THE MESABA ENERGY PROJECT:
FINAL SCIENTIFIC/TECHNICAL REPORT

CLEAN COAL POWER INITIATIVE, ROUND 2

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Abstract

The Mesaba Energy Project is a nominal 600 MW integrated gasification combine cycle power project located in Northeastern Minnesota. It was selected to receive financial assistance pursuant to code of federal regulations ("CFR") 10 CFR 600 through a competitive solicitation under Round 2 of the Department of Energy's Clean Coal Power Initiative, which had two stated goals: (1) to demonstrate advanced coal-based technologies that can be commercialized at electric utility scale, and (2) to accelerate the likelihood of deploying demonstrated technologies for widespread commercial use in the electric power sector. The Project was selected in 2004 to receive a total of $36 million. The DOE portion that was equally cost shared in Budget Period 1 amounted to about $22.5 million. Budget Period 1 activities focused on the Project Definition Phase and included: project development, preliminary engineering, environmental permitting, regulatory approvals and financing to reach financial close and start of construction.

The Project is based on ConocoPhillips' E-Gas™ Technology and is designed to be fuel flexible with the ability to process sub-bituminous coal, a blend of sub-bituminous coal and petroleum coke and Illinois # 6 bituminous coal. Major objectives include the establishment of a reference plant design for Integrated Gasification Combined Cycle ("IGCC") technology featuring advanced full slurry quench, multiple train gasification, integration of the air separation unit, and the demonstration of 90% operational availability and improved thermal efficiency relative to previous demonstration projects. In addition, the Project would demonstrate substantial environmental benefits, as compared with conventional technology, through dramatically lower emissions of sulfur dioxide, nitrogen oxides, volatile organic compounds, carbon monoxide, particulate matter and mercury.

Major milestones achieved in support of fulfilling the above goals include obtaining Site, High Voltage Transmission Line Route, and Natural Gas Pipeline Route Permits for a Large Electric Power Generating Plant to be located in Taconite, Minnesota. In addition, major pre-construction permit applications have been filed requesting authorization for the Project to i) appropriate water sufficient to accommodate its worst case needs, ii) operate a major stationary source in compliance with regulations established to protect public health and welfare, and iii) physically alter the geographical setting to accommodate its construction. As of the current date, the Water Appropriation Permits have been obtained.

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SECTION I. EXECUTIVE SUMMARY

This report on the Mesaba Energy Project (the "Project") covers the milestones and accomplishments achieved during Budget Period 1, through August 31, 2012.

The Project was initially selected for funding by the U.S. Department of Energy ("DOE") because of the significant role it could play in demonstrating integrated gasification combined-cycle ("IGCC") technology at utility scale with high reliability. The Project was an early mover in proposing a multiple-train IGCC facility with a spare gasification train. These design parameters were consistent with DOE's objectives for the Project of demonstrating IGCC at 600 megawatts ("MW") of capacity and 90% availability. In addition, the Project sponsors proposed and developed a design far surpassing the objective of demonstrating criteria pollutant and mercury emission levels equal to or below those of the lowest emission rates for utility-scale, coal-based generation. Finally, the Project demonstrated, based on preliminary engineering and cost studies conducted by Fluor, that with the benefit of federal assistance under the Energy Policy Act of 2005, the plant would be at cost parity with a comparably sized new, greenfield coal facility utilizing conventional supercritical pulverized coal boiler technology, a critical component of DOE's effort to commercialize IGCC technology and start it down the path to cost parity with mature, but considerably higher emitting conventional alternatives. These core accomplishments validated the achievability of the Project's objectives under Round II of the Clean Coal Power Initiative ("CCPI").

Carbon capture and storage was not contemplated by CCPI Round II and was not part of the goals or requirements of the DOE's cost sharing under CCPI Round II. Nonetheless, Excelsior developed a carbon capture and sequestration plan that was the first of its kind ever submitted to a state public utility commission. Subsequent studies and developments confirmed the prudency of that plan, including the economic decision to focus on enhanced oil recovery as the preferred storage approach. A full discussion of the cost and regulatory barriers to CCS are included in the report.

A thorough site selection process was conducted for the Project, which resulted in the identification and development of an excellent site for power plant development. Key advantages of the Project site include access to competitive rail providers, proximity to abundant water resources, minimal network reinforcement costs for transmission interconnection, and strong local community backing as evidenced by over 25 letters of support from political bodies and the securing of local development funding. As a result, the Project was successful in obtaining the first Site and Route permits issued for a coal plant in Minnesota in over 25 years. The Project is the only active coal-fueled power plant development that is exempted from a statewide ban on new coal facilities enacted by Minnesota in 2007 (see Minn. Stat. 216H.03), which is still in effect.

Building upon these merits, the Project reached the memorandum of agreement stage of development with a coalition of prospective power offtakers. Furthermore, as part of its final loan guarantee application, Excelsior developed a financing plan and risk mitigation framework that received a strong preliminary credit rating from Fitch that would have resulted in an economically acceptable subsidy cost under the DOE's loan guarantee program.

A detailed analysis of the progress made to date on the Project is presented in Section 2 of this report, organized by subtask, which include:

Engineering – (1) negotiation of a license agreement with ConocoPhillips ("COP") for E-Gas™ solid fuel gasification technology for the Project, (2) development by COP of the design basis as part of the process design package, (3) completion of preliminary engineering of the plant to define the technical design basis, including optimization studies on all major plant areas, and (4) preparation of a Class 5 cost estimate to define plant capital and operating costs.

Transmission – Completion of all required Midwest Independent Transmission System Operator ("MISO") transmission planning studies and execution of a Large Generator Interconnection ("LGIA") agreement with Minnesota Power and MISO.

Environmental– (1) completion of the Final Environmental Impact Statement ("FEIS") by Minnesota and the DOE, (2) filing of all pre-construction permit applications under state permitting requirements, and (3) completion of preliminary engineering to identify and propose, in the Project's air permit application, significant emission reductions that could be demonstrated in mercury, sulfur and nitrogen oxide, representing reductions of 50-67% below the already ultra-clean emissions levels that were analyzed in the Project's FEIS.

Regulatory – (1) issuance of Siting and Routing Permits from the Minnesota Public Utilities Commission ("MPUC") for the site and all related plant infrastructure (transmission, water pipeline, etc), and (2) certification by the MPUC and the Minnesota Court of Appeals that the Project is an "innovative energy project" under Minnesota law, which entitles the Project to significant regulatory incentives, and issuance by MPUC of an order indicating its support for the Project if output contracts were spread among utilities.

State Government Affairs – (1) exemption of the Project from the moratorium on new coal plants serving Minnesota retail load enacted under 2007 state law (see Minn. Stat. 216H.03), and (2) legislative extension of the validity of the Project's site and route permits through 2019 (see Minn. Stat. 216B.1694).

Community Affairs – Development and maintenance of broad state and local support including financial and other support from the Iron Range Resources and Rehabilitation Board ("IRRRB"), the regional economic development agency of the state of Minnesota, and local support of 25 mayors, county boards, regional organizations, and labor unions in the vicinity of the plant site.

Finance – (1) selection for funding by the MPUC and by the IRRRB, and private funding contributions, (2) selection for federal benefits in competitive solicitations: awarded $133 million in investment tax credits and selected to submit a full Loan Guarantee Application, and (3) submission of Loan Guarantee Application to the DOE Loan Guarantee Project Office which was deemed complete by DOE and included an Independent Engineer's Report prepared by R.W. Beck and a Preliminary Credit Analysis completed by Fitch.

In summary, during Budget Period 1, despite the barriers to the Project's final construction (which include the slow recovery from the recession of 2008, the discovery and production of large volumes of low-cost shale gas, and crippling regulatory uncertainty) described in this report, the Project achieved an advanced stage of development and was positioned to proceed to Front End Engineering and Design ("FEED") and subsequent financing once new coal-fired base load generation was signaled. Despite the Project's ability to comply with guidance as recent as March of 2011 on best available control technology standards for new coal facilities, the Proposed Rule for New Source Performance Standards for CO_2 emissions from new coal-fired power plants issued by the U.S. Environmental Protection Agency ("EPA") in April of 2012 requires new coal facilities to employ carbon capture and storage ("CCS"), which DOE determined to be economically and logistically infeasible at the time of the Project's Final Environmental Impact Statement ("FEIS"). Excelsior has submitted comments on the proposed rule that are included as Appendix A requesting that the Project be treated as a transitional source under the rule. If accepted as a transitional source, the Project would be provided the flexibility to proceed without CCS at its inception, with CCS facilities to be added if and when economically warranted.

SECTION II. PROJECT ACCOMPLISHMENTS AND DISCUSSION

Nomenclature

In this report, the terms "Project," "Phase I," or "Mesaba One" are used synonymously to refer to the first nominal 600 MW power plant project to be constructed. The terms "Mesaba Two" and "Phase II" are used synonymously to refer to the second nominal 600 MW power plant project to be constructed. The combined Phase I and Phase II developments are used synonymously with the term "Mesaba One and Mesaba Two." Note that DOE's involvement was limited to Mesaba One, through the Cooperative Agreement with MEP-I, LLC. MEP-I LLC and MEP-II LLC are the legal entities that would construct, own, and operate Mesaba One and Mesaba Two, respectively. MEP-I LLC and MEP-II LLC are wholly owned subsidiaries of Excelsior Energy Inc.

The following is a summary of the Project's accomplishments for each of the subtasks.

A. SITE STRATEGIC PLANNING

The scope of work for Subtask 1.01 involved determining the specific location/site of the IGCC electric power generating plant, including the requirements for any ancillary services such as grading, access roads, utilities, storage facilities and other infrastructure requirements. It also involved finalizing site option agreements with viable counterparties.

1. SITE SCREENING AND SELECTION PROCESS

Under Minnesota's Power Plant Siting Act ("PPSA"),[1] an applicant seeking a permit for a large electric power generating plant ("LEPGP") site must submit an application wherein a minimum of two viable project sites are proposed.[2] Given the Project's generating capacity and its fuel type, the evaluation of the sites proposed in the Project's Joint Permit Application ("JPA") – the East and West Range sites – was conducted and documented pursuant to Minn. R. 7850.1000 through 7850.2700.[3] The screening process which ultimately identified these two sites is discussed in this section.

a. Step One: Establishing Search Area and Site Selection Criteria

The search area was established as a result of state and federal legislation that enabled the Project. That legislation extended critical incentives to support development of the Project, while specifying that the Project must be located in the Taconite Tax Relief Area ("TTRA") of Northeastern Minnesota in order to be eligible for those incentives. The relevant legislation is described below.

[1] The Minnesota Power Plant Siting Act is authorized under Minn. Stat. 216E.001 and, from the permitting perspective, implemented by the Minnesota Public Utilities Commission in accordance with Minn. R. ch. 7850.
[2] See Minn. R 7850.1900 Subp. 1C.
[3] The Joint Permit Application (i.e., "Mesaba Energy Project, Mesaba One and Mesaba Two, Joint Application to the Minnesota Public Utilities Commission for the Following Pre-Construction Permits: Large Electric Power Generating Plant Site Permit, High Voltage Transmission Line Route Permit and Natural Gas Pipeline Routing Permit") was submitted to the Minnesota PUC on June 16, 2006 by MEP-I LLC and MEP-II LLC in support of the rules specified and, in addition, addressed siting requirements for high voltage transmission line and natural gas pipeline routes.

i. State Incentives

In its 2003 Special Session, the Minnesota Legislature enacted broad-reaching energy policy legislation that, in addition to addressing the storage of spent nuclear fuel, recognized the need to provide for the development of new and alternative sources of energy.[4] Among the options addressed, the Legislature placed special emphasis upon the development of a project "that makes use of an innovative generation technology utilizing coal as a primary fuel in a highly efficient combined-cycle configuration with significantly reduced sulfur dioxide, nitrogen oxide, particulate matter, and mercury emissions from those of traditional technologies."[5] The Innovative Energy Project ("IEP") and the Clean Energy Technology ("CET") Statutes (collectively, the "Enabling Statutes") emerged from the 2003 Session with the ability to provide the State with a path to resolve critical energy issues[6] and deteriorating economic conditions in Northeastern Minnesota.[7] Since passage of the Enabling Statutes, the MPUC has confirmed that the Project is an IEP and is thus entitled to all the regulatory benefits provided therein.[8]

The Minnesota Legislature recognized that special forms of assistance would be necessary to encourage the development of IGCC technology within the state. Thus, the IEP Statute provides important regulatory incentives, including:[9]

- Exemption from the requirements for obtaining a certificate of need;
- Eligibility to increase transmission capacity without additional state review;
- The power of eminent domain for sites and routes approved by the MPUC;
- Status as a "clean energy technology" for the supply of electric energy to a utility that owns a nuclear generating facility;
- The right to enter into a contract with a public utility that owns a nuclear generation facility to provide 450 megawatts of baseload capacity; and
- Eligibility for a $10 million grant from the renewable development account for development and engineering costs.

In order to take advantage of these important and unique incentives for an IEP, the Enabling Statutes specify that the project must be located on a site within the TTRA. A project located elsewhere in the state does not qualify for such incentives.

ii. Federal Incentives

Federal loan guarantees are important to the development of innovative and emerging technologies because the lower cost of capital associated with federally guaranteed loans reduces the typically higher financing costs of such projects, making the cost of electricity more competitive. The United States Congress recognized the importance of the incentives provided by the Enabling Statutes in supporting the

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4 *See* 2003 Minn. Laws, 1st. Spec. Sess., ch. 11.
5 *See* 2003 Minn. Laws, 1st. Spec. Sess., ch. 11, art. 4, § 1, *codified as* Minn. Stat. § 216B.1694, subd. 1(1).
6 *See* Excelsior Energy Inc., Mesaba Energy Report to the Minnesota Public Utilities Commission 1–4, MPUC Docket No. E-6472-/M-05-1993 (Dec. 23, 2005).
7 The Iron Range had lost an additional 2,000 jobs with the closure of the LTV Mining Company in 2001, bringing the total job loss to more than 10,000 in the past decade. *See* 1) http://www.power-eng.com/articles/print/volume-107/issue-7/news-update/minnesota-puts-its-weight-behind-coal-gasification.html and 2) http://friendscvsf.org/Miningreport10-4.pdf. Given these concerns, the benefits of locating IGCC generation facilities on the Iron Range were clear.
8 MPUC, Order Resolving Procedural Issues, Disapproving Power Purchase Agreement, Requiring Further Negotiations, and Resolving to Explore the Potential for a Statewide Market for Project Power Under Minn. Stat. § 216B.1694, Subd. 5, Docket No. E-6472/M-05-1993, Aug. 30, 2007.
9 Minn. Stat. § 216B.1694.

widespread commercialization of IGCC technology. The Energy Policy Act of 2005[10] ("EPAct2005") authorized the Secretary of Energy to make eligible for loan guarantees "a project located in a taconite-producing region of the United States that is entitled under the law of the State in which the plant is located to enter into a long-term contract approved by a State public utility commission to sell at least 450 megawatts of output to a utility."[11] Therefore, the Project's location in the TTRA under Minnesota law was a necessary condition for the federal loan guarantee provided in EPAct2005.

In a July 2008 meeting between the U.S. Army Corps of Engineers ("USACE") and the DOE, the two agencies concurred that, from the standpoint of the Clean Water Act ("CWA") Section 404 analyses, the alternatives analysis would be limited to the TTRA.

iii. Site Selection Criteria

Although numerous studies involving the selection of coal-fired power plant sites have been published, a presentation by the DOE's National Energy Technology Laboratory ("NETL") described the most critical elements as follows:[12]

- Access to transmission lines,
- Available fuel, and
- Water.

The state of Wisconsin published a host of additional power plant siting criteria that are commonly used in the site selection process.[13] Excelsior's site selection efforts addressed these same fundamental concerns.

Site selection criteria represent specific elements of concern that were collectively used to characterize the likelihood of a potential site to accommodate the footprint and infrastructure required for Phase I and Phase II of the Mesaba Energy Project (hereafter, "Mesaba One and Mesaba Two," "IGCC Power Station" or the "Station") while minimizing environmental and societal impacts. Excelsior divided its site selection criteria into three categories: permitting, technical, and site control. Permitting criteria focused on issues related to the relative feasibility of obtaining preconstruction permits necessary to construct and operate the IGCC Power Station. Technical criteria focused on the feasibility of constructing and operating the Station, and site control criteria considered the likelihood of obtaining site ownership and control in a timely manner with landowner cooperation.

Table A-1 lists the specific elements considered under each of these three categories.

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[10] *See* Public Law 109–58, Aug. 8, 2005.
[11] *See* 42 U.S.C. § 16513(c)(1)(C). *See also* 42 U.S.C. § 16514(b)
[12] Hoffmann, Feeley, and Carney, "DOE/NETL's Power Plant Water Management R&D Program –Responding to Emerging Issues," 8th Electric Utilities Environmental Conference, Tucson, AZ, January 24-26, 2005. *See* http://www.netl.doe.gov/technologies/coalpower/ewr/pubs/05_EUEC_Hoffmann_1.pdf.
[13] Public Service Commission of Wisconsin, "Common Power Plant Siting Criteria." September 1999. *See* http://psc.wi.gov/thelibrary/publications/electric/electric05.pdf.

Table A-1. Excelsior's Site Selection Criteria

Code	Permitting Criteria	Description
P1	Air	What is the potential impact on Class I areas, including cumulative impacts of current and proposed projects?
P2	Wetlands	What is the potential for wetland impacts and mitigation if required?
P3	Groundwater	Will there be any solid waste disposal landfills on the site or other structures or operational features that could affect groundwater? If so, what is the depth to groundwater and how might groundwater be impacted?
P4	Floodplains	How will the proposed Project impact floodplains on the site?
P5	Water Supply	Are potential sources of water supply available, in what quantity/quality, and from what source or sources?
P6	Wastewater Discharges	Are publically owned treatment works ("POTW") located in relative proximity to the site, and can such POTWs accommodate plant-derived wastewaters? Are there bodies of water nearby that can accommodate the wastewater after appropriate treatment?
P7	Great Lakes Initiative ("GLI")	Is the proposed site located within the Lake Superior Basin watershed? If so, can wastewater discharges meet the low GLI mercury discharge criteria as such limits can be below the background mercury levels found in some Northeastern Minnesota surface waters?
P8	Natural/Cultural Resources	Does the site present any special concerns with respect to areas of archaeological/architectural importance or with respect to threatened and endangered species?
P9	Land Use	Is the current zoning designation compatible with industrial activities? What are the future land use plans for the proposed site and areas surrounding it?
Code	**Technical Criteria**	**Description**
T1	Plant Expansion	Is there sufficient contiguous acreage, water and related infrastructure available to accommodate the Phase I and Phase II Developments, including rail loop? Is the area sufficiently isolated for safety, security, dissipation of noise, and other considerations?
T2	Physical Characteristics	What are the size, shape, topography, and underlying soil conditions of the site? What are the subsurface characteristics? Are there any geohazards that would preclude use of the proposed site or confine the proposed facilities to specific areas?
T3	Rail Access	Is there adequate rail access for delivery of key pieces of equipment during construction, and for delivery of coal and pet coke for operation? Is it possible to develop more than one rail transportation option? Can Great Lakes ports be utilized to help meet fuel transportation needs?
T4	Transmission	How and where does the generator interconnection to the transmission system occur? What transmission system network reinforcements, beyond the POI, may be required to accommodate planned generating facilities?
T5	Natural Gas	How and where does the interconnection to the natural gas pipeline system occur and what is its available capacity?
T6	Industrial Processing	How close is the nearest large industrial processing facility? Do potential synergies exist with such facilities, including use of warmed water for industrial process uses, syngas as a substitute for natural gas, common use of facilities, etc.?
Code	**Control Criteria**	**Description**
C1	Site Control	Is it likely that site control can be obtained in a timely manner?

b. Step Two: Identifying Initial Sites

Excelsior initiated its siting efforts by identifying within the TTRA numerous sites in separate industrial complexes where the IGCC Power Station might share potential synergies with existing industrial operations. Such industrial sites represented a desirable option for developing the Station based on the infrastructure that was constructed to serve existing industrial operations.

However, any IGCC Power Station or other industrial facility cannot be indiscriminately placed in existing industrial locations. For example, many sites on the Iron Range, but off the "iron formation," have been used as auxiliary mining lands and include areas where large quantities of rocks and soil (stripped to expose natural mineral resources) have been placed. These areas, commonly referred to as "mine dumps" are generally not suitable locations upon which to place the IGCC Power Station. In general, the same is true for large areas where tailings[14] have been sluiced and left to settle.[15]

The owners of two existing industrial operations, Minntac and United Taconite (owned by United States Steel Corporation and Cleveland-Cliffs Inc/Laiwu Steel Group, respectively, showed an initial willingness to consider co-locating the IGCC Power Station on their sites. However, after extended negotiations, the owners were unwilling to commit to terms with Excelsior to develop the IGCC Power Station on their sites. Their unwillingness to execute agreements for use of their industrial sites for the IGCC Power Station required Excelsior to look at other siting options.

Excelsior also considered the use of existing LEPGP sites within the TTRA. Discussion with the owners found such sites to be unavailable for the Project's development. Therefore, it was necessary to conduct a search of greenfield sites, as described below.

i. Screening Process

Excelsior used geographical information system ("GIS") mapping software to identify areas within the TTRA potentially capable of supporting development of the IGCC Power Station. In general, the areas within the TTRA where Excelsior focused its search depended upon access to existing rail lines (i.e., the means by which coal would be delivered to the Station) and the presence of the following attributes:

- Availability of water for cooling and other Station purposes;
- Proximity to existing high voltage transmission line ("HVTL") corridors that could be used to minimize environmental impacts associated with interconnecting the Station to the regional electric grid;
- Feasibility of acquiring large blocks of land in a timely manner;
- Reasonable distance from nearby landowners;
- Reasonable proximity to a major natural gas pipeline; and
- High proportion of upland to wetland areas.

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[14] Waste or refuse left in various processes of milling, mining, etc. From: Webster's New World College Dictionary, 4th Edition, Michael Agnes, Editor, Wiley Publishing, Inc.

[15] Loose, water-saturated sands and silts of low plasticity may have adequate shear strength under static loading conditions; however, if such materials are subjected to vibratory loading, they may lose strength to the point where they flow like a fluid. The process in which susceptible soils become unstable and flow when shocked by vibratory loading is called liquefaction, and it can be produced by vibration from blasting operations, earthquakes, or reciprocating machinery. In very loose and unstable deposits, liquefaction can result from disturbances so small that they are unidentifiable. *See* www.usace.army.mil/publications/eng-manuals/em1110-2-1911/c-3.pdf page 7.

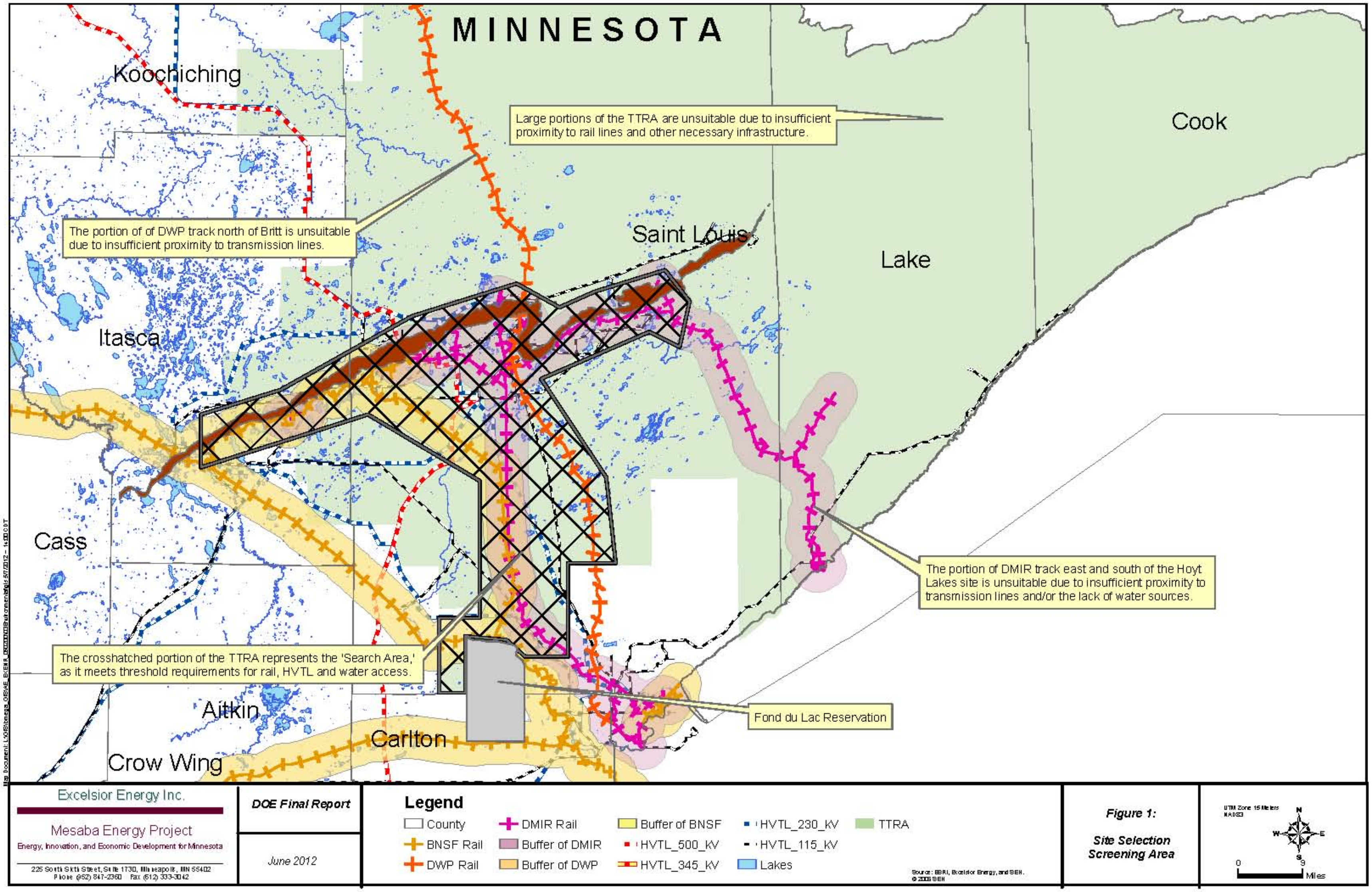
Rail Access

Figure A-1 shows the location of major rail trackage within the TTRA. Excelsior used a six-mile buffer centered on each major rail line (that is, three miles on each side) to provide a general indication of the characteristic area within which Excelsior believed it feasible to construct and operate the IGCC Power Station. The costs and logistical challenges of securing rights of way and constructing rail to a site beyond this buffer, in addition to the likelihood of greater wetland impacts for longer rail alignments, generally rendered such sites unworthy of consideration.

Dual rail service via two major rail suppliers using their own track was identified as a key attribute in Excelsior's siting evaluation. The optionality created by such fuel supply and transportation diversity allows for fuel supply contracting options that would minimize the Project's fuel costs and allow for a fuel and fuel transportation contracting strategy that could incorporate supply contracts of varying terms and quantities, and spot market access. At a minimum, the Project could have a fuel supply cost that is equal to the fuel supply costs of other regional fossil fueled power plants operated by Northern States Power ("NSP" or "Xcel") and Minnesota Power.[16] The dual rail optionality available to the Project would allow for fuel mixes that are lower in overall cost than these regional suppliers over the long term.[17]

[16] Excerpt from October 10, 2006 rebuttal testimony of Ralph Olson before the MPUC.
[17] Ibid, page 2, line 9.

Figure A-1. Site Selection Screening Area



Water Availability

The JPA submitted by Excelsior identified the IGCC Power Station's water requirements, as shown in Table A-2.

Table A-2. IGCC Power Station Water Appropriation Requirements

Phase	Average Annual Appropriation (gal/min)	Peak Appropriation (gal/min)
I	3,500[a]	5,000
I & II	7,000[a]	10,000

[a] Based on 8 cycles of concentration in the gasification island and the power block cooling towers

New facilities (as defined in 40 **CFR** 125.83) locating on waters of the United States and i) withdrawing more than 2 million gallons per day, ii) using more than 25% of that volume for cooling purposes, and iii) using a cooling water intake structure ("CWIS") to divert such volumes of water to the source are restricted as to the amount of water that can be withdrawn from such waters. Since the Mesaba Energy Project would be a new facility and would meet these criteria, it would be subject to rules governing cooling water intake structures (see 66 **FR** 65256). Such rules restrict the amount of water that can be withdrawn from freshwater rivers, streams, lakes and reservoirs. Withdrawals from freshwater rivers or streams must be no greater than 5 percent of the source waterbody mean annual flow; withdrawals from a lake or reservoir must not disrupt the natural thermal stratification or turnover pattern (except where such disruptions are determined to be beneficial to the management of fisheries). In 40 **CFR** 125.84(e), the final rule governing CWISs recognized that a State may include more stringent requirements to the location, design, construction and capacity of a CWIS at a new facility.[18]

In evaluating flows in freshwater rivers or streams, Excelsior used daily flow information obtained from United States Geological Survey gauging stations. Impacts associated with withdrawals from lakes or reservoirs were estimated using information about the area of the specific resource, its maximum depth, and the area of the littoral zone obtained from the Minnesota Department of Natural Resources' ("MDNR") Lake Finder web site.[19] Excelsior assumed no inflow to such resources (approximating conditions that would be present during times of drought) and calculated the time it would take to lower the level of the lake or reservoir to the point where water in the littoral zone was completely depleted.

The use of groundwater in quantities suitable to meet the cooling requirements for the IGCC Power Station is generally discouraged by Minn. R. 7850.4400 ("Prohibited Sites") Subpart 5 ("Sufficient water supply required"). This subpart of Minnesota rules states:

> "No site may be designated that does not have reasonable access to a proven water supply sufficient for plant operation. No use of groundwater may be permitted where removal of groundwater results in material adverse effects on groundwater, groundwater dependent natural resources, or higher priority users in and adjacent to the area, as determined in each case.

[18] In the proposed rules, the maximum amount of water that could be withdrawn from a river was 25 percent of the 7Q10 or 5 percent of the mean annual flow, whichever was lower. Although the language including the 7Q10 was dropped from the final rules, the state could deem it appropriate if it appeared that 5% of the mean annual flow did not sufficiently protect aquatic resources.

[19] See http://www.dnr.state.mn.us/lakefind/index.html. The littoral zone is defined as that portion of the lake that is less than 15 feet in depth. The littoral zone is where the majority of the aquatic plants are found and is a primary area used by young fish. This part of the lake also provides the essential spawning habitat for most warmwater fish (e.g. bass, walleye, and panfish).

> The use of groundwater for high consumption purposes, such as cooling, must be avoided if a feasible and prudent alternative exists."

High Voltage Transmission Lines/Natural Gas Pipelines

Excelsior's strategy for interconnecting the Station to a major electrical substation would be to use existing HVTL corridors to the extent feasible and to minimize distances to the point of interconnection. The further the Station is located from such substations, the higher interconnection costs become. In addition, the lower the HVTL voltage within an existing corridor, the narrower the existing right of way ("ROW") for that corridor is likely to be. The voltage for the preferred generator outlet facilities serving Mesaba One and Two would be 345 kilovolts ("kV"). The required ROW for the 345 kV tower configuration to be used for these facilities is generally found to be less than or equal to the current ROW serving many of Minnesota Power's 115 kV HVTLs. This would not be the case for the smaller distribution HVTLs found in the TTRA north and east of Virginia, Minnesota.[20] Although there is rail track found north of Virginia, there were no suitable sized HVTL corridors within which Mesaba One and Two transmission outlet facilities could have been placed absent the acquisition of additional ROW.

Even though existing rail corridors are present south of and east of Hoyt Lakes, there are no HVTLs corridors of suitable size to accommodate the right of way required for HVTLs sized to carry the output of Mesaba One and Two. A 115 kV HVTL runs along the North Shore of Lake Superior at the extreme southern end of this region, but water could not be feasibly obtained in the quantity required to support Mesaba One and Two.[21]

The only natural gas pipelines capable of providing the capacity required by Mesaba One and Two are the two 36" diameter Great Lakes Gas Transmission Limited Partnership pipelines that parallel the southeastern boundary of the TTRA. The further the distance between the Station and this pipeline, the more costly it would be to interconnect them.

Wetlands

Wetlands and open water cover large areas of the TTRA and represented an important factor in Excelsior's siting decision processes. National Wetland Inventory ("NWI") maps obtained from the U.S. Fish and Wildlife Service ("USFWS") were used to screen areas where development of the Project would have significant impacts. Areas where wetlands represent a primary factor lie in the southern portion of the TTRA within the buffer area of the existing rail lines near the confluence of the St. Louis and Cloquet Rivers. In this proximity, areas that would appear to be capable of supplying sufficient water to Mesaba One and Two were excluded due to their relatively high impact on wetland resources and difficulties associated with obtaining control of the site (see Figure A-2 through Figure A-4).

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[20] HVTLs found north and east of Virginia, Minnesota mostly belong to Great River Energy. See http://www.greatriverenergy.com/about/brochure1.html for a general comparison of right of way widths found in the Great River Energy transmission line portfolio. Also see http://www.tva.gov/power/rightofway/faq.htm,

[21] The only appropriate source of water in the area just north of Lake Superior is the lake itself. Excelsior does not believe it is reasonable to assume that a new, large electric power generating plant would be permitted on the shore of Lake Superior. Further, pumping water from the lake in the quantity necessary to meet Mesaba One and Mesaba Two needs would not be feasible given the distance and head required for a plant located a sufficient distance away from the lake.

Property Size and Ownership

Adequate site size was also necessary to support the development of the Mesaba Energy Project. While the IGCC Power Station Footprint would occupy approximately 200 acres, a large amount of additional land would be necessary for the associated facilities, primarily the rail loop. Buffer land was also desirable to isolate the IGCC Power Station Footprint from residences and other potentially affected land uses. Site specific variables, such as the orientation of available rail access, introduced variability to the land size required at each site. At a screening level, 400-500 acres was deemed a reasonable range below which the development of the Project was unlikely to be practicable.

The rights of existing homeowners were provided substantial deference to minimize impacts upon individuals, families, and local communities. Obtaining sites that consisted primarily of many small landowners was also deemed to present a serious potential logistical problem as compared to acquiring a site from a small number of major landowners who were willing to reach necessary acquisition agreements. Therefore, in the site screening process, deference was given to locations where the number of landowners was low and where no relocation of residents would have been dictated. Additionally, sites owned and used by other industrial entities as part of their mineral extraction activities within the iron formation were not obtainable through purchase, making the avoidance of such sites appropriate.

Exclusion Zones

Iron Formation
Although abandoned mine pits in the iron formation represent an area where there is generally an abundance of water, the iron formation itself represents an exclusion zone within which non-mining operations were unlikely to be allowed to locate.[22]

Native American Reservations
The Fond du Lac Indian Reservation located in the south-central-most part of the TTRA was considered an exclusion zone.

Other
Text boxes included on Figure A-1 identify the relatively large areas of the TTRA that were excluded from consideration as IGCC Power Station sites due to a lack of existing rail service, distance from existing track, lack of sufficient transmission line corridors, the ubiquitous presence of wetlands, and/or their lack of sufficient water resources. These exclusions were discussed and justified in the preceding narrative of power plant siting considerations. The cross hatched area in the TTRA shown in Figure A-1 (hereafter, the "Search Area") indicates where Excelsior thereafter focused its search for potential sites.

Excelsior identified fifteen sites within the Search Area that appeared to have adequate access to required infrastructure and sufficient space to accommodate a LEPGP, and which appeared to minimize potential land-owner conflicts. Resources used in this process included the most recent plat maps and zoning ordinances for St. Louis and Itasca Counties. Excelsior conducted "windshield" surveys of most sites and, where access could be obtained while maintaining some anonymity, walked the sites to gauge their potential feasibility for the Project's use. Figure A-2 through Figure A-7 show the location of the fifteen sites within the TTRA.

[22] Excelsior's use of water obtained from mining pits will most always be outside the boundaries of the iron formation.

Figure A-2. Optimum Orthogonal Layout for Alternative Site 1 to Screen for Potential Wetland Impacts

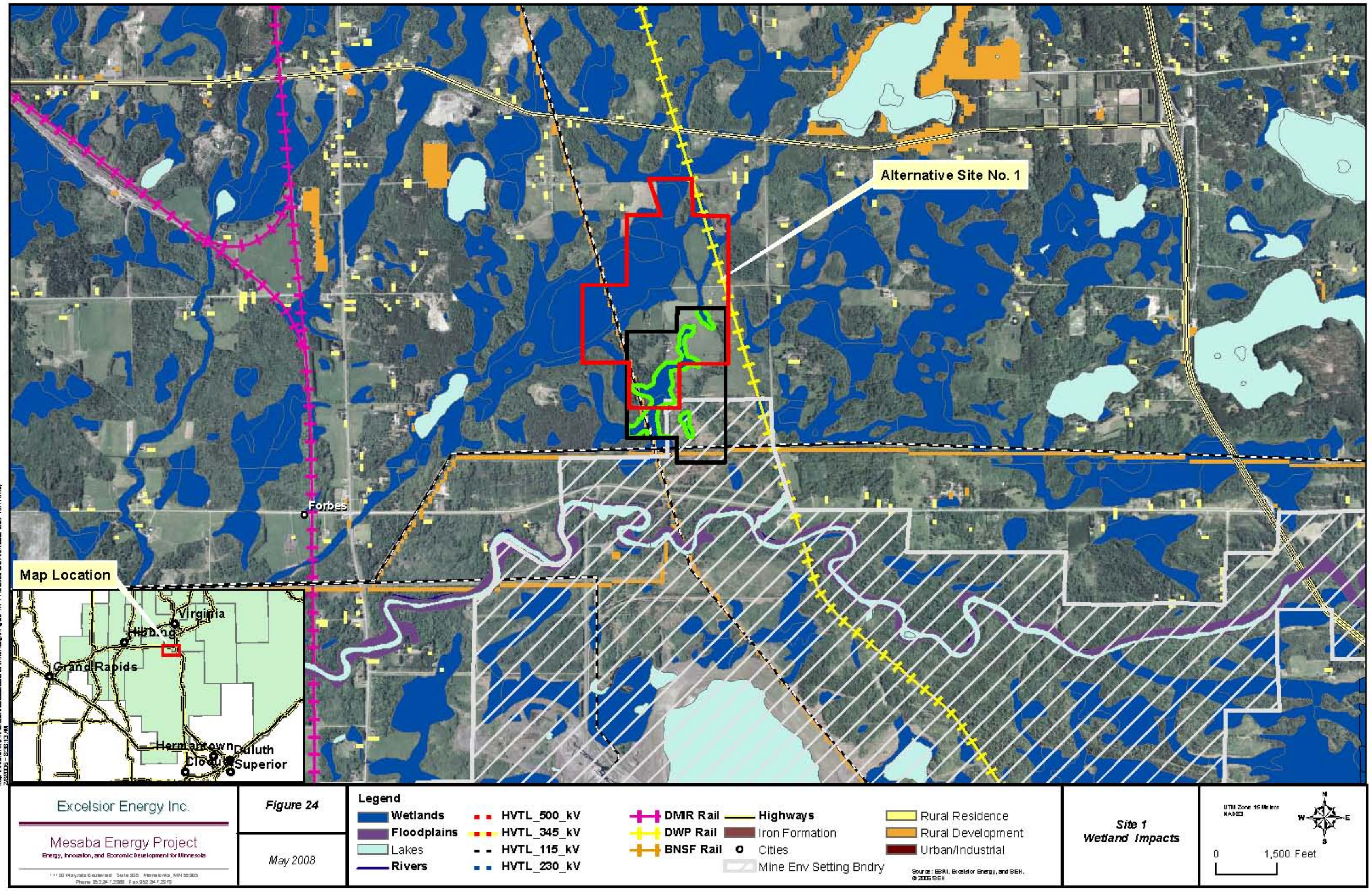


Figure A-3. Optimum Orthogonal Layout for Alternative Sites 2 & 3 to Screen for Potential Wetland Impacts

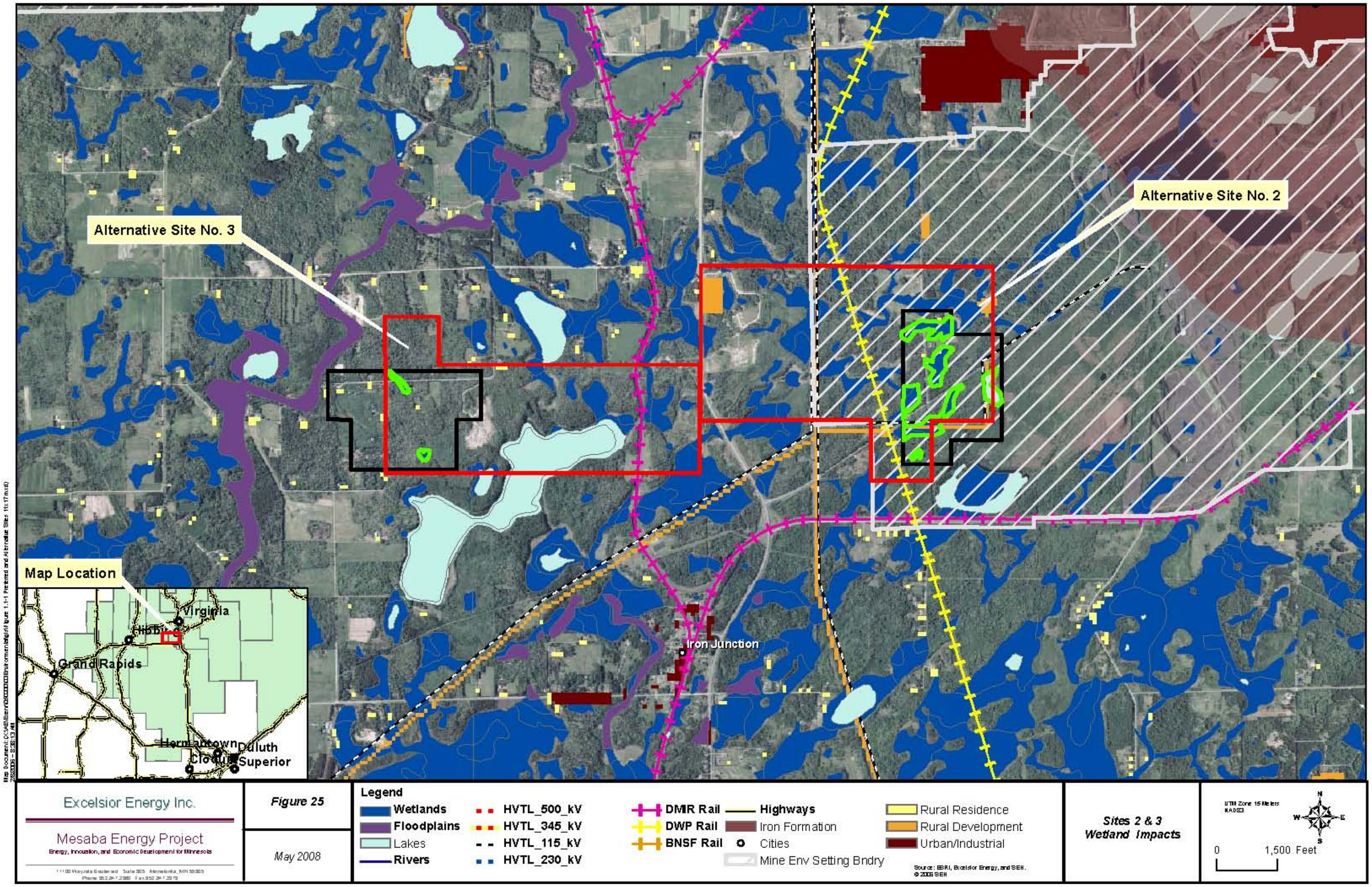


Figure A-4. Optimum Orthogonal Layout for Alternative Sites 4, 5, 8, 10 & 11 to Screen for Potential Wetland Impacts

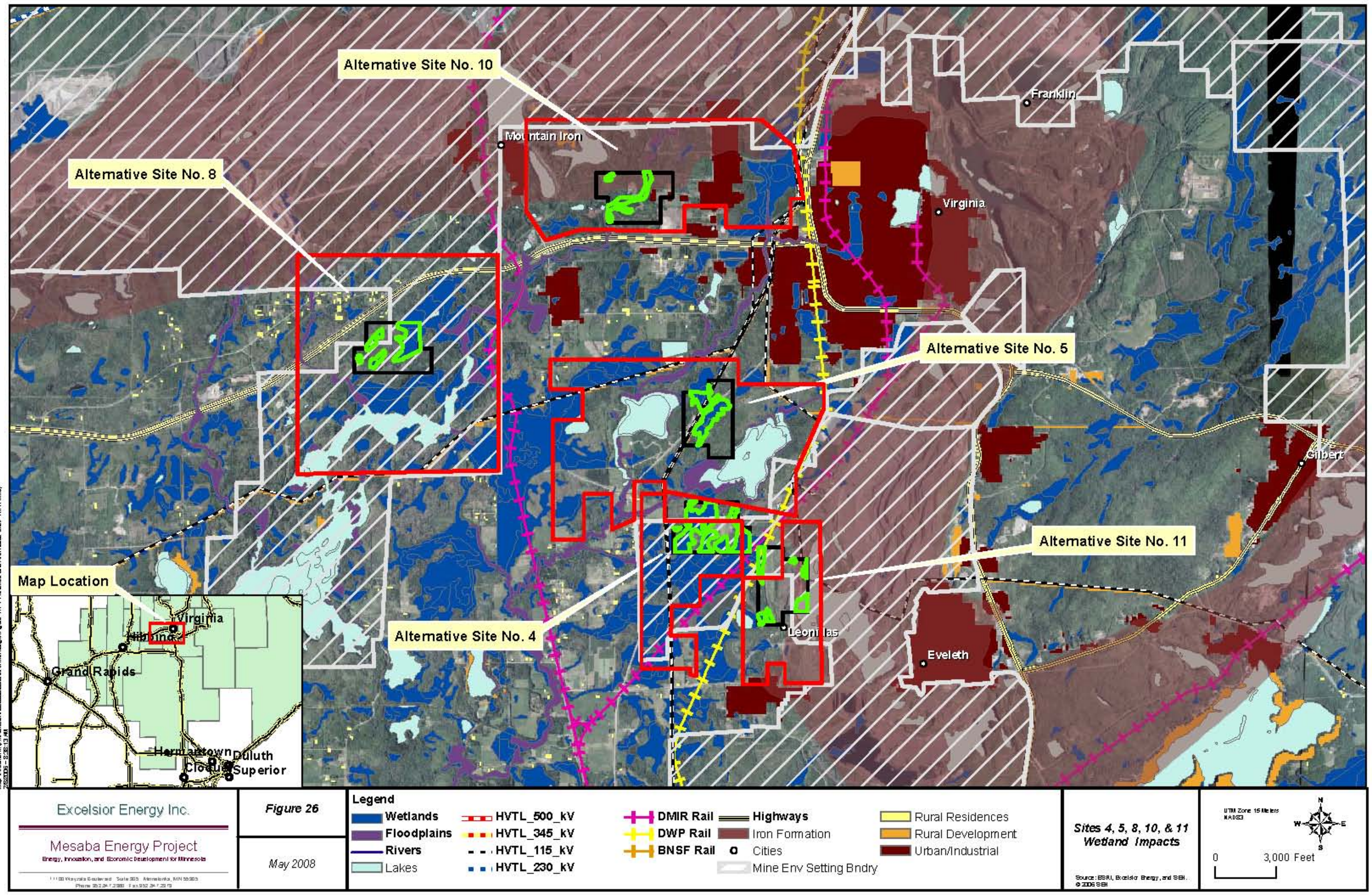


Figure A-5. Optimum Orthogonal Layout for Alternative Sites 6, 7 & 9 to Screen for Potential Wetland Impacts

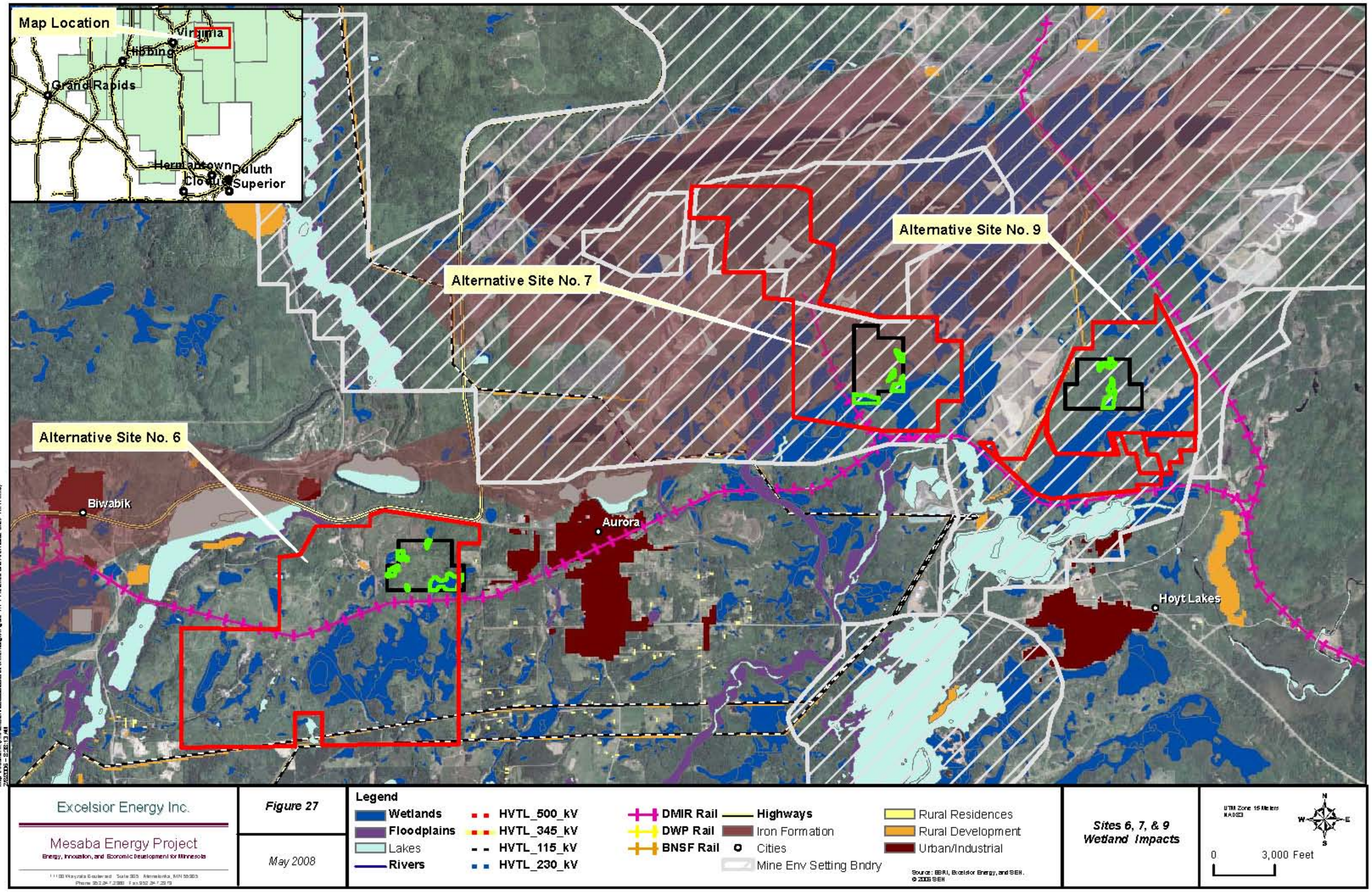


Figure A-6. Optimum Orthogonal Layout for Alternative Sites 12, 13 & 14 to Screen for Potential Wetland Impacts

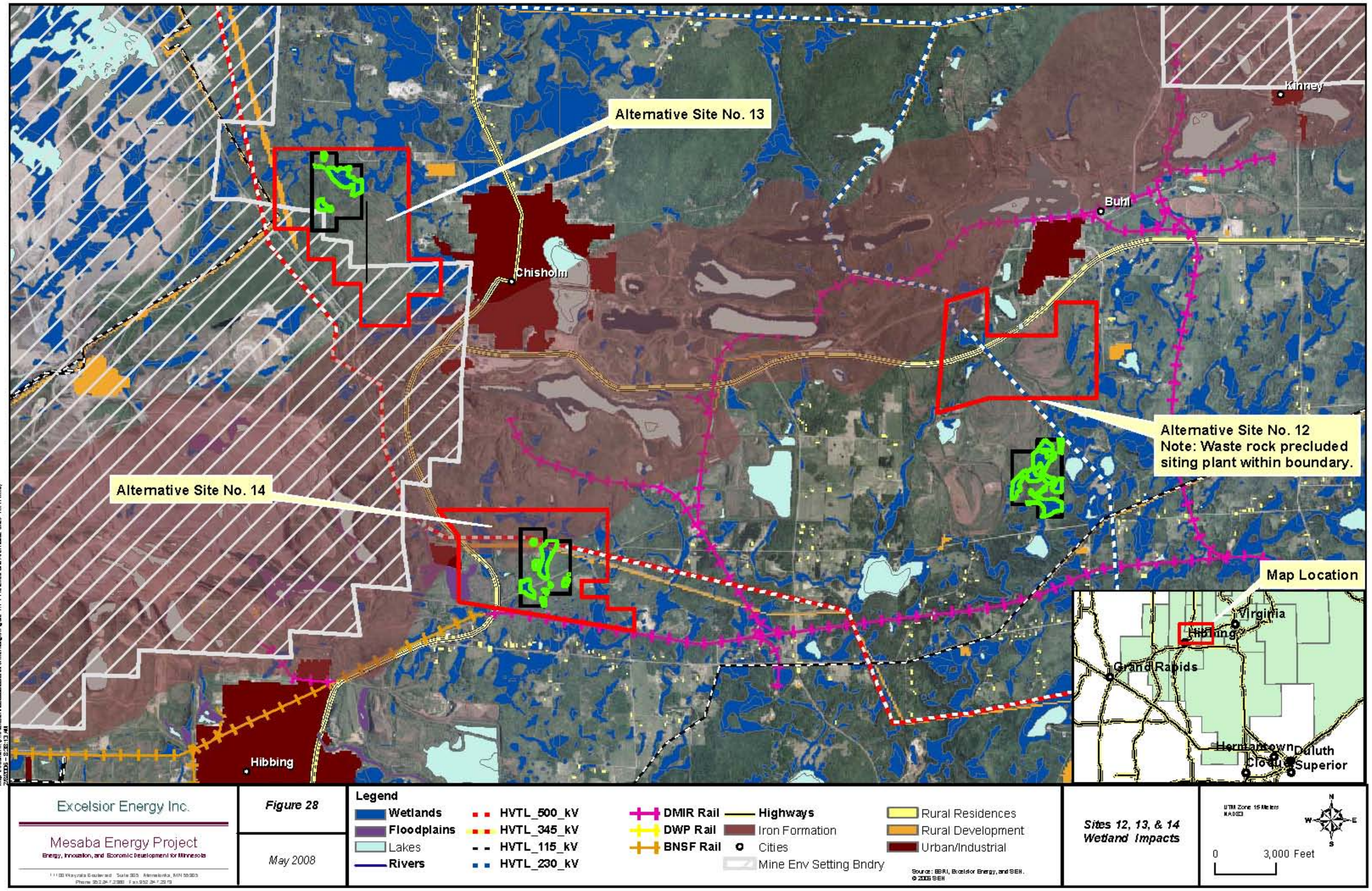
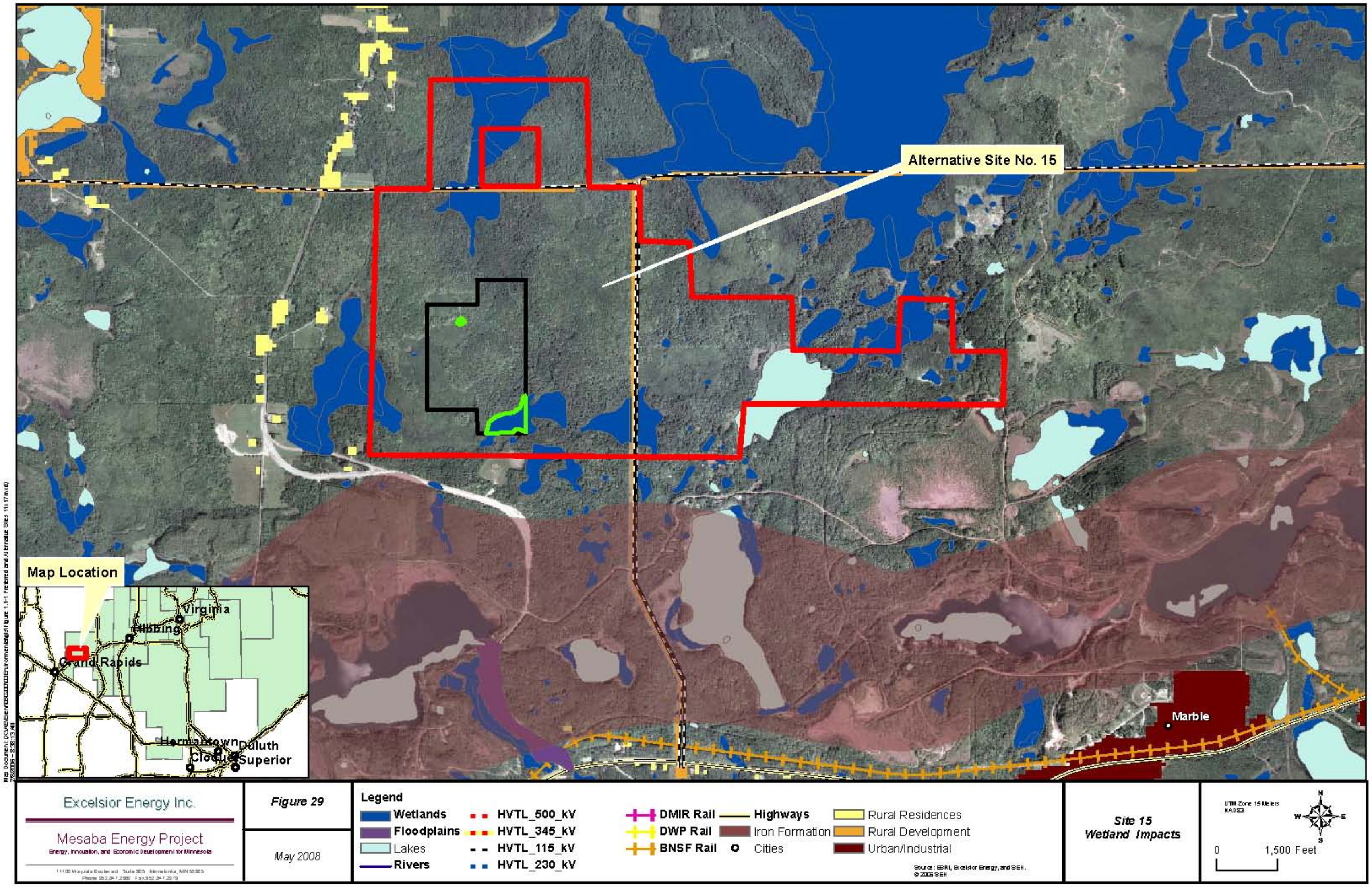


Figure A-7. Optimum Orthogonal Layout for Alternative Site 15 to Screen for Potential Wetland Impacts



c. Step Three: Narrowing the Number of Potential Sites to Practicable Alternatives

The fifteen sites were screened for potential wetland impacts. Excelsior used NWI database information prepared by the USFWS from USGS 1:24,000 quadrangle maps[23] to facilitate this analysis. Excelsior used the footprint of the IGCC Power Station prepared by Fluor to quantify relative wetland impacts by arranging it in one of four orthogonal directions (that is, at 0º, 90º, 180º, and 270º angles) thought to best accommodate the expected rail configuration. Further wetland evaluations were precluded at this stage due to the detailed case-by-case analysis required to correctly establish the grade and orient the rail spur required for each potential IGCC power station layout and correctly align other infrastructure requirements.[24] The results of the wetland screening analysis are presented in Table A-3.

Excelsior worked with city officials and owners of large blocks of land to gain additional insight into the feasibility of using a site for a LEPGF. Such discussions were very informative and, in the case of Sites No. 7 and 10, led to their ultimate dismissal as feasible alternatives.[25] In addition, Excelsior worked with consultants and city engineers to investigate potential constructability issues on sites deemed to have local government's strong support.

In some instances numerous considerations combined to make a location infeasible as an LEPGF site. For example, in the case of Site No. 3, residential proximity/density, existing land uses (i.e., a county recreation site and numerous farms were located in immediate proximity and/or within the site footprint and likely rights of way for road/rail access), natural features restricting site development (i.e., a small river to the west, lakes to the south and northeast, and wetlands to the east across which access to the site would have likely been required) and water supplies that, at best, could have been considered marginal.

The distinguishing factors for the fifteen sites are summarized in Table A-4, which is based on detailed information about each site as presented in their respective site evaluation sheets. These sheets are available in Appendix F1 of the Mesaba FEIS. If a factor either necessitated the dismissal of a site or weighed very heavily against a site, it is shaded and marked in bold in Table 6. Only Site Nos. 9 and 15 had no such factors. Table A-5 provides additional narrative that reinforces the rationale for site dismissal, which is further supported by the detailed information in the aforementioned site evaluation sheets.

The two practicable sites ultimately selected for use in the Power Plant Siting process are represented by the Preferred (Site No. 15) and Alternate (Site No. 9) sites, otherwise known as the West and East Range Sites, respectively. A third site, the Hibbing Industrial Park, would have been considered a practicable alternative, but an agreement between IRRRB and a private developer seeking to develop the property for other uses precluded its consideration.

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[23] *See* U.S. Fish & Wildlife Service web site at http://wetlandsfws.er.usgs.gov/NWI/download.html.

[24] Each site must accommodate a rail spur and loop, access roads for employees and construction vehicles, transmission line and natural gas pipeline interconnections, process water pipelines, and other utility connections.

[25] The owners of Site No. 7 informed Excelsior that they would not consider providing Excelsior an option on the property because the site was located within the Mesabi Iron Range formation and their original purchase of the property was based on the speculative proposition that excavation of the iron resources thereunder would someday become economically viable. The City of Mountain Iron, MN asked for public comments regarding the possibility of optioning Site No. 10 for purchase by Excelsior. In response to the City's request for comments, U.S. Steel indicated that the site was within the iron formation and that the company was currently working on a mining plan to excavate the iron resources underneath Site No. 10. As a result of U.S. Steel's input, the City discouraged Excelsior from pursuing any further the possibility of securing Site No. 10 for use as a Project site.

Table A-3: NWI Wetland Screening Analysis of Preliminary Sites Selected Under Excelsior's Screening Process*

Alt. Site No.	Site Name	NWI Wetland Parcel No. 1 (Acres)	NWI Wetland Parcel No. 2 (Acres)	NWI Wetland Parcel No. 3 (Acres)	NWI Wetland Parcel No. 4 (Acres)	NWI Wetland Parcel No. 5 (Acres)	NWI Wetland Parcel No. 6 (Acres)	NWI Wetland Parcel No. 7 (Acres)	NWI Wetland Parcel No. 8 (Acres)	NWI Wetland Parcel No. 9 (Acres)	NWI Wetland Total Impacts (Acres)
1	Clinton Township S.	28.1	2.3	2.4							32.8
2	Clinton Township E.	0.7	10.9	7.4	5.4	8.9	5.0				38.4
3	Clinton Township W.	1.2	1.6								2.8
4	Clinton Township N.	30.6	9.9	52.0	0.8						93.3
5	Manganika L.	28.7	16.8								45.5
6	W. Aurora	18.4	3.3	1.1	3.7	0.6					27.1
7	Hoyt Lakes W.	10.1	5.1	1.5	2.6						19.3
8	W. Two Rivers Res.	35.0	6.4	6.1	1.4						48.8
9	Hoyt Lakes E. (East Range Site)	10.5	1.7	2.4							14.6
10	Mountain Iron	16.5	1.7	1.9	2.7						22.8
11	Leonidas	9.0	3. 6	2.7	2.7	8.6	1.0				27.6
12	Buhl	40.7	2.5	5.7	19.2						68.1
13	W. Chisholm	25.0	5.0	1.3	1.5						32.8
14	Hibbing Ind. Park	8.6	18.6	2.3	1.9	1.4	0.9	0.7	0.4	0.5	35.4
15	West Range Site	10.3	0.4								10.7

* Sites 16 and 17 were not screened for NWI wetlands as they were eliminated from consideration prior to expanding Excelsior's site selection process (*see* Section II.A.1.b). Mesaba Energy Project Final Environmental Impact Statement, Volume II, Appendix F-1, "Documentation for USACE", U.S. Department of Energy in Cooperation with Minnesota Department of Commerce, November 2009.

Table A-4: Site Selection Screening Summary

Site ID	General Description				Site Attributes					Water Supply			HVTL POI	Proximity to Class I Areas (miles)	
	Size (Acres)	Site Control	Planned/Existing Land Use	Residential Proximity	Physical Features	Site Access: Road	Site Access: Rail	NWI Wetlands	Construct-ability	Potential Source(s)	Adequacy	Water-shed		VNP	BWCA
1	**~380**	Potentially obtainable	**Residential**	**High**	Flat, cleared, wetlands	Good	CN: Good BN: None	**32.8**	Feasible	St. Louis River, Long Lake	**Inadequate**	Lake Superior	Forbes	64	38
2	~620	**Not obtainable; within Environ-mental Setting Boundary of mining company**	**Residential and planned mining/ ancillary use**	**High**	Flat, wetlands	Good	CN: Good BN: None	**38.4**	Feasible	Elbow Lake, Thunderbird Mine Pit	Marginal	Lake Superior	Forbes	60	35
3	**~410**	Potentially obtainable	**Recreation, residential**	**High**	Wooded, lake	Good	CN: Good BN: None	2.8	Feasible	Elbow Lake, Thunderbird Mine Pit	Marginal	Lake Superior	Forbes	61	36
4	**~420**	**Not obtainable, within Environ-mental Setting Boundary of mining company**	**Planned mining/ ancillary use**	Moderate	Wetlands	Good	CN: Good BN: None	**93.3**	Feasible	Various mine dewatering, Virginia WWTP	Marginal	Lake Superior	Forbes	58	33
5	~1,375	Potentially obtainable	**Residential development**	**High**	Lakes	Good	CN: Good BN: None	**45.5**	Feasible	Various mine dewatering, WWTPs	Marginal	Lake Superior	Forbes	58	33
6	~2,500	Potentially obtainable	Zoned forest/ag. management and industrial	**High**	Waste rock, wetlands	Good	CN: Good BN: None	**27.1**	Some areas feasible	Embarrass Lake, mine pits	**Likely inadequate**	Lake Superior	Forbes	55	26
7	~1,630	**Not obtainable, owner unwilling to sell**	**Planned future mining, State Mineral Trust**	Low	Wetland and some former mining	**Poor**	CN: Good BN: None	19.3	Feasible	Abandoned Cliffs Erie mine pits, Colby Lake	Adequate	Lake Superior	Forbes	54	25
8	>2,000	**Not obtainable, within Environ-mental Setting**	**Current ancillary mining use**	Moderate	Wetland	Good	CN: Good BN:	**48.8**	Feasible	Various mine dewatering, WWTPs	**Likely inadequate**	Lake Superior	Forbes	57	33

Site ID	General Description				Site Attributes					Water Supply			HVTL POI	Proximity to Class I Areas (miles)	
	Size (Acres)	Site Control	Planned/Existing Land Use	Residential Proximity	Physical Features	Site Access: Road	Site Access: Rail	NWI Wetlands	Construct-ability	Potential Source(s)	Adequacy	Water-shed		VNP	BWCA
		Boundary of mining company	**(water reservoir)**				None								
9	1,433	Obtainable	Zoned mining; no current or planned land use	Low	Wooded, wetlands	Good	CN: Good BN: None	14.6	Feasible	Abandoned Cliffs Erie mine pits, Colby Lake	Adequate	Lake Superior	Forbes	49	25
10	~1,520	**Likely not obtainable**	**Residential and planned future mining**	**High**	Wooded	Good	CN: Good BN: None	22.8	Feasible	Abandoned mine pits, dewatering, Silver Lake	Marginal	Lake Superior	Forbes	57	32
11	<704	**Not obtainable, within Environmental Setting Boundary of mining company and boundary of iron formation.**	**Residential and planned future mining**	**High**	Waste rock	Good	CN: Good BN: None	**27.6**	**Likely infeasible**	Various mine dewatering, WWTPs	Marginal	Lake Superior	Forbes	58	33
12	850	**Portion is not obtainable**	Previous ancillary mining use	Moderate	Waste rock	Good	**CN: Poor BN: None**	**68.1**	**Likely infeasible**	Sherman and Frasier mine pits, Iron World	Uncertain	Lake Superior	Forbes	58	39
13	785	Potentially obtainable	Previous ancillary mining use	Moderate	Waste rock	Good	**CN: None BN: None Inacces-sible by unit coal trains**	**32.8**	**Potentially infeasible**	N/A	N/A	Lake Superior	Forbes	59	42
14	860	**Likely not obtainable**	**Site of planned race track**	Moderate	Wetland	Good	CN: Good BN:	**35.4**	Feasible, but close to Iron	Abandoned mine pits	Adequate	Lake Superior	Forbes	61	43

Site ID	General Description				Site Attributes					Water Supply			HVTL POI	Proximity to Class I Areas (miles)	
	Size (Acres)	Site Control	Planned/Existing Land Use	Residential Proximity	Physical Features	Site Access		NWI Wetlands	Construct-ability	Potential Source(s)	Adequacy	Water-shed		VNP	BWCA
						Road	Rail								
							Poor		Formation						
15	1,727	Obtainable	Zoned industrial; no current or planned land use	Low to Moderate	Wooded	Good	CN: Good BN: Good	10.7	Feasible	Canisteo, Hill Annex, Lind pits and Prairie River	Abundant	Upper Missis-sippi	Black-berry	75	61
16	N/A	**Not obtainable, industrial owner not willing to commit to terms to allow Excelsior to co-locate an IGCC facility.**	Details of site are proprietary and/or confidential.												
17	N/A	**Not obtainable, industrial owner not willing to commit to terms to allow Excelsior to co-locate an IGCC facility.**	Details of site are proprietary and/or confidential.												

Table A-5: Initial Dismissal of Sites During the Screening Process

Site No.	Site Name	Rationale for Dismissal
1	Clinton Township South	Water unavailable in required quantities; development constrained because of inadequate site size, existing land owners, forcing expansion into areas where relatively high wetland impacts would occur.
2	Clinton Township East	Residential development has occurred on the western part of the site; the eastern part of the site is completely within the environmental setting boundary[1] for Eveleth Taconite making it unlikely that the Project could be obtained and developed there; potential for high wetland impacts and marginal water availability.
3	Clinton Township West	Plant footprint and associated facilities would require displacement of numerous residences and closure of a County recreation area; the site would not readily accommodate the size and shape of the footprint and associated facilities; marginal water availability.
4	Clinton Township North	High proportion of wetland areas; site is small and mostly located within the environmental setting boundary[1] for Eveleth Taconite making it unlikely that the Project could be obtained and developed there; marginal water availability.
5	Manganika Lake	Western part of the site is being developed for lake homes; wetland impacts would be significant for both the plant footprint and rail loop, which would encircle Manganika Lake; marginal water availability; and too close to residential developments in Mountain Iron.
6	West Aurora	Water unlikely to be available in required quantities; site cannot accommodate plant footprint and associated facilities while also avoiding large wetlands, waste rock piles, and close proximity to dense residential development.
7	Hoyt Lakes West	Site is partly located within the Mesabi Iron Range iron formation and may conflict with expanded mining operations; State school trust mineral rights cannot be encumbered. Present property owner has refused to consider sale of land to Excelsior.
8	West Two Rivers Res.	Property considered unobtainable because of its location in environmental setting boundary[1] of U.S. Steel Co.; reservoir and all its surrounding land owned by one industrial entity unwilling to provide access; water availability inadequate without appropriation from that reservoir.
10	Mountain Iron	Site is partly located within the Mesabi Iron Range iron formation and planned for expanded mining operations and also within environmental setting boundary[1] making it unlikely that the Project could be obtained and developed there; nearby residential development is relatively dense; marginal water availability.
11	Leonidas	Constructability concerns[2]; wetland impacts; marginal water availability; site is within the environmental setting boundary[1] for Eveleth Taconite making it unlikely that the Project could be obtained and developed there.
12	Buhl	Constructability concerns; pervasive wetland impacts; poor rail access.
13	West Chisholm	Grade required to reach site is not suitable for rail access by unit coal trains.
14	Hibbing Industrial Park	Site was committed by its owner, Iron Range Resources, to the development of a race track at the time of Excelsior's site selection process, therefore unobtainable; site is constrained by Iron Formation to north, residential developments to south, and U.S. 169 to west. Expansion of area to east would impact wetlands and mineral extraction.
16	Minntac Industrial Site	The industrial owner of the site was ultimately unwilling to commit to terms to allow Excelsior to co-locate the IGCC Power Station.
17	United Taconite Industrial Site	The industrial owner of the site was ultimately unwilling to commit to terms to allow Excelsior to co-locate the IGCC Power Station.

See following page for footnotes.

[1] Detailed investigations of site No. 10 indicated that serious ownership issues were associated with being located in the environmental setting boundary (formerly known as the mine permit boundary) of a company conducting active iron mining operations. Environmental setting boundaries established for such companies were seen thereafter as areas that should be avoided given the ultimate difficulty of obtaining site control. The East Range site was an exception as it was within Cliffs Erie's environmental setting boundary. However, there was no active mining or mining-related land use plans for that site, as evidenced by Excelsior's ability to secure an option agreement. Excelsior's experience indicated that this was not typical, and that those areas are generally very difficult to obtain.

[2]Significant portions of property are devoted to "mine dumps," that is, large piles of rocks of mixed size. Construction is difficult due to the inability to ascertain whether or not one has reached bedrock upon which to build foundations. See "Existing Industrial Facilities" under the section entitled "Step Two."

d. Step Four: Final Evaluation of Practicable Alternatives & Hibbing Industrial Park

In identifying its preferred site for purposes of satisfying the obligation under Minnesota Rule 7850.1990, Subpart 1.C, Excelsior analyzed the two practicable alternatives identified above and the Hibbing Industrial Park, even though the Industrial Park site was not available for development.[26] Excelsior quantitatively ranked the three sites using its site selection criteria and the personal knowledge, judgment, and experience of Excelsior's staff that had significant experience in siting large power plants and transmission facilities. The results of these evaluations and rankings were as follows:

1. West Range (Preferred Site)
2. Hibbing Industrial Park
3. East Range (Alternate Site)

The methodology consisted of aggregating the site evaluation criteria into the following eight categories[27]:

- Licensability (whether and under what circumstances a site could be expected to be permitted considering all regulatory requirements, including such key permits as air, National Pollutant Discharge Elimination System ("NPDES"), water appropriation, Section 404, etc.)
- Water Supply (quantity of water available and ease with which it could be obtained)
- Industrial Synergies (proximity to nearby industrial facilities with the potential capability of creating some synergy with the Project)
- Transmission/Gas Supply (proximity of site to potential points of interconnection with the regional grid/gas supply lines)
- Local community support (general support within the nearby community)
- Site Attributes (physical characteristics of site including topographical relief, wetland areas)
- Dual Rail (capability to accommodate two rail suppliers providing service from their own track)
- Plant Expansion (capability of accommodating two phases of development)

To assist its siting analysis through use of a "quantifiable" (versus experience/judgmental) mechanism, Excelsior employees with various backgrounds and experience (environment, engineering, development, law, marketing, senior management, and operations) produced a pairwise comparison of the above eight categories. Each person compared each category to each of the other categories to establish the relative weights that each category would be given in the final site ranking analysis. The number of times a specific criterion was identified as being the most important in any pairwise comparison was totaled and divided by the total number of possibilities to establish such relative weights.

[26] The Hibbing site was analyzed in the event a change in circumstances which precluded the site's acquisition by Excelsior (i.e., an existing memorandum of understanding between the State of Minnesota [acting through its Office of the Commissioner of Iron Range Resources and Rehabilitation]; the Cities of Hibbing, Balkan, and Chisholm; St. Louis County; and a developer allowed the project developer until September 4, 2006 to acquire financing) occurred sufficiently in advance of the date by which the commitment of substantive resources was required to enable Excelsior's timely preparation of an LEPGP Site Permit Application. Such a change in circumstances never occurred. In fact, the termination date of the existing memorandum of understanding was extended for one year to September 4, 2007. For reference, Excelsior submitted its LEPGP Site Permit Application for the Project on June 16, 2006. Excelsior also included three impracticable alternatives in its analysis (the two industrial sites and the Mountain Iron site [Site No. 10]). The results of the six-site analysis are provided in Excelsior's Environmental Supplement at Section 1.13.1.3.

[27] The categories listed are presented in order of the relative weight (i.e., highest to lowest) given them via the pairwise comparison process noted in the following paragraph.

Following the site ranking and evaluation, Excelsior proceeded to make its final selection of preferred and alternate sites. Two critical factors considered at this stage were site selection rank and the ability to obtain timely site control. The West Range Site ranked highest for these two factors and was selected as Excelsior's preferred large electric power generating plant site for the following principal reasons:

- It received the highest ranking score in Excelsior's quantitative analysis.
- It was outside the Lake Superior Basin watershed, thereby facilitating permitting and licensing.
- Plant make-up water would be readily available from the Canisteo Mine Pit ("CMP") and Hill-Annex Mine Pit Complex ("HAMP"). Continually rising water levels in these abandoned pits posed a significant concern for local communities and the MDNR, respectively, and use of water from such pits provided a solution to such concerns. Alternative sources of water were also available to the site and in likely quantities to supply any shortfall that could be encountered in supplying the Mesaba One and Mesaba Two developments via mine pit waters alone.
- The site was fairly remote, with only a small number of residential property owners potentially impacted, most of who use the property on only a seasonal basis.
- The site and much of the land surrounding it had been zoned for industrial development by regional governmental bodies.
- The site was located in close proximity to adequately sized natural gas pipelines, existing HVTL corridors, and would have the capability of being serviced by two rail providers.
- Excelsior was able to obtain an option to purchase the site, thereby providing immediate site control.
- Preliminary contacts with Itasca County, city officials from nearby communities, and the Itasca Development Council indicated broad support for the site and the project.

The Hibbing Industrial Park site was originally considered as the alternative site because of the following advantages:

- The location was in an area that local communities had identified and set aside for industrial development. IRRRB and St. Louis County both played important roles in assembling a land package of some 850 acres, with additional acreage appearing to be available. Impacts on local residences were deemed manageable and local communities appeared supportive. Additionally, a new Central Range water treatment facility had been proposed for the area.
- Adequate make up water appeared to exist in local mine pits.
- Although the site was located within the Lake Superior Basin watershed, it appeared that the City of Hibbing's publicly owned treatment works ("POTW") may have been of sufficient size to handle discharges and potentially qualify for a variance from the rigid standards imposed on discharges of mercury by regulations implementing the Great Lakes Initiative.
- The site was located in relatively close proximity to two rail service providers, existing transmission line corridors, and a large industrial facility.

The Hibbing Industrial Park site was under the control of the IRRRB, but at the time that Excelsior finalized its site selection process in August of 2005, there were conflicting development plans and commitments for a non-industrial facility at the site that prevented Excelsior from obtaining the site. . These were formalized in a Memorandum of Understanding ("MOU") between the Office of the Commissioner of the IRRRB, the County of St. Louis, the Cities of Hibbing and Chisholm, and the Town of Balkan that established their intention to support, through both pro-rata financial assistance and subsidized property lease or transfer, the development of a multi-venue complex at the Hibbing Industrial Park. The document provided for the execution of a Development Agreement and Financing Plan at any time through September 4, 2006, a date that was subsequently extended by an additional year.

While Excelsior was allowed to conduct some preliminary site investigation work, it was unable to obtain any rights to utilize the site within the timeframe in which Excelsior conducted its site selection process. The extended MOU expired more than two years after Excelsior made its final selection. Over the two intervening years, project development considerations and regulatory processes, including moving through the Minnesota Power Plant Siting Act process, rendered this selection irrevocable.

This left the East Range Site as the best alternate site to evaluate under the Minnesota Power Plant Siting Act process. The rationale for utilizing the East Range Site as the alternate to the West Range Site included the following:

- IRRRB had secured through negotiation in the LTV bankruptcy proceeding (LTV was the original landowner of property now occupied by Cliffs-Erie) an option to acquire land on LTV property near East Range. In a June 15, 2004 letter to U.S. Secretary of Energy Spencer Abraham, the Commissioner of IRRRB indicated that the agency would convey its option to Excelsior in support of the Mesaba Energy Project.
- Adequate make-up water appeared to exist in local mine pits and other surface waters (Colby Lake and Whitewater Reservoir) in amounts sufficient to support Phase I and Phase II facilities.
- The closest residential neighbors were more than 0.5 miles from the site's closest boundary.
- The site provided ready access to infrastructure needed to support plant operations.

The East Range Site was considered to be less suitable than the West Range Site for the following reasons:

- The generator outlet HVTL facilities were longer.
- The longer HVTL corridors dictated the use of two separate corridors to satisfy reliability requirements, resulting in additional line losses over the increased distance.
- The site was within the Lake Superior Basin watershed and subject to regulations implementing the Great Lakes Initiative.
- The Hoyt Lakes POTW would have required an expansion to accommodate discharges of cooling tower blowdown.
- Only one rail service provider appeared to be feasible, and the potential use of a rail-connected Lake Superior port appeared costly and uncertain from an engineering perspective.
- The site was closer to Class I areas, thereby creating the potential for increased adverse impacts on air quality related values, including a potential increase in visibility impacts.

2. Option Agreements Negotiated

Option agreements were pursued with owners of the West and East Range Sites in order to provide maximum access for conducting the environmental evaluations prescribed by the PPSA and for demonstrating site control required under MISO's LGIA process. The general location of the West and East Range Sites is shown in Figure A-8.

a. West Range Site

The first option agreement for the preferred West Range Site was executed on May 23, 2005 between RGGS Land & Minerals, Ltd., L.P. ("RGGS") and Excelsior Energy Inc. This option agreement has been renewed periodically since then to extend the duration of the agreement. The property for which Excelsior holds this option is illustrated in Figure A-9.

b. East Range Site

The first option agreement for the East Range Site was executed on June 20, 2007 between Cliffs Erie, LLC and Excelsior Energy Inc. The property optioned by Excelsior via the agreement is illustrated in Figure A-10.

The option agreement had provisions for two, two year extensions, the agreement terminating in June 2013 as long as the extension payments were made on a timely basis. Excelsior made the required payment to extend the option through June 2011, but elected to let the option lapse thereafter given the MPUC's issuance of the Site Permit and HVTL/Natural Gas Pipeline Route Permits for the preferred West Range Site.

Figure A-8. General Location of West and East Range Sites

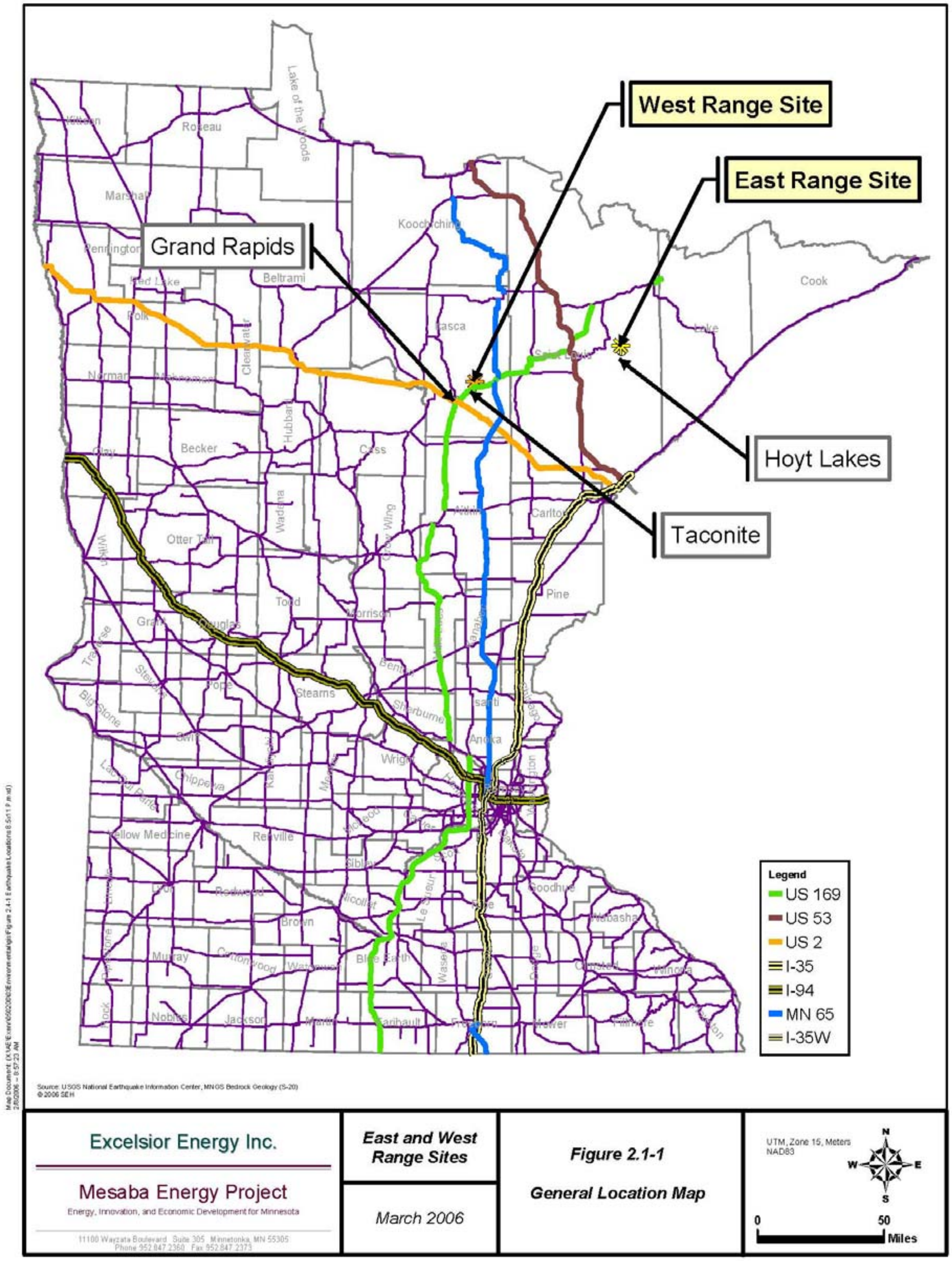


Figure A-9. Property Optioned from RGGS for West Range Site

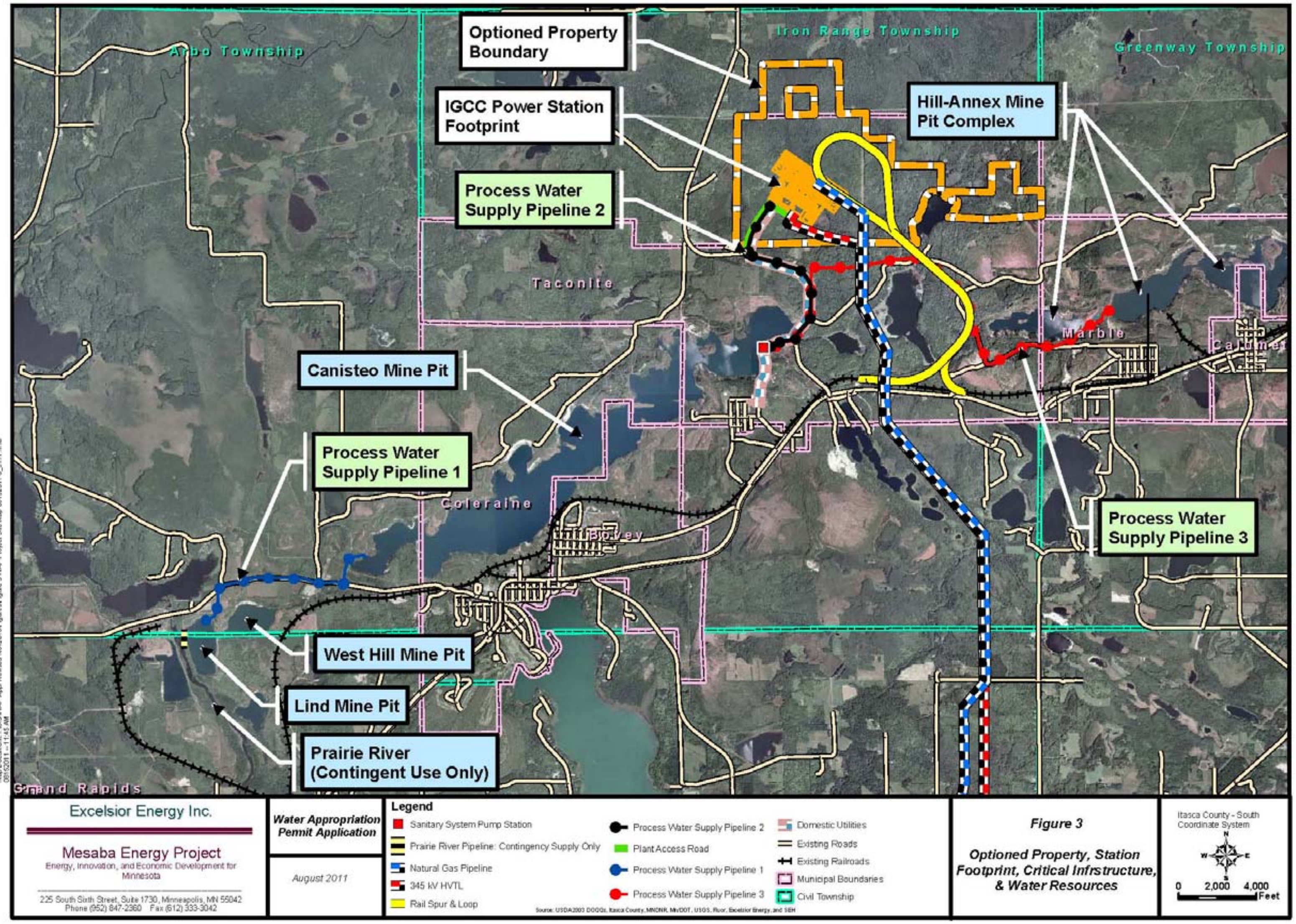
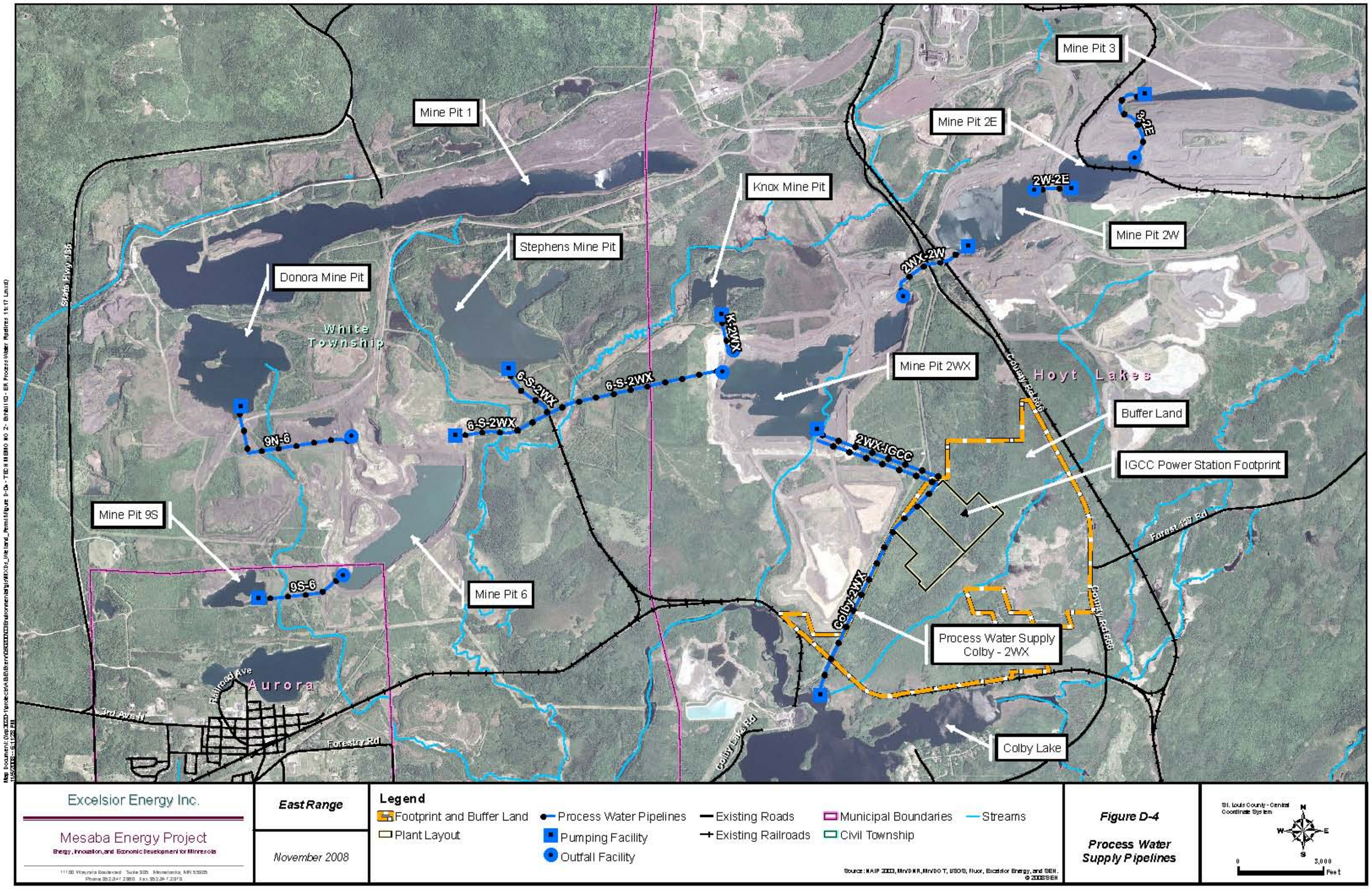


Figure A-10. Property Optioned from Cliffs for East Range Site



B. ENVIRONMENTAL SITE LICENSING

1. *BACKGROUND REGULATORY REVIEW REQUIREMENTS & PROCESSES*

Excelsior was responsible for conducting all activities necessary to prepare and submit all major state and federal preconstruction permits. Excelsior was also responsible for supporting the environmental review processes prescribed under the Minnesota Environmental Policy Act ("MEPA"),[28] and, under the terms of the DOE Cooperative Agreement with MEP-I, for data collection and analysis in support of the DOE's responsibilities under the National Environmental Policy Act ("NEPA").[29]

a. Applicable Statutes/Rules/Orders

The list of potentially applicable statutes, rules and/or orders that was considered by the project is reproduced in Table B-1. This table has been adapted from Chapter 6 of Volume 1 of the Project's FEIS to help differentiate major pre-construction permits and precursor regulatory requirements from construction permits that would be obtained only after it is determined the source is designed to meet applicable federal rules and/or other major pre-construction requirements.

Regulatory mandates that are associated with processes that have issuance of a pre-construction permit as their direct endpoint are identified with a "Y" under the column in the table labeled "Pre-Construction Permit (Y/N)". However, not all regulatory mandates requiring acquisition of a permit are applicable to the Project. The Project must only obtain preconstruction permits for those mandates that are also marked with a "Y" in the column labeled "Applicable to MEP (Y/N)."

Although a regulatory mandate may not require the Project to obtain a pre-construction permit, the Project may still be subject to a formal pre-construction environmental evaluation process that confirms whether the action under consideration is consistent with applicable directives. Actions meeting this description are marked with an "N" under the column labeled "Pre-Construction Permit (Y/N)" and with a "Y" under the column labeled "Applicable to MEP (Y/N)". In the case of actions to be taken by the federal government, the environmental review process under which such evaluations are conducted is dictated by the NEPA; such evaluations in the case of actions to be taken by the state of Minnesota, the environmental review procedures are dictated by the MEPA.[30]

Construction permits are identified in Table B-1 with a "Y" in the column labeled "Construction Permit (Y/N)". Applications for construction permits generally require the highly specific information developed as part of front end engineering and design ("FEED") processes and as a result, cannot be pursued prior to initiation of FEED.

Table B-1 does not include treaties between the federal government and Native American Indian tribes. Although such treaties represent inviolable contracts between these parties, they are addressed – where applicable – within the consultation processes prescribed under the National Historic Preservation Act ("NHPA").[31]

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[28] See Laws of Minnesota1973, chapter 412, Section 1 (https://www.revisor.mn.gov/data/revisor/law/1973/0/1973-412.pdf).
[29] See Pub. L. 91–190, 42 **U.S.C.** 4321 *et seq.*
[30] See Minn. Stat. 116D.01 and Minn. R. 4410.0300, Subp. 1.
[31] See 16 U.S.C. § 470a(d)(1)(C).

Table B-1. Regulatory and Permit Requirements

Statute, Regulation, Order	Citation	Pre-Construction Permit (Y/N)	Applicable to MEP (Y/N)	Construction Permit (Y/N)	Comment(s)*	Status
Acid Rain Permit	40 **CFR** Part 72	N	See comment	N	Application from affected source must be filed 24 months prior to commencing operation of a fossil-fuel-fired combustion device.	Expectation is to file Acid Rain Permit application after FEED is complete but before financial close, the timing of which has not been decided.
American Indian Religious Freedom Act of 1978	42 **USC** 1996	N	Y	N	NEPA-related review process. No sacred locations have been identified to date on the Project site or on land associated with its infrastructure. Further, Project operations will not interfere with access to such locations, use and possession of sacred objects, nor the freedom to worship through ceremonials and traditional rites.	Results of cultural resource investigations to-date are addressed in FEIS. DOE and Excelsior have drafted a Programmatic Agreement ("PA") having exhibits detailing plans for historic property surveys, historic property treatment, and inadvertent discoveries. The DOE's ROD will be contingent upon satisfactory completion of the PA signed – at a minimum - by DOE, Excelsior, the ACHP, and the Minnesota SHPO.
Antiquities Act	16 **USC** 431 *et seq.*	N	N	N	NEPA-related review process. No area of the Project site or its infrastructure will be located on lands owned or controlled by the Government of the United States.	Public lands in the vicinity of the Project Site are identified in FEIS.
Archaeological Resources Protection Act, as amended	16 **USC** 470aa *et seq.*	N	N	N	NEPA-related review process. No area of the Project site or its infrastructure will be located on public or Indian lands (as defined at § 470bb(3)and (4), respectively).	Public and Indian lands in the vicinity of the Project Site are identified in FEIS.
Clean Air Act, Titles I, IV, and V	40 **CFR** Parts 50 – 95	Y	See comment	NA	Title I of the Clean Air Act authorizes the PSD permitting program, Title IV the Acid Deposition Control program, and Title V the operating permit program. Although the Clean Air Act designates only the PSD program as a preconstruction permit requirement, Minnesota, by virtue of Minn. R. 7007.0800 ("Permit Content") requires that construction permits contain provisions assuring compliance with Title V requirements. Although Title IV is a permitting program for fossil-fuel fired steam generating units that requires a permit application to be filed no later than 24 months prior to commencing operation of the Project, such application only binds	CAA requirements pertaining to Title I and Tile V are to be filed as part of a complete Part 70 Permit Application to MPCA. A positive declaration regarding the applicant's filing of a timely Acid Deposition permit application must be included as part of his/her Minnesota's Part 70 permit application. Excelsior has submitted Part 70 permit applications to MPCA on November 21, 2011 and February 21, 2012, each such application having been returned as incomplete for minor concerns.

Statute, Regulation, Order	Citation	Pre-Construction Permit (Y/N)	Applicable to MEP (Y/N)	Construction Permit (Y/N)	Comment(s)*	Status
					the applicant to complying with the provisions controlling i) sulfur dioxide via a cap placed on nationwide emissions and ii) nitrogen oxide emission rates via limits placed on specific utility boiler types.	
Clean Water Act, Title IV	40 **CFR** Parts 104 – 140	Y	See comment	NA	Title IV of the CWA authorizes two pre-construction permit programs applicable to the Project. The first program, the NPDES program, regulates discharges from the Project to waters of the United States. The second preconstruction permit program regulates placement of dredged or fill material in such waters.	An NPDES permit application for the Project was filed on June 28, 2007. However, during the environmental review required under Minnesota's Power Plant Siting Act (Minn. Stat. 216E & Minn. R 7850.1900 Subp. 1C) Excelsior committed to implementing a zero liquid discharge system for purposes of eliminating all Project discharges associated with industrial activity. As a result, the content of the NPDES permit application will be scaled back to address only § 316(b) issues. A permit application to place dredged and/or fill material in waters of the U.S. was filed with the USACE on March 31, 2011. This application is awaiting a completeness review from USACE.
Determination of No Hazard to Air Navigation	14 **CFR** 77.9	N	Y	Y	The Federal Aviation Administration ("FAA") must be notified through use of FAA Form 7460–1 ("Notice of Proposed Construction or Alteration") of any construction greater than 200 feet above ground level and provide a determination of whether such construction represents an obstruction to aviation.	The 14 **CFR** 77.9 notification required of the Project (given its tallest construction is greater than 200 feet above ground level) shall be provided to the FAA after FEED, but before financial close. This timing is compliant with the 45 day deadline dictated in 14 **CFR** 77.7 for filing FAA Form 7460-1.
Emergency Planning and Community Right-to-Know Act of 1986	42 **USC** 1101 *et seq.*	N	Y	N	Notification is required of entities having present on-site extremely hazardous substances ("EHS") in excess of threshold planning quantities ("TPQ"). As well, under EPCRA, releases of hazardous chemicals in amounts exceeding reportable quantities (in any 24-hour period) as specified in 40 **CFR** 302 must be reported (as soon as a person has knowledge of such release) to the National Response Center in accordance with § 302.6(a).	Notification must be made to the State Emergency Response Commission and the Local Emergency Planning Committee within 60 days of first accumulating an amount of an EHS in excess of the TPQ. Compliance with the provisions of 40 CFR Parts 302 and 355 (i.e., rules implementing the Comprehensive Environmental Response, Compensation and Liability Act ["CERCLA"] and EPCRA, respectively) will be required from the time of commencing construction on-site until such time as

Statute, Regulation, Order	Citation	Pre-Construction Permit (Y/N)	Applicable to MEP (Y/N)	Construction Permit (Y/N)	Comment(s)*	Status
						EHS and hazardous chemicals are no longer maintained thereon.
Endangered Species Act of 1973, as amended	16 **USC** 1536 *et seq.*	N	Y	N	NEPA-related review process. DOE's consultation with the USFWS covered the Canada lynx and gray wolf. No critical habitat for either species occurs on the Project site. USFWS concurred with DOE's determinations that i) the Project may affect, but is not likely to adversely affect the lynx and ii) increased traffic occurring as a result of the Project "will occur in areas where wolf are not likely resident..."	Consultation process with USFWS is documented in Volume 2, Appendix E of the Project's FEIS.
Exempt Wholesale Generator Status	15 **USC** 79z-5a(e)	Repealed by Pub. L. 109-58, title XII, § 1263, August 8, 2005, 119 Stat. 974.				
Farmland Protection Policy Act	7 **USC** 4201 *et seq.*	N	Y	N	NEPA related review process.	Farmland potentially affected by Project activities is addressed in Volume 1, Sections 3.4 and 4.4 of FEIS.
Fish and Wildlife Conservation Act of 1980	16 **USC** 2901 *et seq.*	N	Y	N	NEPA related review process.	Non-game fish and wildlife potentially affected by Project are addressed in Volume 1, Sections 3.8 and 4.8 of FEIS.
Fish and Wildlife Coordination Act	16 **USC** 661 *et seq.*	N	Y	N	NEPA related review process.	Coordination efforts with Department of Interior are documented in Volume 2, Appendix E and Volume 3 of Final EIS (Department of Interior's comments [i.e., Commenter 57] on Draft EIS and DOE's response thereto can be found on pp. 153-158 of Volume 3).
Migratory Bird Treaty Act, as amended	16 **USC** 703 *et seq.*	N	Y	N	NEPA-related review process.	Coordination efforts with Department of Interior are documented in Volume 2, Appendix E and Volume 3 of Final EIS (Department of Interior's comments [i.e., Commenter 57] on Draft EIS and DOE's response thereto can be found on pp. 153-158 of Volume 3).
National	42 **USC**	N	Y	N	The starting point for all state and federal pre-	Final EIS for the Project published November 2009 by

Statute, Regulation, Order	Citation	Pre-Construction Permit (Y/N)	Applicable to MEP (Y/N)	Construction Permit (Y/N)	Comment(s)*	Status
Environmental Policy Act (NEPA) of 1969	4321 *et seq.*				construction permitting processes associated with the Project is the analysis presented in DOE's detailed statement on (i) the environmental impacts of the Project, (ii) any adverse environmental effects which cannot be avoided should it be implemented, (iii) alternatives to it, (iv) the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity, and (v) any irreversible and irretrievable commitments of resources which would be involved in the Project should it be implemented.	U.S.DOE in cooperation with the Minnesota Department of Commerce. USACE (St. Paul District, Brainerd Office) and the USDA Forest Service (Superior National Forest, Laurentian District) have participated as cooperating agencies for the EIS.
National Historic Preservation Act of 1966	16 **USC** 470 *et seq.*	N	Y	N	NEPA-related review process.	Matters concerning the NHPA are addressed in Sections 1.8, 3.8, 4.8, and Table 5.3-1 of Final EIS. No historic properties are evident in studies conducted to-date on Project site. Additional field work is planned on Project routes prior to financial close, the timing of which has not been decided.
Native American Graves Protection and Repatriation Act of 1990	25 **USC** 3001	N	N	N	NEPA-related review process.	Project does not impact federal or tribal lands. However, consultation with tribes regarding inadvertent discoveries on Project site/routes is discussed in Section 1.8 of Final EIS. Finalization of ROD by DOE is contingent upon PA with a plan to deal with such inadvertent discoveries having been signed by the Minnesota State Historic Preservation Officer and the Advisory Council on Historic Preservation.
New Source Performance Standards (NSPS)	40 **CFR** Part 60	Y	Y	NA	See comments under Clean Air Act	
Noise Control Act of 1972, as amended	42 **USC** 4901 *et seq.*	N	Y	N	NEPA-related review process.	Noise impacts addressed in sections 3.8, 3.17, 3.18, 4.17, 4.18, 5.2 and 5.7 in Volume 1 of Final EIS. Tables 2.4-1, 5.1-2, and 5.3-1 in Volume 1 also address noise-related concerns.

Statute, Regulation, Order	Citation	Pre-Construction Permit (Y/N)	Applicable to MEP (Y/N)	Construction Permit (Y/N)	Comment(s)*	Status
Notice to the Federal Aviation Administration	14 **CFR** Part 77	N	Y	Y	See comments above related to "Determination of No Hazard to Air Navigation" and timing under which notice of construction is to be provided.	
Occupational Safety and Health Act (OSHA) of 1970, as amended	29 **USC** §651 *et seq.*	N	Y	N	The Project's commitments regarding construction/operational workplace standards and emergency response plans.	Compliance with OSHA standards discussed in Volume 1 of Final EIS in Sections 2.2.4.5, 3.17, 4.13.2.2, 4.13.3, 4.16.2.1, 4.16.2.2. Tables 2.4-1, 5.1-2, and 5.3-1 in Volume 1 also discuss compliance with OSHA standards.
Permanent Exemption for New Facilities	10 **CFR** Part 503	N	N	N	The Project is designed to use coal as a primary energy source.	No exemption from Fuel Use Act is required.
Pollution Prevention Act of 1990	42 **USC** 13101 *et seq*	N	Y	N	Provides definition of source reduction (also described as waste reduction) set forth in various Executive Orders identified below.	Source reduction & pollution prevention techniques pertinent to Project are addressed in Volume 1 of the Final EIS in Sections 2.2.3.6, 2.2.4.1, and 4.3.5.
Prevention of Significant Deterioration (PSD) Permit	40 **CFR** 52.21	Y	Y	NA	See comments under Clean Air Act.	
Resource Conservation and Recovery Act (RCRA) of 1976	40 **CFR** Parts 239 – 299	Y	See comment	N	Project will generate by-products that will be beneficially used (i.e., sulfur and slag). Hazardous waste that is to be disposed will not be stored on the Project site for longer than 90 days and be provided to a properly licensed waste hauler who transports it to a properly-licensed, RCRA-compliant hazardous waste treatment and/or disposal site. Solid wastes will be managed in accordance with provisions outlined in the more stringent of applicable state or federal rules. The Project will not require a permit to manage its wastes in the manner described.	Excelsior will analyze all of the solid wastes generated as a result of the Project's construction/operation to determine whether each exhibits characteristics of a hazardous waste (as defined at 40 **CFR** Part 261). Within 75 days after first generating hazardous waste, prior to any transportation, treatment, storage, or disposal of any hazardous waste, and prior to applying for a license under Minn, R. 7045.0240, a generator must apply for an identification number on forms provided by the commissioner. In the event a solid waste exhibits such characteristics, Solid wastes will be managed in accordance with Minn. R. chapter 7035.
Rivers and	33 **CFR**	Y	N	NA	Project will not require a Rivers and Harbor Act	Not applicable.

Statute, Regulation, Order	Citation	Pre-Construction Permit (Y/N)	Applicable to MEP (Y/N)	Construction Permit (Y/N)	Comment(s)*	Status
Harbor Act Permit	Part 322				permit. No dam or dike will be constructed across navigable waters. No structures will be constructed in or over navigable waters. No wharves, piers, bulkheads, or other such works that could interfere with harbor lines will be constructed as part of the Project. Project will not discharge refuse to navigable waters. No sea wall, bulkhead, jetty, dike, levee, wharf, pier, or other work built by the U.S will be constructed as part of the Project.	
Safe Drinking Water Act	42 **USC** 300 *et seq.*	N	N	NA	Project will obtain its drinking water from the City of Taconite and therefore will not be subject to the requirement of submitting complete plans and specifications for approval prior to initiating construction.	Not applicable.
Sales Tap Approval	18 **CFR** 157.211	N	See comment	N	Certificate holder Great Lakes Gas Transmission Limited Partnership is automatically authorized to construct delivery point for purposes of providing shipper (i.e., Project) given that the Project is not presently an end user being served by a local distribution company.	Automatic authorization will be scheduled at the time Shipper and Transporter execute a Transportation Service Agreement for firm Transportation Service under the applicable rate schedule in Great Lakes tariff.
Surface Mining Control and Reclamation Act of 1977	30 **CFR** Part 700 *et seq.*	N	N	N	Excelsior is not subject to Surface Mining Control and Reclamation Act.	
Executive Order 13514 - Federal Leadership in Environmental, Energy and Economic Performance		N	See comment		Executive orders...are directives or actions by the President...Executive orders are generally directed to, and govern actions by, Government officials and agencies. They usually affect private individuals only indirectly...(From: Staff of House Comm. On Government Operations, 85th Cong., 1st Sess., Executive Orders and Proclamations: A Study of a Use of Presidential Powers (Comm. Print 1957).	See comments and status notes provided below for Executive Order 13423.
Executive Order 13423 - Strengthening Federal Environmental, Energy,		N				See comments and status notes provided above for Pollution Prevention Act of 1999. Executive Order 13423 supersedes Executive Orders 13101 and 13148

Statute, Regulation, Order	Citation	Pre-Construction Permit (Y/N)	Applicable to MEP (Y/N)	Construction Permit (Y/N)	Comment(s)*	Status
and Transportation Management						(see below) by requiring that governmental agencies implement sustainable practices for (i) energy efficiency, greenhouse gas emissions avoidance or reduction, and petroleum products use reduction, (ii) renewable energy, including bioenergy, (iii) water conservation, (iv) acquisition, (v) pollution and waste prevention and recycling, (vi) reduction or hazardous chemicals, (vii) high performance construction, lease, operation, and maintenance of buildings, (viii) vehicle fleet management, and (ix) electronic equipment management. Section 5.3 in Volume 1 of the FEIS outlines mitigation measures that Excelsior will implement to minimize Project impacts.
Executive Order 11988, *Floodplain Management* Executive Order 11990, *Protection of Wetlands*		N				Section F2.4.1 in Appendix F2 in Volume 2 of the FEIS concludes that there would be no anticipated impacts to floodplains for the Project site with respect to the placement of the Mesaba IGCC Power Plant, the HVTL alternatives, the cooling tower blowdown pipelines, Segments 2 and 3 of the Process Water Supply Pipelines, potable water and sewer pipelines, or the transportation corridors because all structures would be situated outside the boundaries of any 100-year floodplain areas. Section F2.5.3 in Appendix F2 in Volume 2 of the Final EIS addresses efforts the Project has taken to minimize and/or avoid wetland impacts on the Project site; Section F2.5.6 confirms the actual extent of the wetland impacts on the Project site. Wetland areas on the Project site and impacts thereto are addressed in Sections 3.7.5 and 4.7.3, respectively.
Executive Order 12856, *Right-to-Know Laws and Pollution Prevention Requirements*		N				See comments and status notes provided above for the Emergency Planning and Community Right-to-Know Act of 1986.

Statute, Regulation, Order	Citation	Pre-Construction Permit (Y/N)	Applicable to MEP (Y/N)	Construction Permit (Y/N)	Comment(s)*	Status
Executive Order 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations*		N				Section 3.12.2.2 and 3.12.2.3 in Volume 1 of the FEIS identify the extent to which minority populations and low-income populations exist on the Project site and its corridors. The summary of impacts related to environmental justice concerns presented in Section 4.12.6 in Volume 1 of the FEIS confirms that no potential environmental justice are indicated relating to minority populations or low-income populations.
Executive Order 13007, *Indian Sacred Sites*		N				See comments and status notes provided above for the American Indian Religious Freedom Act of 1978, the Antiquities Act, and the Archaeological Resources Protection Act.
Executive Order 13112, *Invasive Species*		N				See comments and status notes provided above for NEPA, the Fish and Wildlife Conservation Act of 1980, the Endangered Species Act of 1973, and the Fish and Wildlife Coordination Act.
Executive Order 13175, *Consultation and Coordination with Indian Tribal Governments*		N				See comments and status notes provided above for the NHPA.
Executive Order 13186, *Responsibilities of Federal Agencies to Protect Migratory Birds*		N				See comments and status notes provided above for the Migratory Bird Treaty Act.
Executive Order 13101, *Greening the Government through Waste Prevention, Recycling, and Federal Acquisition*	Revoked; Replaced by Executive Order 13423 on January 24, 2007.					
Executive Order 13148, *Greening the Government through*	Revoked; Replaced by Executive Order 13423 on January 24, 2007.					

Statute, Regulation, Order	Citation	Pre-Construction Permit (Y/N)	Applicable to MEP (Y/N)	Construction Permit (Y/N)	Comment(s)*	Status
Leadership in Environmental Management						
Aboveground Storage Tank Registration	Minn. R. ch. 7001 and 7151	N	Y	N	New above ground storage tanks (“AST”), not excluded from regulation under Minn R. 7151.1300, must be designed in accordance with applicable standards specified at Minn. R. 7151.2100 Subp. 2 and meet applicable state requirements for labeling (including providing emergency contact information), secondary containment, substance transfer safeguards, and corrosion/overfill protection.	Excelsior will not store liquids in outdoor above ground storage tanks in excess of 1 million gallons and are therefore not subject to and will not be subject to obtaining the permit under Minn. R. 7001.4200 – 7001.4300 required for “major facilities”. The MPCA requires an owner of an AST to notify them via Form “t-a1-20”) within 30 days after bringing a tank system(s) into use.
Access Permit	Minn. R. 8810.4400	N	Y	Y	No driveway is to be constructed from or to a trunk highway until such permit has been obtained and supplemented by those permits that may be required by local governing authorities.	The Project is expected to prepare a permit application(s) for driveway permits after FEED and before financial close. Submission of the application(s) to the Minnesota Department of Transportation will be done in accordance with the schedule developed as a part of FEED (i.e., sufficiently in advance of the need to access the Project site for purposes of initiating physical construction activities thereon).
Air Emissions Permit	Minn. R. ch. 7007	Y	Y	NA	See comments under Clean Air Act.	
Air Pollution Episodes Rule	Minn. R. 7009.1000 – 7009.1110	N	Y	N	This rule governs operation of emission facilities during air pollution episodes.	An episode emission reduction plan (“EERP”) is required for facilities having allowable emissions of greater than or equal to 250 tons per year of the pollutant causing the episode. The owner or operator of the emission facility must submit the EERP to the commissioner of the MPCA prior to commencing physical construction on the Project site. The EERP is subject to approval of the commissioner and must be revised and resubmitted within 30 days if disapproved.
Beneficial Use Rule	Minn. R. 7035.2860	**N**	**Y**	**N**	Until the time the MPCA renders a beneficial use determination, a material remains a solid waste until it is incorporated into a manufactured product or	Excelsior will submit any case-specific beneficial use determination after the generation of the waste material itself, i.e., after commencing physical construction of

Statute, Regulation, Order	Citation	Pre-Construction Permit (Y/N)	Applicable to MEP (Y/N)	Construction Permit (Y/N)	Comment(s)*	Status
					utilized in accordance with a standing or a case-specific beneficial use determination. Until the time such a regulatory exemption occurs, the material must be stored in compliance with Minn. R. 7035.2855 and managed as a solid waste in accordance with Minn. R. 7035.	the Project and operation has commenced.
Certificate of Need	Minn. R. ch. 7829, 7849, 7851, 7853, and 7855	Y	N	As an innovative energy project, the Project is exempt from the Certificate of Need requirement by virtue of Minn. Stat. 216B.1694		
Construction of Tunnels Under Highways Permit	Minn. R. 8810.3200 – 8810.3600	N	Y	Y	Utility construction and relocation on trunk highway rights-of-way shall not be commenced until an application for a permit for construction has been made and such permit granted.	The Project is expected to prepare a permit application(s) for constructing or relocating utilities after FEED and before financial close. Submission of the application to the Minnesota Department of Transportation will done in accordance with the schedule developed as a part of FEED (i.e., sufficiently in advance of the time the schedule calls for utility construction to begin). Where applicable, the application will be prepared in coordination with the City Manager of Taconite, Mn.
Cultural Resources Review	36 **CFR** Part 800	N	Y	N	See comments and status notes provided above for the National Historic Preservation Act of 1966.	
Drainage Permit	Minn. R. 8810.3200 – 8810.3600	N	Y	Y	The utility company shall obtain a work permit from the office of the assistant district engineer and prior to performing service and maintenance operations on noninterstate highways when such operations require opening and disturbing the surface of the right-of-way thereof.	The Project is expected to prepare a permit application(s) for service and maintenance activities after FEED and before financial close. Submission of the application to the office of the assistant district manager will done in accordance with the schedule developed as a part of FEED (i.e., sufficiently in advance of the time the schedule calls for utility construction to begin). Where applicable, the

Statute, Regulation, Order	Citation	Pre-Construction Permit (Y/N)	Applicable to MEP (Y/N)	Construction Permit (Y/N)	Comment(s)*	Status
						application will be prepared in coordination with the City Manager of Taconite, MN.
Easement Across State-Owned Land Managed by the MDNR	Minn. Stat. § 84.63 and § 84.631	N	Y	Y	Minn. Stat. § 84.631 requires a private person requesting an easement across state land under the MDNR commissioner's jurisdiction in order to access property owned by the person where there are no reasonable alternatives to obtain access to the property and where the exercise of the easement will not cause significant adverse environmental or natural resource management impacts.	The Project is expected to prepare a permit application(s) for easements across state lands under the MDNR's jurisdiction after FEED and before financial close. Submission of the application to the office of the assistant district manager will done in accordance with the schedule developed as a part of FEED (i.e., sufficiently in advance of the time the schedule calls for use of such easements.
Environmental Laboratory Certification	Minn. R. 4740.2010 – 4740.2120	N	N	NA	Although not required, the Project may apply for accreditation of its environmental testing facilities.	The application for accreditation of the Project's environmental testing laboratories is at the discretion of the Project's owner or operator.
Flammable Liquid Tanks Plan Review	Minn. Stat. § 299F	N	Y	N	The State Fire Code is applicable throughout the state and in all political subdivisions and municipalities therein. Each person who engages in the transportation of natural gas or hazardous liquids or who owns or operates natural gas or hazardous liquid pipeline facilities shall: (1) at all times after the date any applicable safety standard established under sections 299F.56 to 299F.641 takes effect comply with the requirements of such standard; (2) file and comply with a plan for operation and maintenance required by sections 299F.56 to 299F.641.	Excelsior will file the plan required under Minn. Stat. 299F.62 after the completion of FEED, but on or before the date of the Project's financial close, the timing of which has not been decided.
Hazardous Waste Generator License	Minn. R. 7045.0225	N	Y	N	See comments and status notes provided above for the Resource Conservation and Recovery Act of 1976.	
License to Cross Public Lands and	Minn. Stat. 84.415;	N	Y	Y	The commissioner of natural resources may grant licenses permitting passage over, under, or across any part of any school, university, internal improvement,	Excelsior will file the plan required under Minn. Stat. 299F.62 after the completion of FEED, but on or before the date of the Project's financial close, the timing of

Statute, Regulation, Order	Citation	Pre-Construction Permit (Y/N)	Applicable to MEP (Y/N)	Construction Permit (Y/N)	Comment(s)*	Status
Waters	Minn. R. ch. 6135				swamp, tax-forfeited or other land or public water under the control of the commissioner of natural resources, of telephone, telegraph, and electric power lines, cables or conduits, underground or otherwise, or mains or pipe lines for gas, liquids, or solids in suspension.	which has not been decided.
Minnesota Building Code	Minn. R. Chapters 1305, 1306, 1315, 1346, 715, 5225, 5230, 7510, and 7512	N	Y		Construction codes which must be incorporated into the all aspects of the Project's design.	Excelsior will prepare applications for building permits after FEED, but on or before the Project's financial close. Submission of such applications shall follow financial close, the timing of which has not been decided.
Minnesota Endangered Species Law	Minn. Stat. 84.0895; Minn. R. ch. 6134	N	Y	N	MEPA-related review process.	Sections 3.8.3.2, 4.8.7.2, and Table 5.3-1 in Volume 1 of the Final EIS and Appendices D5 and E2 address issues related to the endangered species on or in the vicinity of the Project site.
Minnesota Standards for Stationary Sources	Minn. R. 7011.0150, 7011.0715, and 7011.2300	Y	Y	N	See comments and status notes provided above for Clean Air Act.	
NPDES General Construction Stormwater	40 **CFR** 122.26 Minn. R. 7001.103	N	Y		Permit No. MN R 100001 (expires August 1, 2013) provides coverage for entities discharging storm water in the process of conducting construction activities disturbing a total land area greater than or	The SWPP governing construction activities will be prepared as a part of FEED. The SWPP and permit application required under Minn. R. 7090.2010 will be prepared prior to financial close of the Project and

Statute, Regulation, Order	Citation	Pre-Construction Permit (Y/N)	Applicable to MEP (Y/N)	Construction Permit (Y/N)	Comment(s)*	Status
Permit	5				equal to50 acres. Such entities are required to develop a storm water prevention plan ("SWPP") meeting design specifications elaborated in Part III of MN R 100001 as part of their permit application. Construction activity is prohibited until permit coverage becomes effective.	submitted thereafter a minimum of thirty days prior to the planned date for commencing construction activity.
NPDES General Industrial Stormwater Permit	Minn. R. 7001.1035	N			Even though the Project will be designed to collect all storm water associated with industrial activity, it will store coal and other materials outdoors that will be exposed to precipitation. This precludes the Project from meeting the requirements necessary to provide the "no-exposure" certification specified at Minn. R. 7090.3080 (and 40 CFR § 122.26(g)(4)) and avoiding the need to obtain the general permit (i.e., Permit No. MN R050000) or an individual NPDES Permit authorizing storm water discharges.	The SWPP governing the Project's operations will be prepared as a part of FEED. The permit application and SWPP required under Minn. R. 7090.3000 and 7090.3010, respectively will be prepared prior to financial close of the Project and submitted thereafter a minimum of 180 days prior to the planned date for commencing construction activity. If the MPCA determines that storm water associated with industrial activity on the project site must be handled in an individual NPDES/SDS Permit, submission will be as described below for NPDES/SDS Permit.
NPDES/SDS Permit	Minn. R. 7001.0020	Y	See comment	NA	The Project is being designed to employ ZLD technology to eliminate all discharges of process water and cooling tower blowdown. To eliminate issues associated with discharges of storm water associated with industrial activity, the Project's SWPP will demonstrate that all storm water associated with the 100-year, 24-hour precipitation event (~5.3 inches) will be routed to the ZLD system for purposes of reducing water appropriation requirements. In accordance with Minn. R. 7001.1000, issuance of an NPDES Permit shall satisfy the obligation of obtaining a separate SDS Permit.	The NPDES Permit application will be submitted prior to FEED and financial close and will include commitments and general design information demonstrating the viability of the ZLD system to handle process water, cooling tower blowdown and stormwater associated with industrial activity on the Project site. If the permit is issued prior to completing FEED, it will contain provisions therein for the MPCA to approve the specific ZLD system design and SWPP developed during FEED prior to initiating any construction activity.
Open Burning Permit	Minn. Stat. § 88.16	N	Y	N	Written permission to conduct open burning is required by the authorized fire warden.	Requests to conduct open burning will be provided to the necessary authorities as they are required following commencement of physical construction on the Project

Statute, Regulation, Order	Citation	Pre-Construction Permit (Y/N)	Applicable to MEP (Y/N)	Construction Permit (Y/N)	Comment(s)*	Status
						site or other properties upon which Project-related activities are to occur.
Part 70 Operating Permit	Minn. R. 7007.0200 and 7007.0250	Y	Y	NA	See comments and status notes provided above for Clean Air Act.	
Public Water Supply Plan Review	Minn. R. ch. 4720	N	See comments	Y	No system of water supply or system for the on-site disposal of sewage where such system is for public use or for the use of any considerable number of persons, or in case any such system affects or tends to affect the public health in any manner, shall be installed by any public agency or by any person or corporation, nor shall any such existing system be materially altered or extended, until complete plans and specifications for the installation, alteration, or extension, together with such information as the commissioner of health may require, have been submitted in duplicate and approved by the commissioner of health insofar as any features thereof affect or tend to affect the public health, and no construction shall take place except in accordance with the approved plans.	Excelsior and the engineer conducting FEED will work with the City of Taconite during FEED in preparing plans and specifications required for submission to Minnesota Department of Health. The necessary application materials will be finalized on or before financial close and submitted sometime thereafter in accordance with the construction schedule prepared during FEED.
Public Waters Work Permit (Protected Waters Permit)	Minn. R. 6115.0160 – 6115.0280	N	NA	Y	Permits are required for any activity affecting the course, current, or cross-section of public waters unless specifically exempted.	Provided the two natural gas pipeline crossings of the Swan River are directionally drilled underneath thereof as planned, this construction permit will not be required as no change in course, current, or cross section of the Swan River will occur.
Railroad Grade Crossing Operating License	Minn. R. 8830.2150 and 8830.9991	N	Y	Y	New grade crossings and relocations of existing grade crossings must be designed in accordance with the American Association of State Highway and Transportation Officials ("AASHATO") design manual and be approved by the commissioner of the	When the road authority and the rail carrier agree upon the establishment of a new grade crossing or the relocation of an existing grade crossing, an application must be filed with the commissioner containing the information in Minn. R. 8830.2700 Subp. 5. This

Statute, Regulation, Order	Citation	Pre-Construction Permit (Y/N)	Applicable to MEP (Y/N)	Construction Permit (Y/N)	Comment(s)*	Status
					DOT. When a new railroad crossing is constructed, the rail carrier must assign a crossing inventory number to the crossing before the crossing may be opened to traffic.	application will be completed following FEED and on or before the Project's financial close. Excelsior will require the rail carrier to complete and submit the USDOT-AAR (Association of American Railroads) crossing inventory form for each new crossing (or transmit the required information in any other format approved by the Federal Railroad Administration) subsequent to financial close.
Route Permit for High Voltage Transmission Lines ("HVTL")	Minn. R. ch. 7850	Y	Y		Route Permit application for HVTL filed with Minnesota Public Utilities Commission on June 16, 2006 as part of Mesaba Energy Project's Joint Permit Application.	Route Permit issued March 12, 2010 for West Range site.
Route Permit For Natural Gas Pipeline	Minn. R. ch. 7852	Y	Y		Route Permit application for natural gas pipeline filed with Minnesota Public Utilities Commission on June 16, 2006 as part of Mesaba Energy Project's Joint Permit Application.	Route Permit issued March 12, 2010 for West Range site.
Sanitary Sewer Extension Permit	Minn. R. 7001.0020	N	Y	Y	Excelsior will work in cooperation with the city of Taconite during FEED to complete the city's permit application required under Minn. R. 7001.0020.	The permit application required by Minn. R. 7001.0020 to extend the city of Taconite's sewer system to serve the Project will be submitted to the MPCA prior to the Project's financial close.
Site Permit for Large Electric Generating Power Plant	Minn. R. ch. 7850	Y	Y		Site Permit application filed with Minnesota Public Utilities Commission on June 16, 2006 as part of Mesaba Energy Project's Joint Permit Application.	Site Permit issued March 12, 2010 for West Range site.
Solid Waste Storage Permit	Minn. R. ch. 7001 and 7035	Y	N	Y	See comments and status notes provided above for Resource Conservation and Recovery Act (RCRA) of 1976.	
Underground Storage Tank Registration	Minn. R. 7150.0090	N	Y	Y	Owners and operators of underground storage tanks ("UST") with a capacity exceeding 110 gallons must provide notifications and certifications to the MPCA in accordance with Minn. R. 7150.0090.	During FEED USTs to be used on the Project site will be identified, designed and constructed in accordance with Minn. R. 7150.0205. The notifications and certifications will be prepared following FEED and on

Statute, Regulation, Order	Citation	Pre-Construction Permit (Y/N)	Applicable to MEP (Y/N)	Construction Permit (Y/N)	Comment(s)*	Status
						or before financial close of the Project. The notifications will be submitted to MPCA in accordance with the timetables specified in Minn. R. 7150.0090.
Utility Permit on Trunk Highway ROW	Minn. R. 8810.3100 – 8810.3600	N	Y	Y	See comments and status notes provided above for Construction of Tunnels Under Highways Permit and Drainage Permit.	
Water Appropriation Permit – Long Term (Exceeding two years)	Minn. R. 6115.0600 – 6115.0810, 6115.0010	Y	Y		Water Appropriation Permit Applications originally filed with the MDNR on June 29, 2006 for withdrawals of water from Canisteo Mine Pit Complex, Hill-Annex Mine Pit Complex, Lind Mine Pit, and the Prairie River. Final applications refiled with MDNR on August 18, 2011.	Water appropriation permits issued March 9, 2012 for withdrawals from Canisteo Mine Pit Complex, Hill-Annex Mine Pit Complex, and Lind Mine Pit in amounts not to exceed 5,256 million gallons per year, 2,628 million gallons per year, and 2,628 million gallons per year, respectively.
Water Appropriation Permit – Temporary (1-2 year maximum)	Minn. R. 6115.0600 – 6115.0810, 6115.0010	NA	NA	NA	This permit is not required because Excelsior has obtained all approvals required for water appropriation for a time period exceeding two years.	
Water Supply Management	Minn. Stat. 103G.265, Subd. 3	Y	Y		A water use permit or a plan that requires a permit or the commissioner's approval, involving a consumptive use of more than 2,000,000 gallons per day average in a 30-day period, may not be granted or approved until: (1) a determination is made by the commissioner that the water remaining in the basin of origin will be adequate to meet the basin's water resources needs during the specified life of the consumptive use; and (2) approval of the consumptive use is given by the legislature.	Approval for the Project's consumptive use of water in excess of 2 million gallons per day average in a 30-day period granted by State legislature on May 22, 2006 and signed by Governor Pawlenty on June 1, 2006 (Laws of Minnesota 2006, Chapter 281, Article 5, Section 3).

*All references to Project's potential environmental impacts are made in reference to the site permitted under Minnesota's PPSA (i.e., the West Range site).

b. Applicable Regulatory Processes

i. Environmental Review under NEPA/MEPA/PPSA

Title 40 of the Code of Federal Regulations ("CFR"), Parts 1500 through 1508 provide regulations applicable to and binding on DOE for implementing the procedural provisions of NEPA (except where compliance would be inconsistent with other statutory requirements).[32] NEPA's procedural requirements apply to all DOE decisions on major federal actions, including, among other things, projects and programs entirely or partly financed, assisted, conducted, regulated, or approved by the Department.[33] Therefore, the Project, as a recipient of a financial assistance award pursuant to 10 CFR 600, under the DOE's CCPI Round II program, fell under the umbrella of NEPA and was subject to the Act's procedural requirements for environmental review.

However, major federal actions also include activities that are regulated by or that must be approved via a permit or other regulatory decision issued by a federal agency.[34] On the second page of Table B-1, one other such action by a federal agency was identified. Construction of the Project required greater than 1/2 acre of existing wetlands (waters of the United States as defined in the Clean Water Act) to be filled. Therefore, it was necessary to obtain an individual Section 404 permit issued by the USACE. Such action by the USACE mandated this agency's compliance with NEPA.

DOE and the USACE addressed their independent NEPA compliance requirements by the agreement that DOE would serve as the lead federal agency for preparation of the EIS and the USACE would serve as a cooperating agency, ultimately adopting the Final EIS and using it as part of USACE's permit evaluation process.[35]

In 1973 the State of Minnesota adopted its own version of NEPA (called the Minnesota Environmental Policy Act or "MEPA" for short) creating a state law structure for environmental review.[36] Although the environmental review procedures of MEPA are implemented by Minn. R. chapter 4410.0200 through 4410.6500,[37] the siting and permitting of both LEPGPs and HVTLs in Minnesota is governed by rules implementing the PPSA. Such rules, implemented by the MPUC and promulgated at Minn. R. chapter 7850,[38] require preparation of an EIS by the Minnesota Department of Commerce ("DOC") in accordance with provisions practically identical to those imposed under NEPA and MEPA. Figure B-1, Figure B-2, and Figure B-3 illustrate the pertinent steps in the environmental review processes under the NEPA, MEPA and PPSA, respectively.

