FINAL TECHNICAL REPORT
April 1, 2005, through June 30, 2006

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

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ABSTRACT

The Illinois Clean Coal Institute (ICCI) initiated this study with Eastman Gasification Services Company (Eastman) to evaluate the feasibility of chemicals production from Illinois coals and lay the groundwork for chemicals project development in Illinois.

Eastman evaluated 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 were evaluated, 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 the ability to obtain financing. The economic viability of methanol production in Illinois from a standalone coal to methanol or methanol and power coproduction facility will depend on achieving a competitive manufacturing cost and securing a position in market segments that can be efficiently supplied from a U.S. Midwest location. The North American methanol market can easily absorb production from a new facility located in Illinois. Future methanol market pricing, even after a projected collapse in prices, will be sufficient to cover expected production costs for the proposed plant.

There are many ways to compare the relative value of coals; but, in the final analysis, the value of a coal for gasification still generally correlates to its heating value since higher heating values result in more output per unit cost. Since Illinois coals are positioned just below Pittsburgh #8 coals and above PRB coals, their value will also be between these two coals though Illinois coals can be differentiated due to the vast, un-tapped reserves that are relatively easy to mine, are still available in large contiguous blocks and are close to the highest population centers where demand for syngas derived products is greatest.

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 project has evaluated risks and potential for success, particularly with Illinois coal.

The Illinois Clean Coal Institute (ICCI) provided funding to Eastman Gasification Services Company (Eastman) 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 included:

- 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).

- 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).

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

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

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. A facility to produce methanol from Illinois coal may be one of very few domestic sources of methanol and could fill a capacity need for demand for existing methanol uses in the 2011/2012 timeframe. 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.

While the North American methanol market can easily absorb production from a new facility located in Illinois, emerging new uses of methanol may provide even more outlets. Though the methanol demand in the U.S. is being reduced due to discontinued use of MTBE as gasoline additive, 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. Methanol may have limited use as a transportation fuel due to logistics infrastructure limitations and low heating value density; but if methanol were to gain a significant share of the market for fuel switching from natural gas, it could have a major impact on the demand from an Illinois coal-based methanol plant.

The economic viability of methanol production in Illinois from a standalone coal to methanol facility or methanol co-produced 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 a U.S. Midwest location. The coal-based, methanol cash costs 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 over a full economic cycle based on a forecast by Nexant, Inc. 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. Future methanol market pricing, even after a projected collapse in prices due to the forecast change in price-setting mechanisms, will be sufficient to cover expected production costs for the proposed plant.

TASK 2 – ILLINOIS COAL CHARACTERIZATION

The feasibility assessments done under this effort were based on the site of the Christian County Energy Center project near Taylorville, Illinois so particular attention was 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 were also characterized with respect to key constituents of importance to coal gasification economics. A general guide to understanding the impacts of different quality coals, a list of important coal parameters and a qualitative description of the impact of the parameter on gasification plant design and operation were developed. Since there will always be a trade-off between desired properties and coal price, a more quantitative analysis of these constituents was also completed along with an evaluation of the Illinois coal basin for levels and variability of the highest impact coal characteristics including: carbon, ash, sulfur, chlorine, and moisture content as well as the ash fusion temperature. Each of the coal property cases were run in a proprietary model and then evaluated against the following criteria: cold gas efficiency, coal consumption, oxygen consumption, capital cost, syngas cost, and coal cost at constant or equal syngas price. In addition, a comparison was made to other potential, competitive fuels including coal from other seams, lignite from the western locations, and petroleum coke.

Though there are numerous ways to compare and evaluate the relative value of coals, in the final analysis, the value of a coal for gasification still generally correlates to its heating value since higher heating values result in more output per unit cost. Since Illinois coals are positioned just below Pittsburgh #8 coals and above PRB coals, their value will also be between these two coals. One of the negatives for Illinois coals in the past for power generation has been the higher sulfur levels. However, gasification plants are relatively indifferent to sulfur levels and can easily remove sulfur from the syngas at high levels and turn it into pure sulfur or sulfuric acid to be sold as by-products. Illinois coals can be differentiated due to the vast, un-tapped reserves that are relatively easy to mine, are still available in large contiguous blocks and are close to the highest population centers where demand for syngas derived products is greatest.

To define feedstock suitability and impacts for gasification for chemicals production, the items listed below are deemed most important in approximate order of impact.

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.
2. Ash Chemistry – Ash properties influence 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 influence the acid gas removal unit and sulfur recovery unit sizing.
5. Moisture Content – The coal water content will affect syngas properties and slurry characteristics. 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.

TASK 3 – COAL TO METHANOL FEASIBILITY ANALYSIS

The feasibility of developing an Illinois coal-to-chemicals project based on gasification of Illinois basin coal was completed and the key metrics influencing the financial return for a potential standalone methanol or power and methanol coproduction facility were determined. For the standalone facility, EPC capital costs and methanol pricing have the dominant influence on IRR while coal and O&M cost along with the availability of federal tax credits also have in important impact. Given the relatively high, potential leverage of debt to equity for the coproduction facility with its anchor of long term power contracts, the debt portion was found to have the greatest influence on IRR. As for the standalone facility, EPC capital costs also had a strong influence on IRR for the coproduction facility. Given the substantial quantity of market power sales for coproduction, the power price also has a strong impact on IRR along with the methanol price.

The coproduction facility had higher returns than the standalone facility as a result of the more highly leveraged capital structure and option value provided by dispatching to the most valuable product. The standalone methanol facility only has one major product, while coproduction provides two major products and the option of dispatching to the most valuable on time scales that can be accommodated within the ultimate contract structure. With a storable product, methanol, the coproduction facility was dispatched more heavily to methanol during off-peak power periods within a calendar year while power prices are depressed. In addition, given the cyclic nature of the methanol price forecast and the different long term annual growth rates in relative methanol to power prices, varying the dispatch schedule annually to favor the most valuable product will provide a 2.7% point increase to the coproduction facility return.

TASK EMN-1 – EASTMAN R&D ON COAL-TO-CHEMICALS

The R&D studies have demonstrated 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, more work is needed to verify the findings through additional engineering studies to prove technologies and further evaluate the market fundamentals. Keys to success are securing low-cost supplies of methanol or other feedstocks of interest and reasonable cost process technology. These drivers will determine the ultimate potential of these products to be competitive with foreign-sourced goods. Additional business drivers in the form of alliances, partnerships or incentives enhance viability and reduce risk, but are not prime decision criteria. The final business structure will also have to be finalized to understand all of the inherent risks and how to mitigate or minimize them.

OBJECTIVES

The Illinois Clean Coal Institute (ICCI) provided funding to Eastman Gasification Services Company (Eastman) to evaluate the potential of utilizing Illinois coal for the production of chemicals based on gasification, with particular focus on methanol (MeOH) as a major chemical of interest. This objective was achieved in two sub-phases: Phase 1a, completed in fiscal year (FY) 2005, and Phase 1b completed in FY 2006. The project was subdivided into four major tasks: Task 1: MeOH Market Assessment, Task 2: Illinois Coal Characterization, Task 3: Coal to MeOH Feasibility Analysis, and Task EMN-1: Eastman R&D on Coal to Chemicals.

The MeOH market assessment analyzed the dynamics and impact of recent, significant restructuring of the MeOH industry and addressed the following major items:

- Investigation of traditional and emerging market opportunities for MeOH from Illinois coal with a screening examination of MeOH use as a fuel for combustion turbines and industrial boilers.
- Analysis of supply/demand balance for North American (NA) MeOH with a focus on the Midwest region.
- Cost of MeOH from coal versus imported MeOH and the relative cost difference influence on price setting mechanisms and forecasts.
- Evaluation of potential supply scenarios, modes of transport and logistical costs of servicing target markets from Illinois.

The Illinois coal characterization task focused on evaluating the suitability of Illinois basin coal reserves as gasifier fuel. The study investigated the following key areas:

- Statistical analysis of the Illinois basin coal reserves with a more in depth investigation of Christian County coal deposits, the reference coal for Task 3.
- Identification and quantification of relative importance of key coal properties for use as gasification fuel.
- Evaluation of mining costs and key coal properties of Illinois basin reserves in comparison to alternative fuels.
- Assessment of relative competitiveness of Illinois coal versus competing gasification fuels.

The coal to methanol feasibility analysis examined the technical feasibility, optimum design, and economics of coal-to-methanol based on an Illinois mine-mouth site. The study assessed both standalone methanol production and methanol coproduction with IGCC using Taylorville, IL as the reference site based on the proposed Taylorville Energy Center project [1].

The Eastman R&D effort investigated improved coal-based processes for the production of chemicals. The work focused on several product groups with, for purposes of this project, the most important being the coal-to-methanol group. While the other process groups remain proprietary, this feasibility study has indicated that some are viable.

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. 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 determine this potential, project developers and chemical companies need feasibility assessments that evaluate the economics of chemicals production based on currently available coal processing technologies and detailed site information. The work under ICCI Project DEV 04-3 is aimed at contributing substantially to these feasibility studies.

Prior experience has shown that many chemicals now produced from oil and natural gas and their derivatives can be produced from coal via gasification. However, it is clearly not possible to address the economics of producing a wide range of chemicals in a limited feasibility study. 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 was chosen as the representative chemical for 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.

The scope of DEV 04-3 was completed in Phase 1a during FY 2005 and Phase 1b during FY 2006. The Phase 1 effort aimed at evaluating the feasibility of a chemicals production project in Illinois while the front-end engineering and other development tasks would constitute Phase 2. The current final report reflects results of Phase 1a and 1b with an emphasis on the results in Phase 1b. As such, interested users should look to the earlier, final report from Phase 1a to derive the full value of this work.

EXPERIMENTAL PROCEDURES

The project relied predominantly on non-experimental research, data compilation and reduction, and qualitative and quantitative analysis. Consultants, publicly available sources and the internal expertise and experience of Eastman were relied upon to synthesize results and develop conclusions. A limited amount of coal analysis was conducted using standardized tests conducted by commercial laboratories.

The methanol market assessment task was completed with the assistance of Nexant, Inc. (Nexant) and Sargent & Lundy, L.L.C (S&L). Nexant used its in-house information including pricing and supply/demand databases and forecasting systems for methanol and selectively made other industry contacts as needed to address their scope of work. Data for ethanol from the Energy Information Agency for shipments between Petroleum Administration for Defense Districts (PADDs) was used as a proxy to estimate logistics costs for methanol. S&L helped evaluate the feasibility of using methanol as a fuel for combustion turbines and industrial burners by interviewing key equipment manufacturers and surveying power producing facilities and owners in the Midwest region of interest.

The Illinois coal characterization task was completed with the assistance of S&L and Hill & Associates, Inc. (H&A). S&L utilized data prepared by the United States Geological Survey (USGS) [2] to build a database of Illinois basin coal properties for statistical analysis. H&A used its coal cost modeling system and database to estimate cost for a typical mine in each of the identified coal producing areas of interest. Eastman used proprietary in-house models to quantify the economic impact of coal properties.

The feasibility analysis task was completed with the assistance of S&L and input from select technology vendors. S&L modeled the power block using the GateCycle™ program, a commercially available software application that performs detailed steady-state design and off-design heat balance analyses of thermal power systems. Eastman rigorously modeled the chemical plants using Aspen Plus®, the process modeling software from Aspen Technology, Inc. (Aspen). S&L developed an operating and maintenance (O&M) cost estimate as well as a capital cost estimate for the power block and balance of plant using in-house methods. They based work crew labor rates using the craft rates and fringe benefits from RS Means Labor Rates for the Construction Industry (Annual Edition 2006) Union Wage Data published for Springfield, Illinois. Eastman prepared O&M cost estimates from experience in operating similar plants and capital cost estimates for the chemical processes using Aspen Kbase, Aspen's flagship estimating software built on ASPEN Icarus™ technology for generating conceptual and detailed cost estimates. Mine mouth, coal pricing was based on data from the Energy Information Administration (EIA) [3]. Electric energy and capacity price forecasts were developed by S&L using the MarketPower© model, which they license from New Energy Associates. The MarketPower© model simulates the dispatch of generation units on a region-by-region basis, subject to transmission constraints between different market areas. Detailed financial models were built and the economic analysis completed by adapting the U.S. Department of Energy's *IGCC Model Version 4.0* for the specific needs of this project.

