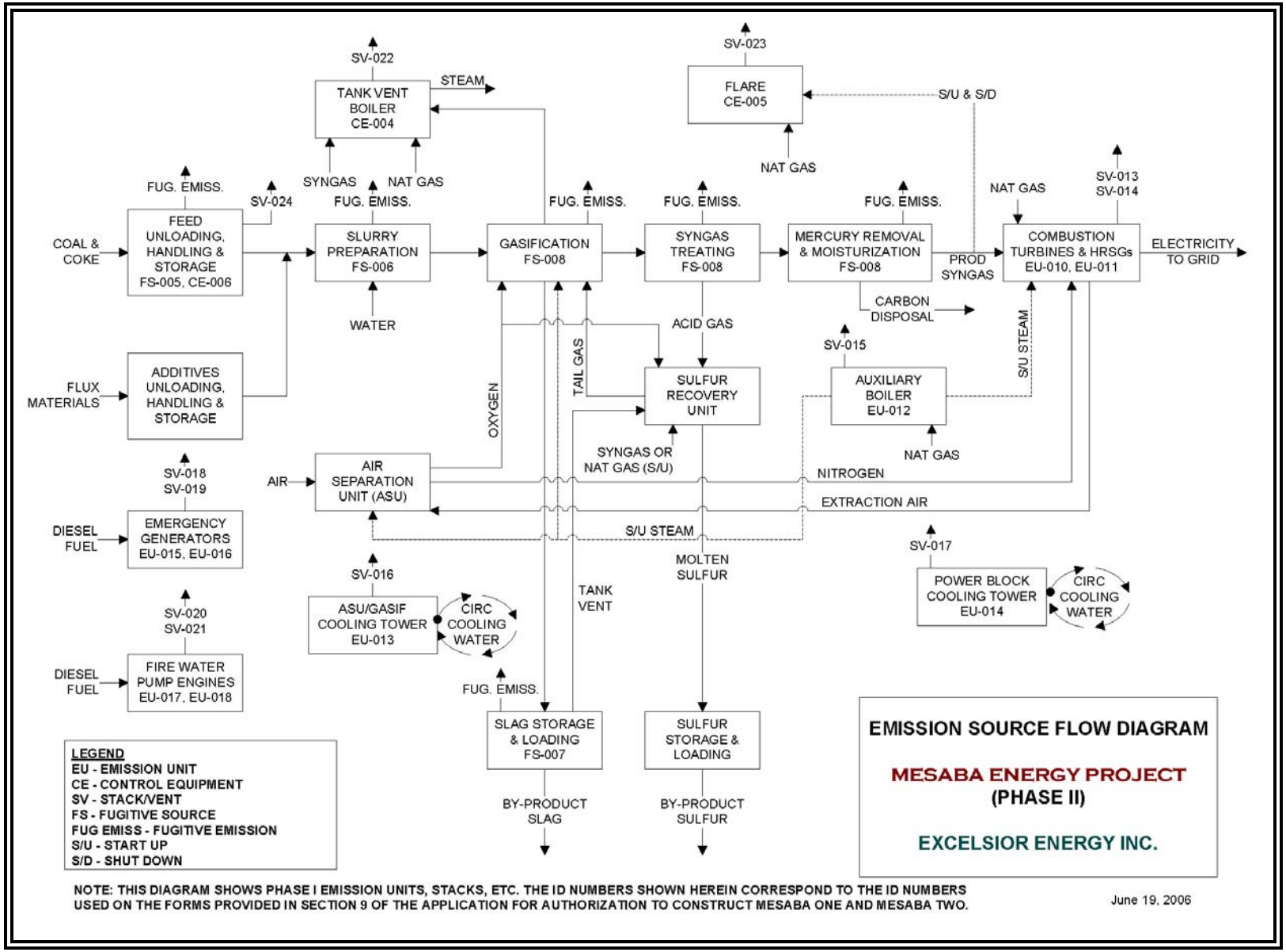


Figure 2.3-2 Block Flow Diagram Showing Air Pollutant Emission Sources for Mesaba Two



2.3.1 Process Chemistry

2.3.1.1 Gasification

Coal and petroleum coke are typically characterized by their heating value, elemental analysis (weight percent carbon, hydrogen, nitrogen and sulfur), mineral matter (also known as ash), and moisture content. Unlike traditional pulverized coal power plants where fuel is actually combusted, in an IGCC power station, coal and/or petroleum coke slurry is fed to the gasifier along with pure oxygen ("O_2"), and a number of complex chemical reactions occur. A portion of the feedstock is partially oxidized to provide the temperatures necessary for gasification. The gasification temperature is high enough to break essentially all the chemical bonds present in the coal and establish a new mix of smaller molecules based on the following primary reactions:

$C + O_2 = CO_2$ (rapid exothermic, or heat releasing, oxidation reaction)

$C + ½ O_2 = CO$ (rapid exothermic oxidation reaction)

$C + H_2O = CO + H_2$ (slower endothermic, or heat consuming, reaction)

$C + CO_2 = 2CO$ (slower endothermic reaction)

$CO + H_2O = H_2 + CO_2$ ("water gas shift reaction", exothermic and rapid)

$CO + 3H_2 = CH_4 + H_2O$ ("methanation reaction", exothermic)

$C + 2H_2 = CH_4$ (direct methanation, exothermic)

Most of the sulfur in the feedstock is converted to hydrogen sulfide ("H_2S") during the gasification process. A small portion of the sulfur is converted into carbonyl sulfide ("COS"). Most of the nitrogen in the feedstock is converted to ammonia ("NH_3"). The syngas composition leaving the gasifier is determined by the gasifier operating temperature and the relative kinetics of the above reactions. Most of the energy in the feedstock is ultimately converted into carbon monoxide ("CO") and hydrogen ("H_2"), and a small amount of methane ("CH_4"). Low grade coals with lower heating values and higher moisture contents will generate a syngas with more CO_2 and H_2, the additional CO_2 generated from the water gas shift reaction shown above. Higher quality coals and petroleum coke will result in a syngas that has a much higher CO content.

2.3.1.2 COS Hydrolysis

Because the small fraction of COS formed in the gasifier is difficult to remove in the Acid Gas Removal ("AGR") system, the COS is "hydrolyzed" in a catalytic reactor before the syngas is sent to the AGR system. The hydrolysis reaction is shown below:

$COS + H_2O = H_2S + CO_2$

The conversion of COS to H_2S is not 100%, and is limited by the equilibrium conditions at the COS reactor operating temperature.

2.3.1.3 Acid Gas Removal

The AGR system uses methyl diethanolamine ("MDEA"), a weak base, to remove the H_2S from the syngas. H_2S is a weak acid that forms weak chemical bonds with the cold lean MDEA solution. Once the MDEA solution absorbs the H_2S, it is called a "rich" solution. The rich MDEA solution is regenerated to a lean MDEA solution by reducing the pressure, applying heat and boiling it. The H_2S released from the rich MDEA under such conditions is sent to the sulfur recovery unit ("SRU").

2.3.1.4 Sulfur Removal

The SRU uses Claus technology to convert H_2S to elemental sulfur. The Claus reactions are shown below:

$$H_2S + \frac{3}{2}O_2 = SO_2 + H_2O$$

$$SO_2 + 2H_2S = 2S + 2\,H_2O$$

The Claus reactions occur in two steps. In the first step a portion of the H_2S is combusted with O_2. The sulfur dioxide ("SO_2") that is formed is mixed with additional H_2S and passed over catalyst beds. The Claus reactions are exothermic and reaction heat is recovered, generating low pressure steam. The "tail gas" stream leaving the Claus reactors contains nitrogen (N_2) and other inert gases that entered with the feeds, along with traces of unconverted H_2S. The tail gas is recycled to the gasifier.

2.4 Process Operations

2.4.1 Slurry Preparation

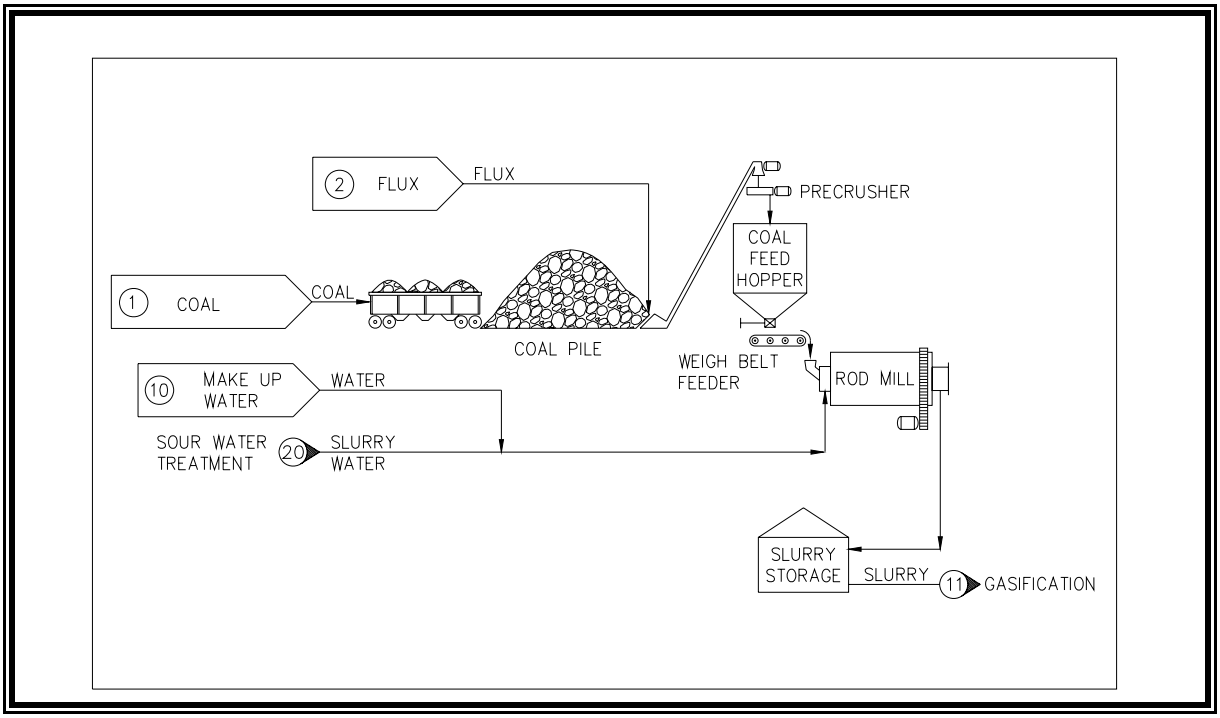
To produce slurry gasifier feed, the solid feedstock is placed on a weigh belt feeder and directed to the rod mill where it is mixed and ground with treated recycled water and slag fines that are recycled from other areas of the gasification island. The resulting slurry has a paste-like consistency. The use of a wet rod mill reduces potential fugitive particulate matter emissions from the grinding operations and is an efficient method for producing essentially homogeneous slurry. Collection and reuse of water within the gasification island minimizes water consumption and discharge.

Slurry feeding allows for consistent and safe introduction of feed into the gasifiers. Prepared slurry will be stored in an agitated tank. The capacity of the slurry storage tank will be sufficiently large to supply the gasifiers' needs without interruption when the rod mill undergoes normal maintenance requirements. The feedstock grinding and slurry preparation area is depicted in Figure 2.4-1-1.

Tanks, drums and other areas of potential atmospheric exposure to the slurry or recycle water will be covered and vented into the tank vent collection system for vapor emission control. The entire feedstock grinding and slurry preparation facility will be paved and curbed to contain

spills, leaks, wash down, and storm water runoff. A trench system will carry this water to a sump where it will be pumped into the recycle water storage tank.

Figure 2.4-1. Feedstock Grinding and Slurry Preparation

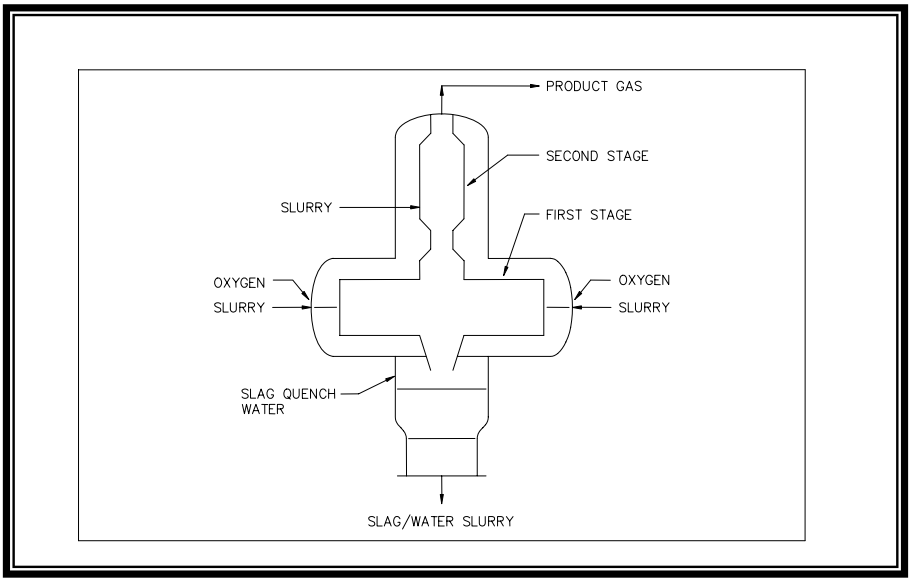


Tanks, drums and other areas of potential atmospheric exposure to the slurry or recycle water will be covered and vented into the tank vent collection system for vapor emission control. The entire feedstock grinding and slurry preparation facility will be paved and curbed to contain spills, leaks, wash down, and storm water runoff. A trench system will carry this water to a sump where it will be pumped into the recycle water storage tank.

2.4.2 Gasification and Slag Handling

The E-Gas™ gasifier consists of two stages: a slagging first stage, and an entrained flow, non-slagging second stage, as depicted in Figure 2.4-2. The first stage is a horizontal refractory-lined vessel in which feedstocks will be exposed to sub-stoichiometric quantities of oxygen at an elevated temperature and pressure. Oxygen and preheated slurry are fed to each of two opposing mixing nozzles, one on each end of the horizontal section of the gasifier. The oxygen feed rate to the nozzles will be carefully controlled to maintain a gasification temperature above the ash fusion point to allow good slag removal and high carbon conversion. The feedstock will be almost totally gasified in this environment to form syngas consisting principally of hydrogen (“H_2”), carbon monoxide (“CO”), carbon dioxide (“CO_2”) and water (“H_2O”).

Figure 2.4-2 E-Gas™ Gasifier



Sulfur in the fuel will be primarily converted to H_2S, with a small portion converted to carbonyl sulfide ("COS"). With the pollutant removal processing system provided downstream, over 99% of the sulfur will be removed from high sulfur feedstocks. Over 97% of the sulfur will be removed from low-sulfur sub-bituminous coal feedstocks. The sulfur removal rate from low sulfur coal results in approximately equal sulfur emissions rates to the higher removal rate from higher sulfur coal. The removal rate from low sulfur coal nonetheless results in approximately equal sulfur emission rates to the higher removal rate from higher sulfur coal. In other words, the final SO_2 emission rate achieved using E-Gas™ technology is independent of the starting sulfur concentration in the feedstock. Therefore the percentage of SO_2 removed from a higher sulfur feedstock that exhibits the same SO_2 emission rate as a lower sulfur feedstock, would show a higher percentage removal rate.

To illustrate, if one assumes the emission rates of Coal A or Coal B equal 0.025 lbs per million Btu heat input, the percentage of SO_2 removed for Coal A and Coal B would be as follows:

% SO_2 removal, Coal A (3.0% S, 11,500 Btu/pound higher heating value):

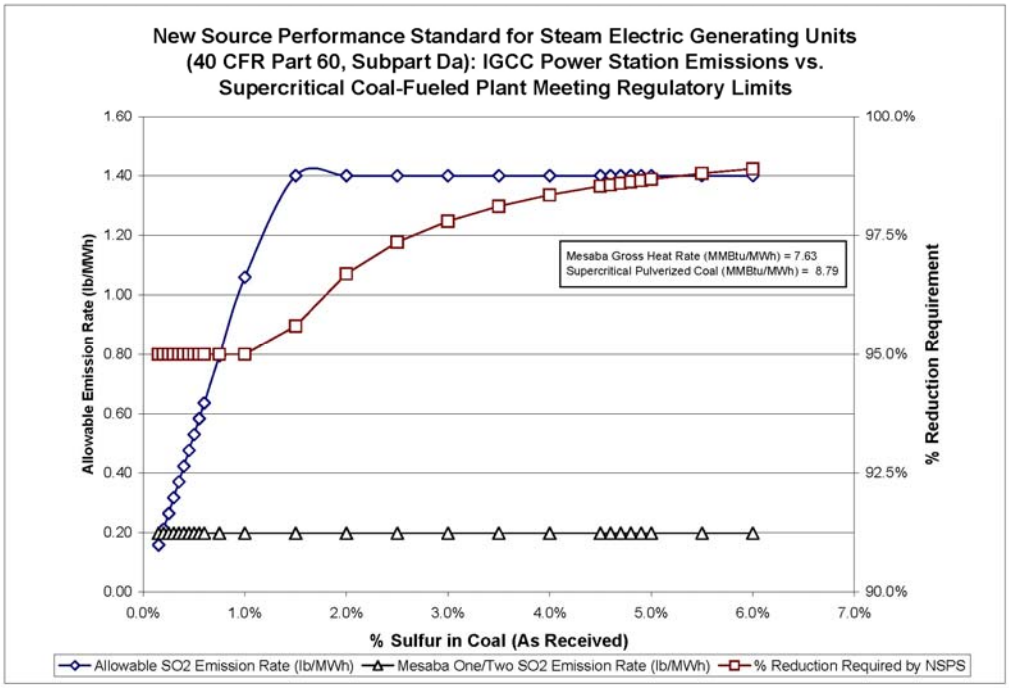
$$\frac{\{[(0.03\text{ lbs S/lb Coal A})*(2\text{ lbs SO2/lb S})*(10^6\text{ Btu/MMBtu})/11{,}500\text{ Btu/lb Coal A}]-0.025\text{ lb/MMBtu}\}}{[(0.03\text{ lbs S/lb Coal A})*(2\text{ lbs SO2/lb S})*(10^6\text{ Btu/MMBtu})/11{,}500\text{ Btu/lb Coal A}]}\times 100\% = 99.5\%$$

% SO_2 removal, Coal B (0.5% S, 8,300 Btu/pound higher heating value):

$$\frac{\{[(0.005\text{ lbs S/lb Coal B})*(2\text{ lbs SO2/lb S})*(10^6\text{ Btu/MMBtu})/8{,}300\text{ Btu/lb Coal B}]-0.025\text{ lb/MMBtu}\}}{[(0.005\text{ lbs S/lb Coal B})*(2\text{ lbs SO2/lb S})*(10^6\text{ Btu/MMBtu})/8{,}300\text{ Btu/lb Coal B}]}\times 100\% = 97.9\%$$

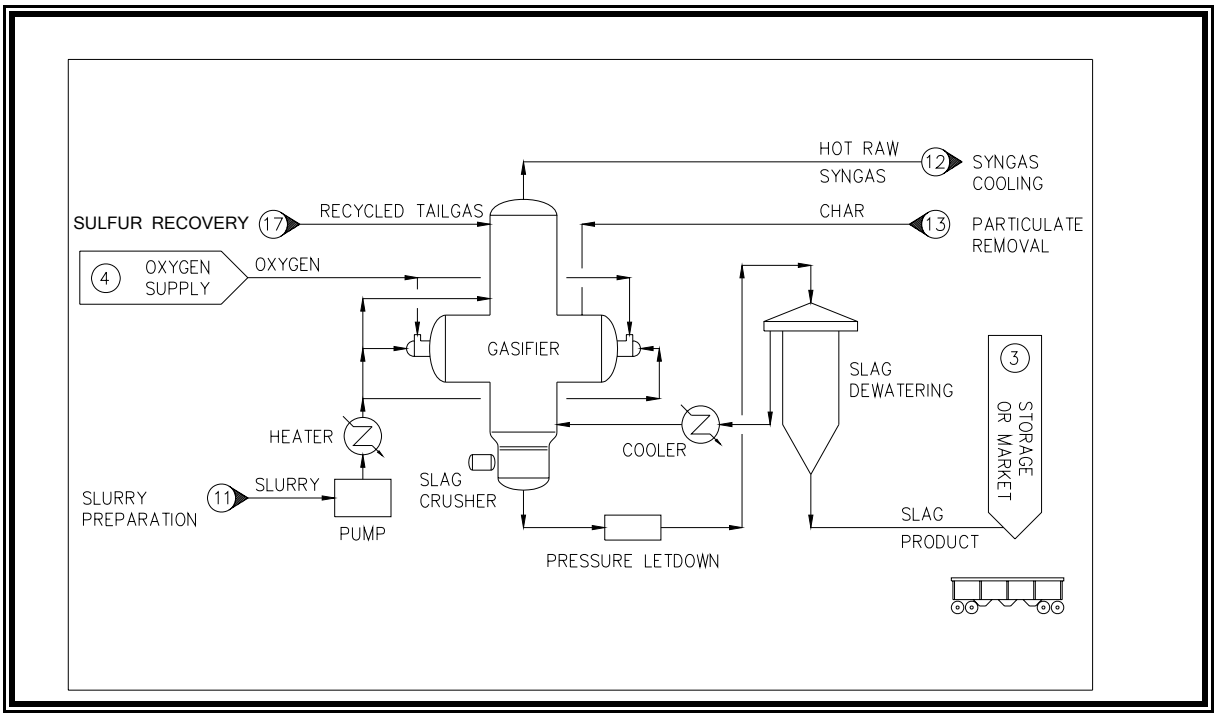
Note that the SO_2 emission rate used in this example approximates the maximum 30-day rolling average emission rate of 0.026 pounds per million Btru heat input expected from Mesaba One and Mesaba Two (see Appendix A-1). This emission rate is far lower than the New Source Performance Standard SO_2 emission rate imposed by Federal law for coal-fueled steam electric generating units shown in Figure 2.4-3.

Figure 2.4-3 New Source Performance Standard vs. Mesaba One and Mesaba Two SO_2 Emission Rates



As to production of slag, mineral matter in the feedstock and added flux forms the molten slag, which flows continuously through a tap hole in the floor of the gasifier horizontal section into a water quench bath, located below the first stage. The characteristics of the slag produced in the gasifier will vary with the mineral matter content of the feedstock. As depicted in Figure 2.4-4, the solidified slag exits the bottom of the quench section, is crushed, and flows through a continuous pressure-letdown system as a slag/water slurry. This continuous slag removal technique eliminates high maintenance, problem-prone lockhoppers and prevents the escape of raw syngas to the atmosphere during slag removal. The slag/water slurry is then directed to a dewatering and handling area (described later). The raw syngas generated in the first stage flows up from the horizontal section into the second stage of the gasifier.

Figure 2.4-4. Gasification and Slag Handling



Typically, the ash content of the coal feedstock will be in the range of 5-11%, as received. Ash in petroleum coke is expected to average about 0.6%, as received. Slag production at full load will vary from about 500 tons per day up to a maximum of about 800 tons per day per phase. The slag will be conveyed from the slag dewatering unit to the slag storage pile using covered conveyors. The slag storage area will be provided with dust suppression systems. Slag from the storage area will be conveyed to rail cars or trucks for transport to market or storage.

The gasifier second stage is a vertical refractory-lined vessel in which additional slurry is reacted with the hot syngas stream exiting the first stage. The feedstock undergoes devolatilization (separation of organic components) and pyrolysis (high temperature decomposition), thereby generating more syngas with higher heat content (less carbon being converted to CO_2) since no additional oxygen is introduced into the second stage. This additional slurry lowers the temperature of the syngas exiting the first stage by the endothermic nature of the devolatilization and pyrolysis reactions. In addition to the above reactions, water reacts with a portion of the carbon to produce additional CO and H_2 for subsequent use as syngas fuel for power generation and CO_2. Unreacted solid fuel (carbonaceous char) is carried out of the second stage with the syngas.

Certain metals present in the feedstocks in trace quantities and volatile at the temperatures typical of the gasifier will also be carried out in their gaseous state as components of the syngas, and removed in the cleanup stage.

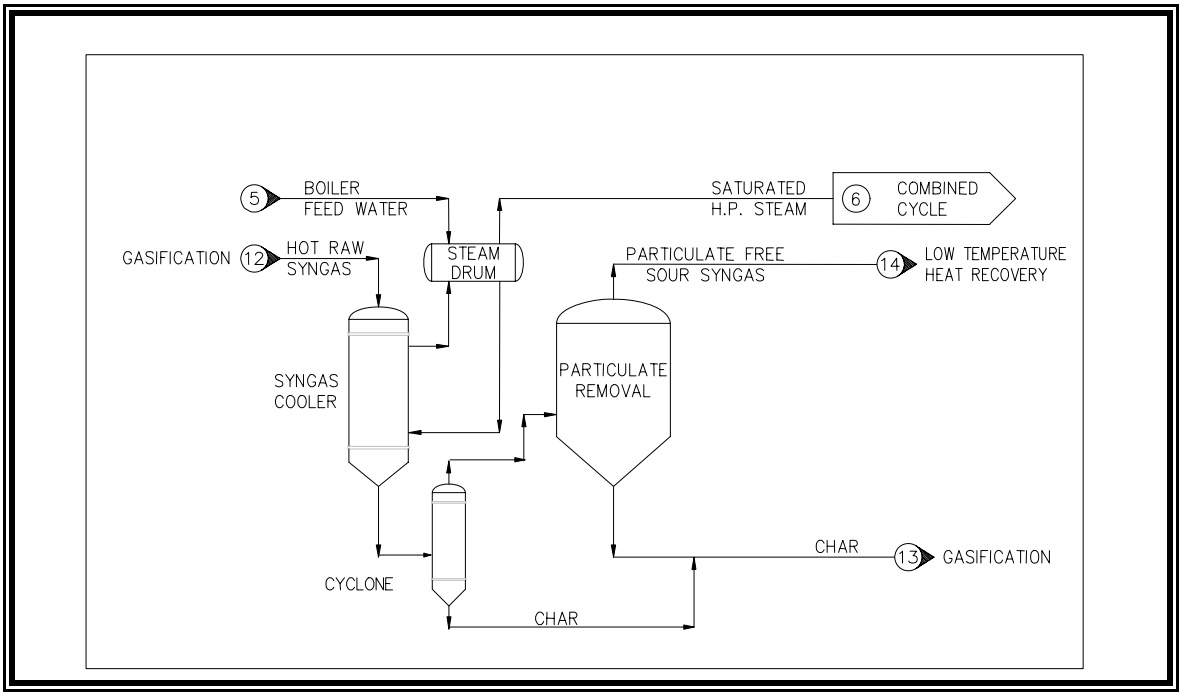
The slag/water slurry will flow continuously into a dewatering bin. The bulk of the slag will settle out in the bin while water overflows into a basin in which the remaining slag fines will settle. The clear water from the settler will pass through heat exchangers where it will be cooled

as the final step before being returned to the gasifier quench section. Dewatered slag is transferred to the slag storage area to be loaded into trucks or rail cars for transport to market or storage. The slurry of fine slag particles from the bottom of the settler will be recycled to the slurry preparation area to be fed back into the gasifier, ensuring maximum carbon utilization.

2.4.3 Syngas Cleanup and Desulfurization

As shown in Figure 2.4-5, the next two steps in the process are to cool the syngas and then remove the particulate matter for recycle to the gasifier. Captured particulate matter is recycled back to the gasifier The hot raw syngas exiting the gasifier system and containing entrained particulate matter will be cooled in the syngas cooler, converting a significant portion of the heat from the gasifier to high pressure steam for use in power generation.

Figure 2.4-5. Particulate Matter Removal



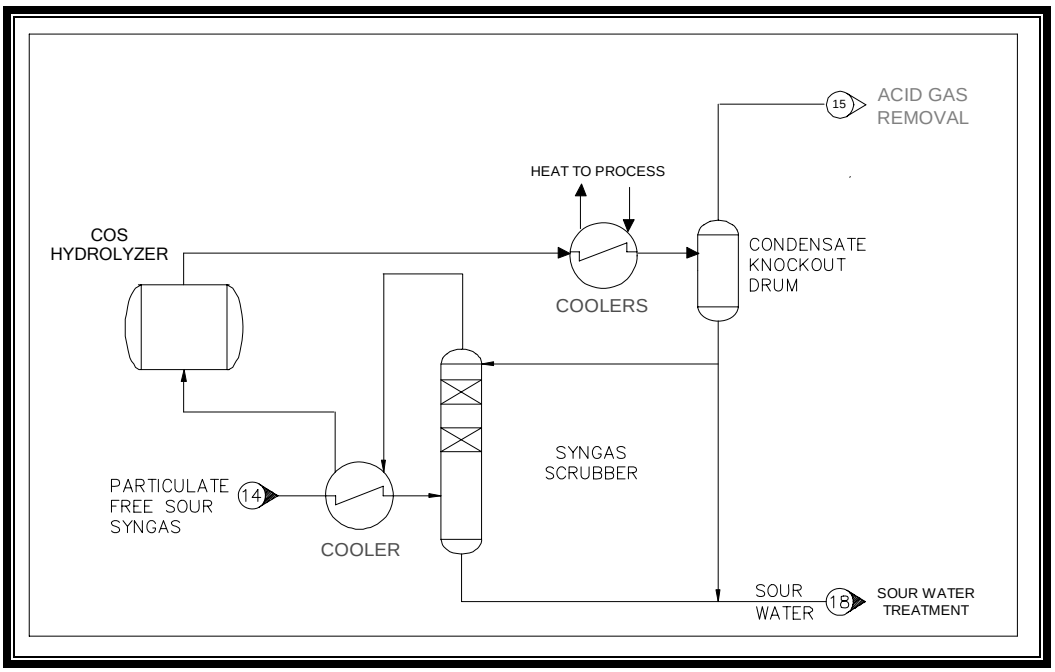
2.4.3.1 Particulate Matter Removal

After cooling, the syngas is directed to the particulate matter removal system, as shown in Figure 2.4-5 above. The gas flows first through a hot gas cyclone for removal of relatively large particulate matter and then passes to the particulate matter filter. The filter vessel contains numerous porous filter elements to remove particulate matter. The cleaned syngas exits the unit as a particle free syngas. Particulate matter removal efficiency is expected to approach 99.9%. Removed particulate matter from both the hot gas cyclone and the dry filter vessel is recycled to the first stage of the gasifier to improve carbon conversion efficiency. With the particulate matter being recycled to the gasifier from both devices, near complete gasification of the carbon content of the feedstock is obtained. The particle free syngas proceeds to the low temperature heat recovery system.

2.4.3.2 Syngas Scrubbing, COS Hydrolysis and Low Temperature Heat Recovery

With particulate matter removed from the syngas, additional gas cleanup and cooling can more easily be performed. The syngas is scrubbed with recycled sour water (water with dissolved sulfur compounds and other contaminants condensed from the syngas) to remove chlorides and trace metals and to reduce the potential of equipment corrosion and formation of undesirable products in the acid gas recovery ("AGR") system. This is shown in Figure 2.4-6.

Figure 2.4-6 Syngas Scrubbing



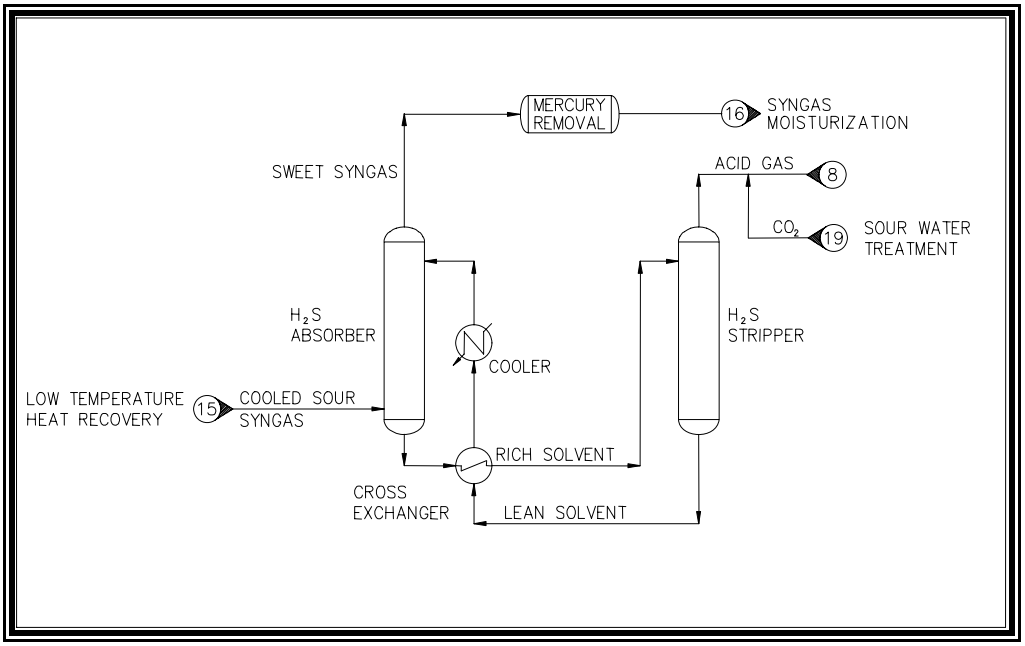
A COS hydrolysis unit is provided to achieve a high level of sulfur removal. The purpose of the COS hydrolysis step is to convert the small amount of COS in the syngas to H_2S, which can then be efficiently removed in the AGR system. After hydrolysis, the syngas is cooled in process heat exchangers to efficiently utilize the available relatively low-temperature heat. Most of the ammonia (NH_3) and a small portion of the CO_2 and H_2S present in the syngas are absorbed in the water condensed by this cooling step. Additionally, some of the trace metals that remained in their gaseous state during the particulate matter removal process will condense. The water is collected and sent to the sour water treatment unit. The cooled sour syngas is fed to the AGR system where the sulfur compounds are removed to produce a low sulfur product syngas.

2.4.3.3 Acid Gas Removal System

The AGR system (shown in Figure 2.4-7) contacts the cool sour syngas with an aqueous solution of MDEA, an amine absorbent that removes the H_2S to produce a clean product syngas. MDEA chemically bonds with H_2S, with a bond that can be easily broken with low level heat in order to regenerate the absorbent. H_2S is absorbed from the syngas by contacting the gas with MDEA solution within the H_2S absorber column. A portion of the CO_2 is also absorbed as well. The H_2S-rich MDEA from the bottom of the absorber flows to a cross heat exchanger to recover heat

from the hot lean MDEA coming from the stripper. The heated rich MDEA is then directed to the H_2S stripper where the H_2S and CO_2 are removed at near atmospheric pressure. A concentrated stream of H_2S and CO_2 exits the top of the H_2S stripper and flows either to the carbon-capture system or directly to the SRU. The lean MDEA is pumped from the bottom of the stripper to the heat exchanger. The lean MDEA is further cooled before being stored and then recirculated to the absorber. This unit is a totally enclosed process with no discharges to the atmosphere.

Figure 2.4-7. Acid Gas Removal



2.4.3.4 Potential Carbon Capture Retrofit

The Applicant believes that some form of Federal greenhouse gas emissions control will be imposed within the next ten years. To provide the State and consumers with a means to deal with such requirements, the Applicant will design Mesaba One and Mesaba Two to be carbon capture ready. Additionally, the Applicant has contracted with the University of North Dakota Energy and Environmental Research Center ("EERC") to assess CO_2 management options for Mesaba One and Mesaba Two. This work is part of the Plains CO_2 Reduction Partnership,[1] Phase II efforts EERC is conducting for DOE to validate the most promising sequestration technologies and infrastructure concepts identified during Phase I of the Program.[2] Sink-source pairs, specific to the composition of CO_2 gas streams that can be removed from the syngas

[1] The Plains CO_2 Reduction Partnership is one of seven regional partnerships funded by the U.S. Department of Energy's National Energy Technology Laboratory Regional Carbon Sequestration Partnership Program.

[2] Plains CO_2 Reduction ("PCOR") Partnership Phase I Final Report/Quarterly Technical Progress Report for the Period July 1-September 30, 2005; DOE Cooperative Agreement No. DE-PS26-03NT41982 EERC Fund Nos. 4251, 4334, 4406, and 9039, January 2006.

produced by Mesaba One and Mesaba Two, will be identified and ranked according to engineering, economic, and public-acceptance considerations.

The carbon capture system that the Applicant will seek to engineer on a preliminary basis can be added after the IGCC plant is in operation. Based on work to date, such CO_2 capture facilities will likely be located within the existing IGCC Power Station Footprint and require an area of approximately 100' X 150' to accommodate necessary equipment. The preferred location for the future plot space would be adjacent to the power block. For PRB coal, the Applicant would expect to capture approximately one third of the carbon (as CO_2) in the solid IGCC feedstock. This capture would likely come at a decrease in capacity and efficiency of the IGCC plant.[3]

2.4.3.5 Mercury Removal and Moisturization

Fixed beds of activated carbon will be provided to remove residual mercury from syngas (see Figure 2.4-7 above). Multiple beds specially impregnated to remove mercury are used to obtain optimized adsorption. The activated carbon capacity for mercury ranges up to 20% by weight of the carbon (Parsons, 2002). The mercury removal system will remove enough mercury from the syngas so that the mercury content of the syngas fuel is no more than 10% of the mercury contained in the solid IGCC feedstock. The mercury removal system will be located immediately upstream or immediately downstream of the AGR. The location will be determined during the next engineering phase of the project by working closely with carbon suppliers to identify the optimum location. After acid gas and mercury removal, the product syngas is moisturized, heated, and diluted with nitrogen for control of nitrogen oxides ("NO_x") before being combusted for power generation in the CTGs.

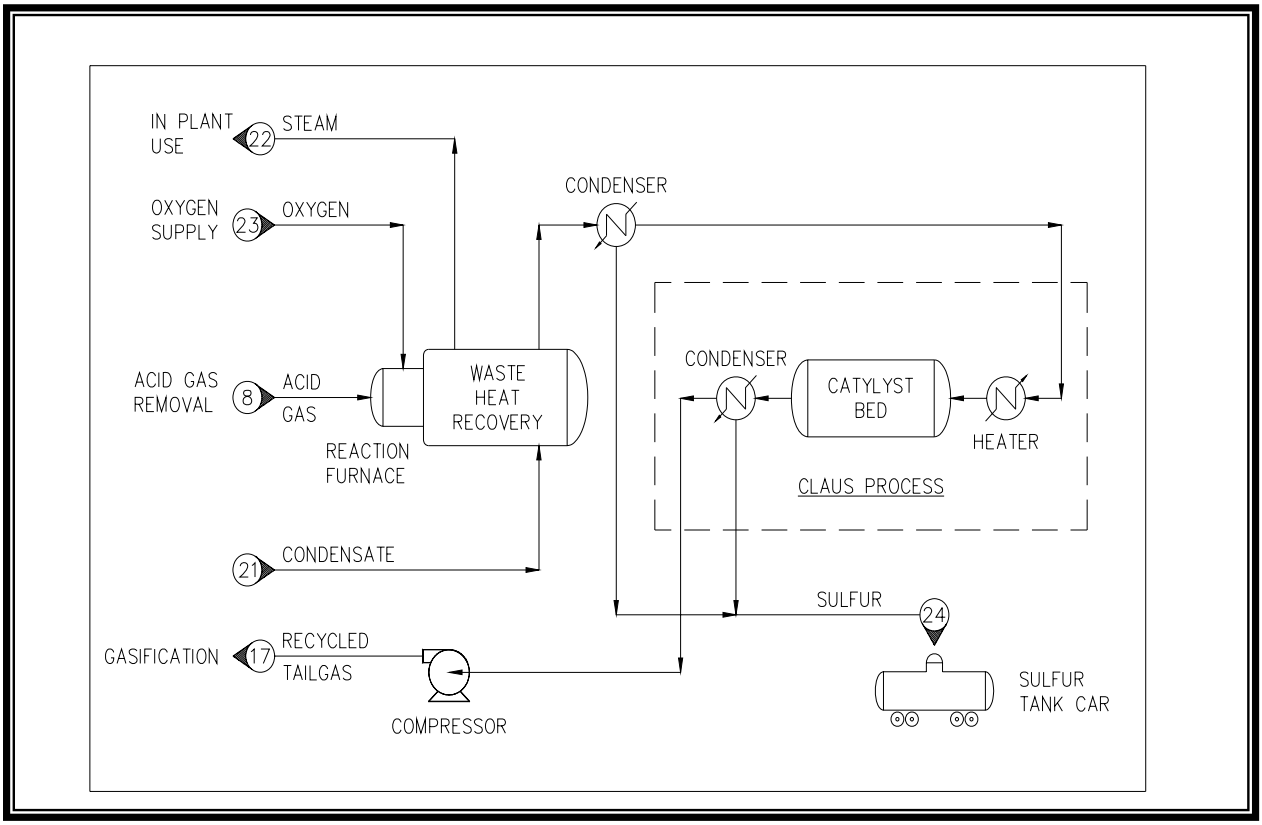
2.4.4 Sulfur Recovery Unit

The H_2S carried along in the acid gas from the AGR system is converted to elemental sulfur in the SRU. This technology is based on the industry-standard Claus process involving the conversion of the H_2S to gaseous elemental sulfur and steam. The sulfur is selectively condensed and collected in molten form (see Figure 2.4-87).

The acid gas stream from the AGR units and the CO_2 /H_2S stripped from the sour water are fed to the SRU. One-third of the H_2S is combusted with oxygen to produce the proper ratio of H_2S and SO_2, which are then reacted together to produce elemental sulfur gas in a reaction furnace. A waste heat boiler is used to recover heat before the furnace off-gas is cooled to condense the first increment of sulfur.

[3] The adverse economic and operational impacts associated with carbon capture are expected to be reduced by research and development initiatives presently underway as part of the DOE's Clean Coal Power Initiative. Future research under that initiative will develop the technological path required to achieve removal of an expected 90% of the total CO_2.

Figure 2.4-8. Sulfur Recovery Unit



Gas exiting the first sulfur condenser is fed to a series of heaters, catalytic reaction stages and sulfur condensers where the H_2S is incrementally converted to elemental sulfur. The sulfur is recovered and stored in molten form and may be sold as a by-product raw material for fertilizer and other beneficial uses. If not sold, the sulfur will be stored on site and/or transported to a storage facility.

The tail gas from the SRU is composed mostly of CO_2 and nitrogen with trace amounts of H_2S and SO_2 as it exits the last condenser. This SRU tail gas is catalytically hydrogenated to convert the remaining sulfur species to H_2S and then recycled to the gasifier. Recycling the SRU tail gas allows for a very high overall sulfur removal in the IGCC process and eliminates the need for a conventional tail gas treating unit and reduces overall plant emissions of SO_2 and NO_x emissions to the atmosphere.

The sulfur production rate is dependent upon the sulfur content of the feedstock, and will vary from about 30 tons per day up to about 165 tons per day for each IGCC unit. The sulfur storage tanks are considered part of the SRU system.

Condensed sulfur from the SRU is collected in the sulfur pit. The liquid sulfur drains into the pit which contains a pump well and sulfur pumps. Sweep nitrogen is introduced into the pit to prevent the accumulation of an otherwise potentially explosive mixture of H_2S and air, and to control fugitive emissions. The sweep nitrogen inlet and outlet are located at opposite ends of the pit to ensure proper sweep of the vapor space. The sweep nitrogen outlet is collected and

recycled to the second stage of the gasifier. Nitrogen is used instead of air as it is readily available from the ASU and since it is undesirable to return air back to the gasifier's second stage.

The liquid sulfur is pumped from the sulfur pit to a sulfur degassing unit. The sulfur degassing unit strips dissolved H_2S out of the liquid sulfur. The degassed sulfur is pumped from the degassing unit to the sulfur storage tank. The stripped H_2S stream is routed to the tail gas recycle stream to the gasifier.

Sulfur loading involves pumping liquid sulfur from the sulfur storage to trucks or rail cars. The sulfur loading arms have vapor recovery systems to control fugitive emissions by returning displaced vapors to the storage tank.

The SRU is a totally enclosed process with no discharges to the atmosphere.

2.4.5 Air Separation Unit

The air separation unit provides oxygen for the gasification process and nitrogen for CTG NO_x control and for purging. The ASU contains an air compression system, an air separation cryogenic distillation system ("cold box"), an oxygen pump system and a nitrogen compression system. Two ASU equipment trains will be provided for each phase of the facility.

A multi-stage, electric motor-driven centrifugal compressor compresses filtered atmospheric air that may be combined with additional compressed air extracted from the gas turbines in the power block. The combined air stream is cooled and directed to the molecular sieve absorbers where moisture, carbon dioxide and atmospheric contaminants are removed to prevent them from freezing in the colder sections of the plant. The dry carbon dioxide-free air is separated into oxygen and nitrogen in the cryogenic distillation system. A stream containing mostly oxygen is discharged from the cold box as a liquid and stored in an intermediate oxygen storage tank, from which it is fed to the gasifier.

The remaining portion of the air is mainly nitrogen and leaves the ASU in three separate nitrogen streams. A small portion of the nitrogen is high purity and is used in the gasification plant for purging and inert blanketing of vessels and tanks. The largest, but less pure, portion of the nitrogen is compressed and sent to the combustion turbines for NO_x emission control. Excess nitrogen is vented to the atmosphere. There will be no emission of regulated air pollutants from the ASU.

2.4.6 Slag Handling, Storage and Loading

The slag/water slurry from the gasifier (see Figure 2.4-4) flows continuously into a dewatering bin. The bulk of the slag settles in the bin while water overflows into a settler in which the remaining slag fines are settled and concentrated. The slurry of fine slag particulates from the bottom of the settler is recycled to the slurry preparation area, ensuring maximum carbon utilization. The clear water from the settler is passed through heat exchangers where it is cooled as the final step before being returned to the gasifier quench section.

Dewatered slag is transferred by in-plant trucks to the slag storage area from where it will be loaded into on-road trucks or rail cars for transport to market or storage. The dewatered slag is relatively inert. At this point, it is also very moist and will not be a source of fugitive particulate matter emissions.

2.4.7 Combined Cycle Power Block

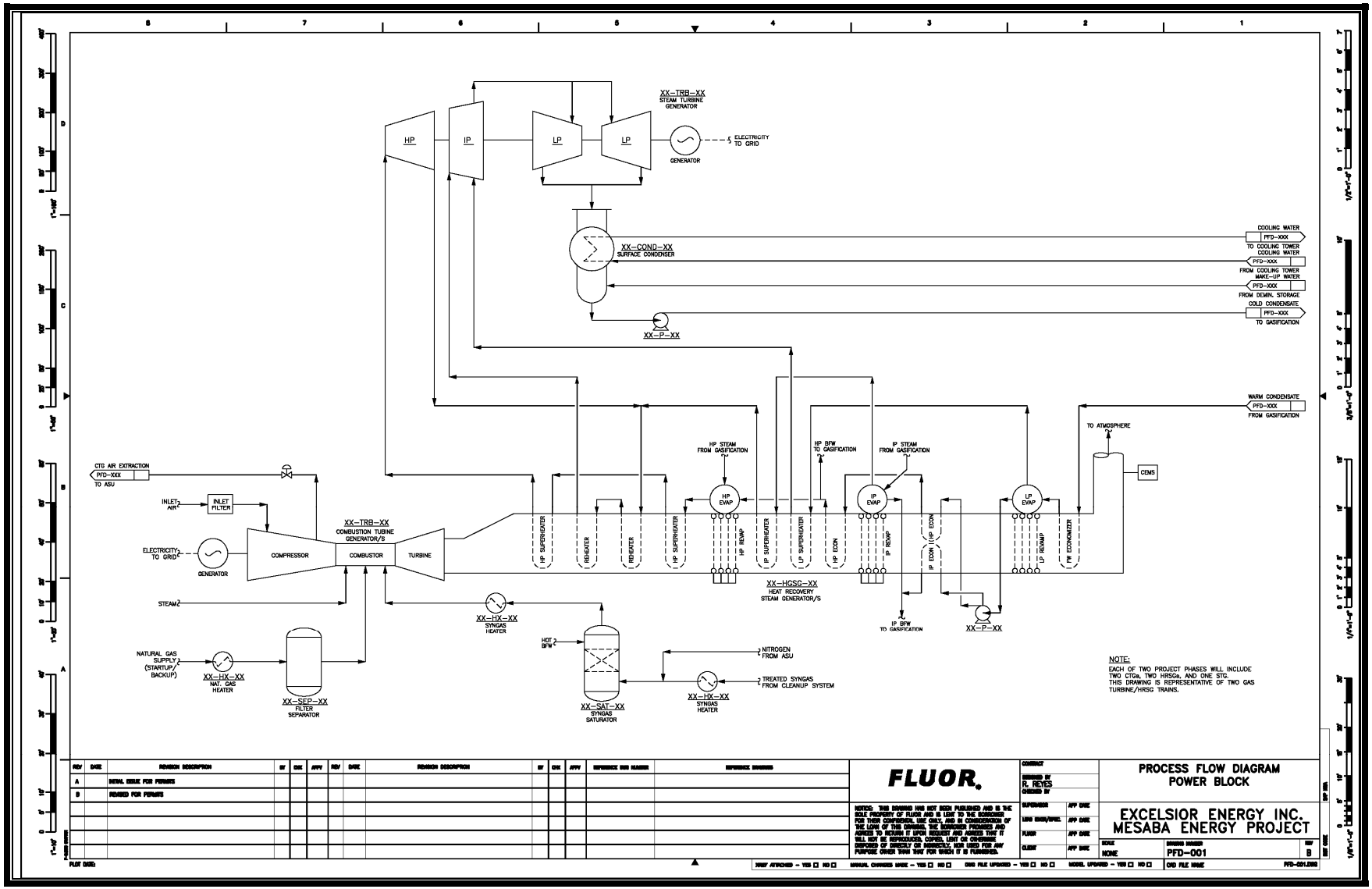
The power generation portion of the IGCC Power Station is similar to a conventional natural gas combined cycle plant. Combined cycle power generation is one of the most efficient commercial electricity generation technologies currently available. Each phase of the IGCC Power Station will include two "F Class" advanced CTGs configured to utilize syngas, two HRSGs, and a single STG. (See Figure 2.4-9). The CTGs will convert the chemical energy contained in the syngas fuel to electricity both directly through the generators integral to the CTGs, and indirectly through the additional thermal energy contained in the CTG exhaust gas. The exhaust gas is converted to high-energy steam in the HRSGs and subsequently to a significant amount of additional electricity in the STGs.

Preheated syngas from the gasification section and compressed air are supplied to the combustion turbine combustor and mixed through diffusion (a diffusion flame combustion turbine). Diluent nitrogen added to the syngas fuel reduces the flame temperature in the combustor and thereby reduces production of nitrogen oxides. The hot exhaust gas exiting the combustor flows to the expander turbine, which drives the generator to produce electricity and also turns the air compressor section of the combustion turbine. Hot exhaust gas from the expander is ducted through the HRSG to generate high-energy steam used to produce additional electricity in the steam turbine generator. Following heat recovery, the cooled CTG exhaust gas is discharged to the atmosphere through the HRSG stacks. The HRSG stacks will be provided with emission monitoring instruments as required to verify compliance with applicable emission standards and permit conditions.

The HRSG generates three pressure levels of steam as well as heating boiler feed water for the syngas cooler in the gasification section. The HRSG also provides additional energy for superheating steam from the gasification section and cold reheat steam from the STG.

The steam turbine generator is comprised of high pressure ("HP"), intermediate pressure ("IP"), and low pressure ("LP") turbine sections, coupled directly to a generator. The LP turbine section exhausts to the surface condenser. Process heat from the gasification plant is used to preheat the condensate from the steam turbine condenser before it is returned to the HRSG to produce steam. STG exhaust steam is condensed in the surface condenser by indirect cooling with circulating cooling water from the cooling tower. The resulting steam condensate is recycled to the HRSG and other heat recovery equipment to once again produce steam for the STG.

Figure 2.4-9. Illustration of Combined Cycle Concept



2.5 IGCC Power Station Utility Systems

2.5.1 Tank Vent Boiler System

A tank vent collection/boiler system is used to convert each off-gas component in the tank vents to its oxidized form (SO_2, NO_x, H_2O, and CO_2) before venting to the atmosphere. The tank vent streams are composed primarily of air purged through various in-process storage tanks, and are routed to the tank vent boiler. This tank purge gas may contain very small amounts of sulfur-bearing components. The high temperature produced in the tank vent boiler thermally converts any H_2S present in the tank vents to SO_2. Heat recovery in the form of steam generation is provided for the hot exhaust gas from the tank vent boiler before it is directed to a stack.

The slag handling dewatering system off-gas contains H_2S which would be a source of relatively significant SO_2 emissions if vented to the tank vent system. In this part of the process, H_2S is released from slag water as the pressure is reduced from approximately 400 pounds per square inch gauge ("psig") to atmospheric conditions. Rather than vent this "flashed" gas to the tank vent boiler, a blower will be provided to combine it with either the tail gas from the SRU for recycle to the gasifier or the SRU feed gas from the AGR, thus eliminating this potential SO_2 emission source.

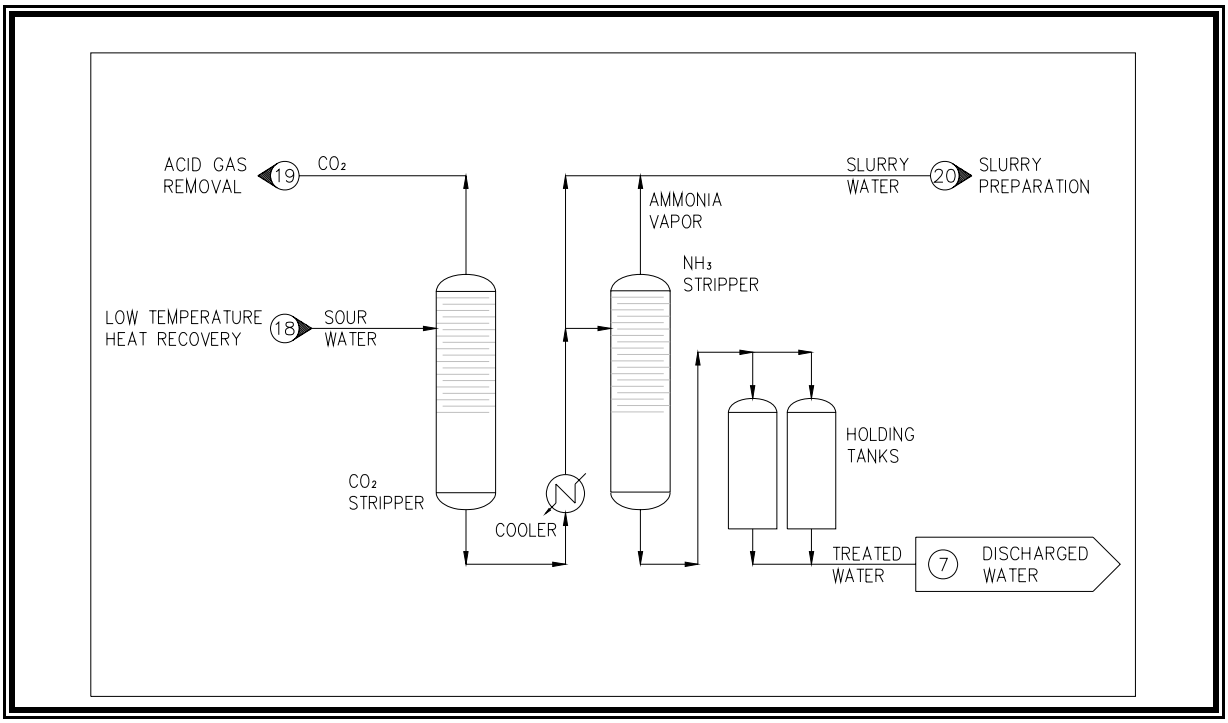
2.5.2 Sour Water Treatment

Process water containing dissolved contaminant gases produced within the gasification process must be treated to remove these dissolved gases before being recycled to the coal grinding and slurry preparation area or being blown down to the Zero Liquid Discharge ("ZLD") System. The sour water treatment process is illustrated in Figure 2.5-1. The dissolved gases are driven from the water using steam-stripping. The steam provides heat and a sweeping medium to expel the gases from the water, resulting in a purification level sufficient for reuse within the plant and/or for blowdown to the ZLD.

Water condensed during cooling of the sour syngas contains small amounts of dissolved gases (CO_2, NH_3, H_2S and other trace contaminants). The gases are stripped from the sour water in a two-step process. First, the CO_2 and most of the H_2S are removed in the CO_2 stripper column by steam stripping and directed to the SRU. The water exits the bottom of this column, is cooled, and a major portion is recycled to feedstock grinding and slurry preparation. The rest is treated in an ammonia stripper column to remove the ammonia and remaining trace components. The stripped ammonia is combined with the recycled slurry water. A portion of the ammonia-stripped water is blown down to the ZLD, with the rest being reused within the plant. Reuse of the water within the gasification plant minimizes water consumption and discharge.

This unit is a totally enclosed process with no discharges to the atmosphere.

Figure 2.5-1 Sour Water Treatment System



2.5.3 Zero Liquid Discharge System

Water from the bottom of the ammonia stripper is treated in a ZLD unit. The blowdown stream is pumped to a brine concentrator which uses steam or vapor compression to indirectly heat and evaporate water from the wastewater stream. Generated water vapor is compressed and condensed, and the high quality distillate is recycled to the syngas moisturization system or to other water uses in the plant. The concentrated brine is further processed in a heated rotary drum dryer/crystallizer. There the remaining water is vaporized and a solid filter cake material is collected for proper disposal. Use of the ZLD system effectively prevents the contaminants in feedstocks from being discharged to surface waters.

2.5.4 Auxiliary Boilers

Two auxiliary boilers, one for each phase of the IGCC Power Station, will provide steam for pre-startup equipment warm up and for other miscellaneous purposes when steam from the gasifiers or HRSGs is not available. These boilers will provide steam in addition to, or in lieu of, the steam that can be generated from the tank vent boilers. Each boiler will produce a maximum of about 100,000 lb/hr of steam and will be fueled by pipeline natural gas. Annual operation of each boiler will be equivalent to or less than 25% of the year at maximum capacity. The auxiliary boilers will be equipped with low NO_x burners to minimize air emissions.

2.5.5 Flare

The gasification island elevated flare is utilized to burn partially combusted natural gas and scrubbed/desulfurized off-specification syngas during unit startup or on-specification syngas

during short-term combustion turbine outages. Syngas sent to the flare during normal planned flaring events will be filtered, water-scrubbed and further treated in the AGR and mercury removal systems to remove regulated contaminants prior to flaring. Flaring of untreated syngas or other streams within the plant would only occur as an emergency safety measure during unplanned plant upsets or equipment failures. The normal start-up sequence for the flare is discussed in Section 2.5.7 and in Tables 2.5-1 and 2.5-2.

2.5.6 Emergency Diesel Engines

For each of Mesaba One and Mesaba Two, one 2 MW emergency diesel generator will be used for the gasification island and one 350 kW emergency diesel generator will be used for the power block. One or two nominal 300 hp diesel-driven firewater pumps will be provided for each phase (emission estimates are based on having two firewater pumps for Mesaba One and two pumps for Mesaba Two). These engines will burn very low sulfur distillate oil. Other than plant emergency situations, the engines will be operated less than five hours per month per engine for routine testing, maintenance, and inspection purposes.

2.5.7 Startup and Shutdown

Two general types of plant startups will occur at the IGCC Power Station. The first type, which will probably be more usual, consists of replacing one of the two operating gasifiers (per phase) with the third, spare gasifier. This procedure would be conducted to avoid extended gasifier outages (and the resulting loss of the Station's electric generating capacity) while performing normal maintenance or repairs on the gasifier taken off line. The other startup type consists of starting up two of the three gasifiers and both combustion turbines (per phase) after the entire Station has been off line for major maintenance or some other reason. Tables 2.5-1 and 2.5-2 list the sequential steps required for each type of startup. The total number of gasifier cold startups is expected to total approximately four per year per gasifier after the IGCC Power Station has achieved commercial operation and completed all testing, inspection, and monitoring requirements.

Prior to introducing coal and/or coke slurry feed to a gasifier during startup, the gasifier must be pressurized and heated. This is accomplished by purging the gasifier vessel and downstream syngas piping with nitrogen from the ASU or storage. This purge gas flows through the normal syngas treating system and is vented to the flare for safe disposal. Nitrogen is then used to pressurize the system to test for leaks. Natural gas and oxygen from the ASU or storage is next combusted in the gasifier to gradually raise the temperature to an adequate level to begin slurry gasification. The products of combustion from heating (CO_2, CO, water vapor, and excess natural gas) also flow through the syngas treating system prior to final combustion in the flare. If available, syngas may be substituted for the natural gas fuel once stable combustion is achieved. When the gasifier has reached the required temperature, the natural gas or syngas fuel flow is stopped and coal and/or coke slurry is introduced to the gasifier (without depressurizing the gasifier or syngas piping system). The initial syngas, which is not yet suitable as combustion turbine fuel due to its low heating value, flows through the normal syngas treating system for removal of particulate matter, sulfur, mercury, and other trace contaminants and is routed to the flare for combustion. Once the syngas product meets the required heating value and other

minimum specifications for CTG fuel, flow to the flare is stopped and the syngas is routed to one or more CTGs for electricity production. At this point the gasifier startup is complete.

CTGs will only be started on natural gas fuel. The startup process is relatively straightforward. First, the CTG rotor is mechanically turned without combustion to purge the CTG/HRSG gas paths of any residual combustible materials. Next, the combustor is ignited with natural gas fuel and the CTG is accelerated to full rotational speed with no load on the generator (full speed, no load). The generator is then loaded (starts producing electricity) and is ramped up (load increased) at a specified rate. Steam for NOx control is injected into the fuel combustor at the appropriate load point. Switching to syngas fuel will normally occur when the CTG reaches 50 to 70 percent of full load operation. At this point the natural gas/steam flow is gradually decreased and replaced with moisturized syngas fuel and diluent nitrogen. After completing the fuel switch, the CTG is ramped to the desired operating load point (typically full load). Startups for natural gas only backup power generation are the same as described above without the fuel switching step.

Table 2.5-1
IGCC Startup – Gasifier Replacement

(Gasifier 2 will be taken off line and replaced by Gasifer 3. Plant is initially in normal operation.)
1. Purge and pressure Gasifier 3 with nitrogen and test vessel and piping for leaks.
2. Introduce natural gas and oxygen mixture into Gasifier 3, light off, and warm up. (Once stable oxidation is achieved, treated product syngas may be substituted for natural gas.) Combustion products from warm-up flow through the syngas treating system to the flare or CTG.
3. Prior to introducing slurry feed to Gasifier 3, ramp down Gasifier 2 and shutdown. Simultaneously ramp down CTGs.
4. When adequate gasifier temperature achieved, introduce slurry and oxygen to Gasifier 3 and stop natural gas, vent syngas though treating system to flare.
5. Switch syngas from flare to CTGs when CTG fuel specifications achieved and ramp up Gasifier 3 and CTGs.
6. Nitrogen purge Gasifier 2, vent purge gas to flare.

Table 2.5-2
IGCC Cold Plant Startup

(Assumes plant utility and supporting systems, e.g., steam, cooling water, etc., are started and available when needed)
1. Cool down ASU.
2. Purge and pressure Gasifier 1 with nitrogen from storage and test vessel and piping for leaks.
3. Warm up amine unit, sulfur recovery unit and gas systems, light flare pilot.
4. Introduce natural gas from pipeline and oxygen from storage into Gasifier 1, light off, and warm up. Combustion products from warm-up flow through normal syngas treating system to flare.
5. Startup COS reactors (bypassing warm-up combustion gases), heat up sulfur recovery unit on natural gas, and start amine circulation.
6. Complete ASU startup, oxygen available.
7. Warm up HRSG and steam turbine with steam from aux boiler.
8. Startup CTG 1 on natural gas.
9. Introduce slurry and oxygen to Gasifier 1 and stop natural gas when adequate gasifier temperature achieved, vent syngas though treating system to flare.
10. Switch syngas from flare to CTG 1 when CTG fuel specifications achieved and CTG 1 is at adequate load, reduce and stop natural gas to CTG, ramp up Gasifier and CTG to required load.
11. Repeat startup sequence for Gasifier 2 and CTG 2, possibly substituting product syngas for natural gas to warm up Gasifier 2.

Emissions that will only occur during startup include:

- Natural gas (or treated syngas) combustion products - resulting from start-up of the gasifiers - that are routed to the flare to ensure complete oxidation. These combustion gases will flow through the normal syngas clean up circuit before being routed to the flare.
- Transient CO and VOC emissions as the CTGs are started up on natural gas fuel.
- Flaring of filtered, scrubbed, and desulfurized syngas after slurry is introduced to the gasfier, but before the syngas product has reached the specified composition and conditions for use in the combustion turbine.

Other plant emissions during startup will be the same or similar as during normal plant operation.

2.6 Major Process Equipment

The major functional process equipment provided for the inside-the-battery-limit ("ISBL") facilities for the IGCC Power Station are identified below. The number of trains and percentage train capacity for each of the functions/components are also identified. Capacities for some of the major components are identified.

2.6.1 *Air Separation Unit (2x 50%)*

- ASU (2,507 tons per day/train, based on PRB1 coal operation)
- N_2 Booster Compressor for CTG Injection
- Liquid Oxygen and Liquid Nitrogen storage

2.6.2 *Feedstock (Coal/Petroleum Coke) Handling (1 x 100%)*

- Feedstock Active Storage (20 days based on PRB1 coal)/Conveying/Reclaiming (based on 8,550 tons/day, as received)
- Feedstock Inactive Storage (45 days based on PRB1 coal)
- Flux Storage (silos)/Conveying/Reclaiming (250 tons/day based on 50:50 blend of PRB2:PRB3 coals)
- Rotary Railcar Unloading Facilities and Thaw Shed (Feedstock)
- Dust Collectors for enclosed feedstock storage areas
- Truck Unloading Facilities (Flux)

2.6.3 *Gasification Island (3 x 50%)*

- Feedstock Grinding and Slurry Preparation (2 x 60%)
- Gasification (4,275 tons per day design coal, as received, per gasifier, based on PRB1 coal)
- High Temperature Heat Recovery
- Dry Char Removal
- Particulate Matter Removal
- Slag Grinding (1 x 100%)
- Slag Dewatering (1 x 100%)
- Slag Storage and Loading System (1 x 100%) (800 tons per day (wet basis), based on 50:50 blend of PRB2:PRB3 coals)

2.6.4 *Syngas Treating (2 x 50%)*

- Syngas Scrubbing
- Low Temperature Syngas Cooling
- COS Hydrolysis
- Recycle Gas Compression
- Acid Gas Removal
- Acid Gas Enrichment (1 x 100%)
- Mercury Removal
- Syngas Moisturization
- Sour Water System (1 x 100%)

2.6.5 *Sulfur Recovery and Tail Gas Recycle (2 x 50%)*

- Claus Plant Sulfur Recovery (O_2-Blown), (Up to 83 tons per day/train, based on high sulfur Illinois No. 6 operation)

- Molten Sulfur Storage
- Molten Sulfur Truck/Rail Loading Facilities (1 x 100%)
- Tail Gas Recycle (1 x 100%)
- Tank Vent Gas Incineration (1 x 100%)

2.6.6 *Power Block*

- CTG (2 x 50%) (220 MW nominal each, based on Siemens-Westinghouse SGT6-5000F combustion turbine assumed for environmental permitting)
- HRSG and Exhaust Stack (2 x 50%)
- STG (1 x 100%), (Up to 300 MW nominal)
- Surface Condenser (1 x 100%)
- Vacuum, Condensate and Boiler Feedwater Systems (1 x 100%)
- Power Block Circulating Water System
- Raw Water/Demineralizer Water Tankage/Pumps
- Demineralizer System
- Filtered Raw Water, Firewater/Tankage/Pumps
- Wastewater Collection/Wastewater Separation
- Plant and Instrument Air
- Step-up Transformers

2.6.7 General Facilities (1 x 100%)

- Gasification/ASU Cooling Water/Tower System
- ZLD Unit (for Process Condensate Blowdown)
- Process Condensate Blowdown Holding Tank
- Gasification Unit Flare
- Emergency Diesel Generator
- Natural Gas Distribution
- Plant Drains
- Nitrogen Distribution
- Potable and Utility Water
- Sanitary Sewage System
- Storm Water Collection and Treatment

2.6.8 Expected Process Operating Characteristics

As noted previously in Section 1.6.3, feedstock variability has been considered along with critical equipment components and operating conditions known to influence plant performance (for example, the combustion turbine selected, its operating mode, the operating mode of the gasifier, and ambient conditions) to identify the operating conditions which would provide a reasonable upper limit or "worst case" scenario for potential pollutant emissions/discharges. Table 1.6-1 quantifies such conditions assuming operation of the gasifier in PSQ mode while Table 1.6-2 assumes operation of the gasifier in FSQ mode. Pollutant emissions, discharges, and waste products are quantified assuming the conservative PSQ conditions (see Sections 1.8 and 4.0).

Table 2.6-1 Key Performance Indicators Used to Assess Worst Case Environmental Impacts Of IGCC Power Station (Phase I, PSQ Mode)

Performance Parameter	Estimated Range	Comments
CTG gross power, MW	440	Total for two CTGs
STG gross power, MW	265 – 300	Varies depending on quantities of steam generated by Gasification Island and HRSGs
Net plant generation, MW	580 – 606	Output from CTGs plus STG, less internal consumption and losses
Coal/coke feed rate, tons/day (as received)	5,300 – 8,550	Feed rate to gasifiers
Coal/coke feed energy, million Btu/hr (HHV)	5,280 – 5,910	Energy content of gasifier feedstock
Product syngas energy, million Btu/hr (HHV)	4,190 – 4,368	Energy content of syngas fuel delivered to CTGs
Coal conversion efficiency	0.71 – 0.80	Fraction of solid feedstock energy in syngas feed to CTGs
Net overall heat rate, Btu/kW-hr (HHV)	8,900 – 9,500	Solid feedstock energy used per unit of net electricity to grid
Flux feed, tons/day	0 – 250	Conditioning agent for gasifier feedstock
Slag by-product production, tons/day	500 – 800	Varies depending on feedstock composition and flux use
Sulfur by-product production, tons/day	30 – 165	Varies depending on feedstock composition

Table 2.6-2 Expected IGCC Power Station Operating Characteristics (Phase I, FSQ Mode)

Feedstock	PRB-1	PRB-1	PRB-1	50/50 Wt% PRB2/PRB3	Illinois No. 6	Sizing Basis
Ambient Temperature:	38°F	80°F	-20°F	38°F	38°F	
Power Generation						
SW SGT6-5000F CTG (x2)	440 MW	440 MW	440 MW	440 MW	440 MW	440 MW
STG	300 MW	300 MW	288 MW	N/A	N/A	300 MW
Gross Power	740 MW	741 MW	728 MW	N/A	N/A	741 MW
Less ASU Auxiliary Load	- 98 MW	-106 MW	- 97 MW	N/A	N/A	N/A
Less Internal Consumption	- 37 MW	- 37 MW	- 35 MW	N/A	N/A	N/A
Net Power (for Export to Grid)	606 MW	598 MW	596 MW	N/A	N/A	606 MW
Coal Feed (as received), tons/day	8225	8119	8136	7397	5477	8225
Coal Feed (dry), tons/day	5716	5643	5655	5461	4957	5716
Coal Feed (HHV), MMBtu/hr	5688	5616	5627	5592	5288	5688
Plant Heat Rate (HHV), Btu/kWh	9391	9397	9439	9412	9033	N/A
Oxygen Feed (contained), tons/day	5014	4950	4960	5005	3894	5014
Flux Feed, tons/day	0	0	0	233	0	
Design capacity, tons/day						233

Feedstock	PRB-1	PRB-1	PRB-1	50/50 Wt% PRB2/PRB3	Illinois No. 6	Sizing Basis
Slag Produced, tons/day	501	495	496	774	772	
Design capacity, tons/day						774
Sulfur Produced, tons/day	30	29	29	45	162	
Design capacity, tons/day						162

The composition and properties of the product syngas will vary depending on the solid feedstocks processed and Power Station operating conditions. Table 2.6-3 shows the expected range of syngas composition and fuel heating value.

Table 2.6-3
Estimated Product Syngas Composition Multiple Feedstock Plant (Phase Independent)

Component [1]	Range
Hydrogen, vol %	30 – 40
Carbon monoxide, vol%	35 – 50
Carbon dioxide, vol%	13 – 26
Methane, vol%	1 – 5
Nitrogen plus argon, vol%	2 – 3
Higher heating value, Btu/scf [2]	240 – 305

[1] Parameters shown for dry syngas fuel (water excluded), prior to nitrogen dilution.
[2] Standard conditions defined as 60 degrees Fahrenheit ("^{o} F"), one atmosphere pressure.

3. AIR QUALITY STANDARDS AND REGULATORY ANALYSIS

This section describes the air quality standards and regulations that apply to the proposed IGCC Power Station. Federal and State regulations limit the amount of emissions from power plants and other sources in order to protect and preserve air quality and public health. The following sections describe the applicable regulations and resulting requirements for the proposed facility.

3.1 Ambient Air Quality Standards

The U.S. Environmental Protection Agency (EPA) Office of Air Quality Planning and Standards (OAQPS) has set National Ambient Air Quality Standards (NAAQS) for pollutants considered harmful to public health and the environment. Primary standards are intended to protect public health, including the health of sensitive populations such as children and the elderly. Secondary standards are intended to protect public welfare, including protection against decreased visibility, and damage to animals, crops, vegetation and buildings. The NAAQS standards are set forth in Table 3.1-1.

Table 3.1-1
National Ambient Air Quality Standards for Criteria Pollutants

Pollutant	Averaging Period	Primary NAAQS ($\mu g/m^3$)	Secondary NAAQS ($\mu g/m^3$)
SO_2	3-hour	None	1300
	24-hour	365	None
	Annual	80	None
PM_{10}	24-hour	150	150
	Annual	50	50
$PM_{2.5}$	24-hour	65	65
	Annual	15	15
NO_x	Annual	100	100
CO	1-hour	40,000	None
	8-hour	10,000	None
Ozone	8-hour	157	None
Lead	Quarterly	1.5	1.5

In addition, Minn. R. 7009.00800 sets out the State of Minnesota Ambient Air Quality Standards (MAAQS), which includes the six criteria pollutants, hydrogen sulfide (H_2S) and Total Suspended Particulate Matter (TSP). The MAAQS are set forth in Table 3.1-2.

Table 3.1-2
Minnesota Ambient Air Quality Standards (MAAQS)

Pollutant	Averaging Period	Primary MAAQS ($\mu g/m^3$)	Secondary MAAQS ($\mu g/m^3$)
SO_2	1-hour	1300	None
	3-hour	None	1300*
	24-hour	365	None
	Annual	80	60
TSP	24-hour	260	150
	Annual	75	60
PM_{10}	24-hour	150	150
	Annual	50	50
$PM_{2.5}$	24-hour	65	65
	Annual	15	15
NO_x	Annual	100	100
CO	1-hour	35,000	35,000
	8-hour	10,000	10,000
Ozone	8-hour	157	157
Lead	Quarterly	1.5	1.5
Hydrogen Sulfide (H_2S)	½-hour (not to be exceeded twice/yr)	70	
	½-hour (not to be exceeded twice in 5 days)	42	

* Not to exceed 915 µg/m3 in northern Minnesota (Air Quality Regions 127, 129, 130, and 132).

3.2 Attainment Status

The IGCC Power Station will be located within the city of Taconite, in Itasca County, Minnesota. The entire state of Minnesota is classified as in attainment with the NAAQS. In addition, the area is in attainment with the MAAQS.

3.3 New Source Review and Prevention of Significant Deterioration

This section discusses the applicability and general requirements of the Federal New Source Review (NSR) Regulations. These regulations include permitting requirements for new or modified major stationary sources located in non-attainment and attainment areas. Since the IGCC Power Station has emissions of at least one regulated pollutant over 100 tons per year, it is considered a major source and is subject to the NSR regulations. Major sources located in attainment areas are required to comply with "Prevention of Significant Deterioration" (PSD) regulations, which are contained in 40 C.F.R. § 52.21, and incorporated by reference into Minn. R. 7007.3000.

An additional criterion of PSD applicability for a new project is that the amount of any one regulated pollutant emitted by the project must be equal to or greater than significance levels

defined by the rule. This evaluation of significance is done on a pollutant-by-pollutant basis. Mesaba One and Mesaba Two have emissions above the PSD significance levels for nitrogen oxides (NO_x), sulfur dioxide ("SO_2"), CO, volatile organic compounds ("VOC"), hydrogen sulfide ("H_2S") and particulate matter less than 10 microns in aerodynamic diameter ("PM_{10}"). Therefore, PSD review is required under the regulations, as demonstrated in Table 3.3-1.

Table 3.3-1
Total IGCC Power Station Emissions

Pollutant	PSD Significance Threshold (TPY)	Plantwide Potential to Emit (TPY)	PSD Review Required?
Carbon Monoxide	100	2,539	Yes
Nitrogen Oxides	40	2,872	Yes
Sulfur Dioxide	40	1390*	Yes
Particulate Matter (PM)	25	503	Yes
Particulate Matter < 10 microns (PM_{10})	15	493	Yes
Ozone (VOC)	40	197	Yes
Lead	0.6	0.03	No
Sulfuric Acid Mist	7	130	Yes
Hydrogen Sulfide	10	17	Yes

*The sulfur dioxide emissions in this table have not been adjusted to account for the formation of sulfuric acid aerosol which is calculated assuming a specified conversion of SO_2 to such species. See Form GI-09C in Section 9 to identify the extent to which SO_2 emissions would decrease taking into account such conversion.

The required PSD review consists of the following elements:

- A case-by-case Best Available Control Technology (BACT) demonstration, which takes into account energy, environmental, and economic impacts as well as technical feasibility. Section 5 of this application provides a BACT analysis demonstrating that the project will achieve the maximum degree of emissions reduction achievable given these considerations.
- An ambient air quality impact analysis to demonstrate that the allowable emissions from the proposed project will not cause or contribute to a violation of the applicable PSD increments and NAAQS. This analysis is presented in Section 7 of this application.
- An assessment of the direct and indirect effects of the proposed project on general growth, soil, vegetation, and visibility. Additionally, a source that might impact a Class 1 Federal area must undergo additional review. These assessments are discussed in Section 7.
- An ambient air quality monitoring program for up to one year may be required if no other representative data are available and if the project impacts are greater than a monitoring de minimis level. The analysis in Section 7 demonstrates that the project impacts are below these threshold levels and no pre-construction monitoring is required.

- Public comment, including an opportunity for a public hearing. This requirement may be addressed by the Minnesota Pollution Control Agency (MPCA) during joint formal public hearings to finalize the Environmental Impact Statement required under State law and the PSD permit.

3.4 New Source Performance Standards (40 C.F.R. Part 60)

New Source Performance Standards (NSPS) have been developed by the EPA for specific source categories. These standards are codified in the Code of Federal Regulations (C.F.R.) under Part 60 (40 C.F.R. 60) based on the equipment to be installed or modified. The standards that apply to Mesaba One and Mesaba Two are as follows:

- Subpart A – General Provisions
- Subpart Da – Standards of Performance for Electric Utility Steam Generating Units For Which Construction is Commenced After September 18, 1978 (IGCC Combustion Turbines)
- Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (Auxiliary Boiler)
- Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (Tank Vent Boiler)
- Subpart HHHH - Emission Guidelines and Compliance Times for Coal-Fired Electric Steam Generating Units (Hg Budget Trading Program General Provisions)
- Subpart Y - Standards Of Performance For Coal Preparation Plants

3.4.1 General Provisions (40 C.F.R. 60 Subpart A)

40 C.F.R. 60 subpart A provides for general notification, record keeping, and monitoring requirements. As specified in 40 C.F.R. 60.1, the requirements contained in Subpart A apply to emission units subject to a regulation contained in 40 C.F.R. 60 (NSPS regulations), unless the applicable NSPS regulation specifically exempts the emission unit from the provisions of Subpart A.

40 C.F.R. 60.8 requires an initial performance test. This part states that an initial performance test should be conducted within 60 days after achieving the maximum production rate at which the source will be operated, but not later than 180 days after initial startup of such source. The specific test methods and procedures to comply with 40 C.F.R. 60.8 are specified in 40 C.F.R. 60.335.

3.4.2 Combustion Turbines: Standards of Performance for Electric Utility Steam Generating Units (40 C.F.R. 60 Subpart Da)

As specified in Section 60.40a(b), Subpart Da applies to any electric utility combined cycle gas turbine that is capable of combusting more than 73 megawatts (250 MMBtu/hour) heat input of fossil fuel in the steam generator, and which commences construction or modification after September 18, 1978. Combustion turbine generators (CTGs) were not typically classified as

electric utility steam generating units. However, in February 2005, the EPA proposed new NSPS for both utility units and CTGs (70 FR 9706 and 70 FR 8314). At that time, EPA clarified and determined that IGCC units (and the CTs that are part of IGCC units) are now to be covered as coal-fired utility units under Subpart Da, Db, or Dc, as applicable based on their size.

The proposed revisions will establish output-based limits for facilities whose construction commenced after February 28, 2005. Based on the size and design of the Mesaba One and Mesaba Two plants described in this document, Subpart Da is the applicable regulation (for electric utility steam generating units). The proposed new limits are shown in Table 3.4-1.

Table 3.4-1
Emission Limits from Proposed NSPS Subpart Da

Pollutant	Proposed Emission Limit
PM	0.015 lb/MMBtu
SO_2	2.0 lb/MWh gross energy output, based on a 30-day rolling average
NO_x	1.0 lb/MWh gross energy output, based on a 30-day rolling average

The revisions to the NSPS proposed for Subpart Da incorporate provisions from the Clean Air Mercury Rule ("CAMR") to control mercury emissions from coal- and oil-fired utility units. In addition, the following definitions were added or revised:

- **Electric Utility Steam Generating Unit** means any fossil fuel-fired combustion unit of more than 25 MW that serves a generator that produces electricity for sale…;
- **Coal** includes synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to….gasified coal
- **Coal-fired electric utility steam generating unit** means an electric steam generating unit that burns coal, coal refuse, or a synthetic gas derived from either coal exclusively, in any combination together, or in any combination with other supplemental fuels in any amount. Examples of supplemental fuels include, but are not limited to, petroleum coke and tire-derived fuels.
- **Gaseous fuel** means any fuel derived from coal or petroleum that is present as a gas at standard conditions and includes, but is not limited to, refinery fuel gas, process gas, and coke-oven gas.
- **IGCC electric steam generating units** means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in combined cycle turbine.

Under the CAMR, a new section 60.45Da for mercury standards includes a specific limit for IGCC units, which is 20 x 10^{-6} lb/MWh or 0.000020 lb/MWh (0.0025 ng/J) on a gross electrical output basis, computed as a 12-month rolling average.

3.4.3 Combustion Turbines: Standards of Performance for Stationary Gas Turbines (40 C.F.R. 60 Subpart GG)

The proposed CTGs will not be subject to NSPS emission limitations for stationary CTGs (Subpart GG of 40 C.F.R. Part 60). The new syngas-fired CTGs associated with the IGCC Power Station will comply with the new proposed NSPS for electric utility steam generating units constructed after February 28, 2005, as listed above. In its proposed revisions to the CTG NSPS, EPA stated that it intends for IGCC units (and the CTGs included as part of IGCC units) to be regulated under the Utility NSPS (see 70 FR 8314).

3.4.4 Combustion Turbines: Proposed New Standards (40 C.F.R. 60 Subpart KKKK)

The EPA proposed new standards for CTGs on February 18, 2005 to update the NO_x and SO_2 emission standards with the performance of current CTGs and their emissions. This standard applies to new, modified, or reconstructed turbines with a power output at peak load of equal to or greater than 1 MW. In the preamble for the proposed rule (70 FR 8322), the EPA stated, "We consider gasification as an emissions control technology for solid fuels. Therefore, we consider it appropriate to cover CTGs fueled by gasified coal under the Utility NSPS." As such, the IGCC Power Station will be covered by NSPS Subpart Da as noted above.

3.4.5 IGCC: Emission Guidelines and Compliance Times for Coal-Fired Electric Steam Generating Units (40 C.F.R. Part 60 Subpart HHHH, Hg Budget Trading Program General Provisions)

Subpart HHHH was included as part of the CAMR package promulgated on May 18, 2005 (70 FR 28606). Key definitions included in 40 C.F.R. 60.4102 for IGCC facilities are listed below:

- **Unit** means a stationary coal-fired boiler, or stationary coal-fired CTG.
- **Coal-fired** means combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during any year.
- **Coal-derived fuel** means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Therefore, IGCC CTGs are affected units governed by this rule, and will need to comply with the mercury budget and trading provisions outlined in Subpart HHHH.

The final rule allows two methodologies for continuously monitoring Hg emissions: (1) Hg CEMS; and (2) sorbent trap monitoring systems. New and existing units under 40 C.F.R. part 60, subpart HHHH must certify the required continuous monitoring systems and begin reporting Hg mass emissions data pursuant to the applicable compliance date in 40 C.F.R. 60.4170(b). Under 40 C.F.R. 60.49a(s), the owner/operator is required to prepare a unit-specific monitoring plan and submit the plan to the Administrator for approval, no less than 45 days before commencing the certification tests of the continuous monitoring systems. The Applicant will choose one of the applicable mercury monitoring options, and provide the required plans prior to startup of the units and their initial performance tests.

3.4.6 Coal Preparation (40 C.F.R. Part 60 Subpart Y)

Coal handling capacity at the IGCC power station will exceed 200 tons per day, and is therefore subject to these NSPS. The rule applies to coal processing and conveying equipment, coal storage systems, and coal transfer and loading systems. These units are subject to an opacity limitation of 20 percent in accordance with 40 C.F.R. 60.252(c).

3.4.7 Auxiliary Boiler: Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (40 C.F.R. Part 60, Subpart Db)

The natural gas-fired auxiliary boiler will be covered by NSPS Db since its heat input will be greater than 100 MMBtu/hr. However, since the unit will be fueled only by natural gas, the only applicable limit for low heat release boilers is NOx at 0.1 lb/MMBtu on a 30-day rolling average. For high heat release boilers the NOX limit is 0.2 lb/MMBtu on a 30-day rolling average (see Table 3.4-2). The SO_2 and PM limits apply only to coal- or oil-fired units. The regulation also requires a continuous emission monitoring system (CEMS) and specific recordkeeping and reporting requirements.

Table 3.4-2
NSPS Subpart Db Limits for Auxiliary Boiler

Pollutant	Emission Limit
SO_2	None for natural-gas fired units
PM	None for natural-gas fired units
NOx	0.1 lb/MMBtu* 0.2 lb/MMBtu**

*Low heat release rate boilers
**High heat release rate boilers

3.4.8 Tank Vent Boiler: Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (40 C.F.R. Part 60, Subpart Dc)

The Tank Vent Boiler will be covered by NSPS Subpart Dc since it is a steam-generating unit that is less than 100 MMBtu/hr, but greater than 10 MMBtu/hr. Since this unit will burn syngas, it is considered a coal-fired unit for the purposes of this regulation, and the emission limits in Table 3.4-3 apply.

Table 3.4-3
NSPS Subpart Dc Limits for Tank Vent Boiler

Pollutant	Emission Limit	Proposed Emission Limits*
SO_2	0.6 lb/MMBtu**	No change
PM	0.10 lb/MMBtu	0.03 lb/MMBtu
Opacity	20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity	No change

*70 FR 9706
**50% reduction in potential combustion concentration applies.

The regulation also requires CEMS or fuel monitoring for demonstrating SO_2 compliance, and continuous opacity monitors (COMS) for particulate matter/opacity compliance. The regulation also includes specific reporting and recordkeeping requirements.

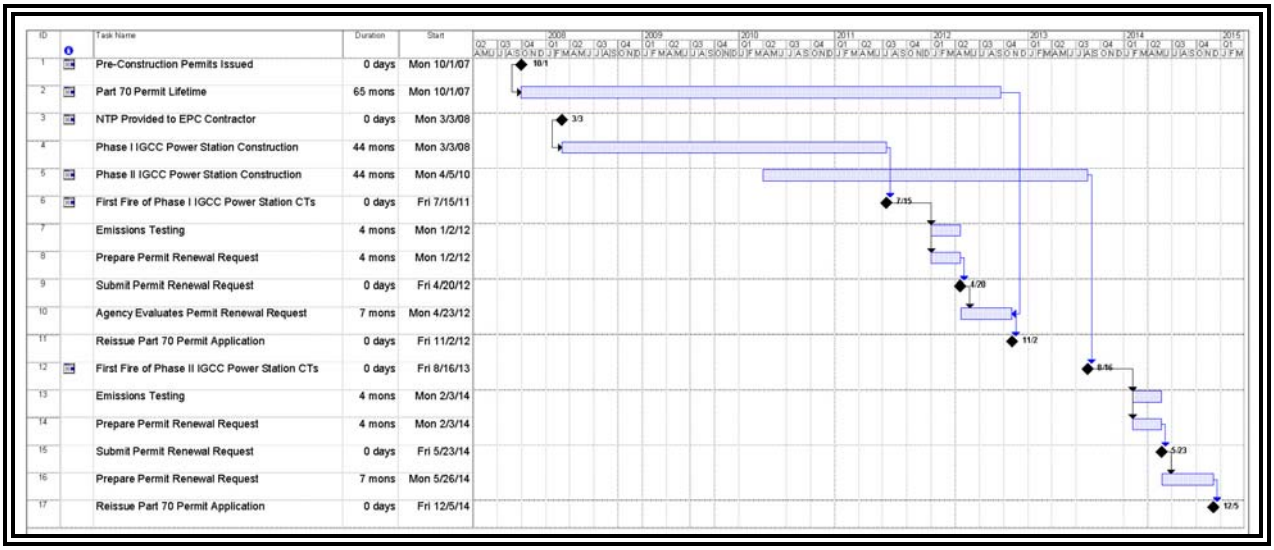
3.5 National Emission Standard for Hazardous Air Pollutants (40 C.F.R. Part 63)

Regulations in 40 C.F.R. Part 63 contain subparts applicable to specific categories of major sources of hazardous air pollutant ("HAP") emissions and specify that Maximum Achievable Control Technology be applied to such sources (hereafter, the "MACT Standards"). Major sources of HAP emissions are defined as sources with the potential to emit ("PTE") 10 tons per year ("TPY") of any individual HAP or 25 TPY of any combination of HAPs. Table 4.2-1 provides evidence that the PTE for HAPs from the Phase I IGCC Power Station will be below the 10 TPY and 25 TPY major source thresholds. Therefore the Phase I IGCC Power Station is not a major source of HAPs as defined under the National Emission Standards for Hazardous Air Pollutants (NESHAP) and is not subject to the MACT Standards thereunder.

Table 4.2-1 shows that the Phase I and II IGCC Power Station has the potential to emit HAPs in a quantity that rounds up to 24 TPY. This PTE equals the major source threshold and, therefore triggers the applicability of the MACT Standards. However, the basis for the HAP emissions estimates presented in Appendix B show such estimates to be extremely conservative (that is, calculated to produce the maximum PTE in the case of every HAP evaluated). The Applicant proposes to confirm the inapplicability of the MACT standards on the Phase I and II IGCC Power Station by testing conducted during operation of the Phase I IGCC Power Station. Such testing would be conducted prior to the submittal of the renewal request for the Part 70 Permit. If testing showed that full load operation of the Phase I and II Power Station would exceed the HAPs major source threshold, the Part 70 Permit could be changed to incorporate the necessary provisions prior to first fire of the Phase II IGCC Power Station. As noted in sections 3.5.1 through 3.5.4 below, the design of the Phase I and II IGCC Power Station will satisfy all emission reduction-related elements of the MACT rules, independent of whether or not the PTE for HAPs emissions from operation of the combined Phase I and II Power Station is shown to be exceeded.

Issuance of the Part 70 Permit for the Phase I and II Power Station is expected by the 2nd quarter of 2007. Therefore, the Applicant would be required to submit 180 days in advance of the Permit's 2nd quarter of 2012 expiration date, an application for the Part 70 Permit's renewal. Such request would contain the results of emissions testing from the Phase I IGCC Power Station. See Figure 3.5-1 to see an overview schedule showing how the emissions testing of the Phase I IGCC Power Station fits into the Part 70 Permit review schedule.

Figure 3.5-1. Part 70 Permit Issuance and Renewal Cycle: Temporal Definition of Emissions Testing of the Phase I IGCC Power Station



Potentially applicable MACT regulations that were reviewed include proposed regulations for Utility MACT, Subpart YYYY (Stationary CTGs), Subpart Q (Industrial Process Cooling Towers) and the requirement for case-by-case MACT. The results of these reviews are presented below.

3.5.1 Utility MACT

In March 2005 at 70 FR 15994, EPA revised a December 2000 appropriate and necessary finding for coal and oil-fired utility units to conclude that is it not appropriate and necessary to regulate coal- and oil-fired utility units under Section 112, and removed these units from the Section 112(c) list.

EPA instead established standards of performance for mercury (Hg) for new and existing coal-fired utility units, as defined in Clean Air Act (CAA) Section 111, pursuant to the CAMR as described in Section 3.4.2 above. The definitions in the new rules, as described in the NSPS sections for Subpart Da and HHHH, include IGCC units as coal-fired units.

In October 2005 at 70 FR 62200, EPA agreed to reconsider certain aspects of its determination that regulation of electric utility steam generating units under section 112 of the Clean Air Act was neither necessary nor appropriate, and removing coal- and oil-fired utility units from the list

of source categories. However, EPA declined to issue a stay, and the new rule therefore remains in effect. Pending the outcome of this reconsideration, the IGCC power station is prepared to comply with any new or modified applicable regulations or required analyses.

3.5.2 Combustion Turbine MACT

On March 5, 2004, EPA published the final NESHAP for Stationary CTGs at 69 FR 10511. The rule applies to owners/operators of stationary CTGs located at a major source of HAP emissions. The final rule included eight subcategories within the Stationary CTG source category:

(1) Emergency Stationary CTGs.
(2) Stationary CTGs, which burn landfill or digester gas equivalent to 10% or more of the gross heat input.
(3) Stationary CTGs <1 MW peak power output.
(4) Lean premix gas-fired CTGs.
(5) Lean premix oil-fired CTGs.
(6) Diffusion flame gas-fired CTGs.
(7) Diffusion flame oil-fired CTGs.
(8) CTGs operated on the North Slope of Alaska.

On August 18, 2004, the EPA issued a final stay of the above provisions for lean premix gas-fired turbines and diffusion flame gas-fired combustion turbines, pending the outcome of the EPA's proposal to delete these subcategories from the source category list. On April 7, 2004, the EPA noticed its intention to delete four subcategories from the Stationary CTGs source category that was developed pursuant to CAA Section 112(c)(1).

Therefore, compliance with this rule is currently not required for the proposed diffusion flame gas-fired CTGs. In addition, during the proposals for the Utility NSPS, CAMR, and CTG NSPS, it became clear that EPA's intention was to regulate IGCCs with coal-fired utility units, rather than CTGs (see Section 3.4.3).

3.5.3 Case-by-Case MACT

Subsection 112(g)(2)(B) of the CAA provides:

> After the effective date of a permit program under Title V in any state, no person may construct any major source of hazardous air pollutants, unless the Administrator (or the State) determines that the maximum achievable control technology emission limitation under this section for new sources will be met. Such determination shall be made on a case-by-case basis where the Administrator has established no applicable emission limitations.

EPA promulgated regulations implementing this section at 40 C.F.R. Part 63, Subpart B. Provisions at 40 C.F.R. 63.40(b) provide that the requirements of sections 63.40 through 63.44 apply to any major source of HAPs constructed after the effective date of Section 112(g)(2)(B)

and the effective date of a state's Title V operating permit program, unless the source has been specifically regulated or exempted from regulation under Section 112.

EPA's action to delist coal- and oil-fired utility units (70 FR 15994, March 29, 2005) represents its conclusion that HAP emissions remaining from coal- and oil-fired utility units after the implementation of the other requirements of the CAA do not cause hazards to public health that would warrant regulation under CAA Section 112. The HAP of greatest concern from coal-fired utility units is mercury (EPA, 70 FR 28609). Therefore, in conjunction with the action described above, the EPA established the CAMR for mercury under Section 111 of the CAA for new and existing sources, which integrated mercury limits into the Utility NSPS rules at 40 C.F.R. 60 Subpart Da.

In addition, as described above, on April 7, 2004, EPA noticed its intention to delete four subcategories from the Stationary CTGs source category that were developed pursuant to CAA Section 112(c)(1).

Therefore, case-by-case MACT is not required for new IGCC facilities since coal-fired utility units and diffusion flame gas-fired turbines have been removed or proposed for removal from the Section 112(c) source category list.

In response to two petitions (one from a coalition of states and the other from five environmental groups and four Indian Tribes), EPA reconsidered portions of the CAMR and the removal of coal-fired utility units from the section 112(c) list. On May 31, 2006, EPA took final action on these petitions reaffirming its determination that regulation of electric utility steam generating units under Section 112 of the CAA was neither necessary nor appropriate.

3.5.4 Industrial Process Cooling Towers (Subpart Q)

Subpart Q is applicable to cooling towers that use chromium-based treatment chemicals. The cooling towers proposed to be used at the IGCC Power Station will not use chromium-based treatment chemicals and are therefore not subject to this regulation.

3.6 Acid Rain Program (40 C.F.R. Parts 72-78)

Pursuant to Title IV of the 1990 CAA Amendments, the EPA established a program to control emissions that contribute to the formation of acid rain. The acid rain regulations, codified under 40 C.F.R. Parts 72, 75 and 76 are applicable to "affected units" as defined in the regulations. As a new utility unit, the IGCC Power Station is classified as an affected unit under 40 C.F.R. 72.6(a)(3), and is therefore subject to the Acid Rain Program.

Owners or operators of an affected unit are subject to the following Acid Rain Program requirements:

- Acid Rain Permit Application.
- SO_2 emission allowances.
- NO_x emission limitations.

- Acid Rain Compliance Plan.
- Emission monitoring requirements.

For new units, an Acid Rain Permit application must be submitted at least 24 months prior to the date of initial operation of the unit. The application must demonstrate compliance with the Acid Rain Program requirements and include a complete compliance and monitoring plan.

3.6.1 Part 72 Permit Regulation

All utility generating units greater than 25 MW are required to obtain a Phase II Acid Rain Permit. This permit is generally incorporated into a facility's Title V Operating Permit and is issued by the state. In order to comply with the requirements of 40 C.F.R. Part 72, the following course of action will be taken by Excelsior:

- The IGCC Power Station will obtain an ORIS code from the U.S. Department of Energy (DOE).
- The Applicant will submit a request letter to the EPA and DOE to issue a public notice identifying a designated representative for the proposed project, as stipulated in 40 C.F.R. 72.20 (Authorization and Responsibilities of the Designated Representative) and 72.24 (Certification).
- A Phase II Acid Rain Permit Application will be submitted at a later date in order to allow a permit to be issued prior to the start of operation of the proposed IGCC Power Station.

3.6.2 Part 73 – Sulfur Dioxide Allowance System

Part 73 of the Acid Rain provisions establishes requirements related to a SO_2 allowance system. These requirements include:

- The allocation of SO_2 emission allowances.
- The tracking, holding and transfer of allowances.
- The deduction of allowances for purposes of compliance.
- Miscellaneous other requirements.

The Applicant is aware of the requirements to secure SO_2 allowances on an annual basis and will comply with the appropriate requirements.

3.6.3 Part 75 Continuous Emission Monitoring

Affected units are also required by 40 C.F.R. Part 75 to continuously monitor emissions of SO_2 and NO_x. In addition, the EPA is requiring affected units to monitor emissions of carbon dioxide (CO_2) and opacity. Generally, this would require the installation of Continuous Emission Monitoring Systems (CEMS). However, several exemptions exist in these regulations that apply to gas-fired units. The IGCC units are considered gas-fired for the purposes of this regulation since the definition of "coal-fired" at 40 C.F.R. 72.2 specifically excludes coal-derived gaseous

fuel that meets the definition of "very low sulfur fuel" (either < 0.05 percent sulfur by weight or < 20 grains sulfur per 100 scf). The sulfur concentration in the undiluted syngas produced by the IGCC Power Station's clean up system will be less than or equal to 50 ppmvd hydrogen sulfide on a rolling 30-day average, which is equivalent to approximately 6 grains of sulfur per 100 scf. Therefore, the IGCC Power Station will be considered gas-fired for purposes of the Acid Rain Program. As a general note, the following items apply to gas-fired units:

- Gas-fired units are exempt from opacity monitoring (40 C.F.R. 75.14(c)).
- Gas-fired units can monitor SO_2 according to the protocol of Appendix D in lieu of a SO_2 CEMS and flow monitoring (40 C.F.R. 75.11 (d)(2)). If the fuel is pipeline quality natural gas, an emission factor of 0.0023 lbs SO_2/MMBtu is used in combination with hourly metered gas usage.
- Gas-fired units can monitor CO_2 according to the protocol of Appendix G in lieu of a CO_2 CEMS and flow monitoring (Section 2.3 of Appendix G of 40 C.F.R. 75). The protocol involves use of an emission factor in combination with calculated hourly heat input.
- Gas-fired units are not exempt from the CEMS requirements unless the units are considered peaking units (less than 20% operation of the nameplate capacity and an average operating factor of 10% over a three-year period).
- According to 40 C.F.R. 75.10(c), the owner or operator shall determine and record the heat input to each affected unit for every hour when fuel is combusted, following the procedures in Appendix F of 40 C.F.R. Part 75.

The Applicant is aware of these requirements and will develop appropriate procedures to comply with the requirements of 40 C.F.R. Part 73 and 75.

3.7 Clean Air Interstate Rule Permit

The final Clean Air Interstate Rule ("Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone [Clean Air Interstate Rule]; Revisions to Acid Rain Program; Revisions to NOx SIP Call; Final Rule") hereafter termed "CAIR," was published in the Federal Register on May 12, 2005 at 70 FR 25162. In August through December 2005, EPA received multiple petitions for reconsideration of various specific portions of the rule. EPA expects to take final action on all issues under reconsideration by March 15, 2006. By that date, EPA would finalize the process of reconsideration by issuing a final rule or proposing a new approach. EPA also expects, by March 15, 2006, to issue decisions on all remaining issues raised in the petitions for reconsideration, including whether or not Minnesota should be included in the CAIR region.

On March 15, 2006, the EPA resolved its issues relating to CAIR and on April 28, 2006 published in the Federal Register its conclusions that reconsideration of CAIR is not warranted under section 307(d)(7)(B) of the CAA and rejected the request to stay implementation of CAIR in Minnesota.

In accordance with 40 C.F.R. 96.121, Excelsior's designated representative will submit a CAIR Permit application at least 18 months before the IGCC Power Station commences operation, such application to include the standard requirements specified at §96.106, as amended.

3.8 Compliance Assurance Monitoring (40 C.F.R. Part 64)

The proposed equipment will not be equipped with add-on air pollution control devices, and therefore Compliance Assurance Monitoring (CAM), as specified in 40 C.F.R. Part 64, will not be required for the project. In addition, the monitoring requirements specified under the Acid Rain Provisions and the applicable NSPS will be sufficient to qualify for exemption under the CAM requirements in 40 C.F.R. 64.2(b).

3.9 Chemical Accident Provisions (40 C.F.R. Part 68)

This regulation applies to stationary sources that will have more than a threshold quantity of the specific regulated toxic and flammable chemicals. The intent of these regulations, as required by section 112(r) of the CAA Amendments, is to prevent accidental releases to the air and mitigate the consequences of any such releases by focusing prevention measures on chemicals that pose the greatest risk to the public and the environment. EPA promulgated a list of 140 regulated substances, with threshold quantities, that is used to define the stationary sources that will be subject to accident prevention regulations mandated by section 112(r)(7) on January 31, 1994 (59 FR 4478). On June 20, 1996, EPA promulgated the full risk management program (RMP) rules for accident prevention (61 FR 31668), which have been incorporated into the Code of Federal Regulations as 40 C.F.R. 68.

Stationary sources covered by this regulation must develop and implement a risk management program that includes a hazard assessment, a prevention program, and an emergency response program. These elements are to be described in a risk management plan that must be submitted to EPA and state and local emergency planning authorities. The plan must also be made available to the public by the date that a regulated substance is first present in a process above a threshold quantity.

The IGCC Power Station is not expected to have any chemicals above the threshold amounts. The Applicant will perform more detailed calculations as the system design is finalized, and will comply will all applicable provisions of the regulation in a timely manner.

3.10 State of Minnesota Requirements

3.10.1 Minnesota Air Pollution Episodes (Minn. R. 7009.1000-.1110)

Since the IGCC Power Station will have allowable emissions of greater than 250 tons per year of any single regulated pollutant, the plant is subject to Minnesota's Air Pollution Episode rules. The rules require preparation of an emergency action plan to be implemented in the event that the Commissioner of the MPCA makes an air pollution episode declaration.

3.10.2 Minnesota Standards of Performance for Stationary Sources (Minn. R Ch. 7011)

3.10.2.1 Control of Fugitive Particulate Matter (Minn. R. 7011.0150)

Bulk material handling operations at the IGCC Power Station including coal, petroleum coke, flux and other materials are subject to Minnesota's fugitive dust control rule, Minn. R. 7011.0150. The rule prohibits the release of "avoidable amounts" of particulate matter. Subject facilities are required to take reasonable precautions to prevent the discharge of visible fugitive emissions beyond the property line.

3.10.2.2 Standards of Performance for New Indirect Heating Equipment (Minn. R. 7011.0515)

The IGCC Power Station will use the following indirect heating equipment: CTGs, tank vent boilers and auxiliary boilers. However, these units will not be subject to Minn. Rules 7011.0515 because they will be subject to federal NSPS (40 C.F.R. 60 subparts Da, Db and Dc). New units subject to the federal standards are exempt from the state standards pursuant Minn. R. 7011.0505, subp. 1.

3.10.2.3 Standards of Performance for Coal Handling Facilities (Minn. Rules 7011.1100-7011.1140)

The only provision of the Standards of Performance for Coal Handling Facilities applicable to IGCC Power Station is the requirement to avoid any nonessential coal handling operations that are not shielded from the wind when steady wind speeds exceed 30 miles per hour (Minn. R. 7011.1125). Since the IGCC Power Station would not be located in the Minneapolis/St. Paul area or the City of Duluth, would not be an existing out-state coal handling facility, and would not operate pneumatic coal-cleaning equipment or thermal dryers, the other provisions of the Standard do not apply. For new coal preparation plants, the Federal NSPS at 40 C.F.R. Part 60, Subpart Y apply.

3.10.2.4 Standards of Performance for Stationary Internal Combustion Engines (Minn. R. 7011.2300)

The IGCC Power Station will occasionally operate the following internal combustion engines that are subject to this rule: emergency fire water pumps and the emergency generators. The rule limits visible emissions from these units to 20 percent opacity and limits SO_2 emissions to 0.5 lb/MMBTU heat input unless a higher limit has been established through modeling.

3.10.2.5 Standards of Performance for Post-1969 Industrial Process Equipment (Minn. R. 7011.0715)

The IGCC Power Station will operate coal, petroleum coke, and slag handling equipment that will generate particulate matter emissions. This equipment will be subject to the Standards of Performance for Post-1969 Industrial Process Equipment. Subject equipment must meet either the numeric PM emission limit calculated using one of the two formulas shown in Table 3.10-1

or use pollution control equipment that achieves the required control efficiency. Since the IGCC Power Station is located outside of Minneapolis, St. Paul and Duluth, and is located more than one quarter mile from any residence or public roadway, the required control equipment efficiency standard to be applied is 85 percent.

Table 3.10-1
Particulate Matter Emission Limit for Process Equipment

PM Emission Limit for equipment that process less than 30 tons/hour	**PM Emission Limit** for equipment that process greater than 30 tons/hour
$E = 3.59\ P^{0.62}$ Where: E = Emission Limit in lbs/hr P = Process Weight in tons/hour	$E = 17.31\ P^{0.16}$ Where: E = Emission Limit in lbs/hr P = Process Weight in tons/hour

This standard also limits emissions from subject equipment to less than 20 percent opacity.

3.10.3 Minnesota Acid Deposition Control (Minn. R. Ch. 7021)

This regulation applies to existing electrical generating facilities that have a total capacity greater than 1,000 megawatts. As Mesaba One and Mesaba Two will be new generating facilities, this provision does not apply. However, the Applicant will be required under the Federal Acid Rain Program to annually purchase SO2 allowances in an amount equal to the total IGCC Power Station annual SO2 emissions. The Federal Acid Rain Program will be superseded by the CAIR when the new rule becomes effective. Pursuant to Minnesota regulations, Excelsior's compliance with the new Federal rule also constitutes compliance with the Minnesota requirements.

The IGCC Power Station would also be subject to the Reasonable Available Control Technology (RACT) requirements of Minn. R. 7021.0050, Subpart 5 because the total indirect heating capacity of the CTGs, tank vent boilers, and auxiliary boilers exceed 5,000 MMBTU/hr. However, since emissions from these units are subject to BACT requirements, no additional limitations are necessary to meet RACT.

4. AIR EMISSIONS INVENTORY

Air emission points are shown on Figure 1.6-5 and in the block flow diagrams presented in Figures 2.3-1 and 2.3-2. The emission unit ("EU") and stack/vent ("SV") identification numbers correspond to those used on the forms provided in Section 9.

The IGCC Power Station will be designed to process a relatively wide variety of feedstocks, including sub-bituminous coal, bituminous coal and petroleum coke. Plant performance will vary depending on a number of factors, including the feedstocks utilized, combustion turbine operating mode, gasifier operating requirements/parameters, and ambient conditions. Table 2.6-1 presents the currently estimated range of key plant performance characteristics expected for each phase of the IGCC Power Station while operating in the PSQ mode.

Maximum and average emission quantities from the IGCC Power Station have been estimated by using:

- Plant performance characteristics identified in Table 2.6-1.
- Equipment supplier data.
- BACT as proposed in this application.
- Test results for similar equipment at other IGCC facilities, especially the existing Wabash River Coal Gasification Repowering Project (an operating IGCC power station that uses E-Gas™ gasification technology; hereafter referred to as "Wabash River").
- Engineering calculations, experience, and judgment.
- Published and accepted average emission factors, such as the U.S. EPA Compilation of Air Pollutant Emission Factors (AP-42).

The following sections describe these estimates and the calculation basis for both criteria and non-criteria pollutants. Detailed calculation descriptions and examples are presented in Appendix A (criteria pollutant emissions) and Appendix B (hazardous air pollutant emissions).

4.1 Criteria Pollutants

Table 4.1-1 presents the normal and maximum short-term emission rates for each source. Table 4.1-2 shows the proposed maximum annual criteria pollutant emission rates for each emission source in the facility.

Table 4.1-1
Short-Term Emission Summary (Phase I and II)

Emission Source	Normal Emission Rate (lb/hr)[1]					Maximum Emission Rate (lb/hr)[1]				
	NOx	SO_2	CO	PM10[2]	VOC	NOx	SO_2	CO	PM10[2]	VOC
Combustion Turbines	624	270	380	100	35	792	732	10,960[3]	100	1,052[3]
Tank Vent Boilers	12	7.2	3.6	0.4	0.2	39	17	12	1.4	0.6
Flares[4]	0.3	negl[5]	2.2	negl	negl	478	2,080	11,400	60	45
Auxiliary Boilers	9.4	0.8	19	1.3	1	9.4	0.74	19	1.3	1
Cooling Towers				9					9	
Fugitive PM10				8.6					8.6	
Fugitive VOC					3.8					3.8
Emergency Generators	158	4.1	36	5.8	6.1	158	4.1	36	5.8	6.1
Emergency Fire Water Pump Engines	37	2.5	8.0	2.6	3.0	37	2.5	8.0	2.6	3.0
Total	**841**	**285**	**449**	**128**	**49**	**1,513**	**2,836**	**22,435**	**189**	**1,112**

[1]See following text for description of normal and maximum short-term emissions.
[2]PM10 includes filterable plus condensable fractions.
[3]Peak startup emission rate for four CTGs; normally startup for these engines will not occur simultaneously.
[4]Normal flare emission rates are for natural gas pilots only.
[5] negl = negligible emissions.

Table 4.1-2
Annual Emission Summary (Phase I and II)

Emission Source	Emission Rate (ton/year)				
	NOx	SO_2	CO	PM10	VOC
Combustion Turbines	2,772	1,332	1,928	440	176
Tank Vent Boilers	53	32	16	1.8	0.8
Flares	27	25	572	3.4	2.6
Auxiliary Boilers	10	0.8	21	1.4	1.2
Cooling Towers				39	
Fugitive PM10				6.7	
Fugitive VOC					17
Emergency Generators	7.9	0.2	1.8	0.29	0.31
Emergency Fire Water Pump Engines	1.9	0.12	0.40	0.13	0.15
Total	**2,872**	**1,390**	**2,539**	**493**	**197**

(See following text for explanation of annual emission basis.)

4.1.1 Combustion Turbine Generators

Emissions from the power block CTGs are primarily controlled through the inherently lower polluting IGCC coal gasification technology. Specifically, the production of syngas at relatively high pressure permits efficient and cost-effective syngas cleanup prior to combustion in the CTGs to produce electricity. As discussed in the preceding process description in Section 2.3, the following treatment steps will be applied to the syngas:

- Hot gas particulate matter filtration via cyclone and ceramic filters to achieve approximately 99.9% particulate matter removal.
- Water scrubbing to remove soluble contaminants, condensable materials, and suspended particulate matter.
- Amine treatment combined with COS hydrolysis to reduce total syngas sulfur to a maximum of 50 ppmvd as H_2S in the undiluted syngas, rolling 30-day average.
- Carbon adsorption for removal of mercury and other trace contaminants.
- Moisturization (water saturation) for NOx control and improved power production.

In addition to these syngas treatment measures, the moisturized syngas fuel is diluted by about 100 percent (one-to-one) with ASU nitrogen for additional NOx reduction. Steam injection, in lieu of nitrogen dilution and moisturization, will be used for NOx control when operating on natural gas. Finally, each CTG will be equipped with inlet air filters to minimize particulate matter emissions potentially caused by advection of suspended atmospheric materials contained in the combustion air.

The following CTG emission rates are proposed as BACT and are used for project emission estimates:

Syngas

- SO_2, based on 50 ppmvd as hydrogen sulfide in the undiluted syngas, rolling 30-day average.
- NOx, 15 ppmvd (@ 15% O_2).
- CO, 15 ppmvd (@ 15% O_2).
- PM_{10}, 25 lb/hr/CTG.
- VOC, 2.4 ppmvd (@15% O_2).

Natural Gas

- SO_2, pipeline-quality natural gas (assumed 1.0 grain/100 scf total sulfur).
- NOx, 25 ppmvd (@ 15% O_2).
- Other criteria pollutants, equal to or less than syngas emission rates.

As is the case with many types of internal combustion engines, CTG emissions of one or more pollutants during startup can exceed the normal operating emission rates for short periods. This temporary higher emission rate is caused by reduced combustion efficiencies during initial operation at low temperatures and low loads, as well as delay in achieving minimum specified combustor conditions to begin steam injection for NOx control.

Table 4.1-3 shows the maximum short-term CTG emission rates for the four principal operating conditions. Since a specific CTG supplier has not yet been selected, the emission rates shown in this table reflect the maximum values for potentially available commercial CTGs.

Table 4.1-3
Maximum CTG Short-Term Emission Rates (Phase I and II)

Operating Mode	Emission Rate (lb/hr)				
	NO_X	SO_2	CO	PM_{10}	VOC
Normal syngas operation[1]	624	270	380	100	35
Maximum syngas operation[2]	624	732	380	100	35
Maximum natural gas operation	792	24	288	72	26
Worst-case startup[3]	484	<24	10,960	44	1052

[1]30-day rolling average fuel sulfur
[2]Peak 1-hour average fuel sulfur
[3]Worst-case startup for four CTGs; normally all four would not start up simultaneously

The maximum annual CTG emission rates and basis are summarized in Tables 4.1-4 and 4.1-5 for the first four years of operation and years 5-30, respectively:

Table 4.1-4
Maximum CTG Annual Emissions Years 1-4 (Phase I and II)

	YEAR NO. 1 TONS/YEAR	YEAR NO. 2 TONS/YEAR	YEAR NO. 3 TONS/YEAR	YEAR NO. 4 TONS/YEAR	BASIS[1]
Hrs/Yr	2630	1750	880	440	Peak natural gas per year
NO_x	2954	2880	2807	2770	Balance of year on syngas at full load
SO_2	964	1088	1210	1271	Balance of year on syngas at full load, 50 ppm annual average sulfur in fuel
CO	1808	1848	1888	1909	Plus 50 hr/yr startup/shutdown, balance of year on syn gas at full load
PM_{10}	401	414	426	432	Balance of year on syn gas at full load
VOC	167	171	174	176	Plus 50 hr/yr startup/shutdown, balance of year on syn gas at full load

[1] Indicated hours of natural gas full load operation plus additional operation described for each pollutant.

Table 4.1-5
Maximum CTG Annual Emissions Years 5-30 (Phase I and II)

	TONS/YEAR	BASIS
NO_x	2,772	440 hours (approx 5% of the year) on full-load natural gas operation; 8,320 hours on full load syngas operation.
SO_2	1,332	Full year (8,760 hours) on full-load syngas operation; 50 ppmv average total sulfur in syngas.
CO	1,928	50 hours startup/shutdown per CTG, balance of year (8,710 hours per CTG) on full-load syngas operation
PM_{10}	440	Full year (8,760 hours) on full load syngas operation
VOC	176	50 hours startup/shutdown per CTG, balance of year (8, 710 hours per CTG) on full load syngas operation

4.1.2 Tank Vent Boilers

The tank vent boilers (TVBs, one for each phase) will be designed to safely and efficiently dispose of recovered process vapors from various process tanks and vessels associated with the gasification process. The TVBs prevent the atmospheric emission of reduced sulfur compounds and other gaseous constituents to the atmosphere that could cause nuisance odors and other undesirable environmental consequences. The TVBs may also be operated on natural gas to produce steam for the IGCC Power Station during gasifier shutdowns. The estimated maximum short-term and annual emission rates, based on supplier estimates for similar equipment, are shown in Table 4.1-6 and Table 4.1-7, respectively.

Table 4.1-6
Tank Vent Boiler Short-Term Emissions (Phase I and II)

Operating Mode	Emission Rate (lb/hr)				
	NO_x	SO_2	CO	PM_{10}	VOC
Normal syngas operation[1]	9	7	2.6	0.3	0.1
Maximum syngas operation[2]	39	17	12	1.4	0.6
Maximum natural gas operation[3]	24	0.2	7.2	0.8	0.3

[1]Assumes 30 mmBtu/hour heat input rate
[2]Assumes 130 mmBtu/hour heat input rate
[3]Assumes 80 MMBtu/hour heat input rate

Table 4.1-7
Maximum Tank Vent Boiler Annual Emissions* (Phase I and II)

	tons/year
NOx	52
SO_2	32
CO	16
PM_{10}	1.8
VOC	0.8

*Based on approximately 280 billion (10^9) Btu/yr syngas plus tank vent vapors, and about 73 billion Btu/yr natural gas combusted. Assumed sulfur in tank vapors averages 1.5 lb/hr (each phase) on annual basis.

4.1.3 Flares

The elevated flares for each project phase will designed for a minimum 99 percent destruction efficiency of carbon monoxide and hydrogen sulfide. As discussed previously, the flares are normally used only to oxidize treated syngas and natural gas combustion products during gasifier startup operations. The flares will also be available to safely dispose of emergency releases from the IGCC Power Station during unplanned upset events.

The estimated maximum short-term and annual emission rates, based on agency guidance and supplier advice, are shown in Table 4.1-8.

Table 4.1-8
Flare Emission Rates (Phase I and II)

Operating Mode	Emission Rate (Lb/Hr)				
	NO_x	SO_2	CO	PM_{10}	VOC
Normal Operation[1]	0.3	0.01	2.2	0.03	.02
Normal Startup Operation[2]	230	370	5,350	28	21
Maximum Flaring Operation[3]	480	2,080	11,400	60	45
	Emission Rate (Tons/Year)				
Maximum Annual[4]	26.8	24.6	572	3.4	2.6

[1]Natural gas pilot, only.
[2]Startup flaring of syngas for two gasifiers and two flares – may occur for several days per event, but not normally for two gasifiers simultaneously.
[3]Maximum flaring capacity for two flares, based on flaring syngas production from two gasifiers for each flare and a worst case upset sulfur content of 400 ppmv in syngas - one hour or less per event.
[4] Maximum annual emission based on combustion of approximately 700 billion Btu of syngas and 136 billion Btu of natural gas during startup, plant upsets, and normal operating conditions – see Appendix A, Exhibit A-2 for assumed worst case annual flaring scenarios and durations.

4.1.4 Fugitive Equipment Leaks

VOC and HAPs emissions associated with normal equipment leakage have been estimated using standard U.S EPA fugitive emissions factors for valve seals, pump and compressor seals, pressure relief valves, flanges, and similar equipment. Most of the estimated VOC emissions are associated with the amine handling system since methyl diethanolamine (MDEA) would be the only VOC handled in relatively significant quantity at the facility. Fugitive emission estimates of HAPs are based on the estimated concentration of each HAP in various syngas streams multiplied by the calculated total leakage rates of process fluid. Fugitive emission estimates for individual HAPs are shown in Table 4.1-9.

Table 4.1-9
Fugitive Emission Estimate (Phase I and II)

Emission Type	Emission Rate	
	lb/hr	ton/yr
Federal HAPs	0.06	0.3
Ammonia	0.2	1.3
Hydrogen sulfide	4.0	17
MDEA	3.2	14
VOC	3.8	16
TRS	4.0	17

[1]Volatile organic compounds (VOC) include MDEA, benzene, carbon disulfide, carbonyl sulfide, ethyl benzene, hexane, hydrogen cyanide, naphthalene, toluene, xylenes, and waste oil,
[2]Total reduced sulfur (TRS) includes carbon disulfide, carbonyl sulfide, and hydrogen sulfide.

4.1.5 Material Handling Systems

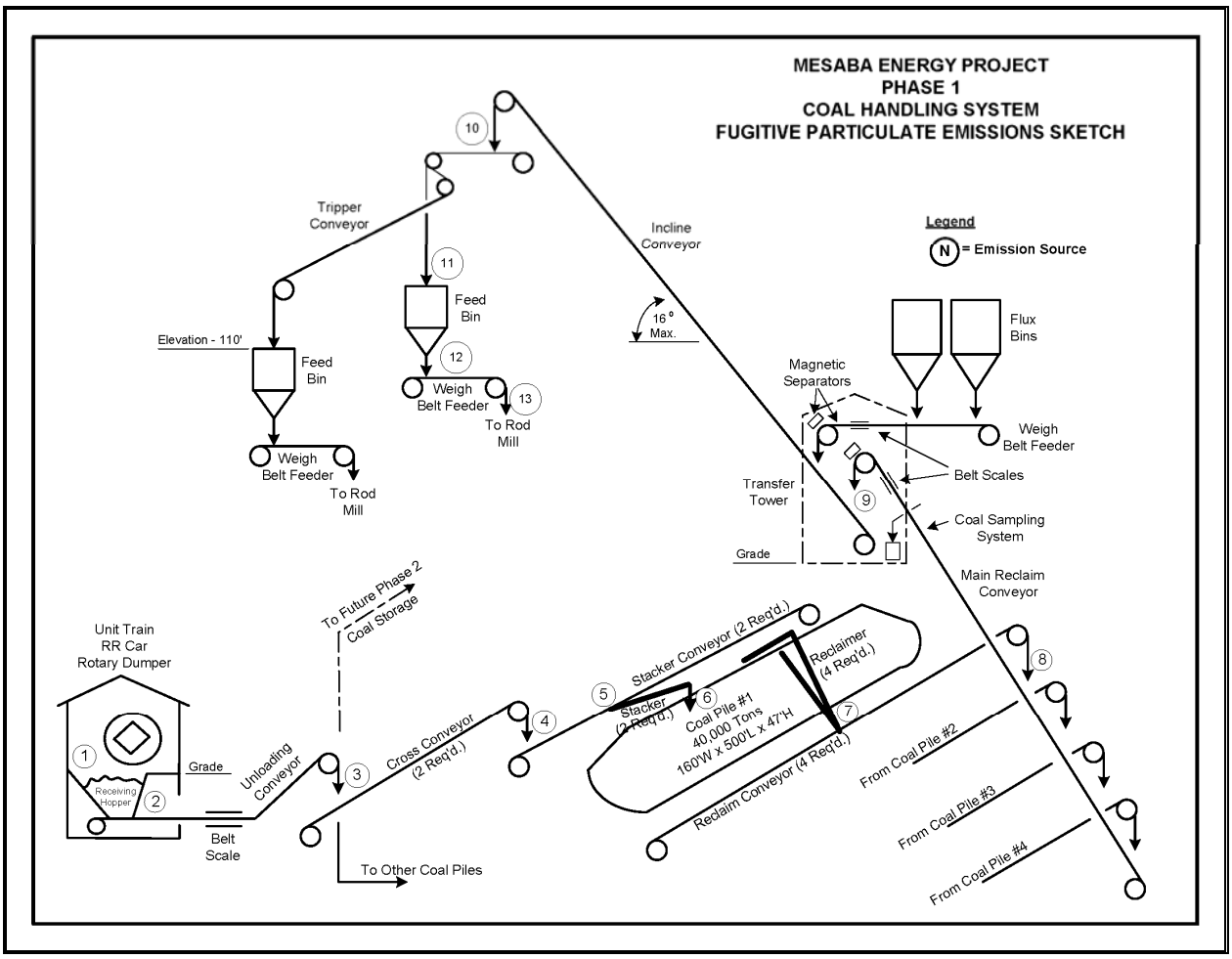
Fugitive particulate matter emissions (fugitive dust) will be generated by coal/coke, flux, slag handling, fuel preparation, and fuel storage during the normal operation of the IGCC Power Station. Sources of these emissions include the active and inactive coal/coke storage piles, conveyors/transfer points, slurry preparation area, and the slag storage area. Estimated emissions of total suspended particulate matter (particulate matter with an aerodynamic diameter no greater than 30 microns) and PM_{10} (particulate matter with an aerodynamic diameter no greater than 10 microns) for these sources are summarized in Table 4.1-10 for Phase I operations (fugitive particulate matter emission rates for Phase I and II would be twice the values shown.). Detailed calculations are presented in Appendix A, Exhibit A-5.

The estimates of particulate matter emission rates (lb/hr, tons/year) are based on methodologies developed by the U.S. EPA and documented in AP-42 ("Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources", 5th Edition). Specific portions of AP-42 utilized in the current analysis include Section 13.2.4 (Aggregate Handling and Storage Piles), Section 13.2.5 (Industrial Wind Erosion), and Section 13.2.2 (Unpaved Roads). These sections were used to estimate emission factors for the various coal/slag handling and moving

components, windage losses from the coal and slag piles, and emissions resulting from (on-site) truck traffic movement of slag from process units to the slag storage pile.

The emission factor for rail car unloading of feedstock was developed from the Electric Power Research Institute (EPRI) report CS-3455, published in June 1984. The peak hourly throughput for this system, as well as for conveyors and transfer points up to the storage pile, is based upon unloading approximately 36 unit train cars per hour (approximately 4,300 tons/hr). Figure 4.1-1 shows a sketch of the proposed feedstock handling system.

Figure 4.1-1
Material Handling System for Phase I IGCC Power Station



The emission factors (expressed in lb/ton) for aggregate handling systems derived from AP-42 are multiplied by the maximum material throughput to estimate an uncontrolled particulate matter emission rate. Peak values are expressed on an hourly basis and represent the maximum system throughput requirements. For the materials handling facilities upstream of the coal pile, this rate is as described above. For materials handling facilities downstream of the storage pile, the peak rate is based upon 120% of the average rate required for the nominal plant output. The annual throughput is based on the average material throughput requirement for the plant at full

load conditions of 8,760 hours per year. The AP-42 methodology correlates the aggregate handling particulate matter emission factor inversely with coal moisture content. Because of this, the maximum plant fugitive particulate matter emission rates were found to be higher on operation with Illinois No. 6 coal vs. the significantly higher moisture content (and higher as-received throughput rate) for PRB-1 coal. The maximum slag generation and throughput rates are also based on operation with Illinois No. 6 coal. The slightly higher slag generation rate associated with use of a blended coal had an insignificant impact on the emissions from the slag handling systems. However, in practice, PRB coal is known to be dusty. To account for this experience, the surface moisture content in PRB coal was assumed to be 4% and the fugitive particulate matter emission rates were recalculated. The fugitive emissions from PRB coal using the revised assumptions are provided in Table 4.1-10.

The uncontrolled particulate matter emissions estimates are modified as appropriate by a control efficiency multiplier. Control efficiencies used in these estimates include:

1.	No control method	0%
2.	Railcar/Feedstock storage pile load-in	50%
3.	Partial enclosure of transfer point	70%
	3a. Partial enclosure w/dust suppression spray	75%
4.	Full enclosure of transfer point	90%
	4a. Full enclosure w/dust suppression spray	95%
	4b. Full enclosure with baghouse filter	99%
5.	Roadway w/watering and cleaning	80%

The control efficiency for railcar unloading and storage pile load-in using an adjustable stacker are based upon engineering judgment for the partial containment systems planned. References to items 3 and 4 are identified in EPA 450/3-81-005b (Sept. 1982) and Environmental Progress (Feb. 1984). The control efficiencies for items 3a, 4a, and 4b are based upon engineering judgment and preliminary discussions with dust suppression system vendors. Reference to item 5 is found in AP-42 (Section 13.2.2).

The wet spray dust suppression systems will require that water be supplied to the various injection points. This water may be blended with glycol (for freeze point suppression) and/or surfactants (wetting agents) or chemical binding or encrusting agents. Because of the glycol addition, any free water draining from the solids will be captured and treated as required before re-use on-site or off-site disposal.

Determination of particulate matter emissions resulting from wind erosion of the storage piles requires information on pile geometry and wind velocities at the plant site. Oval storage piles have been assumed and lengths, widths, angles of repose and heights have been determined to provide the required storage volumes in one or more piles. These values were used to estimate the pile surface areas exposed to winds, as required by the AP-42 procedure. Historical wind velocity profiles (speed and annual frequency of occurrence) were obtained from University of Minnesota Technical Bulletin AD-TB1955 for the local Hibbing, Minnesota area. The reported wind velocities are relatively low, and only infrequently exceed the threshold friction velocity needed to generate quantifiable emissions as defined by the AP-42 procedure. Hence, at these

conditions, the piles were not significant contributors to overall plant particulate matter emissions.

In-plant trucks will be used to transport dewatered, by-product slag from the gasifier slag handling area to the slag storage pile or bins to await shipment by rail or truck offsite. A truck traffic emission factor from AP-42 was used to estimate fugitive road dust from this internal slag transfer operation. A control efficiency of 80% has been applied to this emission source based on watering of the roadway near the pile to suppress dust and periodic removal/cleanup of dust-producing material.

