Coal-to-Fuel Plant Simulation Studies for Optimal Performance and Carbon Management

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ABSTRACT

Baard Energy, L.L.C., through its project company Ohio River Clean Fuels, L.L.C. (ORCF), is developing a coal gasification Fischer Tropsch (FT) synthetic fuels plant in Wellsville, Ohio. The ORCF project is a nominal 50,000 barrel per day FT plant using a dry-fed, entrained-flow gasification process utilizing cobalt FT reactors. A process model for the project has been developed to assist Baard Energy with design and permitting activities. The model has been used to determine optimal design requirements and operating conditions to capture and sequester byproduct carbon dioxide and to study the benefits of blending biomass with coal to reduce greenhouse gas (GHG) emissions. Model results provide estimates for feedstock requirements, product streams, including electrical power for auxiliary and net power generation, plant heat and recycle stream integration, and equipment sizing. A life cycle GHG emissions assessment based on the model results for the ORCF plant, and apportioned to the product mix of LPG, naphtha, diesel fuel, and power, indicate that a 30% reduction in GHG emissions (compared to life-cycle GHG emissions for Arabian Crude) for the ORCF diesel fuel is achievable when concentrated CO_2 is separated from the syngas feed to the FT reactors and sequestered in the sub-terrain. Additional sequestration of CO_2, in the form of an apportioned carbon credit for the net power sales for trading with the average electrical U.S. power mix, will further reduce the GHG emissions approaching 50% of emissions from ultra-low sulfur diesels derived from crude oil.

1. INTRODUCTION

Baard Energy, L.L.C. is a privately held limited liability company that develops, finances, constructs, and owns alternative fuel projects including ethanol, biodiesel, coal to liquids, and biomass to liquids facilities. Based in Vancouver, Washington, Baard Energy has over twenty years experience in alternative energy and fuels. Baard and its affiliates have developed a variety of energy projects, including wood-waste and natural gas electric generating facilities and ethanol production plants used for transportation fuels. Since 1998, and in response to an increased demand for alternative fuel sources, Baard has been working on the engineering and design of gasification of coal and more recently, gasification of coals and biomass to produce transportation fuels (CTL and BTL).

1.1 Project Site

The Ohio River Clean Fuels (ORCF) project will be located on the Ohio River near Wellsville, Ohio. This location is ideally located near Ohio and West Virginia coal reserves as well as abundant sources of biomass feedstocks. The site is located near existing barge loading/unloading terminal being developed by the Columbiana County Port Authority as well as railroads, petroleum and natural gas pipelines, and electrical transmission. An existing oxygen plant is also close to the property as are refineries and chemical industries. The site is also located near prospective targets for enhanced oil recovery as well as deep-well geological sequestration.

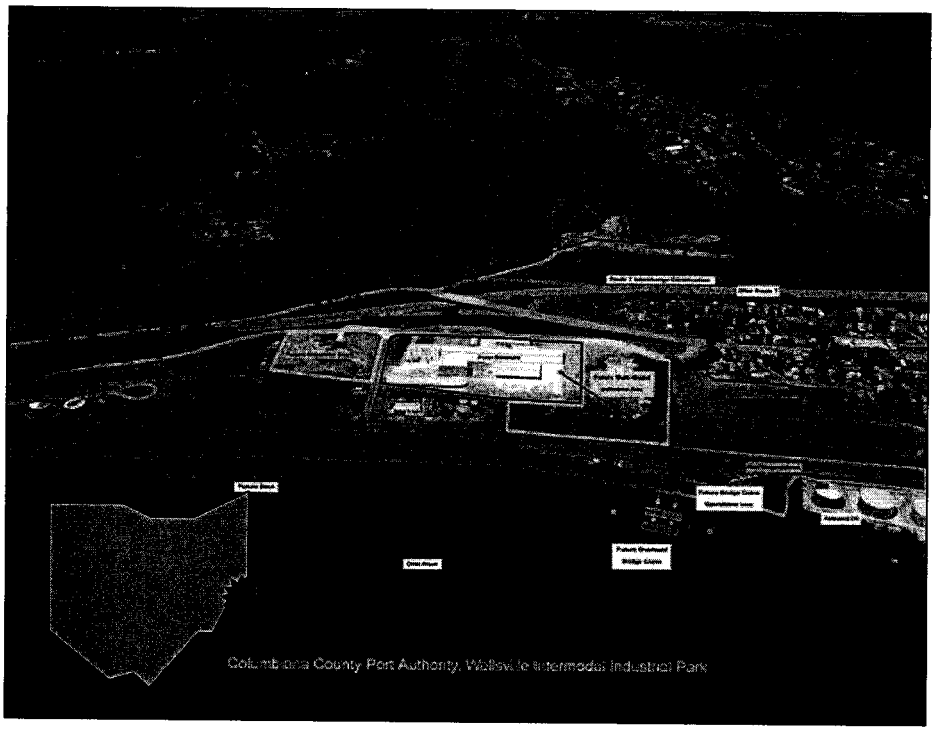

Figure 1. Baard ORCF Project Site

The ORCF plant will nominally produce 50,000 barrels per day of liquid product, comprised of diesel, jet, naphtha, and liquefied petroleum gas (LPG). In addition, the plant will generate electrical power for auxiliary loads using a portion of the plant's FT reactor tail gas and excess process steam in a combined-cycle arrangement.

1.2 Project Objectives

Baard Energy initiated the design of its ORCF project with the following objectives:

1) Develop a technically feasibile and economically viable plant design,
2) Properly match unit operations, incorporate recycle streams, and integrate heat recovery to improve process productivity,
3) Minimize pollutant emissions, including greenhouse gas emissions,
4) Produce a product mix best matching local and regional markets, including power, diesel and jet fuel, and chemical industry opportunities.

Baard's interest in blending biomass with coal and capturing CO_2 as a byproduct stream lead Baard to its decision to incorporate a dry-feed, entrained-flow gasifier. Modern-day gasifiers have been successfully operated using up to 30% biomass blended with coal. Additionally, the plant will separate and capture most CO_2 generated during coal gasification and CO shift with a minimum number of gas cleanup unit operations. Consideration of electrical power costs and market opportunities in the upper Midwest provided incentive to develop a poly-generation plant that would produce sufficient power for plant auxiliary loads while possibly providing net power.

In 2006 Baard Energy entered into a Cooperative Research and Development Agreement (CRADA)with the Idaho National Laboratory (INL) to develop a custom gasification-FT process model in order to allow rapid estimation of material and energy balances for candidate coal and coal-biomass gasifier feed blends, investigate conceptual design options and operational flexibility, improve overall process efficiency by integrating stream recycle and heat recuperation throughout the plant, support a Phase I front end engineering design (FEED) study and equipment sizing, and quantify emissions sources and rates for carbon dioxide (CO_2) and criteria pollutants. INL has been developing modular process models for coal gasification and thermal conversion systems to support clean, efficient and economical development of integrated energy systems. Under the CRADA with Baard Energy, a proprietary process simulation package was developed.