RESULTS AND DISCUSSION

Task 1 - Methanol Market Assessment

As described in the Phase 1a report, the methanol industry in North America (NA) has undergone significant restructuring during the past five years with the startup of large-scale, "mega" methanol 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 was to understand the dynamics and impact of this restructuring on the methanol industry and market place and to forecast the future view.

Current Methanol Markets

Major products derived from methanol in North America are formaldehyde, MTBE, acetic acid, chloromethanes, methyl methacrylate and methylamines. A further description of the uses and consumers of methanol is given in the Phase 1a report and the *Coal to Methanol Market Assessment Final Report* from Nexant in the Appendix.

In the U.S., the major end-users of methanol are concentrated at the U.S. Gulf Coast (USGC) and the East Coast, as shown in Figure 1 though there are some consumers in the Midwest who could be sourced from an Illinois methanol plant.

Figure 1: Major End-Users of Methanol in the U.S.

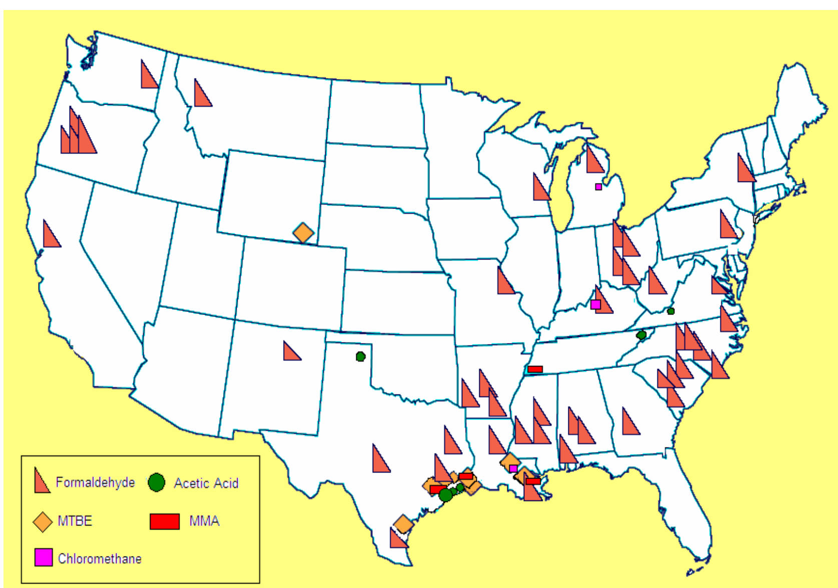


Table 1 summarizes the methanol requirement for the six major end uses with formaldehyde, MTBE, and acetic acid representing almost 90 percent of methanol end uses.

Table 1: Summary of Major End Uses of Methanol in North America

End Use	Consumer	Capacity of End Use (MM tons/yr)	MeOH Demand @ 100% of Capacity (MM tons/yr)	% of MeOH Industry Total
Formaldehyde (37 wt% basis)	Top 5 Consumers	5.59	2.57	
	Industry Total	6.87	3.17	36.8
MTBE	Top 5 Consumers	4.71	1.72	
	Industry Total	6.76	2.47	28.7
Acetic Acid	Top 5 Consumers	3.24	1.83	
	Industry Total	3.39	1.92	22.4
Chloromethanes	Industry Total	0.64	0.43	5.0
Methyl Methacrylate	Industry Total	0.94	0.35	4.0
Methylamines	Industry Total	0.25	0.26	3.1
Grand Total	Top 5 Consumers		7.17	
	Industry		8.60	100

North American methanol demand is dominated by the U.S. that accounts for about 80 percent of the methanol consumed by the North American formaldehyde and MTBE industries. Similarly, the U.S. accounts for 95 to 100 percent of total methanol requirements for each of the other major end use markets.

Methanol demand was also analyzed from the perspective of the Taylorville methanol plant in Illinois. Primary (100 to 300 miles from Taylorville) and secondary (300 to 500 miles from Taylorville) target markets for the Taylorville plant were defined. MTBE was excluded from the target market analysis because the use of MTBE is already banned in most of the Midwest target states since it has been identified as a ground water contaminant as a result of gasoline spills and underground tank leakage. The total methanol requirements for the primary and the secondary target markets are 0.68 and 0.70 MM metric tons per year, respectively, with each target market representing just over 10% of the total industry methanol requirement.

Potential New Methanol Market Opportunities

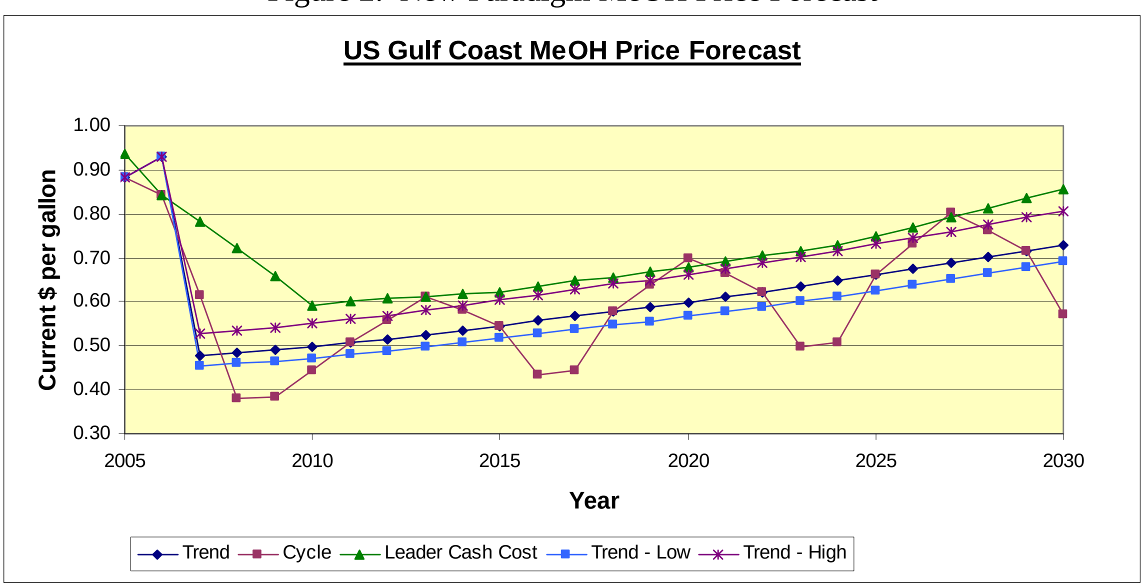
The fuel market is presently a small area for methanol but has the potential to expand significantly in the future given the availability issues and high prices in the petroleum industry along with environmental drivers. Gas turbine vendor testing has demonstrated that methanol is feasible as a combustion turbine fuel and offers improved heat rate, higher power output, and reduced NO_x and SO_2 emissions. A fuel market evaluation focused on gas turbines and burners for heat recovery steam generators (HRSGs) was completed as part of this study and the results are provided in the Appendix. A detailed market survey of target customers within an economic radius of Illinois was also included. Though it is technically feasible to use methanol as a turbine fuel for industrial and power applications, such use faces significant commercial and practical barriers. Plant modifications for increased storage requirements due to the low heating value of methanol may result in the largest modification costs for a facility contemplating switching to methanol fuel. To consider switching to methanol as a fuel, utilities stated a need for long term price stability, reliability and availability of methanol supply. If methanol were to gain a significant share of the market for fuel switching from natural gas, it could have a major impact on the demand for coal-based methanol.

An in-depth analysis of new market opportunities for methanol is included in the Appendix. With declining use 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.

Methanol Pricing

Phase 1a presented data on historical methanol pricing and a near term price forecast range. During Phase 1b, this initial work was extended to generate long term price forecasts. Methanol prices have historically been related to U.S. natural gas prices and the methanol supply/demand balance, with high cost NA production on the margin holding prices up in a tight market effectively establishing a floor price. Global methanol pricing is expected to undergo a fundamental paradigm shift due to the number of new, high capacity methanol plants which are being brought on stream in gas price advantaged locations such as Trinidad. As the largest methanol market, the U.S. will remain important in price setting but it will likely be the delivered costs from the major production hub in Trinidad that will have the most significant influence on pricing. Methanol price projections have been generated assuming a 12 percent (declining by one percent per annum thereafter) return on investment for a 1.65 million metric ton/yr Trinidad plant supplied with natural gas at a price of $1.25 per MMBtu HHV to reflect the expectation that such plants will be built but generate trend prices just below cash cost breakeven to the U.S. Gulf Coast Leader. An upper methanol price scenario has been created based on a higher Trinidad gas price of $1.75/MMBtu along with a lower methanol price scenario based on a Trinidad gas price of $1.00/MMBtu believed to be the floor of existing gas contracts. The resulting "New Paradigm" regional methanol price forecasts are shown in Figure 2.

Figure 2: New Paradigm MeOH Price Forecast



North American Supply/Demand

Consumption for methanol has been relatively level in recent years as demand growth from formaldehyde has been offset by a decline in MTBE. Historical and forecast methanol consumption, split by major end use, is shown below in Figure 3. Methanol consumption for formaldehyde will grow from 2.3 million metric tons in 2005 to almost 3.8 million metric tons in 2025. Methanol consumption for acetic acid will grow from 0.7 million metric tons in 2005 to 1.3 million metric tons in 2025.

