ABSTRACT

This project was a cooperative effort between the US Department of Energy, the Illinois Clean Coal Institute and the Ohio Coal Development Office with the objective of developing a preliminary evaluation of the feasibility of using gasified coal as an industrial fuel source. The project sought to work with the large energy consuming industries in the states of Ohio and Illinois in an effort to document the parameters involved in their energy consumption. Industrial energy consumption information was then to be used to identify “Industry Clusters” – groups of companies having consumption patterns, both in terms of overall demand and demand variation that might support the installation of a coal gasifier in an “energy park” that would provide the energy-related products required by these facilities.

The project identified four potential clusters in Ohio and one in Illinois. A study by the Gas Technology Institute suggests that a co-generation facility producing electricity and synthetic natural gas could be economically viable in the identified clusters under a reasonable set of assumptions covering the anticipated capital cost, future electric and natural gas pricing and anticipated rate of return on capital. The proposed facility would be “carbon capture ready” in that the equipment to capture and pressurize carbon dioxide has been included in the estimate.
EXECUTIVE SUMMARY

Manufacturing is a major basis of the economies of Ohio and Illinois. A significant portion of manufacturing activity in these states are found in the industry groups that were the focus of the US Department of Energy’s “Industries of the Future” program – Aluminum, Chemicals, Forest Products, Glass, Metal Casting, Mining, Petroleum Refining and Steel. Companies in these sectors have found themselves under tremendous competitive pressures as a result of the rising cost of energy whether it be electricity, natural gas (NG), or other chemical items, such as hydrogen, methanol, ammonia, etc. that have traditionally employed either petroleum or natural gas as a feed stock in their manufacture. For example, from 2001 through 2007, manufacturers in Ohio and Illinois have had to deal with natural gas costs averaging approximately 40% higher than the national average in Ohio and 20% higher in Illinois according to figures from the Energy Information Administration of the US Department of Energy (US DOE).

In the overview, coal gasification and post gasification processes seem to be ideal technologies to provide future energy needs in these states at prices that may be competitive with traditional energy sources. These technologies are well established and industrially-hardened with a long history of development and use. However, these technologies also tend to be very capital intensive with economically viable capacities far too large for most individual industrial applications. The current project is based on the belief that by identifying appropriate groups of industrial facilities that in the aggregate have sufficient demand to support the installation of one or more coal gasification units is a critical step in laying the groundwork for coal gasification facilities to serve the industrial sector. The project involved three components:

- definition of industrial needs and “industry clusters”
- technology “matching” of gasifier technology and post-gasifier processing
- preliminary engineering estimates of capital and operating costs.

The intent of the program was to develop an understanding of the overall needs and periodic use patterns of “energy products” at manufacturers in Ohio and Illinois. A questionnaire was developed which included typical energy sources like electricity, natural gas, fuel oil, in addition to other gases and chemical species that might be easily produced in a gasification facility - such as nitrogen, argon, carbon dioxide, etc. (by-products of oxygen production in an air separation unit); coal tar products (by-products of fixed bed gasification); sulfur; and other chemicals that can be produced from syngas such as ammonia, methanol, hydrogen, etc. However, the goal of developing data on various types of energy products and temporal variations in energy use proved too ambitious and yielded data primarily related to electricity and natural gas consumption.

Data on industrial energy consumption for electricity and natural gas was obtained from the questionnaire and a number of sources and used to construct potential industry clusters for each state. Four potential clusters were identified in Ohio centered in Stark, Perry, Seneca and Greene Counties. A single cluster was identified in Illinois centered in Kane County and covering the 15 counties in the northeast part of that state.
The Gas Technology Institute (GTI) conducted a study to determine the economic viability of a gasification facility designed to co-generate electricity and natural gas and serve the energy needs of companies in these clusters. This study highlights the need to co-generate electricity and synthetic natural gas in any proposed facility in order to be economically viable and the dependence of the facilities economics on the relative pricing levels between these two energy products. Their conclusions suggest that a $900 MM carbon-capture-ready facility processing ~ 5350 metric tons of Ohio or Illinois coal per day could be viable assuming coal prices of $35/ton; electric prices of 8 cents/kWh; and natural gas prices in the $4.50 to $5.00/MM Btu range. The economics could become even more attractive by identifying additional markets for potential by-products of the gasification process most particularly the use of captured CO₂ for enhanced oil recovery.
OBJECTIVES

The objective of the program was to build a basis for a coal-based energy resource for manufacturers in Ohio and Illinois that could provide energy stability and increased competitiveness in world markets. The project developed methods of identifying viable clusters of industrial companies as either stand alone users, cluster anchors or cluster members, with sufficient aggregate demand to support the construction of an industrial gasification park based on local coal resources. These parks were envisioned to be “polygeneration facilities” consisting of units that could produce electricity, synthetic natural gas (methane), industrial syngas, Fischer-Tropsch liquids, etc. as needed by the cluster participants. The project involved:

- developing the data to define industrial needs and “industry clusters”,
- matching gasifier and post-gasifier technologies to these needs,
- preliminary estimates of capital and operating costs and overall economic viability.

INTRODUCTION AND BACKGROUND

Many of the companies in the industry groups that were the focus of DOE’s “Industries of the Future” program (Aluminum, Chemicals, Forest Products, Glass, Metal Casting, Mining, Petroleum Refining and Steel) have found themselves under tremendous competitive pressures as a result of the rising cost of energy whether it be electricity, natural gas (NG), or other chemical items, such as hydrogen, methanol, ammonia, etc. that have traditionally employed either petroleum or natural gas as a feed stock in their manufacture.

Manufacturers in these industry sectors form a significant portion of the manufacturing economy in Ohio and Illinois and have been particularly hard hit in the past with natural gas costs averaging approximately 40% higher than the national average in Ohio and 20% higher in Illinois as shown in Figure 1.

While long term supply contracts and volume utility pricing practices modifies the impact of these historical cost figures, the figures represent a disturbing trend that could affect the viability of large, energy-consuming manufacturers in these states.
In the overview, coal gasification seems to be an ideal technology to provide future energy needs. It has been estimated that the United States has over 240 years of proven coal reserves at current usage rates. Coal gasification is a proven, industrially-hardened technology capable of generating electric power as well as synthesis gas (commonly called syngas). Syngas can be used directly as a fuel or it can be manipulated through a variety of well-known, well-established, industrially-proven catalytic processes to produce a myriad of products that can help alleviate energy related cost and supply pressures. These include gaseous products such as fuel gas and synthetic natural gas (SNG or methane); ammonia, a main constituent of fertilizers; and hydrogen. Liquid products can also be produced from syngas such as methanol, a major chemical precursor, and Fischer-Tropsch (FT) liquids, essentially synthetic crude oil. FT liquids can be further refined through proven technologies into diesel fuels, jet fuels, gasoline, lubricating oils and greases and other petroleum derived liquids. A strategy for increasing the use of coal is presented in the recently released report to Energy Secretary Bodman entitled “Coal: America’s Energy Future”. A major portion of this report focuses on the role of coal gasification in sections dedicated to “Coal-to-Natural Gas”, “Coal-to-Liquids” and “Coal-to-Hydrogen”.

Although coal gasification and post-gasification processes are well established, these technologies have their own issues that have, to this point in time, limited their applicability. Foremost among these is that the gasification of coal and other potential carbon-bearing feed stocks such as biomass, black liquor, post-consumer wastes, etc. have been relatively expensive compared to the market price of crude oil and natural gas. While estimates vary, one previous study indicated that gasification derived liquids might be produced at an equivalent of approximately $50 to $55/bbl of oil and gasification-derived SNG from $6.70 to $7.50 per 1000 cu. ft.

In addition, the currently available configurations of these technologies are very capital intensive with economically viable capacities far too large for most individual industrial applications. Capital cost considerations arise from the base unit cost as well as current industrial reliability standards which necessitate building a spare gasifier to insure uninterrupted product availability. Gasification technologies themselves are not all identical. The composition of gasifier outputs varies considerably between fixed-bed, fluid-bed, and entrained flow units as shown in Table 1.

<table>
<thead>
<tr>
<th>Property</th>
<th>Liquid</th>
<th>Epic</th>
<th>Shell</th>
<th>CM</th>
<th>E-Gas</th>
<th>U-Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oxygen Source</td>
<td>Gas Plant</td>
<td>Air</td>
<td>Gas Plant</td>
<td>Gas Plant</td>
<td>Gas Plant</td>
<td>Gas Plant</td>
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<td>(1)</td>
<td>2700</td>
<td>2700</td>
<td>2700</td>
<td>1850</td>
</tr>
<tr>
<td>% CO</td>
<td>17.0</td>
<td>30.0</td>
<td>65.0</td>
<td>50.0</td>
<td>43.0</td>
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<tr>
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<td>4.0</td>
<td>14.0</td>
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<td>25.0</td>
<td>350.0</td>
<td>20.0</td>
<td>37.0</td>
</tr>
<tr>
<td>% Nitrogen</td>
<td>0.5</td>
<td>44.8</td>
<td>6.0</td>
<td>1.0</td>
<td>2.0</td>
<td>1.5</td>
</tr>
<tr>
<td>% Methane</td>
<td>1.0</td>
<td>6.0</td>
<td>------</td>
<td>------</td>
<td>------</td>
<td>------</td>
</tr>
<tr>
<td>% Higher Heat Value</td>
<td>0.6</td>
<td>------</td>
<td>------</td>
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<td>300</td>
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<td>LHV, Btu/scf</td>
<td>263</td>
<td>196</td>
<td>257</td>
<td>247</td>
<td>247</td>
<td>247</td>
</tr>
</tbody>
</table>

(1) The countercurrent flow design of these units causes operating temperatures to vary from top to bottom.
In addition to the variation in gasifier output based on the selected design, further variation is possible based on the operating parameters selected in each particular gasifier installation, such as operating pressure, temperature, coal feed rate, steam feed rate, and oxygen source (air or pure O₂ from an air separation unit). As a result, the selection of a particular design and a particular set of operating parameters for a gasification system is dictated by the intended post-gasification processes and end-product production planned for the facility.

The current project approaches these issues by identifying groups of industrial facilities that have sufficient aggregate demand to support one or more coal gasification units. This approach was believed to be a critical step in laying the groundwork for coal gasification facilities to serve the industrial sector.

EXPERIMENTAL PROCEDURES

The procedures used in the project can be broken into two major divisions. The first of these divisions addresses the procedures employed during the collection and processing of industrial energy data. The second addresses the procedures used in matching gasifier and post-gasifier technologies to the industrial use patterns and those used to generate preliminary capital and operating cost estimates.

DATA COLLECTION AND PROCESSING

This program sought to develop an understanding of the overall needs and use patterns of energy products at manufacturers in Ohio and Illinois. The main tool envisioned was an on-line questionnaire (See Appendix A1). Items in the questionnaire included typical sources like electricity, natural gas and fuel oil. Other material that might be produced as a by-product in a gasification facility were also included such as nitrogen, argon, carbon dioxide, etc. (by-products of oxygen production); coal tar products (by-products of fixed bed gasification); sulfur. In addition, other chemicals that might be readily produced from a syngas stream, such as ammonia, methanol, hydrogen, etc, were also included.

As well as quantifying the overall use of particular energy products the questionnaire also attempted to define the kind of temporal variations that might be present in the use of a particular energy sources within a facility. These variations might include shift scheduling, vacation schedules, maximum electric loads, etc. that might have a potential effect on the operation of a gasification facility, a facility which functions most efficiently in steady-state, continuous operation. Other questions looked to identify the facility’s position on long term supply contracts and their desirability in controlling energy costs.

A combination of individual contacts with prospective responding companies, building relationships with trade organizations and economic development entities in the states and an on-line questionnaire that did not have to be filled out at a single sitting was considered to be the best approach to developing the needed data.
The need for confidentiality was recognized during the proposal phase of the project and led to the development of a Confidentiality Policy that included:

- Each responding company being assigned a randomly-generated user identification number and a user-defined password to prevent unauthorized access to company’s data.
- Segregation of personally identifiable information such as names, telephone numbers, addresses, etc. from the data provided.
- Restricted third-party access to individual company data.
- Appropriate steps to ensure that publicly released information could not be used to identify individual companies.

The primary focus of the data collection activity was to secure use information from the companies whose names were included on the US DOE “Largest Energy Users” list. These companies were categorized into three user groups – those using more than 1 trillion Btu/yr; those using 0.3 to 1.0 trillion Btu/yr; and those using 0.1 to 0.3 trillion Btu/yr. As such, these industrial facilities represented significant energy consumers that could form the basis of an industrial cluster that might support a gasification facility. In addition, the general energy use groupings could be used as a guide for estimating energy use at facilities that might not respond to the questionnaire.

