Chemicals and Power Co-Production by Gasification of Illinois Coal

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Presentation Overview

• Introduction
• Project Overview
• Methanol Market Assessment
• Illinois Coal Characterization
• Coal to Methanol Feasibility Study
• Conclusions
Higher raw material cost is pressuring U.S. chemical producers

• U.S. chemical industry dependent on oil and natural gas
• Recent rise in domestic oil and natural gas prices
• Domestic oil supply shift from U.S. to global sources
• Chemical manufacturing moving from U.S.
• Cost and supply risk for remaining U.S. chemical operations
Introduction

Coal gasification holds promise to improve raw material position

- U.S. coal: abundant, lower cost, lower price volatility
- Gasification is an important technology for utilizing coal
- Gasification for chemical production has hurdles
- Illinois coals well positioned in U.S.

Coal is the World’s Most Abundant Fossil Fuel: U.S. Has > 25% of the World’s Coal Reserves
Objective

Evaluate potential of utilizing Illinois coal for the production of chemicals based on gasification.

Tasks

- Methanol market assessment
  - Traditional and emerging markets
  - Supply/demand balance
  - Price forecasts
  - Logistics evaluation
- Illinois coal characterization
  - Statistical analysis
  - Assessment of key properties
  - Estimation of mining costs
  - Comparison with alternate fuels
- Coal to methanol feasibility study
  - Stand-alone methanol
  - Methanol and power co-production

Illinois supports projects that help the coal industry

Coal to methanol chosen as indicative of co-production potential.
NA methanol market is dominated by three primary uses

### Primary methanol end uses

<table>
<thead>
<tr>
<th>End Use</th>
<th>Consumer</th>
<th>Capacity of End Use (MM tons/yr)</th>
<th>MeOH Demand (MM tons/yr)</th>
<th>% of MeOH Industry</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formaldehyde</td>
<td>Top 5 Consumers</td>
<td>5.59</td>
<td>2.57</td>
<td>36.8</td>
</tr>
<tr>
<td></td>
<td>Industry Total</td>
<td>6.87</td>
<td>3.17</td>
<td>36.8</td>
</tr>
<tr>
<td>MTBE</td>
<td>Top 5 Consumers</td>
<td>4.71</td>
<td>1.72</td>
<td>28.7</td>
</tr>
<tr>
<td></td>
<td>Industry Total</td>
<td>6.76</td>
<td>2.47</td>
<td>28.7</td>
</tr>
<tr>
<td>Acetic Acid</td>
<td>Top 5 Consumers</td>
<td>3.24</td>
<td>1.83</td>
<td>22.4</td>
</tr>
<tr>
<td></td>
<td>Industry Total</td>
<td>3.39</td>
<td>1.92</td>
<td>22.4</td>
</tr>
</tbody>
</table>

An Illinois methanol plant could service customers within an advantaged logistics radius.

Emerging Methanol Markets
- Fuel (combustion turbines, industrial burners)
- Biodiesel
- Olefins
- Transportation fuel, gasoline blending
- Fuel cells
- DME
NA methanol supply is shifting to importers with low cost natural gas

Decline in domestic methanol manufacturing is symptomatic of larger problem facing NA chemical industry.
Methanol price driver anticipated to undergo paradigm change

Nexant, Inc expects that shutdown of non-captive NA methanol production in the near term will lead to change in key pricing driver from high cost natural gas consumers in U.S. to imports from low cost natural gas consumers in Trinidad.
Illinois well situated for methanol transport via barge or rail.

<table>
<thead>
<tr>
<th>Mode</th>
<th>Transportation Cost ($/ton methanol)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Primary Market</td>
</tr>
<tr>
<td>Rail to St. Louis / Net by Barge</td>
<td>3.19</td>
</tr>
<tr>
<td>Rail</td>
<td>5.06</td>
</tr>
<tr>
<td>Truck</td>
<td>10.70</td>
</tr>
</tbody>
</table>

Major barge waterways

Norfolk Southern System Map
Illinois coal properties vary across the basin.