In light of the duplicative state and federal requirements for preparing the Project's EIS, the DOE and the DOC agreed to prepare it as a joint federal and state document.[39]

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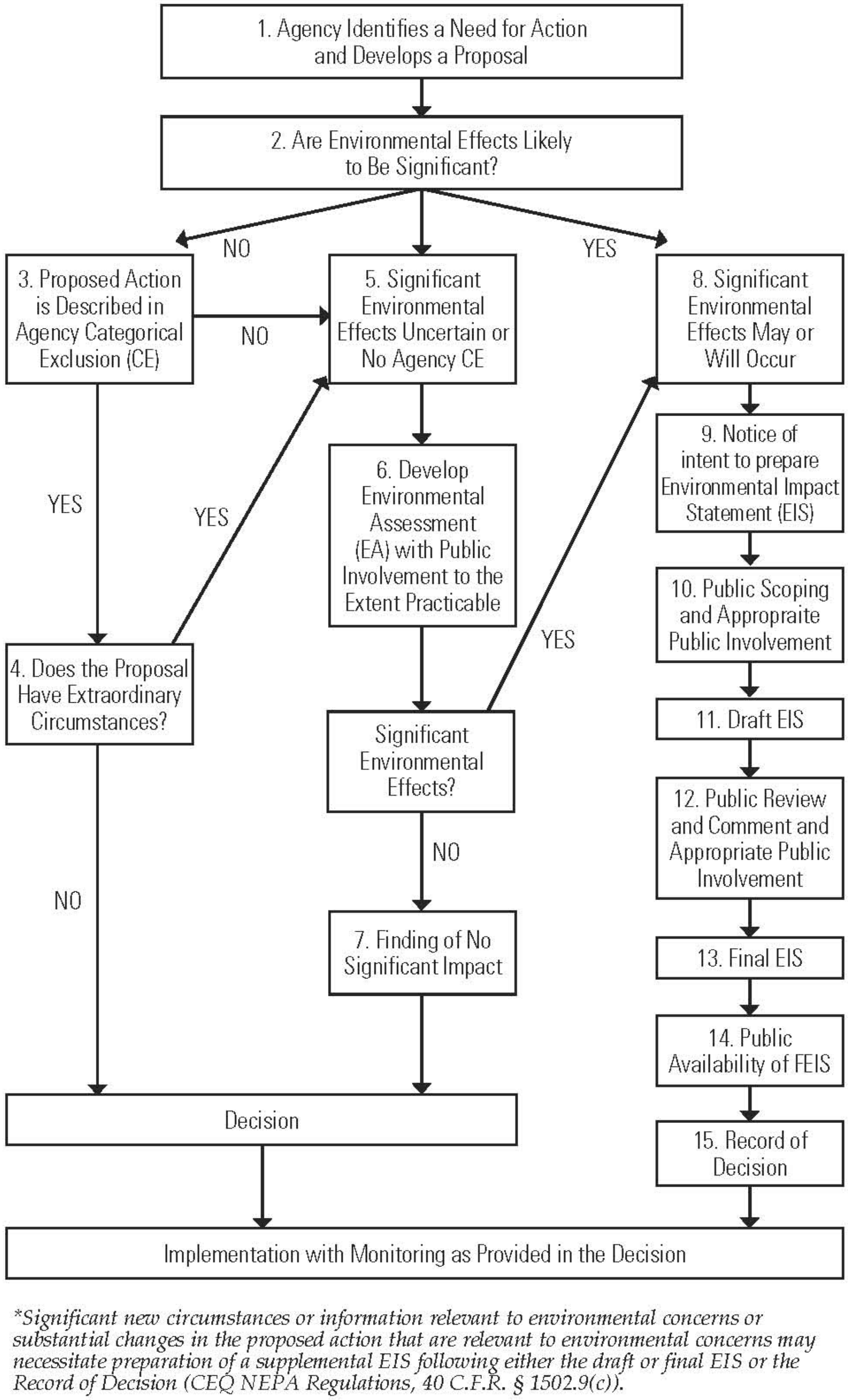
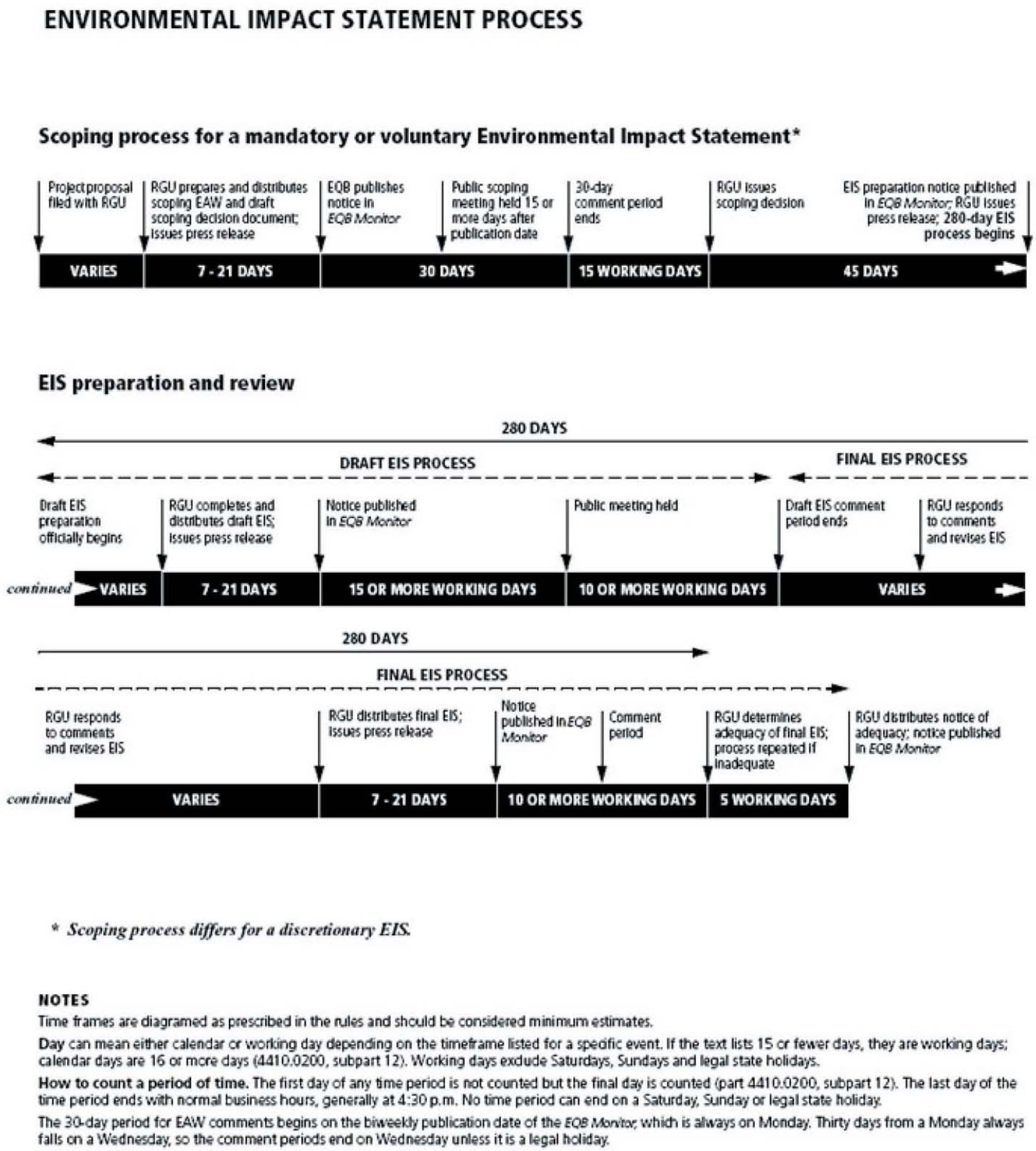
[32] See 40 **CFR** § 1500.3
[33] CEQ NEPA Regulations, 40 **CFR** § 1508.18.
[34] Id.
[35] See Final Environmental Impact Statement, Mesaba Energy Project, Volume 1, pp 1-9 and 1-10.
[36] From "Reforming Environmental Review", **Bench & Bar of Minnesota**, Volume **67**, No. 1, January 2010. See http://mnbenchbar.com/2010/01/reforming-environmental-review/.
[37] See Minn. R. 4410.0300 Subp.1.
[38] Minn R. 4410.4400 Subp. 3 stipulates that for construction of an LEPGP at the permitting stage, environmental review shall be conducted according to Minn. R. 7850.1000 through 7850.5600.
[39] See Final Environmental Impact Statement, Mesaba Energy Project, Volume 1, pp S-1 and 1-16.

Figure B-1. The NEPA Process[40]



[40] Taken from "A Citizen's Guide to the NEPA: Having Your Voice Heard," Council on Environmental Quality, Executive Office of the President, December 2007.

Figure B-2. The MEPA Process[41]



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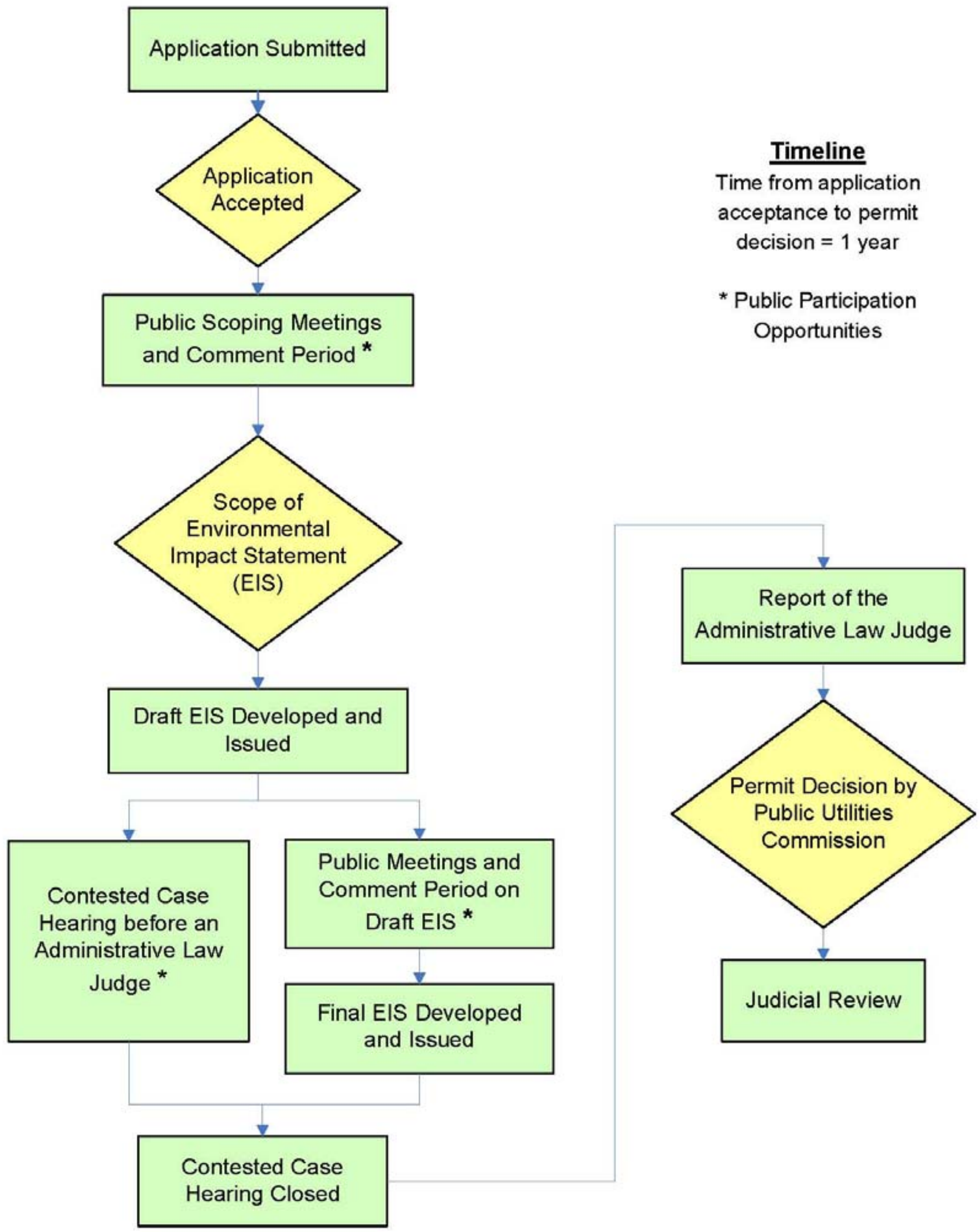
[41] Taken from "A Citizen's Guide: An Introduction to Environmental Review", January 18, 2006, prepared by Minnesota Environmental Quality Board. See http://www.eqb.state.mn.us/documents/Introduction.pdf, page 7.

Figure B-3. Full Permitting Process Under PPSA (Minn. R. Chapter 7850)[42]



[42] Taken from "HVTL Routing and Power Plant Siting, Full Permitting Process, Minnesota Rules 7850," prepared by Minnesota Department of Commerce. See http://mn.gov/commerce/energyfacilities/documents/Full%20Process,%20EIS%20-%20Color%20Flowchart%207850%20DOC.pdf

ii. Federal and State Pre-Construction Permitting/Approval Processes

The pre-construction permitting requirements applicable to the Project (those requirements marked in Table B-1 with a "Y" in the column labeled "Pre-Construction Permit" and with a "Y" in the column labeled "Apply to MEP") have been excerpted to create Table B-2. The specific steps required to obtain each of the permits/approvals identified in Table B-2 are cited in the column marked "Permitting/Approval Process."

Table B-2. Major Pre-construction Permits/Approvals Required for the Project

Pre-Construction Permit Authority	Pre-Construction Permit/Approval	Issuing Agency
Power Plant Siting Act	Site Permit for Large Electric Generating Power Plant	MPUC
	Route Permit for High Voltage Transmission Lines ("HVTL")	
	Route Permit For Natural Gas Pipeline	
Clean Air Act, Titles I, IV, and V	Part 70 Operating Permit	MPCA
Clean Water Act, Title IV	Dredge/Fill Permit (CWA Section 404)	USACE
	National Pollutant Discharge Elimination System Permit* (CWA Sections 316(b) and 402)	MPCA
Minnesota Regulatory Water Policy	Water Appropriation Permit – Long Term (Exceeding two years)	MDNR
Laws of Minnesota	Consumptive Water Use In Excess of 2 million gallons per day on 30-day average	Minnesota Legislature

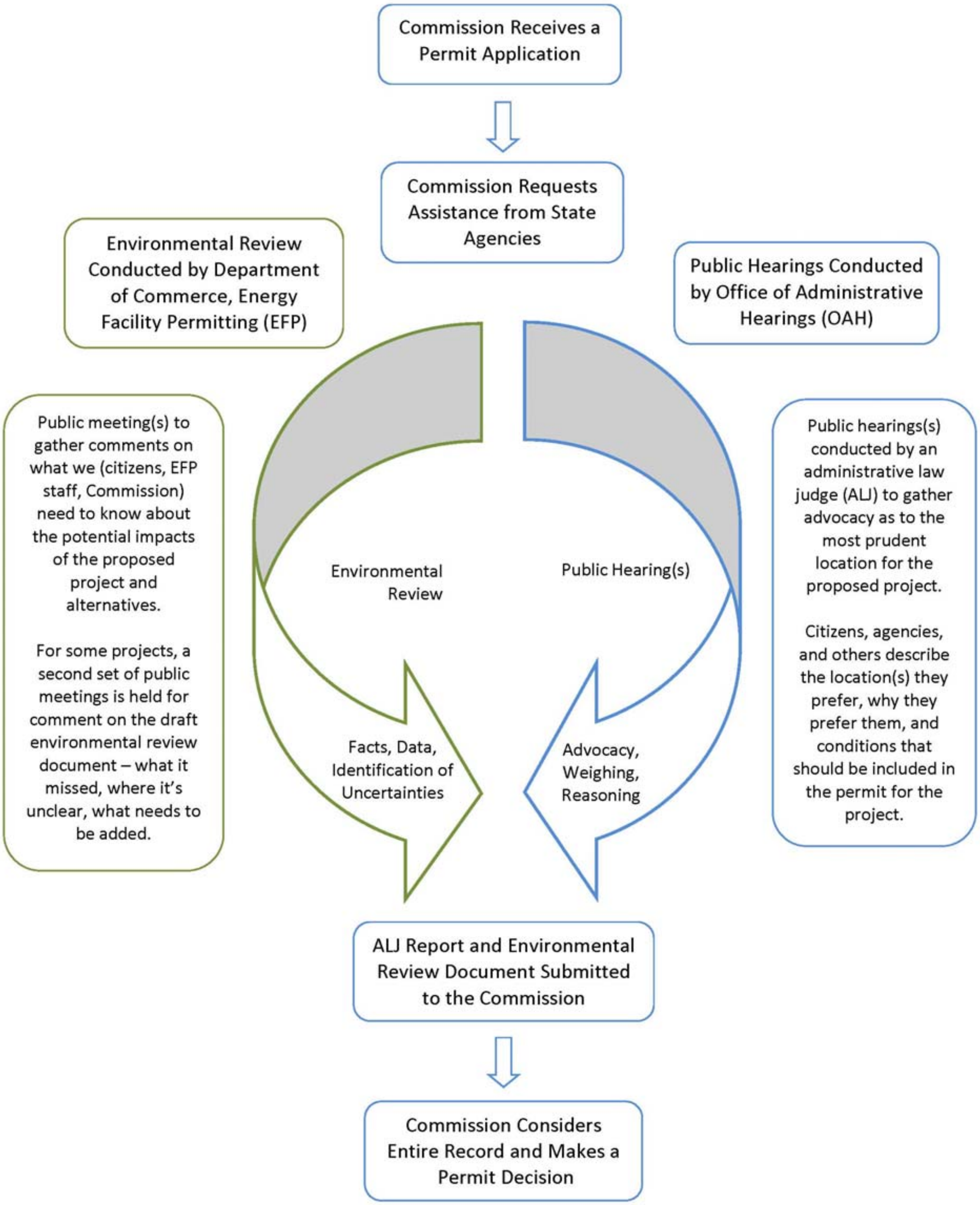
*Application to MPCA regarding NPDES Permit will be to withdraw existing application submitted June 28, 2006 and clarify how ZLD system will be used to eliminate i) all process water and cooling tower blowdown discharges and ii) stormwater associated with industrial activity. CWA Section 316(b) compliance is to be attained through use of screening and control of face velocity across the screens.

2. PPSA/NEPA/MEPA

From a practical perspective, all pre-construction permitting/approval processes in Minnesota begin during the environmental review stage, as all state agencies potentially having the responsibility to issue a permit(s) are required to review and provide comments, if appropriate, on the draft EIS prepared under auspice of the PPSA. With regard to such involvement, Figure B-4 expands on Figure B-3 with respect to the opportunities provided under the PPSA for exchanging information between DOC Energy Facility Permitting staff, other federal/state agencies, and the public.

Relevant federal milestones associated with DOE's participation in the Project are presented in Figure B-5 using a modified version of the NEPA process chart provided in Figure B-3 (steps shown in Figure B-3 that were not undertaken as part of the Project have been removed in Figure B-5). A record of decision ("ROD") was not published by DOE following the release of the Final EIS. Therefore, as part of its permitting process, the USACE will be required to fulfill this responsibility. Relevant state milestones associated with fulfilling the PPSA are presented in Figure B-6.

Figure B-4. MPUC Energy Facility Permitting Process – Who Does What in Routing and Siting[43]



[43] Taken from "Siting and Routing of Energy Facilities, How to Participate," Minnesota Department of Commerce Energy website at http://mn.gov/commerce/energyfacilities/#ui-tabs-6.

Figure B-5. Actual Project Milestones Achieved in the Federal NEPA Process

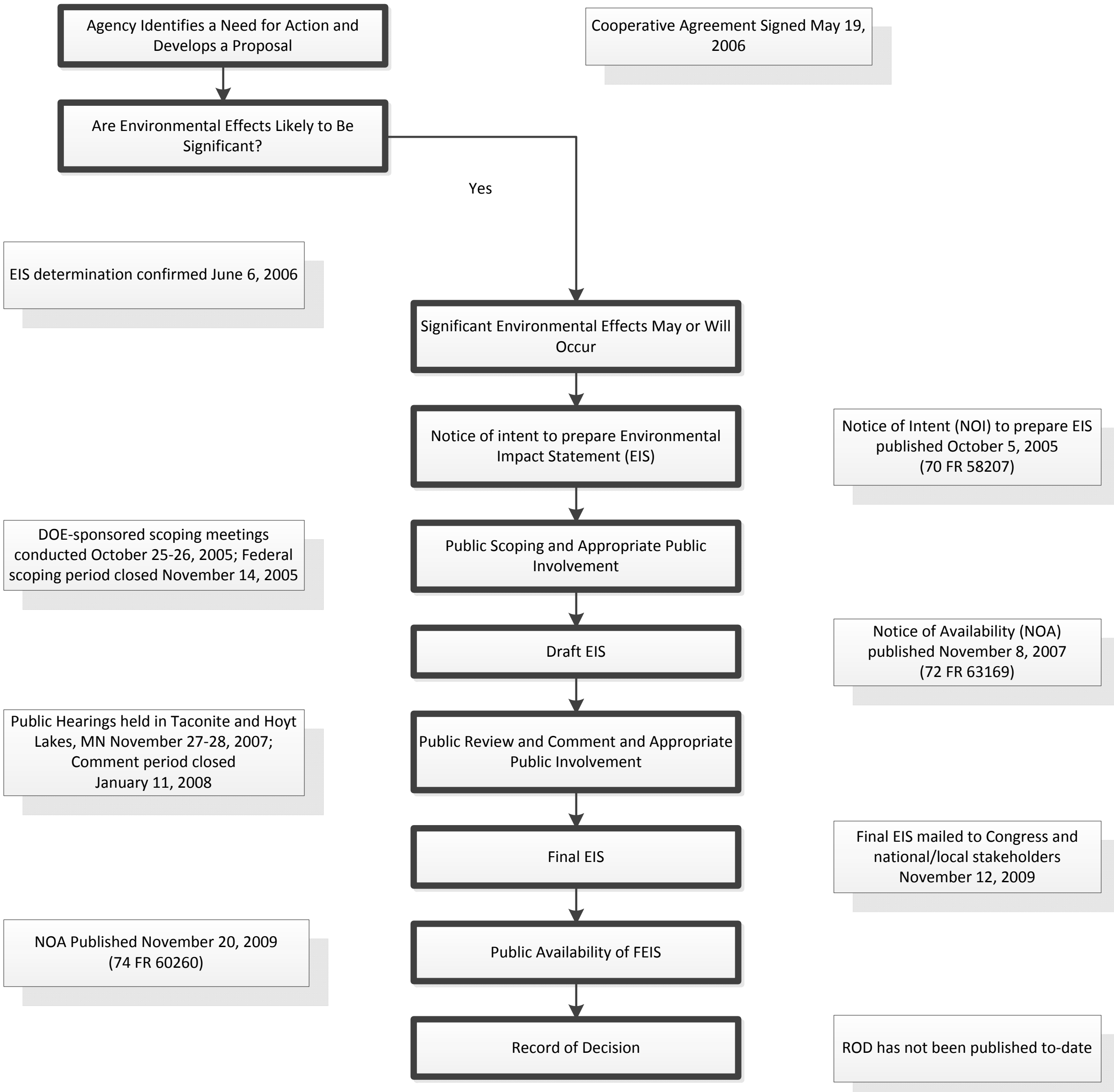
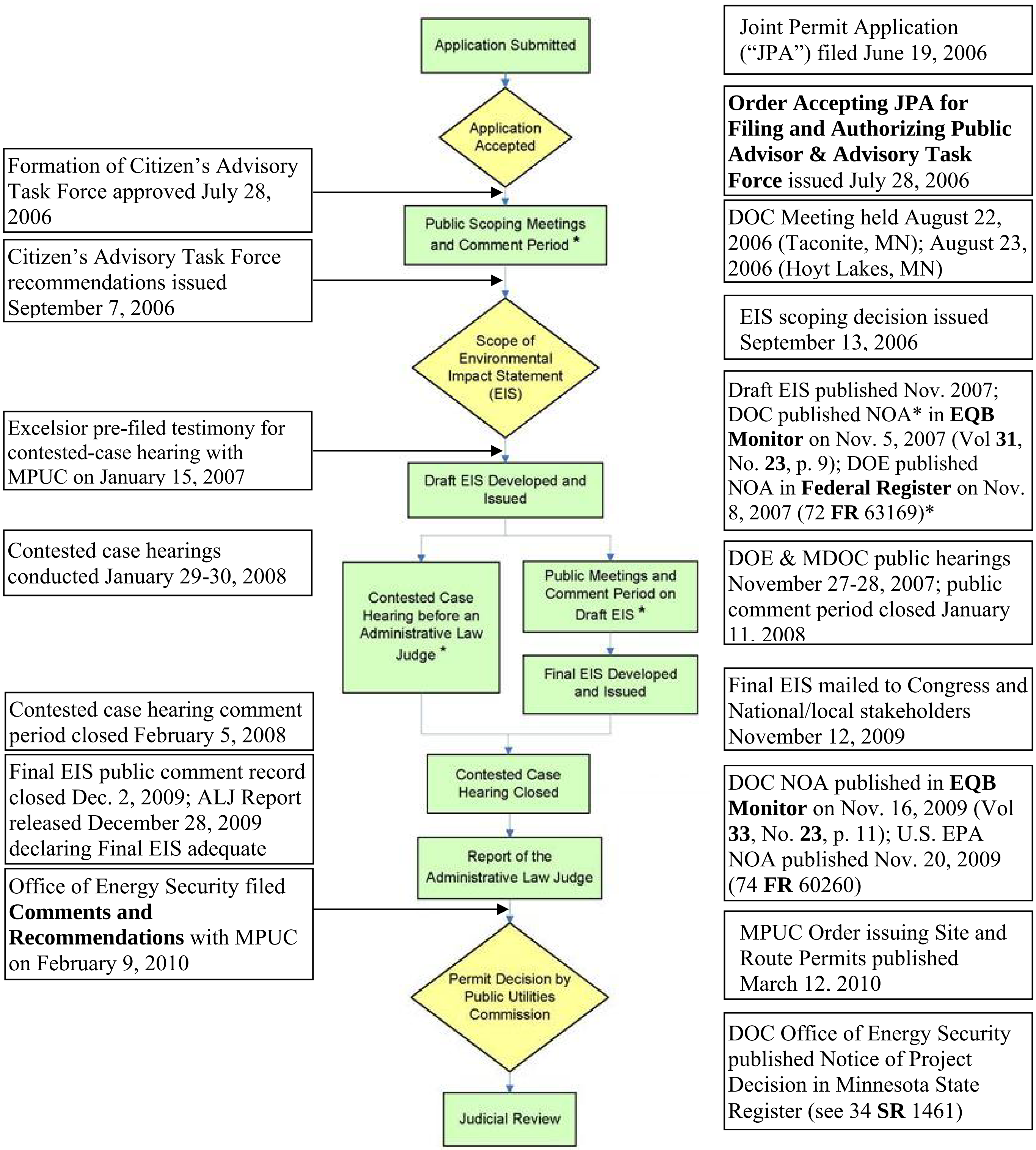


Figure B-6. Actual Project Milestones Achieved in the State PPSA Process



*NOA = Notice of Availability
USEPA published its NOA for the Draft EIS on November 9, 2007 (*see* 72 **FR 63579)

3. Federal Preconstruction Permit: CWA § 404

The only federal pre-construction permit that was necessary is listed in Table B-2. This permit falls under the jurisdiction of the USACE and would be needed to discharge dredged or fill material into wetlands. Excelsior worked extensively with DOE and USACE in preparation of the Final EIS to ensure it included all the information needed by USACE to facilitate its decision-making on the Project's Section 404 permit application submitted on March 31, 2011. At the time this Final Scientific/Technical Report was prepared, the USACE Project permit engineer had finished preparing the public notice required under 33 CFR § 325.3 and had forwarded to his superiors for comment.[44] The public notice had not yet been published.

At the direction of the USACE, the application requested a CWA § 404 permit for impacts related to construction of Mesaba One. The application was limited to Mesaba One as a result of the uncertainty about the HVTL network upgrades that would be required to inject the electrical output from Mesaba Two into the regional electric grid at the Blackberry Substation, the Project's point of interconnection ("POI").

4. State Preconstruction Permits/Approvals

Table B-2 identifies four preconstruction permits/approvals issued by Minnesota State governmental entities. Two of the permits/approvals are issued by the MPCA, one is issued by the MDNR, and one approval is issued by the Minnesota state legislature. The Project has received two of these permits/approvals, both associated with providing the amount of water required by Mesaba One and Mesaba Two assuming their worst case operating conditions.

a. Water Appropriation Approval: Minnesota State Legislature

Consumptive use of water in excess of 2 million gallons per day on a 30-day average basis must be approved by the Minnesota State Legislature (see last line labeled "Water Supply Management" in Table B-2). This legislative approval was mandated for the Project given that the projected annual average appropriation of water needed for Mesaba One was 3,500 gallons per minute[45] based on Mesaba One operating at a 100% capacity factor over a 30-day period sometime during its lifetime.[46] As noted in Table B-1, legislative approval was granted on June 6, 2006 for the Project to consume water in amounts greater than 2 million gallons per day on a 30-day average.

b. Water Appropriation Permits: MDNR

Water appropriation permit applications to withdraw water from the CMP, the HAMP, the Lind Mine Pit ("LMP"), and the Prairie River were originally submitted to the MDNR on June 29, 2006. Following confirmation of the adequacy of the FEIS and issuance of the Project's Site and Route Permits, Excelsior re-filed on August 18, 2011 final applications to appropriate water from the first three of these sources. Although the applications did not include a request to withdraw water from the Prairie River, Excelsior identified the possibility that water from the Prairie River could be used for Mesaba One and Mesaba

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[44] Before preparing the Public Notice of the permit application, the permit engineer must first judge the application to be complete.

[45] Use of the zero liquid discharge system to eliminate wastewater discharges dictates that the amount of water appropriated is equivalent to the amount of water consumed.

[46] Under this circumstance the average daily consumption of water would equal approximately 5 million gallons (i.e., Water Consumption = (3,500 gallons per minute) x (1,440 minutes per day) = 5.04 million gallons per day.

Two in the event of an unexpected contingency. As noted in Table B-1, the MDNR issued Water Appropriation Permits for withdrawals from the three mine pit complexes on March 9, 2012.

c. Air Emission Facility (MPCA)

Excelsior originally submitted an application for a Prevention of Significant Deterioration ("PSD") permit for Mesaba One and Mesaba Two on June 28, 2006. Two of the most important considerations in finalizing the EIS concerned what level of air pollution control constituted best available control technology ("BACT") and the modeling protocol to be used in predicting impacts on ambient air quality and air quality-related values ("AQRV"). The decision-makers on these two matters were the Minnesota Pollution Control Agency ("MPCA") with the U.S. Environmental Protection Agency ("EPA") and the Federal Land Managers ("FLMs"), respectively. Over the nine month period between March 2007 and November 2007, the FLMs and the MPCA argued that the emission rates proposed for the Project by Excelsior did not represent BACT. In October 2007, the MPCA issued a letter to Excelsior documenting their determination of BACT abruptly terminating the effort to reach an agreement based on processes set forth in EPA's New Source Review Workshop Manual[47]. Excelsior contested that determination and requested that EPA be consulted regarding the veracity of MPCA's analysis. In March of 2008, EPA confirmed MPCA had erred in conducting its BACT analysis and contacted the FLMs to inform them likewise. Over the next year, Excelsior worked with the FLMs to finalize the modeling protocol to be used for assessing the Project's air quality impacts as part of the environmental review process. The results of the air quality modeling efforts were presented in the Project FEIS, published in November 2009.

Following confirmation of the adequacy of the FEIS and issuance of the Project's Site and Route Permits, Excelsior requested confirmation from the FLMs that the modeling protocol developed during the EIS process would be acceptable for the air permitting process. Despite the fact that the FLMs had agreed upon a modeling protocol for the EIS after years of effort and negotiation, they required Excelsior to prepare and resubmit a new air modeling protocol for the PSD permitting process. Having to repeat the process of submitting an air modeling protocol, responding to comments raised by the FLMs, and waiting to obtain final confirmation that comments had been addressed, caused significant delay in preparing the revised PSD permit application.

Excelsior re-filed its application for a PSD permit on November 29, 2011. The application was returned to Excelsior on December 30, 2011 (hereafter, the "Initial Notice") after MPCA permitting staff judged it to be incomplete. Excelsior addressed each of the items identified in the Initial Notice as requiring additional information and resubmitted a revised PSD Permit application for Mesaba One and Mesaba Two on February 21, 2012. The MPCA returned this iteration of the PSD Permit application on April 2, 2012 along with a new list of additional information needed (hereafter, the "Second Notice"), most of which had not been identified in the Initial Notice. Had MPCA provided a complete list in the Initial Notice, Excelsior could have addressed all the issues in the February re-submittal. The items identified in the Second Notice were generally of minor consequence and could have been easily supplied.

In between submission of the PSD Permit application on February 21, 2012 and the MPCA's Second Notice, EPA proposed "Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units."[48] The rule as proposed would require new electric utility

[47] "New Source Review Workshop Manual, Prevention of Significant Deterioration and Non-Attainment Area Permitting (Draft October 1990)," U.S. EPA. See http://www.epa.gov/NSR/ttnnsr01/gen/wkshpman.pdf.

[48] EPA originally published its proposed rule on March 16, 2012 on the Agency's web site. The official version of the proposed rule was published in the **Federal Register** on April 13, 2012. See USEPA, "Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units," Proposed rule, Federal Register, Vol. 77, No. 72, April 13, 2012, p. 22436, available at

generating units to comply with a carbon dioxide emission standard of 1,000 pounds per gross megawatt-hour output (averaged on a 12-operating month annual average basis). Compliance with this standard could only be achieved through implementation of carbon capture and sequestration, an alternative that the DOE determined to be economically and logistically infeasible at the time of the Project's FEIS.[49]

EPA purports that the proposed rule is flexible by providing an option to operate without capture for 10 years, provided that a 600 lb CO_2/MWh standard is met for the subsequent 20 years. The proposed rule provided no economic incentives to capture CO_2, nor did it specify the demonstrations EPA would require of an owner/operator to allow use of the 30-year averaging compliance option. Instead, EPA's proposal identified some technical and legal issues associated with implementing the option and solicited comment "on any practical difficulties in compliance and enforcement" and "all other aspects of this 30-year averaging compliance option." Given the present state of uncertainty associated with implementing this option, it does not constitute a feasible compliance alternative for the Project.

EPA also suggests that the proposed rule is flexible by providing exemptions for 'transitional sources'. However, in order to be designated a transitional source, an affected facility must have already obtained an air permit by April 12, 2012 and commence construction on or before April 12, 2013. Excelsior submitted comments on the proposed rule requesting that the Project be treated as a transitional source (Excelsior's comments to EPA are reproduced in Appendix A of this Final Scientific/Technical Report). If successful, the Project would be provided the flexibility to proceed without CCS at its inception and CCS facilities could be added if and when economically warranted. However, resolution of the proposed rule is expected to involve litigation that will take place over an extended timeframe. Uncertainty regarding the ultimate CO_2 standard will linger until that litigation is complete. Until then, the PSD permit application for the Project has been effectively placed on hold.

Prior to the interruption of the air permitting process, the Project was positioned to easily meet the cooperative agreement's objective of achieving emission levels equal to or less than those of the lowest emitting utility-scale, coal-based generation. Following the release of the FEIS and prior to resubmitting the air permit application, Excelsior studied the addition of activated zinc oxide beds downstream of the amine-based acid gas removal system to further reduce sulfur concentrations in the syngas and sulfur dioxide ("SO_2") emissions from the plant. Based on the results of this study, Excelsior decided to include these additional SO_2 controls in its air permit application, as well as selective catalytic reduction ("SCR") control for nitrogen oxides ("NO_X"). As a result, the Project would achieve emission rates of SO_2 and NO_X 60% and 67% below the already low emission levels evaluated in the FEIS. Additionally, Excelsior proposed a permit limit for mercury equal to 95% removal, rather than the 90% considered in the FEIS. Figure B-7 and Figure B-8 compare the Project's proposed emission rates to the most recently permitted utility-scale coal plants, considered representative of state of the art conventional. These figures clearly demonstrate that the Project's ability to achieve dramatic emissions reductions of approximately 70-80% relative to the cleanest conventional plants.

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http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2011-0660-0001

[49] DOE, "Mesaba Energy Project Final Environmental Impact Statement," DOE/EIS-0382, November, 2009, p. 2-24.

Figure B-7. Criteria Pollutants: Mesaba vs. Newest Conventional Coal Plants

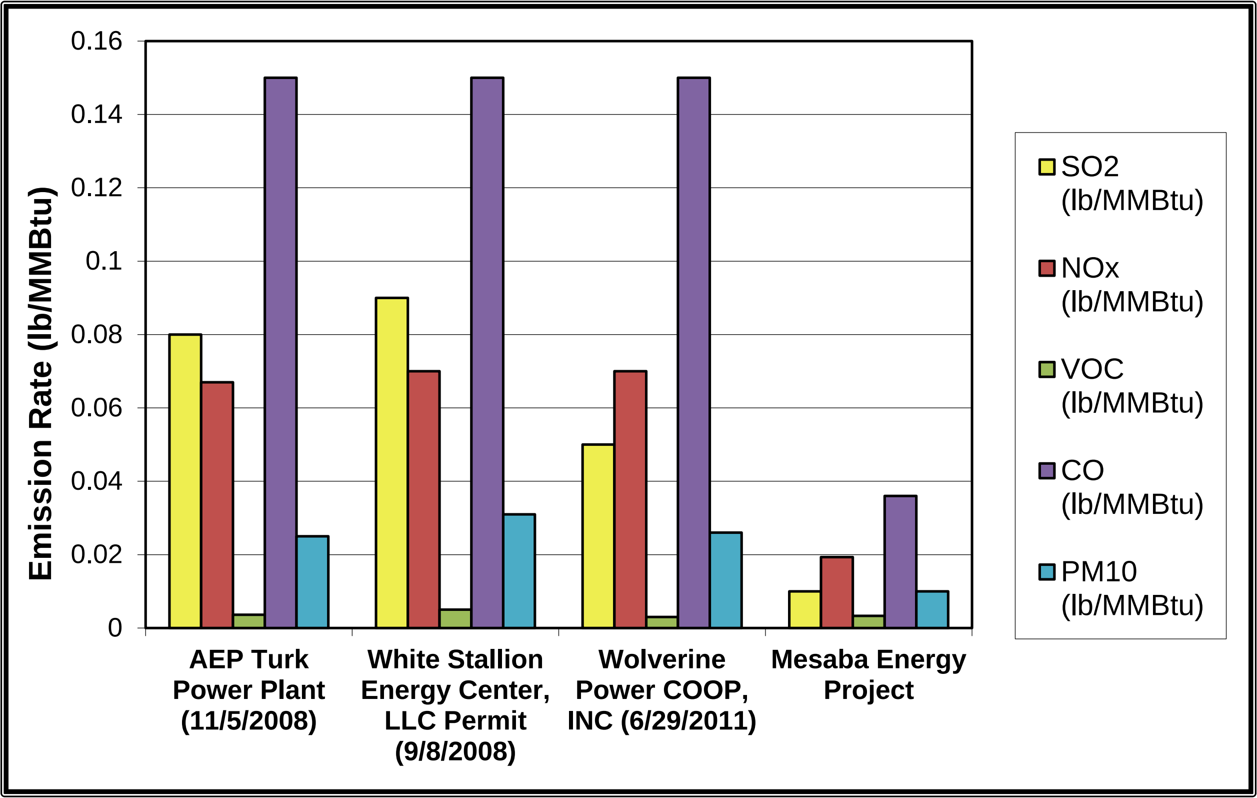
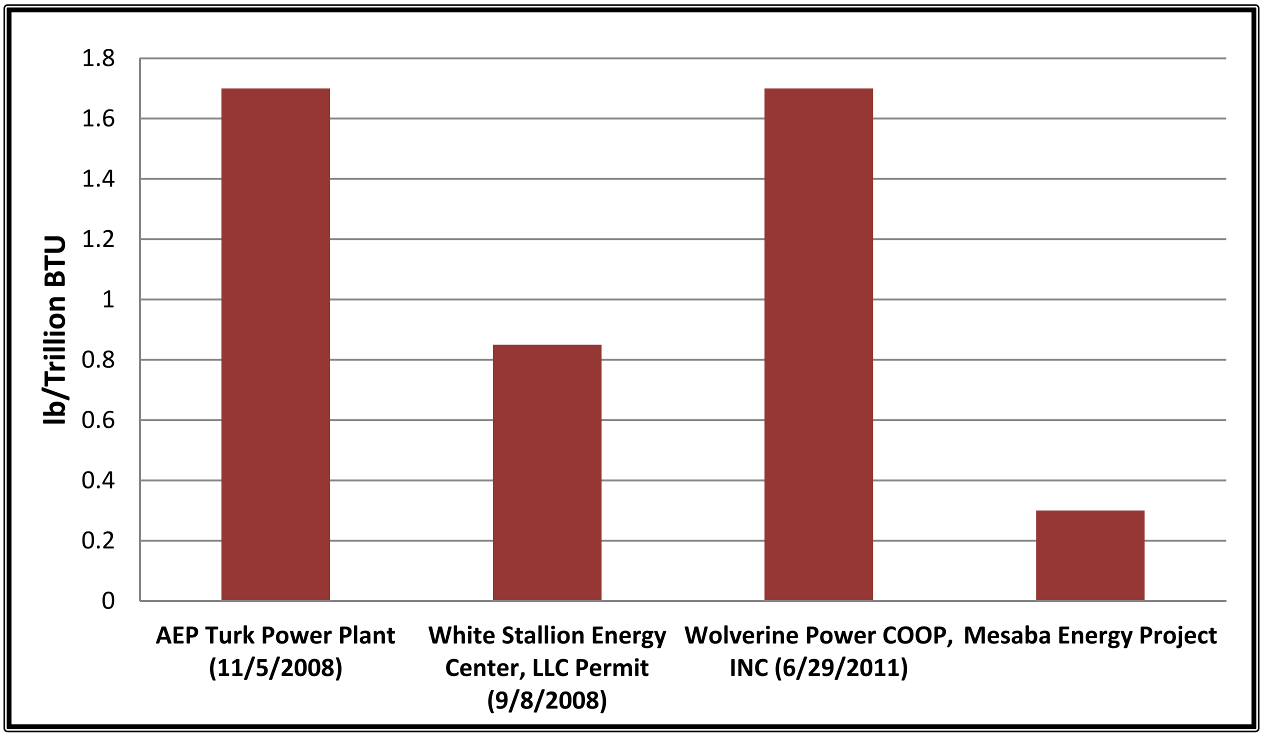


Figure B-8. Mercury: Mesaba vs. Recently Permitted Coal Plants



d. NPDES Permit (MPCA)

Excelsior originally submitted an application for a NPDES Permit for Mesaba One and Mesaba Two on June 28, 2006. The application submitted reflected discharges of cooling tower blowdown and minor process water discharges from the power block as their source; process water discharges associated with the gasification island were eliminated through use of a zero liquid discharge ("ZLD") system. The West Range site was the location for which the original NPDES Permit application was tailored, in part, because of its geographical placement outside the Lake Superior Basin watershed.[50] Concerns over the feasibility of establishing a Total Mass Daily Load ("TMDL") for mercury and dissolved oxygen in the Swan River and the need for determining mercury levels in fish in Holman Lake and the Prairie River dictated the extension of the ZLD system to the entire facility to eliminate all wastewater discharges.[51] The technical study confirming the feasibility of extending the ZLD system is attached as Appendix B.

Extending the ZLD system to all wastewater discharges effectively eliminates any controversy that might be associated with the NPDES requirements and renders any remaining pre-construction NPDES permitting activities to be relatively minor compared to other major pre-construction permits discussed in this section. The report included as Appendix B has been submitted to the MPCA. Two outstanding actions remain regarding NPDES requirements: 1.) compliance with CWA § 316(b) (i.e., the design of cooling water intake structures) and 2.) compliance with sampling stormwater conveyances to confirm that stormwater carried therein does not contain pollutants associated with industrial activity.

The need to submit an NPDES Permit application will be resolved pending resolution of the proposed rule governing GHG New Source Performance Standards.

5. CONCLUSION

Five out of the eight pre-construction permits required for commencing construction of Mesaba One and Mesaba Two have been obtained. Work on the three remaining permits (the PSD Permit, the NPDES Permit [if necessary], and the CWA § 404 Dredge & Fill Permit) will resume upon resolving issues associated with recently proposed standards for GHG emissions from electric utility generating units.

The schedule reflecting the milestones achieved across the entire environmental review and permitting process is attached as Appendix C.

a. Lessons Learned

Completion of joint state and federal environmental review in a timely manner is essential to the feasibility of a large infrastructure project. Extended delays may jeopardize the project's ultimate success, as this increases the project's exposure to changing market conditions, regulations, financing and administrative policies. The following lessons learned identify strategies that could help to minimize

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[50] Water quality standards for the Lake Superior Basin watershed are more stringent than those pertaining to waters within the Upper Mississippi River Watershed where the West Range Site is located (i.e., the water quality criterion for mercury for Class 2B waters in the Upper Mississippi River Watershed is 6.9 nanograms per liter and mixing zones for bioaccumulative chemicals of concern are allowed; the water quality criterion for mercury for Class 2B waters in the Lake Superior Basin is 1.3 nanograms per liter and mixing zones for bioaccumulative chemicals of concern are not allowed).

[51] At the time of Excelsior's decision to extend the ZLD system to the entire facility, the Swan River was considered an impaired water for mercury in fish tissue and dissolved oxygen. These pre-existing conditions and the studies needed to quantify the Project's impacts on them were expected to preclude the Project's timely consideration during the environmental review and permitting processes.

potential delays in the environmental review process:

- Ensure that written inquiries with potential cooperating agencies are followed up by telephone calls and/or face-to-face meetings to ensure that such participants are actively involved at the front end and throughout the entire environmental review process. Additionally, potential cooperating agencies should be required to respond to written inquiries and engage during the EIS scoping stage. A leading source of delays in the environmental review process is cooperating agencies' after-the-fact input, raising major issues during review of the preliminary draft or draft EIS that could be much more efficiently addressed if raised during the scoping process.
- Immediately raise issues to the leadership level within a cooperating agency at the first sign of regulatory delays caused by a local office applying its own regulatory interpretations of federal regulations. During the environmental review process, high level discussions between a cooperating agency's headquarters group and DOE may be essential in order to resolve issues that a local office of the cooperating agency may resolve in a manner inconsistent with regulatory requirements, wittingly or unwittingly creating delay and hindering the federal energy goal being served by the project.. This is particularly true for large commercialization projects that raise first-of-kind policy issues that must be resolved by leadership within federal agencies in order to avoid unacceptably long delays.
- A standard policy should be established to define how to address proposed environmental regulations as part of the environmental review process. For example, DOE should make sure that projects that they are supporting are made known to U.S. EPA and efforts are undertaken to understand and eliminate permitting obstacles associated with such proposals that could unnecessarily delay projects that have been selected for federal assistance due to their material and immediate beneficial impact on the environment,
- Ensure that efforts to consult with Native American tribes are undertaken as early as possible in the project's development phase. The experience gained as part of the Project's consultations confirmed that interested parties are difficult to identify; meetings are difficult to schedule and can be protracted in length; and that meaningful progress occurs only after demonstrating that DOE and company representatives can be trusted as decision-makers.

6. Technical Specifications for Environmental Permitting

The following subsections identify all the latest technical specifications relevant to environmental permitting that have been developed for the Project throughout the environmental review and permitting processes. This includes the inventory of air emissions, water source and usage data, and wetland impacts.

a. Air Emission Inventory

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

- Plant performance characteristics.
- Equipment supplier data.
- BACT as proposed in the air permit 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 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.

i. Criteria Pollutant Emissions

Table B-3 presents the normal and maximum short-term emission rates for each source. Table B-4 shows the proposed maximum annual criteria pollutant emission rates for each emission source in the facility.

Table B-3. Short-Term Emission Summary (Phase I and II)

Emission Source	Normal Emission Rate (lb/hr)[1]					Maximum Emission Rate (lb/hr)[1]				
	NO_X	SO_2	CO	PM_{10}[2]	VOC	NO_X	SO_2	CO	PM_{10}[2]	VOC
Combustion Turbines	204	118	372	100	34	484[3]	283	10,960[3]	100	1,052[3]
Tank Vent Boilers	12	6.4	3.6	0.4	0.2	39	10	12	1.3	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	1.0	9.4	0.74	19	1.3	1.0
Cooling Towers				11					11	
Fugitive PM_{10}				4.9					4.9	
Fugitive VOC					3.8					3.8
Emergency Generators[6]						62	0.07	36	4.1	6.1
Emergency Fire Water Pump Engines[6]						8	0.004	6.9	0.4	2.8

Emission Source	Normal Emission Rate (lb/hr)[1]					Maximum Emission Rate (lb/hr)[1]				
	NO_X	SO_2	CO	PM_{10}[2]	VOC	NO_X	SO_2	CO	PM_{10}[2]	VOC
Total	**226**	**125**	**397**	**121**	**40**					

[1]See following text for description of normal and maximum short-term emissions. Maximum emissions from all sources could not occur simultaneously, so totals are not calculated.
[2]PM_{10} includes filterable plus condensable fractions. PM and $PM_{2.5}$ emission rates are equal to PM_{10} for all non-fugitive sources. See Table B-11 and Table B-12 for detail on fugitive PM/PM_{10}/$PM_{2.5}$ emissions.
[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.
[6]Emergency generators and fire water pumps are not normally operated (limited to 100 hr/yr for testing)

Table B-4. Annual Emission Summary (Phase I and II)

Emission Source	Emission Rate (ton/year)				
	NO_X	SO_2	CO	PM_{10}	VOC
Combustion Turbines	894	516	1,894	440	174
Tank Vent Boilers	53	28	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				48	
Fugitive PM_{10}				6.0	
Fugitive VOC					17
Emergency Generators	3.1	negl.	1.8	0.2	0.3
Emergency Fire Water Pump Engines	0.4	negl.	0.3	0.02	0.15
Total	**988**	**570**	**2,510**	**501**	**197**

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

Combustion Turbine Generators

Emissions from the power block combustion turbine generators ("CTGs") are primarily determined through the inherently lower polluting IGCC coal gasification technology, as the production of syngas at relatively high pressure enables efficient and cost-effective syngas cleanup prior to combustion in the CTGs to produce electricity. As discussed in the process description in Section D.2.b, the following treatment steps would 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 carbonyl sulfide ("COS") hydrolysis and trim sulfur removal with activated zinc oxide to reduce total syngas sulfur to a maximum of 20 parts per million volumetric dry ("ppmvd") as hydrogen sulfide ("H_2S") in the undiluted syngas, 30-day rolling average.
- Activated carbon beds for adsorption of mercury and other trace contaminants.
- Moisturization (water saturation) for NO_X control.

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

The following CTG emission rates have been proposed as BACT and were used for project emission estimates:

Syngas

- SO_2, based on 20 ppmvd as H_2S in the undiluted syngas, rolling 30-day average.
- NO_X, 5 ppmvd (@ 15% O_2).
- Carbon monoxide ("CO"), 15 ppmvd (@ 15% O_2).
- Particulate matter ("PM")/PM_{10}/$PM_{2.5}$, 25 lb/hr/CTG.
- Volatile organic compounds ("VOC"), 2.4 ppmvd (@15% O_2).

Natural Gas

- SO_2, pipeline-quality natural gas (assumed 1.0 grain/100 scf total sulfur).
- NO_X, 5 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 NO_X control.

Table B-5 shows the maximum short-term CTG emission rates for the four principal operating conditions. Since a specific CTG supplier has not yet been fully committed, the emission rates shown in this table reflect the maximum values for potentially available commercial CTGs.

Table B-5. Maximum CTG Short-Term Emission Rates (Phase I and II)

Operating Mode	Emission Rate (lb/hr)				
	NO_X	SO_2	CO	$PM/PM_{10}/PM_{2.5}$	VOC
Normal syngas operation[1]	204	118	380	100	35
Maximum syngas operation[2]	204	283	380	100	35
Maximum natural gas operation	150	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; all four would never actually start up simultaneously

The maximum annual CTG emission rates and basis are summarized in Table B-6:

Table B-6. Maximum CTG Annual Emissions (Phase I and II)

POLLUTANT	TONS/YEAR	BASIS
NO_X	894	Full year (8,760 hours) on full load syngas operation
SO_2	516	Full year (8,760 hours) on full-load syngas operation; 20 ppmvd average total sulfur in syngas.
CO	1,894	50 hours startup/shutdown per CTG, balance of year (8,710 hours per CTG) on full-load syngas operation
$PM/PM_{10}/PM_{2.5}$	440	Full year (8,760 hours) on full load syngas operation
VOC	174	50 hours startup/shutdown per CTG, balance of year (8,710 hours per CTG) on full load syngas operation

Tank Vent Boilers

The tank vent boilers ("TVBs", one for each phase) would 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 B-7 and Table B-8, respectively.

Table B-7. Tank Vent Boiler Short-Term Emissions (Phase I and II)

Operating Mode	Emission Rate (lb/hr)				
	NO_X	SO_2	CO	$PM/PM_{10}/PM_{2.5}$	VOC
Normal syngas operation[1]	9	6.4	2.7	0.3	0.1
Maximum syngas operation[2]	39	10	12	1.3	0.6
Maximum natural gas operation[3]	24	0.2	7.2	0.8	0.3

[1]Assumes 30 MMBtu/hour heat input rate (total for both TVBs)
[2]Assumes 130 MMBtu/hour heat input rate (total for both TVBs)
[3]Assumes 80 MMBtu/hour heat input rate (total for both TVBs)

Table B-8. Maximum Tank Vent Boiler Annual Emissions* (Phase I and II)

Pollutant	tons/year
NO_X	53
SO_2	28
CO	16
$PM/PM_{10}/PM_{2.5}$	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.

Flares

The elevated flares for each project phase would be designed for a minimum 99 percent destruction efficiency of CO and H_2S. As discussed previously, the flares would normally be used only to oxidize treated syngas and natural gas combustion products during gasifier startup operations. The flares would 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 B-9. Note that the maximum flaring operation shown in this table is virtually impossible in practice, because all four gasification trains would never be started up simultaneously and the chances of all four sulfur treatment systems experiencing a simultaneous upset are effectively zero.

Table B-9. Flare Emission Rates (Phase I and II)

Operating Mode	**Emission Rate (Lb/Hr)**				
	NO_X	**SO_2**	**CO**	**$PM/PM_{10}/PM_{2.5}$**	**VOC**
Normal Operation[1]	0.3	0.01	2.2	0.03	0.02
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 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 ppmvd 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.

Fugitive Equipment Leaks

VOC and hazardous air pollutant ("HAP") emissions associated with normal equipment leakage were estimated using standard EPA fugitive emissions factors for valve seals, pump and compressor seals, pressure relief valves, flanges, and similar equipment. Most of the estimated VOC emissions were associated with the amine handling system since methyl diethanolamine ("MDEA") would be the only VOC in relatively significant quantity at the facility. Fugitive emission estimates of HAP were 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 B-10. Fugitive emissions would be monitored and controlled under a Leak Detection Plan.

Table B-10. Fugitive Emission Estimate (Phase I and II)

Emission Type	Emission Rate	
	lb/hr	ton/yr
Federal HAP	0.06	0.3
Ammonia	0.2	1.3
Hydrogen sulfide	4.0	17
MDEA	3.2	14
VOC[1]	3.8	16
TRS[2]	4.0	17

[1] VOC include MDEA, benzene, carbon disulfide, COS, ethyl benzene, hexane, hydrogen cyanide, naphthalene, toluene, xylenes, and waste oil,
[2] TRS includes H_2S.

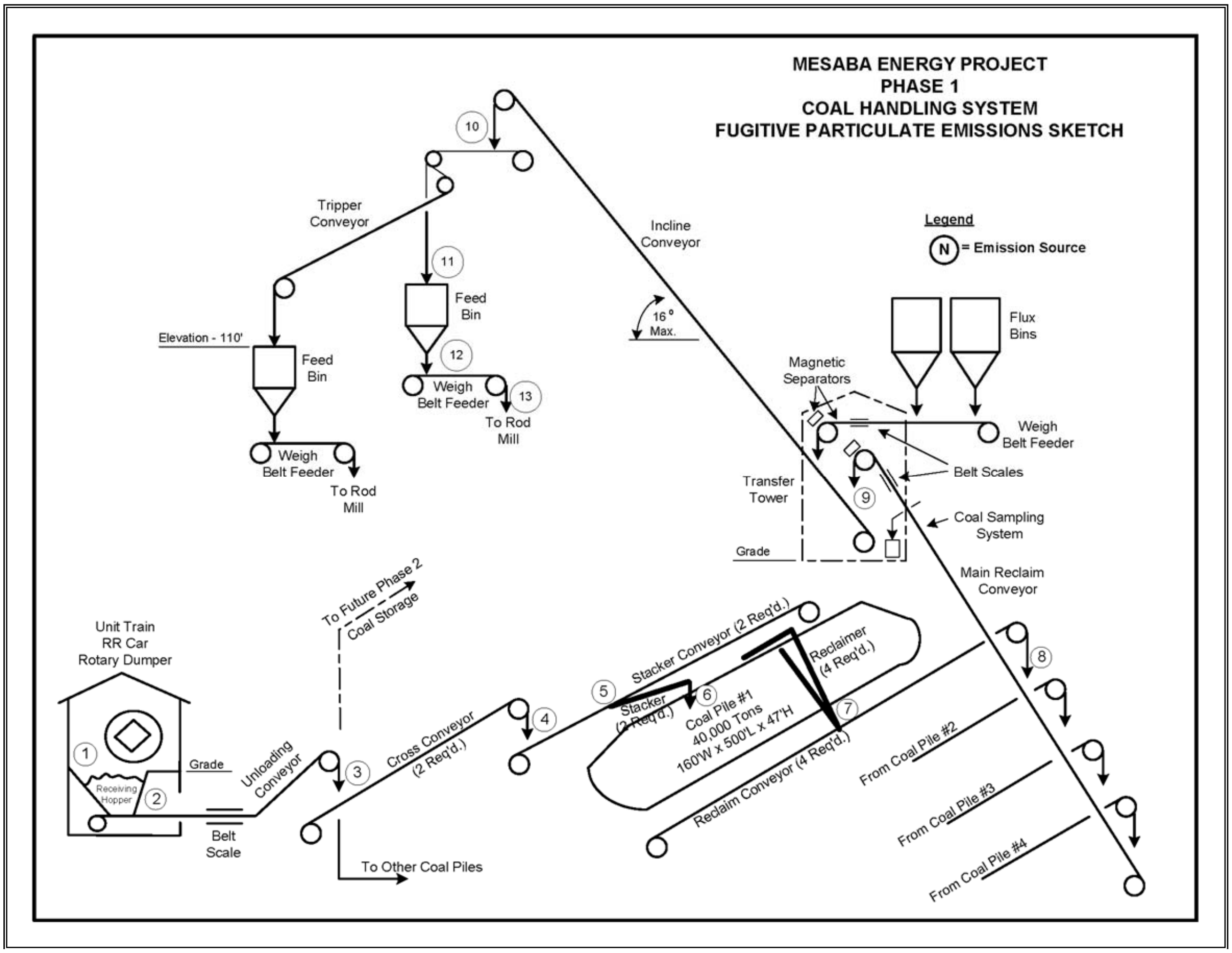
Material Handling Systems

Fugitive particulate matter emissions (fugitive dust) would 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 would include the active coal and 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 B-11 for Phase I operations. Estimated emissions of $PM_{2.5}$ (particulate matter with an aerodynamic diameter no greater than 2.5 microns) are summarized in Table B-12. Fugitive particulate matter emission rates for Phase I and II would be twice the values shown in these tables.

The estimates of particulate matter emission rates (pounds ["lb"] per hour ["hr"], tons per year ["yr"]) were based on methodologies developed by the EPA and documented in AP-42. Specific portions of AP-42 used included 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 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, was based upon unloading approximately 36 unit train cars per hour (approximately 4,300 tons/hr). Figure B-9 shows a sketch of the proposed feedstock handling system.

Figure B-9. Material Handling System for Phase I IGCC Power Station



The emission factors (expressed in lb/ton) for aggregate handling systems derived from AP-42 were 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 was based on three unit trains per day. For materials handling facilities downstream of the storage pile, the peak rate was based upon 120% of the average rate required for the nominal plant output. The annual throughput was 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 Rawhide Powder River Basin ("PRB") coal. The maximum slag generation and throughput rates were 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, rendering it the worst-case feedstock for fugitive emissions. The fugitive emissions from Rawhide PRB coal using the revised assumptions are provided in Table B-11 and Table B-12.

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

1.	No control method	0%
2.	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 storage pile load-in using an adjustable stacker was 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 were 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 would require that water be supplied to the various injection points. This water would 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 would be captured and treated as required before re-use, on-site or off-site disposal.

Particulate matter emissions resulting from wind erosion of the storage piles were calculated according to the data and guidance provided in AP-42 Section 13.2.5, which requires information on wind velocities at the plant site. Wind velocity profiles were obtained from MPCA for the local Hibbing, Minnesota area for the years 2006-2010. The reported wind velocities were 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 relatively small contributors to overall plant particulate matter emissions.

In-plant trucks would be used to transport dewatered, by-product slag from the gasifier slag handling area to either 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% was 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. Fugitive emissions from paved road traffic are not included in Table B-11 or Table B-12, because the emissions estimates were calculated based on vehicle miles traveled rather than material throughput rates. The total estimated emissions per phase from paved road traffic are 0.33 ton/yr PM_{10} and 0.08 ton/yr $PM_{2.5}$.

Table B-11. Fugitive PM and PM_{10} Emission Estimate (Phase I Operation)

Emission Source Description	PM_{30} Emission Factor (lb/ton)	PM_{10} Emission Factor (lb/ton)	Maximum Hourly Throughput (ton/hr)	Maximum Annual Throughput (ton/yr)	Control Method	PM_{30} and PM_{10} Control Efficiency (%)	Controlled PM_{30} Maximum Hourly Emission Rate (lb/hr)	Controlled PM_{30} Maximum Annual Emission Rate (ton/yr)	Controlled PM_{10} Maximum Hourly Emission Rate (lb/hr)	Controlled PM_{10} Maximum Annual Emission Rate (ton/yr)
COAL HANDLING AND STORAGE										
Railcar Unloading to Hopper and Conveyor	0.0032	0.0016	4,300	3,100,000	Fully enclosed transfer point with baghouse dust collector	99	0.139	0.050	0.068	0.024
Unloading conveyor to Cross-Conveyor	0.0015	0.0007	4,300	3,100,000	Fully enclosed transfer point with dust suppression sprays	95	0.320	0.115	0.151	0.055
Cross-Conveyor to Stacker Conveyor	0.0015	0.0007	4,300	3,100,000	Fully enclosed transfer point with dust suppression sprays	95	0.320	0.115	0.151	0.055
Stacker Conveyor to Stacker	0.0015	0.0007	4,300	3,100,000	Fully enclosed transfer point with dust suppression sprays	95	0.320	0.115	0.151	0.055
Stacker to Coal Pile	0.0015	0.0007	4,300	3,100,000	Ring-type dust suppression sprays at discharge point; Adjustable height stacker	50	3.200	1.154	1.514	0.546
Reclaimer to Reclaim Conveyor	0.0015	0.0007	430	3,100,000	Partially Enclosed transfer point with dust suppression sprays	75	0.160	0.577	0.076	0.273
Reclaim Conveyor to Main Conveyor	0.0015	0.0007	430	3,100,000	Fully enclosed transfer point with dust suppression sprays	95	0.320	0.115	0.151	0.055
Main Conveyor to Incline Conveyor	0.0015	0.0007	430	3,100,000	Fully enclosed transfer point with dust suppression sprays inside building	95	0.320	0.115	0.151	0.055
Incline Conveyor to Tripper Conveyor	0.0015	0.0007	430	3,100,000	Fully enclosed transfer point with dust suppression sprays	95	0.320	0.115	0.151	0.055
Tripper Conveyor to Feed Bin	0.0015	0.0007	430	3,100,000	Fully enclosed transfer point with baghouse dust collector	99	0.006	0.023	0.003	0.011
Wind Erosion from Coal Storage	--	--	--	--	None	0	--	1.112	--	0.556
SUBTOTAL							**4.56**	**3.61**	**2.16**	**1.74**

Emission Source Description	PM_{30} Emission Factor (lb/ton)	PM_{10} Emission Factor (lb/ton)	Maximum Hourly Throughput (ton/hr)	Maximum Annual Throughput (ton/yr)	Control Method	PM_{30} and PM_{10} Control Efficiency (%)	Controlled PM_{30} Maximum Hourly Emission Rate (lb/hr)	Controlled PM_{30} Maximum Annual Emission Rate (ton/yr)	Controlled PM_{10} Maximum Hourly Emission Rate (lb/hr)	Controlled PM_{10} Maximum Annual Emission Rate (ton/yr)
COAL SLURRY FACILITY SOURCES										
Feed Bin to Weigh Belt Feeder	0.0015	0.0007	430	3,100,000	Fully enclosed transfer point with dust suppression sprays	95	0.320	0.115	0.151	0.055
Weigh Belt Feeder to Rod Mill Feed Chute	0.0015	0.0007	430	3,100,000	Fully enclosed transfer point with dust suppression sprays	95	0.320	0.115	0.151	0.055
SUBTOTAL							**0.06**	**0.23**	**0.03**	**0.11**
SLAG TRANSPORT AND STORAGE										
Slag Disposal Truck Traffic	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	0	0	0
Windage from Slag Storage	--	--	--	--	None	0	--	0.145	--	0.072
Slag Storage Load-out	0.0039	0.0019	39	281,780	None	0	0.153	0.533	0.072	0.262
SUBTOTAL							**0.83**	**3.67**	**0.25**	**1.13**
TOTAL							**5.46**	**7.51**	**2.44**	**2.97**

Table B-12. Fugitive $PM_{2.5}$ Emission Estimate (Phase I Operation)

Emission Source Description	$PM_{2.5}$ Emission Factor (lb/ton)	Maximum Hourly Throughput (ton/hr)	Maximum Annual Throughput (ton/yr)	Control Method	$PM_{2.5}$ Control Efficiency (%)	Controlled $PM_{2.5}$ Maximum Hourly Emission Rate (lb/hr)	Controlled $PM_{2.5}$ Maximum Annual Emission Rate (ton/yr)
COAL HANDLING AND STORAGE							
Railcar Unloading to Hopper and Conveyor	0.00024	4,300	3,100,000	Fully enclosed transfer point with baghouse dust collector	98.26	0.018	0.006
Unloading conveyor to Cross-Conveyor	0.00011	4,300	3,100,000	Fully enclosed transfer point with dust suppression sprays	89.31	0.049	0.018
Cross-Conveyor to Stacker Conveyor	0.00011	4,300	3,100,000	Fully enclosed transfer point with dust suppression sprays	89.31	0.049	0.018
Stacker Conveyor to Stacker	0.00011	4,300	3,100,000	Fully enclosed transfer point with dust suppression sprays	89.31	0.049	0.018
Stacker to Coal Pile	0.00011	4,300	3,100,000	Ring-type dust suppression sprays at discharge point; Adjustable height stacker	27.80	0.331	0.119
Reclaimer to Reclaim Conveyor	0.00011	430	3,100,000	Partially Enclosed transfer point with dust suppression sprays	46.56	0.024	0.088
Reclaim Conveyor to Main Conveyor	0.00011	430	3,100,000	Fully enclosed transfer point with dust suppression sprays	89.31	0.049	0.018
Main Conveyor to Incline Conveyor	0.00011	430	3,100,000	Fully enclosed transfer point with dust suppression sprays inside building	89.31	0.049	0.018
Incline Conveyor to Tripper Conveyor	0.00011	430	3,100,000	Fully enclosed transfer point with dust suppression sprays	89.31	0.049	0.018
Tripper Conveyor to Feed Bin	0.00011	430	3,100,000	Fully enclosed transfer point with baghouse dust collector	98.26	0.001	0.003
Wind Erosion from Coal Storage	--	--	--	None	0	--	0.083
SUBTOTAL						**0.54**	**0.41**
COAL SLURRY FACILITY SOURCES							
Feed Bin to Weigh Belt Feeder	0.00011	430	3,100,000	Fully enclosed transfer point with dust suppression sprays	89.31	0.049	0.018
Weigh Belt Feeder to Rod Mill Feed Chute	0.00011	430	3,100,000	Fully enclosed transfer point with dust suppression sprays	89.31	0.049	0.018
SUBTOTAL						**0.01**	**0.04**
SLAG TRANSPORT AND STORAGE							
Slag Disposal Truck Traffic	0.226	0.40	3,500	Apply dust suppressant	80	0.018	0.079
Slag Storage Load-in	Nil			Wet slag	100	0	0
Windage from Slag Storage	--	--	--	None	0	--	0.011
Slag Storage Load-out	0.00028	39	281,780	None	0	0.011	0.040
SUBTOTAL						**0.03**	**0.13**
TOTAL						**0.57**	**0.57**

Cooling Towers

Each Phase of the Mesaba Energy Project would have two sets of cooling towers: one for the power block and another for the gasification/ASU processes (resulting in a total of four sets of cooling towers). Table B-13 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 were based on 100% PRB coal feed to the plant, the Siemens-Westinghouse turbine power block (600 MW net nominal plant output), and ten cycles of concentration ("COC"), and are indicative of the maximum combined particulate matter release. The drift rate was 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 was the maximum value estimated from water quality measurement data for the makeup water. Table B-13 shows hourly rates for each Phase and total annual emissions for the Phase I and II cooling towers.

Table B-13. Particulate (PM_{10}) Emissions from Cooling Tower Drift

	Power Block Cooling Towers	Gasification/ASU Cooling Towers
Duty (Phase I, MMBtu/hr)	1,743	690
Recirculation Rate (Phase I, 10^6 lb/hr)	116	46
Drift (Phase I, lb/hr)	1160	460
TDS (ppm by weight)	3370	3370
$PM/PM_{10}/PM_{2.5}$ Emission (Phase I, lb/hr)	3.9	1.6
Total $PM/PM_{10}/PM_{2.5}$ (Phase I and II, TPY)	47.8	

The Power Block cooling towers were configured with 12 cells per phase, and the smaller Gasification/ASU cooling towers with 5 cells per phase. The characteristics of each cell are shown in Table B-14.

Table B-14. 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

Auxiliary Boilers

The auxiliary boilers would 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 NO_X burners for emission control. Emission rates based on supplier guarantees for similar equipment are shown in Table B-15.

Table B-15. Maximum Auxiliary Boiler Short-Term and Annual Emission Rates (Phase I and II)

	lb/hr	ton/year*	Basis
NO_X	9.4	10	Low NO_X burner, 30 ppmvd (@ 3% O2)
SO_2	0.74	0.82	1 grain/100 scf in pipeline gas
CO	19	21	100 ppmvd (@ 3% O2)
$PM/PM_{10}/PM_{2.5}$	1.3	1.4	0.005 lb/MMBtu, HHV
VOC	1.0	1.1	10 ppmvd (@ 3% O2)

* Annual emission based on 25% maximum annual capacity factor.

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), except where applicable Tier standards were lower than AP-42 values, the Tier standard was used, and assumed the use of ultra low sulfur diesel fuel. Table B-16 shows the maximum short-term and annual non-emergency emissions for each engine.

Table B-16. 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)				
			NO_X	SO_2	CO	PM / PM_{10}/ $PM_{2.5}$	VOC	NO_X	SO_2	CO	PM / PM_{10}/ $PM_{2.5}$	VOC
Emergency generators – gasification area	2 MW	2	56	0.1	30	3.8	3.8	2.8	negl.	1.5	0.2	0.2
Emergency generators – power block	350 kW	2	6	0.003	6.3	0.3	2.4	0.3	negl.	0.3	0.02	0.1
Fire pumps	300 hp	4	8	0.004	6.9	0.4	2.8	0.4	negl.	0.3	0.02	0.2

ii. Non-Criteria Pollutant Emissions

Plant emission rates of trace amounts of lead were estimated from published information for a similar IGCC facility.[52] These estimates are shown on Table B-17 in the hazardous air pollutants emission discussion below.

Sulfur trioxide ("SO_3") emissions, expressed as sulfuric acid ("H_2SO_4"), 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 B-17 in the hazardous air pollutants emission discussion below.

[52] NETL, "Major Environmental Aspects of Gasification-Based Power Generation Technologies, Final Report." December, 2002.

Emission rates for HAP, as identified by the EPA and MPCA, 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.
- EPA emission factors (AP-42) for coal combustion.

HAP emissions at the IGCC Power Station will be lower than conventional coal plants due to 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 would be immobilized in the non-hazardous, vitreous slag by-product and prevented from causing adverse environmental effects. Gaseous and particle-bound HAP that may be contained in the raw syngas exiting the gasifiers would be totally or partially removed in the syngas particulate matter removal system, water scrubber, and acid gas recovery ("AGR") systems described in Section D.2.b. In addition, the mercury removal carbon absorption beds would ensure that mercury emissions from the IGCC Power Station would be less than 5 percent of the mercury present in the feedstock as received.

Table B-17 presents a summary of estimated HAP emissions for the Phase I and II IGCC Power Station. Using conservative assumptions for emission factors and 100% annual operating capacity (at a total solid feedstock heat input to the gasifiers of 98 trillion British thermal units ["Btu"]), total facility emissions of federal HAP were estimated to be less than 25 ton/year. No single HAP emissions would exceed 10 ton/year, making Mesaba One and Mesaba Two an area source of HAP.

Table B-17. 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	Other Sources[1]		
75-07-0	Acetaldehyde	0.044	1.6E-04	3.9E-04	4.1E-04	0.045	0.090
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	5.5E-05	0.434	0.869
7440-36-0	Antimony	0.027	2.6E-04	6.6E-04		0.028	0.056
7440-38-2	Arsenic	0.059	1.4E-03	3.5E-03	2.8E-05	0.064	0.127
56-55-3	Benz[a]anthracene	5.6E-05	2.0E-07	5.0E-07	1.8E-06	5.9E-05	1.2E-04
71-43-2	Benzene	0.059	0.026	0.066	0.0079	0.159	0.319
207-08-9	Benzo(k)fluoranthene	1.6E-04	5.8E-07	1.4E-06	5.7E-07	1.6E-04	3.3E-04
50-32-8	Benzo[a]pyrene	5.6E-05	2.0E-07	5.0E-07	5.4E-07	5.7E-05	1.1E-04
100-44-7	Benzyl chloride	1.03	3.7E-03	9.2E-03		1.047	2.094
7440-41-7	Beryllium	0.0064	7.9E-06	2.0E-05	1.7E-06	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	5.3E-05	1.3E-04	1.5E-04	0.236	0.471
75-15-0	Carbon disulfide	1.13	4.0E-03	1.0E-02	0.034	1.175	2.351

CAS # or MPCA #	Compound	Annual Average HAP Emission (ton/yr)				Total Phase I	Phase I and Phase II
		CTGs	TVB	Flare	Other Sources[1]		
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	9.8E-04	2.5E-03	2.0E-04	0.016	0.033
18540-29-9	Chromium, (hexavalent)	0.0038	2.9E-04	7.4E-04		0.0049	0.0097
218-01-9	Chrysene (Benzo(a)phenanthrene)	1.5E-04	5.3E-07	1.3E-06	2.1E-06	1.5E-04	3.0E-04
7440-48-4	Cobalt (1)	0.0064	1.1E-03	2.8E-03	1.2E-05	0.010	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	3.6E-03	1.1E-02	0.0088	0.163	0.326
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	0.030	0.074	9.2E-04	0.244	0.488
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	0.011	0.433	0.866
110-54-3	Hexane	0.10	3.5E-04	8.8E-04	0.251	0.350	0.701
7647-01-0	Hydrochloric acid	0.096	3.0E-04	7.4E-04	0.034	0.131	0.261
7664-39-3	Hydrogen fluoride (Hydrofluoric acid)	1.2	5.3E-05	1.3E-04		1.226	2.451
193-39-5	Indeno(1,2,3-cd)pyrene	9.1E-05	3.2E-07	8.1E-07	8.9E-07	9.3E-05	1.9E-04
78-59-1	Isophorone	0.86	3.1E-03	7.6E-03		0.866	1.732
7439-92-1	Lead	0.014	6.3E-05	1.6E-04		0.014	0.028
7439-96-5	Manganese	0.025	2.2E-03	5.9E-03	5.3E-05	0.033	0.067
7439-97-6	Mercury	0.006	4.4E-05	1.1E-04	3.6E-05	0.006	0.013
74-83-9	Methyl bromide (Bromomethane)	1.17	0.011	0.027		1.207	2.413
74-87-3	Methyl chloride (Chloromethane)	0.78	5.5E-03	1.4E-02		0.801	1.602
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		0.583	1.166
60-34-4	Methyl hydrazine	0.25	9.0E-04	2.2E-03		0.254	0.508

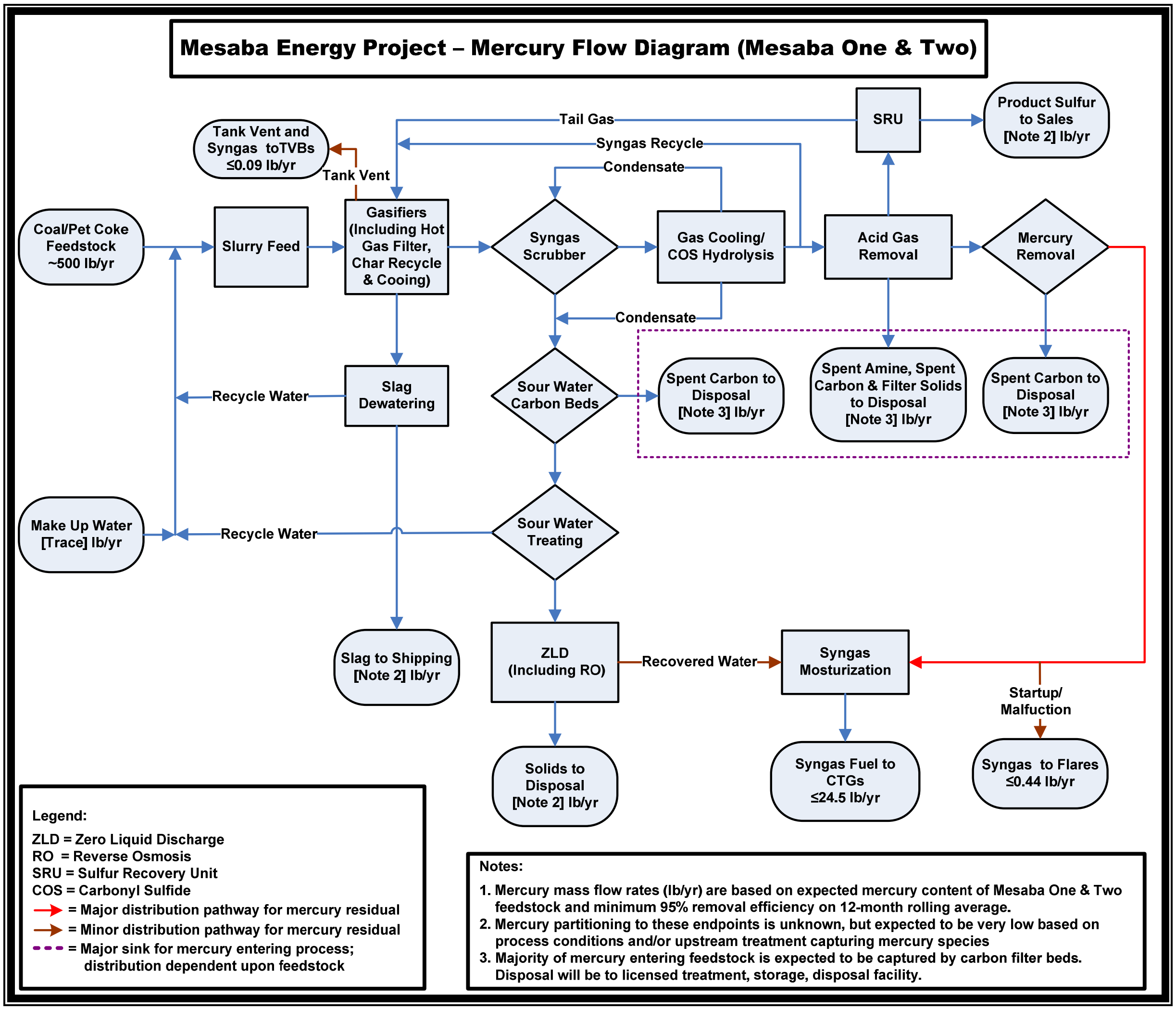
CAS # or MPCA #	Compound	Annual Average HAP Emission (ton/yr)				Total Phase I	Phase I and Phase II
		CTGs	TVB	Flare	Other Sources[1]		
80-62-6	Methyl methacrylate	0.029	1.1E-04	2.6E-04		0.030	0.060
1634-04-4	Methyl tert butyl ether	0.051	1.8E-04	4.6E-04		0.052	0.104
3697-24-3	Methylchrysene, 5-	3.2E-05	1.1E-07	2.8E-07		3.2E-05	6.5E-05
75-09-2	Methylene chloride (Dichloromethane)	0.054	5.2E-04	1.3E-03		0.056	0.111
91-20-3	Naphthalene	0.061	7.5E-04	1.9E-03	3.0E-04	0.064	0.128
7440-02-0	Nickel	0.0096	3.9E-03	9.8E-03	2.9E-04	0.024	0.047
	Other polycyclic organic matter [2]				3.4E-04	3.4E-04	6.8E-04
108-95-2	Phenol	0.90	1.1E-02	2.8E-02	7.8E-08	0.940	1.881
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	5.5E-04	3.35E-06	0.014	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	0.0104	0.0261	0.0017	0.039	0.078
108-05-4	Vinyl acetate	0.011	4.0E-05	1.0E-04		0.011	0.023
1330-20-7	Xylenes	0.055	0.012	0.030	0.0013	0.097	0.195
	Total Federal HAP	***11.2***	***0.1***	***0.4***	***0.4***	***12.1***	***24.3***
	Other Emissions						
7664-93-9 14808-79-8	Sulfuric acid and sulfates	49.5	2.9	1.4		53.9	107.7
	Other VOC				8.3	8.3	16.6
	H_2S			0.07	8.6	8.6	17.2
	Total VOC	9.5	0.1	0.3	8.7	18.7	37.4
	Reduced Sulfur Compounds	1.1	0.004	0.010	8.7	9.8	19.7

[1] 'Other sources' presents the sum of emissions from auxiliary boilers, emergency diesel generators and fire water pumps, and fugitive emissions.
[2] Other polycyclic emissions are the sum of emissions of all other polycyclic organic matter not already specifically listed in this table.

Mercury

The volume of pre-combustion syngas present at the time of its clean-up in the E-Gas™ process would be 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 95 percent of the mercury concentration present in its solid feedstock. For Mesaba One and Mesaba Two, this translates to maximum annual mercury emissions of only 25 pounds on a twelve month rolling average. Excelsior worked with a leading activated carbon supplier, who developed a preliminary design basis for the Project's activated carbon beds targeting a mercury removal rate greater than 99.9 percent. If this performance target were achieved, actual mercury emissions would be less than 3 pounds per year. However, the 95 percent removal rate was proposed for air permitting purposes due to the lack of demonstrated experience with activated carbon bed treatment in domestic IGCC plants. Figure B-10 shows how mercury is expected to partition throughout the IGCC Power Station based on the 95 percent removal rate.

Figure B-10. Expected Mercury Partitioning in the IGCC Power Station (Mesaba One and Mesaba Two)



Greenhouse Gases

Annual emission rates for GHGs have been estimated for each emission source at Mesaba One and Mesaba Two, using the same assumptions for annual operating capacities and fuel consumption that were used for the calculation of criteria pollutant emissions throughout this section. The calculation used broadly accepted GHG emission factors from The Climate Registry for natural gas and diesel fuel.[53] The

[53] The Climate Registry. "2011 Climate Registry Default Emission Factors." January 14, 2011. *See* http://www.theclimateregistry.org/downloads/2009/05/2011-Emission-Factors.pdf

CO_2 emission factor for Mesaba's syngas was estimated at 285 lb/million Btu ("MMBtu"), which is approximately consistent with either full slurry quench ("FSQ") operation for the worst-case PRB feedstock or partial slurry quench ("PSQ") operation for a slightly higher heat content feedstock. This is a reasonably conservative estimate of for worst-case performance on an annual basis. All six GHGs regulated by EPA have been considered, although Mesaba One and Mesaba Two would not use or emit any hydrofluorocarbons or perfluorocarbons. Global warming potential factors prescribed by MPCA and EPA have been applied to methane ("CH_4"), nitrous oxide ("N_2O"), and sulfur hexafluoride ("SF_6") emissions to calculate the CO_2 equivalent ("CO_2e") emission rate.

The GHG emission estimate was determined conservatively, assuming 100% annual operating capacity for all four CTGs on PRB (the worst-case fuel), while also assuming flare and TVB emissions that include some startup, shutdown, and malfunction scenarios throughout the year. Table B-18 shows this inventory of Mesaba One and Mesaba Two's greenhouse gas emissions.

Table B-18. Annual Greenhouse Gas Emission Summary (Phase I and II)

Emission Source	**Emission Rate (ton/year)**				
	CO_2	**CH_4**	**N_2O**	**SF_6**	**CO_2e**
Combustion Turbines	10,600,000	74	115		10,600,000
Tank Vent Boilers	49,900	0.4	0.4		50,000
Flares	108,000	1	0.08		108,000
Auxiliary Boilers	33,300	0.06	0.06		33,500
Fugitive Emissions	64	5		0.03	827
Emergency Generators	392	0.02	0.05		410
Emergency Fire Water Pump Engines	67	negl.	negl.		70
Total	**10,800,000**	**80**	**116**	**0.03**	**10,800,000**

This inventory is consistent with the analysis presented in Section 2.2.3.1 of Mesaba's FEIS, which estimated that Mesaba One and Mesaba Two would directly emit 10.6 million tons of CO_2 per year at 100% capacity factor. In addition to direct emissions, the FEIS analysis also considered indirect emissions due to coal mining, transport and plant operations support and maintenance, which were estimated to total 300,000 additional tons of CO_2 per year. Direct and indirect emissions of other GHGs were estimated at 270,000 tons of CO_2e per year. Construction of Mesaba One and Mesaba Two was estimated to cause a one-time emission of 900,000 tons of CO_2e.

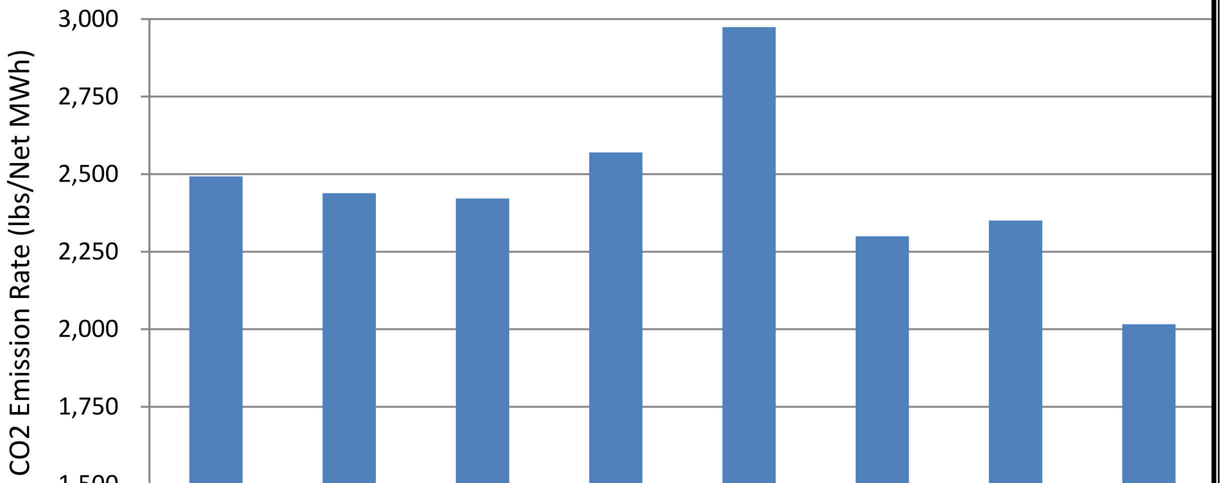
CO_2 emissions from the IGCC Power Station's CTGs were considered the dominant source of greenhouse gas emissions. The emission rate was determined to be primarily a function of the feedstock's carbon content, the feedstock's heating value, and the Station's net heat rate (a measure of the overall efficiency under which the energy in the feedstock is converted to electricity). Based on the heat rates in Table D-4 and emission factors of 202.8 lb CO_2/MMBtu for Illinois No. 6 and 214.6 lb CO_2/MMBtu for Rawhide PRB, the CO_2 emission rate for Mesaba One and Mesaba Two would range from 1,832 lb/net megawatt hours ("MWh_{net}") when operating on 100% bituminous coal to 2,016 lb/MWh_{net} when operating on 100% sub-bituminous coal. These emission rates did not account for any CO_2 removal that would result from future carbon capture.

The CO_2 emission rates from other large coal-fired electric generating units in Minnesota are shown in comparison with the rate associated with Mesaba One and Mesaba Two in Figure B-11.[54] The CO_2

[54] The CO_2 emission rates were calculated by dividing the pounds of CO_2 emitted annually at each facility by the annual net generation.

emission rate associated with 100% sub-bituminous feedstock and worst-case operating assumptions for Mesaba One and Mesaba Two, 2,016 lbs/MWh_{net}, would be 20% lower than the average emission rate of 2,507 lbs/MWh_{net} for the other plants listed in Figure B-11. Due to the conservatism of Mesaba's performance estimates, Excelsior expected actual operating conditions for Mesaba One and Mesaba Two to result in lower overall CO_2 emission rates than those listed in this section. Furthermore, controlling criteria pollutants from conventional coal technology generally reduces efficiency, increasing CO_2 emission rates. Therefore, if Minnesota's existing coal-fired electric generating units added additional criteria pollutant controls, Mesaba's relative advantage in CO_2 emission rates would increase.

Figure B-11. 2007 CO_2 Emission Rates: Existing Minnesota Coal Plants vs. Mesaba



	Allen S King	Black Dog	Boswell	Hoot Lake	Laskin	Sherco	Taconite Harbor	Mesaba One/ Two
Emission Rate	2,493	2,439	2,422	2,570	2,974	2,300	2,350	2,016

Sources: U.S. EPA, Unit Emissions Report, Clean Air Markets - Data and Maps, Unit Level Emissions, 2007, http://camddataandmaps.epa.gov/gdm/index.cfm; U.S. Department of Energy, Energy Information Administration, Form EIA-923, 2007, http://www.eia.doe.gov/cneaf/electricity/forms/eia923.pdf.

b. Water Sources and Usage

This section provides a description of the water sources that were permitted for use by Mesaba One and Mesaba Two, the purpose and quantity of water that the plant would require for use, and the water management plan. While substantial water supply planning was carried out for both the West and East Range Sites, permits were only obtained at the West Range Site following its selection for the Site permit by the MPUC. Therefore, only the technical information relevant to that Site is presented here. Information for the East Range Site is readily available in the Project's FEIS and JPA for Site and Route permits. Similarly, due to the decision during the EIS process to eliminate the discharge of cooling tower blowdown, technical information related to water discharge is not presented, but is available in the JPA.[55]

[55] *See* Appendix 6 to Mesaba Energy Project, Mesaba One and Mesaba Two, Joint Application to the Minnesota Public Utilities Commission for the Following Pre-Construction Permits: Large Electric Power Generating Plant Site

i. Water Sources

Excelsior evaluated a number of potential water sources in order to determine the most appropriate water supplies for Mesaba One and Mesaba Two. The primary sources proposed and permitted for use are three abandoned mine pits or mine pit systems: the CMP, the HAMP, and the LMP. Additionally, the Prairie River was identified as the most likely backup water supply source in the event of some contingency reducing available supply from the permitted sources.

Table B-19 presents the water quality data collected for the abandoned mine pits and Prairie River. Because the mine pits are as much as 300 feet deep, they are primarily groundwater fed, resulting in very good water quality and making them excellent sources of water supply.

Table B-19. Source Water Quality

Constituent		**Water Source**			
	Units	**CMP**	**HAMP Complex**	**LMP**	**Prairie River**
Hardness	mg/l	308	229	--[a]	--[a]
Alkalinity	mg/l	180	163	178	76
Calcium	mg/l	55.3	58.6	73.2	50
Magnesium	mg/l	40.8	20.5	--	22
Iron	mg/l	<0.05	<0.05	--	--
Manganese	mg/l	<0.02	<0.02	--	--
Chloride	mg/l	5.15	5.2	4.9	1.3
Sulfate	mg/l	103.5	59.5	--	<5
TDS	mg/l	337	254	402	--
pH	mg/l	8.4	8.3	7.7	7.4
Aluminum	ug/l	<25	<25	--	91
Barium	ug/l	28.6	29.7	--	--
Cadmium	ug/l	<10	<10	--	--
Chromium (6+)	ug/l	<5	<5	--	--
Copper	ug/l	<10	<10	--	--
Fluoride	mg/l	--	--	--	--
Mercury	ng/l	0.9	0.9	0.8	0.59
Nickel	ug/l	<5	<5	--	--
Selenium	ug/l	<2	<2	--	--
Sodium	mg/l	6.6	6.2	5.0	2.5
Specific Conductivity	umhos/cm	476	418	--	171
Zinc (3)	ug/l	<10	<10	--	--
BOD	mg/l	<2	<2	--	--
COD	mg/l	<2	<2	--	--
TOC	mg/l	1.9	1.9	--	--
TSS	mg/l	1.5	1.5	--	--
Ammonia (as N)	mg/l	<0.1	<0.1	0.1	0.018
Phosphorus	mg/l	<0.1	<0.1	0.01	0.029
[a] --Indicates that no data was collected.					

Permit, High Voltage Transmission Line Route Permit and Natural Gas Pipeline Routing Permit. June 16, 2006.

Table B-20 provides estimates of the water supply capability for each of the preferred water resources. These estimates were developed utilizing information supplied by the MDNR, engineering studies, field studies, and discussions with local government units. Note that the sustainable flows exceed the needs of Mesaba One and Mesaba Two.

Table B-20: Supply Availability

Water Source	Est. Range of Flow (gpm)	Sustainable Flow for Water Appropriation Modeling(gpm)
Canisteo Mine Pit	1,970–4,190[a]	2,800
Hill-Annex Mine Pit Complex	1,600-4,030[b]	2,000-3,500[c]
Lind Mine Pit	1,500-4,400[d]	3,300[e]
Prairie River	0–6,500[f]	0[g]
Total	5,070–19,120	8,100–9,600
Average Use by Mesaba One and Two:		7,000

[a] Based on operating elevations below assumed bedrock level of 1,300 feet msl, bedrock elevation along the south CMP pit wall varies greatly but nearly all of it north of Coleraine and Bovey is below elevation 1300 msl. In the Coleraine and Bovey areas, bedrock elevation ranges from 1220 msl to 1280 msl.[56]
[b] Maximum flow occurs at minimum operating elevation
[c] At operating elevations of 1,230 and 1,100 feet msl, respectively
[d] Low end based on flow into LMP from West Hill and ignoring groundwater recharge; high end based on flow out of LMP
[e] This flow rate will be sustained by operating the LMP at water levels such that the present, continuous discharge to the Prairie River through the existing culvert is curtailed.
[f] Based on 5% of mean annual flow
[g] No use of Prairie River is anticipated, but sustainable flows of more than 1,000 gpm could be available if necessary

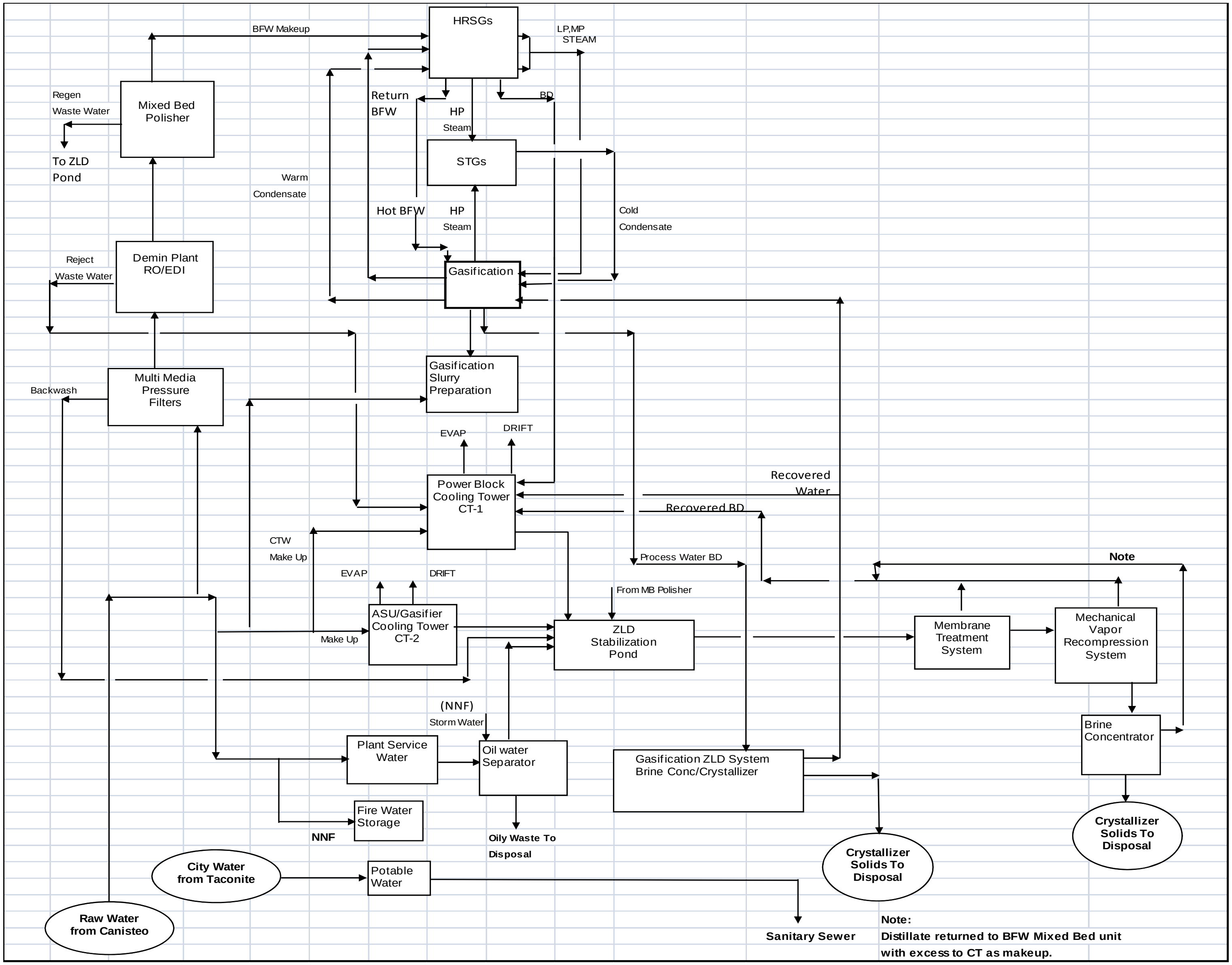
ii. Water Usage

Figure B-12 presents the water balance diagram, showing the proposed flow of water within the plant. Virtually all water would enter the plant as raw water from the Canisteo pump station. All stormwater that falls on the IGCC Power Station footprint would be collected and used. A small amount of potable water for plant employee use would be supplied by the City of Taconite and sanitary sewage would be treated by the Coleraine-Bovey-Taconite municipal treatment system.

As the figure shows, all liquid discharges from the plant would be eliminated through the use of two ZLD systems. Process water blowdown from the gasification systems would be treated by a brine concentrator and crystallizer. A separate ZLD system would treat cooling tower blowdown, as described in more detail below. Nearly all water was designed to be removed from the plant via evaporation from the two blocks of cooling towers. Solids produced by the ZLD treatment would be transported by truck to waste treatment facilities. Some moisture would remain with the solids. See Section B.6.d for further discussion of solid byproducts.

[56] MDNR, Letter to Robert Evans, February 18, 2011.

Figure B-12. Water Balance Diagram



Water usage at the plant would be a consumptive use. Depending on the number of COCs, at least 80% of the process water would initially be evaporated into the atmosphere. As evaporation occurs, solids concentration increases. In order to prevent scaling, corrosion, or other problems from developing in the cooling tower, these solids must be removed. Unlike many electric power generating facilities that discharge cooling tower blowdown, Mesaba One and Mesaba Two was designed to utilize a ZLD treatment system for cooling tower blowdown. The same system would also treat stormwater for re-use to eliminate its discharge. This ZLD system would consist of membrane filtration, mechanical vapor recompression, and brine crystallization processes to produce pure water (to be reused for evaporative cooling or other purposes) and concentrate solids for disposal. As a result, all process water discharges would be eliminated and total water appropriations would be reduced due to reuse of the treated water.

On an annual average basis, Mesaba One would require approximately 3,500 gallons of process and cooling water per minute; Mesaba One and Mesaba Two would require a total water appropriation of 7,000 gpm. Peak utilization rates would occur on hot, humid days and could reach 5,000 gpm for Mesaba One and 10,000 gpm total for Mesaba One and Mesaba Two. Water usage is summarized in the following table.

Table B-21. IGCC Power Station Water Needs

	Average Annual Need (gpm)	**Peak Need (gpm)**
Phase I	3,500	5,000
Phase I & II	7,000	10,000

Water Management Plan

Water supplies for Mesaba One and Mesaba Two would come from the three abandoned mine pits described in the previous section. If necessary, the Prairie River would serve as a contingent water supply. Three pumping stations – one to serve each mine pit – would be required to appropriate necessary amounts of water. Water would be appropriated from the Prairie River in the event of an unexpected contingency occurring after commencing operation of Mesaba Two and resulting from curtailment of the Stations' other Water Resources. Under such a circumstance, water could be transferred from the Prairie River via a gravity flow pipeline or pumping station and be treated and/or stored in a manner to minimize transfers of phosphorus to the CMP.

The following provides a summary of the water management plan:

Phase I

- Water from the HAMP Complex would be pumped via a pump station in the Gross Marble Mine Pit ("GMMP") to the CMP. The CMP pump station would then pump water to the IGCC Power Station.

Phase II

- Water from the HAMP Complex would be pumped via a pump station in the GMMP to the CMP. Additional pumps in the HAMP would likely be required to pump water in the HAMP to the GMMP, if water elevations must be lowered to increase inflow rates.
- A pumping station in the LMP would pump water to the CMP.
- A pump station on the CMP would pump water to the IGCC Power Station.

- Water levels in the three pits and related pumping equipment would be managed during Phase I and Phase I and II to allow for the following:

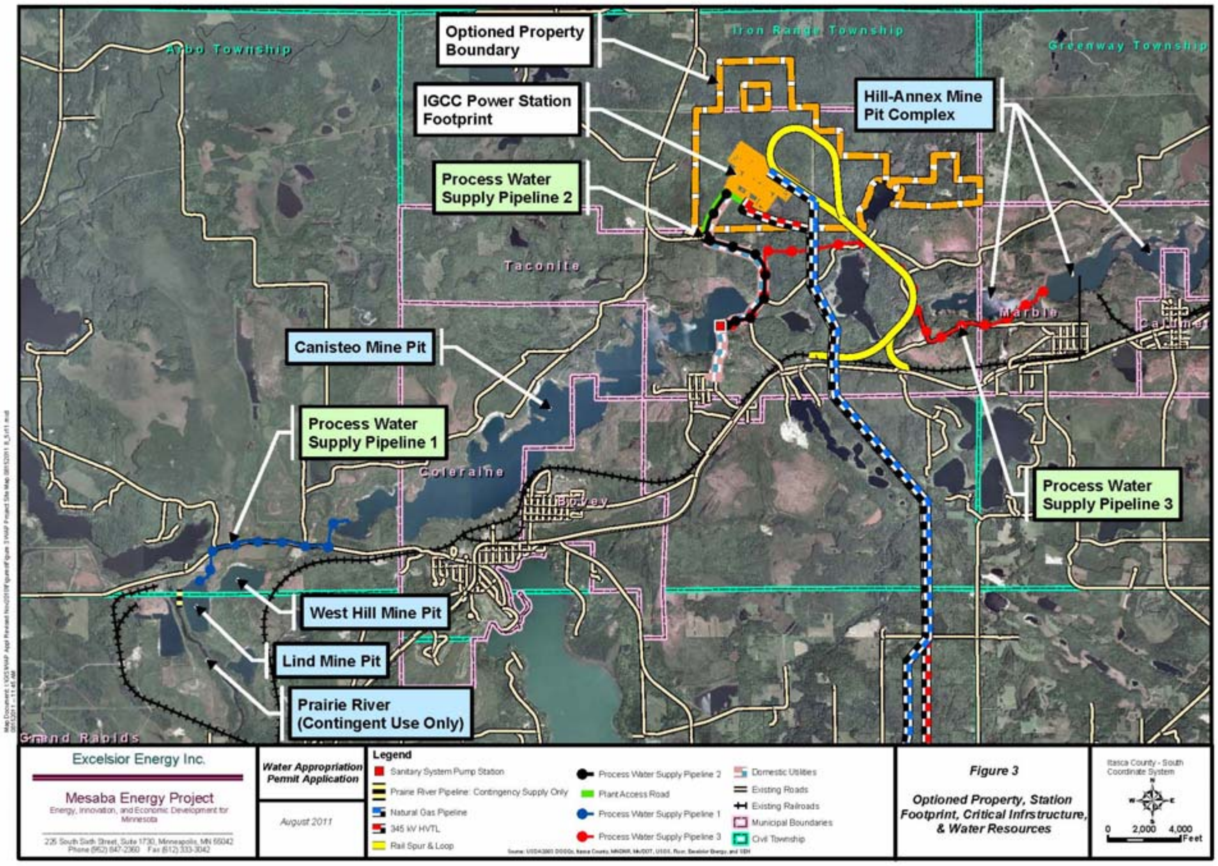
    - Immediate lowering of water levels in the CMP
    - Continued pumping of the HAMP Complex
    - Retention of water in years of excess rainfall
    - Delivery of retained water in years of low rainfall

Based on water availability and need, Excelsior obtained permits (conditional upon securing necessary access easements) for the following:

- A water appropriation permit to withdraw water from the HAMP Complex at a point in the GMMP for up to 3,500 gpm annual average rate, 5,000 gpm peak rate, and a normal operating range of 1,220 to 1,250 feet msl. Under circumstances constituting a contingency, the permit would allow for pumps to be installed in the HAMP and water levels therein to be reduced to 1,100 feet msl through transfers to the GMMP.
- A water appropriation permit at the LMP for 3,500 gpm annual average rate, 5,000 gpm peak rate, and an operating range of 1,255 to 1,264 feet msl.
- A water appropriation permit at the CMP for 7,000 gpm annual average rate, 10,000 gpm peak rate, and an operating range of 1,283 to 1,305 feet msl, although under normal circumstances, water levels would fluctuate between 1,288 and 1,292 feet msl. Under circumstances constituting a contingency, the permit would allow for water levels in the CMP to be reduced to 1,283 feet msl.

Figure B-13 shows the relevant infrastructure and water resources associated with Mesaba One and Two's water appropriation.

Figure B-13. Optioned Property, Relevant Infrastructure, and Water Resources



A series of pumps would provide a pumping capacity between 3,500 gpm and 5,000 gpm for Phase I and between 7,000 gpm and 10,000 gpm for both Phase I and II collectively. This capacity would be provided by a pumping station located in the northeastern-most section of the CMP. The pumping station would be designed to accommodate easy relocation within this section of the CMP (i.e., a floating pump station) or be permanently situated on land with the capability of moving underwater intake pipes should such movement be required. Redundancy would be incorporated for use in case one of the pumps fails or is undergoing maintenance. The pump station intake would meet CWA Section 316(b) requirements for cooling water intake structures. The pipeline that extends from the CMP to the Station Footprint would be up to 36 inches in diameter. The estimated length of the pipeline that would extend from the CMP to the Footprint was determined to be 11,300 feet. During a typical year, approximately 2,800 gpm of the 7,000 gpm total IGCC Power Station use would be supplied by recharge of the CMP, and 4,200 gpm would be pumped into the CMP from the other Water Resources.

A second pump station would be located in the Gross-Marble section of the HAMP. The pump station would have a capacity of 5,000 gpm and be positioned in the GMMP nearby the Arcturus Mine Pit. Water would be directed to the CMP via a pipeline up to 24 inches in diameter and approximately 25,400 feet in length. The pump station intake would meet CWA Section 316(b) requirements for cooling water intake structures. During a typical year, it was anticipated that approximately 2,000 gpm would be supplied by the HAMP Complex and pumped to the CMP. If Essar Steel Minnesota were to use water from the HAMP Complex, additional supply could be drawn from the LMP or from the HAMP Complex by lowering the water levels.

A pump station with a capacity of 5,000 gpm would be installed in the northeast section of the LMP, and water would be directed to the CMP. The pipeline that extends from the LMP to the CMP would be approximately 24 inches in diameter with a pipeline length of 11,300 feet. The pump station intake would meet CWA Section 316(b) requirements for cooling water intake structures. During a typical year, it was anticipated that approximately 2,200 gpm would be supplied by the LMP and pumped to the CMP, leaving approximately 1,300 gpm in reserve supply.

If necessary, a gravity-driven pipeline or pump station from the Prairie River would be installed next to the river and water would be directed into the LMP for storage. The pipeline that extends from the Prairie River to the LMP would be up to 16 inches in diameter and approximately 400 feet in length. The intake would meet CWA Section 316(b) requirements for cooling water intake structures. During a typical year, it was anticipated that no water would need to be supplied by the Prairie River.

Larger pumping capacity at the HAMP Complex and the LMP would provide operational flexibility for the water management plan. This flexibility would help manage seasonal water levels and maximize storage potential in all three mine pits.

Routing for the pipelines would be primarily on public property adjacent to existing transportation corridors. Figure 3 shows an overview of the water supply plan. Table B-22 summarizes the pumping station capabilities needed to serve the IGCC Power Station. Peak flow was defined as the maximum instantaneous flow necessary, which would occur during short, intra-day periods of high ambient air temperatures and humidity, driven by cooling water demands. The maximum average monthly flow would occur in summer and would be approximately 8,000 gpm.

Table B-22: Supply Capability and Pumping Stations

	Peak Flow (gpm)	Typical Annual Average Supply (gpm)
Canisteo Mine Pit	10,000	2,700
Hill-Annex Mine Pit – Gross Marble End of Mine Pit	5,000	2,000
Lind Mine Pit	5,000	2,300
Prairie River (if necessary)	2,000	0

c. Wetland Impacts and Minimization

Substantial efforts were undertaken throughout the environmental review and permitting process to survey wetlands and quantify and minimize the Project's impacts to wetlands at both the West and East Range sites. As with water source and supply analysis, only the West Range information is presented below, because additional surveys and refinements were carried out following issuance of the Site permit. Detailed information regarding wetlands and impacts for the East Range Site can be found in the FEIS.

Table B-23 presents the wetland basins identified through delineation surveys of the accessible portions within and in the immediate vicinity of the West Range Site.

Table B-23. West Range Site Wetland Summary

ID	Total Area within Site (Acres)	Wetland Classification		
		Cowardin	Circular 39	Eggers & Reed
A1	98.67	PEMB, PSS1, PFO4	Type 3/6/8	Shallow Marsh, Shrub Carr, Coniferous Bog
A2	0.06	PFO1B	Type 7	Hardwood Swamp
A3	0.10	PFO1C	Type 7	Hardwood Swamp
A4	103.56	PFO1C/F	Type 7	Hardwood Swamp
A6	0.38	PEMC/PFO1C	Type 7	Hardwood Swamp
A7	0.04	PFO1C	Type 7	Hardwood Swamp
A8	0.04	PEMC	Type 3	Shallow Marsh
A9	1.18	PFO1B	Type 7	Hardwood Swamp
A10	0.17	PEMC	Type 3	Shallow Marsh
A11	0.13	PEMC	Type 3	Shallow Marsh
A12	0.35	PSS1B	Type 6	Alder Thicket
A13	0.45	PFO1B	Type 7	Hardwood Swamp
A15	0.26	PEMC/PFO1C	Type 3/7	Shallow Marsh/Hardwood Swamp
A16	0.07	PEMC	Type 3	Shallow Marsh
A17	0.02	PEMC/PFO1C	Type 3/7	Shallow Marsh/Hardwood Swamp
A18	0.11	PEMC/PFO1C	Type 3/7	Shallow Marsh/Hardwood Swamp
A19	0.02	PEMC/PFO1C	Type 3/7	Shallow Marsh/Hardwood Swamp
A20	0.38	PFO1C	Type 7	Hardwood Swamp
A21	0.01	PEMC/PFO1C	Type 3/7	Shallow Marsh/Hardwood Swamp
A22	0.04	PEMC/PFO1C	Type 3/7	Shallow Marsh/Hardwood Swamp
A23	0.11	PEMC/PFO1C	Type 3/7	Shallow Marsh/Hardwood Swamp
A27	0.11	PFO1C	Type 7	Hardwood Swamp
A28	0.24	PEMC/PFO1C	Type 3/7	Sedge Meadow/Hardwood Swamp
A29	0.08	PEMC/PFO1C	Type 3/7	Sedge Meadow/Hardwood Swamp
A30	0.04	PEMC	Type 3	Shallow Marsh
A32	0.14	PEMC	Type 3	Shallow Marsh
A33	0.07	PEMC	Type 3	Shallow Marsh
A34	0.08	PEMC	Type 3	Shallow Marsh
A35	0.02	PEMC	Type 3	Shallow Marsh
A36	0.04	PEMC	Type 3	Shallow Marsh
A37	0.36	PEMC	Type 3	Sedge Meadow
A38	0.07	PSS1C/PFO1C	Type 6/7	Alder Thicket/Hardwood Swamp
A39	0.27	PEMC/PSS1C	Type 3/6	Sedge Meadow/Alder Thicket
A40	0.23	PEMC/PSS1C	Type 3/6	Shallow Marsh/Alder Thicket
B1	0.15	PFO1B	Type 7	Hardwood Swamp
B2	0.38	PFO1A	Type 7	Hardwood Swamp
B3	1.06	PFO1A	Type 7	Hardwood Swamp
B4	0.25	PFO1A	Type 7	Hardwood Swamp
B5	0.02	PFO1A	Type 7	Hardwood Swamp
B6	0.03	PFO1A	Type 7	Hardwood Swamp
B7	0.03	PFO1A	Type 7	Hardwood Swamp
B8	0.06	PFO1A	Type 7	Hardwood Swamp
B9	0.29	PFO1A	Type 7	Hardwood Swamp
B10	0.06	PFO1A	Type 7	Hardwood Swamp
B11	0.29	PFO1A	Type 7	Hardwood Swamp
B12	0.05	PFO1A	Type 7	Hardwood Swamp
B13	0.16	PFO1A	Type 7	Hardwood Swamp
B14	0.37	PFO1A	Type 7	Hardwood Swamp
B15	11.07	PEMB/PSS1C/ PFO1A	Type 2/6/7	Wet Meadow/Alder Thicket
B16	0.27	PEMC	Type 3	Sedge Meadow
B17	0.03	PEMB	Type 2	Sedge Meadow
C1	0.31	PEMC	Type 3	Shallow Marsh
C2	0.13	PEMB	Type 3	Shallow Marsh
C3	2.47	PEM1H	Type 5	Shallow Open Water

ID	Total Area within Site (Acres)	Wetland Classification		
		Cowardin	Circular 39	Eggers & Reed
C4	79.40	PEM1H	Type 5	Shallow Open Water
C6	0.16	PEMC	Type 3	Shallow Marsh
C9	21.85	PEMC/PFOB7	Type 3/8	Shallow Marsh/Coniferous Bog
C10	4.89	PSS1A	Type 6	Alder Thicket
C11	0.88	PEM2H	Type 5	Shallow Open Water
C12	0.67	PSSC1	Type 6	Alder Thicket
C13	0.90	PSS1C/PFO1C	Type 6/7	Alder Thicket/Hardwood Swamp
C14	1.02	PEM2H	Type 5	Shallow Open Water
C15	1.36	PSS1C	Type 6	Alder Thicket
C16	6.12	PEMC	Type 3	Sedge Meadow
C17	0.54	LAB2	Type 5	Shallow Open Water
C18	0.22	PSS1C	Type 6	Alder Thicket
C19	1.42	PEM2H	Type 5	Shallow Open Water
C20	4.18	PEMC/PSS1C	Type 3/6	Sedge Meadow/Alder Thicket
C21	0.69	PSS1C	Type 6	Alder Thicket
C22	0.92	PSS1C	Type 6	Alder Thicket
C23	0.62	PSS1C/PFO1C	Type 6/7	Alder Thicket/Hardwood Swamp
C24	0.48	PFO2B	Type 8	Coniferous Bog
C26	0.12	PFO1C	Type 7	Coniferous Swamp
C27	3.04	PFO1C	Type 7	Coniferous Swamp
C28	1.10	PFO1C	Type 7	Coniferous Swamp
D1	0.02	PFO1C	Type 7	Hardwood Swamp
D2	3.42	PEMB	Type 3	Shallow Marsh
D3	0.01	PEMC/PFO1C	Type 3/7	Sedge Meadow/Hardwood Swamp
D5	0.10	PEMC	Type 3	Sedge Meadow
D6	0.09	PEMC/PFO1C	Type 3/7	Shallow Marsh/Hardwood Swamp
D8	2.94	PEMC/PFO1C/ PFO4B	Type 3/7/8	Shallow Marsh/Hardwood Swamp/Coniferous Bog
D9	1.46	PEMH/PSS1C	Type 4/6	Deep Marsh/Alder Thicket
D10	1.24	PEMC/PSS1C	Type 3/6	Sedge Meadow/Shrub Carr
D12	0.46	PEMC/PFO1C	Type 3/7	Sedge Meadow/Hardwood Swamp
D13	0.06	PEMC/PFO1C	Type 3/7	Sedge Meadow/Hardwood Swamp
D14	1.13	PSS1C/PFO1C	Type 6/7	Shrub Carr/Hardwood Swamp
E1	1.37	PEMC	Type 3	Shallow Marsh
E2	0.70	PEMB	Type 2	Wet Meadow
E3	0.08	PEMC	Type 3	Shallow Marsh
E4	0.67	PEMC	Type 3	Shallow Marsh
E5	0.65	PEMH	Type 8	Coniferous Bog
E6	0.42	PEMC	Type 3	Shallow Marsh
E7	1.44	PEMC	Type 3	Shallow Marsh
E9	0.24	PEMB	Type 3	Shallow Marsh
E11	18.34	PEMC	Type 3	Shallow Marsh
E12	5.65	PFO2C	Type 8	Coniferous Bog
E13	0.13	PEMC	Type 3	Shallow Marsh
E14	0.49	PEMC/PEMG	Type 3/4	Shallow Marsh/Deep Marsh
E15	0.14	PEMC	Type 3	Shallow Marsh
E16	0.15	PEMC	Type 3	Shallow Marsh
E17	0.76	PEMC	Type 3	Shallow Marsh
E18	8.24	PEMC	Type 3	Shallow Marsh
F1	3.52	PSS1C/PFO1C	Type 6/7	Alder Thicket/Hardwood Swamp
F2	0.06	PEMC/PFO1C	Type 3/7	Shallow Marsh/Hardwood Swamp
G1	0.26	PEMB	Type 2	Wet Meadow
G2	0.12	PFO1B	Type 7	Hardwood Swamp
G3	0.08	PFO1B	Type 7	Hardwood Swamp
G4	0.07	PEMB	Type 2	Wet Meadow
G5	0.04	PEMB	Type 2	Wet Meadow

ID	Total Area within Site (Acres)	Wetland Classification		
		Cowardin	Circular 39	Eggers & Reed
G6	0.04	PFO1B	Type 7	Hardwood Swamp
G7	0.02	PFO1B	Type 7	Hardwood Swamp
G8	0.03	PFO1B	Type 7	Hardwood Swamp
H2	0.05	PEMB	Type 2	Sedge Meadow
H3	0.02	PEMB	Type 2	Sedge Meadow
H4	0.03	PEMB	Type 2	Sedge Meadow
H5	0.40	PFO1B	Type 7	Hardwood Swamp
H12	0.67	PFO1B	Type 7	Hardwood Swamp
H13	0.01	PFO1B	Type 7	Hardwood Swamp
H14	0.09	PEMB	Type 2	Sedge Meadow
H16	0.54	PEMB	Type 2	Sedge Meadow
H17	0.05	PEMB	Type 2	Wet Meadow
H20	0.02	PEMB	Type 2	Wet Meadow
H22	0.10	PEMC	Type 3	Shallow Marsh
H23	0.85	PSS1C	Type 6	Alder Thicket
H24	2.47	PEMD	Type 4	Deep Marsh
I1	0.20	PEMB	Type 2	Sedge Meadow
I2	0.02	PEMB	Type 2	Sedge Meadow
I3	0.33	PSS1B	Type 6	Alder Thicket
Total	**414.39**			

Wetland impact minimization efforts included examination of several alternative plant locations within the boundaries of the West Range Site in conjunction with alternative alignments for the rail loop. Alternative alignments or routes for the access road, pipelines, and transmission lines were also studied. These analyses resulted in shifting the IGCC Power station to the northwest by 280 feet, realigning the access road by approximately half a mile, and moving the rail loop to the southeast to encircle a hill instead of a wetland. Together, these changes would reduce direct wetland impacts by approximately 10 acres, and avoid encircling (and potentially impacting) approximately 65 acres in the rail loop. A summary of total impacts and projected mitigation requirements is provided in Table B-24. The wetland impact minimizing alignments, resulting impacts, and wetland basins are graphically identified in Figure B-14. Wetland mitigation was proposed to be accomplished via obtaining credits from regional wetland banks.

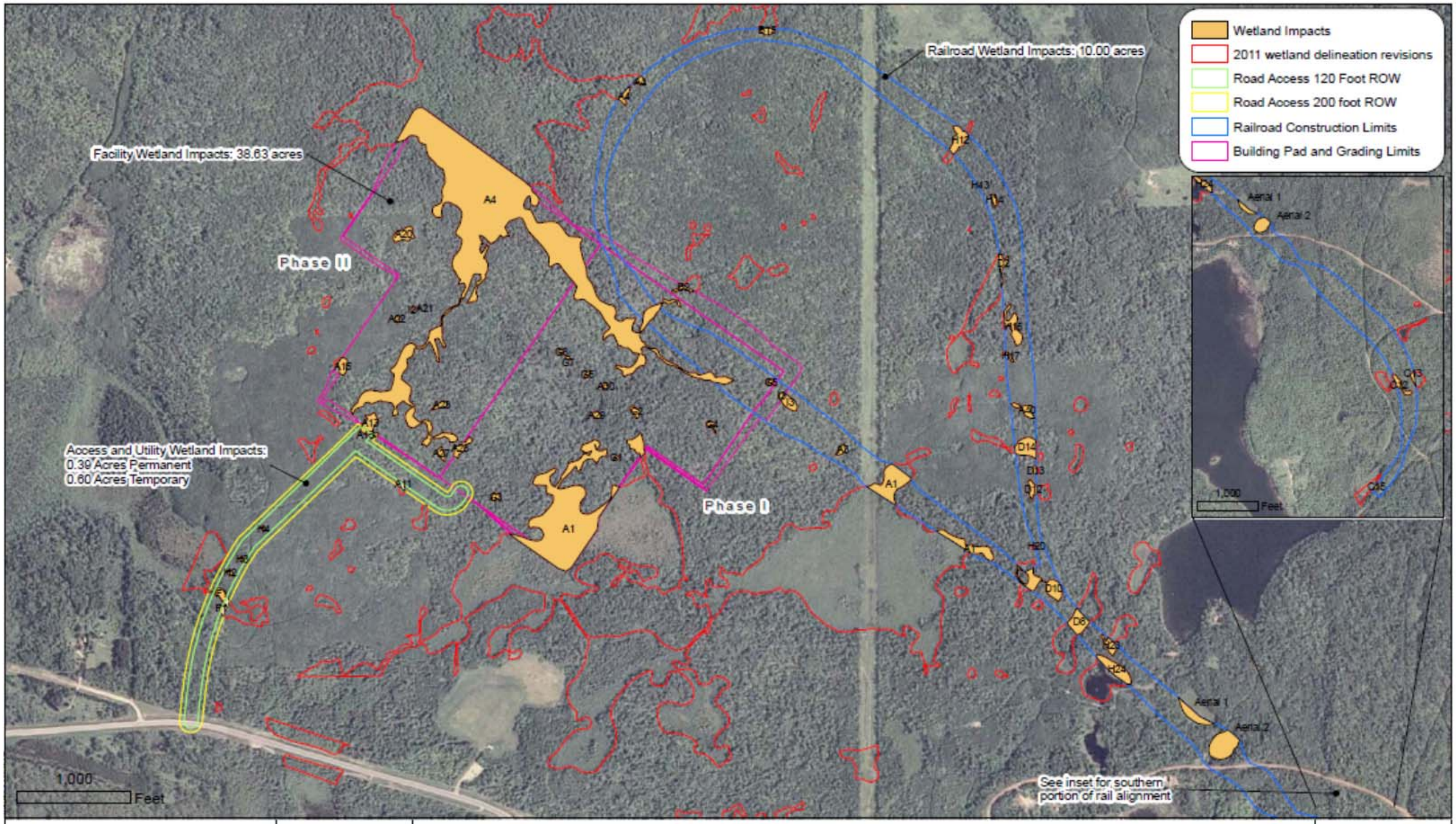
Table B-24. Summary of Wetland Impacts for the West Range IGCC Power Station, Buffer Land, and Associated Facilities

Project Element	Wetland Types													Total Wetland Impacts	Wetland Mitigation Requirements
	Type 1	Type 2		Type 3	Type 4	Type 5	Type 6			Type 7		Type 8			
	Floodplain Forest	Wet Meadow	Sedge Meadow	Shallow Marsh	Deep Marsh	Shallow Open Water	Alder Thicket	Shrub Swamp	Shrub Carr	Hardwood Swamp	Coniferous Swmap	Coniferous Bog	Open Bog		
Permanent Wetland Impacts															**1:1**
IGCC Power Station		0.05	0.15				0.04		8.64	29.75				38.63	
Phase 1		0.03	0.15				0.04		8.64	5.03				13.89	
Phase 2		0.02								24.72				24.74	
Railroad		0.05	1.05	0.20	1.75		1.57		3.75	1.63				10.00	
Access Road			0.10	0.004						0.29				0.394	
HVTL							0.0026		0.0006	0.0026		0.0039		0.01	
													Subtotal Wetland Fill	**49.03**	
Mitigation Requirement Subtotal	**0.00**	**0.10**	**1.30**	**0.204**	**1.75**	**0.00**	**1.61**	**0.00**	**12.39**	**31.67**	**0.00**	**0.00**	**0.00**		**49.03**
Temporary Emergent Wetland Impacts															**0.10:1**
Access Road				0.08										0.08	
Gas Pipe Alt. 1	0.70	1.98		1.22										3.90	
Process Water 1 - Lind Pit to Canisteo														0.00	
Process Water 2 - Canisteo to IGCC site														0.00	
Process Water 3 - Gross Marble to Canisteo					0.62	0.64								1.26	
Potable Water and Sanitary Sewer														0.00	
													Subtotal Temporary Emergent Wetland Disturbance	**5.24**	
Mitigation Requirement Subtotal	**0.07**	**0.20**	**0.00**	**0.13**	**0.06**	**0.06**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**		**0.52**
Temporary Scrub-Shrub Wetland Impacts (TWS)															**0.25:1**
Access Road							0.004							0.00	
HVTL							2.33							2.33	
Gas Pipe Alt. 1							0.83		0.01					0.84	
Process Water 1 - Lind Pit to Canisteo														0.00	
Process Water 2 - Canisteo to IGCC site							0.18							0.18	
Process Water 3 - Gross Marble to Canisteo							1.15							1.15	
Potable Water and Sanitary Sewer														0.00	
													Subtotal Temporary Scrub-Shrub Wetland Disturbance	**4.50**	
Mitigation Requirement Subtotal	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**1.12**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**		**1.12**
Permanent Type Conversion (Scrub-Shrub and Forested)															**0.50:1**
Access										0.13				0.13	
HVTL							9.40			6.84		19.92		36.16	
Gas Pipe Alt. 1							3.00		1.50	9.16		2.72		16.38	
Process Water 1 - Lind Pit to Canisteo														0.00	
Process Water 2 - Canisteo to IGCC site							0.12			1.98				2.10	
Process Water 3 - Gross Marble to Canisteo							1.23			0.46	0.05	0.63		2.37	
Potable Water and Sanitary Sewer														0.00	
													Subtotal Permanent Type Conversion	**57.14**	
Mitigation Requirement Subtotal	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**6.88**	**0.00**	**0.75**	**9.22**	**0.03**	**11.64**	**0.00**		**28.51**
Total Wetland Mitigation Requirement	**0.07**	**0.30**	**1.30**	**0.33**	**1.81**	**0.06**	**9.61**	**0.00**	**13.14**	**40.89**	**0.03**	**11.64**	**0.00**		**79.19**

* Avoids double counting of wetland impacts.

Wetland impacts are first counted for the plant site, rail, road, HVTL, gas pipeline, process water lines, sanitary sewer, in that order.

Figure B-14. Wetland Basins and Impacts



d. Solid Byproducts and Waste

Solid wastes produced would include miscellaneous janitorial streams associated with clean-up of the IGCC Power Station, commercial waste paper, spent activated carbon beds, and spent catalyst materials (associated with the COS hydrolysis and sulfur recovery unit ("SRU") systems). The solid waste streams produced by the ZLD systems are discussed below. Off-site disposal of wastes that cannot otherwise be recycled or reused on-site would be conducted in compliance with all local, state and federal rules and regulations.

Slag and elemental sulfur produced as a result of the mineral matter and sulfur contained in the feedstocks utilized were considered to be potential revenue producing streams that would be actively marketed.

Table B-25 summarizes the expected waste streams that would be generated during operation of the Phase I and II IGCC Power Station. These estimates were based upon experience gained at Wabash River and adjusted for differences in capacity and configuration. Operational wastes would generally include the following process wastes:

- Spent catalysts, adsorbents, and process solvents
- Used oils and fluids
- Cleaning and maintenance wastes
- Miscellaneous materials

The environmental features of E-Gas™ technology would avoid two significant solid waste streams – flue gas desulfurization ("FGD") solids and ash – associated with other types of coal-based power generation:

- Conversion of mineral materials in the plant feed to a non-hazardous, marketable slag by-product eliminates the need to dispose of fly ash and bottom ash waste streams.[57] The properties of the slag product are described in Table B-26.[58]
- Removal of sulfur from IGCC syngas in a relatively concentrated form and the subsequent production of elemental sulfur, another marketable by-product, eliminate the significant solid wastes that could result from the flue gas desulfurization process needed for other types of coal-based plants.

The use of a ZLD process would prevent the discharge of heavy metals and other gasification wastes with the plant wastewater effluent. The solid waste stream from this process, consisting mainly of crystallized solids in a "filter cake," would likely be classified as a hazardous waste due to metals content and would be disposed in an approved hazardous waste landfill or other licensed facility. Table B-27 presents a typical composition of ZLD filter cake from the system serving the gasification island, based on data from Wabash River.

Residual solids from the separate ZLD system serving the cooling towers would be considered nonhazardous, as it consists of the dissolved solids in the raw water from the mine pits serving the plant.

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[57] In some plants that use wet limestone FGD or lime spray dryer FGD systems, a cost cutting step is to remove fly ash along with SO_2 in the post combustion flue gases and place the combined calcium sulfate/sulfite and ash mixture in an on-site landfill.

[58] Trace metals such as chromium, nickel, vanadium, etc., are captured in the impervious glassy matrix of the slag. The slag is non-hazardous, and will pass EPA's TCLP leachate test for metals, semi-volatile and volatile organics listed under RCRA.

Solids production depends on source water TDS and was calculated as follows: Solids = 3,500 gal/min-phase*2 phases*8.33 lb/gal*1,440 min/day*337 lb/10^6 lbs water*1 ton/2000 lbs ≈ 14 tons/day.

Table B-25. Estimated Operational Waste Streams (Phase I and II)

Waste Description	Comments	Annual Quantity	H/NH*	Likely Disposition
Used Catalysts and Sorbents				
COS hydrolysis catalyst	Proprietary composition	42 tons	NH	Non-hazardous landfill
Hydrolysis catalyst support balls	Alumina silicate	14 tons	(NA)	Recycle
Claus sulfur recovery catalyst	Activated alumina	28 tons	NH	Non-hazardous landfill
Claus catalyst support balls	Activated alumina	10 tons	(NA)	Recycle
Hydrogenation catalyst	Cobalt Molybdenum	6 tons	(NA)	Metals reclaim
Hyd. catalyst support balls	Alumina silicate	2 tons	(NA)	Recycle
Amine regenerator carbon filter	Activated carbon	26 tons	H	Stabilize, hazardous waste landfill
Syngas treatment carbon	Activated carbon	60 tons	H	Stabilize, hazardous waste landfill
Mercury removal carbon	Impregnated carbon	14 tons	H	Stabilize, hazardous waste landfill
Sour water carbon	Activated carbon	48 tons	H	Stabilize, hazardous waste landfill
MDEA reclaim ion exchange	Ion exchange resin	0.4 tons	NH	Non-hazardous waste landfill
Trim Sulfur sorbent	Activated zinc oxide	2-5,000 tons	(NA)	Metals reclaim
Other Process Wastes				
ZLD filter cake (Gasification Island)	Inorganic and organic salts	4400 tons	H	Stabilize, hazardous waste landfill
ZLD filter cake (Cooling Tower Blowdown)	Inorganic salts	5000 tons	NH	Non-hazardous waste landfill
Refractory brick and insulation	Gasifier repairs	360 tons	NH	Non-hazardous waste landfill
MDEA sludge	Reclaimer bottoms	10,000 gal	H	Incinerate or hazardous waste landfill
Sour water sludge	Char carryover in syngas	30 tons	H	Incinerate
Waste char and ash	Maintenance cleaning	160 tons	N	Non-hazardous waste landfill
Amine absorber residues	Iron and salts	20 yd^3	N	Non-hazardous waste landfill
Metallic filter elements		60 yd^3	H	Stabilize, hazardous waste landfill

Waste Description	Comments	Annual Quantity	H/NH*	Likely Disposition
Spent citric acid	Cleaning solution	40 drums	H	Approved disposal facility
Spent soda ash	Cleaning solution	40 drums	H	Approved disposal facility
Spent sulfuric acid	Line cleaning solution	14,000 gal	H	Approved disposal facility
Off-line combustion turbine wash wastes	Detergent and residues	15,000 gal	Probably NH	Characterize, dispose as non-hazardous or hazardous wastes
HRSG wash water (infrequent)	Detergent, residues, neutralized acids	100,000 gal	Probably NH	Characterize, dispose as non-hazardous or hazardous wastes
Raw water treatment sludge and used water filter media	Solids removed from makeup water to plant	TBD	Probably NH	TBD
Miscellaneous Streams				
Used oil	Lube oils, oil from oil/water separator	8000 gal	(NA)	Send to reclaimer
Spent grease		16 drums	NH	Blend to gasifier feed
Miscellaneous solvents, coal tars		2 drums	H	Solvent reclaimer
Flammable lab waste		2 drums		Blend to gasifier feed
Scrap metal	Steel, aluminum, etc.	200 yd^3	NH	Recycle
Waste paper and cardboard	Office, shops, packing, etc.	320 yd^3	NH	Recycle
Combined industrial waste	Used PPE, materials, small amounts of refractory, slurry debris, etc.	320 yd^3	NH	Non-hazardous waste landfill

***Legend:** NH = Non-Hazardous; H = Hazardous; NA= Not Applicable

Table B-26. E-Gas™ Slag Properties

Mesh Size	Wt. %
8	28
12	20
16	20
-16	32

TCLP Organics	RCRA Regulatory Level (mg/l)	Leachate from E-Gas Slag (mg/l)
Pyridine	5	<0.05
1,4-Dichlorobenzene	7.5	<0.05
o-Cresol	200	<0.05
m- & p-Cresol	200	<0.05
Hexachloroethane	3	<0.05
Nitrobenzene	2	<0.05
Hexachloro-1,3-butadiene	0.5	<0.05
2,4,6-Trichlorophenol	2	<0.05
2,4,5-Trichlorophenol	400	<0.05
2,4-Dinitrotoluene	0.13	<0.05
Hexachlorobenzene	0.13	<0.05
Pentachlorophenol	100	<0.05

TCLP Volatile Organics	RCRA Regulatory Level (mg/l)	Leachate from E-Gas Slag (mg/l)
Vinyl Chloride	0.2	<0.005
1,1-Dichloroethylene	0.7	<0.005
Methyl Ethyl Ketone	200	<0.005
Chloroform	6	<0.005
1,2-Dichloroethane	0.5	<0.005
Benzene	0.5	<0.005
Carbon Tetrachloride	0.5	<0.005
Trichloroethylene	0.5	<0.005
Tetrachloroethylene	0.7	<0.005
Chlorobenzene	100	<0.005
1,4-Dichlorobenzene	7.5	<0.005

TCLP Metals	RCRA Regulatory Level mg/l	Leachate from E-Gas Slag mg/l
Arsenic	5	<0.1
Barium	100	<0.5
Cadmium	1	<0.5
Chromium	5	<0.1
Lead	5	<1.0
Mercury	0.2	0.002
Selenium	1	<0.1
Silver	5	<0.1

Table B-27. Typical Estimated ZLD Solids Composition

COMPONENT	Wt. % (dry)
Calcium	0.02
Sodium	35.31
Magnesium	0.00
Potassium	0.04
Silica	0.06
Chloride	27.94
Total Sulfur	0.19
Sulfate	0.19
Fluoride	4.46
Total Inorganic Carbon	0.27
Ammonia Nitrogen	0.50
Sulfide	0.01
Thiosulfate	0.16
Total Phosphorus	0.01
Total Organic Carbon	6.02
Volatile Organic acids	21.34
Aluminum	0.01
Arsenic	0.04
Barium	0.00
Boron'	3.10
Cadmium	0.00
Chromium	0.00
Copper	0.00
Iron	0.01
Lead	0.00
Manganese	0.00
Nickel	0.00
Selenium	0.12
Silver	0.00
Strontium	0.00
Zinc	0.00
Total	100.00

Other wastes resulting from the operation and maintenance of the IGCC facility would include:

- Worn and broken internal refractory from the gasifier vessel that would be periodically removed and replaced.
- Spent activated carbon used for purification of syngas fuel, process solvents, and other purposes.
- Sludge resulting from internal amine solvent recycling.

