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Production of Zero Sulfur Diesel Fuel from Domestic Coal: Configurational Options to Reduce Environmental Impact

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NETL Viewpoint

Summary

The conversion of domestic resources such as coal and biomass into diesel fuel is a near-term technology pathway to address the energy security, economic sustainability, and climate change concerns which currently face our nation. This study evaluates the economic viability and environmental impact of producing diesel fuel via Fischer-Tropsch (FT) synthesis. Two facility design approaches – focused on fuels production and the co-production of fuels and electricity, respectively – were evaluated for the conversion of domestic resources such as coal or a mixture of coal and biomass.

It was found that diesel fuel can be produced from coal that has a lower life cycle greenhouse gas (GHG) emissions profile than conventional petroleum-derived diesel fuel on a well-to-wheels basis. This requires the sequestration of carbon dioxide (CO_2) produced at the facility, and methane mitigation practices may be required in the case of certain bituminous coals which are particularly high in methane content. The coal-derived diesel will be economically viable when crude oil prices are as low as $94 per barrel, corresponding to a petroleum-derived diesel price of $2.70 per gallon.

If sufficient biomass resources are available to co-convert with the coal, the GHG emissions profile of the diesel fuel can be significantly reduced at a minimal increase in cost. This synergy represents a near-term pathway to leverage cellulosic biomass at a large-scale, enabling dramatic cost reductions when compared to current technologies for producing fuels from biomass.

Replacing 15 percent of the feedstock to the facility with switchgrass will result in a fuel which produces up to 34 percent less life cycle GHG emissions than petroleum-derived diesel. Such a facility would be economically viable at crude oil prices as low as $104 per barrel, increasing the diesel fuel price by $0.26 to $0.46 per gallon. The choice of switchgrass is notable because it is an herbaceous crop which can be grown on land not-suitable for food crops, alleviating competition with food crops for cropland. Other cellulosic biomass types can also be leveraged, although the change in fuel price and GHG benefits will vary depending on the biomass which is selected and the type of land it is cultivated on.

The co-production of fuels and electricity as a pathway has the potential to produce less overall GHG emissions than conventional pathways, but these benefits are highly sensitive to the methodology utilized to evaluate these emissions. The economic viability is somewhat sensitive to the price at which electricity can be sold – a 10% change in the electric sale price results in a 1% change in the required selling price of the fuel.

Fischer-Tropsch synthesis is a near-term technology pathway which can be leveraged to produce large volumes of fungible transportation fuels from domestic coal and biomass. A commercial-scale plant would produce 50,000 barrels per day, or almost 700 million gallons per year, using technologies which are available, but which require an integrated demonstration. The fuels are economically viable at diesel prices as low as $2.70 per gallon, and technological headroom exists for innovation that will further bring down cost. It is NETL's hope that this study will shed light on how design decisions and feedstock choice can impact the techno-economic performance of FT facilities, informing policy makers and developers on the potential of this pathway in improving America's energy security while addressing climate change concerns.

Background

Recent concerns over dependence on foreign oil, greenhouse gas (GHG) emissions from the transportation sector, and economic sustainability have prompted a renewed interest in fuels produced from domestic feedstocks. The use of biomass-derived feedstocks has been of particular interest due to (1) potential reduction in GHG emissions associated with photosynthetic-derived fuels, (2) the renewable nature of the feedstock, and (3) the widespread domestic availability.

The National Energy Technology Laboratory (NETL) has a history of research and development in the area of liquid transportation fuel production from coal dating back to 1943. Many of the technologies developed for conversion of coal to transportation fuels can also be leveraged for the conversion of biomass-derived feedstocks, either independently or in conjunction with coal.

The renewed interest in domestically produced fuels has prompted NETL to investigate how existing technologies can be leveraged to convert domestic feedstocks such as coal and biomass into transportation fuels which can be utilized in today's fueling infrastructure. These studies, most notably the January 2009 report entitled *Affordable, Low-Carbon Diesel Fuel from Domestic Coal and Biomass* (DOE/NETL-2009/1349), have focused on estimating both the cost of large-scale fuel production and the life cycle GHG emissions impact of the fuels produced, such that different production pathways and feedstock pairings can be evaluated.

This study builds upon that previous work, examining a number of different plant configurations, water management strategies, and feedstock pairings. The methodology and metrics used herein have been refined, and the results presented herein generally supersedes those presented previously in both the January 2009 report, as well as those presented in the April 2007 report entitled *Baseline Technical and Economic Assessment of a Commercial Scale Fischer-Tropsch Liquids Facility* (DOE/NETL-2007/1260).

A number of cases represented in the January 2009 report were not updated due to time and resource constraints, including scenarios where: (1) CO_2 produced by the facility is vented to the atmosphere; (2) a more capital intensive configuration was utilized in order to achieve more aggressive CO_2 emissions reductions; and (3) the facility utilizes biomass alone as a feedstock. The findings of those cases are worth mentioning as they are not reiterated herein:

- Sequestering CO_2 produced at these facilities has a minimal impact on the price of the finished fuel – a price increase of roughly \$0.12/gallon or \$5/barrel – representing a great opportunity for early CO_2 sequestration demonstrations and deployment;
- GHG emissions can be further reduced beyond the cases reported by making changes to the process configuration utilized, but this comes at a cost; and
- Biomass resource constraints prevent biomass-only facilities from being cost-competitive (crude prices in excess of \$200 per barrel are required for economic viability).

Study Objectives

The objective of this study is to evaluate the economic and environmental performance of converting either: (a) coal or (b) a combination of coal with a modest amount (15% by weight) of biomass, into zero sulfur diesel fuel using commercially available technologies. Performance is measured by such metrics as: (1) required selling price of the fuel; (2) crude oil price when the process will become economically viable; (3) the Well-to-Wheels (WTW) life cycle GHG emissions profile of the diesel fuel; and (4) the water usage associated with the facility.

The study expands upon previous work by examining the following new scenarios:

- Conversion of additional coal types (subbituminous coal) at a facility located in the Western part of the United States;
- Poly-generation of electricity with fuels (up to 12% of the total product slate); and
- How different cooling technologies can be leveraged to reduce water usage.

Several additional refinements were also made to update previous results, including modification to the plant configuration, based on lessons learned and updated performance/environmental metrics. These changes have been described below.

Approach

The low temperature Fischer-Tropsch synthesis process was selected for producing zero sulfur diesel fuel from coal and coal/biomass mixtures. This selection was made on the basis of (1) commercial availability and operating experience of the FT process for diesel fuel production, (2) robustness of the supporting technologies (syngas production from coal or coal/biomass), and (3) the ability to produce an ultra-clean diesel fuel which is fungible in today's fueling infrastructure.

In order to provide a comprehensive look at the potential of domestic coal to liquids (CTL) facilities, both bituminous and subbituminous coals were evaluated as taken together these coal types represent 90% of the domestic reserve base (53% and 37%, respectively). Switchgrass was selected as a representative type of biomass for use in evaluating Coal and Biomass to Liquids (CBTL) facilities, based on its potential to be grown on degraded and marginal lands which may not be suitable for food production. It is a drought-resistant, herbaceous biomass which can be grown throughout the United States with a minimum of management after established.

Two broad design approaches were considered: one in which the facility is designed to primarily produce liquid fuels, and a poly-generation plant which is designed to also co-produce electric power for sale into the grid. In the fuels-focused production facility, a portion of the unconverted syngas is recycled back to the FT reactors, resulting in a greater percentage of the original carbon in the feedstock being converted into liquid fuels. A modicum of export electric power for sale may be produced in these cases, up to 4% of the total product slate, based on combustion turbine sizing. In the poly-generation facility, none of unconverted syngas is recycled: instead it only passes through the FT island once and is combusted for power generation, resulting in additional electric power for sale, up to 12% of the total product slate. This latter case is sometimes referred to as a "once-through" configuration.

Both the fuels-focused facility (i.e. the "recycle" configuration) and the once-through configuration are designed to produce 50,000 barrels per day (bpd) of FT liquids, comprised of

34,000 bpd of FT diesel (or 69% of the product) with the balance consisting of FT naphtha.[1] The FT diesel is completely fungible in today's fueling infrastructure and can be used as a drop-in fuel, while the FT naphtha is assumed to be sold for use as an ethylene cracker feedstock.

Applying the 50,000 bpd design constraint to the once-through configuration results in significantly larger gasification, gas-cleanup, and power island areas of the facility, and consequently, higher capital outlays and operating costs for the poly-generation facility. Put simply: more syngas must be generated in the gasification island for the "once-through" cases to make up for the absence of recycled syngas, increasing the size of the facility in those cases.

Finally, life cycle GHG assessments were performed using the "displacement" methodology of accounting for co-products produced in the facilities, namely FT naphtha and in some cases electrical power. As this methodology can be sensitive to the assumed GHG profiles of the co-products, a second methodology was also utilized wherein the life cycle GHG emissions produced prior to the product transportation and use are divided across all of products based on the usable energy fraction of that product. The results of the "energy allocation" LCA are detailed in Appendix B of the report.

Key Design Choices

The decision to evaluate both bituminous and subbituminous coals, as well as biomass, dictated a number of design choices, including plant location and water management strategy. The bituminous coal cases were assumed to be located in Illinois near the coal resource. As water availability is not expected to be a concern in Illinois locations, process cooling was accomplished by the use of mechanical draft evaporative cooling towers, which are the most economical and have the smallest impact on overall plant efficiency.

Subbituminous coal is generally found west of the Mississippi in the Powder River Basin (PRB). The facilities which utilize PRB coal are assumed to be located in Montana where water resources are expected to be scarce, requiring tight water management. This prompted the evaluation of three different strategies for process cooling water management: (1) mechanical draft evaporative cooling towers; (2) hybrid cooling in which a closed loop, air-cooled condenser is utilized to condense steam exiting the low-pressure turbine – reducing evaporative cooling load and therefore water losses – and the remainder of the cooling needs are met through the use of mechanical draft evaporative cooling towers similar to those used in the first strategy; and (3) a closed-loop, indirect, dry cooling system is used in which air is blown through a dry-cooling tower and the only water losses in the process cooling system are those associated with blow-down to maintain water quality. This provided insights into impacts water use reduction on the performance and economics of facility.

The feedstocks, along with the FT operating requirements (high pressure, oxygen-blown operation), also dictated the choice of gasification technology. The use of relatively reactive, high-moisture feedstocks such as the PRB coal and biomass indicate that either a fluidized bed or a dry-feed gasifier would be appropriate. However, a fluidized bed gasifier is not appropriate for bituminous coals due to the reduced reactivity of that feedstock, hence it was determined that a dry feed, entrained flow gasifier would be used for syngas generation in this study.

[1] Liquefied Petroleum Gases, or LPGs, produced were combusted for electricity generation.

A preliminary analysis comparing the performance of the commercially-available dry-feed, entrained flow gasifiers – a notably those offered by Shell and Siemens – concluded that the environmental performance and efficiency of the Shell-type gasifier was better, but that the use of the lower cost Siemens gasifier resulted in a lower price hurdle for the product. The Siemens gasifier was selected for use in this study in order to produce the least expensive fuel, but it is recognized that a choice to place a focus on environmental or system performance might result in different gasifier choice.[1] Similarly, other gasifiers might be appropriate for different feedstocks or feedstock pairings.

A final design choice was to use a combined cycle – gas turbines to combust unconverted syngas and F-T tail gases coupled with a heat recovery steam generator (HRSG) and steam turbine – for the production of electric power to meet the needs of the facility. This marks a shift in design from the *Affordable, Low-Carbon Diesel Fuel* study, in which these gases were combusted in a boiler to raise steam for use in a steam turbine. The shift to a combined cycle has the benefit of a more efficient power generation cycle, but results in the production of excess electrical power in a number of the recycle plant designs based on a need to meet turbine flow rate requirements.

The production of excess power in both the fuels-focused and poly-generation scenarios can make the comparison of the different facilities more difficult due to the:

1) choice of life cycle analysis (LCA) methodology, which can result in significantly different results when evaluating electricity as a co-product, and
2) the power cycle being less efficient than the production of fuels, which can give the appearance that the use of one feedstock over another would be preferred.

Key Results

The over-arching results of this study are that diesel fuel produced from coal:

- Is economically viable when crude oil prices reach $95/bbl or $98/bbl for the recycle and poly-generation scenarios, respectively. This equates to diesel prices in the range of $2.70 to $2.80 per gallon of petroleum diesel.
- Will produce less life cycle GHG emissions than petroleum fuels if produced from a recycle facility, regardless of the LCA methodology employed, so long as CO_2 produced by the facility is sequestered. In the case of particularly high-methane content bituminous coals, methane mitigation may also be required at the site of the mine.
- Will, in the case of the poly-generation scenario, produce either significantly less or slightly more life cycle GHG emissions than petroleum fuels depending on the LCA methodology used. Therefore, poly-generation facilities might require the use of modest amounts of biomass (less than 10% by weight) or more aggressive carbon capture strategies if petroleum parity is required.
- Will require between 1.6 and 7.4 barrels of water for each barrel of FT product produced, depending on the water management strategy utilized.

[1] The NETL report entitled *Cost and Performance Baseline for Fossil Energy Plants Volume 4: Coal-to-Liquids via Fischer-Tropsch Synthesis*, due to be published later this year, examines the use of a Shell gasifier and can be used as counter-point to this study.

If a modest amount of biomass is co-gasified with the coal to produce liquid fuels:

- The point of economic viability is increased by $9 to $15 per bbl, to between $104/bbl and $115/bbl, representing a $0.26 to $0.46 per gallon increase in fuel price over the coal cases.
- The fuel will produce less GHG emissions than petroleum-derived fuels, regardless of the configuration choice or LCA methodology, if 15 percent of the feedstock to the facility is switchgrass. A reduction of up to 34 percent less life cycle GHG emissions than petroleum-derived diesel is possible at this level of biomass usage.

Additional results:

- The overall plant efficiency of the sub-bituminous coal cases is higher than that of the bituminous coal cases. This is due to the increased electrical power produced in the bituminous coal cases, which reduces the efficiency of the facility (as power generation is less efficient than fuel production). Less power is produced in the sub-bituminous cases as some of the steam which would otherwise be used for power production is instead utilized to dry the relatively high-moisture content subbituminous coal.
- The poly-generation cases are all larger and more expensive than the recycle cases due to the 50,000 bpd design constraint. The facilities would be similar in size and cost if the coal input rate – and therefore syngas production rate –was held constant between the two cases, although the poly-generation cases would then have a lower fuels output.

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Acronyms and Abbreviations

AR	As Received
ARR	Annual Revenue Requirement
ASU	Air Separation Unit
BEC	Bare Erected Cost
BFW	Boiler Feedwater
BPD	Barrels per Day
CBM	Coal Bed Methane
CBTL	Coal/Biomass-to-Liquids
CCS	Carbon Capture and Sequestration
CE	Carbon Equivanlent
CH_4	Methane
CMM	Coal Mine Methane
CO_2	Carbon Dioxide
CO_2E	Carbon Dioxide Equivalent
COE	Crude Oil Equivalent
CRF	Capital Recovery Factor
CTEU	Cradle-to-end-user
CT	Cooling Tower
CTL	Coal-to-Liquids
DB	Daily Barrel
DCF	Discounted Cash Flow
DOE	Department of Energy
EISA	Energy Independence and Security Act
EPA	Environmental Protection Agency
EPCC	Engineering, Procurement, and Construction Cost
FT	Fischer-Tropsch
GHG	Greenhouse Gas
GWP	Global Warming Potential
HHV	High Heating Value
HRSG	Heat Recovery Steam Generator
IGCC	Integrated Gasification Combined Cycle
IPCC	Intergovernmental Panel on Climate Change
LCA	Life Cycle Analysis
LHV	Low Heating Value
LP	Low Pressure
LPG	Liquefied Petroleum Gas
MAC	Main Air Compressor
MDEA	Methyldiethanolamine
MF	Monitoring Fund
N_2O	Nitrous Oxide
NETL	National Energy Technology Laboratory
NGCC	Natural Gas Combined Cycle
O&M	Operations and Maintenance

OPEC	Organization of the Petroleum Exporting Countries
OT	Once-Through
PR	Petroleum Ratio
PRB	Powder River Basin
RSP	Required Selling Price
SG	Switchgrass
SWS	Sour Water Stripper
T&D	Transmission and Distribution
TASC	Total as Spent Capital
TCR	Total Capital Requirement
TOC	Total Overnight Cost
TPC	Total Plant Cost
TPD	Tons per day
TS&M	Transport, storage, and monitoring

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Executive Summary

If, in the future, world conventional oil supplies become scarce enough to threaten the security of our nation's energy supply, the ability to produce fungible transportation fuels from our domestic coal and biomass resources could counterbalance this threat.

Because of the continuing concern over global climate change, Section 526 of the Energy Independence and Security Act (EISA) mandates that Government cannot purchase alternative fuels that have a greenhouse gas (GHG) footprint higher than petroleum. To meet this requirement for coal-to-liquids (CTL) plants, successful deployment of carbon capture and sequestration (CCS) will be necessary.

When CCS is applied to CTL the resulting life cycle greenhouse gas (GHG) footprint for production and utilization of CTL fuels can be less than comparable fuels produced from petroleum. Additions of small quantities of biomass that can be gasified together with the coal can further reduce the GHG footprint compared to petroleum. In these ways, with choice of configuration, CCS, and addition of biomass, the life cycle GHG emissions can be considerably less than petroleum.

In addition to concerns over global climate change, availability of fresh water is becoming an important issue. This is particularly the case in semi-arid areas where there is competition for scarce water resources. These areas include the Powder River Basin regions of Montana and Wyoming where about 37 percent of the nation's demonstrated coal reserve base resides. Utilization of this Western coal resource at a near mine mouth location would mandate employment of water management practices that minimize consumption.

Because of these dual concerns of climate change and water availability the National Energy Technology Laboratory (NETL) requested that Noblis perform an analysis of conceptual CTL and Coal/Biomass-to-Liquids (CBTL) plant configurations that could reduce both the GHG footprint as estimated by life cycle analysis (LCA) and the overall consumption of water. In response to this request, Noblis simulated a series of conceptual CTL and CBTL plant configurations with recycle and once-through configurations, with bituminous and subbituminous coals, with CCS, with and without addition of biomass, and with various water management options. These conceptual plants were then analyzed to determine the technical performance, to estimate the economics and required selling price of the fuels, to estimate the overall water consumption, and to compare the life cycle GHG footprint with petroleum derived fuels.

Aspen Plus was used to simulate conceptual CTL and CBTL plants that produced Fischer-Tropsch (FT) diesel fuel, naphtha, and in many cases electric power for sale to the grid. Both bituminous and subbituminous coals were used as feedstock to the CTL plants and 15 percent by mass switchgrass on an as received basis was added in the CBTL configurations. The plants were operated in both recycle and once-through modes.

There are sixteen configurations analyzed in this report. The Case Identifier is a five character code based on the specific case configuration. The first character denotes the coal type with "B" denoting bituminous and "S" denoting subbituminous. The second character denotes the recycle configuration. "R" denotes simple recycle and "O" denotes once-through. The third character denotes the cooling configuration. "W" refers to the system where mechanical draft water cooled cooling towers are used for the plant cooling duties. "A" denotes configurations with maximum air cooling and "H" denotes the hybrid cooling scheme. Only the subbituminous coal plants assumed to be located in Montana, where water resources are scarce, use A and H water management. The fourth and fifth characters designate the mass fraction of biomass on an as-received basis.

