# FINAL TECHNICAL REPORT
April 1, 2005, through August 31, 2005

Project Title: **GASIFICATION-BASED PRODUCTION OF CHEMICALS FROM ILLINOIS COAL STANDALONE AND IGCC COPRODUCTION MODES – PHASE 1a**

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## ABSTRACT

The Illinois Clean Coal Institute (ICCI) initiated this study with Eastman Gasification Services Company (EGSC) to evaluate the feasibility of chemicals production from Illinois coals and lay the groundwork for chemicals project development in the State of Illinois. This report covers the first portion of the work coincident with fiscal year (FY) 2005, and as such reflects work in progress.

EGSC is evaluating two main project options in the course of this work: Standalone coal-to-chemicals based on gasification and syngas processing; and coproduction of chemicals from coal in combination with Integrated Gasification Combined Cycle (IGCC) for power production (Coproduction). This review focuses predominantly on methanol (MeOH) as a representative chemical product in that MeOH is a highly versatile chemical product with a variety of uses in manufacturing and energy applications. However, the results can be extrapolated to a number of additional chemicals that may be particularly advantageous to Illinois.

All major areas that impact the feasibility of a potential coal-to-chemicals project are under evaluation, including the characteristics and suitability of Illinois coals, market prices for chemicals, power, and Illinois coal, capital costs and operating costs of each mode of MeOH production, and commercial factors that ultimately affect financeability.

While methanol demand has traditionally grown with GDP, there will likely be demand growth reductions due to the phase-out of MTBE in North America. However, large potential new markets for methanol may emerge based on high oil and gas prices, new conversion technologies, and the commercialization of gasification based on advantaged coal supplies such as those in Illinois. Such potential markets include methanol for fuel use and methanol-to-olefins, among others. On the supply side, North American methanol production from natural gas, which has historically been a large source for the North American market, has all but disappeared due to high natural gas prices and has been replaced by imported methanol based on "stranded" natural gas supplies. However, a full analysis of the cost targets will necessarily take into account global competition for stranded natural gas, the development of new markets, logistics costs, and the difference in risk and price volatility between domestic, coal-based production and global, gas-based production. That analysis will be done in the next phase of the project.

## EXECUTIVE SUMMARY

The U.S. chemical industry is highly dependent on raw materials derived from petroleum or natural gas. Escalating prices and increased volatility in recent years have magnified the risk of this lack of diversification. The petrochemical industry grew primarily in the Gulf Coast near the bulk of oil and gas reserves and refining capacity. As the cost of oil and gas has risen, chemical complexes in the US have had to modernize, size to scale, or shut down. Many companies have opted to build new facilities in other parts of the world where raw materials and operating costs are more competitive.

However, there are risks associated with relocating to foreign countries including, but not limited to, exchange rate risk, currency risk and the risk of nationalization. Additionally, advantages associated with finding stranded gas for chemical production may become short-lived as countries find alternative outlets for their natural resources.

The escalating prices of oil and gas combined with their inherent volatility have made forecasting future earnings extremely difficult for enterprises dependent on these natural resources, and financial hedges are expensive and limited in duration. Sourcing raw materials in sufficient quality and quantity at a price that ensures some level of profitability has become very difficult.

These issues illustrate the need to diversify energy and raw materials sources. Coal has the potential to be a primary source of energy as well as a feedstock for chemicals due to its abundance of supply, relatively low cost and relatively low price volatility as compared to other fossil fuels. Coal is not without issues and this work is intended to evaluate risks and potential for success, particularly with Illinois coal.

## 1.0 WORK PERFORMED FOR PHASE 1 BY TASK NUMBER

### TASK 1 - METHANOL MARKET ASSESSMENT:

The objective of the methanol market assessment is to understand the dynamics and impact of recent significant restructuring of the methanol industry. The study will address the following:

- Supply/demand analyses for North American (NA) methanol with a focus on the Midwest region.
- Assess potential supply scenarios and analyze the market opportunity for methanol from Illinois coal.
- Evaluate the cost of methanol from coal versus imported methanol.
- Identify the logistical costs of servicing target markets from Illinois.

Phase 1a efforts for this task were focused on industry restructuring, cost models for methanol production (to analyze the competitor costs), and intermediate-term supply/demand forecasts.

TASK 2 – ILLINOIS COAL CHARACTERIZATION (Phase 1a):

In order to determine the overall project feasibility, EGSC needs to gain an understanding of the constituents and variability of the Illinois basin coal resources. Looking only at averages can lead to miscalculations or a plant that cannot perform as designed. To meet this objective, EGSC has obtained core samples from Christian County coal deposits –the design basis coal for the project – and is in the process of developing a broader analysis of Illinois coals from the standpoint of suitability for gasification. To begin this assessment, several questions need to be answered:

- Is the coal a uniform resource?
- What are the critical characteristics?
- What are the impacts of critical characteristics on gasification economics?

In Phase 1a, EGSC has conducted a gasification coal quality impact analysis in which the process and cost effects of major coal constituents on gasification projects are catalogued. EGSC has also developed a model to quantify these impacts, which will be utilized in the subsequent phase of the project.

TASK 3 – FEASIBILITY ANALYSIS – COAL TO METHANOL (Phase 1a):

The detailed work under this task is to be undertaken during Phase 1b, FY2006, of the project. Certain work accomplished under the other tasks has established a foundation for the feasibility analysis as discussed, but full reporting on Task 3 will be done at the conclusion of the project.

TASK EMN-1 – EASTMAN R&D ON COAL-TO-CHEMICALS (Phase 1a):

The work process used for the R&D portion of this study was comprised of four elements:

- Identifying possible chemical product streams,
- Developing economic models and knowledge gap summaries
- Comparing outputs to existing cost metrics
- Determining highest value product streams for further development.

Once the target technologies were identified, efforts were expanded to include the following deliverables: 1) a description of proposed processes, including basic flow sheet, capacity, heat and material balance, cost and capital assumptions; 2) Opinion of technology viability and application (new versus retrofit); and 3) Suggested validation plan, including resource requirements.

Work activities have been focused on several major process groups that reflect perceived manufacturing opportunities in the market. For purposes of the project, the most important of these process groups is the coal-to-methanol group. While the other process groups remain proprietary at this time as part of Eastman's R&D effort, it is believed the present feasibility study will indicate that several of these are viable.

## 2.0 FINDINGS AND COMMENTS ON PHASE 1 WORK

TASK 1 - METHANOL MARKET ASSESSMENT:

The methanol industry in North America (NA) has undergone significant restructuring during the past five years with the startup of so-called “mega” methanol production plants in low-cost natural gas locations outside of the US. Increased production and a lower cost structure will probably culminate in the shutdown of essentially all North American natural gas-based methanol plants by 2007 due to the high cost of gas.

Preliminary findings on the methanol market assessment task include the following:

- After 2007 there will be little, if any, NA MeOH production for commercial markets. A facility to produce MeOH from Illinois coal may be one of very few domestic sources of MeOH and could fill a capacity need for demand for existing methanol uses in the 2011/2012 timeframe.
- The methanol demand in NA will be significantly (20%) impacted in 2006 when MTBE use in the US is discontinued and there may be an oversupply through 2010.
- NA MeOH supply will primarily be sourced from Trinidad and Chile in the near to medium term. Latin American (LA) capacity of 13 million metric tons (MT) per year will be sufficient to meet demand in NA/LA thru 2013 unless new methanol markets develop.
- The fully allocated cost of methanol (manufacturing costs plus depreciation, but excluding return on capital) produced from Illinois coal will need to be in the $0.25-0.30 per gallon range FOB plant to assure a competitive cost position to imports in the near term. However, factors such as the cost of stranded natural gas, the risks of foreign sourcing, and new potential uses for MeOH could dramatically alter this target;
- MeOH produced in Illinois should have advantaged delivery costs for Midwestern and Northern states as well as Canada. To the extent that potential new uses for methanol and related or derived chemicals (e.g., fuel use or coal-to-chemicals infrastructure dispersion) are more evenly distributed geographically, this advantage could prove to be highly significant.

Figure 1 in the report summarizes historical and forecast prices and production costs for North American methanol.

TASK 2 – ILLINOIS COAL CHARACTERIZATION (Phase 1a):

To define feedstock suitability and impacts for gasification for chemicals production, the items listed below are deemed most important in approximate order of impact. For this report, EGSC has identified the critical coal characteristics and outlined how each characteristic impacts design and operations.

1. Carbon Content – The carbon content will set the sizing of the air separation unit (ASU), gasifier, and compressor along with overall auxiliary power consumption.

Carbon content can be varied by washing the coal; therefore, an analysis of potential carbon content versus washing cost may be needed.

2. Ash Chemistry – This sets the gasifier temperature which in turn affects gas composition which then cascades down to all other systems. For a feasibility study, the $T_{250}$ (temperature at which the slag viscosity is 250 centipoise) or the Base/Acid ratio of the mixture of minerals are important ash chemistry measures.
3. Chlorine – The level of chlorine sets the water system chemistry and metallurgy which has a large impact on plant cost and reliability. Illinois coals are typically high in chlorine versus other feedstocks, and therefore this criterion is very important for gasification projects in Illinois.
4. Sulfur – The sulfur content will set the acid gas removal (AGR) unit sizing.
5. Moisture Content – The coal water content will affect syngas properties and slurry characteristic. Unlike ash chemistry and percent carbon, removing moisture in a slurry system requires energy input that could be used elsewhere, and thus has a significant impact on overall efficiency and capital costs.
6. Ash Content – The ash content is expected to be inversely correlated to carbon content. Ash content has a significant impact on design and operations of the gasifier as well as waste disposal costs.
7. Arsenic – Arsenic can cause fouling and therefore needs to be known for sizing, redundancy, and reliability. Inorganic arsenic can be washed out of the coal.

Table 6 in the report shows the process impact analysis in graphical form.

TASK 3 – FEASIBILITY ANALYSIS – COAL TO METHANOL (Phase 1a):

EGSC is evaluating the feasibility of developing a coal-to-chemicals project based on coal gasification in Illinois, utilizing Illinois basin coal. The feasibility analysis will support this objective. Results of this task will be conducted during FY2006 and reported in the corresponding final report.

TASK EMN-1 – EASTMAN R&D ON COAL-TO-CHEMICALS (Phase 1a):

The fundamentals of chemicals from coal appear to be cost-competitive with purchased supplies for several candidate products. Additional process work is needed to define an actionable technology pathway, and this work is under way. Keys to success are identifying and securing low-cost supplies of methanol (or equivalent) plus reasonable cost process technology. Additional business drivers in the form of alliances, partnerships or incentives enhance viability and reduce risk, but are not prime decision criteria. Many of the process technology options under consideration are process enhancements rather than frontier in nature. However, some of the identified process concepts may take longer to achieve due to the need for additional research, testing, and scale-up.

# OBJECTIVES

The Illinois Clean Coal Institute (ICCI) has provided funding to Eastman Gasification Services Company (EGSC) to evaluate the potential of utilizing Illinois coal for the production of chemicals based on gasification, with particular focus on methanol as a major chemical of interest. The objectives of this project include:

- To assess the methanol market and understand supply and demand characteristics as applicable to Illinois-based production, including the competitiveness of coal-based production with oil- and gas-derived chemicals and the impact of logistics on market opportunity (Task 1) .

- To evaluate the suitability of Illinois coals for chemicals production, with emphasis on the impacts of coal variability with respect to key constituents of importance to gasification (Task 2).

- To evaluate the economic feasibility of gasification-based coal-to-methanol production based on (a) a standalone mine-mouth methanol plant; and (b) coproduction of methanol in association with an Integrated Gasification Combined Cycle (IGCC) power project. The evaluations are to be site-specific and based on commercially viable assumptions and inputs (Task 3).

- To evaluate and scope improved coal-based process for the production of methanol and downstream products through an Eastman R&D effort (Task EMN-1).

Note that these objectives are to be achieved in two sub-phases: Phase 1a, completed in FY 2005, and Phase 1b initiated in FY 2006 and in progress at the time this report is being written. This report covers Phase 1a of the work, in which Tasks 1, 2 and EMN-1 were initiated and a framework for Task 3 was established.

# INTRODUCTION AND BACKGROUND

The U.S. chemical industry is highly dependent on raw materials derived from petroleum or natural gas. Escalating prices and increased volatility in recent years have magnified the risk of this lack of diversification. The petrochemical industry grew primarily in the Gulf Coast where the bulk of oil and gas reserves and refining capacity reside in the U.S. Over time, however, U.S. supplies of oil have dwindled and petroleum has increasingly been sourced on a global basis. The U.S. Gulf Coast has remained the primary concentration of refining and chemical industry due to the tremendous infrastructure investment and production synergies of the sector. The port capacity of the region, once a major advantage for exporting U.S. products, has become a vehicle for importing oil and other raw materials to serve U.S. industry and consumers. Increasingly, the shift to imports has also included raw materials derived from global natural gas, such as methanol and LNG.