- Detergents and used chemicals from cleaning of the power generation equipment and other facilities.

The Project would manage operational wastes in accordance with applicable regulations, good industry practices and established internal company procedures. Waste minimization and pollution prevention programs would be implemented. Hazardous and non-hazardous wastes would be properly collected, segregated, and recycled or disposed at approved waste management facilities within regulatory time limits and in accordance with requirements. Plant staff would be adequately trained in proper waste handling procedures. Waste manifests and other records and reporting would be maintained as required by regulations and company procedures.

Construction Wastes

The construction activity associated with the IGCC Power Station would also generate certain amounts of wastes. A preliminary estimate of hazardous and non-hazardous construction wastes is presented in Table B-28. More significant temporary waste streams may include site clearing vegetation, soils, and debris, hydrostatic pressure-testing (hydrotest) water, used equipment lube oils, surplus materials, and empty containers.

Surplus and waste materials would be recycled to the extent practical. If feasible, removed site vegetation would be salvaged for pulp and paper production, or recycled for mulch. Hydrotest water would be reused for subsequent pressure tests if practical. Prior to disposal, used hydrotest water would be checked for contaminants and hazardous characteristics. Potential hydrotest water disposal methods, depending on the quality of the wastewater, include discharge to surface waters via the detention basin (pursuant to NPDES permits), trucking to a local POTW, or disposal at some other approved facility. Scrap and surplus materials and used lube oils would be recycled or reused to the maximum practical extent, or otherwise properly disposed.

Table B-28. Estimated Construction Waste Streams (Phase I and II)

Waste Description	Comments	Approx Quantity Per Period	Likely Disposition
Hazardous or Non-hazardous Liquids			
Used lube oils, flushing oils		10 drums/mo	Recycle
Hydrotest water	One time during commissioning, reuse as practical, test for hazardous characteristics	1.2 million gallons (total Phase I and 2)	Hazardous – approved disposal facility Non-hazardous – drain to detention basin and release (need permit)
Steam turbine and HRSG cleaning wastes	Chelates, mild acids, TSP, and/or EDTA - one time during commissioning	700,000 gallons (total Phase I and 2)	Approved hazardous or non-hazardous disposal facility
Hazardous Liquids			
Solvents, used oils, paint, adhesives, oily rags	Containerize	200 gal/mo	Recycle or approved hazardous waste disposal facility
Hazardous Solids			
Spent welding materials	Containerize	400 lb/mo	Hazardous waste landfill
Used oil filters	Containerize	100 lb/mo	Hazardous waste landfill
Fluorescent/mercury vapor lamps		30 units/yr	Recycle
Masc. oily rags, oil adsorbents	Containerize	1 drum/mo	Recycle or Hazardous waste landfill
Empty hazardous material containers		1 yd^3/wk	Hazardous waste landfill
Used lead/acid and alkaline batteries	Separate and containerize	1 ton/yr	Recycle
Non-hazardous Liquids			
Sanitary waste from workforce	Portable chemical toilets	400 gal/day	Pumped and disposed by contractor
Non-hazardous Solids			
Site clearing - vegetation	Salvageable (?) timber and waste wood, brush, leaves and vegetative wastes	See Land Use/Land Cover Impacts for West Range Power Station Footprint	Sell salvageable timber for pulp and paper production, sell or donate waste wood for use as fire wood, mulch for recycle, or dispose in non-hazardous landfill.

Waste Description	Comments	Approx Quantity Per Period	Likely Disposition
Site clearing – excavation of non suitable soils, masc. debris clearing	Stockpile soils on or off site	2,162,000 yd^3 (total)	Reuse soils for berms and landscaping, mulch and recycle organic debris, recycle or landfill inorganic debris.
Scrap materials, debris, and trash	Wood, metal, plastic, paper, packing, office wastes, etc.	40 yd^3/wk	Recycle or non-hazardous waste landfill

Construction management, contractors, and their employees would be responsible for minimizing the amount of waste produced by construction activities and would be required to fully cooperate with project procedures and regulatory requirements for waste minimization and proper handling, storage, and disposal of hazardous and non-hazardous wastes. Each construction contractor would be required to include waste management and waste minimization components in their overall project health, safety, and environmental site plans. Typical construction waste management measures would include:

- Dedicated areas and a system for waste management and segregation of incompatible wastes, with waste segregation occurring at time of generation.
- A waste control plan detailing waste collection and removal from the site. The plan would identify where waste of different categories would be collected in separate stockpiles or bins, and appropriate signage provided to clearly identify the category of each collection stockpile.
- Hazardous wastes, as defined by the applicable regulations, would be stored separately from non-hazardous wastes (and other, non-compatible hazardous wastes) in accordance with applicable regulations, project-specific requirements, and good waste management practices.
- Periodic construction supervision inspection to verify that wastes are properly stored and covered to prevent accidental spills and releases.
- Appropriately labeled waste disposal containers.
- Good housekeeping procedures. Work areas would be left in a clean and orderly condition at the end of each working day, with surplus materials and waste transferred to the waste management area.
- Appropriate waste management training for the construction workforce.

Primary and Secondary Products

The primary product of the IGCC Power Station would be electric power. The Project would also produce elemental sulfur and a vitreous inert slag. A world-wide market already exists for elemental sulfur, although its value varies considerably with location, purity, and end use. No large scale market exists for slag at this time. It was expected that slag can be marketed for asphalt aggregate, construction backfill, or landfill cover applications. Slag with a carbon content of less than 5 percent by weight could be marketable as a higher value product such as roofing shingle applications. There is also a potential to market the slag produced from petroleum coke gasification for metals recovery. Excelsior conducted a preliminary market analysis for slag and sulfur that was attached as Appendix 8 to the Joint Application.

Storage Requirements

Storage areas and requirements for the major process feedstock and byproducts are shown in Table B-29. The numbers are for each phase, with the total storage for both phases being double that reported in the table below.

Table B-29. Feedstock and Byproduct Storage Requirements (Each Phase)

Material	Storage Requirements
Coal Pile	395,000 tons (5/45 day active/inactive storage based on maximum PRB coal usage); Dust control; Water run-off control
Pet Coke Pile	111,000 tons (5/45 day active/inactive storage; Dust control; Water run-off control
Flux Silo	1,120 tons (5 day active storage)
Sulfur Tanks	(~ 160 tons/day generated, based on Illinois No.6 coal)
Slag Pile	32,265 tons (45 day storage, wet basis, using Illinois No.6 coal)

Toxic and Hazardous Materials

Hazardous materials that would be used or stored for project operations include relatively small quantities of petroleum products, liquid oxygen and nitrogen, molten sulfur, catalysts, flammable and compressed gases, amine replacement and reclamation chemicals, water treatment chemicals, and minor amounts of solvents and paints. Materials and estimated quantities for the gasification/ASU blocks were based on experience at Wabash River. Power block requirements were estimated from similar combined cycle units. Spare catalyst materials such as those used in the COS hydrolysis system and SRU may be selectively stored on-site.

Table B-30 provides a list of potentially hazardous materials that would be utilized and/or stored on-site. For the major bulk items, the approximate quantities expected to be stored on site were estimated, and would be adjusted as the frequency and methods of re-supply (railcar or truck) are optimized. Quantities shown are for Mesaba One and Mesaba Two, with individual phase quantities being approximately one-half of the totals.

Table B-30. On-Site Toxic and Hazardous Materials (Total For Phase I and II)

Material	Form	Quantity (Phases I and II)	General Location On-Site	Use
GASIFICATION/AIR SEPARATION UNIT AREAS				
BULK CHEMICALS				
Chlorine or Sodium Hypochlorite	Gas or Liquid	TBD		Cooling Towers
Sodium Hydroxide	Liquid	60,000 gal	Outdoor	Amine Reclamation and Sour Water Treatment
Potassium Hydroxide	Liquid	2,000 gal	Indoor	Dry Char Filter Cleaning
Water Treatment Chemicals	Liquid	Typ. Small (55 gal) Drums to less than ~ 500 gal tank	Indoor	Pump Bldg, Slurry Prep Bldg, Cooling Towers
Oxygen (95%)	Liquid	1,800 tons	Outdoor	ASU Backup Supply
Nitrogen	Liquid	5,000 tons	Outdoor	ASU Backup Supply
Molten sulfur	Liquid	200,000 gal	Outdoor	By-product for Sale
Ammonium lignosulfonate	Liquid	??	Indoor	Slurry Prep Bldg for maintaining % solids in slurry
MASC./DISTRIBUTED MATERIALS				
Paint/Thinners/etc.	Liquid	Minimal	Indoor	Shop/Warehouse
Lubrication Grease/Oils	Solid/Liquid	Minimal	Indoor	Pump Bldg, Slurry Prep Bldg., Shop/Warehouse
Compressed Gases (Ar, He, H_2)	Pressurized Gas	Minimal	Indoor	Lab
Chemical Reagents (acids/bases/standards)	Liquid	Minimal	Indoor	Lab
OTHER HAZARDOUS MATERIALS				
Flammable/Toxic Gases (H_2, CO, H_2S, SO_2)	Pressurized SynGas Mixture		Distributed	Process Piping/Vessels
Acetylene, Oxygen, other welding gases	Gas	Minimal (approved cylinders)		Welding
Natural Gas	Gas (high pressure)		Supply piping only	Startup/Backup Fuel
Diesel Fuel	Liquid	2,000 gal	Outdoor	Emergency generator/fire water pump fuel

Material	Form	Quantity (Phases I and II)	General Location On-Site	Use
POWER BLOCK AREA				
MASC./DISTRIBUTED CHEMICALS				
Sulfuric Acid	Liquid	12,000 gal	Outdoor	Cooling water and BFW pH control; battery acid
Sodium Hypochlorite	Liquid	20,000 gal	Outdoor	Cooling Tower biological control
Circulating Water Chemical Additives (e.g., Magnesium nitrate, magnesium chloride, 2-bromo-2-nitropropane-1,3-Diol, 5-chloro-2-Methyl-4-Isothizaoline-3-one) (Note 1)	Liquids	Typ. Small (55 gal) Drums to less than 500 gal tank	Indoor	Corrosion Inhibitor/ Biocides
Boiler Feedwater Chemicals, e.g., Carbonic Dihydrazide, Morpholine, Cyclohexamine, sodium sulfite (Note 1)	Liquids	Typ. Small (55 gal) Drums to less than 500 gal tank	Indoor	Boiler feedwater pH/Corrosion/ Dissolved Oxygen/Biocide control
Mineral Insulating Oil	Liquid	30,000 gal (estimated, to be confirmed)	Indoor	Electrical Transformers
Lubricating Oil	Liquid	21,000 gal (estimated, to be confirmed)	Indoor	Combustion Turbine/Steam Turbine/Masc. Equipment Lube Oils
Combustion turbine wash chemicals	Liquids	Intermittent use/ Chemicals not stored onsite/ cleaning by contractor		Combustion Turbine Generator cleaning
HRSG Cleaning Chemicals (e.g., HCl, Citric acid, EDTA Chelant, Sodium Nitrite) (Note 1)	Liquids	Multiyear cleaning requirement/ Temp storage only		HRSG Chemical Cleaning
Carbon Dioxide	Pressurized Gas	50,000 scf	Outdoors	Generator purging
Hydrogen	Pressurized Gas	29,000 scf	Outdoors (Assumes use of multi-tube trailer. Active volume based on 1 of 10 tubes per trailer)	Generator cooling (To be verified - Assumes use of H_2-cooled generators – dependent on selected manufacturer)

Notes: "Typical" chemicals for the application are identified.

Natural gas and syngas, which are flammable, would be used in the power block. Natural gas would be used as a startup or auxiliary fuel directly from the on-site pipeline (which connects to the off-site main pipeline). Natural gas would not be stored on site. Syngas would be the primary fuel for the combustion turbines. The syngas is a mixture of carbon monoxide, hydrogen, carbon dioxide, and water vapor. Gaseous hydrogen ("H_2") would be used as a generator coolant. Hydrogen would be stored in pressurized gas tubes on a multi-tube trailer. The tube trailer would be stored outside near the turbine-generators and would meet required building and fire codes. Carbon dioxide would be stored for purging of the generators after normal and emergency shutdowns.

Bulk quantities of liquid oxygen and nitrogen would be stored in tanks in the ASU to provide capacity for startups and continued plant operation during short-duration ASU system outages.

Other gases stored and used at the facility would include those typically used for maintenance activities, such as shop welding, emission monitoring, and laboratory instrument calibration. These gases would be stored in approved standard-sized portable cylinders, and in appropriate locations.

Water treatment chemicals would be required and stored onsite. Bulk chemicals, such as acids and bases for pH control, would be required to be stored in appropriately designed tankage with secondary containment and monitoring. Gaseous chlorine (used/stored in compliance with all applicable regulatory requirements) or hypochlorite bleach may be used for biological control of the various circulating and cooling tower streams.

Other water treatment chemicals would be required and used as biocides, pH control, dissolved oxygen removal, and corrosion control for boiler feed water ("BFW"), cooling tower and cooling water treatment. For raw water treatment, coagulants and polymers may also be used. Chemicals used for these purposes were generally specified by the water treatment provider, and are available under a number of trade names. Stored quantities of these materials would be relatively small, ranging from 55 gal drums to 500 gal tanks.

Combustion turbine and HRSG washes would be performed by contractors on an intermittent basis. Combustion turbines would be cleaned by injecting wash water into the turbine for three to five minutes while cranking at full speed just prior to shutting down. The wash water would be allowed to soak on the blades for required periods of time. Following the soak, the turbine would be accelerated and rinse water injected for 15 to 20 minutes. The turbine would then be allowed to drain and dry. The process would be repeated until rinse water exiting the drains is clear. The waste water would be collected for disposal. HRSG finned tubes would be cleaned with high pressure water jets. Waste water and deposits would be drained from the bottom of the HRSG and collected for disposal. The chemicals required for the washes would usually be provided by the contractors and are typically not stored long-term on site.

Diesel fuel would be used for the emergency generator and for the fire water pumps. The stored quantity would be based on approximately 8 hours of operation of the diesel generators at full output (about 3 MW per phase). This limited storage would require contracts with fuel providers specifying that deliveries of diesel fuel be provided in less than 8 hours in the case of an emergency. Appropriate containment and monitoring for spillage control would be provided.

Other petroleum-containing hazardous materials would include the combustion and steam turbine lube oils, steam turbine hydraulic fluid, transformer oils and miscellaneous plant equipment lube oils. These materials would be delivered in approved containers, stored in areas with appropriate secondary containment, and used within curbed areas that only drain to internal drains connected to an oil-water separator system. Oil reservoirs, containment areas, and the separators would be checked regularly to identify potential leakage issues and initiate appropriate actions.

C. TRANSMISSION ROUTE LICENSING

The scope of work for Subtask 1.03 involved designing the transmission connection from the IGCC Power Station to the POI with the grid, submitting an interconnection request[59] to MISO, initiating the necessary interconnection studies required to establish the basis for an agreement between the interconnection customer, the transmission owner, and the independent system operator, and submission of the agreement to the Federal Energy Regulatory Commission ("FERC") for approval.

1. PRELIMINARY INTERCONNECTION AND GENERATOR OUTLET STUDIES

In 2003, Excelsior engaged Sherner Power Consulting ("Sherner") to evaluate the best location to interconnect the Mesaba Energy Project into the existing transmission system, and accomplish transmission delivery into the Twin Cities market. In July 2004, Excelsior engaged MAPPCOR[60] to conduct a series of power flow studies to develop positions on these matters.

Excelsior also engaged Sherner to prepare preliminary analyses of concepts for the staged development of the generator outlet ("GO") facilities to deliver the output of each phase of the Project from the potential sites to the associated POI. The East Range site analysis was performed in August 2004 and the West Range site analysis followed in May 2005. Both 230kV and 345kV GO designs were developed, ranging from a single radial GO line wherein the plant would shut down if the line was out of service, to an ultimate development with sufficient redundancy (reliability) such that one GO line could be out of service with the full output still being delivered to the POI. A key assumption in these GO analyses was that the network upgrades associated with Mesaba One could be implemented at 230kV, but 345kV network upgrades would be necessary to the POI and beyond to deliver the Project output after Mesaba Two came online.

To minimize environmental impacts, the transmission plans for both the generator outlet facilities and network upgrade reinforcements were developed with the goal of minimizing the need for creating new transmission rights of way. This was to be accomplished by either upgrading and/or reconstructing as double circuits existing transmission lines. Preliminary discussions with the affected systems and the Northern MAPP Sub-regional Planning Group did not reveal any technical concerns or issues with the POIs chosen or the reinforcement plans presented.

Subsequently, the firm of Laramore, Douglass and Popham ("LDP") initiated preliminary design work in September of 2005 to develop alternatives for the Project's generator outlet configurations, HVTL conductors, structures and corridors through which the HVTLs would traverse. In this same time frame, Fluor established the maximum unit output at 600MW and included in their scope of work and cost estimates a 230kV substation at the power plant with two GO line terminals. LDP proposed 230kV and 345kV structure types and conductor arrangements that would meet the Project GO line requirements. In late November/early December 2005, Sherner completed updated analyses for the GO facilities for both sites using the new cost estimates and loss calculations provided by LDP. The key early assumption that Mesaba Two required 345kV network upgrades at the associated POI and beyond was confirmed.

[59] An "interconnection request" is defined as an interconnection customer's request to interconnect a new generating facility with the regional high voltage transmission system.
[60] MAPPCOR is the service provider to members of the Mid-Continent Area Power Pool ("MAPP"), an association of electric utilities and other electric industry participants in a region which spans nine states and two Canadian provinces. MAPPCOR was incorporated in June 1990 as a not-for-profit cooperative organization which has been providing transmission and reliability services to the MAPP members and industry participants since that time.

Therefore, all development plans included the necessary transformation between the 230kV and 345kV systems. The alternatives developed by LDP provided the basis for the HVTL costs, illustrations, and electromagnetic force ("EMF") computations presented in documents required as part of the environmental review process, to support development of a power purchase agreement ("PPA") between Xcel Energy and Excelsior, and to further the resolution of issues associated with finalizing an interconnection agreement between Minnesota Power and Excelsior.[61]

2. MISO Large Generator Interconnection Procedure

In addition to designing the GO transmission facilities as described above, connecting to the electric grid requires the approval of MISO, the regional independent system operator. This section describes the process involved in obtaining the necessary approvals and agreements, and the following section describes the work carried out by Excelsior in accomplishing that task.

a. Background

By virtue of FERC Order No. 2003, the FERC amended its regulations under the Federal Power Act to require public utilities that own, control, or operate facilities for transmitting electric energy in interstate commerce to file revised open access transmission tariffs containing standard generator interconnection procedures and a standard agreement to provide interconnection service to devices used for the production of electricity having a capacity of more than 20 megawatts.[62] Any non-public utility (e.g., MISO) that seeks voluntary compliance with the reciprocity condition of an open access transmission tariff may satisfy this condition by adopting the Order's procedures and its interconnection service agreement.[63]

On January 20, 2004, MISO made its filing to comply with FERC Order No. 2003. The compliance filing adopted the majority of the FERC pro forma terms and conditions into MISO's Interconnection Agreements. Each generating resource greater than 20 MW seeking to interconnect with the bulk transmission system within the MISO footprint is required to adhere to MISO's Large Generator Interconnection Procedures ("LGIP") set forth at the time in Attachment X to MISO's Open Access Transmission and Energy Markets Tariff, FERC Electric Tariff, Second Revised Volume No. 1 ("MISO Tariff"). With regard to the Project, the LGIP provided step-by-step procedures for completing the necessary interconnection studies and established the framework for negotiations leading to the execution of a Large Generator Interconnection Agreement ("LGIA"), a *pro forma* agreement instituted under FERC Order No. 2003. Three subsequent rehearings of FERC Order No. 2003 have been published since its promulgation in the Federal Register on August 19, 2003.[64]

One of the significant benefits resulting from MISO's adoption of FERC Order 2003 involved the addition of Network Resource Interconnection Service ("NRIS"); a type of service previously unavailable to MISO participants. NRIS allowed Excelsior to integrate Mesaba One with the transmission system in

[61] The documents within which LDP study results appeared included the Environmental Supplement (June 2006), the Joint Permit Application (June 2006), the Report to the Minnesota Public Utilities Commission (December 2005), and in expert testimony filed in support of i) contested case permit hearings conducted under the Power Plant Siting Act and ii) the showing contemplated by statute (Minn. Stat. § 216B.1694, subd. 2(a)(7)) to demonstrate that a PPA between Xcel Energy and Excelsior for Mesaba One would be in the public interest.
[62] Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003, 68 **FR** 49845 (Aug. 19, 2003), FERC Stats. & Regs. ¶ 31,146 (2003) (Order No. 2003)
[63] Id.
[64] Order on rehearing, Order No. 2003-A, 69 **FR** 15932 (Mar. 26, 2004), FERC Stats. & Regs. ¶ 31,160 (2004) (Order No. 2003-A), Order on rehearing, Order No. 2003-B, 70 **FR** 265 (Jan. 4, 2005), FERC Stats. & Regs. ¶ 31,171 (2005) (Order No. 2003-B). See also Notice Clarifying Compliance Procedures FERC, 106 ¶ 61,009 (2004).

the same manner as any large generation resource being designated as a Network Resource.[65] As a Network Resource, Mesaba One could be used by Xcel Energy (a MISO Network Customer) as a resource to serve its native load through MISO's Network Integration Transmission Service and to contribute to Xcel's firm reserves for resource adequacy purposes.[66]

b. Description of MISO Interconnection Study Process

A generator seeking NRIS must be studied to ensure it can operate over a broad range of system operating conditions without adversely impacting the local/regional transmission system performance and reliability. NRIS allowed Mesaba One to be designated as a Network Resource, up to its full output, on the same basis as existing Network Resources that are interconnected to the transmission system, and required Mesaba One to be studied as a Network Resource in the interconnection process on the assumption that such a designation will occur. More simply, until proven differently, interconnection studies performed on behalf of the Project must be conducted recognizing deliveries to MISO network service customers[67] that are remote from the control area in which the Project POI is located.

The interconnection process related to NRIS has several different components, but primarily consists of three separate studies undertaken by MISO and the applicable transmission owner(s): the Interconnection Feasibility Study (the "Feasibility Study"), the System Impact Study, and the Interconnection Facilities Study (the "Facilities Study").

A block flow diagram of MISO's LGIP applicable at the time Excelsior submitted the above interconnection requests is presented in Figure C-1. Optional Study procedures and Restudy Process deadlines are presented in Figure C-2.

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[65] Under MISO's Tariff, a Network Resource is defined to mean any designated generating resource owned, purchased, or leased by a Network Customer under the Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.
[66] Module E of MISO's Tariff sets forth mandatory requirements to be met by the transmission provider, market participants serving load in the transmission provider region or serving load on behalf of a load serving entity, or other market participants, to ensure access to deliverable, reliable and adequate planning resources to meet peak demand requirements on the transmission system.
[67] For example, Xcel, GRE, municipal power companies, etc.

Figure C-1. MISO LGIP Process

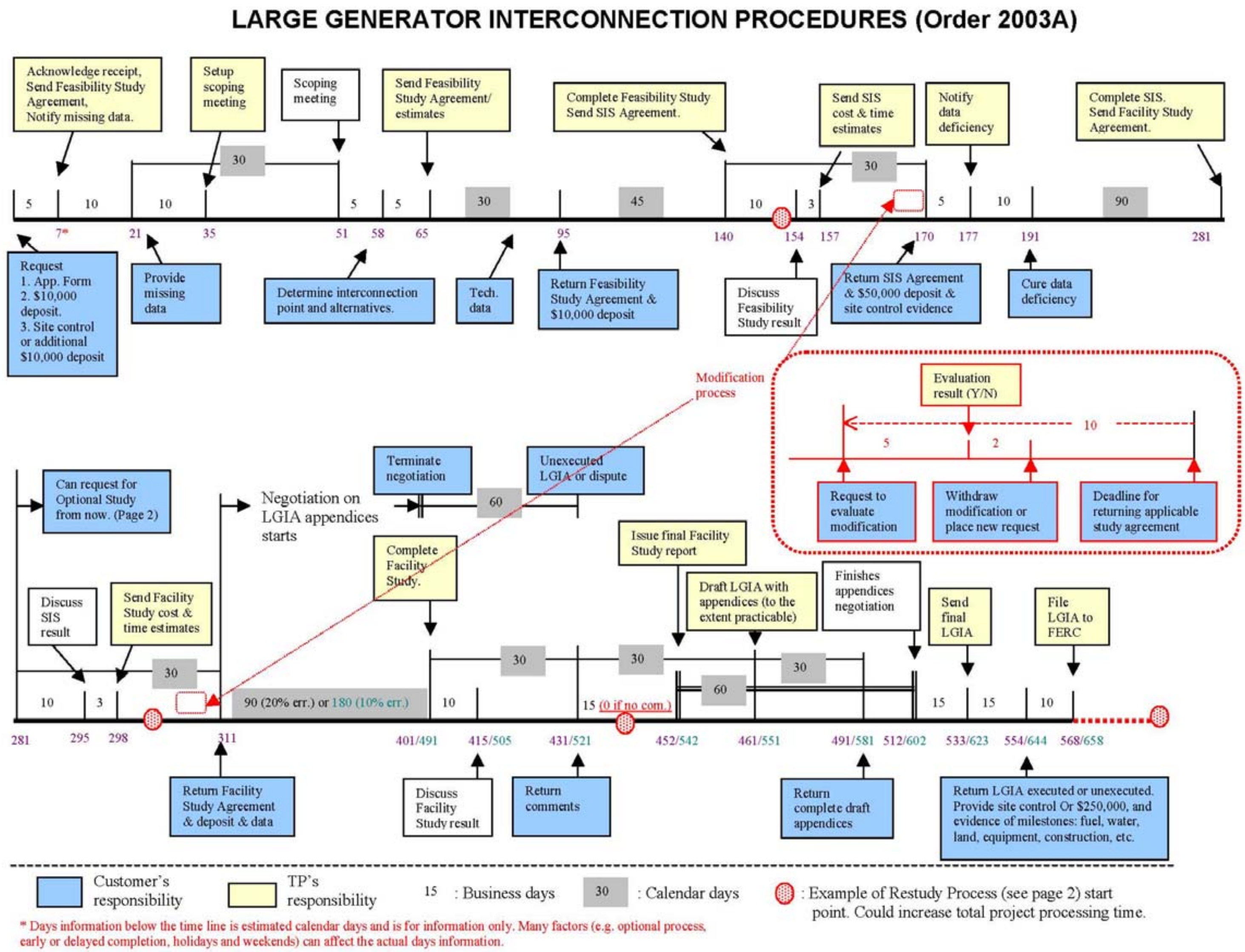
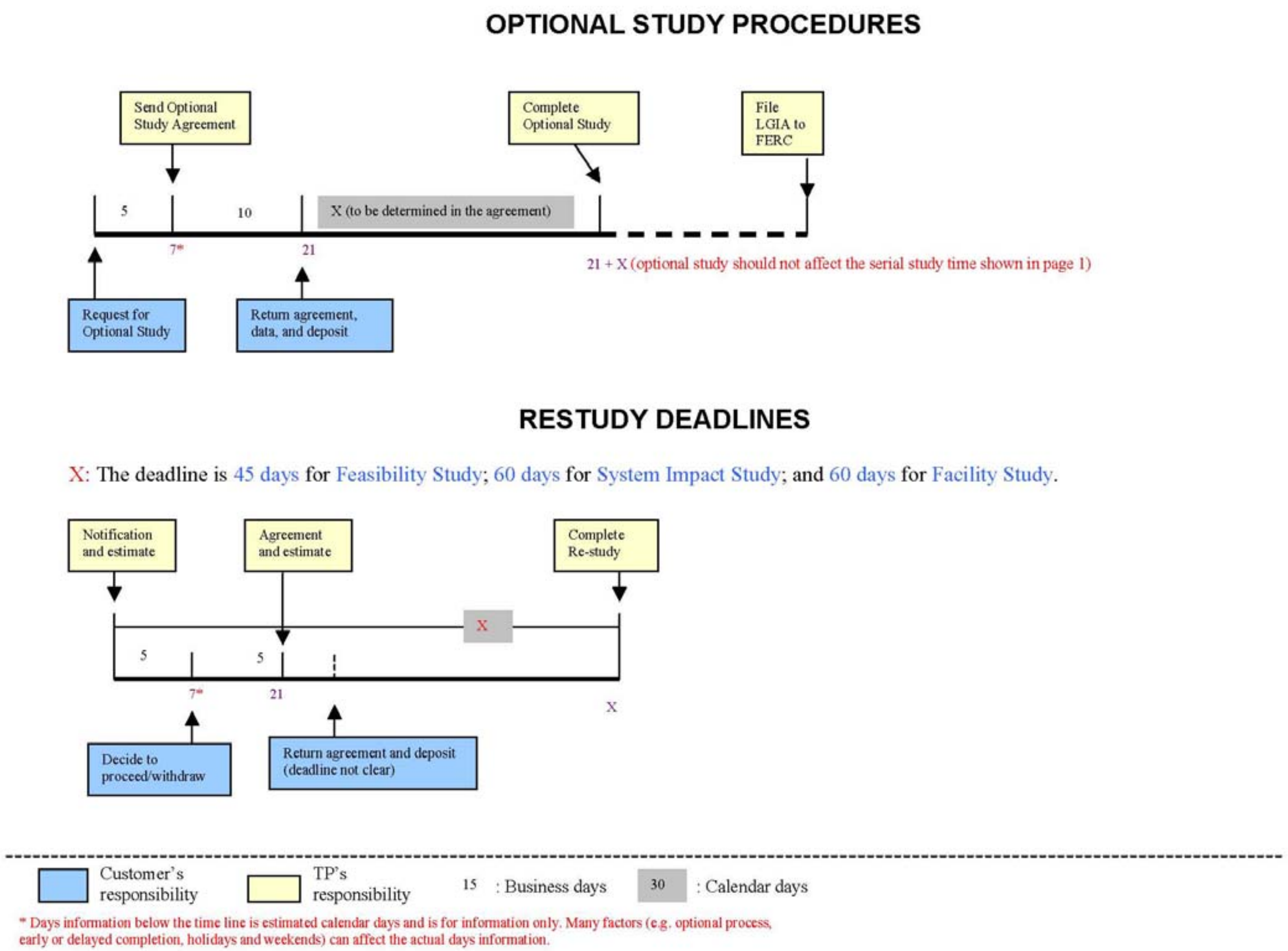


Figure C-2. MISO Optional Study Procedures and Restudy Process Deadlines



3. MISO Studies and LGIA

Consistent with the LGIP described above, on October 14, 2004, Excelsior submitted a Large Generator Interconnection Request for Mesaba One (if located at the East Range Site) requesting NRIS with Minnesota Power's control area with the designated POI[68] proposed at Minnesota Power's Forbes 230kV Substation. MISO designated this request as Project G477 and assigned it a queue number of 38280-01.[69] Excelsior submitted a second request for NRIS on May 18, 2005 for Mesaba One for the West Range site with the proposed point of interconnection at Minnesota Power's Blackberry 230kV Substation. MISO designated this as Project G519 and assigned it a queue number of 38491-01. This initiated parallel study processes for each site, described below, to support the execution of an LGIA capable of accommodating selection of either site by the MPUC.

a. Feasibility Studies

The Feasibility Study looked at the feasibility and consequences of interconnecting Mesaba One into the existing transmission system at the proposed POI identified in the generator interconnection request. The primary purpose of Feasibility Study was to provide a preliminary screening for potential impacts that the generation facility seeking to interconnect will have on the transmission system. In the analysis, steady-state performance was evaluated under various system configurations. These configurations included an intact transmission system, as well as configuring conditions that could affect outlet capability specifically at the point of interconnection and the surrounding transmission system in general. The outcome of the analysis was identification of potential substation and transmission equipment problems and unacceptable system operating conditions.

i. East Range Site

On December 13, 2004, Excelsior submitted an executed Generation Interconnection Feasibility Agreement for its East Range site (MISO Project G477, Queue 38280-01), such study being based upon information set forth in the Interconnection Request and agreed upon in the Scoping Meeting held on November 19, 2004. The results of the G477 Feasibility Study,[70] reflected injection of 531 MW of electricity at Minnesota Power's Forbes 500/230 kV Substation and treatment of the generator as an Energy Resource, concluded that the Project would be required to mitigate all thermal injection overloads and voltage degradation problems in order to connect as an Energy Resource,[71] but did not identify any thermal injection issues for the proposed interconnection. Solutions for addressing the voltage degradation observed at the buses identified in the G477 Feasibility Study were to be identified in the System Impact Study.

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[68] The POI is the location on the MISO-controlled transmission system where Mesaba One intends to inject capacity and energy.
[69] Under the applicable LGIP, the Queue Position determines the order of the interconnection studies necessary to facilitate the Interconnection Requests. At the time, Mesaba One was the only base load large energy facility in the MISO interconnection queue for Minnesota, and therefore had priority with respect to the completion of studies necessary to interconnect a base load resource to the grid
[70] Siemens Power Transmission & Distribution, Inc.. Power Technologies International. "Generator G477 Interconnection Feasibility Study", Report prepared for MISO, March 10, 2005.
[71] The Feasibility Study stipulated that additional deliverability analysis would be required to evaluate whether G477 could be certified as a Network Resource.

ii. West Range Site

On May 18, 2005, Excelsior submitted a Generator Interconnection Request for the Project's preferred West Range site (MISO Project G519, Queue 38491-01), designating the POI as Minnesota Power's Blackberry 230/115-kV Substation and the injection quantity for Phase I as 580 MW. In its request, Excelsior expressed the desire to coordinate the processing of studies for G519 and G477 to the maximum extent possible and stated that for Project G519, Excelsior would be willing to combine the Feasibility Study into the System Impact Study in support thereof. By virtue of a Letter Agreement executed by Excelsior on August 1, 2005, Excelsior allowed MISO to proceed with a combined Interconnection Feasibility Study and Interconnection System Impact Study, the terms and conditions of the Letter Agreement delineating how the LGIP would be implemented for the "out-of-queue-order studies" and defining the circumstances under which Excelsior would be responsible for additional costs upon any limited restudy completed by MISO subsequent to such studies. Excelsior executed on August 18, 2005 a Generator Interconnection System Impact Study Agreement confirming that "[the] Interconnection Customer has elected to forego the Interconnection Feasibility Study and include any related study criteria in this System Impact Study."

b. System Impact and Deliverability Studies

The second analysis performed as part of the MISO LGIP was the System Impact Study. The analysis used information from the Feasibility Study, and involved a more rigorous analysis of the impacts of Mesaba One on the existing transmission system. Specifically, the study was to identify problems with substation breaker interrupting capability, system thermal overload or voltage limitations resulting from the interconnection, and instability or inadequately-dampened response to system NRIS resource service requests. The System Impact Study also provided a preliminary list of facilities (including Interconnection Facilities, Network Upgrades, Distribution Upgrades, Generator Upgrades and, if such upgrades have been determined, upgrades on Affected Systems) that were required as a result of the interconnection request. In addition, the System Impact Study provided a preliminary estimate of the Interconnection Facilities and Network Upgrade costs.

Generator interconnection projects must pass a Generator Deliverability Study to be granted NRIS. Interconnection projects that had not filed an Interconnection Agreement by September 1, 2004 are studied in their interconnection queue order to determine their deliverability.

i. East Range Site

On April 12, 2005, Excelsior submitted an executed Interconnection System Impact Study Agreement for Project G477. The results of the System Impact Study published on April 6, 2006 and subsequently revised on April 28, 2006[72] showed that no new network upgrades were required for the Project to interconnect with the grid as an energy resource being dispatched at 531 MW. The System Impact Study confirmed that additional deliverability analyses were required to evaluate whether the Project could be certified as a Network Resource. A sensitivity analysis was conducted for G477 to evaluate whether such conclusions would be valid if the Project's output was increased to 600 MW. The results of the sensitivity analysis were published on October 9, 2006 and showed consistency with those of the System Impact Study reflecting the lower generating capacity.

[72] Siemens PTI. 2006. "G477 System Impact Study, MISO Queue #38280-01." Report prepared for MISO, revised April 28, 2006.

The results of the deliverability study posted on MISO's website[73] confirmed that the 531 MW of capacity studied was fully deliverable at the Forbes Substation with no constraints. However, this conclusion was based on a model that assumed construction and subsequent operation of a proposed HVTL between the Wilton Substation near Bemidji, Minnesota and the Clay Boswell Generating Station located in Cohasset, Minnesota. See the discussion in the following paragraph for information about the current status of this HVTL.

ii. West Range Site

As previously noted, Excelsior executed on August 18, 2005 a Generator Interconnection System Impact Study Agreement. The results of that work were first published on April 6, 2006 and subsequently revised on May 8, 2006 and June 6, 2006,[74] and confirmed network upgrades beyond MP's Blackberry Substation would be required. In order to resolve all adverse effects resulting from interconnection as an Energy Resource, a new 73 mile 230 kV line from the Clay Boswell Generating Station to the Riverton Substation was required. In addition, four potentially over-dutied 115 kV circuit breakers at the Nashwauk Substation were shown to be in need of replacement. The results of the original deliverability study published on December 15, 2006 and posted on MISO's website[75] confirmed that the full 600 MW of capacity studied was deliverable to the Xcel Energy footprint contingent upon the in-service of a 9.3 mile HVTL between Minnesota Power's Baxter Substation and Great River Energy's ("GRE") Southdale Substation (i.e., Southdale to Scearcyville 115 kV HVTL and Breaker Station,[76] aka, the Baxter–Southdale 115 kV project[77]), which at the time of this writing is currently under construction and scheduled to be in-service in 2012.[78]

Optional System Impact Studies were conducted in the fourth quarter of 2008[79] to evaluate the impact of two newly committed regional projects on the need for such network upgrades. The newly committed projects included a 230 kV HVTL between MP's Clay Boswell Generating Station and the Wilton Substation (hereafter, the "Wilton-Boswell CapX2020 Project") and the Essar Steel plant in Nashwauk, Minnesota, the latter requiring an average load of 237 MW (sufficient to provide the necessary power for the taconite processing facilities and Phase I of the two-phase steel manufacturing plant).[80] At this time, the Wilton-Bemidji CapX2020 Project is under construction.[81] Current timelines for the Essar Steel

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[73] See https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=13542 to download a copy of a zipped file containing a copy of the deliverability test report dated December 15, 2006.
[74] Siemens PTI. 2006. "System Impact Study, Report R7-06." Report prepared for MISO, Final Revision June 6, 2006.
[75] See https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=35182. The model used for this test reflected the addition of the 73 mile HVTL between the Clay Boswell and the Riverton Substations.
[76] Great River Energy ("GRE") submitted on July 17, 2008 a permit application for the 9.3 mile 115 kV HVTL to connect the existing GRE 115 kV HVTL in the City of Baxter to a new Minnesota Power breaker station proposed for the north portion of Sylvan Township (the permit application for the proposed 9.3 mile 115 kV HVTL project can be found at http://mn.gov/commerce/energyfacilities/documents/19661/071808%20Application%20Text.pdf).
[77] See http://minnelectrans.com/documents/2011_Biennial_Report/html/Ch_6_Needs.htm for confirmation that the Southdale-Searcyville 115 kV HVTL and Baxter-Southdale 115 kV HVTL projects are different names for the same project.
[78] See http://www.greatriverenergy.com/deliveringelectricity/currentprojects/projects_southdalescearcyville.html .
[79] Siemens PTI. 2008. "Optional System Impact Study G519, MISO Queue #38491-01." Report prepared for MISO, December 17, 2008.
[80] Although each of the two projects had been proposed at the time of the first System Impact Study, neither had advanced to the point where it was considered to be committed.
[81] The Project Manager for the Wilton-Boswell CapX2020 Project's partners (i.e., Otter Tail Power Company (now a wholly owned subsidiary of Otter Tail Corporation), Minnesota Power, and Minnkota Power Cooperative) is Otter Tail Power Company. The Form 10-K filed by Otter Tail Corporation for fiscal year 2011 reports that construction on the CapX2020 Project "began in December 2010". Personal communication on April 24, 2012 with Cindy

Minnesota project, as reported by Steve Rutherford (project manager and local company spokesperson), call for taconite mining to begin in the fourth quarter of 2012 with steel making to be in place by the end of 2015.[82]

The Optional System Impact Study showed that the construction and operation of the two newly committed projects would negate the need for the Boswell-Riverton 230 kV line and circuit breakers. However, upon the completion and final posting of the Optional Study results, a new concern was raised by Minnesota Power (the local transmission owner) indicating they had overlooked potential adverse impacts that the Mesaba One output would have on their No. 11 115 kV line between the Grand Rapids and Riverton Substations. Excelsior and Minnesota Power subsequently agreed that the resolution of this concern should be addressed by amending the Facilities Study Agreement originally executed on June 8, 2006 to include work required to identify the most appropriate solution and estimate the costs associated therewith. Additional information detailing the results obtained under the amended Facilities Study Agreement is discussed in the following section.

c. Facilities Study

The Facilities Study – the last of the three studies required by the LGIP – provides an engineering plan that includes equipment definition and estimated construction cost/schedule for required facilities needed to interconnect Mesaba One to the transmission system as a Network Resource. The study report provided solutions for all the relevant issues identified in System Impact Study. An appendix of the Facilities Study documents the final agreement negotiated between Excelsior (the Interconnection Customer), the affected Transmission Owners and MISO for the required Interconnection Facilities and Network Upgrades.

i. East Range Site

On May 10, 2006, MISO requested from Minnesota Power a "Request for Proposal" to complete a Generation Interconnection Facilities Study Report associated with MISO Project G477. The final report was published on December 13, 2006[83] and identified additions to the Forbes Substation necessary to accommodate 531 MW of generating capacity and estimated the total interconnection cost (including the capital cost of the required equipment) at approximately $4.6 million. No network upgrades were projected to be required.

ii. West Range Site

On May 10, 2006, MISO requested from Minnesota Power a "Request for Proposal" to complete a Generation Interconnection Facilities Study Report associated with MISO Project G519. The final report was published on February 8, 2007[84] and identified four options for constructing a 230 kV HVTL between the Clay Boswell Generating Station and the Riverton Substation ranging from approximately $59 million to $83 million. In addition, the study identified substation upgrade costs ranging from $5.3

Kuismi, the Project Manager's communication specialist, confirms that the first tower structure was placed in August 2011. See Form 10-K at http://google.brand.edgar-online.com/displayfilinginfo.aspx?FilingID=8450703-982-684178&type=sect&TabIndex=2&companyid=807724&ppu=%252fdefault.aspx%253fsym%253dOTTR

[82] See http://www.businessnorth.com/exclusives.asp?RID=3979.

[83] Minnesota Power, 2006. "Facility Study Report, Generator Interconnection Request Excelsior Power – Forbes Interconnect, MISO #G477." Report prepared for MISO, December 13, 2006.

[84] Minnesota Power, 2007. "Facility Study Report, Generator Interconnection Request Excelsior Power – Blackberry Interconnect, MISO #G519." Report prepared for MISO, February 8, 2007.

million to $13.1 million. Based on the results of the December 17, 2008 Optional System Impact Study,[85] MISO authorized Minnesota Power to perform a Facility Study to determine the cost of upgrading the utility's 115 kV No. 11 Line to provide a continuous summer rating of 90 MVA. The results of the study were published on January 22, 2010[86] and estimated the cost of such upgrades at approximately $3.7 million.

d. Large Generator Interconnection Agreement

As noted in Figure C-1, simultaneous to the start of the Interconnection Facilities Study, negotiations began on the appendices for the LGIA. Although the LGIA is a *pro forma* Agreement already approved by FERC, the appendices contain additional details including the identification of all facilities, cost responsibilities, milestones for construction, and ownership. In total, the interconnection process is designed to take approximately twenty-four (24) months to complete. Negotiations on the LGIA may not last more than 60 days after the issuance of the Final Facilities Study Report.

On July 9, 2007, Excelsior, Minnesota Power and MISO executed an LGIA for both the West Range and East Range sites. Appendix B of each LGIA sets forth the milestones/deadlines that are to govern the sequencing of the permitting, construction and payment for the upgrades necessary to interconnect the Project to the Grid (i.e., all facilities that MP as the transmission owner must build).

Following the MPUC's March 12, 2010 issuance of Site, HVTL Route, and Natural Gas Pipeline Route Permits for the West Range Site, Excelsior confirmed in writing to MISO and Minnesota Power on July 7, 2010, its intent to withdraw MISO Project G477 from the MISO Queue.[87]

To ensure compliance with milestones to be specified in the West Range LGIA, Excelsior and Minnesota Power initiated work in June 2007 – before the LGIA was finalized – to prepare an HVTL Route Permit application for the network upgrades between the Clay Boswell and Riverton Substations (such upgrades having been identified in response to System Impact Studies finalized on June 6, 2006). A letter agreement dated May 31, 2007 (provided by MISO to Excelsior and Minnesota Power on that date and executed by the two parties on May 31, 2007 and June 1, 2007, respectively) dictated the terms and conditions under which preparation of the application was to be conducted.

The first task undertaken as part of preparing the HVTL Route Permit application was to identify potential routes within which the network upgrades could traverse. This task, including the tabulation of evaluation criteria to be used in selecting the preferred route as described in the Route Permit application, was completed in the third quarter of 2007. Further work in support of permitting the Boswell-Riverton HVTL was placed on hold on October 16, 2007 until the second quarter of 2008 to avoid conflicts with

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[85] As previously noted, the results of the Optional System Impact Study confirmed the 230 kV HVTL between the Clay Boswell Generating Station and the Riverton Substation was not required provided i) the 230 kV HVTL between the Station and the Wilton Substation was placed in-service and ii) the Essar Steel Minnesota's taconite processing facilities and the first phase of their steel manufacturing facility were operating and requiring an average electric load of 273 MW.

[86] Minnesota Power. 2010. "Facility Study Report, Generator Interconnection Supplemental Study, MISO #G519, 11 Line Upgrade." Report prepared for MISO, January 22, 2010. The report confirmed that 86 HVTL structures would require replacement to achieve the ground clearance needed to operate the 11 Line at a summer rating of 90 MVA. In addition, distribution lines at six different locations must be placed underground to achieve the necessary clearance.

[87] Appendix A of the G-477 LGIA, states that Project G-477 and Project G-519 are mutually exclusive projects, and "only one of the two projects shall be constructed and the other shall be withdrawn from the queue." Issuance of the Site, HVTL Route and Natural Gas Pipeline Route Permits for the West Range Site dictated that the G-477 Project be withdrawn.

the contested case hearing that Excelsior was concomitantly undertaking.[88] All work under the G-519 LGIA was suspended between December 10, 2007 through April 30, 2008 awaiting MPUC's determination of whether the network upgrades necessary to interconnect the Project to the electrical grid were exempt from the requirements for a certificate of need under Minn. Stat. § 216.243.[89] Efforts in support of permitting the network upgrades were restarted May 8, 2008; work on drafting the Route Permit Application was initiated on September 29, 2008.

On December 16, 2008, Excelsior advised Minnesota Power that the 90-day local government unit notification required prior to filing a route permit application with the MPUC should be delayed until formal publication of the G-519 Optional Study results. Although the filing of the 90-day notification was delayed, work on the route permit application continued until January 29, 2009 when the Study results were officially obtained.[90] Since the Optional Study results showed that the network upgrades between the Boswell and Riverton Substations were not required given the expected construction of two regional projects (the Wilton-Boswell CapX2020 Project and the Essar Steel plant in Nashwauk, Minnesota), all work in support of permitting the network upgrades was immediately discontinued. The impact of the Optional Study results on the G-519 LGIA milestone schedule was formally communicated to MISO and Minnesota Power on July 1, 2009 and addressed a Facility Study proposed by MISO to rectify adverse impacts reported by Minnesota Power on its No. 11 HVTL.

On April 6, 2010 after the results of the new Facility Study had been published, Excelsior provided a letter to MISO placing the G-519 LGIA in suspension until further notice. The G-519 LGIA has not been reactivated since providing the April 6, 2010 notice to MISO.

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[88] Delays in issuance of the Draft EIS until November 2007 caused delays in scheduling the contested case hearings required for the Project under the Power Plant Siting Act (Minn. Stat. 216E and Minn. R. 7850.1000 to 7850.5600) until the 1st quarter of 2008.

[89] On December 20, 2007, Excelsior filed a petition with the Minnesota PUC asking the Commission to issue an Order affirming that the certificate of need exemption set forth at Minn. Stat. § 216B.1694, subd. 2(a)(1) applies to all transmission infrastructure associated with the power generation facilities of the Project. The Commission issued such Order on April 18, 2008. The Minnesota PUC had previously ordered on August 30, 2007 that the Project met the definition of an innovative energy project set forth at Minn. Stat. § 216B.1694, subd. 1.

[90] The Optional Study results were posted on MISO's web site on January 27, 2009.

D. PRE-ENGINEERING AND DESIGN

The scope of work for Subtask 1.04 involved conducting plant optimization studies in support of making two primary determinations early in the Project Definition phase – selection of the combustion turbine for the project and identification of the project fuel source(s).

1. TECHNICAL TEAM AND PRE-FEED STUDIES

The Project proposal included specification of COP's E-Gas™ gasification technology, which Excelsior selected due to its demonstrated operating experience in fuel-flexible gasification. Excelsior had negotiated a license agreement with COP for the Project's use of E-Gas™ technology. Excelsior subsequently assembled a gasification and engineering team consisting of COP and Fluor Engineers and Constructors ("Fluor"). The team performed preliminary engineering and plant design studies to develop the IGCC conceptual plant design, which included heat and material balances, plant drawings, plant capital and operating cost estimates, and a plant construction schedule. The original design basis was for a 500 MW 2 on 1 combined cycle plant, located in northeast Minnesota. The fuel was Illinois #6 bituminous coal. A number of optimization studies were performed on this preliminary design which included the following:

(a) Fuel flexible design which included PRB sub-bituminous coal and a blend of PRB coal and petroleum coke. Based on a combination of factors, including commodity pricing and fuel transportation, it was determined that the economic choice of feedstock(s) were a blend of PRB coal and petroleum coke, or a blend of PRB coals from Northern and Southern PRB basin. The flexibility to process Illinois #6 coal was also retained.

(b) Syngas and natural gas duct firing of the HRSG to increase plant capacity. This option was evaluated but not included in the plant design basis, because it was not economically justified. Due to the lack of capacity markets and relatively stable power prices in the region, the benefits of additional peaking capacity would have been minimal and most likely insufficient to cover the capital cost of duct firing.

(c) Selective catalytic reduction and deep sulfur removal. For permitting purposes, Excelsior needed to select the acid gas removal system and the NO_X control technology. Based on the COP experience at its Wabash River IGCC plant in Indiana, the plant design used an aqueous solution of MDEA, an amine absorbent, for hydrogen sulfide reduction and nitrogen dilution of the syngas for NO_X reduction. Initially, Excelsior decided against SCR and deep sulfur removal due to plant performance penalties and increased capital and operating costs. However, in the interest of avoiding delays associated with the BACT analysis in the air permitting process, it was decided to include activated zinc oxide sulfur removal after the MDEA process and SCR in the HRSGs. These additional controls resulted in a 60% reduction in SO_2 emission rates and a 67% reduction in NO_X emission rates relative to the initially proposed rates.

(d) Dry cooling rather than cooling towers for the heat rejection system. Dry cooling reduces the plant water consumption and is typically considered in areas of limited water supply. Due to adequate water supply in the plant vicinity and cost and performance penalties associated with dry cooling, cooling towers were selected as the plant heat rejection system.

(e) Staging of the combined cycle island such that the plant would be able to initially start up on natural gas while the gasification island was being constructed. This would have been an option if the power purchaser had a need for power prior to the planned completion of the IGCC plant, but it would have lengthened the overall construction schedule for the total facility. Based on discussions with the potential power purchaser, power was not needed prior to the planned completion date, so it was determined not to pursue this option.

(f) Combustion turbine selection. Fluor prepared an analysis of vendor offerings from Siemens, GE, and Mitsubishi. Based on cost and performance considerations, commercial readiness to operate on syngas, and Siemens' willingness to participate as a member of the engineering, procurement, and construction consortium, the Siemens SGT6-5000F syngas machine was selected.

(g) Partial CO_2 removal technology. Fluor evaluated CO_2 removal technology options and concluded that MDEA was the lowest cost option for removing CO_2 from the unshifted syngas. However, due to added capital and operating costs, plant performance penalties, and the absence of regulatory requirements or carbon price signals in the foreseeable future, carbon capture was not included in the plant design basis. Space was provided for future capture, if it became a requirement. See further discussion of carbon capture and sequestration activities in Section J.2.

(h) Plant capacity. The plant capacity was revised based upon evaluation of a modest scale-up (approximately 35%) of the E-Gas™ gasifier size. The result of this analysis concluded that a nominal 600 MW IGCC plant size was the optimum capacity for the selected technology and site location.

Based on the decisions resulting from the above described optimization studies, a Preliminary Design Basis document was prepared. The roles of the various parties were as follows: COP was responsible for the fuel preparation, gasification island and gas clean-up sections, Siemens was responsible for the combined cycle island, and Fluor was responsible for the balance of plant. During development of the Design Basis document, Siemens acquired its own gasification technology and exited the engineering consortium. Based on a recommendation from Fluor, which was based primarily on cost and performance considerations, Excelsior selected the GE 7FB syngas CT and Fluor assumed responsibility for the combined cycle island. The Preliminary Design Basis document describes all the major systems, design capacities, sparing philosophy, and site related design factors and is provided as Appendix D. The following narrative provides a description of the plant subsystems within the IGCC power plant.

2. Plant Design Description

Detailed qualitative 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. Overall schematic block flow diagrams identifying important equipment and processes related to air pollutant emissions from Mesaba One and Mesaba Two are presented in Figure D-1 and Figure D-2. A preliminary plot plan of the IGCC Power Station is provided in Figure D-3.

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

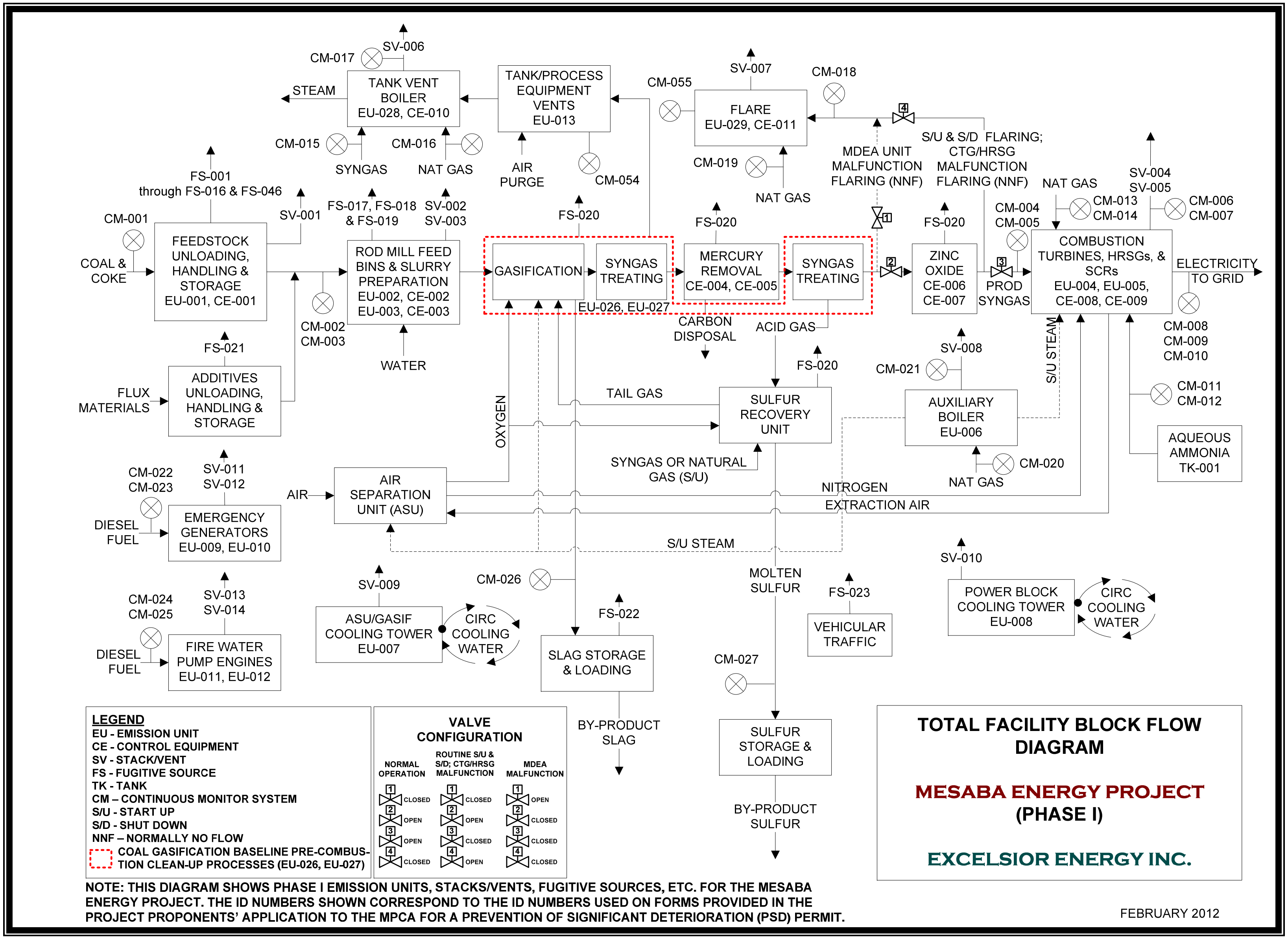


Figure D-2. Block Flow Diagram Showing Air Pollutant Emission Sources for Mesaba Two

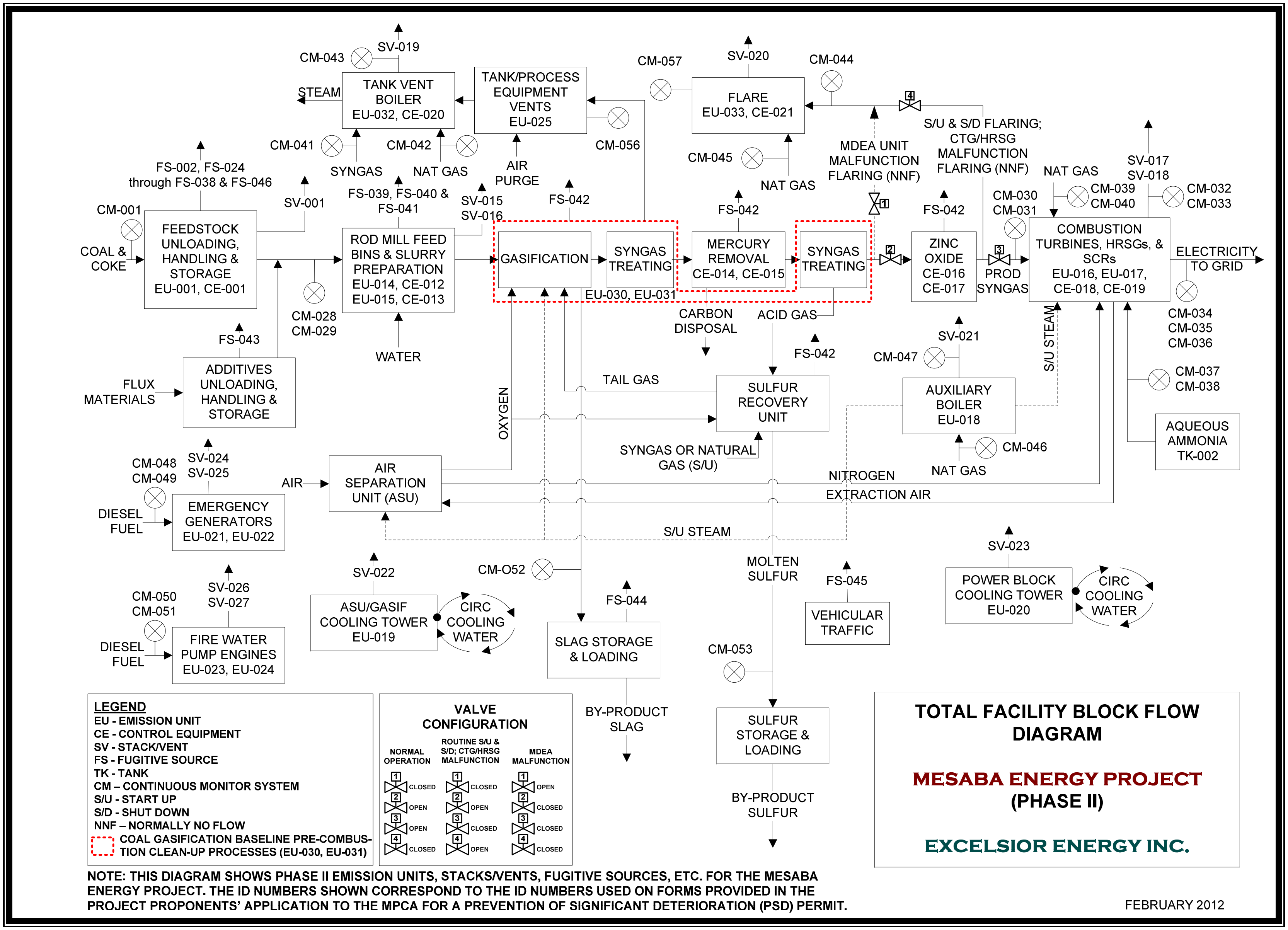
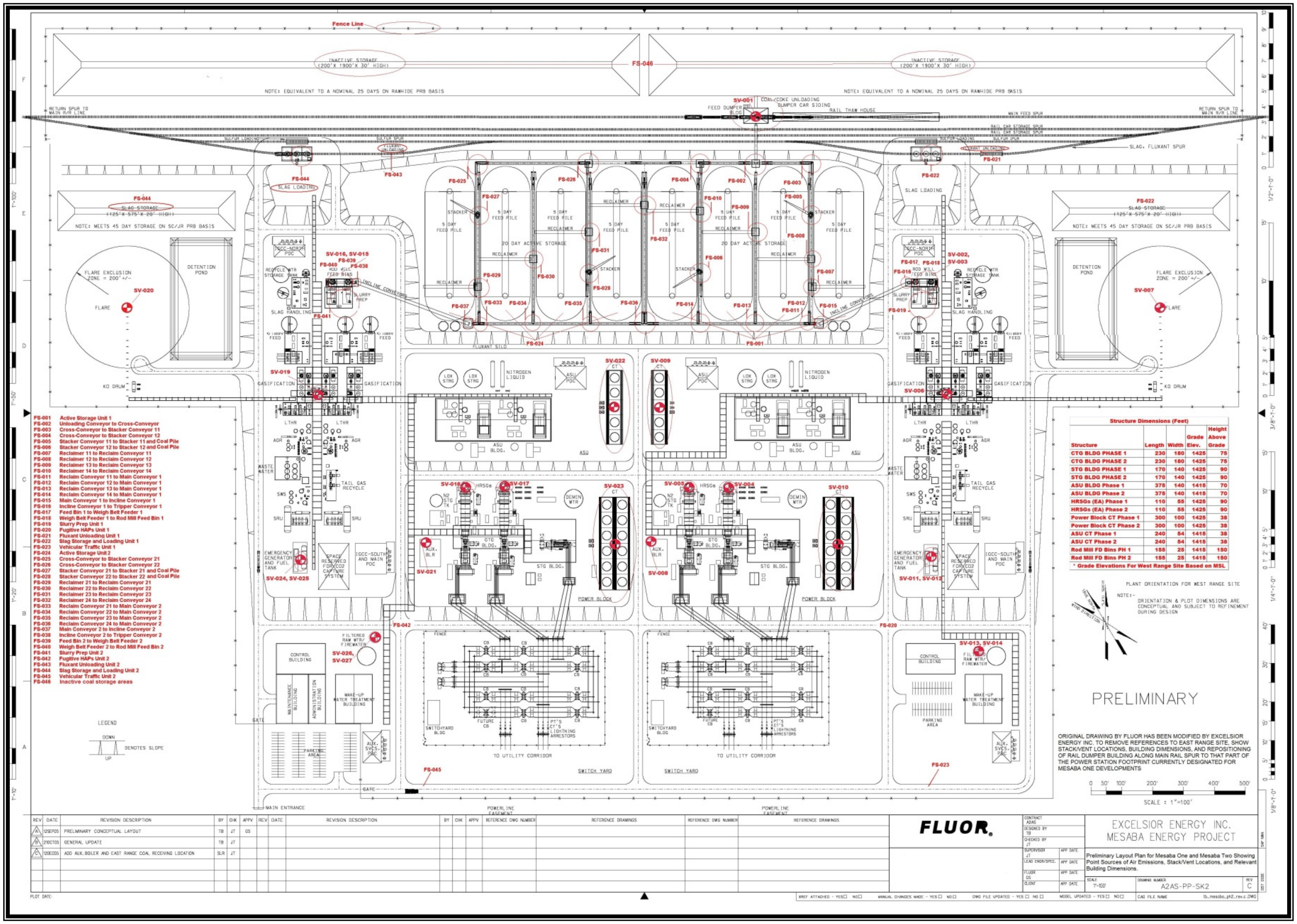


Figure D-3. Preliminary Layout Plan for Mesaba One and Mesaba Two



a. Process Chemistry

Gasification

Coal and petroleum coke are typically characterized by their heating value, elemental analysis (weight percent carbon, hydrogen, nitrogen (“N_2”) 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 would be fed to the gasifier along with pure oxygen, and a number of complex chemical reactions would occur. A portion of the feedstock would be partially oxidized to provide the temperatures necessary for gasification. The gasification temperature would be 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)
$C + \frac{1}{2} O_2 = CO$ (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 would be converted to H_2S during the gasification process. A small portion of the sulfur would be converted into COS. Most of the nitrogen in the feedstock would be converted to ammonia (“NH_3”). The syngas composition leaving the gasifier would be determined by the gasifier operating temperature and the relative kinetics of the above reactions. Most of the energy in the feedstock would be ultimately converted into CO and H_2, and a small amount of CH_4. Low grade coals with lower heating values and higher moisture contents would generate a syngas with more CO_2 and H_2 (the additional CO_2 would be generated from the water gas shift reaction shown above). Higher quality coals and petroleum coke would result in a syngas that has a much higher CO content.

COS Hydrolysis

Because the small fraction of COS formed in the gasifier would be difficult to remove in the AGR system, the COS would be “hydrolyzed” in a catalytic reactor before the syngas would be 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 would be limited by the equilibrium conditions at the COS reactor operating temperature.

Acid Gas and Sulfur Removal

The AGR system would use 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 would be 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 would be sent to the SRU.

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

b. Process Operations

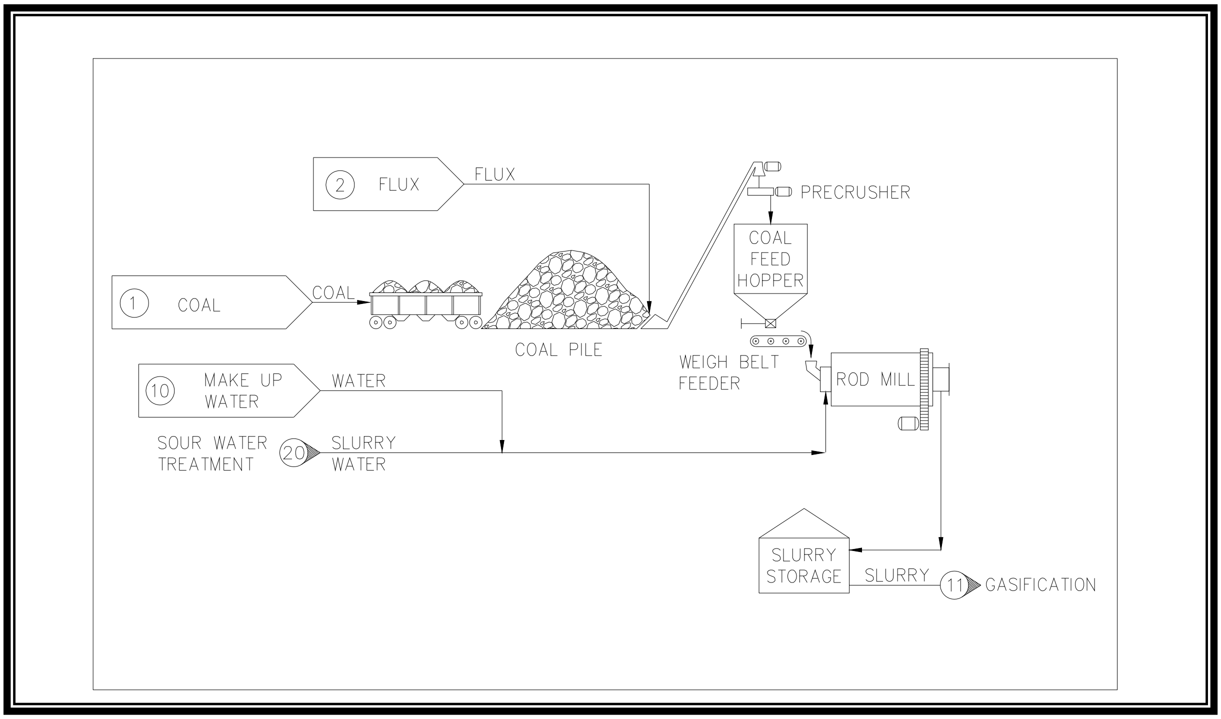
Slurry Preparation

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

Slurry feeding would allow for consistent and safe introduction of feed into the gasifiers. Prepared slurry would be stored in an agitated tank. The capacity of the slurry storage tank would 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 D-4.

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

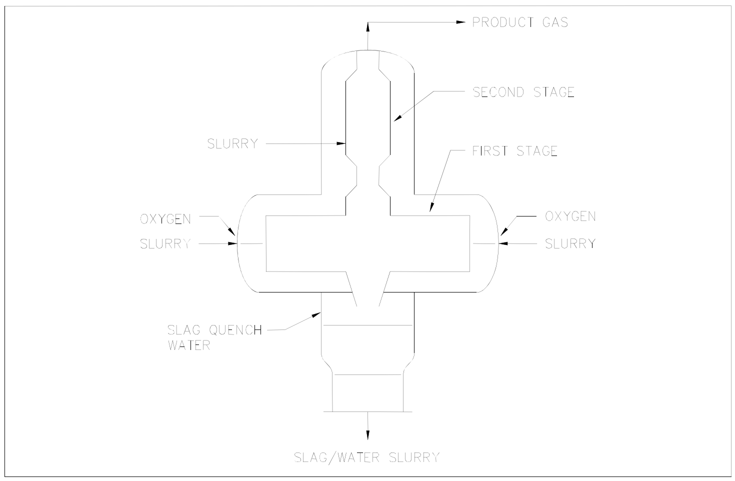
Figure D-4. Feedstock Grinding and Slurry Preparation



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 D-5. The first stage is a horizontal refractory-lined vessel in which feedstocks would be exposed to sub-stoichiometric quantities of oxygen at an elevated temperature and pressure. Oxygen and preheated slurry would be 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 would 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 completely gasified in this environment to produce syngas that would consist primarily of H_2, CO, CO_2 and water ("H_2O").

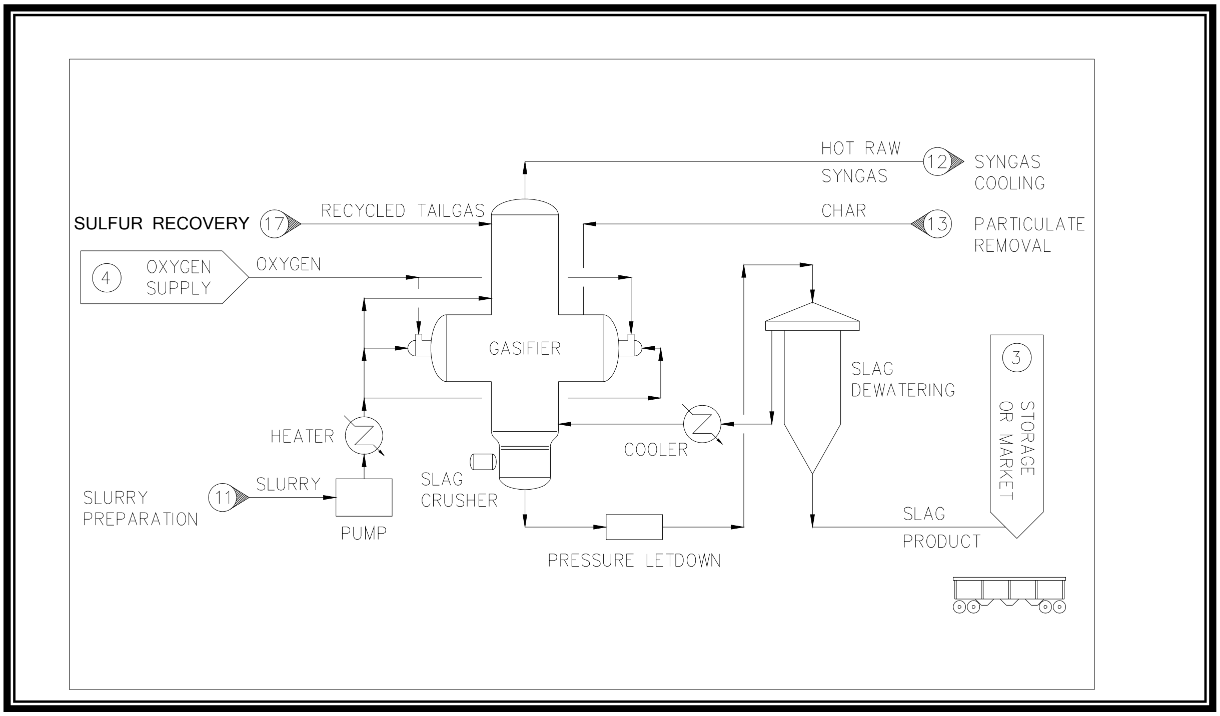
Figure D-5. E-Gas™ Gasifier



Sulfur in the fuel would be primarily converted to H_2S, with a small portion converted to COS. With the pollutant removal processing system provided downstream, over 99% of the sulfur would be removed from high sulfur feedstocks. Over 97% of the sulfur would be removed from low-sulfur sub-bituminous coal feedstocks. The removal rate from low sulfur coal nonetheless would result in approximately equal sulfur emission rates as for high sulfur coal despite having a higher removal rate. 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.

As to production of slag, mineral matter in the feedstock and added flux forms the molten slag, which would flow 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 that would be produced in the gasifier would vary with the mineral content of the feedstock. As depicted in Figure D-6, the solidified slag would exit the bottom of the quench section, after which it would be crushed, and would then flow through a proprietary continuous pressure-letdown system as a slag/water slurry. This continuous slag removal technique would eliminate high maintenance, problem-prone lockhoppers and would prevent the escape of raw syngas to the atmosphere during slag removal. The slag/water slurry would then be directed to a dewatering and handling area (described later). The raw syngas generated in the first stage would flow up from the horizontal section into the second stage of the gasifier.

Figure D-6. Gasification and Slag Handling



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

The gasifier second stage would consist of a vertical refractory-lined vessel in which additional slurry would be reacted with the hot syngas stream exiting the first stage. The feedstock would undergo 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 would lower 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 would react with a portion of the carbon to produce additional CO and H_2 for subsequent use as syngas fuel for power generation. Unreacted solid fuel (carbonaceous char) would be carried out of the second stage with the syngas.

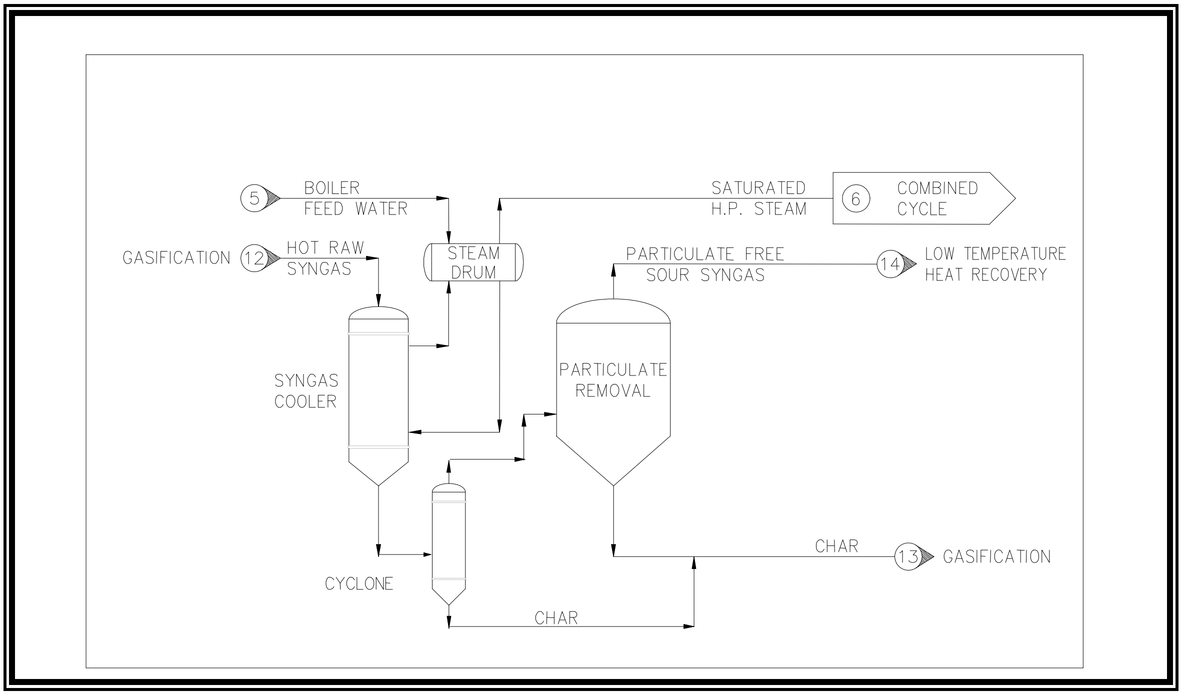
Certain trace quantities of metals present in the feedstock and volatile at the temperatures typical of the gasifier would also be carried out in their gaseous state as components of the syngas to be removed in the cleanup stage.

The slag/water slurry would flow continuously into a dewatering bin. The bulk of the slag would settle out in the bin while water would overflow into a basin that would allow the remaining slag fines to settle. The clear water from the settler would pass through heat exchangers where it would be cooled before being returned to the gasifier quench section. Dewatered slag would be transferred to the slag storage area and loaded into trucks or rail cars for transport to market or storage. The slurry of fine slag particles from the bottom of the settler would be recycled to the slurry preparation area and fed back into the gasifier, ensuring maximum carbon utilization.

Syngas Cleanup and Desulfurization

As shown in Figure D-7, the next two steps in the process would be to cool the syngas and then remove particulate matter, which would be recycled to the gasifier. The hot raw syngas exiting the gasifier system and containing entrained particulate matter would be cooled in the syngas cooler, converting a significant portion of the heat from the gasifier to high pressure ("HP") steam to be used in power generation.

Figure D-7. Particulate Matter Removal System



Particulate Matter Removal System

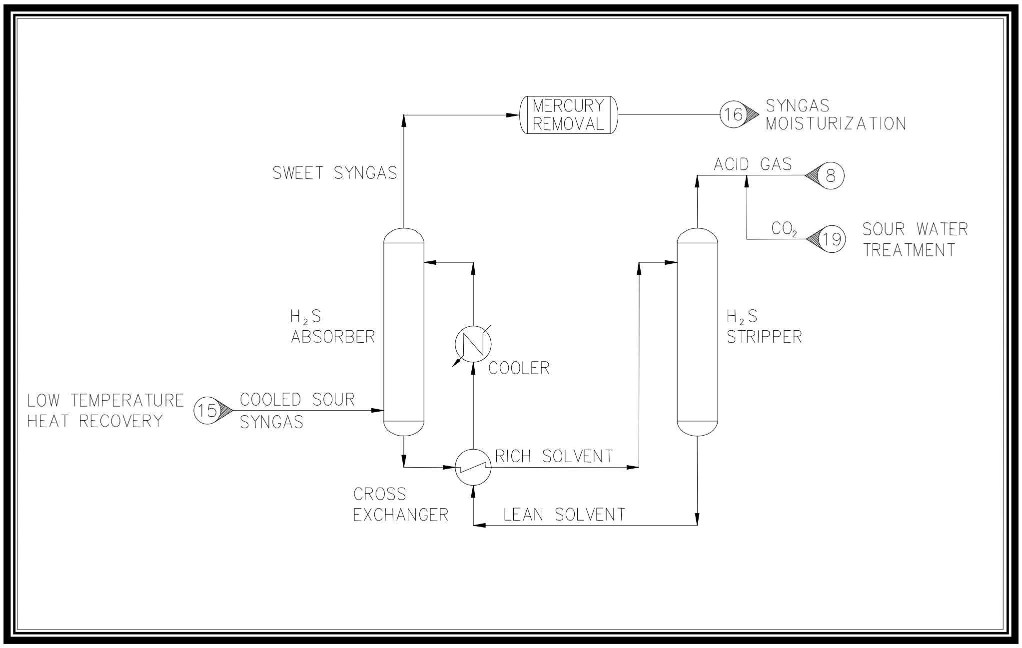
After cooling, the syngas would be directed to the particulate matter removal system, as shown in Figure D-7 above. The gas would flow through a hot gas cyclone to remove relatively large particulate matter and then on to the particulate matterfilter. The filter vessel would contain numerous porous filter elements to remove particulate matter. Particulate matter removal efficiency would be expected to approach 99.9%. Removed particulate matter from both the hot gas cyclone and the dry filter vessel would be recycled to the first stage of the gasifier to improve carbon conversion efficiency that would result in near complete gasification of the carbon content of the feedstock. The particle-free syngas would then proceed to the low temperature heat-recovery system.

Acid Gas Removal System

The AGR system (shown in Figure D-8) would contact the cool sour syngas with an aqueous solution of MDEA, an amine absorbent that removes H_2S to produce a clean product syngas. MDEA chemically bonds with H_2S and that bond can easily be broken with low level heat to regenerate the absorbent. H_2S

would be absorbed from syngas through contact with MDEA solution within the H_2S absorber column. A portion of the CO_2 would also be absorbed. The H_2S-rich MDEA stream from the bottom of the absorber would then flow to a cross-flow heat exchanger to recover heat from the hot lean MDEA stream. The heated rich MDEA would then be processed in the H_2S stripper, which would remove H_2S and CO_2 at near atmospheric pressure. A concentrated stream of H_2S and CO_2 would exit the top of the H_2S stripper and flow directly to the SRU. If a carbon-capture system were included, the stripper exit stream would be processed by the carbon-capture system prior to the SRU. The lean MDEA stream would be pumped from the bottom of the stripper to the cross-flow heat exchanger. The lean MDEA would be further cooled before being re-circulated to the absorber. This process unit would be totally enclosed with no gaseous discharges to the atmosphere.

Figure D-8. Acid Gas Removal



The AGR system would reduce the total sulfur concentration of the syngas to 50 ppmvd or lower (based on a 30-day rolling average). This performance would be limited by the fact that much of the sulfur present as COS would be not adsorbed. In order to achieve deeper sulfur removal, which Excelsior committed to do in the interest of expediting the air permitting process, a trim sulfur removal system downstream of the AGR system would be necessary and would consist of fixed beds of activated zinc oxide. Additional COS hydrolysis would occur within the activated zinc oxide beds, followed by adsorption of sulfur to form zinc sulfide ("ZnS"). This would reduce the total sulfur concentration in the syngas to 20 ppmvd or lower (based on a 30-day rolling average). The activated zinc oxide beds would be operated in a lead-lag configuration to facilitate replacement of the zinc oxide during operation. Saturated zinc oxide would be removed and sent to an approved facility for recovery or disposal.

Potential Carbon Capture Retrofit

In order to comply with potential future regulation of GHG emissions, Mesaba One and Mesaba Two were both designed to be carbon capture ready. Additionally, Excelsior has worked 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 was part of the Plains CO_2 Reduction ("PCOR")

Partnership's[91] Phase II efforts conducted for DOE to validate the most promising sequestration technologies and infrastructure concepts identified during Phase I of the Program.[92]

The carbon capture system that was studied could be added after the IGCC plant becomes operational. The system would remove approximately 90% of the carbon present as CO_2 in the syngas and would be located downstream of the AGR system. For PRB coal, this would result in the removal of approximately one third of the total carbon present in the solid IGCC feedstock. Based on work to date, such CO_2 capture facilities would 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. This capture would cause a decrease in capacity and efficiency of the IGCC plant. Carbon capture and storage is discussed in detail in Section J.2.

Mercury Removal and Moisturization

Fixed beds of activated carbon would be provided to remove residual mercury from syngas. Multiple beds specially impregnated to remove mercury would be used to obtain optimized adsorption. The activated carbon capacity for mercury ranges up to 20% by weight of the carbon.[93] The mercury removal system would reduce the mercury content of the syngas to no more than 5% of the mercury contained in the solid IGCC feedstock. The mercury removal system would be located either immediately upstream or immediately downstream of the AGR. The optimum location would be determined by working closely with activated carbon suppliers during the next engineering phase of the project. After acid gas and mercury removal, the product syngas would be moisturized, heated, and diluted with nitrogen for control of NO_X before being combusted for power generation in the CTGs.

Sulfur Recovery Unit

The H_2S carried along in the acid gas from the AGR system would be 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 would be selectively condensed and collected in molten form (see Figure D-9).

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

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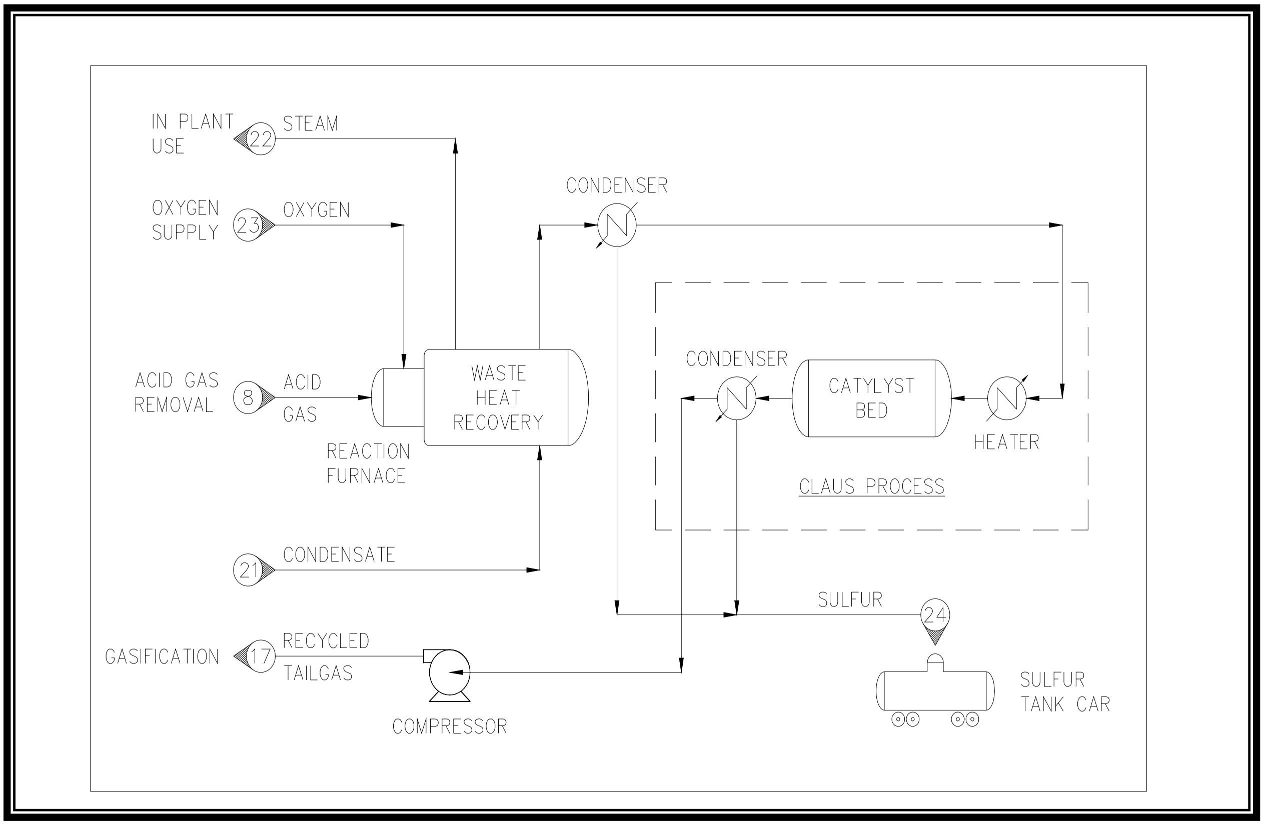
[91] The Plains CO_2 Reduction Partnership is one of seven regional partnerships funded by the DOE/NETL's Regional Carbon Sequestration Partnership Program.

[92] 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.

[93] Parsons Infrastructure and Technology Group Inc. "The Cost of Mercury Removal in an IGCC Plant." September, 2002. *See* http://www.netl.doe.gov/technologies/coalpower/gasification/pubs/pdf/MercuryRemoval%20Final.pdf.

Figure D-9. Sulfur Recovery Unit



Gas exiting the first sulfur condenser would be fed to a series of heaters, catalytic reaction stages and sulfur condensers where the H_2S is incrementally converted to elemental sulfur. The sulfur would be 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 transported to an approved storage and disposal facility.

The tail gas from the SRU would be 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 would be catalytically hydrogenated to convert the remaining sulfur species to H_2S and then recycled to the gasifier. Recycling the SRU tail gas would allow for a very high overall sulfur removal from the IGCC process and eliminate the need for a conventional tail gas treating unit. This would reduce overall plant emissions of SO_2 and NO_X to the atmosphere.

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

Condensed sulfur from the SRU would be collected in the sulfur pit. The liquid sulfur would drain into the pit which contains a pump well and sulfur pumps. Sweep nitrogen would be 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 would be located at opposite ends of the pit to ensure proper sweep of the vapor space. The sweep nitrogen outlet would be collected and recycled to the second stage of the gasifier. Nitrogen would be readily available from the ASU and would be used instead of air since nitrogen is inert and it is undesirable to return air back to the gasifier's second stage.

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

Sulfur loading would involve pumping liquid sulfur from sulfur storage to trucks or rail cars. The sulfur loading arms would contain vapor recovery systems to control fugitive emissions by returning displaced vapors to the storage tank. The SRU process would be totally enclosed with no discharges to the atmosphere.

Air Separation Unit

The air separation unit would provide oxygen for the gasification process and nitrogen for CTG NO_X control and for purging. The ASU would consist of 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 would be necessary for each phase of the facility.

A multi-stage, electric motor-driven centrifugal compressor compresses filtered atmospheric air that may subsequently be combined with additional compressed air extracted from the gas turbines in the power block. The combined air stream would be cooled and directed to the molecular sieve absorbers where moisture, CO_2 and atmospheric contaminants are removed to prevent them from freezing in the colder sections of the ASU. The dry CO_2-free air would be separated into oxygen and nitrogen in the cold box. A stream containing mostly oxygen would be discharged from the cold box as a liquid and stored in an intermediate oxygen storage tank that supplies the gasifier.

The ASU would also produce three different purity streams of nitrogen. A small portion of the nitrogen is of 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 would be no emission of regulated air pollutants from the ASU.

Slag Handling, Storage, and Loading

The slag/water slurry from the gasifier (see Figure D-6) would flow continuously into a dewatering bin. The bulk of the slag would settle in the bin while water overflows into a settler which would allow the remaining slag fines to settle and be concentrated. The slurry of fine slag particulate matter from the bottom of the settler would be recycled to the slurry preparation area, ensuring maximum carbon utilization. The clear water from the settler would be cooled by heat exchangers prior to being returned to the gasifier quench section.

Dewatered slag would be transferred by in-plant trucks to the slag storage area to be loaded into on-road trucks or rail cars for transport to market or storage. The dewatered slag will be relatively inert and moist and would not be a source of particulate matter emissions.

Combined Cycle Power Block

The power generation portion of the IGCC Power Station would be similar to a conventional natural gas combined cycle plant. Combined cycle power generation is one of the most efficient commercial electric generation technologies currently available. Each phase of the IGCC Power Station would include two "F Class" advanced CTGs configured to utilize syngas, two HRSGs, and a single steam turbine generator ("STG") (see Figure D-10). The CTGs would convert the chemical energy contained in the syngas fuel to electricity both directly through integral generators (approximately 220 MW per CTG), and indirectly through the additional thermal energy contained in the CTG exhaust gas. The high temperature exhaust gas would be used to produce high-energy steam in the HRSGs. The steam would then be used to produce a significant amount of additional electricity in the STGs. Each phase of the IGCC Power Station would have one STG capable of producing approximately 300 MW.

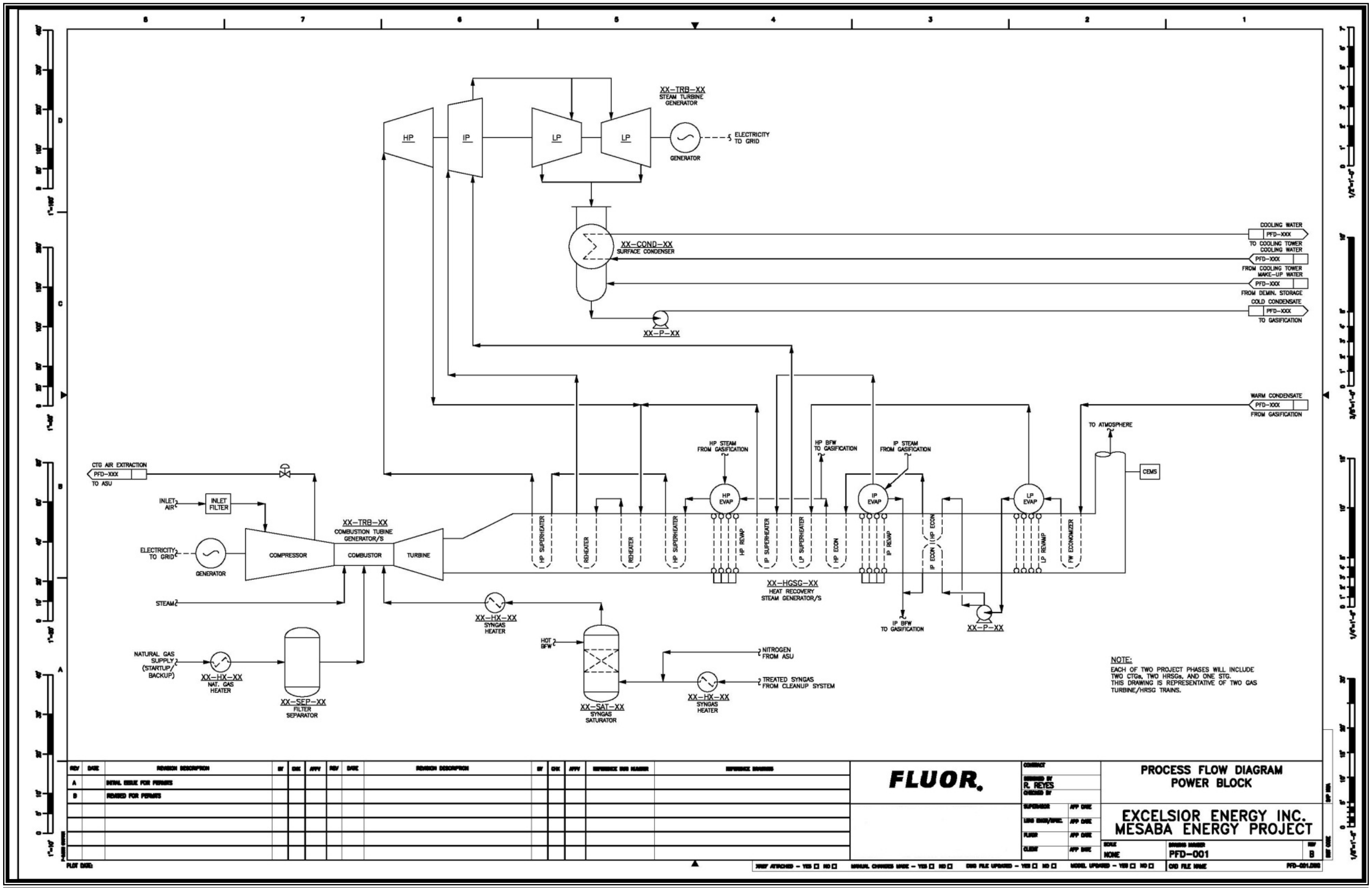
Preheated syngas from the gasification section and compressed air would be supplied to the combustion turbine combustor and mixed through diffusion (a diffusion flame combustion turbine). Unlike pre-mix combustors that are traditionally used in gas turbines that mix the natural gas fuel and air upstream of the combustor, diffusion combustors supply the fuel and air via separate passages, and the mixing of air and fuel occurs at the location of the flame. Diluent nitrogen would be added to the syngas fuel to reduce the flame temperature in the combustor and thereby reduce production of nitrogen oxides. The hot exhaust gas exiting the combustor would flow to the expander turbine, which drives both the generator to produce electricity and the air compressor section of the combustion turbine. Hot exhaust gas from the expander would be ducted through the HRSG to generate high-energy steam, which in turn would be used to produce additional electricity in the STG. Following heat recovery, the cooled CTG exhaust gas would be discharged to the atmosphere through the HRSG stacks. The HRSG stacks would be provided with emission monitoring instruments as required to verify compliance with applicable emission standards and permit conditions.

Because the proposed deep sulfur removal would largely address feasibility concerns, an SCR system would be installed in the HRSG to reduce NO_X from flue gas with a catalytic reactor. The primary feasibility concern was that ammonia from the SCR would combine with sulfates in the CTG exhaust to form ammonium sulfate, which would subsequently be deposited on the narrow fins of the HRSG, causing degraded performance and potentially forced plant outages. Deep sulfur removal in the syngas leads to lower sulfate concentrations in the exhaust, keeping ammonium sulfate formation and associated feasibility concerns in check. The SCR would be composed of an aqueous ammonia storage tank, an injection grid (system of nozzles that spray NH_3 into the exhaust gas ductwork), a reactor that contains catalyst, and instrumentation and electronic controls. The typical effective temperature range for SCR catalysts is 600-800˚F, which would be the basis for the placement of the SCR within the HRSG.

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

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

Figure D-10. Illustration of Combined Cycle Concept



IGCC Power Station Utility Systems

Tank Vent Boiler System

A tank vent collection/boiler system would be 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 would be composed primarily of air and/or nitrogen purged through various in-process storage tanks. These streams would then be routed to the tank vent boiler. This tank purge gas may contain very small amounts of sulfur-bearing components. The high temperature that would be present in the tank vent boiler would thermally convert any H_2S present in the tank vents to SO_2. Hot exhaust gas from the tank vent boiler would then be used to produce steam before it is directed to a stack.

The slag handling dewatering system off-gas would also contain H_2S that 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 would be 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 would 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.

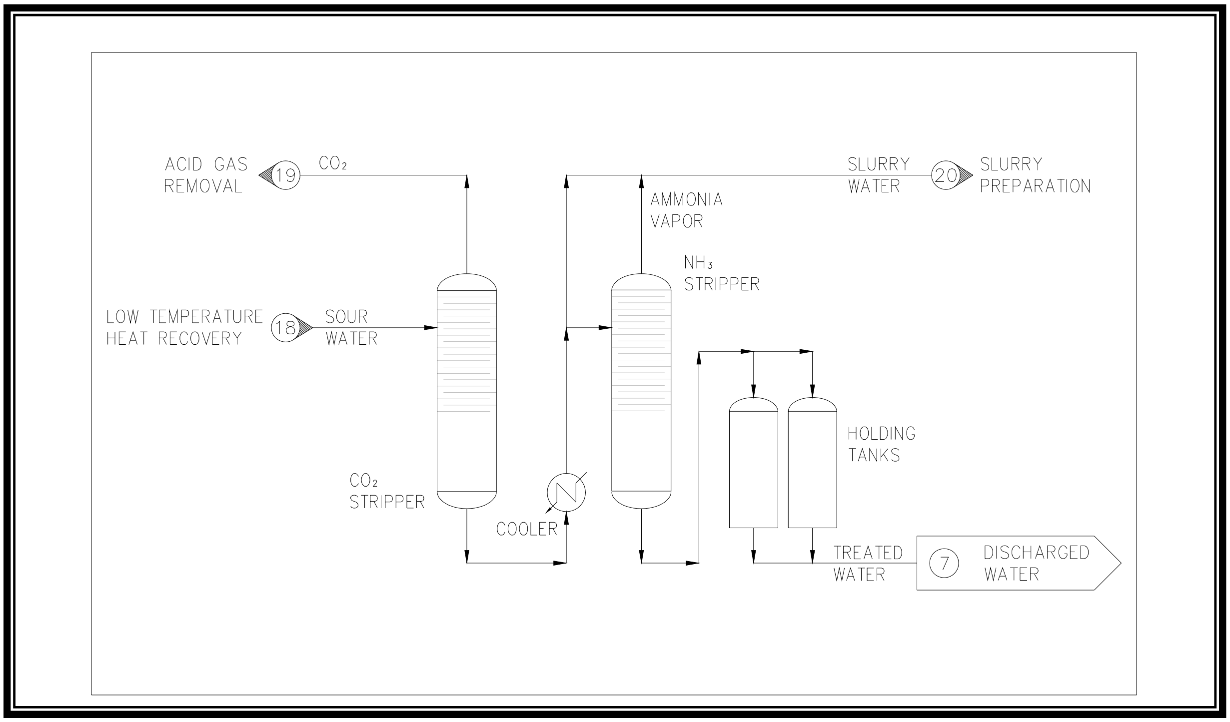
Sour Water Treatment

Process water that would contain dissolved contaminant gases produced within the gasification process would be treated to remove these dissolved gases before being recycled to the coal grinding and slurry preparation area or being blown down to the ZLD System. The sour water treatment process is illustrated in Figure D-11. The dissolved gases would be removed via steam-stripping. The steam would provide both 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 blowdown to the ZLD.

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

This process unit would be totally enclosed with no discharges to the atmosphere.

Figure D-11. Sour Water Treatment System

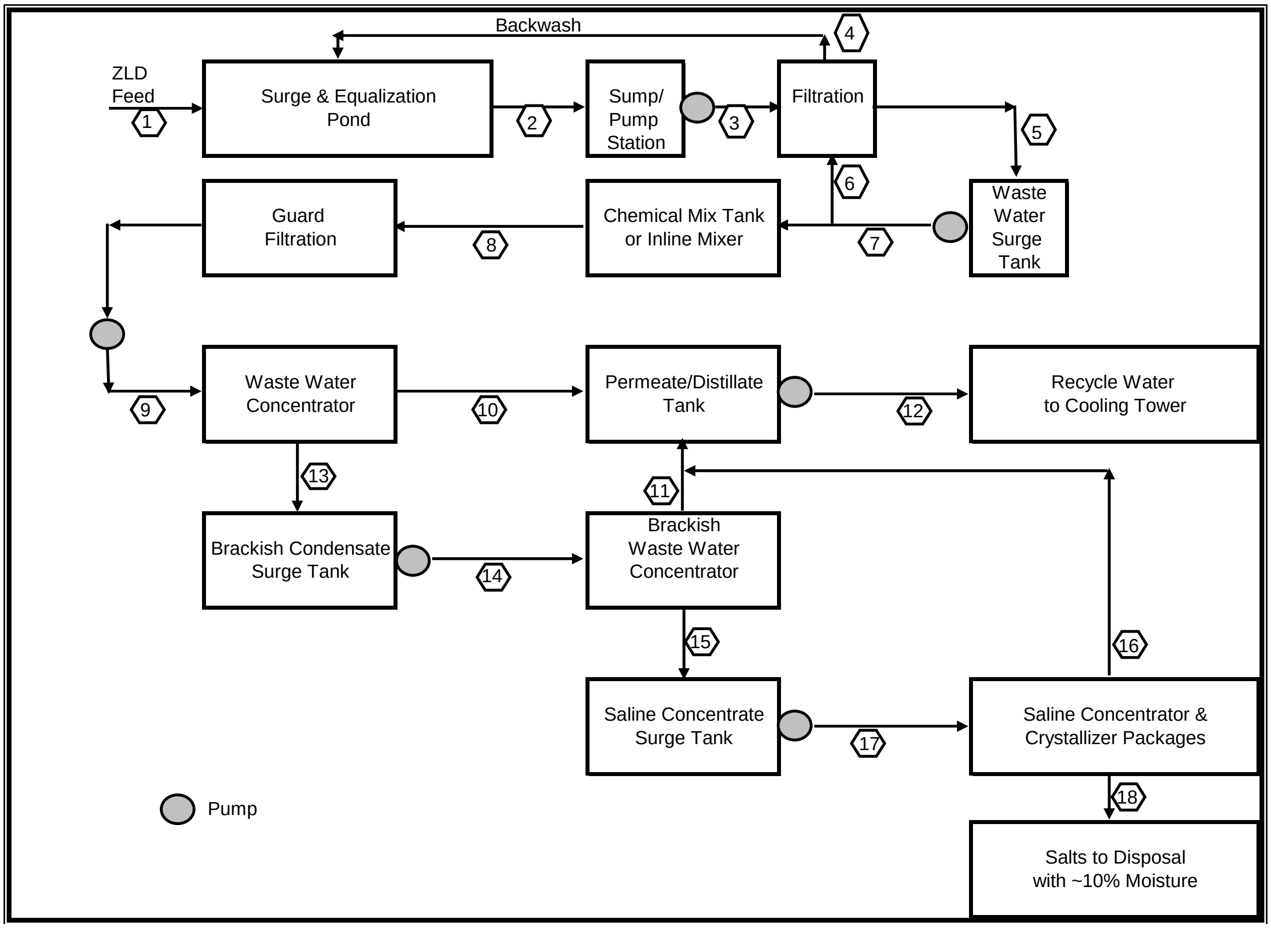


Zero Liquid Discharge Systems

Water from the bottom of the ammonia stripper would be treated by a ZLD unit. The blowdown stream would be pumped to a brine concentrator which would use steam or vapor compression to indirectly heat and evaporate water from the wastewater stream. Generated water vapor would be compressed and condensed resulting in a high quality distillate that would be recycled to the syngas moisturization system or to other water uses in the plant. The concentrated brine would then be processed in a heated rotary drum dryer/crystallizer to vaporize the remaining water and produce a solid filter cake for proper disposal. Use of the ZLD system would effectively prevent contaminants in plant feedstock from being discharged to surface waters.

Wastewater streams that do not contact fuel, such as blowdown from the cooling towers and most stormwater, would be treated in a separate ZLD system. The design and operation of this ZLD system would be similar to that described above, except that membrane treatment precedes the brine concentrator. The non-contact water ZLD treatment system is illustrated in Figure D-12.

Figure D-12. Zero Liquid Discharge Treatment System



Auxiliary Boilers

Two auxiliary boilers, one for each phase of the IGCC Power Station, would 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 would provide steam in addition to, or in lieu of, the steam that can be generated from the tank vent boilers. Each boiler would produce a maximum of about 100,000 lb/hr of steam and would be fueled solely by pipeline natural gas. Annual operation of each boiler would be equivalent to or less than 25% of the year at maximum capacity due to intermittent operation. The auxiliary boilers would be equipped with low NO_X burners to minimize air emissions.

Flares

The gasification island elevated flare would be 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 that would be sent to the flare during normal planned flaring events (e.g., during start-up) would 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 D.3.d and in Table D-6 and

Table D-7.

Emergency Diesel Engines

For each of Mesaba One and Mesaba Two, one 2-MW emergency diesel generator would be used for the gasification island and one 350-kW emergency diesel generator would be used for the power block. One or two nominal 300-hp diesel-driven firewater pumps would 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 would burn ultra low sulfur diesel. Other than plant emergency situations, the engines would be operated less than 100 hours per year per engine for routine testing, maintenance, and inspection purposes.

3. Plant Specifications

The following subsections describe various specifications for the IGCC Power Station, including fuel/feedstock design basis and delivery, plant performance, major equipment list, startup and shutdown operation, and the preliminary construction schedule.

a. Feedstock Delivery and Specifications

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

The maximum feedstock feed rate for the gasifiers operating in FSQ mode would require a maximum of 8,230 tons of coal per day on an as-received basis. For operation in 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 would typically be required to unload one unit train. An estimated 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% capacity factor. Excelsior would expect to normally operate in FSQ mode a majority of the time. Factoring in yearly planned maintenance outages and assuming a 90% capacity factor in FSQ mode, a maximum of 2.7 million tons of feedstock could be used per year. Specific fuel utilization most likely would change periodically throughout the lifetime of the IGCC Power Station due to the plant's fuel-flexible capability. Fuel selection would be based upon the conditions and terms available from various fuel and transportation suppliers.

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

The feedstock handling system would 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 would be provided for two feedstock materials, coal and petroleum coke. Storage facilities would also be provided for flux, a feedstock conditioning material. The feedstock storage facilities would include, for each phase of the facility, approximately 20 days of active storage and approximately 25 days of inactive storage. The storage areas would incorporate dust suppression systems (including covered conveyers and other enclosures, dust suppression sprays, and vent filters) and would be paved, lined, or otherwise controlled to enable collection and treatment of storm water runoff to prevent ground water infiltration of any chemicals leached from feedstock materials and/or flux.

Unloading facilities would include a thawing shed to loosen frozen cargo during the winter season, and a rotary car dumping building equipped with a baghouse for control of fugitive PM. Initially, the unit train locomotive would position the first car in the rotary dumper. Subsequent cars would be placed in the dumping position by an automatic electro-hydraulic positioner. This system would reduce the fuel consumption and emissions of the locomotives/switch engines that would otherwise occur if all engines were required to run during the entire unloading process. During the unloading process, feedstock material would gravity feed from the rail cars into an enclosed pit. The feedstock material would then be transferred via a feeder/conveyor system to active storage pile stackers. Four active storage piles for each phase of the facility would provide working feedstock storage. Additional inactive storage would be located on the opposite side of the rail sidings to provide reserve feedstock material in the event normal deliveries of unit trains are interrupted. If needed, feedstock from the inactive pile would 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 would move coal and petroleum coke from the active piles to the slurry feed preparation area.

Mesaba One and Mesaba Two were 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 would 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 sub-bituminous 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, would provide ongoing future cost benefits. By utilizing the lowest available cost feedstock, the Station would minimize the cost of power over the life of the facility. . Feedstock flexibility would provide Mesaba One and Mesaba Two cost protection against a single feedstock supplier or transportation provider, and physical dependency protection against supply disruptions from any mine or carrier. Table D-1 shows the feedstock design specifications being utilized to design the Station's unique feedstock flexibility.

Table D-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.
Higher Heating Value ("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 would be syngas produced from the feedstock specified above, the IGCC Power Station would also be capable of operating on pipeline natural gas. The power island would be a combined-cycle unit optimized for syngas operation. The ability to operate on natural gas would provide 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 would allow the installation of the combined-cycle power island prior to the gasification section. Once complete, the power island could produce electricity from natural gas while the gasification section construction was being completed. Then the IGCC Power Station would begin full-time, base load operation on coal-derived syngas.

While operating on natural gas, the power block of the Phase I IGCC Power Station would not achieve the nominal 600 MW_{net} output attainable with syngas operation. This is due, in part, to the lack of high-pressure steam that would otherwise be generated from operation of the gasification island. The maximum natural gas utilization by the IGCC Power Station is predicted to be about 105 million standard cubic feet ("scf") of gas per day per phase.

Natural gas would be supplied through a direct connection with the Great Lakes Gas Transmission Company pipeline located about 12 miles due south of the IGCC Power Station or from Northern Natural Gas company's tapping point located in La Prairie, Minnesota, about 10 miles west-southwest of the Station. Access to multiple pipeline infrastructure alternatives would be beneficial. The Project would contract with either or both entities for natural gas transportation capacity for quantities and pressures sufficient to operate the IGCC Power Station. Natural gas would be purchased through contracts with gas suppliers in order to obtain the lowest overall fuel price and best contract conditions for this commodity. Metering equipment would be installed and operated to monitor purchases. Typical natural gas composition is shown in Table D-2.

Table D-2. Typical Natural Gas Specification

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)	0.57–0.58
Net Heating Value (Btu per scf)	935

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

Mineral content in the ash would determine both the melting temperature of the ash in the gasifier and the slag viscosity at the specific gasifier operating temperature. If the slag is too viscous, it would not flow easily from the gasifier and possibly plug the bottom. Conversely, if the slag is too fluid, it may be excessively erosive to the refractory in the gasifier. Flux, typically silica/sand, limestone, iron oxide (or iron ore), or a mixture of these, would be blended with the feed as necessary to control the slag melting point and viscosity. Therefore, careful monitoring and control of flux blended with the feed would be important.

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

b. Plant Performance

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 D-3 quantifies such conditions assuming operation of the gasifier in PSQ mode while Table D-4 assumes operation of the gasifier in FSQ mode. The parameters in the following tables are based on optimization studies in 2005. Updated studies conducted in 2009 and 2010, including improvements resulting from activated zinc oxide treatment, result in an estimated heat rate for the Project of 8,885 Btu/kWh on Rawhide PRB. Given that using bituminous coal reduces the heat rate by approximately 5% relative to PRB, the Project would be expected to achieve the 8,600 Btu/kWh heat rate objective set forth in the cooperative agreement.

Table D-3. 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 – 4,230	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 – 9,700	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 D-4. Expected IGCC Power Station Operating Characteristics (Phase I, FSQ Mode)

Feedstock	Rawhide PRB	Rawhide PRB	Rawhide PRB	50/50 Wt% SC/JR	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	233
Slag Produced, tons/day	501	495	496	774	772	774
Sulfur Produced, tons/day	30	29	29	45	162	162

The composition and properties of the product syngas vary depending on the solid feedstocks processed and Power Station operating conditions. Table D-5 shows the expected range of syngas composition and fuel heating value.

Table D-5. Estimated Product Syngas Composition Multiple Feedstock Plant (Phase Independent)

Component [1]	Range
H_2, 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 ("° F"), one atmosphere pressure.

c. Major Equipment List

The major functional process equipment provided for Mesaba One's facilities 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. Mesaba Two's facilities and equipment would be identical to those for Mesaba One.

Air Separation Unit (2 x 50%)

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

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

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

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 Rawhide PRB 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 Spring Creek and Jacob's Ranch PRB coals)

Syngas Treatment (2 x 50%)

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

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%)

Power Block

- CTG (2 x 50%) (220 MW nominal each, based on Siemens-Westinghouse SGT6-5000F combustion turbine assumed for environmental permitting)
- HRSG, SCR, 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

General Facilities (1 x 100%)

- Gasification/ASU Cooling Water/Tower System
- ZLD Unit (for Process Condensate Blowdown)
- ZLD Unit (for Non-Contact Wastewater Streams)
- 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

d. Startup and Shutdown

Two general types of plant startups would occur at the IGCC Power Station. The first type, which is expected to be more common, would consist 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 type would consist 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. Table D-6 and

Table D-7 list the sequential steps required for each type of startup. Four cold gasifier startups per year per gasifier would be expected 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 would be accomplished by purging the gasifier vessel and downstream syngas piping with nitrogen from the ASU or storage. This purge gas would flow through the normal syngas treatment system and would be routed to the flare for safe disposal. Nitrogen would then be used to pressurize the system to test for leaks. Natural gas and oxygen from the ASU or storage would then be 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) would also flow through the syngas treatment system prior to final combustion in the flare. If available, syngas may be substituted for the natural gas fuel once stable combustion would be achieved. When the gasifier has reached the required temperature, the natural gas or syngas fuel flow would stop and coal and/or coke slurry would be introduced to the gasifier (without depressurizing the gasifier or syngas piping system). The initial syngas, which would not yet be suitable as combustion turbine fuel due to its low heating value, would flow through the normal syngas treatment system for removal of particulate matter, sulfur, mercury, and other trace contaminants and would be 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 would be stopped and the syngas would be routed to one or more CTGs for electricity production. At this point the gasifier startup would be complete.

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

Table D-6. IGCC Startup – Gasifier Replacement

Assumes Gasifier 2 would be taken off line and replaced by Gasifer 3. Plant is assumed to be 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 treatment 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.

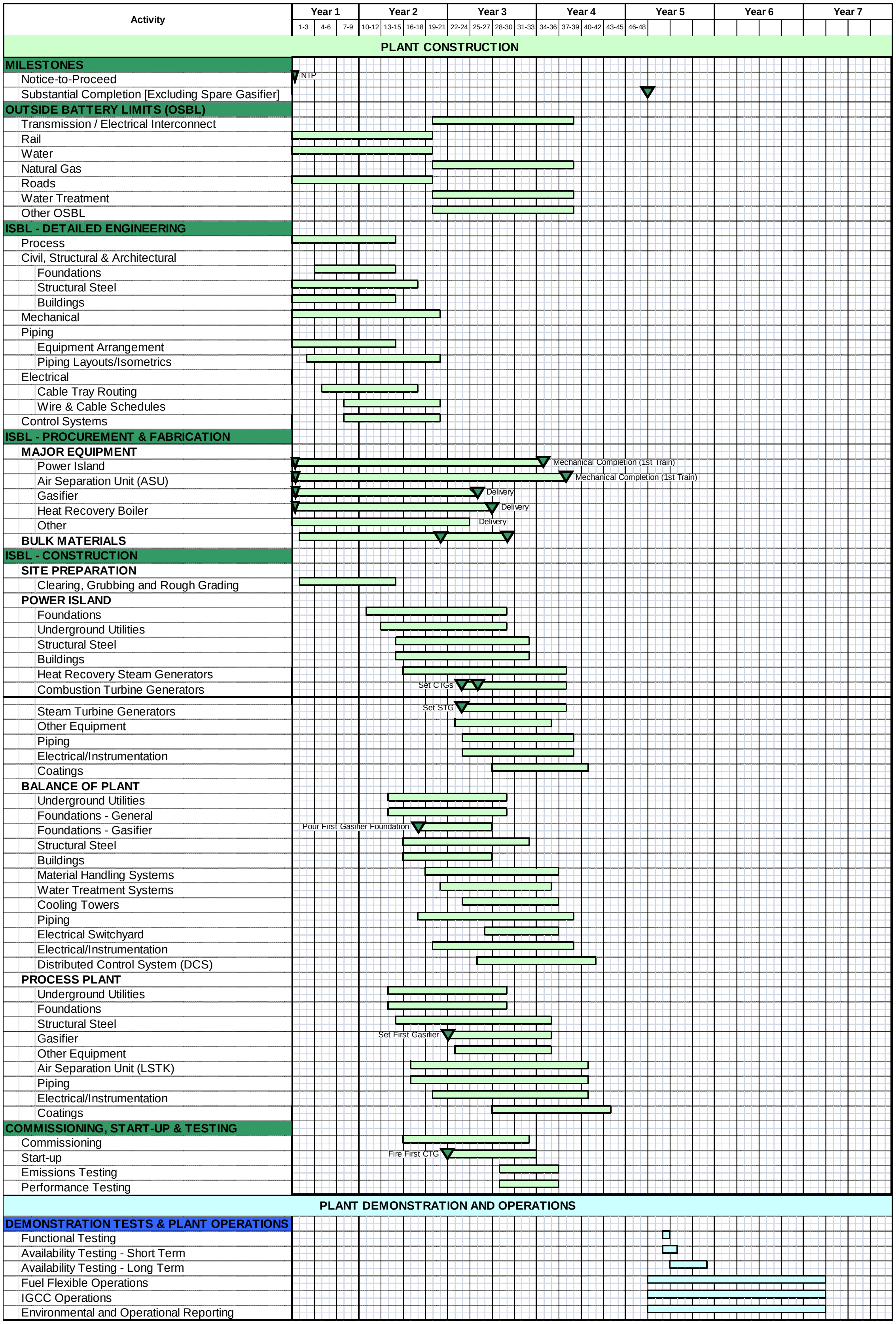
Table D-7. IGCC Cold Plant Startup

Assumes plant utility and supporting systems, e.g., steam, cooling water, etc., would be 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 treatment 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.

e. Construction Schedule

The proposed IGCC Power Station would be constructed in two phases. The preliminary construction schedule for Mesaba One is provided in Figure D-13, which shows that construction of each phase would take approximately four years. Depending on the timing of its need, construction of Mesaba Two could partially overlap construction of Mesaba One, beginning as soon as two years after construction of Mesaba One commences.

Figure D-13. Preliminary Construction Schedule



E. Fuel Supply

The Project has licensed solid fuel gasification technology, E-Gas™, from ConocoPhillips for the gasification island. The plant would be designed with fuel flexibility allowing the processing of Powder River Basin coal, Illinois Basin coal and a blend of Powder River Basin coal and petroleum coke. The gasification section would consume approximately 2.7 million tons per year of Powder River Basin coal, which represents 4 to 5 round trip unit train movements per week. The delivery distance to the plant site from the majority of PRB mines in Wyoming is approximately 1200 miles and from Southern Montana mines approximately 850 miles. Illinois Basin coal consumption would be approximately 2.0 million tons per year and would be sourced from approximately 850 miles from the site. A fuel blend of petroleum coke at 75% PRB sub-bituminous coal and 25% petroleum coke would result in consumption of approximately 410,000 tons per year of coke. Petroleum coke would be sourced from the Flint Hills refinery in Rosemount, MN, which is located approximately 200 miles from the site.

The Project site is in Taconite, MN and is served by two railroads, which provides unique fuel flexibility. The BNSF would access coal from the Powder River Basin in Wyoming and Montana. The CN would provide access to the Illinois Basin and Illinois #6 bituminous coal and petroleum coke produced at the Flint Hills refinery.

Excelsior engaged Marston, a nationally recognized coal consulting company, to analyze fuel supply options and fuel transportation options, and to develop an overall fuel plan. The plan would be to:

- Pursue annual and intermediate contracting strategies for the Project's commodity portion of the delivered cost, which would take advantage of the liquidity in the PRB market and the fuel flexibility of the plant design.
- Develop a transportation contracting strategy which would allow the Project to be competitive on a long term basis without being tied into a fixed price. This could be accomplished by developing pricing mechanisms which would adjust to the regional delivered cost of coal compared to competing generating facilities.
- Allow flexibility in the coal contracting strategy to procure petroleum coke on a spot market basis Use of petcoke would lower the Project's overall cost of production, which would benefit the Project's utility customers.
- Be vigilant in tracking near term and long term changes and trends in all fuel commodity and fuel transportation markets.

Marston provided information to Excelsior regarding PRB, Illinois #6 and petroleum coke supply sources, reserves, production, commodity pricing and transportation costs to support the Project forecasting the projected price of electricity under various scenarios. This information can be found in Appendix E.

Further work on this subtask was suspended when the MPUC determined that the power purchase agreement that the Project requested with Xcel Energy was not in the public interest.

F. Power Sales/PPA and PUC Case

The scope of work for subtask 1.06 included seeking and negotiating PPAs or other regulator approved offtake arrangements to facilitate the construction, financing and operation of the Project. The scope of work for subtask 1.07 directly stemmed from 1.06, and included filing and seeking approval of the long-term PPA of other offtake arrangements with the MPUC, as well as maintaining and developing interaction with all necessary government bodies to achieve commercialization of the Project. Because these two subtasks are so integrally related, both are summarized together.

1. Legislative Context for the Mesaba PPA

A long-term power offtake agreement, approved by the MPUC, is a necessary component to building a large power generation facility in Minnesota, given the vertically integrated and largely bilateral nature of the market for capacity and energy in the state and region.

Rights to secure such a long-term power purchase agreement were provided to the Project in 2003, when the Minnesota Legislature enacted the IEP Statute and the CET Statute (collectively, the "Statutes"), which provided broad additional regulatory incentives for the Project.

The Statutes were intended to provide the state with a path forward to resolve critical energy issues. The market conditions that prompted the Legislature to seek to proactively foster the construction of IGCC facilities in Northeastern Minnesota included:

- <u>Rising natural gas prices and proposals to significantly increase reliance on gas-based generation</u>. In 2002 through 2003, natural gas prices had begun what proved to be a steady upward climb. In 2002 and 2003, the average price for natural gas had risen to the level of $4.54 to $5.25 per thousand cubic feet and the State had experienced a few winters where gas prices peaked above those levels.
- <u>No plans for base load</u>. No new base load facilities were on the drawing board in the State, and it was recognized that base load resources require significant lead times for development and construction. Xcel forecasted needing an additional 4,100 MW to 5,800 MW of new generating resources by 2017 in its 2002 Resource Plan (which was ultimately abandoned before approval). The plan called for 1,804 MW of new base load coal capacity by 2015.
- <u>Concerns over higher-polluting out-of-state plants</u>. Minnesota's environmental leadership record made it advantageous to site traditional coal-based resources to meet Minnesota's growing needs in neighboring states, resulting in the forfeiture by Minnesota of more than a billion dollars of direct investment for each plant, and the export of jobs and import of the pollution from high emission, conventional coal technologies.
- <u>Transmission constraints</u>. Transmission infrastructure was tapped out and the region was experiencing a record number of transmission curtailments. Xcel's 2002 Resource Plan stated that "[W]ith few exceptions, major new transmission infrastructure improvements will be necessary for any of the generation options discussed," and concluded that significant lead-time was necessary to complete the transmission planning, permitting and construction process. (Xcel 2002 Resource Plan, pp. 171–179.)
- <u>Tightening emission limits</u>. Air emission limits appeared likely to tighten, but the precise form the limits would take was unclear. Pressure had begun to build on the U.S. government to adopt some form of limits on greenhouse gases, which could force older, less efficient power plants to shut down.

- Oil price forecasts. Forecasts were emerging that oil production was about to peak, with accompanying rising world oil prices.
- Deteriorating economic conditions in Northeastern Minnesota. The Iron Range had lost an additional 2,000 jobs with the closure of LTV Mining, bringing the total to more than 10,000 in the then-preceding decade.

Given these concerns, the benefits that IGCC generation facilities on the Iron Range could deliver to the State were clear.

The barriers to such a project's success were also considerable. These included:

- The lower installed costs of conventional coal technologies.
- The difficulty in securing a certificate of need and accomplishing significant transmission upgrades without the cooperation of the State's electric monopoly, public utility franchisees.
- The long lead time necessary to permit and construct coal-fueled facilities.
- Strong utility resistance to a shift in technology that did not have a combustion boiler as the centerpiece of its design, and the inability of new market participants to sponsor and build IGCC facilities without access to long-term customers in Minnesota's vertically integrated power market.
- The shortcomings of a competitive bidding process not designed to give appropriate weight to the benefits of advanced technologies such as IGCC.
- The higher up-front costs to develop and engineer advanced technologies.
- The absence of a reference design and commercial framework for a multi-train IGCC plant.

The Legislature, with the support of the Governor, addressed the barriers that were within the State's control by the enactment of the Statutes. The regulatory incentives in the Statutes were designed to overcome many of these identified barriers. These incentives included:

- Exempting the Project from certificate of need requirements.
- Affording the Project the right of eminent domain for sites and routes approved by the Environmental Quality Board.
- Providing eligibility for development funding.

Most importantly, the Statutes provide the Project with the right to secure long-term off-take customers, subject to findings by the Commission that confirm the Project benefits. This incentive—providing a secure off-take arrangement—was acknowledged by industry analysts as the key to overcoming the largest single barrier to widespread deployment of the IGCC technology.

2. MINNESOTA PUC CASE

In December 2005, Excelsior filed a petition for approval of a power purchase agreement with Xcel Energy by the MPUC. The petition and all related filings are available online at: https://www.edockets.state.mn.us/EFiling/search.jsp, under Docket No. 05-1993. A detailed, multi-volume report containing technical information, a detailed cost analysis, environmental benefits studies and other evidence that the Project met the requirements of the Statutes was filed in support of the petition, as well as testimony from more than a dozen national energy policy experts supporting approval of the PPA. At the time of the filing, the market conditions that were the foundation for enactment of the Statues had only become more pronounced, including:

- At the time Excelsior filed its petition in late 2005, natural gas prices had risen above \$11/MMBtu, nearly triple the \$4-5/MMBtu price levels Minnesota had experienced during the period leading up to the enactment of the Statutes,[94] and utilities had no plans other than gas-fired generation to meet the significant forecasted load growth and need to retire old coal and nuclear plants that were reaching the end of their useful lives.
- Conventional coal plants had been announced in the Dakotas and Iowa.
- No new transmission resources had been added to transfer power to or within Xcel's system, and the transition to MISO's new regulatory regime has complicated the situation and made the need for a proactive, project-specific plan critical.
- New criteria pollutant emission limits had been proposed and promulgated that underscore the stake the State has in ensuring that each addition to capacity provides the State with tools to proactively reduce criteria pollutant emissions. In addition, the possibility of carbon constraints was starting to take shape on the horizon.
- Oil prices had risen to and have remained at record levels, raising concerns that a fundamental shift is occurring in energy import pricing.
- In 2003, domestic supplies of natural gas had been depleted at much higher rates than expected and the importation of liquefied natural gas ("LNG") required to fill the gap did not materialize. In the 12 months after the U.S. Energy Information Administration ("EIA") issued its Annual Energy Outlook for 2005, the Agency reduced its projected LNG imports to the U.S. by 30% for 2015, and 33% for 2020. EIA assumed in these forecasts that the gap created by this reduction would be filled to a significant degree by a major building program of coal and nuclear power plants.
- The Iron Range continued to experience much higher unemployment than the rest of the State.

In short, the Legislature's rationale for enacting the Statutes was validated and magnified by these subsequent developments.

In this same period of time, the barriers to IGCC technology implementation that could not be addressed by the Minnesota Legislature were addressed by very dramatic developments related to IGCC technology and the economic factors resulting from its competitive position. Key developments include the following:

- Natural gas prices had risen to levels that make gas-fired generation more expensive than IGCC, which was not the case at the time the Statutes were enacted.
- The cost of conventional coal-fired generation versus IGCC had narrowed considerably after enactment of the Statutes. This convergence resulted from advances in IGCC technology and the additional costs imposed upon conventional coal plants to meet stricter emission limits through a myriad of expensive and energy-intensive post-combustion controls.
- A national consensus had emerged that IGCC was a clean technology that would keep coal in the power generation mix. This was viewed as critical to the U.S. balance of trade, economic prosperity, energy security, national security, environmental protection and flexibility to address increasing calls for constraints on carbon emissions. Because of the national energy security goals furthered by the technology, the Project secured funding for development and engineering from a competitive solicitation under the CCPI of the DOE.[95] This, together with funding at the

[94] EIA, "Natural Gas Citygate Price in Minnesota." See http://www.eia.gov/dnav/ng/hist/n3050mn3m.htm.
[95] The funding opportunity announcement for Round II of the Clean Coal Power Initiative laid out the national energy policy goals underlying the solicitation, which included research on clean coal technologies in order to maintain a reliable fuel mix for the Nation's future and reduce the potential for price spikes and energy disruptions resulting from excessive reliance on fuels prone to shortages due to fluctuations in supply and demand or to transportation delays. See DOE, "Financial Assistance Announcement of Funding Opportunity, Clean Coal Power

State level, defrayed much of the higher up-front developmental and permitting costs associated with an innovative technology.

- Congress recognized the benefits of IGCC by including significant benefits for the first mover projects in EPAct2005. A project-specific authorization for a loan guarantee for the Mesaba Project was included in the Act, and the Project was awarded tax credits under a competitive solicitation authorized under the Act.
- Most importantly, private industry had stepped up to address the remaining hurdles to IGCC market adoption. As the large potential emerging market for IGCC facilities became apparent, the leading gasification technologies were acquired by parties willing to provide the significant financial backing required to bring the first multi-unit projects to fruition. This development was followed by the formation of alliances between the gasification licensors, turbine manufacturers and the world's leading engineering, procurement and construction firms to deliver a one-stop shopping approach to the design, construction and guarantee of performance from IGCC facilities.

In short, since the enactment of the Statutes, the imperatives of IGCC had become much more compelling, and the remaining key barriers to the Project had been addressed.

