Coal- and Biomass-to-Liquids:
A Comparative Analysis

by

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Abstract

Globally, there is growing interest in advancing alternatives to petroleum-derived transportation fuel in order to mitigate the risks posed by energy insecurity and global climate change. Coal-to-liquids (CTL) and biomass-to-liquids (BTL) represent promising means of supplementing or supplanting refined petroleum products, particularly diesel fuel. This work evaluates the technical and economic aspects of coal-to-liquids and biomass-to-liquids, and concludes that both technologies may offer an economic means of replacing petroleum products. It is shown that CTL is more technically proven and more economic, but represents a potentially tremendous new source of carbon dioxide emissions.

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I. General Introduction

Alternative fuels are currently attracting considerable political and economic interest in the U.S. and around the world. A sustained high oil price environment, widespread concerns about the stability of liquid fuel supplies, the maturation of new technologies and growing pressure for limits on global carbon emissions have come together to create a wave of support for alternatives to petroleum.

Perhaps the most well-known of these alternatives is ethanol, which is currently made from edible crops like corn and sugar cane, and is likely to also be produced from non-edible biomass sources in the coming years. Another seldom-discussed but increasingly important alternative technology is gas-to-liquids (GTL), which produces a high-purity diesel fuel. Major oil companies are currently allocating a great deal of capital to Gas-to-Liquids projects in order to monetize stranded natural gas resources in places like Qatar and Nigeria (Malone 2006).

Technologies exist to convert coal or non-edible biomass into the same high-quality diesel fuel, but, unlike GTL and ethanol, coal-to-liquids and biomass-to-liquids have not yet attracted a large amount of investment by governments or private firms. As the technology becomes more tested and the economics become more favorable, coal-to-liquids and biomass-to-liquids will draw increased government interest and private investment. The purpose of this work is to provide an introduction to the key technical considerations of coal- and biomass-to-liquids and to evaluate the economics of both types of plants. Additionally, a macroscopic picture of the future for coal-to-liquids is presented.

II. Coal-to-Liquids

History

During the rise of the Third Reich in Germany, a chemist named Franz Fischer, working at the Kaiser Wilhelm Institute for Coal Research, was laying the scientific foundations for the modern-day Fischer-Tropsch Coal-to-Liquids (CTL) facility. At the height of the World War II, Germany was using a related process to produce 124,000 barrels of fuel per day from coal in order to power their ground forces and the Luftwaffe.

Beginning in the 1950's, South Africa and its state oil company, Sasol, played an integral role in the development of CTL and the Fischer-Tropsch process. South African national policy encouraged Sasol, incorporated in 1950, to take advantage of the nation's large reserves of cheap domestic coal to produce fuels and chemicals. In 1955, Sasol first delivered fuels to market from its Sasolburg CTL plant.

Despite a broad falloff of interest in coal-to-liquids technologies after the oil price crash of the early 1980s, several companies have sprung up with pilot-scale coal-to-liquids technologies, including two publicly-traded American firms, Syntroleum and Rentech. Oil giant Shell and the now-public Sasol have plans for major coal-to-liquids developments in China, where rich coal reserves, rising liquid fuel demand and government support provide favorable conditions.

Technology Background

Feedstock

Key considerations for a coal feedstock include energy content, carbon:hydrogen ratio, moisture content, ash properties and pretreatment specifications. Different gasifiers will require different levels of coal pretreatment. Typically, the coal particles must be reduced in size, and, depending on the gasifier type, combined with water to form a slurry. Utilizing coal with consistent ash properties and sulfur content contributes to operational efficiency in any gasification process (Eastman Gasification Services Co. 2006).

Generally, the delivered coal feedstock can be expected to add a cash cost of $5 to $15 per barrel for a CTL plant. Obviously the feedstock cost is a key determinant of the economics of a CTL project, and total cost of goods sold will be heavily dependent on the cost of feedstock.

Gasification

Oxygen from an Air Separation Unit (ASU), pretreated feedstock and steam are combined in a gasifier under high temperature (900-1600 ^{o}C) and pressure (2-10 MPa) to produce a synthesis gas, or, syngas. The amount of oxygen input is approximately one quarter of the amount that would be needed for complete combustion of the feedstock (Collot 2006). Selecting a suitable gasifier is heavily dependent on project specifics, particularly the type and specs of the feedstock.

Gasifiers fall into roughly three categories: fixed bed, entrained flow and fluidized bed. These gasifiers are distinguished by their "flow geometry". In fixed bed gasifiers, the steam and oxygen (or air) gas mixture moves upwards through the gasifier, countercurrent to a flow of solid coal particles coming in through the top of the unit. Entrained flow models create syngas from a rapid stream of pulverized feedstock mixed with the injected gases. Entrained flow units require pulverizing and drying of the feed coal, but because this stream flows rapidly through the unit, they can gasify a lot of feedstock at a high rate. Coal is fed into an entrained flow gasifier either as dry, dust-sized particles or as a slurry mixture of coal and water. Fluidized bed gasifiers split the difference between entrained and fixed units. The bed of feedstock particles is fluidized (given the dynamic properties of a liquid) through combination with the injected gases (Collot 2006).

Table 1. While fixed bed units gasify more total coal globally, entrained flow units are now more commonly chosen for new gasification operations.

Gasifier Type	Selected Models
Fixed Bed	Sasol-Lurgi, British Gas Lurgi
Entrained Flow	Shell SCGP, GE Texaco, ConocoPhillips E-Gas, Siemens, Koppers-Totzek
Fluidized Bed	KRW, U-Gas, EAGLE, HTW

Fixed bed gasifiers are generally considered sturdy workhorses that can take most any pulverized carbonaceous feedstock (Zheng, Ligang et al. 2005). Sasol's CTL plants in Secunda and Sasolburg have operated fixed bed (also confusingly called "moving bed") Sasol-Lurgi gasifers for more than fifty years. Now running 97 fixed bed gasifiers, Sasol's CTL plants consume more coal than any other gasification operation (van Dyk, Keyser et al.). Fixed bed gasifiers have been faulted for producing undesirable tar byproducts and for not being easily scaleable (Eastman Gasification Services Co. 2006; Gangwal 2006).

Entrained flow gasifiers are currently the most widely used systems. These gasifiers operate at higher temperatures, reducing tar production (Gangwal 2006). Fluidized bed gasifiers have limited commercial experience – only two models have been used on an industrial scale. An important advantage to fluidized bed gasifiers is their capacity to efficiently gasify low-rank, high-moisture coals, such as that from the Powder River Basin (Maurstad 2005).

Key considerations in selecting a gasifier include capital cost, total throughput capacity, oxygen requirement, syngas output composition, coal/biomass feed requirements (i.e. pulverization and pretreatment), technical life, net heat output and operating history. The gasifier is a keystone component for a CTL facility. It can be expected to cost nearly 40% of capital expense, and its capital cost adds roughly $8 per barrel of output (Eyster 2006).[1] The air separation unit, which produces oxygen for the gasification reaction can be expected to contribute 20% of capex.

[1] Cash cost per barrel for capital components is computed as a percentage of depreciation cost annualized over the project life.

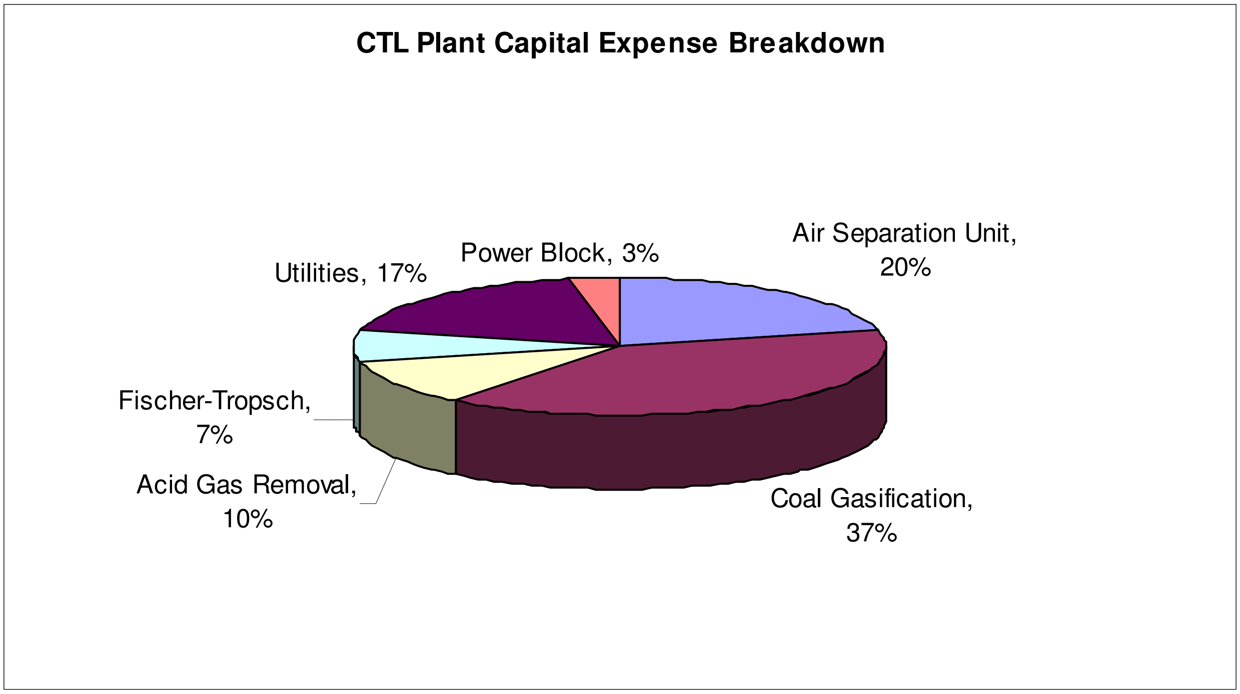

Figure 1. Nearly 70% of total capital cost goes to the production of clean syngas for injection into the Fischer-Tropsch reactor. (Figure is adapted from General Electric, "Coal: A Fuel for all Seasons".)

Gas Cleanup, Emissions and Waste

Prior to the synthesis of Fischer-Tropsch (FT) fuels and chemicals, the raw syngas coming out of the gasifier must be cooled, cleaned and conditioned. Syngas directly from the gasifier contains sulfur, carbon dioxide, mercury and trace elements. Both iron and cobalt catalysts are irreversibly poisoned by sulfur contamination (Oukaci 2003). Once quenched and cleaned, the syngas contains about 70-80% of the energy originally present in the feed coal (Larson and Tingjin 2003).

Prior to cleaning, syngas from the gasifier is quenched, a process which creates steam for power generation in the heat recovery steam generator. The first cleaning step involves vapor-phase removal of mercury from the quenched syngas, a process for which there exist commercial technologies to achieve approximately 90% reduction. Tests at Eastman Chemical Company's coal gasification plant have demonstrated such levels of mercury removal (Trapp, Moock et al. 2004). Sulfur oxides (SOx) can then be removed using established technologies such as MDEA, Selexol or Rectisol. Using the Claus process, the sulfur is converted from gas to elemental solids, which can be sold. Capital for the acid gas removal process can be expected to add 10% to total plant capex for a CTL plant.