Figure 3: U.S. Methanol Consumption by End Use, 1996-2025

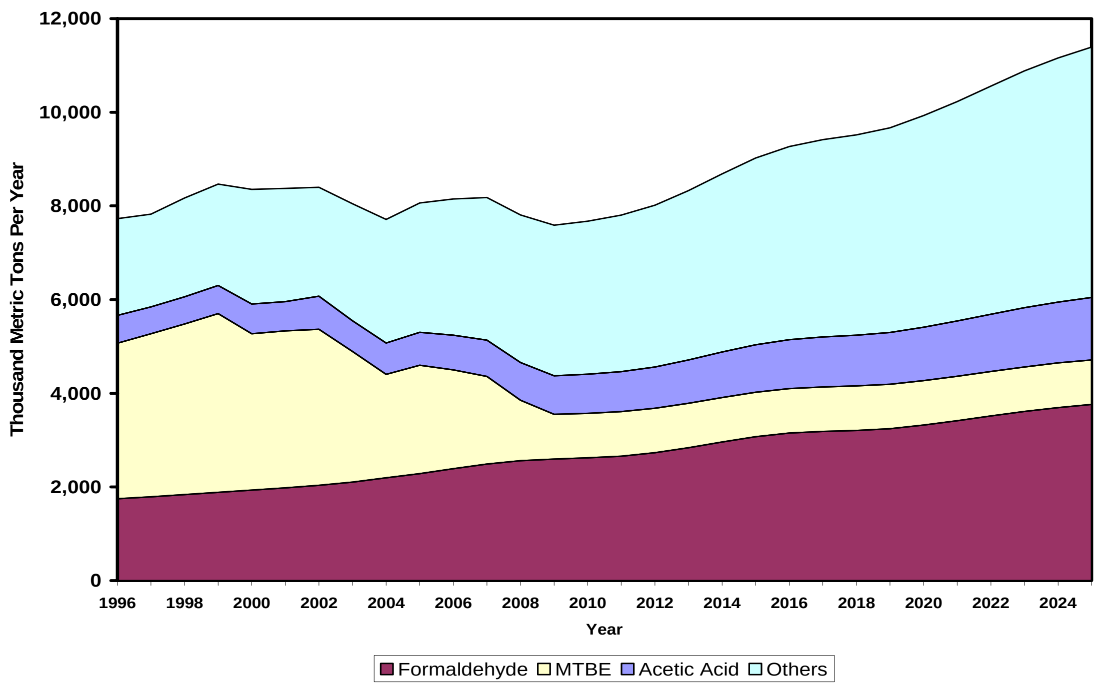


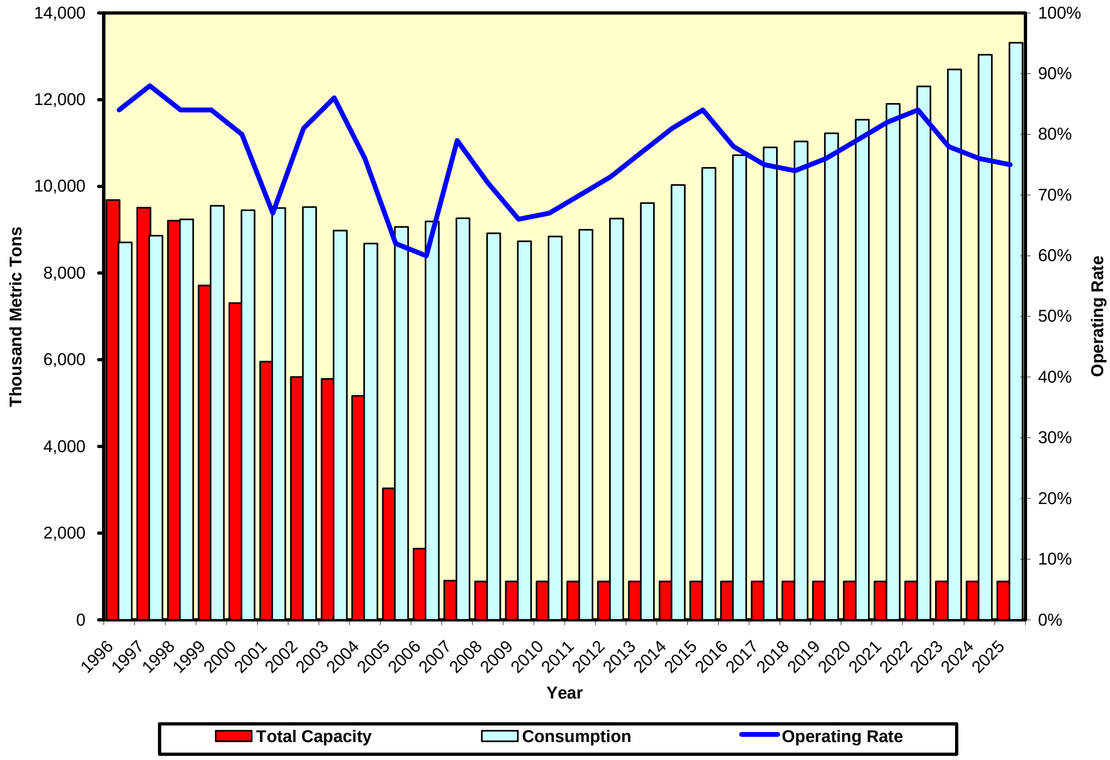
Table 2 lists the methanol plants with nameplate capacities in North America. There were 11 methanol plants operating in North America in early 2005. Only 2 to 3 are expected to remain in operation long-term due to the high prices for U.S. natural gas.

Table 2: North America Methanol Plants

Country	Company	Location	2005	2006	2007	2008
Canada	Celanese	Edmonton, Alberta	740	740	0	0
Canada	Methanex	Kitimat, BC	530	0	0	0
Mexico	Pemex	Texmelucan	16	0	0	0
Mexico	Pemex	Texmelucan	112	0	0	0
US	Celanese	Bishop, TX	329	0	0	0
US	Clear Lake MeOH	Clear Lake, TX	255	0	0	0
US	Coastal	Cheyenne, WY	75	75	75	75
US	Eastman	Kingsport, TN	195	195	195	195
US	Millennium	Deer Park, TX	660	660	660	660
US	Terra International	Woodward, OK	150	0	0	0
US	Terra Meth Industries	West Covina, CA	17	17	17	0

Figure 4 shows the North America supply/demand balances from 1996 to 2025.

Figure 4: North America Methanol Supply/Demand Forecast



On a global basis, after a 2009/2010 market downturn, the demand growth rate will outpace the capacity growth from 2010 to 2020. Essentially, all new capacity is expected to be built in regions with very low cost natural gas, although coal-based and possibly bio-based methanol plants are expected to be built in certain regions. Global operating rates are projected to decline to historical lows by 2009 while longer term operating rates are forecast to fluctuate in a pattern more typical of the past, with sharp increases to high rates for a short period, followed by a longer period of low rates. The scale of the new plants currently under development (1.5-2 million tons per year) represent a capacity increment of a greater proportion of installed capacity than seen with the last generation of plants (0.85-1 million tons), and global operating rates, and hence margins, are therefore expected to be as volatile as they were over the last decade.

Logistics from an Illinois Coal Mine Location

A plant at Taylorville, IL has several options to transport methanol to market including: railing its methanol to St. Louis, and then barging it to markets in the Midwest and Southeast; direct shipment by rail only, and direct shipment by truck. Building a methanol pipeline to St. Louis for connection with barge transport is another alternative as well though the pipeline would need to be about 80 miles long. The central U.S. and Gulf Coast along with much of Appalachia and the east coast are served by barge-navigable rivers and the inland waterway. The U.S. freight railway infrastructure is extensive and provides ready access to customers throughout the US and into Canada. Taylorville, Illinois, the assumed site for the coal-based methanol, is served by the Norfolk Southern (NS) railway, which runs a line south-southwest to the St. Louis area, where transfer to barges is feasible. NS does not serve west of Kansas City, but does serve New Orleans, the east coast, and the southeast, where a large part of the customer base for the proposed plant may be located. To serve Western states, NS would need to transfer to other railroads, such as Burlington Northern Santa Fe. Estimated, typical transportation costs from Taylorville, Illinois to the potential customers in the region based on average distances of 200 miles to the primary markets and 400 miles to the secondary markets are as shown in Table 3.

Table 3: Typical Methanol Transportation Cost

Mode	Transportation Cost ($/ton methanol)	
	Primary Market	Secondary Market
Rail to St. Louis / Net by Barge	3.19	5.13
Rail	5.06	10.12
Truck	10.70	21.40

Task 2 - Illinois Coal Characterization

The feasibility assessments done under this effort were based on the site of the Christian County Energy Center project near Taylorville, Illinois [1]. To have a ready basis for comparison, it was decided to use the same design basis coal, as shown in Table 4, to develop process design for task 3. Samples of the Herrin No. 6 Seam were obtained from the Christian County Coal Company and analyzed to assess composition and properties at this specific location with the complete set of analytical results provided in the Phase 1a report. Though particular attention was paid to the Taylorville site, in order to help translate these site-specific feasibility results to a range of locations within the State of Illinois, coals from across the state were also characterized with respect to key constituents of importance to coal gasification economics.

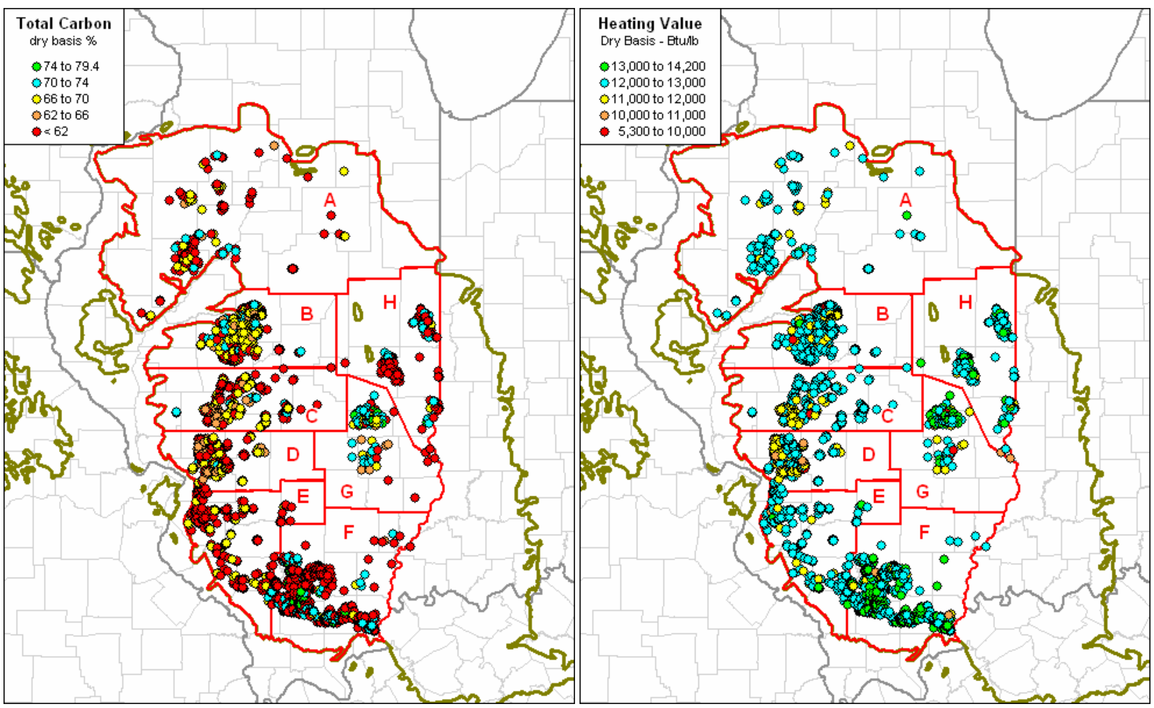
Table 4: Taylorville Design Basis Coal

Property	Design Basis Coal
Ultimate Analysis, wt% dry basis	
Carbon	72.01
Hydrogen	5.13
Nitrogen	1.2
Sulfur	5.02
Oxygen	4.54
Ash	12.08
Moisture, wt%	12.81
Chlorides, ppmw as received	2,200
Higher Heating Value, Btu/lb dry	13,245

In addition to establishing a design basis coal, it is necessary to understand the particular characteristics and variability of the feedstock to be used. A coal quality impact guide, list of important coal properties, and qualitative description of the impact of the properties on gasification plant design and operation were provided in the Phase 1a report. Since there will always be a trade-off between desired properties and coal price, a more quantitative analysis was conducted during Phase 1b along with an evaluation of the Illinois coal basin for levels and variability of the highest impact coal characteristics.

The characteristics of Illinois Coals were defined for use in the evaluation using an ISGS database prepared by the United States Geological Survey (USGS) dated 2002 [2]. The coal quality parameters were grouped and mapped to show their geographical distribution throughout the state, and a statistical analysis was performed for each group of coals. Typical maps for carbon content and heating value are shown below.

Figures 5 and 6: Illinois Basin Total Carbon and Heating Value



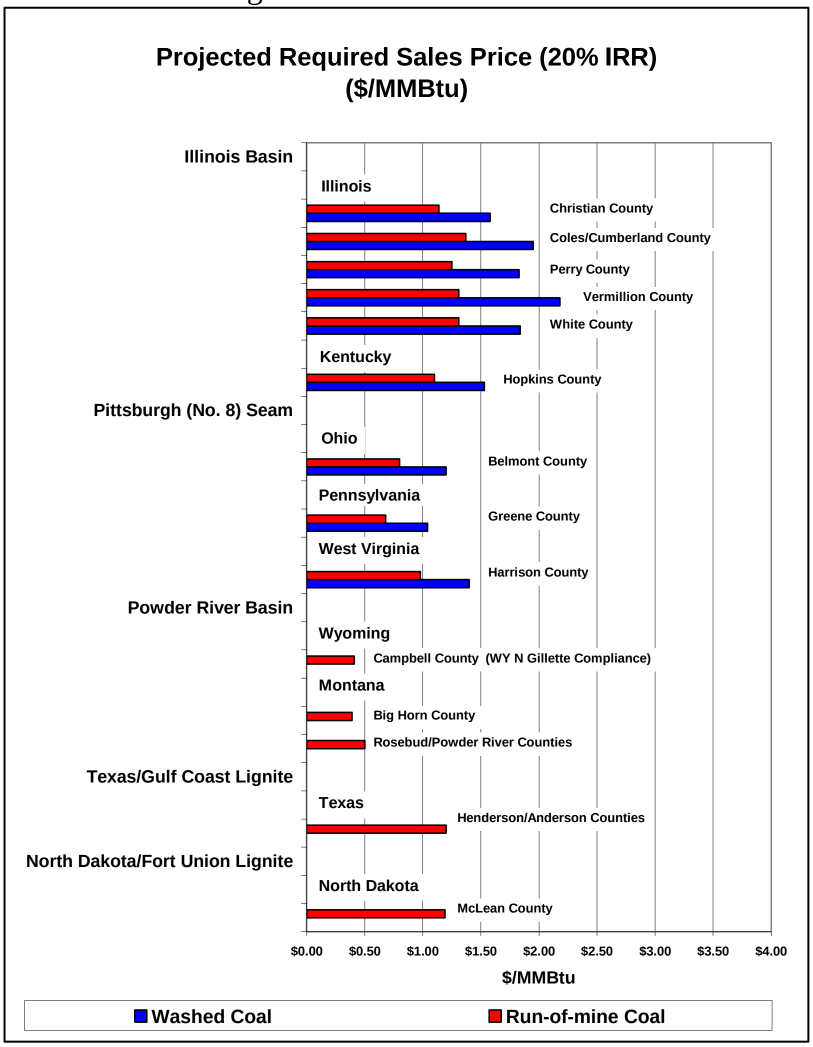
The database for the set of coal samples, a summary showing the statistical analysis for each group, and a full set of maps for the following primary properties can be found in the Appendix.