As long as global oil and natural gas prices remained low, the shift from domestic to global raw materials supply did not appear to make much of a difference to the competitiveness and health of U.S. industry. However, as the costs of oil and gas in the U.S. have risen during the past several years, many chemical complexes in the U.S. have had to modernize, size to scale or shut their doors. In an effort to remain competitive, many companies have opted to build new facilities in other parts of the world where raw materials and operating costs are more competitive. Companies that continue operations in the United States face both price and security of supply issues as domestic sources of raw materials are stressed and increasingly are imported from abroad.

It should be noted that the picture for raw materials costs has been made more complex by changes in the relationships among primary sources of hydrocarbons both within the U.S. and globally, coupled with the impacts of technology and logistics on these relationships. Petroleum remains the primary source of raw materials for fuels and chemical feedstocks throughout the world. However, for a variety of important reasons, natural gas in various forms has become increasingly important in the energy and chemicals picture going forward. Key commodities that now rely largely on global natural gas include methanol and liquefied natural gas (LNG). Such commodities rely primarily on reserves of natural gas that are geographically isolated from large and valuable markets supplied by pipeline infrastructures such as the United States and Europe. These reserves (located in island nations such as Trinidad, hydrocarbon-rich regions such as the Middle East and parts of Central and South America, or less developed countries such as Nigeria) are often referred to as "stranded" natural gas reserves because of their remoteness from consuming areas.

The risks for petrochemical companies that remain in the U.S. are higher raw materials costs and reduced security of supply. Where U.S. industry has relocated abroad to mitigate raw materials costs, reduced near-term cost pressure is replaced by such risks as exchange rate risk, currency risk and the risk of nationalization or punitive taxation. These risks also extend to the level of the United States economy in the form of loss of jobs, loss of energy security through reliance on foreign governments and industrial entities, and macroeconomic pressures on the U.S. trade balance. Further, advantages associated with utilizing so-called stranded natural gas for chemicals production may become short-lived as countries find additional or alternative outlets for their natural resources.

The escalating prices of oil and gas combined with their inherent volatility have made forecasting future earnings for industries highly dependent on those commodities practically impossible. Additionally, reducing earnings volatility through financial hedging can only be done for short periods of time and the potential to source raw materials in sufficient quality and quantity at a price that ensures some level of profitability has become increasingly difficult.

These issues illustrate the need to diversify energy and raw material sources. For the United States, coal has the potential to be a primary source of energy as well as a feedstock for chemicals due to its abundance of supply, relatively low cost and relatively low price volatility as compared to other fossil fuels. A primary means of utilizing coal for chemicals production is coal gasification technology. However, there are several hurdles to overcome in applying this technology to chemicals production:

1. High capital costs and the consequent need for large scale economies.
2. Lack of recent U.S. commercial experience with coal gasification and limited perceived support for the technology by technology vendors and constructors.
3. Operational challenges associated with gasification technology, particularly reliable operation at low cost.
4. Adaptation of traditional chemical processes to coal-derived syngas, and the potential development of new processes and routes from coal-derived syngas to downstream chemicals.

Given all the factors above, Illinois coals have the potential to play a major role in the development of a U.S. coal-to-chemicals industry. Like the U.S. Gulf Coast during the last century, the significant concentration of low-cost hydrocarbons in Illinois and neighboring states, coupled with developments in coal processing technologies such as gasification, give Illinois the potential to emerge as an important geographical center for the development of a coal-based chemical industry. In order to assess this potential, feasibility assessments that evaluate the economics of chemicals production based on currently available coal processing technologies and detailed site assumptions must be available to project developers and chemical companies. The work under ICCI Project DEV 04-3 is aimed at contributing substantially to these feasibility assessments.

Prior experience has shown that many if not all chemicals now produced from oil and natural gas and their derivatives can be produced starting from coal through coal gasification (see Figure 2). However, it is clearly not possible to address the economics of producing such a wide range of chemicals in a single and limited feasibility study. However, from an Eastman perspective, one of the most versatile chemicals that can be produced from coal is methanol, which is one of the anchor chemicals produced through coal gasification for over 20 years at Eastman's chemical manufacturing operations in Kingsport, Tennessee. Methanol is particularly relevant for the focus of this study because it is a chemical end product, an intermediary for many widespread downstream chemicals, and a versatile energy carrier that has potential as a major transportation and thermal fuel. Therefore, the current evaluation is based primarily on methanol as a representative and versatile chemical feedstock and fuel.

With respect to the feasibility assessment, EGSC has identified two main modes of production for analysis. As with Eastman's Kingsport gasification facility, a coal gasification-based plant dedicated solely to the production of methanol or other chemicals – what is called herein a "standalone" facility – is clearly the default choice for the producer of valuable downstream projects who needs to control all aspects of development, financing, construction and operations. However, a second mode of production, referred to in this study as "coproduction" or "polygeneration," is a promising approach in which methanol is manufactured as a major byproduct or coproduct along with electric power based on Integrated Gasification Combined Cycle (IGCC) technology.

The scope of DEV 04-3-Phase 1a has been presented to the State of Illinois as Phase 1 of an effort aimed at developing a chemicals production project in Illinois, where the front-end engineering and other development tasks would constitute Phase 2. Further, the work under Phase 1 has been funded over two fiscal years (FY): FY 2005 and FY 2006, and thus reference is made to Phase 1a and Phase 1b where tasks span both fiscal years. The current final report reflects results of FY 2005 only. The work under this Phase 1 is divided into four major tasks, viz., Task 1 – Methanol Market Assessment, Task 2 – Illinois Coal Characterization, Task 3 – Feasibility Analysis – Coal to Methanol, and Task EMN-1 – Eastman R&D on Coal to Chemicals. Work on all tasks continues in the next phase of the project. As such, the results summarized herein are necessarily introductory and partial, and interested users should look to the final report from the project to derive the full value and conclusions of this work.

It should also be mentioned that Task EMN-1 – Eastman R&D on Coal to Chemicals represents a significant effort undertaken by Eastman's R&D organization to expand understanding of chemicals production starting with coal. A portion of this ongoing program is being offered as part of the cost sharing for Project ICCI 04-07. As is typical for industrial R&D, much of the results of this innovative program is and will remain proprietary, and as such cannot be published in these reports. However, the R&D will guide the work conducted herein with respect to methanol and, more importantly, will form a major part of the basis for decisions around the further implementation of coal to chemicals projects by Eastman and its partners or customers within the State of Illinois.

## EXPERIMENTAL PROCEDURES

The rationale for Phase 1a of the project is to lay the groundwork for economic feasibility assessments of coal-to-methanol projects by evaluating the characteristics of Illinois coal as a gasification feedstock, assessing the cost structure supply and demand of methanol markets, and conducting screening assessments of various coal-to-chemical manufacturing options. Phase 1a of the project relies predominantly on non-experimental research, data compilation and reduction, and qualitative and quantitative analysis. Both publicly available sources and the internal expertise and experience of Eastman were relied upon to synthesize results and develop conclusions. A limited amount of chemical analysis of coal samples was conducted during this phase, with additional analysis to be done in Phase 1b. All procedures utilized during this phase were standardized tests conducted by commercial laboratories.

# RESULTS AND DISCUSSION

## Task 1 - Methanol Market Assessment

The economic viability of methanol production from a standalone coal gasification facility or methanol coproduced with an IGCC power project will depend on achieving a competitive manufacturing cost and securing a position in one or more market segments that can be efficiently supplied from an Illinois location.

The methanol industry in North America (NA) has undergone significant restructuring during the past five years with the startup of large-scale (so-called "mega") methanol production plants in low-cost natural gas locations outside the NA region. The increased production capacity with substantially improved cost structure coupled with escalation of natural gas prices in NA will result in the shutdown of essentially all NA natural gas based methanol plants by 2007. The objective of the methanol market assessment is to understand the dynamics and impact of this restructuring on the methanol industry and market place and to forecast the future view. The deliverables of this assessment will include the following:

- Forecast of the supply/demand picture and pricing for methanol specifically focused on North America and the Midwest region based on analysis of current uses and potential new markets.
- Determination of the expected supply scenarios possible to meet the demand requirements and analysis of the opportunity to participate in this market with methanol produced from Illinois coal.
- Understanding of the cost structure for imported methanol and the methanol market pricing dynamics to determine the methanol-from-coal cost/pricing levels needed to be competitive.
- Quantification of the logistic costs associated with servicing the target markets from an Illinois location.

Phase 1a efforts for this task have been focused primarily on industry restructuring, development of cost models for methanol production to analyze the competitive cost position, and near-term forecasting of supply and demand based on current markets. Results based on this first phase of work are presented here.

## Methanol Industry Restructuring

The majority of methanol around the world is produced by converting natural gas to synthesis gas (CO and $H_2$) via steam reforming and/or partial oxidation. The synthesis gas is then converted to methanol in a second series of catalyzed reactions. Methanol is also produced via conversion of coal to synthesis gas and then to methanol as practiced by Eastman. Methanol production in China is primarily from coal due to its abundance as compared to the limited availability of natural gas. Methanol technology is licensed primarily from JM Catalyst (ICI) and Lurgi, with JM representing 60 percent of the market and Lurgi representing 30 percent.

Some of the initial methanol plants based on low-cost (stranded) natural gas came on line in the 1980's with plants in Saudi Arabia (1983), Trinidad (1984), and Chile (1988). The transition to mega methanol plants progressed at a significant rate through the 1990's and continued into 2005 with the addition of as many as 21 new plants (19 million metric tons/year capacity) in Latin America and the Middle East. The scale of the plants increased from 1500 MT per day to 3000 MT per day and then to current world scale of 5000 MT per day with the two most recent plants in Trinidad started up in 2004 and 2005.

As the low-cost methanol production capacity increased, rationalization of high cost production primarily in NA accelerated with closure of 6.4 million MT of capacity in the 2000 to 2004 time frame. An additional 2 million MT will shutdown in 2005 and another 1.5 million MT by 2007. In 2008 methanol production capacity in NA will be less than 500,000 MT per year at integrated sites for internal consumption. The production capacity in the Latin America (LA) region is projected at 13 million MT, primarily in Trinidad (6.6 million) and Chile (3.8 million). Methanol imports to NA will be around 8 million MT/yr supplied primarily from Latin America.

The current cash cost for NA produced methanol based on $8 to $9/MBtu natural gas is approaching $1.00 per gallon. With spot methanol prices at $0.80 per gallon it is easy to understand why remaining NA production will be shutdown as soon as possible.

The industry restructuring has also resulted in a consolidation of methanol producers with four major producers supplying over 40 percent of the market. The following table shows the projected 2006 capacity for methanol producers.

| **Methanol Producers** | **Estimated 2006 Capacity** **M MT/Yr*** | **% of Total** |
|---|---|---|
| Methanex | 5.8 | 16 |
| Methanol Holding Trinidad Ltd | 4.1 | 11 |
| SABIC (Saudi Arabia) | 4.1 | 11 |
| Iran NPC | 1.7 | 5 |
| Others (< 1M MT) | 21.3 | 58 |
| Total Industry Capacity | 37M MT | |

* M = million; MT = metric tons

**Table 1**

## Methanol Cost Structure

Methanol manufacturing costs have improved significantly with low-cost natural gas sources and the increased plant scale from 500,000 MT (typical NA plant) to current world scale of 1.7 million MT. As part of the coal-to-chemicals project, cost models have been developed to estimate the fully allocated manufacturing cost (including depreciation) with delivery to the U.S. Gulf Coast (USGC) based on various natural gas prices, plant scale and plant location. The table below summarizes the expected competitive cost position for suppliers to NA.