Table 4.1-10. Fugitive Particulate Emission Estimate (Phase I Operation)

Emission Source Description		Notes	PM30 Emission Factor (lb/ton)	PM10 Emission Factor (lb/ton)	Maximum Hourly Throughput (ton/hr)	Maximum Annual Throughput (ton/yr)	Control Method	Control Efficiency (%)	Controlled PM30 Maximum Hourly Emission Rate (lb/hr)	ControlledPM 30 Maximum Annual Emission Rate (ton/yr)	Controlled PM10 Maximum Hourly Emission Rate (lb/hr)	Controlled PM10 Maximum Annual Emission Rate (ton/yr)
COAL HANDLING AND STORAGE												
1	Railcar Unloading	1,9	0.00174	0.00087	4,300	3,100,000	Partially Enclosed Shed with dust suppression sprays	75	1.871	0.674	0.935	0.337
2	Unloading hopper to Unloading Conveyor	2,9	0.0020	0.0010	4,300	3,100,000	Fully enclosed transfer point with dust suppression sprays	95	0.432	0.156	0.204	0.074
3	Unloading conveyor to Cross-Conveyor	2,9	0.0020	0.0010	4,300	3,100,000	Fully enclosed transfer point with dust suppression sprays	95	0.432	0.156	0.204	0.074
4	Cross-Conveyor to Stacker Conveyor	2,9	0.0020	0.0010	4,300	3,100,000	Fully enclosed transfer point with dust suppression sprays	95	0.432	0.156	0.204	0.074
5	Stacker Conveyor to Stacker	2,9	0.0020	0.0010	4,300	3,100,000	Fully enclosed transfer point with dust suppression sprays	95	0.432	0.156	0.204	0.074
6	Stacker to Coal Pile	2,9	0.0020	0.0010	4,300	3,100,000	Ring-type dust suppression sprays at discharge point; Adjustable height stacker	50	4.323	1.558	2.044	0.737
7	Reclaimer to Reclaim Conveyor	2,8	0.0020	0.0010	430	3,100,000	Partially Enclosed transfer point with dust suppression sprays	75	0.216	0.779	0.102	0.368
8	Reclaim Conveyor to Main Conveyor	2,8	0.0020	0.0010	430	3,100,000	Fully enclosed transfer point with dust suppression sprays	95	0.043	0.156	0.020	0.074
9	Main Conveyor to Incline Conveyor	2,8	0.0020	0.0010	430	3,100,000	Fully enclosed transfer point with dust suppression sprays inside building	95	0.043	0.156	0.020	0.074
10	Incline Conveyor to Tripper Conveyor	2,8	0.0020	0.0010	430	3,100,000	Fully enclosed transfer point with dust suppression sprays	95	0.043	0.156	0.020	0.074
11	Tripper Conveyor to Feed Bin	2,8	0.0020	0.0010	430	3,100,000	Fully enclosed transfer point with baghouse dust collector	99	0.009	0.031	0.004	0.015

Emission Source Description		Notes	PM30 Emission Factor (lb/ton)	PM10 Emission Factor (lb/ton)	Maximum Hourly Throughput (ton/hr)	Maximum Annual Throughput (ton/yr)	Control Method	Control Efficiency (%)	Controlled PM30 Maximum Hourly Emission Rate (lb/hr)	ControlledPM 30 Maximum Annual Emission Rate (ton/yr)	Controlled PM10 Maximum Hourly Emission Rate (lb/hr)	Controlled PM10 Maximum Annual Emission Rate (ton/yr)
	Windage from Coal Storage	3,5	--	--	--	--	None	0	--	0.104	--	0.052
	SUBTOTAL								**8.28**	**4.24**	**3.97**	**2.02**
COAL SLURRY FACILITY SOURCES												
12	Feed Bin to Weigh Belt Feeder	2,8	0.0020	0.0010	430	3,100,000	Fully enclosed transfer point with dust suppression sprays	95	0.043	0.156	0.020	0.074
13	Weigh Belt Feeder to Rod Mill Feed Chute	2,8	0.0020	0.0010	430	3,100,000	Fully enclosed transfer point with dust suppression sprays	95	0.043	0.156	0.020	0.074
	SUBTOTAL								**0.09**	**0.31**	**0.04**	**0.15**
SLAG TRANSPORT AND STORAGE												
	Slag Disposal Truck Traffic	4	8.5	2.26	0.40	3,500	Apply dust suppressant	80	0.680	2.975	0.181	0.791
	Slag Storage Load-in		Nil	Nil			Wet slag	100	0.000	0.000	0.000	0.000
	Windage from Slag Storage	3,6	--	--	--	--	None	0	--	0.027	--	0.013
	Slag Storage Load-out	7	0.0053	0.0025	39	281,780	None	0	0.207	0.748	0.098	0.354
	SUBTOTAL								**0.89**	**3.75**	**0.28**	**1.16**
	TOTAL								**9.25**	**8.30**	**4.28**	**3.33**

4.1.6 Cooling Towers

Table 4.1-11 shows the expected maximum particulate matter emissions from the cooling towers resulting from drift. Alternate feedstock cases have shown slightly different conditions for the two cooling towers, which would affect emissions rates. The emission estimates below are based on 100% PRB coal feed to the plant, the Siemens-Westinghouse turbine power block (606 MW net nominal plant output), and eight cycles of concentration, and are indicative of the maximum combined particulate matter release. The drift rate is based on 0.001% of the tower recirculation rate as provided by equipment suppliers and reflects the use of high efficiency drift eliminators. The total dissolved solids (TDS) content of the drift is the maximum value estimated from water quality measurement data for the makeup water (the water quality data from which such maxima were derived are provided in Appendix A, Exhibit A-6). Table 4.1-11 shows emissions for the combined Phase I and II cooling towers.

Table 4.1-11
Particulate (PM_{10}) Emissions from Cooling Tower Drift (Per Phase)

	Power Block Cooling Tower	Gasification/ASU Cooling Tower
Duty (MMBtu/hr)	1,743	690
Recirculation Rate (10^6 lb/hr)	116	46
Drift (lb/hr)	1160	460
TDS (ppmw)	2700	2700
PM_{10} Emission (lb/hr/tower)	3.1	1.2
Total PM_{10} **(Phase 1 and II, TPY)**	38.4	

The Power Block cooling tower is configured with 12 cells, and the smaller Gasification/ASU cooling tower with 5 cells. The characteristics of each cell are shown in Table 4.1-12.

Table 4.1-12
Cooling Tower Characteristics (Per Cell)

Characteristic	Value
Exhaust Flow, 10^6 acfm (wet)	1.37
Exhaust Temperature, ^oF	104
Outlet Elevation (above grade), ft	48
Outlet Diameter, ft	33

4.1.7 Auxiliary Boilers

The auxiliary boilers will normally operate only when steam is not available from the gasifiers or HRSGs. The annual capacity factor for these boilers is estimated at 25% or less. The auxiliary boilers will be equipped with low NOx burners for emission control. Emission rates based on supplier guarantees for similar equipment are shown in Table 4.1-13.

Table 4.1-13
Maximum Auxiliary Boiler Short-Term and Annual Emission Rates
(Phase I and II)

	lb/hr	ton/year*	Basis
NOx	9.4	10	Low NOx burner, 30 ppmvd (@ 3% O2)
SO2	0.74	0.82	1 grain/100 scf in pipeline gas
CO	19	21	100 ppmvd (@ 3% O2)
PM_{10}	1.3	1.4	0.005 lb/million Btu, HHV
VOC	1.0	1.1	10 ppmvd (@ 3% O2)

Annual emission based on 25% maximum annual capacity factor.

4.1.8 Emergency Diesel Engines.

Other than the emergency uses for which they are intended, the diesel engines driving the emergency generators and fire protection pumps will each be operated no more than 100 hours per year. Emissions for each engine are estimated using accepted agency-published factors (AP-42) and low sulfur diesel fuel. Table 4.1-14 shows the maximum short-term and annual non-emergency emissions for each engine.

Table 4.1-14
Emergency Diesel Engines Emissions (Phase I and II)

Diesel Engine	Approx Capacity, ea	Total No. of Engines - Phases I plus II	Short-term emission (lb/hr)					Annual emission (ton/yr)				
			NOx	SO2	CO	PM_{10}	VOC	NOx	SO2	CO	PM_{10}	VOC
Emergency generators – gasification area	2 MW	2	129	2	30	4	4	6.4	0.1	1.5	0.2	0.2
Emergency generators – power block	350 kW	2	29	2	6	2	2	1.5	0.1	0.3	0.1	0.1
Fire pumps	300 hp	4	37	2.5	8.0	2.6	3.0	1.9	0.1	0.4	0.1	0.1

4.2 Lead and Non-Criteria Pollutants

4.2.1 Lead Emissions

Plant emission rates of trace amounts of lead were estimated from published information for a similar IGCC facility (NETL - National Energy Technology Laboratory, U.S. Dept of Energy, *Major Environmental Aspects of Gasification-based Power Generation Technologies, Final Report*, December 2002). These estimates are shown on Table 4.2-1 in the hazardous air pollutants emission discussion below.

4.2.2 Sulfuric Acid Emissions

Sulfur trioxide (SO_3) emissions, expressed as sulfuric acid (H_2SO_2), for the CTGs and other plant emission sources were estimated based on supplier information and measurements at the Wabash River. These estimates are also shown on Table 4.2-1 in the hazardous air pollutants emission discussion below.

4.2.3 Hazardous Air Pollutant Emissions

Emission rates for HAPs, as identified by the Minnesota Pollution Control Agency, have been estimated for the project using the following sources (listed in order of preference):

- Results of regulatory test programs at Wabash River - adjusted, if appropriate, for the expected worst-case feedstocks slated for use by the Mesaba Energy Project.
- Equipment supplier information.
- Published emission factors and reports applicable to IGCC facilities.
- Engineering calculations and judgment.
- U.S. EPA emission factors (AP-42) for coal combustion.

HAP emissions at the IGCC Power Station will be reduced by the inherently low polluting IGCC technology and many of the same process features that control criteria emissions. A large portion of the heavy metals and other undesirable constituents of the feed will be immobilized in the non-hazardous, vitreous slag by-product and prevented from causing adverse environmental effects. Gaseous and particle-bound HAPs that may be contained in the raw syngas exiting the gasifiers will be totally or partially removed in the syngas particulate matter removal system, water scrubber, and AGR systems described above. In addition, the mercury removal carbon absorption beds will ensure that mercury emissions from the IGCC Power Station will be less than 10 percent of the mercury present in the feedstock as received.

Table 4.2-1 presents a summary of estimated HAPs emissions for the Phase I and II IGCC Power Station. Appendix B presents the methodology used to estimate HAP emissions, shows example calculations, and identifies the sources of HAPs data used.

Table 4.2-1
Annual Hazardous Air Pollutant Emissions (Phase I and II)

CAS # or MPCA #	Compound	Annual Average HAP Emission (ton/yr)				Total Phase I	Phase I and Phase II
		CTGs	TVB	Flare	Fugitive		
75-07-0	Acetaldehyde	0.044	1.6E-04	3.9E-04		0.045	0.089
98-86-2	Acetophenone	0.022	7.9E-05	2.0E-04		0.022	0.045
107-02-8	Acrolein	0.43	1.5E-03	3.8E-03		0.43	0.87
7440-36-0	Antimony	0.027	2.8E-04	7.0E-04		0.028	0.056
7440-38-2	Arsenic	0.059	1.5E-03	3.7E-03		0.064	0.128
71-43-2	Benzene	0.061	0.028	0.071	0.0063	0.167	0.333
100-44-7	Benzyl chloride	1.03	3.7E-03	9.2E-03		1.0	2.1
7440-41-7	Beryllium	0.0064	7.9E-06	2.0E-05		0.0064	0.0128
92-52-4	Biphenyl	0.0025	9.0E-06	2.2E-05		0.0025	0.0051
117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)	0.11	3.9E-04	9.6E-04		0.109	0.218
75-25-2	Bromoform	0.06	2.0E-04	5.0E-04		0.057	0.114
7440-43-9	Cadmium	0.24	5.7E-05	1.4E-04		0.24	0.47
75-15-0	Carbon disulfide	1.13	4.0E-03	1.0E-02	0.034	1.18	2.35
463581	Carbonyl sulfide				0.058	0.058	0.116
532-27-4	Chloroacetophenone, 2-	0.0103	3.7E-05	9.2E-05		0.0104	0.0208
108-90-7	Chlorobenzene	0.032	1.1E-04	2.8E-04		0.032	0.065
67-66-3	Chloroform	0.088	3.2E-04	7.9E-04		0.089	0.179
0-00-5	Chromium, total (1)	0.013	1.1E-03	2.6E-03		0.016	0.033
18540-29-9	Chromium, (hexavalent)	0.0038	3.2E-04	7.9E-04		0.0049	0.0099
7440-48-4	Cobalt (1)	0.0064	1.2E-03	3.0E-03		0.011	0.021
98-82-8	Cumene	0.0078	2.6E-05	6.6E-05		0.0079	0.0159
57-12-5	Cyanide (Cyanide ion, Inorganic cyanides, Isocyanide)	0.140	4.6E-03	1.2E-02	0.0088	0.16	0.33
77-78-1	Dimethyl sulfate	0.071	2.5E-04	6.3E-04		0.072	0.144
121-14-2	Dinitrotoluene, 2,4-	4.2E-04	1.5E-06	3.7E-06		4.2E-04	8.4E-04
100-41-4	Ethyl benzene	0.14	0.032	0.079	5.4E-06	0.25	0.50
75-00-3	Ethyl chloride (Chloroethane)	0.061	2.2E-04	5.5E-04		0.062	0.124
106-93-4	Ethylene dibromide (Dibromoethane)	0.0018	6.3E-06	1.6E-05		0.0018	0.0036
107-06-2	Ethylene dichloride (1,2-Dichloroethane)	0.059	2.1E-04	5.3E-04		0.060	0.119
50-00-0	Formaldehyde	0.42	1.5E-03	3.7E-03	1.1E-06	0.42	0.84
110-54-3	Hexane	0.10	3.5E-04	8.8E-04	1.5E-06	0.10	0.20
7647-01-0	Hydrochloric acid	0.096	3.0E-04	7.4E-04	0.034	0.13	0.26
7664-39-3	Hydrogen fluoride (Hydrofluoric acid)	1.2	5.3E-05	1.3E-04		1.2	2.5

CAS # or MPCA #	Compound	Annual Average HAP Emission (ton/yr)				Total Phase I	Phase I and Phase II
		CTGs	TVB	Flare	Fugitive		
78-59-1	Isophorone	0.86	3.1E-03	7.6E-03		0.87	1.73
7439-92-1	Lead	0.014	6.3E-05	1.6E-04		0.014	0.028
7439-96-5	Manganese	0.025	2.4E-03	5.9E-03		0.034	0.068
7439-97-6	Mercury	0.012	6.6E-04	1.6E-04		0.013	0.026
74-83-9	Methyl bromide (Bromomethane)	1.23	0.011	0.029		1.3	2.5
74-87-3	Methyl chloride (Chloromethane)	0.78	6.0E-03	1.5E-02		0.80	1.61
71-55-6	Methyl chloroform (1,1,1 - Trichloroethane) (4)	0.029	1.1E-04	2.6E-04		0.030	0.060
78-93-3	Methyl ethyl ketone (2-Butanone)	0.58	2.1E-03	5.1E-03		0.58	1.17
60-34-4	Methyl hydrazine	0.25	9.0E-04	2.2E-03		0.25	0.51
80-62-6	Methyl methacrylate	0.029	1.1E-04	2.6E-04		0.030	0.060
1634-04-4	Methyl tert butyl ether	0.051	1.8E-04	4.6E-04		0.052	0.104
75-09-2	Methylene chloride (Dichloromethane)	0.056	5.5E-04	1.4E-03		0.058	0.117
91-20-3	Naphthalene	0.064	8.1E-04	2.0E-03	2.6E-05	0.067	0.133
7440-02-0	Nickel	0.0096	4.2E-03	1.0E-02		0.024	0.048
108-95-2	Phenol	0.95	1.2E-02	3.0E-02	7.8E-08	0.99	1.98
123-38-6	Proprionaldehyde	0.561	2.0E-03	5.0E-03		0.568	1.136
7784-49-2	Selenium	0.014	2.4E-04	5.9E-04		0.015	0.029
100-42-5	Styrene	0.037	1.3E-04	3.3E-04		0.037	0.075
127-18-4	Tetrachloroethylene (Perchloroethylene)	0.063	2.3E-04	5.7E-04		0.064	0.129
108-88-3	Toluene	0.00081	0.0112	0.0280	6.6E-04	0.041	0.081
108-05-4	Vinyl acetate	0.011	4.0E-05	1.0E-04		0.011	0.023
1330-20-7	Xylenes	0.055	0.013	0.032	1.0E-05	0.10	0.20
	Total federal HAPs	***11.4***	***0.2***	***0.4***	***0.1***	***12.0***	***24.1***
	Other Emissions						
56-55-3	Benz[a]anthracene	5.6E-05	2.0E-07	5.0E-07		5.7E-05	1.1E-04
207-08-9	Benzo(k)fluoranthene	1.6E-04	5.8E-07	1.4E-06		1.6E-04	3.3E-04
50-32-8	Benzo[a]pyrene	5.6E-05	2.0E-07	5.0E-07		5.7E-05	1.1E-04
218-01-9	Chrysene (Benzo(a)phenanthrene)	1.5E-04	5.3E-07	1.3E-06		1.5E-04	3.0E-04
193-39-5	Indeno(1,2,3-cd)pyrene	9.1E-05	3.2E-07	8.1E-07		9.2E-05	1.8E-04
3697-24-3	Methylchrysene, 5-	3.2E-05	1.1E-07	2.8E-07		3.2E-05	6.5E-05
7664-93-9 14808-79-8	Sulfuric acid and sulfates	62.0	0.2	0.6		62.8	125.6
	Other VOC				8.3	8.3	16.6
	Hydrogen sulfide				8.6	8.6	17.2

CAS # or MPCA #	Compound	Annual Average HAP Emission (ton/yr)				Total Phase I	Phase I and Phase II
		CTGs	TVB	Flare	Fugitive		
	Total Volatile Organic Compounds (VOC)	9.6	0.1	0.4	8.4	18.6	37.1
	Total Reduced Sulfur (TRS) Compounds	1.1	0.004	0.010	8.7	9.8	19.7

4.2.3.1 Mercury

The volume of pre-combustion syngas present at the time of its clean-up in the E-Gas™ process is about one hundred times less than the volume of the post-combustion gas handled in a typical conventional pulverized coal-fired boiler. An inherent advantage that IGCC technology has over such conventional systems is that gas clean up equipment can be much smaller in size and the residence time for allowing contact between a chemical (like mercury) and an absorbent (like activated carbon) can be increased, thereby providing for greater pollutant removal efficiency. This pre-combustion gas clean-up process allows for highly effective mercury removal rates, which in the case of Mesaba One and Mesaba Two will be at least 90 percent of the as-received combustion concentration present in its incoming fuel. For Mesaba One and Mesaba Two, this translates to maximum annual mercury emissions of only 54 pounds on a twelve month rolling average. Figure 4.2-1 shows how mercury is expected to partition throughout the IGCC Power Station.

4.3 Carbon Dioxide

Carbon dioxide emissions from the IGCC Power Station are a function of the feedstock consumed and the Station's net heat rate (a measure of the overall efficiency under which the energy in the feedstock is converted to electricity). The characteristics of the feedstock that dictate the rate at which CO_2 is emitted are its carbon content and higher heating value. Figure 4.3-1 illustrates the rates at which CO_2 will be produced by Mesaba One and Mesaba Two when using 100% bituminous coal and 100% subbituminous coal as a feedstock. The CO_2 emission rates shown in Figure 4.3-1 do not account for any CO_2 removal that would occur as a result of the equipment additions described in Section 2.4.3.4. For purposes of comparison, the CO_2 generation rate of Sherco 3 (a pulverized coal-fired electric generating unit using western subbituminous coal) is also shown in Figure 1.8-3.

Emissions of CO_2 from other large coal-fired electric generating units in Minnesota are shown in comparison with Mesaba One and Mesaba Two in Figure 1.8-4. For those units shown in Figure 1.8-4 that use wet limestone scrubbers (for example Boswell Energy Center and Sherburne County Unites 1 and 2) CO_2 emissions will be underestimated as CO_2 is produced as a consequence of removing SO_2 from the combustion gases. For those units that use lime spray dryers to remove SO_2 from their combustion gases (for example, Sherburne County Unit 3), CO_2 is produced as a consequence of producing lime (CaO) from limestone ($CaCO_3$). Some SO_2 will be removed by soluble oxides present in coal ash, thereby lowering the quantity of CO_2 produced as a result of reacting SO_2 and limestone slurry added for such reason.

Figure 4.2-1 Expected Mercury Partitioning in the IGCC Power Station (Mesaba One and Mesaba Two)

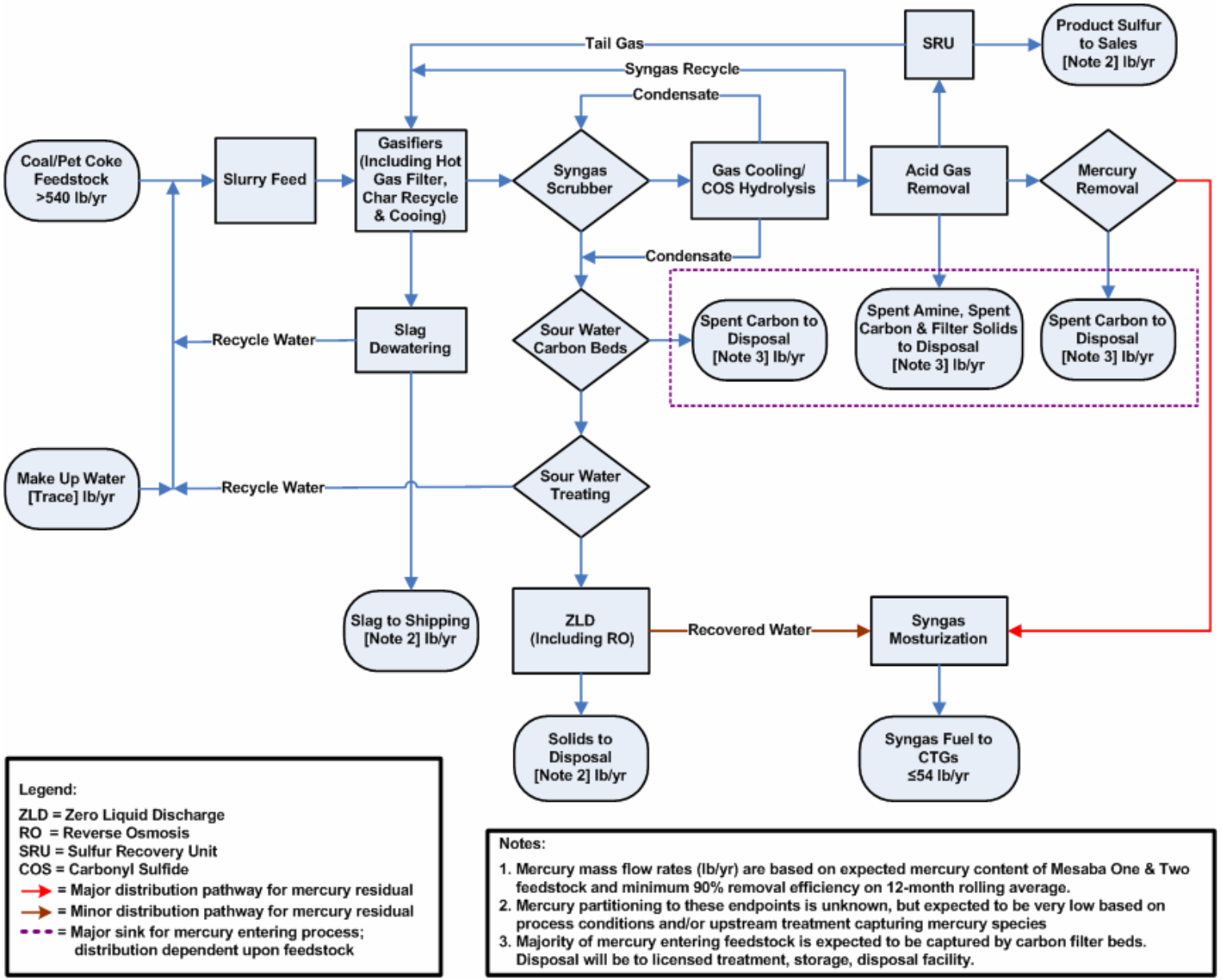


Figure 4.2-2 Carbon Dioxide Emissions From Mesaba Energy Project vs. Sherco Unit 3

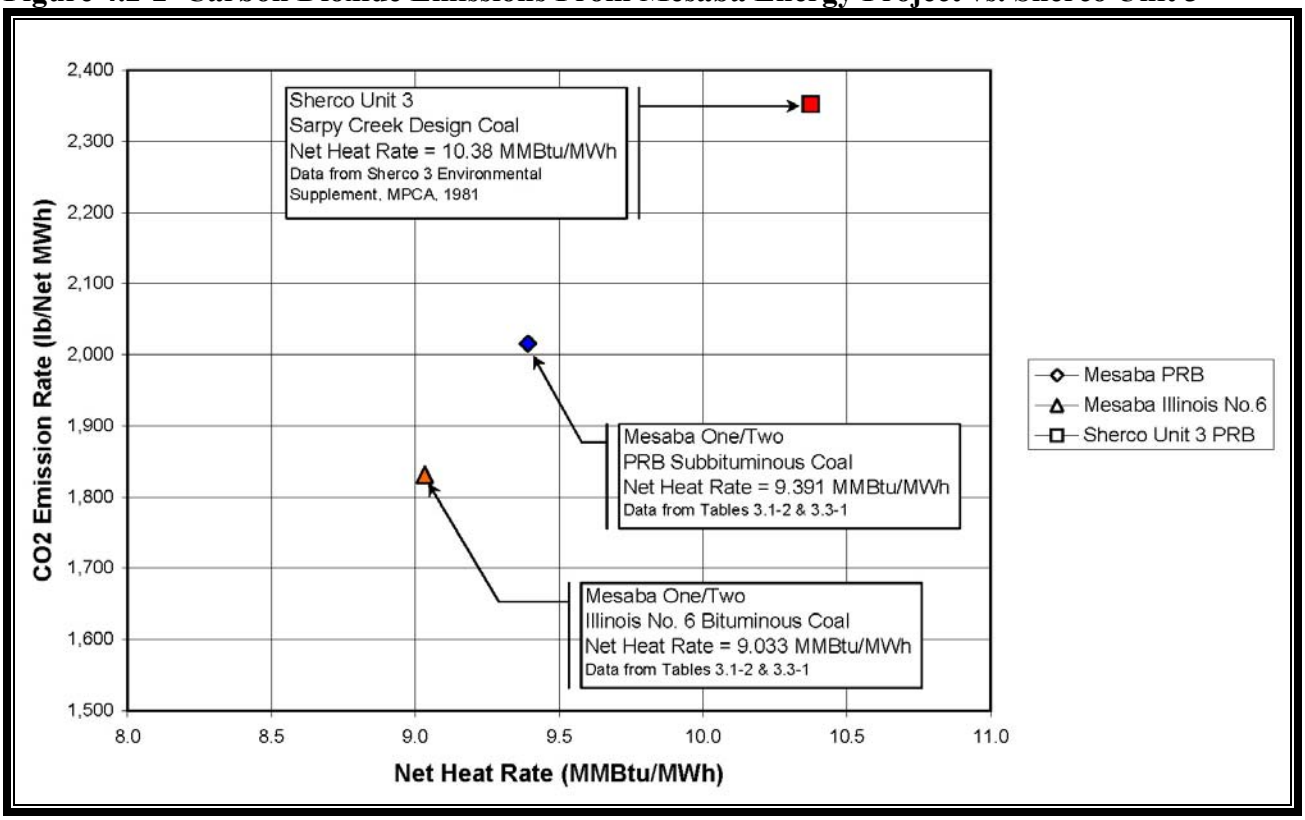
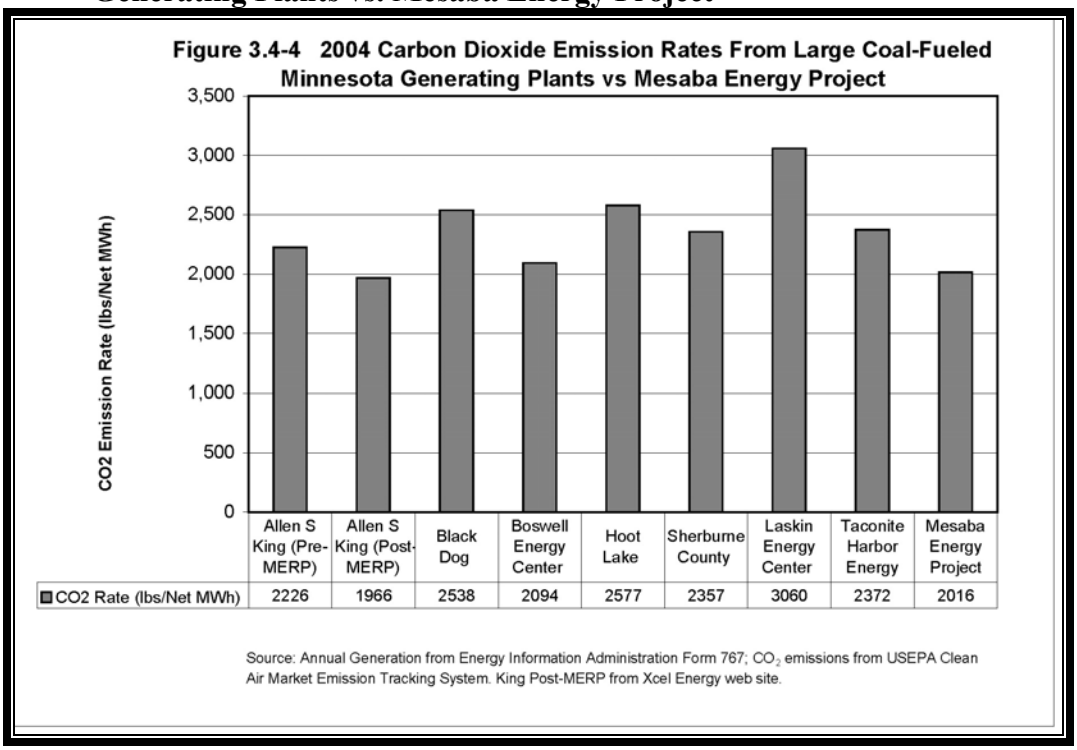


Figure 4.2-3 2004 Carbon Dioxide Emission Rates From Large Coal-Fueled Minnesota Generating Plants vs. Mesaba Energy Project



5. BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

This section presents a BACT analysis for the IGCC Power Station. As discussed above, the IGCC Power Station will be a new major source of regulated pollutant emissions under the PSD regulations, which require a BACT analysis for each pollutant that is emitted in excess of the regulatory thresholds. Table 5.0-1 presents the IGCC Power Station emissions compared to the PSD significance thresholds and the applicability of PSD review.

Table 5.0-1
Potential IGCC Power Station Emissions and PSD Thresholds

Pollutant	PSD Significance Threshold (TPY)	Plantwide Potential to Emit (TPY)	PSD Review Required?
Carbon Monoxide	100	2539	Yes
Nitrogen Oxides	40	2872	Yes
Sulfur Dioxide	40	1390	Yes
Particulate Matter (PM)	25	15	Yes
Particulate Matter < 10 microns (PM_{10})	15	491	Yes
Ozone (VOC)	40	197	Yes
Lead	0.6	0.03	No
Sulfuric Acid Mist	7	131	Yes
Hydrogen Sulfide	10	17	Yes

5.1 BACT Results Summary

A summary of the proposed BACT controls and associated emission rates for each emission unit is shown in Table 5.1-1. This analysis includes the syngas-fired CTGs, tank vent boilers, cooling towers, flare, emergency diesel generators, and fire water pumps.

Table 5.1-1
Proposed BACT for the IGCC Power Station

Pollutant	Control	Emissions Limits
Syngas-Fired Combustion Turbines (emissions shown per CTG)		
NO_x	Diluent Injection	15 ppm NOx @ 15%O_2; 156 lb/hr per CTG on syngas fuel
		25 ppm NOx @ 15%O_2; 198 lb/hr per CTG on natural gas fuel
CO	Good Combustion Practice ("GCP")	15 ppm @ actual O_2 (above 50% load) 95 lb/hr per CTG
PM/PM_{10}	GCP, gas cleanup, Gaseous Fuels only	25 lb/hr
SO_2	Gas cleanup/Use of Clean Syngas	76 lb/hr SO_2 per CTG, 30-day rolling average; (approx. 50 ppmvd sulfur, as H_2S, in undiluted syngas)
VOC	GCP	9 lb/hr per CTG
Lead	Gas cleanup/Use of Clean Syngas	0.007 tons/yr per CTG
H_2SO_4	Gas cleanup/Use of Clean Syngas	5.3 lb/hr, 30-day rolling average
Cooling Towers		
PM_{10}	High Efficiency Drift Eliminators	0.001% drift
Tank Vent Boiler		
NO_x, SO_2, CO, VOC, PM_{10}	GCP, Gas cleanup/Use of Clean Syngas or Natural Gas	0.3 lbsNOX/MMBtu; 30-day rolling average 0.035 lbs SO2/MMBtu; 30-day rolling avg. 0.004 lbs VOC/MMBtu; 3-hr avg. 0.09 lbs CO/MMBtu; 3-hr avg. 0.01 lbs PM10/MMBtu; 3-hr avg.
Flare		
NO_x, SO_2, CO, VOC, PM_{10}	Good Flare Design, Flaring only treated Syngas	0.064 lbsNOX/MMBtu; 24-hr avg. 0.105 lbs SO2/MMBtu; 24-hr avg. 0.006 lbs VOC/MMBtu; 3-hr avg. 1.5 lbs CO/MMBtu; 3-hr avg. 0.01 lbs PM10/MMBtu; 3-hr avg.
Auxiliary Boiler		
NO_x, SO_2, CO, VOC, PM_{10}	Low NOX burners, good combustion practice, pipeline natural gas only	0.036 lbsNOX/MMBtu; 24-hr avg. 0.003 lbs SO2/MMBtu; 24-hr avg. 0.004 lbs VOC/MMBtu; 3-hr avg. 0.074 lbs CO/MMBtu; 3-hr avg. 0.01 lbs PM10/MMBtu; 3-hr avg.
Fire Pumps		
NO_x, SO_2, CO, VOC, PM_{10}	GCP, limited hours of operation, and use of very low-sulfur fuel oil	Less than 100 hrs/yr operation; Very low sulfur fuel oil
Emergency Diesel Generators		
NO_x, SO_2, CO, VOC, PM_{10}	GCP, limited hours of operation, and use of very low-sulfur fuel oil	Less than 100 hrs/yr operation; Very low sulfur fuel oil

The following sections describe the BACT review process in general, the unique characteristics of IGCC, and the individual control technology evaluations for each emission unit and pollutant that support the summary in Table 5.1-1.

To properly evaluate BACT for the emission units at an IGCC plant, an understanding of the IGCC process is important. Detailed process descriptions for the proposed facilities are given in Section 2.3 and 2.4 of this application. Section 5.3 provides a general overview of IGCC and its unique characteristics for BACT evaluation. Section 5.4 describes existing or proposed IGCC facilities in the United States, their permitted emission levels, and compares such levels to those proposed for Mesaba One and Mesaba Two.

5.2 BACT Review Process

BACT is defined in the PSD regulations as:

> *"... an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source ... which [is determined to be achievable], on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs." [40 C.F.R. 52.21(b)(12)]*

In a December 1, 1987 memorandum from the EPA Assistant Administrator for Air and Radiation, the EPA provided guidance on the "top-down" methodology for determining BACT (EPA, 1987). The "top-down" process involves the identification of all applicable control technologies according to control effectiveness. The owner or operator then evaluates the "top," or most stringent, control alternative. If the most stringent is shown to be technically or economically infeasible, or if secondary environmental impacts are severe enough to preclude its use, then the next most stringent control technology is similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by technical or economic considerations, energy impacts, or environmental impacts.

The five basic steps of a top-down BACT analysis are shown in Table 5.2-1 below (from the EPA's Draft New Source Review Workshop Manual, October 1990, EPA Office of Air Quality Planning and Standards).

Table 5.2-1
Steps Involved in Top-Down BACT Analysis

Step 1.	Identify all available control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation.
Step 2.	Eliminate all technically infeasible control technologies.
Step 3.	Rank remaining control technologies by control effectiveness and tabulate a control hierarchy.
Step 4.	Evaluate most effective controls and document results.
Step 5.	Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

The BACT assessment described herein is in compliance with the EPA guidelines set forth above.

The EPA has consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements that must be met by any BACT determination, irrespective of whether it is conducted in a "top-down" manner or otherwise. First, the BACT analysis must include consideration of the most stringent available technologies; that is, those technologies that provide the "maximum degree of emissions reduction." Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of "energy, environmental, and economic impacts" contained in the record of the permit decisions.

The minimum control efficiency to be considered in a BACT analysis must result in an emission rate less than or equal to any New Source Performance Standard (NSPS) emission rate applicable to the source. The applicable NSPS represents the maximum allowable emission limit from the source.

As part of the IGCC Power Station BACT analysis, control options for potential reductions in criteria pollutants were identified. Potential control options were identified by researching the EPA database known as the RACT/BACT/LAER Clearinghouse (RBLC), drawing upon previous environmental permitting for similar units, engineering experience, and researching available literature. Available controls are further evaluated based on an analysis of economic, environmental, and energy impacts.

Assessing the technical feasibility of emission control alternatives is discussed in EPA's draft "New Source Review Workshop Manual." Using terminology from this manual, if a control technology has been "demonstrated" successfully for the type of emission unit under review, it would normally be considered technically feasible. For an undemonstrated technology, "availability" and "applicability" determine technical feasibility. An available technology is one that is commercially available, meaning that it has advanced through the following steps:

- Concept stage.
- Research and patenting.
- Bench scale or laboratory testing.
- Pilot scale testing.
- Licensing and commercial demonstration.
- Commercial sales.

Applicability involves not only commercial availability (as evidenced by past or expected near-term deployment on the same or similar type of emission unit), but also involves consideration of the physical and chemical characteristics of the exhaust gas stream to be controlled. A control method applicable to one emission unit may not be applicable to a similar unit depending on differences in the exhaust gas streams' physical and chemical characteristics.

For the IGCC Power Station's BACT analysis, the available control options were identified by reviewing the EPA's RBLC and by consulting available literature and vendors on control options for IGCC. Applications and/or permits from existing IGCC facilities were also reviewed and

studied. Together, such information was used in determining BACT for the IGCC Power Station. A brief summary of the IGCC process is provided in Section 5.3, and a description of other IGCC facilities (operating. or permitted, but not yet constructed) in the United States and their emissions limits is provided in Section 5.4.

5.3 IGCC Process Description

To evaluate possible emission control technologies, it is first important to describe and understand the unique IGCC process. This section presents a summary of the various sub processes that make up the IGCC process (more detailed process descriptions are included in Sections 2.3 and 2.4).

The primary function of the gasification portion of the IGCC process is the conversion of coal, petroleum coke, or a combination of those feedstocks into a synthesis gas (syngas), which can then be used to fuel CTGs in lieu of using natural gas or liquid fuels as a primary fuel. Gasification technologies have been developed by several companies and can be used to create syngas for many uses, including chemical plant feedstocks, pipeline quality natural gas, clean liquid fuels, and hydrogen to power fuel cells and ultimately electric generation, pursuant to U.S. Department of Energy's FutureGen Program.

The proposed gasification process is designed to convert the carbon-based slurried feedstock into a syngas product (essentially a mixture of H_2 and CO, with significantly smaller amounts of other constituents), enabling the separation of many contaminants from the product syngas. One of the primary raw syngas clean-up steps involves the removal of sulfur species and the production of either elemental sulfur or sulfuric acid. Removal of over 99 percent of the sulfur (present primarily as H_2S) can be achieved using commercial amine-based acid gas scrubbing technology on higher sulfur feedstocks (>97 percent removal is expected on low sulfur PRB coals). For processes that incorporate sulfur recovery, molten elemental sulfur will be generated from the sulfur recovery equipment. Sulfur removal in the AGR system and SRU minimize SO_2 emissions from the syngas combustion in the CTGs.

The IGCC Power Station will utilize the ConocoPhillips' E-Gas™ gasification technology, which is an oxygen-blown, entrained flow process based on a coal or coal/petroleum coke slurry feed to a two-stage gasifier, coupled to a unique high-temperature heat recovery unit (syngas cooler). A two-train gasifier system is being proposed for each of the IGCC Power Station's two phases, with an additional gasifier train for each phase to be used as a spare.

In addition to the gasifier, the IGCC process also includes a number of gas clean-up steps. After exiting the gasifier, the raw hot syngas is cooled prior to filtration of the particulate matter. The particulate matter removal system consists of a hybrid hot gas cyclone and a filter vessel with numerous porous filter elements to remove particles, including unreacted char. Removal efficiency is expected to be better than 99.9%. Removed PM is recycled to the first stage of the gasifier. After particulate matter removal, the syngas proceeds to additional syngas cleanup and cooling steps. In the first of these steps, the syngas is scrubbed with recycled sour water (water with dissolved sulfur compounds condensed from the syngas) to remove chlorides and trace metals.

In the next step, a carbonyl sulfide (COS) hydrolysis unit is provided to convert the small amount of COS in the syngas to H_2S, which is more efficiently removed in the AGR system. This configuration permits a higher level of sulfur removal. After hydrolysis, the syngas is cooled in process heat exchangers to utilize the available low-temperature heat. The cooled sour syngas is fed to the AGR system where it is contacted with an amine absorbent to remove the H_2S and produce a clean product syngas. The solvent is regenerated and recycled for reuse, and the off-gas containing the recovered H_2S is fed to the SRU, which uses the industry-standard Claus process to convert the H_2S to gaseous elemental sulfur. The sulfur is recovered and stored in molten form and potentially sold as a commercial by-product. After the sulfur is removed, the syngas passes through a fixed bed of activated carbon that is specially impregnated with additives to remove mercury from the syngas stream. The mercury removal system will be designed to remove enough mercury so that the mercury content of the HRSG stack gas is no more than 10% of the mercury content originally in the solid feedstock. After mercury removal, the product syngas is moisturized, heated, and diluted with nitrogen before being used as fuel for power generation in the combined cycle CTGs.

Additional facilities to support the gasification and power generation systems include a tank vent collection and boiler system, a flare for use during startups, shutdowns and for combusting excess syngas during short-term CTG outages or other plant upsets (treated product syngas would be combusted in short-term CTG outages), cooling towers, and emergency diesel generators and fire water pumps.

5.4 Inherently Lower Polluting Technology

As introduced in Section 5.2, the first step in a BACT determination process is to identify all available control technologies that could potentially be used to minimize the emissions of the source and pollutant under evaluation. The most common control technologies considered in a BACT analysis are add-on control measures. However, it is sometimes possible to modify the production process or work practices to improve the emissions performance of a proposed project. These types of process modifications/measures, when applicable, should also be considered in a BACT analysis. However, EPA has not historically required a BACT analysis to consider completely "redefining the design" of the proposed process (1990 Draft New Source Review Workshop Manual, Section IV.A.3). Nevertheless, IGCC technology is indeed the lowest emitting coal-based electricity generating technology available. This section of the BACT analysis compares Mesaba One and Mesaba Two to other potential coal-based electrical generating technologies. The other portions of this BACT analysis address the potential controls specific to minimizing the emissions from the IGCC process.

5.4.1 Generalized Comparison with Conventional Coal-Fired Power Plants

Table 5.4-1 illustrates the proposed emissions performance from Mesaba One and Mesaba Two compared to two other available coal-based power generation technologies: Pulverized Coal ("PC")-fired Boiler and Circulating Fluidized Bed ("CFB") Boiler. IGCC emissions for all criteria pollutants, except VOC, are well below the emissions from a well-controlled PC or CFB power plant. VOC emissions are comparable.

Table 5.4-1
Comparison of Emissions from Coal Based Electrical Generating Technologies

Pollutant	Mesaba One and Mesaba Two* lbs/MMBtu coal	Pulverized Coal [1] lb/MMBtu coal	Circ. Fluidized Bed lb/MMBtu coal
NO_x	0.057	0.076	0.09
SO_2	0.025	0.104	0.15
PM	0.009	0.016	0.015
VOC	0.0032	0.0034	0.004
CO	0.0345	0.144	0.15

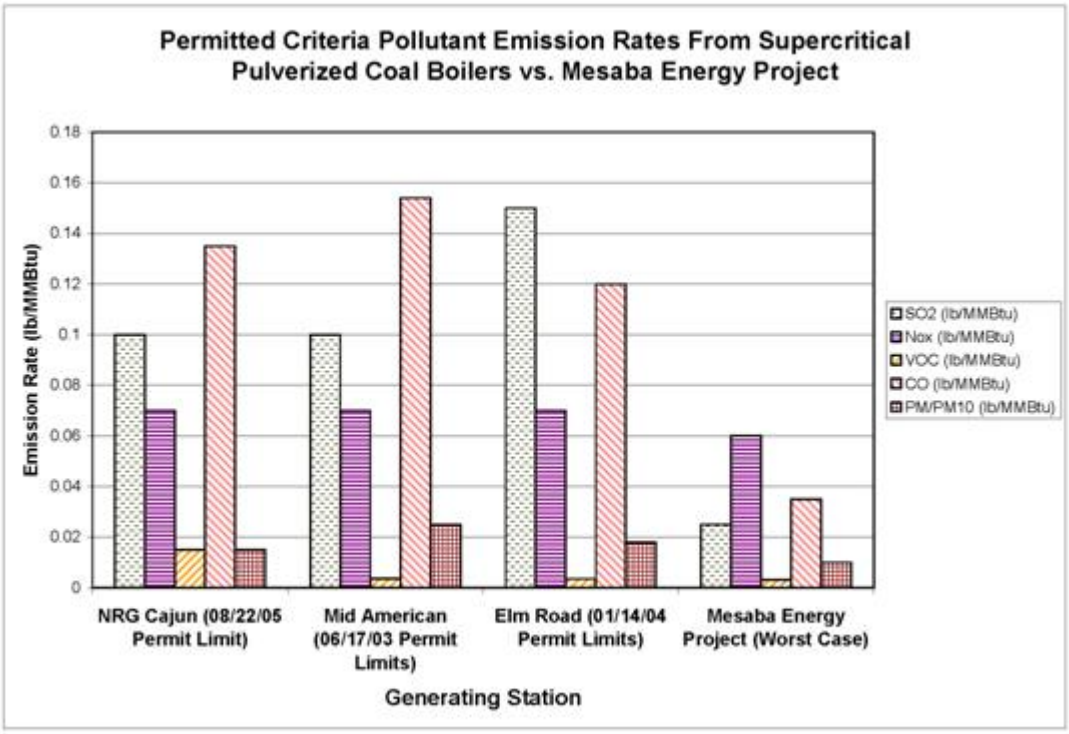
*The emission rates in lbs/MMBtu are based on the heat input to the gasifier, not the CTG.
[1]U.S. EPA Presentation at Pittsburgh Coal Conference Sept. 2005, "Environmental Impact Comparisons IGCC vs. PC Plants."

This comparison illustrates that Mesaba One and Mesaba Two would utilize the lowest polluting commercially available process for generating electricity from coal and/or petroleum coke. The proposed use of an inherently lower polluting, innovative technology does not necessarily excuse an applicant from also considering the use of additional add-on controls to further lower the emissions of the plant. However, the fact that emissions from Mesaba One and Mesaba Two are significantly below competing technologies decreases the need for, and relative value of, further controls.

5.4.2 Mesaba vs. Recently Permitted Supercritical Pulverized Coal Plants

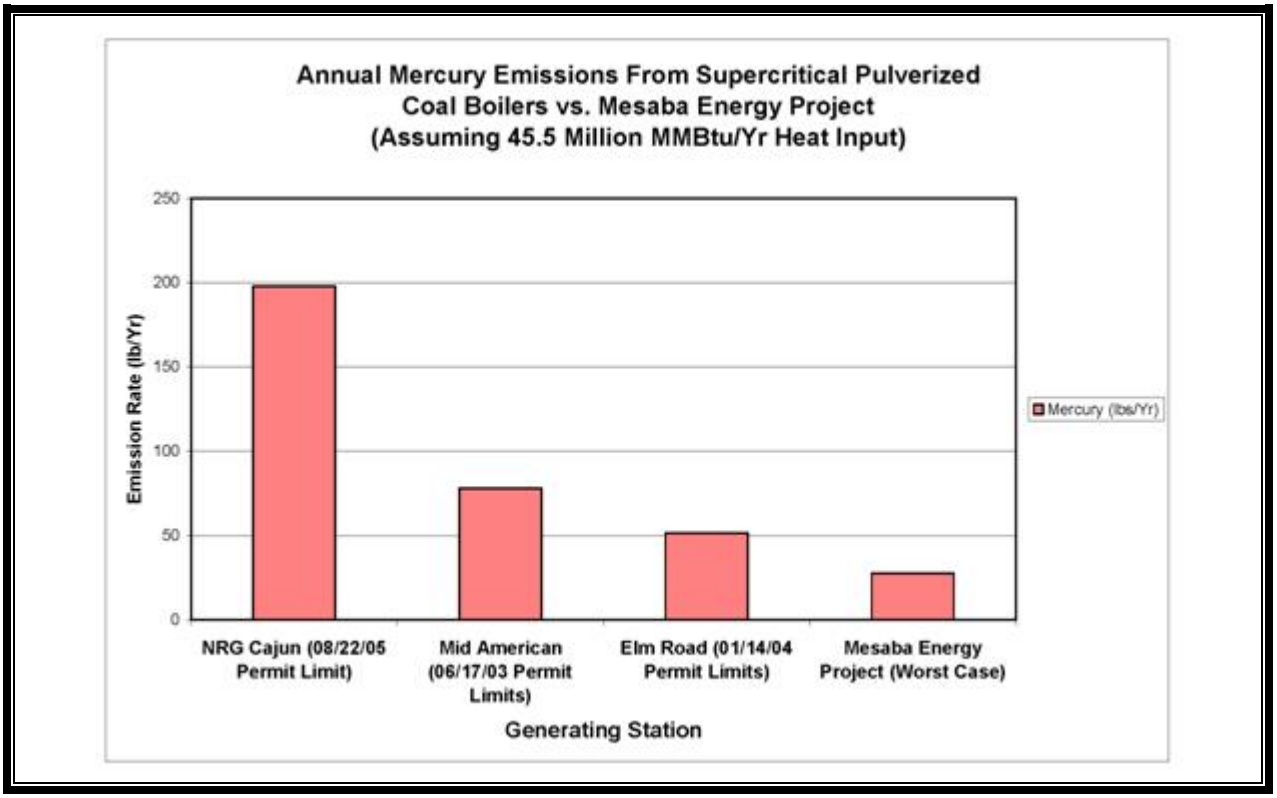
The analysis below compares Mesaba to the following three recently permitted, utility-scale, supercritical pulverized coal ("SCPC") plants: i) NRG Cajun in Louisiana, permitted August 22, 2005; ii) Mid American Council Bluffs Energy Center Unit 4 in Iowa, permitted June 17, 2003; and iii) Elm Road in Wisconsin, permitted January 14, 2004. This group of plants typifies the emissions profile of an SCPC plant with a full suite of pollution control technology. Figure 5.4-1 below compares the permitted criteria pollutant levels for each of these facilities with the maximum expected emission levels from Mesaba One and Mesaba Two. The first column for each plant represents sulfur dioxide emissions. Mesaba One and Mesaba Two's sulfur emissions are 75-85% less than those of the best comparison SCPC facility. The second column for each plant represents emissions of NO_X. NO_X emissions from Mesaba One and Mesaba Two are lower than the emissions rates of these newest coal plants by about 15%. The third column for each plant represents volatile organic compounds (VOCs) emission rates. Mesaba One and Mesaba Two's VOC emission rate is comparable to two of the comparison units, but about 80 percent less than one of the comparison units. Column four for each plant represents carbon monoxide (CO) emission rates. Compared to the most recently permitted SCPC facilities, carbon monoxide (CO) emission rates for Mesaba One and Mesaba Two are 70-80% lower. Finally, column five for each plant represents particulate matter emissions. Particulate matter emissions from Mesaba One and Mesaba Two are 30-60% less than those from the SCPC comparison plants.

Figure 5.4-1. All Criteria Pollutants: Mesaba vs. Newest SCPC Plants



With respect to mercury as shown in Figure 5.4-2, mercury emissions from Mesaba One and Mesaba Two will be half of the mercury emissions from the Elm Road SCPC plant in Wisconsin, and will represent a two-thirds to seven-eighths reduction in the mercury emissions from the other recently permitted SCPC plants in Iowa and Louisiana.

Figure 5.4-2. Mercury: Mesaba vs. Recently Permitted Coal Plants



5.4.3 Mesaba vs. Nation's Cleanest Coal Plants: Criteria Pollutants

Mesaba One and Mesaba Two will achieve substantially better across-the-board criteria pollutant emission results than the nation's cleanest coal-fueled power plants permitted over the past 10 years. In order to establish the comparison group of power plants to demonstrate this, regulatory decision-making was reviewed to find the coal-fueled power plants that emit the least of each criteria pollutant to compare to the emissions from Mesaba One and Mesaba Two. The comparison plants were selected as "best in class" by conducting a review of U.S. EPA's RACT/BACT/LAER clearinghouse ("RBLC") and other governmental agency databases. All recently permitted, utility scale, coal-fueled electric generating units of any type that have triggered review under the Prevention of Significant Deterioration (PSD) regulations and were subject to top-down BACT review were reviewed. The emissions of the coal facilities that have met the most stringent BACT determinations for any coal-fueled, utility scale source were selected to compare emission rates for the criteria pollutants sulfur dioxide, nitrogen oxides, particulate matter, volatile organic compounds, and carbon monoxide.

The comparisons illustrate that whenever a combustion facility achieves emission parity with Mesaba One and Mesaba Two for one pollutant, that same facility has significantly, and often times dramatically, higher emissions of other pollutants than do Mesaba One and Mesaba Two. The fact that the emission rate of each criteria pollutant from Mesaba One and Mesaba Two is essentially equal to or lower than the corresponding emission rate from the best controlled coal-fueled plants in the nation – regardless of the technology utilized by such plants, underscores the

superior environmental profile of Mesaba One and Mesaba Two. Figures 5.4-3 though 5.4-7 illustrate the results of comparing emission rates from Mesaba One and Mesaba Two to these "best in class" existing coal-fueled plants.

Figure 5.4-3. Sulfur Dioxide: Mesaba One and Mesaba Two Emission Rates vs. Cleanest Coal Plants

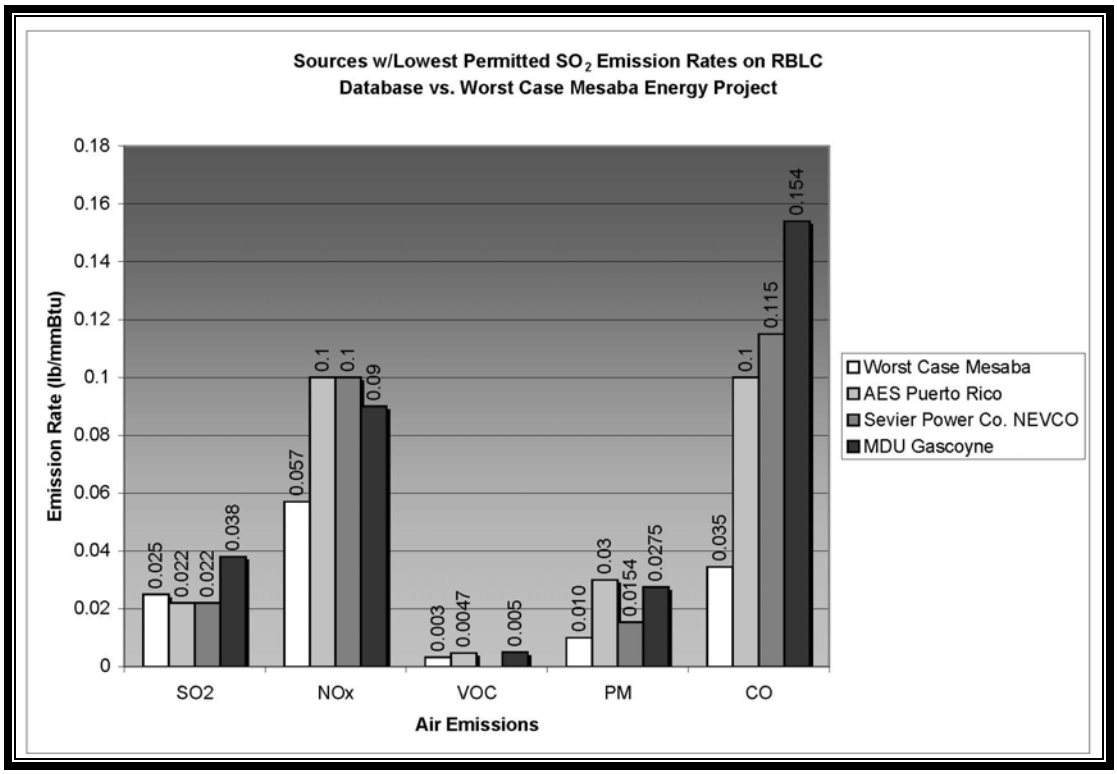


Figure 5.4-4. Nitrogen Oxides: Mesaba One and Mesaba Two Emission Rates vs. Cleanest Coal Plants

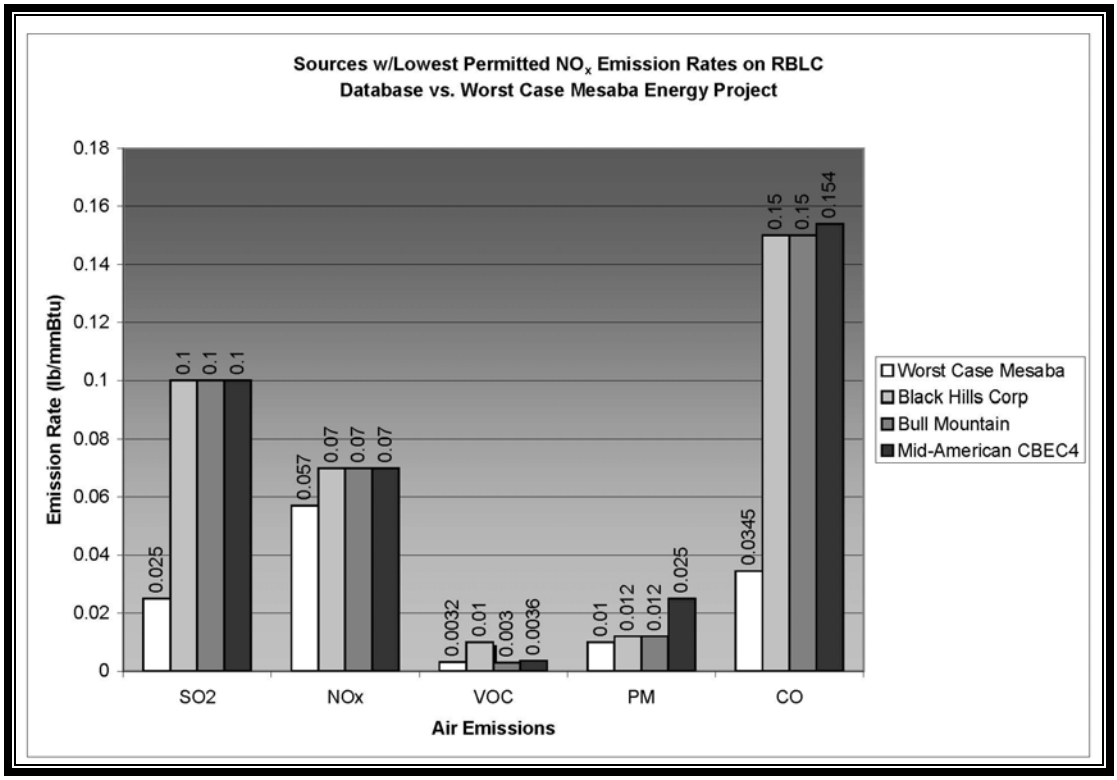


Figure 5.4-5. Particulate Matter: Mesaba One and Mesaba Two Emission Rates vs. Cleanest Coal Plants

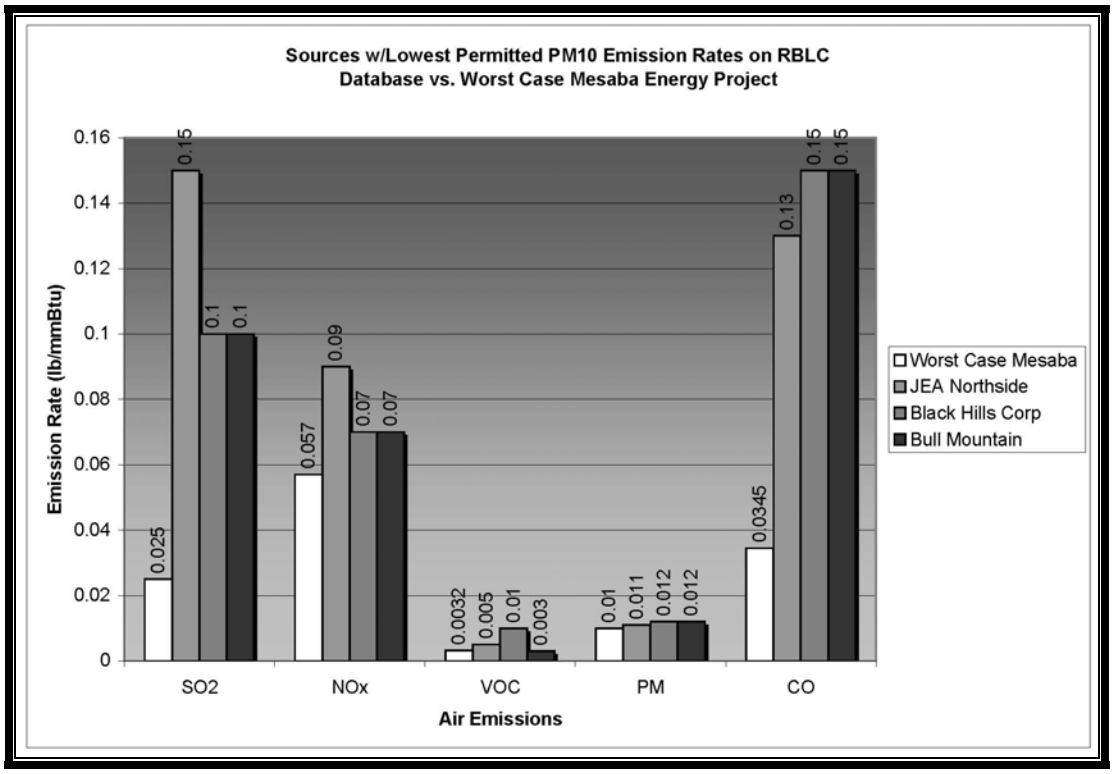


Figure 5.4-6. VOC: Mesaba One and Mesaba Two Emission Rates vs. Cleanest Coal Plants

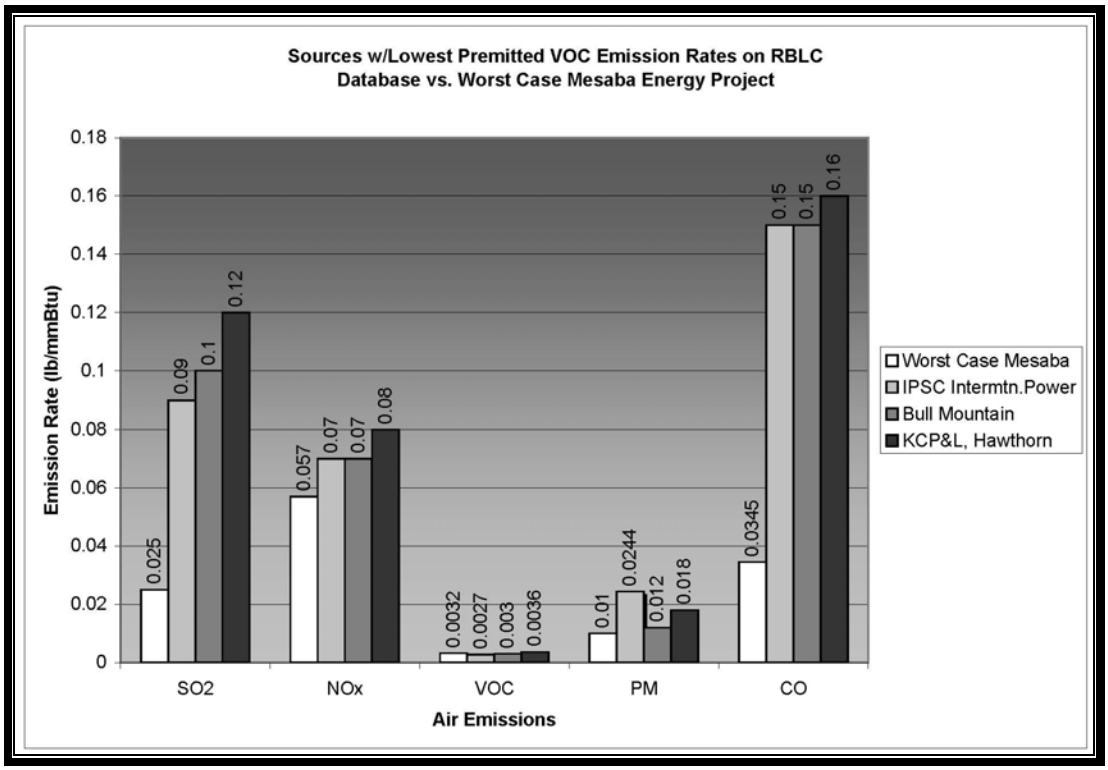
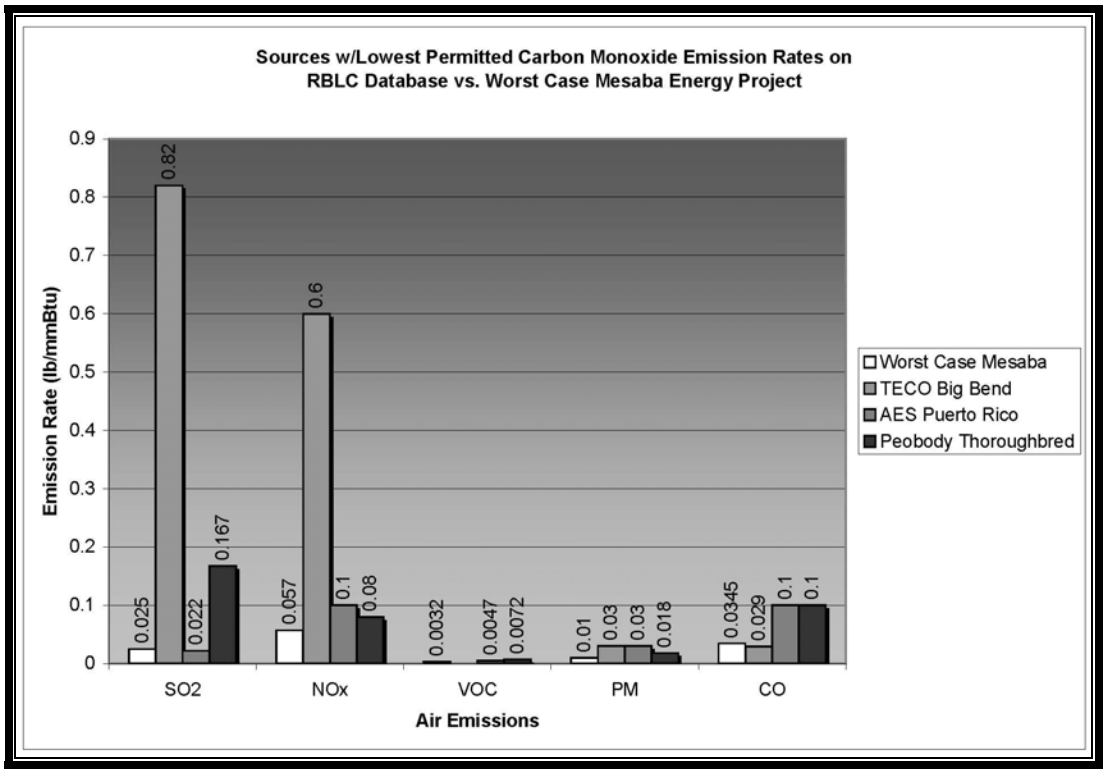


Figure 5.4-7. Carbon Monoxide: Mesaba One and Mesaba Two Emission Rates vs. Cleanest Coal Plants



In sum, the superior across-the-board emission rates achieved by Mesaba One and Mesaba Two in comparison to those of traditional technologies are dramatic.

The remainder of this BACT analysis discusses the various control options specific to IGCC processes and demonstrates that the proposed IGCC Power Station would achieve the lowest emissions rate technically and economical feasible for a such processes.

5.5 Existing and Permitted IGCC Facilities

During the review of available control technologies, existing BACT determinations from conventional pulverized coal (PC) boilers and gas-fired CTGs were examined. Emphasis was given to BACT determinations from existing and permitted IGCC plants, since the power generation and emission control technologies used in a PC plant are significantly different from the IGCC process.

For this BACT analysis, the available control options were identified by querying the RBLC and by consulting available literature and vendors on control options for IGCC. In addition, applications and/or permit information from the facilities listed below were reviewed, studied, and considered. Such information is what was used in this analysis of the IGCC BACT. A summary of the other permitted IGCC plants in the United States and their emissions limits is presented in this section, and include the following:

- SG Solutions, Wabash River Generating Station, West Terre Haute, IN (operating).
- Tampa Electric Company, Polk Power Station, Mulberry, Florida (operating).
- We Energies, Elm Road Generating Station, Wisconsin (permitted).
- Global Energy, Inc.'s Kentucky Pioneer Energy LLC, Trapp, Kentucky (permitted).
- Global Energy, Inc.'s Lima Energy Company, Lima, Ohio (permitted).

The air permits, BACT analyses and additional literature for each of these existing or proposed facilities was reviewed. Each facility is discussed briefly below and Table 5.5-1 presents the criteria pollutant emission levels permitted for each facility. The facilities that were subject to BACT determinations are listed as such.

Wabash River Generating Station and PSI Combined Cycle Power Station: The DOE and a Joint Venture formed in 1990 between Destec Energy Inc. and Public Service of Indiana (PSI) initiated the Wabash River Coal Gasification Repowering Project. The gasification island includes an E-Gas (originally developed by Dow Chemical and known earlier as Destec Technology, and now operated by SG Solutions) two-stage, oxygen blown gasifier with full heat recovery that is integrated with the power block. This facility has been operating since 1995.

Tampa Electric Company Polk Power Station: The DOE partly funded the Polk Power Station IGCC project. The facility includes a Texaco (now GE Energy) oxygen blown gasifier with full heat recovery using both radiant and convective syngas coolers. The GE STAG-107FA power block integrates process syngas, steam, and nitrogen. This IGCC facility has been operating since 1996.

Global Energy Kentucky Pioneer Power Station: Global Energy USA (Global), owner of Kentucky Pioneer Energy, LLC, negotiated with the DOE and Clean Energy Partners, LP to acquire a conditionally approved IGCC Demonstration Project. The British Gas/Lurgi (BG/L) slagging fixed-bed gasification technology has been proposed in a new 540 MW (net) IGCC facility using both coal and refuse derived fuel as a feedstock. The gasification system would be coupled with Fuel Cell Energy, Inc.'s molten carbonate fuel cell. The air permit for this facility was originally issued in June 2001, and has been extended conditioned on revision of the BACT analysis. Construction of the facility has not begun.

Global Energy Lima Energy Power Station: Lima Energy Company, a Global Energy company, obtained a final Ohio EPA Permit to Install an IGCC facility in Lima, Ohio. The 540 MW (net) IGCC is expected to use entrained flow gasification technology to convert high sulfur coal or petroleum coke into synthesis gas. The air permit was issued in 2002, but construction of the IGCC plant has not yet begun.

We Energies Elm Road Generating Station: We Energies recently proposed a new 600 MW net nominal base-load IGCC generating unit at the Elm Road Generating Station. The facility includes a gasification plant, sulfuric acid plant, CTG and HRSG, and STG. The permit for this facility was received in January 2004. Construction of this facility is subject to a determination of need.

Table 5.5-1
Permitted Emission Rates for Syngas-Fired CTGs
In lbs/MMBtu Coal Heat Input (Approximate)

Location	MMBtu/hr to gasifier (estimated)	CO	NO_x	SO_2	PM	VOC
Wabash River	2,356	0.036	0.087	0.126	0.005	0.001
Polk Power Station	2,191	0.045	0.101	0.163	0.008	0.001
Kentucky Pioneer	4,413	0.026	0.059	0.026	0.009	0.004
Lima Energy	4,413	0.035	0.067	0.017	0.008	0.007
We Energies	5,424	0.024	0.059	0.023	0.008	0.003
Mesaba One	5,910	0.035	0.057	0.026	0.009	0.003

The emissions listed in Table 5.5-1 above have been estimated based on permit documents and converted to units of lbs per million Btu of gasifier feedstock, for purposes of general comparison. The actual permitted levels and/or BACT determinations, in many cases, is expressed in units different than lbs/MMBtu, and may be expressed on the basis of MMBtu input of syngas fuel to the CTGs instead of MMBtu to the gasifier (the correct basis). The proposed limits for the IGCC Power Station are quite similar to other recent IGCC permits.

5.6 Combustion Turbine Control Technology Review

The following BACT analysis evaluates each of the criteria pollutants emitted from the syngas-fired CTGs of the proposed IGCC Power Station to determine what is considered to be Best Available Control Technology. BACT today is based on the current state of technology, best engineering judgment, and current expected economics, energy, and other impacts.

5.6.1 Nitrogen Oxides BACT Analysis

NO_x is primarily formed in combustion processes in two ways: 1) the reaction of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal NO_x), and 2) the oxidation of nitrogen contained in the fuel (fuel NO_x). Syngas contains negligible amounts of fuel-bound nitrogen, although some molecular nitrogen is present. Therefore, it is expected that essentially all NO_x emissions from the turbine originate as thermal NO_x.

IGCC is an inherently lower-emitting process that prevents emissions of NO_x at the high levels often seen in conventional PC power plants. Typical emissions from a new state-of-the-art PC plant utilizing selective catalytic reduction ("SCR") technology are in the range of 0.07 – 0.10 lb NO_x/MMBtu ("Environmental Impact Comparisons IGCC vs. PC Plants", Kahn, Wayland, and Schmidt of US EPA, presented at Pittsburgh Coal Conference, September 2005) while Mesaba One and Mesaba Two are expected to achieve 0.057 lb/MMBtu without add-on controls. Emissions from existing, well controlled PC plants without SCR can be as low as 0.15 lb/MMBtu (such plants would be likely to have installed low NO_x burners; staged combustion; overfire air; selective non-catalytic reduction technology; artificial intelligence burner control

management systems; or a combination of such controls). Nonetheless, the BACT analysis considers the use of IGCC in conjunction with add-on controls that might further control and reduce emissions after they are produced.

The rate of formation of thermal NO_x is a function of residence time and the preponderance of oxygen radicals which increase exponentially with peak flame temperature. Front-end NO_x control techniques are aimed at controlling one or more of these variables during combustion. Examples include diluent injection (steam, water, or nitrogen) and dry low-NO_x burners. These technologies are considered pollution prevention techniques.

Other control methods utilize add-on control equipment to remove NO_x from the exhaust gas stream after its formation during the combustion process. The most common add-on control technique – SCR- involves the injection of NH_3 into the exhaust gas stream in the presence of a special catalyst, allowing the NO_x and NH_3 to react, forming molecular nitrogen and water.

5.6.1.1 Identify Control Technologies

Possible control technologies were identified through the examination of previous IGCC permits and through RBLC queries for natural gas-fired combined cycle CTGs. All previous BACT and LAER determinations for IGCC facilities have resulted in the best available controls for NO_x to be diluent injection. However, the BACT analyses for the IGCC CTGs evaluated all of the following technologies:

Combustion Process Controls

- Dry Low NO_x burners.
- Diluent injection.

Post Combustion Controls

- $SCONO_x$™
- SCR.
- Selective non-catalytic reduction (SNCR).

5.6.1.2 Evaluate Technical Feasibility

Each identified technology must be examined to determine if it is technically feasible for IGCC CTGs burning syngas, as follows:

5.6.1.2.1 Dry Low NOx Burners

Dry Low-NO_x (DLN) burners control NO_x formation in conventional natural gas-fired CTGs by staged combustion. This is done by designing the burners to control both the stoichiometry and temperature of combustion by tuning of the fuel and air locally within each individual burner's flame envelope. Burner design includes features that regulate the aerodynamic distribution and mixing of the fuel and air. A lean, pre-mixed burner design pre-mixes the fuel and air prior to combustion. This results in a homogeneous air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_x emissions. A lean fuel-

to-air ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower combustion temperatures, which lowers thermal NO_x formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment.

The existing DLN technology was designed for natural gas (methane-based) fuels and will not operate on syngas (hydrogen/CO-based) fueled IGCC turbines. DLN combustors are not technically feasible for this application due to the potential for explosive mixtures in the combustion section resulting primarily from the high hydrogen content of the syngas. Syngas differs from natural gas in heating value, gas composition, and flammability characteristics. Turbine vendors are currently researching DLN for syngas-fueled CTGs, but these combustors are not yet commercially available.

No manufacturer currently makes DLN burners that can be used for a CTG burning coal-derived syngas. Therefore, DLN burners are not deemed to be a technically feasible control option for the combustion turbines.

5.6.1.2.2 Diluent Injection

The addition of an inert diluent such as water or nitrogen into the syngas before combustion, and/or steam or nitrogen injection into the high temperature region of a combustor flame serves to minimize NO_x formation by reducing the peak flame temperature. Higher combustion temperatures may result in greater thermodynamic efficiency; however, higher temperatures also increase NO_x production. Syngas can be diluted with water or nitrogen (if available) while conditioning it for use in the CTG. This effectively lowers the combustion temperature, and therefore reduces NO_x emissions. Steam can also be injected directly into the combustion zone to cool temperatures and reduce NO_x formation. Diluent injection can achieve emission levels of 15 ppmvd NO_x (at 15 percent oxygen) when firing 100% syngas fuel. A secondary benefit of diluent injection is that it will increase the mass flow of the CTG exhaust and thereby increase power output.

During firing of the back-up fuel, natural gas, the diffusion flame burners will achieve 25 ppm NO_x. Diluent injection cannot achieve as low a NOx concentration on natural gas fuel as with syngas. However, natural gas is proposed for long-term use at a maximum of 5% of the time on an annual basis.

Diluent injection represents an inherently lower-emitting process for syngas-fired CTGs, and is a technically feasible control technology. Diluent injection, achieving NOx levels of 15 ppmvd (at 15% O_2) was considered as the baseline case for the CTG NO_x BACT analysis. This NO_x performance has also been determined as BACT for all other recent IGCC permits.

5.6.1.2.3 SCR

SCR is a process that involves post-combustion reduction of NO_x from flue gas with a catalytic reactor. An SCR system is composed of an ammonia storage tank, an injection grid (system of nozzles that spray NH_3 into the exhaust gas ductwork), and a reactor, which contains the catalyst, and instrumentation and electronic controls. This is an increasingly common control technology

for use on natural gas-fired CTGs, but would have feasibility problems on a syngas-fired CTG system, as discussed later in this section.

In the SCR process, NH_3, usually diluted with air or steam, is injected through a grid system into the exhaust gas upstream of a catalyst bed. On the catalyst surface, the NH_3 reacts with NO_x to form molecular nitrogen and water. The basic reactions are:

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

$$8NH_3 + 6NO_2 \rightarrow 7N_2 + 12H_2O$$

A fixed bed catalytic reactor is typically used for SCR systems. The function of the catalyst is to lower the activation energy required for NO_x decomposition to occur. In natural gas service, NO_x removal of 90 percent and higher is theoretically achievable at optimum conditions. Removal efficiency is dependent on gas temperature, residence time, NO_x/NH_3 stoichiometry, and catalyst activity. Certain compounds such as sulfur and various metals, if present in the exhaust gas stream, will "poison" the catalyst, reducing its performance, useful life, and impact catalyst activity and/or conversion efficiency.

The typical effective temperature range for base-metal SCR catalysts is 600 – 800˚F. If the exhaust gas temperature drops below 600˚F, the reaction efficiency becomes too low and increased amounts of NO_x and NH_3 will be released into the atmosphere. HRSG exhaust temperatures are in the vicinity of 250˚F, and thus too low for the SCR reactions to occur. The catalyst must therefore be located within the HRSG where temperature conditions are favorable.

An environmental consideration in implementation of SCR is that while it will reduce NO_x emissions, operation of the SCR will add NH_3 emissions. A portion of the unreacted NH_3 passes through the catalyst and is emitted from the stack. This is called ammonia slip and is impacted by the catalyst activity and the degree of NO_x control desired.

A significant feasibility issue for the IGCC Power Station is the fact that the syngas contains sulfur and several other compounds that act as catalyst poisons. It is important to consider the ammonium sulfate and bisulfate problems unique to SCR use on a combined cycle CTG with sulfur-bearing fuels such as coal-derived syngas. The oxidation of sulfur present in the syngas fuel during combustion produces primarily SO_2 and also a small portion of SO_3. If SCR were installed, the vanadium in the SCR catalyst will oxidize additional amounts of the SO_2 in the flue gas to SO_3. Some of the NH_3 added to initiate the SCR process will react with the available SO_3 to form ammonium sulfate and bisulfate salts. These salts can cause serious corrosion and plugging/fouling problems in a conventional HRSG, as well as a loss of heat transfer. This is a serious concern, even at the relatively low levels of sulfur present in the syngas.

These ammonium salts would deposit onto heat transfer fins located inside the HRSG. As the exhaust gas passes over the heat transfer fins of the HRSG, ammonium sulfate and bisulfate condense from the gas and deposit directly onto the fins. The heat transfer efficiency of the fins gradually decreases as they become increasingly fouled with deposits. Power output from the turbine will also be significantly affected due to an increase in pressure drop within the HRSG resulting from the partial blockage of gas flow by these deposits. This pressure rise can also

impact HRSG casing design requirements. In addition, ammonium bisulfate is corrosive and corrodes the heat transfer fins or tubes, impacting the reliability of the HRSG, and therefore the entire IGCC facility.

As deposits of ammonium salts increase, they would need to be cleaned from the surface of heat transfer fins in order to restore heat transfer efficiency and pressure within the HRSG. Adequate cleaning of the fins is difficult in a conventional HRSG due to the following:

- Access to interior tube banks in a HRSG is restricted.
- HRSG heat exchange elements are not designed for removal/replacement.
- The catalyst in a HRSG is in close proximity to areas that would need water washing, increasing the possibility of inadvertent wetting of the catalyst (which would cause damage).

In addition to the above-described sulfur/salting issue, another significant feasibility issue with syngas (vs. natural gas) is the potential presence of metals in syngas, which are known to deactivate the sensitive SCR catalyst. For example, SCR is impacted by compounds such as arsenic, even at levels significantly below those which might be health risk concerns. The concentrations of trace compounds such as arsenic, nickel, lead, cadmium, and other catalyst poisons makes it difficult to determine system performance, control efficiency, or catalyst life for this unique application.

There is a growing experience base of SCR on conventional PC units that might, on the surface, seem to suggest that SCR should work in the seemingly less extreme exhaust conditions of a syngas-fired CTG. However, there are key differences when compared to a PC plant SCR system application, including:

- SCR performance expectation in conventional PC unit service is significantly lower (i.e., higher outlet NO_x) than would be needed in the IGCC case. PC-based SCR systems typically achieve about 0.08 lb NO_x/MMBtu with SCR, which is greater than the IGCC Power Station's proposed level (0.057 lb/MMBtu) without any add-on controls.
- Ammonium bisulfate salts would form in the PC plant's air preheater, which is of a very different design from a HRSG and is well-suited to handling precipitation/deposits/ corrosion. Compared to a HRSG, a PC unit's air preheater is designed for cleaning and replacement of components, and deposits do not significantly inhibit heat transfer as they would in a HRSG. Air preheater heat transfer baskets are not impacted as much by corrosion as the heat transfer fins in a HRSG.
- Ammonia preferentially adsorbs onto the fly ash produced from a PC unit, and sulfates and bisulfate can be captured in downstream particulate matter control equipment.

The technological, operational, and economic issues noted above dictate against any requirement to apply SCR to the IGCC Power Station. Significant additional testing and research on SCR in IGCC service is necessary to gain full understanding of and confidence in predicting system performance and cost determinations. EPA does not consider a technology "available" until it has reached commercial availability for its intended service. While SCR is clearly an "available"

technology and commercially demonstrated for many applications, SCR is only at the "concept stage" for coal derived syngas-fired CTGs. The Applicant is unaware of any research or testing (at any scale) that has been done on this unique application, and should not be required to experience extended outages, significant costs, and extended trials to learn if this expensive control technology could be effectively utilized on this already environmentally superior source. EPA's New Source Review Workshop Manual (page 12, "New Source Review Workshop Manual" Draft 1990, EPA Office of Air Quality Planning and Standards) specifically states that "Technologies which have not been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice." On this basis, SCR technology is not commercially available for use as part of an IGCC power station using coal-derived syngas.

As described further in the SO_2 BACT section (Section 5.5.2), there are acid gas removal (AGR) technologies that can reduce the amount of sulfur in the syngas to levels (< 10 ppm) that might mitigate the concerns with sulfate salt plugging and corrosion. However, these physical solvents (Selexol and Rectisol) are extremely costly. In addition, SCR has still not been applied to coal-based IGCC power station even with deep sulfur removal.

In summary, SCR has never been employed at an IGCC facility using a solid feedstock such as coal or petroleum coke. This is primarily due to various feasibility, cost and operational concerns. The lack of SCR vendor guarantees is also an important factor in this consideration The question of SCR feasibility in IGCC service has been recently addressed by several other proposed projects and their state and regional environmental agencies. Polk Power Station in Florida, Kentucky Pioneer LLC in Kentucky, Lima Energy LLC in Ohio, and We Energies in Wisconsin have all finalized or updated BACT determinations for their IGCC projects. The state environmental agencies in Florida, Kentucky, Ohio, and Wisconsin, along with US EPA Region IV and Region V have determined BACT for those IGCC projects to be 15 ppm NO_x @15% O_2 using diluent injection. In each case, SCR was rejected as BACT.

Due to significant technical concerns and the lack of demonstrated commercial performance in IGCC service, SCR is judged to be commercially unavailable for this IGCC application. This finding is consistent with recent previous BACT determinations for syngas-fired CTGs that are part of IGCC facilities using solid feedstocks such as coal and/or petroleum coke.

5.6.1.2.4 SCONOx

The $SCONO_x$™ system is an add-on control device that reduces multiple pollutants. $SCONO_x$™ control technology is provided by Emerachem, LLC (formerly Goal Line Environmental Technologies). $SCONO_x$™ utilizes a single catalyst for the reduction of CO, VOC and NO_x and results in the emission of CO_2, H_2O and N_2. The system does not use NH_3 and operates most effectively at temperatures ranging from 300°F to 700°F. $SCONO_x$™ requires natural gas, water, steam, electricity and ambient air to operate, and no special chemicals or processes are necessary. Steam is used periodically to regenerate the catalyst bed and is an integral part of the process.

There are currently several $SCONO_x$™ units in commercial installations worldwide. All are operated on fairly small CTG facilities. The original installation is at the Federal Plant in Vernon, California owned by Sunlaw Cogeneration. This installation is on a GE LM2500, an approximately 25 MW combined cycle system, which has had an operating $SCONO_x$™ system since December 1996. That system has undergone many changes over the years. The second commissioning of a $SCONO_x$™ system was at the Genetics Institute in Massachusetts on a 5 MW Solar Turbine Model Taurus 50. This facility has reported problems with meeting permitted NO_x levels of 2.5 ppm and received a permit modification extending their $SCONO_x$™ demonstration period. Three other units were recently installed, two on 13 MW Solar Titan CTs at the University of California, San Diego, and one on an 8 MW Allison CTG at Los Angeles International airport.

There are no current $SCONO_x$ applications on large CTG units such as Mesaba One and Mesaba Two. Similarly, there are no applications with the sulfur levels of syngas-fired CTGs. $SCONO_x$™ was considered at some larger CTG applications including a 250 MW CTG at the La Paloma plant near Bakersfield, and a 510 MW plant in Otay Mesa. However, the La Paloma and Otay Mesa projects were given the alternative to install SCR and have done so. In evaluating technical feasibility of $SCONO_x$ for use in large IGCC power stations, the major concerns are as follows:

- $SCONO_x$™ uses a series of dampers to regenerate the catalyst. The IGCC Power Station is much larger than the smaller facilities where $SCONO_x$ has been used and would require a significant redesign of the damper system, which raises feasibility concerns regarding adequate operation of larger dampers.
- The catalyst is very susceptible to poisoning by sulfur compounds. Because of the sulfur content of the syngas, a catalyst to absorb SO_2 would be required. The vendor offers a $SCOSO_x$™ catalyst; however, its operation is not proven and it would create an H_2S stream that must be treated.
- $SCONO_x$™ would not be expected to achieve lower NOx levels than SCR, and it is anticipated to have the same feasibility concerns that were previously raised in connection with SCR.

For the above reasons, $SCONO_x$™ is considered technically infeasible for application to this large IGCC CTG.

5.6.1.2.5 SNCR

Selective Non-Catalytic Reduction (SNCR) is a post-combustion NO_x control technology in which a reagent (NH_3 or urea) is injected into the exhaust gases to react chemically with NO_x, forming nitrogen and water without the use of a catalyst. The success of this process in reducing NO_x emissions is highly dependent on the ability to uniformly mix the reagent into the flue gas. This must occur at a zone within the exhaust stream at which the flue gas temperature is within a narrow range, typically from 1,700°F to 2,000°F. In order to achieve the necessary mixing and reaction, the residence time of the flue gas within this temperature window should be at least 0.5 to 1.0 seconds. The consequences of operating outside the optimum temperature range are severe. Above the upper end of the temperature range, the reagent will be converted to NO_x.

Below the lower end of the temperature range, the reagent will not react with the NO_x and the NH_3 slip concentrations (NH_3 discharge from the stack) will be very high.

This technology is occasionally used in conventional fired heaters or boilers, but to the applicant's knowledge, it has never been applied in CTG service. This is primarily because there are no flue gas locations within the CTG or HRSG with the right temperature and residence times to allow use of SNCR technology.

Since SNCR has not been applied to any CTGs or IGCC units (according to the RBLC database and the applicant's permit review) and because of the incompatibility of the exhaust temperatures, SNCR is considered to be technically infeasible.

5.6.1.3 Rank Control Technologies

Diluent injection with a control level of 15 ppm NO_x was the only control technology determined to be technically feasible and commercially available for an IGCC application. Table 5.6-1 below shows this control option versus the NSPS Subpart Da emissions level that is considered the BACT "floor" for this source category.

It should be noted that during firing of the back-up fuel, natural gas, the diffusion flame burners will achieve 25 ppm NO_x. The Applicant proposes to use natural gas for less than 440 hours per year on a long-term basis. Therefore, the annual emissions estimates for diluent injection include NO_x at the higher rate for 440 hours per year, with the balance of the year firing syngas at the lower NO_x emission rate of 15 ppmvd at 15% oxygen.

Table 5.6-1
Ranking Of NO_X Control Technologies

Control Technology Option	Uncontrolled Emissions	Emissions Reduction	Emissions Achievable	Annual Emissions per IGCC CTG[1]
Nitrogen/Steam Injection	N/A	N/A	0.0566 lb/MMBtu	693 TPY
NSPS Subpart Da Proposed Limit	N/A	N/A	1.0 lb/MWh (~ 0.11 lb/MMBtu)	~1,050 TPY

Notes: Annual emissions are based on one CTG firing 440 hours per year on natural gas at 25 ppmvd, and the balance on syngas at the 15 ppmvd level at full load. (Mesaba One and Mesaba Two include 4 CTGs total.)

5.6.1.4 Evaluate Control Options

The next step in the BACT process is to conduct an analysis of the energy, environmental and economic impacts associated with each feasible control technology. Based on the previous evaluation, the applicant believes that the only technically feasible and available technology for IGCC Power Station is diluent injection in the CTG, which has no negative energy or environmental impacts.

5.6.1.5 Select Control Technologies

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. As has been explained, for this unique application of a syngas-fired CTG as part of the IGCC facility, diluent injection in the CTG is chosen as BACT. This technology will achieve an emission rate of 15 ppm NO_x at 15% O_2 for syngas firing, and 25 ppm NO_x at 15% O_2 for natural gas firing.

The BACT selection of diluent injection to the NO_x levels described above is strongly supported by recent precedent for similar IGCC projects. Diluent injection was designated as LAER for an IGCC turbine project in Delaware (Motiva/Star Enterprises), as BACT for three proposed IGCC projects in Wisconsin (We Energies), Kentucky and Ohio (Global Energy) and as BACT in a BACT re-evaluation of an existing IGCC in Florida (Tampa Electric).

Add-on controls such as SCR and $SCONO_x$™ have been determined to have significant problems regarding the technical feasibility of their application to IGCC CTGs, and are not commercially demonstrated or available for such an application. IGCC is an inherently lower-polluting technology, and should not be burdened with the additional costs and technical uncertainties of add-on pollution control technologies for NO_x. Therefore, diluent injection is the most stringent and technically feasible control technology, and is the best available option. As such, the applicant proposes that NO_x BACT is 15 ppmvd @ 15% O_2, or 157 lb/hr per CTG stack, when firing syngas.

5.6.2 Sulfur Dioxide and Sulfuric Acid Mist BACT Analysis

5.6.2.1 Identify Control Technologies

The combustion of syngas in the CTG creates SO_2 and sulfur trioxide (SO_3) by the oxidation of the sulfur species in the fuel. The vast majority of the sulfur forms SO_2. A small percentage of the sulfur forms SO_3, which combines with the moisture in the exhaust to form sulfuric acid mist, or H_2SO_4. Sulfur emissions from any combustion process are directly related to the sulfur content of the fuel being combusted. Emissions can be controlled either by limiting the sulfur content of the fuel (pre-combustion control) or by scrubbing the SO_2 from the exhaust gas (post-combustion control). Possible control technologies include:

<u>Pre-Combustion Process Controls</u>

- Chemical Absorption Acid Gas Removal (AGR).
- Physical Absorption AGR.

<u>Post-Combustion Controls</u>

- Flue Gas Desulfurization (FGD).

5.6.2.1.1 Acid Gas Removal (AGR)

Sulfur in the feedstock converts to either H_2S or COS in the gasification process. A COS hydrolysis unit is provided to achieve a high level of sulfur removal. The COS is converted to

H_2S, which is more efficiently removed in the AGR system. Solvent-based acid gas cleanup is commonly used for "gas sweetening" processes in refinery fuel gas or tail gas treatment settings where H_2S in the process gas may be treated before use as a fuel or released to the atmosphere. The removed H_2S is then recovered either as elemental sulfur in a SRU or converted to H_2SO_4 in a sulfuric acid plant.

AGR systems can employ either chemical absorption or physical absorption methods. Chemical absorption occurs in amine-based systems that use solvents such as methyl diethanolamine (MDEA). Amine solvents chemically bond with the H_2S. The H_2S can be easily liberated with low-level heat in a stripper to regenerate the solvent. This is the technology that has been used in all existing and recently-permitted IGCCs, and is considered the base level of control for an IGCC facility.

Alternate AGR systems include those utilizing a physical absorption solvent such as methanol (Rectisol) or mixtures of dimethyl ethers of polyethylene glycol (Selexol). When using physical solvents, the H_2S is dissolved under pressure into the solvent. Dissolved acid gases can be removed by depressurization to regenerate the solvent for reuse. Physical absorption methods have been used to purify gas streams in the chemical processing and natural gas industries. However, physical absorption has not been used to remove H_2S from syngas at a solid fuel based IGCC power station.

5.6.2.1.2 Flue Gas Desulfurization

A FGD application usually operates by contacting the exhaust gas with an alkaline slurry or solution that absorbs and subsequently reacts with the acidic SO_2. FGD technologies may be wet, semi-dry, or dry based on the state of the reagent as it is injected or pumped into the absorber vessel. Also, the reagent may be regenerable (where it is treated and reused) or non-regenerable (all waste streams are de-watered and either discarded or sold). Wet, calcium-based processes, which use lime (CaO) or limestone ($CaCO_3$) as the alkaline reagent, are the most common FGD processes in PC unit applications. After the exhaust gas has been scrubbed, it is passed through a mist eliminator and exhausted to the atmosphere through a stack

FGD systems are commonly employed in conventional PC plants where the level of sulfur emissions in the exhaust is relatively high, and can achieve >95% reduction.

5.6.2.2 Evaluate Technical Feasibility

Both chemical and physical absorption methods for AGR are considered potentially feasible for an IGCC application and are further considered in this analysis. FGD does not provide a higher level of control than the pre-combustion AGR systems, and is not considered a reasonable technical option for IGCC. Since the sulfur would be removed more efficiently and economically from syngas prior to combustion in the CTGs, it is concluded that FGD will not be considered further in this BACT analysis.

5.6.2.3 Rank Control Technologies

Technically feasible control technologies are summarized in Table 5.6-2 in ascending order of control efficiency. Emissions in pounds per million Btu of coal and annual emissions for each of four combustion turbines are also shown along with uncontrolled and NSPS emissions for comparison.

Table 5.6-2
SO_2 Control Technology Options

Control Technology Option	Control Efficiency	SO_2 Emissions (lb/MMBtu)	Annual SO_2 Emissions (one CTG)	Emissions Reduction with Ill. No. 6 Coal (tons/yr, 1 CTG)
Uncontrolled	-	5.0	66,662 tons	-
Proposed NSPS Da	95.8%	~0.21	2,800 tons	63,862 tons
Chemical Solvent AGR (MDEA – Base IGCC Level)	99.5%	0.026	333 tons	66,329 tons
Physical Solvent AGR (Selexol)	>99.8 %	0.01	133 tons	66,529 tons

5.6.2.4 Evaluate Control Options

The syngas initially produced will contain as much as 10,000 ppm sulfur (assuming the IGCC Power Station's worst case feedstock) primarily in the form of H_2S. In an IGCC process, the sulfur in the syngas can be reduced dramatically and relatively easily prior to combustion of syngas in the CTGs. Chemical absorption processes such as AGR with MDEA have been used in all existing and permitted IGCC facilities, and are therefore considered the base level of control for IGCC. This removal of sulfur in a chemical process prior to combustion is part of what makes IGCC an inherently-lower polluting technology.

The most effective SO_2 control system that is considered to be technically feasible is the physical absorption AGR system. The second most effective SO_2 control option is the base IGCC level of amine (MDEA) chemical absorption AGR system. Both of these options are evaluated in the economic analysis below.

The MDEA system is typical for IGCC units, and is currently considered the optimum level of control for this application of gasification-polluting technology. The costs per gasifier train for adding a Selexol physical absorption AGR system were estimated and are shown below at Table 5.6-3. The Selexol system is considerably more expensive than a conventional amine-based AGR, and also results in an unacceptable economic penalty on plant performance of 2 %, or 12 MW for the Phase 1 IGCC Power Station, and a 4% penalty for the Phase I and II Power Station. These energy costs are included in the annual operating costs shown in Table 5.6-3.

Table 5.6-3
Cost Comparison for SO_2 Control Technology

Control Technology	Capital Investment*	Annual Operating Costs	Total Annual Costs	Incremental Tons SO_2 Reduced	Cost Effectiveness ($/ton)
Physical Solvent AGR (Selexol)	$22,200,000	$2,600,000	$5,000,000	200	$25,200
Chemical Solvent AGR (MDEA)	*N/A – Base level of control for IGCC*				

*2Q 2005 cost estimate basis

As is illustrated in Table 5.6-3 above, a Selexol system will cost approximately $20 million in additional capital costs and over $2.5 million in additional annual operating costs (per combustion turbine), while only reducing an additional 200 tons per year of SO_2. This results in a removal cost of $25,000 per additional ton of SO_2 reduced, an amount which the Applicant believes to be prohibitively expensive.

5.6.2.5 Select Control Technologies

The applicant proposes that SO_2 emissions from the CTGs will be minimized through treatment of the syngas with MDEA, which will remove greater than 99% of sulfur in the syngas when using Illinois No. 6 bituminous coal; for PRB sub-bituminous coals the removal of sulfur from syngas is expected to be greater than 97 percent. The syngas sulfur content will be reduced to less than 50 ppmvd as hydrogen sulfide in the undiluted syngas on a 30-day rolling average basis. Syngas at this reduced level of sulfur will result in CTG SO_2 emissions of less than 0.026 lb/MMBtu and sulfuric acid mist emissions of less than 0.0026 lb/MMBtu (See Section 2.2.4 for additional details on the proposed process).

Additional SO_2 reductions that could be achievable through a physical absorption AGR method are too costly and represent an economic burden for consumers.

The IGCC Power Station's emission rates are extremely low when compared to SO_2 emissions BACT determinations for recent PC units that average 0.25 lb/MMBtu, and the proposed NSPS for PC boilers which requires 2.0 lb/MWh, or approximately 0.21 lb/MMBtu. This is one of the major environmental advantages of IGCC technology. The proposed level of syngas treatment to 50 ppmvd maximum H_2S concentration in the undiluted syngas is, for perspective, significantly below the stringent NSPS Subpart J allowed concentration (160 ppm) for new petroleum refinery combustion devices. The Applicant proposes that cleaning the syngas to 50 ppmvd sulfur content (expressed as H_2S in the undiluted syngas) is BACT for SO_2 and sulfuric acid mist for the CTG/HRSG exhaust. This corresponds to approximately 5 ppm SO_2 and 76 lb SO_2/hr for each CTG exhaust.

5.6.3 Volatile Organic Compound BACT Analysis

VOCs are a product of incomplete combustion of the organic fuel. Reduction of VOC emissions is accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion.

The primary technologies identified for reducing VOC emissions from the CTGs are oxidation catalysts and good combustion controls. A survey of the RBLC database indicates that good combustion control and burning clean gas fuel are the VOC control technologies primarily determined to be BACT. Additionally applicable to the IGCC technology is the fact that it uses a very low VOC fuel, syngas, which when burned yields very low levels of uncombusted VOC emissions.

5.6.3.1 Identify Control Technologies

Three technologies were identified as potentially applicable to the IGCC Power Station's CTGs for control of VOC emissions:

Combustion Process Controls

- IGCC technology (use of low VOC syngas)
- Good Combustion Practices (GCP)

Post Combustion Controls

- Oxidation Catalysts

5.6.3.2 Evaluate Technical Feasibility

Each identified technology is examined to determine if it is technically feasible for IGCC turbines burning syngas.

5.6.3.3 Rank Control Technologies

Combustion of any hydrocarbon material can produce trace levels of uncombusted VOCs. Combustion of fuels with very low hydrocarbon content can lower these VOC emissions. The very nature of the IGCC process leads to unusually low levels of organic emissions from syngas combustion.

The gasification process involves feeding a slurry of carbon-containing materials into a heated and pressurized chamber (the gasifier) along with a controlled and limited amount of oxygen. At the extremely high operating temperatures and pressures in the gasifier, chemical bonds are broken by oxidation and steam at temperatures sufficiently high to promote very rapid reactions. The various constituents that are in the feedstock are broken down into their fundamental elements in the gasifier, and are reformed into the syngas composed primarily of diatomic hydrogen (H_2) and CO gas. Very few hydrocarbons are left unreacted. The VOC content of the clean syngas is estimated to contain less than 0.1% VOC (this is the concentration of VOCs before being burned in the CTG). These compounds are efficiently burned in the CTG to create

water (H_2O) and carbon dioxide (CO_2). Emissions of VOCs are expected to be a small fraction of the level that would be emitted from conventional gas-fired CTGs.

5.6.3.3.1 Good Combustion Practices

Good combustion practices (GCPs) applied to the proposed sources can achieve VOC emission levels of 2.4 ppmvd (at 15 percent O_2) as reflected in current supplier quotations. GCPs include operational and design elements to control the amount and distribution of excess air in the flue gas to ensure that there is sufficient oxygen present for complete combustion. This is the technology option used as BACT for all other recent IGCC permits.

5.6.3.3.2 Oxidation Catalyst

Catalytic oxidation is a post-combustion technology where the products of combustion are introduced to a catalytic bed at the appropriate temperature point in the HRSG. The catalyst promotes the oxidation of VOC. The catalyst beds that reduce CO can also be effective in reducing VOC emissions. However, such systems typically achieve a maximum efficiency of 50 percent. Oxidation catalyst vendors declined to quote a system due to the presence of low sulfur levels in the exhaust as further described in the CO BACT evaluation. Oxidation catalysts have never been used on coal-based combustion systems. For these reasons, catalytic oxidation is not considered a practical or feasible technology for this IGCC application.

It is also worth noting that a typical additional incentive, when feasible, to using an oxidation catalyst is the incidental control of organic HAPs. For example, uncontrolled formaldehyde (CHOH) emissions can be fairly significant from conventional combustion of natural gas (CH_4). However, since syngas contains primarily H_2 and CO with less than 0.1% VOCs, uncontrolled emissions of formaldehyde, or other organic HAP emissions, are significantly less. For this reason, an oxidation catalyst, even if feasible, would provide less benefit for a syngas-fired CTG versus a natural gas-fired CTG.

5.6.3.4 Evaluate Control Options

Catalytic oxidation is an infeasible method of controlling VOC emissions from the proposed CTGs. The only feasible alternatives are use of low VOC fuel and GCPs.

5.6.3.5 Select Control Technologies

The recommended control of VOC emissions from each of the proposed turbines is use of the IGCC process (low VOC fuel) and GCPs at the CTG. These practices will meet a VOC emission limit of 9 lb/hr/CTG while operating under steady state conditions and firing syngas. The Applicant concludes that VOC BACT is 9 lb/hr/CTG using these practices.

5.6.4 Carbon Monoxide BACT Analysis

CO is a product resulting from incomplete combustion. Control of CO is typically accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. These control factors, however, can also tend to result in increased emissions of NO_x. Conversely, a lower NO_x emission rate achieved through flame temperature

control (by diluent injection or dry lean pre-mix) can sometimes result in higher levels of CO emissions. Thus, a balancing of these conditions is necessary so that the flame temperature reduction is set to achieve the lowest NO_x emission rate possible while keeping CO emissions to an acceptable level.

CO emissions from CTGs are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. Possible post-combustion control involves the use of catalytic oxidation while front-end control involves controlling the combustion process to suppress CO formation.

5.6.4.1 *Identify Control Technologies*

Three technologies were identified as potentially applicable to the IGCC Power Station's CTGs for control of CO emissions:

Combustion Process Controls

- GCPs

Post Combustion Controls

- $SCONO_x$™
- Oxidation Catalyst

5.6.4.2 *Evaluate Technical Feasibility*

Each identified technology is examined to determine if it is technically feasible for IGCC CTGs burning syngas.

5.6.4.2.1 SCONOx™ System

The $SCONO_x$™ system was described in the BACT analysis for NO_x. It is commercially available for small frame CTGs for controlling CO and can reduce emissions by up to 95 percent. However, it is not commercially available for large frame turbines (like those to be used for Mesaba One and Mesaba Two) for the same reasons set forth in the NO_x BACT discussion. Therefore, $SCONO_x$™ is considered to be technically infeasible for the IGCC Power Station.

5.6.4.2.2 Oxidation Catalysts

Oxidation catalysts are a post-combustion technology which do not rely on the introduction of additional chemicals, such as NH_3 with SCR, for a reaction to occur. They have occasionally been permitted for use in CTG applications when natural gas fuel is used. The oxidation of CO to CO_2 utilizes excess air present in the CTG exhaust and the activation energy required for the reaction to proceed is lowered in the presence of a catalyst. Products of combustion are introduced into a catalytic bed, with the optimum temperature range for these systems being between 700°F and 1,100°F. At higher temperatures, catalyst sintering may occur, potentially

causing permanent damage to the catalyst. The addition of a catalyst bed onto the turbine exhaust will create a pressure drop, resulting in back pressure to the turbine. This has the effect of reducing the efficiency of the CTG and power generating capabilities.

By placing the catalyst at a selected position within the HRSG, the temperature can fall within the parameters appropriate for CO catalytic oxidation. However, the applicant believes that the same feasibility issues described in the NO_x SCR catalyst will exist with a CO oxidation catalyst.

Additionally, as previously mentioned, an additional potential incentive to using a CO oxidation catalyst would be the incidental control of VOC and organic HAPs. However, as discussed in the VOC BACT section, because syngas has a very low VOC content, the uncontrolled emissions of VOC and organic HAPs from a syngas-fired CTG are already much lower than conventional CTG exhausts.

5.6.4.2.3 Combustion Control

GCPs include operational and boiler design elements to control the amount and distribution of excess air in the flue gas to ensure that there is sufficient oxygen present for complete combustion. Such control practices applied to the proposed CTGs can achieve CO emission levels of 15 ppm during steady state, full load operation. It should be noted that at lower loads (<50-70%), CTG combustion efficiency drops off notably, and resulting CO emissions would be higher. However, since the proposed IGCC Power Station will operate above this minimum load except during startup and shutdown, low load conditions are not appropriate as the basis of the BACT analysis.

GCPs are a technically feasible method of controlling CO emissions from the proposed CTGs.

5.6.4.3 *Rank Control Technologies*

The only technically feasible CO control technology is GCPs as presented in Table 5.6-4.

Table 5.6-4
Ranking Of CO Control Technologies

Control Technology	Removal Efficiency Range (%)	Controlled Emission Level (ppm)
GCPs	Not Applicable (baseline)	15

5.6.4.4 *Evaluate Control Options*

GCP is considered the baseline and only feasible control technology. Additionally, it has been selected as BACT for all other recent IGCC permits.

5.6.4.5 *Select Control Technologies*

GCPs is the only technology that is both technically and economically feasible at this time. the Applicant concludes that CO BACT is 15 ppmvd @ 15 percent O_2 (loads > 50-70%) using GCPs.

5.6.5 Particulate Matter BACT Analysis

Particulate matter emissions from natural gas-fired combustion sources consist of inert contaminants in natural gas, sulfates from fuel sulfur, dust drawn in from the ambient air that passes through the CTG inlet air filters, and particles of carbon and hydrocarbons resulting from incomplete combustion. Generating units firing fuels with low ash content and high combustion efficiency exhibit correspondingly low particulate matter emissions. Clean gaseous fuel, such as syngas, will also be low emitting. The hot raw syngas exiting the gasifier is cooled and sent to a filter system for particulate matter removal prior to other gas treatment systems such as scrubbing and AGR. This filter system contains a hot gas cyclone and a particulate matter filter that uses numerous porous filter elements to remove PM/PM_{10}, and is expected to achieve 99.9% removal efficiency.

The EPA has indicated that particulate matter control devices are not typically installed on CTGs and that the cost of installing a particulate matter control device is prohibitive (EPA, September 1977). When the NSPS for Stationary Gas Turbines (40 C.F.R. 60 Subpart GG) was promulgated in 1979, the EPA indicated that, "Particulate emissions from stationary gas turbines are minimal." Therefore, performance standards for particulate matter control of stationary gas turbines were not proposed or promulgated.

Post combustion controls, such as electrostatic precipitators (ESPs) or baghouses, have never been applied to commercial gas-based CTGs. Therefore, the use of ESPs and baghouses is considered technically infeasible, and does not represent feasible control technology.

In the absence of add-on controls, the most effective control method demonstrated for CTGs is the use of low ash fuel, such as natural gas or syngas. This was confirmed by a survey of the RBLC database which showed no add-on PM/PM_{10} control technologies for combined-cycle CTG units. Proper combustion control and the firing of fuels with negligible or zero ash content (such as natural gas or syngas) is the predominant control method listed.

The use of clean syngas fuel and good combustion control is concluded to represent BACT for PM/PM_{10} control in the proposed turbines. These operational controls will limit PM/PM_{10} emissions to approximately 25 lb/hr per CTG when operating on syngas.

5.7 Tank Vent Boiler Control Technology Review

The tank vent boiler (TVB) is a combustion device that has a nominal 65 MMBtu/hr firing capacity. It will combust streams from various in-process storage tanks that may contain small amounts of sulfur, creating potential SO_2 emissions. Additionally, the process streams may contain other components similar to syngas, creating a unique fuel stream that is unlike any found for permitted combustors in the RBLC database. For this reason, pollutant emissions are

addressed on an individual basis and compared to existing facilities where appropriate. The combustor emissions are largely dependent on burner specifications for this unique fuel.

5.7.1 Nitrogen Oxides BACT Analysis

In order to achieve adequate destruction efficiencies, the TVB requires a relatively high combustion flame temperature and residence time, both of which are fundamentally incompatible with low NO_x burner technology. Dry low NO_x burners are considered technically infeasible for this reason.

SCR is not an economically feasible control option for installation on a 65 MMBtu/hr boiler. Using SCR cost data in a 2001 EPA report regarding BACT for oil refinery gas-fired heaters (US EPA Report "Petroleum Refinery Tier 2 BACT Analysis Report, Final Report," January 16, 2001, prepared by ERG, Morrisville NC), the applicant conservatively estimates that an SCR system for this small source, even if technically feasible, would have annualized costs of over $75,000/yr. Even if it controlled 80% of the NO_x (to 7 ppmvd @ 3% O_2), the cost-effectiveness would be greater than $13,000/ton of NO_x controlled, which is deemed to be prohibitively expensive.

Burner design is specified by the vendor to accommodate this unique process fuel stream. No add-on combustion controls are technically feasible. BACT for this unique application is proposed at 0.3 lb NO_x/MMBtu.

5.7.2 Sulfur Dioxide BACT Analysis

For the same reasons given for the CTG exhaust in Section 5.5.2, applicant proposes that cleaning the synthesis gas to 50 ppmvd sulfur content (expressed as H_2S in the undiluted syngas) is BACT for SO_2 for the tank vent boiler exhaust.

5.7.3 Volatile Organic Compound BACT Analysis

VOCs are a product of incomplete combustion in the tank vent boiler. Recent BACT determinations for facilities permitted in Minnesota with small (< 100 MMBtu/hr) natural gas- or fuel oil-fired boilers had the requirements listed in Table 5.7-1.

Table 5.7-1
Recent VOC BACT Requirements for Comparable Minnesota Facilities

Facility	Fuel Fired	Capacity (MMBtu/hr)	VOC BACT Limit lb/MMBtu	Control Requirement
Fairbault Energy Park (7/15/2004)	Natural Gas	40	0.006	Good combustion
Fairbault Energy Park (7/15/2004)	#2 Fuel Oil	40	0.003	Good combustion
Mankato Energy Center (9/29/2004)	Natural Gas	70	0.007	Good combustion

VOC emissions from the tank vent boiler will be minimized by utilizing good combustion practices (GCPs) and achieving high combustion efficiency. BACT for VOC is proposed at 0.004 lb/MMBtu through the use of GCPs.

5.7.4 Carbon Monoxide BACT Analysis

Recent BACT determinations for facilities permitted in Minnesota with small (< 100 MMBtu/hr) natural gas- or fuel oil-fired boilers had the requirements listed in Table 5.7-2.

Table 5.7-2
Recent CO BACT Requirements for Comparable Minnesota Facilities

Facility	Fuel Fired	Capacity (MMBtu/hr)	CO BACT Limit lb/MMBtu	Control Requirement
Fairbault Energy Park (7/15/2004)	Natural Gas	40	0.084	Good combustion
Fairbault Energy Park (7/15/2004)	#2 Fuel Oil	40	0.036	Good combustion
Mankato Energy Center (9/29/2004)	Natural Gas	70	0.06	Good combustion

CO emissions from the tank vent boiler will be minimized by utilizing GCPs and achieving a high combustion efficiency. BACT for CO for the unique application within which the TVB is used is proposed at 0.09 lb/MMBtu through the use of GCPs.

5.7.5 Particulate Matter BACT Analysis

Recent BACT determinations for natural gas- or fule oil-fired boilers similar in size to the TVB permitted in Minnesota had the requirements listed in Table 5.7-3.

Table 5.7-3
Recent PM BACT Requirements for Comparable Minnesota Facilities

Facility	Fuel Fired	Capacity (MMBtu/hr)	PM BACT Limit lb/MMBtu	Control Requirement
Fairbault Energy Park (7/15/2004)	Natural Gas	40	0.008	Clean fuel and good combustion
Fairbault Energy Park (7/15/2004)	#2 Fuel Oil	40	.024	Clean fuel and good combustion
Mankato Energy Center (9/29/2004)	Natural Gas	70	0.008	Clean fuels

PM/PM_{10} emissions from the tank vent boiler will be minimized by utilizing GCPs and firing inherently low ash fuels. BACT for PM/PM_{10} is proposed at 0.01 lb/MMBtu through the use of GCPs.

5.8 Flare Control Technology Review

Venting to the flare will occur during startup or short-term combustion turbine outages. The gasifier system can be shut down rapidly through removal of slurry and oxygen injection, which provides isolation of the gasifier. This will avoid a flare or vent release of raw, untreated syngas. Therefore, potential emissions are estimated to be negligible.

5.8.1 Nitrogen Oxides BACT Analysis

The majority of BACT determinations in the RBLC database (see Appendix EI) show no controls required with emissions at or below 0.064 lb/MMBtu, the proposed NO_x emission rate. Good flare design is considered BACT for this level of emissions.

5.8.2 Sulfur Dioxide and Sulfuric Acid Mist BACT Analysis

SO_2 emissions are minimized from the pilot flame by the use of clean natural gas as the pilot. In addition, syngas sent to the flare during plant startup events will be treated in the AGR system, significantly reducing emissions. Given the negligible emissions, no control technologies are deemed to be cost effective.

5.8.3 Volatile Organic Compound, Carbon Monoxide, and Particulate BACT Analysis

As a product of combustion, CO and VOC will be emitted from the flare. Good flare design and GCPs will limit these CO emissions. Given minimal emissions, no control technologies are deemed to be cost effective.

5.9 Fugitive Equipment Leak Technology Review

Potential control methods for fugitive equipment leaks include typical "good work practices" (GWPs) where leaks are repaired soon after discovery and piping and equipment are maintained in good condition pursuant to an established Leak Detection and Repair (LDAR) program consisting of a structured program of inspection, monitoring, and repair. An LDAR program would be the top control alternative.

IGCC facilities do not have any permitted requirements for fugitive equipment leaks of VOC emissions because of the very low VOC levels in the process streams. Similarly, applicant proposes that GWPs are BACT for minimizing VOC emissions from fugitive equipment leaks.

5.10 Material Handling Technology Review

Mesaba One and Mesaba Two will employ multiple material handling activities for coal, petroleum coke, flux, and slag (see Section 4.1.5). These activities are similar to those found at facilities with coal-fired boilers. The types of activities and proposed BACT control technologies are summarized in the Table 5.10-1.

Table 5.10-1
IGCC Power Station Proposed BACT Activities

IGCC Power Station Facility	Processing Activity	BACT Control Technology	% Reduction
Coal Handling and Storage	Railcar Unloading	Partial Enclosure/ dust suppression	75
	Unloading hopper to Unloading Conveyor	Full Enclosure/ dust suppression	95
	Unloading conveyor to Cross-conveyor	Full Enclosure/ dust suppression	95
	Cross-conveyor to Stacker Conveyor	Full Enclosure/ dust suppression	95
	Stacker Conveyor to Stacker	Full Enclosure/ dust suppression	95
	Stacker to Coal Pile	Dust suppression/ adjustable stacker	50
	Reclaimer to Reclaim Conveyor	Partial Enclosure/ dust suppression	75
	Reclaim Conveyor to Main Conveyor	Full Enclosure/ dust suppression	95
	Main Conveyor to Incline Conveyor	Full Enclosure/ dust suppression	95
	Incline Conveyor to Tripper Conveyor	Full Enclosure/ dust suppression	95
	Tripper Conveyor to Feed Bin	Full Enclosure/ baghouse	99
	Windage from Coal Storage	None	0
Coal Slurry Facility Sources	Feed Bin to Weigh Belt Feeder	Full Enclosure/ dust suppression	95
	Weigh Belt Feeder to Rod Mill Feed Chute	Full Enclosure/ dust suppression	95
Slag Transport and Storage	Slag Disposal Truck Traffic	Dust suppression	80
	Slag Storage Load-in	Wet slag	100
	Windage from Slag Storage	None	0
	Slag Storage Load-out	None	0

Material handling of various raw materials and byproducts creates fugitive particulate emissions. Fugitive dust emissions may be controlled by one of the following methods (Source: EPA 450/3-81-005b (September 1982), Environmental Progress (February 1984)):

- Total enclosure with ventilation to a fabric filter
- A partial enclosure
- A water spray system
- A wet suppression system using water and chemical wetting agents

In general, BACT for material handling activities such as those at the Mesaba Plant consists of applying one of the control measures above at least at the partial enclosure, or 70% control, level. The 'stacker to coal pile' coal handling activity is a unique activity that uses partial containment at a 50% reduction. This is the most appropriate control technology for this activity.

Those activities that do not have any proposed additional control measures have potential (uncontrolled) emissions less than 0.5 tons TSP per year. Additional control measures applied to such small emitters would not be cost effective. Total proposed (controlled) emissions are less than 5 tons TSP and less than 2 TPY PM_{10} per year for all material handling activities for Phase I of the project. Phase II will be comprised of the same activities and same proposed controls, with the same total emissions as Phase I.

5.11 Cooling Tower Technology Review

Dissolved solids are emitted from the cooling towers in fine droplets of water entrained (carried) with the high air flows in the tower needed for the evaporative cooling process (commonly referred to as cooling tower drift). These droplets often fall very close to the tower. The cooling towers for the IGCC Power Station would employ high efficiency mist eliminators that will minimize drift from the cooling towers. The design drift rate will be less than 0.001% of the circulating cooling water flow. This design parameter along with the estimated emission rate meets or exceeds the majority of BACT determinations for cooling towers in the EPA RBLC database records (see Appendix EI for the last five years of RBLC determinations) as well as for similar recently permitted Minnesota facilities. Therefore, this technology represents BACT for cooling towers to minimize particulate matter emissions through minimizing drift rates.

5.12 Diesel Engine Technology Review

The fire water pump and emergency generators will be run by diesel engines and will be a source of emissions from combustion due to firing diesel fuel oil. Fire water pump operation will be voluntarily limited to 100 hours per year per engine. According to the EPA's draft Alternative Control Techniques (ACT) Document NO_x Emissions from Reciprocating Internal Combustion Engines (EPA-453/R-93-032, 1996) and the RBLC database records for BACT determinations of diesel engines for the years 2000 – 2005, there are no add-on controls that provide cost effective reductions. BACT for all criteria pollutants is represented by GCPs, limited hours of operation, and the use of low sulfur diesel fuel.

5.13 Auxiliary Boiler Technology Review

The natural gas-fired auxiliary boiler will be rated at approximately 130 MMBtu/hr and will only operate when there is not steam available from the gasifiers or HRSGs. It is therefore expected to operate less than 25% of maximum capacity each year. Natural gas will be the only fuel used, and emissions of NO_x, CO, SO_2, PM_{10}, and VOC will be generated.

The RBLC database pertaining to large (>100 MMBtu/hr) natural gas-fired boilers was reviewed for potential control technologies, and indicates that low-NO_x burners have been the most prevalent control applied over the past five years. Table 5.13-1 below summarizes the requirements of five similar facilities having natural gas-fired auxiliary boilers with throughputs of approximately 130 MMBtu/hr.

Table 5.13-1
Recent BACT Requirements for Comparable Facilities

Facility	Fuel Fired	Capacity (MMBtu/hr)	BACT Limit (lb/MMBtu)					Control Requirement
			NO_x	CO	PM_{10}	SO_2	VOC	
Rebud Power Plant (October 2002- OK)	Natural Gas	120	0.049	0.082	0.007	6E-04	0.005	GCP, Low NO_x Burners
Tenaska Arkensas Partners, LP (October 2001- AR)	Natural Gas	122	0.040	0.110	0.005	0.006	0.004	GCP, FGR, Fuel Specification: NG
Rocky Mountain Energy Center, LLC (September 2003- CO)	Natural Gas	129	0.038	0.039				GCP, Low NO_x burners. Limited hours of operation
PSEG Lawrenceburg Energy Facility (December 2002- IN)	Natural Gas	124.6	0.036	0.082	0.928	0.006	0.0054	GCP, Low NO_x burners, Fuel Specification: NG
AES Red Oak LLC (November 2003- NJ)	Natural Gas	120	0.036					GCP, Fuel Specification: NG, Limited hours of operation

Based on a review of similar natural-gas fired boilers, the only control technology determined to be technically feasible and commercially available for an IGCC application of auxiliary boilers was the use of combustion controls. Combustion controls will ensure essentially complete combustion, and minimize emissions of NO_x, CO, and VOC. Use of only natural gas as a fuel will minimize emissions of PM and SO_2.

BACT proposed for the IGCC auxiliary boiler is therefore proposed as:

- Exclusive use of natural gas as the fuel type
- Low NO_x Burners
- Good combustion practices

6. PHYSICAL, METEOROLOGICAL, AND AIR QUALITY CHARACTERISTICS OF THE IGCC POWER STATION FOOTPRINT AND BUFFER LAND

6.1 Land Use and Topography

The IGCC Power Station Footprint and Buffer Land includes approximately 1,260 acres of mostly undeveloped property. The land cover on and adjacent to the IGCC Power Station Footprint and Buffer Land include forest lands consisting of coniferous forest, mixed wood forest and regeneration/young forests; wetland areas; and scattered areas of grassland. Portions of the Site are presently used for timber production. Two high voltage transmission line corridors intersect within the Site boundary facilitating use by local sport enthusiasts for hunting or all terrain vehicle touring.

Regionally, the same land cover and land uses are prevalent where neither open pit mines nor rural residences are located. The northern boundary of the City of Taconite is located 1300 feet south of the IGCC Power Station Footprint and Buffer Land with the density of residential development around the Site being low. Residential developments nearby include rural homes located off County Road 7 west of the IGCC Power Station Footprint and Buffer Land and off the heavy haul road located to the south. About a dozen residents use the heavy haul road to access their lots located on the northern and western shores of Big Diamond Lake and on the southeast shore of Dunning Lake. Figures 6.3-1 and 6.3-2 are detailed maps showing existing zoning/land use and land cover in the area immediately surrounding the IGCC Power Station Footprint and Buffer Land.

The dominant geographic feature on the IGCC Power Station Footprint is a hill that rises approximately 60 feet east-northeast above the 1425-foot elevation at which the IGCC Power Station's HRSGs will be located. Surrounding topography is generally hilly. Figure 6.3-3 shows the shows ground elevations of the land surrounding the IGCC Power Station Footprint.

6.2 Climatology and Meteorology

Northern Minnesota has a continental-type climate and is subject to frequent outbreaks of continental polar air throughout the year, with occasional Arctic outbreaks during the cold season. Occasional periods of prolonged heat occur during summer, particularly in the southern portion of the State when warm air pushes northward from the Gulf of Mexico and the southwestern United States.

6.3 Background Air Quality

The state of Minnesota uses ambient air monitoring stations to define the air quality of a particular region. Concentrations measured at the monitors are compared to Federal and/or state ambient air quality standards. Monitoring results from the closest monitors to Itasca County are shown in Table 6.3-1. The table includes the average ambient air concentrations over the past three years (2002-2005) for each pollutant and averaging period.