Oxides of nitrogen (NOx) are created and emitted during combustion of off gases in the turbine generator. Injection of nitrogen from the ASU into the combustion turbine to reduce flame temperatures can reduce NOx formation considerably (to 3X below the emissions of a super critical pulverized coal plant of equal size) (Rentech 2005). It is not thoroughly understood where other, trace elements from the gasified coal end up, but they do not appear to represent an environmental liability for CTL facilities. It is believed that trace elements are "locked" in the gasifier slag which can be sold or disposed of (Maurstad 2005).

Other environmental considerations include solid waste production, waste water production, net water usage and volatile organic compound emissions. Solid wastes come predominantly from gasifier slag, which can be a saleable byproduct. Waste water can be recycled or disposed of based on local considerations. Air cooling can substitute for water cooling in areas of low water availability. VOC and CO emissions are typically low compared to coal-fired power plants of equivalent size (Rentech 2005).

Carbon Dioxide Emissions

The production of FT fuels from coal is a highly carbon dioxide intensive process. Approximately half a metric ton2 of carbon dioxide (not including combustion of the fuel product) is created per barrel of FT diesel from coal (Marano and Ciferno 2001). Sasol's commercial CTL plant in South Africa is the single largest point source of carbon dioxide in the world (Carbon Mitigation Initiative 2005). As the figure below shows, producing Fischer-Tropsch fuels from CTL plants that vent carbon emissions creates approximately 125% of the carbon dioxide emissions as conventional diesel refining. With capture and storage, this can be reduced by up to 25% above conventional diesel refining (Edwards, Larive et al. 2007).

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[2] A metric ton is also a 'tonne' or 't'

The coal gasification/Fischer-Tropsch process allows for the capture of carbon dioxide with a lower energy penalty than would be suffered through capture of CO2 from the flue gas of a coal-fired power plant. A "shift reactor" will create additional carbon dioxide and hydrogen from some of the carbon monoxide present in the syngas. Much of the total carbon dioxide from this new syngas stream can be removed using Selexol and Rectisol acid gas removal units, and a high purity stream of carbon dioxide can be generated. This stream can be further pressurized, conditioned and piped away for storage. Capturing CO2 from a refinery or a coal-fired power plant would be comparatively much more costly and energy-intensive (Ratafia-Brown, Manfredo et al. 2002).

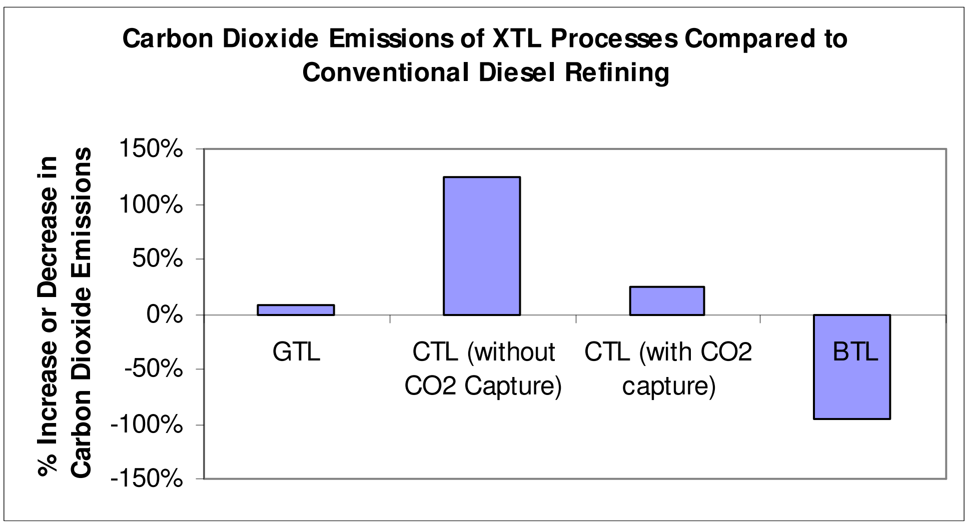


Figure 2. A CTL plant without carbon dioxide capture and storage produces about 125% more carbon emissions per unit of diesel fuel output as compared to conventional diesel refining. Figure is adapted from Edwards et al.

The imposition of a tax or tradeable permit system for carbon emissions would have a substantial effect on CTL project economics (discussed below), and with the specter of climate policy looming, conventional wisdom is that developers of CTL projects in the U.S. should be taking a proactive approach towards carbon sequestration. A proactive developer could site a facility in an area with good potential for enhanced oil recovery, enhanced coal bed methane recovery or industrial uses of CO2, and leave a footprint in the facility for carbon capture equipment. DKRW Energy, an American developer of CTL projects will sell carbon dioxide from its proposed Medicine Bow, Wyoming CTL plant to nearby enhanced oil recovery operations (DKRW Energy 2006).

Fischer-Tropsch Synthesis of Fuels & Chemicals

The precise chemistry of the Fischer-Tropsch reaction is still not thoroughly understood, despite more than eighty years of laboratory history (Dry 2002). Clean syngas (predominantly carbon monoxide and hydrogen) is injected into a reactor vessel containing a cobalt or iron catalyst, where the carbon atoms are linked together and combined with hydrogen to form long-chain hydrocarbons. Minor refining creates saleable diesel, naptha and other products.

Catalysts

Although other metals have been explored in the laboratory as potential catalysts, iron and cobalt have emerged after eighty years as the most technically and economically viable options for Fischer-Tropsch catalysis. Several companies own patents on various processes employing these catalysts. The choice between the two is determined by the properties of the syngas entering the reactor, namely the ratio of H_2 to CO.

Cobalt catalysts were first introduced by Franz Fischer in 1935 (Schulz 1999). Cobalt is the preferred catalyst for the Fischer-Tropsch conversion of syngas derived from natural gas, which has a H_2:CO ratio of approximately 1.7, significantly higher than that of coal-derived syngas, approximately 0.7 (O'Brien et al 2000). With hydrogen-heavy syngas, cobalt is a substantially more productive catalyst than iron. Cobalt is also roughly 1000X more expensive than scrap iron, but its higher conversion rates have made it the catalyst of choice for major GTL projects such as those by Shell and SasolChevron (Dry 2002).

For the Fischer-Tropsch conversion of coal-derived syngas, which is poor in hydrogen (H_2:CO of ~0.7), iron catalysts are preferable. Iron catalysts exhibit the “shift” activity mentioned above, meaning they enrich the syngas with H_2 and create more waste CO_2 as a result. This is necessary for making long-chain hydrocarbons from hydrogen-poor coal syngas. However, iron catalysts are not as productive, and very thorough carbon conversion with iron catalysts requires recycling of tail gas to the reactor unit (Schulz 1999; Steynberg and Nel 2004).

Reactors

The Fischer-Tropsch reactor unit is on par with the gasifier as a keystone component of the CTL plant. FT reactors can be broadly divided into two types: high temperature (HTFT), which operates at 300-350 oC and low temperature (LTFT), which operates at 200-250 oC. The latter has become favored for several technical and economic reasons. Cobalt catalysts are only used in LTFTs because they create excess methane under high temperature operation. Also, iron catalysts are susceptible to fouling by carbon disposition when operated under high temperatures (Dry 2002).

Within the category of HTFTs, there are two reactor designs, fixed fluidized bed and circulating fluidized bed. Both designs contain only compounds in solid and gas phases. In a circulating unit, the catalyst operates in two fluidized phases in different "zones" of the reactor, and the contents of these zones circulate. In a fixed fluidized bed reactor, there is no circulation between reactor zones; rather, the syngas is fed into the bottom of the reactor, where it moves upwards in a fluidized catalyst stream, undergoing synthesis. Circulating fluidized bed reactors were originally installed at Sasol's Secunda facility, but they have since given way to Sasol's improved fluidized bed technology. HTFT reactor designs are generally preferable for the production of lighter, more olefinic hydrocarbons (Dry 2002).

Slurry phase bubble column and multitubular reactors are used for LTFT conversion. Multitubular reactors are employed at Shell's Bintulu GTL plant and were originally installed at Sasol's Sasolburg CTL plant. However, slurry phase bubble column reactors are becoming increasingly popular, as the cost of the slurry reactor train is three quarters less than the cost of a multitubular system. Additionally, less catalyst is required and productivity is higher for slurry phase systems. Slurry phase systems also allow for easy removal of the excess heat generated during the Fischer-Tropsch reaction (Gangwal 2006).

Deployment of slurry phase reactors, in which the catalyst is suspended in a solution where the FT reaction occurs, has been slowed by the difficulty of wax separation.

Rentech's Fischer-Tropsch process uses an iron catalyst in a slurry phase reactor. Attrition of the catalyst and downstream removal of the catalyst from the wax has presented a challenge for this system(Gangwal 2006). In recent years, patents have been issued that deal with catalyst-wax separation mechanisms. This issue notwithstanding, slurry phase bubble column reactors have become one of the most commonly promoted means of producing CTL fuels and chemicals (Schulz 1999).

During the Fischer-Tropsch reaction, considerable heat is generated, which is captured as steam and sent to the HRSG for power production in all reactor types. Many different process designs can be imagined for CTL plants, depending on the desired outputs. Often, some hydrogen is removed from the syngas prior to FT synthesis for later product upgrading. Depending on the desired quantity of power for export, syngas and FT product can be redirected to the plant's combined cycle turbine for power production (Rentech 2005).

The overall efficiency of converting coal Btus to liquid fuels and electrical power is approximately 45-55%. Newer plants with low-temperature FT, once-through design with power export should be able to approach the upper end of this range (Steynberg and Nel 2004; Gray 2005; Gangwal 2006). This is greater than integrated gasification combined cycle coal plants, which have an efficiency of approximately 40% (Maurstad 2005). The efficiency for a CTL plant is, however, considerably less than a natural gas-to-liquids plant at about 60-65% (Steynberg and Nel 2004).

Costs for F-T reactors vary significantly but can generally be expected to make up 7% of the total capital cost of a CTL facility.

Product Upgrading

Fischer-Tropsch synthesis produces hydrocarbons of various chain lengths, which can be upgraded into several saleable products. Varying FT reactor conditions create different products, but the final breakdown generally includes naptha, middle distillates and waxes. Typically, these waxes are cracked into more high quality diesel fuel if they are not used for specialty chemicals manufacturing. Research by Sasol showed that after wax hydrocracking, product yields from their reactors were 80% diesel, 15% naptha and 5% C1-C4 hydrocarbons.

The diesel fuel is extremely high quality, boasting ultra-low aromatics, ultra-low sulfur and a very high cetane index (Dry 2002). Because of its superior quality, this FT diesel can fetch a significant premium over conventional diesel fuel. The naptha product is highly paraffinic and not ideal for gasoline production. In some locations this naptha can be sold at a premium to crude oil as a petrochemical feedstock.