- 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

USGS database analyzed for coal characteristics important for use as gasification fuel and results mapped to basin geographic regions.
Coal location influences mining costs.

**Coal Mining Cost Basis**
- Hypothetical mine based on data for existing mines and commonly used mining techniques in selected region.
- Coal properties and heating values from Hill & Associates, Inc. database.
- Mining productivity based on history of selected region.
- Royalties and severance taxes determined for state where hypothetical mine was located.
- Reclamation, Black Lung and income taxes included.
- Excess production assumed sold to third parties.
- 100% equity investment

**Projected Required Sales Price (20% IRR) ($/MMBtu)**

- **Illinois Basin**
  - Illinois
  - Christian County
  - Coles/Cumberland County
- **Pittsburgh (No. 8) Seam**
  - Ohio
  - Belmont County
  - Pennsylvania
  - Greene County
  - West Virginia
  - Harrison County
- **Powder River Basin**
  - Wyoming
  - Campbell County (WY N Gillette Compliance)
  - Montana
  - Big Horn County
  - Rosebud/Powder River Counties
- **Texas/Gulf Coast Lignite**
  - Texas
  - Henderson/Anderson Counties
- **North Dakota/Fort Union Lignite**
  - North Dakota
  - McLean County

**Coal Price**
- Price estimated as cost + return for 20% IRR
- Data may not be indicative of market price.
- Illinois Basin cost will be lower for new mines using more efficient mining techniques at larger scale.

Cost and price analysis by Hill & Associates, Inc.
Coal properties impact use as gasification fuel.

**Coal Properties Study**
- Range of Illinois basin coal properties used
- Slurry fed, oxygen blown quench gasifiers assumed
- Quantify impact of most significant coal properties on gasification fuel use
- Each property varied separately to isolate influence
- Evaluation criteria:
  - Cold gas efficiency
  - Coal consumption
  - Oxygen consumption
  - Capital cost
  - Syngas cost
  - Coal cost at equal or constant syngas price

**Coal Property Value Drivers**
Primary influences on coal value as gasification fuel is determined by carbon content, ash content, moisture level and sulfur content.
Coal location within Illinois Basin affect value as gasification fuel.

**Illinois Basin Study**

- Possible mine-mouth locations considered across Illinois Basin
- Slurry-fed, oxygen-blown quench gasifiers assumed
- Composition for run of mine and washed coals from Hill & Associates, Inc.
- Considerable variability in coal characteristics within close geographic proximity makes specific conclusions on best general location difficult to draw.

**Coal Washing**

Washing provides an average coal value increase of $8.40 per short ton and intangible benefits associated with reduced coal composition variability.
Illinois coals are positioned above some alternate gasification fuels.

**Relative Coal Value - Various Coals**
Change in Coal Price to Obtain Equal Syngas Price

<table>
<thead>
<tr>
<th>Coal Location</th>
<th>Relative Value from Reference Coal, $/s Ton</th>
</tr>
</thead>
<tbody>
<tr>
<td>Avg</td>
<td>-0.35</td>
</tr>
<tr>
<td>Hopkins - KY</td>
<td>-0.39</td>
</tr>
<tr>
<td>Bellefont - OH</td>
<td>6.01</td>
</tr>
<tr>
<td>Greene - PA</td>
<td>10.02</td>
</tr>
<tr>
<td>Harrison - WY</td>
<td>5.51</td>
</tr>
<tr>
<td>Campbell - WY</td>
<td>-17.67</td>
</tr>
<tr>
<td>Big Horn - MO</td>
<td>1.47</td>
</tr>
<tr>
<td>Rosebud - MO</td>
<td>16.66</td>
</tr>
<tr>
<td>Henderson - TX</td>
<td>22.85</td>
</tr>
<tr>
<td>McLean - ND</td>
<td>24.44</td>
</tr>
<tr>
<td>PET Coke, Gulf</td>
<td>5.24</td>
</tr>
<tr>
<td>Coal Location</td>
<td>Good</td>
</tr>
</tbody>
</table>

**High Moisture Fuel Observations**
PRB and Lignite coals disadvantaged with slurry-fed gasifiers though they would fare better with dry coal fed gasifiers or slurry gasifiers with more highly efficient thermal recovery systems.