- Total Carbon Content – % on dry basis
- Fluid Ash Fusion Temperature – °F on dry basis
- Arsenic Content – dry whole-coal ppm
- Chlorine Content - % on dry basis
- Total Sulfur Content - % on dry basis
- Ash Yield - % on dry basis
- Moisture Content – as received %
- Heating Value – Btu/lb

Additional characteristics of secondary importance such as: nitrogen, hydrogen, mercury, volatiles, and oxygen content are included in the database as well.

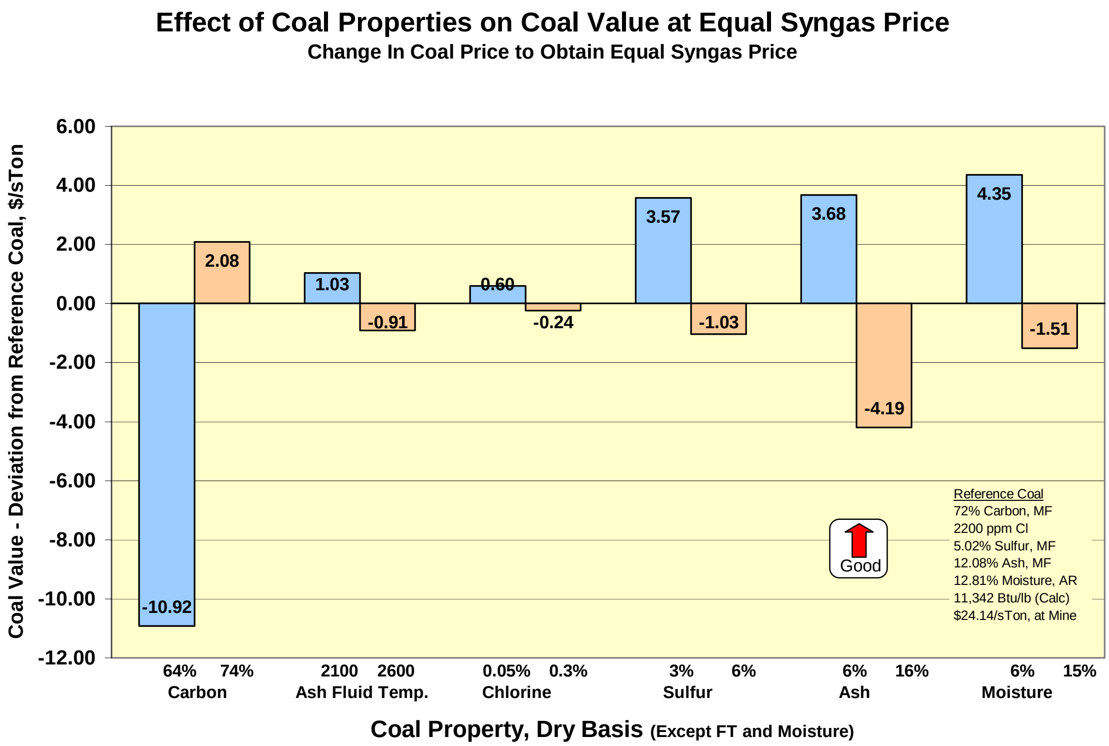
In addition to evaluating the coal characteristics, an assessment was made of the mining costs across the Illinois basin and a comparison made to other potential, competitive fuels. Hill & Associates (H&A) prepared a cost analysis of typical coal in Illinois, Western Kentucky, the Pittsburgh (No. 8) Seam, the Powder River Basin coals, and Texas/Gulf Coast and North Dakota/Fort Union lignite fields. H&A prepared cost models for a hypothetical mine based on existing mines or properties in the selected areas and solved for the required sales price for a 20% IRR. The full report is found in the Appendix and a summary of the results found in the figure below.

Figure 7: Gasifier Fuel Prices



A coal properties study was done to quantify the economic impact of the following coal properties thought to have the most significance for gasification processes: carbon, ash, sulfur, chlorine, and moisture content as well as the ash fusion temperature. These properties were analyzed by starting with the design basis coal and varying each property one at a time to isolate its influence. The range of Illinois basin coal properties to study was determined from the earlier statistical analysis of the ISGS database. Each of the coal property cases were run in a proprietary model and then evaluated against the following criteria: cold gas efficiency, coal consumption, oxygen consumption, capital cost, syngas cost, and coal cost at constant or equal syngas price. One of the most useful charts to evaluate the impact of coal quality on overall economics is given below in Figure 8 while the full analysis is provided in the Appendix.

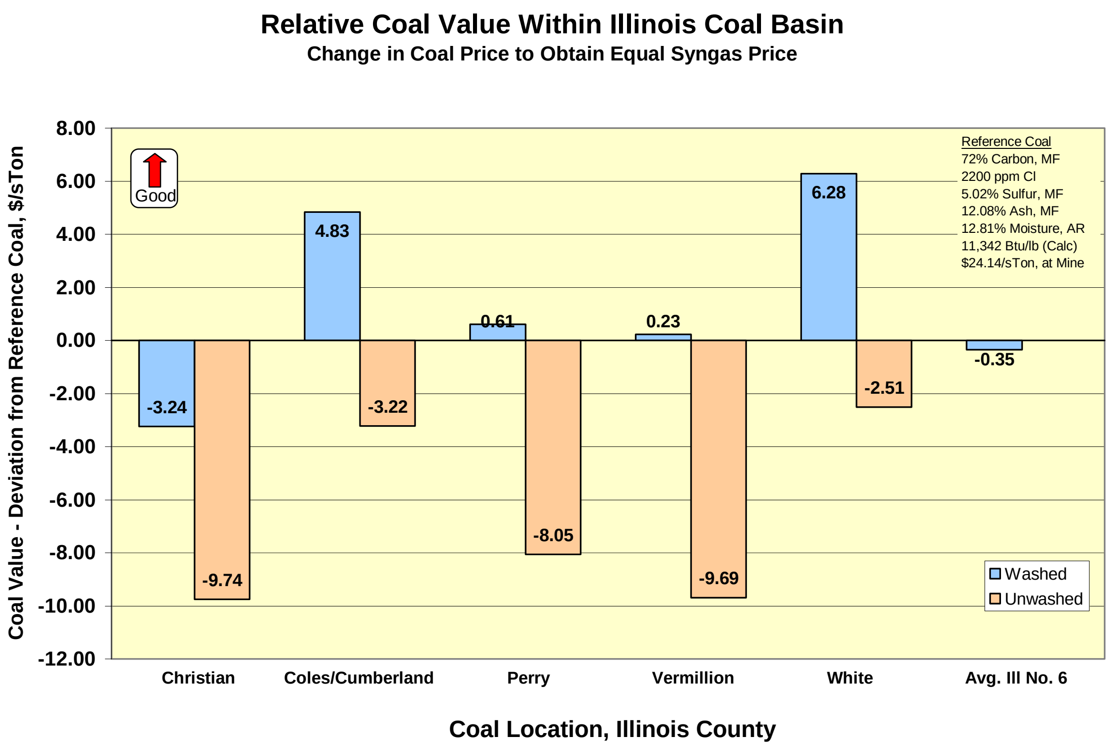
Figure 8: Coal Cost at Equal Syngas Cost



Syngas cost was first determined by dividing syngas production by the estimated production costs that included coal at the reference coal price, oxygen, capital recovery at 10% per year, steam and sulfur credits and other operation and maintenance costs. No assumption was made about the final use of the syngas. Coal cost (value) at equal syngas price was determined by adjusting the coal cost for each case until the syngas cost was equal to the syngas cost for the reference coal. For example, an owner could afford to pay $2.08/sTon more than the reference coal price for a coal with 74% carbon (dry basis) to get the same final clean syngas price. Likewise, the owner would pay $10.92/sTon less than the reference coal for a coal that had 64% carbon (dry basis) and still get the same syngas price.

After the coal properties economic assessment was done, a similar analysis was done for the Illinois coals identified in the H&A report though only syngas cost and coal price were used for the basis of comparison. The cold gas efficiency, oxygen consumption, coal consumption and capital cost effects are captured within these two measures and have similar trends as shown in the coal properties study. Figure 9 compares the Illinois coals both washed and unwashed on a basis of relative coal price that produces an equal cost of syngas. As shown by the graph, there is significant variation between the Illinois coals with White County being the most favorable. This may be indicative of the region or may be only representative of the specific mine where the sample was obtained. There is also a significant difference at the same location for washed and unwashed ROM coals. The difference in the equivalent price of coal to get an equal syngas price between washed and unwashed coal averages $8.40/short ton so that a plant owner could pay at least $8.40/ short ton more for washed coal and break even on overall value. This does not count some of the intangible benefits of washed coals, especially the increased consistency of the feed for washed coals.

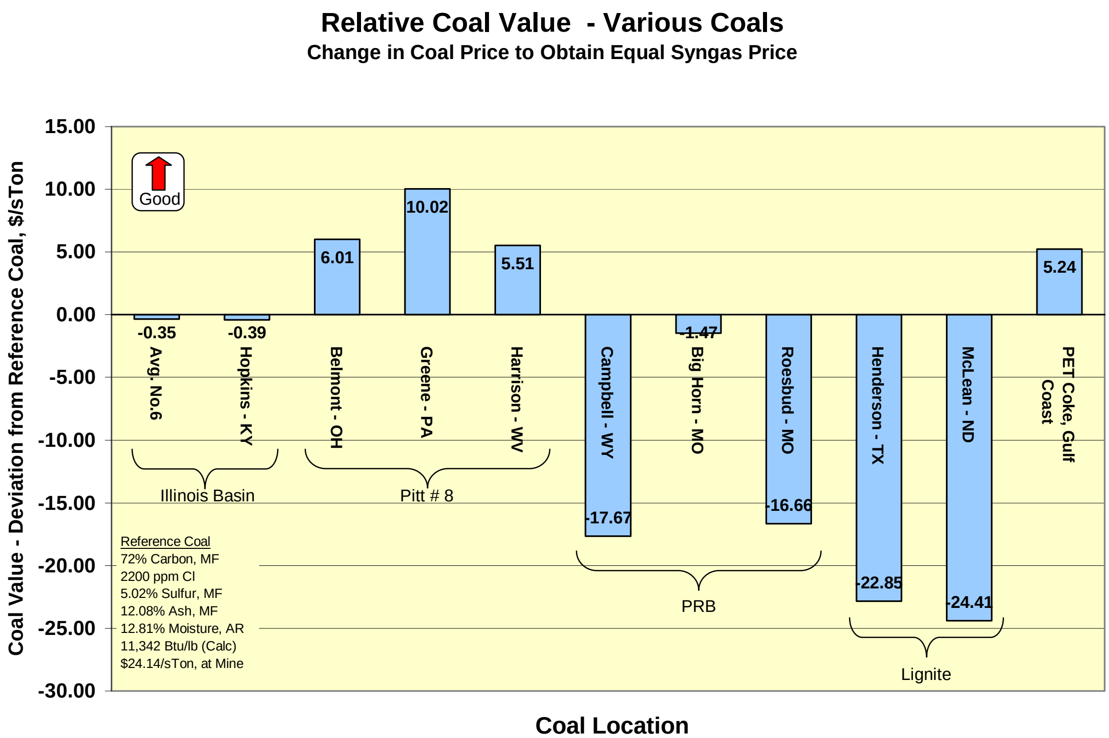
Figure 9: Coal Cost at Equal Syngas Cost – Illinois Coals