1.3 Plant Description

A simplified block flow diagram of major process operations for the ORCF process is shown in Figure 2. Gasification and syngas cleaning technology selection and operation are paramount to minimizing technical risk for a first-in-kind plant; therefore, ORCF will utilize Rectisol™ with sulfur and mercury guard beds to purify the syngas prior to FT fuels synthesis. The nominal plant capacity is 50,000 bbl/day total synthetic liquids with cogeneration of all auxiliary power load and LPG. Additionally, light hydrocarbons, and FT reactor tail gas can be combusted to produce net power.

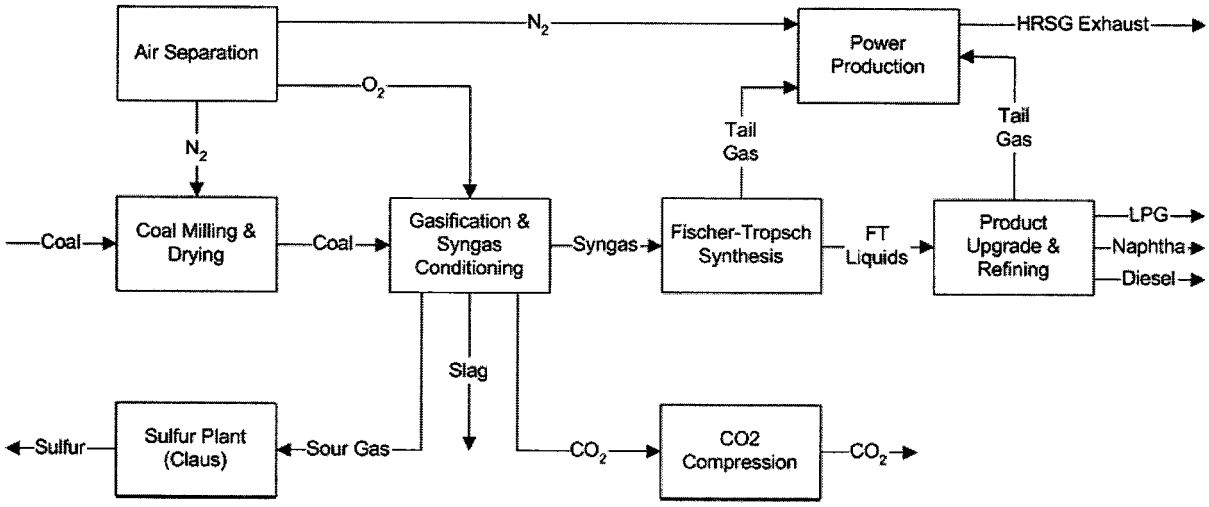

Figure 2. Block flow diagram for the ORCF project

The design basis prescribed the use of Pittsburg # 8 coals which will be obtained from near-by reserves and delivered by barge or railcar to the plant. Biomass will also be delivered to the plant by barge, train or truck-delivery and blended with the coal for feed to the gasifiers. Auxiliary power will be generated by the plant using unconverted fuel gas and steam using a combined-cycle system. Net power will be produced and sold as will the sulfur and slag byproduct and compressed carbon dioxide (CO_2). Opportunities to use CO_2 for enhanced oil recovery and/or to sequester the CO_2 are being developed.

2. PROCESS SIMULATION

A plant computer model was developed using Aspen Plus® (AspenTech, 2006). Aspen Plus® is a steady-state process simulator that includes extensive thermodynamic databases, built-in routines for common unit operations, and the ability to properly handle complex chemical feedstocks such as coal and biomass. Due to the size and complexity of the process, the simulation was constructed using "hierarchy" blocks (INL, 2006). In this fashion, submodels for each major plant section can be constructed separately and then combined to represent the entire process. Significant emphasis was placed on heat integration between unit operations and different sections of the plant. To facilitate energy tracking, Aspen's "utility" blocks were used extensively.

2.1 Air Separations

Air separation is modeled as a standard cryogenic Linde-type ASU. Water is first removed from the compressed air stream in a knockout drum, followed by drying using a molecular sieve. The compressed air streams entering the cold box are cooled to cryogenic temperatures by heat exchange with the cold ASU product streams. The larger air stream is fed to the high-pressure column, while the smaller air stream is expanded to further cool it before entering the low-pressure column. Distillate from the low-pressure column is 99.9% pure N_2, while the bottoms product is 99.5% pure O_2. A waste stream is also withdrawn from the low-pressure column to maintain both the energy balance and product stream purities.

2.2 Gasification

Coal drying, gasification, heat recovery, gas quenching, shifting, slag/ash handling, and syngas cooling are modeled using a hierarchy block developed for the dry-feed, entrained-flow process and associated operations. This block uses a set of Gibbs reactors and calculation blocks that enable the process model to adequately simulate the gasifier product, steam generation, quench, and particle removal. Coal drying can be accomplished using a fired-heater or low pressure steam. Coal injection is accomplished using a dry-feed system.

The shift reactor, Rectisol™ columns, and guard beds are also modeled using reactor block constructs, calibrated with vendor data and/or to operating experience. The Aspen model adjusts a number of operating conditions (mainly flows) to meet functional requirements, such as the H_2:CO ratio in the syngas entering the FT reactor and the temperature of shift reactors. Commercial software, such as ProMax® (Bryan Research & Engineering, 2007), could also be useful for *a-priori* calculation of chilled methanol as a mass separating agent as well as other separation solvents that can be used to separate CO_2, sulfur species, and other contaminants from the syngas stream.

2.3 Sulfur Management

For the ORCF project, the Aspen model simulates a straight-through Claus plant due to the high concentration of H_2S in the feed gas to the sulfur recovery unit (SRU). The Claus furnace is modeled as an Aspen Gibbs reactor. Flow of air is controlled to react one-third of the H_2S to SO_2 according to the following reaction:

$$H_2S + \frac{3}{2}O_2 \longleftrightarrow H_2O + SO_2 \qquad (1)$$

In addition to SO_2 formation, some elemental sulfur formation is also predicted in this block. Intermediate pressure steam is generated when cooling the product stream from the Claus furnace. Following industrial practice, two catalytic sulfur reactors are used to convert the residual H_2S leaving the Claus reactor to elemental sulfur.

A standard Claus plant includes a hydrogenation and hydrolysis unit to convert all residual sulfur compounds to H_2S. In addition, amine absorption is utilized to recover H_2S downstream of the hydrogenation/hydrolysis unit. For the ORCF plant, however, only the hydrogenation and hydrolysis unit is required, as the H_2S-laden offgas is simply recycled to the Rectisol™ unit to recover residual H_2S and CO_2. In this manner, sulfur emissions for the plant are driven to extinction while CO_2 capture is enhanced.

2.4 Fischer Tropsch Reactors

The ORCF plant model is based on cobalt catalyst slurry bubble column (SBC) reactors. The Aspen simulations for FT fuels production were completed using a generalized approach developed by INL process engineering. The model uses two reactors in series, with recycle of unreacted syngas to the second reactor to improve conversion efficiencies. Syngas flow to the first reactor is preheated to a reaction temperature of 428°F. Heat for this operation is supplied by the exothermic Fischer Tropsch reactions.