For the bituminous coal cases (BRW00, BOW00, BRW15, and BOW15) the following findings can be made by referring to Table ES-1:

- For the two CTL plants with no biomass addition (cases BRW00 and BOW00) the petroleum ratio (PR) calculated by using the LCA displacement methodology was found to be less than one. The PR is defined in Section 3.4 and if it is less than one the life cycle GHG emissions are less than diesel fuel produced from crude oil (petroleum-derived diesel fuel). The PR for once-through configurations was lower than for recycle because the displacement methodology was used for the GHG LCA and credit was taken for co-produced power and naphtha. This implies that if the LCA displacement methodology is used, CTL plants with CCS are able to produce fuels compliant with Section 526 with no biomass addition if the appropriate configuration is used to capture the CO_2 produced during fuels production.
- One feasible option to further reduce the PR of CTL plants with CCS is to add biomass. This study analyzed the impact of adding 15 percent by mass of switchgrass (on an as-received basis). For the recycle case this reduced the PR from 0.91 to 0.70; well below the GHG footprint of petroleum-derived fuels. However for this size plant this required the addition of 3,500 TPD of biomass. To obtain that quantity of biomass on a continuous basis for 328 days per year could well be a challenge. The encouraging aspect is that only a relatively small percentage of biomass would be needed to be significantly below a PR of one. This implies that amounts lower than 15 percent would insure that the CBTL plant would be capable of producing fuels easily compliant with Section 526 of EISA. The lowest petroleum ratio of 0.53 was for the 15 percent biomass once-through case. This is the result of taking the biomass carbon credit and the power and naphtha displacement credits.
- For the bituminous coal cases the overall efficiency was higher for plants configured in the recycle mode of operation. This is because it is generally more efficient to produce fuels than power.
- For the bituminous coal cases there was no effort made to reduce water consumption and conventional water cooling was used. For recycle cases water consumption was around 7.5 barrels per barrel of fuel product[‡]. For once-through cases water demand increased

[‡] Note that this analysis ratios the water use to the fuels products, not the total energy products. If there was no excess power, the water usage ratio would be smaller.

(around 8.5 barrels per barrel) because of additional cooling duty needed for turbine steam condensation.

- In the recycle mode, addition of 15 percent biomass imposes about a $10 per barrel penalty on the required selling price (RSP) of the FT diesel product. In the once-through mode the penalty increases to $13 per barrel of FT diesel product ($13/bbl$_{FTD}$). This penalty is the result of the high cost of biomass on a Btu basis ($5.34/MMBtu) and the pretreatment and biomass preparation costs. The penalty is exacerbated in the once-through case by the increased biomass feed rate required to the facility, associated with the larger overall size of the once-through plants.
- The resulting RSP of zero sulfur diesel fuel from these bituminous C/BTL plants averages $122/bbl$_{FTD}$ ($2.90/gallon$_{FTD}$).

For the subbituminous coal only cases (SRW00, SRA00, SRH00, SOW00, SOA00, and SOH00) the following findings can be made by referring to Table ES-2:

- The six subbituminous cases all produce fuels with slightly lower PRs than petroleum-derived fuel. The once-through cases have lower PRs than the recycle cases because of the electric power GHG displacement credit.
- The subbituminous cases investigated three different water management techniques to assess their impact on performance and costs. For a benchmark, case SRW00 used all water cooling although this would be unlikely in practice because of the semi-arid plant location. Using indirect air cooling for the recycle case reduced water use from 6.7 barrels of water per barrel of fuel product (bbl/bbl) to 1.6 bbl/bbl. The hybrid water management system had a water use in between air and water cooling at 3.9 bbl/bbl. Similar results were obtained for the once-through configurations although water use is increased over that of the recycle cases.
- Air and hybrid cooling impose an additional energy penalty that results from the power use for the air cooling fans. This increases the parasitic power requirement for these cases.
- Using air and hybrid cooling imposes a cost penalty that is reflected in the increase in the RSP of the diesel fuel produced. Air cooling increases the RSP of diesel in the recycle case by $5.40/bbl$_{FTD}$. Hybrid cooling adds a $3.20/bbl$_{FTD}$ penalty. Because of the value of the co-produced power the penalty for the once-through cases is less.
- For water cooling cases the total overnight cost (TOC) is higher for the subbituminous plants than for the bituminous. This is primarily because of the greater coal throughput in the subbituminous cases. However, the lower coal cost tends to compensate for this and the resulting diesel RSPs for Cases BRW00 and SRW00 are very close, as are the RSPs for Cases BOW00 and SOW00.

For the subbituminous coal cases with biomass (SRW15, SRA15, SRH15, SOW15, SOA15, and SOH15) the following findings can be made by referring to Table ES-2:

- The PRs are significantly reduced compared to the subbituminous coal-only cases. Section 526 compliance would be readily attained with these configurations.

- As expected the trends in water usage follow those of the subbituminous coal-only cases.
- The TOC for this series of cases is the highest. This is because of the higher plant coal through put and the costs of biomass pretreatment. This results in the highest RSP for the FT diesel product.

This comprehensive study of C/BTL using different coals, different configurations, and several water management options has produced a matrix of results that can be used to gain a better understanding of the complexities of these integrated systems. The overall findings of this study are that both Eastern bituminous and Western subbituminous coals could be used to produce high quality, fungible diesel fuel for transportation if future circumstances warranted. Further, that this fuel could be produced with a smaller GHG footprint than petroleum fuels[§] and with low water consumption.

However, the estimated capital cost of these C/BTL plants is high, in the range of $135,000 to $170,000 per daily barrel on a TOC basis. This combined with feedstock and other operating and maintenance costs results in RSPs for the diesel fuel produced in the range of $113-$137 per barrel$_{FTD}$ ($2.68 -$3.27/gallon$_{FTD}$). These fuels will be economically viable to produce when crude oil is as low as $94 to $95 per barrel ($94-$95/bbl$_{COEP}$, or crude oil equivalent price) for the coal-only cases (subbituminous and bituminous coal cases, respectively) or as low as $104 to $109/bbl$_{COEP}$ for the coal/biomass cases (bituminous and subbituminous cases, respectively).

It should also be emphasized that this study is a conceptual design study. The technologies utilized are all commercially available, however, the specific plant configurations evaluated have not been built. Therefore, while the configurations are technically feasible, an integrated demonstration will be required to reduce the potentially significant uncertainty in both the estimated capital and operating costs of the plants.

There are also technical performance uncertainties. Primary among these is the suitability of the biomass switchgrass to be used as a feed for high pressure entrained flow gasification. Pretreatment of this material will be challenging and other more amenable biomass may have to be used in a commercial plant. Although there will be some differences in the results if other biomass is used it is not expected to change the overall conclusions of the study.

In this study it is assumed that once the CO_2 produced in the C/BTL plant has been captured and compressed it can be sequestered for a certain cost and these costs are accounted for in the cost of the fuel. One sequestration pathway, enhanced oil recovery (EOR), has been proven and may be the best near-term solution for CO_2 long-term sequestration. This report, however, assumes sequestration in a geologic reservoir owing to the larger sequestration potential of such reservoirs. Technologies and potential storage reservoirs for this approach are currently being demonstrated and the hope is that many of them will prove successful. Another uncertainty is the costs and penalties associated with using total indirect air cooling for cooling duty. The costs and

[§] In the case of the CTL configurations, the actual plant configuration and feedstock choice required for the fuel to meet this requirement will vary based on the LCA methodology utilized, as certain methodologies favor a recycle configuration, while others favor the co-production of electricity (once-through). The co-utilization of small fractions of biomass in the C/BTL configurations ensures that the fuel has a smaller GHG footprint than petroleum fuels.

penalties involved may be higher than have been estimated in this study. Another issue is the disposition and value of the FT co-product naphtha. Although an excellent feed stock for ethylene production, production of large quantities of this material may not be readily marketable. Additional studies being performed by NETL are examining the potential of upgrading this naphtha to gasoline of a sufficient octane to be used as a fungible fuel in today's fueling infrastructure.

Table ES-1: Results of Bituminous Coal Configurations

	Coal Only		Coal/Biomass	
Case Identifier	**BRW00**	**BOW00**	**BRW15**	**BOW15**
Efficiency, HHV (%)	51.6	49.9	50.8	48.6
Petroleum Ratio	0.91	0.74	0.70	0.53
Export Power (MW)	109.9	397.3	48.9	319.4
Parasitic Power (MW)	516.9	585.9	570	650.8
Water (gpm)	10,815	12,508	10,583	12,601
Water(bbl water/bbl FT product)	7.42	8.58	7.26	8.64
BEC ($MM)	4,084	4,556	4,247	4,776
Coal ($MM/yr)	283	318	255	289
Biomass ($MM/yr)	0	0	93	106
O&M ($MM/yr)	371	409	386	430
TOC ($MM)	6,781	7,561	7,061	7,936
TOC ($/DB)	135,640	151,220	141,220	158,700
RSP ($/bbl FT diesel)	114.5	117.5	125.0	130.8
COE($/bbl petroleum)	95.4	97.9	104.2	109.0

Table ES-2: Results of Subbituminous Coal Configurations

	Coal Only Configurations						Biomass And Coal					
Case Identifier	**SRW00**	**SRA00**	**SRH00**	**SOW00**	**SOA00**	**SOH00**	**SRW15**	**SRA15**	**SRH15**	**SOW15**	**SOA15**	**SOH15**
Efficiency, HHV(%)	53.0	51.3	52.2	50.6	50.1	50.5	50.0	48.2	49.5	48.9	48.4	48.8
Petroleum Ratio	0.93	0.97	0.95	0.82	0.86	0.83	0.66	0.70	0.67	0.52	0.57	0.53
Export Power (MW)	0.0	0.0	0.0	227.2	190.9	213.9	0.0	0.0	0.0	190.3	150.5	177.2
Parasitic Power(MW)	504.5	539.0	524.6	568.4	588.0	581.9	605.3	648.9	624.9	659.1	679.2	672.4
Water (gpm)	9,741	2,348	5,715	11,540	2,693	6,798	10,688	2,386	6,590	11,881	2,490	7,005
Water(bbl water/bbl FT product)	6.68	1.61	3.92	7.91	1.85	4.66	7.33	1.64	4.52	8.15	1.71	4.8
BEC ($MM)	4,238	4,473	4,384	4,735	4,848	4,822	4,681	4,963	4,815	5,069	5,180	5,152
Coal ($MM/yr)	116	120	118	130	130	130	107	112	109	116	116	116
Biomass($MM/yr)	0	0	0	0	0	0	117	121	118	126	126	126
O&M ($MM/yr)	411	424	418	454	455	455	447	462	453	479	479	480
TOC ($MM)	7,020	7,400	7,255	7,836	8,015	7,975	7,763	8,221	7,978	8,403	8,577	8,533
TOC ($//DB)	140,380	148,020	145,100	156,720	160,300	159,480	155,240	164,420	159,560	168,040	171,540	170,660
RSP ($/bbl FT diesel)	112.7	118.1	115.9	117.3	120.7	119.4	130.4	137.0	133.4	133.8	137.3	135.8
COE($/bbl petroleum)	93.9	98.4	96.6	97.8	100.6	99.5	108.7	114.2	111.2	111.5	114.4	113.2

1 Introduction

If, in the future, world conventional oil supplies became scarce enough to threaten the security of our nation's energy supply, the ability to produce fungible transportation fuels from our domestic coal and biomass resources could counterbalance this threat.

Because of the continuing concern over global climate change, Section 526 of the Energy Independence and Security Act (EISA) mandates that Government cannot purchase alternative fuels that have a greenhouse gas (GHG) footprint higher than petroleum. To meet this requirement for coal-to-liquids (CTL) plants successful deployment of carbon capture and sequestration (CCS) will be necessary.

When CCS is applied to CTL the resulting life cycle greenhouse gas (GHG) footprint for production and utilization of CTL fuels can be less than comparable fuels produced from petroleum. Additions of small quantities of biomass, which can be gasified together with the coal, can further reduce the GHG footprint compared to petroleum. In these ways, with choice of configuration, CCS, and addition of biomass the life cycle GHG emissions can be considerably less than petroleum.

In addition to concerns over global climate change, availability of fresh water is becoming an important issue. This is particularly the case in semi-arid areas where there is competition for scarce water resources. These areas include the Powder River Basin regions of Montana and Wyoming where about 37 percent of the nation's demonstrated coal reserve base resides. Utilization of this Western coal resource at a near mine mouth location would mandate employment of water management practices that minimize consumption.

Because of these dual concerns of climate change and water availability the National Energy Technology Laboratory (NETL) requested that Noblis perform an analysis of conceptual CTL and Coal/Biomass-to-Liquids (CBTL) plant configurations that could reduce both the GHG footprint as estimated by life cycle analysis and the overall consumption of water. In response to this request, Noblis simulated a series of conceptual, Fisher-Tropsch-based CTL and CBTL plant configurations with recycle and once-through configurations, with bituminous and subbituminous coals, with CCS, with and without addition of biomass, and with various water management options. These conceptual plants were then analyzed to determine the technical performance, to estimate the economics and required selling price of the fuels, to estimate the overall water consumption, and to compare the life cycle GHG footprint with petroleum derived fuels.

The GHG emissions reported here are for the diesel product and these estimates are based on applying displacement credits for the co-products naphtha and electric power. An alternative methodology for estimating GHG emissions in a co-production scenario is to allocate the emissions amongst the products separately. The results of the GHG estimates based on an energy allocation method are provided in Appendix B.

1.1 Scope of the Study

Table 1-1and Table 1-2 define the scope of the conceptual plant configurations analyzed in this study. All of the plants are configured to produce 50,000 barrels per day (BPD) of zero sulfur diesel fuel and naphtha. All plants use CCS to capture the carbon dioxide produced during the production of the fuels and electric power. In contrast to some prior studies, the configurations analyzed in this study did not use aggressive strategies to decarbonize fuel gas streams and hence the amount of CO_2 captured will be less than the 90% value attained in some previous studies[1]. Also, this study did not include a non-CCS (CO_2 vent) case since part of the focus was on Section 526 compliance. Previous work did include a non-CCS case. The minimum crude oil price required for economic feasibility for the non-CCS case for that study was $83.57/bbl. There was a 3% increase for the all coal feed with CCS case. Likewise, the required selling price of diesel for the non-CCS case was $2.49/gal and $2.56/gal for the all coal feed with CCS case.

All plants generate the parasitic electricity needed to power the facility and in some cases, excess power for sale. Four of the configurations use Eastern Bituminous coal (Illinois #6) and are located in the Eastern U.S. where adequate water is assumed to be available. The other plants use Western PRB coal from Montana and the plants are assumed to be located in Montana where water resources are scarce.

All configurations use Siemens entrained flow gasification with full water quench to produce the raw synthesis gas from the coal feed[2,3]. Raw synthesis gas (syngas) conditioning is accomplished using conventional cold gas cleaning for sulfur removal and recovery and for bulk CO_2 removal. Synthesis is accomplished using low temperature Fischer-Tropsch (FT) slurry phase reactor technology using iron based FT catalysts[4].

Table 1-1: Bituminous Coal Configurations

Case Identifier	**BRW00**	**BOW00**	**BRW15**	**BOW15**
Biomass Type	NONE	NONE	SG	SG
Biomass Mass (%)	0	0	15	15
Configuration	Recycle	Once-Through	Recycle	Once-Through
Water Management	Water / CT	Water / CT	Water / CT	Water / CT

All use Siemens gasifier, LT Slurry reactor, CCS, plant located at Eastern US, produce 50,000 BPD of diesel and naphtha.

For plants cases designated “Once-Through”, the clean syngas is passed through the FT reactors one time only. After product recovery and CO_2 removal, the unconverted syngas and light hydrocarbons are sent to gas turbines for power generation. These configurations produce liquid fuels and a large quantity of power as a co-product. Plant cases designated “Recycle” use the recycle configuration where most of the unconverted syngas and light hydrocarbons are recycled back to the FT reactors (after CO_2 removal) to increase the liquid production. The balance of the unconverted syngas and light hydrocarbons are diverted to the gas turbines for power generation.

Half of the configurations are coal/biomass-to-liquids (CBTL) configurations where 15 percent biomass (switchgrass, SG) by mass, on an as-received basis, is added to the coal and co-fed to the gasifiers to produce the syngas.

Three water management systems are used in the configurations evaluated. Columns in Table 1-1 and Table 1-2 designated “Water / CT” refer to the water management system where mechanical draft, water-cooled, cooling towers are used for the plant cooling duties. Columns designated “Max Air” use maximum air cooling to minimize the consumption of water. This system uses indirect air cooling for the plant cooling duties. Columns designated by “Hybrid” use a combination of water cooling and direct air cooling for the plant cooling duties. Only the plants assumed to be located in Montana where water resources are scarce use maximum air cooling or hybrid cooling.

There are sixteen configurations analyzed in this report. The Case Identifier is a five character code based on the specific case configuration. The first character denotes the coal type with “B” denoting bituminous and “S” denoting subbituminous. The second character denotes the recycle configuration. “R” denotes simple recycle and “O” denotes once-through. The third character denotes the cooling configuration. “W” refers to the system where mechanical draft water cooled cooling towers are used for the plant cooling duties. “A” denotes configurations with maximum air cooling and “H” denotes the hybrid cooling scheme. The fourth and fifth characters designate the mass fraction of biomass on an as-received basis.

For example, Case “BRW00” is shorthand for bituminous coal, recycle mode, water cooling, and no biomass. In a similar manner, “BOW15” is bituminous coal, once-through mode, water cooling, with 15 percent biomass. For the subbituminous coal cases, “SRA00” means subbituminous coal, recycle, air cooling, and no biomass. Similarly, “SOH15” is subbituminous coal, once-through mode, hybrid cooling, with 15 percent biomass.