The gasification fuel economic comparisons were broadened to compare Illinois coals with other potential gasification feed stocks identified in the H&A report including: Pittsburgh #8 Seam, the Powder River Basin and Texas and North Dakota Lignite. In addition, a data point for a typical petroleum coke feed stock was evaluated. One caution, however, is that because the properties cover such a wide range, the models used to evaluate theses coals will be less accurate. This is particularly true for the PRB and Lignite coals that incurred a steep penalty due to their very high moisture contents since the evaluation was done assuming a slurry-fed, quench gasifier. Although a slurry-fed, quench gasifier will operate with high moisture fuel, much of the coal's chemical energy will go to produce heat to vaporize the excess water. Dry coal fed gasifiers or slurry gasifiers with highly efficient thermal recovery systems may be more appropriate for these low rank coals. An evaluation of different coals in different gasifiers was outside the scope of this study. Papers on this topic presented at the 2002 Gasification Technology Conference [4] and at the 2004 Gasification Technology Conference [5] present similar trends. The relative capital cost/unit output of Illinois #6 in these papers is reported to be 6% to 8% higher than Pittsburgh #8. PRB is 22% higher and Lignite is 36% to 38% higher than Pittsburgh #8.

Figure 10 is a comparison of the relative coal cost for the different feed stocks that would give a constant syngas cost. Not unexpectedly, the Pittsburgh #8 seam coals and the Petroleum coke feed stocks yield the highest coal value. Illinois coals are slightly higher than the Pittsburgh #8 coals. PRB and Lignite coals are much higher than the reference coal. This chart would indicate that the very worst lignite should be priced $24.41/ton less than the reference coal to produce overall equal values. These prices are mine mouth and do not include transportation.

Figure 10: Coal Cost at Equal Syngas Cost – All Coals



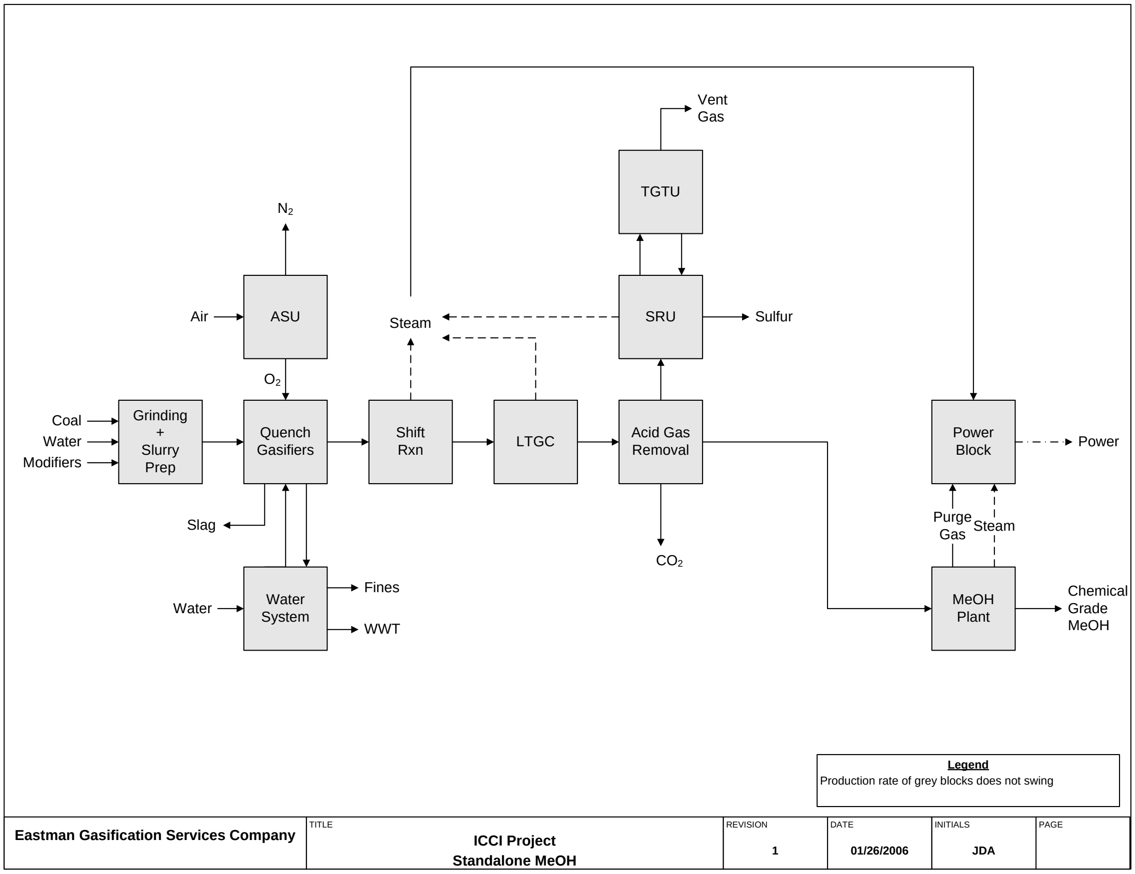
Task 3 - Coal-to-Methanol Feasibility Analysis

Two alternative facility designs were evaluated for the feasibility analysis task. A coal gasification-based plant dedicated solely to the production of methanol or other chemicals, a "standalone" facility, is clearly the default choice for a single owner 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" is a promising approach in which methanol is manufactured as a major coproduct along with electric power based on Integrated Gasification Combined Cycle (IGCC) technology.

Process Description

A simplified, block flow diagram for the standalone facility is shown in Figure 11.

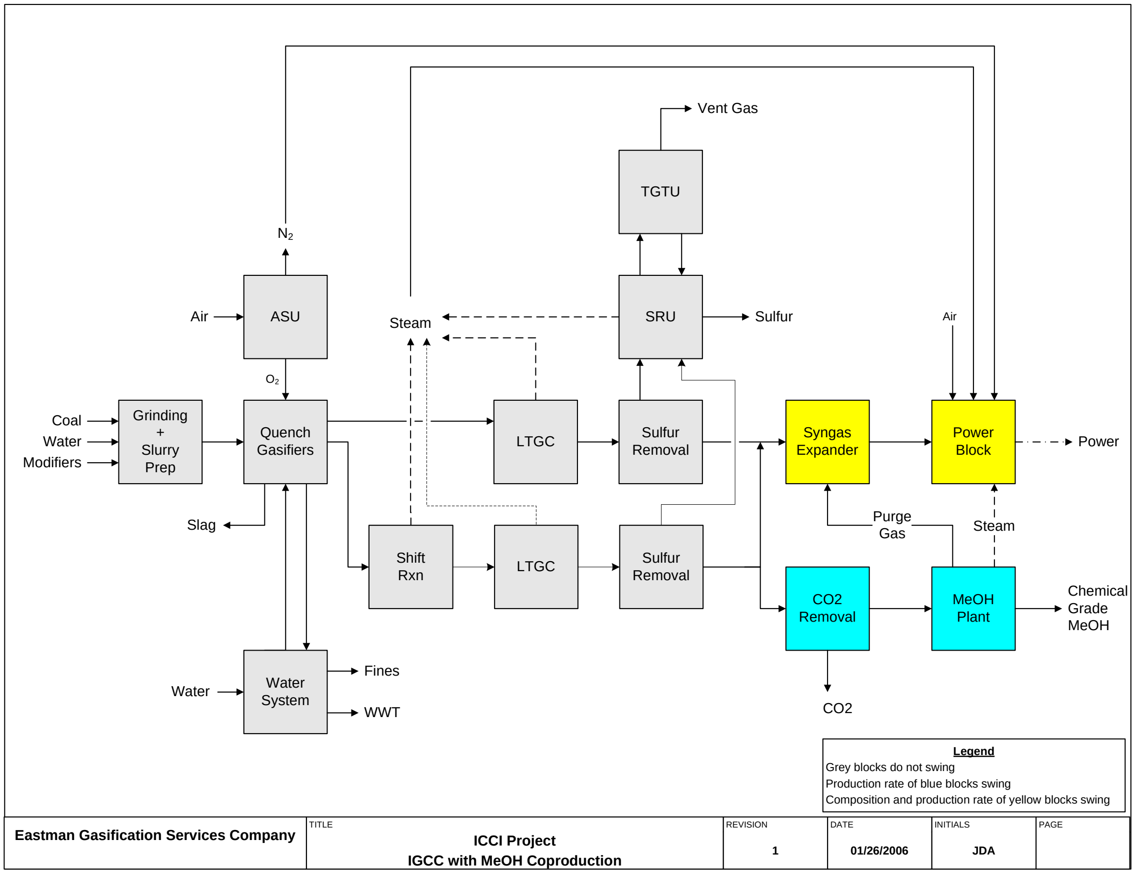
Figure 11: Standalone MeOH from Coal Facility



As-received coal will be crushed and wet ground to the appropriate particle size range. The resulting coal slurry will be pumped into high pressure, quench gasifiers where it will be reacted with oxygen supplied from a cryogenic air separation plant (ASU). A small portion of the nitrogen from the ASU will be used for process purging, vessel inerting and CO_2 stripping. Unreacted solids from the gasifier will be removed as a slag for further processing to recover unreacted carbon for recycle and ash for landfill or sale. Black water will be blowdown from the gasifiers to purge chlorides and other contaminants. Raw, hot sour syngas from the gasifiers will be passed through a water gas shift reaction system to change to the required composition for MeOH production and then processed through a low temperature gas cooling train (LTGC) to be cooled by generating steam and heating boiler feed water. Cool, sour shifted gas will be cleaned of ammonia and mercury and fed to an acid gas removal (AGR) for removal of sulfur bearing components and CO_2. Recovered CO_2 will be vented to the atmosphere or compressed for sale or sequestration. Concentrated acid gas from the AGR will be sent to a Claus sulfur recovery unit (SRU) for conversion to molten sulfur for sale while the Claus plant tail gas is processed through a SCOT tail gas treating unit (TGTU) to minimize sulfur emissions in the process vent. Clean, shifted syngas will be fed to a MeOH plant for conversion to chemical grade quality product for sale. Unreacted purge gas from the MeOH plant synthesis loop will be fed to an aux boiler in the power block along while excess process steam from various plants will be fed to a steam turbine to generate electricity to reduce net purchase requirements. More detailed block flow diagrams and material balances are shown in the Appendix.

Figure 12 shows a block flow diagram for the coproduction facility option.

Figure 12: IGCC and MeOH Coproduction Facility



The front end processing scheme from coal handling through gasification is quite similar to the standalone option. Downstream of gasification, however, the hot sour syngas from the gasifiers will be split into two streams for further processing. As for the standalone case, one hot sour syngas stream will be passed through a water gas shift reaction system to change to the required composition for MeOH production and then processed through a LTGC to be cooled by generating steam and heating boiler feed water. The remaining, hot sour syngas will be fed directly to a LTGC for cooling. The cool, sour shifted gas stream and the cool unshifted gas stream will be separately cleaned of ammonia and mercury and fed to an AGR for removal of sulfur bearing components. CO_2 will be removed as needed from the shifted syngas to meet MeOH feed gas requirements and vented, sold or sequestered while CO_2 removal from the unshifted syngas will be minimized as the CO_2 serves as a useful diluent in the downstream combustion turbines in the power block. As for the standalone case, concentrated acid gas from the AGR will be sent to the SRU/TGTU for conversion to molten sulfur for sale. Clean, shifted syngas will be fed to a MeOH plant while the unshifted gas and MeOH purge gas will be fed through a syngas expander and into combustion turbines along with diluent nitrogen from the ASU to generate power for sale. Excess process steam from various plants will be fed to a steam turbine to generate additional electricity for sale.