It was recognized that the data collection activity would not be successful in all cases in securing direct input from all major energy consumers within Ohio and Illinois. In order to extend the usefulness of the study, actual energy consumption data was secured from other programs within government agencies in Ohio and Illinois and all the data obtained was used to estimate the energy consumption at other facilities within the same North American Industry Classification System (NAICS) classification from the major energy consumers list provided by the US DOE. As an example, data obtained from integrated steel facilities could be used to approximate energy use at other integrated facilities based on public data published on blast furnace capacity. This approach would result in a greater number of companies being included in locating viable clusters.

Once the necessary data had been collected and developed it was segregated into clusters. Discussions with GTI personnel indicated that their past experience had shown that a cluster should be no greater than 50 miles in radius in order to economically deliver the end products in a cost effective manner through dedicated lines. In order to implement this recommendation and yet simplify data acquisition the decision was made to construct clusters by county rather than through a strict 50 mile radius decision rule.

After facility energy use was developed, each facility was located in its appropriate county and grouped into potential clusters. Counties having no reporting facilities or only minor facility energy use were not considered in cluster development. In addition, counties that may have been located in more than one cluster were placed in the cluster that had the largest overall potential demand under the assumption that the economic viability of any cluster would be dictated by the overall economies of scale that would accompany the largest possible clusters.
TECHNOLOGY MATCHING AND COST ESTIMATION PROCEDURES

Based on the industry use data generated, the Gas Technology Institute (GTI) undertook to develop estimated costs of potential gasification facilities to serve the needs as defined in each cluster. To do so, GTI used heat, material balance and cost data generated through three published case studies. One of these case studies was based on processing Illinois #6 coal; one was based on processing Eastern Kentucky coal which is characteristic of eastern coals available in Ohio, Pennsylvania and Kentucky; and one was based on Texas lignite and could be adjusted in a fashion to be useful in the current investigation. This information was used to develop four different scenarios for the production of SNG and electricity from bituminous coal each geared to address some or all of the needs in each identified cluster. Capital cost estimates were adjusted to 2009 dollars using the Chemical Engineering Plant Cost Index (CEPCI). The complete report from GTI, detailing the methodology, approach, results and recommendations appears in Appendix A4.

RESULTS AND DISCUSSION

Task 1. Develop an Energy Use Questionnaire.

An energy use questionnaire was developed that sought to determine a company’s current energy consumption patterns and attitudes with respect to the use of possible use of gasification-based alternative fuels. A copy of that questionnaire appears in Appendix A1. The questionnaire captured data such as a determination of the types of fuels currently used and their nominal Btu values; the amount of fuels consumed on a daily basis and daily variations in this demand; the amount of gaseous or liquid feed stocks used in the process; the amount of electricity consumed and the general daily load variation; the process in which alternative fuels might be used and the attributes of the process combustion system; the impact of various air quality regulations that might impact the use of alternative fuels, production operating shifts, etc.

Task 2. Develop Project Policies.

The confidentiality and non-disclosure policies that appear in Appendix A2 were developed. These policies sought to reassure participating facilities that the data they provided would not be publicly disclosed in a format which would inform competitors of their specific energy use patterns.

Task 3. Define Cluster Criteria.

Discussions between Energy Industries of Ohio (EIO) and Gas Technology Institute (GTI) personnel adopted the past experience that GTI had developed with respect to the geographic extent of a workable industry cluster. GTI’s experience had determined that an energy generation facility could economically deliver end products in a fifty-mile radius. In an attempt to facilitate discussions with economic development organizations and streamline data acquisition the decision was made to construct clusters on a county-by-county basis that would approximate a strict 50 mile radius.

The DOE’s list of the largest energy consuming companies for Ohio and Illinois included approximately 187 entries for Ohio and approximately 145 entries for Illinois. These locations were plotted as shown in Figure 2 with attendant 50 mile radius circles drawn.

Figure 2. Potential Ohio and Illinois Clusters

It appeared that Ohio might have approximately 5 clusters which included 182 of the 187 entries on the DOE list. In Illinois, six potential clusters covering 134 of the 139 companies on the DOE list seemed possible. However, 4 of the 6 Illinois clusters appear to have significantly lower potential energy use than the other Ohio/Illinois clusters.

Task 5. Contacting Companies to Explain and Discuss the Project.

Contacting Companies to Explain and Discuss the Project. As the project entered the data collection phase the economy began its precipitous decline. With companies cutting back operations and reducing expenses to the greatest extent possible, it did not seem practical to expect that manufacturers would attend centralized meetings to discuss a project that was not directly related to their daily operations.

As a result, EIO personnel contacted companies, trade associations and economic development groups in Ohio and Illinois to discuss the project and answer any questions. These calls were followed up by e-mails containing a brief letter of explanation, the project confidentiality policy, and the on-line questionnaire. Approximately a week after sending out this e-mail, a follow-up phone call was placed to make certain that there were no additional questions that had not been addressed. In total, 173 of the large energy consumers in Ohio and 120 in Illinois were contacted directly using this approach. In addition to contacting companies EIO personnel also contacted 36 groups to solicit their assistance in contacting their stakeholders and encouraging them to respond to the questionnaire. Among this group were national and state industrial trade associations and
state and local economic development organizations in Ohio and Illinois.

Task 6. Data Acquisition.

The development of actual company energy data proved the most problematical portion of the project for a number of reasons, including:

- The economy proved to be extremely uncooperative but highly instructive. As data collection activities began in earnest, prices for oil, natural gas began their free fall with oil prices reaching the $40/bbl level and natural gas prices falling below $6/mm Btu. This development highlights the difficulty encountered in planning large scale gasification facilities. Market demand and facility economics are based on prices of traditional energy sources. When they rise or when they are higher than normal, demand for alternatives is great. When they fall or are lower than normal, demand and interest in alternatives disappears. The dramatic drop in energy prices essentially sapped any enthusiasm for the proposed effort.

- In addition to dramatic drop in energy prices resulting from the economic downturn, companies were scaling back operations and personnel in an effort to maintain margins and profitability. A number of the large energy consuming manufacturers, such as steel mills, went into shutdown. At other facilities the remaining personnel were focused on operating issues and did not have the time or interest to participate in anything not directly related to their core business.

- The objective of the project – to identify overall and temporal use patterns for electricity and natural gas as well as data on related energy products that could be provided by a gasification facility – resulted in an on-line questionnaire that was deemed too imposing or intrusive for many companies. A far simpler approach may have been more successful but would not have satisfied these objectives.

- A number of individuals contacted felt that they had to have their participation approved at the corporate level and, given the state of the economy and energy prices, were not interested in going through this process.

- The assistance from trade associations and county/state economic development organizations never materialized to the level anticipated. Even those organizations that had input into the project proposal during its preparation were unwilling to assist in developing contacts at their member companies given the economic conditions facing their industry.

In order to add additional substance to the investigation, data on traditional energy consumption developed by other state-sponsored programs in Illinois and Ohio were obtained through the state energy offices. This data was limited to overall consumption of electricity and natural gas with limited data available on other energy uses. As a result, data on other energy product use was so limited that little of this data is shown in the tables and none were included in the work performed by GTI on economic viability.
A more comprehensive view of potential energy consumption in each cluster was estimated by extrapolating the actual energy data obtained to other facilities included in the US DOE’s Large Energy User list but for which actual data was not available. These extrapolations were based on NAICS classifications, publicly available data on facility capacities and the general consumption levels shown in the list. No attempt was made to adjust energy consumption figures, whether actual or extrapolated, to account for the current economic situation. As a result, the energy use data represent what should be anticipated under “normal” economic conditions. Appendix A3 contains the coded data that was transmitted to GTI to determine potentially viable clusters. The entries in light green represent data provided by individual facilities. The data shaded in gray were extrapolated from the company submitted data for other facilities in the US DOE Large Energy User list.

The potential clusters located in Ohio are shown in Figure 3. Four potential clusters were identified and transmitted to GTI for evaluation. The Southeast Ohio Cluster is the smallest of the four clusters in Ohio at ~ 1 trillion kWh/year of electricity and 12.5 trillion Btu/year of natural gas. The center of this cluster is in north central Perry County. The Northwest and Southwest clusters are essentially equal in size at ~ 1.6 T kWh/year of electricity and 30 T Btu/year of natural gas. These clusters are centered in northwestern Seneca County and near the border between northwestern Greene and northeastern Montgomery County, respectively.

The largest cluster is the Northeast Ohio cluster, centered in Stark County. This cluster is expected to consume ~ 4.5 T kWh/year of electricity and nearly 70 T Btu/year of natural gas. In addition to the size of this cluster is its relatively close proximity to the coal fields of eastern Ohio and its location over the Clinton Formation oil fields of eastern Ohio would facilitate coal delivery and carbon sequestration through enhanced oil recovery.

Figure 4 shows the only significant cluster identified from the Illinois data. This result may have come from a lack of response outside the Chicago area or from a focus of state efficiency programs in the Chicago area. However, the DOE Large Energy User list contained facilities from across the
entire state that were considered during the development of clusters. Even with this data included, industrial areas outside the Chicago cluster simply did not rise to a level of aggregated energy consumption where they would be deemed to represent a reasonably sized cluster. On the other hand, companies in the Chicago cluster have significant needs for electricity (1.6 T kWh), and natural gas 271 T Btu/yr and represented the largest potential cluster identified.

**Task 7. Evaluate Cluster Viability.**

The data developed during Task 6 were transmitted to GTI to determine whether the proposed cluster actually constitutes a viable candidate that could support a gasification facility. As explained in the comments on Task 6, this data was limited to the anticipated needs for electricity and natural gas and, as such, limited GTI’s evaluation to gasification facilities that produced SNG in a process with co-generated electricity rather than a much larger facility producing other energy products as well.

The measure of economic viability adopted by GTI personnel for this effort was whether the gasification facility could produce products (electricity and SNG) at prices that would be competitive in the market place with the products generated from traditional sources. Under the assumption that such a gasification facility would take a number of years to construct, the prices for energy in 2015 developed by DOE’s Energy Information Agency (EIA) were used as the measure of economic viability.

Three published case studies, involving electric and SNG production through coal gasification, were used as the basis of GTI’s evaluation. These studies were based on Illinois #6 coal, eastern Kentucky coal (representative of eastern coals from Ohio, Pennsylvania and Kentucky in general) and Texas lignite. The lignite study was modified to represent coals of interest for the purpose of the evaluation. Four separate “economic cases” were developed using the information available from these studies. Three of these cases demonstrated the importance of the gasification technology chosen; the need for design flexibility maximize facility revenues; and the overall limitations of coal feed rates and facility capital cost.

The fourth economic case indicates that a gasification facility that could satisfy a portion of or all the energy needs in the proposed clusters would be economically viable under “suitable market environments” and a relatively modest-sized gasification facility. The assumptions used in developing this case were a retail sales price for SNG of $4.00 to $4.50/MM Btu, electric prices of $0.08/kWh; coal supply contracts at $35/metric ton and a rate of return on capital of 12 to 13%. The facility would cost approximately $900MM and would consume ~ 5,345 metric tons of coal per year.

One aspect of the facility design in the fourth economic case is that it is “carbon capture ready”. The capital and operating costs for recovering ~ 8,000 metric tons/day of pipeline quality CO2 at a pressure of 2000 psig are included in this case since it was considered unreasonable to assume that such a facility would be permitted without carbon capture technologies. However, since there are currently no CO2 pipelines in Ohio or Illinois a
revenue stream commensurate to the availability of this quantity of CO₂ was not included in the evaluation of facility economics. The development costs for such a pipeline are referenced in the report and the development of such a market for enhanced oil recovery, particularly for the NE Ohio cluster that sits over the Clinton Formation oil field would improve the overall facility economics. For a complete discussion of the economic evaluation of gasification facilities of the clusters identified in this project, refer to the GTI report which appears in Appendix A4.

**Task 8. Reporting.**

This report represents the report anticipated in the proposal. Originally it was felt that the volume of information that would be developed would make it possible to prepare separate reports for each state but this proved to be unnecessary.

**Task 9. Project Management.**

The project has been completed on-time and on budget, given the varying project periods granted by the three funding sources.

**CONCLUSIONS AND RECOMMENDATIONS**

1. Four industry clusters were identified in Ohio that are large enough to support an economically justified coal gasification system for manufacturers. These clusters were centered in Stark, Perry, Greene and Seneca Counties.

2. A single industrial cluster was identified in Illinois that is large enough to support a coal gasification system for manufacturers. This cluster was centered in Kane County serving the Chicago area and the northeastern counties of the state.

3. The capital need for a plant co-producing ~ 50 MM SCF/day of SNG and ~ 230 MW of net electricity from ~ 5,345 metric tons/day of bituminous Ohio or Illinois coal would be about $900 MM (May 2009 dollars). This cost estimate includes a very high recovery factor (plus compression to 2,000 psig) for nearly pure CO₂ that would be produced in such a facility. With a price of about $35/metric ton for Ohio/Illinois coals, electricity prices of about 8 cents/kW-hr, and a target ROI of about 12-13%, a retail selling price for SNG of about $4.5-$5.0/MM Btu (2009 dollars) can be achieved.

