# Milestone 4 Report:
# Summary of Financial Analysis for FOAK LBJ Plant and Prospective NOAK Commercial Plants

Design/Cost Study and Commercialization Analysis for Synthetic Jet Fuel Production at a Mississippi site from Lignite and Woody Biomass with $CO_2$ Capture and Storage via EOR

(DOE/NETL DE-FE0023697)

prepared by

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# 1. KEY FINDINGS

# First-of-a-Kind (FOAK) Demonstration Project

**Key Findings:**

- A process design was developed for a plant to be sited near Meridian, Mississippi, that could demonstrate the technical feasibility of co-gasifying lignite and woody biomass in a TRIG gasifier and converting the syngas via Fischer-Tropsch processing into synthetic jet fuel, with $CO_2$ captured and sold for enhanced oil recovery (EOR) and byproduct electricity sold to the grid. The plant would produce 1,000 barrels per day of synthetic paraffinic kerosene (SPK) and 250 bpd of synthetic naphtha. The plant would also export 15 MW of electricity and sell 1,326 metric t/day of captured $CO_2$.
- With 25% of the input feedstock energy as biomass supplied from existing pine plantations managed for increased production, the resulting SPK would have net lifecycle GHG emissions less than half of those for conventional jet fuel made from crude oil. An alternative characterization of the GHG emissions footprint of the LBJ facility is that the combined set products (electricity and liquid fuels) would have net lifecycle GHG emissions about 20% below the 2005 U.S. level of emissions for an equivalent mix of liquid products made from crude oil and electricity made from the average generating mix of the electric grid.
- The estimated total plant capital cost (TPC) is $1.3 billion (2015$).
- For a base-case set of financial assumptions, including an assumed levelized crude oil price of $80/bbl and a weighted average cost of capital of 5% (nominal), achieving an NPV of zero over an assumed 20-year plant operating lifetime would require a capital grant of $1.5 billion, i.e., more than the estimated TPC. Alternatively, with no capital grant, a production cost subsidy of $350/bbl of SPK would be required. The high subsidy requirements are due to the capital intensity of the plant, which arises as a result of its small scale and relatively high contingency factors used in estimating TPC. Evidence from recent pioneering projects, including coal-IGCC plants at Edwardsport, Indiana, and Kemper County, Mississippi, and a post-combustion $CO_2$ capture retrofit at the coal-fired Boundary Dam plant support the use of high contingency allowances at this stage of project definition.

# N^th^-of-a-Kind (NOAK) Commercial Plants

**Key Findings:**

- The economics of post-FOAK plants can be expected to improve as a result of building larger scale plants and of learning that occurs as additional plants are built. To help understand the potential extent of improvement, preliminary design and analysis of NOAK plants was undertaken by simulating cost reductions that would accompany up-scaling of plant capacities from the demonstration (FOAK) plant and by assuming significant cost reductions gained via experience in designing and building successive plants. Only well-known technologies were included in NOAK plant designs. (Assessing impacts of R&D-driven technological and process integration advances on plant performance and/or capital and operating costs was beyond the scope of the present analysis.) Several commercial NOAK process configurations were assessed, with lignite-to-biomass input ratios ranging from 1 to 0.
- For plants that co-process lignite and biomass, the prospective economics for any of the NOAK plants investigated are not particularly encouraging, even with revenue provided by sale of captured $CO_2$ for use in enhanced oil recovery (EOR). The unfavorable economics arise from the inherently high capital intensity of these plants, exacerbated by high auxiliary power loads that must be satisfied by onsite power generation.
- To facilitate comparisons with prior coal-to-liquids studies, designs were developed for plants producing 50,000 barrels/day of liquids from coal only. Auxiliary power loads for these designs are considerably higher than estimated in prior studies, as are the bare-erected costs (BEC) per unit of liquids produced. These observations suggest that the level of engineering effort expended to estimate BEC in prior studies, including analysis of auxiliary loads, was not as substantial as the present effort.
- For GHG emissions prices above about \$40/$tCO_{2e}$, plant designs using only biomass are favored over those co-processing lignite. Breakeven crude oil prices for biomass-only plants fall rapidly as a result of credits received for their significant negative emissions. For a given GHG emissions price, internal rates of return on equity are comparable for biomass-only plants producing liquid fuels, electricity, or a mix of these.
- Because of its highly negative net lifecycle GHG emissions a NOAK plant designed to make only electricity using only biomass as feedstock and capturing and storing $CO_2$ in a deep saline formation (and not receiving revenue for $CO_2$ sales) would have a lower levelized cost of electricity generation than a natural gas combined cycle plant venting $CO_2$ when the GHG emission price is \$75/$tCO_{2eq}$ or more.

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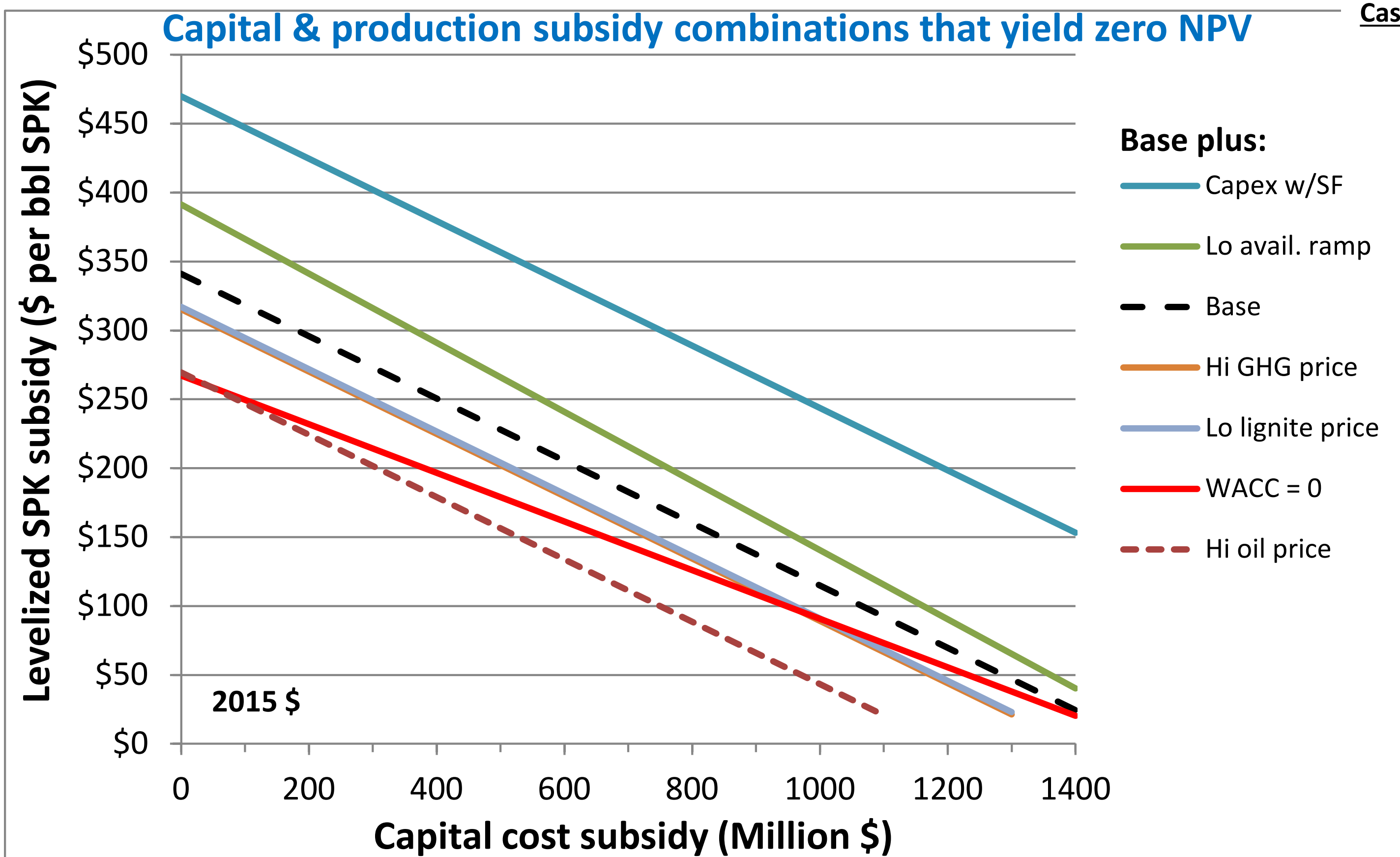
# 2. EXECUTIVE SUMMARY

# FOAK Demonstration Project (1)

- The goal of this effort was to 1) design a first-of-a-kind (FOAK) plant that could be built within the next few years (no technology breakthroughs required) to demonstrate the technical feasibility of an integrated process that co-gasifies lignite and woody biomass and converts the syngas via Fischer-Tropsch processing into synthetic jet fuel, with $CO_2$ captured and sold for enhanced oil recovery (EOR) and byproduct electricity sold to the grid, and 2) develop design documentation for the plant to the level of detail necessary to support development of capital and O&M cost estimates by WorleyParsons Engineering, Inc. to enable a preliminary financial evaluation of the project.
- Such a plant has been designed for a location near Meridian, Mississippi. It produces 1,000 barrels per day of synthetic paraffinic kerosene (SPK) and 250 bpd of synthetic naphtha from Mississippi lignite and woody biomass using a TRIG gasifier and cobalt-catalyzed FT synthesis. In addition to the liquids, it exports electricity (15 $MW_e$) and $CO_2$ (1,326 metric t/day).
- A key objective for the design was to produce SPK with greenhouse gas (GHG) emissions no greater than for petroleum-derived jet fuel. The plant design includes 25% of the input feedstock energy as biomass to help meet this goal. For the biomass supply strategy proposed for supplying the plant's biomass feedstock from intensively managed pine plantations, the resulting SPK has estimated lifecycle GHG emissions about half that for conventional petroleum-derived jet fuel.
- Given the small scale of the demonstration plant, a relatively high bare-erected capital cost (BEC) per unit of output capacity was expected. Moreover, because the level of engineering effort expended in the design work was only a small fraction (perhaps 1%) of the effort the would be needed to reach a fully-built and operating demonstration project – and because the plant would be a FOAK plant – relatively high contingency factors were warranted in estimating the total plant cost ($TPC_{FOAK}$). Evidence from recent pioneering projects, including coal-IGCCs at Edwardsport, IN and at Kemper County, MS, and a post-combustion $CO_2$ capture retrofit at the coal-fired Boundary Dam plant support the application of relatively high contingency allowances.
- The $TPC_{FOAK}$ is estimated to be \$1.3 billion (2015\$) for this plant. In terms of BEC, $TPC_{FOAK}$ = 2.24 x BEC.
- A FOAK demonstration project would be an important step toward development of a commercial industry capable of producing alternative liquid transportation fuels with low lifecycle greenhouse gas emissions from domestic coal and biomass resources. However, with high estimated capital and O&M costs, favorable economics for a FOAK demonstration project on commercial terms were not anticipated.

# FOAK Demonstration Project (2)

- For a base-case financial analysis scenario, including an assumed crude oil price of $80/bbl, a capital grant of $1.5 billion would be required to achieve zero NPV over an assumed 20-year operating lifetime (with weighted average cost of capital at 5% nominal). Alternatively, with no capital grant, a production cost subsidy of $350/bbl of SPK would be required.
- Because of the high capital intensity of the plant, variations in capital-related parameters (supplemental funds allowance, WACC, capacity factor) have the most significant influence on the required subsidies (see graph).
- Subsidies for a FOAK demonstration project might be justified to prove out the concept, if prospective economics for commercial-scale N$^{th}$-of-a-kind (NOAK) facilities appear promising.




**<u>Sensitivity cases generated using Base Case input assumptions, except for:</u>**

**Capex w/SF:** 40% supplementary funds [base case = 0]

**Lo avail. ramp**: 25% in year 1, ramping to 100% in year 6 [base case: 50% in year 1, ramping to 100% in year 5]

**Hi GHG price:** $125/tCO$_{2eq}$ levelized [base case = $75/tCO2]

**Lo lignite price:** $1.4/GJ$_{HHV}$ levelized [~ 0.5 x base case)]

**WACC = 0:** real WACC set to zero [base case = 1.9%]

**Hi oil price:** → $120/bbl levelized (and $41/tCO$_2$ revenue for EOR-CO$_2$) [base case = $80/bbl, $26/tCO$_2$]

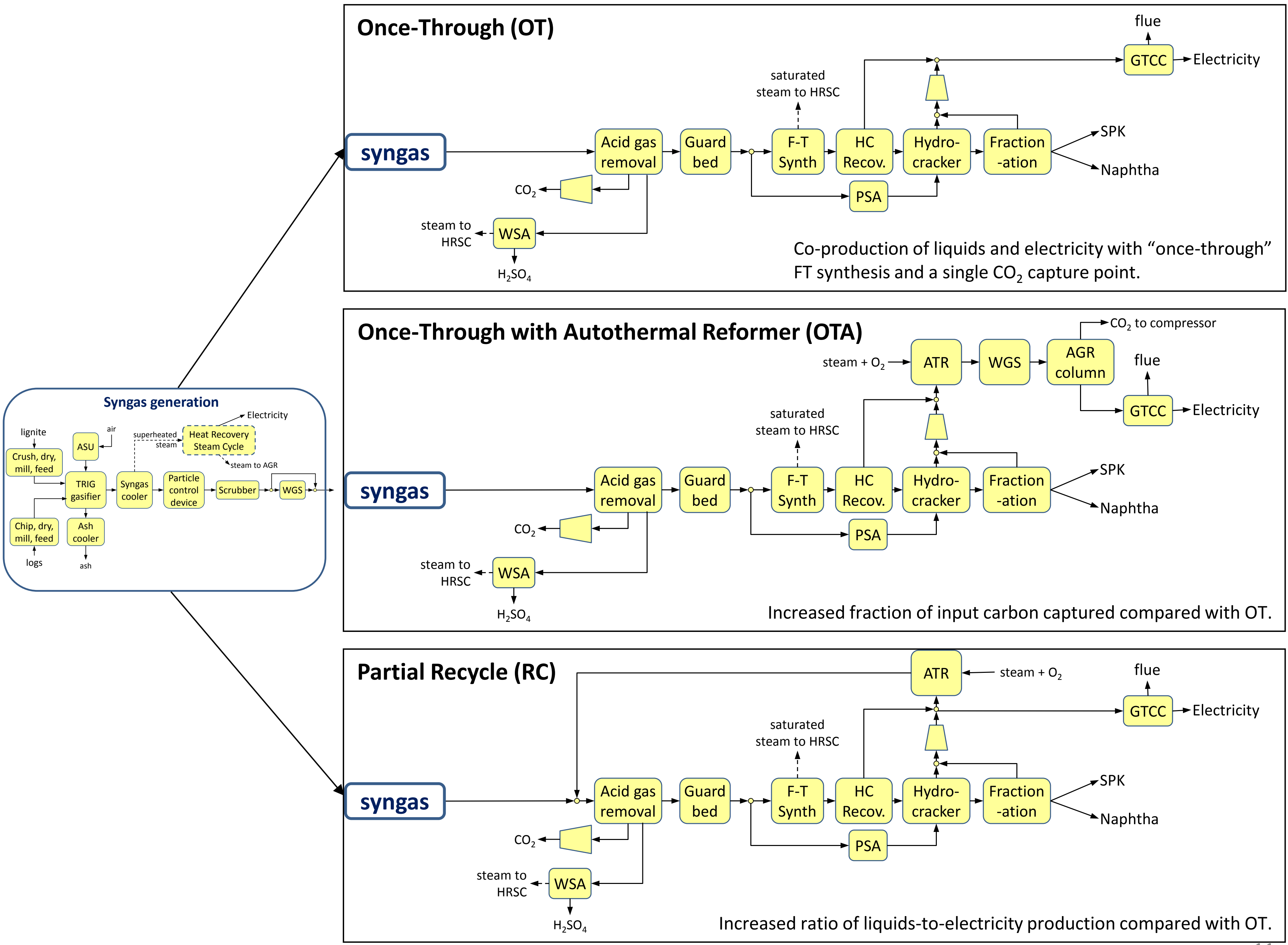
# NOAK Plant Analysis

- The economics of LBJ plants built after the FOAK demonstration plant can be expected to improve as a result of building larger scale plants and of learning that occurs as an LBJ industry matures. To help understand the extent to which economics might improve, preliminary design and analysis of NOAK plant designs were undertaken.
- Our NOAK plant designs involve no advanced technology – the designs are basically scaled-up versions of our FOAK plant design, but our NOAK process simulations accounted for 1) performance improvements that accompany larger scale, 2) alternative process configurations, and 3) biomass input fractions from 0 to 1. The input feedstock rate for any given design was set by two constraints: an assumed biomass input capacity of about 3,000 tonnes/day (a maximum for truck-delivered biomass) and a specified lifecycle greenhouse gas emissions target for the plant. The latter determines the allowable lignite-to-biomass input ratio.
- R&D is ongoing on new technologies that might lead to improved plant performance and/or reduced capital and operating costs and thereby improve on the NOAK plant economics presented here, but an assessment of such options is beyond the scope of this project.
- Methodology for estimating NOAK plant costs :
  - Without actual experience in constructing and operating LBJ plants, there is no real basis for estimating NOAK plant costs with certainty. Our analysis provides one perspective and adopts what we consider to be optimistic (low-end) estimates of NOAK capital costs, subject to the constraint mentioned above that only equipment components that are already commercial today would be used in the NOAK plant designs.
  - For each major plant area (gasifier island, FT island, power island, etc.), using appropriate scaling exponents, we scaled WorleyParsons' bare erected cost (BEC) estimates for the 1,250 bpd FOAK demonstration plant with capacities determined from our NOAK process simulations. When a plant area in a NOAK design requires multiple equipment trains we calculate $BEC_{NOAK}$ for multiple trains as the single-train BEC x $N^{0.9}$, where N is the number of trains.
  - To simulate cumulative cost reductions that may come with experience designing and building successive plants, we dramatically reduce EPCM and contingency allowances compared with the FOAK plant. For our NOAK plants, EPCM is 12% of BEC, process contingency is 0, and project contingency is 10% of BEC. Thus, $TPC_{NOAK}$ = 1.22 x $BEC_{NOAK}$.
  - In estimating liquid fuels production costs, we assume an optimistic 90% plant capacity factor.

# NOAK Plant Configurations

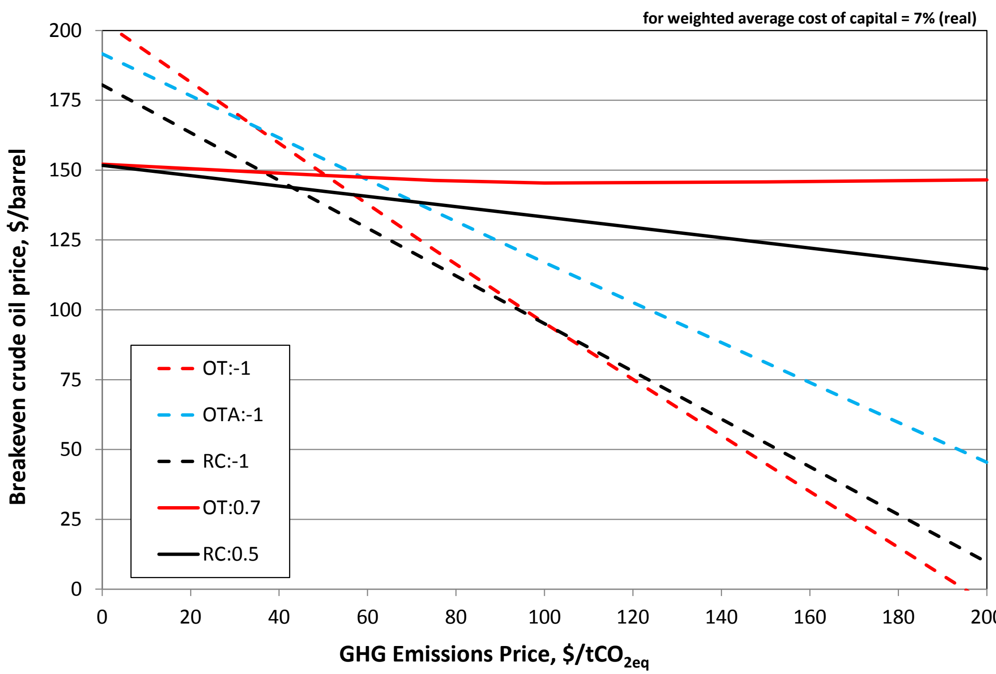
- We developed NOAK plant designs that co-process lignite and biomass, as well as designs that process exclusively coal or exclusively biomass.
- We developed two sets of co-processing plant designs: one set of plants is designed to achieve a greenhouse gas emissions index defined in the body of this report, of $GHGI_{2005} > 0$, which means its products are characterized by net positive lifecycle GHG emissions. For $GHGI_{2005} = 1$, the emissions would equal those for the equivalent mix of conventional products (liquid fuels made from crude oil and electricity from the U.S. grid-average grid mix of generators in 2005). The second set of plants is designed to have $GHGI_{2005} < 0$, i.e., such that its products are characterized by net negative lifecycle GHG emissions. Each set of plants includes three variations in process configuration, simplified process schematics for which are shown on the next slide:

  **OT -** Co-production of liquids and electricity with "once-through" FT synthesis and a single $CO_2$ capture point.
  **OTA -** Increased fraction of input carbon captured compared with OT.
  **RC -** Increased ratio of liquids-to-electricity production compared with OT.
- Plants with the RC configuration were also designed to use only coal as the feedstock to enable meaningful comparisons with prior coal-to-liquids studies. These included one plant using lignite and one using sub-bituminous coal.
- Finally, some plant designs using only biomass as feedstock were also investigated. These provide insights into the prospects for biomass-to-liquids plants using TRIG gasification. (The TRIG technology was originally developed for low-rank coals, but was subsequently demonstrated to work well with mixtures of low-rank coals and biomass. Informal discussions during this project with engineers involved in the original design, scale-up, and coal/biomass co-processing trials of the TRIG gasifier suggest that the technology would be capable of operating using 100% biomass input. Testing would be required to verify this.)


Once-Through (OT)
syngas
Acid gas removal
Guard bed
F-T Synth
HC Recov.
Hydro-cracker
Fraction -ation
PSA
WSA
GTCC
flue
Electricity
saturated steam to HRSC
SPK
Naphtha
$CO_2$
steam to HRSC
$H_2SO_4$
Co-production of liquids and electricity with "once-through" FT synthesis and a single $CO_2$ capture point.
Once-Through with Autothermal Reformer (OTA)
steam + $O_2$
ATR
WGS
AGR column
$CO_2$ to compressor
Increased fraction of input carbon captured compared with OT.
Partial Recycle (RC)
Increased ratio of liquids-to-electricity production compared with OT.
Syngas generation
lignite
Crush, dry, mill, feed
ASU
air
TRIG gasifier
Chip, dry, mill, feed
logs
Ash cooler
ash
Syngas cooler
superheated steam
Heat Recovery Steam Cycle
Electricity
steam to AGR
Particle control device
Scrubber
WGS

# Economics for NOAK Co-Processing Plants

- Considering the relatively optimistic assumptions we used in developing our NOAK capital cost estimates, the prospective economics for NOAK plants coprocessing lignite and biomass are not especially promising in the absence of R&D-driven technological and process-integration advances (not included in our analysis) that might improve performance and reduce costs. For plant designs with $GHGI_{2005} > 0$ breakeven crude oil prices (BECOP) are lower than for plants with $GHGI_{2005} < 0$ up to a GHG emissions price of \$40 to \$60 per $tCO_{2eq}$. At higher emission prices, the RC:-1 and OT:-1 cases show the most favorable economics, with the OT:-1 design gaining a slight edge when the GHG emission price exceeds about \$100/$tCO_{2e}$.




| Plant name >> | | $GHGI_{2005} < 0$ OT: -1 | OTA: -1 | RC: -1 | $GHGI_{2005} > 0$ OT: 0.7 | OTA: 0.9 | RC: 0.5 |
|---|---|---|---|---|---|---|---|
| **$GHGI_{2005}$, Southeast average** | | **-1.12** | **-0.96** | **-1.34** | **0.72** | **0.87** | **0.50** |
| Biomass input fraction | % HHV | 46% | 31% | 44% | 12% | 4% | 17% |
| Lignite input | t/d, as-received | 5,871 | 10,871 | 6,350 | 37,193 | 110,506 | 24,823 |
| | MW, HHV | 836 | 1,548 | 904 | 5,297 | 15,738 | 3,535 |
| Biomass input | t/d, as-received | 5,365 | 5,365 | 5,365 | 5,365 | 5,365 | 5,365 |
| | MW, HHV | 711 | 711 | 711 | 711 | 711 | 711 |
| Total feedstock input | MW, HHV | 1,547 | 2,259 | 1,615 | 6,008 | 16,449 | 4,246 |
| SPK output | bbl/day | 5,352 | 7,865 | 7,164 | 21,093 | 57,930 | 19,062 |
| | MW, LHV | 332 | 488 | 445 | 1,309 | 3,596 | 1,183 |
| Naphtha output | bbl/day | 1,323 | 1,944 | 1,771 | 5,215 | 14,322 | 4,713 |
| | MW, LHV | 74 | 109 | 99 | 292 | 803 | 264 |
| Total liquids output | bbl/day | 6,675 | 9,809 | 8,935 | 26,309 | 72,252 | 23,775 |
| Electricity | | | | | | | |
| Gross production | $MW_e$ | 326 | 437 | 233 | 1,273 | 3,194 | 613 |
| Auxiliary load | $MW_e$ | 208 | 359 | 233 | 804 | 2606 | 613 |
| Net export | $MW_e$ | 119 | 78 | 0 | 469 | 588 | 0 |
| Aux load, % of feedstock HHV | % | 13.4% | 15.9% | 14.5% | 13.4% | 15.8% | 14.4% |
| $CO_2$ captured for storage | metric t/day | 7,057 | 13,661 | 7,699 | 26,636 | 97,748 | 19,827 |
| | % of input C | 57% | 76% | 60% | 56% | 75% | 59% |
| **Total Plant Cost ($TPC_{NOAK}$)** | **million 2015\$** | **2,486** | **3,711** | **2,621** | **7,563** | **19,638** | **5,964** |
| **Levelized FT liquids cost** | **\$ per $GJ_{LHV}$** | **27.7** | **33.7** | **27.7** | **40.4** | **39.1** | **36.9** |
| Capital charges | | 35.9 | 36.5 | 28.3 | 27.7 | 26.2 | 24.2 |
| O&M | | 11.5 | 11.1 | 9.0 | 8.7 | 7.9 | 7.4 |
| Lignite feedstock | | 4.4 | 5.6 | 3.6 | 7.1 | 7.7 | 5.2 |
| Biomass feedstock | | 6.5 | 4.4 | 4.8 | 1.6 | 0.6 | 1.8 |
| GHG emissions (@ \$100/$tCO_{2eq}$) | | -15.9 | -10.9 | -11.9 | 10.2 | 9.8 | 4.4 |
| $CO_2$ sales for EOR (@ \$34/$tCO_2$) | | -6.7 | -8.9 | -5.5 | -6.4 | -8.6 | -5.3 |
| Co-product electricity (@ \$97/MWh) | | -7.3 | -3.2 | 0.0 | -7.3 | -3.3 | 0.0 |
| $H_2SO_4$ sales | | -0.7 | -0.9 | -0.6 | -1.2 | -1.3 | -0.9 |
| **Breakeven crude oil price** | **\$ per barrel** | **95** | **117** | **95** | **145** | **136** | **133** |
| **IRRE (with \$100/bbl crude oil)** | **% per year** | **10.8%** | **7.5%** | **11.0%** | **0.9%** | **1.6%** | **3.0%** |

Assumed prices (20-year levelized):

- Minemouth lignite: 2.1 \$/$GJ_{HHV}$
- Delivered biomass logs: 3.7 \$/$GJ_{HHV}$
- Sulfuric acid co-product revenue: \$133/tonne
- $CO_2$ revenue (for EOR): \$/$tCO_2$ = [0.386 x COP] – 5, where COP = oil price in \$/bbl
- GHG emissions: \$100/$tCO_{2eq}$ (and other values)
- Crude oil: \$100/bbl (and other values)
- Electricity sales: price equals levelized generating cost for least costly natural gas electricity, including GHG emissions tax..

# Coal-to-Liquids Plants @ ~50,000 bbl/day

Prior studies of 50,000 barrel/day plant designs were compared with NOAK designs generated in this project. Three prior studies (one by Princeton, two by NETL) agree reasonably with each other on plant performance and TPC, despite differences in coal type, gasifier type, and other factors. (In the prior Princeton study, capital costs for some major plant components were scaled from costs reported in NETL baseline power studies.) Of the three prior studies, the Skone study used the TRIG gasifier and so is most appropriate for comparative analysis with the current study. To facilitate comparisons, process simulations were developed for lignite and for the same sub-bituminous PRB coal used by Skone. The Princeton (ESAG) designs produce the same total FT liquids and net electricity as Skone after a minor adjustment we made to the latter to simulate the use of the LPG product for power generation. The adjusted case is labelled Skone*.

**ESAG-2011**: Liu, G., Larson, E.D., Williams, R.H., Kreutz, T.G., and Guo, X., "Making Fischer-Tropsch Fuels and Electricity from Coal and Biomass: Performance and Cost Analysis," *Energy & Fuels*, 25(1): 415-437, 2011.