Table 1-2: Subbituminous Coal Configurations

Case Identifier	SRW00	SRA00	SRH00	SOW00	SOA00	SOH00	SRW15	SRA15	SRH15	SOW15	SOA15	SOH15
Biomass Type	NONE	NONE	NONE	NONE	NONE	NONE	SG	SG	SG	SG	SG	SG
Biomass Mass (%)	0	0	0	0	0	0	15	15	15	15	15	15
Configuration	Re-cycle	Re-cycle	Re-cycle	Once-Through	Once-Through	Once-Through	Recycle	Recycle	Recycle	Once-Through	Once-Through	Once-Through
Water Management	Water / CT	Max Air	Hybrid	Water / CT	Max Air	Hybrid	Water / CT	Max Air	Hybrid	Water / CT	Max Air	Hybrid

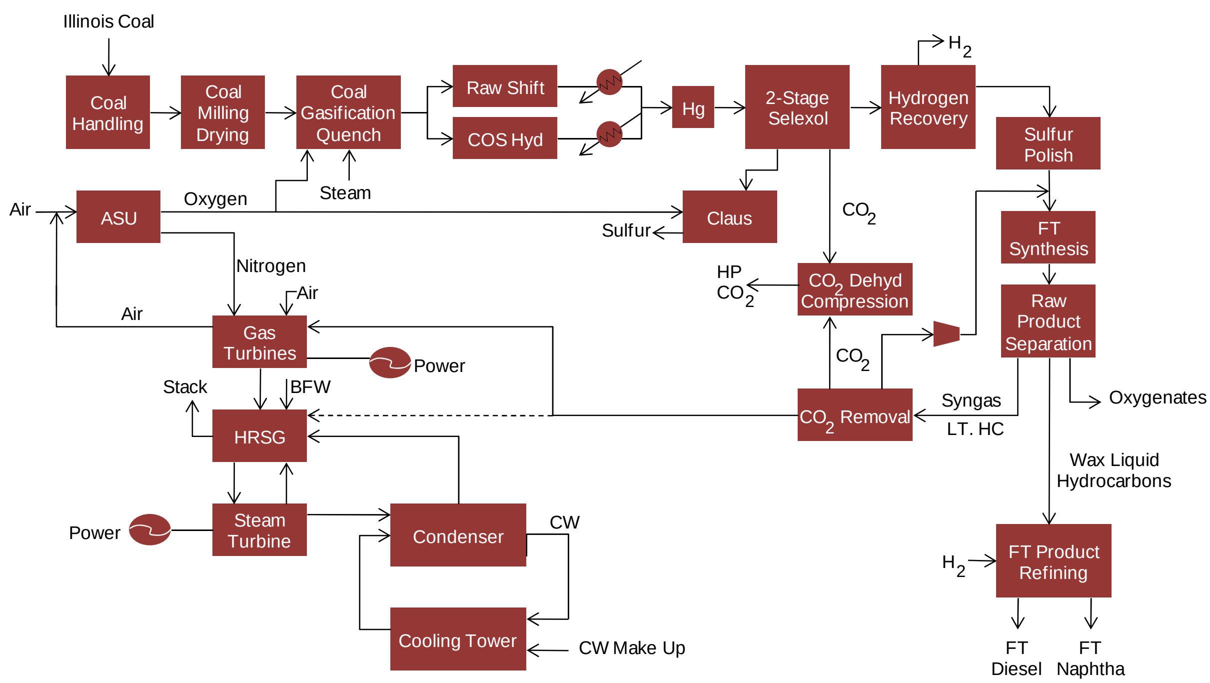
All use Siemens gasifier, LT Slurry reactor, CCS; plant located at Western US, produce 50,000 BPD of diesel and naphtha.

2 Basis of Conceptual Plant Designs

2.1 Case BRW00: CTL Recycle Configuration, Bituminous Coal

Figure 2-1 shows a block flow schematic for the Case BRW00 CTL simple recycle configuration. As received (AR) Illinois #6 coal is reclaimed and milled and dried to 6 percent moisture before it is fed via lock hoppers to the Siemens full water quench gasifiers. Steam and 95 percent oxygen are added and the mixture undergoes gasification in the water-wall cooled, down flow, entrained gasifiers. The raw syngas exiting the gasification section enters the water quench chamber where recycled quench water rapidly cools and saturates the syngas. The slag is removed from the bottom of the gasifier quench section, is crushed and exits as granulated, non-leachable slag. The raw syngas stream is further scrubbed to remove remaining particulates, cyanide, and ammonia, then split with one portion being sent to raw shift and the other to COS hydrolysis. This allows a syngas H_2:CO ratio of 1:1 to 1.1:1 to be achieved – the ratio required for FT synthesis with an iron catalyst – without over-shifting. The gas is cooled and the majority of the condensate is recycled to the quench and some is sent to the sour water stripper (SWS). The syngas streams are combined and mercury is removed from the cooled gas and the syngas enters the two-stage Selexol acid gas removal unit. The H_2S is recovered and sent to the Claus unit for sulfur recovery and the CO_2 is removed in the second stage of the Selexol unit and sent to CO_2 dehydration and purification before being compressed to 2200 psi.

Figure 2-1: Block Flow Schematic for the Case BRW00 CTL



The cleaned syngas containing a few ppm of sulfur is sent to hydrogen recovery using PRISM/PSA to recover enough hydrogen for the FT refining section. The syngas is then polished using zinc oxide to remove the last of the sulfur before being sent to the slurry phase FT reactors.

The cleaned conditioned syngas is passed to the FT section of the plant that has several trains of FT reactors with each train consisting of two slurry phase FT reactors in series. Overall syngas conversion to FT products is about 80 percent. The overhead from the FT reactors is sent to raw product cooling and separation where the products are separated into a gaseous phase consisting of unconverted syngas, CO_2, nitrogen, and light hydrocarbon gases; a hydrocarbon liquids phase; and an aqueous phase containing the FT oxygenates. The gases are sent to a MDEA unit for CO_2 removal and then the gas stream is split so that a portion is recycled back to the FT reactors and the remaining gas is sent to the combustor of the gas turbines. The removed CO_2 is sent to CO_2 dehydration, purification and compression. The hydrocarbon liquids are sent to the refinery and the aqueous phase is sent to wastewater treatment to remove oxygenates. The raw wax product is removed from the FT reactors and also sent to the refinery for further upgrading into diesel fuel.

The plant power island consists of one “FB-class” syngas turbine, heat recovery steam generator (HRSG), and steam turbine generator. The air separation units (ASU) provide nitrogen diluent to the gas turbine and there is air extraction from the gas turbine compressors to reduce the ASU main air compressors (MAC) power requirements.

Carbon dioxide is recovered from the two-stage Selexol units before the syngas enters the FT section to reduce inert gas volume through the slurry reactors. Carbon dioxide produced in the FT reactors is recovered from the FT tail gas prior to being sent to the gas turbine combustors. This reduces the carbon content of the gas turbine feed. The combined CO_2 streams are dehydrated and purified using auto-refrigeration to meet the Kinder Morgan CO_2 pipeline specification of 95 percent purity. The CO_2 is then compressed to 2200 psi and sent by pipeline to a suitable geological site for sequestration.

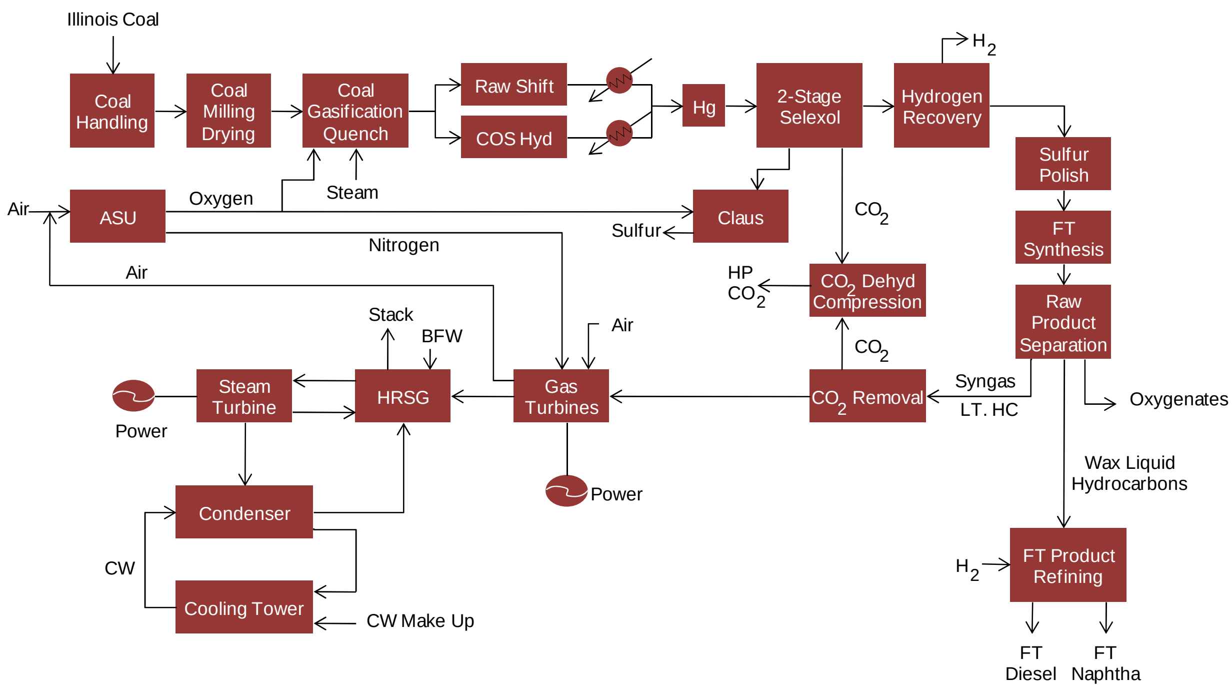
The FT refining section of the plant upgrades the raw FT products into specification diesel fuel and essentially unrefined FT naphtha. The raw separated liquid hydrocarbon FT product from the separator is distilled into a distillate (diesel) fraction and straight run naphtha. No more refining is applied to the straight run naphtha. The distillate fraction undergoes mild hydrotreatment to saturate olefins and the product from the hydrotreater is distilled to produce some hydrotreated naphtha and hydrotreated diesel. The raw wax product is sent to a hydrocracker where it is cracked to produce an essentially C_{23} endpoint diesel fraction. The hydrocracker product is distilled to separate refinery off-gas, hydrotreated naphtha, and diesel. This diesel hydrocrackate is blended with the hydrotreated diesel to produce the diesel product. The hydrotreated naphtha is blended with the straight run naphtha to produce the naphtha product. The refinery off-gases are used as fuel gas for fired heaters etc.

In this case, because adequate water is assumed to be available, all of the plant cooling duty is accomplished using conventional circulating cooling water with mechanical draft cooling towers.

2.2 Case BOW00: CTL Once-Through Configuration, Bituminous Coal

Figure 2-2 shows a block flow schematic for the Case BOW00 CTL once-through configuration. The production of the clean syngas is the same as for Case BRW00 described above. The difference between the cases is that the clean syngas is sent to the FT reactors only once and there is no unconverted gas recycle. All of the overhead gas phase effluent from the FT reactors is sent to CO_2 removal and then it is all sent to the gas turbines for electric power generation. The lack of a recycle stream has two notable impacts on the facility: (1) plant generates a larger amount of excess electric power for sales, as off-gasses which were recycled are now combusted; and (2), the entire facility – save the FT process area – is larger, and a higher coal flow rate is required to produce the additional syngas needed to compensate for the lack of a recycle. To accommodate the larger FT tail gas flow, the power island consists of two "FB-class" gas turbines, each with a HRSG, and one steam turbine. The power island is therefore larger by one "FB-class" combustion turbine than in Case BRW00, and produces a commensurate amount of additional power from the gas turbine section of the plant. . Again the plant cooling duty is accomplished with conventional mechanical draft cooling towers.

Figure 2-2: Block Flow Schematic for the Case BOW00 CTL



2.3 Case BRW15: CBTL Recycle Configuration, Bituminous Coal and 15 Percent Switchgrass

Figure 2-3 shows a block flow schematic for Case BRW15 CTL recycle configuration with addition of 15 mass percent switchgrass. In this case both coal and biomass are feeds to the gasification section and both feedstocks have to be handled and prepared to be suitable for feeding to the pressurized gasifiers. Coal preparation and feeding to high pressure entrained gasifiers is commercially demonstrated and the processes for this are well understood. Siemens suggests drying the coal to 6 percent moisture to allow smooth feeding through the lock hoppers and fluidized injection system.

Figure 2-3: Block Flow Schematic for Case BRW15 CBTL

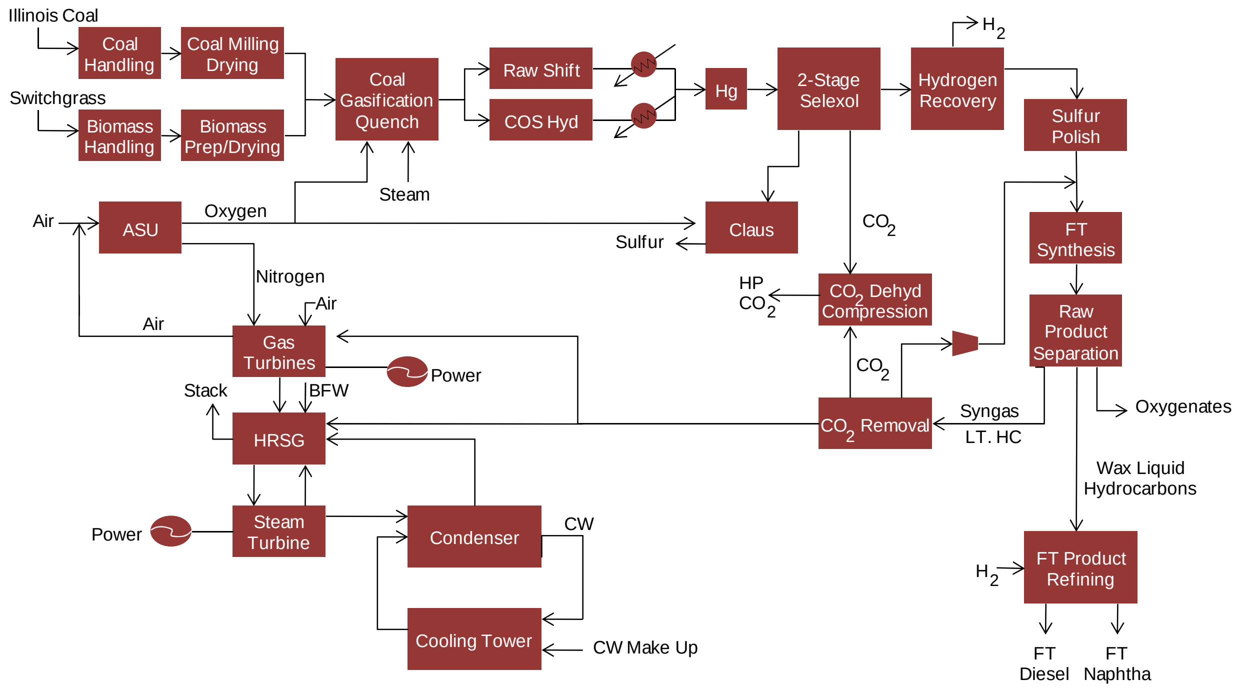
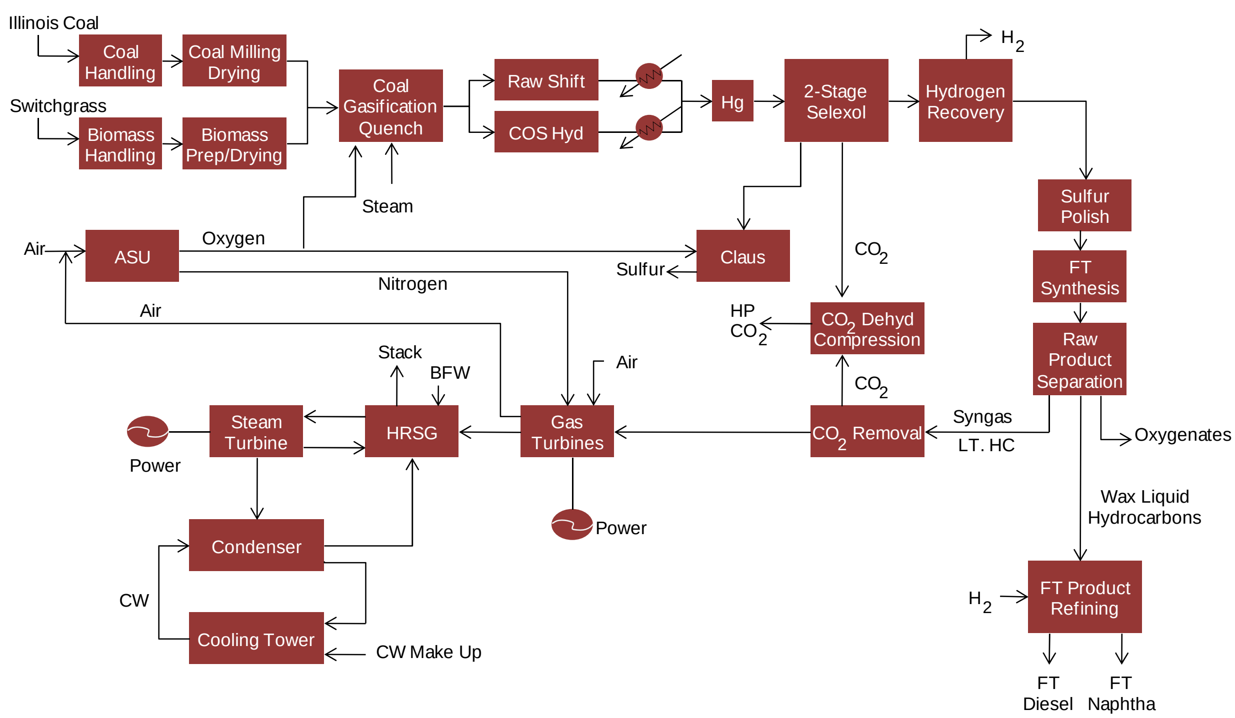


Figure 2-4: Block Flow Schematic for Case B0W15 CBTL



The situation for switchgrass is different. There is commercial experience in feeding up to 30 percent woody biomass and other wastes (notably chicken litter and sewage sludge) at the Shell IGCC plant in the Netherlands, which uses an entrained flow, high pressure gasifier which is similar to the Siemens gasifier evaluated in this study[4]. Similar tests attempted to feed 100 percent biomass into the Siemens gasifier (as conducted by Future Energy GmbH, the previous owners of the Siemens SFG technology) concluded that willow wood (pulverized to a d_{50} diameter of 210 microns) was not suitable for their fluidized pneumatic gasifier feeding system[5]. It proved to be impossible to fluidize this material at the 100 percent biomass level because of the fiber-like structures and the resulting high cohesion forces between the particles.

Additionally, as far as these authors are aware, there is no commercial experience in feeding switchgrass to entrained flow, high pressure gasifiers, and the fibrous and compressible nature of this feedstock may result in different feed characteristics and pre-treatment requirements prior to operation at larger biomass percentages.

The co-gasification of coal and biomass cases analyzed in this report utilize a feed which is predominantly pulverized coal with only 15 percent by mass of switchgrass. Because of this ratio it is assumed that the coal will effectively dilute the pulverized biomass particles so that the combination of the pulverized coal and switchgrass can still be fluidized and thus can be fed using the same feeding system as coal. This assumption is supported by the success in feeding up to 30 percent woody biomass into the Shell gasifier, and the relatively conservative estimate of 15 percent by weight is meant to provide a further margin for operational learning experience with switchgrass. Previous modeling efforts have shown that the use of different biomass types – such as woody biomass or corn stover in the place of switchgrass – would change the performance of the facility, but not appreciably, and the overall trends are expected to be similar.

Apart from this feed combination the plant configuration is the same as recycle configuration Case BRW00.

2.4 Case BOW15: CBTL Once-Through Configuration, Bituminous Coal and 15 Percent Switchgrass

Figure 2-4 shows the configuration for Case BOW15. This case has the same overall plant configuration as Case BOW00 except that the feed contains 15 percent switchgrass in addition to the bituminous coal.