4. The economics of such a facility look quite favorable if the EIA projections for the price of natural gas and electricity in the period 2015-2025 materialize. However, optimal economic viability and maximization of profit for this facility make it important to secure long-term purchase price agreements for electricity and coal, and to develop a suitable plant design with sufficient flexibility to take advantage of the seasonal price variation for SNG and electricity.

5. The economic evaluation that was undertaken as part of this project did not include the sale of any by-product materials associated with the operation of the gasification
facility but did include the capital and operating costs of recovering a high percentage of the CO₂ generated. The development of by-product markets, particularly the sale of CO₂ for EOR applications, would positively impact the economics of the facility.

6. If there is an interest on the part of any of the funding agencies, EIO and GTI could work with specific firms offering gasification technologies to develop detailed mass and energy balances and cost estimates for a plant in a specific Ohio/Illinois location with coal feed rates and product distributions similar to those in economic Case D of the GTI study (Appendix A4). Included in this more detailed study would be an effort to identify markets for by-products generated by the facility as well as attempting to further define the nature and extent of potential geologic and/or EOR carbon storage options.
REFERENCES

6. U-Gas Data provided by Dennis Perrin, GTI.
DISCLAIMER STATEMENT

This report was prepared by Lawrence C. Boyd Jr., Energy Industries of Ohio, with support, in part, by grants made possible by the Illinois Department of Commerce and Economic Opportunity through the Office of Coal Development and the Illinois Clean Coal Institute. Neither Lawrence C. Boyd Jr., Energy Industries of Ohio, nor any of its subcontractors, nor the Illinois Department of Commerce and Economic Opportunity, Office of Coal Development, the Illinois Clean Coal Institute, nor any person acting on behalf of either:

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Appendix A1.
On-line Energy Use Survey
FACILITY OPERATION
How many shifts does your facility operate?

☐ 1  ☐ 2  ☐ 3

What are the hours for each shift?
First Shift: _____ to _____; Second Shift: _____ to _____; Third Shift: _____ to _____

If your facility has regularly scheduled production downtimes for maintenance or vacation, please indicate the typical timing of these shutdowns and the typical shutdown duration.

<table>
<thead>
<tr>
<th>Scheduled Downtime, Month</th>
<th>Expected Duration</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
</tbody>
</table>

ENERGY PRODUCT USE
Please provide the annual volumes purchased by your facility for each energy product.

☐ Electricity – Usage and peak demand for the prior 12 months

<table>
<thead>
<tr>
<th>Month</th>
<th>Usage (kWh)</th>
<th>Peak Demand (kWd)</th>
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</thead>
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<td></td>
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<tr>
<td>February</td>
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<td>March</td>
<td></td>
<td></td>
</tr>
<tr>
<td>April</td>
<td></td>
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</tr>
<tr>
<td>May</td>
<td></td>
<td></td>
</tr>
<tr>
<td>June</td>
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<tr>
<td>July</td>
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<tr>
<td>August</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>November</td>
<td></td>
<td></td>
</tr>
<tr>
<td>December</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Do you have a Long-term Supply Contract?

☐ Yes  ☐ No  Years remaining in contract _______ years

Do you have an Interruptible Supply Contract?

☐ Yes  ☐ No

Would you be willing to pay a premium for Non-Interruptible service

☐ Yes  ☐ No

What Percent of your Electric usage occurs during each operating shift?
(If accurate figures are not available, estimates are acceptable)

<table>
<thead>
<tr>
<th>Shift</th>
<th>First</th>
<th>Second</th>
<th>Third</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric Use, %</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Would you be interested in a long term electricity contract (~ 10 yr)?

☐ Yes  ☐ No

Would you be willing to pay an initial premium for electricity to obtain a known, guaranteed price over the entire term of the contract?

☐ Yes  ☐ No

Do you have a “take or pay” provision in your electric supply agreements?

☐ Yes  ☐ No

☐ Natural Gas  Usage for prior 12 months.
<table>
<thead>
<tr>
<th>Usage (mm Btu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
</tr>
<tr>
<td>February</td>
</tr>
<tr>
<td>March</td>
</tr>
<tr>
<td>April</td>
</tr>
<tr>
<td>May</td>
</tr>
<tr>
<td>June</td>
</tr>
<tr>
<td>July</td>
</tr>
<tr>
<td>August</td>
</tr>
<tr>
<td>September</td>
</tr>
<tr>
<td>October</td>
</tr>
<tr>
<td>November</td>
</tr>
<tr>
<td>December</td>
</tr>
</tbody>
</table>

Do you have an Interruptible Supply provision in your contract?

☐ Yes  ☐ No

Do you have a long-term Supply Contract?

☐ Yes  ☐ No  Years remaining in contract _____ years

Would you be interested in a long-term Natural Gas contract (~ 10 yr)?

☐ Yes  ☐ No

Would you be willing to pay an initial premium for Natural Gas to obtain a known, guaranteed price over the entire term of the contract?

☐ Yes  ☐ No

Approximately how many Natural Gas burners are used in your plant? ____

Would you consider replacing these burners with low Btu burners if you could obtain low Btu gas at a significant savings?

☐ Yes  ☐ No. What percent lower cost would be necessary ____% 

☐ Fuel Oil Use

<table>
<thead>
<tr>
<th>Usage (gallons)</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
</tr>
<tr>
<td>February</td>
</tr>
<tr>
<td>March</td>
</tr>
<tr>
<td>April</td>
</tr>
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<td>May</td>
</tr>
<tr>
<td>June</td>
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<td>July</td>
</tr>
<tr>
<td>August</td>
</tr>
<tr>
<td>September</td>
</tr>
<tr>
<td>October</td>
</tr>
<tr>
<td>November</td>
</tr>
<tr>
<td>December</td>
</tr>
</tbody>
</table>

Do you have a long-term Fuel Oil Supply Contract?

☐ Yes  ☐ No  Years remaining in contract _______ years

Would you be interested in securing Fuel Oil under a long-term contract (~ 10 yr)?

☐ Yes  ☐ No

Would you be willing to pay an initial premium for Fuel Oil to obtain a known, guaranteed price over the entire term of the contract?
☐ Yes  ☐ No

Does your company use at least the stated volumes for any of the following chemicals?

<table>
<thead>
<tr>
<th>Volume</th>
<th>Chemicals</th>
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</thead>
<tbody>
<tr>
<td>10,000 Standard Cubic Feet / week</td>
<td>Oxygen, Hydrogen, Nitrogen</td>
</tr>
<tr>
<td>20 tons / week</td>
<td>Coal, Sulfur, LPG, Anhydrous Ammonia, Coal Tar, Dimethyl Ether, Urea, Waxes, Carbon Dioxide (at 2,000 psi)</td>
</tr>
<tr>
<td>5,000 gallons / week</td>
<td>Aqueous Ammonia, Methanol, Naphtha, Phenols, Cresylic Acid, Catechols</td>
</tr>
</tbody>
</table>

☐ Yes  ☐ No (If answer is Yes, display the Chemical Feedstock page.)

### CHEMICAL FEEDSTOCK USE

Please provide the annual volumes purchased (along with units of measure) by your facility for each feedstock.

<table>
<thead>
<tr>
<th>Item</th>
<th>Monthly Usage</th>
<th>Units</th>
<th>Quality Requirements</th>
</tr>
</thead>
<tbody>
<tr>
<td>☐ Fuel / Town / Reducing Gas</td>
<td>mm Std Cu Ft</td>
<td>☐ mm Std Cu Ft</td>
<td></td>
</tr>
<tr>
<td>☐ Oxygen – 95%</td>
<td>mm Std Cu Ft</td>
<td>☐ mm Std Cu Ft</td>
<td></td>
</tr>
<tr>
<td>☐ Oxygen – 99.5%</td>
<td>mm Std Cu Ft</td>
<td>☐ mm Std Cu Ft</td>
<td></td>
</tr>
<tr>
<td>☐ Carbon Dioxide – Liquid @ 2000 psi</td>
<td>Tons</td>
<td>☐ Tons</td>
<td></td>
</tr>
<tr>
<td>☐ Carbon Dioxide – Food Grade</td>
<td>Tons</td>
<td>☐ Tons</td>
<td></td>
</tr>
<tr>
<td>☐ Nitrogen</td>
<td>mm Std Cu Ft</td>
<td>☐ mm Std Cu Ft</td>
<td></td>
</tr>
<tr>
<td>☐ Sulfur</td>
<td>Tons</td>
<td>☐ Tons</td>
<td></td>
</tr>
<tr>
<td>☐ LPG</td>
<td>Tons</td>
<td>☐ Tons</td>
<td></td>
</tr>
<tr>
<td>☐ Anhydrous Ammonia</td>
<td>Tons</td>
<td>☐ Tons</td>
<td></td>
</tr>
<tr>
<td>☐ Aqueous Ammonia</td>
<td>1,000 Gal</td>
<td>☐ 1,000 Gal</td>
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</tr>
<tr>
<td>☐ Hydrogen</td>
<td>mm Std Cu Ft</td>
<td>☐ mm Std Cu Ft</td>
<td></td>
</tr>
<tr>
<td>☐ Methanol</td>
<td>1,000 Gal</td>
<td>☐ 1,000 Gal</td>
<td></td>
</tr>
<tr>
<td>☐ Gasoline (for petroleum refineries only – gasoline from methanol-to-gasoline process as a blend stock)</td>
<td>1,000 Gal</td>
<td>☐ 1,000 Gal</td>
<td></td>
</tr>
<tr>
<td>☐ Coal Tar</td>
<td>Tons</td>
<td>☐ Tons</td>
<td></td>
</tr>
<tr>
<td>☐ Dimethyl Ether</td>
<td>Tons</td>
<td>☐ Tons</td>
<td></td>
</tr>
<tr>
<td>☐ Urea</td>
<td>Tons</td>
<td>☐ Tons</td>
<td></td>
</tr>
<tr>
<td>☐ Naphtha</td>
<td>1,000 Gal</td>
<td>☐ 1,000 Gal</td>
<td></td>
</tr>
<tr>
<td>☐ Waxes</td>
<td>Tons</td>
<td>☐ Tons</td>
<td></td>
</tr>
<tr>
<td>Coal Tar Derivatives</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>☐ Phenols</td>
<td>1,000 Gal</td>
<td>☐ 1,000 Gal</td>
<td></td>
</tr>
<tr>
<td>☐ Cresylic Acids</td>
<td>1,000 Gal</td>
<td>☐ 1,000 Gal</td>
<td></td>
</tr>
<tr>
<td>☐ Catechols</td>
<td>1,000 Gal</td>
<td>☐ 1,000 Gal</td>
<td></td>
</tr>
<tr>
<td>☐ Coal</td>
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<td>☐ Tons</td>
<td></td>
</tr>
<tr>
<td>☐ Other (rows added as needed by user)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Appendix A2
Confidentiality Policies
Confidentiality Policy

Energy Industries of Ohio (EIO) depends upon your company’s cooperation and trust to complete the first step in the effort to develop an alternate supply of energy and chemical feedstocks to improve the cost position for your company. EIO appreciates your company’s willingness to share information on your company’s usage and sourcing of these products through the EIO Internet-based survey.

Given that some or all of the information that your company provides is confidential, EIO takes several steps to maintain both the trust that your company has invested in our organization. With these steps, your company can be assured that the confidentiality of your information from competitors, suppliers, customers and other potential third parties will be maintained:

Privacy Principles

1. Necessity: Every question that EIO asks in the survey is required to determine the optimal configuration of a proposed plant based upon the collective needs of the companies to be served.

2. Confidentiality: EIO takes a number of steps to protect your information:
   a. Each responding company will be assigned a randomly-generated user identification number and a user-defined password to prevent unauthorized access to any data that you may provide.
   b. EIO has designed the survey and processes such that company specific information such as names, telephone numbers, addresses, etc. are segregated from the data that you provide.
   c. Access to individual company data is restricted to EIO and the Gas Technology Institute (GTI), which is our technical partner on this project. EIO has a non-disclosure agreement in place with GTI that extends to all information that you share with EIO for this project.

3. EIO has put in place security measures that block outside access to any confidential information stored on EIO computers.

4. Statistical Safeguards: EIO will take appropriate steps to ensure that the publicly available statistics cannot be used to identify individual companies. These methods include extensive review and analysis of all data and use of disclosure avoidance methodologies (such as data suppression and modification) to screen out data that might identify individual companies.