MPUC approval of the PPA hinged on two findings: that the PPA was in the public interest, taking into account five public interest factors delineated in the Statutes, and that IGCC was or was likely to be a least cost resource. Excelsior submitted a detailed report in support of these findings. Below is an overview of the report, which contained analysis that was accurate at the end of 2005, but in some cases is no longer accurate due to changes in the economic and regulatory landscape since its preparation and filing.

a. Overview of the Mesaba Energy Project Report

The report[96] was divided into seven sections.

Section I contained an analysis of the following five criteria specified in the IEP Statute that the Commission was directed to consider in making its public interest determination with respect to the PPA.

- Economic development benefits. Subsection A demonstrated that the economic development benefits of the Project included:
    - The creation of new jobs.
    - Economic stimulus
    - Syngas production that can retain existing industry and attract new entrants from the transportation fuel, pipeline quality gas, hydrogen and chemical industries.
    - Stable energy prices that create a strong business environment.
    - A cleaner natural environment that will attract and retain human capital and promote tourism.

  The economic benefits of Unit One were quantified in a report prepared by the University of Minnesota, Duluth.[97]

Initiative, DE-PS26-04NT42061," February 13, 2004, available at: http://www.fossil.energy.gov/programs/powersystems/cleancoal/ccpi/ccpi_sol_round2.pdf

[96] The petition and all related filings are available online at: https://www.edockets.state.mn.us/EFiling/search.jsp, under Docket No. 05-1993.

[97] University of Minnesota Duluth, Labovitz School of Business. "The Economic Impact of Constructing and

- Use of abundant domestic fuel. Subsection B established that the Project would use coal, an abundant domestic fuel resource, as a primary feedstock. The public interest benefits of coal use were described, including price stability, avoiding use of natural gas for power generation, and energy independence and national security.
- Price stability. Subsection C described the price stability benefits the Project would bring to the State's energy portfolio. Many factors contributed to the stability of the price of the Project's output. These included the fact that the cost of power would be hedged under a long-term power purchase agreement and the payments under the PPA were going to be largely fixed in the form of a capacity payment tied to availability of the facility. The PPA structure would provide a price hedge advantage as compared to a utility rate-based structure. That is, the PPA would lock in current low interest rates for the life of the Project. The variable fuel costs of generation from the Project would be a small component of the total costs, and would be tied to stable coal prices. The Project would use a wide variety of coal qualities as well as petroleum coke, and would be able to minimize the costs of production by selecting the optimal mix of fuel as dictated by market conditions over the life of the Project. This flexibility to use a wide range of coal qualities would produce cost advantage for the IGCC technology over conventional combustion technologies. The ability of the facility's combined-cycle power island to run on natural gas when the gasification island is offline for maintenance would bring additional price stability and benefit over conventional technologies. IGCC's low emissions profile and flexibility to adapt to ever-tightening environmental control requirements would provide a means to capture carbon dioxide if greenhouse gas limits are imposed, further ensuring the price of energy produced by the Project would remain stable and competitive for the long term. The perils associated with dependence on natural gas and LNG for power generation, given the outlook for natural gas markets at the time that the report was prepared in November 2005 (prior to the advent of shale gas development), were described in a report prepared by Andrew Weissman of FTI Consulting.[98]

- Potential to contribute to a transition to hydrogen. Subsection D detailed the role IGCC and the Project would play in the addition of hydrogen into the national energy fuel mix. The Mesaba Project would have the potential to serve as a large, centralized source of hydrogen, which at the time would have been a critical to the national energy policy goal of transitioning to hydrogen as a fuel source.

- Emission reductions achieved compared to alternative solid fuel technologies. Subsection E demonstrated that the Mesaba Project would have been the cleanest coal-fueled power plant conceptualized to date in the nation. Detailed analysis was provided comparing the Project's environmental performance to:

    a. Permit limits for new supercritical pulverized coal plants permitted prior to the Project.
    b. Emissions from the existing Minnesota coal powered fleet.
    c. Emissions from, at that time, the cleanest coal facilities with respect to each category of pollutants that were subject to unusually restrictive emission control requirements.

Operating An Integrated Gasification Combined-Cycle Power-Generation Facility on the Iron Range." September 2005. See https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={DBBDAD12-8E57-4552-AB06-7B987050DC11}&documentTitle=2592719

[98] FTI Consulting, Inc. "Selecting a Robust Generation Resource Plan to Defend Consumers from High Natural Gas Prices." November 23, 2005. See https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={DA71980B-C762-40DB-8DAD-E62D2B46742C}&documentTitle=2592956

The importance of this clean profile to avoiding costly retrofits or stranded investments in conventional coal plants was described, as well as the human health benefits the cleaner profile would bring. Because most of Minnesota's pollution comes from out-of-state sources, the benefits of catalyzing the rapid market penetration of IGCC was another benefit highlighted in this section. Analysis of the costs of fine particulate matter and mercury was provided in a report prepared by ICF Consulting, detailing the health benefits of IGCC compared to the SCPC technology.[99]

Section II provided analysis of the integrated gasification combined-cycle technology, which is the "clean energy technology" described in the CET Statute.

- Subsection A provided information related to the Commission's required determination as to whether the IGCC technology was or was likely to be a least-cost resource. The analysis demonstrated that because the costs associated with generation from combustion technologies have rapidly escalated due to changes in environmental law, the cost penalty formerly associated with IGCC generation had largely disappeared. The 60% reduction in emissions achieved by IGCC compared to the next best new coal alternative would provide the State a valuable hedge in dealing with federally imposed emission reduction requirements that must be met with plans implemented by the State. In addition, the adaptability of the technology to meet tightening limits and the research and development plan to ensure continuous improvement is achieved in the technology's capability would contribute to the technology being a likely least-cost resource.
- The appropriate percentage of NSP's generation mix that should be supplied from IGCC was analyzed in Subsection B. The fact that natural gas prices were nearly three times the price levels existing when the CET Statute was enacted, and the fact that the percentage of coal-based generating capacity would shrink to below 30% by 2012 in the absence of Commission action, indicated that proactive planning was necessary.
- Subsection C discussed the requirement that an innovative energy project supply the minimum under the CET requirement unless it is contrary to the public interest.

Section III demonstrated that the cost of energy from the Project would, at the time of the report, be competitive with the cost of energy from a utility-owned supercritical pulverized coal ("SCPC") alternative plant, even on a direct cost basis. A consensus was emerging at this time that an IGCC plant would be least cost over the life of the facility, as compared to a SCPC facility, even if initial direct costs are significantly higher for the IGCC facility. The cost parity that the Project would achieve with a utility-owned SCPC unit would have been due, in part, to the benefits available under EPAct2005 that first movers such as the Project were positioned to receive.

Subsection A provided a detailed description of the tariff to be provided by the PPA and the cost of energy from the Project.

Subsection B provided a detailed analysis of the cost of energy from a utility-owned SCPC unit located in central Minnesota. The detailed capital and operating costs for both the Project and the SCPC facility were provided in a report from Fluor that is attached to Section III as Exhibit F. In addition, the Addendum to the Fluor Report attached as Exhibit G provided the detailed analysis of the cost of energy from the utility-owned SCPC facility.

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[99] ICF Consulting, "Air Quality and Health Benefits Modeling: Relative Benefits Derived from Operation of the MEP-I/II IGCC Power Station." December, 2005. See https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={C23EBADD-C304-4E96-84AE-71F570645B6D}&documentTitle=2593114

Subsection C compared the direct costs from each facility.

Subsection D provided a detailed analysis of the externality costs as established by the Commission and the quantified costs associated with other emissions.

Subsection E considered the addition of quantified values for fine particulate matter. These quantified costs would result in a very significant increase in the Project's cost advantage over a utility-owned SCPC plant.

Subsection F qualitatively analyzed other cost benefits associated with the Project, including its then-projected ability to be in service in 2011, the benefits that the PPA would provide to ratepayers by shifting risks to the Project that would be borne by ratepayers in a utility self-build alternative, and the benefits provided by the transmission upgrades proposed in conjunction with the Project.

Section IV is a Project Overview that provided details about the Mesaba Energy Project. Included in the overview is key information regarding:

- The IGCC technology and process (Subsection C)
- All fuel, water and other inputs (Subsection D)
- All emissions and discharges from the Project (Subsection E) and the Project's pollution prevention, recycling and reuse plans (Subsection F)
- A project milestone schedule and a list of all material permits required for the Project (Subsection G)
- Labor and construction requirements (Subsection H)
- A transmission and interconnection plan and status report (Subsection I)
- The Projects' pipeline requirements (Subsection J), details on required water resources (Subsection K) and fuel supply (Subsection L)
- The human health benefits associated with the Project (Subsection M)
- The Project's financing plan (Subsection N)

Section V contained the power purchase agreement for which the public interest and cost findings were sought in this proceeding.

Section VI provided a summary of the key terms of the PPA.

Section VII described the national consensus that was emerging on the role the IGCC technology should play in meeting our Nation's energy, environmental and national security objectives.

b. Summary of PUC Case Findings and Outcomes

The MPUC case took several years to complete. On August 30, 2007, the MPUC issued an order confirming that the Mesaba Project was an innovative energy project and therefore entitled to the significant regulatory benefits afforded under state law.[100] It did not, however, approve the proposed power purchase agreement. It ordered Excelsior and Xcel to negotiate different terms and conditions and to find additional utilities to share in the output of the facility.

[100] Minnesota PUC. "Order Resolving Procedural Issues, Disapproving Power Purchase Agreement, Requiring Further Negotiations, and Resolving to Explore the Potential for a Statewide Market for Project Power under Minn. Stat. § 216B.1694 Subd. 5." August 30, 2007. Docket No. E-6472/M-05-1993. *See* https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={825E0DB0-0D4B-4261-BF18-84643EAC49BD}&documentTitle=4762105.

Excelsior sought to implement the order by attempting to negotiate the provisions of the PPA that were challenged. In addition, Excelsior began identifying additional potential customers and sponsors for portions of the Project's output to meet the MPUC's preference of having the participation of multiple utilities in the region. Excelsior initiated negotiations with a coalition of prospective power offtakers, reaching the memorandum of agreement stage of development.

Prospects for securing ownership and offtake agreements appeared promising until the onset of the financial crisis in 2008 prevented further progress. The resulting recession caused domestic electric power demand to plunge 4.5%, as net electric load fell from 4,013 terawatt-hours (TWh) in 2007 to 3,833 TWh in 2009.[101] Even as energy demand plummeted, natural gas producers were dramatically increasing domestic natural gas production via expanding horizontal drilling and fracking of shale formations, which resulted in significantly lower natural gas prices. While new coal plants are not economically competitive with natural gas at current prices, the long term sustainable cost of shale gas production is not yet known.

In addition to the 2008 drop in current and forecasted power demand, Minnesota utilities began implementing both the renewable energy and energy conservation mandates imposed as part of the Minnesota Next Generation Energy Act of 2007. As a result, potential power customers for the Project began to factor the forecasted rapid and large-scale development of wind power resources into their resource plans, in combination with the demand lost in the recession following the crisis. Because utilities were forecasting large-scale production of wind power which could not be used in off-peak periods, it became apparent that a glut of cheap off-peak power would result from utilities producing or purchasing wind resources at high prices and then dumping the overproduction of energy into the spot market at much lower prices. Off-peak spot prices emerged in the MISO system that did not reflect the production price of wind. The assumption embedded in utility planning that wind capacity would in all modeling scenarios be added first, and then the balance of capacity and energy needs calculated predicated on this assumption, changed the mix of forecasted new generation required. This approach was in stark contrast to the traditional least-cost planning principles embedded in Minnesota utility regulation prior to the renewable mandate.

Nonetheless, significant fossil resources will still be needed when the economy and demand recover.[102] Therefore, Excelsior has continued to complete the permitting requirements for the Project, since certainty of permitting, plant design emissions profile, and schedule are important factors in contracting project offtake agreements. As of early 2012, Excelsior had completed its joint state and federal EIS, received its site and route permits from the State of Minnesota and extended its validity through 2019 (see Section G), and received its water appropriation permits from the State (see details in Section B). In addition, Excelsior had submitted an air permit application with the Minnesota Pollution Control Agency and was in the process of responding to requests for additional details in anticipation of a finding of completeness decision by the MPCA.

As described in Section B.4.c, on April 13, 2012 EPA issued its Proposed Rule for New Source Performance Standards applicable to CO_2 emissions from proposed new coal-fueled power generation facilities. In essence, the Proposed Rule requires all proposed coal facilities to capture and store CO_2, predicated on the assumption EPA states in the rule that capture and storage is available and feasible nationwide for all such projects. The Proposed Rule does not "grandfather" or otherwise provide relief

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[101] EIA, "Electric Power Annual 2010 Data Tables, Table 4.2.A. Net Energy for Load by North American Electric Reliability Corporation Assessment Area, 1990-2010 Actual," Release Date: Nov 9, 2011, available at http://205.254.135.7/electricity/annual/html/table4.2a.cfm.
[102] Minnesota DOC, "Minnesota Resource Assessment Study," available at http://www.state.mn.us/mn/externalDocs/Commerce/Minnesota_Resource_Assessment_102109022827_MN_Resource_Assessment.pdf.

for proposed facilities that have achieved an advanced stage of development, unless such a proposed facility has a final air permit and starts construction by April of 2013. In addition, the Proposed Rule states that EPA will be issuing new CO_2 limits for existing coal power plants, which would apply to the Project even in the event it were granted transitional relief as a new source. This abrupt change in the air regulatory regime for advanced clean coal facilities effectively halts the Project's ability to market the output from the IGCC facility, or to further advance its air permit for the coal gasification portion of the facility. Excelsior has submitted comments on the proposed rule that are included as Appendix A requesting that the Project be treated as a transitional source under the rule. If accepted as a transitional source, the Project would be provided the flexibility to proceed without CCS at its inception, with CCS facilities to be added if and when economically warranted.

G. PUBLIC AFFAIRS

The Project developed and still maintains significant relationships with the public and media at-large to facilitate public support for its implementation. Public education was conducted through a local office near the plant site, as well as regular meetings with leaders and citizens throughout the region. Many periodic informational meetings were held.

In addition, the public was engaged in the site selection process conducted by the MPUC, with a Citizen Advisory Task Force concluding that both proposed sites were acceptable.

In addition, there were more than a dozen open houses, public hearings, and meetings conducted either voluntarily or as part of the EIS and site permitting processes. These events served to inform the public and encourage public participation and input. More than 700 questions and comments were received as part of the EIS process, each of which was addressed.

The Project earned strong public support throughout the citizenry and leaders of the region. More than 25 mayors, county boards, regional organizations, and labor unions have expressed formal support for the Project. A letter of support signed by 12 local mayors is included as Appendix F. There is also broad bi-partisan support among elected officials at the state level, which has allowed the Project to continue development for over a decade, during very significant changes in state law and policy regarding fossil power plant development. This support was crucial in securing the Project's exemption from Minnesota's ban on new baseload coal plants in the Next Generation Energy Act of 2007, as well as 2011 legislation that extended the validity of the Project's site and route permits until 2019.

H. FINANCING

1. BACKGROUND [103]

Construction of the Project will hinge on its ability to attract debt and equity investors. Ultimately, debt investors rely on credit ratings formulated by independent rating agencies that examine each project's technical, economic and legal issues. It is essential that a project, including the project entity, be structured to maximize its integrity and insulation from credit problems affecting project sponsors, suppliers and other contractors. Contracts must be structured to properly allocate risk and responsibility for project problems, including the failure of equipment to perform to specification or failure of the project facility to be completed on a timely basis for the contracted cost. The project's contracts must also provide for possible contingencies such as licensing delays, equipment delivery problems and additional governmental or regulatory requirements. Assuming a satisfactory project structure, rating agencies will also examine and assess the creditworthiness of all material project participants as well as the projected financial performance of the project and the assumptions underlying such projections.[104] Risks not allocated to other project participants remain with the equity investors in the project, and the project's equity return, on a projected basis, must be sufficient to justify the risks associated with the investment.

Private power producers generally finance projects on a stand-alone basis. The credit support for project finance comes in large part from the power purchase agreement between the project developer and the purchasing utility. This agreement reduces the risk that the project will not find a buyer for its product.[105] The power purchase agreement not only provides a guaranteed purchaser but also incorporates pricing terms. This makes for an extremely secure market.[106]

The lender's problem in the case of project finance is to assure that revenues from the single asset will be sufficient to repay the loan. Ultimately, repayment depends upon the economic viability of the project. The power purchase agreement assures that there will be a buyer for the project output at specified prices and performance levels. The lender must be assured that costs will be sufficiently below revenues to generate enough cash to meet debt service payments with an acceptable margin. A fundamental component of the credit review process is to assure that performance requirements, which are always part of the power purchase agreement, can be met by the project developer. To provide this assurance, lenders include extensive restrictions, called loan covenants, in their agreement with borrowers. Broadly speaking, the loan covenants restrict the borrower's freedom of action in ways that help assure the lender that not only will things work as expected, but that prudent measures have been taken to deal with possible adversities.

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[103] Unless otherwise noted by footnote, the material in this section has been extracted largely verbatim from "Analysis of Debt Leveraging in Private Power Projects", E.P. Kahn, *et al* (August 1992). Prepared for the U.S. Department of Energy under Contract Number DE-AC03-76SF00098.

[104] The discussion presented to this point in the paragraph is extracted mostly verbatim from J. Paul Forrester's "Securitization of Project Finance Loans" . See http://people.stern.nyu.edu/igiddy/ABS/projectloans.htm.

[105] The remaining risk is that the regulator of the utility will disallow the costs associated with the purchase. [106] The material in this paragraph has been taken mostly verbatim from "Comparison of Financing Costs for Wind Turbine and Fossil Powerplants", E.P. Kahn (February 1995). Work funded by the Analysis and Systems Division, Office of Coal, Nuclear, Electric and Alternative Fuels, Energy Information Administration of the U.S. Department of Energy under Contract Number DE-AC03-76SF00098.

[106] The material in this paragraph has been taken mostly verbatim from "Comparison of Financing Costs for Wind Turbine and Fossil Powerplants", E.P. Kahn (February 1995). Work funded by the Analysis and Systems Division, Office of Coal, Nuclear, Electric and Alternative Fuels, Energy Information Administration of the U.S. Department of Energy under Contract Number DE-AC03-76SF00098.

a. The Project Lender's Role in Risk Allocation and Management

Private power projects are essentially a structure of contracts designed by developers to bring the factors of production together in a specific configuration. It is the developer's role to structure the project's contracts so that the inherent risks of power generation are allocated to those project participants who are willing or able to bear them. The developer's reward for allocating risks carefully is the opportunity to secure construction and permanent financing at an attractive rate, thereby profiting on the difference between costs of production and power purchase prices.

The lender's role is to review the structure of the project and the quality of the project participants to assess the level of risk associated with a potential loan to the project, and to price the loan appropriately for the level of risk assumed. The lender will seek to limit its risk exposure at the outset, and to impose constraints on the behavior of project owners and operators to manage risks over the life of the investment.

The lender's commitment is made toward the end of the project development process, in contrast to the utility's commitment to purchase power, which is made in the initial stages of project development. As a result, the lender has both the ability and the incentive to exert its influence over the final structure of all project contracts (including, as the result of negotiations, the power purchase agreement), and to structure the loan agreement to control and restrict the developer's activities under those contracts. In theory, then, the lender can impose controls and restrictions on project owners beyond what is typically found in power purchase agreements, improving project viability and reliability, to the benefit of the lender and, ultimately, to the benefit of the utility and its ratepayers.

b. Process of Making a Loan

Table H-1 shows the steps in the project development process and the role of the project lender in that process. In contrast to the power purchase agreement, which is typically negotiated and executed very early on in the project development process, the loan agreement is generally the last major agreement that the developer must secure to start project construction. Typically, the following project contracts will be executed prior to or simultaneously with execution of construction financing documents:

- Power purchase agreement
- Construction contract
- Fuel supply and transport agreements
- Operating and maintenance agreements
- Waste disposal agreements
- Ancillary financing agreements (equity funding commitments, interest rate protection, etc.)

Although many contracts may be executed prior to active involvement of the lender, the developer knows that all project contracts will have to be negotiated and structured to the lender's satisfaction, giving the lender significant influence over the final characteristics of the project. In making a loan decision, the lender examines the extent to which project risks are shifted to participants who are equipped to manage and control them, so that operating margins are maintained over the long run and investment value is preserved. Often, contracts (including power sales agreements) are renegotiated or amended to meet lender requirements. The developer's incentive to structure contracts to meet lender's requirements is, ultimately, a lower cost of financing.

Table H-1 Developer's and Lender's Roles in Project Development and Operation*

Project phase		Developer's Role	Lender's Role
Risk Allocation	Initial project development		
		Execute Power Purchase Agreement (PPA) (through competitive bid or negotiations)	May provide input as to financeability
		Site selection & permitting	Environmental/hazardous waste assessment
		Negotiate other project contracts • Construction • Steam sales [if applicable] • Fuel supply & transport • Operation and Maintenance	May provide input as to financeability
	Lender credit review and loan negotiations	Solicit indications of interest from lenders	Provide preliminary pricing, loan terms and conditions
		Finalize project documents to meet lender requirements	Credit review and due diligence • Review of project by independent consultants • Legal review of contracts • Assessment of project participants • Financial and sensitivity analysis
		Solicit equity, subordinated debt or other sources of funding as necessary	Loan pricing based on allocation of risk
Risk Management	Loan documentation	Satisfy lender's conditions precedent	Establish procedures to preserve allocation of risk and maintain credit quality over loan term
		Receive funds to construct project	Execute loan commitment
	Loan monitoring during project construction and operation	Project management	Enforcement of loan terms
		Reporting to Lender, secure approvals for modifications from Lender as necessary	Approval of changes as necessary
		Compliance with and enforcement of other project contracts	Receive interest and principal payments on loan

*From "Analysis of Debt Leveraging in Private Power Projects", E.P. Kahn, *et al* (August 1992).

The lender's involvement in the project exists in three stages: (i) credit review, (ii) loan documentation, and (iii) loan monitoring. *Risk allocation* occurs during the credit review process and *risk management* occurs during loan documentation and loan monitoring.

The *credit review process* (or "due diligence" process) starts during the project development stage, typically after a power purchase agreement has been executed. In some cases, lenders will provide preliminary feedback to developers as to the "financeability" of certain contract provisions prior to contract execution, or will provide preliminary indications of interest in financing to be included as part of a developer's bid package for a utility RFP. The lender will assess the quality of the relevant project contracts and the quality of the contracting parties, among other things. Although the level and extent of credit review will vary from lender to lender, this process provides an independent assessment of project viability, project risks, how those risks have been allocated, and to what extent the contracting parties are able to bear those risks. During the credit review process, the lender typically engages independent consultants to assess specific kinds of project risks and proposed mitigation strategies. These reviews could include the following:

- Independent engineering review of project design and equipment specifications, review of the reasonableness of the construction budget, schedule and performance testing requirements, and verification of operating assumptions used in *pro forma* projections of revenues and expenses;
- Independent review of fuel supply and transport arrangements, the adequacy of supplier's reserves, availability of alternatives, potential for interruption of firm transportation, and review of projections of the cost of fuel and price of electricity (utility's avoided cost) under different dispatch scenarios and fuel escalation rates;
- Independent review of insurance policies to verify that required insurance is in place and that carriers meet quality requirements;
- Independent review of the site by an environmental consultant for hazardous wastes, and review of the adequacy and quality of permits or other approvals required for construction and operation of the project.

Input from these independent consultants often results in modifications to the project to better allocate risks, including modification of contract pricing provisions, changes in the design and engineering of the project (such as provision of redundant equipment), and modifications to the construction budget and schedule.

The *loan documentation process* is intended to provide the lender with assurances that the structure of the contracts, the quality of the contracting parties, and the performance and profitability of the project will be maintained over the term of the loan. The loan document establishes procedures to be followed throughout the course of the loan, and outlines steps to be taken when problems arise. (3) The *loan monitoring process* commences once the loan documentation process is completed, and continues through the construction and operating phases of the project. In this phase, the lender enforces the terms and conditions of the financing agreements.

Some projects with power purchase agreements are never constructed, and in other cases power purchase agreements are renegotiated or restructured prior to the start of construction. The reasons for project failure or contract restructuring are many (including inability to secure adequate fuel supplies, permitting and siting difficulties, and the like), but often result from lenders' discomfort with allocations of risk and unwillingness to accept certain project risks, as evidenced by their refusal to provide sufficient financing for a project at a reasonable cost.

2. MESABA ENERGY PROJECT FINANCING EFFORTS

Accurate financial assumptions and planning are necessary for the Project. Projects of this scale can be few and far between, thus requiring the availability of bankers with demonstrated experience financing large commercial scale power plants. The $2+ billion Project was slated to be the first base-load coal fired plant to be built in the State of Minnesota in over 25 years. The sizeable equity and debt needs of the Project along with the changing financial market conditions during the Project's development required evaluation of various financing structures ranging from traditional project financing to more unique and specialized financing arrangements. Excelsior also had to maintain current financing assumptions in its Project financial model that reflected the current market conditions.

The Project had already been receiving important outside development funding from the Iron Range Resources and Rehabilitation Board (IRR) and the Xcel Energy Renewable Development Fund prior to the reporting period. In order to source, structure, negotiate, and secure future debt and equity funding for the design, construction, and commercial operation, the Project retained two investment banks, Credit Suisse First Boston LLC (CSFB) and Barclays Capital Inc. (Barclays).

a. The Project's Investment Banks

CSFB's experience in providing financing expertise to the power generation sector is unquestionable. In November 2011, Credit Suisse Group was listed as the ninth largest global financier of coal-fired power plant projects undertaken since 2005[107]. New coal-fired power projects being funded by the company include:[108]

- Longleaf (GA)
- Council Bluffs Energy Center Unit 4 (IA)
- LS Power Elk Run Energy Station (IA)
- Prairie State Energy Campus (IL)
- Edwardsport Plant (IN)
- Smith Station (KY)
- Thoroughbred Generating Station (KY)
- Midland Power Plant (MI)
- Cliffside Plant (NC)
- Mustang Energy Project (NM)
- White Pine Energy Station (NV)
- Sallisaw Project (OK)
- Marion City Project (SC)
- Big Brown 3 (TX)
- Lake Creek 3 (TX)
- Martin Lake 4 (TX)
- Monticello 4 (TX)
- Morgan Creek 7 (TX)
- Oak Grove Plant (TX)
- Sandy Creek Plant (TX)
- Tradinghouse 3 & 4 (TX)

[107] "Bankrolling Climate Change: A Look into the Portfolios of the World's Largest Banks". urgewald, groundWork, Earthlife Africa Johannesburg and BankTrack, November 2011, p. 32.
[108] Sourcewatch, September 2012. See http://www.sourcewatch.org/index.php/Credit_Suisse_Group.

- Valley 4 (TX)
- Hunter 4 (UT)
- Intermountain Power Project Unit 3 (UT)
- LS Power Sussex proposal (VA)
- Jim Bridger Unit 5 (WY).

Barclays, as one of the world's largest banks, was also included in the November 2011 financing analysis. Since 2005, Barclays represents the second largest global financier of coal-fired power plant projects.[109]

b. Role of Project's Investment Bankers

Excelsior and its investment bankers maintained dialogues with interested equity and debt participants. This process required regular monitoring of the markets and input from the investment bankers regarding potential project participants.

The Project, with the assistance of the financial advisors, developed and maintained a proprietary financial model to support fund raising and power marketing efforts. The financial model is central to the project's development as it is used to evaluate the financing structure and costs of the Project and calculate the resulting cost of electricity charged to customers. The model is instrumental in determining what financing structures would result in the Project providing adequate debt service while also providing the required return on equity. Cases evaluated to date include the project company ownership selling capacity and energy through a power purchase agreement as well as Municipal / Co-Op ownership of the Project, and other scenarios. The model is highly detailed and included key capital and operating cost assumptions, financing terms, financial projections, complete balance sheet, income statement, and cash flows details for the project and all necessary calculations and results to provide a detailed, accurate forecast of the projects costs and revenue that can be provided to and reviewed by interested third parties. Several equity investors and debt providers were identified and developed during the project development phase. Both Barclays and CSFB regularly reviewed and provided input to the project financial model, confirming that the financing assumptions contained in the model accurately reflected terms that were financeable in the marketplace by meeting investor and debt service requirements. The expertise provided by the bankers resulted in improvements to the financial model that allowed additional scenario analysis and model functionality, including modeling the effects of Federal tax credits and Federal loan guarantee benefits on the cost of power, and preparing for a commercial market, Term Loan B financing, and more.

CSFB provided advisory services during development of the Project to ensure the Project was being structured in a manner that would allow for debt and equity financing that accommodated the terms of the risk profile created by the key Project contracts (EPC, O&M, PPA, fuel supply, etc.), the insurance available, and the requirements of the capital markets. Retention of a leading investment bank was necessary given the multi-billion dollar nature of the Project and the need to potentially place more than a billion dollars in a public debt offering.

CSFB provided analysis and evaluation of the business operations and financial position of Excelsior to identify any significant structural issues which would affect the financing terms of the Project and assisted in structuring and negotiating equity financing, debt financing, and interim financing.

Excelsior initially intended to finance the Project through CSFB in a traditional project financing structure. The terms and conditions of the Project contracts were developed to permit either a private, large bank syndicated loan, or a commercial debt market offering. The Project team worked with

[109] urgewald, groundWork, Earthlife Africa Johannesburg and BankTrack, op. cit., p. 32.

ConocoPhillips, two potential EPC contractors, outside legal counsel and CSFB to structure the Project in a manner that would facilitate limited-recourse financing in either the private bank or commercial bond markets. To that end, the Project expected to enter into an EPC contract, long-term fuel supply arrangements, an O&M agreement, and supporting arrangements that would tap existing industry expertise to ensure a smooth startup and transition to commercial operation of the facility.

CSFB prepared offering documents, screened interested prospective purchasers, investors, and lenders, and provided Excelsior leads and introductions to potential project participants.

In 2004 Excelsior submitted an application for funding under Round II of the U.S. DOE Clean Coal Power Initiative (CCPI). In 2006 the Project was selected as a recipient and has subsequently drawn development funding through the program. The principal benefit of the CCPI funding was to enhance the terms of the financing and Project economics through a reduction in the projected interest expense.

The markets were rapidly changing throughout the Project's development and Excelsior and its investment bankers looked at several financing structures, ranging from a rated public bond offering (using AMBAC as guarantor) –lead by CSFB, and a "Term Loan B" bank loan structure which Barclays had greater experience in and lead.

Barclays was engaged for their specific expertise in structuring project financing of a coal facility. The Barclays bankers engaged had recently project-financed other coal projects, which was a difficult proposition given the large size of the projects and market conditions and was very different from a public debt offering, whether stand-alone or government guaranteed. Barclays, similar to CSFB, was engaged in project structuring to ensure that project contracts were being developed in a manner that would support debt and equity financing. In their project finance approach Barclays reviewed all project documents and term sheets to ensure they would support a non-recourse project financing of the Project, or a structured loan guarantee where cash flows are isolated in a project ownership company.

Excelsior and its bankers worked throughout the development period to develop the most financeable Project structure. Specifically, two Federal programs, in addition to CCPI funding, allowed the company to provide more attractive financing terms to potential Project investors while simultaneously reducing the Project's cost of electricity. These two programs were the Section 48A Federal Tax Credit program and Section 1703 Federal Loan Guarantees made available through EPACT 2005.

CSFB and Barclays played significant roles in Excelsior's applications under these two programs and contributed their expertise in structuring the terms to meet federal requirements. The complexity of the federal programs required a thorough analysis of the requirements contained in the guidance issued for the programs to confirm the Projects was eligible to apply, and to ensure the project structure would lead to strong applications. The investment bankers were instrumental in reviewing and improving the Project financial models that supported the applications and were involved in and supported the development of all financial data included in the applications. Barclays specifically supported all analysis and presentations provided to Fitch Ratings seeking the preliminary credit rating and credit scoring that was submitted during the Federal Loan Guarantee Program application process. The Project was selected as a recipient under both the tax credit and loan guarantee programs. These successful applications provided Excelsior improved financing terms for as long as the programs continued to be available to the Project.

The Project was positioned (and re-positioned, as market conditions changed), to put in place all the necessary contractual components for financing, in a form acceptable to the lenders, potential funds suppliers, and DOE, including:

- Fixed price turn-key construction contract(s) with a full guarantee package or "wrap" sufficient for project finance purposes (this was undertaken in advance of the filing of the PPA, in order to ascertain construction costs on a plus-or-minus basis);
- Long-term PPA (see Section F) – a very detailed, IGCC-specific power purchase agreement was developed by the Project and negotiations were undertaken with the proposed offtake customer to ensure that the terms and conditions were technically and practically workable for the utility's system;
- A fuel supply plan was developed by Excelsior and Marston, a coal supply expert, and submitted to the PUC as an addendum to the PPA. The plan included utility and regulator involvement in the establishment of a mix of short-term and long-term coal supply arrangements designed to optimize the plant's fuel costs with respect to the offtake customer's larger fuel portfolio;
- The terms of an Operations & Maintenance ("O&M") agreement with the technology and construction providers to operate and maintain the facility were developed;
- Transmission arrangements and interconnection agreements were completed (see Section C);
- An acceptable site was identified and a site permit issued by the MPUC (see Sections A and B);
- A license agreement was executed with ConocoPhillips establishing rights to use all relevant technology;
- Required permits and licenses were developed sufficiently to understand the compliance costs associated with operation of the facility. Several final permits were issued, including the Site and Route Permit (see Section B.2) and the water appropriations permit (see Section B.4.b), and a proposed final air permit was filed with the MPCA; and,
- The terms of facility financing documents were developed and periodically revised with the assistance of investment bankers as market conditions changed over the development of the Project. This ensured that both debt and equity could be arranged and financial closing could occur on the targeted financial closing date.

Excelsior prepared and delivered independent reports required for the financing effort under the DOE's loan guarantee program, which included:

- A satisfactory report from a fuel and/or power market consultant analyzing the prospective fuel markets and electricity market environment for the Project;
- A report from R.W. Beck, Inc., a nationally recognized independent engineer evaluating the technical aspects of the project; and
- A Preliminary Credit Analysis completed by Fitch.

3. LESSONS LEARNED

The electric power sector, which is both extremely capital intensive and risk adverse, poses unique challenges for the demonstration and commercialization of innovative technologies. Government financial incentives must be adequately sized and carefully tailored to overcome those challenges. Most commercialization power projects are subject to approval by state public utility commissions. Because the national benefits of demonstration projects are large but diffuse, federal incentives must be of sufficient size for such projects to be in the public interest for a set of ratepayers that are a small fraction of the nation as a whole.

Furthermore, financial incentives must be well-designed. Because capital costs and market conditions can fluctuate widely, especially during the long interval between the date an incentive is awarded or made available and the date of financial closing, incentives of fixed amounts, such as CCPI awards and Section 48A tax credits, can easily prove to be insufficient. Percentage based tax credits, such as the solar investment tax credit, or other flexible mechanisms like feed-in tariffs might be more likely to result in successful deployment of innovative technologies.

I. INSURANCE

Engagement of a world class insurance advisor was a critical link in the development of the Project to ensure the underlying assets were properly protected.

Marsh USA Inc. (Marsh) is a highly regarded insurance broker and risk management consultant with globally demonstrated capabilities in assessing risk, advising, and assisting with the development and placement of comprehensive insurance packages. Marsh specifically has experience providing these insurance and risk management services to clients involved in the design and construction of energy and utility projects.

Marsh had been engaged by Excelsior Energy Inc to provide insurance brokerage services related to the following lines of coverage since 2004:

- Non-Owned Auto
- Umbrella/Excess Liability
- Directors & Officers Liability
- Employment Practices Liability
- Property/Casualty Package

Marsh has been instrumental in establishing the appropriate market-based insurance coverage required by Excelsior. Marsh reviewed the insurance requirements contained in contracts including office space leases, land option agreements, and the Large Generator Interconnect Agreement among others. Marsh compared the required coverage levels to those in place and either proposed modifications to the contract if deemed necessary or adjusted Excelsior's corporate insurance coverage appropriately.

Marsh was also separately retained under agreement in June 2005 to specifically advise and assist Excelsior in designing and placement of a program addressing the risks specific to the Mesaba Energy Project. Marsh worked with Excelsior to assess the insurance risks of the overall development, financing, construction and operation of the Project. The programs evaluated by Marsh included insurance, reinsurance, and financing structures intended to address risks, whether such structure took the form of an insurance policy, financial guarantee or any other financial arrangement.

Marsh developed a three phase project scope and timeline. Phase one, due diligence, began immediately and Marsh reviewed pertinent data to assess the risks and develop a strategy for successfully structuring a program. Marsh specifically set out to understand the potential exposure, available monetary resources to apply to the risks, and to articulate the level of coverage required and the merits of the risks to insurance providers. Phase two, Underwriting Presentation, Negotiation and Indications, and Phase Three, Implementation would follow subsequent to or near completion of phase one.

During phase one, Marsh specifically reviewed and provided their input into contracts that were instrumental to the Projects development. These included the land option agreements, Large Generator Interconnect Agreement, Engineering Procurement and Construction Term Sheet, and the Front End Engineering and Design Agreement. Their thorough review ensured that the insurance requirements contained in the documents were reasonable, market-based, and provided adequate coverage for the both Excelsior and the other parties involved.

Marsh also provided specific inputs into the project financial model by providing formula calculations that allowed Excelsior to model the estimated costs of insurance coverage during both the construction and operating phases of the Project. Calculations were provided for competing technologies (Non IGCC

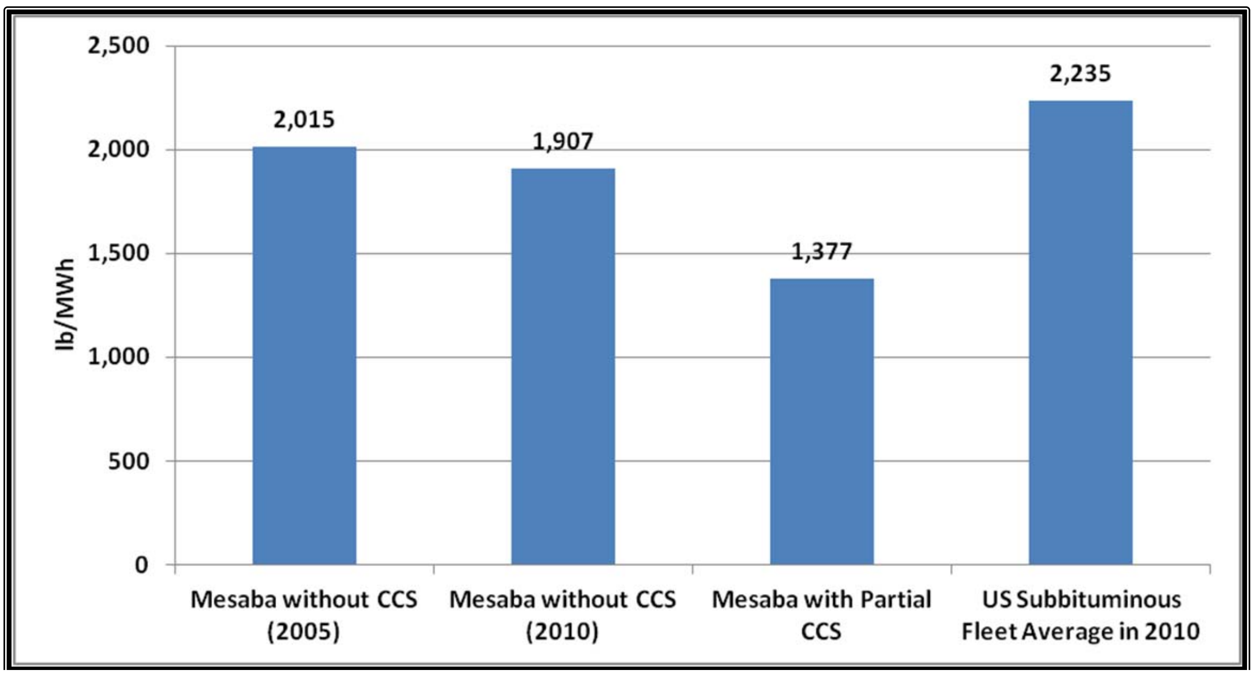
Coal and Natural Gas) as well as the Project specific calculation. This allowed Excelsior to continue providing accurate cost estimates and comparisons to potential investors, regulators, and other parties involved in development of the Project.

Marsh and Excelsior remained involved in phase one activities, and advised and assisted in project development until the key components of the risk mitigation approach were fully understood and integrated into the project's development approach. Marsh continues to provide Excelsior its auto, liability and property coverage and it is anticipated that Marsh will be engaged again prior to financial closing to ensure that the final profile of the project takes into account the cost and availability of insurance to mitigate various risks.

J. Carbon Sequestration Planning

Carbon sequestration planning was not part of the original scope of work for the Mesaba Energy Project since it was not an objective contained within the DOE Cooperative Agreement. Prior to adding carbon sequestration planning, the Project could play an important role in advancing national goals for carbon management due to the lower emission profile of the IGCC technology. As set forth in the Statement of Project Objectives, the overarching goal of the Mesaba Energy Project was to "demonstrate technologies to produce electricity via the IGCC process." Commercial demonstration of IGCC is important because the technology showed promise for meeting the performance targets in DOE's Clean Coal Technology Roadmap, which included at least 90% CCS by 2020.[110] Additionally, one objective for the Project was to achieve carbon dioxide emission rates 15-20% below the average for U.S. coal-based power plants fueled by similar feedstock. It was expected that the Project would achieve that target due to its superior efficiency compared to the existing coal fleet, as shown in Figure J-1. Updated studies conducted in 2009 and 2010, including improvements resulting from activated zinc oxide treatment, reduced the Project's estimated heat rate to 8,885 Btu/kWh. This would translate to a CO_2 emission rate of 1,907 lb/MWh based on an emission rate of 214.6 lb CO_2/MMBtu of PRB coal. This is 15% lower than the 2010 national average for sub-bituminous-fueled units as reported in EIA's Form EIA-923.

Figure J-1. CO_2 Emission Rates: US Sub-bituminous Fleet vs. Mesaba



Beyond the intrinsic carbon management progress projected with IGCC technology, Excelsior has sought to make additional progress by proactively exploring carbon capture and storage opportunities for the Project. Likewise, sequestration was one of DOE's highest priorities in the CCPI Round 3 solicitation. Also, since the establishment of the original scope of work, carbon dioxide emissions have been a subject of growing interest and concern nationally, particularly following the U.S. Supreme Court's April 2, 2007 ruling in *Massachusetts v. EPA* that opened the door for regulation of greenhouse gases under the Clean

[110] DOE/NETL, "Financial Assistance Announcement of Funding Opportunity, Clean Coal Power Initiative," DE-PS26-04NT42061, February 13, 2004. *See* http://www.netl.doe.gov/technologies/coalpower/cctc/ccpi/solicitations/CCPI-2_SOL.pdf.

Air Act. As a result of these considerations, DOE and Excelsior jointly agreed to add carbon management planning as a specific subtask under the Project's scope of work.

The following sections describe the major study and planning efforts undertaken for carbon capture and sequestration by the Project, the plan that resulted from these efforts, and the conclusions reached based on those efforts.

1. Carbon Capture and Sequestration Studies

Recognizing the rising significance of climate change concerns and the Project's potential to play a role in addressing those concerns, Excelsior proactively began studying CCS in 2005. As part of the preliminary design engineering for the Project, Excelsior directed Fluor to develop a conceptual design for future implementation of CO_2 capture and compression and to ensure that the base Project was designed to readily accommodate CO_2 capture and compression equipment in the future. Also in 2005, Excelsior joined PCOR, one of DOE's seven regional carbon sequestration partnerships. PCOR is administered by EERC, with whom Excelsior engaged directly to analyze the available CO_2 transportation and sequestration options.

Based upon collaboration with these project partners, Excelsior developed its *Plan for Carbon Capture and Sequestration* (referred to hereafter as the "CCS Plan") and voluntarily filed the document with the MPUC in October, 2006.[111] The public version of this document is attached as Appendix G. To Excelsior's knowledge, this was the first plan filed with a state public utilities commission to initiate planning for a large scale CCS project. The CCS Plan described the capture and compression design based on Fluor's studies, as well as the range of CO_2 transport and storage options based on EERC's analysis and Excelsior's use of the Decision Support System (a web-based geographic information system), available via PCOR. The CCS Plan included recommendations of the most viable approach for both elements and provided the MPUC with preliminary and confidential estimates of cost and performance impacts.

Excelsior continued studying CCS following the development of the initial CCS Plan. With ongoing collaboration with EERC and PCOR, the *Carbon Management Plan for Excelsior Energy* ("CMP") was completed in November, 2007.[112] This document is attached as Appendix H. EERC prepared the CMP as a standalone report outlining carbon management options available for the Project. The CMP complements the CCS Plan by providing a thorough, third-party review of CO_2 storage options with assessments based on EERC's technical expertise on geological and regulatory merits of each.

In response to DOE's Funding Opportunity Announcement for CCPI Round 3, Excelsior submitted an application in July 2009 proposing to implement CCS. While Excelsior's application was not selected to receive funding under CCPI Round 3, the Project's CCS planning was advanced through the process of preparing the application. In support of that application, Excelsior refined its CCS plan and developed additional details to meet objectives and fully respond to the CCPI Round 3 solicitation. As part of these efforts, Excelsior engaged Fluor to conduct a more specific study of the design of the capture and compression system, with updated estimates of cost and performance impacts. Through further collaboration with EERC and PCOR, the transport and storage plans were further refined, including the identification of a specific CO_2 storage site candidate.

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[111] Excelsior Energy Inc., "Plan for Carbon Capture and Sequestration." *See* Exhibit RS-1 to Richard Stone's rebuttal testimony filed October 10, 2006 in MPUC Docket No. E-6472-/M-05-1993.

[112] EERC. "Carbon Management Plan for Excelsior Energy." November 30, 2007. Available from National Technical Information Service, U.S. Department of Commerce, 5285 Port Royal Road, Springfield, VA 22161; phone orders accepted at (703) 487-4650.

2. Summary of Mesaba's Carbon Capture and Storage Plan

The following section summarizes the CCS plan for the Mesaba Project that has resulted from the study efforts described above. The summary is divided into the capture and compression portion of CCS that would occur at the IGCC Power Station and the transport and storage portion of CCS.

a. Carbon Dioxide Capture and Compression

Excelsior selected a 'partial' capture design in which CO_2 that is produced through partial oxidation in the gasifiers and present in the syngas would be removed prior to nitrogen dilution and combustion in the CTGs. This approach would result in a lower capture rate but target the 'lowest hanging fruit' by avoiding the need for a shift reaction to convert CO to CO_2. This would minimize cost and risk, as described in more detail below. Based on the Project's design fuel (100% sub-bituminous PRB coal), this approach would reduce CO_2 emissions by approximately one third, capturing about 1.5 million tons of CO_2 per year.

i. Technical Description and Specifications

Carbon dioxide would be removed from the cleaned syngas streams in each of Mesaba One's two gasification trains prior to dilution, moisturization, and combustion. Excelsior proposed to target a 90% removal efficiency of the CO_2 from these streams using a non-proprietary activated MDEA with flash regeneration. Excelsior selected this approach after examination of the cost and performance of three capture design alternatives for Mesaba One, including 80% and 90% capture rates with flash regeneration of the MDEA and 90% capture with thermal regeneration.

A process flow diagram of the CO_2 capture equipment is provided in Figure J-2, and a list of major stream compositions with heat and material balance information is provided in Table J-1. Syngas to be treated would be fed to the bottom of the Activated MDEA Absorber. Here, it would travel up the column in counter-current contact against hot flash-regenerated semi-lean solvent which would enter at the top of the column. The solvent circulation rate would be 15,000 gpm, which is less than 70% of the rate required in the thermal regeneration system. Additionally, the use of hot solvent would significantly reduce the vapor-liquid contact time required to absorb the CO_2. As a result, a packed bed column may be used, and only one Activated MDEA Absorber would be required. The treated gas exiting the Activated MDEA Absorbers would meet the proposed CO_2 removal efficiency of 90%. This treated syngas would be reconstituted with compressed N_2 from the ASU and medium-pressure steam before combustion to replace the removed CO_2 and control flame temperature, NO_X formation, and performance in the combustion turbines.

CO_2 rich solvent ("rich solvent") would exit the bottom of the Activated MDEA Absorber and would be heated in the Rich Amine Heater. The solvent temperature must be increased by only a few degrees in order to significantly reduce the solvent's solubility for co-absorbed gases (e.g., CO, H_2, CH_4, etc). The heat source for the Rich Amine Heater would be the low-level heat recovered from the existing IGCC power plant. One potential source for this low-level energy is waste heat rejected by the ASU main compressor intercooler/aftercooler at temperatures around 250–350°F. These exchangers would be designed to reject this heat to cooling water during initial operations, and to easily integrate later with the retrofit CO_2 Capture unit.

Figure J-2. CO_2 Capture Equipment Process Flow Diagram

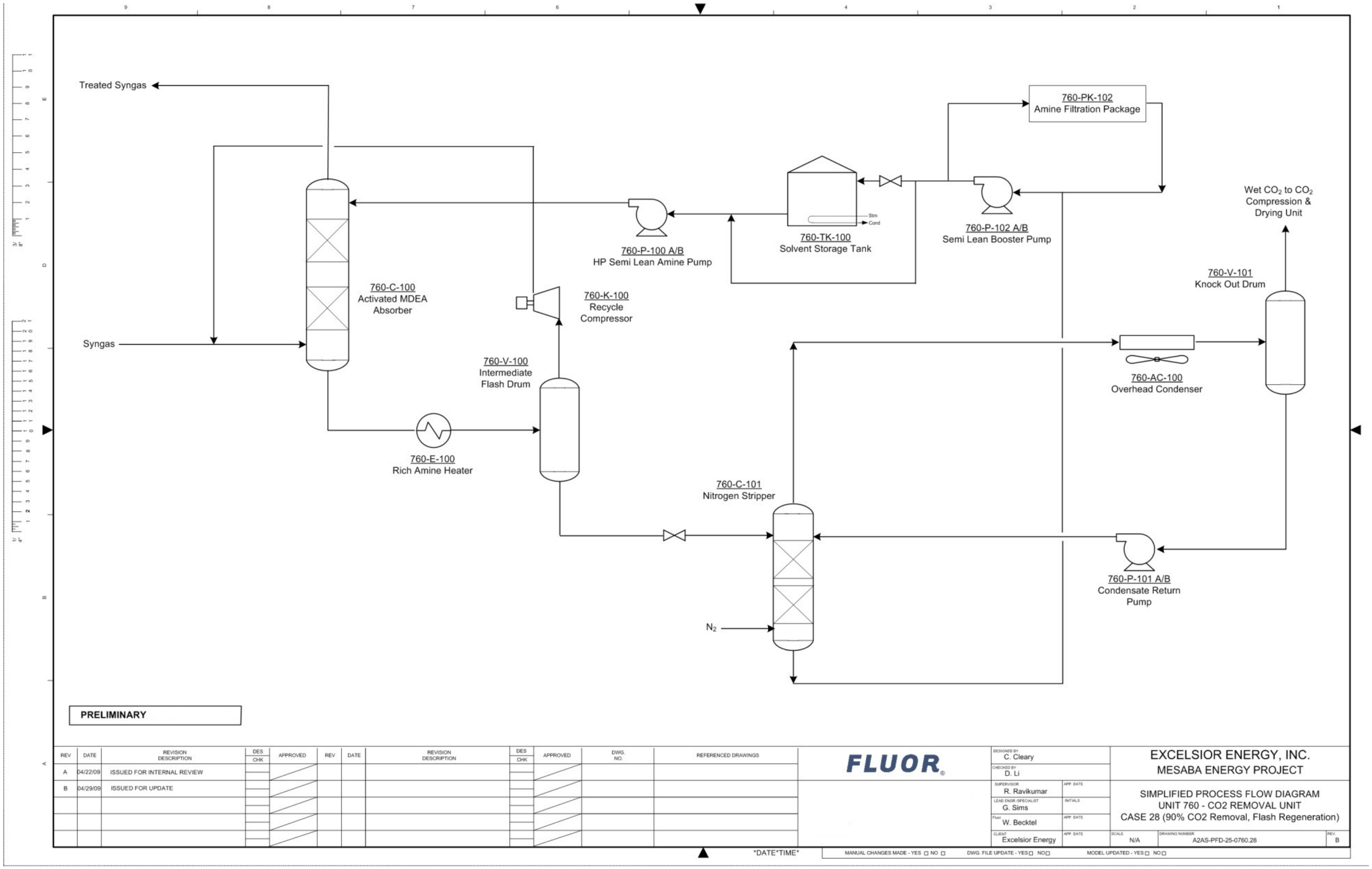

Table J-1. Heat and Material Balance 90% CO_2 Capture, Activated MDEA with Flash Regeneration

Stream:	Syngas Feed to CO_2 Removal Unit		Treated Gas from CO_2 Removal Unit		Wet CO_2 from CO_2 Removal Unit		Product CO_2 from CO_2 Compression	
Components:	Lbmol/hr	Mol %	Lbmol/hr	Mol %	Lbmol/hr	Mol %	Lbmol/hr	Mol %
CO	15,801	37.61	15,788	46.83	13	0.10	13	0.14
H_2	14,709	35.01	14,691	43.57	18	0.14	18	0.20
CO_2	9,550	22.73	933	2.77	8,617	86.24	8,618	95.17
H_2O	75	0.18	431	1.28	982	9.58	1	0.01
CH_4	766	1.82	760	2.25	5	0.04	5	0.06
Ar	476	1.13	474	1.41	1	0.01	1	0.01
N_2	638	1.52	640	1.90	399	3.88	399	4.00
H_2S + COS	< 1	< 0.01	< 1	< 0.01	<1	< 0.01	<1	< 0.01
Total, lbmol/hr	42,015	100.00	33,717	100.00	10,035	100.00	9,054	100.00
Mass Flow, lb/hr	943,100		569,739		408,611		391,498	
Mol Weight	22.45		16.89		40.72		43.24	
Temperature, °F	100		172		124		120	
Pressure, psia	456		446		17		2015	

The heated rich solvent would be fed to the Intermediate Flash Drum where most of the co-absorbed gases other than CO_2 would flash out of the solvent. The vapor that would exit the Intermediate Flash Drum would be compressed in a Recycle Compressor and recycled back into the syngas feed to the Activated MDEA Absorber.

The solvent that would exit the Intermediate Flash Drum would be routed through pressure let-down valves, where most of the CO_2 would be flashed off. The flashed solvent would then be fed to the Nitrogen Stripper, where it would be stripped of residual CO_2 as it travels down the Nitrogen Stripper column in counter-current contact against a rising stream of N_2.

The CO_2-rich overhead vapor that would exit the Nitrogen Stripper would be air cooled in the Overhead Condenser and routed to the Knock-Out Drum, where the gas and condensed liquids would be separated. Carbon dioxide saturated with water vapor would exit the top of the Knock-Out Drum to the CO_2 Compression & Drying system, and the condensed liquids would be returned to the top of the Nitrogen Stripper via the Condensate Pump.

The semi-lean solvent that would exit the Nitrogen Stripper would be pumped by the Semi-Lean Booster Pump. Most of the solvent would be directed either to the High Pressure Semi-Lean Amine Pump or to the Solvent Storage Tank. Approximately 10% of the solvent would be directed through the Lean Amine Filtration Package, where it would be passed through particulate filters and a carbon bed to remove any corrosion products and amine degradation products. The filtered solvent would be discharged back to the suction of the Semi Lean Booster Pump.

The Solvent Storage Tank would be insulated and provided with an internal heater to keep the solvent at a suitable temperature in extreme cold weather conditions. The tank would also be N_2 blanketed to prevent solvent contact with air. This would minimize the absorption of atmospheric oxygen into the circulating amine solution, which would lead to accelerated corrosion in the hot sections of the plant. The tank would be sized to hold 15 minutes of solvent flow at the normal circulation rate. Solvent make-up, when required, would be supplied directly into the Solvent Storage Tank.

The HP Semi Lean Amine Pumps would pump hot semi-lean solvent from either the Semi-Lean Booster Pumps or the Solvent Storage Tank to the top tray of the Activated MDEA Absorber, where the semi lean solvent would remove CO_2 from the syngas as described previously.

The wet CO_2 exiting the top of the Knockout Drum would be fed to the suction of the Multi-Stage CO_2 Compressor Package which would compresses the gas into a supercritical fluid at 2000 psig. Intercoolers and knockout drums would be used between stages to cool the compressed CO_2 vapor and separate out condensed liquids. The supercritical CO_2 product stream would then be cooled in an aftercooler before being discharged to the pipeline.

The compressor intercoolers and aftercooler would transfer heat from the hot CO_2 streams to coolant circulated through an air-cooled, closed-loop cooling system, the Compressor Intercooler/ Aftercooler Air Cooled System. Final drying of the CO_2 vapor would occur between late stages of compression and is achieved in the CO_2 Dehydration Package, a glycol-based drying system which would operate at a compressor interstage pressure between 450–800 psig. The composition of the product CO_2 stream is provided in the rightmost column of Table J-1 above.

Partial capture from IGCC would minimize performance impacts of CCS and potentially represents one of the lowest cost opportunities for CO_2 capture available to the electric power industry. The estimated performance impacts of the partial capture approach are summarized below in Table J-2, along with comparisons to the alternative implementations. Excelsior has estimated that the capture and compression equipment would increase the cost of electricity from the Project by approximately 15% (exclusive of transport and storage costs and CO2 sales revenues or avoided emission costs).

Table J-2. Power Plant Performance Impact of CO_2 Capture and Sequestration

Case:	CASE 25	CASE 26	CASE 27	CASE 28
Description:	Base IGCC Power Plant (w/o CO2 Capture)	Modified IGCC Power Plant with 90% CO2 Capture (Thermal Regeneration)	Modified IGCC Power Plant with 80% CO2 Capture (Flash Regeneration)	Modified IGCC Power Plant with 90% CO2 Capture (Flash Regeneration)
Feedstock:	PRB Coal	PRB Coal	PRB Coal	PRB Coal
Ambient Temperature:	38°F	38°F	38°F	38°F
Carbon Capture, %	0%	33% (Level II)	30% (Level I)	33% (Level II)
Power Generation				
GE 7FB CTG (x 2)	446 MW	446 MW	446 MW	446 MW
Steam Turbine-Generator	298 MW	284 MW	294 MW	293 MW
Gross Power	744 MW	730 MW	740 MW	739 MW
Less ASU Auxiliary Load	- 103 MW	- 112 MW	- 112 MW	- 112 MW
Less CO2 Removal/Compress Load	N/A	- 29 MW	-22 MW	- 25 MW
Less Other Internal Consumption	- 39 MW	- 39 MW	- 38 MW	- 38 MW
Net Power (after transformation)	602 MW	550 MW	568 MW	564 MW
Coal Feed (as received), stpd	7,791	7,822	7,800	7,802
Coal Feed (dry), stpd	5,415	5,436	5,421	5,423
Coal Feed (HHV), MMBtu/h	5,388	5,410	5,395	5,396
Plant Heat Rate (HHV), Btu/kWh	8,943	9,836	9,501	9,575
Oxygen Feed (contained), stpd	4,750	4,769	4,756	4,757
MP N2 to CTGs for NOx Control, stpd	10,618	12,528	12,410	12,394
Steam Injection for NOx Control, stpd	0	648	549	741
N2 for Amine Regeneration, stpd	N/A	0	118	134
Slag Produced, stpd	475	477	476	476
Sulfur Product, stpd	28	28	28	28
Supercritical CO2 Product, stpd	0	4,539	4,093	4,545
Raw Water, gpm	3,188	2,995	3,163	3,139
Waste Water, gpm	0	0	0	0

ii. Rationale for Partial Capture Approach

With respect to carbon capture at a large baseload power plant, IGCC offers a unique opportunity for minimizing cost and risk since the syngas stream it produces is intrinsically well-suited for CO_2 removal. Syngas is well-suited for CO_2 removal since it has very low volume (less than 1% of flue gas produced by a comparably sized conventional coal plant), is at high pressure, and contains a significant amount of CO_2 due to the thermodynamics of the gasification reaction. In the case of Mesaba One using 100% PRB coal as a feedstock, approximately 36.5% of the carbon that would be in the syngas is in the form of CO_2 (this percentage varies by gasification technology and feedstock, generally from 20–40%). The CO_2 would readily be removed from the syngas as described above. The impacts on plant operations and performance would be relatively modest since the CO_2 is not a fuel for the combustion turbines. Its mass and combustion-controlling characteristics would be replaced by excess N_2 from the ASU and a modest amount of medium pressure steam (steam turbines can operate efficiently below maximum capacity). Capturing CO_2 would not greatly alter the optimal size for the balance of the plant or its operating conditions. This would allow Mesaba One to operate as efficiently and competitively as possible both prior to and after commencement of CO_2 capture. Furthermore, the CO_2 capture and compression equipment could be installed while Mesaba One operates, requiring minimal down time and disruption to base plant operations. These considerations are very important, as they allow the CO_2 capture and compression equipment, pipeline, and enhanced oil recovery ("EOR")/storage process to be developed at the lowest cost and risk, in tandem with, but commercially distinct from, the IGCC power plant.

Early-mover IGCC plants proposing higher percentage capture would face higher risks and impediments to implementation and rapid commercialization. For example, targeting a higher removal rate of CO_2 would require changes to the intrinsic properties of the syngas—namely, an energy-intensive shift reaction is necessary to convert CO into CO_2. This would convert a larger portion of the carbon in the syngas into CO_2 that can be captured. While shift reactors themselves are commercially proven, their application in IGCC plants is not. The impact of a shift reaction on IGCC plant performance and optimal design would be considerable. As described below, two design approaches would be possible for high-capture plants. Optimal operation can be achieved either prior to or after commencement of CO_2 capture, but not both.

The shift reaction would reduce the chemical potential energy in the syngas. If an IGCC plant were designed to operate its combustion turbines at full load without a shift reaction and CO_2 capture, it would no longer be able to fully load the combustion turbines when shifting the syngas to capture CO_2. (Note that combustion turbines are less efficient at partial load than steam turbines.) Alternatively, an IGCC plant designed to operate its combustion turbines at full load with a shift reaction and CO_2 capture would be unlikely to be able to bypass the CO_2 shift and capture equipment. Such a plant would be forced to inefficiently capture and vent CO_2 until all downstream transport and sequestration equipment is in place, or when that equipment is unavailable. Furthermore, in the case of lower rank coals (such as 100% PRB), the size of currently available gasifiers may not be sufficient to fully load an F-class gas turbine when using a shift reaction.

Based upon the previous discussion, no high-capture plant can operate efficiently and competitively both with and without CO_2 capture. Such a plant's commercial success is inextricably tied to the timely success of the capture, compression, transport, and storage of CO_2. This makes the power generation and CO_2 transportation and sequestration facilities commercially inseparable and increases risk for both the power generation and CCS projects. It is unlikely that construction of a plant optimized for high capture levels could commence operation until all permits, commercial arrangements, and financing are in place for both the pipeline and sequestration portions of the project. In addition, the economics of high capture projects would most likely be dependent on higher market values of CO_2 and/or electricity than currently exist. Therefore, Mesaba One's ability to operate efficiently and economically both with and without capturing CO_2 is a major risk mitigating factor for a first-of-a-kind commercial CCS demonstration project. This is especially important given the large distance to viable CO_2 storage sites, as discussed in the next section.

b. Carbon Dioxide Transport and Storage

Through its membership in the PCOR Partnership, Excelsior has worked with EERC to identify the nearest geologic formations capable of storing large quantities of CO_2. In short, the conclusion is that storage via EOR operations is the best and potentially only viable option for the Project. The following section describes the various storage opportunities that were considered and the reasons for their elimination or selection.

According to the PCOR Partnership Atlas, the only known geologic formation in the state of Minnesota with any potential whatsoever for storing CO_2 is the Mid-Continental Rift.[113] However, based on EERC's studies, the characterization to date is insufficient and too much uncertainty exists to consider the formation suitable for large scale storage at this time. This conclusion is corroborated by a report by the

[113] EERC. "PCOR Partnership Atlas." 3rd Edition, Revised 2010. See http://www.undeerc.org/PCOR/newsandpubs/atlas.pdf, page 28.

Minnesota Geological Survey,[114] which found that the formation cannot be considered technically feasible based on currently available information:

> The key conclusion of the report is, therefore, that, unlike better known rocks in oil or coal producing regions, we have little information on the Rift. A major effort costing tens to hundreds of millions of dollars would therefore be required to test the Rift sedimentary rocks in Minnesota for required reservoir capacity and properties, and the probability that these requirements would not be confirmed, despite this effort, is high.

Beyond Minnesota, the closest geologic formation is the Williston Basin, which lies below portions of North and South Dakota, Montana, and Canada. Although it extends nearly 275 miles from Mesaba One and Two, active oil and gas development is approximately 400 miles away.[115] The Williston Basin holds more promise for geologic storage than the Mid-Continental Rift, as the PCOR Partnership Phase I Final Report estimated that the potential storage capacity of the Williston Basin enhanced oil recovery fields and saline formations is in excess of 9 billion tons.[116] However, the report includes the following caution with respect to saline formation storage:

> The inherent heterogeneity found in nearly all geologic formations means that detailed subsurface mapping and characterization must be conducted in any area prior to the initiation of large-scale injection of CO_2.

As noted above, detailed subsurface mapping and characterization is extremely expensive to develop, and generally already exists only in oil and gas producing regions. Saline formations cannot be considered technically feasible storage options where such mapping and characterization has not been carried out.

Because closer saline formations were ruled out due to lack of data and therefore confidence in their ability to store large quantities of CO_2, the conclusion based on collaboration with EERC is that the nearest feasible option for CO_2 storage would be enhanced oil recovery. EOR offers critical feasibility advantages over other geological storage options, including a wealth of pre-existing geological characterization data, the opportunity for revenues from CO_2 sales, and certainty regarding liability. Under North Dakota law, the operator of a carbon sequestration project holds title to the CO_2 and remains liable for damages caused by any leakages until the North Dakota Industrial Commission issues a certificate of project completion, which can be issued as soon as 10 years after CO_2 injections end.[117] Before issuing the certificate, the North Dakota Industrial Commission must determine that the sequestration project has complied with applicable permit conditions, uses a storage reservoir that is stable and reasonably expected to retain the CO_2 stored in it, and has facilities that are in good condition and retain mechanical integrity.[118] Upon issuance of the certificate of project completion, the State of North Dakota would take title to and responsibility for the sequestered CO_2, including liability for damages caused by any leakages.[119]

The nearest EOR opportunities to the Project would be in the Northeast Flank portion of the Williston Basin. These oil fields, near the 'Newburg' point shown in Figure J-3, are approximately 400 miles from

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[114] Thorleifson, L. H., ed., "Potential capacity for geologic carbon sequestration in the Midcontinent Rift System in Minnesota," Minnesota Geological Survey Open File Report OFR-08-01. 2008. *See* http://purl.umn.edu/117609, page 10.
[115] EERC. "PCOR Partnership Atlas." 3rd Edition, Revised 2010. *See* http://www.undeerc.org/PCOR/newsandpubs/atlas.pdf, page 32.
[116] EERC. "PCOR Partnership (Phase I) Final Report." January 2006. *See* http://www.undeerc.org/PCOR/newsandpubs/pdf/finalreport.pdf, Table 9.
[117] N.D. CENT. CODE § 38-22-16.
[118] *Id.*
[119] *Id.* § 38-22-17

Mesaba, and have a potential demand for 314 billion cubic feet (about 18 million tons) of CO_2 as shown in Table J-3. Much larger potential demand exists further west in the Williston Basin (see Appendix H for discussion of additional EOR potential). For the purposes of CCPI 3, Excelsior proposed a more distant oil field located in southwestern North Dakota with larger EOR potential due to the level of interest of the oil field operator.

Figure J-3. Location of Potential Sequestration Sites Relative to Mesaba

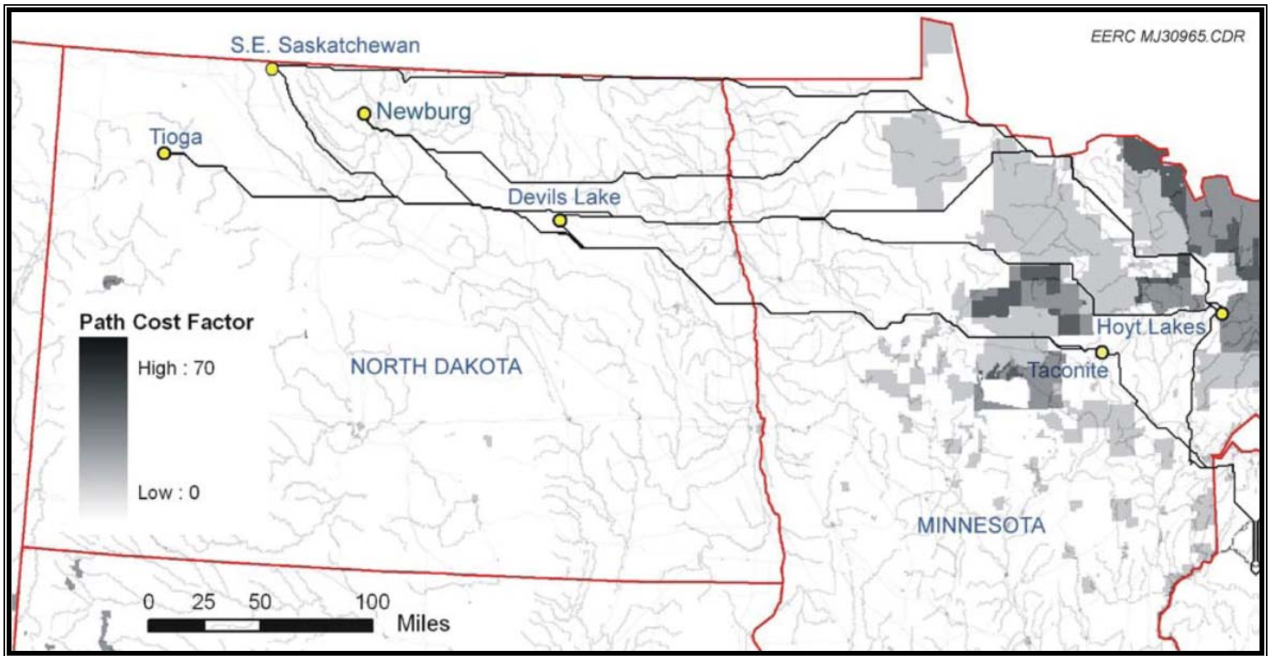

Table J-3. Summary of Potential Incremental Oil Recovery from CO_2 Injection for Selected Northeast Flank Oil Fields

Field Name	Pool Unitized	Potential CO_2 Oil Recovery at 12% Original Oil In Place, million bbl	CO_2 Needed, Bcf
Newburg	Spearfish–Charles	12	92
Wiley	Glenburn	12	92
Rival	Madison	9	76
Lignite	Madison	4	31
Mohal	Madison	2	15
Landa	Madison	1	8
Total		**40**	**314**

c. Recent Regulatory Developments and Conclusions

While anticipation of comprehensive climate change legislation escalated in the mid to late 2000s and peaked following the 2008 election, Congress failed to enact any such legislation. Prospects for legislation that would establish a market for CO_2 have grown very distant. Major economic forecasters now project that there will be no carbon pricing until at least 2020.[120] In the absence of carbon pricing, CCS is economically unviable without significant financial assistance and/or additional revenue streams.[121] Excelsior's proposed CCS project was not selected for funding under CCPI Round 3. For these reasons, CCS is not feasible for the Project at this time, as confirmed by DOE in the Project's FEIS.[122]

Despite these economic realities, EPA proposed in March, 2012 to establish New Source Performance Standards ("NSPS") for CO_2 emissions from power plants. The NSPS sets a level of 1,000 lb CO_2/MWh which coal plants could only meet with CCS. See Section B.4.c for further discussion of this proposed rule. Excelsior has submitted comments (Appendix A) on the proposed rule requesting that the Project be treated as a transitional source under the rule. If successful, the Project would be provided the flexibility to proceed without CCS at its inception and CCS facilities could be added if and when economically warranted.

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[120] Xcel Energy, Comments Re Establishing an Updated 2012 Estimate of the Costs of Future Carbon Dioxide Regulation, Docket No. E999/CI-07-1199, March 9, 2012.

[121] The only domestic utility scale power plant that has commenced construction and is to capture CO_2 is Southern Company's IGCC plant in Kemper County, MS, which received a total of $682 million in federal financial assistance through tax credits and CCPI funding. See Energy Central, "Mississippi Power receives additional federal support for Kemper County IGCC Project," May 10, 2010, available online at http://www.energycentral.com/generationstorage/fossilandbiomass/news/vpr/8989/Mississippi-Power-receives-additional-federal-support-for-Kemper-County-IGCC-Project.

[122] DOE, "Mesaba Energy Project Final Environmental Impact Statement," DOE/EIS-0382, November, 2009, p. 2-24.

K. DOE Reporting And Management

The Cooperative Agreement requires reporting by Excelsior to NETL's Project Manager on a periodic basis and at the end of the budget period and cooperative agreement. The following section describes the periodic reports that Excelsior has prepared and filed with DOE, as well as the final reports that will be filed.

1. Periodic Reporting

Periodic reports consisted of project management reporting and financial reporting.

a. Management Reports

On a weekly basis, Excelsior reported to DOE via conference calls and/or emails a summary of its progress in achieving the goals of each major activity by subtask.

Within 30 days after the end of each calendar quarter Excelsior submitted both a progress report and an earned value analysis report. These narrative reports described the current status of work by communicating developments, achievements, changes and problems that occurred in the previous quarter to DOE.

The submitted reports included a summary highlighting the important accomplishments made during the reporting period including noteworthy advancements in research, design, manufacture or commercialization of technological developments. The summary included a progress update and notes any milestones met or missed, accomplishments, changes in approach, as well as a status assessment and forecast.

A baseline plan was included in each quarterly report to present a specific outline of the work breakdown structure and the projected time to completion, with a delineation of the projects major milestones, and cost involved. This served as the standard against which status and progress could be measured during the performance period.

The status reports detailed the approved budget and actual costs incurred, the current schedule, and the work completed to date relative to the baseline plan. The status reports were organized according to work breakdown structure and included a discussion of milestones met / not met, anticipated completion dates, and actual completion dates.

b. Financial Reports

Excelsior submitted monthly invoices to DOE for reimbursement of 50% of allowable costs using form SF-270. Excelsior submitted financial status reports using federal forms SF-269 or SF-425 on a quarterly basis to provide an accounting of project funds expended on an accrual basis. These reports identified the federal and non-federal share of project outlays.

On an annual basis, within 180 days after end of calendar year, Excelsior prepared reports required by 10 **CFR** 600.316 as supplemented by *For-Profit Audit Guidance,* Parts I through IV.[123] This includes an

[123] *See* http://energy.gov/management/downloads/profit-audit-guidance-fy-2010 and http://energy.gov/management/downloads/final-profit-audit-guidance-fy-2011-and-following.

audit of for-profit recipients along with audited financial statements. This audit was first required for fiscal year 2010. The report for FY 2011 was submitted in the second quarter of 2012.

Additionally, on an annual basis within 180 days after end of calendar year and as required in accordance with the applicable cost principles, Excelsior has submitted annual indirect cost proposals reconciled to our audited financial statements. The report was used to determine the final allowable indirect cost rates used to recover corporate / administrative indirect costs.

2. FINAL REPORTS

The Final Scientific/Technical Report is this document, and is due within 90 days after the Budget Period 1 ends. The Report documents and summarizes all work performed during the award period in a comprehensive manner. Additionally, upon closeout of the Cooperative Agreement, Excelsior must file patent certification (DOE F 2050.11) in order to disclose any inventions developed in association with the award and property certificate (NETL F 580.1-9), to identify the status of any real or personal property provided or funded by DOE.

CONCLUSION

The funding opportunity announcement for Round II of the Clean Coal Power Initiative laid out the national energy policy goals underlying the solicitation:

> "A primary goal of the [National Energy Policy] is to add electricity supply from diverse sources, including coal – our most abundant energy source. The NEP identified research on clean coal technologies as an objective for increasing the attractiveness of coal as an energy source for new generating plants. In addition to maintaining a reliable fuel mix for the Nation's future, energy supplied from coal will reduce the potential for price spikes and energy disruptions resulting from excessive reliance on fuels prone to shortages due to fluctuations in supply and demand or to transportation delays. While other fuels may offer environmental and capital cost advantages, their benefits are reduced when considering the issue of long-term availability at a stable price."
>
> "Overall, the mission of DOE's Coal and Power Systems Program is to help assure the availability of abundant, low-cost, domestic energy to fuel economic prosperity and strengthen energy security. That mission is being achieved through development of technological capability to eliminate environmental concerns associated with coal use. Near-term objectives focus on the ability to meet all existing and anticipated environmental regulations at low cost and to increase the power generation efficiency for existing and new plants. For the longer term, the objectives are to nearly double coal power plant efficiencies (from 33% to 60%), to progress toward achieving near-zero emissions from coal-based power generation technologies, to create the capability to produce low-cost hydrogen from coal, and to sequester (capture and store) all carbon from future coal plants at affordable costs of electricity, thus allowing coal to remain a key, strategic fuel for the United States."[124]

The Mesaba Energy Project has made significant progress towards the DOE objectives that were the basis of selection in Round II of the Clean Coal Power Initiative. Based on the work to date as summarized in this Final Report, the Project may be capable of achieving its objectives under the CCPI award. The project developed a reference design for a commercial IGCC plant, one of its key objectives. Specifically, the objectives for the Mesaba Energy Project as set forth in the Cooperative Agreement with DOE are as follows:

- Increased Capacity – Demonstrate more than double the generating capacity of the Wabash River Coal Gasification Repowering Project, or nominally 600 MWe(net).
- Advanced Gasfier – Demonstrate a significantly more advanced full-slurry quench multiple train gasifier system having an operational ability of about 90% or better.
- Air Separation Unit – Demonstrate a configuration to (a) extract bleed air from the combustion turbine to reduce the parasitic load of the main air compressor in the ASU, increasing net plant output and reducing capital cost, and (b) recycle nitrogen from the air entering the ASU for injection into the combustion turbine to reduce formation of nitrogen oxides by reducing the flame temperature in the combustor and the time that the combustion gases remain at elevated temperatures.
- Feedstock Flexibility – Demonstrate greater feedstock flexibility with the capability of gasifying bituminous coal (e.g., Illinois No. 6), sub-bituminous coal (e.g., Powder River Basin), blends of sub-bituminous coal and petroleum coke, and/or other combinations of these feedstocks.
- Improved Environmental Performance – The Project is intended to improve upon the previous clean coal Wabash River Coal Gasification Repowering Project by deploying processes and

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[124] DOE, "Financial Assistance Announcement of Funding Opportunity, Clean Coal Power Initiative, DE-PS26-04NT42061," February 13, 2004, available at: http://www.fossil.energy.gov/programs/powersystems/cleancoal/ccpi/ccpi_sol_round2.pdf

technologies that would make it among the cleanest coal-based power generating plants in the world. Emission levels for criteria pollutants (SO_2, NO_X, CO, VOC, and PM) and mercury are expected to be equal to or below those of the lowest emission rates for utility-scale, coal-based generation fueled by similar feedstock. In addition, CO_2 emissions are expected to be 15 to 20% lower than the current average for U.S. coal-based power plants fueled by similar feedstocks.

- Thermal Efficiency – Demonstrate a design heat rate of about 8,600 Btu/kWh when using bituminous coal.
- Reference Plant – Demonstrate, from a broad perspective, the commercial development, engineering and design necessary to construct a large feedstock-flexible reference plant for IGCC, thus establishing a standard replicable design configuration with a sound basis for providing firm installed cost information for future commercialization.

The preliminary design and optimization studies performed were consistent with the first three objectives. As discussed in Section D of this report, the Project was designed to produce 600 MW, achieve FSQ, and integrate the ASU and CTGs via air extraction and nitrogen dilution. By including a spare gasifier in the Project's design, the Project would be expected to achieve solid feedstock availability of 91%, which would exceed the objectives.

The Project's design and fuel supply plan are fully consistent with the objective of demonstrating feedstock Flexibility. Section D.3.a, Section E, and Appendix D describe the range of feedstocks that the Project would be designed to use, including three sub-bituminous coals (Rawhide, Spring Creek, and Jacobs Ranch), Illinois No. 6 bituminous coal, and petroleum coke (blended with Rawhide PRB). This feedstock flexibility, as well as the Project's immediate access to two rail suppliers, offers potentially significant advantages for fuel cost and fuel supply security.

The proposed permit limits for the Project would readily surpass the environmental performance objectives. Section B.4.c demonstrates that the Project's emissions of criteria pollutants and mercury would be 70-80% lower than for the most recently permitted conventional coal-fired plants. As shown in Figure J-1, Mesaba's CO_2 emission rate would meet the 15% targeted improvement relative to the existing U.S. fleet of sub-bituminous coal plants, and Figure B-11 shows that its performance would be 20% superior to that of Minnesota's fleet of sub-bituminous plants. This reduced emission rate would be achieved prior to any CO_2 capture, due to the Project's superior efficiency. As discussed in Section D.3.b, the projected heat rate on Rawhide PRB would be 8,885 Btu/kWh. This is consistent with the 8,600 Btu/kWh design target objective for bituminous coal due to the heat rate advantage realized with higher heat content feedstock.

Finally, based on the credit analysis and independent engineer report as well as ongoing consultation with project finance experts and investment banks as described in Section H, the commercial development plan and preliminary design developed for the Project were confirmed to be commercially feasible. If the Project secures offtake arrangements under Minnesota law, it is positioned to achieve the objective of developing a reference design to support commercialization of IGCC.

During the five year timeframe required to develop and finalize the Project's Final EIS, sweeping and unforeseeable changes in the macroeconomy, law and regulation have created significant barriers for a coal-based project to proceed, as discussed in Sections B.4.c and F.2.b. While critical macroeconomic trends are currently unfavorable, they are historically cyclical, and some cycles are already returning to more favorable conditions. Additionally, Excelsior is hopeful that under the final CO_2 NSPS, the Project will be provided the flexibility to proceed without CCS at its inception, with CCS facilities to be added if and when economically warranted. Recognizing the value of keeping an innovative, coal-based power supply option on the table, the Minnesota Legislature acted in 2011 to extend the life of the Project's site permit through 2019, providing additional opportunity for cyclic trends to run their course and for current regulatory uncertainties to be resolved. Therefore, the Project is positioned as a resource option that is available to Minnesota and capable of providing the innovation needed to realize the national energy policy goal underlying Round II of the Clean Coal Power Initiative of commercializing cleaner ways to utilize our nation's abundant coal resources.

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LIST OF ACRONYMS AND ABBREVIATIONS

Acronym / Abbreviation	Definition
AGR	acid gas recovery
AP-42	USEPA Compilation of Air Pollutant Emission Factors
AQRV	air quality-related values
ASU	air supply unit
BACT	best available control technology
BFW	boiler feed water
BNSF	Burlington Northern Santa Fe Railway
Btu	British thermal units
CCPI	Clean Coal Power Initiative
CCS	carbon capture and storage
CET	Clean Energy Technology
CFR	Code of Federal Regulations
CH_4	methane
CMP	Canisteo Mine Pit
CMP	Carbon Management Plan
CN	Canadian National Railway
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
COC	cycles of concentration
COP	ConocoPhillips
COS	carbonyl sulfide
CTG	combustion turbine generator
CWA	Clean Water Act
CWIS	cooling water intake structure
DOC	[Minnesota] Department of Commerce
DOE	U.S. Department of Energy
EERC	Energy and Environmental Research Center
EIA	U.S. Energy Information Administration
EMF	electromagnetic force
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
EPAct2005	Energy Policy Act of 2005
FEED	front end engineering and design
FEIS	Final Environmental Impact Statement
FERC	Federal Energy Regulatory Commission
FGD	flue gas desulfurization
FLMs	Federal Land Managers
Fluor	Fluor Engineers and Constructors
FSQ	full slurry quench
gal	gallon
GHG	greenhouse gases
GIS	geographical information system
GMMP	Gross Marble Mine Pit

Acronym / Abbreviation	Definition
GO	generator outlet
GRE	Great River Energy
H_2	hydrogen
H_2O	water
H_2S	hydrogen sulfide
H_2SO_4	sulfuric acid
HAMP	Hill-Annex Mine Pit Complex
HAP	hazardous air pollutant
HP	high pressure
hr	hour
HRSG	heat recovery steam generator
HVTL	high voltage transmission line
IEP	Innovative Energy Project
IGCC	integrated gasification combined cycle
IP	intermediate pressure
IRRRB	Iron Range Resources and Rehabilitation Board
JPA	Joint Permit Application
kV	kilovolts
lb	pounds
LDP	Laramore, Douglass and Popham
LEPGP	large electric power generating plant
LGIA	Large Generator Interconnection
LGIP	Large Generator Interconnection Procedures
LMP	Lind Mine Pit
LNG	liquefied natural gas
LP	low pressure
MDEA	monodiethanolamine
MDNR	Minnesota Department of Natural Resources
MEPA	Minnesota Environmental Policy Act
min	minute
MISO	Midwest Independent Transmission System Operator
MMBtu	million Btu
MOU	Memorandum of Understanding
MPCA	Minnesota Pollution Control Agency
MPUC	Minnesota Public Utilities Commission
MW	megawatts
MWh_{net}	net megawatt hours
N_2	nitrogen
N_2O	nitrous oxide
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NH_3	ammonia
NHPA	National Historic Preservation Act
NO_X	nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NRIS	Network Resource Interconnection Service
NSP	Northern States Power

Acronym / Abbreviation	Definition
NSPS	New Source Performance Standards
NWI	National Wetland Inventory
O&M	Operations & Maintenance
PC	pulverized coal
PCOR	Plains CO_2 Reduction [Partnership]
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter no greater than 10 microns
$PM_{2.5}$	particulate matter with an aerodynamic diameter no greater than 2.5 microns
POI	point of interconnection
POTW	publicly owned treatment works
PPA	power purchase agreement
Ppmvd	parts per million volumetric dry
PPSA	[Minnesota's] Power Plant Siting Act
PRB	Powder River Basin
Project	Mesaba Energy Project
PSD	Prevention of Significant Deterioration
psig	pounds per square inch gauge
PSQ	partial slurry quench
RGGS	RGGS Land & Minerals, Ltd., L.P.
ROW	right of way
scf	standard cubic feet
SCPC	supercritical pulverized coal
SCR	selective catalytic reduction
SF_6	sulfur hexafluoride
Sherner	Sherner Power Consulting
SO_2	sulfur dioxide
SO_3	sulfur trioxide
SRU	sulfur recovery unit
STG	steam turbine generator
TMDL	Total Mass Daily Load
total dissolved solids	TDS
TTRA	Taconite Tax Relief Area
TVB	tank vent boiler
TWh	terawatt-hours
USEPA	U.S. Environmental Protection Agency
USFWS	U.S. Fish and Wildlife Service
VOC	volatile organic compounds
Wabash River	Wabash River Coal Gasification Repowering Project
yr	year
ZLD	zero liquid discharge
ZnS	zinc sulfide

APPENDICES

Excelsior Energy Inc.'s Comments on Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units

EPA Docket Center
U.S. Environmental Protection Agency
Mail Code: 2822T
1200 Pennsylvania Avenue. NW.
Washington, DC 20460
Attn: Docket ID No. EPA-HQ-OAR-2011-0660

June 11, 2012

Re: Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units

Introduction

Excelsior Energy, Inc. ("Excelsior") submits the following comments as the developer of the Mesaba Energy Project (the "Project"), a 1200 megawatt integrated gasification combined-cycle (IGCC, or "coal gasification") power plant to be located in Northeastern Minnesota. The Project was selected by the U.S. Department of Energy ("DOE") in its competitive Clean Coal Power Initiative Round II solicitation to receive federal funding. As established in the Project's final Environmental Impact Statement ("EIS"):

> "The DOE purpose in the context of the CCPI is to demonstrate the commercial-readiness of the ConocoPhillips E-Gas™ gasification technology in a fully integrated and quintessential IGCC utility-scale application. The principal need addressed by DOE, pursuant to Public Law 107-63 and subsequent legislative appropriations, is to accelerate the commercialization of clean coal technologies that achieve greater efficiencies, environmental performance, and cost-competitiveness."

The Project was also selected by the Minnesota Public Utilities Commission ("MPUC") and Iron Range Resources and Rehabilitation Board to receive $19.5 million in state funding, in the latter instance an economic development loan. The MPUC approved the FEIS and issued site and route permits for the Project in March of 2010. This was the first site permit issued for a new coal plant in Minnesota in over 30 years. The joint state/federal EIS process required more than five years to complete, and established that the site is suitable for 1200 MW of coal capacity additions. Transmission Interconnection Agreements were also signed and approved by MISO. The Project is also exempt from the state moratorium on new coal plants to serve Minnesota's needs. Because of forward-looking enabling legislation passed by the Minnesota Legislature in 2003, a new large, in-state, clean coal power plant has been developed and is ready to be constructed to meet the State's future energy needs.

Impact of the Proposed Rule

As currently proposed, the U.S. Environmental Protection Agency's ("EPA") Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units (the "Proposed Rule" or "Rule") would preclude completion of the Project. The proposed standard cannot be met by any

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coal power plant without carbon capture and storage ("CCS"). In contrast to EPA's assertion that CCS is a feasible technology option,[1] the DOE has deemed it infeasible for the Project in its EIS:

> "Based on an analysis of the commercial readiness of carbon capture and sequestration presented in Appendix A2, CCS is not considered technically or economically feasible for the Mesaba Energy Project during the DOE demonstration period. While both carbon capture and carbon dioxide transport are technically feasible, the technical feasibility of carbon sequestration for the Mesaba Energy Project cannot be validated in the near-term until extensive field tests are conducted to fully characterize potential storage sites and the long-term storage of sequestered carbon has been demonstrated and verified through ongoing efforts conducted under the DOE Carbon Sequestration Program."[2] (p. 2-24)

A key fallacy underlying EPA's assertion of CCS's feasibility is the conclusion that transportation of CO_2 is not a significant stumbling block to CCS's feasibility, since 95 percent of the largest CO_2 point sources are within 50 miles of a possible geologic sequestration site.[3] Proximity to theoretically 'possible' sequestration sites is not the appropriate standard, since sequestration can only occur in fully characterized storage sites as confirmed by the DOE above. 'Possible' sequestration sites are completely unacceptable to permitting authorities for sequestration until fully characterized, and that process may prove them to be unsuitable. This is illustrated by the fact that the study cited by EPA included the Mid-Continent Rift formation when calculating the 95 percent statistic. However, the Minnesota Geological Survey concluded the following regarding the Mid-Continent Rift:

> "The key conclusion of the report is, therefore, that, unlike better known rocks in oil or coal producing regions, we have little information on the Rift. A major effort costing tens to hundreds of millions of dollars would therefore be required to test the Rift sedimentary rocks in Minnesota for required reservoir capacity and properties, and the probability that these requirements would not be confirmed, despite this effort, is high."[4]

The Mid-Continent Rift therefore is not a 'feasible' sequestration site. For the Project, the nearest sites meeting the 'fully characterized' standard for sequestration would be oil and gas fields in western North Dakota, approximately 400 miles away.[5] Transporting CO_2 this distance is a significant stumbling block to the feasibility of implementing CCS at the inception of plant operations.

Furthermore, the 30-year averaging provision does not provide the flexibility to allow for construction of the Project, even if it has developed technically feasible plans to commence CCS when regulatory and economic conditions warrant. EPA acknowledges that the Administration's "CCS Task Force report recognized that CCS would not become more widely available without the advent of a regulatory framework that promoted

[1] EPA. "Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units (Proposed Rule)." Federal Register 77:72 (April 13, 2012) p.22414.
[2] DOE. "Mesaba Energy Project Final Environmental Impact Statement." DOE/EIS-0382. November, 2009. p. 2-24.
[3] EPA. "Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units (Proposed Rule)." Federal Register 77:72 (April 13, 2012) p.22415.
[4] Thorleifson, L. H., ed., "Potential capacity for geologic carbon sequestration in the Midcontinent Rift System in Minnesota," Minnesota Geological Survey Open File Report OFR-08-01. 2008. See http://purl.umn.edu/117609, page 10.
[5] Energy & Environmental Research Center. "Carbon Management Plan for Excelsior Energy." November 30, 2007.

CCS or a strong price signal for CO_2."[6] No regulatory price signal exists that would support CCS, nor is there any reasonable prospect for such a signal to be established in the foreseeable future. In addition, to ensure that the power plant is capable of meeting the 30 year standard, project lenders for the power plant would require that the future CCS project (which includes a ~400 mile pipeline in the Project's case) be fully engineered with all necessary permits and contracts in place before construction of the power plant could begin. Due to these economic and logistical obstacles, further development of the Project is impossible unless the issues raised by this Proposed Rule are resolved by deeming the Project a transitional source.

Transitional Sources

As established above, the Proposed Rule would eliminate the Project as a potential future clean coal power supply option, ensuring that its demonstrative purposes will remain unmet and that over $40 million in sunk costs that have been expended over the past eight years to develop the Project may not be recovered. Imposing such an acutely disruptive standard on the Project after such substantial investment has been made would be wasteful, in direct opposition with EPA's stated intention to avoid precisely this result. Implementing this profound disruption without relief for projects in the development pipeline will deter future participation in DOE public/private partnerships designed to address national energy security priorities. Local and state government contributed over $20 million toward cooperative development of the Project through the partnership with DOE in order to help advance national energy policy, and it is important that the federal government send the signal that it will not leave such investments stranded by its own future actions. This result would be contrary to EPA's projection that the cost of the rule would be zero. Such a capricious and unpredictable regulatory climate for the electric power industry (where ten year project development and construction cycles are now typical) creates insurmountable barriers to innovation. EPA presumably does not seek to stifle innovation, and has explicitly recognized that wasting sunk costs is unacceptable and not intended under Section 111 of the Clean Air Act:

> "Applying the 1,000 lb CO_2/MWh standard would likely result in the loss of their sunk costs and would likely cause multi-year delays, or even abandonment, of their plans to construct. (Nor is the 1,000 lb CO_2/MWh standard appropriate for CCS sources, as discussed below.) This is not within the scope of BSER."[7]

In an attempt to avoid wasting sunk costs, creating regulatory discontinuity, and discouraging innovation, EPA is properly proposing to exempt 'transitional sources' from the new source performance standard ("NSPS").[8] However, the proposed definition for transitional sources is too narrow and the relief provided to such sources is too brief to achieve this goal. This can be remedied by broadening the definition of transitional sources and extending their period of exemption. Doing so would ensure that the goals driving the establishment of transitional sources are met, without threatening the only benefit that EPA has identified to the Proposed Rule[9] – i.e., the signal it sends that future coal plants must be positioned to implement CCS or similar GHG reductions. Even with a broader definition and longer exemption for transitional sources, the Proposed Rule would send the intended signal not to develop a coal project that does not incorporate

[6] EPA. "Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units (Proposed Rule)." Federal Register 77:72 (April 13, 2012) p.22416.
[7] *Ibid.* p. 22422.
[8] *Ibid.* p. 22421.
[9] *Ibid.* p. 22401.

CCS from inception to anyone who has not already expended tens of millions of dollars and years of development toward a project that was not conceived and developed to meet the proposed standard.

Broadening the definition of "transitional sources" would help to avoid stranding the investment of time and resources in the Project. EPA's proposal to define transitional sources as only those with final air permits is excessively narrow, because it does not adequately recognize the substantial preconstruction planning and sunk costs that are incurred long before reaching that milestone in today's complex regulatory process for large baseload power project development. EPA acknowledges that it "does not have information as to the extent of their costs, their preconstruction planning, or their overall business plans."[10] This statement recognizes the need for EPA to consider the factual information provided in these comments and make a determination regarding inclusion of the Project within the final definition of "transitional projects." Requiring a final air permit ignores the permitting complexities that exist in certain jurisdictions. For example, Minnesota's power plant siting process required that two sites be considered, and in the case of the Mesaba Project, this necessitated development of a joint state and Federal EIS that fully characterized both sites. Uncertainty regarding which site would be selected prevented earnest pursuit of the air permit until the site permit was issued, at which point tens of millions of dollars in development and years of effort had already been invested. Absent this requirement, the final air permit would likely have been issued. The Mesaba Project has conducted extensive preconstruction planning and incurred substantial sunk costs, and should be given the opportunity to recover those costs. This could be easily remedied by including in the definition of transition projects both those having site construction permits, as well as air permits. It is unlikely that this would significantly increase the pool of transition sources, and as mentioned above, the cost of doing so is negligible considering EPA's certainty regarding how few will actually proceed to construction.

Furthermore, it is appropriate to preserve projects that are part of federal clean coal initiatives that have the potential to advance the interests of commercializing CCS, in order to give those projects the opportunity to achieve their objectives as well as repay loans. Toward this end, EPA made an exception to its definition of transition sources in the Proposed Rule to include projects that have expired air permits but have also received a DOE CCS loan or grant.[11] This exception should be extended to any active project that has received DOE clean coal funding. NGCC cannot be considered the Best System of Emission Reduction for such projects, because conversion to NGCC would frustrate the project's purpose of technology demonstration. While CCS is currently economically infeasible for the Mesaba Project, construction of the Project would still advance clean coal technology, as acknowledged by DOE:

> "It is important to recognize that the successful operation of the Mesaba Energy Project will mark an important milestone towards both the eventual co-production of electric power, hydrogen, and strategic transportation fuels and chemicals (from the synthesis gas) and the implementation of emerging carbon management strategies through IGCC technologies. In short, the commercialization of IGCC is a vital milestone toward meeting the growing demand for electric power generation capacity, ensuring the nation's energy security (through co-production), and enabling more stringent future environmental regulation(s) (through carbon capture and sequestration technologies).
>
> …
>
> Advancements in IGCC and CCS must converge before the two can be fully integrated and the benefits fully realized. DOE expects that the combined efforts of these programs will enable large-

[10] *Ibid.* p. 22422.
[11] *Ibid.* p. 22422.

> scale commercial designs to be available by 2020 that offer 90% carbon capture with 99% storage permanence at less than a 10% increase in the cost of energy services. Although the planned in-service date for the Mesaba Energy Project is well in advance of the timeline for achieving the DOE goal, projects like Mesaba that are amenable to carbon management will advance the state-of-the-art in gasification technology and thereby make CCS more likely to be deployed in the future."[12]

Extending the period of transition is also necessary to avoid stranding the investment to date in the Project. EPA proposes to establish a 12 month deadline to initiate construction "as a mechanism for revealing which of these sources qualifies as a transitional source" because they lack sufficient information to determine which sources are truly transitional.[13] Given the persistent economic downturn and accompanying natural gas overproduction, this approach is inadequate to avoid cancellation of advanced stage projects. The primary information that EPA does not have and appears concerned with ascertaining is the extent of sunk costs that have been incurred: "We believe that any of these 15 proposed sources that commences construction within 12 months of today's rulemaking proposal should be considered to have incurred substantial sunk costs and will have engaged in sufficient preconstruction planning so that the 1,000 lb CO_2/MWh standard should not apply."[14] Sunk costs and preconstruction planning can be easily determined – in the case of the Mesaba Project, $40 million has been expended over 8 years, and advanced development milestones have been achieved. By contrast, power plant development schedules are notoriously unpredictable and can be subject to myriad exogenous delays that are wholly outside a developer's control. Rather than 'revealing' a project's status, imposing an arbitrary deadline to initiate construction merely adds unacceptable developmental risk. In fact, this Proposed Rule itself virtually assures that the 12 month deadline is unachievable by any project. Most of the 12 month period will be consumed before the final rule is even issued, and court challenges will not be resolved until long after that deadline has passed. Additionally, "transitional sources would become subject to the requirements the EPA would promulgate at the appropriate time, for existing sources under 111(d)."[15] There is no certainty that the existing source standard will not, when issued, also require CCS and potentially force closure of transitional sources long before their investment is recovered. For these reasons, arranging financing for $2-3 billion coal power plant projects in the next 12 months subject to this level of regulatory uncertainty is impossible.

Therefore, extending the 12 month deadline is necessary. A project's status as a transitional source should be valid for at least as long as the permits it has been issued remain valid. Additionally, status as a transitional source should not be revoked before EPA promulgates final new source performance standards for existing sources under Section 111(d), as resolution of that uncertainty will be critical to securing financing of the transitional sources. Imposing a shorter deadline only ensures that sunk costs will in fact be lost, while providing no benefit associated with the signal sent domestically and internationally by the Proposed Rule. As alluded to above, an even better solution is simply to have the Rule provide that any CCPI project will be treated as a transitional source.

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[12] DOE. Testimony submitted to the Mesaba Energy Project Contested Case Hearings, January 29, 2008. Docket No. E-6472/GS-06-668, filed under public comments, ALJ Batch 4.

[13] EPA. "Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units (Proposed Rule)." Federal Register 77:72 (April 13, 2012) p.22422.

[14] EPA. "Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units (Proposed Rule)." Federal Register 77:72 (April 13, 2012) p.22422.

[15] *Ibid.*

In justifying why transitional sources must be exempted from the proposed standard, EPA states the following:

> "Transitional sources have already incurred substantial costs in permitting and taking other steps preparatory to commencing construction as coal-fired power plants within 12 months of the date of this proposal, which may include purchasing land for the new facility. Considering these sunk costs, converting their plant design to NGCC would be significantly more expensive than for proposed non-transitional sources that have not reached the stage of development that transitional sources have reached. The EPA is required to consider costs in determining the BSER adequately demonstrated, and under these circumstances, the costs factor points away from treating NGCC as BSER for transitional sources."[16]

The same considerations apply to sources that have incurred substantial costs but have not obtained an air permit or cannot initiate construction within 12 months. The costs associated with developing large coal plants are much greater than those of developing NGCC, and it is not practical to recover the development costs of the former through construction of the latter. At the least, projects that have received a site permit should be included and granted sufficient time to commence construction, until the later of permit expiration or three years after the CO_2 NSPS for existing sources is final. CCPI projects should receive even further consideration, especially when substantial state funding and legislative action was associated with the project's development.

Inconsistency between the Proposed Rule and Previous EPA Guidance

Exacerbating the disruptiveness of the Proposed Rule is the fact that it is an abrupt departure from the historical relationship between NSPS and best available control technology ("BACT"), recent BACT guidance from EPA, and a recent order from EPA on the subject. The former EPA New Source Review Section Chief described the relationship between NSPS and BACT as follows:

> "The NSPS are established after long and careful consideration of a standard that can be reasonably achieved by new source anywhere in the nation. This means that even a very recent NSPS does not represent the best technology available; it instead represents the best technology available nationwide, regardless of climate, water availability, and many other highly variable case-specific factors. The NSPS is the least common denominator and must be met; there are no variances. The BACT requirement, on the other hand, is the greatest degree of emissions control that can be achieved at a specific source and accounts for site-specific variables on a case-by-case basis."[17]

A comparison of recent BACT determinations with applicable NSPS for conventional pollutants confirms the fact that EPA sets NSPS at a less stringent level than what is required under BACT.[18] In stark contrast, in the context of CO_2 and the Proposed Rule, several air permits have recently been issued for coal-fueled power plants, and BACT for CO_2 was determined to be much *less stringent* than the NSPS for CO_2 in the

[16] *Ibid.*

[17] McCutcheon, Gary, New Source Review Chief, EPA. Letter to Mr. Richard E. Grusnick, July 28, 1987. *See* http://www.epa.gov/region07/air/nsr/nsrmemos/crucial.pdf.

[18] For example, according to EPA's BACT/RACT/LAER Clearinghouse, recent BACT determinations for SO2 have been around 0.06-0.08 lb/mmBTu (see Karn Weadock Generating Complex and John W. Turk Jr. Power Plant), which at any reasonable heat rate is much lower than the recently updated NSPS of 1.0 lb/MWh(gross) or 1.2 lb/MWh(net), at 40 CFR 60.43Da(l)(1).

Proposed Rule.[19] It is unprecedented and unreasonable for an NSPS to be established that is more stringent than any previous BACT determination.

Furthermore, as stated by USEPA in guidance on BACT for greenhouse gases:

> "CCS may be eliminated from a BACT analysis in Step 2 if the three components working together are deemed technically infeasible for the proposed source, taking into account the integration of the CCS components with the base facility and site-specific considerations (e.g., space for CO_2 capture equipment at an existing facility, right-of-ways to build a pipeline or access to an existing pipeline, access to suitable geologic reservoirs for sequestration, or other storage options).
>
> While CCS is a promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases. As noted above, to establish that an option is technically infeasible, the permitting record should show that an available control option has neither been demonstrated in practice nor is available and applicable to the source type under review. EPA recognizes the significant logistical hurdles that the installation and operation of a CCS system presents and that sets it apart from other addon controls that are typically used to reduce emissions of other regulated pollutants and already have an existing reasonably accessible infrastructure in place to address waste disposal and other offsite needs. Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, and developing a site for secure long term storage."[20]

In this guidance, EPA took a measured and thoughtful approach to determining whether CCS is technically feasible on a case-by-case basis, and indicated that there were circumstances where its application is not appropriate. CCS would presumably be determined infeasible in locations like Minnesota with no access to suitable geologic storage, as described above. Gina McCarthy, EPA's Assistant Administrator directly supported this presumption by stating that EPA "want[s] to be clear as we're moving forward that the rules will not require carbon capture and storage at every facility."[21] In stark contrast, the language in the Proposed Rule incorrectly states that CCS is feasible throughout the US. Developers following and relying upon EPA's BACT guidance that apparently confirmed the regulatory viability of the Mesaba Project could not anticipate EPA's sudden reversal in the Proposed Rule. This unanticipated reversal of EPA's public guidance unnecessarily increased the amount of sunk costs that will now be stranded due to the Rule unless the relief sought by these comments is granted.

A recent order provided significant assurance to the Mesaba Project that EPA would not seek to fundamentally alter the project or its purpose. In its order on the Cash Creek Generation case on the subject

[19] For example, the CO_2 BACT limit for the Wolverine Power Supply Cooperative's plant in Rogers City, MI was established at 2.1 lb/kW-hr gross output (see permit No. 317-07 issued June 29, 2011), which is more than double the proposed 1,000 lb/MWh NSPS. Also, the CO_2 BACT limit for Tenaska's Taylorville Energy Center is 5,031,409 tons/yr (see http://yosemite.epa.gov/r5/in_permt.nsf/91890e7b650daf8f8625763f00504d0d/0cb5c14de3c78d39862579f3006f24b7/$FILE/ATTM5GSQ/05040027.pdf), which would be approximately 2,100 lb/MWh(net) based on a 602 MW capacity.

[20] EPA. "PSD and Title V Permitting Guidance for Greenhouse Gases," p. March, 2011. EPA-457/B-11-001, p. 36. See http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf.

[21] Bravender, Robin. "EPA Signals Push for Efficiency to Control Greenhouse Gas Emissions." New York Times. April 26, 2010. See http://www.nytimes.com/gwire/2010/04/26/26greenwire-epa-signals-push-for-efficiency-to-control-gre-63224.html

of requiring an IGCC facility to use natural gas as a clean fuel under BACT, the Environmental Appeals Board and EPA established clear limits on the extent to which BACT may be used to alter a source:

> "On the question of whether an option may be excluded because it redefines the proposed source, the EAB has developed an analytical framework that EPA uses to assess this issue in its own permitting decisions. See, e.g., Prairie State, slip op. at 26-37; Desert Rock, slip op. at 59- 65. The framework calls for the permitting authority to first determine from the particular record how the permit applicant "defines the proposed facility's end, object, aim, or purpose" (the "basic" or "fundamental" design of the facility). The relevant definition of the facility should reflect "reasons independent of air quality permitting." The next step is for the permitting authority to then take a "hard look" at the applicant's determination in order to "discern which design elements are inherent for the applicant's purpose and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility." As part of the latter step, the permitting authority should keep in mind that "BACT, in most cases, should not be applied to regulate the applicant's purpose or objective for the proposed facility.""[22]

According to DOE, the purpose of the Project is to demonstrate coal gasification technology. Pursuant to the above guidance from EPA, BACT should not be applied to regulate the Project's purpose. Yet the Proposed Rule would enable NSPS (which is by definition less stringent than BACT) to circumvent this important protection and force the Project convert to NGCC (thereby frustrating the project purpose) or be canceled. This requirement is inconsistent with previous public statements by EPA, such as Assistant Administrator McCarthy's acknowledgement of EPA's long-held precedent is not to require fuel-switching, where she noted that "there's been good reason why we haven't done it in the past."[23] By ensuring the Project is deemed a transitional project and remains so for a sufficient period of time, this abrupt regulatory reversal and its attendant waste can be avoided.

Contingency Planning

EPA proposes to establish NGCC as the Best System of Emission Reduction for coal plants based on its projection that gas-fired EGUs will be less costly than coal fired EGUs.[24] This projection necessarily relies on current natural gas price projections,[25] which history demonstrates are volatile and unpredictable. In its regulatory impact analysis, EPA did not consider any scenarios in which delivered natural gas prices exceed $8/mmBtu, despite the fact that prices exceeded $12/mmBtu as recently as 2008.[26] Unbridled optimism regarding natural gas supplies led to an extremely costly overbuild of natural gas power supply only ten years ago. By effectively placing a moratorium on contingency planning with coal plant development, EPA is once

[22] USEPA. "Order Responding to Issues Raised in January 31, 2008 and February 13, 2008 Petitions, and Denying in Part and Granting in Part Requests for Objection to Permit." See http://www.epa.gov/Region7/air/title5/petitiondb/petitions/cashcreek_response2008.pdf.

[23] Bravender, Robin. "EPA Signals Push for Efficiency to Control Greenhouse Gas Emissions." New York Times. April 26, 2010. See http://www.nytimes.com/gwire/2010/04/26/26greenwire-epa-signals-push-for-efficiency-to-control-gre-63224.html

[24] EPA. "Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units (Proposed Rule)." Federal Register 77:72 (April 13, 2012) p.22418.

[25] EPA. "Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units." EPA-452/R-12-001. March 2012. p. 5-13.

[26] U.S. Energy Information Administration. "U.S. Natural Gas Electric Power Price." Monthly data 2002-2012. *See* http://www.eia.gov/dnav/ng/hist/n3045us3m.htm.

again placing a huge and long-term bet on projections of low natural gas prices. In the event that natural gas prices rise above levels assumed by EPA, the Rule would result in billions of dollars of expenditures, which is not consistent with the Unfunded Mandates Reform Act of 1995.[27]

Maintaining a diverse range of electricity supply options is essential to ensuring a secure energy future. Towards this end, the Project was initially enabled under Minnesota state law with the purpose of developing energy generation facilities using innovative generation technology with significantly reduced emissions relative to traditional technologies, and capable of providing long-term supply at a hedged, predictable price.[28] While current economic trends do not favor coal, until the promulgation of this Rule, the Project remained a valuable electric supply option to protect Minnesota in the event that natural gas prices once again begin exhibiting their historic price and supply volatility. Elimination of this protective hedge would be imprudent, particularly given that EPA projects no quantifiable economic benefit from doing so. The Proposed Rule will halt all development of coal power plants, effectively embargoing contingency planning until the Rule is withdrawn or overturned, or until CCS actually becomes available and economic. In the event relying nearly entirely on natural gas for baseload power generation becomes costly or results in supply shortages, Minnesota and the nation will face anew the ten-plus year development and construction cycle before any new coal plant could be available to address this contingency.

Conclusion

Without making necessary changes to the definition and treatment of transitional sources, the Proposed Rule will unnecessarily frustrate the important project purposes of the Mesaba Energy Project, and strand the substantial sunk costs invested in its development. It is particularly important to remedy these issues since a substantial portion of the sunk costs were incurred while relying on EPA's previous public guidance, and given that the Proposed Rule represents such a disruptive and unexpected shift from that guidance. Therefore, Excelsior Energy respectfully requests that EPA make the changes that are suggested in this comment letter. Alternatively, at a minimum, EPA should provide a mechanism in the Rule or institute some other relief to reimburse the Project proponents and the state and local governments for their investment in the Project, and support the completion of permitting of the power block portion of the Project to be fired by natural gas in compliance with the Proposed Rule. Thank you very much for your consideration of these comments.

Should you have any questions regarding these comments, please direct them to me at 952-847-2362.

Sincerely,

Thomas A. Micheletti

Thomas A. Micheletti
Co-President and Co-CEO
Excelsior Energy, Inc.

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[27] EPA. "Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units (Proposed Rule)." Federal Register 77:72 (April 13, 2012) p.22434.

[28] Minn. Statutes 216B.194. *See* https://www.revisor.mn.gov/statutes/?id=216B.1694.

Granherne Report on Zero Liquid Discharge Treatment of Cooling Tower Blowdown

Mesaba Energy Project

Final Water Retention, Recovery & Reuse Report

West Range Site

Taconite, Minnesota

Prepared for:

Excelsior Energy Inc.

11100 Wayzata Blvd.
Minnetonka, MN 55305

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Project Number J5682

Revision H

January 14, 2009

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1.0 INTRODUCTION

The following is a report for a water retention, recovery and reuse system to service the Excelsior Energy Inc. (Excelsior) Mesaba Energy Project to be located in Taconite, Minnesota (its “West Range Site” in Itasca County). The purpose of this report is to supplement Excelsior’s National Pollutant Discharge Elimination System (NPDES) permit application dated June 18, 2006, by describing the water/wastewater management systems to be used at the site to achieve Excelsior’s objectives of eliminating all wastewater discharges including storm water discharges associated with industrial activities within the facility’s footprint and achieving maximum water recovery and reuse of such wastewaters.

Section 2.0 of this report provides a discussion of the project facility, permit approach, overall water/wastewater management and assumptions used for the systems. A general description of the raw water supply, water retention and recovery and reuse systems are provided in **Section 3.0**. **Section 4.0** provides a more detailed description of the water retention and recovery and reuse systems.

Because the Mesaba facility is still under development/engineering, and because of the evaluation/engineering work required to completely configure the system operation and integrate it into the production operations, the information provided herein is preliminary in nature. As detailed engineering work is performed, the best overall design solution to achieve Excelsior’s objectives will be refined.

The intent of this report is to provide a discussion/description of the system operations to be utilized at the facility. In particular, it addresses the design philosophy, general character and approach to be used for the systems so that the permit reviewer can see that the site can achieve its zero discharge objectives. Water and water constituent balances are provided for the project. Once the facility engineering is more established and the system operation can be more completely described an updated version of this report can be provided, along with a set of plans and specifications for the system.

2.0 PROJECT BACKGROUND

The technical background for the project, including a description of the proposed production facility is provided in this section. Additionally, a summary of the overall strategy for the raw water supply, water retention and recovery and reuse systems are provided.

2.1 Technical Background

Excelsior is in the process of seeking regulatory approvals for the first two phases of its Mesaba Energy Project in Taconite, Minnesota. The Project's first phase is included in the portfolio of the U.S. DOE Clean Coal Power Initiative (CCPI) Round 2 series of projects, the capstone of the National Coal RD&D Program managed by the U.S. Department of Energy (DOE) Office of Fossil Energy. It will demonstrate a commercial utility-scale "next-generation" Integrated Gasification Combined Cycle (IGCC) electric power generating facility fueled by coal or other solid, petroleum based feedstocks. The two phases consist of two nominal 600 MW units, Mesaba One and Mesaba Two, for a total nominal capacity of 1,200 MW. A planning perspective of the proposed facilities is shown below in Figure 1-1.

Figure 1-1

The Mesaba Energy Project will deploy substantial technology advancements in gasification, air separation and other plant systems and their integration. It will incorporate design and operational lessons learned from the successful but smaller-scale 262 MW Wabash River Coal Gasification Repowering Project, located in Terre Haute, Indiana; a previous Round 1 DOE clean coal technology project.

2.2 Permit Approach

Excelsior has decided to implement zero discharge for the facility. This report addresses Mesaba One, because the design for Mesaba Two would be substantially identical.

The gasification island of the facility will incorporate a separate zero liquid discharge (ZLD) system. This system will recover and treat wastewater generated from the gasification and slag processing operations that contain certain levels of heavy metals and other contaminants for the facility feedstocks. This system will recover distilled water for reuse in the power plant, reducing fresh water consumption, and more importantly, concentrate heavy metals and other contaminants of concern into a solid waste stream that will be effectively disposed of in an approved waste management facility.

The project's environmental permit applications were submitted to regulatory authorities in 2006. The above ZLD system serving the gasification island has been included in the permit applications and is not further addressed within this report as it is a separate stand alone system from those described herein.

This report identifies the system for treating the project's non-contact wastewater and stormwater streams. These streams include cooling tower blowdown, smaller flows from water treatment system regeneration, use of service water, and surface runoff streams from the project.

Also addressed is the retention of precipitation (rain and snow) for the IGCC Power Station Footprint not including off-site areas, i.e. railroad, power lines, pump stations, pipelines, etc.

2.3 Overall Water/Wastewater Management

The proposed systems for the site utilize processes that are environmentally sound and are practical approaches to implementing a pollution prevention framework. The general strategy for water retention, recovery and reuse will consist of the following concepts:

- Excelsior will operate non-contact cooling towers for the Air Separation Unit (ASU) and gasification equipment (CT-2) and for the power island portion (CT-1) of the facility with cycles of concentration (COC) of 5 (or more) to minimize the amount of cooling tower blowdown to be handled. The resultant blowdown streams will be directed to an Equalization and Surge Pond.
- Water treatment regeneration wastewaters will be directed to either the

cooling towers as make-up or to the Equalization and Surge Pond as the quality dictates.

- Other non-contact wastewaters are collected and pretreated, if required, prior to entering the Surge and Equalization Pond.
- The water as a result of precipitation will be treated by an oil water separator (if necessary) and then directed into the Surge and Equalization Pond. This water will then be treated, if required, and used as cooling tower makeup or directed into the ZLD system for treatment.

2.4 Assumptions/Requirements

Assumptions/requirements for the design of the systems are indicated below.

1. Reliability and maintainability objectives for the ZLD system are high due to the continuous flows into the system. The ZLD system on-line target is 99% (i.e., less than 7.2 hours per month or ~ one 8 hour shift per month of total downtime).
2. Process area surface drainage will be conveyed by a segregated drain system and then to an Oil Water Separator. Recovered oil will be held in a tank for off-site disposal, underflow will be directed to the Surge and Equalization Pond.
3. Rainfall precipitation design shall be based upon a 100 year – 24 hour storm event of ~5.3" per Technical Paper No. 40. Annual snow fall quantities are not considered as their snow melt volumes will be less than the equivalent of the 5.3" per day rainfall event.
4. The gasification/power production facility can be out of service during the design rainfall without discharge from the site.
5. Leachate collection and monitoring systems for ground water protection will be employed.
6. Equipment redundancy shall be provided throughout the systems.

7. Average raw water flow required for Mesaba One is about 3,360 gpm and the peak raw water flow is about 4,980 gpm for Mesaba One based upon 5 COC for the cooling towers. Raw Water will be from the Canisteo Mine Pit (CMP) with mixing with HAMP (Hill Annex Mine Pit) Complex water.
8. Cooling tower operations are defined as 5 COC based upon initial review of raw water supply with calcium as the limiting specie. If it is determined during final design that higher cycles of concentration can be economically achieved, cooling tower operations and ZLD system equipment sizing will be adjusted accordingly.

3.0 WATER UTILITY GENERAL DESCRIPTIONS

This section provides a general description of the raw water supply and the water retention and recovery and reuse systems.

3.1 Raw Water Supply System

The facility will require significant amounts of water with varying specifications for use in the production of electrical power. The purpose of the raw water supply system is to reliably and cost effectively provide sufficient quantity of water service for the process needs.

Section 3.6.1.1 (Pages 262 - 266) of the MPUC Joint Application discusses the West Range Raw Water System in detail. Table 3.2-2 from the NPDES Permit Application below shows raw water source capabilities for the facility.

Table 3.2-2
Water Source Supply Capability

Water Source	Est. Range of Flow (gpm)	Assumed Sustainable Flow for Water Balance Modeling (gpm)
CMP	810-4,190	2,800
HAMP Complex	1,590-4,030	2,000[a] 3,500[b]
LMP	Not yet quantified	1,800[c]
Prairie River	0-2,470[d]	0[e]
Discharge from IGCC Power Station	0-3,500	Varies

[a]At an operating elevation of 1,230 ft.
[b]At minimum operating elevation
[c]Based on a single observation and flow estimate
[d]Maximum available flow assumed to be 25% of the 7Q10 flow of the Prairie River
[e]For modeling purposes, the Prairie River contributions determined to be unnecessary provided LMP flow rate is sustained a 1,800 gpm.

Mixing in the ratio of 2800 gpm from CMP to 2000 gpm from HAMP Complex for investigation of water quality parameters was used for this report and its calculations.

For Mesaba One, water from the HAMP Complex will be pumped via a pump station to the CMP and from the CMP another pump station will pump the water to the facility. Pump redundancy will be provided within each of these pumping stations.

Figure 3-1 below is a conceptual presentation of the raw water flow case for the average case of 890 gpm to the ZLD system and Figure 3-2 is for the raw water flow case for the peak ZLD case of 1,300 gpm.

Figure 3-1 - Average Raw Water Case

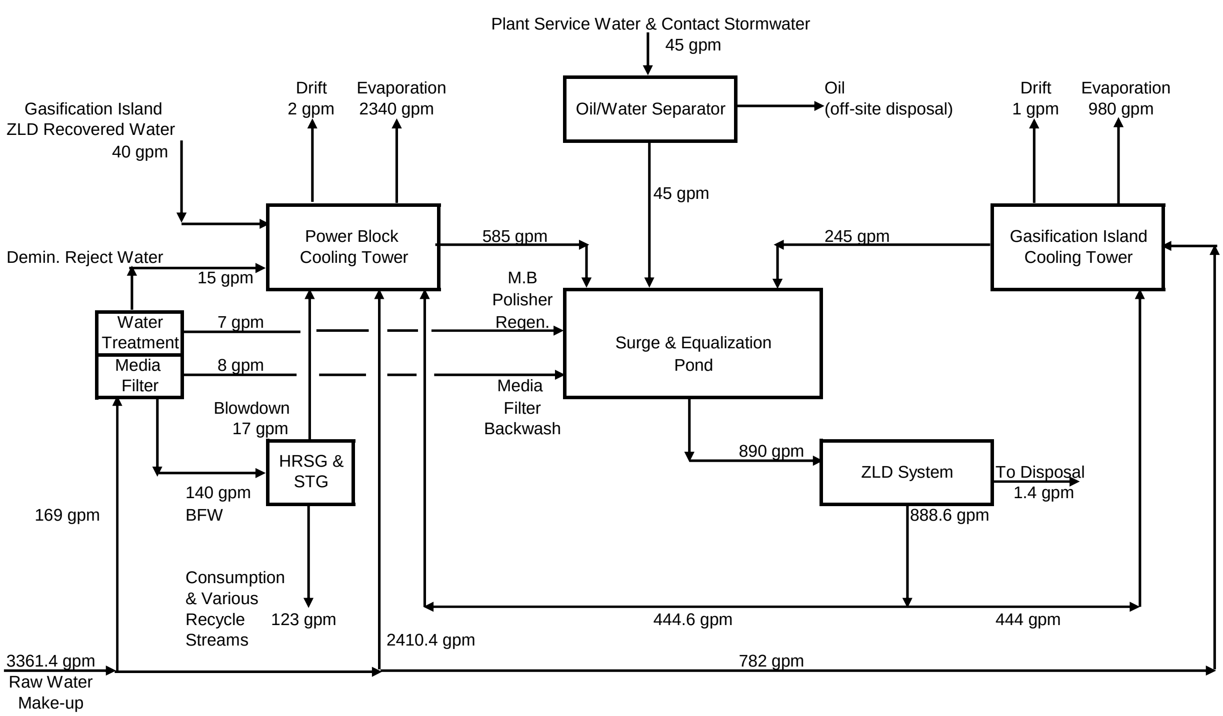
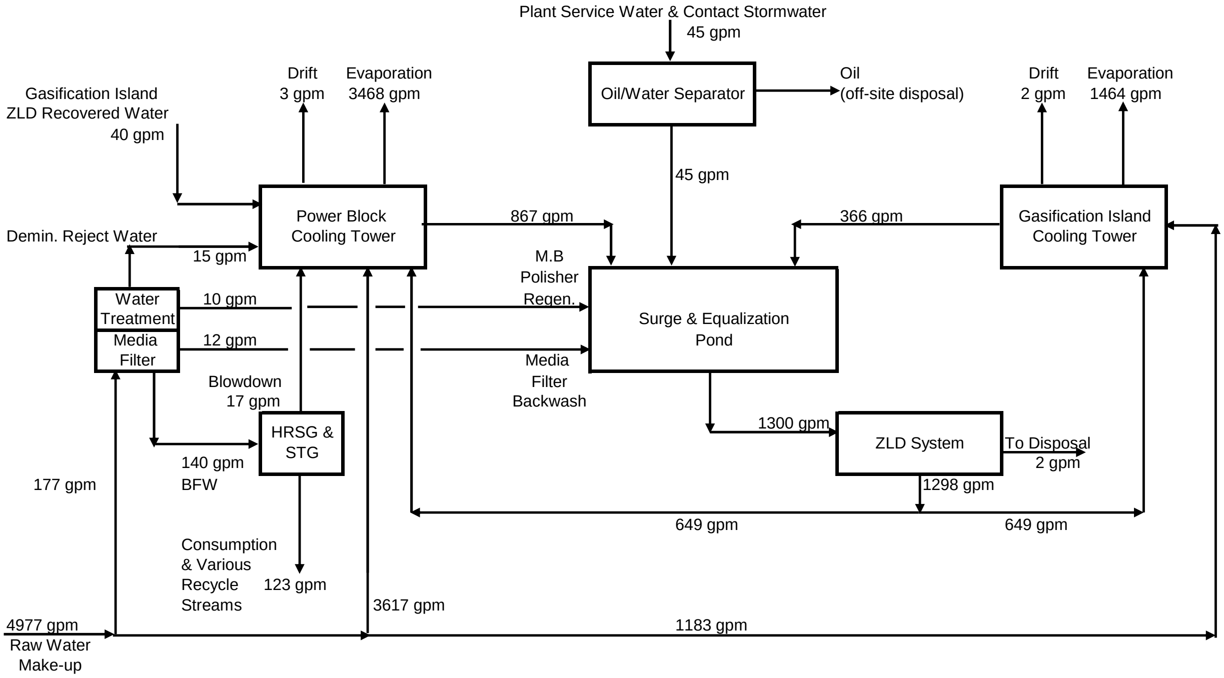


Figure 3-2 - Peak Raw Water Case



3.2 Raw Water Quality

Water quality from CMP and HAMP Complex were evaluated for ionic balance, i.e., to check their cation and anion characterizations and determine any need to adjust the given analyses before their use alone or with any ratioed chemical values. As the following analytical reviews show: cations appear to exceed anions for CMP water by 8.6% and for HAMP Complex by 5.1%.

Table 3-1 - CMP Water Quality

	As ION	As $CaCO_3$	476		As ION	As $CaCO_3$
CALCIUM	55.3	138.1	pH	ALKALINITY	219.5	180.0
MAGNESIUM	40.8	168.1	8.4	CHLORIDE	5.2	7.3
SODIUM	6.6	14.4	TEMP	SULPHATE	103.5	108.0
POTASSIUM	0.0	0.0	25	NITRATE (as NO_3)	0.0	0.0
		320.6				295.3
TRUE COLOUR	0	Pt/Co (HZ) UNITS		TDS ACTUAL	337	mg/L
TURBIDITY	0.0	NTU				
IRON	0.03	mg/L				
MANGANESE	0.01	mg/L				
CALCULATED RAW WATER PARAMETERS						
SCATIONS/SANIONS	108.6%			TDS CALC'D from "AS IONS"	431	mg/L
HARDNESS	306.2	mg/L, as $CaCO_3$		TDS CALC'D from EC	305	mg/L
ALK/(Cl+SO_4)	1.6			TDS	6.2	meq/L
SO4/(Cl+SO_4)	94%			IONIC STRENGTH: SPECIES	0.01029	mol/L
S MONOVALENT IONS	0.00403	meq/L		IONIC STRENGTH: TDS	0.00862	mol/L
S DIVALENT IONS	0.00827	meq/L		ACIDITY	177.1	mg/L, as $CaCO_3$
SODIUM ADSORPTION RATIO	0.16			(ALK-Ca)	41.9	mg/L, as $CaCO_3$
CORROSIVITY INDICES						
LANGELIER SATURATION INDEX (LSI)	1.03			AGGRESSIVENESS INDEX	13.1	
LARSON INDEX	1.2			[Ca_{SAT}]	120	mg/L, as $CaCO_3$
				CALCIUM CARBONATE PRECIPITATION POTENTIAL (CCPP)	18.1	mg/L, as $CaCO_3$

Table 3-2 - HAMP Complex Water Quality

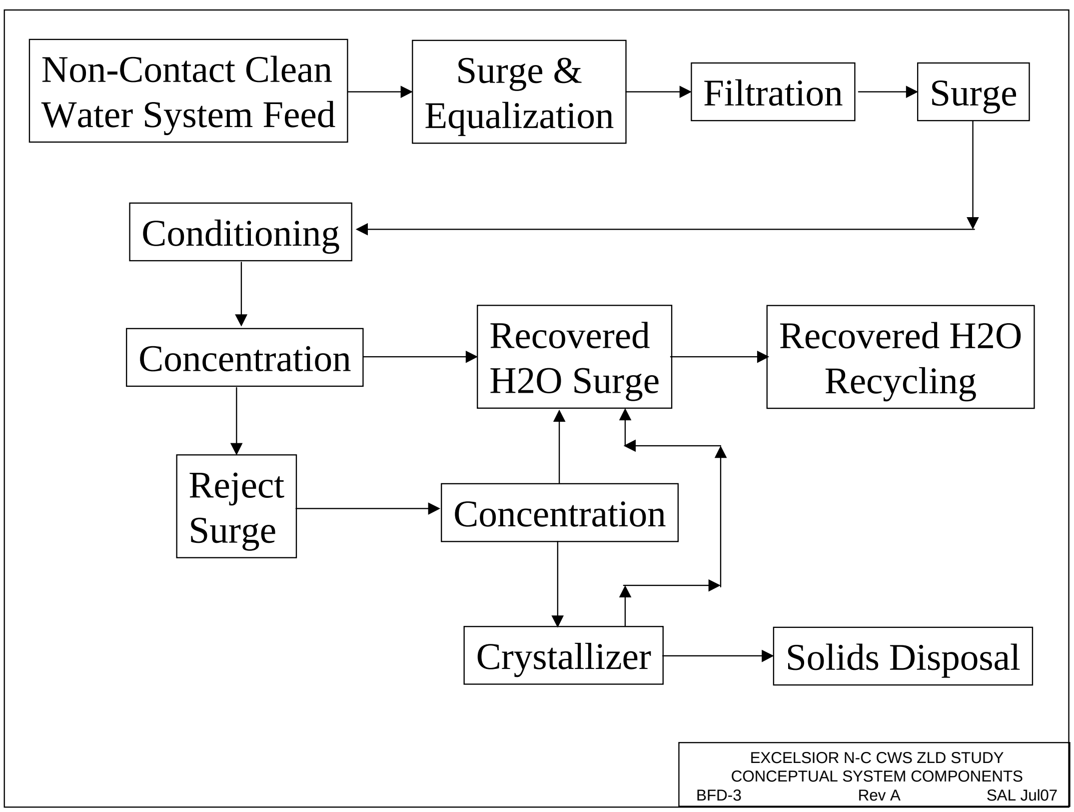
	As ION	As $CaCO_3$	418		As ION	As $CaCO_3$
CALCIUM	58.6	146.3	pH	ALKALINITY	198.8	163.0
MAGNESIUM	20.5	84.4	8.3	CHLORIDE	5.2	7.3
SODIUM	6.2	13.5	TEMP	SULPHATE	59.5	62.1
POTASSIUM	0.0	0.0	25	NITRATE (as NO_3)	0.0	0.0
		244.2				232.4
TRUE COLOUR	80	Pt/Co (HZ) UNITS		TDS ACTUAL	254	mg/L
TURBIDITY	6.0	NTU				
IRON	0.03	mg/L				
MANGANESE	0.01	mg/L				
CALCULATED RAW WATER PARAMETERS						
SCATIONS/SANIONS	105.1%			TDS CALC'D from "AS IONS"	349	mg/L
HARDNESS	230.8	mg/L, as $CaCO_3$		TDS CALC'D from EC	268	mg/L
ALK/(Cl+SO_4)	2.3			TDS	4.8	meq/L
SO4/(Cl+SO_4)	89%			IONIC STRENGTH: SPECIES	0.00769	mol/L
S MONOVALENT IONS	0.00367	meq/L		IONIC STRENGTH: TDS	0.00698	mol/L
S DIVALENT IONS	0.00585	meq/L		ACIDITY	162.3	mg/L, as $CaCO_3$
SODIUM ADSORPTION RATIO	0.18			(ALK-Ca)	16.7	mg/L, as $CaCO_3$
CORROSIVITY INDICES						
LANGELIER SATURATION INDEX (LSI)	0.93			AGGRESSIVENESS INDEX	12.9	
LARSON INDEX	0.8			[Ca_{SAT}]	120	mg/L, as $CaCO_3$
				CALCIUM CARBONATE PRECIPITATION POTENTIAL (CCPP)	26.3	mg/L, as $CaCO_3$

Refer to **Appendix 1** – Average Raw Water Analysis, for the constituents contained in each of the CMP and HAMP Complex water streams. Also included in **Appendix 1** is an equivalent constituent basis when combining 2,800 gpm of CMP water and 2,000 gpm of HAMP Complex water. This equivalent water is the basis for this report.

3.3 ZLD System

The ZLD system combines wastewater system unit operations as depicted in the conceptual block flow diagram, Figure 3-3. The engineering design challenge is to apply appropriately sized and energy efficient technology in recovering water and removing solids for disposal.

Figure 3-3 –ZLD Conceptual Components



3.4 Wastewater Characterization

ZLD system feeds are qualitatively characterized relative to their Total Dissolved Solids (TDS) and Total Suspended Solids (TSS) levels, which ultimately determine sludge generation rates for off-site disposal. Additional parameters of interest include pH as well as dissolved and free organics. Quantitative values of concentration and flow were established to define the feed to the ZLD system.

The following are the feed streams to the ZLD system:

- Cooling Towers (CT-1 and CT-2) Blowdown - These streams are characterized as having elevated TDS levels due to COC within the cooling tower systems. TSS levels are mitigated by filtered raw water makeup and settling in the cooling tower basin.
- Raw water Multi-Media Pressure Filters Backwash - This stream is characterized as having raw water TDS levels and high TSS levels due to its solids removal from the incoming supply water.
- ZLD Pressure Filters Backwash - This stream is characterized as having generally the level of TDS and TSS from the cooling tower blowdown streams since these are the predominant flows.
- Oil-Water Separator Underflow - This stream is characterized as clarified and filtered raw water with minimal oil and grease content.
- Mixed Bed Polisher Regeneration Flows - This stream is characterized as having high TDS and little to no TSS levels due to regeneration chemical strengths; concentrations are diluted somewhat from rinse and backwash volumes used at the end of the regeneration cycle.
- Storm water and snow melt flows will carry some TSS, but have very low TDS.