**Shah**: V. Shah, N.J. Kuehn, M.J. Turner, and S.J. Kramer, "Cost and Performance Baseline for Fossil Energy Plants, Vol 4: Coal-to-Liquids via Fischer-Tropsch Synthesis," DOE/NETL-2011/1477, 15 Oct 2014.

**Skone**: T. Skone, T. Eckard, J. Marriott, G. Cooney, J. Littlefield, C. White, D. Gray, J. Plunkett, and W. Smith, "Comprehensive Analysis of Coal and Biomass Conversion to Jet Fuel: Oxygen Blown, Transport Reactor Integrated Gasifier (TRIG) and Fischer-Tropsch (F-T) Catalyst Configurations," DOE/NETL-2012/1563, 19 February 2014. [Report and Spreadsheet]

**Skone***: Skone case adjusted for no LPG production.

**ESAG-PRB, ESAG-lig**: Partial recycle configurations developed for this study.

| Coal-Only FT, nominal 50k bbl/d | ESAG-2011 | Shah | Skone | Skone* | ESAG-PRB | ESAG-lig |
|---|---|---|---|---|---|---|
| Coal type | Ill #6 bit. | Ill #6 bit. | PRB sub-bit | PRB sub-bit | PRB sub-bit | lignite |
| Gasifier type | slurry entrained | dry entrained | TRIG | TRIG | TRIG | TRIG |
| Coal input, metric t/d, as-received | 24,087 | 19,097 | 27,712 | 27,712 | 34,769 | 63,268 |
| Coal input, MW HHV | 7,559 | 5,985 | 6,375 | 6,375 | 8,016 | 9,010 |
| Carbon input as coal, kgCO2e/s | 653 | 515 | 588 | 588 | 740 | 847 |
| FT liquids output, (actual) barrels per day | 52,916 | 49,992 | 50,000 | 46,386 | 45,514 | 45,514 |
| FT liquids output, MW HHV | 3,399 | 3,220 | 3,176 | 2,982 | 2,982 | 2,982 |
| FT liquids, % of coal input (HHV) | 45% | 54% | 50% | 47% | 37% | 33% |
| Liquids out, MW LHV | 3,159 | 2,992 | 2,952 | 2,771 | 2,771 | 2,771 |
| Diesel and/or kerosene, MW LHV | 1,990 | 2,148 | 1,801 | 1,801 | 2,265 | 2,265 |
| Naptha, MW LHV | 1,169 | 844 | 970 | 970 | 506 | 506 |
| LPG, MW LHV | 0 | 0 | 181 | 0 | 0 | 0 |
| Gross electricity generation, MWe | 849 | 427 | 794 | 899 | 1,332 | 1,587 |
| Aux load, MWe | 554 | 423 | 562 | 562 | 995 | 1,250 |
| Net Electricity, MWe | 295 | 5 | 232 | 337 | 337 | 337 |
| Aux load as % of HHV coal in | 7.3% | 7.1% | 8.8% | 8.8% | 12.4% | 13.9% |
| Total Efficiency, HHV | 49% | 54% | 53% | 52% | 41% | 37% |
| CO2 capture, metric t/d | 29,039 | 23,970 | 28,006 | 28,006 | 33,843 | 40,562 |
| Percent of input C captured | 52% | 54% | 56% | 56% | 53% | 56% |
| t/d pure O2 | 21,634 | 13,693 | 16,218 | 16,218 | 19,652 | 23,091 |
| O2 input, t per MW-day of coal HHV input | 2.9 | 2.3 | 2.5 | 2.5 | 2.5 | 2.6 |
| Recycle fraction to FT synthesis (mass%) | 97% | na | 54% | 52% | 35% | 28% |
| **Bare Erected Cost (BEC), MM2015$** | na | **3,939** | **4,394** | **4,416** | **7,489** | **8,869** |
| **Total Plant Cost (TPC), MM2015$** | **5,213** | **5,548** | **6,138** | **6,168** | **9,137** | **10,821** |
| **Specific TPC, $/ (actual)bbl/d** | **98,514** | **110,974** | **122,757** | **132,975** | **200,753** | **237,743** |

# ESAG-PRB compared with Skone* (1)

- The fraction of input coal energy converted to liquid products is 20% lower for ESAG-PRB than for Skone*, which necessitates a larger coal input to achieve the same liquids output rate. The lower liquids conversion in ESAG-PRB is largely attributable to the higher auxiliary electric load estimated for this design: more unconverted syngas and FT light ends are used for power generation rather than for additional liquids production by recycling to the FT synthesis unit. The auxiliary electric load per unit of coal energy input for ESAG-PRB is 41% higher than for Skone*, and in absolute terms the auxiliary load is 70% higher. Several line items included in the ESAG-PRB auxiliary load estimate were not included in the Skone* estimate, and estimates of auxiliary load per unit of capacity for four key items are significantly higher for ESAG-PRB than for Skone* (right table). Reasons for some of these differences are not known.

- The larger total auxiliary load for ESAG-PRB contributes to a total plant cost that is 1.5 times that for Skone*, because larger equipment capacities are required for the same liquid and net electricity outputs. The difference in bare erected cost (BEC) accounts for most of difference in TPC:

| | Skone* | ESAG-PRB | ESAG-lig |
|---|---|---|---|
| Bare Erected Cost, MM$ | 4,416 | 7,489 | 8,869 |
| EPC and contingencies, MM$ | 1,753 | 1,648 | 1,951 |
| Total Plant Cost, MM$ | 6,168 | 9,137 | 10,821 |

| **Auxiliary Loads (MWe)** | Skone* | ESAG-PRB | ESAG-lig |
|---|---|---|---|
| Solids Handling / Coal Preparation | 5 | 67 | 121 |
| Air separation and compression | 286 | 415 | 488 |
| $CO_2$ Compressor | 92 | 175 | 209 |
| Gasification/Quench | 1 | 1 | 1 |
| BFW & Circulating Water Pumps | 19 | 26 | 31 |
| Cooling Tower Fans | 5 | | |
| H2S conversion | 7 | 2 | 5 |
| AGR | 65 | 132 | 158 |
| Recycle compressor | | 7 | 6 |
| FT Processing | 14 | 28 | 28 |
| Hydrogen recovery system | 49 | 5 | 5 |
| GT fuel gas compressor | | 54 | 59 |
| Tempered water system | | 1 | 2 |
| Cooling water system | | 35 | 58 |
| Water treatment | | 9 | 14 |
| Wastewater treatment | | 7 | 12 |
| Miscellaneous | 20 | 32 | 53 |
| **Total auxiliary load** | **562** | **995** | **1250** |
| **Auxiliary loads per tonne processed** | | | |
| Coal handling/preparation, $kW/MW_{LHV}$ coal | 0.8 | 8.6 | 15.4 |
| ASU and compression, kWh/t pure O2 | 424 | 507 | 507 |
| CO2 compression, kWh/t CO2 | 78 | 124 | 124 |
| Acid gas removal, kWh/tCO2 | 56 | 94 | 94 |

# ESAG-PRB compared with Skone* (2)

- The BEC per unit of capacity for the ASU and the gasifier are each within 10% of each other between the ESAG-PRB and Skone* designs, but all other items have larger, or much larger, cost differentials. It is difficult to make direct comparisons of line items because of unknown scope differences between the estimates, but the higher total BEC for the same total liquids output for ESAG-PRB suggests that the level of engineering effort expended to estimate BEC for Skone, including analysis of auxiliary loads, was not as substantial as the present effort.

| BARE ERECTED COST (1000s 2015$) | Skone* | ESAG-PRB | % diff |
|---|---|---|---|
| Coal and sorbent handling | 125,447 | 188,957 | 51% |
| Coal prep and feeding | 398,248 | 643,441 | 62% |
| Feedwater systems and misc. BOP | 118,110 | 311,434 | 164% |
| Gasifier and accessories | 1,000,140 | 1,313,441 | 31% |
| ASU and compression | 769,751 | 1,023,279 | 33% |
| Gas cleanup & piping, incl. H2S conv. | 58,461 | 459,588 | 686% |
| Acid gas removal (AGR) | 308,498 | 1,148,868 | 272% |
| F-T synthesis and upgrading | 736,900 | 986,378 | 34% |
| $CO_2$ removal and compression | 85,967 | 186,762 | 117% |
| Autothermal reformer | 144,810 | 61,036 | -58% |
| GTCC and heat recovery steam cycle | 271150 | 526,619 | 94% |
| Cooling water system | 48,976 | 172,773 | 253% |
| Ash/spent sorbent handling | 98,076 | 267,618 | 173% |
| Accessory electric plant | 72,633 | 125,728 | 73% |
| Instrumentation and control | 75,403 | 23,726 | -69% |
| Improvements to the site | 50,269 | 36,884 | -27% |
| Building and structures | 52,782 | 12,947 | -75% |
| **TOTAL BEC** | **4,415,621** | **7,489,479** | **70%** |

| UNIT BEC ($ per unit of capacity) | Skone* | ESAG-PRB | % diff |
|---|---|---|---|
| Coal handling & prep, $\$/MW_{coal}$ | 85,245 | 107,766 | 26% |
| Feedwater & misc BOP, $\$/MW_{coal}$ | 19,225 | 40,320 | 110% |
| Gasifier & accessories, $\$/MW_{coal}$ | 162,798 | 170,045 | 4% |
| ASU, \$/metric t/d pure $O_2$ | 47,462 | 52,070 | 10% |
| Gas cleanup & piping, $\$/MW_{coal}$ | 9,516 | 59,501 | 525% |
| AGR, \$/metric t $CO_2$ captured | 11,015 | 33,947 | 208% |
| FT Island, $\$/MW_{FTL}$ | 265,923 | 355,964 | 34% |
| $CO_2$ compression, \$/metric t/d $CO_2$ | 3,070 | 5,519 | 80% |
| Power island, \$/kW gross | 302 | 395 | 31% |
| Cooling water system | 7,972 | 22,368 | 181% |
| Ash/spent sorbent handl., $\$/MW_{coal}$ | 15,964 | 34,647 | 117% |
| Accessory electric plant, $\$/MW_{coal}$ | 11,823 | 16,277 | 38% |
| Instrumentation & control, $\$/MW_{coal}$ | 12,274 | 3,072 | -75% |
| Site improvements, $\$/MW_{coal}$ | 8,183 | 4,775 | -42% |
| Buildings & structures, $\$/MW_{coal}$ | 8,592 | 1,676 | -80% |
| ATR, $\$/MW_{FTL}$ | 52,257 | 22,027 | -58% |
| TOTAL, $\$ / MW_{FTL}$ | 1,593,450 | 2,702,807 | 70% |
| **\$/ (actual)bbl/d** | **95,193** | **164,552** | **73%** |

- The differences between the Skone* and ESAG-PRB designs lead to very different overall economics. For example, using Princeton's financial methodology and assumptions, including a GHG emissions price of $\$100/tCO_{2eq}$ and a $CO_2$ sale price for EOR of \$34/t, the breakeven crude oil price is \$103/bbl for Skone* and \$139/bbl for ESAG-PRB.

# ESAG-PRB compared with ESAG-lig

- Finally, comparing ESAG-PRB with ESAG-lig cases in the tables on the two previous slides, we see that using lignite instead of sub-bituminous coal increases auxiliary loads, because solids handling, ASU, AGR, and $CO_2$ compression loads are all significantly increased as a result of a larger coal input requirement for the same level of liquids production.
- The 12% higher coal energy input is due to a lower gasifier cold gas efficiency with lignite that arises primarily from the higher ash fraction of lignite (22% vs. 11%, dry basis) and to the lower FT recycle fraction that must be used to enable sufficient electricity generation (using the unrecycled fraction) to meet the larger auxiliary load.
- The larger coal input necessitates more oxygen consumption and results in more $CO_2$ being captured, which leads to increased auxiliary loads for the ASU, AGR, and $CO_2$ compressor. The load for solids handling scales with as-received coal input tonnage, which is 82% higher for lignite than for sub-bituminous due to higher ash and moisture fractions.
- The TPC for ESAG-lig is 18% higher than for ESAG-PRB due to the larger coal input required to produce the same quantities of products.

| Coal-Only FT, nominal 50k bbl/d | ESAG-PRB | ESAG-lig |
|---|---|---|
| Coal type | PRB sub-bit | lignite |
| Gasifier type | TRIG | TRIG |
| Coal input, metric t/d, as-received | 34,769 | 63,268 |
| Coal input, MW HHV | 8,016 | 9,010 |
| Carbon input as coal, kgCO2e/s | 740 | 847 |
| FT liquids output, (actual) barrels per day | 45,514 | 45,514 |
| FT liquids output, MW HHV | 2,982 | 2,982 |
| FT liquids, % of coal input (HHV) | 37% | 33% |
| Liquids out, MW LHV | 2,771 | 2,771 |
| Diesel and/or kerosene, MW LHV | 2,265 | 2,265 |
| Naptha, MW LHV | 506 | 506 |
| LPG, MW LHV | 0 | 0 |
| Gross electricity generation, MWe | 1,332 | 1,587 |
| Aux load, MWe | 995 | 1,250 |
| Net Electricity, MWe | 337 | 337 |
| Aux load as % of HHV coal in | 12.4% | 13.9% |
| Total Efficiency, HHV | 41% | 37% |
| CO2 capture, metric t/d | 33,843 | 40,562 |
| Percent of input C captured | 53% | 56% |
| t/d pure O2 | 19,652 | 23,091 |
| O2 input, t per MW-day of coal HHV input | 2.5 | 2.6 |
| Recycle fraction to FT synthesis (mass%) | 35% | 28% |
| **Bare Erected Cost (BEC), MM2015$** | **7,489** | **8,869** |
| **Total Plant Cost (TPC), MM2015$** | **9,137** | **10,821** |
| **Specific TPC, $/ (actual)bbl/d** | **200,753** | **237,743** |

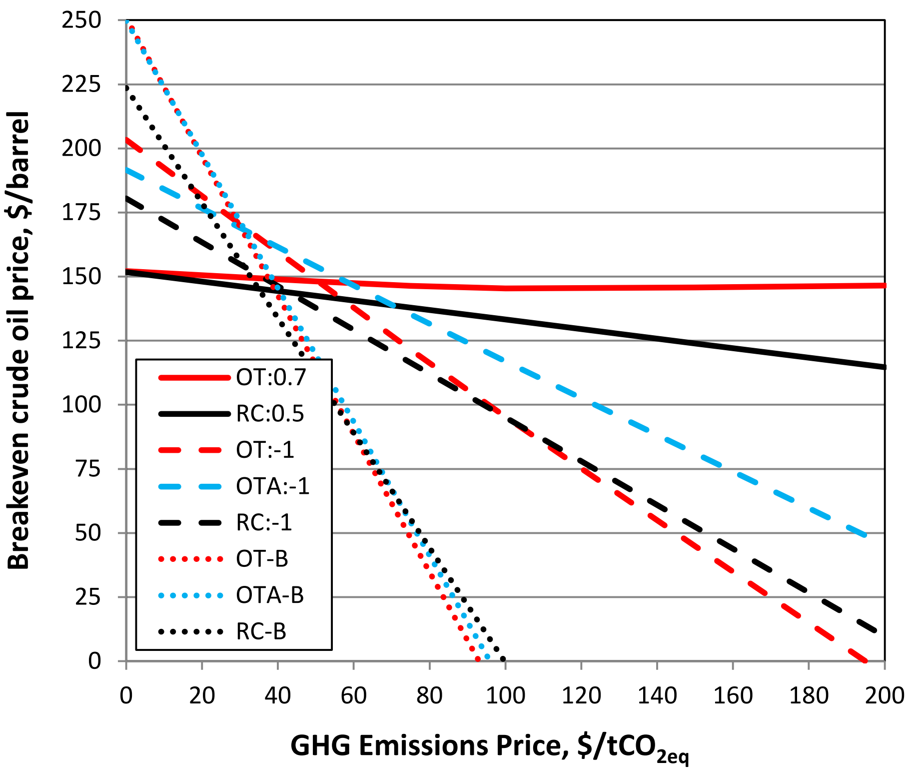
# Plants Using Only Biomass Feedstocks

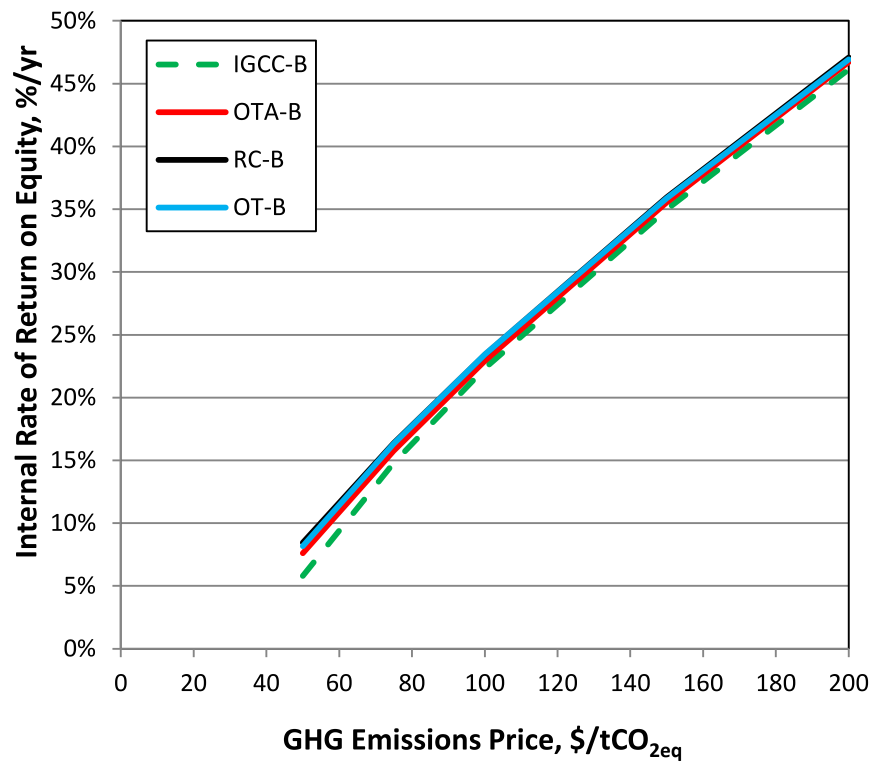
- The carbon mitigation goal agreed to by world leaders at the Paris climate conference in 2015 is to strive to limit global warming to less than 2°C. The Intergovernmental Panel on Climate Change, in its 5th Assessment Report, suggests that achieving this will require the availability of bioenergy, CCS, and their combination. NOAK plant designs using biomass only in OT, OTA, and RC configurations were investigated, because in the presence of a strong carbon mitigation policy, the highly negative greenhouse gas emissions associated with the liquid fuels from such plants make these designs more economically attractive than other plant designs described in this report. A configuration producing only electricity (IGCC-B) was also investigated.

| | | OT-B | OTA-B | RC-B | IGCC-B |
|---|---|---|---|---|---|
| **$GHGI_{2005}$, Southeast average** | | **-4.15** | **-5.86** | **-5.25** | **-3.95** |
| Annual biomass input (90% CF) | $10^6$ dry metric t/y | 1.00 | 1.00 | 1.00 | 1.00 |
| Biomass input | t/d, as-received | 5,365 | 5,365 | 5,365 | 5,365 |
| | MW, HHV | 711 | 711 | 711 | 711 |
| SPK output | bbl/day | 2,400 | 2,400 | 3,081 | na |
| | MW, LHV | 149 | 149 | 191 | na |
| Naphtha output | bbl/day | 593 | 593 | 762 | na |
| | MW, LHV | 33 | 33 | 43 | na |
| Total liquids output | bbl/day | 2,994 | 2,994 | 3,842 | na |
| Electricity | | | | | |
| Gross production | MWe | 149 | 136 | 102 | 281 |
| Auxiliary load | MWe | 96 | 114 | 103 | 108 |
| Net export | MWe | 53 | 22 | -1 | 173 |
| Aux load, % of feedstock HHV | % | 13.5% | 16.0% | 14.5% | 15.2% |
| $CO_2$ captured for storage | metric t/day | 3,387 | 4,487 | 3,532 | 5,099 |
| | % of input C | 58% | 77% | 61% | 87% |
| **Total Plant Cost ($TPC_{NOAK}$)** | **million 2015$** | **1,316** | **1,411** | **1,349** | **1,299** |
| **Levelized Production Costs** | | | **$ / $GJ_{LHV}$** | | **$/MWh** |
| Capital charges | | 42.4 | 45.5 | 33.9 | 167.8 |
| O&M | | 14.4 | 14.9 | 11.4 | 56.7 |
| Biomass feedstock | | 14.4 | 14.4 | 11.2 | 54.6 |
| GHG emissions (@ $100/$tCO_{2eq}$) | | -59.0 | -65.4 | -46.7 | -261.1 |
| $CO_2$ sales for EOR (@ $34/$tCO_2$) | | -7.2 | -9.5 | -5.9 | -37.2 |
| Co-product electricity (@ $97/MWh) | | -7.2 | -3.1 | 0.1 | na |
| $H_2SO_4$ sales | | -0.04 | -0.04 | -0.03 | -0.13 |
| **Total Levelized Cost** | | **-2.3** | **-3.2** | **4.0** | **-19.2** |
| **IRRE (with $100/bbl crude oil)** | **% per year** | **23.4%** | **22.9%** | **23.4%** | **22.3%** |

# Biomass-Only Cases: NOAK Financial Analysis

- For liquid fuels production, OT-B, OTA-B, or RC-B, despite their smaller sizes, are favored over co-processing systems when the GHG emissions price is above about \$40/t$CO_{2e}$, and their BECOPs fall very rapidly with increasing GHG emissions price due to revenues received for significant negative emissions.
- IRRE for the biomass-only designs can be compared with that for the power-only design (IGCC-B). For a crude oil price of \$100/bbl the IRREs for all four biomass-only plants are essentially identical across the full range of GHG emission prices considered.




Assumptions:
- Delivered biomass price ((20-year levelized): 3.7 \$/$GJ_{HHV}$
- Sulfuric acid co-product revenue: \$133/tonne, levelized
- Crude oil price = \$100/bbl
- Plant gate price of $CO_2$ sold for EOR: \$33.5/t$CO_2$ (as determined by oil price – see slide 54)
- Electricity sales price as in slide 65.

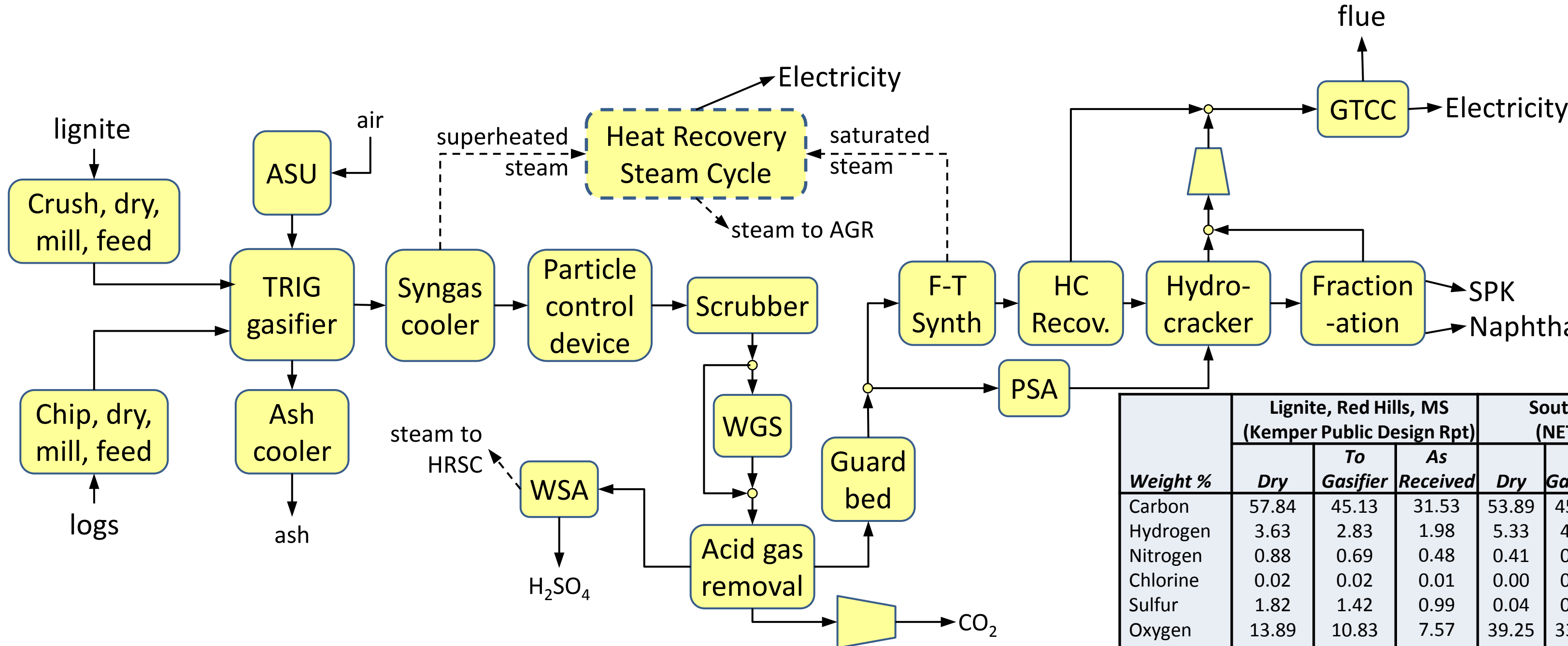
Milestone 4 Report:
Summary of Financial Analysis for FOAK LBJ Plant and Prospective NOAK Commercial Plants

# 3. FIRST-OF-A-KIND (FOAK) LBJ DEMONSTRATION PLANT

Milestone 4 Report:
Summary of Financial Analysis for FOAK LBJ Plant and Prospective NOAK Commercial Plants

# 3.1. DESIGN AND PERFORMANCE

# LBJ FOAK Process Flow Overview




| Weight % | Lignite, Red Hills, MS (Kemper Public Design Rpt) Dry | To Gasifier | As Received | Southern Pine (NETL, 2014) Dry | To Gasifier | As Received |
|---|---|---|---|---|---|---|
| Carbon | 57.84 | 45.13 | 31.53 | 53.89 | 45.81 | 30.56 |
| Hydrogen | 3.63 | 2.83 | 1.98 | 5.33 | 4.53 | 3.02 |
| Nitrogen | 0.88 | 0.69 | 0.48 | 0.41 | 0.34 | 0.23 |
| Chlorine | 0.02 | 0.02 | 0.01 | 0.00 | 0.00 | 0.00 |
| Sulfur | 1.82 | 1.42 | 0.99 | 0.04 | 0.03 | 0.02 |
| Oxygen | 13.89 | 10.83 | 7.57 | 39.25 | 33.36 | 22.25 |
| Ash | 21.92 | 17.10 | 11.95 | 1.09 | 0.93 | 0.62 |
| Moisture | | 22.00 | 45.50 | | 15.00 | 43.30 |
| HHV, MJ/kg | 22.58 | 17.61 | 12.30 | 20.19 | 17.17 | 11.45 |
| LHV, MJ/kg | 21.79 | 16.46 | 10.76 | 19.03 | 15.81 | 9.73 |

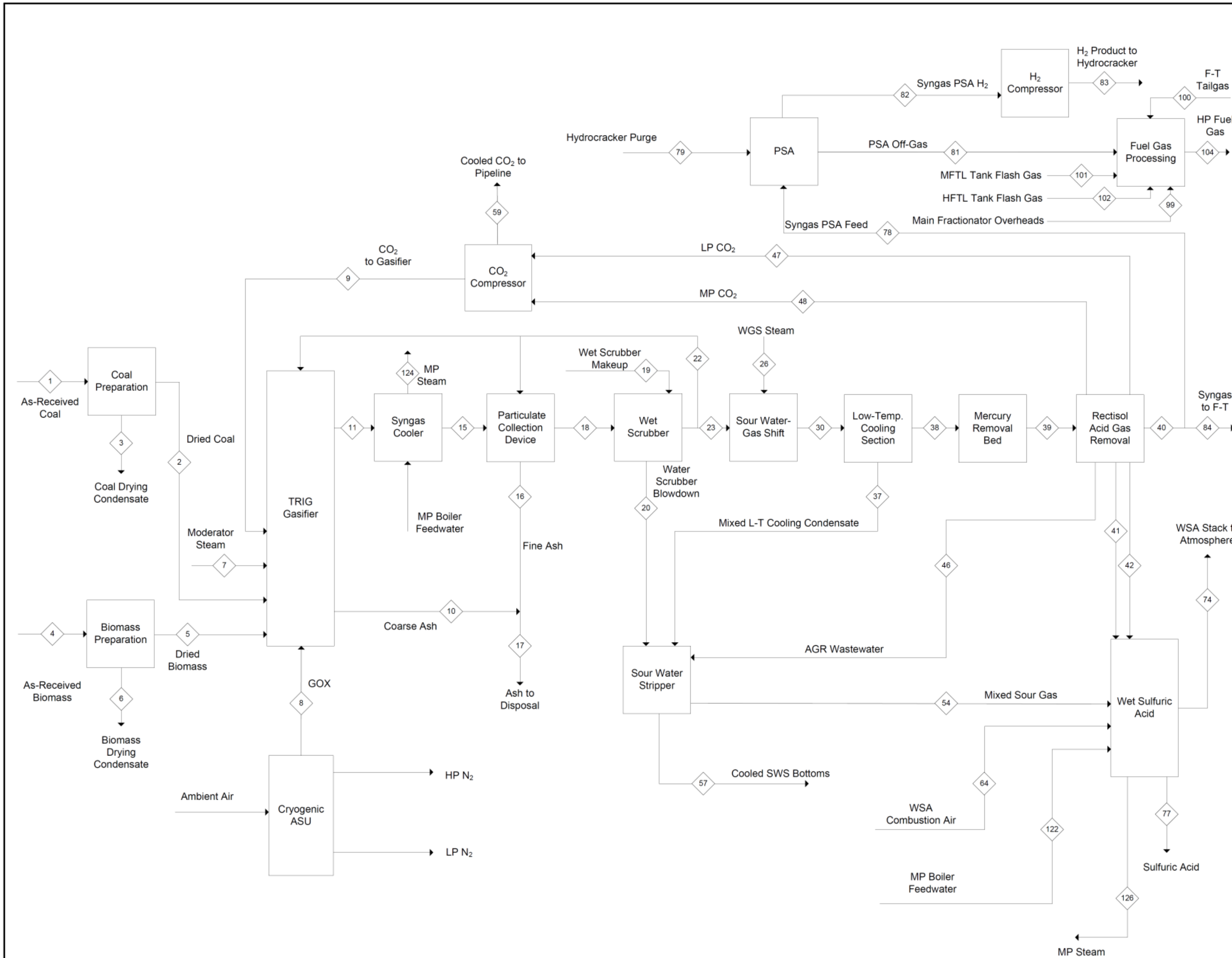
The plant receives lignite and pulpwood-grade logs that are separately subjected to sizing and drying before being fed to a pressurized $O_2$-blown TRIG gasifier using 99.5% purity oxidant from a dedicated air separation unit (ASU). The resulting syngas is cooled, filtered, and scrubbed before a partial sour water gas shift (WGS) to set the $H_2$/CO ratio at the Fischer-Tropsch (F-T) synthesis inlet to the desired value. $CO_2$, $H_2S$, and trace impurities are then removed using a methanol solvent (Rectisol®) at the acid gas removal (AGR) island. The $CO_2$ is compressed for delivery by pipeline. The $H_2S$ is converted to wet sulfuric acid (WSA) for sale. A guard bed downstream of the AGR protects the cobalt-based F-T synthesis catalyst. F-T synthesis produces a crude product that undergoes hydrocarbon recovery. Permanent gases are collected for use as fuel in a gas turbine combined cycle (GTCC). Crude F-T liquids are subjected to hydrocracking and fractionation, resulting in synthetic paraffinic kerosene (SPK) and naphtha as final products. Hydrogen for the hydrocracker is supplied from a slipstream of post-AGR syngas via pressure swing adsorption (PSA). The PSA raffinate and the light ends from the hydrocracking and fractionation are collected and used as additional GTCC fuel. Electricity from the GTCC is supplemented with electricity from a separate heat recovery steam cycle (HRSC) that utilizes process heat primarily from syngas cooling and F-T synthesis. Process heat is also used for feedstock drying and some other needs.