Figure 6.3-1. Land Use/Zoning Within the Immediate Vicinity of the West Range IGCC Power Station

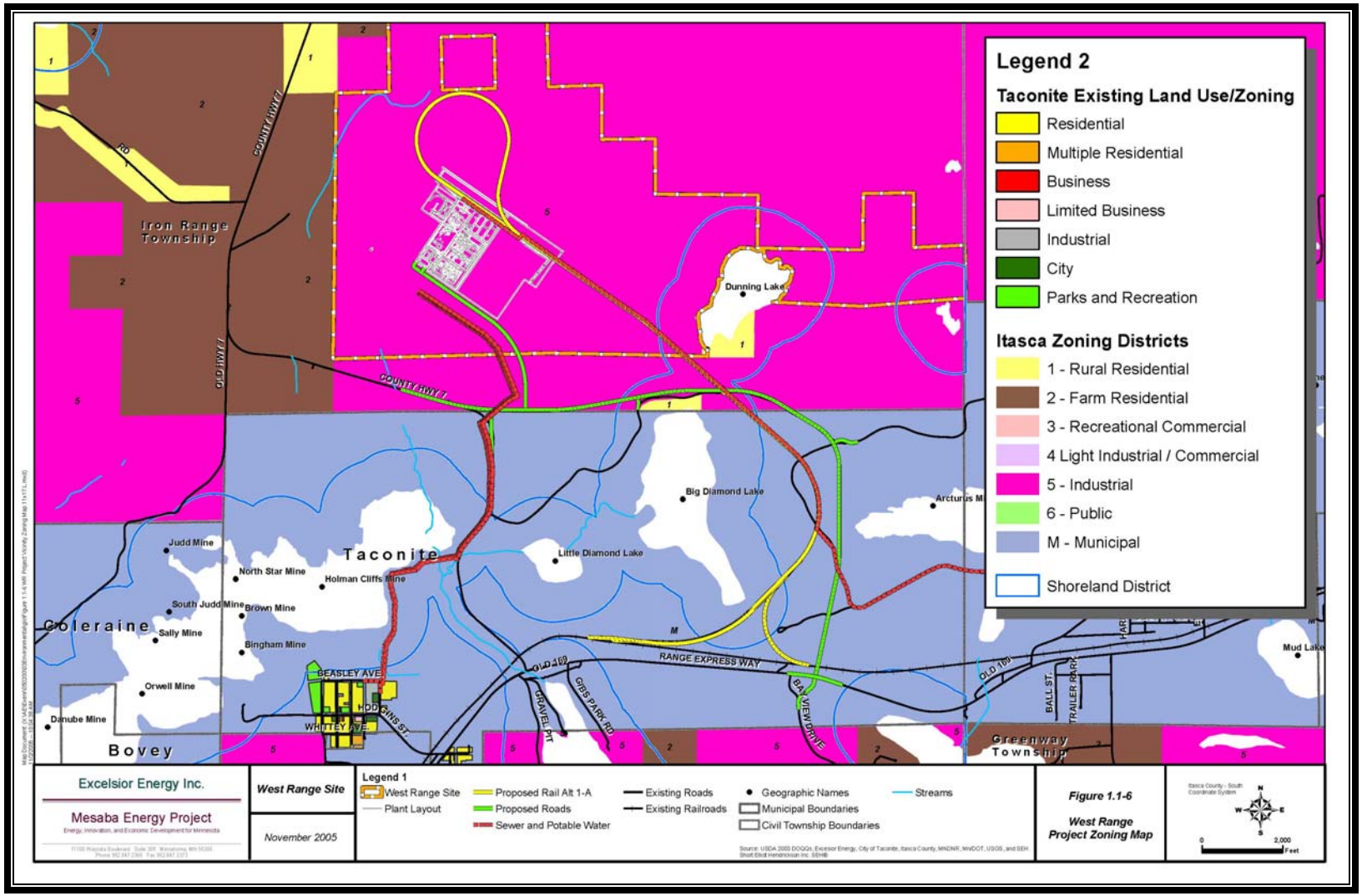


Figure 6.3-2. Land Use and Land Cover Within the Immediate Vicinity of the West Range Site

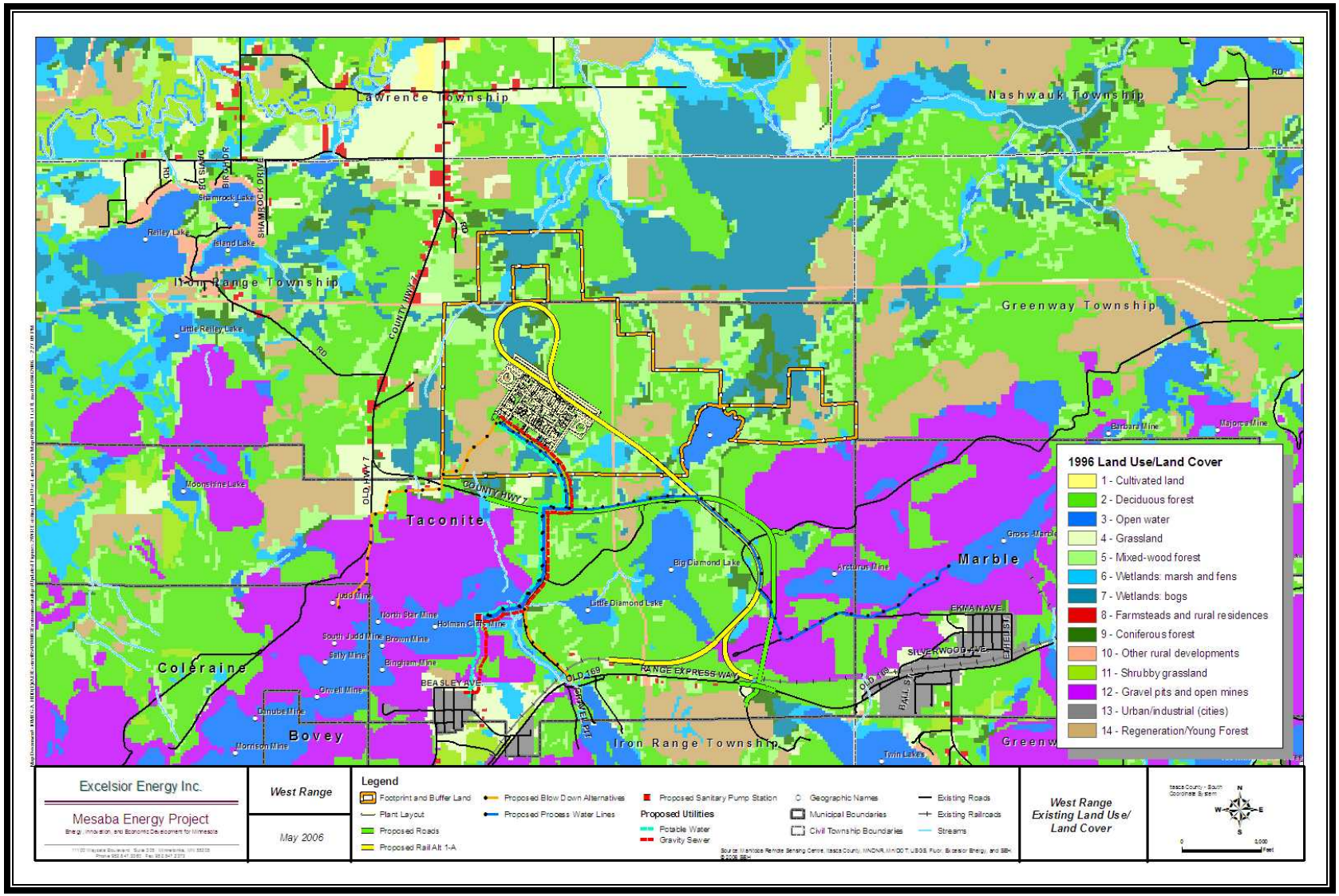


Figure 6.3-3. Topography of the IGCC Power Station Footprint and Buffer Land

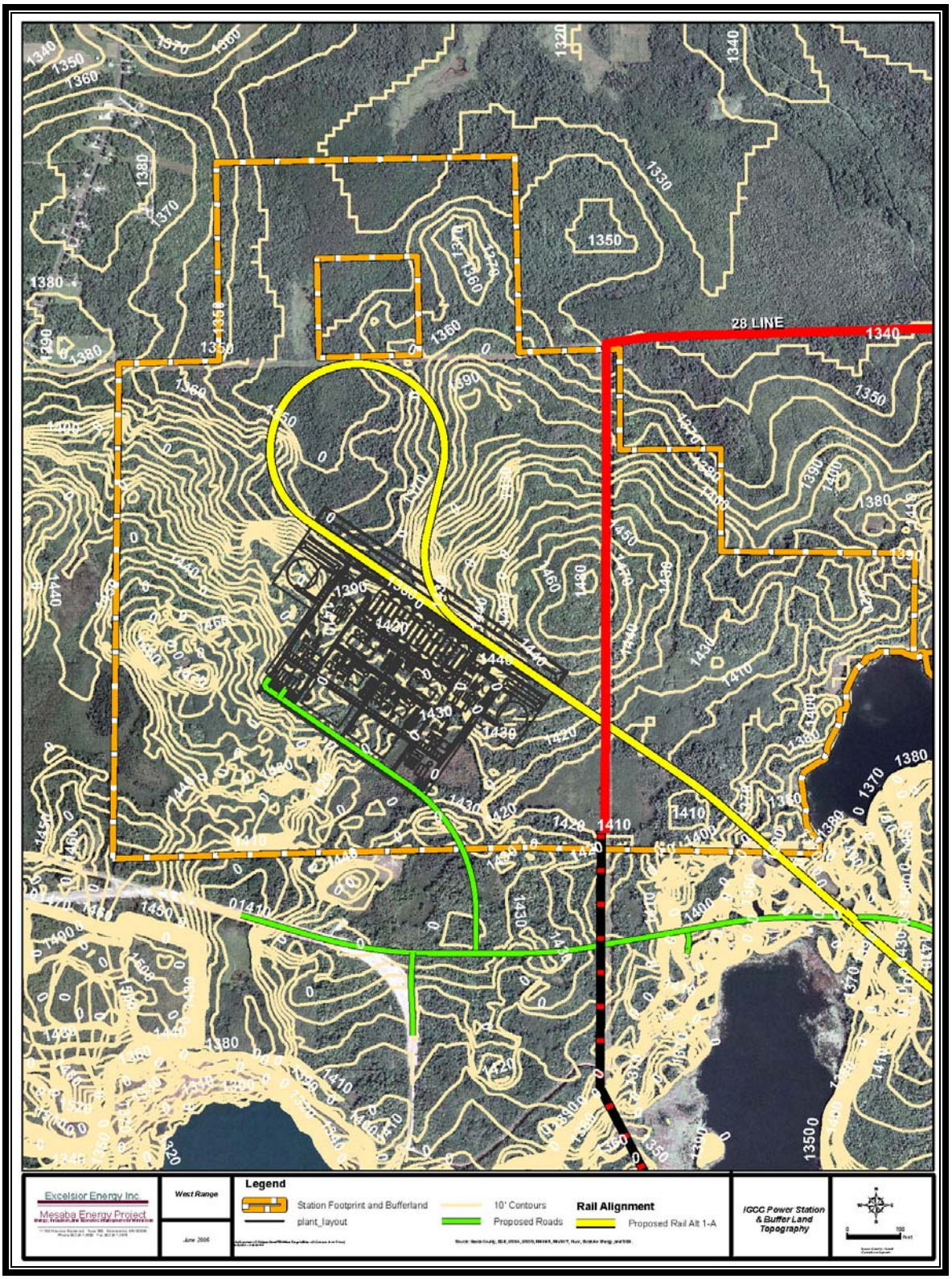


Table 6.3-1
Monitored Background Concentrations

Pollutant	Averaging Period	Monitored Background Concentration	Monitoring Station
Carbon Monoxide	8-Hour	1.6 ppm	314 West Superior Street, Duluth
	1-Hour	3.3 ppm	314 West Superior Street, Duluth
Nitrogen Dioxide	Annual	0.004 ppm	Carlton County
Ozone	8-Hour	0.066 ppm	Voyageurs National Park
Lead	Quarterly	0.01 µg/m3	Virginia City Hall
Total Suspended Particulate (TSP)	Annual	16 µg/m3	Virginia City Hall
	24-Hour	35.7 µg/m3	Virginia City Hall
PM10	Annual	16 µg/m3	Virginia City Hall
	24-Hour	35.7 µg/m3	Virginia City Hall
$PM_{2.5}$	Annual	6.1 µg/m3	Virginia City Hall
	24-Hour	19 µg/m3	Virginia City Hall
Sulfur Dioxide (SO2)	Annual	0.001 ppm	Rosemount, MN
	24-Hour	0.005 ppm	Rosemount, MN
	3-Hour	0.010 ppm	Rosemount, MN
	1-Hour	0.019 ppm	Rosemount, MN

7. AIR QUALITY IMPACT ASSESSMENT

7.1 Modeling Approach

Initial air quality modeling addressed the individual point sources for Mesaba One and Mesaba Two (four CTG stacks, two tank vent boiler (TVB) stacks, two auxiliary boilers, and two flare stacks) as well as all fugitive PM_{10} sources. The modeling was conducted to determine which pollutants will have significant ambient air impacts, and the significant impact area ("SIA") for each pollutant. Applicable significant impact levels are shown in Table 7.1-1.

Modeling was conducted for each pollutant (SO_2, NO_x, CO, PM_{10}), each applicable averaging time, and each emission scenario identified in Section 4.0. The SIA was determined for those pollutants which are shown to have a significant impact in ambient air at any point. The SIA was defined for each pollutant as a circle, centered on the plant site, with a radius equal to the greatest distance to a significant impact for any applicable averaging time or emission scenario.

If any pollutant did not have a significant impact, no further modeling was necessary. For all other pollutants, additional modeling was carried out to evaluate compliance with PSD increments and NAAQS.

PSD increment analyses were implemented for SO_2, NO_2, and PM10. Allowable increments are listed in Table 7.1-1. Source input for increment modeling included all point sources associated with Mesaba One and Mesaba Two and all regional increment-consuming sources included in the emissions inventory provided by the MPCA.

NAAQS analyses were conducted for SO_2, NO_2, PM_{10}, and CO. Applicable NAAQS are given in Table 7.1-1. In addition to those sources included in the increment analysis, additional nearby sources (provided by MPCA) were added to the source inventory. Regional source impacts were included (for worst-case modeled impact times and receptors) by modeling the "FARDATA" emission inventory appropriate to the vicinity of the West Range Site as provided by MPCA modeling staff. For comparison to the NAAQS, a background concentration representing natural or pristine background plus one significant impact level ("SIL") was added to all model-predicted concentrations.

In addition to the modeling analyses described above, model results were applied to address other PSD requirements: the potential need for pre-construction monitoring and additional impact analyses relating to growth, soils and vegetation, visibility impairment, and deposition.

Table 7.1-1
Applicable Air Quality Standards, Increments and SILs for Mesaba One and Mesaba Two*

Pollutant	Averaging Time	NAAQS ($\mu g/m^3$)	PSD Class II Increment ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)
SO_2	One-Hour	1300	512	25
	Three-Hour	915	512	25
	24-Hour	365	91	5
	Annual	60	20	1
NO_2	Annual	100	25	1
PM10	24-Hour	150	30	5
	Annual	50	17	1
CO	One-Hour	40,000	NA	2000
	Eight-Hour	10,000	NA	500

* There are also criteria pollutant NAAQS for ozone (0_3) and Lead. 0_3 modeling is not normally appropriate for PSD application analyses. Lead emissions will be less than the PSD Significant Emission Rate.

7.2 Modeled Emission Rates

Table 7.2-1 shows estimated annual emissions of criteria pollutants for each of the two phases associated with Mesaba One and Mesaba Two. Based upon these data, Mesaba One and Mesaba Two will be a major stationary source to be located in a PSD area, and will therefore be subject to PSD new source review permitting requirements for each of the pollutants shown. Air quality modeling demonstrations of compliance with PSD increments is also required for SO_2, NO_2, and PM_{10}, and a demonstration of compliance with Minnesota/National Ambient Air Quality Standards (NAAQS) is required for SO_2, NO_2, PM_{10}, and CO.

Tables 7.2-2, 7.2-3, and 7.2-4 present maximum expected point source criteria pollutant emission rates from each phase of Mesaba One and Mesaba Two for different averaging times and operating scenarios. All emission rates are taken directly from the specifications presented in Section 4. The emission rates shown, along with the stack parameters in Table 7.2-5, were used as model input for the air modeling analyses.

The data presented in Table 7.2-2 represent emissions during normal operation of Mesaba One and Mesaba Two. These emission rates were modeled as the "base case" to define the expected air quality impacts of the power station.

Emission rates and stack gas conditions for short-term averaging times can be different from those shown in Table 7.2-2 during non-steady-state operating scenarios such as startup and flaring of syngas. To address these short-term conditions, air modeling was also carried out for applicable averaging times (24 hours and less) using the emission rates given in Tables 7.2-3 and 7.2-4. The emission rates represent worst-case maximum emissions for each scenario. The applicable stack parameters are also shown in Table 7.2-5.

Other sources at the IGCC Power Station consist of two emergency fire pumps and two emergency diesel generators per phase. Since these sources will operate for only short time periods when the primary emission sources are not in operation, they were not included in the air modeling analyses. Hours of operation of such facilities will likely be limited by permit conditions. The emissions from periodic testing of these emergency resources are negligible.

Fugitive emissions of PM_{10} will result from the storage and handling of coal and other materials. Annual emissions from these fugitive sources are shown in Table 7.2-2. All fugitive PM_{10} sources were included in the air modeling, as described subsequently in this Application.

Table 7.2-1
Worst-Case Annual Emissions (Tons/year) From Mesaba One and Mesaba Two (Each Phase)

Source	SO_2	NO_x	CO	VOC	PM10
Combustion Turbines (total for two)	666	1386	964	88	220
Tank Vent Boiler	15.8	26.4	7.9	0.4	0.9
Auxiliary Boiler	0.4	5.1	10.5	0.6	0.7
Flare	12.3	13.4	285.9	1.3	1.7
Cooling Towers					19.7
Coal Handling					2.0
Slag Handling					1.0
Coal Slurry Facility					0.2
Total	694.5	1430.9	1268.3	90.3	246.2

Table 7.2-2
Modeling Emission Rates for Normal Operation of Mesaba One and Mesaba Two[(1)] – Each Phase

Source/Averaging Time	SO_2		CO		PM10[(2)]		NO_x	
	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
Combustion Turbines (each of two)								
One-Hour	183	23.06	95	11.97				
Three-Hour	152	19.15						
Eight-Hour			95	11.97				
24-Hour	114	14.36			25	3.15		
Annual	76	9.58			25	3.15	158	19.91
Tank Vent Boiler								
One-Hour	8.4	1.06	5.9	0.74				
Three-Hour	7.5	0.94						
Eight-Hour			5.9	0.74				
24-Hour	6.4	0.81			0.7	0.09		
Annual	3.6	0.45			0.2	0.03	6.0	0.76
Auxiliary Boiler								
One-Hour	0.37	0.05	9.6	1.21				
Three-Hour	0.37	0.05						
Eight-Hour			9.6	1.21				
24-Hour	0.37	0.05			0.65	0.08		
Annual	0.09	0.01			0.16	0.02	1.16	0.15

Table 7.2-2
Modeling Emission Rates for Normal Operation for Mesaba One and Mesaba Two[(1)] – Each Phase Continued

Source/Averaging Time	SO_2		CO		PM10[(2)]		NO_x	
	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
Flare								
One-Hour	0.01	0.001	1.10	0.14				
Three-Hour	0.01	0.001						
Eight-Hour			1.10	0.14				
24-Hour	0.01	0.001			0.02	0.002		
Annual	2.8	0.35			0.38	0.05	3.1	0.39

[(1)]Short-term emissions represent normal plant operation on syngas fuel; annual emissions are worst-case annual operation including flaring, gasifier outages, etc.
[(2)]PM_{10} emissions include filterable and condensable portions.

Table 7.2-3
Modeling Emission Rates for Worst-Case Flaring Scenario for Mesaba One and Mesaba Two-Each Phase

Source/Averaging Time	SO_2		CO		PM_{10}[(1)]		NO_x	
	lb/hr	g/s	lb/hr	g/s	lb/hr	G/s	lb/hr	g/s
Combustion Turbines (each of two)								
One-Hour								
Three-Hour								
Eight-Hour								
24-Hour								
Tank Vent Boiler								
One-Hour								
Three-Hour								
Eight-Hour								
24-Hour								
Auxiliary Boiler								
Flare								
One-Hour	1040	131.04	5680	715.67				
Three-Hour	734	92.48						
Eight-Hour			5345	637.46				
24-Hour	183	23.06			14.1	1.78		

[(1)] PM_{10} emissions include filterable and condensable portions

Table 7.2-4
Modeling Emission Rates for Worst-Case Start-up Operating Scenario – One Phase

Source/Averaging Time	SO_2		CO		PM10[1]		NO_x	
	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
Combustion Turbines								
(each of two)								
One-Hour	183	23.06	2740	345.23				
Three-Hour	152	19.15						
Eight-Hour			541	68.21				
24-Hour	114	14.36			25	3.15		
Tank Vent Boiler								
One-Hour	8.4	1.06	5.9	0.74				
Three-Hour	7.5	0.94						
Eight-Hour			5.9	0.74				
24-Hour	6.4	0.81			0.7	0.09		
Auxiliary Boiler	0.37	0.05	9.6	1.21	0.65	0.08		
Flare								
One-Hour	0.11	0.01	22	2.77				
Three-Hour	0.11	0.01						
Eight-Hour			22	2.77				
24-Hour	0.11	0.01			0.32	0.04		

[1] PM_{10} emissions include filterable and condensable portions
All flare emissions and Combustion Turbine CO emissions represent start-up operation. These rates exceed Normal Operation values. All other emission rates are worst-case Normal Operation values, which are higher than during startup.

Table 7.2-5
Modeling Stack Parameters

Source/Scenario Averaging Time	Stack Height. (m)	Stack Diameter (m)	Gas Temperature (K)	Velocity (m/s)
Combustion Turbines (each)				
Normal Operation	45.72	6.10	394.3	20.08
Startup	45.72	6.10	366.5	11.64
Tank Vent Boiler				
Short-term	64.01	1.83	579.8	8.46
Annual	64.01	1.83	579.8	1.95
Start-up	64.01	1.83	579.8	5.21
Auxiliary Boiler	12.19	1.52	422.1	9.70
Flare[(1)]				
Normal Operation	56.39	0.25	1273.0	20.0
Start-up	56.39	1.11	1273.0	20.0
Flaring: One-Hour	56.39	10.72	1273.0	20.0
Three-Hour	56.39	10.40	1273.0	20.0
Eight-Hour	56.39	10.40	1273.0	20.0
24-Hour	56.39	7.36	1273.0	20.0
Annual	56.39	0.25	1273.0	20.0

[(1)] Flare parameters determined by SCREEN 3 methodology based on total heat release

7.3 Modeling Methodology

7.3.1 Model and Options

The AERMOD air quality model was used with the PRIME building downwash algorithm (Version 04300) for all IGCC Power Station Class II modeling. As MPCA prefers the AERMOD modeling system for this application, and since EPA has now included AERMOD as an approved Guideline model, AERMOD is deemed to be the preferred choice for IGCC Power Station permitting.

AERMOD was used with all regulatory options, and included:

- stack-tip downwash
- elevated terrain effects
- calms processing
- missing data processing
- "upper bound" values for supersquat buildings
- no exponential decay

No wet or dry depletion/deposition was included. The model was set to RURAL dispersion as the terrain/land use within three kilometers of the site is almost totally rural.

7.3.2 Meteorological Data

The MPCA has processed meteorological data suitable for input to AERMOD for many locations in Minnesota. At the Applicant's request, Mr. Dennis Becker provided on July 5, 2005 an AERMET data file (HI475935.ZIP) that was processed specifically for the area including the IGCC Power Station Footprint. The meteorological data are based upon Hibbing, Minnesota hourly surface weather observations for the years 1972 through 1976. These meteorological data were used for all IGCC Power Station modeling with AERMOD.

7.3.3 Building Downwash

Building wake effects on dispersion are accounted for using the PRIME downwash algorithm in AERMOD. Direction-specific building dimensions and related parameters are generated with EPA's BPIP PRIME program.

7.3.4 Receptor Grid

The receptor grid for the IGCC Power Station consists of seven nested Cartesian grids covering a total 441 km^2 area (21 x 21 km) surrounding the plant site. The grid is shown in Figure 7.3-1.

Receptors are located along the IGCC Power Station fence line with a spacing of 10 meters. The inner Cartesian grid, with a spacing of 25 m, covers an approximate 2.5 km^2 area surrounding the plant site. Successive grids at greater distances from the fence line have gradually increasing spacing. The dimensions and spacing of all grids are provided in Table 7.3-1.

Figure 7.3-1. Modeling Receptor Grid and Terrain Elevations (m)

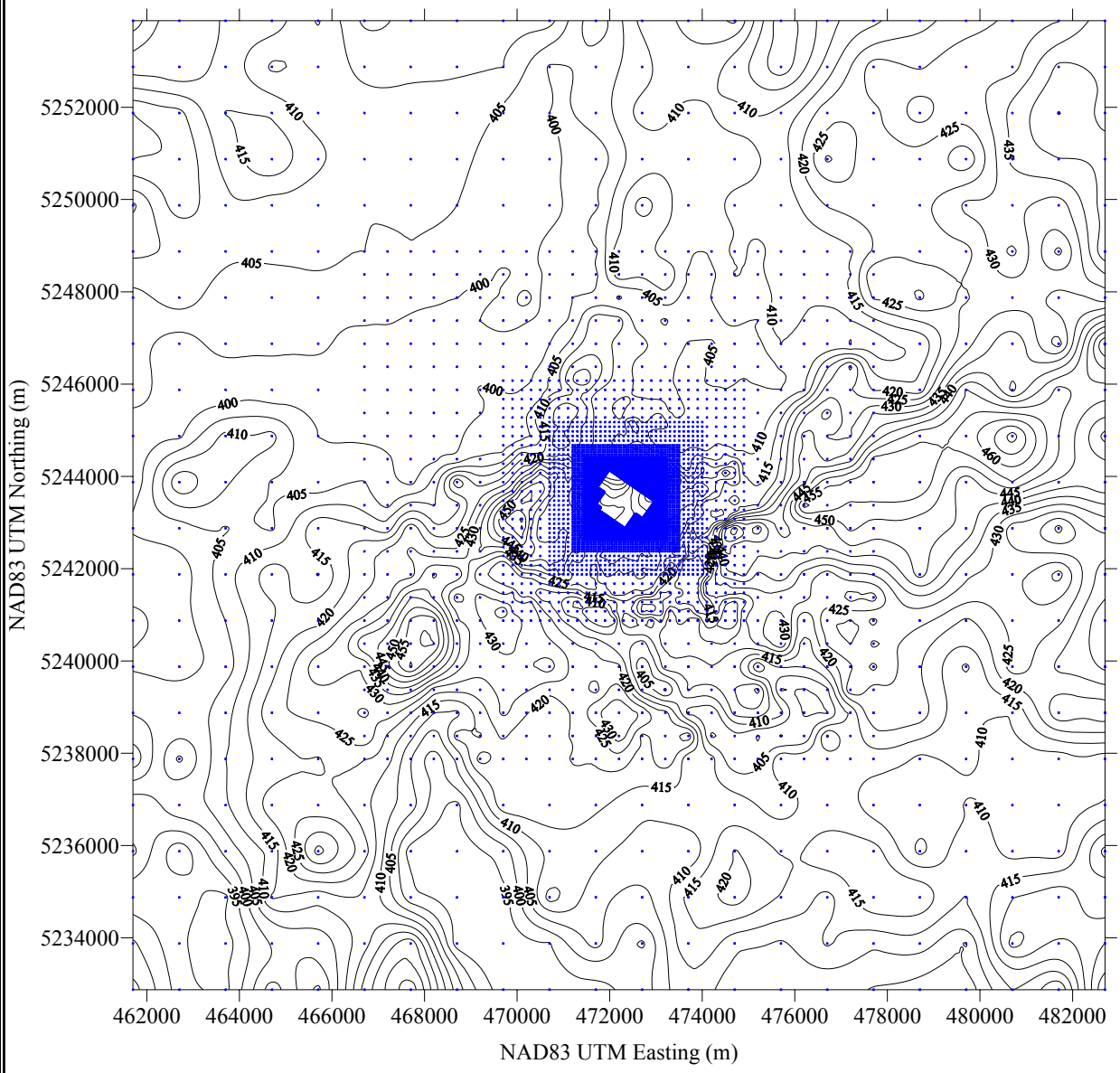


Figure 7.3-1
Modeling Receptor Grid and
Terrain Elevations (m)

McVehil-Monnett Associates, Inc.
Air Quality • Environmental Management

Table 7.3-1
IGCC Power Station Receptor Grids

Grid Level	Level Description	Spacing
1st	IGCC Power Station fence line	10-meter
2nd	2.4 km area around site	25-meter
3rd	0.25-km wide border	50-meter
4th	0.5-km wide border	100-meter
5th	1.0-km border	200-meter
6th	3.0-km border	500-meter
7th	5.0-km wide border	1000-meter

Terrain elevations for all receptors were determined from USGS 7.5 minute DEM data and were processed with AERMAP.

7.3.5 Regional Source Input

A request was submitted to the MPCA for regional source inventories applicable to modeling for the West Range IGCC Power Station. Data were provided by Chris Nelson (8/17/05) that included increment consuming sources, and "nearby" major sources of air pollutant emissions. Increment consuming (and expanding) source emissions were provided for the following:

- Blandin Paper Company/Rapids Energy Center
- Potlatch – Grand Rapids
- Minnesota Power – Clay Boswell

Other nearby source data were provided for:

- Keewatin Taconite
- Minnesota Power – Clay Boswell

The appropriate input data for the above sources were included, along with IGCC Power Station data, for all increment and NAAQS modeling analyses. All increment modeling employed the "two-entry" approach using negative emission rates for emissions on the minor source baseline date and positive emission rates for post-baseline data conditions. Of note, the major emission reduction proposals recently announced by Minnesota Power were not included in the Applicant's modeling, thereby introducing a further degree of conservatism into the resulting emission profiles.

7.4 Background Concentrations

To account for impacts of distant and regional sources, the First-Approximation Run (FAR) data approach developed by D. Becker at MPCA was applied. With this approach, a distant/regional modeling inventory (FARDATA) was included in EVENT model runs for highest impact cases. The FAR data provide an approximation of the date/time specific impacts of all regional sources, which were added to the impacts from the IGCC Power Station and nearby sources. An inventory developed specifically for use within the vicinity of the West Range IGCC Power Station has been provided by the MPCA (FARDATA, C. Nelson, 8/17/05).

For comparison to PSD increments, one significant impact level (SIL) is added to final model-predicted concentrations, in accordance with MPCA guidance. For the NAAQS analyses, one SIL plus a "natural background" concentration was added to total model-predicted concentrations. The following natural background concentrations were utilized and are proposed:

- SO_2 10 µg/m^3 short-term averaging periods
  2 µg/m^3 annual average
- NO_2 5 µg/m^3 annual average
- PM_{10} 20 µg/m^3 24-hour average
  10 µg/m^3 annual average

7.5 Significant Impact Analysis

The Mesaba facility (two phases) was modeled alone to determine the highest predicted concentration for each pollutant, each averaging time, and all operating scenarios. The results of this modeling are summarized in Table 7.5-1

The modeling for each scenario in Table 7.5-1 represents a worst-case emissions scenario. For normal operation, the emissions are included from both phases at 100% capacity for 8760 hours per year. The flaring scenario represents both flares at maximum SO_2 emissions for the applicable averaging times, with no emissions from other plant sources. Only SO_2 and CO impacts of the flares are relevant, since PM_{10} and NO_x emissions for the total facility are far below normal operation values. The startup scenario assumes all combustion turbines in startup mode, with other sources at maximum emission rates for any condition. Startup modeling was limited to CO, since facility-wide emissions of all other pollutants will be less than in normal operation.

Table 7.5-1
Highest Model-Predicted Concentrations For Mesaba One and Mesaba Two (Both Phases) (µg/m^3)

Pollutant and Averaging Time	Normal Operation	Flaring	Startup	SIL
SO_2				
one-hour	130.2	75.8	N/A	25.0
three-hour	77.6	22.8	N/A	25.0
24-hour	31.2	5.4	N/A	5.0
Annual	1.29	N/A	N/A	1.0
PM10				
24-hour	27.9	N/A	N/A	5.0
Annual	1.68	N/A	N/A	1.0
CO				
one-hour	172.2	414.1	3167.5	2000
eight-hour	59.8	122.7	379.0	500
NO_x				

Inspection and review of the data presented in Table 7.5-1 produces the following conclusions:

(1) Impacts are above the applicable SIL for all pollutants and all averaging times except for eight hours for CO.
(2) Impacts are greatest under normal operating conditions, except for CO; highest CO impacts will occur during startup.

Because the highest predicted impacts were significant, increment and NAAQS compliance modeling was necessary for SO_2, PM10, and NO_x. For CO there are no applicable PSD increments, and NAAQS compliance need only be demonstrated for the one-hour ambient standard. The normal operation scenario was addressed in all increment and NAAQS analyses for SO_2, PM10, and NO_x since they represent the highest concentrations. The startup scenario was addressed only for the CO one-hour NAAQS demonstration. No further modeling was conducted for the flaring scenario since it produces lower concentrations than created under other scenarios.

Figures 7.5.1 though 7.5-6 show outlines of the model-predicted areas that can experience significant impacts for each pollutant and averaging time. Based upon the contours shown, the maximum radius of the Significant Impact Area (SIA) for each pollutant is:

SO_2	4.4 km
PM10	1.6 km
NOx	3.0 km
CO	0.9 km

All highest predicted concentrations were found to occur within approximately one kilometer of the IGCC Power Station Footprint. Thus, impacts of Mesaba and Two will be limited to a small area in close proximity to the Site. Specific locations, dates, and times of highest predicted impacts are included in Appendix D of this Application.

Figure 7.5-1. SO_2 3-Hour Significant Impact Area (µg/m^3)

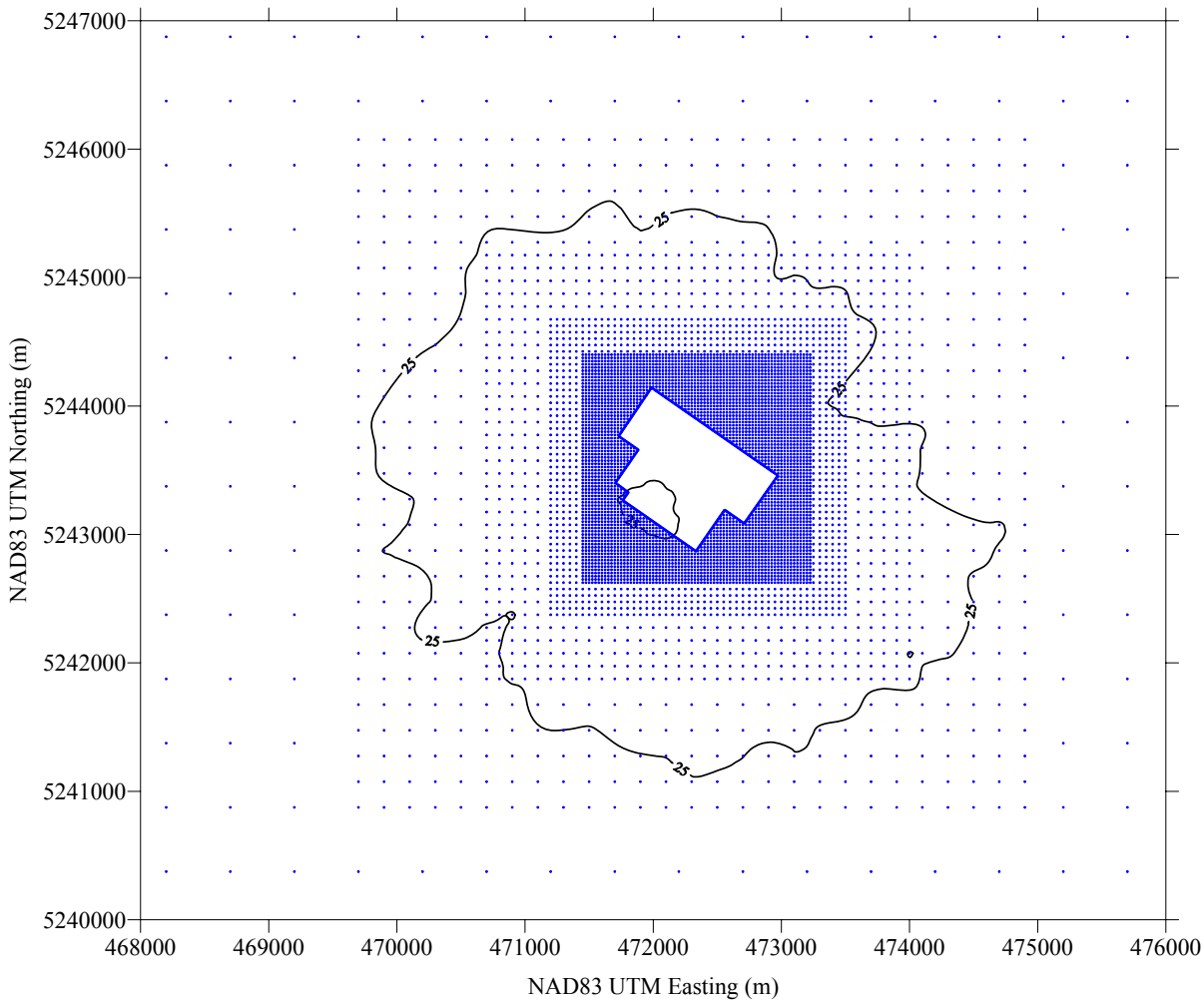


Figure 7.5-1
SO_2 3-Hour Significant Impact Area (µg/m^3)
For Mesaba Phase I and II – Normal Operations
Data Years 1972-1976

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Figure 7.5-2. SO_2 24-Hour Highest Second High Impacts (µg/m^3)

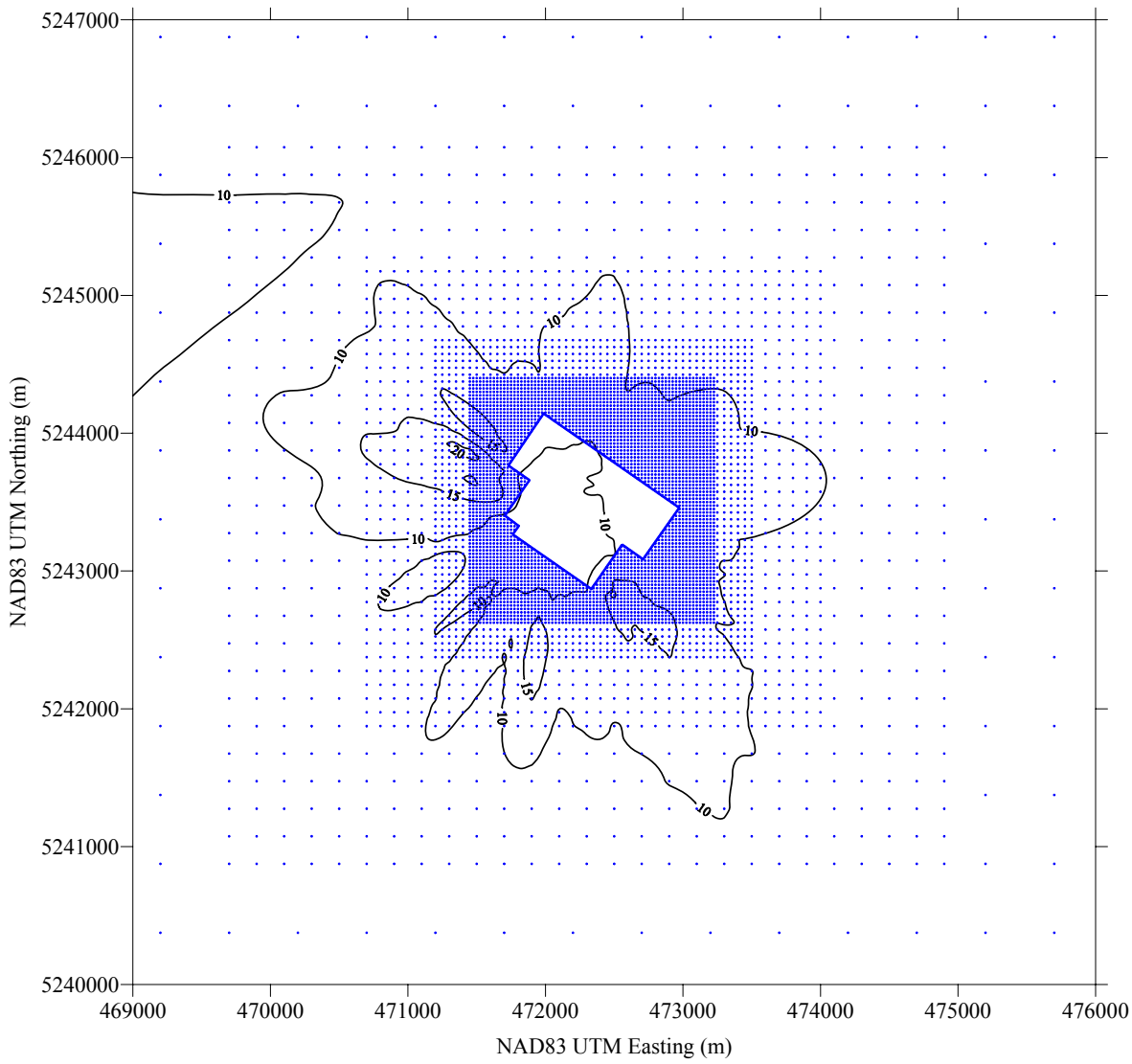

Figure 7.5-2
SO_2 24-Hour Highest Second High Impacts (µg/m^3)
For Mesaba Project Phase I and II and Nearby Sources
Data Year 1975

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Figure 7.5-3. SO_2 Annual Significant Impact Area (µg/m^3)

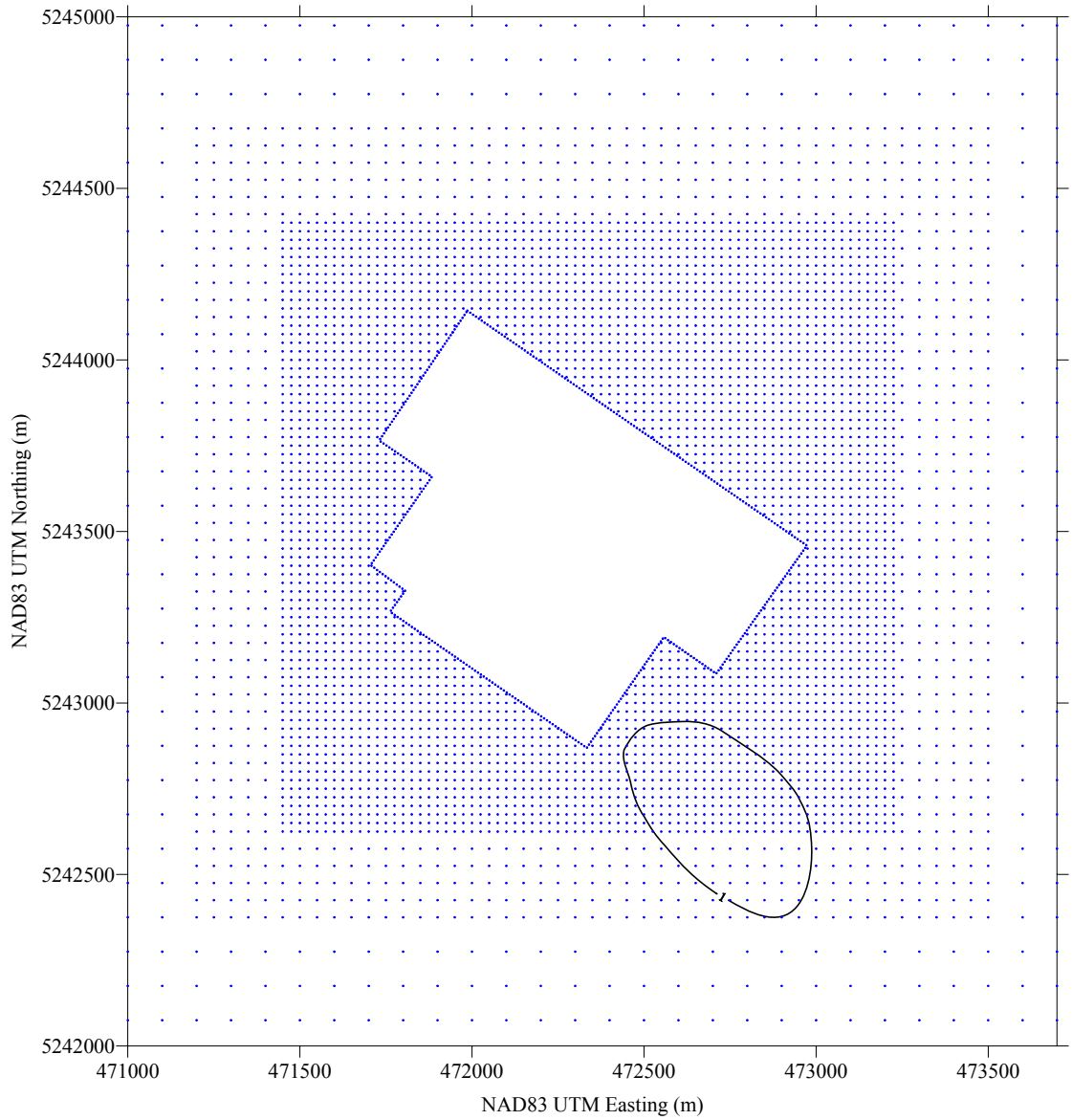

Figure 7.5-3
SO_2 Annual Significant Impact Area (µg/m^3)
For Mesaba Phase I and II – Normal Operations
Data Years 1972-1976

Figure 7.5-4. PM_{10} 24-Hour Significant Impact Area (µg/m^3)

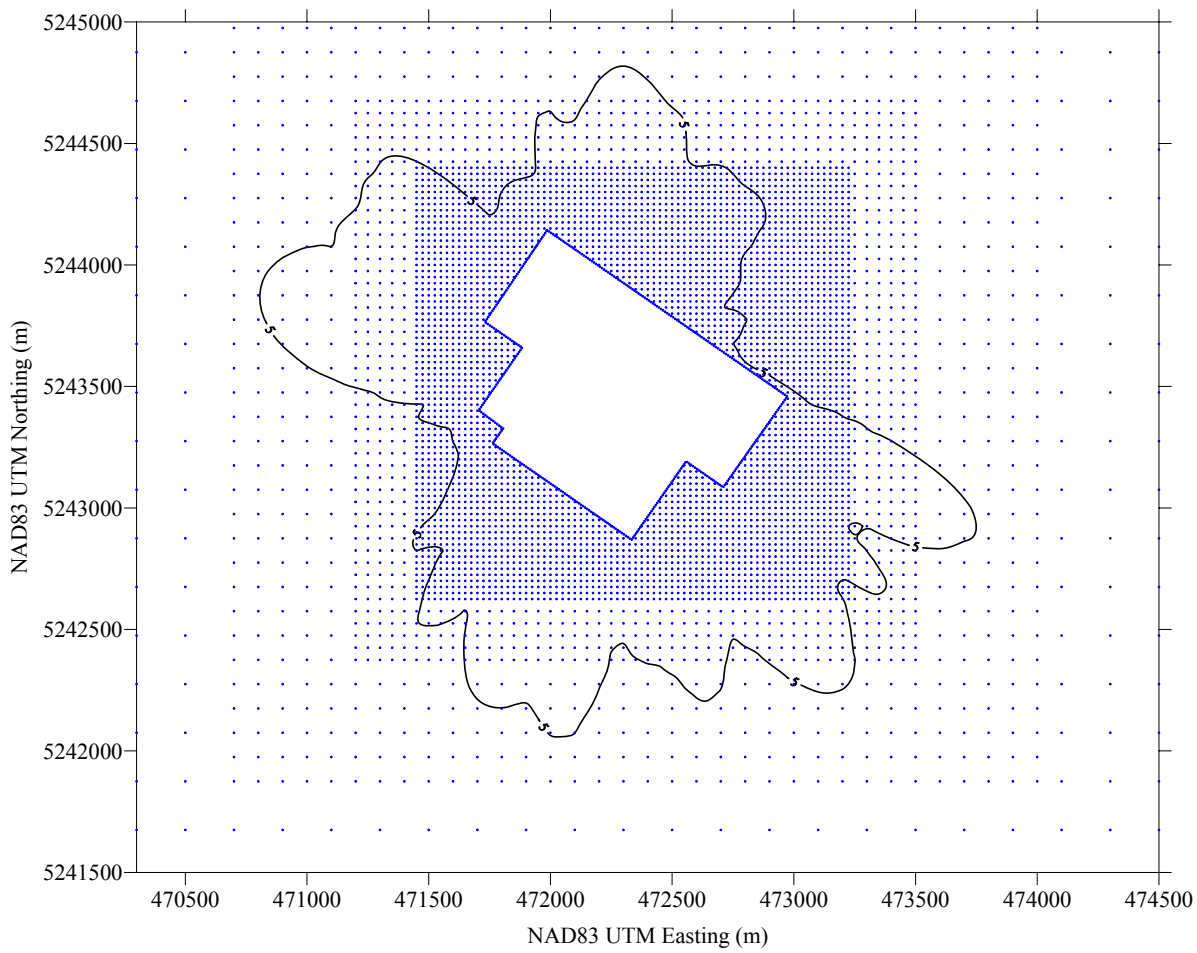

Figure 7.5-4
PM_{10} 24-Hour Significant Impact Area (µg/m^3)
For Mesaba Phase I and II – Normal Operations
Data Years 1972-1976

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Figure 7.5-5. PM_{10} Annual Significant Impact Area (µg/m^3) Mesaba One and Mesaba Two – Normal Operations

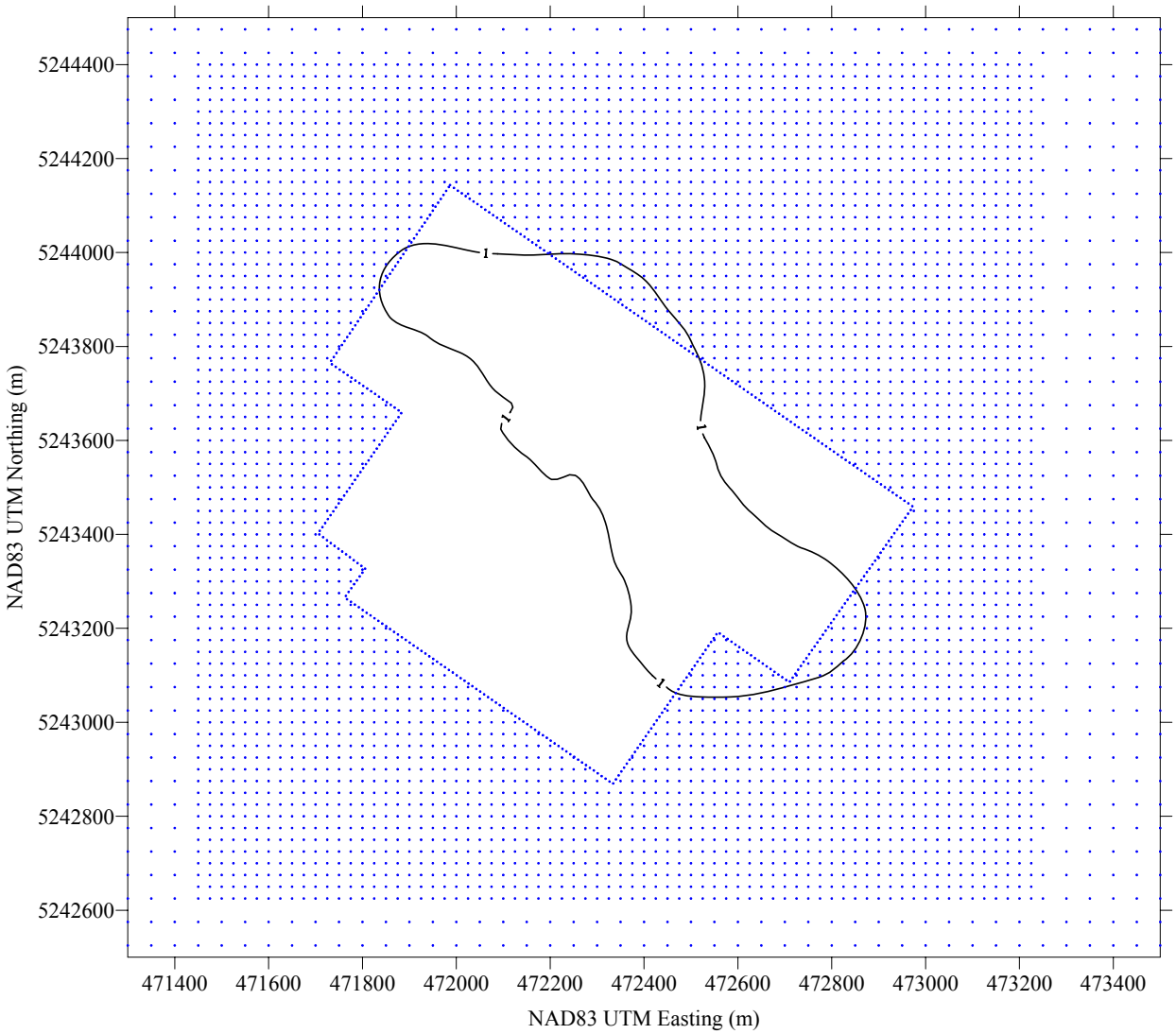

Figure 7.5-5
PM_{10} Annual Significant Impact Area (µg/m^3)
For Mesaba Phase I and II – Normal Operations
Data Years 1972-1976

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Figure 7.5-6. CO 1-Hour Significant Impact Area (µg/m^3) Mesaba One and Mesaba Two Startup

Figure 7.5-6
Figure 40
CO 1-Hour Significant Impact Area (µg/m^3)
For Mesaba Phase I and II – Startup
Data Years 1972-1976

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Figure 7.5-7. NO_X Annual Significant Impact Area (µg/m^3) Mesaba One and Mesaba Two Normal Operations

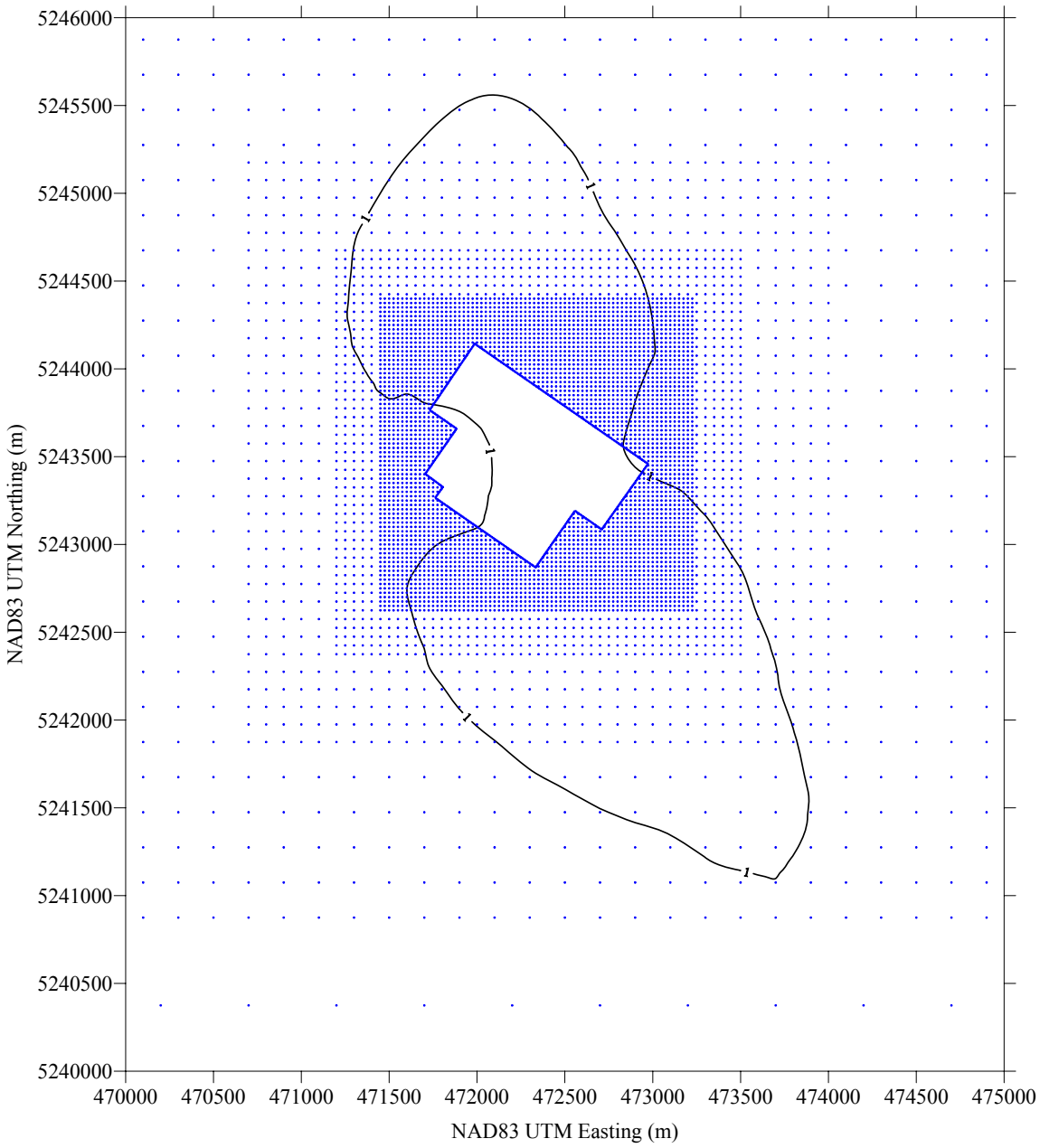

Figure 7.5-7

NO_X Annual Significant Impact Area (µg/m^3)
For Mesaba Phase I and II – Normal Operations
Data Years 1972-1976

7.6 PSD Increment Analysis

Increment analyses were completed for SO_2, PM10, and NO_x. The modeling included all Mesaba One and Mesaba Two sources at maximum emission rates in normal capacity operation, plus all regional increment consuming (and expanding) emissions listed in inventories provided by the MPCA. Increment consuming emissions were included in the input file as positive numbers and increment-expanding emissions (decreases since the baseline date) were included as negative numbers. Total modeled emissions of regional increment sources are listed in Table 7.6-1. Importantly, the emissions listed in Table 7.6-1 for the Clay Boswell plant relate to the permitted short-term limits for Boiler No. 4. A review of historical data over the past 2.5 years revealed that the actual peak short-term SO_2 emissions for that boiler averaged approximately 1,600 pounds per hour. Nonetheless, the permitted emission rate of 6,131 pounds per hour for Clay Boswell Unit No. 4 was used for the near-field increment analysis to provide a conservative estimate of total increment consumption.

Table 7.6-1
Regional Source Increment Consuming Emissions for Mesaba One and Mesaba Two PSD Increment Modeling

Source	SO_2		PM10		NO_x	
	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
Blandin Paper Company	-178.68	-22.513	-0.13	-0.016	-116.91	-14.730
	+595.66	+75.052	+53.84	+6.784	+117.72	+14.832
Minnesota Power – Clay Boswell	6130.89	772.48	510.90	64.373		
Potlatch – Grand Rapids			63.40	7.988	95.67	12.054

The results of the increment analyses are shown in Table 7.6-2, along with a comparison to the allowable Class II PSD increments. The data in Table 7.6-2 demonstrate that the Mesaba One and Mesaba Two, in combination with all other regional PSD sources, will comply with all increment limits. All highest increment impacts leave a margin of at least one SIL for future growth. Maximum increment impacts of Mesaba One and Mesaba Two and regional sources are generally in the same location and are of nearly the same magnitude as those of Mesaba One and Mesaba Two alone. Thus, there is very little impact by other regional increment-consuming sources in the area of Mesaba One and Mesaba Two impacts. Significant increment impacts of Mesaba One and Mesaba Two are limited to the immediate vicinity of the IGCC Power Station Footprint (see Figures 7.3-1 through 7.5-6), and are well within allowable limits.

Table 7.6-2
Results of Mesaba Class II PSD Increment Analysis (µg/m3)

Pollutant/Averaging Time	Highest* Concentration	PSD Increment
SO_2: One-hour	122.4	512
Three-hour	73.4	512
24-hour	21.1	91
Annual	1.40	20
PM10: 24-hour	23.5	30
Annual	1.72	17
NO_2: annual	2.62	25

*For short-term periods, the highest second-high concentration from five years of meteorological data is shown. For annual average, the highest concentration for any of the five years is listed.

7.7 NAAQS Analysis

The NAAQS modeling demonstration consisted of calculating the maximum impact of Mesaba One and Mesaba Two sources and all other regional sources, and comparing the highest total impacts, plus background concentrations, to the applicable Minnesota Ambient Air Quality Standards and NAAQS. For Mesaba One and Mesaba Two, maximum emission rates in normal operation were modeled for all sources and pollutants, except in the case of CO for which the startup scenario has maximum impacts.

For inclusion of other regional sources, a two step procedure was utilized following the recommendations of MPCA modeling staff. In the first step, Mesaba One and Mesaba Two were modeled along with nearby sources for which emission parameters were provided by the MPCA. The location and time of high and highest second-high concentrations were defined by these model results. These specific high impact events were then remodeled, through use of the AERMOD EVENT option and included a much larger inventory of all regional sources. The full regional inventory, referred to as First Approximation Run ("FAR") data, was provided by the MPCA. FAR data files were generated specifically for the IGCC Power Station and separate files were provided for each pollutant and averaging time.

The application of the FAR data provides an approximation of the combined impacts of all sources for the specific times and receptors that were modeled. If predicted impacts threaten ambient standards, or if there is indication of significant interaction between multiple sources, then more refined multiple source modeling could be necessary. However, as shown in the following, the highest predicted impacts in the Mesaba analysis are far below applicable standards, and there are very low impacts of regional sources within the Mesaba SIA. Therefore, the FAR DATA methodology in this case provides assurance of compliance with all NAAQS limits.

Table 7.7-1 summarizes results of the NAAQS model analysis. For SO_2, PM_{10}, and NO_x the table shows i) maximum impacts of Mesaba One and Mesaba Two alone, ii) Mesaba One and Mesaba Two plus local sources that were explicitly included in the five-year model runs, and iii) Mesaba One and Mesaba Two plus all regional sources from FAR modeling of the highest impact days. For CO, no inventory of regional emissions is available. The data in Table 7.7-1 show CO concentrations from Mesaba One and Mesaba Two alone, and conservative total concentration estimates obtained by adding an urban background concentration to Mesaba One and Mesaba Two impacts.

Table 7.7-1 compares total impact estimates to the applicable NAAQS. All predicted concentrations are far below allowable levels and the results demonstrate compliance with all Minnesota and federal ambient air quality standards.

Contours of maximum predicted impacts from Mesaba One and Mesaba Two and nearby sources are shown In the vicinity of the IGCC Power Station in Figures 7.5-7 through 7.7-8. These maps show that the highest impacts (still well below ambient standards) will occur over limited areas in close proximity to the site.

The nearby sources that were included in the five-year NAAQS model runs were:

- Minnesota Power-Clay Boswell Plant (Units 1-4)
- Keewatin Taconite

These major sources are both located within 25 kilometers of the IGCC Power Station Footprint: Minnesota Power to the southwest and Keewatin Taconite to the northeast. In the case of short-term SO_2 impacts, the maximum combined source impacts shown in Table 7.7-1 are primarily due to these nearby sources and occur at locations far from the Mesaba One and Mesaba Two site. The other maximum impact points reflect Mesaba One and Mesaba Two emissions and occur near the site. Details of the locations and times of highest predicted concentrations are included in Appendix D.

Table 7.7-1
Results of Mesaba Class II NAAQS Modeling (Concentrations in µg/m^3)

Pollutant Averaging Time	Highest [1] Mesaba Alone	Highest[1] Mesaba and Nearby	Highest[1] All Sources	Background	Total	NAAQS
SO2						
1-hour	122.4	322.2	327.4	10	337.4	1300
3-hour	73.4	134.4	136.5	10	146.5	915
24-hour	22.1	30.6	41.4	10	51.4	365
annual	1.29	1.99	2.67	2	4.67	60
PM10	13.3					
24-hour	11.0	13.7	15.8	20	35.8	150
Annual	1.59	1.95	3.14	10	13.14	50
NOx						
Annual	2.60	3.18	5.09	5	10.09	100
CO						
1-hour	2669.8	N/A	N/A	7000[2]	9670	40,000

[1]Listed Highest Concentrations are highest second-high for one to 24-hour averaging times except for PM10, which is the highest 6th high from five years. Annual average values are the highest for any year.
[2]Background CO concentrations are very conservative estimates from urban monitors in Minneapolis/St. Paul. No background data exist for the IGCC Power Station area.

Figure 7.7-1 SO_2 1-Hour Highest Second High Impacts (µg/m^3) Mesaba One and Mesaba Two and Nearby Sources

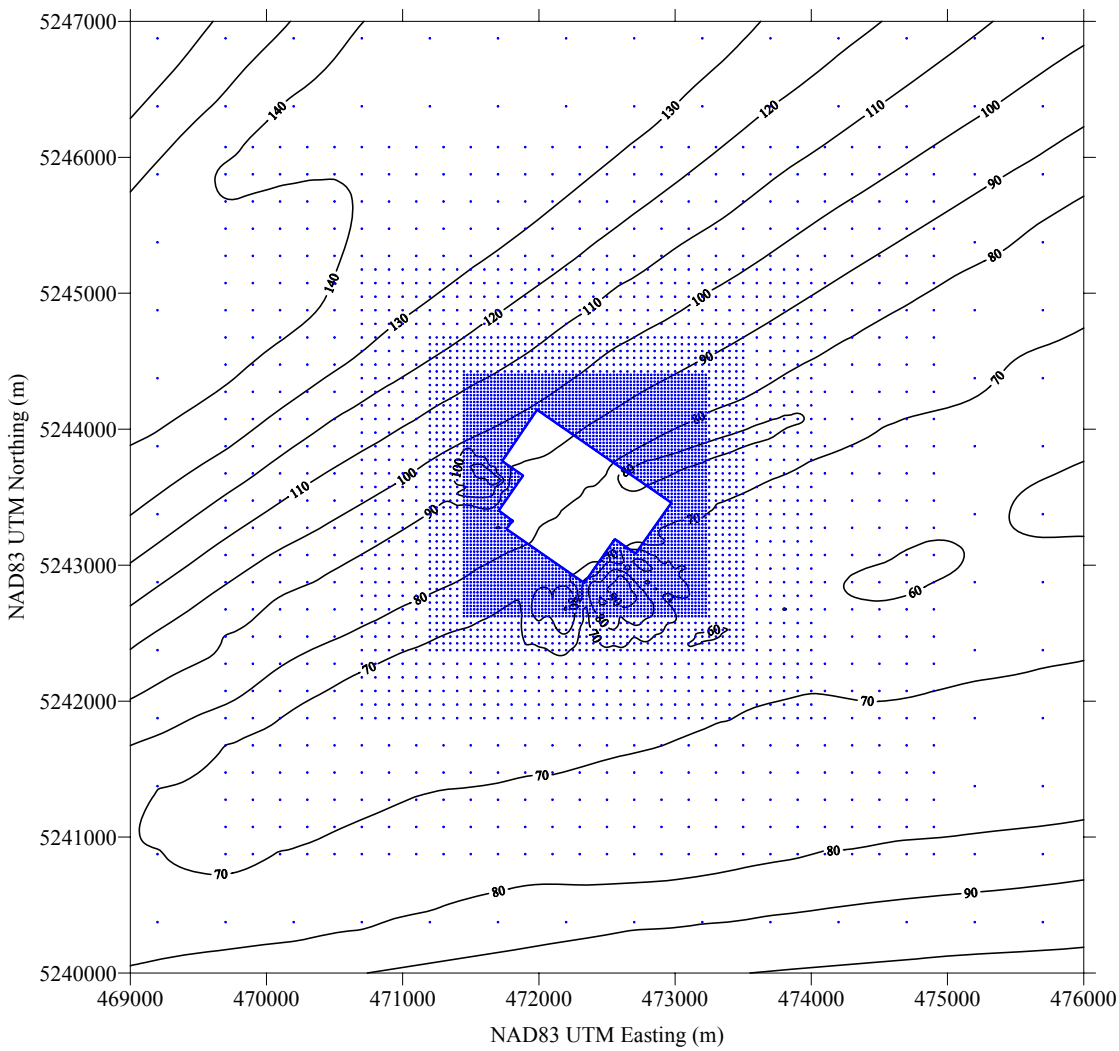

Figure 7.7-1
SO_2 1-Hour Highest Second High Impacts (µg/m^3)
For Mesaba Project Phase I and II and Nearby Sources
Data Year 1975

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Figure 7.7-2. SO_2 3-Hour Highest Second High Impacts (µg/m^3) Mesaba One and Mesaba Two and Nearby Sources

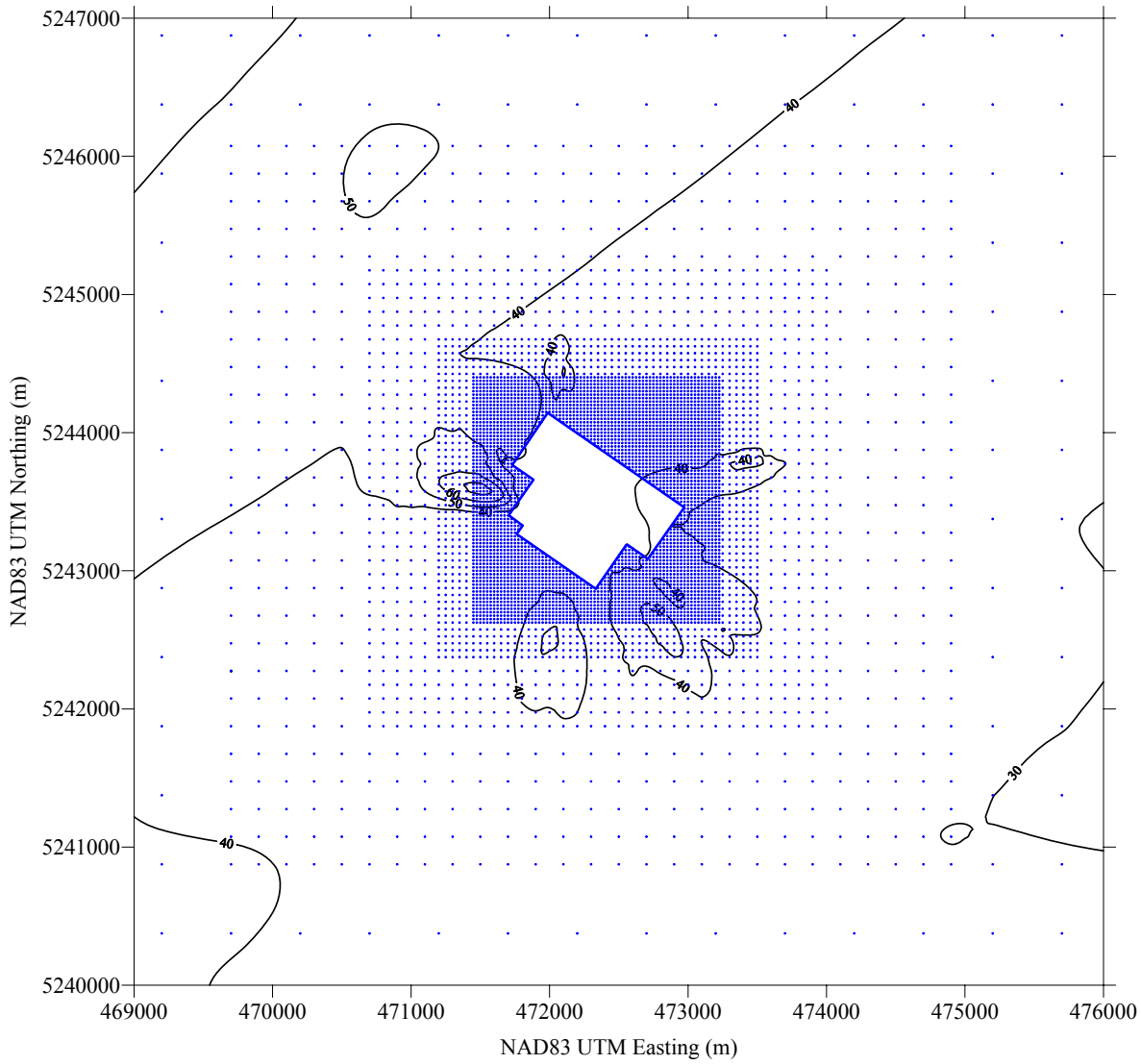

Figure 7.7-2

SO_2 3-Hour Highest Second High Impacts (µg/m^3)
For Mesaba Project Phase I and II and Nearby Sources
Data Year 1975

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Figure 7.7-3. SO_2 24-Hour Highest Second High Impacts (µg/m^3) Mesaba One and Mesaba Two and Nearby Sources

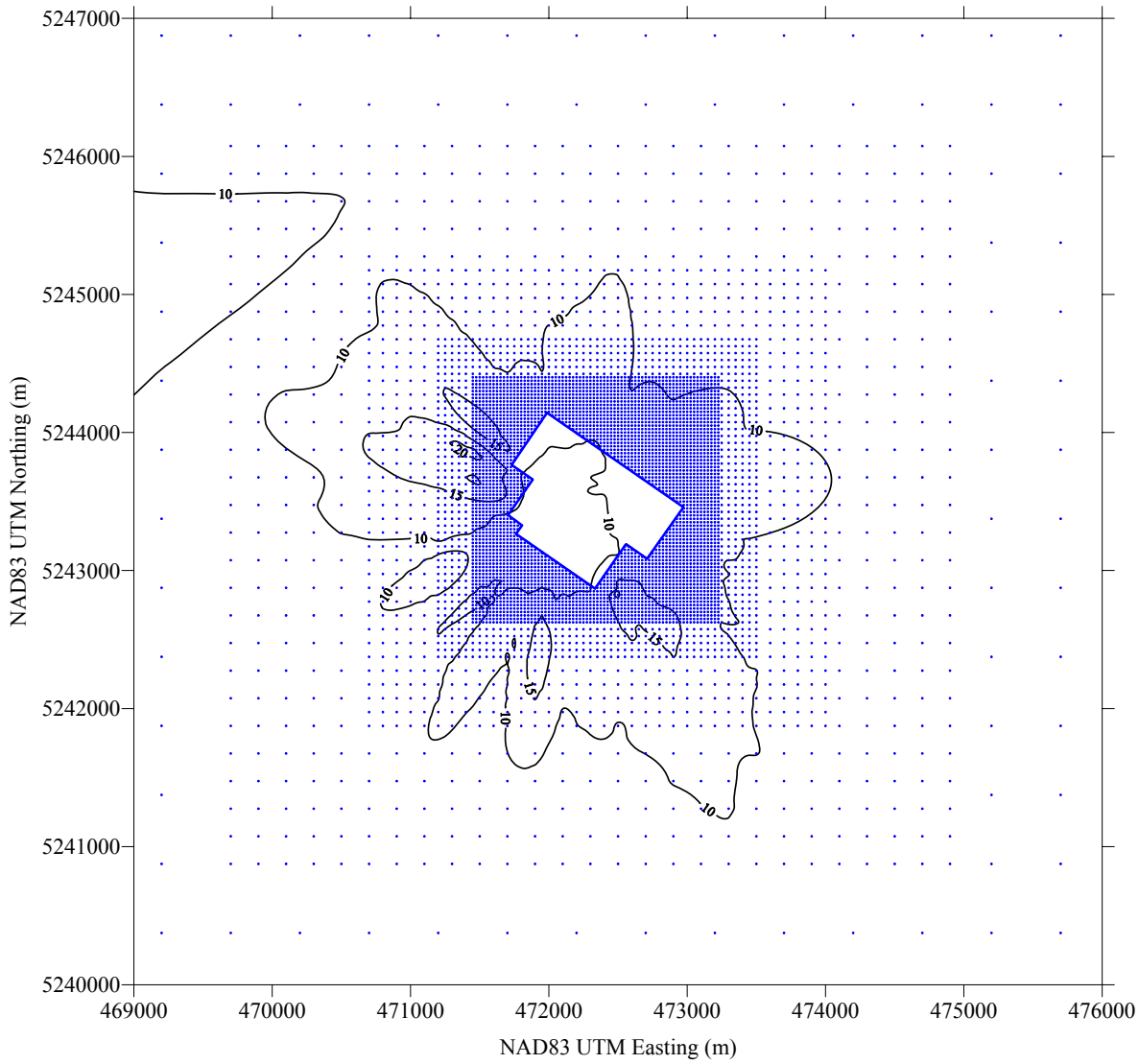

Figure 7.7-3

SO_2 24-Hour Highest Second High Impacts (µg/m^3)
For Mesaba Project Phase I and II and Nearby Sources
Data Year 1975

McVEHIL-MONNETT ASSOCIATES, INC.
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Figure 7.7-4. SO_2 Annual Maximum Impacts (µg/m^3) Mesaba One and Mesaba Two and Nearby Sources

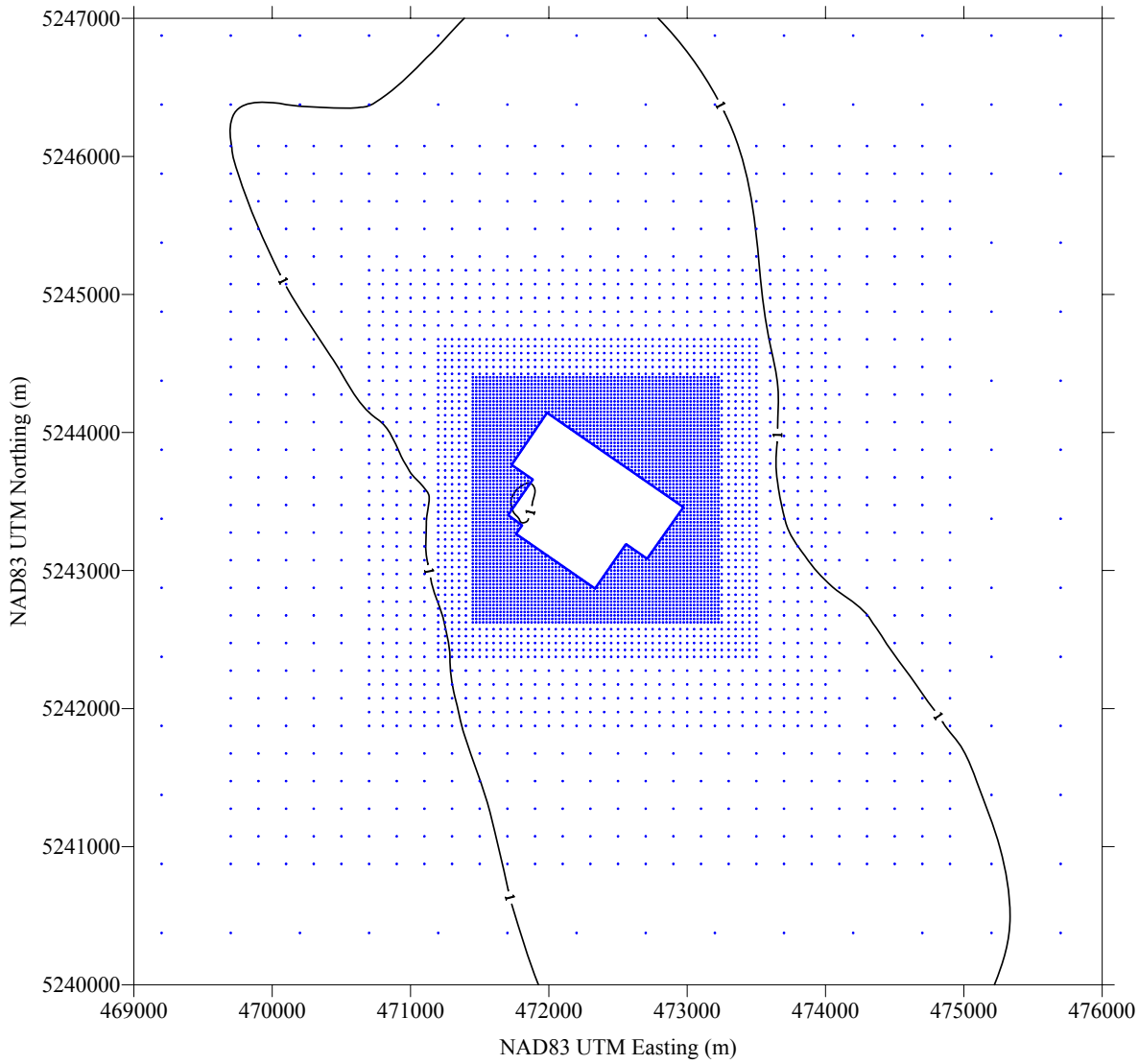

Figure 7.7-4
SO_2 Annual Maximum Impacts (µg/m^3)
For Mesaba Project Phase I and II and Nearby Sources
Data Year 1976

MCVEHIL-MONNETT ASSOCIATES, INC.
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Figure 7.7-5. PM_{10} Highest Sixth-High Impacts ($\mu g/m^3$) Mesaba One and Mesaba Two and Nearby Sources

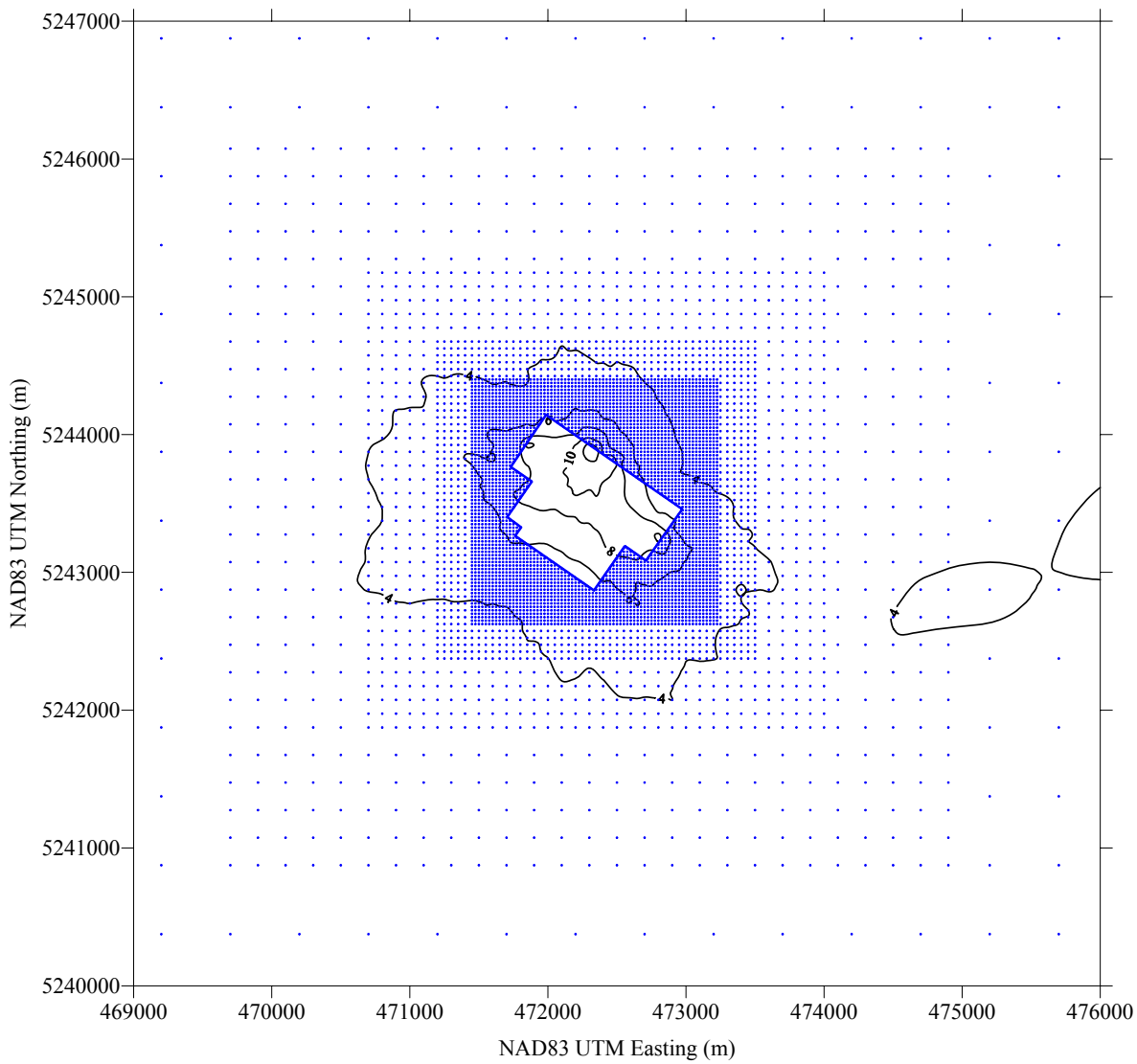

Figure 7.7-5

PM_{10} Highest Sixth-High Impacts ($\mu g/m^3$)
For Mesaba Project Phase I and II and Nearby Sources
Data Years 1972 through 1976

MCVEHIL-MONNETT ASSOCIATES, INC.
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Figure 7.7-6. PM_{10} Maximum Annual Impacts ($\mu g/m^3$) Mesaba One and Mesaba Two and Nearby Sources

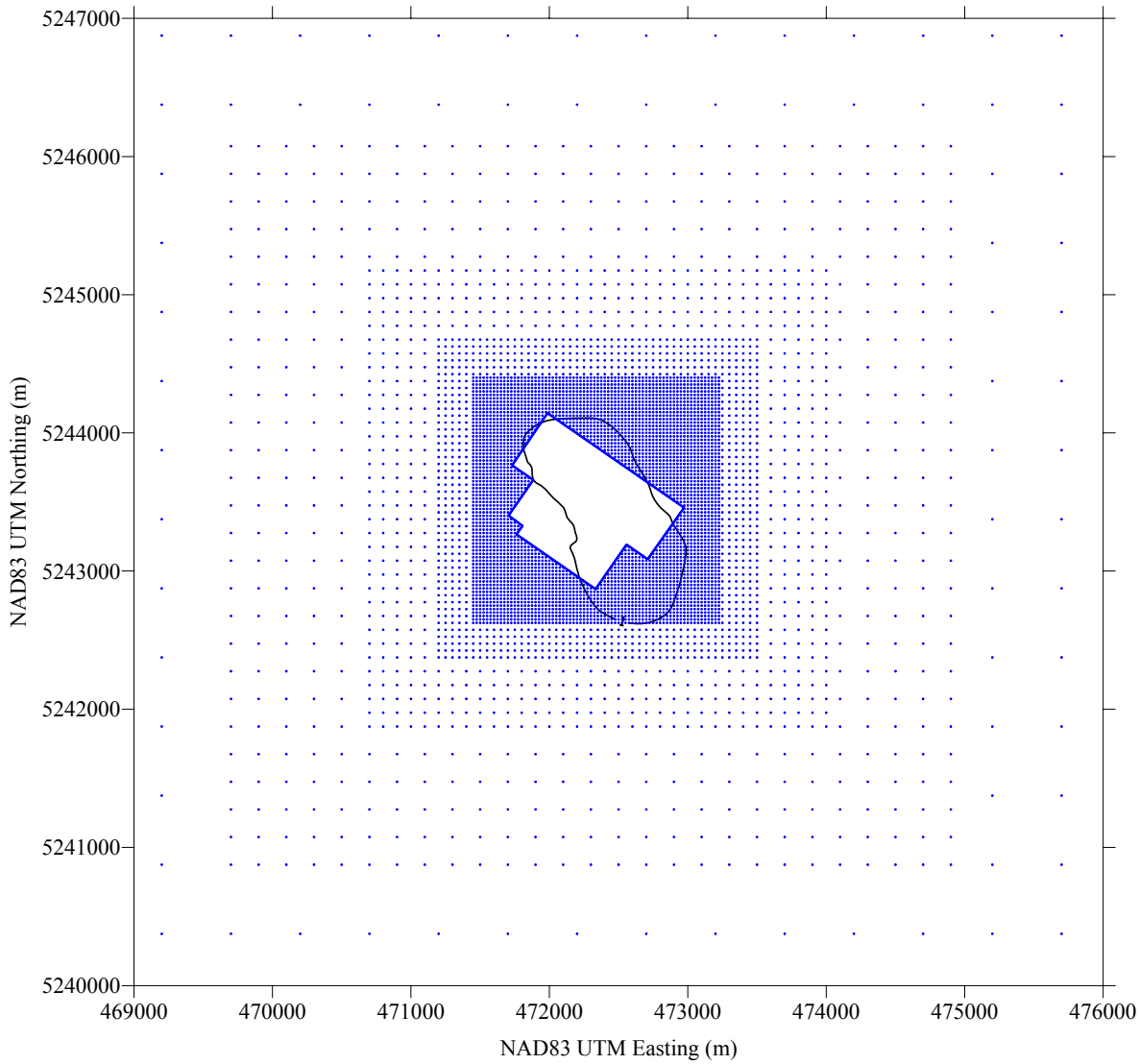

Figure 7.7-6
PM_{10} Maximum Annual Impacts ($\mu g/m^3$)
For Mesaba Project Phase I and II and Nearby Sources
Data Year 1976

McVehil-Monnett Associates, Inc.
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Figure 7.7-7. NO_X Annual Maximum Impacts (µg/m^3) Mesaba One and Mesaba Two and Nearby Sources

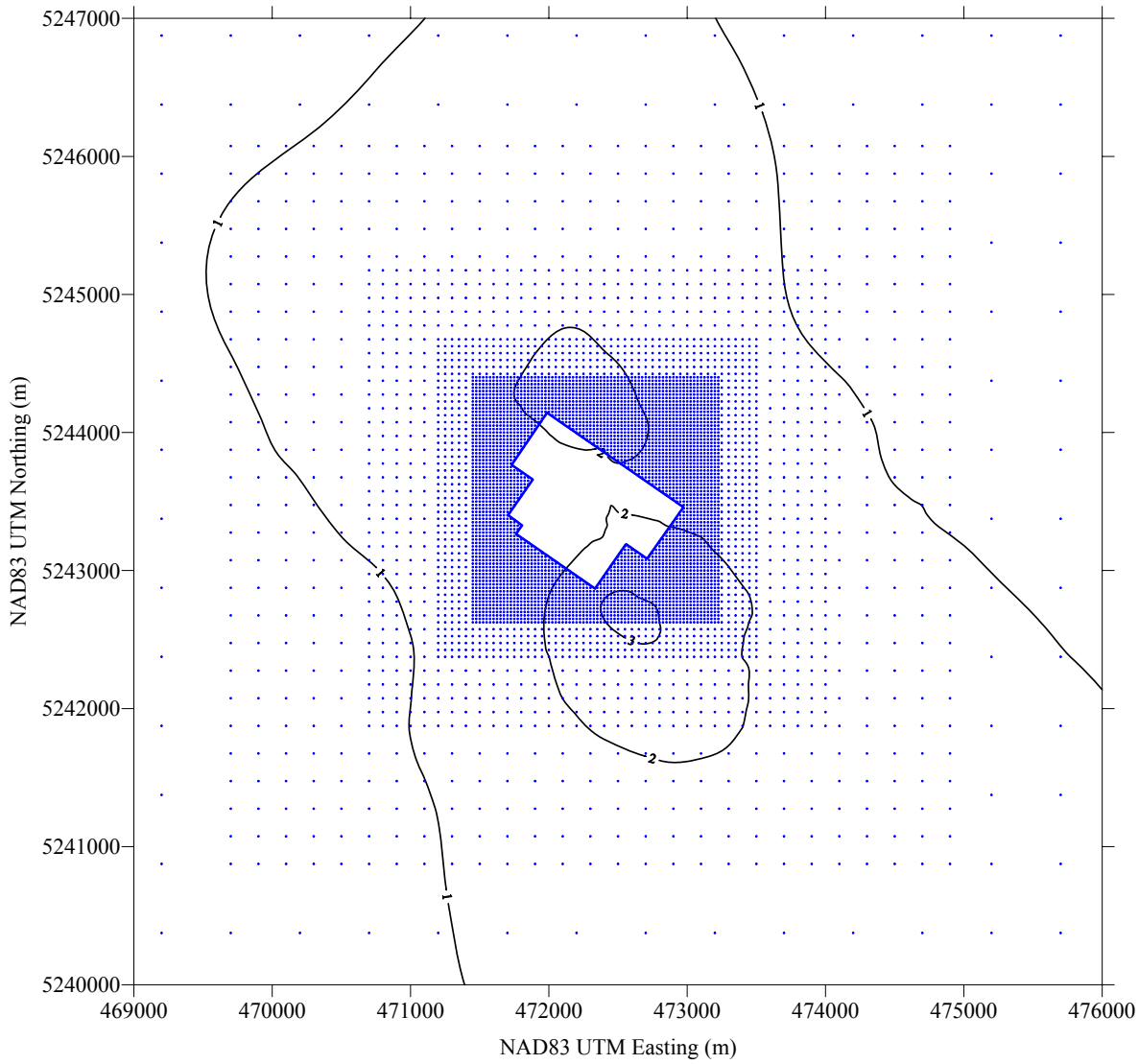

Figure 7.7-7
NO_X Annual Maximum Impacts (µg/m^3)
For Mesaba Project Phase I and II and Nearby Sources
Data Year 1974

McVEHIL-MONNETT ASSOCIATES, INC.
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Figure 7.7-8. CO 1-Hour Highest Second-High Impacts (µg/m^3) Mesaba One and Mesaba Two

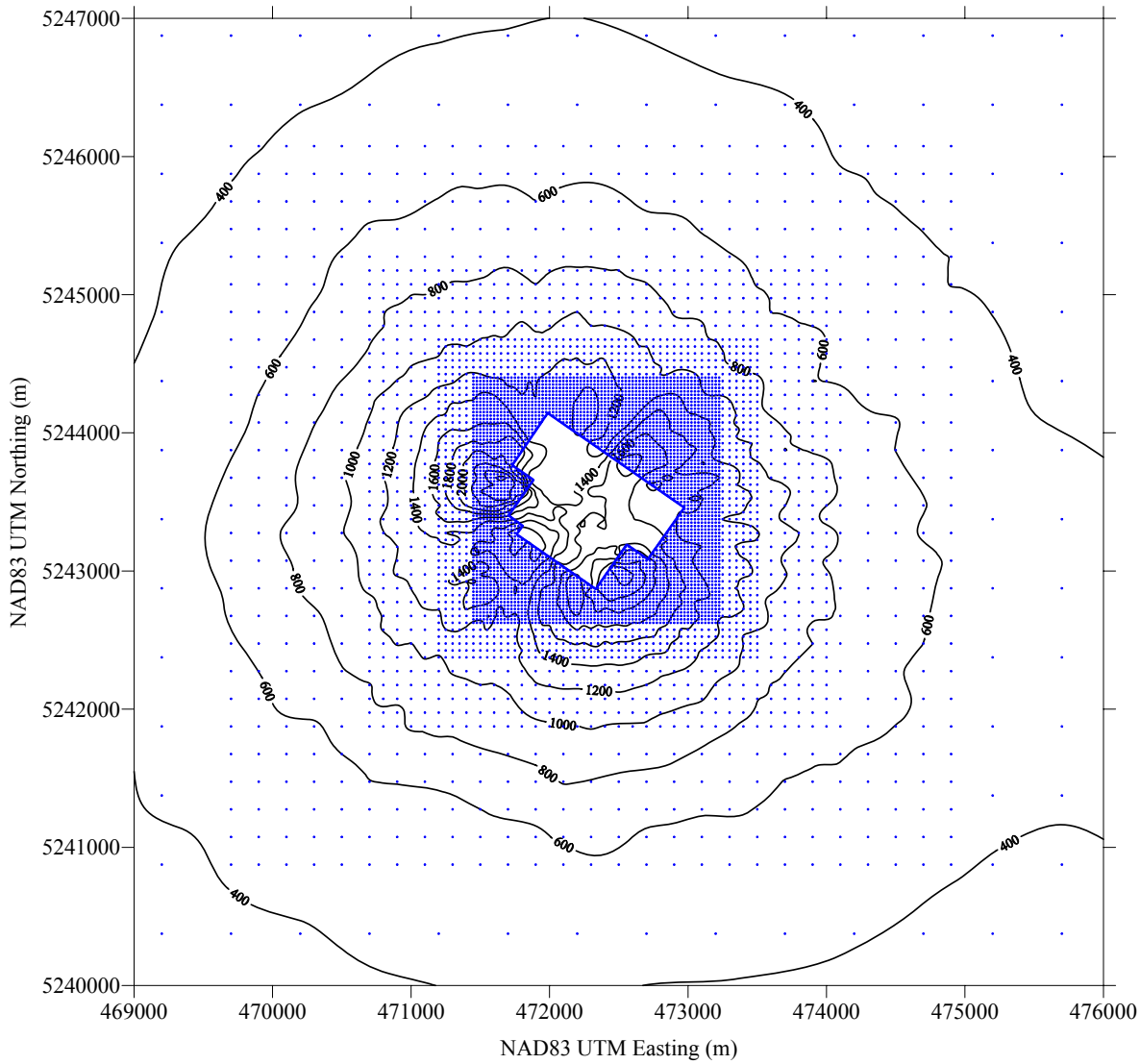

Figure 7.7-8
CO 1-Hour Highest Second-High Impacts (µg/m^3)
For Mesaba Project Phase I and II (Startup Operations)
Data Year 1975

MCVEHIL-MONNETT ASSOCIATES, INC.
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7.8 Preconstruction Monitoring

Minnesota and federal PSD regulations specify "de minimis" monitoring concentrations. If these threshold levels will be exceeded by projected emissions from Mesaba One and Mesaba Two and/or are currently exceeded in the vicinity of the IGCC Power Station by existing sources, preconstruction monitoring may be appropriate to better quantify background air quality levels. The PSD de minimis monitoring concentrations are shown in Table 7.8-1, along with the maximum projected Mesaba One and Mesaba Two concentrations shown in Section 7.5 (see Table 7.5-1).

Table 7.8-1 indicates that Mesaba impacts for NO_2, CO, and ozone are below the de minimis monitoring concentrations. For SO_2 and PM_{10}, model-predicted impacts from Mesaba One and Mesaba Two exceed the threshold monitoring concentrations.

Background PM_{10} monitoring data are available in northeast Minnesota from Virginia, Duluth, and IMPROVE monitoring in the northern Minnesota Class I areas. Limited SO_2 data also exist from Ely MN and Voyageurs National Park. These data indicate that background PM_{10} and SO_2 levels are very low in northern Minnesota, and are generally below the de minimis monitoring levels. Existing air quality data are presented in Section 6.3 of this Application.

The results of the NAAQS compliance analysis presented above indicate that Mesaba One and Mesaba Two will not violate any air quality standards, and total ambient pollutant concentration levels will remain far below applicable limits. The existence of representative regional monitoring data, in combination with the low predicted impacts of Mesaba One and Mesaba Two, indicate that preconstruction monitoring is not necessary and would not contribute to a significant improvement in impact assessments. Similarly, adequate meteorological data are available from Hibbing and other regional monitoring sites. Because of these factors, the applicant requests a waiver of preconstruction monitoring requirements for Mesaba One and Mesaba Two.

Table 7.8-1
PSD Significant Monitoring Concentrations and Maximum Mesaba One and Mesaba Two

Pollutant	Averaging Time	Highest Mesaba Impact ($\mu g/m^3$)	De Minimis Monitoring Level ($\mu g/m^3$)
Sulfur Dioxide	24-hour	31.2	13
PM10	24-hour	27.9	10
Nitrogen Dioxide	Annual	2.6	14
Carbon Monoxide	8-hour	379	575
Ozone	1-hour	N/A	100 TPY VOC Emissions

7.9 Other Impacts

7.9.1 Visible Plume Effects

A complete analysis of Mesaba One and Mesaba Two impacts, including visibility, in Class I areas is presented in Section 8.0 of this application. In addition to the CALPUFF modeling of Class I impacts, the VISCREEN model was applied as a screening tool to assess the potential of visible plumes from Mesaba emissions sources. VISCREEN modeling was carried out for distances of 100 km from the site (the shortest distance to the newest Class I area, the BWCA) and 75 km. VISCREEN model results indicate whether pollutants in the combined plume from all Mesaba One and Mesaba Two sources could be visible against the sky or distant terrain under the most limiting meteorological conditions.

Modeled emissions from Mesaba One and Mesaba Two consisted of total NO_x, PM_{10}, and sulfate from combustion turbines and tank vent boilers. The 24-hour rates used for modeling were:

NO_x	663 lb/hr	=	83.56 g/s
PM_{10}	71 lb/hr	=	8.91 g/s
SO_4	30 lb/hr	=	3.78 g/s

VISCREEN model results are shown on the following two pages. The results are all less than the critical screening criteria, and it can be concluded that there will be no visible plume impacts at or near the nearest Class I areas.

7.9.2 Impacts of Cooling Towers

The evaporative cooling towers used by Mesaba One and Mesaba Two will discharge warm saturated air to the atmosphere as well as small quantities of liquid water droplets. The wet plumes are emitted vertically from 33 feet diameter fan stacks at an elevation of 48 feet above grade. Because of the buoyancy of the warm moist air and the vertical velocity imparted by the fans, the wet plumes will rise to significant heights above the ground.

Because cooling tower plumes consist of ambient air containing only evaporated water and very small quantities of liquid water from the plant cooling water system, there are negligible air pollutants contained in the emissions. The potential environmental impacts of cooling tower emissions are limited to fogging or icing at nearby locations, deposition of water droplets or snow crystals and solids from the circulating water, and visible condensed water plumes.

The most obvious impact of Mesaba cooling towers will be visible condensed water (steam) clouds. These will exist during periods of low air temperature and light winds. The steam clouds, which appear similar to small natural cumulus clouds, can rise to heights of several thousand feet above the ground in extremely cold weather, and can persist for several miles downwind. Because the steam plumes consist entirely of condensed water, they have no adverse effects other than their visual impact.

Experience with large cooling towers at power plants in cold climates has shown that fogging and icing impacts of mechanical draft towers similar to those used by Mesaba One and Mesaba

Two are minimal. Extensive research was carried out during the 1970s when many large cooling tower installations were constructed or proposed at power generating facilities. These studies led to development of mathematical models for prediction of cooling tower effects and the collection of field observations at operating towers. See Exhibit E. In general, it was found that environmental impacts are negligible except within 500 to 1000 feet of the towers. Because of the buoyancy of cooling tower emissions, they rise to heights above ground level and dissipate in the ambient air as they are transported by prevailing winds.

Relevant experience with cooling towers in Minnesota is available from Xcel Energy's SHERCO generating station near Becker, Minnesota. Detailed studies were carried out at SHERCO because the plant is located in close proximity to Interstate Highway 94 and Minnesota Highway 10. Modeling analyses were conducted during permitting of SHERCO Unit 3. These analyses predicted no significant impacts on nearby highways. Subsequent experience has shown that effects of SHERCO cooling towers have been limited to isolated observation of very light snow on a few occasions per year, but no significant fog or other impacts have been observed. See Exhibit E.

The SHERCO cooling tower facility is approximately twice as large as the Mesaba One and Mesaba Two cooling towers in terms of total heat dissipation to the atmosphere. Thus, despite the somewhat colder climate in northern Minnesota, there is no reason to anticipate off-site fog or icing impacts.

Liquid water droplets emitted by cooling towers (referred to as "drift") constitute a very small fraction of the total emitted water. Drift droplets represent circulating cooling water from the tower and contain dissolved solids from the circulating water. Deposition of drift solids has been identified as a potential cooling tower impact where towers use saline water or water with a high solids content. The drift rate of the cooling towers serving Mesaba One and Mesaba Two will be very low (0.001 percent of the circulating water) and the solids content is also modest (2,740 ppm by weight). Thus, the total solids emission rate from cooling towers serving Mesaba One and Mesaba Two will be a maximum of nine pounds per hour. As shown by the PM_{10} modeling results, impacts of cooling tower particulate matter emissions on ambient air concentrations will be very small. Deposition of these particles on surrounding ground surfaces will be negligible.

There are no major highways, airports, or other sensitive facilities in the immediate proximity to the IGCC Power Station Footprint. Given data and experience at other cooling tower installations, it is concluded that there will be no significant fogging, icing, or drift deposition impacts of the cooling towers serving Mesaba One and Mesaba Two on off-site human activities or the environment. The only predicted impacts are the visual impact of steam plumes in cold, moist weather conditions, and occasional very light localized fallout of snow crystals during times of very low temperature.

7.10 Growth

Construction activities associated with Mesaba One and Mesaba Two will provide approximately 1,400 construction jobs during peak construction periods. Operation of the facility will require approximately 180 workers following construction of the Phase II IGCC Power Station, which is expected to be completed and fully operational in 2013. To the extent practical and consistent

with skill and operational requirements, employees will be hired from the buildings trades in the local labor market. There are numerous motels, lodges, and apartments in the surrounding communities with sufficient total capacity to accommodate pre and post-construction workforce needs.

According to the US Census Bureau, Itasca County had a population of 44,316 in 2004, with an increase of 7.7% between 1990 and 2000. The Itasca County Comprehensive Plan adopted in May 2000 indicates that population projections for the next 20 years vary from the population remaining flat to an increase of 9,000 new residents, which indicates a recognized potential for growth in the County. 59% of the 2004 population was between 18 and 65 years of age, which may generally be considered as the working age population. The 180 permanent employment positions will not be added all at once due to the phased nature of facility construction and startup, allowing for a gradual increase in employment rather than a one-time jump in employment. The number of permanent positions required is not expected to significantly affect population, labor, or housing trends in the Itasca County area. Similarly, this number is not expected to represent an unusual burden to the local utility services (potable water, sewer, roadway, etc.) or social services (schools, medical facilities, fire and police protection). Operation of the IGCC Power Station will not result in significant worker relocation into the area relative to the previously anticipated growth rate.

In summary, secondary growth is not expected to result in new significant emissions during either operation or construction of the IGCC Power Station.

7.11 Soils and Vegetation

The PSD regulation requires analysis of air quality impacts on sensitive vegetation and soil types. Evaluation of impacts on sensitive vegetation and soils was performed by comparing predicted IGCC Power Station impacts to screening levels presented in the 1980 EPA document titled: *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals* (EPA, December 1980, EPA 450/2-81-078). These screening levels represent the minimum concentrations in either plant tissue or soils at which adverse growth effects or tissue injury was reported in the literature. The procedures specify that predicted impact concentrations used for comparison account for facility impacts added to ambient background concentrations. Most of the designated vegetation screening levels are equivalent to or exceed PSD increments. The 3-hour and 1-hour SO_2 sensitive vegetation screening levels are more stringent than comparable NAAQS and State Ambient Air Quality Standards. Air quality modeling indicates that IGCC Power Station impacts will be below PSD increments and NAAQS (see Tables 7.6-2 and 7.7-1, respectively).

A comparison of the SO_2 sensitive vegetation screening levels with SO_2 impacts from the proposed IGCC Power Station is presented in Table 7.11-1. The comparison includes ambient background concentrations in the impact levels. Maximum impacts for the 1-hour and 3-hour averaging periods (see Table 7.5-1) are less than 20% of the allowable concentrations.

Table 7.11-1
Vegetative Sensitivity Screening for SO_2 Concentrations

Averaging Time	Background Concentration ($\mu g/m^3$)	Maximum Contribution from IGCC Power Station ($\mu g/m^3$)	Maximum Total Concentration ($\mu g/m^3$)	Sensitive Vegetation Screening Level ($\mu g/m^3$)
1-Hour	10	130.2	140.2	917
3-Hour	10	77.6	87.6	786

8. IMPACTS TO AIR QUALITY RELATED VALUES (AQRVS) IN CLASS I AREAS

8.1 Introduction

An air quality modeling analysis was conducted to estimate impacts of the Phase I and II IGCC Power Station (the Station) on air quality in Class I areas. The analysis addressed impacts to the Boundary Waters Canoe Area (BWCA), Voyageurs National Park (VNP) and the Rainbow Lakes Wilderness (RLW). The distance from the Station to the closest point in each of these Class I areas is approximately 61 miles (98 km) for the BWCA, 75 miles (121 km) for VNP, and 117 miles (188 km) for RLW. The next closest Class I area, Isle Royale National Park, is more than 300 km from the station, beyond the distance where long-range transport modeling has been shown to provide realistic impact predictions.

The Class I AQRV analyses addressed PSD Class I increments for SO_2, PM10, and NO_2, sulfur and nitrogen deposition, and visibility impairment (regional haze). The dispersion modeling analysis used standard EPA long-range transport modeling methodologies, and followed guidance as presented in EPA's Guideline on Air Quality Models, the IWAQM Phase 2 report, and the FLAG Phase I report. The analyses also incorporated suggestions and guidance received in pre-application meetings with the U.S. Forest Service and the National Park Service. Details of the AQRV analyses are presented in Appendix D of this Application.

8.2 Air Quality Model and Application

The CALPUFF air quality model was used for all Class I area analyses. CALPUFF is the approved EPA long-range transport model referenced in the Guideline on Air Quality Models. It consists of three components: the CALMET model for processing of meteorological data; CALPUFF for the transport and dispersion calculations; and CALPOST for analysis and post-processing of model results. Input options and data utilized in the models generally corresponded to default or recommended values. Table 8.2-1 provides a list of input parameters that are specific to the Mesaba application and that differ from standard default values.

8.2.1 Pollutant Emissions

Pollutant emission rates for CALPUFF modeling represent the maximum expected emissions from Mesaba One and Mesaba Two for the appropriate averaging times. Modeling parameters are given in Table 8.2-2.

Table 8.2-1
CALMET/CALPUFF Non-Default Input Parameters

Input Group	Parameter	Mesaba Selection	Explanation
CALMET			
5	IKINE	1	Kinemateic effects option used to better account for terrain effects
	RMAX 1	30 km	No default values
	RMAX 2	40 km	No default values
	RMAX 3	40 km	No default values
	TERRAD	15 km	No default values
	R1	5	No default values
	R2	15	No default values
CALPUFF			
3	Species Modeled	SO_2, SO_4, NO_x, EC, SOA, $PM_{2.5}$, HNO_3, NO_3	Modeled all species emitted by Mesaba sources, and others (HNO_3, NO_3) involved in plume chemistry
4	LSAMP	F	No gridded receptors (sampling grid) used
8	Part. Size	Mean = 0.48 Std. Dev. = 2	All particulate species assumed $PM_{2.5}$
11	MOZ	0	Constant ozone background
	BCK03	40.0 ppb	Representation background ozone concentration
	BCKNH3	1.0 ppb	Conservative background ammonia concentration (0.5 ppb recommended for forested lands)
12	NSPLIT	3	Puff-splitting used (default)

Table 8.2-2
Modeling Parameters For Mesaba One and Mesaba Two CALPUFF Modeling

Parameter	Combustion Turbines (each of four)	Tank Vent Boilers (each of two)
stack height (m)	45.72	64.01
stack diameter (m)	6.1	1.83
temp (K)	394.3	579.8
velocity (m/s) – short-term	20.1	8.46
annual	20.1	1.95
SO_2 - 3-hr (g/s)	19.15	0.94
24-hr	14.36	0.81
annual	9.58	0.45
NO_x - 3-hr (g/s)	19.66	2.46
24-hr	19.66	2.46
annual	19.91	0.76
Elemental Carbon (g/s) all time periods	0.787	0
Sulfate (g/s) all time periods	0.945	0
Organic aerosol (g/s) all time periods	1.397	0
$PM_{2.5}$ (g/s) all time periods	0	0.088
PM_{10} (g/s)	0	0

The operating scenario that will have maximum short-term impacts is normal operation of all Mesaba One and Mesaba Two combustion turbines at full capacity. During normal operation of Mesaba One and Mesaba Two, the only significant air pollutant emissions will be from the combustion turbines and tank vent boilers. During short-term upset conditions when untreated syngas could be flared, SO_2 emissions from the flares may exceed the combined SO_2 emissions from the CTGs during normal operations (see Appendix A, Exhibit A-2). This situation represents a low probability event because the Applicant is designing the gasification island to ensure that only treated syngas would be flared during start-ups. Further, during such abnormal upset conditions, flow of syngas to the CTGs would be interrupted and operation of the gasifier(s) would be reduced or shut down if the upset condition appeared significant (that is, threatened compliance) and/or persistent, thus limiting the need to flare large quantities of untreated syngas. Notwithstanding the increased short term emissions of SO_2 relative to normal baseload operations of the CTGs, NO_X and PM_{10} emissions from the total facility during such short term upsets will be reduced to levels below normal NO_X and PM_{10} emissions from the CTGs given the rapid turn down capability of the CTGs and gasifiers. A second scenario of interest concerns times when the combustion turbines would operate on natural gas rather than syngas. During such events, NO_X emission rates will be slightly higher than under syngas operation, but SO_2 emissions would be lower. Therefore, the normal operating scenario for Mesaba One and Mesaba Two represents the highest combined-source pollutant emission profile justifying use of normal operation as the worst-case scenario for both short-term and annual Class I area impacts, and the emission rates presented in Table 8.2-2 represent this operating scenario.

Speciation of particulate matter emissions from the combustion turbines, as shown in Table 8.2-2, was based on available data for Mesaba One and Mesaba Two sources and Federal Land Manager (FLM) guidance on emissions from natural gas-fired turbines. The total particulate matter emissions (filterable plus condensable) and total sulfuric acid emissions are from Mesaba design specifications. The partitioning of filterable and condensable fractions, elemental carbon emissions, and organic aerosol emissions were calculated using the FLM consensus methodology. All filterable particulate matter was assumed to be elemental carbon less than 2.5 microns in diameter. All particulate matter emissions from the Tank Vent Boilers were assumed to be $PM_{2.5}$. Calculations are shown in Appendix D.

Emissions from other Mesaba One and Mesaba Two sources (flares, auxiliary boilers, and fugitive PM10) will be negligible in comparison to the turbine and TVB emissions, and were not included in the CALPUFF modeling.

8.2.2 Meteorological Data

The CALPUFF modeling analysis utilized meteorological data for the years 1990, 1992, and 1996. These are the same years used for other recent CALPUFF applications in northern Minnesota. Gridded meteorological fields used as input to the CALMET processor were MM4 (1990) and MM5 (1992, 1996) prognostic data acquired from the National Park Service (NPS). Additional surface, upper air, and precipitation data were used in CALMET to refine the meteorological fields. Hourly surface data from 13 stations were used along with precipitation data from 28 stations. Upper air data from two stations were used: St. Cloud MN and

International Falls MN for 1990 and 1992, and Minneapolis MN and International Falls for 1996. The surface and precipitation stations are listed in Appendix D.

8.2.3 Modeling Domain

The CALMET/CALPUFF modeling domain was a 700km by 500km area approximately centered on the Station site, with a four kilometer grid spacing. The coordinate system was Lambert Conformal. Receptor locations within each of the Class I areas were obtained from the National Park Service. Figure 7.7-8 shows the modeling domain, terrain elevation contours, and the modeling receptors. Figure 8.2-1 shows the locations of meteorological stations used for the CALMET processing.

Figure 8.2-1. CALMET Modeling Domain and Class I Areas Included in Analysis

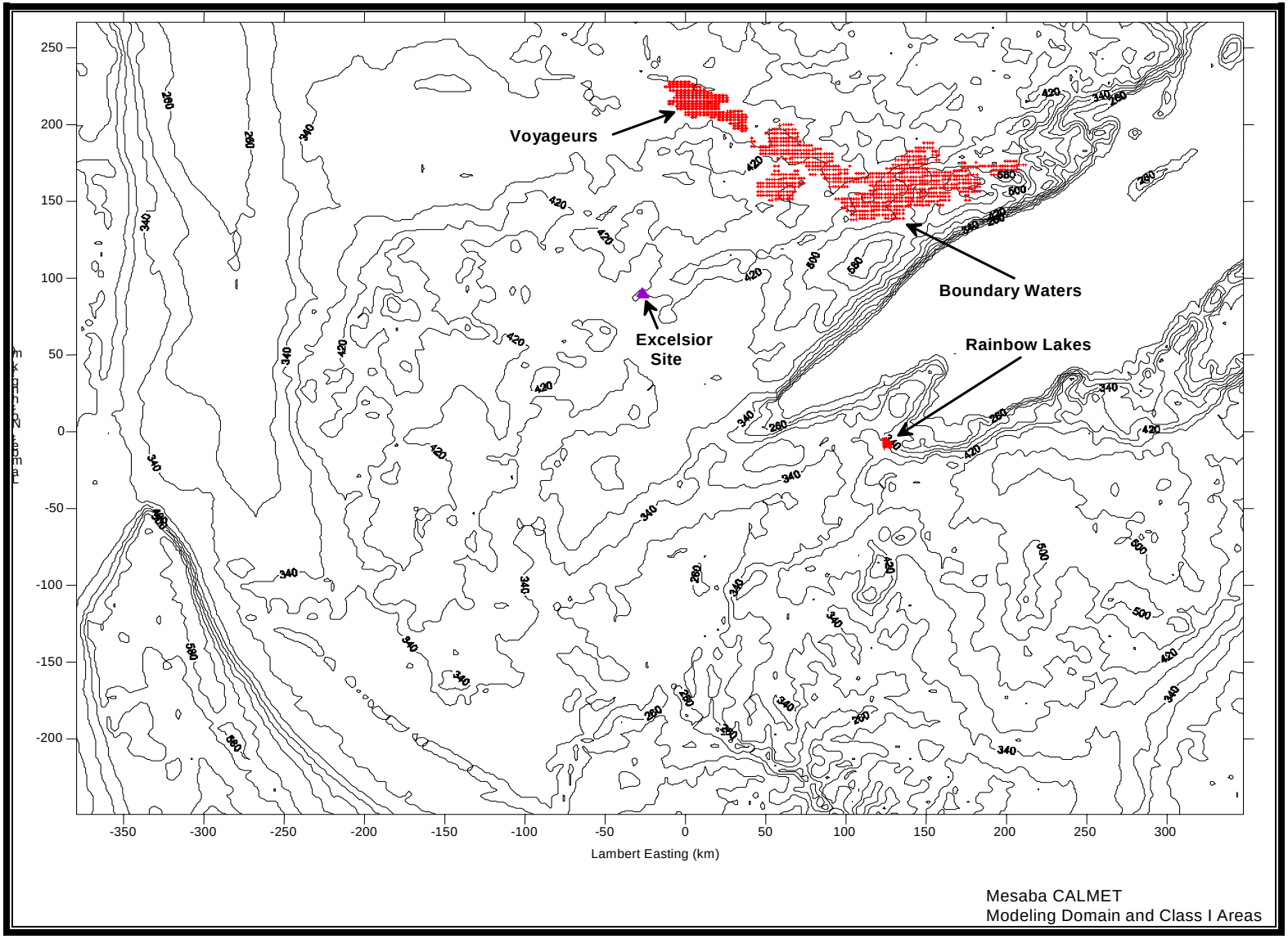
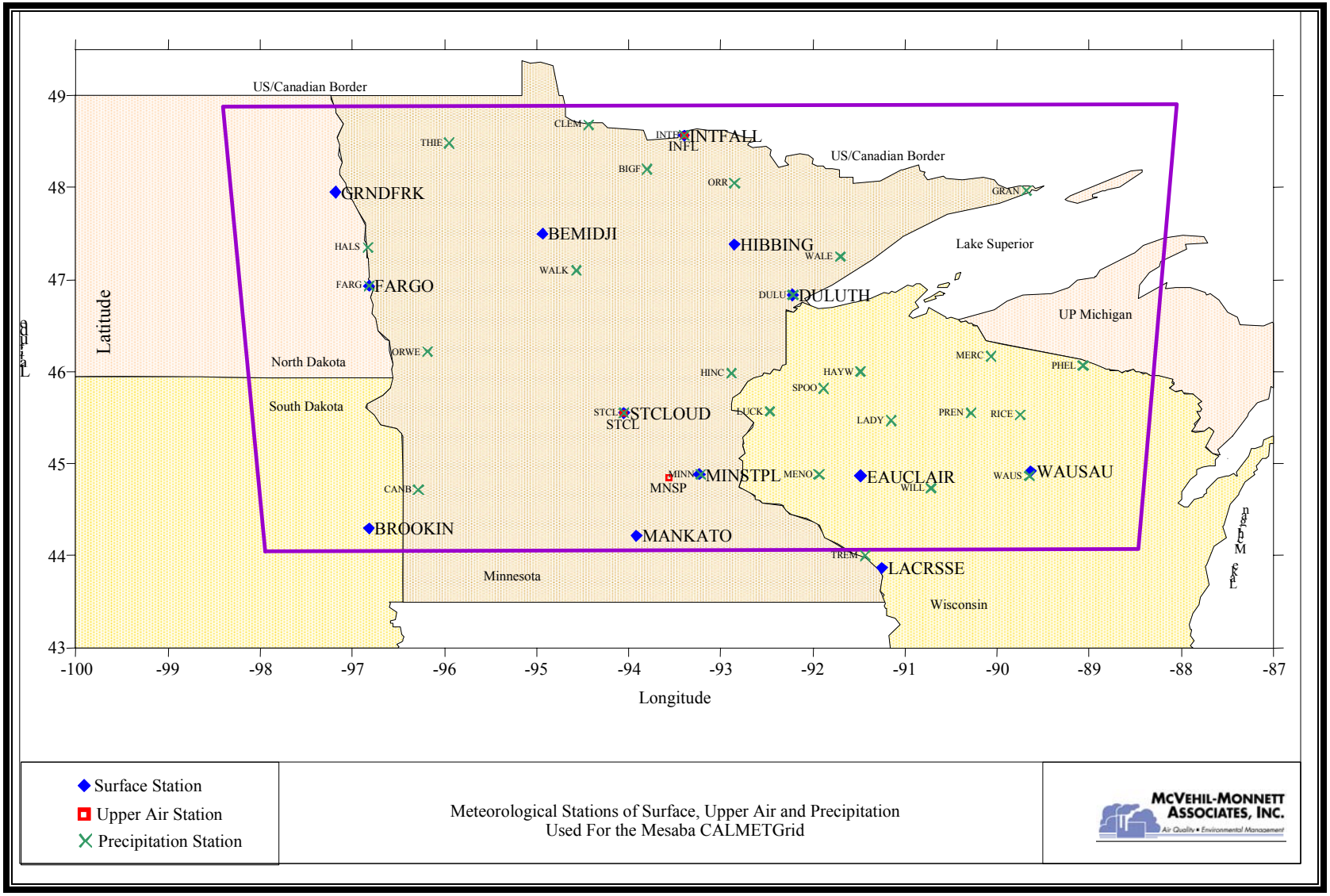


Figure 8.2-2. Meteorological Stations of Surface, Upper Air, and Precipitation Used for CALMET Modeling of Mesaba One and Mesaba Two



8.3 Class I Impacts and Increment Consumption

The CALPUFF model was used to calculate pollutant impacts at each receptor for each year of meteorological data, and for three-hour, 24-hour, and annual averaging periods. The two-phase Mesaba facility alone was modeled, with the stack parameters and emission rates shown in Table 8.2-2.

Class I PSD increments and Significant Impact Levels (SILs) exist for SO_2, NO_x, and PM10. Table 8.4-1 summarizes the highest CALPUFF model results for each Class I area, and shows the applicable Increment and SIL values. The data indicate that maximum Mesaba impacts are far below allowable increments for all pollutants and Class I areas. Impacts are also below the SIL in most cases, indicating that impacts will be insignificant and that no further analysis is necessary. However, for short-term SO_2 concentrations, impacts were indicated to exceed the SIL in the BWCA and VNP. Because the 3-hour and 24-hour SO_2 impacts could be significant, it was deemed necessary and appropriate to carry out a cumulative analysis, including other regional SO_2 increment sources, to verify and quantify total PSD increment consumption.

8.4 Cumulative Increment Analysis

The short-term cumulative SO_2 increment analysis used the CALPUFF model to calculate the combined impacts of all regional increment consuming and increment expanding sources at each of the Class I areas. In response to a request for SO_2 increment inventories, the MPCA provided emissions and stack data for those northern Minnesota sources with a potential for Class I impacts. The sources and net increment-consuming emissions are given in Table 8.4-2.

For some of the sources in Table 8.4-2, there are both positive (increment-consuming) and negative (increment-expanding) emissions. Only the net change in emissions is shown in the Table. Because the CALPUFF model cannot accommodate negative emission rates, it was necessary to model the positive and negative impacts in separate CALPUFF executions, and then determine the net impact on an hour by hour, receptor by receptor basis by post-processing of the CALPUFF SO_2 concentration results. To minimize computation time, some sources were combined in the model input. However, all combinations used the stack parameters appropriate to the major emission point, and separate applicable stack parameters were used for the positive and negative model runs.

The net emissions changes for increment modeling should be the change in actual emissions for sources that are or have been in operation. The increment-consuming emissions in the MPCA inventories generally represent potential (maximum allowable) emissions. These were used directly in the cumulative increment analysis with one exception.

The allowable SO_2 short-term emission rate for the Minnesota Power Clay Boswell Unit # 4 is 6131 lb/hr. Because of the high value of this limit, historical CEMS data for the source were reviewed to better define actual SO_2 emissions. Based upon data for the period 2003 through

Table 8.4-1
PSD Increment Modeling Results for Mesaba Energy Project

Boundary Waters/Pollutant Averaging Period	1990	1992	1996	Class I Inc (ug/m3)	Class I SIL (ug/m3)	Max (ug/m3)
SO_2 3-Hour	1.3804	1.4547	1.5505	25.0	1.00	1.5505
SO_2 24-Hour	0.4554	0.3382	0.3589	5.0	0.20	0.4554
SO_2 Annual	0.0147	0.0127	0.0095	2.0	0.10	0.0147
NOx Annual	0.0174	0.0152	0.0109	2.5	0.10	0.0174
PM_{10} 24-Hour	0.0866	0.0617	0.0586	8.0	0.30	0.0866
PM_{10} Annual	0.0041	0.0037	0.0026	4.0	0.20	0.0041

Voyageurs Pollutant/ Averaging Period	1990	1992	1996	Class I Inc (ug/m3)	Class I SIL (ug/m3)	Max (ug/m3)
SO_2 3-Hour	1.5911	1.0477	1.4836	25.0	1.00	1.5911
SO_2 24-Hour	0.2506	0.2943	0.4492	5.0	0.20	0.4492
SO_2 Annual	0.0128	0.0110	0.0113	2.0	0.10	0.0128
NOx Annual	0.0151	0.0125	0.0142	2.5	0.10	0.0151
PM_{10} 24-Hour	0.0537	0.0500	0.0745	8.0	0.30	0.0745
PM_{10} Annual	0.0037	0.0032	0.0031	4.0	0.20	0.0037

Rainbow Lakes Pollutant/ Averaging Period	1990	1992	1996	Class I Inc (ug/m3)	Class I SIL (ug/m3)	Max (ug/m3)
SO_2 3-Hour	0.7088	0.7567	0.7012	25.0	1.00	0.7567
SO_2 24-Hour	0.1806	0.1917	0.1711	5.0	0.20	0.1917
SO_2 Annual	0.0075	0.0083	0.0065	2.0	0.10	0.0083
NOx Annual	0.0081	0.0071	0.0068	2.5	0.10	0.0081
PM_{10} 24-Hour	0.0369	0.0462	0.0316	8.0	0.30	0.0462
PM_{10} Annual	0.0022	0.0028	0.0019	4.0	0.20	0.0028

Table 8.4-2
Modeled Increment Consuming SO_2 Emissions For Cumulative Class I Increment Analysis

Source	Net Increment SO_2 Emissions	
	lb/hr	g/s
Mesaba One and Mesaba Two		
3-hour	622.9	78.48
24-hour	468.7	59.06
Minnesota Power – Hibbard	416.8	52.51
Blandin Paper – Rapids Energy	417.0	52.54
Northshore Mining	-20.8	-2.62
Minnesota Power – Clay Boswell	1686	212.4
Potlatch Paper – Cloquet	-34.5	-4.35
Hibbing Taconite – Hibbing	772.3	97.31
Boise Cascade	141.6	17.84
Mesabi Nugget – Hoyt Lakes	225.6	28.42

June 2005, the 95th percentile 3-hour and 24-hour average emission rates were 1600 and 1565 lb/hr, respectively. Thus, maximum actual short-term SO_2 emissions rarely exceed about 1600 lb/hr. Accordingly, a conservative emission rate of 1686 lb/hr, equal to the annual average allowable emissions for Unit 4, was used for Clay Boswell in the cumulative analysis.

The results of the cumulative SO_2 increment analysis are shown in Table 8.5-1. The maximum predicted increment consumption in each of the Class I areas is shown to be well within the PSD Class I limits, and it is clear that Mesaba One and Mesaba Two will not cause or contribute to any violation of Class I PSD increments.

8.5 Deposition of Nitrogen and Sulfur

The CALPUFF results for each of the Class I areas were processed with CALPOST to calculate total annual deposition of nitrogen and sulfur at each receptor as a result of Mesaba One and Mesaba Two

Table 8.5-1
Mesaba One and Mesaba Two Cumulative SO_2 Increment Results (µg/m3)*

Boundary Waters/Pollutant Averaging Period	1990	1992	1996	Class I Inc (µg/m3)	Max (µg/m3)	Violation? (Y/N)
SO_2 3-Hour	6.1	7.0	5.8	25.0	7.0	NO
SO_2 24-Hour	2.6	2.1	2.2	5.0	2.6	NO
Voyageurs Pollutant/ Averaging Period	1990	1992	1996	Class I Inc (µg/m3)	Max (µg/m3)	Violation? (Y/N)
SO_2 3-Hour	5.2	4.6	5.5	25.0	5.5	NO
SO_2 24-Hour	1.6	1.5	1.6	5.0	1.6	NO
Rainbow Lakes Pollutant/ Averaging Period	1990	1992	1996	Class I Inc (µg/m3)	Max (µg/m3)	Violation? (Y/N)
SO_2 3-Hour	4.5	4.3	4.7	25.0	4.7	NO
SO_2 24-Hour	1.4	1.2	1.3	5.0	1.4	NO

* High-second highs

emissions. Model results for annual impacts (maximum annual average emissions) were used following the methodology given in the IWAQM Phase I report. Total sulfur deposition is calculated from the wet and dry deposition of SO_2 and sulfate; total nitrogen is represented by the sum of nitrogen from wet and dry fluxes of nitric acid, nitrate, ammonium sulfate and ammonium nitrate, and the dry flux of NOx. Results are shown in Table 8.6-1.

Table 8.6-1
Maximum Annual Deposition of S and N from Mesaba One and Mesaba Two in Class I Areas (kg/ha-yr)

Class I Area/Year	Sulfur	Nitrogen
Boundary Waters Canoe Area		
1990	1.217×10^{-2}	9.549×10^{-3}
1992	9.797×10^{-3}	7.085×10^{-3}
1996	8.400×10^{-3}	6.217×10^{-3}
Voyageurs National Park		
1990	1.016×10^{-2}	7.864×10^{-3}
1992	1.110×10^{-2}	8.562×10^{-3}
1996	9.780×10^{-3}	7.835×10^{-3}

Class I Area/Year	Sulfur	Nitrogen
Rainbow Lakes Wilderness		
1990	5.188×10^{-3}	4.225×10^{-3}
1992	6.336×10^{-3}	4.617×10^{-3}
1996	5.936×10^{-3}	4.749×10^{-3}

8.6 Impacts on Soils, Waters, and Vegetation

Potential impacts to soils, waters, and vegetation in Class I areas were evaluated on the basis of the model-predicted pollutant concentrations and the magnitude of predicted annual deposition of sulfur and nitrogen. The evaluation for Mesaba One and Mesaba Two impacts at the BWCA, VNP, and RLW is presented in this section.

Screening criteria for potential air pollution impacts on vegetation have been given by the U.S. Forest Service. (Hanna, 1984.) According to the USFS "Green Line" screening values "were set at levels at which it was reasonably certain that no significant change would be observed in ecosystems that contain large numbers of sensitive components." The Green Line screening levels for SO_2 are 5 $\mu g/m^3$ maximum annual average and 100 $\mu g/m^3$ maximum three-hour average. Though the USFS screening levels were established specifically for Class I areas administered by the Forest Service (BWCA and RLW) it is reasonable to apply the same criteria to VNP, which is administered by the National Park Service (NPS) but does not have a published standard similar to the USFS. (USFS, 1991.)

Table 8.6-2 compares CALPUFF projections of Mesaba impacts and existing background concentrations to the Green Line screening levels for each Class I area. Current concentrations, Mesaba contributions, and the sum of the two are all well below the Green Line levels. It can therefore be concluded that there will be no threat to sensitive vegetation from Mesaba SO_2 emissions. There are no established screening criteria for NO_2 and PM10. However, as shown in Section 8.3, Class I area concentrations of NO_2 and PM_{10} from Mesaba One and Mesaba Two will be below significance levels and therefore can be expected to have negligible impacts.

The USFS has also established a Green Line screening value for ozone concentration. The green line level is a second-highest one-hour concentration during the growing season of 80 ppb. Existing background monitoring data indicate current concentrations near the Green Line level, but below the red line concentration of 120 ppb. Ozone modeling is not required for Mesaba One and Mesaba Two, but the modest level of VOC and NO_x emissions indicate that the IGCC Power Station will not cause a significant increase in ozone impacts in the Class I areas.

Criteria for assessment of deposition impacts are different for USFS areas (BWAC and RLW) and NPS areas (VNP). The NPS has established a Deposition Analysis Threshold (DAT) of 0.01 kg/ha-yr for both sulfur (S) and nitrogen (N) deposition for Class I areas in the eastern United States. The DAT is a level below which adverse impacts are not anticipated. As shown in Table 8.5-1, the CALPUFF model results for deposition in VNP are very close to the 0.01 DAT for S, and below the DAT for N. In the case of S, two of the three years modeled produced a total

sulfur deposition value slightly greater than 0.01, and the third year resulted in a value slightly below 0.01. When it is considered that the deposition values in Table 8.6-1 represent the highest deposition for any receptor in the Class I area, and that the annual emissions for Mesaba used in the model are very conservative (worst-case emissions assuming two phases operating 8760 hours per year), it can be concluded that it is unlikely that the DAT threshold for S deposition will be exceeded at any point in VNP. The DAT represents a screening level to assess any possibility of adverse impact, and is not a regulatory limit. Based upon these considerations, it has been concluded that S and N deposition from Mesaba One and Mesaba Two will not cause adverse effects in VNP.

Table 8.6-2
Comparison of Projected Class I SO_2 Concentrations to Green Line Screening Criteria for Vegetation Impacts

Class I Area	Background [1] ($\mu g/m^3$)		Max. Mesaba ($\mu g/m^3$)		Total ($\mu g/m^3$)		Green Line ($\mu g/m^3$)	
	3-hr	annual	3-hr	annual	3-hr	annual	3-hr	annual
Boundary Waters Canoe Area	10.8	1.2	1.55	.015	12.35	1.215	100	5
Voyageurs National Park	6.3	0.7	1.59	.013	7.89	.713	100	5
Rainbow Lake Wilderness	14.4	1.6	.76	.008	15.16	1.608	100	5

[1] Background SO_2 concentrations from Mesaba Nugget Class I Air Modeling Report, Barr Engineering Company, May 2005.

Table 8.6-3
Comparison of Projected S and N Deposition Rates to Green Line Criteria for Impacts to Terrestrial and Aquatic Ecosystems

Class I Area	Parameter	Background [1] (kg/ha-yr)	Maximum Mesaba Impact (kg/ha-yr)	Total (kg/ha-yr)	Green Line [2] Value (kg/ha-yr)
BWCA	Terrestrial				
	Total S Depo	2.85	.012	2.86	5-7
	Total N Depo	4.75	.010	4.76	5-8
	Aquatic				
	Total S Depo	2.85	.012	2.86	7.5-8
	S + 20% N	3.80	.014	3.81	9-10
RLW	Terrestrial				
	Total S Depo	2.98	.006	2.99	5-7
	Total N Depo	5.88	.005	5.89	5-8
	Aquatic				
	Total S Depo	2.98	.006	2.99	3.5-4.5
	S + 20% N	4.16	.007	4.17	4.5-5.5

[1]Background values from Mesabi Nugget Class I Air Modeling Report, Barr Engineering Company, May 2005.
[2]Green Line Values from Screening Procedure to Evaluate Effects of Air Pollution on Eastern Region Wildernesses Cited as Class I Air Quality Areas, USFS, 1991.

For the USFS Class I areas (BWCA and RLW), different screening criteria are recommended for assessment of deposition impacts to terrestrial and aquatic ecosystems. For terrestrial impacts, Green Line criteria are total S deposition of 5 to 7 kg/ha-yr, and total N deposition of 5 to 8 kg/ha-yr. For aquatic impacts, the Green Line values differ for the two Class I areas because of the different chemistry of sensitive lakes in the two areas. The Green Line values, shown in Table 8.6-3, are expressed in terms of S deposition plus 20% of N deposition.