5. Individual company data will only be released to third-parties not listed above with prior written consent of your company.
Appendix A3
Coded Industrial Energy Use Data
<table>
<thead>
<tr>
<th>ID#</th>
<th>Elect. kWh</th>
<th>Fuel</th>
<th>Use</th>
<th>Other Fuels</th>
<th>Use</th>
<th>Units</th>
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<td>other</td>
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</tr>
<tr>
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<td>72,940</td>
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<td>3,580</td>
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<td>70,400</td>
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</tr>
<tr>
<td>151</td>
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<td>86,100</td>
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<td>Elec. kWh</td>
<td>Fuel</td>
<td>Use MM Btu</td>
<td>Other Fuels</td>
<td>Use</td>
<td>Units</td>
</tr>
<tr>
<td>------</td>
<td>-----------</td>
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**Northwest Ohio Cluster**

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<td>65,089</td>
</tr>
</tbody>
</table>

**Southwest Ohio Cluster**

<table>
<thead>
<tr>
<th>Yearly Totals</th>
<th>Elect, KWH</th>
<th>NG, mm BTU</th>
<th>Steam, tons</th>
<th>Diesel, bbl</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1,476,467,536</td>
<td>29,537,891</td>
<td>641,994</td>
<td>214,429</td>
</tr>
</tbody>
</table>

**Southeast Ohio Cluster**

<table>
<thead>
<tr>
<th>Yearly Totals</th>
<th>Elect, KWH</th>
<th>NG, mm BTU</th>
<th>Lpg, tons</th>
<th>Steam, tons</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1,042,846,902</td>
<td>12,571,294</td>
<td>3</td>
<td>168,749</td>
</tr>
</tbody>
</table>

**Chicago Cluster**

<table>
<thead>
<tr>
<th>Total Yearly</th>
<th>Steam, tons</th>
<th>257,867</th>
</tr>
</thead>
<tbody>
<tr>
<td>Elect, KWH</td>
<td>1,853,726,811</td>
<td>Nat Gas, mm Btu</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Diesel, bbl</td>
</tr>
<tr>
<td></td>
<td></td>
<td>LFG, tons</td>
</tr>
</tbody>
</table>


Appendix A4
Gas Technology Institute Report #20896

“Evaluation of Feasibility of Industrial Coal Gasification for SNG and/or Electricity in Illinois and Ohio Markets”
REPORT
GTI PROJECT NUMBER 20896

Evaluation of Feasibility of Industrial Coal Gasification for SNG and/or Electricity in Illinois and Ohio Markets

Report Issued:
October 16, 2009

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<th>Page</th>
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</tr>
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<td>1</td>
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<td>EIA Projections on Prices of U.S. Coals</td>
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<td>EIA Projections on the Price (2007 dollars) for Natural Gas</td>
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<tr>
<td>Figure 9</td>
<td>EIA Projections on the Price of Electricity During 2010-2030</td>
<td>17</td>
</tr>
</tbody>
</table>
Executive Summary

Purpose and Background

Various studies related to the natural gas industry in the U.S. have indicated that the production of natural gas will not be able to meet the projected overall demand in the foreseeable future. The DOE/EIA (Energy Information Administration) projections on the natural gas shortfall in the U.S. are shown in Figure 2; other studies also indicate that the shortfall in production is expected to grow from 4.1 TCF (trillion cubic feet) in 2010 to about 4.6 TCF by 2015. Five new LNG regasification facilities are currently under construction in the U.S., but the required quantity of LNG may not be available because of the uncertainties in the global LNG market.

Thus, there could be significant opportunities for the expanded use of coal as a means to meet the projected shortfall in the supply of natural gas in the U.S. from the production of synthetic natural gas (SNG) from oxygen-blown gasification of coal. The intent of this study, sponsored by Energy Industries of Ohio (EIO), U.S. DOE, Ohio Coal Development Office, Gas Technology Institute (GTI), and the Illinois Clean Coal Institute (ICCI) is to estimate the approximate cost of producing SNG plus electricity from bituminous coals at locations in either Ohio or Illinois. These organizations are interested in determining the circumstances under which industrial companies in Ohio and Illinois would be willing to purchase SNG and electricity from a coal gasification plant.

Currently, the only commercial coal-to-SNG plant in the U.S. is being operated by Dakota Gasification Company at their North Dakota plant (the Great Plains Synfuels Plant) located in Beulah, ND; the plant produces about 145 MM SCF/day (million standard cubic feet per day) of SNG. The plant began operation during 1984 and now also supplies about 150 MM SCF/day of carbon dioxide to two Canadian oil fields for enhanced oil recovery. This plant uses the Lurgi Fixed-Bed gasification technology for the production of syngas (a mixture of hydrogen + carbon monoxide) from coal, Rectisol Acid Gas Removal (AGR) technology for the removal of sulfur compounds and CO₂, and Lurgi’s methanation technology for the production of methane (the primary component of SNG) from syngas. There are also a number of minor by-products, such as ammonium sulfate and phenolic compounds.

During August 2009, the market price of natural gas in the U.S. had dropped to a 7-year low of under $3/MM Btu. However, as shown in Table 13, based on projections by the U.S. EIA for the year 2015 through 2025:

- Similarly, the average U.S. retail electricity price during 2015 could be in the range of 8-10 cents/kW-hr (2007 dollars; see Figure 9).

It seems that, based on the projected significant supply shortfall for natural gas and these relatively robust market price estimates for electricity and natural gas for the period 2015-2025, several companies in the U.S. are currently planning specific projects (details given in Table 5) for the production of SNG from coal. This includes, as an example, the recent announcement of a project proposed by ConocoPhillips and Peabody Energy for the production of about 125-175 MM SCF/day of SNG in Kentucky.
This Study

Based on a detailed survey by EIO\(^{6}\), the current approximate usages of natural gas and electricity in the Chicago, IL area and four “cluster” areas in Ohio are presented in Table 1:

<table>
<thead>
<tr>
<th></th>
<th>Chicago, IL Area</th>
<th>Northwest Ohio</th>
<th>Northeast Ohio</th>
<th>Southwest Ohio</th>
<th>Southeast Ohio</th>
</tr>
</thead>
<tbody>
<tr>
<td>SNG, MM SCF/day</td>
<td>740</td>
<td>80</td>
<td>180</td>
<td>80</td>
<td>33</td>
</tr>
<tr>
<td>Electric Power, MW</td>
<td>190</td>
<td>210</td>
<td>520</td>
<td>170</td>
<td>120</td>
</tr>
</tbody>
</table>

Economic Cases Analyzed

We have used key material/heat (M/H) balance and cost data from three literature references (referred to as Design Cases 1, 2, and 3, as noted in Table 3) to estimate the required selling price (RSP at about 13% Return on Investment) for SNG from typical bituminous coals from Ohio or Illinois for four specific plant configurations (summarized in Table 2) involving different coal feed rates as well as different SNG:electric power production ratios:

<table>
<thead>
<tr>
<th>Scoping Economic Case</th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
</tr>
</thead>
<tbody>
<tr>
<td>Design Cases Used to</td>
<td>Combine Design</td>
<td>Combine Design</td>
<td>Design Case</td>
<td>Design Case</td>
</tr>
<tr>
<td>Develop Key M/H Plus</td>
<td>Cases 1 &amp; 3</td>
<td>Cases 2 &amp; 3</td>
<td>2 only</td>
<td>3 only</td>
</tr>
<tr>
<td>Cost Data</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SNG, MM SCF/day*</td>
<td>79.5</td>
<td>125</td>
<td>74</td>
<td>51</td>
</tr>
<tr>
<td>Net Sale of Electric</td>
<td>215</td>
<td>240</td>
<td>8</td>
<td>232</td>
</tr>
<tr>
<td>Power, MW</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal Feed Rate,</td>
<td>6,383</td>
<td>9,738</td>
<td>4,394</td>
<td>5,344</td>
</tr>
<tr>
<td>Metric Tons/day</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO(_2) Capture Plus</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Compression to 2,000 psig</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO(_2) Captured,</td>
<td>9455</td>
<td>15,404</td>
<td>7,454</td>
<td>7,950</td>
</tr>
<tr>
<td>Metric Tons/day</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*Delivery Pressure is 1,000 psig

Case B (which would meet a part of the SNG and electric power demands in NE Ohio as well as in the Chicago area) economics were developed with the goals of limiting the maximum coal feed rate, and total capital requirement for a given plant. Cases A and B could be applicable for the NW and SW Ohio cluster locations; these cases show the importance of optimization for various factors including the choice of gasification technology, coal feed, and the plant design flexibility in changing the ratio of SNG:electric power production depending on their relative market prices (e.g., the price of $0.08/kW-hr for electricity reflects a value of about $23.40/MM Btu). Case C economics (with SNG as the primary product) were developed to emphasize the importance of co-production (and sale) of a large quantity of electricity as a means to improve the economics for the production of SNG, assuming that the EIA estimates for relatively high prices for electricity during 2015-2025 materialize.
Case D economics for bituminous coals from Ohio or Illinois were developed to indicate that with suitable market environments (e.g., high prices for electricity) and choice of gasification technology, the RSP of SNG could potentially be reduced to an attractive range about $4.0-4.50/MM Btu (2009 dollars) even with a relatively modest size coal-to-SNG plant (coal feed rate of about 5,400 metric tons/day; capital cost about $900 million, 2009 dollars).

Basic Design Cases (for mass/heat balances & cost data) Developed from Literature Data

<table>
<thead>
<tr>
<th>Design Case</th>
<th>Gasifier Type</th>
<th>Coal feed, metric tons/day</th>
<th>SNG Production, MM SCF/day</th>
<th>CO₂ Capture &amp; Compression to 2,000 psig</th>
<th>Electric Power, MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Case 1β</td>
<td>British Gas Lurgi, BGL-1000</td>
<td>1,039</td>
<td>19.2 (produced at 254 psig)</td>
<td>Yes (CO₂ removal: by Rectisol process)</td>
<td>(15.9); net Import</td>
</tr>
<tr>
<td>Case 2β</td>
<td>Single-Stage Slurry-Fed with Quench</td>
<td>4,394</td>
<td>74 (at 1,000 psig)</td>
<td>Yes (Slexol process)</td>
<td>8 (net Export)</td>
</tr>
<tr>
<td>Case 3β</td>
<td>Single-Stage Dry-feed Quench</td>
<td>5,344</td>
<td>51 (at 295 psig)</td>
<td>Yes (Slexol process)</td>
<td>232 (net Export)</td>
</tr>
</tbody>
</table>

b. Reference 7: Univ. of Kentucky/Mitreetek Systems.
c. Reference 8: Mitreetek Systems/DOE-NETL.

The DOE/NETL/Worley Parsons study is based on IL# 6 bituminous coal. The University of Kentucky study is based on Eastern bituminous coal which encompasses Kentucky, Ohio, and Western Pennsylvania coals. The third study (by Mr. Marano/Mitreetek Systems/NETL) was based on Texas lignite with specific design cases developed using moderately dried (to about 12% moisture level) lignite. We have modified this case for IL# 6 coal by assuming the same coal feed rate on a moisture and ash-free basis, and the same overall efficiency (48% based on HHV of feed coal) for the production of SNG and electric power.
Key Scoping Economics Results

The key results for the four economic cases are summarized below in Table 4.

<table>
<thead>
<tr>
<th>Economic Case</th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal feed rate, metric tons/day</td>
<td>6,383</td>
<td>9,738</td>
<td>4,394</td>
<td>5,344</td>
</tr>
<tr>
<td>SNG production, MM SCF/day</td>
<td>70.5</td>
<td>125</td>
<td>74</td>
<td>51</td>
</tr>
<tr>
<td>Net electric power for sale, MW</td>
<td>215</td>
<td>240</td>
<td>8</td>
<td>232</td>
</tr>
<tr>
<td>Total capital need, $MM (May 2009 dollars)</td>
<td>965</td>
<td>1,588</td>
<td>883</td>
<td>882</td>
</tr>
<tr>
<td>Total operating costs, including coal, $MM/yr</td>
<td>142.9</td>
<td>216.5</td>
<td>109.5</td>
<td>107.0</td>
</tr>
<tr>
<td>Credit for sale of electric power, $MM/yr (at 3 cents/kW-hr)</td>
<td>135.6</td>
<td>151.4</td>
<td>5.1</td>
<td>146.3</td>
</tr>
<tr>
<td>Credit for any sale of CO₂?</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Base case RSP of SNG at about 13% ROI, $/MM Btu*</td>
<td>5.73</td>
<td>6.61</td>
<td>9.01</td>
<td>4.48</td>
</tr>
<tr>
<td>SNG Selling Price, $/MMBtu, Sensitivity with Electric Power Prices at:</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>10 cents/kW-hr</td>
<td>4.27</td>
<td>5.69</td>
<td>8.96</td>
<td>2.29</td>
</tr>
<tr>
<td>7 cents/kW-hr</td>
<td>6.46</td>
<td>7.07</td>
<td>9.04</td>
<td>5.57</td>
</tr>
<tr>
<td>4 cents/kW-hr</td>
<td>8.66</td>
<td>8.45</td>
<td>9.11</td>
<td>8.84</td>
</tr>
</tbody>
</table>

* Coal Price at $35/metric ton (May 2009 dollars), electricity price at $0.08/kW-hr, and 13% capital charge factor.