# WorleyParson’s Process Design Development

A heat and material balance (HMB) for the facility was generated in Aspen Plus to a level of detail necessary to support cost estimation work.

- Inputs to WorleyParson’s process model were provided by Princeton and Politecnico di Milano. Additionally, WorleyParsons adjusted their model to agree with OEM performance data for the gasifier, AGR unit, $CO_2$ compressor, WSA unit and hydrogen recovery unit. Other unit operations were specified based on general engineering principles and judgement. The HMB for the Fischer-Tropsch island provided by Emerging Fuels Technology (EFT) was modified slightly to account for changes in syngas flow rate and composition to the F-T unit as the process design matured. Power block performance based on predicted fuel gas composition from the FT off-gases. The SGT-700 gas turbine performance estimated by Siemens was transferred to Thermoflow GTPro software for combined cycle simulation. The mechanical-draft cooling tower for the entire facility was also included in the GTPro environment. The separate heat recovery steam cycle (HRSC) was simulated in Aspen Plus, with OEM performance data for the steam turbine incorporated.
- No spare gasifier. (Sparing is provided only for relatively low-cost active components whose failure could lead to plant trips and outages.) Mature plant designs using a single gasifier can expect availability of 80% to 85% after the fifth year of operation.
- The plant was sized such that off-gases from the FT island are sufficient to fire a Siemens SGT-700 gas turbine generator making electricity. The GT exhaust heat recovery steam generator (HRSG) provides steam for steam turbine generator for additional electric power production.
- The pinch-optimized heat exchanger network recovers process heat and generates steam used to meet process needs, with the excess operating a second steam turbine generator specified and manufactured to purpose.
- Sulfur removal is via a Rectisol system. $NO_X$ is controlled by SCR in the appropriate gas temperature zone of the HRSG and in the wet sulfuric acid combustor unit.
- The GTCC and separate HRSC generate sufficient power to meet the full auxiliary load and export some power to the grid.

# Process Flow Diagram – Syngas Generation

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|---|---|---|
| A | 06/01/2016 | INITIAL ISSUE |
| REV | DATE | DESCRIPTION |

ENGINEER/TECH SPECIALIST: E.J. Mace — DATE: 06/01/2016

CHECKED BY: — PROJECT MANAGER: H.N. Goldstein

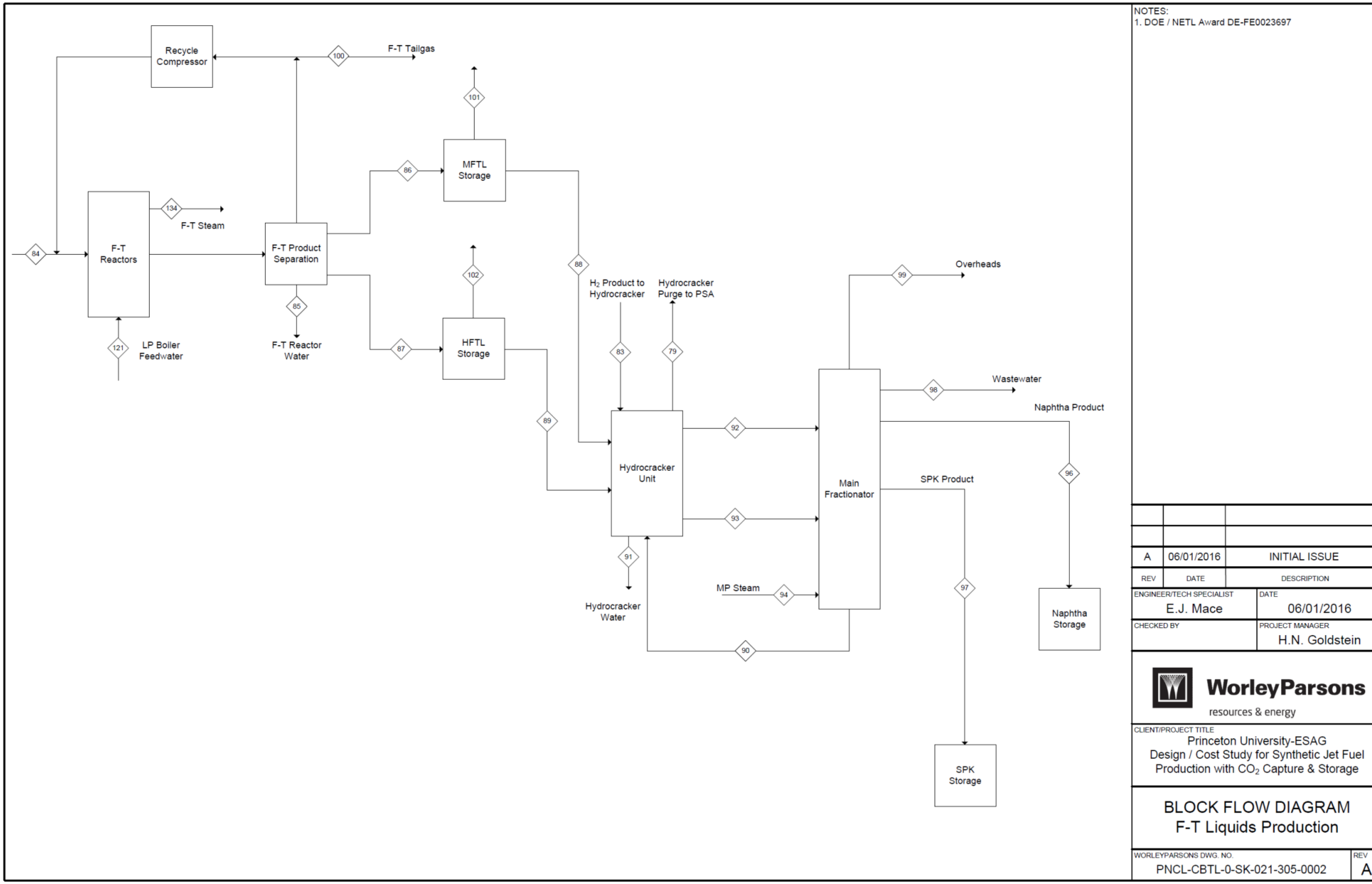
WorleyParsons resources & energy

CLIENT/PROJECT TITLE: Princeton University-ESAG Design / Cost Study for Synthetic Jet Fuel Production with $CO_2$ Capture & Storage

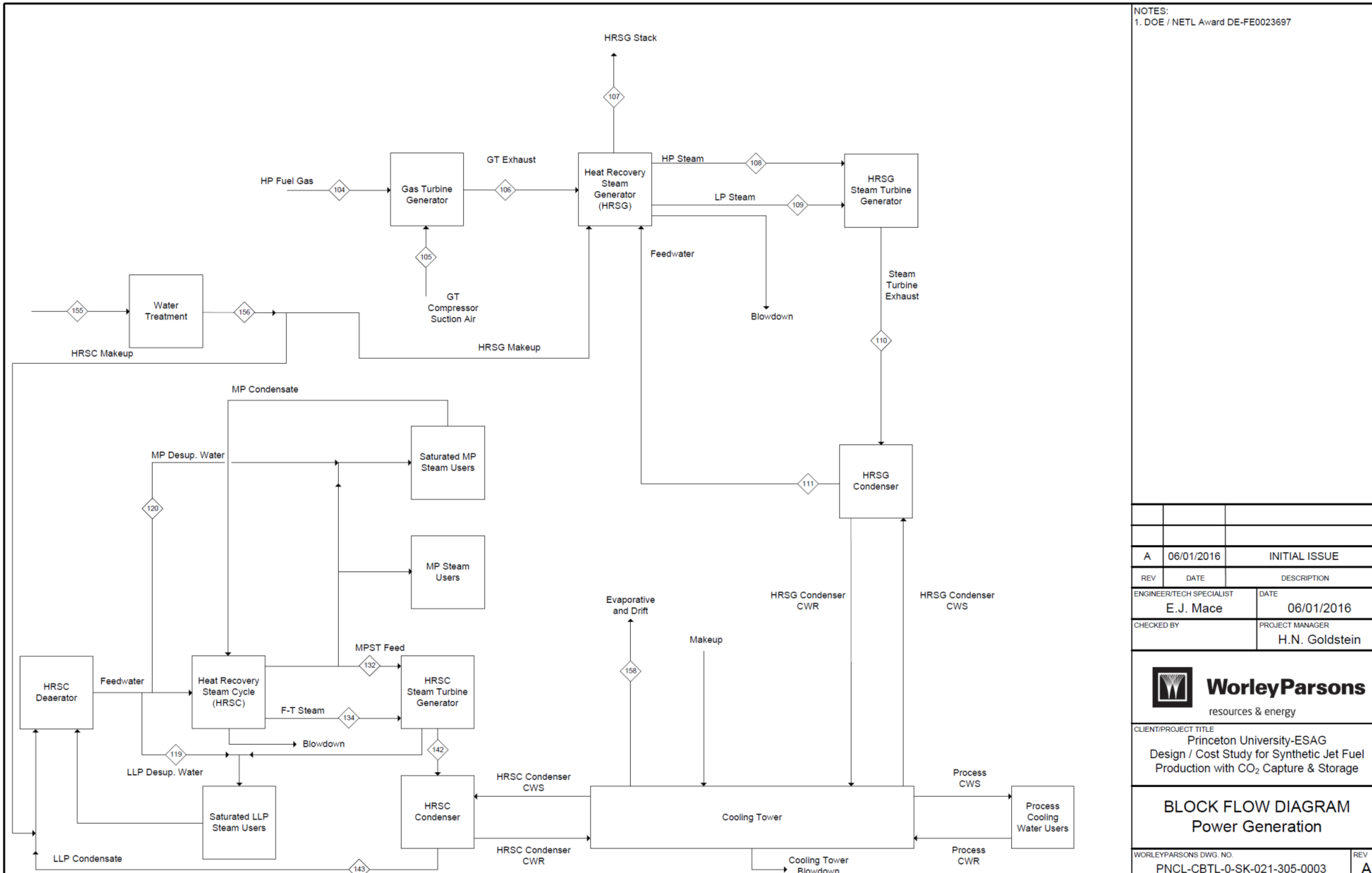
BLOCK FLOW DIAGRAM
Syngas Generation

WORLEYPARSONS DWG. NO. PNCL-CBTL-0-SK-021-305-0001 — REV A

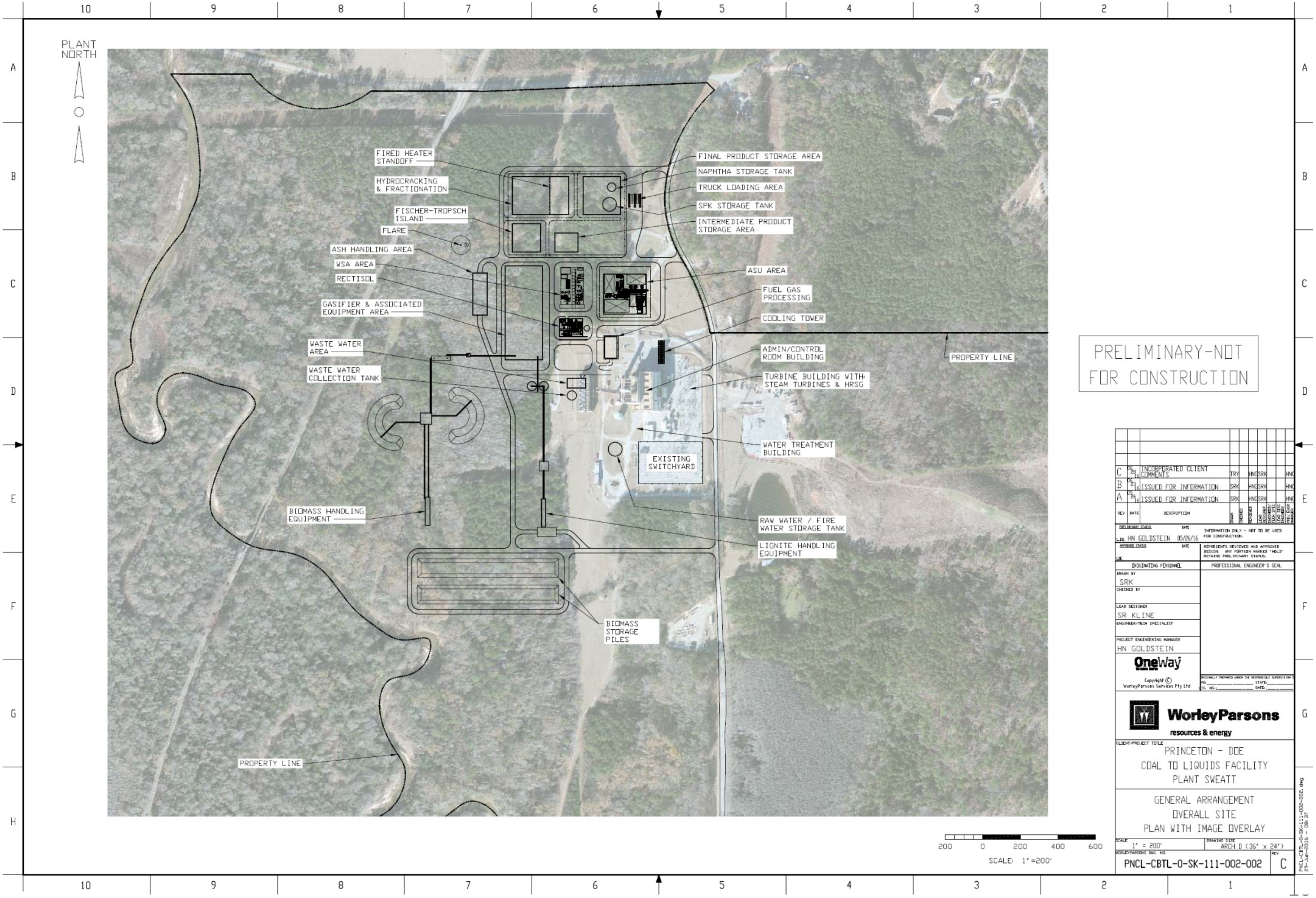
# Process Flow Diagram – FTL Production



# Process Flow Diagram – Power Generation



# LBJ General Site Arrangement @ Plant Sweatt



# LBJ FOAK Mass/Energy/Carbon Balances

| Feedstock inputs | | |
|---|---|---|
| Total feedstock input | MW, HHV | 295 |
| Biomass % of feedstock | % of HHV | 25.0% |
| Lignite | metric t/d A.R. | 1,551 |
| | MW, HHV | 221 |
| Biomass | metric t/d A.R. | 556 |
| | MW, HHV | 74 |
| **FT liquid outputs** | | |
| Synthetic Paraffinic Kerosene (SPK) | MW, LHV | 62.3 |
| | actual bbl/day | 1,004 |
| | bbl/day equiv. petroleum-SPK | 900 |
| Synthetic naphtha | MW, LHV | 13.9 |
| | actual bbl/day | 248 |
| | bbl/day equiv. petro-naphtha | 223 |
| Total liquids production | MW, LHV | 76.2 |
| | actual bbl/day | 1,252 |
| | bbl/day equiv. petroleum | 1,123 |
| **Other products** | | |
| $CO_2$ to pipeline | metric t/day | 1,326 |
| Sulfuric acid (93 wt% $H_2SO_4$) | metric t/day | 49 |
| **Electricity** | | |
| GTCC generation | $MW_e$ | 43.22 |
| HRSC generation | $MW_e$ | 11.10 |
| Total generation | $MW_e$ | 54.32 |
| On-site use, $MW_e$ | $MW_e$ | 39.17 |
| Net electricity production | $MW_e$ | 15.1 |
| Net electricity, % of output LHV | % | 16.6% |

| Auxiliary Loads | $MW_e$ |
|---|---|
| Lignite prep | 2.98 |
| Biomass prep | 1.07 |
| Gasifier | 0.03 |
| AGR | 5.18 |
| Sour water stripper | 0.02 |
| $CO_2$ compressor | 6.84 |
| WSA | 0.12 |
| H2 recovery | 0.13 |
| F-T island | 0.76 |
| Fuel gas system | 1.56 |
| GTCC | 0.84 |
| Air separation unit | 14.73 |
| HRSC | 0.24 |
| Tempered water sys | 0.08 |
| Cooling water sys | 2.04 |
| Water treatment | 0.47 |
| Wastewater treat. | 0.39 |
| Miscellaneous | 1.72 |
| TOTAL | 39.17 |

| Carbon balance | $tCO_{2eq}/d$ |
|---|---|
| Lignite input | 1,792 |
| Biomass input | 622 |
| TOTAL INPUT | 2,414 |
| C in SPK product | 378 |
| C in naphtha | 83 |
| $CO_2$ captured | 1,326 |
| $CO_2$ vented | 538 |
| C in gasifier ash | 57 |
| TOTAL OUTPUT | 2,382 |

| Lifeycle GHG emiss (t $CO_{2eq}$/d) | |
|---|---|
| Plant emissions | 538 |
| **Upstream** | |
| Upstream lignite | 94 |
| Upstream biomass | 25 |
| Net landscape | -877 |
| **Downstream** | |
| Fuel transport to user | 2 |
| SPK combustion | 378 |
| Naphtha combustion | 83 |
| CO2 pipeline operation | 9 |
| EOR increment | 118 |
| **Net lifecycle** | |
| Total | 370 |

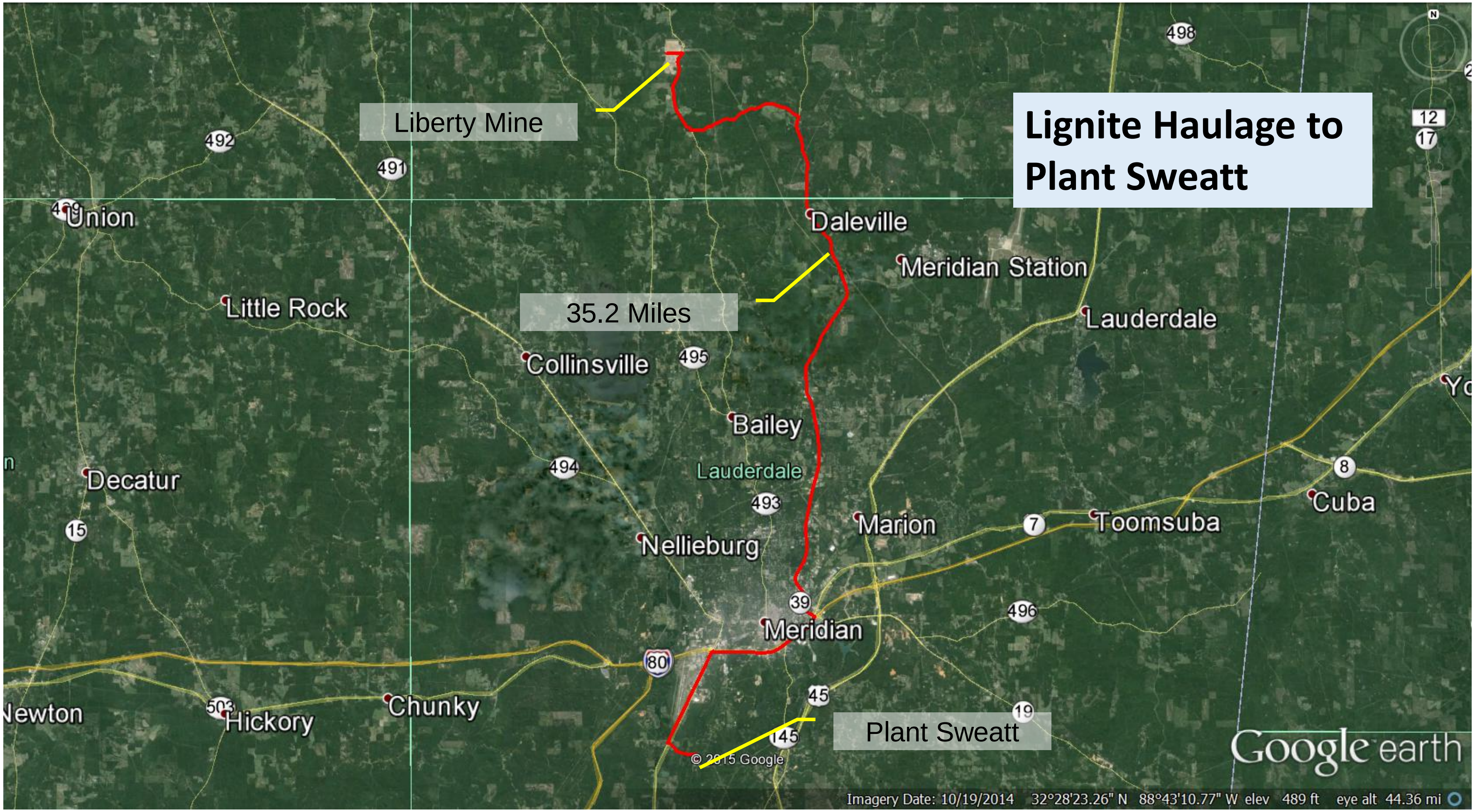
*Note*: These balances are based on Princeton's Aspen Plus process simulation, which incorporates minor changes that resulted from additional process understanding developed after WorleyParsons completed their HMB used as the basis for capital and O&M cost estimation.

Milestone 4 Report:
Summary of Financial Analysis for FOAK LBJ Plant and Prospective NOAK Commercial Plants

# 3.2. LIGNITE AND BIOMASS SUPPLY

# Lignite Supply (1)

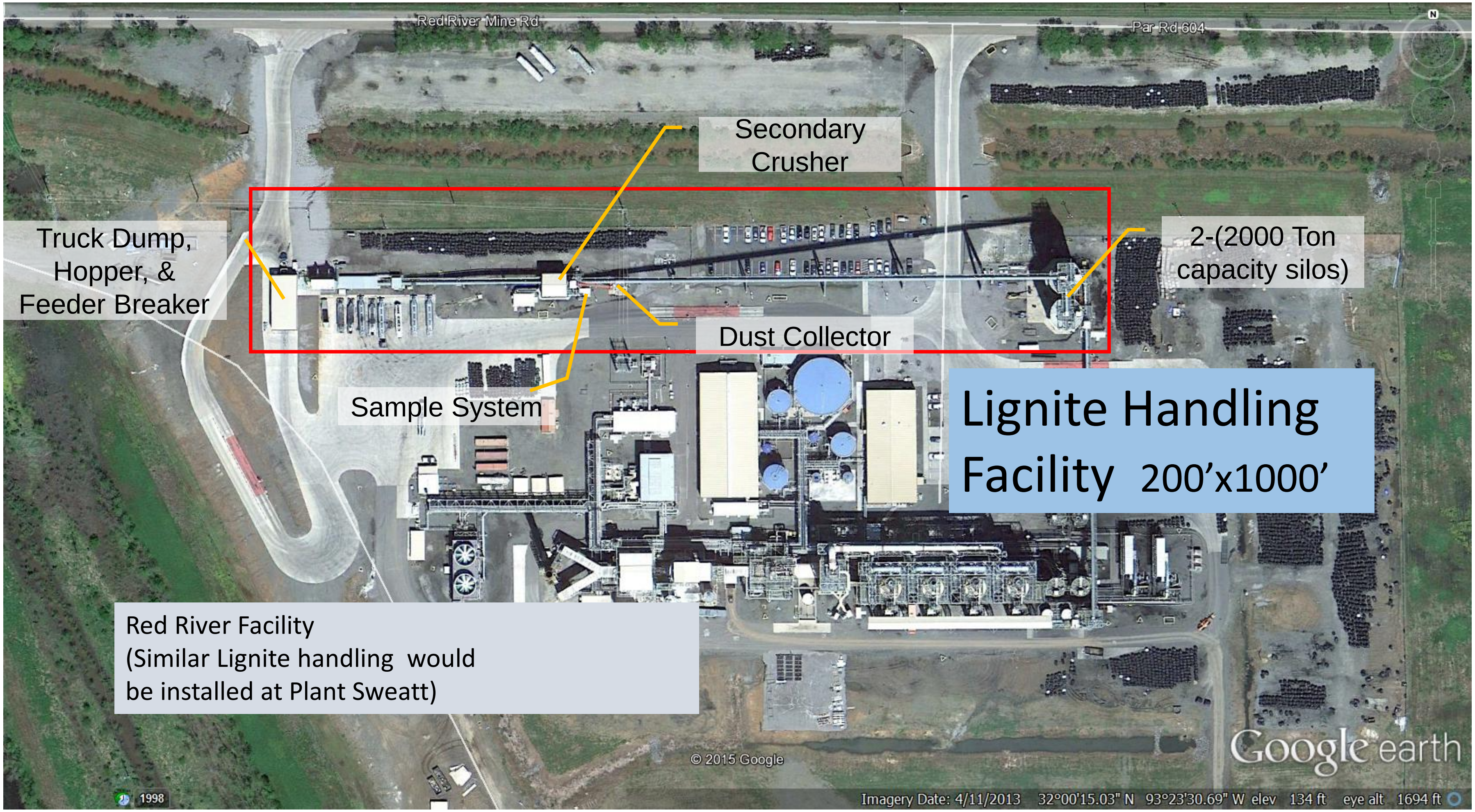
- Lignite will be trucked from the Liberty Mine adjacent to the Kemper County IGCC plant, approximately 35 miles to the LBJ demonstration plant site. (This will require approval by Mississippi Power Company, the owners of the lignite resources in the Liberty Mine.)
- The estimated delivered price for this lignite is \$2.7 per $GJ_{HHV}$, or \$33/tonne (as-received).




Information on prospective lignite supply logistics provided by Tres Tipton, VP of Engineering, LA & MS Operations, The North American Coal Corporation, Dallas, TX.

# Lignite Supply (2)

- Lignite receiving and storage system will resemble similar-scale system at the Red River facility (Coushatta, LA). Considering the modest scale of the LBJ plant, on-site lignite storage will be in silos.




Information on Red River facility provided by Tres Tipton, VP of Engineering, LA & MS Operations, The North American Coal Corporation, Dallas, TX.