Table 8.6-3 summarizes projected deposition rates in the BWCA and RLW, calculated as background plus Mesaba One and Mesaba Two predicted deposition, and provides a comparison to the USFS Green Line values. It is shown that all deposition rates are within or below the acceptable Green Line levels. It can also be noted that all S deposition rates are below the State of Minnesota's limit for wet sulfate deposition of 11 kg/ha-yr (approximately 6 kg/ha-yr of total S deposition). It is therefore concluded that Mesaba One and Mesaba Two will not cause adverse impacts to terrestrial and aquatic ecosystems in the BWCA or RLW.

8.7 Regional Haze Analysis

A visibility/regional haze impact analysis was carried out for BWCA and VNP. Visibility analysis is not required for Rainbow Lakes. The recommended methodology for assessing visibility impacts according to the FLAG guidance involves the use of CALPOST to process the data on concentrations of pollutants from the CALPUFF modeling of 24-hour emissions. In CALPOST a daily value of light extinction is defined by the concentrations of each pollutant that can effect visibility, taking into account the efficiency of each particle type in scattering light, and the relative humidity which influences the size of hygroscopic pollutants (sulfates and nitrates). The 24-hour average light extinction caused by emissions from the modeled source(s) is then compared to the background light extinction, a value based upon "natural" or pristine unpolluted conditions for each Class I area.

The FLMs have established threshold changes in light extinction (as a percentage of natural background) that are believed to represent potential adverse impacts on visibility. These thresholds are 5% (a potentially detectable change) and 10% (a level that may represent an unacceptable degradation).

Table 8.7-1 presents results of the initial CALPUFF visibility analysis following the FLAG methodology, and using "Method 2" of CALPOST for calculation of visibility impacts. In Method 2, relative humidity data from the nearest surface weather station is used to calculate both source and background light extinction. Other methods, discussed below, use average relative humidity values, consider natural visibility impairment, and take into account average light extinction over a line-of-sight rather than extinction at a single receptor location.

The data in Table 8.7-1 indicate that calculated visibility impacts greater than 5 or 10% could occur at some point within the BWCA and VNP on a small number of days each

year. Because these data suggest a potential for detectable visibility degradation due to Mesaba emissions, additional analyses were carried out to better quantify and evaluate the possibility of visibility impacts. These analyses are described in following sections.

Table 8.7-1
Visibility Results for Mesaba One and Mesaba Two (FLAG Method 2 Analysis)

Year and Parameter	Boundary Waters Canoe Area	Voyageurs National Park
1990 Meteorological Data		
Days > 5%	39	16
Days > 10%	10	1
Maximum Change in light extinction	16.4%	11.8%
1992 Meteorological Data		
Days > 5%	36	25
Days > 10%	15	4
Maximum Change in light extinction	24.1%	19.0%
1996 Meteorological Data		
Days > 5%	17	18
Days > 10%	6	4
Maximum Change in light extinction	15.0%	22.5%

8.7.1 Visibility Considerations

Under 40 C.F.R. 51.301, an adverse impact on visibility is defined as "visibility impairment which interferes with the management, protection, preservation, or enjoyment of the visitor's visual experience of the Federal Class I area. This determination must be made on a case-by-case basis taking into account the geographic extent, intensity, duration, frequency and time of visibility impairments, and how these factors correlate with (1) times of visitor use of the Federal Class I area, and (2) the frequency and timing of natural conditions that reduce visibility." This definition indicates that a model-predicted extinction change exceeding a given threshold value does not necessarily imply an adverse impact. Some consideration should be given to local conditions at the time and location of the model result, and factors that may have contributed to the predicted impact.

There are several factors inherent in the FLAG Method 2 methodology that are conservative in the sense that they lead to the highest likely impact. These include:

- The extinction change calculated for a Class I area represents the largest change for any receptor within the area.

- The change is calculated relative to natural or pristine background: that is, the best visibility in the absence of any industrial pollution or abnormal natural events such as forest fires.
- No natural visibility impairment due to fog, precipitation, or clouds is considered.
- The calculations assume emissions from the modeled source, at the highest daily rate, for every hour and day of the year.

Possible errors in the CALPUFF model simulation should also be considered. There are various uncertainties in the CALPUFF dispersion models, all of which may lead to over- or under-prediction of concentrations at any given point and time. However, the atmospheric chemistry calculations in CALPUFF are the most critical, since they are responsible for predicted concentrations of sulfate and nitrate particles that largely define light extinction. Morris et al. have reported on an evaluation of the CALPUFF chemistry algorithms by comparison to measured concentrations and the more sophisticated CMAQ model. (Morris, et al., 2005.) They conclude that:

"The quantitative evaluation of the CALPUFF chemistry algorithms found that they greatly overstate the amount of nitrate in the atmosphere and sulfate is likely overstated in the winter and understated in the summer. An analysis of sulfate and nitrate concentration increments suggest that winter sulfate and nitrate impacts from individual sources (e.g. PSD or BART analysis) are overstated by both versions of the CALPUFF chemistry algorithms."

These conclusions are directly relevant to the present analysis, where the greatest visibility impacts were predicted in winter months, and the largest contribution to light extinction is generally from nitrate particles.

It should also be noted that relative humidity is a critical input to the light extinction calculation. Because of the hygroscopic nature of sulfate and nitrate particles, light extinction is greatly magnified under high humidity conditions. The CALPOST visibility calculation uses measured relative humidity at the nearest surface weather station to calculate the humidity effect of given concentrations of sulfate and nitrate particles. The nearest weather station is often some distance from the Class I area of concern, and the observed relative humidity may or may not be representative of the analysis area. Most important, high relative humidity values are frequently associated with fog, precipitation, and low clouds, all of which can create natural visibility impairment. The possible occurrence of these natural phenomena are not considered in the FLAG method 2 calculation. The association of high humidity and natural weather events with predicted Class I impacts is discussed below.

Finally, the definition of visibility impairment in 40 C.F.R. 51.301 refers to "any humanly perceptible change in visibility". It has generally been considered that a change in light extinction of 5 to 10% constitutes a noticeable change in viewing a scene through the atmosphere. However, it has been pointed out by Richards that this threshold is only appropriate over a line-of-sight equal to the natural visual range (for the Class I areas in this analysis, a distance on the order of 175 km). (Richards, 1999) For shorter sight lines, a 5 to 10% change in light extinction may not be perceptible. Or, a 5 to 10% local

increase in light extinction is not likely to be perceptible over a long sight path for which the average extinction is less.

The considerations discussed here indicate that the FLAG Method 2 visibility results in Table 8.7-1 are not definitive in suggesting that there could be adverse impacts of Mesaba One and Mesaba Two for a number of days per year in the BWCA and VNP. Most of these factors suggest that actual impacts may be substantially lower than indicated. Additional analyses are presented in the following section to provide further information on implications of the CALPUFF results.

8.7.2 Additional Visibility Analyses

There are currently no practical and acceptable ways to include all of the factors discussed above in making a more rigorous and realistic assessment of the probability of actual visibility impairment. However, some procedures have been suggested to account, in part, for potential errors or omissions in the FLAG calculations.

The CALPOST post-processing software contains several alternative algorithms for calculating the change in light extinction due to the modeled source. Method 6 substitutes monthly average relative humidity values (specific to each Class I area) for the hourly relative humidity data at nearby weather stations. This substitution mitigates, to some extent, the high extinction values calculated when very high humidity values are reported throughout the day at the nearest observation site. It is intended to account for the fact that the observed humidity may be unrepresentative of the Class I area, and that very high relative humidities are frequently associated with natural impairment by fog, clouds, and precipitation. The Method 6 calculation is recommended by the U.S. EPA for state regional haze BART analyses.

Method 7 is another modification of the standard Method 2 as it attempts to account for natural visibility reduction due to fog or precipitation. In Method 7, the actual measured visibility at the nearest weather station is used as background (instead of natural pristine background) on those hours when fog or precipitation are reported. Method 7 represents another attempt to account for natural visibility reduction in assessing the impact of man-made pollution.

A criticism of Method 7 is that it tends to minimize the effect of source-induced haze on days when natural impairment may only exist for a small part of the day. It is possible that the impact of the source could still be significant during other hours of the day. This is a valid point, but the FLAG procedures specify visibility calculation on a 24-hour daily basis, on the grounds that model predictions for any single hour are subject to significant error. If the 24-hour averaging is appropriate for the basic visibility calculation, it may be reasonable to also utilize some 24-hour averaging in the effect of natural visibility impairing events. Certainly the occurrence of fog or precipitation on specific hours at a nearby weather station indicates the likelihood of these events at other times and/or locations within the Class I area.

Table 8.7-2 shows the results of Method 6 and Method 7 visibility calculations for Mesaba One and Mesaba Two, with comparison to the Method 2 data. Both alternative

analyses indicate lower frequency and magnitude of impacts relative to Method 2. For Method 7, there are only two days of predicted impacts from three years of data exceeding 10% change in light extinction at the BWCA, and none at VNP.

In EPA's BART guidance for regional haze, the 98th percentile of light extinction predictions is recommended as a threshold for significant impact. This means that an average of seven days per year or more of impacts exceeding 5% indicates a significant impact. Under this criterion, the Method 7 results show no significant visibility impact of Mesaba One and Mesaba Two at either Boundary Waters or Voyageurs.

As discussed in the proceeding section, a perceptible change in visibility at the 5% level is properly defined over an extended line-of-sight equal to the background visual range. Calculations were made of the average change in light extinction over several 150 km sight lines for the day of highest predicted impact in the BWCA. Using Method 2, the highest Mesaba One and Mesaba Two impact was 24.1% on February 3, 1992 at a receptor near the southern BWCA boundary northeast of the IGCC Power Station. Three sight lines were evaluated: one from the highest receptor directly southwest to the IGCC Power Station, one in the opposite direction from the highest receptor away from the IGCC Power Station, and one extending across the BWCA in an approximate east-west orientation. A separate CALPUFF model run was made for receptors along the three sight lines, and average changes in light extinction were calculated, by Method 2, along each of the three lines. The results showed average extinction changes of 13% (toward Mesaba One and Mesaba Two); 9% (away from the IGCC Power Station), and 13.6% (across the BWCA). Though still significant, these calculated average changes are 50% or less than those at the maximum receptor.

Examination of the meteorology for this single "worst day" shows that temperatures in the BWCA were approximately 22 to 30 deg F, there were a few snow flurries, and a cloud cover of 100% existed at approximately 500 feet above the ground for much of the day. Fog was reported at Hibbing from midnight until 8 PM, with visibility between ½ and 5 miles; at International Falls, fog existed from midnight until 3 PM with visibility less than 1.2 miles until mid-afternoon. Under these conditions, natural conditions would have precluded access to extended scenic views for Park visitors.

An analysis was carried out to characterize the times and meteorological conditions for those days on which CALPUFF, with Method 2, indicated light extinction changes exceeding five percent in either the BWCA or VNP. Hourly meteorological data from Hibbing were assumed to represent the BWCA, and data from International Falls were used for days of impacts at VNP. Days on which fog, precipitation, or low ceiling (less than 3000 feet) occurred were tabulated, along with relative humidity measurements at 6 AM and 12 noon. These times typically represent near highest and lowest humidity values for the day. Also listed for each day was the value of f(RH) used in the CALPOST light extinction calculation. f(RH) represents the daily mean value of the relative humidity parameter that accounts for growth of sulfate and nitrate particles; high values of f(RH) indicate high humidity conditions under which light scattering by these particles is dramatically increased. The value of f(RH) varies from 1.0 for humidity less than 37%, to 9.8 at the maximum CALPOST humidity of 95%.

Results of the meteorological analysis are presented in Table 8.7-3. The main conclusions evident from the Table are:

- Predicted impacts occur predominantly during the winter part of the year; 47 to 61% of all occurrences are indicated between November and March.
- A very high percentage of occurrences coincide with days of natural visibility degradation due to fog, precipitation, or low clouds. 82% to 100% of the days had some occurrence of these weather elements.
- All occurrences of predicted visibility impact were on days of very high relative humidity.

Of the 40 days (in three years) when an extinction change greater than 10% was indicated at either BWCA or VNP, only two days had no direct observations of natural visibility impairment. These days, both at the BWCA, were February 14, 1990 and January 10, 1992. On the first day, temperature was -20 deg F, with relative humidity ranging from 72 to 100% during the 24-hour day. On January 10, 1992, temperatures were near zero deg F, relative humidity ranged from 91 to 96%, and weather maps suggest that snow flurries related to a stationary front probably occurred in some parts of the BWCA. Given these facts, it seems likely that some natural visibility impairment existed in the BWCA, though none was observed at Hibbing.

Of course, the occurrence of natural visibility degradation on some hours of the day does not necessarily imply that visual impacts of Mesaba emissions could not exist during other periods of the day. There is no practical means of evaluating impacts on an hour-by-hour basis. But as noted above, since the visibility calculation is made on a daily average basis, it is reasonable to consider natural impacts also in terms of some spatial and time-averaged indicators. At the least, the data in Table 61 indicate that there were some natural visibility impacts within the Class I areas on nearly all days of predicted Mesaba One and Mesaba Two effects. The analysis shows that modeled impacts overwhelmingly occur on days of inclement weather. The high model-predicted light extinction values are always caused by high relative humidity measurements at the nearest weather station, and these high humidities may not be truly representative of larger-scale conditions within the Class I area. If the high humidity values are local anomalies, the CALPUFF impacts are overstated. If the humidity data are representative, they are indicative of a high probability of natural visibility impairment.

To summarize the Mesaba visibility impact analysis, CALPUFF modeling suggests some days of potential impact at both the BWCA and VNP. However, a number of very conservative elements exist in the FLAG evaluation methodology, and the CALPUFF model chemistry has been shown to significantly overestimate hygroscopic particle concentrations. In consideration of these facts and the meteorological analysis of impact days, it is concluded that Mesaba One and Mesaba Two will have detectable visibility effects on few if any days, and that impacts are extremely unlikely to interfere with the visual experience of park visitors.

Table 8.7-2
Mesaba CALPUFF Visibility Results

Speciated PM 12/5/2005	**1990 Method 2** > 5 %	**1990 Method 2** > 10 %	**1990 Method 2** Max %	**1992 Method 2** > 5 %	**1992 Method 2** > 10 %	**1992 Method 2** Max %	**1996 Method 2** > 5 %	**1996 Method 2** > 10 %	**1996 Method 2** Max %
Boundary Waters Wilderness	39	10	16.43	36	15	24.11	17	6	14.98
Voyageurs National Park	16	1	11.82	25	4	18.97	18	4	22.47
Speciated PM 12/5/2005	1990 **Method 6** > 5 %	1990 **Method 6** > 10 %	1990 **Method 6** Max %	1992 **Method 6** > 5 %	1992 **Method 6** > 10 %	1992 **Method 6** Max %	1996 **Method 6** > 5 %	1996 **Method 6** > 10 %	1996 **Method 6** Max %
Boundary Waters Wilderness	24	1	12.12	19	2	11.54	9	0	8.13
Voyageurs National Park	13	0	8.43	14	1	10.22	8	1	12.49
Speciated PM 12/5/2005	1990 **Method 7*** > 5 %	1990 **Method 7** > 10 %	1990 **Method 7** Max %	1992 **Method 7** > 5 %	1992 **Method 7** > 10 %	1992 **Method 7** Max %	1996 **Method 7** > 5 %	1996 **Method 7** > 10 %	1996 **Method 7** Max %
Boundary Waters Wilderness	11	1	10.43	7	1	19.22	2	0	7.63
Voyageurs National Park	3	0	7.93	2	0	6.13	3	0	8.13

* Hibbing MN used as primary weather station for Boundary Waters Wilderness, International Falls used for Voyageurs NP.

Table 8.7-3
Characteristics of Days with Predicted Visibility Impacts

Meteorological Characteristic	Boundary Waters Canoe Area		Voyageurs National Park	
	Days > 5%	Days > 10%	Days > 5%	Days > 10%
	Total 92 Days	Total 31 days	Total 59 days	Total 9 days
Percentage of days November through March	57%	61%	47%	56%
Percentage of days with precipitation	60%	68%	78%	100%
fog	54%	77%	64%	89%
ceiling < 3000 ft	68%	81%	69%	78%
Percentage of days with some natural visibility impairment	82%	94%	88%	100%
Average morning (0600) relative humidity	95%	97%	92%	94%
Average mid-day (1200) relative humidity	76%	85%	75%	83%
Mean daily f((RH)	5.34	6.45	4.73	5.91
equivalent relative humidity	91%	92.5%	90%	92%

Statistics for BWCA from hourly surface weather data at Hibbing MN; statistics for VNP from hourly surface data at International Falls, MN.

9. REFERENCES

Screening Procedure to Evaluate Effects of Air Pollution on Eastern Region Wildernesses Cited as Class I Air Quality Areas. USFS General Technical Report NE-151, 1991.

Morris, R., S. Lau, and B. Koo, 2005: Evaluation of the CALPUFF Chemistry Algorithms. AWMA Annual Conference, Minneapolis MN, June 21 – 24, 2005.

Richards, 1999: Use of the Deciview Haze Index as an Indicator for Regional Haze. J. Air & Waste Management Assoc. 49: 1230-1237.

U.S. EPA, 2003: Guidance for Tracking Progress Under the Regional Haze Rule. EPA-454/B-03-004, September 2003.

Richards, 1999: Use of the Deciview Haze Index as an Indicator for Regional Haze. J. Air & Waste Management Assoc. 49: 1230-1237.

USDOE/NETL, 2002. Major Environmental Aspects of Gasification-Based Power Generation Technologies, Final Report. December 2002. Science Applications International Corporation (SAIC)

10. AIR PERMIT APPLICATION FORMS

The permit application forms completed in support of this application are identified in Table 9.0-1 below.

Table 9.0-1
Permit Application Forms

Name of Form	Equipment or Facilities Covered (Phase I and II)	No. of Forms	Reserved.
CP-01 Cover Page	IGCC Power Station	1	
CR-01 Certification	IGCC Power Station	1	
CR-03 Confidentiality Certification	IGCC Power Station	1	
GI-01 Facility Information	IGCC Power Station	1	
GI-02 Process Flow Diagram	IGCC Power Station	1	
GI-03 Facility and Stack/Vent Diagram	IGCC Power Station	1	
GI-04 Stack/Vent Info	IGCC Power Station	1	
GI-05A Pollution Control Equip Info	IGCC Power Station	1	
GI-05B Emission Unit Info	IGCC Power Station	1	
GI-05D Fugitive Emission Source Info	IGCC Power Station	1	
GI-09 Requirements Form	IGCC Power Station	1	
GI-09A Requirements NESHAP (40 C.F.R. 63)	IGCC Power Station	1	
GI-09B Requirements NESHAP (40 C.F.R. 61)	IGCC Power Station	1	
GI-09C Requirements New Source Review	IGCC Power Station	1	
GI-09D Requirements NSPS	IGCC Power Station	1	
GI-09G Risk Management Programs For Chemical Accidental Release Prevention	IGCC Power Station	1	
GI-09H CAM (40 C.F.R. 64)	IGCC Power Station	1	
GI-09 I State Rules	IGCC Power Station	1	
HG-2003 Mercury Releases	IGCC Power Station	1	
EC-01 General Process/Unit Calculation	Flares, cooling towers	6	
		1	
		1	
		1	
		1	
		1	
		1	
EC-02 External Combustion (Boilers)	Aux boilers, tank vent boilers	4	
		1	
		1	
		1	

Table 9.0-1
Permit Application Forms Continued

EC-03 IC Engines	CTGs, diesel generators and FW pump engines	14	
		1	
		1	
		1	
		1	
		1	
		1	
		1	
		1	
		1	
		1	
		1	
		1	
		1	
		1	
EC-13A Hazardous Air Pollutants (VOC)	IGCC Power Station, fugitive HAPs and VOC	1	
EC-13C Hazardous Air Pollutants (Fuel Combustion)	CTGs, tank vent boilers, flares	6	
		1	
		1	
		1	
		1	
		1	
		1	
EC-15 Fugitive Particulate Emission	Solid feed unloading, storage, handling and slag handling	1	
IA-01 Insignificant Activities List	IGCC Power Station	1	
AERA-01	Contained in Appendix E	1	
AERA-02	Contained in Appendix E	1	
AERA-03	Contained in Appendix E	1	
AERA-04	Contained in Appendix E	1	
AERA-05	Contained in Appendix E	1	

Minnesota Pollution Control Agency

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520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **CP-01**

TOTAL FACILITY OPERATING PERMIT COVER PAGE

7/25/05

1a) AQ Facility ID No.: _____

1b) AQ File No.: _____

2) Facility Name: Mesaba One and Mesaba Two

THIS TOTAL FACILITY OPERATING PERMIT APPLICATION IS FOR: (check all that apply)

☐ A Part 70 permit (Minn. Rules pt. 7007.0200)

☐ A State permit (Minn. Rules pt. 7007.0250)

☐ with EMS provisions

☒ Construction of a New Facility (Minn. Rules pt. 7007.0150, subp. 1)

☒ A Project subject to Prevention of Significant Deterioration (PSD) (40 C.F.R. § 52.21)

CONFIDENTIALITY:

☐ This application contains material which is claimed to be confidential under Minnesota Statutes Chapter 13 and Section 116.075 and Minn. Rules pt. 7000.1300.

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One and Mesaba Two

CERTIFICATION

I certify under penalty of law that the enclosed documents and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete.

I also certify, in accordance with Minnesota Rules 7007.0500, subp. 2 (K)(2) and subp. 2 (K)(3), that I have reviewed the procedures implemented by my facility to maintain compliance and that those procedures are, to the best of my knowledge and belief, reasonable to maintain compliance with all applicable requirements, including those that will become applicable during the term of the permit.

Owner:		**Operator:**	
Mr./Ms.	Robert S. Evans II	Mr./Ms.	Robert S. Evans II
Title:	Vice President-Environmental Affairs	Title:	Vice President-Environmental Affairs
Signature:		Signature:	
Date:	June 19, 2006	Date:	June 19, 2006

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **CR-03**

CONFIDENTIALITY CERTIFICATION

5/3/05

1) AQ Facility ID No.: _____

2) Facility Name and Address: Not Applicable; No data claimed to be confidential

NOTICE OF PUBLIC AVAILABILITY OF DATA SUBMITTED TO THE MPCA

The information you submit to the MPCA with your permit application is available to the public under state and federal laws, except for certain specific kinds of information meeting statutory standards for confidential treatment. However, to have your information treated confidentially by the MPCA, you must certify that the information qualifies for confidential treatment and explain why. This document describes the most relevant laws that allow the MPCA to treat application information confidentially, and the steps you must take to obtain confidential treatment of your data. If you do not seek confidential treatment of any data, you do not need to return this form.

CERTIFYING DATA FOR THE CONFIDENTIAL USE OF THE MPCA

Information in a permit application may be considered confidential (or non-public) if any state law makes it so. The two legal provisions most likely to apply to permit applications protect the following kinds of data:

> Data furnished to the agency that relates to (a) sales figures, (b) processes or methods of production **unique** to the owner or operator, OR (c) information which would tend to affect adversely the competitive position of said owner or operator. (Minn. Stat. § 116.075, subd. 2)
>
> Data including a formula, pattern, compilation, program, device, method, technique or process (1) that was supplied by the affected individual or organization, (2) that is the subject of efforts by the individual or organization that are reasonable under the circumstances to maintain its secrecy, AND (3) that derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use. (Minn. Stat. § 13.37, subd. 1(b))

However, even if the information falls under one of the above categories, if it is considered emissions data (defined in 40 C.F.R. § 2.301), then the information is considered public. Both the Clean Air Act and Environmental Protection Agency (EPA) regulations require that "emission data" submitted to the MPCA under Title V or Minnesota's State Implementation Plan must be available to the public. In addition, EPA has issued guidance on what type of information it generally considers to be emission data (Federal Register Vol. 56, No. 35; February 21, 1991).

Please note that only **specific** data within an application can be considered confidential and not the entire application or permit. The procedures below describe how confidential information must be submitted to the MPCA. If you do not follow these procedures, the MPCA will not provide any special protections for your application, and it is possible that your information could be released to the public.

CERTIFICATION

To certify data for the confidential use of the MPCA, a responsible official must read the following, certify to its truth by filling in the signature block below, and provide the stated attachments.

I certify that the enclosed permit application(s) and all attachments have been reviewed by me and do contain confidential material. I understand that only specific data can be considered confidential and not the entire application or permit. I certify that I have enclosed the following to comply with the proper procedure for confidential material:

a. I have enclosed a statement identifying which data contained in my application I consider confidential, and I have explained why I believe the information qualifies for confidential (or non-public) treatment under Minnesota Statutes.

b. I have explained why the data for which I am seeking confidential treatment should not be considered "emissions data" which the MPCA is required to make available to the public under federal law.

c. I have enclosed an application containing all pertinent information to allow for completion and issuance of my permit. This document has been clearly marked "confidential".

d. I have enclosed a second copy of my application with the confidential data blacked out (not omitted or deleted entirely). It is evident from this copy that information was there, but that it is not for public review. This document has been clearly marked "public copy".

Permittee Responsible Official:		**Co-Permittee Responsible Official (if applicable)**	
Mr. / Ms.	_____	Mr. / Ms.	_____
Title:	_____	Title:	_____
Signature:	_____	Signature:	_____
Date:	_____	Date:	_____

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **GI-01**

FACILITY INFORMATION

5/3/05

1a) AQ Facility ID No.: _____

1b) AQ File No.: _____

2) Facility Name: Mesaba One and Mesaba Two

3) Facility Location:

Street Address: _____

City: Taconite State: MN ZIP Code: _____ County: Itasca

Mailing Address: 11100 Wayzata Boulevard
Suite 305
City: Minnetonka State: MN ZIP Code: 55305

4) Corporate/Company Owner:

Name: MEP-I LLC & MEP-II LLC

Mailing Address: 11100 Wayzata Boulevard
Suite 305
City: Minnetonka State: MN ZIP Code: 55305

Owner Classification: ☒ Private ☐ Local Govt ☐ State Govt. ☐ Federal Govt. ☐ Utility

5) Corporate/Company Operator (if different than owner):

Name: _____

Mailing Address: _____

City: _____ State: _____ ZIP Code: _____

6) Co-permittee (if applicable):

Name: _____

Mailing Address: _____

City: _____ State: _____ ZIP Code: _____

7) Legally responsible official for this permit/facility:

Mr/Ms: Robert S. Evans II Phone: (952) 847-2355

Title: Vice President-Environmental Affairs Fax: (952) 847-2373

At (check one): ☒ Owner Address ☐ Operator Address ☐ Emission Facility Address

☒ Other address (specify) Email address: BobEvans@excelsiorenergy.com

8) Contact person for this permit:

Mr/Ms: Mr. Robert S. Evans II Phone: (952) 847-2355

Title: Vice President-Environmental Affairs Fax: (952) 847-2373

At (check one): ☒ Owner Address ☐ Operator Address ☐ Emission Facility Address

☐ Other address (specify) _____

E-mail address: BobEvans@excelsiorenergy.com

9) All billings for annual fees should be addressed to:

Mr/Ms: Mr. Robert S. Evans II Phone: (952) 847-2355

Title: Vice President-Environmental Affairs Fax: (952) 847-2355

At (check one): ☒ Owner Address ☐ Operator Address ☐ Emission Facility Address

☐ Other (specify) _____

10) Standard Industrial Classification (SIC) Code and description for the facility and North American Industry Classification System (NAICS) Code and description:

Primary SIC code: 4911 / Electrical services

Secondary (if applicable): _____ / _____

Tertiary (if applicable): _____ / _____

Primary NAICS code:: 221112 / Fossil Fuel Electric Power Generation

11) Primary product produced (or activity performed) at the facility is:

Electricity

12) Facility is: ☒ Stationary ☐ Portable

13) Check the one that applies best to your facility:

☒ New facility planned or under construction (first permit application)

☐ Existing facility, applying for renewal of a total facility Air Quality operating permit issued by the MPCA

☐ Existing facility, and have never had a total facility operating permit, but have had another type of Air Quality permit issued by the MPCA

☐ Existing facility, but have never had a total facility operating permit or any other type of Air Quality permit issued by the MPCA

14) Is environmental review required (either an Environmental Assessment Worksheet (EAW) or an Environmental Impact Statement (EIS)) for this facility? Call the Minnesota Environmental Quality Board for more information (1-800-657-3794, or 296-8253 in the Twin Cities metro area).

☒ Yes ☐ No

Note: If you answered "Yes" to this question, you may also be required to perform a state air toxics review for your facility. Please call (800) 646-6247 or (651) 297-2274.

15) Are you required to submit a Toxics Release Inventory (Form R) under SARA Title 313 for this facility? Call the Minnesota Department of Public Safety, Emergency Response Commission for more information (651-297-7372).

☒ No ☐ Yes, but we are not required to submit a pollution prevention plan under Minn. Stat. § 115D.07;

☐ Yes, and we are required to submit a pollution prevention plan and have submitted the most recently required progress report to the Emergency Response Commission under Minn. Stat. § 115D.09.

16) Is this facility within 50 miles of another state or the Canadian border:

☐ Yes (specify which ones) _____ ☒ No

17) Brief description of the facility or proposed facility to be permitted (attach additional sheet if necessary):

IGCC Electric Power Generating Station - See Section 2 of Permit Application for detailed description.

18) Are you proposing any alternative operating or emissions trading scenarios in this application (see Minn. R. 7007.0800, subp. 10 and 11)?

☐ Yes ☒ No

If yes, attach a description of your proposal, including a statement on how the proposal will meet all applicable requirements (in particular, please address federal New Source Review requirements, if applicable). See Form GI-09(C).

19) Person preparing this permit application:

Mr. / Ms. Mr. Robert S. Evans II

Title: Vice President-Environmental Affairs E-mail address: BobEvans@excelsiorenergy.com

Phone: (952) 847-2355 Fax: (952) 847-2373 Date: June 19, 2006

PERMIT APPLICATION FORM **GI-02**

PROCESS FLOW DIAGRAM

5/13/98

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One and Mesaba Two

3) Flow Diagram: See Figures 2.3-1 and 2.3-2 in permit application.

Minnesota Pollution Control Agency

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PERMIT APPLICATION FORM **GI-03**

FACILITY AND STACK/VENT DIAGRAM

2/16/05

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One and Mesaba Two

3) Facility and Stack/Vent Diagram: See Figures 1.6-5, 2.3-1, and 2.3-2 in permit application.

Minnesota Pollution Control Agency

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ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **GI-04**
STACK/VENT INFORMATION
7/25/05

1) AQ Facility ID No.: _____ **2)** Facility Name: Mesaba One and Mesaba Two

TBD = Specifications to be determined during Front End Engineering Design period.

3a) SV ID No.	**3b)** Operator's Description	**3c)** Height of Opening From Ground (ft.)	**3d)** Inside Diameter in ft. (left column only) or Length x Width in ft. (both columns)		**3e)** Design Flow Rate at Exit (acfm)	**3f)** Exit Gas Temperature (° F)	**3g)** Rate/Temp Information Source	**3h)** Discharge Direction
001	CTG/HRSG, Phase I	150	20		1,240,000	250	M	U
002	CTG/HRSG, Phase I	150	20		1,240,000	250	M	U
003	Auxiliary Boiler, Phase I	40	5		37,500	300	E	U
004	ASU Cooling Tower, Phase I (each of 5 cells)	48	33		1,370,000	104	M	U
005	Power Block Cooling Tower, Phase I (each of 12 cells)	48	33		1,370,000	104	M	U
006	Emergency Diesel Generator - Gasification Island, Phase I	TBD	TBD		TBD	TBD		
007	Emergency Diesel Generator - Power Block, Phase I	TBD	TBD		TBD	TBD		
008	Emergency Firewater Pump Engine, Phase I	TBD	TBD		TBD	TBD		

009	Emergency Firewater Pump Engine, Phase I	TBD	TBD		TBD	TBD		
010	Tank Vent Boiler, Phase I	210	6		47,100	584	E	U
011	Flare, Phase I	185	5.5		(NA)	(NA)	E	U
012	Feed Bin Baghouse, Phase I	TBD	TBD		TBD	TBD		U
013	CTG/HRSG, Phase II	150	20		1,240,000	250	M	U
014	CTG/HRSG, Phase II	150	20		1,240,000	250	M	U
015	Auxiliary Boiler, Phase II	40	5		37,500	300	E	U
016	ASU Cooling Tower, Phase II (each of 5 cells)	48	33		1,370,000	104	M	U
017	Power Block Cooling Tower, Phase II (each of 12 cells)	48	33		1,370,000	104	M	U
018	Emergency Diesel Generator - Gasification Island, Phase II	TBD	TBD		TBD	TBD		
019	Emergency Diesel Generator - Power Block, Phase II	TBD	TBD		TBD	TBD		
020	Emergency Firewater Pump Engine, Phase II	TBD	TBD		TBD	TBD		
021	Emergency Firewater Pump Engine, Phase II	TBD	TBD		TBD	TBD		
022	Tank Vent Boiler, Phase II	210	6		47,100	584	E	U
023	Flare, Phase II	185	5.5		(NA)	(NA)	E	U
024	Feed Bin Baghouse, Phase II	TBD	TBD		TBD	TBD		U

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **GI-05A**
POLLUTION CONTROL EQUIPMENT INFORMATION
07/25/05

1) AQ Facility ID No.: _____ **2)** Facility Name: Mesaba One and Mesaba Two

IGCC Power Station represents inherently low emitting technological process providing superior emissions control across all criteria and non-criteria pollutants.

3a) Control Equip ID No.	**3b)** CE Type Code	**3c)** Description	**3d)** Manufacturer	**3e)** Model No.	**3f)** Pollutants Controlled	**3g)** Capture Efficiency	**3h)** Destruct/ Collect Efficiency	**3i)** Afterburner Combustion Parameters
001	022	Tank Vent Boiler, Phase I (SV010)	TBD		CO	100%	99%	>1600 deg F
					VOC	100%	99%	> 0.8 sec
					TRS	100%	99%	
002	023	Flare, Phase I (SV011)	TBD		CO	100%	99%	
					VOC	100%	99%	
					TRS	90%	99%	
003	018	Feed Bin Baghouse, Phase I (SV012)	TBD		PM10	100%	99%	
004	022	Tank Vent Boiler, Phase II (SV022)	TBD		CO	100%	99%	>1600 deg F

					VOC	100%	99%	> 0.8 sec
					TRS	100%	99%	
005	023	Flare, Phase II (SV023)	TBD		CO	100%	99%	
					VOC	100%	99%	
					TRS	90%	99%	
006	024	Feed Bin Baghouse, Phase II (SV024)	TBD		PM10	100%	99%	

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PERMIT APPLICATION FORM **GI-05B**
EMISSION UNIT INFORMATION, PART 1
07/25/05

1) AQ Facility ID No.: _____ **2)** Facility Name: Mesaba One and Mesaba Two

TBD = Manufacturer and Model No. to be determined during Front End Engineering and Design period.

3a) Emis Unit ID No.	**3b)** SV ID No(s).	**3c)** Relation Type	**3d)** Control Equip ID No.	**3e)** Emission Unit Operator's Description	**3f)** Manufacturer	**3g)** Model No.
001	001	(M)ain		Combustion Turbine Generator (CTG)/Heat Recovery Steam Generator (HRSG) (Phase I)	CTG - Siemens or similar	SGT6-5000F or similar
002	002	(M)ain		CTG/HRSG (Phase I)	CTG - Siemens or similar	SGT6-5000F or similar
003	003	(M)ain		Auxiliary Boiler (Phase I)	TBD	TBD
004	004	(M)ain		ASU Cooling Tower (Phase I)	TBD	TBD
005	005	(M)ain		Power Block Cooling Tower (Phase I)	TBD	TBD
006	006	(M)ain		Emergency Diesel Generator - Gasification Island (Phase I)	TBD	TBD
007	007	(M)ain		Emergency Diesel Generator - Power Block (Phase I)	TBD	TBD
008	008	(M)ain		Emergency Firewater Pump Engine (Phase I)	TBD	TBD
009	009	(M)ain		Emergency Firewater Pump Engine (Phase I)	TBD	TBD

010	013	(M)ain		CTG/HRSG (Phase II)	CTG - Seimens or similar	SGT6-5000F or similar
011	014	(M)ain		CTG/HRSG (Phase II)	CTG - Seimens or similar	SGT6-5000F or similar
012	015	(M)ain		Auxiliary Boiler (Phase II)	TBD	TBD
013	016	(M)ain		ASU Cooling Tower (Phase II)	TBD	TBD
014	017	(M)ain		Power Block Cooling Tower (Phase II)	TBD	TBD
015	018	(M)ain		Emergency Diesel Generator - Gasification Island (Phase II)	TBD	TBD
016	019	(M)ain		Emergency Diesel Generator - Power Block (Phase II)	TBD	TBD
017	020	(M)ain		Emergency Firewater Pump Engine (Phase II)	TBD	TBD
018	021	(M)ain		Emergency Firewater Pump Engine (Phase II)	TBD	TBD
					TBD	
					TBD	

MINNESOTA POLLUTION CONTROL AGENCY
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PERMIT APPLICATION FORM **GI-05B**

EMISSION UNIT INFORMATION, PART 2

1) AQ Facility ID No.: _____ **2)** Facility Name: Mesaba One and Mesaba Two

TBD = To be determined during Front End Engineering and Design period.

3a) Emis Unit ID No.	**3h)** Maximum Design Capacity	**3i)** Maximum Design Capacity Units	**3j)** Maximum Fuel Input (MMBTU)	**3k)** Commence Construction Date (MM/DD/YY)	**3l)** Initial Startup Date (MM/DD/YY)	**3m)** Firing Method (coal-burning units only)	**3n)** % Fuel for Space Heat (boilers only)	**3o)** Bottle-neck? F = facility G = group of sources	**3p)** SIC Code
001	220	MW	2184, HHV (syngas)	Q1 2006	Q4 2011		TBD		
002	220	MW	2184, HHV	Q1 2006	Q4 2011		TBD		
003	100,000	lb/hr steam	130, HHV	Q1 2006	Q4 2011		TBD		
004	46	million lb/hr cooling water	NA	Q1 2006	Q4 2011				
005	116	million lb/hr cooling water	NA	Q1 2006	Q4 2011				
006	2	MW	TBD	Q1 2006	Q4 2011				
007	350	kW	TBD	Q1 2006	Q4 2011				
008	300	HP	TBD	Q1 2006	Q4 2011				
009	300	HP	TBD	Q1 2006	Q4 2011				

010	220	MW	2184, HHV (syngas)	Q1 2006	Q4 2011		TBD		
011	220	MW	2184, HHV	Q1 2006	Q4 2011		TBD		
012	100,000	lb/hr steam	130, HHV	Q1 2006	Q4 2011		TBD		
013	46	million lb/hr cooling water	NA	Q1 2006	Q4 2011				
014	116	million lb/hr cooling water	NA	Q1 2006	Q4 2011				
015	2	MW	TBD	Q1 2006	Q4 2011				
016	350	kW	TBD	Q1 2006	Q4 2011				
017	300	HP	TBD	Q1 2006	Q4 2011				
018	300	HP	TBD	Q1 2006	Q4 2011				

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PERMIT APPLICATION FORM **GI-05D**
FUGITIVE EMISSION SOURCE INFORMATION
07/25/05

1) AQ Facility ID No.: _____ **2)** Facility Name: Mesaba One and Mesaba Two

3a) Fugitive Source ID No.	**3b)** Pollutant Emitted (particulate matter (PM) or VOC)	**3c)** Control Equip ID No.	**3d)** Description of Fugitive Emission Source
001	PM	003	Coal Handling and Storage, Phase I
002	PM		Coal Slurry Facilities, Phase I
003	PM		Slag Transport and Storage, Phase I
004	VOC/HAP		Fugitive VOC and HAPs, Phase I
005	PM	006	Coal Handling and Storage, Phase II
006	PM		Coal Slurry Facilities, Phase II
007	PM		Slag Transport and Storage, Phase II
008	VOC/HAP		Fugitive VOC and HAPs, Phase II

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PERMIT APPLICATION FORM **GI-09**

REQUIREMENTS FORM

2/16/05

Federal and State Requirements

This packet of forms, **GI-09 REQUIREMENTS**, will help you to determine the federal and state requirements with which your facility must comply. Be advised that you must include any applicable requirement that may not be addressed in this part of the application.

The first section of this form asks questions to find out if your facility is subject to specific federal and state regulations. To assist you in filling out this form, there are nine attachments, forms **GI-09A** through **GI-09I**. This form will direct you to each of the attachments as necessary, which will help you determine if your facility is subject to these regulations. When you are directed to an attachment, complete it as required, but *always* return to this **GI-09 REQUIREMENTS** form.

1) National Emission Standards for Hazardous Air Pollutants for Source Categories
(NESHAP for Source Categories, 40 C.F.R. pt. 63)

1a) To determine if any requirements for the National Emission Standards for Hazardous Air Pollutants (NESHAPS) for Source Categories (40 C.F.R. pt. 63) apply to your facility, you must complete attached form **GI-09A REQUIREMENTS: NESHAP FOR SOURCE CATEGORIES** (40 C.F.R. pt. 63).

1b) After completing form GI-09A, check one of the following boxes:
☐ YES, my facility **is currently** subject to NESHAP for Source Categories requirements.
☒ NO, my facility **is not currently** subject to NESHAP for Source Categories requirements.

1c) After completing form GI-09A, check one of the following boxes:
☐ YES, my facility **is** subject to requirements of case-by-case MACT under Section 112(g)(2)(B).
☒ NO, my facility **is not** subject to requirements of case-by-case MACT under Section 112(g)(2)(B).

2) National Emission Standards for Hazardous Air Pollutants
(NESHAP; 40 C.F.R. pt. 61)

2a) To determine if any of the National Emission Standards for Hazardous Air Pollutants (NESHAP) (40 C.F.R. pt. 61) apply to your facility, you must complete the attached form **GI-09B REQUIREMENTS: NESHAP** (40 C.F.R. pt. 61).

2b) After completing item 2a, check one of the following boxes:
☐ YES, my facility **is** subject to NESHAP requirements.
☒ NO, my facility **is not** subject to NESHAP requirements.

3) **New Source Review** – Nonattainment and Prevention of Significant Deterioration
(NSR, New Source Review, 40 C.F.R. pt. 51 and 52)

3a) Did you construct, make any physical change to (as defined in 40 C.F.R. § 51.165 or 52.21) or change the method of operation of (as defined in 40 C.F.R. § 51.165 or 52.21) your facility since August 7, 1980?

☒ YES. Go to form **GI-09C REQUIREMENTS: NEW SOURCE REVIEW**.
☐ NO. Go to question 3b and answer NO.

3b) After completing the above question (and form GI-09C if necessary) check one of the following boxes:

☒ YES, my facility **is** subject to NSR requirements.
☐ NO, my facility **is not** subject to NSR requirements until I make a qualifying change.
☐ UNKNOWN. You may only check this box if directed to do so from **GI-09C REQUIREMENTS: NEW SOURCE REVIEW**.

4) **Prevention of Significant Deterioration: Increment**
(1990 Clean Air Act, as amended, Sections 109 and 160-169(B))

MPCA staff will advise on the applicability of this requirement after receipt of the application.

5) **Standards of Performance for New Stationary Sources**
(NSPS, New Source Performance Standards, 40 C.F.R. pt. 60)

5a) Is your facility a Sulfuric Acid Plant?

☒ NO.
☐ YES, you may be subject to this regulation; complete the attached form **GI-09D REQUIREMENTS: NSPS** (you may skip question 5b).

5b) Have you constructed, modified (as defined in 40 C.F.R. § 60.14), or reconstructed (as defined in 40 C.F.R. § 60.15) your emission facility, or any portion thereof, after August 17, 1971?

☐ NO.
☒ YES, you may be subject to this regulation. Complete the attached form **GI-09D REQUIREMENTS: NSPS**.

5c) If you answered NO to questions 5a and 5b your facility is not subject to federal NSPS requirements. Answer "NO" to question 5d.

5d) After completing the above questions (and the attachment if necessary) check one of the following boxes:

☒ YES, my facility (or a portion of it) **is** subject to NSPS requirements.
☐ NO, my facility **is not** subject to NSPS requirements.

6) Acid Rain Program under Title IV
(40 C.F.R. pt. 72, 40 C.F.R. pt. 73; and 1990 Clean Air Act, as amended, Sections 401-416)

6a) Is your facility one of the Phase I or Phase II units listed below?

☒ NO. Go to question 6b.
☐ YES. Go to question 6c and answer YES.

Austin Utilities:	Northeast Station		
Interstate Power:	Fox Lake		
Minnesota Power and Light:	Clay Boswell	M.L. Hibbard	Syl Laskin
Northern States Power:	High Bridge Sherburne County Na. 1 -- 7237	Minnesota Valley Allen S. King Future Base	Riverside Black Dog
Otter Tail Power:	Hoot Lake		
Rochester Public Utility:	Silver Lake		

6b) Does your facility combust fossil fuel and generate electricity for wholesale or retail sale, such as a cogeneration facility, a qualifying facility (as defined in the Federal Power Act), independent power producer, or solid waste incinerator?

☐ NO. Go to question 6c and answer NO.
☒ YES. Your facility may be subject to Acid Rain Requirements. Refer to the applicability definitions in 40 C.F.R. § 72.6 to find out if they apply.

6c) After completing question 6a and 6b, are you subject to Acid Rain Requirements?

☐ NO, my facility **is not** subject to Acid Rain Requirements.
☒ YES, my facility **is** subject to Acid Rain Requirements. Refer to Form **GI-09E REQUIREMENTS: ACID RAIN** for more information about applying for an acid rain permit.

7) Stratospheric Ozone Protection
(1990 Clean Air Act, as amended, Sections 601-618)

7a) To determine if this federal regulation applies to your facility, you must complete the attached form **GI-09F REQUIREMENTS: STRATOSPHERIC OZONE**.

7b) After completing form **GI-09F REQUIREMENTS: STRATOSPHERIC OZONE**, check one of the following boxes:

☐ YES, my facility **is** subject to this requirement.
☒ NO, my facility **is not** subject to this requirement.

8) **RISK MANAGEMENT PROGRAMS FOR CHEMICAL ACCIDENTAL RELEASE PREVENTION**(40 C.F.R. pt. 68, Section 112(r) of the Clean Air Act Amendments)

8a) Section 112(r) of the Clean Air Act requires facilities that produce, process, store or use any of the substances listed in form **GI-09G: RISK MANAGEMENT PROGRAMS FOR CHEMICAL ACCIDENTAL, RELEASE PREVENTION** (40 C.F.R. pt. 68), in amounts greater than the listed thresholds, to develop and implement a risk management plan for accidental releases.

8b) Determine if you produce, process, store or use any of the substances listed in form **GI-09G: RISK MANAGEMENT PROGRAMS FOR CHEMICAL ACCIDENTAL, RELEASE PREVENTION**, and check one of the following boxes:

☐ Yes, my facility **does** produce, process, store or use one or more of the substances listed in form **GI-09G**, in amounts exceeding the listed thresholds.

☒ No, my facility **does not** produce, process, store or use any of the substances listed in form **GI-09G**, in amounts exceeding the listed thresholds.

9) **Compliance Assurance Monitoring**
(CAM, 40 C.F.R. pt. 64)

9a) To determine if the CAM regulations apply to your facility, you must complete the attached form **GI-09H REQUIREMENTS: CAM**.

9b) After completing question 9a, above, check one of the following boxes:

☐ YES, my facility **is** subject to CAM requirements.

☒ NO, my facility **is not** subject to CAM requirements.

10) **Federal Ozone Measures for the Control of Emissions from Certain Sources**
(1990 Clean Air Act, as amended, Section 183(e))

10a) Rules have been promulgated under the above section of the Clean Air Act regulating VOCs from consumer or commercial products that emit volatile organic compounds. Does your facility manufacture: (check all that apply)

☐ Household consumer products containing VOCs

☐ Architectural coatings containing VOCs

☐ Autobody refinishing coatings containing VOCs

☒ My facility does not manufacture any of the above. Go to question 11).

10b) If you checked any boxes in question 10a) review the regulations at http://www.epa.gov/ttn/atw/183e/gen/183epg.html to determine whether your facility may be subject to any rules that are adopted under § 183(e) requiring emission reductions. After reviewing the regulations, check one of the following boxes.

☐ Yes, my facility is subject to consumer and commercial products regulation under section 183(e). Go to question 10c).

☐ No, my facility is not subject to consumer and commercial products regulation under section 183(e). Go to question 11).

10c) Check the box that best describes your source's compliance status with regards to applicable 183(e) requirements on the date of application, then go on to question 11).

☐ Compliance.

☐ Non-Compliance. Describe: _____

_____

_____

11) Minnesota State Air Quality Rules

11a) To determine which Minnesota State rules you may be subject to, go to form **GI-09I REQUIREMENTS: STATE RULES**.

11b) Whether permitted or not, **every business** and activity in Minnesota **is subject to the rules listed in the following table**:

Title of the Rule	Minnesota Rules (Chapter or Part)	What the Content of the Rule is:
Air Quality Emission Fees	Part 7002.0025 - 7002.0095	Requires facilities to pay emission fees every year within 60 days of MPCA billing.
Air Emission Permits	Parts 7007.0050 - 7007.1850	Outlines when an air emission permit is required and procedures for obtaining one.
Minnesota and National Ambient Air Quality Standards	Part 7009.0010 - 7009.0080	No one is allowed to emit any of the limited pollutants in such a manner that ambient levels of the pollutant are higher than the maximum level.
Applicability of Standards of Performance	Parts 7011.0010, and 7011.0050	Indicates that facilities must comply with all applicable state air pollution rules.
Circumvention	Part 7011.0020	States that no one may conceal or dilute emissions which would otherwise violate a federal or state air pollution control rule.
Emission Standards for Visible Air Contaminants	Part 7011.0100 - 7011.0120	Outlines restrictions against emitting opaque smoke from facilities.
Preventing Particulate Matter from Becoming Airborne	Part 7011.0150	States that no person shall cause particulate matter to become airborne if it can be avoided with listed preventative measures.
Continuous Monitors	Part 7017.1000	Outlines requirements for continuous monitoring systems.
Performance Tests	Part 7017.2001 - 7017.2060	Outlines procedures and methods for emissions and performance testing if required.
Notifications	Part 7019.1000	Requires facilities to notify the MPCA of shutdowns and breakdowns.
Reports	Part 7019.2000	Requires specific records and reports from facilities with continuous monitoring systems.
Emission Inventory	Part 7019.3000 - 7019.3100	Requires facilities to submit an Emission Inventory Report by April 1 every year.
Motor Vehicles	Part 7023.0100 - 7023.0120	Outlines restrictions against emitting opaque smoke from motor vehicles, trains, boats, construction equipment and stationary internal combustion engines.
Noise Pollution Control	Part 7030.0010 - 7030.0080	Sets noise standards which cannot be exceeded.

12) You have completed the Applicable Requirements form.

Minnesota Pollution Control Agency

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PERMIT APPLICATION FORM **GI-09A**

REQUIREMENTS: NESHAP FOR SOURCE CATEGORIES (40 C.F.R. pt. 63)

02/17/05

National Emission Standards for Hazardous Air Pollutants for source categories
(NESHAP for Source Categories, 40 C.F.R. pt. 63)

1) Read through Table A, the list of Hazardous Air Pollutants (HAP) and check one of the following:

☐ No, my facility **does not currently** emit any pollutants from the list, and therefore is not subject to the requirements for NESHAP for Source Categories. Go to question 7.

☒ Yes, my facility **does** emit one or more pollutants from the list. Go on to question 2a.

2a) Does your source have the potential to emit 10 tons per year or more of any single pollutant listed in Table A?

☐ Yes, my facility is a major source of HAP emissions. Go to question 3.

☒ No. Go to question 2b.

2b) Does your source have the potential to emit 25 tons per year or more of any combination of pollutants listed in Table A?

☐ Yes, my facility is a major source of HAP emissions. Go to question 3.

☒ No. Go to question 6.

3) If you answered yes to question 2a or 2b, it may be possible to avoid the requirements associated with being a major source of HAP emissions. If the **actual emissions** of HAPs from your facility will not exceed 10 tons per year of a single HAP or 25 tons per year of all HAPs combined during each of the next five years, you may propose federally enforceable permit conditions to limit your potential HAP emissions to less than 10 tons per year for each HAP and/or 25 tons per year for all HAPs combined. Do you want to accept permit limitations on HAPs to avoid being a major source of HAPs?

☐ No. Go to question 4.

☐ Yes. Briefly describe the limitations you would be willing to accept and abide by in your permit so that your HAP emissions will not exceed 10 tons per year for each HAP and 25 tons per year for all HAPs combined (use separate sheet if needed). Description must include each of the HAP pollutants. Refer to the Application General Instructions for guidance in establishing these limitations, and include your proposed limit, monitoring, recordkeeping, and reporting on Form CD-01. Your facility may be subject to NESHAP for Source Categories requirements until you receive a federally enforceable permit limiting your facility's HAP emissions to a nonmajor source. When you return to form **GI-09 Requirements**, you must answer "YES" to question 1b. To determine whether your facility is subject to NESHAP for nonmajor sources, go to question 6.

4) The attached Table D is a list of NESHAP for Source Categories and important dates associated with each of them. Does your facility have any equipment that fits any of the source categories listed?

☐ No. Go to question 6.
☐ Yes. List all the source categories applicable to your facility, and the associated dates shown in Table D.

_____

_____

_____

_____

_____

5) If you answered no to question 3 **and** yes to question 4, please read all applicable sections of 40 C.F.R. pt. 63 to determine all applicable requirements in each of the NESHAP for Source Categories. When you return to form **GI-09 Requirements**, you must answer "YES" to question 1b.

6) If your source has any equipment that belongs to the following area source categories, place a check in the box next to that category and read the specified NESHAP for Source Categories to determine all applicable requirements for area sources. The rules for these source categories may apply whether or not your facility is considered a major source for hazardous air pollutants. If you check one or more boxes below, you must answer "YES" to question 1b when you return to form **GI-09 Requirements**. Go on to question 7.

☐ Hard and Decorative Chromium Electroplating (40 C.F.R. pt. 63, subp. N)
☐ Chromium Anodizing Tanks (40 C.F.R. pt. 63, subp. N)
☐ Ethylene Oxide Commercial Sterilization and Fumigation Operations (40 C.F.R. pt. 63, subp. O)
☐ Perchloroethylene Dry Cleaning Facilities (40 C.F.R. pt. 63, subp. M)
☐ Secondary Lead Smelting Facilities (40 C.F.R. pt. 63, subp. X)
☐ Halogenated Solvent Degreasers (40 C.F.R. pt. 63, subp. T)

7) Does this permit application seek authorization to construct or reconstruct a major source of HAP (10 TPY or more of any pollutant listed on Table A, or 25 TPY or more of any combination of pollutants listed in Table A)?

☐ Yes. Go on to question 8.
☒ No. Return to form **GI-09 Requirements** and answer "NO" to question 1c.

8) Is your proposed project subject to any of the promulgated standards as listed in Table D?

☐ Yes, my facility is subject to the preconstruction review requirements under its MACT standard and to the General Provisions of the MACT standard. Return to form **GI-09 Requirements** and answer "YES" to question 1b and "NO" to question 1c.
☐ No, my facility may be subject to preconstruction review requirements under section 112(g)(2)(B). Go to question 9.

9) If you answered "No" to question 8, it may be possible to avoid the section 112(g)(2)(B) requirement of performing a case-by-case MACT determination for your proposed project by proposing a federally enforceable permit conditions to limit your potential HAP emissions to less than 10 tons per year for each HAP and/or 25 tons per year for all HAPs combined from the new proposed project. Do you want to accept permit limitations on HAPs to avoid the section 112(g)(2)(B) requirement?

☐ No. Go to question 10.

☐ Yes. Briefly describe the limitations you would be willing to accept and abide by in your permit so that your HAP emissions will not exceed 10 tons per year for each HAP and 25 tons per year for all HAPs combined (use separate sheet if needed). Description must include all the HAP pollutants. Refer to the Application General Instructions for guidance in establishing these limitations, and include your proposed limit, monitoring, recordkeeping, and reporting on Form CD-01. Your facility may be subject to NESHAP for Source Categories requirements until you receive a federally enforceable permit limiting your facility's HAP emissions from the proposed project to below the major source thresholds. When you return to form **GI-09 Requirements**, you must answer "YES" to question 1c.

_____

_____

_____

_____

_____

_____

_____

10) If you answered "No" to question 8 **and** "No" to question 9, please read 40 C.F.R. § 63.43 to 63.44 to determine all applicable requirements, including application requirements for a case-by-case MACT determination and what is required for your facility when a subsequent MACT standard for your facility is promulgated. When you return to form **GI-09 Requirements**, you must answer "YES" to question 1c.

11) Return to form **GI-09 Requirements**, and answer questions 1b and 1c using the above information.

Minnesota Pollution Control Agency

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PERMIT APPLICATION FORM **GI-09B**

REQUIREMENTS: NESHAP (40 C.F.R. pt. 61)

05/11/98

National Emission Standards for Hazardous Air Pollutants
(NESHAP, 40 C.F.R. pt. 61)

1) Part 61 NESHAPs were the regulations in existence before the 1990 Clean Air Act Amendments. They apply only to air emission sources listed in Table C (attached) that emit the pollutants listed. Table C contains:

- a pollutant;
- a facility description;
- a Minnesota Rules reference;
- a Code of Federal Regulation 40 part 61 (40 C.F.R. pt. 61) subpart reference.

2) Read through Table C. If your facility emits any of the listed pollutants, and your facility type, process or equipment matches those associated with the pollutant, a NESHAP may apply to you. To determine if a standard applies to your facility, refer to the corresponding 40 C.F.R. pt. 61 subpart(s) and Minnesota Rules listed and read the requirements in detail.

3) After reviewing the NESHAP reference list and reading the corresponding 40 C.F.R. pt. 61 subpart(s) check one of the following boxes:

☒ NO, my facility **is not** subject to NESHAP requirements. Return to form **GI-09 Requirements**, and answer "NO" to question 2b.

☐ YES, my facility (or a portion of it) **is** subject to NESHAP requirements. Answer "YES" to question 2b when you return to form **GI-09 Requirements**.

If you have determined that your facility must comply with federal NESHAP requirements, you are also subject to state NESHAP requirements. Minn. R. ch. 7011 lists Minnesota State NESHAP requirements.

4) Check and complete the following questions (4a, 4b, and 4c). Some NESHAPs apply to an entire mine, plant or shop. Others apply to specific units, like a reactor, valve or vessel. If you check 4c, you must complete a group of questions for each emission unit subject to a NESHAP. Attach additional pages as necessary to identify all emission units subject to NESHAP at your facility. Photocopy each 40 C.F.R. pt. 61 subpart you have listed (*except* the Asbestos NESHAP), ***highlight*** the portions of the subpart that directly applies to your facility, and attach the copies to this application form.

4a) ☐ My business is only subject to the NESHAP for the Demolition and Renovation of Asbestos containing structures identified in 40 C.F.R. § 61.145; I do not need an Air Emission Permit. I have contacted the MN Department of Health and the asbestos team at the MN Pollution Control Agency regarding any renovation or demolition projects and have obtained an asbestos abatement permit if necessary. (For more information refer to Minn. Rules 7007.0300, subp. 1.C.)

4b) ☐ My entire facility is subject to NESHAP requirements.

Describe Emission Facility _____
Date of Facility Construction _____
Applicable 40 C.F.R. pt. 61 subparts(s) _____
Applicable Minnesota State Rule Reference _____
Has this Source Been Permitted Previously?
☐ NO
☐ YES, list Air Emission Permit Number

4c) ☐ My facility has one or more emission unit(s) subject to NESHAP requirements. Provide the information requested below for each unit that is subject to a NESHAP.

Describe Emission Equipment _____
Emission Unit Number _____
Stack/Vent Number _____
Date of Original Equipment Installation _____ (Month/Date/Year)
Applicable 40 C.F.R. pt. 61 subpart(s) _____
Applicable Minnesota State Rule Reference _____
Has this Unit Been Permitted Previously?
☐ NO
☐ YES, list Air Emission Permit Number _____

Describe Emission Equipment _____
Emission Unit Number _____
Stack/Vent Number _____
Date of Original Equipment Installation _____ (Month/Date/Year)
Applicable 40 C.F.R. pt. 61 subpart(s) _____
Applicable Minnesota State Rule Reference _____
Has this Unit Been Permitted Previously?
☐ NO
☐ YES, list Air Emission Permit Number _____

Describe Emission Equipment _____
Emission Unit Number _____
Stack/Vent Number _____
Date of Original Equipment Installation _____ (Month/Date/Year)
Applicable 40 C.F.R. pt. 61 subpart(s) _____
Applicable Minnesota State Rule Reference _____
Has this Unit Been Permitted Previously?
☐ NO
☐ YES, list Air Emission Permit Number _____

5) Return to form **GI-09 Requirements**, question 2b.

TABLE C
NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

POLLUTANT	FACILITY OR EMISSION UNIT TYPE	MINN RULES	40 C.F.R. 61 SUBPART
RADON	Underground Uranium Mines; Department of Energy Facilities; Phosphorus Fertilizer Plants; and Facilities Processing or Disposing of Uranium Ore and Tailings	7011.9960	B, Q, R, T, W
BERYLLIUM	Beryllium Extraction Plants; Ceramic Plants, Foundries, Incinerators, Propellant Plants, and Machine Shops that Process Beryllium Containing Material; and Rocket Motor Firing Test Sites	7011.9940 - 7011.9945	C, D
MERCURY	Mercury Ore Processing; Manufacturing Processes Using Mercury Chloralkali Cells; and Sludge Incinerators	7011.9950 - 7011.9955	E
VINYL CHLORIDE	Ethylene Dichloride Manufacturing Via Oxygen, HCl and Ethylene; Vinyl Chloride Manufacturing; and Polyvinyl Chloride Manufacturing	7011.9980	F
RADIO-NUCLIDES	Department of Energy; Nuclear Regulatory Commission Licensed Facilities; Other Federal Facilities; and Elemental Phosphorus Plants	7011.9970	H, I, K
BENZENE	Fugitive Process, Storage, and Transfer Equipment Leaks; Coke By-Product Recovery Plants; Benzene Storage Vessels; Benzene Transfer Operations; and Benzene Waste Operations	7011.9930	J, L, Y, BB, FF
ASBESTOS*	Asbestos Mills; Roadway Surfacing with Asbestos Tailings; Manufacture of Products Containing Asbestos; Demolition; Renovation; and Spraying and Disposal of Asbestos Waste	7011.9920 - 7011.9927	M
INORGANIC ARSENIC	Glass Manufacturer; Primary Copper Smelter; Arsenic Trioxide and Metallic Arsenic Production Facilities	7011.9910	N, O, P
VOLATILE HAZARDOUS AIR POLLUTANTS (VHAP)	Pumps, Compressors, Pressure Relief Devices, Connections, Valves, Lines, Flanges, Product Accumulator Vessels, etc. in VHAP Service (As of 11/30/94 only vinyl chloride and benzene are regulated by 40 C.F.R. 61, subp. V)	7011.9990	V

*If you are only subject to 40 C.F.R. §61.145 (subp. M Standard for Demolition and Renovation), because you are doing asbestos abatement, you do not need a Minnesota Air Emission Permit, but you must contact the Minnesota Department of Health at (612) 627-5097 and the asbestos team at the Minnesota Pollution Control Agency at (651) 297-8685 before beginning any abatement activity.

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **GI-09C**

REQUIREMENTS: NEW SOURCE REVIEW (40 C.F.R. pt. 52)

05/11/98

New Source Review
(NSR; 40 C.F.R. pt. 52)

Throughout this form you are asked for the Potential to Emit (PTE) of your facility or of changes to your facility. The PTE values in most cases are defined as the maximum uncontrolled PTE of the emission facility. In some cases, PTE calculations may reflect factors such as control equipment or permit limitations, but **ONLY** if proof is given that such factors were provisions of a federally enforceable permit issued to the facility.

New Source Review (NSR) regulations may apply to modifications to existing facilities or for the construction of a new facility. There are two kinds of review: one for nonattainment areas and one for attainment areas. For a nonattainment pollutant, if the potential to emit is more than 100 tons per year, New Source Review could apply. For attainment areas, the threshold is 100 or 250 tons per year depending on the type of facility.

This form is rather complex, but addresses a complicated regulatory program. Each item is intended to assist you in the process of determining applicability as easily and quickly as possible. Items 1-3 will help you determine the threshold -- a federally established pollutant level -- for your facility. The next two items, 4 and 5, determine if, based on your current PTE, you are considered a major stationary source. If your facility is not a major source now, item 6 asks if it was major in the past. Item 7 determines if you can accept "synthetic minor" limitations, while item 8 requires you to specify what these limitations would be.

It may be possible for sources that were major to become synthetic minor facilities. Items 9-10 are basic criteria questions that need to be answered. Sources who wish to pursue this option will need to work closely with MPCA staff to determine if the facility does qualify for the synthetic minor status. Items 11, 12, and 13 determine if you constructed a major facility. Item 14 requires a description of each change (physical or operational) made at your facility after it actually began emitting pollutants at a rate higher than your threshold. A detailed description is required for each change, including dates and emission levels through today. If necessary and/or allowed, item 14f requires you to specify "synthetic minor" limitations for just the change. Item 14 must be filled out separately for each change made, requiring duplication of those two pages. Item 15 directs specific sources to contact the MPCA for further guidance.

1) Is your facility defined as one of the following, (Some SIC Code(s) applying to specific categories are given in parentheses):

Coal Cleaning Plants-With Thermal Dryers	Kraft Pulp Mills (2611, 2621)
Portland Cement Plants (3241)	Primary Zinc Smelters (3339)
Iron and Steel Mills (332X)	Primary Aluminum Ore Reduction Plants (3334)
Primary Copper Smelters (3331)	Municipal Incinerators Capable of Charging More Than 250 Tons of Refuse per Day
Hydrofluoric Acid Plants (2819, 2899)	Sulfuric Acid Plants (2819)
Nitric Acid Plants (2873)	Petroleum Refineries (2911)
Lime Plants (3274)	Phosphate Rock Processing Plants (1475)
Coke Oven Batteries (3312)	Sulfur Recovery Plants (2819)
Carbon Black Plants (Furnace Process, 2895)	Primary Lead Smelters (3339)
Fuel Conversion Plants	Sintering Plants*
Secondary Metal Production Plants (334X)	Chemical Process Plants (28XX)
Fossil-Fuel Boilers (or combination thereof) totaling more than 250 MMBtu/hr	Petroleum Storage & Transfer Units, Total Storage Capacity over 300,000 Barrels
Taconite Ore Processing Plants (1011)	Glass Fiber Processing Plants
Charcoal Production Plants (2819, 2861)	Fossil Fuel-Fired Steam Electric Plants of more than 250 MMBtu/hr

* Processing of fine grain materials into coarser lumps (performed primarily on ores).

☐ NO, my facility is not classified as one of the 28 sources listed above. Go to item 2.
☒ YES, my facility is classified as one of the 28 sources listed above. An air emission source having PTE (potential to emit) more than 100 TPY (tons per year) of any single regulated pollutant is considered a major stationary source. **For the rest of this form, 100 TPY is the threshold you must use in answering the questions**. Go to item 4.

2) Is your facility located in a nonattainment area (see form **GI-01 Facility Information**, question 14)?
☐ NO. Go to item 3.
☐ YES. Check all of the following pollutants that apply:

☐ PM_{10} ☐ SO_2 ☐ CO

An air emission source having the potential to emit more than 100 TPY of any pollutant(s) checked above, or 250 TPY of any single regulated pollutant not checked above is considered a major stationary source. **For the rest of this form, 100 TPY is the threshold for any pollutant(s) checked above, and 250 TPY is the threshold for the remaining regulated pollutants. You must use these values in answering the remaining questions**. Go to item 4.

3) I answered NO to items 1 and 2; my facility is not one of the 28 sources listed and my facility is not located in a non-attainment area. An air emission source having the potential to emit of more than 250 TPY of any single regulated pollutant is considered a major stationary source. **For the rest of this form, 250 TPY is the threshold you must use in answering the questions.**

4) In the boxes below, enter the current PTE (in tons per year) of your entire facility under each regulated pollutant. ("Current PTE" means the PTE of your facility prior to receiving the permit for which you are now applying.)

PM_{10}	PM (includes PM_{10})	SO_2	NO_X	VOC	CO	Pb	Fluorides

Sulfuric Acid Mist	H_2S	Total reduced sulfur (includes H_2S)	Reduced sulfur compounds (includes H_2S)	MWC organics	MWC metals	MWC acid gases	MSW landfill gases	Ozone-depleting substances

5) Is the current PTE of your facility above the 100/250 TPY threshold for your facility, making your facility a major stationary source?

☐ YES. My facility is currently considered a major stationary source, go to question 7.
☐ NO. Go to question 6.

6) Since August 7, 1980, has the PTE of your facility ever exceeded your 100/250 TPY threshold value?

☐ YES. Go to question 7.
☐ NO. My facility is not subject to NSR until I make a qualifying change. Return to form **GI-09 Requirements** and answer "NO" to question 3b.

[Note: If you do not know what the PTE of your facility has been in the past, it is sufficient for the purposes of **this question only** to use the following formula to ***roughly estimate*** PTE:

(8760 hours/year) x (actual emissions of a pollutant for a given year in tons/year)/(the number of hours of operation for that year).

Again, **this formula cannot be used for any other purpose.** This is only a screening test, it does not represent the required PTE calculation method for air permitting.

7) Since August 7, 1980, have the **actual emissions** from your facility ever exceeded the 100/250 TPY threshold value for your facility?

☐ YES. Go to item 9.
☐ NO. My facility is allowed to accept federally enforceable permit limitations to limit potential emissions to less than a major source (below the threshold). Go to question 8.

8) The **actual emissions** from your facility have never exceeded the 100/250 TPY threshold established for your facility. Would you be willing to accept federally enforceable permit limitations to limit potential emissions from your facility to less than the 100/250 TPY threshold?

☐ NO. Go to item 11.

☐ YES. You are required to specify limitations (called synthetic minor limits) for your facility. These limitations will limit your air emissions. This will be dependent on your emission sources and can have some flexibility. Briefly describe what limitations you would be willing to accept and abide by. Refer to the Application General Instructions for guidance in establishing these limitations. Include the specific limits, monitoring, recordkeeping, and reporting on Form CD-01.

_____

_____

_____

_____

_____

_____

(DUPLICATE THIS FORM OR ADD EXTRA PAGES AS NEEDED)

Return to form **GI-09 Requirements**, question 3b, and check Unknown.

9) Have you removed any equipment from your facility since the **actual emissions** exceeded the 100/250 TPY threshold?

☐ NO. Go to question 11.

☐ YES. Go to question 10.

10) Have the actual emissions from the facility remained under the 100/250 TPY threshold for the last two years?

☐ NO. Go to question 11.

☐ YES. It may be possible to obtain a synthetic minor permit for your facility. **Complete the remaining items in this form and contact the MPCA for further guidance as listed in item 15.**

11) Did you construct your facility after August 7, 1980?

☐ NO. Go to question 14.

☐ YES, construction on my facility began on (date) _____. The PTE of my facility (in tons per year) when constructed was:

PM_{10}	PM (includes PM_{10})	SO_2	NO_X	VOC	CO	Pb	Fluorides

Sulfuric Acid Mist	H_2S	Total reduced sulfur (includes H_2S)	Reduced sulfur compounds (includes H_2S)	MWC organics	MWC metals	MWC acid gases	MSW landfill gases	Ozone-depleting substances

12) Are any of the PTE values entered in question 11 greater than the 100/250 TPY threshold for your facility?

☐ NO. Go to question 14.

☐ YES. Go to question 13.

13) Have the actual emissions for the operations installed during the facility's construction ever exceeded the 100/250 TPY threshold for any year after the construction date?

☐ NO. Go to question 14.

☐ YES. My facility was a major source when it was constructed. If a BACT/LAER analysis **was not** done at the time of construction, the facility may be subject to backward looking NSR (if the analysis was not done at the time of construction but has been done since, it may not be necessary to repeat it). Contact the Permit Technical Advisor at (651)282-5844 or (800)646-6247 for additional guidance. Go to question 14**.**

14) NSR groups changes made during the same budget or planning period as a single modification. This means that changes need to be grouped together based on budgeting or planning periods and evaluated as one modification to determine if NSR/PSD applies to the changes that have been made.

Items 14a through 14g need to be completed for each modification made at your facility, through the current date (include any modifications you are proposing in this application, too). Begin with the first modification after the PTE of your facility exceeded the 100/250 TPY threshold or the first modification made after August 7, 1980, whichever is later. DO NOT INCLUDE modifications which were authorized by a permit from the MPCA. Duplicate and add additional pages as necessary. (Note: if your facility was under the 100/250 TPY threshold and the first modification you made was over 100/250 TPY, provide the information listed in items 14a, b, c, d, e, and f on a separate sheet of paper.) If you have not modified your facility since meeting the 100/250 TPY threshold, go to form **GI-09 Requirements**, question 3b, and answer "NO."

14a) Describe the physical change in or change in method of operation to your facility:
Construction of Mesaba One and Mesaba Two is subject of this permit application.

14b) In what year(s) did the modification occur? **Construction of Mesaba One will commence in the 1st quarter of 2008; construction of Mesaba Two will commence in 2010.**

14c) List the potential emissions increase (in tons per year) of each pollutant for this modification.

PM_{10}	PM (includes PM_{10})	SO_2	NO_X	VOC	CO	Pb	Fluorides
493	503	1250	2872	197	2539	0.028	

Sulfuric Acid Mist	H_2S	Total reduced sulfur (includes H_2S)	Reduced sulfur compounds (includes H_2S)	MWC organics	MWC metals	MWC acid gases	MSW landfill gases	Ozone-depleting substances
126	17	20						

NOTE; SO_2 is decreased based on conversion to H_2SO_4. Other tables assume 1390 TPY SO_2. PM_{10} includes sulfuric acid mist. Emissions reflect Mesaba One and Mesaba Two.

14d) Are the values you entered in item 14c for this modification greater than the values listed in item 14e for each regulated pollutant?

☐ NO. This was a minor change, go to question 14g.

☒ YES. Go to question 14e.

14e) Beginning with the year entered in item 14b through the current date, did the actual emissions of regulated pollutants resulting only from this modification ever exceed the values listed in the following table?

Pollutant	Threshold (tons/year)	Effective Date
PM_{10}	15	July 31, 1987
PM	25	August 7, 1980
SO_2	40	August 7, 1980
NO_X	40	August 7, 1980
VOC	40	August 7, 1980
CO	100	August 7, 1990
Pb	0.6	August 7, 1980
Fluorides	3	August 7, 1980
Sulfuric Acid Mist	7	August 7,. 1980
H_2S	10	August 7, 1980
Total reduced sulfur	10	August 7, 1980
Reduced sulfur compounds	10	August 7, 1980
MWC organics	3.5×10^{-6}	August 12, 1991
MWC metals	15	August 12, 1991
MWC acid gases	40	August 12, 1991
MSW landfill gases	50	March 12, 1996
Ozone depleting substances	100	March 19, 1998 (EPA memo)

☐ YES. This modification is subject to backward looking NSR, unless a BACT/LAER analysis was done at the time of modification. (If analysis was not done at the time of modification, but has been done since then, it may not be necessary to repeat it.) Contact the Permit Technical Advisor at (651)282-5844 or (800)646-6247 for additional guidance.

☒ NO. Go to question 14f.

14f) The actual emissions from this modification have never exceeded the levels listed in item 14e. Are you willing to accept federally enforceable permit limitations to limit the potential emissions increase of the modification to less than those levels?

☒ NO. Go to item 14g. **Emissions for Mesaba One and Mesaba Two will not commence until 2010 and 2012/2013, respectively.**

☐ YES. You are required to specify limitations (called "synthetic minor" limits) for this change. These limits will limit your air emissions to below the levels listed in item 14e. This will be dependent on your emissions sources and can have some flexibility. Briefly describe what limitations you would be willing to accept and abide by. Refer to the Application General Instructions for guidance in establishing these limitations. Include the specific limits, monitoring, recordkeeping, and reporting on Form CD-01.

(DUPLICATE THIS FORM OR ADD EXTRA PAGES AS NEEDED)

Go to item 14g.

14g) Repeat item 14 until each non-permitted physical change or change in method of operation to your facility has been identified, duplicating item 14 as necessary.

15) It may be possible to accept synthetic minor permit limitations if your actuals have exceeded the threshold levels, if you have removed equipment and the actual emissions for the last two calendar years of operation have remained under the threshold levels. You should contact the MPCA for more guidance on whether your facility qualifies for synthetic minor limitations.

If you have triggered NSR/PSD levels and cannot or choose not to accept synthetic minor limitations, you need to check YES to question 3b on **Form GI-09 Requirements**. If your facility has received permits for modifications or completed NSR/PSD reviews as requested by the MPCA, you should work with MPCA staff to determine the compliance status of your facility regarding NSR/PSD and establishing limits.

Minnesota Pollution Control Agency

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PERMIT APPLICATION FORM **GI-09D**

REQUIREMENTS: NSPS (40 C.F.R. pt. 60)

05/11/05

Standards of Performance for New Stationary Sources
(NSPS, New Source Performance Standards, 40 C.F.R. pt. 60)

1) NSPS are federal rules that define limits, testing and monitoring for certain specific emission units. These standards are proposed and promulgated in the Federal Register and published in the Code of Federal Regulations, title 40 part 60 (40 C.F.R. pt. 60). Table D lists the standards promulgated through April 1998. Table D may not be complete if a new NSPS has been promulgated since this form was last revised. The table contains:

- a brief emission source description;
- a corresponding 40 C.F.R. pt. 60 subpart reference;
- an effective date for all performance standards promulgated as of April 1998.

[Please note: the best way to keep up-to-date on NSPS regulations is through the EPA's Web page (www.epa.gov) or the Federal Register since there can be a significant time lag between the date when a standard is proposed or promulgated and when it is finally published in the Code of Federal Regulations.]

2) Please read through the emission sources in Table D. If you have modified (as defined in 40 C.F.R. § 60.14), reconstructed (as defined in 40 C.F.R. § 60.15) or constructed the described emission source on or after the effective date listed in the table, your facility may be subject to the requirements of 40 C.F.R. pt. 60. Generally, reconstruction means that the cost of a repair exceeds 50 percent of what it would cost to install a new emission unit. If you have had an extensive and expensive repair, it may count as a reconstruction.

If you know or suspect standards may apply to your facility you must refer to the corresponding 40 C.F.R. pt. 60 subpart and read the requirements in detail to make a final determination. Note: the general provisions found in 40 C.F.R. pt. 60, subp. A, apply to <u>all</u> facilities subject to any other NSPS requirements.

3) After you review the list of sources subject to NSPS and read any applicable 40 C.F.R. pt. 60 subparts, check one of the following boxes:

☐ NO, my facility is not subject to NSPS. Return to Form **GI-09 Requirements**, and answer "NO" to question 5d.

☒ YES, my facility is subject to NSPS.

4) The following page lists information needed to identify your facility's emission sources subject to NSPS. Complete the group of questions for all emission equipment subject to NSPS, attaching additional pages if necessary. Photocopy each 40 C.F.R. pt. 60 subpart you have listed and highlight the portions of each subpart that directly apply to your facility, including the general provisions found in Subpart A. Attach the copies to this application form.

The MPCA has reprinted Subpart A and some additional NSPS regulations from the *Code of Federal Regulations*. The available regulations are starred in Table D. To obtain copies, contact the Permit Document Coordinator at (651)282-5843.

5) Return to Form **GI-09 Requirements**, and answer "YES" to question 5d.

Describe Emission Equipment	Mesaba One and Mesaba Two CTG	
Emission Unit Number	001, 002, 010, 011	
Stack/Vent Number	001, 002, 013, 014	
Date of Equipment Manufacture		(Month/Date/Year)
Date of Equipment Installation	Construction start Q1 2008	(Month/Date/Year)
Date of Reconstruction (if applicable)		(Month/Date/Year)
Date of Modification (if applicable)		(Month/Date/Year)
Applicable 40 C.F.R. pt. 60 subpart or Federal Register Reference	70 FR 9706, 2/28/05 Proposed Revisions to NSPS Subpart Da	

This source is also subject to the general provisions of 40 C.F.R. pt. 60, subp. A.

Has this Unit Been Permitted Previously?

- ☒ NO
- ☐ YES, list Air Emission Permit Number

Have you attached a photocopied, highlighted version of the 40 C.F.R. pt. 60 subpart?

- ☒ YES
- ☐ NO

Describe Emission Equipment	Mesaba One and Mesaba Two Auxiliary Boilers	
Emission Unit Number	003, 012	
Stack/Vent Number	003, 015	
Date of Equipment Manufacture		(Month/Date/Year)
Date of Equipment Installation	Construction start Q1 2008	(Month/Date/Year)
Date of Reconstruction (if applicable)		(Month/Date/Year)
Date of Modification (if applicable)		(Month/Date/Year)
Applicable 40 C.F.R. pt. 60 subpart or Federal Register Reference	Subpart Db	

This source is also subject to the general provisions of 40 C.F.R. pt. 60, subp. A.

Has this Unit Been Permitted Previously?

- ☒ NO
- ☐ YES, list Air Emission Permit Number

Have you attached a photocopied, highlighted version of the 40 C.F.R. pt. 60 subpart?

- ☒ YES
- ☐ NO

Describe Emission Equipment	Mesaba One and Mesaba Two Tank Vent Boiler	
Emission Unit Number	CE-001, CE-004	
Stack/Vent Number	010, 022	
Date of Equipment Manufacture		(Month/Date/Year)
Date of Equipment Installation	Construction start Q1 2008	(Month/Date/Year)
Date of Reconstruction (if applicable)		(Month/Date/Year)
Date of Modification (if applicable)		(Month/Date/Year)
Applicable 40 C.F.R. pt. 60 subpart or Federal Register Reference	Subpart Dc	

This source is also subject to the general provisions of 40 C.F.R. pt. 60, subp. A.

Has this Unit Been Permitted Previously?

- ☒ NO
- ☐ YES, list Air Emission Permit Number

Have you attached a photocopied, highlighted version of the 40 C.F.R. pt. 60 subpart?

- ☒ YES
- ☐ NO

DUPLICATE THIS FORM AS NEEDED

TABLE D
STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Performance standards promulgated as of October 20, 2003		
Source categories subject to federal performance standards	**40 C.F.R. 60 Subpart**	**Effective date constructed, modified or reconstructed**
Fossil-Fuel Fired Steam Generators >250 MMBtu	D	After: 08/17/71
Electric Utility Steam Generators >250 MMBtu	Da	After: 09/18/78
Industrial-Commercial-Institutional Steam Generators >100 MMBtu	Db	After: 06/19/84
Small Industrial-Commercial-Institutional Steam Generators >10 MMBtu but <100 MMBtu	Dc	After: 06/09/89
Incinerators	E, CCCC, DDDD	varies
Hospital/Medical/Infectious Waste Incinerators	Ec, Ce	Initial Construction
Municipal Waste Combustors	Cb, Ea, Eb, AAAA, BBBB	varies
Portland Cement Plants	F	After: 08/17/71
Nitric Acid Plants	G	After: 08/17/71
Sulfuric Acid Plants	H, Cd	Initial Construction
Asphalt Concrete Plants	I	After: 06/11/73
Petroleum Refineries	J	After: 06/11/73
Storage Vessels for Petroleum Liquids	K, Ka	After: 06/11/73
Volatile Organic Liquid Storage Vessels (Including Petroleum Liquids)	Kb	After: 07/23/84
Secondary Lead Smelters	L	After: 06/11/73
Secondary Brass and Bronze Production Plants	M	After: 06/11/73
Oxygen Process Furnaces	N	After: 06/11/73
Oxygen Process Steelmaking Facilities	Na	After: 01/20/83
Sewage Treatment Plants	O	After: 06/11/73
Primary Copper Smelters	P	After: 10/16/74
Primary Zinc Smelters	Q	After: 10/16/74
Primary Lead Smelters	R	After: 10/16/74
Primary Aluminum Reduction Plants	S	After: 10/23/74
Phosphate Fertilizer Industry	T,U,V,W,X	After: 10/22/74
Coal Preparation Plants	Y	After: 10/24/74
Ferroalloy Production Facilities	Z	After: 10/24/74
Steel Plants	AA, AAa	After: 10/21/74
Kraft Pulp Mills	BB	After: 09/24/76
Glass Manufacturing Plants	CC	After: 06/15/79
Grain Elevators	DD	After: 08/03/78
Surface Coating of Metal Furniture	EE	After: 11/28/80
Stationary Gas Turbines	GG	After: 10/03/77
Lime Manufacturing Plants	HH	After: 05/03/77
Lead-Acid Battery Manufacturing Plants	KK	After: 01/14/80
Metallic Mineral Processing Plants	LL	After: 08/24/82
Automobile and Light-Duty Truck Surface Coating Operations	MM	After: 10/05/79

Table 1, continued

Source categories subject to federal performance standards	40 C.F.R. 60 Subpart	Effective date constructed, modified or reconstructed
Phosphate Rock Plants	NN	After: 09/21/79
Ammonium Sulfate Manufacture	PP	After: 02/04/80
Graphic Arts Industry: Publication Rotogravure Printing	QQ	After: 08/28/80
Pressure Sensitive Tape and Label Surface Coating Operations	RR	After: 12/30/80
Industrial Surface Coating: Large Appliances	SS	After: 12/24/80
Metal Coil Surface Coating	TT	After: 01/05/81
Asphalt Processing and Asphalt Roofing Manufacture	UU	After: 11/18/80
Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry	VV	After: 01/05/81
Beverage Can Surface Coating Industry	WW	After: 11/26/80
Bulk Gasoline Terminals	XX	After: 12/17/80
New Residential Wood Heaters *	AAA	After: 07/01/88
Rubber Tire Manufacturing Industry	BBB	After: 01/20/83
VOC Emissions from the Polymer Manufacturing Industry	DDD	After: 09/30/87
Flexible Vinyl and Urethane Coating and Printing	FFF	After: 01/18/83
Equipment Leaks of VOC in Petroleum Refineries	GGG	After: 01/04/83
Synthetic Fiber Production Facilities	HHH	After: 11/23/82
VOC Emissions from the Synthetic Organic Chemical Manufacturing Industry Air Oxidation Unit Processes	III	After: 10/21/83
Petroleum Dry Cleaners	JJJ	After: 12/14/82
Onshore Natural Gas Processing: VOC Equipment Leaks and SO_2 Emissions	KKK, LLL	After: 01/20/84
VOC Emissions from Synthetic Organic Chemical Manufacturing Industry Distillation Operations	NNN	After: 12/30/83
Nonmetallic Mineral Processing Plants (Including Sand and Gravel Processing)	OOO	After: 08/31/83
Wool Fiberglass Insulation Manufacturing Plants	PPP	After: 02/07/84
VOC Emissions from Petroleum Refinery Wastewater Systems	QQQ	After: 05/04/87
VOC Emissions from the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes	RRR	After: 06/29/90
Magnetic Tape Coating Facilities	SSS	After: 01/22/86
Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	TTT	After: 01/08/86
Calciners and Dryers in Mineral Industries	UUU	After: 04/23/86
Polymeric Coating of Supporting Substrates Facilities	VVV	After: 04/30/87
Municipal Solid Waste Landfills	WWW, Cc	Initial Construction

** According to Minn. Rules Pt. 7007.0300, subp. 1(B), "any stationary source that would be required to obtain a permit solely because it is subject to Code of Federal Regulations, title 40, part 60, subp. AAA" is exempt from permitting.

Minnesota Pollution Control Agency

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PERMIT APPLICATION FORM **GI-09G**

REQUIREMENTS: RISK MANAGEMENT PROGRAMS FOR CHEMICAL ACCIDENTAL RELEASE PREVENTION (40 C.F.R. pt. 68)

05/11/98

If you produce, process, store or use any of the substances, in excess of the threshold listed in the following table, you may be subject to the requirements under Section 112(r) of the Clean Air Act. After reviewing Table G, return to form **GI-09 Requirements** and answer question 8b.

TABLE G
LIST OF REGULATED TOXIC SUBSTANCES AND THRESHOLD QUANTITIES FOR ACCIDENTAL RELEASE PREVENTION

Chemical Name	CAS No.	Threshold Quantity (lbs)
Acetaldehyde	75-07-0	10,000
Acetylene [Ethyne]	74-86-2	10,000
Acrolein [2-Propenal]	107-02-8	5,000
Acrylonitrile [2-Propenenitrile]	107-13-1	20,000
Acrylyl chloride [2-Propenoyl chloride]	814-68-6	5,000
Allyl alcohol [2-Propen-1-ol]	107-18-6	15,000
Allylamine [2-Propen-1-amine]	107-11-9	10,000
Ammonia (anhydrous)	7664-41-7	10,000
Ammonia (conc 20% or greater)	7664-41-7	20,000
Arsenous trichloride	7784-34-1	15,000
Arsine	7784-42-1	1,000
Boron trichloride [Borane, trichloro-]	10294-34-5	5,000
Boron trifluoride [Borane, trifluoro-]	7637-07-2	5,000
Boron trifluoride compound with methyl ether (1:1) [Boron, trifluoro[oxybis[metane]]-, T-4-	353-42-4	15,000
Bromine	7726-95-6	10,000
Bromotrifluorethylene [Ethene, bromotrifluoro-]	598-73-2	10,000
1,3-Butadiene	106-99-0	10,000
Butane	106-97-8	10,000
1-Butene	106-98-9	10,000
2-Butene	107-01-7	10,000
Butene	25167-67-3	10,000
2-Butene-*cis*	590-18-1	10,000
2-Butene-*trans* [2-Butene, (E)]	624-64-6	10,000
Carbon disulfide	75-15-0	20,000
Carbon oxysulfide [Carbon oxide sulfide (COS)]	463-58-1	10,000
Chlorine	7782-50-5	2,500
Chlorine dioxide [Chlorine oxide (ClO_2)]	10049-04-4	1,000
Chlorine monoxide [Chlorine oxide]	7791-21-1	10,000
Chloroform [Methane, trichloro-]	67-66-3	20,000
Chloromethyl ether [Methane, oxybis[chloro-]	542-88-1	1,000
Chloromethyl methyl ether [Methane, chloromethoxy-]	107-30-2	5,000
2-Chloropropylene [1-Propene, 2-chloro-]	557-98-2	10,000
1-Chloropropylene [1-Propene, 1-chloro-]	590-21-6	10,000

TABLE G (Continued)

Chemical Name	CAS No.	Threshold Quantity (lbs)
Crotonaldehyde [2-Butenal]	4170-30-3	20,000
Crotonaldehyde, (E)- [2-Butenal, (E)-]	123-73-9	20,000
Cyanogen [Ethanedinitrile]	460-19-5	10,000
Cyanogen chloride	506-77-4	10,000
Cyclohexylamine [Cyclohexanamine]	108-91-8	15,000
Cyclopropane	75-19-4	10,000
Diborane	19287-45-7	2,500
Dichlorosilane [Silane, dichloro-]	4109-96-0	10,000
Difluoroethane [Ethane, 1,1-difluoro-]	75-37-6	10,000
Dimethyldichlorosilane [Silane, dichlorodimethyl-]	75-78-5	5,000
1,1-Dimethylhydrazine [Hydrazine, 1,1-dimethyl-]	57-14-7	15,000
Dimethylamine [Methanamine, N-methyl-]	124-40-3	10,000
2,2-Dimethylpropane [Propane, 2,2-dimethyl-]	463-82-1	10,000
Epichlorohydrin [Oxirane, (chloromethyl)-]	106-89-8	20,000
Ethane	74-84-0	10,000
Ethyl acetylene [1-Butyne]	107-00-6	10,000
Ethylamine [Ethanamine]	75-04-7	10,000
Ethyl chloride [Ethane, chloro-]	75-00-3	10,000
Ethylene [Ethene]	74-85-1	10,000
Ethylenediamine [1,2-Ethanediamine]	107-15-3	20,000
Ethyleneimine [Aziridine]	151-56-4	10,000
Ethylene oxide [Oxirane]	75-21-8	10,000
Ethyl ether [Ethane, 1,1'-oxybis-]	60-29-7	10,000
Ethyl mercaptan [Ethanethiol]	75-08-1	10,000
Ethyl nitrite [Nitrous acid, ethyl ester]	109-95-5	10,000
Fluorine	7782-41-4	1,000
Formaldehyde (solution)	50-00-0	15,000
Furan	110-00-9	5,000
Hydrazine	302-01-2	15,000
Hydrochloric acid (conc 30% or greater)	7647-01-0	15,000
Hydrocyanic acid	74-90-8	2,500
Hydrogen	1333-74-0	10,000
Hydrogen chloride (anhydrous) [Hydrochloric acid]	7647-01-0	5,000
Hydrogen fluoride/Hydrofluoric acid (conc 50% or greater) [Hydrofluoric acid]	7664-39-3	1,000
Hydrogen selenide	7783-07-5	500
Hydrogen sulfide	7783-06-4	10,000
Iron, pentacarbonyl- [Iron carbonyl (Fe(CO)5), (TB-5-11)-]	13463-40-6	2,500
Isobutane [Propane, 2-methyl]	75-28-5	10,000
Isobutyronitrile [Propanenitrile, 2-methyl-]	78-82-0	20,000
Isopentane [Butane, 2-methyl-]	78-78-4	10,000
Isoprene [1,3-Butadiene, 2-methyl-]	78-79-5	10,000
Isopropylamine [2-Propanamine]	75-31-0	10,000
Isopropyl chloride [Propane, 2-chloro-]	75-29-6	10,000
Isopropyl chloroformate [Carbonochloridic acid, 1-methylethyl ester]	108-23-6	15,000
Methacrylonitrile [2-Propenenitrile, 2-methyl-]	126-98-7	10,000

TABLE G (Continued)

Chemical Name	CAS No.	Threshold Quantity (lbs)
Methane	74-82-8	10,000
Methylamine [Methanamine]	74-89-5	10,000
3-Methyl-1-butene	563-45-1	10,000
2-Methyl-1-butene	563-46-2	10,000
Methyl chloride [Methane, chloro-]	74-87-3	10,000
Methyl chloroformate [Carbonochloridic acid, methylester]	79-22-1	5,000
Methyl ether [Methane, oxybis-]	115-10-6	10,000
Methyl formate [Formic acid, methyl ester]	107-31-3	10,000
Methyl hydrazine [Hydrazine, methyl-]	60-34-4	15,000
Methyl isocyanate [Methane, isocyanato-]	624-83-9	10,000
Methyl mercaptan [Methanethiol]	74-93-1	10,000
2-Methylpropene [1-Propene, 2-methyl-]	115-11-7	10,000
Methyl thiocyanate [Thiocyanic acid, methyl ester]	556-64-9	20,000
Methyltrichlorosilane [Silane, trichloromethyl-]	75-79-6	5,000
Nickel carbonyl	13463-39-3	1,000
Nitric acid (conc 80% or greater)	7697-37-2	15,000
Nitric oxide [Nitrogen oxide (NO)]	10102-43-9	10,000
Oleum (Fuming Sulfuric acid) [Sulfuric acid, mixture with sulfur trioxide]	8014-95-7	10,000
1,3-Pentadiene	504-60-9	10,000
Pentane	109-66-0	10,000
1-Pentene	109-67-1	10,000
2-Pentene, (E)-	646-04-8	10,000
2-Pentene, (Z)-	627-20-3	10,000
Peracetic acid [Ethaneperoxoic acid]	79-21-0	10,000
Perchloromethylmercaptan [Methanesulfenyl chloride, trichloro-]	594-42-3	10,000
Phosgene [Carbonic dichloride]	75-44-5	500
Phosphine	7803-51-2	5,000
Phosphorus oxychloride [Phosphoryl chloride]	10025-87-3	5,000
Phosphorus trichloride [Phosphorous trichloride]	7719-12-2	15,000
Piperidine	110-89-4	15,000
Propadiene [1,2-Propadiene]	463-49-0	10,000
Propane	74-98-6	10,000
Propionitrile [Propanenitrile]	107-12-0	10,000
Propyl chloroformate [Carbonochloridic acid, propylester]	109-61-5	15,000
Propylene [1-Propene]	115-07-1	10,000
Propyleneimine [Aziridine, 2-methyl-]	75-55-8	10,000
Propylene oxide [Oxirane, methyl-]	75-56-9	10,000
Propyne [1-Propyne]	74-99-7	10,000
Silane	7803-62-5	10,000
Sulfur dioxide (anhydrous)	7446-09-5	5,000
Sulfur tetrafluoride [Sulfur fluoride (SF4), (T-4)-]	7783-60-0	2,500
Sulfur trioxide	7446-11-9	10,000
Tetrafluoroethylene [Ethene, tetrafluoro-]	116-14-3	10,000
Tetramethyl lead [Plumbene, tetramethyl-]	75-74-1	10,000
Tetramethylsilane [Silane, tetramethyl-]	75-76-3	10,000
Tetranitromethane [methane, tetranitro-]	509-14-8	10,000

TABLE G (Continued)

Chemical Name	CAS No.	Threshold Quantity (lbs)
Titanium tetrachloride [Titanium chloride ($TiCl_4$) (T-4)-]	7550-45-0	2,500
Toluene 2,4-diisocyanate [Benzene, 2,4-diisocyanato-1-methyl-]	584-84-9	10,000
Toluene 2,6-diisocyanate [Benzene, 1,3-diisocyanato-2-methyl-]	91-08-7	10,000
Toluene diisocyanate (unspecified isomer) [Benzene, 1,3-diisocyanatomethyl-]	26471-62-5	10,000
Trichlorosilane [Silane, trichloro-]	10025-78-2	10,000
Trifluorochloroethylene [Ethene, chlorotrifluoro-]	79-38-9	10,000
Trimethylamine [Methanamine, N,N-dimethyl-]	75-50-3	10,000
Trimethylchlorosilane [Silane, chlorotrimethyl-]	75-77-4	10,000
Vinyl acetate monomer [Acetic acid ethenyl ester]	108-05-4	15,000
Vinyl acetylene [1-Buten-3-yne]	689-97-4	10,000
Vinyl chloride [Ethene, chloro-]	75-01-4	10,000
Vinyl ethyl ether [Ethene, ethoxy-]	109-92-2	10,000
Vinyl flouride [Ethene, fluoro-]	75-02-5	10,000
Vinylidene chloride [Ethene, 1,1-dichloro-]	75-35-4	10,000
Vinylidene flouride [Ethene, 1,1-difluoro-]	75-38-7	10,000
Vinyl methyl ether [Ethene, methoxy-]	107-25-5	10,000

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Compliance Assurance Monitoring (40 C.F.R. pt. 64)

The CAM rule applies to certain emission units at facilities required to obtain a Part 70 permit.

In general, CAM applies to emission units meeting the following criteria:

1. The emission unit is subject to an emission limit or standard (including limits and standards in Minnesota Rules contained in the State Implementation Plan) for an air pollutant regulated by Part 70;

2. Compliance with the applicable limit or standard is achieved through the use of add-on control equipment; and

3. The emission unit has pre-controlled potential emissions of the applicable regulated air pollutant that are equal to or greater than 100 percent of the Part 70 major source level for that pollutant (in tons per year).

For exemptions, see Table C at the end of this form.

Use of continuous emissions monitoring system (CEMS), continuous opacity monitoring system (COMS), or predictive emission monitoring system (PEMS) does not qualify as an exemption to the CAM rule. However, §64.3(d) states that use of a CEMS, COMS, or PEMS meets the requirements of CAM.

CAM applicability is determined on a pollutant-by-pollutant basis for each "pollutant specific emissions unit," defined at 40 C.F.R. § 64.1 as "an emissions unit considered separately with respect to each regulated air pollutant." For purposes of CAM submittal requirements, a "**large pollutant specific emissions unit**" is an emissions unit with potential controlled emissions equal to or greater than 100% of the major source threshold amount for a given regulated pollutant. ("Major source threshold amount" as it applies to Minnesota, means 100 tons per year of particulate matter smaller than ten microns in aerodynamic diameter (PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), volatile organic compounds (VOC), carbon monoxide (CO), or lead; 10 tons per year of any hazardous air pollutant (HAP); or 25 tons per year of any combination of HAPs. The levels may be different in current or future nonattainment areas. Refer to 40 C.F.R. § 70.2 under the definition of "major source" for further detail.) "**Other pollutant specific emissions units**" are those units whose uncontrolled potential emissions may be equal to or greater than 100% of the major source threshold amount, but controlled emissions are less than that threshold.

If you are applying for the first time for a Part 70 permit, after determining the uncontrolled and controlled potential emissions of the emissions units, the following questions must be considered for each **large** pollutant specific emissions unit, as defined above..

If you are applying for a major amendment to an existing Part 70 permit, after determining the uncontrolled and controlled potential emissions of the emissions units, the following questions must be considered for each **large** pollutant specific emissions unit, as defined above, to which the amendment is applicable.

If you are applying for reissuance of an existing Part 70 permit, after determining the uncontrolled and controlled potential emissions of the emissions units, the following questions must be considered for each pollutant specific emissions unit **(large and other)** for which CAM applicability has not already been determined through a Part 70 permitting action.

1) Is the unit subject to an emission limitation or standard, specified in either a rule or permit? For existing emission units, check your current permit to see if there are any emission limits specified for the emission unit.

☐ No, the emission unit is not subject to CAM. Repeat question 1 with next emission unit.
☒ Yes, the emission unit is subject to an emission limitation or standard. Go on to question 2.

2) Is an add-on control device used to achieve compliance with that limitation or standard? (For example, a boiler may have a NO_X limit and an SO_2 limit. If the boiler uses lime injection for SO_2 control but relies on a low-NO_X burner to meet the NO_X limit, then the emission unit would be subject to CAM for SO_2 but not for NO_X.)

☒ No, the emission unit is not subject to CAM. Return to question 1 and repeat with next emission unit.
☐ Yes. Go on to question 3.

3) There are some exemptions allowed by the rule. Review the list of exemptions in Table C, then answer the following question.

☐ No, the emission unit is subject to CAM. List the emission unit in Table A and repeat questions 1 through 3 for the next emissions unit. When each emission unit has been considered, go on to complete the rest of Table A and Table D.

☐ Yes, the emission unit is exempt from CAM. List the emission unit in Table D and repeat questions 1 through 3 for the next emissions unit. When each emission unit has been considered, go on to complete the rest of Table A and Table D.

Table A. Emission Units Subject to CAM

EU #	Emission Unit	CE #	Description of Control Equipment	Pollutant(s) which are subject to CAM

Duplicate this table as needed.

You must prepare a CAM submittal for each unit listed in Table 4, and provide it with the permit or amendment application. The CAM submittal, also referred to as the monitoring approach submittal, should include:

- information on indicators (gauges, meters, or other devices used to monitor operating parameters of control equipment)
- indicator ranges, or the process by which indicators are to be established
- performance criteria
- justification for the proposed monitoring
- control device operating data recorded during a performance test, supplemented by engineering assessments or manufacturer's recommendations to justify the proposed indicator range
- a test plan and schedule for obtaining data if performance test data are not available
- an implementation plan, if monitoring requires installation, testing or other activities prior to implementation

Some of this information will be incorporated into the operating permit. The permit will specify the approved monitoring approach and the indicator range(s), including the averaging periods.

Table D. Emission Units EXEMPT from CAM

EU #	Why exempt (not large enough, uncontrolled, exemption category from Table C, etc.)
CTGs (EU-001, 002, 010,& 011)	NOx, CO, PM, SO2 > 100 TPY, but no add-on control devices
Flares (CE-002 & 005)	CO > 100 TPY, but no add-on control devices
Aux Boiler, Engines, Fire Pumps, Cooling Tower	No other EUs are "large pollutant specific emission units"

For additional information, please refer to the CAM rule at 40 C.F.R. pt. 64.
Additional information, including a Technical Guidance Document that includes example submittals, is available on the Internet at http://www.epa.gov/ttn/emc/cam.html

Table C
CAM RULE EXEMPTIONS

The CAM rule does not apply to:

1. Units subject to emission limitations or standards proposed by EPA after November 15, 1990, pursuant to section 111 or 112 of the Clean Air Act. In situations where some portions of a facility operate control devices in order to comply with emission standards issued prior to November 15, 1990, only those portions of the facility must comply with the requirements of the CAM rule.

2. Situations where continuous compliance monitoring is already specified in an operating permit. The CAM rule exempts the Permittee from additional monitoring requirements and directs the Permittee to use the continuous compliance monitoring data to fulfill the CAM rule monitoring and certification requirements.

3. Stratospheric ozone protection requirements

4. Acid Rain Program requirements

5. Emission limitations or standards that apply solely under an emissions trading program

6. Municipally-owned utility peak-shaving units where
   - ⇒ the unit is exempt from all Acid Rain Program monitoring requirements, and
   - ⇒ the unit operates for the sole purpose of providing electricity during periods of peak electrical demand or emergency situations, and
   - ⇒ the unit will be operated consistent with that purpose throughout the permit term, and
   - ⇒ emissions from the unit are less than 50 percent of the amount required for the source to be classified as a major source, based on an average of the last 3 years, and are expected to remain so.

Minnesota Pollution Control Agency

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Minnesota State Air Quality Rules

Some businesses and activities in Minnesota are subject to the following rules. Read each question to determine if the rule applies to you.

1) Minnesota Air Pollution Episodes
(Minn. R. 7009.1000-7009.1110)

1a) After your facility is permitted, will your facility be allowed to emit more than 250 tons per year of any one of the following pollutants: particulate matter, sulfur dioxide, nitrogen oxides, ozone [volatile organic compounds], carbon monoxide, or non-methane hydrocarbons?

☐ No, my facility is not subject to the Minn. R. 7009.1000-7009.1110.
☒ Yes, my facility is subject to the Minn. R. 7009.1000-7009.1110

2) Minnesota Standards of Performance for Stationary Sources (Minn. R. ch. 7011)

2a) Does your facility have any equipment that meets the following definition?

"A furnace, boiler or other combustion equipment in Minnesota which burns fossil fuel for the purpose of producing steam, hot water, hot air, or other hot liquid, gas, or solid, where the smoke doesn't have direct contact with the heated medium for which another standard of performance has not been promulgated."

☒ No, my facility **is not** subject to Minn. R. 7011.0500-7011.0551. Go to question 2b.
☐ Yes, my facility **is** subject to Minn. R. 7011.0500-7011.0551 Standards of Performance for Indirect Heating Fossil-Fuel Burning Equipment. List the units subject to this rule below. Read the rule to determine the specific requirements that apply to each subject unit ("new" or "existing" as defined in the rule), and use Form CD-01 to list those requirements. Then go on to question 2b)

Note: The indirect heating units at Mesaba Energy are not subject to the state standard because the are subject to the federal NSPS (40 C.F.R. 60 Subparts Da, Db, and Dc)

2b) Is your facility type or process equipment found in Table J on page 7? This table contains only state-specific requirements; it does not include state rules that incorporate federal rules by reference.

☐ No, none of the Minnesota Rules listed in Table J apply to my facility. Go to question 3).
☒ Yes, my facility or process equipment may be subject to the rule associated with it in Table J. Read the associated rule to see if it applies. Then go to item 2c).

2c) After reading through Table J and any rule that may apply to your facility or equipment, list the ones that do apply to your air emission source(s) in Table H on page 2. Again, Table J includes only state-specific requirements; it does not include state rules that incorporate federal rules by reference. You do not need to list state rules that incorporate federal rules by reference. You do not need to list the Standards of Performance for Indirect Heating Fossil-Fuel Burning Equipment again, if it applies (see 2a, above).

Table H: Equipment Subject to Minnesota Standards of Performance

Emission Source ID Number	Minnesota Rule Part that Applies	What the Rule Part Applies to (Whole facility or Specific Piece of Equipment)
FS-001 & FS-005	7011.1100	Coal Handling Facilities
EU-001, 002, 006, 007, 008, 009, 101, 011, 015, 016, 017 & 018	7011.2300	Internal Combustion Engines - Emergency Fire Water Pumps and Emergency Generators

(DUPLICATE THIS TABLE AS NEEDED)

3) Minnesota Acid Deposition Control (Minn. R. 7021.0050)

3a) Does your facility generate electricity?

☐ No. My facility is not subject to Acid Deposition Control Requirements. Go to question 4.
☒ Yes. Go to question 3b.

3b) Does your facility contain indirect heating equipment with a rated heat input of more than 5,000 million BTUs per hour?

☐ No. Go to question 3c.
☒ Yes. My facility is subject to Acid Deposition Control Requirements.

3c) If your facility is an electric utility, is the total generating capacity of all the electric generating facilities in Minnesota which are owned by your facility's parent company more than 1,000 megawatts?

☐ No. My facility is not subject to Acid Deposition Control Requirements.
☒ Yes. My facility is subject to Acid Deposition Control Requirements.

4) Standards of Performance for Industrial Process Equipment (Minn. R. 7011.0700 - 7011.0735)

4a) Do you have any industrial process equipment on-site that is not regulated by any other Standard of Performance (NSPS or MN Rules Standard of Performance)? **If you have any equipment/emission source that is <u>not</u> listed above in item 2a) or Table H, or listed on Form GI-09D, then the answer to this question is YES.**

☐ No, my equipment is not subject to this rule. Go to question 5**).**
☒ Yes. This equipment is subject to the Industrial Process Equipment Rule. List these units in Table I, indicating whether the equipment was or was not in operation before July 9, 1969. Then go to question 4b).

4b) **Opacity Standard**

(Note: Opacity is a measure of visible emissions or how much of the view is obscured by stack emissions. The emissions causing opacity are often smoke or dust.)

For industrial process equipment which was *in operation before July 9, 1969*, the equipment shall not exhibit greater than 20 percent opacity, except that a maximum of 60 percent opacity shall be permissible for four minutes in any 60 minute period and a maximum of 40 percent opacity shall be permissible for four additional minutes in any 60 minute period.

For industrial process equipment which was *not in operation before July 9, 1969*, the equipment shall not exhibit greater than 20 percent opacity.

Go to 4c).

4c) Does any of the industrial process equipment you listed in Table I have particulate control equipment with a collection efficiency of at least 99 percent if it was in operation before July 9, 1969, or 99.7 percent if it was not in operation before July 9, 1969?

☒ No. Go to question 4d).
☐ Yes. These units are considered to be in compliance with the remaining requirements of this rule.

For those units meeting this criterion which were in operation before July 9, 1969, complete Table I by checking the box labeled "Collection Efficiency > 90%."

For those units meeting these criterion which were not in operation before July 9, 1969, complete Table I by checking the box labeled "Collection Efficiency > 99.7%."

Then, if there are units listed in Table I which are not controlled by control equipment with a collection efficiency of 99% or 99.7% (as applicable), go on to question 4d).

4d) Has it been demonstrated that the operation of the entire facility in compliance with all ambient air quality standards? This is typically shown through some level of computer dispersion modeling.

☒ Yes. Go to question 4e).
☐ No. Skip to item 4i).

4e) Is the facility located outside of the seven county Minneapolis-St. Paul metropolitan region?

☒ Yes. Go to question 4f)
☐ No. Skip to item 4i).

4f) Is the facility located outside of the city of Duluth?

☒ Yes. Go to question 4g).
☐ No. Skip to item 4i).

4g) Is the facility located at least 1/4 mile from any residence or public roadway?

☒ Yes. Go to question 4h).
☐ No. Skip to item 4i).

4h) Answer this question individually for each remaining unit listed in Table I (those which were not identified in item 4c) as being controlled by control equipment having a control efficiency of 99% or 99.7% (as applicable)). Does the industrial process equipment have particulate control equipment with a collection efficiency of at least 85 percent?

☒ Yes, the unit is considered to be in compliance with the remaining requirements of this rule. For each unit for which you can answer "yes" to question 4h), complete Table I by checking the box labeled "Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85%." Answer question 4h) for each remaining unit on Table I.

☐ No. For each unit for which you answered "No" to question 4h), complete Table I as described in item 4i). Then go to question 5).

4i) Complete Table I for all remaining industrial process equipment listed (those which were not identified in question 4c) as being controlled by control equipment having a control efficiency of 99% or 99.7% (as applicable)). Use Table K to determine the particulate limit in either pounds per hour (lb/hr) or grains per dry standard cubic foot (gr/dscf). Then go to question 5).

TABLE I: EQUIPMENT SUBJECT TO INDUSTRIAL PROCESS EQUIPMENT RULE

Equipment Subject to Industrial Process Equipment Rule (list EU number(s))		Applicable Particulate Limit
FS-002, 005	☐ In operation before July 9, 1969	☐ Collection Efficiency > 90% ☐ Collection Efficiency > 99.7% ☒ Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85% ☐ _____ gr/dscr ☐ _____ lb/hr
	☒ Not in operation before July 9, 1969	
	☐ In operation before July 9, 1969	☐ Collection Efficiency > 90% ☐ Collection Efficiency > 99.7% ☐ Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85% ☐ _____ gr/dscr ☐ _____ lb/hr
	☐ Not in operation before July 9, 1969	
	☐ In operation before July 9, 1969	☐ Collection Efficiency > 90% ☐ Collection Efficiency > 99.7% ☐ Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85% ☐ _____ gr/dscr ☐ _____ lb/hr
	☐ Not in operation before July 9, 1969	
	☐ In operation before July 9, 1969	☐ Collection Efficiency > 90% ☐ Collection Efficiency > 99.7% ☐ Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85% ☐ _____ gr/dscr ☐ _____ lb/hr
	☐ Not in operation before July 9, 1969	
	☐ In operation before July 9, 1969	☐ Collection Efficiency > 90% ☐ Collection Efficiency > 99.7% ☐ Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85% ☐ _____ gr/dscr ☐ _____ lb/hr
	☐ Not in operation before July 9, 1969	
	☐ In operation before July 9, 1969	☐ Collection Efficiency > 90% ☐ Collection Efficiency > 99.7% ☐ Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85% ☐ _____ gr/dscr ☐ _____ lb/hr
	☐ Not in operation before July 9, 1969	
	☐ In operation before July 9, 1969	☐ Collection Efficiency > 90% ☐ Collection Efficiency > 99.7% ☐ Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85% ☐ _____ gr/dscr ☐ _____ lb/hr
	☐ Not in operation before July 9, 1969	
	☐ In operation before July 9, 1969	☐ Collection Efficiency > 90% ☐ Collection Efficiency > 99.7% ☐ Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85% ☐ _____ gr/dscr ☐ _____ lb/hr
	☐ Not in operation before July 9, 1969	

(DUPLICATE THIS TABLE AS NEEDED)

5) Waste Combustors
(Minn. Rules 7011.1201-7011.1290)

Note: Depending on the type of waste combustor you operate, you may be instructed to fill out one or more of the following forms:

WC-01 -- Required if you determine that your waste combustor requires a permit.
WC-02 -- Required if you install/operate a Class IV waste combustor at a hospital.
WC-03 -- Required if you do not met the stack height requirements of Minn. R. 7011.1235.

If after reading through the following section, you determine that you are required to fill out one or more of the WC forms, contact the Air Quality Permit Document Coordinator.

5a) Do you operate a waste combustor?

"Waste Combustor" means any emissions unit or emission facility where mixed municipal solid waste, solid waste, or refuse-derived fuel is combusted, and includes incinerators, energy recovery facilities, or other combustion devices. A metals recovery incinerator is a waste combustor. A combustion device combusting primarily wood, or at least 70 percent fossil fuel and wood in combination with up to 30 percent papermill wastewater treatment plant sludge is not a waste combustor. A soil treatment facility, paint burn-off oven, wood heater, or residential fireplace is not a waste combustor.

"Wood" is defined as: wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including sawdust, sander dust, wood chips, wood scraps, slabs, millings, shavings, and processed pellets made from wood and other forest residues.

A facility that is co-firing RDF or MSW at rates less than 30 percent by weight is not regulated as a waste combustor, but is regulated as a boiler.

☐ Yes, I operate a waste combustor. Answer questions 5b through 5e to determine whether you are allowed to continue to operate, and what type of permit the waste combustor requires. Allowed waste combustors must obtain an air emissions permit.
☒ No, the facility equipment is not subject to this rule. Go to question 6.

5b) Is the waste combustor solely a crematory, pathological or an animal carcass incinerator?

☐ Yes. It is subject to standards of performance in 7011.1215, subp. 3. The waste combustor is an insignificant activity that does not need to be reported. Go to question 6.
☐ No, the facility equipment is not subject to this rule. Go to question 6.

5c) Is the design capacity of the waste combustor equal to or greater than 3 million Btu/hr?

"Design capacity" means: the hourly throughput of the waste combustor unit based on heat input from solid waste to the combustion system as stated by the manufacturer or designer, based on accepted design and engineering practices. For a non-continuous feed system, design capacity means the total heat input from solid waste per cycle.

If you don't have a manufacturer's design capacity in terms of heat input, you may estimate heat input by the following formula:

$$\mathbf{H_{in} = (HHV) \times (R)}$$

Where:

H_{in} = Heat input rate
HHV = heat value of waste
R = waste input rate, in lb/hr, as defined by the manufacturer
Commercial/Retail/Institutional Wastes = 7000 Btu/lb
General Industrial Wastes = 9000 Btu/lb
Medical/Infectious Wastes = 10,000 Btu/lb

☐ Yes, the waste combustor has a design capacity of 3 million Btu/hr or greater. The waste combustor is subject to the standards of performance applicable to waste combustors. There are also additional permit application requirements for this unit, as described in Minn. R. 7007.0501, or 7011.1210. Complete form WC-01.

☐ No, the heat input rate is below 3 million Btu/hr. Go to question 5d.

5d) Is the waste combustor used as a metal recover incinerator?

"Metals recovery incinerator" means a furnace or incinerator used primarily to recover precious and non-precious metals by burning the combustible fraction from waste. An aluminum sweat furnace is not a metals recovery incinerator.

☐ Yes. The waste combustor is subject to the standards of performance applicable to waste combustors. There are also additional permit application requirements for this unit, as described in Minn. R. 7007.0501, or 7011.1210. Complete form WC-01.

☐ No. Go to question 5e.

5e) Is the waste combustor located at a hospital?

☐ Yes. The waste combustor is subject to the standards of performance applicable to Class IV waste combustors. There are also additional permit application requirements for this unit, as described in Minn. R. 7007.0501, or 7011.1210. Complete form WC-02 if the waste combustor will comply with all of the design, operating, and standards of performance in parts 7011.1201 to 7011.1290. Otherwise, an air emissions permit must be issued, and you must complete for WC-01. [**Please Note:** There are federal Standards of Performance that must also be met for new sources (see Form GI-09D), and the state will be adopting more stringent standards for existing incinerators by December of 1998.]

☐ No, the waste combustor is not located at a hospital. The operation of this waste combustor was banned after January 30, 1996. Your compliance plan must contain specific steps to cease operation of this waste combustor.

6) Return to Form **GI-09 REQUIREMENTS**, question 11b.

Table J: Minnesota Standards of Performance for Stationary Sources *

Facility or Equipment Type	Associated Minnesota Rule
Direct Heating Equipment	7011.0600 through 7011.0625
Concrete Manufacturing Plants	7011.0850 through 7011.0860
Stage One Vapor Recovery	7011.0865 through 7011.0870
Hot Mix Asphalt Plants	7011.0900 through 7011 0925
Bulk Agricultural Commodity Facilities (Grain Elevators)	7011.1000 through 7011.1015
Coal Handling Facilities	7011.1100 through 7011.1140
Incinerators (waste combustors)	7011.1201 through 7011.1285
Sewage Sludge Incinerators	7011.1300 through 7011.1325
Petroleum Refineries	7011.1400 through 7011.1430
Liquid Petroleum and VOC Storage Vessels	7011.1500 through 7011.1515
Sulfuric Acid Plants	7011.1600 through 7011.1630
Nitric Acid Plants	7011.1700 through 7011.1725
Brass and Bronze Plants	7011.1900 through 7011.1915
Iron and Steel Plants	7011.2000 through 7011.2015
Inorganic Fibrous Materials	7011.2100 through 7011.2105
Stationary Internal Combustion Engine (Generators)	7011.2300
Municipal Solid Waste Landfills	7011.3500 through 7011.3510
Asbestos	7011.9921 through 701109927

* This table does NOT include Minnesota Rules which incorporate federal NSPS and/or NESHAP by reference.

TABLE K:
INSTRUCTIONS FOR DETERMINING YOUR PARTICULATE LIMIT

Minnesota has a State rule for the concentration of particulate matter that may be in your exhaust stream. The unit of the standard is grains per dry standard cubic foot. You need to convert your actual exhaust flow to dry standard cubic feet per minute to find the emission limit from the rule.

Sources subject to this rule are required to meet the emission limits established at all times. These limits will vary depending on operating conditions. To determine compliance at any point in time (i.e. for a stack test), follow the steps below:

1. Determine the amount of dry material (subtract any water or moisture content) in pounds per hour that is processed by your equipment.

2. Use Table K.1 to determine your allowed emission rate based on process weight rate. If your process weight rate falls between two values on the table, interpolate or extrapolate using the equation:

$$E = 3.59 \times \left(\frac{P}{2000}\right)^{0.62} \qquad \text{for} \qquad P \leq 60{,}000 \text{ lbs/hour; and:}$$

$$E = 17.31 \times \left(\frac{P}{2000}\right)^{0.16} \qquad \text{for} \qquad P > 60{,}000 \text{ lbs/hour}$$

where:

E = emission rate in lbs/hour; and
P = process weight rate in lbs/hour

3. If your process equipment is vented to the atmosphere, determine the airflow through your stack. Correct to 68 F and 14.7 psi, and correct to remove any moisture in the gas stream to obtain the air flow in dry standard cubic feet per minute (dscfm).

4. Use Table K.2 to determine your allowed concentration in grains per dry standard cubic foot (gr/dscf). Interpolate using the equation:

$$c = 1.7627 \times V^{-0.3241}$$

where:

c = concentration in gr/dscf,
V = gas volume in dscfm

5. Determine which of the two emission rates calculated above is *less stringent*. To convert a concentration (calculated in step 4) to an emission rate (calculated in step 2), use the following equation:

$$E = c \times V \times \left(\frac{60}{7000}\right)$$

where:

E = emission rate in lbs/hour;
c = concentration in gr/dscf,
V = gas volume in dscfm

Table K.1

Process Rate (lbs/hour)	Emission Rate (lbs/hour)
50	0.37
100	0.55
500	1.53
1,000	2.25
5,000	6.34
10,000	9.73
20,000	14.99
60,000	29.60
80,000	31.19
120,000	33.28
160,000	34.85
200,000	36.11
400,000	40.35
1,000,000	46.72

Table K.2

Source Gas Volume (dscfm)	Concentration (gr/dscf)
7,000 or less	0.100
8,000	0.096
9,000	0.092
10,000	0.089
20,000	0.071
30,000	0.062
40,000	0.057
50,000	0.053
60,000	0.050
80,000	0.045
100,000	0.042
120,000	0.040
140,000	0.038
160,000	0.036
180,000	0.035
200,000	0.034
300,000	0.030
400,000	0.027
500,000	0.025
600,000	0.024
800,000	0.021
1,000,000 or more	0.020

Regardless of the allowable emission rates calculated from Tables K.1 and K.2, no process equipment is allowed to emit more than 0.30 grains per standard cubic foot of exhaust gas.

MINNESOTA POLLUTION
CONTROL AGENCY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

HG-2003

ASSESSING THE IMPACTS OF MERCURY RELEASES TO AMBIENT AIR

11/24/03

Purpose: Recognizing that Minnesota's surface waters are impaired by unacceptable levels of mercury, virtually all of which comes from the air, and that sometimes releases to the air are unavoidable, the MPCA's goal is to minimize increases in mercury emissions associated with new facilities or expansions. Of particular focus in this guidance are mercury releases from taconite production, secondary metal processors, the combustion of fuels in electricity generating stations and industrial boilers (except when burning only natural gas), and sewage sludge, municipal or other incineration.

Applications for modifications (as defined in Chapter 7007) or new facilities in these sectors should demonstrate that mercury emissions have been accurately quantified, and that the project's mercury emissions have been minimized through an effort to identify cost-effective emission reduction alternatives. Demonstration of an appropriate level of effort should be achieved through the following steps:

1. Provide estimates of potential, current actual, and future actual emissions, in pounds per year (see attached Table 1).

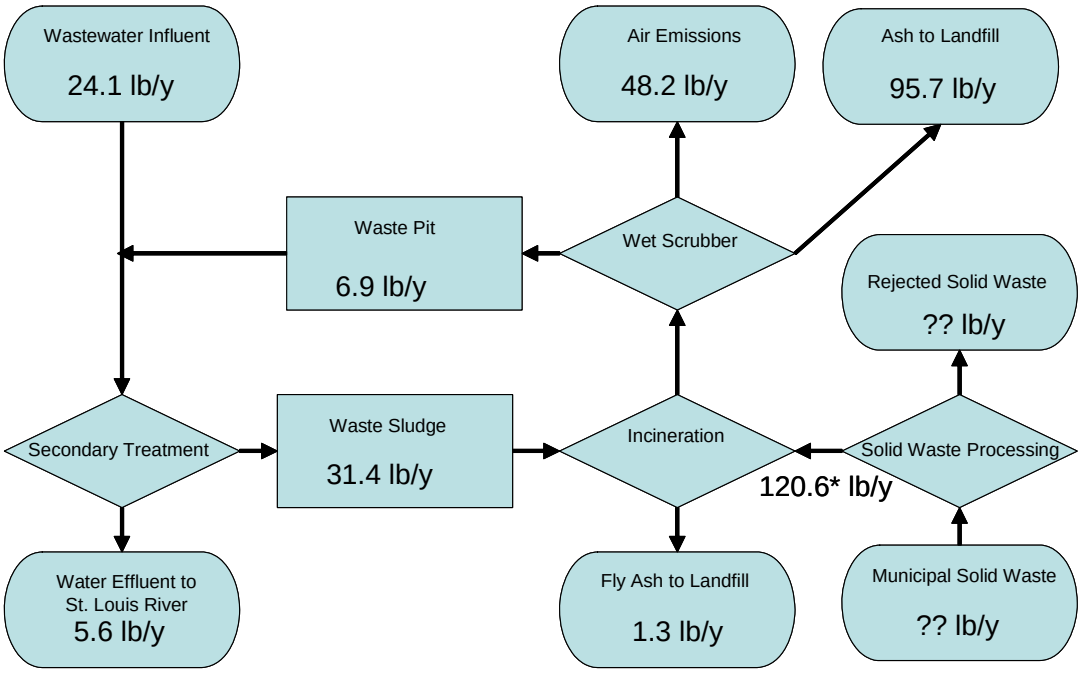
2. Describe any measures currently in use at the facility to reduce mercury emissions. Reduction measures may include pre-processing methods or technologies, selection of process units that are inherently-low emitting technologies, or downstream/add-on control equipment.

3. Provide a diagram that shows the flow of mercury through the facility. The MPCA has found that opportunities for mercury reduction often become evident from an analysis of mercury inputs, flow through the process, and outputs. Accordingly, the MPCA recommends that proposals include a diagram of mercury flow through the facility to identify significant pathways of mercury associated with the project. Mercury Flow Diagrams are most useful when quantitative estimates are made, but qualitative diagrams are a useful first step. Figure 1 is an example of a Mercury Flow Diagram, as produced by the Western Lake Superior Sanitary District (WLSSD) for their process in 1993. WLSSD has since discontinued incineration, but nevertheless, this flow diagram serves as an excellent example.

4. Provide an evaluation of alternatives that could be used to reduce mercury emissions, including a comparison of reduction potential and cost. This evaluation can be summarized in a table that lists alternatives that could be used to reduce mercury emissions, including a comparison of reduction potential and cost (see, for example, Table 2). The reduction alternatives should not be limited to industry-standard controls for the source category. The alternatives should include methods to avoid introducing mercury into the process, controls applied to similar types of sources, innovative control technologies and strategies, modification of the existing process or process equipment, pollution prevention measures, and combinations of these alternatives. If the alternative selected for implementation is not the lowest in

mercury emissions, then the project proposer is expected to demonstrate that the alternatives lower in mercury emissions are either not technically or economically feasible.

Example: WLSSD Mercury Flow Diagram, for May 1993



•Determined by difference; all other flows measured.

Data Source: Tim Tuominen, WLSSD

Figure 1. An example of a mercury flow diagram, based on the operation of the incinerator operated by the Western Lake Superior Sanitary District (WLSSD), for May 1993. The incinerator had two mercury inputs, wastewater and municipal solid waste. The wet scrubber caught a portion of the mercury, but put that mercury back into the process. Later, WLSSD exploited the capture of mercury by the wet scrubber by removing the mercury before putting the water back into the secondary treatment. WLSSD also worked to minimize emissions to the air by working aggressively with industry and the public to reduce mercury loading to both wastewater and municipal solid waste (MSW). An example of wastewater minimization was a project with Potlatch that identified a mercury-contaminated chemical feedstock used at their mill- low mercury feedstock was substituted at no additional cost. An example of MSW minimization is Duluth's early ban on the sale of mercury thermometers, which was feasible because cost-effective substitutes were available.

The mass of mercury may not balance between inputs and outputs because the flux rates are largely based on unadjusted concentrations and mass transfer rates. Nevertheless, even in the absence of precise balance, a mercury flow diagram such as this reveals

information that is useful for mercury reduction efforts. When conducting mass balances at existing facilities, multiple measurements should be taken in order to ascribe a sense of confidence to each number, either through a range or standard deviation.

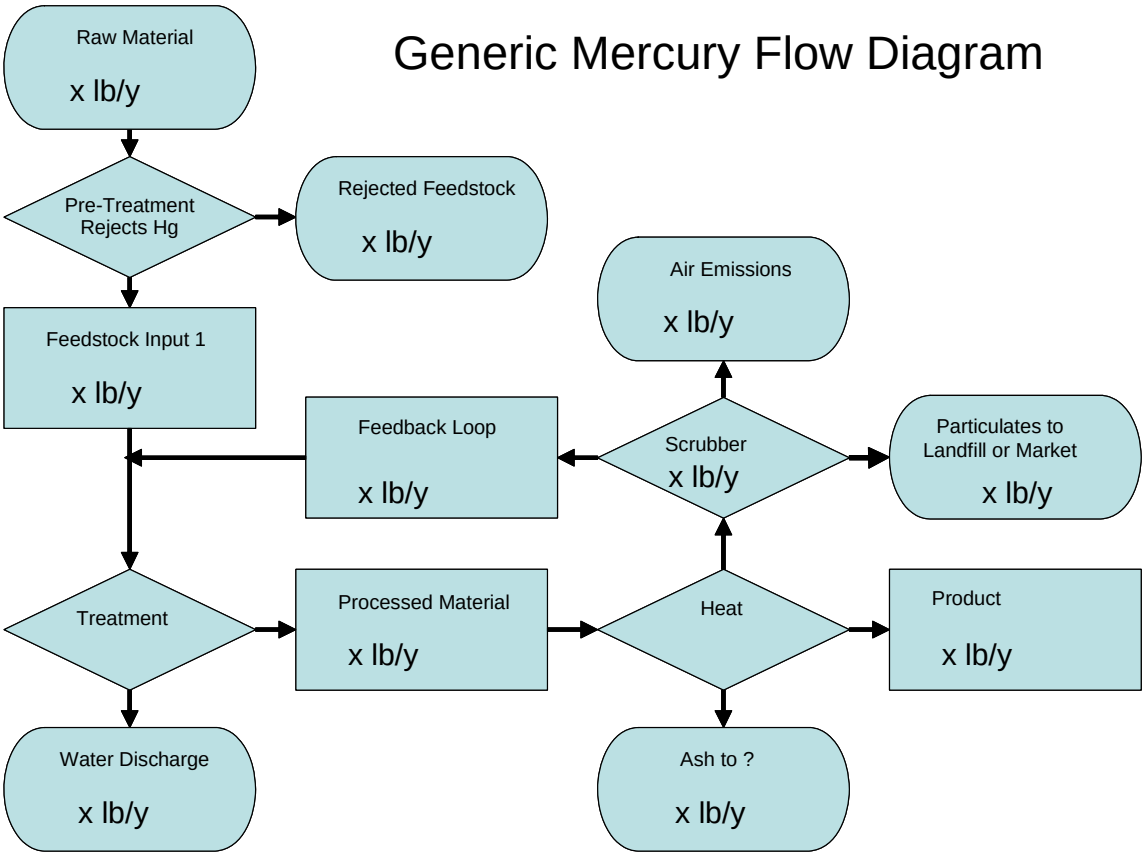
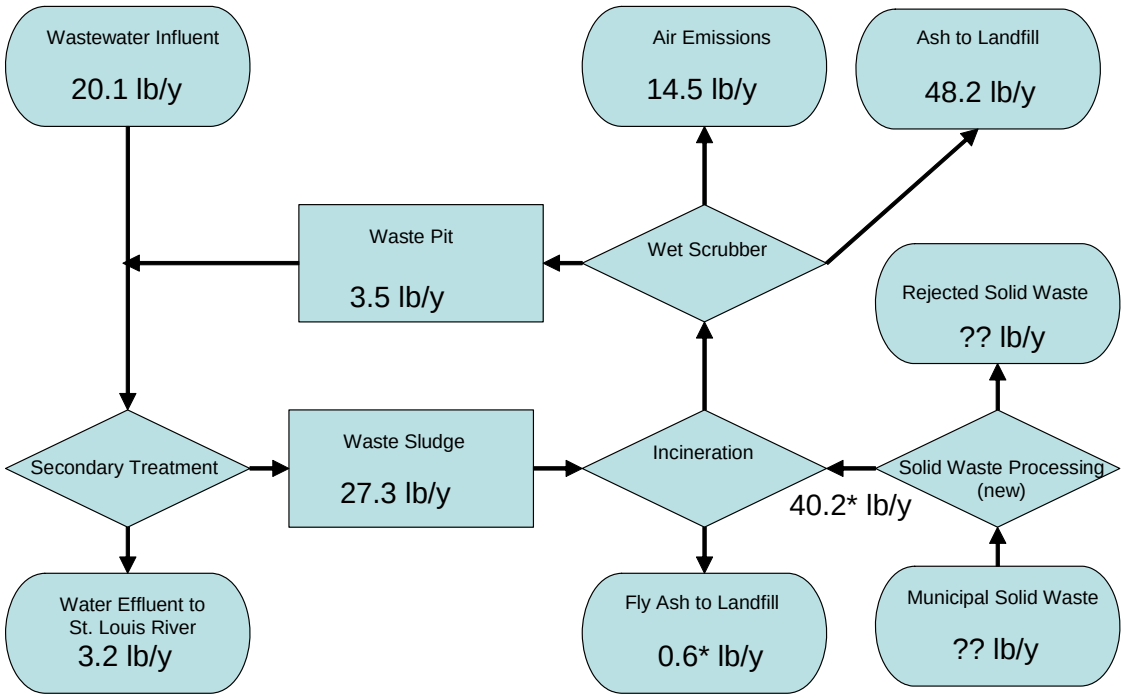


Figure 2. A generic mercury flow diagram that proposers may modify to describe mercury flow at their facility. Different shaped boxes are used as described in the key, Figure 4. The shapes and arrows are available in a variety of software packages, including Microsoft PowerPoint (Flowchart, in AutoShapes).