3.5 Design Feed to the ZLD System

The annual average ZLD feed stream is 890 gpm and the peak feed is 1,300 gpm per Figures 3-1 and 3-2 of this report. The constituents within both the average and peak feed streams are assumed to be the same, i.e. 1357 mg/l of TDS and 66 mg/l of TSS, as the major contributors are the cooling tower blowdown streams.

Table 3-3 below indicates the estimated properties, TDS, TSS and Total Solids expected for the average inlet flow case for the ZLD and Table 3-4 is for the peak case, both for 5 COC for the cooling towers.

Table 3-3 – Water Retention Recovery and Reuse System - Average Case

	Stream	1	2	3	4	5	6	7	8
Parameter	**Description**	**Power Block Cooling Tower Blowdown (@ 5 COC)**	**Gasifier/ ASU Cooling Tower Blowdown (@ 5 COC)**	**Plant Service Water via O/W Separator**	**Mixed Bed Polisher Regen.**	**Media Filter Bacwash**	**WRRS Feed (1+2+3+4+5)**	**Low TDS Streams (3+5)**	**High TDS Streams (1+2+4)**
Temperature	°F	86	86	76	110	76	85.6	68.3	86.2
Pressure	psig	atm	atm	atm	atm	atm	atm	atm	atm
Mass Flow	lb/hr	294,277	123,244	22,524	3,574	4,004	447,623	26,528	421,095
Density	lb/ft3	62.712	67.712	62.4	63.648	62.4	62.4	62.4	62.4
Specific Gravity	H2O = 1	1.005	1.005	1.000	1.020	1.000	1.000	1.000	1.000
Liquid Volume Flow, Avg.	gpm	585	245	45	7	8	890	53	837
Liquid Volume Flow, Avg.	mgd	0.842	0.353	0.065	0.010	0.012	1.282	0.076	1.205
Liquid Volume Flow, Peak	gpm	867	366	45	10	12	1,300	57	1,243
Liquid Volume Flow, Peak	mgd	1.248	0.527	0.065	0.014	0.017	1.872	0.082	1.790
Total Dissolved Solids	mg/l	1402	1402	200	4000	100	1357	125	1431
Total Suspended Solids	mg/l	50	50	20	10	2000	66	116	50
Total Solids	mg/l	1452	1452	220	4010	2100	1423	241	1481
Total Dissolved Solids	lb/hr	410.6	172.0	4.5	14.0	0.4	604.7	3.3	599.7
Total Suspended Solids	lb/hr	14.6	6.1	0.5	0.0	8.0	29.4	3.1	21.0
Total Solids	lb/hr	425.3	178.1	5.0	14.1	8.4	634.1	6.4	620.6
Total Dissolved Solids	lb/day	9,855.3	4,127.4	108.1	336.5	9.6	14,512.3	79.6	14,392.3
Total Suspended Solids	lb/day	351.5	147.2	10.8	0.9	192.3	705.8	73.9	502.9
Total Solids	lb/day	10,206.7	4,274.6	119	337.4	201.9	15,218.1	153.5	14,895.2
Total Dissolved Solids	ton/day	4.928	2.064	0.054	0.168	0.005	7.256	0.040	7.196
Total Suspended Solids	ton/day	0.176	0.074	0.005	0.000	0.096	0.353	0.037	0.251
Total Solids	ton/day	5.103	2.137	0.059	0.169	0.101	7.609	0.077	7.448

Table 3-4 - Water Retention Recovery and Reuse System - Peak Case

	Stream	1	2	3	4	5	6	7	8
Parameter	**Description**	**Power Block Cooling Tower Blowdown (@ 5 COC)**	**Gasifier/ ASU Cooling Tower Blowdown (@ 5 COC)**	**Plant Service Water via O/W Separator**	**Mixed Bed Polisher Regen.**	**Media Filter Bacwash**	**WRRS Feed (1+2+3+4+5)**	**Low TDS Streams (3+5)**	**High TDS Streams (1+2+4)**
Temperature	°F	86	86	76	110	76	85.6	68.3	86.2
Pressure	psig	atm	atm	atm	atm	atm	atm	atm	atm
Mass Flow	lb/hr	294,277	123,244	22,524	3,574	4,004	447,623	26,528	421,095
Density	lb/ft3	62.712	67.712	62.4	63.648	62.4	62.4	62.4	62.4
Specific Gravity	H2O = 1	1.005	1.005	1.000	1.020	1.000	1.000	1.000	1.000
Liquid Volume Flow, Peak	gpm	867	366	45	10	12	1,300	57	1,243
Liquid Volume Flow, Peak	mgd	1.248	0.527	0.065	0.014	0.017	1.872	0.082	1.790
Total Dissolved Solids	mg/l	1402	1402	200	4000	100	1357	125	1431
Total Suspended Solids	mg/l	50	50	20	10	2000	66	116	50
Total Solids	mg/l	1452	1452	220	4010	2100	1423	241	1481
Total Dissolved Solids	lb/hr	608.6	256.9	4.5	20.0	0.6	883.2	3.6	890.6
Total Suspended Solids	lb/hr	21.7	9.2	0.5	0.1	12.0	43.0	3.3	31.1
Total Solids	lb/hr	630.3	266.1	5.0	20.1	12.6	926.2	6.9	921.7
Total Dissolved Solids	lb/day	14,606.0	6,165.9	108.1	480.6	14.4	21,197.7	85.6	21,373.5
Total Suspended Solids	lb/day	520.9	219.9	10.8	0.9	288.4	1031.0	79.5	746.8
Total Solids	lb/day	15,126.9	6,385.8	119	481.5	302.8	22,228.7	165.1	22,120.3
Total Dissolved Solids	ton/day	7.303	3.083	0.054	0.240	0.007	10.599	0.043	10.687
Total Suspended Solids	ton/day	0.260	0.110	0.005	0.000	0.144	0.515	0.040	0.373
Total Solids	ton/day	7.563	3.193	0.059	0.241	0.151	11.114	0.083	11.060

4.0 DETAILED PROCESS DESCRIPTIONS

The following are detailed descriptions of the water retention, recovery and reuse systems.

4.1 Precipitation Retention and Recovery System

Based upon the design rainfall of 5.3 inches/day, the average rainfall is 2.25gpm/1,000 square feet of plot area. Areas that are paved will have a runoff coefficient of 1.0 (all water to retention). Other areas that are not paved will have runoff coefficients of less than 1.0 depending upon the type of surface covering. Calculations show that this rainfall event would result in 30.8 acre-feet of runoff for Mesaba One and 33.6 acre-feet of runoff for Mesaba Two. (Mesaba Two's drainage area is slightly larger due to differences in site grading.)

Equipment areas such as cooling towers will retain the rainfall and will not contribute to the calculations of retention.

Runoff from rainfall and snow melt will be collected in the Surge and Equalization Pond located in the flare area and stored while the water is being recovered and recycled within the facility. The design shows that a pond capacity of 35 acre-feet could be achieved in this location. This capacity is very conservative, as it is more than adequate to accommodate a 24-hr, 100-yr storm event that coincides with a plant outage. During normal plant operation, capacity requirements would be reduced by the cooling towers' ability to work off accumulated runoff.

The collected water will be pumped to the cooling tower basins as makeup over time or, should it for some reason require treatment, be directed into the ZLD system.

The water will be transferred from the Surge and Equalization Pond to the cooling towers via pump(s).

4.2 ZLD System

Figure 4-1 below is a block diagram representation of the ZLD system.

Figure 4-1 - ZLD System Schematic

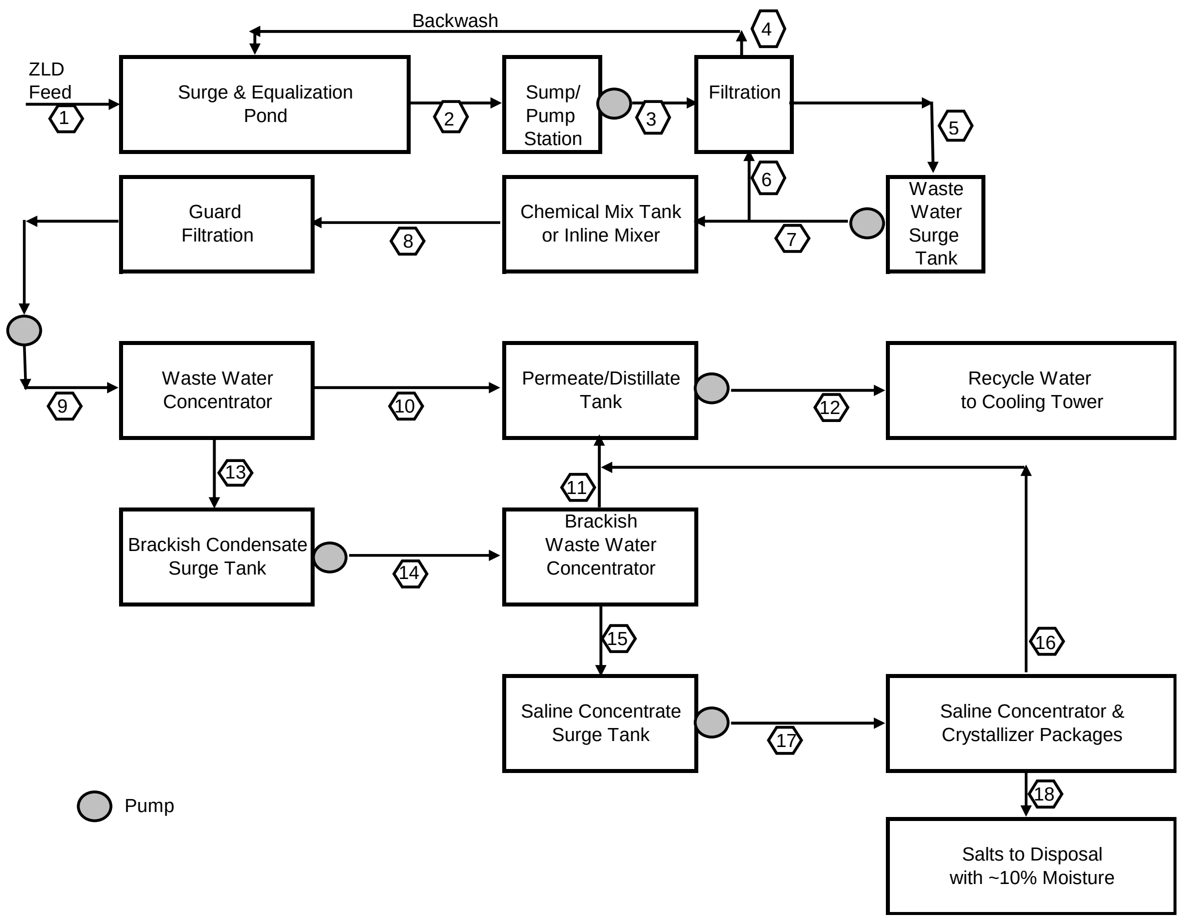


Table 4-1 below indicates the flows and estimated TDS levels at key points (noted in Figure 4-1 above) throughout the ZLD System.

Table 4-1 - ZLD Stream Table

Stream No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Average Case	890	890	890	0	890	0	890	890	890	668	166	888.6	222	222	56	54.6	56	1.4
Peak Case	1,300	1,300	1,300	0	1,300	0	1,300	1,300	1,300	975	244	1,298	325	325	81	79	81	2
Approximate TDS	1,357	1,357	1,357	0	1,357	0	1,357	1,357	1,357	2	73	33	5,423	5,423	21,473	288	21,473	840,410

All of the ZLD feeds will be directed to the Surge and Equalization Pond. Surge and equalization capacity is required to enable system maintenance to be accomplished and to handle intermittent surges of water to regain operational control or balance concentrations in the chemical treatment programs. Accommodation of variable stream compositions and diluting effects from storm water inputs is also a process need to allow downstream systems to operate in an approach to steady state conditions. These needs would be met by the pond described in **Section 4.1** and do not increase the capacity requirements for that pond. A pond would be double lined storage with leak detection and leachate collection. A divided capacity pond system will be provided such that one side can be cleaned of solids from the feed and the backwash from filtration. The second half of the pond would continue to operate during these times.

Settled solids would be removed from the pond on a periodic basis and disposed of off-site at an approved disposal facility.

A common sump with isolation from either side of the pond would be provided with pumps to transfer the feed into the ZLD system or directly to the cooling towers as makeup.

ZLD inlet filtration is required to limit TSS in downstream equipment, especially membrane based systems with extremely small pore diameters. Anthracite coal or activated carbon is typically used as filter media, which allow backwashing and low attrition as well as protection from trace incoming organic compounds.

Backwash for the filters is directed back to the Surge and Equalization Pond where suspended solids will settle out and water is then recycled to the ZLD system.

After passing through the filters the filtered wastewater is directed to a Surge Tank which provides capacity to allow short-term downstream equipment maintenance activities and as a reservoir for backwash water for the filtration equipment.

Pumps take suction from the Surge Tank and pump it through conditioning equipment. Conditioning is a generic term for pH adjustment, anti-scale addition and fine filtering (guard filtration) used in front of wastewater concentrator membrane systems.

After passing through the conditioning equipment pumps increase the wastewater’s pressure before entering the first stage of wastewater concentration.

Concentration is a generic term used for describing physical and molecular separation of solids from wastewater. Modern membrane based systems such as reverse osmosis (RO) and electrodialysis reversal (EDR) act as molecular/ion filters under high to medium pressures, respectively. Concerns with membrane fouling, scaling, and blinding require the upstream conditioning identified above. These conditioning needs and other special design items are what ultimately control the efficiency of water recovery.

Concentrator reject waters typically vary from 10-50% of concentrator feed flow, depending on operating pressures and membrane conditions. Brackish Concentrate Surge Tank capacity is provided after the first concentrator to allow short-term downstream equipment maintenance activities and as a reservoir for backwashing concentration equipment with or without cleaning chemical addition.

Recovered water (permeate) from the concentrator is directed into a Permeate/Distillate Tank from which it is pumped back to the recycle water users.

High pressure pumps take suction from the Brackish Concentrate Surge Tank and pass it through a second concentrator for further water recovery.

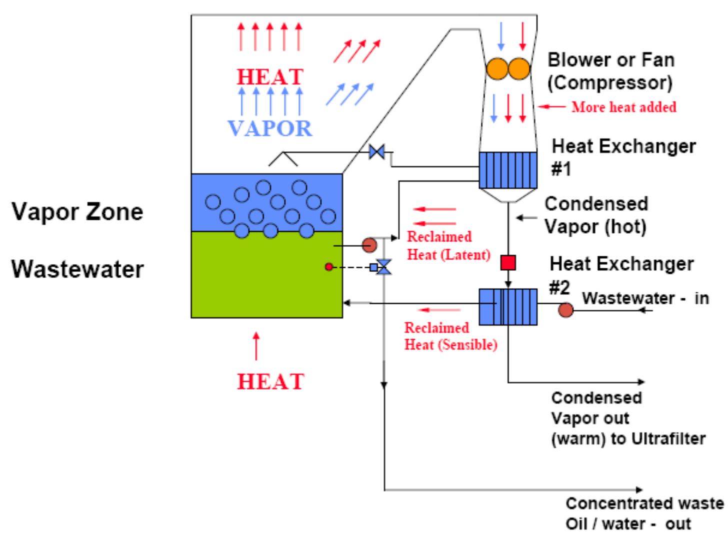
Recovered water is again directed into the Permeate/Distillate Tank while rejected water is directed into a Saline Concentrate Surge Tank.

From the Saline Concentrate Surge Tank the concentrated wastewater is pumped to the Saline Concentrator and Crystallizer equipment.

A mechanical vapor recompression (MVR) type evaporator, which can use 15-20 times less energy, was selected over a simple cycle evaporator. The MVR evaporator efficiency is accomplished by employing electrical energy to drive a compressor to boost the pressure of steam from the evaporator, so that it can be condensed against recirculated feed and provide the driving energy for the system after initial startup on imported steam. Refer to Figure 4-2 for a generic MVR design.

Figure 4-2

Basic Mechanical Vapor Compression Evaporator Model



The high levels of dissolved solids entering an evaporator act to increase the boiling point well beyond that of pure water. For instance, seawater with a TDS of approximately 30,000 mg/l exhibits a boiling point elevation of less than 1°F. While saturated sodium chloride at 360,000 mg/l has a boiling point elevation of about 13°F. This boiling point elevation represents a challenge for vapor-compression evaporation in that it increases the pressure ratio that the steam compressor must attain to effect vaporization. Since boiling point elevation determines the pressure ratio in the compressor, it is the main overall factor in operating costs.

Crystallizer operations are tightly linked with the pre-crystallizer concentrator as the high solids concentration feed is taken to its saturation point, creating a "mother liquor" from which solids are precipitated and removed via a centrifuge or other separation or filtration device. Control of the mother liquor concentration is critical to producing a manageable amount of suspended salt crystals and separating them on a routine basis. The controlled continued evaporation of water drives recovery rates, thus steady state operations are highly desirable. The solids disposal objective is production of a 10% moisture content paste, suitable for off-site landfill disposal in an approved facility. Recovered water from the Saline Concentrator and Crystallizer equipment is returned to the Permeate/Distillate Tank.

4.3 System Redundancy and Capacity Requirements

The systems will be able to meet the criteria of processing the required quantity of wastewaters anticipated. Below is the preliminary philosophy to accomplish this.

Pumps throughout the systems including for chemical feed will have spares installed. During detailed engineering arrangements such as 2 – 100%, 3 – 50%, 4 – 33%, etc. will be employed. Tanks in the systems will not have any redundancy.

The Surge and Equalization Pond for each phase will be a single pond which will be divided into two areas such that cleaning of solids can occur in one side while the other is in use. Should an event occur and the complete capacity is required an overflow to the isolated area will be provided such that no water is discharged from the site.

A common sump with pumps installed will be provided with the capability of isolating each side of the pond from the sump. Pumps with redundancy will be provided to transfer the water to the cooling towers or the ZLD system as required.

The pumps in the sump will provide the necessary pressure to pass the water through the ZLD inlet filters. These filters are normally very reliable and an arrangement where the number of filters that are required to process the wastewater during peak period flows will be provided. During backwashing of the filters the surge capacity of the Surge and Equalization Pond will be used until the backwash unit is returned to service.

The guard filters prior to the wastewater concentrator will have a spare filter such that cleaning of one can occur while the system is processing the full throughput.

The concentrators are membrane stacks of multiple vessels. The number of stacks to be provided will be developed during detailed engineering but the sparing philosophy will be that the throughput can be processed while a unit is in its regeneration and/or cleaning mode.

Spare capacity will be built into the ZLD system, but if for some reason a component within the system cannot process the required throughput, the flow through the system will backup into the preceding process storage unit and back through the system until ultimately the Surge & Equalization Pond capacity would be used. For example (see Figure 4-1), if a unit in the Waste Water Concentrator could not process the output from the Guard Filtration system, flow through the Guard Filtration system would be reduced accordingly by controlling the pumps at the outlet of the Waste Water Surge Tank. Once the high level in the Waste Water Surge Tank was reached, one or more of the Sump Pumps taking suction from the Surge & Equalization Pond would shutdown and the level in the pond would begin to rise. After the portion of the system that was not able to process the required throughput returned to service this wastewater in the pond would then be processed through the system over time to return the pond to normal operating level.

As described in **Section 4.1**, the capacity of the Surge and Equalization Pond was determined by the worst-case conditions, i.e., the 24-hr, 100-yr storm during a plant outage. Flow backups caused by partial or complete outages of the ZLD system would not increase the capacity required for the Surge and Equalization Pond. This is because such backups would only occur during plant operation, when the rainfall could be worked off by evaporation from the cooling towers at a rate as high as 3-5,000 gpm, while flow backups from the ZLD system could not exceed 1,300 gpm.

Outside of significant precipitation events, the Surge and Equalization Pond theoretically has capacity to store peak ZLD treatment flows (of 1,300 gpm) for six days. Most of that capacity would be reserved in case a precipitation event did occur, but due to the large size of the pond and the high availability provided by redundant design of the ZLD system, it would be extremely rare that the power plant would need to shut down due to a complete outage of the ZLD system.

4.4 Waste Streams Generated

The waste streams that would be generated as a result of the systems are as follows:

- Solids that would settle out in the cooling tower basins which are periodically cleaned out.
- Solids sludge that would settle out in the Surge and Equalization Pond which are periodically cleaned out.
- Salts generated by the Saline Concentrator and Crystallizer equipment which would contain approximately 10% moisture.

These streams would be transported off-site for disposal in approved facilities. All trace elements that are in the feed to the ZLD system would be retained in the above streams.

The only vent to the atmosphere would be a small moisture vent from the Saline Concentrator and Crystallizer equipment.

4.5 Future Considerations

During the detailed design of the facility further analysis of the water usages and discharges to the ZLD systems within the plant will be undertaken. The ultimate end product of these analyses is to reduce the inlet raw water demands economically.

One primary area where this will be addressed is the COC for the facility's cooling towers. Should higher COC occur, lower raw water needs and lower feed to the ZLD would result.

As noted in Appendix H of the DOE/EIS-0382D Draft Environmental Impact Statement, cooling tower particulate matter emissions from cooling tower drift will increase as the COC at which the cooling towers operate increases. These potentially additional emissions are not addressed further in the report.

5.0 REFERENCES

The following references were used in preparation of this report.

- Application to the Minnesota Pollution Control Agency for a National Pollution Discharge Elimination System Permit, dated June 18, 2006
- Joint Application to the Minnesota Public Utilities Commission for the following Pre-Construction Permits: Large Electric Generating Plant Site Permit, High Voltage Transmission Line Route Permit and Natural Gas Pipeline Routing Permit, dated June 16, 2006
- US DOE Clean Coal Power Initiative Round 2, Project 342 Fact Sheet, 12/06
- MPCA Design Flow and Loading Determination Guidelines for Wastewater Treatment Plants, Water/Wastewater Technical Review and Guidance/#5.20, February 2002
- Issue Paper "B", Precipitation Frequency Analysis And Use, January 6, 2005, To: Minnesota Stormwater Manual Sub-Committee, From: Emmons & Oliver Resources and Center for Watershed Protection
- Technical Paper No. 40, Rainfall Frequency Atlas of the United States for Durations from 30 Minutes to 24 Hours and Return Periods from 1 to 100 years

APPENDIX 1 – Average Raw Water Analyses

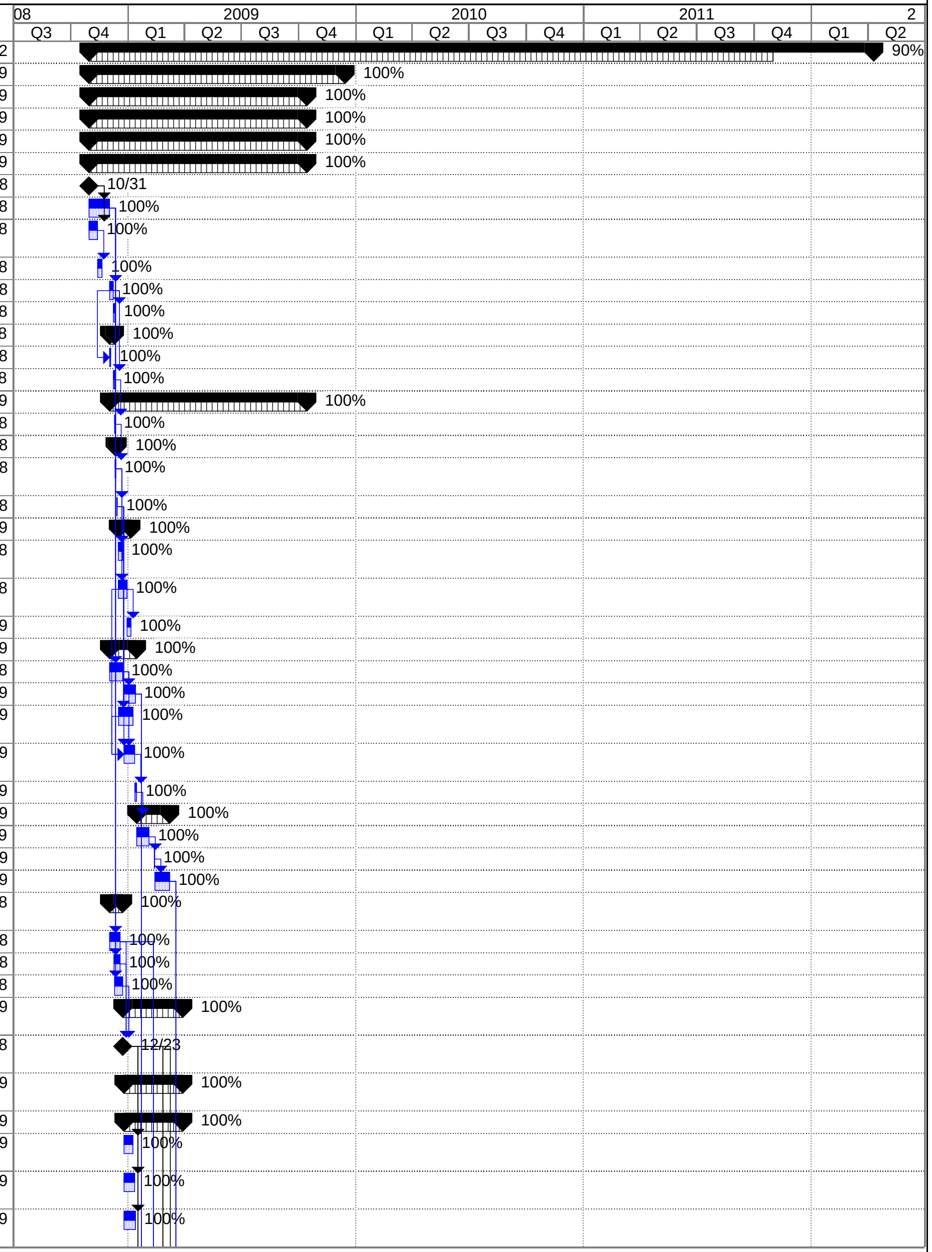
Raw Water Analysis and Future Mix

		gpm Mix % Mix	2800 58% CMP	2000 42% HAMP	<DL	Equiv.
Aluminum	mg/L		0.0125	0.0125	1/2	0.013
Antimony	mg/L					0.000
Arsenic	mg/L					0.000
Barium	mg/L		0.028	0.0297		0.029
Beryllium	mg/L					0.000
Cadmium	mg/L		0.005	0.005	1/2	0.005
Calcium	mg/L		55.3	58.6		56.7
Chromium, total	mg/L		0.005	0.005	hex	0.005
Copper	mg/L		0.005	0.005	1/2	0.005
Iron	mg/L		0.025	0.025	1/2	0.025
Lead	mg/L					0.000
Magnesium	mg/L		40.8	20.5		32.3
Manganese	mg/L		0.01	0.01	1/2	0.010
Mercury	mg/L		9E-07	9E-07		0.000
Nickel	mg/L		0.0025	0.0025	1/2	0.003
Potassium	mg/L					0.000
Selenium	mg/L		0.001	0.001	1/2	0.001
Silver	mg/L					0.000
Sodium	mg/L		6.6	6.2		6.4
Strontium	mg/L					0.000
Zinc	mg/L		0.005	0.005	1/2	0.005
INORGANICS						
Alkalinity-Bicarbonate	mg/L					0.000
Alkalinity-Carbonate	mg/L					0.000
Carbon Dioxide (aq)	mg/L					0.000
Chloride	mg/L		5.15	5.2		5.2
Cyanide, free	mg/L					0.000
Fluoride	mg/L					0.000
Nitrate (as N)	mg/L					0.000
o-Phosphate	mg/L					0.000
Sulfate	mg/L		103.5	59.5		85.2
Silica	mg/L					0.000
pH	pH		8.4	8.3		8.358
Solids (TS)	mg/L					0.000
Total Suspended Solids:	mg/L					0.000
BULK PROPERTIES						
Hardness as CACO3			308	229		275.083
Alkalinity			180	163		172.917
TDS			337	254		302.417
Sp. Conductivity	umhos/cm		476	418		451.833
BOD			1	1	1/2	1.000
COD			1	1	1/2	1.000
TOC			1.9	1.9		1.900
TSS			1.5	1.5		1.500
NH3-N			0.05	0.05	1/2	0.050
P, T			0.05	0.05	1/2	0.050

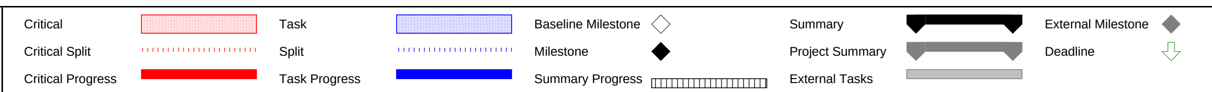
Microsoft Project Schedule of Environmental Permitting Milestones

Mesaba Energy Project Permitting Milestones

ID	Task ID	Task Name	Finish
1	1	Site/Route Licensing	Tue 4/10/12
2	1.1	Finalization of EIS	Tue 12/15/09
3	1.1.1	PFEIS	Thu 10/15/09
4	1.1.1.1	DEIS Studies	Thu 10/15/09
5	1.1.1.1.1	Class I Area Impacts	Thu 10/15/09
6	1.1.1.1.1.1	Finalize Class I Area Modeling Protocol	Thu 10/15/09
7	1.1.1.1.1.1.1	Submit Class I Area Modeling Protocol to FLMs	Fri 10/31/08
8	1.1.1.1.1.1.2	FLMs Review Protocol & Provide Comments to Excelsior	Tue 12/2/08
9	1.1.1.1.1.1.3	Conduct Model Sensitivity Runs in Anticipation of Establishing Final Model Runs	Thu 11/13/08
10	1.1.1.1.1.1.4	Draft Schedule to Complete Modeling	Thu 11/20/08
11	1.1.1.1.1.1.5	Excelsior Drafts Responses to FLM Comments	Mon 12/8/08
12	1.1.1.1.1.1.6	FLMs Review Excelsior Responses	Thu 12/11/08
13	1.1.1.1.1.1.7	FLM Conference Call Preparations	Wed 12/10/08
14	1.1.1.1.1.1.7.1	Model Run Analysis	Thu 12/4/08
15	1.1.1.1.1.1.7.2	Pre-Call Conferences	Wed 12/10/08
16	1.1.1.1.1.1.8	Conference Call w/FLMs & Follow-up	Thu 10/15/09
17	1.1.1.1.1.1.8.1	Conference Call w/FLMs	Thu 12/11/08
18	1.1.1.1.1.1.8.2	Conference Call Follow-Up	Mon 12/15/08
19	1.1.1.1.1.1.8.2.1	Technical Subgroup Conference Call to Resolve Outstanding Issues	Fri 12/12/08
20	1.1.1.1.1.1.8.2.2	Technical Subgroup Debrief	Mon 12/15/08
21	1.1.1.1.1.1.8.3	Further Analysis (TRC)	Tue 1/6/09
22	1.1.1.1.1.1.8.3.1	Generate 4 km Wind Fields (CALMET) for Comparison Purposes	Tue 12/23/08
23	1.1.1.1.1.1.8.3.2	Demonstrate Superiority of Fine Resolution Grid (1 km vs. 4 km Grid Size)	Tue 12/30/08
24	1.1.1.1.1.1.8.3.3	Analyze Impact of Background Ammonia Concentration	Tue 1/6/09
25	1.1.1.1.1.1.8.4	Revise Protocol	Thu 1/15/09
26	1.1.1.1.1.1.8.4.1	Define Worst-Case Flaring/Start-up Emissions	Tue 12/23/08
27	1.1.1.1.1.1.8.4.2	Integrate Worst-Case Flaring/Start-Up Emissions Into Model	Tue 1/13/09
28	1.1.1.1.1.1.8.4.3	Add Clarifications Promised During Technical Subgroup Follow-Up (Evaluate Rmax, TERRAD, Buoy Data, Inventory,	Fri 1/9/09
29	1.1.1.1.1.1.8.4.4	Draft Revised Addendum for Protocol & Circulate for Internal Comment	Mon 1/12/09
30	1.1.1.1.1.1.8.4.5	Finalize Protocol & Addendum and Submit to FLMs	Thu 1/15/09
31	1.1.1.1.1.1.8.5	Agreement on Final Class I Modeling Protocol Achieved	Mon 3/9/09
32	1.1.1.1.1.1.8.5.1	Conduct Conference Call to Confirm FLMs' Position	Wed 2/4/09
33	1.1.1.1.1.1.8.5.2	Conduct Follow-Up Call to Resolve Differences	Fri 2/13/09
34	1.1.1.1.1.1.8.5.3	FLMs Provide Confirming Letter Regarding Final Protocol	Mon 3/9/09
35	1.1.1.1.1.1.8.6	Obtain PSD Increment Consuming/Expanding Inventories (Excelsior/MMA)	Tue 12/23/08
36	1.1.1.1.1.1.8.6.1	Minnesota Sources	Fri 12/19/08
37	1.1.1.1.1.1.8.6.2	Wisconsin Sources	Fri 12/19/08
38	1.1.1.1.1.1.8.6.3	Michigan Sources	Tue 12/23/08
39	1.1.1.1.1.1.8.7	QA/QC Inventory Information to Confirm Increment Expanding/Consuming SO2/PM10 Sources	Mon 3/30/09
40	1.1.1.1.1.1.8.7.1	Assign TRC Task of Reviewing Power Plant & Agency Increment Files Provided	Tue 12/23/08
41	1.1.1.1.1.1.8.7.2	Obtain Existing Protocol Emission Inventories for MSI, Mesabi Nugget, & Keewatin Taconite & Provide to TRC	Mon 3/30/09
42	1.1.1.8.7.2.1	Class I & Class II Increment Data: SO2 & PM10	Mon 3/30/09
43	1.1.1.8.7.2.1.1	Obtain & Forward Minnesota Steel Class I Modeling Files from MPCA	Fri 1/9/09
44	1.1.1.8.7.2.1.2	Obtain & Forward Class I Protocol and Model Inputs for Keewatin Taconite Project from Howard Gebhart	Mon 1/12/09
45	1.1.1.8.7.2.1.3	Obtain & Forward Mesabi Nugget II Class I CALPUFF Modeling Files from Howard Gebhart	Tue 1/13/09



Project: MEP Permitting Work Plan 01
Date: Fri 11/9/12



Mesaba Energy Project Permitting Milestones

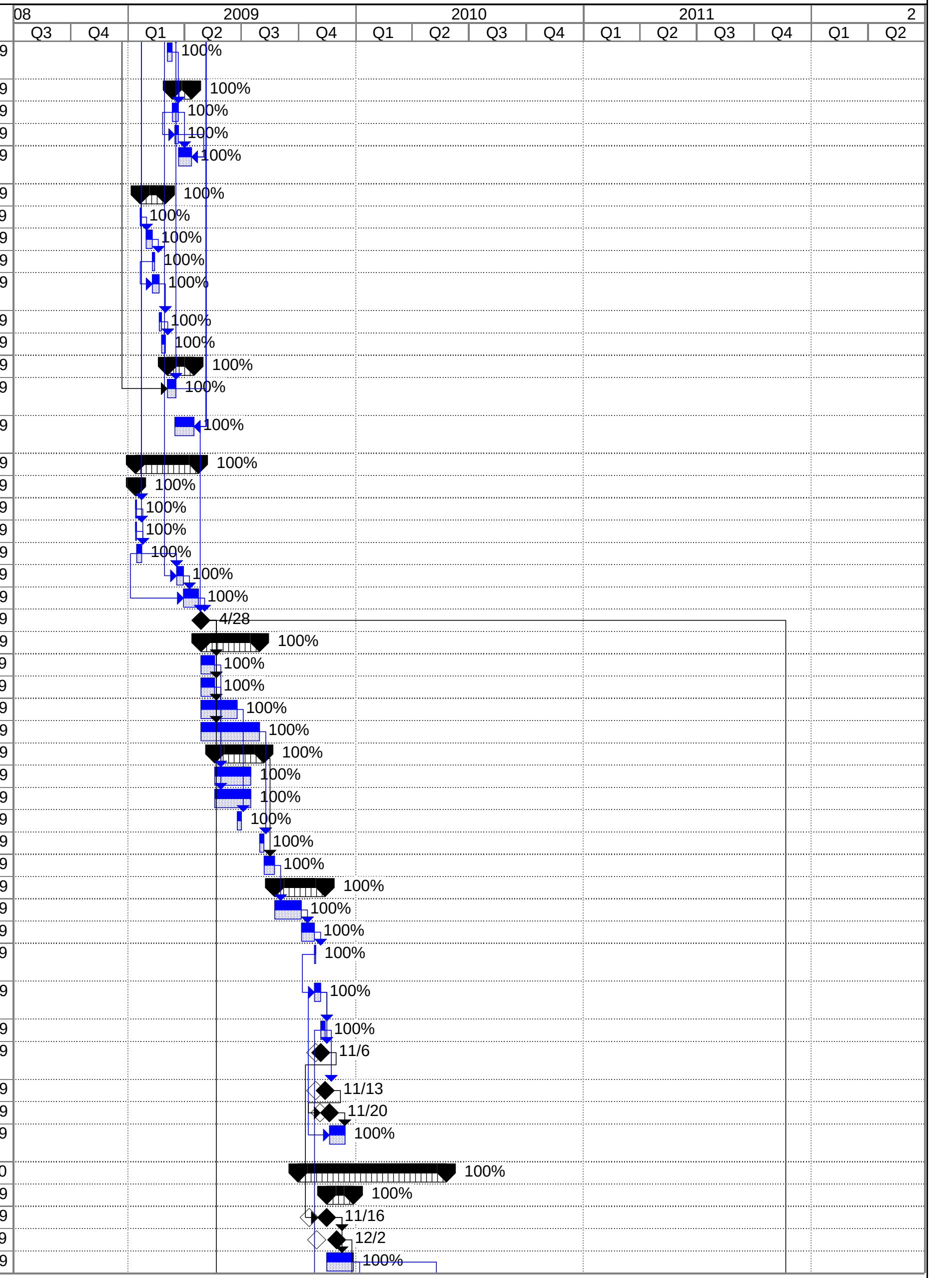
ID	Task ID	Task Name	Finish	08 / 2009 / 2010 / 2011 / 2 (Q3 Q4 Q1 Q2 Q3 Q4 Q1 Q2 Q3 Q4 Q1 Q2 Q3 Q4 Q1 Q2)
46	1.1.1.8.7.2.1.4	TRC Conducts QA/QC of Increment Expanding/Consuming Source Emissions & Protocol	Mon 3/30/09	100%
47	1.1.8.7.2.1.4.1	SO2	Wed 3/18/09	100%
48	1.1.8.7.2.1.4.2	PM-10 (SO2 Sources)	Thu 3/26/09	100%
49	1.1.8.7.2.1.4.3	NOX (SO2 Sources)	Mon 3/30/09	100%
50	1.1.1.1.8.7.2.2	Class II NAAQS: Existing Information	Tue 3/24/09	100%
51	1.1.1.8.7.2.2.1	Obtain & Forward Mesabi Nugget I Class II NAAQS Modeling Files from Barr Engineering	Tue 1/13/09	100%
52	1.1.1.8.7.2.2.2	Obtain Class II NAAQS Modeling Information from MPCA: Keewatin Taconite	Wed 3/18/09	100%
53	1.1.1.8.7.2.2.3	Obtain and Forward Minnesota Steel Class II NAAQS Modeling from Barr Engineering	Tue 3/24/09	100%
54	1.1.1.1.1.1.8.8	QAQC Class II NAAQS Database	Fri 3/27/09	100%
55	1.1.1.1.1.8.8.1	Review NAAQS Source Information Previously Provided by MPCA & Cross-Check With More Recent Information Obtained	Thu 3/26/09	100%
56	1.1.1.1.1.8.8.2	Review Information on MPCA Permitting Databases	Fri 3/27/09	100%
57	1.1.1.1.1.1.8.9	Finalize Class I Inventory Databases & Provide to Agencies and FLMs for Review & Comment	Mon 6/1/09	100%
58	.1.1.1.1.1.8.10	Obtain Input from EPA/MPCA	Thu 10/15/09	100%
59	1.1.1.1.1.2	Final AQRV/Increment Modeling	Fri 4/17/09	100%
60	1.1.1.1.1.2.1	Establish Offset Scenarios	Thu 1/22/09	100%
61	1.1.1.1.1.2.1.1	West Range	Thu 1/22/09	100%
62	1.1.1.1.1.2.1.2	East Range	Thu 1/22/09	100%
63	1.1.1.1.1.2.2	Set Up & Run Final 2002-2004 36 km MM5/1 km Gridded Domain (CALPUFF, POSTUTIL, CALPOST)(TRC)	Fri 2/27/09	100%
64	1.1.1.1.1.2.2.1	Set Up and Conduct Single Source AQRV & Increment Runs	Wed 12/31/08	12/31
65	1.1.1.1.1.2.2.2	Tabulate AQRV & Increment Runs	Fri 1/16/09	1/16
66	1.1.1.1.1.2.2.3	Set Up & Conduct Multisource SO2 Inventory Runs	Fri 1/23/09	1/23
67	1.1.1.1.1.2.2.4	Tabulate Multi-Source SO2 Increment Run Results	Fri 2/27/09	2/27
68	1.1.1.1.1.2.3	Set Up & Run Single Source AQRVs and Concentration for 2002-2004 36 km MM5/4 km Gridded Domain (Method 2 & Method 8 Runs)	Mon 4/13/09	100%
69	1.1.1.1.1.2.3.1	Process 36 km MM5 Data for 4 km Grid as Per FLM Directive to Generate CALMET Wind Fields for Domain	Fri 3/13/09	100%
70	1.1.1.1.1.2.3.2	Extinction, Deposition, & Concentration	Mon 4/13/09	100%
71	1.1.1.1.2.3.2.1	West Range: Method 2/8	Mon 3/23/09	100%
72	1.1.1.2.3.2.1.1	Mesaba One: Baseline BACT Emission Rates: 4 Runs	Wed 3/18/09	100%
73	1.1.1.2.3.2.1.2	Mesaba Two:Baseline BACT Emission Rates: 2 Runs	Fri 3/20/09	100%
74	1.1.1.2.3.2.1.3	Mesaba Two: Beyond BACT Emission Rates: 2 Runs	Mon 3/23/09	100%
75	1.1.1.1.2.3.2.2	East Range: Method 2/8	Mon 3/30/09	100%
76	1.1.1.2.3.2.2.1	Mesaba One: Baseline BACT Emission Rates: 4 Runs	Thu 3/19/09	100%
77	1.1.1.2.3.2.2.2	Mesaba Two: Baseline BACT Emission Rates: 3 Runs	Wed 3/25/09	100%
78	1.1.1.2.3.2.2.3	Mesaba Two: Beyond BACT Emission Rates: 2 Runs	Mon 3/30/09	100%
79	1.1.1.1.2.3.2.3	Post Process, Tabulate & Analyze Class I Extinction, Deposition & Concentration Results	Mon 4/13/09	100%
80	1.1.1.2.3.2.3.1	West Range	Mon 4/13/09	100%
81	1.1.1.2.3.2.3.2	East Range	Mon 4/13/09	100%
82	1.1.1.1.1.2.4	Cumulative Analyses Modeling & Offsets: 2002-2004 36 km MM5/4 km Gridded Domain	Mon 4/13/09	100%
83	1.1.1.1.1.2.4.1	Cumulative SO2 Increment Analysis	Fri 4/10/09	100%
84	1.1.1.1.2.4.1.1	Set Up & Run Cumulative SO2 Increment Impacts Analysis Using Revised Inventory	Wed 3/25/09	100%
85	1.1.1.1.2.4.1.2	Post Process, Tabulate & Analyze Cumulative Increment Impacts Analysis Using Updated Inventory	Fri 4/10/09	100%
86	1.1.1.1.1.2.4.2	Cumulative PM10 Increment Analysis	Mon 4/13/09	100%
87	1.1.1.1.2.4.2.1	Set Up & Run Cumulative PM10 Increment Impacts Analysis Using Revised Inventory	Thu 4/2/09	100%
88	1.1.1.1.2.4.2.2	Post Process, Tabulate & Analyze Cumulative Increment Impacts Analysis Using Updated Inventory	Mon 4/13/09	100%
89	1.1.1.1.1.2.5	Set Up & Run Single Source AQRVs and Concentration for 2002 12 km MM5/1 km Gridded Domain (Method 2 & Method 8 Runs)	Mon 4/13/09	100%

Project: MEP Permitting Work Plan 01
Date: Fri 11/9/12

Critical | Task | Baseline Milestone | Summary | External Milestone
Critical Split | Split | Milestone | Project Summary | Deadline
Critical Progress | Task Progress | Summary Progress | External Tasks

Mesaba Energy Project Permitting Milestones

ID	Task ID	Task Name	Finish
90	1.1.1.1.1.2.5.1	Process 12 km MM5 Data for 1 km Grid as Per FLM Directive to Generate CALMET Wind Fields for Domain	Fri 3/13/09
91	1.1.1.1.1.2.5.2	Extinction, Deposition, & Concentration	Mon 4/13/09
92	1.1.1.1.2.5.2.1	West Range: Method 2/8	Mon 3/23/09
93	1.1.1.1.2.5.2.2	East Range: Method 2/8	Mon 3/23/09
94	1.1.1.1.2.5.2.3	Post Process, Tabulate & Analyze AQRV Single Source Runs	Mon 4/13/09
95	1.1.1.1.1.2.6	Plume Impairment	Mon 3/2/09
96	1.1.1.1.1.2.6.1	Research Potential Observer Outposts w/in 50 km of ER Site	Wed 1/21/09
97	1.1.1.1.1.2.6.2	Use VISCREEN to Assess Potential Plume Impairment Impacts	Mon 2/9/09
98	1.1.1.1.1.2.6.3	Preliminary Analyses at One Viewpoint (need Class II met data)	Fri 2/13/09
99	1.1.1.1.1.2.6.4	Integrate Plume Impairment Analysis via VISCREEN Into Protocol	Fri 2/20/09
100	1.1.1.1.1.2.6.5	Make Final VISCREEN Runs	Tue 2/24/09
101	1.1.1.1.1.2.6.6	Analyze Results & Integrate into Class I Air Modeling Report	Mon 3/2/09
102	1.1.1.1.1.2.7	Prepare Modeling Report & Submit to DOE/PHE	Fri 4/17/09
103	1.1.1.1.1.2.7.1	Start Drafting Text for Background Material (i.e., Protocol Development; Emission Scenarios; Inventory; Tables, 1 km grid	Thu 3/19/09
104	1.1.1.1.1.2.7.2	Tabulate Remaining Modeling Results, Finalize Report Text & Submit to DOE/PHE	Fri 4/17/09
105	1.1.1.1.2	Class II Ambient Air Quality Impacts	Fri 4/24/09
106	1.1.1.1.2.1	Set Up For New Class II Modeling Runs	Thu 1/15/09
107	1.1.1.1.2.1.1	West Range	Thu 1/15/09
108	1.1.1.1.2.1.2	East Range	Thu 1/15/09
109	1.1.1.1.2.2	Run & Analyze Class II AAQS/PSD Increment Single Source Impacts	Fri 1/23/09
110	1.1.1.1.2.3	Set Up & Run Cumulative SO2 Impacts Scenario	Tue 3/31/09
111	1.1.1.1.2.4	Prepare Final Interim Report & Submit to DOE/PHE	Fri 4/24/09
112	1.1.2	PFEIS Presented to U.S. DOE HQ & Cooperating Agencies	Tue 4/28/09
113	1.1.3	Comments Received from Cooperating Agencies, Fossil Energy & DOE HQ	Fri 7/31/09
114	1.1.3.1	FE-6	Wed 5/20/09
115	1.1.3.2	GS-20	Wed 5/20/09
116	1.1.3.3	USACE	Thu 6/25/09
117	1.1.3.4	USFS	Fri 7/31/09
118	1.1.4	Responses Prepared and Finalized	Fri 8/7/09
119	1.1.4.1	FE-6	Fri 7/17/09
120	1.1.4.2	GS-20	Fri 7/17/09
121	1.1.4.3	USACE	Thu 7/2/09
122	1.1.4.4	USFS	Fri 8/7/09
123	1.1.5	Publication of FEIS for NETL Concurrence	Mon 8/24/09
124	1.1.6	NETL Concurrence & Publication of FEIS	Fri 11/13/09
125	1.1.6.1	NETL Internal Review & Comment	Tue 10/6/09
126	1.1.6.2	NETL Evaluates Need for Further EIS Input	Tue 10/27/09
127	1.1.6.3	Integrate Responses to Comments Throughout FEIS (This Schedule Assumes No Significant Changes Are Required)	Thu 10/29/09
128	1.1.6.4	Print FEIS, NETL/DOE Sign Release Letter & Distribute Copies of FEIS to Congress	Fri 11/6/09
129	1.1.6.5	DOE Distributes FEIS to Remaining Parties	Fri 11/13/09
130	1.1.6.6	OES Provides Notice of Availability To EQB Monitor, Files EIS with ALJ, and Serves EIS to Public	Fri 11/6/09
131	1.1.6.7	DOE Provides USEPA Certification of Distribution	Fri 11/13/09
132	1.1.7	EPA Publishes Notice of Availability of FEIS in Federal Register	Fri 11/20/09
133	1.1.8	Excelsior Reviews Draft Notices, Provides Feedback & Logs Compliance with Administrative Procedures Established by Law	Tue 12/15/09
134	1.2	Site/Route Permitting Process	Wed 5/26/10
135	1.2.1	ALJ Report & Recommendation	Mon 12/28/09
136	1.2.1.1	FEIS NOA Published in EQB Monitor	Mon 11/16/09
137	1.2.1.2	Comments on FEIS Adequacy Due	Wed 12/2/09
138	1.2.1.3	ALJ Reviews FEIS & Releases Report & Recommendations	Mon 12/28/09



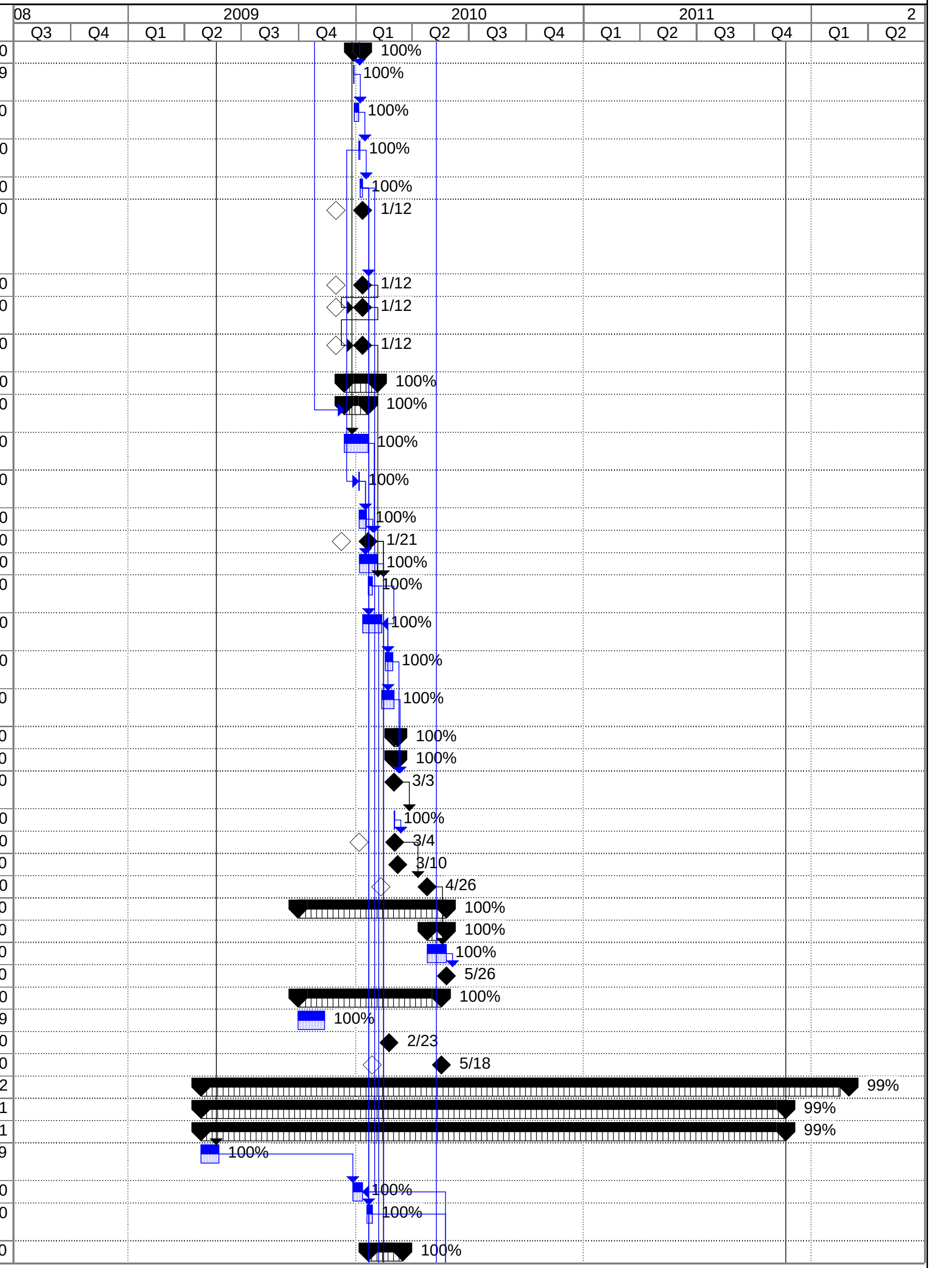
Project: MEP Permitting Work Plan 01
Date: Fri 11/9/12

Critical		Task		Baseline Milestone		Summary	
Critical Split		Split		Milestone		Project Summary	
Critical Progress		Task Progress		Summary Progress		External Tasks	

External Milestone
Deadline

Mesaba Energy Project Permitting Milestones

ID	Task ID	Task Name	Finish
139	1.2.2	File Excelsior's Exceptions To ALJ Report & Comments on EIS Adequacy	Tue 1/12/10
140	1.2.2.1	Excelsior Reviews ALJ Report, Comments on EIS Adequacy & Meets to Plan/Confirm Response	Tue 12/29/09
141	1.2.2.2	Excelsior Drafts Exceptions to ALJ Report, EIS Adequacy & Circulates for Internal Review	Wed 1/6/10
142	1.2.2.3	Excelsior Comments Integrated Into Internal Drafts; Meeting Conducted to Discuss Issues	Fri 1/8/10
143	1.2.2.4	Finalize Excelsior's Exceptions to ALJ Report, Comments on EIS Adequacy & Submi	Tue 1/12/10
144	1.2.2.5	Review Others' Exceptions (This Schedule Assumes No One But Parties Can Submit Exceptions; Since OES Is Only Other Party, Excelsior Would Be Submitting Exceptions, If Any, On OES Findings Once They Are Published)	Tue 1/12/10
145	1.2.2.5.1	Excelsior Reviews Others' Submittals & Meets to Plan Responses	Tue 1/12/10
146	1.2.2.5.2	Excelsior Drafts Responses to Others' Exceptions & Circulates for Internal Comments	Tue 1/12/10
147	1.2.2.5.3	Integrate Internal Comments, Finalize Comments to Others' Exceptions and File with MPUC	Tue 1/12/10
148	1.2.3	Excelsior Prepares Narrative of Revisions to Joint Application	Fri 2/5/10
149	1.2.3.1	Narrative of Revisions Prepared by Excelsior; Excelsior Undertakes Administrative Procedures to Comply With State Rules	Thu 1/21/10
150	1.2.3.1.1	Draft Letter for OES Confirming FEIS Represents Current Status of Project	Thu 1/21/10
151	1.2.3.1.2	Conference with Bill Storm; Obtain Input from Minnesota Department of Agriculture on Agricultural Mitigation Plan	Thu 1/7/10
152	1.2.3.1.3	Prepare Materials Requested	Mon 1/18/10
153	1.2.3.1.4	Document Published & Submitted to MPUC/OES	Thu 1/21/10
154	1.2.3.2	Excelsior Finalizes Agricultural Mitigation Plan & Submits to OES	Fri 2/5/10
155	1.2.3.3	Review Text of Site & Route Permits as Drafted by OES & Provide Comments	Thu 1/28/10
156	1.2.4	OES Prepares Report for Commissioners Recommending Adequacy of EIS, Evaluating ALJ's Findings, & Responding to Exceptions	Fri 2/12/10
157	1.2.5	Excelsior Meets to Assess Preparations Required for PUC's March 4th Deliberations	Mon 3/1/10
158	1.2.6	PUC Staff Reviews OES Report and Prepares Recommendation to MPUC Board	Wed 3/3/10
159	1.2.7	PUC Appearances	Wed 3/10/10
160	1.2.7.1	Excelsior Prepares Responses to OES'/PUC's Comments	Wed 3/10/10
161	1.2.7.1.1	Evaluate OES/PUC Comments, Permit Conditions & Prepare Oral Presentation	Wed 3/3/10
162	1.2.7.1.2	Present Oral Presentation	Thu 3/4/10
163	1.2.7.1.3	Final Decision of MPUC on EIS Adequacy and Site/Route Permits	Thu 3/4/10
164	1.2.7.1.4	PUC Issues Order Granting Site & Route Permits	Wed 3/10/10
165	1.2.8	PUC Decision Published in EQB Monitor & State Register	Mon 4/26/10
166	1.2.9	Potential Appeals	Wed 5/26/10
167	1.2.9.1	Site & Route Permits: West Range Site	Wed 5/26/10
168	1.2.9.1.1	Appeal Period	Wed 5/26/10
169	1.2.9.1.2	No Appeals Filed	Wed 5/26/10
170	1.2.9.2	PPA: Court of Appeals	Tue 5/18/10
171	1.2.9.2.1	Prepare & Submit Appellate Reply Brief	Thu 11/12/09
172	1.2.9.2.2	Oral Arguments	Tue 2/23/10
173	1.2.9.2.3	COA Decision	Tue 5/18/10
174	1.3	NSR Construction Authorization	Fri 3/2/12
175	1.3.1	Permit Application Update	Mon 11/21/11
176	1.3.1.1	Preparation, Publication & Filing of Air Permit Application Update	Mon 11/21/11
177	1.3.1.1.1	Conduct IGCC Permit Reviews (i.e., Tabulate Permit Conditions Established in Other Projects to Confirm Excelsior CD-01 Forms Include Such Limitations)	Wed 5/27/09
178	1.3.1.1.2	Update Table of BACT for Other "Traditional" Technologies	Tue 1/12/10
179	1.3.1.1.3	Review Literature Regarding Recent IGCC Project Status & Update Table of BACT Decisions Associated Therewith	Thu 1/28/10
180	1.3.1.1.4	Confirm Basis for Permit Application Update	Wed 3/17/10

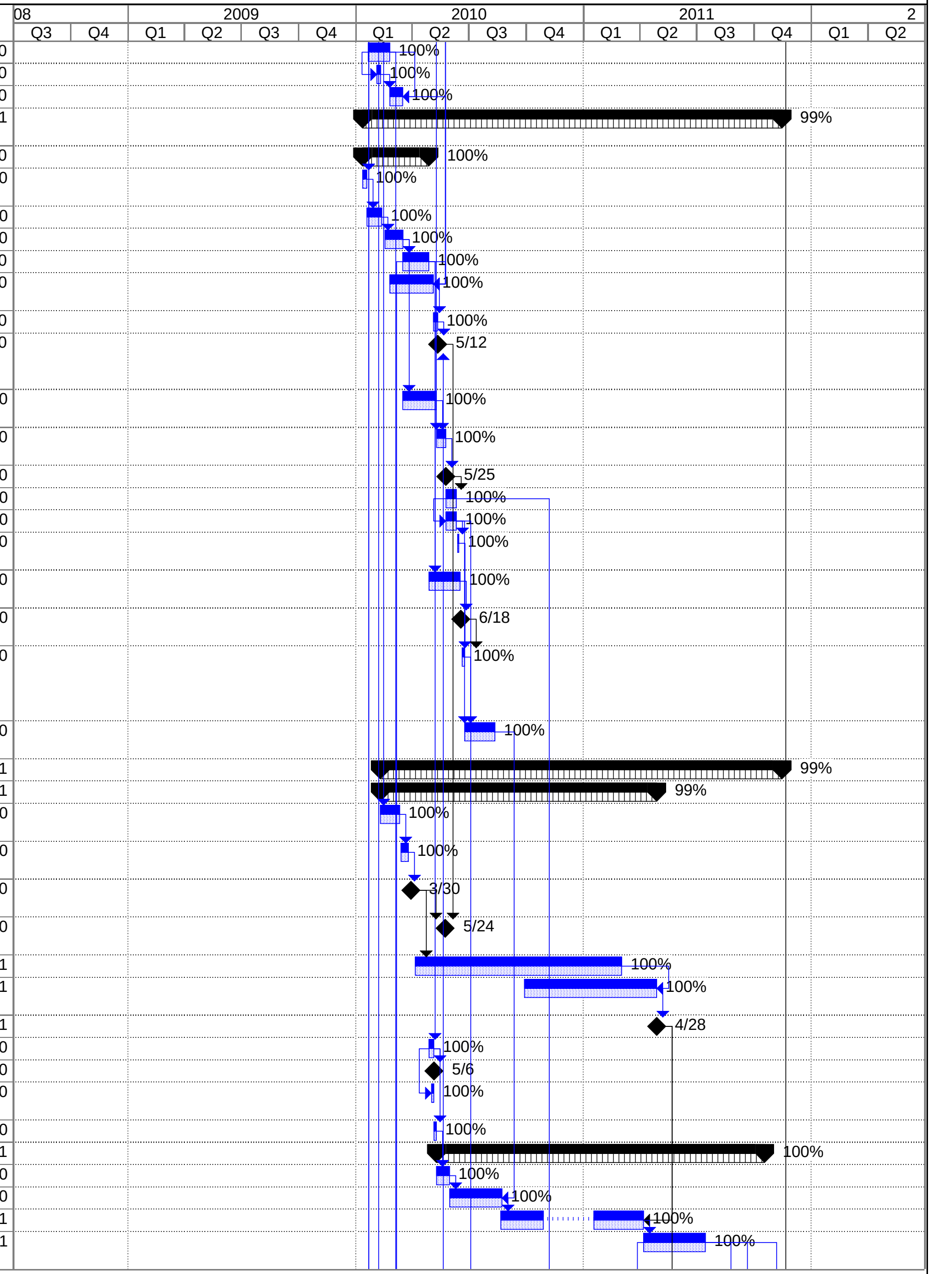


Project: MEP Permitting Work Plan 01
Date: Fri 11/9/12

Critical		Task		Baseline Milestone		Summary		External Milestone	
Critical Split		Split		Milestone		Project Summary		Deadline	
Critical Progress		Task Progress		Summary Progress		External Tasks			

Mesaba Energy Project Permitting Milestones

ID	Task ID	Task Name	Finish
181	1.3.1.1.4.1	Specify Strategic Options for Updating Application	Wed 2/24/10
182	1.3.1.1.4.2	Provide Project Update to Bob Wyman & Assess MDEA Support	Wed 2/10/10
183	1.3.1.1.4.3	Select Strategy	Wed 3/17/10
184	1.3.1.1.5	Prepare Position Paper Reassessing BACT Position for Mesaba One & Mesaba Two	Tue 11/15/11
185	1.3.1.1.5.1	Confirm MDEA Cost & Emission Rate on Fuel-by-Fuel Basis	Wed 4/28/10
186	1.3.1.1.5.1.1	Provide Fluor and ConocoPhillips (COP) Explanation of What is Required to Update Permit Application (i.e., SOW)	Tue 1/19/10
187	1.3.1.1.5.1.2	Obtain Input on SOW from Fluor and COP	Fri 2/12/10
188	1.3.1.1.5.1.3	Respecify SOW & Release Fluor and/or COP to Conduct Work	Thu 3/18/10
189	1.3.1.1.5.1.4	Fluor and/or COP Conduct SOW and Prepare Final Report	Wed 4/28/10
190	1.3.1.1.5.2	Prepare Draft BACT Analysis for Internal Review (SO2, NOX & PM); CO2 BACT On Hold	Wed 5/5/10
191	1.3.1.1.5.3	Finalize Draft BACT Analysis for Submittal to MPCA	Wed 5/12/10
192	1.3.1.1.5.4	Excelsior Submits BACT Analysis to MPCA Showing Trim Sulfur Removal and SCR; Other Criteria Pollutants & CO2 Intentionally Delayed	Wed 5/12/10
193	1.3.1.1.5.5	Confirm New Paradigm to Bob Wyman & Work to Arrange Meeting With USEPA	Mon 5/10/10
194	1.3.1.1.5.6	Prepare Project Update for USEPA (Requesting Input on BACT [SO2, NOX & CO2], Consideration in Preparing Rules, and Liaison Between Region V	Tue 5/25/10
195	1.3.1.1.5.7	Meet/Conference With USEPA & Region V	Tue 5/25/10
196	1.3.1.1.5.8	Confirm USEPA's HQ's Intent to Support Ongoing Liaison	Fri 6/11/10
197	1.3.1.1.5.9	"Trickle Down" USEPA HQ Intent to Region V, MPCA & FLMs	Fri 6/11/10
198	1.3.1.1.5.10	Inform MPCA of Company's Discussions With USEPA HQ & Region V and Interest in Conducting Joint Meeting	Tue 6/15/10
199	1.3.1.1.5.11	Fluor Confirms They Will Provide Commercial Guarantees for ZnO/SCR System	Thu 6/17/10
200	1.3.1.1.5.12	R.W. Beck Confirms Positive Perspective They Would Provide to Lenders Regarding ZnO/SCR System	Fri 6/18/10
201	1.3.1.1.5.13	Provide MPCA Verbal Description of Permitting Approach (i.e., Install ZnO/SCR on Mesaba One and Mesaba Two; Operate on Mesaba One Only to Extent Reduced Emissions Can Be Monitized; Operate Mesaba One At Reduced Emissions Until First Fire of Mesaba Two))	Thu 6/24/10
202	1.3.1.1.5.14	Finalize MEP-I/II BACT Emission Rates for SO2, NOX & PM for Initial Modeling Efforts	Thu 8/12/10
203	1.3.1.1.5.15	Update Modeling Sections (AQ & AERA)	Tue 11/15/11
204	1.3.1.1.5.15.1	Resolve AQ Modeling Inventory Concerns	Thu 4/28/11
205	.3.1.1.5.15.1.1	Conduct Modeling Studies of PolyMet Mining Emissions & Update Modeling Results	Fri 3/12/10
206	.3.1.1.5.15.1.2	Prepare Letter to MPCA Asking for Approval of Inventory & Involvement of USEPA	Fri 3/26/10
207	.3.1.1.5.15.1.3	Submit Letter Requesting MPCA & USEPA Comments on Emission Inventory	Tue 3/30/10
208	.3.1.1.5.15.1.4	Conduct Conference Call to Familiarize MPCA With Inventory and Methodology Used To Assemble It	Mon 5/24/10
209	.3.1.1.5.15.1.5	MPCA & USEPA Review Emission Inventory	Thu 3/3/11
210	.3.1.1.5.15.1.6	Update Emission Inventory As Per MPCA/USEPA/Internal Comments	Thu 4/28/11
211	.3.1.1.5.15.1.7	Finalize Complete Emission Inventory for Modeling	Thu 4/28/11
212	1.3.1.1.5.15.2	Finalize Stack Parameters & Forward to Fluor for Approval	Thu 5/6/10
213	1.3.1.1.5.15.3	Fluor Approves Stack Parameters	Thu 5/6/10
214	1.3.1.1.5.15.4	Prepare NTP and Other Materials to Initiate Visibility & NAAQS Modeling Efforts For Internal Purposes	Thu 5/6/10
215	1.3.1.1.5.15.5	Issue Limited NTP To MMA & TRC	Mon 5/10/10
216	1.3.1.1.5.15.6	Conduct Class II Modeling Studies	Tue 10/18/11
217	.3.1.1.5.15.6.1	Prepare Draft Protocol for Class II Modeling	Mon 5/31/10
218	.3.1.1.5.15.6.2	Review & Submit Protocol for Approval by MPCA & USEPA	Mon 8/23/10
219	.3.1.1.5.15.6.3	MPCA & USEPA Review & Approve Class II Protocol	Thu 4/7/11
220	.3.1.1.5.15.6.4	Conduct Modeling Studies & Prepare Draft Report for Internal Review	Fri 7/15/11



Project: MEP Permitting Work Plan 01
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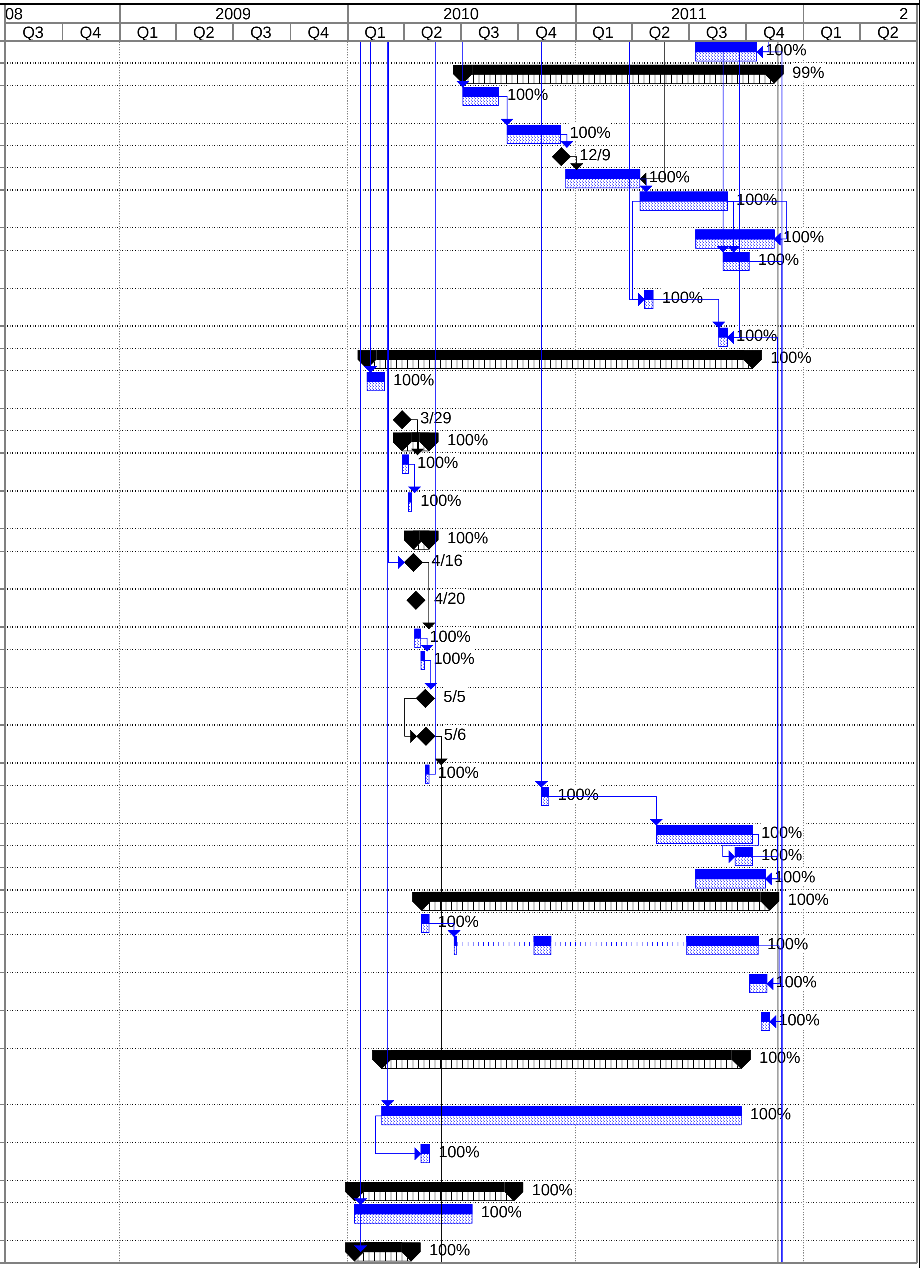
Critical | Task | Baseline Milestone | Summary | External Milestone
Critical Split | Split | Milestone | Project Summary | Deadline
Critical Progress | Task Progress | Summary Progress | External Tasks

Mesaba Energy Project Permitting Milestones

ID	Task ID	Task Name	Finish
221	.3.1.1.5.15.6.5	Finalize Modeling Report & Incorporate in Revised Application	Tue 10/18/11
222	1.3.1.1.5.15.7	Conduct Class I Modeling Studies	Tue 11/15/11
223	.3.1.1.5.15.7.1	Contact FLMs To Update Them on Project Status, Confirm New Emissions Paradigm, & Request Input on Existing Protocol	Mon 8/30/10
224	.3.1.1.5.15.7.2	Update Class I Modeling Protocol	Wed 12/8/10
225	.3.1.1.5.15.7.3	Submit Protocol for Approval by FLMs	Thu 12/9/10
226	.3.1.1.5.15.7.4	FLMs Review & Approve Class I Protocol	Thu 4/14/11
227	.3.1.1.5.15.7.5	Incorporate FLM Comments in Protocol, Conduct Modeling Studies & Prepare Draft Report for Internal Review	Thu 9/1/11
228	.3.1.1.5.15.7.6	Finalize Modeling Report & Incorporate in Revised Application	Tue 11/15/11
229	1.3.1.1.5.15.8	Update Air Emission Risk Assessment (AERA) & Incorporate in Revised Application	Thu 10/6/11
230	1.3.1.1.5.16	If Necessary, Conduct Design Review Reflecting Changes To Mitigate NAAQS, PSD Increment and/or AQRV Impacts	Thu 5/5/11
231	1.3.1.1.5.17	Update Emission Mitigation Plan, If Necessary	Thu 9/1/11
232	1.3.1.1.6	Integrate CO2 Into BACT Analysis	Tue 10/11/11
233	1.3.1.1.6.1	Review and Analyze Recent Permits and Decisions Relevant to GHG BACT Analysis	Mon 3/1/10
234	1.3.1.1.6.2	EPA Reconsideration of Johnson Memo on Regulated Pollutant	Mon 3/29/10
235	1.3.1.1.6.3	Assess Likelihood of Air Permit Being Issued Prior to January 2, 2011	Tue 5/11/10
236	1.3.1.1.6.3.1	Confirm DOE's Position on Supplementing EIS If Trim Sulfur Controls Added	Thu 4/8/10
237	1.3.1.1.6.3.2	Confirm OES Position On Supplementing EIS If Trim Sulfur and SCR Added to Controls	Tue 4/13/10
238	1.3.1.1.6.3.3	Confirm MPCA Position	Tue 5/11/10
239	1.3.1.1.6.3.3.1	Meet with MPCA to Discuss Permitting Approach & Present "Deal"; Request Response in One Week	Fri 4/16/10
240	1.3.1.1.6.3.3.2	Meet With Fluor to Confirm Feasibility & Cost of Trim Sulfur Using Zinc Oxide for SO2; SCR for NOX	Tue 4/20/10
241	1.3.1.1.6.3.3.3	Discuss MPCA's Response to Excelsior's "Deal" With DT & DS	Wed 4/28/10
242	1.3.1.1.6.3.3.4	Further Follow Up Discussions with DS & CS Regarding MPCA Staffing Approach	Tue 5/4/10
243	1.3.1.1.6.3.3.5	Conference With DT & DS to Confirm MPCA Position Regarding Schedule	Wed 5/5/10
244	1.3.1.1.6.3.3.6	Excelsior Confirms MPCA Will Not Take Necessary Steps to Issue Permit Before Year End	Thu 5/6/10
245	1.3.1.1.6.3.3.7	Excelsior & MPCA Prepare Schedules for Each Others' Review	Tue 5/11/10
246	1.3.1.1.6.4	Review of USEPA Guidance (Issued November 10, 2010) for Top-Down GHG BACT Analyses	Fri 11/19/10
247	1.3.1.1.6.5	Prepare Draft GHG BACT Analysis for Air Permit Application	Tue 10/11/11
248	1.3.1.1.6.6	Finalize Internal BACT Analysis of GHGs	Tue 10/11/11
249	1.3.1.1.7	Finalize BACT Analysis for All Pollutants	Tue 11/1/11
250	1.3.1.1.8	Update CD-01 & Other Forms	Tue 11/8/11
251	1.3.1.1.8.1	Work With Wenck to Organize & Update Old CD-01 Forms	Tue 5/11/10
252	1.3.1.1.8.2	Perform QA/QC and Continue Updating Forms to Assure Consistency With Which Compliance Data Are Presented	Fri 10/21/11
253	1.3.1.1.8.3	Distribute CD-01 Forms for Review and Comment; Meet to Discuss Required Changes	Fri 11/4/11
254	1.3.1.1.8.4	Incorporate Comments, Update Forms to Reflect Internal BACT Determinations, and Finalize Forms	Tue 11/8/11
255	1.3.1.1.9	Redline Text To Correct Errata, Partnership Corrections, Regulatory Changes, MPCA Clarifications, Update/Identify New Permit Applications, etc.	Fri 9/23/11
256	1.3.1.1.9.1	Review & Update Federal (i.e., NSPS, NESHAPs, CAIR & PSD-Related) & State Regulations	Fri 9/23/11
257	1.3.1.1.9.2	Address MPCA Questions Regarding Recent Regulatory Developments; Provide Courtesy Draft	Wed 5/12/10
258	1.3.1.1.10	Confirm Offsets for Mercury TMDL "Expected" Emissions	Fri 9/24/10
259	1.3.1.1.10.1	Develop Legal Position That TMDL Support Must Be Less Rigorous Than PSD	Mon 7/19/10
260	1.3.1.1.10.2	Confirm Vendors' Willingness to Provide Removal Guarantees	Tue 4/13/10



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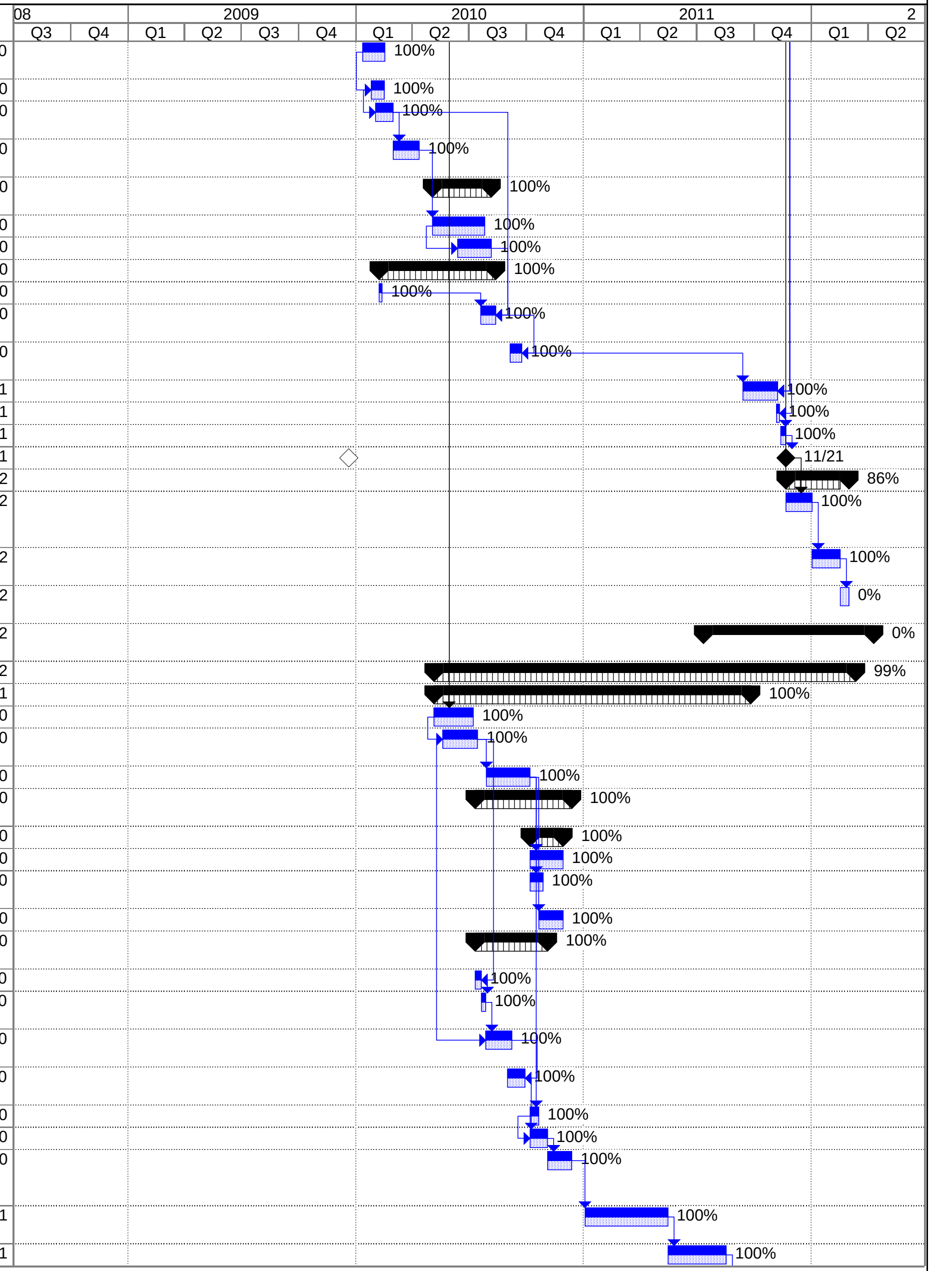
Mesaba Energy Project Permitting Milestones

ID	Task ID	Task Name	Finish
261	1.3.1.1.10.2.1	Research Relevant Mercury Removal Technology Options & Identify Vendors of Control Equipment	Wed 2/17/10
262	1.3.1.1.10.2.2	Determine the parameters specified for MEP	Tue 2/16/10
263	1.3.1.1.10.2.3	Contact catalyst providers, discuss removal technologies and tests conducted, and Issue SOW to Clarify Information Needs	Tue 3/2/10
264	1.3.1.1.10.2.4	Obtain Written Response Specifying Vendor Performance Commitments	Tue 4/13/10
265	1.3.1.1.10.3	Determine Proposed Emission Limit & Testing Program Supported by Vendor Guarantees and Endorsed by Excelsior's Principals	Fri 8/6/10
266	1.3.1.1.10.3.1	Propose Internal Mercury Limit for Sr. Management Approval	Tue 7/27/10
267	1.3.1.1.10.3.2	Finalize Mercury Limit for Permit Application	Fri 8/6/10
268	1.3.1.1.10.4	Develop Offset Contingency Plan	Fri 8/13/10
269	1.3.1.1.10.4.1	Obtain and Review Approved Hg Offset Plan and TMDL	Fri 2/12/10
270	1.3.1.1.10.4.2	Propose Potential Offset Plan for Approval by Excelsior Sr. Management	Fri 8/13/10
271	1.3.1.1.10.5	Draft, Review and Finalize Hg Offset Plan for Revised Permit Application	Fri 9/24/10
272	1.3.1.1.11	Complete Draft Update of Application & Release for Internal Review	Tue 11/8/11
273	1.3.1.1.12	Conduct Internal Review; Meet to Discuss Comments	Fri 11/11/11
274	1.3.1.1.13	Integrate Comments & Finalize Application	Mon 11/21/11
275	1.3.1.1.14	Copy Permit Application Update & Submit to MPCA & FLMs	Mon 11/21/11
276	1.3.2	Negotiate Draft Permit Conditions	Fri 3/2/12
277	1.3.2.1	Meetings with MPCA and FLMs to Consider Additional Work, If Any, to be Conducted By Excelsior In Support of Permit Application (i.e., Completeness Review)	Mon 1/2/12
278	1.3.2.2	Conduct Additional Work As Required to Obtain Completeness Determination & Re-Submit to MPCA	Fri 2/17/12
279	1.3.2.3	Preliminary Determination of Intent to Issue Permit (i.e., Reassessment of Completeness)	Fri 3/2/12
280	1.4	Other Appeals (Assume Adversely Affected Party Would Pursue Appeal via Minnesota Court of Appeals)	Tue 4/10/12
290	1.5	Water Appropriation Permit	Tue 3/13/12
291	1.5.1	Permit Application Update	Mon 9/26/11
292	1.5.1.1	Demonstrate Control of Riparian Rights to Water	Thu 7/8/10
293	1.5.1.2	Prepare Agenda & Materials for Meeting with MDNR to Discuss Permitting Issues	Thu 7/15/10
294	1.5.1.3	Meet With MDNR	Thu 10/7/10
295	1.5.1.4	Create Redline Version of Permit Application (Pump Station Design & Operation)	Mon 12/13/10
296	1.5.1.4.1	Confirm Water Supply Is Secure (Considers Contingencies)	Mon 11/29/10
297	1.5.1.4.1.1	Describe Pump Stations and Pumping Operations	Mon 11/29/10
298	1.5.1.4.1.2	Prepare Justification for Exclusion Zone(s) Around Water Intake Structures	Thu 10/28/10
299	1.5.1.4.2	Conduct Additional Studies & Incorporate into Application	Mon 11/29/10
300	1.5.1.4.3	Prepare Hydrological Monitoring Plan (Monitoring Well Installation, Modeling System, Data Collection & Analysis) & Specify Exclusion Zones	Thu 11/4/10
301	1.5.1.4.3.1	Establish Goals for Baseline Hydrogeological Monitoring Program	Wed 7/21/10
302	1.5.1.4.3.2	Identify Baseline Physical/Chemical Parameters to Be Analyzed for Each Critical Water Resource (to satisfy program goals)	Wed 7/28/10
303	1.5.1.4.3.3	Identify Baseline Hydrogeological Data Required to Address Program Goals	Wed 9/8/10
304	1.5.1.4.3.4	Prepare Draft Hydrogeological Monitoring Plan & Budget Requirements For Internal Review & Comment	Wed 9/29/10
305	1.5.1.4.3.5	Obtain MDNR Input to Refine Monitoring Plan	Thu 10/21/10
306	1.5.1.4.3.6	Finalize Monitoring Plan	Thu 11/4/10
307	1.5.1.4.4	Assemble Components of Application, Update Graphics, Circulate for Internal Review, Incorporate Final Comments and Submit to MDNR for Courtesy Review	Mon 12/13/10
308	1.5.1.5	Meet/Conference with MDNR to Refine Permit Application Contents & DNR's Review of Revised Application (3/30/11, 4/20/11 & 4/26/11 Follow Up	Mon 5/16/11
309	1.5.1.6	Revise Application as Appropriate and Submit to MDNR	Thu 8/18/11



Project: MEP Permitting Work Plan 01
Date: Fri 11/9/12

Critical | Critical Split | Critical Progress | Task | Split | Task Progress | Baseline Milestone | Milestone | Summary Progress | Summary | Project Summary | External Tasks | External Milestone | Deadline

Mesaba Energy Project Permitting Milestones

ID	Task ID	Task Name	Finish	
310	1.5.1.7	MDNR Performs Completeness Review	Mon 9/26/11	100%
311	1.5.2	Cure Application Defects and Negotiate Terms of Permit	Fri 2/10/12	100%
312	1.5.3	MDNR Commissioner Waives Hearing on Application & Publishes Notice of Order Issuing Permit	Tue 3/13/12	3/13
313	1.6	CWA Section 404 Permit	Thu 4/5/12	79%
314	1.6.1	Offset Mitigation Plan	Wed 10/19/11	56%
315	1.6.1.1	Obtain Indication from Mesabi Mining (MM)/Steel Dynamics (SD) of Interest in Participating With Excelsior in Wetland Mitigation Project	Mon 3/2/09	3/2
316	1.6.1.2	Excelsior Develops Schedule & Draft Terms for Negotiating Agreement with MM/SD	Wed 3/18/09	100%
317	1.6.1.3	Excelsior Works with MM/SD to Determine Presence of Fatal Flaw(s) in Terms	Thu 10/15/09	100%
318	1.6.1.4	Excelsior Abandons Discussions with Magnetation	Mon 9/27/10	100%
319	1.6.1.5	Excelsior Opts to Use Banked Wetland Credits to Satisfy Wetland Mitigation Requirements	Wed 2/9/11	100%
320	1.6.1.6	Option Agreement for Banked Wetland Credits Is Executed	Wed 10/19/11	0%
321	1.6.2	DOE Project Deliberations Pertinent to Section 404 Permit	Thu 12/16/10	100%
322	1.6.2.1	Assemble and Submit Documentation to DOE Justifying Basis for Renegotiating Cooperative Agreement	Fri 7/2/10	100%
323	1.6.2.2	DOE Reviews & Approves One Year Cost Extension	Wed 9/1/10	100%
324	1.6.2.3	DOE Takes Under Advisement Excelsior Concerns Regarding PA & USACE Section 404 Permit	Wed 11/24/10	100%
325	1.6.2.4	Excelsior Establishes Strategy for Dealing With DOE's Decision Regarding ROD & Formulates Options to Present to USACE	Thu 12/16/10	100%
326	1.6.3	USACE Project Deliberations Pertinent to Section 404 Permit	Thu 1/6/11	100%
327	1.6.3.1	Excelsior Presents Alternatives to USACE for Complying with Section 106 Tribal Consultation Responsibilities	Thu 12/16/10	12/16
328	1.6.3.2	USACE Establishes Preferred Approach for Undertaking Permitting Process	Thu 1/6/11	100%
329	1.6.4	Excelsior Updates Section 404 Permit Application Consistent with FEIS, Assembles New Information & Circulates for Internal Review	Thu 3/3/11	100%
330	1.6.5	Excelsior Conducts Internal Review of Permit Application, Incorporates Applicable Comments & Finalizes Application	Thu 3/31/11	100%
331	1.6.6	Excelsior Submits Section 404 Permit Application to USACE	Thu 3/31/11	3/31
332	1.6.7	USACE Evaluates Application for Completeness & Identifies Additional Information Requirements	Thu 3/1/12	90%
333	1.6.8	Excelsior Conducts Re-Delineation of Wetlands, Assembles Additional Information & Submits to USACE	Thu 3/8/12	100%
334	1.6.9	USACE Reviews Information Submitted and Declares Application Complete	Thu 3/22/12	90%
335	1.6.10	USACE Provides Public Notice of Receipt of Permit Application	Thu 4/5/12	0%
336	1.7	Consultation Processes	Fri 6/4/10	99%
337	1.7.1	Programmatic Agreement	Fri 6/4/10	99%
338	1.7.1.1	Preparations for October 2009 Consultation Meeting	Wed 9/16/09	100%
339	1.7.1.1.1	Announce Meeting to Review PA	Fri 8/28/09	8/28
340	1.7.1.1.2	Prepare Draft of PA for DOE/Excelsior Review	Wed 9/2/09	100%
341	1.7.1.1.3	Incorporate Internal Comments & Release for ACHP Review	Fri 9/4/09	100%
342	1.7.1.1.4	ACHP Reviews and Provides Comment on Draft PA	Tue 9/8/09	100%
343	1.7.1.1.5	Redraft PA As Per ACHP	Fri 9/11/09	100%
344	1.7.1.1.6	Provide Redraft of PA to Upper Sioux for Review & Comment	Wed 9/16/09	100%
345	1.7.1.2	Upper Sioux	Wed 9/30/09	99%
346	1.7.1.2.1	Meet with Upper Sioux Community to Obtain Feedback on Draft PA	Wed 9/16/09	9/16
347	1.7.1.2.2	Consult with ACHP	Mon 9/28/09	100%
348	1.7.1.2.3	Incorporate Upper Sioux & ACHP Comments on Re-Drafted PA	Tue 9/29/09	100%
349	1.7.1.2.4	Send Revised PA to Upper Sioux for Signature	Wed 9/30/09	9/30
350	1.7.1.3	All Other Tribes	Mon 10/19/09	100%
351	1.7.1.3.1	Follow-Up From July	Tue 9/29/09	100%
352	1.7.1.3.1.1	Draft Letter to MIAC & Circulate for Internal Review	Fri 9/18/09	100%
353	1.7.1.3.1.2	Integrate Internal Comments & Provide to MIAC for Review	Tue 9/22/09	100%
354	1.7.1.3.1.3	MIAC Review of Draft Letter	Tue 9/29/09	100%
355	1.7.1.3.2	October 2009 Consultation Meeting	Mon 10/19/09	100%

Project: MEP Permitting Work Plan 01
Date: Fri 11/9/12

Critical | Task | Baseline Milestone | Summary | External Milestone
Critical Split | Split | Milestone | Project Summary | Deadline
Critical Progress | Task Progress | Summary Progress | External Tasks

Mesaba Energy Project Permitting Milestones

ID	Task ID	Task Name	Finish	08 Q3 – 2012 Q2
356	1.7.1.3.2.1	Provide Draft PA, MIAC Letter, and Meeting Agenda to Tribes	Wed 9/30/09	9/30
357	1.7.1.3.2.2	Meet with Remaining Tribes to Review PA	Thu 10/8/09	100%
358	1.7.1.3.2.3	Redraft & Mail Letter to MIAC to Confirm Section 106 Process is Consistent with State Process	Mon 10/19/09	100%
359	1.7.1.4	Incorporate Comments of Remaining Tribes & Upper Sioux into PA; Update Flow Chart (Revised Materials For NETL Review)	Mon 3/15/10	100%
360	1.7.1.5	Appear at Tribal Councils and/or at February 23, 2009 MIAC Board Meeting to Address Section 106/NEPA Concerns	Fri 6/4/10	6/4
361	1.7.2	Conduct TCP Surveys	Mon 2/15/10	100%
362	1.7.2.1	Stake Out Sites	Thu 11/12/09	100%
363	1.7.2.2	Perform Preliminary TCP Survey of WR Site	Fri 11/13/09	100%
364	1.7.2.3	Provide Letter Report, and Assess Implications	Mon 2/15/10	100%

Project: MEP Permitting Work Plan 01
Date: Fri 11/9/12

Critical | Critical Split | Critical Progress | Task | Split | Task Progress | Baseline Milestone | Milestone | Summary Progress | Summary | Project Summary | External Tasks | External Milestone | Deadline

Mesaba Preliminary Design Basis

EXCELSIOR ENERGY

ATTACHMENT 1

MEP-1 PRELIMINARY DESIGN BASIS*

***The following document is an Excelsior document, with the information contained within generated by Fluor and ConocoPhillips under a contract with Excelsior Energy Inc.**

EXCELSIOR ENERGY

1.0 INTRODUCTION

This Engineering Design Basis will provide Contractor and ConocoPhillips with the technical information required to proceed effectively with design work. The information provided will enable Contractor and ConocoPhillips to proceed with proper consideration for the client's preferences and specific technical requirements. The Design Basis will also provide a common design criteria document for the other Mesaba Energy Project team members.

The Project consists of two nominal 600 MW_{net} IGCC plants (each representing a separate development phase) to be located adjacent to each other on a common site. Although two sites are under formal consideration as part of a State-sanctioned environmental review process, the Design Basis is currently focused on Excelsior's preferred West Range Site. Phase 1 is expected to proceed as soon as practical given the permitting and financing schedules. Most of Phase 2 will be constructed after the Phase 1 demonstration period is completed; however, several facilities constructed during Phase 1 will serve Phase 2 as well. These common facilities include water and natural gas pipelines, pumping stations, rail lines, access roads, office and maintenance buildings, etc. Applications for the Project's environmental approvals/permits are based on both Phase 1 and Phase 2.

The plant description and requirements in the Design Basis are for Phase 1 only. The requirements for Phase 2 are assumed to be identical to Phase 1.

2.0 CODES AND STANDARDS

The plant will generally be designed to Contractor standard specifications and practices. Applicable state and local standards will be incorporated in the overall design standards. ConocoPhillips (COP) design guidelines and requirements will be used within COP's technology battery limit (TBL). Where practical, manufactures' standard designs will be used for pre-engineered equipment packages, such as, combustion turbines, packaged boilers, water treatment equipment, air separation unit, feed storage and handling system, zero liquid discharge unit, etc.

3.0 UNITS OF MEASUREMENT

Contractor's engineering design calculations will use the English / US system of measurements.

4.0 UNIT AND EQUIPMENT NUMBERING

Contractor's unit numbering and equipment designation and numbering system will be used. ConocoPhillips PDP deliverables will be based on COP unit, equipment, and drawing numbers.

5.0 PLANT / UNIT DEFINITION

A. Name and Location:

CLIENT NAME:
Excelsior Energy Inc.

PROJECT NAME
Mesaba Energy Project

PROJECT LOCATION:
Itasca County, Minnesota

The Mesaba Project will be located in Itasca County, Minnesota, near the town of Taconite (West Range Site). An alternate site near Hoyt Lakes (East Range Site) is also being considered. The design will be based on the West Range Site unless Excelsior advises that the alternate site has been selected.

B. Scope of Facilities:

General

The plant shall be designed to be fuel-flexible, i.e., to operate on a range of predefined fuel feedstocks subject to certain limitations that are defined below:

A) Rawhide PRB Coal
B) Blend of 50 wt% (dry) Spring Creek PRB Coal and 50 wt% (dry) Jacobs Ranch Wyodak (upper) PRB coal
C) Illinois #6 Coal
D) Blend of 50^{+} wt% (dry) Flint Hills Petroleum Coke with up to 50 wt% (dry) Rawhide PRB Coal (as limited by sulfur plant capacity designed for Illinois #6 coal)

Plant facilities will be based on the maximum capacities required to accommodate operation on any of the above fuel feedstocks, as defined in appropriate sections below.

Preliminary IGCC plant performance on each of the above feedstocks shall be based on the site's annual mean temperature of 38°F at 70% relative humidity (RH). Worst case seasonal combinations of temperature and humidity will be considered as appropriate.

The plant performance rating will be based on Rawhide PRB coal at a rating temperature of 80°F and 65% RH (summer 5%). The unit capacities of the process units shall be adjusted for operation with the feedstock blends described above.

Plant systems will be evaluated to incorporate use of automation in their design, including feed handling, water treating, and others as determined during FEED execution.

The feedstock storage and blending will be designed for operation with two different feeds (plus fluxant) at a time. Blending of the feeds shall be done in a building or within the covered conveying system. A storage facility for fluxant will also be included (Assume imported silica.)

The Phase 1 plant will be sized for a nominal 600 MW base load using two operating (plus one spare) ConocoPhillips gasifiers with another adjacent, equal sized Phase 2 plant to be added in the future. Preconstruction permits applications have been submitted and contain proposed conditions allowing both phases of development. The acid gas removal system shall be based on using MDEA solvent and no SCR in the gas turbine exhaust. Compliance with stack emission limits and/or other environmental control parameters specified in the Design Basis must be assured given the worst case conditions that could be reasonably considered to occur given the design feed stocks presented herein.

Plot space will be allocated in both Phase 1 and Phase 2 plants to retrofit a CO2 capture system into the plant at a later date.

Supply of raw water and natural gas to the plant battery limit and the high voltage transmission lines from the plant are not within the scope of the Design Basis. Unless otherwise amended at a later date, the Design Basis assumes that non-sanitary wastewaters will be eliminated through use of zero liquid discharge systems. Sanitary wastewaters will be discharged to a publicly-owned treatment system (POTW). The off site waste water pipeline and outfall facilities are by others.

The General Electric 7FB gas turbine will be used for preliminary design work and permitting support. Permitting activities will be performed by others with support from

ConocoPhillips and Contractor.

The redundancy level (trains within units and equipment sparing philosophy) shall be designed to achieve an overall plant availability of 90% or more.

Startup, shutdown and malfunction sequences/ conditions will be specified for point source emissions/discharges. (See Section 9.0)

Design will allow compliance with applicable state and federal regulations that cover, among other things, the following:

- Petroleum tanks and storage areas (i.e., underground storage tanks/pipelines; aboveground storage tanks);
- Spill prevention, control and countermeasure (SPCC);
- Stormwater pollution prevention (i.e., industrial activities associated runoff controls);
- Hazardous waste storage areas;
- VOC storage tanks;
- Process safety;
- Noise;
- Chemical/material storage tanks (acid, caustic, flux, etc.);
- Continuous emissions monitoring equipment and protocols:
  - Acid rain program;
  - NOx Budget Program or Clean Air Interstate Rule (whichever is most stringent);
  - Clean Air Mercury Rule
  - 40CFR60, Part 75
  - 40CFR60, Subpart Da “Standards of Performance for Electric Utility Steam Generating Units for which Construction Is Commenced after September 18, 1978”
- Air permit compliance demonstration conditions (as specified in the CD-01 Form attached to the Air Permit.

Gasification Technology

ConocoPhillips E-Gas Gasification Technology	Preliminary gasifier performance data is based on full slurry quench. Equipment designs developed during FEED will also support partial slurry quench at the maximum equivalent quench rate demonstrated at that time.

Feedstock Handling

Coal/Coke Handling Equipment	Designed to minimize fugitive emissions in accordance with NSPS for coal conveying equipment (40CFR60, Subpart Y – "Standards of Performance for Coal Preparation Plants"), as applicable. Coal/Coke conveyors and transfer points shall be covered, with dust filters on vents. Fugitive emissions will be determined for solids handling transfer points, based on applicable procedures. Calculations based on throughput rate, operating schedule and applicable emissions controls.
Coal/Coke Receiving	Coal and coke received by unit train. Coke can be received by truck. Rotary railcar dumper facility equipped with a fabric filter dust collection system meeting all necessary fire protection codes and applicable rules governing particulate matter emissions. Railcar thawing shed Designed to unload one unit train (up to 135 railcars in length) in 4 hours. Each railcar is assumed to hold 119 tons of feedstock.
Coal/Coke Storage	Active Storage: 20 days (four 5-day piles) Inactive Storage: 25 days (nominal). Piles are uncovered with dust controls. Liners and/or secondary containment to avoid ground water contamination, in accordance with applicable regulations. Storage volumes based on Rawhide PRB coal feed rate.

Coal/Coke Reclaiming	Feedstock A design feed rate: 8225 stpd Rawhide PRB Coal (as received). Feedstock B design feed rates: Blend of 3660 stpd Spring Creek PRB Coal (as received) and 3739 stpd Jacobs Ranch Upper Wyodak PRB Coal (as received) Feedstock C design feed rate: 5477 stpd Illinois #6 Coal (as received) Feedstock D design feed rates: Design feed rates for Flint Hills Petcoke and Rawhide PRB Coal in this blended feedstock are TBD. The petcoke fraction of the blend is limited by sulfur plant capacity, which is sized for the Illinois No. 6 coal feedstock. Specifications for each feedstock provided in Attachment 1.
Fluxant Receiving, Storage and Reclaiming	Fluxant Material: Silica (assumed) Reclaim feed rate: 233 stpd (basis: Feedstock blend of Spring Creek PRB coal/Jacobs Ranch PRB coal) Unloading Facilities: Truck/Rail 20 days storage (4660 tons) Fluxant silos heated to prevent freezing. Electrical heating to thaw trucks. All transfer points enclosed and equipped with fabric filters/baghouses, as required. Silos with fabric filters/baghouses, as required. Conveyors shall be covered. Specification for fluxant silica is TBD.

Air Separation

Air Separation Unit	2 trains @ 50% Oxygen Purity: 95 mole % Oxygen Temperature 240 F Oxygen Pressure [TBD] PSIA Capacity per train: 2507 stpd O_2 [contained] (basis: Rawhide PRB coal feedstock) Gas turbine extraction air used as makeup. HP N2 product used as gasifier purge gas. MP N2 product used as syngas diluent for gas turbine NOx control. LP N2 product used as inert purging gas. Main and Booster Air Compressors housed in building for weather protection Liquid oxygen storage for 8 hr of max usage for one gasification train (~900 tons) Liquid oxygen pumped to delivery pressure and vaporized Liquid nitrogen storage for gasifier and system purging (~20 tons) [Additional facilities and/or dynamic response for switching from N2 to steam as syngas diluent for GT NOx control to be evaluated]

Gasification Units

Grinding & Slurry Preparation	2 trains @ 60 % Capacity per train: 4935 stpd (as received) (basis: Rawhide PRB coal) Winterization: Located inside building
Slurry Storage, Pumping & Heating	3 trains @ 50% Capacity per train: 4113 stpd (as received) (basis: Rawhide PRB coal) Slurry Storage: 12 hours
Gasification, HT Heat Recovery, Dry Char Removal, & Slag Grinding	3 trains @ 50 % Capacity per train: 4113 stpd (as received) (basis: Rawhide PRB coal)
Slag Handling	1 train @ 100 % Capacity: 774 stpd (basis: Spring Creek/Jacobs Ranch PRB coals)

Slag Storage	Storage capacity = 45 days Open storage on concrete pad *[with lined containment, if required]*, no dust control required due to high surface moisture on slag; Storage pad heated to avoid icing, if required. Drainage from slag storage area collected and treated in plant waste water system. Loading Facilities: Rail and Truck loading from overhead slag bins (normal operation) Specification for slag properties is TBD.

Gas Treating Units

Gas Scrubbing (Chloride)	2 trains @ 50 % each
COS Hydrolysis	2 trains @ 50 % each
Low Temperature Heat Recovery	2 trains @ 50 % each
Recycle Syngas Compression	2 trains @ 50 %
Process Sour Water Treatment	1 train @ 100 % Zero Liquid Discharge: Assumed required for process water blowdown using brine concentrator and crystallizer. Upstream processing will include carbon filter, degassing column, ammonia stripper, etc. Aqueous streams from coal /coke storage areas will be collected and reused internally.
Acid Gas Removal	2 trains @ 50 % each Solvent: MDEA Total Sulfur in syngas: 50 ppmvd 30 day avg Total Sulfur in syngas: 120 ppmvd max hourly
Acid Gas Enrichment	1 train @ 100% Required with low sulfur feedstocks; increases acid gas H2S concentration to make it suitable for feeding to Sulfur Recovery Unit Solvent: MDEA

Mercury Removal (from Syngas)	2 trains @ 50 % Absorbent: Sulfur impregnated activated Carbon or other sorbent providing 90 % removal (minimum) across control system
Fuel Gas (Syngas) Moisturization	2 trains @ 50 %

Sulfur Recovery & Tail Gas Recycle

Sulfur Recovery Unit	2 trains @ 50 % Capacity per train: 81 tpd sulfur product (basis: Illinois #6 coal) Oxygen blown, multistage Claus units The sulfur recovery system will be designed for the range of H2S concentrations in the acid gas from the AGR or the AGE (required for low sulfur feedstocks) systems.
Sulfur Storage (molten)	2 trains @ 50 % each Onsite storage: 7 days Rail Storage: 30 railcars parked onsite Loading Facilities: Rail and Truck loading
Tail Gas Recycle Compressor	3 trains @ 50 % Type: Reciprocating (multi-stage)
Tank Vent Incinerator	1 @ 100% Includes tank vent collection system. Provides emergency tail gas incineration

Power Block

Combined Cycle Configuration	Two General Electric 7FB Gas Turbines (nominal 220 MW each). Gas turbine fuels: Product syngas (normal), Natural gas (startup and backup) HRSG: 2 trains @ 50 % each Steam Turbine: 1 train @ 100 % Steam Cycle: Reheat (Nominal 1575 psia/ 1000 °F/ 1000 °F) Gas Turbines and Steam Turbine will be housed in a building for weather protection. BFW Treating: Chemical additives containing phosphorous or mercury shall be avoided. If a phosphorous containing treatment chemical must be temporarily used due to an upset situation, BFW blowdown will not be discharged to surface waters (via the cooling tower basin). Alternate disposal options, such as utilization for slurry preparation or routing to the ZLD process, will be provided for this abnormal condition.

Offsites & Utilities

Plant Cooling	Process Cooling Water System Power Block Cooling Water System Closed cooling water system with glycol (for winterization).
Flare	1 train @ 100 %
Water Treating	
General Makeup Water	1 train @ 100 %
Demineralized Water	1 train @ 100 %
Potable Water	1 train @ 100 %
Firewater	1 train @ 100 %
Utility Water	1 train @ 100 % Water treatment equipment will be housed in a building for winterization
Gasification Island Wastewater Treatment	Via zero liquid discharge system with adequate redundancy.
Cooling Tower Blowdown Treatment	Provide a separate zero Liquid Discharge system (3 trains @ 50%) for treatment of cooling tower and other non-contact plant water to eliminate all CTB discharges.

Plant & Instrument Air	Supplied by ASU 1 train @ 100 % (backup)
Alternative General Wastewater Treating	1 train @ 100 %, pH control, chlorine removal, anti-foam (if required) for cooling tower blowdown. CPI separator/s for oil removal from process drains. Segregated chemical drains where required (MDEA).
Natural Gas Supply	1 train @ 100 %; Moisture separation, filtration and redundant pressure control valves to be included with natural gas letdown station. The natural gas supply yard will also include custody transfer metering and gas analysis with communication facilities to the Plant DCS. Natural gas heaters if required.
Nitrogen Distribution	1 train @ 100 %
Drains and Blowdowns	1 train @ 100 %
Auxiliary Boiler	1 train @ 100 % Capacity: 100,000 lb/hr MP Steam
Emergency Generator	Essential services (3 MW nominal, to be verified during FEED); Diesel storage tank with required containment and monitoring for leakage control to provide ~8 hr operation at full load. Periodic testing as required by applicable codes/procedures.
Black Start Capability	Not Required
Administration Building	Building sized to allow future buildout for Phase 2
Gas Turbines, Steam Turbine and HRSGs	Turbine building/s for gas turbines and steam turbine. HRSGs to have enclosed "penthouse", covered stair towers and any other necessary winterization. Stacks to be equipped with testing ports and CEM extraction ports.
Power Block Integration with ASU	Air Extraction from GT to ASU (as appropriate) MP Nitrogen from ASU provided as diluent for GT NOx Control

Plant Configuration

Normal Plant Configuration	Two operating gasification trains producing syngas for a Combined Cycle Plant (2 GTG/ 2 HRSGs/ 1 STG) Spare gasification train on cold standby
Turndown Configuration	One gasification train off-line One gas turbine off-line Each gasifier operating to 70% capacity (turndown case)
Gas Turbine Back-Up Fuel	Natural Gas (for start up and shutdown) Natural gas as a gas turbine back up fuel with NOx permit level for this mode is 25 ppmvd @ 15 % O2. Power block will be designed to operate on 100 % natural gas when necessary. Gas turbines designed for co-firing of natural gas and syngas subject to CTG supplier's limitations.
Operating Scenarios	Potential operating and turndown configurations for the plant based on available combinations of operating gasifiers, combustion turbines, and fuel types are tabulated in Attachment 2.
Future Build-Out Scenario	Nominal 600 MW (duplicate) plant in Phase 2. Phase 1 design to leave plot space for Phase 2. Common facilities for Phase 1 are designed for minimum pre-investment in Phase 2. Plot plan for Phase 1 and 2 to allocate space for future addition of CO2 capture facilities (amine absorption/flash CO2 recovery, compression and dehydration). Initial plants to include stub-outs for process fuel gas supply and return to/from CO2 capture facility. No additional pre-investment for this facility provided. An optional scope will be required for a 30% carbon capture (85% captured from the syngas when operating on the performance fuel), drying and compression to be included in the design.
Design Life	40 year Operating Life

Winterization	Preliminary winterization criteria are -43°F and 10 mph wind for outdoor piping and equipment. Electric tracing for freeze protection. Steam tracing only if needed for process conditions. Thaw shed required for coal unloading facilities.

C. Feedstocks [See Attachment #1 for Coal, Petroleum Coke and Fluxant Analyses]

D. Products

Electric Power:	
Basis for Net Electrical Output	At utility custody transfer meters
Grid Interconnect	
Line Voltage	230 kV
Frequency	60 Hz
Power Factor	Generators capable of providing 0.9-1.0 lagging, 0.95-1.00 leading power factor.
Location of Power Line Interconnect Location	Phase 1 – two transmission lines terminate in the plant switchyard high voltage bushings (south side of plant) Phase 2 – [Expected to require third 230 KV transmission line. Design to allow space for future transmission line and associated breakers and meters]
Interconnect Control Scheme	By Excelsior through interface with Midwest Independent System Operator (MISO)
Slag By-Product:	
Quantity	774 stpd (Spring Creek/Jacobs Ranch basis)
Quality	See Attachment 1 for slag properties
Sulfur By-Product:	
Liquid Sulfur Product	162 stpd (Illinois 6 coal basis)
Quality	Commercial Grade Liquid Sulfur
Color	Bright Yellow

6.0 BATTERY LIMIT REQUIREMENTS [West Range Site]

Raw Water Source Primary (from Canisteo Pit, Hill Annex Complex and Prairie River)	Canisteo Mine Pit, located ~ 1 mile south-southwest from site. Raw water pumping station and raw water pipeline are by others. (See Raw Water Analysis for Canisteo Mine Pit below) The Hill Annex Mine Pit complex is located about 2.5-3.5 miles east-southeast from site. (See Raw Water Analysis for Hill Annex Mine Pit below)
Natural Gas Supply	Natural gas data to be supplied by Excelsior New pipeline and metering station by others Source location: [TBD]
Pressure	600/700 PSIA (min/max)
Btu Content, HHV	935 Btu/Scf
Specific Gravity	0.57-0.58
Composition (Mol %)	
Methane	96.9 mol %
Ethane	2.00 mol %
Propane	0.50 mol %
Normal Butane	0.10 mol %
Isobutane	0.10 mol %
Normal Pentane	0.00 mol %
Isopentane	0.00 mol %
Hexane+	0.10 mol %
Nitrogen + Argon	0.30 mol %
Carbon Dioxide	0.00 mol %
Oxygen	0.00 mol%
Sulfur	14.8 ppmv
Water	[TBD] lb/MMScf

Raw Water Analysis (Canisteo Mine Pit)

(Based on data obtained March 30-31, 2005)

All units mg/l
unless otherwise noted

	Detect Limit	Mean	std dev	Max	Min
Alkalinity-m	1	173.667	35.149	190.000	102.000
Alkalinity-p	1	10.000	0.000	10.000	10.000
Aluminium	0.025	0.025	0.000	0.026	0.025
Arsenic	0.002	0.002	0.000	0.002	0.002
Barium	0.01	0.028	0.001	0.030	0.026
BOD	2	2.000	0.000	2.000	2.000
Boron	0.035	0.036	0.003	0.044	0.035
Cadmium	0.01	0.010	0.000	0.010	0.010
Calcium	0.5	55.600	3.088	59.600	50.200
Chloride	0.5	4.783	0.972	5.200	2.800
Chlorophyll-a	0.001	0.001	0.000	0.001	0.001
Chromium	0.005	0.005	0.000	0.005	0.005
Chromium III	0.01	0.010	0.000	0.010	0.010
Chromium, Hexavalent	0.01	0.010	0.000	0.010	0.010
Cobalt	0.005	0.005	0.000	0.005	0.005
COD	2	2.000	0.000	2.000	2.000
Copper	0.005 - 0.01	0.008	0.003	0.010	0.005
Fecal Coliform, #/100 mls	2	2.000	0.000	2.000	2.000
Hardness (Calculated)	1	306.753	15.430	324.924	278.352
Iron	0.03 - 0.05	0.045	0.023	0.110	0.030
Kjeldahl Nitrogen, Total as N	0.5	0.532	0.078	0.690	0.500
Lead	0.001	0.001	0.000	0.001	0.001
Lithium	0.02	0.020	0.000	0.020	0.020
Magnesium	0.5	40.717	1.891	42.700	37.100
Manganese	0.01 - 0.05	0.018	0.011	0.050	0.010
Mercury, ng/l *	0.5	0.567	0.121	0.800	0.500
Molybdeum	0.005	0.005	0.000	0.005	0.005
Nickel	0.005	0.008	0.009	0.033	0.005
Nitrogen, Ammonia	0.1	0.100	0.000	0.100	0.100
Nitrogen, Nitrate + Nitrite	0.1	0.451	0.989	2.900	0.100
Oil and Grease	2	2.000	0.000	2.000	2.000
Orthophosphate as PO4	0.03	0.036	0.012	0.060	0.030
Phosphorus,Total	0.1	0.100	0.000	0.100	0.100
Potassium	2.5	4.117	0.160	4.300	3.900
Selenium	0.002	0.002	0.000	0.002	0.002
Silica, Total	1	5.174	0.203	5.580	4.770
Silver	0.001	0.001	0.000	0.001	0.001
Sodium	0.5	6.767	0.250	7.000	6.300
TDS	10	308.833	68.671	342.000	169.000
TSS	1	1.500	0.837	3.000	1.000
Strontium	0.004	0.127	0.005	0.133	0.117
Sulfate	1	80.633	39.519	107.000	10.000
Thallium	0.002	0.002	0.000	0.002	0.002
Tin	0.01	0.010	0.000	0.010	0.010
Titanium	0.01	0.010	0.000	0.010	0.010
TOC	1	1.933	0.082	2.100	1.900
Total Nitrogen	0.1 - 1	1.117	0.940	2.900	0.110
Turbidity, NTU	0.05	0.788	0.655	1.800	0.100
Vanadium	0.004	0.004	0.000	0.004	0.004
Zinc	0.01	0.010	0.000	0.010	0.010

Notes * Mercury values from reanalysis 4/13/05
[*Additional seasonal water analyses will be supplied as available*]

Raw Water Analysis (Hill Annex Mine Pit)
(Based on data obtained March 30-31, 2005)

All units mg/l
unless otherwise noted

	Detect Limit	Mean	std dev	Max	Min
Alkalinity-m	1	145.117	33.305	168.000	79.700
Alkalinity-p	1	10.000	0.000	10.000	10.000
Aluminium	0.025	0.036	0.039	0.159	0.025
Arsenic	0.002	0.002	0.000	0.002	0.002
Barium	0.01	0.029	0.003	0.035	0.024
BOD	2	2.000	0.000	2.000	2.000
Boron	0.035	0.035	0.000	0.035	0.035
Cadmium	0.01	0.010	0.000	0.010	0.010
Calcium	0.5	57.717	2.010	59.600	54.600
Chloride	0.5	4.900	1.051	5.700	2.800
Chlorophyll-a	0.001	0.001	0.000	0.001	0.001
Chromium	0.005	0.005	0.000	0.005	0.005
Chromium III	0.01	0.010	0.000	0.010	0.010
Chromium, Hexavalent	0.01	0.010	0.000	0.010	0.010
Cobalt	0.005	0.005	0.000	0.005	0.005
COD	2	2.000	0.000	2.000	2.000
Copper	0.005 - 0.01	0.008	0.003	0.010	0.005
Fecal Coliform, #/100 mls	2	2.667	1.633	6.000	2.000
Hardness (Calculated)	1	228.271	7.575	237.168	218.488
Iron	0.03 - 0.05	0.078	0.122	0.460	0.030
Kjeldahl Nitrogen, Total as N	0.5	0.623	0.195	0.930	0.500
Lead	0.001	0.001	0.000	0.001	0.001
Lithium	0.02	0.020	0.000	0.020	0.020
Magnesium	0.5	20.383	0.694	21.400	19.400
Manganese	0.01 - 0.05	0.016	0.007	0.030	0.010
Mercury, ng/l *	0.5	1.117	0.556	2.000	0.500
Molybdeum	0.005	0.005	0.000	0.005	0.005
Nickel	0.005	0.005	0.000	0.005	0.005
Nitrogen, Ammonia	0.1	0.100	0.000	0.100	0.100
Nitrogen, Nitrate + Nitrite	0.1	0.107	0.005	0.110	0.100
Oil and Grease	2	2.000	0.000	2.000	2.000
Orthophosphate as PO4	0.03	0.055	0.048	0.160	0.030
Phosphorus,Total	0.1	0.100	0.000	0.100	0.100
Potassium	2.5	2.650	0.152	2.900	2.500
Selenium	0.002	0.002	0.000	0.002	0.002
Silica, Total	1	10.856	0.652	11.800	9.370
Silver	0.001	0.001	0.000	0.001	0.001
Sodium	0.5	6.183	0.293	6.600	5.700
TDS	10	228.833	52.002	270.000	128.000
TSS	1	9.000	11.524	29.000	1.000
Strontium	0.004	0.139	0.009	0.148	0.119
Sulfate	1	46.383	15.412	59.000	25.700
Thallium	0.002	0.169	0.577	2.000	0.002
Tin	0.01	0.010	0.000	0.010	0.010
Titanium	0.01	0.010	0.000	0.010	0.010
TOC	1	1.900	0.110	2.100	1.800
Total Nitrogen	0.1 - 1	0.955	0.081	1.000	0.800
Turbidity, NTU	0.05	5.933	6.690	16.000	0.900
Vanadium	0.004	0.004	0.000	0.004	0.004
Zinc	0.01	0.010	0.000	0.010	0.010

Notes
* Mercury values from reanalysis 4/13/05
[*Additional seasonal water analyses will be supplied as available*]

7.0 SITE / METEOROLOGICAL DATA

Site Characteristics

Location	West Range Site: Itasca county, Minnesota, near the town of Taconite (between Grand Rapids and Hibbing)
Available Plot Space	Phase 1: Approx 95 acres (including ~13 acres for inactive feedstock storage and rail spur) Additional 80 acres for construction laydown Phase 2: Approx 190 acres for Phase 1 + Phase 2 (Refer to preliminary Site Plan and Plot Plan)
Condition	Greenfield, *[Site topographical map and preliminary soils information to be attached later.]*
Elevation	Graded site elevation is expected to range from 1390 - 1440 feet above mean sea level.
Access	Rail Access Road Access Note: Lake Superior access to nearby port for heavy haul (port closed in winter)
Seismic Conditions	Seismic Zone UBC 0
Geotechnical Data (soils report)	As specified in “Preliminary Geotechnical Investigation, SEH No. A-EXENR0502.00”, dated September 20, 2005.
Soil bearing capacity	As specified in “Preliminary Geotechnical Investigation, SEH No. A-EXENR0502.00”, dated September 20, 2005.
Piling requirement	As specified in “Preliminary Geotechnical Investigation, SEH No. A-EXENR0502.00”, dated September 20, 2005.
Water table	As specified in “Preliminary Geotechnical Investigation, SEH No. A-EXENR0502.00”, dated September 20, 2005.

Site Meteorology

Annual Mean Temperature, Dry Bulb	38°F
Annual Mean Relative Humidity	70 %
Design Dry Bulb Temperature, Summer	80 °F (use for plant performance)
Design Relative Humidity, Summer	65 % (use for plant performance)
Design Wet Bulb Temperature, Summer	70 °F (use for plant design)
Extreme Temperature, High	98 °F (Historic Maximum)
Extreme Temperature, Low	-43 °F (Historic Minimum) Use for mechanical design
Design Dry Bulb Temperature, Winter	-20 °F (use for plant performance)
Relative Humidity, Winter	75 %
Design Barometric Pressure	13.95 psia
Wind Design	Design code: UBC Exposure: C Basic Wind Velocity: 80 mph (See frequency of occurrence of wind speed classes for Hibbing, MN below) (See Annual (2004) Wind Rose for Hibbing, MN below) (See monthly (2004) Wind Rose data for Hibbing, MN in Attachment 3)

Rainfall

Design storm based on 10 year period.	Average (annual): 27.5 inches Maximum: 38 inches 24 hour: 4 inches

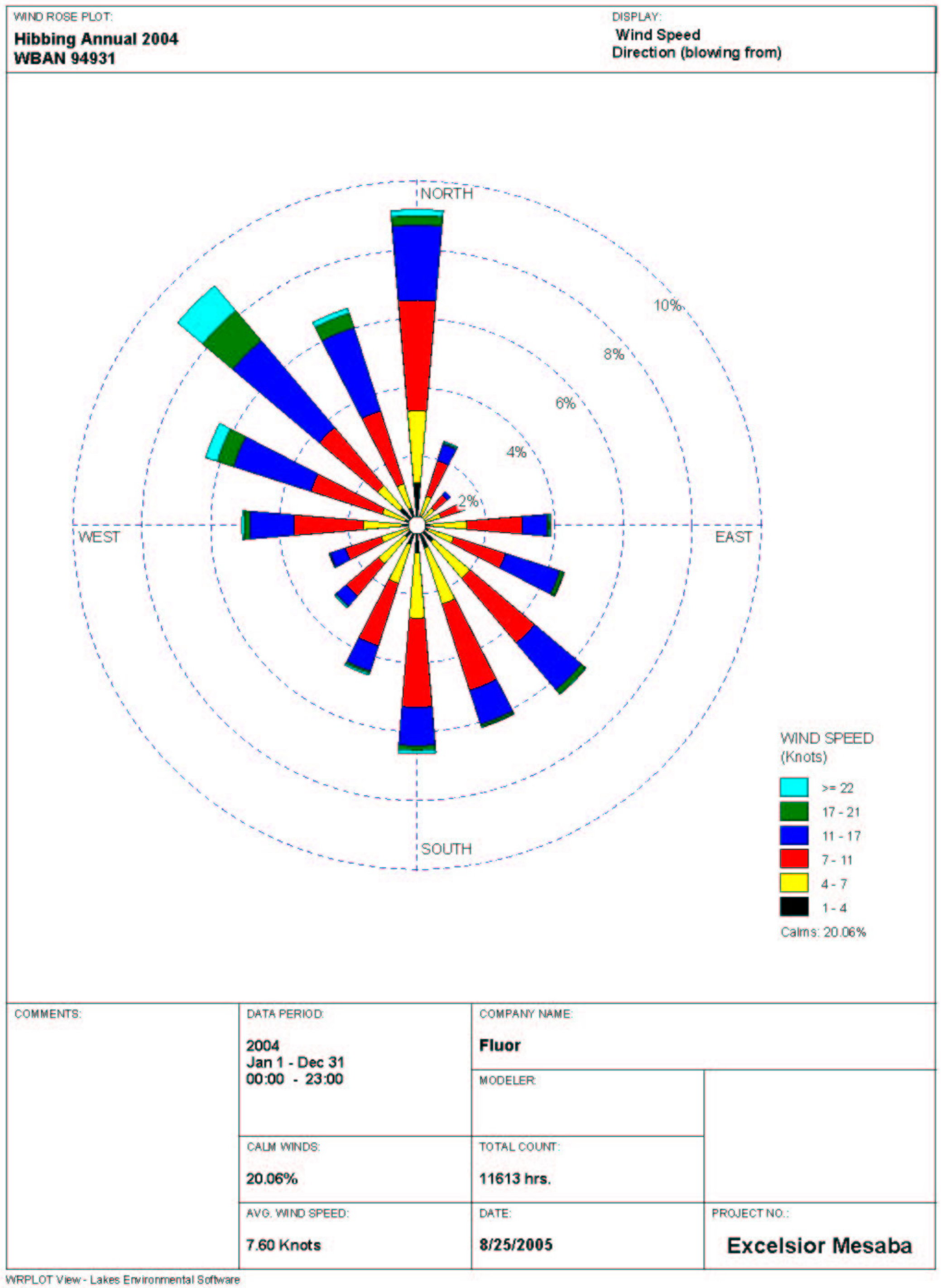
Snowfall

Design storm based on 10 year period.	Average (annual): 74 inches Maximum (annual): 151 inches 24 hour: 19 inches
Equivalent water depth	[TBD] inches
Maximum in 24 hours	[TBD] inches
Maximum depth	[TBD} inches
Design snowload for structure	[TBD] lb/ft2
Design Frost Depth	8 ft

Table 20. Frequency of occurrence of wind speed classes at Hibbing.

Month	0	1-3	4-7	8-12	13-18	19-24	25-31	32-38	39-46	>46	Mean speed	Median speed
	Wind speed classes in miles per hour											
	percent										mi/hr	mi/hr
Jan	13.5	3.5	21.3	31.2	27.5	2.7	0.2	0.0	0.0	0.0	9.3	9.9
Feb	15.9	2.8	19.1	31.6	27.2	2.9	0.5	0.0	0.0	0.0	9.2	9.9
Mar	13.5	2.8	20.5	31.3	28.3	3.2	0.5	0.0	0.0	0.0	9.5	10.1
Apr	10.8	2.5	17.3	30.7	32.4	5.7	0.6	0.0	0.0	0.0	10.6	11.2
May	10.8	2.7	20.2	19.1	41.8	4.6	0.8	0.0	0.0	0.0	10.8	12.3
Jun	15.0	2.5	23.6	31.8	24.0	2.9	0.2	0.0	0.0	0.0	9.0	9.4
Jul	17.8	3.2	24.6	31.4	21.0	2.0	0.1	0.0	0.0	0.0	8.3	8,7
Aug	21.0	3.2	24.2	29.4	19.8	2.3	0.1	0.0	0.0	0.0	7.9	8.3
Sep	17.8	2.8	22.9	30.7	23.5	2.1	0.1	0.0	0.0	0.0	8.6	9.0
Oct	12.2	2.8	20.1	30.9	28.3	5.0	0.6	0.1	0.0	0.0	9.9	10.4
Nov	13.6	2.9	20.8	31.9	27.6	2.9	0.4	0.0	0.0	0.0	9.5	10.0
Dec	14.6	3.2	21.5	35.0	22.5	3.0	0.2	0.0	0.0	0.0	8.9	9.6
Annual	14.7	2.9	21.3	30.4	27.0	3.3	0.4	0.0	0.0	0.0	9.3	9.8

Ref.: Climate of Minnesota, Part XIV – Wind Climatology and Wind Power; AD-TB1955; University of Minnesota, 1983


WIND ROSE PLOT:
Hibbing Annual 2004
WBAN 94931
DISPLAY:
Wind Speed
Direction (blowing from)
NORTH
SOUTH
WEST
EAST
2%
4%
6%
8%
10%
WIND SPEED
(Knots)
>= 22
17 - 21
11 - 17
7 - 11
4 - 7
1 - 4
Calms: 20.06%
COMMENTS:
DATA PERIOD:
2004
Jan 1 - Dec 31
00:00 - 23:00
COMPANY NAME:
Fluor
MODELER:
CALM WINDS:
20.06%
TOTAL COUNT:
11613 hrs.
AVG. WIND SPEED:
7.60 Knots
DATE:
8/25/2005
PROJECT NO.:
Excelsior Mesaba
WRPLOT View - Lakes Environmental Software

8.0 UTILITY CONDITIONS

Steam	Operating/Design		
High Pressure	1775/2000 PSIG		
	670/700°F		
Intermediate Pressure	625/675 PSIG		
	530/550°F		
Low Pressure	50/75 PSIG		
	298/350°F		
Boiler Feed Water	2200/2400 PSIG		
	560/600°F		
Fire water	125 PSIG		
	1,500 GPM		
Circulating Cooling water supply/return	<u>Summer</u>	<u>Avg Ambient</u>	<u>Winter</u>
	90°F / 105°F	58°F / 73°F	50°F / 65°F
Closed Cooling Water Supply/Return	<u>Summer</u>	<u>Avg. Ambient</u>	<u>Winter</u>
	95°F / 110°F	63°F / 78°F	55°F / 70°F
Cooling Water Blowdown	Based on 4.5 cycles of concentration		
Cooling Water Drift	0.0005 % of circulation flow.		

Steam	Operating/Design		
High Pressure	1775/2000 PSIG		
	670/700°F		
Intermediate Pressure	625/675 PSIG		
	530/550°F		
Low Pressure	50/75 PSIG		
	298/350°F		
Boiler Feed Water	2200/2400 PSIG		
	560/600°F		
Fire water	125 PSIG		
	1,500 GPM		
Circulating Cooling water supply/return	<u>Summer</u>	<u>Avg Ambient</u>	<u>Winter</u>
	85°F / 100°F	40°F / 55°F	40°F / 55°F
Closed Cooling Water Supply/Return	<u>Summer</u>	<u>Avg. Ambient</u>	<u>Winter</u>
	90°F / 105°F	45°F / 60°F	45°F / 60°F
Cooling Water Blowdown	Based on 5 cycles of concentration		
Cooling Water Drift	0.0005 % of circulation flow.		

9.0 ENVIRONMENTAL AND SAFETY REQUIREMENTS

Environmental Design Criteria

Atmospheric Emission Sources	HRSG Stacks Tank Vent Gas Incinerator Auxiliary Boiler Flare Diesel Generator Diesel Firewater pump Feedstock and Flux Receiving, Storage, & Handling System fugitive emissions Slag Loading Systems fugitive emissions Process piping fugitive emissions Cooling Towers
Emission Data Requirements	Peak short-term and annual average emission rates, plus stack parameters, as specified in Project permits and permit applications. ▫ Worst-case emission operating conditions ▫ Startup/shutdown and malfunction emissions
Continuous Emissions Monitoring	As required by regulations. See Section 5B.
<u>Atmospheric Emission Requirements</u>	(outside allowed startup/shutdown periods)
Combustion Turbines	NSPS for new stationary sources (CFR 40, Part 60, Subpart Da) *[Values below subject to change based on BACT analysis, final supplier guarantees, and contractual requirements]*
NOx: Syngas fuel Natural gas fuel	15 ppmvd in gas turbine exhaust (@15% O_2) 25 ppmvd (@15% O_2)
SOx	50 ppmvd total sulfur in syngas (30 day average)
CO	15 ppmvd (@15% O_2)
VOC	2.4 ppmvd (@15% O_2)
Particulate Matter	26 lb/hr [per turbine] (filterable + condensable)
Stack Heights	EPA Good Engineering Practice (GEP), 40 CFR, Part 51
Tank Vent Gas Incinerator	(later)
Flare	(later)
Cooling Towers	Drift emission no more than 0.001% of

	circulating cooling water rate
Liquid Effluents	
Mercury	Mercury concentration is critical in aqueous effluents. State regulations regarding allowable mercury discharge are currently being revised. It is expected that plant discharges will need to meet an annual average mercury limit of 6.9 ng/l (outside Lake Superior watershed) or 1.8 ng/l (inside Lake Superior watershed), as well as not increase the total mass of mercury in surface waters.
Phosphorus	No addition of phosphorus (mass basis) above that present in makeup water allowed.
[Additional limits for specific discharge parameters to be added as identified]	
Gasification Process Water Blowdown	Collected and Discharged to ZLD unit
Storm/Surface Water	Collected and Discharged offsite to detention pond; plant drain systems design must i) provide basis for minimizing impacts of stormwater surges, ii) account for separation of stormwater associated with industrial activity and stormwater unassociated with such activities, and iii) be developed in accordance with an overall stormwater pollution prevention plan (SWPPP) for the plant.
Steam System Blowdown	Collected and Discharged to cooling tower makeup
Demin System Wastewater	Collected and Discharged offsite to plant wastewater
Cooling Tower Blowdown	Collected and Discharged offsite to plant wastewater
	Cooling water intake and discharges structures will be designed in compliance with Clean Water Act Sections 316 (a) and (b) and state requirements as applicable

<u>Solid Effluents</u>	
Sour water sludge	
Slag from Gasification	Collected and shipped offsite for sale or disposed as non-hazardous material
Spent Absorbent from Hg Absorbers	Collected and shipped offsite as hazardous waste
Spent COS Hydrolysis Catalyst (Co/Mo)	Collected and shipped offsite to landfill
Spent Claus Plant Catalyst	Collected and shipped offsite to landfill
ZLD solids	Collected and shipped offsite as hazardous waste
<u>Noise</u>	85 db @ 3 ft [TBD] db @ fence line (night and day), as necessary to meet MPCA noise requirement for nearest residential area. (~ 4000 ft); MPCA residential noise classification 1(50 dBA nighttime, 60 dBA daytime based on L50).
Proposed Plant Emission Limits	Preliminary proposed plant emission limits are based on the largest values considering the following plant feedstocks (as defined in Section B, Scope of Facilities – General) and plant performance cases: ▫ Feedstock 1, Partial Slurry Quench, CTGs with maximum air extraction, 38°F ambient temperature ▫ Feedstock 1, Full Slurry Quench, CTGs with maximum air extraction, 38°F ambient temperature ▫ 50/50 Blend of Feedstock 3 and 4, Full Slurry Quench, CTGs with maximum air extraction, 38°F ambient temperature ▫ Feedstock 5, Full Slurry Quench, CTGs with maximum air extraction, 38°F ambient temperature

This design basis incorporates by reference the latest revisions of the following project environmental documents:

- Mesaba Energy Project, Environmental Information Volume (EIV), as submitted to the U.S. Dept of Energy and the subsequent federal EIS prepared by DOE;
- Air Quality and NPDES (wastewater) permit applications as submitted to the Minnesota Pollution Control Agency (PCA) and subsequent permits and approvals issued by PCA in response to these applications;
- The "Joint Application" for power plant approval as submitted to the Minnesota Dept of Commerce (DOC) and subsequent project approvals issued by DOC in response to this application.