# Biomass Supply to the LBJ Plant

- Biomass supply and GHG accounting were developed by Antares Group, Inc. (funded by Southern Co. Services).*
- Antares estimates there are currently 5.9 million tons/yr pulpwood quality wood available (in excess of demands) within 100 mile radius of Meridian, MS, and the small quantity of supply required by the LBJ plant would not materially impact prevailing prices, which Antares estimated for delivered biomass as follows:

*Exhibit 12 Published Data on Market Prices for Fuel and Fiber Quality Biomass*

| | -------$/dry ton------- | | | -------$/MMBtu------- | | |
|---|---|---|---|---|---|---|
| **Type of material** | **Base** | **High** | **Low** | **Base** | **High** | **Low** |
| Forest residues | 38 | 59 | 29 | 2.22 | 3.42 | 1.69 |
| Mill chips | 58 | 76 | 52 | 3.38 | 4.40 | 3.03 |
| Log length pulpwood | 59 | 74 | 40 | 3.43 | 4.27 | 2.32 |
| Chipped pulpwood | 66 | 83 | 46 | 3.83 | 4.79 | 2.64 |
| Pellet fuel (premium) | 190 | 203 | 162 | 11.04 | 11.79 | 9.41 |

Forest residue costs from ANTARES internal logging cost model back checked with published values. Mill chip and base pulpwood costs from 2014 published values for South Central U.S. (RISI 2014). High/low pulpwood costs from ANTARES internal logging cost model back checked with published values. Pellet prices from Argus Biomass Markets (Argus Media 2015). Assumed wood moisture of 45% for green wood; 10% for pellets. Assumed wood heating value: 8,607 Btu/dry lb (20.0194 MJ/dry kg). Transportation costs range from 40 miles for low cost scenario to 120 miles for high cost scenario for round-trip haul.

- Forest residues are the preferred biomass feedstock on a cost basis, but engineers involved with development of biomass feeding systems for the TRIG gasifier indicated that the input biomass should have a maximum particle dimension of 1/8" and moisture content of 15% to ensure flowability. The particle size specification is difficult to achieve on a consistent basis using forest residues because of its bark and extraneous matter content. As a result, log length pulpwood was recommended by Antares, who estimated that the delivered cost to the LBJ facility would be about \$54 per ton, or \$2.9/$GJ_{HHV}$.

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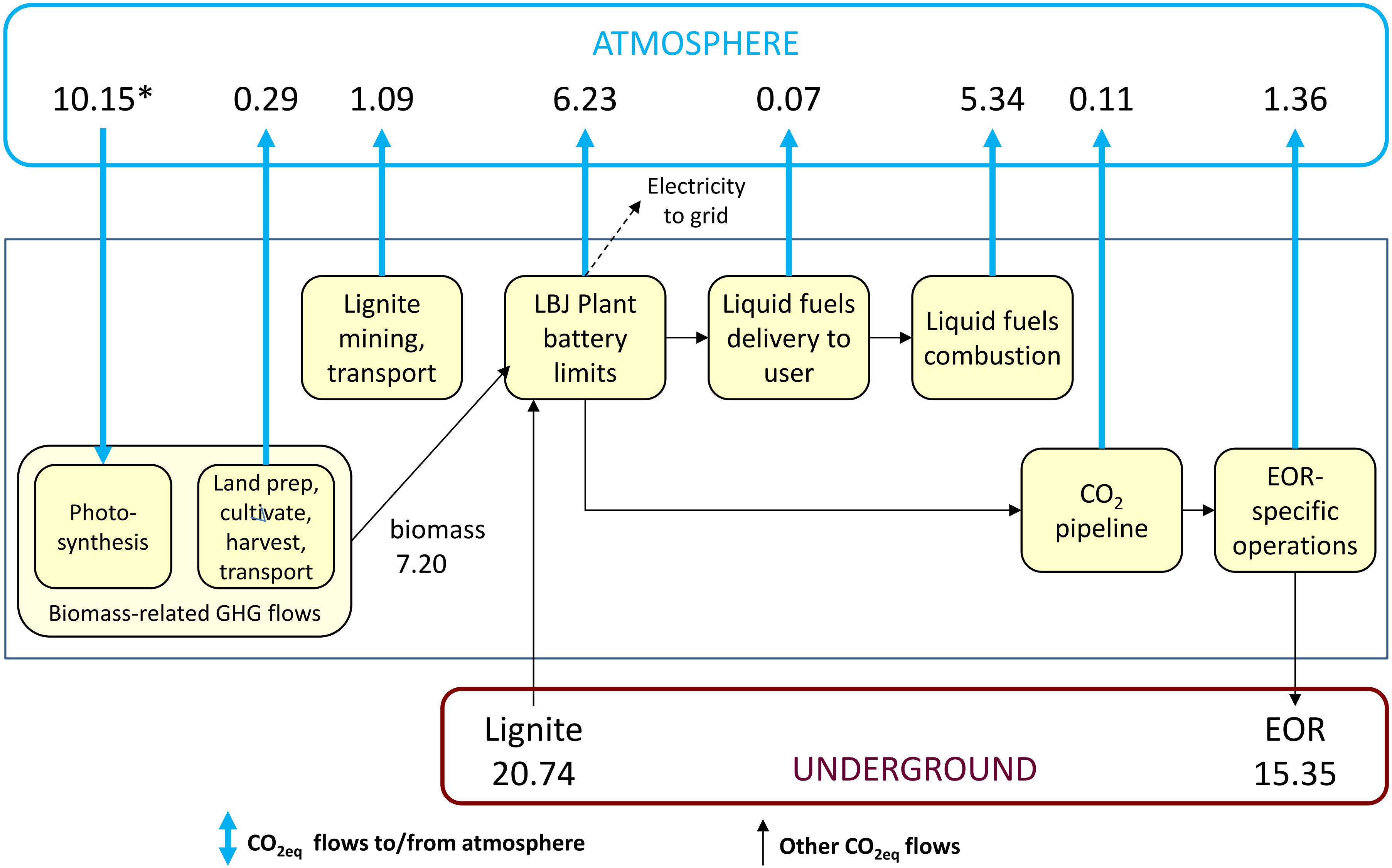
- T. Rooney and E. Gray, 2015. "Biomass Supply and Biogenic Carbon Impacts Evaluation for Lignite-Biomass to Jet Fuel Project, Final Report," Antares Group Inc., 9 January 2016.
- Also, T. Rooney, A. Schmidt, and E. Gray (Antares Group) presentation to Southern Company Services and Princeton LBJ project team members on 26 July 2016.

Milestone 4 Report:
Summary of Financial Analysis for FOAK LBJ Plant and Prospective NOAK Commercial Plants

# 3.3. GREENHOUSE GAS EMISSIONS

# LBJ System-Wide Greenhouse Gas Flows

average $kgCO_{2eq}$ /second




* Assuming Region 2 (AL, MS) medium scenario value of the Biomass Accounting Factor ( = - 0.41, as discussed in later slides)

# Biomass Greenhouse Gas Emissions Accounting

- Using plantation-grown pulpwood logs for the LBJ plant poses a carbon accounting challenge. When a log is harvested and used for energy, its carbon returns to the atmosphere over a relatively short period of time (leaving aside for the moment the complication that some $CO_2$ is captured at the LBJ plant), while a tree planted to replace the harvested tree requires a much longer time to reabsorb an equal amount of carbon from the atmosphere. To understand whether using the pulpwood log for the LBJ plant results in a net carbon benefit to the atmosphere or not requires answering the question: Would emissions over time have been higher or lower without the LBJ project? The answer depends on what would have happened without the LBJ project, i.e., on what is the business-as-usual or counterfactual scenario.
- Answering this question is at the heart of a framework proposed by the U.S. Environmental Protection Agency for carbon accounting for biomass power plants.* Antares adopted the framework to estimate GHG emissions associated with pulpwood logs as feedstock for the LBJ plant.
- Antares explains their assumption for BAU: **

  *The logical comparison of carbon impacts for the LBJ project is between a base case wherein the current end uses and methods are employed for the production of wood on managed forest land if the LBJ project did not exist and the case including the additional production of biomass feedstocks for the LBJ facility. The definition of the base, or business as usual (BAU), case for the LBJ project requires correctly characterizing the resource base from which the project would procure feedstocks. The LBJ project would procure wood from land that will be sustainably managed for wood harvests and has been actively managed for wood production for decades. Thinning operations on planted southern yellow pine forests would remove wood for the LBJ project from forest land well along in the production cycle that has been purposely cultivated for wood production, in contrast to forest land that is permitted to grow wild and unattended with no plan for harvesting.*

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* EPA, *Framework for Assessing Biogenic $CO_2$ Emissions from Stationary Sources*, November 2014. (Expected to be finalized in time for implementation of the EPA Clean Power Plan rules.) http://www3.epa.gov/climatechange/downloads/Framework-for-Assessing-Biogenic-CO2-Emissions.pdf.

** T. Rooney and E. Gray, "Biomass Supply and Biogenic Carbon Impacts Evaluation for Lignite-Biomass to Jet Fuel Project, Final Report," Antares Group Inc., Jan. 9, 2016.

# Forest Biomass Resources in the LBJ Plant Region

- Southern forests cover about 200 million acres, or 40% of the land area of the 13 states that make up the US Forest Service 'Southern Region'.
  - 27% of forest acreage is owned by large private companies, including Timberland Investment Management Organizations (TIMOs), Timber Real Estate Investment Trusts (TREITs), and forest product companies. These entities typically fertilize and thin stands to increase final saw timber and pulpwood yield (25-year rotation). Thinning (typically done at 15 years) produces pulpwood quality stems.
  - 57% of forest acreage is family forests (non-industrial private forests, NIPF). These owners tend to rely on state forestry program assistance to better manage their holdings, but typically do not fertilize or thin during 25-year rotations, after which stands are clear cut to yield saw timber and pulpwood.
- NIPFs make up 70% of forest acreage in Mississippi, with a similar percentage in Alabama. Antares estimates that at least half of the NIPF acres in Mississippi (and in Alabama?) would be amenable to the type of forest management improvement strategy proposed for the LBJ project.
- Most NIPF owners in the South today do not thin (or fertilize) over a 25-yr rotation. Clear cutting the stand after 25 years produces saw timber and pulpwood. This constitutes the counterfactual (or business-as-usual, BAU) scenario used in comparing the net GHG emissions impact of the LBJ biomass supply scenario, which involves forest management improvement, as discussed later in this report.

# Tree-Growth Data Processing Using County Level Inputs from Forest Inventory Analysis (FIA)

FIA data elements (cubic feet) → Process Data → Results (tons)

**Annual Growth** (1)
- Species (2)
- Size(DBH) (3)
- Regen Type (4)
- Age (5)

**Annual Removals**
- Species
- Size(DBH)
- Regen Type
- Age

Parse location; add null counties; lookup FIPS; convert symbols to zero.

Apply density factors; compute growth minus removals.

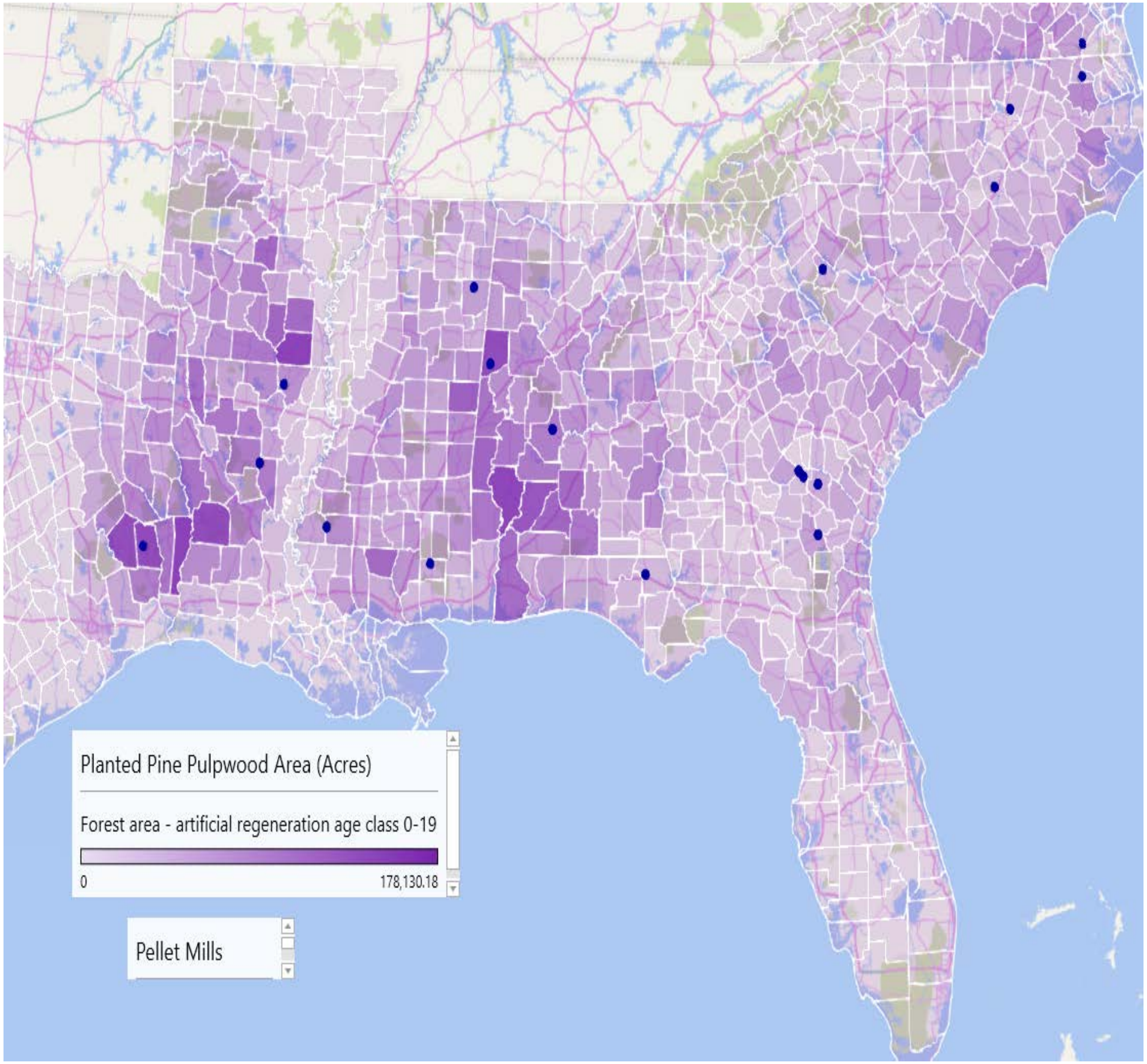
**Net Growth**
- Species
- Size(DBH)
- Regen Type
- Age

---

1. Average annual net growth of live trees, on timberland. 2. Pine (Shortleaf/loblolly and longleaf/slash), Hardwood. 3. At least 5 inches dbh/drc. 4. Regeneration types: Natural and Artificial (Planted Pine). 5. Age class from 1 to 19 years

* This slide and next few slides are based on a presentation by T. Rooney, A. Schmidt, and E. Gray (Antares Group) to LBJ project team members on 26 July 2016.

# Planted Pine Acreage (Age Class 0 to 19 years) by County in the Southeast Region



# Biomass Supply Scenarios for Carbon Accounting*

**High Scenario**

- Management changes include improved planting stock, thinning, fertilization after thinning, and active control of competing vegetation . (Net 80% increase in above-ground biomass over 25-year rotation.)
- 75% of landowners apply increased management practices

**Medium Scenario**

- Management changes include improved planting stock, thinning, and fertilization after thinning. (Net 55% increase in above-ground biomass over 25-year rotation.)
- 50% of landowners apply increased management practices

**Low Scenario**

- Management changes limited to thinning and fertilization after thinning.
- 25% of landowners apply increased management practices

| Scenario >>> | Low | Medium | High |
|---|---|---|---|
| Growth increases by management option | | | |
| Improved planting stock | 0% | 33% | 33% |
| Fertilization & thinning | 22% | 22% | 22% |
| Improved competing vegetation mgmt. | 0% | 0% | 25% |
| **Total due to intensified management practices** | 22% | 55% | 80% |
| **Fraction of landowners participating** | **25%** | **50%** | **75%** |

* T. Rooney, A. Schmidt, and E. Gray (Antares Group) presentation to LBJ project team members, 26 July 2016.

# EPA's Biomass Accounting Factor (BAF)

- EPA defines BAF as a factor used to calculate net biogenic emissions for biomass burning power plants. The EPA framework has in mind biomass power generation without CCS, and net biogenic emissions for this situation are calculated as BAF x stack $CO_2$ emissions originating from carbon in biomass. However, BAF itself is calculated without regard to how the biomass carbon is used, i.e., BAF characterizes the emissions from/to the landscape from which the biomass originated.
- In the LBJ case, not all carbon input to the plant as biomass goes out the stack – some is captured and some leaves in liquid products – so we apply BAF as follows to calculate the net landscape emissions: $GHG_{landscape} = C_{input} \times (BAF – 1)$, where $GHG_{landscape}$ are the net emissions that occur in the LBJ scenario relative to the BAU scenario (including photosynthesis as a negative emission), and $C_{input}$ is the amount of carbon in the biomass delivered to the LBJ plant.

$BAF > 1.0$ ➔ net biogenic $CO_{2e}$ emissions have magnitude greater than the amount of biomass $CO_{2eq}$ input to LBJ.

$0 < BAF < 1.0$ ➔ net biogenic $CO_{2e}$ emissions are positive, but with magnitude lower than the amount of biomass $CO_{2eq}$ input to LBJ.

$BAF = 0$ ➔ net biogenic $CO_{2eq}$ emissions are zero, i.e., the amount of $CO_{2eq}$ extracted from atmosphere equals amount of biomass $CO_{2eq}$ input to LBJ.

$BAF < 0$ ➔ net biogenic $CO_{2eq}$ emissions are negative, i.e., photosynthesis removes more $CO_2$ from atmosphere than the amount of biomass $CO_{2eq}$ input to LBJ.

# Calculated BAF Values *

| BAF (including $N_2O$ from fertilizer) for three scenarios | | | |
|---|---|---|---|
| For pine plantation thinnings | **Low** | **Medium** | **High** |
| **Region 1: AR, LA, TX** | **- 0.48** | **- 0.53** | **- 0.56** |
| **Region 2: AL, MS** | **- 0.08** | **- 0.41** | **- 0.67** |
| **Region 3: VA, NC, SC, GA** | **- 0.85** | **- 1.59** | **- 2.17** |
| **Region 4: FL** | **- 1.17** | **- 2.43** | **- 3.39** |
| **Southeast region average** | **- 0.57** | **- 1.06** | **- 1.43** |
| For residues (SE average)** | - 0.77 | | |

* T. Rooney, A. Schmidt, and E. Gray (Antares Group) presentation to LBJ project team members, 26 July 2016. Details of the BAF calculations will be available in the final report for this project.

** The BAU scenario for residues is that they are left on the ground to decompose, as is widely practiced on pine plantations in the SE region today.

# Greenhouse Gas Emission Metrics

Two metrics are calculated to characterize the lifecycle GHG emissions for the LBJ system:

1. Allocate a portion of system-wide LBJ lifecycle emissions to the electricity and naphtha coproducts based on emissions these coproducts displace:

$$SPK\ emissions\ \left(\frac{kgCO_{2e}}{GJ_{SPK,LHV}}\right) = \frac{System\text{-}wide\ LBJ\ emissions\ -\ electricity\ emissions - \ naphtha\ emissions}{Energy\ content\ of\ SPK}$$

Electricity-allocated emissions are taken to be 661 $kgCO_{2e}$/MWh, the estimated U.S. grid average in 2005. Naphtha-allocated emissions are taken to be 91.4 $kgCO_{2e}/GJ_{LHV}$, the estimate of lifecycle emissions for petroleum-derived gasoline.* The resulting SPK emissions can be compared against reference values, e.g., lifecycle emissions for equivalent petroleum-derived jet fuel (88.3 $kgCO2e/GJ_{LHV}$), to quantify extent of GHG emissions reduction.

2. Alternatively, calculate a "Greenhouse Gas Emissions Index" (GHGI**)**:

$$GHGI_{2005} = \frac{System\text{-}wide\ LBJ\ emissions}{Reference\ system\ lifecycle\ emissions\ (2005\ reference\ year)}$$

– The reference system is defined to include average 2005 U.S. emissions for an equivalent mix of petroleum-derived jet and naphtha (90.7 $kgCO_{2e}/GJ_{FTL,LHV}$) and grid electricity (661 $kgCO_{2e}$/MWh).

– $GHGI_{2005}$ measures LBJ emissions against U.S. average emissions for the equivalent product mix in 2005, the year against which US national carbon mitigation goals are measured.

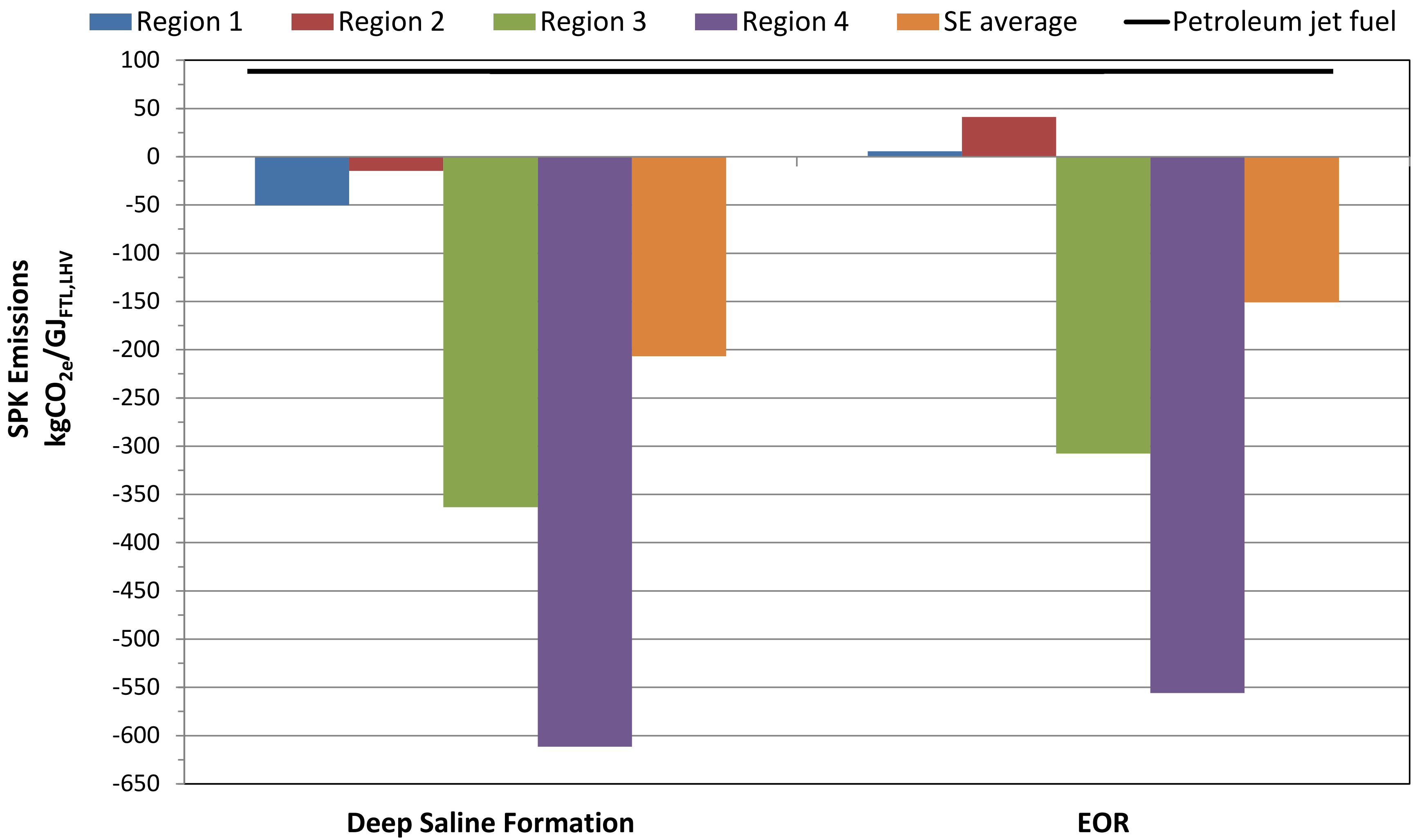
– For GHGI < 1, the LBJ system provides emissions reductions relative to the equivalent 2005 product mix.

* T. Skone and K. Gerdes, 2009. "Petroleum-Based Fuels Life Cycle Greenhouse Gas Analysis - 2005 Baseline Model," NETL.

# SPK Lifecycle GHG Emissions

for two $CO_2$ storage options (Medium Scenario for biomass production)

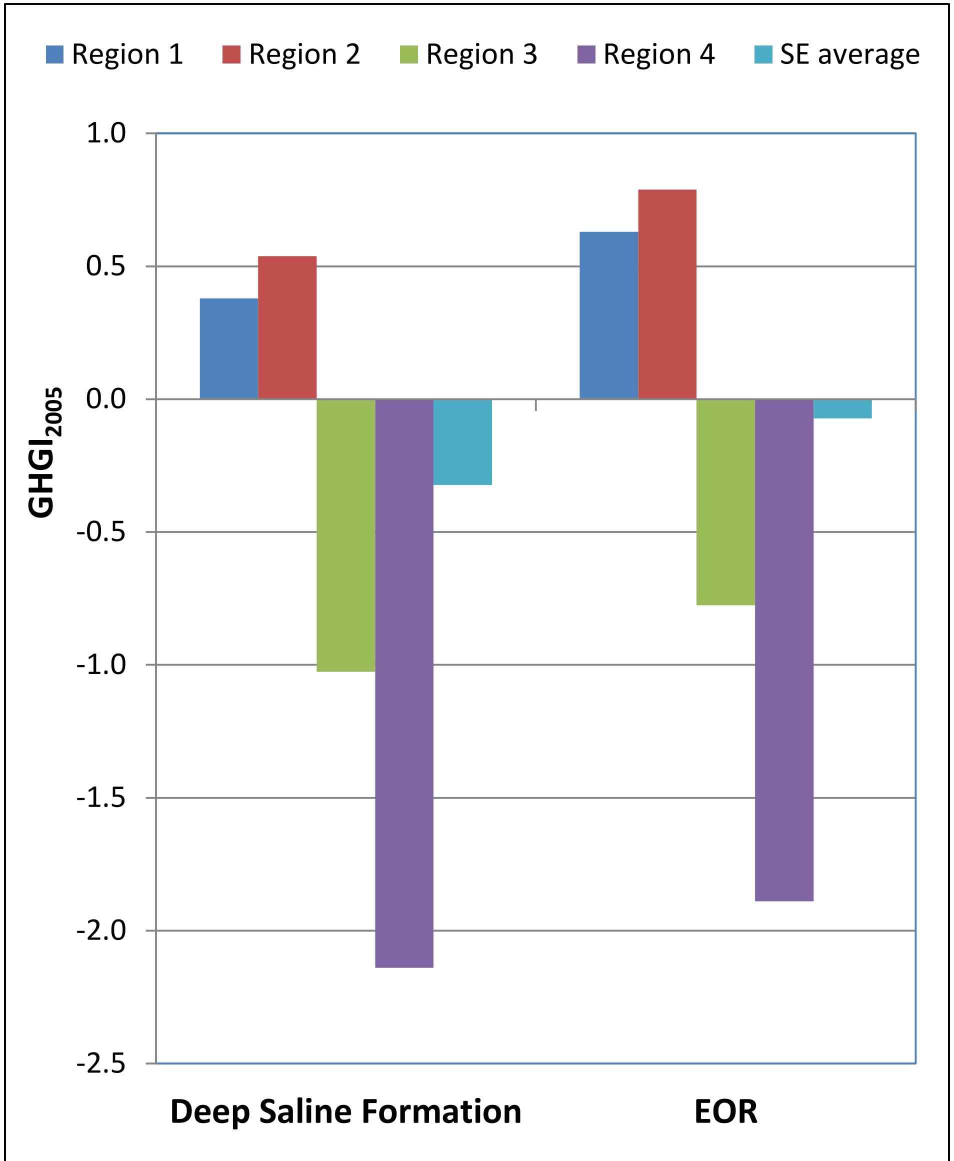
**Net lifecycle emissions for the synthetic jet fuel SPK, are about half those for petroleum-derived jet fuel**




Emissions allocated to co-product electricity = avoided grid emissions: 661 $kgCO_{2e}$/MWh.
Emissions allocated to co-product naphtha represented by avoided emissions from petroleum-derived gasoline: 91.4 $kgCO_{2e}/GJ_{LHV}$.