Example: WLSSD Mercury Flow Diagram, for February 1996

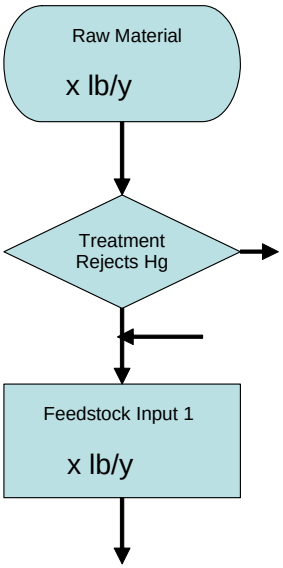


•Determined by difference; all other flows measured.

Data Source: Tim Tuominen, WLSSD

Figure 3. Mercury flow through the WLSSD facility after modifications in waste processing. The difference between this operation and that in 1993 (Figure 1) is described in Table 3. Multiple measurements of a flow stream will help describe the range or variability of a stream.

Key



An rounded rectangle is used to show the materials that are the input or output to the process.

An diamond shows those points in the process where the outflow splits in two or more directions, potentially offering an opportunity to segregate mercury and keep it out of the environment.

A rectangle is used to show a particular stage in the process that doesn't offer any option for segregating mercury. Although multiple arrows may come into each box, usually only one output or arrow leaves each box.

Figure 4. Key for the different shaped boxes used in a mercury flow diagram.

Table 1. Mercury emissions associated with Mesaba One and Mesaba Two (See Block Flow Diagram Provided on the Following Page).

Source Name/Id	potential to emit (pounds per year)				current actual emissions (pounds per year)				future estimated actual emissions (pounds per year)			
	particulate-bound	ionized	elemental	total	particulate-bound	ionized	elemental	total	particulate-bound	ionized	elemental	total
CTGs				51	(NA)							51
TVBs				2								2
Flares				1								1

1. Provide an estimate of mercury emissions for each emissions source expected to release mercury,
2. If the mercury emissions can be speciated into its chemical form, please provide an estimate for each fraction and the total.
3. Provide a description of the data sources relied upon in generating the data for this table.

Notes for mercury estimates:

1) Estimated total mercury emissions based on average expected mercury content of preferred feedstock and assuming between 90% to 95% overall removal by IGCC Power Station systems. PTE based on acceptance of permit limit compliance with which to be verified by continuous monitoring. See Appendix B, Exhibit B-1 for note on mercury content of fuels.

2) Mercury speciation is presumed to be predominantely in elemental form based on reducing atmosphere in gasifier.

3. E-Gas™ Vendor and Wabash River Coal Gasification Repowering Project test results.

Table 2. A table that can be used to summarize alternative methods to reduce mercury emissions from a facility.

Alternative	Total Mercury Emitted (lb/year)	Alternative Description	Reduction Potential (lb/year)	Annualized Cost ($)	Cost Effectiveness ($ per lb Hg)
Worst Case	54	Inherently low-emitting IGCC technology combined with impregnated carbon adsorption systems for treatment of syngas fuel and process water streams. Long term ability to blend low mercury fuels (i.e., petroleum coke) to compensate for higher sulfur fuel use on short term.	>486	TBD	TBD

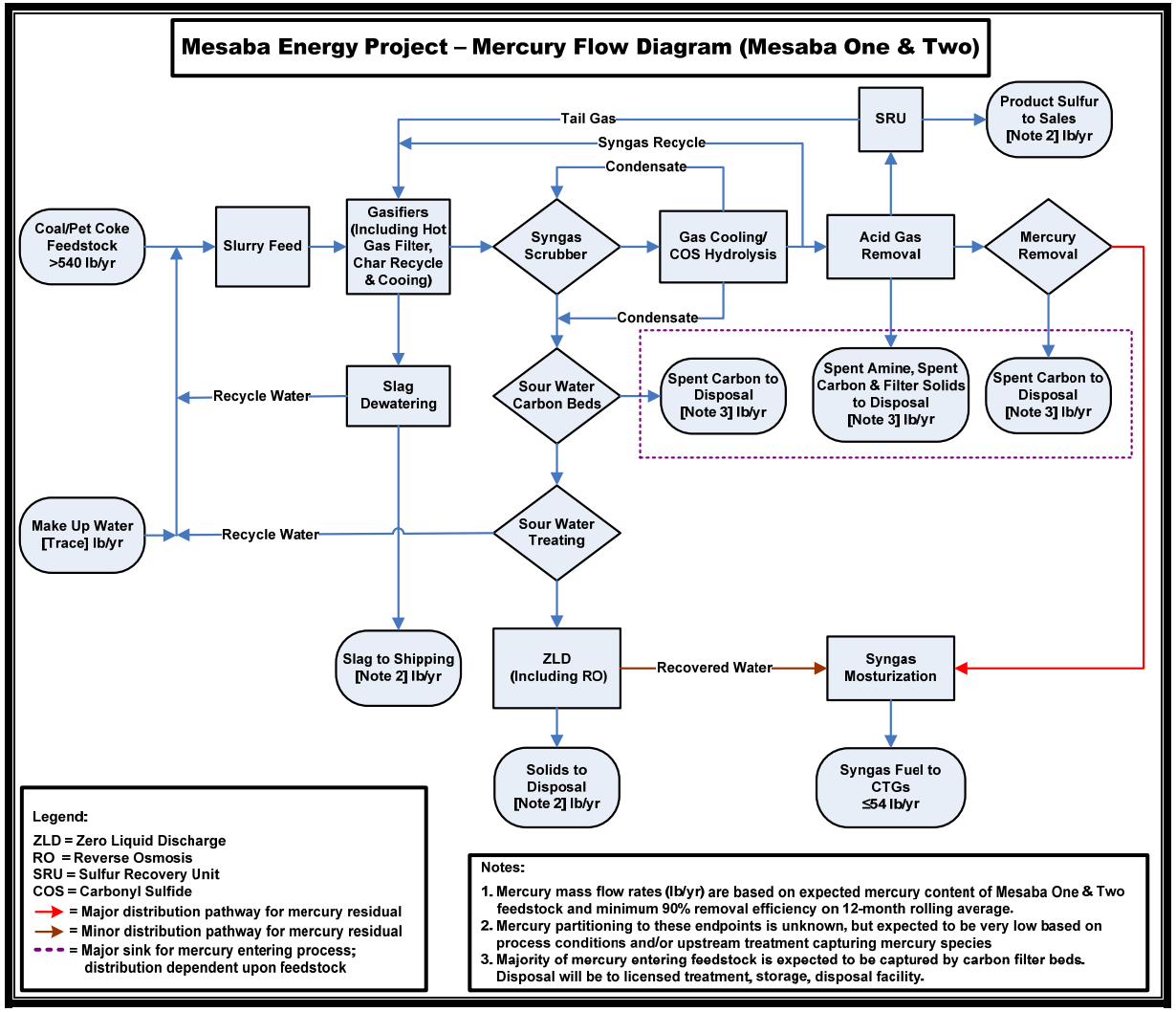

Mesaba Energy Project – Mercury Flow Diagram (Mesaba One & Two)
Tail Gas
Syngas Recycle
Condensate
SRU
Product Sulfur to Sales [Note 2] lb/yr
Coal/Pet Coke Feedstock >540 lb/yr
Slurry Feed
Gasifiers (Including Hot Gas Filter, Char Recycle & Cooing)
Syngas Scrubber
Gas Cooling/ COS Hydrolysis
Acid Gas Removal
Mercury Removal
Condensate
Recycle Water
Slag Dewatering
Sour Water Carbon Beds
Spent Carbon to Disposal [Note 3] lb/yr
Spent Amine, Spent Carbon & Filter Solids to Disposal [Note 3] lb/yr
Spent Carbon to Disposal [Note 3] lb/yr
Make Up Water [Trace] lb/yr
Recycle Water
Sour Water Treating
Slag to Shipping [Note 2] lb/yr
ZLD (Including RO)
Recovered Water
Syngas Mosturization
Solids to Disposal [Note 2] lb/yr
Syngas Fuel to CTGs ≤54 lb/yr
Legend:
ZLD = Zero Liquid Discharge
RO = Reverse Osmosis
SRU = Sulfur Recovery Unit
COS = Carbonyl Sulfide
= Major distribution pathway for mercury residual
= Minor distribution pathway for mercury residual
= Major sink for mercury entering process; distribution dependent upon feedstock
Notes:
1. Mercury mass flow rates (lb/yr) are based on expected mercury content of Mesaba One & Two feedstock and minimum 90% removal efficiency on 12-month rolling average.
2. Mercury partitioning to these endpoints is unknown, but expected to be very low based on process conditions and/or upstream treatment capturing mercury species
3. Majority of mercury entering feedstock is expected to be captured by carbon filter beds. Disposal will be to licensed treatment, storage, disposal facility.

Table 3. An example based on modifications to WLSSD's process in 1996 (see 1996 flow diagram in Figure 3). New MSW processing reduced mercury in the combusted solid waste by 67%, to 40.2 lb/year. In addition, influent loading was reduced by 17%, to 20.1 lb/year. Total loading was reduced from about 145 to 60 lb/year, or 58%, and air emissions were reduced by 70%. Emissions were therefore reduced more than loading, probably because the wet scrubber and its operation were improved prior to the testing, capturing 68% of the incinerated mercury in 1993 and 79% in 1996. Cost information is not available.

Alternative	Total Mercury Emitted (lb)	Alternative Description	Reduction Potential (lb)	Annualized Cost ($)	Cost Effectiveness ($ per lb Hg)
A	48.2	WLSSD base operation, as documented in May 1993			
B		Reduction in loading due to change in solid waste processing.	80.4	Unknown	
C		Reduction in loading due to reduced mercury in liquid waste.	4.0	Unknown	
D		Improvement in wet scrubber and its operation	unknown	Unknown	
B + C + D	14.5	The effect of alternatives B, C, and D were evaluated simultaneously, so emissions are known for only the sum.	84.4	Unknown	

Background to "Assessing the Impacts of Mercury Releases to Ambient Air"

Over 80 percent of lakes assessed in Minnesota have been classified as impaired due to mercury contamination, under section 303(d) of the federal Clean Water Act. People and wildlife are at risk of impaired health from eating fish from these waters, and the Minnesota Department of Health must issue very restrictive fish-consumption advisories for these listed waters. As required by the Clean Water Act, the Minnesota Pollution Control Agency must work to reduce mercury in the fish including reducing mercury releases to air, water and land.

Based on the recommendation of a stakeholder advisory council, the 1999 Minnesota Legislature set goals for reducing mercury air emissions and established a voluntary reduction initiative. Minnesota's goals are to reduce mercury emissions 60 percent from 1990 levels by 2000 and 70 percent by 2005 from 1990 levels. Sources emitting mercury can submit agreements to the MPCA by which they voluntarily reduce mercury releases. As long as adequate progress is made using voluntary efforts, MPCA has agreed not to pursue additional regulations for sources participating in the voluntary program. If voluntary efforts are not sufficient, the MPCA will consider pursuing additional regulatory authority. The MPCA will report to the Legislature in 2005 on the Minnesota's mercury reduction efforts, including the voluntary agreements.

Since 1990, emissions of mercury from sources within Minnesota have been reduced by approximately 68% according to MPCA estimates for 2000. Nearly all of this decrease is due to discontinued use of mercury in products such as paint and batteries and improvements in pollution control equipment on garbage incinerators. During this time, emissions from coal-fired power plants and taconite processing facilities have increased, but only slightly. Total mercury emissions from all Minnesota sources in 2000 are estimated to be 3,642 pounds. The MPCA expects emissions to decrease slightly from this level by 2005.

Due to the long-range transport of mercury in the atmosphere, most of the mercury emitted in Minnesota is deposited outside of the state. Similarly, most of the mercury deposited in Minnesota originates from sources outside of the state. MPCA staff estimates that only about 10 percent of deposition within Minnesota is due to emissions within Minnesota. Even though reductions of emissions in Minnesota will have little effect on deposition in Minnesota, it is still important and necessary to reduce our emissions to reduce deposition in other parts of the region and world, just as reductions are need from regional and global sources to reduce mercury contamination of fish in Minnesota. This guidance describes a means of determining whether air releases have been minimized to the greatest extent possible. Besides ensuring that increases in mercury releases are minimized, this guidance recognizes that it is equally important that new or expanding sources of mercury air emissions do not also increase releases to other environmental media through other pathways.

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **EC-01**

GENERAL EMISSIONS CALCULATION FORM

03/31/99

- Use this form to calculate actual emissions for processes or units that cannot be accounted for in the process/unit specific emissions calculations forms.
- Duplicate this form as necessary to identify all emission units, or attach sheets with equivalent information..

1) AQ Facility ID No.:

2) Facility Name: Mesaba One (ASU Cooling Tower); Mesaba Two identical

3) Emission Unit Identification Number: 004; 013

4) Stack/Vent Designation Number: 004; 016

5) Pollution Control Equipment Identification Number(s): (high efficiency drift eliminators)

6) Process Type: ☐ Batch Process ☒ Continuous Process

7) Operating Capacity: 46 Units: million lb/hr cooling water

8) Source of Emission Factors used in Table Delow: Supplier data

9) Calculations Summary: **Shown for Mesaba One; Mesaba Two is identical.**

9a) Pollutant	**9b)** Emission Factor (lbs/Unit)	**9c)** Emission Rate (lbs/hr)	**9d)** Maximum Uncontrolled Emissions (tons/yr)	**9e)** Actual Uncontrolled Emissions (tons/yr)	**9f)** Pollution Control Efficiency (%)	**9g)** Maximum Controlled Emissions (tons/yr)	**9h)** Actual Controlled Emissions (tons/yr)	**9i)** Limited Controlled Emissions (tons/yr)
PM	0.0272	1.3	5.5			5.5		
PM10	0.0272	1.3	5.5			5.5		
SOx								
NOx								
VOC								
CO								
Lead								

10) Check all of the following that are appropriate:

☐ This process/unit combusts fuel. Include fuel combustion emissions on Form EC-02 (Boilers), EC-03 (Internal Combustion Engines), or EC-08 (Ovens, Dryers, Furnaces), as appropriate.

☐ This process/unit uses clean-up solvents in addition to the process described by the emissions above. Include clean-up solvent emissions on Form EC-12.

☐ This process/unit emits Hazardous Air Pollutants (HAPs). Include HAP emissions on Form EC-13A (VOC HAPs), EC-13B (Particulate HAPs), or EC-13C (Combustion HAPs), as appropriate.

11) Operating Limitations, if applicable:

No operating limits are proposed.

Notes: Units for Item 9b) are lb/million lbs of cirulating cooling water. Emission factor is based on maximum drift of 0.001% of circulating cooling water and maximum 2720 ppm total dissolved solids in cooling water based on eight cycles of concentration.

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **EC-01**

GENERAL EMISSIONS CALCULATION FORM

03/31/99

- Use this form to calculate actual emissions for processes or units that cannot be accounted for in the process/unit specific emissions calculations forms.
- Duplicate this form as necessary to identify all emission units, or attach sheets with equivalent information..

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One (Flare); Mesaba Two identical

3) Emission Unit Identification Number: CE-002; CE-005)

4) Stack/Vent Designation Number: 011; 023

5) Pollution Control Equipment Identification Number(s): CE-002; CE-005

6) Process Type: ☐ Batch Process ☒ Continuous Process

7) Operating Capacity: 2 - 3730 (intermittant) Units: million Btu/hr

8) Source of Emission Factors used in Table Delow: Estimates based on operation of similar equipment

9) Calculations Summary: **Shown for Mesaba One; Mesaba Two is identical.**

9a) Pollutant	**9b)** Emission Factor (lbs/Unit)	**9c)** Emission Rate (lbs/hr)	**9d)** Maximum Uncontrolled Emissions (tons/yr)	**9e)** Actual Uncontrolled Emissions (tons/yr)	**9f)** Pollution Control Efficiency (%)	**9g)** Maximum Controlled Emissions (tons/yr)	**9h)** Actual Controlled Emissions (tons/yr)	**9i)** Limited Controlled Emissions (tons/yr)
PM	0.008	30				1.7		1.7
PM10	0.008	30				1.7		1.7
SOx	0.003 - 0.28	1040				12.3		12.3
NOx	0.064	239				13.4		13.4
VOC	0.006	22			(includ'd)	1.3		1.3
CO	0.55 - 1.52	5680			(includ'd)	286		286
Lead	0.89E-06	0.003				0.0015		0.0002

10) Check all of the following that are appropriate:

☐ This process/unit combusts fuel. Include fuel combustion emissions on Form EC-02 (Boilers), EC-03 (Internal Combustion Engines), or EC-08 (Ovens, Dryers, Furnaces), as appropriate.

☐ This process/unit uses clean-up solvents in addition to the process described by the emissions above. Include clean-up solvent emissions on Form EC-12.

☒ This process/unit emits Hazardous Air Pollutants (HAPs). Include HAP emissions on Form EC-13A (VOC HAPs), EC-13B (Particulate HAPs), or EC-13C (Combustion HAPs), as appropriate.

11) Operating Limitations, if applicable:

This equipment is an emergency safety device that is also used to dispose of non-useable gases during gasifier startup and shutdown. The emission estimates shown are based on approximately 1260 annual hours of startup and shutdown operation plus about 200 annual hours of intermittant syngas flaring due to upset events in the IGCC Power Station (see attached permit application Section 4.1.3 and emission calculations in Appendix A, Exhibit A-4.

Notes:

Item 9b) - Units are lb/10^6 Btu of gas flared. SO2 emission factors are calculated from expected worst-case range of flared gas sulfur content. See attached emission calcuation appendix for source of non-SO2 emission factors.

Item 9i) - See attached emission calculation appendix for assumed worst case annual operating scenario.

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **EC-01**

GENERAL EMISSIONS CALCULATION FORM

03/31/99

- Use this form to calculate actual emissions for processes or units that cannot be accounted for in the process/unit specific emissions calculations forms.
- Duplicate this form as necessary to identify all emission units, or attach sheets with equivalent information..

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One (Power Block Cooling Tower); Mesaba Two is identical

3) Emission Unit Identification Number: 005; 012

4) Stack/Vent Designation Number: 005; 015

5) Pollution Control Equipment Identification Number(s): (high efficiency drift eliminators)

6) Process Type: ☐ Batch Process ☒ Continuous Process

7) Operating Capacity: 116 Units: million lb/hr cooling water

8) Source of Emission Factors used in Table Delow: Supplier data

9) Calculations Summary: **Shown for Mesaba One; Mesaba Two is identical.**

9a) Pollutant	**9b)** Emission Factor (lbs/Unit)	**9c)** Emission Rate (lbs/hr)	**9d)** Maximum Uncontrolled Emissions (tons/yr)	**9e)** Actual Uncontrolled Emissions (tons/yr)	**9f)** Pollution Control Efficiency (%)	**9g)** Maximum Controlled Emissions (tons/yr)	**9h)** Actual Controlled Emissions (tons/yr)	**9i)** Limited Controlled Emissions (tons/yr)
PM	0.0272	3.1	14			14		
PM10	0.0272	3.1	14			14		
SOx								
NOx								
VOC								
CO								
Lead								

10) Check all of the following that are appropriate:

☐ This process/unit combusts fuel. Include fuel combustion emissions on Form EC-02 (Boilers), EC-03 (Internal Combustion Engines), or EC-08 (Ovens, Dryers, Furnaces), as appropriate.

☐ This process/unit uses clean-up solvents in addition to the process described by the emissions above. Include clean-up solvent emissions on Form EC-12.

☐ This process/unit emits Hazardous Air Pollutants (HAPs). Include HAP emissions on Form EC-13A (VOC HAPs), EC-13B (Particulate HAPs), or EC-13C (Combustion HAPs), as appropriate.

11) Operating Limitations, if applicable:

No operating limits are proposed.

Notes: Units for Item 9b) are lb/million lbs of cirulating cooling water. Emission factor is based on maximum drift of 0.001% of circulating cooling water and maximum 2720 ppm total dissolved solids in cooling water based on eight cycles of concentration.

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
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PERMIT APPLICATION FORM **EC-02**

EXTERNAL COMBUSTION (BOILER) CALCULATION FORM

10/27/03

- Fill out this form for each boiler, or attach sheets with equivalent information.
- Instructions begin on Page 6.
- If the boiler emits Hazardous Air Pollutants (HAPs), fill out and attach Form EC-13C.

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One (Tank Vent Boiler); Mesaba Two is identical.

3) Emission Unit Identification Number: CE-001; CE-004

4) Stack/Vent Designation Number: 010; 022

5) Maximum Rated Boiler Capacity: 65 (HHV) million BTU/hr

6) Control Equipment: 010; 022

7) Fuel Parameters

Shown for Mesaba One; Mesaba Two is identical.

7a) Fuel Type	**7b)** % Sulfur	**7c)** % Ash	**7d)** Heat Value	Units	**7e)** Fuel Consumption Rate	Units
Syngas and tank vent gas	0.005		240 Btu/cf (approx HHV)	Btu/ton, Btu/gal, Btu/cf	270,000 cf/hr (approx)	ton/hr; gal/hr; cf/hr
Natural gas			1000 Btu/cf (approx)	Btu/ton, Btu/gal, Btu/cf	40,000 cf/hr	ton/hr; gal/hr; cf/hr
				Btu/ton, Btu/gal, Btu/cf		ton/hr; gal/hr; cf/hr

When calculating Potential Emissions, use items 8a, 8b, 8d, 8e, 8g, 8h, and 8i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 8a, 8b, 8c, 8f, 8g, and 8j.

8) Calculations Summary - Primary Fuel:

8a Pollutant	**8b** Emission Factor (lbs/ton, lbs/gal, lbs/cf, etc.)	**8c** Actual Annual Fuel Use (tons, gallons, cf, etc.)	**8d** Emission Rate (lbs/hr)	**8e** Maximum Uncontrolled Emissions (tons/yr)	**8f** Actual Uncontrolled Emissions (tons/yr)	**8g** Pollution Control Efficiency (%)	**8h** Maximum Controlled Emissions (tons/yr)	**8i** Limited Controlled Emissions (tons/yr)	**8j** Actual Controlled Emissions (tons/yr)
PM	0.01		0.65	2.8				0.9	
PM_{10}	0.01		0.65	2.8				0.9	
SOx	0.035 - 0.084		5.2 - 8.5	37				15.8	
NOx	0.3		19.5	85.4				26.4	
VOC	0.004		0.3	1.1				0.4	
CO	0.09		5.9	25.6				7.9	
Lead	0.8E-06		0.0003	0.001				7.0E-05	

When calculating Potential Emissions, use items 9a, 9b, 9d, 9e, 9g, 9h, and 9i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 9a, 9b, 9c, 9f, 9g, and 9j.

9) Calculations Summary - Back-up Fuel:

9a Pollutant	**9b** Emission Factor (lbs/ton, lbs/gal, lbs/cf, etc.)	**9c** Actual Annual Fuel Use (tons, gallons, cf, etc.)	**9d** Emission Rate (lbs/hr)	**9e** Maximum Uncontrolled Emissions (tons/yr)	**9f** Actual Uncontrolled Emissions (tons/yr)	**9g** Pollution Control Efficiency (%)	**9h** Maximum Controlled Emissions (tons/yr)	**9i** Limited Controlled Emissions (tons/yr)	**9j** Actual Controlled Emissions (tons/yr)
PM	0.01		0.4	1.8			0.9		
PM_{10}	0.01		0.4	1.8			0.9		
SOx	0.00286		0.1	0.5			0.3		
NOx	0.3		12	52.6			26.4		
VOC	0.004		0.02	0.7			0.4		
CO	0.09		3.6	15.8			7.9		
Lead	NA								

When calculating Potential Emissions, use items 10a, 10b, 10d, 10e, 10g, 10h, and 10i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 10a, 10b, 10c, 10f, 10g, and 10j.

10) Calculations Summary - Back-up Fuel:

10a Pollutant	**10b** Emission Factor (lbs/ton, lbs/gal, lbs/cf, etc.)	**10c** Actual Annual Fuel Use (tons, gallons, cf, etc.)	**10d** Emission Rate (lbs/hr)	**10e** Maximum Uncontrolled Emissions (tons/yr)	**10f** Actual Uncontrolled Emissions (tons/yr)	**10g** Pollution Control Efficiency (%)	**10h** Maximum Controlled Emissions (tons/yr)	**10i** Limited Controlled Emissions (tons/yr)	**10j** Actual Controlled Emissions (tons/yr)
PM									
PM_{10}									
SOx									
NOx									
VOC									
CO									
Lead									

11) Worse-Case Potential-to-Emit Summary: (Ignore this item if filling out this form for a Registration Permit Option D)

Pollutant	**11a)** ***Before Operating Limits:*** (tons/yr)	**11b)** ***After Operating Limits:*** (tons/yr)
PM	2.8	0.9
PM_{10}	2.8	0.9
SOx	37	15.8
NOx	85.4	26.4
VOC	1.1	0.4
CO	25.6	7.9
Lead	0.001	0.0003

12) Operating Limitations, if applicable: (Ignore this item if filling out this form for a Registration Permit Option D)

Total sulfur in syngas fuel will be limited to 120 ppmv/1-hr avg, 100 ppmv/3- and 8-hr avg, 75 ppmv/24-hr avg, and 50 ppmv/30-day rolling avg. Annual fuel consumption of syngas plus tank vent gas plus natural gas will not exceed 176,000 x 10^6 Btu/yr - See attached permit application Section 4.1.2 and emission calculation Appendix A, Exhibit A-2 for assumed worst case annual operating scenario and other details.

Notes:

Item 8) - This equipment also oxidizes tank vent gas containing about 1.5 lb/hr equivalent sulfur, which will be converted to 3 lb/hr SO2. Mass emission rates listed include this SO2 from tank vent gas, the emission factors do not include it.

Items 8b) and 9b) - Units are lb/10^6 Btu of gas fired, non-SO2 emission factors are based on supplier data or test results for similar equipment using similar fuels. SO2 emission factors are calculated from expected worst-case range of fuel sulfur content (excluding tank sulfur in tank vent gas - see above).

Item 8i) - See attached permit application for assumed worst case annual operating scenario and other details.

- Fill out this form for each boiler, or attach sheets with equivalent information.
- Instructions begin on Page 6.
- If the boiler emits Hazardous Air Pollutants (HAPs), fill out and attach Form EC-13C.

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One (Aux Boiler); Mesaba Two is identical

3) Emission Unit Identification Number: 003; 012

4) Stack/Vent Designation Number: 003; 015

5) Maximum Rated Boiler Capacity: 130 (HHV) million BTU/hr

6) Control Equipment: Low NOx burner

7) Fuel Parameters

Shown for Mesaba One; Mesaba Two is identical.

7a) Fuel Type	**7b)** % Sulfur	**7c)** % Ash	**7d)** Heat Value	Units	**7e)** Fuel Consumption Rate	Units
Natural gas (only fuel proposed)			1000 Btu/cf (approx)	Btu/ton, Btu/gal, Btu/cf	130,000 cf/hr	ton/hr; gal/hr; cf/hr
				Btu/ton, Btu/gal, Btu/cf		ton/hr; gal/hr; cf/hr
				Btu/ton, Btu/gal, Btu/cf		ton/hr; gal/hr; cf/hr

When calculating Potential Emissions, use items 8a, 8b, 8d, 8e, 8g, 8h, and 8i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 8a, 8b, 8c, 8f, 8g, and 8j.

8) Calculations Summary - Primary Fuel:

8a Pollutant	**8b** Emission Factor lb/(10^6)Btu	**8c** Actual Annual Fuel Use (tons, gallons, cf, etc.)	**8d** Emission Rate (lbs/hr)	**8e** Maximum Uncontrolled Emissions (tons/yr)	**8f** Actual Uncontrolled Emissions (tons/yr)	**8g** Pollution Control Efficiency (%)	**8h** Maximum Controlled Emissions (tons/yr)	**8i** Limited Controlled Emissions (tons/yr)	**8j** Actual Controlled Emissions (tons/yr)
PM	0.005		0.65	2.8				0.7	
PM_{10}	0.005		0.65	2.8				0.7	
SOx	0.00286		0.37	1.6				0.4	
NOx	0.036		4.7	20.5				5.1	
VOC	0.004		0.52	2.3				0.6	
CO	0.074		9.6	42.1				10.5	
Lead									

When calculating Potential Emissions, use items 9a, 9b, 9d, 9e, 9g, 9h, and 9i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 9a, 9b, 9c, 9f, 9g, and 9j.

9) Calculations Summary - Back-up Fuel:

9a Pollutant	**9b** Emission Factor (lbs/ton, lbs/gal, lbs/cf, etc.)	**9c** Actual Annual Fuel Use (tons, gallons, cf, etc.)	**9d** Emission Rate (lbs/hr)	**9e** Maximum Uncontrolled Emissions (tons/yr)	**9f** Actual Uncontrolled Emissions (tons/yr)	**9g** Pollution Control Efficiency (%)	**9h** Maximum Controlled Emissions (tons/yr)	**9i** Limited Controlled Emissions (tons/yr)	**9j** Actual Controlled Emissions (tons/yr)
PM									
PM_{10}									
SOx									
NOx									
VOC									
CO									
Lead									

When calculating Potential Emissions, use items 10a, 10b, 10d, 10e, 10g, 10h, and 10i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 10a, 10b, 10c, 10f, 10g, and 10j.

10) Calculations Summary - Back-up Fuel:

10a Pollutant	**10b** Emission Factor (lbs/ton, lbs/gal, lbs/cf, etc.)	**10c** Actual Annual Fuel Use (tons, gallons, cf, etc.)	**10d** Emission Rate (lbs/hr)	**10e** Maximum Uncontrolled Emissions (tons/yr)	**10f** Actual Uncontrolled Emissions (tons/yr)	**10g** Pollution Control Efficiency (%)	**10h** Maximum Controlled Emissions (tons/yr)	**10i** Limited Controlled Emissions (tons/yr)	**10j** Actual Controlled Emissions (tons/yr)
PM									
PM_{10}									
SOx									
NOx									
VOC									
CO									
Lead									

11) Worse-Case Potential-to-Emit Summary: (Ignore this item if filling out this form for a Registration Permit Option D)

Pollutant	**11a)** ***Before Operating Limits:*** (tons/yr)	**11b)** ***After Operating Limits:*** (tons/yr)
PM	2.8	0.7
PM_{10}	2.8	0.7
SOx	1.6	0.4
NOx	20.5	5.1
VOC	2.3	0.6
CO	42.1	10.5
Lead		

12) Operating Limitations, if applicable: (Ignore this item if filling out this form for a Registration Permit Option D)

Because the Auxiliary Boiler will normally operate only when there is not steam available from the gasifiers or HRSGs, it is anticipated to operate at less than 25% annual capacity factor - see permit application text Section 4.1.7 and Appendix A, Exhibit A-3.

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **EC-03**

INTERNAL COMBUSTION ENGINE (SINGLE-FUEL) FORM
PART 1: EMISSION CALCULATIONS

02/17/05

- Fill out Part 1 of this form for each fuel burned in each engine, or attach sheets with equivalent information. If the engine emits Hazardous Air Pollutants (HAPs), fill out and attach form EC-13C.
  Fill out Part 2 of this form only if you are installing a generator to be used for other than emergencies.

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One (CTG - natural gas); Mesaba Two is identical

3) Emission Unit Identification Number: 001; 010

4) Stack/Vent Designation Number: 001; 013

5) Control Equipment Identification Number: (steam injection for NOx control)

6) Engine Type: ☐ Reciprocating ☒ Turbine ☐ Other: _____

7) Engine is Used For: ☒ Non-Emergency use **(If you check this box, you must complete Part 2 of this form.)** ☐ Emergency use only

8) Rated Heat Input: 2077 (HHV) mmBtu/hr

9) Rated Mechanical Output: 220 MW ~~HP~~ @ 3600 RPM

10) Fuel Type: p/l natural gas (startup/backup fuel) @ _____ % Sulfur

11) Fuel Consumption Rate: 2,080,000 cf/hr (gal/hr or cf/hr)

12) Calculations Summary: **Shown for Mesaba One; Mesaba Two is identical.**

12a) Pollutant	**12b)** Emission Factor (lbs/unit)	**12c)** Emission Rate (lbs/hr)	**12d)** Maximum Uncontrolled Emissions (tons/yr)	**12e)** Pollution Control Efficiency (%)	**12f)** Maximum Controlled Emissions (tons/yr)	**12g)** Limited Controlled Emissions (tons/yr)	**12h)** Actual Emissions (tons/yr)
PM	0.0087	18	79			4.0	
PM10	0.0087	18	79			4.0	
SO_2	0.00286	5.9	25.8			1.3	
NO_X	0.0953	198	867			43.6	
VOC	0.00318	6.6	28.9			1.5	
CO	0.0347	72	315			15.8	
Lead	NA						

13) Operating Limitations, if applicable:

After first 36 mos. of operation, natural gas use would be limited to 440 hr/yr. Increased natural gas use is requested during first 36 mos - see application text Section 4.1.1 and emission calculation Appendix A, Exhibit A-1 for details.

Note for 12b) - units are lb/10^6 Btu (HHV) gas fired, emission data from equip mfr, except SO2 based on 1 grain sulfur/100 scf nat gas. Nominal heating value of about 1000 Btu/scf (HHV) is assumed.

1) **AQ Facility ID No. --** Fill in your Air Quality Facility ID Number as indicated on Form GI-01 or Form RP-01, item 1a.

2) **Facility Name --** Enter your facility name as indicated on Form GI-01 or Form RP-01, item 2.

3) **Emission Unit Identification Number --** Fill in the identification number of the emission unit. Obtain this number from Form GI-05B, unless you are using this form for Registration Permit Option D. In that case, just provide a description of the emission unit.

4) **Stack/Vent Designation Number --** [Skip this item if using this form for Registration Permit Option D.] Fill in the designation number of the stack(s) or vent(s) through which the engine will exhaust into the atmosphere. Obtain these numbers from Form GI-05B.

5) **Control Equipment Identification Number --** Fill in the identification number of the control equipment. Obtain this number from Form GI-05B, unless you are using this form for Registration Permit Option D. In that case, enter the description from Form RP-D2.

6) **Engine Type --** Indicate the appropriate engine type.

7) **Engine is Used For --** Indicate if the engine is used for routine operation or for emergency use.

8) **Rated Heat Input --** Enter the rated heat input of the engine, in units of million British thermal units (mmBtu) per hour.

9) **Rated Mechanical Output** -- Fill in the rated output of the engine in horsepower at a specified rpm.

10) **Fuel Type --**Fill in the fuel type (e.g., natural gas, diesel). **Fill out this form for each fuel burned.** Fill in the weight percent sulfur content, if applicable.

11) **Rated Fuel Consumption --** Fill in the manufacturer's rated fuel consumption for the engine. This information can be obtained from the manufacturer. If the engine has been derated, attach the supporting documentation. Circle the appropriate units.

12) **Calculations Summary:**

12a) **Pollutant --** For each pollutant listed in the table, calculate the engine's emissions.

12b) **Emission Factor --** Fill in the emission factors from Table EC-03.1 (Columns A - I) or obtain this information from the Compilation of Air Pollutant Emission Factors (AP-42) or EPA document 450/4-90-003. Circle the applicable units. [If you choose not to use Table EC-03.1, remember to use only uncontrolled emission factors.]

12c) **Emission Rate --** Fill in the Emission Rate in lb/hr. Calculate the emission rate by using one of the following methods:

If the emission factor is in units of pounds per quantity of fuel (gallons or cubic feet):

$$\begin{aligned}&\text{Emission Rate [lb / hr]:}\\&\quad = \text{Fuel Consumption Rate [qty / hr]} \times \text{Emission Factor [lb / qty]}\\&\quad = (\text{item 11}) \times (\text{item 12b})\end{aligned}$$

If the emission factor is in units of pounds per hp-hr power output:

$$\begin{aligned}&\text{Emission Rate [lb / hr]:}\\&\quad = \text{Rated Mechanical Output [hp]} \times \text{Emission Factor [lb / hp - hr]}\\&\quad = (\text{item 9}) \times (\text{item 12b})\end{aligned}$$

If the emission factor is in units of pounds per MMBtu heat input:

$$\begin{aligned}&\text{Emission Rate [lb / hr]}\\&\quad = \text{Rated Heat Input [MMBtu / hr]} \times \text{Emission Factor [lb / MMBtu]}\\&\quad = (\text{item 8}) \times (\text{item 12b})\end{aligned}$$

12d) **Maximum Uncontrolled Emissions --** [Skip this item if using this form for Registration Permit Option D.] Fill in the maximum uncontrolled emissions in tons per year. If the engine is an "emergency generator" (a generator whose sole function is to provide back-up power when power from the local utility is interrupted), the U.S. EPA has stated in a memorandum dated September 6, 1995, that maximum uncontrolled emissions may be based on operating the generator 500 hours per year. Use the following equation:

$$\begin{aligned}&\text{Maximum Uncontrolled Emissions [tons / yr]:}\\&\quad = \text{Emission Rate}\left[\frac{\text{lb}}{\text{hr}}\right] \times 0.25\left[\frac{\text{hrs}}{\text{yr}}\cdot\frac{\text{ton}}{\text{lbs}}\right]\\&\quad = (\text{item 12c}) \times 0.25\end{aligned}$$

The September 6, 1995 EPA memo applies only to emergency generators as defined above. It does not apply to peaking units at electric utilities (peak shaving units); generators at industrial facilities that typically operate at low rates but are not confined to emergency use; or any standby generator that is also used during times when power is available from the utility. If your engine is not an emergency generator, you must base maximum uncontrolled emissions on operating the engine 8,760 hours per year. Use the following equation:

$$\begin{aligned}&\text{Maximum Uncontrolled Emissions [tons / yr]:}\\&\quad = \text{Emission Rate}\left[\frac{\text{lb}}{\text{hr}}\right] \times 4.38\left[\frac{\text{hrs}}{\text{yr}}\cdot\frac{\text{ton}}{\text{lbs}}\right]\\&\quad = (\text{item 12c}) \times 4.38\end{aligned}$$

12e) **Pollution Control Efficiency --** The pollution control efficiency is the product of the capture efficiency and the destruction/collection efficiency indicated on Form GI-05A, or, if you are using this form for Registration Permit Option D, the control efficiency is indicated on Form RP-D2. Enter the number here and remember to include on Form CD-01 a plan to demonstrate and maintain the destruction/collection efficiency. [If you are using this form for Registration Permit Option D, you do not need to fill out Form

CD-01.] The efficiency should be expressed for each pollutant. If there is no control equipment for the particular pollutant, then indicate zero.

12f) **Maximum Controlled Emissions --** [Skip this item if you are using this form for Registration Permit Option D.] Fill in the maximum controlled emissions (i.e., after taking into consideration the pollution control equipment) of the process/unit in tons per year. Calculate the maximum controlled emissions (in tons per year) by using the following formula:

Max. Controlled Emissions [tons / yr]:

$$= \text{Max. Uncontrolled Emissions}\left[\frac{\text{tons}}{\text{yr}}\right] \times \left(\frac{100 \text{ - Pollution Control Efficiency}}{100}\right)$$

$$= (\text{item 12d}) \times \left(\frac{100 \text{ - (item 12e)}}{100}\right)$$

12g) **Limited Controlled Emissions** -- [Skip this item if using this form for Registration Permit Option D.] The Limited Controlled Emissions are calculated by taking into account all proposed limitations on operation of the source. These limitations include limits on hours of operation, on the amount of material mined, handled, crushed, screened, etc. The proposed limit should be described in item 13 and on Form CD-01. You start the calculation of Limited Controlled Emissions by repeating the calculation of Emission Rate (item 12c) but taking into account the limits you propose.

If an emission unit is subject to an emission limitation specified in 40 C.F.R. pt. 60, 40 C.F.R. pt. 61, 40 C.F.R. pt. 63 or Minn. Rules ch. 7011, you must show this requirement in the calculation of Limited Controlled Emissions and take this into account in calculating the Limited Controlled Emissions. If you choose to propose to comply with more a stringent limit, you should state this clearly and show the resulting allowed emissions in this calculation.

12h) **Actual Emissions** -- If this is an existing unit and historical records exist, calculate actual emissions using the average of the previous two calendar years of equipment or fuel usage data (last 12 months if using this form for Registration Permit Option D], or average the previous two emission inventory reports if an inventory was submitted. Report actual emissions in tons/year.

Calculate actual emissions using the following method.:

- If the emission factor is in units of pounds per quantity of fuel (gallons or cubic feet):

Actual Emissions [ton / yr]:

$$= \text{Fuel Consumption Rate [qty / yr]} \times \text{Emission Factor [lb / qty]} \times \frac{1}{2000}\left[\frac{\text{ton}}{\text{lb}}\right] \times \left(\frac{100 - \text{Pollution Control Efficiency}}{100}\right)$$

$$= \text{Consumption Rate} \times (\text{item 12b}) \times 0.0005 \times \left(\frac{100 - (\text{item 12e})}{100}\right)$$

- If the emission factor is in units of pounds per hp-hr power output or pounds per MMBtu heat input:

Actual Emissions [ton / year]:

$$= \text{Emission Rate}\left[\text{lb / hr}\right] \times \text{Actual Operating Hours [hr]} \times \frac{1}{2000}\left[\frac{\text{ton}}{\text{lb}}\right] \times \left(\frac{100 - \text{Pollution Control Efficiency}}{100}\right)$$

$$= (\text{item 12c}) \times \text{Actual Operating Hours} \times 0.0005 \times \left(\frac{100 - (\text{item 12e})}{100}\right)$$

If this is a new unit or no records exist, use a reasonable estimate of how many hours the unit will be operated, how much fountain solution will be used, how much cleaning solution, etc.

13) **Operating Limitations --** Describe any permit limits you plan to take to restrict your PTE (fuel type and/or usage, hours of operation, etc.). Attach additional sheets, if necessary. Describe the limiting factors and cite any rules that apply (e.g. Minn. Rules, Best Available Control Technology (BACT)). The associated limits must be used to calculate your PTE. If you used vendor certification or stack test data to limit your PTE, that factor will become a permit limit. Include all proposed limits on Form CD-01.

TABLE EC-03.1: Emission factors[a] for internal combustion engines and fuels

Columns	A	B	C	D	E	F	G	H	I	J	K
	PM[b] (lb/unit)	PM10 (lb/unit)	PM Filterable [c] (lb/unit)	PM Condensable [d] (lb/unit)	SOx (lb/unit)	NOx (lb/unit)	VOC (lb/unit)	CO (lb/unit)	Lead (lb/unit)	Heat Value (BTU/Unit)	UNITS
Industrial Reciprocating Engines :											
Distillate (diesel) oil, <600 hp	0.002 2	0.002 2	- - - -	- - - -	0.002 05	0.031	0.002 514	0.006 68	- - - -	n/a[f]	hp-hr power output
	0.31	0.31	- - - -	- - - -	0.29	4.41	0.36	0.95	- - - -	n/a[f]	MMBtu fuel input
Distillate (diesel) oil, ≥600 hp	0.000 7	0.000 7	- - - -	- - - -	0.008 09 S[e]	0.024	0.000 642	0.005 5	- - - -	n/a[f]	hp-hr power output
	0.069 7	0.057 3	0.062 0	0.007 7	1.01 S[e]	3.2	0.082	0.85	- - - -	n/a[f]	MMBtu fuel input
Gasoline	0.000 721	0.000 721	- - - -	- - - -	0.000 591	0.011	0.021 591	0.439	- - - -	n/a[f]	hp-hr power output
	0.10	0.10	- - - -	- - - -	0.084	1.63	3.030	62.7	- - - -	n/a[f]	MMBtu fuel input
Natural Gas	0.000 010	0.000 010	- - - -	- - - -	0.000 000 6	0.003 40	0.000 082 9	0.000 430	- - - -	1,050	cubic feet burned
Kerosene/Naphtha	0.033 5	0.032 0	- - - -	- - - -	0.006 2	0.469 0	0.032 1	0.102 0	- - - -	135,000	gallons burned
Propane	0.005 0	0.005 0	- - - -	- - - -	0.000 35	0.139 0	0.083 0	0.129 0	- - - -	91,500	gallons burned
Butane	0.005 0	0.005 0	- - - -	- - - -	0.000 35	0.139 0	0.083 0	0.129 0	- - - -	102,600	gallons burned
Natural Gas-Fired Pipeline Compressor Engines:											
2-cycle lean burn											
= 90% Load	0.038 4	0.038 4	- - - -	0.009 91	0.000 588	3.17	0.12	0.386	- - - -	n/a[f]	MMBtu fuel input
< 90% Load	0.038 4	0.038 4	- - - -	0.009 91	0.000 588	1.94	0.12	0.353	- - - -	n/a[f]	MMBtu fuel input
4-cycle lean burn											
= 90% Load	0.000 077 1	0.000 077 1	- - - -	0.009 91	0.000 588	4.08	0.118	0.317	- - - -	n/a[f]	MMBtu fuel input
< 90% Load	0.000 077 1	0.000 077 1	- - - -	0.009 91	0.000 588	0.847	0.118	0.557	- - - -	n/a[f]	MMBtu fuel input
4-cycle rich burn											
= 90% Load	0.009 5	0.009 5	- - - -	0.009 91	0.000 588	2.21	0.029 6	3.72	- - - -	n/a[f]	MMBtu fuel input
< 90% Load	0.009 5	0.009 5	- - - -	0.009 91	0.000 588	2.27	0.029 6	3.51	- - - -	n/a[f]	MMBtu fuel input

Columns	A	B	C	D	E	F	G	H	I	J	K
	PM[b] (lb/unit)	PM10 (lb/unit)	PM Filterable [c] (lb/unit)	PM Condensable [d] (lb/unit)	SOx (lb/unit)	NOx (lb/unit)	VOC (lb/unit)	CO (lb/unit)	Lead (lb/unit)	Heat Value (BTU/Unit)	UNITS
Turbine Engines (Electrical Generation):											
Natural Gas [g]											
Water/steam injection	0.006 6	0.006 6	0.001 9	0.004 7	0.94 S[e]	0.13	0.002 1	0.03	- - - -	n/a[f]	MMBtu fuel input
uncontrolled	- - - -	- - - -	- - - -	- - - -	0.94 S[e]	0.32	0.002 1	0.082	- - - -	n/a[f]	MMBtu fuel input
Distillate Oil (Diesel)[g]											
Water/steam injection	0.012	0.012	0.004 3	0.007 2	1.01 S[e]	0.24	0.000 41	0.076	0.000 014	n/a[f]	MMBtu fuel input
uncontrolled	- - - -	- - - -	- - - -	- - - -	1.01 S[e]	0.88	0.000 41	0.003 3	- - - -	n/a[f]	MMBtu fuel input
Kerosene/Naphtha	0.005 0	0.004 8	- - - -	- - - -	0.006 2	0.067 8	0.004 77	0.015 4	- - - -	135,000	gallons burned
Landfill Gas [g]	0.023	0.023	- - - -	- - - -	0.045	0.14	0.013	0.44	- - - -	n/a[f]	MMBtu fuel input
Digester Gas [g]	0.012	0.012	- - - -	- - - -	0.006 5	0.16	0.005 8	0.017	0.000 0034	n/a[f]	MMBtu fuel input

Notes:

[a] Emission factors adapted from EPA documents AP-42 and 450/4-90-003. An "- - - -" indicates that there is currently no emission factor available.

[b] PM refers to all particulate matter of all sizes, PM_{10} refers only to particulate matter from 0.0 to 10.0 microns in diameter.

[c] Filterable PM is that particulate matter collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.

[d] Condensable PM is that particulate matter collected in the impinger portion of an EPA Method 5 (or equivalent) sampling train.

[e] An "S" denotes a weighted emission factor. To obtain the corrected emission factor, multiply the listed factor by the sulfur content of the fuel (in percent). For the distillate oil/turbine engine combination using 0.5% sulfur fuel, the corrected emission factor for SOx would be determined:

SOx emission factor = 1.01 x 0.5 = 0.525 lb/MMBtu fuel input

[f] n/a = not applicable

[g] Data is for turbine engines operated at high load (>80%). For emissions data at other loads, see the background report for AP-42 Chapter 3, available online at www.epa.gov/ttn/chief.

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PERMIT APPLICATION FORM **EC-03**

INTERNAL COMBUSTION ENGINE (SINGLE-FUEL) FORM

PART 2: AMBIENT AIR IMPACTS

01/03/00

Complete Part 2 (Screen Model for Ambient Air Impacts) for each fuel burned in each engine with a generator to be used for other than emergency purposes, or attach sheets with equivalent information.

NOTE: Applicant has conducted ambient air modeling using AERMOD and provided the results of such modeling in the Application in Section 7. Ambient air impacts are shown to be in compliance with all ambient air quality standards.

Running the Screen Model:

14) Run SCREEN, enter name for this run

15) Source Type: _____

16) Emission Rate: _____ gram/second

17) Stack Height: _____ feet

18) Stack Inside Diameter: _____ feet

19) Stack Velocity:

- ☐ Option 1: the velocity directly in meters/second as a number only (default) _____
- ☐ Option 2: the flowrate in cubic meters/second _____
- ☐ Option 3: the flowrate in cubic feet/minute *for ambient temp= 293K (67.7 deg F) _____

20) Stack Temperature:

- ☐ Option 1 (default) _____
- ☐ Option 2: the manufacturer's estimated typical operating temp (K) _____

21) Ambient Air Temperature (K): _____

22) Receptor Height: _____

23) Urban or Rural? _____

24) Consider Building Downwash? _____

25) Building Height: (meters) _____

26) Building Horizontal Dimensions (meters): minimum: _____ maximum: _____

27) Complex Terrain Option _____

28) Simple Terrain Option _____

29) Select Full Meteorology, Option 1

30) Select Automated Distance Array _____

31) Enter distances _____

32) Record highest ambient air impact: _____

33) Select Discreet Distances

34) Highest predicted 1-hour ambient air impact _____

35) Ambient Air Impact Table

Pollutant and Averaging Time	35a) Maximum Uncontrolled Emissions lb/hour	35b) Pollution Control Efficiency %	35c) Maximum Controlled Emissions lb/hr	35d) Maximum Controlled Emissions grams/sec	35e) 1-hour Ambient Air Impact at 1 gm/sec microgm/m3	35f) Averaging time scaling factor	35g) Ambient Air Impact for stated Averaging Time microgm/m3
PM_{10} 24 hr							
SO_2 3 hr							
SO_2 24 hr							
NO_X 1 hr							
NO_X 24 hr							
CO 1 hr							
CO 8 hr							

36) Compare ambient air impacts for the appropriate averaging time to the following target levels in micrograms/cubic meter:

PM_{10} 24 hour target	= 150	NOx 1 hour target	= 1130
		NOx 24 hour target	= 282
SO_2 3 hour target	= 1300	CO 1 hour target	= 40,000
SO_2 24 hour target	= 365	CO 8 hour target	= 10,000

37) If any target level is exceeded, rerun SCREEN using a different stack height, until no exceedance is predicted. That is the stack height that must be used with the engine.

Running the Screen Model: You can obtain the SCREEN model from U.S. EPA at the following web page: **www.epa.gov/ttn/scram**. Instructions are provided here, but if you find you need additional assistance with obtaining or using SCREEN, you can contact the Air Quality Helpline at (651) 282-5844 or (800) 646-6247. Air Quality staff at those numbers will be able to answer your questions or direct your call to someone who can.

14) Start SCREEN, enter a name for this run.

15) For "Source Type" choose "P" for Point Source.

16) Emission Rate: Enter 1.0 gram/second. At the end of this form, you will adjust the results from the SCREEN model for the calculated maximum grams/second for each pollutant.

17) Stack Height: Enter the stack height above grade level in meters (3.28 feet = 1 meter).

18) Stack Inside Diameter: Enter the stack inside diameter in meters.

19) Stack Velocity: SCREEN provides three ways to enter this data. The default (Option 1) is to enter the exhaust gas velocity directly in meters/second as a number only. As an alternative, you can enter the flowrate in cubic meters/second (Option 2) or cubic feet/minute (Option 3) but you must include the appropriate notation so the program will know which data you are giving it. The diesel engine manufacturer will be able to provide this data for the engine.

20) Stack Temperature: The exhaust gas temperature must be entered in degrees Kelvin (K). Enter the manufacturer's estimated typical operating temperature, converted to K, or use 700 as default.

As an example, a typical temperature might be 800 degrees F. First convert to Celsius (C) using the following equation:

$$\text{degrees C} = \frac{5}{9} \times (\text{degrees F} - 32)$$

$$427 \text{ degrees C} = \frac{5}{9} \times (800 \text{ degrees F} - 32)$$

Next convert to Kelvin (K) by adding 273:

$$\text{degrees K} = \text{degrees C} + 273$$

$$700 \text{ degrees K} = 427 \text{ degrees C} + 273$$

21) Ambient Air Temperature: Enter 293

22) Receptor Height: Enter 0.0

23) Urban or Rural option: Choose "Urban" unless the generator is in a truly rural area. If there are several buildings in the vicinity of the generator, the urban option should be selected.

24) Consider Building Downwash: Enter Yes. **NOTE:** For a generator located far from any buildings, the generator enclosure itself acts as a building and can cause downwash. For buildings that are short in height compared to the length and width, and the generator is located more than 5 building heights from the closest wall, use the generator enclosure dimensions for building downwash. For tall buildings, use 5 times the projected width,

which is the diagonal length across the roof of the building. In general, use 5 times the LESSER of the building height or projected width to determine if a building is close enough to cause downwash.

25) Building Height: Enter the roofline height of the nearby building that dictates the most severe building downwash effect. This may be difficult to predict, and you may need to run SCREEN more than once, using different nearby buildings and the generator enclosure, to determine which one produces the highest ambient air impact.

26) Building Minimum and Maximum Horizontal Dimensions: Enter the horizontal dimensions of the building used in item 25.

27) Complex Terrain Option: Enter NO.

28) Simple Terrain Option: Enter NO.

29) Meteorology: Select the full meteorology option, Option 1.

30) Automated Distance Array: Select by entering YES.

31) Enter Distances: Enter "100,1000". SCREEN will automatically calculate and display the ambient air impact from 100 to 1000 meters in increments of 100 meters.

32) Record highest ambient air impact: Record the highest ambient air impact for 100 to 1000 meters.

33) Select Discrete Distances: Enter distances of 10, 20, 30, 40, 50, 60, 70, 80, and 90. As you enter each one, SCREEN will compute the ambient air impact at that distance and display it.

34) Record the highest predicted 1-hour ambient air impact. Also enter this number in all rows under column 35e in the Ambient Air Impact table on page 9.

35) Ambient Air Impact Table.

35a) Emission Rate in lb/hr: Enter the emission rates calculated in Part 1, item 12c, for PM_{10}, SO_2, NO_X, and CO. Use the same hourly emission rate for each averaging time for SO_2, NO_X , and CO.

35b) Pollution Control Efficiency: Enter the pollution control efficiency from Part 1, item 12e, for each pollutant. Use the same SO_2 efficiency for both SO_2 lines, and the same NO_X efficiency for both NO_X lines.

35c) Maximum Controlled Emissions in lb/hour: For each line, calculate the maximum controlled emissions in lb/hour using the following equation:

$$\text{Maximum ntrolled Emissions}\left[\frac{\text{lb}}{\text{hour}}\right] = \text{Emission Rate}\left[\frac{\text{lb}}{\text{hour}}\right] \times \left(\frac{100 - \text{Pollution Control Efficiency}}{100}\right)$$

$$\text{(Item 35c)} = \text{(item 35a)} \times \left(\frac{100 - \text{(item 35b)}}{100}\right)$$

35d) Maximum Controlled Emissions in grams/second: For each line, calculate the maximum controlled emissions in grams/second by dividing the maximum controlled emissions in lb/hour by 7.94:

$$\text{Maximum} \quad \text{ntrolled Emissions}\left[\frac{\text{grams}}{\text{second}}\right] = \frac{\text{Maximum} \quad \text{ntrolled Emissions}\left[\frac{\text{lb}}{\text{hour}}\right]}{7.94}$$

$$(\text{ item 35d }) = \frac{(\text{ item 35c })}{7.94}$$

35e) **1-hour Ambient Air Impact at 1 gm/second:** This is the number identified in item 34. This should be the same number in each line of the table.

35f) **Averaging Time Scaling Factor:** This has been provided for you.

35g) **Ambient Air Impact for Stated Averaging Time:** This is the number you will compare to the standards shown in item 36. Calculate this number by multiplying the maximum controlled emissions in grams/second by the 1-hour ambient impact at 1 gram/second and then by the averaging time scaling factor, as follows:

$$\text{Ambient Air Impact}\left[\frac{\text{microgram}}{\text{cubic meter}}\right] = \text{Maximum Controlled Emissions}\left[\frac{\text{grams}}{\text{second}}\right] \times 1-\text{hour Ambient Impact}\left[\frac{\text{microgram}}{\text{cubic meter}}\right] \times \text{scaling factor}$$

$$(\text{ item 32g }) = (\text{ item 32d }) \times (\text{ item 32e }) \times (\text{ item 32f })$$

36) Compare ambient air impact for each pollutant and for the appropriate averaging time to the following target levels:

PM_{10} 24 hour ambient air standard	=	150 micrograms/cubic meter
SO_2 3 hour ambient air standard	=	1300 micrograms/cubic meter
SO_2 24 hour ambient air standard	=	365 micrograms/cubic meter
NO_x 1 hour emergency episode level	=	1130 micrograms/cubic meter
NO_x 24 hour emergency episode level	=	282 micrograms/cubic meter
CO 1 hour ambient air standard	=	40,000 micrograms/cubic meter
CO 8 hour ambient air standard	=	10,000 micrograms/cubic meter

37) If any target level is exceeded, rerun SCREEN using a different stack height, until no exceedance is predicted. That is the stack height that must be installed.

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PERMIT APPLICATION FORM **EC-03**

INTERNAL COMBUSTION ENGINE (SINGLE-FUEL) FORM
PART 1: EMISSION CALCULATIONS

02/17/05

- Fill out Part 1 of this form for each fuel burned in each engine, or attach sheets with equivalent information. If the engine emits Hazardous Air Pollutants (HAPs), fill out and attach form EC-13C.
  Fill out Part 2 of this form only if you are installing a generator to be used for other than emergencies.

1) AQ Facility ID No.: _____
2) Facility Name: Mesaba One (CTG - syngas); Mesaba Two is identical
3) Emission Unit Identification Number: 001; 010
4) Stack/Vent Designation Number: 001; 013
5) Control Equipment Identification Number: (desulfurized fuel, N2 injection for NOx control)
6) Engine Type: ☐ Reciprocating ☒ Turbine ☐ Other: _____
7) Engine is Used For: ☒ Non-Emergency use (If you check this box, you must complete Part 2 of this form.) ☐ Emergency use only
8) Rated Heat Input: 2184 (HHV) mmBtu/hr
9) Rated Mechanical Output: 220 MW ~~HP~~ @ 3600 RPM
10) Fuel Type: IGCC syngas @ 0.005 % Sulfur
11) Fuel Consumption Rate: 9,000,000 cf/hr (approx) (gal/hr or cf/hr)
12) Calculations Summary: **Shown for Mesaba One; Mesaba Two is identical.**

12a) Pollutant	12b) Emission Factor (lbs/unit)	12c) Emission Rate (lbs/hr)	12d) Maximum Uncontrolled Emissions (tons/yr)	12e) Pollution Control Efficiency (%)	12f) Maximum Controlled Emissions (tons/yr)	12g) Limited Controlled Emissions (tons/yr)	12h) Actual Emissions (tons/yr)
PM	0.0114	25	110		110		
PM10	0.0114	25	110		110		
SO2	0.028 - 0.084	59 - 183	802		333		
NOX	0.0714	156	683		683		
VOC	0.004	8.7	38		38		
CO	0.0435	95	416		416		
Lead	0.8E-06	0.0002	0.007		0.007		

13) Operating Limitations, if applicable:

Total sulfur in syngas fuel will be limited to 120 ppmv/1-hr avg, 100 ppmv/3- and 8-hr avg, 75 ppmv/24-hr avg, and 50 ppmv/30-day rolling avg - see permit application text Section 4.1.1 and Appendix A, Exhibit A-2 for more description.

Notes:

Item 11) - Volumetric fuel flow, dry and excluding dilution nitrogen, based on minimum expected syngas heating value. Syngas heating value will range from about 240 to 305 Btu/dscf, HHV.

Item 12b) - Units are lb/10^6 Btu (HHV) gas fired based on minimum expected heating value, emission data from potential equip mfrs, except lead factor is from available IGCC literature (see applicationj text). Range shown for SO2 is based on 50 to 120 ppmv total fuel sulfur and expected range of syngas HHV.

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INTERNAL COMBUSTION ENGINE (SINGLE-FUEL) FORM
PART 1: EMISSION CALCULATIONS

02/17/05

- Fill out Part 1 of this form for each fuel burned in each engine, or attach sheets with equivalent information. If the engine emits Hazardous Air Pollutants (HAPs), fill out and attach form EC-13C.
  Fill out Part 2 of this form only if you are installing a generator to be used for other than emergencies.

1) AQ Facility ID No.: _____
2) Facility Name: Mesaba One (CTG - syngas); Mesaba Two is identical
3) Emission Unit Identification Number: 002; 011
4) Stack/Vent Designation Number: 002; 014
5) Control Equipment Identification Number: (desulfurized fuel, N2 injection for NOx control)
6) Engine Type: ☐ Reciprocating ☒ Turbine ☐ Other: _____
7) Engine is Used For: ☒ Non-Emergency use (If you check this box, you must complete Part 2 of this form.) ☐ Emergency use only
8) Rated Heat Input: 2184 (HHV) mmBtu/hr
9) Rated Mechanical Output: 220 MW ~~HP~~ @ 3600 RPM
10) Fuel Type: IGCC syngas @ 0.005 % Sulfur
11) Fuel Consumption Rate: 9,000,000 cf/hr (approx) (gal/hr or cf/hr)
12) Calculations Summary: **Shown for Mesaba One; Mesaba Two is identical.**

12a) Pollutant	12b) Emission Factor (lbs/unit)	12c) Emission Rate (lbs/hr)	12d) Maximum Uncontrolled Emissions (tons/yr)	12e) Pollution Control Efficiency (%)	12f) Maximum Controlled Emissions (tons/yr)	12g) Limited Controlled Emissions (tons/yr)	12h) Actual Emissions (tons/yr)
PM	0.0114	25	110		110		
PM10	0.0114	25	110		110		
SO2	0.028 - 0.084	59 - 183	802		333		
NOX	0.0714	156	683		683		
VOC	0.004	8.7	38		38		
CO	0.0435	95	416		416		
Lead	0.8E-06	0.0002	0.007		0.04		

13) Operating Limitations, if applicable:

Total sulfur in syngas fuel will be limited to 120 ppmv/1-hr avg, 100 ppmv/3- and 8-hr avg, 75 ppmv/24-hr avg, and 50 ppmv/30-day rolling avg - see permit application text Section 4.1.1 and Appendix A, Exhibit A-1 for more description.

Notes:

Item 11) - Volumetric fuel flow, dry and excluding dilution nitrogen, based on minimum expected syngas heating value. Syngas heating value will range from about 240 to 305 Btu/dscf, HHV.

Item 12b) - Units are lb/10^6 Btu (HHV) gas fired based on minimum expected heating value, emission data from potential equip mfrs, except lead factor is from available IGCC literature (see applicationj text). Range shown for SO2 is based on 50 to 120 ppmv total fuel sulfur and expected range of syngas HHV.

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INTERNAL COMBUSTION ENGINE (SINGLE-FUEL) FORM
PART 1: EMISSION CALCULATIONS

02/17/05

- Fill out Part 1 of this form for each fuel burned in each engine, or attach sheets with equivalent information. If the engine emits Hazardous Air Pollutants (HAPs), fill out and attach form EC-13C.
  Fill out Part 2 of this form only if you are installing a generator to be used for other than emergencies.

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One (Emergency Fire Water Pump Engines); Mesaba Two is identical

3) Emission Unit Identification Number: 008/009; 017/018

4) Stack/Vent Designation Number: 008/009; 020/021

5) Control Equipment Identification Number: _____

6) Engine Type: ☒ Reciprocating ☐ Turbine ☐ Other: _____

7) Engine is Used For: ☐ Non-Emergency use **(If you check this box, you must complete Part 2 of this form.)** ☒ Emergency use only

8) Rated Heat Input: TBD mmBtu/hr

9) Rated Mechanical Output: 300 HP @ TBD RPM

10) Fuel Type: Low sulfur diesel @ 0.05 % Sulfur

11) Fuel Consumption Rate: TBD (gal/hr or cf/hr)

12) Calculations Summary: **Shown for Mesaba One; Mesaba Two is identical.**

12a) Pollutant	**12b)** Emission Factor (lbs/unit)	**12c)** Emission Rate (lbs/hr)	**12d)** Maximum Uncontrolled Emissions (tons/yr)	**12e)** Pollution Control Efficiency (%)	**12f)** Maximum Controlled Emissions (tons/yr)	**12g)** Limited Controlled Emissions (tons/yr)	**12h)** Actual Emissions (tons/yr)
PM	0.0022	0.7	0.2			0.03	
PM10	0.0022	0.7	0.2			0.03	
SO_2	0.00205	0.6	0.2			0.03	
NO_X	0.031	9.3	2.3			0.5	
VOC	.0025	0.7	0.2			0.04	
CO	0.0067	2.0	0.5			0.1	
Lead							

13) Operating Limitations, if applicable:

Emergency and engine maintenance operation, only. Maintenance operation limited to 100 hours per year.

Notes:

Information shown is for one of two identical units to be installed with each phase, 1200 hp (four engines) to be installed for Phases I plus II.

Item 12b) - Units are lb/hp-hr based on AP-42, Table 3.3-1.

Items 12d) and 12g) - Maximum uncontrolled emission based on 500 hr/yr operation as defined by U.S. EPA; limited controlled emission based on proposed maximum annual operation of 100 hr/yr.

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PERMIT APPLICATION FORM **EC-03**

INTERNAL COMBUSTION ENGINE (SINGLE-FUEL) FORM
PART 1: EMISSION CALCULATIONS

02/17/05

- Fill out Part 1 of this form for each fuel burned in each engine, or attach sheets with equivalent information. If the engine emits Hazardous Air Pollutants (HAPs), fill out and attach form EC-13C.
  Fill out Part 2 of this form only if you are installing a generator to be used for other than emergencies.

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One (Emergency Diesel Generator - Gasification Island); Mesaba Two is identical

3) Emission Unit Identification Number: 006; 015

4) Stack/Vent Designation Number: 006; 018

5) Control Equipment Identification Number: _____

6) Engine Type: ☒ Reciprocating ☐ Turbine ☐ Other: _____

7) Engine is Used For: ☐ Non-Emergency use **(If you check this box, you must complete Part 2 of this form.)** ☒ Emergency use only

8) Rated Heat Input: TBD mmBtu/hr

9) Rated Mechanical Output: 2 MW ~~HP~~ @ TBD RPM

10) Fuel Type: Low sulfur diesel @ 0.05 % Sulfur

11) Fuel Consumption Rate: TBD (gal/hr or cf/hr)

12) Calculations Summary: **Shown for Mesaba One; Mesaba Two is identical.**

12a) Pollutant	**12b)** Emission Factor (lbs/unit)	**12c)** Emission Rate (lbs/hr)	**12d)** Maximum Uncontrolled Emissions (tons/yr)	**12e)** Pollution Control Efficiency (%)	**12f)** Maximum Controlled Emissions (tons/yr)	**12g)** Limited Controlled Emissions (tons/yr)	**12h)** Actual Emissions (tons/yr)
PM	0.94	1.9	0.5			0.09	
PM10	0.94	1.9	0.5			0.09	
SO_2	0.54	1.1	0.3			0.05	
NO_X	32.2	64.4	16			3.2	
VOC	0.95	1.9	0.5			0.09	
CO	7.4	14.8	3.7			0.7	
Lead							

13) Operating Limitations, if applicable:

Emergency and engine maintenance operation, only. Maintenance operation limited to 100 hours per year.

Notes:

Item 12b) - Units are lb/MW-hr based on AP-42, Table 3.4-1 and using 1341 hp/MW to convert units shown in AP-42.

Item 12c) - SO2 emission based on 0.05 wt % sulfur in diesel fuel.

Items 12d) and 12g) - Maximum uncontrolled emission based on 500 hr/yr operation as defined by U.S. EPA; limited controlled emission based on proposed maximum annual operation of 100 hr/yr.

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **EC-03**

INTERNAL COMBUSTION ENGINE (SINGLE-FUEL) FORM
PART 1: EMISSION CALCULATIONS

02/17/05

- Fill out Part 1 of this form for each fuel burned in each engine, or attach sheets with equivalent information. If the engine emits Hazardous Air Pollutants (HAPs), fill out and attach form EC-13C.
  Fill out Part 2 of this form only if you are installing a generator to be used for other than emergencies.

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One (Emergency Diesel Generator - Power Block)

3) Emission Unit Identification Number: 007; 016

4) Stack/Vent Designation Number: 007; 019

5) Control Equipment Identification Number: _____

6) Engine Type: ☒ Reciprocating ☐ Turbine ☐ Other: _____

7) Engine is Used For: ☐ Non-Emergency use ☒ Emergency use only
(If you check this box, you must complete Part 2 of this form.)

8) Rated Heat Input: TBD mmBtu/hr

9) Rated Mechanical Output: 350 kW ~~HP~~ @ TBD RPM

10) Fuel Type: Low sulfur diesel @ 0.05 % Sulfur

11) Fuel Consumption Rate: TBD (gal/hr or cf/hr)

12) Calculations Summary: **Shown for Mesaba One; Mesaba Two is identical.**

12a) Pollutant	**12b)** Emission Factor (lbs/unit)	**12c)** Emission Rate (lbs/hr)	**12d)** Maximum Uncontrolled Emissions (tons/yr)	**12e)** Pollution Control Efficiency (%)	**12f)** Maximum Controlled Emissions (tons/yr)	**12g)** Limited Controlled Emissions (tons/yr)	**12h)** Actual Emissions (tons/yr)
PM	3.0	1.0	0.25			0.05	
PM10	3.0	1.0	0.25			0.05	
SO_2	2.7	1.0	0.25			0.05	
NO_X	41.6	14.6	3.6			0.7	
VOC	3.3	1.2	0.3			0.06	
CO	9.0	3.1	0.8			0.2	
Lead							

13) Operating Limitations, if applicable:

+

Notes:

Item 12b) - Units are lb/MW-hr based on AP-42, Table 3.3-1 and using 1341 hp/MW to convert units shown in AP-42.

Items 12d) and 12g) - Maximum uncontrolled emission based on 500 hr/yr operation as defined by U.S. EPA; limited controlled emission based on proposed maximum annual operation of 100 hr/yr.

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **EC-13C**

HAZARDOUS AIR POLLUTANTS CALCULATION FORM (FUEL COMBUSTION HAPS)

5/27/98

- Duplicate this form as necessary, or attach sheets with equivalent information.
- Instructions begin on Page 6.

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One (Tank Vent Boiler); Mesaba Two is identical

3) Emission Unit Identification Number: _____

4) Stack/Vent Designation Number: 010; 022

5) Maximum Rated Equipment Capacity: 65 (HHV) million BTU/hr

6) Control Equipment Designation Number: CE001; CE-004

7) Fuel Parameters

Shown for Mesaba One; Mesaba Two is identical.

7a) Fuel Type	**7b)** % Sulfur	**7c)** % Ash	**7d)** Heat Value	Units	**7e)** Fuel Consumption Rate	Units
Syngas	0.005		240 Btu/cf (HHV)	Btu/ton, Btu/gal, Btu/cf	270,000 cf/hr	tons/hr; gal/hr; cf/hr
Natural Gas			1000 Btu/cf (approx HHV)	Btu/ton, Btu/gal, Btu/cf	40,000 cf/hr	tons/hr; gal/hr; cf/hr
				Btu/ton, Btu/gal, Btu/cf		tons/hr; gal/hr; cf/hr

When calculating Potential Emissions, use items 8a, 8b, 8d, 8e, 8g, 8h, and 8i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 8a, 8b, 8c, 8f, 8g, and 8j.

8) Calculations Summary - Primary Fuel:

8a HAP Name (CAS)	**8b** Emission Factor (lbs/ton, lbs/gal, lbs/MMcf, etc.)	**8c** Actual Annual Fuel Use (tons, gallons, MMcf, etc.)	**8d** Emission Rate (lbs/hr)	**8e** Maximum Uncontrolled Emissions (tons/yr)	**8f** Actual Uncontrolled Emissions (tons/yr)	**8g** Pollution Control Efficiency (%)	**8h** Maximum Controlled Emissions (tons/yr)	**8i** Limited Controlled Emissions (tons/yr)	**8j** Actual Controlled Emissions (tons/yr)
See attached permit application Section 4.2.3 and emissions calculations, Appendix B, Exhibit B-3, for description of HAPs emissions.									

When calculating Potential Emissions, use items 9a, 9b, 9d, 9e, 9g, 9h, and 9i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 9a, 9b, 9c, 9f, 9g, and 9j.

9) Calculations Summary - Back-up Fuel:

9a HAP Name (CAS)	**9b** Emission Factor (lbs/ton, lbs/gal, lbs/MMcf, etc.)	**9c** Actual Annual Fuel Use (tons, gallons, MMcf, etc.)	**9d** Emission Rate (lbs/hr)	**9e** Maximum Uncontrolled Emissions (tons/yr)	**9f** Actual Uncontrolled Emissions (tons/yr)	**9g** Pollution Control Efficiency (%)	**9h** Maximum Controlled Emissions (tons/yr)	**9i** Limited Controlled Emissions (tons/yr)	**9j** Actual Controlled Emissions (tons/yr)
N/A									

When calculating Potential Emissions, use items 10a, 10b, 10d, 10e , 10g, 10h, and 10i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 10a, 10b, 10c, 10f, 10g, and 10j.

10) Calculations Summary - Back-up Fuel:

10a HAP Name (CAS)	**10b** Emission Factor (lbs/ton, lbs/gal, lbs/MMcf, etc.)	**10c** Actual Annual Fuel Use (tons, gallons, MMcf, etc.)	**10d** Emission Rate (lbs/hr)	**10e** Maximum Uncontrolled Emissions (tons/yr)	**10f** Actual Uncontrolled Emissions (tons/yr)	**10g** Pollution Control Efficiency (%)	**10h** Maximum Controlled Emissions (tons/yr)	**10i** Limited Controlled Emissions (tons/yr)	**10j** Actual Controlled Emissions (tons/yr)

11) Worst-Case Potential-to-Emit Summary: (Ignore this item if filling out this form for a Registration Permit Option D)

HAP Name (CAS)	**11a)** ***Before Operating Limits:*** (tons/yr)	**11b)** ***After Operating Limits:*** (tons/yr)	HAP Name (CAS)	**11a)** ***Before Operating Limits:*** (tons/yr)	**11b)** ***After Operating Limits:*** (tons/yr)

12) Operating Limitations, if applicable: (Ignore this item if filling out this form for a Registration Permit Option D)

See Form EC-02 and permit application Section 4.1.2.

- Duplicate this form as necessary, or attach sheets with equivalent information.
- Instructions begin on Page 6.

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One (CTG); Mesaba Two is identical

3) Emission Unit Identification Number: 001; 010

4) Stack/Vent Designation Number: 001; 013

5) Maximum Rated Equipment Capacity: 2184 (HHV, syngas), 2077 (HHV, natural gas) for each of two CTGs million BTU/hr

6) Control Equipment Designation Number: (NA)

7) Fuel Parameters

Shown for Mesaba One; Mesaba Two is identical.

7a) Fuel Type	**7b)** % Sulfur	**7c)** % Ash	**7d)** Heat Value	Units	**7e)** Fuel Consumption Rate	Units
syngas (primary)	0.005 vol %		240-305 Btu/scf (approx HHV)	Btu/ton, Btu/gal, Btu/cf	2184 million Btu/hr HHV, each	tons/hr; gal/hr; cf/hr
natural gas (startup, backup)	1 grain /100 scf		1020 Btu/scf (approx HHV)	Btu/ton, Btu/gal, Btu/cf	2077 million Btu/hr HHV, each	tons/hr; gal/hr; cf/hr
				Btu/ton, Btu/gal, Btu/cf		tons/hr; gal/hr; cf/hr

When calculating Potential Emissions, use items 8a, 8b, 8d, 8e, 8g, 8h, and 8i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 8a, 8b, 8c, 8f, 8g, and 8j.

8) Calculations Summary - Primary Fuel:
Shown for Mesaba One; Mesaba Two is identical.

8a HAP Name (CAS)	**8b** Emission Factor (lbs/ton, lbs/gal, lbs/MMcf, etc.)	**8c** Actual Annual Fuel Use (tons, gallons, MMcf, etc.)	**8d** Emission Rate (lbs/hr)	**8e** Maximum Uncontrolled Emissions (tons/yr)	**8f** Actual Uncontrolled Emissions (tons/yr)	**8g** Pollution Control Efficiency (%)	**8h** Maximum Controlled Emissions (tons/yr)	**8i** Limited Controlled Emissions (tons/yr)	**8j** Actual Controlled Emissions (tons/yr)
See attached permit application text Section 4.2.3 and Appendix B, Exhibit B-2 for HAPs discussion and emission calculations.									

When calculating Potential Emissions, use items 9a, 9b, 9d, 9e, 9g, 9h, and 9i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 9a, 9b, 9c, 9f, 9g, and 9j.

9) Calculations Summary - Back-up Fuel:

9a HAP Name (CAS)	**9b** Emission Factor (lbs/ton, lbs/gal, lbs/MMcf, etc.)	**9c** Actual Annual Fuel Use (tons, gallons, MMcf, etc.)	**9d** Emission Rate (lbs/hr)	**9e** Maximum Uncontrolled Emissions (tons/yr)	**9f** Actual Uncontrolled Emissions (tons/yr)	**9g** Pollution Control Efficiency (%)	**9h** Maximum Controlled Emissions (tons/yr)	**9i** Limited Controlled Emissions (tons/yr)	**9j** Actual Controlled Emissions (tons/yr)
Natural gas (backup fuel) - NA									

When calculating Potential Emissions, use items 10a, 10b, 10d, 10e , 10g, 10h, and 10i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 10a, 10b, 10c, 10f, 10g, and 10j.

10) Calculations Summary - Back-up Fuel:

10a HAP Name (CAS)	**10b** Emission Factor (lbs/ton, lbs/gal, lbs/MMcf, etc.)	**10c** Actual Annual Fuel Use (tons, gallons, MMcf, etc.)	**10d** Emission Rate (lbs/hr)	**10e** Maximum Uncontrolled Emissions (tons/yr)	**10f** Actual Uncontrolled Emissions (tons/yr)	**10g** Pollution Control Efficiency (%)	**10h** Maximum Controlled Emissions (tons/yr)	**10i** Limited Controlled Emissions (tons/yr)	**10j** Actual Controlled Emissions (tons/yr)
NA									

11) Worst-Case Potential-to-Emit Summary: (Ignore this item if filling out this form for a Registration Permit Option D)

HAP Name (CAS)	**11a)** ***Before Operating Limits:*** (tons/yr)	**11b)** ***After Operating Limits:*** (tons/yr)	HAP Name (CAS)	**11a)** ***Before Operating Limits:*** (tons/yr)	**11b)** ***After Operating Limits:*** (tons/yr)
See attached permit application text and appendices.					

12) Operating Limitations, if applicable: (Ignore this item if filling out this form for a Registration Permit Option D)

No operating limits proposed for syngas fuel. Natural gas startup and backup operation will be limited to 440 hours per year after first 36 months of operation (see attached application text Section 4.1.1)..

- Duplicate this form as necessary, or attach sheets with equivalent information.
- Instructions begin on Page 6.

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One (CTG); Mesaba Two is identical

3) Emission Unit Identification Number: 002; 011

4) Stack/Vent Designation Number: 002; 011

5) Maximum Rated Equipment Capacity: 2184 (HHV, syngas), 2077 (HHV, natural gas) million BTU/hr

6) Control Equipment Designation Number: (NA)

7) Fuel Parameters

Shown for Mesaba One; Mesaba Two is identical.

7a) Fuel Type	**7b)** % Sulfur	**7c)** % Ash	**7d)** Heat Value	Units	**7e)** Fuel Consumption Rate	Units
syngas (primary)	0.005 vol %		240-305 Btu/scf (approx HHV)	Btu/ton, Btu/gal, Btu/cf	2184 million Btu/hr HHV	tons/hr; gal/hr; cf/hr
natural gas (startup, backup)	1 grain /100 scf		1020 Btu/scf (approx HHV)	Btu/ton, Btu/gal, Btu/cf	2077 million Btu/hr HHV	tons/hr; gal/hr; cf/hr
				Btu/ton, Btu/gal, Btu/cf		tons/hr; gal/hr; cf/hr

When calculating Potential Emissions, use items 8a, 8b, 8d, 8e, 8g, 8h, and 8i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 8a, 8b, 8c, 8f, 8g, and 8j.

8) Calculations Summary - Primary Fuel:

8a HAP Name (CAS)	**8b** Emission Factor (lbs/ton, lbs/gal, lbs/MMcf, etc.)	**8c** Actual Annual Fuel Use (tons, gallons, MMcf, etc.)	**8d** Emission Rate (lbs/hr)	**8e** Maximum Uncontrolled Emissions (tons/yr)	**8f** Actual Uncontrolled Emissions (tons/yr)	**8g** Pollution Control Efficiency (%)	**8h** Maximum Controlled Emissions (tons/yr)	**8i** Limited Controlled Emissions (tons/yr)	**8j** Actual Controlled Emissions (tons/yr)
See attached permit application text Section 4.2.3 and Appendix B, Exhibit B-2 for HAPs discussion and emission calculations.									

When calculating Potential Emissions, use items 9a, 9b, 9d, 9e, 9g, 9h, and 9i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 9a, 9b, 9c, 9f, 9g, and 9j.

9) Calculations Summary - Back-up Fuel:

9a HAP Name (CAS)	**9b** Emission Factor (lbs/ton, lbs/gal, lbs/MMcf, etc.)	**9c** Actual Annual Fuel Use (tons, gallons, MMcf, etc.)	**9d** Emission Rate (lbs/hr)	**9e** Maximum Uncontrolled Emissions (tons/yr)	**9f** Actual Uncontrolled Emissions (tons/yr)	**9g** Pollution Control Efficiency (%)	**9h** Maximum Controlled Emissions (tons/yr)	**9i** Limited Controlled Emissions (tons/yr)	**9j** Actual Controlled Emissions (tons/yr)
Natural gas (backup fuel) - NA									

When calculating Potential Emissions, use items 10a, 10b, 10d, 10e , 10g, 10h, and 10i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 10a, 10b, 10c, 10f, 10g, and 10j.

10) Calculations Summary - Back-up Fuel:

10a HAP Name (CAS)	**10b** Emission Factor (lbs/ton, lbs/gal, lbs/MMcf, etc.)	**10c** Actual Annual Fuel Use (tons, gallons, MMcf, etc.)	**10d** Emission Rate (lbs/hr)	**10e** Maximum Uncontrolled Emissions (tons/yr)	**10f** Actual Uncontrolled Emissions (tons/yr)	**10g** Pollution Control Efficiency (%)	**10h** Maximum Controlled Emissions (tons/yr)	**10i** Limited Controlled Emissions (tons/yr)	**10j** Actual Controlled Emissions (tons/yr)
NA									

11) Worst-Case Potential-to-Emit Summary: (Ignore this item if filling out this form for a Registration Permit Option D)

HAP Name (CAS)	**11a)** ***Before Operating Limits:*** (tons/yr)	**11b)** ***After Operating Limits:*** (tons/yr)	HAP Name (CAS)	**11a)** ***Before Operating Limits:*** (tons/yr)	**11b)** ***After Operating Limits:*** (tons/yr)
See attached permit application text and appendices.					

12) Operating Limitations, if applicable: (Ignore this item if filling out this form for a Registration Permit Option D)

No operating limits proposed for syngas fuel. Natural gas startup and backup operation will be limited to 440 hours per year after first 36 months of operation (see attached application text Section 4.1.1)..

PERMIT APPLICATION FORM **EC-13C**

HAZARDOUS AIR POLLUTANTS CALCULATION FORM (FUEL COMBUSTION HAPS)

5/27/98

- Duplicate this form as necessary, or attach sheets with equivalent information.
- Instructions begin on Page 6.

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One (Flare) ; Mesaba Two is identical

3) Emission Unit Identification Number: (CE-002); (CE-005)

4) Stack/Vent Designation Number: 011; 023

5) Maximum Rated Equipment Capacity: 2 - 3730 (intermittant) million BTU/hr

6) Control Equipment Designation Number: 002; 005

7) Fuel Parameters

Shown for Mesaba One; Mesaba Two is identical.

7a) Fuel Type	**7b)** % Sulfur	**7c)** % Ash	**7d)** Heat Value	Units	**7e)** Fuel Consumption Rate	Units
Syngas and waste gas (+ nat gas pilot)	0.005 - 0.040		250 Btu/cf (approx)	Btu/ton, Btu/gal, Btu/cf	NA	tons/hr; gal/hr; cf/hr
				Btu/ton, Btu/gal, Btu/cf		tons/hr; gal/hr; cf/hr
				Btu/ton, Btu/gal, Btu/cf		tons/hr; gal/hr; cf/hr

When calculating Potential Emissions, use items 8a, 8b, 8d, 8e, 8g, 8h, and 8i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 8a, 8b, 8c, 8f, 8g, and 8j.

8) Calculations Summary - Primary Fuel:

8a HAP Name (CAS)	**8b** Emission Factor (lbs/ton, lbs/gal, lbs/MMcf, etc.)	**8c** Actual Annual Fuel Use (tons, gallons, MMcf, etc.)	**8d** Emission Rate (lbs/hr)	**8e** Maximum Uncontrolled Emissions (tons/yr)	**8f** Actual Uncontrolled Emissions (tons/yr)	**8g** Pollution Control Efficiency (%)	**8h** Maximum Controlled Emissions (tons/yr)	**8i** Limited Controlled Emissions (tons/yr)	**8j** Actual Controlled Emissions (tons/yr)
(See attached permit application Section 4.2.3 and emissions calculations, Appendix B, Exhibit B-4, for description of HAPs emissions.									

When calculating Potential Emissions, use items 9a, 9b, 9d, 9e, 9g, 9h, and 9i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 9a, 9b, 9c, 9f, 9g, and 9j.

9) Calculations Summary - Back-up Fuel:

9a HAP Name (CAS)	**9b** Emission Factor (lbs/ton, lbs/gal, lbs/MMcf, etc.)	**9c** Actual Annual Fuel Use (tons, gallons, MMcf, etc.)	**9d** Emission Rate (lbs/hr)	**9e** Maximum Uncontrolled Emissions (tons/yr)	**9f** Actual Uncontrolled Emissions (tons/yr)	**9g** Pollution Control Efficiency (%)	**9h** Maximum Controlled Emissions (tons/yr)	**9i** Limited Controlled Emissions (tons/yr)	**9j** Actual Controlled Emissions (tons/yr)
NA									

When calculating Potential Emissions, use items 10a, 10b, 10d, 10e , 10g, 10h, and 10i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 10a, 10b, 10c, 10f, 10g, and 10j.

10) Calculations Summary - Back-up Fuel:

10a HAP Name (CAS)	**10b** Emission Factor (lbs/ton, lbs/gal, lbs/MMcf, etc.)	**10c** Actual Annual Fuel Use (tons, gallons, MMcf, etc.)	**10d** Emission Rate (lbs/hr)	**10e** Maximum Uncontrolled Emissions (tons/yr)	**10f** Actual Uncontrolled Emissions (tons/yr)	**10g** Pollution Control Efficiency (%)	**10h** Maximum Controlled Emissions (tons/yr)	**10i** Limited Controlled Emissions (tons/yr)	**10j** Actual Controlled Emissions (tons/yr)

11) Worst-Case Potential-to-Emit Summary: (Ignore this item if filling out this form for a Registration Permit Option D)

HAP Name (CAS)	**11a)** ***Before Operating Limits:*** (tons/yr)	**11b)** ***After Operating Limits:*** (tons/yr)	HAP Name (CAS)	**11a)** ***Before Operating Limits:*** (tons/yr)	**11b)** ***After Operating Limits:*** (tons/yr)

12) Operating Limitations, if applicable: (Ignore this item if filling out this form for a Registration Permit Option D)

See Form EC-01 and permit application Section 4.1.3.

- Duplicate this form as necessary, or attach sheets with equivalent information.
- Instructions begin on Page 4.

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One and Mesaba Two (fugitive HAP/VOC)

3) Emission Unit Identification Number: FS-004 and FS-008

4) Stack/Vent Designation Number: N/A

5) Control Equipment Designation Number: _____

Complete item 6 or 7, not both.

6) Calculations Summary using Material Content: **Shown for Mesaba One; Mesaba Two is identical.**

Potential Emissions (Do not complete this table if using this form for Registration Permit Option D. Go to Actual Emissions Table in item 6.)

6a) Volatile HAP Name (CAS)	**6b)** Maximum HAP Content (lbs/gal)	**6c)** Maximum Material Usage Rate (gal/hr)	**6d)** Maximum Uncontrolled HAP Emission Rate (lbs/hr)	**6e)** Maximum Uncontrolled HAP Emissions (tons/yr)	**6f)** Pollution Control Efficiency (%)	**6g)** Maximum Controlled HAP Emissions (tons/yr)	**6h)** Limited Controlled HAP Emissions (tons/yr)
See permit application text, Section 4.1.4 and Appendix B, Exhibit B-5 for description of fugitive HAP/VOC emissions and calculations							

Actual Emissions

6a) Volatile HAP Name (CAS)	**6i)** Actual HAP Content (lbs/gal)	**6j)** Actual Material Usage Rate (gal/hr)	**6k)** Actual Uncontrolled HAP Emission Rate (lbs/hr)	**6l)** Actual Uncontrolled HAP Emissions (tons/yr)	**6f)** Pollution Control Efficiency (%)	**6m)** Actual Controlled HAP Emissions (tons/yr)
(N/A)						

7) Calculations Summary using Emission Factors:

Potential Emissions (Do not complete this table if using this form for Registration Permit Option D. Go to the Actual Emission Table in item 7.)

7a) Volatile HAP Name (CAS)	**7b)** Maximum Emission Factor	**7c)** Maximum Hourly Production or Material Use	**7d)** Maximum HAP Emission Rate (lbs/hr)	**7e)** Maximum Uncontrolled HAP Emissions (tons/yr)	**7f)** Pollution Control Efficiency (%)	**7g)** Maximum Controlled HAP Emissions (tons/yr)	**7h)** Limited Controlled HAP Emissions (tons/yr)

Actual Emissions

7a) Volatile HAP Name (CAS)	**7i)** Actual Emission Factor	**7j)** Actual Hourly Production or Material Use	**7k)** Actual Uncontrolled HAP Emission Rate (lbs/hr)	**7l)** Actual Uncontrolled HAP Emissions (tons/yr)	**7f)** Pollution Control Efficiency (%)	**7m)** Actual Controlled HAP Emissions (tons/yr)

8) Operating Limitations, if applicable: (Ignore this item if using the form for Registration Permit Option D).

none proposed

the PTE after limiting factors are taken into account. Attach additional sheets that show calculations and assumptions.

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **IA-01**

INSIGNIFICANT ACTIVITIES (REQUIRED TO BE LISTED)

06/01/04

1) AQ Facility ID No.: _____

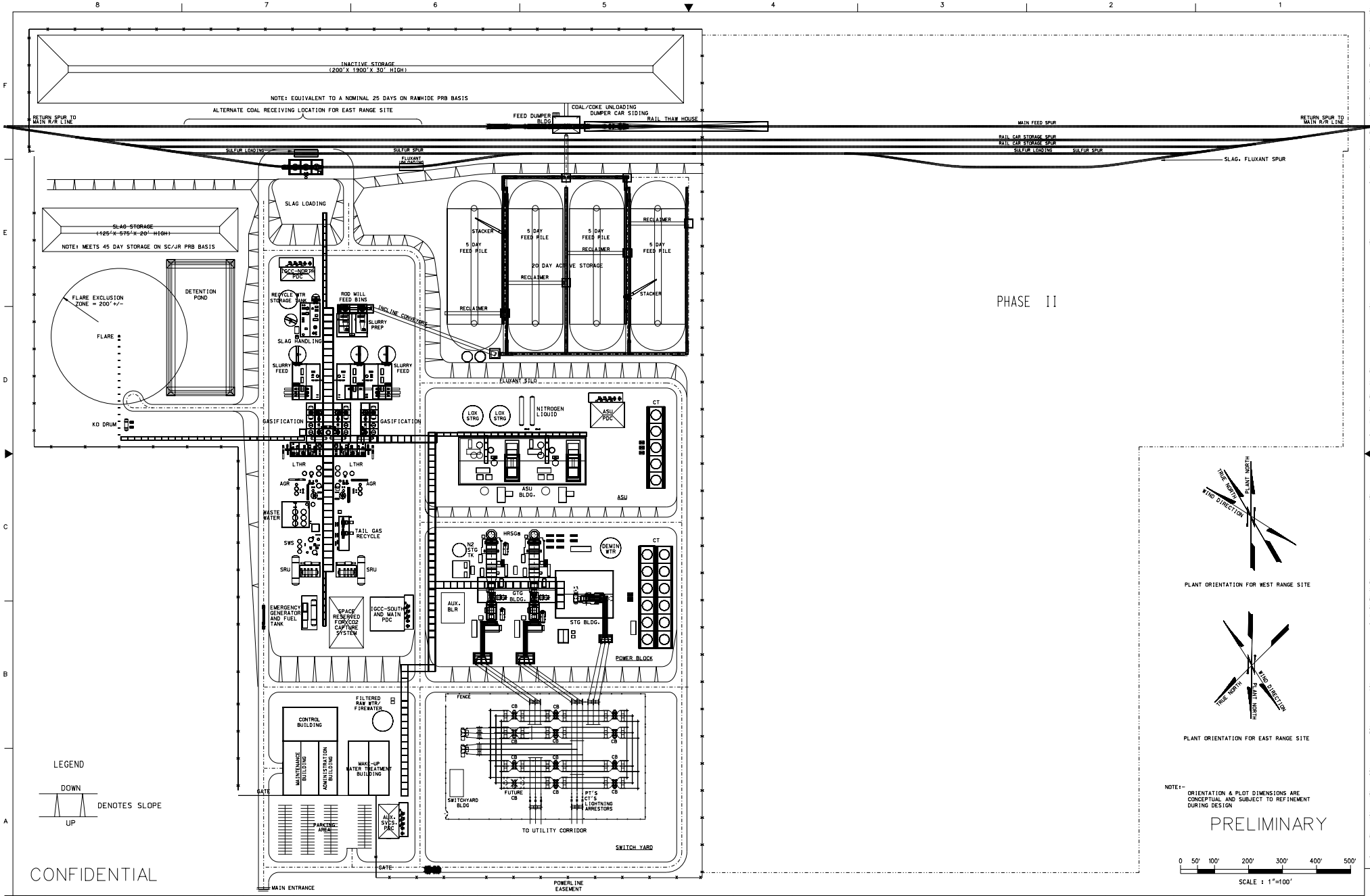
2) Facility Name: Mesaba One and Mesaba Two

3) Description of Activities

3a)	Rule Citation	**3b)** Description of Activities at the Facility
☒	7007.1300, subp. 3(A)	Portable space heaters for miscellaneous winter use during construction and plant operations and maintenance
☒	7007.1300, subp. 3(B)(1)	Infrared heaters used in rail car thaw shed
☐	7007.1300, subp. 3(B)(2)	
☐	7007.1300, subp. 3(C)	
☐	7007.1300, subp. 3(D)	
☐	7007.1300, subp. 3(E)(1)	

☒	7007.1300, subp. 3(E)(2)	Low sulfur diesel fuel storage for stationary emergency egines
☐	7007.1300, subp. 3(F)	
☒	7007.1300, subp. 3(G)	Plant chem lab
☐	7007.1300, subp. 3(H)(1)	
☒	7007.1300, subp. 3(H)(2)	Hydraulic and hydrostatic testing equipment used for construction and plant maintenance
☒	7007.1300, subp. 3(H)(3)	Brazing, soldering and welding equipment used for construction and plant maintenance
☒	7007.1300, subp. 3(H)(4)	Office blueprint machine
☐	7007.1300, subp. 3(H)(5)	
☐	7007.1300, subp. 3(H)(6)	
☒	7007.1300, subp. 3(H)(7)	Various construction and operations maintenance equipment cleaning operations

☐	7007.1300, subp. 3(I)	
☒	7007.1300, subp. 3(J)	Some graveled (unpaved) roads included in permanent plant facilities
☒	7007.1300, subp. 3(K)	Spray paint equipment for plant equipment and facility maintenance work
☐	7007.1300, subp. 4	
☐	7008.4100	
☐	7008.4110	



REV	DATE	REVISION DESCRIPTION	BY	CHK	APPV	REV	DATE	REVISION DESCRIPTION	BY	CHK	APPV	REFERENCE DWG NUMBER	REFERENCE DRAWINGS	REFERENCE DWG NUMBER	REFERENCE DRAWINGS
A	17MAY05	PRELIMINARY CONCEPTUAL LAYOUT FOR PLOT SPACE ALLOCATION	TB	JT	GS										
B	29JUN05	GENERAL UPDATE	TB	JT											
C	11AUG05	ADD 3RD GASIFICATION TRAIN, RECONFIGURE SIZE OF FEED STRG. AREA	CB	JT											
D	21OCT05	GENERAL UPDATE	SR	JT											
E	12DEC05	ADD AUX. BOILER AND EAST RANGE COAL RECEIVING LOCATION	SR	JT											

PLOT DATE:

FLUOR

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DESIGNED BY TB
CHECKED BY JT
SUPERVISOR JT — APP DATE
LEAD ENGR/SPEC. — APP DATE
FLUOR GS — APP DATE
CLIENT — APP DATE

EXCELSIOR ENERGY INC.
MESABA ENERGY PROJECT

PHASE I CONCEPTUAL PLOT PLAN

SCALE 1"=100'
DRAWING NUMBER A2AS-PP-SK1
REV E
CAD FILE NAME tb_mesaba_pht_rev.e.DWG

XREF ATTACHED - YES☐ NO☐ MANUAL CHANGES MADE - YES☐ NO☐ DWG FILE UPDATED - YES☐ NO☐ MODEL UPDATED - YES☐ NO☐

Appendix A

Criteria Air Pollutant Emission Calculations

APPENDIX A – CRITERIA POLLUTANT EMISSION CALCULATIONS

This appendix presents the calculations and assumptions used to estimate criteria[4] pollutant emissions resulting from the Mesaba Energy Project. The criteria pollutants are sulfur dioxide (SO_2), nitrogen oxides (NOx), carbon monoxide (CO), volatile organic compounds (VOC), and particulate matter (PM, or PM less than 10 microns, PM10). Lead is also considered a criteria pollutant, but this for application lead emissions are included with the hazardous air pollutant (HAP) estimates.

Emission estimates are presented in the following sections:

Exhibit A-1 Combustion Turbine Emission Rates

Exhibit A-2 Tank Vent Boiler Emission Rates

Exhibit A-3 Auxiliary Boiler Emission Rates

Exhibit A-4 Flare Emission Rates

Exhibit A-5 Cooling Tower Emission Rates

Exhibit A-6 Emergency Diesel Engines Emission Rates

Exhibit A-7 Fugitive Particulate Emission Calculations

Each section describes how the emission estimates presented in Section 4 of this application were developed and include example calculations, key assumptions, and reference citations. For simplicity, only calculations for Phase I of the project are presented. Phase II emissions will be numerically identical to Phase I.

[4] "Criteria" pollutants are those for which quantitative ambient air quality standards have been established.

Exhibit A-1 Combustion Turbine Generators

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Exhibit A-1 COMBUSTION TURBINE EMISSION RATES

Basis: Siemens SGT6-5000Fperformance estimates for Mesaba Project or estimated worst case for other suppliers

Short-term Emissions on Syn Gas

Syngas fuel rate per CTG 2110 to 2184 x 10^6 Btu/hr, HHV (from Siemens)

Min Coal conversion efficency **0.714** Syngas heating value = 242 Btu/dscf (HHV) (PRB coal)
Max Coal conversion efficency **0.793** Syngas heating value = 303 Btu/dscf (HHV) (Illinois coal)
Gasifiers coal feed (per CTG) 2955 (max) 2754 (min) x 10^6 Btu/hr (HHV)

1-, 3-, 8-, 24-hr and 30-day averages*				
	lb/hr (per stack)	lb/10^6 Btu coal min	lb/10^6 Btu coal max	Basis
NOx	156	0.053	0.057	15 ppmvd (@15% O2)
CO	95	0.032	0.034	15 ppmvd (@ 15% O2)
PM10	25	0.008	0.009	filterable (front-half) + condensible (back half)
VOC	8.7	0.003	0.003	2.4 ppmvd (@ 15% O2)

* Mass emission rate from CTG suppliers for basis stated.

Energy Bill Limits	
	lb/10^6 Btu coal
NOx	0.08
CO	NA
PM10	0.01
VOC	NA

Syn Gas SO2 Emission from Combustion Turbine					
Avg time	Syn gas avg sulfur, ppm	SO2, lb/hr (min) (per stack)	SO2, lb/hr (max) (per stack)	lb/10^6 Btu coal min	lb/10^6 Btu coal max
1-hr	120	141	183	0.051	0.062
3-hr	100	117	152	0.043	0.052
8-hr	100	117	152	0.043	0.052
24-hr	75	88	114	0.032	0.039
30-day	50	59	76	0.021	0.026
Energy Bill Limit				0.05	0.05

Example calculations for SO2
(From Ideal Gas Law, 1 lbmol gas = 380 scf, scf defined @ 60 deg F, 1 atm)
Max SO2 for 50 ppmv total sulfur in fuel
= (2184 x10^6 Btu/hr)/(242 Btu/scf) x (50 scf sulfur/10^6 scf) x (64 lb SO2/380 scf) = 76 lb SO2/hr/CTG
Min SO2 for 50 ppmv total sulfur in fuel
= (2110 x10^6 Btu/hr)/(303 Btu/scf) x (50 scf sulfur/10^6 scf) x (64 lb SO2/380 scf) = 59 lb SO2/hr/CTG

Short-term Emissions on Natural Gas

Nat gas fuel rate per CTG= 2077 x 10^6 Btu/hr, HHV (supplier data)

1-, 3-, 8-, 24-hr and 30-day averages*		
	lb/hr (per stack)	Basis
NOx	198	25 ppmvd (@15% O2)
CO	72	15 ppmvd (@ 15% O2)
PM10	18	filterable (front-half) + condensible (back half)
VOC	6.6	2.4 ppmvd (@ 15% O2)
SO2	5.9	1 grain sulfur/100 scf in pipeline nat gas.

* Mass emission rate from CTG suppliers for basis stated.

CTG Startup/shutdown Emissions per CTG (supplier data)

Avg Startup/shutdown Emission, lb/hr				
	Hot Start	Warm Start	Cold Start	Worst Case, lb/hr
NOx	108	116	121	121
CO	2116	2740	2205	2740
PM10	10	11	11	11
VOC	204	263	212	263
Typical duration	52 min	81 min	101 min	(N/A)

Notes: - Only CO and VOC hourly average startup emission rates exceed normal full load operation emission rates.
- CO and VOC shutdown emission rates (not shown) will also exceed normal full load emission rates, but are less than worst-case startup emissions.
- CTG fuel consumption, and therefore also SO2 emissions, are less during startup/shutdown than normal full load operation

Exhibit A-1 CTG Page 1 of 2

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Exhibit A-1 COMBUSTION TURBINE EMISSION RATES

Worst Case Estimated Annual Emissions

Worst Case Annual Emissions			
	ton/yr (per stack)	avg lb/hr (per stack)	Basis
NOx*	739	169	1st yr - 2630 hr nat gas full load operation, balance on syn gas at full load
	720	164	2nd yr - 1750 hr nat gas full load operation, balance on syn gas at full load
	702	160	3rd yr - 880 hr nat gas full load operation, balance on syn gas at full load
	693	158	4th yr and later - 440 hr nat gas full load operation, balance on syn gas at full load
CO	482	110	50 hr/yr startup/shutdown, balance of year on syn gas at full load**
PM10	110	25	8760 hr/yr on syn gas at full load
VOC	44	10	50 hr/yr startup/shutdown, balance of year on syn gas at full load**
SO2	333	76	50 ppm ann avg sulfur in fuel, 8760 hr/yr on syn gas at full load

* Maximum natural gas use assumed as 30% during first year (2630 hours during first 12 calendar months after initial commercial operation), 20% during second year, 10% during third year, and 5% during fourth and following years (all excluding startup operations

** Startup/shutdown based on approximately 25 starts per year per CTG and about 2 hours per event.

Actual Annual Emissions for Backup Natural Gas Emissions

Actual Emissions for Natural Gas and Syngas Operating Scenarios					
Year	1	2	3	4	Basis - Idicated hours of natural gas full load operation plus additional operation as stated below
Hr/yr	2630	1750	880	440	
Ton/yr (per stack)					
NOx	739	720	702	693	Balance of year on syn gas at full load
SO2	241	272	302	318	Balance of year on syn gas at full load, 50 ppm ann avg sulfur in fuel
CO	452	462	472	477	Plus 50 hr/yr startup/shutdown, balance of year on syn gas at full load
PM10	100	103	106	108	Balance of year on syn gas at full load
VOC	42	43	44	44	Plus 50 hr/yr startup/shutdown, balance of year on syn gas at full load

Phase I plus Phase II, ton/yr				
NOx	2954	2880	2807	2770
SO2	964	1088	1210	1271
CO	1808	1848	1888	1909
PM10	401	414	426	432
VOC	167	171	174	176

Exhibit A-1 CTG Page 2 of 2

Exhibit A-2 Tank Vent Boiler

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Exhibit A-2 TANK VENT BOILER EMISSION RATES (Phase I)

Basis: ConocoPhillips estimates and supplier data for similar equipment

TVB emission factors (lb/10^6 Btu fired)

	SG	NG	Basis
SO2	*	0.00286	1 grain/100 scf nat gas
NOx	0.3	0.3	supplier data for similar equipment
CO	0.09	0.09	60 ppmvd (12% O2), supplier data for similar equipment
PM10	0.01	0.01	supplier data for similar equipment
VOC	0.004	0.004	CoP estimate

(SG = syngas, NG = natural gas)

* See emission table below

SO2 from sulfur in tank vent gas during normal oper = 3 lb/hr (CoP estimate)

Operating Modes	Capacities, 10^6 Btu/hr SG	NG
Gasifier outage		40
Startup	10	30
Maximum operation, short-term	65	
Normal operation, long-term	15	

syngas HHV = 242 Btu/dscf

Worst Case SO2 Emissions							
	Emission Averaging Time						
Operating Modes	1-hr	3-hr	8-hr	24-hr	30-day	12-mo avg	Ton/yr
Gasifier outage, hrs							
Startup, hrs							
Max operation, short-term hrs	1	3	8	24	100	400	
Normal operation, long-term hrs					620	8,360	
SG consumed, 10^6 Btu	65	195	520	1560	15,800	151,400	
NG consumed, 10^6 Btu	0	0	0	0	0	0	
Sulfur in SG, ppmv	120	100	100	75	50	50	
SO2 from SG, lb/10^6 Btu SG*	0.084	0.070	0.070	0.052	0.035	0.035	
SO2 from SG or NG, lbs	5	14	36	82	551	5,275	
SO2 from tank vent gas, lbs	3	9	24	72	2,160	26,280	
Total SO2, lb/hr	8.4	7.5	7.5	6.4	3.8	3.6	15.8

* Example SO2 emission factor calculations.
SO2 (syngas) = (50 scf S/10^6 scf fuel) x (64 lb SO2/380 scf S)/(242 Btu/scf fuel) = 0.035 lb SO2/10^6 Btu
SO2 (natural gas) = 1 grain S/100 scf x 10^3 scf/10^6 Btu x 1 lb/7000 grain x 2 lb SO2/lb SO2 = 0.00286 lb SO2/10^6 Btu

Worst Case Non-Sulfur Emissions							
	Emission Averaging Time						
Operating Modes	1-hr	3-hr	8-hr	24-hr	30-day	12-mo avg	Ton/yr
Gasifier outage, hrs					620	720	
Startup, hrs						263	
Max operation, short-term hrs	1	3	8	24	100	400	
Normal operation, long-term hrs						7,377	
SG consumed, 10^6 Btu	65	195	520	1560	6,500	139,285	
NG consumed, 10^6 Btu	0	0	0	0	24,800	36,690	
NOx,lb/hr	19.5	19.5	19.5	19.5	13.0	6.0	26.4
CO, lb/hr	5.9	5.9	5.9	5.9	3.9	1.81	7.9
PM10, lb/hr	0.7	0.7	0.7	0.7	0.4	0.20	0.9
VOC, lb/hr	0.3	0.3	0.3	0.3	0.2	0.1	0.4

Exhibit A-2 TVB Page 1 of 1

Exhibit A-3 Auxiliary Boiler

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Exhibit A-3 AUXILIARY BOILER EMISSION ESTIMATES (Phase I)

(Mainly used for startups, could be used for other purposes, primarily during power block outages)

Maximum steam generation 100,000 lb/hr
Maximum heat release 130 10^6 Btu/hr, HHV
Natural gas fuel, only

Emission factors

	lb/10^6 Btu, HHV	Basis
SO2	0.00286	1.0 grain total sulfur/100 scf pipeline natural gas
NOx	0.036	Low NOx burner, based on similar equipment from previous project
CO	0.074	Similar equipment from previous project
PM10	0.005	Similar equipment from previous project
VOC	0.004	Similar equipment from previous project

Emission calulations

	Max short-term lb/hr (1)	Annual average ton/yr (2)
SO2	0.37	0.41
NOx	4.7	5.1
CO	9.6	10.5
PM10	0.65	0.71
VOC	0.52	0.57

Notes:
(1) Maximum 1-hr, 3-hr, 8-hr, 24-hr, and 30-day average emission rates.
(2) Maximum annual capacity factor of 25% (i.e., annual fuel consumption less than 0.25 x 8760 hr/yr x 130 million Btu/hr = 285 billion Btu/yr)

Exhibit A-3 Aux Boiler Page 1 of 1

Exhibit A-4 Flare

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Exhibit A-4 FLARE EMISSION RATES (Phase I)

Emission Factors

	lb/10^6 Btu fired, HHV		
	SG	NG	Basis
SO2	see table	0.00286	1 grain sulfur/100 scf pipeline natural gas
NOx	0.064	0.064	TRNCC guidance document (1)
CO	1.5	0.55	Assumed 99% destruction of CO in SG (2), TRNCC factor for NG (1)
PM10	0.008	0.008	Very little unoxidized carbon in syngas, therefore very little PM, used AP-42 factor for NG in boiler (a small value) (3)
VOC	0.006	0.006	Virtually no VOC in syngas, used AP-42 factor for NG in boiler (a small value) (3)

Notes:
(1) Texas Natural Resource Conservation Commission (now Texas Commission on Environmental Quality), *Technical Guidance Package for Chemical Sources, Flares and Oxidizers (RG-109)*, May 1997
(2) CO emission factor based on 50 vol % CO in flared gas, assumed 99% destruction efficiency, and 242 Btu/scf HHV,
CO = (0.50 scf/scf) x (1 - 0.99)/(242 Btu/scf) x (28 lb/380 scf) x (10^6/10^6) = 1.52 lb/10^6 Btu, HHV
(3) U.S. EPA, AP-42, Table 1.4-2

	Capacities, 10^6 Btu/hr		
Operating Modes	SG	NG	
Steady state (pilot only)		2	
Heatup/deslag		40	
Flaring syn gas, max 1-hr avg	3730		(85% of max capacity for two gasifiers)
Flaring syn gas, max > 1-hr avg	3510		
Flaring syn gas, max >8-hr avg	1755		

Syngas HHV = 242 Btu/dscf

Worst Case Emissions							
	Emission Averaging Time						
Operating Modes	1-hr	3-hr	8-hr	24-hr	30-day	12-mo avg	Ton/yr
Steady state (pilot only) hrs	1	3	8	24	720	8760	
Heatup/deslag hrs					210	1260	
Flaring hrs syn gas, max 1-hr	1						
Flaring hrs syn gas, max >1-hr		3	8				
Flaring hrs gas, max >8-hr				24	100	200	
SG flared, 10^6 Btu	3730	10530	28,080	42,120	175,500	351,000	
NG consumed, 10^6 Btu	2	6	16	48	9840	67920	
Sulfur in SG, ppmv	400	300	200	150	100	100	
SO2 from SG, lb/10^6 Btu SG	0.279	0.209	0.139	0.105	0.070	0.070	
SO2,lb/hr (total SG + NG)	1,040	734	489	183	17.0	2.8	12.3
NOx,lb/hr	238.8	224.8	224.8	112.4	16.5	3.1	13.4
CO, lb/hr	5,680	5,345	5,345	2,673	379	65	285.9
PM10, lb/hr	29.9	28.1	28.1	14.1	2.1	0.38	1.7
VOC, lb/hr	22.4	21.1	21.1	10.5	1.5	0.29	1.3

Exhibit A-4 Flare Page 1 of 1

Exhibit A-5 Cooling Towers

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Exhibit A-5 COOLING TOWER EMISSION RATE (Phase I)

Basis: Similar equipment from previous project.

Cooling Tower Operating Data and Emission Calculation			
Parameter	Power Block	Gasification/ ASU	Basis
Heat rejected, million Btu/hr	1740	690	Preliminary heat balances
Cooling water (CW) circulation rate, million lb/hr	116	46	Typical cooling tower design
Max CW dissolved solids, ppmw	2700	2700	TDS of water supply plus eight cycles of concentration
Drift, fraction of circulating CW	0.0010%	0.0010%	Typical supplier guarantee
PM10 emission rate, lb/hr	3.1	1.2	Calculated
PM10 emission rate, ton/yr	13.7	5.4	Calculated

Total PM10 cooling tower emission, Phase I = 19.2 ton/yr

Example calculation:
Maximum expected total dissolved solids (TDS) in makeup water = 337 parts per million by weight (ppmw)
Maximum expected TDS in circulating cooling water at eight cycles of concentration = 8 x 337 = 2700 ppmw
Power Block cooling tower PM10 = (116 x 10^6 lb/hr) x (0.00001 lb drift/lb) x (2700 lb PM/10^6 lb drift) = 3.1 lb PM10/hr

Exhibit A-5 Cooling Towers Page 1 of 1

Exhibit A-6 Emergency Generators and Fire Pumps

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Exhibit A-6 EMERGENCY DIESEL ENGINES EMISSION RATES (Phase I)

Basis: AP-42, Sections 3.3 and 3.4

Short-term Emission Rates						
		Emission Factor or Emission Rate				
Engines	Total hp	NOx	SO2*	CO	PM102	VOC
Emission Factors						
Large Stationary Diesel And All Stationary Dual-fuel Engines, >600 hp - emission factor from AP-42, Table 3.4-1, lb/hp-hr		0.024	8.09E-03	5.50E-03	0.0007	7.05E-04
Emission factor - Gasoline And Diesel Industrial Engines, <600 hp - emission factor from AP-42, Table 3.3-1, lb/hp-hr		0.031	2.05E-03	6.68E-03	2.20E-03	2.47E-03
Emission Rates						
Emergency Generator, 2 MW - emission, lb/hr	2682	64	1.1	15	1.9	1.9
Emergency Generator, 350 kW - emission, lb/hr	469	15	1.0	3.1	1.0	1.2
2 Emergency Fire Water Pump Engines, 300 hp each - emission, lb/hr	600	19	1.2	4.0	1.3	1.5
Total	**3751**					

* Large engine SO2 emission factor to be multiplied by the wt % sulfur in fuel (small engine factor is not adjusted)

Fuel sulfur = 0.05 wt%
1 MW = 1341 bhp

Annual Emission Rates**					
	Emission Rate, ton/yr				
Engines	NOx	SO2	CO	PM102	VOC
Emergency Generator, 2 MW - emission, ton/yr	3.2	0.05	0.7	0.09	0.09
Emergency Generator, 350 kW - emission, ton/yr	0.7	0.05	0.2	0.05	0.06
2 Emergency Fire Water Pump Engines, 300 hp each - emission, ton/yr	0.9	0.06	0.2	0.07	0.07
Total	**4.9**	**0.2**	**1.1**	**0.2**	**0.2**

** Maximum annual emission based on 100 hr/yr normal maintenance operation per engine.

Example Calculation
2 MW generator SO2:
2 MW x 1341 hp/MW = 2682 hp
SO2 = 2682 hp x 0.00809lb/hp-hr x 0.05 wt% S = 1.08 lb/hr
Annual SO2 = 1.08 lb/hr x 100hr/yr x 1 ton/2000 lb = 0.05 ton/yr

Exhibit A-6 Emergency Engines Page 1 of 1

Exhibit A-7 Material Handling System

Mesaba Energy Project
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Exhibit A-7 FUGITIVE PARTICULATE MATTER EMISSION CALCULATIONS

TABLE OF CONTENTS

1.0 EMISSION FACTORS
2.0 THROUGHPUT RATES
3.0 COAL AND PILE SURFACE AREAS
4.0 COAL PILE WIND EROSION
5.0 SLAG PILE WIND EROSION

1.0 EMISSION FACTORS

1.1 For Rail Car Unloading, E is obtained from EPRI CS-3455 (6/84)

1.2 For Transfer Points 2 through 13, Coal Emission Factors are calculated from the equation given in AP-42, Section 13.2.4

E= k*0.0032*{(U/5)^1.3/(M/2)^1.4} lb/ton

where, k=particle size multiplier (dimensionless). Its value is 0.74 for PM30 and 0.35 for PM10.

U=mean wind speed, miles per hour (mph)

M=material moisture content (%)

For the Mesaba Energy Project Site, wind speed frequency data were obtained from University of Minnesota Technical Bulletin AD-TB1955 for the Hibbing, MN area. (web link http://climate.umn.edu/pdf/climate_of_minnesota/comXIV.pdf), where the mean annual average wind speed is 9.3 miles per hour.

The assumed surface moisture content for PRB coal is 4%*

This gives

For PM30, E= 0.74*0.0032*{(9.3/5)^1.3/(4/2)^1.4} = 0.002011 lb/ton

and

For PM10, E= 0.35*0.0032*{(9.3/5)^1.3/(4/2)^1.4} = 0.000951 lb/ton

1.3 For slag handling, emission factors are given by the same equations on substituting the moisture content of slag = 2%

For PM30, E= 0.74*0.0032*{(9.3/5)^1.3/(2/2)^1.4} = 0.005306 lb/ton

and

For PM10, E= 0.35*0.0032*{(9.3/5)^1.3/(2/2)^1.4} = 0.002509 lb/ton

1.4 For onsite truck traffic (slag transfer) emission factors are obtained from AP-42 Section 13.2.2

For vehicles traveling on unpaved surfaces at industrial sites,

E=k*(s/12)^a * (W/3)^b lb/ Vehicle Miles Travelled (VMT)

where k,a and b are emperical constants and

s= surface material silt content (%)

W= mean vehicle weight (tons)

From Tables in AP-42 Section 13.2.2

	PM30	PM10
k	4.9	1.5
a	0.7	0.9
b	0.45	0.45

Assuming s=6% and W= 30 tons (30 tons represents the mean weight between the estimated loaded (40 tons) and empty (20 ton) truck weights)

For PM30, E=4.9*(6/12)^0.7 * (30/3)^0.45= 8.5

For PM10, E=1.5*(6/12)^0.9 * (30/3)^0.45= 2.3

* PRB coal ranges from 20 to 30% in total moisture, however much of this water is chemically bound to the coal. In the absence of specific data, these calculations assume an average surface moisture for PRB coal of about 4%, somewhat less than the mean reported for a range of coals in AP-42, Table 13.2.4-1, to account for the "dustyness" observed by some users of PRB coal.

2.0 THROUGHPUT RATES

As received maximum feed rate for PRB Coal, tpd, 8550
Slag production rate, tpd, 772

2.1 Coal, for materials handling upstream of coal pile:

2.1.1 Maximum hourly feed rate is based on unloading of 36 cars (119 tons per car) per hour

=119*36= 4284 , say 4,300 tons per hour

Time to Unload 115-car train = 115*119/4300= 3.18 , say 3.2 hours

2.1.2 Maximum annual throughput rate based on 100% capacity factor
=8550*365= 3120750 , say, 3,100,000 tons per year

2.2 For materials handling downstream of coal pile:
Peak rate is based on 120% of the normal average coal rate required for the nominal plant output

= 120% of 8550/24= 427.5 , say 430 tons per hour

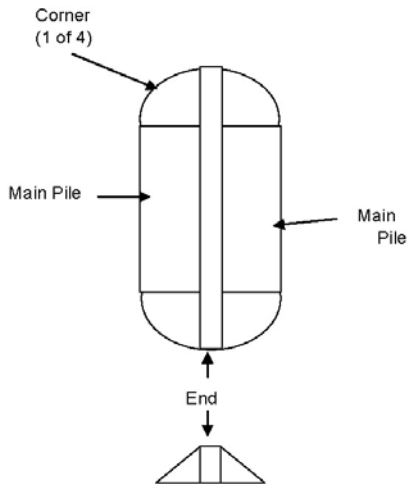
5.3 Slag
2.3.1 Max. hourly throughput based on 120% of the normal average coal rate required for the nominal plant c
= 120% of 772/24= 38.6 , say 39 tons per hour

2.3.2 Maximum annual throughput rate based on 100% capacity factor
=772*365= 281780 tons per year

2.4 For Slag disposal truck traffic, the throughput rate is based on vehicle miles travelled.
Assuming 20 ton trucks, number of trucks required per hour = 772/(24*20)= 1.608 , use 2
Assuming 0.2 miles round trip, VMT/hour= 0.2*2= 0.4 VMT/hour
Maximum annual throughput rate based on 100% capacity factor
=0.4*8760= 3504 , say, 3,500 VMT per year

3.0 COAL AND SLAG PILE SURFACE AREAS

3.1 **Surface Area of Coal Pile**



Givens

Length of pile, ft	500
Width of pile, ft	160
Angle of repose, degrees	35
Height of pile, ft	47

Calculated

Edge width, ft	67.1	
Area of sides= 2*(500-2*67.1)*47/sin 35o =		59,941 ft^2
Area of Top= (500-2*67.1)*(160-2*67.1) =		9,420 ft^2
Area of 4 corners, assuming conical shape= PI*67.1*(67.1^2+47^2)^0.5		17,279 ft^2
Area of 2 ends= 2*67.1*(160-2*67.1)		3,457 ft^2
		90,098 ft^2

3.2 **Surface Area of Slag Pile**

Length of pile, ft	575
Width of pile, ft	125
Angle of repose, degrees	27
Height of pile, ft	20

Calculated

Edge width, ft	39.3	
Area of sides= 2*(500-2*39.3)*20/sin 27o =		43,745 ft^2
Area of Top= (500-2*39.3)*(160-2*39.3) =		40,462 ft^2
Area of 4 corners, assuming conical shape= PI*39.3*(39.3^2+20^2)^0.5		5,432 ft^2
Area of 2 ends= 2*39.3*(160-2*39.3)		3,650 ft^2
		93,290 ft^2

4.0 COAL PILE WIND EROSION:

Windage emissions were calculated based on AP-42 Section 13.2.5

4.1 Source Activity and control application parameters:

		Source
Frequency of disturbance (days/yr):	365	Assumed
Height of pile (ft)	47	Sheet 5
Length of pile (ft)	500	Sheet 5
Width of pile (ft)	160	Sheet 5
Total surface area (ft2)	90,098	Sheet 5
Threshhold friction velocity (m/s)	1.12	From AP-42 Section 13.2.5, Table 13.2.5-2 for uncrusted coal pile
Threshhold wind velocity @ 10 m (m/s)	21	From AP-42 Section 13.2.5, Table 13.2.5-2 for uncrusted coal pile
Number of Active Piles	4	

4.2 Pile surface area within each surface wind speed range:

Based on AP-42 Section 13.2.5, Fig. 13.2.5-2, Pile B3 (Configuration B3 used based on slag pile shape and estimated relative wind direction, per Phase 1 Conceptual Plot Plan)
Contours of normalized surface wind speeds, where us=surface wind speed and ur=approach wind speed

Area ID	us/ur	%	area (ft2)
1.1	1.1	4	3604
0.9	0.9	14	12614
.6b	0.6	26	23425
.6a	0.6	28	25227
.2b	0.2	25	22525
.2a	0.2	3	2703

4.3 Calculate emission factor E=k*sum(P)

where k = 1 for PM
k = 0.5 for PM10

From AP-42 Section 13.2.5, Table 13.2.5-2, Section 13.2.5.3

4.4 Climatic data:

From Climate of Minnesota, University of Minnesota Document AD-TB1955 data (1983) for Hibbing

Mean wind speed: 9.3 mph
Wind speed Distribution

Spd (mph)	Assume	% of year	days/yr
<8	6	38.9	141.985
8-12	10	30.4	110.96
13-18	18	27	98.55
19-24	24	3.3	12.045
25-31	31	0.4	1.46
highest			
		100	365

Percent of year from Climate of Minnesota data (1983) for Hibbing (AD-TB 1955 Table 20)

4.5 Erosion Potential $P = 58 (u^*-u_t^*)^2 + 25 (u^*-u_t^*)$ where u*= friction velocity (m/s) and ut=threshold friction velocity (m/s)

u+ is the fastest mile value
u+ is the fastest mile value

Days	Peak wind (u10+) mph	m/s	u+s = (us/ur) * u10+ us/ur=.2	us/ur=.6	us/ur=.9	us/ur=1.1
142.0	6	2.68	0.54	1.61	2.41	2.95
111.0	10	4.47	0.89	2.68	4.02	4.92
98.6	18	8.05	1.61	4.83	7.24	8.85
12.0	24	10.73	2.15	6.44	9.66	11.80
1.5	31	13.86	2.77	8.31	12.47	15.24
365.0						

Days	u* = 0.1 u+s us/ur*.2	us/ur*.6	us/ur*.9	us/ur*1.1	Daily P(g/m2) us/ur*.2	us/ur*.6	us/ur*.9	us/ur*1.1
142.0	0.05	0.16	0.24	0.30	0	0	0	0
111.0	0.09	0.27	0.40	0.49	0	0	0	0
98.6	0.16	0.48	0.72	0.89	0	0	0	0
12.0	0.21	0.64	0.97	1.18	0	0	0	1.711357
1.5	0.28	0.83	1.25	1.52	0	0	4.115648	19.58594

4.6 Emission Results

					TOTAL		
Sum (P*#Days)	0.000	0.000	6.009	49.209		g/m2	
Areas	2343.6	4519.9	1171.8	334.8		m^2	
Emission/yr/active pile	0	0	0.008	0.018	**0.026**	ton/yr	PM
	0	0	0.004	0.009	**0.013**	ton/yr	PM10
Total Emissions/yr (active)	0	0	0.031	0.073	**0.104**	ton/yr	PM
	0	0	0.016	0.036	**0.052**	ton/yr	PM10

5.0 SLAG STORAGE PILE WIND EROSION:

5.1 Source Activity and control application parameters:

Frequency of disturbance (days/yr):	365
Height of pile (ft)	20
Length of pile (ft)	575
Width of pile (ft)	125
Total surface area (ft2)	93,290
Threshhold friction velocity (m/s)	1.12
Threshhold wind velocity @ 10 m (m/s)	21
Number of Active Piles	1

5.2 Pile surface area within each surface wind speed range:

Area ID	us/ur	%	area (ft2)
1.1	1.1	4	3732
0.9	0.9	14	13061
.6b	0.6	26	24255
.6a	0.6	28	26121
.2b	0.2	25	23323
.2a	0.2	3	2799

5.3 Calculate emission factor E=k*sum(P)

k = 1 for PM30
k = 0.5 for PM10

P = 58 (u*-u*t)^2 + 25 (u*-u*t)

5.4 Climatic data:

Mean wind speed: 9.3 mph
Wind speed Distribution

speed (mph)		% of year	days/yr
<8	6	38.9	141.985
8-12	10	30	109.5
13-18	18	27	98.55
19-24	24	3.3	12.045
25-31	31	0.4	1.46
		99.6	

Percent of year from Climate of Minnesota data (1983) for Hibbing

5.5 Erosion Potential:

Days Peak wind (u10+) u+s = (us/ur) * u10+

	mph	m/s	us/ur-=.2	us/ur=.6	us/ur=.9	us/ur=1.1
142.0	6	2.68	0.54	1.61	2.41	2.95
109.5	10	4.47	0.89	2.68	4.02	4.92
98.6	18	8.05	1.61	4.83	7.24	8.85
12.0	24	10.73	2.15	6.44	9.66	11.80
1.5	31	13.86	2.77	8.31	12.47	15.24
363.5						

Days

	u* = 0.1 u+s				Daily P(g/m2)			
	us/ur*.2	us/ur*.6	us/ur*.9	us/ur*1.1	us/ur*.2	us/ur*.6	us/ur*.9	us/ur*1.1
142.0	0.05	0.16	0.24	0.30	0	0	0	0
109.5	0.09	0.27	0.40	0.49	0	0	0	0
98.6	0.16	0.48	0.72	0.89	0	0	0	0
12.0	0.21	0.64	0.97	1.18	0	0	0	1.711357
1.5	0.28	0.83	1.25	1.52	0	0	4.115648	19.58594

5.6 Emission Results

Sum (P*#Days)	0.000	0.000	6.009	49.209		g/m2	
Areas	2426.7	4680.0	1213.3	346.7		m^2	
					TOTAL		
Emission/yr/active pile	0	0	0.008	0.019	**0.027**	ton/yr	PM30
	0	0	0.004	0.009	**0.013**	ton/yr	PM10
Total Emissions/yr (active)	0	0	0.008	0.019	**0.027**	ton/yr	PM30
	0	0	0.004	0.009	**0.013**	ton/yr	PM10

Appendix B

Hazardous Air Pollutant Emission Calculations

This appendix presents the calculations and assumptions used to estimate hazardous air pollutant (HAP) emissions potentially resulting from the Mesaba Energy Project

Emission estimates are presented in the following sections:

Exhibit B-1 HAPs Emission Summary
Exhibit B-2 Combustion Turbine HAPs Emission Summary
Exhibit B-3 Tank Vent Boiler HAPs Emission Summary
Exhibit B-4 Flare HAPs
Exhibit B-5 Fugitive HAPs Emission Summary
Exhibit B-6 HAP Metals Emission Factors
Exhibit B-7 AP-42 and NETL Coal HAP Emission Factors
Exhibit B-8 Wabash River CTG HAPs
Exhibit B-9 Wabash River Syngas HAPs
Exhibit B-10 Wabash River TVB HAPs

In general, the HAPs evaluation includes those CAA § 112(b)(1) chemicals/compounds that either have been measured at the Wabash River or are listed in the *U.S. EPA Compilation of Air Pollutant Emission Factors (AP-42)* for coal combustion. Emission factors for the targeted HAPs were developed from the following sources, listed in order of preference:

1. Process stream analytical results and stack emission test results from the Wabash River Coal Gasification Repowering Demonstration Project.
2. Preliminary material balances and engineering design for the Mesaba Energy Project.
3. Published HAPs emission data for IGCC processes, such as the NETL 2002 report regarding the environmental aspects of coal gasification-based power generation (USDOE/NETL, 2002).
4. Published coal combustion (not gasification) average emission factors from AP-42.