The plant emission and discharge estimates from project permit applications known to-date are appended to this design basis as Attachment 4. These documents represent the best available estimates of the likely project environmental permit conditions and limitations and are included herein to provide additional guidance to Contractor in connection with the plant design to be developed as a part of the FEED Agreement. While Contractor recognizes the significance of this information, these estimates are not guaranteed. Specific emission guarantees will be negotiated between the Parties as a part of the EPC Contract.

ATTACHMENT 1

FEEDSTOCK SPECIFICATIONS

Coal

Coke

Fluxant

Feedstock 1 | **Rawhide PRB Coal**

(Performance coal specification for optimization studies. Design Specification TBD See Attached Data)

Solids Feed: Supplied by rail

Size (as received): 2” x 0”

Proximate Analysis	Performance	Design
Moisture (as received)	30.50 wt %	___ wt %
Ash (as received)	4.93 wt %	___ wt%
Fixed Carbon	____ wt %	___ wt %
Volatile Matter	____ wt %	___ wt %

Ultimate Analysis (MAF)	Performance	Design
Carbon	75.24 wt %	____ wt %
Hydrogen	5.17 wt %	____ wt %
Nitrogen	0.97 wt %	____ wt %
Sulfur	0.57 wt %	____ wt %
Chloride	0.00 wt %	____ wt %
Oxygen	18.05 wt %	____ wt %
Mercury	____ ppmw	____ ppmw
Higher Heating Value (HHV), Dry	11,942 Btu/lb	____ Btu/lb
Higher Heating Value (HHV), AR	8,300 Btu/lb	____ Btu/lb

Ash Analysis	Performance	Design
SiO_2	____ wt %	____ wt %
Al_2O_3	____ wt %	____ wt %
Fe_2O_3	____ wt %	____ wt %
TiO_2	____ wt %	____ wt %
CaO	____ wt %	____ wt %
MgO	____ wt %	____ wt %
Na_2O	____ wt %	____ wt %
K_2O	____ wt %	____ wt %
P_2O_5	____ wt %	____ wt %
SO_3	____ wt %	____ wt %
Undetermined	____ wt %	____ wt %
Total	100.00 wt %	100.00 wt %

Ash Fusion Temperature - Reducing	
Initial Deformation	_____°F
Softening	_____°F
Hemispherical	_____°F
Fluid	_____°F

Ash Fusion Temperature - Oxidizing	
Initial Deformation	_____°F
Softening	_____°F
Hemispherical	_____°F
Fluid	_____°F

Feedstock 2	**Flint Hills Petroleum Coke** to be used in a blend with Rawhide PRB as limited by sulfur plant capacity or other limits determined by other feed blends. *(Performance coal specification for optimization studies. Design Specification TBD)*	
Solids Feed	Supplied by rail	
Size (as received)	2” x 0”	
Proximate Analysis	Performance	Design
Moisture (as received)	9.86 wt %	___ wt %
Ash (as received)	0.63 wt %	___ wt%
Fixed Carbon	____ wt %	___ wt %
Volatile Matter	____ wt %	___ wt %
Ultimate Analysis (MAF)	Performance	Design
Carbon	87.93 wt %	____ wt %
Hydrogen	3.70 wt%	____ wt %
Nitrogen	1.32 wt %	____ wt %
Sulfur	6.31 wt %	____ wt %
Chloride	0.01 wt %	____ wt %
Oxygen	0.74 wt %	____ wt %
Mercury	____ ppmw	____ ppmw
Higher Heating Value (HHV), Dry	15,198 Btu/lb	____ Btu/lb
Higher Heating Value (HHV), AR	13,699 Btu/lb	____ Btu/lb
Ash Analysis	Performance	Design
SiO2	____ wt %	____ wt %
Al2O3	____ wt %	____ wt %
Fe2O3	____ wt %	____ wt %
TiO2	____ wt %	____ wt %
CaO	____ wt %	____ wt %
MgO	____ wt %	____ wt %
Na2O	____ wt %	____ wt %
K2O	____ wt %	____ wt %
P2O5	____ wt %	____ wt %
SO3	____ wt %	____ wt %
Undetermined	____ wt %	____ wt %
Total	100.00 wt %	_____wt %
Ash Fusion Temperature - Reducing	Performance	Design
Initial Deformation	_____°F	__°F
Softening	_____°F	__°F
Hemispherical	_____°F	__°F
Fluid	_____°F	__°F

Ash Fusion Temperature - Oxidizing

Initial Deformation	_____°F	__°F
Softening	_____°F	__°F
Hemispherical	_____°F	__°F
Fluid	_____°F	_ _°F

Fluxant (if required)

Material: ____________________
Purity: _____ wt %
____ stpd
Provision to add up to ____ stpd (space only)

Feedstock 3 — **Spring Creek PRB Coal –** Fed as a blend with Jacobs Ranch *(Performance coal specification for optimization studies. Design Specification TBD)*

Solids Feed	Supplied by rail	
Size (as received)	2” x 0”	
Proximate Analysis	Performance	Design
Moisture (as received)	25.40 wt %	___ wt %
Ash (as received)	4.12 wt %	___ wt%
Fixed Carbon	___ wt %	___ wt %
Volatile Matter	____ wt %	___ wt %
Ultimate Analysis (dry)	Performance	Design
Carbon	76.81 wt %	_ ___ wt %
Hydrogen	5.39 wt %	____ wt %
Nitrogen	1.01 wt %	____ wt %
Sulfur	0.48 wt %	____ wt %
Chloride	____ wt %	____ wt %
Oxygen	16.31 wt %	____ wt %
Mercury	____ ppmw	____ ppmw
Higher Heating Value (HHV), Dry	12,534 Btu/lb	____ Btu/lb
Higher Heating Value (HHV), AR	9,350 Btu/lb	____ Btu/lb
Ash Analysis	Performance	Design
SiO2	____ wt %	____ wt %
Al2O3	____ wt %	____ wt %
Fe2O3	____ wt %	____ wt %
TiO2	____ wt %	____ wt %
CaO	____ wt %	____ wt %
MgO	____ wt %	____ wt %
Na2O	____ wt %	____ wt %
K2O	____ wt %	____ wt %
P2O5	____ wt %	____ wt %
SO3	____ wt %	____ wt %
Undetermined	____ wt %	____ wt %
Total	100.00 wt %	100.00 wt %
Ash Fusion Temperature - Reducing		
Initial Deformation	_____°F	
Softening	_____°F	
Hemispherical	_____°F	
Fluid	_____°F	
Ash Fusion Temperature - Oxidizing		
Initial Deformation	_____°F	
Softening	_____°F	
Hemispherical	_____°F	
Fluid	_____°F	

Feedstock 4	**Jacobs Ranch PRB Coal–** Fed as a blend with Spring Creek *(Performance coal specification for optimization studies. Design Specification TBD See Attached Data)*	
Solids Feed	Supplied by rail	
Size (as received)	2" x 0"	
Proximate Analysis	Performance	Design
Moisture (as received)	26.94 wt %	___ wt %
Ash (as received)	6.80 wt %	___ wt%
Fixed Carbon	____ wt %	___ wt %
Volatile Matter	____ wt %	___ wt %
Ultimate Analysis (dry)	Performance	Design
Carbon	77.35 wt %	____ wt %
Hydrogen	5.87 wt %	____ wt %
Nitrogen	1.21 wt %	____ wt %
Sulfur	1.33 wt %	____ wt %
Chloride	___ wt %	____ wt %
Oxygen	14.24 wt %	____ wt %
Mercury	____ ppmw	____ ppmw
Higher Heating Value (HHV), Dry	12,044 Btu/lb	____ Btu/lb
Higher Heating Value (HHV), AR	8,800 Btu/lb	____ Btu/lb
Ash Analysis	Performance	Design
SiO2	____ wt %	____ wt %
Al2O3	____ wt %	____ wt %
Fe2O3	____ wt %	____ wt %
TiO2	____ wt %	____ wt %
CaO	____ wt %	____ wt %
MgO	____ wt %	____ wt %
Na2O	____ wt %	____ wt %
K2O	____ wt %	____ wt %
P2O5	____ wt %	____ wt %
SO3	____ wt %	____ wt %
Undetermined	____ wt %	____ wt %
Total	100.00 wt %	100.00 wt %
Ash Fusion Temperature - Reducing		
Initial Deformation	_____°F	
Softening	_____°F	
Hemispherical	_____°F	
Fluid	_____°F	
Ash Fusion Temperature - Oxidizing		
Initial Deformation	_____°F	
Softening	_____°F	
Hemispherical	_____°F	
Fluid	_____°F	

Feedstock 5	**Illinois #6 Coal** *(Performance coal specification for optimization studies. Design Specification TBD)*	
Solids Feed	Washed coal Supplied by rail	
Size (as received)	2" x 0"	
Proximate Analysis	Performance	Design
Moisture (as received)	11.30 wt %	___ wt %
Ash (as received)	9.50 wt %	___ wt%
Fixed Carbon	____ wt %	___ wt %
Volatile Matter	____ wt %	___ wt %
Ultimate Analysis (dry)	Performance	Design
Carbon	80.91 wt %	___ wt %
Hydrogen	5.50 wt %	____ wt %
Nitrogen	1.73 wt %	____ wt %
Sulfur	3.79 wt %	____ wt %
Chloride	____wt %	____ wt %
Oxygen	7.91 wt %	____ wt %
Mercury	____ ppmw	____ ppmw
Higher Heating Value (HHV), Dry	12,802 Btu/lb	____ Btu/lb
Higher Heating Value (HHV), AR	11,586 Btu/lb	____ Btu/lb
Ash Analysis	Performance	Design
SiO_2	____ wt %	____ wt %
Al_2O_3	____ wt %	____ wt %
Fe_2O_3	____ wt %	____ wt %
TiO_2	____ wt %	____ wt %
CaO	____ wt %	____ wt %
MgO	____ wt %	____ wt %
Na_2O	____ wt %	____ wt %
K_2O	____ wt %	____ wt %
P_2O_5	____ wt %	____ wt %
SO_3	____ wt %	____ wt %
Undetermined	____ wt %	____ wt %
Total	100.00 wt %	_____wt %
Ash Fusion Temperature - Reducing	<u>Performance</u>	Design
Initial Deformation	_____°F	__°F
Softening	_____°F	__°F
Hemispherical	_____°F	__°F
Fluid	_____°F	__°F
<u>Ash Fusion Temperature - Oxidizing</u>		
Initial Deformation	_____°F	__°F
Softening	_____°F	__°F
Hemispherical	_____°F	__°F
Fluid	_____°F	_ _°F

Fluxant (if required)	Material: ____________________ Purity: _____ wt % ____ stpd Provision to add up to ____ stpd (space only)

Fluxant Specification:

(Later - To be provided by ConocoPhillips)

ATTACHMENT 2

POTENTIAL OPERATING SCENARIOS

POTENTIAL OPERATING SCENARIOS

Number of Combustion Turbine/Generators (CTGs) Operating	Number/Loading of Gasifiers	Fuel to each CTG (as % of Max fuel load to CTG) NG / Syngas (SG)	CTG Loading
1	0	70% (or less) NG / 0% SG	Minimum NG (1,2)
1	1 @ 70%	0% NG / 70 % SG	Minimum SG
1	1 @ 70%	30% NG / 70% SG	Full
1	0	100% NG / 0% SG	Full
1	1 @ 100%	0% NG / 100% SG	Full
2	1 @ 70%	35% (or less) NG / 35% SG	Minimum (3)
2	0	70% (or less) NG / 0% SG	Minimum NG (1,2)
2	2 @ 70%	0 % NG / 70% SG	Minimum SG
2	1 @ 70%	65% NG / 35% SG	Full
2	2 @ 70%	30% NG / 70% SG	Full
2	0	100% NG / 0% SG	Full
2	2 @ 100%	0% NG / 100% SG	Full

1. Minimum CTG load on NG maintaining emissions compliance expected to be ~ 50-60% load (will depend on CTG manufacturer and fuel).
2. Minimum flow of natural gas to be determined, based on minimum CTG load remaining within emissions compliance.
3. Minimum turndown on mixed natural gas/syngas fuel to be determined, based on minimum CTG load remaining within emissions compliance.

ATTACHMENT 3

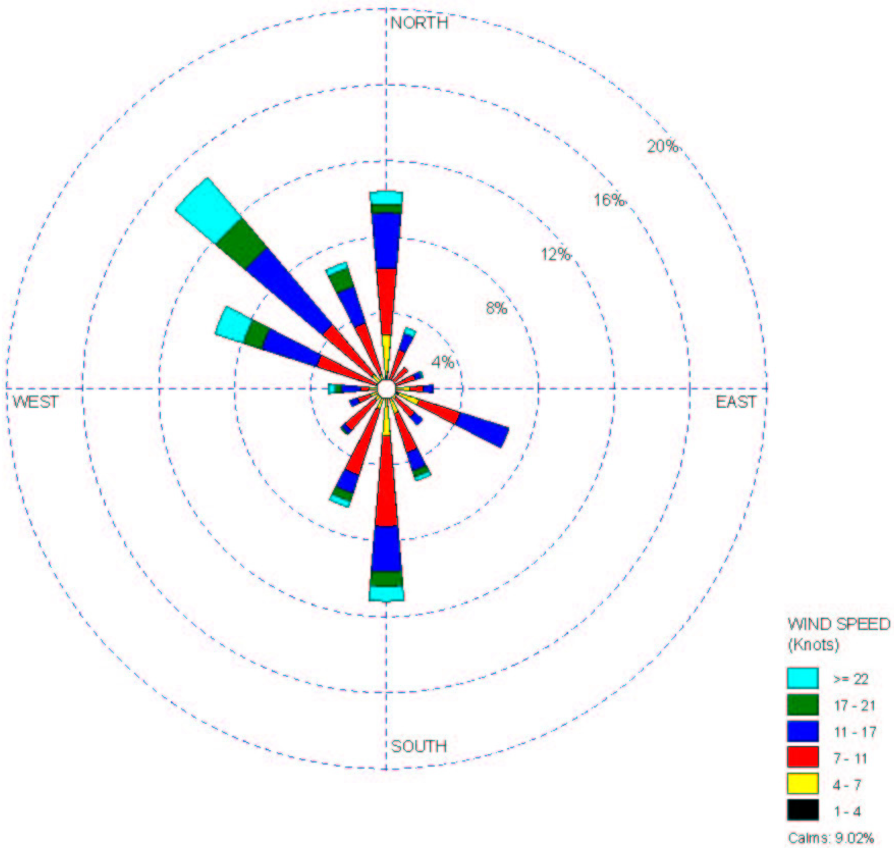
MONTHLY WIND ROSE DATA (HIBBING)

WIND ROSE PLOT:

Hibbing December 04
WBAN 94931

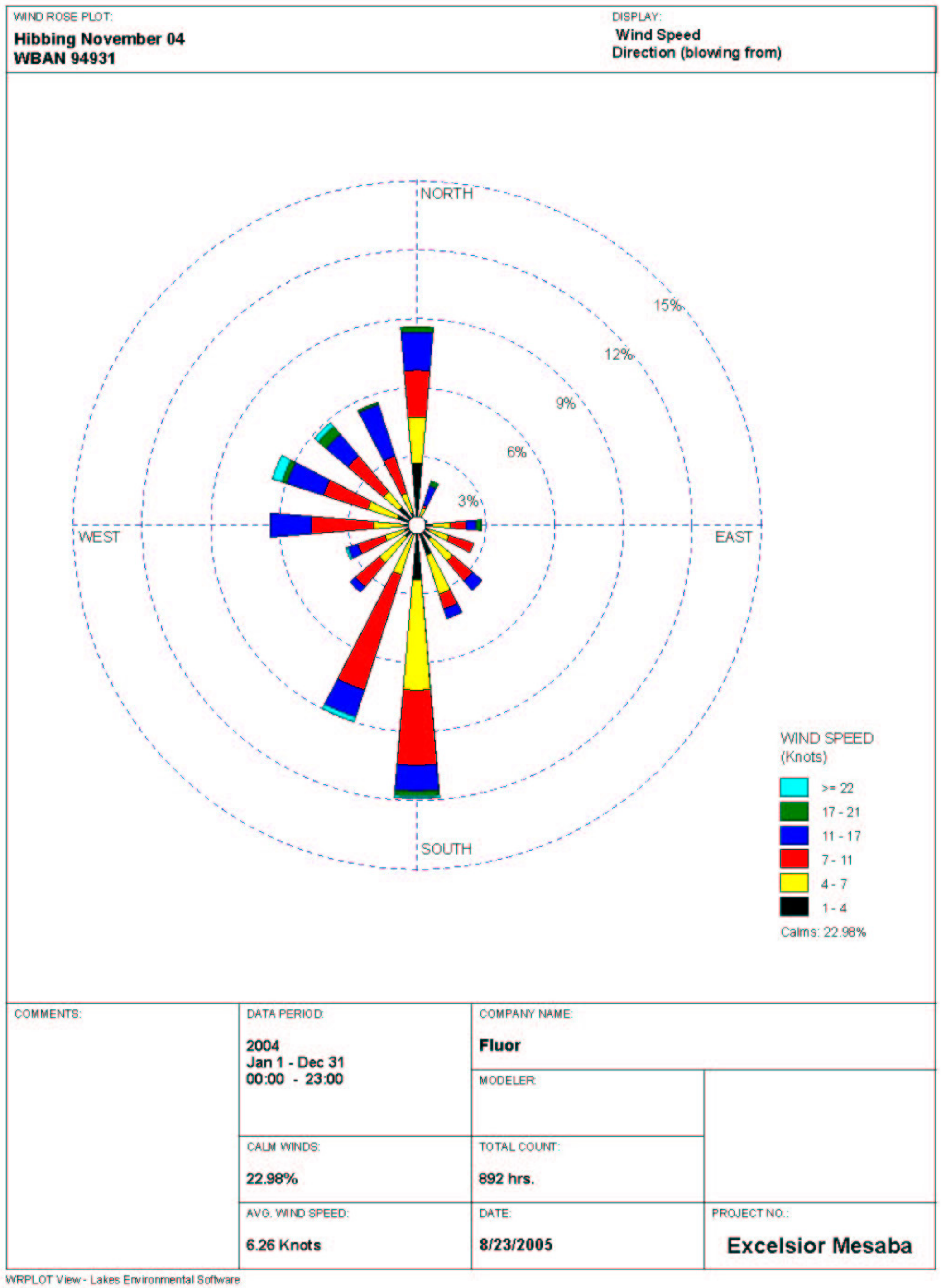
DISPLAY:

Wind Speed
Direction (blowing from)



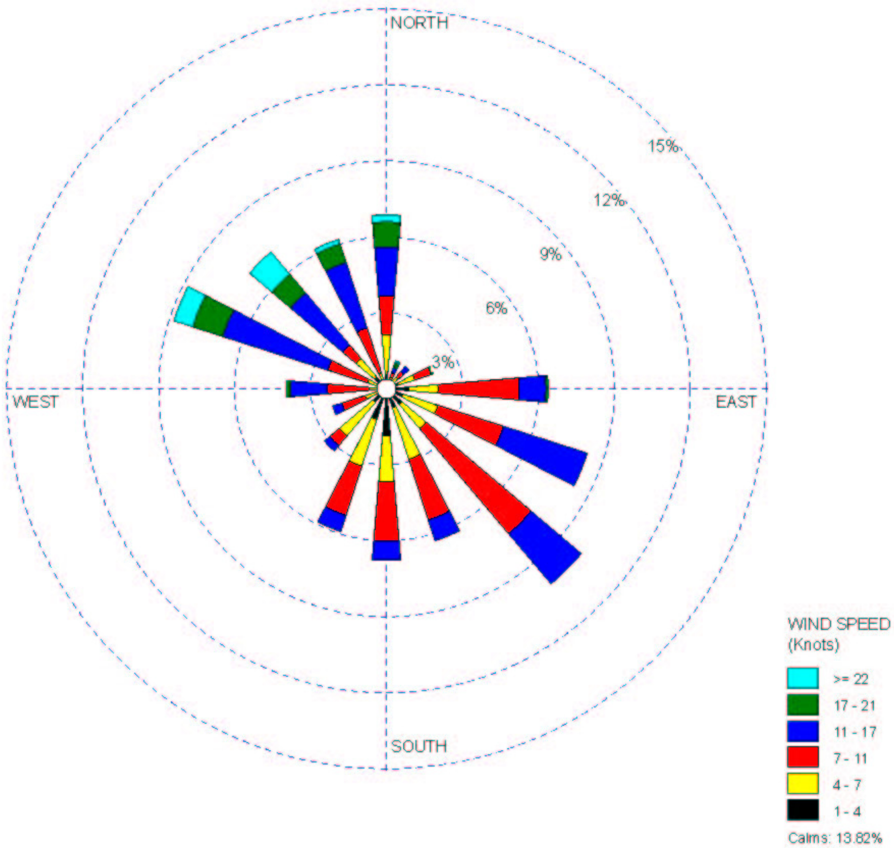
COMMENTS:	DATA PERIOD: **2004** **Jan 1 - Dec 31** **00:00 - 23:00**	COMPANY NAME: **Fluor**	
		MODELER:	
	CALM WINDS: **9.02%**	TOTAL COUNT: **887 hrs.**	
	AVG. WIND SPEED: **10.43 Knots**	DATE: **8/23/2005**	PROJECT NO.: **Excelsior Mesaba**

WRPLOT View - Lakes Environmental Software


WIND ROSE PLOT:
Hibbing November 04
WBAN 94931
DISPLAY:
Wind Speed
Direction (blowing from)
NORTH
SOUTH
WEST
EAST
3%
6%
9%
12%
15%
WIND SPEED
(Knots)
>= 22
17 - 21
11 - 17
7 - 11
4 - 7
1 - 4
Calms: 22.98%
COMMENTS:
DATA PERIOD:
2004
Jan 1 - Dec 31
00:00 - 23:00
COMPANY NAME:
Fluor
MODELER:
CALM WINDS:
22.98%
TOTAL COUNT:
892 hrs.
AVG. WIND SPEED:
6.26 Knots
DATE:
8/23/2005
PROJECT NO.:
Excelsior Mesaba
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:
Hibbing October 04
WBAN 94931

DISPLAY:
Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	2004 **Jan 1 - Dec 31** **00:00 - 23:00**	**Fluor**	
		MODELER:	
	CALM WINDS: **13.82%**	TOTAL COUNT: **1035 hrs.**	
	AVG. WIND SPEED: **8.40 Knots**	DATE: **8/23/2005**	PROJECT NO.: **Excelsior Mesaba**

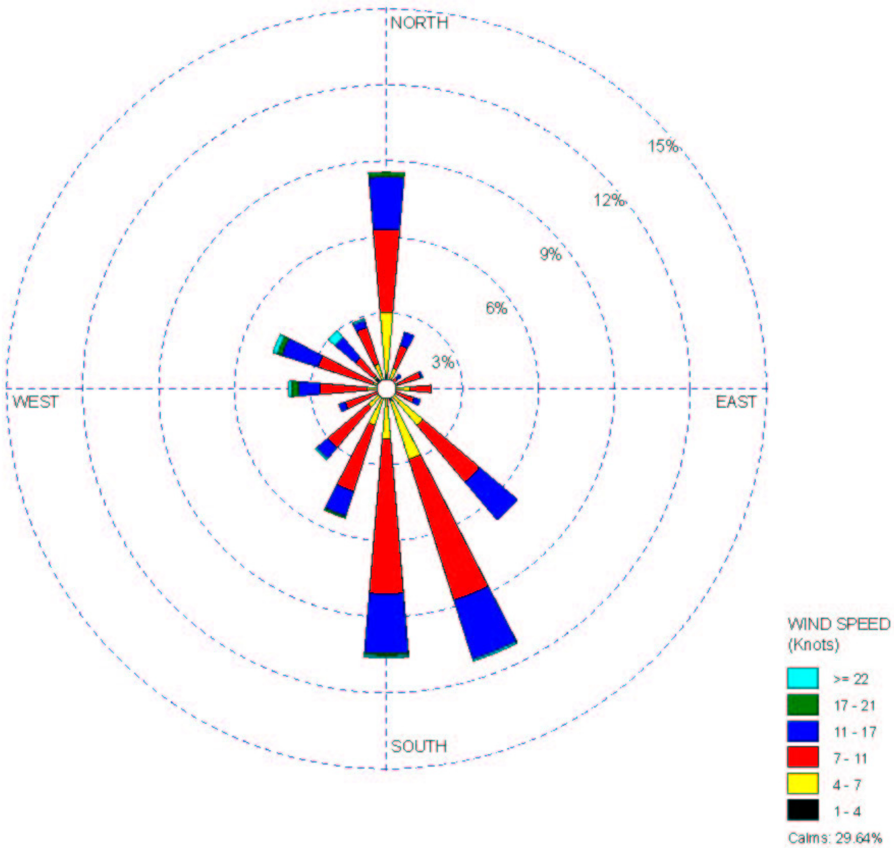
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

Hibbing September 04
WBAN 94931

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD: **2004** **Jan 1 - Dec 31** **00:00 - 23:00**	COMPANY NAME: **Fluor**	
		MODELER:	
	CALM WINDS: **29.64%**	TOTAL COUNT: **1066 hrs.**	
	AVG. WIND SPEED: **6.31 Knots**	DATE: **8/23/2005**	PROJECT NO.: **Excelsior Mesaba**

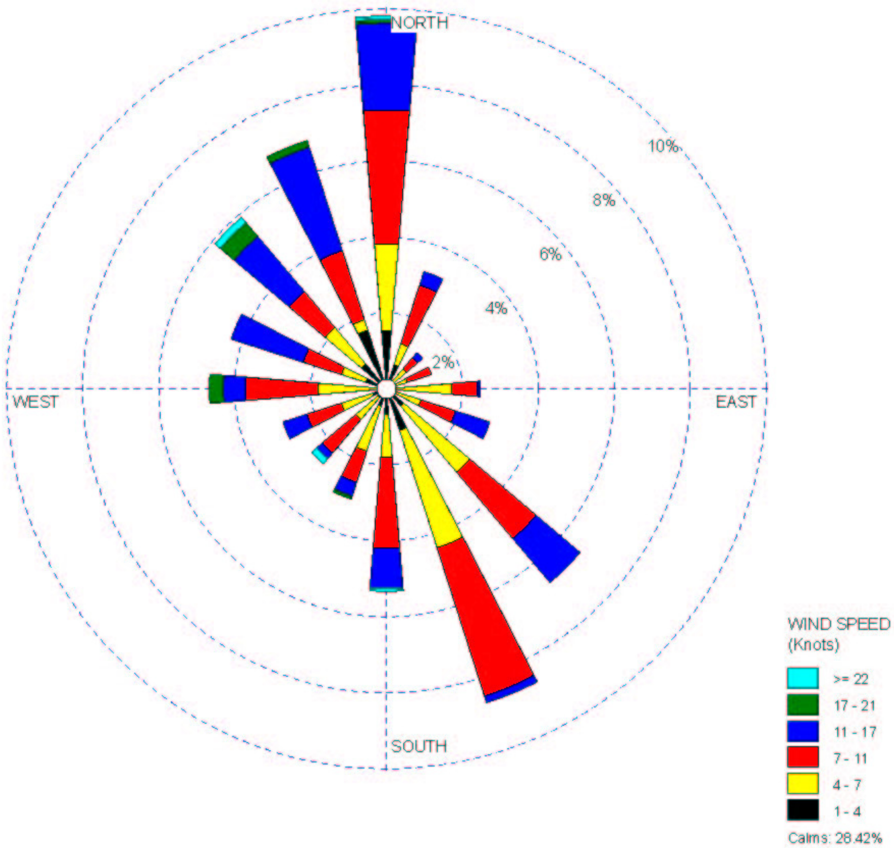
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

Hibbing August 04
WBAN 94931

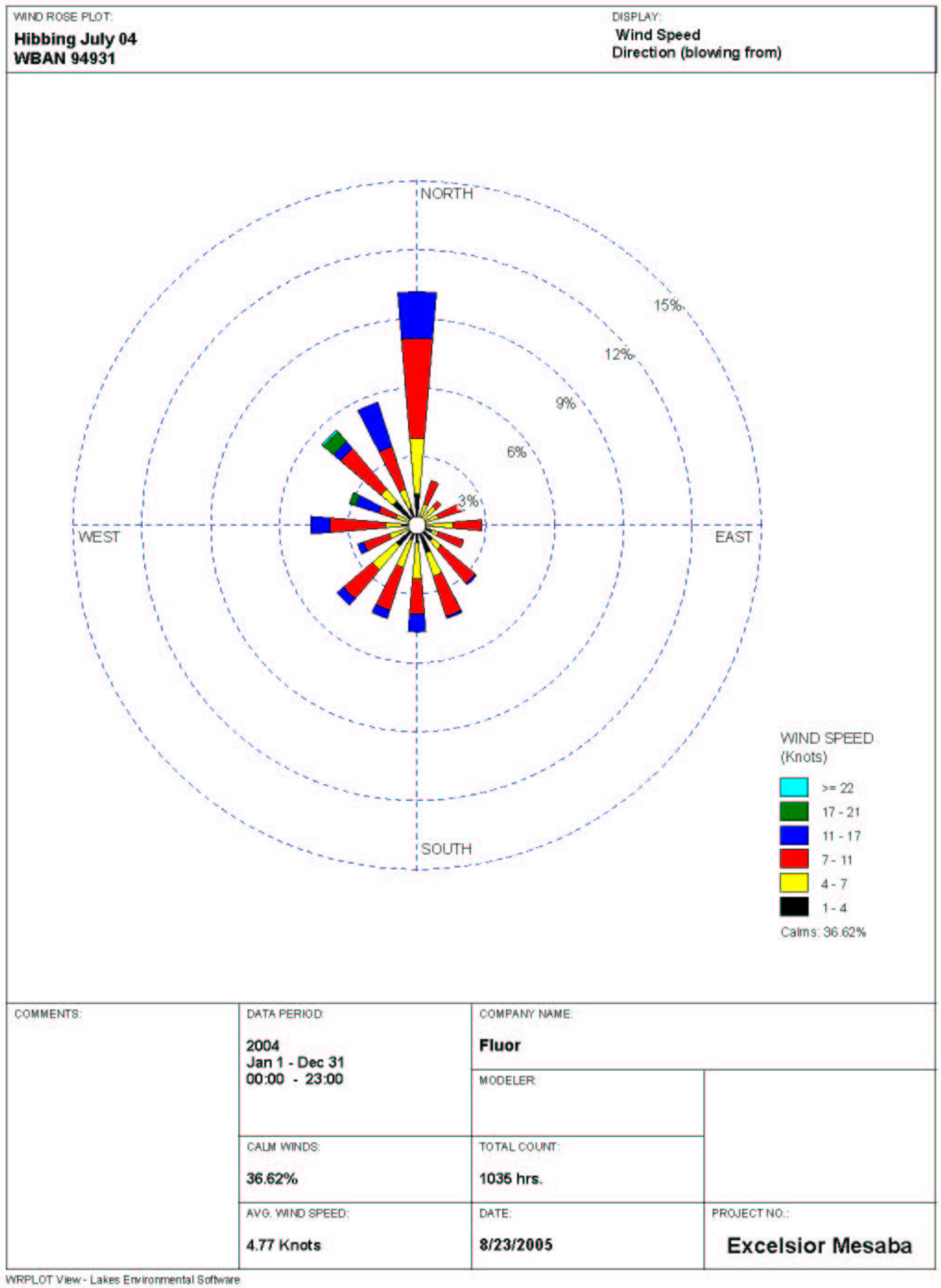
DISPLAY:

Wind Speed
Direction (blowing from)



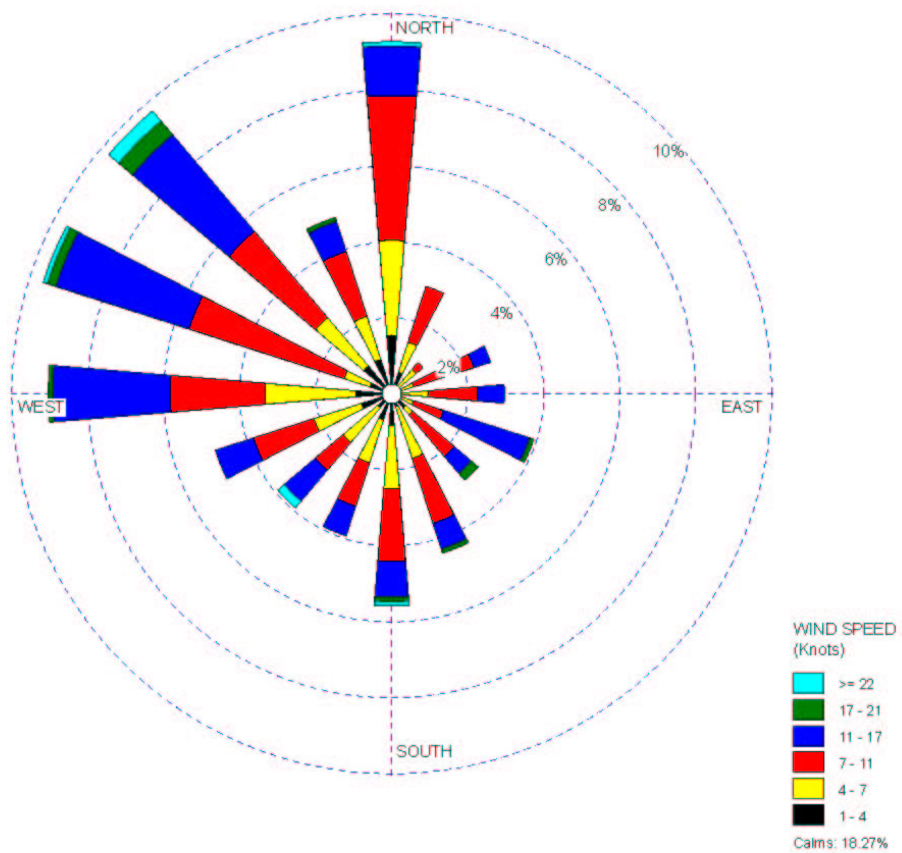
COMMENTS:	DATA PERIOD: **2004** **Jan 1 - Dec 31** **00:00 - 23:00**	COMPANY NAME: **Fluor**	
		MODELER:	
	CALM WINDS: **28.42%**	TOTAL COUNT: **1052 hrs.**	
	AVG. WIND SPEED: **5.93 Knots**	DATE: **8/23/2005**	PROJECT NO.: **Excelsior Mesaba**

WRPLOT View - Lakes Environmental Software


WIND ROSE PLOT:
Hibbing July 04
WBAN 94931
DISPLAY:
Wind Speed
Direction (blowing from)
NORTH
SOUTH
WEST
EAST
3%
6%
9%
12%
15%
WIND SPEED
(Knots)
>= 22
17 - 21
11 - 17
7 - 11
4 - 7
1 - 4
Calms: 36.62%
COMMENTS:
DATA PERIOD:
2004
Jan 1 - Dec 31
00:00 - 23:00
COMPANY NAME:
Fluor
MODELER:
CALM WINDS:
36.62%
TOTAL COUNT:
1035 hrs.
AVG. WIND SPEED:
4.77 Knots
DATE:
8/23/2005
PROJECT NO.:
Excelsior Mesaba
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:
Hibbing June 04
WBAN 94931

DISPLAY:
Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD: **2004** **Jan 1 - Dec 31** **00:00 - 23:00**	COMPANY NAME: **Fluor**	
		MODELER:	
	CALM WINDS: **18.27%**	TOTAL COUNT: **843 hrs.**	
	AVG. WIND SPEED: **7.32 Knots**	DATE: **8/23/2005**	PROJECT NO.: **Excelsior Mesaba**

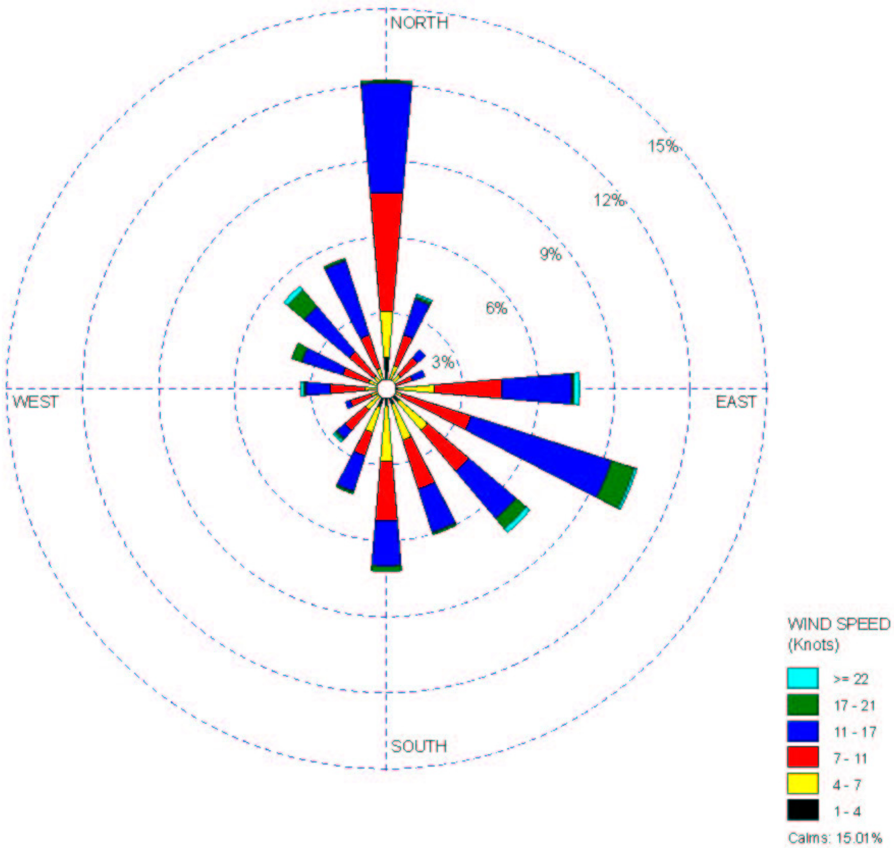
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

Hibbing May 04
WBAN 94931

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	2004 **Jan 1 - Dec 31** **00:00 - 23:00**	**Fluor**	
		MODELER:	
	CALM WINDS: **15.01%**	TOTAL COUNT: **946 hrs.**	
	AVG. WIND SPEED: **8.72 Knots**	DATE: **8/23/2005**	PROJECT NO.: **Excelsior Mesaba**

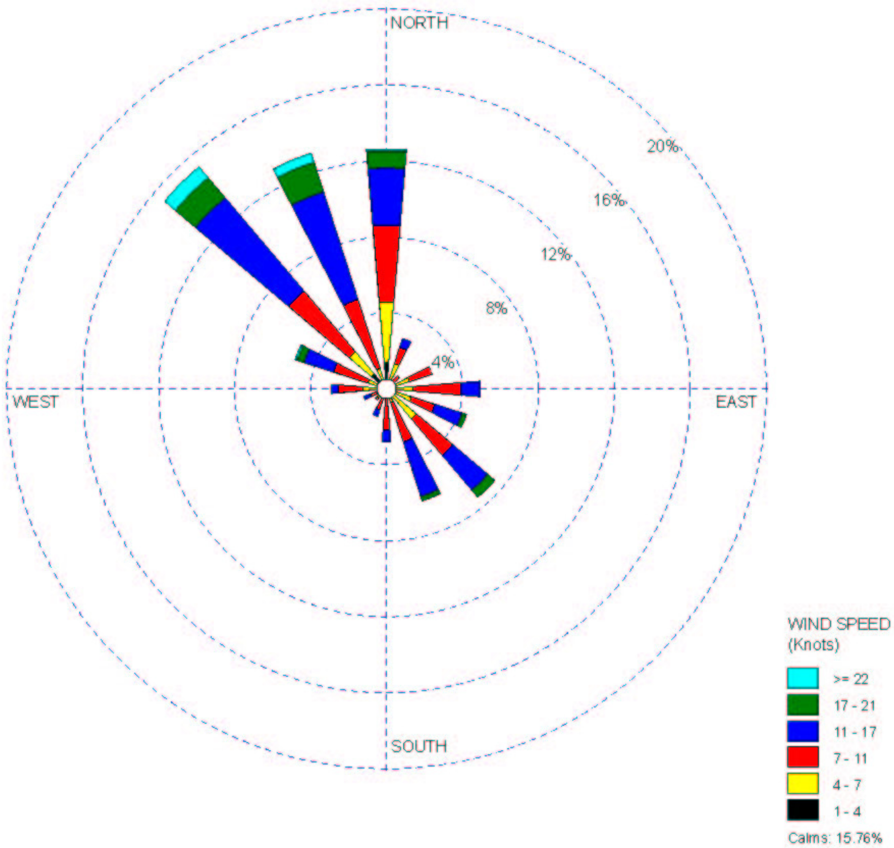
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

Hibbing April 04
WBAN 94931

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD: **2004** **Jan 1 - Dec 31** **00:00 - 23:00**	COMPANY NAME: **Fluor**	
		MODELER:	
	CALM WINDS: **15.76%**	TOTAL COUNT: **793 hrs.**	
	AVG. WIND SPEED: **8.65 Knots**	DATE: **8/23/2005**	PROJECT NO.: **Excelsior Mesaba**

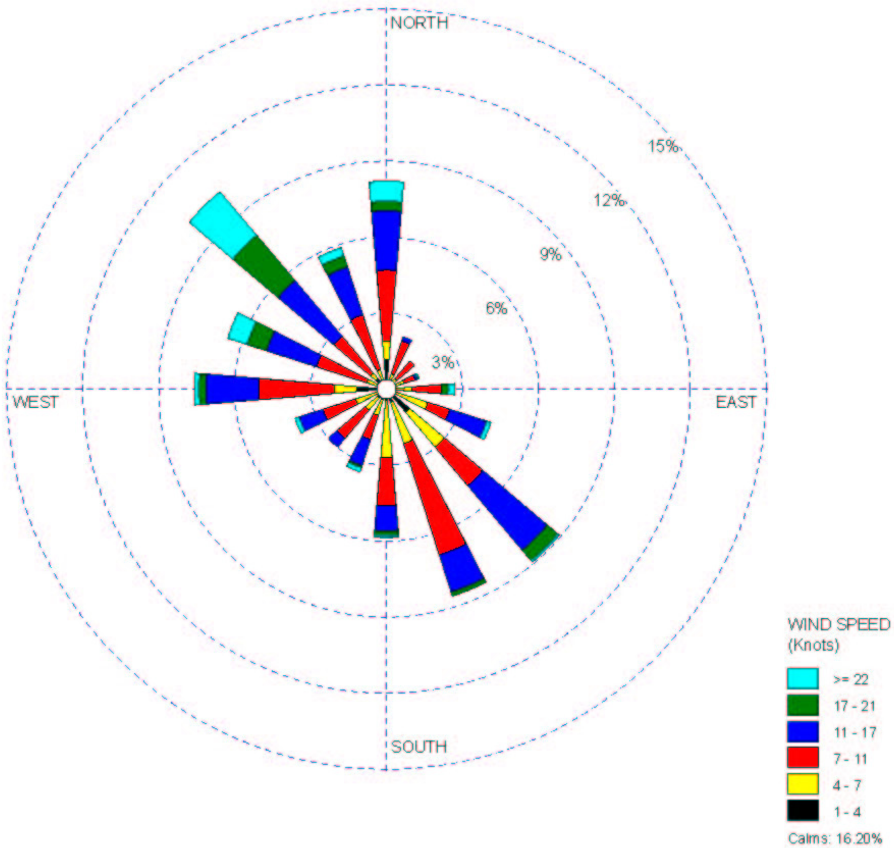
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

Hibbing March 04
WBAN 94931

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD: **2004** **Jan 1 - Dec 31** **00:00 - 23:00**	COMPANY NAME: **Fluor**	
		MODELER:	
	CALM WINDS: **16.20%**	TOTAL COUNT: **1111 hrs.**	
	AVG. WIND SPEED: **8.86 Knots**	DATE: **8/23/2005**	PROJECT NO.: **Excelsior Mesaba**

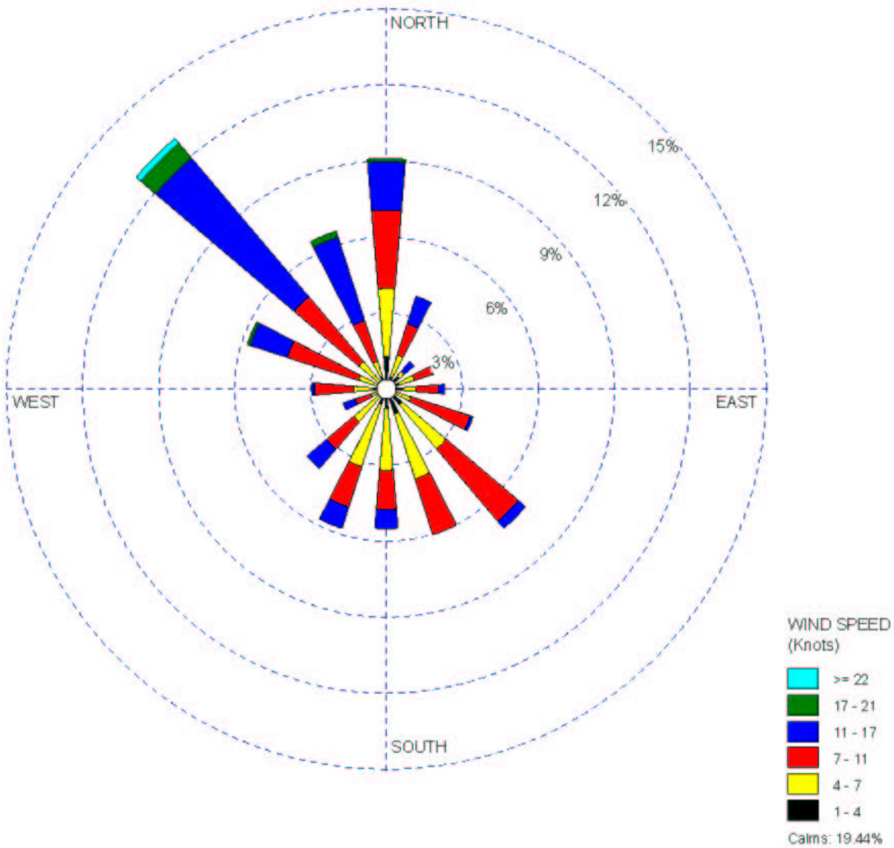
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

Hibbing February 04
WBAN 94931

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	2004 **Jan 1 - Dec 31** **00:00 - 23:00**	**Fluor**	
		MODELER:	
	CALM WINDS: **19.44%**	TOTAL COUNT: **782 hrs.**	
	AVG. WIND SPEED: **6.91 Knots**	DATE: **8/23/2005**	PROJECT NO.: **Excelsior Mesaba**

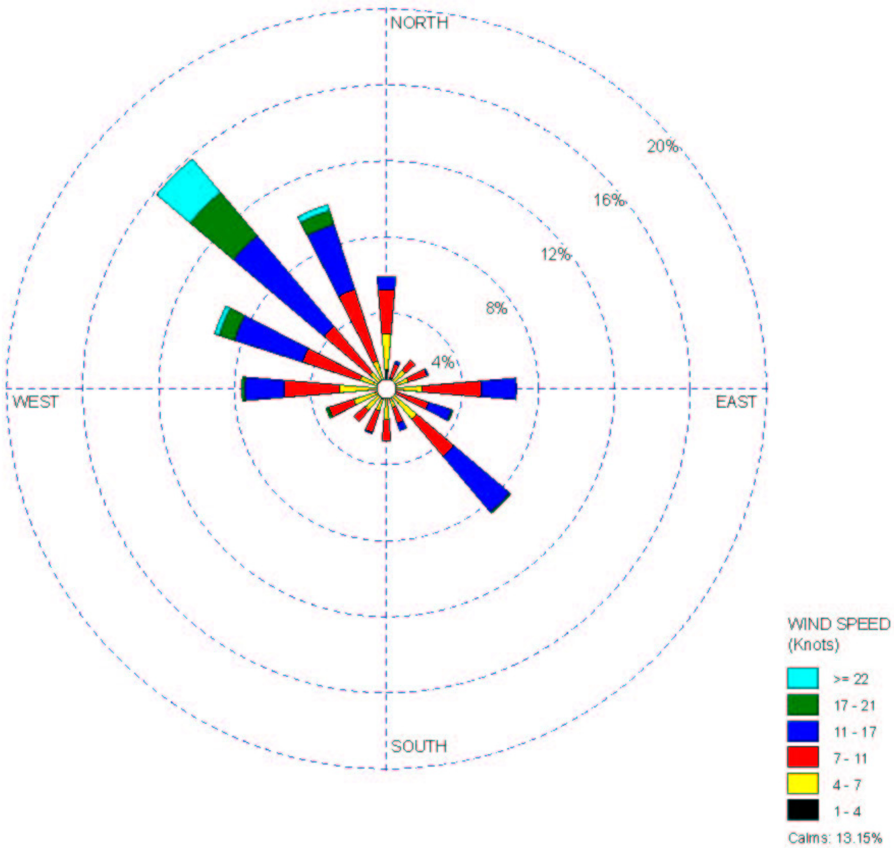
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

Hibbing January 04
WBAN 94931

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD: **2004** **Jan 1 - Dec 31** **00:00 - 23:00**	COMPANY NAME: **Fluor**	
		MODELER:	
	CALM WINDS: **13.15%**	TOTAL COUNT: **1171 hrs.**	
	AVG. WIND SPEED: **8.81 Knots**	DATE: **8/23/2005**	PROJECT NO.: **Excelsior Mesaba**

WRPLOT View - Lakes Environmental Software

ATTACHMENT 4

PLANT EMISSION AND DISCHARGE ESTIMATES

AS SPECIFIED BY PROJECT PERMIT APPLICATIONS

AIR EMISSIONS INVENTORY

(The following is an excerpt from the Air Permit Application for Mesaba One & Two. The FEED package is not exempt from addressing emission requirements to which the Project is subject that are omitted from this document.)

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).

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.)

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

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.

Flares

The elevated flares for each project phase will be 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 rate 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.

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.

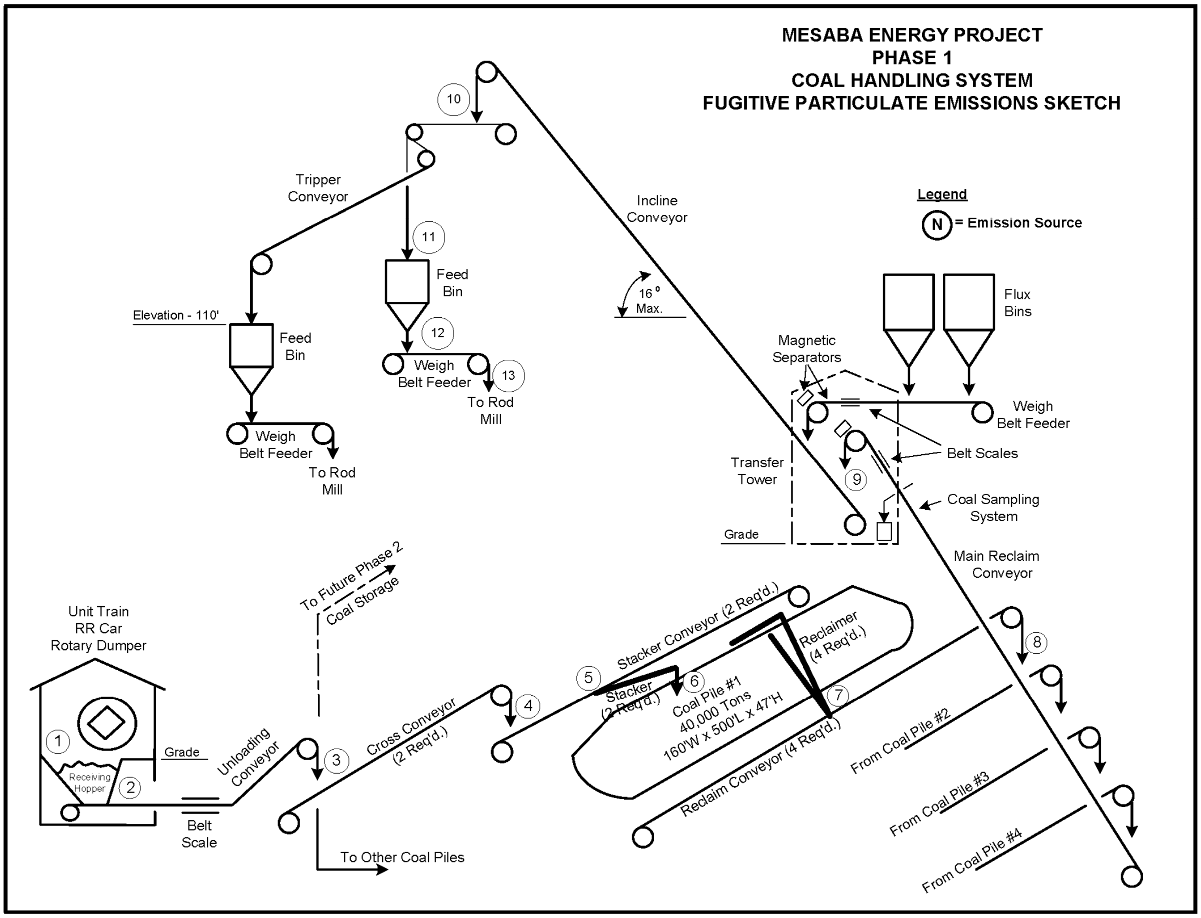
Material Handling Systems

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			PM_{30} Emission Factor (lb/ton)	PM_{10} Emission Factor (lb/ton)	Maximum Hourly Throughput (ton/hr)	Maximum Annual Throughput (ton/yr)	Control Method	Control Efficiency (%)	Controlled PM_{30} Maximum Hourly Emission Rate (lb/hr)	Controlled PM_{30} Maximum Annual Emission Rate (ton/yr)	Controlled PM_{10} Maximum Hourly Emission Rate (lb/hr)	Controlled PM_{10} Maximum Annual Emission Rate (ton/yr)
COAL HANDLING AND STORAGE												
1	Railcar Unloading		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		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		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		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		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

Emission Source Description			PM_{30} Emission Factor (lb/ton)	PM_{10} Emission Factor (lb/ton)	Maximum Hourly Throughput (ton/hr)	Maximum Annual Throughput (ton/yr)	Control Method	Control Efficiency (%)	Controlled PM_{30} Maximum Hourly Emission Rate (lb/hr)	Controlled PM_{30} Maximum Annual Emission Rate (ton/yr)	Controlled PM_{10} Maximum Hourly Emission Rate (lb/hr)	Controlled PM_{10} Maximum Annual Emission Rate (ton/yr)
6	Stacker to Coal Pile		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		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		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		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		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		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			PM_{30} Emission Factor (lb/ton)	PM_{10} Emission Factor (lb/ton)	Maximum Hourly Throughput (ton/hr)	Maximum Annual Throughput (ton/yr)	Control Method	Control Efficiency (%)	Controlled PM_{30} Maximum Hourly Emission Rate (lb/hr)	Controlled PM_{30} Maximum Annual Emission Rate (ton/yr)	Controlled PM_{10} Maximum Hourly Emission Rate (lb/hr)	Controlled PM_{10} Maximum Annual Emission Rate (ton/yr)
	Windage from Coal Storage		--	--	--	--	None	0	--	0.104	--	0.052
									8.28	**4.24**	**3.97**	**2.02**
12	Feed Bin to Weigh Belt Feeder		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		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
									0.09	**0.31**	**0.04**	**0.15**
	Slag Disposal Truck Traffic		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		--	--	--	--	None	0	--	0.027	--	0.013
	Slag Storage Load-out		0.0053	0.0025	39	281,780	None	0	0.207	0.748	0.098	0.354

Emission Source Description		PM_{30} Emission Factor (lb/ton)	PM_{10} Emission Factor (lb/ton)	Maximum Hourly Throughput (ton/hr)	Maximum Annual Throughput (ton/yr)	Control Method	Control Efficiency (%)	Controlled PM_{30} Maximum Hourly Emission Rate (lb/hr)	Controlled PM_{30} Maximum Annual Emission Rate (ton/yr)	Controlled PM_{10} Maximum Hourly Emission Rate (lb/hr)	Controlled PM_{10} Maximum Annual Emission Rate (ton/yr)
	SUBTOTAL							**0.89**	**3.75**	**0.28**	**1.16**
	TOTAL							**9.25**	**8.30**	**4.28**	**3.33**

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

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.

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

Lead and Non-Criteria Pollutants

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.

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.

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

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.

WATER DISCHARGE INVENTORY

(The following is an excerpt from the NPDES Permit Application for Mesaba One & Two. The FEED package is not exempt from addressing discharge requirements to which the Project is subject that are omitted from this document.)

- **STORMWATER MANAGEMENT**
  - **CONSTRUCTION**

In accordance with 40 C.F.R. Part 122.26(b)(14)(x), The Applicant will develop and submit to the MPCA a Storm Water Pollution Prevention Plan (SWPPP) that identifies erosion prevention and sediment BMPs. The SWPPP will be a combination of narrative and plan sheets that address foreseeable conditions at any stage in construction or post construction timeframes. The SWPPP will include a description of the nature of the construction activity and address the following:

- Potential for discharging sediment and/or other potential pollutants from the Optioned Property.
- Location and type of all temporary and permanent erosion prevention and sediment control BMPs along with procedures to be used to establish additional temporary BMPs as necessary for Site conditions during construction.
- Site map with existing and final grades, including dividing lines and direction of flow for all pre and post-construction stormwater runoff drainage areas located within the project limits. The site map will also identify impervious surfaces and soil types.
- Location of areas that are to remain undisturbed.
- Location of areas where construction will be phased to minimize duration of exposed soil areas.
- All surface waters and existing wetlands, which can be identified on maps such as United States Geological Survey 7.5 minute quadrangle maps or equivalent maps, located within one-half mile from the construction site and which, during or after construction, will receive stormwater runoff.
- Methods to be used for final stabilization of all exposed soil areas.

  - **OPERATION**

Stormwater generated during operation of the IGCC Power Station will be managed in three ways:

1. Stormwater with the potential to become impacted with process solids will be segregated from process equipment by curbs, elevated drain funnels and other means and returned as makeup to the feedstock slurrying system or for other process water use.

2. Stormwater that could become impacted with oil (such as runoff from parking lots) will be routed through an oil/water separator to the cooling tower blowdown sump prior to being discharged off-site through Outfall 001.

Stormwater from other areas not associated with industrial activity will be routed to the stormwater detention ponds where settling can occur and initial rainfall ("first flush") can be contained, checked, and released in a controlled manner to Outfall 005 and Outfall 006.

- **WASTEWATER GENERATION AND DISCHARGE OUTFALLS**
  - **WASTEWATER GENERATION**

Zero Liquid Discharge System

The IGCC Power Station gasification island will incorporate a significant environmental feature to protect the quality of local streams and lakes. Significantly, wastewater generated from the gasification and slag processing operations, containing certain levels of heavy metals and other contaminants from the feedstocks, will be treated in a Zero Liquid Discharge ("ZLD") process that will recover distilled water for reuse in the power plant, (reducing fresh water consumption) and, more importantly, concentrate heavy metals and other contaminants of concern into a solid waste stream. This solid waste will be disposed in a solid waste management facility operating in accordance with all applicable rules and regulations governing such facilities. No wastewater streams from this system will be discharged or require disposal(see Figure 3.1-1).

Discharges From the IGCC Power Station

As shown in Table 3.1-2, wastewater from the power block will consist primarily of cooling tower blowdown blended with relatively low-flow additional wastewater streams from other plant systems (including HRSG blowdown, boiler feed water demineralizers and intermittent treated water from the oil/water separator serving the plant drainage system). Estimated average annual flow rates of the waste streams contributing to discharge to CMP and/or Holman Lake during IGCC Power Station operation are shown in Figure 3.1-2a (for Mesaba One) and Figure 3.1-2b (for Mesaba One and Mesaba Two). Calculated total wastewater discharge rates to the CMP vary for the range of expected coals and petroleum coke feedstocks to be processed in the plant and the COC in the cooling towers. The discharge to the CMP may also vary due to the discharge of a portion of the IGCC Power Station effluent directly to Holman Lake. The expected range of wastewater discharge rates is summarized in Table 4.1-1 (see also Figures 3.1-2a and 3.1-2b and Table 3.1-2).

Table 4.1-1
Wastewater Discharge Rates

Phase	Peak Discharge (gpm)	Average Annual Discharge	
		(gpm)	(MGD)
Mesaba One (5 COC)	1,300	890	1.3
Mesaba One and Mesaba Two (3 COC)	5,140	3,500	5.0

Because almost all of the wastewater discharged from the IGCC Power Station operations is due to the need to remove a portion of the condenser cooling water for control of dissolved solids, the constituents in the discharge are essentially the same materials present in the background water supply delivered to the plant, but more concentrated. Based on the IGCC Power Station equipment operating requirements and expected water source quality, the plant cooling towers are expected to be limited to between approximately three to five COC. Therefore, the contaminants in the cooling water blowdown are expected to be concentrated (due to evaporation in the cooling tower) by about three to five times the concentration in the water supply. Information regarding discharges associated with eight COC is presented in Table 3.1-2 given the potential to operate at that level.

Sanitary Discharges

The sanitary wastewater produced during operation of the Phase I and II IGCC Power Station will be relatively small (about 30 gallons per day per person) and will be discharged to the City of Taconite's sanitary sewer system. As an alternative, the sanitary wastewater could be treated in an on-site septic system. In either case, this wastewater stream is not included under this NPDES permit application.

- **CHEMICAL ADDITIVES**

Typical chemicals that are expected to be added to the water stream that ultimately will be discharged from the IGCC Power Station to the CMP and/or Holman Lake are listed in Table 4.2-1. These chemicals are primarily needed to control cooling water corrosion and fouling and to neutralize certain undesirable constituents in the plant discharge stream. The point of introduction for each of the chemicals is also indicated in the table and shown in Figure 4.2-1. Material Safety Data Sheets (MSDS) representative of the chemical additives are provided in Appendix C. The estimated usage for Mesaba One and Mesaba Two are listed (half the indicated amount will be used for Mesaba One only). To be noted is that the majority of these chemicals will be consumed in the plant processes and only residual amounts are expected to be present in the water ultimately discharged. These quantities are preliminary estimates only and are subject to revision when the specific water chemistry program for the facility is developed.

Table 4.2-1
Chemical Additives

Chemical	Point(s) of Introduction	Estimated Usage (lbs/year)	Estimated Residual in Discharge	Basis, % in Discharge
Dechlorination - Sodium Bisulfite	**Cooling Tower Blowdown Sump, Reverse Osmosis System**	**15,000** **7500**	**150** **75**	**1%**
Oxygen Scavenger	**Boiler Feed Water**	**6,600**	**66**	**1%**
Condensate Corrosion Inhibitor-Neutralizing Amine/ammonia	**Boiler Feed Water**	**2,200**	**22**	**1%**
Chlorination - Sodium Hypochlorite	**Cooling Towers**	**300,000**	**1,500**	**0.5%**
pH control-93% Sulfuric acid	**Cooling Towers,** **Reverse Osmosis,** **Mixed Bed**	**18,000** **3,000** **11,000**	**36** **6** **22**	**0.2%**
Sodium Hydroxide	**Mixed Bed regeneration**	**11,000**	**0**	**(totally neutralized)**
Anti-Scalant	**Reverse Osmosis,** **Deionizer**	**150** **200**	**2** **2**	**1%**
Cleaning chemicals (intermittent), hydrochloric acid, caustic, surfactant	**Reverse Osmosis**	**1000 lb/yr**	**10**	**1%**
Non-Oxidizing Biocide	**Cooling Towers**	**11,000**	**22**	**0.2%**

- **NPDES PERMIT APPLICATION CONSIDERATIONS**

The IGCC Power Station operating plan described and analyzed in this section was developed to provide a worst-case analysis of discharges from Mesaba One and Mesaba Two that would meet all applicable water quality standards and the requirements of 40 C.F.R. 122.4 (that no new or expanded discharge will "cause or contribute" to violations of water quality standards in impaired waters).

- **WATER BALANCE SUMMARY**

Makeup water needs of the IGCC Power Station, primarily for cooling water needs (see Section 3), will be met by withdrawals from the CMP. Makeup water needs in excess of that otherwise available from the CMP will first be addressed by pumping water from the HAMP Complex into the CMP (at Outfall 003). Additional makeup water needs will next be met by transferring water from the LMP (and the Prairie River) into CMP (at Outfall 004). Natural inflows to all these pits occur from direct precipitation, surface water runoff and groundwater infiltration. IGCC Power Station discharges, primarily consisting of cooling tower blowdown, will be discharged into CMP (at Outfall 001) and/or into Holman Lake (at Outfall 002). Water will be discharged from the CMP to Holman Lake (at Outfall 002) to control water levels in the CMP and to manage pit water quality. Water levels will be maintained in the HAMP Complex by discharging water as necessary to Panasa Lake under the existing NPDES permitted outfall. Water use and discharge scenarios have been developed for Mesaba One and Mesaba One and Mesaba Two operations based on the expected water availability and water quality from each of the mine pit and river water sources described in earlier sections of this report, and the water quality considerations discussed later in this section.

The expected average annual flow rates for each water stream for operation of Mesaba One are shown in Figure 5.1-1a. The illustrated water balance for such operation is based on five COC in the cooling towers and assumes a portion of the plant effluent is discharged to the CMP (Outfall 001) and a portion is discharged to Holman Lake (Outfall 002). The volume of water discharged to Holman Lake is based on the currently permitted mass of mercury and phosphorus now allowed from the HAMP Complex. The exact flow rate and volume discharged to Holman Lake will be dependent upon the water quality discharged from the IGCC Power Station. In addition, provisions will be made for direct discharge from the CMP to Holman Lake if required to control water levels in the CMP.

The expected average annual flow rates for each water stream for operation of Mesaba One and Mesaba Two is shown in Figure 5.1-1b. The illustrated water balance for such operation is based on three COC in the cooling towers and assumes that a portion of the plant discharge is discharged through Outfall 001 to the CMP and a portion of the plant discharge is directed to Holman Lake through Outfall 002. Normally, during operation of Mesaba One and Mesaba One and Mesaba Two, no discharge is expected occur from the CMP to Holman Lake. As with operation of Mesaba One, the ability to discharge through Outfall 002 from the CMP during operation of Mesaba One and Mesaba Two is desired to provide operational flexibility.

Figure 5.1-1a
Mesaba One Water Operations Flow Rates

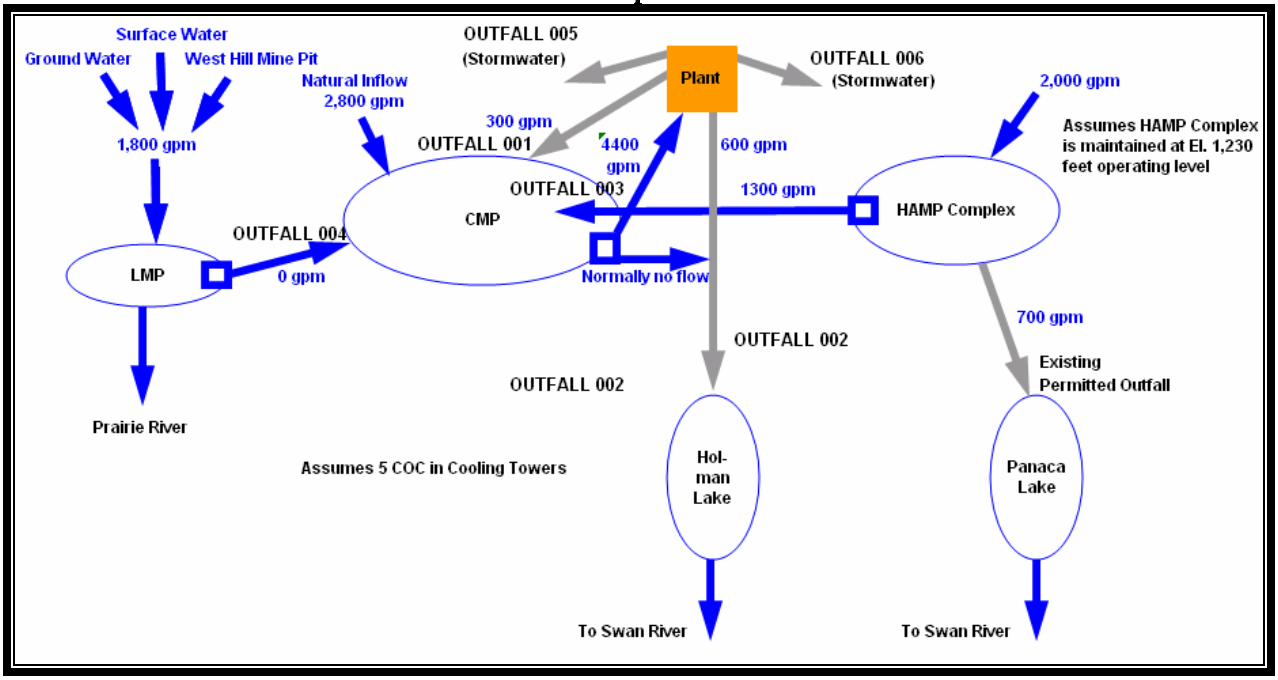
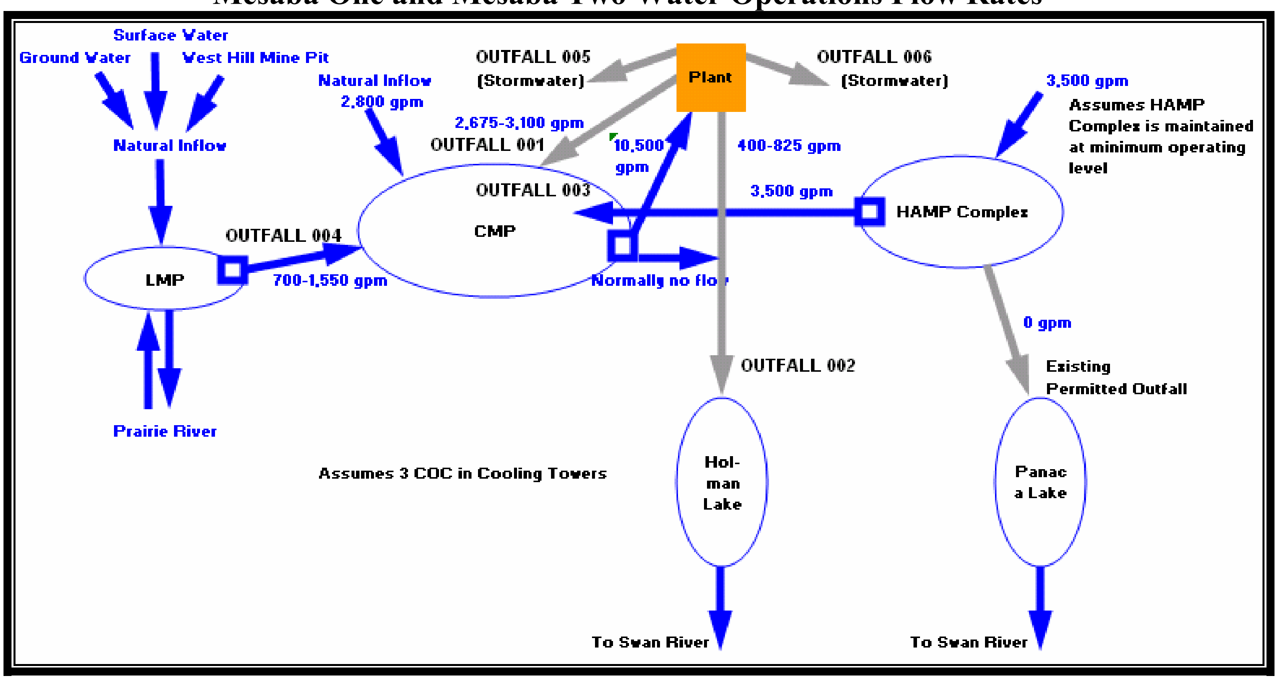


Figure 5.1-1b
Mesaba One and Mesaba Two Water Operations Flow Rates



The expected average annual flow rate and proposed permitted peak flow rate for each outfall for Phase I and Phase I and II operation are summarized in Table 5.1-1. The expected average annual discharge rates are based on the water balances presented above. The proposed peak discharge rates are typically based on modeled peak rates plus some additional capacity to provide operational flexibility.

Table 5.1-1
Discharge Flow Rates

Outfall	Mesaba One		Mesaba One and Mesaba Two	
	Average (gpm/MGD)	Peak (gpm/MGD)	Average (gpm/MGD)	Peak (gpm/MGD)
001	300/.43	3,000/4.3	3,500/5.0	6,000/8.6
002	600/0.9[a]	3,000/4.3	825/1.2[a]	6,000/8.6
003	1,300/1.9	7,000/10.1	3,500/5.0	7,000/10.1
004	0	0	1,500/2.2	7,000/10.1
005	To be determined	To be determined	To be determined	To be determined
[a] Limited by mercury mass discharge, see Section 5.2.1				

o **WATER QUALITY**

As demonstrated in this Application, the IGCC Power Station's proposed operation will be in compliance with the Minnesota water quality requirements set forth in Minn. R. ch. 7050.
The water discharged from Mesaba One through Outfall 001 and Outfall 002 will essentially be CMP water concentrated up to several times the background concentration found in the pit water sources. The relatively minor amounts of other water streams and chemical additives will not significantly alter the water quality of the concentrated mine pit water (cooling tower blowdown). Beyond a reasonable mixing zone, the discharge from the IGCC Power Station mixed with mine pit water will be below applicable water quality criteria. CMP water will, over time, have limited increases in both the mass and concentration of the current constituents as a result of receiving Outfall 001 discharges

Outfalls 003 and 004 will be discharge points for the transfer of water from the HAMP Complex and LMP to the CMP without intervening treatment or use. The water quality of the source and receiving mine pits is similar, so adverse impacts from such transfers will not occur.

Existing Water Quality

The existing water quality data for the two proposed receiving waters (the CMP and Holman Lake) are presented in Table 5.2-1. As noted above, there will be a limited increase in the concentration of the various constituents in the CMP over time as a result of receiving Outfall 001 discharges.

Table 5.2-1
Current Water Quality of Receiving Waters

Constituent	Units	CMP	Holman Lake
Hardness	mg/l	308	--[a]
Alkalinity	mg/l	180	186
Calcium	mg/l	55.3	50.2
Magnesium	mg/l	40.8	--
Iron	mg/l	<0.05	0.75
Manganese	mg/l	<0.02	0.04
Chloride	mg/l	5.15	8.4
Sulfate	mg/l	103.5	10.1
TDS	mg/l	337	236
pH	mg/l	8.4	7.9

Constituent	Units	CMP	Holman Lake
Aluminum	ug/l	<25	--
Barium	ug/l	28.6	--
Cadmium	ug/l	<10	--
Chromium (6+)	ug/l	<5	--
Copper	ug/l	<10	--
Fluoride	mg/l	n/a	--
Mercury	ng/l	0.9	<4.0
Nickel	ug/l	<5	--
Selenium	ug/l	<2	--
Sodium	mg/l	6.6	7.4
Specific Conductivity	umhos/cm	476	--
Zinc (3)	ug/l	<10	--
BOD	mg/l	<2	--
COD	mg/l	<2	--
TOC	mg/l	1.9	--
TSS	mg/l	1.5	--
Ammonia (as N)	mg/l	<0.1	<0.1
Phosphorus	mg/l	<0.1	0.01
[a] – Indicates that no data was collected.			

Numerical Water Quality Standards

A comparison of expected IGCC Power Station discharges and applicable state numerical water quality standards (Minn. Rules 7050.0222) is summarized in 5.2-2 and discussed below. All IGCC Power Station outfalls discharge to Class 2 waters. This is the case since none of the abandoned mine pits are listed on the Public Waters Inventory ("PWI") or listed in the published rules. Applicant believes that the Class 2B water standards are thus applicable (Minn. R. 7050.0430) to mine pit waters, and also with respect to Holman Lake as while it is listed on the PWI, it is not included in Minnesota Rules (so Class 2B water standards therefore apply).

Table 5.2-2
Expected IGCC Power Station Discharges and Applicable State Numerical Water Quality Standards

Constituent	Units	Class 2 WQ Standard	Anticipated Effluent Water Quality – Phase I (5 COC)	Anticipated Effluent Water Quality – Phase II (3 COC)
Hardness	mg/l	250	0 .07	0.03
Alkalinity	mg/l	n/a	4	--
Calcium	mg/l	n/a	--	--
Magnesium	mg/l	n/a	--	--
Iron	mg/l	n/a	--	--
Manganese	mg/l	n/a	--	--
Chloride	mg/l	230	38	16
Sulfate	mg/l	n/a	470	280
TDS	mg/l	700	2,317	1,039
pH	mg/l	6 – 9	6 – 9	6 - 9
Aluminum	ug/l	125	73	31
Arsenic	ug/l	53	--	--
Barium	ug/l	n/a	--	--

Constituent	Units	Class 2 WQ Standard	Anticipated Effluent Water Quality – Phase I (5 COC)	Anticipated Effluent Water Quality – Phase II (3 COC)
Cadmium	ug/l	2.0[1]	Note 3	Note 3
Chromium (6+)	ug/l	32[1]	Note 3	Note 3
Copper	ug/l	15[1]	Note 3	Note 3
Fluoride	mg/l	n/a	--	--
Mercury	ng/l	6.9	6.6	2.8
Nickel	ug/l	283[1]	37	16
Selenium	ug/l	5	Note 3	Note 3
Sodium	mg/l	n/a	--	--
Specific Conductivity	umhos/cm	1,000	12,380	1,400
Zinc (3)	ug/l	191[1]	Note 3	Note 3
Phosphorus	mg/l	1[2]	0.07	0.03

[1] indicates a hardness based standard. It is assumed hardness in the receiving water is >200 mg/L based on available data.
[2]phosphorus standard is an effluent limit and not a water quality standard.
[3]results below detection limit.
[4]not analyzed.

- **Modeled Discharge Water Quality-Outfalls 001 and 002**

A mass balance model was created to estimate the IGCC Power Station effluent water quality over various periods of operation of the IGCC Power Station and under various operating scenarios. The model is described and detailed study results are presented in Appendix D. The model calculates the anticipated water quality from the IGCC Power Station discharge and that anticipated in the CMP as a result of various inflows from the HAMP Complex and the LMP, and discharges from the IGCC Power Station.

The modeling results indicate that key water quality constituents associated with Outfall 001 and 002 discharges will be mercury, total dissolved solids (TDS), and hardness. As shown below, mercury discharges will be addressed by operating the IGCC Power Station such that the concentration of mercury in its effluent discharges will not exceed the water quality standard of 6.9 ng/L. In addition, operation of the system will be such that the mass of mercury discharged to Holman Lake through Outfall 002, combined with the mass of mercury discharged to Panasa Lake from the continued pumping of the HAMP Complex, will not exceed the mass of mercury currently permitted to be discharged to Panasa Lake under existing NPDES Permit No. MN0030198. Both Holman Lake and Panasa Lake are tributary to the Swan River. In this way, this system will not contribute additional pollutants to the Swan River watershed. TDS and hardness discharge concentrations will be acceptable with the inclusion of a mixing zone as discussed below.

Based on the results of the mass balance modeling, the following operating scenario was selected: The IGCC Power Station will operate at five COC during operation of Mesaba One and at three cycles of concentration for Mesaba One and Mesaba Two. A portion of the IGCC Power Station effluent will be discharged to the CMP and a portion will be discharged to Holman Lake. The volume of water discharged directly to Holman Lake from the IGCC Power Station will be controlled such that the total mass of mercury discharged to the Swan River watershed (the sum of any future discharge from the HAMP Complex to Panasa Lake and the IGCC Power Station discharge directed to Holman Lake) is less than the mass currently permitted to be discharged to the watershed from the HAMP Complex. The outcome of this operating scenario is no net increase in the mass of mercury permitted to be discharged to the Swan River watershed under the existing NPDES Permit. The volume of water discharged directly to Holman Lake will be adjusted approximately every five years, or as needed during Phase I and II operation, to limit the mass of mercury discharged to Holman Lake.
Figure 5.1-1a and Figure 5.1-1b present the water balance results of the modeling for Phase I and Phase I and II, respectively. The results for mercury, hardness and TDS are presented below.

MERCURY

The mercury water quality standard for Class 2B waters outside of the Lake Superior Basin is 6.9 ng/L[1]. Twice monthly sampling, testing and sampling variability give rise to permit limits of 10 ng/L on a monthly average basis, 17 ng/L on a per sample basis[2].

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[1] *See* Minn. R. 7050.0222, subp. 4.
[2] Correspondence with Richard Clark & Gary Kimble, MPCA

The median mercury concentration in the 2005 samples of CMP water is 0.9 ng/L; the median mercury concentration in the Hill-Annex Mine Pit water is also 0.9 ng/L. With limited analytical data available for the LMP, the applicant has assumed in the mass balance model that all water sources have a mercury concentration of 0.9 ng/L. The mass balance model described in Appendix D was used to model mercury concentrations assuming the Phase I water balance presented in Figure 5.1-1a and the Phase I and II water balance presented in Figure 5.1-1b. In this case, the majority of the Phase I and II 3,500 gpm of IGCC Power Station discharge is directed through Outfall 001 to the CMP. A portion of the total volume, starting at approximately 825 gpm (annual average) in the first year and decreasing to approximately 400 gpm in year 30, is directed through Outfall 002 to Holman Lake (the volume discharged through Outfall 002 is limited by the concentration of mercury which, in the model, is gradually increasing in the CMP source water, and thus requires a gradual reduction in the discharge rate. See Section 5.2.3).

The estimated mercury concentration in the IGCC Power Station discharge water and in the CMP over 30 years of IGCC Power Station operation is depicted in Figure 5.2-1. The results demonstrate that the IGCC Power Station can operate for more than 30 years before the mercury water quality standard of 6.9 ng/L would be exceeded in the IGCC Power Station discharge. Beyond 30 years of operation the water quality standards for mercury will be met by either mercury removal, treatment of the IGCC Power Station's effluent, a reduction in the COC, or establishing a total mass daily load for the chemical species for which the Swan River is impaired. Figure 5.2-1 also shows that the concentration of mercury in the CMP increases slightly, from 0.9 ng/L to about 2.2 ng/L, over that same time period.

Similarly, it is anticipated that the concentration of sulfate in the IGCC Power Station discharge water will also increase over time and concern has been raised regarding the link between sulfate and methyl mercury. While it has been demonstrated that the addition of sulfate may stimulate the formation of methyl mercury in peatlands (Branfireun et al. 1999; 2001)[3], the relationship may depend on several variables in addition to sulfate. These include organic carbon, the fraction of bioavailable mercury, and the microbial community structure (not all sulfate reducing bacteria methylate mercury) (Porvari and Verta 1995; Branfireun et al. 1999; Macalady et al. 2000).[4] In addition, the thermal modeling presented in Section 5.3 below has demonstrated that the discharge water from the IGCC Power Station is anticipated to remain at or near the surface of the receiving water and will have limited mixing with the bottom waters.

---

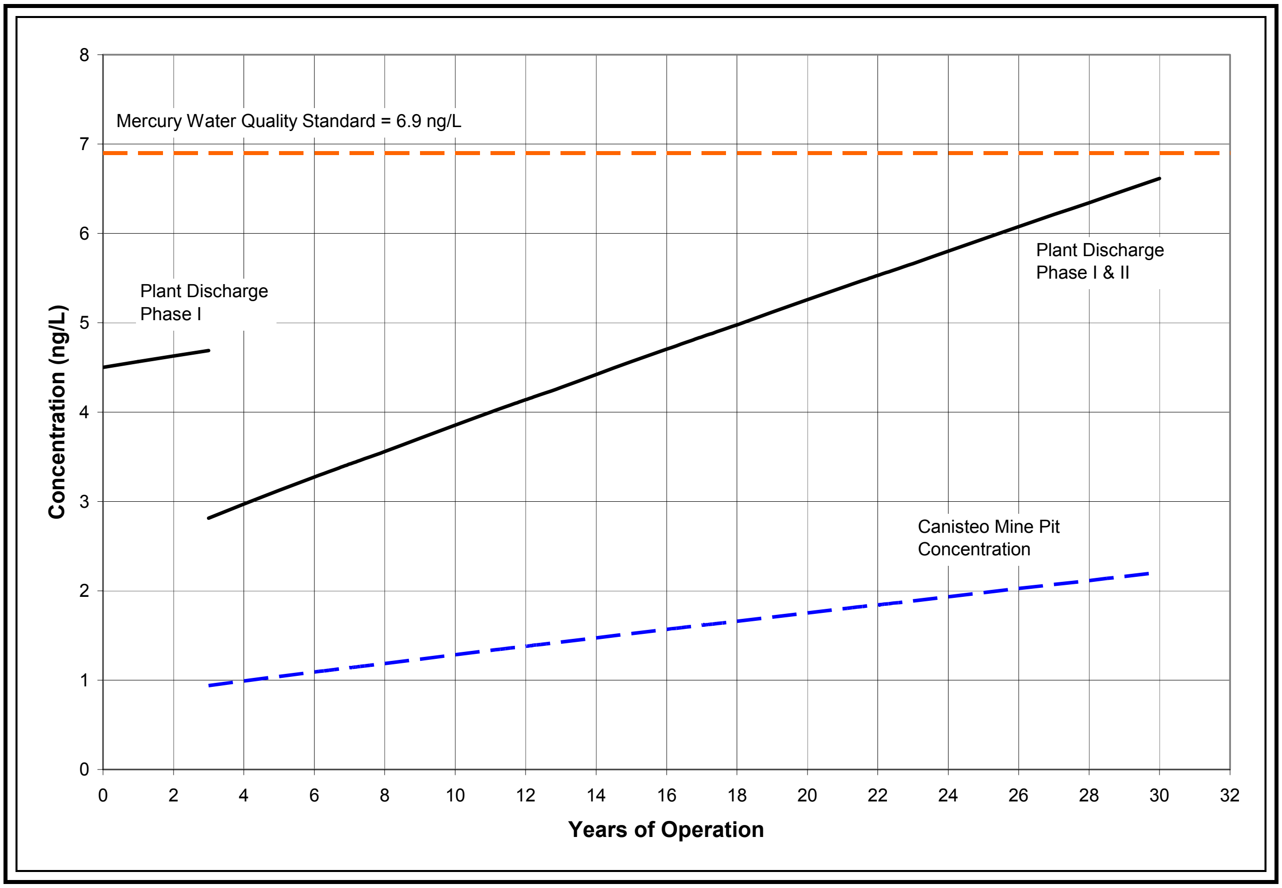
[3] Branfireun BA, Roulet NT, Kelly CA & Rudd JWM (1999) In situ sulphate stimulation of mercury methylation in a boreal peatland: toward a link between acid rain and methylmercury contamination in remote environments. Global Geochemical Cycles 13: 743-750.

Branfireun BA, Bishop K, Roulet NT, Granberg G & Nilsson M (2001) Mercury cycling in boreal ecosystems: The long-term effect of acid rain constituents on peatland pore water methylmercury concentrations. Geophys. Res. Lett. 28: 1227-1230.

[4] Macalady JL, Mack EE & Scow KM (2000) Sediment Microbial Community Structure and Mercury Methylation in Mercury-Polluted Clear Lake, California. Appl. Environ. Microbiol. 66: 1479.

Porvari P & Verta M (1995) Methylmercury production In flooded soils - a laboratory study. Water, Air, and Soil Poll. 80: 765-773.

Figure 5.2-1
Modeled Mercury Concentrations in IGCC Power Station Discharge and CMP



TDS AND HARDNESS

The Class 2B water quality standards for total dissolved solids (TDS) and hardness are 700 mg/L and 250 mg/L, respectively. It is understood that the hardness standard is proposed to be increased to 500 mg/L. Current source water quality for these two constituents (based on the median of recent analytical results) is presented in Table 5.2-3.

Table 5.2-3
Current Source Water Quality-TDS and Hardness

Constituent	Units	WQ Standard	Water Source		
			CMP	HAMP Complex	LMP
TDS	mg/l	700	337	252	369.5
Hardness	mg/l	250	308	229	n/a

The modeled TDS and hardness concentrations for the IGCC Power Station discharge water and in the CMP over 30 years of IGCC Power Station operation are illustrated in Figure 5.2-2 and Figure 5.2-3. The results demonstrate that a mixing zone will be necessary to comply with water quality standards for TDS and hardness. The figures also show that the concentrations of TDS and hardness in the CMP increase slightly over time, but the TDS concentration remains below the water quality standard for more than 24 years. The hardness concentration in the CMP will remain below the proposed water quality standard of 500 mg/L for more than 14 years. Beyond these time frames, the water quality standards for TDS and hardness will be met by either treating effluent from the IGCC Power Station for TDS and hardness or further reducing the COC at which the IGCC Power Station operates.

Figure 5.2-2
Modeled TDS Concentrations in IGCC Power Station Discharge and CMP

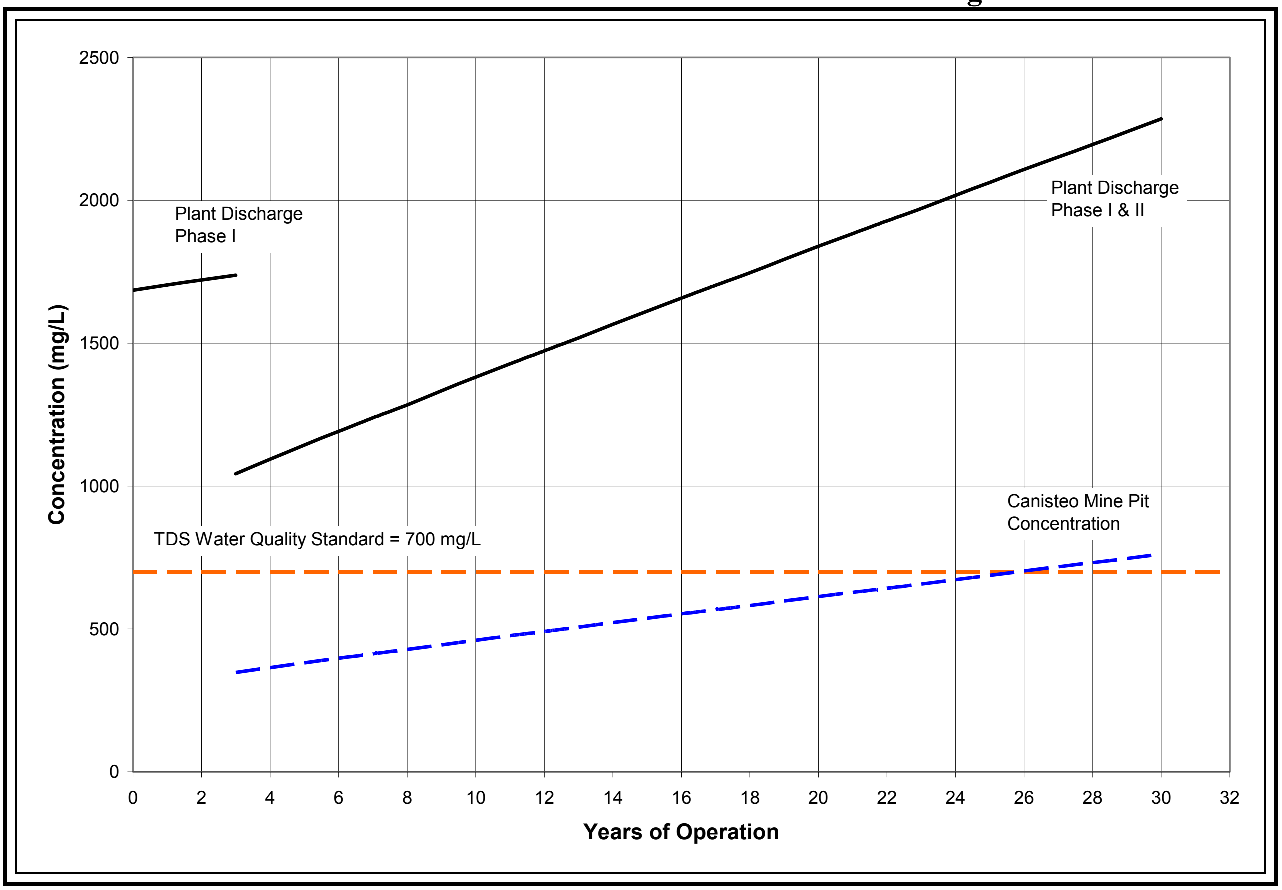
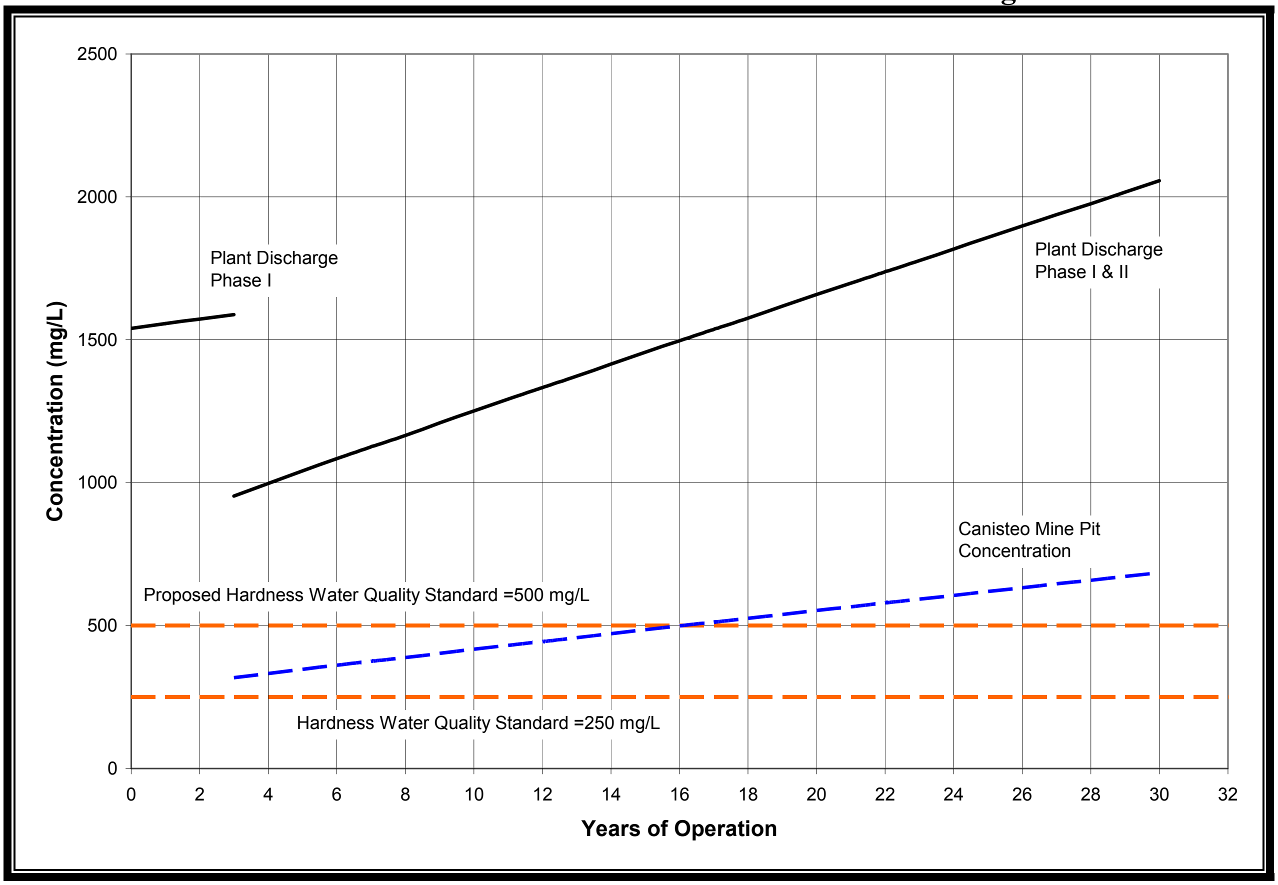


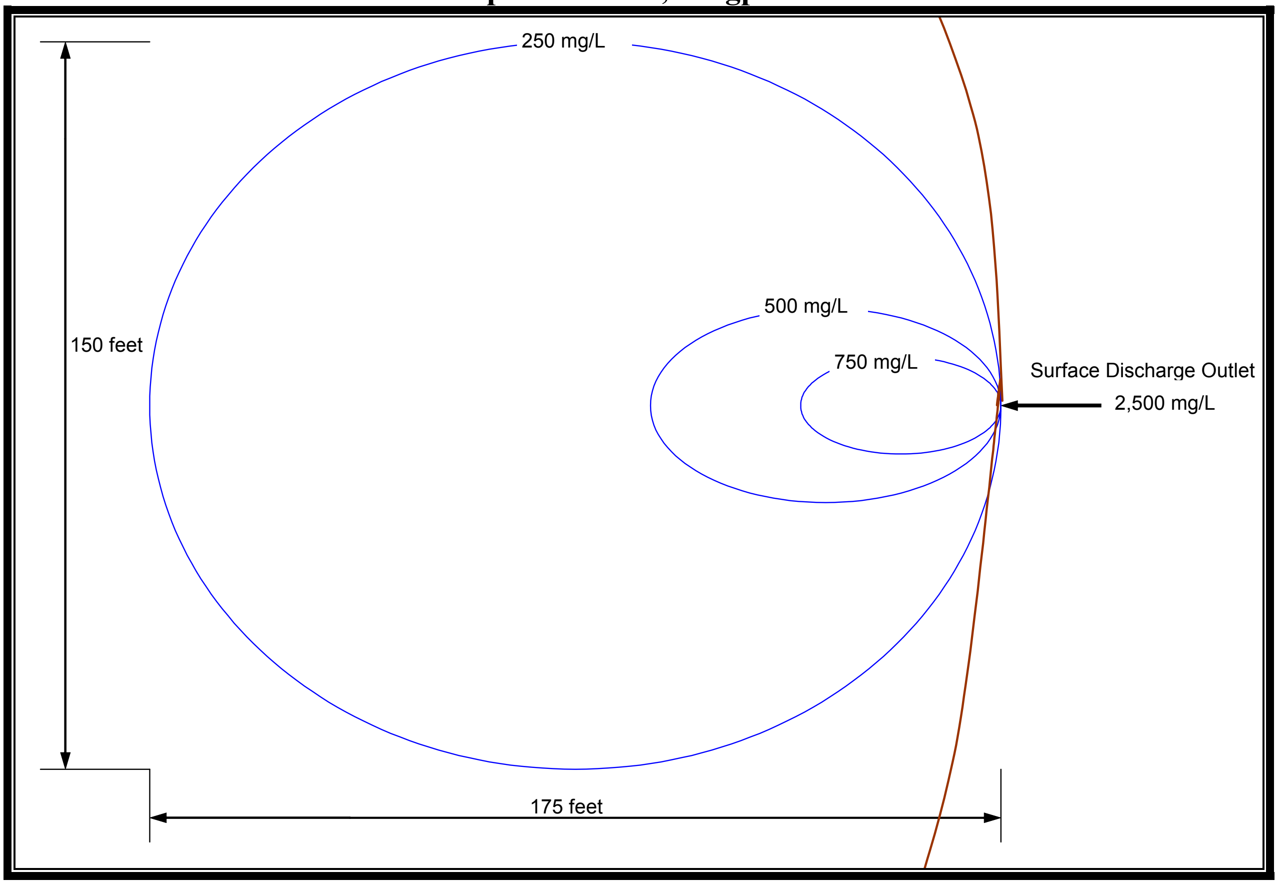
Figure 5.2-3
Modeled Hardness Concentrations in IGCC Power Station Discharge and CMP



An analysis of the constituent plumes resulting from the plant discharge into both the CMP and Holman Lake was performed using CORMIX modeling software. CORMIX is an EPA-supported mixing zone model for environmental impact assessment of regulatory mixing zones resulting from continuous point source discharges (http://www.cormix.info/). The worst case scenario, occurring at the 30th year of operation, was modeled to determine the maximum mixing zone required. A maximum discharge rate of 3,500 gpm and a TDS concentration of 2,500 mg/L into the CMP were assumed. While the concentrations discharged into Holman Lake will be identical to that discharged into the CMP, the discharge flow rate will be more than 75 percent lower. The hardness concentration in the plant effluent after 30 years of operation is estimated to be approximately 2,100 mg/L.

The evaluation demonstrated that even after 30 years of operation the applicable water quality criteria (Minn. R. 7050.0222) will be met with a reasonable mixing zone, as allowed under Minn. R. 7050.0210, subp. 5. With mixing zones extending about 175 feet beyond Outfall 001, concentrations of TDS and hardness, assuming average discharge rates, will be below the applicable water quality standards as demonstrated by discharge plume modeling. The mixing zone required for Outfall 002 into Holman Lake will be smaller given the reduced flow rates. The modeled TDS concentration plume, assuming an end-of-pipe concentration of 2,500 mg/L, as calculated by the CORMIX model, is illustrated in Figure 5.2-4.

Figure 5.2-4
Modeled IGCC Power Station TDS Discharge Plume After 30 Years of Operation at 3,500 gpm.



- **Expected Discharge Water Quality-Outfalls 003 and 004**

The expected discharge water quality for Outfalls 003 and 004 is anticipated to be identical to the source raw water quality. Since no treatment or use of the water will occur, water will simply be transferred from one abandoned mine pit to another. No applicable water standards are expected to be exceeded in the discharges at Outfalls 003 and 004. A comparison of expected discharge water quality from Outfalls 003 and 004 and applicable state water quality standards (Minn. Rules 7050.0222) is presented in Appendix D.

- **Expected Discharge Water Quality-Outfalls 005 and 006**

The stormwater runoff discharged at Outfalls 005 and 006 will be from areas not associated with industrial activity and will be routed to the stormwater detention ponds where settling can occur and initial rainfall ("first flush") can be contained, checked, and released in a controlled manner prior to being discharged. In addition, Applicant will develop a SWPPP that identifies erosion prevention and sediment Best Management Practices (BMPs) as outlined in Section 2. The detention basins will reduce the potential for discharging sediment and/or other potential pollutants from the site.

Therefore, the quality of the stormwater discharged at Outfalls 005 and 006 will meet all applicable water quality standards.

Impaired Waters

Holman Lake, Panasa Lake, the CMP and the HAMP Complex are not impaired waters. However, the water from those water bodies, either now or in the future, will ultimately discharge into the Swan River, which is impaired for mercury and dissolved oxygen (DO) based on the Draft 2006 TMDL list. The Swan River flows into a reach of the Mississippi River between Swan River and Sandy River. That reach of the Mississippi River that is also impaired for mercury (*http://www.pca.state.mn.us/publications/wq-iw1-03.pdf*).
Other downstream reaches of the Mississippi River are impaired for:

- Mercury
- Fecal Coliform
- PCBs
- Low DO (excess nutrients, primarily phosphorus)
- Turbidity

The IGCC Power Station discharge will not contain Fecal Coliform or PCBs. Any turbidity discharged will be minimal and will meet effluent limits.
Phosphorus concentrations in recent samples collected from proposed source waters (CMP, HAMP Complex and the LMP) have been shown to be below 0.01 mg/L. While there is currently no water quality standard for phosphorus, the MPCA has established a discharge standard of 1.0 mg/L that is applied at end-of-pipe discharges. However, it is understood that while a discharge may be able to meet the discharge standard of 1 mg/L, because this discharge is upstream of an impaired body of water, the discharge cannot cause or contribute to the violation of the water quality standard of issue. The mercury standard was discussed in section 5.5.2 above. The following analysis of impaired water issues is focused on mercury and phosphorus discharged through Outfall 002 into Holman Lake and ultimately into the Swan and Mississippi Rivers.

- **Regulatory Background**

The following paragraphs provide information on the applicable regulatory requirements related to impaired waters.

Rules published at 40 C.F.R. 122.4 address prohibitions on permitting discharges to impaired waters (emphasis added):

> ***"No permit may be issued***:
> *(i) To a* ***new source*** *or a new discharger, if the discharge from its construction or operation* ***will cause or contribute*** *to the violation of water quality standards. The owner or operator of a new source or new discharger proposing to discharge into a water segment which does not meet applicable water quality standards or is not expected to meet those standards even after the application of the effluent limitations required by sections 301(b)(1)(A) and 301(b)(1)(B) of CWA, and for which the State or interstate agency has performed a pollutants load allocation*

for the pollutant to be discharged, must demonstrate, before the close of the public comment period, that:
(1) There are sufficient remaining pollutant load allocations to allow for the discharge; and
(2) The existing dischargers into that segment are subject to compliance schedules designed to bring the segment into compliance with applicable water quality standards. The Director may waive the submission of information by the new source or new discharger required by paragraph (i) of this section if the Director determines that the Director already has adequate information to evaluate the request. An explanation of the development of limitations to meet the criteria of this paragraph (i)(2) is to be included in the fact sheet to the permit under §124.56(b)(1) of this chapter."

Information provided in this section demonstrates that the proposed IGCC Power Station discharge will not cause or contribute to the impairment of the water bodies downstream of the proposed discharge, and is therefore allowed under the Clean Water Act.

- **No Mercury or Phosphorus will be added to Water Discharged from the IGCC Power Station**

The operation of the IGCC Power Station will not add mercury, phosphorus or other pollutants that are associated with the impairment concerns and therefore will not add these constituents to the receiving waters. There will be no added mercury or phosphorus to the proposed Outfall 002 discharge into Holman Lake. Waste streams that will be discharged from the IGCC Power Station will consist mostly of cooling tower blowdown, blended with relatively low-flow additional wastewater streams from other plant systems, including HRSG blowdown, boiler feed water demineralizers and intermittent treated water from the oil/water separator serving the plant drainage system. All other contact process water is managed in the ZLD system. All sanitary wastewater will be sent to a nearby POTW.

- **Mass Discharge from IGCC Power Station will be Lower than Currently Permitted Discharges**

The proposed operation of the IGCC Power Station will result in no increase in the mass of mercury or phosphorus over that currently permitted from the HAMP Complex under NPDES Discharge Permit MN0030198. The MDNR also holds a water use permit, No. 510144, for appropriating water from the Hill-Annex Mine Pit. General permit information is summarized in Table 5.2-4. The MDNR has been pumping water out of the Hill-Annex Mine Pit since 1989 to control water levels in the pit and has discharged the water into Panasa Lake and ultimately to the Swan River[5]. Prior to 1989, the HAMP Complex was pumped to allow mining activities.

[5] Discharges of Canisteo Mine Pit water to the Swan River watershed has also occurred during past mining operations. NPDES permits for those discharges are available in MPCA files but detailed records of actual pumping activities are limited.

Table 5.2-4
Summary of Hill-Annex Mine Pit NPDES and Appropriations Permits

Permit Number	Date Issued	Expiration Date	Permit Holder	Average Discharge Rate (MGD/ gpm)	Maximum Discharge Rate (MGD/ gpm)	Annual Average Discharge Volume (acre-feet)	Receiving Water Body
NPDES Permit							
0030198	June 3, 2003	May 31, 2008	MDNR	4.5/3,125	9.0/6,250	--	Panasa Lake
Appropriations Permit							
510144	Not available	NA	MDNR	10.08/7,000	--.	10,485	--

Based on the permitted average discharge rate from the NPDES permit, assumed mine pit water concentration based on the analytical results from the HAMP Complex, and concentrations monitored in other regional water bodies, the mass of a constituent permitted to be discharged to the Swan River watershed under the existing HAMP Complex pumping permit was estimated. [Limited low-level phosphorus analyses are available for the region and none is available for the HAMP. The actual concentration of phosphorus in the HAMP is believed to be on the order of 0.01 to 0.05 mg/L and with one exception, has not been detected in samples analyzed with a 0.1 mg/L reporting limit. Therefore, the permitted mass discharge of phosphorus is conservatively based on a 0.01 mg/L concentration in the HAMP]. The estimated mass of mercury and phosphorus permitted annually is shown in Table 5.2-5.

Table 5.2-5
Estimated Annual Mass Permitted to the Swan River Watershed
From the Hill-Annex Mine Pit

Constituent	Estimated Concentration	Permitted Average Annual Discharge Rate	Permitted Annual Mass Discharge
Mercury	0.9 ng/L	3,125 gpm	5.6 g
Phosphorus	0.01 mg/L		62 kg

Applicant will operate Mesaba One and Mesaba One and Mesaba Two such that the actual mass of mercury and phosphorus discharged to the Swan River will be less than or equal to that currently allowed under the existing NPDES permit. The mass discharged will be the sum of each constituent associated with:

1. Water discharged into Holman Lake at Outfall 002 from the IGCC Power Station or the CMP. (Mercury and phosphorus contained in the minor volume water streams that ultimately flow to the ZLD system is expected to be small and need not be considered in the water discharge mass balance calculations. Similarly, mercury volatization in the cooling towers and elsewhere in the process is expected to be negligible and is not considered in this calculation.).

2. Water pumped to Panasa Lake from the Hill-Annex Complex Mine Pits for water level control permitted under existing NPDES Permit MN0030198.

Mass balance calculations, based on expected source water quality (Table 3.2-5), expected IGCC Power Station operation, and assumed HAMP Complex water level management pumping rates are illustrated in Figure 5.2-6 (mercury) and Figure 5.2-7 (phosphorus). The mass balance calculation shows that mercury and phosphorus discharged from Outfall 002 and the existing Panasa Lake outfall will be maintained at annual quantities less than that allowed under the current permit.

Figure 5.2-5
Annual Mass of Mercury Discharged to Holman Lake

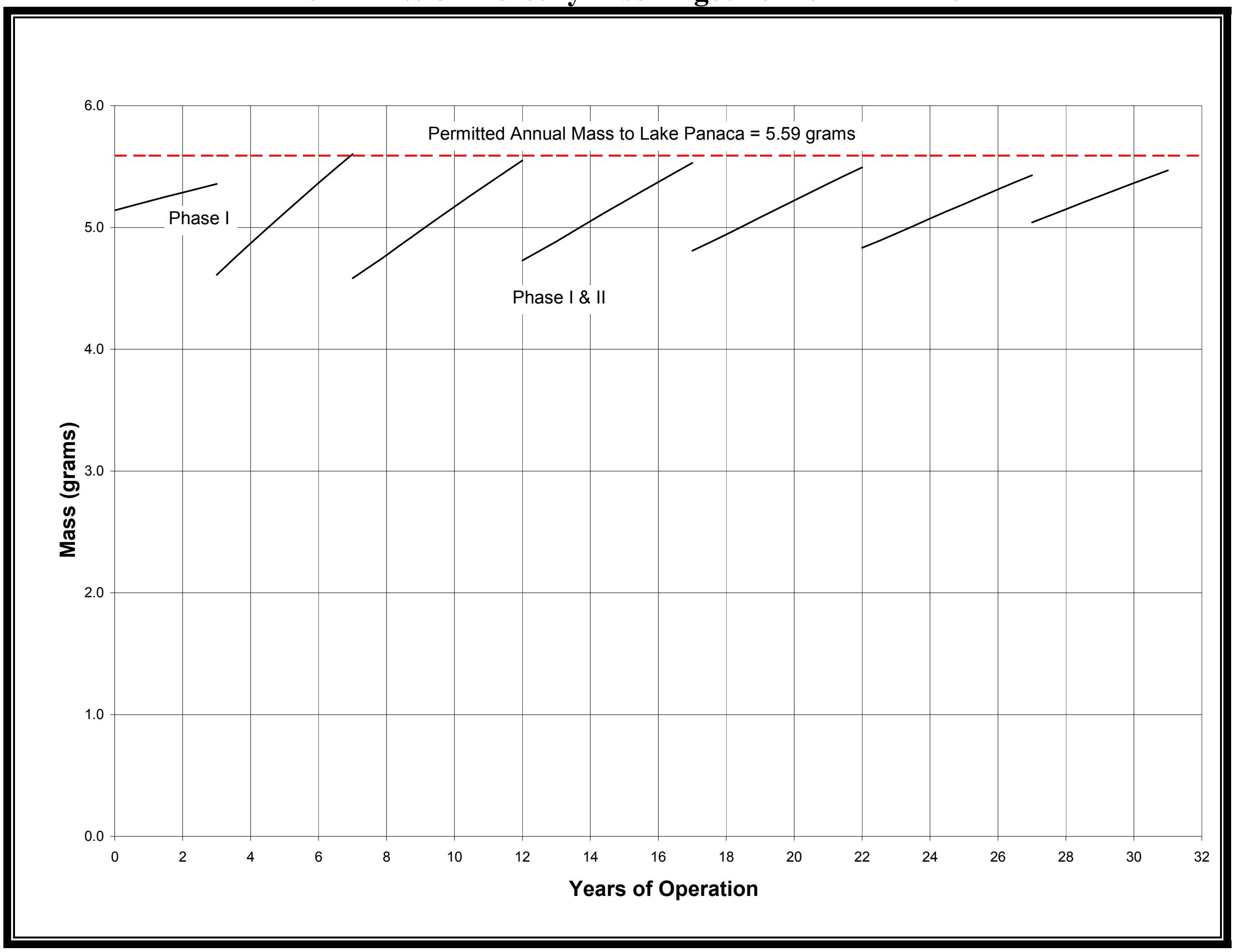
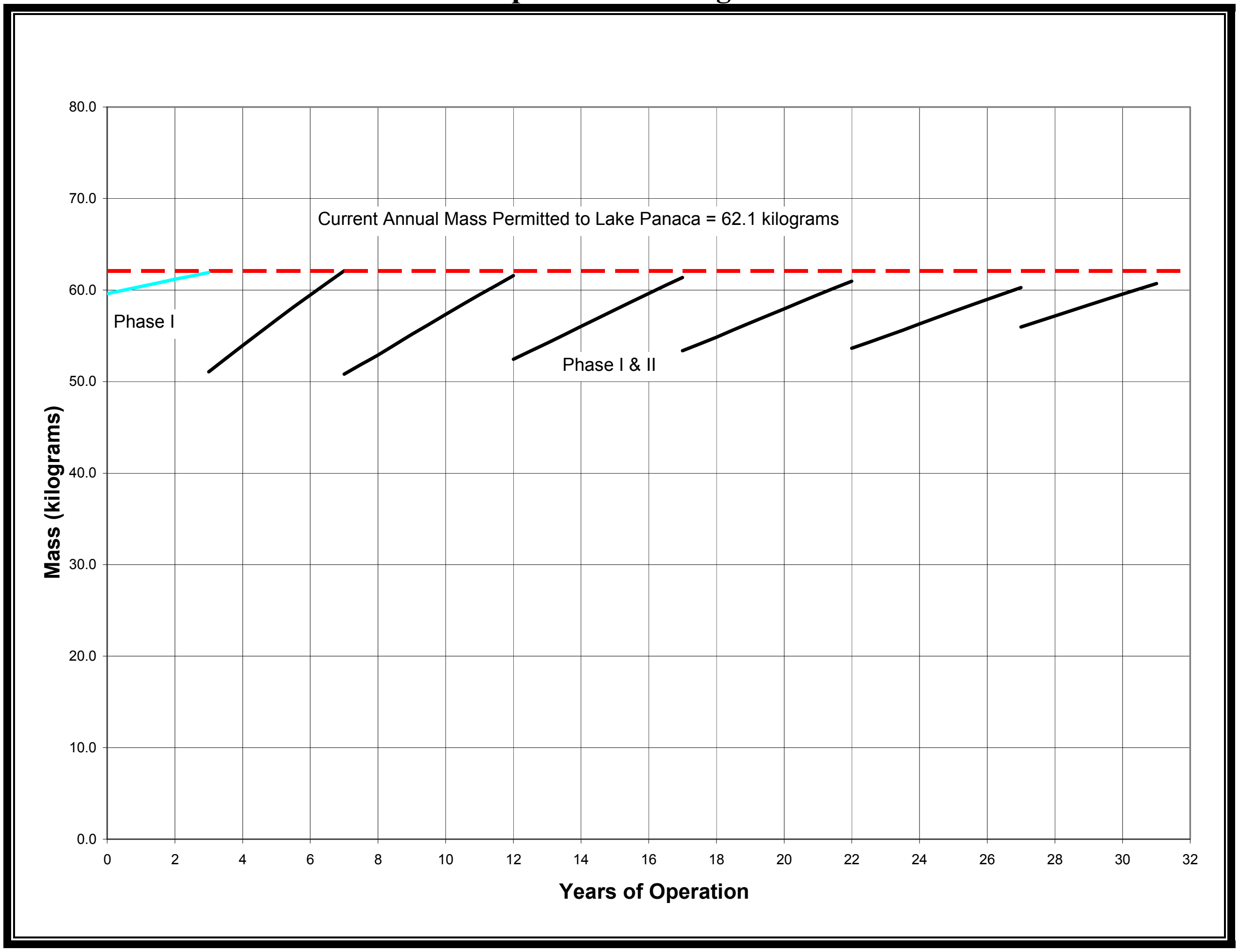


Figure 5.2-6
Annual Mass of Phosphorus Discharged to Holman Lake



In addition to no increase in the total mass of phosphorus discharged to the Swan River, the point of discharge will be moved downstream. This will result in a decrease in mass loading of phosphorus (as well as mercury) in that reach of the Swan River between the outfall from Lake Panasa and the outfall from Holman Lake.

O THERMAL DISCHARGES (CLEAN WATER ACT SECTION 316(A))

The IGCC Power Station will discharge cooling tower blowdown directly to the CMP and Holman Lake. This section presents an assessment of the thermal impacts of the IGCC Power Station cooling tower blowdown discharge (from both Mesaba One and Mesaba One and Mesaba Two) that demonstrates that the applicable temperature water quality criteria in Minn. R. ch. 7050 and the Clean Water Act (CWA) Section 316(a) will be met with a reasonable mixing zone as allowed under Minn. R. 7050.0210, subp. 5.

Thermal Modeling

Thermal modeling of the IGCC Power Station discharge into the CMP and Holman Lake was conducted. A detailed description of the modeling procedure and results are presented in Appendix E. Seasonal water temperatures of the surface layer after the addition of the cooling tower blowdown are shown in Figure 5.3-1 for the CMP and Figure 5.3-2 for Holman Lake. The temperature rise in the CMP due to the addition of the cooling tower blowdown is relatively small, in the vicinity of 1 to 2 °F.

Figure 5.3-1
Water Temperature of Surface Layers of CMP

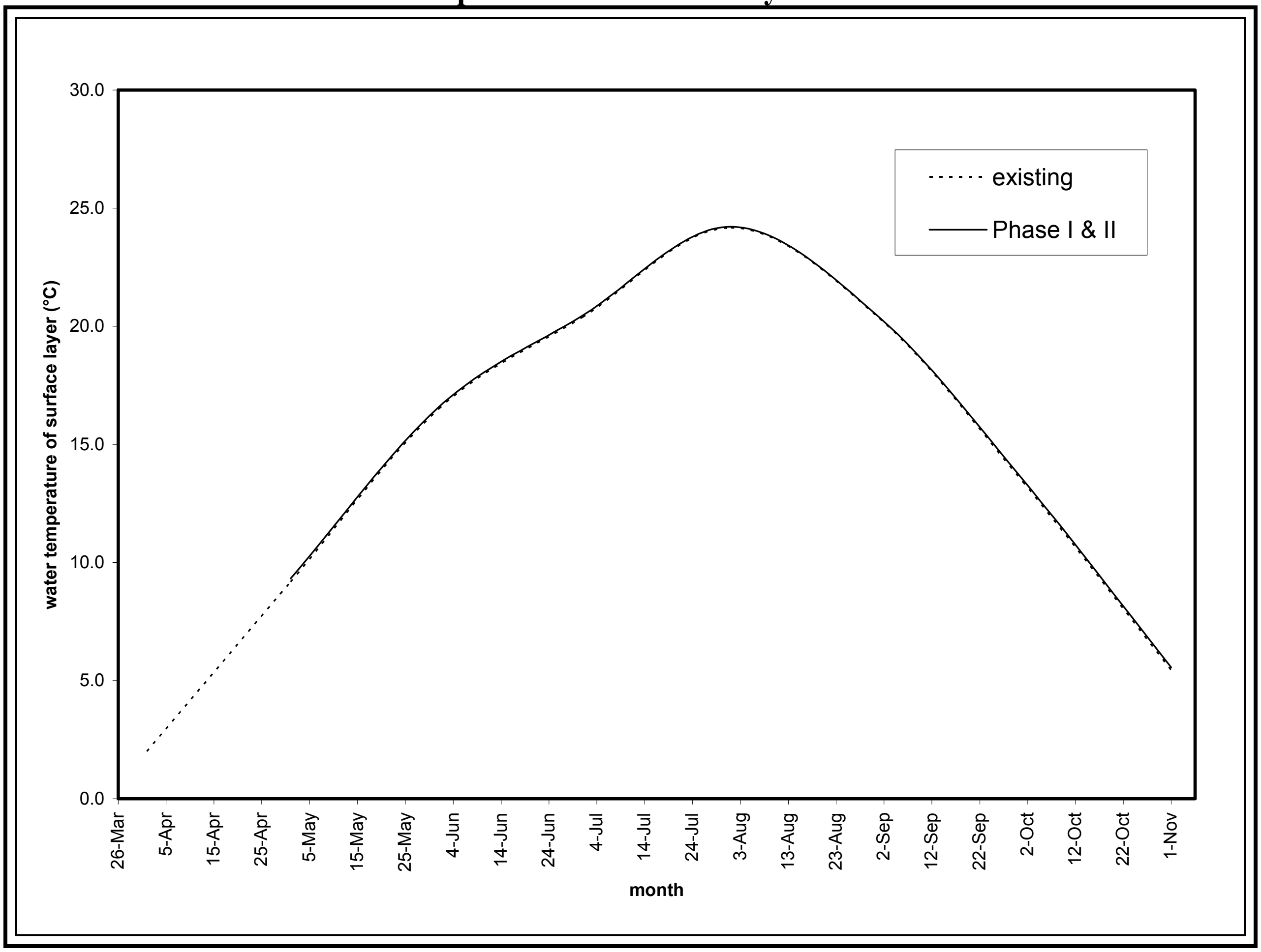
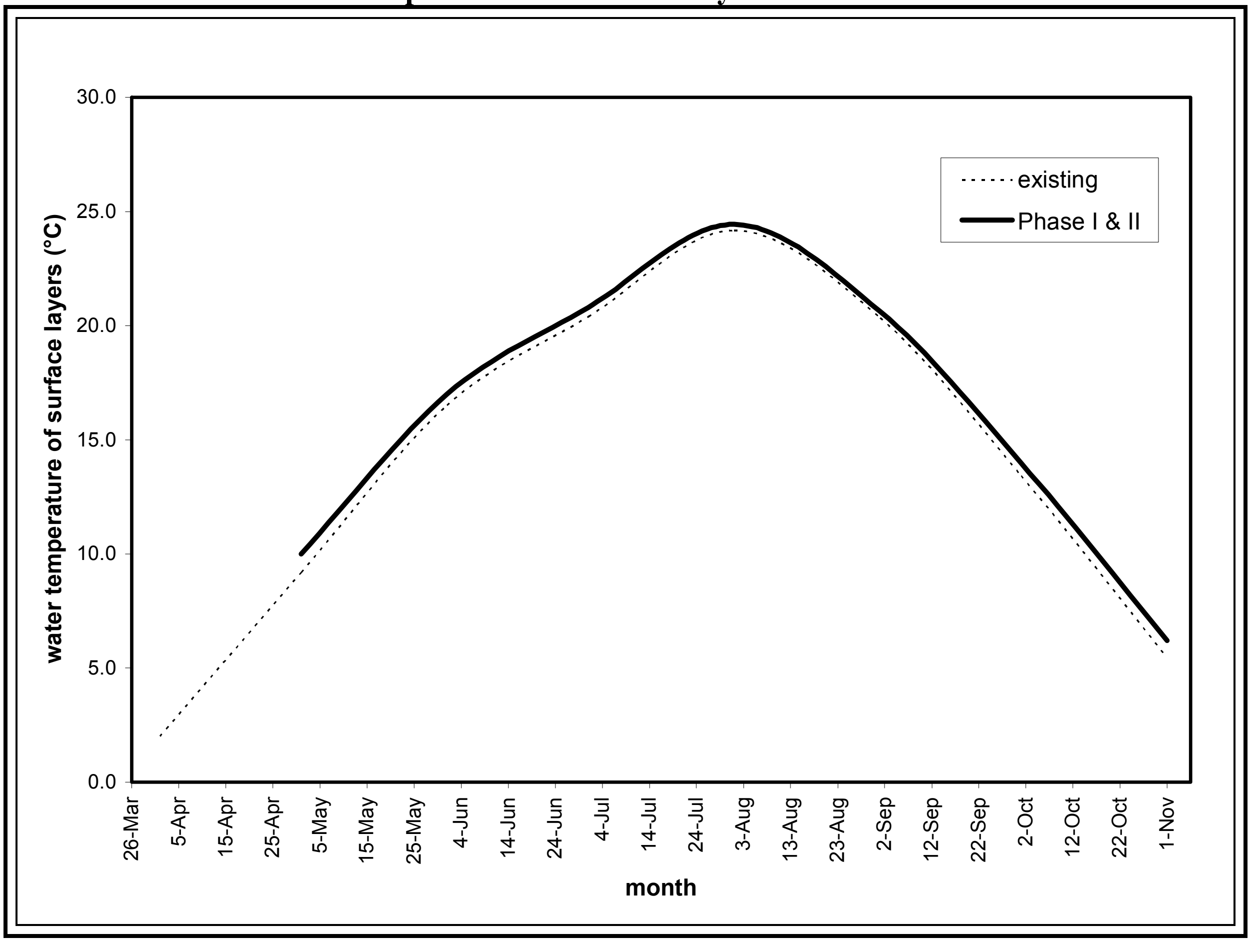


Figure 5.3-2
Water Temperature of Surface Layers of Holman Lake



The temperature rise in the CMP and Holman Lake due to the addition of the cooling tower blowdown is also relatively small for several reasons:

1. The mine pit has a relatively large surface area over which to dissipate the additional heat back to the atmosphere.

2. The discharge flow volume is small relative to the volume of the receiving water bodies, and the small heated flow is easily diluted in the large receiving water body.

3. The cooling tower blowdown is only 10 to 15 °F warmer than the summertime temperature of the receiving water body. In contrast, once-through cooling operations often have discharge temperatures 25 to 30 °F or more above ambient.

This heat balance analysis is intended to provide general information on the effect of the cooling tower discharges on the overall temperature of surface layers of the receiving water body. It assumes a well-mixed uniform temperature throughout the surface layers. In reality, the cooling tower discharge will have a greater effect on water temperatures closer to the point of discharge, and a lesser effect far from the point of discharge. The thermal effects in the proximity of the point of discharge are discussed in the following section on plume modeling.

Thermal Plume Modeling

CMP and Holman Lake are Class 2B waters (Minn. Rules 7050.0430). State water quality standards (Minn. Rules 7050.0220, Subp. 5a) limit the temperature of heated discharges to Class 2B waters to 3°F above ambient water temperature (based on monthly average of maximum daily temperature), and in no case can the discharge daily average temperature exceed 86°F. If the temperature at the point of discharge exceeds these standards, mixing zones can be granted by the MPCA on a case-by-case basis (Minn. Rules 7050.0210, Subp. 5). Thermal water quality standards must then be met at the edge of the mixing zone.

To determine the extent of the mixing zone required, an analysis of the thermal plumes resulting from the cooling tower blowdown discharge into the CMP and Holman Lake was performed using CORMIX modeling software (see Appendix E). The modeling indicates a mixing zone of approximately 100 feet in length will be necessary for a surface discharge. Discharges at deeper depths (10 ft and 40 ft) would be diluted more quickly and require a smaller mixing zone.

Thermal Assessment Conclusions

Cooling tower blowdown discharged to the CMP will have a minimal effect on the overall temperature of the surface water. Surface layers of the water body will rise less than 2 °F with the addition of Mesaba One and Mesaba Two cooling tower blowdown. Temperatures in the immediate proximity of the discharge will need to utilize a mixing zone to comply with thermal standards.

The dimensions of the required mixing zones are relatively small in comparison to other permitted power plants throughout the state. This is primarily due to the low flow rate and low temperature of the cooling tower blowdown from the IGCC Power Station compared to typical once-through cooling operations which can require mixing zone lengths on large rivers of thousands of feet .

Marston Fuel Supply Study

HIGHLIGHTS OF ATTACHED CHARTS

1. U.S. COAL PRODUCTION - FOUR LARGEST SUPPLY REGIONS
    a. The Southern Powder River Basin (SPRB) is the only major basin to experience production volume growth over the past 15 years.
    b. The production loss experienced in the Illinois Basin (ILB) is due to its high production costs relative to the SPRB's costs and lower sulfur dioxide emission standards implemented through the Clean Air Act of 1990.
    c. The production loss experienced in Central Appalachia (CAPP) since 2001 is due to depleting reserves and difficulties with acquiring permits for new mines.
2. SO2 EMISSIONS – HISTORICAL AND PROPOSED EMISSIONS AND LIMITS
    a. Current sulfur dioxide emissions are depicted by the yellow bars and approximate 10.3 million tons in 2004.
    b. Emission allowances (EAs) allocated under Title IV will be 9.54 million through 2009.
    c. Effective EAs allocated under CAIR for all U.S. sources approximates 5.4 million through 2014 and 4.3 million thereafter.
    d. With the growth in generation, the effective emission rate in 2010 and 2015 is 0.37 and 0.28 lbs. SO_2/mmBtu.
        i. Since no coal's sulfur content is low enough to meet these emission rates, Marston projects considerable scrubber retrofits to the coal fleet.
3. COAL-FIRED GENERATION MODEL ASSUMPTIONS
    a. The Energy Information Administration's (EIA) recently announced forecast for annual growth in coal-fired generation is 1.6% over the next 20 years. The graph shows 1.75% since it is last year's EIA's forecast.
    b. Marston's and EIA's cumulative average growth forecast is very similar by 2020 with timing differences over the 20 years.
    c. Growth in coal-fired generation and the assumption of considerable scrubbing leads to a strong demand forecast for low cost, typically high sulfur coal.
4. COAL DEMAND FORECAST
    a. The second y-axis is used only for the SPRB demand.
    b. SPRB growth is based on utilization growth at current plants and new capacity in the SPP and MAPP NERC regions.

c. ILB growth is based on new demand at existing plants that add scrubbers and new capacity in MAIN, ECAR and SERC.
d. CAPP demand decreases as eastern plants add scrubbers, switching to lower cost, higher sulfur coals, and then grows after 2015 as new capacity is added in SERC and ECAR.
e. Pittsburgh 8 seam demand growth is based on scrubber retrofits along the Ohio River and new units in ECAR and MAAC.
f. Texas lignite growth is a function of new capacity in ERCOT.
g. Imports growth is to unscrubbed eastern plants that will require low sulfur coal and new capacity in SERC and FRCC.

5. ILLINOIS BASIN SUPPLY AND DEMAND
    a. Marston sees new mine developments in anticipation of new demand.
    b. The announced new capacity appears to be several years prior to the demand increase, which should soften the ILB market until the end of the decade.
6. PITTSBURGH SEAM COAL PRODUCTION FORECAST
    a. Marston sees new mine developments in anticipation of new demand.
    b. The announced new capacity also appears to be several years prior to the demand increase, which should soften the Pitt 8 market until the end of the decade.
    c. Since Pitt 8 and ILB production competes directly along the Ohio River, the projected oversupply in both basins throughout the balance of the decade should ensure price decreases over the next several years.
7. HISTORICAL AND FUTURE ILLINOIS BASIN COAL PRICES
    a. Chart shows historic coal prices, which are currently at record levels.
    b. Prices soften as new production enters the market prior to 2010.
    c. As demand significantly increases after 2010, prices increase to justify new mine development.
8. SPRB SUPPLY AND DEMAND FORECAST
    a. Marston believes production will be sufficient to meet demand through 2033.
    b. Marston assumes that transportation capacity will be developed to meet demand.
9. SPRB RATIO AND DIRECT COST FORECAST
    a. Production costs are the basis of Marston's price forecasts.
    b. Mining ratios in the SPRB are the basis of production costs.

c. Ratios are expected to increase only approximately 1.0 to 1.7 points over the next 20 years.
d. Direct Operating Costs (DOC) for both 8800 and 8400 BTU mines are projected to increase only 2% per year over the next 35 years.

10. SPRB CASH COST OF SALES FORECAST
    a. Costs are the sum of DOC and revenue-related expenses.
    b. Revenue-related expenses approximate 29% at $10/ton coal price.
    c. The coal price assumed is the forecast price from the following slide, Figure 11.
    d. Cash Cost of Sales peaks and subsides through 2008 due to rising and falling prices.
11. HISTORICAL AND FUTURE SOUTHERN POWDER RIVER BASIN COAL PRICES
    a. Southern PRB prices are also at record levels.
    b. At these current prices, producers are likely earning a 200% cash margin.
    c. Marston believes these extraordinary returns will motivate mine owners to add incremental production and develop new mines, thereby increasing the likelihood of decreasing prices.
    d. Marston believes SPRB prices will decrease as new production is developed from School Creek, Coal Creek, Belle Ayr, Buckskin and other mines.
    e. The price forecast is based on the DOC and sales related costs that maintain an approximate $4/ton cash margin.
12. SPRB TOTAL RESERVE SUPPLY CURVE
    a. Represents the cash cost of sales for all reserves in the SPRB.
    b. Includes leased and unleased reserves that are at a depth of less than 1000 feet
    c. Cash Cost of Sales include DOC and revenue-related expense.
13. SPRB CASH COSTS
    a. Represents a specific year's cash cost of sales over the next thirty years.
    b. Over the next thirty years, approximate average cash cost of sales will increase only $0.1/mmBtu, which is less than $2.00/ton.