The product distribution is estimated using a modified version of the Anderson-Shulz-Flory (ASF) distribution. The following arbitrary correction was used to shift the product distribution slightly toward increased production of light components.

$$W_n(Modified\ ASF) = W_n(Classical\ ASF) \times \left[1 - \alpha + 0.78^{\alpha}\right] \quad (2)$$

where W_n is the weight fraction produced for a given carbon number and α is the chain growth factor. This correlation provides a reasonable but simple correlation over a range of chain growth factors from 0.70 to 0.95. A chain growth factor of 0.92 was selected for the ORCF plant which is a reasonable value for a cobalt catalyst at the specified operating temperature of 428°F. Conversion per pass in the FT reactors was set at 60%, which represents the upper limit demonstrated for a commercial reactor.

The weight fraction of the combined $C_1 - C_4$ products is calculated by difference as follows:

$$W_{C1-C4} = 1 - \sum_{n=5}^{\infty} W_n(Classical\ ASF) \quad (3)$$

where the distribution of $C_1 - C_4$ products was selected to match experimental data as shown in Figure 3.

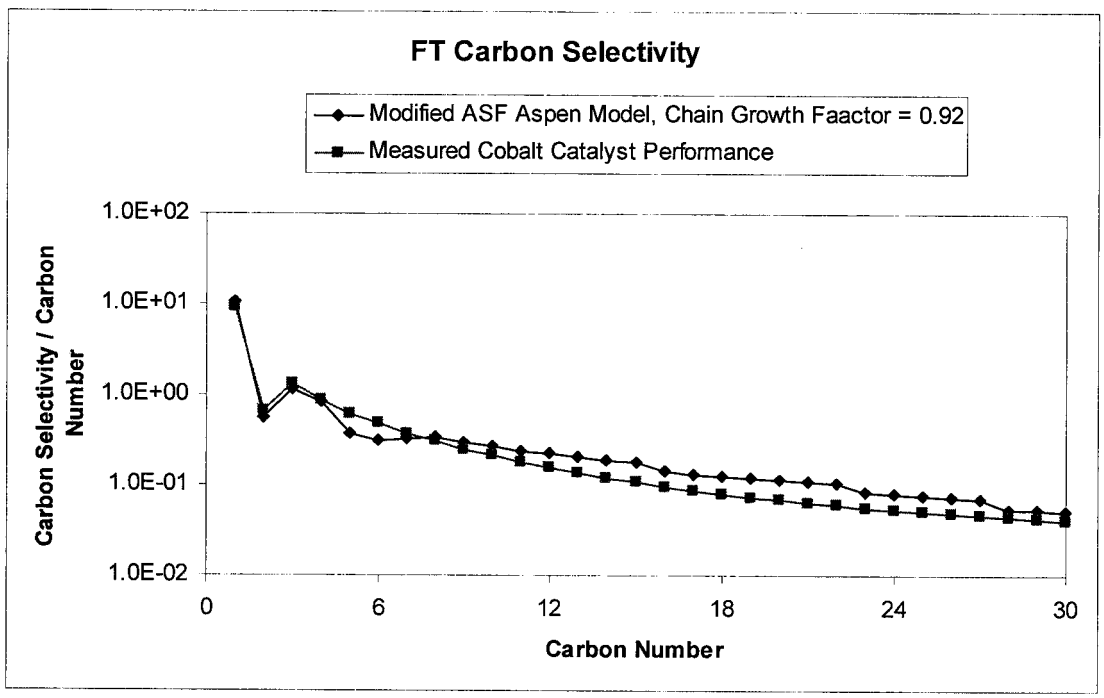

Figure 3. Performance of modified ASF distribution vs. measured product distribution

To differentiate products for the carbon number predicted by the modified ASF distribution, product distribution data for a cobalt catalyst (Table 1) were used to divide the product mix among paraffin, olefins, and oxygenates (Dry, 2001, and Bartholomew, 2006). Aspen contains property data for paraffin in the $C_1 - C_{30}$ range, olefins in the $C_2 - C_{20}$ range, and alcohols in the $C_1 - C_{20}$ range. These species were included in the model, and alcohols were used to represent all oxygenates that may be produced. Long chain paraffin greater than C_{30} were included in the C_{30}.

Table 1. FT product distribution assumed for each carbon number (428°F)

	$C_1 - C_2$	$C_3 - C_4$	$C_5 - C_{12}$	C_{13}+
Paraffin	87.09%	64.17%	59.00%	94.50%
Olefins	4.58%	27.50%	40.00%	5.00%
Oxygenates	8.33%	8.33%	1.00%	0.50%
Total	100.00%	100.00%	100.00%	100.00%

2.5 Product Upgrade

The Aspen hierarchy block for the product upgrade and refining section models includes hydrotreating, distillation, and hydrocracking to maximize the diesel and jet product fraction. An optional isomerization reactor can be used to convert the naphtha to transportation fuel. As a result of refining the wax and middle distillate fractions, some additional crude naphtha is produced. LPG is produced by separation and compression-refrigeration of the FT tail gas. In this manner, light hydrocarbons are incorporated into a higher value product, with the residual tail gas being used as fuel gas for fired heaters and power generation. Heat recuperation is extensively utilized to optimize power production and overall plant efficiency.

Hydrogen is mixed with the FT middle distillate cut prior to being fed to the hydrotreater. The following reactions are specified to go to completion:

$$C_2H_4 + H_2 \longrightarrow C_2H_6 \tag{4}$$

$$CH_3OH + H_2 \longrightarrow CH_4 + H_2O \tag{5}$$

$$SO_2 + 3H_2 \longrightarrow H_2S + 2H_2O \tag{6}$$

$$COS + H_2 \longrightarrow CO + H_2S \tag{7}$$

$$2NO + 5H_2 \longrightarrow 2NH_3 + 2H_2O \tag{8}$$

$$2NO_2 + 7H_2 \longrightarrow 2NH_3 + 4H_2O \tag{9}$$

$$O_2 + 2H_2 \longrightarrow 2H_2O \tag{10}$$

Reaction 4 is representative of hydrogenation reactions for $C_2 - C_{20}$ olefins. A reaction for each of these species is included in the hydrotreater block. Similarly, Reaction 5 is representative of alcohol conversion for $C_1 - C_{20}$ alcohols – a reaction for each of these species is included in the hydrotreater block. Hence, the hydrotreater block contains a total of 44 reactions. The hydrotreated middle distillate stream is flashed to near atmospheric pressure prior to distillation. Light gas from this separation is recompressed and mixed with other tailgas produced during refining. Water is also removed in this separation prior to feeding the liquid hydrocarbon stream to a distillation column to produce the diesel and naphtha products. Hydrogen is extracted from the syngas using a pressure-swing absorption (PSA) unit.