**Methanol Competitive Cost Benchmarks**
**Project Model Developed by EGSC**

| Location | % Mkt Capacity | NG Price* $/MBtu | Freight USGC $/Gal | Dlvd Cost** $/Gal | Cost + ROC $/Gal |
|---|---|---|---|---|---|
| Trinidad | 18 | 1.45 | 0.036 | 0.26 | 0.40 |
| Chile | 10 | 1.25 | 0.051 | 0.25 | 0.39 |
| Venezuela | 4 | 1.10 | 0.036 | 0.23 | 0.38 |
| Eq Guinea | 2 | 0.50 | 0.063 | 0.20 | 0.34 |
| Saudi Arabia | 14 | 0.75 | 0.090 | 0.24 | 0.38 |

** NG price for Latin America countries includes $0.35/MMBtu premium for profit share based on $200/MT methanol market price.*
***Delivered cost includes all mfg costs plus depreciation. Cost + ROC adds a 10% after tax return on capital(ROC) invested.*

**Table 2**

Based on this analysis, a manufacturing cost of methanol from Illinois coal in the $0.25 per gallon range FOB the plant site would achieve a competitive position versus low cost imports. Methanol imports achieve acceptable returns with prices at the $0.40 per gallon level and above. A source of competitive methanol in Illinois will be well positioned to serve markets in the Midwest and Northern states as well as Canada. A domestic alternative based on local and stable raw materials will eliminate inherent risks of imported products based on foreign government-controlled raw materials and ocean transportation, with the added risk of delivery into Gulf ports subject to weather interruptions and outages.

LNG (liquefied natural gas) and GTL (gas to liquids) projects are competing for low-cost natural gas sources. With natural gas prices in the U.S. exceeding $8/MMBtu the return from LNG to gas suppliers is at $3.00/MMBtu and is an attractive alternative for monetizing natural gas reserves. Given these influences there is a general expectation that natural gas costs for new contracts may be as high as $2.00/MMBtu, which is equivalent to an 8 cents per gallon increase over current prevailing prices. Current long term gas contracts begin to run out in 2014.

Phase 1b work for Task 1 will validate the competitive cost position data and provide improved forecasts and relationships for key raw materials.

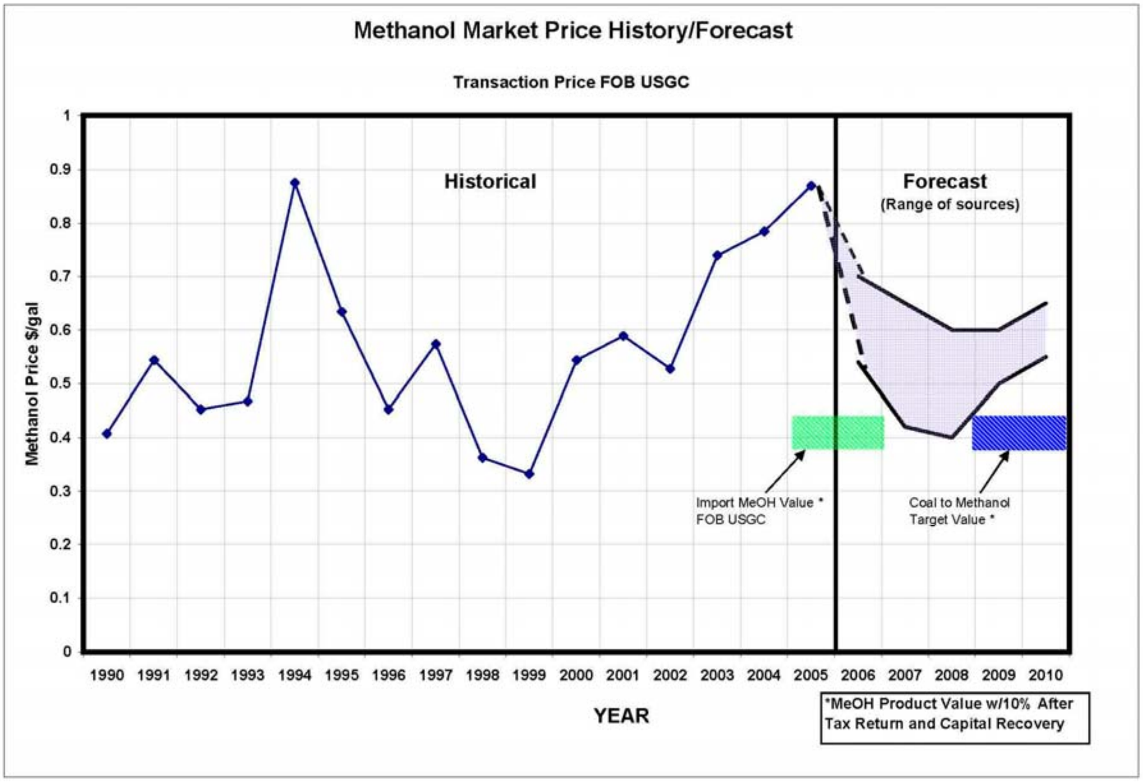


**Figure 1**

## Methanol Pricing

Figure 1, developed by EGSC within FY 2005, provides an overview of methanol price history along with views of future costs and prices. Historically, methanol prices have averaged \$150 per MT or \$0.45 per gallon. Methanol prices peaked above the \$0.90 per gallon level during 2004 and 2005. Prices are beginning to moderate but will remain unsettled until recently started new plants have lined out and the decline of the MTBE market in the U.S. plays out in 2006. Most near-term forecasts indicate that prices will decline to the 50 to 60 cents per gallon range by 2007. However, there is substantial variability among forecasts, and forecasts that do not reflect the latest volatility in oil and gas prices will need to be updated. An extended price forecast with updated information and potential scenario ranges will be provided as part of Phase 1b work.

Methanol prices have historically been related to U.S. natural gas prices and the methanol supply and demand balance, with high cost NA production on the margin holding prices up in a tight market – effectively establishing a floor price. Methanol capacity utilization typically runs in the 80 to 90 percent range. With NA production essentially shut down by the end of 2005, the future floor price mechanism is uncertain. However, methanol pricing will certainly be influenced by the following:

- High cost production will now be in Europe and China and may support floor pricing for some time going forward.
- The NA natural gas prices (Henry Hub) and new LNG capacity competing for natural gas will put pressure on future natural gas prices for methanol in LA.
- China's smaller scale coal-based plants are not cost competitive on a global basis and have typically operated only when methanol import prices have exceeded $160/MT. China has announced numerous new larger scale plants, some of which are well advanced and are more sophisticated in terms of integration with downstream chemicals and energy production. These plants, if built, will likely push China's indifference point down. The rate at which China builds new capacity will have an impact on the global balance.
- The supply/demand balance for methanol going forward will be sensitive to the pace of anticipated capacity build in the Middle East balanced with increase in demand in China and the rate of China capacity build.

## North American Supply/Demand

Global demand for methanol is running at about 32 million MT per year; approximately 86 percent of capacity. Major markets for methanol are industrial intermediate chemicals which themselves become intermediate raw materials for the production of a wide variety of chemical products. The major end-use markets for methanol are listed in the table below with global and North America consumption indicated. This study will focus on methanol demand in North America to identify target regional opportunities best suited for supply from future methanol production from Illinois coal.

| **Methanol Demand** | **Volume - M MT/YR** | | **NA Growth** |
|---|---|---|---|
| **End Use** | **Global** | **NA** | **%** |
| Formaldehyde | 11.8 | 2.5 | 4.0 |
| MTBE | 6.7 | 2.2 | * |
| Acetic Acid | 3.7 | 1.2 | 7.5 |
| DMT & MMA** | 1.8 | 0.5 | 2.0 |
| Fuels | 1.2 | 0.1 | 2.5 |
| Other Misc | 6.8 | 2.0 | 4.5 |
| Total | 32.0 | 8.6 | 4.7 |

**MTBE demand in U.S. is expected to decline to 0.5M MT or less Q206*

***DMT is the abbreviation for Dimethyl Terephthalate and MMA is the abbreviation for Methyl Methacrylate*

**Table 3**

The projected capacity in the NA/LA region of 13 million MT in 2007 will be more than sufficient to supply the projected demand of 10 million MT (post MTBE) through 2010. LA producers will continue to compete against the Middle East (ME) for export business to the Asia Pacific (AP)/China and Europe. Lower natural gas and freight costs will favor the ME producers. In the absence of new market opportunities for methanol the growth rate in NA will continue at the 4 to 5% range and current capacities will likely meet demand through 2013. Methanol from coal production coming on line in

2011/2012 could fill a capacity need at that time based on current methanol markets and market growth, as well as positioning suppliers to serve new markets.

The balance looking forward coupled with the threat of higher natural gas prices as well as escalating capital costs would imply that there will be no new plants built in LA for the foreseeable future. An indication of this is that the two major producers in LA have announced their next plants are under study for locations in Egypt and Oman. There are no additional plants announced for the LA region. The next methanol plant slated for startup is a 1.7 million MT mega plant in Iran and is the only plant outside of China expected to start up in 2006. Plants in Saudi Arabia, Oman, and Brunei have been announced for completion in 2007. Over 13 million MT of new capacity has been "announced" for 2008 completion with more than10 million MT of this capacity increase in the Middle East. The capacity build in the ME will be dependent on companion downstream projects being executed and on the demand growth in China and the extent to which China builds capacity to meet their internal needs. Announced projects in China will more than meet demand growth but execution will depend on economics versus ME imports.

## Current Methanol Markets

Formaldehyde manufacture is the largest global consumer of methanol at 37 percent and is used primarily in the production of resins and glues for particle board, plywood, oriented strand board and other engineered wood products. Demand is primarily driven by the home building and construction industry and is closely connected to GDP growth rates. Formaldehyde was reclassified in 2004 by the International Agency for Research as carcinogenic to humans and the US EPA is currently updating the cancer risk assessment. This regulatory attention has the potential to drive alternative product development and impact demand.

The NA formaldehyde industry is characterized by a host of regional plants primarily located adjacent to the timber and lumber industries. The five major formaldehyde producers account for 90 percent of the market, as shown in Table 4.

| **NA Formaldehyde Producers** | **Capacity – k MT/YR*** | |
|---|---|---|
| | **Formaldehyde** | **Methanol** |
| Borden Chemical – 17 Plants | 2372 | 1067 |
| Georgia Pacific – 12 Plants | 1061 | 477 |
| Dynea – 9 Plants | 845 | 380 |
| Celanese - Bishop TX | 862 | 388 |
| Edmonton, AL, Canada | 159 | 72 |
| DB Western – La Porte TX | 545 | 245 |

**Thousand metric tons per year*

**Table 4**

Two of the largest plant sites – Celanese in Bishop, Texas and DB Western in La Porte, Texas – are currently supplied with methanol from the Celanese plant in Bishop and the Millennium/Lyondell methanol plant in La Porte, respectively. These high-cost methanol plants are expected to be shut down and these formaldehyde plants will likely have long-term supply agreements with the major methanol producers in Trinidad. Borden Chemical shutdown 1M MT of methanol production capacity in December 2001 likely in favor of long term contracts for lower cost imported methanol. A regional review of the remaining formaldehyde producers indicates a market for approximately 1 million MT per year of methanol in the Midwest and Northern states and Canada regions that may favor logistics from an Illinois location compared to imports transported from the USGC. A more in-depth review of these developments and opportunities will be completed in Phase 1b study.

MTBE (methyl tertiary butyl ether) is used as a gasoline additive to increase blended octane and reduce automobile exhaust emissions. An oxygenate such as MTBE or ethanol has been required in reformulated gasoline used in areas of the country with higher air pollution levels. However, MTBE has been identified as a ground water contaminant as a result of gasoline spills and underground tank leakage and has been banned from use in nearly 50 percent of the states. The Energy Bill passed in May 2005 did not provide liability protection sought by MTBE producers and will rescind the oxygenate regulation in March of 2006. As a result the usage of MTBE as a fuel additive in the U.S. will likely be eliminated. Other countries continue to use MTBE and U.S. production will presumably be limited to exports.

Acetic acid accounts for 14 percent of methanol usage in NA and is primarily used to produce polyvinyl acetate, polyvinyl alcohol, and ethyl vinyl acetate which end up in adhesives, coatings and textiles. Acetic acid will be the second largest market after the expected demise of MTBE with NA production essentially consisting of those plants listed below.

| **NA Acetic Acid Producers** | **Capacity –k MT/YR*** | |
|---|---|---|
| | **Acetic Acid** | **Methanol** |
| Celanese – Clear Lake, Pampa TX | 1710 | 900 |
| Eastman Chemical – Kingsport TN | 540 | 285 |
| Millenium – LaPorte TX | 455 | 240 |
| Sterling/BP – Texas City TX | 455 | 240 |

**Thousand metric tons per year*

**Table 5**

Celanese has historically operated methanol plants in Clear Lake, Bishop, and Edmonton and supplied their internal requirements as well as the commercial market. Driven by the high cost of natural gas, Celanese has secured long-term methanol supply agreements with Methanol Holdings (Trinidad), Ltd and as a consequence shut down the Clear Lake plant in June 2005 and announced plans to shut down Bishop and Edmonton by early 2006. Millennium Chemicals' acetic acid production is integrated with methanol production at LaPorte that is projected to shut down in 2007. At that time it is speculated that the acetic acid plant will be supplied by Methanex. The Sterling/BP acid plant is likely supplied from the Methanex/BP plant in Trinidad. Eastman acetic acid is integrated with methanol production based on coal. Opportunities to sell methanol to the acetic acid market may be limited in the near-term by existing contracts. However, longer term opportunities associated with chemicals from coal may well depend on the ability to achieve competitive prices and provide a hedge against long-term price and price volatility risk.