Figure 1
U.S. COAL PRODUCTION - FOUR LARGEST SUPPLY REGIONS

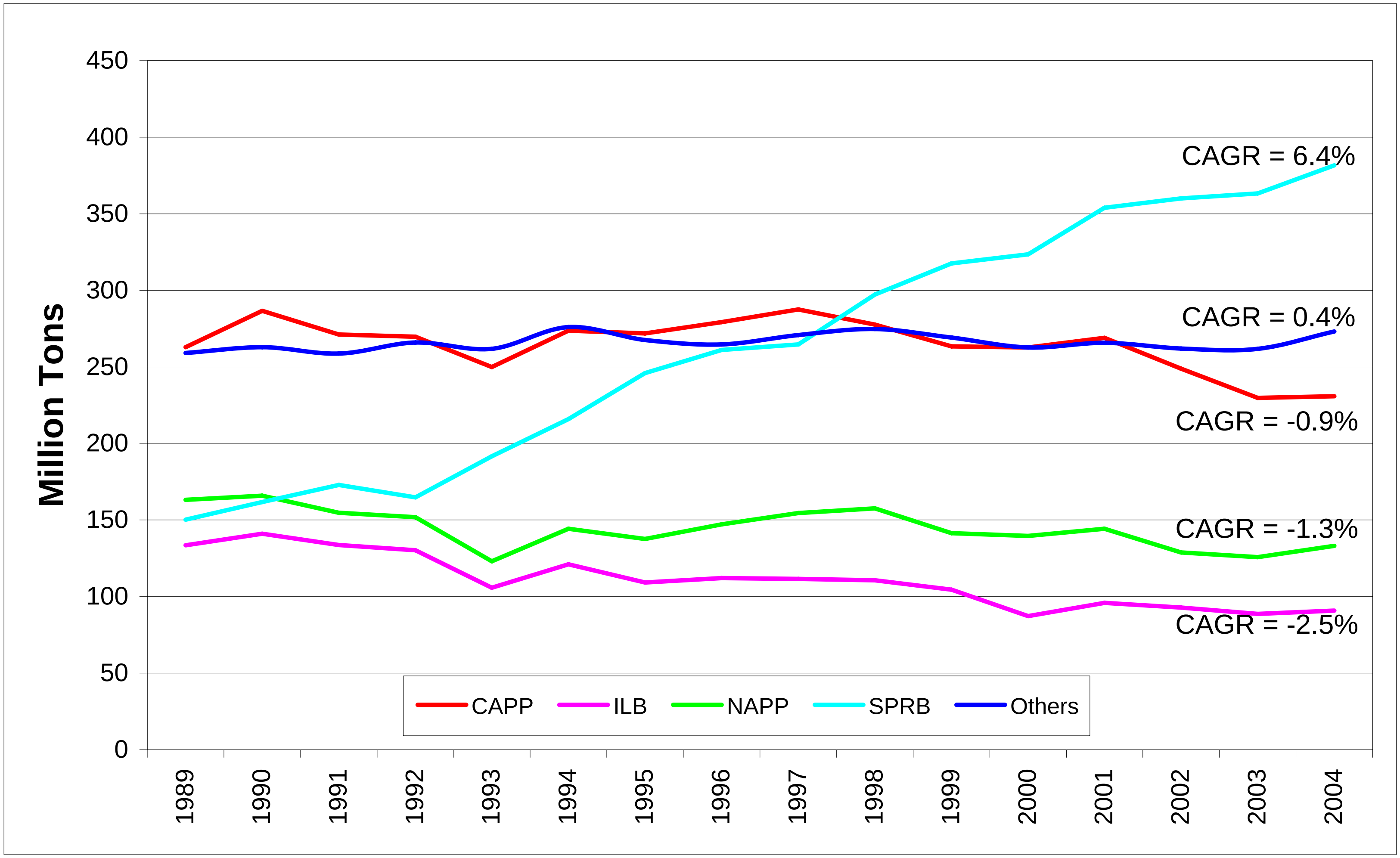


Figure 2
SO_2 EMISSIONS – HISTORICAL AND PROPOSED EMISSIONS AND LIMITS

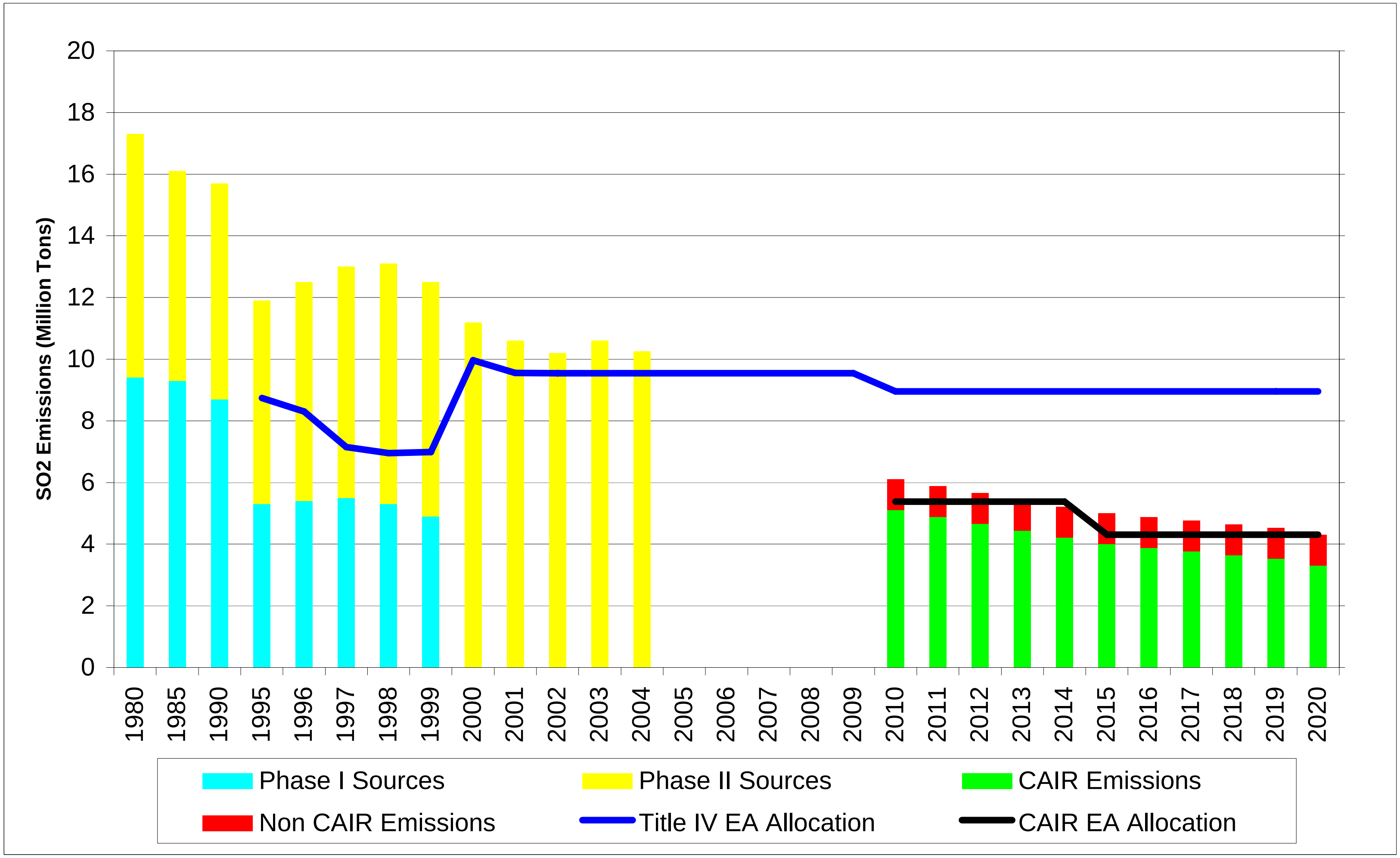


Figure 3
COAL-FIRED GENERATION MODEL ASSUMPTIONS

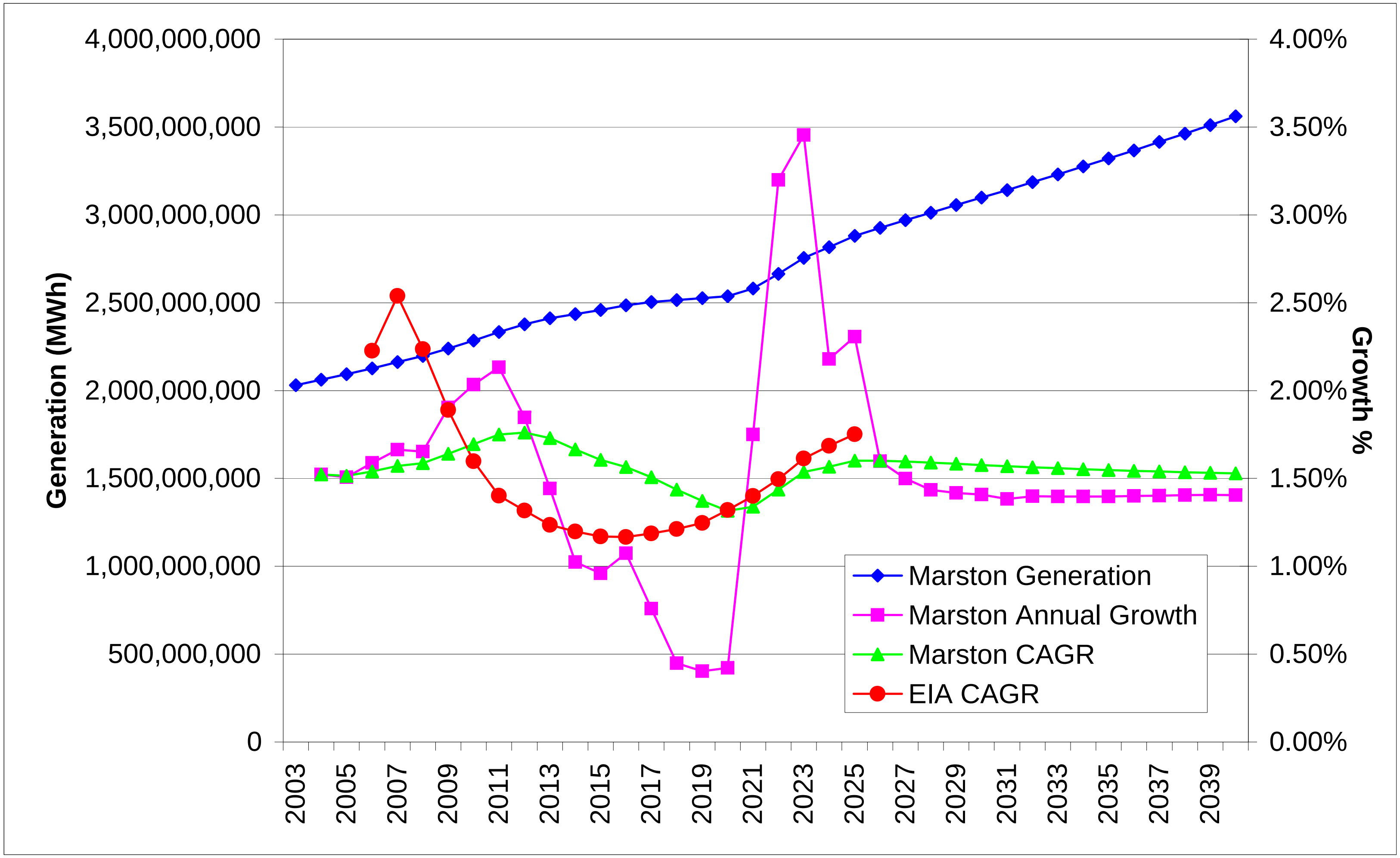


Figure 4
COAL DEMAND FORECAST

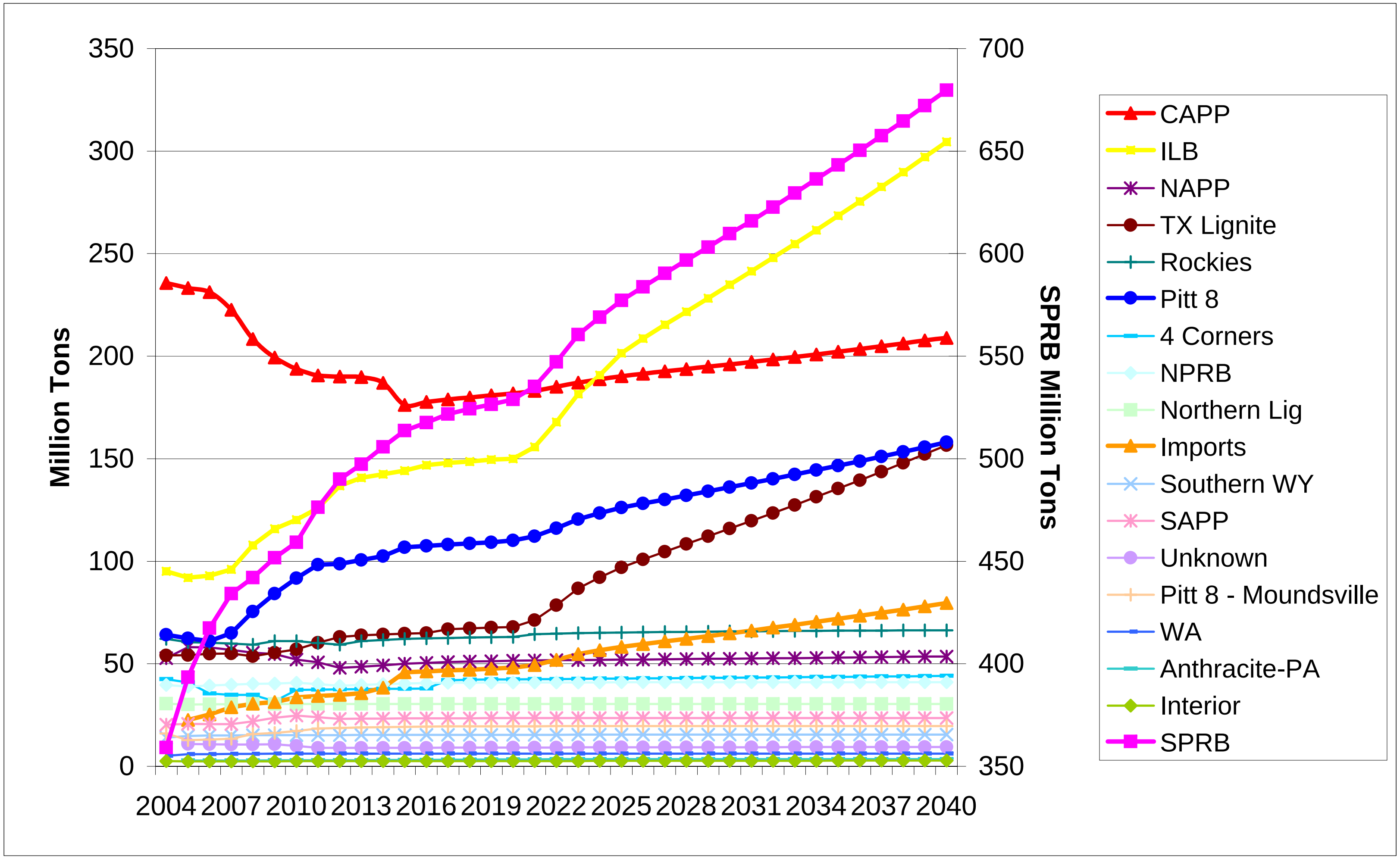


Figure 5
ILLINOIS BASIN SUPPLY AND DEMAND

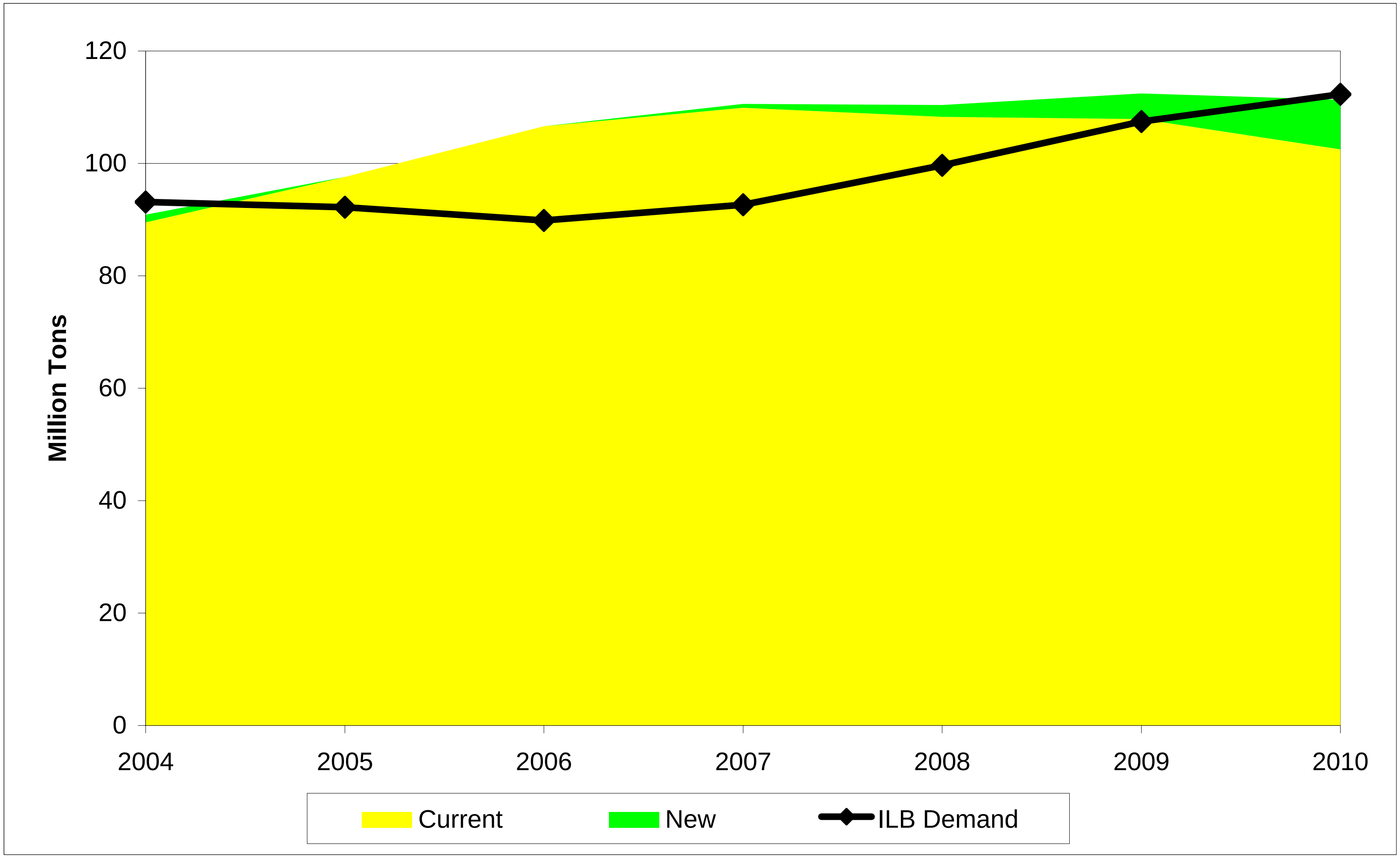


Figure 6
PITTSBURGH SEAM COAL PRODUCTION FORECAST

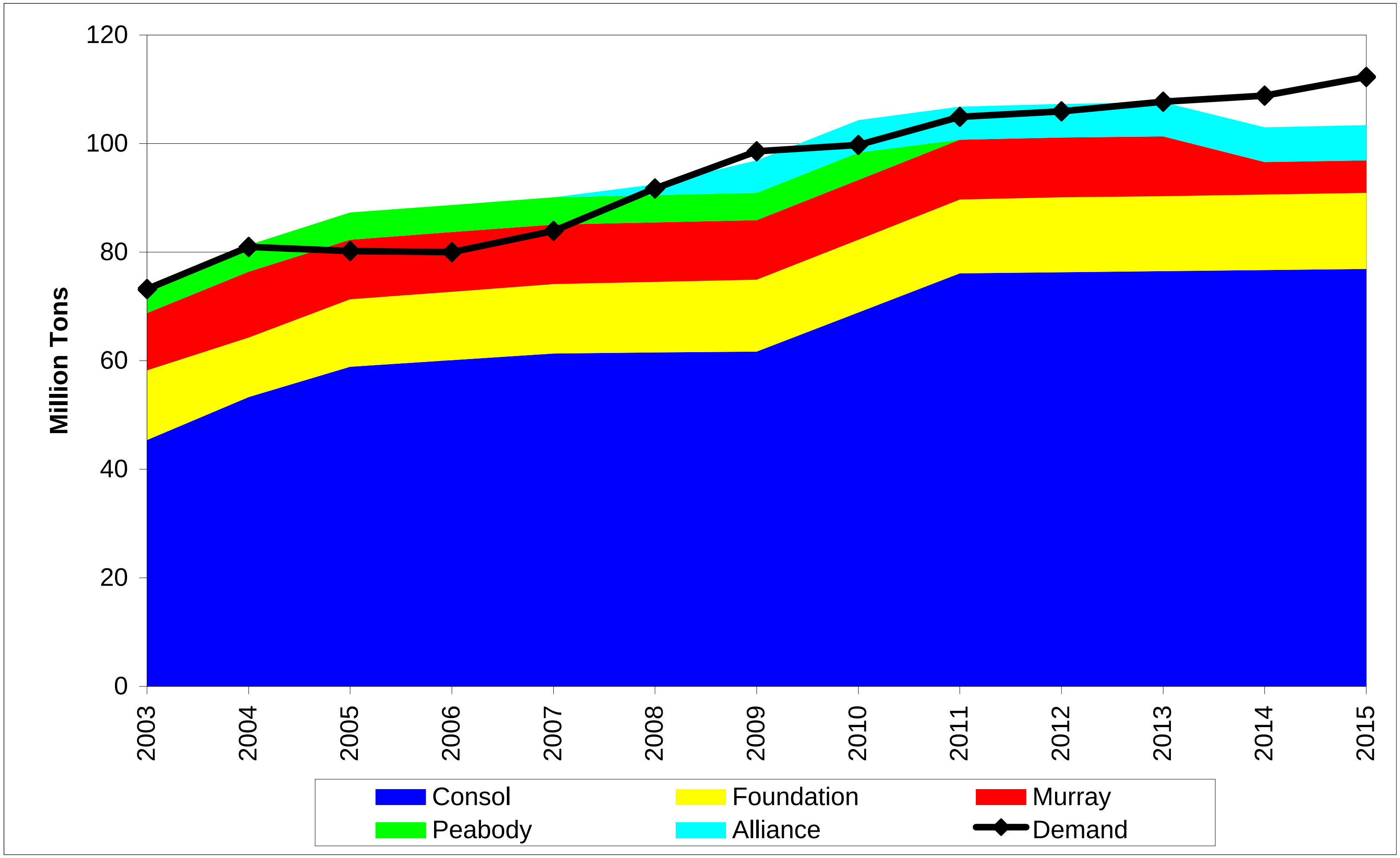


Figure 7
HISTORICAL AND FUTURE ILLINOIS BASIN COAL PRICES

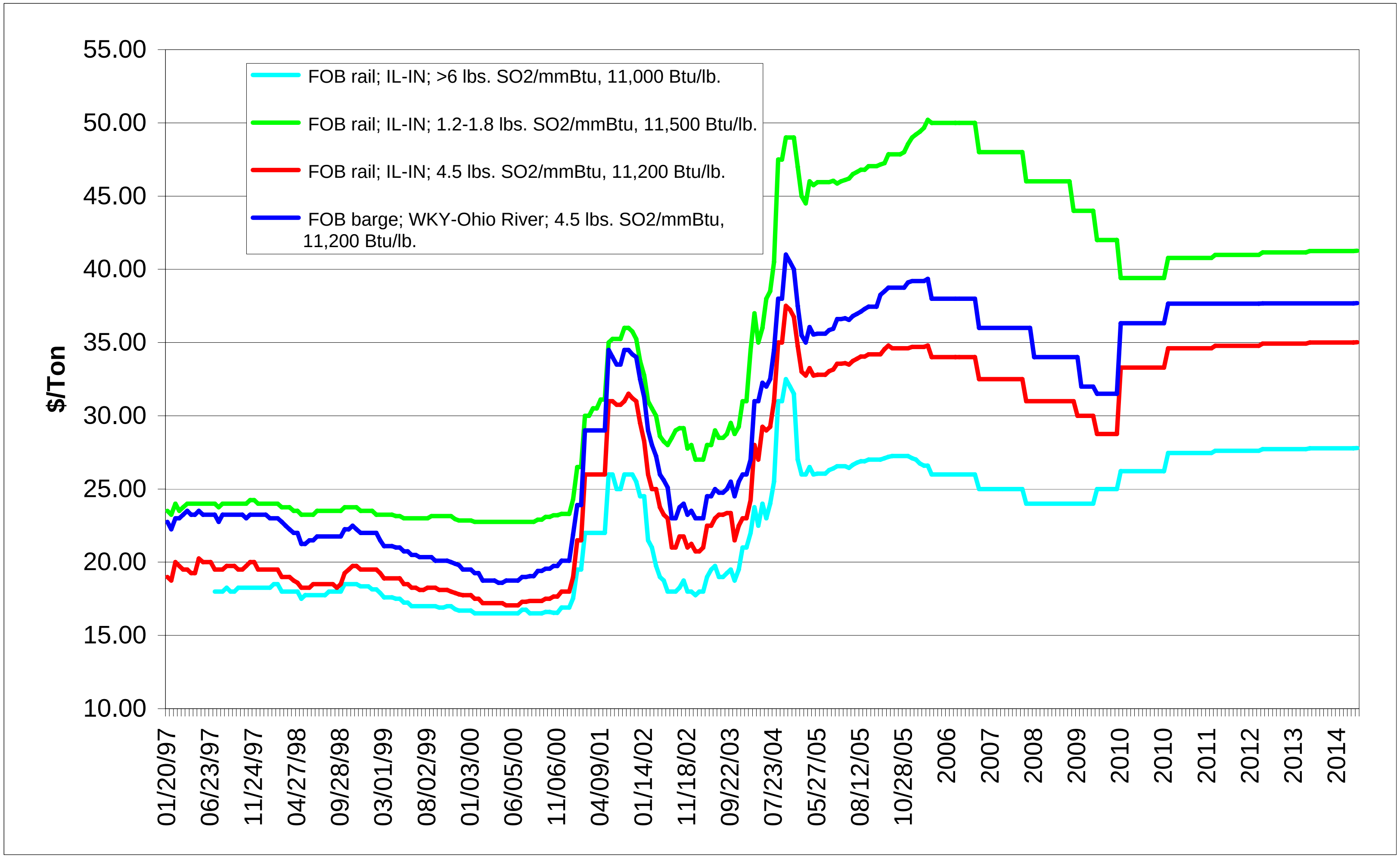


Figure 8
SPRB SUPPLY AND DEMAND FORECAST

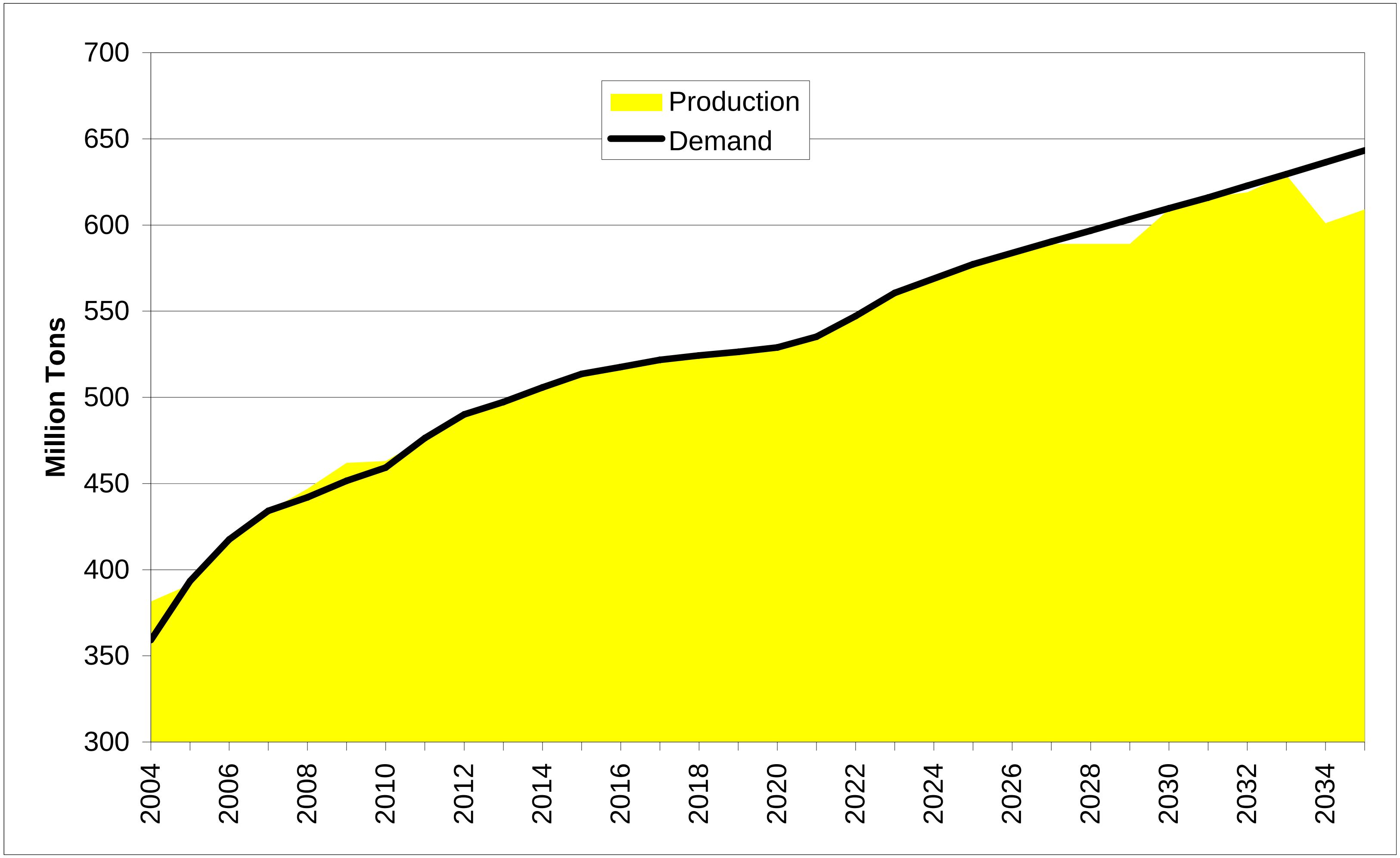
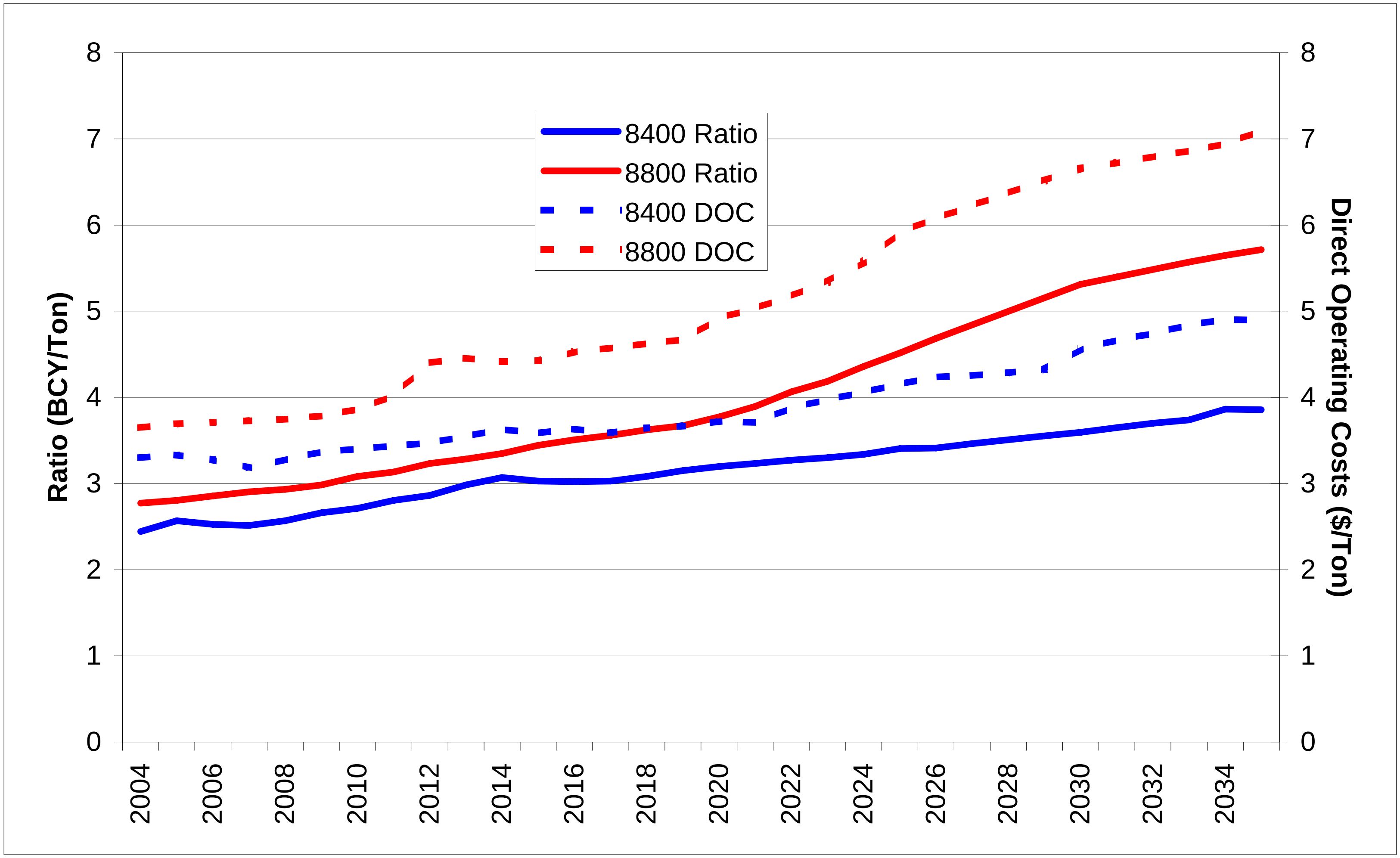


Figure 9
SPRB RATIO AND DIRECT COST FORECAST



EXCELSIOR ENERGY INC.
DECEMBER 2005

Figure 10
SPRB CASH COST OF SALES FORECAST

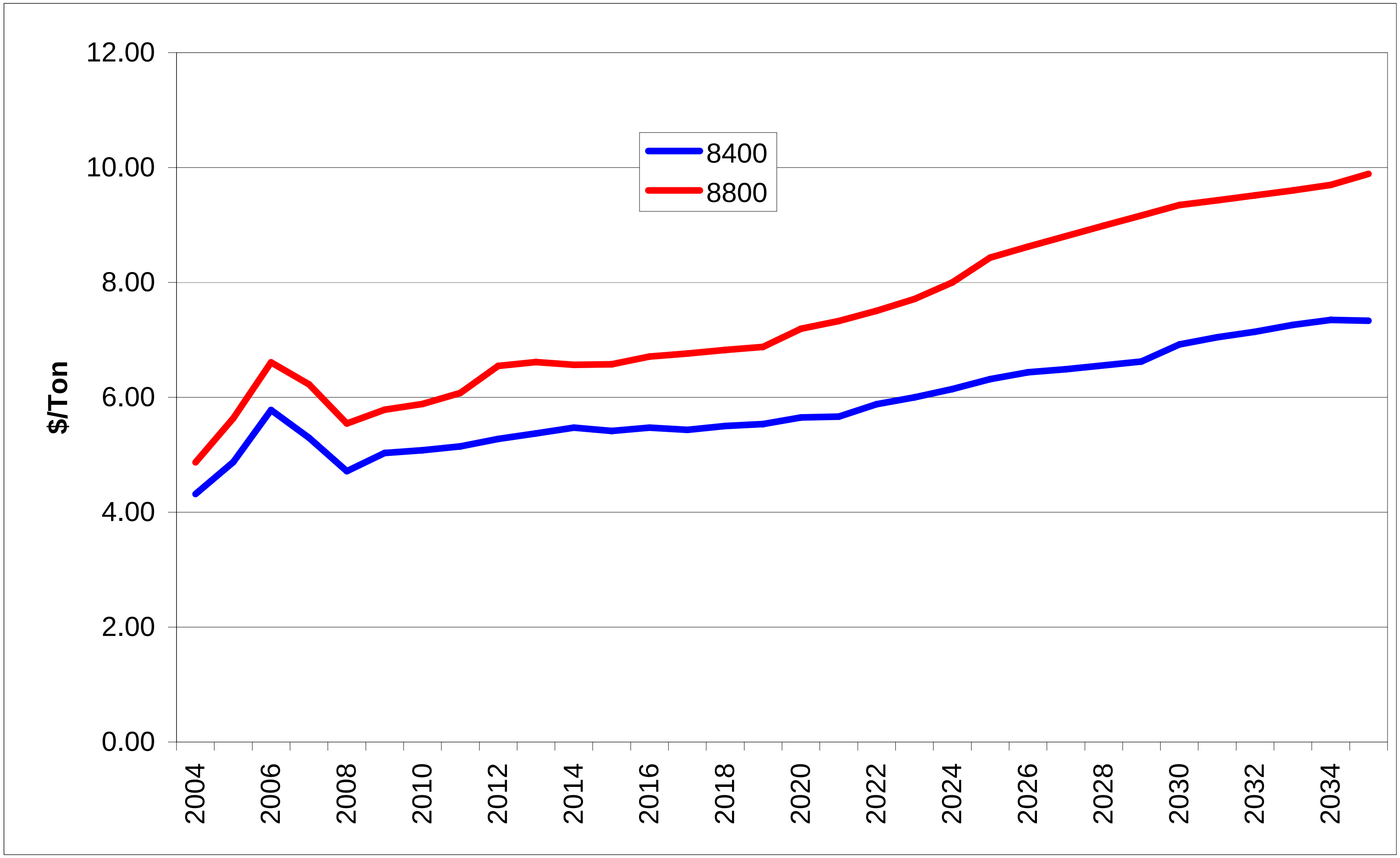
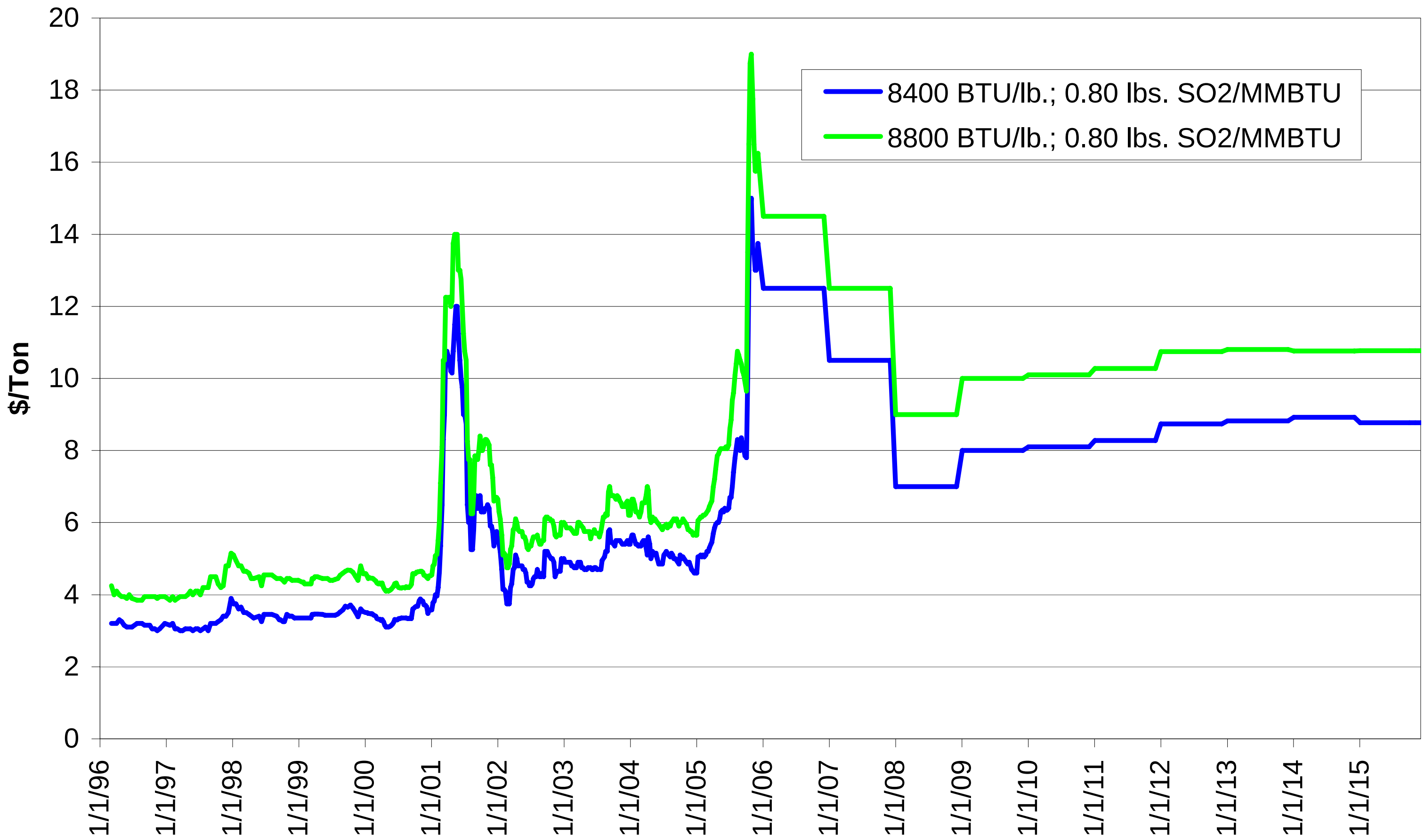


Figure 11
HISTORICAL AND FUTURE SOUTHERN POWDER RIVER BASIN COAL PRICES



Note: Short-term supply and demand events may create short-term price volatility that is not represented in the forecast.

Figure 12
SPRB TOTAL RESERVE SUPPLY CURVE

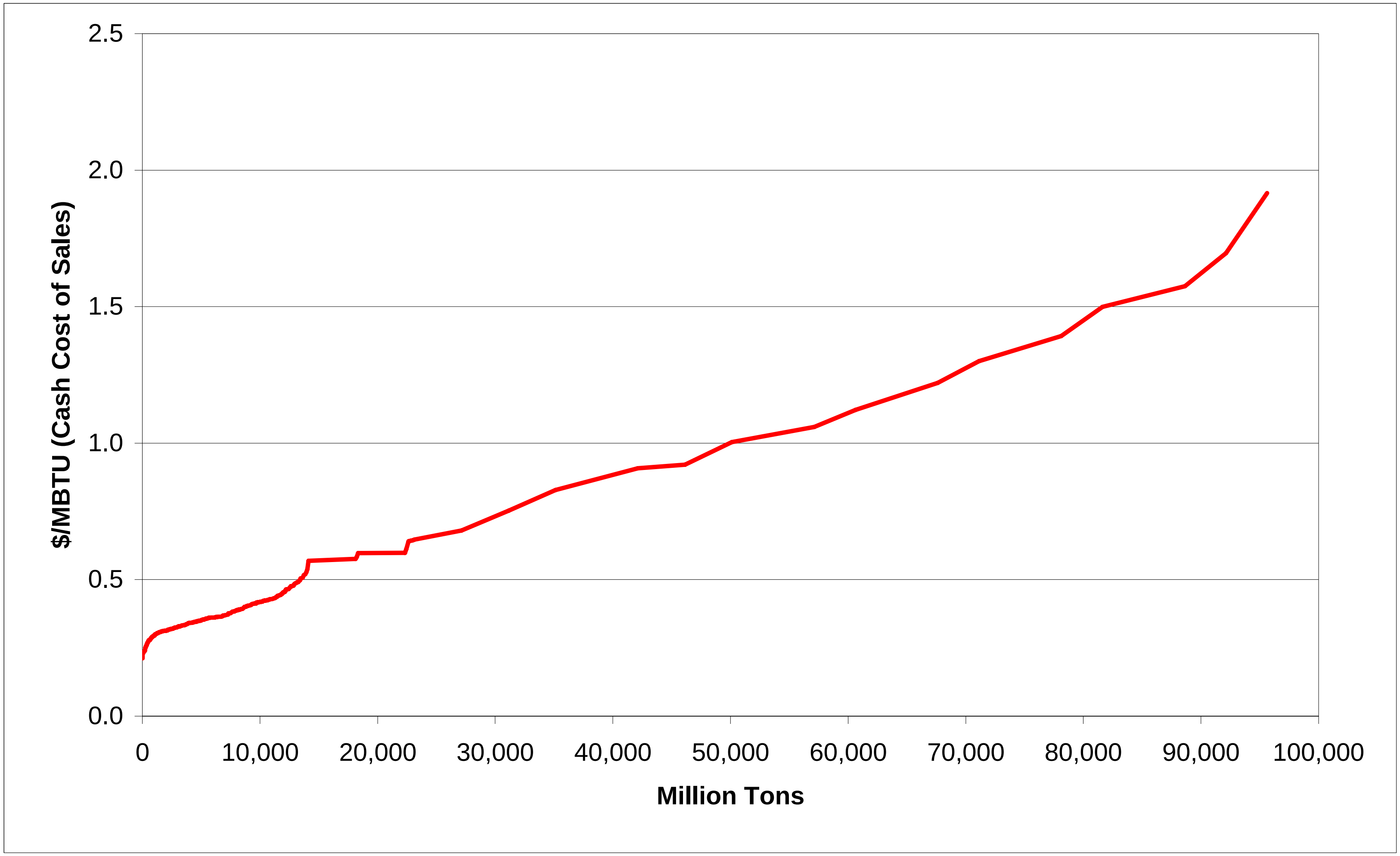
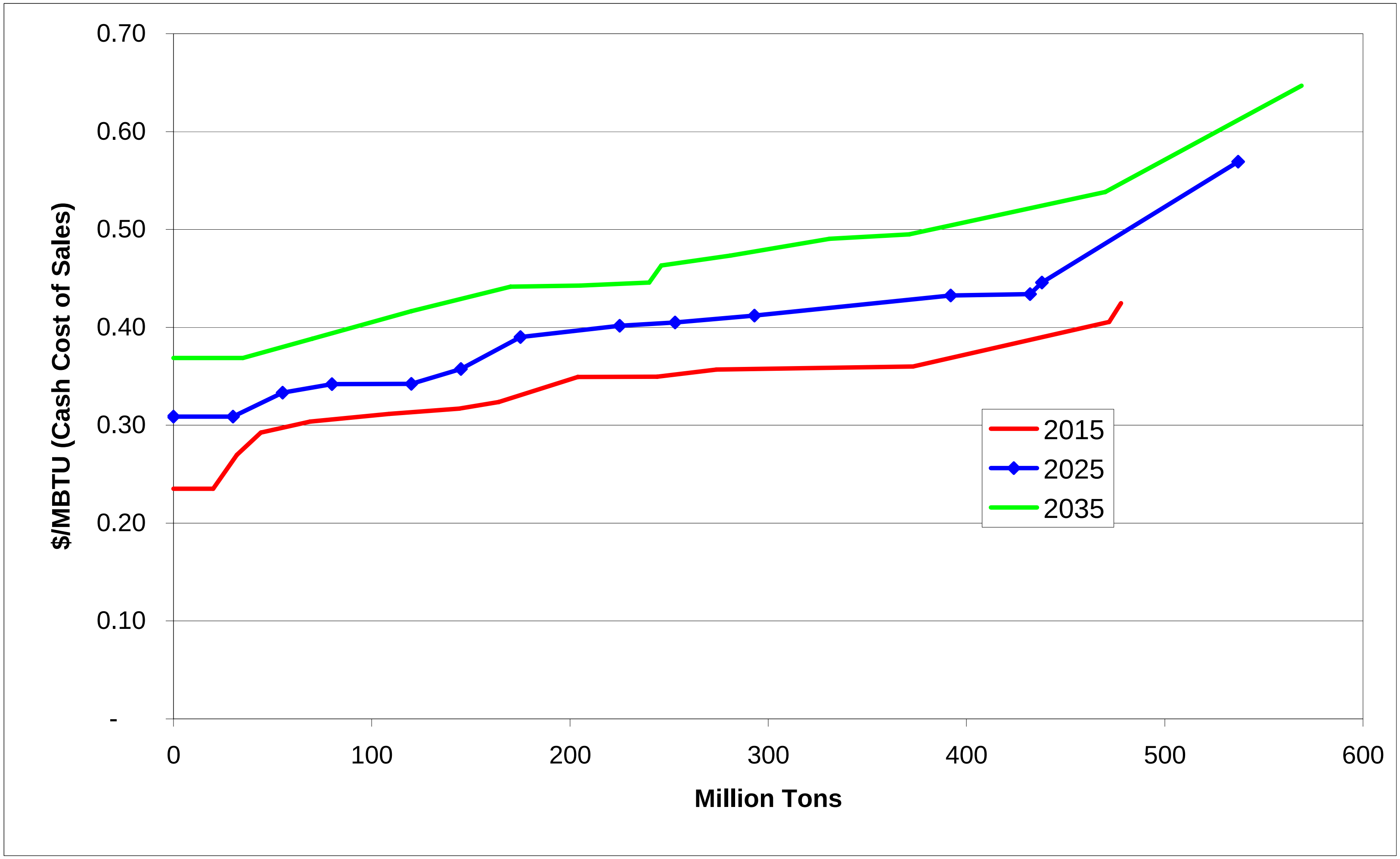


Figure 13
SPRB CASH COSTS OF SALES



Mayoral Letter of Support

LETTER OF SUPPORT
MESABA ENERGY PROJECT

May 30, 2007

Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

RE: Docket Nos. E-6472-/M-05-1993 and E-6472-/M-06-668

Dear Commissioners:

On behalf of our cities, we are signing this letter to demonstrate our support for the Mesaba Energy Project. We believe that this project would be a positive addition for the region because of its economic development benefits and its environmental profile that is significantly cleaner than similar power plants.

The economic development benefits to the region include a substantial addition to the tax base, 1000 construction jobs, and over 100 permanent jobs. These attributes will combine to provide direct and indirect growth opportunities, which will aid communities in our region.

The Mesaba Project's coal gasification technology will provide drastic emission reductions compared to existing coal-fired power plants. Even compared to state-of-the-art conventional coal power plants, the Mesaba Project will provide significantly cleaner electricity to the state.

For these reasons, we support the Mesaba Energy Project.

Sincerely,

Daniel A. Lotti Mayor of marble, mn.	Marlene Pospeck Hoyt Lakes Mayor of
Michael A. [illegible] Chisholm Mayor of	John Sloan Coleraine Mayor of
Taconite [illegible] Mayor of	[illegible] Keewatin Mayor of
Gary W. Shelton Mayor of	Martin [illegible] Mayor of
[illegible] ELY Mayor of	William Hendricks Mayor of Nashwauk

Craig Rufard - BUHL
Mayor of

Mayor of

Rodger L. Brown City of Calumet
Mayor of

Mayor of

Mayor of

Mayor of

Mayor of

Mayor of

Mayor of

Mayor of

Mesaba Energy Project Plan for Carbon Capture and Sequestration (Public Version)

Mesaba Energy Project

Mesaba One and Mesaba Two

Plan for Carbon Capture and Sequestration

Public Version

Prepared by

EXCELSIOR ENERGY INC.

October 10, 2006 Revision 1

Executive Summary

Excelsior Energy Inc., the developer of the Mesaba Energy Project has prepared this plan to identify the opportunities for capture and sequestration of carbon dioxide (“CO_2”) emissions from its integrated gasification combined-cycle (“IGCC”) power stations. This carbon capture and sequestration plan (“CCS Plan”) was prepared to provide a concrete option for the State of Minnesota to meet its obligations under future CO_2 regulations, which if promulgated, would affect coal-fired power plants, including the Mesaba Energy Project. We undertook the plan with the goal of providing the Minnesota Public Utilities Commission (the “Commission”) with information about all options that available now and in the future with respect to carbon management through capture and geological sequestration from the Mesaba Project.

The decision to implement a carbon capture and sequestration (“CCS”) program is one that the Commission must weigh from time to time, based upon the costs to ratepayers associated with CCS and the benefits to ratepayers associated with a CCS program. This Plan provides a framework within which the Commission can make such a decision. The costs to ratepayers of implementing CCS would include additional capital and operating costs, reduced output and plant efficiency and potential downtime to implement the system. The benefits would include (a) any revenues from enhanced oil recovery (EOR), and (b) the ability to cost-effectively comply with any form of legislation limiting or regulating carbon dioxide emissions as part of an initiative to stabilize atmospheric concentrations of greenhouse gases (“Carbon Constraints”), whether in the form of avoiding carbon taxes or the purchase of allowance credits, or the ability to reduce carbon emissions to levels specified on a fleetwide or statewide basis.

The first option for CCS presented by the Mesaba Project entails capture and sequestration carbon dioxide present in the syngas, which represents 30% of the total carbon dioxide emissions from the plant. Technologically, this option would entail the installation of amine scrubbers downstream of the acid gas removal system in the IGCC power stations to remove up to 85% of the CO_2 in the synthesis gas that fuels the plants, resulting in an overall CO_2 capture rate of 30% for the plant. This technology is available now to achieve 30% capture at a relatively low cost to ratepayers. This option could be implemented as early as 2014, following the commercial operation date for the first unit of the Mesaba Energy Project. Implementation of CCS prior to the availability of credits or carbon avoidance benefits would rely exclusively on revenues that may be available from EOR. Sequestration at EOR sites would have higher costs, due to the longer distances to the candidate oil fields, than would sequestration in saline formations closer to the plant site. Those additional costs would be weighed against the revenues that would accompany the supply of CO_2 for EOR. A decision to implement this form of CCS prior to the imposition of Carbon Constraints would have to weigh the likelihood that the base line emissions year would be established such that reductions implemented before that date would be given credit.

The second, longer-term option for CCS presented by the Mesaba Project would reduce CO_2 emissions by approximately 90%. This option could be implemented following the successful demonstration by the DOE’s FutureGen of full capture from an IGCC plant. The costs of this option are significantly higher than the 30% capture approach using currently available technology. Significant ongoing research and development efforts sponsored by the Department of Energy ("DOE") are expected to reduce these costs significantly and result in commercial offerings of these technologies. Given the fact that IGCC is a least-cost source of carbon reductions in the power sector, these deeper reductions are likely to be cost justified in the event Carbon Constraints are imposed that require any meaningful reduction in total greenhouse gas emissions. Implementation of 30% capture option would not preclude later decisions to increase capture levels to 90%.

In an EOR scenario, the captured carbon dioxide would be transported via pipeline to oil fields in North Dakota, southwestern Manitoba, and/or southeastern Saskatchewan. Once the CO_2 arrives at its destination, it would be sequestered underground, potentially in connection with enhanced oil recovery operations.

Alternatively, the saline formation scenario would entail transporting the CO_2 to a saline formation located much closer to the plant site, reducing the pipeline costs but also eliminating the revenues associated with the sale and beneficial use of the CO_2.

The economics of CCS look promising. The 30% capture option identified in the CCS Plan would enable CO_2 capture at a cost per ton below that of any other existing power plant in the state. IGCC plants' ability to economically capture CO_2, combined with the potential for revenues described above, have the potential to significantly decrease the cost of CCS.

Under this proposed Plan, Excelsior would commit to undertake capture, transportation and sequestration of carbon dioxide, upon a decision by, and at the direction of, the Commission, upon approval of a modification to the proposed power purchase agreement that would allow for Excelsior to be compensated at a reasonable cost of capital for the necessary capital investments, and to be made whole on the other costs associated with the CCS program. This commitment, together with Excelsior's ongoing work to refine the costs and technical means to implement CCS, will position the State to respond in a timely and economic fashion to carbon constraints.

I. Introduction

This ability to capture and sequester CO_2 is important because Carbon Constraints are likely to be implemented within the next ten years. As evidence of this, various proposals to regulate greenhouse gas emissions ("GHGs") have been introduced in the United States Congress, and various states have embarked upon their own GHG programs.

Identification of strategies to comply with likely Carbon Constraints is a critical element of protecting Minnesota's consumers and economy. Excelsior is working in conjunction with the Energy and Environmental Research Center ("EERC") as part of the Plains CO_2 Reduction Partnership ("PCOR") initiative to develop CO_2 management options for the Mesaba Energy Project based on evaluations of sequestration opportunities associated with regional geologic formations/features and nearby terrestrial features.[1]

[1] The EERC is part of the University of North Dakota and has been selected by the Department of Energy to develop a regional vision and strategy for dealing with carbon management in the Plains Region

What follows is Excelsior's CCS Plan for the first two of six IGCC units to be constructed over time on three state-authorized sites within the Taconite Tax Relief Area of Northeastern Minnesota. The proximity of the three sites with IGCC units, together with the potential opportunities for carbon sequestration identified by the EERC, affords the State of Minnesota the opportunity to carefully plan for and implement the most cost-effective and flexible response to carbon constraints.

II. Background: Mesaba Energy Project Phases I and II

The IGCC Power Station described in this document consists of Phase I and Phase II of the Mesaba Energy Project ("Mesaba One" and "Mesaba Two," respectively). Each phase is nominally rated at peak to deliver 606 megawatts ("MW") of electricity to the bus bar.

Excelsior has submitted the necessary regulatory petitions and preconstruction permit applications to support construction of Mesaba One and Mesaba Two. The key pending regulatory filings made in connection with the Mesaba Project include the following: On December 22, 2005, Excelsior submitted to the Commission a petition to approve a Power Purchase Agreement with Xcel Energy under Minn. Stat. § 216B.1693 and 1694. On June 16, 2006, Excelsior submitted a Joint Permit Application for a Large Electric Power Generating Plant Site Permit, a High Voltage Transmission Line Route Permit, and a Natural Gas Pipeline Route Permit to the Commission for Mesaba One and Mesaba Two. On June 28, 2006, Excelsior submitted applications for New Source Review Construction Authorization and National Pollutant Discharge Elimination System Permits to the Minnesota Pollution Control Agency for Mesaba One and Mesaba Two. On June 29, 2006, Excelsior submitted an application for a Water Appropriation Permit to the Minnesota Department of Natural Resources.

When operational, the Mesaba Energy Project will allow Minnesota and the nation to benefit from the environmental advantages that IGCC technology offers over conventional, solid fuel alternatives. Beyond its capability for achieving an emission profile unmatched by conventional coal combustion systems, IGCC is adaptable to capture significant amounts of carbon dioxide from the synthesis gas prior to its combustion. Mesaba One and Two will be configured to allow for the installation of additional equipment that can capture up to 30% of the potential carbon in its selected feedstock.

III. Regulatory Context for Carbon Capture and Sequestration

Excelsior's intent in proposing a framework for CCS is to commence a process to identify and define conditions for development of CCS when state or national considerations require GHG reductions, and/or when such reductions might otherwise become an economic choice for the ratepayers of Northern States Power Company under the PPA, in the context of Mesaba One and

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(including the Canadian Provinces of Alberta, Saskatchewan, and Manitoba, and the states of Montana, NE Wyoming, North Dakota, South Dakota, Nebraska, Minnesota, Wisconsin, Iowa, and Missouri). *See* PCOR Partnership Profile, http://www.undeerc.org/pcor/partnership.asp.

Mesaba Two. Excelsior's efforts will advance State decision makers' practical knowledge regarding the role IGCC and the Mesaba Energy Project can play in achieving actual reductions in the state's CO_2 emissions.

Several states are undertaking initiatives to reduce greenhouse gas emissions, most notably carbon dioxide, in isolated sectors of their economies.[2] To achieve significant reductions of such emissions, it is probable that future climate change initiatives will extend nationwide and to all sectors of the economy. The ability to physically reduce the volume of GHG emissions from Minnesota's economic activity will be a critical component to the State's economic health, whether the constraints require roll-backs from any one sector or sources, or whether the constraints take the form of a tax or a cap-and-trade system. The precise form that the carbon limits take is outside the scope of this CCS Plan, and in any event is not critical to the analysis of IGCC, which has the lowest cost of capture of any fossil fuel technology. In a carbon-managed economy, large sources of CO_2 emissions that can economically achieve significant GHG reductions will likely be the major source of CO_2 offsets for other economic sectors whose only meaningful alternative for achieving reductions may be the purchase of GHG offset credits. Because IGCC is the technology best suited to carbon capture of all the fossil technologies, it is a least-cost means to achieve actual reductions in GHG emissions, and will therefore very likely be able to achieve emission reductions at a cost below where credits will trade or where tax levels are established in order to signal sufficient reductions to meet the national program goals.

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[2] Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York and Vermont have formed the Regional Greenhouse Gas Initiative ("RGGI") with the goal of creating a regional cap-and-trade program. The plan will begin addressing carbon dioxide emissions from power plants in the member states by capping 2009 carbon dioxide emissions at current levels. Beginning in 2015, RGGI states will begin reducing carbon dioxide emissions to achieve a 10% reduction by 2019. To facilitate the process, power plants will receive CO_2 emission allowances, which they may trade with other power plants. *See* Press Release, Regional Greenhouse Gas Initiative, States Reach Agreement on Proposed Rules for the Nation's First Cap-and-Trade Program to Address Climate Change (Aug. 15, 2006), *available at* http://www.rggi.org/docs/model_rule_release_8_15_06.pdf; Regional Greenhouse Gas Initiative, Model Rule (Aug. 15, 2006), *available at* http://www.rggi.org/docs/model_rule_8_15_06.pdf.

Similarly, California recently enacted legislation that calls for the development of regulations and market mechanisms that will reduce the state's greenhouse gas emissions by 25% by 2020. The law will impose mandatory caps beginning in 2012 and will incrementally tighten emission limits to reach the 2020 goals. *See* Press Release, Gov. Arnold Schwarzenegger, Gov. Schwarzenegger Signs Landmark Legislation to Reduce Greenhouse Gas Emissions (Sept. 27, 2006), *available at* http://gov.ca.gov/index.php?/press-release/4111/; California Global Warming Solutions Act of 2006, Assembly Bill No. 32, *available at* http://www.leginfo.ca.gov/pub/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf.

In 2001, Massachusetts developed regulations that apply to power plants in the state. Under the regulations, CO_2 emissions may not exceed the historical actual emissions for the three-year period from 1997 to 1999, and CO_2 emissions may not exceed 1800 lbs/MWh. See Massachusetts Dept. of Environmental Protection, Governor Swift Unveils Nation's Toughest Power Plant Regulations, Inside DEP, April/May 2001, at 1, *available at* http://www.environmentalleague.org/Issues/Enforcement/DEPMay2001.pdf#search=%22Governor%20Swift%20air%20regulations%22; 310 Mass. Code Regs. 7.29 (2004), *available at* http://enviro.blr.com/display_reg.cfm/id/48436.

Mesaba One and Mesaba Two are therefore likely to be ideal sources of carbon offsets under such circumstances, and are likely to provide the State with a meaningful, cost-effective hedge in meeting any federally-imposed GHG reductions.

IV. Preliminary Plan Description and Analysis

There are two primary components of the CCS Plan. First, Excelsior identifies the most promising, commercially available CO_2 capture technology to install at the IGCC power station. As described later in this section, an amine scrubber process currently has the most potential for carbon capture at the Mesaba Project. Second, Excelsior develops engineering plans for different methods of sequestering the captured CO_2. Based upon studies to date, the CCS Plan suggests a staged development of CO_2 pipelines from its Iron Range plant sites to North Dakota oil fields and proximate locations. The pipelines would likely utilize existing railroad, pipeline, or transmission line rights of way.

A. CO_2 Capture

Several processes have been proposed for carbon capture in coal power plants, consisting primarily of scrubbing or membrane separation-based processes. In conventional coal plants, the carbon must be scrubbed from very large volumes of stack gases at low pressures and temperatures. The most mature and proven of these is amine scrubbing, which is similar to the process used by the Mesaba Energy Project to capture sulfur from the syngas. In this process, the amine solution first adsorbs carbon dioxide from the gas being treated, and then CO_2-enriched amine is regenerated, recycling the amine and producing a relatively pure stream of CO_2.

IGCC plants enable pre-combustion capture of CO_2, which provides the intrinsic advantages of treating an undiluted and pressurized gas stream. An additional advantage enjoyed by IGCC is that CO_2 captured from high-pressure syngas requires less compression before transport and/or storage.

The Mesaba Energy Project features a design that is adaptable to carbon capture, which enables relatively simple upgrades to be made in order to commence carbon capture. These upgrades entail installing a CO_2 amine scrubber downstream of the acid gas removal system and adding driers and compressors for captured CO_2. In this design, the CO_2 available for capture is limited by the proportion of carbon dioxide in the syngas, which varies for different fuels. Up to 30% of the potential CO_2 could be removed from the design subbituminous coal, while up to 20% could be removed from other design feedstocks.

Higher capture rates are not commercially available today, but will be demonstrated in the future. This is the primary objective of DOE's FutureGen project, which aims to capture at least 90% of the CO_2 from a non-commercial plant to begin operation in 2013. After such a demonstration of commercial viability, the Mesaba Energy Project could achieve 90% capture by adding a gas reheater and a water gas shift reactor upstream of the CO_2 amine scrubber. The shift reactor process converts CO to CO_2 by the following reaction:

$$CO + H_2O \rightarrow CO_2 + H_2$$

Nearly all of the carbon in the resulting syngas stream is in the form of CO_2, enabling the amine scrubber to remove at least 90% of the CO_2. However, at the current state of technology, this process would increase capital cost and reduce efficiency of the plant, making it more expensive for capturing CO_2 on a per ton basis than the 30% configuration. It should be noted that a plant that has implemented 30% capture would still be technically capable of being converted to capture 90% once the technology is demonstrated by DOE's FutureGen project.

Because the 90% approach has not yet been demonstrated and the 30% approach is the most mature and proven option, Excelsior concludes that the 30% approach is the most likely candidate for CCS in the near term. The 30% CO_2 capture configuration represents a cost-effective, commercially available option today for the Mesaba Project.

B. Economic Considerations Relating to Sequestration

The potential economic drivers for CCS by the Mesaba Energy Project include opportunities to supply the CO_2 to an oil field for sale and use in enhanced oil recovery ("EOR"), and the opportunity for financial benefits to ratepayers from reductions in the costs of complying with carbon limits imposed in the future. This CCS Plan contains information on economical sequestration opportunities within the oil fields located in closest proximity to the Mesaba IGCC power stations. Because CO_2 used for EOR is also sequestered, the Mesaba Energy Project would likely earn carbon credit revenues (or avoid costs in other carbon limit scenarios) once regulations limit CO_2 emissions, which would be in addition to the EOR revenues. Therefore, investments in pipeline infrastructure for EOR will provide additional value as a method of sequestration once a carbon credit market is established.

1. Enhanced Oil Recovery

Carbon dioxide has been proven to be very effective for secondary and tertiary oil recovery by both displacing and decreasing the viscosity of otherwise unrecoverable oil. Upon extraction of the oil, the EOR process easily removes pressurized CO_2 and recycles it by reinjecting into the pool. Economic benefits from EOR have been realized in at least two regions in North America. Kinder Morgan CO_2 has a CO_2 pipeline network of 1100 miles servicing the Permian Basin in western Texas and eastern New Mexico.[3] Similarly, the Dakota Gasification Project in the Northern Plains pipes CO_2 over 200 miles to the Weyburn oil field in southeastern Saskatchewan. The market for CO_2-based EOR is still available in oil fields across the country, so the Mesaba Energy Project, by virtue of its advanced stage of development, may be poised to exploit some of the most economical oil recovery operations available to the benefit of Minnesota ratepayers.

2. Carbon Credits or Other Economic Benefits of CCS

Carbon credits or other economic benefits derived from CCS under other forms of potential carbon regulation also represent a potential economic driver for the Mesaba CCS development,

[3] See Kinder Morgan CO_2, http://www.kindermorgan.com/about_us/about_us_kmp_co2.cfm.

with future regulation in the U.S. determining the final value of the Carbon Benefits generated by CCS undertaken by the Mesaba Energy Project.

D. CCS Approach

This CCS Plan analyzes the most promising initial approach for CCS from the Mesaba Energy Project under present circumstances, which would entail capture of 30% of the CO_2 generated by the power stations and would direct that captured CO_2 to EOR sites. This approach requires a longer pipeline than would direct sequestering of CO_2 in closer, non-EOR sites. Therefore, targeting EOR sites will require higher front-end costs than if Excelsior were to sequester carbon simply to meet carbon limits without providing CO_2 for EOR opportunities. EOR and future carbon credit markets may offset the higher costs associated with initially targeting EOR sequestration sites.

While the timetable for implementation of regulations governing the operation of a carbon-managed economy is unknown, Excelsior anticipates that it would have adequate time to implement the power station upgrades and construct a CO_2 pipeline.

Numerous in-depth studies exist describing the technological means to capture 90% of the carbon dioxide from an IGCC plant.[4] Because of the real-time research and development efforts with respect to 90% capture, and the expected reductions in costs of this option as the technologies are demonstrated, Excelsior has not attempted to quantify the costs nor describe the technological approach in detail in this phase of the plan.

V. Currently Available Regional Sequestration Studies and Experience with CO_2 Pipelines

A. Regional Sequestration Studies

The EERC has extensively characterized three major types of sinks for carbon sequestration that are within the appropriate geographic proximity of the Mesaba Energy Project. The options are geological sequestration in oil fields (for enhanced oil recovery or storage only) or saline formations, and terrestrial sequestration (primarily using wetlands). Terrestrial sites are not suited to accommodate direct injection of CO_2 because such sites rely on changing the existing physical configuration of large areas of the earth’s surface, rather than accepting the direct input of CO_2 at a stationary point. This CCS Plan focuses on geological sequestration, to which IGCC is uniquely suited.

Oil fields have proven to be CO_2 sinks with sufficient storage capacity to accommodate CCS projects equivalent to the long-term output of all six phases of the Mesaba Energy Project. Fields in the Permian Basin in western Texas have sequestered CO_2 for decades at scales even larger than those addressed in this CCS Plan.

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[4] For a summary of such studies, see the Oct. 10, 2006 testimony of Douglas H. Cortez, OAH Docket No. 12-2500-17260-2, MPUC Docket No. E-6472-/M-05-1993.

During Phase I of the PCOR project, the EERC conducted exhaustive bottom-up characterizations of the EOR potential for each field in the PCOR region.[5] The EERC's methodology has produced reliable and conservative estimates of the CO_2 capacity for EOR in each field. This data forms the basis for the EOR-driven scenarios in the CCS Plan by the Mesaba Energy Project presented below. The economic benefits that could be achieved from EOR alone (that is, not including sales of carbon credits) are substantial. For example, the EERC projects that the total value of oil that could be recovered by EOR in North Dakota alone exceeds $15 billion (at a price per barrel of $59.50).[6]

Saline formations have the potential for still greater sequestration capacity than oil fields. The EERC's studies of the CO_2 sequestration capacity of the Broom Creek Formation in North Dakota have confirmed this observation.[7]

B. Experience with CO_2 Pipelines

Carbon dioxide suppliers, purchasers, and third parties that own existing CO_2 pipelines provide practical knowledge about how such pipelines operate. CO_2 pipelines are similar to natural gas pipelines, and they can transport CO_2 from its source to a sink. The primary difference between CO_2 and natural gas pipelines is that CO_2 pipelines require higher pressures (roughly 2,000 psi instead of 1,000 psi). Dedicated CO_2 pipelines are currently used for EOR in the Permian Basin and the Weyburn Oil Field. In the Kinder Morgan pipeline, which services the Permian Basin, 1 billion cubic feet per day of CO_2 is compressed from 800 to 2,000 psi and transported 500 miles.[8] Applying this knowledge, IGCC power stations will dry and compress carbon dioxide and inject it into pipelines. Over long pipeline distances, booster stations will periodically recompress the CO_2.

VI. Scenarios to Be Further Investigated

This section evaluates five CCS configurations associated with the Mesaba Energy Project in an effort to give policymakers further information about potential CCS options. CCS based on EOR alone will be examined for the 30% capture configuration, across one to six Mesaba Energy Project units (each unit is assumed to have roughly 600 megawatts of capacity). As discussed in Section IV, the 90% capture configuration is not yet commercially available. Therefore, although this may change in time, Excelsior does not assume 90% capture for the purpose of generating the economics in this CCS Plan. As a simplifying baseline assumption, this CCS Plan further assumes that cost-sharing opportunities with other CO_2 sources will not be available.

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[5] *See* PCOR Partnership, *Plains CO2 Reduction (PCOR) Partnership (Phase I) Final Report/July–September 2005 Quarterly Report*, January 2006, *available at* http://gis.undeerc.org/website/PCORP/cdpdfs/FinalReport.pdf.

[6] EERC, Presentation, Potential Sequestration Options in the Plains CO2 Reduction (PCOR) Partnership Region & Estimated Capacities, Aug. 9, 2006 (on file with Excelsior Energy).

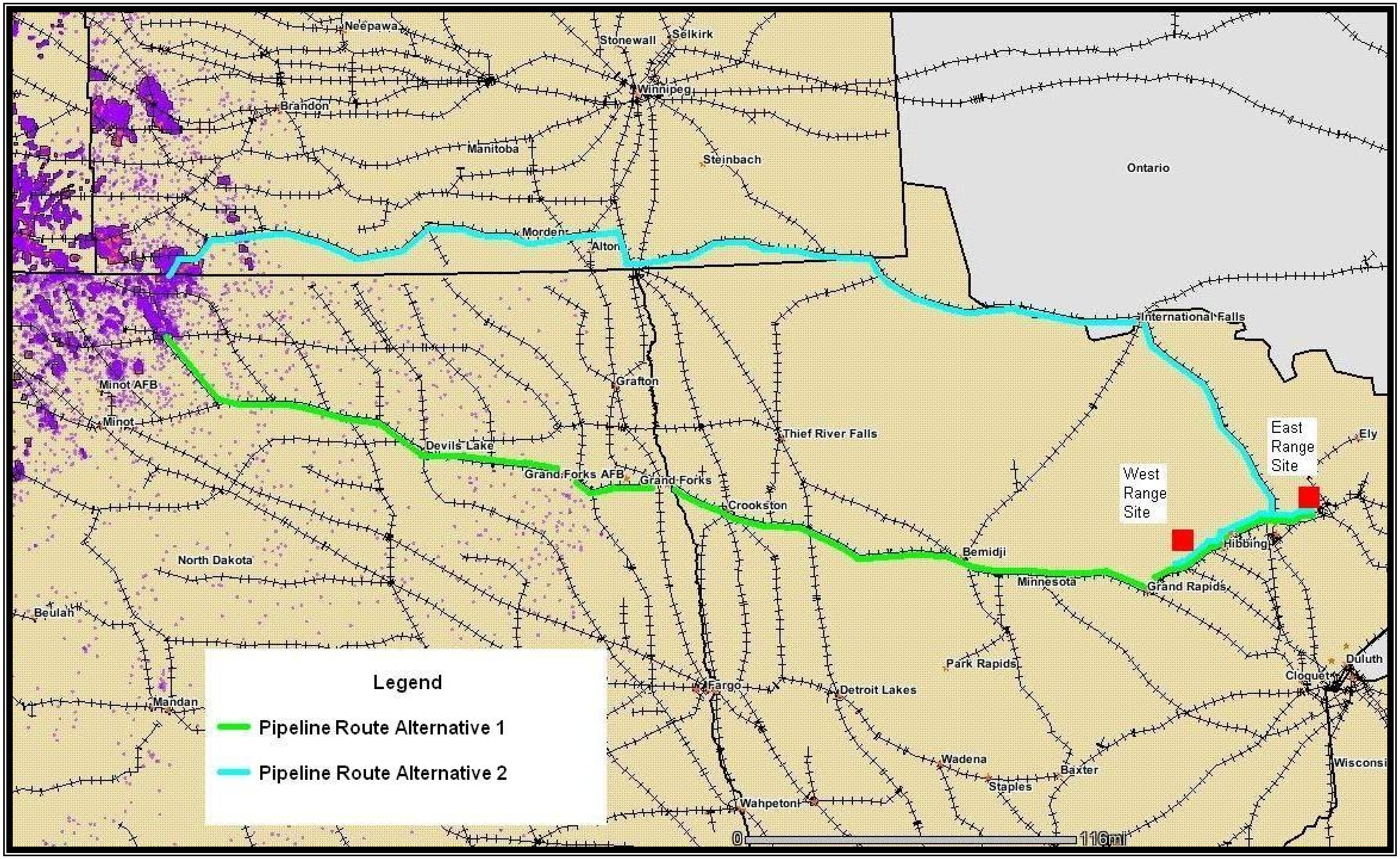
[7] Testimony of Edward N. Steadman, Oct. 10, 2006, MPUC Docket No. E-6472/M-05-1993, OAH Docket No. 12-2500-17260-2.

[8] Kinder Morgan, Cortez Pipeline and McElmo Dome, http://www.kindermorgan.com/business/co2/transport_cortez.cfm.

A. Scenario 1

For Scenario 1 and its alternatives, pipelines would be constructed between the three Mesaba Energy Project's Iron Range plant sites (each site containing two generating units) and a cluster of oil fields in north central North Dakota, the southwestern corner of Manitoba, and the southeastern corner of Saskatchewan. Many of these oil fields are either unitized or run by a single operator, which expedites the establishment of EOR in a field. (Unitization is a process by which field operators combine all oil and gas interests in a field into a single operation.) Non-unitized, multiple operator fields may take longer to set up EOR, so the readily available fields would be advantageous and the likely economic choice. For the main trunk pipeline connecting the plants and oil fields, two options for rights of way ("ROWs") are shown in Figure 1. The pipeline corridors in these scenarios follow existing rail ROWs only for the purpose of illustration – other potential corridors may exist.

Figure 1. Potential Pipeline Routes for the Mesaba Energy Project CO_2 Pipeline

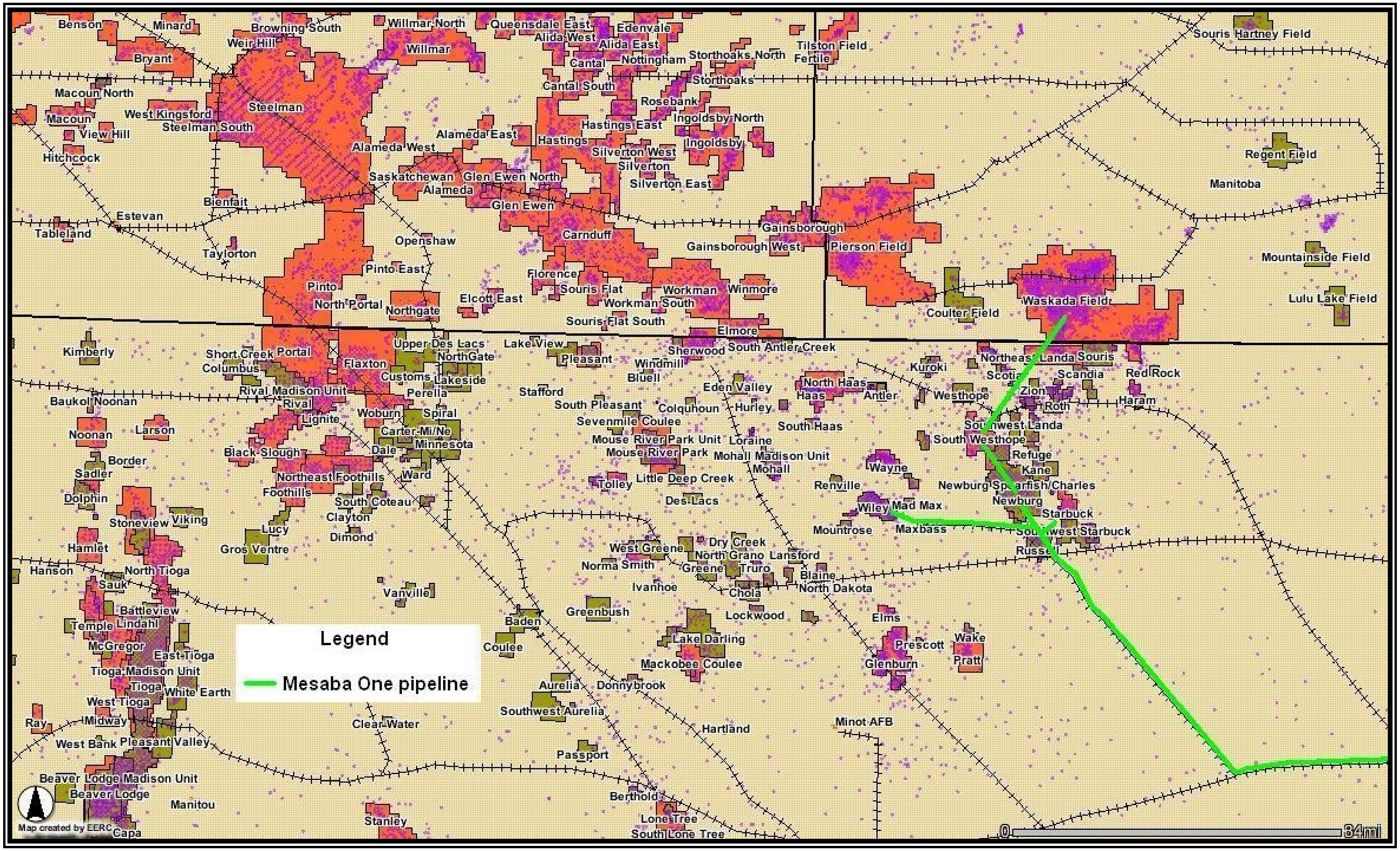


Source: EERC

B. Scenario 1A

For the CO_2 captured at Mesaba One, a cluster of oil fields in north-central North Dakota and southwestern Manitoba are targeted, with preliminary expectations that such fields could accommodate EOR for 22 years. This duration, which is used throughout the analysis of the various scenarios, corresponds to that of the financial model and does not reflect cessation of capture. Following existing railroad track (for purposes of illustration) from the preferred West Range site, a 12-inch pipeline approximately 405 miles long could reach the first proposed oil field. Over the course of 22 years, an additional 40 miles of pipeline would be needed to connect to nearby fields. Two of the fields are unitized. The pipeline network needed to serve this scenario is shown in Figure 2.

Figure 2. Western Terminus of CO_2 Pipeline Serving Mesaba One

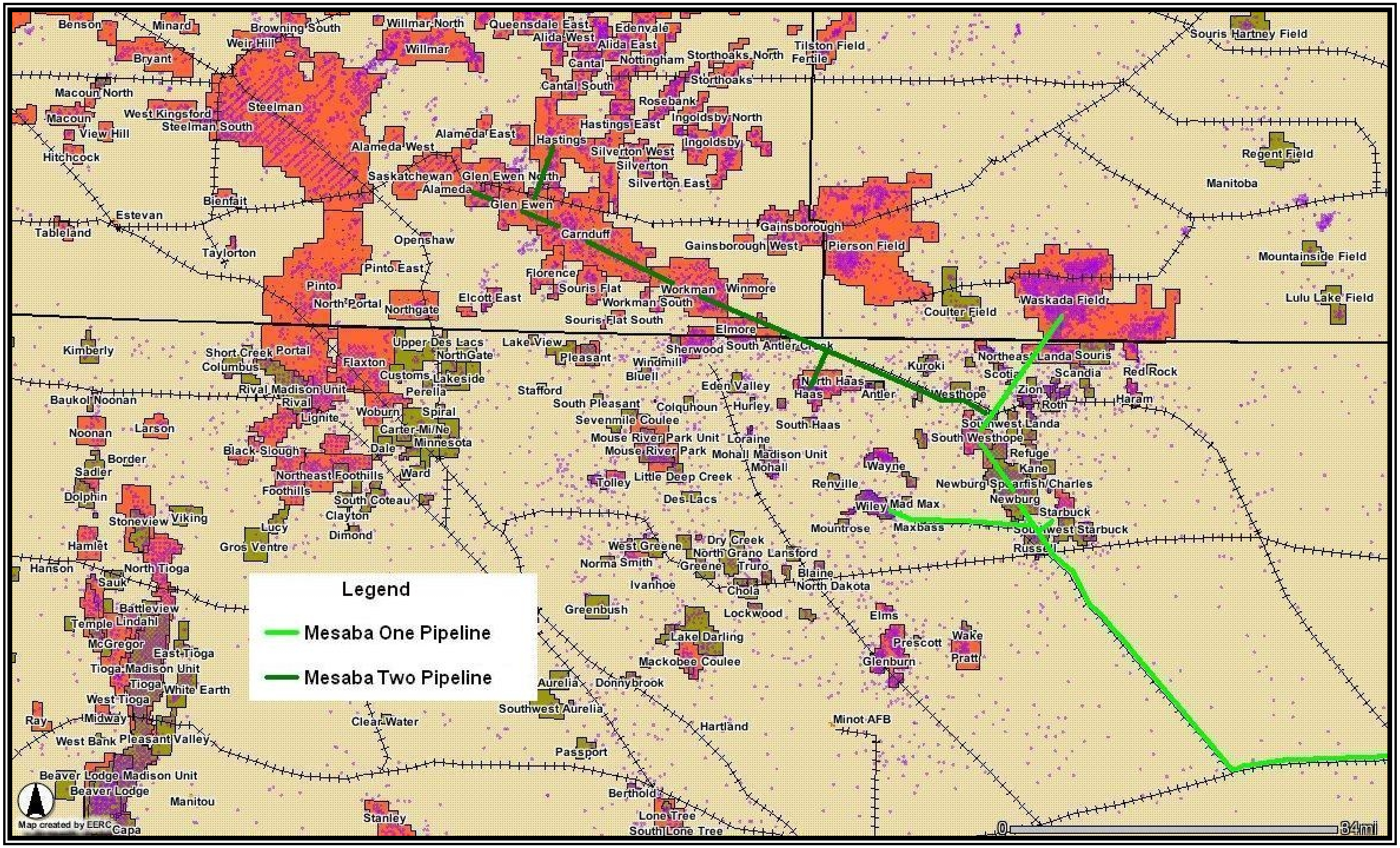


Source: EERC

C. Scenario 1B

For Mesaba One and Two, the network of pipelines would expand to a chain of oil fields in southeastern Saskatchewan. To accommodate 22 years of EOR from both units, approximately 120 additional miles of pipeline would be added for a total system length of 525 miles. This length is inclusive of additions required for a single unit as described above, and such additions could be staged. To illustrate the economies of scale, it will be assumed that the trunk pipeline is sized to accommodate two units, such that looping (i.e., duplicating) the 405 mile base pipeline is not necessary. The pipeline network for this scenario is shown in Figure 3.

Figure 3. Extension of Western Terminus of Mesaba One Pipeline to Accommodate Mesaba Two



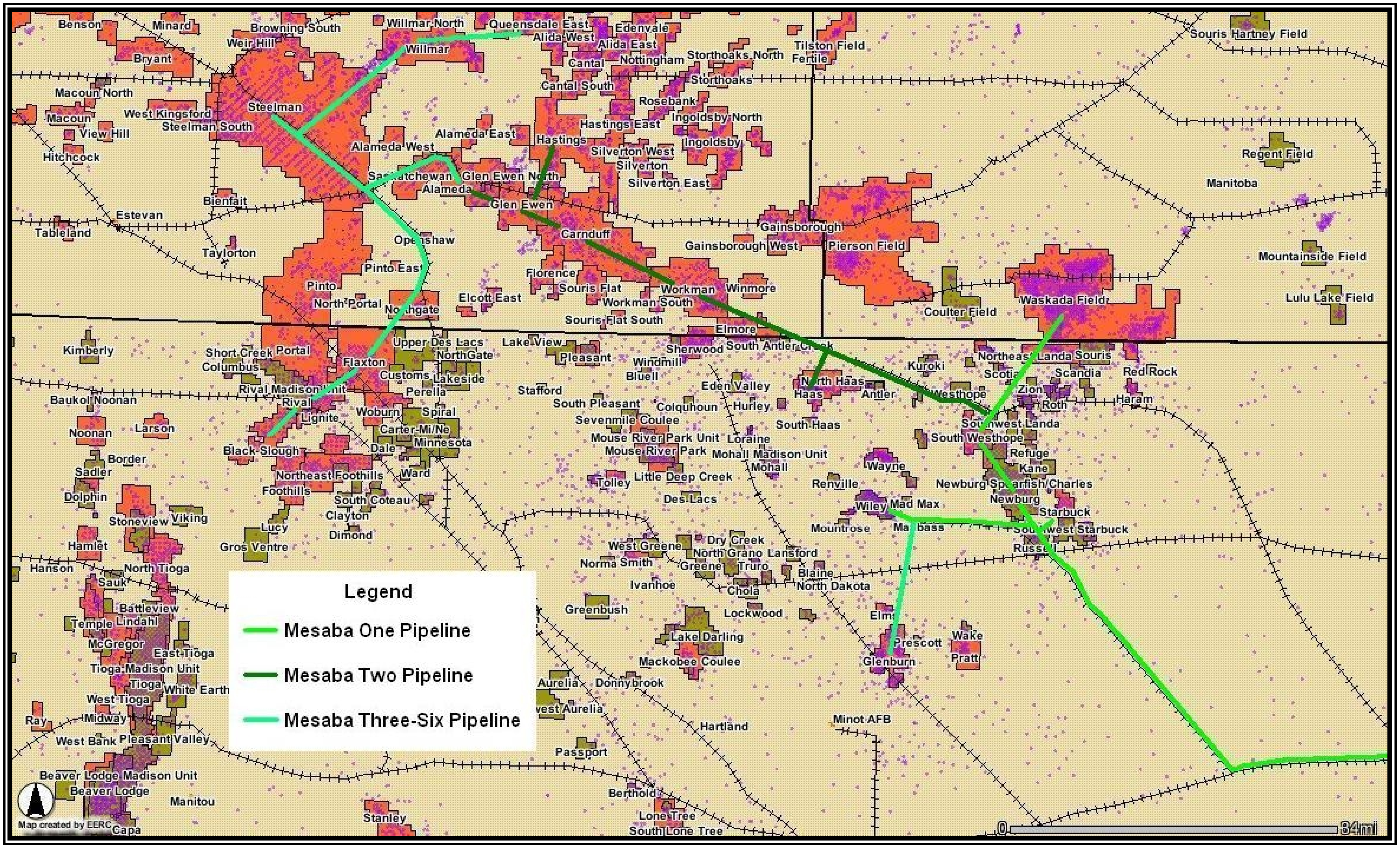
Source: EERC

D. Scenario 1C

For Mesaba Units One through Six, the pipeline network could reach much larger fields in Saskatchewan and North Dakota. The incremental pipeline additions for these units would include 85 new miles, for a total system length of 610 miles, as shown in Figure 4. While this scenario would be the most efficient and economical, the degree of uncertainty is too great to model even on a preliminary basis at this time. This scenario demonstrates that the potential for EOR present a CCS opportunity, and that a cost-shared pipeline accommodating multiple sources is a very promising means to defray the overall final costs of CCS.

The introduction of carbon credits or other benefits for reductions under mandated carbon constraints to these scenarios would improve the economics presented in the CCS Plan and would not otherwise intrinsically alter the ideal implementation of pipeline routes. Other sources may be induced to pursue EOR, but the relative cost competitiveness among those sources would not likely change.

Figure 4. Extension of Western Terminus of Pipeline to Accommodate Mesaba One Through Mesaba Six



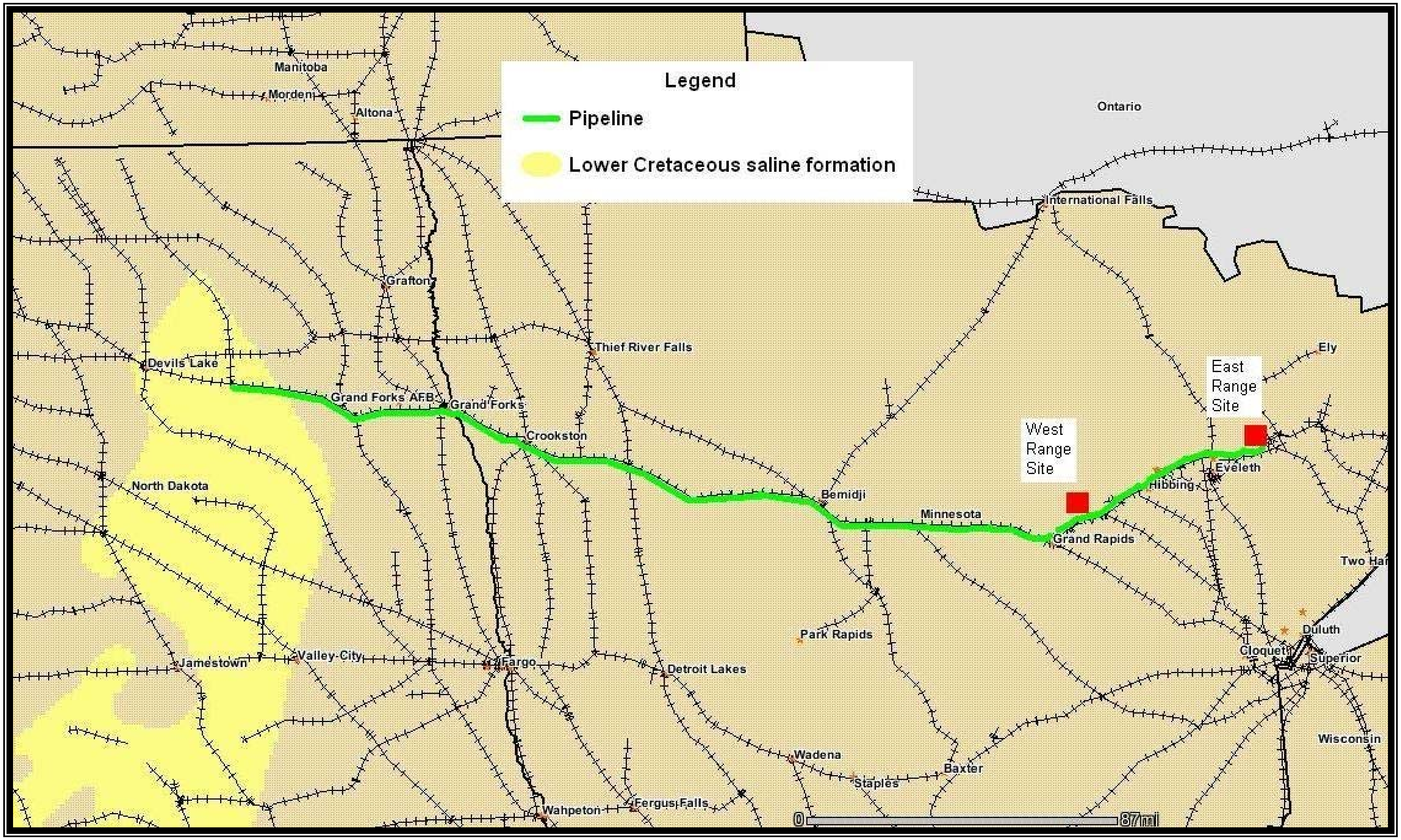
Source: EERC

E. Scenario 2

Scenario 2 considers CCS based solely on carbon credit revenues or other benefits of CCS under carbon constraints, with the Mesaba Energy Project as the only source. In this case, CO_2 would only need to be piped approximately 265 miles from the West Range site to the Lower Cretaceous saline formation in eastern North Dakota. Once again, existing right-of-way is shown for purposes of illustration. The EERC projects that the capacity of this saline formation dwarfs that of the oil fields considered in Scenario 1, so it is expected that the same pipeline route could serve all units at 30% or 90% capture.[9] The route in Scenario 2 is shown in Figure 5.

[9] EERC, Presentation, Potential Sequestration Options in the Plains CO2 Reduction (PCOR) Partnership Region & Estimated Capacities, Aug. 9, 2006 (on file with Excelsior Energy).

Figure 5. CO_2 Pipeline to Saline Formations for Carbon Credits (No EOR)

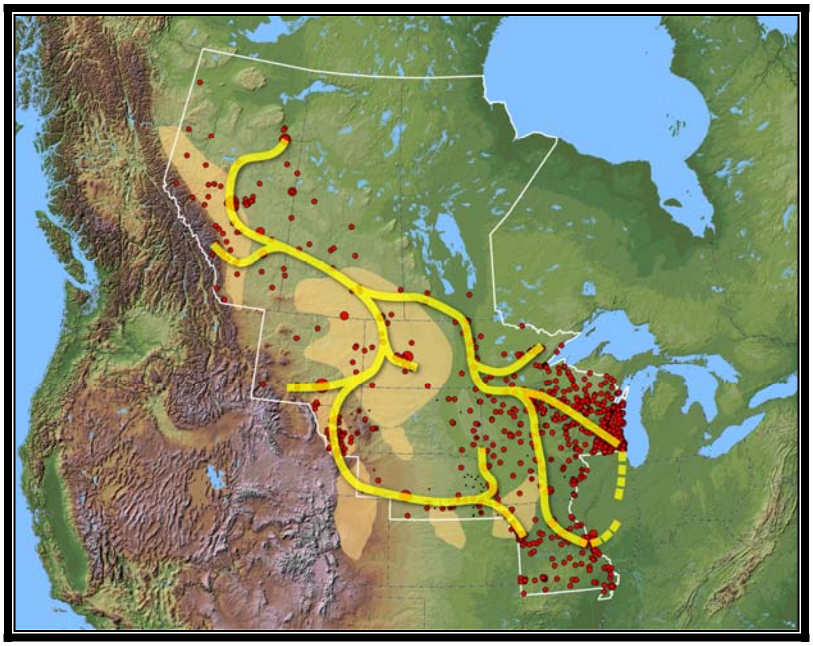


Source: EERC

E. Scenario 3

As Scenario 1C begins to demonstrate, the economies of scale for CO_2 transport could be significant. In a fully implemented GHG regulatory scheme, it would be conceivable that the majority of large industrial facilities (epitomized by large electric generation facilities) would be capturing CO_2. The EERC's vision for a major pipeline system serving the PCOR region is laid out in Figure 6. As the map shows, the concentration of industry on the Iron Range makes it a likely route for a major artery of the CO_2 network.

Figure 6. EERC's Vision of CCS in a Carbon Managed Economy



Source: EERC

VII. Preliminary Economic Analysis

Excelsior used the Mesaba Energy Project's proprietary financial model to identify the breakeven value of CO_2 (in 2006$ per ton) captured in the 30% approach for each scenario identified in Section VI. This modeling is preliminary in nature and is intended to i) illustrate economic dependencies around important CCS Plan variables rather than absolute costs and ii) determine whether a more thorough investigation is justified. All cases assumed that capital outlays associated with CCS occur in 2011, and that CO_2 capture commences in the third quarter of 2014 and continues for 22 years (through the duration of the financial model).

The financing structure and economic assumptions used in the modeling of these carbon capture scenarios are consistent with Excelsior's assumptions in its current financial model used to evaluate the Mesaba Energy Project. The cases are modeled to recover the costs associated with the CCS program and maintain the required return to the projects equity investors. The effects of the sensitivities shown below are displayed as changes in NPV from a base case and are calculated using an 8% discount rate. Estimates for the cost of 90% removal are not available, so only 30% capture was modeled.

Fluor developed an estimate for the cost of the 30% capture configuration,[10] and Excelsior integrated that estimate into the Mesaba Energy Project's financial model. There are two main economic impacts associated with carbon capture: equipment capital cost and reduced plant capacity, which also causes an increase in plant heat rate. The equipment includes the amine stripper and the CO_2 drier and compressor. Plant capacity is reduced and heat rate is increased because these processes are steam driven, and because the CO_2 would need to be replaced by steam as a diluent for NO_x control. In an attempt to determine if CCS can be accomplished without additional costs to utility ratepayers, the cost of fuel increase on a megawatt-hour (MWh) basis corresponding to the heat rate increase was attributed and charged to the CCS project in the model assumptions. Total capital cost additions are currently estimated to be [**BEGIN TRADE SECRET: END TRADE SECRET**] and the anticipated increased O&M costs for that equipment is [**BEGIN TRADE SECRET: END TRADE SECRET**]. The capacity reduction for the IGCC Power Station is currently estimated to be [**BEGIN TRADE SECRET: END TRADE SECRET**], with the increased heat rate expected to be [**BEGIN TRADE SECRET: END TRADE SECRET**].

As for pipeline cost estimates, the Dakota Gasification Project's ("DGP") CO_2 pipeline to the Weyburn oil field was used as the basis for estimating costs. The DGP pipeline was built for $120 million in 1997, and consisted of 204 miles of nominal 12" and 14" Schedule 40 pipeline. Conservatively assuming it was all 12" pipeline and escalated to 2005 dollars, the total cost for a CO_2 pipeline in the Northern Plains is assumed to be $60,920 per inch-mile. Based on the design capacity of the Weyburn pipeline, a nominal 12" Schedule 40 pipeline is sufficient to transport CO_2 produced by 30% capture at Mesaba One, with the Mesaba One and Two units requiring a 14" pipeline. A further conservative assumption utilized in the analysis is that the total pipeline network is built up front. Costs could be reduced by deferring network expansions to additional oil fields

Excelsior Energy modeled Scenarios 1A, 1B, and 2, and the results are presented in Table 2. For Scenarios 1A and 1B, revenues could be earned from both EOR and carbon credits sales (or through other carbon reduction benefits to ratepayers when constraints are imposed). This data illustrates that the economies of scale are important for CCS – the required price per ton drops significantly with larger volumes of CCS, despite the fact that 80 additional miles and an increased diameter for the pipeline would be necessary. Scenario 2 demonstrates that the Mesaba Energy Project could capture and sequester carbon at an even lower overall cost, although such capture could not reap EOR revenues. As explained above, these cost estimates are illustrative rather than predictive, and conclusions should be limited accordingly. The accuracy of these estimates must be refined by additional study before the economic viability of the project can be judged.

[10] Fluor Enterprises, Inc., *Mesaba Energy Project Partial Carbon Dioxide Capture Case,* October 2006, attached as Exhibit DC __ (DC-7) to the Oct. 10, 2006 testimony of Douglas H. Cortez, OAH Docket No. 12-2500-17260-2, MPUC Docket No. E-6472-/M-05-1993.

Table 2. Cost of Captured CO_2

	EOR	Pipeline length	Total CCS Cost ($/ton)
Scenario 1A	Yes	445 miles	$40
Scenario 1B	Yes	525 miles	$35
Scenario 2	No	265 miles	$32

Due to the high degree of uncertainty in many of the important assumptions, Excelsior conducted a sensitivity analysis. Scenario 1A was used as the base case for this analysis, and the results are shown in Table 3. Pipeline costs represent the greatest source of uncertainty, both in terms of the uncertainty of the cost assumed and impact that assumption has on total project cost. It is crucial that the range of this cost be narrowed, and the engineering studies proposed in Section I would address these and other issues. While the effect of capacity loss is nearly as material to the analysis, there is greater modeling certainty in the assumed values.

Table 3. Sensitivity Analysis of CCS Costs

Factor	Case	Input Value Assumed	Required CO2 Value/Total CCS Cost
Pipeline Cost	Low	$30,145/in-mi	$30/ton CO_2
	Base	$60,290/in-mi	$40/ton CO_2
	High	$90,435/in-mi	$50/ton CO_2
Plant Capital	Low	[**BEGIN TRADE SECRET:**	**END TRADE SECRET**]
	Base	[**BEGIN TRADE SECRET:**	**END TRADE SECRET**]
	High	[**BEGIN TRADE SECRET:**	**END TRADE SECRET**]
Capacity/ Heat Rate	Low	[**BEGIN TRADE SECRET:**	**END TRADE SECRET**]
	Base	[**BEGIN TRADE SECRET:**	**END TRADE SECRET**]
	High	[**BEGIN TRADE SECRET:**	**END TRADE SECRET**]
Plant O&M	Low	[**BEGIN TRADE SECRET:**	**END TRADE SECRET**]
	Base	[**BEGIN TRADE SECRET:**	**END TRADE SECRET**]
	High	[**BEGIN TRADE SECRET:**	**END TRADE SECRET**]
Pipeline O&M	Low	$890/mi-yr	$40/ton CO_2
	Base	$1,780/mi-yr	$40/ton CO_2
	High	$2,760/mi-yr	$41/ton CO_2

It is important to note that the greatest uncertainty surrounding the economics of a CCS project is revenue, as EOR depends upon volatile oil prices and carbon credit prices (or other economic benefits from reductions under carbon constraints) depend upon future regulation. However, such uncertainties are not specific to the Mesaba Energy Project and must be overcome by any major undertaking of CCS. The figures presented in the remainder of this section elaborate upon the modeled impact of CO_2 prices on the net present value of different scenarios in the CCS Plan.

Figure 7 shows the impact that the value of CO_2 has on project economics. This value for CO_2 is derived from either EOR or a combination of EOR and carbon credits or other CCS regulatory benefits, and corresponds to Scenario 1A with the baseline assumptions described above. Similarly, Figure 8 examines this impact if revenues are from carbon credits exclusively (that is, no EOR). CO_2 would be sequestered in saline formations, corresponding to Scenario 2. Thus, for Figure 8 the impact to the NPV is based on Scenario 2's $32/ton case as the $0 NPV reference.

Figure 7. Sensitivity to Changes in Total CO_2 Revenue (\$/ton CO_2) in Scenario 1A

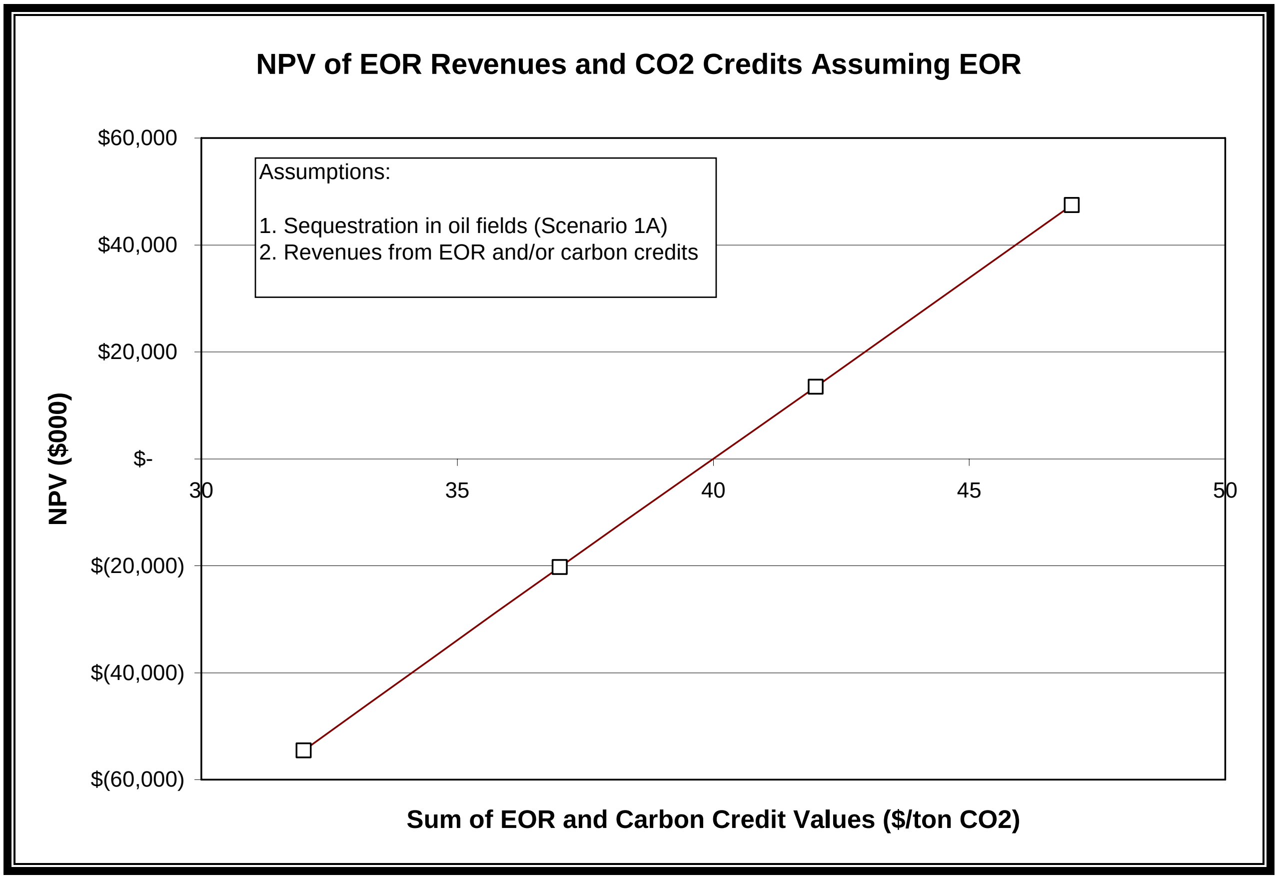
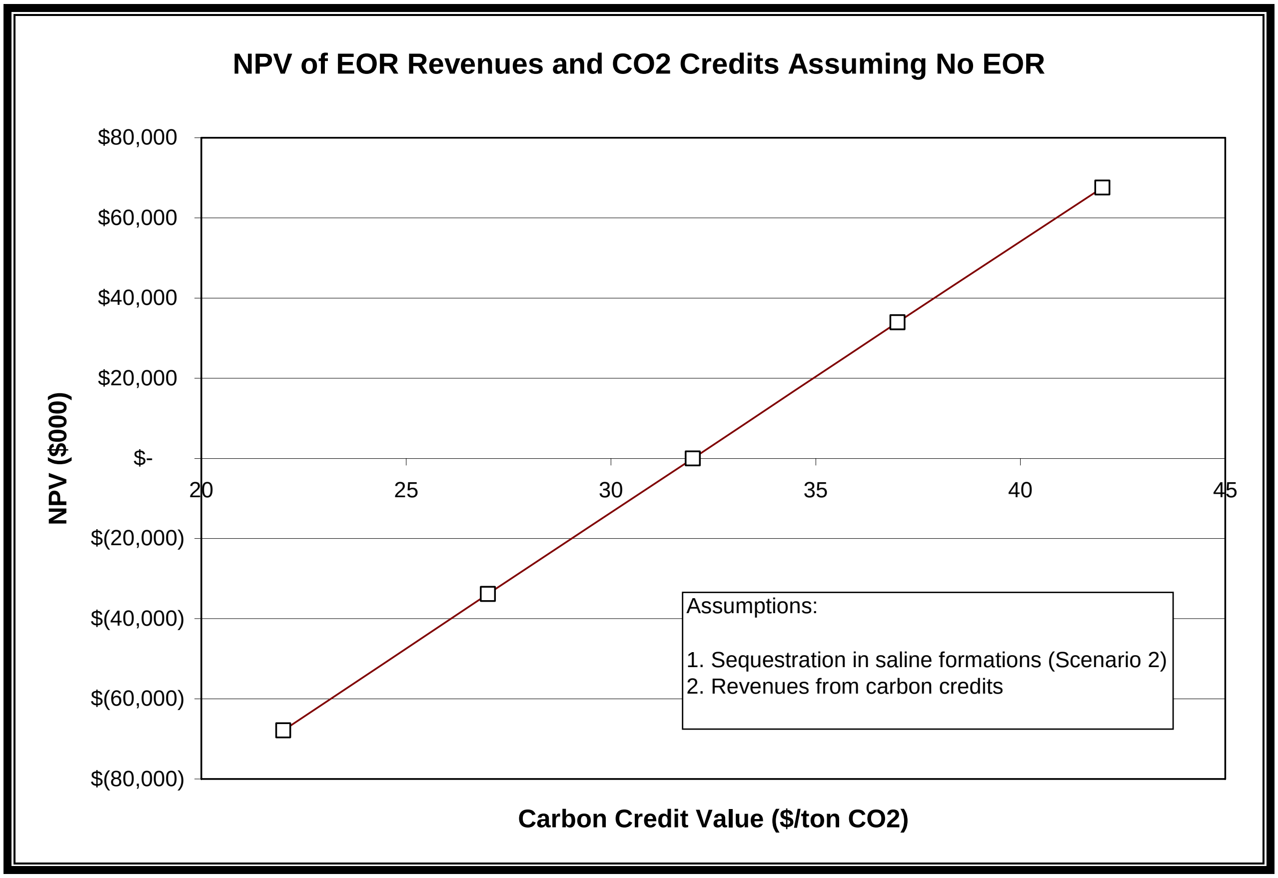
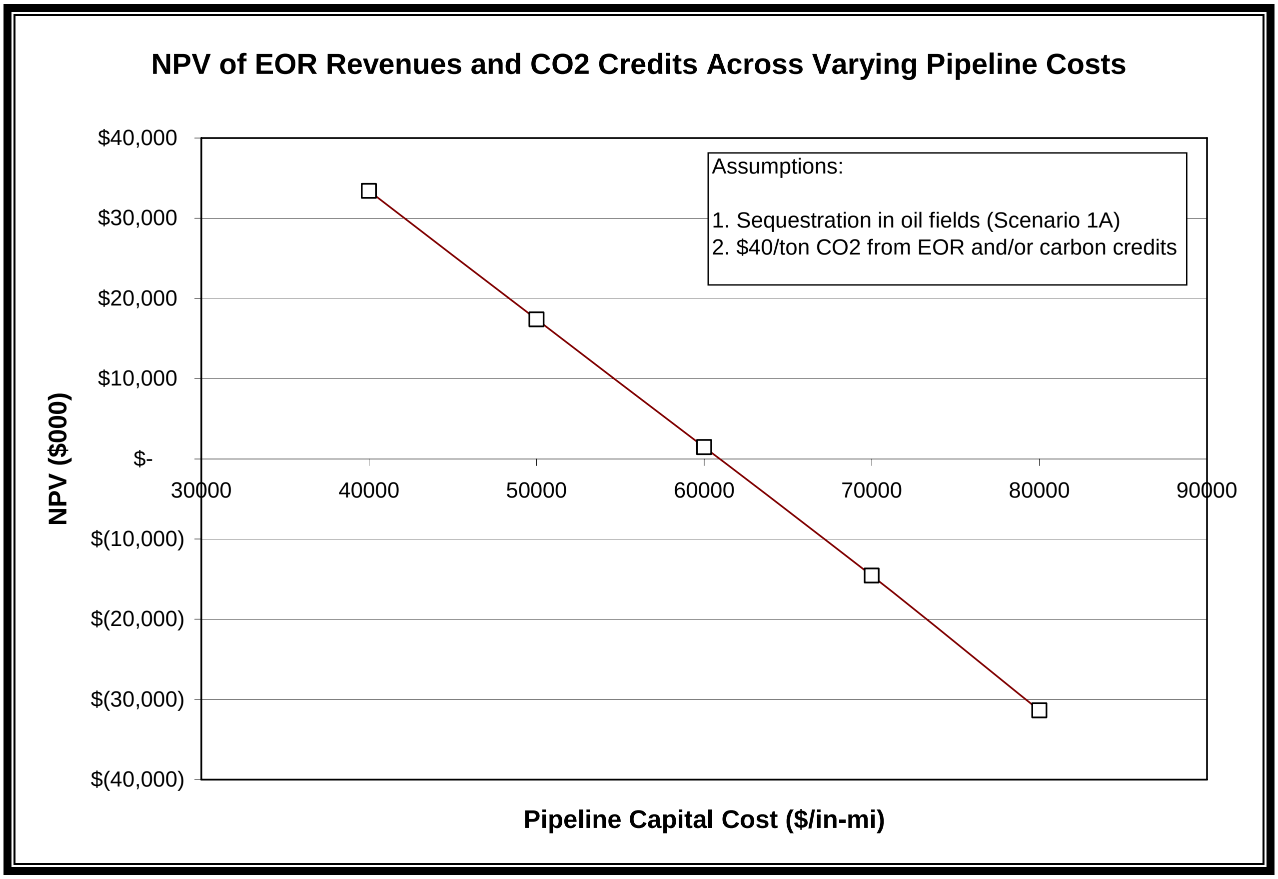


Figure 8. Sensitivity to Changes in Carbon Credit Revenue ($/ton CO_2) in Scenario 2



Changes in the NPV of different scenarios in the CCS Plan due to changes in pipeline costs are shown in Figure 9. This figure assumes that the total value of CO_2 will average $40/ton.

Figure 9. Sensitivity to Changes in Pipeline Costs ($/in-mi) in Scenario 1A



Carbon credits are currently trading at approximately $17/ton in Europe. The value of CO_2 for EOR is highly variable according to oil prices, specific field geology, and source competition. At oil prices of $15–20/bbl, CO_2 can be worth $10–16/ton for EOR, and more at higher prices of oil.[11] As carbon regulations are introduced and become stricter, and as the price of oil increases, the price of CO_2 can be expected to rise. Although it is premature to conclude whether CCS in any scenario presented here is economical, Excelsior believes that additional study towards that end is warranted.

The alternative sources of CO_2 for EOR in the fields identified in Scenario 1 are limited. The largest of these by far are conventional coal plants in the region, but post-combustion CO_2 capture for such sources has only been demonstrated at pilot scale. The cost per ton is expected to be higher for conventional coal than for the Mesaba Energy Project, even if a much shorter pipeline is assumed for the former. Ethanol plants and natural gas processing facilities are able to produce CO2 at a much lower cost than conventional coal plants, but lack the capacity to saturate the EOR market. Fields along the pipeline built by the Dakota Gasification Project can

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[11] Intergovernmental Panel on Climate Change, IPCC Special Report: Carbon Dioxide Capture and Storage, p. 33 (2005), *available at* http://arch.rivm.nl/env/int/ipcc/pages_media/SRCCS-final/ccsspm.pdf.

accommodate its supply for decades to come. Therefore, it is reasonable to expect that EOR revenues could be available to the Mesaba Energy Project across the time frames proposed.

Excelsior assumes that it will be positioned to obtain partial DOE cost sharing for construction of the CO2 pipeline. However, irrespective of such funding potential, Excelsior believes it is in the interests of the both the Mesaba Project and the State to better understand the economic drivers for CCS programs and the need to firm up equipment/construction costs at the plant, along the pipeline route, and at the oil fields. Detailed engineering studies conducted under carefully defined scopes of work will help refine such costs.

The EERC, in conjunction with Excelsior, will develop CO_2 management options for the Mesaba Energy Project based on evaluations of sequestration opportunities associated with regional geologic formations/features and nearby terrestrial features. The study will match carbon sinks to the Mesaba Project and rank the sinks according to engineering, economic, and public-acceptance considerations. The schedule calls for the EERC to complete an analysis of the identified CO_2 management options in December 2006. Excelsior will use the results of this analysis to narrow the scope of its Phase III proposal to the DOE for demonstrating the commercial readiness of carbon sequestration via IGCC.

In preparing the Phase III proposal, the EERC and Excelsior will formulate best practices required to accomplish sequestration of CO2 from IGCC facilities and publish the results as part of a manual that can be used by others undertaking IGCC projects.

VIII. Summary and Conclusions

Excelsior has prepared this CCS Plan to offer the Commission and Minnesota ratepayers options to capture and sequester a significant portion of the CO_2 emissions from the Mesaba Energy Project. Based on the scientific and technical considerations, marketplace and operating assumptions, the financial analyses, and future carbon regulations assumed in this CCS Plan, Excelsior anticipates that future technical studies will verify that it will be feasible to capture and sequester CO_2 emissions from the Mesaba Energy Project. As explained in the CCS Plan, the most promising CCS scenario is for Excelsior to transport its CO_2 via high-pressure pipelines to the depleted oil fields associated in the Williston Basin located in North Dakota, southwestern Manitoba, and southeastern Saskatchewan.

This CCS Plan reflects the work undertaken to date by Excelsior and the PCOR initiative. Significant work remains to refine the engineering and economic information it contains. This work will be advanced by the PCOR initiative. Excelsior will continue to update this information as its work with PCOR progresses. Excelsior would be amenable to exploring a commitment with the Commission to apply the final $2 million of its RDF award to further efforts to refine this plan. If feasible from the Commission's perspective, Excelsior would propose to accelerate the funding of that amount in order to facilitate a more rapid completion of a detailed engineering plan and cost proposal for CCS. Excelsior anticipates that such a detailed plan could be developed within a year from the date such funding is made available. The CCS Plan could also serve as the foundation for a competitive proposal in response to the Department of Energy's ("DOE") planned Phase III solicitation for demonstrating full scale CCS projects. Accelerating development of a very detailed plan would enhance Minnesota and the Mesaba

Project's prospects to obtain federal matching funds under DOE programs.

It is in the long-term interests of the State to proceed expeditiously with the development of feasible CCS options. Excelsior looks forward to working with regulators, stakeholders, and industry participants to provide the important hedge to Minnesota consumers offered by the timely development of carbon capture and sequestration.

Carbon Management Plan for Excelsior Energy

January 25, 2007

Mr. Robert S. Evans II
Vice President, Environmental Affairs
Excelsior Energy, Inc.
11100 Wayzata Boulevard, Suite 305
Minnetonka, MN 55305

Dear Mr. Evans:

Subject: Carbon Management Plan for Excelsior Energy

Enclosed please find the final Carbon Management Plan that we have prepared for the Mesaba Energy Project. The document is based on the draft carbon management plan that was developed in December 2006. Time-sensitive information was updated, estimated pipeline routes were fine-tuned, a section devoted to pipeline permitting experience and approach was added, and specific comments made by Excelsior Energy personnel were addressed. The document has also been sent electronically.

If you have any questions or comments, please contact me by phone at (701) 777-5279, by fax at (701) 777-5181, or by e-mail at esteadman@undeerc.org.

Sincerely,

Edward N. Steadman
Senior Research Advisor

ENS/kmd

Enclosure

Plains CO_2 Reduction (PCOR) Partnership

CARBON MANAGEMENT PLAN FOR EXCELSIOR ENERGY

Prepared for:

Robert S. Evans II

Vice President, Environmental Affairs
Excelsior Energy, Inc.
11100 Wayzata Boulevard, Suite 305
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January 2008

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EERC DISCLAIMER

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CARBON MANAGEMENT PLAN FOR EXCELSIOR ENERGY

EXECUTIVE SUMMARY

A study was performed for Excelsior Energy to identify the various options for management of CO_2 that will be produced by the Mesaba Energy Project currently under development. Mesaba Energy Project sites under consideration are in Minnesota's Iron Range, and sequestration sinks were evaluated that are within approximately 500 mi of that location. The first phase of the Mesaba project (Mesaba One) will be constructed as "capture-ready," meaning that room will be left for construction of a CO_2 capture facility at a later time. Excelsior Energy has chosen an activated methyldiethanolamine (aMDEA) chemical absorption system to capture the CO_2. When constructed, the aMDEA system will capture up to 30 wt% of the CO_2 generated by the plant during gasification and will produce about 4500 tons/day of a high-purity CO_2 stream.

Carbon management strategies considered herein are focused on geologic sequestration, with options for the CO_2 produced at Mesaba One offered based on the assumption that the aforementioned CO_2 production and purity specifications would be met. Geologic sequestration scenarios in which the CO_2 would be used for enhanced oil recovery (EOR) were investigated first, as these have the potential to offer a return on the investment of CO_2 capture through its sale. In the Permian Basin in Texas, the current Denver City Hub price of CO_2 is about $20/ton. The EOR opportunities consist of the following areas of the Williston Basin:

- **Nesson Anticline** – About 465 to 560 mi from the proposed Mesaba sites, the Nesson Anticline oil fields have a capacity of 53 million tons of CO_2 representing roughly 34 years' worth of CO_2 from Mesaba One.

- **Northeast Flank** – The Northeast Flank has a capacity of about 18 million tons of CO_2, or almost 11 years' worth of CO_2 from Mesaba One. It is 385 to 475 mi from the two potential sites.

- **Southeastern Saskatchewan** – The oil fields of southeastern Saskatchewan are about 440 to 500 mi from the Mesaba sites and, with a capacity of about 88 million tons, could hold 53.5 years' worth of CO_2 from Mesaba.

Pipelines are probably the most cost-effective means of transporting the CO_2 produced by the Mesaba Energy Project, although they represent a substantial capital investment. Using a common estimate for capital costs of roughly $40,000 per inch diameter per mile, the capital costs of pipelines from the proposed Mesaba sites to the EOR opportunities that were identified are estimated to range from $128 million to $179 million. In a CO_2-managed future, regional pipelines may be developed to transport CO_2, which would likely lessen the costs and logistical challenges associated with the transport of CO_2 to geologic sinks located closer to the demand for CO_2 such as in western North Dakota or eastern Montana.

Opportunities for the sale of CO_2 for use in enhanced coalbed methane (ECBM) activities have not been quantified because the estimations that have been made of recoverable natural gas in the region's lignite seams to date are speculative. It is hoped that the data necessary to more accurately predict natural gas production during ECBM recovery will be available at some point in the future.

The region's deep saline formations offer the opportunity to sequester significant quantities of CO_2, although a return on investment into CO_2 capture would not be immediately realized with this option. From the estimated theoretical maximum capacities of the deep saline formations, it can be seen that all of the CO_2 produced at Mesaba One could easily be sequestered in the saline formations of the Williston Basin for an indefinite period of time. It should be noted that extensive site characterization must be performed prior to large-scale sequestration into saline formations. The cost of this type of characterization for an injection area at Sleipner in Norway's North Sea was $1.9 million.

The cost of monitoring, mitigation, and verification (MMV) activities must also be taken into account when considering sequestration of CO_2. Types of MMV that may be considered include collection of dynamic reservoir data (pressure, temperature, formation fluid production rates), coring activities, well logs, collection of geosphere and biosphere fluid samples (both historic and new), seismic studies, and reservoir modeling (both historic and new).

Risks associated with CO_2 sequestration were identified and include the chemical effects of dissolved CO_2 in subsurface fluids, the displacement of fluids by injected CO_2, and long- or short-term (i.e., catastrophic) releases of large quantities of CO_2 to the atmosphere. Appropriate monitoring and safeguards can mitigate or eliminate most of these risks.

Terrestrial sequestration is also an option for a portion of the CO_2 produced by the Mesaba Energy Project. Conversion of agricultural land to forest sequesters up to three times more carbon than other agricultural techniques. Considering that the majority of land use/land cover in northern Minnesota is forest, the best opportunities include afforestation, reforestation, forest conservation, and improved forest management practices.

Carbon markets may offer another way to realize a return on the investment associated with CO_2 capture. Significant possibilities exist in the region for both terrestrial and geologic sequestration and trading of carbon offsets as a significant aspect of a carbon management strategy for the Mesaba Energy Project. However, North American carbon markets are in their infancy, and the exact type of market structure and associated value of credits have not been determined.

CARBON MANAGEMENT PLAN FOR EXCELSIOR ENERGY

INTRODUCTION

Excelsior Energy has requested that the Plains CO_2 Reduction (PCOR) Partnership prepare a carbon management plan for Excelsior Energy's Mesaba Energy Project. To accommodate Excelsior Energy's time line, the carbon management plan was broken into two activities. The first was a broad overview summarizing the Mesaba Energy Project's CO_2 production, possible options and locations for CO_2 sequestration, infrastructure necessary for geological sequestration, an overview of the existing regulations governing the sequestration of CO_2, and a look at carbon markets. This document refines the broad overview through the inclusion of updated information and overviews of additional topics.

THE MESABA ENERGY PROJECT

The Mesaba Energy Project is currently under development in two phases that are referred to as Mesaba One and Mesaba Two. Sites under consideration are in the Taconite Tax Relief Area of Minnesota's Iron Range and are shown in Figure 1. Each phase is a nominal 606-MW_{net} integrated gasification combined cycle (IGCC) baseload electric power-generating station. The plant will be fired on coal (either Powder River Basin subbituminous or bituminous coal) and petroleum coke, with natural gas serving as the backup fuel (Evans, 2006). Mesaba One will be built as a "capture-ready" facility; that is, it is designed so that a carbon capture plant can be retrofitted to the facility after the IGCC plant is in operation. It is anticipated that up to 30 wt% of the carbon will be captured using an activated methyldiethanolamine (aMDEA) chemical absorption system (Ruzynski, 2006). This particular process operates at a removal efficiency of 85% to 90% (Lynch, 2006). It is estimated that if 5543 tons/day (dry basis) of subbituminous coal was fired at Mesaba One, product gas totaling 4500 tons/day with high-purity CO_2 would be produced by this system (Lynch, 2006).

REGULATORY CONSIDERATIONS FOR THE CAPTURE, TRANSPORTATION, AND SEQUESTRATION OF CO_2

A significant driver for capture, compression, and sequestration of CO_2 is the possibility of regulation and pending legislation that may affect CO_2 emissions. Current federal regulations do not specifically address CO_2 emissions, although there are regulations that address the transportation of CO_2 and its injection for enhanced resource recovery purposes. For example,

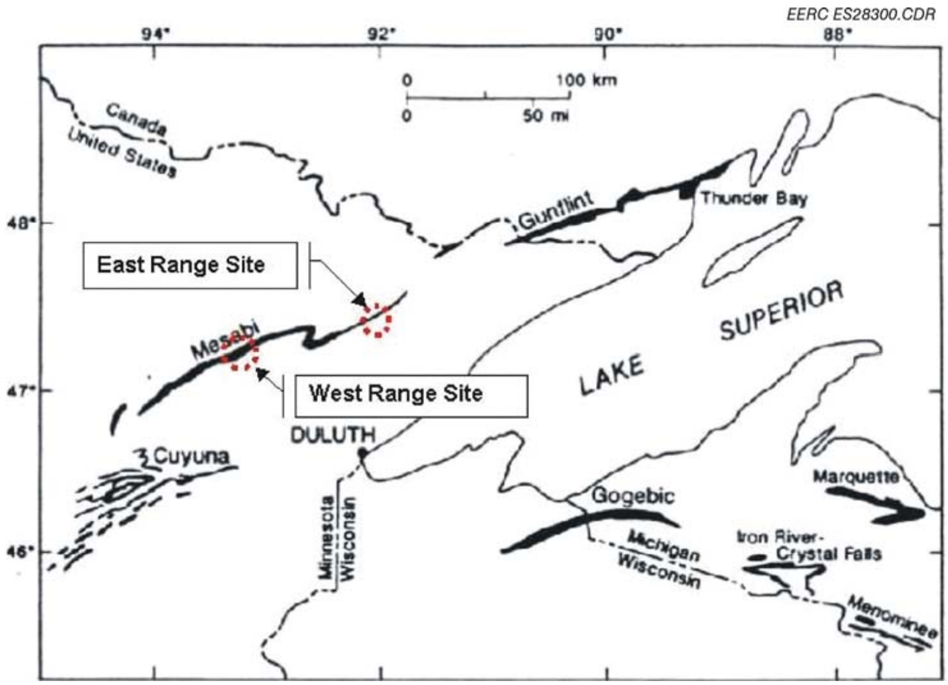

Figure 1. Potential Mesaba IGCC power plant sites on the Minnesota Iron Range (figure taken from Evans, 2006).

the U.S. Department of Transportation (DOT) Office of Pipeline Safety regulates pipeline transport of CO_2 under the Code of Federal Regulations, Title 49, Part 195. Regulations also address worker safety, particularly human health exposure limits, which are enforced by the Occupational Safety and Health Administration.

The following is a list of existing government regulations that can affect power plant location, pipeline routing, and injection locations:

- Clean Water Act (CWA, 1977)
- Safe Drinking Water Act (SDWA, 1974)
- Endangered Species Act (ESA, 1973)
- Migratory Bird Treaty Act (MBTA, 1918)
- Bald Eagle Protection Act (BEPA, 1940)
- Executive Order on Invasive Species (EOIS, 1999)

The National Environmental Policy Act (NEPA, 1969) may be applicable if federal funds are used, federal permits are required, or if federal lands will need to be crossed or accessed. The Clean Air Act (CAA, 1963, 1970, 1990, 1997) contains the New Source Review permit program. However, CO_2 is not currently listed as one of the criteria "pollutants."

Although no federal regulations currently exist that affect the use of CO_2 for sequestration, several proposed government actions could potentially affect CO_2 emissions and/or sequestration, including:

Massachusetts et al. v. Environmental Protection Agency (EPA). On November 29, 2006, the U.S. Supreme Court heard arguments as to whether or not EPA should regulate greenhouse gases (GHGs), especially CO_2 from cars, under Section 202(a)(1) of the CAA. On April 2, 2007, the Supreme Court, in a 5 to 4 ruling, decided that EPA has the authority to regulate CO_2 emissions from cars and that the agency cannot bypass its authority to regulate GHGs that contribute to global climate change unless it provides a scientific basis for its refusal. Senate leaders have announced that they intend to call EPA officials to testify before Congress concerning their plans to respond to the decision. The overall ramifications of this ruling remain to be seen and will likely evolve over time (Supreme Court, 2007).

Congressional actions. Thus far in the 110th Congress, numerous hearings have been held related to GHG emissions and their impact on climate change. Numerous bills have been introduced that relate to reducing GHG emissions or their impacts. They range from targeting specific economic sectors to covering all segments of the economy, with varying levels of reductions and caps. Some require reductions as great as 80% below 1990 levels economywide by 2050. There are also various options for offsets and allowances, including some limits on the amount that "credits" can account for emission reductions. The status of current and pending legislation can be found by viewing the floor and committee schedules of both houses of Congress.

EPA guidance on geologic sequestration, March 2007. EPA released its final guidance on geologic sequestration in March 2007. The guidance is entitled "Using the Class V Experimental Technology Well Classification for Pilot Carbon Geologic Sequestration Projects – UIC Program Guidance." EPA is initiating work to develop regulations under its current UIC program for commercial-scale geologic sequestration projects. The agency is expected to propose its regulations in the summer of 2008 (U.S. Environmental Protection Agency, 2007).

Interstate Oil and Gas Compact Commission (IOGCC). In September 2007, IOGCC's Carbon Capture and Geological Storage Regulatory Task Force released model regulations that deal with site licensing, well operation, well/site closure, and long-term storage (Interstate Oil and Gas Compact Commission, 2007).

California Global Warming Solutions Act of 2006. The California Global Warming Solutions Act of 2006 caps global warming emissions at 1990 levels by 2020 (a 25% reduction). It establishes a mandatory reporting program to the Air Resources Board (ARB) for significant GHG emissions. The act requires ARB to adopt regulations for significant GHG emission sources (allowing ARB to design a cap-and-trade program) and gives ARB the authority to enforce the regulations beginning in 2012.

By January 2009, the California Air Resources Board must prepare a scoping plan that outlines the direct reduction measures, market-based mechanisms, and incentives needed to meet the 2020 cap. This act could potentially affect opportunities in other states if California entities enter into agreements with other states (California Air Resources Board, 2007).

Regional Greenhouse Gas Initiative (RGGI). RGGI includes the states of Maine, Vermont, New Hampshire, New York, Connecticut, New Jersey, Delaware, Massachusetts, Rhode Island,

and Maryland. RGGI is an initiative to design and implement a flexible, market-based cap-and-trade program to reduce carbon dioxide emissions from power plants in the northeastern United States.

Currently, geologic carbon sequestration is not a project area that is eligible for offset allowances. However, should geologic carbon sequestration become allowable under the program, it could affect opportunities in the Williston Basin as offset projects in other states are allowed (Regional Greenhouse Gas Initiative, 2007).

The Climate Registry. The Climate Registry was incorporated in Washington, D.C., in March 2007. As of November 7, 2007, 39 U.S. states, four Canadian provinces, four Native American Tribes, and one Mexican state have become members (The Climate Registry, 2007). The Climate Registry intends to establish standardized best practices in GHG emission data reporting and management, establish a set of common protocols, and support a common reporting system.