The data for Case D indicate that, with a total capital investment of about $900 million (May 2009 dollars), a bituminous coal (from Ohio or Illinois) price of $35/metric ton, electricity price of about 8 cents/kW-hr, and a target ROI of about 13%, a "required selling price" (RSP) for SNG of about $4.50-5.00/MM Btu (2009 dollars) can be achieved by co-producing about 51 MM SCF/day of SNG and a relatively large amount (≈ 232 MW) of net electrical power for sale. These economics look quite favorable, if the EIA projections on the price of natural gas and electricity for the period 2015-2025 materialize. However, for economic viability and maximization of overall profits for such capital-intensive projects, it would be important to have long-term contracts on the price of electricity as well as coal, and suitable plant design flexibility such that the output of SNG and electric power could be varied to meet seasonal price variations for these products.

The importance of the market prices for electricity on the economic viability of a Case D type SNG/electricity co-production project is shown in Figure 1.

We did not include any potential credit for selling near-pure CO₂ for EOR (enhanced oil recovery) as there is currently no CO₂ pipeline in Illinois or Ohio (Appendix A). Various groups (e.g., Denbury Resources Inc.) are currently evaluating the potential of building CO₂ pipelines to utilize CO₂ from multiple coal gasification projects in the Midwest for EOR applications in the U.S. and Canada. Based on a report from the Institute of Transportation Studies, University of California, Davis, a pipeline carrying 10,000 metric tons/day of CO₂ would cost about $50 million (2009 dollars) for a length of 100 kilometers and $275 million for a length of 500 km.
As the NE Ohio cluster is located in the middle of a large oil field (the Clinton Formation), this area has the greatest chance of economically implementing CCS (carbon sequestration and capture) through EOR. For transporting 10,000 tons/day of nearly pure CO₂, the approximate RSP (at an ROI of about 12-13%, assuming 25% of CAPEX cost/year to account for capital, operating and related expenses) would need to be about $3.5/ton (2009 dollars) of CO₂ for a 100 km pipeline and $19/ton for a 500 km pipeline. For the Case D scenario, the CO₂ production rate is about 7,950 metric tons/day.

![Coal to SNG - Case D: Economic Sensitivities, May 2009 $](image)

**Figure 1.** RSP of SNG vs. Price of Electricity (Economic Case D)

Conclusions

Our key conclusions are:

1. A specific Coal-to-SNG technology (licensed by Lurgi for the Great Plains Synfuels Plant in North Dakota) has been commercially proven in the U.S. at a scale of about 145 MM SCF/day. There are other technology licensors for syngas-to-methane processes.

2. Various estimates indicate a significant shortfall (of about 4-7 TCF per year in the next 5-20 years) of future supplies of natural gas in the U.S. According to key projections by the U.S. EIA for the year 2015 through 2025:
   - Similarly, based on the EIA projections, the average U.S. retail electricity price during 2015 could be in the range of $0.08-$0.10/kW-hr (2007 dollars).
3. As shown in Table 1, based on the recent survey by the Energy Industries of Ohio (EIO), multiple coal-to-SNG (+ electricity) plants can be constructed in Ohio and Illinois.

4. Based on the Case D scoping economic analysis of this study:

a. The approximate capital need for a plant producing about 50 MM SCF/day of SNG and about 230 MW of net electricity for sale (after meeting in-plant requirements) from about 5,345 metric tons/day of bituminous coals from Ohio or Illinois would be about $900 MM (May 2009 dollars). This cost estimate includes very high recovery (plus compression to 2,000 psig) of nearly pure CO₂ that would be produced in such a plant. With a price of about $35/metric ton of bituminous coals from Ohio/Illinois, electricity prices of about 8 cents/kW-hr, and a target ROI of about 12-13%, an RSP for SNG of about $4.5-$5.0/MM Btu (2009 dollars) can be achieved.

b. These economics look quite favorable if the EIA projections on the prices for natural gas and electricity for the period 2015-2025 materialize. However, for optimal economic viability and maximization of net profit for such capital-intensive projects, it would be important to have long-term purchase price agreements for electricity and coal, and suitable plant design flexibility so that production can be varied to take advantage of the seasonal price variation for SNG and electricity.

c. As there is no existing CO₂ pipeline in Illinois or Ohio that could transport CO₂ to key EOR markets in the U.S. or in Canada, we have not included any credit for the sale of CO₂ for our economic analysis. However, the sale of CO₂ for EOR applications would positively impact the economics of the facility should this become feasible. As the NE Ohio cluster is located in the middle of a large oil field (the Clinton Formation), this area has the greatest chance of economically implementing CCS (carbon sequestration and capture) through EOR. For a CCS project, with 10,000 tons/day of nearly pure CO₂ for sale in EOR applications, the RSP for CO₂ would need to be about $3.5/ton for a 100 km pipeline and $19/ton for a 500 km pipeline. For our Case D scenario, the CO₂ production rate is about 7,950 metric tons/day.

Recommendations

If there is an interest on the part of EIO, GTI could work with specific firms (e.g., Synthesis Energy Systems Inc. that has commercialized GTI’s U-Gas coal gasification technology, or Allied Syngas Corporation, the marketer of the BGL gasification technology, and Haldor Topsoe that has developed the TREMP methanation technology to produce SNG from coal-derived syngas) to develop detailed mass/energy balances and cost estimates of a plant (for a specific Ohio location) with coal feed rate and product distributions similar to the economic Case D presented in this study.
Introduction

The intent of this study, sponsored by Energy Industries of Ohio (EIO), U.S. DOE, Ohio Coal Development Office, the Illinois Clean Coal Institute (ICCI), and Gas Technology Institute (GTI) is to estimate the cost of producing SNG (Synthetic Natural Gas) plus electricity at a location in Illinois or Ohio using oxygen-blown gasification of bituminous coals from Ohio and Illinois. This Group is interested in convincing industrial firms in Illinois and Ohio to share energy and chemical feedstock supply usage and determining the circumstances under which industrial companies in Ohio and Illinois would be willing to purchase SNG and electricity from a coal gasification plant.

While various studies (e.g., DOE/EIA data shown in Figure 2) indicate that the production of natural gas in the U.S. would not be able to meet the projected overall demand in the foreseeable future, there are several challenges in making the co-production of SNG and electricity from coal economically and environmentally competitive with other sources of natural gas supply, including import of LNG. These challenges include:

- The economic barrier where various techno-economic studies, primarily by the U.S. DOE and EPRI (Electric Power Research Institute), indicate a relatively high capital cost for the production of electricity plus specific liquid and chemical products via coal gasification. This is especially important as the market price of natural gas has recently dropped to a 7-year low of under $3/MM Btu, and
- The environmental concerns related to global warming and the ongoing technical, as well as cost, uncertainties in the capture and long-term sequestration of CO₂ that would be emitted from such coal gasification plants.

![Figure 2. DOE/EIA Projections on U.S. Production and Consumption of Natural Gas](image)
Proposed Commercial-Scale Coal-to-SNG Projects in the U.S.

As shown in Table 5, several coal-to-SNG projects have been proposed in the U.S., all of which are in different stages of development. Some of these projects are also considering carbon capture and storage. For example, the joint ConocoPhillips/Peabody Energy project in the Midwest is considering CO₂ capture and storage for its proposed mine-mouth facility.

Table 5. Proposed Coal-to-SNG Plants in the U.S.

<table>
<thead>
<tr>
<th>Project Name/Owner</th>
<th>Location</th>
<th>Status</th>
<th>Capacity, MM SCF/day</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>ConocoPhillips/Peabody Energy</td>
<td>Kentucky</td>
<td>Planned</td>
<td>125-175</td>
<td>--</td>
</tr>
<tr>
<td>Lockwood Project</td>
<td>Texas</td>
<td>Planned</td>
<td>160</td>
<td>CO₂ will be captured for EOR usage</td>
</tr>
<tr>
<td>South Heart Coal Gasification Project (Great Northern Power Development, LP and Allied Syngas Corp.)</td>
<td>North Dakota</td>
<td>Planned</td>
<td>100-115</td>
<td>CO₂ will be captured for EOR usage</td>
</tr>
<tr>
<td>Secure Energy Inc.</td>
<td>Illinois</td>
<td>Front-End Engineering &amp; Design (FEED)</td>
<td>60-65</td>
<td>Would likely use 10% biomass as co-feed</td>
</tr>
<tr>
<td>Taylorville Energy Center (Temaska Inc.)</td>
<td>Illinois</td>
<td>FEED to Burns &amp; McDonnell</td>
<td>Coproduce SNG +electricity</td>
<td>DOR has announced a loan guarantee offer of $2.6 billion (July, 2009); Estimated Capital cost: $3.5 billion</td>
</tr>
<tr>
<td>Oswego SNG Project (Transgas)</td>
<td>New York</td>
<td>Planned</td>
<td>--</td>
<td>Coal feed: 20,000 tons/day; Projected Capital $2&quot; billion</td>
</tr>
<tr>
<td>Texas Syngas (NC12) + C-Change Investment Inc</td>
<td>Louisiana</td>
<td>Planned</td>
<td>--</td>
<td>-0</td>
</tr>
</tbody>
</table>

Great Plains Synfuels Plant: An Existing SNG Plant

The Great Plains Synfuels Plant (owned by Dakota Gasification Company) in Beulah, North Dakota, which has been operating since 1984, is the only commercial coal-to-SNG plant in the U.S. The key performance data for the plant are listed in Table 6.

Table 6. Key Performance Data for the Great Plains Synfuels Plant

<table>
<thead>
<tr>
<th></th>
<th>Lignite</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal Type</td>
<td></td>
</tr>
<tr>
<td>Annual lignite consumption, million tons</td>
<td>6</td>
</tr>
<tr>
<td>Daily SNG Production, MM SCF/day</td>
<td>145-150</td>
</tr>
<tr>
<td>Annual Capacity factor, %</td>
<td>90-92</td>
</tr>
<tr>
<td>CO₂ sold for EOR, MM SCF/day (to Weyburn Oil Field, in SW Saskatchewan, Canada)</td>
<td>~95</td>
</tr>
</tbody>
</table>
Key Chemistry

For the production of SNG from coal (Schematic shown in Figure 3), synthesis gas (syngas: a mixture of hydrogen + carbon monoxide) is first produced from coal via gasification using steam and oxygen. The syngas, following various clean-up steps to remove specific contaminants that would poison the catalyst(s) used in the methanation process, is further treated to modify its H2/CO ratio to about 3.0 in a WGS (water gas shift) reactor to facilitate the following key methanation reactions and remove sulfur compounds and CO2 in an AGR (acid gas removal) unit such as Selexol or Rectisol. The sweet syngas from the AGR step is then processed in a methanation unit.

\[
\text{CO} + 3 \text{H}_2 \rightarrow \text{CH}_4 + \text{H}_2\text{O} \quad \text{(exothermic reaction: a large amount of heat is liberated)}
\]

\[
\text{CO}_2 + 4 \text{H}_2 \rightarrow \text{CH}_4 + 2 \text{H}_2\text{O} \quad \text{(exothermic reaction: a large amount of heat is liberated)}
\]

The reaction equilibrium for the methanation process is highly favored at lower temperatures. Due to the relatively high heat of reaction and the upper limits on allowable maximum catalyst temperature, most of methanation processes use significantly large quantities of recycle gas to control the catalyst bed temperature. Various methanation technologies have been developed by specific firms that include: Lurgi/Linde fixed-bed process, Haldor Topsoe (HTAS) TREMP fixed-bed process, Comflux fluidized-bed and HICOM fixed-bed processes.11,12,13

![Figure 3. Schematic of a Coal-to-SNG Process Using Steam/Oxygen Gasification of Coal](image)

The Lurgi process has been commercialized in the U.S. by Dakota Gasification Company at their North Dakota lignite-to-SNG plant (the Great Plains Synfuels Plant) located in Beulah, ND. The plant started operation in 1984, producing about 145 MM SCF/day of SNG and supplying about 150 MM SCF/day of CO2 to two Canadian oil fields for enhanced oil recovery. Information published by the Dakota Gasification Company indicates that the lignite-to-SNG plant has successfully operated 14 Lurgi gasifiers without a spate while maintaining an annual plant loading as high as 92%.25 That is, the plant annually produces up to 92% of its rated output capacity. Based on available information from the Great Plains Synfuels Plant, corrosion issues in the boiler system, which uses H2S-rich waste gas from the Rectisol Process as fuel, account for over 2% of the loss on production capacity.