**Alternate Fuel Study**
- Possible mine-mouth locations considered across U.S.
- Composition and properties for various coals from Hill & Associates, Inc.
- Slurry-fed, oxygen-blown quench gasifiers assumed with other types outside scope of study
- Illinois coals are positioned just below Pittsburgh #8 coals and pet coke and above PRB and lignite.
Gasification fuels can be compared based on heating value.

**Heating Value Trend**
- Numerous ways to compare relative value of gasification fuels
- Relative value of syngas plotted against heating values regardless of seam or location
- Gasification fuel value generally correlates to heating value
- Higher heating values result in more syngas output per unit cost.

**Illinois Coal Considerations**
Illinois coals have intermediate heating values but are differentiated due to vast, untapped reserves that are relatively easy to mine, are still available in large contiguous blocks and are close to population centers with demand for syngas derived products.
Chemicals and power co-production holds promise.

Coproduction Approach
- Produce methanol utilizing one of three gasifiers during peak power price periods
- Swing syngas from second gasifier to make additional methanol during off-peak power price periods
Stand-alone methanol process was base case for comparison.
Co-production enhances project through product mix options.
Co-production shifts some syngas use to make more power.

### Key Design and Performance Parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Stand-alone Facility¹</th>
<th>Co-production Facility²</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal Usage (as received)</td>
<td>7,277 short ton/day</td>
<td>7,277 short ton/day</td>
</tr>
<tr>
<td>Oxygen Usage (100 mol% basis)</td>
<td>6,011 short ton/day</td>
<td>6,011 short ton/day</td>
</tr>
<tr>
<td>Power</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Gross</td>
<td>66 MW</td>
<td>455 MW</td>
</tr>
<tr>
<td>- Aux</td>
<td>129 MW</td>
<td>168 MW</td>
</tr>
<tr>
<td>- Net</td>
<td>63 MW purchased</td>
<td>287 MW sold</td>
</tr>
<tr>
<td>Net Electric Capacity</td>
<td>N/A</td>
<td>418 MW</td>
</tr>
<tr>
<td>MeOH</td>
<td>4,491 metric ton/day</td>
<td>2,523 metric ton/day</td>
</tr>
<tr>
<td>Byproducts</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Slag (50% solids)</td>
<td>1,493 short ton/day</td>
<td>1,493 short ton/day</td>
</tr>
<tr>
<td>- Sulfur</td>
<td>297 metric ton/day</td>
<td>287 metric ton/day</td>
</tr>
<tr>
<td>- CO₂ (100 mol% basis)</td>
<td>4,349 metric ton/day</td>
<td>2,369 metric ton/day</td>
</tr>
<tr>
<td>O&amp;M Employees &amp; Contractors</td>
<td>262</td>
<td>281</td>
</tr>
</tbody>
</table>

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

### Process Comparison

- Both have similar front-end with the same coal and oxygen usage  
- Co-production diverts a portion of syngas to meet all of aux power needs and produce market power via combined cycle power block  
- Stand-alone uses all of syngas for chemicals thereby making more methanol  
- Higher methanol production requires more syngas shifting and generates more CO₂
Both facility options require a similar amount of land.

Co-Production Site 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

Approximately 300 acre site would provide space for syngas, methanol and power island operations as well as landfill for unsold ash slag, fines and brine salt landfill. Allowance must be made for construction activities as well as normal operating facilities.
MarketPower© model was used to estimate Midwest power prices.

Market Power Forecast
- Sargent & Lundy, LLC generated using MarketPower© software leased from New Energy Associates
- Midwest region included Illinois and surrounding states
- Electric energy pricing set at fuel and variable O&M cost for marginal generating unit
- Electric capacity pricing driven by all-in cost of least expensive generating resource to serve peak demand plus reserve.