A distillation column is used in the Aspen model to separate the product into the various distillate streams. Feed is preheated in a furnace prior to introduction to the lower section of the column. Wax is withdrawn from the bottom of the column, while naphtha is condensed at the top of the column. A multi-

stage stripper with liquid draw from an intermediate tray is employed to recover the diesel fraction. The model currently assumes that heat will be supplied to the column using a fired heater. The fuel source for this heater is tailgas generated by the PSA unit.

Wax from the bottom of the distillation column is mixed with wax separated in the FT area and pressurized for hydrocracking. This wax stream is mixed with recycle wax from the hydrocracker. The combined wax stream is mixed with hydrogen and preheated before being fed to the hydrocracker. The hydrocracker is modeled as two separate reactor blocks in Aspen. The reactions are specified similar to the hydrotreater (discussed above) to convert all remaining olefins and alcohols to paraffin.

Product from the hydrocracker is separated with a flash block. The pressure of this flash is controlled to achieve a ratio of total-to-fresh feed to the hydrocracker of 1.5 (literature indicates that reasonable values are between 1.0 and 2.0) (Hsu & Robinson, 2006). Wax product from this flash is repressurized and recycled to the hydrocracker. Additional cooling is accomplished in two flash steps to recover middle distillate, crude naphtha, and light gas fractions.

2.6 Power

An accurate model of the gas turbine is essential, as it will directly impact calculation of net power output from the plant. For the ORCF project, a commercial software package, GT PRO (Thermoflow, 2006) was used to model the commercial gas turbines selected for the plant. These predictions were in turn used to calibrate Aspen compressor and turbine blocks that were developed to simulate the gas turbine. Nitrogen from the ASU was used as a diluent in the gas turbine. A reactor block was used immediately downstream of the combustor to predict NO_x formation.

2.7 *CO_2 Capture*

An important objective of the ORCF project was to optimize carbon management by separating most of the CO_2 generated in the gasifier and shift reactors to provide a high-purity stream of CO_2. In consideration of future potential uses of CO_2 for enhanced oil recovery, geological sequestration, and possibly agriculture uses, the ORCF design is tailored to optimize CO_2 capture and utilization.

3. MODEL RESULTS

Model results from two cases compare the differences in plant resource requirements and product yield for a pure coal-to-liquids (CTL) plant and a feedstock containing 30 wt.% wood biomass (CTL-BTL) are listed in Table 2. The composition of coal is compared to wood biomass in Table 3 to illustrate the relative amount of moisture, ash, and elements in the different feedstock materials. Use of lower moisture, and lower ash biomass will increase the synthetic fuels product yield while also decreasing greenhouse gas emissions associated with the overall process. For example, poplar contains 3.5 wt% more carbon and 3% less ash than the wood biomass specified for the model cases presented in Table 2. In other case predictions, dried poplar wood was used to help reduce greenhouse gas emissions. Similarly, the choice of coal also impacts the product yield commensurate with the carbon content in the coal. Therefore, one benefit of the model is to consider plant productivity on the basis of feedstock composition and feedstock preparation.

Table 2. Summary of Modeling Case Study Results

bbl = 42 U.S. gal **ton = short ton = 2000 lbm**	**Pitts # 8 Coal**	**70 wt.% Pitts # 8 Coal, 30% wt.% Woody Biomass**
INPUTS		
Raw Coal/Biomass feed rate, short tons/day	27,575	30,791
Dried feed rate (coal to 1.5%, wood to 15%), short tons/day	26,455	26,455
OUTPUTS		
Total Liquids, bbl/day	53,000	48,200
Diesel product, bbl/day	34,750	31,550
Crude Naphtha, bbl/day	16,250	14,750
Crude LPG Product, bbl/day	2,000	1,900
Net Power Generated, MW_e	254	240
Gas Turbine, MW_e	334	303
Steam Turbines, MW_e	608	562
MATERIAL BALANCE SUMMARY		
Carbon Balance		
Coal Feed Input, ton C/day	+16,860	+15,245
Liquid Fuel Product, ton C/day	-5,553	-5,039
CO_2 Product, ton C/day	-7,940	-7,038
Turbine, heaters, and vent CO_2 releases, ton C/day	-3,300	-3,107

Table 3. Composition of Coal and Woody Biomass Feedstock Materials

	Pitt #8	Wood	Poplar
Proximate (% dry basis, except moisture)			
Moisture	5.5	50	50
Fixed Carbon	42.83	15.26	14.01
Volatile Matter	34.87	79.05	83.25
Ash	22.3	5.69	2.74
Ultimate (% dry basis)			
Ash	22.3	5.69	2.74
Carbon	64.7	44.74	48.19
Hydrogen	3.9	5.5	5.89
Nitrogen	1.19	0.57	0.09
Chlorine	0.05	0	0
Sulfur	4.25	0.05	0.06
Oxygen	3.61	43.45	43.03
HHV (Btu/lb, dry basis)	11,620	9,154	9,154
HHV (Btu/lb, as received basis)	10,981	4,577	4,577

4. EMISSIONS CALCULATIONS

A life-cycle analysis of greenhouse gas (GHG) emissions for the production of synthetic diesel fuel and electrical power produced by the ORCF project will next be presented for the following cases:

Case 1 - 100% coal fed FT process

Case 2 - 100% coal fed FT process with carbon capture and sequestration (CCS)

Case 3 – 70 wt. %, dry, coal and 30 wt.%, dry, poplar biomass fed FT process (as fed to the gasifier)

Case 4 – 70 wt. %, dry, coal and 30 wt.%, dry, poplar biomass fed FT process with CCS (as fed to the gasifier)

The GHG emissions calculations follow the approach developed by NETL for a coal to liquids plant (*Life-Cycle Greenhouse-Gas Emissions Inventory for Fischer-Tropsch Fuels*, NETL, 2001). Emissions for CH_4 and N_2O are converted into CO_2 equivalents using the 100-year global warming potentials for CH_4 and N_2O of 23 and 296, respectively (EIA 2006a). This analysis can be compared to a "well-to-wheel" (WTW) analysis for petroleum diesel produced from refining crude. In the case of the CTL plant, the analysis is broken down into the following major emissions sources and sinks, as depicted in Figure 4:

- Emissions from resource extraction, production and transportation of coal and biomass to the plant
- As with the case for ethanol production, credit is given for CO_2 that is adsorbed from the atmosphere by biomass regrowth
- Emissions for conversion of the coal and biomass to synthetic fuels and other products
- Credit for CO_2 that is captured and sequestered
- Emissions for resource and product transportation from the plant to the market (the "tank")