The fuel market is presently a small area for methanol but has the potential to expand significantly in the future given the availability issues and high prices in the petroleum industry along with environmental drivers. However, it is likely that historical prices commanded for methanol as a chemical feedstock versus historically low prices for petroleum and natural gas fuels in the U.S. have essentially postponed any consideration of methanol as a fuel—a situation that could now be changing. Additional comments on the potential fuel use of methanol are included below in the discussion of potential new markets.

The other miscellaneous uses for methanol are a significant piece of the market. This category includes a wide range of minor volume uses including solvents, windshield wiper solution and use for dehydration in oil field applications. One of the objectives of the Phase 1b study will be to get a clear picture of the "other" uses to determine if there are any niche markets that can be served from an Illinois location.

**Potential New Methanol Market Opportunities**

An in-depth analysis of new market opportunities for methanol will be an important part of the Phase 1b portion of the market assessment. With the demise of MTBE in the U.S. and health risk concerns with formaldehyde, improved growth in the methanol market could be dependent on the development of new uses of methanol.

As indicated above, the fuel market offers several potential opportunities with alternate fuel applications including gasoline blends, biodiesel, and DME (dimethyl ether). Following are some illustrations and comments on fuel use:

- Blends of methanol with gasoline (10-15%) are in use primarily in China.
- Biodiesel is a fuel diesel substitute derived from renewable feedstocks such as vegetable oils or animal fats. The majority of biodiesel is produced from the esterification of the fatty acids in soybean or rapeseed oil using methanol at about the 10% level. Glycerol is produced as a byproduct of the reaction.
- Currently DME, produced via dehydration of methanol, is used mainly in aerosol production but could emerge as a replacement for liquefied petroleum gas (LPG) as well as power generation and transportation fuel. Several Chinese companies have announced projects for integrated methanol–DME plants. Iran NPC is building a large DME plant for projected use in 20-percent blends with LPG.

Gas turbine vendor testing has demonstrated that methanol is feasible as a combustion turbine fuel and offers improved heat rate, higher power output, and reduced NOx and $SO_2$ emissions. A fuel market assessment focused primarily on gas turbines will be completed as part of Phase 1b of this study and will include a detailed market survey of target customers within an economic radius of Illinois as well as a technical feasibility assessment directly involving combustion turbine vendors.

Another potential new market for methanol is as an alternative feedstock for the manufacture of various petrochemicals now produced using oil and gas derivatives. Among the leading candidates in terms of commercial readiness is based on available technology for methanol-to-olefins. Recent project announcements have been made that represent the initial commercial scale practice of these technologies.

However, it is technically feasible to synthesize virtually any hydrocarbon starting with coal, and the current price environment coupled with technological innovation open up many other potential applications for both synthesis gas and methanol -- derived from coal through gasification -- as starting points for downstream hydrocarbon-based chemicals. One broad area of practice in addition to methanol-to-olefins is termed gas-to-liquids, or GTL. While GTL is often assumed to start with stranded natural gas, the technologies can also be adapted to coal-derived syngas. The Fischer-Tropsch process is one example of a GTL process that is attracting substantial interest in the coal-to-chemicals context. Another area of practice involves methanol as a route to a variety of chemicals and fuels. One perhaps ambitious example here is methanol-to-gasoline (MTG), which has been practiced since 1985 in New Zealand. Short of this type of application, many other simpler intermediates can be envisioned through a methanol route. Eastman is assessing a range of potential processes using methanol to produce downstream chemical products. The status of this effort is reported in under the heading of Task EMN-1, below.

**Task 2 - Illinois Coal Characterization (Phase 1a)**

An important aspect of any feasibility study is establishing the design basis fuel. As noted, EGSC will conduct site-specific feasibility assessments under the current evaluation based on the site of the Christian County Energy Center project near Taylorville, Illinois. Therefore, particular attention will be paid to the design basis coal for the Taylorville site. However, in order to help translate the site-specific feasibility results to a range of sites within the State of Illinois, coals from across the state will be characterized with respect to key constituents of importance to coal gasification economics. Results to this point in the project have focused on utilizing Eastman's extensive gasification experience to establish key coal characteristics of interest, adapt methods for predicting the impacts of these constituents on economics, and analyze the particular Christian County design basis coal as a first application of these methods.

Gasification is considered a robust technology for gasifying many carbonaceous feedstocks for power and chemical generation. The gasification process has been used in China, Japan, Germany, and the United States to gasify over 60 types of coals and coal/petroleum coke blends. However, as with most chemical and power processes, there are always tradeoffs among feedstock cost, plant design and equipment, and onstream time. For instance, a higher ash, higher moisture coal should lead to a lower feedstock cost on a $/MMBtu basis, but the higher ash will impact the wear-and-tear on process equipment, and higher ash and moisture will require more feedstock on a tons per hour basis and change the gas composition due to more thermal energy required to heat the ash and water.

Feedstock selection for gasification projects is typically done in two ways; i) establish the plant design and find a feedstock to match, or ii) identify a feedstock and then design a plant. The approach applied is usually a function of the market to be served by the end products versus the location and cost of suitable feedstocks -- often involving a complex optimization process. Both approaches may be somewhat flawed in the event that flexibility is left out because options are poorly explored and feedstock impacts are understood late in the engineering phase.

Ultimately, the plant owner's revenues are often impacted because the design basis feedstock was not properly evaluated, consideration was not given to identifying alternative feedstocks that may need to be obtained in case of unforeseen mine issues, or market pressures and opportunities lead to lower cost feedstock options that were not considered in the design of the plant.

In order to avoid expensive scope changes to the project late in the design or construction phase, it is necessary to understand the particular characteristics of the feedstock to be used and the variability and impacts of those characteristics before the plant design begins. As a general guide to understanding the impacts of different quality coals, a list of coal parameters and a qualitative description of the impact of the parameter on gasification plant design and operation. Since there will always be a trade-off between desired properties and coal price, a more quantitative analysis of these constituents is also needed and will be provided in the next phase. In addition, EGSC has initiated a survey of the Illinois coal basin for levels and variability of the highest impact coal characteristics summarized below.

**Impacts of Coal Constituents on Design and Economics**

**Carbon –** Unlike a boiler that converts all of a coal's chemical energy into thermal energy, coal gasification converts a portion of the coal's chemical energy into chemical energy in the form of gaseous carbon monoxide (CO) and hydrogen ($H_2$), the main components of syngas. For oxygen-fed gasification processes, byproducts of this conversion process consist primarily of carbon dioxide and water. Carbon dioxide ($CO_2$) in large quantities is typically not advantageous for chemical production in that it is inert to many reactions and increases the size and cost of gas processing and cleanup equipment. For some types of chemical production, $CO_2$ interferes with desired reactions and must be removed, which also adds cost and complexity.

For power production in an IGCC plant, $CO_2$ at pressure and temperature is beneficial for increasing the mass loading to, and hence power output of, the combustion turbines. Also, a portion of the thermal energy recovered in the oxidation of carbon to $CO_2$ can be integrated into the steam cycle of the power plant for additional power output. However, as more $CO_2$ is produced, the chemical energy in the syngas declines and more coal must be fed to the gasifier to meet the input requirements of the gas turbines. In addition, $CO_2$ takes up reactor volume and reduces the capacity of the unit for valuable syngas ($CO+H_2$). Therefore, in general it is desirable to minimize the amount of $CO_2$ in the syngas feed in order to achieve the highest fuel efficiency.

Where both chemicals and power are being produced via gasification, the overall design specification for the project must define the optimal $CO_2$ concentration at each stage in the process in order to optimize among chemicals production, power production, and the cost and efficiency of removing pollutants and such as mercury, sulfur, and other gas-borne species.

In order to minimize the $CO_2$ in the syngas when using a slurry-fed coal gasifier, the more carbon that can be "packed" into the slurry (less water), the higher the CO concentration will be in the syngas at the expense of $CO_2$. This in turn will allow more good ($CO+H_2$) syngas to move through equipment without increasing equipment sizing. The amount of oxygen used for the project is also based on the amount of coal and slurry water being sent to the gasifier. If a lower quality coal is used versus design basis, then more $CO_2$ will be produced which requires more oxygen and the ASU may not have enough oxygen capacity to meet full load, especially during the summer. The $CO_2$ concentration in the syngas could also impact the amount of $N_2$ diluent sent to the combustion turbine in a power application and/or the amount of saturation required since $CO_2$ acts as a diluent.

Another impact of carbon in the feedstock is the amount of coal that must be fed to the unit. Utilizing a 77-percent rather than a 72-percent carbon coal would amount to an extra 91 tons of coal per day on a 1000 ton-per-day carbon feed rate basis. Paying the same price of $25/ton for these two coals would result in around $800,000 per year difference in coal expense, not counting the impacts on capital and operating costs of feeding more mass to the plant and reduce unit capacity.

*Impact* – ASU and AGR design, syngas composition, coal consumption, gas turbine performance and integration scheme.

**Nitrogen** – The nitrogen content is mainly a concern with ammonia formation in the gasifier. An important aspect of gasification operations and maintenance is managing the water streams and recombining these streams in different areas of the plant to optimize efficiency, reliability, water use and wastewater treatment. Most of the coal nitrogen is converted to ammonia and enters the water system where it raises the pH. In order to prevent a high concentration from building up, a blow down of the water system needs to be done.

Some of the high pH water may be used in a beneficial way and mixed with low pH water due to formic and hydrochloric acids in other parts of the water system. Higher nitrogen may also lead to additional cyanide formation. Cyanide needs to be removed and destroyed prior to entering the wastewater treatment plant.

*Impact* – Ammonia blow down, water mixing for pH control, wastewater treatment design.

**Hydrogen** - Higher hydrogen in feedstocks will typically alter the gas composition but have little effect on operations for a power plant. Because hydrogen has low molecular weight and unique properties for heat transfer, the amount of hydrogen in the syngas can affect the plant design and energy balance, particularly with respect to chemical coproduction. The hydrogen balance in the gas will also vary based on water entering the gasifier and the presence or absence of a water-gas shift unit to convert the CO to $H_2$ to change the syngas stoichiometric balance. Finally, hydrogen burns more rapidly in the gas turbine combustors, and therefore the final composition needs to be known by the combustion turbine vendor. For chemical production hydrogen may be desired depending on the chemical to be produced and its required $H_2$/CO ratio.

*Impact* – Gas composition, cold box efficiency, compressor efficiency, shift unit design, turbine performance, pressure swing absorption for $H_2$ separation, if included.

**Oxygen (in the coal analysis)** – After the ash, carbon, nitrogen, and hydrogen are added up, oxygen is typically calculated by difference. Consequently, it represents analytical error and oxygenates within the coal structure. A high oxygen value may be beneficial in that less oxygen may be consumed from the ASU. However, the coal oxygen is typically ignored in the design. The amount of coal oxygen could have a slight impact on conversion, especially if it is ignored in the design, but turns out to be an extreme (high or low) level.

*Impact* – ASU, slag disposal (carbon conversion), lock hopper/quench chamber size, gas composition.

**Volatiles** – Coal petrography has a classification system based on the three main macerals found in coal; vitrinite, liptinite, and inertinite. The distribution of these macerals may make certain coals more reactive in the gasifier. Typically, the more volatiles (liptinite fraction), and less fixed carbon, the quicker and easier it is for the gasification reactions to occur. The reactivity translates into less oxygen usage for a given level of conversion. Less oxygen should also lead to lower $CO_2$ production and more CO. Finally, more volatile coals have a lower ignition threshold and can be "lit" easier in the gasifier. This may allow for firing the gasifier at lower initial temperatures, thus allowing for a longer window for restarts (gasifier can cool down further and still restart) and increased reliability. During re-firing, the feed injector is left in place and the unit can be restarted once the safety system is reset, or the technical issue causing the trip is fixed. As the gasifier sits waiting for re-firing, heat is lost from the refractory which decreases the temperature in the gasifier. If the temperature becomes too low, a preheat must be applied to raise the gasifier temperature back up, leading to lost production time and increased fuel cost.

*Impact* - ASU, slag disposal, gas composition, reliability, startup time.