2.5 Case SRW00: CTL Recycle Configuration, PRB Coal and Wet Cooling Tower Water Management

Case SRW00 has the same overall plant configuration as Case BRW00 with bituminous coal. In this case Montana Rosebud Powder River Basin (PRB) subbituminous coal is the feed rather than Illinois #6 bituminous coal and the location is assumed to be in Montana. This coal is a high moisture coal (25.77 percent as-received basis) and must be dried to about 6 percent before feeding to the gasifiers. Drying is accomplished using the RWE WTA process with vapor condensation[6]. The WTA process is a proprietary RWE Power technology developed for drying lignite and other high moisture coals with plants operating at Frechen and Niederaussem in Germany. In this process the coal is fluidized using steam in a compact fluid bed and drying is accomplished through heat exchange with steam pipes within the bed. The overhead vapors containing the coal moisture are sent to electrostatic precipitators to remove fines and some of the vapor is re-circulated to the bed for fluidization and the rest is condensed. This condensed moisture can be treated and used for process water. This is an advantage in the PRB cases where the CTL plants are assumed to be located in Montana close to the mine mouth where water resources are scarce.

Although this case is conceptually located in an arid region, for the purposes of comparing the impact of water management on overall water consumption, water cooled mechanical draft cooling towers were assumed for this case.

The plant power island consists of a single “FB-class” hydrogen-rich syngas gas turbine, one HRSG and one steam turbine. The higher elevation in the Montana location results in lower atmospheric pressure and this correspondingly reduces the power output from the gas turbine.

2.6 Case SRA00: CTL Recycle Configuration, PRB Coal, Maximum Air Cooling

The overall process configuration for this case is essentially the same as for Case BRW00. PRB coal is the feedstock and the location is assumed to be in Montana. The major difference in this case is the water management scheme. Instead of allowing circulating cooling water to evaporate in mechanical draft cooling towers, all of the cooling duty of the plant is accomplished by means of an indirect dry cooling system. In this system the circulating cooling water is in a closed loop and the heat is dispersed by blowing ambient air over-finned tube banks through which the circulating cooling water flows. These finned tubes are contained in a dry cooling tower structure. Indirect dry cooling is used rather than direct air cooling because of the multitude of necessary plant cooling duties in various locations of the plant infrastructure. The steam condensation duty from the steam turbine is also accomplished by this indirect air cooling system.

Because the largest water usage in conventionally water cooled towers results from cooling tower evaporation and blow down, dry cooling will significantly reduce the water use footprint of the plant because there is no cooling tower evaporation and drift loss.

Even though maximum air cooling is used in this case there will still be net raw water consumption in the plant. There is water needed for reactions and necessary blow down from the essentially closed-loop circulating cooling water in the indirect dry cooling system. In addition there are other water make up requirements in the plant. Net raw water consumption is very dependent on assumptions made for percent blow down needed to maintain circulating cooling water quality and for percent recycle achieved.

Indirect air cooling systems are more capital intensive than standard mechanical draft water cooling and the power requirements for the dry cooling tower fans are significantly higher than for mechanical draft fans.

2.7 Case SRH00: CTL Recycle Configuration, PRB Coal, Hybrid Cooling

The overall process configuration for this case is essentially the same as for Case BRW00. PRB coal is the feedstock and the location is assumed to be in Montana. The major difference in this case is the water management scheme. Instead of using indirect dry cooling for all the plant cooling duties a hybrid cooling system was used. In this hybrid cooling system, steam condensing duty from the LP turbine was accomplished using a direct dry air cooled condenser (ACC). This system uses aluminized carbon steel tube/aluminum fin tube bundles in an A-frame configuration that directly cools and condenses the steam from the LP steam turbine with air flowing across the A-frame. All the other cooling plant duties were accomplished using a conventional mechanical draft water cooling tower. This approach reduces the overall plant water consumption by eliminating almost half of the water cooled cooling duty.

2.8 Cases SOW00, SOA00, SOH00: CTL Once-Through Configuration, PRB Coal

These cases are analogous to the previous three cases described except that a once-through configuration is used. This leads to the generation of excess power for sales. The three cases encompass the three water management systems.

2.9 Cases SRW15, SRA15, SRH15, SOW15, SOA15, SOH15: CBTL Configurations, PRB Coal and 15 Percent Switchgrass

This series of configurations mirrors the previous six cases (cases SRW00 through SOH00) except that the feed is both PRB coal and 15 percent switchgrass. Three of the cases are recycle mode and three are once-through. In a similar manner to the above series all three water management systems are used.

3 Methodology

3.1 Process Performance Estimates

The conceptual process designs for all of the cases were based on systems level models for indirect coal liquefaction technology. Aspen Plus simulation models for the plants were developed to determine the composition and flows of all of the major streams in the plants. These were used to develop conceptual level cost estimates for capital and operating costs for the major process units. Because the cases were assumed to be located at two very different sites, site specific data was incorporated into the Aspen Plus models to adjust the performance predictions for the plants to the given conditions.

Where appropriate, additional specialized software packages were used to extrapolate the performance of certain unit operations under site-specific conditions. For example, GTPRO was used to validate gas turbine and steam cycle operating conditions and performance under the specific plant conditions and PROMAX was used to validate simulation of operations like sour water stripping. These performance predictions were then incorporated into the Aspen Plus systems models.

The Aspen Plus models have been validated against vendor data where possible and/or predictions from more detailed design models and are considered to be of appropriate accuracy for this conceptual feasibility study.

3.2 Cost Estimates

In most cases, the capital and operating cost estimates were obtained from conceptual-level cost algorithms that scale costs based on one or more measures of unit capacity. These algorithms have been developed based on information from the open literature[7]. In some cases, cost estimates were based on vendor quotes.

The methodology used to determine total capital requirement (TCR) is as follows. The bare erected cost (BEC) estimates for the various conceptual plants consist of equipment cost, material cost, and installation labor costs. These three components are added to give the BEC of the individual unit operations. The engineering, procurement, and construction cost (EPCC) is the sum of the BEC and the home office costs. The home office costs include detailed design costs and construction and project management costs. Home office costs are estimated as 9.5 percent of the BEC. The total plant cost (TPC) is the sum of the EPCC, the process contingencies, and the overall project contingency. The TPC is a depreciable capital expense. The process contingencies are added to the plant sections and the amount of the contingency depends on an engineering assessment of the level of commercial maturity of the process. The overall project contingency is assumed to be 15 percent of the sum of the BEC and process contingencies. This is added to compensate for uncertainty in the overall cost estimate.

The Total Overnight Cost (TOC) of the plants is defined as the sum of the TPC, the Owner's Cost, and the CO_2 monitoring fund. Table 3-1 shows the components of the Owner's Costs and Table 3-2 shows components of the as-spent capital.

Table 3-1: Components of Owner's Costs

Owners Cost Components
Initial Cost Of Catalyst & Chemicals
Land Cost ($3,000/Acre)
Financing Fee (2.7% Of TPC)
Other Owner's Cost (15% TPC)
Pre-Production Costs
1 Month Maintenance Materials
1 Month Non-Fuel Consumables
25% Of 1 Month Fuel Cost (100% Capacity Factor)
6 Months Plant Labor
1 Month Waste Disposal
2% Of TPC
Inventory Costs
60 Day Fuel/Consumables At 100% Capacity Factor
Spare Parts (0.5% Of TPC)

Table 3-2: Components of the Total As Spent Capital

Parameter	Consists Of
Bare Erected Cost (BEC)	Sum of the installed equipment costs for the various plant sections
EPCC	BEC + Home Office Costs
Total Plant Cost (TPC)	EPCC + Process Contingency + Project Contingency
CO_2 Monitoring Fund (MF)	Sinking fund for CO_2 monitoring and pore space acquisition costs
Total Overnight Cost (TOC)	TPC + CO_2 MF + Owner's Costs
Total As Spent Capital (TASC)	**TOC * TASC Multiplier of 1.14**

The CO_2 monitoring fund is a sinking fund set up for CO_2 monitoring and pore acquisition for the expected spreading of the CO_2 plume over the 30 operating years of the plants and continuing for 50 years after decommissioning.

The annual operating expenses for the plants are composed of fuel costs and variable and fixed operating costs. Fuel cost is the cost of the coal and switchgrass feedstocks to the plants based on assumed delivered prices. Non-fuel variable operating costs include catalysts and chemicals, water, solids disposal, maintenance materials, and CO_2 storage. The small quantities of natural gas and electric power needed for start-up are not included. Fixed operating costs include labor, administrative and overhead costs, local taxes and insurance and fixed CO_2 transport and storage costs. Gross annual operating costs are the sum of the fuel, variable, and fixed operating costs and are expressed in million dollars per annum based on 90 percent capacity factor. By-product credits include any sales of electric power to the grid. No credit is taken for the sale of elemental sulfur. No value is assumed for the carbon dioxide captured. Feedstock costs delivered to the plant on an as-received basis and the credit for electric power are shown below in Table 3-3 and Table 3-4. These values were provided by NETL[8].

Table 3-3: Feedstock Costs

Feedstock	Cost ($/ton)	Cost ($/MMBtu)
Illinois #6 Bituminous Coal (AR)	38.18	1.64
Montana Rosebud PRB Coal (AR)	12.17	0.71
Switchgrass (Dry)	88.00	5.46

Table 3-4: By-Product Value

By-Product	Value
Electricity ($/MWH)	70.59
Sulfur ($/ton)	0
Carbon Dioxide ($/tonne)	0

3.3 Required Selling Price Estimates for Products

The key measure of the economic viability of these C/BTL plants is the estimation of the required selling price (RSP) of the products. The RSP is the minimum price at which the products must be sold to recover the annual revenue requirement (ARR) of the plant. The ARR is the annual revenue needed to pay the operating costs, service the debt, and provide the expected rate of return for the investors. If the market price of the products is equal to or above the calculated RSP, the CTL project is considered economically viable.

The ARR is the sum of the fuel cost, variable operating cost, fixed operating cost, and annual capital component minus the by-product credits for electric power sale revenues. The annual capital component of the ARR is determined as the product of the total overnight cost (TOC) and the capital recovery factor (CRF). The CRF is determined from a standard discounted cash flow (DCF) analysis using the financial parameters shown in Table 3-5. The resulting CRF for these high risk plants is determined to be 16.95%.

The conceptual plants produce at most three products for sale if it is assumed that the CO_2 cannot be sold. These products are: (1) zero sulfur diesel fuel, (2) FT naphtha, and (3) electric power. All light gases including LPG are used within the plant. FT naphtha, although it has a similar boiling range to gasoline, has not traditionally been considered to be suited for refining into high octane gasoline because of its highly paraffinic nature, although NETL is examining this in a separate study. This analysis assumes that the naphtha can be sold at a discounted price compared to the diesel fuel. The discount price is assumed to be 0.7692 (1/1.3) the value of the diesel fuel. This relative value is used to determine the equivalent diesel fuel yield from the CTL plant in terms of barrels per year.

Table 3-5: Economic Parameters Used in DCF Analysis

Parameter	Value
Debt: Equity ratio	60:40
Interest rate on debt	4.56% nominal
Return on equity	20%
Income Tax Rate	38% (Effective 34% Federal, 6% State)
Repayment Term of Debt	30 years
Grace Period on Debt Repayment	0 years
Debt Reserve Fund	None
Depreciation	20 years, 150% declining balance
Working Capital	Zero for all parameters
Plant Economic Life	30 years
Investment Tax Credit	0%
Tax Holiday	0 years
EPC escalation	3.6%
Duration of Construction	5 years
General Inflation	3%
Escalation rate for coal	3%
Escalation rate for products	3%

The quotient of the ARR and the diesel fuel equivalent barrels gives the RSP. It is often convenient to express the RSP in terms of an equivalent crude oil price. Historically the ratio of the price of diesel to the crude oil price has been about 1.2.[5] This ratio was checked by averaging the ratios of refined diesel product price to the price of West Texas Intermediate crude for the years 2009 and 2010[9]. Assuming that this ratio is valid then dividing the RSP by 1.2 will give an estimate of the crude oil equivalent (COE) price.

3.4 Limited Life Cycle GHG Estimates

The comparison of greenhouse gas (GHG) emissions, reported on a carbon dioxide equivalent (CO_2E) basis, between petroleum-derived fuels and Fischer-Tropsch (FT) derived fuels is based on a limited life cycle analysis (LCA). The limited LCA for the FT fuel includes the major GHG sources from the production and transportation of the feedstocks to the plant (the mining and transportation of the coal and the growing, harvesting and delivery of the biomass), the CO_2 emitted during conversion of the feedstocks to naphtha and diesel at the CTL plant, the emissions resulting from transportation of the products from the CTL plant to the end user, and the combustion of the fuels by the end user.

This is, then, a limited well/mine/field-to-wheels LCA and most of the emissions result from the energy used in each processing step and the final combustion step. The major limit imposed on the life cycle analysis is that the GHG emissions resulting from the actual construction of the CTL facility and the fabrication of the equipment were not considered.

The reference point for the GHG balance is the CO_2E level in the atmosphere. Any processing step that increases atmospheric CO_2E levels has a positive emissions value and any step that decreases atmospheric CO_2E levels has a negative emissions value.

The GHG emissions in this study only account for CO_2, methane (CH_4), and nitrous oxide (N_2O). To normalize the effect of these gases in terms of the CO_2 equivalent value (CO_2E) the global warming potential (GWP) is used. These GWPs are based on the 2007 IPCC values: for CH_4 the value of 25 is used and for N_2O the value of 298 is used.

GHG emissions associated with coal mining include both non-methane and methane sources. Non-methane emissions are produced as a result of the energy used in extracting the coal and in transporting the coal from the mine to the plant. Coal mine methane (CMM) emissions occur when coal is mined with the result that the methane in the coal is released to the atmosphere unless it is recovered as coal bed methane (CBM). The quantity of these emissions is difficult to estimate because of wide variation within different basins and mines and with different coal ranks.

For the Illinois #6 bituminous coal, this report assumes that the coal is gassy and the mine uses CMM recovery techniques to recover the CBM. This reduces the atmospheric emissions of the methane. The CBM is assumed to be combusted for use in mining equipment such as heaters or natural gas-powered vehicles (e.g. forklifts) and the CO_2 emissions resulting from this

[5] A ratio of 1.25 may be more appropriate based on the lack of sulfur in, and the combustion properties of the FT diesel product, which are likely to afford a price premium. That ratio has been used in previous studies and is based on the ratio between crude oil and Ultra-Low Sulfur Diesel.

combustion are also accounted for. If certain conditions are met, this CBM may also be sold, but that scenario is not considered in this study. The value used in this analysis for total coal production and transport is 50.29 pounds carbon equivalent per ton of Illinois #6 coal (see Table 3-6).

For the PRB surfaced mined coal it is assumed that there is no CMM recovery and the total emissions are estimated to be 10.98 pounds carbon equivalent per ton. More details on the methane content of coals can be found in the reports from Tarka[9,10].

For the switchgrass,

Table 3-7 summarizes the LCA GHG emissions associated with the planting, harvesting, and transportation of the switchgrass to the CTL plant for conversion to fuels. The switchgrass was assumed to be grown on both conservation resource program (CRP) lands (30% of feed) and grasslands or pasture converted to energy crop production (70% of the feed). The emissions profile was generated utilizing the Calculating Uncertainty in Biomass Emissions Model developed by NETL and the RAND Corporation (version 2.0). Land availability for biomass production is expected to vary in Eastern and Western plant sites. This study presumes that for Eastern plant locations, 20% of the area around the plant consists of grassland or pasture which can be converted to plant energy crops on, while 5% of the area surrounding the plant is conservation reserve program (CRP) land which is suitable for energy crop cultivation. For Western plant sites, more land is expected to be available, with 30% of the surrounding area consisting of pasture or grassland suitable for cultivation, and 15% of the land consisting of CRP land which is suitable.

The value used in this analysis is 85.36 and 101.20 pounds carbon equivalent per dry ton of switchgrass (lb CE/dt biomass) for Eastern and Western plant locations, respectively.

Table 3-6: GHG Emissions from Coal Mining

	Units	Illinois #6 Coal	PRB Coal
Mining Emissions (Non Methane)	KgCO_2E/Kg Coal	0.010	0.0009
Transportation Emissions (CO_2 Emissions)	KgCO_2E/Kg Coal	0.007	0.007
CMM No Recovery (Coal Mine Methane)	KgCO_2E/Kg Coal	0.170	0.004
CMM With Recovery	KgCO_2E/Kg Coal	0.0780	n/a
Total Coal Production/Transport	kg CO_2E/kg Coal	0.092	0.020
Total Coal Production/Transport	lb CE/ton Coal	98.86	10.98

Table 3-7: GHG Emissions from Switchgrass Production and Transportation

	GHG EQ	
(kg CO_2E per kg dry biomass)	**Eastern U.S. Plant Site**	**Western U.S. Plant Site**
Planting & Harvesting	0.145	0.174
Transportation	0.011	0.011
Carbon Equivalent Emissions		
Total Emissions (kg CO_2E/kg dry biomass)	0.156	0.185
Total Emissions (lb CE/ ton dry biomass)	85.36	101.20

For the reference petroleum-derived diesel fuel GHG baseline, data was obtained from the EPA and represents diesel fuel sold or distributed in the United States in the year 2005. This EPA methodology relies heavily on the methodology developed by DOE and described in the NETL report entitled "Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels" dated November 2008. The petroleum baseline for conventional diesel fuel sold or distributed in the United States in 2005, on a national average basis, is 97.0 kg CO_2E/MMBtu (LHV) of fuel consumed. This value has been adjusted to 97.4 kg CO_2E/MMBtu (LHV) based on a conversion from the 1996 IPCC GHG GWP values to the 2007 GWP values. Table 3-8 summarizes the values used[11].

In addition to producing FT diesel fuel these sixteen plants produce FT naphtha. Some of the plants co-produce electric power (more or less depending on whether operated in once-through or recycle mode). In this LCA methodology, displacement CO_2E values are used to account for the GHG emissions off-set by producing these co-products. For FT naphtha the displacement value is based on the average for the production of kerosene jet fuel by U.S. refineries. Kerosene was used rather than gasoline because of the paraffinic nature and refining similarities between kerosene and FT naphtha. The value used represents average well-to-refinery gate GHG emissions of 75.8 kg CO_2E/bbl (see

Table 3-9).

Table 3-8: Baseline Petroleum Diesel GHG Values

Value	Units
97.4	KgCO_2E/MMBtu (LHV)
214.7	lbCO_2E/MMBtu (LHV)

58.6	lbCE/MMBtu (LHV)

Table 3-9: FT Naphtha Displacement Values

Value	Units
75.8	$KgCO_2$/bbl
167.11	$lbCO_2$/bbl
45.575	lbC/bbl
9.734	lbC/MMBtu (LHV)

The displacement LCA GHG value for co-product electricity is based on the U.S. electric grid mix for the year 2005. The cradle-to-end-user (CTEU) emissions are estimated to be 273.2 $kgCO_2E$/MMBtu, but this includes 7 percent loss for transmission and distribution (T&D). Accounting for this, the gate-to-busbar displacement value used in this report is 254.1 $kgCO_2E$/MMBtu. Table 3-10 summarizes the displacement values for electricity for several reference scenarios. If IGCC with CCS is used for the reference instead of the grid average the displacement off-set would be reduced from 152.78 to 26.61 pounds of carbon per MMBtu.