Table 2. FT diesel from a CTL plant is substantially cleaner burning than petroleum-based diesel by all conventional metrics. Figure is adapted from Rentech Inc., "The Economic Viability of an FT Facility Using PRB Coals".

	FT Diesel (Rentech)	EPA Standards, June 2006	European Union
Cetane Index	72	>40	>50
Aromatics (vol %)	<4%	<35	<10
Sulfur (ppm)	<1%	<15	<10

CTL Project Economics

Background and Assumptions

Herold's analysis of a hypothetical 20,000 barrel per day CTL plant confirms the conventional wisdom that a sustained crude oil price of approximately $30-40 per barrel is required to achieve a competitive rate of return. In this simplified model, a constant $10 premium for FT diesel over WTI crude is assumed. While this premium is greater than the historical average for diesel, drivers for a widening spread are highly positive right now. Ever-tightening environmental regulations are leading to increasing cost pressure for conventional refiners of diesel fuel, and an ever-tightening refining market is creating increased spreads for all refined products. A $10 price premium for FT diesel over WTI crude is therefore conservative.

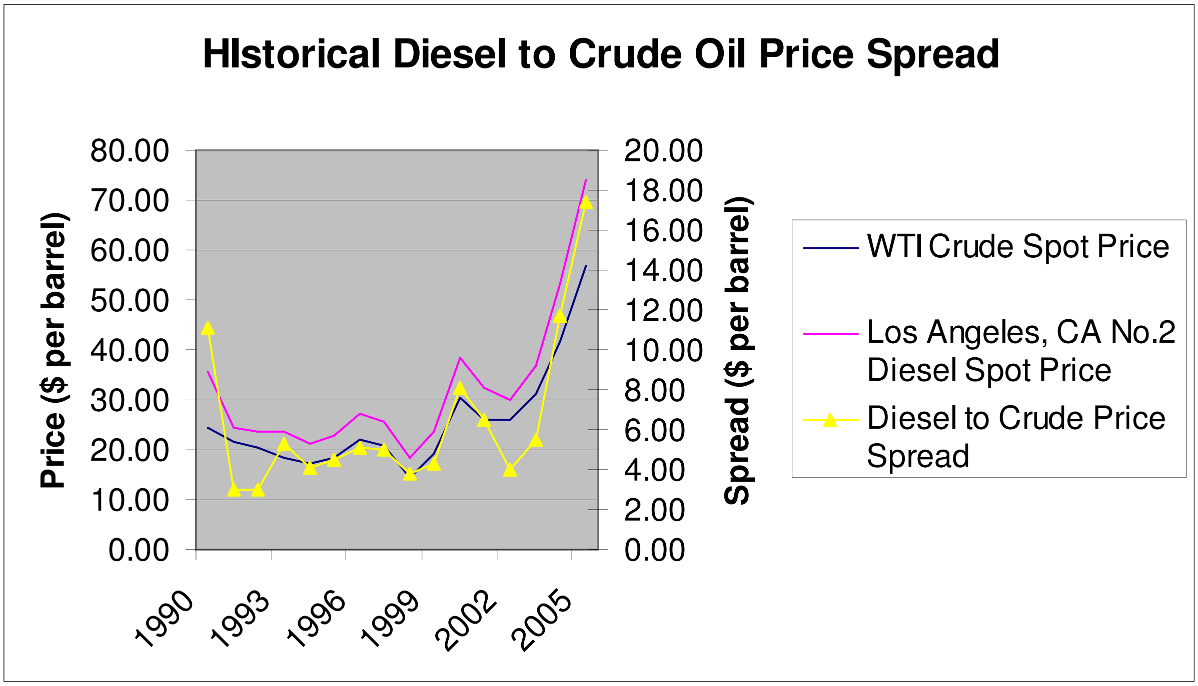


Figure 3. The historical price spread between diesel fuel and crude oil has been in the $5 per barrel range, but recent tightening of refining capacity has caused this spread to widen substantially. Figure is adapted from Energy Information Administration, Petroleum Navigator.

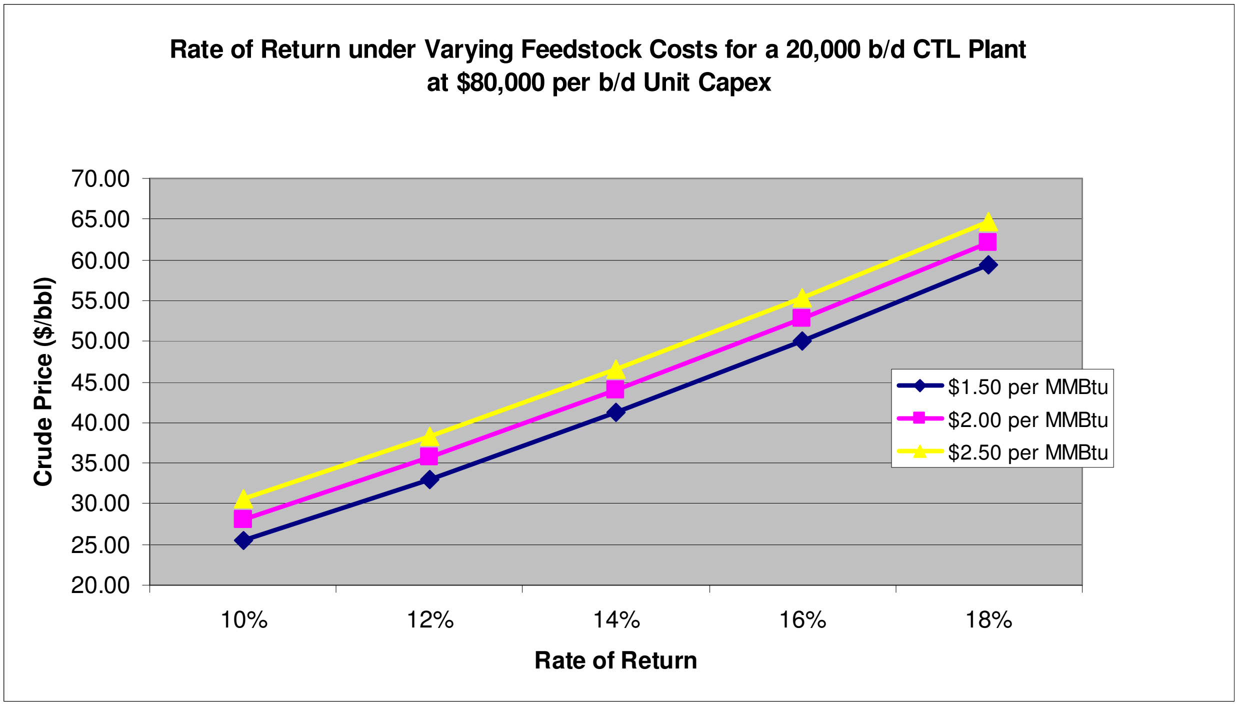
No commercial CTL plants are currently operating in the United States, and some measure of speculation is required to create a financial model of a CTL plant. Operating expenses are assumed to be $12 and transportation expenses $2 per barrel of output. Plant utilization is assumed to be 90%. Conversion efficiency of the liquid fuels process, which in this case produces only diesel, is assumed to be 40%. Electricity used on site is not modeled, but the model does have 5% of coal energy producing exportable electricity for sale. This electricity is sold on a per megawatt-hour basis for $20/MWhr; no capacity contracting is assumed. Additional products such as carbon dioxide, elemental sulfur and slag do not add any revenues or removal costs in this model.

The plant in this model is all equity financed and capital is depreciated on a 10 year, straight line basis. A tax rate of 35% is used, and the U.S. federal $0.50 per gallon tax credit for CTL fuels is assumed to persist throughout the project life. Because the federal tax credit is given to blenders of the fuel, producers will be able to charge a premium for their fuels in an amount equal to the tax credit. In essence, this adds a revenue stream equal to $21 per barrel for a CTL plant.

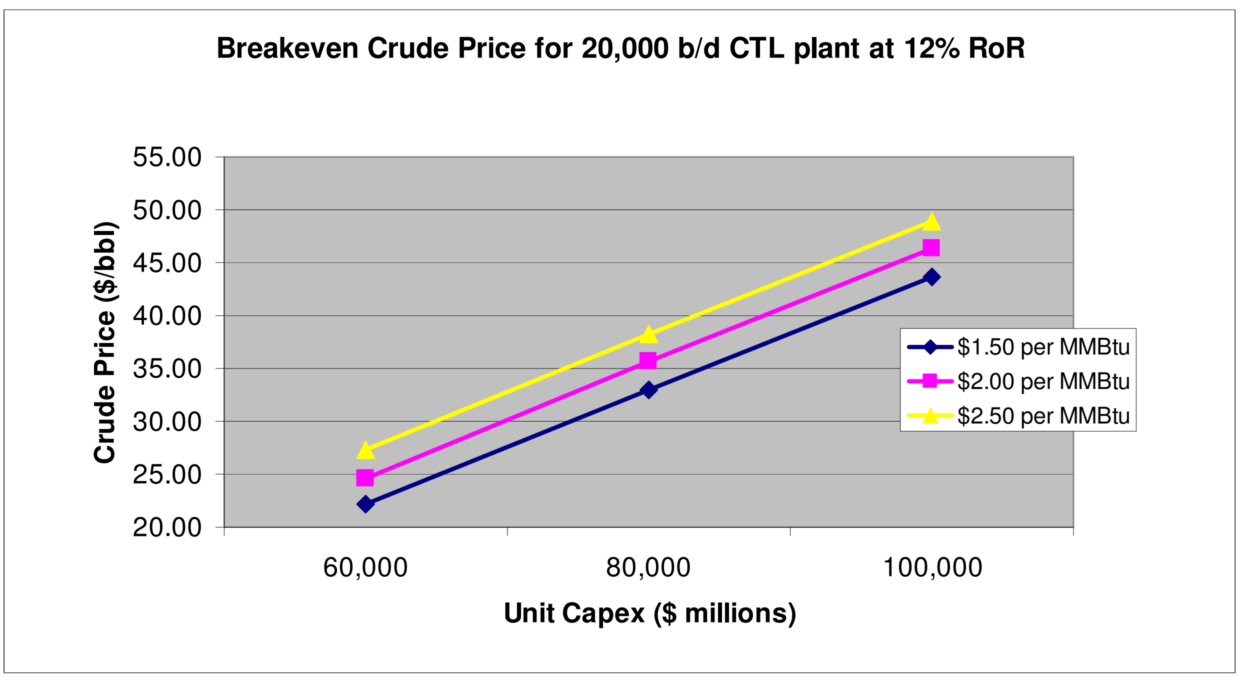
Variables in this project economics model include coal feedstock cost and unit capital expense (capital cost per barrel of plant capacity). Coal purchasing contracts are highly variable in duration and cost per MMBtu. Here, a range of \$1.50 to \$2.50 per MMBtu of coal is evaluated. A range of unit capital costs for engineering, procurement and construction (EPC) is also considered. While EPC figures of \$60,000 per b/d have been given as a baseline in the past (U.S. Energy Information Administration 2006), recent rapid increases in EPC costs make this figure appear low. Unit capital costs of \$60,000, \$80,000 and \$100,000 per b/d are evaluated here.