**Moisture** – Coal is composed of two types of moisture; i) inherent, and ii) surface. Moisture affects all gasification processes in that the following reaction (water-gas shift) occurs:

$$CO + H_2O \rightarrow CO_2 + H_2$$

The more moisture that comes in with the coal, the more $CO_2$ and $H_2$ will be produced. $H_2$ (and $CO_2$) produced via the shift reaction can be beneficial depending on the ultimate syngas use. However, $CO_2$ produced by over-oxidation of C or CO to produce thermal energy is essentially useless in chemical applications and at some point is inefficient for power applications. To limit the impact of moisture on overall process economics, it may be cost-effective -- especially for dry feed gasification process --to dry the coal to reduce the surface moisture. However, inherent moisture may not be as easy to eliminate in that it is bound in the coal structure. For a given per ton price of coal, high surface moisture may also equate to buying water at carbon prices while requiring more $CO_2$ production with expensive $O_2$. Water content needs to be carefully specified and held for proper design and optimum performance.

In a slurry system, surface moisture is not a major issue unless it is excessive, where sticking in silos or hoppers may occur. At very low moisture content, concerns will arise concerning dust suppression. Inherent moisture is more of a concern with slurry systems in that additional water will lower the solid loading in the slurry. Since inherent moisture is bound within the coal particles, most of it is not available to "slurry" the coal. Enough water has to be added to the slurry to obtain acceptable viscosity levels for slurry handling and pumping without the benefit of the inherent moisture. Therefore, more total water is fed to the gasifier for the same slurry viscosity in the case of a coal with high inherent moisture. In this case, the amount of $CO_2$ increases in the syngas both from the water gas shift reaction, and more thermal energy required to evaporate the excess moisture.

*Impact* – Silos, slurry, syngas composition, coal cost, AGR, ASU, water balance.

**Sulfur –** A big benefit with gasification is its ability to use high-sulfur feedstocks. While some additional cost is required in the Acid Gas Removal (AGR) area, the general rule is that a high-sulfur coal sells for much less than a low-sulfur coal, other things being equal. During gasification the sulfur in the coal is converted to hydrogen sulfide ($H_2S$) and carbonyl sulfide (COS). Depending on the design of the AGR a COS hydrolysis unit may be needed to meet emissions requirements or process conditions. Typically the ratio of COS:$H_2S$ varies with coal characteristics, so it is difficult to determine if a plant requires the unit. If Rectisol is used for sulfur clean-up, a COS unit is not required because COS is removed in the Rectisol AGR.

Also, not all of the sulfur in the coal is converted to $H_2S$. Part of it will recombine with the iron in the coal and be removed in-situ through the following reactions:

$$FeS_2 + O_2 \rightarrow Fe_xO_x + SO_x$$
$$SO_x + H_2 \rightarrow H_2S + xO_2$$
$$FeO + H_2S \rightarrow FeS + H_2$$

Depending on coal storage, sulfur also affects the pH of the coal. Higher sulfur coals when stored and oxidized will create an acidic slurry that will corrode equipment faster or require a pH additive. Fresh coal is less of an issue.

*Impact* – AGR, slag resale, COS unit, sulfur storage, metallurgy.

**Ash Content** - Ash in the gasifier acts as a moderator in that it absorbs heats out of the process. If the gasifier is operating near the coal's melt point, then additional heat must be supplied by converting CO to $CO_2$ to raise the temperature to ensure good slag removal. Also, higher ash means less carbon which results in more water being fed per unit of carbon into the gasifier. The extra water will then produce more $CO_2$. To meet the carbon balance, more coal must be fed, thus feedstock costs increase.

In addition to changing the syngas composition, the ash will have to be removed. In the case of a slagging gasifier, the ash will drop into the water system for ultimate removal. The mineral matter is circulated with the water, resulting in more erosion of equipment and piping. Slag removal equipment such as the lockhopper and, in the case of quench-type gasifiers, the lower quench chamber must be enlarged to accommodate more ash. Additional ash will also result in larger filter presses and settlers and possibly chemical addition to remove the fine material from the water. Dry ash gasifiers will experience similar impacts from ash in the coal.

Finally, the ash must be hauled away. Although usually non-hazardous, landfill costs for ash and slag can be as high as $15/ton and require on-site permitting for temporary and/or permanent storage. The potential exists to separate slag from unburned carbon and sell the slag as an aggregate byproduct, resulting in some additional revenues and savings on disposal costs at the expense of separation equipment and operating costs.

*Impact* – Gas composition, feedstock pricing, equipment wear, lockhopper/quench sizing, slag disposal design and costs.

**Ash Chemistry** - The ash chemistry dictates where the gasifier needs to operate to remove the slag. Coals for boiler applications are typically specified to be low in concentrations of cations (Na, Mg, Ca, K, Fe) in order to reduce fouling in boiler superheater sections. As the cation concentration decreases, the melting point of the ash increases and more thermal energy is required to melt and remove the slag and raise the overall reactor temperature. Conversely, higher iron and calcium concentrations are better to assure fluid slag at lower temperatures.

To help determine the melting point of the slag, the $T_{250}$ temperature (the temperature at which the slag viscosity is 250 centipoise) or the ash melting point under reducing conditions can be used. The $T_{250}$ gives guidance with regard to the desired operating region of the gasifier. The ratio of iron oxide to alumina and silica, and/or the base-to-acid ratio can also provide guidance as to the gasifier operating temperature required to keep the slag fluid. Because most of the correlations used for predicting coal ash behavior were derived from boiler operations, corrections must be done to the values to predict the gasifier slag behavior.

In addition to the effects on reactor operations, the ash chemistry will also impact the water system. Higher amounts of free calcium in the ash will result in more calcium in the water. If the water pH becomes too high, the $CO_2$ concentration increases in the water, and/or hot metal surfaces are present, then calcium carbonate scaling will typically occur. Chemicals can be used to control the water system, but have a high cost and are usually temperature sensitive. Therefore, the correct chemicals and location points must be selected to provide maximum benefits. Alternatively, pH control can be done by carefully selecting the location and type of water streams that are being mixed together in the process.

Other mineral matter constituents in the coal will also precipitate from solution in the water system. For instance, high magnesium in the coal can result in magnesium silicate hydroxide precipitating in the quench area which can cause fouling of equipment. High sodium may sequester chlorine and lead to corrosive sodium chloride crystals. Chemicals and cleaning traps may need to be added to control these effects.

*Impact* – Water chemicals, blow down, waste water treatment, O&M fouling and cleaning, gasifier temperature, water system design.

**Chlorine** - Chlorine is a concern for metallurgy and catalyst poisoning. The chlorine in the coal is converted to HCl and is in the gas phase. The HCl will increase the dew point of the syngas prior to quenching which can lead to dew point corrosion. After scrubbing with water, most of the HCl should be in the water phase. Part of the HCl may be neutralized by ammonia. However, during flashing and cooling, ammonia and HCl typically concentrate in different areas. The blowdown from a gasification system is usually set to keep chlorides from building up in the system. Higher chloride levels generally result in higher blowdown and water make-up rates. Chlorine-rich mineral matter can still concentrate under deposits or move through the system as salts and later break down to release chlorine.

Metallurgical considerations along with proper downtime practices are required to reduce maintenance and capital cost. With high chloride coals, metals that are prone or even listed as resistant to HCl need to be avoided. While blowdown can handle chlorides to some extent, if the chloride can be cost effectively removed by washing the coal, maintenance and capital cost should decrease.

*Impact* – Metallurgy, blowdown, wastewater treatment, shutdown procedures and impacts, guard beds (chemical production), water balance.

**Arsenic** - All coals contain arsenic. During gasification the arsenic is believed to be converted to arsine. Some of the arsenic may deposit in vessels and/or pipes in the gasifier cooling train causing a pressure drop. The clean syngas still may have trace amounts of arsine. As the gas passes through the combustion turbine in the case of IGCC, it will be converted to arsenic oxide and may be deposited on the tubes of the heat recovery steam generator.

*Impact* – Guard bed sizing, catalyst life, maintenance precautions, plugging.

**Mercury** – All coals contain trace amounts of mercury. The mercury will volatize and follow the syngas. Activated carbon guard beds can be placed in the lines to remove the mercury. Size depends on the amount of mercury and other trace elements in the coal, and water removal prior to the beds. Eastman has been using an activated, sulfur-impregnated carbon bed for over 22 years to remove greater than 90 percent of the volatile mercury.

*Impact* – Guard bed sizing, catalyst life, maintenance precautions, plugging.

**Heating Value** – Heating value can be calculated based on the ultimate and proximate analysis or measured through test methods. Coals are typically categorized by their heating value. The heating value is largely tied to the carbon content, thus high heating value coals are preferred for the same reasons that high carbon content is preferred. Both ASTM test methods and theoretical calculations can be done to confirm the proximate and ultimate analyses.

*Impact* – Covered under components that impact heating value, notably carbon, ash, and moisture.

**Grindability** – In the case of a slurry-fed gasification process, the coal is usually sent to rod mills for slurry preparation. If the coal is too large from the mine, either additional crushing must be done on-site, or a coal specification is given to the mine to reduce the size. At 100 percent washing, sizing usually is not an issue because of the required crushing prior to the wash circuit. A Hardgrove Grinding Index (HGI) is supplied to the rod mill vendors to determine equipment sizing and types of rods. Typically, subbituminous and bituminous coals do not pose major challenges with regard to grinding.

*Impact* - Rod mill sizing, conversion, coal handling, slurry concentration.

**Slurryability** – This property obviously pertains to slurry-fed gasifiers. The coal slurry and amount of solids that can be loaded into the slurry depends on surface characteristics of the coal, inherent moisture, chemistry of make-up water, rod mill charge, chemical additives, and the ability to control the weigh belt feeders and slurry make-up water. As stated previously, excessive water in the slurry will result in more $CO_2$ and less efficient use of the carbon. Maximum slurry concentration cannot always be predicted, so testing on specific coals is recommended. However, in general, coals with more inherent moisture will generally have a lower maximum slurry concentration. Coals with extremely high water and ash contents such as Powder River Basin coal are probably not suited for slurry-fed gasifiers since the total water feed to the gasifier would be extremely high. Dry feed gasifiers would be more appropriate for coals with high inherent moisture. Also, surfactants can be used to decrease the slurry viscosity which ultimately allows for higher solids concentration. Even for bituminous coals with low water content, additives are needed to reliably run at high solids levels.

*Impact* – Conversion, rod mill sizing, chemicals usage, syngas composition.

**Recoverability –** Coal occurs in seams that change in thickness and banding layers. Some coal seams may be classified as 36" thick, but have only 28" of useful coal. Coal washing must be done to remove rock seams, clay layers, chlorine, pyrites, etc. Washing obviously adds cost to the final coal delivered to the plant, but may be economical depending on the yield and resulting coal quality improvement. Testing can be done to determine what the yield should be from a given core sample to assist in determining coal pricing and variability required in equipment.

Over washing may remove too much pyrite and cause the ash fusion temperature to decrease. Therefore, there is a trade off between ash reduction and ash chemistry.

*Inpact* – Coal cost, feedstock storage/consumption, wash plant sizing.

**Summary of Coal Impact Analysis –** The discussion above is summarized in two tables, shown below. Tables 6 and 7 will provide the basic road map for evaluating the impacts of Illinois coal constituents and variability on the economics of gasification-based coal-to-chemicals projects in the subsequent phases of this study.

## Coal Properties Impact on Process

| | ASU Sizing | Slurry Char. | Gasifier D & O | Shift Design | AGR | Guard Bed | Water Design | Metal-lurgy | Gas Comp |
|---|---|---|---|---|---|---|---|---|---|
| Carbon | Medium | Medium | Medium | Medium | Minor | | Minor | | High |
| Nitrogen | | | | | | | Medium | Minor | Minor |
| Hydrogen | | | | Medium | | | | | Medium |
| Sulfur | | Minor | | | High | | Minor | Medium | Minor |
| Moisture | Minor | Medium | Medium | Minor | Minor | | Minor | Minor | High |
| Ash | Minor | Minor | Medium | | Minor | | Minor | Minor | Minor |
| Ash Comp | | Minor | Medium | | | Medium | Medium | | Medium |
| Chlorine | | Minor | | | | Medium | High | High | |
| Arsenic | | | | | | Medium | | | |
| Mercury | | | | | | Medium | | | |
| Hardness | Minor | Medium | Medium | | | | | Medium | Medium |
| Volatiles | | | Medium | | | | | | Minor |
| Oxygen | Minor | | Minor | | | | | | Minor |

Minor Medium High

**Table 6**

**Table Definitions**

ASU Sizing – Size or capacity of the air separation unit (oxygen requirement).
Slurry Char. – Properties of the slurry such as stability and viscosity, ease of handling and ability to concentrate the solids.
Gasifier D&O – Gasifier design and operating criteria such as capacity, solids removal, refractory life, feed system, etc.
Shift Design – Size and capacity of the shirt reactor catalyst bed.
AGR – Acid gas removal system or H2S, CO2 removal from the raw syngas.
Guard bed – Protection beds that remove trace quantities of catalyst poisons.
Water design – Quantity of water, metallurgy of the system and solids removal schemes.
Metallurgy – the degree of special, high-cost alloys required in the plant.
Gas Comp – Composition of the final syngas.