Unlike the standalone facility that was designed to produce a maximum amount of MeOH as limited by gasifier availability, the coproduction facility was designed for multiple operating modes. During peak power periods, the coproduction facility would dispatch syngas to maximize power production while during off-peak power periods syngas would be dispatched to maximize MeOH production. As a result, the coproduction facility block flow diagram has a color code to indicate processing blocks whose production rate swings with syngas dispatch in blue and those that have significant composition and production rate swings with syngas dispatch in yellow. Minimizing the processing blocks that experience production rate or composition changes will allow the entire facility to change between operating modes more rapidly.

Design Basis

A summary of the key design and performance parameters for both process options are listed in Table 5. The data is shown for periods when all gasifiers would be in operation at design rates with the coproduction data provided as a time weighted average between the peak and off-peak operating modes.

Table 5: Key Design and Performance Parameters

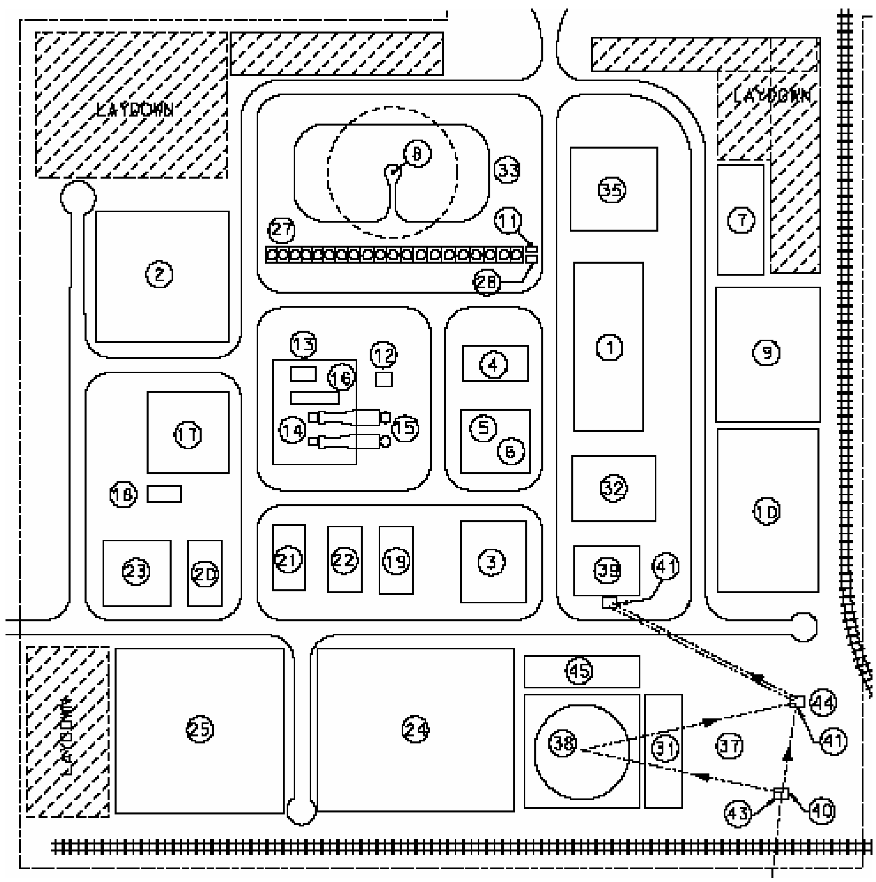
Parameter	Standalone Facility[1]	Coproduction Facility[2]
Coal Usage (as received)	7,277 short ton/day	7,277 short ton/day
Oxygen Usage (99.5 mol%)	6,049 short ton/day	6,049 short ton/day
Power		
- Gross	66 MW	455 MW
- Aux	129 MW	168 MW
- Net	63 MW purchased	287 MW sold
MeOH	4,491 metric ton/day	2,523 metric ton/day
Byproducts		
- Slag (50% solids)	1,493 short ton/day	1,493 short ton/day
- Sulfur	297 metric ton/day	287 metric ton/day
- CO_2 (100 mol% basis)	4,349 metric ton/day	2,369 metric ton/day
O&M Employees & Contractors	262	281

[1] All gasifiers operating
[2] Time weighted average of peak and off-peak operating modes when all gasifiers operating

Site Plan

A preliminary site plan for the co-production facility at the reference location outside Taylorville, Illinois is shown in Figure 13. The standalone MeOH option could also be arranged in a similar way. The approximately 290 acre site would consist of a lower 145 acre chemical and power processing tract and an upper 145 acre tract for solid waste disposal. Coal would be received from a mine mouth located to the south or via rail. A detailed plan showing the entire site and full legend is located in the Appendix. Purchase of additional land would be useful to serve as a buffer to the surrounding area.

Figure 13: Chemical and Power Processing Tract Plot Plan



Legend

1. Gasification
2. Air Separation
3. Acid Gas Removal
4. Tail Gas Treating
5. Sulfur Recovery
6. Sulfur Storage
7. Brine Handling
8. Flare
9. MeOH
10. MeOH Storage
11. Laboratory
12. Aux Boiler
13. Steam Turbine
14. Gas Turbine
15. HRSG
16. Steam Turbine
17. Switchyard
18. Gas Metering
19. Control Room
20. Admin
21. Warehouse
22. Maintenance
23. Parking
24. Construction

Environmental Permitting Assessment

Construction of a standalone methanol or coproduction facility will be subject to a variety of environmental reviews and permitting requirements. Specific permitting requirements, and the scope of the environmental review process, are dependent upon the type of facility and the potential environmental impacts, including air emissions, wastewater discharges, and solid wastes. The facility will be required to obtain permits for air emissions, wastewater treatment and discharge, and solid waste management. The Appendix includes a report prepared by S&L of the potential permits and approvals required.

Project Cost Estimate

Tables 6 and 7 summarize the EPC and capital cost estimates for the standalone and coproduction facilities.

Table 6: EPC Cost Summary

Area	Standalone EPC Cost ($,000s)	Coproduction EPC Cost ($,000s)	Coproduction - Standalone EPC Cost Difference ($,000s)
Air Separation	$130,442	$153,773	$23,331
Slurry Prep	$60,363	$60,363	$0
Gasification	$179,952	$173,560	-$6,392
Acid Gas Removal	$97,772	$87,858	-$9,914
Refrigeration	$10,747	$11,028	$281
Sour Water Stripper	$5,987	$5,971	-$16
SRU & TGTU	$30,198	$29,545	-$653
Methanol	$134,533	$98,269	-$36,264
Syngas Expander	$0	$4,178	$4,178
Power Island & BOP	$182,865	$481,008	$298,143
Process Steam Turbine	$40,720	$45,065	$4,345
Flare	$5,687	$5,687	$0
Waste Water Treatment	$39,026	$39,026	$0
Total	$918,292	$1,195,331	$277,039

Table 7: Project Cost Summary

Category	Standalone Cost ($,000s)	Coproducton Cost ($,000s)
EPC Costs	918,292	1,195,331
Initial Working Capital	19,920	19,551
Owner's Contingency	18,366	23,906
Licenses and Royalties	45,919	40,623
Startup Costs	13,845	8,149
Debt Reserve Fund	93,407	46,189
Owner's Cost	25,000	25,000
Total Capital	1,134,749	1,358,749
IDC	50,644	106,122
Financing Fee	9,560	20,800
Financing Costs	60,204	126,922
Total Costs	1,194,953	1,485,671

The coproduction facility cost is higher since the added cost of the ASU and Power Island more than offset the savings associated with gasification, AGR and MeOH. Since less MeOH is made for the coproduction facility because a portion of the syngas is used to make power, the shift reaction requirements are less in gasification and the CO_2 removal load is lower for the AGR. The ASU cost increased for the coproduction facility since larger nitrogen compressors are required to supply diluent to the combustion turbines.

Operations & Maintenance Requirements

The labor requirements for the coproduction facility will be higher than the standalone facility due to the added complexity of the power island as indicated in Table 8.

Table 8: O&M Labor Requirements

Category	Standalone Labor (#)	Coproduction Labor (#)
Site Management & Admin	7	8
Technical Staff	9	14
Operations	98	111
Maintenance	84	86
Contract Maintenance	64	62
Total	262	281

Power Market Forecast

Electric forward market price projections for regions in the Midwest were developed using a MarketPower© model to simulate the dispatch of generation units subject to transmission constraints between different market areas. Electric energy prices were derived from a dispatch algorithm that accounted for the dispatch price of each unit, based on its fuel and variable O&M costs, and ascertained the cost of the marginal generating unit for each hour. The most expensive unit dispatched thus established the market price of electric energy. Electric capacity prices were driven by the all-in cost of the least expensive generating resource required in a given period to serve the peak demand plus any reserve requirements. Therefore, during periods where new generating capacity was required to meet peak demand requirements, the market price of capacity was established as the total all-in cost including fixed O&M plus capital recovery to construct new generation capacity. A detailed report is located in the Appendix with the price projections and related assumptions including: 1) existing and planned generating units, 2) fuel prices, 3) future environmental compliance costs for NO_x, SO_2 and mercury emission allowances, 4) load profiles, and 5) transmission network links and interfaces.

A summary of the annual average, peak and off-peak power price forecasts for the south central Illinois area in the vicinity of the Taylorville, Illinois reference plant location are provided in Figures 14 and 15. The base case and results of sensitivity analysis for +3% local load growth, +3% regional load growth, +/-3% natural gas prices, +3% coal prices and a +100% increase for the cost of environmental compliance costs are included. For the ranges evaluated, natural gas prices have the most significant influence on peak power prices while coal prices have the largest impact on off-peak prices.