- Emissions for end use combustion

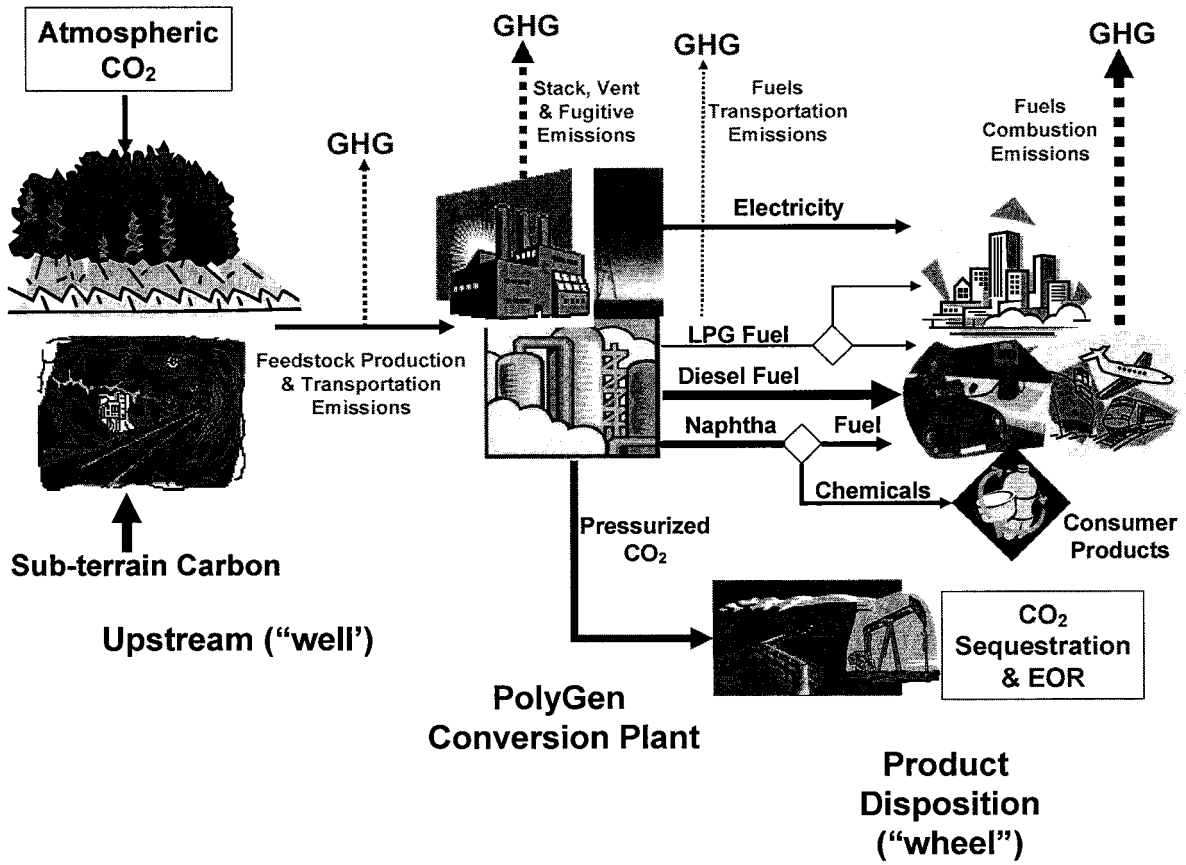

Figure 4. Greenhouse gas life cycle emissions sources and sinks for PolyGen FT plant

The GHG emissions for the ORCF plant are apportioned to the total energy content of the products (LPG, naphtha, diesel, and electricity production) on the basis of the total lower heating value (LHV), or electrical production for power, of the respective products. The emissions for the diesel product were subsequently converted to a gram-per-mile basis using a vehicle fuel economy of 24.4 miles per gallon, the average fuel economy of a diesel fueled SUV using FT diesel (NETL 2001). The emissions for the net (exportable) electrical power are calculated on a per-kilowatt-hour basis.

Table 4 shows a breakdown of the four case studies, indicating the product mix and its apportionment by volume, net MW_e power, and LHV. All upstream ("well-to-plant") GHG emissions, and all plant conversion emissions are apportioned to the various products on the basis of the LHV energy ratio in each product, respectively. The emissions apportionment is summarized in Table 5.

Table 4. FT Plant Input and Product Distribution

		Case 1	Case 2	Case 3	Case 4
Resources					
Coal (tpd)	5.5 wt% moist	27,575	27,575	18,509	18,509
Coal (tpd,)	1.5 wt% moist.	26,500	26,500	17,750	17,750
Wood (tpd)	50 wt% moist.	0	0	14,992	14,992
Wood (tpd,)	15 wt% moist.	0	0	8,819	8,819
Natural Gas (tpd)		0.077	0.077	0.077	0.077
Methanol (tpd)		19	19	19	19
Products					
LPG					
Volume (bbl/d)		2,300	2,300	1,800	1,800
Energy (LHV, MM BTU/d)		8,540	8,540	7,535	7,535
Naphtha					
Volume (bbl/d)		16,250	16,250	14,250	14,250
Energy (LHV, MM BTU/d)		72,328	72,328	62,589	62,589
Diesel Fuel					
Volume (bbl/d)		34,750	34,750	30,500	30,500
Energy (LHV, MM BTU/d)		176,609	176,609	149,941	149,941
Net Electric Power					
Energy (MW)		395	239	351	215
Energy (MM BTU/d)		32,318	19,602	28,738	17,643

Table 5. Product Apportionment for Upstream Production and Conversion Plant GHG Emissions

	Case 1	Case 2	Case 3	Case 4
Emissions Apportionment, % of Total				
LPG	2.95%	3.08%	3.03%	3.17%
Naphtha	24.96%	26.10%	25.16%	26.33%
Diesel Fuel	60.94%	63.74%	60.26%	63.08%
Electric Power	11.15%	7.07%	11.55%	7.42%

In order to reduce the GHG emissions for the plant, geological CO_2 sequestration and product conversion to durable materials can be considered. Naphtha, for example, can be converted to gasoline additives through isomerization or to ethylene through cracking. The high normal paraffin concentration of synthetic naphtha is ideal for ethylene production. Ethylene that is converted to plastics amounts to carbon removal from the biosphere. Naphtha that is converted to fuel would contribute to the overall lifecycle GHG emissions from the plant. The net power produced by the plant can also help reduce overall GHG emissions since a significant portion of the power is generated from heat recovery from the steam as will be presently discussed. This sets up an opportunity to trade carbon credits for the emissions generated by combustion of the liquid fuels.

4.1 Resource Extraction and Production

Coal extraction emissions result from activities associated with coal mining, post mining operations, and coal bed methane. Biomass production emissions results from activities associated with biomass cultivation and harvesting as well as the credit for GHGs absorbed during biomass growth. The ORCF FT plant will use Pittsburgh #8 bituminous coal or a close equivalent. The majority of this coal will be mined in the state of West Virginia. In 2005, approximately 59% of the coal mined in West Virginia was mined using underground mining methods, the remaining was surface mined (EIA 2006). In this study, underground mining mainly consists of longwall mining, where the majority of the equipment operated is powered by electricity to maintain safe air quality in the mines. As a result, the emissions associated with underground mining include emissions from electricity consumption and chemical transport. Surface mining, or strip mining, utilizes electricity, heavy equipment burning diesel fuel, and explosives to extract coal. Thus, the emissions associated with surface mining include emissions from electricity consumption, heavy equipment emissions, and chemical transport (NREL 1999). Once the coal has been extracted there are post-mining operations, mainly coal sizing and cleaning, which generate emissions associated with electricity consumption. Finally, coal bed methane emissions are calculated for the methane released during mining operations (EPA 2007).