**Coal Characteristic Impact on Cost Factors**

| | Feedstock | Capital | Operation | Maintenance | Reliability |
|---|---|---|---|---|---|
| Carbon | | | | | |
| Nitrogen | | | | | |
| Hydrogen | | | | | |
| Sulfur | | | | | |
| Moisture | | | | | |
| Ash | | | | | |
| Ash Comp | | | | | |
| Chlorine | | | | | |
| Arsenic | | | | | |
| Mercury | | | | | |
| Hardness | | | | | |
| Volatiles | | | | | |
| Oxygen | | | | | |

Minor Medium High

**Table 7**

**Fitness for Use – Taylorville Coal Analyses –** Forty core samples of the Herrin No. 6 Seam were taken by Christian County Coal Company. Two of the complete core samples were sent to Eastman for analysis. The results are shown in Tables 7 and 8. The entire core sample was approximately 9 feet long. Samples were taken from sections of the core to get an indication of the variability within the seam. The bottom 3 to 4 feet of the core in both samples is very high in ash, 65% in one sample, indicating a rock or sand layer within the seam. The low quality section of the seam is not suitable for use as a gasifier feed and even when blended with the remaining portion of the core sample, the average is still too low for efficient gasification (51% carbon). A decision will have to be made either to mine only the upper portion of the seam or mine a larger fraction of the seam and wash the coal to remove ash. The remaining 38 core samples were analyzed by the Christian County Coal Company. The analysis package was less complete, but the coal was analyzed as raw coal and as washed to a 1.60 Sp. Gr. Float. The results, Table 10 indicate significant improvement by washing. The raw coal data averaged 12.26% ash and 10,066 Btu/lb on an as-received basis, the washed data averaged 7.55% ash and 10,717 Btu/lb. The recovery of 84.5% for the washed coal was also very good. In addition to the improvement in the level of ash, the variability was greatly reduced. The range and standard deviation for the ash in the raw coal (as received) was 12.01% and 2.56% respectively. The washed coal range and standard deviation were 1.71% and 0.42%. Since gasifiers operate on the coal that is in the reactor at any one moment and not the average of the coal shipment, variability is very important to a reliable operation. More quantitative analysis will be done in the next phase, but a preliminary look at the beneficiation provided by washing would indicate that the cost of washing will be justified for this particular coal. The retained samples from the two core samples sent to Eastman will be analyzed for washability to determine the optimum wash specific gravity. Once the optimum is determined, the rest of the core sample will be washed to that level and then a slurriability test will be performed to determine the viscosity/slurry solids relationship so that an estimate of the maximum slurry concentration can be made.

Core Drill Samples from Christian County Coal Reserves Analyzed by Eastman Gasification Services Company

| | Core Sample No. 1 Sent to Eastman | | | | | Core Sample 2 sent to Eastman | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Sample Number | CCC 51-1 | CCC 51-2 | CCC 51-3 | CCC 51-4 | CCC 51-5 | CCC 52-1 | CCC 52-2 | CCC 52-3 | CCC 52-4 | CCC 52-5 | | |
| Date Sampled | 3/11/2005 | 3/12/2005 | 3/13/2005 | 3/14/2005 | 3/15/2005 | 3/15/2005 | 3/16/2005 | 3/17/2005 | 3/18/2005 | 3/19/2005 | | |
| Top depth, ft | 492 | 494 | 496 | 498 | 500 | 535.7 | 537.7 | 538.7 | 540.7 | 542.7 | Weighted | Weighted |
| Bottom depth, ft | 494 | 496 | 498 | 500 | 501 | 537.7 | 538.7 | 540.7 | 542.7 | 544.7 | Average of | Average of |
| | 2 | 2 | 2 | 2 | 1 | 2 | 1 | 2 | 2 | 2 | All Samples | Top 3 Sections |
| Proximate Analysis | | | | | | | | | | | | |
| As Received | | | | | | | | | | | | |
| % Moisture | 12.22 | 13.15 | 15.02 | 4.18 | 6.99 | 14.3 | 14.24 | 14.43 | 7.55 | 13.79 | 11.70 | 13.86 |
| % Ash | 5.1 | 6.84 | 5.32 | 50.66 | 31.76 | 4.32 | 7.3 | 6.32 | 65.1 | 8.76 | 19.11 | 5.74 |
| % Volatile | 39.05 | 34.67 | 37.2 | 19.03 | 27.74 | 39.68 | 36.41 | 36.07 | 14.82 | 38.22 | 32.31 | 37.25 |
| % Fixed Carbon | 43.63 | 45.34 | 42.46 | 26.13 | 33.51 | 41.7 | 42.05 | 43.18 | 12.53 | 39.23 | 36.89 | 43.15 |
| Total | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 |
| Btu/lb | 11,842 | 11,921 | 11,279 | 3,528 | 6,839 | 11,141 | 10,974 | 11,162 | 3,066 | 8,348 | 9,022 | 11,424 |
| % Sulfur | 3.31 | 4.68 | 2.73 | 23.24 | 17.57 | 3.48 | 4.28 | 3.18 | 1.13 | 2.91 | 6.18 | 3.55 |
| Alk. As Sodium Oxide | 0.34 | 0.37 | 0.35 | 0.38 | 0.39 | 0.32 | 0.41 | 0.43 | 1.43 | 0.43 | 0.49 | 0.37 |
| Dry Basis | | | | | | | | | | | | |
| % Ash | 5.81 | 7.88 | 6.26 | 52.87 | 34.15 | 5.04 | 8.51 | 7.39 | 70.42 | 10.16 | 21.64 | 6.66 |
| % Volatile | 44.49 | 39.92 | 43.78 | 19.86 | 29.82 | 46.30 | 42.46 | 42.15 | 16.03 | 44.33 | 36.59 | 43.24 |
| % Fixed Carbon | 49.70 | 52.20 | 49.96 | 27.27 | 36.03 | 48.66 | 49.03 | 50.46 | 13.55 | 45.51 | 41.77 | 50.10 |
| Total | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 |
| Btu/lb | 13,491 | 13,726 | 13,273 | 3,682 | 7,353 | 13,000 | 12,796 | 13,044 | 3,316 | 9,683 | 10,216 | 13,262 |
| % Sulfur | 3.77 | 5.39 | 3.21 | 24.25 | 18.89 | 4.06 | 4.99 | 3.72 | 1.22 | 3.38 | 6.99 | 4.12 |
| MAF Btu | 14,322 | 14,900 | 14,159 | 7,812 | 11,166 | 13,690 | 13,986 | | | | | |
| Alk. As Sodium Oxide | 0.39 | 0.43 | 0.41 | 0.40 | 0.42 | 0.37 | 0.48 | 0.50 | 1.55 | 0.50 | 0.56 | 0.43 |
| Ultimate Analysis | | | | | | | | | | | | |
| As Received | | | | | | | | | | | | |
| % Moisture | 12.22 | 13.15 | 15.02 | 4.18 | 6.99 | 14.3 | 14.24 | 14.43 | 7.55 | 13.79 | 11.70 | 13.86 |
| % Carbon | 66.99 | 67.4 | 64.9 | 18.17 | 37.94 | 64.34 | 62.63 | 63.92 | 16.59 | 51.23 | 51.54 | 65.25 |
| % Hydrogen | 3.93 | 3.61 | 3.65 | 1.55 | 2.45 | 3.79 | 3.61 | 3.69 | 1.66 | 3.7 | 3.18 | 3.72 |
| % Nitrogen | 1.11 | 1.1 | 1.18 | 0.34 | 0.59 | 1.12 | 1.11 | 1.17 | 0.39 | 1.16 | 0.94 | 1.13 |
| % Sulfur | 3.31 | 4.68 | 2.73 | 23.24 | 17.57 | 3.48 | 4.28 | 3.18 | 1.13 | 2.91 | 6.18 | 3.55 |
| % Ash | 5.1 | 6.84 | 5.32 | 50.66 | 31.76 | 4.32 | 7.3 | 6.32 | 65.1 | 8.76 | 19.11 | 5.74 |
| % Chlorine | | | | | | | | | | | | |
| % Oxygen (diff) | 7.34 | 3.22 | 7.2 | 1.86 | 2.7 | 8.65 | 6.83 | 7.29 | 7.58 | 18.45 | 7.37 | 6.75 |
| Total | 100 | 100 | 100 | 100 | 100 | 100.00 | 100 | 100 | 100 | 100 | 100 | 100 |
| Dry Basis | | | | | | | | | | | | |
| % Carbon | 76.32 | 77.61 | 76.37 | 18.96 | 40.79 | 75.08 | 73.03 | 74.70 | 17.94 | 59.42 | 58.36 | 75.75 |
| % Hydrogen | 4.48 | 4.16 | 4.30 | 1.62 | 2.63 | 4.42 | 4.21 | 4.31 | 1.80 | 4.29 | 3.60 | 4.32 |
| % Nitrogen | 1.26 | 1.27 | 1.39 | 0.35 | 0.63 | 1.31 | 1.29 | 1.37 | 0.42 | 1.35 | 1.06 | 1.32 |
| % Sulfur | 3.77 | 5.39 | 3.21 | 24.25 | 18.89 | 4.06 | 4.99 | 3.72 | 1.22 | 3.38 | 6.99 | 4.12 |
| % Ash | 5.81 | 7.88 | 6.26 | 52.87 | 34.15 | 5.04 | 8.51 | 7.39 | 70.42 | 10.16 | 21.64 | 6.66 |
| % Chlorine | | | | | | | | | | | | |
| % Oxygen (diff) | 8.36 | 3.71 | 8.47 | 1.94 | 2.90 | 10.09 | 7.96 | 8.52 | 8.20 | 21.40 | 8.35 | 7.83 |
| Total | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 |

**Table 8**

Core Drill Samples from Christian County Coal Reserves Analyzed by Eastman Gasification Services Company