Table 3-10: Displacement Values for Co-produced Electric Power

	Value	Units
Average Grid	867	$KgCO_2$/MWH
	1911	$lbCO_2$/MWH
	521	lbC/MWH
	152.78	lbC/MMBtu
NGCC No CCS	448	$KgCO_2$/MWH
	987.67	$lbCO_2$/MWH
	269.36	lbC/MWH
	78.95	lbC/MMBtu
IGCC With CCS	151	$KGCO_2$/MWH
	332.89	$lbCO_2$/MWH
	90.79	lbC/MWH
	26.61	lbC/MMBtu
CTEU -T&D	254.1	$KgCO_2$/MMBtu
	560.19	$lbCO_2$/MMBtu
	152.78	lbC/MMBtu

Below in Table 3-11are tabulated the greenhouse gas items used in the carbon accounting methodology for the LCA.

Table 3-11: GHG Items Used in Accounting

LCA GHG Item	
Sources	
	Total Carbon Input
	Biomass Production & Transportation
	Coal Production & Transportation
	Diesel Transportation
	CO_2 Transportation & Storage
Credits	
	Biomass Carbon Input
	Power Credit
	Sequestered Carbon
	Slag Carbon
	Naphtha Credit

The first source item is the total carbon input to the C/BTL plant. This includes coal and biomass carbon. Source items 2 and 3 represent upstream GHG emissions associated with the production and delivery of the biomass and coal mining and coal transport to the plant. The fourth source item is the GHG emissions from transporting the C/BTL product fuel to the end user. The final source item is the CO_2 lost to the atmosphere during transport (1.65%) and storage (1%) of the captured CO_2.

The GHG credits include the biomass carbon, the electricity generation carbon off-set that is allowed because this power does not have to be generated elsewhere, the CO_2 that is captured in the plant and subsequently sequestered, the coal and biomass carbon that is unconverted during gasification and thus remains in the slag, and the off-set carbon credit from production of the naphtha. The total effective carbon is then the difference between the sum of the source items and the sum of the credits. This is the total effective carbon associated with the diesel fuel, the naphtha, and the FT oxygenates. The diesel effective carbon is therefore the total effective carbon minus the carbon content contained in the naphtha and oxygenates.

Once this diesel effective carbon number has been computed, it is divided by the heating value of the diesel fuel on an LHV basis to give the effective pounds of carbon per MMBtu LHV. This value is then divided by 58.6 lb carbon/MMBtu (see Table 3-8) to obtain the “petroleum ratio” (PR). If the PR is 1.0 then both the petroleum and FT derived diesel fuel have the same GHG emissions based on this LCA. If the PR is less than 1.0 then the FT diesel has lower GHG emissions than petroleum derived diesel. If the PR is higher than 1.0 then the petroleum diesel has lower GHG emissions than the FT fuel.

4 Feedstock Analysis and Site Conditions

4.1 Feedstock Analysis

The analysis if the Illinois #6 bituminous coal used in this analysis is shown in Table 4-1. The analysis if the Montana Rosebud PRB coal used in this analysis is shown in Table 4-2. The analysis of the Switchgrass biomass used in this analysis is shown in Table 4-3.

Table 4-1: Analysis of Illinois #6 Bituminous Coal

	As Received	Dry Basis	As Fed
Proximate Analysis			
Moisture (%)	11.12	0.00	6.00
Ash (%)	9.70	10.91	10.26
Volatile Matter (%)	34.99	39.37	37.00
Fixed Carbon (%)	44.19	49.72	46.74
Total (%)	100.00	100.00	100.00
Ultimate Analysis			
C (%)	63.75	71.72	67.42
H (%)	4.50	5.06	4.76
O (%)	6.89	7.75	7.29
N (%)	1.25	1.41	1.33
S (%)	2.51	2.82	2.65
Cl (%)	0.29	0.33	0.31
Ash (%)	9.70	10.91	10.26
Moisture (%)	11.12	0.00	6.00
Total (%)	100.00	100.00	100.00
Heating Value			
HHV (Btu/lb)	11,666	13,125	12,337
LHV (Btu/lb)	11,252	12,712	11,899

Table 4-2: Analysis of Montana Rosebud PRB Coal

	As Received	Dry Basis	As Fed
Proximate Analysis			
Moisture (%)	25.77	0.00	6.00
Ash (%)	8.19	11.04	10.37
Volatile Matter (%)	30.34	40.87	38.42
Fixed Carbon (%)	35.70	48.09	45.20
Total (%)	100.00	100.00	100.00
Ultimate Analysis			
C (%)	50.07	67.45	63.40
H (%)	3.38	4.56	4.29
O (%)	11.14	15.01	14.11
N (%)	0.71	0.96	0.90
S (%)	0.73	0.98	0.92
Cl (%)	0.01	0.01	0.01
Ash (%)	8.19	11.03	10.37
Moisture (%)	25.77	0.00	6.00
Total (%)	100.00	100.00	100.00
Heating Value			
HHV (Btu/lb)	8,564	11,516	10,825
LHV (Btu/lb)	8,252	11,096	10,430

4.2 Site Conditions

Two separate site locations are assumed for the C/BTL plants analyzed in this report. Conceptual plants using Illinois #6 bituminous coal as feedstock are assumed to be located in Illinois and the ambient conditions are summarized in Table 4-4. The site is a greenfield facility occupying approximately 1,300 acres. Access is by road and rail and plant water requirements are assumed to be available. Treated wastewater is allowed to be discharged.

Table 4-3: Analysis of Switchgrass Biomass

	As Received	Dry Basis	As Fed
Ultimate Analysis			
C (%)	39.92	46.97	44.15
H (%)	4.86	5.72	5.37
O (%)	34.16	40.19	37.78
N (%)	0.73	0.86	0.80
S (%)	0.08	0.09	0.08
Cl (%)	0.00	0.00	0.00
Ash (%)	5.26	6.19	5.82
Moisture (%)	15.00	0.00	6.00
Total (%)	100.00	100.00	100.00
Heating Value			
HHV (Btu/lb)	6,851	8,060	7,576
LHV (Btu/lb)	6,405	7,536	7,084

Table 4-4: Site Conditions for Eastern U.S. and Western U.S. C/BTL Plants

Site Condition	Eastern U.S.	Western U.S.
Elevation (Feet)	0	3,400
Barometric Pressure (PSIA)	14.7	13.0
Design Ambient Temperature, Dry Bulb (F)	60	42
Wet Bulb Temperature (F)	52	37
Ambient Relative Humidity (%)	60	62

The assumed site location for the Rosebud coal feedstock plant is in Montana. The site conditions are shown in Table 4-4.

The site is a greenfield facility occupying approximately 1,300 acres. The site is assumed to be close to the Rosebud mining area. This is an inland facility with access by road and rail. The site is in an arid area of the country and water resources are scarce. Apart from Cases SRW00, SOW00, SRW15, and SOW15, it is assumed that tight water management must be practiced. Treated wastewater is allowed to be discharged.

5 Results

In evaluating sixteen CTL and CBTL plant configurations, it was determined that diesel fuel produced from coal:

- Is economically viable when crude oil prices reach $95/bbl or $98/bbl for the recycle and poly-generation scenarios, respectively. This equates to diesel prices in the range of $2.70 to $2.80 per gallon of petroleum diesel.
- Will produce less life cycle GHG emissions than petroleum fuels if produced from a recycle facility, regardless of the LCA methodology employed, so long as CO_2 produced by the facility is sequestered. In the case of particularly high-methane content bituminous coals, some methane mitigation may also be required at the site of the mine.
- Will, in the case of the poly-generation scenario, produce either significantly less or slightly more life cycle GHG emissions than petroleum fuels depending on the LCA methodology used. Therefore, poly-generation facilities might require the use of modest percentage of biomass (less than 10% by weight) or more aggressive carbon capture strategies if petroleum parity is required.
- Will require between 1.6 and 7.4 barrels of water for each barrel of FT product produced, depending on the water management strategy utilized.

If a modest percentage of biomass is co-gasified with the coal to produce liquid fuels:

- The point of economic viability is increased by $9 to $15 per bbl, to between $104/bbl and $115/bbl, representing a $0.26 to $0.46 per gallon increase in fuel price over the coal cases.
- The fuel will produce less GHG emissions than petroleum-derived fuels, regardless of the configuration choice or LCA methodology, if 15 percent of the feedstock to the facility is switchgrass. A reduction of up to 48 percent less life cycle GHG emissions than petroleum-derived diesel is possible at this level of biomass usage.

Additional results:

- The overall plant efficiency of the sub-bituminous coal cases is higher than that of the bituminous coal cases. This is due to the increased electrical power produced in the bituminous coal cases, which reduces the efficiency of the facility (as power generation is less efficient than coal generation). Less power is produced in the sub-bituminous cases as some of the steam which would otherwise be used for power production is instead utilized to dry the relatively high-moisture content subbituminous coal.
- The poly-generation cases are all larger and more expensive than the recycle cases due to the 50,000 bpd design constraint. The facilities would be similar in size and cost if the coal input rate – and therefore syngas production rate –was held constant between the two cases, although the poly-generation cases would have a lower fuels output.

5.1 Overall Results Summary for Bituminous Coal Configurations

Table 5-1 is a synopsis of the overall performance summary for the four bituminous coal configurations (BRW00, BOW00, BRW15, and BOW15). Overall plant HHV efficiency for once through CTL cases are lower than for the recycle cases because of the excess power produced and the relatively improved efficiency of fuels production over electric power production. The efficiency of the CBTL cases is slightly lower than the CTL cases mostly because of the energy penalties associated with biomass preparation.

Using the LCA displacement methodology the resulting petroleum ratio in all cases is less than one indicating that **CTL and CBTL derived fuels can comply with Section 526 in EISA if the appropriate configuration is used and all plants practice CCS.** Section 526 compliance is also very sensitive to the methane content of the coal. If a high methane content coal is utilized, coal mine methane recovery practices may be required for compliance. **The two CBTL plants with 15 percent biomass (Cases BRW15 and BOW15) have significantly lower petroleum ratios than plants with no biomass because of the biomass carbon credit.** The two once-through CTL plants (Cases BOW00 and BOW15) have lower petroleum ratios than the recycle cases because of the displacement value methodology used for the co-produced electric power, although this result is very sensitive to the assumed GHG profile of the displaced electric power.

Details of the carbon balances around the four plants on tons of carbon per day basis are shown in

Table A-1 in Appendix A. During the production of fuels and the generation of electricity, carbon as CO_2 is captured using Selexol and MDEA units and this CO_2 is assumed to be sequestered in suitable geologic formations. Carbon is contained in the liquid fuels product naphtha and diesel and this carbon is not released until the products are combusted, or otherwise utilized, by the end user. The ungasified coal carbon remains in the slag. In steady state operations the carbon in the stack gas and the fuel gases is the only carbon released to the atmosphere from the plants. Overall carbon capture for the plants is between 81 and 88 percent.

Table A-2 shows the values of the various accounts used in the limited GHG life cycle analysis. The units are in tons of carbon equivalents per annum. "Total carbon in" is the sum of the carbon contained in the coal and biomass (where applicable). Section 0 and Table 3-11 explain the accounting procedure used to estimate the "diesel effective carbon". The resulting "petroleum ratio" is calculated from this LCA diesel effective carbon equivalent value as the quotient of the diesel effective carbon equivalent value on a pounds per MMBtu (LHV) and the reference petroleum value of 58.6 pounds carbon equivalent per MMBtu (LHV) (see Table 3-8).

Details of the electric power generation and the auxiliary plant power requirements for the plants are shown in Table A-3. All plants are self sufficient in electric power generation and all generate some additional net power for sales. **The two once-through configurations generate a large excess of net power (9% to 11% of the total product slate on an energy basis).** The largest parasitic power requirement is for air separation followed by CO_2 compression and acid gas cleaning. Biomass pretreatment is also a large energy user.

A summary of the plant water balances for the configurations is shown in Table A-4. Inputs to the C/BTL plants included in the "CTL Process Inputs" account are: coal moisture; gasification steam; gasifier syngas quench makeup water; BFW makeup water; moisture contained in the input air; and small miscellaneous inputs. Included in the “Water Generated/Consumed” account are: the net consumption of water during coal gasification; the water contained in the raw wet syngas; resulting from the water quench; that is consumed for shift and COS hydrolysis; water produced in the FT and Claus reactors; and water produced as a result of the combustion of fuels in the gas turbines and fired heaters. A positive number denotes water generated and a negative number denotes water consumed. The “CTL Process Outputs” account includes: the water contained in the exhaust streams from the plant consisting of combustion air moisture; deaerator carry over; coal dryer moisture; water contained in the slag and other solid wastes; and discharged water. This shows a water balance as the sum of the “CTL Process Inputs” and “Water Generated/Consumed” accounts is equal to the “CTL Process Outputs” account.

Table A-5 shows details of the cooling water circuits for the plant configurations. The cooling water flow is obtained from the total cooling utility requirements and an assumed 20 °F temperature rise in the cooling water. All of these bituminous coal plants use mechanical draft cooling towers for all plant cooling duties and the cooling tower evaporation and drift losses are shown. Cooling tower water blow down is shown for an assumed 4 cycles of concentration. The make-up water requirement reflects the water usage and estimates for recycled water.

Table 5-1 also shows the net raw water consumption for the plants. This is also expressed as barrels of water used per barrel of FT product. For the recycle standard water configurations a raw water consumption of about 7 barrels of water per barrel of FT product is estimated from this analysis. Higher water consumption is estimated for the once-through cases, although some of this water is associated with the generation of electrical power for sale.

Table 5-1 shows the bare erected costs (BEC) for the plant configurations. The total BEC is the sum of the costs of the unit operations. The major cost item in all cases is for feedstock gasification. Other large cost accounts are for air separation and biomass preparation. The total cost of producing the clean synthesis gas from coal constitutes about 65-70 percent of the BEC. Details of the components of the BEC are shown in Table A-6. Table A-7 details the cost components of the “Syngas Cleaning & Shift” account in the BEC.

Details of the annual operating and maintenance costs for the plants are shown in Table A-8. Total fixed O&M includes labor, taxes and insurance and fixed TS&M costs. Total variable O&M includes maintenance materials, water, catalysts and chemicals, waste disposal, and variable TS&M costs. Fuel costs include the cost of coal and biomass (when applicable).

The Total Overnight Cost (TOC) of the plants is shown in Table 5-1. Table A-9 summarizes the components that constitute the total plant capital costs. The total plant cost (TPC) is the sum of the BEC, home office, and contingencies. The total overnight cost is the sum of the TPC, the owner’s costs, and the CO_2 monitoring fund. The components of the Owner’s Costs are detailed in Table 3-1. The capital costs on a dollar per daily barrel basis (on a TOC basis) are shown in Table 5-1.

The required selling price (RSP) and crude oil equivalent selling price in $/barrel are shown at the bottom of Table 5-1. Details of the calculations are shown in Table A-10. The Annual Revenue Requirement (ARR) is the sum of the capital, fixed and variable operating, and fuel cost components minus the revenue from electric power sales. It represents the annual revenue needed to pay the operating costs, service the debt, and provide the expected rate of return for the investors. The required selling price (RSP) of the diesel fuel produced by the plants is calculated by dividing the ARR by the annual production of barrels of equivalent crude (equivalent crude is described in Section 3.3). The RSP is the minimum price at which the products must be sold to recover the annual revenue requirement (ARR) of the plant.

Table 5-1: Results Summary for Bituminous Coal Configuration

	Coal Only		Coal/Biomass	
Case Identifier	**BRW00**	**BOW00**	**BRW15**	**BOW15**
Coal Feed (TPD)	22,562	25,349	20,357	23,062
Biomass Feed (TPD)	0	0	3,592	4,070
Diesel (BPD)	34,302	34,303	34,303	34,302
Naphtha (BPD)	15,698	15,698	15,698	15,698
Export Power (MW)	109.9	397.3	48.9	319.4
Parasitic Power(MW)	516.9	585.9	570	650.8
Diesel Enthalpy (MMBtu/d LHV)	171,300	171,300	171,300	171,300
Naphtha Enthalpy (MMBtu/d LHV)	73,500	73,500	73,500	73,500
Diesel Enthalpy (MMBtu/d HHV)	183,600	183,600	183,600	183,600
Naphtha Enthalpy (MMBtu/d HHV)	78,800	78,800	78,800	78,800
Efficiency, HHV (%)	51.6	49.9	50.8	48.6
Diesel Effective Carbon(lb/MMBtu)	53.04	43.29	41.01	31.21
Petroleum Ratio	0.91	0.74	0.70	0.53
Water (gpm)	10,815	12,508	10,583	12,601
Water (bbl/bbl FT product)	7.42	8.58	7.26	8.64
BEC($MM)	4,084	4,556	4,247	4,776
Coal ($MM/yr)	283	318	255	289
Biomass($MM/yr)	0	0	93	106
O&M ($MM/yr)	371	409	386	430
TOC ($MM)	6,781	7,561	7,061	7,936
TOC($/DB)	135,640	151,220	141,220	158,700
RSP ($/bbl FT diesel)	114.5	117.5	125.0	130.8
COE($/bbl petroleum)	95.4	97.9	104.2	109.0

5.2 Overall Results Summary for Subbituminous Coal Only Configurations

Table 5-2 shows the overall performance summary for the six subbituminous coal only configurations (SRW00, SRA00, SRH00, SOW00, SOA00, and SOH00). Overall plant HHV efficiency for once through CTL cases are lower than for the recycle cases because it is more efficient to produce fuels than electric power. Similarly, less excess power is generated in the subbituminous cases than in the corresponding bituminous cases, resulting in the subbituminous cases having a higher efficiency. The difference in excess power generation is associated with the higher moisture content of the subbituminous coal: more coal drying is required in these cases, diverting steam which would otherwise be used for power generation to the coal dryers.

Using the LCA displacement methodology the petroleum ratios are all slightly below one. The once-through CTL plants have lower petroleum ratios than the recycle cases because of the displacement value methodology used for the co-produced electric power. In contrast to the bituminous coal cases, the Section 526 compliance of the subbituminous coal cases is not sensitive to the coal mine methane content or whether coal mine methane recovery has been implemented, due to the generally low methane content of subbituminous coals.

Details of the carbon balances are shown in Table A-11 in Appendix A. Overall carbon capture for the plants is between 83 and 89 percent. Table A-12 shows the values of the various accounts used in the limited GHG life cycle analysis.

Details of the electric power generation and the auxiliary plant power requirements for the plants are shown in Table A-13. All plants are self sufficient in electric power generation and the once-through configurations generate excess power for sales. The recycle cases produce no net power and duct firing is required in the HRSG.

A summary of the plant water balances for the configurations is shown in Table A-14. Air cooling reduces water demand to below 2 barrels per barrel of fuels. Table A-15 shows details of the cooling water circuits for the plant configurations.

Details of components of the bare erected costs (BEC) for the plant configurations are shown in

Table A-16 and Table A-17. Details of the annual operating and maintenance costs for the plants are shown in

Table A-18. Total Overnight Cost (TOC) of the plants is shown in Table 5-2 and

Table A-19 summarizes the components that constitute the total plant capital costs. The capital costs on a dollar per daily barrel basis (on a TOC basis) are shown in Table 5-2. The required selling price (RSP) and crude oil equivalent selling price in $/barrel are shown at the bottom of Table 5-2. Details of the calculations are shown in

Table A-20.