Results

In this model, a "middle of the road" scenario for the 20,000 b/d CTL plant would be unit capex of \$80,000 per b/d (\$1.6 billion total) and a feedstock cost of \$2.00 per MMBtu. Such a plant would achieve a 12% rate of return with a crude price of about \$36 per barrel. Annually, it would output 6.6 million barrels of FT diesel and about 500 gigawatt-hours of electricity. It would consume approximately 1.7 million short tons of coal (with U.S. average Btu content), costing just under \$70 million per year, or about \$10 million less than annual plant operating expenses. With a carbon price (imposed through a tax or tradeable permit system) of \$20 per metric ton of CO_2 emitted, a \$75 million cost line would be added to annual expenses.



Output 1.



Output 2.

III. CTL Sector Outlook

Introduction

There is enormous variation among forecasts for growth in the coal-to-liquids sector. For example, two scenario models run by the International Energy Agency, one in which efficiency technology progresses at a modest pace and one in which efficient technologies rapidly become pervasive, differ by 16 million barrels per day of global CTL capacity in 2050 (Peckham 2005).

There is some consensus among professional analysts and energy modelers over CTL plant economics: $40 oil is generally believed to be sufficient to support a CTL operation. But CTL requires enormous upfront capital investment – approximately $80,000 per b/d – which discourages CTL development when the product price is not certain. When energy forecasting models like the International Energy Agency's incorporate a low oil price, CTL capacity collapses.

All published models predict that there will be at least one million b/d of global CTL capacity and 200,000 b/d of U.S. CTL capacity by 2030. Several forecasters envision global and U.S. CTL capacities that are more than ten times these quantities. Advances in CTL technology, a potentially favorable policy environment and the entry of major strategic players foretell that the sector is indeed poised for rapid expansion.

CTL Sector Forecasts

Table 3. There is wide variation in published forecasts for U.S. and global CTL capacity

	2010	2015	2020	2030	2050
U.S. Forecasts (b/d)					
EIA 2006 Reference Case		80,000	110,000	760,000	
EIA 2006 High Oil Price Case		80,000	220,000	1,700,000	
EIA 2006 High Coal Cost Case				200,000	
EIA 2007 Reference Case				372,000	
Southern States Energy Board 2006		800,000	2,700,000	5,600,000	
EIA 2007 Ethanol Reference Case				*952,000*	
Global and Regional Forecasts (b/d)					
IEA 2005 Reference Scenario					20,000,000
IEA 2005 "Map" Efficiency Scenario					4,000,000
DKRW Projects Forecast		132,000			
EIA 2006 Reference Case				1,800,000	
EIA 2006 High Oil Price Case				2,300,000	
Bear Stearns Asia-Pacific Region "Planned"	186,000	996,000	1,396,000		
Bear Stearns Asia-Pacific Region "Possible"	186,000	4,540,000	10,960,000		
Bear Stearns Asia-Pacific Region "Extreme"	186,000	8,080,000	20,540,000		
RBC Capital Markets	60,000				
EIA 2006 Ethanol Reference Case				*1,700,000*	
EIA 2006 GTL Reference Case				*1,100,000*	

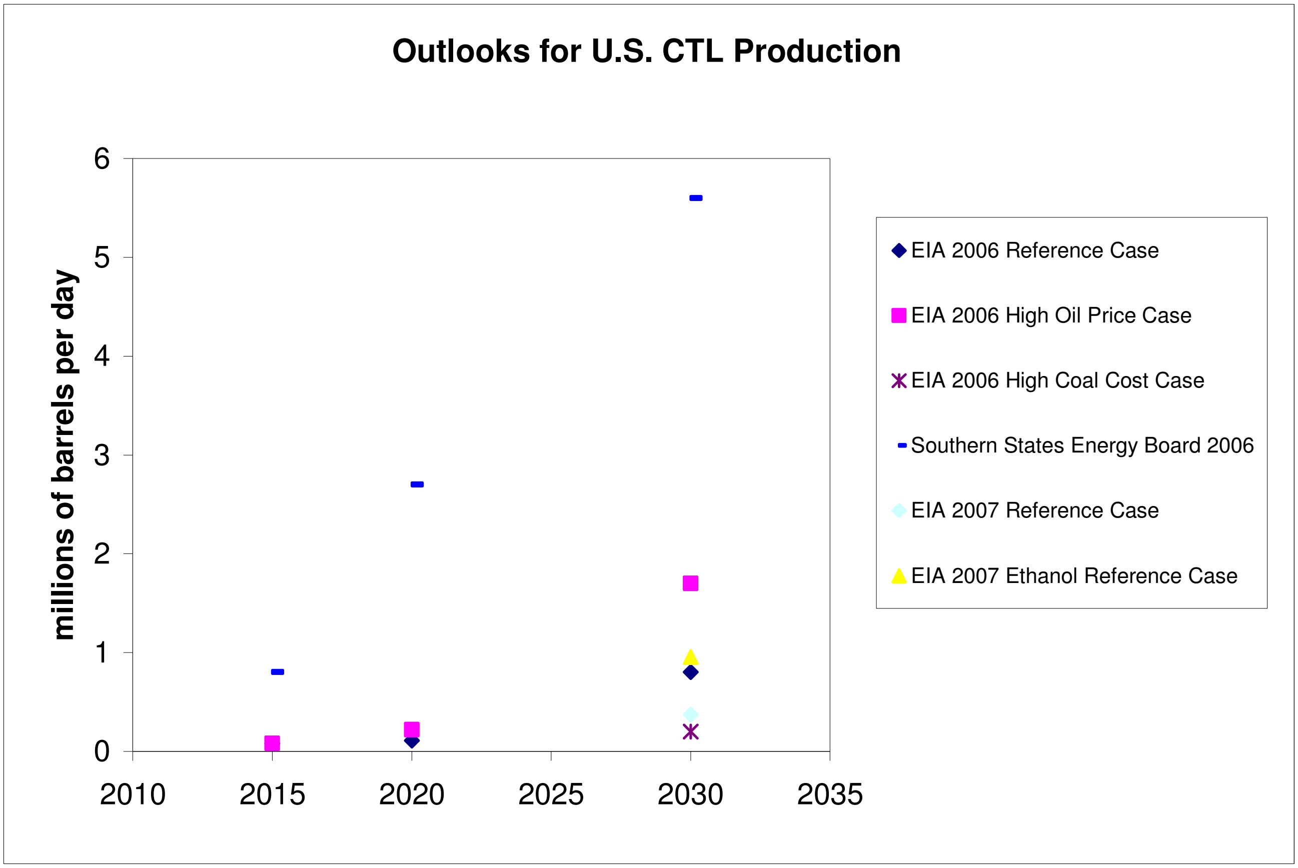


Figure 4. Outlooks for U.S. CTL forecasts from published sources.

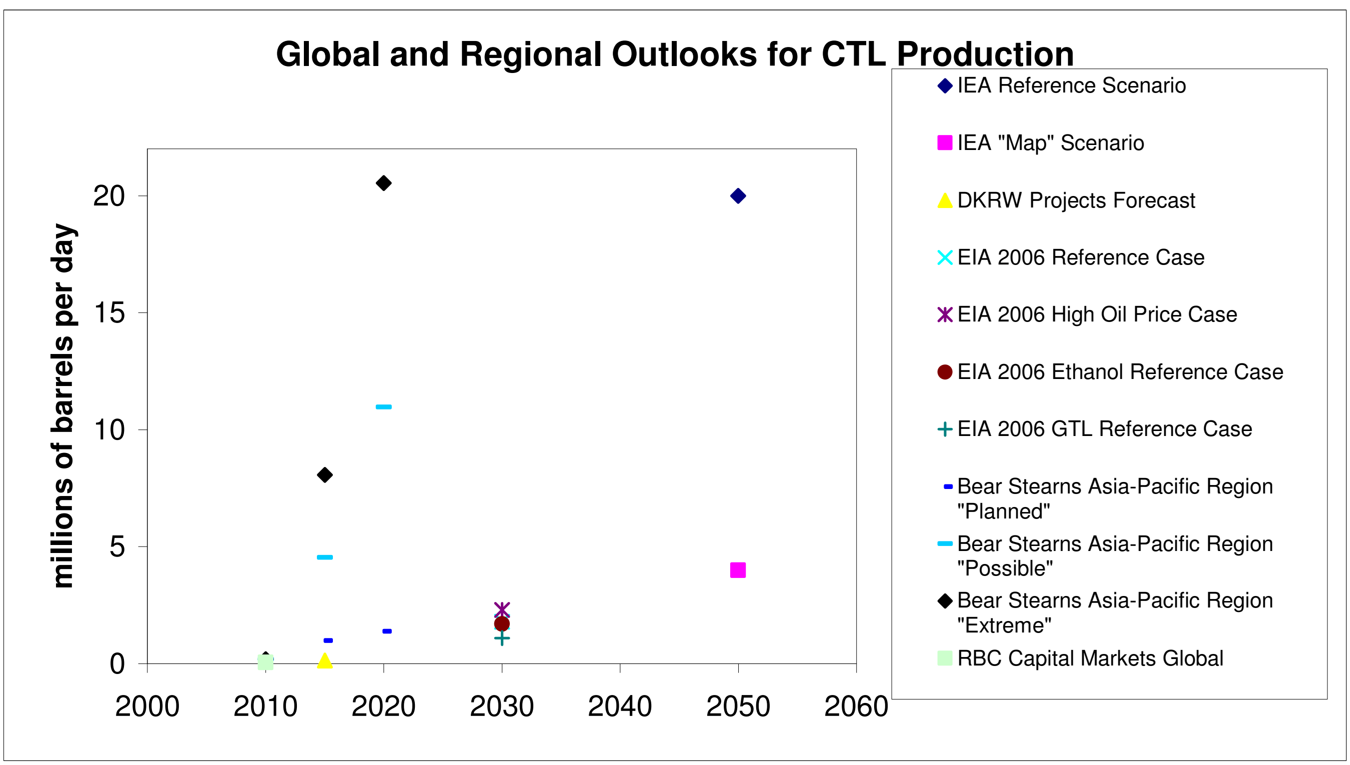


Figure 5. Global and regional outlooks for CTL production from published sources.

The Energy Information Administration (EIA) within the U.S. Department of Energy uses the National Energy Modeling System (NEMS) to create the Annual Energy Outlook (AEO), the most respected comprehensive forecast for the U.S. energy system. EIA's 2003 report on NEMS stated "[i]t is assumed that coal-to-liquids facilities will be built when low sulfur distillate prices are high….Petroleum product production from CTL is assumed to be competitive when distillate prices rise above the cost of CTL production – adjusted for credits from the sale of electricity co-products." Plant economics in NEMS are affected primarily by coal cost and distillate product price, both of which are derived through many factors intrinsic to the energy model (U.S. Energy Information Administration 2003).