| | Core Sample No. 1 Sent to Eastman | | | | | Core Sample 2 sent to Eastman | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Sample Number | CCC 51-1 | CCC 51-2 | CCC 51-3 | CCC 51-4 | CCC 51-5 | CCC 52-1 | CCC 52-2 | CCC 52-3 | CCC 52-4 | CCC 52-5 | | |
| Date Sampled | 3/11/2005 | 3/12/2005 | 3/13/2005 | 3/14/2005 | 3/15/2005 | 3/15/2005 | 3/16/2005 | 3/17/2005 | 3/18/2005 | 3/19/2005 | | |
| Top depth, ft | 492 | 494 | 496 | 498 | 500 | 535.7 | 537.7 | 538.7 | 540.7 | 542.7 | Weighted | Weighted |
| Bottom depth, ft | 494 | 496 | 498 | 500 | 501 | 537.7 | 538.7 | 540.7 | 542.7 | 544.7 | Average of | Average of |
| | 2 | 2 | 2 | 2 | 1 | 2 | 1 | 2 | 2 | 2 | All Samples | Top 3 Sections |
| Fusion Temperature of Ash | | | | | | Reducing | | | | | | |
| Initial Deformation | 1,974 | 1,980 | 2,184 | 2,003 | 1,980 | 2,024 | 2,043 | 2,428 | 2700+ | 2,404 | | 2,111 |
| Softening | 1,992 | 1,997 | 2,223 | 2,024 | 2,007 | 2,091 | 2,098 | 2,478 | 2700+ | 2,448 | | 2,151 |
| Hemispherical | 2,017 | 2,036 | 2,264 | 2,040 | 2,031 | 2,147 | 2,167 | 2,514 | 2700+ | 2,499 | | 2,193 |
| Fluid | 2,034 | 2,087 | 2,308 | 2,052 | 2,063 | 2,266 | 2,307 | 2,560 | 2700+ | 2,545 | | 2,256 |
| Ash Analysis | | | | | | | | | | | | |
| SiO2 | 45.1 | 24.6 | 38.7 | 15.4 | 11.4 | 47.1 | 51.6 | 52.8 | 71 | 57.1 | 42.59 | 42.56 |
| Al2O3 | 12.8 | 11 | 17.3 | 7.98 | 5.36 | 16.7 | 14.5 | 21.5 | 21.5 | 11.9 | 14.51 | 15.74 |
| TiO2 | 0.66 | 0.35 | 0.8 | 0.44 | 0.26 | 0.94 | 0.67 | 0.89 | 1.28 | 0.74 | 0.73 | 0.72 |
| FeO | 21 | 46.4 | 8.02 | 74.1 | 77.6 | 17.3 | 22.8 | 8.32 | 1.95 | 6.42 | 25.97 | 20.44 |
| CaO | 5.35 | 4.94 | 13 | 0.41 | 2.41 | 2.28 | 1.25 | 4.48 | 0.53 | 8.85 | 4.63 | 5.58 |
| MgO | 0.92 | 0.6 | 1.12 | 0.23 | 0.34 | 1.28 | 0.85 | 1.13 | 0.56 | 0.9 | 0.82 | 1.00 |
| K2O | 1.67 | 0.63 | 1.6 | 0.51 | 0.68 | 2.46 | 1.64 | 2.13 | 1.75 | 1.86 | 1.53 | 1.69 |
| Na2O | 5.65 | 5.06 | 5.44 | 0.41 | 0.79 | 5.81 | 4.57 | 5.41 | 1.05 | 3.7 | 3.91 | 5.39 |
| SO3 | 6.17 | 5.68 | 13.2 | 0.1 | 0.71 | 5.56 | 1.7 | 2.74 | 0.1 | 7.87 | 4.74 | 6.22 |
| P2O5 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 |
| SrO | 0.06 | 0.05 | 0.07 | 0.01 | 0.01 | 0.07 | 0.05 | 0.06 | 0.02 | 0.04 | 0.05 | 0.06 |
| BaO | 0.03 | 0.02 | 0.03 | 0.01 | 0.01 | 0.04 | 0.03 | 0.03 | 0.05 | 0.03 | 0.03 | 0.03 |
| MnO | 0.08 | 0.07 | 0.16 | 0.03 | 0.04 | 0.04 | 0.02 | 0.05 | 0.02 | 0.1 | 0.06 | 0.07 |
| Undetermined | 0.44 | 0.53 | 0.49 | 0.3 | 0.32 | 0.35 | 0.25 | 0.39 | 0.12 | 0.42 | 0.37 | 0.42 |
| Total | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 |
| Silica Value | 62.32 | 32.14 | 63.61 | 17.08 | 12.43 | 69.31 | 67.45 | 79.12 | 95.89 | 77.93 | 59.70 | 61.86 |
| Base:Acid Ratio | 0.59 | 1.6 | 0.51 | 3.18 | 4.81 | 0.45 | 0.47 | 0.29 | 0.06 | 0.31 | 1.07 | 0.67 |
| T250 Temperature | 2,250 | 2,150 | 2,310 | 2,150 | 2,150 | 2,360 | 2,340 | 2,570 | 2900+ | 2,540 | | 2,329 |
| Ash Type | Bituminous | Bituminous | Lignitic | Bituminous | Bituminous | Bituminous | Bituminous | Bituminous | Bituminous | Lignitic | | |
| Fouling Index | 3.33 | 8.1 | 5.44 | 1.3 | 3.8 | 2.61 | 2.15 | 1.57 | 0.06 | 3.7 | 3.23 | 4.02 |
| Slagging Index | 2.22 | 8.62 | 2200 | 77.11 | 90.86 | 1.83 | 2.35 | 1.08 | 0.07 | 2423 | 528.95 | 402.71 |

**Table 9**

**Core Drill Results supplied by Christian County Coal Reserves, Herrin No. 6 Seam**

| | Raw Quality | | | | | | | | Washed Quality @ 1.60 Float | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Dry Basis | | | As-Received Basis | | | | | Dry Basis | | | | As-Received Basis | | | | |
| Drill Hole Number | Ash | Sul | BTU | Moist. | Ash | Sul | SO2 | BTU | Ash | Sul | BTU | Core Rec. | Moist. | Ash | Sul | SO2 | BTU |
| | | | | | | | | | | | | | | | | | |
| CCC-00-06 | 11.70 | 4.57 | 12,438 | 12.00 | 10.30 | 4.02 | 7.35 | 10,945 | 8.25 | 3.42 | 13,026 | 91.55% | 12.00 | 7.26 | 3.01 | 5.25 | 11,463 |
| CCC-00-07 | 13.70 | 5.92 | 12,039 | 12.00 | 12.06 | 5.21 | 9.83 | 10,594 | 9.03 | 4.03 | 12,811 | 89.79% | 12.00 | 7.95 | 3.55 | 6.29 | 11,274 |
| CCC-00-08 | 12.24 | 4.98 | 12,371 | 12.00 | 10.77 | 4.38 | 8.05 | 10,886 | 9.25 | 3.94 | 12,903 | 92.32% | 12.00 | 8.14 | 3.47 | 6.11 | 11,355 |
| CCC-00-09 | | | | | | | | | | | | | | | | | |
| CCC-00-10 | 12.59 | 5.28 | 12,302 | 12.00 | 11.08 | 4.65 | 8.58 | 10,826 | 8.88 | 4.12 | 12,924 | 91.55% | 12.00 | 7.81 | 3.63 | 6.38 | 11,373 |
| CCC-00-11 | 15.14 | 5.07 | 11,963 | 12.00 | 13.32 | 4.46 | 8.48 | 10,527 | 8.64 | 4.07 | 12,972 | 86.68% | 12.00 | 7.60 | 3.58 | 6.28 | 11,415 |
| CCC-00-12 | 12.76 | 5.15 | 12,182 | 12.00 | 11.23 | 4.53 | 8.46 | 10,720 | 9.07 | 4.30 | 12,806 | 91.02% | 12.00 | 7.98 | 3.78 | 6.72 | 11,269 |
| CCC-00-13 | 14.12 | 5.44 | 12,042 | 12.00 | 12.43 | 4.79 | 9.04 | 10,597 | 9.64 | 4.08 | 12,796 | 87.55% | 12.00 | 8.48 | 3.59 | 6.38 | 11,260 |
| CCC-00-14 | 14.29 | 6.28 | 12,067 | 12.00 | 12.58 | 5.53 | 10.41 | 10,619 | 10.05 | 3.72 | 12,832 | 89.83% | 12.00 | 8.84 | 3.27 | 5.80 | 11,292 |
| CCC-00-15 | 17.80 | 5.13 | 11,588 | 12.00 | 15.66 | 4.51 | 8.85 | 10,197 | 8.74 | 4.07 | 12,959 | 80.32% | 12.00 | 7.69 | 3.58 | 6.28 | 11,404 |
| CCC-00-16 | 16.38 | 8.24 | 11,677 | 12.00 | 14.41 | 7.25 | 14.11 | 10,276 | 8.95 | 4.17 | 12,946 | 83.43% | 12.00 | 7.88 | 3.67 | 6.44 | 11,392 |
| CCC-00-17 | 14.38 | 7.21 | 12,006 | 12.00 | 12.65 | 6.34 | 12.01 | 10,565 | 9.18 | 4.19 | 12,901 | 87.46% | 12.00 | 8.08 | 3.69 | 6.50 | 11,353 |
| CCC-00-18 | 15.44 | 5.13 | 11,886 | 12.00 | 13.59 | 4.51 | 8.63 | 10,460 | 9.07 | 3.59 | 12,923 | 88.16% | 12.00 | 7.98 | 3.16 | 5.56 | 11,372 |
| CCC-00-19 | | | | | | | | | | | | | | | | | |
| CCC-00-20 | 23.84 | 6.28 | 10,346 | 12.00 | 20.98 | 5.53 | 12.14 | 9,104 | 9.74 | 4.59 | 12,838 | 71.14% | 12.00 | 8.57 | 4.04 | 7.15 | 11,297 |
| CCC-00-21 | 12.47 | 5.30 | 12,332 | 12.00 | 10.97 | 4.66 | 8.60 | 10,852 | 8.77 | 4.67 | 12,946 | 91.09% | 12.00 | 7.72 | 4.11 | 7.21 | 11,392 |
| CCC-00-22 | 13.89 | 5.92 | 12,077 | 12.00 | 12.22 | 5.21 | 9.80 | 10,628 | 8.47 | 3.70 | 13,000 | 88.89% | 12.00 | 7.45 | 3.26 | 5.69 | 11,440 |
| CCC-00-23 | 14.98 | 6.48 | 11,879 | 12.00 | 13.18 | 5.70 | 10.91 | 10,454 | 9.87 | 4.53 | 12,752 | 86.33% | 12.00 | 8.69 | 3.99 | 7.10 | 11,222 |
| CCC-00-24 | 11.53 | 5.96 | 12,420 | 12.00 | 10.15 | 5.24 | 9.60 | 10,930 | 8.58 | 4.55 | 12,920 | 92.10% | 12.00 | 7.55 | 4.00 | 7.04 | 11,370 |
| CCC-00-25 | 13.43 | 4.81 | 12,137 | 12.00 | 11.82 | 4.23 | 7.93 | 10,681 | 9.55 | 4.05 | 12,782 | 91.97% | 12.00 | 8.40 | 3.56 | 6.34 | 11,248 |
| CCC-00-26 | 14.45 | 6.35 | 11,932 | 12.00 | 12.72 | 5.59 | 10.64 | 10,500 | 8.79 | 3.71 | 12,892 | 88.22% | 12.00 | 7.74 | 3.26 | 5.76 | 11,345 |
| CCC-00-27 | 12.82 | 5.17 | 12,269 | 12.00 | 11.28 | 4.55 | 8.43 | 10,797 | 9.94 | 4.48 | 12,762 | 92.99% | 12.00 | 8.75 | 3.94 | 7.02 | 11,231 |
| CCC-00-28 | 11.17 | 4.48 | 12,542 | 12.00 | 9.83 | 3.94 | 7.14 | 11,037 | 8.43 | 4.07 | 13,005 | 93.25% | 12.00 | 7.42 | 3.58 | 6.26 | 11,444 |
| CCC-00-29 | | | | | | | | | | | | | | | | | |
| CCC-00-30 | 11.41 | 5.37 | 12,443 | 12.00 | 10.04 | 4.73 | 8.63 | 10,950 | 8.46 | 3.99 | 12,958 | 92.06% | 12.00 | 7.44 | 3.51 | 6.16 | 11,403 |
| CCC-00-31 | 11.84 | 5.21 | 12,357 | 12.00 | 10.42 | 4.58 | 8.43 | 10,874 | 8.76 | 4.03 | 12,896 | 90.99% | 12.00 | 7.71 | 3.55 | 6.25 | 11,348 |
| CCC-00-32 | 12.61 | 5.40 | 12,240 | 12.00 | 11.10 | 4.75 | 8.82 | 10,771 | 8.65 | 4.17 | 12,924 | 90.69% | 12.00 | 7.61 | 3.67 | 6.45 | 11,373 |
| CCC-00-33 | 14.71 | 6.65 | 11,870 | 12.00 | 12.94 | 5.85 | 11.20 | 10,446 | 9.15 | 4.17 | 12,811 | 87.63% | 12.00 | 8.05 | 3.67 | 6.51 | 11,274 |
| CCC-00-34 | 13.19 | 6.62 | 12,119 | 12.00 | 11.61 | 5.83 | 10.92 | 10,665 | 8.96 | 4.31 | 12,858 | 90.53% | 12.00 | 7.88 | 3.79 | 6.70 | 11,315 |
| CCC-00-35 | 12.86 | 4.99 | 12,140 | 12.00 | 11.32 | 4.39 | 8.22 | 10,683 | 8.90 | 3.96 | 12,812 | 91.09% | 12.00 | 7.83 | 3.48 | 6.18 | 11,275 |
| CCC-00-36 | 10.19 | 4.44 | 12,588 | 12.00 | 8.97 | 3.91 | 7.05 | 11,077 | 8.87 | 4.21 | 12,805 | 96.56% | 12.00 | 7.81 | 3.70 | 6.58 | 11,268 |
| CCC-01-37 | 12.58 | 5.99 | 12,193 | 12.00 | 11.07 | 5.27 | 9.83 | 10,730 | 9.41 | 4.19 | 12,753 | 91.04% | 12.00 | 8.28 | 3.69 | 6.57 | 11,223 |
| CCC-04-41 | 17.73 | 5.68 | 11,453 | 12.00 | 15.60 | 5.00 | 9.92 | 10,079 | | | | | | | | | |
| CCC-04-45 | 14.68 | 6.24 | 11,947 | 12.00 | 12.92 | 5.49 | 10.45 | 10,513 | 8.11 | 4.02 | 13,020 | 88.14% | 12.00 | 7.14 | 3.54 | 6.18 | 11,458 |
| CCC-04-46 | 19.94 | 5.57 | 11,215 | 12.00 | 17.55 | 4.90 | 9.93 | 9,869 | 9.06 | 3.94 | 12,910 | 81.03% | 12.00 | 7.97 | 3.47 | 6.10 | 11,361 |
| CCC-04-47 | 19.90 | 5.36 | 11,271 | 12.00 | 17.51 | 4.72 | 9.51 | 9,918 | 8.95 | 4.29 | 12,903 | 79.18% | 12.00 | 7.88 | 3.78 | 6.65 | 11,355 |
| CCC-04-48 | 17.52 | 5.44 | 11,563 | 12.00 | 15.42 | 4.79 | 9.41 | 10,175 | 9.62 | 4.06 | 12,748 | 82.94% | 12.00 | 8.47 | 3.57 | 6.37 | 11,218 |
| CCC-04-49 | 10.83 | 4.97 | 12,617 | 12.00 | 9.53 | 4.37 | 7.88 | 11,103 | 8.76 | 4.18 | 12,954 | 95.01% | 12.00 | 7.71 | 3.68 | 6.45 | 11,400 |
| | | | | | | | | | | | | | | | | | |
| Range | 13.65 | 3.80 | 2,271 | 0.00 | 12.01 | 3.34 | 7.06 | 1,998 | 1.94 | 1.25 | 278 | 25.42% | 0.00 | 1.71 | 1.10 | 1.96 | 245 |
| Std Dev | 2.91 | 0.80 | 454.11 | 0.00 | 2.56 | 0.71 | 1.52 | 399.62 | 0.48 | 0.28 | 82.73 | 0.05 | 0.00 | 0.42 | 0.24 | 0.45 | 72.80 |
| AVERAGE | 13.94 | 5.45 | 11,439 | 11.35 | 12.26 | 4.80 | 9.13 | 10,066 | 8.58 | 3.92 | 12,178 | 84.53% | 11.33 | 7.55 | 3.45 | 6.09 | 10,717 |