Figure 14: Average South Central Illinois Market Peak Prices

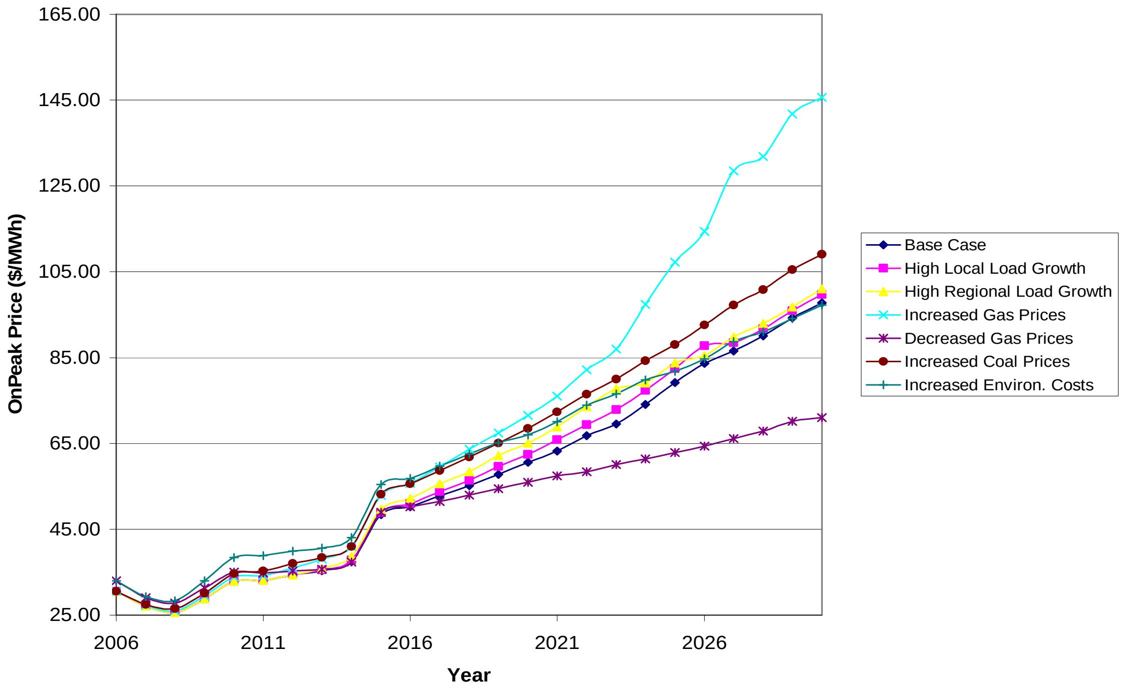
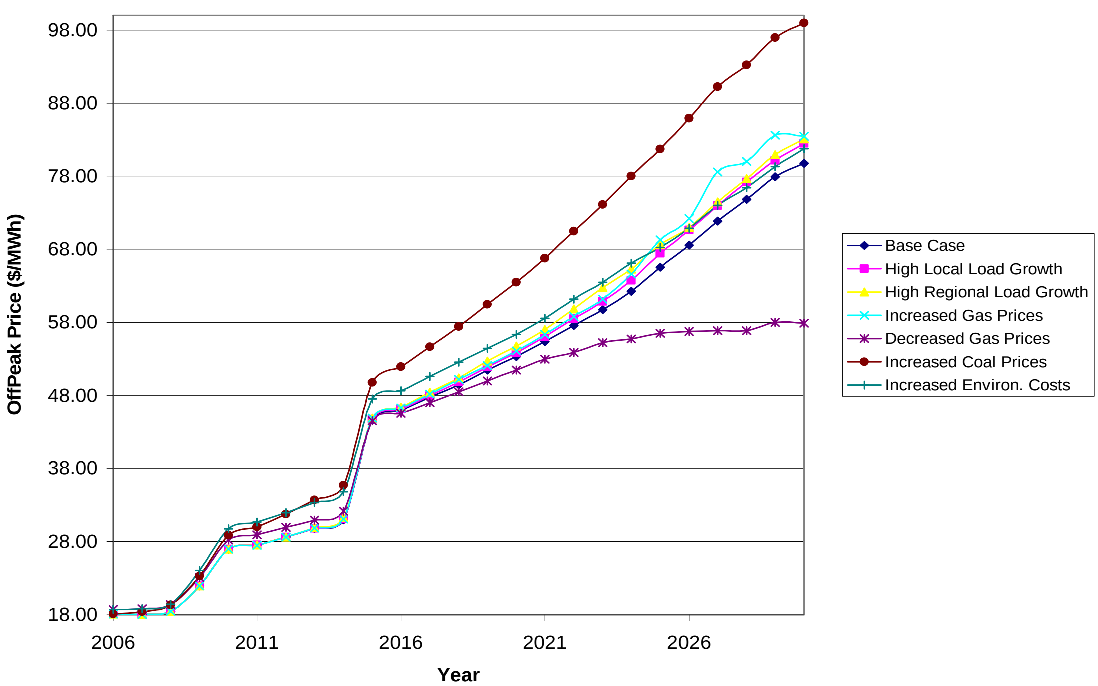


Figure 15: Average South Central Illinois Market Off-Peak Prices



On average, the MarketPower© model predictions had a $20/MWh premium above the historical Locational Marginal Prices (LMP). LMP values are expected to be higher during high load periods due to local congestion pricing not included in the model. However, LMP values were higher across the range of system loads, suggesting other market factors at work given the short time the market has been operating.

Financial Analysis

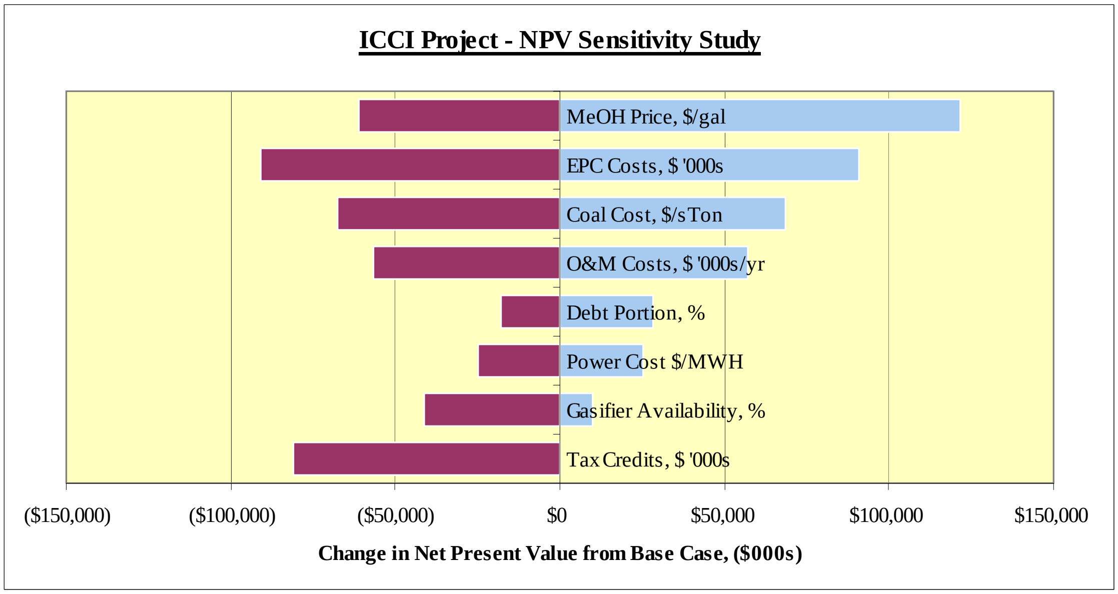
Financial models were developed from the perspective of an equity owner typically consisting of a power project developer, private equity investor, coal company, or a consortium of companies focused on gasification. With wide price cycles forecast for methanol, the standalone facility was assumed to sell its methanol output with short term contracts so a base case debt/equity ratio of 40:60 was used due to the volatility and lack of long-term fixed payments. A base case debt/equity ratio of 70:30 was used for coproduction assuming a financial anchor from a long term power contract based on levelized market forecasts. Table 9 and Figure 16 show the sensitivity of net present value (NPV) to key financial metrics for the standalone coal to methanol facility. Table 9 shows the range for variables evaluated and the corresponding NPV while the tornado diagram in Figure 16 indicates the change in NPV from the baseline value. Higher values for MeOH price, debt portion, gasifier availability and tax credits increase NPV while lower values for EPC costs, coal cost, O&M costs, and power cost increase NPV.

Table 9: Standalone Methanol NPV Sensitivity Study Results

Variable	Variable Range			NPV @ 10% IRR ($,000s)	
	Low NPV	Base Case	High NPV	Low Value	High Value
[1] MeOH Price, $/gal	0.48	0.51	0.56	($29,974)	$153,025
EPC Costs, $ '000s	$1,101,950	$918,292	$734,634	($59,490)	$121,888
[1] Coal Cost, $/sTon	35.29	29.41	23.53	($36,577)	$99,480
[1] O&M Costs, $ '000s/yr	$69,712	$58,093	$46,474	($25,473)	$88,182
Debt Portion, %	30%	40%	60%	$13,340	$59,544
Power Cost $/MWH	40.68	33.90	27.12	$6,144	$56,296
Gasifier Availability, %	75.00%	85.00%	90.00%	($10,184)	$41,270
Tax Credits, $ '000s	$0	$130,000	$130,000	($49,559)	$31,161

[1] MeOH Price and Coal Cost for 2011 – 1st operating year, O&M Cost for 2013 – 1st year at 100% rate

Figure 16: Standalone Methanol NPV Sensitivity Study Results



Stated methanol price, coal cost, and power cost are for 2011, the first year of operation while O&M costs are for 2013, the first year of full capacity operation. Revenue driven by methanol pricing over the Nexant's forecast range of approximately -5% to +10% has the largest impact on NPV while EPC capital, coal, O&M and power cost varied over a +/- 20% range also have a relatively strong influence on NPV. The inability to secure federal tax credits would have a substantial negative effect on NPV. Base case methanol pricing would have to be 40% higher to yield a similar return as the coproduction facility base case.

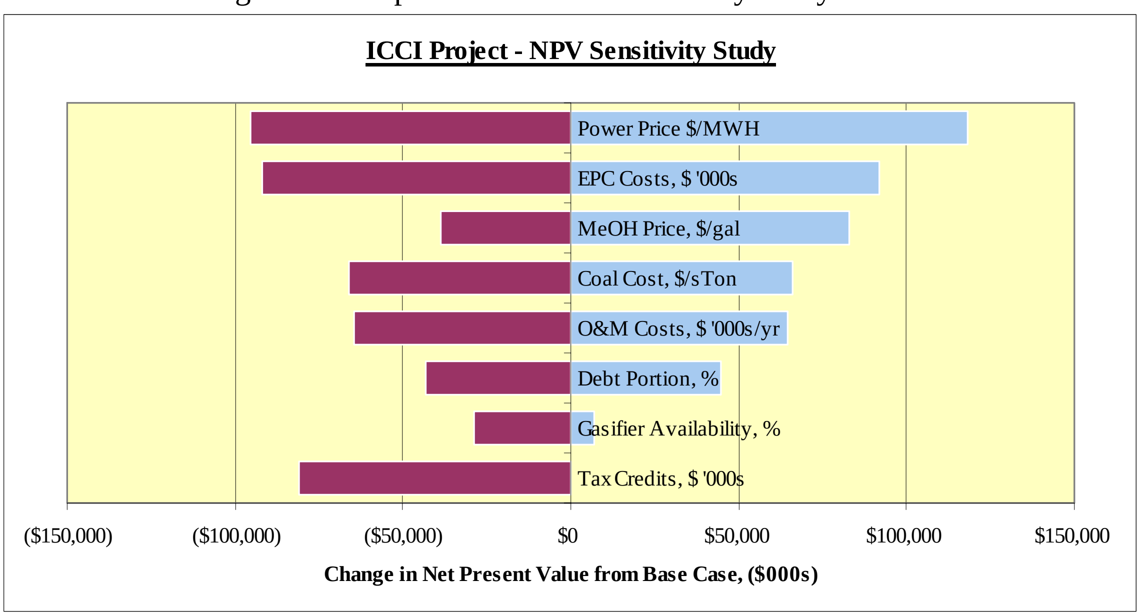
Table 10 and Figure 17 show a similar NPV sensitivity summary for the methanol and power coproduction facility. Revenue as driven by power price varied over a +/- 20% range and methanol price varied over the Nexant high to low forecast has the largest influence on NPV for coproduction followed by the strongest cost drivers of EPC capital, coal and O&M costs varied over a +/- 20% range. As for the standalone option, federal tax credits provide a significant boost to the project NPV.