The following sections show how the HAP emission estimates presented in Section 4 of this application were developed and include example calculations, key assumptions, and reference citations. For simplicity, only calculations for Phase I of the IGCC Power Station are presented. Phase II emissions will be numerically identical to Phase II.

To further illustrate the methodologies used, the following step-by-step example calculations are provided.

<u>Total chromium (Cr) emission from CTGs</u>

1. From Exhibit B-9, total Cr concentration in product syngas was not detected at the Wabash River during a test in November 2005. Using one-half the detection limit for the sample size, the assumed Cr concentration in product syngas is less than 0.0024 mg/dscm (milligram per dry standard meter).
2. From Exhibit B-8, assuming an average Wabash coal conversion efficiency (coal energy converted to syngas energy) of 0.77 and a representative heating value for syngas of 280 Btu/dscf HHV, this Cr concentration is equivalent to:

   $Cr = 0.0024\ mg/m^3 \times 1\ lb/454 \times 10^3\ mg \times 1\ m^3/35.3\ ft^3 \times 1\ ft^3/280\ Btu \times 0.77 \times 10^{12}/10^{12}$
   $= 0.41\ lb\ Cr/10^{12}\ Btu\ coal$

3. Exhibit B-6 shows how the Wabash metals emission factors are adjusted for the worst-case Mesaba feed concentrations. Available information indicates that the potential Mesaba solid feedstocks could range from 2.4 to 7 mg/kg CR concentration, while the Wabash feed contains about 5.5 mg/kg Cr. Multiplying the Wasbash emission factor by the ratio of the worst-case Mesaba concentration to the Wabash concentration gives the maximum expected Mesaba emission factor:

   Cr = 0.41 lb Cr/10^{12} Btu x 7/5.5 = 0.52 lb Cr/10^{12} Btu coal.

4. Exhibit B-2 presents the estimated HAPs emission rates for the Phase I CTGs. Based on an average feed rate to the gasifiers of 5775x10^6 Btu/hr, the annual Cr emission rate would be:

   Cr = 0.52 lb Cr/10^{12} Btu x 5595x10^6 Btu/hr x 8760 hrs/yr x 1 ton/2000 lbs = 0.013 ton/yr.

<u>Methyl tertiary butyl ether (MTBE) emission from CTGs</u>

1. Inspection of Exhibit B-8 shows that MTBE was apparently not measured for the Wabash River CTGs. No data for this HAP were found in available IGCC-specific reports. Therefore, AP-42 will be used to estimate this emission rate.

2. Exhibit B-7shows the AP-42 default emission factors for coal combustion-related HAPs. This table shows a factor of 3.5E-05 lb/ton of coal combusted. This factor is converted to units of heat input, based on the lowest as-received heating value expected for Mesaba, as follows:

   MTBE = 0.000035 lb/ton x 1 ton/2000 lbs x 1 lb/8300 Btu/lb x $10^{12}/10^{12}$ = 2.1 lb/10^{12} Btu

3. Exhibit B-2 shows the calculated emission rate of MTBE from the CTGs:

   MTBE = 2.1 lb/10^{12} Btu x 5595x10^6 Btu/hr x 8760 hrs/yr x 1 ton/2000 lbs = 0.1053 ton/yr.

Exhibit B-1 HAPs Emission Summary

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Exhibit B-1 HAPs EMISSION SUMMARY
(Phase I)

CAS # or MPCA #	Compound	Annual Average HAP Emission (ton/yr)				
		CTGs	TVB	Flare	Fugitive	Total
75-07-0	Acetaldehyde	0.044	1.6E-04	3.9E-04		0.045
98-86-2	Acetophenone	0.022	7.9E-05	2.0E-04		0.022
107-02-8	Acrolein	0.43	1.5E-03	3.8E-03		0.43
7440-36-0	Antimony	0.027	2.8E-04	7.0E-04		0.028
7440-38-2	Arsenic	0.059	1.5E-03	3.7E-03		0.064
71-43-2	Benzene	0.061	0.028	0.071	0.0063	0.167
100-44-7	Benzyl chloride	1.03	3.7E-03	9.2E-03		1.0
7440-41-7	Beryllium	0.0064	7.9E-06	2.0E-05		0.0064
92-52-4	Biphenyl	0.0025	9.0E-06	2.2E-05		0.0025
117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)	0.11	3.9E-04	9.6E-04		0.109
75-25-2	Bromoform	0.06	2.0E-04	5.0E-04		0.057
7440-43-9	Cadmium	0.24	5.7E-05	1.4E-04		0.24
75-15-0	Carbon disulfide	1.13	4.0E-03	1.0E-02	0.034	1.18
463581	Carbonyl sulfide				0.058	0.058
532-27-4	Chloroacetophenone, 2-	0.0103	3.7E-05	9.2E-05		0.0104
108-90-7	Chlorobenzene	0.032	1.1E-04	2.8E-04		0.032
67-66-3	Chloroform	0.088	3.2E-04	7.9E-04		0.089
0-00-5	Chromium, total (1)	0.013	1.1E-03	2.6E-03		0.016
18540-29-9	Chromium, (hexavalent)	0.0038	3.2E-04	7.9E-04		0.0049
7440-48-4	Cobalt (1)	0.0064	1.2E-03	3.0E-03		0.011
98-82-8	Cumene	0.0078	2.6E-05	6.6E-05		0.0079
57-12-5	Cyanide (Cyanide ion, Inorganic cyanides, Isocyanide)	0.140	4.6E-03	1.2E-02	0.0088	0.16
77-78-1	Dimethyl sulfate	0.071	2.5E-04	6.3E-04		0.072
121-14-2	Dinitrotoluene, 2,4-	4.2E-04	1.5E-06	3.7E-06		4.2E-04
100-41-4	Ethyl benzene	0.14	0.032	0.079	5.4E-06	0.25
75-00-3	Ethyl chloride (Chloroethane)	0.061	2.2E-04	5.5E-04		0.062
106-93-4	Ethylene dibromide (Dibromoethane)	0.0018	6.3E-06	1.6E-05		0.0018
107-06-2	Ethylene dichloride (1,2-Dichloroethane)	0.059	2.1E-04	5.3E-04		0.060
50-00-0	Formaldehyde	0.42	1.5E-03	3.7E-03	1.1E-06	0.42
110-54-3	Hexane	0.10	3.5E-04	8.8E-04	1.5E-06	0.10
7647-01-0	Hydrochloric acid	0.096	3.0E-04	7.4E-04	0.034	0.13
7664-39-3	Hydrogen fluoride (Hydrofluoric acid)	1.2	5.3E-05	1.3E-04		1.2
78-59-1	Isophorone	0.86	3.1E-03	7.6E-03		0.87
7439-92-1	Lead	0.014	6.3E-05	1.6E-04		0.014
7439-96-5	Manganese	0.025	2.4E-03	5.9E-03		0.034
7439-97-6	Mercury	0.012	6.6E-04	1.6E-04		0.013
74-83-9	Methyl bromide (Bromomethane)	1.23	0.011	0.029		1.3
74-87-3	Methyl chloride (Chloromethane)	0.78	6.0E-03	1.5E-02		0.80
71-55-6	Methyl chloroform (1,1,1 - Trichloroethane) (4)	0.029	1.1E-04	2.6E-04		0.030
78-93-3	Methyl ethyl ketone (2-Butanone)	0.58	2.1E-03	5.1E-03		0.58
60-34-4	Methyl hydrazine	0.25	9.0E-04	2.2E-03		0.25
80-62-6	Methyl methacrylate	0.029	1.1E-04	2.6E-04		0.030
1634-04-4	Methyl tert butyl ether	0.051	1.8E-04	4.6E-04		0.052

Exhibit B-1 Summary 1 of 2

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Exhibit B-1 HAPs EMISSION SUMMARY
(Phase I)

CAS # or MPCA #	Compound	Annual Average HAP Emission (ton/yr)				
		CTGs	TVB	Flare	Fugitive	Total
75-09-2	Methylene chloride (Dichloromethane)	0.056	5.5E-04	1.4E-03		0.058
91-20-3	Naphthalene	0.064	8.1E-04	2.0E-03	2.6E-05	0.067
7440-02-0	Nickel	0.0096	4.2E-03	1.0E-02		0.024
108-95-2	Phenol	0.95	1.2E-02	3.0E-02	7.8E-08	0.99
123-38-6	Proprionaldehyde	0.561	2.0E-03	5.0E-03		0.568
7784-49-2	Selenium	0.014	2.4E-04	5.9E-04		0.015
100-42-5	Styrene	0.037	1.3E-04	3.3E-04		0.037
127-18-4	Tetrachloroethylene (Perchloroethylene)	0.063	2.3E-04	5.7E-04		0.064
108-88-3	Toluene	0.00081	0.0112	0.0280	6.6E-04	0.041
108-05-4	Vinyl acetate	0.011	4.0E-05	1.0E-04		0.011
1330-20-7	Xylenes	0.055	0.013	0.032	1.0E-05	0.10
	Total federal HAPs	***11.4***	***0.2***	***0.4***	***0.1***	***12.0***
	Other Emissions					
56-55-3	Benz[a]anthracene	5.6E-05	2.0E-07	5.0E-07		5.7E-05
207-08-9	Benzo(k)fluoranthene	1.6E-04	5.8E-07	1.4E-06		1.6E-04
50-32-8	Benzo[a]pyrene	5.6E-05	2.0E-07	5.0E-07		5.7E-05
218-01-9	Chrysene (Benzo(a)phenanthrene)	1.5E-04	5.3E-07	1.3E-06		1.5E-04
193-39-5	Indeno(1,2,3-cd)pyrene	9.1E-05	3.2E-07	8.1E-07		9.2E-05
3697-24-3	Methylchrysene, 5-	3.2E-05	1.1E-07	2.8E-07		3.2E-05
7664-93-9 14808-79-8	Sulfuric acid and sulfates	62.0	0.2	0.6		62.8
	Other VOC				8.3	8.3
	Hydrogen sulfide				8.6	8.6
	Total Volatile Organic Compounds (VOC)	9.6	0.1	0.4	8.4	18.6
	Total Reduced Sulfur (TRS) Compounds	1.1	0.004	0.010	8.7	9.8

Significant HAPs	ton/yr	Basis
Acrolein	0.4	AP-42 coal combustion
Benzyl chloride	1.0	AP-42 coal combustion
Carbon disulfide	1.2	NETL report
Formaldehyde	0.4	NETL report
Hydrogen fluoride (Hydrofluoric acid)	1.2	NETL report
Isophorone	0.9	AP-42 coal combustion
Methyl bromide (Bromomethane)	1.3	Wabash data
Methyl chloride (Chloromethane)	0.8	AP-42 coal combustion
Methyl ethyl ketone (2-Butanone)	0.6	AP-42 coal combustion
Phenol	1.0	Wabash data
Proprionaldehyde	0.6	AP-42 coal combustion
	9	

Exhibit B-1 Summary 2 of 2

Exhibit B-2 Combustion Turbine HAPs Emission Summary

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Exhibit B-2 COMBUSTION TURBINE HAPs EMISSION SUMMARY
(Phase I)

Plant Performance

Syngas fuel 2115 x 10^6 Btu/hr/CTG, HHV (SW Case 2)
Min Coal conversion efficency **0.719** (PRB coal)
Max Coal conversion efficency **0.793** (Illinois coal)
Gasifiers coal feed, total Phase 1 5883 x 10^6 Btu/hr, HHV (max, use for short-term emission calculation)
5595 x 10^6 Btu/hr, HHV (avg, use for annual emission calculation)

CAS # or MPCA #	Compound	Emission Factor (lb/10^6 Btu coal)	Short-term Emission, 1-hr and 30-day avg (lb/hr)	Annual Emission (ton/yr)	Emission Factor Source
75-07-0	Acetaldehyde	1.8	0.011	0.044	NETL, Table 2-17 (see Reference 1)
98-86-2	Acetophenone	0.90	0.01	0.02	AP-42, Table 1.1-14 (see Reference 2)
107-02-8	Acrolein	17.5	0.10	0.43	AP-42, Table 1.1-14 (see Reference 2)
7440-36-0	Antimony (1)	1.1	0.0065	0.027	Wabash River test data
7440-38-2	Arsenic (1)	2.4	0.0141	0.059	Wabash River test data
56-55-3	Benz[a]anthracene	0.0023	0.000014	0.000056	NETL, Table 2-17 (see Reference 1)
71-43-2	Benzene	2.5	0.015	0.061	Wabash River test data
207-08-9	Benzo(k)fluoranthene (5)	0.0066	0.000039	0.00016	AP-42, Table 1.1-13 (see Reference 2)
50-32-8	Benzo[a]pyrene (3)	0.0023	0.000014	0.000056	AP-42, Table 1.1-13 (see Reference 2)
100-44-7	Benzyl chloride	42.2	0.25	1.03	AP-42, Table 1.1-14 (see Reference 2)
7440-41-7	Beryllium (1)	0.26	0.0015	0.0064	Wabash River test data
92-52-4	Biphenyl	0.10	0.00060	0.0025	AP-42, Table 1.1-13 (see Reference 2)
117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)	4.4	0.026	0.11	AP-42, Table 1.1-14 (see Reference 2)
75-25-2	Bromoform	2.3	0.014	0.056	AP-42, Table 1.1-14 (see Reference 2)
7440-43-9	Cadmium (1)	9.6	0.06	0.24	Wabash River test data
75-15-0	Carbon disulfide	46	0.27	1.13	NETL, Table 2-17 (see Reference 1)
532-27-4	Chloroacetophenone, 2-	0.42	0.0025	0.010	AP-42, Table 1.1-14 (see Reference 2)
108-90-7	Chlorobenzene	1.3	0.0076	0.032	AP-42, Table 1.1-14 (see Reference 2)
67-66-3	Chloroform (4)	3.6	0.021	0.09	AP-42, Table 1.1-14 (see Reference 2)
0-00-5	Chromium, total (1)	0.52	0.0031	0.013	Wabash River test data
18540-29-9	Chromium, (hexavalent)	0.16	0.00092	0.0038	Portion of total chromium emitted in +6 valenece state, assumed to be 30% of total (see permit application, Section 4.2).
218-01-9	Chrysene (Benzo(a)phenanthrene)	0.0060	0.000035	0.00015	AP-42, Table 1.1-13 (see Reference 2)
7440-48-4	Cobalt (1)	0.26	0.0015	0.0064	Wabash River test data
98-82-8	Cumene	0.32	0.0019	0.0078	AP-42, Table 1.1-14 (see Reference 2)
57-12-5	Cyanide (Cyanide ion, Inorganic cyanides, Isocyanide)	5.7	0.034	0.14	NETL, Table 2-6 (see Reference 1)
77-78-1	Dimethyl sulfate	2.9	0.017	0.071	AP-42, Table 1.1-14 (see Reference 2)
121-14-2	Dinitrotoluene, 2,4-	0.017	0.00010	0.00042	AP-42, Table 1.1-14 (see Reference 2)
100-41-4	Ethyl benzene	5.7	0.034	0.14	AP-42, Table 1.1-14 (see Reference 2)
75-00-3	Ethyl chloride (Chloroethane)	2.5	0.015	0.061	AP-42, Table 1.1-14 (see Reference 2)
106-93-4	Ethylene dibromide (Dibromoethane)	0.072	0.00042	0.0018	AP-42, Table 1.1-14 (see Reference 2)
107-06-2	Ethylene dichloride (1,2-Dichloroethane)	2.4	0.014	0.059	AP-42, Table 1.1-14 (see Reference 2)
50-00-0	Formaldehyde	17	0.10	0.42	NETL, Table 2-17 (see Reference 1)
110-54-3	Hexane	4.0	0.024	0.10	AP-42, Table 1.1-14 (see Reference 2)
7647-01-0	Hydrochloric acid (1)	3.9	0.023	0.096	Wabash River test data
7664-39-3	Hydrogen fluoride (Hydrofluoric acid) (6)	50	0.29	1.23	NETL, Table 2-5 (see Reference 1)
193-39-5	Indeno(1,2,3-cd)pyrene	0.0037	0.000022	0.00009	AP-42, Table 1.1-13 (see Reference 2)
78-59-1	Isophorone	34.9	0.21	0.86	AP-42, Table 1.1-14 (see Reference 2)
7439-92-1	Lead	0.56	0.0033	0.014	Wabash River test data
7439-96-5	Manganese (1)	1.0	0.0061	0.025	Wabash River test data
7439-97-6	Mercury	0.5	0.0029	0.012	(See Note 2)
74-83-9	Methyl bromide (Bromomethane)	50.2	0.30	1.23	Wabash River test data
74-87-3	Methyl chloride (Chloromethane)	31.9	0.19	0.78	AP-42, Table 1.1-14 (see Reference 2)

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Exhibit B-2 COMBUSTION TURBINE HAPs EMISSION SUMMARY
(Phase I)

Plant Performance

Syngas fuel 2115 x 10^6 Btu/hr/CTG, HHV (SW Case 2)
Min Coal conversion efficency **0.719** (PRB coal)
Max Coal conversion efficency **0.793** (Illinois coal)
Gasifiers coal feed, total Phase 1 5883 x 10^6 Btu/hr, HHV (max, use for short-term emission calculation)
5595 x 10^6 Btu/hr, HHV (avg, use for annual emission calculation)

CAS # or MPCA #	Compound	Emission Factor (lb/10^6 Btu coal)	Short-term Emission, 1-hr and 30-day avg (lb/hr)	Annual Emission (ton/yr)	Emission Factor Source
75-07-0	Acetaldehyde	1.8	0.011	0.044	NETL, Table 2-17 (see Reference 1)
98-86-2	Acetophenone	0.90	0.01	0.02	AP-42, Table 1.1-14 (see Reference 2)
107-02-8	Acrolein	17.5	0.10	0.43	AP-42, Table 1.1-14 (see Reference 2)
7440-36-0	Antimony (1)	1.1	0.0065	0.027	Wabash River test data
7440-38-2	Arsenic (1)	2.4	0.0141	0.059	Wabash River test data
56-55-3	Benz[a]anthracene	0.0023	0.000014	0.000056	NETL, Table 2-17 (see Reference 1)
71-43-2	Benzene	2.5	0.015	0.061	Wabash River test data
207-08-9	Benzo(k)fluoranthene (5)	0.0066	0.000039	0.00016	AP-42, Table 1.1-13 (see Reference 2)
50-32-8	Benzo[a]pyrene (3)	0.0023	0.000014	0.000056	AP-42, Table 1.1-13 (see Reference 2)
100-44-7	Benzyl chloride	42.2	0.25	1.03	AP-42, Table 1.1-14 (see Reference 2)
7440-41-7	Beryllium (1)	0.26	0.0015	0.0064	Wabash River test data
92-52-4	Biphenyl	0.10	0.00060	0.0025	AP-42, Table 1.1-13 (see Reference 2)
117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)	4.4	0.026	0.11	AP-42, Table 1.1-14 (see Reference 2)
75-25-2	Bromoform	2.3	0.014	0.056	AP-42, Table 1.1-14 (see Reference 2)
7440-43-9	Cadmium (1)	9.6	0.06	0.24	Wabash River test data
75-15-0	Carbon disulfide	46	0.27	1.13	NETL, Table 2-17 (see Reference 1)
532-27-4	Chloroacetophenone, 2-	0.42	0.0025	0.010	AP-42, Table 1.1-14 (see Reference 2)
108-90-7	Chlorobenzene	1.3	0.0076	0.032	AP-42, Table 1.1-14 (see Reference 2)
67-66-3	Chloroform (4)	3.6	0.021	0.09	AP-42, Table 1.1-14 (see Reference 2)
0-00-5	Chromium, total (1)	0.52	0.0031	0.013	Wabash River test data
18540-29-9	Chromium, (hexavalent)	0.16	0.00092	0.0038	Portion of total chromium emitted in +6 valenece state, assumed to be 30% of total (see permit application, Section 4.2).
218-01-9	Chrysene (Benzo(a)phenanthrene)	0.0060	0.000035	0.00015	AP-42, Table 1.1-13 (see Reference 2)
7440-48-4	Cobalt (1)	0.26	0.0015	0.0064	Wabash River test data
98-82-8	Cumene	0.32	0.0019	0.0078	AP-42, Table 1.1-14 (see Reference 2)
57-12-5	Cyanide (Cyanide ion, Inorganic cyanides, Isocyanide)	5.7	0.034	0.14	NETL, Table 2-6 (see Reference 1)
77-78-1	Dimethyl sulfate	2.9	0.017	0.071	AP-42, Table 1.1-14 (see Reference 2)
121-14-2	Dinitrotoluene, 2,4-	0.017	0.00010	0.00042	AP-42, Table 1.1-14 (see Reference 2)
100-41-4	Ethyl benzene	5.7	0.034	0.14	AP-42, Table 1.1-14 (see Reference 2)
75-00-3	Ethyl chloride (Chloroethane)	2.5	0.015	0.061	AP-42, Table 1.1-14 (see Reference 2)
106-93-4	Ethylene dibromide (Dibromoethane)	0.072	0.00042	0.0018	AP-42, Table 1.1-14 (see Reference 2)
107-06-2	Ethylene dichloride (1,2-Dichloroethane)	2.4	0.014	0.059	AP-42, Table 1.1-14 (see Reference 2)
50-00-0	Formaldehyde	17	0.10	0.42	NETL, Table 2-17 (see Reference 1)
110-54-3	Hexane	4.0	0.024	0.10	AP-42, Table 1.1-14 (see Reference 2)
7647-01-0	Hydrochloric acid (1)	3.9	0.023	0.096	Wabash River test data
7664-39-3	Hydrogen fluoride (Hydrofluoric acid) (6)	50	0.29	1.23	NETL, Table 2-5 (see Reference 1)
193-39-5	Indeno(1,2,3-cd)pyrene	0.0037	0.000022	0.00009	AP-42, Table 1.1-13 (see Reference 2)
78-59-1	Isophorone	34.9	0.21	0.86	AP-42, Table 1.1-14 (see Reference 2)
7439-92-1	Lead	0.56	0.0033	0.014	Wabash River test data
7439-96-5	Manganese (1)	1.0	0.0061	0.025	Wabash River test data
7439-97-6	Mercury	0.5	0.0029	0.012	(See Note 2)
74-83-9	Methyl bromide (Bromomethane)	50.2	0.30	1.23	Wabash River test data
74-87-3	Methyl chloride (Chloromethane)	31.9	0.19	0.78	AP-42, Table 1.1-14 (see Reference 2)

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Exhibit B-3 Tank Vent Boiler HAPs Emission Summary

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Exhibit B-3 TANK VENT BOILER HAPs EMISSION SUMARY
(Phase I)

Syngas fuel consumption rates

65 x 10^6 Btu/hr, HHV (max, use for short-term emission calculation)
20 x 10^6 Btu/hr, HHV (avg, use for annual emission calculation)

CAS # or MPCA #	Compound	Emission Factor ($lb/10^{12}$ Btu syngas) (1)	Short-term Emission, 1-hr and 30-day avg (lb/hr)	Annual Emission (ton/yr)	Emission Factor Source
75-07-0	Acetaldehyde	1.8	1.2E-04	1.6E-04	NETL, Table 2-17 (see Reference 1)
98-86-2	Acetophenone	0.90	5.9E-05	7.9E-05	AP-42, Table 1.1-14 (see Reference 2)
107-02-8	Acrolein	17.5	1.1E-03	1.5E-03	AP-42, Table 1.1-14 (see Reference 2)
7440-36-0	Antimony	3.2	2.1E-04	2.8E-04	Wabash River test data
7440-38-2	Arsenic	16.9	1.1E-03	1.5E-03	Wabash River test data
56-55-3	Benz[a]anthracene	0.0023	1.5E-07	2.0E-07	NETL, Table 2-17 (see Reference 1)
71-43-2	Benzene	323	2.1E-02	2.8E-02	Wabash River test data
207-08-9	Benzo(k)fluoranthene (4)	0.0066	4.3E-07	5.8E-07	AP-42, Table 1.1-13 (see Reference 2)
50-32-8	Benzo[a]pyrene (2)	0.0023	1.5E-07	2.0E-07	AP-42, Table 1.1-13 (see Reference 2)
100-44-7	Benzyl chloride	42.2	2.7E-03	3.7E-03	AP-42, Table 1.1-14 (see Reference 2)
7440-41-7	Beryllium	0.09	5.9E-06	7.9E-06	NETL, Table 2-11 (see Reference 1)
92-52-4	Biphenyl	0.10	6.7E-06	9.0E-06	AP-42, Table 1.1-13 (see Reference 2)
117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)	4.4	2.9E-04	3.9E-04	AP-42, Table 1.1-14 (see Reference 2)
75-25-2	Bromoform	2.3	1.5E-04	2.0E-04	AP-42, Table 1.1-14 (see Reference 2)
7440-43-9	Cadmium	0.65	4.2E-05	5.7E-05	Wabash River test data
75-15-0	Carbon disulfide	46	3.0E-03	4.0E-03	NETL, Table 2-17 (see Reference 1)
532-27-4	Chloroacetophenone, 2-	0.42	2.7E-05	3.7E-05	AP-42, Table 1.1-14 (see Reference 2)
108-90-7	Chlorobenzene	1.3	8.5E-05	1.1E-04	AP-42, Table 1.1-14 (see Reference 2)
67-66-3	Chloroform (3)	3.6	2.3E-04	3.2E-04	AP-42, Table 1.1-14 (see Reference 2)
0-00-5	Chromium, total	12	7.8E-04	1.1E-03	Wabash River test data
18540-29-9	Chromium, (hexavalent)	3.6	2.3E-04	3.2E-04	Portion of total chromium emitted in +6 valenece state, assumed to be 30% of total (see permit application, Section 4.2).
218-01-9	Chrysene (Benzo(a)phenanthrene)	0.006	3.9E-07	5.3E-07	AP-42, Table 1.1-13 (see Reference 2)
7440-48-4	Cobalt	13.7	8.9E-04	1.2E-03	Wabash River test data
98-82-8	Cumene	0.30	2.0E-05	2.6E-05	AP-42, Table 1.1-14 (see Reference 2)
57-12-5	Cyanide (Cyanide ion, Inorganic cyanides, Isocyanide) (2)	53	3.4E-03	4.6E-03	Wabash River test data
77-78-1	Dimethyl sulfate	2.9	1.9E-04	2.5E-04	AP-42, Table 1.1-14 (see Reference 2)
121-14-2	Dinitrotoluene, 2,4-	0.017	1.1E-06	1.5E-06	AP-42, Table 1.1-14 (see Reference 2)
100-41-4	Ethyl benzene	362	2.4E-02	3.2E-02	Wabash River test data
75-00-3	Ethyl chloride (Chloroethane)	2.5	1.6E-04	2.2E-04	AP-42, Table 1.1-14 (see Reference 2)
106-93-4	Ethylene dibromide (Dibromoethane)	0.072	4.7E-06	6.3E-06	AP-42, Table 1.1-14 (see Reference 2)
107-06-2	Ethylene dichloride (1,2-Dichloroethane)	2.4	1.6E-04	2.1E-04	AP-42, Table 1.1-14 (see Reference 2)
50-00-0	Formaldehyde	17	1.1E-03	1.5E-03	NETL, Table 2-17 (see Reference 1)
110-54-3	Hexane	4.0	2.6E-04	3.5E-04	AP-42, Table 1.1-14 (see Reference 2)
7647-01-0	Hydrochloric acid	3.4	2.2E-04	3.0E-04	Wabash River test data (for syngas)
7664-39-3	Hydrogen fluoride (Hydrofluoric acid) (5)	0.6	3.9E-05	5.3E-05	NETL, Table 2-5 (see Reference 1)
193-39-5	Indeno(1,2,3-cd)pyrene	0.0037	2.4E-07	3.2E-07	AP-42, Table 1.1-13 (see Reference 2)
78-59-1	Isophorone	34.9	2.3E-03	3.1E-03	AP-42, Table 1.1-14 (see Reference 2)
7439-92-1	Lead	0.72	4.7E-05	6.3E-05	Wabash River test data (for syngas)
7439-96-5	Manganese	27.1	1.8E-03	2.4E-03	Wabash River test data
7439-97-6	Mercury	7.5	4.9E-04	6.6E-04	Wabash River test data
74-83-9	Methyl bromide (Bromomethane)	131	8.5E-03	1.1E-02	Wabash River test data
74-87-3	Methyl chloride (Chloromethane) (2)	68	4.4E-03	6.0E-03	Wabash River test data
71-55-6	Methyl chloroform (1,1,1 - Trichloroethane) (3)	1.2	7.8E-05	1.1E-04	AP-42, Table 1.1-14 (see Reference 2)

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Exhibit B-3 TANK VENT BOILER HAPs EMISSION SUMARY
(Phase I)

Syngas fuel consumption rates

65 x 10^6 Btu/hr, HHV (max, use for short-term emission calculation)
20 x 10^6 Btu/hr, HHV (avg, use for annual emission calculation)

CAS # or MPCA #	Compound	Emission Factor ($lb/10^{12}$ Btu syngas) (1)	Short-term Emission, 1-hr and 30-day avg (lb/hr)	Annual Emission (ton/yr)	Emission Factor Source
78-93-3	Methyl ethyl ketone (2-Butanone)	23.5	1.5E-03	2.1E-03	AP-42, Table 1.1-14 (see Reference 2)
60-34-4	Methyl hydrazine	10.2	6.7E-04	9.0E-04	AP-42, Table 1.1-14 (see Reference 2)
80-62-6	Methyl methacrylate	1.2	7.8E-05	1.1E-04	AP-42, Table 1.1-14 (see Reference 2)
1634-04-4	Methyl tert butyl ether	2.1	1.4E-04	1.8E-04	AP-42, Table 1.1-14 (see Reference 2)
3697-24-3	Methylchrysene, 5-	0.0013	8.5E-08	1.1E-07	AP-42, Table 1.1-13 (see Reference 2)
75-09-2	Methylene chloride (Dichloromethane) (2)	6.3	4.1E-04	5.5E-04	Wabash River test data
91-20-3	Naphthalene (2)	9.2	6.0E-04	8.1E-04	Wabash River test data
7440-02-0	Nickel	47.9	3.1E-03	4.2E-03	Wabash River test data
108-95-2	Phenol	135	8.8E-03	1.2E-02	Wabash River test data
123-38-6	Proprionaldehyde	22.9	1.5E-03	2.0E-03	AP-42, Table 1.1-14 (see Reference 2)
7784-49-2	Selenium	2.7	1.8E-04	2.4E-04	Wabash River test data
100-42-5	Styrene	1.51	9.8E-05	1.3E-04	AP-42, Table 1.1-14 (see Reference 2)
7664-93-9 14808-79-8	Sulfuric acid and sulfates	2,530	1.6E-01	2.2E-01	(See Note 6)
127-18-4	Tetrachloroethylene (Perchloroethylene) (3)	2.59	1.7E-04	2.3E-04	AP-42, Table 1.1-14 (see Reference 2)
108-88-3	Toluene (2)	128	8.3E-03	1.1E-02	Wabash River test data
108-05-4	Vinyl acetate	0.46	3.0E-05	4.0E-05	AP-42, Table 1.1-14 (see Reference 2)
1330-20-7	Xylenes (2)	145	9.4E-03	1.3E-02	Wabash River test data

Notes:
(1) Emission factors are based on Wabash River test data where available. Otherwise, the same NETL IGCC or AP-42 coal combustion average emission factors are used as for the CTGs.
(2) Wabash test results show "non-detects" for benzo(a)pyrene, cyanide, methyl chloride, methylene chloride, naphthalene, toluene, and xylenes. The values shown in the table are one-half the values of the reported detection limits, except for benzo(a)pyrene where the AP-42 coal combustion factor is used because the reported detection limits are four orders of magnitude greater than the AP-42 factor.
(3) Wabash test results show only non-detects for chloroform, trichloroethane, and tetra chloro ethane with no detection limits reported. The values shown are the AP-42 coal combustion factors.
(4) AP-42 Section 1.1 gives only a factor for benzo(b,j,k)fluoranthene. This factor shown on table in the cell for the "k" isomer.
(5) Hydrofluoric acid is estimated using the fraction of total feed fluorine measured in the LGTI incinerator stack, as reported in Reference 2, and the highest expected concentrations of fluorine in the Mesaba feed steams. (See AP-24/NETL calculation spreadsheet.)
(6) Sulfuric acid and sulfates calculated using same emission factor as CTGs.

References:
(1) NETL - National Energy Technology Laboratory, U.S. Dept of Energy, *Major Environmental Aspects of Gasification-based Power Generation Technologies, Final Report*, December 2002.
(2) AP-42 - U.S. EPA, *Compilation of Air Pollutant Emission Factors, Vol 1, Fifth Ed (Publication AP-42)*, January 1995.

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Exhibit B-4 Flare HAPs

Mesaba Energy Project
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Exhibit B-4 FLARE HAPs EMISSION SUMMARY
(Phase I)

Syngas combustion rates

3730 x 10^6 Btu/hr, HHV (maximum 1-hr avg) (Note 1)
260 x 10^6 Btu/hr, HHV (maximum 30-day avg)
50 x 10^6 Btu/hr, HHV (annual avg)

CAS # or MPCA #	Compound	Emission Factor ($lb/10^{12}$ Btu syngas) (2)	Short-term Emission (lb/hr) 1-hr avg	Short-term Emission (lb/hr) 30-day avg	Annual Emission (ton/yr)	Emission Factor Source
75-07-0	Acetaldehyde	1.8	6.7E-03	4.7E-04	3.9E-04	NETL, Table 2-17 (see Reference 1)
98-86-2	Acetophenone	0.90	3.4E-03	2.3E-04	2.0E-04	AP-42, Table 1.1-14 (see Reference 2)
107-02-8	Acrolein	17.5	6.5E-02	4.6E-03	3.8E-03	AP-42, Table 1.1-14 (see Reference 2)
7440-36-0	Antimony	3.2	1.2E-02	8.3E-04	7.0E-04	Wabash River test data
7440-38-2	Arsenic	16.9	6.3E-02	4.4E-03	3.7E-03	Wabash River test data
56-55-3	Benz[a]anthracene	0.0023	8.6E-06	6.0E-07	5.0E-07	NETL, Table 2-17 (see Reference 1)
71-43-2	Benzene	323	1.2E+00	8.4E-02	7.1E-02	Wabash River test data
207-08-9	Benzo(k)fluoranthene	0.0066	2.5E-05	1.7E-06	1.4E-06	AP-42, Table 1.1-13 (see Reference 2)
50-32-8	Benzo[a]pyrene	0.0023	8.6E-06	6.0E-07	5.0E-07	AP-42, Table 1.1-13 (see Reference 2)
100-44-7	Benzyl chloride	42.2	1.6E-01	1.1E-02	9.2E-03	AP-42, Table 1.1-14 (see Reference 2)
7440-41-7	Beryllium	0.09	3.4E-04	2.3E-05	2.0E-05	NETL, Table 2-11 (see Reference 1)
92-52-4	Biphenyl	0.10	3.8E-04	2.7E-05	2.2E-05	AP-42, Table 1.1-13 (see Reference 2)
117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)	4.4	1.6E-02	1.1E-03	9.6E-04	AP-42, Table 1.1-14 (see Reference 2)
75-25-2	Bromoform	2.3	8.6E-03	6.0E-04	5.0E-04	AP-42, Table 1.1-14 (see Reference 2)
7440-43-9	Cadmium	0.65	2.4E-03	1.7E-04	1.4E-04	Wabash River test data
75-15-0	Carbon disulfide	46	1.7E-01	1.2E-02	1.0E-02	NETL, Table 2-17 (see Reference 1)
532-27-4	Chloroacetophenone, 2-	0.42	1.6E-03	1.1E-04	9.2E-05	AP-42, Table 1.1-14 (see Reference 2)
108-90-7	Chlorobenzene	1.3	4.8E-03	3.4E-04	2.8E-04	AP-42, Table 1.1-14 (see Reference 2)
67-66-3	Chloroform	3.6	1.3E-02	9.4E-04	7.9E-04	AP-42, Table 1.1-14 (see Reference 2)
0-00-5	Chromium, total	12	4.5E-02	3.1E-03	2.6E-03	Wabash River test data
18540-29-9	Chromium, (hexavalent)	3.6	1.3E-02	9.4E-04	7.9E-04	Portion of total chromium emitted in +6 valenece state, assumed to be 30% of total (see permit application, Section 4.2).
218-01-9	Chrysene (Benzo(a)phenanthrene)	0.006	2.2E-05	1.6E-06	1.3E-06	AP-42, Table 1.1-13 (see Reference 2)
7440-48-4	Cobalt	13.7	5.1E-02	3.6E-03	3.0E-03	Wabash River test data
98-82-8	Cumene	0.30	1.1E-03	7.8E-05	6.6E-05	AP-42, Table 1.1-14 (see Reference 2)
57-12-5	Cyanide (Cyanide ion, Inorganic cyanides, Isocyanide)	53	2.0E-01	1.4E-02	1.2E-02	Wabash River test data
77-78-1	Dimethyl sulfate	2.9	1.1E-02	7.5E-04	6.3E-04	AP-42, Table 1.1-14 (see Reference 2)
121-14-2	Dinitrotoluene, 2,4-	0.017	6.3E-05	4.4E-06	3.7E-06	AP-42, Table 1.1-14 (see Reference 2)
100-41-4	Ethyl benzene	362	1.4E+00	9.4E-02	7.9E-02	Wabash River test data
75-00-3	Ethyl chloride (Chloroethane)	2.5	9.3E-03	6.5E-04	5.5E-04	AP-42, Table 1.1-14 (see Reference 2)
106-93-4	Ethylene dibromide (Dibromoethane)	0.072	2.7E-04	1.9E-05	1.6E-05	AP-42, Table 1.1-14 (see Reference 2)
107-06-2	Ethylene dichloride (1,2-Dichloroethane)	2.4	9.0E-03	6.2E-04	5.3E-04	AP-42, Table 1.1-14 (see Reference 2)
50-00-0	Formaldehyde	17	6.3E-02	4.4E-03	3.7E-03	NETL, Table 2-17 (see Reference 1)
110-54-3	Hexane	4.0	1.5E-02	1.0E-03	8.8E-04	AP-42, Table 1.1-14 (see Reference 2)
7647-01-0	Hydrochloric acid	3.4	1.3E-02	8.8E-04	7.4E-04	Wabash River test data (for syngas)
7664-39-3	Hydrogen fluoride (Hydrofluoric acid)	0.6	2.2E-03	1.6E-04	1.3E-04	NETL, Table 2-5 (see Reference 1)
193-39-5	Indeno(1,2,3-cd)pyrene	0.0037	1.4E-05	9.6E-07	8.1E-07	AP-42, Table 1.1-13 (see Reference 2)
78-59-1	Isophorone	34.9	1.3E-01	9.1E-03	7.6E-03	AP-42, Table 1.1-14 (see Reference 2)
7439-92-1	Lead	0.72	2.7E-03	1.9E-04	1.6E-04	Wabash River test data (for syngas)
7439-96-5	Manganese	27.1	1.0E-01	7.0E-03	5.9E-03	Wabash River test data
7439-97-6	Mercury (3)	0.75	2.8E-03	2.0E-04	1.6E-04	Wabash River test data, reduced by 90%
74-83-9	Methyl bromide (Bromomethane)	131	4.9E-01	3.4E-02	2.9E-02	Wabash River test data
74-87-3	Methyl chloride (Chloromethane)	68	2.5E-01	1.8E-02	1.5E-02	AP-42, Table 1.1-14 (see Reference 2)
71-55-6	Methyl chloroform (1,1,1 - Trichloroethane)	1.2	4.5E-03	3.1E-04	2.6E-04	AP-42, Table 1.1-14 (see Reference 2)
78-93-3	Methyl ethyl ketone (2-Butanone)	23.5	8.8E-02	6.1E-03	5.1E-03	AP-42, Table 1.1-14 (see Reference 2)
60-34-4	Methyl hydrazine	10.2	3.8E-02	2.7E-03	2.2E-03	AP-42, Table 1.1-14 (see Reference 2)
80-62-6	Methyl methacrylate	1.2	4.5E-03	3.1E-04	2.6E-04	AP-42, Table 1.1-14 (see Reference 2)

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Exhibit B-4 FLARE HAPs EMISSION SUMMARY
(Phase I)

Syngas combustion rates

3730 x 10^6 Btu/hr, HHV (maximum 1-hr avg) (Note 1)
260 x 10^6 Btu/hr, HHV (maximum 30-day avg)
50 x 10^6 Btu/hr, HHV (annual avg)

CAS # or MPCA #	Compound	Emission Factor (lb/10^12 Btu syngas) (2)	Short-term Emission (lb/hr) 1-hr avg	Short-term Emission (lb/hr) 30-day avg	Annual Emission (ton/yr)	Emission Factor Source
1634-04-4	Methyl tert butyl ether	2.1	7.8E-03	5.5E-04	4.6E-04	AP-42, Table 1.1-14 (see Reference 2)
3697-24-3	Methylchrysene, 5-	0.0013	4.8E-06	3.4E-07	2.8E-07	AP-42, Table 1.1-13 (see Reference 2)
75-09-2	Methylene chloride (Dichloromethane)	6.3	2.3E-02	1.6E-03	1.4E-03	Wabash River test data
91-20-3	Naphthalene	9.2	3.4E-02	2.4E-03	2.0E-03	Wabash River test data
7440-02-0	Nickel	47.9	1.8E-01	1.2E-02	1.0E-02	Wabash River test data
108-95-2	Phenol	135	5.0E-01	3.5E-02	3.0E-02	Wabash River test data
123-38-6	Proprionaldehyde	22.9	0.085	0.0060	0.0050	AP-42, Table 1.1-12 (see Reference 2)
7784-49-2	Selenium	2.7	1.0E-02	7.0E-04	5.9E-04	Wabash River test data
100-42-5	Styrene	1.51	5.6E-03	3.9E-04	3.3E-04	AP-42, Table 1.1-14 (see Reference 2)
7664-93-9 14808-79-8	Sulfuric acid and sulfates	2,530	9.4E+00	6.6E-01	5.5E-01	(See Note 4)
127-18-4	Tetrachloroethylene (Perchloroethylene)	2.59	9.7E-03	6.7E-04	5.7E-04	AP-42, Table 1.1-14 (see Reference 2)
108-88-3	Toluene	128	4.8E-01	3.3E-02	2.8E-02	Wabash River test data
108-05-4	Vinyl acetate	0.46	1.7E-03	1.2E-04	1.0E-04	AP-42, Table 1.1-14 (see Reference 2)
1330-20-7	Xylenes	145	5.4E-01	3.8E-02	3.2E-02	Wabash River test data

Notes:
(1) Combustion rates shown are assumed worst-case to allow for planned plant startup and shut down operations as well as an allowance for unplanned operational upsets such as combustion turbine trips and pressure safety valve releases. Only treated syngas will be combusted in the flare during planned flaring events.
(2) No Wabash River emission test data are available for the flare. HAPs emissions are estimated using the same emission factors as the tank vent boiler and the assumed syngas combustion rate in the flare. The notes for the tank vent incinerator HAPs emission summary also apply to the flare.
(3) Mercury emission factor based on the TVB factor reduced by 90 %, since most gas routed to the flare will flow through the normal syngas treating system, including the activated carbon beds for mercury removal.
(4) Sulfuric acid calculated asuming 7% of SOx in combustion products converts to SO3 which reacts with water to form H2SO4.
Assuming 100 ppmvd total sulfur in flared gas and about 275 Btu/ft3 HHV,
Sulfuric acid = 0.07 x 100 ft3/10^6 ft3 x 1 ft3/275 Btu x 98 lb/380 ft3 = 6565 lb/10^12 Btu

References:
(1) NETL - National Energy Technology Laboratory, U.S. Dept of Energy, *Major Environmental Aspects of Gasification-based Power Generation Technologies, Final Report,* December 2002.
(2) AP-42 - U.S. EPA, *Compilation of Air Pollutant Emission Factors, Vol 1, Fifth Ed (Publication AP-42),* January 1995.

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Exhibit B-5 Fugitive HAPs Emission Summary

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Exhibit B-5 FUGITIVE HAPs EMISSION SUMMARY
(Phase I)

Process Stream[1]		Raw Syngas			SourSyngas			Product Syngas			Acid Gas			SRU and Tail Gas			Sour CO2 gas		
Total process fluid leak rate, lb/hr[2]		8.7			6.0			1.5			2.0			13.1			0.7		
CAS # or MPCA #	Compound	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr
	Federal HAPs																		
71-43-2	Benzene	95	A	0.0008	95	A	0.0006	20	A	3.0E-05									
75-15-0	Carbon disulfide	575	A	0.0050	438	A	0.0026	2.7	A	4.1E-06									
463581	Carbonyl sulfide	1,300	B	0.011	83	B	0.00050	4.8	B	0.000007	700	B	0.0014				30.0	B	0.000021
100-41-4	Ethyl benzene	0.076	A	6.63E-07	0.076	A	4.55E-07	0.076	A	1.153E-07									
50-00-0	Formaldehyde	0.016	A	1.4E-07	0.016	A	9.57E-08	0.016	A	2.427E-08									
110-54-3	Hexane	0.021	A	1.8E-07	0.021	A	1.3E-07	0.021	A	3.2E-08									
7647-01-0	Hydrochloric acid	0.017	A	1.5E-07	0.017	A	1.0E-07	0.017	A	2.6E-08									
74-90-8	Hydrogen cyanide	83	B	0.00072	83	B	0.00050	0	B	0							1,000	B	0.0007
81-20-3	Naphthalene	0.4	A	3.5E-06	0.4	A	2.4E-06	0.008	A	1.2E-08									
108-95-2	Phenol	0.0011	A	9.6E-09	0.0011	A	6.6E-09	0.0011	A	1.7E-09									
108-88-3	Toluene	10.3	A	0.00009	10.3	A	6.16E-05	0.066	A	1.0E-07									
1330-20-7	Xylenes	0.14	A	1.22E-06	0.14	A	8.37E-07	0.14	A	2.124E-07									
	Total Federal HAPs			0.018			0.004			4.2E-05			0			0			0.0007
	Other																		
7664-41-7	Ammonia	4,000	B	0.035	6.5	B	3.9E-05	0	B	0							74,000	B	0.051
7783-06-4	Hydrogen sulfide	15,000	B	0.13	18,000	B	0.11	50	B	7.6E-05	460,000	B	0.92	58,000	B	0.76	27,000	B	0.019
	MDEA																		
	VOC[4]			0.018			0.004			0.000			0.001			0.000			0.001
	TRS[5]			0.15			0.11			8.7E-05			0.83			0.76			0.02

Process Stream		Rich MDEA			Lean MDEA			Sour Water			Stripped Sour Water			Recoverd Oil			Total Estimated Gaseous Fugitive Emissions		
Total process fluid leak rate, lb/hr[2]		1.5			1.7			1.3			0.5			0.3					
CAS # or MPCA #	Compound	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr		lb/hr	ton/yr
	Federal HAPs																		
71-43-2	Benzene																	0.0014	0.0063
75-15-0	Carbon disulfide																	0.008	0.034
463581	Carbonyl sulfide	25	B	3.9E-05				2	B	2.7E-06								0.013	0.058
100-41-4	Ethyl benzene																	1.2E-06	5.4E-06
50-00-0	Formaldehyde																	2.6E-07	1.1E-06
110-54-3	Hexane																	3.4E-07	1.5E-06
7647-01-0	Hydrochloric acid							4000	B	0.005	4700	B	0.002					0.008	0.034
74-90-8	Hydrogen cyanide							70	B	0.00009								0.0020	0.0088
81-20-3	Naphthalene																	5.9E-06	2.6E-05
108-95-2	Phenol																	1.8E-08	7.8E-08
108-88-3	Toluene																	0.00015	6.6E-04
1330-20-7	Xylenes																	2.3E-06	1.0E-05
	Total Federal HAPs			0			0			0.005			0.002			0		***0.032***	***0.14***
	Other																		
7664-41-7	Ammonia			0			0	30,000	B	0.04	300	B	0.0002			0		0.1	0.6
7783-06-4	Hydrogen sulfide	20,000	B	0.03	350	B	0.0006	1,500	B	0.0020			0			0		2.0	8.6
	MDEA	500,000	B	0.8	500,000	B	0.8			0			0			0		1.6	7.1
	VOC[4]			0.774			0.849			0.000			0.000	1E+06	B	0.25		1.9	8.3
	TRS[5]			0.03			0			0.0020			0			0		2.0	8.7

[1]Process stream descriptions for fugitive emission estimates:

Stream	Description	Stream	Description
Raw syngas	Gasifier outlet to COS hyrolysis reactor outlet	Rich amine	H2S/CO2-laden MDEA from absorber to acid gas stripper
Sour syngas	Hydrolysis reactor outlet to AGR/AGE absorbers overhead	Lean amine	Regenerated amine from stripper to absorber (incl storage)
Product syngas	AGR/AGE to CTGs	Sour water	Sour water from various sources to sour water stripper
Acid gas	Acid gas stripper overhead to SRU inlet	Stripped SW	Stripper bottoms to slurry recycle and ZLD
SRU and tail gas	SRU inlet through tail gas recycle to gasifier	Recovered oil	Oil recovered from drainage oily water separator
Sour CO2 gas	Sour water degassing column to AGR		

[2]Estimated fugitive emission quantities for the total process stream components based on U.S. EPA average emission factors (see next page). This value is multiplied by each component concentration to determine the individual component emission rates. ***Example:*** Benzene fugitive emission from raw syngas = 8.7 lb/hr x 95 lb/10^6 lb = 0.00083 lb/hr.
[3]Basis for emission factors; "A" denotes test results from the Wabash River gasification facility, "B" denotes calculated from the ConocoPhillips/Fluor material balance.
[4]Volatile organic compounds (VOC) include MDEA, benzene, carbon disulfide, carbonyl sulfide, ethyl benzene, hexane, hydrogen cyanide, naphthalene, toluene, and xylenes.
[5]Total reduced sulfur (TRS) includes carbon disulfide, carbonyl sulfide, and hydrogen sulfide.

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Exhibit B-5 FUGITIVE HAPs EMISSION SUMMARY
(Phase I)

Fugitve Emission Sources Estimates[1]

	Gas		Light Liquid		Heavy Liquid			Sample
Process Stream	Valves	Comp seals	Valves	Pumps	Valves	Pumps	Connectors	Connects
Raw syngas	510						500	1
Sour syngas	230	4					230	1
Product syngas	80						100	2
Acid gas	120						100	1
SRU and tail gas	480	9					560	
Sour CO2 gas	40						40	
Rich MDEA					350		340	
Lean MDEA					330	19	290	
Sour water					240	21	200	
Stripped sour water					120	2	100	
Recovered oil					30	4	40	
Totals	1460	13	0	0	1070	46	2500	5

Total Fugitive Emission Rates[2]

	Gas		Light Liquid		Heavy Liquid			Sample	
	Valves	Comp seals	Valves	Pumps	Valves	Pumps	Connectors	Connects	
Emission factor lb.hr/source	0.0131	0.502	0.00888	0.0438	0.00051	0.019	0.00403	0.033	Total
Process Stream	Estimated emission rate, lb/hr								
Raw syngas	6.68						2.02	0.03	8.73
Sour syngas	3.01	2.01					0.93	0.03	5.98
Product syngas	1.05						0.40	0.07	1.52
Acid gas	1.57						0.40	0.03	2.01
SRU and tail gas	6.29	4.52					2.26		13.06
Sour CO2 gas	0.52						0.16		0.69
Rich MDEA					0.18		1.37		1.55
Lean MDEA					0.17	0.36	1.17		1.70
Sour water					0.12	0.40	0.81		1.33
Stripped sour water					0.06	0.04	0.40		0.50
Recovered oil					0.02	0.08	0.16		0.25
									37.3
									163 tpy

[1]Emission source estimates based on conceptual equipment inventory for the Mesaba IGCC Power Station and an estimate from piping and instrumentation diagrams (P&IDs) for a similar E-Gas IGCC project. An allowance is added to account for valves and other components not shown on the P&IDs.
[2]Estimated emission rates for all components (including non-VOC and non-HAPs) in each process stream, based on *Protocol for Equipment Leak Estimates*, U.S EPA 453-R95-017, November 1995, Table 2-1.

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Exhibit B-6 HAP Metals Emission Factors

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Exhibit B-6 HAP METALS EMISSION FACTORS

The following two tables summarize the adjustment of the Wabash HAP emission factors for the worst case Mesaba feed metals content, assuming that the Wabash factors are representative of the Illinois Basin coal and pet coke feed. The first table compares the trace metal data available for the range of Mesaba solid feed streams for the metals that have been measured at Wabash River.and identifies the maximum values for each trace metal. The second table shows the calculation of the Mesaba worst case emission factors by multiplying the Wabash factors by the ratio of the worst case concentrations to the actual Wabash concentrations.

HAPs factors for metals corrected for worst case Mesaba feeds.

	Mean concentration in solid fuel, mg/kg					
Element	Jacobs Ranch[a]	Spring Creek[b]	Rawhide[c]	Illinois or Petcoke [d]	Flint Hills Coke[e]	Mesaba Worst Case
Antimony	0.5		0.86	3.5		3.5
Arsenic	5.1	1.5	1.2	7.6		7.6
Beryllium	0.40	0.21	0.22	1.8		1.8
Cadmium	0.30	0.16	0.18	7.6		7.6
Chromium	7	2.4	3.8	5.55		7.0
Cobalt	4		1.9	7.3		7.3
Lead	3.4	2.6	2.4	17.3		17.3
Manganese	30	16.2		12.33		30
Mercury			0.06			
Nickel	14	1.5		370	257	370
Selenium	2	1.2		3		3.0
Chlorides	147	0	130	100		147

Sources: a) Jacobs Ranch Mine Quality Specifications, Typical Upper Wyodak Product
b) Spring Creek Coal Mine 2005 Quality Specifications
c) Rawhide 2005 - 2007 Typical Analysis and production data base for 1993 - 2005
d) Larger value for Illinois Basin coal or Pine Bend petcoke.sources: Wabash River Coal Gasification Repowering Project Final Technical Report (coal slurry dry compositon data for 1997 and 1998) or Koch Refining data for Pine bend petcoke.
e) Sample Analysis of pertoleum coke for Flint Hill Resources, Commercial testing & Engineering Co., February 19, 2004

Emission Factor Adjustment for Treated Syngas

Element	Mesaba Worst Case Feed Conc, mg/kg	Wabash Actual Feed Conc, mg/kg	Wabash HAP Emission Factor lb/10^12 Btu coal	Calculated Worst Case Mesaba HAP Factor lb/10^12 Btu coal	
Antimony	3.5	3.5	1.1	1.1	
Arsenic	7.6	7.6	2.4	2.4	
Beryllium	1.81	1.81	0.26	0.26	
Cadmium	7.6	7.6	9.6	9.6	
Chromium	7.0	5.55	0.41	0.52	
Cobalt	7.3	7.3	0.26	0.26	
Lead	17.3	17.3	0.56	0.56	
Manganese	30	12.33	0.43	1.04	
Mercury	(see calculation below)			0.50	(90% O/A removal)
Nickel	370	370	0.39	0.39	
Selenium	3.0	3.0	0.56	0.56	
Chlorides	147	100	2.6	3.9	

Mercury based on Rawhide PRB feed, 0.06 ppmwd avg Hg, approx 12,000 Btu/lb HHV
Hg = (0.10) x 0.06 lb/10^6 lb /(12,000 Btu/lb) x 10^6/10^6 = 0.5 lb/10^12 Btu

Ex B-6 Metals Emission Factors Page 1 of 1

Exhibit B-7 AP-42 and NETL Coal HAP Emission Factors

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Exhibit B-7 AP-42 and NETL COAL HAP EMISSION FACTORS

CAS # or MPCA #	Chemical Name	Emission Factor used for HAPs calculation (lb/10^{12} Btu coal)	AP-42, Section 1.1 (lb/ton coal)	NETL IGCC Env Report, data from LGTI (lb/10^{12}Btu)	Comments
75-07-0	Acetaldehyde	1.8		1.8	NETL, Table 2-17
98-86-2	Acetophenone	0.90	0.000015		AP-42, Table 1.1-14, see Example Calulation (1)
107-02-8	Acrolein	17.5	0.00029		AP-42, Table 1.1-14
56-55-3	Benz[a]anthracene	0.0023		0.0023	NETL, Table 2-17
207-08-9	Benzo(k)fluoranthene	0.0066	1.10E-07		AP-42, Table 1.1-13
50-32-8	Benzo[a]pyrene	0.0023	3.80E-08		AP-42, Table 1.1-13
100-44-7	Benzyl chloride	42.2	0.0007		AP-42, Table 1.1-14
7440-41-7	Beryllium	0.090		0.09	NETL, Table 2-11
92-52-4	Biphenyl	0.10	1.70E-06		AP-42, Table 1.1-13
117-81-7	Bis(2-ethylhexyl)phthalate	4.40	0.000073		AP-42, Table 1.1-14
75-25-2	Bromoform	2.3	0.000039		AP-42, Table 1.1-14
75-15-0	Carbon disulfide	46		46	NETL, Table 2-17
532-27-4	Chloroacetophenone, 2-	0.42	0.000007		AP-42, Table 1.1-14
108-90-7	Chlorobenzene	1.3	0.000022		AP-42, Table 1.1-14
67-66-3	Chloroform	3.6	0.000059		AP-42, Table 1.1-14
218-01-9	Chrysene (Benzo(a)phenanthrene)	0.0060	1.00E-07		AP-42, Table 1.1-13
98-82-8	Cumene	0.32	0.0000053		AP-42, Table 1.1-14
57-12-5	Cyanide (cyanide ion, Inorganic cyanides, Isocyanide)	5.7		3.2 ug/Nm3 (CTG)	NETL, Table 2-6, see Example Calulation (2)
77-78-1	Dimethyl sulfate	2.9	0.000048		AP-42, Table 1.1-14
121-14-2	Dinitrotoluene, 2,4-	0.017	2.80E-07		AP-42, Table 1.1-14
100-41-4	Ethyl benzene	5.7	0.000094		AP-42, Table 1.1-14
75-00-3	Ethyl chloride (chloroethane)	2.5	0.000042		AP-42, Table 1.1-14
106-93-4	Ethylene dibromide	0.072	0.0000012		AP-42, Table 1.1-14
107-06-2	Ethylene dichloride (1,2-Dichloroethane)	2.4	0.00004		AP-42, Table 1.1-14
50-00-0	Formaldehyde	17		17	NETL, Table 2-17
110-54-3	Hexane	4.0	0.000067		AP-42, Table 1.1-14
7664-39-3	Hydrogen fluoride (hydrofluoric acid)	0.6 or 50		0.012% (TVB) or 1% (CTG) of fluoride in feed	NETL, Table 2-5, see Example Calulation (3)
193-39-5	Indeno(1,2,3-cd)pyrene	0.0037	6.10E-08		AP-42, Table 1.1-13
78-59-1	Isophorone	34.9	0.00058		AP-42, Table 1.1-14
74-87-3	Methyl chloride (chloromethane)	32	0.00053		AP-42, Table 1.1-14
71-55-6	Methyl chloroform (1,1,1-Trichloroethane)	1.20	2.00E-05		AP-42, Table 1.1-14
78-93-3	Methyl ethyl ketone (2-butanone)	23	0.00039		AP-42, Table 1.1-14
60-34-4	Methyl hydrazine	10	0.00017		AP-42, Table 1.1-14
80-62-6	Methyl methacrylate	1.2	0.00002		AP-42, Table 1.1-14
1634-04-4	Methyl tert butyl ether	2.1	0.000035		AP-42, Table 1.1-14
3697-24-3	Methyl chrysene, 5-	0.0013	2.20E-08		AP-42, Table 1.1-13
123-38-6	Proprionaldehyde	23	0.00038		AP-42, Table 1.1-14
100-42-5	Styrene	1.5	0.000025		AP-42, Table 1.1-14
127-18-4	Tetrachloroethylene (perchloroethylene)	2.6	0.000043		AP-42, Table 1.1-14
108-88-3	Toluene	0.033		0.033	NETL, Table 2-17
108-05-4	Vinyl acetate	0.46	0.0000076		AP-42, Table 1.1-14
1330-20-7	Xylenes	2.23	0.000037		AP-42, Table 1.1-14

Example calculations:

1) Worst case coal HHV (as received) to convert AP-42 factors
= 8300 Btu/lb HHV for PRB
Acetophenone = 0.000015 lb/ton x 1 ton/2000 lb x 1 lb/8300 Btu x $10^{12}/10^{12}$ =
= 0.90 lb/10^{12} Btu coal

2) Cynanide = 3.2 ug/m3 in CTG exhaust, assume CTG exhaust gas = 38,000 scf/10^6 Btu (see CTG HAPs calc for Wabash River) and about 0.75 overall coal conversion
= 3.2 g/10^6 m3 x 1 lb/454 g x 1 m3/35.3 ft3 x 38,000 scf/10^6 Btu SG x 0.75 Btu SG/Btu coal
= 5.7 lb/10^{12} Btu coal

3) Fluorides = 1% of fluorine in coal feed for CTGs, worst case PRB, 60 ppm F by wt, dry, 12,000 Btu/lb HHV, dry
= 0.01 x 60 lb F/10^6 lb coal x 1 lb/12,000 Btu x 10^6/10^6
= 50 lb/10^{12} Btu coal;
= 0.012% of fluorine in coal feed for TVB
= 0.6 lb/10^{12} Btu

Ex B-7 AP-42 and NETL factors Page 1 of 1

Exhibit B-8 Wabash River CTG HAPs

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Exhibit B-8 WABASH RIVER CTG HAPs

Assumptions

CTG exhaust flow = 40,000 scf(@ 15% O2)/10^6 Btu SG (based on Siemens perf summary)
Coal conversion = 0.77
Syngas HHV = 280 Btu/dscf

WABASH RIVER IGCC TEST DATA

Compound	Units	Nov-97 HRSG (coke)	Jan-98 HRSG (coal)	Use for HAP calc	Lb/10^12 Btu coal	
HAP Metals						
(based on metals per unit vol of syngas, see syngas spreadsheet)						
Antimony	mg/dscm (SG)			0.0065	1.1	
Arsenic	"			0.014	2.4	
Beryllium	"			0.0015	0.3	
Cadmium	"			0.05575	9.6	
Chromium	"			0.0024	0.41	
Cobalt	"			0.0015	0.26	
Lead				0.0033	0.56	
Manganese	"			0.0025	0.43	
Mercury	"	(Use 10% of worst feed)			0.50	
Nickel	"			0.0023	0.39	
Selenium	"			0.00325	0.56	
HAP Organics						
Benzene	ug/m3	2.06	0.539	1.30	2.5	
Bromomethane (methyl bromide)	ug/m3	52	0.255	26.13	50.2	
Chloromethane (methyl chloride)	ug/m3	ND	ND			
Methylene chloride	ug/m3	1.2	ND	1.2	2.31	
Chloroform		ND	ND			
1,1,1-trichloroethane		ND	ND			
Tetrachloroethane		ND	ND			
Benzo(a)pyrene	ug/m3	1.155	1.56	1.36	2.6	(used AP-42, instead)
Naphthalene	ug/m3	1.155	1.56	1.36	2.6	
Phenol	ug/m3	2.8	37.5	20.15	38.7	
Other HAPs						
Hydrogen chloride (MW=36.5)	ppmv	(based on syngas)		0.01	2.6	

	highlight denotes not detected, value shown is one-half reported detection limit
ND	denotes not detected, no detection limit reported

Example calculations

Antimony = 0.0065 mg/m3 x 1 lb/454x10^3 mg x 1 m3/35.3 ft3 x 1 ft3/280 Btu x 0.77 x 10^12 = 1.1 lb/10^12 Btu coal

Mercury (worst-case PRB) = 0.06 ppmw = 0.06 lb/10^6 lb x 1 lb/12,000 Btu x 0.1 x 10^6 = 0.50 lb/10^12 Btu coal (dry, HHV)

Benzene = 1.30 ug/m3 x 1 lb/454x10^6 ug x 1 m3/35.3 ft3 x 40000 ft3/10^6 Btu x 0.77 = 2.5 lb10^12 Btu coal

HCl = 0.01 scf/10^6 scf x 36.5 lb/380 scf x 1 scf/280 Btu x 0.77 x 10^6/10^6 = 2.64 lb/10^12 Btu coal

Exhibit B-8 WR CTG Page 1 of 1

Exhibit B-9 Wabash River Syngas HAPs

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Exhibit B-9 WABASH RIVER SYNGAS HAPs

Assumptions
syngas HHV = 280 Btu/dscf
syngas MW = 21 lb/lbmol

1 gmole = 24.0 x 10^-3 m3 @ 293 K

WABASH RIVER IGCC TEST DATA

		May-97		October 1998		September 1999		Mar-03	Nov-05	Use for	Use for Fugitive HAP calc			ppm (wt)			Lb/10^12 Btu syngas
Compound	Units	Raw Syngas	Sour Syngas	Raw Syngas	Sour Syngas	Raw Syngas	Sour Syngas	Product Syngas	Product Syngas	fuel comb HAP calc	Raw Syngas	Sour Syngas	Product Syngas	Raw Syngas	Sour Syngas	Product Syngas	Product Syngas
HAP Metals																	
Antimony	mg/dscm	< 0.03	<0.037	0.006	< .001	0.004	0.0065			0.0065	N/A	N/A	N/A				1.45
Arsenic	"	0.1	0.1133	0.294	0.0305	0.0401	0.0996	0.005	0.0231	0.014	N/A	N/A	N/A				3.13
Beryllium	"								0.0015	0.0015	N/A	N/A	N/A				0.33
Cadmium	"	<0.0017	<0.0019	0.0005	0.0004	0.0006	0.0011	0.11	0.0015	0.056	N/A	N/A	N/A				12.42
Chromium	"	1.33	0.0916	1.191	0.0096	0.1256	0.0527		0.0024	0.0024	N/A	N/A	N/A				0.53
Cobalt	"	0.009	<0.0038	0.014	0.0019	0.002	0.0041		0.0015	0.0015	N/A	N/A	N/A				0.33
Lead								0.005	0.0015	0.003	N/A	N/A	N/A				0.72
Manganese	"	0.805	0.124	0.328	0.0219	0.1249	0.0706		0.0025	0.0025	N/A	N/A	N/A				0.56
Mercury	"	0.016	0.038	0.075	0.0446	< 0.0036	0.011	0.005	0.0015	0.003	N/A	N/A	N/A				0.72
Nickel ( )	"	0.266	0.038	0.796	0.106	0.2378	0.093		0.0023	0.0023	N/A	N/A	N/A				0.51
Selenium	"	0.755	0.033	0.314	0.0026	0.056	0.0095	0.005	0.0015	0.003	N/A	N/A	N/A				0.72
HAP Organics																	
Benzene (MW=78)	ppmv	39		25		13		6.3	4.5	N/A	25.7	25.7	5.4	95	95	20	
Hexane (MW=86)	ppmv							0.005		N/A	0.005	0.005	0.005	0.021	0.021	0.021	
Ethyl-benzene (MW=106)	ppmv							0.005	0.025	N/A	0.015	0.015	0.015	0.076	0.076	0.076	
Formaldehyde (MW=30)	mg/dscm								0.014	N/A			0.0140			0.016	
Toluene (MW=92)	ppmv		0.192		0.055		6.8	0.005	0.025	N/A	2.3	2.3	0.015	10.3	10.3	0.066	
xylenes (MW=106)	ppmv							0.005	0.05	N/A	0.028	0.028	0.028	0.14	0.14	0.14	
Phenol	mg/dscm								0.001	N/A			0.0010			0.0011	
Naphthalene (MW = 128)	mg/dscm		<0.165		0.244		0.454		0.007	N/A	0.349	0.349	0.0070	0.40	0.40	0.0080	
Carbon disulfide (MW = 76)	ppmv	< 333	167	< 333	167	159	31	1.18	0.32	N/A	159	121	0.75	575	439	2.7	
Other HAPs																	
Hydrogen Chloride (MW=36.5)	ppmv							0.010		0.010	0.01	0.01	0.01	0.017	0.017	0.017	3.4

highlight denotes not detected, value shown is one-half reported detection limit

Example calculations
(See also CTG spreadsheet)

Antimony = 0.0065 mg/m3 x 1 lb/454x10^3 mg x 1 m3/35.3 ft3 x 1 ft3/280 Btu x 10^12 = 1.45 lb/10^12 Btu syngas

Benzene = 19 ppmv = 19 lbmol Bz/10^6 lbmol SG x 78 lb/lbmol Bz/21 lb/lbmol SG = 71 ppm(wt)

Naphthalene = 0.349 mg/m3 x (24 x10^-3 m3 SG)/(21 x 10^3 mg) = 0.40 ppm(wt)

Hydrogen chloride = 0.01 ppmv = 0.01 ft3/10^6 ft3 x 36.5 lb/380 ft3 x 1 scf/280 Btu x 10^6/10^6 = 3.4 lb/10^12 Btu

Exhibit B-9 WR Syngas Page 1 of 1

Exhibit B-10 Wabash River TVB HAPs

Mesaba Energy Project
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05/03/2006

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Exhibit B-10 WABASH RIVER TVB HAPs

Assumptions
TVI flue gas flow = 30,000 dscf/10^6 Btu (@ 13% O2), see below

WABASH RIVER IGCC TEST DATA

Compound	Units	May-97 TGI Stack	Nov-97 TGI Stack (coke)	Jan-98 TGI Stack (coal)	Oct-98 TGI Stack	Sep-99 TGI Stack	Nov-05 TGI Stack	Use for HAP calc	Lb/10^12 Btu gas
HAP Metals									
Antimony	mg/dscm	0.0045			0.00038	0.000195		0.0017	3.2
Arsenic	"	0.0138			0.0129	0.00866	0.0008	0.0090	16.9
Cadmium	"	0.00023			0.00032	0.000134	0.0007	0.00035	0.65
Chromium	"	0.0086			0.00655	0.00872	0.0017	0.0064	12.0
Cobalt	"	0.0006			0.000424	0.0275	0.0007	0.0073	13.7
Manganese	"	0.0358			0.0107	0.0101	0.0014	0.0145	27.1
Mercury	"	0.00375			0.00922	0.00152	0.0015	0.0040	7.5
Nickel	"	0.0037	0.0481	0.0103	0.00792	0.0818	0.0018	0.026	47.9
Selenium	"	0.0045			0.00011	0.000483	0.0007	0.0014	2.7
HAP Organics									
Benzene (MW = 78)	ug/m3	813	25.6	14.8	141.4	17.6	24.1	173	323
Bromomethane (methyl bromide)	ug/m3		137	ND			3.5	70	131
Chloromethane (methyl chloride)	ug/m3		64	8.6				36	68
Methylene chloride	ug/m3		1.7	5.1				3.4	6.3
Chloroform			ND	ND					
1,1,1-trichloroethane			ND	ND					
Tetrachloroethane			ND	ND					
Ethyl-benzene (MW = 94)	ppmv	0.15			0.0435	0.0012	0.00026	0.049	362
Toluene (MW= 92)	ppmv	0.025			0.0435	0.0012	0.0006	0.018	128
xylenes (MW= 107)	ppmv	0.0235			0.0435	0.0012	0.00026	0.017	145
Benzo(a)pyrene	ug/m3		1.4	12.9				7.1	13.4
Naphthalene	ug/m3		1.4	12.9			0.4	4.9	9.2
Phenol	ug/m3	222	3.12	166	4.4	37.2	0.8	72	135
Cyanide	mg/dscm	0.068			0.016		0.0014	0.028	53

highlight denotes not detected, value shown is one-half reported detection limit
ND denotes not detected, no detection limit reported

TVB flue gas calc: Based on data from Mesaba CTG supplier, CTG exhaust gas for syngas fuel = approx 40,000 dscf (@ 15% O2)/10^6 Btu, HHV
Based on test data, Wabash TVB typically operates at about 13% O2 (dry).
Convert CTG flue gas to 13% O2 = 40,000 x (0.2095 - 0.15)/(0.2095 - 0.13) = 29937 , so use about 30,000 dscf (@13@ O2)/10^6 Btu,

Example HAP factor: Antimony = 0.00029 mg/m3 x (1 lb/454 x 10^3 mg) x 0.3048^3 m3/ft3 x 30,000 ft3/10^6 Btu x 10^3/10^3 = 3.17 lb/10^12 Btu

Exhibit B-10 WR TVB Page 1 of 1

APPENDIX C

AIR MODELING PROTOCOL

AIR QUALITY MODELING PROTOCOL
CLASS I AREA IMPACT ANALYSES

EXCELSIOR ENERGY
MESABA ENERGY PROJECT

January, 2006
Revised June 2006

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MMA Project Number 1877-05

1.0 INTRODUCTION

Excelsior Energy Inc. ("Excelsior"), an energy development company based in Minnetonka, Minnesota has created two wholly-owned project companies, MEP-I LLC and MEP-II LLC (MEP-I LLC and MEP-II LLC, together, the "Company") to construct, own and operate at a site in Northeastern Minnesota a 1,212 megawatt$_{(net)}$ integrated gasification combined cycle ("IGCC") steam electric power generating station (hereafter, the "IGCC Power Station") fueled by coal and other solid, petroleum-based feedstocks. The IGCC Power Station consists of Phase I and Phase II of the Mesaba Energy Project each phase of which is nominally rated at peak to deliver 606 meagawatts$_{(net)}$ of electricity to the bus bar of the high voltage switchyard located within the IGCC Power Station's fenced boundary. The IGCC Power Station will be located in Itasca County within the city limits of Taconite. Approximate UTM coordinates (NAD83) for the site center are 472,210m E, 5,243,370m N.

The IGCC Power Station will require PSD new source review, including an evaluation of impacts on Class I areas. The present document comprises an Air Quality Modeling Protocol, describing the methodology proposed for analysis of Class I impacts. It is being submitted to the Minnesota Pollution Control Agency (MPCA) and the cognizant Federal Land Managers (FLMs) for review and comment.

The Class I analyses will address impacts to the Boundary Waters Canoe Area (BWCA), Voyageurs National Park (VNP) and the Rainbow Lakes Wilderness (RLW). The distance from the IGCC Power Station to the closest point in each of these Class I areas is approximately 61 miles (98 km) for the BWCA, 75 miles (121 km) for VNP, and 117 miles (188 km) for RLW. The next closest Class I area, Isle Royale National Park, is more than 300 km from the station, beyond the distance where long-range transport modeling has been shown to provide realistic impact predictions.

This Protocol has been developed in accordance with the U.S. EPA Guideline on Air Quality Models (40 CFR Part 51, Appendix W), the IWAQM Phase 2 report (December, 1998), and the Phase I FLAG report (December 2000). Excelsior representatives and their consultants met with the U.S. Forest Service in Duluth on September 20, 2005, and with the National Park Service in Denver on November 9, 2005 to discuss Class I issues and analyses. Information from those meetings has been incorporated in this Protocol. Because of schedule requirements, some Class I analyses have been conducted prior to submittal of this protocol. The methodology that has been applied, as well as potential refinements that will be implemented in an updated analysis, are described herein.

2.0 IGCC POWER STATION AIR POLLUTANT EMISSIONS

Table 2-1 shows estimated annual emissions of criteria pollutants for each phase of the two-phase IGCC Power Station. Based upon these data, the IGCC Power Station will be a major stationary source to be located in a PSD area, and will therefore be subject to PSD new source review permitting requirements for each of the pollutants shown.

The primary emission sources at the IGCC Power Station will be combustion turbines (two turbines and stacks for each phase), tank vent boilers, flares, and auxiliary boilers (one of each per phase). Other sources will include evaporative cooling towers, material handling operations, and emergency diesel generators and fire pumps. The emergency sources will only operate for short time periods, generally when other sources are not in operation.

Emissions of air pollutants will be minimized through the inherently low-emission IGCC technology and application of BACT to the emission units. Controls will include diluent injection and good combustion practices for the combustion turbines, and optimum design and combustion practices for the tank vent boilers, flares, and other combustion sources. Cooling tower emissions will be controlled by high efficiency drift eliminators, and fugitive particulate matter emissions will be controlled by enclosures and dust suppressant spray systems.

During normal operation of the full two-phase IGCC Power Station, the only significant air pollutant emissions will be from the combustion turbines and tank vent boilers. During short periods when flaring of syngas takes place, SO_2 emissions from the flares will exceed total facility SO_2 emissions for normal operation. However, at these times facility NO_x and PM10 emissions will be much less than normal. The combustion turbines may for limited time periods operate on natural gas rather than syngas. During these times NO_x emission rates will be slightly higher than for syngas operation, but SO_2 emissions will be very low. Therefore, the normal operation scenario represents highest combined-source pollutant emissions; only normal operation emissions will be modeled for the Class I analyses.

Pollutant emission rates for long-range transport modeling represent maximum expected emissions for a two-phase plant for the appropriate averaging periods. All maximum emission rates and stack emission parameters are based upon engineering design specifications, as documented in the formal air permit application. Modeling parameters for Class I analyses are given in Table 2-2.

Speciation of particulate matter emissions from the combustion turbines, as shown in Table 2-2, was based on available data for IGCC Power Station sources and Federal Land Manager (FLM) guidance on emissions from natural gas-fired turbines. The total particulate emissions (filterable plus condensable) and total sulfuric acid emissions are from Mesaba design specifications. The partitioning of filterable and condensable fractions, elemental carbon emissions, and organic aerosol emissions were calculated using the FLM consensus methodology. All filterable particulate was assumed to be elemental carbon less than 2.5 microns in diameter. All particulate emissions from the tank vent boilers were assumed to be $PM_{2.5}$. Calculations are shown in Table 2-3.

Table 2-1. Worst-Case Annual Emissions (Tons/year) Excelsior IGCC Power Station (for each Phase)

Source	SO_2	NO_x	CO	VOC	PM10
Combustion Turbines (total for two)	666	1386	964	88	220
Tank Vent Boiler	15.8	26.4	7.9	0.4	0.9
Auxiliary Boiler	0.4	5.1	10.5	0.6	0.7
Flare	12.3	13.4	285.9	1.3	1.7
Cooling Towers					19.7
Coal Handling					2.0
Slag Handling					1.0
Coal Slurry Facility					0.2
Total	694.5	1430.9	1268.3	90.3	246.2

Table 2-2. Modeling Parameters For Mesaba CALPUFF Modeling

Parameter	Combustion Turbines (each of four)	Tank Vent Boilers (each of two)
stack height (m)	45.72	64.01
stack diameter (m)	6.1	1.83
temp (K)	394.3	579.8
velocity (m/s) – short-term	20.1	8.46
annual	20.1	1.95
SO_2 - 3-hr (g/s)	19.15	0.94
24-hr	14.36	0.81
annual	9.58	0.45
NO_x - 3-hr (g/s)	19.66	2.46
24-hr	19.66	2.46
annual	19.91	0.76
Elemental Carbon (g/s) all time periods	0.787	0
Sulfate (g/s) all time periods	0.945	0
Organic aerosol (g/s) all time periods	1.397	0
$PM_{2.5}$ (g/s) all time periods	0	0.088
PM10 (g/s)	0	0

Table 2-3. Estimation of Particulate Matter Speciation for Combustion Turbine Stacks (each)

Total PM Emissions, Filterable plus Condensable, from Plant Design Specifications = 25 lb/hr.

Assume, as per FLM guidance for gas-fired CTs, that 25% of PM10 is filterable, and 75% is condensable.

Then Filterable PM10 = 6.25 lb/hr.

Assume that 100% of Filterable PM10 is elemental carbon.

Then EC = 6.25 lb/hr

Condensable PM10 = 0.75(25) = 18.75 lb/hr.

H_2SO_4 = 7.66 lb/hr per design specifications

Then condensable SO_4 = 7.5 lb/hr

Assume remainder of condensable PM10 is organic (SOA).

Then final speciation is:

EC = 6.25 lb/hr = 0.787 g/s
SO_4 = 7.5 lb/hr = 0.945 g/s
SOA = 11.09 lb/hr = 1.397 g/s

3.0 AIR QUALITY MODEL AND APPLICATION

The CALPUFF air quality model will be used for all Class I area analyses. CALPUFF is the approved EPA long-range transport model as referenced in the Guideline on Air Quality Models. It consists of three components: the CALMET model for processing of meteorological data, CALPUFF for the transport and dispersion calculations, and CALPOST for analysis and post-processing of model results. The CALMET model version will be 5.53a, Level 040716; CALPUFF will be version 5.711a, Level 040716. Input options and data utilized in the models will generally corresponded to default or recommended values; table 3-1 provides a list of input options that are specific to the Mesaba application and differ from standard default values.

For background ozone (O_3) concentration, a constant value of 40 ppb has been used for initial CALPUFF modeling. Some hourly O_3 monitoring data may be available for the analysis region. If appropriate data can be acquired, hourly ozone files will be utilized for future modeling. A constant ammonia background of 1.0 ppb will be assumed.

The CALMET/CALPUFF modeling domain will be a 700km by 500km area approximately centered on the IGCC Power Station footprint, with a four kilometer grid spacing. The coordinate system is Lambert Conformal. Receptor locations within each of the Class I areas were obtained from the National Park Service. Figure 3-1 shows the modeling domain, terrain elevation contours, and the modeling receptors.

Terrain elevations were derived with the TERREL preprocessor; an average elevation was extracted for each cell in the modeling domain. Land use data were obtained from USGS 1:250,000 scale land use and land cover digital data, using CTGCOMP (version 1.0, 961113) and CTGPROC (version 1.2, 010206). The elevation and land use files were combined for CALMET input using MAKEGEO (version 1.1, 010206).

Source input to CALPUFF will consist of four combustion turbines and two tank vent boilers for a two-phase Mesaba facility. Building downwash effects on stack emissions will be included through use of output from the BPIP PRIME wake effects program. Copies of complete CALMET and CALPUFF input files are included with this Protocol (Appendix A).

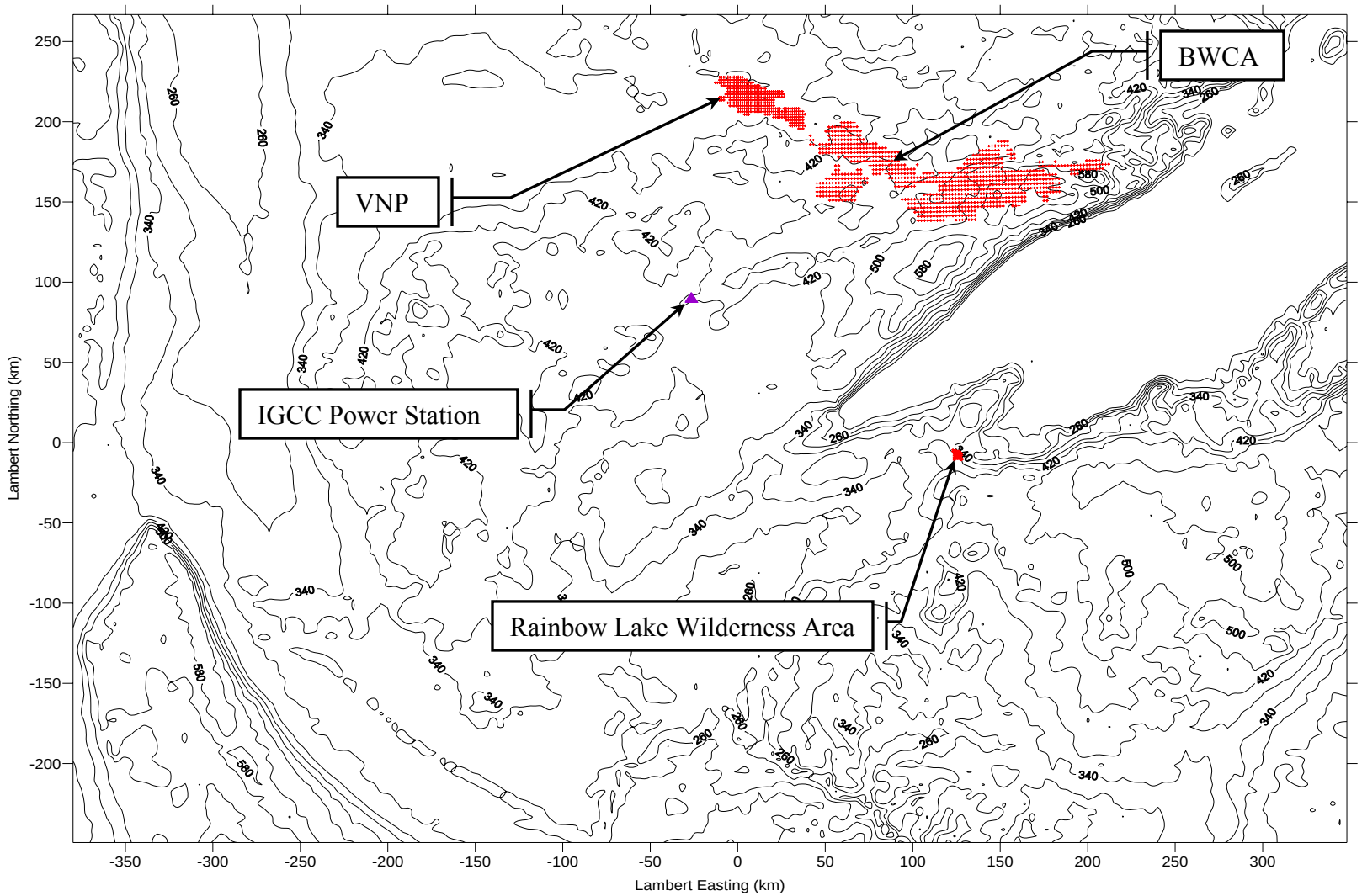
Initial CALPUFF modeling analyses utilized meteorological data for the years 1990, 1992, and 1996. These are the same years used for other recent CALPUFF applications in northern Minnesota and the data were readily available. Gridded meteorological fields used as input to the CALMET processor were MM4 (1990) and MM5 (1992, 1996) prognostic data acquired from the National Park Service (NPS). Additional surface, upper air, and precipitation data were used in CALMET to refine the meteorological fields. Hourly surface data from 13 stations were used along with precipitation data from 28 stations. Upper air data from two stations were used; St. Cloud MN and International Falls MN for 1990 and 1992, and Minneapolis and International Falls for 1996. The surface and precipitation stations are listed in Appendix B.

MM5 data with higher resolution for more recent years are now available from the State of Minnesota. These later MM5 data sets will be used, with surface and upper air data from representative regional stations, for subsequent CALMET/CALPUFF modeling.

Table 3-1. CALMET/CALPUFF Non-Default Input Parameters

Input Group	Parameter	Mesaba Selection	Explanation
	CALMET		
5	IKINE	1	Kinemateic effects option used to better account for terrain effects
5	RMAX 1	30 km	No default values
	RMAX 2	40 km	No default values
	RMAX 3	40 km	No default values
	TERRAD	15 km	No default values
	R1	5	No default values
	R2	15	No default values
	CALPUFF		
3	Species Modeled	SO_2, SO_4, NO_x, EC SOA, $PM_{2.5}$, HNO_3, NO_3	Modeled all species emitted by Mesaba sources, and others (HNO_3, NO_3) involved in plume chemistry
4	LSAMP	F	No gridded receptors (sampling grid) used
8	Part. Size	Mean = 0.48 st. dev. = 2	All particulate species assumed $PM_{2.5}$
11	MOZ	0	Constant ozone background
11	BCK03	40.0 ppb	Representation background ozone concentration
11	BCKNH3	1.0 ppb	Conservative background ammonia concentration (0.5 ppb recommended for forested lands)
12	NSPLIT	3	Puff-splitting used (default)

Figure 3-1 Mesaba Calmet Modeling Domain and Class 1 areas.



4.0 INCREMENT ANALYSES

CALPUFF model results for pollutant concentration at each Class I area receptor will be processed with CALPOST to determine the highest and highest second-high concentration for each pollutant and averaging time in each Class I area. Allowable Class I increments and Significant Impact Levels (SILs) are shown in Table 4-1.

The IGCC Power Station emission rates appropriate to each averaging time, as listed in Table 2-2, will be used in separate CALPUFF model runs to evaluate 3-hour, 24-hour, and annual increment consumption. Each model simulation will be carried out for each year of meteorological data; the highest concentration for any year will be compared to the applicable SIL, and the highest second-high from the three years will be compared to the allowable increment limit.

For calculation of particulate matter (PM10) impacts, the sum of all particle species (EC, SOA, FPM, CPM, and SO_4) will be calculated to represent the total PM10 concentration.

Initial CALPUFF modeling for the IGCC Power Station has indicated that predicted SO_2 concentrations may exceed the SIL in the BWCA and VNP for 3-hour and 24-hour averaging times. It will therefore be appropriate to carry out "cumulative" SO_2 modeling to assess the impact of the IGCC Power Station and all regional increment-consuming emissions.

Excelsior Energy contacted the Minnesota Pollution Control Agency (MPCA) and requested modeling information for regional SO_2 increment sources. MPCA provided detailed emission and stack data for those Minnesota sources with potential for Class I SO_2 impacts. The sources and net increment-consuming emissions are listed in Table 4-2. The MPCA inventory generally lists maximum allowable emissions for post-baseline sources. The allowable emissions will be used in increment modeling for all sources except Minnesota Power-Clay Boswell. Actual emissions data were acquired for the most recent two years for Clay Boswell; the emission rate in Table 4-2 represents the maximum actual hourly rate for that time period.

Some individual sources in the MPCA increment inventory have negative emission rates (i.e., actual SO_2 emissions have decreased since the baseline date, resulting in increment expansion). Since the CALPUFF model does not accept negative emission rates, two model runs will be carried out; one with the positive emissions and one with the negative emission rates. Concentration impacts of the negative sources will be subtracted from those of the positive sources for each hour/receptor to derive total increment impacts of all sources.

Results of the cumulative increment modeling (highest second-high 3-hour and 24-hour concentration for BWCA and VNP) will be compared to the PSD Class I increment limits to demonstrate compliance.

Table 4-1. Class I Area Increment Limits and Significant Impact Levels (SILs)

Pollutant	Averaging Time	Class I Increment ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)
SO_2	3-hour	25.0	1.0
	24-hour	5.0	0.2
	annual	2.0	0.1
PM10	24-hour	8.0	0.3
	annual	4.0	0.2
NO_2	annual	2.5	0.1

Table 4-2. Modeled Increment Consuming SO_2 Emissions For Cumulative Class I Increment Analysis

Source	Net Increment SO_2 Emissions	
	lb/hr	g/s
IGCC Power Station		
3-hour	622.9	78.48
24-hour	468.7	59.06
Minnesota Power – Hibbard	416.8	52.51
Blandin Paper – Rapids Energy	417.0	52.54
Northshore Mining	-20.8	-2.62
Minnesota Power – Clay Boswell	1686	212.4
Potlatch Paper – Cloquet	-34.5	-4.35
Hibbing Taconite – Hibbing	772.3	97.31
Boise Cascade	141.6	17.84
Mesabi Nugget – Hoyt Lakes	225.6	28.42

5.0 DEPOSITION OF NITROGEN AND SULFUR

The CALPUFF results for each of the Class I areas will be processed with CALPOST to calculate total annual deposition of nitrogen and sulfur at each receptor as a result of IGCC Power Station emissions. Model results for annual impacts (maximum annual average emissions) will be used following the methodology given in the IWAQM Phase I report. Total sulfur deposition is calculated from the wet and dry deposition of SO_2 and sulfate; total nitrogen is represented by the sum of nitrogen from wet and dry fluxes of nitric acid, nitrate, ammonium sulfate and ammonium nitrate, and the dry flux of NOx. For deposition calculations, MNITRATE will be set to a value of 1.0 in POSTUTIL to account for ammonia availability.

Results of deposition calculations for VNP will be compared to the NPS Deposition Analysis Threshold (DAT) of 0.01 kg/ha-yr for both sulfur and nitrogen. For the BWCA and RLW, total deposition (IGCC Power Station impact plus background) will be compared to the USFS "green line" values for terrestrial and aquatic ecosystems. The green line values are:

BWCA – Terrestrial

Total sulfur	5 - 7 kg/ha-yr
Total nitrogen	5 - 8

- Aquatic

Total sulfur	7.5 – 8 kg/ha-yr
Sulfur + 20% nitrogen	9 – 10

RLW – Terrestrial

Total sulfur	5 - 7 kg/ha-yr
Total nitrogen	5 - 8

- Aquatic

Total sulfur	3.5 – 4.5 kg/ha-yr
Sulfur + 20% nitrogen	4.5 – 5.5

6.0 REGIONAL HAZE ANALYSIS

A visibility/regional haze impact analysis will be carried out for BWCA and VNP. Visibility analysis is not required for Rainbow Lakes. The recommended methodology for assessing visibility impacts according to the FLAG guidance involves the use of CALPOST to process the data on concentrations of pollutants from the CALPUFF modeling of 24-hour emissions. In CALPOST a daily value of light extinction is defined by the concentrations of each pollutant that can effect visibility, taking into account the efficiency of each particle type in scattering light, and the relative humidity which influences the size of hygroscopic pollutants (sulfates and nitrates). The 24-hour average light extinction caused by emissions from the modeled source(s) is then compared to the background light extinction, a value based upon "natural" or pristine unpolluted conditions for each Class I area.

The FLMs have established threshold changes in light extinction (as a percentage of natural background) that are believed to represent potential adverse impacts on visibility. These thresholds are 5% (a potentially detectable change) and 10% (a level that may represent an unacceptable degradation).

The standard FLAG visibility analysis will be carried out using the CALPOST processing program and Method 2 for calculating source and background light extinction and the percentage change. Results will be presented in terms of the maximum percentage change and the number of days (24-hour periods) with percent change exceeding five and ten percent for the BWCA and RLW, for each year of meteorological data.

Natural background light extinction will be as given for the BWCA and VNP in the FLAG document. Relative humidity data for calculation of f(RH) in Method 2 is taken from the nearest surface weather station hourly observations. For receptors in the two Class I areas of concern the nearest station is either International Falls, MN or Hibbing MN. A maximum relative humidity cut-off of 95% will be specified.

The CALPOST program calculates f(RH) according to the data tabulated in FLAG. In the US EPA's regional haze modeling guidance [5] they have recommended a slightly different f(RH) function based upon Tang's smoothed data for ammonium sulfate. The EPA data give slightly larger values of f(RH) at intermediate RH, and significantly lower f(RH) at high humidity. The FLAG f(RH) data have been used for initial visibility modeling, but it is proposed to modify CALPOST to use the EPA function for subsequent modeling.

Under 40 CFR 51.301, an adverse impact on visibility is defined as "visibility impairment which interferes with the management, protection, preservation, or enjoyment of the visitor's visual experience of the Federal Class I area. This determination must be made on a case-by-case basis taking into account the geographic extent, intensity, duration, frequency and time of visibility impairments, and how these factors correlate with (1) times of visitor use of the Federal Class I area, and (2) the frequency and timing of natural conditions that reduce visibility". This definition indicates that a model-predicted extinction change exceeding a given

[5] U.S. EPA, 2003: Guidance for Tracking Progress Under the Regional Haze Rule. EPA-454/B-03-004, September 2003.

threshold value does not necessarily imply an adverse impact. Some consideration should be given to local conditions at the time and location of the model result, and factors that may have contributed to the predicted impact.

There are several factors inherent in the FLAG Method 2 methodology that are conservative in the sense that they lead to the highest likely impact. These include:

- the extinction change calculated for a Class I area represents the largest change for any receptor within the area.
- the change is calculated relative to natural or pristine background; i.e., the best visibility in the absence of any industrial pollution or abnormal natural events such as forest fires.
- no natural visibility impairment due to fog, precipitation, or clouds is considered
- the calculations assume emissions from the modeled source, at the highest daily rate, for every hour and day of the year

It should also be noted that relative humidity is a critical input to the light extinction calculation; because of the hygroscopic nature of sulfate and nitrate particles, light extinction is greatly magnified under high humidity conditions. The CALPOST visibility calculation uses measured relative humidity at the nearest surface weather station to calculate the humidity effect of given concentrations of sulfate and nitrate particles. The nearest weather station is often some distance from the Class I area of concern, and the observed relative humidity may or may not be representative of the analysis area. Most important, high relative humidity values are frequently associated with fog, precipitation, and low clouds, all of which can create natural visibility impairment. But the possible occurrence of these natural phenomena are not considered in the FLAG method 2 calculation.

Because of these factors, it is planned that additional visibility impact assessments will be carried out to better characterize the potential impacts of the IGCC Power Station on regional haze in Class I areas. These assessments will include application of CALPOST Methods 6 and 7, as well as meteorological analysis of those days on which impacts are projected, analysis of seasonal distribution of impacts, and estimates of average light extinction over extended lines-of-sight within or adjacent to the Class I areas. Based on discussions with the responsible FLMs, no cumulative visibility analyses are proposed at this time.

7.0 IMPACTS ON SOILS, WATERS, AND VEGETATION

Potential impacts to soils, waters, and vegetation in Class I areas will be evaluated on the basis of the model-predicted pollutant concentrations, and the magnitude of predicted annual deposition of sulfur and nitrogen.

Screening criteria for potential air pollution impacts on vegetation have been given by the U.S. Forest Service.[6] The USFS "Green Line" screening values "were set at levels at which it was reasonably certain that no significant change would be observed in ecosystems that contain large numbers of sensitive components." The Green Line screening levels for SO_2 are 5 $\mu g/m^3$ maximum annual average and 100 $\mu g/m^3$ maximum three-hour average. Though the USFS screening levels were established specifically for Class I areas administered by the Forest Service (BWCA and RLW) it is reasonable to apply the same criteria to VNP, which is administered by the National Park Service (NPS). There are no established screening criteria for NO_2 and PM10; however, Class I area concentrations of NO_2 and PM10 from the IGCC Power Station are indicated to be below significance levels and therefore can be expected to have negligible impacts.

The USFS has also established a green line screening value for ozone concentration. The green line level is a second-highest one-hour concentration during the growing season of 80 ppb. Existing background monitoring data indicate current concentrations near the green line level, but below the red line concentration of 120 ppb. Ozone modeling is not required for the IGCC Power Station, but the modest level of VOC and NO_x emissions indicate that the IGCC Power Station will not cause a significant increase in ozone impacts in the Class I areas.

The USFS has expressed concern about impacts of mercury deposition in the BWCA and RLW. Mercury modeling is not included in the proposed CALPUFF modeling analyses. However, impacts of mercury emissions and possible mercury deposition will be evaluated in separate toxics analyses required by the MPCA as a part of the permitting process.

All results of the Class I area modeling and impact analyses will be included in the formal IGCC Power Station PSD permit application. Moreover, the application will include an Air Modeling Report which will provide details of all analyses, methodology, and results. CALMET, CALPUFF, and CALPOST modeling files in electronic format will be submitted with the application to allow detailed review by the MPCA and FLMs.

[6] Screening Procedure to Evaluate Effects of Air Pollution on Eastern Region Wildernesses Cited as Class I Air Quality Areas. USFS General Technical Report NE-151, 1991.

APPENDIX A

CALMET
and
CALPUFF

Input Listings

The CALMET and CALPUFF input listings are attached to the Application for a Part 70/New Source Review Construction Authorization Permit as eletronic files named "calmet92mn.xls" and "calpuff_24hr.xls," respectively.

APPENDIX B

Regional Weather Stations

used for CALMET data processing

Weather Stations Included in CALMET Meteorological Data Processing

C:\Programmer's File Editor\upper.da2
Printed at 12:54 on 29 Nov 2005

Upper Air Stations included in CALMET

WBAN Number	Station Name	State	County	Years
14926	ST CLOUD	Minnesota	Sherburne	90,92
94983	MINNEAPOLIS	Minnesota	Hennepin	96
14918	INTERNATION FALLS	Minnesota	Koochiching	90,92,96

C:\Programmer's File Editor\surface.da2
Printed at 12:50 on 29 Nov 2005

Surface Stations included in CALMET (1990, 1992 and 1996)

WBAN Number	Station Name	CALMET Number	State	County
94902	BROOKINGS	26515	South Dakota	Brookings
14926	ST CLOUD	26550	Minnesota	Sherburne
14954	MANKATO	26585	Minnesota	Blue Earth
14914	FARGO	27530	North Dakota	Cass
14958	BEMIDJI	27550	Minnesota	Beltrami
14916	GRAND FORKS	27576	North Dakota	Grand Forks
14922	MINNEAPOLIS	26580	Minnesota	Hennepin
14913	DULUTH	27450	Minnesota	St. Louis
94931	HIBBING	27455	Minnesota	St. Louis
14918	INTERNATION FALLS	27470	Minnesota	Koochiching
14920	LA CROSSE	26430	Wisconsin	La Crosse
14991	EAU CLAIR	26435	Wisconsin	Chippewa
14897	WAUSAU	26463	Wisconsin	Marathon

C:\Programmer's File Editor\precip.da2
Printed at 13:48 on 29 Nov 2005

Precipitation Stations included in CALMET (1990, 1992 and 1996)

COOP ID	Station Name	State	County
474894	LUCK	Wisconsin	Polk
473511	HAYWARD RS	Wisconsin	Sawyer
478027	SPOONER EXP FARM	Wisconsin	Washburn
474396	LADYSMITH RS	Wisconsin	Rusk
475335	MENOMONIE	Wisconsin	Dunn
478589	TREMPEALEAU DAM 6	Wisconsin	Trempealeau
475352	MERCER RS	Wisconsin	Iron
476854	PRENTICE	Wisconsin	Price
479218	WILLARD	Wisconsin	Clark
476518	PHELPS	Wisconsin	Vilas
477140	RICE RSVR TOMAHAWK	Wisconsin	Lincoln
478963	WAUSAU 7 SSW	Wisconsin	Marathon
218235	THIEF LAKE REFUGE	Minnesota	Marshall
213463	HALSTAD	Minnesota	Norman
216228	ORWELL DAM	Minnesota	Otter Tail
211263	CANBY	Minnesota	Yellow Medicine
211589	CLEMENTSON	Minnesota	Lake of the Woods
218621	WALKER RANGER	Minnesota	Cass
217294	ST. CLOUD/WHITNEY MN.	Minnesota	Sherburne
215435	MINNEAPOLIS WSFO AP, MN	Minnesota	Hennepin
210746	BIG FALLS	Minnesota	Koochiching
214026	INT.FALLS/FALLS INT.MN.	Minnesota	Koochiching
216213	ORR	Minnesota	St. Louis
212248	DULUTH/INT.MN.	Minnesota	St. Louis
213793	HINCKLEY	Minnesota	Pine
218613	WALES 2 ENE	Minnesota	Lake
213290	GRAND PORTAGE R S	Minnesota	Cook
322859	FARGO/HECTOR FIELD ND.	North Dakota	Cass

```
Minnesota/Wisconsin CALMET - 1992 for Excelsior
with MM4 data, 13 surface met stations, 28 precipitation stations
2 Upper Air Stations
---------------- Run title (3 lines) ----------------------------------------

                 CALMET MODEL CONTROL FILE
                 -------------------------

-------------------------------------------------------------------------------

INPUT GROUP: 0 -- Input and Output File Names


Subgroup (a)
------------
Default Name  Type          File Name
------------  ----          ---------
GEO.DAT       input    ! GEODAT= mn4km.geo !
SURF.DAT      input    ! SRFDAT= .\sfc\MNWIsfc92.dat  !
CLOUD.DAT     input    * CLDDAT=            *
PRECIP.DAT    input    ! PRCDAT= pmerge9096.dat !
MM4.DAT       input    ! MM4DAT= mn1992.mm5 !
WT.DAT        input    * WTDAT=             *

CALMET.LST    output   ! METLST= MnWICalmet92.LST     !
CALMET.DAT    output   ! METDAT= \\cluster8\e\project\2005\1877-05\CALMET\1992\MNWICALMET92.DAT!
PACOUT.DAT    output   * PACDAT=            *

All file names will be converted to lower case if LCFILES = T
Otherwise, if LCFILES = F, file names will be converted to UPPER CASE
        T = lower case      ! LCFILES = T !
        F = UPPER CASE

NUMBER OF UPPER AIR & OVERWATER STATIONS:

   Number of upper air stations (NUSTA)  No default     ! NUSTA =  2  !
   Number of overwater met stations
                           (NOWSTA) No default     * NOWSTA =  0  *

                    !END!
-------------------------------------------------------------------------------
Subgroup (b)
--------------------------------
Upper air files (one per station)
--------------------------------
Default Name  Type       File Name
------------  ----       ---------
UP1.DAT       input     1  ! UPDAT= .\ua\intfls92.dat !  !END!
UP2.DAT       input     2  ! UPDAT= .\ua\stcloud92.dat  !  !END!
-------------------------------------------------------------------------------
Subgroup (c)
----------------------------------------
```

Overwater station files (one per station)

Default Name Type File Name
--- --- ---
SEA1.DAT input 1 * SEADAT= *

Subgroup (d)

Other file names

Default Name Type File Name
--- --- ---
DIAG.DAT input * DIADAT= *
PROG.DAT input * PRGDAT= *

TEST.PRT output * TSTPRT= *
TEST.OUT output * TSTOUT= *
TEST.KIN output * TSTKIN= *
TEST.FRD output * TSTFRD= *
TEST.SLP output * TSTSLP= *

NOTES: (1) File/path names can be up to 70 characters in length
(2) Subgroups (a) and (d) must have ONE 'END' (surround by delimiters) at the end of the group
(3) Subgroups (b) and (c) must have an 'END' (surround by delimiters) at the end of EACH LINE

!END!

INPUT GROUP: 1 -- General run control parameters

Starting date: Year (IBYR) -- No default ! IBYR= 1992 !
Month (IBMO) -- No default ! IBMO= 1 !
Day (IBDY) -- No default ! IBDY= 4 !
Hour (IBHR) -- No default ! IBHR= 1 !

Base time zone (IBTZ) -- No default ! IBTZ= 6 !
PST = 08, MST = 07
CST = 06, EST = 05

Length of run (hours) (IRLG) -- No default ! IRLG= 8616 !

Run type (IRTYPE) -- Default: 1 ! IRTYPE= 1 !

0 = Computes wind fields only
1 = Computes wind fields and micrometeorological variables

```
        (u*, w*, L, zi, etc.)
      (IRTYPE must be 1 to run CALPUFF or CALGRID)

    Compute special data fields required
    by CALGRID (i.e., 3-D fields of W wind
    components and temperature)
    in additional to regular          Default: T    ! LCALGRD = T !
    fields ? (LCALGRD)
    (LCALGRD must be T to run CALGRID)

     Flag to stop run after
     SETUP phase (ITEST)            Default: 2       ! ITEST=  2   !
     (Used to allow checking
     of the model inputs, files, etc.)
     ITEST = 1 - STOPS program after SETUP phase
     ITEST = 2 - Continues with execution of
                 COMPUTATIONAL phase after SETUP

!END!

-------------------------------------------------------------------------------

INPUT GROUP: 2 -- Map Projection and Grid control parameters
--------------

    Projection for all (X,Y):
    -------------------------

    Map projection
    (PMAP)                    Default: UTM    ! PMAP = LCC  !

       UTM :  Universal Transverse Mercator
       TTM :  Tangential Transverse Mercator
       LCC :  Lambert Conformal Conic
        PS :  Polar Stereographic
        EM :  Equatorial Mercator
      LAZA :  Lambert Azimuthal Equal Area

    False Easting and Northing (km) at the projection origin
    (Used only if PMAP= TTM, LCC, or LAZA)
    (FEAST)                   Default=0.0     ! FEAST  = 0.000  !
    (FNORTH)                    Default=0.0     ! FNORTH = 0.000  !

    UTM zone (1 to 60)
    (Used only if PMAP=UTM)
    (IUTMZN)                   No Default      ! IUTMZN =     !

    Hemisphere for UTM projection?
    (Used only if PMAP=UTM)
    (UTMHEM)                     Default: N      ! UTMHEM = N  !
       N   :  Northern hemisphere projection
       S   :  Southern hemisphere projection
```

Latitude and Longitude (decimal degrees) of projection origin
(Used only if PMAP= TTM, LCC, PS, EM, or LAZA)
(RLAT0) No Default ! RLAT0 = 46.5N !
(RLON0) No Default ! RLON0 = 93.0W !

TTM : RLON0 identifies central (true N/S) meridian of projection
RLAT0 selected for convenience
LCC : RLON0 identifies central (true N/S) meridian of projection
RLAT0 selected for convenience
PS : RLON0 identifies central (grid N/S) meridian of projection
RLAT0 selected for convenience
EM : RLON0 identifies central meridian of projection
RLAT0 is REPLACED by 0.0N (Equator)
LAZA: RLON0 identifies longitude of tangent-point of mapping plane
RLAT0 identifies latitude of tangent-point of mapping plane

Matching parallel(s) of latitude (decimal degrees) for projection
(Used only if PMAP= LCC or PS)
(XLAT1) No Default ! XLAT1 = 30N !
(XLAT2) No Default ! XLAT2 = 60N !

LCC : Projection cone slices through Earth's surface at XLAT1 and XLAT2
PS : Projection plane slices through Earth at XLAT1
(XLAT2 is not used)

Note: Latitudes and longitudes should be positive, and include a
letter N,S,E, or W indicating north or south latitude, and
east or west longitude. For example,
35.9 N Latitude = 35.9N
118.7 E Longitude = 118.7E

Datum-region

The Datum-Region for the coordinates is identified by a character
string. Many mapping products currently available use the model of the
Earth known as the World Geodetic System 1984 (WGS-G). Other local
models may be in use, and their selection in CALMET will make its output
consistent with local mapping products. The list of Datum-Regions with
official transformation parameters is provided by the National Imagery and
Mapping Agency (NIMA).

NIMA Datum - Regions(Examples)

WGS-G WGS-84 GRS 80 Spheroid, Global coverage (WGS84)
NAS-C NORTH AMERICAN 1927 Clarke 1866 Spheroid, MEAN FOR CONUS (NAD27)
NWS-27 NWS 6370KM Radius, Sphere
NWS-84 NWS 6370KM Radius, Sphere
ESR-S ESRI REFERENCE 6371KM Radius, Sphere

```
    Datum-region for output coordinates
    (DATUM)                  Default: WGS-G     ! DATUM = NAS-C  !


    Horizontal grid definition:
    ---------------------------

    Rectangular grid defined for projection PMAP,
    with X the Easting and Y the Northing coordinate

          No. X grid cells (NX)      No default     ! NX =   183  !
          No. Y grid cells (NY)      No default     ! NY =   130  !

    Grid spacing (DGRIDKM)           No default     ! DGRIDKM = 4. !
                                 Units: km

    Reference grid coordinate of
    SOUTHWEST corner of grid cell (1,1)

       X coordinate (XORIGKM)        No default     ! XORIGKM = -381.90 !
       Y coordinate (YORIGKM)        No default     ! YORIGKM = -251.20 !
                                 Units: km
    Vertical grid definition:
    -------------------------

       No. of vertical layers (NZ)    No default     ! NZ =  9  !

       Cell face heights in arbitrary
       vertical grid (ZFACE(NZ+1))    No defaults
                                 Units: m
      ! ZFACE = 0.,20.,50.,100.,200.,500.,1000.,1500.,2500.,3500. !
!END!


------------------------------------------------------------------------------

INPUT GROUP: 3 -- Output Options
--------------


   DISK OUTPUT OPTION

      Save met. fields in an unformatted
      output file ?             (LSAVE)  Default: T     ! LSAVE = T !
      (F = Do not save, T = Save)

      Type of unformatted output file:
      (IFORMO)                         Default: 1    ! IFORMO =  1  !

          1 = CALPUFF/CALGRID type file (CALMET.DAT)
          2 = MESOPUFF-II type file     (PACOUT.DAT)
```

LINE PRINTER OUTPUT OPTIONS:

Print met. fields ? (LPRINT) Default: F ! LPRINT = F !
(F = Do not print, T = Print)
(NOTE: parameters below control which
met. variables are printed)

Print interval
(IPRINF) in hours Default: 1 ! IPRINF = 1 !
(Meteorological fields are printed
every 1 hours)

Specify which layers of U, V wind component
to print (IUVOUT(NZ)) -- NOTE: NZ values must be entered
(0=Do not print, 1=Print)
(used only if LPRINT=T) Defaults: NZ*0
! IUVOUT = 0 , 0 , 0 , 0 , 0 , 0 , 0 , 0, 0 !

Specify which levels of the W wind component to print
(NOTE: W defined at TOP cell face -- 10 values)
(IWOUT(NZ)) -- NOTE: NZ values must be entered
(0=Do not print, 1=Print)
(used only if LPRINT=T & LCALGRD=T)

Defaults: NZ*0
! IWOUT = 0 , 0 , 0 , 0 , 0 , 0 , 0 , 0, 0 !

Specify which levels of the 3-D temperature field to print
(ITOUT(NZ)) -- NOTE: NZ values must be entered
(0=Do not print, 1=Print)
(used only if LPRINT=T & LCALGRD=T)

Defaults: NZ*0
! ITOUT = 0 , 0 , 0 , 0 , 0 , 0 , 0 , 0, 0 !

Specify which meteorological fields
to print
(used only if LPRINT=T) Defaults: 0 (all variables)

Variable	Print ? (0 = do not print, 1 = print)

```
!  STABILITY  =          0          ! - PGT stability class
!  USTAR      =          0          ! - Friction velocity
!  MONIN      =          0          ! - Monin-Obukhov length
!  MIXHT      =          0          ! - Mixing height
!  WSTAR      =          0          ! - Convective velocity scale
!  PRECIP     =          0          ! - Precipitation rate
!  SENSHEAT   =          0          ! - Sensible heat flux
!  CONVZI     =          0          ! - Convective mixing ht.


 Testing and debug print options for micrometeorological module

   Print input meteorological data and
   internal variables (LDB)        Default: F       ! LDB = F !
   (F = Do not print, T = print)
   (NOTE: this option produces large amounts of output)

   First time step for which debug data
   are printed (NN1)               Default: 1       ! NN1 =  1  !

   Last time step for which debug data
   are printed (NN2)               Default: 1       ! NN2 =  1  !


 Testing and debug print options for wind field module
 (all of the following print options control output to
  wind field module's output files: TEST.PRT, TEST.OUT,
  TEST.KIN, TEST.FRD, and TEST.SLP)

   Control variable for writing the test/debug
   wind fields to disk files (IOUTD)
   (0=Do not write, 1=write)       Default: 0       ! IOUTD =  0  !

   Number of levels, starting at the surface,
   to print (NZPRN2)               Default: 1       ! NZPRN2 =  0  !

   Print the INTERPOLATED wind components ?
   (IPR0) (0=no, 1=yes)            Default: 0       !  IPR0 =  0  !

   Print the TERRAIN ADJUSTED surface wind
   components ?
   (IPR1) (0=no, 1=yes)            Default: 0       !  IPR1 =  0  !

   Print the SMOOTHED wind components and
   the INITIAL DIVERGENCE fields ?
   (IPR2) (0=no, 1=yes)            Default: 0       !  IPR2 =  0  !

   Print the FINAL wind speed and direction
   fields ?
   (IPR3) (0=no, 1=yes)            Default: 0       !  IPR3 =  0  !

   Print the FINAL DIVERGENCE fields ?
```

```
        (IPR4) (0=no, 1=yes)            Default: 0      !  IPR4 =  0  !

        Print the winds after KINEMATIC effects
        are added ?
        (IPR5) (0=no, 1=yes)            Default: 0      !  IPR5 =  0  !

        Print the winds after the FROUDE NUMBER
        adjustment is made ?
        (IPR6) (0=no, 1=yes)            Default: 0      !  IPR6 =  0  !

        Print the winds after SLOPE FLOWS
        are added ?
        (IPR7) (0=no, 1=yes)            Default: 0      !  IPR7 =  0  !

        Print the FINAL wind field components ?
        (IPR8) (0=no, 1=yes)            Default: 0      !  IPR8 =  0  !

!END!


-------------------------------------------------------------------------------

INPUT GROUP: 4 -- Meteorological data options
--------------

   NO OBSERVATION MODE            (NOOBS)  Default: 0     ! NOOBS =  0   !
        0 = Use surface, overwater, and upper air stations
        1 = Use surface and overwater stations (no upper air observations)
           Use MM5 for upper air data
        2 = No surface, overwater, or upper air observations
           Use MM5 for surface, overwater, and upper air data

   NUMBER OF SURFACE & PRECIP. METEOROLOGICAL STATIONS

      Number of surface stations   (NSSTA)  No default     ! NSSTA =  13 !

      Number of precipitation stations
      (NPSTA=-1: flag for use of MM5 precip data)
                                   (NPSTA)  No default     ! NPSTA =  28  !

   CLOUD DATA OPTIONS
      Gridded cloud fields:
                                 (ICLOUD)  Default: 0     ! ICLOUD =  0  !
      ICLOUD = 0 - Gridded clouds not used
      ICLOUD = 1 - Gridded CLOUD.DAT generated as OUTPUT
      ICLOUD = 2 - Gridded CLOUD.DAT read as INPUT
      ICLOUD = 3 - Gridded cloud cover from Prognostic Rel. Humidity

   FILE FORMATS

      Surface meteorological data file format
                                 (IFORMS)  Default: 2     ! IFORMS =  2  !
```

```
      (1 = unformatted (e.g., SMERGE output))
      (2 = formatted   (free-formatted user input))

      Precipitation data file format
                              (IFORMP)  Default: 2     ! IFORMP =  2  !
      (1 = unformatted (e.g., PMERGE output))
      (2 = formatted   (free-formatted user input))

      Cloud data file format
                              (IFORMC)  Default: 2     ! IFORMC =  2  !
      (1 = unformatted - CALMET unformatted output)
      (2 = formatted   - free-formatted CALMET output or user input)

!END!


-------------------------------------------------------------------------------

INPUT GROUP: 5 -- Wind Field Options and Parameters
--------------


   WIND FIELD MODEL OPTIONS
      Model selection variable (IWFCOD)     Default: 1      ! IWFCOD =  1  !
        0 = Objective analysis only
        1 = Diagnostic wind module

      Compute Froude number adjustment
      effects ? (IFRADJ)                    Default: 1      ! IFRADJ =  1  !
      (0 = NO, 1 = YES)

      Compute kinematic effects ? (IKINE)   Default: 0      ! IKINE  =  1  !
      (0 = NO, 1 = YES)

      Use O'Brien procedure for adjustment
      of the vertical velocity ? (IOBR)     Default: 0      ! IOBR =  0  !
      (0 = NO, 1 = YES)

      Compute slope flow effects ? (ISLOPE) Default: 1      ! ISLOPE  =  1  !
      (0 = NO, 1 = YES)

      Extrapolate surface wind observations
      to upper layers ? (IEXTRP)            Default: -4     ! IEXTRP =  -4 !
      (1 = no extrapolation is done,
       2 = power law extrapolation used,
       3 = user input multiplicative factors
           for layers 2 - NZ used (see FEXTRP array)
       4 = similarity theory used
      -1, -2, -3, -4 = same as above except layer 1 data
           at upper air stations are ignored

      Extrapolate surface winds even
```

if calm? (ICALM) Default: 0 ! ICALM = 0 !
(0 = NO, 1 = YES)

Layer-dependent biases modifying the weights of
surface and upper air stations (BIAS(NZ))
-1<=BIAS<=1
Negative BIAS reduces the weight of upper air stations
(e.g. BIAS=-0.1 reduces the weight of upper air stations
by 10%; BIAS= -1, reduces their weight by 100 %)
Positive BIAS reduces the weight of surface stations
(e.g. BIAS= 0.2 reduces the weight of surface stations
by 20%; BIAS=1 reduces their weight by 100%)
Zero BIAS leaves weights unchanged (1/R**2 interpolation)
Default: NZ*0
! BIAS = 0 , 0 , 0 , 0 , 0 , 0, 0 , 0 , 0 !

Minimum distance from nearest upper air station
to surface station for which extrapolation
of surface winds at surface station will be allowed
(RMIN2: Set to -1 for IEXTRP = 4 or other situations
where all surface stations should be extrapolated)
Default: 4. ! RMIN2 = -1.0 !

Use gridded prognostic wind field model
output fields as input to the diagnostic
wind field model (IPROG) Default: 0 ! IPROG = 4 !
(0 = No, [IWFCOD = 0 or 1]
1 = Yes, use CSUMM prog. winds as Step 1 field, [IWFCOD = 0]
2 = Yes, use CSUMM prog. winds as initial guess field [IWFCOD = 1]
3 = Yes, use winds from MM4.DAT file as Step 1 field [IWFCOD = 0]
4 = Yes, use winds from MM4.DAT file as initial guess field [IWFCOD = 1]
5 = Yes, use winds from MM4.DAT file as observations [IWFCOD = 1]
13 = Yes, use winds from MM5.DAT file as Step 1 field [IWFCOD = 0]
14 = Yes, use winds from MM5.DAT file as initial guess field [IWFCOD = 1]
15 = Yes, use winds from MM5.DAT file as observations [IWFCOD = 1]

Timestep (hours) of the prognostic
model input data (ISTEPPG) Default: 1 ! ISTEPPG = 1 !

RADIUS OF INFLUENCE PARAMETERS

Use varying radius of influence Default: F ! LVARY = F!
(if no stations are found within RMAX1,RMAX2,
or RMAX3, then the closest station will be used)

Maximum radius of influence over land
in the surface layer (RMAX1) No default ! RMAX1 = 30.0 !
Units: km
Maximum radius of influence over land
aloft (RMAX2) No default ! RMAX2 = 40.0 !
Units: km
Maximum radius of influence over water

(RMAX3) No default ! RMAX3 = 40.0 !
Units: km

OTHER WIND FIELD INPUT PARAMETERS

Minimum radius of influence used in
the wind field interpolation (RMIN) Default: 0.1 ! RMIN = 0.1 !
Units: km
Radius of influence of terrain
features (TERRAD) No default ! TERRAD = 15. !

Units: km
Relative weighting of the first
guess field and observations in the
SURFACE layer (R1) No default ! R1 = 5. !
(R1 is the distance from an Units: km
observational station at which the
observation and first guess field are
equally weighted)

Relative weighting of the first
guess field and observations in the
layers ALOFT (R2) No default ! R2 = 15. !
(R2 is applied in the upper layers Units: km
in the same manner as R1 is used in
the surface layer).

Relative weighting parameter of the
prognostic wind field data (RPROG) No default ! RPROG = 0. !
(Used only if IPROG = 1) Units: km

Maximum acceptable divergence in the
divergence minimization procedure
(DIVLIM) Default: 5.E-6 ! DIVLIM= 5.0E-06 !

Maximum number of iterations in the
divergence min. procedure (NITER) Default: 50 ! NITER = 50 !

Number of passes in the smoothing
procedure (NSMTH(NZ))
NOTE: NZ values must be entered
Default: 2,(mxnz-1)*4 ! NSMTH =
2 , 4 , 4 , 4 , 4 , 4 , 4 , 4 , 4 !

Maximum number of stations used in
each layer for the interpolation of
data to a grid point (NINTR2(NZ))
NOTE: NZ values must be entered Default: 99. ! NINTR2 =
99 , 99 , 99 , 99 , 99 , 99 , 99, 99 , 99 !

Critical Froude number (CRITFN) Default: 1.0 ! CRITFN = 1. !

Empirical factor controlling the
influence of kinematic effects
(ALPHA) Default: 0.1 ! ALPHA = 0.1 !

Multiplicative scaling factor for
extrapolation of surface observations
to upper layers (FEXTR2(NZ)) Default: NZ*0.0
! FEXTR2 = 0., 0., 0., 0., 0., 0., 0., 0., 0.!
(Used only if IEXTRP = 3 or -3)

BARRIER INFORMATION

Number of barriers to interpolation
of the wind fields (NBAR) Default: 0 ! NBAR = 0 !

THE FOLLOWING 4 VARIABLES ARE INCLUDED
ONLY IF NBAR > 0
NOTE: NBAR values must be entered No defaults
for each variable Units: km

X coordinate of BEGINNING
of each barrier (XBBAR(NBAR)) ! XBBAR = 0. !
Y coordinate of BEGINNING
of each barrier (YBBAR(NBAR)) ! YBBAR = 0. !

X coordinate of ENDING
of each barrier (XEBAR(NBAR)) ! XEBAR = 0. !
Y coordinate of ENDING
of each barrier (YEBAR(NBAR)) ! YEBAR = 0. !

DIAGNOSTIC MODULE DATA INPUT OPTIONS

Surface temperature (IDIOPT1) Default: 0 ! IDIOPT1 = 0 !
0 = Compute internally from
hourly surface observations
1 = Read preprocessed values from
a data file (DIAG.DAT)

Surface met. station to use for
the surface temperature (ISURFT) No default ! ISURFT = 10 !
(Must be a value from 1 to NSSTA)
(Used only if IDIOPT1 = 0)

Domain-averaged temperature lapse
rate (IDIOPT2) Default: 0 ! IDIOPT2 = 0 !
0 = Compute internally from
twice-daily upper air observations

```
  1 = Read hourly preprocessed values
     from a data file (DIAG.DAT)

  Upper air station to use for
  the domain-scale lapse rate (IUPT) No default     ! IUPT   =  1  !
  (Must be a value from 1 to NUSTA)
  (Used only if IDIOPT2 = 0)
  --------------------------

  Depth through which the domain-scale
  lapse rate is computed (ZUPT)      Default: 200.  ! ZUPT = 200. !
  (Used only if IDIOPT2 = 0)         Units: meters
  --------------------------

Domain-averaged wind components
(IDIOPT3)                            Default: 0     ! IDIOPT3 =  0  !
  0 = Compute internally from
     twice-daily upper air observations
  1 = Read hourly preprocessed values
     a data file (DIAG.DAT)

  Upper air station to use for
  the domain-scale winds (IUPWND)    Default: -1    ! IUPWND = -1  !
  (Must be a value from -1 to NUSTA)
  (Used only if IDIOPT3 = 0)
  --------------------------

  Bottom and top of layer through
  which the domain-scale winds
  are computed
  (ZUPWND(1), ZUPWND(2))        Defaults: 1., 1000. ! ZUPWND= 1., 1000. !
  (Used only if IDIOPT3 = 0)    Units: meters
  --------------------------

Observed surface wind components
for wind field module (IDIOPT4)  Default: 0     ! IDIOPT4 =  0  !
  0 = Read WS, WD from a surface
     data file (SURF.DAT)
  1 = Read hourly preprocessed U, V from
     a data file (DIAG.DAT)

Observed upper air wind components
for wind field module (IDIOPT5)  Default: 0     ! IDIOPT5 =  0  !
  0 = Read WS, WD from an upper
     air data file (UP1.DAT, UP2.DAT, etc.)
  1 = Read hourly preprocessed U, V from
     a data file (DIAG.DAT)

LAKE BREEZE INFORMATION

  Use Lake Breeze Module  (LLBREZE)
                              Default: F      ! LLBREZE = F !
```

```
        Number of lake breeze regions (NBOX)          ! NBOX =  0  !

      X Grid line 1 defining the region of interest
                                          ! XG1 = 0. !
      X Grid line 2 defining the region of interest
                                          ! XG2 = 0. !
      Y Grid line 1 defining the region of interest
                                          ! YG1 = 0. !
      Y Grid line 2 defining the region of interest
                                          ! YG2 = 0. !

       X Point defining the coastline (Straight line)
              (XBCST)  (KM)   Default: none    ! XBCST = 0. !

       Y Point defining the coastline (Straight line)
              (YBCST)  (KM)   Default: none    ! YBCST = 0. !

       X Point defining the coastline (Straight line)
              (XECST)  (KM)   Default: none    ! XECST = 0. !

       Y Point defining the coastline (Straight line)
              (YECST)  (KM)   Default: none    ! YECST = 0. !


     Number of stations in the region     Default: none ! NLB =  0 !
     (Surface stations + upper air stations)

     Station ID's  in the region   (METBXID(NLB))
     (Surface stations first, then upper air stations)
       ! METBXID =  0 !

!END!


-------------------------------------------------------------------------------

INPUT GROUP: 6 -- Mixing Height, Temperature and Precipitation Parameters
--------------

   EMPIRICAL MIXING HEIGHT CONSTANTS

     Neutral, mechanical equation
     (CONSTB)                        Default: 1.41   ! CONSTB = 1.41 !
     Convective mixing ht. equation
     (CONSTE)                        Default: 0.15   ! CONSTE = 0.15 !
     Stable mixing ht. equation
     (CONSTN)                        Default: 2400.  ! CONSTN = 2400.!
     Overwater mixing ht. equation
     (CONSTW)                         Default: 0.16   ! CONSTW = 0.16 !
     Absolute value of Coriolis
     parameter (FCORIOL)                  Default: 1.E-4  ! FCORIOL = 1.0E-04!
```

Units: (1/s)

SPATIAL AVERAGING OF MIXING HEIGHTS

Conduct spatial averaging
(IAVEZI) (0=no, 1=yes) Default: 1 ! IAVEZI = 1 !

Max. search radius in averaging
process (MNMDAV) Default: 1 ! MNMDAV = 1 !
Units: Grid
cells
Half-angle of upwind looking cone
for averaging (HAFANG) Default: 30. ! HAFANG = 30. !
Units: deg.
Layer of winds used in upwind
averaging (ILEVZI) Default: 1 ! ILEVZI = 1 !
(must be between 1 and NZ)

OTHER MIXING HEIGHT VARIABLES

Minimum potential temperature lapse
rate in the stable layer above the
current convective mixing ht. Default: 0.001 ! DPTMIN = 0.001 !
(DPTMIN) Units: deg. K/m
Depth of layer above current conv.
mixing height through which lapse Default: 200. ! DZZI = 200. !
rate is computed (DZZI) Units: meters

Minimum overland mixing height Default: 50. ! ZIMIN = 50. !
(ZIMIN) Units: meters
Maximum overland mixing height Default: 3000. ! ZIMAX = 3500. !
(ZIMAX) Units: meters
Minimum overwater mixing height Default: 50. ! ZIMINW = 50. !
(ZIMINW) -- (Not used if observed Units: meters
overwater mixing hts. are used)
Maximum overwater mixing height Default: 3000. ! ZIMAXW = 3500. !
(ZIMAXW) -- (Not used if observed Units: meters
overwater mixing hts. are used)

TEMPERATURE PARAMETERS

3D temperature from observations or
from prognostic data? (ITPROG) Default:0 !ITPROG = 0!