The last three Annual Energy Outlooks have produced wide variations in coal-to-liquids forecasts. In AEO 2005, no CTL capacity was predicted to arise within the two decade forecast period (U.S. Energy Information Administration 2005). In the 2006 reference case – in which oil prices moderate to about $50 per barrel – 760,000 b/d was forecasted to come on line by 2030 (U.S. Energy Information Administration 2006). In the AEO 2007 Early Release, this same forecast fell by half (U.S. Energy Information Administration 2007). AEO 2006 also contains a "High Price" forecast, which predicts 1.7 million b/d in the U.S. by 2030 when oil prices rise steadily from $60 per barrel in 2007 to $100 in 2030. CTL capacity increases by more than 100% with high crude prices. Other alternative fuels, such as ethanol, do not show such a large increase in the High Price case.

The International Energy Agency of the OECD forecasts that in 2050, under current policy and business-as-usual technology development, there will be 1,039 million tons of oil equivalent (~20 million b/d) in liquid fuels produced by global CTL plants. Under the "Map" high-efficiency technology scenario – in which 85% of vehicles have hybridized power trains – 346 million tons of oil equivalent (~4 million b/d) will be produced in 2050. The IEA's Map scenario is equivalent to a drop in oil prices, which adversely affects CTL plant economics.

The Southern States Energy Board's American Energy Security Study, which seeks to lay out a strategy through which the U.S. could eliminate U.S. oil imports by 2030, sees a rapidly expanding role for CTL. By 2015, the plan envisions 34 CTL plants with a total capacity of 800,000 b/d, nearly the same amount that the EIA forecasts for 2030 in AEO 2006. By 2030, 206 CTL plants are producing 5.6 million b/d of liquid fuels in the U.S.

Analysts in Bear Stearns Asian Equity Research group see CTL (and biofuels) playing a major role in meeting the Asia-Pacific region's growing need for liquid transportation fuels. In particular, Australia, China, Indonesia and India are likely to use coal to displace imported petroleum. The Bear Stearns analysts estimate that "it is possible for regional CTL capacity to replace up to 12.0% of Asia-Pacific oil consumption by 2015, 25.1% by 2020, and up to 21.4% of 2015 and 47.0% of 2020 oil consumption on an extreme basis." Bear Stearns' "Extreme" scenario, in which the Asia-Pacific region alone has over 20 million b/d of capacity in 2020, could be considered the upper boundary of CTL sector forecasts.

Clearly, forecasts for the coal-to-liquids sector are highly variable. Some amount of capacity increase is inevitable – if only that of currently planned projects. And it is conceivable that CTL could supply as much as a third of world transportation fuel by mid-century. Energy models seem to show that the trajectory of world oil prices, more than any other factor, will determine the rate at which CTL capacity expands.

Feedstock Cost

When the EIA models a high coal cost scenario – one in which the price of coal rises steadily from $1.50 to $2.25 per MMBtu (in 2004$) – CTL output drops by more than 70% from 760,000 b/d to 200,000 b/d in 2030. According to Herold's CTL plant economics model, the cash cost per barrel of FT diesel rises from $13 at $1/MMBtu of coal, to $20 per barrel at $1.50/MMBtu and to $30 at $2.25/MMBtu. At $1/MMBtu, internal rate of return (IRR) for a middle of the road plant and $50 oil is 16%. When coal feedstock cost rises to $2.25, the IRR for the CTL plant drops to 12%.

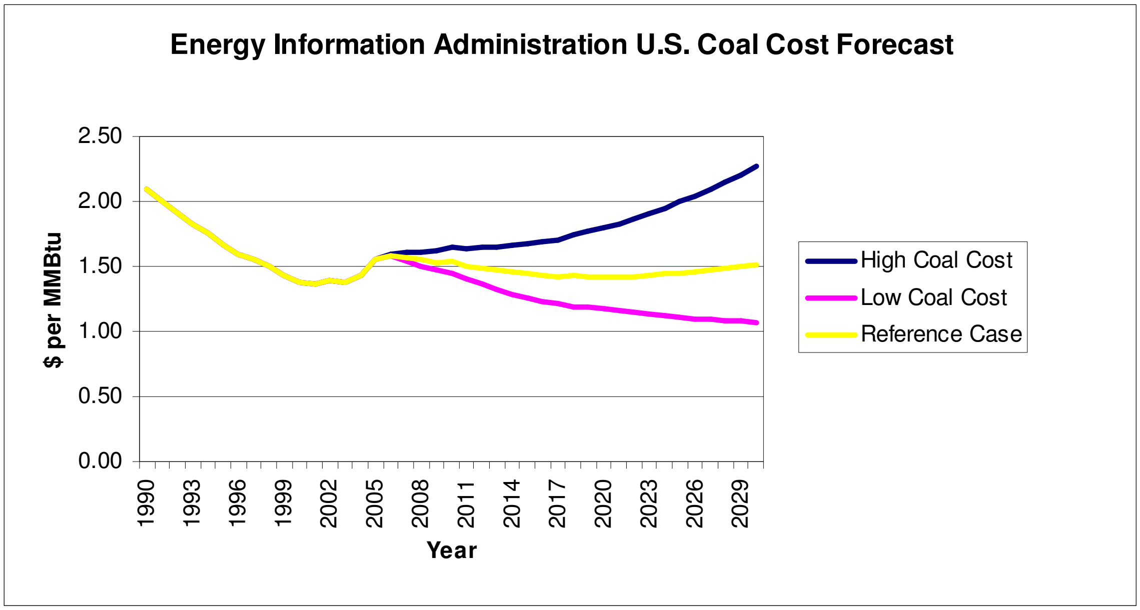


Figure 6. U.S. Coal Cost forecast from the EIA's *Annual Energy Outlook 2006*

Feedstock cost will primarily depend on the location of the CTL plant. Location will determine the type of coal that is utilized as well as the cost of transporting that coal to the plant hopper. The delivered cost of coal can be highly variable in the U.S. According to the EIA's Annual Coal Report, in 2005, open market sales price for Wyoming's subbituminous Powder River Basin coal was about $8 per short ton, less than $0.50 per MMBtu. Meanwhile, Pennsylvania's anthracite coal had an average open market price of over $40 per short ton, more than $1.50 per MMBtu (U.S. Energy Information Administration 2005).

Construction Costs

Construction indices such as those maintained by the Engineering News-Record and Turner Construction show a steady march upwards in construction costs.

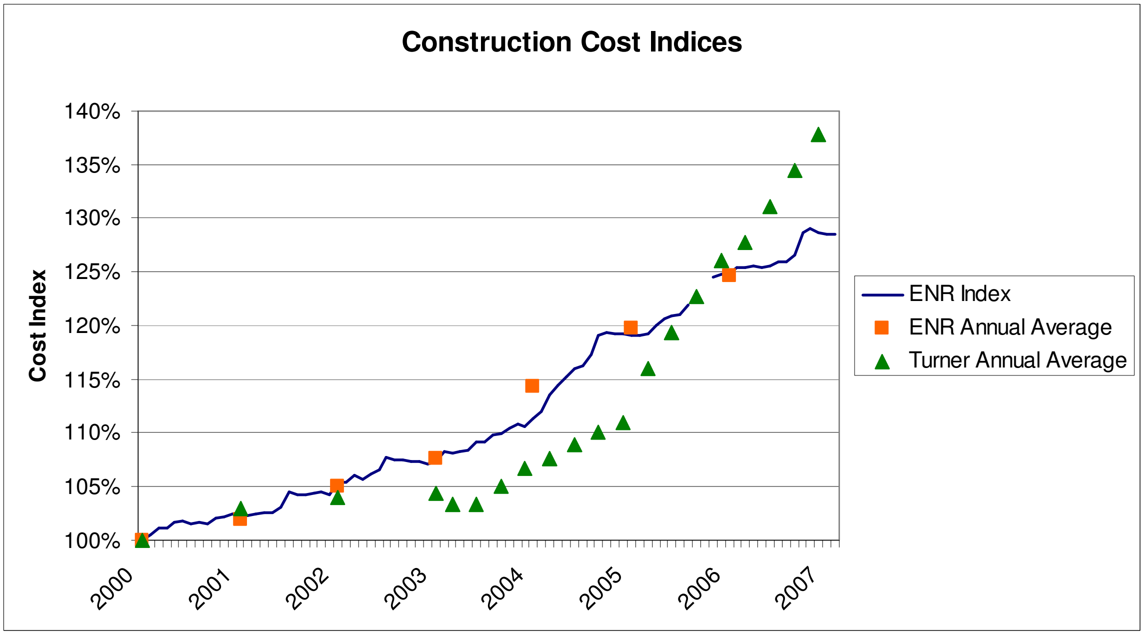


Figure 7. Construction cost indices from Turner Construction and McGraw-Hill's *Engineering News-Record*

In the Annual Energy Outlook 2007, the U.S. Energy Information Administration singles out rising construction and equipment costs for its special "Issues in Focus" section. The EIA states that cost indices have shown a 7% average annual increase over the past three years in real dollars, reversing a thirty year downward trend. Virtually every sector of the energy industry, from power plant construction to offshore drilling rig rates, has been affected by rising costs.

Product Prices

FT diesel's low sulfur and aromatic content as well as its high cetane number make it suitable for use as a straight-run diesel fuel or as a refinery blending stock. CTL-derived fuels will be able to fetch a substantial premium over the market price of crude oil. The spread between crude and diesel has been expanding rapidly over the past several years as growth in refinery capacity has lagged behind growth in demand for transportation fuel. Going forward, demand for diesel fuel is expected to grow at a faster rate than other petroleum products as more consumers and businesses take advantage of the diesel engine's inherently higher efficiency (U.S. Energy Information Administration 2006).

The EIA does not project the price refiners will pay for distillate blending stock, so we use commercial end-user price, the price least impacted by state and federal taxes, as a proxy. In AEO 2006, the EIA predicts a decline in distillate prices from current levels followed by a slow and steady climb. However, EIA's model predicts that a tightening of the world oil market could bring distillate prices as high as $100 per barrel.