# $GHGI_{2005}$

## for two $CO_2$ storage options (Medium Scenario for biomass production)




In the medium scenario, with $CO_2$ stored underground via enhanced oil recovery, lifecycle emissions for combined liquid fuels and electricity supply by LBJ are reduced by about 20% ($GHGI_{2005}$ = 0.78) in Region 2, which includes AL and MS. For the weighted-average biomass supply situation in the Southeast, lifecycle emissions are essentially zero ($GHGI_{2005}$ = - 0.07).

| GHG Flows, EOR case (kg$CO_{2e}$/sec) | | | | | |
|---|---|---|---|---|---|
| **LBJ System (Medium Scenario for BAF)** | | | | | |
| **Region >>>** | **1** | **2** | **3** | **4** | **SE Avg** |
| Upstream lignite | 1.09 | 1.09 | 1.09 | 1.09 | 1.09 |
| Upstream biomass | 0.29 | 0.29 | 0.29 | 0.29 | 0.29 |
| Biogenic plant em | 1.61 | 1.61 | 1.61 | 1.61 | 1.61 |
| Lignite-origin plant em | 4.62 | 4.62 | 4.62 | 4.62 | 4.62 |
| Fuel transport to user | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 |
| Fuel combustion | 5.34 | 5.34 | 5.34 | 5.34 | 5.34 |
| $CO_2$ pipeline operation | 0.11 | 0.11 | 0.11 | 0.11 | 0.11 |
| EOR operations | 1.36 | 1.36 | 1.36 | 1.36 | 1.36 |
| Landscape emissions | - 11.02 | - 10.15 | - 18.65 | - 24.70 | - 14.84 |
| **Net LBJ emissions** | **3.42** | **4.29** | **- 4.21** | **- 10.26** | **- 0.40** |
| **2005 Reference System** | | | | | |
| Liquids | 2.71 | 2.71 | 2.71 | 2.71 | 2.71 |
| Electricity | 2.78 | 2.78 | 2.78 | 2.78 | 2.78 |
| **Total reference system** | **5.49** | **5.49** | **5.49** | **5.49** | **5.49** |
| **GHGI >>>** | **0.62** | **0.78** | **- 0.77** | **- 1.87** | **- 0.07** |

# GHG emissions estimate sources

- Biomass
  - Pine plantations land prep, cultivation (excl. any fertilization), harvest, delivery [1]
  - Photosynthesis, fertilizer and land use change impacts (incremental to BAU) [2]
- Lignite mining and delivery [3]
- LBJ plant emissions (Princeton/Worley Parsons process simulation)
- Liquid fuels delivery to user [4]
- Liquid fuels combustion (Princeton/Worley Parsons process simulation)
- $CO_2$ pipeline transport to EOR user [1]
- EOR operations (incremental to crude oil production emissions) [1, 4]
- Average U.S. grid emissions in 2005: Princeton estimate based on EPA and EIA data.

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[1] T.J. Skone, *et al.*, 2014. "Comprehensive Analysis of Coal and Biomass Conversion to Jet Fuel: Oxygen Blown, Transport Reactor Integrated Gasifier (TRIG) and Fischer-Tropsch (F-T) Catalyst Configurations," DOE/NETL-2012/1563, NETL, February.

[2] T. Rooney, A. Schmidt, and E. Gray (Antares Group) presentation to LBJ project team members, 26 July 2016.

[3] P. Pietro, 2010. "Life Cycle Analysis of Coal and Natural Gas-fired Power Plants," ppt at EPRI Coal Fleet, July 20.

[4] T. Skone and K. Gerdes, 2009. "Petroleum-Based Fuels Life Cycle Greenhouse Gas Analysis - 2005 Baseline Model," NETL.

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# 3.4. CAPITAL AND O&M COSTS

# WorleyParson's Capex Estimation Basis (1)

**Bare erected costs (BEC) and total plant cost (TPC)**

- BEC includes the cost of equipment and its delivery to the site, construction materials and the associated installation labour (direct and indirect). TPC includes BEC plus the cost of Engineering, Design, and Construction Management (EPCM) Services and both process and project contingencies. Owner's costs are excluded.
- BEC is based on equipment and processes that are representative of mature commercial technologies. TPC encompasses integration of these technologies into a first-of-a-kind (FOAK) plant.`
- Costs are "overnight" costs in U.S. dollars for mid-2015.
- Cost estimate boundary limit is the facility's "fence line," including lignite and wood receiving and water supply system. $CO_2$ transmission and electric utility connections within the fence line are included. The existing Plant Sweatt switchyard will be re-used. No new switchyard or switchyard modifications are included. The project site will be furnished in a clean, level condition.

**Equipment and material pricing**

- Vendor quotations were received for the following major subsystems and components and adjusted as required to include freight to site, vendor technical direction during installation, incomplete or missing scope items, and/or changes in capacity, as well conversion to U.S. dollars:

  Air separation unit (AIR PRODUCTS); Biomass preparation & drying (BRUKS); Lignite drying (ANDRITZ); Rectisol unit (AIR LIQUIDE); Pressure swing adsorption unit (AIR LIQUIDE); $CO_2$ compressor (DRESSER RAND); Fischer-Tropsch synthesis and upgrading units (EMERGING FUELS TECHNOLOGY); Wet sulfuric acid unit (HALDOR TOPSOE); Gas turbine (SIEMENS); HRSC steam turbine (SIEMENS); Zero liquid discharge system (SUEZ)
- Lignite receiving and unloading costs were escalated and scaled from a quotation for a similar facility built in the region within the past few years.

# WorleyParson’s Capex Estimation Basis (2)

**Equipment and material pricing (continued)**

- TRIG gasifier, coal milling/drying/handling, and ash removal costs were initially developed by escalating and scaling a high-level budgetary quotation from a previous project. The initial costs were then reviewed with Southern Company Services and adjusted based on their recommendations.
- The balance of the cost accounts were estimated using WorleyParsons in-house database and conceptual estimating model. This database and model are maintained by WorleyParsons as part of a commercial power plant design base of experience for similar equipment, materials, and construction labor requirements in the company’s range of power and process projects.

**Labour Pricing**

- Installation labour cost is based on merit-shop rates for Mississippi and reflects a competitive bidding environment, with adequate skilled craft labour available locally.
- 50-hour work-week (five 10s), and no additional incentives such as per-diems or bonuses.
- The labour cost is considered all-inclusive, including: craft wages, burdens and benefits, payroll taxes and insurance, supervision, indirect craft, scaffolding, temporary facilities and utilities, field office, small tools and consumables, safety, mobilization/demobilization, construction rental equipment (with associated fuel, oil, and maintenance), contractors’ labour-related overhead and profit.

**Exclusions**

- The following items are excluded from the capital cost estimate: demolition/removal of existing facilities/structures, removal/remediation of hazardous or contaminated materials, removal/ relocation of underground obstructions, infrastructure external to plant boundary (e.g. $CO_2$ pipeline), all taxes except payroll taxes, and owner’s costs.

# WorleyParson’s Opex Estimation Basis

**Operation and Maintenance (O&M) Costs**

- O&M costs were estimated on a mid-2015 “overnight” cost basis consistent with the capital costs. The costs are presented on an average annual basis and do not include initial start-up costs. The O&M costs are split into fixed and variable. Fixed costs are independent of plant capacity factor. Variable costs are proportional to capacity factor. Annual property taxes & insurance are included as a fixed operating cost equal to 2% of TPC.
- Operating labour cost is based on the estimated staffing required by equipment area. The corresponding hours were converted to equivalent around-the-clock (24/7) operating jobs.
- Maintenance cost has been evaluated on the basis of relationships of maintenance cost to initial capital cost for similar equipment items and processes.
- Consumables (water, chemicals, catalysts) costs were determined on the basis of individual rates of consumption, the unit cost of each consumable, and the plant annual operating hours. The quantities for initial fills and daily consumables were calculated on a 100 percent operating capacity basis.
- Waste disposal costs were determined on the basis of individual consumption / production rates, the unit costs for each item and the plant annual operating hours.

# EPCM and Contingencies Estimates

- WorleyParsons developed the LBJ capital cost estimate on a bare-erected cost (BEC) basis. The total overnight plant cost (TPC) includes BEC plus allowances for EPCM and contingencies. The latter two were developed in discussions involving Princeton, Queensland, and WorleyParsons.
- **EPCM costs** are estimated as 20% of BEC. WorleyParsons would typically allow 10-15% of BEC for EPCM costs, but 20% reflects the FOAK nature of the project.
- Experience indicates that **contingency allowances** will be spent, but understanding where they will be spent requires more engineering work than has been done in this project. Moreover, historical experience* and evidence from recent pioneering projects, including coal-IGCC at Edwardsport, IN and Kemper County, MS, and post-combustion capture retrofit to a pulverized coal plant (Boundary Dam) support relatively high contingency allowances at this stage of the LBJ project.
  - **Process contingencies** are estimated as 40% of BEC, reflecting the commercial immaturity of the LBJ process. Projects using very mature technologies and processes, such as pulverised coal power plants, would attract no process contingency. Coal or biomass gasification based combined cycles number less than a dozen globally, and none have been integrated with CCS and FT liquids production, warranting the 40% level.
  - **Project contingency** is an allowance for errors and uncertainties in the cost estimate and the unknown items that have been overlooked in the estimate. Project contingencies cover *scope growth* that is likely as project definition improves; allowances for *cost changes* reflecting the lack of specific information at this early stage on procurement strategies and market conditions, and *contingency for events* that are statistically likely to occur, but not included in the base estimate (to cover such items as changes to the execution plan, 'normal' allowances for weather problems, labour problems, etc.). For this project and its stage of definition (estimated to be in the range of 1%), a Project Contingency of 40% is applied to BEC + EPCM + process contingency.
- In summary, $TPC_{FOAK}$ = BEC x (1 + 0.2 +0.4) x (1 + 0.4) = 2.24 x BEC.

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* See C. Greig, A. Garnett, J. Oesch, S. Smart, "Guidelines for Scoping and Estimating Early Mover CCS Projects," Milestone 5 Final Report, The University of Queensland, 19 June 2014 and
E.W. Merrow, K.E. Phillips, C.W. Myers, "Understanding Cost Growth and Performance Shortfalls in Pioneer Process Plants," for U.S. DOE (contract DE-AC01-79PE79978) by the Rand Corp., Santa Monica, CA, Sept. 1981

# Supplementary Funds Allowance

- For complex first-of-a-kind (FOAK) projects, an additional **supplementary funds** (SF) allowance at this early stage of project definition is prudent to cover risks of unforeseen events or outcomes that add to the most likely cost outcome ($TPC_{FOAK}$) estimated on the previous slide.* SF ultimately may not need to be spent, but technology performance, gross scope growth arising from local or market issues, regulatory changes, process integration challenges, slow plant ramp-up to full capacity, redesign and rectification requirements, or other issues may arise, and the project would be unable to proceed if SF are not available to address such issues. An SF allowance up to 40% of $TPC_{FOAK}$ would not be unreasonable at this stage of project development.
- $TPC_{FOAKw/SF} = 1.4 \times TPC_{FOAK} = 3.14 \times BEC$.
- Project economics are investigated without and with an SF allowance.

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* See C. Greig, A. Garnett, J. Oesch, S. Smart, "Guidelines for Scoping and Estimating Early Mover CCS Projects," Milestone 5 Final Report, The University of Queensland, 19 June 2014.

# LBJ Plant Capex Estimate (1000 $)

| CAPEX ESTIMATE (1000s mid-2015 $) | Equipment | Material | Labor | Bare Erected |
|---|---|---|---|---|
| COAL & SORBENT HANDLING | 7,364 | 3,682 | 3,682 | 14,728 |
| COAL & BIOMASS PREP & FEED | 41,171 | 11,474 | 23,342 | 75,986 |
| FEEDWATER & MISC. BOP SYSTEMS | 7,935 | 4,370 | 7,022 | 19,327 |
| GASIFIER & ACCESSORIES | 63,065 | 35,975 | 50,352 | 149,392 |
| GAS CLEANUP & PIPING, including AGR | 110,239 | 2,615 | 4,052 | 116,907 |
| F-T SYNTHESIS AND PRODUCT UPGRADE | 29,465 | 13,029 | 25,775 | 68,269 |
| CO2 COMPRESSION | 8,500 | 2,152 | 3,228 | 13,880 |
| COMBUSTION TURBINE/ACCESSORIES | 14,414 | 185 | 697 | 15,296 |
| HRSG, DUCTING & STACK | 4,190 | 111 | 899 | 5,200 |
| STEAM TURBINE GENERATOR | 12,776 | 1,455 | 3,787 | 18,018 |
| COOLING WATER SYSTEM | 2,791 | 5,469 | 4,386 | 12,646 |
| ASH/SPENT SORBENT HANDLING SYS | 10,258 | 3,139 | 4,557 | 17,953 |
| ACCESSORY ELECTRIC PLANT | 7,157 | 6,058 | 12,315 | 25,529 |
| INSTRUMENTATION & CONTROL | 5,719 | 1,171 | 4,521 | 11,411 |
| IMPROVEMENTS TO SITE | 3,451 | 2,034 | 10,020 | 15,506 |
| BUILDINGS & STRUCTURES | - | 3,423 | 4,134 | 7,556 |
| **TOTALS** | **328,495** | **96,339** | **162,769** | **587,603** |

| | |
|---|---|
| Bare Erected Cost | 587,603 |
| Engineering, Procurement, & Construction Mgmt | 117,521 |
| Process Contingencies | 235,041 |
| Project Contingencies | 376,066 |
| **Base Case Total Plant Cost ($TPC_{FOAK}$)** | **1,316,230** |
| **TPC + Supplemental Funds ($TPC_{FOAKw/SF}$)** | **1,842,722** |

# LBJ Plant O&M Cost Estimate

OPERATING & MAINTENANCE LABOR

Operating Labor

| | | |
|---|---|---|
| Operating Labor Rate(base): | 45.60 | $/hour |
| Operating Labor Burden: | 30.00 | % of base |
| Labor O-H Charge Rate: | 25.00 | % of labor |

| | |
|---|---|
| Skilled Operator | 5.0 |
| Operator | 9.5 |
| Foreman | incl |
| Lab Tech's, etc. | 6.5 |
| TOTAL-O.J.'s (equiv 24/7) | 21.0 |

| | Annual Cost $ |
|---|---|
| Annual Operating Labor Cost | $10,905,149 |
| Maintenance Labor Cost | $7,048,746 |
| Administrative & Support Labor | $4,488,474 |
| Property Taxes and Insurance (at 2% of TPC) | $26,324,604 |
| **TOTAL FIXED OPERATING COSTS** | **$48,766,972** |

VARIABLE OPERATING COSTS

| | |
|---|---|
| **Maintenance Material Cost** | **$12,612,129** |

| Consumables | Consumption Initial Fill | Consumption /Day | Unit Cost | Initial Fill Cost | |
|---|---|---|---|---|---|
| **Water (/1000 gallons)** | 0 | 860 | 0.00 | **$0** | **$0** |
| **Chemicals** | | | | | |
| MU & WT Chem. (lb) | 0 | 5,121.7 | 0.27 | $0 | $400,565 |
| Carbon (Mercury Removal) (lb) | 12,585 | 17.2 | 1.63 | $20,454 | $8,176 |
| Water Gas Shift Guard Catalyst (ft3) | 248 | 0.2 | 452.00 | $112,061 | $22,389 |
| Water Gas Shift Catalyst (ft3) | 744 | 0.5 | 600.00 | $446,400 | $89,219 |
| Methanol (gal) | 19,402 | 467.0 | 1.00 | $19,402 | $136,364 |
| WSA Catalyst (ft3) | 2,400 | 0.8 | 208.33 | $500,000 | $49,966 |
| SCR Catalyst (ft3) - WSA | w/ equip | 0.0 | 8,938.80 | $0 | $126,610 |
| SCR Catalyst (ft3) - HRSG | w/ equip | 0.2 | 8,938.80 | $0 | $624,014 |
| Aqueous Ammonia (ton) - WSA | 99 | 1.2 | 330.00 | $32,573 | $114,136 |
| Aqueous Ammonia (ton) - HRSG | 84 | 1.0 | 330.00 | $27,849 | $97,582 |
| F-T Reactor Catalyst (lb) | 90,459 | 123.8 | 30.00 | $2,713,768 | $1,084,764 |
| F-T Hydrocracking Catalyst (lb) | 19,628 | 10.7 | 15.00 | $294,422 | $47,075 |
| **Subtotal Chemicals** | | | | **$4,166,928** | **$2,800,859** |
| **Other** | | | | | |
| Supplemental Fuel (MBtu) - Nat Gas | 0 | 208.2 | 3.00 | $0 | $182,377 |
| Supplemental Fuel (MBtu) - #2 Fuel Oil | 6,048 | 17.1 | 3.00 | $18,144 | $15,023 |
| Gases,N2 etc. (/100scf) | 0 | 0.0 | 0.00 | $0 | $0 |
| **Subtotal Other** | | | | **$18,144** | **$197,400** |
| **Waste Disposal** | | | | | |
| Spent Catalyst - Mercury (lb) | | 17.2 | 0.65 | $0 | $3,270 |
| Spent Catalyst - WGS (ft3) | | 0.7 | 0.00 | $0 | $0 |
| Spent Catalyst - WSA (ft3) | | 0.8 | 0.00 | $0 | $0 |
| Spent Catalyst - SCR (ft3) | | 0.3 | 0.00 | $0 | $0 |
| Spent Catalyst - F-T (lb) | | 134.6 | 0.00 | $0 | $0 |
| Ash (ton) | | 197.6 | 25.11 | $0 | $1,448,939 |
| **Subtotal Waste Disposal** | | | | **$0** | **$1,452,210** |
| **TOTAL NON-FEEDSTOCK VARIABLE OPERATING COSTS** | | | | **$4,185,072** | **$17,062,598** |

$0.47/bbl FTL

Milestone 4 Report:
Summary of Financial Analysis for FOAK LBJ Plant and Prospective NOAK Commercial Plants

# 3.5. FINANCIAL ANALYSIS

# Discounted Cash Flow NPV Analysis (1)

## Assumptions for all scenarios

- 2020 plant startup; no construction cost escalation; 20-yr operating life; 85% capacity factor after ramp-up period; GHG accounting uses BAF for medium scenario in Region 2 (see slide 41).
- After-tax weighted average cost of capital = 5% nominal (1.9% real, assuming 3% inflation).* A modest WACC is appropriate for LBJ evaluation, because of the expectation that subsidies will be required for positive economics.
- 15-year MACRS depreciation schedule, 38% tax rate (combined federal + state)
- Grid electricity displaced assumed to have 661 $kgCO_{2eq}$/MWh lifecycle GHG emissions (U.S. average in 2005).
- In the presence of a GHG emissions price, the plant operator
  - pays for the lifecycle emissions associated with production and consumption of its products.
  - is paid prices for its products that include a base price plus the value of GHG emissions associated with the lifecycle of products displaced (petroleum-derived liquids and grid electricity).
- GTCC operates on natural gas when FT synthesis plant is not operating

## Base Case levelized prices (2015$) over project lifetime

| | | |
|---|---|---|
| Inputs | | |
| Lignite, delivered | $/GJ_{HHV}$ | 2.6 |
| Biomass, delivered | $/GJ_{HHV}$ | 2.9 |
| Natural gas | $/GJ_{HHV}$ | 5.0 |
| Outputs | | |
| SPK at plant gate | $/bbl | 94 |
| Naphtha at plant gate | $/bbl | 90 |
| Electricity to grid | $/MWh | 70 |
| EOR-$CO_2$ at plant gate** | $/tonne | 26 |
| Sulfuric acid, plant gate | $/tonne | 131 |
| Other prices | | |
| Crude oil | $/bbl | 80 |
| GHG emissions | $/tonne $CO_{2eq}$ | 75 |

## Base Case plant-availability ramp rate

- 50% in year 1, and 70%, 85%, 95%, and 100% in following years.

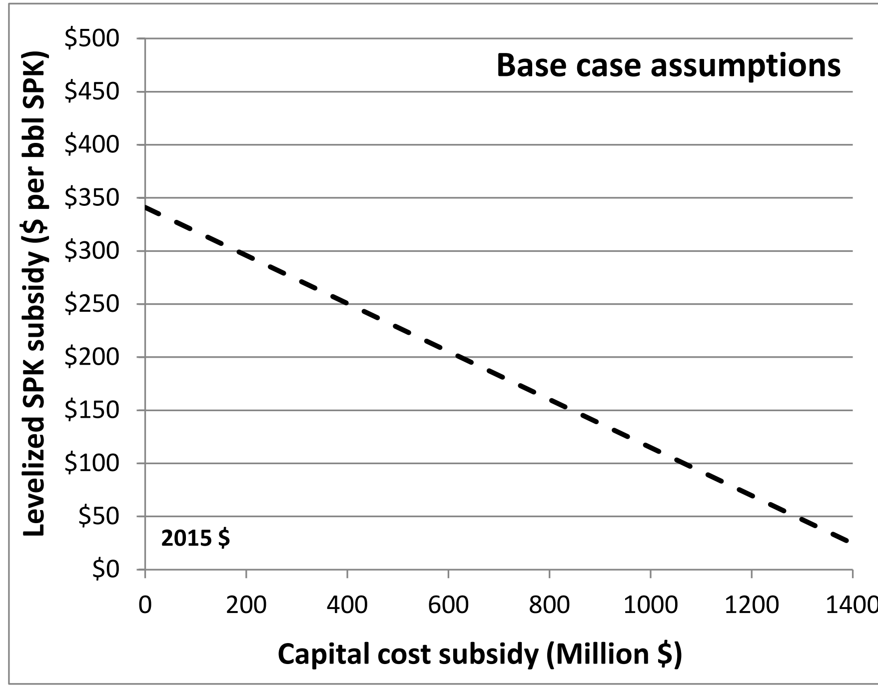
**Notes:**

* For comparison, some recent corporate WACCs (nominal): Southern Co., 2.6%; Con. Edison, 2.8%; Duke Energy, 3%; PGE, 3.5%; PSEG, 4%; NRG, 7.1% ; BP, 7%; ExxonMobil, 7.8%; Shell, 8.1%; Chevron, 9.6%. (downloaded from www.gurufocus.com 11 June 2016.)

** According to Rubin, Davison, and Herzog ("The cost of $CO_2$ capture and storage," *Int. J GHG Control*, **40**: 378-400, 2015), "…conventional wisdom suggests that the price that EOR projects can afford to pay for $CO_2$ (in $/thousand standard cubic feet) is 2% of the oil price in $/bbl." We have assumed this price at the oil field and $5/t as the cost of transporting the $CO_2$ to the field. Thus, for an oil price of $80/bbl, the $CO_2$ price is (80 x 0.02 x 19.3 – 5) = 25.9 $/t

# Discounted Cash Flow NPV Analysis (2)

- As anticipated for this complex FOAK demonstration project, positive cash flows cannot be generated without subsidies.
- A capital subsidy in excess of the plant's TPC or a production subsidy of $350 per barrel of SPK would enable a zero NPV to be achieved.
- Various combinations of capital and production subsidies would also give zero NPV, as shown on the graph to the right.
- The sensitivity of the economics to key input assumptions were investigated (next slide).



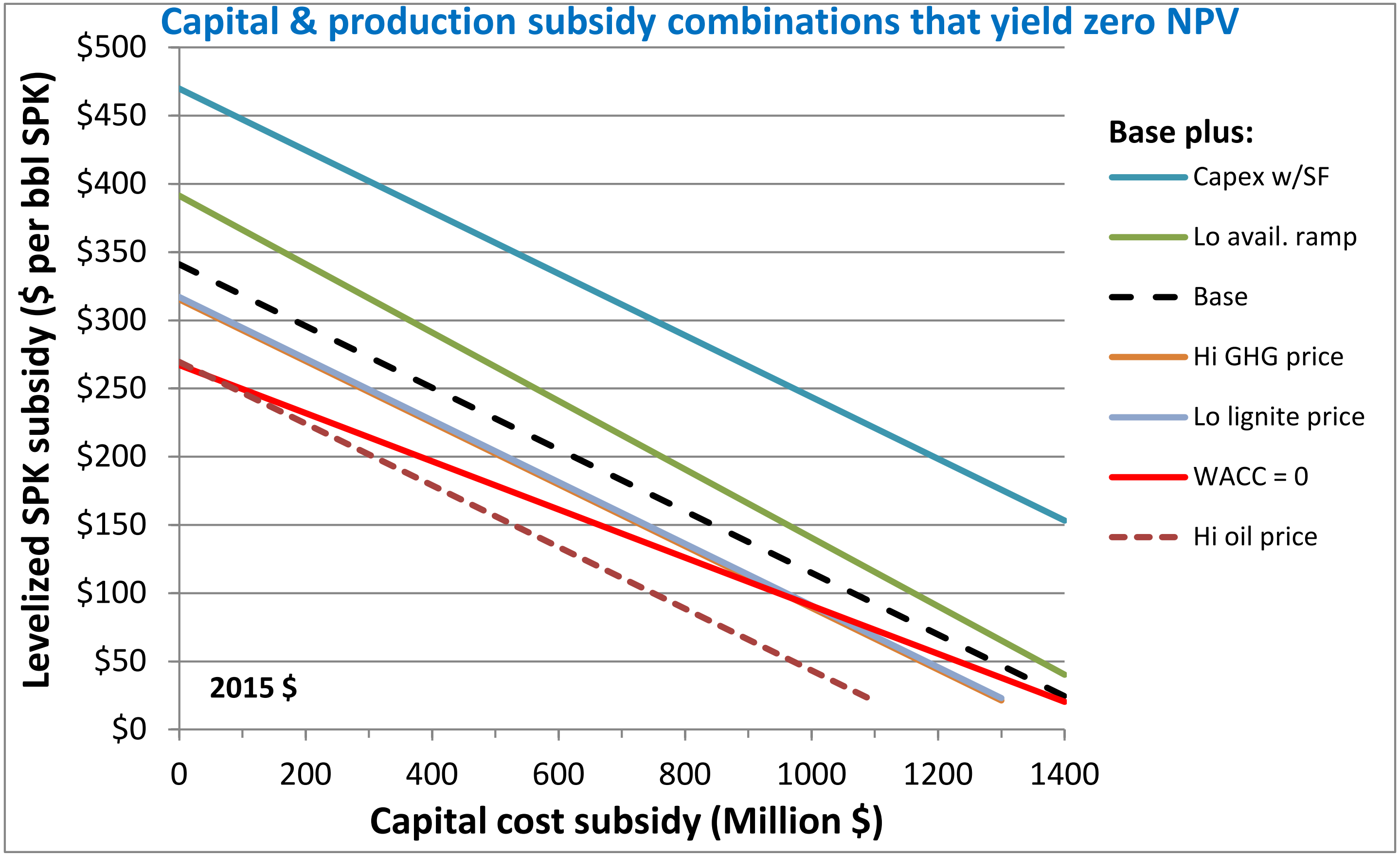

Illustrative cash flows. (Base case without capital grant, but with SPK production cost subsidy.)