0 = Use Surface and upper air stations
(only if NOOBS = 0)
1 = Use Surface stations (no upper air observations)
Use MM5 for upper air data
(only if NOOBS = 0,1)
2 = No surface or upper air observations
Use MM5 for surface and upper air data

```
        (only if NOOBS = 0,1,2)

    Interpolation type
    (1 = 1/R ; 2 = 1/R**2)              Default:1        ! IRAD =  1  !

    Radius of influence for temperature
    interpolation (TRADKM)              Default: 500.     ! TRADKM =500. !
                                   Units: km

    Maximum Number of stations to include
    in temperature interpolation (NUMTS)  Default: 5        ! NUMTS = 5  !

    Conduct spatial averaging of temp-
    eratures (IAVET)  (0=no, 1=yes)        Default: 1     ! IAVET =  1  !
    (will use mixing ht MNMDAV,HAFANG
     so make sure they are correct)

    Default temperature gradient       Default: -.0098 ! TGDEFB = -0.0098 !
    below the mixing height over
    water (K/m) (TGDEFB)

    Default temperature gradient       Default: -.0045 ! TGDEFA = -0.0045 !
    above the mixing height over
    water (K/m) (TGDEFA)

    Beginning (JWAT1) and ending (JWAT2)
    land use categories for temperature                 ! JWAT1 =  999  !
    interpolation over water -- Make                   ! JWAT2 = 999  !
    bigger than largest land use to disable

  PRECIP INTERPOLATION PARAMETERS

    Method of interpolation (NFLAGP)      Default = 2    ! NFLAGP =  2  !
     (1=1/R,2=1/R**2,3=EXP/R**2)
    Radius of Influence (km) (SIGMAP)     Default = 100.0  ! SIGMAP =100. !
     (0.0 => use half dist. btwn
      nearest stns w & w/out
      precip when NFLAGP = 3)
    Minimum Precip. Rate Cutoff (mm/hr)   Default = 0.01  ! CUTP = 0.01 !
     (values < CUTP = 0.0 mm/hr)
!END!


-------------------------------------------------------------------------------

INPUT GROUP: 7 -- Surface meteorological station parameters
--------------

   SURFACE STATION VARIABLES
   (One record per station -- 13  records in all)
```

```
          1     2
       Name   ID          X coord.   Y coord.   Time   Anem.
                          (km)       (km)       zone   Ht.(m)
     -------------------------------------------------------
! SS1  ='BROOKIN '   26515   -293.2558  -229.2143     6    10.0 !
! SS2  ='STCLOUD '   26550   -78.9386   -101.4754     6    6.10 !
! SS3  ='MANKATO '   26585   -70.5793   -244.7148     6   10.00 !
! SS4  ='FARGO   '   27530  -279.7845     53.1641     6    8.53 !
! SS5  ='BEMIDJI '   27550  -140.2581    109.0812     6   10.00 !
! SS6  ='GRNDFRK '   27576  -300.8847    163.5914     6   10.00 !
! SS7  ='MINSTPL '   26580   -17.7257   -173.5780     6   10.00 !
! SS8  ='DULUTH  '   27450    57.5194     36.0370     6    6.40 !
! SS9  ='HIBBING '   27455    10.9086     94.8316     6   10.00 !
! SS10 ='INTFALL '   27470   -28.4539    222.1096     6    6.10 !
! SS11 ='LACRSSE '   26430   135.5070   -281.2290     6   10.00 !
! SS12 ='EAUCLAIR'   26435   115.4331   -174.2282     6   10.00 !
! SS13 ='WAUSAU  '   26463   255.9194   -164.5718     6   10.00 !


-------------------
                                                                                                                                1

       Four character string for station name
       (MUST START IN COLUMN 9)


                                                                                                                                2

       Five digit integer for station ID

!END!


-------------------------------------------------------------------------------

INPUT GROUP: 8 -- Upper air meteorological station parameters
--------------

    UPPER AIR STATION VARIABLES
    (One record per station --  2  records in all)

          1     2
       Name    ID      X coord.   Y coord.  Time zone
                       (km)       (km)
       ----------------------------------------------
! US1  ='INFL'  14918   -28.24100   222.0010 6    !
! US2  ='STCL'  14926   -79.09602  -102.0104 6    !


-------------------
                                                                                                                                1

       Four character string for station name
       (MUST START IN COLUMN 9)

                                                                                                                                2
```

Five digit integer for station ID

!END!

INPUT GROUP: 9 -- Precipitation station parameters

PRECIPITATION STATION VARIABLES
(One record per station -- 28 records in all)
(NOT INCLUDED IF NPSTA = 0)

```
          1          2
       Name   Station    X coord.  Y coord.
              Code       (km)      (km)
       -------------------------------------
! PS1  ='LUCK' 474894    40.05945   -100.0348    !
! PS2  ='HAYW' 473511   113.1287    -52.60986    !
! PS3  ='SPOO' 478027    83.57548    -72.7456    !
! PS4  ='LADY' 474396   139.2798    -109.2948    !
! PS5  ='MENO' 475335    81.17084   -173.0629    !
! PS6  ='TREM' 478589   121.0592    -267.2398    !
! PS7  ='MERC' 475352   218.033      -31.7587    !
! PS8  ='PREN' 476854   204.2297    -98.52768    !
! PS9  ='WILL' 479218   174.1174   -187.22720    !
! PS10 ='PHEL' 476518   292.8459    -39.29507    !
! PS11 ='RICE' 477140   244.3478    -98.85872    !
! PS12 ='WAUS' 478963   254.8526   -169.9897     !
! PS13 ='THIE' 218235  -210.1333    216.8804     !
! PS14 ='HALS' 213463  -278.8134     97.95155    !
! PS15 ='ORWE' 216228  -236.3947    -25.68501    !
! PS16 ='CANB' 211263  -250.4186   -186.2932     !
! PS17 ='CLEM' 211589  -101.7078    235.4188     !
! PS18 ='WALK' 218621  -114.5457     65.54837    !
! PS19 ='STWH' 217294   -78.93861   -101.4754    !
! PS20 ='MINN' 215435   -16.5085    -173.5814    !
! PS21 ='BIG ' 210746   -57.30112    182.8797    !
! PS22 ='INTF' 214026   -28.45387    222.1096    !
! PS23 ='ORR ' 216213    10.77433    166.4852     !
! PS24 ='DULU' 212248   57.51939    36.03699     !
! PS25 ='HINC' 213793    8.72834   -55.50035     !
! PS26 ='WALE' 218613   94.76866    81.30602     !
! PS27 ='GRAN' 213296   238.5576    162.4988     !
! PS28 ='FARG' 322859  -279.7845    53.16407     !
```

Four character string for station name

(MUST START IN COLUMN 9)

2

Six digit station code composed of state
code (first 2 digits) and station ID (last
4 digits)

!END!

Excelsior 1992 - West
183x130 4 km Grid 24-Hour Emission Rates

11/21/2005

```
---------------- Run title (3 lines) ----------------------------------------

                 CALPUFF MODEL CONTROL FILE
                 --------------------------

-------------------------------------------------------------------------------

INPUT GROUP: 0 -- Input and Output File Names

--------------
Default Name  Type          File Name
------------  ----          ---------
CALMET.DAT    input    ! METDAT = \\cluster8\e\project\2005\1877-05\calmet\1992\mnwicalmet92.dat  !
   or
ISCMET.DAT    input    * ISCDAT =            *
   or
PLMMET.DAT    input    * PLMDAT =            *
   or
PROFILE.DAT   input    * PRFDAT =            *
SURFACE.DAT   input    * SFCDAT =            *
RESTARTB.DAT  input    * RSTARTB=            *
-------------------------------------------------------------------------------
CALPUFF.LST   output   ! PUFLST =excel92puff2w11210524hr.lst  !
CONC.DAT      output   ! CONDAT =excel92puff2w11210524hr.con  !
DFLX.DAT      output   ! DFDAT  =excel92puff2w11210524hr.dry  !
WFLX.DAT      output   ! WFDAT  =excel92puff2w11210524hr.wet  !

VISB.DAT      output   ! VISDAT =excel92puff2w11210524hr.vis  !
RESTARTE.DAT  output   * RSTARTE=            *
-------------------------------------------------------------------------------
Emission Files
--------------
PTEMARB.DAT   input    * PTDAT  =            *
VOLEMARB.DAT  input    * VOLDAT =            *
```

```
BAEMARB.DAT   input    * ARDAT  =           *
LNEMARB.DAT   input    * LNDAT  =           *
-------------------------------------------------------------------------------
Other Files
-----------
OZONE.DAT     input    * OZDAT  =           *
VD.DAT        input    * VDDAT  =           *
CHEM.DAT      input    * CHEMDAT=           *
H2O2.DAT      input    * H2O2DAT=           *
HILL.DAT      input    * HILDAT=            *
HILLRCT.DAT   input    * RCTDAT=            *
COASTLN.DAT   input    * CSTDAT=            *
FLUXBDY.DAT   input    * BDYDAT=            *
BCON.DAT      input    * BCNDAT=            *
DEBUG.DAT     output   * DEBUG =            *
MASSFLX.DAT   output   * FLXDAT=            *
MASSBAL.DAT   output   * BALDAT=            *
FOG.DAT       output   * FOGDAT=            *
-------------------------------------------------------------------------------
All file names will be converted to lower case if LCFILES = T
Otherwise, if LCFILES = F, file names will be converted to UPPER CASE
        T = lower case      ! LCFILES = F !
        F = UPPER CASE
NOTE: (1) file/path names can be up to 70 characters in length


Provision for multiple input files
----------------------------------

    Number of CALMET.DAT files for run (NMETDAT)
                              Default: 1       ! NMETDAT =   1   !

    Number of PTEMARB.DAT files for run (NPTDAT)
                              Default: 0       ! NPTDAT =  0  !

    Number of BAEMARB.DAT files for run (NARDAT)
                              Default: 0       ! NARDAT =  0  !
```

```
    Number of VOLEMARB.DAT files for run (NVOLDAT)
                                Default: 0       ! NVOLDAT =  0  !

!END!

-------------
Subgroup (0a)
-------------

  The following CALMET.DAT filenames are processed in sequence if NMETDAT>1

Default Name  Type          File Name
------------  ----          ---------
 none         input    * METDAT=     *   *END*


--------------------------------------------------------------------------------

INPUT GROUP: 1 -- General run control parameters
--------------

   Option to run all periods found
   in the met. file     (METRUN)   Default: 0       ! METRUN =   1  !

       METRUN = 0 - Run period explicitly defined below
       METRUN = 1 - Run all periods in met. file

    Starting date:   Year (IBYR) -- No default       ! IBYR =   1992 !
    (used only if   Month (IBMO) -- No default       ! IBMO =     !
     METRUN = 0)      Day (IBDY) -- No default       ! IBDY =     !
                   Hour (IBHR) -- No default       ! IBHR =     !

    Base time zone        (XBTZ) -- No default       ! XBTZ = 6    !
      PST = 8., MST = 7.
      CST = 6., EST = 5.
```

```
Length of run (hours) (IRLG) -- No default       ! IRLG =      !

Number of chemical species (NSPEC)
                          Default: 5       ! NSPEC =  9 !

Number of chemical species
to be emitted  (NSE)           Default: 3       ! NSE =  7   !

Flag to stop run after
SETUP phase (ITEST)            Default: 2       ! ITEST =  2   !
(Used to allow checking
of the model inputs, files, etc.)
     ITEST = 1 - STOPS program after SETUP phase
     ITEST = 2 - Continues with execution of program
                 after SETUP

Restart Configuration:

   Control flag (MRESTART)      Default: 0       ! MRESTART =  0   !

      0 = Do not read or write a restart file
      1 = Read a restart file at the beginning of
          the run
      2 = Write a restart file during run
      3 = Read a restart file at beginning of run
          and write a restart file during run

   Number of periods in Restart
   output cycle (NRESPD)        Default: 0       ! NRESPD =  0   !

      0 = File written only at last period
     >0 = File updated every NRESPD periods

Meteorological Data Format (METFM)
                          Default: 1       ! METFM =  1   !

     METFM = 1 - CALMET binary file (CALMET.MET)
```

```
        METFM = 2 - ISC ASCII file (ISCMET.MET)
        METFM = 3 - AUSPLUME ASCII file (PLMMET.MET)
        METFM = 4 - CTDM plus tower file (PROFILE.DAT) and
                    surface parameters file (SURFACE.DAT)

    PG sigma-y is adjusted by the factor (AVET/PGTIME)**0.2
    Averaging Time (minutes) (AVET)
                                Default: 60.0    ! AVET = 60. !
    PG Averaging Time (minutes) (PGTIME)
                                Default: 60.0    ! PGTIME = 60. !


!END!


-----------------------------------------------------------------------------

INPUT GROUP: 2 -- Technical options
--------------


    Vertical distribution used in the
    near field (MGAUSS)                 Default: 1     ! MGAUSS =  1   !
      0 = uniform
      1 = Gaussian

    Terrain adjustment method
    (MCTADJ)                            Default: 3     ! MCTADJ =  3   !
      0 = no adjustment
      1 = ISC-type of terrain adjustment
      2 = simple, CALPUFF-type of terrain
          adjustment
      3 = partial plume path adjustment

    Subgrid-scale complex terrain
    flag (MCTSG)                        Default: 0     ! MCTSG =  0   !
      0 = not modeled
```

1 = modeled

Near-field puffs modeled as
elongated 0 (MSLUG) Default: 0 ! MSLUG = 0 !
0 = no
1 = yes (slug model used)

Transitional plume rise modeled ?
(MTRANS) Default: 1 ! MTRANS = 1 !
0 = no (i.e., final rise only)
1 = yes (i.e., transitional rise computed)

Stack tip downwash? (MTIP) Default: 1 ! MTIP = 1 !
0 = no (i.e., no stack tip downwash)
1 = yes (i.e., use stack tip downwash)

Method used to simulate building
downwash? (MBDW) Default: 1 ! MBDW = 1 !
1 = ISC method
2 = PRIME method

Vertical wind shear modeled above
stack top? (MSHEAR) Default: 0 ! MSHEAR = 0 !
0 = no (i.e., vertical wind shear not modeled)
1 = yes (i.e., vertical wind shear modeled)

Puff splitting allowed? (MSPLIT) Default: 0 ! MSPLIT = 0 !
0 = no (i.e., puffs not split)
1 = yes (i.e., puffs are split)

Chemical mechanism flag (MCHEM) Default: 1 ! MCHEM = 1 !
0 = chemical transformation not
modeled
1 = transformation rates computed
internally (MESOPUFF II scheme)
2 = user-specified transformation
rates used

3 = transformation rates computed
internally (RIVAD/ARM3 scheme)
4 = secondary organic aerosol formation
computed (MESOPUFF II scheme for OH)

Aqueous phase transformation flag (MAQCHEM)
(Used only if MCHEM = 1, or 3) Default: 0 ! MAQCHEM = 0 !
0 = aqueous phase transformation
not modeled
1 = transformation rates adjusted
for aqueous phase reactions

Wet removal modeled ? (MWET) Default: 1 ! MWET = 1 !
0 = no
1 = yes

Dry deposition modeled ? (MDRY) Default: 1 ! MDRY = 1 !
0 = no
1 = yes
(dry deposition method specified
for each species in Input Group 3)

Method used to compute dispersion
coefficients (MDISP) Default: 3 ! MDISP = 3 !

1 = dispersion coefficients computed from measured values
of turbulence, sigma v, sigma w
2 = dispersion coefficients from internally calculated
sigma v, sigma w using micrometeorological variables
(u*, w*, L, etc.)
3 = PG dispersion coefficients for RURAL areas (computed using
the ISCST multi-segment approximation) and MP coefficients in
urban areas
4 = same as 3 except PG coefficients computed using
the MESOPUFF II eqns.
5 = CTDM sigmas used for stable and neutral conditions.
For unstable conditions, sigmas are computed as in

MDISP = 3, described above. MDISP = 5 assumes that
measured values are read

Sigma-v/sigma-theta, sigma-w measurements used? (MTURBVW)
(Used only if MDISP = 1 or 5) Default: 3 ! MTURBVW = 3 !
1 = use sigma-v or sigma-theta measurements
from PROFILE.DAT to compute sigma-y
(valid for METFM = 1, 2, 3, 4)
2 = use sigma-w measurements
from PROFILE.DAT to compute sigma-z
(valid for METFM = 1, 2, 3, 4)
3 = use both sigma-(v/theta) and sigma-w
from PROFILE.DAT to compute sigma-y and sigma-z
(valid for METFM = 1, 2, 3, 4)
4 = use sigma-theta measurements
from PLMMET.DAT to compute sigma-y
(valid only if METFM = 3)

Back-up method used to compute dispersion
when measured turbulence data are
missing (MDISP2) Default: 3 ! MDISP2 = 3 !
(used only if MDISP = 1 or 5)
2 = dispersion coefficients from internally calculated
sigma v, sigma w using micrometeorological variables
(u*, w*, L, etc.)
3 = PG dispersion coefficients for RURAL areas (computed using
the ISCST multi-segment approximation) and MP coefficients in
urban areas
4 = same as 3 except PG coefficients computed using
the MESOPUFF II eqns.

PG sigma-y,z adj. for roughness? Default: 0 ! MROUGH = 0 !
(MROUGH)
0 = no
1 = yes

Partial plume penetration of Default: 1 ! MPARTL = 1 !

elevated inversion?
(MPARTL)
  0 = no
  1 = yes

Strength of temperature inversion Default: 0 ! MTINV = 0 !
provided in PROFILE.DAT extended records?
(MTINV)
  0 = no (computed from measured/default gradients)
  1 = yes

PDF used for dispersion under convective conditions?
Default: 0 ! MPDF = 0 !
(MPDF)
  0 = no
  1 = yes

Sub-Grid TIBL module used for shore line?
Default: 0 ! MSGTIBL = 0 !
(MSGTIBL)
  0 = no
  1 = yes

Boundary conditions (concentration) modeled?
Default: 0 ! MBCON = 0 !
(MBCON)
  0 = no
  1 = yes, using formatted BCON.DAT file
  2 = yes, using unformatted CONC.DAT file

Note: MBCON > 0 requires that the last species modeled
be 'BCON'. Mass is placed in species BCON when
generating boundary condition puffs so that clean
air entering the modeling domain can be simulated
in the same way as polluted air. Specify zero
emission of species BCON for all regular sources.

Analyses of fogging and icing impacts due to emissions from arrays of mechanically-forced cooling towers can be performed using CALPUFF in conjunction with a cooling tower emissions processor (CTEMISS) and its associated postprocessors. Hourly emissions of water vapor and temperature from each cooling tower cell are computed for the current cell configuration and ambient conditions by CTEMISS. CALPUFF models the dispersion of these emissions and provides cloud information in a specialized format for further analysis. Output to FOG.DAT is provided in either 'plume mode' or 'receptor mode' format.

Configure for FOG Model output?
Default: 0 ! MFOG = 0 !
(MFOG)
0 = no
1 = yes - report results in PLUME Mode format
2 = yes - report results in RECEPTOR Mode format

Test options specified to see if
they conform to regulatory
values? (MREG) Default: 1 ! MREG = 0 !

0 = NO checks are made
1 = Technical options must conform to USEPA
Long Range Transport (LRT) guidance
METFM 1 or 2
AVET 60. (min)
PGTIME 60. (min)
MGAUSS 1
MCTADJ 3
MTRANS 1
MTIP 1
MCHEM 1 or 3 (if modeling SOx, NOx)
MWET 1
MDRY 1

```
MDISP    2 or 3
MPDF     0 if MDISP=3
         1 if MDISP=2
MROUGH   0
MPARTL   1
SYTDEP   550. (m)
MHFTSZ   0


!END!


--------------------------------------------------------------------------------

INPUT GROUP: 3a, 3b -- Species list
-------------------

-------------
Subgroup (3a)
-------------

  The following species are modeled:

! CSPEC =        SO2 !        !END!
! CSPEC =        SO4 !        !END!
! CSPEC =        NOX !        !END!
! CSPEC =       HNO3 !        !END!
! CSPEC =        NO3 !        !END!
! CSPEC =       PM10 !        !END!
! CSPEC =         EC !        !END!
! CSPEC =        SOA !        !END!
! CSPEC =       PM25 !        !END!


                                        Dry              OUTPUT GROUP
   SPECIES        MODELED        EMITTED       DEPOSITED              NUMBER
    NAME       (0=NO, 1=YES)   (0=NO, 1=YES)   (0=NO,              (0=NONE,
```

```
  (Limit: 12                          1=COMPUTED-GAS       1=1st CGRUP,
   Characters                           2=COMPUTED-PARTICLE   2=2nd CGRUP,
   in length)                         3=USER-SPECIFIED)     3= etc.)
!        SO2  =       1,          1,        1,          0   !
!        SO4  =       1,          1,        2,          0   !
!        NOX  =       1,          1,        1,          0   !
!       HNO3  =       1,          0,        1,          0   !
!        NO3  =       1,          0,        2,          0   !
!       PM10  =       1,          1,        2,          0   !
!         EC  =       1,          1,        2,          0   !
!        SOA  =       1,          1,        2,          0   !
!       PM25  =       1,          1,        2,          0   !
!END!
```

Note: The last species in (3a) must be 'BCON' when using the boundary condition option (MBCON > 0). Species BCON should typically be modeled as inert (no chem transformation or removal).

Subgroup (3b)

The following names are used for Species-Groups in which results for certain species are combined (added) prior to output. The CGRUP name will be used as the species name in output files. Use this feature to model specific particle-size distributions by treating each size-range as a separate species. Order must be consistent with 3(a) above.

```
INPUT GROUP: 4 -- Map Projection and Grid control parameters
--------------

    Projection for all (X,Y):
    -------------------------

    Map projection
    (PMAP)                    Default: UTM    ! PMAP = LCC  !

       UTM :  Universal Transverse Mercator
       TTM :  Tangential Transverse Mercator
       LCC :  Lambert Conformal Conic
        PS :  Polar Stereographic
        EM :  Equatorial Mercator
      LAZA :  Lambert Azimuthal Equal Area

    False Easting and Northing (km) at the projection origin
    (Used only if PMAP= TTM, LCC, or LAZA)
    (FEAST)                   Default=0.0     ! FEAST  = 0.000  !
    (FNORTH)                  Default=0.0     ! FNORTH = 0.000  !

    UTM zone (1 to 60)
    (Used only if PMAP=UTM)
    (IUTMZN)                  No Default      ! IUTMZN =       !

    Hemisphere for UTM projection?
    (Used only if PMAP=UTM)
    (UTMHEM)                  Default: N      ! UTMHEM = N  !
       N   :  Northern hemisphere projection
       S   :  Southern hemisphere projection

    Latitude and Longitude (decimal degrees) of projection origin
    (Used only if PMAP= TTM, LCC, PS, EM, or LAZA)
    (RLAT0)                   No Default      ! RLAT0 =46.5N !
    (RLON0)                   No Default      ! RLON0 =93.0W !
```

TTM : RLON0 identifies central (true N/S) meridian of projection
RLAT0 selected for convenience
LCC : RLON0 identifies central (true N/S) meridian of projection
RLAT0 selected for convenience
PS : RLON0 identifies central (grid N/S) meridian of projection
RLAT0 selected for convenience
EM : RLON0 identifies central meridian of projection
RLAT0 is REPLACED by 0.0N (Equator)
LAZA: RLON0 identifies longitude of tangent-point of mapping plane
RLAT0 identifies latitude of tangent-point of mapping plane

Matching parallel(s) of latitude (decimal degrees) for projection
(Used only if PMAP= LCC or PS)

(XLAT1)	No Default	! XLAT1 = 30N !
(XLAT2)	No Default	! XLAT2 = 60N !

LCC : Projection cone slices through Earth's surface at XLAT1 and XLAT2
PS : Projection plane slices through Earth at XLAT1
(XLAT2 is not used)

Note: Latitudes and longitudes should be positive, and include a
letter N,S,E, or W indicating north or south latitude, and
east or west longitude. For example,
35.9 N Latitude = 35.9N
118.7 E Longitude = 118.7E

Datum-region

The Datum-Region for the coordinates is identified by a character
string. Many mapping products currently available use the model of the
Earth known as the World Geodetic System 1984 (WGS-G). Other local
models may be in use, and their selection in CALMET will make its output
consistent with local mapping products. The list of Datum-Regions with

```
    official transformation parameters is provided by the National Imagery and
    Mapping Agency (NIMA).

    NIMA Datum - Regions(Examples)
    ------------------------------------------------------------------------------
    WGS-G     WGS-84 GRS 80 Spheroid, Global coverage (WGS84)
    NAS-C     NORTH AMERICAN 1927 Clarke 1866 Spheroid, MEAN FOR CONUS (NAD27)
    NWS-27    NWS 6370KM Radius, Sphere
    NWS-84    NWS 6370KM Radius, Sphere
    ESR-S     ESRI REFERENCE 6371KM Radius, Sphere

    Datum-region for output coordinates
    (DATUM)                   Default: WGS-G     ! DATUM = NAS-C  !


METEOROLOGICAL Grid:

    Rectangular grid defined for projection PMAP,
    with X the Easting and Y the Northing coordinate

          No. X grid cells (NX)      No default     ! NX =  183  !
          No. Y grid cells (NY)      No default     ! NY =  130  !
       No. vertical layers (NZ)      No default     ! NZ =  9  !

         Grid spacing (DGRIDKM)      No default     ! DGRIDKM =  4. !
                                     Units: km

             Cell face heights
                (ZFACE(nz+1))        No defaults
                                     Units: m
      ! ZFACE = 0.,20.,50.,100.,200.,500.,1000.,1500.,2500.,3500. !

          Reference Coordinates
         of SOUTHWEST corner of
              grid cell(1, 1):

          X coordinate (XORIGKM)     No default     ! XORIGKM =-381.90!
```

Y coordinate (YORIGKM) No default ! YORIGKM =-251.20!
Units: km

COMPUTATIONAL Grid:

The computational grid is identical to or a subset of the MET. grid.
The lower left (LL) corner of the computational grid is at grid point
(IBCOMP, JBCOMP) of the MET. grid. The upper right (UR) corner of the
computational grid is at grid point (IECOMP, JECOMP) of the MET. grid.
The grid spacing of the computational grid is the same as the MET. grid.

X index of LL corner (IBCOMP) No default ! IBCOMP = 1 !
(1 <= IBCOMP <= NX)

Y index of LL corner (JBCOMP) No default ! JBCOMP = 1 !
(1 <= JBCOMP <= NY)

X index of UR corner (IECOMP) No default ! IECOMP = 183 !
(1 <= IECOMP <= NX)

Y index of UR corner (JECOMP) No default ! JECOMP = 130 !
(1 <= JECOMP <= NY)

SAMPLING Grid (GRIDDED RECEPTORS):

The lower left (LL) corner of the sampling grid is at grid point
(IBSAMP, JBSAMP) of the MET. grid. The upper right (UR) corner of the
sampling grid is at grid point (IESAMP, JESAMP) of the MET. grid.
The sampling grid must be identical to or a subset of the computational
grid. It may be a nested grid inside the computational grid.
The grid spacing of the sampling grid is DGRIDKM/MESHDN.

Logical flag indicating if gridded

```
      receptors are used (LSAMP)         Default: T     ! LSAMP = F !
      (T=yes, F=no)

      X index of LL corner (IBSAMP)      No default     ! IBSAMP =      !
       (IBCOMP <= IBSAMP <= IECOMP)

      Y index of LL corner (JBSAMP)      No default     ! JBSAMP =      !
       (JBCOMP <= JBSAMP <= JECOMP)


      X index of UR corner (IESAMP)      No default     ! IESAMP =       !
       (IBCOMP <= IESAMP <= IECOMP)

      Y index of UR corner (JESAMP)      No default     ! JESAMP =       !
       (JBCOMP <= JESAMP <= JECOMP)


     Nesting factor of the sampling
      grid (MESHDN)                      Default: 1     ! MESHDN =     !
      (MESHDN is an integer >= 1)

!END!


-------------------------------------------------------------------------------


INPUT GROUP: 5 -- Output Options
--------------
                                    *                        *
    FILE                     DEFAULT VALUE            VALUE THIS RUN
    ----                    -------------            --------------

   Concentrations (ICON)            1                  !  ICON =  1   !
   Dry Fluxes (IDRY)               1                  !  IDRY =  1   !
   Wet Fluxes (IWET)                1                  !  IWET =  1   !
   Relative Humidity (IVIS)         1                  !  IVIS =  1   !
```

```
 (relative humidity file is
  required for visibility
  analysis)
Use data compression option in output file?
(LCOMPRS)                        Default: T        ! LCOMPRS = T !

*
 0 = Do not create file, 1 = create file


 DIAGNOSTIC MASS FLUX OUTPUT OPTIONS:

   Mass flux across specified boundaries
   for selected species reported hourly?
   (IMFLX)                       Default: 0        ! IMFLX =  0  !
     0 = no
     1 = yes (FLUXBDY.DAT and MASSFLX.DAT filenames
             are specified in Input Group 0)

   Mass balance for each species
   reported hourly?
   (IMBAL)                       Default: 0        ! IMBAL =  0  !
     0 = no
     1 = yes (MASSBAL.DAT filename is
          specified in Input Group 0)


 LINE PRINTER OUTPUT OPTIONS:

   Print concentrations (ICPRT)    Default: 0        ! ICPRT =  1   !
   Print dry fluxes (IDPRT)        Default: 0        ! IDPRT =  1   !
   Print wet fluxes (IWPRT)        Default: 0        ! IWPRT =  1   !
   (0 = Do not print, 1 = Print)

   Concentration print interval
   (ICFRQ) in hours                Default: 1        ! ICFRQ =  24   !
   Dry flux print interval
```

```
(IDFRQ) in hours              Default: 1        ! IDFRQ =  24  !
Wet flux print interval
(IWFRQ) in hours              Default: 1        ! IWFRQ =  24  !

Units for Line Printer Output
(IPRTU)                       Default: 1        ! IPRTU =  3   !
              for          for
          Concentration   Deposition
   1 =      g/m**3        g/m**2/s
   2 =     mg/m**3        mg/m**2/s
   3 =     ug/m**3        ug/m**2/s
   4 =     ng/m**3        ng/m**2/s
   5 =    Odour Units

Messages tracking progress of run
written to the screen ?
(IMESG)                       Default: 2        ! IMESG =  2   !
  0 = no
  1 = yes (advection step, puff ID)
  2 = yes (YYYYJJJHH, # old puffs, # emitted puffs)


SPECIES (or GROUP for combined species) LIST FOR OUTPUT OPTIONS

            ---- CONCENTRATIONS ----   ------ DRY FLUXES ------   ------ WET FLUXES ------   -- MASS FLUX --
SPECIES
/GROUP       PRINTED?  SAVED ON DISK?   PRINTED?  SAVED ON DISK?   PRINTED?  SAVED ON DISK?   SAVED ON DISK?
-------      ------------------------   ------------------------   ------------------------   ---------------
!       SO2 =    1,         1,         1,         1,         1,         1,         0   !
!       SO4 =    1,         1,         1,         1,         1,         1,         0   !
!       NOX =    1,         1,         1,         1,         0,         0,         0   !
!      HNO3 =    1,         1,         1,         1,         1,         1,         0   !
!       NO3 =    1,         1,         1,         1,         1,         1,         0   !
!      PM10 =    1,         1,         1,         1,         1,         1,         0   !
!        EC =    1,         1,         1,         1,         1,         1,         0   !
!       SOA =    0,         1,         0,         1,         0,         1,         0   !
!      PM25 =    0,         1,         0,         1,         0,         1,         0   !
```

Note: Species BCON (for MBCON > 0) does not need to be saved on disk.

OPTIONS FOR PRINTING "DEBUG" QUANTITIES (much output)

Logical for debug output
(LDEBUG) Default: F ! LDEBUG = F !

First puff to track
(IPFDEB) Default: 1 ! IPFDEB = 1 !

Number of puffs to track
(NPFDEB) Default: 1 ! NPFDEB = 1 !

Met. period to start output
(NN1) Default: 1 ! NN1 = 1 !

Met. period to end output
(NN2) Default: 10 ! NN2 = 10 !

!END!

INPUT GROUP: 6a, 6b, & 6c -- Subgrid scale complex terrain inputs
---

Subgroup (6a)

Number of terrain features (NHILL) Default: 0 ! NHILL = 0 !

Number of special complex terrain
receptors (NCTREC) Default: 0 ! NCTREC = 0 !

```
    Terrain and CTSG Receptor data for
    CTSG hills input in CTDM format ?
    (MHILL)                          No Default     ! MHILL =  0   !
    1 = Hill and Receptor data created
       by CTDM processors & read from
       HILL.DAT and HILLRCT.DAT files
    2 = Hill data created by OPTHILL &
       input below in Subgroup (6b);
       Receptor data in Subgroup (6c)

    Factor to convert horizontal dimensions  Default: 1.0   ! XHILL2M = 0. !
    to meters (MHILL=1)

    Factor to convert vertical dimensions    Default: 1.0   ! ZHILL2M = 0. !
    to meters (MHILL=1)

    X-origin of CTDM system relative to      No Default     ! XCTDMKM = 0.0E00 !
    CALPUFF coordinate system, in Kilometers (MHILL=1)

    Y-origin of CTDM system relative to      No Default     ! YCTDMKM = 0.0E00 !
    CALPUFF coordinate system, in Kilometers (MHILL=1)

! END !

---------------
Subgroup (6b)
---------------

                    1 **
   HILL information


HILL          XC       YC      THETAH  ZGRID  RELIEF    EXPO 1    EXPO 2   SCALE 1    SCALE 2    AMAX1     AMAX2
 NO.         (km)     (km)     (deg.)  (m)     (m)      (m)       (m)       (m)       (m)       (m)       (m)
----         ----     ----     ------  -----  ------    ------    ------   -------    -------    -----     -----
```

Subgroup (6c)

COMPLEX TERRAIN RECEPTOR INFORMATION

XRCT (km)	YRCT (km)	ZRCT (m)	XHH

Description of Complex Terrain Variables:

XC, YC = Coordinates of center of hill
THETAH = Orientation of major axis of hill (clockwise from North)
ZGRID = Height of the 0 of the grid above mean sea level
RELIEF = Height of the crest of the hill above the grid elevation
EXPO 1 = Hill-shape exponent for the major axis
EXPO 2 = Hill-shape exponent for the major axis
SCALE 1 = Horizontal length scale along the major axis
SCALE 2 = Horizontal length scale along the minor axis
AMAX = Maximum allowed axis length for the major axis
BMAX = Maximum allowed axis length for the major axis

XRCT, YRCT = Coordinates of the complex terrain receptors
ZRCT = Height of the ground (MSL) at the complex terrain Receptor
XHH = Hill number associated with each complex terrain receptor (NOTE: MUST BE ENTERED AS A REAL NUMBER)

**
NOTE: DATA for each hill and CTSG receptor are treated as a separate input subgroup and therefore must end with an input group terminator.

```
-------------------------------------------------------------------------------


INPUT GROUP: 7 -- Chemical parameters for dry deposition of gases
--------------

     SPECIES     DIFFUSIVITY      ALPHA STAR      REACTIVITY    MESOPHYLL RESISTANCE     HENRY'S LAW COEFFICIENT
      NAME       (cm**2/s)                                       (s/cm)                (dimensionless)
     -------     -----------      ----------      ----------    --------------------     -----------------------
!        SO2 =    0.1509,         1000.,           8.,              0.,                 0.04 !
!        NOX =    0.1628,           1.,            8.,              5.,                 3.5 !
!       HNO3 =    0.1628,           1.,           18.,              0.,            0.00000008 !
!END!


-------------------------------------------------------------------------------


INPUT GROUP: 8 -- Size parameters for dry deposition of particles
--------------
!        SO4 =        0.48,                    2.   !
!        NO3 =        0.48,                    2.   !
!       PM10 =         7.00,                   2.   !
!         EC =        0.48,                   2.   !
!        SOA =        0.48,                    2.   !
!       PM25 =         0.48,                   2.   !

    For SINGLE SPECIES, the mean and standard deviation are used to
    compute a deposition velocity for NINT (see group 9) size-ranges,
    and these are then averaged to obtain a mean deposition velocity.

    For GROUPED SPECIES, the size distribution should be explicitly
    specified (by the 'species' in the group), and the standard deviation
    for each should be entered as 0.  The model will then use the
    deposition velocity for the stated mean diameter.

     SPECIES      GEOMETRIC MASS MEAN        GEOMETRIC STANDARD
```

```
      NAME            DIAMETER                  DEVIATION
                    (microns)                 (microns)
     -------      -------------------        ------------------
!END!


-------------------------------------------------------------------------------


INPUT GROUP: 9 -- Miscellaneous dry deposition parameters
--------------

    Reference cuticle resistance (s/cm)
    (RCUTR)                        Default: 30    !  RCUTR = 30.0 !
    Reference ground resistance  (s/cm)
    (RGR)                          Default: 10    !    RGR = 10.0 !
    Reference pollutant reactivity
    (REACTR)                        Default: 8     ! REACTR = 8.0 !

    Number of particle-size intervals used to
    evaluate effective particle deposition velocity
    (NINT)                         Default: 9     !   NINT =  9  !

    Vegetation state in unirrigated areas
    (IVEG)                         Default: 1     !   IVEG =  1   !
      IVEG=1 for active and unstressed vegetation
      IVEG=2 for active and stressed vegetation
      IVEG=3 for inactive vegetation

!END!


-------------------------------------------------------------------------------


INPUT GROUP: 10 -- Wet Deposition Parameters
---------------
```

```
                    Scavenging Coefficient -- Units: (sec)**(-1)

      Pollutant      Liquid Precip.       Frozen Precip.
      ---------      --------------       --------------
!        SO2 =        3.0E-05,             0.0E00 !
!        SO4 =        1.0E-04,            3.0E-05 !
!       HNO3 =         6.0E-05,            1.0E-07 !
!        NO3 =        1.0E-04,            3.0E-05 !
!       PM10 =         1.0E-04,            3.0E-05 !
!         EC =        1.0E-04,            3.0E-05 !
!        SOA =        1.0E-04,            3.0E-05 !
!       PM25 =         1.0E-04,            3.0E-05 !
!END!
-------------------------------------------------------------------------------


INPUT GROUP: 11 -- Chemistry Parameters
---------------

    Ozone data input option (MOZ)     Default: 1            ! MOZ =  0   !
    (Used only if MCHEM = 1, 3, or 4)
      0 = use a monthly background ozone value
      1 = read hourly ozone concentrations from
          the OZONE.DAT data file

    Monthly ozone concentrations
    (Used only if MCHEM = 1, 3, or 4 and
     MOZ = 0 or MOZ = 1 and all hourly O3 data missing)
    (BCKO3) in ppb                    Default: 12*80.
    !  BCKO3 = 40.00, 40.00, 40.00, 40.00, 40.00, 40.00, 40.00, 40.00, 40.00, 40.00, 40.00, 40.00 !

    Monthly ammonia concentrations
    (Used only if MCHEM = 1, or 3)
    (BCKNH3) in ppb                   Default: 12*10.
    !  BCKNH3 =  1.0,  1.0,  1.0,  1.0,  1.0,  1.0,  1.0,  1.0,  1.0,  1.0,  1.0,  1.0 !
```

```
   Nighttime SO2 loss rate (RNITE1)
   in percent/hour                Default: 0.2        ! RNITE1 = .2 !

   Nighttime NOx loss rate (RNITE2)
   in percent/hour                Default: 2.0        ! RNITE2 = 2.0 !

   Nighttime HNO3 formation rate (RNITE3)
   in percent/hour                Default: 2.0        ! RNITE3 = 2.0 !

   H2O2 data input option (MH2O2)    Default: 1          ! MH2O2 =  0   !
   (Used only if MAQCHEM = 1)
     0 = use a monthly background H2O2 value
     1 = read hourly H2O2 concentrations from
         the H2O2.DAT data file

   Monthly H2O2 concentrations
   (Used only if MQACHEM = 1 and
    MH2O2 = 0 or MH2O2 = 1 and all hourly H2O2 data missing)
   (BCKH2O2) in ppb               Default: 12*1.
   *  BCKH2O2 =                                                  *


--- Data for SECONDARY ORGANIC AEROSOL (SOA) Option
   (used only if MCHEM = 4)

   The SOA module uses monthly values of:
       Fine particulate concentration in ug/m^3 (BCKPMF)
       Organic fraction of fine particulate     (OFRAC)
       VOC / NOX ratio (after reaction)        (VCNX)
   to characterize the air mass when computing
   the formation of SOA from VOC emissions.
   Typical values for several distinct air mass types are:

     Month    1    2    3    4    5    6    7    8    9   10   11   12
            Jan  Feb  Mar  Apr  May  Jun  Jul  Aug  Sep  Oct  Nov  Dec

   Clean Continental
```

```
   BCKPMF   1.   1.   1.   1.   1.   1.   1.   1.   1.   1.   1.   1.
   OFRAC  .15  .15  .20  .20  .20  .20  .20  .20  .20  .20  .20  .15
   VCNX    50.  50.  50.  50.  50.  50.  50.  50.  50.  50.  50.  50.

Clean Marine (surface)
   BCKPMF  .5   .5   .5   .5   .5   .5   .5   .5   .5   .5   .5   .5
   OFRAC  .25  .25  .30  .30  .30  .30  .30  .30  .30  .30  .30  .25
   VCNX    50.  50.  50.  50.  50.  50.  50.  50.  50.  50.  50.  50.

Urban - low biogenic (controls present)
   BCKPMF  30.  30.  30.  30.  30.  30.  30.  30.  30.  30.  30.  30.
   OFRAC  .20  .20  .25  .25  .25  .25  .25  .25  .20  .20  .20  .20
   VCNX     4.   4.   4.   4.   4.   4.   4.   4.   4.   4.   4.   4.

Urban - high biogenic (controls present)
   BCKPMF  60.  60.  60.  60.  60.  60.  60.  60.  60.  60.  60.  60.
   OFRAC  .25  .25  .30  .30  .30  .55  .55  .55  .35  .35  .35  .25
   VCNX    15.  15.  15.  15.  15.  15.  15.  15.  15.  15.  15.  15.

Regional Plume
   BCKPMF  20.  20.  20.  20.  20.  20.  20.  20.  20.  20.  20.  20.
   OFRAC  .20  .20  .25  .35  .25  .40  .40  .40  .30  .30  .30  .20
   VCNX    15.  15.  15.  15.  15.  15.  15.  15.  15.  15.  15.  15.

Urban - no controls present
   BCKPMF 100. 100. 100. 100. 100. 100. 100. 100. 100. 100. 100. 100.
   OFRAC  .30  .30  .35  .35  .35  .55  .55  .55  .35  .35  .35  .30
   VCNX     2.   2.   2.   2.   2.   2.   2.   2.   2.   2.   2.   2.

Default: Clean Continental
!  BCKPMF = 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00 !
!  OFRAC  = 0.15, 0.15, 0.20, 0.20, 0.20, 0.20, 0.20, 0.20, 0.20, 0.20, 0.20, 0.15 !
!  VCNX   = 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00 !


!END!
```

INPUT GROUP: 12 -- Misc. Dispersion and Computational Parameters
---

Horizontal size of puff (m) beyond which
time-dependent dispersion equations (Heffter)
are used to determine sigma-y and
sigma-z (SYTDEP) Default: 550. ! SYTDEP = 5.5E02 !

Switch for using Heffter equation for sigma z
as above (0 = Not use Heffter; 1 = use Heffter
(MHFTSZ) Default: 0 ! MHFTSZ = 0 !

Stability class used to determine plume
growth rates for puffs above the boundary
layer (JSUP) Default: 5 ! JSUP = 5 !

Vertical dispersion constant for stable
conditions (k1 in Eqn. 2.7-3) (CONK1) Default: 0.01 ! CONK1 = .01 !

Vertical dispersion constant for neutral/
unstable conditions (k2 in Eqn. 2.7-4)
(CONK2) Default: 0.1 ! CONK2 = .1 !

Factor for determining Transition-point from
Schulman-Scire to Huber-Snyder Building Downwash
scheme (SS used for Hs < Hb + TBD * HL)
(TBD) Default: 0.5 ! TBD = .5 !
TBD < 0 ==> always use Huber-Snyder
TBD = 1.5 ==> always use Schulman-Scire
TBD = 0.5 ==> ISC Transition-point

Range of land use categories for which
urban dispersion is assumed

```
(IURB1, IURB2)                    Default: 10     ! IURB1 =  10  !
                                 19     ! IURB2 =  19  !

Site characterization parameters for single-point Met data files ---------
(needed for METFM = 2,3,4)

   Land use category for modeling domain
   (ILANDUIN)                     Default: 20     ! ILANDUIN =  20  !

   Roughness length (m) for modeling domain
   (Z0IN)                        Default: 0.25   ! Z0IN = .25 !

   Leaf area index for modeling domain
   (XLAIIN)                      Default: 3.0    ! XLAIIN = 3.0 !

   Elevation above sea level (m)
   (ELEVIN)                      Default: 0.0    ! ELEVIN = .0 !

   Latitude (degrees) for met location
   (XLATIN)                      Default: -999.  ! XLATIN = -999.0 !

   Longitude (degrees) for met location
   (XLONIN)                      Default: -999.  ! XLONIN = -999.0 !

Specialized information for interpreting single-point Met data files -----

   Anemometer height (m) (Used only if METFM = 2,3)
   (ANEMHT)                      Default: 10.    ! ANEMHT = 10.0 !

   Form of lateral turbulance data in PROFILE.DAT file
   (Used only if METFM = 4 or MTURBVW = 1 or 3)
   (ISIGMAV)                     Default: 1      ! ISIGMAV =  1  !
      0 = read sigma-theta
      1 = read sigma-v

   Choice of mixing heights (Used only if METFM = 4)
   (IMIXCTDM)                    Default: 0      ! IMIXCTDM =  0  !
```

0 = read PREDICTED mixing heights
1 = read OBSERVED mixing heights

Maximum length of a slug (met. grid units)
(XMXLEN) Default: 1.0 ! XMXLEN = 1.0 !

Maximum travel distance of a puff/slug (in
grid units) during one sampling step
(XSAMLEN) Default: 1.0 ! XSAMLEN = 1.0 !

Maximum Number of slugs/puffs release from
one source during one time step
(MXNEW) Default: 99 ! MXNEW = 99 !

Maximum Number of sampling steps for
one puff/slug during one time step
(MXSAM) Default: 99 ! MXSAM = 99 !

Number of iterations used when computing
the transport wind for a sampling step
that includes gradual rise (for CALMET
and PROFILE winds)
(NCOUNT) Default: 2 ! NCOUNT = 2 !

Minimum sigma y for a new puff/slug (m)
(SYMIN) Default: 1.0 ! SYMIN = 1.0 !

Minimum sigma z for a new puff/slug (m)
(SZMIN) Default: 1.0 ! SZMIN = 1.0 !

Default minimum turbulence velocities
sigma-v and sigma-w for each
stability class (m/s)
(SVMIN(6) and SWMIN(6)) Default SVMIN : .50, .50, .50, .50, .50, .50
Default SWMIN : .20, .12, .08, .06, .03, .016

Stability Class : A B C D E F

```
                    ---   ---   ---   ---   ---   ---
          ! SVMIN = 0.500, 0.500, 0.500, 0.500, 0.500, 0.500!
          ! SWMIN = 0.200, 0.120, 0.080, 0.060, 0.030, 0.016!

Divergence criterion for dw/dz across puff
used to initiate adjustment for horizontal
convergence (1/s)
Partial adjustment starts at CDIV(1), and
full adjustment is reached at CDIV(2)
(CDIV(2))                    Default: 0.0,0.0  ! CDIV = .00, .00 !

Minimum wind speed (m/s) allowed for
non-calm conditions. Also used as minimum
speed returned when using power-law
extrapolation toward surface
(WSCALM)                      Default: 0.5    ! WSCALM = .5 !

Maximum mixing height (m)
(XMAXZI)                      Default: 3000.  ! XMAXZI = 3500.0 !

Minimum mixing height (m)
(XMINZI)                     Default: 50.    ! XMINZI = 50.0 !

Default wind speed classes --
5 upper bounds (m/s) are entered;
the 6th class has no upper limit
(WSCAT(5))              Default   :
          ISC RURAL : 1.54, 3.09, 5.14, 8.23, 10.8 (10.8+)

       Wind Speed Class :  1     2     3     4     5
                    ---   ---   ---   ---   ---
          ! WSCAT = 1.54, 3.09, 5.14, 8.23, 10.80 !

Default wind speed profile power-law
exponents for stabilities 1-6
(PLX0(6))               Default   : ISC RURAL values
          ISC RURAL : .07, .07, .10, .15, .35, .55
```

```
                    ISC URBAN : .15, .15, .20, .25, .30, .30

                Stability Class :  A     B     C     D     E     F
                                  ---   ---   ---   ---   ---   ---
                         ! PLX0 = 0.07, 0.07, 0.10, 0.15, 0.35, 0.55 !

Default potential temperature gradient
for stable classes E, F (degK/m)
(PTG0(2))                Default: 0.020, 0.035
                         ! PTG0 = 0.020,   0.035 !

Default plume path coefficients for
each stability class (used when option
for partial plume height terrain adjustment
is selected -- MCTADJ=3)
(PPC(6))             Stability Class :  A     B     C     D     E     F
                   Default  PPC : .50,  .50,  .50,  .50,  .35,  .35
                                  ---   ---   ---   ---   ---   ---
                         !  PPC = 0.50, 0.50, 0.50, 0.50, 0.35, 0.35 !

Slug-to-puff transition criterion factor
equal to sigma-y/length of slug
(SL2PF)                  Default: 10.       ! SL2PF = 5.0 !

Puff-splitting control variables ------------------------

  VERTICAL SPLIT
  --------------

  Number of puffs that result every time a puff
  is split - nsplit=2 means that 1 puff splits
  into 2
  (NSPLIT)                 Default:   3       ! NSPLIT =  3  !

  Time(s) of a day when split puffs are eligible to
  be split once again; this is typically set once
  per day, around sunset before nocturnal shear develops.
```

24 values: 0 is midnight (00:00) and 23 is 11 PM (23:00)
0=do not re-split 1=eligible for re-split
(IRESPLIT(24)) Default: Hour 17 = 1
! IRESPLIT = 0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,1,0,0,0,0,0,0 !

Split is allowed only if last hour's mixing
height (m) exceeds a minimum value
(ZISPLIT) Default: 100. ! ZISPLIT = 100.0 !

Split is allowed only if ratio of last hour's
mixing ht to the maximum mixing ht experienced
by the puff is less than a maximum value (this
postpones a split until a nocturnal layer develops)
(ROLDMAX) Default: 0.25 ! ROLDMAX = 0.25 !

HORIZONTAL SPLIT

Number of puffs that result every time a puff
is split - nsplith=5 means that 1 puff splits
into 5
(NSPLITH) Default: 5 ! NSPLITH = 5 !

Minimum sigma-y (Grid Cells Units) of puff
before it may be split
(SYSPLITH) Default: 1.0 ! SYSPLITH = 1.0 !

Minimum puff elongation rate (SYSPLITH/hr) due to
wind shear, before it may be split
(SHSPLITH) Default: 2. ! SHSPLITH = 2.0 !

Minimum concentration (g/m^3) of each
species in puff before it may be split
Enter array of NSPEC values; if a single value is
entered, it will be used for ALL species
(CNSPLITH) Default: 1.0E-07 ! CNSPLITH = 1.0E-07 !

Integration control variables ----------

Fractional convergence criterion for numerical SLUG
sampling integration
(EPSSLUG) Default: 1.0e-04 ! EPSSLUG = 1.0E-04 !

Fractional convergence criterion for numerical AREA
source integration
(EPSAREA) Default: 1.0e-06 ! EPSAREA = 1.0E-06 !

Trajectory step-length (m) used for numerical rise
integration
(DSRISE) Default: 1.0 ! DSRISE = 1.0 !

Boundary Condition (BC) Puff control variables ----------

Minimum height (m) to which BC puffs are mixed as they are emitted
(MBCON=2 ONLY). Actual height is reset to the current mixing height
at the release point if greater than this minimum.
(HTMINBC) Default: 500. ! HTMINBC = 500. !

Search radius (km) about a receptor for sampling nearest BC puff.
BC puffs are typically emitted with a spacing of one grid cell
length, so the search radius should be greater than DGRIDKM.
(RSAMPBC) Default: 10. ! RSAMPBC = 10. !

Near-Surface depletion adjustment to concentration profile used when
sampling BC puffs?
(MDEPBC) Default: 1 ! MDEPBC = 1. !
0 = Concentration is NOT adjusted for depletion
1 = Adjust Concentration for depletion

!END!

INPUT GROUPS: 13a, 13b, 13c, 13d -- Point source parameters

Subgroup (13a)

Number of point sources with
parameters provided below (NPT1) No default ! NPT1 = 6 !

Units used for point source
emissions below (IPTU) Default: 1 ! IPTU = 1 !
1 = g/s
2 = kg/hr
3 = lb/hr
4 = tons/yr
5 = Odour Unit * m**3/s (vol. flux of odour compound)
6 = Odour Unit * m**3/min
7 = metric tons/yr

Number of source-species
combinations with variable
emissions scaling factors
provided below in (13d) (NSPT1) Default: 0 ! NSPT1 = 0 !

Number of point sources with
variable emission parameters
provided in external file (NPT2) No default ! NPT2 = 0 !

(If NPT2 > 0, these point
source emissions are read from
the file: PTEMARB.DAT)

!END!

Subgroup (13b)
---

a
POINT SOURCE: CONSTANT DATA

```
                                                                b         c
 Source      X UTM     Y UTM          Stack   Base     Stack      Exit   Exit    Bldg.  Emission
  No.     Coordinate Coordinate        Height Elevation Diameter    Vel.  Temp.   Dwash    Rates
            (km)      (km)             (m)     (m)       (m)     (m/s)  (deg. K)
 ------   ---------- ---------- ------   ------   -------- ----- -------- ----- --------
      1  ! SRCNAM = CT1PI      !
      1  ! X =   -26.60188, 90.47040, 45.72,  434.30,    6.10,   20.08,  394.3, 1.0, 14.36,0.945,19.66,0,0,0,
                 0.787,    1.397,      0   !
      1  ! FMFAC  =      1.0 !   !END!
      2  ! SRCNAM = CT2PI      !
      2  ! X =   -26.57211, 90.44989, 45.72,  434.30,    6.10,   20.08,  394.3, 1.0, 14.36,0.945,19.66,0,0,0,
                 0.787,    1.397,      0   !
      2  ! FMFAC  =      1.0 !   !END!
      3  ! SRCNAM = TVIPI      !
      3  ! X =   -26.66799, 90.62411, 64.01,  434.30,    1.83,    8.46,  579.8, 1.0,  0.81,0,2.46,0,0,0,
                 0,           0,     0.088 !
      3  ! FMFAC  =      1.0 !   !END!
      4  ! SRCNAM = CT1PII     !
      4  ! X =   -26.42979, 90.34962, 45.72,  434.30,    6.10,   20.08,  394.3, 1.0, 14.36,0.945,19.66,0,0,0,
                 0.787,    1.397,      0   !
      4  ! FMFAC  =      1.0 !   !END!
      5  ! SRCNAM = CT2PII     !
      5  ! X =   -26.40002, 90.32912, 45.72,  434.30,    6.10,   20.08,  394.3, 1.0, 14.36,0.945,19.66,0,0,0,
                 0.787,    1.397,      0   !
      5  ! FMFAC  =      1.0 !   !END!
      6  ! SRCNAM = TVIPII     !
      6  ! X =   -26.17563, 90.27560, 64.01,  434.30,    1.83,    8.46,  579.8, 1.0,  0.81,0,2.46,0,0,0,
                 0,           0,     0.088 !
      6  ! FMFAC  =      1.0 !   !END!
--------
```

a

Data for each source are treated as a separate input subgroup
and therefore must end with an input group terminator.

SRCNAM is a 12-character name for a source
(No default)
X is an array holding the source data listed by the column headings
(No default)
SIGYZI is an array holding the initial sigma-y and sigma-z (m)
(Default: 0.,0.)
FMFAC is a vertical momentum flux factor (0. or 1.0) used to represent
the effect of rain-caps or other physical configurations that
reduce momentum rise associated with the actual exit velocity.
(Default: 1.0 -- full momentum used)

b
0. = No building downwash modeled, 1. = downwash modeled
NOTE: must be entered as a REAL number (i.e., with decimal point)

c
An emission rate must be entered for every pollutant modeled.
Enter emission rate of zero for secondary pollutants that are
modeled, but not emitted. Units are specified by IPTU
(e.g. 1 for g/s).

Subgroup (13c)

BUILDING DIMENSION DATA FOR SOURCES SUBJECT TO DOWNWASH

Source a
No. Effective building height, width, length and X/Y offset (in meters)
every 10 degrees. LENGTH, XBADJ, and YBADJ are only needed for
MBDW=2 (PRIME downwash option)
------ ---
1 ! SRCNAM = CT1PI !
1 ! HEIGHT = 27.43, 27.43, 22.86, 27.43, 27.43, 27.43,

```
          27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
          27.43,  27.43,  27.43,  27.43,  27.43,  45.72,
          45.72,  27.43,  22.86,  27.43,  27.43,  27.43,
          27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
          27.43,  27.43,  27.43,  27.43,  27.43,  27.43 !
     1  !  WIDTH =   29.14,  60.85,  71.65,  20.00,  61.24,  29.67,
          33.21,  35.75,  37.20,  37.52,  36.61,  34.68,
          35.03,  36.82,  37.51,  37.05,  35.46,  43.30,
          46.18,  60.85,  71.65,  20.00,  61.24,  29.67,
          33.21,  35.75,  37.20,  37.52,  36.61,  34.68,
          35.03,  36.82,  37.51,  37.05,  35.46,  32.80 !
     1  !  LENGTH =  37.52,  45.96,  27.58,  35.03,  46.93,  37.51,
          37.05,  35.46,  32.80,  29.14,  24.60,  19.31,
          20.00,  25.14,  29.58,  33.12,  35.75,  33.00,
          26.47,  45.96,  27.58,  35.03,  46.93,  37.51,
          37.05,  35.46,  32.80,  29.14,  24.60,  19.31,
          20.00,  25.14,  29.58,  33.21,  35.65,  37.20 !
     1  !  XBADJ =  -38.99, -49.06, -64.17, -39.39, -39.51, -38.43,
         -36.19, -32.84, -28.50, -23.29,  18.88,  26.38,
          -7.48,  29.78,  28.84,  27.02,  -1.86,-226.50,
        -222.12,   3.10,  36.60,   4.36,  -7.42,   0.93,
          -0.86,  -2.62,  -4.30,  -5.85, -43.47, -45.68,
         -12.52, -54.92, -58.42, -29.74, -60.03, -37.00 !
     1  !  YBADJ =    8.72, -13.05, -16.33,  -2.52, -24.30,  -9.86,
         -13.13, -16.01, -18.40, -20.23, -30.75, -24.88,
         -21.87, -10.99,  -3.47,   4.16, -15.11,  11.95,
         -24.70,  13.05,  16.33,   2.52,  24.30,   9.86,
          13.13,  16.01,  18.40,  20.23,  30.75,  24.88,
          21.87,  10.99,   3.47,  17.66, -11.66,  12.10 !

!END!
     2  ! SRCNAM = CT2PI      !
     2  !  HEIGHT =  27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
          27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
          27.43,  27.43,  27.43,  27.43,  45.72,  45.72,
          27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
          27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
```

```
          27.43,  27.43,  27.43,  27.43,  27.43,  27.43 !
     2  !  WIDTH =   29.14,  60.75,  54.90,  83.81,  61.24,  29.58,
          33.12,  35.65,  37.10,  37.42,  36.61,  34.68,
          35.03,  36.82,  37.51,  37.05,  39.10,  43.21,
          29.14,  60.75,  54.90,  83.81,  61.24,  29.58,
          33.12,  35.65,  37.10,  37.42,  36.61,  34.68,
          35.03,  36.82,  37.51,  37.05,  35.46,  32.80 !
     2  !  LENGTH =  37.42,  54.25,  46.56,  65.39,  46.93,  37.51,
          37.05,  35.46,  32.80,  29.14,  24.60,  19.31,
          20.00,  25.14,  29.58,  33.12,  38.52,  33.00,
          37.42,  54.25,  46.56,  65.39,  46.93,  37.51,
          37.05,  35.46,  32.80,  29.14,  24.60,  19.31,
          20.00,  25.14,  29.58,  33.12,  35.65,  37.10 !
     2  !  XBADJ =  -38.89, -86.87, -76.94, -69.67, -49.55, -38.38,
         -36.15, -32.82, -28.50, -23.31, -17.41, -10.98,
         -44.78,  -6.32,  -4.97,  -3.47,-250.24,-247.70,
           1.47,  32.62,  30.38,   4.28,   2.62,   0.88,
          -0.89,  -2.64,  -4.30,  -5.83,  -7.19,  -8.32,
          24.78, -18.82, -24.61, -29.65, -33.79, -36.90 !
     2  !  YBADJ =    8.74, -29.83, -39.76, -34.42,  11.80,  -9.82,
         -13.09, -15.96, -18.35, -20.18, -21.40, -21.97,
         -25.49, -21.03, -19.63, -17.63,  21.49, -18.95,
          -8.74,  29.83,  39.76,  34.42, -11.80,   9.82,
          13.09,  15.96,  18.35,  20.18,  21.40,  21.97,
          25.49,  21.03,  19.63,  17.63,  15.09,  12.10 !

!END!
     3  ! SRCNAM = TVIPI      !
     3  !  HEIGHT =   0.00,   0.00,  45.72,  45.72,  45.72,  45.72,
          45.72,  45.72,   0.00,   0.00,   0.00,   0.00,
           0.00,   0.00,   0.00,   0.00,   0.00,   0.00,
           0.00,   0.00,  45.72,  45.72,  45.72,  45.72,
          45.72,  45.72,   0.00,   0.00,   0.00,   0.00,
           0.00,   0.00,   0.00,   0.00,   0.00,   0.00 !
     3  !  WIDTH =    0.00,   0.00,  47.70,  47.79,  47.58,  45.93,
          42.88,  38.52,   0.00,   0.00,   0.00,   0.00,
           0.00,   0.00,   0.00,   0.00,   0.00,   0.00,
```

```
            0.00,   0.00,  47.70,  47.79,  47.58,  45.93,
           42.88,  38.52,   0.00,   0.00,   0.00,   0.00,
            0.00,   0.00,   0.00,   0.00,   0.00,   0.00 !
     3  !  LENGTH =   0.00,   0.00,  11.23,  12.21,  20.06,  27.30,
           33.71,  39.10,   0.00,   0.00,   0.00,   0.00,
            0.00,   0.00,   0.00,   0.00,   0.00,   0.00,
            0.00,   0.00,  11.23,  12.21,  20.06,  27.30,
           33.71,  39.10,   0.00,   0.00,   0.00,   0.00,
            0.00,   0.00,   0.00,   0.00,   0.00,   0.00 !
     3  !  XBADJ =    0.00,   0.00,  78.83,  84.74,  84.46,  81.61,
           76.28,  68.63,   0.00,   0.00,   0.00,   0.00,
            0.00,   0.00,   0.00,   0.00,   0.00,   0.00,
            0.00,   0.00, -90.06, -96.95,-104.52,-108.91,
         -109.99,-107.73,   0.00,   0.00,   0.00,   0.00,
            0.00,   0.00,   0.00,   0.00,   0.00,   0.00 !
     3  !  YBADJ =    0.00,   0.00, -44.26, -28.92, -12.71,   3.89,
           20.37,  36.24,   0.00,   0.00,   0.00,   0.00,
            0.00,   0.00,   0.00,   0.00,   0.00,   0.00,
            0.00,   0.00,  44.26,  28.92,  12.71,  -3.89,
          -20.37, -36.24,   0.00,   0.00,   0.00,   0.00,
            0.00,   0.00,   0.00,   0.00,   0.00,   0.00 !
!END!
     4  ! SRCNAM = CT1PII     !
     4  !  HEIGHT =  27.43,  27.43,  22.86,  27.43,  27.43,  27.43,
           27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
           27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
           27.43,  27.43,  22.86,  27.43,  27.43,  27.43,
           27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
           27.43,  27.43,  27.43,  27.43,  27.43,  27.43 !
     4  !  WIDTH =   29.14,  60.85,  71.60,  19.94,  61.24,  29.58,
           33.12,  35.65,  37.10,  37.42,  36.61,  34.68,
           35.03,  36.82,  37.51,  37.05,  35.46,  32.80,
           29.14,  60.85,  71.60,  19.94,  61.24,  29.58,
           33.12,  35.65,  37.10,  37.42,  36.61,  34.68,
           35.03,  36.82,  37.51,  37.05,  35.46,  32.80 !
     4  !  LENGTH =  37.52,  45.96,  27.58,  35.03,  46.93,  37.51,
           37.05,  35.46,  32.80,  29.14,  24.60,  19.31,
```

```
          19.94,  25.14,  29.58,  33.21,  35.75,  37.20,
          37.52,  45.96,  27.58,  35.03,  46.93,  37.51,
          37.05,  35.46,  32.80,  29.14,  24.60,  19.31,
          19.94,  25.14,  29.58,  33.12,  35.75,  37.20 !
    4  !  XBADJ =  -53.91, -48.59, -64.17, -39.07, -39.26, -38.27,
         -36.11, -32.85, -28.60, -23.48, -17.64, -11.27,
          -7.80,  -6.71,  -5.41,  26.45,  23.79,  20.40,
          16.39,   2.63,  36.60,   4.04,  -7.67,   0.76,
          -0.94,  -2.61,  -4.20,  -5.66,  -6.96,  -8.04,
         -12.14, -18.44, -24.17, -29.18, -59.54, -57.60 !
    4  !  YBADJ =  -25.19, -12.78, -16.31,  -2.17, -23.92,  -9.38,
         -12.62, -15.47, -17.85, -19.69, -20.93, -21.53,
         -21.55, -20.85, -19.52,   4.23,  11.64,  18.70,
          25.19,  12.78,  16.31,   2.17,  23.92,   9.38,
          12.62,  15.47,  17.85,  19.69,  20.93,  21.53,
          21.55,  20.85,  19.52,  17.59, -11.64, -18.70 !

!END!
    5  ! SRCNAM = CT2PII     !
    5  !  HEIGHT =  27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
          27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
          27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
          27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
          27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
          27.43,  27.43,  27.43,  27.43,  27.43,  27.43 !
    5  !  WIDTH =   29.14,  60.81,  54.94,  84.07,  61.24,  29.58,
          33.12,  35.65,  37.10,  37.42,  36.61,  34.68,
          35.03,  36.82,  37.51,  37.05,  35.46,  32.80,
          29.14,  60.81,  54.94,  84.07,  61.24,  29.58,
          33.12,  35.65,  37.10,  37.42,  36.61,  34.68,
          35.03,  36.82,  37.51,  37.05,  35.46,  32.80 !
    5  !  LENGTH =  37.52,  54.12,  46.42,  64.77,  46.93,  37.51,
          37.05,  35.46,  32.80,  29.14,  24.60,  19.31,
          19.94,  25.14,  29.67,  33.21,  35.75,  37.20,
          37.52,  54.12,  46.42,  64.77,  46.93,  37.51,
          37.05,  35.46,  32.80,  29.14,  24.60,  19.31,
          19.94,  25.14,  29.67,  33.21,  35.75,  37.20 !
```

```
     5  !  XBADJ =  -38.40, -85.82, -75.86, -68.74, -49.31, -54.43,
           -57.90, -59.60, -59.50, -57.59, -53.93, -48.63,
           -45.10, -42.81,  -5.49,  -4.04,  -2.45,  -0.80,
             0.88,  31.70,  29.44,   3.96,   2.37,  16.92,
            20.85,  24.14,  26.70,  28.45,  29.33,  29.32,
            25.16,  17.67, -24.17, -29.18, -33.29, -36.40 !
     5  !  YBADJ =    8.92, -30.06, -39.81, -34.17,  12.19,  24.43,
            17.87,  10.77,   3.35,  -4.18, -11.58, -18.62,
           -25.18, -30.90, -19.47, -17.55, -15.11, -12.20,
            -8.92,  30.06,  39.81,  34.17, -12.19, -24.43,
           -17.87, -10.77,  -3.35,   4.18,  11.58,  18.62,
            25.18,  30.90,  19.47,  17.55,  15.11,  12.20 !

!END!
     6  ! SRCNAM = TVIPII     !
     6  !  HEIGHT =  45.72,  45.72,  45.72,  45.72,  45.72,   0.00,
             0.00,   0.00,   0.00,  21.34,  21.34,  21.34,
             0.00,   0.00,   0.00,   0.00,   0.00,  45.72,
            45.72,  45.72,  45.72,  45.72,  45.72,   0.00,
             0.00,   0.00,   0.00,   0.00,   0.00,   0.00,
             0.00,   0.00,   0.00,   0.00,   0.00,  45.72 !
     6  !  WIDTH =   46.18,  47.67,  47.70,  47.79,  47.58,   0.00,
             0.00,   0.00,   0.00,  86.08,  69.74,  51.28,
             0.00,   0.00,   0.00,   0.00,   0.00,  43.30,
            46.18,  47.67,  47.70,  47.79,  47.58,   0.00,
             0.00,   0.00,   0.00,   0.00,   0.00,   0.00,
             0.00,   0.00,   0.00,   0.00,   0.00,  43.30 !
     6  !  LENGTH =  26.47,  19.14,  11.23,  12.21,  20.06,   0.00,
             0.00,   0.00,   0.00, 121.80, 121.41, 117.32,
             0.00,   0.00,   0.00,   0.00,   0.00,  33.00,
            26.47,  19.14,  11.23,  12.21,  20.06,   0.00,
             0.00,   0.00,   0.00,   0.00,   0.00,   0.00,
             0.00,   0.00,   0.00,   0.00,   0.00,  33.00 !
     6  !  XBADJ =   71.20,  77.94,  82.30,  79.56,  70.77,   0.00,
             0.00,   0.00,   0.00,-215.27,-220.50,-219.04,
             0.00,   0.00,   0.00,   0.00,   0.00, -95.30,
           -97.67, -97.08, -93.53, -91.76, -90.82,   0.00,
```

```
            0.00,   0.00,   0.00,   0.00,   0.00,   0.00,
            0.00,   0.00,   0.00,   0.00,   0.00,  62.30 !
     6  !  YBADJ =  -25.07, -10.03,   5.32,  20.51,  35.07,   0.00,
            0.00,   0.00,   0.00,  44.77,  17.29, -10.72,
            0.00,   0.00,   0.00,   0.00,   0.00,  39.35,
           25.07,  10.03,  -5.32, -20.51, -35.07,   0.00,
            0.00,   0.00,   0.00,   0.00,   0.00,   0.00,
            0.00,   0.00,   0.00,   0.00,   0.00, -39.35 !

!END!
--------
```

a

Building height, width, length, and X/Y offset from the source are treated as a separate input subgroup for each source and therefore must end with an input group terminator.

Subgroup (13d)

---

a

POINT SOURCE: VARIABLE EMISSIONS DATA

Use this subgroup to describe temporal variations in the emission rates given in 13b. Factors entered multiply the rates in 13b. Skip sources here that have constant emissions. For more elaborate variation in source parameters, use PTEMARB.DAT and NPT2 > 0.

IVARY determines the type of variation, and is source-specific:

(IVARY) Default: 0

- 0 = Constant
- 1 = Diurnal cycle (24 scaling factors: hours 1-24)
- 2 = Monthly cycle (12 scaling factors: months 1-12)
- 3 = Hour & Season (4 groups of 24 hourly scaling factors, where first group is DEC-JAN-FEB)
- 4 = Speed & Stab. (6 groups of 6 scaling factors, where

first group is Stability Class A,
and the speed classes have upper
bounds (m/s) defined in Group 12

5 = Temperature (12 scaling factors, where temperature
classes have upper bounds (C) of:
0, 5, 10, 15, 20, 25, 30, 35, 40,
45, 50, 50+)

---

a

Data for each species are treated as a separate input subgroup
and therefore must end with an input group terminator.

INPUT GROUPS: 14a, 14b, 14c, 14d -- Area source parameters

Subgroup (14a)

Number of polygon area sources with
parameters specified below (NAR1) No default ! NAR1 = 0 !

Units used for area source
emissions below (IARU) Default: 1 ! IARU = 1 !

1 = g/m**2/s
2 = kg/m**2/hr
3 = lb/m**2/hr
4 = tons/m**2/yr
5 = Odour Unit * m/s (vol. flux/m**2 of odour compound)
6 = Odour Unit * m/min

7 = metric tons/m**2/yr

Number of source-species
combinations with variable
emissions scaling factors
provided below in (14d) (NSAR1) Default: 0 ! NSAR1 = 0 !

Number of buoyant polygon area sources
with variable location and emission
parameters (NAR2) No default ! NAR2 = 0 !
(If NAR2 > 0, ALL parameter data for
these sources are read from the file: BAEMARB.DAT)

!END!

Subgroup (14b)
---

a
AREA SOURCE: CONSTANT DATA
---

b

Source No.	Effect. Height (m)	Base Elevation (m)	Initial Sigma z (m)	Emission Rates
---	---	---	---	---

a
Data for each source are treated as a separate input subgroup
and therefore must end with an input group terminator.
b
An emission rate must be entered for every pollutant modeled.
Enter emission rate of zero for secondary pollutants that are
modeled, but not emitted. Units are specified by IARU
(e.g. 1 for g/m**2/s).

Subgroup (14c)

COORDINATES (UTM-km) FOR EACH VERTEX(4) OF EACH POLYGON

Source a
No. Ordered list of X followed by list of Y, grouped by source
------ ---
---
a
Data for each source are treated as a separate input subgroup
and therefore must end with an input group terminator.

Subgroup (14d)
---

a
AREA SOURCE: VARIABLE EMISSIONS DATA

Use this subgroup to describe temporal variations in the emission
rates given in 14b. Factors entered multiply the rates in 14b.
Skip sources here that have constant emissions. For more elaborate
variation in source parameters, use BAEMARB.DAT and NAR2 > 0.

IVARY determines the type of variation, and is source-specific:
(IVARY) Default: 0

0 = Constant
1 = Diurnal cycle (24 scaling factors: hours 1-24)
2 = Monthly cycle (12 scaling factors: months 1-12)
3 = Hour & Season (4 groups of 24 hourly scaling factors,
where first group is DEC-JAN-FEB)
4 = Speed & Stab. (6 groups of 6 scaling factors, where
first group is Stability Class A,
and the speed classes have upper
bounds (m/s) defined in Group 12

5 = Temperature (12 scaling factors, where temperature
classes have upper bounds (C) of:
0, 5, 10, 15, 20, 25, 30, 35, 40,
45, 50, 50+)

---
a
Data for each species are treated as a separate input subgroup
and therefore must end with an input group terminator.

INPUT GROUPS: 15a, 15b, 15c -- Line source parameters

Subgroup (15a)

Number of buoyant line sources
with variable location and emission
parameters (NLN2) No default ! NLN2 = 0 !

(If NLN2 > 0, ALL parameter data for
these sources are read from the file: LNEMARB.DAT)

Number of buoyant line sources (NLINES) No default ! NLINES = 0 !

Units used for line source
emissions below (ILNU) Default: 1 ! ILNU = 1 !
1 = g/s
2 = kg/hr
3 = lb/hr
4 = tons/yr

```
      5 =     Odour Unit * m**3/s  (vol. flux of odour compound)
      6 =     Odour Unit * m**3/min
      7 =     metric tons/yr

   Number of source-species
   combinations with variable
   emissions scaling factors
   provided below in (15c)       (NSLN1) Default: 0  !  NSLN1 =  0  !

   Maximum number of segments used to model
   each line (MXNSEG)                          Default: 7   ! MXNSEG =  7  !

   The following variables are required only if NLINES > 0.  They are
   used in the buoyant line source plume rise calculations.

     Number of distances at which              Default: 6   ! NLRISE =  6  !
     transitional rise is computed

     Average building length (XL)              No default   ! XL = .0 !
                                    (in meters)

     Average building height (HBL)             No default   ! HBL = .0 !
                                    (in meters)

     Average building width (WBL)              No default   ! WBL = .0 !
                                    (in meters)

     Average line source width (WML)           No default   ! WML = .0 !
                                    (in meters)

     Average separation between buildings (DXL)  No default   ! DXL = .0 !
                                    (in meters)

     Average buoyancy parameter (FPRIMEL)      No default   ! FPRIMEL = .0 !
                                    (in m**4/s**3)

!END!
```

Subgroup (15b)

BUOYANT LINE SOURCE: CONSTANT DATA

Source No.	Beg. X Coordinate (km)	Beg. Y Coordinate (km)	End. X Coordinate (km)	End. Y Coordinate (km)	Release Height[a] (m)	Base Elevation (m)	Emission Rates

---

a
Data for each source are treated as a separate input subgroup and therefore must end with an input group terminator.

b
An emission rate must be entered for every pollutant modeled. Enter emission rate of zero for secondary pollutants that are modeled, but not emitted. Units are specified by ILNTU (e.g. 1 for g/s).

Subgroup (15c)

BUOYANT LINE SOURCE: VARIABLE EMISSIONS DATA[a]

Use this subgroup to describe temporal variations in the emission rates given in 15b. Factors entered multiply the rates in 15b. Skip sources here that have constant emissions.

IVARY determines the type of variation, and is source-specific:

(IVARY) Default: 0

0 = Constant
1 = Diurnal cycle (24 scaling factors: hours 1-24)
2 = Monthly cycle (12 scaling factors: months 1-12)
3 = Hour & Season (4 groups of 24 hourly scaling factors, where first group is DEC-JAN-FEB)
4 = Speed & Stab. (6 groups of 6 scaling factors, where first group is Stability Class A, and the speed classes have upper bounds (m/s) defined in Group 12
5 = Temperature (12 scaling factors, where temperature classes have upper bounds (C) of: 0, 5, 10, 15, 20, 25, 30, 35, 40, 45, 50, 50+)

---

a

Data for each species are treated as a separate input subgroup and therefore must end with an input group terminator.

INPUT GROUPS: 16a, 16b, 16c -- Volume source parameters

Subgroup (16a)

Number of volume sources with parameters provided in 16b,c (NVL1) No default ! NVL1 = 0 !

Units used for volume source

```
    emissions below in 16b       (IVLU)     Default: 1  !  IVLU =   1  !
         1 =        g/s
         2 =       kg/hr
         3 =       lb/hr
         4 =     tons/yr
         5 =     Odour Unit * m**3/s  (vol. flux of odour compound)
         6 =     Odour Unit * m**3/min
         7 =     metric tons/yr

    Number of source-species
    combinations with variable
    emissions scaling factors
    provided below in (16c)      (NSVL1)    Default: 0  !  NSVL1 =  0  !

    Number of volume sources with
    variable location and emission
    parameters                   (NVL2)     No default  !  NVL2 =   0   !

    (If NVL2 > 0, ALL parameter data for
     these sources are read from the VOLEMARB.DAT file(s) )

!END!

---------------
Subgroup (16b)
---------------
                                   a
         VOLUME SOURCE: CONSTANT DATA
         ------------------------------
                                                                b
       X UTM      Y UTM      Effect.    Base     Initial    Initial    Emission
    Coordinate  Coordinate   Height   Elevation  Sigma y    Sigma z     Rates
       (km)       (km)         (m)       (m)        (m)       (m)
    ----------  ----------   ------    ------    --------   --------   --------
--------
    a
    Data for each source are treated as a separate input subgroup
```

and therefore must end with an input group terminator.

b
An emission rate must be entered for every pollutant modeled.
Enter emission rate of zero for secondary pollutants that are
modeled, but not emitted. Units are specified by IVLU
(e.g. 1 for g/s).

Subgroup (16c)
---

a
VOLUME SOURCE: VARIABLE EMISSIONS DATA

Use this subgroup to describe temporal variations in the emission
rates given in 16b. Factors entered multiply the rates in 16b.
Skip sources here that have constant emissions. For more elaborate
variation in source parameters, use VOLEMARB.DAT and NVL2 > 0.

IVARY determines the type of variation, and is source-specific:
(IVARY) Default: 0

0 = Constant
1 = Diurnal cycle (24 scaling factors: hours 1-24)
2 = Monthly cycle (12 scaling factors: months 1-12)
3 = Hour & Season (4 groups of 24 hourly scaling factors,
where first group is DEC-JAN-FEB)
4 = Speed & Stab. (6 groups of 6 scaling factors, where
first group is Stability Class A,
and the speed classes have upper
bounds (m/s) defined in Group 12
5 = Temperature (12 scaling factors, where temperature
classes have upper bounds (C) of:
0, 5, 10, 15, 20, 25, 30, 35, 40,
45, 50, 50+)

```
--------
   a
    Data for each species are treated as a separate input subgroup
    and therefore must end with an input group terminator.


-------------------------------------------------------------------------------

INPUT GROUPS: 17a & 17b -- Non-gridded (discrete) receptor information
-----------------------

---------------
Subgroup (17a)
---------------

    Number of non-gridded receptors (NREC)  No default  !  NREC = 1272 !

!END!

---------------
Subgroup (17b)
---------------
                                        a
          NON-GRIDDED (DISCRETE) RECEPTOR DATA
          ------------------------------------

                 X UTM       Y UTM        Ground        Height   b
Receptor       Coordinate   Coordinate    Elevation   Above Ground
  No.            (km)        (km)           (m)          (m)
--------       ----------   ----------    ---------   ------------
     1 ! X =     103.1693,    138.2968,   487.0 !!END!   Boundary Waters
     2 ! X =     104.9739,    138.3293,   483.0 !!END!   Boundary Waters
     3 ! X =     106.7784,    138.3624,   475.0 !!END!   Boundary Waters
     4 ! X =     108.5829,    138.3960,   472.0 !!END!   Boundary Waters
     5 ! X =     110.3874,    138.4302,   474.0 !!END!   Boundary Waters
     6 ! X =     112.1918,    138.4650,   472.0 !!END!   Boundary Waters
```

7 ! X =	113.9963,	138.5003,	468.0	!!END!	Boundary Waters
8 ! X =	115.8007,	138.5361,	469.0	!!END!	Boundary Waters
9 ! X =	117.6052,	138.5726,	480.0	!!END!	Boundary Waters
10 ! X =	124.8228,	138.7240,	490.0	!!END!	Boundary Waters
11 ! X =	126.6272,	138.7632,	498.0	!!END!	Boundary Waters
12 ! X =	128.4316,	138.8030,	502.0	!!END!	Boundary Waters
13 ! X =	130.2359,	138.8434,	502.0	!!END!	Boundary Waters
14 ! X =	132.0403,	138.8844,	503.0	!!END!	Boundary Waters
15 ! X =	133.8446,	138.9259,	502.0	!!END!	Boundary Waters
16 ! X =	135.6489,	138.9679,	511.0	!!END!	Boundary Waters
17 ! X =	103.1214,	140.9822,	457.0	!!END!	Boundary Waters
18 ! X =	104.9251,	141.0147,	460.0	!!END!	Boundary Waters
19 ! X =	106.7288,	141.0478,	472.0	!!END!	Boundary Waters
20 ! X =	108.5324,	141.0814,	472.0	!!END!	Boundary Waters
21 ! X =	110.3361,	141.1155,	457.0	!!END!	Boundary Waters
22 ! X =	112.1397,	141.1503,	455.0	!!END!	Boundary Waters
23 ! X =	113.9433,	141.1856,	472.0	!!END!	Boundary Waters
24 ! X =	115.7469,	141.2214,	456.0	!!END!	Boundary Waters
25 ! X =	117.5505,	141.2578,	473.0	!!END!	Boundary Waters
26 ! X =	119.3541,	141.2948,	472.0	!!END!	Boundary Waters
27 ! X =	121.1577,	141.3324,	473.0	!!END!	Boundary Waters
28 ! X =	122.9613,	141.3705,	478.0	!!END!	Boundary Waters
29 ! X =	124.7648,	141.4091,	489.0	!!END!	Boundary Waters
30 ! X =	126.5684,	141.4484,	487.0	!!END!	Boundary Waters
31 ! X =	128.3719,	141.4882,	487.0	!!END!	Boundary Waters
32 ! X =	130.1754,	141.5285,	501.0	!!END!	Boundary Waters
33 ! X =	131.9789,	141.5695,	502.0	!!END!	Boundary Waters
34 ! X =	133.7824,	141.6110,	499.0	!!END!	Boundary Waters
35 ! X =	135.5859,	141.6530,	518.0	!!END!	Boundary Waters
36 ! X =	101.2706,	143.6356,	487.0	!!END!	Boundary Waters
37 ! X =	103.0735,	143.6675,	447.0	!!END!	Boundary Waters
38 ! X =	104.8763,	143.7000,	441.0	!!END!	Boundary Waters
39 ! X =	106.6791,	143.7330,	470.0	!!END!	Boundary Waters
40 ! X =	108.4820,	143.7666,	472.0	!!END!	Boundary Waters
41 ! X =	110.2848,	143.8007,	478.0	!!END!	Boundary Waters
42 ! X =	112.0876,	143.8354,	472.0	!!END!	Boundary Waters
43 ! X =	113.8904,	143.8707,	472.0	!!END!	Boundary Waters

44 ! X =	115.6931,	143.9066,	472.0	!!END!	Boundary Waters
45 ! X =	117.4959,	143.9430,	472.0	!!END!	Boundary Waters
46 ! X =	119.2986,	143.9799,	472.0	!!END!	Boundary Waters
47 ! X =	121.1014,	144.0175,	481.0	!!END!	Boundary Waters
48 ! X =	122.9041,	144.0556,	487.0	!!END!	Boundary Waters
49 ! X =	124.7068,	144.0942,	503.0	!!END!	Boundary Waters
50 ! X =	126.5095,	144.1334,	502.0	!!END!	Boundary Waters
51 ! X =	128.3122,	144.1732,	502.0	!!END!	Boundary Waters
52 ! X =	130.1149,	144.2135,	506.0	!!END!	Boundary Waters
53 ! X =	131.9176,	144.2545,	522.0	!!END!	Boundary Waters
54 ! X =	133.7202,	144.2959,	533.0	!!END!	Boundary Waters
55 ! X =	135.5229,	144.3380,	510.0	!!END!	Boundary Waters
56 ! X =	97.6195,	146.2593,	456.0	!!END!	Boundary Waters
57 ! X =	99.4215,	146.2900,	441.0	!!END!	Boundary Waters
58 ! X =	101.2235,	146.3214,	441.0	!!END!	Boundary Waters
59 ! X =	103.0255,	146.3532,	446.0	!!END!	Boundary Waters
60 ! X =	104.8275,	146.3857,	467.0	!!END!	Boundary Waters
61 ! X =	106.6295,	146.4187,	463.0	!!END!	Boundary Waters
62 ! X =	108.4315,	146.4523,	463.0	!!END!	Boundary Waters
63 ! X =	110.2335,	146.4864,	475.0	!!END!	Boundary Waters
64 ! X =	112.0354,	146.5211,	472.0	!!END!	Boundary Waters
65 ! X =	113.8374,	146.5564,	475.0	!!END!	Boundary Waters
66 ! X =	115.6393,	146.5922,	474.0	!!END!	Boundary Waters
67 ! X =	117.4412,	146.6286,	487.0	!!END!	Boundary Waters
68 ! X =	119.2432,	146.6655,	472.0	!!END!	Boundary Waters
69 ! X =	121.0451,	146.7030,	487.0	!!END!	Boundary Waters
70 ! X =	122.8469,	146.7411,	493.0	!!END!	Boundary Waters
71 ! X =	124.6488,	146.7798,	487.0	!!END!	Boundary Waters
72 ! X =	126.4507,	146.8190,	502.0	!!END!	Boundary Waters
73 ! X =	128.2525,	146.8587,	528.0	!!END!	Boundary Waters
74 ! X =	130.0544,	146.8990,	531.0	!!END!	Boundary Waters
75 ! X =	131.8562,	146.9399,	518.0	!!END!	Boundary Waters
76 ! X =	133.6580,	146.9814,	527.0	!!END!	Boundary Waters
77 ! X =	135.4598,	147.0234,	516.0	!!END!	Boundary Waters
78 ! X =	137.2616,	147.0660,	533.0	!!END!	Boundary Waters
79 ! X =	139.0634,	147.1091,	530.0	!!END!	Boundary Waters
80 ! X =	140.8652,	147.1528,	558.0	!!END!	Boundary Waters

81 ! X =	142.6669,	147.1971,	544.0	!!END!	Boundary Waters
82 ! X =	144.4686,	147.2419,	542.0	!!END!	Boundary Waters
83 ! X =	146.2704,	147.2873,	600.0	!!END!	Boundary Waters
84 ! X =	148.0721,	147.3332,	589.0	!!END!	Boundary Waters
85 ! X =	149.8737,	147.3797,	557.0	!!END!	Boundary Waters
86 ! X =	151.6754,	147.4268,	559.0	!!END!	Boundary Waters
87 ! X =	157.0804,	147.5714,	521.0	!!END!	Boundary Waters
88 ! X =	158.8820,	147.6208,	548.0	!!END!	Boundary Waters
89 ! X =	160.6836,	147.6706,	563.0	!!END!	Boundary Waters
90 ! X =	97.5741,	148.9446,	441.0	!!END!	Boundary Waters
91 ! X =	99.3753,	148.9754,	438.0	!!END!	Boundary Waters
92 ! X =	101.1764,	149.0067,	455.0	!!END!	Boundary Waters
93 ! X =	102.9776,	149.0385,	459.0	!!END!	Boundary Waters
94 ! X =	104.7788,	149.0710,	471.0	!!END!	Boundary Waters
95 ! X =	106.5799,	149.1040,	463.0	!!END!	Boundary Waters
96 ! X =	108.3811,	149.1375,	471.0	!!END!	Boundary Waters
97 ! X =	110.1822,	149.1716,	457.0	!!END!	Boundary Waters
98 ! X =	111.9833,	149.2063,	451.0	!!END!	Boundary Waters
99 ! X =	113.7844,	149.2416,	456.0	!!END!	Boundary Waters
100 ! X =	115.5855,	149.2774,	457.0	!!END!	Boundary Waters
101 ! X =	117.3866,	149.3138,	458.0	!!END!	Boundary Waters
102 ! X =	119.1877,	149.3507,	467.0	!!END!	Boundary Waters
103 ! X =	120.9887,	149.3882,	472.0	!!END!	Boundary Waters
104 ! X =	122.7898,	149.4262,	481.0	!!END!	Boundary Waters
105 ! X =	124.5908,	149.4649,	502.0	!!END!	Boundary Waters
106 ! X =	126.3919,	149.5040,	484.0	!!END!	Boundary Waters
107 ! X =	128.1929,	149.5438,	487.0	!!END!	Boundary Waters
108 ! X =	129.9939,	149.5841,	494.0	!!END!	Boundary Waters
109 ! X =	131.7949,	149.6250,	517.0	!!END!	Boundary Waters
110 ! X =	133.5958,	149.6664,	524.0	!!END!	Boundary Waters
111 ! X =	135.3968,	149.7084,	512.0	!!END!	Boundary Waters
112 ! X =	137.1978,	149.7509,	519.0	!!END!	Boundary Waters
113 ! X =	138.9987,	149.7941,	533.0	!!END!	Boundary Waters
114 ! X =	140.7996,	149.8377,	530.0	!!END!	Boundary Waters
115 ! X =	142.6005,	149.8820,	548.0	!!END!	Boundary Waters
116 ! X =	144.4014,	149.9268,	561.0	!!END!	Boundary Waters
117 ! X =	146.2023,	149.9721,	563.0	!!END!	Boundary Waters

118 ! X =	148.0032,	150.0181,	562.0	!!END!	Boundary Waters
119 ! X =	149.8040,	150.0646,	609.0	!!END!	Boundary Waters
120 ! X =	151.6049,	150.1116,	557.0	!!END!	Boundary Waters
121 ! X =	153.4057,	150.1592,	563.0	!!END!	Boundary Waters
122 ! X =	155.2065,	150.2074,	551.0	!!END!	Boundary Waters
123 ! X =	157.0073,	150.2561,	568.0	!!END!	Boundary Waters
124 ! X =	158.8081,	150.3055,	573.0	!!END!	Boundary Waters
125 ! X =	160.6088,	150.3553,	578.0	!!END!	Boundary Waters
126 ! X =	162.4096,	150.4057,	571.0	!!END!	Boundary Waters
127 ! X =	164.2103,	150.4567,	561.0	!!END!	Boundary Waters
128 ! X =	175.0143,	150.7745,	533.0	!!END!	Boundary Waters
129 ! X =	176.8150,	150.8294,	561.0	!!END!	Boundary Waters
130 ! X =	52.5172,	151.0445,	426.0	!!END!	Boundary Waters
131 ! X =	54.3177,	151.0612,	450.0	!!END!	Boundary Waters
132 ! X =	56.1183,	151.0784,	441.0	!!END!	Boundary Waters
133 ! X =	57.9188,	151.0962,	440.0	!!END!	Boundary Waters
134 ! X =	59.7193,	151.1146,	475.0	!!END!	Boundary Waters
135 ! X =	61.5198,	151.1335,	481.0	!!END!	Boundary Waters
136 ! X =	63.3203,	151.1530,	477.0	!!END!	Boundary Waters
137 ! X =	65.1208,	151.1731,	472.0	!!END!	Boundary Waters
138 ! X =	66.9213,	151.1937,	427.0	!!END!	Boundary Waters
139 ! X =	93.9279,	151.5703,	441.0	!!END!	Boundary Waters
140 ! X =	95.7283,	151.5999,	437.0	!!END!	Boundary Waters
141 ! X =	97.5287,	151.6301,	450.0	!!END!	Boundary Waters
142 ! X =	99.3290,	151.6609,	449.0	!!END!	Boundary Waters
143 ! X =	101.1293,	151.6922,	462.0	!!END!	Boundary Waters
144 ! X =	102.9297,	151.7240,	445.0	!!END!	Boundary Waters
145 ! X =	104.7300,	151.7564,	474.0	!!END!	Boundary Waters
146 ! X =	106.5303,	151.7894,	457.0	!!END!	Boundary Waters
147 ! X =	108.3306,	151.8230,	472.0	!!END!	Boundary Waters
148 ! X =	110.1309,	151.8571,	451.0	!!END!	Boundary Waters
149 ! X =	111.9312,	151.8917,	453.0	!!END!	Boundary Waters
150 ! X =	113.7314,	151.9269,	452.0	!!END!	Boundary Waters
151 ! X =	115.5317,	151.9627,	451.0	!!END!	Boundary Waters
152 ! X =	117.3320,	151.9991,	459.0	!!END!	Boundary Waters
153 ! X =	119.1322,	152.0360,	457.0	!!END!	Boundary Waters
154 ! X =	120.9324,	152.0735,	472.0	!!END!	Boundary Waters

155 ! X =	122.7326,	152.1115,	472.0	!!END!	Boundary Waters
156 ! X =	124.5328,	152.1501,	462.0	!!END!	Boundary Waters
157 ! X =	126.3330,	152.1893,	479.0	!!END!	Boundary Waters
158 ! X =	128.1332,	152.2290,	517.0	!!END!	Boundary Waters
159 ! X =	129.9334,	152.2693,	502.0	!!END!	Boundary Waters
160 ! X =	131.7335,	152.3102,	487.0	!!END!	Boundary Waters
161 ! X =	133.5336,	152.3516,	517.0	!!END!	Boundary Waters
162 ! X =	135.3338,	152.3935,	516.0	!!END!	Boundary Waters
163 ! X =	137.1339,	152.4361,	496.0	!!END!	Boundary Waters
164 ! X =	138.9340,	152.4792,	518.0	!!END!	Boundary Waters
165 ! X =	140.7341,	152.5228,	533.0	!!END!	Boundary Waters
166 ! X =	142.5341,	152.5670,	578.0	!!END!	Boundary Waters
167 ! X =	144.3342,	152.6118,	569.0	!!END!	Boundary Waters
168 ! X =	146.1342,	152.6572,	588.0	!!END!	Boundary Waters
169 ! X =	147.9343,	152.7031,	588.0	!!END!	Boundary Waters
170 ! X =	149.7343,	152.7496,	582.0	!!END!	Boundary Waters
171 ! X =	151.5343,	152.7966,	566.0	!!END!	Boundary Waters
172 ! X =	153.3343,	152.8442,	539.0	!!END!	Boundary Waters
173 ! X =	155.1342,	152.8923,	563.0	!!END!	Boundary Waters
174 ! X =	156.9342,	152.9411,	588.0	!!END!	Boundary Waters
175 ! X =	158.7341,	152.9903,	532.0	!!END!	Boundary Waters
176 ! X =	160.5341,	153.0402,	563.0	!!END!	Boundary Waters
177 ! X =	162.3340,	153.0906,	561.0	!!END!	Boundary Waters
178 ! X =	164.1339,	153.1415,	563.0	!!END!	Boundary Waters
179 ! X =	174.9329,	153.4591,	604.0	!!END!	Boundary Waters
180 ! X =	176.7327,	153.5140,	606.0	!!END!	Boundary Waters
181 ! X =	45.2939,	153.6694,	452.0	!!END!	Boundary Waters
182 ! X =	47.0936,	153.6838,	455.0	!!END!	Boundary Waters
183 ! X =	48.8933,	153.6988,	437.0	!!END!	Boundary Waters
184 ! X =	50.6930,	153.7144,	434.0	!!END!	Boundary Waters
185 ! X =	52.4927,	153.7305,	442.0	!!END!	Boundary Waters
186 ! X =	54.2924,	153.7471,	442.0	!!END!	Boundary Waters
187 ! X =	56.0921,	153.7644,	447.0	!!END!	Boundary Waters
188 ! X =	57.8918,	153.7822,	461.0	!!END!	Boundary Waters
189 ! X =	59.6915,	153.8005,	472.0	!!END!	Boundary Waters
190 ! X =	61.4912,	153.8195,	488.0	!!END!	Boundary Waters
191 ! X =	63.2909,	153.8389,	479.0	!!END!	Boundary Waters

192 ! X =	65.0905,	153.8590,	472.0	!!END!	Boundary Waters
193 ! X =	66.8902,	153.8796,	458.0	!!END!	Boundary Waters
194 ! X =	106.4807,	154.4750,	455.0	!!END!	Boundary Waters
195 ! X =	108.2802,	154.5085,	453.0	!!END!	Boundary Waters
196 ! X =	110.0796,	154.5426,	451.0	!!END!	Boundary Waters
197 ! X =	111.8791,	154.5773,	456.0	!!END!	Boundary Waters
198 ! X =	113.6785,	154.6125,	456.0	!!END!	Boundary Waters
199 ! X =	115.4779,	154.6483,	460.0	!!END!	Boundary Waters
200 ! X =	117.2773,	154.6846,	457.0	!!END!	Boundary Waters
201 ! X =	119.0767,	154.7215,	472.0	!!END!	Boundary Waters
202 ! X =	120.8761,	154.7590,	487.0	!!END!	Boundary Waters
203 ! X =	122.6755,	154.7970,	487.0	!!END!	Boundary Waters
204 ! X =	124.4748,	154.8356,	460.0	!!END!	Boundary Waters
205 ! X =	126.2742,	154.8747,	480.0	!!END!	Boundary Waters
206 ! X =	128.0735,	154.9144,	484.0	!!END!	Boundary Waters
207 ! X =	129.8728,	154.9547,	495.0	!!END!	Boundary Waters
208 ! X =	131.6721,	154.9955,	505.0	!!END!	Boundary Waters
209 ! X =	133.4715,	155.0369,	488.0	!!END!	Boundary Waters
210 ! X =	135.2707,	155.0789,	487.0	!!END!	Boundary Waters
211 ! X =	137.0700,	155.1214,	487.0	!!END!	Boundary Waters
212 ! X =	138.8693,	155.1645,	503.0	!!END!	Boundary Waters
213 ! X =	140.6685,	155.2081,	533.0	!!END!	Boundary Waters
214 ! X =	142.4678,	155.2523,	533.0	!!END!	Boundary Waters
215 ! X =	144.2670,	155.2971,	563.0	!!END!	Boundary Waters
216 ! X =	146.0662,	155.3424,	594.0	!!END!	Boundary Waters
217 ! X =	147.8654,	155.3883,	609.0	!!END!	Boundary Waters
218 ! X =	149.6645,	155.4347,	609.0	!!END!	Boundary Waters
219 ! X =	151.4637,	155.4817,	582.0	!!END!	Boundary Waters
220 ! X =	153.2628,	155.5293,	563.0	!!END!	Boundary Waters
221 ! X =	155.0620,	155.5774,	562.0	!!END!	Boundary Waters
222 ! X =	156.8611,	155.6261,	563.0	!!END!	Boundary Waters
223 ! X =	158.6602,	155.6754,	563.0	!!END!	Boundary Waters
224 ! X =	160.4593,	155.7252,	579.0	!!END!	Boundary Waters
225 ! X =	162.2584,	155.7756,	562.0	!!END!	Boundary Waters
226 ! X =	164.0574,	155.8265,	560.0	!!END!	Boundary Waters
227 ! X =	171.2535,	156.0359,	578.0	!!END!	Boundary Waters
228 ! X =	173.0524,	156.0897,	613.0	!!END!	Boundary Waters

229 ! X =	174.8514,	156.1440,	608.0	!!END!	Boundary Waters
230 ! X =	176.6503,	156.1989,	604.0	!!END!	Boundary Waters
231 ! X =	178.4493,	156.2543,	608.0	!!END!	Boundary Waters
232 ! X =	180.2482,	156.3103,	608.0	!!END!	Boundary Waters
233 ! X =	182.0471,	156.3668,	629.0	!!END!	Boundary Waters
234 ! X =	183.8459,	156.4240,	658.0	!!END!	Boundary Waters
235 ! X =	45.2728,	156.3556,	457.0	!!END!	Boundary Waters
236 ! X =	47.0717,	156.3700,	436.0	!!END!	Boundary Waters
237 ! X =	48.8705,	156.3850,	427.0	!!END!	Boundary Waters
238 ! X =	50.6694,	156.4005,	427.0	!!END!	Boundary Waters
239 ! X =	52.4683,	156.4166,	453.0	!!END!	Boundary Waters
240 ! X =	54.2671,	156.4333,	441.0	!!END!	Boundary Waters
241 ! X =	56.0660,	156.4505,	442.0	!!END!	Boundary Waters
242 ! X =	57.8648,	156.4683,	457.0	!!END!	Boundary Waters
243 ! X =	59.6637,	156.4866,	457.0	!!END!	Boundary Waters
244 ! X =	61.4625,	156.5056,	467.0	!!END!	Boundary Waters
245 ! X =	63.2614,	156.5250,	457.0	!!END!	Boundary Waters
246 ! X =	65.0602,	156.5451,	457.0	!!END!	Boundary Waters
247 ! X =	66.8590,	156.5656,	454.0	!!END!	Boundary Waters
248 ! X =	68.6578,	156.5868,	457.0	!!END!	Boundary Waters
249 ! X =	115.4241,	157.3340,	471.0	!!END!	Boundary Waters
250 ! X =	117.2226,	157.3703,	464.0	!!END!	Boundary Waters
251 ! X =	119.0212,	157.4072,	497.0	!!END!	Boundary Waters
252 ! X =	120.8198,	157.4446,	502.0	!!END!	Boundary Waters
253 ! X =	122.6183,	157.4826,	472.0	!!END!	Boundary Waters
254 ! X =	124.4168,	157.5212,	483.0	!!END!	Boundary Waters
255 ! X =	126.2153,	157.5603,	486.0	!!END!	Boundary Waters
256 ! X =	128.0138,	157.6000,	484.0	!!END!	Boundary Waters
257 ! X =	129.8123,	157.6403,	488.0	!!END!	Boundary Waters
258 ! X =	131.6108,	157.6811,	487.0	!!END!	Boundary Waters
259 ! X =	133.4093,	157.7224,	487.0	!!END!	Boundary Waters
260 ! X =	135.2077,	157.7644,	484.0	!!END!	Boundary Waters
261 ! X =	137.0061,	157.8069,	487.0	!!END!	Boundary Waters
262 ! X =	138.8046,	157.8499,	517.0	!!END!	Boundary Waters
263 ! X =	140.6030,	157.8936,	518.0	!!END!	Boundary Waters
264 ! X =	142.4014,	157.9377,	533.0	!!END!	Boundary Waters
265 ! X =	144.1998,	157.9825,	548.0	!!END!	Boundary Waters

266 ! X =	145.9981,	158.0278,	587.0	!!END!	Boundary Waters
267 ! X =	147.7965,	158.0736,	563.0	!!END!	Boundary Waters
268 ! X =	149.5948,	158.1201,	563.0	!!END!	Boundary Waters
269 ! X =	151.3931,	158.1671,	579.0	!!END!	Boundary Waters
270 ! X =	153.1914,	158.2146,	563.0	!!END!	Boundary Waters
271 ! X =	154.9897,	158.2627,	563.0	!!END!	Boundary Waters
272 ! X =	156.7880,	158.3114,	543.0	!!END!	Boundary Waters
273 ! X =	158.5863,	158.3606,	544.0	!!END!	Boundary Waters
274 ! X =	160.3845,	158.4104,	579.0	!!END!	Boundary Waters
275 ! X =	162.1828,	158.4608,	578.0	!!END!	Boundary Waters
276 ! X =	163.9810,	158.5117,	624.0	!!END!	Boundary Waters
277 ! X =	165.7792,	158.5632,	564.0	!!END!	Boundary Waters
278 ! X =	167.5773,	158.6152,	579.0	!!END!	Boundary Waters
279 ! X =	169.3755,	158.6678,	589.0	!!END!	Boundary Waters
280 ! X =	171.1737,	158.7210,	587.0	!!END!	Boundary Waters
281 ! X =	172.9718,	158.7747,	582.0	!!END!	Boundary Waters
282 ! X =	174.7699,	158.8290,	596.0	!!END!	Boundary Waters
283 ! X =	176.5680,	158.8838,	549.0	!!END!	Boundary Waters
284 ! X =	178.3661,	158.9393,	532.0	!!END!	Boundary Waters
285 ! X =	180.1642,	158.9952,	540.0	!!END!	Boundary Waters
286 ! X =	181.9622,	159.0518,	579.0	!!END!	Boundary Waters
287 ! X =	183.7602,	159.1088,	559.0	!!END!	Boundary Waters
288 ! X =	45.2517,	159.0416,	442.0	!!END!	Boundary Waters
289 ! X =	47.0497,	159.0560,	457.0	!!END!	Boundary Waters
290 ! X =	48.8478,	159.0710,	427.0	!!END!	Boundary Waters
291 ! X =	50.6458,	159.0865,	437.0	!!END!	Boundary Waters
292 ! X =	52.4438,	159.1026,	436.0	!!END!	Boundary Waters
293 ! X =	54.2418,	159.1193,	442.0	!!END!	Boundary Waters
294 ! X =	56.0399,	159.1365,	433.0	!!END!	Boundary Waters
295 ! X =	57.8379,	159.1543,	455.0	!!END!	Boundary Waters
296 ! X =	59.6359,	159.1726,	443.0	!!END!	Boundary Waters
297 ! X =	61.4339,	159.1915,	463.0	!!END!	Boundary Waters
298 ! X =	63.2319,	159.2110,	488.0	!!END!	Boundary Waters
299 ! X =	65.0299,	159.2310,	458.0	!!END!	Boundary Waters
300 ! X =	66.8278,	159.2516,	456.0	!!END!	Boundary Waters
301 ! X =	68.6258,	159.2727,	457.0	!!END!	Boundary Waters
302 ! X =	70.4238,	159.2944,	487.0	!!END!	Boundary Waters

303 ! X =	90.2009,	159.5703,	426.0	!!END!	Boundary Waters
304 ! X =	91.9988,	159.5987,	402.0	!!END!	Boundary Waters
305 ! X =	93.7967,	159.6277,	421.0	!!END!	Boundary Waters
306 ! X =	95.5945,	159.6573,	409.0	!!END!	Boundary Waters
307 ! X =	97.3924,	159.6874,	441.0	!!END!	Boundary Waters
308 ! X =	99.1902,	159.7181,	435.0	!!END!	Boundary Waters
309 ! X =	100.9880,	159.7493,	423.0	!!END!	Boundary Waters
310 ! X =	115.3703,	160.0195,	435.0	!!END!	Boundary Waters
311 ! X =	117.1680,	160.0558,	435.0	!!END!	Boundary Waters
312 ! X =	118.9657,	160.0927,	435.0	!!END!	Boundary Waters
313 ! X =	120.7634,	160.1301,	465.0	!!END!	Boundary Waters
314 ! X =	122.5611,	160.1681,	476.0	!!END!	Boundary Waters
315 ! X =	124.3588,	160.2067,	472.0	!!END!	Boundary Waters
316 ! X =	126.1565,	160.2458,	466.0	!!END!	Boundary Waters
317 ! X =	127.9541,	160.2854,	481.0	!!END!	Boundary Waters
318 ! X =	129.7518,	160.3257,	513.0	!!END!	Boundary Waters
319 ! X =	131.5494,	160.3665,	484.0	!!END!	Boundary Waters
320 ! X =	133.3471,	160.4078,	484.0	!!END!	Boundary Waters
321 ! X =	135.1447,	160.4497,	491.0	!!END!	Boundary Waters
322 ! X =	136.9423,	160.4922,	487.0	!!END!	Boundary Waters
323 ! X =	138.7399,	160.5353,	508.0	!!END!	Boundary Waters
324 ! X =	140.5374,	160.5789,	540.0	!!END!	Boundary Waters
325 ! X =	142.3350,	160.6230,	543.0	!!END!	Boundary Waters
326 ! X =	144.1325,	160.6677,	548.0	!!END!	Boundary Waters
327 ! X =	145.9300,	160.7130,	566.0	!!END!	Boundary Waters
328 ! X =	147.7276,	160.7589,	530.0	!!END!	Boundary Waters
329 ! X =	149.5251,	160.8053,	543.0	!!END!	Boundary Waters
330 ! X =	151.3225,	160.8522,	518.0	!!END!	Boundary Waters
331 ! X =	153.1200,	160.8998,	533.0	!!END!	Boundary Waters
332 ! X =	154.9175,	160.9478,	552.0	!!END!	Boundary Waters
333 ! X =	156.7149,	160.9965,	548.0	!!END!	Boundary Waters
334 ! X =	158.5123,	161.0457,	533.0	!!END!	Boundary Waters
335 ! X =	160.3097,	161.0955,	578.0	!!END!	Boundary Waters
336 ! X =	162.1071,	161.1458,	571.0	!!END!	Boundary Waters
337 ! X =	163.9045,	161.1967,	594.0	!!END!	Boundary Waters
338 ! X =	165.7019,	161.2482,	604.0	!!END!	Boundary Waters
339 ! X =	167.4992,	161.3002,	606.0	!!END!	Boundary Waters

340 ! X =	169.2966,	161.3528,	594.0	!!END!	Boundary Waters
341 ! X =	171.0939,	161.4059,	594.0	!!END!	Boundary Waters
342 ! X =	172.8912,	161.4596,	624.0	!!END!	Boundary Waters
343 ! X =	174.6884,	161.5139,	639.0	!!END!	Boundary Waters
344 ! X =	176.4857,	161.5687,	645.0	!!END!	Boundary Waters
345 ! X =	178.2829,	161.6241,	645.0	!!END!	Boundary Waters
346 ! X =	180.0802,	161.6800,	632.0	!!END!	Boundary Waters
347 ! X =	181.8774,	161.7365,	670.0	!!END!	Boundary Waters
348 ! X =	183.6746,	161.7936,	624.0	!!END!	Boundary Waters
349 ! X =	45.2306,	161.7275,	442.0	!!END!	Boundary Waters
350 ! X =	47.0278,	161.7419,	440.0	!!END!	Boundary Waters
351 ! X =	48.8250,	161.7569,	439.0	!!END!	Boundary Waters
352 ! X =	50.6222,	161.7724,	437.0	!!END!	Boundary Waters
353 ! X =	52.4194,	161.7885,	436.0	!!END!	Boundary Waters
354 ! X =	54.2165,	161.8051,	427.0	!!END!	Boundary Waters
355 ! X =	56.0137,	161.8223,	447.0	!!END!	Boundary Waters
356 ! X =	57.8109,	161.8401,	442.0	!!END!	Boundary Waters
357 ! X =	59.6081,	161.8584,	442.0	!!END!	Boundary Waters
358 ! X =	61.4052,	161.8773,	457.0	!!END!	Boundary Waters
359 ! X =	63.2024,	161.8968,	452.0	!!END!	Boundary Waters
360 ! X =	64.9995,	161.9168,	457.0	!!END!	Boundary Waters
361 ! X =	66.7967,	161.9374,	446.0	!!END!	Boundary Waters
362 ! X =	68.5938,	161.9585,	457.0	!!END!	Boundary Waters
363 ! X =	70.3909,	161.9802,	466.0	!!END!	Boundary Waters
364 ! X =	72.1881,	162.0025,	480.0	!!END!	Boundary Waters
365 ! X =	73.9852,	162.0253,	445.0	!!END!	Boundary Waters
366 ! X =	90.1589,	162.2559,	440.0	!!END!	Boundary Waters
367 ! X =	91.9559,	162.2843,	416.0	!!END!	Boundary Waters
368 ! X =	93.7529,	162.3133,	414.0	!!END!	Boundary Waters
369 ! X =	95.5499,	162.3429,	422.0	!!END!	Boundary Waters
370 ! X =	97.3469,	162.3730,	412.0	!!END!	Boundary Waters
371 ! X =	99.1439,	162.4037,	412.0	!!END!	Boundary Waters
372 ! X =	100.9409,	162.4349,	420.0	!!END!	Boundary Waters
373 ! X =	102.7379,	162.4667,	440.0	!!END!	Boundary Waters
374 ! X =	104.5349,	162.4991,	424.0	!!END!	Boundary Waters
375 ! X =	106.3318,	162.5320,	438.0	!!END!	Boundary Waters
376 ! X =	108.1288,	162.5654,	408.0	!!END!	Boundary Waters

377 ! X =	109.9257,	162.5995,	455.0	!!END!	Boundary Waters
378 ! X =	111.7226,	162.6341,	457.0	!!END!	Boundary Waters
379 ! X =	113.5196,	162.6693,	436.0	!!END!	Boundary Waters
380 ! X =	115.3165,	162.7050,	436.0	!!END!	Boundary Waters
381 ! X =	117.1134,	162.7413,	442.0	!!END!	Boundary Waters
382 ! X =	118.9102,	162.7781,	457.0	!!END!	Boundary Waters
383 ! X =	120.7071,	162.8155,	457.0	!!END!	Boundary Waters
384 ! X =	122.5040,	162.8535,	472.0	!!END!	Boundary Waters
385 ! X =	124.3008,	162.8920,	472.0	!!END!	Boundary Waters
386 ! X =	126.0977,	162.9311,	471.0	!!END!	Boundary Waters
387 ! X =	127.8945,	162.9707,	488.0	!!END!	Boundary Waters
388 ! X =	129.6913,	163.0110,	484.0	!!END!	Boundary Waters
389 ! X =	131.4881,	163.0517,	517.0	!!END!	Boundary Waters
390 ! X =	133.2849,	163.0931,	497.0	!!END!	Boundary Waters
391 ! X =	135.0816,	163.1350,	503.0	!!END!	Boundary Waters
392 ! X =	136.8784,	163.1774,	520.0	!!END!	Boundary Waters
393 ! X =	138.6751,	163.2204,	512.0	!!END!	Boundary Waters
394 ! X =	140.4719,	163.2640,	516.0	!!END!	Boundary Waters
395 ! X =	142.2686,	163.3082,	514.0	!!END!	Boundary Waters
396 ! X =	144.0653,	163.3529,	523.0	!!END!	Boundary Waters
397 ! X =	145.8620,	163.3981,	521.0	!!END!	Boundary Waters
398 ! X =	147.6587,	163.4439,	503.0	!!END!	Boundary Waters
399 ! X =	149.4553,	163.4903,	521.0	!!END!	Boundary Waters
400 ! X =	151.2520,	163.5373,	533.0	!!END!	Boundary Waters
401 ! X =	153.0486,	163.5848,	567.0	!!END!	Boundary Waters
402 ! X =	154.8452,	163.6328,	580.0	!!END!	Boundary Waters
403 ! X =	156.6418,	163.6815,	552.0	!!END!	Boundary Waters
404 ! X =	158.4384,	163.7307,	552.0	!!END!	Boundary Waters
405 ! X =	160.2350,	163.7804,	542.0	!!END!	Boundary Waters
406 ! X =	162.0315,	163.8307,	553.0	!!END!	Boundary Waters
407 ! X =	163.8281,	163.8816,	563.0	!!END!	Boundary Waters
408 ! X =	165.6246,	163.9330,	592.0	!!END!	Boundary Waters
409 ! X =	167.4211,	163.9850,	594.0	!!END!	Boundary Waters
410 ! X =	169.2176,	164.0376,	573.0	!!END!	Boundary Waters
411 ! X =	171.0141,	164.0907,	591.0	!!END!	Boundary Waters
412 ! X =	172.8105,	164.1444,	579.0	!!END!	Boundary Waters
413 ! X =	174.6070,	164.1986,	574.0	!!END!	Boundary Waters

414 ! X =	176.4034,	164.2534,	572.0	!!END!	Boundary Waters
415 ! X =	178.1998,	164.3087,	575.0	!!END!	Boundary Waters
416 ! X =	179.9962,	164.3647,	583.0	!!END!	Boundary Waters
417 ! X =	181.7926,	164.4211,	564.0	!!END!	Boundary Waters
418 ! X =	183.5889,	164.4782,	564.0	!!END!	Boundary Waters
419 ! X =	50.5986,	164.4584,	442.0	!!END!	Boundary Waters
420 ! X =	52.3949,	164.4745,	442.0	!!END!	Boundary Waters
421 ! X =	54.1912,	164.4911,	427.0	!!END!	Boundary Waters
422 ! X =	55.9876,	164.5083,	427.0	!!END!	Boundary Waters
423 ! X =	57.7839,	164.5261,	455.0	!!END!	Boundary Waters
424 ! X =	59.5802,	164.5444,	450.0	!!END!	Boundary Waters
425 ! X =	61.3766,	164.5633,	445.0	!!END!	Boundary Waters
426 ! X =	63.1729,	164.5827,	458.0	!!END!	Boundary Waters
427 ! X =	64.9692,	164.6028,	432.0	!!END!	Boundary Waters
428 ! X =	66.7655,	164.6233,	442.0	!!END!	Boundary Waters
429 ! X =	68.5618,	164.6445,	443.0	!!END!	Boundary Waters
430 ! X =	70.3581,	164.6661,	436.0	!!END!	Boundary Waters
431 ! X =	72.1544,	164.6884,	453.0	!!END!	Boundary Waters
432 ! X =	73.9506,	164.7112,	461.0	!!END!	Boundary Waters
433 ! X =	86.5244,	164.8866,	411.0	!!END!	Boundary Waters
434 ! X =	88.3206,	164.9138,	399.0	!!END!	Boundary Waters
435 ! X =	90.1168,	164.9417,	408.0	!!END!	Boundary Waters
436 ! X =	91.9130,	164.9701,	419.0	!!END!	Boundary Waters
437 ! X =	93.7092,	164.9991,	396.0	!!END!	Boundary Waters
438 ! X =	95.5053,	165.0286,	422.0	!!END!	Boundary Waters
439 ! X =	97.3015,	165.0587,	400.0	!!END!	Boundary Waters
440 ! X =	99.0977,	165.0894,	406.0	!!END!	Boundary Waters
441 ! X =	100.8938,	165.1206,	397.0	!!END!	Boundary Waters
442 ! X =	102.6900,	165.1524,	396.0	!!END!	Boundary Waters
443 ! X =	104.4861,	165.1848,	411.0	!!END!	Boundary Waters
444 ! X =	106.2822,	165.2177,	423.0	!!END!	Boundary Waters
445 ! X =	108.0783,	165.2511,	427.0	!!END!	Boundary Waters
446 ! X =	109.8744,	165.2851,	427.0	!!END!	Boundary Waters
447 ! X =	111.6705,	165.3197,	408.0	!!END!	Boundary Waters
448 ! X =	113.4666,	165.3549,	427.0	!!END!	Boundary Waters
449 ! X =	115.2627,	165.3906,	442.0	!!END!	Boundary Waters
450 ! X =	117.0587,	165.4268,	431.0	!!END!	Boundary Waters

451 ! X =	118.8548,	165.4637,	424.0	!!END!	Boundary Waters
452 ! X =	120.6508,	165.5011,	433.0	!!END!	Boundary Waters
453 ! X =	122.4468,	165.5390,	466.0	!!END!	Boundary Waters
454 ! X =	124.2428,	165.5775,	471.0	!!END!	Boundary Waters
455 ! X =	126.0388,	165.6166,	472.0	!!END!	Boundary Waters
456 ! X =	127.8348,	165.6562,	497.0	!!END!	Boundary Waters
457 ! X =	129.6308,	165.6964,	504.0	!!END!	Boundary Waters
458 ! X =	131.4267,	165.7372,	531.0	!!END!	Boundary Waters
459 ! X =	133.2227,	165.7785,	488.0	!!END!	Boundary Waters
460 ! X =	135.0186,	165.8204,	503.0	!!END!	Boundary Waters
461 ! X =	136.8145,	165.8628,	533.0	!!END!	Boundary Waters
462 ! X =	138.6104,	165.9058,	518.0	!!END!	Boundary Waters
463 ! X =	140.4063,	165.9494,	518.0	!!END!	Boundary Waters
464 ! X =	142.2022,	165.9935,	494.0	!!END!	Boundary Waters
465 ! X =	143.9981,	166.0382,	491.0	!!END!	Boundary Waters
466 ! X =	145.7939,	166.0834,	491.0	!!END!	Boundary Waters
467 ! X =	147.5898,	166.1292,	506.0	!!END!	Boundary Waters
468 ! X =	149.3856,	166.1756,	519.0	!!END!	Boundary Waters
469 ! X =	151.1814,	166.2225,	518.0	!!END!	Boundary Waters
470 ! X =	152.9772,	166.2700,	531.0	!!END!	Boundary Waters
471 ! X =	154.7730,	166.3180,	595.0	!!END!	Boundary Waters
472 ! X =	156.5687,	166.3666,	575.0	!!END!	Boundary Waters
473 ! X =	158.3645,	166.4158,	549.0	!!END!	Boundary Waters
474 ! X =	160.1602,	166.4655,	547.0	!!END!	Boundary Waters
475 ! X =	161.9559,	166.5158,	549.0	!!END!	Boundary Waters
476 ! X =	163.7516,	166.5667,	570.0	!!END!	Boundary Waters
477 ! X =	165.5473,	166.6181,	598.0	!!END!	Boundary Waters
478 ! X =	167.3430,	166.6700,	609.0	!!END!	Boundary Waters
479 ! X =	169.1386,	166.7225,	610.0	!!END!	Boundary Waters
480 ! X =	170.9343,	166.7756,	597.0	!!END!	Boundary Waters
481 ! X =	172.7299,	166.8293,	595.0	!!END!	Boundary Waters
482 ! X =	174.5255,	166.8835,	585.0	!!END!	Boundary Waters
483 ! X =	176.3211,	166.9383,	573.0	!!END!	Boundary Waters
484 ! X =	178.1166,	166.9936,	578.0	!!END!	Boundary Waters
485 ! X =	179.9122,	167.0495,	579.0	!!END!	Boundary Waters
486 ! X =	181.7077,	167.1060,	569.0	!!END!	Boundary Waters
487 ! X =	190.6852,	167.3966,	564.0	!!END!	Boundary Waters

488 ! X =	192.4806,	167.4565,	572.0	!!END!	Boundary Waters
489 ! X =	194.2760,	167.5168,	589.0	!!END!	Boundary Waters
490 ! X =	54.1659,	167.1774,	443.0	!!END!	Boundary Waters
491 ! X =	55.9614,	167.1945,	426.0	!!END!	Boundary Waters
492 ! X =	57.7569,	167.2123,	424.0	!!END!	Boundary Waters
493 ! X =	59.5524,	167.2306,	442.0	!!END!	Boundary Waters
494 ! X =	61.3479,	167.2495,	428.0	!!END!	Boundary Waters
495 ! X =	63.1434,	167.2689,	427.0	!!END!	Boundary Waters
496 ! X =	64.9389,	167.2889,	426.0	!!END!	Boundary Waters
497 ! X =	66.7343,	167.3095,	426.0	!!END!	Boundary Waters
498 ! X =	68.5298,	167.3306,	432.0	!!END!	Boundary Waters
499 ! X =	70.3252,	167.3523,	430.0	!!END!	Boundary Waters
500 ! X =	77.5070,	167.4446,	458.0	!!END!	Boundary Waters
501 ! X =	79.3024,	167.4691,	461.0	!!END!	Boundary Waters
502 ! X =	81.0978,	167.4941,	439.0	!!END!	Boundary Waters
503 ! X =	84.6886,	167.5459,	426.0	!!END!	Boundary Waters
504 ! X =	86.4840,	167.5726,	426.0	!!END!	Boundary Waters
505 ! X =	88.2793,	167.5999,	404.0	!!END!	Boundary Waters
506 ! X =	90.0747,	167.6277,	427.0	!!END!	Boundary Waters
507 ! X =	91.8701,	167.6561,	396.0	!!END!	Boundary Waters
508 ! X =	93.6654,	167.6851,	396.0	!!END!	Boundary Waters
509 ! X =	95.4608,	167.7146,	397.0	!!END!	Boundary Waters
510 ! X =	97.2561,	167.7447,	396.0	!!END!	Boundary Waters
511 ! X =	99.0514,	167.7753,	396.0	!!END!	Boundary Waters
512 ! X =	100.8467,	167.8065,	400.0	!!END!	Boundary Waters
513 ! X =	106.2326,	167.9035,	396.0	!!END!	Boundary Waters
514 ! X =	108.0279,	167.9370,	411.0	!!END!	Boundary Waters
515 ! X =	109.8231,	167.9710,	411.0	!!END!	Boundary Waters
516 ! X =	111.6184,	168.0056,	400.0	!!END!	Boundary Waters
517 ! X =	115.2088,	168.0764,	405.0	!!END!	Boundary Waters
518 ! X =	117.0041,	168.1126,	426.0	!!END!	Boundary Waters
519 ! X =	118.7993,	168.1494,	427.0	!!END!	Boundary Waters
520 ! X =	120.5945,	168.1868,	429.0	!!END!	Boundary Waters
521 ! X =	122.3896,	168.2247,	447.0	!!END!	Boundary Waters
522 ! X =	124.1848,	168.2632,	457.0	!!END!	Boundary Waters
523 ! X =	125.9800,	168.3023,	488.0	!!END!	Boundary Waters
524 ! X =	127.7751,	168.3419,	469.0	!!END!	Boundary Waters

525 ! X =	129.5702,	168.3821,	463.0	!!END!	Boundary Waters
526 ! X =	131.3654,	168.4228,	564.0	!!END!	Boundary Waters
527 ! X =	133.1605,	168.4641,	534.0	!!END!	Boundary Waters
528 ! X =	134.9556,	168.5060,	548.0	!!END!	Boundary Waters
529 ! X =	136.7506,	168.5484,	539.0	!!END!	Boundary Waters
530 ! X =	138.5457,	168.5914,	518.0	!!END!	Boundary Waters
531 ! X =	140.3408,	168.6349,	549.0	!!END!	Boundary Waters
532 ! X =	142.1358,	168.6790,	494.0	!!END!	Boundary Waters
533 ! X =	143.9308,	168.7236,	518.0	!!END!	Boundary Waters
534 ! X =	145.7258,	168.7689,	548.0	!!END!	Boundary Waters
535 ! X =	147.5208,	168.8147,	514.0	!!END!	Boundary Waters
536 ! X =	149.3158,	168.8610,	514.0	!!END!	Boundary Waters
537 ! X =	151.1108,	168.9079,	549.0	!!END!	Boundary Waters
538 ! X =	152.9057,	168.9554,	561.0	!!END!	Boundary Waters
539 ! X =	154.7007,	169.0034,	564.0	!!END!	Boundary Waters
540 ! X =	156.4956,	169.0520,	553.0	!!END!	Boundary Waters
541 ! X =	158.2905,	169.1011,	533.0	!!END!	Boundary Waters
542 ! X =	160.0854,	169.1508,	549.0	!!END!	Boundary Waters
543 ! X =	161.8803,	169.2011,	564.0	!!END!	Boundary Waters
544 ! X =	163.6752,	169.2519,	571.0	!!END!	Boundary Waters
545 ! X =	165.4700,	169.3033,	567.0	!!END!	Boundary Waters
546 ! X =	167.2648,	169.3552,	576.0	!!END!	Boundary Waters
547 ! X =	169.0597,	169.4077,	580.0	!!END!	Boundary Waters
548 ! X =	170.8545,	169.4608,	594.0	!!END!	Boundary Waters
549 ! X =	172.6492,	169.5144,	606.0	!!END!	Boundary Waters
550 ! X =	174.4440,	169.5686,	610.0	!!END!	Boundary Waters
551 ! X =	190.5961,	170.0815,	518.0	!!END!	Boundary Waters
552 ! X =	192.3907,	170.1413,	518.0	!!END!	Boundary Waters
553 ! X =	194.1853,	170.2016,	518.0	!!END!	Boundary Waters
554 ! X =	195.9798,	170.2625,	524.0	!!END!	Boundary Waters
555 ! X =	197.7744,	170.3240,	545.0	!!END!	Boundary Waters
556 ! X =	199.5688,	170.3860,	541.0	!!END!	Boundary Waters
557 ! X =	201.3633,	170.4486,	566.0	!!END!	Boundary Waters
558 ! X =	203.1578,	170.5118,	572.0	!!END!	Boundary Waters
559 ! X =	204.9523,	170.5755,	555.0	!!END!	Boundary Waters
560 ! X =	206.7467,	170.6398,	476.0	!!END!	Boundary Waters
561 ! X =	208.5411,	170.7046,	445.0	!!END!	Boundary Waters

562 ! X =	55.9353,	169.8809,	423.0	!!END!	Boundary Waters
563 ! X =	57.7300,	169.8987,	426.0	!!END!	Boundary Waters
564 ! X =	68.4978,	170.0169,	430.0	!!END!	Boundary Waters
565 ! X =	70.2924,	170.0386,	427.0	!!END!	Boundary Waters
566 ! X =	77.4708,	170.1308,	442.0	!!END!	Boundary Waters
567 ! X =	79.2653,	170.1553,	442.0	!!END!	Boundary Waters
568 ! X =	81.0599,	170.1803,	453.0	!!END!	Boundary Waters
569 ! X =	82.8545,	170.2059,	426.0	!!END!	Boundary Waters
570 ! X =	84.6490,	170.2321,	410.0	!!END!	Boundary Waters
571 ! X =	86.4436,	170.2588,	405.0	!!END!	Boundary Waters
572 ! X =	88.2381,	170.2861,	411.0	!!END!	Boundary Waters
573 ! X =	90.0326,	170.3139,	411.0	!!END!	Boundary Waters
574 ! X =	91.8272,	170.3423,	411.0	!!END!	Boundary Waters
575 ! X =	93.6217,	170.3712,	429.0	!!END!	Boundary Waters
576 ! X =	95.4162,	170.4007,	419.0	!!END!	Boundary Waters
577 ! X =	97.2107,	170.4308,	400.0	!!END!	Boundary Waters
578 ! X =	99.0051,	170.4614,	428.0	!!END!	Boundary Waters
579 ! X =	100.7996,	170.4926,	452.0	!!END!	Boundary Waters
580 ! X =	125.9211,	170.9881,	424.0	!!END!	Boundary Waters
581 ! X =	127.7154,	171.0277,	442.0	!!END!	Boundary Waters
582 ! X =	129.5097,	171.0679,	469.0	!!END!	Boundary Waters
583 ! X =	131.3040,	171.1086,	460.0	!!END!	Boundary Waters
584 ! X =	133.0983,	171.1499,	533.0	!!END!	Boundary Waters
585 ! X =	134.8925,	171.1917,	472.0	!!END!	Boundary Waters
586 ! X =	136.6868,	171.2341,	480.0	!!END!	Boundary Waters
587 ! X =	138.4810,	171.2771,	470.0	!!END!	Boundary Waters
588 ! X =	140.2752,	171.3206,	476.0	!!END!	Boundary Waters
589 ! X =	142.0694,	171.3647,	547.0	!!END!	Boundary Waters
590 ! X =	143.8636,	171.4093,	505.0	!!END!	Boundary Waters
591 ! X =	145.6578,	171.4545,	511.0	!!END!	Boundary Waters
592 ! X =	147.4519,	171.5003,	520.0	!!END!	Boundary Waters
593 ! X =	149.2461,	171.5466,	533.0	!!END!	Boundary Waters
594 ! X =	151.0402,	171.5935,	533.0	!!END!	Boundary Waters
595 ! X =	172.5686,	172.1997,	564.0	!!END!	Boundary Waters
596 ! X =	174.3625,	172.2539,	582.0	!!END!	Boundary Waters
597 ! X =	176.1564,	172.3086,	549.0	!!END!	Boundary Waters
598 ! X =	177.9503,	172.3639,	533.0	!!END!	Boundary Waters