Biomass is a renewable material which can be replaced using regrowth practices. The current study assumes hybrid poplar biomass is produced on a plantation specifically as an energy crop. The agricultural practices are assumed to follow those presented in the National Renewable Energy Laboratory (NREL) *Life Cycle Assessment of a Biomass Gasification Combined-Cycle System* (NREL 1997). Emissions are estimated from the NREL report for the cultivation and harvesting of the biomass as well as the credit for GHGs absorbed during biomass regrowth. The cultivation and harvesting emissions include emissions associated with fertilizer and pesticide use, biogenic emissions, transportation of chemicals, and plantation operations.

Table 6 summarizes the GHG emissions for the resource extraction and production of coal and biomass for the four cases; note that negative values indicate net carbon sequestration from biomass regrowth.

Table 6. GHG Emissions for Resource Extraction and Production

GHG Emission	Case 1	Case 2	Case 3	Case 4
g CO_2/bbl-diesel	5,536	5,790	-231,262	-242,057
g CH_4/bbl-diesel	2,344	2,452	1,779	1,862
g N_2O/bbl-diesel	0.31	0.32	2.73	2.86
g CO_2-eq/bbl-diesel	59,540	62,272	-189,537	-198,384
g CO_2-eq/mile for diesel	**58**	**61**	**-185**	**-194**
g CO_2-eq/kWh	**40**	**42**	**-132**	**-138**

4.2 Resource Transportation

The emissions associated with the various transportation methods for delivering feedstock to the conversion plant include the combustion of fuel (or electricity use) necessary for the transportation method as well as the upstream emissions associated with producing the fuel or electricity. GHG emissions increase when biomass is added to the system due to the fact that 50% of the biomass

transported is water, due to its high moisture content. Table 7 lists the distances and modes of transportation assumed for the various resources and products to the ORCF plant site in addition to the transportation of products from the plant to the end use point, while Table 8 summarizes the cumulative GHG emissions for the four cases.

Table 7. Transportation Information for Resources and Products

Product Transported	Miles Transported	Mode of Transport
Chemicals to Mine	20	Truck
Biomass to FT Plant	100	Truck
Coal to FT Plant	50	Barge
Petroleum Products to FT Plant	50	Rail
CO_2 to Sequestration Area	40	Pipeline
Diesel – Plant to Distribution Point	80	Pipeline
Diesel – Distribution Point to Tank	50	Truck

Table 8. GHG Emissions for Transportation of Resources to the FT Plant

GHG Emission	Case 1	Case 2	Case 3	Case 4
g CO_2/bbl-diesel	1,045	1,093	5,728	5,996
g CH_4/bbl-diesel	0.18	0.19	0.40	0.42
g N_2O/bbl-diesel	0.02	0.03	0.18	0.19
g CO_2-eq/bbl-diesel	1,056	1,105	5,790	6,061
g CO_2-eq/mile for diesel	**1.0**	**1.1**	**5.7**	**5.9**
g CO_2-eq/kWh	**1**	**1**	**4**	**4**

4.3 Conversion and Refining

GHG emissions are generated from several sources within the FT plant, including: combustion emissions, vents, and fugitive emissions. The combustion emissions are associated with burning fuels within the plant. Combustion emissions for the ORCF plant include: fired heaters fueled with syngas, HRSG stack emissions, and high pressure (HP) and low pressure (LP) flare systems. Vent emissions are point source emissions from directly venting process and utility streams to the atmosphere. Point source emissions include coal milling and drying operations and fugitive releases from the Rectisol™ unit operations. Other fugitive emissions associated with valves, pumps, etc., storage tanks, and wastewater treatment facilities are taken into account. Table 9 summarizes the calculated GHG emissions for the conversion and refining portions of the system.

Table 9. GHG Emissions for Conversion and Refining

GHG Emission	Case 1	Case 2	Case 3	Case 4
g CO_2/bbl-diesel	636,178	184,463	625,891	179,548
g CH_4/bbl-diesel	29	30	30	31
g N_2O/bbl-diesel	0.47	0.49	0.47	0.49
g CO_2-eq/bbl-diesel	636,982	185,305	626,710	180,405
g CO_2-eq/mile for diesel	**622**	**181**	**612**	**176**
g CO_2-eq/kWh	**429**	**125**	**435**	**125**

4.4 Transportation of the Diesel Product

Transportation of the diesel product is a relatively small contributor to the overall GHG emissions, in addition to transportation of the resources to the FT plant as shown in Table 12. GHG emissions increase for the CCS cases since the sequestered CO_2 must be transported via pipeline to its final destination.

Table 12. GHG Emissions for Transportation of the Diesel Product

GHG Emission	Case 1	Case 2	Case 3	Case 4
g CO_2/bbl-diesel	1,192	1,812	1,156	1,774
g CH_4/bbl-diesel	1	2	1	2
g N_2O/bbl-diesel	0.04	0.08	0.04	0.08
g CO_2-eq/bbl-diesel	1,218	1,885	1,182	1,845
g CO_2-eq/mile (diesel)	**1.2**	**1.8**	**1.2**	**1.8**
g CO_2-eq/kWh	**0**	**0.31**	**0**	**0.31**

4.5 End Use Combustion

Emissions for the end use combustion of the synthetic diesel were estimated from the carbon content of the fuel. It was assumed that all carbon present in the fuel is completely combusted to form CO_2. Thus, vehicle combustion emissions are the same for all cases, as the carbon content of the FT diesel does not change. The GHG emissions for the FT diesel are presented in Table 13. There are no end use combustion emissions associated with the power production.

Table 13. GHG Emissions for Transportation of the Diesel Product

GHG Emission	Case 1	Case 2	Case 3	Case 4
g CO_2/bbl-diesel	376,748	376,748	376,748	376,748
g CO_2-eq/bbl-diesel	376,748	376,748	376,748	376,748
g CO_2-eq/mile (diesel)	**367.6**	**367.6**	**367.6**	**367.6**

4.6 Electrical Power Generation

Electricity used for coal mining is assumed to come from the US average electrical power production mix (EIA 2006b). Emission factors are available for electricity produced, including upstream processes, from coal boilers, fuel oil boilers, natural gas boilers, natural gas turbines, and nuclear power plants (ANL 1993). However, 9% of the US energy mix comes from renewable energy resources, which do not have an emission factor available. Therefore, the renewable energy resources were equated to nuclear power for the present assessment. Table 14 tabulates the life cycle GHG emissions for the individual power plants and the total based on the individual percentages. The average electrical power GHG emissions rates for the production mix, and which were used for the ORCF life cycle GHG emissions, are complied in Table 15.