Table 5-2: Results Summary for Subbituminous CTL Configurations

	Coal Only Configurations					
Case Identifier	**SRW00**	**SRA00**	**SRH00**	**SOW00**	**SOA00**	**SOH00**
Coal Feed (TPD)	28,985	29,923	29,413	32,469	32,452	32,452
Biomass Feed (TPD)	0	0	0	0	0	0
Diesel (BPD)	34,302	34,302	34,302	34,302	34,302	34,302
Naphtha (BPD)	15,698	15,698	15,698	15,698	15,698	15,698
Export Power (MW)	0.0	0.0	0.0	227.1	190.9	213.9
Parasitic Power (MW)	504.5	539.0	524.6	568.4	588.0	581.9
Diesel Enthalpy (MMBtu/d LHV)	171,300	171,300	171,300	171,300	171,300	171,300
Naphtha Enthalpy (MMBtu/d LHV)	73,500	73,500	73,500	73,500	73,500	73,500
Diesel Enthalpy (MMBtu/d HHV)	183,600	183,600	183,600	183,600	183,600	183,600
Naphtha Enthalpy (MMBtu/d HHV)	78,800	78,800	78,800	78,800	78,800	78,800
Efficiency, HHV (%)	53.0	51.3	52.2	50.6	50.1	50.5
Diesel Effective Carbon (lb/MMBtu)	54.31	57.11	55.58	47.81	50.40	48.72
Petroleum Ratio	0.93	0.98	0.95	0.82	0.86	0.83
Water (gpm)	9,741	2,348	5,715	11,540	2,693	6,798
Water (bbl/bbl FT product)	6.68	1.61	3.92	7.91	1.85	4.66
BEC ($MM)	4,238	4,473	4,384	4,735	4,848	4,822
Coal ($MM/yr)	116	120	118	130	130	130
Biomass ($MM/yr)	0	0	0	0	0	0
O&M ($MM/yr)	411	424	418	454	455	455
TOC ($MM)	7,020	7,400	7,255	7,836	8,015	7,975
TOC ($/DB)	140,380	148,020	145,100	156,720	160,300	159,480
RSP ($/bbl FT diesel)	112.7	118.1	115.9	117.3	120.7	119.4
COE($/bbl petroleum)	93.9	98.4	96.6	97.8	100.6	99.5

5.3 Overall Results Summary for Subbituminous CBTL Configurations

Table 5-3 shows the results summary for the six subbituminous/biomass configurations. Again, overall plant HHV efficiency for once through CBTL cases are lower than for the recycle cases because it is more efficient to produce fuels than electric power. As in the bituminous coal cases, the efficiency of the CBTL cases is slightly lower than the CTL cases mostly because of the energy penalties associated with biomass preparation.

Using the LCA displacement methodology the resulting petroleum ratio in all cases is well below one. The once-through cases have lower petroleum ratios than the recycle cases because of the displacement value methodology used for the co-produced electric power.

Details of the carbon balances around the four plants on tons of carbon per day basis are shown in Table A-21 in the appendix. Overall carbon capture for the plants is between 83 and 87 percent. Table A-22 shows the values of the various accounts used in the limited GHG life cycle analysis.

Details of the electric power generation and the auxiliary plant power requirements for the plants are shown in Table A-23. All plants are self sufficient in electric power generation and once-through configurations generate excess power for sales. The largest parasitic power requirement is for air separation followed by CO2 compression and acid gas cleaning. Biomass pretreatment is also a large energy user.

A summary of the plant water balances for the configurations is shown in Table A-24. Table A-25 shows details of the cooling water circuits for the plant configurations. Table 5-3 shows the net raw water consumption for the plants. This is also expressed as barrels of water used per barrel of FT product. Water consumption savings is very significant for the air cooling cases with less than 2 barrels per barrel of fuel product being attained.

Table 5-3 shows the bare erected costs (BEC) for the plant configurations. Details of the components of the BEC are shown in Table A-26. Table A-27 details the cost components of the "Syngas Cleaning & Shift" account in the BEC.

Details of the annual operating and maintenance costs for the plants are shown in Table A-28. Table A-29 summarizes the components that constitute the total plant capital costs. The required selling price (RSP) and crude oil equivalent selling price in $/barrel are shown at the bottom of Table 5-3. Details of the calculations are shown in Table A-30.

Table 5-3: Results Summary for Subbituminous CBTL Configurations

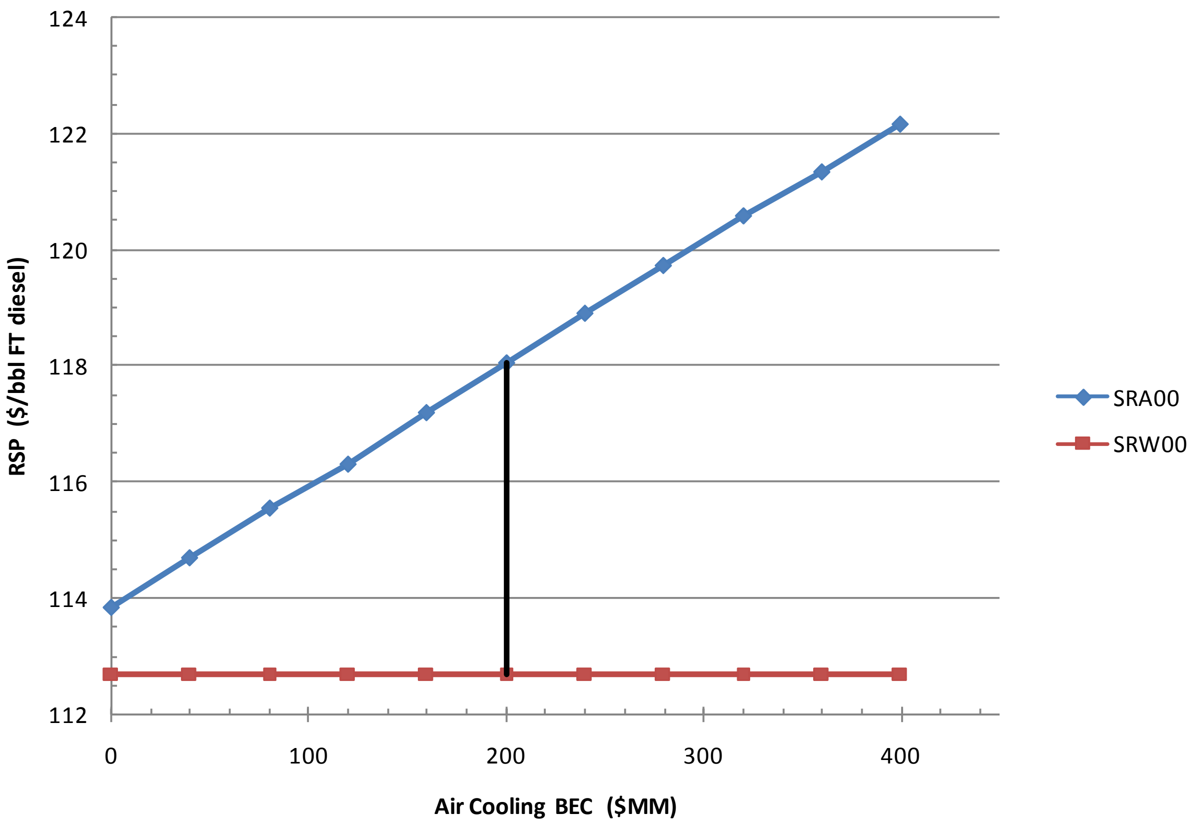
	CBTL Configurations					
Case Identifier	**SRW15**	**SRA15**	**SRH15**	**SOW15**	**SOA15**	**SOH15**
Coal Feed (TPD)	26,883	27,908	27,183	29,119	29,104	29,104
Biomass Feed (TPD)	4,744	4,925	4,797	5,139	5,136	5,136
Diesel (BPD)	34,301	34,302	34,302	34,302	34,302	34,301
Naphtha (BPD)	15,698	15,698	15,698	15,698	15,698	15,698
Export Power (MW)	0.0	0.0	0.0	190.3	150.5	177.2
Parasitic Power (MW)	605.1	648.9	625.0	659.1	679.2	672.4
Diesel Enthalpy (MMBtu/d LHV)	171,300	171,300	171,300	171,300	171,300	171,300
Naphtha Enthalpy (MMBtu/d LHV)	73,500	73,500	73,500	73,500	73,500	73,500
Diesel Enthalpy (MMBtu/d HHV)	183,600	183,600	183,600	183,600	183,600	183,600
Naphtha Enthalpy (MMBtu/d HHV)	78,800	78,800	78,800	78,800	78,800	78,800
Efficiency, HHV (%)	50.0	48.2	49.5	48.9	48.4	48.8
Diesel Effective Carbon (lb/MMBtu)	38.60	41.19	39.32	30.30	33.19	31.25
Petroleum Ratio	0.66	0.70	0.67	0.52	0.57	0.53
Water (gpm)	10,688	2,386	6,590	11,881	2,490	7,005
Water (bbl/bbl)	7.33	1.64	4.52	8.15	1.71	4.8
BEC ($MM)	4,681	4,963	4,815	5,069	5,180	5,152
Coal ($MM/yr)	107	112	109	116	116	116
Biomass ($MM/yr)	117	121	118	126	126	126
O&M ($MM/yr)	447	462	453	479	479	480
TOC ($MM)	7,763	8,221	7,978	8,403	8,577	8,533
TOC ($/DB)	155,240	164,420	159,560	168,040	171,540	170,660
RSP ($/bbl FT diesel)	130.4	137.0	133.4	133.8	137.3	135.8
COE($/bbl petroleum)	108.7	114.2	111.2	111.5	114.4	113.2

6 Sensitivity Analyses

6.1 Sensitivity to Indirect Air Cooling Capital Cost Estimate

The capital cost estimates for the air cooling system were based on ROM estimates provided by SPX[12] and these estimates have a relatively larger uncertainty than other capital cost estimates. At an estimated cost of approximately $200 million for air cooling systems of this size, the penalty in substituting indirect air cooling for standard mechanical draft cooling in the subbituminous coal-only recycle configurations (SRW00 and SRA00) is estimated to be about $5.50 per barrel of diesel produced. If the cost of the air cooling system was to be increased by 50 percent to $300 million the difference in diesel RSP between these two cases would increase to $7.40 per barrel. Figure 6-1 shows a plot of diesel RSP versus the capital cost (BEC) of the air cooling system for Case SRA00.

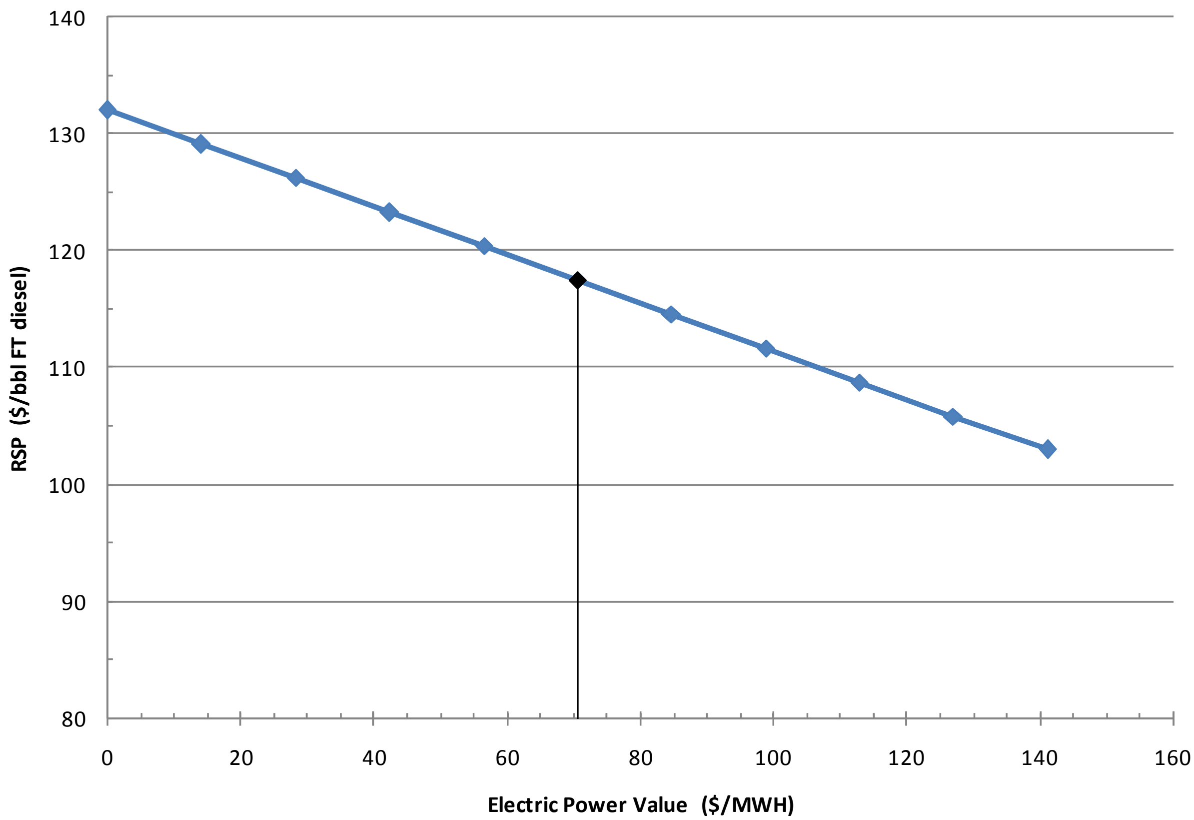
Figure 6-1: Sensitivity of Diesel RSP to Air Cooling Capital Cost



6.2 Sensitivity to Co-produced Electric Power Value

The RSP of diesel fuel produced in once through configurations that co-produce electric power is influenced by the value assigned to the electric power. The reference value used was $70.59 per MWH. For case BOW00, if the power value was reduced by 30 percent to $49.41/MWH the resulting RSP of the diesel would increase from $117.5/bbl to $121.8/bbl. Conversely, if the power value was 30 percent higher at $91.77/MWH the RSP of the FT diesel would decrease to $113.1/bbl. Figure 6-2 shows a plot of diesel RSP versus electric power value.

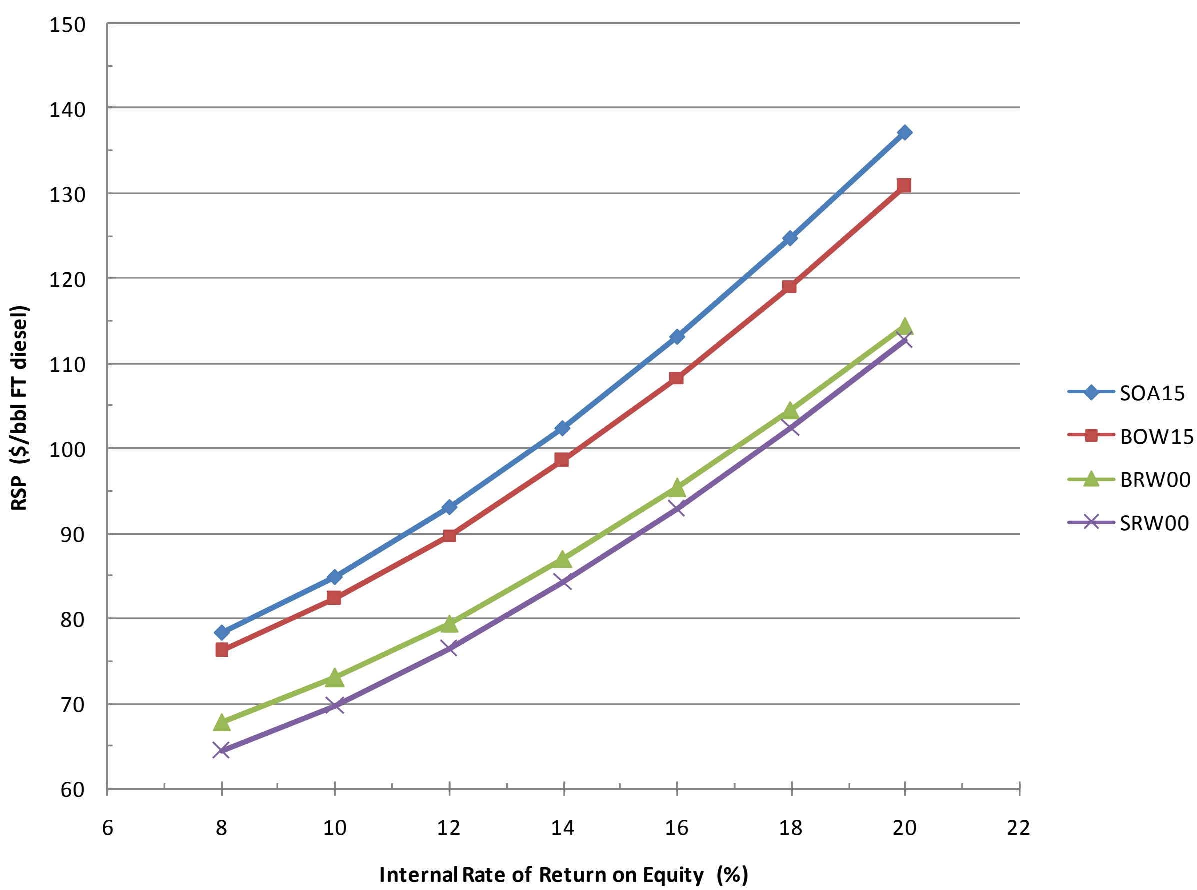
Figure 6-2: Sensitivity of Diesel RSP to Electric Power Value



6.3 Sensitivity to Return on Equity

The diesel RSP estimates are based on an internal rate of return on equity (IRROE) of 20%. With a lower risk profile and lower IRROE, the RSP would be correspondingly lower. Figure 6-3 shows a plot of diesel RSP versus IRROE for Cases SOA15, BOW15, BRW00, and SRW00. These cases span the range of capital cost among the various configurations. On average, the RSP drops $4-5/bbl for each percentage point drop in IRROE.

Figure 6-3: Sensitivity of Diesel RSP to IRROE



7 Findings and Conclusions

For the bituminous coal cases (BRW00, BOW00, BRW15, and BOW15) the following findings can be made by referring to Table 5-1:

- For the two CTL plants with no biomass addition (cases BRW00 and BOW00) the petroleum ratio (PR) calculated by using the LCA displacement methodology was found to be less than one in both cases. The PR for once-through configurations was lower than for recycle because of the displacement GHG credit taken for co-produced power. This implies that if the LCA displacement methodology is used, CTL plants with CCS are able to produce fuels compliant with Section 526 with no biomass addition if the appropriate configuration is used to capture the CO_2 produced during fuels production.
- One feasible option to further reduce the PR of CTL plants with CCS is to add biomass. This study analyzed the impact of adding 15 percent by mass of switchgrass (on an as-received basis). For the recycle case this reduced the PR from 0.91 to 0.70, well below the GHG footprint of petroleum-derived fuels. However for this size plant this required the addition of 3,500 TPD (as-received) of biomass. To obtain that quantity of biomass on a continuous basis for 328 days per year could well be a challenge. The encouraging aspect is that only a relatively small amount of biomass is needed to significantly reduce the PR. This implies that amounts lower than 15 percent would insure that the CBTL plant would be capable of producing fuels easily compliant with Section 526 of EISA. The lowest petroleum ratio of 0.53 was for the 15 percent biomass once-through case. This is the result of taking the biomass carbon credit and the power and naphtha displacement credits.
- For the bituminous coal cases the overall efficiency was higher for the recycle mode of operation. This is because it is generally more efficient to produce fuels than power.
- For the bituminous coal cases there was no effort made to reduce water consumption and conventional water cooling was used. For recycle cases water consumption was around 7.5 barrels per barrel of fuel product. For once-through cases water demand increased (around 8.5 barrels per barrel) because of additional cooling duty needed for turbine steam condensation.
- Addition of 15 percent biomass imposes a $10 per barrel penalty on the recycle mode RSP of diesel. In the once-through mode the penalty increases to $13 per barrel. This penalty is the result of the high cost of biomass on a Btu basis ($5.34/MMBtu) and the pretreatment and biomass preparation costs.
- The resulting RSP of zero sulfur diesel from these bituminous CTL and CBTL plants averages $122/bbl FT diesel ($2.90/gallon FT diesel). These fuels will be economically viable to produce when crude oil is as low as $\$95/\text{bbl}_{COEP}$ for the coal-only cases or as low as $\$104/\text{bbl}_{COEP}$ for the coal/biomass cases.