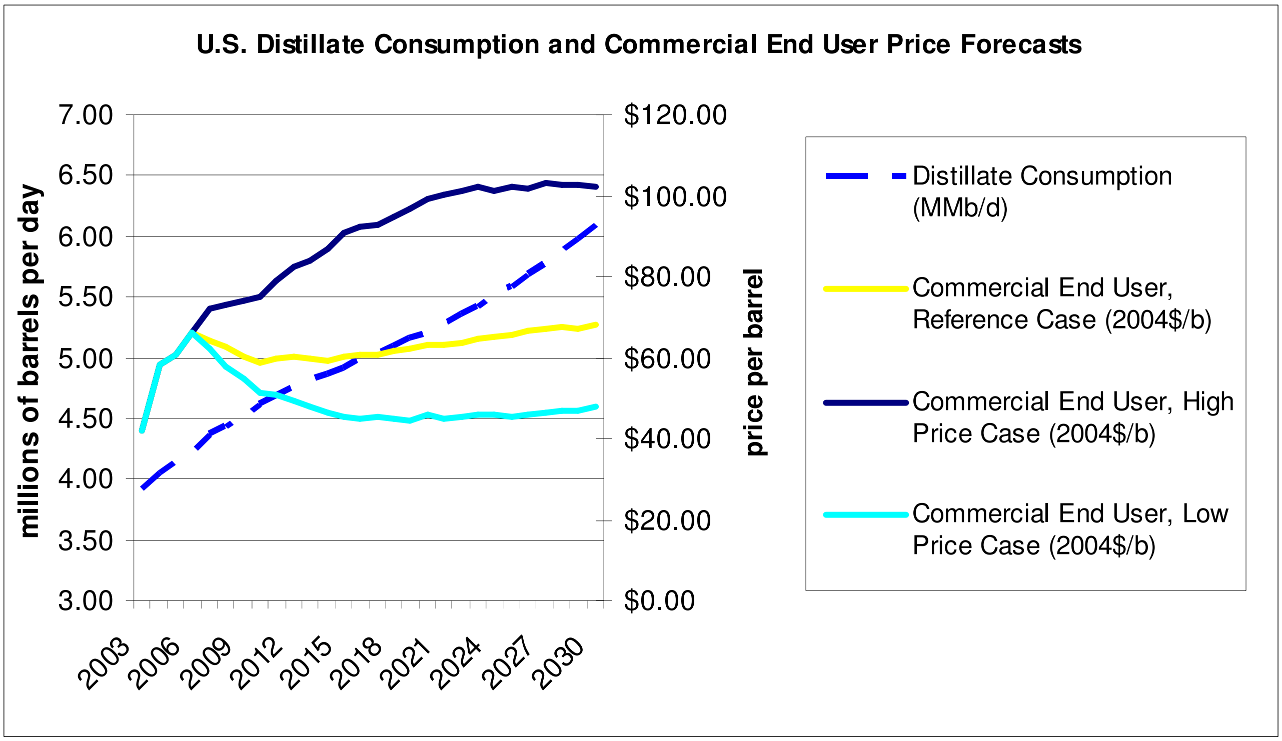


Figure 8. Forecasts from the Energy Information Administration show rising U.S. diesel consumption and some potential trajectories for diesel prices.

CTL Strengths, Risks and Uncertainties

Infrastructure

For an alternative fuel to succeed in the marketplace, compatibility with existing infrastructure is a tremendous advantage. In this regard, XTL has a leg up on other alternative fuels such as hydrogen and ethanol. Foremost, there exists a large end user market for Fischer-Tropsch products, such as diesel and naptha. Also, whereas ethanol cannot flow through existing oil pipeline infrastructure because of its affinity for water, FT fuels are as compatible with multi-purpose hydrocarbon pipelines as refined petroleum products. Additionally, FT products can be delivered to refiners and marketers via barge, truck and railcar.

Technology

While there remains some trepidation among potential project developers, data indicates that gasification is a relatively proven technology. The World Gasification Database maintained by the National Energy Technology Laboratory of the DOE shows that, globally, there are 45 existing or planned coal gasification projects. Additionally, two medium scale biomass gasification projects (and many small-scale ones) currently operate. Most coal/petroleum coke gasifiers use the GE entrained flow or the Shell fixed bed gasifiers, using the syngas to produce various products including ammonia fertilizers, methanol and electricity (U.S. Department of Energy 2006). Sasol of South Africa has gasified coal using SasolLurgi gasifiers for more than fifty years (van Dyk, Keyser et al.). In the U.S., Eastman Chemical Company has produced various industrial chemicals from coal-derived syngas for more than twenty years. Eastman found that from September 2000 to September 2003, syngas production was on stream 98.1% of the time (Trapp, Moock et al. 2004).

The conversion of syngas to fuels and chemicals via Fischer-Tropsch catalysis has been performed on a commercial scale at several locations. In the early 1990's two natural gas-to-liquids plants were commissioned, including PetroSA's Mossgas plant in South Africa and Shell's Bintulu plant in Malaysia. Both have produced high quality fuels and chemicals for two decades (van Dyk, Keyser et al.). Natural gas-derived syngas has a different profile than coal-derived syngas, and only Sasol's Secunda and Sasolburg CTL facilities have operated commercially using the latter. However, U.S. CTL firms Syntroleum and Rentech have synthesized thousands of barrels of CTL fuels at more than a dozen pilot and bench scale reactors. Syntroleum claims that after 4,500 hours of runtime at their Catoosa demonstration facility, their cobalt catalyst had "negligible" attrition. Rentech has patented a process for removing spent iron catalyst from the wax created in the FT reactor (Kerr 2006; Syntroleum Corp. 2006). Both companies are aware that there is some risk that these pilot plants will not scale up without operational problems, but both companies are also proceeding with CTL development plans (Rentech 2006; Syntroleum Corp. 2006).

Feedstock

Significant expansion of the CTL sector will place additional demands on coal supply infrastructure. Meeting the higher CTL point forecasts presented here will require a tremendous amount of new coal. Approximately 215 million short tons of coal are required annually for each incremental million b/d of CTL capacity. To put this in perspective, the U.S. currently produces approximately 1,100 million short tons of coal per year (U.S. Energy Information Administration 2006).

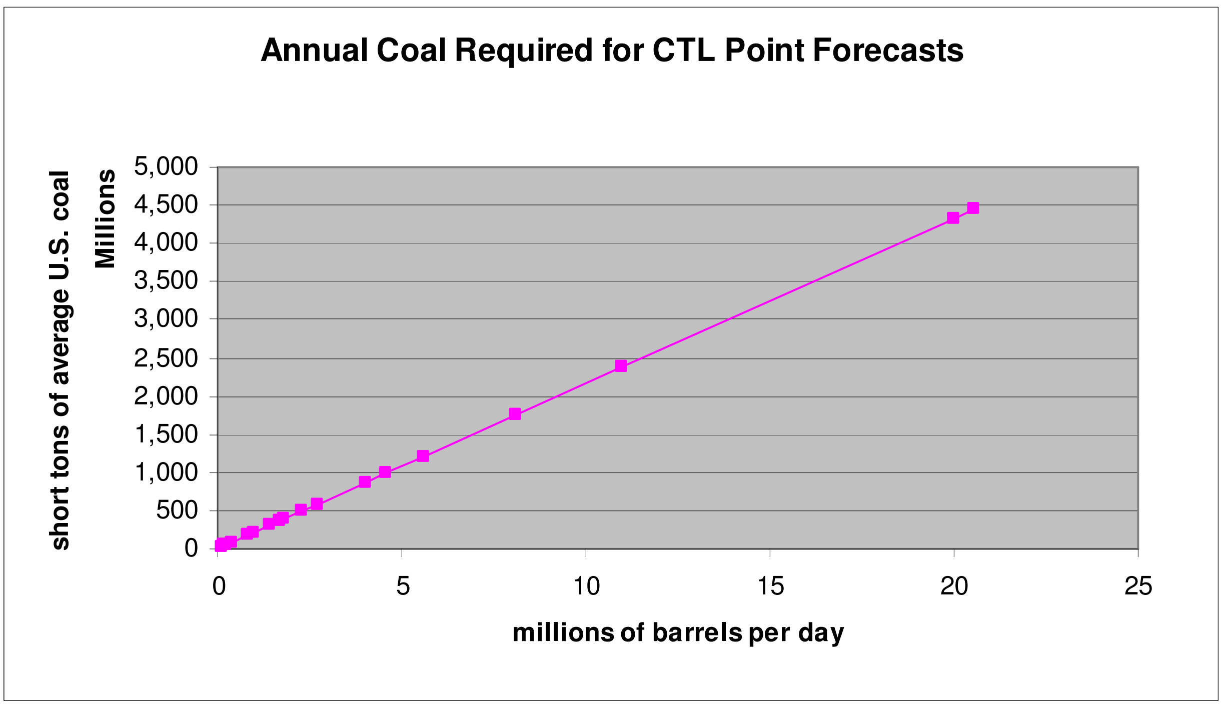


Figure 9. Annual coal required to meet CTL point forecasts assuming uniform conversion efficiency

In the U.S., transportation has become a key limiting factor in coal supply growth. As the EIA states in the Annual Coal Report for 2005, "the overriding issue for the U.S. coal industry in 2005 was transportation of coal from the mines to the consumers." U.S. rail companies are expanding capacity, particularly in the Powder River Basin, where a shutdown for maintenance in 2005 caused major disruptions in coal markets. One of the principles of coal gasification is to use coal with the same properties for as long as it is available. In the event of a disruption of this type, a CTL plant would be forced to source coal with similar specifications from another mine.

In their report "King Coal", Bear Stearns analysts identify other major issues that will have to be resolved if the U.S. coal industry is to expand, including permitting, labor and equipment. Bear Stearns analysts estimate that a new mine requires one and a half to two years to acquire the necessary permits. The EIA notes that water permitting limitations could curb CTL growth. Water-cooled CTL plants require approximately ten barrels of water for each barrel of product; air-cooled CTL plants require approximately one barrel of water per barrel of product (Garman 2006). CTL developers will need to carefully consider water supply in plant siting decisions.

Policy

The Energy Policy Act of 2005 (EPACT) contained several provisions designed to advance integrated gasification combined cycle (IGCC) coal power plants. The act authorized DOE to provide loan guarantees and tax incentives for advanced fossil technologies and carbon capture and sequestration systems. CTL will benefit indirectly through greater penetration and acceptance of gasification technology, and a CTL project employing CCS may be able to take advantage of the EPACT incentives. CTL research funds were also directed to universities in coal states through EPACT (Spring 2005; U.S. Energy Information Administration 2006).

One of the most aggressive and promising pieces of U.S. CTL legislation is the "Coal to Liquid Fuel Promotion Act of 2007," introduced by Senators Bunning of Kentucky and Obama of Illinois last spring, and then reintroduced at the start of the year. The act would extend the alternative fuel excise tax credit of $0.50 per gallon of FT diesel. It also authorizes loan guarantees similar to those provided for IGCC in EPACT. Finally, it authorizes the Department of Defense to buy and test CTL fuels (Bunning 2007).

A suite of existing and proposed state policies are encouraging CTL deployment in the U.S. State governments in West Virginia and Pennsylvania have indicated that they will use their fuel purchasing power to boost CTL development. Because most CTL plants will be project financed (nonrecourse financing), securing such liquids off-take and power purchase agreements will be critical to project execution. WMPI, a private developer of a CTL project in Pennsylvania, has received a great deal of assistance from that state including a product purchase contract, $47 million in tax credits and $465 million in loan guarantees. Mississippi will provide $15 million in bond financing for site improvements at Rentech's proposed Natchez CTL location. Governor Manchin of West Virginia has proposed several policies aimed at promoting CTL, including expedited permitting and facilitation of the grid interconnection process. And perhaps most famously, Montana's Governor Brian Schweitzer has been a vociferous champion of CTL, appearing on several media programs including *60 Minutes*. His state has several incentives that could benefit CTL developers, and the legislature is considering more (Southern States Energy Board 2006).