Table 10: Coproduction NPV Sensitivity Study Results

Variable	Variable Range			NPV@ 10% IRR ($,000s)	
	Low NPV	Base Case	High NPV	Low Value	High Value
[1] Power Price $/MWH	28.70	35.87	43.05	$133,639	$347,379
EPC Costs, $ '000s	$1,434,397	$1,195,331	$956,265	$137,228	$320,676
[1] MeOH Price, $/gal	0.48	0.51	0.56	$190,042	$311,860
[1] Coal Cost, $/sTon	35.29	29.41	23.53	$162,861	$295,047
[1] O&M Costs, $ '000s/yr	$80,093	$66,745	$53,396	$164,628	$293,275
Debt Portion, %	60%	70%	80%	$185,822	$273,535
Gasifier Availability, %	75.00%	85.00%	90.00%	$199,927	$235,714
Tax Credits, $ '000s	$0	$130,000	$130,000	$148,232	$228,952

[1] MeOH/Power Price & Coal Cost for 2011 – 1st operating year, O&M Cost for 2013 – 1st year at 100% rate

Figure 17: Coproduction NPV Sensitivity Study Results

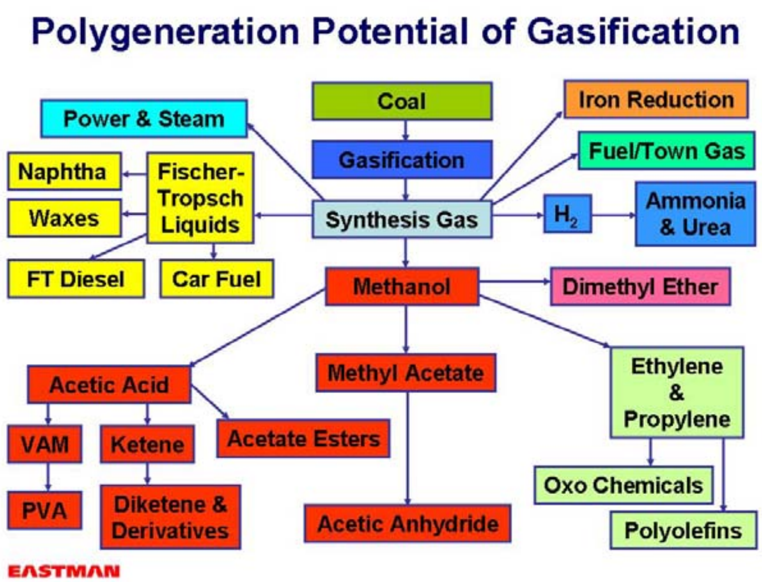


Task EMN-1 – Eastman R&D on Coal-to-Chemicals

The Eastman R&D effort was reflected as a part of Eastman's cost sharing in support of the project, and as such was identified as Task EMN-1. Much of the specific results of this Eastman effort are necessarily proprietary and confidential. 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 contributed to the overall project through the development of process definitions, process models, and economic inputs that were used in the feasibility assessment focused on methanol chemistry.

Eastman's experience with gasification for chemicals production indicates that a wide range of chemical families and products can be derived from gasification. Figure 18 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 18: Chemical Families and Products Derived from Gasification



The R&D studies have demonstrated 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. Keys to success are identification and securing low-cost feedstocks and reasonable cost process technology. 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.

CONCLUSIONS AND RECOMMENDATIONS

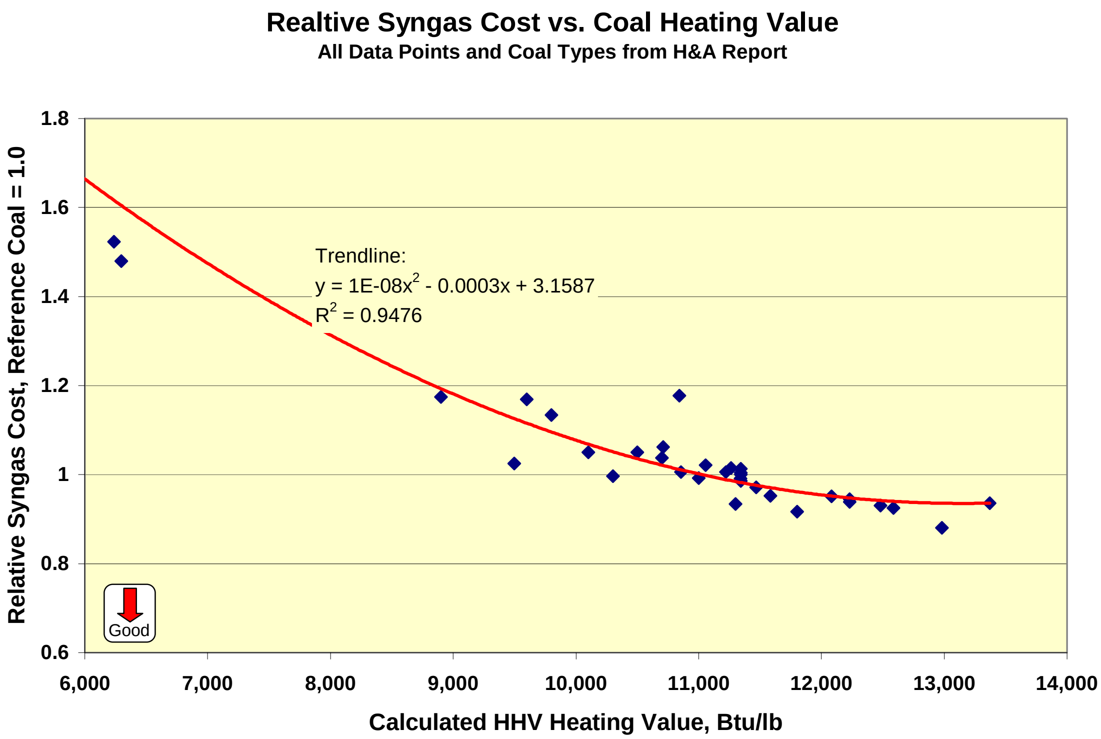
To date, Eastman's R&D program on coal to chemicals has found that several candidate products produced through coal gasification appear to be cost-competitive with purchased supplies. Keys to success are identifying and securing low-cost supplies of coal and/or syngas plus reasonable-cost process technology 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 the U.S. is being reduced due to discontinued use of MTBE as a gasoline additive, 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. 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.

The economic viability of methanol production in Illinois from a standalone coal to methanol facility or methanol co-produced 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 a U.S. Midwest location. The coal-based, methanol cash costs 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 over a full economic cycle based on a forecast by Nexant. 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. Future methanol market pricing, even after a projected collapse in prices due to the forecast change in price-setting mechanisms, will be sufficient to cover expected production costs for the proposed plant. The North American methanol market can easily absorb production from a new facility located in Illinois.

There are numerous ways to compare and evaluate the relative value of coals. In the final analysis, the value of a coal for gasification still generally correlates to its heating value since higher heating values result in more output per unit cost as seen in Figure 19. In this chart, the relative syngas cost of all of the data points evaluated in this report were plotted against their heating values, regardless of location or seam. Since Illinois coals are positioned just below Pittsburgh #8 coals and above PRB coals, their value will also be between these two coals. One of the negatives for Illinois coals in the past for power generation has been the higher sulfur levels. However, gasification plants are relatively indifferent to sulfur levels and can easily remove sulfur from the syngas at high levels and turn it into pure sulfur or sulfuric acid to be sold as by-products. Illinois coals can be differentiated due to the vast, un-tapped reserves that are relatively easy to mine, are still available in large contiguous blocks and are close to the highest population centers where demand for syngas derived products is greatest.

Figure 19: Syngas Cost vs. Heating Value, All Coals



The key metrics influencing the financial return for a potential standalone methanol or power and methanol coproduction facility have been determined as shown in Figures 20 and 21 on the following page. The range of values for the various financial parameters for the study was previously shared in Tables 9 and 10. For the standalone facility, EPC capital costs and methanol pricing have the dominant influence on IRR while coal and O&M cost along with the availability of federal tax credits also have in important impact. Given the relatively high leverage for the coproduction facility, the debt portion had the greatest influence on IRR. As for the standalone facility, EPC capital costs also had a strong influence on IRR for the coproduction facility. Given the substantial quantity of market power sales for coproduction, the power price also has a strong impact on IRR along with the methanol price.

The coproduction facility had higher returns than the standalone facility as a result of the more highly leveraged capital structure and option value provided by dispatching to the most valuable product. The standalone methanol facility only has one major product, while coproduction provides two major products and the option of dispatching to the most valuable on time scales that can be accommodated within the ultimate contract structure. With a storable product, methanol, the coproduction facility was dispatched more heavily to methanol during off-peak power periods within a calendar year while power prices are depressed. In addition, given the cyclic nature of the methanol price forecast and the different long term annual growth rates in relative methanol to power prices, varying the dispatch schedule annually to favor the most valuable product will provide a 2.7% point increase to the coproduction facility return.

Figure 20: Standalone IRR Sensitivity Study Results

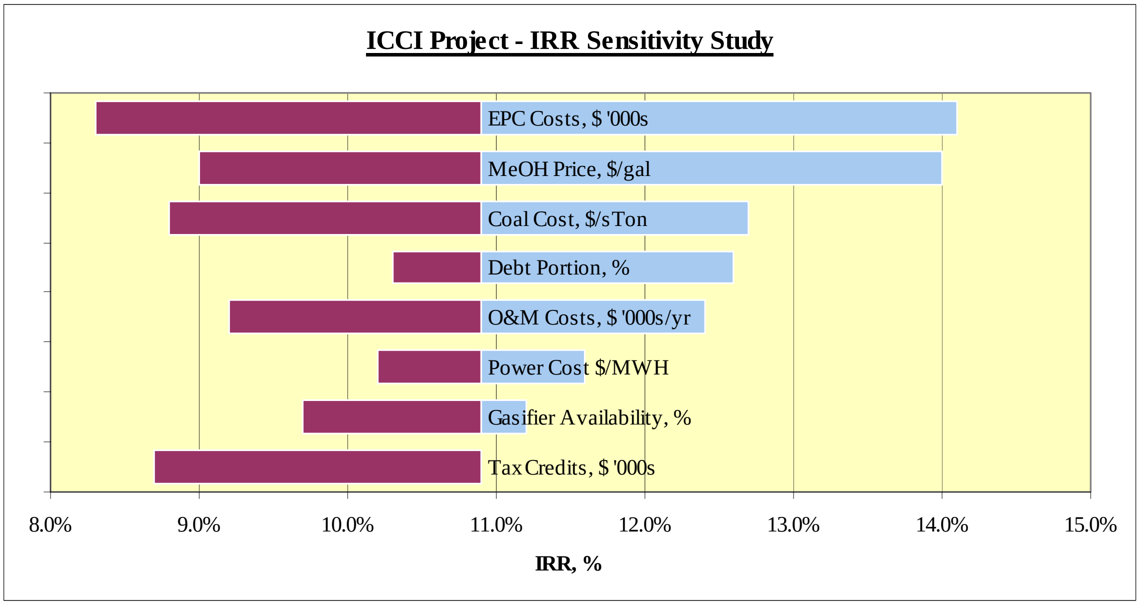
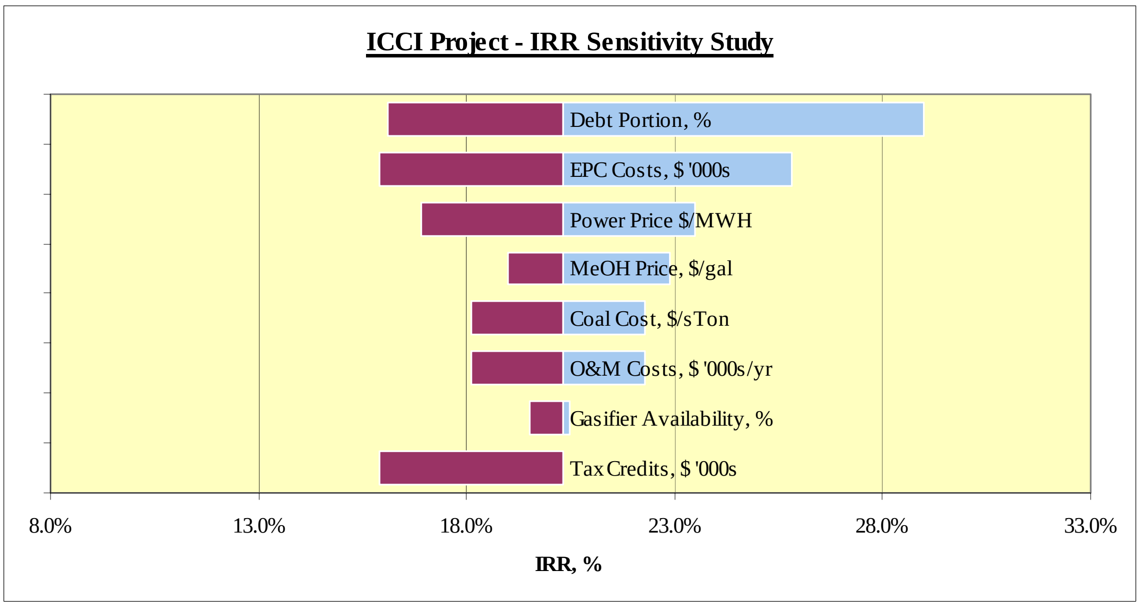


Figure 21: Coproduction IRR Sensitivity Study Results



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