For the subbituminous coal-only cases (SRW00, SRA00, SRH00, SOW00, SOA00, and SOH00) the following findings can be made by referring to Table 5-2:

- For the subbituminous cases the PRs are slightly below that of petroleum-derived fuel. The once-through cases have lower PRs because of the electric power GHG displacement credit.
- The subbituminous cases investigated three different water management techniques to assess their impact on performance and costs. For comparison case SRW00 used all water cooling although this would be unlikely in practice because of the semi-arid plant location. Using indirect air cooling for the recycle case reduced water use from 6.7 barrels of water per barrel of fuel product (bbl/bbl)[††]to 1.6 bbl/bbl. The hybrid water management system had a water use in between air and water cooling at 3.9 bbl/bbl. Similar results were obtained for the once-through configurations, although water use is increased over that of the recycle cases.
- Air and hybrid cooling impose an additional energy penalty that results from the power use for the air cooling fans. This increases the parasitic power requirement for these cases.
- Using air and hybrid cooling imposes a cost penalty that is reflected in the increase in the RSP of the diesel fuel produced. Air cooling increases the RSP of the diesel fuel in the recycle case by $5.40/bbl compared to the water cooling case. Hybrid cooling adds a $3.20/bbl penalty. Because of the value chosen for the co-produced power the penalty for the once-through cases is less.
- For water cooling cases the TOC is higher for the subbituminous plants than for the bituminous. This is primarily because of the greater coal throughput in the subbituminous cases. However, the lower coal cost tends to compensate for this and the resulting diesel RSP for cases BRW00 and SRW00 are very close as are the RSPs for cases BOW00 and SOW00.
- The resulting RSP of zero sulfur diesel from these subbituminous CTL plants averages $117/bbl FT diesel ($2.79/gallon FT diesel). These fuels will be economically viable to produce when crude oil is as low as \$94/bbl$_{COEP}$.

For the subbituminous coal cases with biomass (SRW15, SRA15, SRH15, SOW15, SOA15, and SOH15) the following findings can be made by referring to Table 5-3:

- As expected the PRs are significantly reduced compared to the subbituminous coal-only cases. Section 526 compliance would be readily attained for these configurations.
- As expected the trends in water usage follow those of the subbituminous coal-only cases.
- The TOC for this series of cases is the highest. This is because of the plant coal through put and the costs of biomass pretreatment. This, together with the high cost of the biomass feed stock, results in the highest RSP for the FT diesel product.

[††] Note that this analysis ratios the water use to the fuels products, not the total energy products. If there was no excess power, the water usage ratio would be smaller.

- The resulting RSP of zero sulfur diesel from these subbituminous CBTL plants averages \$117/bbl FT diesel (\$2.79/gallon FT diesel). These fuels will be economically viable to produce when crude oil is as low as \$94/bbl$_{COEP}$ for the coal-only cases or as low as \$104/bbl$_{COEP}$ for the coal/biomass cases.

This comprehensive study of C/BTL using different coals, different configurations, and several water management options has produced a matrix of results that can be used to gain a better understanding of the complexities of these integrated systems. The overall findings of this study are that both Eastern bituminous and Western subbituminous coals could be used to produce high quality, fungible diesel fuel for transportation if future circumstances warranted. Further, that this fuel could be produced with a smaller GHG footprint than petroleum fuels, especially when a small percentage of biomass is added, and with low water consumption.

However, the estimated capital cost of these C/BTL plants is high, in the range of \$135,000 to \$170,000 per daily barrel on a TOC basis. This combined with feedstock and other operating and maintenance costs results in RSPs for the diesel fuel produced in the range of \$113-\$137 per barrel FT diesel (\$2.68 -\$3.27/gallon FT diesel).

It should, however, also be emphasized that this study is only a conceptual design study. The technologies utilized are all commercially available, however, the specific plant configurations evaluated have not been built. Therefore, while the configurations are technically feasible, an integrated demonstration will be required to reduce the potentially significant uncertainty in both the estimated capital and operating costs of the plants.

There are also technical performance uncertainties. Primary among these is the suitability of the biomass switchgrass to be used as a feed for high pressure entrained gasification. Pretreatment of this material will be challenging and other more amenable biomass may have to be used in a commercial plant. In this study it is assumed that once the CO_2 produced in the C/BTL plant has been captured and compressed it can be sequestered for a certain cost. One sequestration pathway, enhanced oil recovery (EOR), has been proven and may be the best near-term solution for CO_2 long-term sequestration. This report, however, assumes sequestration in a geologic reservoir owing to the larger sequestration potential of such reservoirs. Technologies and potential storage reservoirs for this approach are currently being demonstrated and the hope is that many of them will prove successful.

Another uncertainty is the costs and penalties associated with using total indirect air cooling for cooling duty. The costs and penalties involved may be higher than have been assumed in this study. Another issue is the disposition and value of the FT co-product naphtha. Although an excellent feed stock for ethylene production, production of large quantities of this material may not command the value assumed in this study. NETL has initiated a separate study to investigate opportunities to refine FT naphtha into a fungible gasoline.

8 References

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Appendix A: Case Parameters and Results

Table A-1: Bituminous - Plant Carbon Balances

Case Identifier	**BRW00**	**BOW00**	**BRW15**	**BOW15**
Input Carbon (TPD)				
Coal	14,382	16,159	12,976	14,701
Biomass	0	0	1,434	1,625
Input Total	14,382	16,159	14,410	16,326
Output Carbon (TPD)				
FT Products	5,401	5,401	5,401	5,401
Slag / Ash	34	38	34	38
Stack Gas	998	1,878	936	1,879
Fuel Gas	135	140	144	151
Co_2 Capture, Vented	0	0	0	0
Co_2 Capture, Sequestered	7,814	8,702	7,895	8,857
Output Total	14,382	16,159	14,410	16,326
Carbon Capture %	87.1	81.0	87.7	81.2

Table A-2: Bituminous - Overall Carbon Credits and Debits (ton/yr)

Case Identifier	BRW00	BOW00	BRW15	BOW15
Total Carbon In	4,724,487	5,308,232	4,733,685	5,363,091
Biomass Carbon	0	0	471,069	533,813
Biomass Production	0	0	39,726	45,012
Biomass Transport	0	0	3,080	3,490
Coal Prod & Transportation	186,356	209,375	168,143	190,485
Fuels Transportation	9,921	9,921	9,921	9,921
Power Credit	225,998	817,007	100,558	656,813
Naphtha Credit	117,591	117,591	117,592	117,590
Sequestered	2,566,888	2,858,627	2,593,357	2,909,649
Slag Carbon	11,140	12,517	11,162	12,646
Non-Diesel Product Carbon	534,192	534,192	534,192	534,192
CO_2 Transportation & Storage	67,599	75,282	68,296	76,626
Diesel Effective Carbon	1,491,033	1,216,795	1,152,867	877, 314

Table A-3: Bituminous - Plant Power Summary (MWe)

Case Identifier	BRW00	BOW00	BRW15	BOW15
Power Generation				
Gas Turbines	232.0	464.0	232.0	464.0
Steam Turbine	394.8	519.2	386.9	506.2
Expanders	0.0	0.0	0.0	0.0
Total Power	626.8	983.2	618.9	970.2
Auxiliary Load Summary				
Coal Processing	9.9	11.1	9.0	10.2
Biomass Processing	0.0	0.0	57.0	64.6
Coal Dryer Boost Compressor	0.0	0.0	0.0	0.0
Air Separation Mac	238.4	259.4	235.5	258.4
Oxygen Compressor	29.4	33.0	29.1	32.9
Nitrogen Compressor	20.5	38.5	20.5	38.5
CO_2 Compressor	84.5	94.1	85.4	95.7
Gasification/Quench	3.4	3.9	3.4	3.9
BFW& Circ Water Pumps	12.2	15.0	11.8	15.4
Cooling Tower Fans	5.5	6.3	5.5	6.4
Air Cooler Fans	0.0	0.0	0.0	0.0
Claus Plant	6.5	7.5	6.5	7.5
Selexol	65.8	77.3	65.3	77.5
MDEA	13.4	13.2	13.5	13.2
FT Processing	5.2	4.4	5.3	4.4
Hydrogen Compressors	2.2	2.2	2.2	2.2
Miscellaneous	20.0	20.0	20.0	20.0
Total Auxiliaries	516.9	585.9	570.0	650.8
Net Power	109.9	397.3	48.9	319.4

Table A-4: Bituminous - Plant Water Balance (gpm)

Case Identifier	BRW00	BOW00	BRW15	BOW15
CTL Process Inputs				
Coal/Biomass Moisture	418	469	467	529
Gasification Steam	207	232	8	0
Syngas Quench Makeup	565	814	610	893
BFW Make Up	68	79	66	80
Moisture In Air	130	182	129	181
Selexol Purge	10	10	10	10
Subtotal	1,398	1,787	1,289	1,694
Water Generated/Consumed				
Burners	91	69	67	75
Gas Turbine	420	884	419	883
Claus	67	75	61	70
FT Reactor	586	576	587	576
Gasification	-73	-80	101	119
WGS & COS Hydrolysis	-1,116	-1,363	-1,147	-1,420
Subtotal	-25	161	88	303
CTL Process Outputs				
Exhaust	846	1,365	858	1,415
Solids Waste	447	492	442	491
Discharge	79	91	77	92
Subtotal	1,372	1,948	1,377	1,997

Table A-5: Bituminous - Cooling Water Circuit (gpm)

Case Identifier	BRW00	BOW00	BRW15	BOW15
Cooling Water Flow	571,409	652,041	567,058	666,122
Cooling Tower Evap/Drift Loss	9,200	10,498	9,130	10,725
Cooling Water Blowdown	3,067	3,499	3,043	3,575
Cooling Water Make Up	9,966	11,373	9,890	11,618
Net Raw Water Consumed	10,815	12,508	10,583	12,601

Table A-6: Bituminous - Bare Erected Cost Summary ($MM)

Case Identifier	BRW00	BOW00	BRW15	BOW15
Coal/Biomass Handling	96	106	101	113
Coal/Biomass Prep & Feed	481	535	610	682
Feedwater Bop Systems	51	59	50	59
Gasification	820	912	861	965
Air Separation	752	845	743	842
Syngas Cleaning & Shift*	471	525	468	528
CO_2Compression	79	88	80	90
Gas Turbine	50	100	50	100
HRSG	51	65	48	66
Steam Turbine	114	142	112	139
FT Synthesis	368	367	368	367
FT Refining	181	181	181	181
Tankage & Shipping	46	46	46	46
Ash Handling	87	96	86	96
AccesElec Plant	62	84	61	84
Instrument/Control	64	70	67	74
Site Improvements	43	47	45	50
Build/Structures	45	49	47	52
Cooling Water System	53	59	53	60
Air Cooling System	0	0	0	0
CO_2Transportation & Storage	170	180	170	182
Bare Erected Cost	4,084	4,556	4,247	4,776

**Cost details provided in Table A-7*

Table A-7: Bituminous - Cost Details of Syngas Cleaning & Shift ($MM/yr)

Case Identifier	BRW00	BOW00	BRW15	BOW15
Raw Shift	14	17	14	17
COS Hydrolysis	25	26	24	26
Mercury Removal	9	10	9	10
Selexol 2-Stage	217	255	221	263
Claus	87	97	80	90
Other	19	21	20	23
Hydrogen Recovery	8	8	8	8
MDEA	92	91	92	91
Total	471	525	468	528

Table A-8: Bituminous - Annual Operating and Maintenance Costs ($MM/yr)

Case Identifier	BRW00	BOW00	BRW15	BOW15
Labor	107	121	114	129
Maintenance Materials	92	102	95	107
Water	6	6	5	6
Chemicals	49	49	49	49
Waste Disposal	9	10	9	10
TS&M Variable	0	0	0	0
Nonfuel Consumables	55	56	55	56
Tax & Insurance	108	121	113	127
TS&M Fixed	1	1	1	1
Total Fixed O&M	216	242	227	257
Total Variable O&M	155	167	159	173
Coal Cost	283	318	255	289
Biomass Cost	0	0	93	106

Table A-9: Bituminous - Total Capital Costs Summary ($MM)

Case Identifier	BRW00	BOW00	BRW15	BOW15
Bare Erected Cost (BEC)	4,084	4,556	4,247	4,776
Home Office	388	433	403	454
Process Contingency	286	319	297	334
Project Contingency	655	731	682	766
Total Plant Cost (TPC)	5,413	6,039	5,629	6,330
CO_2 Monitoring Fund (ND)	78	87	79	89
Owner's Costs	1,290	1,435	1,353	1,517
Total Overnight Cost (TOC)	6,781	7,561	7,061	7,936
Capital ($/Daily Barrel)	135,640	151,220	141,220	158,700

Table A-10: Bituminous - Overall Economic Summary

Case Identifier	BRW00	BOW00	BRW15	BOW15
Parameters				
Capital Charge Factor	0.16953	0.16953	0.16953	0.16953
Coal Cost ($/ton AR)	38.18	38.18	38.18	38.18
Biomass Cost ($/ton Dry)	N/A	N/A	88	88
Components of RSP ($MM/Annum)				
Capital	1,150	1,282	1,197	1,345
Fixed Operating Cost	216	242	227	257
Variable Operating Cost	155	167	159	173
Coal Cost	283	318	255	289
Biomass Cost	0	0	93	106
Power Credit	61	221	27	178
Annual Revenue Required	1,744	1,790	1,905	1,992
Required Selling Price (RSP, $/bbl)				
RSP ($/bbl FT diesel)	114.5	117.5	125.0	130.8
COE ($/bbl petroleum)	95.4	97.9	104.2	109.0

Table A-11: SubbituminousCTL - Plant Carbon Balances

Case Identifier	SRW00	SRA00	SRH00	SOW00	SOA00	SOH00
Input Carbon (TPD)						
Coal	14,512	14,982	14,726	16,257	16,248	16,248
Biomass	0	0	0	0	0	0
Input Total	14,512	14,982	14,726	16,257	16,248	16,248
Output Carbon (TPD)						
FT Products	5,401	5,401	5,401	5,401	5,401	5,401
Slag / Ash	34	35	35	38	38	38
Stack Gas	886	1,118	991	1,724	1,719	1,719
Fuel Gas	73	73	73	72	72	72
CO_2Capture, Vented	0	0	0	0	0	0
CO_2Capture, Sequestered	8,118	8,355	8,226	9,022	9,018	9,018
Output Total	14,512	14,982	14,726	16,257	16,248	16,248
Carbon Capture %	89.2	87.3	88.3	83.2	83.2	83.2

Table A-12: Subbituminous CTL - Overall Carbon Credits and Debits (ton/yr)

Case Identifier	SRW00	SRA00	SRH00	SOW00	SOA00	SOH00
Total Carbon In	4,767,192	4,921,587	4,837,491	5,340,425	5,337,468	5,337,468
Biomass Carbon	0	0	0	0	0	0
Biomass Production	0	0	0	0	0	0
Biomass Transport	0	0	0	0	0	0
Coal Prod & Transportation	52,287	53,979	53,059	58,572	58,541	58,541
Fuels Transportation	9,921	9,921	9,921	9,921	9,921	9,921
Power Credit	0	0	0	467,214	392,772	439,863
Naphtha Credit	117,595	117,596	117,595	117,595	117,595	117,595
Sequestered	2,666,739	2,744,759	2,702,172	2,963,863	2,962,501	2,962,459
Slag Carbon	11,241	11,605	11,407	12,593	12,586	12,586
Non-Diesel Product Carbon	534,242	534,242	534,242	534,242	534,242	534,242
CO_2 Transportation & Storage	70,229	72,283	71,162	78,053	78,017	78,016
Diesel Effective Carbon	1,526,590	1,605,440	1,562,369	1,344,044	1,416,791	1,369,499

Table A-13:Subbituminous CTL - Plant Power Summary (MWe)

Case Identifier	SRW00	SRA00	SRH00	SOW00	SOA00	SOH00
Power Generation						
Gas Turbines	220.7	217.9	219.2	428.9	428.4	428.4
Steam Turbine	283.7	321.1	305.4	366.6	350.5	367.4
Expanders	0.0	0.0	0.0	0.0	0.0	0.0
Total Power	504.4	539.0	524.6	795.5	778.9	795.8
Auxiliary Load Summary						
Coal Processing	12.7	13.1	12.9	14.2	14.2	14.2
Biomass Processing	0.0	0.0	0.0	0.0	0.0	0.0
Coal Dryer Boost Compressor	1.3	1.4	1.4	1.5	1.5	1.5
Air Separation Mac	236.3	247.5	243.1	256.1	259.4	259.4
Oxygen Compressor	27.7	29.1	28.6	31.0	31.5	31.5
Nitrogen Compressor	18.1	17.7	18.0	32.5	33.0	33.0
CO_2 Compressor	88.5	93.3	91.9	98.1	100.5	100.5
Gasification/Quench	0.9	0.9	0.9	1.0	1.0	1.0
BFW & Circ Water Pumps	9.2	11.1	10.1	12.2	12.3	12.2
Cooling Tower Fans	5.2	0.0	2.4	6.1	0.0	2.8
Air Cooler Fans	0.0	17.3	9.3	0.0	18.9	10.1
Claus Plant	5.7	5.9	5.8	6.5	6.5	6.5
Selexol	58.7	61.5	60.0	69.7	69.7	69.7
MDEA	13.5	13.5	13.5	13.0	13.0	13.0
FT Processing	4.6	4.5	4.6	4.4	4.4	4.4
Hydrogen Compressors	2.1	2.1	2.1	2.1	2.1	2.1
Miscellaneous	20.0	20.0	20.0	20.0	20.0	20.0
Total Auxiliaries	504.4	539.0	524.6	568.4	588.0	581.9
Net Power	0.0	0.0	0.0	227.1	190.9	213.9

Table A-14:Subbituminous CTL - Plant Water Balances (gpm)