Strategic Players

Over the past several years, large energy firms have begun to position themselves to take advantage of any boom that may occur in the coal- or biomass-to-liquids sector. Witnessing the "Btu spread" between coal and crude oil grow over the past several years, Peabody Coal signed a joint development agreement with Rentech in July 2006. Under the agreement, the two firms would evaluate potential opportunities for minemouth, CCS-ready CTL plants in Montana and the Midwest (Peabody Energy 2006). The following month, Arch Coal (the second largest coal producer in the U.S. after Peabody) acquired a 25% equity stake in DKRW Advanced Fuels, a subsidiary of DKRW Energy. DKRW Advanced Fuels' minemouth Medicine Bow, Wyoming CTL plant – which will use coal from an Arch mine in the Carbon Basin – is as far into the development process as any U.S. CTL project; it is due to be operational in 2011. Arch has agreed to secure reserves for two more CTL projects and extend the coal feedstock option DKRW currently has for its Medicine Bow plant (Arch Coal 2006). Energy giant Shell is working on developing large-scale CTL projects in China, and holds a minority equity interest in the German biomass-to-liquids company CHOREN Industries (CHOREN Industries 2005).

Carbon Dioxide

Because of the enormous capital outlays required to construct a CTL plant, developers will want to have confidence in the project economics. The Herold CTL plant analysis shows that the price paid or payment received from carbon dioxide emissions impacts operating expenses and return on investment significantly. When a carbon dioxide penalty of $25 per metric ton is added to a CTL plant's income statement, this creates an annual expense of over $90 million, dropping IRR from 14.5% to 11% with $50 oil. For comparison, when coal costs $2.00 per MMBtu, annual feedstock expense is approximately $130 million per year.

Large scale deployment of CTL will create a tremendous new source of carbon dioxide emissions. As the figure below shows, if the highest CTL point forecast of 20 million b/d is met, 3.7 billion metric tons of CO_2 will result annually. In 2006, all U.S. sources emitted approximately 6 billion metric tons of CO_2(U.S. Energy Information Administration 2006).

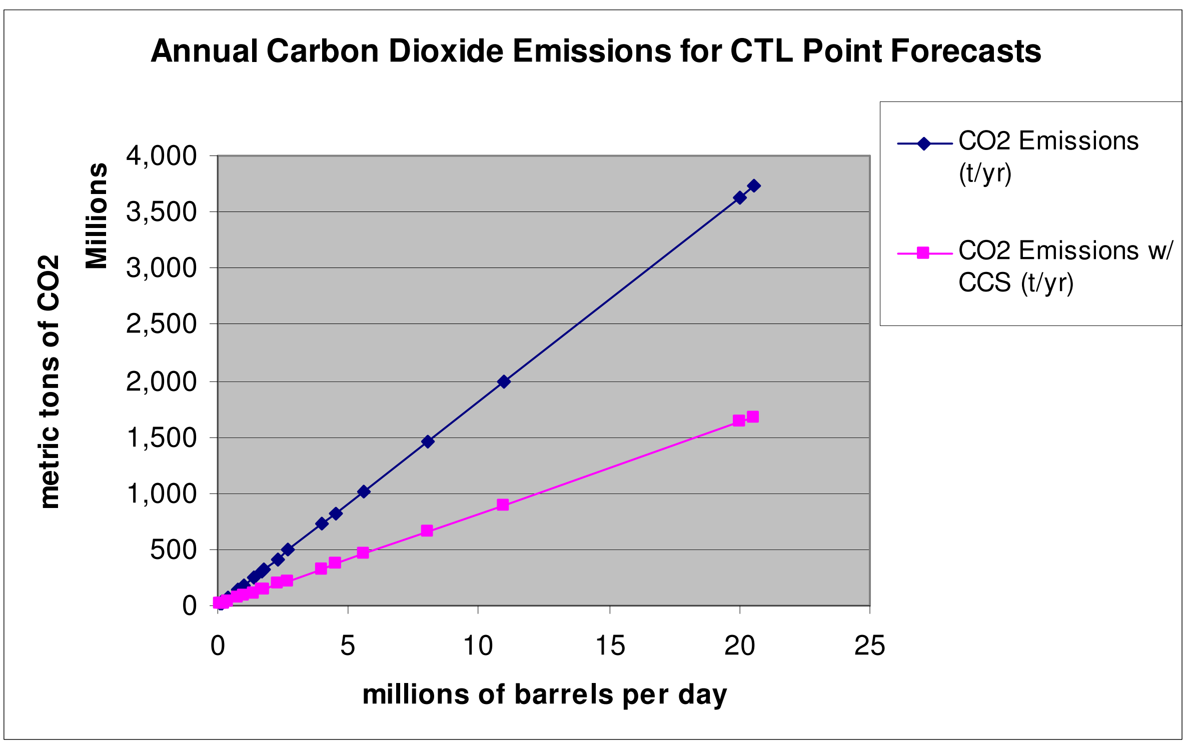


Figure 10. Annual carbon dioxide production resulting from CTL point forecasts assuming uniform rate of carbon dioxide production and carbon capture and storage (CCS) efficiency

A likely mitigation option for CTL plants will be carbon capture and storage (CCS). Storage in exhausted oil fields through enhanced oil recovery will positively impact CTL plant economics, as will sales to industrial CO_2 users. When no buyer is available, the U.S. DOE estimates that the cost of sequestering carbon emissions at an IGCC or CTL plant is approximately $30 per metric ton CO_2 (Marano and Ciferno 2001). In their study for the Wyoming Governor's Office, Rentech found that carbon dioxide distribution equipment for enhanced oil recovery would add $165 million to plant capex. An additional $11 million in capex would be needed for CO_2 compression and drying. Rentech concludes that, for a 10,200 b/d CTL plant, CCS is economically attractive – even in the absence of a carbon emissions price – if a metric ton of CO_2 can fetch $8.25 or more.

IV. Biomass-to-Liquids

Introduction

It has been shown that Fischer-Tropsch conversion of coal to liquid fuels is a carbon dioxide intensive process, emitting roughly half a metric ton per barrel of CTL fuel (Marano and Ciferno 2001). Accordingly, the imposition of a tax per unit of emissions, or an economic equivalent like a tradeable permit system, significantly affects CTL project economics. In the Herold CTL model, rate of return for a "middle-of-the-road" CTL plant ($2.00 per MMBtu coal and $80,000 per b/d unit capital cost) falls from 14.1% to 11.4% under a $20 per metric ton carbon emissions cost. In short, CTL developers face significant regulatory risk with regards to carbon dioxide. Planned projects in the U.S. are seeking to mitigate this risk through carbon capture and sequestration (CCS), but at present this is no panacea to the problem of CTL carbon emissions. CCS cannot reduce CTL process emissions to zero – in the Herold model, the reduction is only a little more than one half compared to the conventional process – and there remain major technical and regulatory barriers to large-scale deployment of CCS (Marano and Ciferno 2001; Interstate Oil and Gas Compact Commission 2005).

Biomass-to-Liquids (BTL) is technologically akin to CTL: a carbonaceous feedstock is gasified and converted into long-chain hydrocarbons, which are further cracked into diesel fuel. But the former process can produce a diesel with extremely low life-cycle carbon intensity. When the biomass feedstock is managed on a closed-loop system, carbon emitted during feedstock conversion and product combustion is reabsorbed in new biomass tissue. From a life cycle perspective, the only noteworthy emissions result from plant construction and feedstock transportation. If, however, the biomass feedstock would have had a linear fate, e.g. landfilling of woody construction debris, the life-cycle carbon intensity of the produced fuel becomes less clear. Perhaps the carbon in the woody debris would remain locked their for many years. Perhaps the microorganisms present in the landfill would immediately begin anaerobically decomposing the woody debris, producing methane, which has more than twenty times the greenhouse warming potential of carbon dioxide. Further analysis would be required to show if the greenhouse gas offset is higher or lower when using biomass with a linear fate than biomass managed on a closed-loop system. For the purposes of this report, we will simply note that BTL diesel *can be* a renewable fuel. For this reason, it has attracted significant interest from government, academic and private organizations. The Energy Research Centre of the Netherlands, a large private energy research group, has in recent years produced a significant amount of engineering and economic analysis of BTL opportunities in the European Union. Oil major Shell has purchased a stake in the BTL technology and project development firm CHOREN Industries, which has also been collaborating with carmakers Volkswagen and DaimlerChrysler (Green Car Congress 2005).

The use of biomass to produce energy in valuable forms is certainly not new. In the U.S., biomass provided approximately 3 quadrillion Btu (quads) in 2005, considerably more energy than was produced by wind and solar combined. In its 2007 forecast, the U.S. Energy Information Administration projects that this quantity will grow to 4.2 quads by 2010, 4.7 quads by 2020 and 5.3 quads by 2030. Wood waste and byproducts from the pulp and paper industry are often gasified to produce electricity for on-site use and for export. There are also more than 100 dedicated “biopower” facilities in the U.S., many of which have only few megawatts of capacity, and the largest of which are in the range of 50MW. Many of the nation’s coal-fired thermal power plants co-fire quantities of biomass in order to reduce important emissions (Wright, Boundy et al. 2006). Presently, biomass is the only significant source of alternative liquid transportation fuels: sugar, corn, soybeans and other edible grains are used to produce ethanol and biodiesel. However, the production of transportation fuels from nonedible biomass sources has not yet reached a measurable level in the U.S. or elsewhere (U.S. Energy Information Administration 2007).