| CASH FLOWS | | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Sales Revenue** | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Electricity Revenue (LBJ) | $'000 | | | | | $ 7,746 | $ 11,139 | $ 13,932 | $ 16,038 | $ 17,436 | $ 17,910 | $ 18,447 | $ 19,001 | $ 19,624 | $ 20,158 | $ 20,763 | $ 21,385 | $ 22,027 | $ 22,688 | $ 23,368 | $ 24,069 | $ 24,792 | $ 25,535 | $ 26,301 | $ 27,090 | $ 27,903 |
| Electricity Capacity Payments | $'000 | | | | | $ 159 | $ 163 | $ 168 | $ 173 | $ 179 | $ 184 | $ 189 | $ 195 | $ 202 | $ 207 | $ 213 | $ 220 | $ 226 | $ 233 | $ 240 | $ 247 | $ 255 | $ 262 | $ 270 | $ 278 | $ 287 |
| Electricity Revenue (NGCC) | $'000 | | | | | $ 13,718 | $ 8,455 | $ 4,354 | $ 1,495 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| SPK Revenue | $'000 | | | | | $ 23,915 | $ 34,391 | $ 43,013 | $ 49,515 | $ 53,832 | $ 55,296 | $ 56,955 | $ 58,663 | $ 60,589 | $ 62,236 | $ 64,103 | $ 66,026 | $ 68,007 | $ 70,047 | $ 72,148 | $ 74,313 | $ 76,542 | $ 78,838 | $ 81,204 | $ 83,640 | $ 86,149 |
| Naphtha Revenue | $'000 | | | | | $ 5,642 | $ 8,114 | $ 10,148 | $ 11,683 | $ 12,701 | $ 13,046 | $ 13,438 | $ 13,841 | $ 14,295 | $ 14,684 | $ 15,124 | $ 15,578 | $ 16,046 | $ 16,527 | $ 17,023 | $ 17,533 | $ 18,059 | $ 18,601 | $ 19,159 | $ 19,734 | $ 20,326 |
| Sulfuric Acid Revenue | $'000 | | | | | $ 1,057 | $ 1,521 | $ 1,902 | $ 2,189 | $ 2,380 | $ 2,445 | $ 2,518 | $ 2,594 | $ 2,679 | $ 2,752 | $ 2,834 | $ 2,919 | $ 3,007 | $ 3,097 | $ 3,190 | $ 3,286 | $ 3,384 | $ 3,486 | $ 3,591 | $ 3,698 | $ 3,809 |
| CO2 Revenue from EOR | $'000 | | | | | $ 6,137 | $ 8,825 | $ 11,037 | $ 12,706 | $ 13,813 | $ 14,189 | $ 14,615 | $ 15,053 | $ 15,547 | $ 15,970 | $ 16,449 | $ 16,942 | $ 17,451 | $ 17,974 | $ 18,513 | $ 19,069 | $ 19,641 | $ 20,230 | $ 20,837 | $ 21,462 | $ 22,106 |
| SPK Subsidy | $'000 | | | | | $ 4,294 | $ 6,174 | $ 7,722 | $ 8,890 | $ 9,665 | $ 9,928 | $ 10,225 | $ 10,532 | $ 10,878 | $ 11,174 | $ 11,509 | $ 11,854 | $ 12,210 | $ 12,576 | $ 12,953 | $ 13,342 | $ 13,742 | $ 14,154 | $ 14,579 | $ 15,016 | $ 15,467 |
| **Total Revenue** | $'000 | | | | | $ 62,668 | $ 78,782 | $ 92,277 | $ 102,689 | $ 110,007 | $ 112,998 | $ 116,387 | $ 119,879 | $ 123,814 | $ 127,180 | $ 130,995 | $ 134,925 | $ 138,973 | $ 143,142 | $ 147,436 | $ 151,859 | $ 156,415 | $ 161,107 | $ 165,941 | $ 170,919 | $ 176,046 |
| **Operating Costs** | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Lignite Expenditure | $'000 | | | | | $ 8,961 | $ 12,886 | $ 16,117 | $ 18,553 | $ 20,171 | $ 20,719 | $ 21,341 | $ 21,981 | $ 22,703 | $ 23,320 | $ 24,019 | $ 24,740 | $ 25,482 | $ 26,247 | $ 27,034 | $ 27,845 | $ 28,680 | $ 29,541 | $ 30,427 | $ 31,340 | $ 32,280 |
| Biomass Expenditure | $'000 | | | | | $ 3,217 | $ 4,627 | $ 5,787 | $ 6,661 | $ 7,242 | $ 7,439 | $ 7,662 | $ 7,892 | $ 8,151 | $ 8,373 | $ 8,624 | $ 8,882 | $ 9,149 | $ 9,423 | $ 9,706 | $ 9,997 | $ 10,297 | $ 10,606 | $ 10,924 | $ 11,252 | $ 11,590 |
| Natural Gas Expenditure | $'000 | | | | | $ 4,589 | $ 2,828 | $ 1,457 | $ 500 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Labour | $'000 | | | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Variable O&M | $'000 | | | | | $ 102 | $ 147 | $ 184 | $ 212 | $ 230 | $ 237 | $ 244 | $ 251 | $ 259 | $ 266 | $ 274 | $ 282 | $ 291 | $ 300 | $ 309 | $ 318 | $ 327 | $ 337 | $ 347 | $ 358 | $ 369 |
| Fixed O&M | $'000 | | | | | $ 54,888 | $ 56,534 | $ 58,230 | $ 59,977 | $ 61,777 | $ 63,630 | $ 65,539 | $ 67,505 | $ 69,530 | $ 71,616 | $ 73,764 | $ 75,977 | $ 78,257 | $ 80,604 | $ 83,023 | $ 85,513 | $ 88,079 | $ 90,721 | $ 93,443 | $ 96,246 | $ 99,133 |
| GHG Emissions charges (net LCA emissions) | $'000 | | | | | $ 9,007 | $ 9,926 | $ 10,745 | $ 11,425 | $ 11,985 | $ 12,311 | $ 12,680 | $ 13,060 | $ 13,489 | $ 13,856 | $ 14,271 | $ 14,700 | $ 15,140 | $ 15,595 | $ 16,063 | $ 16,544 | $ 17,041 | $ 17,552 | $ 18,079 | $ 18,621 | $ 19,180 |
| **Total Opex** | | | | | | $ 80,764 | $ 86,948 | $ 92,519 | $ 97,329 | $ 101,405 | $ 104,335 | $ 107,465 | $ 110,689 | $ 114,132 | $ 117,430 | $ 120,953 | $ 124,582 | $ 128,319 | $ 132,169 | $ 136,134 | $ 140,218 | $ 144,424 | $ 148,757 | $ 153,220 | $ 157,816 | $ 162,551 |
| **Net Cashflows $'000** | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Land | | | - | - | - | | | | | | | | | | | | | | | | | | | | | |
| FEED Study | | $0 | ($15,965) | ($4,774) | $0 | | | | | | | | | | | | | | | | | | | | | |
| Construction Costs | | $0 | $0 | ($465,463) | ($958,854) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Capital Subsidies (Grants) | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total capital costs | | $0 | ($15,965) | ($470,237) | ($958,854) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Sales Revenue | | $0 | $0 | $0 | $0 | $ 58,374 | $ 72,607 | $ 84,554 | $ 93,799 | $ 100,342 | $ 103,070 | $ 106,162 | $ 109,347 | $ 112,936 | $ 116,006 | $ 119,486 | $ 123,071 | $ 126,763 | $ 130,566 | $ 134,483 | $ 138,517 | $ 142,673 | $ 146,953 | $ 151,362 | $ 155,903 | $ 160,580 |
| Operating Costs | | $0 | $0 | $0 | $0 | ($80,764) | ($86,948) | ($92,519) | ($97,329) | ($101,405) | ($104,335) | ($107,465) | ($110,689) | ($114,132) | ($117,430) | ($120,953) | ($124,582) | ($128,319) | ($132,169) | ($136,134) | ($140,218) | ($144,424) | ($148,757) | ($153,220) | ($157,816) | ($162,551) |
| Operating Subsidies | | $0 | $0 | $0 | $0 | $4,294 | $6,174 | $7,722 | $8,890 | $9,665 | $9,928 | $10,225 | $10,532 | $10,878 | $11,174 | $11,509 | $11,854 | $12,210 | $12,576 | $12,953 | $13,342 | $13,742 | $14,154 | $14,579 | $15,016 | $15,467 |
| Operating Margin | | $0 | $0 | $0 | $0 | ($18,096) | ($8,167) | ($242) | $5,360 | $8,602 | $8,662 | $8,922 | $9,190 | $9,682 | $9,750 | $10,042 | $10,343 | $10,654 | $10,973 | $11,302 | $11,641 | $11,991 | $12,350 | $12,721 | $13,103 | $13,496 |
| Taxes paid | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($4,693) | ($4,834) | ($4,979) | ($5,128) |
| Cashflow from operations | | $0 | $0 | $0 | $0 | ($18,096) | ($8,167) | ($242) | $5,360 | $8,602 | $8,662 | $8,922 | $9,190 | $9,682 | $9,750 | $10,042 | $10,343 | $10,654 | $10,973 | $11,302 | $11,641 | $11,991 | $7,657 | $7,887 | $8,124 | $8,367 |
| **Net Cashflow (nominal after tax)** | | $0 | ($15,965) | ($470,237) | ($958,854) | ($18,096) | ($8,167) | ($242) | $5,360 | $8,602 | $8,662 | $8,922 | $9,190 | $9,682 | $9,750 | $10,042 | $10,343 | $10,654 | $10,973 | $11,302 | $11,641 | $11,991 | $7,657 | $7,887 | $8,124 | $8,367 |
| **Net Cashflow (real after tax)** | | $0 | ($15,500) | ($443,243) | ($877,487) | ($16,078) | ($7,045) | ($203) | $4,358 | $6,791 | $6,639 | $6,639 | $6,639 | $6,791 | $6,639 | $6,639 | $6,639 | $6,639 | $6,639 | $6,639 | $6,639 | $6,639 | $4,116 | $4,116 | $4,116 | $4,116 |
| Cumulative Cashflow (nominal) | | $0 | ($15,965) | ($486,202) | ($1,445,055) | ($1,463,152) | ($1,471,319) | ($1,471,561) | ($1,466,201) | ($1,457,598) | ($1,448,936) | ($1,440,014) | ($1,430,824) | ($1,421,142) | ($1,411,393) | ($1,401,351) | ($1,391,007) | ($1,380,354) | ($1,369,381) | ($1,358,078) | ($1,346,437) | ($1,334,446) | ($1,326,789) | ($1,318,902) | ($1,310,779) | ($1,302,411) |

# Discounted Cash Flow NPV Analysis (3)

**Sensitivity cases generated using Base Case input assumptions, except for:**

- Capex w/SF → 40% supplementary funds allowance (base case = 0)
- Lo availability → 25% in year 1, ramping to 100% by year 6 (base case: 50% in year 1, ramping to 100% in year 5)
- Hi GHG emissions price → \$125/t$CO_{2eq}$ levelized (base case = \$75/t$CO_2$)
- Lo lignite price → \$1.4/$GJ_{HHV}$ levelized (~ ½ base case)
- Hi oil price → \$120/bbl levelized and \$41/t$CO_2$ revenue for EOR (base case = \$80/bbl, \$26/t$CO_2$)
- WACC = 0 → real WACC set to zero (base case = 1.9%)
- (Not shown) Electricity prices different from \$70/MWh base case do not affect results significantly



# Conclusions for FOAK LBJ Demonstration Plant

- Given the level of design and engineering effort expended to develop the total plant cost (TPC) estimate, together with the FOAK nature of the LBJ project, high contingency factors are warranted in estimating TPC.
- The estimated $TPC_{FOAK}$ is \$1.3 for the LBJ plant with capacity of 1,250 bbls per day of liquids + 15 $MW_e$.
- The financial impact of an additional “supplementary funds” allowance of \$0.5 billion was also considered. This allowance may not be needed, but evidence from historical and recent pioneer projects (e.g., Kemper County, Edwardsport, Boundary Dam) would support including such an allowance at this early stage of project definition.
- The small size of the demonstration plant contributes to high unit capital costs and also to high fixed unit costs for operating and maintenance labor.
- Positive economics for the demonstration project (even without considering a supplemental funds allowance) cannot be achieved without subsidy:
    - For any scenario examined, achieving NPV = 0 without a production-cost subsidy requires a capital grant at least equal to $TPC_{FOAK}$. In most cases, the grant must exceed TPC, in some cases by a large margin.
    - To achieve NPV = 0 without a capital grant requires a production cost subsidy of \$350 per barrel of SPK in the base scenario and \$470 per barrel with the supplementary funds allowance.
- Because of the high capital intensity of the plant, capital-related parameters all have significant influence on the required subsidies: WACC, supplemental funds allowance, and the ramp-up rate in plant availability.
- Prices assumed for GHG emissions, exported electricity, and input feedstocks individually have relatively minor influence on the required subsidy levels.
- The high crude oil price scenario shows the most favorable economics (i.e., lowest required subsidies), which arise because of increased revenues from sale of SPK and $CO_2$.

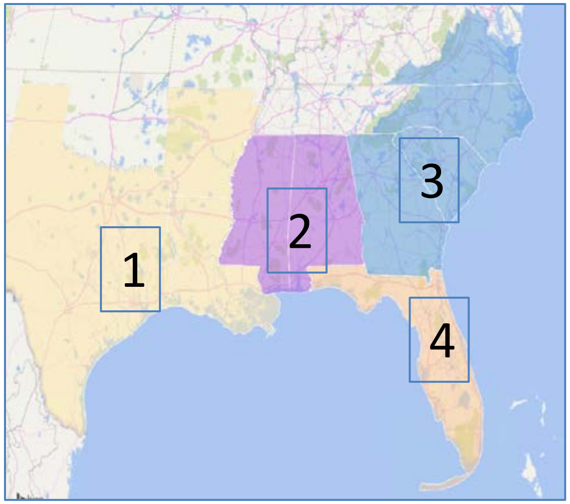
Milestone 4 Report:
Summary of Financial Analysis for FOAK LBJ Plant and Prospective NOAK Commercial Plants

# 4. PROSPECTIVE $N^{TH}$-OF-A-KIND (NOAK) COMMERCIAL PLANTS

# Biomass Resource Availability Summary

- Understanding what are the prospective supplies of biomass feedstocks in the Southeast region is a pre-requisite for assessing the prospects for commercial, $N^{th}$-of-a-kind plants.
- Analysis* by the Antares Group (funded by Southern Company Services in support of this project) found that under the medium scenario of intensified pine plantation management considered for biomass supply (see slide 38), some 8.1 million short tons/year of thinnings (as pulp-grade logs) from these plantations could be available as feedstocks to an LBJ industry. Additionally, Antares estimates that there are nearly 16 million tons/year of forest harvest residues that are currently unutilized and which might also be considered as feedstocks for LBJ plants. Both the thinnings and the residues have favorable GHG emissions footprints, as described earlier. Regions 2 and 3 have the largest supply potentials.
- The potential biomass supplies across the Southeast are sufficient to launch a major industry processing woody biomass with or without co-processing of coal.
- The estimated marginal price for an 8 million ton market of pulpwood-quality logs (delivered) is $\$4.6/GJ_{HHV}$ ($84/short t, dry), and for residues is $\$3.3/GJ_{HHV}$ ($60/short t, dry).** We use the weighted average of these, $\$3.7/GJ_{HHV}$, for the NOAK plant economic analysis presented below.

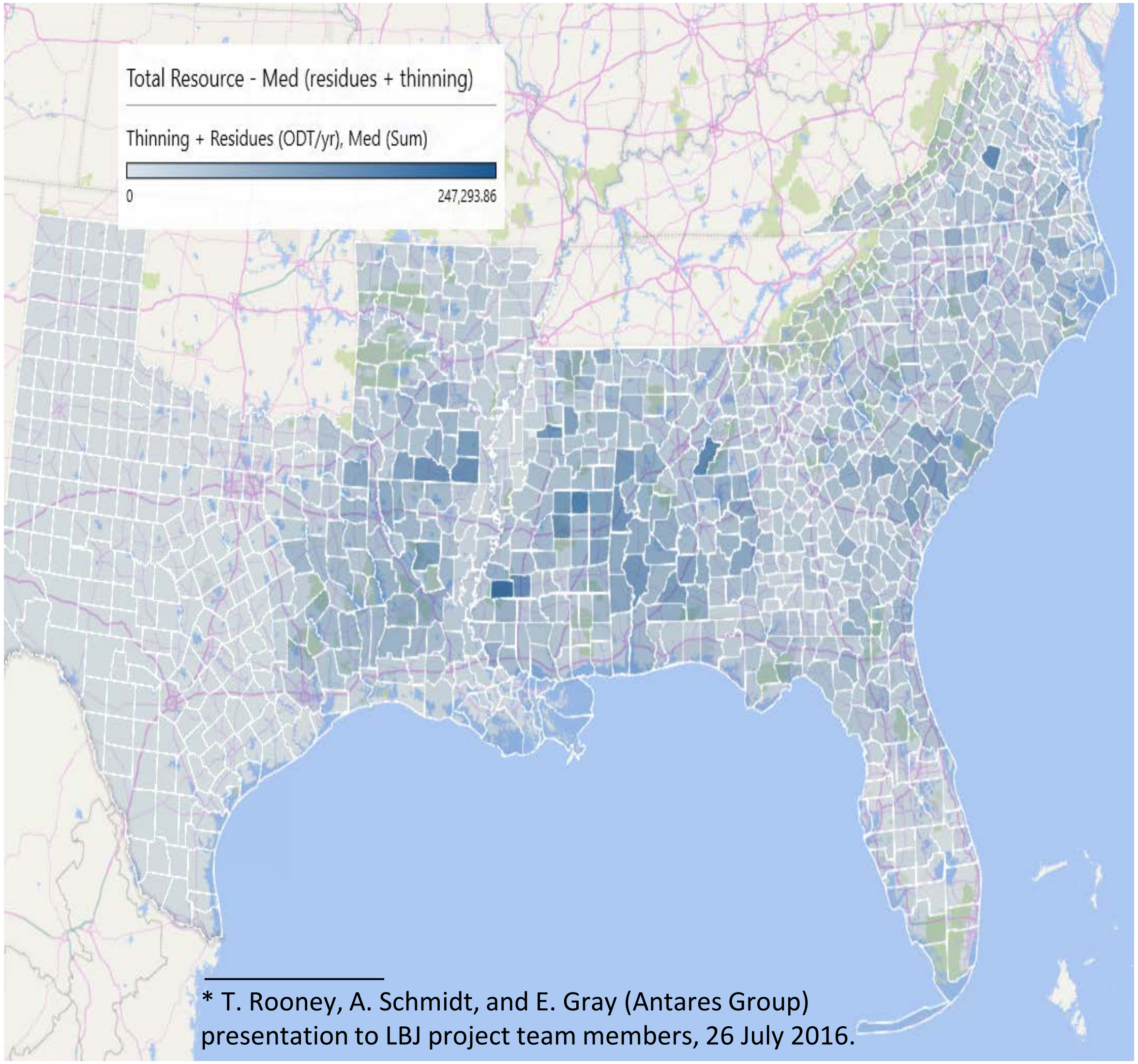
| | Biomass supply (oven-dry short tons/year) | | |
|---|---|---|---|
| Region | Forest harvest residues | Thinnings from pine plantations (medium scenario) | Total |
| Region 1: AR, LA, TX | 4,099,068 | 1,102,366 | 5,201,434 |
| Region 2: AL, MS | 4,360,495 | 3,771,294 | 8,131,789 |
| Region 3: VA, NC, SC, GA | 6,488,402 | 2,846,501 | 9,334,903 |
| Region 4: FL | 731,097 | 388,447 | 1,119,544 |
| Total | 15,679,061 | 8,108,607 | 23,787,668 |




* T. Rooney, A. Schmidt, and E. Gray (Antares Group) presentation to LBJ project team members, 26 July 2016.

** T. Rooney and E. Gray, 2015. "Biomass Supply and Biogenic Carbon Impacts Evaluation for Lignite-Biomass to Jet Fuel Project, Final Report," Antares Group Inc., 9 January 2016.

# Distribution of Potential Thinnings and Forest Residue Resources by County in the Southeast Region (Medium Scenario)




* T. Rooney, A. Schmidt, and E. Gray (Antares Group) presentation to LBJ project team members, 26 July 2016.

# Prelude to NOAK Financial Analysis

- The economics of LBJ plants built after the FOAK demonstration plant can be expected to improve as a result of building larger scale plants and learning that occurs as an LBJ industry matures. To help understand the extent to which economics might improve, preliminary analyses of N$^{th}$-of-a-kind (NOAK) plant designs were undertaken.
- Our NOAK plant designs involve no advanced technology – the designs are basically scaled-up versions of the FOAK design discussed in Section 3 of this report, but with adjustments to process efficiencies that can be expected with larger-scale equipment and with adjustments to capital and O&M cost estimates that account both for larger scale and for cost learning that might occur as an LBJ industry matures from FOAK to NOAK plants.
- Without actual experience in constructing and operating LBJ plants, there is no rigorous basis for estimating what NOAK plant costs will be. Our analysis provides one perspective on NOAK costs: we have adopted what we consider to be optimistic (low-end) capital cost estimates for the NOAK plants we designed, which are subject to the constraint mentioned above that only equipment components that are already commercial today would be used in the NOAK plant designs.
- R&D is ongoing on new technologies that might lead to improved plant performance and/or reduced capital and operating costs and thereby improve the NOAK plant economics presented here. An assessment of such options is beyond the scope of this project.

# Methodology for NOAK Analysis

- We modified the Aspen Plus model developed to simulate the LBJ FOAK plant and used it to simulate performance of larger plants, alternative process configurations, and biomass input fractions from 0 to 1. We incorporated efficiency improvements that accompany larger scale for the power island, but retained unit performance characteristics for other plant components.
- To estimate bare-erected capital costs (BEC) for individual component trains, we
  - scaled WorleyParsons' component BEC estimates for the LBJ FOAK plant by the ratio of capacities (e.g., for the gasifier island, the scaling parameter is total feedstock energy input) raised to equipment-specific exponents developed from Turner and Pinkerton (2013).*
  - Assumed equal capacities for individual trains when multiple trains are required.
  - Calculated BEC for multiple trains as equal to BEC for one train x $N^{0.9}$, where N is the number of trains.
- We estimated O&M costs by scaling WorleyParsons' estimates for the FOAK plant. For example, annual fixed operating labor cost is scaled with total feedstock input rate raised to the 0.29 exponent, annual fixed maintenance labor is 1.4% of BEC, and annual fixed admin labor is 25% of the sum of fixed O&M labor.
- We assumed cost learning, such that in the NOAK Total Plant Cost ($TPC_{NOAK}$):
  - EPCM allowance is 12% of BEC (compared with 20% for a FOAK plant)
  - Process contingency is zero, reflecting a fully proven out commercial process.
  - Project contingency is 10% of BEC (compared with 64% of BEC for a FOAK plant).
- Thus, $TPC_{NOAK}$ = 1.22 x BEC.
- Owner's costs equal to 22.8% of TPC are assumed, and the EPRI TAG financial accounting methodology is used to estimate breakeven oil prices and internal rates of return on equity for NOAK plants.
- Additional key assumptions
  - Input biomass capacity is limited in all designs to about 3,000 dry t/day, corresponding to about 1 million t/yr, a logistical maximum for truck-delivered biomass. Together with a specified target GHG footprint, this biomass capacity constraint determines the overall size of a plant co-processing lignite and biomass.
  - Optimistically, plant capacity factor is assumed to be 90% (with no ramp-up period), and no spare equipment trains are used.

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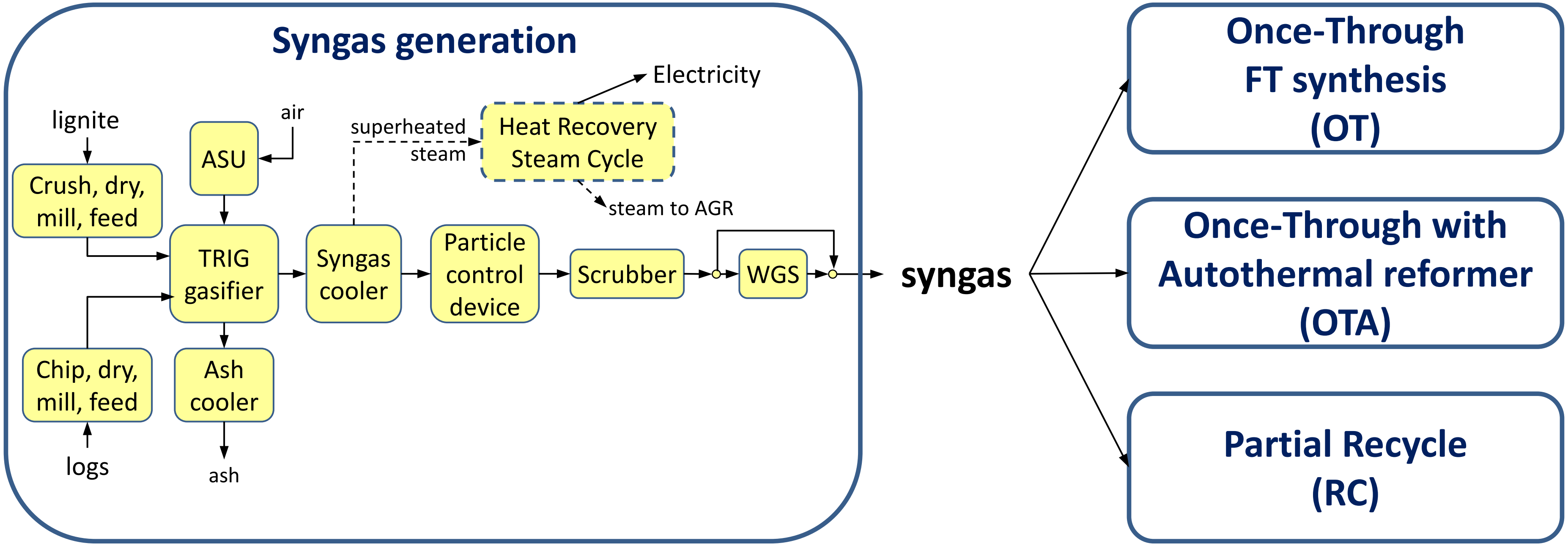
* M.J. Turner and L.L. Pinkerton, "Quality Guidelines for Energy System Studies: Capital Cost Scaling Methodology," DOE/NETL-341/013113, National Energy Technology Laboratory, 31 January 2013.

# Alternative Process Configurations Investigated




[identical syngas generation design for all configurations]

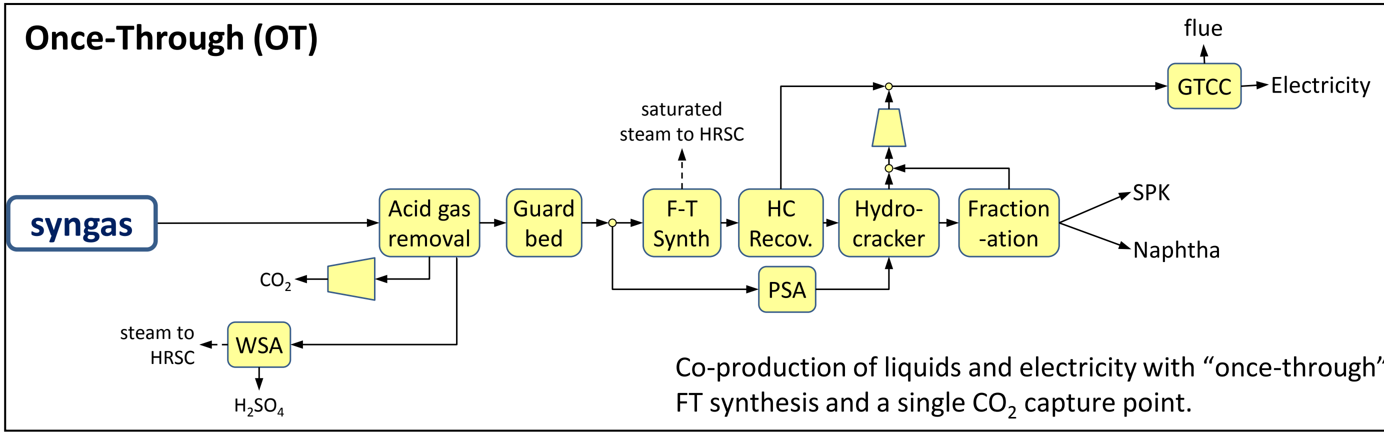
[process schematics on next page]

**OT** Co-production of liquids and electricity with "once-through" FT synthesis and single $CO_2$ capture point.

**OTA** Increased fraction of input carbon captured compared with OT.

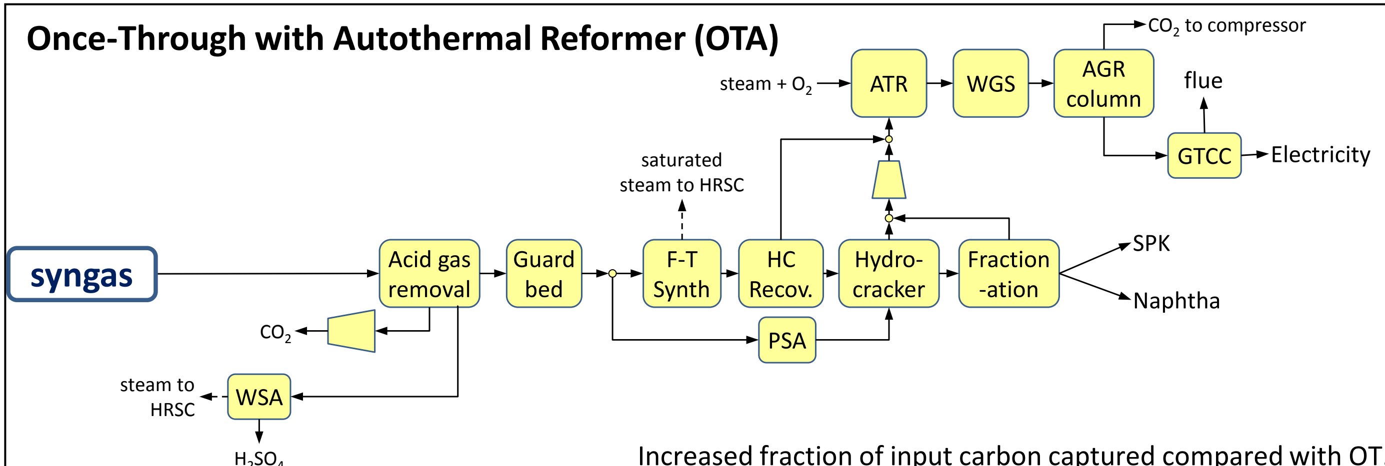
**RC** Increased ratio of liquids-to-electricity production compared with OT.

## Once-Through (OT)



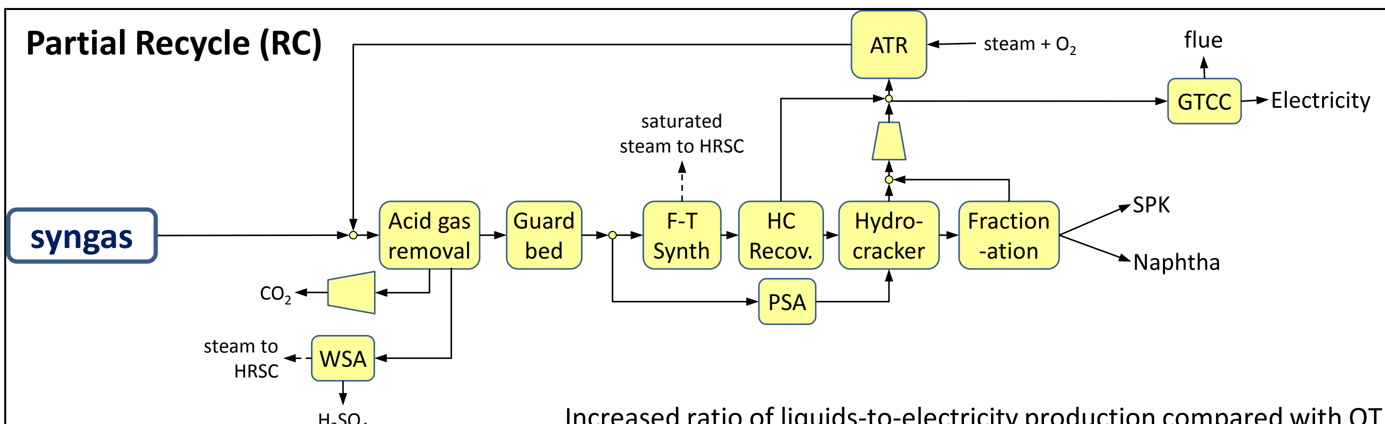

Co-production of liquids and electricity with “once-through” FT synthesis and a single $CO_2$ capture point.

## Once-Through with Autothermal Reformer (OTA)




Increased fraction of input carbon captured compared with OT.