The HTAS-TREMP process has been demonstrated at a scale of about 2 MM SCF/day. Both the Lurgi and the HTAS fixed-bed processes use cooled recycle gas feed and interstage cooling to the staged reactors to control the catalyst bed temperature. The Comflux process, which uses a fluidized bed reactor with internal cooling to control the reaction temperature, was developed in the mid 1970’s by Thyssengas (currently owned by RWE of Germany) and Didier Engineering with financial support from the (West)
German government. This technology apparently has not been commercialized. The HICOM process was developed by British Gas. A demonstration plant has been constructed at their Westfield Development Center, but apparently, no independent units have been sold.

**Study Basis**

The EIO has recently completed a detailed survey on the current usage of natural gas and electricity in the Chicago, IL area and four “cluster” areas of Ohio. The data are presented in Table 1.

Based on the EIO natural gas demand profile and literature data, we have developed the basic mass/energy balances plus cost data for three different coal-to-SNG (plus specific co-production of electricity for sale) plant design cases that are summarized in Table 7.

<table>
<thead>
<tr>
<th>Table 7. Design Basis Developed from Literature Data</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Design Basis</strong></td>
</tr>
<tr>
<td>Coal Type used in the literature document</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>Coal feed rate, metric tons/day</td>
</tr>
<tr>
<td>SNG production, MM SCF/day</td>
</tr>
<tr>
<td>Pressure of SNG product, psig</td>
</tr>
<tr>
<td>Net electric power for export, MW</td>
</tr>
<tr>
<td>CO₂ Capture and Compression to 2,000 psig</td>
</tr>
<tr>
<td>CO₂ Captured, metric tons/day</td>
</tr>
<tr>
<td>Literature cost basis</td>
</tr>
<tr>
<td>Total capital need, $MM (May 2009 dollars)</td>
</tr>
<tr>
<td>SNG Selling Price (ROI of about 12%, 13% capital charge factor), $/MM Btu</td>
</tr>
</tbody>
</table>

1. Coal at $35/metric ton (May 2009 $); electricity at $0.08/kW-hr; SNG at 254 psig, operating factor of 95%
2. Same coal/electricity prices, but operating factor at 90% (SNG delivery pressure at 1,000 psig).

The Chemical Engineering Plant Cost Index (CEPCI) was used to adjust the cost basis to reflect our economic analysis in May 2009 dollars.

- **Design Case 1**: A smaller plant that would produce about 19 MM SCF/day of SNG (at 254 psig) using about 1,040 metric tons/day of Illinois No. 6 bituminous coal (typical elemental analysis is shown in Table 8).

For this case, we modified the heat/material balance and cost data provided by the DOE/NETL report, authored by Worley Parsons Group Inc. (with collaboration of Research & Development Solutions, LLC.). For this design, oxygen required for coal gasification would be purchased from a third party contractor; in addition, about 15.8 MW of electric power would need to be imported.

- **Design Case 2**: A moderately bigger plant (study basis: ref. 7) that would use about 4,400 metric tons/day of Eastern Kentucky bituminous coal (ultimate analysis given in Table 1) to co-produce
about 74 MM SCF/day of SNG (at 1,000 psig) and 184 MW of electrical power of which about 176 MW is used for the coal-to-SNG plant and about 8 MW is available for export. Eastern Kentucky bituminous coals are very similar to Ohio coals as shown in Table 8 and, as a result, this study represents the outcomes that would be anticipated for Ohio coals.

- **Design Case-3:** A moderately bigger plant (study basis: ref. 8) that would use about 5,345 metric tons/day of Illinois No. 6 coal to co-produce about 51 MM SCF/day of SNG (at 295 psig) plus 235 MW of net electric power for sale. This specific presentation (Marano et al.) included a specific design case for using a “Single-Stage Dry-Feed Quench” type gasifier with CO₂ recovery and compression to 2,000 psig, for the co-production of SNG and electricity from moderately fired (12 wt % moisture) lignite. We modified this case for Illinois No. 6 coal by assuming the same feed rate moisture and ash-free coal and the same overall efficiency (48% based on HHV of feed coal) for the production of SNG and electric power. As Ohio bituminous coals (analysis shown in Table 8) are very similar to Illinois No. 6 bituminous coal, the scoping economics developed in this study using the Design Case-3 would be very similar if we use Ohio bituminous coals. Further, the price of Ohio coal, at least as far as recent data indicates, is quite close to that of Illinois coal – EIA reports⁵ that the average price of Illinois coal was $40.28 per ton while the corresponding price of Ohio coal was $41.91. Based on price and composition being similar we would expect SNG price for minemouth plants to also be similar. The lower sulfur, higher carbon and higher heating value of the Ohio coal would compensate for the slightly higher price on a per ton basis.

As a comparison, the only coal-to-SNG commercial scale plant in the U.S. (owned by Dakota Gasification Company) produces about 145 MM SCF/day of SNG from lignite.

For all these design cases, most of the CO₂ produced during coal-to-SNG processing is recovered at about 95+ mol % purity for delivery at about 2,000 psig.

<table>
<thead>
<tr>
<th>Bituminous Coal Source</th>
<th>Illinois No. 6 (Case-1)</th>
<th>Eastern Kentucky (Case-2)</th>
<th>Typical Ohio Bituminous Coal⁴,⁵</th>
</tr>
</thead>
<tbody>
<tr>
<td>Component, wt %</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Carbon</td>
<td>64.98</td>
<td>69.91</td>
<td>71.07</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>4.36</td>
<td>4.57</td>
<td>5.07</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>1.28</td>
<td>1.39</td>
<td>1.37</td>
</tr>
<tr>
<td>Chlorine</td>
<td>0.09</td>
<td>0.09</td>
<td>0.10</td>
</tr>
<tr>
<td>Sulfur</td>
<td>3.15</td>
<td>0.77</td>
<td>2.62</td>
</tr>
<tr>
<td>Oxygen</td>
<td>7.41</td>
<td>7.15</td>
<td>7.74</td>
</tr>
<tr>
<td>Ash</td>
<td>11.76</td>
<td>10.03</td>
<td>9.70</td>
</tr>
<tr>
<td>Moisture</td>
<td>6.97</td>
<td>6.09</td>
<td>2.33</td>
</tr>
<tr>
<td>Total</td>
<td>100.00</td>
<td>100.00</td>
<td>100.00</td>
</tr>
<tr>
<td>Higher Heating Value, Btu/lb</td>
<td>11,714</td>
<td>12,581</td>
<td>12,855</td>
</tr>
</tbody>
</table>
Design Case 1

A schematic of the coal-to-SNG process used in the DOE/Worley Parsons Group report is shown in Figure 4. This study is based on the use of (i) oxygen-blown BGL-1000 (British Gas Lurgi) coal gasifiers, which are being marketed in North America by Allied Syngas Corporation and (ii) Lurgi's syngas-to-methane technology. As shown in Figure 1, syngas from coal gasification is cooled and processed to remove tar and other liquids plus water and a part of the gas is sent to a Water Gas Shift reactor to convert carbon monoxide and water to hydrogen and carbon dioxide. The total syngas is then sent to a Rectisol AGR (Acid Gas Removal) unit to remove sulfur compounds and CO₂. The sweet syngas is then processed in a syngas-to-SNG plant.

The SNG plant, producing about 34,469 lb/hr (~19.2 million SCF/day) of SNG, involves the use of about 95,409 lb/hr of #6 coal. About 2,944 lb/hr of elemental sulfur is produced as a co-product. A sketch of the major process steps used in the process is presented in Figure A-1 (Appendix A). The system contains the following key process steps:

- The gasification process consists of (i) an oxygen-fired BGL gasifier producing about 1,000 MM Btu/hr of syngas, (ii) coal/limestone feed lock for introducing feedstock into the gasifier, (iii) syngas wash cooler and primary heat exchanger for cooling syngas and removing tars, oils, and particulates from the syngas, (iv) gas/liquid separation and tar/oil recycle process for removing tars and oils from syngas condensate for reinjection into the gasifier, (v) syngas coolers for reducing the temperature of the syngas to meet the requirements of syngas cleanup system and (vi) a slag quench vessel and slag lock for removing slag from the gasifier.
- A spare gasifier with coal/limestone feed lock, gas wash cooler, slag quench vessel, and slag lock vessel.
- A syngas cleanup system consisting of (i) a Rectisol acid gas removal system (AGR) for removal and concentration of acid gases (H₂S and COS) from the syngas to the levels required for the syngas methanation process, and (ii) a Claus plant for producing elemental sulfur by-product. The Rectisol AGR system is also used to remove benzene, toluene, and xylene (naphtha-BTX) from the syngas stream for recycle to the gasifier.
- A part of the syngas is processed in a water-gas shift reactor (WGR) system for increasing the hydrogen/carbon ratio of the syngas to that required (about 3.2) for the methanation process.
- A methanation process (schematic shown in Figure 4) for producing SNG from the syngas.
- A wastewater treatment system for removing contaminants from the liquor prior to recycling the waste water or discharging it to the environment.
- Suitable coal and limestone (used as a flux) receiving, storage and delivery systems.
- A slag handling system for collecting the slag discharged from the slag lock and transporting the slag to a storage and truck loading area.
- An air separation unit (ASU) owned and operated by a third party that provides oxygen and nitrogen to the gasification process.
- A steam system for providing deaerated water to process and generating steam for the gasification process.
- Balance of Plant systems including (i) a process water supply system, (ii) a flare system, (iii) an air supply system, (iv) a natural gas supply system, (v) instrumentation and control systems, and (vi) chemical and by-product storage facilities.
Figure 4. Sketch of the Major Systems Comprising the Coal-to-SNG Plant (Design Case 1)

Table A-1 (Appendix A) provides flow rates and temperature/pressure conditions of key process streams (identified in Figure A-1) of the plant. A summary of the estimated performance resulting from heat and mass balance calculations (based on the DOE/NETL study plus process modifications made for this specific GTI study) are presented in Table A-2. The capital cost estimates are given in Tables A-3 and A-4. The annual operating cost projections are given in Table A-5.

The plant consumes about 1,039 tons (1,118 MM Btu/hr on HHV basis) of Illinois No. 6 coal/day to produce about 34,469 lb/hr (~19.2 MM SCF/day or 791 MM Btu/hr on HHV basis) of SNG. Therefore, about 70% of the energy content of the coal is recovered in the SNG product. SNG product specifications for the Design Cases 1 and 2 are given in Table 9. For Design Case 3, a HHV of 969 Btu/SCF was assumed for the product SNG.

<table>
<thead>
<tr>
<th>Table 9. SNG Product Specifications</th>
</tr>
</thead>
<tbody>
<tr>
<td>Design Case</td>
</tr>
<tr>
<td>SNG Constituents</td>
</tr>
<tr>
<td>Methane, CH₄</td>
</tr>
<tr>
<td>Carbon Dioxide, CO₂</td>
</tr>
<tr>
<td>Hydrogen, H₂</td>
</tr>
<tr>
<td>Carbon Monoxide, CO</td>
</tr>
<tr>
<td>Nitrogen, N₂ + Argon, Ar</td>
</tr>
<tr>
<td>Trace Hydrocarbons</td>
</tr>
<tr>
<td>Higher Heating Value, HHV (Btu/SCF) at 14.7 psia/60°F</td>
</tr>
</tbody>
</table>

CO₂ Capture and Sequestration

For CO₂ capture and sequestration, we have assumed that the CO-rich tail gas from the Rectisol AGR system would be combusted with oxygen and the flue gas would be cooled and dehydrated prior to compression to 2,000 psig. In the DOE/NETL report, this tail gas stream is used as a fuel in a fired boiler (with air as oxidant) to generate steam for the SNG plant. As oxygen would be available at about 500 psig, we have assumed that the oxygen is first depressurized to 1 atm pressure before combustion of the tail gas; the flue gas is compressed to remove water and the CO₂ rich stream is compressed to about 2,000 psig. The capital costs for tail gas compression and CO₂ compression are included in the capital cost estimate.

Design Case 2

A schematic of the basic process steps chosen for Design Case 2 is shown in Figure 5. For the gasification reactor type, a single-stage, slurry-fed gasifier with quench has been used. The quench removes most of the hydrogen chloride and particulate matter before further processing of the syngas. The syngas stream leaving the gasifier is split and a fraction is sent to a raw water gas shift reactor to adjust the hydrogen-to-carbon monoxide molar ratio to that required for the methanation process. The
other portion of the syngas is sent to a COS (carbonyl sulfide) hydrolysis unit for the conversion of COS to hydrogen sulfide. The two streams, with a molar H$_2$/CO ratio of about 3.0, are then combined and cooled before removal of residual mercury. The cooled gas is then processed in a Selexol type AGR unit for removal of hydrogen sulfide and CO$_2$.