Note: Washed Quality listed for drill holes 00-06 through 01-37 is for plus 100 Mesh size material only. Recovery listed is assuming that minus 100 mesh material will go to refuse.

**Table 10**

**Task 3: Feasibility Analysis – Coal-to-Methanol**

The detailed work under this task is to be undertaken during Phase 1b, FY2006, of the project. Certain work accomplished under the other tasks has established a foundation for the feasibility analysis as discussed, but full reporting on Task 3 will be done at the conclusion of the project.

**Task EMN-1 – Eastman R&D on Coal-to-Chemicals**

EGSC is well positioned to assist in clearing the hurdles regarding development of a coal gasification program encompassing chemicals production in the State of Illinois. Eastman established a unique position in coal based raw materials in 1983 with the startup and later expansion of the gasification, methanol, and acetic anhydride facility in Kingsport. A strong reputation for practical coal gasification know-how and the industry's best gasification operating record has been developed as a result. In early 2005, a coal-to-chemicals R&D effort was established to assess the technical feasibility and potential economic impact of expanded coal-based chemistries.

The Eastman R&D effort has been reflected as a part of EGSC's cost sharing in support of the project, and as such has been identified as Task EMN-1. Much of the specific results of this Eastman effort are necessarily proprietary and confidential to Eastman at this time. A nonproprietary discussion of the work to date is provided in this report as a means of indicating the level of effort invested and the potential to establish realistic and substantial coal-to-chemicals projects in the State of Illinois based on Illinois coal and coal gasification. The R&D effort also contributes to the overall project through the development of process definitions, process models, and economic inputs that will be used in the feasibility assessment focused on methanol chemistry.

The R&D effort has been working on technology element definitions; in an effort to identify chemistries that allow economic production of raw materials from coal gasification. The objectives of the study were to identify possible technical routes for the focus group of raw materials, develop economic models, identify technical gaps and research needs, and develop scenario sets that warrant further investigation.

In framing out its R&D effort, Eastman developed a set of principles which provide a useful guide for the work undertaken in this project. Key elements of a successful gasification based raw materials strategy from Eastman's perspective are:

<u>Carbon Supply</u> – low-cost, predictable cost for raw materials
<u>Front-end Technology</u> – robust, reliable process for converting carbon source to a storable intermediate
<u>Back-end Technology</u> – economic, validated processes for converting intermediates to desired products
<u>Finance</u> – ability to secure funding for highly capital intensive facilities
<u>Off-Take</u> – known and predictable demand for products/co-products
<u>Economy of Scale</u> – sufficient volume to spread fixed investment costs

Eastman's experience with gasification for chemicals production indicates that a wide range of chemical families and products can be derived from gasification. Figure 2 provides a map of derivatives available from two main products of gasification: synthesis gas and, in an additional step, methanol. In particular, the versatility of methanol for products currently manufactured by Eastman and other chemical companies is evident from this figure.

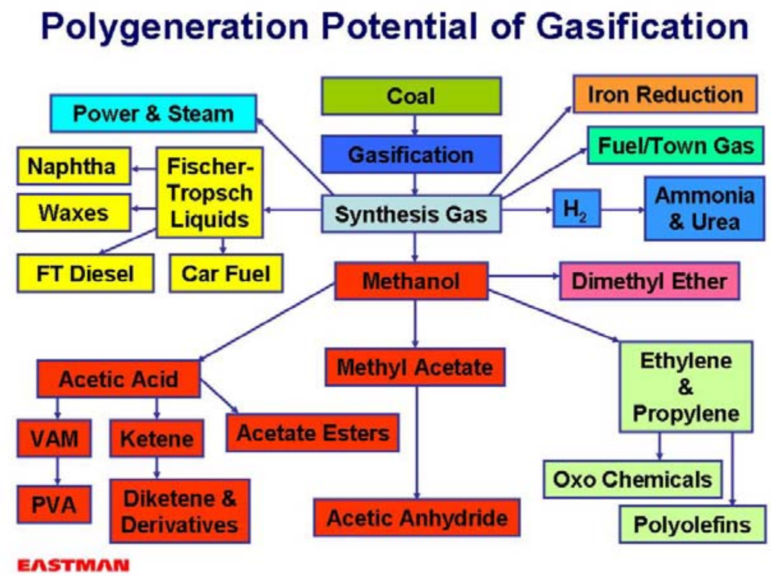


**Figure 2**

## Work Process

The work process used for the R&D portion of this study was comprised of four elements:

- Identifying possible chemical product streams,
- Developing economic models and knowledge gap summaries
- Comparing outputs to existing cost metrics
- Determining highest value product streams for further development.

Once the target technologies were identified, efforts were expanded to include the following deliverables from the technology group: 1) a description of proposed processes, including basic flow sheet, capacity, heat and material balance, cost and capital assumptions; 2) Opinion of technology viability and application (new versus retrofit); and 3) Suggested validation plan, including resource requirements (time and personnel).

Utilizing the output of the Technology group, a financial summary for each major product route will be developed. This will be structured in a way to allow development of rational scenarios. Outputs of this effort will include financial analyses of the micro and macro economics.

**Findings of R&D Studies (To Date):**

The R&D studies demonstrate that coal feedstocks are very competitive with purchased supplies even when commodity prices are in a down cycle and superior in an up cycle for many of the core product streams evaluated. In all cases, additional process work is needed to define an actionable technology pathway and verify the findings based on additional engineering studies to prove out technologies, verify findings and further evaluation of the market fundamental.

Work activities have been focused on several major process groups that reflect perceived manufacturing opportunities in the market. For purposes of ICCI DEV 04-3-Phase 1a, the most important of these process groups is the coal-to-methanol group. While the other process groups remain proprietary at this time as part of Eastman's R&D effort, it is believed that the results of the present feasibility study will be highly indicative of several of the other and most promising opportunities represented by Eastman's R&D. Many of the process technology options under consideration are process enhancements rather than frontier in nature. However, some of the other identified process groups may take longer to achieve due to the need for additional research, testing, and scale-up.

Keys to success are identification and securing low-cost feedstocks and reasonable cost process technology practice. These drivers will determine the ultimate potential of these products to be competitive with foreign-sourced goods. The final business structure will also have to be finalized to understand all of the risks inherent in this type of project and how one might mitigate or minimize certain risks.

**Path Forward**

The following summarizes the recommended development pathway for the R&D program.

- Finalize review and analysis of existing technology.
- Fund process validation/definition work for selected streams and development of optimization scenarios.
- Consider options for methanol process.

**Action Plan**

An overall project schedule and resourcing plan has been developed. Work in the next phase would include development of an actionable business case for the most attractive process group and validation and closure of process technology knowledge gaps. In addition, the demand/cost picture for critical raw materials would be verified. An additional function to ensure up-to-date knowledge of adjacent chemistries is also suggested, which may lead to additional new product opportunities.

# CONCLUSIONS AND RECOMMENDATIONS

To date, Eastman's R&D program on coal to chemicals has found that several candidate products produced through coal gasification appear to be cost-competitive with purchased supplies. In all cases, additional process work is needed to define an actionable technology pathway. Keys to success are identifying and securing low-cost supplies of coal and/or syngas plus reasonable-cost process technology practice. Additional business drivers in the form of alliances, partnerships or incentives enhance viability and reduce risk, but are not prime decision criteria.

Coal to methanol remains a process of special interest and promise based on the work to date. After 2007 there will be little, if any, North American methanol production for commercial markets. A facility to produce methanol from Illinois coal may be one of very few domestic sources of market methanol and could fill a capacity need for demand for existing methanol uses in the 2011/2012 timeframe. While the methanol demand in North America will be significantly (20-percent) impacted in 2006 when MTBE use in the U.S. is discontinued, new markets for methanol and its derivatives show great promise given the higher cost and volatility of oil and natural gas. New markets include such processes as methanol-to-olefins and the use of methanol as a fuel, among others still under study.

The fully allocated cost of methanol (manufacturing costs plus depreciation, excluding return on capital) produced from Illinois coal should ideally be in the $0.25-0.30 per gallon range FOB the plant site to assure a sustainable competitive cost position to imports in the near term. In addition, factors such as the cost of stranded natural gas, the risks of foreign sourcing, and new potential uses for MeOH could dramatically improve the competitive position of coal-based methanol at a given manufactured cost.

Methanol produced in Illinois should have advantaged delivery costs for Midwestern and Northern states as well as Canada. To the extent that potential new uses for methanol and related or derived chemicals (e.g., fuel use or coal-to-chemicals) are more evenly distributed geographically, this advantage could prove to be highly significant.

To set a solid foundation for the feasibility study in the next phase of the project, the feedstock characteristics need to be defined based on a thorough knowledge of gasification. Based on EGSC's analysis, the items listed below are deemed most important in approximate order of importance.

1. Carbon Content – The carbon content will set the sizing of the air separation unit, gasifier, and compressor along with overall auxiliary power consumption. Carbon content can be varied by washing the coal; therefore, an analysis of potential carbon content versus washing cost may be needed.
2. Ash Chemistry – This sets the gasifier temperature which in turn affects gas composition which then cascades down to all other systems. For a feasibility study, the $T_{250}$ or Base/Acid ratio are important ash chemistry measures.

3. Chlorine – The level of chlorine sets the water system chemistry and metallurgy which has a large impact on plant cost and reliability. Illinois coals are typically high in chlorine versus other feedstocks, and therefore this criterion is very important for gasification projects in Illinois.
4. Sulfur – The sulfur content will set the acid gas removal unit sizing.
5. Moisture Content – The coal water content will affect syngas properties and slurry characteristic. Unlike ash chemistry and percent carbon, removing moisture in a slurry system require energy input that could be used elsewhere, and thus has a significant impact on overall efficiency and capital costs.
6. Ash Content – The ash content is expected to be inversely correlated to carbon content. Ash content has a significant impact on design and operations of the gasifier as well as waste disposal costs.
7. Arsenic – Arsenic can foul the cooling system and therefore needs to be known for sizing, redundancy, and reliability. Inorganic arsenic can be washed out of the coal.

The Phase 1b portion of the methanol market assessment task will include consultant studies by Nexant and Sargent & Lundy to help validate and refine the conclusions above as well as accomplishing the following:

- Provide clearer definition of methanol marketplace with a strong focus on potential new opportunities and identification of target markets for Illinois production.
- Extend the supply/demand and price forecasts thru 2020.
- Clearly understand the methanol market price drivers and analyze the opportunity to participate with production from Illinois coal.
- Determine logistics cost to serve the target markets from an Illinois location.

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