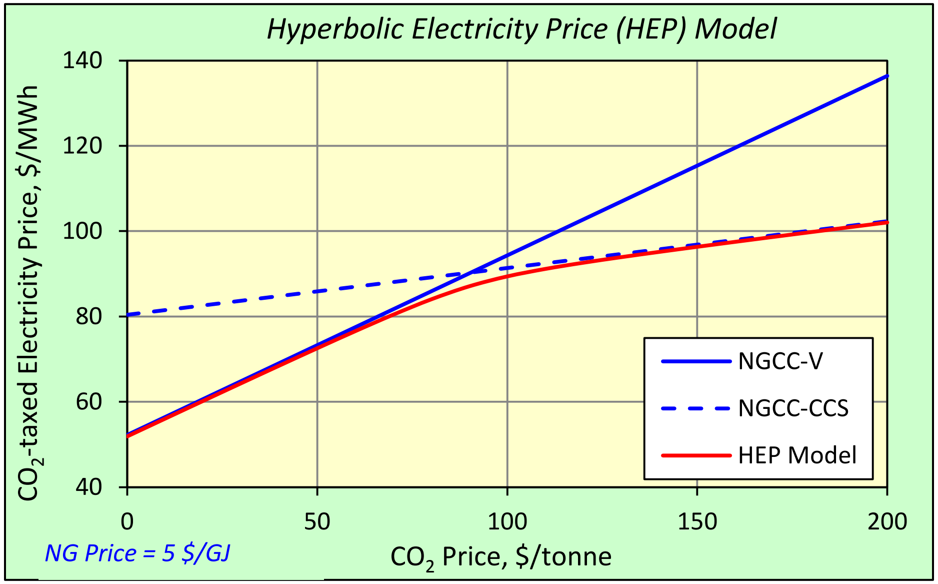
## Partial Recycle (RC)




Increased ratio of liquids-to-electricity production compared with OT.

# Financial Assumptions for All NOAK Plant Analyses

- In the presence of a GHG emissions price, the plant operator pays for the full lifecycle emissions associated with production and consumption of its products and is paid prices for its products that include a base price plus the value of GHG emissions associated with the lifecycle of products displaced (petroleum-derived liquids and grid electricity).
    - Electricity sale price assumed to equal LCOE for least costly natural gas electricity (with $CO_2$ vented or stored in deep saline formation) – see graph of "hyperbolic" electricity price (HEP) model.
    - Liquid product prices depend on the assumed crude oil price.
- Other assumed prices (20-year levelized): Minemouth lignite: 2.1 $\$/GJ_{HHV}$ / Delivered biomass: 3.7 $\$/GJ_{HHV}$ / Sulfuric acid co-product revenue: \$133/tonne / $CO_2$ revenue (for EOR): $\$/tCO_2$ = [0.386 x COP] – 5, where COP = crude oil price in \$/bbl (See slide 54.) / GHG emissions and crude oil: varying prices.
- Biomass-related GHG accounting uses average BAF value for the Southeast, medium scenario (see slide 40).
- Levelized FT liquids production costs (in $\$/GJ_{LHV}$) are estimated using EPRI TAG revenue requirement methodology:
    - 55:45 debt:equity split
    - 20 year book/tax life, MACRS depreciation sched.
    - Cost of debt: 4.4%/yr real (6.5%/yr nominal)
    - Cost of equity: 10.2%/yr real (12.4%/yr nominal) = "hurdle rate"
    - Owner's costs (OC): 22.8% of TPC
    - Annual property tax + ins. = 1.9% of (TPC + OC).
    - Above assumptions result in capital charge rate of 15.6% of (TPC+AFUDC)
    - 3 year construction time, with allowance for funds during construction (AFUDC) = 7.2% of TPC.




- Breakeven crude oil prices (BECOP) are also estimated.
- Internal rate of return on equity (IRRE) is also estimated. IRRE is the cost of equity (in EPRI TAG methodology) that gives levelized FT liquids production cost equal to the assumed FT liquids sale price.

Milestone 4 Report:
Summary of Financial Analysis for FOAK LBJ Plant and Prospective NOAK Commercial Plants

# 4.1. DESIGNS AND COSTS OF PLANTS CO-PROCESSING LIGNITE AND BIOMASS

# Designs Investigated

- We developed two sets of plant designs for co-processing lignite and biomass: one set of plants is designed to achieve a greenhouse gas emissions index, defined in the body of this report, of $GHGI_{2005} > 0$, which means its products are characterized by net positive lifecycle GHG emissions. For $GHGI_{2005} = 1$, the emissions would equal those for the equivalent mix of conventional products (liquid fuels made from crude oil and electricity from the U.S. grid-average grid mix of generators in 2005). The second set of plants is designed to have $GHGI_{2005} < 0$, i.e., such that its products are characterized by net negative lifecycle GHG emissions. Each set of plants includes three variations in process configuration: OT, OTA, and RC.
- The following three slides summarize the performance and economics of all six plant designs. Also included for comparison are results for a NOAK plant the size of the demonstration FOAK plant. Because commercial LBJ plants capturing $CO_2$ are unlikely to be built absent any carbon mitigation policy, we examined the impact on a GHG emissions price (as a surrogate for carbon policy) on the economics of alternative NOAK plant designs. Our financial analysis excludes any consideration of subsidies.

# Co-Processing: Performance Summaries

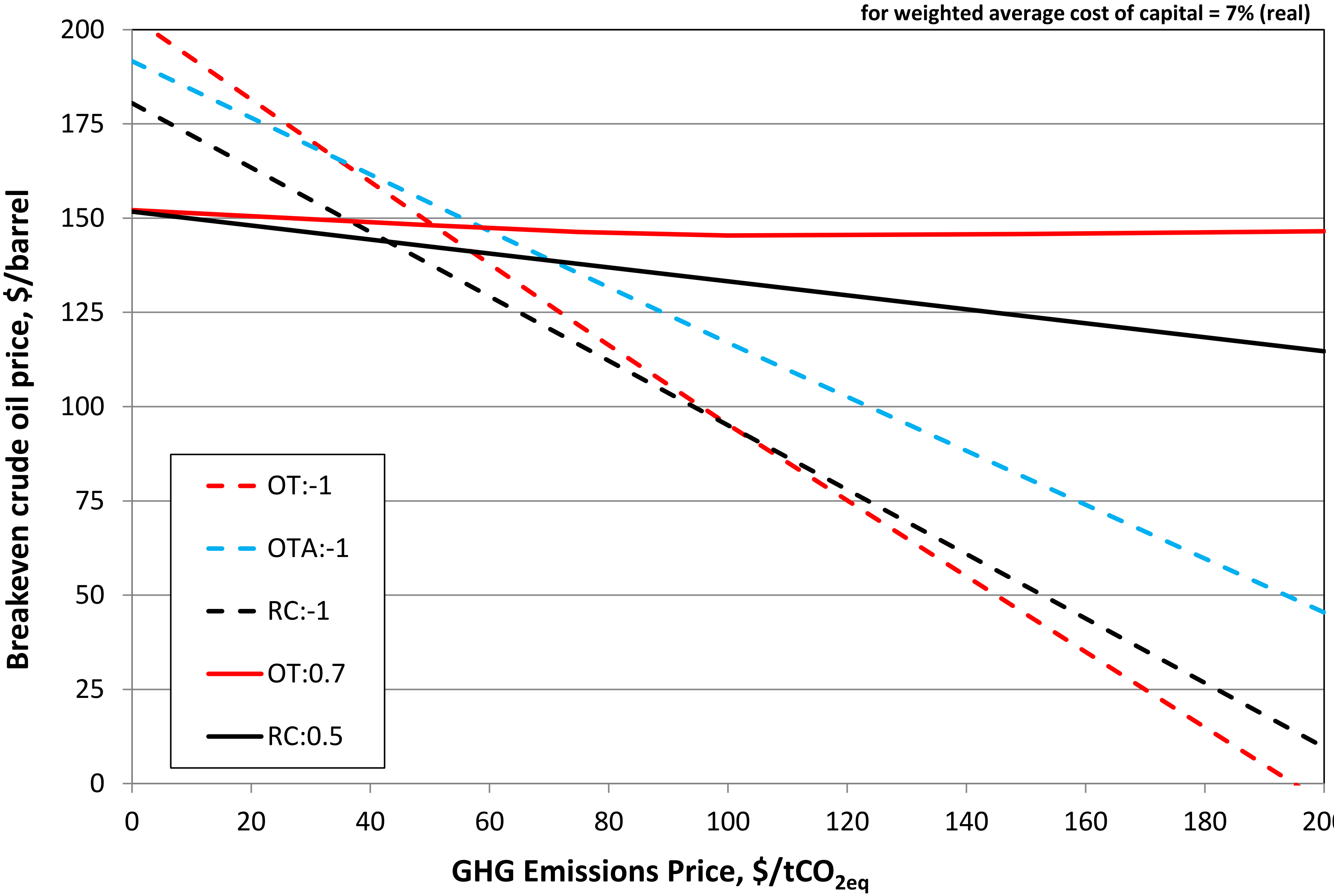
| | | | $GHGI_{2005}$ < 0 | | | $GHGI_{2005}$ > 0 | | |
|---|---|---|---|---|---|---|---|---|
| **Plant name >>** | | **OT - Small** | **OT: -1** | **OTA: -1** | **RC: -1** | **OT: 0.7** | **OTA: 0.9** | **RC: 0.5** |
| **$GHGI_{2005}$, Southeast average** | | **0.00** | **-1.12** | **-0.96** | **-1.34** | **0.72** | **0.87** | **0.50** |
| $GHGI_{2005}$, Region 1 | | 0.40 | -0.48 | -0.41 | -0.58 | 0.88 | 0.94 | 0.78 |
| $GHGI_{2005}$, Region 2 | | 0.49 | -0.34 | -0.29 | -0.41 | 0.91 | 0.96 | 0.85 |
| $GHGI_{2005}$, Region 3 | | -0.40 | -1.76 | -1.51 | -2.10 | 0.55 | 0.79 | 0.21 |
| $GHGI_{2005}$, Region 4 | | -1.03 | -2.76 | -2.38 | -3.31 | 0.30 | 0.68 | -0.24 |
| Annual biomass input (90% CF) | $10^6$ metric t/y (dry) | 0.10 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Biomass input fraction | % HHV | 25% | 46% | 31% | 44% | 12% | 4% | 17% |
| Lignite input | t/d, as-received | 1,551 | 5,871 | 10,871 | 6,350 | 37,193 | 110,506 | 24,823 |
| | MW, HHV | 221 | 836 | 1,548 | 904 | 5,297 | 15,738 | 3,535 |
| Biomass input | t/d, as-received | 556 | 5,365 | 5,365 | 5,365 | 5,365 | 5,365 | 5,365 |
| | MW, HHV | 74 | 711 | 711 | 711 | 711 | 711 | 711 |
| Total feestock input | MW, HHV | 295 | 1,547 | 2,259 | 1,615 | 6,008 | 16,449 | 4,246 |
| SPK output | bbl/day | 1,004 | 5,352 | 7,865 | 7,164 | 21,093 | 57,930 | 19,062 |
| | MW, LHV | 62 | 332 | 488 | 445 | 1,309 | 3,596 | 1,183 |
| Naphtha output | bbl/day | 248 | 1,323 | 1,944 | 1,771 | 5,215 | 14,322 | 4,713 |
| | MW, LHV | 14 | 74 | 109 | 99 | 292 | 803 | 264 |
| Total liquids output | bbl/day | 1,252 | 6,675 | 9,809 | 8,935 | 26,309 | 72,252 | 23,775 |
| Electricity | | | | | | | | |
| Gross production | $MW_e$ | 54 | 326 | 437 | 233 | 1,273 | 3,194 | 613 |
| Auxiliary load | $MW_e$ | 39 | 208 | 359 | 233 | 804 | 2606 | 613 |
| Net export | $MW_e$ | 15 | 119 | 78 | 0 | 469 | 588 | 0 |
| Aux load, % of feedstock HHV | % | 13.3% | 13.4% | 15.9% | 14.5% | 13.4% | 15.8% | 14.4% |
| $CO_2$ captured for storage | metric t/day | 1,326 | 7,057 | 13,661 | 7,699 | 26,636 | 97,748 | 19,827 |
| | % of input C | 57% | 57% | 76% | 60% | 56% | 75% | 59% |

# Co-Processing: Cost Summaries

| | | | GHGI$_{2005}$ < 0 | | | GHGI$_{2005}$ > 0 | | |
|---|---|---|---|---|---|---|---|---|
| | | OT - Small | OT:-1 | OTA:-1 | RC:-1 | OT:0.7 | OTA:0.9 | RC:0.5 |
| **Capital Costs** | **million 2015$** | | | | | | | |
| Lignite handling, drying & feeding | | 35 | 191 | 316 | 201 | 837 | 2,204 | 615 |
| Biomass handling, drying & feeding | | 32 | 163 | 179 | 163 | 212 | 272 | 203 |
| Air Separation Unit (ASU) | | 70 | 244 | 400 | 274 | 795 | 2,288 | 653 |
| Gasifier & ash handling | | 72 | 398 | 564 | 409 | 1,263 | 3,154 | 965 |
| Gas cleanup (AGR, SWS, WSA) | | 133 | 373 | 636 | 391 | 1,238 | 3,574 | 947 |
| CO2 compression | | 15 | 42 | 77 | 45 | 141 | 435 | 109 |
| FT synthesis & refining | | 76 | 225 | 291 | 267 | 658 | 1,598 | 601 |
| ATR & downstream WGS | | 0 | 0 | 70 | 20 | 0 | 362 | 49 |
| GTCC | | 22 | 98 | 117 | 67 | 298 | 595 | 147 |
| HRSC | | 20 | 73 | 96 | 75 | 192 | 394 | 150 |
| BOP | | 94 | 230 | 296 | 235 | 564 | 1,221 | 450 |
| **Subtotal - Bare Erected Cost** | **million 2015$** | **569** | **2,038** | **3,042** | **2,148** | **6,199** | **16,097** | **4,888** |
| EPCM and contingencies | | 125 | 448 | 669 | 473 | 1,364 | 3,541 | 1,075 |
| **Total Plant Cost (TPC$_{NOAK}$)** | **million 2015$** | **695** | **2,486** | **3,711** | **2,621** | **7,563** | **19,638** | **5,964** |
| **Levelized FT liquids production cost,** | **\$ per GJ$_{LHV}$** | **76.2** | **27.7** | **33.7** | **27.7** | **40.4** | **39.1** | **36.9** |
| Capital charges | | 59.6 | 35.9 | 36.5 | 28.3 | 27.7 | 26.2 | 24.2 |
| O&M | | 20.7 | 11.5 | 11.1 | 9.0 | 8.7 | 7.9 | 7.4 |
| Lignite feedstock | | 6.2 | 4.4 | 5.6 | 3.6 | 7.1 | 7.7 | 5.2 |
| Biomass feedstock | | 2.8 | 6.5 | 4.4 | 4.8 | 1.6 | 0.6 | 1.8 |
| GHG emissions (@ \$100/t$CO_{2eq}$) | | 0.0 | -15.9 | -10.9 | -11.9 | 10.2 | 9.8 | 4.4 |
| $CO_2$ sales for EOR (@ \$34/t$CO_2$) | | -6.8 | -6.7 | -8.9 | -5.5 | -6.4 | -8.6 | -5.3 |
| Co-product electricity (@ \$97/MWh) | | -5.4 | -7.3 | -3.2 | 0.0 | -7.3 | -3.3 | 0.0 |
| $H_2SO_4$ sales | | -1.0 | -0.7 | -0.9 | -0.6 | -1.2 | -1.3 | -0.9 |
| **Gasoline-equivalent cost** | **\$/gal gasoline eq** | 9.1 | 3.3 | 4.0 | 3.3 | 4.8 | 4.7 | 4.4 |
| **Breakeven crude oil price** | **\$ per barrel** | **283** | **95** | **117** | **95** | **145** | **136** | **133** |
| **IRRE (with \$100/bbl crude oil)** | **% per year** | **0.0%** | **10.8%** | **7.5%** | **11.0%** | **0.9%** | **1.6%** | **3.0%** |

* IRRE calculated for GHG emissions price of \$100/t$CO_{2eq}$, crude oil price of \$100/bbl, and electricity sale price of \$97/MWh. The breakeven crude oil price assumes a GHG emission price of \$100/t$CO_{2eq}$ and a weighted average cost of capital of 7% (real).

# Co-Processing: NOAK Financial Analysis Summary




* *Note*: OTA:0.9 is not shown. This design has such a small BF that, when combined with the design constraint (applied to all plants) that biomass input capacity is 3000 t/d, leads to an implausibly large plant (with TPC of nearly $20 billion).

# NOAK Plants Co-Processing Lignite and Biomass

With reference to the preceding slides in this section of the report:

- As expected, building larger plants improves economics, which can be seen by comparing OT-small and OT:-1 cases, which have identical equipment configurations. Total input feedstock is more than 5 times larger for OT:-1 than for OT-small, and the breakeven crude oil price is halved.
- When considering commercial-scale plants (i.e., leaving aside the OT-small design), the plant designs with negative GHG emissions footprints (GHGI < 0) require a larger input biomass fraction (BF) than the same plant configurations having GHGI > 0. The smaller BF for a GHGI > 0 plant yields a larger plant than the same plant configuration having GHGI < 0 because of the design constraint applied to all plants that biomass input capacity is fixed at 3,000 t/d. The OTA:-1 design has a higher $CO_2$ capture fraction than OT:-1 or RC:-1, which reduces the BF needed to reach a similar GHGI level. However, the economic benefits that come with scale-economy gains are more than offset because the increased scale for OTA:-1 comes largely as a result of adding equipment trains rather than significant upscaling of individual train capacities. Also, the revenues OTA:-1 receives for its negative GHG emissions per barrel of liquids produced is lower because OTA:-1 has about the same level of absolute negative emissions as OT:-1 or RC:-1.
- The cases with $GHGI_{2005} > 0$ have lifecycle emissions for the liquid fuels produced that are closer to those for equivalent petroleum-derived fuels they would displace. As a result, breakeven crude oil prices (BECOP) for these plants are much less sensitive to GHG emissions price than for the plants with $GHGI_{2005} < 0$.
- Cases with $GHGI_{2005} < 0$ have BECOP values higher than for plants with $GHGI_{2005} > 0$ when the GHG emissions price is below \$40 to \$60 per barrel, but are the more competitive option for higher GHG emission prices.
- The RC:-1 and OT:-1 cases show the most favorable economics among the cases with $GHGI_{2005} < 0$, with the OTL:-1 design gaining a slight edge when the GHG emission price exceeds about \$100/t$CO_{2e}$.

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* The OTA-1 design is not included in this comparison, because it has such a small BF that, when combined with the design constraint (applied to all plants) that biomass input capacity is 3000 t/d, leads to an implausibly large plant (with TPC of nearly \$20 billion).

Milestone 4 Report:
Summary of Financial Analysis for FOAK LBJ Plant and Prospective NOAK Commercial Plants

# 4.2. COMPARISONS OF 50K BBL/DAY COAL-ONLY DESIGNS WITH PRIOR STUDIES

# NOAK Coal-to-Liquids Plants @ ~50,000 bbl/day

Prior studies of 50,000 barrel/day plant designs were compared with NOAK designs generated in this project. Three prior studies agree reasonably with each other on plant performance and TPC, despite differences in coal type, gasifier type, and other factors. Of the three, the Skone study used the TRIG gasifier and so is most appropriate for comparative analysis. To facilitate comparisons, Princeton process simulations were developed for lignite and for the same sub-bituminous PRB coal used by Skone. The Princeton (ESAG) cases were designed to produce the same total FT liquids and net electricity as Skone after a minor adjustment was made to Skone to simulate the use of the LPG produced in that design for power generation. The resulting case is labelled Skone*. Skone's plant configuration is shown on the next slide, and the three yellow-shaded cases in the table are compared in the following slides.

**ESAG-2011**: Liu, G., Larson, E.D., Williams, R.H., Kreutz, T.G., and Guo, X., "Making Fischer-Tropsch Fuels and Electricity from Coal and Biomass: Performance and Cost Analysis," *Energy & Fuels*, 25(1): 415-437, 2011.
**Shah**: V. Shah, N.J. Kuehn, M.J. Turner, and S.J. Kramer, "Cost and Performance Baseline for Fossil Energy Plants, Vol 4: Coal-to-Liquids via Fischer-Tropsch Synthesis," DOE/NETL-2011/1477, 15 Oct 2014.
**Skone**: T. Skone, T. Eckard, J. Marriott, G. Cooney, J. Littlefield, C. White, D. Gray, J. Plunkett, and W. Smith, "Comprehensive Analysis of Coal and Biomass Conversion to Jet Fuel: Oxygen Blown, Transport Reactor Integrated Gasifier (TRIG) and Fischer-Tropsch (F-T) Catalyst Configurations," DOE/NETL-2012/1563, 19 February 2014. [Report and Spreadsheet]
**Skone***: Skone case adjusted for no LPG production.
**ESAG-PRB, ESAG-lig**: Partial recycle configurations developed for this study.

| Coal-Only FT, nominal 50k bbl/d | ESAG-2011 | Shah | Skone | Skone* | ESAG-PRB | ESAG-lig |
|---|---|---|---|---|---|---|
| Coal type | Ill #6 bit. | Ill #6 bit. | PRB sub-bit | PRB sub-bit | PRB sub-bit | lignite |
| Gasifier type | slurry entrained | dry entrained | TRIG | TRIG | TRIG | TRIG |
| Coal input, metric t/d, as-received | 24,087 | 19,097 | 27,712 | 27,712 | 34,769 | 63,268 |
| Coal input, MW HHV | 7,559 | 5,985 | 6,375 | 6,375 | 8,016 | 9,010 |
| Carbon input as coal, kgCO2e/s | 653 | 515 | 588 | 588 | 740 | 847 |
| FT liquids output, (actual) barrels per day | 52,916 | 49,992 | 50,000 | 46,386 | 45,514 | 45,514 |
| FT liquids output, MW HHV | 3,399 | 3,220 | 3,176 | 2,982 | 2,982 | 2,982 |
| FT liquids, % of coal input (HHV) | 45% | 54% | 50% | 47% | 37% | 33% |
| Liquids out, MW LHV | 3,159 | 2,992 | 2,952 | 2,771 | 2,771 | 2,771 |
| Diesel and/or kerosene, MW LHV | 1,990 | 2,148 | 1,801 | 1,801 | 2,265 | 2,265 |
| Naptha, MW LHV | 1,169 | 844 | 970 | 970 | 506 | 506 |
| LPG, MW LHV | 0 | 0 | 181 | 0 | 0 | 0 |
| Gross electricity generation, MWe | 849 | 427 | 794 | 899 | 1,332 | 1,587 |
| Aux load, MWe | 554 | 423 | 562 | 562 | 995 | 1,250 |
| Net Electricity, MWe | 295 | 5 | 232 | 337 | 337 | 337 |
| Aux load as % of HHV coal in | 7.3% | 7.1% | 8.8% | 8.8% | 12.4% | 13.9% |
| Total Efficiency, HHV | 49% | 54% | 53% | 52% | 41% | 37% |
| CO2 capture, metric t/d | 29,039 | 23,970 | 28,006 | 28,006 | 33,843 | 40,562 |
| Percent of input C captured | 52% | 54% | 56% | 56% | 53% | 56% |
| t/d pure O2 | 21,634 | 13,693 | 16,218 | 16,218 | 19,652 | 23,091 |
| O2 input, t per MW-day of coal HHV input | 2.9 | 2.3 | 2.5 | 2.5 | 2.5 | 2.6 |
| Recycle fraction to FT synthesis (mass%) | 97% | na | 54% | 52% | 35% | 28% |
| **Bare Erected Cost (BEC), MM2015$** | na | **3,939** | **4,394** | **4,416** | **7,489** | **8,869** |
| **Total Plant Cost (TPC), MM2015$** | **5,213** | **5,548** | **6,138** | **6,168** | **9,137** | **10,821** |
| **Specific TPC, $/ (actual)bbl/d** | **98,514** | **110,974** | **122,757** | **132,975** | **200,753** | **237,743** |

# Plant Configuration of Skone, *et al.*

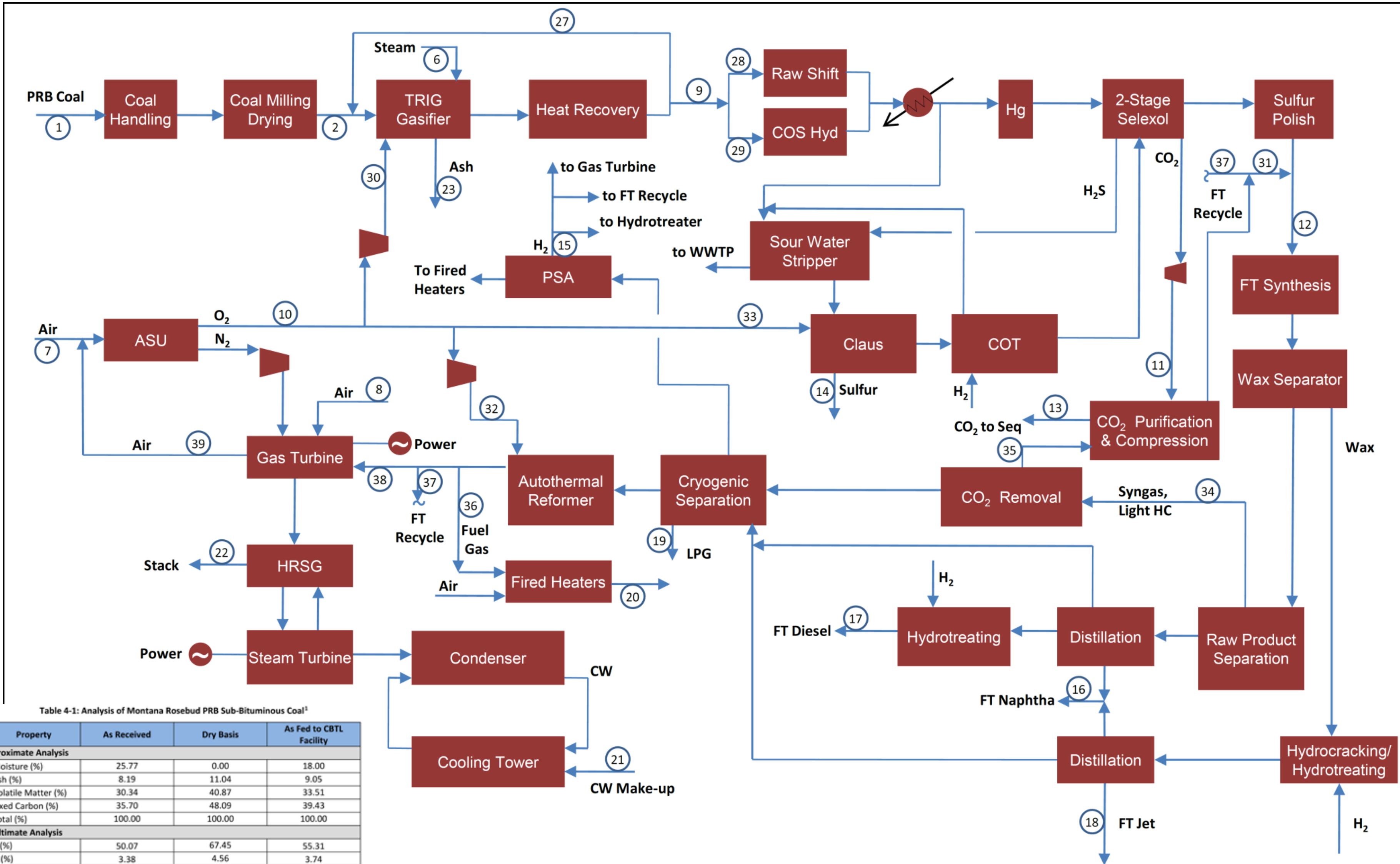



Table 4-1: Analysis of Montana Rosebud PRB Sub-Bituminous Coal[1]

| Property | As Received | Dry Basis | As Fed to CBTL Facility |
|---|---|---|---|
| **Proximate Analysis** | | | |
| Moisture (%) | 25.77 | 0.00 | 18.00 |
| Ash (%) | 8.19 | 11.04 | 9.05 |
| Volatile Matter (%) | 30.34 | 40.87 | 33.51 |
| Fixed Carbon (%) | 35.70 | 48.09 | 39.43 |
| Total (%) | 100.00 | 100.00 | 100.00 |
| **Ultimate Analysis** | | | |
| C (%) | 50.07 | 67.45 | 55.31 |
| H (%) | 3.38 | 4.56 | 3.74 |
| O (%) | 11.14 | 15.01 | 12.31 |
| N (%) | 0.71 | 0.96 | 0.79 |
| S (%) | 0.73 | 0.98 | 0.80 |
| Cl (%) | 0.01 | 0.01 | 0.01 |
| Ash (%) | 8.19 | 11.03 | 9.04 |
| Moisture (%) | 25.77 | 0.00 | 18.00 |
| Total (%) | 100.00 | 100.00 | 100.00 |
| **Heating Value** | | | |
| HHV (Btu/lb) | 8,564 | 11,516 | 9,443 |
| LHV (Btu/lb) | 8,252 | 11,096 | 9,079 |