Table 14. GHG Emissions from Power Plants and Upstream Processes

g GHG/kWh Average Energy Mix	Coal Boiler 51%	Fuel Oil Boiler 2%	NC Boiler 18%	NG Turbine 18%	Nuclear Power & Renewables 29%	Total Energy Mix
Upstream Processes						
CO_2	29.3	141.8	72.0	72.0	45.9	44.0
CH_4	3.129	0.376	0.776	0.776	0.129	1.780
N_2O	0.001	0.018	0.002	0.002	0.002	0.002
Power Plant						
CO_2	1,075.4	875.9	606.3	605.2	6.5	676.9
CH_4	0.005	0.010	0.000	0.171	0.005	0.019
N_2O	0.056	0.034	0.034	0.034	0.011	0.039

Table 15. GHG Emissions for Electricity Generation

GHG	g/kWh
CO_2	720.9
CH_4	1.8
N_2O	0.041

5.0 EMISSIONS SUMMARY

The life cycle GHG emissions for the four cases are summarized in Table 16. Figure 5 presents a graphical comparison of the WTW GHG emissions for the ORCF FT plant operating scenarios considered in this study. The life cycle GHG emissions for the synthetic diesel are greatly reduced when CO_2 is captured (Case 2). Feeding 30% biomass (Case 3) reduces GHG emissions by 24% versus the base case while combining 30% biomass feed with CCS reduces GHG emissions by 66% (Case 4). This plot also shows the relatively small contributions of transportation of the resources to the plant and transportation of the products to the market (i.e., tank).

Table 16. GHG Emissions Summary

GHG Emission	Case 1	Case 2	Case 3	Case 4
g CO_2/bbl diesel	1,020,699	569,907	778,262	322,009
g CH_4/bbl diesel	2,374	2,484	1,809	1,895
g N_2O/bbl diesel	0.85	0.92	3.42	3.62
g CO_2-eq/bbl-diesel	1,075,545	627,315	820,893	366,675
g CO_2-eq/mile for diesel	**1,050**	**612**	**801**	**358**
g CO_2-eq/kWh	**470**	**168**	**307**	**-8**

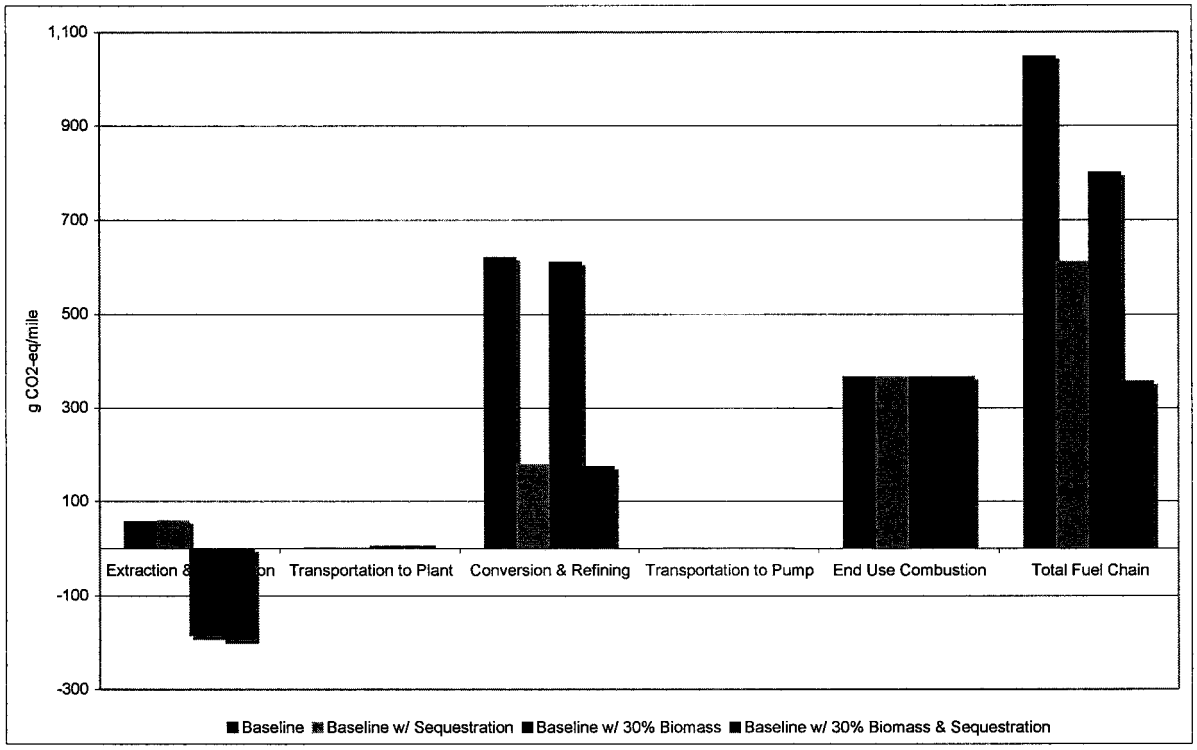

Figure 5. Full Life-Cycle GHG Emissions for FT Plant Scenarios

GHG emissions for the power produced by the FT plant for the four scenarios are plotted in Figure 6. These values are compared to GHG emissions for the current US power mix to illustrate the potential reduction in GHG emissions for the power produced at the plant. Net power produced with no CO_2 capture (Case 1) has significantly lower GHG emissions than traditional power, and reduces GHG emissions by 39%. When CO_2 is captured (Case 2), GHG emissions for the power are 78% lower than traditional power. Similarly incorporating 30% biomass into the feed (Case 3), without CO_2 capture, decreases GHG emissions by 60% while CO_2 capture with 30% biomass co-feed with coal is 101% lower that the average power mix.