Depending on operating conditions, the syngas effluent from the AGR process would contain about 1-2 ppmv hydrogen sulfide which is too high for typical catalyst systems used in a methanation process. For this reason, a “sulfur polishing” step would be used to reduce the level of hydrogen sulfide to typically below 0.03 ppmv. The clean syngas from the “sulfur polishing” step is sent to the methanation section of the plant. For this literature report, the authors had conducted simulation studies based on expected performance of the Haldor-Topsoe TREMP process. The SNG product from this step is cooled, dried, and compressed to 1,000 psig.

For the “power generation” block, a portion of the clean syngas from the AGR step is processed in a package boiler for combustion with air. The hot flue gas is used to produce steam for generating electricity in steam turbine. The steam generated from the methanation unit is also used in this steam turbine.

The plant performance data are given in Table A-6 (Appendix A); the overall thermal efficiency for this case is 58.9% (HHV basis). The estimated capital and operating cost data are given in Tables A-6, A-7 and A-8. For this design case, the net excess electrical power for sale is about 8 MW.
Figure 5. Process Schematic – Design Case 2
Table 10. Parameters for Gasifier Operations Assumed in Design Case 3

<table>
<thead>
<tr>
<th>Gasifier Type</th>
<th>Single-Stage Dry Feed Quench (Shell type)</th>
<th>Single-Stage Dry Feed Quench Advanced (GSP Process)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity Factor, %</td>
<td>85</td>
<td>90</td>
</tr>
<tr>
<td>Carbon Utilization, %</td>
<td>95</td>
<td>99</td>
</tr>
<tr>
<td>Feed Coal Moisture, wt %</td>
<td>12</td>
<td>8</td>
</tr>
<tr>
<td>Cold Gas Efficiency (HHV), %</td>
<td>77.5</td>
<td>80</td>
</tr>
</tbody>
</table>

For this GTI study, we used the “quench advanced” (based on the GSP Process) performance data. The GSP process was formerly known as the Babcock Borsig Power (BBP) Noell process. Future Energy GmbH acquired the IP rights, the test facilities, and the entire patent portfolio from BBP in 2002. The GSP process was used at Schwarze Pumpe Germany until 1991. The gasifier had a coal feed capacity of about 700 tons/day (~130 MW thermal). The plant had been used to produce synthesis gas for a methanol plant.

As shown in Figure 6, following gasification and after water quench, the raw syngas is sent to a raw gas shift unit where the hydrogen-to-carbon monoxide ratio is adjusted to about 3:1 to be compatible with methanation. The shift effluent is cooled and passed to the activated carbon reactor to remove mercury. The syngas is then sent to sulfur removal to produce a concentrated stream of hydrogen sulfide for processing in a Claus SCOT combination for sulfur recovery. After sulfur removal, the syngas is sent to a bulk CO₂ removal system. The recovered CO₂ is dehydrated and compressed to about 2,000 psig. The CO₂-lean syngas is then sent to a sulfur polishing reactor to remove residual hydrogen sulfide before it is processed in a methanation unit. Some of the syngas exiting the bulk CO₂ removal system is sent to a gas turbine for generation of electric power. The hot effluent from the gas turbine is further processed in a heat recovery steam generator (HRSG) to produce high pressure steam which is used to generate additional electric power.

- Table 11 provides the key mass balance and cost data reported by Marano et al. for the coproduction of SNG/electricity for the “quench advanced” case. We have modified the data to reflect differences in heating values for Illinois No. 6 coal and the Texas lignite referred to in the Marano study. As Ohio bituminous coals (analysis shown in Table 8) are very similar to Illinois No.6 bituminous coal, the scoping economics developed in this study using the Design Case-3 would be very similar if we use Ohio bituminous coals.

The cost numbers (reported in 2004 dollars) were modified to May 2009 dollars by using the CEPCI (Chemical Eng. Plant Cost Index) data. For the operating costs in 2009 dollars, we used an inflation number of 3% per year.
Table 11. Modifications of the Key Mass Balance and Cost Data for Design Case 3

<table>
<thead>
<tr>
<th></th>
<th>Data Reported by Marano et al. Using Texas Lignite</th>
<th>Modified Data Using Illinois No. 6 Coal</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal Feed rate</td>
<td>5,707 short tons/day (as received)*</td>
<td>5,344 metric tons/day (as received)</td>
</tr>
<tr>
<td>SNG produced, MM SCFD</td>
<td>39</td>
<td>51</td>
</tr>
<tr>
<td>Pressure of SNG Product Stream (delivered), psig</td>
<td>295</td>
<td>1,000</td>
</tr>
<tr>
<td>Power Net, MW</td>
<td>235</td>
<td>232**</td>
</tr>
<tr>
<td>Overall efficiency (HHV basis), %</td>
<td>48</td>
<td>48</td>
</tr>
<tr>
<td>Capital, $MM</td>
<td>760 (2004 dollars)</td>
<td>882 (May '09 $)</td>
</tr>
<tr>
<td>O &amp; M (less coal), $MM/yr</td>
<td>39</td>
<td>45 (May '09 $)</td>
</tr>
<tr>
<td>CO₂ Captured</td>
<td>7,713 Short tons/day 7,950 metric tons/day**</td>
<td></td>
</tr>
</tbody>
</table>

* As received lignite (following drying) moisture level at 8 wt%; HHV is 12,890 Btu/lb for MAF (moisture & ash free basis) lignite.
** Extra power need for the compression of SNG to 1,000 psig = 3.0 MW.
*** This reflects roughly 10% higher carbon (MAF basis) in Illinois No. 6 coal vs. Texas lignite.

Example Case: Texas Lignite to Power and SNG

Figure 6. Conceptual Process Flow Diagram: Coal to SNG + Electricity (Design Case 3)
Scoping Economics

Based on the mass/heat balance plus cost data noted above for three design cases and EIO data on the demand scenario for different clusters in Ohio and Illinois, we have developed scoping economics (summarized in Table 12) for four different cases with different coal feed rates and different ratios for SNG: Net Electrical Power production.

Table 12. Summary of Scoping Economics Results for Four Cases Analyzed in this Study

<table>
<thead>
<tr>
<th>Scoping Economics Case, May 2009$</th>
<th>A</th>
<th>B</th>
<th>C only</th>
<th>D only</th>
</tr>
</thead>
<tbody>
<tr>
<td>Design Basis</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Capacity Factor, %</td>
<td>90</td>
<td>90</td>
<td>90</td>
<td>90</td>
</tr>
<tr>
<td>Coal feed rate, Metric tons/day</td>
<td>6,383</td>
<td>9,738</td>
<td>4,394</td>
<td>5,344</td>
</tr>
<tr>
<td>SNG production, MM SCF/Day</td>
<td>70.5</td>
<td>125</td>
<td>74</td>
<td>51</td>
</tr>
<tr>
<td>Pressure of SNG Product (delivered), psig</td>
<td>1,000</td>
<td>1,000</td>
<td>1,000</td>
<td>1,000</td>
</tr>
<tr>
<td>Net Electric Power for sale, MW</td>
<td>215.0</td>
<td>240</td>
<td>8</td>
<td>232</td>
</tr>
<tr>
<td><strong>Total Capital, $MM</strong></td>
<td>965 $a</td>
<td>1,588 $b</td>
<td>883</td>
<td>882</td>
</tr>
<tr>
<td>Annual Capital-related costs (13% capital charge), $/MM/yr</td>
<td>125.5</td>
<td>206.4</td>
<td>114.8</td>
<td>114.7</td>
</tr>
<tr>
<td>Total O&amp;M Costs, $/MM/yr, excluding coal</td>
<td>69.5</td>
<td>104.6</td>
<td>58.8</td>
<td>45.2</td>
</tr>
<tr>
<td>Cost of coal at $35/metric ton, $/MM/yr</td>
<td>73.4</td>
<td>112.0</td>
<td>50.5</td>
<td>61.4</td>
</tr>
<tr>
<td>Credit from sale of electric power, $/MM/yr at $0.08/kW-hr</td>
<td>135.6</td>
<td>151.4</td>
<td>5.1</td>
<td>146.3</td>
</tr>
<tr>
<td>Credit for CO₂ sale</td>
<td>None</td>
<td>None</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>Net annual cost, $MM/yr</td>
<td>132.8</td>
<td>271.6</td>
<td>219.0</td>
<td>75.0</td>
</tr>
<tr>
<td>Selling Price of SNG at about 13% ROI (electric power at $0.08/kW-hr), $/MM Btu</td>
<td>5.73</td>
<td>6.61</td>
<td>9.01</td>
<td>4.48</td>
</tr>
<tr>
<td>SNG Selling Price, $/MM Btu, Sensitivity with Electric Power at $0.10/kW-hr</td>
<td>4.27</td>
<td>5.69</td>
<td>8.96</td>
<td>2.29</td>
</tr>
<tr>
<td>at $0.07/kW-hr</td>
<td>6.46</td>
<td>7.07</td>
<td>9.04</td>
<td>5.57</td>
</tr>
<tr>
<td>at $0.04/kW-hr</td>
<td>8.66</td>
<td>8.45</td>
<td>9.11</td>
<td>8.84</td>
</tr>
</tbody>
</table>

*a. Assume 8% reduction in total CAPEX due to plant integration.
  b. Assume 10% reduction in total CAPEX due to plant integration.*
For estimation of the "Required Selling Price" (RSP) for SNG, we have assumed a ROI target of about 12-13% by using a "capital charge factor" of 13% of capital cost as the capital-related expenses. As there are currently no CO₂ pipelines in Illinois and Ohio, we have not taken any credit for potential sale of CO₂ for EOR applications.

**EIA Projections on the Price of Coal, Electricity, and Natural Gas**

Figure 7 shows the recent EIA projections for the price of U.S. coals for the period 2010-2030. The data on "Interior" coals reflect coal supplies from coal mines in Ohio, Illinois, and Indiana, etc. For as-received Ohio coals (typical analysis shown in Table 8), a price of $35/metric ton (2009 dollars) corresponds to about $1.24/MM Btu; for Illinois No. 6 coal, a price of $35/metric ton would correspond to about $1.36/MM Btu.

![Figure 7. EIA Projections on Prices of U.S. Coals](image)

Figure 8 shows the recent EIA projections for prices of natural gas the U.S. for the period 2010-2025. Similar data from EIA and other agencies are also presented in Table 13. Based on these projections, the price of natural gas during 2015 could be:

- $6.9-$9.4/MM Btu (2007 dollars) for the generation of electricity,
- $12.32-$14.59/MM Btu for residential markets,
- $7.21-$10.67/MM Btu for industrial markets, and
- $10.86-$13.06/MM Btu for commercial markets.

EIA projections on the price (2007 dollars) of electricity for the period 2010-2030 are shown in Figure 9. These data indicate:

- The average U.S. retail electricity price during 2015 could be in the range of 8-10 cents/kW-hr (2007 dollars).
Figure 64. Lower 48 wellhead and Henry Hub spot market prices for natural gas, 1990-2030 (2007 dollars per million Btu)

Figure 65. Lower 48 wellhead natural gas prices in five cases, 1990-2030 (2007 dollars per thousand cubic feet)

Figure 8. EIA Projections on the Price (2007 dollars) for Natural Gas
Table 13. EIA Projection on Natural Gas Price (2007 dollars) for Specific Markets in 2015 and 2025

Annual Energy Outlook 2009 with Projections to 2030

Table 19. Comparison of natural gas projections, 2015, 2025, and 2050 (trillion cubic feet, except where noted)

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Figure 9. EIA Projections on the Price of Electricity during 2010-2030
Results and Discussion

Various estimates from EIA and others indicate the potential for a significant shortfall (about 4-7 TCF, trillion cubic feet per year) of natural gas in the U.S. in the next 5-20 years. Although the price of natural gas has dropped to below $3/MM Btu recently, various projections indicate that the future price for the period 2015-2025 could reach about $6.9-$9.4/MM Btu (2007 dollars) for the electricity generation market, about $12.3-$14.6/MM Btu for residential markets, about $7.2-$10.7/MM Btu for industrial markets, and about $10.9-$13.1/MM Btu for commercial markets. Similarly, the average U.S. retail electricity price during 2015-2025 could be in the range of $0.08-$0.10/kW-hr (2007 dollars) and higher.

Our analysis on Economic Case D indicates that the approximate capital cost of a coal-to-SNG plant (using about 5,345 metric tons/day of bituminous coals from Ohio or Illinois) producing about 50 MM SCF/day of SNG and about 230 MW of net electricity for sale would be about $500 million (May 2009 dollars). This cost estimate includes very high recovery (plus compression to 2000 psig) of nearly pure CO₂ that would be generated in such a plant. With a price of about $35/metric ton for bituminous coals from Ohio and Illinois, an electricity price of $0.08/kW-hr and a target ROI of about 12-13%, the required selling price for SNG of about $4.50-$5.00/MM Btu (2009 dollars) can potentially be achieved. These estimates look quite attractive based on the future price projections for natural gas by EIA.