599 ! X =	179.7442,	172.4197,	541.0	!!END!	Boundary Waters
600 ! X =	181.5380,	172.4761,	521.0	!!END!	Boundary Waters
601 ! X =	183.3319,	172.5331,	555.0	!!END!	Boundary Waters
602 ! X =	185.1257,	172.5906,	503.0	!!END!	Boundary Waters
603 ! X =	186.9195,	172.6487,	500.0	!!END!	Boundary Waters
604 ! X =	188.7133,	172.7073,	547.0	!!END!	Boundary Waters
605 ! X =	190.5071,	172.7665,	515.0	!!END!	Boundary Waters
606 ! X =	192.3008,	172.8263,	556.0	!!END!	Boundary Waters
607 ! X =	194.0945,	172.8866,	594.0	!!END!	Boundary Waters
608 ! X =	195.8882,	172.9475,	526.0	!!END!	Boundary Waters
609 ! X =	197.6820,	173.0089,	518.0	!!END!	Boundary Waters
610 ! X =	199.4756,	173.0709,	598.0	!!END!	Boundary Waters
611 ! X =	201.2693,	173.1335,	570.0	!!END!	Boundary Waters
612 ! X =	203.0629,	173.1966,	518.0	!!END!	Boundary Waters
613 ! X =	204.8565,	173.2603,	472.0	!!END!	Boundary Waters
614 ! X =	206.6501,	173.3245,	479.0	!!END!	Boundary Waters
615 ! X =	208.4437,	173.3893,	469.0	!!END!	Boundary Waters
616 ! X =	210.2372,	173.4547,	464.0	!!END!	Boundary Waters
617 ! X =	212.0308,	173.5206,	495.0	!!END!	Boundary Waters
618 ! X =	55.9092,	172.5672,	411.0	!!END!	Boundary Waters
619 ! X =	57.7030,	172.5849,	443.0	!!END!	Boundary Waters
620 ! X =	75.6408,	172.7931,	440.0	!!END!	Boundary Waters
621 ! X =	77.4346,	172.8170,	457.0	!!END!	Boundary Waters
622 ! X =	79.2283,	172.8414,	430.0	!!END!	Boundary Waters
623 ! X =	81.0220,	172.8664,	451.0	!!END!	Boundary Waters
624 ! X =	82.8157,	172.8920,	427.0	!!END!	Boundary Waters
625 ! X =	84.6095,	172.9181,	427.0	!!END!	Boundary Waters
626 ! X =	86.4032,	172.9448,	411.0	!!END!	Boundary Waters
627 ! X =	88.1969,	172.9721,	427.0	!!END!	Boundary Waters
628 ! X =	89.9906,	172.9999,	426.0	!!END!	Boundary Waters
629 ! X =	91.7842,	173.0283,	396.0	!!END!	Boundary Waters
630 ! X =	93.5779,	173.0572,	401.0	!!END!	Boundary Waters
631 ! X =	95.3716,	173.0867,	396.0	!!END!	Boundary Waters
632 ! X =	102.5461,	173.2103,	400.0	!!END!	Boundary Waters
633 ! X =	129.4492,	173.7536,	457.0	!!END!	Boundary Waters
634 ! X =	131.2426,	173.7943,	426.0	!!END!	Boundary Waters
635 ! X =	133.0361,	173.8355,	421.0	!!END!	Boundary Waters

636 ! X =	134.8295,	173.8773,	421.0	!!END!	Boundary Waters
637 ! X =	136.6229,	173.9197,	441.0	!!END!	Boundary Waters
638 ! X =	138.4163,	173.9627,	487.0	!!END!	Boundary Waters
639 ! X =	140.2097,	174.0062,	451.0	!!END!	Boundary Waters
640 ! X =	142.0030,	174.0502,	471.0	!!END!	Boundary Waters
641 ! X =	143.7964,	174.0948,	479.0	!!END!	Boundary Waters
642 ! X =	145.5897,	174.1400,	488.0	!!END!	Boundary Waters
643 ! X =	147.3830,	174.1857,	492.0	!!END!	Boundary Waters
644 ! X =	149.1763,	174.2320,	503.0	!!END!	Boundary Waters
645 ! X =	150.9696,	174.2789,	518.0	!!END!	Boundary Waters
646 ! X =	172.4879,	174.8848,	490.0	!!END!	Boundary Waters
647 ! X =	174.2810,	174.9390,	472.0	!!END!	Boundary Waters
648 ! X =	181.4532,	175.1611,	473.0	!!END!	Boundary Waters
649 ! X =	199.3824,	175.7557,	505.0	!!END!	Boundary Waters
650 ! X =	201.1752,	175.8182,	524.0	!!END!	Boundary Waters
651 ! X =	202.9680,	175.8813,	549.0	!!END!	Boundary Waters
652 ! X =	204.7608,	175.9449,	541.0	!!END!	Boundary Waters
653 ! X =	206.5535,	176.0091,	454.0	!!END!	Boundary Waters
654 ! X =	64.8479,	175.3475,	411.0	!!END!	Boundary Waters
655 ! X =	66.6408,	175.3680,	426.0	!!END!	Boundary Waters
656 ! X =	68.4337,	175.3891,	440.0	!!END!	Boundary Waters
657 ! X =	70.2267,	175.4108,	427.0	!!END!	Boundary Waters
658 ! X =	72.0196,	175.4330,	411.0	!!END!	Boundary Waters
659 ! X =	73.8125,	175.4557,	427.0	!!END!	Boundary Waters
660 ! X =	75.6055,	175.4790,	443.0	!!END!	Boundary Waters
661 ! X =	77.3984,	175.5029,	439.0	!!END!	Boundary Waters
662 ! X =	79.1913,	175.5274,	396.0	!!END!	Boundary Waters
663 ! X =	80.9841,	175.5524,	433.0	!!END!	Boundary Waters
664 ! X =	82.7770,	175.5779,	427.0	!!END!	Boundary Waters
665 ! X =	84.5699,	175.6041,	430.0	!!END!	Boundary Waters
666 ! X =	86.3628,	175.6308,	422.0	!!END!	Boundary Waters
667 ! X =	88.1556,	175.6580,	427.0	!!END!	Boundary Waters
668 ! X =	89.9485,	175.6858,	404.0	!!END!	Boundary Waters
669 ! X =	91.7413,	175.7142,	427.0	!!END!	Boundary Waters
670 ! X =	131.1813,	176.4798,	421.0	!!END!	Boundary Waters
671 ! X =	132.9739,	176.5210,	432.0	!!END!	Boundary Waters
672 ! X =	134.7664,	176.5628,	442.0	!!END!	Boundary Waters

673 ! X =	136.5590,	176.6052,	457.0	!!END!	Boundary Waters
674 ! X =	138.3516,	176.6481,	472.0	!!END!	Boundary Waters
675 ! X =	140.1441,	176.6916,	456.0	!!END!	Boundary Waters
676 ! X =	141.9366,	176.7356,	472.0	!!END!	Boundary Waters
677 ! X =	143.7291,	176.7802,	439.0	!!END!	Boundary Waters
678 ! X =	145.5216,	176.8254,	442.0	!!END!	Boundary Waters
679 ! X =	147.3141,	176.8711,	442.0	!!END!	Boundary Waters
680 ! X =	149.1066,	176.9174,	442.0	!!END!	Boundary Waters
681 ! X =	150.8990,	176.9642,	446.0	!!END!	Boundary Waters
682 ! X =	156.2763,	177.1080,	457.0	!!END!	Boundary Waters
683 ! X =	158.0687,	177.1571,	457.0	!!END!	Boundary Waters
684 ! X =	57.6490,	177.9572,	411.0	!!END!	Boundary Waters
685 ! X =	61.2333,	177.9944,	417.0	!!END!	Boundary Waters
686 ! X =	63.0254,	178.0137,	426.0	!!END!	Boundary Waters
687 ! X =	64.8175,	178.0337,	398.0	!!END!	Boundary Waters
688 ! X =	66.6096,	178.0542,	396.0	!!END!	Boundary Waters
689 ! X =	68.4017,	178.0753,	411.0	!!END!	Boundary Waters
690 ! X =	70.1938,	178.0969,	411.0	!!END!	Boundary Waters
691 ! X =	71.9859,	178.1191,	406.0	!!END!	Boundary Waters
692 ! X =	73.7780,	178.1419,	438.0	!!END!	Boundary Waters
693 ! X =	75.5701,	178.1652,	409.0	!!END!	Boundary Waters
694 ! X =	77.3621,	178.1891,	425.0	!!END!	Boundary Waters
695 ! X =	79.1542,	178.2135,	396.0	!!END!	Boundary Waters
696 ! X =	80.9463,	178.2385,	427.0	!!END!	Boundary Waters
697 ! X =	82.7383,	178.2641,	422.0	!!END!	Boundary Waters
698 ! X =	84.5303,	178.2902,	413.0	!!END!	Boundary Waters
699 ! X =	86.3224,	178.3168,	396.0	!!END!	Boundary Waters
700 ! X =	88.1144,	178.3441,	442.0	!!END!	Boundary Waters
701 ! X =	89.9064,	178.3719,	433.0	!!END!	Boundary Waters
702 ! X =	91.6984,	178.4002,	427.0	!!END!	Boundary Waters
703 ! X =	134.7034,	179.2485,	457.0	!!END!	Boundary Waters
704 ! X =	136.4951,	179.2908,	472.0	!!END!	Boundary Waters
705 ! X =	138.2868,	179.3337,	433.0	!!END!	Boundary Waters
706 ! X =	140.0786,	179.3772,	448.0	!!END!	Boundary Waters
707 ! X =	141.8702,	179.4212,	459.0	!!END!	Boundary Waters
708 ! X =	143.6619,	179.4658,	457.0	!!END!	Boundary Waters
709 ! X =	145.4536,	179.5109,	440.0	!!END!	Boundary Waters

710 ! X =	147.2452,	179.5566,	473.0	!!END!	Boundary Waters
711 ! X =	149.0368,	179.6029,	451.0	!!END!	Boundary Waters
712 ! X =	154.4116,	179.7450,	453.0	!!END!	Boundary Waters
713 ! X =	156.2032,	179.7935,	457.0	!!END!	Boundary Waters
714 ! X =	157.9948,	179.8425,	460.0	!!END!	Boundary Waters
715 ! X =	46.8742,	180.5458,	411.0	!!END!	Boundary Waters
716 ! X =	48.6655,	180.5607,	385.0	!!END!	Boundary Waters
717 ! X =	50.4568,	180.5762,	396.0	!!END!	Boundary Waters
718 ! X =	52.2481,	180.5922,	411.0	!!END!	Boundary Waters
719 ! X =	54.0394,	180.6088,	411.0	!!END!	Boundary Waters
720 ! X =	55.8307,	180.6260,	411.0	!!END!	Boundary Waters
721 ! X =	57.6220,	180.6437,	397.0	!!END!	Boundary Waters
722 ! X =	59.4133,	180.6620,	426.0	!!END!	Boundary Waters
723 ! X =	61.2046,	180.6808,	396.0	!!END!	Boundary Waters
724 ! X =	62.9959,	180.7002,	372.0	!!END!	Boundary Waters
725 ! X =	64.7872,	180.7201,	385.0	!!END!	Boundary Waters
726 ! X =	66.5785,	180.7406,	380.0	!!END!	Boundary Waters
727 ! X =	68.3697,	180.7617,	383.0	!!END!	Boundary Waters
728 ! X =	70.1610,	180.7833,	381.0	!!END!	Boundary Waters
729 ! X =	71.9522,	180.8055,	398.0	!!END!	Boundary Waters
730 ! X =	73.7435,	180.8282,	396.0	!!END!	Boundary Waters
731 ! X =	75.5347,	180.8516,	396.0	!!END!	Boundary Waters
732 ! X =	77.3259,	180.8754,	381.0	!!END!	Boundary Waters
733 ! X =	79.1172,	180.8998,	396.0	!!END!	Boundary Waters
734 ! X =	80.9084,	180.9248,	407.0	!!END!	Boundary Waters
735 ! X =	82.6996,	180.9504,	411.0	!!END!	Boundary Waters
736 ! X =	84.4908,	180.9765,	412.0	!!END!	Boundary Waters
737 ! X =	86.2820,	181.0031,	378.0	!!END!	Boundary Waters
738 ! X =	88.0732,	181.0303,	396.0	!!END!	Boundary Waters
739 ! X =	89.8643,	181.0581,	378.0	!!END!	Boundary Waters
740 ! X =	91.6555,	181.0865,	378.0	!!END!	Boundary Waters
741 ! X =	138.2221,	182.0195,	424.0	!!END!	Boundary Waters
742 ! X =	140.0130,	182.0630,	454.0	!!END!	Boundary Waters
743 ! X =	141.8038,	182.1069,	455.0	!!END!	Boundary Waters
744 ! X =	143.5947,	182.1515,	456.0	!!END!	Boundary Waters
745 ! X =	145.3855,	182.1966,	450.0	!!END!	Boundary Waters
746 ! X =	147.1763,	182.2423,	457.0	!!END!	Boundary Waters

747 ! X =	148.9671,	182.2885,	448.0	!!END!	Boundary Waters
748 ! X =	154.3394,	182.4306,	457.0	!!END!	Boundary Waters
749 ! X =	156.1301,	182.4790,	437.0	!!END!	Boundary Waters
750 ! X =	46.8522,	183.2321,	382.0	!!END!	Boundary Waters
751 ! X =	48.6427,	183.2471,	400.0	!!END!	Boundary Waters
752 ! X =	50.4332,	183.2625,	401.0	!!END!	Boundary Waters
753 ! X =	52.2237,	183.2785,	396.0	!!END!	Boundary Waters
754 ! X =	54.0141,	183.2951,	411.0	!!END!	Boundary Waters
755 ! X =	55.8046,	183.3123,	393.0	!!END!	Boundary Waters
756 ! X =	57.5951,	183.3300,	396.0	!!END!	Boundary Waters
757 ! X =	59.3855,	183.3483,	427.0	!!END!	Boundary Waters
758 ! X =	61.1760,	183.3671,	402.0	!!END!	Boundary Waters
759 ! X =	62.9664,	183.3864,	411.0	!!END!	Boundary Waters
760 ! X =	64.7568,	183.4064,	396.0	!!END!	Boundary Waters
761 ! X =	66.5473,	183.4269,	380.0	!!END!	Boundary Waters
762 ! X =	68.3377,	183.4480,	381.0	!!END!	Boundary Waters
763 ! X =	70.1281,	183.4696,	381.0	!!END!	Boundary Waters
764 ! X =	71.9185,	183.4917,	396.0	!!END!	Boundary Waters
765 ! X =	73.7089,	183.5145,	396.0	!!END!	Boundary Waters
766 ! X =	75.4993,	183.5378,	395.0	!!END!	Boundary Waters
767 ! X =	77.2897,	183.5616,	381.0	!!END!	Boundary Waters
768 ! X =	79.0801,	183.5860,	396.0	!!END!	Boundary Waters
769 ! X =	80.8705,	183.6110,	378.0	!!END!	Boundary Waters
770 ! X =	82.6609,	183.6365,	378.0	!!END!	Boundary Waters
771 ! X =	84.4512,	183.6626,	382.0	!!END!	Boundary Waters
772 ! X =	143.5274,	184.8371,	436.0	!!END!	Boundary Waters
773 ! X =	145.3174,	184.8822,	479.0	!!END!	Boundary Waters
774 ! X =	147.1074,	184.9279,	436.0	!!END!	Boundary Waters
775 ! X =	148.8973,	184.9741,	436.0	!!END!	Boundary Waters
776 ! X =	150.6873,	185.0208,	442.0	!!END!	Boundary Waters
777 ! X =	152.4772,	185.0682,	452.0	!!END!	Boundary Waters
778 ! X =	154.2671,	185.1160,	442.0	!!END!	Boundary Waters
779 ! X =	41.4613,	185.8773,	420.0	!!END!	Boundary Waters
780 ! X =	43.2509,	185.8906,	381.0	!!END!	Boundary Waters
781 ! X =	46.8303,	185.9187,	351.0	!!END!	Boundary Waters
782 ! X =	48.6199,	185.9336,	389.0	!!END!	Boundary Waters
783 ! X =	50.4096,	185.9491,	365.0	!!END!	Boundary Waters

784 ! X =	52.1992,	185.9651,	365.0	!!END!	Boundary Waters
785 ! X =	53.9888,	185.9816,	408.0	!!END!	Boundary Waters
786 ! X =	55.7785,	185.9988,	396.0	!!END!	Boundary Waters
787 ! X =	57.5681,	186.0165,	411.0	!!END!	Boundary Waters
788 ! X =	59.3577,	186.0347,	411.0	!!END!	Boundary Waters
789 ! X =	61.1473,	186.0535,	402.0	!!END!	Boundary Waters
790 ! X =	62.9369,	186.0729,	396.0	!!END!	Boundary Waters
791 ! X =	64.7265,	186.0928,	387.0	!!END!	Boundary Waters
792 ! X =	66.5161,	186.1133,	411.0	!!END!	Boundary Waters
793 ! X =	68.3057,	186.1344,	365.0	!!END!	Boundary Waters
794 ! X =	70.0953,	186.1560,	366.0	!!END!	Boundary Waters
795 ! X =	71.8848,	186.1781,	395.0	!!END!	Boundary Waters
796 ! X =	73.6744,	186.2009,	374.0	!!END!	Boundary Waters
797 ! X =	75.4640,	186.2242,	372.0	!!END!	Boundary Waters
798 ! X =	77.2535,	186.2480,	372.0	!!END!	Boundary Waters
799 ! X =	79.0431,	186.2724,	378.0	!!END!	Boundary Waters
800 ! X =	148.8276,	187.6598,	436.0	!!END!	Boundary Waters
801 ! X =	150.6167,	187.7065,	436.0	!!END!	Boundary Waters
802 ! X =	152.4058,	187.7538,	436.0	!!END!	Boundary Waters
803 ! X =	154.1948,	187.8017,	443.0	!!END!	Boundary Waters
804 ! X =	41.4418,	188.5641,	396.0	!!END!	Boundary Waters
805 ! X =	43.2307,	188.5773,	350.0	!!END!	Boundary Waters
806 ! X =	52.1747,	188.6517,	354.0	!!END!	Boundary Waters
807 ! X =	53.9635,	188.6683,	354.0	!!END!	Boundary Waters
808 ! X =	55.7523,	188.6855,	380.0	!!END!	Boundary Waters
809 ! X =	57.5411,	188.7031,	412.0	!!END!	Boundary Waters
810 ! X =	59.3299,	188.7214,	411.0	!!END!	Boundary Waters
811 ! X =	61.1186,	188.7402,	411.0	!!END!	Boundary Waters
812 ! X =	62.9074,	188.7596,	399.0	!!END!	Boundary Waters
813 ! X =	64.6962,	188.7795,	396.0	!!END!	Boundary Waters
814 ! X =	66.4849,	188.7999,	415.0	!!END!	Boundary Waters
815 ! X =	68.2737,	188.8210,	396.0	!!END!	Boundary Waters
816 ! X =	70.0624,	188.8426,	362.0	!!END!	Boundary Waters
817 ! X =	71.8512,	188.8647,	363.0	!!END!	Boundary Waters
818 ! X =	41.4224,	191.2507,	351.0	!!END!	Boundary Waters
819 ! X =	52.1503,	191.3383,	411.0	!!END!	Boundary Waters
820 ! X =	53.9382,	191.3549,	396.0	!!END!	Boundary Waters

821 ! X =	55.7262,	191.3720,	426.0	!!END!	Boundary Waters
822 ! X =	57.5141,	191.3897,	396.0	!!END!	Boundary Waters
823 ! X =	59.3020,	191.4079,	396.0	!!END!	Boundary Waters
824 ! X =	61.0900,	191.4267,	411.0	!!END!	Boundary Waters
825 ! X =	62.8779,	191.4460,	372.0	!!END!	Boundary Waters
826 ! X =	64.6658,	191.4660,	396.0	!!END!	Boundary Waters
827 ! X =	66.4538,	191.4864,	363.0	!!END!	Boundary Waters
828 ! X =	68.2417,	191.5074,	366.0	!!END!	Boundary Waters
829 ! X =	70.0296,	191.5290,	361.0	!!END!	Boundary Waters
830 ! X =	50.3387,	194.0090,	357.0	!!END!	Boundary Waters
831 ! X =	52.1258,	194.0250,	386.0	!!END!	Boundary Waters
832 ! X =	53.9129,	194.0416,	411.0	!!END!	Boundary Waters
833 ! X =	55.7000,	194.0587,	396.0	!!END!	Boundary Waters
834 ! X =	57.4871,	194.0764,	408.0	!!END!	Boundary Waters
835 ! X =	59.2742,	194.0946,	393.0	!!END!	Boundary Waters
836 ! X =	61.0613,	194.1134,	381.0	!!END!	Boundary Waters
837 ! X =	62.8484,	194.1327,	396.0	!!END!	Boundary Waters
838 ! X =	64.6355,	194.1526,	362.0	!!END!	Boundary Waters
839 ! X =	66.4226,	194.1731,	371.0	!!END!	Boundary Waters
840 ! X =	68.2096,	194.1941,	360.0	!!END!	Boundary Waters
841 ! X =	69.9967,	194.2157,	361.0	!!END!	Boundary Waters
842 ! X =	52.1013,	196.7116,	361.0	!!END!	Boundary Waters
843 ! X =	53.8876,	196.7282,	381.0	!!END!	Boundary Waters
844 ! X =	55.6739,	196.7453,	390.0	!!END!	Boundary Waters
845 ! X =	57.4601,	196.7629,	396.0	!!END!	Boundary Waters
846 ! X =	59.2464,	196.7811,	397.0	!!END!	Boundary Waters
847 ! X =	61.0327,	196.7999,	397.0	!!END!	Boundary Waters
848 ! X =	62.8189,	196.8193,	392.0	!!END!	Boundary Waters
849 ! X =	64.6052,	196.8392,	360.0	!!END!	Boundary Waters
850 ! X =	66.3914,	196.8596,	365.0	!!END!	Boundary Waters
851 ! X =	68.1776,	196.8806,	360.0	!!END!	Boundary Waters
852 ! X =	59.2186,	199.4679,	360.0	!!END!	Boundary Waters
853 ! X =	61.0040,	199.4866,	360.0	!!END!	Boundary Waters
854 ! X =	62.7894,	199.5060,	360.0	!!END!	Boundary Waters
855 ! X =	64.5748,	199.5259,	360.0	!!END!	Boundary Waters
856 ! X =	66.3602,	199.5463,	366.0	!!END!	Boundary Waters
857 ! X =	34.8392,	195.6850,	353.0	!!END!	Voyageurs

858 ! X =	36.0302,	195.6924,	351.0	!!END!	Voyageurs
859 ! X =	37.2213,	195.7000,	353.0	!!END!	Voyageurs
860 ! X =	30.0655,	197.4492,	376.0	!!END!	Voyageurs
861 ! X =	31.2562,	197.4556,	379.0	!!END!	Voyageurs
862 ! X =	32.4469,	197.4622,	351.0	!!END!	Voyageurs
863 ! X =	33.6376,	197.4691,	351.0	!!END!	Voyageurs
864 ! X =	34.8283,	197.4762,	373.0	!!END!	Voyageurs
865 ! X =	36.0190,	197.4836,	347.0	!!END!	Voyageurs
866 ! X =	37.2097,	197.4912,	354.0	!!END!	Voyageurs
867 ! X =	38.4003,	197.4991,	341.0	!!END!	Voyageurs
868 ! X =	30.0561,	199.2402,	381.0	!!END!	Voyageurs
869 ! X =	31.2464,	199.2466,	351.0	!!END!	Voyageurs
870 ! X =	32.4367,	199.2533,	351.0	!!END!	Voyageurs
871 ! X =	33.6270,	199.2601,	351.0	!!END!	Voyageurs
872 ! X =	34.8174,	199.2673,	374.0	!!END!	Voyageurs
873 ! X =	36.0077,	199.2746,	365.0	!!END!	Voyageurs
874 ! X =	37.1980,	199.2822,	347.0	!!END!	Voyageurs
875 ! X =	27.6667,	201.0195,	366.0	!!END!	Voyageurs
876 ! X =	28.8567,	201.0254,	385.0	!!END!	Voyageurs
877 ! X =	30.0467,	201.0315,	373.0	!!END!	Voyageurs
878 ! X =	31.2366,	201.0379,	379.0	!!END!	Voyageurs
879 ! X =	32.4266,	201.0446,	344.0	!!END!	Voyageurs
880 ! X =	33.6165,	201.0514,	373.0	!!END!	Voyageurs
881 ! X =	34.8065,	201.0585,	356.0	!!END!	Voyageurs
882 ! X =	35.9964,	201.0659,	341.0	!!END!	Voyageurs
883 ! X =	37.1864,	201.0735,	341.0	!!END!	Voyageurs
884 ! X =	20.5205,	202.7806,	366.0	!!END!	Voyageurs
885 ! X =	21.7101,	202.7850,	388.0	!!END!	Voyageurs
886 ! X =	22.8997,	202.7897,	351.0	!!END!	Voyageurs
887 ! X =	24.0893,	202.7946,	351.0	!!END!	Voyageurs
888 ! X =	25.2789,	202.7997,	396.0	!!END!	Voyageurs
889 ! X =	26.4685,	202.8051,	381.0	!!END!	Voyageurs
890 ! X =	27.6581,	202.8107,	387.0	!!END!	Voyageurs
891 ! X =	28.8477,	202.8166,	381.0	!!END!	Voyageurs
892 ! X =	30.0372,	202.8227,	381.0	!!END!	Voyageurs
893 ! X =	31.2268,	202.8291,	373.0	!!END!	Voyageurs
894 ! X =	32.4164,	202.8357,	358.0	!!END!	Voyageurs

895 ! X =	33.6060,	202.8426,	341.0	!!END!	Voyageurs
896 ! X =	34.7956,	202.8497,	369.0	!!END!	Voyageurs
897 ! X =	35.9851,	202.8571,	352.0	!!END!	Voyageurs
898 ! X =	37.1747,	202.8647,	341.0	!!END!	Voyageurs
899 ! X =	3.8650,	204.5366,	350.0	!!END!	Voyageurs
900 ! X =	5.0542,	204.5375,	350.0	!!END!	Voyageurs
901 ! X =	6.2434,	204.5387,	372.0	!!END!	Voyageurs
902 ! X =	15.7572,	204.5570,	402.0	!!END!	Voyageurs
903 ! X =	16.9464,	204.5604,	366.0	!!END!	Voyageurs
904 ! X =	18.1357,	204.5640,	365.0	!!END!	Voyageurs
905 ! X =	20.5141,	204.5721,	366.0	!!END!	Voyageurs
906 ! X =	21.7033,	204.5765,	367.0	!!END!	Voyageurs
907 ! X =	22.8925,	204.5811,	357.0	!!END!	Voyageurs
908 ! X =	24.0818,	204.5860,	366.0	!!END!	Voyageurs
909 ! X =	25.2710,	204.5911,	370.0	!!END!	Voyageurs
910 ! X =	26.4602,	204.5965,	366.0	!!END!	Voyageurs
911 ! X =	27.6494,	204.6022,	364.0	!!END!	Voyageurs
912 ! X =	28.8386,	204.6080,	366.0	!!END!	Voyageurs
913 ! X =	30.0278,	204.6142,	362.0	!!END!	Voyageurs
914 ! X =	31.2170,	204.6205,	360.0	!!END!	Voyageurs
915 ! X =	32.4062,	204.6272,	389.0	!!END!	Voyageurs
916 ! X =	33.5954,	204.6340,	379.0	!!END!	Voyageurs
917 ! X =	34.7846,	204.6411,	362.0	!!END!	Voyageurs
918 ! X =	35.9739,	204.6485,	347.0	!!END!	Voyageurs
919 ! X =	37.1631,	204.6561,	350.0	!!END!	Voyageurs
920 ! X =	38.3523,	204.6640,	341.0	!!END!	Voyageurs
921 ! X =	0.2972,	206.3266,	348.0	!!END!	Voyageurs
922 ! X =	1.4861,	206.3268,	350.0	!!END!	Voyageurs
923 ! X =	2.6749,	206.3272,	353.0	!!END!	Voyageurs
924 ! X =	3.8638,	206.3279,	350.0	!!END!	Voyageurs
925 ! X =	5.0526,	206.3288,	350.0	!!END!	Voyageurs
926 ! X =	6.2415,	206.3300,	373.0	!!END!	Voyageurs
927 ! X =	7.4303,	206.3314,	396.0	!!END!	Voyageurs
928 ! X =	8.6192,	206.3331,	375.0	!!END!	Voyageurs
929 ! X =	9.8080,	206.3350,	362.0	!!END!	Voyageurs
930 ! X =	10.9969,	206.3372,	352.0	!!END!	Voyageurs
931 ! X =	12.1857,	206.3396,	358.0	!!END!	Voyageurs

932 ! X =	13.3746,	206.3423,	352.0	!!END!	Voyageurs
933 ! X =	14.5634,	206.3452,	344.0	!!END!	Voyageurs
934 ! X =	15.7523,	206.3483,	370.0	!!END!	Voyageurs
935 ! X =	16.9411,	206.3517,	363.0	!!END!	Voyageurs
936 ! X =	18.1300,	206.3554,	341.0	!!END!	Voyageurs
937 ! X =	19.3188,	206.3593,	368.0	!!END!	Voyageurs
938 ! X =	20.5077,	206.3634,	351.0	!!END!	Voyageurs
939 ! X =	21.6965,	206.3678,	341.0	!!END!	Voyageurs
940 ! X =	22.8854,	206.3725,	351.0	!!END!	Voyageurs
941 ! X =	24.0742,	206.3773,	356.0	!!END!	Voyageurs
942 ! X =	25.2630,	206.3825,	377.0	!!END!	Voyageurs
943 ! X =	26.4519,	206.3878,	369.0	!!END!	Voyageurs
944 ! X =	27.6407,	206.3935,	353.0	!!END!	Voyageurs
945 ! X =	28.8296,	206.3994,	353.0	!!END!	Voyageurs
946 ! X =	30.0184,	206.4055,	345.0	!!END!	Voyageurs
947 ! X =	31.2072,	206.4118,	351.0	!!END!	Voyageurs
948 ! X =	32.3961,	206.4185,	367.0	!!END!	Voyageurs
949 ! X =	33.5849,	206.4253,	354.0	!!END!	Voyageurs
950 ! X =	34.7737,	206.4325,	346.0	!!END!	Voyageurs
951 ! X =	35.9626,	206.4398,	346.0	!!END!	Voyageurs
952 ! X =	37.1514,	206.4474,	341.0	!!END!	Voyageurs
953 ! X =	0.2971,	208.1182,	341.0	!!END!	Voyageurs
954 ! X =	1.4856,	208.1184,	341.0	!!END!	Voyageurs
955 ! X =	2.6741,	208.1188,	341.0	!!END!	Voyageurs
956 ! X =	3.8626,	208.1195,	341.0	!!END!	Voyageurs
957 ! X =	5.0510,	208.1204,	346.0	!!END!	Voyageurs
958 ! X =	6.2395,	208.1216,	341.0	!!END!	Voyageurs
959 ! X =	7.4280,	208.1230,	346.0	!!END!	Voyageurs
960 ! X =	8.6165,	208.1247,	341.0	!!END!	Voyageurs
961 ! X =	9.8050,	208.1266,	341.0	!!END!	Voyageurs
962 ! X =	10.9934,	208.1288,	341.0	!!END!	Voyageurs
963 ! X =	12.1819,	208.1312,	341.0	!!END!	Voyageurs
964 ! X =	13.3704,	208.1338,	341.0	!!END!	Voyageurs
965 ! X =	14.5589,	208.1367,	351.0	!!END!	Voyageurs
966 ! X =	15.7473,	208.1399,	341.0	!!END!	Voyageurs
967 ! X =	16.9358,	208.1433,	341.0	!!END!	Voyageurs
968 ! X =	18.1243,	208.1469,	344.0	!!END!	Voyageurs

969 ! X =	19.3128,	208.1508,	341.0	!!END!	Voyageurs
970 ! X =	20.5012,	208.1550,	341.0	!!END!	Voyageurs
971 ! X =	21.6897,	208.1594,	341.0	!!END!	Voyageurs
972 ! X =	22.8782,	208.1640,	341.0	!!END!	Voyageurs
973 ! X =	24.0667,	208.1689,	341.0	!!END!	Voyageurs
974 ! X =	26.4436,	208.1794,	341.0	!!END!	Voyageurs
975 ! X =	27.6321,	208.1850,	341.0	!!END!	Voyageurs
976 ! X =	28.8205,	208.1909,	341.0	!!END!	Voyageurs
977 ! X =	30.0090,	208.1970,	341.0	!!END!	Voyageurs
978 ! X =	31.1975,	208.2034,	341.0	!!END!	Voyageurs
979 ! X =	32.3859,	208.2100,	341.0	!!END!	Voyageurs
980 ! X =	33.5744,	208.2169,	341.0	!!END!	Voyageurs
981 ! X =	34.7628,	208.2240,	344.0	!!END!	Voyageurs
982 ! X =	-4.4554,	209.9111,	347.0	!!END!	Voyageurs
983 ! X =	-3.2673,	209.9103,	341.0	!!END!	Voyageurs
984 ! X =	-2.0792,	209.9097,	341.0	!!END!	Voyageurs
985 ! X =	-0.8911,	209.9094,	341.0	!!END!	Voyageurs
986 ! X =	0.2970,	209.9093,	341.0	!!END!	Voyageurs
987 ! X =	1.4851,	209.9095,	347.0	!!END!	Voyageurs
988 ! X =	2.6732,	209.9099,	341.0	!!END!	Voyageurs
989 ! X =	3.8613,	209.9106,	341.0	!!END!	Voyageurs
990 ! X =	5.0495,	209.9116,	341.0	!!END!	Voyageurs
991 ! X =	6.2376,	209.9127,	341.0	!!END!	Voyageurs
992 ! X =	7.4257,	209.9142,	341.0	!!END!	Voyageurs
993 ! X =	8.6138,	209.9158,	343.0	!!END!	Voyageurs
994 ! X =	9.8019,	209.9177,	341.0	!!END!	Voyageurs
995 ! X =	10.9900,	209.9199,	381.0	!!END!	Voyageurs
996 ! X =	12.1781,	209.9223,	365.0	!!END!	Voyageurs
997 ! X =	13.3662,	209.9250,	365.0	!!END!	Voyageurs
998 ! X =	14.5543,	209.9279,	365.0	!!END!	Voyageurs
999 ! X =	15.7424,	209.9310,	349.0	!!END!	Voyageurs
1000 ! X =	16.9305,	209.9344,	346.0	!!END!	Voyageurs
1001 ! X =	18.1186,	209.9381,	341.0	!!END!	Voyageurs
1002 ! X =	19.3067,	209.9420,	341.0	!!END!	Voyageurs
1003 ! X =	20.4948,	209.9461,	341.0	!!END!	Voyageurs
1004 ! X =	-5.6417,	211.7038,	351.0	!!END!	Voyageurs
1005 ! X =	-4.4540,	211.7028,	341.0	!!END!	Voyageurs

1006 ! X =	-3.2663,	211.7020,	341.0	!!END!	Voyageurs
1007 ! X =	-2.0785,	211.7014,	341.0	!!END!	Voyageurs
1008 ! X =	-0.8908,	211.7011,	341.0	!!END!	Voyageurs
1009 ! X =	0.2969,	211.7010,	341.0	!!END!	Voyageurs
1010 ! X =	1.4847,	211.7012,	353.0	!!END!	Voyageurs
1011 ! X =	2.6724,	211.7016,	349.0	!!END!	Voyageurs
1012 ! X =	3.8601,	211.7023,	361.0	!!END!	Voyageurs
1013 ! X =	5.0479,	211.7032,	365.0	!!END!	Voyageurs
1014 ! X =	6.2356,	211.7044,	366.0	!!END!	Voyageurs
1015 ! X =	7.4233,	211.7058,	365.0	!!END!	Voyageurs
1016 ! X =	8.6111,	211.7075,	381.0	!!END!	Voyageurs
1017 ! X =	9.7988,	211.7094,	381.0	!!END!	Voyageurs
1018 ! X =	10.9865,	211.7116,	353.0	!!END!	Voyageurs
1019 ! X =	12.1743,	211.7140,	350.0	!!END!	Voyageurs
1020 ! X =	13.3620,	211.7167,	356.0	!!END!	Voyageurs
1021 ! X =	14.5497,	211.7196,	365.0	!!END!	Voyageurs
1022 ! X =	15.7375,	211.7227,	370.0	!!END!	Voyageurs
1023 ! X =	16.9252,	211.7261,	364.0	!!END!	Voyageurs
1024 ! X =	18.1129,	211.7298,	351.0	!!END!	Voyageurs
1025 ! X =	19.3007,	211.7337,	341.0	!!END!	Voyageurs
1026 ! X =	20.4884,	211.7378,	341.0	!!END!	Voyageurs
1027 ! X =	-10.3894,	213.5018,	347.0	!!END!	Voyageurs
1028 ! X =	-9.2020,	213.4997,	347.0	!!END!	Voyageurs
1029 ! X =	-8.0147,	213.4979,	341.0	!!END!	Voyageurs
1030 ! X =	-4.4526,	213.4940,	341.0	!!END!	Voyageurs
1031 ! X =	-3.2652,	213.4932,	341.0	!!END!	Voyageurs
1032 ! X =	-2.0779,	213.4927,	341.0	!!END!	Voyageurs
1033 ! X =	-0.8905,	213.4924,	341.0	!!END!	Voyageurs
1034 ! X =	0.2968,	213.4923,	341.0	!!END!	Voyageurs
1035 ! X =	1.4842,	213.4925,	341.0	!!END!	Voyageurs
1036 ! X =	2.6716,	213.4929,	377.0	!!END!	Voyageurs
1037 ! X =	3.8589,	213.4936,	381.0	!!END!	Voyageurs
1038 ! X =	5.0463,	213.4945,	393.0	!!END!	Voyageurs
1039 ! X =	6.2336,	213.4957,	381.0	!!END!	Voyageurs
1040 ! X =	7.4210,	213.4971,	396.0	!!END!	Voyageurs
1041 ! X =	8.6084,	213.4988,	366.0	!!END!	Voyageurs
1042 ! X =	9.7957,	213.5007,	378.0	!!END!	Voyageurs

1043 ! X =	10.9831,	213.5029,	380.0	!!END!	Voyageurs
1044 ! X =	12.1705,	213.5053,	390.0	!!END!	Voyageurs
1045 ! X =	13.3578,	213.5079,	398.0	!!END!	Voyageurs
1046 ! X =	14.5452,	213.5108,	396.0	!!END!	Voyageurs
1047 ! X =	15.7325,	213.5140,	396.0	!!END!	Voyageurs
1048 ! X =	16.9199,	213.5174,	377.0	!!END!	Voyageurs
1049 ! X =	18.1072,	213.5210,	374.0	!!END!	Voyageurs
1050 ! X =	19.2946,	213.5249,	366.0	!!END!	Voyageurs
1051 ! X =	20.4819,	213.5291,	361.0	!!END!	Voyageurs
1052 ! X =	-10.3861,	215.2933,	350.0	!!END!	Voyageurs
1053 ! X =	-9.1992,	215.2912,	349.0	!!END!	Voyageurs
1054 ! X =	-8.0122,	215.2894,	344.0	!!END!	Voyageurs
1055 ! X =	-6.8252,	215.2879,	341.0	!!END!	Voyageurs
1056 ! X =	-5.6382,	215.2866,	341.0	!!END!	Voyageurs
1057 ! X =	-4.4512,	215.2855,	341.0	!!END!	Voyageurs
1058 ! X =	-3.2642,	215.2847,	341.0	!!END!	Voyageurs
1059 ! X =	-2.0772,	215.2842,	341.0	!!END!	Voyageurs
1060 ! X =	-0.8902,	215.2839,	341.0	!!END!	Voyageurs
1061 ! X =	0.2967,	215.2838,	361.0	!!END!	Voyageurs
1062 ! X =	1.4837,	215.2840,	381.0	!!END!	Voyageurs
1063 ! X =	2.6707,	215.2844,	366.0	!!END!	Voyageurs
1064 ! X =	3.8577,	215.2851,	365.0	!!END!	Voyageurs
1065 ! X =	5.0447,	215.2860,	366.0	!!END!	Voyageurs
1066 ! X =	6.2317,	215.2872,	366.0	!!END!	Voyageurs
1067 ! X =	7.4187,	215.2886,	360.0	!!END!	Voyageurs
1068 ! X =	8.6057,	215.2903,	360.0	!!END!	Voyageurs
1069 ! X =	9.7927,	215.2922,	359.0	!!END!	Voyageurs
1070 ! X =	10.9796,	215.2944,	365.0	!!END!	Voyageurs
1071 ! X =	12.1666,	215.2968,	381.0	!!END!	Voyageurs
1072 ! X =	13.3536,	215.2994,	381.0	!!END!	Voyageurs
1073 ! X =	14.5406,	215.3023,	387.0	!!END!	Voyageurs
1074 ! X =	15.7276,	215.3055,	394.0	!!END!	Voyageurs
1075 ! X =	16.9146,	215.3089,	381.0	!!END!	Voyageurs
1076 ! X =	18.1016,	215.3125,	381.0	!!END!	Voyageurs
1077 ! X =	19.2885,	215.3164,	347.0	!!END!	Voyageurs
1078 ! X =	20.4755,	215.3206,	356.0	!!END!	Voyageurs
1079 ! X =	21.6625,	215.3250,	366.0	!!END!	Voyageurs

1080 ! X =	22.8495,	215.3296,	369.0	!!END!	Voyageurs
1081 ! X =	24.0365,	215.3345,	366.0	!!END!	Voyageurs
1082 ! X =	25.2234,	215.3396,	338.0	!!END!	Voyageurs
1083 ! X =	26.4104,	215.3450,	338.0	!!END!	Voyageurs
1084 ! X =	-6.8230,	217.0793,	350.0	!!END!	Voyageurs
1085 ! X =	-5.6364,	217.0780,	342.0	!!END!	Voyageurs
1086 ! X =	-4.4498,	217.0769,	341.0	!!END!	Voyageurs
1087 ! X =	-3.2632,	217.0761,	341.0	!!END!	Voyageurs
1088 ! X =	-2.0766,	217.0756,	350.0	!!END!	Voyageurs
1089 ! X =	-0.8900,	217.0753,	369.0	!!END!	Voyageurs
1090 ! X =	0.2967,	217.0752,	364.0	!!END!	Voyageurs
1091 ! X =	1.4833,	217.0754,	366.0	!!END!	Voyageurs
1092 ! X =	2.6699,	217.0758,	395.0	!!END!	Voyageurs
1093 ! X =	3.8565,	217.0765,	407.0	!!END!	Voyageurs
1094 ! X =	5.0431,	217.0774,	396.0	!!END!	Voyageurs
1095 ! X =	6.2297,	217.0786,	366.0	!!END!	Voyageurs
1096 ! X =	7.4163,	217.0800,	391.0	!!END!	Voyageurs
1097 ! X =	8.6030,	217.0817,	354.0	!!END!	Voyageurs
1098 ! X =	9.7896,	217.0836,	358.0	!!END!	Voyageurs
1099 ! X =	10.9762,	217.0858,	351.0	!!END!	Voyageurs
1100 ! X =	12.1628,	217.0882,	367.0	!!END!	Voyageurs
1101 ! X =	13.3494,	217.0908,	354.0	!!END!	Voyageurs
1102 ! X =	14.5360,	217.0937,	364.0	!!END!	Voyageurs
1103 ! X =	15.7226,	217.0969,	351.0	!!END!	Voyageurs
1104 ! X =	16.9093,	217.1003,	365.0	!!END!	Voyageurs
1105 ! X =	18.0959,	217.1039,	381.0	!!END!	Voyageurs
1106 ! X =	19.2825,	217.1078,	371.0	!!END!	Voyageurs
1107 ! X =	20.4691,	217.1120,	367.0	!!END!	Voyageurs
1108 ! X =	21.6557,	217.1163,	381.0	!!END!	Voyageurs
1109 ! X =	22.8423,	217.1210,	366.0	!!END!	Voyageurs
1110 ! X =	24.0289,	217.1258,	351.0	!!END!	Voyageurs
1111 ! X =	25.2155,	217.1310,	338.0	!!END!	Voyageurs
1112 ! X =	26.4021,	217.1363,	338.0	!!END!	Voyageurs
1113 ! X =	-5.6347,	218.8696,	350.0	!!END!	Voyageurs
1114 ! X =	-4.4484,	218.8686,	350.0	!!END!	Voyageurs
1115 ! X =	-3.2622,	218.8678,	365.0	!!END!	Voyageurs
1116 ! X =	-2.0759,	218.8672,	366.0	!!END!	Voyageurs

1117 ! X =	-0.8897,	218.8669,	366.0	!!END!	Voyageurs
1118 ! X =	0.2966,	218.8668,	365.0	!!END!	Voyageurs
1119 ! X =	1.4828,	218.8670,	366.0	!!END!	Voyageurs
1120 ! X =	2.6690,	218.8675,	368.0	!!END!	Voyageurs
1121 ! X =	3.8553,	218.8681,	381.0	!!END!	Voyageurs
1122 ! X =	5.0415,	218.8691,	366.0	!!END!	Voyageurs
1123 ! X =	6.2278,	218.8702,	368.0	!!END!	Voyageurs
1124 ! X =	7.4140,	218.8717,	380.0	!!END!	Voyageurs
1125 ! X =	8.6003,	218.8733,	349.0	!!END!	Voyageurs
1126 ! X =	9.7865,	218.8752,	348.0	!!END!	Voyageurs
1127 ! X =	10.9727,	218.8774,	341.0	!!END!	Voyageurs
1128 ! X =	12.1590,	218.8798,	338.0	!!END!	Voyageurs
1129 ! X =	13.3452,	218.8825,	338.0	!!END!	Voyageurs
1130 ! X =	14.5315,	218.8854,	338.0	!!END!	Voyageurs
1131 ! X =	15.7177,	218.8885,	338.0	!!END!	Voyageurs
1132 ! X =	16.9039,	218.8919,	338.0	!!END!	Voyageurs
1133 ! X =	18.0902,	218.8955,	338.0	!!END!	Voyageurs
1134 ! X =	19.2764,	218.8994,	338.0	!!END!	Voyageurs
1135 ! X =	20.4626,	218.9036,	338.0	!!END!	Voyageurs
1136 ! X =	21.6489,	218.9080,	338.0	!!END!	Voyageurs
1137 ! X =	22.8351,	218.9126,	338.0	!!END!	Voyageurs
1138 ! X =	24.0213,	218.9175,	338.0	!!END!	Voyageurs
1139 ! X =	25.2076,	218.9226,	338.0	!!END!	Voyageurs
1140 ! X =	-5.6329,	220.6611,	343.0	!!END!	Voyageurs
1141 ! X =	-4.4470,	220.6601,	347.0	!!END!	Voyageurs
1142 ! X =	-3.2611,	220.6593,	366.0	!!END!	Voyageurs
1143 ! X =	-2.0753,	220.6587,	381.0	!!END!	Voyageurs
1144 ! X =	-0.8894,	220.6584,	351.0	!!END!	Voyageurs
1145 ! X =	0.2965,	220.6584,	373.0	!!END!	Voyageurs
1146 ! X =	1.4823,	220.6586,	367.0	!!END!	Voyageurs
1147 ! X =	2.6682,	220.6590,	358.0	!!END!	Voyageurs
1148 ! X =	3.8541,	220.6597,	351.0	!!END!	Voyageurs
1149 ! X =	5.0399,	220.6606,	365.0	!!END!	Voyageurs
1150 ! X =	6.2258,	220.6618,	345.0	!!END!	Voyageurs
1151 ! X =	7.4117,	220.6632,	338.0	!!END!	Voyageurs
1152 ! X =	8.5976,	220.6649,	338.0	!!END!	Voyageurs
1153 ! X =	9.7834,	220.6668,	338.0	!!END!	Voyageurs

1154 ! X =	10.9693,	220.6689,	338.0	!!END!	Voyageurs
1155 ! X =	12.1552,	220.6713,	338.0	!!END!	Voyageurs
1156 ! X =	13.3410,	220.6740,	338.0	!!END!	Voyageurs
1157 ! X =	14.5269,	220.6769,	338.0	!!END!	Voyageurs
1158 ! X =	15.7128,	220.6800,	338.0	!!END!	Voyageurs
1159 ! X =	-9.1876,	222.4575,	339.0	!!END!	Voyageurs
1160 ! X =	-8.0021,	222.4557,	350.0	!!END!	Voyageurs
1161 ! X =	-6.8166,	222.4542,	338.0	!!END!	Voyageurs
1162 ! X =	-5.6311,	222.4529,	345.0	!!END!	Voyageurs
1163 ! X =	-4.4456,	222.4519,	338.0	!!END!	Voyageurs
1164 ! X =	-3.2601,	222.4510,	350.0	!!END!	Voyageurs
1165 ! X =	-2.0746,	222.4505,	365.0	!!END!	Voyageurs
1166 ! X =	-0.8891,	222.4502,	379.0	!!END!	Voyageurs
1167 ! X =	0.2964,	222.4501,	365.0	!!END!	Voyageurs
1168 ! X =	1.4819,	222.4503,	348.0	!!END!	Voyageurs
1169 ! X =	2.6674,	222.4507,	338.0	!!END!	Voyageurs
1170 ! X =	3.8529,	222.4514,	338.0	!!END!	Voyageurs
1171 ! X =	5.0384,	222.4523,	338.0	!!END!	Voyageurs
1172 ! X =	6.2239,	222.4535,	338.0	!!END!	Voyageurs
1173 ! X =	7.4094,	222.4549,	338.0	!!END!	Voyageurs
1174 ! X =	8.5948,	222.4566,	338.0	!!END!	Voyageurs
1175 ! X =	9.7803,	222.4585,	338.0	!!END!	Voyageurs
1176 ! X =	10.9658,	222.4607,	338.0	!!END!	Voyageurs
1177 ! X =	12.1513,	222.4631,	338.0	!!END!	Voyageurs
1178 ! X =	-12.7401,	224.2560,	356.0	!!END!	Voyageurs
1179 ! X =	-11.5550,	224.2535,	338.0	!!END!	Voyageurs
1180 ! X =	-10.3698,	224.2512,	351.0	!!END!	Voyageurs
1181 ! X =	-9.1847,	224.2492,	352.0	!!END!	Voyageurs
1182 ! X =	-7.9996,	224.2474,	352.0	!!END!	Voyageurs
1183 ! X =	-6.8145,	224.2458,	352.0	!!END!	Voyageurs
1184 ! X =	-5.6293,	224.2446,	351.0	!!END!	Voyageurs
1185 ! X =	-4.4442,	224.2435,	339.0	!!END!	Voyageurs
1186 ! X =	-3.2591,	224.2427,	339.0	!!END!	Voyageurs
1187 ! X =	-2.0740,	224.2422,	341.0	!!END!	Voyageurs
1188 ! X =	-0.8888,	224.2419,	340.0	!!END!	Voyageurs
1189 ! X =	0.2963,	224.2418,	351.0	!!END!	Voyageurs
1190 ! X =	1.4814,	224.2420,	348.0	!!END!	Voyageurs

```
1191 ! X =      2.6665,   224.2424,   347.0 !!END!   Voyageurs
1192 ! X =      3.8517,   224.2431,   340.0 !!END!   Voyageurs
1193 ! X =      5.0368,   224.2440,   338.0 !!END!   Voyageurs
1194 ! X =      6.2219,   224.2452,   338.0 !!END!   Voyageurs
1195 ! X =      7.4070,   224.2466,   338.0 !!END!   Voyageurs
1196 ! X =      8.5921,   224.2483,   338.0 !!END!   Voyageurs
1197 ! X =    -10.3666,   226.0428,   338.0 !!END!   Voyageurs
1198 ! X =     -9.1818,   226.0407,   338.0 !!END!   Voyageurs
1199 ! X =     -7.9971,   226.0390,   338.0 !!END!   Voyageurs
1200 ! X =     -6.8123,   226.0374,   338.0 !!END!   Voyageurs
1201 ! X =     -5.6276,   226.0361,   338.0 !!END!   Voyageurs
1202 ! X =     -4.4428,   226.0351,   338.0 !!END!   Voyageurs
1203 ! X =     -3.2581,   226.0343,   338.0 !!END!   Voyageurs
1204 ! X =     -2.0733,   226.0337,   338.0 !!END!   Voyageurs
1205 ! X =     -0.8886,   226.0334,   338.0 !!END!   Voyageurs
1206 ! X =      0.2962,   226.0333,   338.0 !!END!   Voyageurs
1207 ! X =      1.4809,   226.0335,   338.0 !!END!   Voyageurs
1208 ! X =      2.6657,   226.0340,   339.0 !!END!   Voyageurs
1209 ! X =      3.8504,   226.0346,   338.0 !!END!   Voyageurs
1210 ! X =      5.0352,   226.0356,   338.0 !!END!   Voyageurs
1211 ! X =    -10.3633,   227.8346,   338.0 !!END!   Voyageurs
1212 ! X =     -9.1789,   227.8325,   338.0 !!END!   Voyageurs
1213 ! X =     -7.9946,   227.8307,   338.0 !!END!   Voyageurs
1214 ! X =     -6.8102,   227.8292,   338.0 !!END!   Voyageurs
1215 ! X =     -5.6258,   227.8279,   338.0 !!END!   Voyageurs
1216 ! X =     -4.4414,   227.8269,   338.0 !!END!   Voyageurs
1217 ! X =     -3.2570,   227.8260,   338.0 !!END!   Voyageurs
1218 ! X =     -2.0727,   227.8255,   338.0 !!END!   Voyageurs
1219 ! X =     -0.8883,   227.8252,   338.0 !!END!   Voyageurs
1220 ! X =      0.2961,   227.8251,   338.0 !!END!   Voyageurs
1221 ! X =      1.4805,   227.8253,   338.0 !!END!   Voyageurs
1222 ! X =      2.6649,   227.8257,   338.0 !!END!   Voyageurs
1223 ! X =    123.7310,  -10.78810,   388.0 !!END!   Rainbow Lakes
1224 ! X =    127.4331,  -10.70968,   395.0 !!END!   Rainbow Lakes
1225 ! X =    128.0501,  -10.69639,   389.0 !!END!   Rainbow Lakes
1226 ! X =    123.7123,  -9.893789,   382.0 !!END!   Rainbow Lakes
1227 ! X =    124.3293,  -9.880882,   395.0 !!END!   Rainbow Lakes
```

1228 ! X =	124.9462,	-9.867910,	396.0	!!END!	Rainbow Lakes
1229 ! X =	125.5631,	-9.854875,	393.0	!!END!	Rainbow Lakes
1230 ! X =	126.1801,	-9.841774,	394.0	!!END!	Rainbow Lakes
1231 ! X =	126.7970,	-9.828610,	385.0	!!END!	Rainbow Lakes
1232 ! X =	127.4139,	-9.815382,	380.0	!!END!	Rainbow Lakes
1233 ! X =	128.0308,	-9.802089,	380.0	!!END!	Rainbow Lakes
1234 ! X =	123.6937,	-8.999110,	396.0	!!END!	Rainbow Lakes
1235 ! X =	124.3105,	-8.986204,	396.0	!!END!	Rainbow Lakes
1236 ! X =	124.9273,	-8.973234,	386.0	!!END!	Rainbow Lakes
1237 ! X =	125.5442,	-8.960200,	378.0	!!END!	Rainbow Lakes
1238 ! X =	126.1610,	-8.947103,	381.0	!!END!	Rainbow Lakes
1239 ! X =	126.7778,	-8.933940,	380.0	!!END!	Rainbow Lakes
1240 ! X =	127.3947,	-8.920713,	374.0	!!END!	Rainbow Lakes
1241 ! X =	123.6750,	-8.104692,	387.0	!!END!	Rainbow Lakes
1242 ! X =	124.2917,	-8.091788,	393.0	!!END!	Rainbow Lakes
1243 ! X =	124.9085,	-8.078821,	395.0	!!END!	Rainbow Lakes
1244 ! X =	125.5252,	-8.065789,	392.0	!!END!	Rainbow Lakes
1245 ! X =	126.1420,	-8.052692,	375.0	!!END!	Rainbow Lakes
1246 ! X =	126.7587,	-8.039533,	366.0	!!END!	Rainbow Lakes
1247 ! X =	127.3754,	-8.026308,	365.0	!!END!	Rainbow Lakes
1248 ! X =	127.9922,	-8.013020,	364.0	!!END!	Rainbow Lakes
1249 ! X =	123.6563,	-7.209905,	395.0	!!END!	Rainbow Lakes
1250 ! X =	124.2730,	-7.197003,	395.0	!!END!	Rainbow Lakes
1251 ! X =	124.8896,	-7.184038,	395.0	!!END!	Rainbow Lakes
1252 ! X =	125.5063,	-7.171008,	403.0	!!END!	Rainbow Lakes
1253 ! X =	126.1229,	-7.157913,	384.0	!!END!	Rainbow Lakes
1254 ! X =	126.7396,	-7.144755,	372.0	!!END!	Rainbow Lakes
1255 ! X =	127.3562,	-7.131533,	365.0	!!END!	Rainbow Lakes
1256 ! X =	127.9729,	-7.118246,	365.0	!!END!	Rainbow Lakes
1257 ! X =	123.6377,	-6.315380,	411.0	!!END!	Rainbow Lakes
1258 ! X =	124.2542,	-6.302481,	386.0	!!END!	Rainbow Lakes
1259 ! X =	124.8708,	-6.289516,	381.0	!!END!	Rainbow Lakes
1260 ! X =	125.4873,	-6.276489,	381.0	!!END!	Rainbow Lakes
1261 ! X =	126.1039,	-6.263396,	359.0	!!END!	Rainbow Lakes
1262 ! X =	126.7204,	-6.250240,	335.0	!!END!	Rainbow Lakes
1263 ! X =	127.3370,	-6.237020,	365.0	!!END!	Rainbow Lakes
1264 ! X =	123.0025,	-5.433951,	393.0	!!END!	Rainbow Lakes

```
 1265 ! X =     123.6190,   -5.421118,   381.0 !!END!   Rainbow Lakes
 1266 ! X =     124.2355,   -5.408220,   380.0 !!END!   Rainbow Lakes
 1267 ! X =     124.8519,   -5.395258,   380.0 !!END!   Rainbow Lakes
 1268 ! X =     125.4684,   -5.382232,   348.0 !!END!   Rainbow Lakes
 1269 ! X =     126.0849,   -5.369142,   350.0 !!END!   Rainbow Lakes
 1270 ! X =     126.7013,   -5.355988,   329.0 !!END!   Rainbow Lakes
 1271 ! X =     122.9840,   -4.539317,   365.0 !!END!   Rainbow Lakes
 1272 ! X =     124.2167,   -4.513590,   335.0 !!END!   Rainbow Lakes
-------------
  a
   Data for each receptor are treated as a separate input subgroup
   and therefore must end with an input group terminator.

  b
   Receptor height above ground is optional.  If no value is entered,
   the receptor is placed on the ground.
```

APPENDIX D

AIR DISPERSION MODELING ANALYSIS

MESABA ONE AND MESABA TWO

McVehil-Monnett Associates, Inc.
44 Inverness Dr. E., Bldg. C
Englewood, CO 80112

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PART I: NEAR-FIELD MODELING ANALYSIS

1.0 MODELING METHODOLOGY

1.1 Model and Options

All near-field modeling was conducted with the AERMOD PRIME air quality model (version 04300). The application used all regulatory default options, including stack tip downwash, elevated terrain effects, calms processing, missing data processing, "upper bound" values for supersquat buildings, and no decay of pollutant concentrations due to chemical transformation, deposition, or wet depletion. Rural dispersion coefficients were used in accord with the prevailing land use at the Mesaba site.

1.2 Building Downwash

Building downwash effects on dispersion from Mesaba One and Mesaba Two stacks were accounted for by use of the EPA PRIME downwash algorithm. The locations of all IGCC Power Station buildings and stacks were digitized based on the two-phase plant layout drawings. These locations and the dimensions of all significant plant structures were entered in the EPA BPIP PRIME model to calculate direction-specific building dimensions and other parameters required as input to the AERMOD model. The layout of the IGCC Power Station buildings and stacks as entered into BPIP PRIME is shown in Figure D-1. Input and output files for BPIP PRIME are included with the permit application on compact disk.

1.3 Meteorological Data

Five years of meteorological data were used for all AERMOD dispersion calculations. The data were prepared and processed using the AERMET program by the Minnesota Pollution Control Agency (MPCA). The meteorological data are based upon Hibbing, Minnesota hourly surface weather observations for the years 1972 through 1976, and were developed specifically for the local area of the IGCC Power Station. The data file (HI475935.ZIP) was provided by Mr. Dennis Becker of the MPCA on July 12, 2005 and is included on the application Modeling Files CD.

1.4 Receptor Grid

The near-field receptor grid was developed following MPCA guidance to provide detailed coverage of the area within which Mesaba One and Mesaba Two will have significant impacts. Receptors consist of nested Cartesian grids covering a 21 km x 21 km area centered on the plant site. Receptors were placed at 10 meter spacing along the proposed plant fence line (which will preclude public access). Successive grids beyond the fence line have receptor spacing of 25 meters, 50, 100, 200, 500 and 1000 meters at increasing distances. The receptor grid, with terrain elevation contours, is shown in Figure D-2.

Figure D-1. Significant Building and Stack Locations

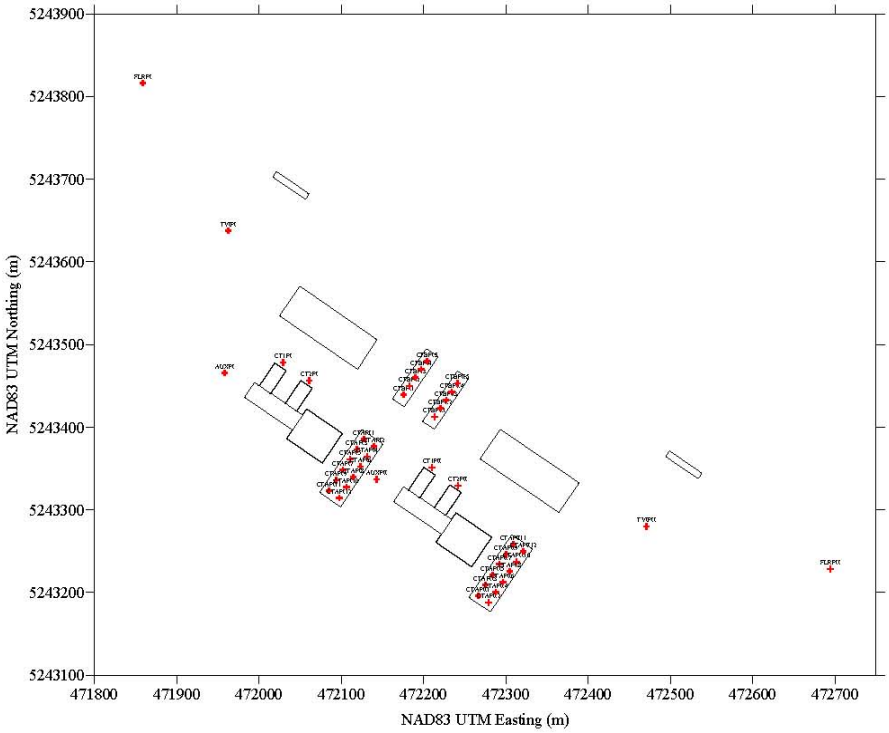

Figure D-1
Significant Building and Stack Locations
For Mesaba Project Phase I and II

McVEHIL-MONNETT ASSOCIATES, INC.
Air Quality • Environmental Management

Figure D-2. Modeling Receptor Grid and Terrain Elevations (m)

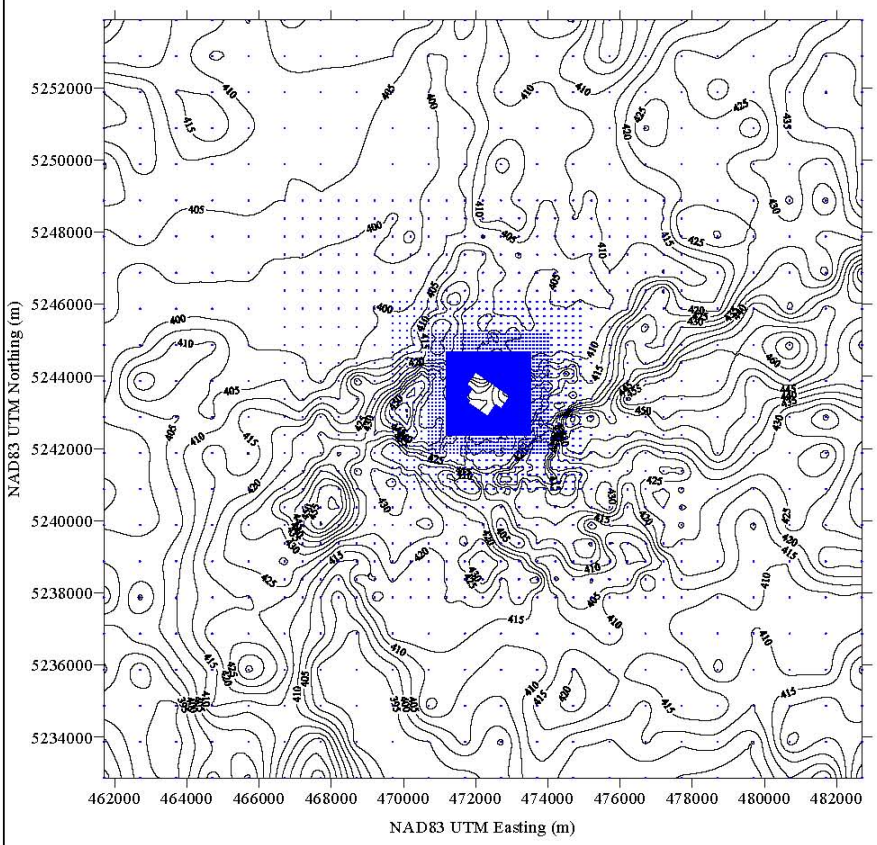

Figure D-2
Modeling Receptor Grid and Terrain Elevations (m)

McVEHIL-MONNETT ASSOCIATES, INC.
Air Quality • Environmental Management

Terrain elevations for all IGCC Power Station sources and buildings were taken from the engineering design plan for the site. Receptor terrain elevations were determined from USGS 7.5 minute DEM data and processed by AERMAP.

Modeling results demonstrated that all maximum impacts of Mesaba One and Mesaba Two occur within approximately one kilometer of the site. Thus all high impacts occur within a dense receptor grid (50 meter or less receptor spacing) and the grid resolution is adequate to define maximum IGCC Power Station impacts.

1.5 Mesaba Emissions for Modeling

Tables B-1 through B-3 present maximum expected emission rates for Mesaba One and Mesaba Two's major point sources for different averaging times and operating scenarios. All emission rates are taken directly from data provided by Excelsior Energy Inc. ("Excelsior"). The emission rates shown, along with the design stack parameters in Table D-4, were used as model input for the air modeling analyses.

The data presented in Table D-1 represent emissions during normal operation of the Mesaba plant. These emission rates were modeled as the "Normal" case to define the expected air quality impacts of the IGCC Power Station.

Emission rates and stack gas conditions for short-term averaging times can be different from those shown in Table D-1 during non-steady-state operating scenarios such as startup and flaring of syngas. To address these short-term conditions, air modeling was also carried out for applicable averaging times (24 hours and less) using the emission rates given in Tables B-2 and B-3. The emission rates represent worst-case maximum emissions for each scenario. The applicable stack parameters for alternate operating scenarios are also shown in Table D-4.

Other sources at Mesaba One and Mesaba Two will consist of two emergency fire pumps (each phase) and two emergency diesel generators (each phase). Since these sources will operate for short time periods, when the primary emission sources will not be in operation, they were not included in the air modeling analyses. Hours of operation will be limited by permit conditions. Their emissions are negligible in comparison to the sources shown in Tables B-1 through B-3.

Cooling towers at Mesaba One and Mesaba Two will emit PM10 as dissolved solids in drift droplets. Each phase of the IGCC Power Station will have one 12-cell and one five-cell cooling tower. Each cell of each tower was included in PM10 modeling as a point source. Stack characteristics were taken directly from engineering design parameters: height = 14.63 m, diameter = 10.06m, exit velocity = 8.14 m/s, and temperature = 313 deg K. Emission rate for PM10 was set equal to 0.0336 g/s for each cell of the 12-cell towers, and 0.0328 g/s per cell for 5-cell towers. These rates correspond to the design drift rate of 0.001 percent and dissolved solids of 2,740 ppm by weight. All cooling towers were assumed to operate for 8,760 hours per year. The cooling towers and emission points are shown on Figure D-1.

Table D-1
Modeling Emission Rates for Normal Operation[1] – One Phase

Source/Averaging Time	SO_2		CO		PM10[2]		NO_x	
	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
Combustion Turbines (each of two)								
One-Hour	183	23.06	95	11.97				
Three-Hour	152	19.15						
Eight-Hour			95	11.97				
24-Hour	114	14.36			25	3.15		
Annual	76	9.58			25	3.15	158	19.91
Tank Vent Boiler								
One-Hour	8.4	1.06	5.9	0.74				
Three-Hour	7.5	0.94						
Eight-Hour			5.9	0.74				
24-Hour	6.4	0.81			0.7	0.09		
Annual	3.6	0.45			0.2	0.03	6.0	0.76
Auxiliary Boiler								
One-Hour	0.37	0.05	9.6	1.21				
Three-Hour	0.37	0.05						
Eight-Hour			9.6	1.21				
24-Hour	0.37	0.05			0.65	0.08		
Annual	0.09	0.01			0.16	0.02	1.16	0.15

Table D-1
Modeling Emission Rates for Normal Operation[1] – One Phase Continued

Source/Averaging Time	SO_2		CO		PM10[2]		NO_x	
	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
Flare								
One-Hour	0.01	0.001	1.10	0.14				
Three-Hour	0.01	0.001						
Eight-Hour			1.10	0.14				
24-Hour	0.01	0.001			0.02	0.002		
Annual	2.8	0.35			0.38	0.05	3.1	0.39

[1]Short-term emissions represent normal plant operation on syngas fuel; annual emissions are worst-case annual operation including flaring, gasifier outages, etc.
[2]PM10 emissions include filterable and condensable portions.

Table D-2
Modeling Emission Rates for Worst-Case Flaring Scenario-One Phase

Source/Averaging Time	SO_2		CO		PM10[1]		NO_x	
	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
Combustion Turbines (each of two)								
One-Hour								
Three-Hour								
Eight-Hour								
24-Hour								
Tank Vent Boiler								
One-Hour								
Three-Hour								
Eight-Hour								
24-Hour								
Auxiliary Boiler								
Flare								
One-Hour	1040	131.04	5680	715.67				
Three-Hour	734	92.48						
Eight-Hour			5345	637.46				
24-Hour	183	23.06			14.1	1.78		

[1]PM10 emissions include filterable and condensable portions

Table D-3
Modeling Emission Rates for Worst-Case Start-up Operating Scenario – One Phase

Source/Averaging Time	SO_2		CO		PM10[1]		NO_x	
	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
Combustion Turbines (each of two)								
One-Hour	183	23.06	2740	345.23				
Three-Hour	152	19.15						
Eight-Hour			541	68.21				
24-Hour	114	14.36			25	3.15		
Tank Vent Boiler								
One-Hour	8.4	1.06	5.9	0.74				
Three-Hour	7.5	0.94						
Eight-Hour			5.9	0.74				
24-Hour	6.4	0.81			0.7	0.09		
Auxiliary Boiler	0.37	0.05	9.6	1.21	0.65	0.08		
Flare								
One-Hour	0.11	0.01	22	2.77				
Three-Hour	0.11	0.01						
Eight-Hour			22	2.77				
24-Hour	0.11	0.01			0.32	0.04		

[1]PM10 emissions include filterable and condensable portions

Table D-4
Modeling Stack Parameters

Source/Scenario Averaging Time	Stack Ht. (m)	Stack Dia. (m)	Gas Temp (K)	Velocity (m/s)
Combustion Turbines (each)				
Normal Operation	45.72	6.10	394.3	20.08
Startup	45.72	6.10	366.5	11.64
Tank Vent Boiler				
Short-term	64.01	1.83	579.8	8.46
Annual	64.01	1.83	579.8	1.95
Startup	64.01	1.83	579.8	5.21
Auxiliary Boiler	12.19	1.52	422.1	9.70
Flare[1]				
Normal Operation	56.39	0.25	1273.0	20.0
Startup	56.39	1.11	1273.0	20.0
Flaring: One-Hour	56.39	10.72	1273.0	20.0
Three-Hour	56.39	10.40	1273.0	20.0
Eight-Hour	56.39	10.40	1273.0	20.0
24-Hour	56.39	7.36	1273.0	20.0
Annual	56.39	0.25	1273.0	20.0

[1] Flare parameters determined by SCREEN 3 methodology based on total heat release

There will also be PM10 emissions from fugitive sources related to coal and material handling. Modeling emission rates for fugitive PM10 are shown in Table D-5. The fugitive sources were represented in the AERMOD model input as area sources. Area sources were defined to occupy the plant areas from which fugitive emissions will be generated, as identified on the plant layout drawing. Modeling specifications for the area sources are given in Table D-6. Emission heights are based on the actual heights of emissions sources and storage piles.

All fugitive emission rates were calculated from applicable emission factors, material throughput rates, and control efficiencies as shown in Section 4.1.5 of the permit application. Maximum hourly emission rates shown in Section 4.1.5 are not appropriate in all cases for modeling of 24-hour average PM10 concentration. The 24-hour emission rates shown in Table D-5 assume a maximum of three unit coal trains unloaded in a 24-hour period; i.e., 41,005 tons per day of coal unloaded and conveyed to active storage. All other 24-hour emission rates are maximum hourly rates as given in Section 4.1.5.

1.6 Modeling of Storage Pile Wind Erosion

Fugitive PM10 emissions from storage piles were calculated according to the methodology of AP-42, Section 13.2.5, and represented in the air quality model as a function of wind speed. Wind speed (STAR) scalers were utilized in AERMOD to simulate the emissions of PM10 during hours of high wind speed.

The calculation of annual wind erosion emissions is shown in Tables B-7. The calculation was made for the active coal storage area for one phase of Mesaba One and Mesaba Two; this same annual emission rate was applied to both phase active coal storage piles and the two slag piles. The inactive coal storage area will be stabilized with surface crusting agents and no wind erosion was included.

The calculations in Tables B-7 are based on Hibbing wind frequency statistics (University of Minnesota Document AD-TB1955 (1983)); Table D-7 (a) shows the wind speed distribution for hourly wind measurements at 10 m height. It was conservatively assumed that the "fastest mile" wind speed (U_{10}^{+}) is given by 1.5 times the hourly speed (U_{10}).

Other assumptions for the wind erosion calculations are:

Threshold friction velocity (U_t^*) = 1.12 m/s
Roughness length (Z_o) = 0.5 cm

both from AP-42 Table 13.2.5-2 for an uncrusted coal pile. The coal storage pile for a single phase was assumed to occupy a horizontal area of 7432 m^2, with an actual surface area exposed to the wind of 8370 m^2. The pile will be 152 m in length, 49 m in width, and 14.3 m in height.

Table D-5
Fugitive PM10 Emission Rates for Modeling – Mesaba One and Mesaba Two

Source	24-Hour Max		Annual Max	
	lb/hr	g/s	ton/yr	g/s
1 Railcar Unloading	0.372	0.0469	0.674	0.0194
2 Transfer to Conveyor	0.086	0.0108	0.155	0.0045
3 Coal Conveyor Transfers (3)	0.257	0.0324	0.465	0.0134
4 Coal Stacking	0.855	0.1077	1.550	0.0446
5 Coal Reclaim	0.215	0.0271	0.775	0.0223
6 Reclaim Conveyor Transfers (3)	0.129	0.0163	0.465	0.0134
7 Transfer to Feed Bin	0.009	0.0011	0.031	0.0009
8 Coal Slurry Facility Transfers (2)	0.086	0.0108	0.310	0.0089
9 Slag Storage Load-out	0.195	0.0246	0.705	0.0203
10 Slag Disposal Truck Traffic	0.304	0.0383	1.330	0.0383

Table D-6
Area source Modeling Parameters For Fugitive PM10 Emissions – Mesaba One and Mesaba Two

Source ID	Sources Included (Table D-5)	UTM Coordinates		Area Dimensions		Area Orientation	Release Height	Initial σ_z
		E(m)	N(m)	x(m)	y(m)	(deg)	(m)	(m)
COALHNDL	3, 4, 5, 6, 7	472,066.4	5,243,640.0	470	160	34.4	10	3
SLURPI	8 (Phase I)	471,992.5	5,243,673.5	49	14	34.4	3	2
SLAGPI	9, 10 (Phase I)	471,867.0	5,243,903.5	240	35	34.4	5	2
RAILUNLD	1, 2	472,273.5	5,243,740.5	26	16	34.4	3	2
SLURPII	8 (Phase II)	472,465.6	5,243,337.5	49	14	34.4	3	2
SLAGPII	9, 10 (Phase II)	472,532.7	5,243,431.5	300	35	34.4	5	2
COALHDWE	Wind Erosion	472,066.4	5,243,640.0	470	160	34.4	10	3
SLGPIWE	Wind Erosion	471,867.0	5,243,903.5	140	35	34.4	5	2
SLGPIIWE	Wind Erosion	472,664.7	5,243,341.0	140	35	34.4	5	2

Table D-7 (b) lists the surface wind speeds (U_s^+), friction velocities, and erosion potential (P) for each pile sub-area and wind speed class per AP-42 equations and data.

The calculation of annual average wind erosion is shown in Table D-7 (c), where the contributions from each wind speed event where winds exceed the erosion threshold are summed to obtain the total annual PM emission for the storage pile. It was assumed that the pile is disturbed daily, so that each day with a high fastest mile wind speed produces emissions. The annual average emission rate of 0.22 tons per acre per year was assumed to apply to all active storage piles.

For simulation of wind erosion impacts in AERMOD, wind speed scalers are defined to multiply by the average annual emission rate. The scalers are zero for wind speeds below the erosion threshold, and increase with wind speed for hours with speeds exceeding the threshold. Derivation of the wind speed scalers is given in Table D-8. The calculation method assures that total annual wind erosion emissions will equal the value determined in Table D-7, given the wind speed distribution for Hibbing. Table D-8 shows the wind speed classes (U_{10}) used in AERMOD modeling for PM10, and the scalers for each of the six speed classes.

Table D-7
(a).Hibbing MN Wind Frequencies and Assumed Fastest Mile Wind Speed for Each Speed Category

U_{10} (mph)	U_{10} (m/s)	Frequency (%)	U_{10}^{+} (m/s)	Assumed U_{10}^{+} (m/s)
< 8	< 3.58	38.9	< 5.36	5.0
8 – 12	3.58 – 5.58	30.4	5.36 – 8.38	8.0
13 – 18	5.59 – 8.27	27.0	8.39 – 12.41	12.0
19 – 24	8.28 – 10.95	3.3	12.42 – 16.43	16.0
> 24	> 10.95	0.4	> 16.43	20.0

Table D-7
(b) Erosion Potential for Wind Speed Classes and Pile Sub-Areas

U_{10}^{+}	$U_s/U_r = 0.2$			$U_s/U_r = 0.6$			$U_s/U_r = 0.9$			$U_s/U_r = 1.1$		
	U_s^{+}	U^*	P	U_s^{+}	U^*	P	U_s^{+}	U^*	P	U_s^{+}	U^*	P
5	1.0	0.10	0	3.0	0.30	0	4.5	0.45	0	5.5	0.55	0
8	1.6	0.16	0	4.8	0.48	0	7.2	0.72	0	8.8	0.88	0
12	2.4	0.24	0	7.2	0.72	0	10.8	1.08	0	13.2	1.32	7.320
16	3.2	0.32	0	9.6	0.96	0	14.4	1.44	13.939	17.6	1.76	39.757
20	4.0	0.40	0	12.0	1.20	2.371	18.0	1.80	43.819	22.0	2.20	94.651

Data from AP-42 Table 13.2.5-3 and Figure 13.2.5-2 (Pile B3).

$$P = 58(U^* - U_t^*)^2 + 25(U^* - U_t^*)$$

Table D-7
(c). Calculation of Annual Wind Erosion

U_{10}^{+} (m/s)	P (g/m^2)	Days per Year	Fraction of Pile Area (%)	Area (m^2)	Emissions (kg/yr)
12	7.320	98.550	4	335	241.664
16	13.939	12.045	14	1172	196.773
16	39.757	12.045	4	335	160.422
20	2.371	1.460	54	4520	15.647
20	43.819	1.460	14	1172	74.980
20	94.651	1.460	4	335	46.294
				Total	735.780

Annual Average Emission Rate:
735.78 x 10^3 grams x 1/7432m^2 x 1/31.536 x 10^6 sec/yr

= 3.1393 x 10^{-6} g/m^2-s (PM)

or 1.5696 x 10^{-6} g/m^2-s (PM10) = 0.22 ton/acre-year

Table D-8
Calculation of Wind Speed Scalers for AERMOD

Wind Speed Class	Wind Speed Range (U_{10}) (m/s)	U_{10}^{+} (m/s)	Fraction of Area	P (g/m^2)	$\overline{P}$ (g/m^2)	Wind Speed Frequency F	$\overline{P}$ x F
1	< 2.0	3.0	0	0	0		0
2	2.0 – 3.6	5.0	0	0	0		0
3	3.6 – 5.8	8.0	0	0	0		0
4	5.8 – 8.5	12.0	.04	7.320	0.293	.270	.0791
5	8.5 – 10.7	16.0	.14 .04	13.939 39.757	3.542	.033	.1169
6	> 10.7	20.0	.54 .14 .04	2.371 43.819 94.651	11.201	.004	.0448
						Sum of $\overline{P}$ x F = .2408	

$\overline{P}$ = area weighted average of P based on total pile area

Wind Speed Scalers:

a_1 = 0/.2408 = 0.0
a_2 = 0/.2408 = 0.0
a_3 = 0/.2408 = 0.0
a_4 = .293/.2408 = 1.2168
a_5 = 3.542/.2408 = 14.7093
a_6 = 11.201/.2408 = 46.5158

2.0 SIGNIFICANT IMPACT MODELING

Initial air quality modeling was carried out to define maximum impacts of Mesaba One and Mesaba Two alone, for each pollutant and averaging time. Modeling included both phases of the project, with emission rates and stack parameters given in Section 1.0. All relevant operating scenarios were modeled in order to determine highest concentrations for any operating condition.

Results of significant impact area (SIA) modeling are given in Table D-9. All concentrations shown are the highest predicted concentration for any receptor or year of meteorological data.

Minnesota significant impact levels (SILs) are also shown in Table D-9. The data indicate that most predicted impacts are significant; i.e., exceed the applicable SIL. CO impacts are significant only for the worst-case startup scenario (both phases in startup). Thus, startup is the worst-case for CO. For SO_2, PM10, and NO_x, normal operation produces the highest concentrations.

Based upon the results in Table D-9, full increment and NAAQS compliance analyses are necessary for SO_2, PM10, and NO_x. The normal operation scenario only need be modeled, since impacts are less for flaring and startup. A NAAQS compliance demonstration is necessary for CO in the startup mode (one-hour only). Since no regional CO inventory is available, the CO compliance demonstration has utilized the Mesaba-only CO SIA model run.

The SIA is defined as the area over which concentrations exceeding the SIL are predicted. SIA maps are shown in Section 7.0 of the permit application for each pollutant. Maximum radii for the SIA are:

SO_2	4.4 km
PM10	1.6 km
NO_x	3.0 km
CO	0.9 km

All SIAs are limited to an area within less than 5 km from the center of the Mesaba plant site.

Table D-9
Results of Significant Impact Modeling

Operating Scenario	Pollutant	Averaging Time	Max ($\mu g/m^3$)	Time (yr/mo/dy/hr)	UTM Coordinates of Max (m) Easting	Northing	SIL ($\mu g/m^3$)
Normal Operation	SO_2	1-hour	130.2	75042724	471,675	5,243,675	25
		3-hour	77.6	75042724	471,500	5,243,750	25
		24-hour	31.2	75042824	471,475	5,243,650	5
		annual	1.29	76	472,700	5,242,725	1
	PM10	24-hour	27.9	74010224	472,304	5,243,924	5
		annual	1.68	76	472,810	5,243,228	1
	CO	1-hour	172.2	76072301	472,543	5,243,171	2000
		8-hour	59.8	72011408	472,561	5,243,189	500
	NO_x	annual	2.60	76	472,700	5,242,725	1
Flaring	SO_2	1-hour	75.8	74082007	472,454	5,243,819	25
		3-hour	22.8	75032721	470,300	5,244,075	25
		24-hour	5.4	75042824	470,800	5,244,175	5
	CO	1-hour	414.1	74082007	472,454	5,243,819	2000
		8-hour	122.7	72092116	473,450	5,242,775	500
Startup	CO	1-hour	3167.5	75083122	471,750	5,243,600	2000
		8-hour	379.0	75060608	472,500	5,242,925	500

3.0 PSD INCREMENT ANALYSIS

Increment consumption modeling included all IGCC Power Station sources exactly as they were represented in the SIA modeling described in the preceding section (normal operation scenario). In addition, all increment-consuming and increment-expanding sources were included as provided by the MPCA. Regional sources and increment emissions are summarized in Table D-10. No editing or modification of MPCA source files was done, except for deletion of duplicate sources where indicated by an updated source file.

All current/future emission rates in the MPCA files are understood to be potential (allowable) emissions. They were used directly for increment modeling. The "two entry" method of increment modeling was applied; i.e., increment-consuming sources were modeled with positive emission rates and increment-expanding sources were entered in the input file with negative emission rates.

Results of the increment analysis are presented in Table D-11. The results demonstrate that all maximum modeled increment consumption is far below applicable PSD increment limits. Much more than one SIL remains between the highest concentration and the allowable increment as a margin for future growth.

It can be noted that the highest combined-source impacts are nearly equal to the highest concentrations from Mesaba One and Mesaba Two alone. Thus, there is minimal impact of regional increment sources within the Mesaba SIA. Similarly, Mesaba impacts are insignificant in areas most affected by regional sources. On a region-wide basis, Mesaba One and Mesaba Two will have negligible effect on PSD increment consumption.

The geographical distribution of Mesaba increment impacts is the same as the distribution of total Mesaba concentrations; isopleth maps are shown in Section 7.0 of the permit application.

Table D-10
Regional Increment Sources Included in Increment Analyses [1]

Source	File Name	Source Type	Number Of Sources	Increment Emissions					
				SO_2		PM10		NO_x	
				lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
Minnesota Power	MPCB77S	Point	1	6130.89[2]	772.48[2]				
Clay Boswell #4	MPC77P	Point	1			510.90	64.373		
Potlatch	PGR0900.PM1	Point	12			62.77	7.91		
Grand Rapids		Volume	96			0.62	.079		
		Area	2			0.0005	.00007		
	PGR0900.NOX	Point	4					95.50	12.03
		Volume	102					0.17	0.02
Blandin Paper Co.	BPCDEC04.NOX	Point	6					-116.91	-14.73
		Point	20					117.72	14.83
	BMPIS072	Point	11	-178.68	-22.51				
		Point	40	595.64	75.05				
		Volume	5	0.02	.002				
	BPC89P	Point	5			-0.13	-.016		
		Point	7			53.44	6.73		
		Volume	4			0.40	0.05		

[1]Source: Christopher Nelson, MPCA; 8/17/05
[2]Annual SO_2 emission limit for Clay Boswell Boiler 4 is 1686 lb/hr = 212.43 g/s; short-term limit shown here.

Table D-11
Results of Mesaba One and Mesaba Two PSD Increment Modeling[1]

Pollutant	Averaging Time	Mesaba [2] ($\mu g/m^3$)	Regional [2] ($\mu g/m^3$)	All [2] ($\mu g/m^3$)	Time yr/mo/day/hr	UTM Coordinates (m)		Allowable ($\mu g/m^3$)
						Easting	Northing	
SO_2	1-hour	122.4	113.0	122.4	75032718	471,650	5,243,650	512
	3-hour	73.4	38.2	73.4	75042821	471,500	5,243,600	512
	24-hour	21.1	10.6	21.1	75042724	471,475	5,243,850	91
	annual	1.29	0.45	1.40	76	472,700	5,242,725	20
PM10	24-hour	23.4	1.2	23.5	74010124	472,329	5,243,906	30
	annual	1.68	0.15	1.72	76	472,810	5,243,228	17
NO_x	annual	2.60	0.13	2.62	76	472,700	5,242,725	25

[1]For 1-hour, 3-hour, and 24-hour periods, the listed concentration is the highest second-high from five years. Annual concentration is the highest for any year.

[2]Mesaba and regional concentrations are highest from each source group for the year of highest total concentration. They usually do not occur at the same time or receptor. The "All" column lists the high or high second-high for all increment sources combined.

4.0 NAAQS COMPLIANCE ANALYSIS

The NAAQS modeling demonstration consisted of calculating the maximum impact of Mesaba One and Mesaba Two sources and all other regional sources, and comparing the highest total impacts, plus background concentrations, to the applicable Minnesota and National Ambient Air Quality Standards (NAAQS). For Mesaba One and Mesaba Two, maximum emission rates in normal operation were modeled for all sources and pollutants, except in the case of CO for which the startup scenario has maximum impacts.

For inclusion of other regional sources, a two step procedure was utilized following the recommendations of MPCA modeling staff. In the first step, Mesaba One and Mesaba Two were modeled along with nearby sources for which emission parameters were provided by the MPCA. The location and time of high and highest second-high concentrations were defined by these model results. These specific high impact events were then remodeled, through use of the AERMOD EVENT option, including a much larger inventory of all regional sources. The full regional inventory, referred to as First Approximation Run (FAR) data, was provided by the MPCA. FAR data files were generated specifically for the Mesaba site location; separate files were provided for each pollutant and averaging time.

The regional sources that were included explicitly in the full five-year NAAQS model runs are detailed in Table D-12. All data were provided by MPCA modeling staff and represent maximum allowable emissions.

Background concentrations, representing natural and remote sources, were estimated on the basis of data from pristine areas and general knowledge of North American background levels. The assumed background levels, shown in Table D-13, are believed to be generally conservative.

Table D-13 lists maximum model-predicted concentrations for Mesaba One and Mesaba Two alone, Mesaba One and Mesaba Two plus nearby sources, and Mesaba One and Mesaba Two plus all regional and FAR sources. Table D-14 shows a comparison of highest modeled impacts from all sources, plus background and one SIL, to the applicable NAAQS. Table D-14 demonstrates that Mesaba One and Mesaba Two emissions will not cause or contribute to an exceedance of any NAAQS.

Isopleth maps, showing the distribution of Mesaba One and Mesaba Two highest impacts near and within the SIA for each pollutant, are presented in Section 7.0 of the air permit application.

Table D-12
Nearby Source Data for Sources Included in Initial NAAQS Modeling (Before Addition of Regional FAR Sources)

Source	Elev. (m)	St. Ht. (m)	St. Dia (m)	Temp. (K)	Vel. (m/s)	Emission Rate					
						SO_2		PM10		NO_x	
						lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
Keewatin Taconite	469	45.11	3.87	394.3	16.44	449	56.57	2182	274.93	3188	401.68
MN Pwr-Boswell 1, 2, 3	395	213.36	8.84	352.6	15.59	19420	2446.88	2163	272.53	4664	587.66
MN Pwr-Boswell 4	395	182.88	6.10	343.2	35.85	6131	772.48	511	64.39	3576	450.57
(annual)						1686	212.44				

Source UTM Coordinates

Keewatin Taconite	495,361.0 E, 5,251,235.0 N
Boswell 1, 2, 3	450,543.2 E, 5,234,354.5 N
Boswell 4	450,653.8 E, 5,234,624.3 N

Elevations determined from DEM data

Table D-13
Model-Predicted Concentrations [1, 2] for Mesaba One and Mesaba Two NAAQS Analysis (µg/m^3).

Pollutant & Averaging Time	Mesaba	Mesaba & Nearby	All Sources	Time	Location – UTM (m)	
					Easting	Northing
SO_2						
one-hour	122.4	322.2	327.4	75012612	461,700	5,232,875
three-hour	73.4	134.4	136.5	75111315	461,700	5,234,875
24-hour	22.1	30.6	41.4	75030824	463,700	5,232,875
annual	1.29	1.99	2.67	76	472,700	5,242,725
PM10						
24-hour	13.3	13.7	15.8	73011224	472,329	5,243,906
annual	1.59	1.95	3.14	76	472,810	5,243,228
NO_2						
annual	2.60	3.18	5.09	74	472,625	5,242,700
CO						
one-hour	2669.8	N/A	N/A	75042723	471,650	5,243,675

(1) Short-term gaseous pollutant concentrations are highest second-high; short-term PM10 is the highest 6th high from 5 years; all annual concentrations are highest for any year.
(2) "Mesaba and "Mesaba & Nearby" columns are for the respective worst-case year; the "Time" and "Location" data refer specifically to the "All Sources" maximum.

Table D-14
Comparison of Maximum Model-Predicted Concentrations (μg/m^3) to Ambient Air Quality Standards.

Pollutant & Averaging Time	Modeled[1] Concentration	Background	SIL	Total	NAAQS
SO_2					
one-hour	327.4	10.0	25.0	362.4	1300
three-hour	136.5	10.0	25.0	171.5	915
24-hour	41.4	10.0	5.0	56.4	365
annual	2.67	2.0	1.0	5.67	60
PM10					
24-hour	15.8	20.0	5.0	40.8	150
annual	3.14	10.0	1.0	14.14	50
NO_2					
annual	5.09	5.0	1.0	11.09	100
CO					
one-hour	2669.8	7000[2]	2000	11,669.8	40,000

[1] Modeled concentration is highest second-high for short-term periods, except for PM10 (highest 6th high), and highest for annual average; includes Mesaba and all regional sources.
[2] CO background is conservative estimate from urban monitors in Minneapolis/St. Paul. No background data are available for northern Minnesota.

PART II: LONG RANGE TRANSPORT (CALPUFF) MODELING

The Class I CALPUFF analyses addressed impacts to the Boundary Waters Canoe Area (BWCA), Voyageurs National Park (VNP) and the Rainbow Lake Wilderness (RLW). The distance from the IGCC Power Station to the closest point in each of these Class I areas is approximately 61 miles (98 km) for the BWCA, 75 miles (121 km) for VNP, and 117 miles (188 km) for RLW. The next closest Class I area, Isle Royale National Park, is more than 300 km from the station, beyond the distance where long-range transport modeling has been shown to provide realistic impact predictions.

Modeling was carried out in accordance with the U.S. EPA Guideline on Air Quality Models (40 C.F.R. Part 51, Appendix W), the IWAQM Phase 2 report (December, 1998), and the Phase I FLAG report (December 2000). Excelsior representatives and their consultants met with the U.S. Forest Service in Duluth on September 20, 2005, and with the National Park Service in Denver on November 9, 2005 to discuss Class I issues and analyses. Information from those meetings was incorporated in the modeling

5.0 MESABA ONE AND MESABA TWO EMISSIONS FOR CALPUFF

During normal operation of Mesaba One and Mesaba Two, the only significant air pollutant emissions will be from the combustion turbines and tank vent boilers. During short-term, upset conditions when untreated syngas could be flared, SO_2 emissions from the flares may exceed the combined SO_2 emissions from the CTGs during normal operations (see Appendix A, Exhibit A-2). This situation represents a low probability event because Excelsior is designing the gasification island such that only treated syngas would be flared during start-ups. Further, during such abnormal upset conditions, flow of syngas to the CTGs would be interrupted and operation of the gasifier(s) would be reduced or shutdown if the upset condition appeared significant (that is, threatened compliance) and/or persistent, thus limiting the need to flare large quantities of untreated syngas. Notwithstanding the increased short term emissions of SO_2 relative to normal baseload operations of the CTGs, NO_X and PM_{10} emissions from the total facility during such short term upsets will be reduced to levels below normal NO_X and PM_{10} emissions from the CTGs given the rapid turn down capability of the CTGs and gasifiers. A second scenario of interest concerns times when the combustion turbines would operate on natural gas rather than syngas. During such events, NO_X emission rates will be slightly higher than under syngas operation, but SO_2 emissions will be very low. Therefore, the normal operating scenario for Mesaba One and Mesaba Two represents the highest combined-source pollutant emission profile. This justifies limiting Class I modeling analyses to emissions released during normal operations.

Pollutant emission rates for long-range transport modeling represent maximum expected emissions for a two-phase plant for the appropriate averaging periods. All maximum emission rates and stack emission parameters are based upon engineering design specifications, as documented in the air permit application. Modeling parameters for Class I analyses are given in Table D-15.

Speciation of particulate matter emissions from the combustion turbines, as shown in Table D-15, was based on available data for Mesaba One and Mesaba Two sources and Federal Land Manager (FLM) guidance on emissions from natural gas-fired turbines. The total particulate emissions (filterable plus condensable) and total sulfuric acid emissions are from Mesaba design specifications. The partitioning of filterable and condensable fractions, elemental carbon emissions, and organic aerosol emissions were calculated using the FLM consensus methodology. All filterable particulate was assumed to be elemental carbon less than 2.5 microns in diameter. All particulate emissions from the tank vent boilers were assumed to be $PM_{2.5}$. Calculations are shown in Table D-16.

Table D-15
Modeling Parameters For Mesaba CALPUFF Modeling

Parameter	Combustion Turbines (each of four)	Tank Vent Boilers (each of two)
stack height (m)	45.72	64.01
stack diameter (m)	6.1	1.83
temp (K)	394.3	579.8
velocity (m/s) – short-term	20.1	8.46
annual	20.1	1.95
SO_2 - 3-hr (g/s)	19.15	0.94
24-hr	14.36	0.81
annual	9.58	0.45
NO_x - 3-hr (g/s)	19.66	2.46
24-hr	19.66	2.46
annual	19.91	0.76
Elemental Carbon (g/s) all time periods	0.787	0
Sulfate (g/s) all time periods	0.945	0
Organic aerosol (g/s) all time periods	1.397	0
$PM_{2.5}$ (g/s) all time periods	0	0.088
PM_{10} (g/s)	0	0

Table D-16
Estimation of Particulate Matter Speciation for Combustion Turbine Stacks (each)

Total PM Emissions, Filterable plus Condensable, from Plant Design Specifications = 25 lb/hr.

Assume, as per FLM guidance for gas-fired CTs, that 25% of PM_{10} is filterable, and 75% is condensable.

Then Filterable PM_{10} = 6.25 lb/hr.

Assume that 100% of Filterable PM_{10} is elemental carbon.

Then EC = 6.25 lb/hr

Condensable PM_{10} = 0.75(25) = 18.75 lb/hr.

H_2SO_4 = 7.66 lb/hr per design specifications

Then condensable SO_4 = 7.5 lb/hr

Assume remainder of condensable PM_{10} is organic (SOA).

Then final speciation is:

EC = 6.25 lb/hr = 0.787 g/s
SO_4 = 7.5 lb/hr = 0.945 g/s
SOA = 11.09 lb/hr = 1.397 g/s

6.0 AIR QUALITY MODEL AND APPLICATION

The CALPUFF air quality model was used for all Class I area analyses. CALPUFF is the approved EPA long-range transport model as referenced in the Guideline on Air Quality Models. It consists of three components: the CALMET model for processing of meteorological data, CALPUFF for the transport and dispersion calculations, and CALPOST for analysis and post-processing of model results. The CALMET model version is 5.53a, Level 040716; CALPUFF is version 5.711a, Level 040716. Input options and data utilized in the models generally corresponded to default or recommended values; Table D-17 provides a list of input options that are specific to the Mesaba One and Mesaba Two application and differ from standard default values.

For background ozone (O_3) concentration, a constant value of 40 ppb was used for CALPUFF modeling. A constant ammonia background of 1.0 ppb was assumed.

The CALMET/CALPUFF modeling domain is a 700km by 500km area approximately centered on the IGCC Power Station, with a four kilometer grid spacing. The coordinate system is Lambert Conformal. Receptor locations within each of the Class I areas were obtained from the National Park Service. Figure D-3 shows the modeling domain, terrain elevation contours, and the modeling receptors.

Terrain elevations were derived with the TERREL preprocessor; an average elevation was extracted for each cell in the modeling domain. Land use data were obtained from USGS 1:250,000 scale land use and land cover digital data, using CTGCOMP (version 1.0, 961113) and CTGPROC (version 1.2, 010206). The elevation and land use files were combined for CALMET input using MAKEGEO (version 1.1, 010206).

Source input to CALPUFF consisted of four combustion turbines and two tank vent boilers for a two-phase Mesaba facility. Building downwash effects on stack emissions were included through use of output from the BPIP PRIME wake effects program. Complete CALMET and CALPUFF input files are included with the application modeling files.

CALPUFF modeling analyses utilized meteorological data for the years 1990, 1992, and 1996. These are the same years used for other recent CALPUFF applications in northern Minnesota and the data were readily available. Gridded meteorological fields used as input to the CALMET processor were MM4 (1990) and MM5 (1992, 1996) prognostic data acquired from the National Park Service (NPS). Additional surface, upper air, and precipitation data were used in CALMET to refine the meteorological fields. Hourly surface data from 13 stations were used along with precipitation data from 28 stations. Upper air data from two stations were used; St. Cloud MN and International Falls MN for 1990 and 1992, and Minneapolis and International Falls for 1996. The surface and precipitation stations are listed in Table D-18.

Table D-17
CALMET/CALPUFF Non-Default Input Parameters

Input Group	Parameter	Mesaba Selection	Explanation
	CALMET		
5	IKINE	1	Kinemateic effects option used to better account for terrain effects
5	RMAX 1	30 km	No default values
	RMAX 2	40 km	No default values
	RMAX 3	40 km	No default values
	TERRAD	15 km	No default values
	R1	5	No default values
	R2	15	No default values
	CALPUFF		
3	Species Modeled	SO_2, SO_4, NO_x, EC SOA, $PM_{2.5}$, HNO_3, NO_3	Modeled all species emitted by Mesaba sources, and others (HNO_3, NO_3) involved in plume chemistry
4	LSAMP	F	No gridded receptors (sampling grid) used
8	Part. Size	Mean = 0.48 st. dev. = 2	All particulate species assumed $PM_{2.5}$
11	MOZ	0	Constant ozone background
11	BCK03	40.0 ppb	Representation background ozone concentration
11	BCKNH3	1.0 ppb	Conservative background ammonia concentration (0.5 ppb recommended for forested lands)
12	NSPLIT	3	Puff-splitting used (default)

Figure D-3. Mesaba CALMET Modeling Domain and Class I Areas

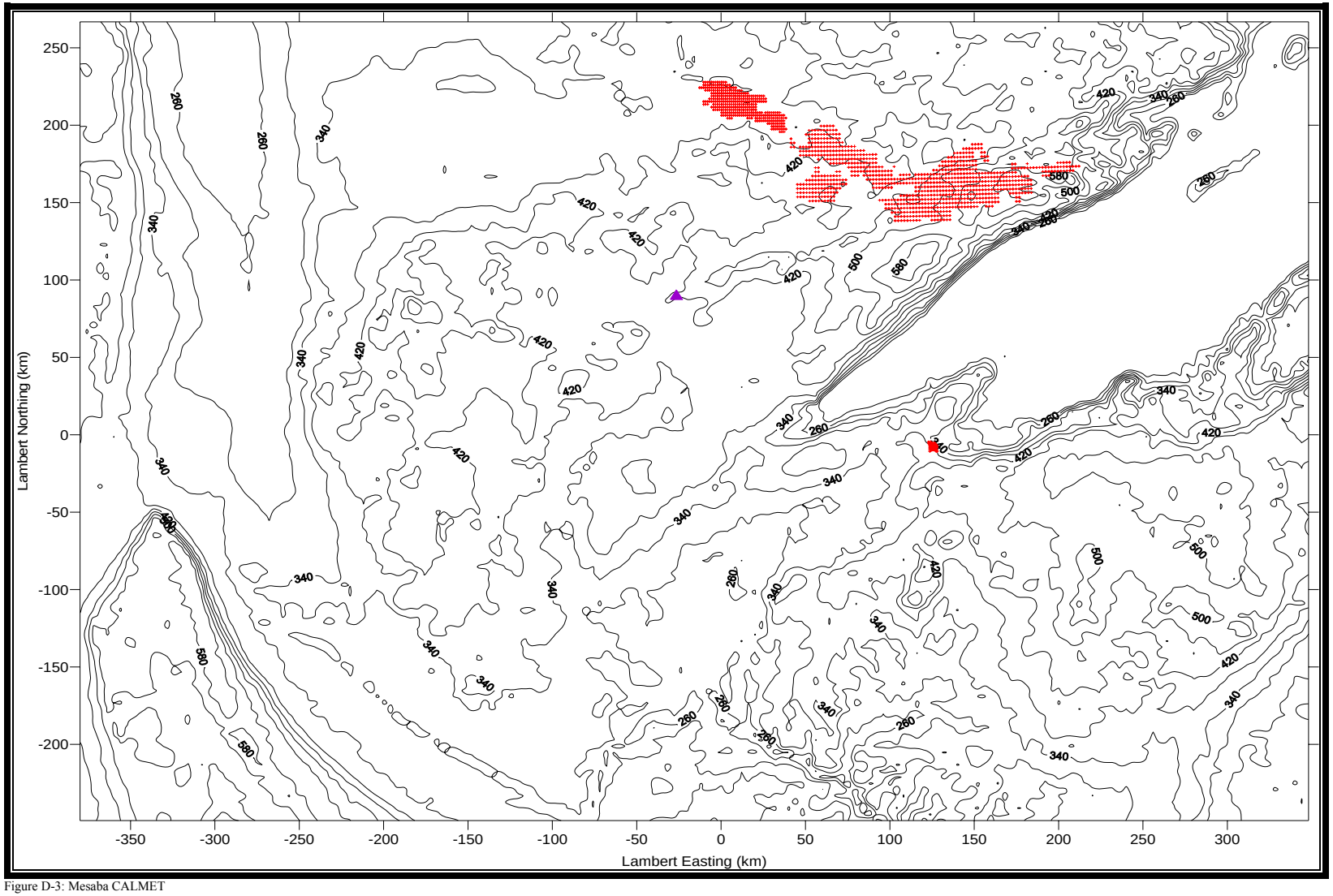

Figure D-3: Mesaba CALMET
Modeling Domain and Class I Areas

Table D-18
Weather Stations Included in CALMET Meteorological Data Processing

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Upper Air Stations included in CALMET

WBAN Number	Station Name	State	County	Years
14926	ST CLOUD	Minnesota	Sherburne	90,92
94983	MINNEAPOLIS	Minnesota	Hennepin	96
14918	INTERNATION FALLS	Minnesota	Koochiching	90,92,96

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Surface Stations included in CALMET (1990, 1992 and 1996)

WBAN Number	Station Name	CALMET Number	State	County
94902	BROOKINGS	26515	South Dakota	Brookings
14926	ST CLOUD	26550	Minnesota	Sherburne
14954	MANKATO	26585	Minnesota	Blue Earth
14914	FARGO	27530	North Dakota	Cass
14958	HEMIDJI	27550	Minnesota	Beltrami
14916	GRAND FORKS	27576	North Dakota	Grand Forks
14922	MINNEAPOLIS	26580	Minnesota	Hennepin
14913	DULUTH	27450	Minnesota	St. Louis
94931	HIBBING	27455	Minnesota	St. Louis
14918	INTERNATION FALLS	27470	Minnesota	Koochiching
14920	LA CROSSE	26430	Wisconsin	La Crosse
14991	EAU CLAIR	26435	Wisconsin	Chippewa
14897	WAUSAU	26463	Wisconsin	Marathon

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Precipitation Stations included in CALMET (1990, 1992 and 1996)

COOP ID	Station Name	State	County
474894	LUCK	Wisconsin	Polk
473511	HAYWARD RS	Wisconsin	Sawyer
478027	SPOONER EXP FARM	Wisconsin	Washburn
474396	LADYSMITH RS	Wisconsin	Rusk
475335	MENOMONIE	Wisconsin	Dunn
478589	TREMPEALEAU DAM 6	Wisconsin	Trempealeau
475352	MERCER RS	Wisconsin	Iron
476854	PRENTICE	Wisconsin	Price
479218	WILLARD	Wisconsin	Clark
476518	PHELPS	Wisconsin	Vilas
477140	RICE RSVR TOMAHAWK	Wisconsin	Lincoln
478963	WAUSAU 7 SSW	Wisconsin	Marathon
218235	THIEF LAKE REFUGE	Minnesota	Marshall
213463	HALSTAD	Minnesota	Norman
216228	ORWELL DAM	Minnesota	Otter Tail
211263	CANBY	Minnesota	Yellow Medicine
211589	CLEMENTSON	Minnesota	Lake of the Woods
218621	WALKER RANGER	Minnesota	Cass
217294	ST. CLOUD/WHITNEY MN.	Minnesota	Sherburne
215435	MINNEAPOLIS WSFO AP, MN	Minnesota	Hennepin
210746	BIG FALLS	Minnesota	Koochiching
214026	INT.FALLS/FALLS INT.MN.	Minnesota	Koochiching
216213	ORR	Minnesota	St. Louis
212248	DULUTH/INT.MN.	Minnesota	St. Louis
213793	HINCKLEY	Minnesota	Pine
218613	WALES 2 ENE	Minnesota	Lake
213296	GRAND PORTAGE R S	Minnesota	Cook
322859	FARGO/HECTOR FIELD ND.	North Dakota	Cass

7.0 INCREMENT ANALYSES

CALPUFF model results for pollutant concentration at each Class I area receptor were processed with CALPOST to determine the highest and highest second-high concentration for each pollutant and averaging time in each Class I area. Allowable Class I increments and Significant Impact Levels (SILs) are shown in Table D-19.

Mesaba One and Mesaba Two emission rates appropriate to each averaging time, as listed in Table D-15, were used in separate CALPUFF model runs to evaluate 3-hour, 24-hour, and annual increment consumption. Each model simulation was carried out for each year of meteorological data; the highest concentration for any year was compared to the applicable SIL, and the highest second-high from the three years was compared to the allowable increment limit. For calculation of particulate matter (PM_{10}) impacts, the sum of all particle species (EC, SOA, FPM, CPM, and SO_4) was calculated to represent the total PM_{10} concentration.

The CALPUFF-generated concentration output was processed with CALPOST to tabulate the highest predicted concentration for each Class I area, pollutant/averaging time, and year of meteorological data. Results are shown in Table D-20. Predicted impacts are less than the applicable SIL, except for short-term SO_2 at the BWCA and VNP. Following FLM guidance, cumulative increment analyses were therefore carried out for short-term SO_2.

Excelsior contacted the MPCA and requested modeling information for regional SO_2 increment sources. MPCA provided detailed emission and stack data for those Minnesota sources with potential for Class I SO_2 impacts. The sources and net increment-consuming emissions are listed in Table D-21. The MPCA inventory generally lists maximum allowable emissions for post-baseline sources. The allowable emissions were used in increment modeling for all sources except Minnesota Power-Clay Boswell. Actual emissions data were acquired for the most recent two years for Clay Boswell; the emission rate in Table D-21 represents the maximum actual hourly rate for that time period.

Table D-19
Class I Area Increment Limits and Significant Impact Levels (SILs)

Pollutant	Averaging Time	Class I Increment ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)
SO_2	3-hour	25.0	1.0
	24-hour	5.0	0.2
	annual	2.0	0.1
PM_{10}	24-hour	8.0	0.3
	annual	4.0	0.2
NO_2	annual	2.5	0.1

Table D-20
PSD Increment Modeling Results for Mesaba Energy Project

Boundary Waters/Pollutant Averaging Period	1990	1992	1996	Class I Inc (ug/m3)	Class I SIL (ug/m3)	Max (ug/m3)
SO_2 3-Hour	1.3804	1.4547	1.5505	25.0	1.00	1.5505
SO_2 24-Hour	0.4554	0.3382	0.3589	5.0	0.20	0.4554
SO_2 Annual	0.0147	0.0127	0.0095	2.0	0.10	0.0147
NOx Annual	0.0174	0.0152	0.0109	2.5	0.10	0.0174
PM_{10} 24-Hour	0.0866	0.0617	0.0586	8.0	0.30	0.0866
PM_{10} Annual	0.0041	0.0037	0.0026	4.0	0.20	0.0041

Voyageurs Pollutant/ Averaging Period	1990	1992	1996	Class I Inc (ug/m3)	Class I SIL (ug/m3)	Max (ug/m3)
SO_2 3-Hour	1.5911	1.0477	1.4836	25.0	1.00	1.5911
SO_2 24-Hour	0.2506	0.2943	0.4492	5.0	0.20	0.4492
SO_2 Annual	0.0128	0.0110	0.0113	2.0	0.10	0.0128
NOx Annual	0.0151	0.0125	0.0142	2.5	0.10	0.0151
PM_{10} 24-Hour	0.0537	0.0500	0.0745	8.0	0.30	0.0745
PM_{10} Annual	0.0037	0.0032	0.0031	4.0	0.20	0.0037

Rainbow Lakes Pollutant/ Averaging Period	1990	1992	1996	Class I Inc (ug/m3)	Class I SIL (ug/m3)	Max (ug/m3)
SO_2 3-Hour	0.7088	0.7567	0.7012	25.0	1.00	0.7567
SO_2 24-Hour	0.1806	0.1917	0.1711	5.0	0.20	0.1917
SO_2 Annual	0.0075	0.0083	0.0065	2.0	0.10	0.0083
NOx Annual	0.0081	0.0071	0.0068	2.5	0.10	0.0081
PM_{10} 24-Hour	0.0369	0.0462	0.0316	8.0	0.30	0.0462
PM_{10} Annual	0.0022	0.0028	0.0019	4.0	0.20	0.0028

Table D-21
Modeled Increment Consuming SO_2 Emissions For Cumulative Class I Increment Analysis

Source	Net Increment SO_2 Emissions lb/hr	g/s
IGCC Power Station		
3-hour	622.9	78.48
24-hour	468.7	59.06
Minnesota Power – Hibbard	416.8	52.51
Blandin Paper – Rapids Energy	417.0	52.54
Northshore Mining	-20.8	-2.62
Minnesota Power – Clay Boswell	1686	212.4
Potlatch Paper – Cloquet	-34.5	-4.35
Hibbing Taconite – Hibbing	772.3	97.31
Boise Cascade	141.6	17.84
Mesabi Nugget – Hoyt Lakes	225.6	28.42

Some individual sources in the MPCA increment inventory have negative emission rates (i.e., actual SO_2 emissions have decreased since the baseline date, resulting in increment expansion). Since the CALPUFF model does not accept negative emission rates, two model runs were carried out; one with the positive emissions and one with the negative emission rates. Concentration impacts of the negative sources were subtracted from those of the positive sources for each hour/receptor to derive total increment impacts of all sources. To minimize computation time, some sources were combined in the model input. All combined emissions used the stack parameters appropriate to the source with highest emission rate; separate and applicable stack parameters were used for the positive and negative model runs.

Results of the cumulative increment modeling (highest second-high 3-hour and 24-hour concentration for BWCA and VNP) were compared to the PSD Class I increment limits to demonstrate compliance. Results are given in Table D-22. Maximum predicted increment consumption in each of the Class I areas is well below allowable Class I increment limits.

Table D-22
Mesaba Cumulative SO_2 Increment Results (ug/m3)*

Boundary Waters/Pollutant Averaging Period	1990	1992	1996	Class I Inc (ug/m3)	Max (ug/m3)	Violation? (Y/N)
SO_2 3-Hour	6.1	7.0	5.8	25.0	7.0	NO
SO_2 24-Hour	2.6	2.1	2.2	5.0	2.6	NO

Voyageurs Pollutant/ Averaging Period	1990	1992	1996	Class I Inc (ug/m3)	Max (ug/m3)	Violation? (Y/N)
SO_2 3-Hour	5.2	4.6	5.5	25.0	5.5	NO
SO_2 24-Hour	1.6	1.5	1.6	5.0	1.6	NO

Rainbow Lakes Pollutant/ Averaging Period	1990	1992	1996	Class I Inc (ug/m3)	Max (ug/m3)	Violation? (Y/N)
SO_2 3-Hour	4.5	4.3	4.7	25.0	4.7	NO
SO_2 24-Hour	1.4	1.2	1.3	5.0	1.4	NO

* High-second highs

8.0 DEPOSITION OF NITROGEN AND SULFUR

The CALPUFF results for each of the Class I areas were processed with CALPOST to calculate total annual deposition of nitrogen and sulfur at each receptor as a result of Mesaba One and Mesaba Two emissions. Model results for annual impacts (maximum annual average emissions) were used following the methodology given in the IWAQM Phase I report. Total sulfur deposition is calculated from the wet and dry deposition of SO_2 and sulfate; total nitrogen is represented by the sum of nitrogen from wet and dry fluxes of nitric acid, nitrate, ammonium sulfate and ammonium nitrate, and the dry flux of NOx. For deposition calculations, MNITRATE was set to a value of 1.0 in POSTUTIL to account for ammonia availability. Results are presented in Table D-23.

Results of deposition calculations for VNP were compared to the NPS Deposition Analysis Threshold (DAT) of 0.01 kg/ha-yr for both sulfur and nitrogen. For the BWCA and RLW, total deposition (IGCC Power Station impact plus background) was compared to the USFS "green line" values for terrestrial and aquatic ecosystems. The green line values are:

BWCA – Terrestrial

Total sulfur	5 - 7 kg/ha-yr
Total nitrogen	5 - 8

- Aquatic

Total sulfur	7.5 – 8 kg/ha-yr
Sulfur + 20% nitrogen	9 – 10

RLW – Terrestrial

Total sulfur	5 - 7 kg/ha-yr
Total nitrogen	5 - 8

- Aquatic

Total sulfur	3.5 – 4.5 kg/ha-yr
Sulfur + 20% nitrogen	4.5 – 5.5

The comparison of Mesaba One and Mesaba Two deposition to NPS and USFS impact thresholds and a discussion of results is presented in Section 8.0 of the permit application. All model-predicted impacts are within or below the acceptable ranges for impacts on sensitive ecosystems.

Table D-23
Maximum Annual Deposition of S and N from IGCC Power Station in Class I Areas (kg/ha-yr)

Class I Area/Year	Sulfur	Nitrogen
Boundary Waters Canoe Area		
1990	1.217×10^{-2}	9.549×10^{-3}
1992	9.797×10^{-3}	7.085×10^{-3}
1996	8.400×10^{-3}	6.217×10^{-3}
Voyageurs National Park		
1990	1.016×10^{-2}	7.864×10^{-3}
1992	1.110×10^{-2}	8.562×10^{-3}
1996	9.780×10^{-3}	7.835×10^{-3}
Rainbow Lakes Wilderness		
1990	5.188×10^{-3}	4.225×10^{-3}
1992	6.336×10^{-3}	4.617×10^{-3}
1996	5.936×10^{-3}	4.749×10^{-3}

9.0 REGIONAL HAZE ANALYSIS

A visibility/regional haze impact analysis was carried out for BWCA and VNP. Visibility analysis is not required for Rainbow Lakes. The recommended methodology for assessing visibility impacts according to the FLAG guidance involves the use of CALPOST to process the data on concentrations of pollutants from the CALPUFF modeling of 24-hour emissions. In CALPOST a daily value of light extinction is defined by the concentrations of each pollutant that can effect visibility, taking into account the efficiency of each particle type in scattering light, and the relative humidity which influences the size of hygroscopic pollutants (sulfates and nitrates). The 24-hour average light extinction caused by emissions from the modeled source(s) is then compared to the background light extinction, a value based upon "natural" or pristine unpolluted conditions for each Class I area.

The standard FLAG visibility analysis was carried out using the CALPOST processing program and Method 2 for calculating source and background light extinction and the percentage change. Results are presented in terms of the maximum percentage change and the number of days (24-hour periods) with percent change exceeding five and ten percent for the BWCA and RLW, for each year of meteorological data.

Natural background light extinction for the BWCA and VNP was calculated from data in the FLAG document. Relative humidity data for calculation of f(RH) in Method 2 is taken from the nearest surface weather station hourly observations. For receptors in the two Class I areas of concern the nearest station is either International Falls, MN or Hibbing MN. A maximum relative humidity cut-off of 95% was specified.

The CALPOST program calculates f(RH) according to the data tabulated in FLAG. In the U.S. EPA's regional haze modeling guidance (U.S. EPA, 2003), they have recommended a slightly different f(RH) function based upon Tang's smoothed data for ammonium sulfate. The EPA data give slightly larger values of f(RH) at intermediate RH, and significantly lower f(RH) at high humidity. The FLAG f(RH) data have been used for visibility modeling, but it would be appropriate to modify CALPOST to use the EPA function for future modeling.

Table D-24 presents results of the CALPUFF visibility analysis following the FLAG methodology, and using "Method 2" of CALPOST for calculation of visibility impacts. The data in Table D-24 indicate that calculated visibility impacts greater than 5 or 10% could occur at some point within the BWCA and VNP on a small number of days each year. Because these data suggest a potential for detectable visibility degradation due to Mesaba One and Mesaba Two emissions, additional analyses were carried out to better quantify and evaluate the possibility of visibility impacts.

There are several factors inherent in the FLAG Method 2 methodology that are conservative in the sense that they lead to the highest likely impact. These include:

- the extinction change calculated for a Class I area represents the largest change for any receptor within the area.
- the change is calculated relative to natural or pristine background; i.e., the best visibility in the absence of any industrial pollution or abnormal natural events such as forest fires.

- no natural visibility impairment due to fog, precipitation, or clouds is considered
- the calculations assume emissions from the modeled source, at the highest daily rate, for every hour and day of the year

There are currently no practical and acceptable ways to include these factors in making a rigorous and more realistic assessment of the probability of actual visibility impairment. However, some procedures have been suggested to account, in part, for potential errors or omissions in the FLAG calculations.

The CALPOST post-processing software contains several alternative algorithms for calculating the change in light extinction due to the modeled source. Method 6 substitutes monthly average relative humidity values (specific to each Class I area) for the hourly relative humidity data at nearby weather stations. This substitution mitigates, to some extent, the high extinction values calculated when very high humidity values are reported throughout the day at the nearest observation site. It is intended to account for the facts that the observed humidity may be unrepresentative of the Class I area, and that very high relative humidities are frequently associated with natural impairment by fog, clouds, and precipitation. The Method 6 calculation is recommended by the U.S. EPA for state regional haze BART analyses.

Method 7 is another modification of the standard Method 2; it attempts to account for natural visibility reduction due to fog or precipitation. In Method 7, the actual measured visibility at the nearest weather station is used as background (instead of natural pristine background) on those hours when fog or precipitation are reported. Method 7 represents another attempt to account for natural visibility reduction in assessing the impact of man-made pollution.

Table D-25 shows the results of Method 6 and Method 7 visibility calculations for Mesaba One and Mesaba Two, with comparison to the Method 2 data. Both alternative analyses indicate lower frequency and magnitude of impacts relative to Method 2. For Method 7, there are only two days of predicted impacts from three years of data exceeding 10% change in light extinction at the BWCA, and none at VNP.

In EPA's BART guidance for regional haze, the 98th percentile of light extinction predictions is recommended as a threshold for significant impact. This means that an average of seven days per year or more of impacts exceeding 5% indicates a significant impact. Under this criterion, the Method 7 results show no significant visibility impact of Mesaba One and Mesaba Two at either Boundary Waters or Voyageurs.

Table D-24
Visibility Results for Mesaba One and Mesaba Two (FLAG Method 2 Analysis)

Year and Parameter	Boundary Waters Canoe Area	Voyageurs National Park
1990 Meteorological Data		
Days > 5%	39	16
Days > 10%	10	1
Maximum Change in light extinction	16.4%	11.8%
1992 Meteorological Data		
Days > 5%	36	25
Days > 10%	15	4
Maximum Change in light extinction	24.1%	19.0%
1996 Meteorological Data		
Days > 5%	17	18
Days > 10%	6	4
Maximum Change in light extinction	15.0%	22.5%

The definition of visibility impairment in 40 C.F.R. 51.301 refers to "any humanly perceptible change in visibility". It has generally been considered that a change in light extinction of 5 to 10% constitutes a just noticeable change in viewing a scene through the atmosphere. But it has been pointed out by Richards (Richards, 1999) that this threshold is only appropriate over a line-of-sight equal to the natural visual range (for the Class I areas in this analysis, a distance on the order of 175 km). For shorter sight lines, a 5 to 10% change in light extinction may not be perceptible. Or, a 5 to 10% local increase in light extinction is not likely to be perceptible over a long sight path for which the average extinction is less. Calculations were made of the average change in light extinction over several 150 km sight lines for the day of highest predicted impact in the BWCA. Using Method 2, the highest Mesaba One and Mesaba Two impact was 24.1% on February 3, 1992 at a receptor near the southern BWCA boundary northeast of the IGCC Power Station. Three sight lines were evaluated: one from the highest receptor directly southwest to the IGCC Power Station, one in the opposite direction from the highest receptor away from the IGCC Power Station, and one extending across the BWCA in an approximate east-west orientation. A separate CALPUFF model run was made for receptors along the three sight lines, and average changes in light extinction were calculated, by Method 2, along each of the three lines. The results showed average extinction changes of 13% (toward Mesaba One and Mesaba Two). 9% (away from Mesaba One and Mesaba Two), and 13.6% (across the BWCA). Though still significant, these calculated average changes are 50% or less of those at the maximum receptor.

Table D-25
Mesaba CALPUFF Visibility Results

Speciated PM 12/5/2005	1990 **Method 2** > 5 %	1990 **Method 2** > 10 %	1990 **Method 2** Max %	1992 **Method 2** > 5 %	1992 **Method 2** > 10 %	1992 **Method 2** Max %	1996 **Method 2** > 5 %	1996 **Method 2** > 10 %	1996 **Method 2** Max %
Boundary Waters Wilderness	39	10	16.43	36	15	24.11	17	6	14.98
Voyageurs National Park	16	1	11.82	25	4	18.97	18	4	22.47

Speciated PM 12/5/2005	1990 **Method 6** > 5 %	1990 **Method 6** > 10 %	1990 **Method 6** Max %	1992 **Method 6** > 5 %	1992 **Method 6** > 10 %	1992 **Method 6** Max %	1996 **Method 6** > 5 %	1996 **Method 6** > 10 %	1996 **Method 6** Max %
Boundary Waters Wilderness	24	1	12.12	19	2	11.54	9	0	8.13
Voyageurs National Park	13	0	8.43	14	1	10.22	8	1	12.49

Speciated PM 12/5/2005	1990 **Method 7*** > 5 %	1990 **Method 7** > 10 %	1990 **Method 7** Max %	1992 **Method 7** > 5 %	1992 **Method 7** > 10 %	1992 **Method 7** Max %	1996 **Method 7** > 5 %	1996 **Method 7** > 10 %	1996 **Method 7** Max %
Boundary Waters Wilderness	11	1	10.43	7	1	19.22	2	0	7.63
Voyageurs National Park	3	0	7.93	2	0	6.13	3	0	8.13

* - Hibbing MN used as primary weather station for Boundary Waters Wilderness, International Falls used for Voyageurs NP.

Examination of the meteorology for this single "worst day" shows that temperatures in the BWCA were approximately 22 to 30 deg F, there were a few snow flurries, and a cloud cover of 100% existed at approximately 500 feet above the ground for much of the day. Fog was reported at Hibbing from midnight until 8 PM, with visibility between ½ and 5 miles; at International Falls, fog existed from midnight until 3 PM with visibility less than 1.2 miles until mid-afternoon. Under these conditions, natural conditions would have precluded access to extended scenic views for Park visitors.

An analysis was carried out to characterize the times and meteorological conditions for those days on which CALPUFF, with Method 2, indicated light extinction changes exceeding five percent in either the BWCA or VNP. Hourly meteorological data from Hibbing were assumed to represent the BWCA, and data from International Falls were used for days of impacts at VNP. Days on which fog, precipitation, or low ceiling (less than 3000 feet) occurred were tabulated, along with relative humidity measurements at 6 AM and 12 noon. These times typically represent near highest and lowest humidity values for the day. Also listed for each day was the value of f(RH) used in the CALPOST light extinction calculation. f(RH) represents the daily mean value of the relative humidity parameter that accounts for growth of sulfate and nitrate particles; high values of f(RH) indicate high humidity conditions under which light scattering by these particles is dramatically increased. The value of f(RH) in CALPOST varies from 1.0 for humidity less than 37%, to 9.8 at the maximum CALPOST humidity of 95%.

Results of the meteorological analysis are presented in Table D-26. The main conclusions evident from the Table are:

- Predicted impacts occur predominantly during the winter part of the year; 47 to 61% of all occurrences are indicated between November and March.

- A very high percentage of occurrences coincide with days of natural visibility degradation due to fog, precipitation or low clouds. From 82 to 100% of the days had some occurrence of these weather elements.

- All occurrences of predicted visibility impact were on days of very high relative humidity.

The occurrence of natural visibility degradation on some hours of the day does not necessarily imply that visual impacts of Mesaba One and Mesaba Two emissions could not exist during other periods of the day. There is no practical means of evaluating impacts on an hour-by-hour basis. But since the visibility calculation is made on a daily average basis, it is reasonable to consider natural impacts also in terms of some spatial and time-averaged indicators. At the least, the data in Table D-26 indicate that there were some natural visibility impacts within the Class I areas on nearly all days of predicted Mesaba One and Mesaba Two effects. The analysis shows that modeled impacts overwhelmingly occur on days of inclement weather.

Table D-26
Characteristics of Days with Predicted Visibility Impacts.

Meteorological Characteristic	Boundary Waters Canoe Area		Voyageurs National Park	
	Days > 5% Total 92 Days	Days > 10% Total 31 days	Days > 5% Total 59 days	Days > 10% Total 9 days
Percentage of days November through March	57%	61%	47%	56%
Percentage of days with precipitation	60%	68%	78%	100%
fog	54%	77%	64%	89%
ceiling < 3000 ft	68%	81%	69%	78%
Percentage of days with some natural visibility impairment	82%	94%	88%	100%
Average morning (0600) relative humidity	95%	97%	92%	94%
Average mid-day (1200) relative humidity	76%	85%	75%	83%
Mean daily f((RH)	5.34	6.45	4.73	5.91
equivalent relative humidity	91%	92.5%	90%	92%

Statistics for BWCA from hourly surface weather data at Hibbing MN; statistics for VNP from hourly surface data at International Falls, MN.

To summarize, CALPUFF modeling suggests some days of potential impact at both the BWCA and VNP. However, a number of very conservative elements exist in the FLAG evaluation methodology, and the CALPUFF model chemistry has been shown to significantly overestimate hygroscopic particle concentrations. In consideration of these facts and the meteorological analysis of impact days, it is concluded that Mesaba One and Mesaba Two will have detectable visibility effects on few if any days, and that impacts are highly unlikely to interfere with the visual experience of park visitors.

Results of the Class I area modeling and a more detailed discussion of the impact analyses are presented in Section 8.0 of the permit application. All CALMET, CALPUFF, and CALPOST modeling files in electronic format are included with the application to facilitate review by regulatory agency and FLM modeling staff.

Appendix E

Air Emission Risk Analysis

The Air Emission Risk Analysis and its appendices are attached as electronic files contained in the directory "AERA."