Case Identifier	SRW00	SRA00	SRH00	SOW00	SOA00	SOH00
CTL Process Inputs						
Coal/Biomass Moisture	1,244	1,284	1,262	1,393	1,393	1,393
Gasification Steam	145	146	146	156	156	156
Syngas Quench Makeup	-344	-306	-327	-199	-200	-200
BFW Make Up	49	56	52	62	62	62
Moisture In Air	72	74	73	101	101	101
Selexol Purge	10	10	10	10	10	10
Subtotal	1,177	1,265	1,216	1,523	1,522	1,522
Water Generated/Consumed						
Burners	31	32	32	34	34	34
Gas Turbine	385	390	387	811	809	809
Claus	29	30	29	33	33	33
FT Reactor	588	587	587	595	596	596
Gasification	18	20	19	24	24	24
WGS & COS Hydrolysis	-1,131	-1,200	-1,162	-1,403	-1,402	-1,402
Subtotal	-80	-140	-108	94	93	93
CTL Process Outputs						
Exhaust	509	518	513	969	967	967
Solids Waste	478	491	483	526	526	526
Discharge	110	117	112	123	123	123
Subtotal	1,096	1,125	1,109	1,617	1,615	1,615

Table A-15: Subbituminous CTL - Cooling Water Circuit (gpm)

Case Identifier	SRW00	SRA00	SRH00	SOW00	SOA00	SOH00
Cooling Water Flow	532,217	575,082	551,239	621,752	628,896	622,985
Cooling Tower Evap/Drift Loss	8,569	0	3,946	10,010	0	4,682
Cooling Water Blowdown	2,856	8,626	5,907	3,337	9,433	6,543
Cooling Water Make Up	9,283	1,725	5,128	10,844	1,887	5,991
Net Raw Water Consumed	9,741	2,348	5,715	11,540	2,693	6,798

Table A-16: Subbituminous CTL - Bare Erected Cost Summary ($MM)

Case Identifier	SRW00	SRA00	SRH00	SOW00	SOA00	SOH00
Coal/Biomass Handling	130	134	132	146	146	146
Coal/Biomass Prep & Feed	627	647	636	702	702	702
Feedwater Bop Systems	46	11	27	54	13	32
Gasification	874	900	886	971	970	970
Air Separation	712	735	723	797	797	797
Syngas Cleaning & Shift*	440	452	445	488	488	488
CO_2 Compression	83	88	86	92	94	94
Gas Turbine	50	50	50	100	100	100
HRSG	41	51	50	58	58	58
Steam Turbine	87	96	93	107	103	107
FT Synthesis	367	367	367	367	367	367
FT Refining	181	181	181	181	181	181
Tankage & Shipping	46	46	46	46	46	46
Ash Handling	93	95	94	102	102	102
AccesElec Plant	53	55	54	73	72	73
Instrument/Control	78	80	79	86	86	86
Site Improvements	52	54	53	57	57	57
Build/Structures	55	56	56	60	60	60
Cooling Water System	50	0	31	57	0	35
Air Cooling System	0	200	122	0	215	130
CO_2 Transportation & Storage (T&S)	173	175	174	191	191	191
Bare Erected Cost	4,238	4,473	4,384	4,735	4,848	4,822

**Cost details provided in Table A-17*

Table A-17: Subbituminous CTL - Cost Detail of Syngas Cleaning & Shift ($MM/yr)

Case Identifier	SRW00	SRA00	SRH00	SOW00	SOA00	SOH00
Raw Shift	14	15	14	17	17	17
COS Hydrolysis	25	25	25	26	26	26
Mercury Removal	11	11	11	12	12	12
Selexol 2 Stage	229	239	234	270	270	270
Claus	36	37	36	40	40	40
Other	24	25	24	26	26	26
Hydrogen Recovery	8	8	8	8	8	8
MDEA	93	92	93	89	89	89
Total	440	452	445	488	488	488

Table A-18: Subbituminous CTL - Annual Operating and Maintenance Cost ($MM/yr)

Case Identifier	SRW00	SRA00	SRH00	SOW00	SOA00	SOH00
Labor	138	143	140	155	155	155
Maintenance Materials	95	100	98	106	108	107
Water	5	1	3	6	1	3
Chemicals	49	49	49	49	49	49
Waste Disposal	11	11	11	12	12	12
TS&M Variable	0	0	0	0	0	0
Nonfuel Consumables	54	50	52	55	51	53
Tax & Insurance	112	119	116	126	129	128
TS&M Fixed	1	1	1	1	1	1
Total Fixed O&M	251	262	257	281	284	283
Total Variable O&M	160	162	161	173	171	172
Coal Cost	116	120	118	130	130	130
Biomass Cost	0	0	0	0	0	0

Table A-19: Subbituminous CTL - Total Capital Cost Summary ($MM)

Case Identifier	SRW00	SRA00	SRH00	SOW00	SOA00	SOH00
Bare Erected Cost (BEC)	4,238	4,473	4,384	4,735	4,848	4,822
Home Office	403	425	417	450	461	458
Process Contingency	297	313	307	331	339	338
Project Contingency	680	718	704	760	778	774
Total Plant Cost (TPC)	5,618	5,929	5,812	6,276	6,426	6,392
CO_2 Monitoring Fund (ND)	81	84	82	90	90	90
Owner’s Costs	1,321	1,387	1,361	1,470	1,499	1,493
Total Overnight Cost (TOC)	7,020	7,400	7,255	7,836	8,015	7,975
Capital ($/Daily Barrel)	140,380	148,020	145,100	156,720	160,300	159,480

Table A-20: Subbituminous CTL - Overall Economic Summary

Case Identifier	SRW00	SRA00	SRH00	SOW00	SOA00	SOH00
Parameters						
Capital Charge Factor	0.16953	0.16953	0.16953	0.16953	0.16953	0.16953
Coal Cost ($/ton AR)	12.17	12.17	12.17	12.17	12.17	12.17
Biomass Cost ($/ton Dry)	N/A	N/A	N/A	N/A	N/A	N/A
Components Of RSP ($MM/Annum)						
Capital	1,190	1,255	1,230	1,328	1,359	1,352
Fixed Operating Cost	251	262	257	281	284	283
Variable Operating Cost	160	162	161	173	171	172
Coal Cost	116	120	118	130	130	130
Biomass Cost	0	0	0	0	0	0
Power Credit	0	0	0	126	106	119
Annual Revenue Required	1,717	1,799	1,766	1,787	1,839	1,819
Required Selling Price (RSP, $/bbl)						
RSP ($/bbl FT diesel)	112.7	118.1	115.9	117.3	121.7	119.4
COE ($/bbl petroleum)	93.9	98.4	96.6	97.8	100.6	99.5

Table A-21: Subbituminous CBTL - Plant Carbon Balances

Case Identifier	SRW15	SRA15	SRH15	SOW15	SOA15	SOH15
Input Carbon (TPD)						
Coal	13,460	13,973	13,610	14,579	14,572	14,572
Biomass	1,894	1,966	1,915	2,052	2,051	2,051
Input Total	15,354	15,939	15,525	16,631	16,623	16,623
Output Carbon (TPD)						
FT Products	5,401	5,401	5,401	5,401	5,401	5,401
Slag / Ash	36	38	37	38	39	38
Stack Gas	1,238	1,516	1,316	1,843	1,839	1,840
Fuel Gas	73	72	73	72	72	72
CO_2 Capture, Vented	0	0	0	0	0	0
CO_2 Capture, Sequestered	8,606	8,912	8,698	9,076	9,272	9,271
Output Total	15,354	15,939	15,525	16,631	16,623	16,623
Carbon Capture %	86.6	84.7	86.0	82.7	82.7	82.7

Table A-22: Subbituminous CBTL - Overall Carbon Credits and Debits (ton/yr)

Case Identifier	SRW15	SRA15	SRH15	SOW15	SOA15	SOH15
Total Carbon In	5,043,789	5,235,962	5,099,963	5,463,284	5,460,656	5,460,656
Biomass Carbon	622,179	645,831	629,078	674,082	673,754	673,754
Biomass Production	62,875	65,274	63,578	68,110	68,071	68,071
Biomass Transport	4,822	5,006	4,876	5,224	5,221	5,221
Coal Prod & Transportation	48,495	50,334	49,036	52,529	52,502	52,502
Fuels Transportation	9,921	9,921	9,921	9,921	9,921	9,921
Power Credit	0	0	0	391,365	309,401	364,310
Naphtha Credit	117,597	117,596	117,593	117,596	117,596	117,596
Sequestered	2,827,101	2,927,432	2,857,340	3,047,065	3,045,691	3,045,567
Slag Carbon	11,893	12,347	12,026	12,882	12,876	12,876
Non-Diesel Product Carbon	534,242	534,242	534,242	534,242	534,242	534,242
CO_2 Transportation & Storage	74,452	77,094	75,248	80,244	80,208	80,205
Diesel Effective Carbon	1,085,124	1,157,811	1,105,394	851,632	933,132	878,557

Table A-23: Subbituminous CBTL - Plant Power Summary (MWe)

Case Identifier	SRW15	SRA15	SRH15	SOW15	SOA15	SOH15
Power Generation						
Gas Turbines	217.2	215.2	216.3	428.0	427.5	427.5
Steam Turbine	388.1	433.7	408.6	421.4	402.2	422.1
Expanders	0.0	0.0	0.0	0.0	0.0	0.0
Total Power	605.3	648.9	624.9	849.4	829.7	849.6
Auxiliary Load Summary						
Coal Processing	11.8	12.3	11.9	12.8	12.8	12.8
Biomass Processing	75.2	78.1	76.1	81.5	81.4	81.4
Coal Dryer Boost Compressor	1.5	1.5	1.5	1.6	1.6	1.6
Air Separation Mac	248.2	261.5	254.4	260.0	263.3	263.3
Oxygen Compressor	29.0	30.7	29.9	31.5	32.0	32.0
Nitrogen Compressor	17.2	17.0	17.3	32.4	32.9	32.9
CO_2 Compressor	93.8	99.4	97.1	100.9	103.3	103.3
Gasification/Quench	0.9	1.0	0.9	1.0	1.0	1.0
BFW & Circ Water Pumps	11.9	14.2	12.6	13.0	13.1	13.0
Cooling Tower Fans	5.8	0.0	3.0	6.4	0.0	3.1
Air Cooler Fans	0.0	19.6	9.2	0.0	19.9	10.1
Claus Plant	6.0	6.3	6.1	6.6	6.6	6.6
Selexol	63.8	67.4	64.9	71.7	71.6	71.6
MDEA	13.4	13.3	13.4	13.2	13.2	13.2
FT Processing	4.5	4.5	4.5	4.4	4.4	4.4
Hydrogen Compressors	2.1	2.1	2.1	2.1	2.1	2.1
Miscellaneous	20.0	20.0	20.0	20.0	20.0	20.0
Total Auxiliaries	605.3	648.9	624.9	659.1	679.2	672.4
Net Power	0.0	0.0	0.0	190.3	150.5	177.2

Table A-24: Subbituminous CBTL - Plant Water Balance (gpm)

Case Identifier	SRW15	SRA15	SRH15	SOW15	SOA15	SOH15
CTL Process Inputs						
Coal/Biomass Moisture	1,272	1,321	1,286	1,378	1,377	1,377
Gasification Steam	0	0	0	0	0	0
Syngas Quench Makeup	-279	-235	-265	-181	-182	-182
BFW Make Up	61	70	64	66	66	66
Moisture In Air	75	77	75	102	102	102
Selexol Purge	10	10	10	10	10	10
Subtotal	1,139	1,242	1,170	1,374	1,373	1,373
Water Generated/Consumed						
Burners	32	33	33	33	33	33
Gas Turbine	394	398	395	807	805	805
Claus	28	30	29	31	31	31
FT Reactor	587	585	586	586	586	586
Gasification	199	207	202	217	217	217
WGS & COS Hydrolysis	-1,245	-1,330	-1,271	-1,433	-1,433	-1,432
Subtotal	-5	-77	-28	242	241	241
CTL Process Outputs						
Exhaust	522	529	524	965	963	963
Solids Waste	491	507	495	525	525	525
Discharge	121	130	124	126	126	126
Subtotal	1,134	1,166	1,143	1,616	1,614	1,614

Table A-25 Subbituminous CBTL – Cooling Water Circuit (gpm)

Case Identifier	SRW15	SRA15	SRH15	SOW15	SOA15	SOH15
Cooling Water Flow	598,008	650,988	612,338	651,919	659,980	653,163
Cooling Tower Evap/Drift Loss	9,628	0	4,967	10,496	0	5,152
Cooling Water Blowdown	3,209	9,765	6,213	3,499	9,900	6,715
Cooling Water Make Up	10,430	1,953	6,210	11,371	1,980	6,495
Net Raw Water Consumed	10,688	2,386	6,590	11,881	2,490	7,005

Table A-26: Subbituminous CBTL - Bare Erected Cost Summary ($MM)

Case Identifier	SRW15	SRA15	SRH15	SOW15	SOA15	SOH15
Coal/Biomass Handling	142	147	143	154	154	154
Coal/Biomass Prep & Feed	821	852	830	889	888	888
Feedwater Bop Systems	50	11	31	56	12	33
Gasification	966	1,000	976	1,041	1,040	1,040
Air Separation	747	775	755	809	808	808
Syngas Cleaning & Shift*	464	479	470	501	499	500
CO_2 Compression	88	93	91	95	97	97
Gas Turbine	50	50	50	100	100	100
HRSG	59	70	63	66	66	66
Steam Turbine	112	123	117	120	115	120
FTSynthesis	367	367	367	367	367	367
FT Refining	181	181	181	181	181	181
Tankage & Shipping	46	46	46	46	46	46
Ash Handling	95	98	96	102	102	102
AccesElec Plant	60	63	61	76	75	76
Instrument/Control	84	87	85	90	90	90
Site Improvements	56	58	57	60	60	60
Build/Structures	59	61	59	63	63	63
Cooling Water System	55	0	36	59	0	38
Air Cooling System	0	221	121	0	223	130
CO_2 Transportation & Storage (T&S)	179	182	180	194	194	194
Bare Erected Cost	4,681	4,963	4,815	5,069	5,180	5,152

**Cost details provided in Table A-27*

Table A-27: Subbituminous CBTL - Cost Details of Syngas Cleaning & Shift ($MM/yr)

Case Identifier	SRW15	SRA15	SRH15	SOW15	SOA15	SOH15
Raw Shift	15	16	16	17	17	17
COS Hydrolysis	26	26	26	27	26	27
Mercury Removal	12	12	12	13	13	13
Selexol 2 Stage	251	264	255	281	280	280
Claus	34	35	35	37	37	37
Other	26	27	26	28	28	28
Hydrogen Recovery	8	8	8	8	8	8
MDEA	92	91	92	90	90	90
Total	464	479	470	501	499	500

Table A-28: Subbituminous CBTL - Annual Operating and Maintenance Cost ($MM/yr)

Case Identifier	SRW15	SRA15	SRH15	SOW15	SOA15	SOH15
Labor	151	156	152	163	163	163
Maintenance Materials	104	110	107	113	115	114
Water	5	1	3	6	1	4
Chemicals	49	49	49	49	49	49
Waste Disposal	12	12	12	12	12	12
TS&M Variable	0	0	0	0	0	0
Nonfuel Consumables	55	50	53	55	51	53
Tax & Insurance	124	132	128	134	137	137
TS&M Fixed	1	1	1	1	1	1
Total Fixed O&M	276	289	281	298	301	300
Total Variable O&M	171	173	172	181	178	180
Coal Cost	107	112	109	116	116	116
Biomass Cost	117	121	118	126	126	126

Table A-29: Subbituminous CBTL - Total Capital Cost Summary ($MM)

Case Identifier	SRW15	SRA15	SRH15	SOW15	SOA15	SOH15
Bare Erected Cost (BEC)	4,681	4,963	4,815	5,069	5,180	5,152
Home Office	445	472	457	482	492	489
Process Contingency	328	347	337	355	363	361
Project Contingency	751	797	773	814	831	827
Total Plant Cost (TPC)	6,205	6,579	6,382	6,720	6,866	6,829
CO_2 Monitoring Fund (ND)	86	89	87	93	93	93
Owner's Costs	1,472	1,553	1,509	1,590	1,618	1,611
Total Overnight Cost (TOC)	7,763	8,221	7,978	8,403	8,577	8,533
Capital ($/Daily Barrel)	155,240	164,420	159,560	168,040	171,540	170,660

Table A-30: Subbituminous CBTL - Overall Economic Summary

Case Identifier	SRW15	SRA15	SRH15	SOW15	SOA15	SOH15
Parameters						
Capital Charge Factor	0.16953	0.16953	0.16953	0.16953	0.16953	0.16953
Coal Cost ($/ton AR)	12.17	12.17	12.17	12.17	12.17	12.17
Biomass Cost ($/ton Dry)	88	88	88	88	88	88
Components Of RSP ($MM/Annum)						
Capital	1,316	1,394	1,353	1,424	1,454	1,447
Fixed Operating Cost	276	289	281	298	301	300
Variable Operating Cost	171	173	172	181	178	180
Coal Cost	107	112	109	116	116	116
Biomass Cost	117	121	118	126	126	126
Power Credit	0	0	0	106	84	99
Annual Revenue Required	1,987	2,088	2,033	2,038	2,091	2,070
Required Selling Price (RSP, $/bbl)						
RSP ($/bbl FT diesel)	130.4	137.2	133.4	133.8	137.3	135.8
COE ($/bbl petroleum)	108.7	114.2	111.2	111.5	114.4	113.2

Appendix B: LCA Methodologies Comparison

The LCA analysis results in the report that are used to calculate the petroleum ratios are estimated using the “displacement methodology”. In this method GHG credits are given for the co-produced electric power and for the FT naphtha produced. An alternative LCA approach is to use the “energy allocation methodology”. In this method the GHG emissions are allocated to each product based on the lower heating value of the product. Table B-1 shows the comparison of these two methods for calculating the petroleum ratio for the 16 configurations.

Using the energy allocation method, the PRs for coal-only cases are all very close to 1. In general, the recycle configurations are at or slightly below one while the once-through cases are all just above 1. This is opposite to the trend observed with the displacement method in which the PRs for once-through configurations were lower than for the corresponding recycle configuration.

For the coal and biomass cases, the PRs estimated using the energy allocation method are all significantly below 1, although they are uniformly higher than the PRs estimated using the displacement method.

Table B-2: Comparison of Petroleum Ratio Values for Displacement and Energy Allocation LCA Methodologies

Case Identifier	Displacement Method	Energy Allocation Method
Bituminous Cases		
BRW00	0.905	0.998
BOW00	0.739	1.097
BRW15	0.700	0.810
BOW15	0.533	0.913
Subbituminous Cases		
SRW00	0.927	0.927
SRA00	0.975	0.960
SRH00	0.949	0.942
SOW00	0.816	1.027
SOA00	0.860	1.029
SOH00	0.832	1.027
SRW15	0.659	0.739
SRA15	0.703	0.770
SRH15	0.671	0.748
SOW15	0.517	0.803
SOA15	0.567	0.804
SOH15	0.533	0.803

In general, the PRs estimated by the energy allocation method show a much smaller range than those estimated using the displacement method.

Despite the differences in the estimated PRs, the overall conclusions of the study are not significantly altered. For coal only processes, configurations exist to produce diesel with lower life-cycle GHG emissions than petroleum-derived diesel. The results using the energy allocation method also show that CBTL configurations produce diesel with significantly lower GHG emissions than petroleum-derived diesel, even with relatively small amounts of biomass.

The biggest discrepancy in the results from the two GHG methodologies is whether recycle or once-through configurations produce diesel with lower GHG emissions than petroleum-derived diesel. Efforts are currently underway within EPA and other agencies to establish a standard methodology for life-cycle GHG estimates.