As there is no existing CO₂ pipeline in Illinois or Ohio that could transport CO₂ to key EOR markets in Canada or the U.S., it would be very expensive (e.g., about $500-$1000 million) to build a new CO₂ pipeline. Various groups (e.g., Denbury Resources Inc.) are currently evaluating the potential of building CO₂ pipelines to utilize CO₂ from multiple coal gasification projects in the Midwest for EOR applications in the U.S. and Canada. Based on a report from the Institute of Transportation Studies, University of California, Davis, a pipeline carrying 10,000 metric tons/day of CO₂ would cost about $50 million (2009 dollars) for a length of 100 kilometers and $275 million for a length of 500 km.

As the NE Ohio cluster is located in the middle of a large oil field (the Clinton Formation), this area has the greatest chance of economically implementing CCS (carbon capture and storage) through EOR. For transporting 10,000 tons/day of nearly pure CO₂, the approximate required selling price (at about 12-13% ROI; assuming 25% of CAPEX cost/year to account for capital, operating and related expenses) would need to be about $3.5/ton (2009 dollars) of CO₂ for a 100 km pipeline, and $19/ton for a 500 km pipeline. For Case D economic scenario, the CO₂ production rate is about 7,950 metric tons/day.

If there is an interest on the part of EIO, GTI could work with specific firms (e.g., Synthesis Energy Systems Inc. that has commercialized GTI's U-Gas coal gasification technology, or Allied Syngas Corporation which is the marketer of the BGL gasification technology in the US, and an SNG technology licensor like Haldor Topsoe) to develop detailed mass/energy balances and cost estimates of a plant (for a specific Ohio location) with coal feed rate and product distributions similar to the Economic Case D presented in this study.
Figure A-1: Conceptual Process Flow Diagram: Coal to SNG (Design Case 1; Key Mass Balances Given in Table A-1)
### Appendix-A

**Table A-1. Production of SNG from Illinois No. 6 Coal: Flow Rates and T/P Conditions for Specific Streams (stream numbers are given in Figure A-1), Design Case-1**

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Evaluation of Feasibility of Industrial Gasification...  Page 20
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**Table-A-1 Continued**
### Table A-2. SNG Production Plant Estimated Performance Summary (Design Case 1)

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<td>Elemental Sulfur Products, lb/hr</td>
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<td>Recovered Carbon Dioxide Stream, lb/hr</td>
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<td>Auxiliary Electric Power (Syngas plant + Tail Gas/CO₂ Compression), kWe¹</td>
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<td>ASU Electric Power, kWe</td>
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<td>Energy in SNG Product, MM Btu/hr (HHV)</td>
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<td>Plant net Thermal Efficiency, %</td>
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1. Electric power to compress CO₂ is 1,837 kW and tail gas to Oxy-Combustor is 5,162 kW
2. This reflects SNG delivery pressure of 254 psig. An additional 1.1 MW is needed for compression to 1,000 psig
3. Auxiliary power and ASU power expressed as thermal energy to utility power generation plant with HHV efficiency of 32.8%
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<td></td>
<td>Total Field Cost</td>
<td>120.85</td>
<td></td>
<td>131.43</td>
</tr>
</tbody>
</table>

CE Plant Cost Index: 2005=468.2, May 09=509.2
Ref.: IECM Technical Manual for IGCC

Evaluation of Feasibility of Industrial Gasification... Page 24
### Table A-4. Additional Capital Costs (MMS): Design Case 1

<table>
<thead>
<tr>
<th>Description</th>
<th>MMS (May 2009 $)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Home Office, 8% of Total Field Cost (TFC)</td>
<td>10.5</td>
</tr>
<tr>
<td>Process Contingency, 2.4% of TIC</td>
<td>3.2</td>
</tr>
<tr>
<td>Project Contingency (including land), 5.5% of TIC</td>
<td>7.2</td>
</tr>
<tr>
<td>License Fees, 3.5% of TIC</td>
<td>4.6</td>
</tr>
<tr>
<td>Financing/Legal, 3.5% of TIC</td>
<td>4.6</td>
</tr>
<tr>
<td>Non-depreciable Capital, 4% of TIC</td>
<td>5.3</td>
</tr>
<tr>
<td>Additional Capital Costs Subtotal, $MM</td>
<td>35.4</td>
</tr>
<tr>
<td>Total Field Cost, $MM</td>
<td>131.4</td>
</tr>
<tr>
<td>Total Capital Cost, $MM (May 2009 $)</td>
<td>167</td>
</tr>
</tbody>
</table>

### Table A-5. Estimated Annual Operating & Maintenance Costs (Capacity factor: 95%)—Case 1

<table>
<thead>
<tr>
<th>Description</th>
<th>$MM/yr (June 2005$)</th>
<th>$MM/yr (May 2009$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating Labor</td>
<td>3.28</td>
<td></td>
</tr>
<tr>
<td>Maintenance Labor</td>
<td>1.69</td>
<td></td>
</tr>
<tr>
<td>Administrative &amp; Support Labor</td>
<td>1.24</td>
<td></td>
</tr>
<tr>
<td>Chemicals $^a$</td>
<td>0.61</td>
<td></td>
</tr>
<tr>
<td>Maintenance Materials</td>
<td>2.53</td>
<td></td>
</tr>
<tr>
<td>Oxygen at $34.5/metric ton</td>
<td>7.03</td>
<td></td>
</tr>
<tr>
<td>Supplemental fuel</td>
<td>0.18</td>
<td></td>
</tr>
<tr>
<td>Waste Slag Disposal</td>
<td>0.92</td>
<td></td>
</tr>
<tr>
<td>Sub-total</td>
<td>17.48</td>
<td>19.70</td>
</tr>
<tr>
<td>Coal feed at $35/metric ton</td>
<td>12.61</td>
<td></td>
</tr>
<tr>
<td>Royalties</td>
<td>1.2</td>
<td>(operating factor of 95%)</td>
</tr>
<tr>
<td>Auxiliary power (excluding ASU) at $0.08/kW-hr</td>
<td>10.5</td>
<td></td>
</tr>
<tr>
<td>Local Taxes/Insurance, 2.6% of TFC</td>
<td>3.42</td>
<td></td>
</tr>
<tr>
<td>Total Annual Operating costs</td>
<td>47.43</td>
<td></td>
</tr>
<tr>
<td>By-Product Credit, Sulfur at $50/ton</td>
<td>(0.61)</td>
<td></td>
</tr>
<tr>
<td><strong>Net Annual Operating Costs, $MM/year</strong></td>
<td><strong>46.82</strong></td>
<td></td>
</tr>
</tbody>
</table>

$^a$ Water-gas shift + SNG catalysts, Limestone Flux, methanol.
<table>
<thead>
<tr>
<th>Production Figures</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>SNG Product Flow, MM SCF/day</td>
<td>74</td>
</tr>
<tr>
<td>SNG Product, MM Btu/day (HHV)</td>
<td>71,736</td>
</tr>
<tr>
<td>SNG Higher Heating value (HHV), Btu/lb</td>
<td>22,956</td>
</tr>
<tr>
<td></td>
<td>969</td>
</tr>
<tr>
<td>Elemental Sulfur Products, metric tons/day</td>
<td>34.5</td>
</tr>
<tr>
<td>Recovered CO₂ stream, metric tons/day</td>
<td>7,454</td>
</tr>
<tr>
<td>CO₂ Released, metric tons/day</td>
<td>150</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Consumption Figures</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal Feed, lb/hr</td>
<td>403,668</td>
</tr>
<tr>
<td>Metric tons/day</td>
<td>4,394.4</td>
</tr>
<tr>
<td>Oxygen to Gasifier, metric tons/day</td>
<td>3,886</td>
</tr>
<tr>
<td>Gross Electric Power, MW</td>
<td>184</td>
</tr>
<tr>
<td>Parasitic Electric Power for the Plant, MW</td>
<td>176</td>
</tr>
<tr>
<td>Net Power to Sale, MW</td>
<td>8</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Plant Equivalent Efficiency</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy in Coal (HHV), MM Btu/day</td>
<td>121,885</td>
</tr>
<tr>
<td>Energy in Products (HHV), MM Btu/day</td>
<td>71,736</td>
</tr>
<tr>
<td>Plant Net Thermal Efficiency (HHV Basis), %</td>
<td>58.9%</td>
</tr>
</tbody>
</table>
Table A-7. Summary of Capital Cost Estimate Design Case 2

<table>
<thead>
<tr>
<th>Item</th>
<th>Total Field Cost (TFC), $Million (2007$)</th>
<th>Comments</th>
<th>TFC, May 09 $</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal and Sorbent Handling</td>
<td>20</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal and Sorbent Prep and Feed</td>
<td>34</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Feed Water and Misc. Balance of Plant Systems</td>
<td>26</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gasifier and Accessories</td>
<td>153</td>
<td>Single Stage, Slurry-feed Gasifier with Quench Design</td>
<td></td>
</tr>
<tr>
<td>Air Separation Unit and Compression</td>
<td>81</td>
<td>Oxygen purity: 99.5 mole %</td>
<td></td>
</tr>
<tr>
<td>Syngas Cleanup and Water-gas Shift</td>
<td>113</td>
<td>Includes Selexol AGR System</td>
<td></td>
</tr>
<tr>
<td>CO₂ Compression</td>
<td>17</td>
<td>For this Univ. of Kentucky study, CO₂ is delivered at 2,000 psig</td>
<td></td>
</tr>
<tr>
<td>Methanation</td>
<td>79</td>
<td>Based on the Haldor-Topsoe TREMP Technology</td>
<td></td>
</tr>
<tr>
<td>Boiler with Ducts and Stack</td>
<td>38</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Steam Turbine and Accessories</td>
<td>51</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cooling Water System</td>
<td>27</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ash and Spent Sorbent Handling Systems</td>
<td>29</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Accessory Electric Plant</td>
<td>12</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Instrumentation and Controls</td>
<td>14</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Improvements to Site</td>
<td>12</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Buildings and Structures</td>
<td>12</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total Field Cost (Capital Equipment), TFC, $MM</strong></td>
<td><strong>718</strong></td>
<td></td>
<td><strong>781</strong></td>
</tr>
</tbody>
</table>

CE Plant Cost Index: 2005=468.2, May 09=509.2
## Table A-8. Additional Capital Costs (MMS): Design Case 2

<table>
<thead>
<tr>
<th>Description</th>
<th>$MM, 2007$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Home Office, 8% of Total Field Cost (TFC)</td>
<td>57.4</td>
</tr>
<tr>
<td>Process Contingency, 2.4% of TIC</td>
<td>17.2</td>
</tr>
<tr>
<td>Project Contingency (including land), 5.5% of TIC</td>
<td>39.5</td>
</tr>
<tr>
<td>License Fees, 3.5% of TIC</td>
<td>25.1</td>
</tr>
<tr>
<td>Financing/Legal, 3.5% of TIC</td>
<td>25.1</td>
</tr>
<tr>
<td>Non-depreciable Capital, 4% of TIC</td>
<td>28.7</td>
</tr>
<tr>
<td>Total Field Cost, TFC, $MM (2007$)</td>
<td>718</td>
</tr>
<tr>
<td>Total Capital Requirement, $MM (May 2007$)</td>
<td>911</td>
</tr>
<tr>
<td><strong>Total Capital Cost, $MM (May 2009$)</strong></td>
<td><strong>883</strong></td>
</tr>
</tbody>
</table>

Index: 2009 = 509.2 vs. 525.4 for 2007

## Table A-9. Estimated Annual Operating & Maintenance Costs

(Capacity factor: 95%) – Case 2

<table>
<thead>
<tr>
<th>Description</th>
<th>$MM/yr (2007$)</th>
<th>$MM/yr (May 2009$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating Labor/Overhead</td>
<td>18</td>
<td></td>
</tr>
<tr>
<td>Administrative and Support Labor</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>Catalysts + Chemicals</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>Maintenance Materials</td>
<td>7</td>
<td></td>
</tr>
<tr>
<td>Other Operating Costs</td>
<td>2</td>
<td></td>
</tr>
<tr>
<td>Royalties</td>
<td>4</td>
<td></td>
</tr>
<tr>
<td>Local Taxes/Insurance</td>
<td>19</td>
<td></td>
</tr>
<tr>
<td>Subtotal, $MM</td>
<td>56</td>
<td>59.4*</td>
</tr>
<tr>
<td>Coal feed at $35/metric ton</td>
<td>50.5</td>
<td></td>
</tr>
<tr>
<td>Total Annual Operating costs</td>
<td>109.9</td>
<td></td>
</tr>
<tr>
<td>By-product credit, Sulfur at $50/metric ton</td>
<td>(0.57)</td>
<td></td>
</tr>
<tr>
<td>Net Annual Operating Costs with coal, $MM/year</td>
<td><strong>109.3</strong></td>
<td></td>
</tr>
</tbody>
</table>

* At 3% annual increase
Figure A-2. Existing U.S. CO₂ Pipelines
References