Western Climate Initiative. In February 2007, the Governors of Washington, Oregon, California, New Mexico, and Arizona jointly established the Western Climate Initiative to collaborate in identifying, evaluating, and implementing ways to reduce GHG emissions. Since that time, Utah and the Canadian provinces of British Columbia and Manitoba have joined this effort. The partners set an overall regional goal in August 2007 for reducing GHG emissions. By August 2008 they expect to complete the design of a market-based mechanism to help achieve the reduction goals. The group has developed a work plan and is currently seeking public input into the process (Western Climate Initiative, 2007).

Midwestern Regional Greenhouse Gas Reduction Accord. In November 2007, governors from Illinois, Iowa, Kansas, Michigan, Minnesota, and Wisconsin and the premier of Manitoba signed the Midwestern Regional Greenhouse Gas Reduction Accord. South Dakota, Indiana, and Ohio signed as observers. The governors will establish targets for GHG reductions as well as set up a cap-and-trade program within the next year (Milwaukee Journal Sentinel, 2007).

While this list is not all inclusive, it provides some guidance as to the variety of entities that are looking at the regulatory status of CO_2.

CO_2 CAPTURE TECHNOLOGIES

To better understand the CO_2 capture technologies that might be used by other CO_2-producing facilities, they are summarized here. Two types of CO_2 capture systems are commercially available: chemical absorption systems and physical absorption systems.

Chemical Absorption

The most readily available chemical absorption system is amine scrubbing (Jensen et al., 2005). An amine-scrubbing system consists of cooling the flue gas to a temperature that is below 50°C; absorption (scrubbing) of CO_2 from the flue gas by countercurrent contact with lean (CO_2-deficient), cool amine in a packed or tray column; heat exchange of rich amine (CO_2-loaded) with lean amine in a cross exchanger; and stripping of the rich amine to liberate CO_2 and regenerate the amine. A reboiler provides the steam needed to regenerate the amine. A reclaimer is used to remove degradation products and other contaminants. A typical amine-scrubbing system is shown in Figure 2.

Alkanolamines are a group of amines used for CO_2 removal that includes monoethanolamine (MEA), diethanolamine (DEA), diglycolamine (DGA), diisopropanolamine (DIPA), and triethanolamine (TEA). Of these, MEA is the most alkaline; it has the highest dissociation constant and the highest pH in water solution. The chemical reaction with CO_2 is fastest with MEA and decreases with the others. Commercial providers of MEA technology include Fluor Daniel and ABB Lummus Global.

The MEA process can achieve recoveries of 85% to 95% with CO_2 purities over 99 vol% (Jensen et al., 2005). However, the MEA process also requires a significant amount of power to operate pumps and blowers for gas and solvent circulation. Additional issues with the process are equipment corrosion; solvent degradation caused by the presence of dissolved O_2 and other impurities; or reaction with SO_2, SO_3, and NO_x to produce nonregenerable, heat-stable salts. This requires SO_2 levels below 10 ppm, NO_2 levels below 20 ppm, and NO_x below 400 ppm (Jensen et al., 2005). Solvent degradation and loss also occur during regeneration.

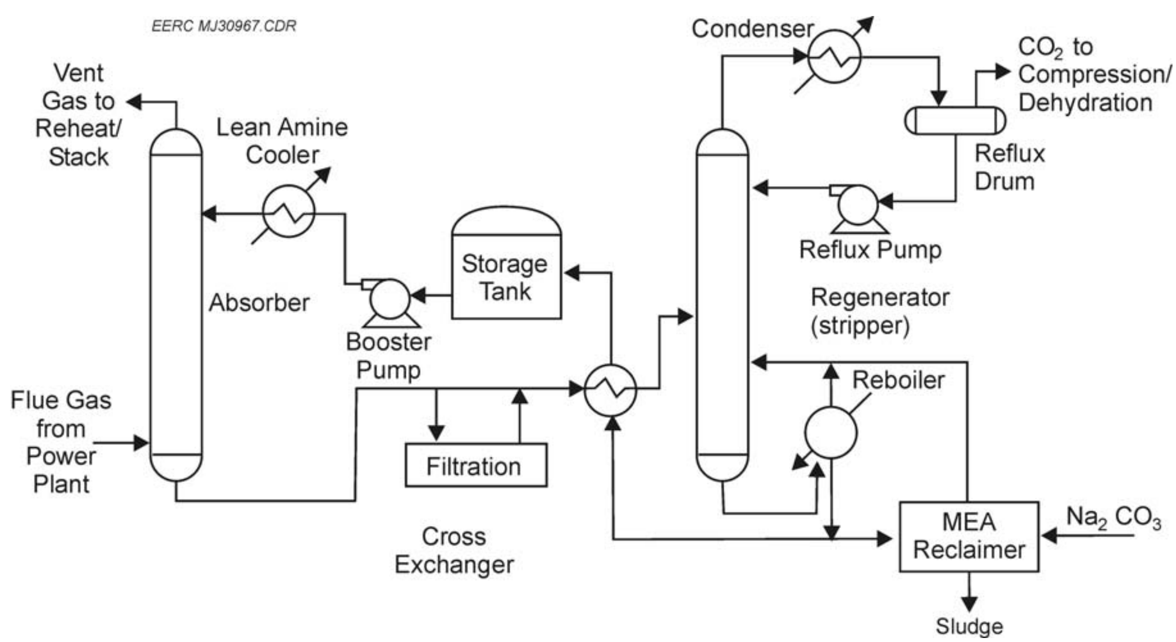

Figure 2. Schematic of a typical MEA-scrubbing system for CO_2 capture (Chen et al., 2004).

MDEA and hot potassium carbonate (e.g., Benfield™) can also be used for gasification systems. They are generally employed for H_2 recovery in refineries and ammonia production facilities where H_2-rich syngas is produced by gas reforming (Jensen et al., 2005). The MDEA process is also used for sulfur removal in IGCC applications because bulk CO_2 removal is also achieved. MDEA is frequently used to sweeten sour natural gas by removing H_2S and CO_2. MDEA reacts quickly with H_2S but, because the kinetics of CO_2 absorption are relatively slow, the MDEA is activated to accelerate its reaction with the CO_2. Activators that are used include piperazine (Lu. et al., 2005) and secondary amines (Total, 2007).

An aMDEA system consists of a CO_2 absorber, a heat exchanger, a cooler, a heater, and a CO_2 flash drum, as shown in Figure 3. Cooled sweet syngas from the H_2S absorber at a pressure of about 450 psig is fed into the bottom of the absorption column. The CO_2-lean syngas exits the top of the column, while the aMDEA containing CO_2 flows out the bottom of the column, is heated, and enters the top of the CO_2 flash drum. In the flash drum, the CO_2 is stripped from the aMDEA and flows out the top to the dehydration and compression systems. The CO_2-lean aMDEA is cooled and recycled back to the absorption tower. As is the case with MEA, MDEA also forms heat-stable salts when it reacts with SO_x and NO_x compounds (Rooney et al., 1996). The aMDEA® acid gas removal process is provided commercially by BASF AG.

Physical Absorption

Physical absorption is primarily used to remove CO_2 from postgasification gas streams. These systems include the Rectisol® and Selexol™ processes. The Rectisol process removes CO_2

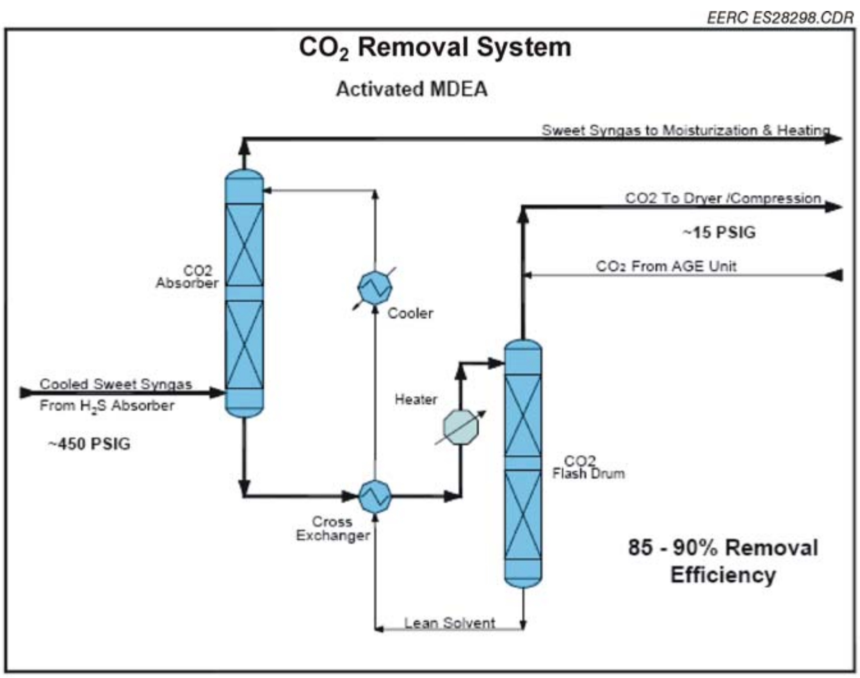

Figure 3. Schematic of an MDEA CO_2 absorption system (Lynch, 2006).

and H_2S in methanol at −94°F, requiring significant gas cooling and reheating. With respect to potential future requirements for high (>90%) CO_2 recovery during gasification, the double-stage Selexol process, in which desulfurization and CO_2 separation are combined, is favored and is considered to be state-of-the-art for IGCC (National Energy Technology Laboratory, 2006). The Selexol™ process is typically installed after a water–gas shift reactor that converts CO to CO_2 for subsequent capture in a double-stage or double-absorber Selexol unit. The Selexolunit preferentially removes H_2S in one product stream and then removes CO_2 as a second product stream. The synthesis gas enters the first absorber unit where H_2S is removed by "loading" the lean Selexol solvent with CO_2. The CO_2-saturated solvent preferentially removes H_2S. The rich solution is regenerated in a stripper by heating. The stripper acid gas stream, consisting of 34% H_2S and 58% CO_2 and water, is then sent to a Claus sulfur removal unit.

Following processing in the Claus unit, cleaned fuel gas from the first absorber is cooled and routed to the second absorber unit. In this absorber, the fuel gas is contacted with lean solvent. The solvent removes approximately 97% of the CO_2 from the fuel gas stream. The fuel gas from the second absorber is warmed and humidified in the fuel gas saturator, reheated and expanded, and then sent to the burner of the combustion turbine. CO_2 is flashed from the rich solution and is then ready for dehydration and compression to pipeline-ready conditions. The Selexol process (without a water–gas shift reactor) is shown in the Figure 4 schematic.

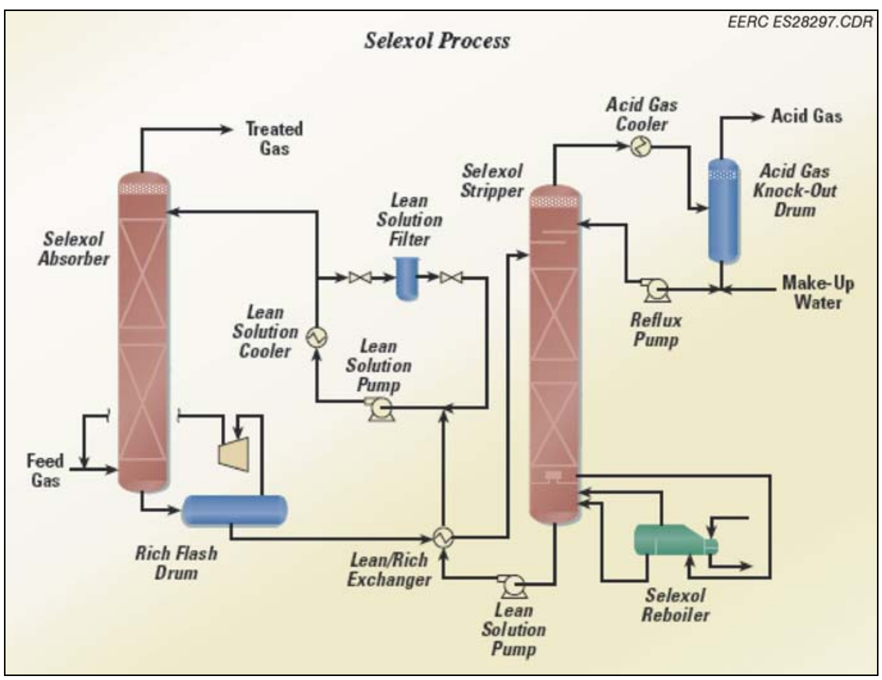

Figure 4. Schematic of the Selexol process (figure taken from Selexol Process [2006]).

Characteristics of a Capture-Ready Facility

Excelsior Energy's plan for implementing carbon capture and sequestration will happen in phases and will begin as soon as Excelsior is either directed by the Minnesota Public Utilities Commission to initiate capture or when economic circumstances justify it. Because higher capture rates result in greater increases in the cost of electricity, Excelsior Energy is taking the approach that the capture of up to 30% of the potential combustion concentration of CO_2 in its incoming feedstock (the percentage of CO_2 captured will vary as the feedstock changes) will ultimately best serve the state's energy consumers. Excelsior expects that in subsequent phases of the Mesaba Energy Project's development, higher percentages of carbon capture will be proven on a commercial scale and become economically justified. As such experience is gained, the company will modify new phases of the Project's development accordingly.

Several issues must be taken into account when designing a capture-ready IGCC facility if the cost of retrofitting a capture plant into the facility is to be minimized. The most obvious of the issues is that sufficient space (usually at least 2 to 2.5 acres [Higman, 2007]) must be available within and around the plant for the chosen capture technology. The gasifier must be oversized so that the electricity output can be maintained after capture is added to the facility, even though it might not be operated at full capacity until the capture plant is installed. A sweet-shift process such as is planned at the Mesaba Energy Project will require a saturator–desaturator to minimize the loss of steam to the power. The balance-of-plant equipment must be sized to meet the requirements not only of the power block but the capture plant as well for cooling water, compressed air, wastewater treatment, control and instrumentation, electrical, and piping and ductwork (IEA Greenhouse Gas R&D Programme, 2007). Additional considerations include higher H_2 content that may require derating of the firing temperature; a reduction in available extraction air; loss of steam to the steam cycle; and additional internal power consumption for the air separation unit, the acid-gas removal process, and the CO_2 compressors (Higman, 2007). Depending upon several factors, it may be more difficult to retrofit a double-stage Selexol system than an aMDEA plant into an IGCC facility.

THE DEHYDRATION AND COMPRESSION PROCESSES

Dehydration is generally performed by one of two methods: cooling followed by removal of the condensed moisture from the gas stream or via the use of a glycol dehydration process. In a glycol dehydration process, drying occurs when a wet gas stream contacts "dry" glycol and the glycol absorbs water from the gas. Figure 5 is a schematic of the entire system, including the contacting and glycol reconcentration systems. The wet gas stream enters the tower at the bottom. Dry glycol flows down the tower from the top. The dehydrated gas leaves the tower at the top, where it flows to the compressor system or other processing units. The water-rich glycol leaves the tower at the bottom and flows to the regeneration system. In the regeneration system, impurities are filtered out of the wet glycol, and it is heated to 400°F. The water escapes as steam, and the glycol is recycled to the tower (NATCO Glycol Dehydration Systems, 2006).

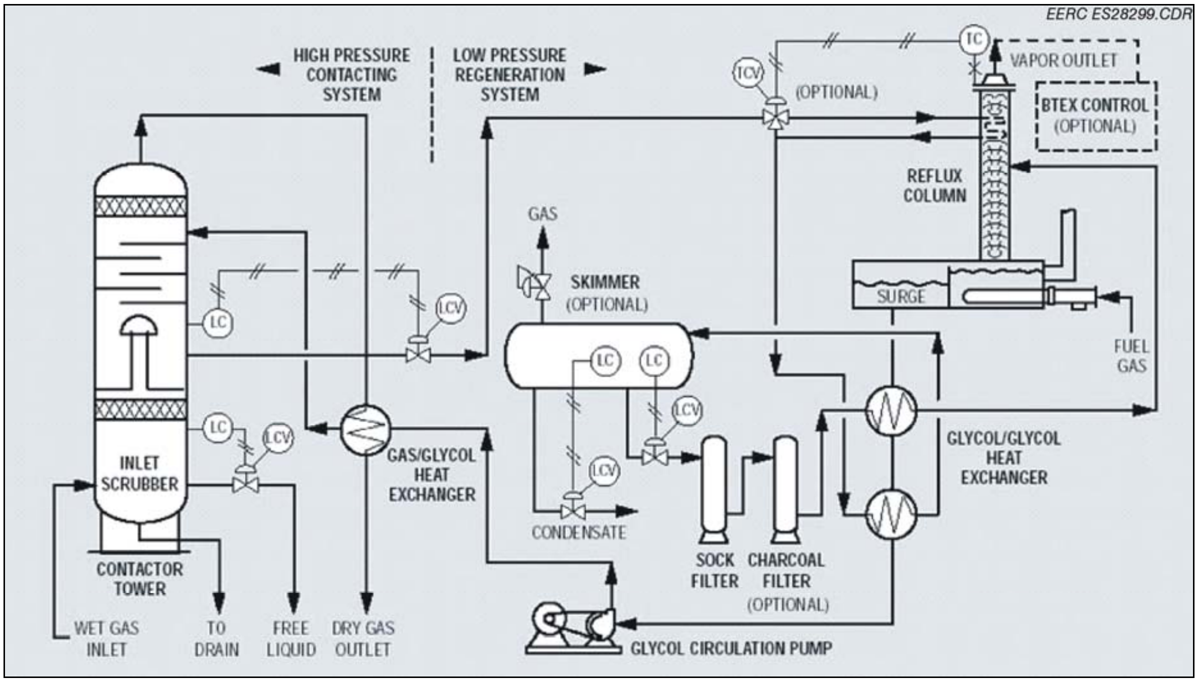

Figure 5. Typical flow diagram for a glycol dehydration unit (figure taken from NATCO Glycol Dehydration Systems [2006]).

Multistage compressors are used to pressurize the dehydrated CO_2 product to supercritical stage (over 1070 psi) for pipeline transportation. Typical pipeline pressure for CO_2 is between 1400 and 2500 psi, depending upon the end use requirements. Compression is a well-established technology, and off-the-shelf compressors are usually available. When they are not, manufacturers are willing to work with plant engineers to design appropriate compressors. For example, Borsig GHH (now MAN Turbomaschinen AG) worked with Dakota Gasification Company (DGC) engineers to modify the design of the compressors that are used to move CO_2 from its facility in Beulah, North Dakota, to Weyburn, Saskatchewan. The DGC compressors are each 8-stage, 19,500-hp centrifugal compressors that move 55 MMscfd at a discharge pressure of 2700 psig (Perry and Eliason, 2004).

The literature indicates that compression costs may vary from as low as \$5.40 per ton (Wong, 2005) to as high as \$12 per ton (Dooley et al., 2006). Assuming the Mesaba Power Plant transports approximately 1.6 million tons of CO_2 per year, the compression costs may range from \$8.64 million to \$19.2 million per year. Actual compression costs will be based primarily on discharge pressure, size of the CO_2 stream, energy cost, and other facility-specific characteristics. Ramgen Power Systems is developing a novel compression technology based on supersonic aircraft technology that may require only one-third the capital expenditure of a typical CO_2 compressor (Koopman, 2007).

PIPELINE TRANSPORTATION

Transport of large quantities of CO_2 off-site is usually performed by pipeline. The United States has several CO_2 pipeline networks, most of which are located in Texas and Colorado. In the future, a broader network of CO_2 pipelines may be constructed to accommodate movement of captured CO_2 for use in enhanced oil recovery (EOR), enhanced coalbed methane (ECBM) recovery, or for sequestration. The PCOR Partnership vision for our region includes the potential for a major network of CO_2 pipelines that connect major sources and sinks, shown hypothetically in Figure 6. We anticipate that the initial legs of a pipeline system will be developed for EOR projects and that they will be used for saline formation injection after the EOR opportunities have been exhausted. In our vision, the CO_2 sources that are first adopters will benefit from the revenues produced through the commercial sale of CO_2. Once carbon markets fully develop, the economics of carbon credit trading will control the development of sequestration opportunities.

Pipeline Considerations

When pipeline installation is planned, several factors must be considered:

- Pipeline length and diameter

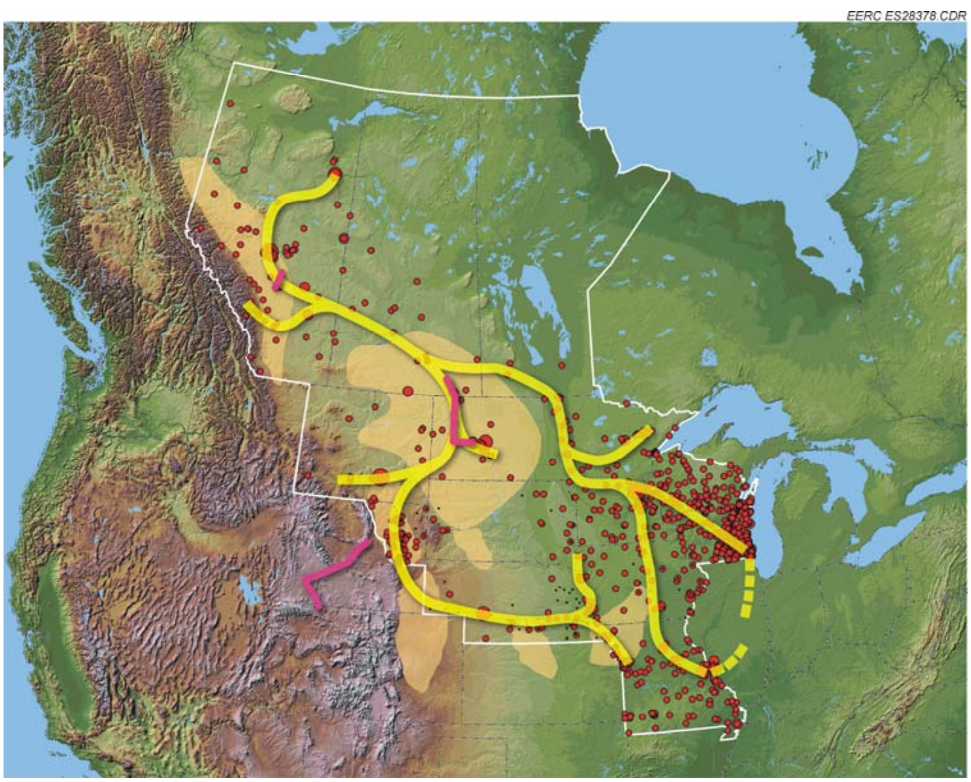

Figure 6. PCOR Partnership general vision of CO_2 pipeline infrastructure that may develop in a carbon-managed future.

- Wall thickness
- Inlet and outlet pressures
- Right-of-way (ROW) issues
- Route (i.e., crossing federal or tribal lands, terrain, existing infrastructure, soil physical and chemical properties)
- Construction issues (e.g., interconnections, mainline block valves, tees, flow rate meters)
- Pipeline investment costs (construction, operation, maintenance)
- Permits and regulations (federal, state, local)
- Need for and likely locations of compression and recompression (booster) stations (typically required every 100 mi along the pipeline route)
- Variable corrosion monitoring, leak detection, inspection, and security systems
- Chemical nature of supercritical CO_2 (temperature, pressure, corrosivity, hazardous material classification)
- Composition of the CO_2 stream to minimize or eliminate corrosion, safety, operations, and materials issues. The U.S. CO_2 pipeline quality specifications are shown in Table 1.
- Storage capacity of the target CO_2 sink or sinks
- Distribution network to injection wells and the ownership of such a network
- Variable equipment, costs, and methods for CO_2 injection, reservoir types, and depths

Table 1. U.S. CO_2 Pipeline Quality Specifications (Kinder Morgan, 2006)

Component	Concentration Limit	Reason for Limit
CO_2	95% minimum	MMP[a] concern
Nitrogen	4% maximum	MMP concern
Hydrocarbons	5% maximum	MMP concern
Water	30 lbs/MMcf maximum	Corrosion
Oxygen	10 ppm maximum	Corrosion
H_2S	10–200 ppm maximum	Safety
Glycol	0.3 gal/MMcf maximum	Operations
Temperature	120°F maximum	Materials

[a] Minimum miscibility pressure.

Existing rules and practices for CO_2 transport appear to be adequate for CO_2 capture and storage projects. The transportation of dense-phase CO_2 has been practiced for at least 30 years and now is incorporated into steel pipeline standards. Further development of the standards may be required to accommodate higher volumes of CO_2 and potential implications of pipeline leaks.

Several unique properties of supercritical CO_2 are taken into account in pipeline design and construction, including the following (Reilkoff et al., 2005):

- Reactive with water (reaction of CO_2 or other acid gas contaminants [including SO_2] in the gas stream with water creates a corrosive mixture)
- Variable equipment, costs, and methods for CO_2 injection, reservoir types, and depths
- Incompatible with some petroleum-based and synthetic lubricants
- Incompatible with some elastomer sealing materials
- Has poor lubricating properties
- Transmission at supercritical conditions can result in both brittle and ductile fracture propagation
- Dramatic cooling during decompression

In addition to manufacturing standards placed on pipeline materials to prevent damage because of corrosion, safety regulations for pipeline construction include the implementation of an automatic pressure control system to monitor volumetric flow and pressure and block valves placed regularly along the length of the pipeline to minimize the risk of inadvertent release. Fracture arresters are also commonly used to limit the extent of a fracture along the length of the pipeline in the event of blowout. Unlike natural gas, CO_2 is neither flammable nor explosive. However, because it has a higher density than air, there is risk of elevated levels of CO_2 collecting in low-lying areas and poorly ventilated spaces in the vicinity of the leak, resulting in an asphyxiation hazard. In open areas, CO_2 typically will quickly dissipate in the air, returning to safe concentrations. The rate of dissipation, however, will depend on the nature of the release, topography, and weather conditions (Reilkoff et al., 2005).

Methods for pipeline inspection and testing have been adequately developed and proven effective for the safe transport of CO_2. SCADA (supervisory control and data acquisition) systems are in place along current pipeline infrastructure to remotely monitor such parameters as volumetric flow and pressures and provide rapid response in the event of pipeline failure or unsafe conditions. Inspections to assess pipeline integrity are conducted on a regular basis. Some of the techniques currently employed include hydrostatic testing, close interval potential, and direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG) surveying, and ultrasonic inspection. New technologies, including advanced smart pigs, are being developed for application in CO_2 pipeline inspection. Dense-phase CO_2 penetrates current smart pig components, causing significant damage resulting from expansion upon decompression. Researchers are focusing on sealing materials that would prevent CO_2 penetration (Kinder Morgan, 2004).

Pipeline Regulation

The U.S. DOT Office of Pipeline Safety (OPS) regulates the pipeline transport of CO_2 under Code of Federal Regulations Title 49, Part 195. Permitting for pipeline construction falls under numerous jurisdictions and varies by state. Pipeline access for CO_2 transport is currently unregulated, as CO_2 pipelines are privately owned.

Federal pipeline safety regulations: 1) ensure safety in design, construction, inspection, testing, operation, and maintenance of pipeline facilities; 2) set out parameters for administering the pipeline safety program; 3) require pipeline operators to implement and maintain antidrug and alcohol misuse prevention programs for employees who perform safety-sensitive functions; and 4) delineate requirements for onshore oil pipeline response plans. The regulations are written as minimum performance standards, setting the level of safety to be attained while allowing the pipeline operators discretion in achieving that level (U.S. Department of Transportation, 2004).

A thorough, comprehensive compliance program, conducted by regional offices, is a key aspect of pipeline safety regulation. OPS regional offices are not only responsible for overseeing the compliance of interstate operators, but also responsible for monitoring the performance of state agencies participating in the federal/state pipeline safety program and performing inspections of interstate pipeline systems and those intrastate facilities not under state jurisdiction. OPS investigates major pipeline accidents to determine if regulatory violations occurred, if additions or revisions to the regulations are warranted, and to ascertain the cause of an accident. The purpose of an OPS investigation is to ensure the future integrity of the pipeline and develop a solid basis for any enforcement actions that may need to be taken. This cooperative methodology is intended to increase the potential for developing widespread improvements in pipeline safety (U.S. Department of Transportation, 2004).

Permitting

Permitting for construction of CO_2 pipelines falls under various jurisdictions, and numerous permits may be required. Typically, a pipeline route application is submitted to the permitting authority, in this case, the Minnesota Public Utilities Commission and the North Dakota Public Service Commission. Various aspects of the proposed pipeline construction must be addressed in the application. These aspects include, but are not limited to, ROW; easements and potential cultural, socioeconomic, human health, environmental, and ecological impacts. Crossing various waterbodies and wetlands, federal lands, tribal lands, roadways, and railroads may, and often does, require permits from federal, state, provincial, and local agencies. Additionally, the state of Minnesota may require an environmental review or environmental impact statement (EIS) under the Minnesota Environmental Policy Act. Many of the issues included in the route application will also need to be addressed in a state-required EIS but will need to be discussed in greater detail. If a federal EIS is required, Minnesota Rules Chapter 4410.3900 allows for joint federal and state environmental documents as long as the federal EIS complies with the scoped issues and standards set forth by Minnesota Rules (Minnesota Rules, 2007).

Pipeline Costs

The capital costs for CO_2 transportation pipelines have been shown to be very site-specific. Cost differences between pipelines are generally based on regional variations in both economic factors (e.g., costs of materials and labor) and natural factors (e.g., surface topography and soil type). A common estimate for capital costs for CO_2 transport pipelines is roughly \$40,000 per inch of diameter per mile of pipeline (Heddle et al., 2003; and Dooley et al., 2006). Figure 7 shows the relationship between the mass flow rate of CO_2 and the total annual cost of a pipeline.

Costs associated with ROW must be considered when the total financial obligations related to developing a pipeline are determined. If a currently existing ROW that had space enough to accommodate a pipeline, such as one associated with an existing railway line or highway, could be utilized, then ROW costs could be significantly reduced through negotiation with the ROW owner. In cases where ROW does not currently exist, then a variety of costs needs to be evaluated. In agricultural areas, these costs typically include property acquisition costs and loss-of-opportunity costs associated with the interruption of agriculture. These costs can and will vary considerably along the pipeline route based on the type of crop typically grown in any given area and the average crop yield of the acreage in question. In areas where existing ROWs cannot be

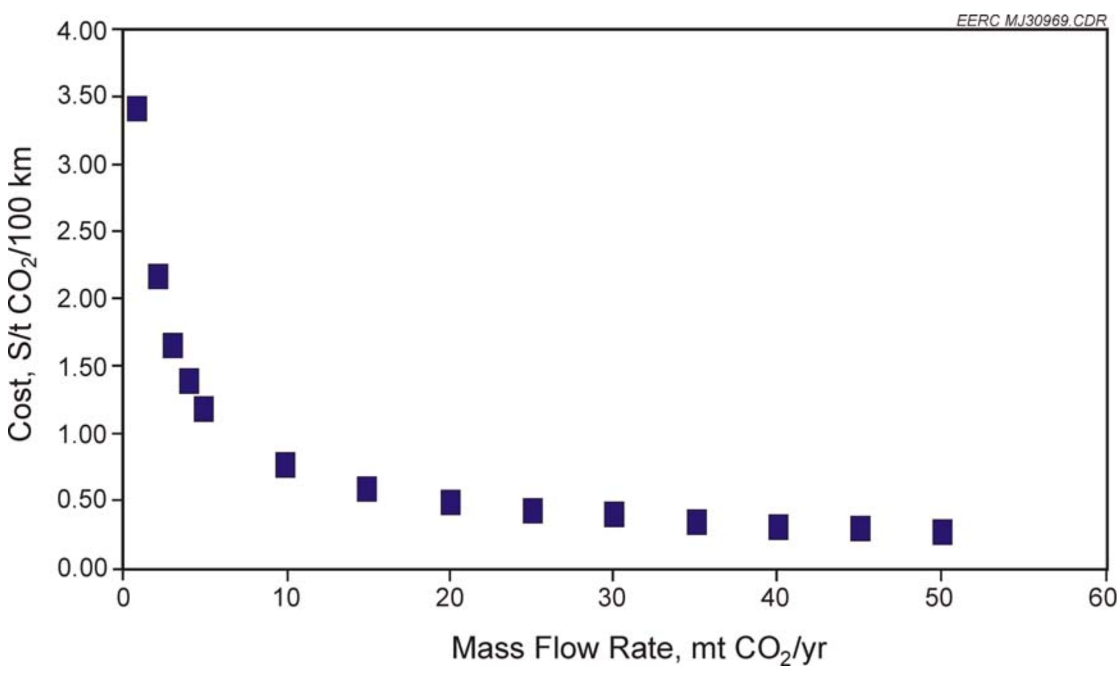

Figure 7. Pipeline cost as a function of mass flow rate of CO_2 (Heddle et al., 2003).

utilized, these costs will have to be estimated for potential routes during the early phases of project planning. Literature suggests that the projected damage payment for crop loss associated with ROW issues will be 3.5 times the average crop yield of the acreage occupied during pipeline construction (Reilkoff et al., 2005).

Pipeline development will accrue costs associated with the need for professional services over the course of the planning, construction, and operation phases. Professional services required for the planning and construction phases will include, but are not necessarily limited to, engineering, survey, mapping, ROW acquisition, legal, permit acquisition, environmental consulting, geotechnical analysis, vendor inspection, and construction inspection. The need for many of these services will continue, at least on a periodic basis, for the operational phase of the pipeline. This is especially true of inspection, legal, engineering, and environmental services (Reilkoff et al., 2005).

Many other logistical elements must be considered when a thorough estimate of pipeline costs is developed for delivering CO_2 to a specific market. If the pipeline will deliver CO_2 to an area without existing CO_2 infrastructure, then the number of end users, their relative locations to each other, and their compression requirements must be determined and included in the overall costs of pipeline network development. Whether the costs associated with a particular distribution network are borne by Excelsior Energy, the CO_2 purchaser, or a combination thereof will be a matter for negotiation.

Pipeline operating costs probably will be nominal compared with the costs of installation (Heddle et al., 2003). Recently, work conducted as part of the PCOR Partnership Phase II activities resulted in estimated operating costs of $667 per mile for each year of operation.

POTENTIALLY PROFITABLE GEOLOGIC SEQUESTRATION OPTIONS FOR MESABA ENERGY PROJECT'S CO_2

Potential Geological Sinks for the Mesaba Power Plant

The PCOR Partnership region is home to many geologic sequestration options. Figure 8 shows the major sedimentary basins that are the primary targets for geologic sequestration. The major types of geologic formations amenable to geologic sequestration are oil reservoirs, coal deposits, and deep sedimentary rock formations saturated with saltwater (brine formations, sometimes referred to in the literature as saline aquifers) have the potential to serve as sinks for CO_2. Under certain conditions, these geological features can be capable of providing secure, long-term storage for large volumes of CO_2. They generally occur in geological settings known as sedimentary basins, which in the PCOR Partnership region underlie nearly 40% of the geographical area. However, the proposed Mesaba sites are not located within a sedimentary basin, and the specific locales of the Mesaba sites are underlain by rocks that are largely crystalline in nature, with very little interconnected pore space within which to inject large volumes of CO_2. Table 2 shows the relative distances from the proposed plant locations to

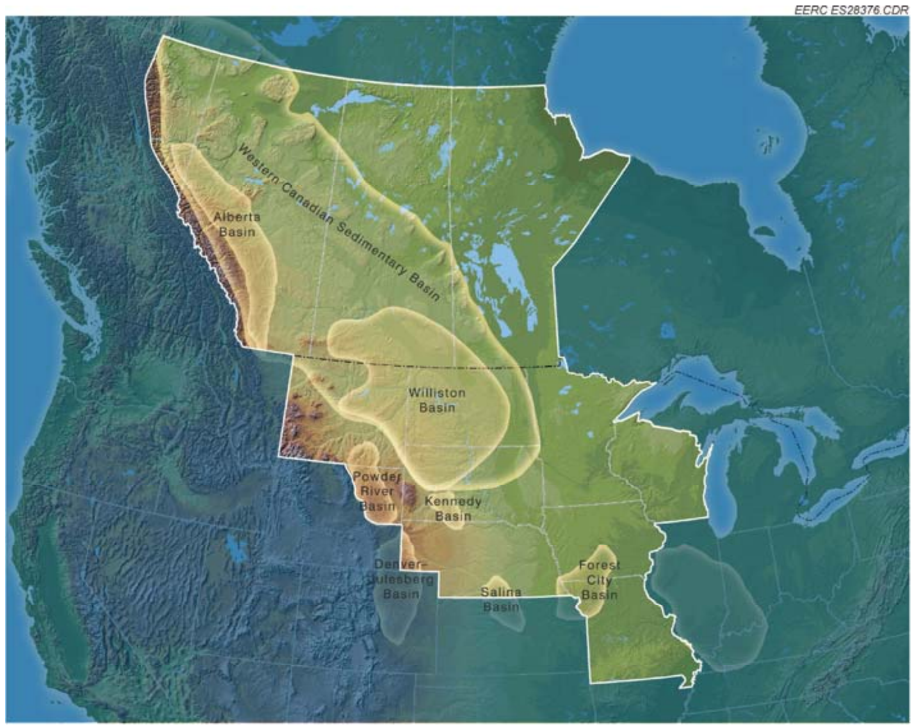

Figure 8. Major sedimentary basins in the PCOR Partnership region.

Table 2. Relative Distances from Potential Mesaba One Locations to Potential Geological Sinks

Potential Sink and Location	Distance from Taconite, MN (miles)	Distance from Hoyt Lakes, MN (miles)
Williston Basin Northeast Flank Oil Fields (Newburg Field)[1]	383	475
Williston Basin Nesson Anticline Oil Fields (Tioga Field)[1]	465	560
Williston Basin Dakota Group Brine Formations[1]	275	330
Williston Basin Madison Group Brine Formations[1]	350	430
Illinois Basin Oil Fields (EOR fairway)[2]	680	660
Illinois Basin Coalfields (sequestration fairway)[2]	525	530
Illinois Basin Mt. Simon Brine Formation[2]	520	500
Iowa Coalfields[3]	440	450
Midcontinent Rift System Sedimentary Rock Formations[3]	80–150 (?)	100–175 (?)

1 Based on PCOR Partnership Phase I regional characterization results.
2 Based on Midwest Geological Sequestration Consortium (Illinois Basin Partnership) Phase I regional characterization results.
3 Geological formations to be evaluated as part of PCOR Partnership Phase II characterization activities.

potential geological sinks in the Williston Basin, the Illinois Basin, Iowa, and Minnesota. The Williston Basin, which extends into eastern North Dakota, is the closest well-understood sedimentary basin to the proposed Mesaba Power Plant sites. All three major types of geological sinks (oil fields, coal seams, and saline formations) are present in the Williston Basin.

As part of the PCOR Partnership Phase I activities, the CO_2 sequestration capacities of numerous geologic sinks in the region were estimated. Thousands of oil reservoirs, three major coalfield deposits, and two regional deep brine formations were evaluated using available characterization data. Portions of a third brine formation in western North Dakota have been evaluated as part of ongoing Phase II characterization activities. The characterization data that were available for each sink varied widely; therefore, all of the values for CO_2 storage capacity that were developed under Phase I should be considered reconnaissance-level estimates. These estimates provide an order-of-magnitude comparison of the potential storage capacities of selected geologic sinks in the region. Figure 9 shows the locations of the proposed sites relative to the oil fields and brine formations evaluated as part of the PCOR Phase I activities. The map also shows a general outline of the Midcontinent Rift, which may also include deep sedimentary rock units that could be suitable for sequestration. While the sedimentary rocks of the Midcontinent Rift lie closer to the proposed sites than any other potential geological sink, they are also among the least understood formations in the region. Significant, time-consuming, and expensive, field- and laboratory-based characterization efforts would have to be conducted to develop reasonable estimates of their potential capacity to store CO_2.

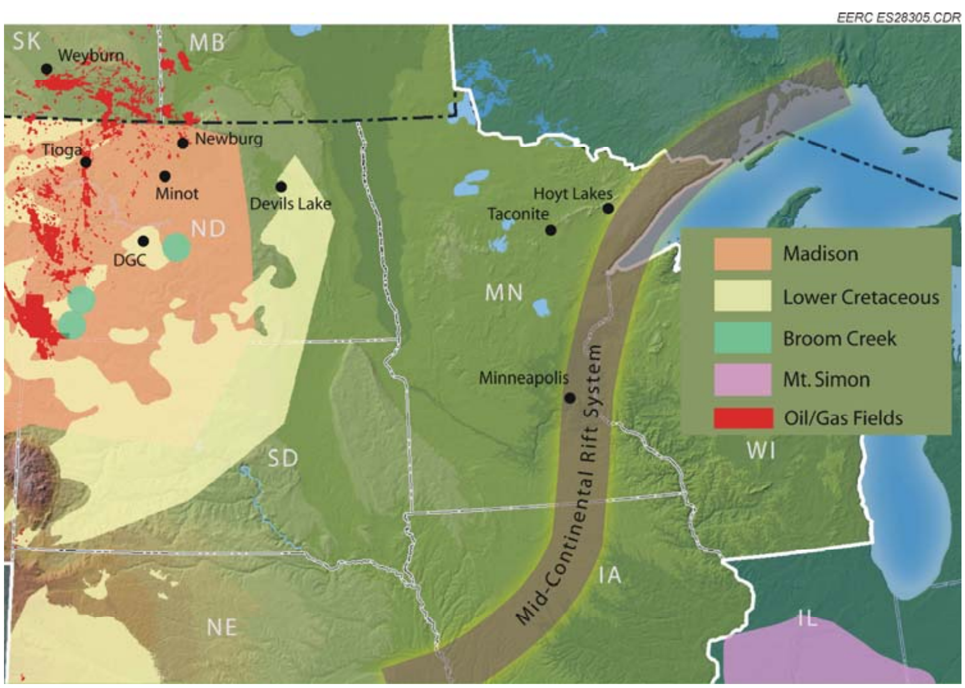

Figure 9. Brine formations and oil fields that have potential to serve as geological sinks for CO_2.

Enhanced Oil Recovery

Overview of EOR

Oil can be produced from a reservoir in three distinct phases, or stages, of operation. During the first stage, commonly referred to as the primary recovery phase, the production of oil is driven primarily by the natural pressure of the oil field. Once the rate of primary production has fallen below an economically acceptable rate, an operator may choose to stimulate production by a variety of means which are collectively referred to as EOR operations. Secondary-phase EOR typically involves the injection of large volumes of water into the production zone to maintain reservoir pressure and to sweep oil from the reservoir. This technique is commonly referred to as waterflooding, or waterflood EOR, and in many cases can be conducted economically for decades longer than the primary recovery phase. The secondary recovery stage reaches its limit when the injected water is produced in considerable amounts along with the oil and the overall production of the reservoir is no longer economical. The successive use of primary recovery and secondary recovery in an oil reservoir typically produces about 15% to 40% of the original oil in place (OOIP). If economic and technical conditions are favorable, an operator may elect to move the reservoir into a third, or tertiary, stage of oil production. Tertiary EOR techniques are generally centered around the injection of fluids, most often CO_2, that alter the original properties of the oil in the reservoir. The injection of CO_2 not only restores pressure, but the dissolution of CO_2 into the oil also lowers its viscosity, improving oil displacement and flow in the reservoir and incrementally increasing its productivity. As with waterflooding, CO_2-based EOR can increase the operational lifetime of an oil field by decades.

Regional EOR Opportunities

A regional evaluation of many of the oil fields within the Williston Basin, including those in North Dakota and Saskatchewan, was conducted as part of Phase I of the PCOR Partnership. The evaluation was performed to determine the fields' potential to both sequester CO_2 and incrementally produce oil through CO_2-based EOR. Data were gathered from readily available public sources at state agencies throughout the region. Production data were usually combined into cumulative field statistics, and fields with a current cumulative production of at least 800,000 barrels of oil were selected for reservoir data collection. Sequestration potential and incremental oil production potential were determined from the reservoir data. Only those fields that have gone through, or are currently in, a secondary recovery phase were considered because, in general, secondary performance data are necessary for accurate prediction of tertiary EOR performance. The methodology by which the oil fields were evaluated is similar to that applied by Nelms and Burke (2004) in their evaluation of CO_2 EOR to North Dakota oil reservoirs.

A detailed discussion of the process used for the identification and sequestration capacity of pools with suitable properties for carbon sequestration through EOR is outside the scope of a Carbon Management Plan (CMP). However, because Excelsior Energy personnel have expressed an interest in learning more about the methodology, the information is included in Appendix A.

Two oil-producing areas of the Williston Basin that should be considered as potentially economically viable sinks for CO_2 from the proposed Mesaba Energy Project sites are the

Nesson Anticline area in northwestern North Dakota and the Northeast Flank area of north-central North Dakota and southeastern Saskatchewan. The potential incremental oil resource, volumes of CO_2 required to realize the production of the incremental oil resource, and the general locations of these areas relative to the proposed Mesaba sites are provided in Tables 3–5 and Figures 10–12.

Pipeline Infrastructure Needed to Reach the Regional EOR Opportunities

Pipeline routes were estimated using a geographic information system-based model for CO_2 pipeline transport and source–sink matching optimization that was developed at the Massachusetts Institute of Technology (MIT) (Herzog, 2006). The MIT model implements 1 × 1-km obstacle grid layers in which local terrain, crossings, protected areas, and populated places are assigned relative cost factors to estimate the least-cost route between a single CO_2 source and a geologic sink. Obstacles can increase the cost for the length of pipeline that is routed through an obstacle from roughly 3 times (highway or railroad crossing) to 30 times (national park crossing) (MIT CO_2 Pipeline Transport and Cost Model, 2007). For a given route, the length, diameter, pipeline construction cost, annual operations and maintenance cost, and total cost per ton of CO_2 are calculated. As is sometimes the case with new software, the model provides only a first estimate of route and cost because to date not all obstacle layers have been added to the model.

To provide a second estimate, pipeline capital costs were also estimated using the $40,000/in. per mile "rule of thumb." Because this method does not adjust pipeline costs for road or waterway crossings, routing through federal or protected land, or routing through populated areas, the costs it generates should be considered low-end, base-case estimates. Distances and cost estimates for pipelines from the two Mesaba Energy Project sites to key regional geological sinks are given in Table 6. The MIT software calculates that a 12-in.-diameter pipe would adequately transport the estimated 1.6 million tons of CO_2 that will be captured at the Mesaba One annually. Not including the costs of booster stations, the estimated cost of a 12-in.-diameter pipe is approximately $480,000 per mile. Therefore, for example, the estimated total capital cost of a 385-mile pipeline from Taconite, Minnesota, to the Newburg oil field in North Dakota is roughly $184 million. Pipeline operations and maintenance costs are much less significant and are estimated to be $667/mi annually. Based on this estimate, the cost of operating a 385-mile pipeline from Mesaba One to the Newburg oil field would be on the order of $257,000 per year.

Table 3. Summary of Potential Incremental Oil Recovery from CO_2 Injection for Selected Nesson Anticline Oil Fields

Unit Name	Pool Unitized	Potential Oil Recovery at 12% OOIP, million bbl	CO_2 Needed, Bcf
Beaver Lodge	Duperow	28	224
Tioga	Madison	26	207
Beaver Lodge	Madison, Silurian, Ordovician	27	165
Antelope	Madison	12	96
Blue Buttes	Madison	11	89
Charlson North	Madison	10	77
Clear Creek	Madison	3	26
Antelope	Devonian	2	16
Bear Creek	Duperow	2	13
Charlson South	Madison	1	9
Total		122	922

Table 4. Summary of Potential Incremental Oil Recovery from CO_2 Injection for Selected Northeast Flank Oil Fields

Field Name	Pool Unitized	Potential CO_2 Oil Recovery at 12% OOIP, million bbl	CO_2 Needed, Bcf
Newburg	Spearfish–Charles	12	92
Wiley	Glenburn	12	92
Rival	Madison	9	76
Lignite	Madison	4	31
Mohal	Madison	2	15
Landa	Madison	1	8
Total		40	314

Table 5. Summary of Potential Incremental Oil Recovery from CO_2 Injection for Selected Southeastern Saskatchewan Oil Fields

Field Name	Pool Unitized	Potential Oil Recovery at 12% OOIP, million bbl	CO_2 Needed Using 8 Mcf/bbl Oil Recovered, Bcf	CO_2 Needed Using 8 Mcf/bbl Oil Recovered, million tons
Steelman	Midale	84	669	41
Midale	Midale	65	516	32
Pinto	Frobisher	15	119	7
Steelman	Frobisher	14	109	7
Workman	Frobisher	5	41	3
Midale	Frobisher	5	37	2
Workman	Midale	1	11	1
Pinto	Frobisher	1	7	0.4
Total		190	1509	93.4

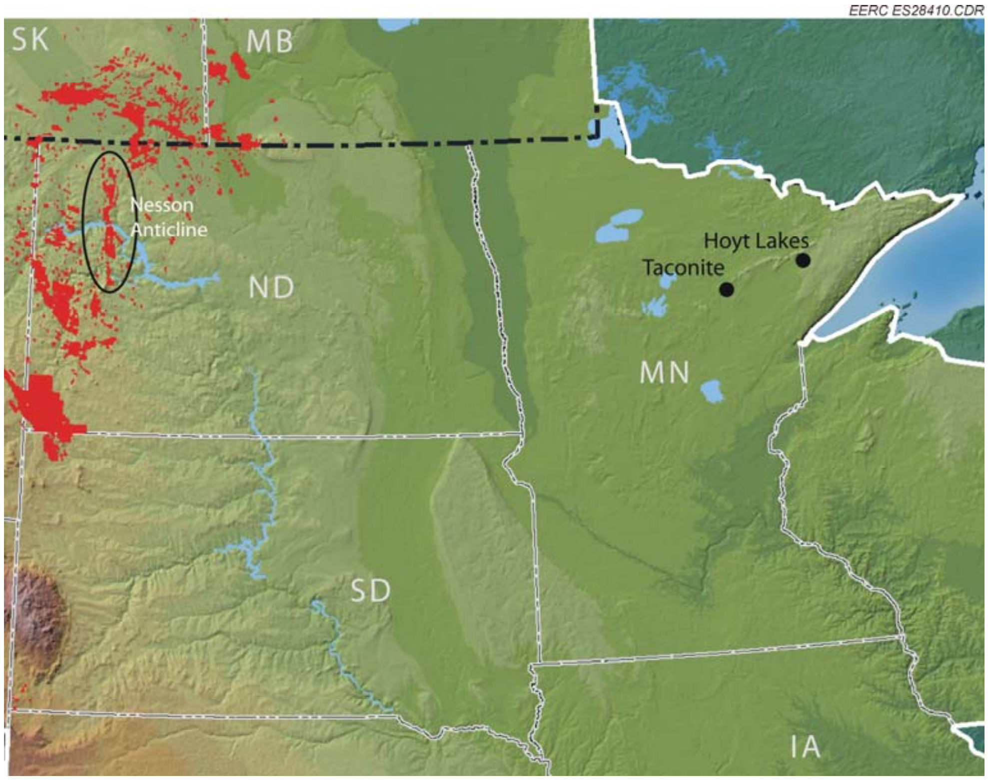

Figure 10. Oil fields of the Nesson Anticline region of the Williston Basin.

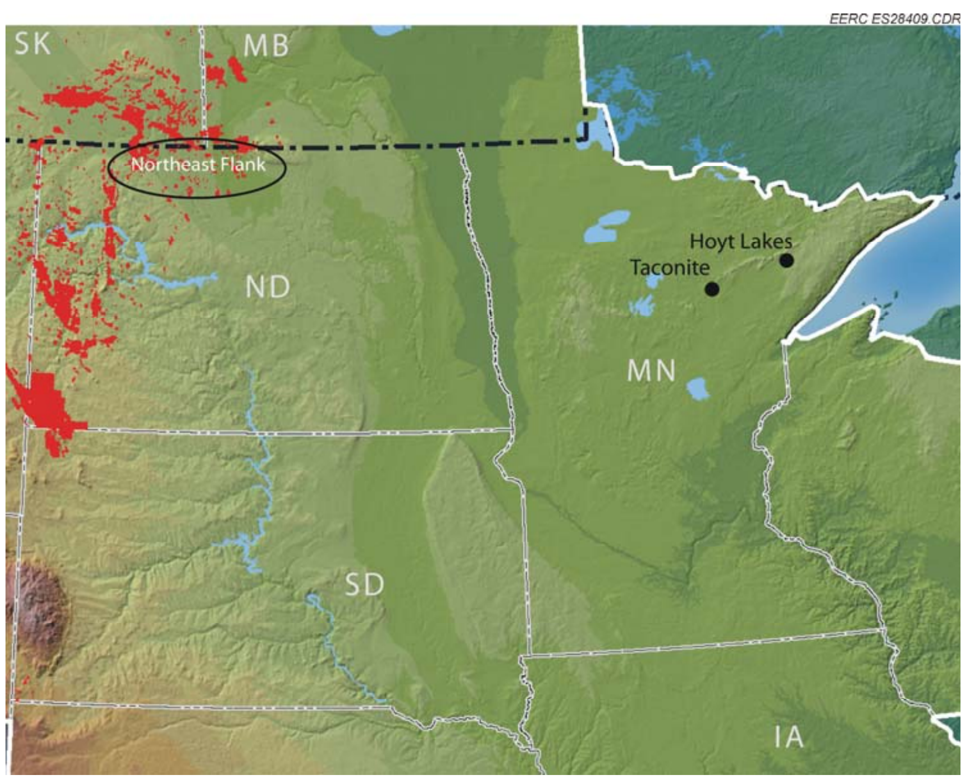

Figure 11. Oil fields of the Northeast Flank region of the Williston Basin.

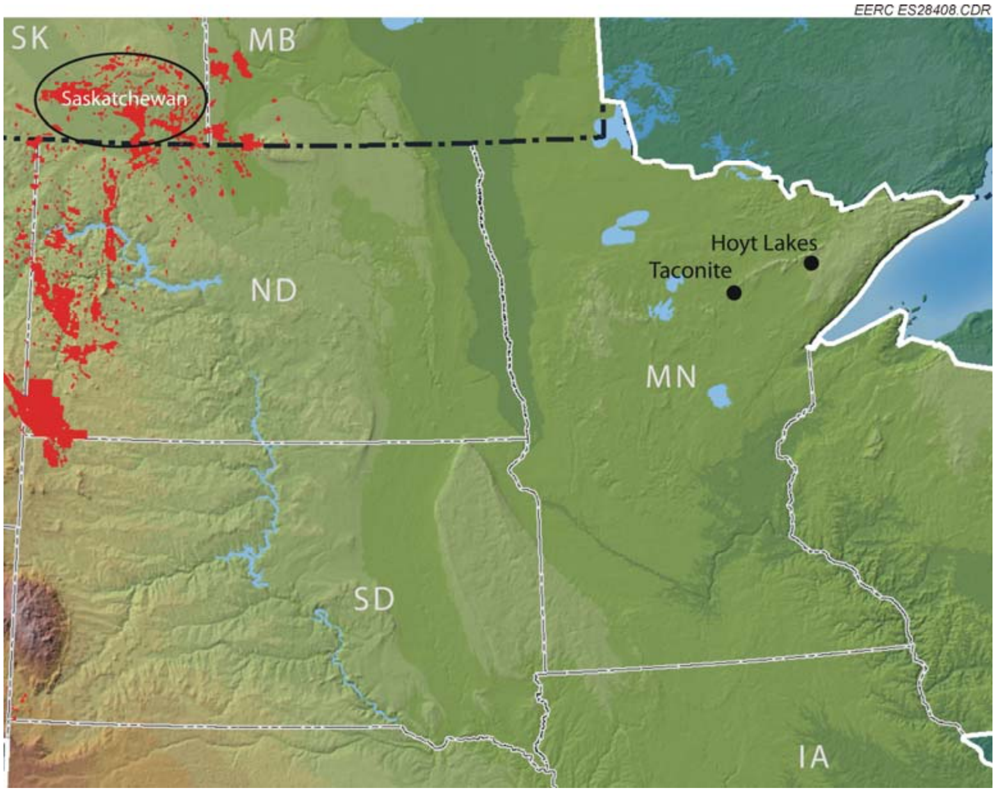

Figure 12. Oil fields of the Saskatchewan region of the Williston Basin.

Table 6. Distances from and Estimated Costs for Pipeline from the Proposed Mesaba Energy Project Sites to Geologic Sequestration Sites

	From Taconite, MN			From Hoyt Lakes, MN		
Sink/Location	**Distance, mi**	**MIT[a] cost, $millions**	**RoT[b] cost, $millions**	**Distance, mi**	**MIT[a] cost, $millions**	**RoT[b] cost, $millions**
Williston Basin Northeast Flank Oil Fields/ Newburg Field	385	177	184	475	213	228
Williston Basin Nesson Anticline Oil Fields/Tioga Field	465	209	223	560	245	269
Devils Lake (saline formation)	275	232	252	332	157	159
Southeast Saskatchewan (oil fields)	440	200	211	500	221	240
Illinois Basin (oil fields)	525	232	252	530	260	254

[a] Using MIT software.
[b] Using "Rule of Thumb" of $40,000 per inch diameter per mile length.

Figure 13 shows the locations of the proposed Mesaba Energy Project sites relative to the oil fields of the Williston Basin. The oil field that is closest to the potential Mesaba locations is the Newburg field in the North Dakota portion of the Northeast Flank of the Williston Basin. Assuming routes similar to those shown in Figures 14 and 15, the Newburg Field is located approximately 380 miles from the West Range site and 475 miles from the East Range site. To reach the oil fields of this region, a new mainstem pipeline will be needed to the vicinity of Newburg, North Dakota. New distribution pipelines will also be necessary, located according to individual user requirements within the Northeast Flank area. Pipelines will likely cross several existing utility, transportation, and oil/gas lines. Booster station(s) will also be needed roughly every 100 miles, with the size depending on the CO_2 volumes being transported. The larger oil fields of the Nesson Anticline are an additional 80 miles to the west of Newburg. Numerous fields in the Nesson Anticline could be accessed by tying into the DGC pipeline, should that option be available.

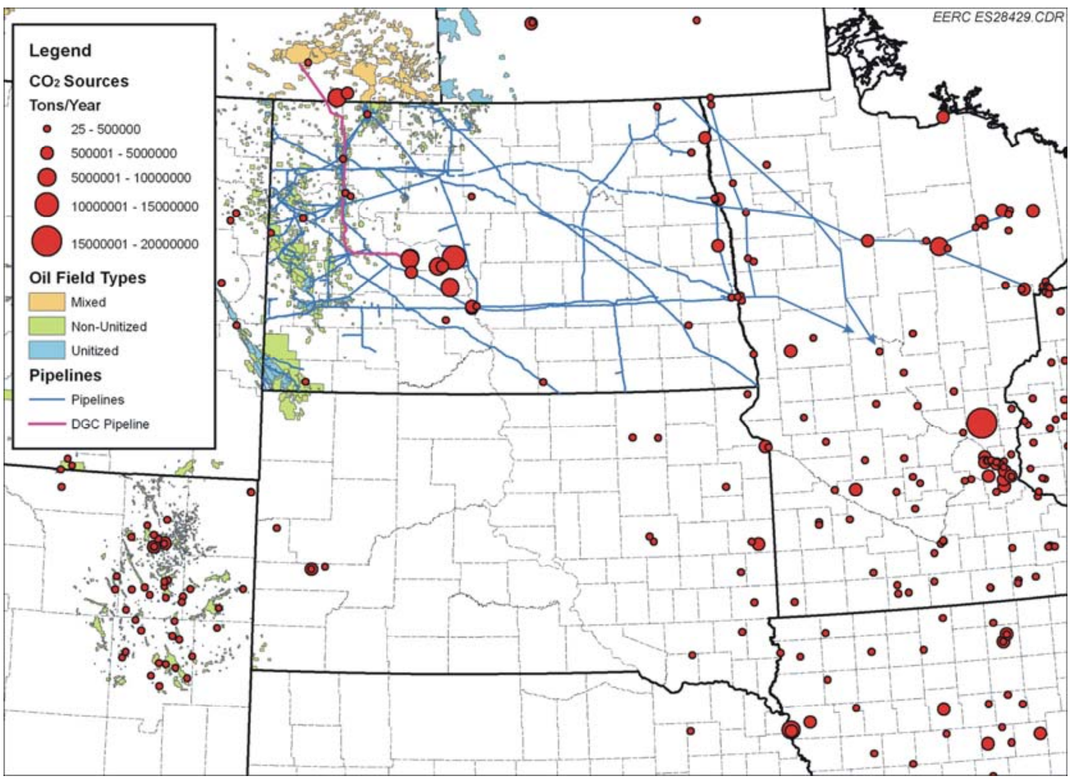

Figure 13. Oil fields, major stationary CO_2 sources, and pipelines in the Williston Basin.

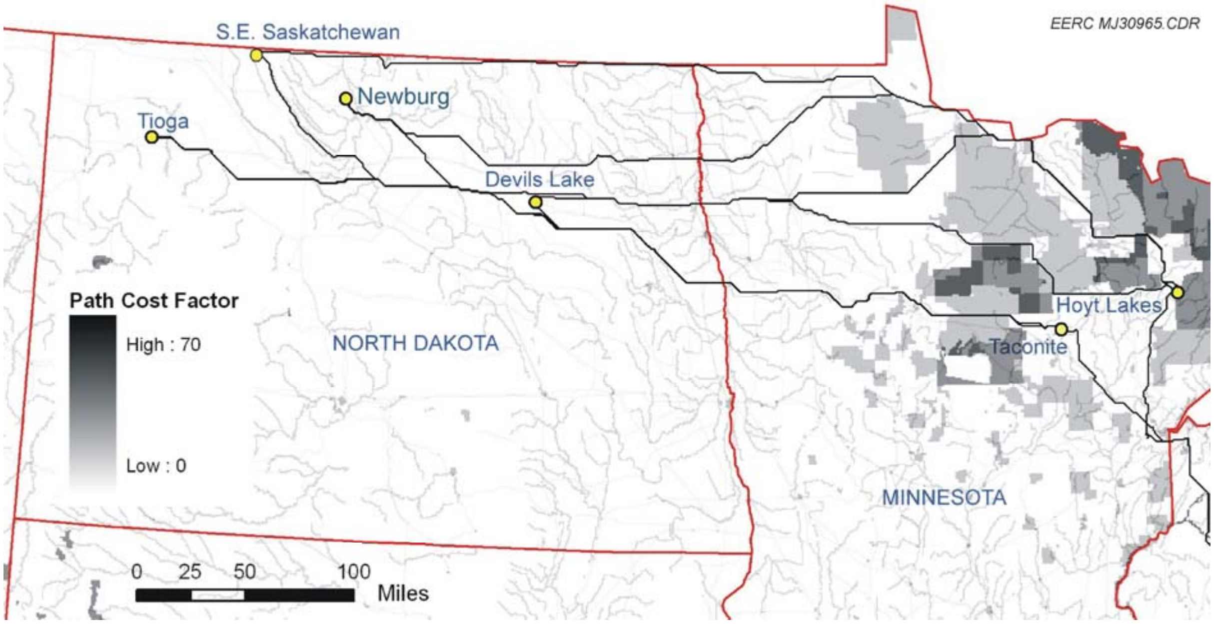

Figure 14. Possible pipeline route from Mesaba Energy Project sites to geologic sinks in the Williston Basin.

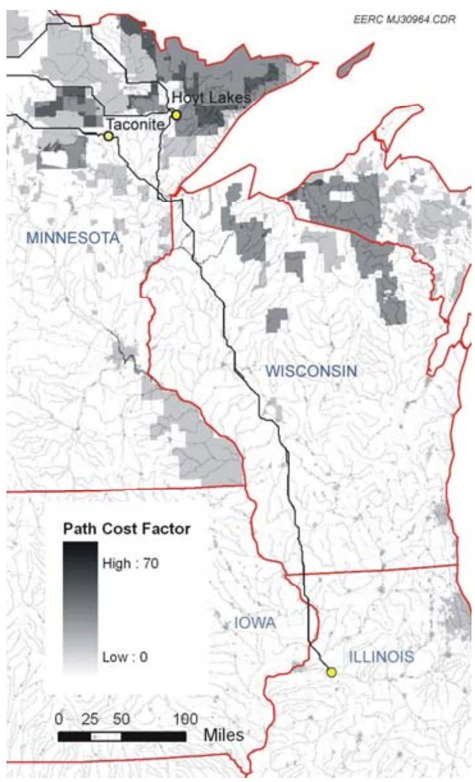

Figure 15. Possible pipeline route from Mesaba Energy Project sites to the Illinois Basin.

While the distances from Mesaba to the Williston Basin oil fields may seem to be long, there is some precedence for CO_2 to be piped such distances. Table 7 lists examples of existing CO_2 pipelines, providing points of reference that may be valuable when considering the viability of transporting CO_2 from Mesaba to EOR project locations.

Contractual Agreements Required to Transport and Sequester CO_2 for EOR

Any contract developed must meet the needs of the entities involved. This will vary greatly depending on the reasons for the transaction and the risk tolerances and profiles of the parties involved. Most types of agreements will include standard contractual language that discusses the scope of the agreement, termination, indemnity and liability, and insurance clauses. Some may have special provisions for confidentiality, intellectual property developments, and public relations campaigns. In addition to the terms listed previously, carbon credit agreements would most likely at a minimum include delivery warranties, verification clauses, and clauses that cover noncompliance, trading authority, and transaction methods.

EOR Market

Potential Customers

Potential customers for CO_2 to be used for EOR will vary from area to area. In the Northeast Flank area, the operators of the largest ongoing waterflood EOR operations include Amerada Hess, a major vertically integrated oil company headquartered in New York, and Eagle Operating, an independent production company headquartered in Kenmare, North Dakota. Other operators in the Northeast Flank include Ballantyne Oil Company and Ward Williston. The predominant oil producer in the Nesson Anticline area is Amerada Hess, with Petro-Hunt and Berco Resources also operating fields in the area that might be suitable for CO_2-based EOR. Marathon Oil Corporation operates wells and fields in the Billings–Dickinson Area, the Nesson Anticline, and the Northeastern Flank regions of the North Dakota portion of the Williston Basin.

Table 7. Examples of Existing CO_2 Pipelines

Pipeline	Pipe Diameter, in.	CO_2 Capacity, Mt/yr	Length, mi
Cortez	30	19.3	502
Bravo Dome	20	7.3	217
Canyon Reef	16	4.4	140
Choctaw	20	4.3	183
Sheep Mountain I/II	20/24	6.5/10	184/224
Val Verde	10	2.9	83
Weyburn	14/12	1.8	205

While Marathon's operations in North Dakota are significant, the company's primary focus is on developing resources in the Bakken Formation, placing less emphasis on tertiary EOR. In Saskatchewan, EnCana and Apache Canada are actively engaged in purchasing CO_2 from DGC and have expressed their desire to expand their current operations within the Weyburn and Midale Fields over the coming decades. Devon Canada and Canetic have also expressed serious interest in conducting CO_2-based EOR projects in some of their Saskatchewan fields.

Price Structure

When the potential price structure of the marketplace for Mesaba-produced CO_2 is considered, it is useful to not only look at the current price of CO_2 in the Williston Basin, but also to examine the price structure in an oil-producing region where the market for CO_2 is more mature and robust, such as the Permian Basin. The Permian Basin, located in southeastern New Mexico and western Texas, has the largest CO_2 market in the world. In 2001, there were 43 active CO_2-based EOR projects in the Permian Basin. The market has continued to expand since then, with over 1700 MMcfd (100,000 tons/day) being sold and a supply shortage that has been estimated to be 500 MMcfd (29,000 tons/day) (Lyons and Hopper, 2006). Multiple sources of CO_2 provide product to the oil fields, and while a majority of the CO_2 used in the Permian Basin is from natural sources located hundreds of miles away in Colorado and New Mexico, significant quantities are also provided by nearby gas-processing plants (Jarrell et al., 2002). CO_2 in the Permian Basin sells for approximately \$20/ton (\$1.14/mcf), based on Denver City Hub prices. This price is a combination of a "base" price and a "float" price. In 2006, the base price was approximately \$10/ton. The float price, which depends on the price of oil, generally ranges from \$0 to \$10/ton. Determination of the float price is based on a linear relationship that ranges from \$0/ton when oil prices are \$25/bbl or less to \$10/ton when oil prices are \$50/bbl or higher. The "float" price has not changed significantly in the last year even though the petroleum marketplace has been volatile. Past prices are not necessarily indicative of future prices. Recent shortages coupled with high oil prices have resulted in spot prices for CO_2 in the Permian Basin that were reported in the summer of 2006 to be as high as \$2.25 to \$2.60 per mcf (Lyons and Hopper, 2006). While those prices were not sustained, they may be indicative of what the market might bear under certain circumstances.

In contrast to the Permian Basin, only two CO_2-based EOR projects are active in the Williston Basin, purchasing a total of approximately 121 MMcf/day (7025 tons/day). The precise terms of the purchase agreements between DGC and the purchasing operators are not publicly available. However, the price of CO_2 delivered to Weyburn has been reported in the literature to range from \$0.60 to \$1.25/mcf (\$10.40 to \$22/ton), with most sources reporting prices of \$1 to \$1.25/mcf (\$18.30 to \$22/ton) (Harrison and Ross, 2006; Torp and Brown, 2004; Petromin, 2003).

Estimates of Current and Future CO_2 Demand

Currently, sales of CO_2 in the Williston Basin are exclusively focused on the two fields in southeastern Saskatchewan: the Weyburn Field operated by EnCana and the Midale Field (located directly adjacent to the Weyburn Field) operated by Apache Canada. The total volume of CO_2 sold to these two fields is approximately 121 MMscfd (7025 tons/day). The CO_2 is provided to those operators by DGC via its pipeline from Beulah, North Dakota, to Weyburn.

Some oil field operators would like to expand the market to other areas of the Williston Basin in the near future. The Nesson Anticline area appears to be particularly attractive because oil field operators have been actively negotiating in recent years with source industries to bring CO_2 to their fields in the area. The potential for near-term market development in the Nesson Anticline is also enhanced by the fact that some of the infrastructure is already in place in the form of the DGC pipeline that runs directly over or adjacent to nearly all of the Nesson Anticline oil fields. Finally, the Nesson Anticline area contains a CO_2-based EOR resource of approximately 122 million barrels of oil. It has been estimated that approximately 56 million tons of CO_2 would need to be purchased in order to produce that volume of oil in the Nesson Anticline area (Smith et al., 2005).

While the Nesson Anticline is perhaps the area in the Williston Basin most poised for near-term expansion of the CO_2 market, key operators in the Northeast Flank area (approximately 90 miles closer to the proposed Mesaba Energy Project sites) have also expressed interest in conducting CO_2 EOR operations. The total potential CO_2–EOR resource in the Northeast Flank of the Williston Basin has been estimated to be approximately 18 million barrels of oil in the North Dakota oil fields. It is worth noting that while the Northeast Flank also includes several large oil fields in southwestern Manitoba, reconnaissance-level examination of the Manitoba fields indicates that their suitability for CO_2-based EOR operations may be suspect; therefore, they have not been included as part of the potential market for CO_2 in the Williston Basin.

Current and Potential Future Suppliers in the Region

The DGC Plant in Beulah, North Dakota, is currently the only supplier of CO_2 in volumes large enough to support EOR activities. As mentioned in the previous section, the DGC Plant currently sells approximately 121 MMscfd (7024 tons/day) through its pipeline to the Weyburn and Midale Fields in Saskatchewan. While there are no published reports of the total amount of CO_2 that DGC could transport through its existing pipeline, some estimates suggest that as much as 250 MMscfd could be produced by the DGC Plant. The current availability of the estimated 129 MMscfd that are not being sold to the Saskatchewan oil fields is not a matter of public record.

Potential future suppliers of significant volumes of CO_2 in the Williston Basin include a variety of industries that are not currently capturing their CO_2 emissions. Of the currently existing industries, the coal-fired power plants produce by far the largest volumes of CO_2, with seven plants producing 37 million tons/year (602 Bcf/year). However, while much research is being conducted on the subject, commercial technologies cannot economically capture CO_2 from coal-fired power plants and large-scale capture of CO_2 from these types of sources is not likely to happen in the near term. Other industrial sources in the region produce CO_2 that is more easily captured but in volumes that are significantly smaller than those of the coal-fired power plants. These sources include gas-processing plants located in western North Dakota that currently produce nearly 5070 mcf/day (294 tons/day) of CO_2 with a purity greater than 90% and ethanol plants that produce streams with a CO_2 content of 99%. There are currently 17 ethanol plants in

Minnesota that produce a total of about 8550 tons CO_2 per day, and at least three ethanol plants are in various stages of development in western North Dakota. Each of these plants will produce at least 7700 mcfd (450 tons/day) of 99%-pure CO_2. It is possible that at least some of these smaller, but readily capturable, CO_2 sources could become part of the EOR CO_2 marketplace within the next 5 years.

Enhanced Coalbed Methane Recovery

Estimates of CO_2 Storage Capacity in Some of the PCOR Partnership Region's Coal Beds

Numerous laboratory- and field-based studies have shown that coalbeds can have significant capacities for sequestering CO_2 (Nelson et al., 2005a). Coal can physically adsorb many gases and has a higher affinity for CO_2 than for methane (Chikatamarla and Bustin, 2003). Gaseous CO_2 injected into a coal seam will flow through the cleat system and become adsorbed onto the coal surface, effectively replacing and releasing gases with lower affinity for coal, such as methane. The injection of gaseous CO_2 into a coal seam can result in simultaneous sequestration of CO_2 and ECBM production.

Phase I of the PCOR Partnership examined the potential to sequester CO_2 in coal seams in three basins of the region. The coals and their respective basins for which reconnaissance-level evaluations were performed include the Wyodak–Anderson coal zone of the Powder River Basin, the Harmon–Hanson coal seams of the Williston Basin, and the Ardley coals of the Alberta Basin. These coal seams are shown in Figure 16. Iowa, which is a part of the PCOR Partnership region, also contains significant coal seams and the sequestration potential of those seams will be evaluated as part of the PCOR Partnership Phase II activities.

While CBM production projects in Wyoming and Alberta have met with considerable economic success, there has been only sporadic exploration for CBM in North Dakota and Iowa, with no commercially viable production reported to date in those states. The coal seams of the Williston Basin and Iowa are the closest coal seams to the proposed Mesaba Energy Project locations, with both areas being located approximately 500 miles from northern Minnesota. Coal seams of the Illinois Basin were also considered as potential geological sinks for Mesaba Energy Project's CO_2, but the unminable seams of that basin that have been evaluated by the Illinois Basin Partnership are located approximately 600 miles from the proposed Mesaba locations.

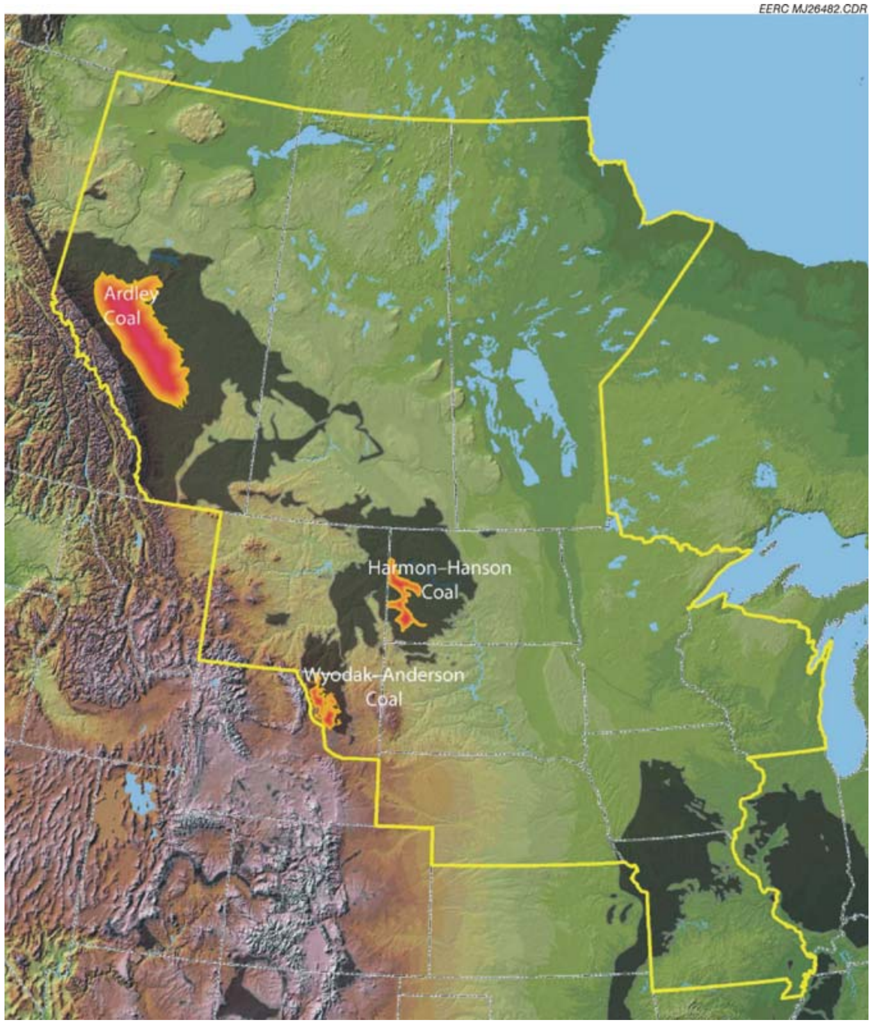

Figure 16. Map of the coal resources of the PCOR Partnership region. The three coal seams that were evaluated for CO_2 sequestration as part of PCOR Partnership Phase I regional characterization activities are highlighted and labeled. Iowa coal seams will be evaluated as part of Phase II regional characterization.

The CO_2 sequestration potential for the unminable areas (where the overburden is more than 500 ft thick) of the Williston Basin Harmon–Hanson coal seams was estimated to be 380 million tons. Although there is currently no CBM production from seams in the Williston Basin, some exploratory activities for CBM have been conducted in recent years. Very little site-specific data are available, although a methane content of 20 scf/ton has been reported from a test hole in the Harmon seam of Slope County in southwestern North Dakota.

Assuming an average seam thickness of 15 feet, a coal density of 1750 tons/acre-foot (which is typical for lignite), and an estimated area of 13,000 mi^2, if the reported methane gas content of 20 scf/ton were shown to be a common characteristic of the Harmon lignite, then the total CBM gas in place for the Harmon coal seam could be calculated to be as high as 4.4 Tcf.

Even if only 25% of this total is recoverable, there could be as much as 1.1 Tcf of recoverable natural gas in the Harmon lignite of North Dakota (Nelson et al., 2005b).

While the nature of this estimate is speculative and highly debatable, it does speak to the potential size of a gas resource that might provide an economic incentive to sequester CO_2 in Williston Basin coal seams. Detailed laboratory- and field-based data are required to fully determine the potential CBM resources of the Williston Basin and the role that CO_2 injection may play in exploiting any reserves that exist. Phase II of the PCOR Partnership includes a task devoted to evaluating the viability of simultaneous CO_2 sequestration and ECBM production in a lignite seam in northwestern North Dakota. Field- and laboratory-based activities will be conducted to quantify the CO_2 sequestration capacity of lignite seams, determine the effects that CO_2 injection have on the physical and chemical properties of the lignite, and evaluate the potential to enhance methane production from the lignite seams through the injection of CO_2. The experimental design includes the drilling of five wells for the injection of CO_2, potential production of CBM, and monitoring of subsurface effects due to CO_2 injection and ECBM production activities over the course of the project. Available data developed during the PCOR Partnership Lignite Field Demonstration task will be incorporated into the final carbon management plan for the proposed Mesaba Energy Project.

OTHER GEOLOGIC CO_2 SEQUESTRATION OPTIONS FOR THE MESABA ENERGY PROJECT

Sequestration in Oil Fields Not Suitable for EOR under Current Economic Conditions (depleted fields)

As production within the basin matures, some fields that have not yet been unitized and undergone EOR, or are considered depleted and abandoned, may become candidates for CO_2 sequestration. Sequestration may be accomplished in the producing pools of some of these fields by initiating EOR with CO_2 miscible flooding or by considering the pool as a storage tank and filling it to capacity. The potential capacity for sequestration continues to expand when the entire Williston Basin region and its approximately 1100 oil-producing fields are considered. While not the primary goal, injection into fields economically unsuitable for EOR can be engineered toward maximizing incremental oil production. Revenue from this could help offset the cost of CO_2 compression and transmission (Kovscek, 2002). The methods and criteria for determining the quantity of CO_2 that could be sequestered per oil field are described in Appendix A. The results of Phase I PCOR Partnership characterization activities suggest that the oil fields not considered suitable for EOR in the Northeast Flank and Nesson Anticline areas have a maximum theoretical storage capacity of nearly 2 billion tons of CO_2. While the practical capacity will be significantly less than the theoretical maximum, even if only 5% of the capacity is available, there would be enough space in these oil fields to sequester many decades worth of CO_2 from the Mesaba Plant.

Sequestration in Saline Formations

Deep saline or brine formations represent a significant portion by volume of the sedimentary basins in the PCOR Partnership region. This is especially true in the Williston Basin, which comprises sedimentary rock formations that are over 14,000 feet thick in the center of the basin. Several of these rock formations are significantly porous and permeable and have water chemistries that make them amenable to CO_2 sequestration. Many of these are, in turn, overlain by rocks with very low porosity and permeability, making them excellent seals that will ensure that any injected CO_2 remains in the intended formation. Figure 17 shows the stratigraphic column for the Williston Basin with the relative depths of saline formations and sealing formations that were evaluated as part of the PCOR Partnership Phase I regional characterization activities.

The sequestration of CO_2 in saline formations has been conducted in the field at both the experimental scale (one-time injection of hundreds of tons at Frio in Texas) and commercial scale (ongoing injection of 1 million tons per year at Sleipner in the North Sea). Other research-oriented projects focused on the injection of CO_2 into saline formations are planned for the near-future. Figure 18 shows the location of various projects around the world in which CO_2 is being or will be sequestered in saline formations.

Mechanistically, the CO_2 capacity of a brine formation may be considered in terms of free-phase CO_2 in the pore space of the rock, dissolved-phase CO_2 in the formation water, and CO_2 converted to solid minerals that become part of the rock matrix. The degree to which each mechanism will affect sequestration under the range of geologic, hydrodynamic, and geochemical conditions that can occur in any given field is currently not well understood and is difficult to predict. The focus of Phase I of the PCOR Partnership was to conduct reconnaissance-level evaluations of geologic sinks in the region; therefore, capacity estimates for brine formations only considered the characteristics that control solubility and hydrodynamic trapping mechanisms. Mineral trapping and the effects it may have on the sequestration of CO_2 in the studied formations were not considered.

Results of Saline Formation Evaluations Within the PCOR Partnership Region

Results indicate that saline formations within the PCOR Partnership region have the potential to store vast quantities of anthropogenic CO_2. Two saline formation systems have been evaluated for their regional continuity, hydrodynamic characteristics, fluid properties, and ultimate storage capacities using published data: the Mississippian Madison System and the Lower Cretaceous System, shown in Figure 19. Data for the U.S. portion of the region were obtained from U.S. Geological Survey reports (Downey, 1984, 1986, 1989; Downey and

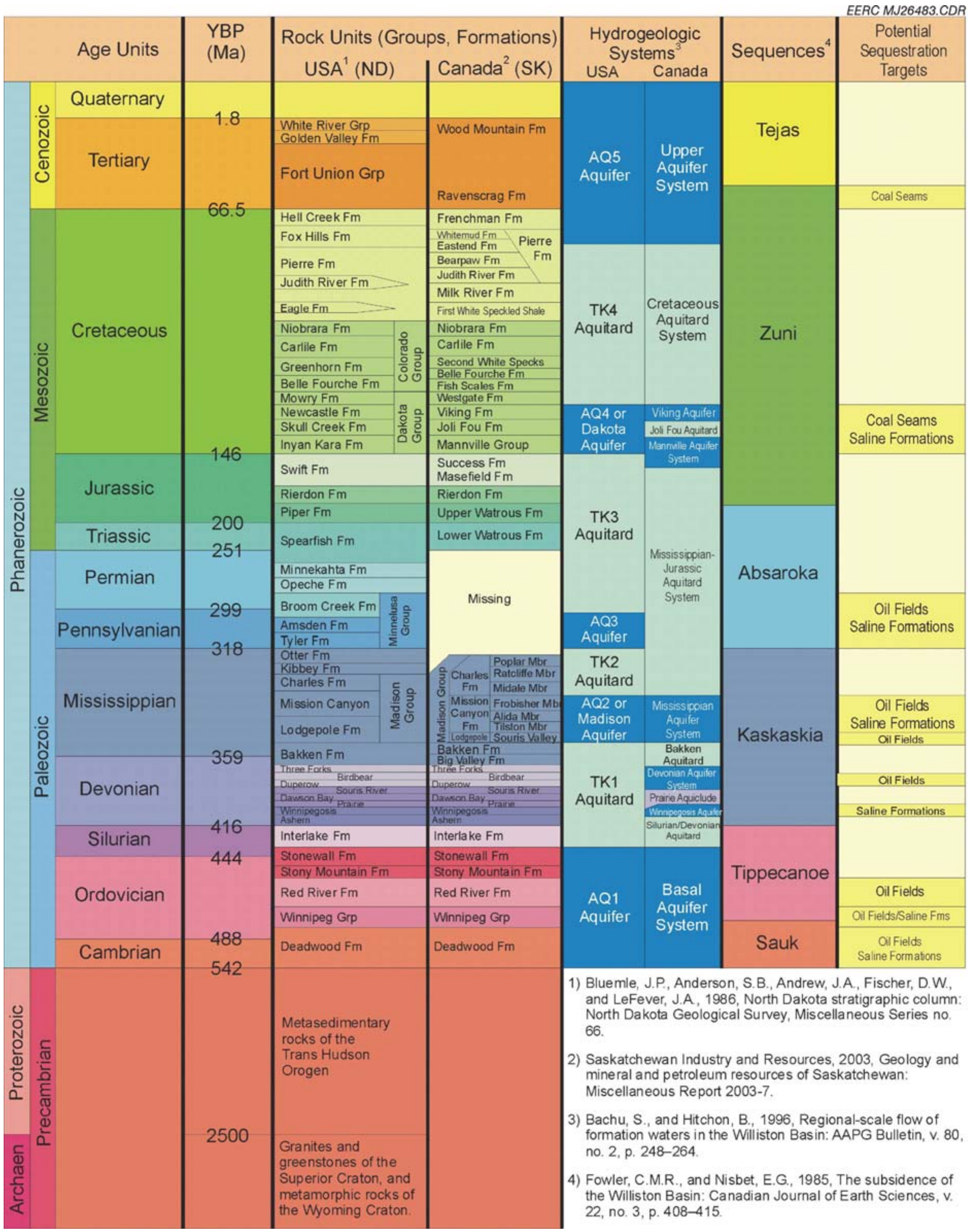

Figure 17. Stratigraphic column for the Williston Basin showing the relative depths of saline formations and sealing formations that were evaluated as part of PCOR Partnership Phase I regional characterization activities.

Figure 18. Location of injections of CO_2 into saline formations. Red boxes indicate that the project is ongoing, while blue boxes indicate planned future injections (Intergovernmental Panel on Climate Change, 2005).

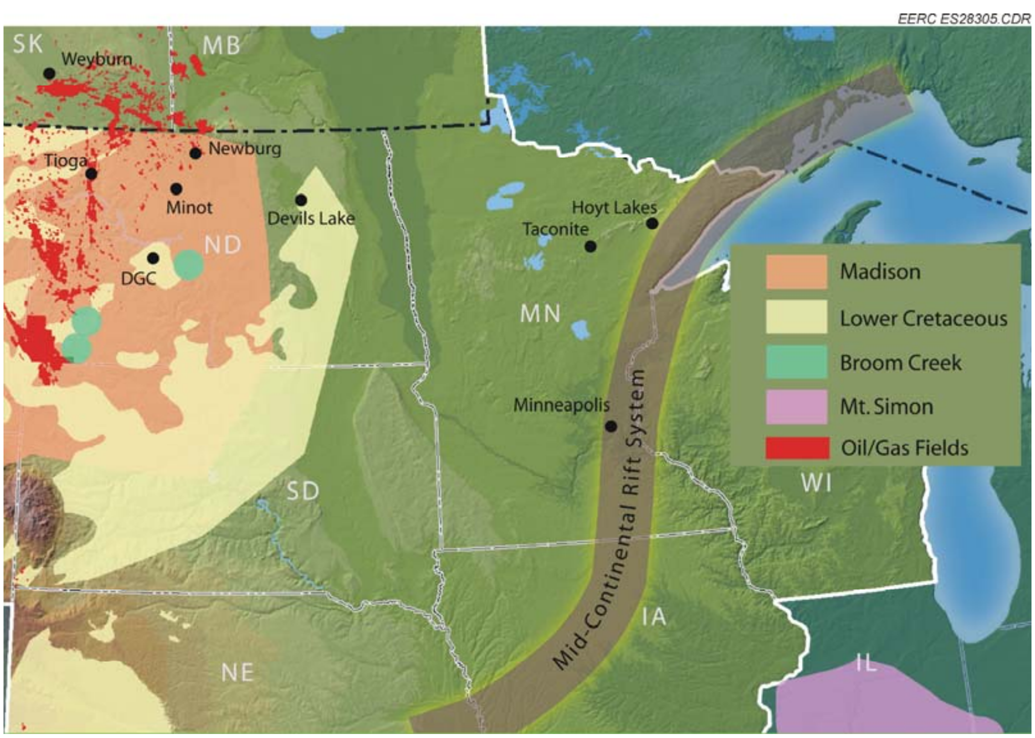

Figure 19. The Mississipian Madison and Lower Cretaceous Aquifer Systems.

Dinwiddie, 1988; Downey et al., 1987). The unique lateral extent of these saline formation systems, the current understanding of their storage potential gained through produced fluid disposal, and the geographic proximity to major CO_2 sources suggest that they may be suitable sinks for future storage needs. A third saline formation in the Williston Basin, the Broom Creek Formation, was also evaluated in a more detailed, site-specific manner at three locations in western North Dakota. The estimates of theoretical maximum capacity of each of these formations in the Williston Basin, which resulted from the PCOR Partnership Phase I activities, are presented in Table 8. It is important to note that these values should be considered for reconnaissance purposes only. While large-scale injection of CO_2 into saline formations is being conducted at a few locations in the world, it should be stressed that the technology is still in the early stages of development, effectiveness is dependent on a wide variety of very site-specific factors, and a significant amount of detailed site-specific characterization and predictive modeling must be done before reasonably accurate estimations of sink capacity can be made for any given location.

Of the three formations that have been evaluated in detail by the PCOR Partnership to date, the sandstones of the Dakota Group of the Lower Cretaceous system are in the closest proximity to the proposed Mesaba Energy Project sites. Specifically, a portion of the Dakota Group that underlies the Devils Lake region of eastern North Dakota is located about 280 to 350 miles west of the proposed locations near the West Range and East Range sites, respectively. However, although they are farther away, the saline formations of the Madison Group and the Broom Creek Formation appear to have greater storage capacities than those of the Dakota Group. More detailed evaluation of the easternmost portions of the Madison and Broom Creek saline formations may be considered if larger sink capacity is determined to be necessary.

The estimation of CO_2 sequestration capacities for the saline formations of the Lower Cretaceous System and the Madison Group have thus far only been conducted on a regional, or basinwide, scale. Therefore, estimated capacities for specific areas of these saline formations (such as the Lower Cretaceous rocks underlying the Devils Lake area) are not currently available. As was done with the Broom Creek Formation for three locations in western North Dakota, more detailed estimates of CO_2 capacity and injectivity may be developed for specific saline formation locations in eastern North Dakota that may be of interest to Excelsior Energy as sequestration sinks.

Table 8. Estimated Theoretical Maximum Capacities of Saline Formations in the Williston Basin Evaluated as Part of PCOR Partnership Phase I Regional Characterization Activities

Saline Formation/Group	Approximate CO_2 Sequestration Capacity in the Williston Basin
Dakota Group (Lower Cretaceous)	20 billion tons
Madison Group	50 billion tons
Broom Creek Formation	100 billion tons

The PCOR Partnership region includes many other areas besides the Williston Basin that are underlain by thick sequences of sedimentary rock. With respect to proximity to the proposed Mesaba sites, geological features in northern Minnesota, particularly the Lake Superior region, may hold some potential for the sequestration of CO_2. At this time, these features have not been systematically evaluated with respect to CO_2 sequestration potential. Neither the technical feasibility nor the potential storage capacity has been examined for any of the features.

The Midcontinent Rift Zone

The Midcontinent Rift Zone is an ancient rift zone (over 1 billion years old) that stretches from eastern Nebraska across central Iowa and south-central Minnesota to the western portion of Lake Superior (Figure 20) (Iowa Geological Survey, 2006; Van Schmus and Hinze, 1985). The Midcontinent Rift Zone includes thick (up to 8 km) sequences of sedimentary rock and volcanic basalts, some of which may be viable locations for CO_2 sequestration. Unfortunately, efforts to

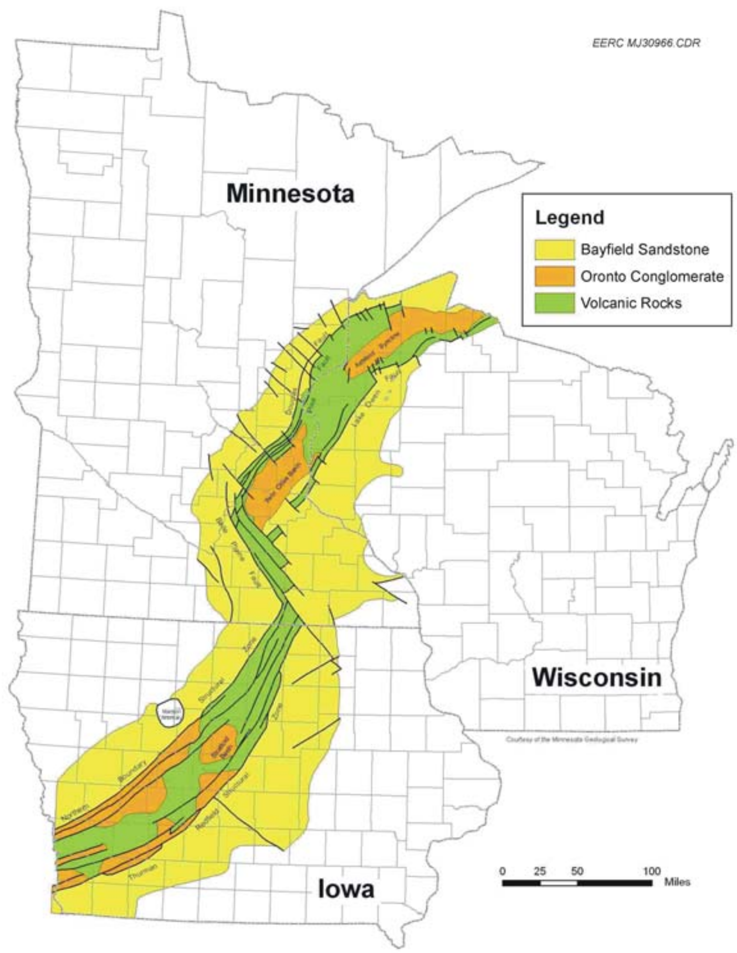

Figure 20. The Midcontinent Rift Zone in Minnesota, Iowa, and Wisconsin. The black lines in the zone indicate the locations of known faults. These faults may act as leakage pathways for injected CO_2 (map courtesy of the Minnesota Geological Survey).

evaluate the porosity and permeability of these rocks, determine the existence of competent overlying seals, and estimate the potential capacity for the Midcontinent Rift Zone to sequester CO_2 have been hindered by a severe lack of data on the characteristics of the deep subsurface in that area. Because oil and gas have never been discovered in the Midcontinent Rift Zone, very few deep wells have been drilled in the area; therefore, little is known about the characteristics of these rocks. Continued regional characterization activities being conducted under Phase II of the PCOR Partnership will result in a better understanding of the potential for the sedimentary rocks of the Midcontinent Rift Zone to sequester large volumes of CO_2.

The Duluth Complex

The Duluth Complex, shown in Figure 21, is a geological feature in the North Shore region of Minnesota that comprises massive occurrences of intrusive igneous rocks (granites, gabbros, anorthosites) (Minnesota Geological Survey, 2007). Many of these rocks are high in magnesium and iron (i.e., "mafic"), which under certain conditions can chemically react with CO_2 to form stable carbonate minerals, thereby resulting in permanent sequestration. This form of CO_2 sequestration is commonly referred to in the literature as "mineralization." Experimental research

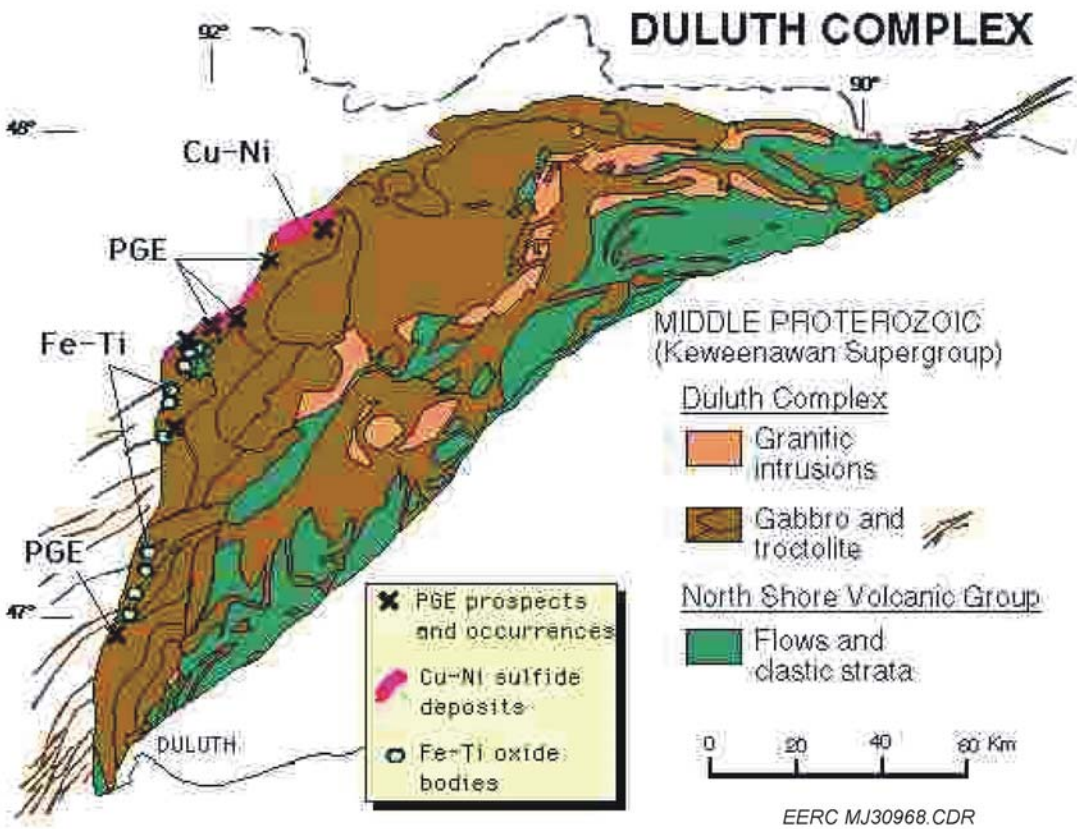

Figure 21. Map of rock formations in the Duluth Complex, northern Minnesota (courtesy of the Minnesota Geological Survey, 2007).

conducted on similar mafic rocks from eastern Canada demonstrates the technical feasibility of the mineralization process. The process as currently envisioned involves mining and crushing the rock, contacting the crushed rock with supercritical CO_2 (which can then form carbonate minerals such as magnesite, siderite, and rhodochrosite) and, finally, backfilling the mine with the newly formed carbonate minerals. Obviously, such a process would have tremendous economic and environmental challenges. Data from a University of Minnesota study (Zanko et al., 2003) indicate that the mineralogy of the tailings from some of the iron mines in northern Minnesota may be suitable to consider as a feedstock for the mineralization process. Substantial laboratory-, bench-, and pilot-scale research would have to be conducted to determine the economic and technical feasibility of using iron mine tailings for CO_2 sequestration.

Basalts

Both the Midcontinent Rift Zone in Minnesota and the Duluth Complex include significant accumulations of volcanic basalt. The Big Sky Carbon Sequestration Partnership has conducted some evaluations of the potential to sequester CO_2 in basalts in Idaho and Washington. The Big Sky Partnership has focused its research activities on examining the feasibility of injecting CO_2 into basalt aquifers to achieve both dissolution and mineralization of CO_2. Basalts are rich in mafic minerals and hold significant potential to react with supercritical CO_2 to form stable iron and magnesium carbonates, thereby sequestering CO_2 through mineralization. No results of the Big Sky Partnership activities on basalts have been published, and conclusions from presentations that have been given on the subject are only qualitative in nature with respect to the practical sequestration potential of these volcanic rocks. While the physical and chemical properties of some basalts may be conducive to sequestering CO_2 under laboratory conditions, field-based evaluations have not yet been conducted, and statements on the potential ability of basalts to sequester large volumes of CO_2 are largely speculative. With respect to the basalts found in Minnesota, it is also important to note that unlike many basalt formations in the western United States which have up to 15% porosity, the Minnesota basalts are characterized by extremely low to nonexistent porosity and permeability which would preclude any injection-based sequestration scheme.

Site Characterization for Large-Scale Injection into Saline Formations

As mentioned previously, the PCOR Partnership Phase I capacity estimates for saline formations are reconnaissance-level only. These estimates are based on a maximum, best-case scenario approach to the evaluation of saline formation storage and are meant to illustrate the potential order-of-magnitude value of these formations with respect to their ultimate storage. The inherent heterogeneity found in nearly all geologic formations means that detailed subsurface mapping and characterization will likely need to be conducted in any area that is being considered for large-scale injection of CO_2, particularly with respect to seal formations. The saline formation and its overlying sealing formation at any site that is considered as a location for large-scale CO_2 injection operations would have to be thoroughly characterized at local, intermediate, and large scales in the early stages of the planning process. These early characterization activities are necessary to develop accurate predictions with respect to storage capacity and the ultimate fate of CO_2 within the target formation. The data from early characterization also provide the baseline information necessary in order to design and conduct cost-effective monitoring, mitigation, and verification (MMV) strategies.

The costs of baseline characterization will be influenced greatly by site-specific factors, including availability of historical data from previous oil and gas exploration activities and the costs of acquiring new data (i.e., geophysical surveys, drilling rigs for collecting new core), which typically varies from region to region. This makes it difficult to estimate the likely costs of thorough characterization of a location. However, some guidance with respect to the general magnitude of such costs is available in a published case study of the saline formation injection activities at Sleipner in Norway's North Sea. Specifically, it has been estimated that the total characterization costs incurred prior to injection at Sleipner were approximately \$1.9 million. These costs included the gathering of existing data, a series of 3-D seismic surveys, collection and analysis of rock cores, well logging, and reservoir simulation modeling. It is important to note that the Sleipner injection field is in one of the most actively explored and productive oil-producing regions of the world. The availability of preexisting data and cost-effective, state-of-the-art subsurface characterization technologies was likely significant. It is our belief that characterization costs for Williston Basin saline formations may be greater than those reported in the literature for Sleipner. More detailed evaluation of the costs of geological characterization will be determined over the course of the PCOR Partnership geological sequestration demonstration activities. Those costs, which will be more applicable to the characterization of geological sinks for the sequestration of Mesaba CO_2, will be discussed in the carbon management plan final report.

MMV Options and Requirements for Sequestration in Oil Fields and Saline Formations

If carbon sequestration credits are associated with the injection of CO_2 into oil fields or saline formations, then MMV activities will have to be conducted to ensure that the CO_2 is not leaking from its intended geological storage site. Because the application of geologic storage methods for the sequestration of CO_2 has only recently begun to move from the research and development stages into the demonstration stage, there are not currently any MMV activities that are specifically required. However, it is almost certain that MMV plans will be a necessary component of large-scale geologic CO_2 sequestration schemes, including those which include EOR as a component. While a detailed discussion of MMV approaches and technologies is beyond the scope of a CMP, it is worth enumerating some of the data types that have been collected as part of the MMV plans for past and current EOR-based CO_2 sequestration projects. Below is a list of data that were collected during Phase I of the Weyburn Project as well as data that will be collected as part of the PCOR Partnership Phase II Zama Demonstration:

- Weyburn Phase I
  - Reservoir dynamics data (pressure, temperature, formation fluid production rates)
  - Core
  - Well logs
  - Geosphere and biosphere fluid samples (historic and new)
  - Seismic (historic and new)
  - Reservoir modeling (historic and new)

– Aeromagnetic (historic and new)
– Aerial photo interpretation
– Soil gas survey

- PCOR Phase II Zama
  – Reservoir dynamics data (pressure, temperature, formation fluid production rates)
  – Core
  – Well logs
  – Geosphere and biosphere fluid samples (historic and new)
  – Seismic (historic)
  – Reservoir modeling (historic and new)
  – Geomechanical testing of reservoir and seal rocks

RISKS TO GEOLOGIC SEQUESTRATION

Potential Environmental Risks and Mitigation Options

The risks associated with geologic CO_2 sequestration are typically divided into two categories: 1) local environmental impacts, including risks to the environment and human health and safety, and 2) global atmospheric impacts arising from leaks that return stored CO_2 to the atmosphere (Reilkoff et al., 2005).

Local risks may arise from:

- Elevated CO_2 in the shallow subsurface or atmosphere.
- Chemical effects of dissolved CO_2 in subsurface fluids.
- The displacement of fluids by injected CO_2.

Global risks arise from the long- or short-term release of large quantities of CO_2 to the atmosphere, potentially reducing, if not negating altogether, the benefits of CO_2 sequestration. The consequences of CO_2 release to the atmosphere are dependent on the volume of CO_2 released, emission rates, and ambient atmospheric CO_2 concentration at the time of the release.

In situ risks are not well defined or easily understood. To ensure safe and effective long-term storage of CO_2, thorough investigation of the chemical and physical properties of the local geology as well as geochemical, geophysical, and hydrogeological interactions with CO_2 injection is needed. Pathways of migration include direct and indirect losses of CO_2 to the atmosphere from the subsurface through fractures or faults in the confining caprock; natural or induced seismic events; water movement; vegetation; and poorly constructed or sealed injection, monitoring, or production wells. In addition to direct and indirect losses to the atmosphere, transformation within the geological reservoir, including mineralization and demineralization, can occur.

The migration of CO_2 from the storage reservoir to a freshwater aquifer or surface waters poses potential risks to water quality and local biota. The effects of CO_2 on groundwater and surface waters are dependent on the volume of CO_2 released, the time period over which the release occurs, the buffer capacity of the water, and the mixing rate. Accumulation of CO_2 eventually increases the acidity of the water through formation of carbonic acid, leading to impairment of biological function and dissolution and/or mobilization of metals and organic compounds naturally sorbed or precipitated on sediments or aquifer minerals. Heavy metals such as iron, manganese, copper, lead, and arsenic can all be mobilized at low pH. Reaction with alkaline materials such as limestone may lead to increases in soil and groundwater salinity at low-pH conditions.

Catastrophic release from a storage reservoir is highly unlikely and can be mitigated through operational safeguards and monitoring. Migration of CO_2 to overlying groundwater sources would most likely occur along the injection well if it were not properly constructed or through poorly constructed or deteriorating wells that reach the storage reservoir. While proper siting, well construction, and well closure will minimize the risk of CO_2 migration to water supplies, chemical analysis of surface waters and groundwater may be required to identify if leakage from the storage formation has occurred.

Injection-induced displacement of reservoir fluid or gas to overlying freshwater sources also poses concern for water quality and ecological health and safety. Displaced fluids or gases are likely to follow the same migration pathways as CO_2. Again, proper site characterization, construction, operation, and monitoring will limit potential risks.

Geological sequestration of large volumes of CO_2 will be accomplished through the use of injection wells. Injection wells are classified and regulated under the Underground Injection Control (UIC) Program of the federal SDWA of 1974 (U.S. Environmental Protection Agency, 2007). The SDWA is intended to protect subsurface sources of drinking water by regulating drinking water systems and waste disposal in the subsurface. Following the rules and guidelines of the UIC Program will ensure that risks posed to groundwater resources are minimized.

Potential Commercial Risks and Mitigation Options

The capture, processing, transportation, and injection of CO_2 are proven practices with well-known risks and established risk management strategies. The most noted operational risks of CO_2 sequestration deal with pipeline or well failure, covering pinhole-sized leaks, and catastrophic pipeline or well blowouts. Potential hazards of engineered systems can include failures caused by corrosion, vibration, external impact, operator error, inadequate maintenance, or equipment degradation (Vendrig et al., 2003). Engineering controls and specifications for transportation, storage containers, pipelines, and well construction and operation cannot eliminate all risks but can greatly limit the likelihood of catastrophic failures (Reilkoff et al., 2005). It should be noted that oil reservoirs have trapped fluids over geologic periods of time. One can safely assume that essentially 100% of the CO_2 purchased for EOR is ultimately sequestered (Suebsiri et al., 2006).

TERRESTRIAL SEQUESTRATION

Overview of Terrestrial Sequestration

The PCOR Partnership region land surface is dominated by agricultural regions (including croplands and grasslands), forested areas, and wetlands, as shown in Figure 22. Each of these major landforms offers opportunity for terrestrial sequestration. Terrestrial carbon sequestration is the process by which CO_2 from the atmosphere is absorbed by trees, plants, and crops through photosynthesis and is stored as carbon in biomass and soils (U.S. Environmental Protection Agency, 2006). Carbon incorporated into plant biomass is typically stored in tree trunks, branches, plant foliage, stems, roots, and seeds. The amount of carbon stored in aboveground biomass (such as branches and leaves) versus the amount stored in belowground biomass (such as roots) varies considerably between ecosystems.

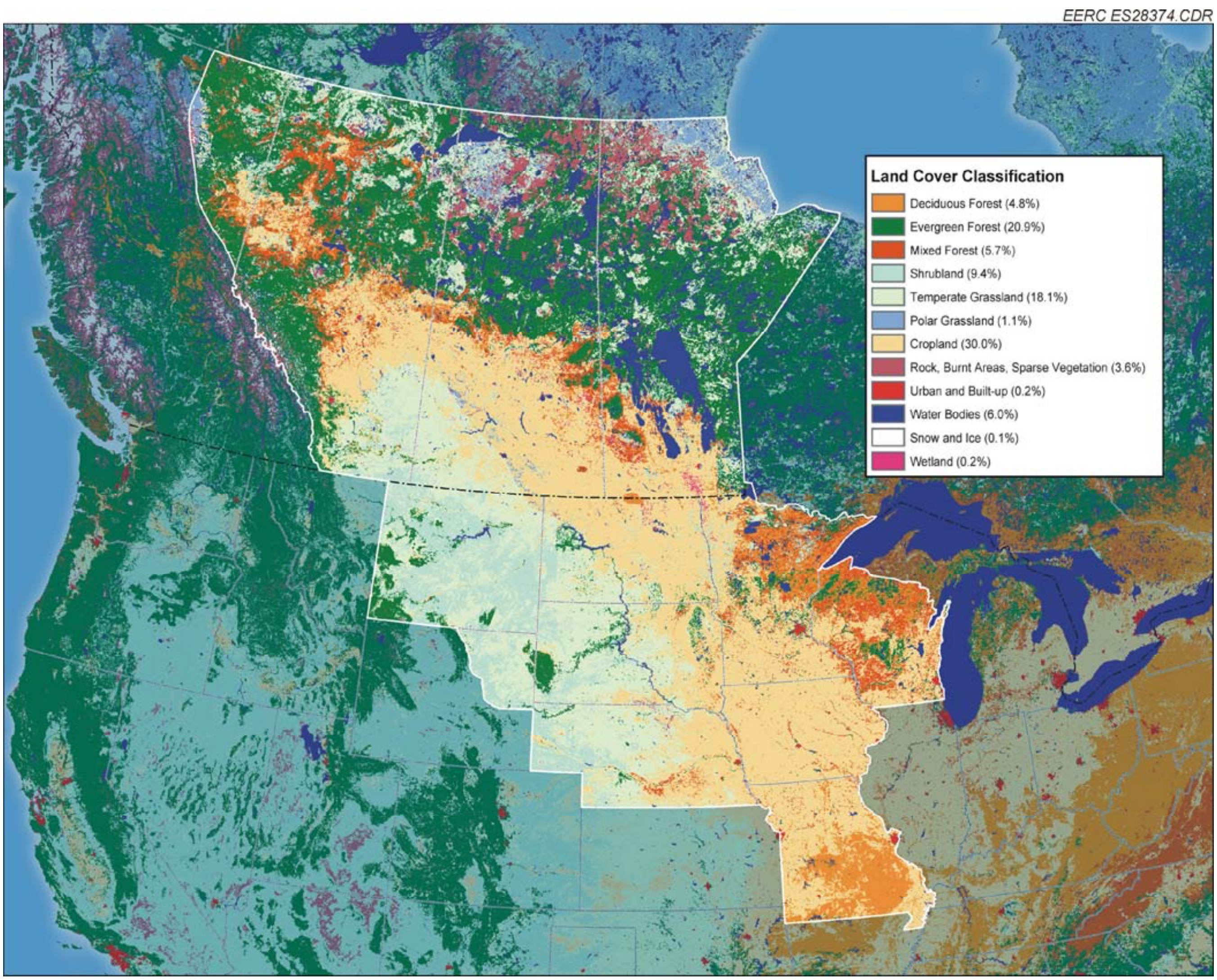

Figure 22. Land cover in the PCOR Partnership region.

Plant biomass adds to soil carbon reserves through detritus (such as fallen leaves and branches) and root mortality. The primary factors that affect the amount of carbon sequestered in soils include soil type, texture, drainage properties, and acidity (Cihacek, 2004). Most soil carbon reenters the atmospheric carbon cycle through microbial decomposition; however, a small portion of the carbon may resist decomposition and remain in the soil in an inert (recalcitrant) form (Farquhar et al., 2001; Amonette et al., 1999). In continuously wet soils with limited oxygen capacity, such as those found in wetlands and areas of poor drainage, an ideal setting is provided for slowing microbial decomposition, resulting in increased carbon stock (Paustian and Cole, 1998). Stored carbon in soils can also be released as CO_2 if soils are tilled and exposed to oxygen in the atmosphere (North Dakota Farmer's Union, 2006).

Land management practices for terrestrial carbon sequestration often focus on the optimization of carbon uptake and long-term storage in soils and in biomass. The most common land use changes and/or management practices that enhance soil carbon storage include (Bangsund et al., 2005, and references therein):

- Reforestation, afforestation, forest conservation, forest enrichment, and urban tree planting.
- Wetland creation or restoration.
- Grassland restoration.
- Implementation of alternative management practices on agricultural land, such as reduced- or no-till farming, contour farming, crop residue management, and precision fertilizer application.

Because natural and/or anthropogenic activities can release portions of the carbon fixed in biomass and soils, only those practices that result in a net increase in carbon storage are considered viable means of carbon sequestration. These land use/land cover types and associated management practices are typically referred to as carbon "sinks."

The length of carbon storage varies significantly between terrestrial sinks. Carbon can be sequestered in agricultural soils for 15 years or more, depending on soil type, climate, and land management practices (U.S. Environmental Protection Agency, 2006). When sequestered in forests, carbon is typically stored over decades or even centuries (U.S. Environmental Protection Agency, 2006). Rerelease of the carbon stored in forests can occur through forest fires, natural decay, or harvesting (U.S. Environmental Protection Agency, 2006); however, implementation of forest management practices designed for carbon sequestration can reduce the amount of carbon release and/or extend carbon storage.

Local Opportunities and Rough Cost Estimates

Based on the Major Land Resource Area designations by the Natural Resources Conservation Service, the majority of land cover/land use in northern Minnesota includes forests, lakes, wetlands, swamps, and bogs and, to a lesser degree, agricultural land. Primary opportunities for terrestrial carbon sequestration include afforestation, reforestation, forest conservation, improved forest management practices, wetland restoration, and implementation of alternative agricultural land management practices, such as no-till farming.

The carbon sequestration rates for various land management alternatives in the PCOR Partnership region are shown in Table 9 (Lewandrowski et al., 2004). As the table shows, conversion of agricultural land to forest sequesters up to three times more carbon than other agricultural techniques. Considering that the majority of land use/land cover in northern Minnesota is forest, afforestation, reforestation, forest conservation, and improved forest management practices are likely to offer the best opportunities for terrestrial carbon sequestration. According to a comprehensive economic evaluation of U.S. forest-based carbon sequestration costs conducted by Stavins and Richards (2005), some of the key factors that affect the cost of forest carbon sequestration include:

- Tree species, forestry practices, and corresponding carbon uptake rates.
- Land opportunity cost (i.e., value of the land for uses other than forestry).
- Potential fate of the biomass, such as burning, harvesting, and forest product sinks.
- Forest and agricultural product prices.
- Analytical methods utilized for carbon accounting.
- Policies that influence carbon sequestration and carbon credit markets.

The costs of terrestrial carbon storage could be offset somewhat through emerging voluntary carbon credit markets, such as the Chicago Climate Exchange (CCX®). The CCX is a voluntary carbon credit certification and trading system for terrestrial carbon sequestration practices within the United States that is discussed in more detail in a later section of this report. Member organizations include corporations such as Ford and Dupont, electric utilities, universities, nongovernmental organizations, cities, farmers, and farm organizations. The CCX handles transactions of carbon credits (historically at prices ranging from $0.91 to $4.54 per ton of CO_2) for carbon sequestration on agricultural land, for forest-based carbon sequestration, for implementation of renewable energy projects, and for methane collection and combustion from landfills and livestock operations. One member, the North Dakota Farmers Union (NDFU), has

Table 9. Carbon Sequestration Rates[a] in the PCOR Partnership Study Region for Selected Changes in Land Use/Management

States	Cropland to Forest	Pasture to Forest	Continuous Crop to Grassland	Continuous Crop to Conservation Tillage
Northern Plains (ND, SD, NE)			0.417	0.148
Mountain (MT, WY)			0.274	0.094
Lake States (WI, MN)	1.467	1.367	0.468	0.165
Corn Belt (IA, MO)	1.034	0.934	0.541	0.187

[a] In tons/acre/yr.

been active in the region and is currently offering carbon credits on the CCX at a price (as of December 2006) of approximately \$3.60 per ton of CO_2 or about \$13.35 per ton of carbon (Minot Daily News, 2006). The carbon credits on the CCX by the NDFU are purchased from farmers at rates ranging from approximately \$2 to \$3 per acre per year, depending on the type of land management or conservation practice the farmer agrees to implement. Whereas this program was previously only available to farmers in North Dakota, it has now been extended into Minnesota (Minot Daily News, 2006).

Potential Impacts of Terrestrial Carbon Sequestration

No matter which terrestrial carbon sequestration practice is employed, additional environmental benefits are likely (Polasky and Liu, 2006; CSITE, 2002; Farquhar et al., 2001). Reduced or no-till farming and grassland restoration improves soil carbon stocks, increases soil moisture, and reduces soil erosion. Restored wetlands may attenuate floodwater, retain sediment, create waterfowl and wildlife habitat, improve water quality, and recharge groundwater (Mitsch and Gosselink, 2000). Afforestation, reforestation, and forest management also help prevent soil erosion, increase infiltration, and create wildlife habitat.

The primary environmental concern regarding terrestrial sequestration is the global risk of large-scale CO_2 release from plant or soil systems subsequent to sequestration. To be an effective means of mitigating elevated levels of atmospheric carbon, terrestrial sequestration must be successful over very long time frames. One obvious threat to sequestration success is forest fires. While suppression, prevention, and management techniques may be employed to limit large-scale burning, forest fires are an integral part of nature's ecosystems and are, therefore, inevitable. Management techniques that encourage small-scale burning or the clearing of dead growth to reduce the fuel available for a fire may limit the amount of CO_2 released during any single event. In addition, harvesting trees in an environmentally sound manner to produce durable wood products may increase long-term carbon sequestration potential.

It is important that management strategies for terrestrial carbon sequestration are planned with the intent of long-term storage and that sequestration activities in one area do not cause deleterious use of land in another. It is important that any changes in land management practices following implementation of sequestration activities do not upset sequestration gains. Given the long-term variability and uncertainty in the agricultural market, realizing long-term benefits of the land management practices adopted today may be challenging. There are currently no standard methods for addressing duration or permanence in sequestration projects. Proposed ideas for addressing this important issue include the use of insurance mechanisms, diversification of projects, issuance of temporary credits, and discounting credits as sequestration efforts change.

Adverse environmental impacts of carbon sequestration practices at the local level may result from field application of chemicals to promote biomass growth. Unintended consequences of fertilizers, herbicides, and pesticides may include nutrient loading in rivers and streams, contamination of surface waters or groundwater, and negative impact on soil health and terrestrial and aquatic ecology. These risks are not only familiar but also largely manageable. It is important that any sequestration plan that requires the use of chemical amendments be carefully managed to prevent or limit any negative impact from their use.

CARBON MARKETS

Current Status of Emerging North American "Markets"

Voluntary Reporting of Greenhouse Gases 1605(b) Program

On April 17, 2006, the U.S. Department of Energy released the final revised guidelines for the Voluntary Reporting of Greenhouse Gases 1605(b) Program. The program provides tools and guidance for companies to strengthen GHG management efforts through high-quality emission inventories and entitywide assessments of emission reductions. Entities can submit detailed annual reports on their emissions and reductions of GHGs. These companies, which include utilities, industries, and other emitters of GHGs that participate, are credited with registered reductions. The guidelines include assistance and tools for estimating emissions associated with agriculture, forestry, and other sectors of the economy and for calculating reductions from geologic sequestration, energy efficiency programs, and other efforts.

Chicago Climate Exchange (CCX)

The Chicago CCX operates a pilot market for trading carbon credits throughout North America. CCX is a voluntary, rules-based, self-regulatory exchange that issues carbon credits for carbon sequestration resulting from continuous no-till, strip-till, or ridge-till cropping; grass plantings; and tree plantings, as well as emission reductions resulting from agricultural methane collection or combustion systems. Issuance of carbon credits is based on storage quantification protocols developed by CCX. While current sequestration-related carbon credits offered on the CCX are limited to terrestrial sequestration, there is hope that there will be an expansion to include geologic sequestration in the future (Chicago Climate Exchange, 2006)

Regional Greenhouse Gas Initiative

The RGGI is the first mandatory U.S. cap-and-trade program for carbon dioxide. RGGI is a cooperative effort by northeast and mid-Atlantic states to develop a regional cap-and-trade program. Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, Massachusetts, Rhode Island, Maryland, and Vermont have agreed to participate in the RGGI cap-and-trade program (Regional Greenhouse Gas Initiative, 2007).

The program will initially be aimed at developing a program to reduce CO_2 emissions from power plants in the current participating states in a cost-effective manner. The RGGI goal is to set a cap on power plant emissions at current levels (approximately 120 million tons of CO_2) between 2009 and 2015. Once the initial cap-and-trade program for power plants is put into operation, further options for expanding the program to other kinds of sources will be examined (Regional Greenhouse Gas Initiative, 2007).

The Climate Registry

The Climate Registry was incorporated in Washington, D.C., in March 2007. As of November 7, 2007, 39 U.S. states, four Canadian provinces, four Native American Tribes, and one Mexican state have become members (The Climate Registry, 2007). The Climate Registry intends to establish standardized best practices in GHG emission data reporting and management, establish a set of common protocols, and support a common reporting system.

Blue Source, LLC

Blue Source, LLC is developing GHG emission offsets and physical CO_2 capture and sequestration projects. Blue Source, LLC was founded in 2001 to identify, create, acquire, aggregate, and market GHG emission reduction benefits created from various sources and types of suppliers, and then commingle such benefits in order to enhance value for their clients (Blue Source, 2007).

Factors That May Influence the Future of North American Carbon-Trading Markets

No federal regulations are currently set to be implemented that may affect the use of CO_2 for sequestration. However, several proposed government actions could potentially affect CO_2 emissions, including:

- Massachusetts et al. versus EPA (www.supremecourtus.gov/docket/05-1120.htm)
- Western Climate Initiative (www.westernclimateinitiative.org/Index.cfm)
- Midwestern Regional Greenhouse Gas Reduction Accord (www.jsonline.com/story/index.aspx?id=686485)
- California Global Warming Solutions Act of 2006 (www.environmentcalifornia.org/global-warming)
- RGGI (www.rggi.org)
- The Climate Registry (www.theclimateregistry.org)

While this list is not all-inclusive, it provides some guidance as to the variety of entities looking at the status of CO_2.

Foreign Markets (European Union emission-trading scheme) (United Kingdom Department for Environment, Food and Rural Affairs, 2006)

In January 2005, the European Union Emission Trading Scheme (EU ETS) began its operation as the first international trading system for CO_2 emissions in the world. The scheme was developed by all 25 members of the EU as a policy to combat climate change in a cost-effective manner in conjunction with the Kyoto Protocol.

Currency within the ETS is defined as the trading of allowances (or CO_2). One allowance gives the holder the right to emit one tonne of CO_2. The scheme is divided into phases, and under each phase, participating countries must proposes a National Allocation Plan (NAP). The NAP must be approved by the European Commission and determines how many emission allowances each installation (company) covered by the scheme in member states can receive. At the end of each year, installations are required to verify they have enough allowances to account for their actual emissions. They are able to buy additional allowances if necessary or sell any excess allowances that may be generated.

Carbon dioxide is the only GHG covered in the first phase (2005–2007) of the scheme. Other GHGs could be covered in the second phase (2008–2012) if member states choose to add additional gases or activities. Phase II will coincide with the first Kyoto Commitment Period and will obligate the EU to make an 8% reduction in emissions from that of 1990 levels.

CONCLUSIONS

This document summarizes the salient points with respect to the development of a carbon management plan for the proposed Excelsior Energy IGCC facilities in northern Minnesota.

There are ample opportunities for carbon sequestration as a means of offsetting CO_2 emissions from the proposed facilities. Both geologic and terrestrial sequestration options are available. The final decisions with respect to carbon management will be made in the context of the carbon emission regulatory environment and the state of the carbon-trading options available at the time. Both the regulatory and trading environments with respect to carbon management are extremely dynamic, and it is difficult to predict their eventual form and function. One can expect that these issues will become much more defined and stable over the course of the next 5 years.

With respect to geologic sequestration, there is considerable demand for CO_2 for EOR and capacity for sequestration in the Williston Basin, although the costs associated with CO_2 capture and compression are likely to be significant. The Williston Basin opportunities are located at least 400 miles from the proposed plant sites, making pipeline construction an expensive proposition. EOR offers the possibility of economic recovery for at least a portion of the separation, capture, compression, and transportation costs since there are willing customers for the CO_2. In a CO_2-managed future, regional pipelines may be developed to transport CO_2, which would lessen the costs and logistical challenges associated with moving the CO_2 long distances.

The purchase of terrestrial-based carbon offsets is also a possibility, and the CCX and other entities have developed fledgling trading platforms for just this purpose. Terrestrial offsets have the added attraction of ancillary ecological benefits, and projects may be based in Minnesota forests, wetlands, or agricultural areas to make this option attractive from a public relations and political perspective.

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APPENDIX A

CALCULATIONAL METHODS USED TO DETERMINE CO_2 SEQUESTRATION CAPACITY OF GEOLOGIC FORMATIONS

CALCULATIONAL METHODS USED TO DETERMINE CO_2 SEQUESTRATION CAPACITY OF GEOLOGIC FORMATIONS

METHODS USED TO DETERMINE CO_2 SEQUESTRATION CAPACITY THROUGH EOR

Data for North Dakota unitized oil pools were acquired from the North Dakota Industrial Commission's (NDIC's) Web site (North Dakota Industrial Commission, 2006). All units considered are at least in secondary recovery phase (water injection). The specific pools were selected through a joint meeting between the Energy & Environmental Research Center (EERC) and the North Dakota Oil and Gas Division and the North Dakota Geological Survey (NDGS) (two NDIC agencies) as being good candidates for CO_2 enhanced oil recovery (EOR). NDGS has been assessing all aspects of the CO_2 sequestration problem as a research provider for the International Energy Agency's (IEA's) Weyburn CO_2 Monitoring and Storage Project (Burke, 2003), including CO_2 injection for EOR to enhance production in the Williston Basin (Burke and Nelms, 2004), which has been the emphasis of the Oil and Gas Division. Historically, this technique has been engineered to reduce the amount of CO_2 needed for injection while maximizing incremental oil production. The objective of the method employed herein is to maximize the volume of sequestration CO_2. This will be done using the knowledge gained from past and present CO_2 studies coupled with production and injection histories. The following list of reservoir and fluid properties was suggested by Bachu et al. (2004) and provides a simple guideline for screening reservoirs for CO_2 EOR:

- Oil gravity between 27° and 48° API
- Temperature between 90° and 250°F (32°and 121°C)
- Reservoir pressure greater than 1100 psi (77.3 kg/cm^2)
- Pressure greater by at least 200 psi (14 kg/cm^2) than the minimum miscibility pressure (1450–2175 psi [102–153 kg/cm^2])
- Oil saturation greater than 25%

This study considers these properties as well as the overall production history of the field, secondary recovery performance, depth to production, rock properties, and characteristics of the produced fluid. For example, the average temperatures and pressures across the Williston Basin will exceed these suggested values. For North Dakota, average reservoir temperature and pressure were found to be greater than 200°F (93°C) and 4000 psi (281 kg/cm^2), respectively.

In determining the sequestration capacity for the unitized pools, some assumptions were made. The first major assumption was to simplify the process for projecting the oil recovery potential from injection of CO_2. Shaw and Bachu (2002) noted that the oil production increase could be anticipated to be between 7% and 23% of the original oil in place (OOIP) through successful miscible flooding techniques, while Nelms and Burke (2004) suggest a value of 7% to 11%. The spreadsheet used herein uses an average value of 12% recovery of the OOIP. Next, the quantity of CO_2 necessary to recover incremental oil was needed. Nelms and Burke (2004) discuss the quantity of CO_2 required for EOR. The purchase requirement they used was 13 thousand cubic feet (13 Mcf) per barrel of oil recovered. Of this purchase quantity, about 3 to 5 Mcf per barrel (bbl) of oil will be recovered at the surface and reinjected after separation. This evaluation uses 8 Mcf per bbl incremental oil recovered. The total quantity of CO_2 injected for tertiary recovery should be the amount left in the reservoir for long-term storage. Postproduction treatment of the reservoir, such as blowdown, must be evaluated to determine the effect on the fate of CO_2 storage.

The calculation of CO_2 sequestration capacity was performed as follows:

$$Q = OOIP \times 0.1 \times 8000$$

Where: $Q = CO_2$ remaining in the reservoir after flooding process is complete, ft^3
OOIP = original oil in place, bbl
0.12 = fraction of estimated recovery of oil from CO_2 flood
8000 = CO_2 purchase requirement to produce 1 bbl of oil from CO_2 flooding, ft^3/bbl

METHODS USED FOR GEOLOGIC SEQUESTRATION CAPACITY IN CURRENTLY ABANDONED OR DEPLETED OIL FIELDS

Using the same production criterion of 800 MBO (cumulative field production) that was used on the EOR pools, a detailed spreadsheet of geologic and fluid characteristics was developed for North Dakota.

Data for this spreadsheet were compiled from a number of sources, including Web-based data sets and data collection at state (Burke and Nelms, 2004; www.state.nd.us/ndgs) and federal agencies. Each pool in a field appears as a unique entry in the database; some of these include unitized fields. This same procedure was used for pools in the Williston Basin region for which data were available prior to the writing of this paper. In calculating the sequestration capacity, the following criteria were used:

- Field surface area
- Average pay thickness
- Average porosity
- Reservoir temperature
- Initial reservoir pressure

Field area, thickness, and porosity were used to determine the pore volume of the producing reservoir. Reservoir temperature and pressure were used to determine the density of CO_2 at reservoir conditions. These temperature and pressure values were used to determine reservoir suitability for miscible flooding. Because there is significant variability in temperature and pressure throughout the oil-producing formations in North Dakota, the resulting sequestration values were considered as general reconnaissance values.

The calculation of sequestration capacity was performed according to the following equation:

$$Q = A \times T \times \Phi \times \rho_{CO2} \times (1 - S_w)$$

Where: Q = storage capacity of the oil reservoir, lb CO_2
A = field area, ft^2
T = producing interval thickness, ft
Φ = average reservoir porosity, fraction of reservoir
ρ_{CO2} = density of CO_2, lb/ft^3
$(1 - S_w)$ = saturation of oil, where S_w is the fraction of the reservoir initially saturated with water

This calculation yields the maximum storage capacity of an oil-bearing reservoir in pounds (lb) of CO_2.

The major assumption made for these fields was that all of the fluid in the reservoir would be replaced with CO_2, effectively giving the maximum sequestration volume. While actual sequestration volumes will be significantly less, this means of developing approximate sequestration volumes has been used in prior studies (Bradshaw et al., 2004). With further study, a more detailed understanding of the exact sequestration capacity of the basin can be accomplished.

METHODOLOGY FOR RECONNAISSANCE-LEVEL ESTIMATES OF SALINE FORMATION CO_2 SEQUESTRATION CAPACITIES

To calculate storage potentials for the evaluated aquifer systems, a model was developed to produce a continuous gridded surface representing the volume of CO_2 that could be sequestered per square meter. In general, the model is based on existing, publicly available data relating to hydrological studies of regional aquifer systems, oil, gas, water well data, and existing GIS (geographic information system) map data. Because the Lower Cretaceous System is used for potable water in some areas of the Plains CO_2 Reduction Partnership region, the portions of that regional aquifer system where the water salinity was low enough to be considered by the U.S. Environmental Protection Agency to have the potential for beneficial use (i.e., containing total dissolved solids <10,000 mg/L) were removed from the final evaluation. The depth and salinity of the waters within the Madison Group and the Broom Creek Formation are generally great enough to exclude them as being potential potable resources, so a greater percentage of their total areas is available for CO_2 injection.

The calculation used to estimate the theoretical maximum sequestration capacity of the evaluated saline formations is a straightforward estimate that relates the pore volume in the reservoir as the product of area, thickness, and porosity and the solubility of CO_2 in the reservoir water at spatially varying pressures and temperatures. Salinity is a key factor when considering the solubility of CO_2 and the state at which it will exist in the reservoir; the correlation between formation water salt content and solution phase storage is clearly evident. Depth to the top of the formation was also considered, and storage was only considered viable where the formation was deeper than 2500 ft. The calculation used is shown below:

$$Q = 7758 \times A \times T \times \Phi \times CO_{2s}$$

Where: $Q = CO_2$ remaining in the aquifer after injection, ft^3
$7758 = (43{,}560\ ft^2/acre) \times (0.1781\ bbl/ft^3)$
A = Area, acres
T = Producing interval thickness, ft
Φ = Average reservoir porosity, fraction of reservoir
CO_{2s} = Solubility of CO_2, ft^3/bbl

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