# ESAG-PRB compared with Skone* (1)

- The fraction of input coal energy converted to liquid products is 20% lower for ESAG-PRB than for Skone*, which necessitates a larger coal input to achieve the same liquids output rate. The lower liquids conversion in ESAG-PRB is largely attributable to the higher auxiliary load in this design. The higher aux load mandates that more unconverted syngas and FT light ends are used for power generation rather than for additional liquids production by recycling to the FT synthesis unit: the recycle fraction in Skone* is 53%, compared with 35% in ESAG-PRB. An additional factor contributing to the lower liquids conversion in ESAG-PRB may the use of a cobalt-based FT synthesis catalyst, which is more selective than the iron-based catalyst used in Skone*.
- The auxiliary electric load per unit of coal energy input for ESAG-PRB is 41% higher than for Skone*, and the auxiliary load itself is 70% higher. Several line items included in ESAG-PRB aux load estimate were not included in Skone*, as detailed in the table below. Also, the auxiliary load per unit of capacity (lower section of table) for coal handling/preparation and for $CO_2$ compression are significantly higher in ESAG-PRB for unknown reasons. The higher ASU load per $tO_2$ is partially due to the higher oxygen purity in ESAG-PRB (99.5%) than in Skone* (95%). The difference in specific power consumption for acid gas removal may be due in part to different technologies: Skone* uses a 2-stage Selexol upstream of FT synthesis and an MDEA unit downstream. ESAG-PRB uses an upstream Rectisol system.
- The larger total auxiliary load for ESAG-PRB contributes to a higher total plant cost, because larger equipment capacities are required for the same liquid and net electricity outputs. Additional cost comparisons are on the next slide.
- Using lignite instead of sub-bituminous coal increases the auxiliary load: The total auxiliary load is 26% higher for the ESAG-lig design than for ESAG-PRB. Aux loads for solids handling, ASU, AGR, and $CO_2$ compression are all significantly increased as a result of the larger coal input requirement. The 12% higher coal input is explained by 2 factors: a lower TRIG cold gas efficiency with lignite (82% vs. 79%, HHV basis) due to the higher ash fraction of lignite (22% vs. 11%, dry basis) and the lower FT recycle fraction (28% vs. 35%) which is needed to generate sufficient electricity to meet the larger auxiliary load.
    - The larger coal input necessitates more $O_2$ use and leads to more $CO_2$ capture, increasing the auxiliary loads for the ASU, AGR, and $CO_2$ compression.
    - The aux load for solids handling is scaled with as-received coal tonnage, which is 82% higher for lignite than for sub-bituminous coal due to higher ash and moisture fractions.

| **Auxiliary Loads (MWe)** | ESAG-2011 | Shah | Skone | Skone* | ESAG-PRB | ESAG-lig |
|---|---|---|---|---|---|---|
| Solids Handling / Coal Preparation | 21 | 12 | 5 | 5 | 67 | 121 |
| Air separation and compression | 324 | 281 | 286 | 286 | 415 | 488 |
| $CO_2$ Compressor | 109 | 43 | 92 | 92 | 175 | 209 |
| Gasification/Quench | | | 1 | 1 | 1 | 1 |
| BFW & Circulating Water Pumps | | 13 | 19 | 19 | 26 | 31 |
| Cooling Tower Fans | | 4 | 5 | 5 | | |
| H2S conversion | | 2 | 7 | 7 | 2 | 5 |
| AGR | 40 | 14 | 65 | 65 | 132 | 158 |
| Recycle compressor | 16 | 3 | | | 7 | 6 |
| FT Processing | 33 | 32 | 14 | 14 | 28 | 28 |
| Hydrogen recovery system | | | 49 | 49 | 5 | 5 |
| GT fuel gas compressor | | | | | 54 | 59 |
| Tempered water system | | | | | 1 | 2 |
| Cooling water system | | | | | 35 | 58 |
| Water treatment | | | | | 9 | 14 |
| Wastewater treatment | | | | | 7 | 12 |
| Miscellaneous | 11 | 19 | 20 | 20 | 32 | 53 |
| **Total auxiliary load** | **554** | **423** | **562** | **562** | **995** | **1250** |
| **Auxiliary loads per tonne processed** | | | | | | |
| Coal handling/preparation, kW/$MW_{LHV}$ coal | 2.9 | 2.1 | 0.8 | 0.8 | 8.6 | 15.4 |
| ASU and compression, kWh/t pure O2 | 359 | 493 | 424 | 424 | 507 | 507 |
| CO2 compression, kWh/t CO2 | 90 | 44 | 78 | 78 | 124 | 124 |
| Acid gas removal, kWh/tCO2 | 33 | 14 | 56 | 56 | 94 | 94 |

# ESAG-PRB compared with Skone* (2)

- The total plant cost for ESAG-PRB is 1.5 times that for Skone*. The difference in bare erected cost (BEC) accounts for most of this difference.
- The TPC for ESAG-lig is 18% higher than for ESAG-PRB due to the larger coal input for the given liquid fuels and electricity production.

| | Skone* | ESAG-PRB | ESAG-lig |
|---|---|---|---|
| Bare Erected Cost, MM$ | 4,416 | 7,489 | 8,869 |
| EPC and contingencies, MM$ | 1,753 | 1,648 | 1,951 |
| Total Plant Cost, MM$ | 6,168 | 9,137 | 10,821 |

- The BEC for ESAG-PRB is 1.7 times that for Skone* (left table below). BEC per unit of capacity (right table below) for the ASU and for the gasifier are each within 10% of each other between the two designs, but all other items have larger or much larger cost differentials. It is difficult to make direct comparisons of line items because the scope of items may be different between the estimates. However, the higher total BEC per unit of capacity for ESAG-PRB suggests that equipment and labor costs might have risen substantially since the Skone work and/or the level of engineering effort expended to estimate BEC, including analysis of auxiliary loads, was not as substantial.
- The differences between the Skone* and ESAG-PRB designs lead to significantly different overall economics. For example, using Princeton's financial methodology and assumptions, including a GHG emissions price of $100/tCO$_{2eq}$ and a $CO_2$ sale price for EOR of $34/t, the breakeven crude oil price is nearly 40% higher for ESAG-PRB than for Skone* ($139/bbl compared with $103/bbl).

| BARE ERECTED COST (1000s 2015$) | Skone* | ESAG-PRB | % diff |
|---|---|---|---|
| Coal and sorbent handling | 125,447 | 188,957 | 51% |
| Coal prep and feeding | 398,248 | 643,441 | 62% |
| Feedwater systems and misc. BOP | 118,110 | 311,434 | 164% |
| Gasifier and accessories | 1,000,140 | 1,313,441 | 31% |
| ASU and compression | 769,751 | 1,023,279 | 33% |
| Gas cleanup & piping, incl. H2S conv. | 58,461 | 459,588 | 686% |
| Acid gas removal (AGR) | 308,498 | 1,148,868 | 272% |
| F-T synthesis and upgrading | 736,900 | 986,378 | 34% |
| $CO_2$ removal and compression | 85,967 | 186,762 | 117% |
| Autothermal reformer | 144,810 | 61,036 | -58% |
| GTCC and heat recovery steam cycle | 271150 | 526,619 | 94% |
| Cooling water system | 48,976 | 172,773 | 253% |
| Ash/spent sorbent handling | 98,076 | 267,618 | 173% |
| Accessory electric plant | 72,633 | 125,728 | 73% |
| Instrumentation and control | 75,403 | 23,726 | -69% |
| Improvements to the site | 50,269 | 36,884 | -27% |
| Building and structures | 52,782 | 12,947 | -75% |
| **TOTAL BEC** | **4,415,621** | **7,489,479** | **70%** |

| UNIT BEC ($ per unit of capacity) | Skone* | ESAG-PRB | % diff |
|---|---|---|---|
| Coal handling & prep, $/MW$_{coal}$ | 85,245 | 107,766 | 26% |
| Feedwater & misc BOP, $/MW$_{coal}$ | 19,225 | 40,320 | 110% |
| Gasifier & accessories, $/MW$_{coal}$ | 162,798 | 170,045 | 4% |
| ASU, $/metric t/d pure $O_2$ | 47,462 | 52,070 | 10% |
| Gas cleanup & piping, $/MW$_{coal}$ | 9,516 | 59,501 | 525% |
| AGR, $/metric t $CO_2$ captured | 11,015 | 33,947 | 208% |
| FT Island, $/MW$_{FTL}$ | 265,923 | 355,964 | 34% |
| $CO_2$ compression, $/metric t/d $CO_2$ | 3,070 | 5,519 | 80% |
| Power island, $/kW gross | 302 | 395 | 31% |
| Cooling water system | 7,972 | 22,368 | 181% |
| Ash/spent sorbent handl., $/MW$_{coal}$ | 15,964 | 34,647 | 117% |
| Accessory electric plant, $/MW$_{coal}$ | 11,823 | 16,277 | 38% |
| Instrumentation & control, $/MW$_{coal}$ | 12,274 | 3,072 | -75% |
| Site improvements, $/MW$_{coal}$ | 8,183 | 4,775 | -42% |
| Buildings & structures, $/MW$_{coal}$ | 8,592 | 1,676 | -80% |
| ATR, $/MW$_{FTL}$ | 52,257 | 22,027 | -58% |
| TOTAL, $ / MW$_{FTL}$ | 1,593,450 | 2,702,807 | 70% |
| **$/ (actual)bbl/d** | **95,193** | **164,552** | **73%** |

# ESAG-PRB compared with ESAG-lig

- Finally, comparing ESAG-PRB with ESAG-lig cases in the tables on the two previous slides, we see that using lignite instead of sub-bituminous coal increases auxiliary loads, because solids handling, ASU, AGR, and $CO_2$ compression loads are all significantly increased as a result of a larger coal input requirement for the same level of liquids production.
- The 12% higher coal energy input is due to a lower gasifier cold gas efficiency with lignite that arises primarily from the higher ash fraction of lignite (22% vs. 11%, dry basis) and to the lower FT recycle fraction that must be used to enable sufficient electricity generation (using the unrecycled fraction) to meet the larger auxiliary load.
- The larger coal input necessitates more oxygen consumption and results in more $CO_2$ being captured, which leads to increased auxiliary loads for the ASU, AGR, and $CO_2$ compressor. The load for solids handling scales with as-received coal input tonnage, which is 82% higher for lignite than for sub-bituminous due to higher ash and moisture fractions.
- The TPC for ESAG-lig is 18% higher than for ESAG-PRB due to the larger coal input required to produce the same quantities of products.

| Coal-Only FT, nominal 50k bbl/d | ESAG-PRB | ESAG-lig |
|---|---|---|
| Coal type | PRB sub-bit | lignite |
| Gasifier type | TRIG | TRIG |
| Coal input, metric t/d, as-received | 34,769 | 63,268 |
| Coal input, MW HHV | 8,016 | 9,010 |
| Carbon input as coal, kgCO2e/s | 740 | 847 |
| FT liquids output, (actual) barrels per day | 45,514 | 45,514 |
| FT liquids output, MW HHV | 2,982 | 2,982 |
| FT liquids, % of coal input (HHV) | 37% | 33% |
| Liquids out, MW LHV | 2,771 | 2,771 |
| Diesel and/or kerosene, MW LHV | 2,265 | 2,265 |
| Naptha, MW LHV | 506 | 506 |
| LPG, MW LHV | 0 | 0 |
| Gross electricity generation, MWe | 1,332 | 1,587 |
| Aux load, MWe | 995 | 1,250 |
| Net Electricity, MWe | 337 | 337 |
| Aux load as % of HHV coal in | 12.4% | 13.9% |
| Total Efficiency, HHV | 41% | 37% |
| CO2 capture, metric t/d | 33,843 | 40,562 |
| Percent of input C captured | 53% | 56% |
| t/d pure O2 | 19,652 | 23,091 |
| O2 input, t per MW-day of coal HHV input | 2.5 | 2.6 |
| Recycle fraction to FT synthesis (mass%) | 35% | 28% |
| **Bare Erected Cost (BEC), MM2015$** | **7,489** | **8,869** |
| **Total Plant Cost (TPC), MM2015$** | **9,137** | **10,821** |
| **Specific TPC, $/ (actual)bbl/d** | **200,753** | **237,743** |

Milestone 4 Report:
Summary of Financial Analysis for FOAK LBJ Plant and Prospective NOAK Commercial Plants

# 4.3. BIOMASS-ONLY PLANT DESIGNS

# Motivations for Considering Biomass-Only Designs

- The carbon mitigation goal agreed to by world leaders at the Paris climate conference in 2015 is to strive to limit global warming to less than 2$^{o}$C. The Intergovernmental Panel on Climate Change, in its 5$^{th}$ Assessment Report, after reviewing low-carbon futures modeled by a wide variety of integrated assessment models, concluded that "Many models could not limit likely warming to below 2°C if bioenergy, CCS, and their combination are limited (*high confidence*)."
- Our NOAK analysis of plants that co-process biomass and lignite indicated that in the presence of a carbon mitigation policy strong enough to achieve the goal of the Paris agreement, the larger the biomass fraction of the input feedstock (i.e., the more negative the $GHGI_{2005}$ value), the better the economics.
- NOAK plant designs that have biomass as 100% of the input feedstock would be characterized by highly negative GHG emissions.
- The TRIG gasification technology was originally developed for use with low-rank coals, but was subsequently demonstrated to work well with mixtures of low-rank coals and biomass. In the course of our project, informal discussions with engineers involved in the original design, scale-up, and coal/biomass co-processing trials of the TRIG gasifier suggest that the technology would be capable of operating solely using biomass. (Testing would be required to verify this.)

# Biomass-Only Cases: Performance Summaries

- Plant designs include a liquids plant (RC-B), two coproduction systems (OT-B and OTA-B) and a power-only design (IGCC-B). In all cases, biomass input capacity is fixed as in earlier analyses at 3,000 t/day.
- The auxiliary load as a fraction of the input feedstock energy is high in all cases; high auxiliary loads appear to be a characteristic of gasification systems regardless of the mix of liquids and/or electricity produced.

| | | OT-B | OTA-B | RC-B | IGCC-B |
|---|---|---|---|---|---|
| **$GHGI_{2005}$, Southeast average** | | **-4.15** | **-5.86** | **-5.25** | **-3.95** |
| $GHGI_{2005}$, Region 1 | | -2.73 | -4.05 | -3.48 | -2.79 |
| $GHGI_{2005}$, Region 2 | | -2.41 | -3.64 | -3.08 | -2.53 |
| $GHGI_{2005}$, Region 3 | | -5.57 | -7.68 | -7.03 | -5.11 |
| $GHGI_{2005}$, Region 4 | | -7.82 | -10.55 | -9.84 | -6.95 |
| Annual biomass input (90% CF) | $10^6$ dry metric t/y | 1.00 | 1.00 | 1.00 | 1.00 |
| Biomass input fraction | % HHV | 100% | 100% | 100% | 100% |
| Biomass input | t/d, as-received | 5,365 | 5,365 | 5,365 | 5,365 |
| | MW, HHV | 711 | 711 | 711 | 711 |
| SPK output | bbl/day | 2,400 | 2,400 | 3,081 | na |
| | MW, LHV | 149 | 149 | 191 | na |
| Naphtha output | bbl/day | 593 | 593 | 762 | na |
| | MW, LHV | 33 | 33 | 43 | na |
| Total liquids output | bbl/day | 2,994 | 2,994 | 3,842 | na |
| Electricity | | | | | |
| Gross production | MWe | 149 | 136 | 102 | 281 |
| Auxiliary load | MWe | 96 | 114 | 103 | 108 |
| Net export | MWe | 53 | 22 | -1 | 173 |
| Aux load, % of feedstock HHV | % | 13.5% | 16.0% | 14.5% | 15.2% |
| $CO_2$ captured for storage | metric t/day | 3,387 | 4,487 | 3,532 | 5,099 |
| | % of input C | 58% | 77% | 61% | 87% |

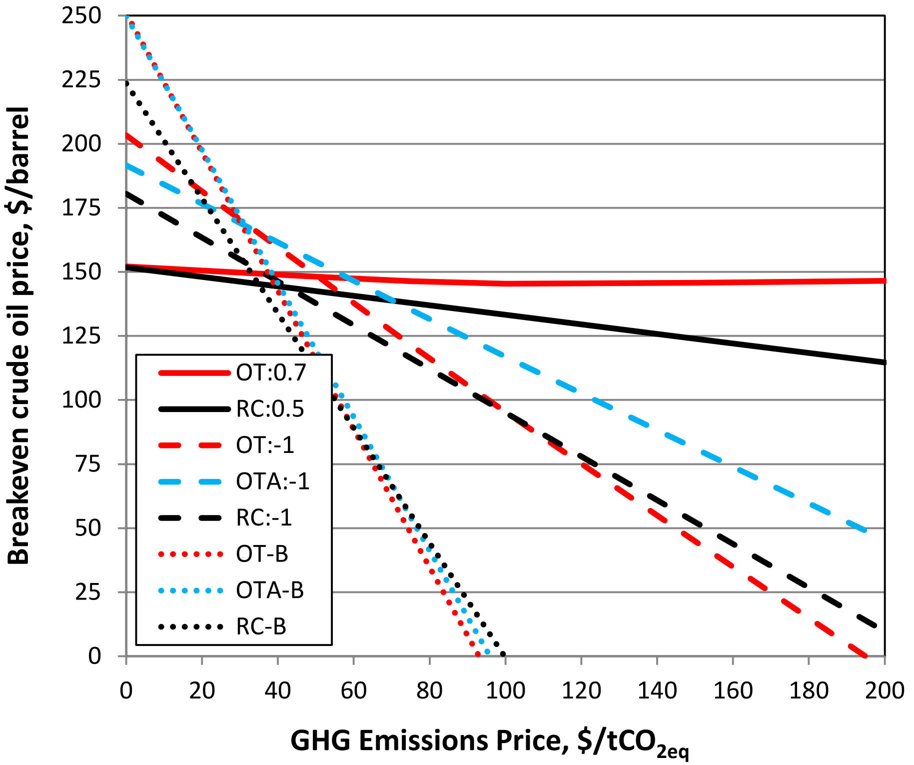
# Biomass-Only Cases: Cost Summaries

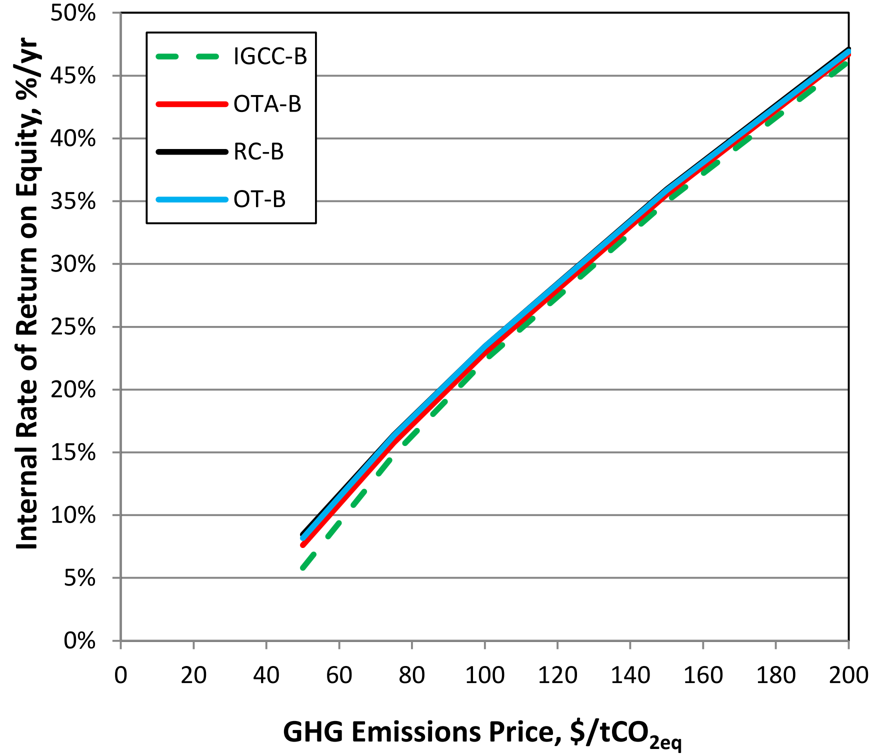
| | | OT-B | OTA-B | RC-B | IGCC-B |
|---|---|---|---|---|---|
| **Capital Costs** | **million 2015$** | | | | |
| Biomass handling, drying & feeding | | 138 | 138 | 138 | 138 |
| Air Separation Unit (ASU) | | 120 | 140 | 131 | 120 |
| Gasifier & ash handling | | 202 | 202 | 202 | 202 |
| Gas cleanup (AGR, SWS, WSA) | | 221 | 253 | 225 | 269 |
| CO2 compression | | 26 | 31 | 27 | 34 |
| FT synthesis & refining | | 133 | 133 | 152 | na |
| ATR & downstream WGS | | 0 | 28 | 10 | 21 |
| GTCC | | 52 | 45 | 34 | 94 |
| HRSC | | 42 | 42 | 42 | 42 |
| BOP | | 144 | 145 | 145 | 144 |
| **Subtotal - Bare Erected Cost** | | 1,078 | 1,156 | 1,106 | 1,065 |
| EPCM and contingencies | | 237 | 254 | 243 | 234 |
| **Total Plant Cost ($TPC_{NOAK}$)** | **million 2015$** | **1,316** | **1,411** | **1,349** | **1,299** |
| **Levelized Production Costs** | | **$ / $GJ_{LHV}$** | | | **$/MWh** |
| Capital charges | | 42.4 | 45.5 | 33.9 | 167.8 |
| O&M | | 14.4 | 14.9 | 11.4 | 56.7 |
| Biomass feedstock | | 14.4 | 14.4 | 11.2 | 54.6 |
| GHG emissions (@ $100/$tCO_{2eq}$) | | -59.0 | -65.4 | -46.7 | -261.1 |
| $CO_2$ sales for EOR (@ $34/$tCO_2$) | | -7.2 | -9.5 | -5.9 | -37.2 |
| Co-product electricity (@ $97/MWh) | | -7.2 | -3.1 | 0.1 | na |
| $H_2SO_4$ sales | | -0.04 | -0.04 | -0.03 | -0.13 |
| **Total Levelized Cost** | | **-2.3** | **-3.2** | **4.0** | **-19.2** |
| Gasoline equivalent cost | $/gal gasoline eq | -0.28 | -0.38 | 0.48 | na |
| **Breakeven crude oil price** | **$ per barrel** | **-19** | **-11** | **-1** | **na** |
| **IRRE (with $100/bbl crude oil)** | **% per year** | **23.4%** | **22.9%** | **23.4%** | **22.3%** |

* IRREs shown on this slide are calculated for GHG emissions price of $100/$tCO_{2eq}$, crude oil price of $100/bbl, and electricity sale price of $97/MWh. The breakeven crude oil prices assume a GHG emission price of $100/$tCO_{2eq}$ and a weighted average cost of capital of 7% (real).

# Biomass-Only Cases: NOAK Financial Analysis

- For liquid fuels production, OT-B, OTA-B, or RC-B, despite their smaller sizes, are favored over co-processing systems when the GHG emissions price is above about $40/tCO_{2e}$, and their BECOPs fall very rapidly with increasing GHG emissions price due to revenues received for significant negative emissions.
- IRRE for the biomass-only designs can be compared with that for the power-only design (IGCC-B). For a crude oil price of $100/bbl the IRREs for all four biomass-only plants are essentially identical across the full range of GHG emission prices considered.



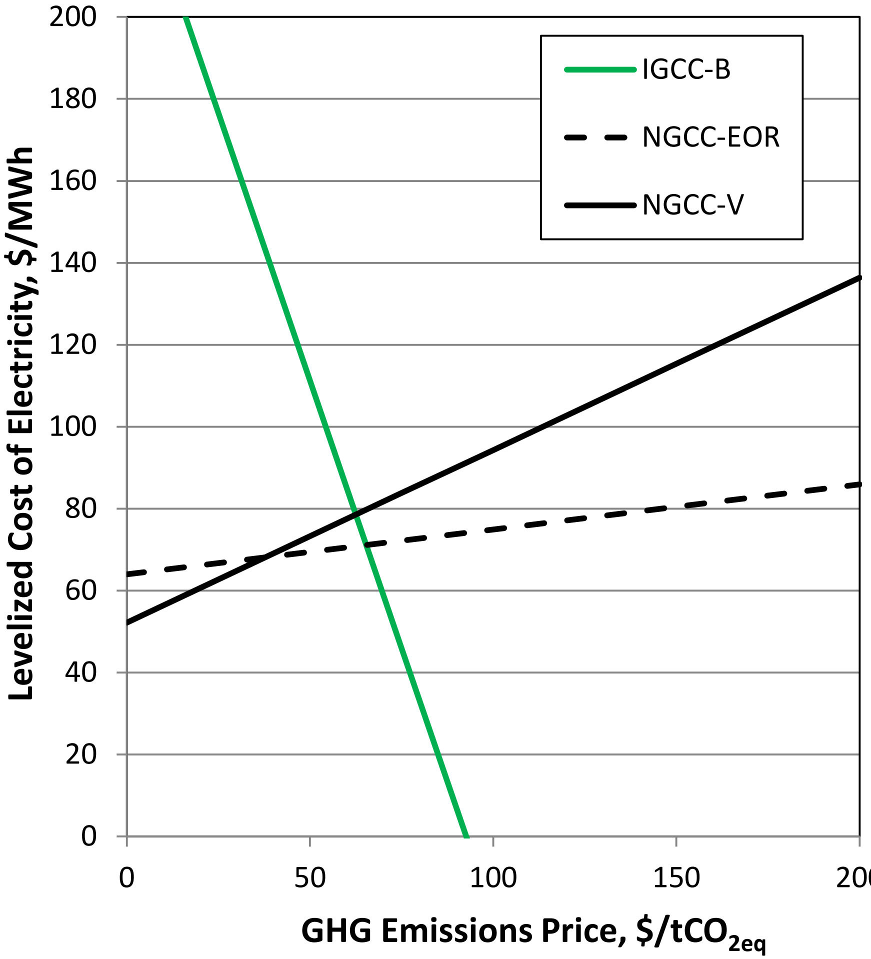



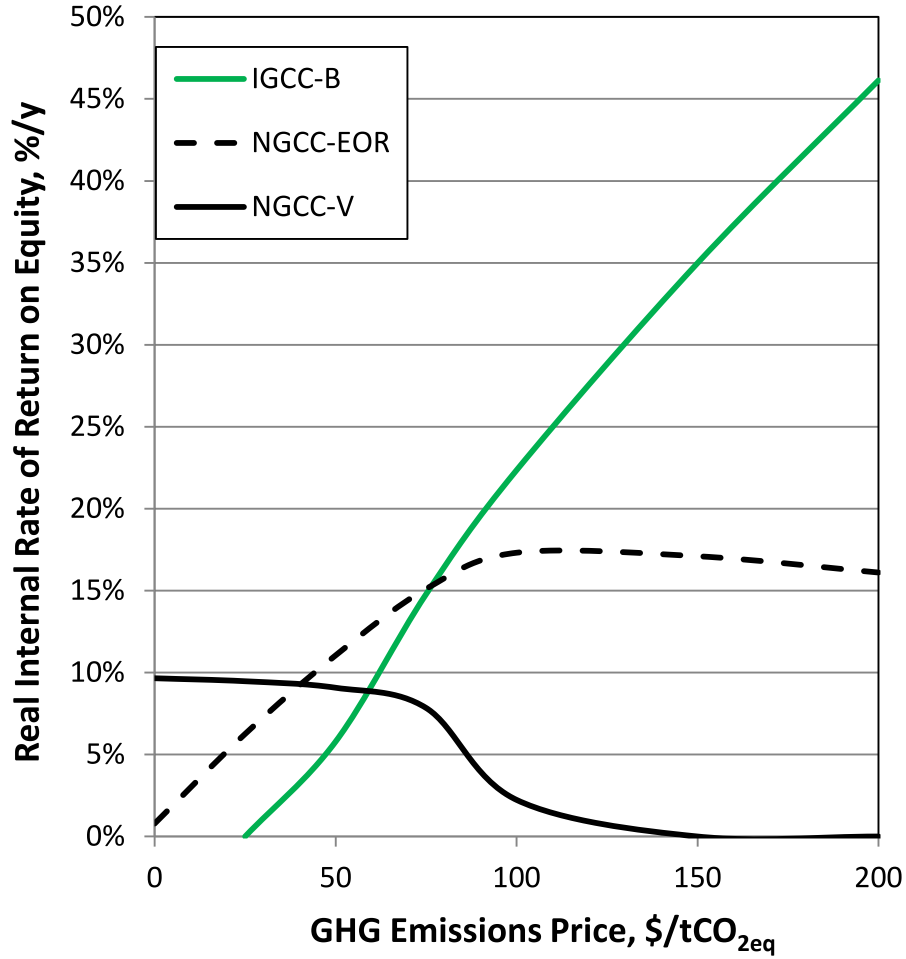

Assumptions:

- Delivered biomass price ((20-year levelized): 3.7 $/GJ$_{HHV}$
- Sulfuric acid co-product revenue: $133/tonne, levelized
- Crude oil price = $100/bbl
- Plant gate price of $CO_2$ sold for EOR: $33.5/tCO_2$ (as determined by oil price – see slide 54)
- Electricity sales price as in slide 65.

# Electricity Generation Comparison

- The highly negative GHG emissions footprint of the IGCC-B plant enables it to compete with natural gas combined cycles on a levelized cost basis (or IRRE basis) when the GHG emissions price exceeds about $75/tCO_{2eq}$.




Assumptions as in previous slide, plus:

- Natural gas price: $5/GJ_{HHV}$.
- EPRI TAG revenue requirement methodology (see slide 62)

End