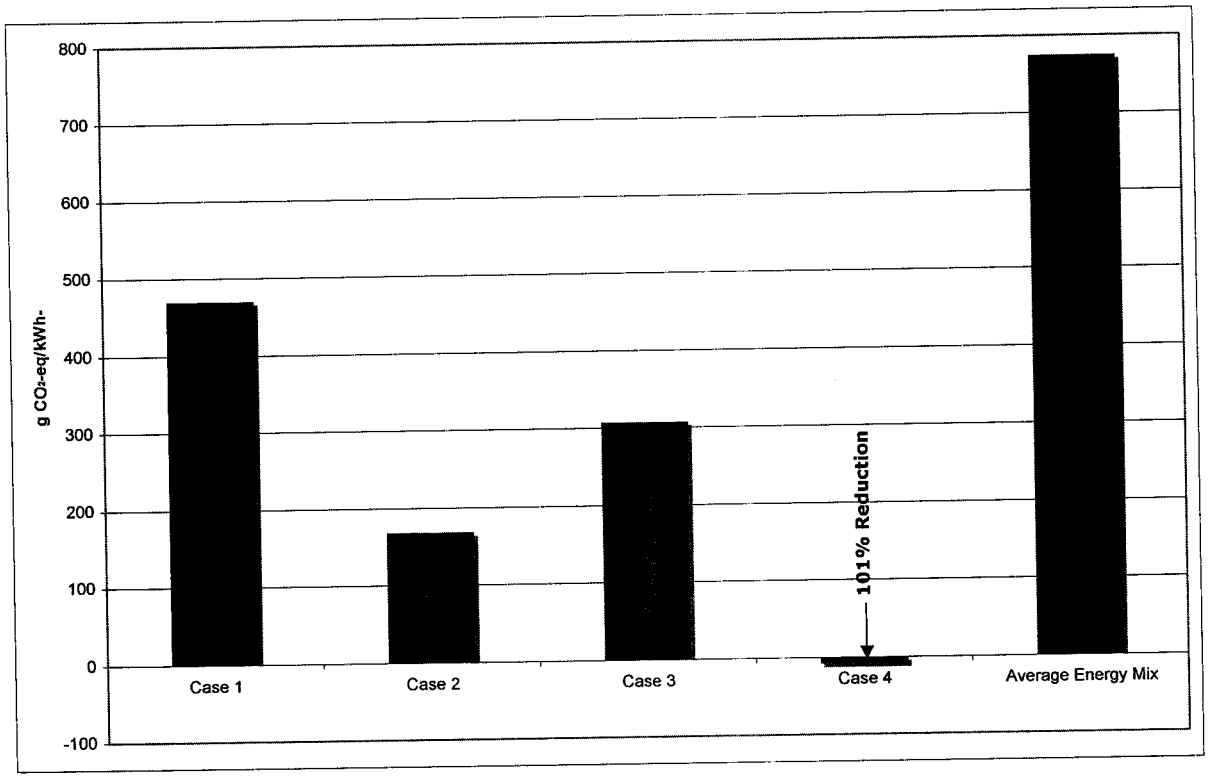

Figure 6. Power Production GHG Emissions for FT Plant and Average US Energy Mix

Figure 7 compares the GHG emissions for the four cases when no credit is taken for the GHG emissions reductions realized by power sales, and when credit is taken for the difference between GHG emissions for each case relative to the average energy mix apportioned to LPG, naphtha, and the diesel product mix. In other words, when the carbon credits realized by sale of the plant's net power, in proportion to the relative energy content of the products produced (LHV apportionment basis), the life cycle emissions for the 4 separate cases are reduced as shown in Figure 6. In comparison to Arabian crude life cycle GHG vehicle emissions, the GHG gas emissions for the ORCF project are reduced 47% when this credit is applied.

Life cycle emissions for naphtha converted to fuel would be approximately 10-15% higher than diesel when accounting for the additional conversion step of isomerization that would be required to produce a gasoline additive, plus the lower combustion efficiency of gasoline in a spark-ignited engine. On the other hand, any naphtha used to produce ethylene may provide a life cycle GHG emissions reduction when biomass is used in the product synthesis plant and when CO_2 byproduct from the conversion plant is sequestered. Care must be taken to consider all products and product end states when assessing the GHG emissions from a combined CTL-BTL plant.

Finally, Baard Energy and the INL are cooperatively developing new technology to separate and capture CO_2 from the FT reactor tail gas and stack exhaust to further reduce GHG emissions. Baard Energy is also interested in developing opportunities to capture CO_2 for algae growth as well as efficient use of CO_2 for enhanced oil recovery (EOR) and permanent geological sequestration. At the same time, INL is investigating co-electrolysis of CO_2 with H_2O in a fuel cell to produce CO, H_2, and O_2. While all of these additional processes could be incorporated into the plant at some future date, discussion of these opportunities is beyond the scope of this paper.

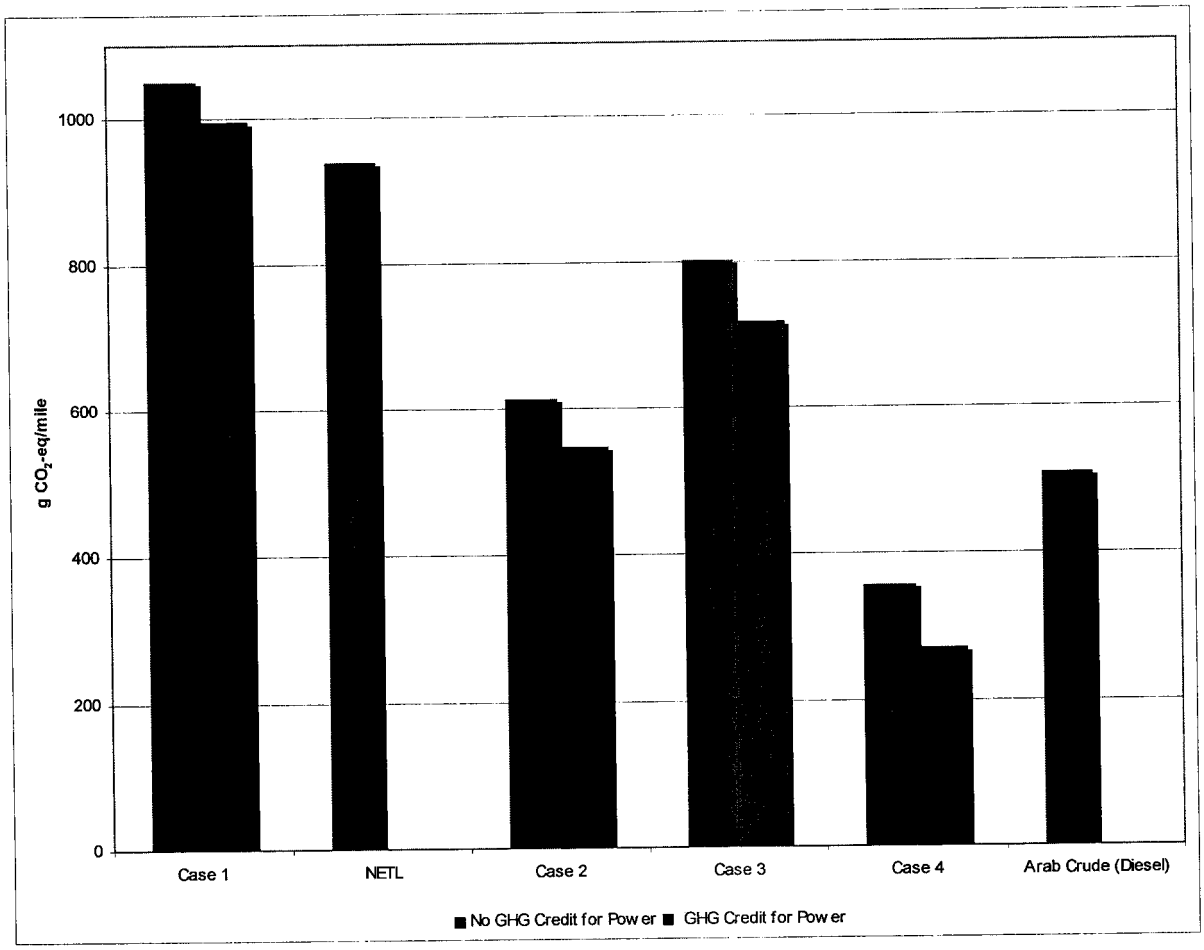

Figure 7. GHG Emissions Comparison for ORCF FT Diesel and Crude Diesel

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