Increases driven by cost to comply with Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) in 2009 and 2015 for NO_x, SO_2, and mercury emission reductions.
### Coal to Methanol Feasibility Study

**Co-production facility costs more but ...**

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

**Co-Production Impact**

- ASU cost increased due to compressing diluent nitrogen for combustion turbines
- Reduced syngas shift requirements dropped gasification costs
- Decline in syngas shift cut production of CO2 and load on AGR, SRU and TGTU
- Methanol plant size reduced since portion of syngas diverted to power block
- Power island cost increased with addition of combined cycle
- Process steam turbine cost increased with more net steam produced with less needed for methanol
Co-Production facility delivers higher range of returns.

**Standalone Facility - IRR Sensitivity Study**

- **MeOH Price, $/gal**: 0.48 [Low IRR], 0.51 [Base Case], 0.56 [High IRR]
- **EPC Costs, $'000s**: $1,101,950 [Low IRR], $918,292 [Base Case], $734,634 [High IRR]
- **Coal Cost, $/sTon**: 35.29 [Low IRR], 29.41 [Base Case], 23.53 [High IRR]
- **O&M, $'000s/yr**: $69,712 [Low IRR], $58,093 [Base Case], $46,474 [High IRR]
- **Debt Portion, %**: 30% [Low IRR], 40% [Base Case], 60% [High IRR]
- **Power, $/MWH**: 40.68 [Low IRR], 33.90 [Base Case], 27.12 [High IRR]
- **Gasifier Availability, %**: 75.0% [Low IRR], 85.0% [Base Case], 90.0% [High IRR]
- **Tax Credits, $'000s**: $0 [Low IRR], $130,000 [Base Case], $130,000 [High IRR]

**Co-production Facility - IRR Sensitivity Study**

- **MeOH Price, $/gal**: 0.48 [Low IRR], 0.51 [Base Case], 0.56 [High IRR]
- **EPC Costs, $'000s**: $1,434,397 [Low IRR], $1,195,331 [Base Case], $956,265 [High IRR]
- **Coal Cost, $/sTon**: 35.29 [Low IRR], 29.41 [Base Case], 23.53 [High IRR]
- **O&M, $'000s/yr**: $80,093 [Low IRR], $66,745 [Base Case], $53,396 [High IRR]
- **Debt Portion, %**: 60% [Low IRR], 70% [Base Case], 80% [High IRR]
- **Gasifier Availability, %**: 75.0% [Low IRR], 85.0% [Base Case], 90.0% [High IRR]
- **Tax Credits, $'000s**: $0 [Low IRR], $130,000 [Base Case], $130,000 [High IRR]

*Long-term market power contract allows higher % debt.*
**Conclusions**

**Chemicals and power co-production possible with Illinois coals.**

<table>
<thead>
<tr>
<th>Methanol Market Assessment</th>
<th>Illinois Coal Characterization</th>
</tr>
</thead>
<tbody>
<tr>
<td>• NA methanol production moving offshore due to high cost, domestic natural gas</td>
<td>• There are tradeoffs in desired coal properties and market price</td>
</tr>
<tr>
<td>• Growth in traditional and emerging methanol markets creating demand that could be well served from U.S. Midwest via methanol from Illinois coal</td>
<td>• Coal's gasification fuel value generally correlates to heating value</td>
</tr>
<tr>
<td>• Methanol from coal must achieve competitive manufacturing position with imports based on low cost natural gas</td>
<td>• Illinois coals have intermediate heating values but have vast, untapped reserves that are relatively easy to mine and are close to population centers with demand for syngas derived products.</td>
</tr>
</tbody>
</table>

**Coal to Methanol Feasibility Analysis**

• Co-producing power with methanol improved returns given more leveraged capital structure and option value provided by dispatching to most valuable product over time
• Most important factors influencing return were EPC costs along with methanol and power prices