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Mesaba Energy Project Partial Carbon Dioxide Capture Case

Prepared for Excelsior Energy

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1. Introduction

Excelsior Energy, Inc. (Excelsior) is a Minnesota company developing the Mesaba Energy Project, an Integrated Gasification Combined Cycle (IGCC) baseload electric power generating facility, which will be located on Minnesota's Iron Range. Mesaba Energy Project Unit I will be a nominal 600 MW plant that utilizes ConocoPhillips E-Gas technology. Fluor Enterprises, Inc. (Fluor) has been selected to provide project feasibility, plant engineering, and environmental services for the project.

Excelsior has requested that Fluor provide an overview of a partial carbon capture system that could be retrofitted to the IGCC unit. The analysis presented in this report is based on western subbituminous Powder River Basin (PRB) coal fuel from the Rawhide Mine with a higher heating value of 8300 btu/lb (as received) and an ambient temperature of 38°F.

This report provides a process description of the carbon capture scheme and presents estimates of the cost and performance impact of the retrofit. A comparison of the cost and performance of a 600 MW IGCC Plant and a 600 MW SCPC plant with 30% carbon capture is also provided.

2. Process Description

In the base case, with no carbon capture, the raw synthesis gas (syngas) leaving the E-Gas™ Gasification Unit is cooled and treated with amine in the Acid Gas Removal Unit. The acid gas removed is sent to the Sulfur Recovery Unit where sulfur compounds are converted to elemental sulfur. The tail gas from the Sulfur Recovery Unit, including any carbon dioxide removed in the Acid Gas Removal Unit, is recycled back to the process so no carbon is captured other than a small quantity of unconverted carbon contained in the slag leaving the gasifiers (estimated at 20 short tons per day carbon). The total carbon contained in the Rawhide coal fuel is estimated at 4000 short tons per day. The clean syngas leaving the Acid Gas Removal Unit, a mixture of carbon dioxide, carbon monoxide, hydrogen, and water, is treated in the Mercury Removal Unit, moisturized, and then fired in the Siemens SGT6-5000F combustion turbines.

In the partial carbon capture case, the physical configuration and sizing of the existing IGCC plant is not modified except that a new unit is inserted downstream of the Mercury Removal Unit. The syngas is not "shifted" so carbon present in the syngas as carbon monoxide cannot be captured.

In the Carbon Capture Unit, a proprietary formulated amine is used to remove carbon dioxide from the clean syngas. The configuration of the process is similar to conventional amine unit except that **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]**, which lowers the energy penalty of the system. A number of commercially-proven formulated amines would be suitable for this process.

A process sketch of the Carbon Capture Unit is presented in Figure 1.

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Figure 1: Carbon Capture Unit Process Sketch

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It is estimated that 1200 short tons per day of carbon, or 30% of the carbon contained in the fuel, can be removed in the Carbon Capture Unit (as carbon dioxide). The carbon dioxide leaving the amine regenerator is dehydrated and compressed to 2000 psig at which point it is a supercritical fluid suitable for transportation by pipeline. The power required for carbon dioxide compression is estimated at 20 MW.

As carbon dioxide has been removed from the syngas fired to the combustion turbines, the lost mass must be replaced by an alternative diluent in order to maintain adequate NO_X control. Additional steam is added to the synthesis gas for this purpose, which lowers the steam turbine generator output by an estimated 14 MW.

3. Plant Performance Impact

It is estimated that the net output of the plant will decrease by 35 MW if the Carbon Capture Unit is implemented. 20 MW of this loss is attributed to carbon dioxide compression, 14 MW to the use of steam as replacement diluent, and 1 MW to the amine unit and auxiliary systems.

As the fuel consumed by the IGCC plant remains unchanged, the reduction in net output raises the net heat rate. The estimated impact is 580 btu/kWh.

4. Plant Cost Impact

The impact of the Carbon Capture Unit on the EPC cost is estimated at $42 million on an overnight 3rd quarter 2005 basis. This is a rough order of magnitude estimate. When combined with the lower net plant output, the net impact on the per-kW EPC cost is $200/kW.

The estimate includes the carbon dioxide compression system but not the pipeline outside of the battery limits. The estimate is for the typical scope of a facility supplied under a lump sum turnkey EPC contract and exclude those costs typically borne by the owner and operator such as permitting, land, owner's staff and support, operations staff during commissioning and performance testing, start-up fuel, initial fills of catalysts and chemicals, capital spares, owner's insurance, sales tax, and owner's contingency.

5. O&M Cost Impact

A rough order of magnitude estimate for the incremental direct O&M cost is $1.5 million per year. This estimate includes operating labor, maintenance, and solvent make-up costs. Property taxes and insurance are excluded.

6. Comparison to Supercritical Pulverized Coal Plant

The December 2005 report "Independent Analysis of Generation Technologies for a 600 MW Coal-Fired Power Plant in Minnesota" prepared by Fluor for Excelsior compares the cost and performance of the Mesaba Energy Project Unit I with a hypothetical 600 MW grassroots Supercritical Pulverized Coal (SCPC) plant located near Monticello, Minnesota. This table extends that analysis to evaluate both technologies with 30% carbon capture.

The uncontrolled carbon dioxide emissions from the SCPC and IGCC plants will be similar as the estimated heat rates for the two technologies are close.

It is widely accepted that it is less costly to capture and sequester carbon dioxide from an IGCC plant than from an SCPC plant. This is because the carbon dioxide can be removed from the syngas prior to combustion (pre-combustion capture). With a SCPC plant, carbon dioxide can only be captured from the flue gas (post-combustion capture). Syngas is at a much higher pressure than flue gas and the carbon dioxide is more concentrated due to the absence of nitrogen that accompanies combustion air.

For the SCPC case, a proprietary flue gas treating process, such as the Fluor Econamine FG[SM] Plus Process, is installed downstream of all other flue gas treatment systems. Carbon dioxide is recovered at low pressure and must be dehydrated and compressed to meet pipeline specifications.

In both cases, the carbon capture facilities can be retrofitted to the base plants and minimal pre-investment would be required if an uncontrolled plant were to be built initially.

The results of this evaluation are presented in Table 1.

Table 1: Impact of 30% Carbon Capture on Plant Cost and Performance

		SCPC	**IGCC**
Output Penalty	MW (net)	55	35
Adjusted Net Output	MW (net)	545	565
Heat Rate Penalty	btu/kWh (HHV)	950	580
Adjusted Net Heat Rate	btu/kWh (HHV)	10400	9970
EPC Cost Penalty	$ (Q3 2005)	138 million	42 million
EPC Cost Penalty	$/kW (Q3 2005)	440	200
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Adjusted EPC Cost	$/kW (Q3 2005)		
		TRADE SECRET DATA ENDS]	

The EPC costs are on the same basis as outlined in the original report.

Table 1 clearly shows that, with 30% carbon capture, the cost and performance of the IGCC plant, with higher output, lower heat rate, and lower EPC cost, is superior to that of the SCPC plant.