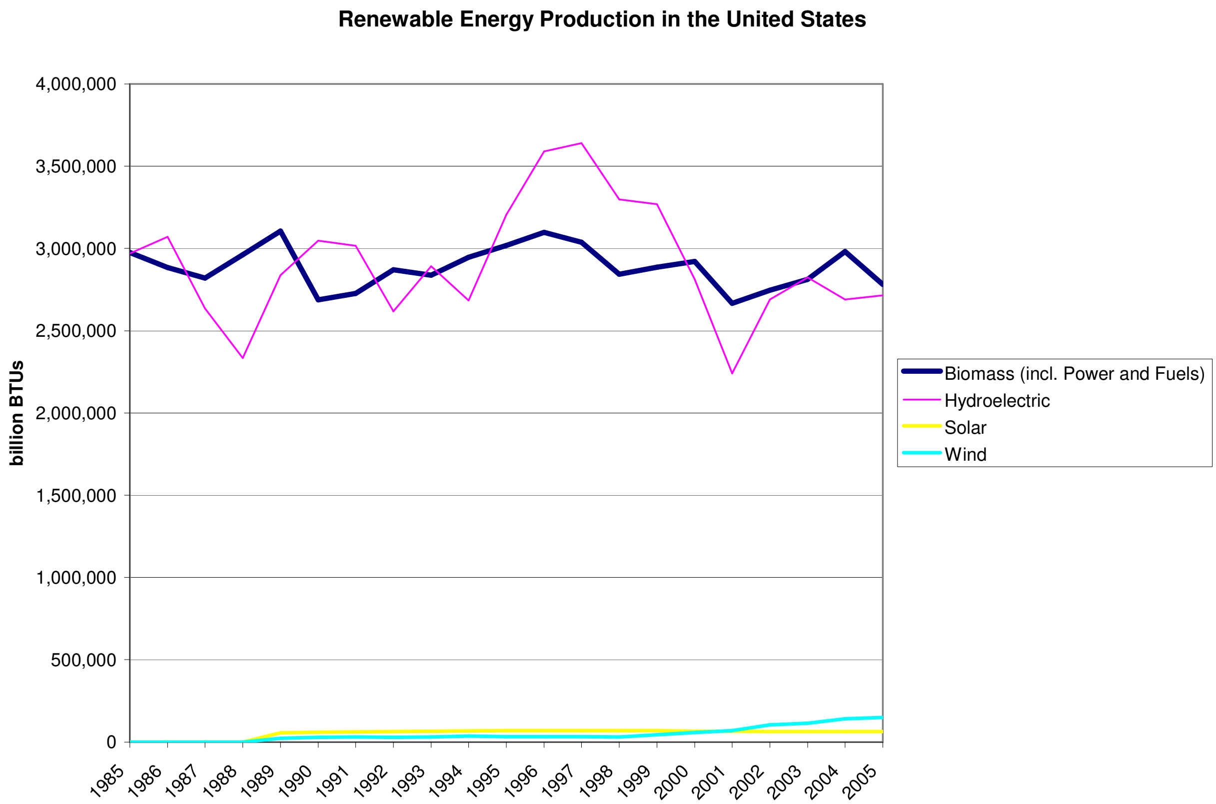


Figure 11. Energy production from all renewable sources in the U.S. shows that biomass already produces a considerable quantity of energy, currently more than hydropower.

BTL Technology

Feedstock and Conversion

There is considerable variation in the definition of biomass, and there is some confusion about when it is an appropriate term. We may legitimately break down biomass into five categories (adapted from McKendry 2002a),

- herbaceous plant matter,
- woody plant matter,
- aquatic plants,
- edible crops, and
- manure.

The last three are viable sources of bioenergy, but they are not technically or economically suited for BTL conversion at present. In this report, the term biomass will refer only to herbaceous plant matter (i.e. grasses) and woody plant matter. Within just these two categories there is enormous variation in important attributes, such as moisture content, chemical composition, heat content and bulk density.

Table 4. Approximate values for key biomass attributes. Adapted from McKendry 2002a and Energy Research Centre of the Netherlands, PHYLLIS database.

Biomass Type	Moisture Content	Ash Content	Lignin Content	Bulk Density (ton/m³)	LHV (GJ/dry ton)
Wood Chips	10-70%	0.1-2%	20-30%	0.2-0.25	16
Cereal Straw	6%	4.3%	15-20%	0.1-0.2 (baled)	15
Switchgrass	13-15%	4.5%	5-20%	0.1-0.2 (baled)	15
Illinois #6 Coal	8.4%	10%	-	0.9	24

While virtually every form of biomass can be dried and combusted for thermal and electrical energy, we will only consider processes that convert our two types of biomass to liquid fuels. For the two types of biomass considered here, there are two broad routes of conversion, thermochemical and biochemical. Cellulosic ethanol is the biochemical breakdown of woody or herbaceous lignocellulosic plant matter for fermentation into ethanol. It is, like BTL, considered a "second generation" biofuels technology; it appears destined to become the heir to the starch/sugar ethanol industry. While the technology to enzymatically break down whole plant matter into fermentable sugars is much more complex than making ethanol from corn or other grains, there is considerable overlap in equipment and process (Torry-Smith 2005).

Thermochemical conversion options include gasification and slow pyrolysis. Slow pyrolysis is a highly efficient process in which biomass is heated in the absence of air to produce "bio-oil", a substance that can be processed further or used directly in certain applications (McKendry 2002a). Tests with these bio-oils in diesel engines have shown that the fuel is not suitable for direct use in the current fleet of diesel vehicles (Shihadeh and Hochgreb 2000). Gasification is the partial oxidation of biomass to produce syngas for downstream combustion or catalysis. Gasification is the conversion technology considered in this report and is explained in more detail below.

Gasification

Small scale gasification of bark and other residues in the pulp and paper industry has been proven commercially. Additionally, several dedicated biomass integrated gasification combined cycle power plants and biomass gasification chemical plants are in operation around the world. The British Gas/Lurgi fixed bed gasifier at the Schwarze Pumpe power and methanol plant in Germany produces 410 MW of thermal output gasifying a mixture that includes waste and biomass. Funded through a grant from the Global Environmental Facility, a TPS circulating fluidized bed gasifier in northeastern Brazil will be fed with eucalyptus wood to produce more than 30 MW of electric power. Biomass gasification plants of similar size have operated in Europe, particularly in the Scandinavian nations, for decades (U.S. Department of Energy 2006). Perhaps the most famous U.S. biomass operation is the Joseph C. McNeil Generating Station of Burlington Electric Department in Vermont. The plant, which has operated since the early 1980's, has a rated capacity of 50 MW, of which 12 MW is supplied through gasification. It is fed with urban waste wood, chips from low-quality trees, as well as other forestry and mill residues (Burlington Electric Department 2007).

Biomass Gasifiers

Fluidized bed and entrained flow gasification technologies are considered the most suitable for biomass gasficiation. While the former has a longer operating history, the latter has recently established itself as the preferred gasifier type in the technical literature due to its higher throughput and higher operating temperature. Entrained flow gasifiers are pickier about their feed, but once gasification begins, the raw syngas produced is much easier to work with. Additionally, the success of entrained flow gasifiers in coal IGCC plants has increased the technical understanding of these units, including their ability to accept biomass feed. For a commercial scale BTL plant, the gasifier should be pressurized and oxygen-blown no matter which technology is chosen. Gasification throughput increases with approximately the square of operating pressure, and the use of oxygen instead of air more than doubles the calorific value of the raw syngas (McKendry 2002b; Henrich and Weirich 2004).

Circulating fluidized bed (CFB) gasifiers, as the name implies, circulate a sandy bed material throughout the gasifier cavity in order to maintain uniform heat and maximize conversion of biomass to syngas. Many small scale CFBs are in operation in the pulp and paper industry. Compared to other fluidized bed gasifiers, such as the bubbling bed gasifier, they are capable of the highest throughput and reaction temperature. Nevertheless, the operating temperature is not sufficiently high to prevent significant tar creation in the raw syngas stream, typically about 1-5% of the biomass feed (Hamelinck, Faaij et al. 2004). This tar is a major menace to downstream equipment in the gas conditioning and Fischer-Tropsch processes. Therefore it must be either cracked or removed and recycled back to the gasifier. Thermal or catalytic cracking and recycling add considerably to the complexity of the system arrangement. For this reason primarily, investigators have moved away from touting CFBs as an optimal technology for commercial scale gasification of biomass (Henrich and Weirich 2004; Zwart, Boerrigter et al. 2006).

Entrained flow (EF) gasifiers, demonstrated widely for the gasification of coal, solve many of the problems that plague fluidized bed gasifiers. Coal Integrated Gasification Combined Cycle (IGCC) pilot projects using EF gasifiers have co-fired biomass in low blends without major disruptions (Tampa Electric Company 2002). Several authors have recently stated that only entrained flow gasifiers are suitable for large scale commercial gasification of biomass (Henrich and Weirich 2004; Zwart, Boerrigter et al. 2006). Of the two types of EF gasifiers, slagging and non-slagging, the slagging entrained flow gasifier, in which ash becomes molten and slides down the walls of the gasifier cavity, is generally believed to be the best option. Though feedstocks with very low ash content may be better suited to non-slagging EF gasifiers, slagging gasifiers will be generally more fuel flexible than their non-slagging counterparts (Drift, Boerrigter et al. 2004). The slag and fly ash produced from an EF gasifier are free of carbon, and can thus become saleable byproducts, whereas carbon-containing ash from lower temperature gasifiers may need to be disposed of as hazardous waste (Boerrigter and Rauch 2006b). The only noteworthy drawbacks of the EF gasifier are its increased operating complexity (compared to some fixed and fluidized bed gasifiers) and the lower calorific value of its raw syngas, due primarily to absence of tar (Henrich and Weirich 2004).

Feedstock Pretreatment

Prior to gasification, coal, wood chips or any other feed must be pretreated to precise specifications dictated by the gasifier model. However, creating ready-to-gasify biomass of the right specifications requires significantly more extensive pretreatment than coal. Biomass has intrinsically higher moisture content and a structure that is less conducive to fine pulverization than coal. When gasifying coal in an EF gasifier, the coal is pumped as slurry containing approximately 75% coal and 25% water. Because biomass already has a lower calorific value than coal due to a preponderance of carbon-oxygen bonds, it is not desirable to further dilute the biomass feed with water (Calis, Haan et al. 2002).

The pretreatment of woody biomass for entrained flow gasification entails several steps which transform de-branched tree lengths into tiny particles or a pumpable liquid suitable for gasification. No pretreatment route has been conclusively proven as the most economic or technically viable. All routes begin, not surprisingly, with chipping, and all routes contain stages in which the biomass is pulverized and/or ground. However, simply pulverizing and grinding of biomass over and over until the particles are the size of pulverized coal consumes too much electricity to be economic, 7-20% of the energy in the original biomass, and may not achieve biomass particles of sufficiently small size and moisture content for EF gasification (Zwart, Boerrigter et al. 2006). Recent work at the Energy Research Centre of the Netherlands (ECN) has suggested that, because wood is more reactive than coal, perhaps biomass particles as large as 1mm can be piston compressed and screw fed into an EF gasifier, resulting in high biomass-to-syngas efficiency. However, this method has not been demonstrated, and if it proves technically unsatisfactory, more complex pretreatment methods will need to be employed. The two most promising methods, torrefaction and flash pyrolysis, are believed to have an overall biomass-to-syngas efficiency of approximately 75% compared to 84% with piston compression and screw feeding of 1mm particles (Henrich and Weirich 2004).

The ECN has done important work on the process of torrefaction, in which biomass is heated to approximately 250^{o}C in the absence of oxygen. This “slow roasting” of the biomass (the name torrefaction comes from the roasting of coffee beans) makes it more conducive to pulverization down to the size required for gasification. Experimental work has shown that if biomass is first torrefied, it is much more easily milled: mill energy requirements are reduced by 85% and mill throughput is increased 6.5 times. The final product is a more energy-dense char which in total contains about 85-100% of the energy in the original biomass feed (Bergman, Boersma et al. 2005). Torrefied biomass can then be pumped into the EF gasifier using pneumatic feeding.

Alternatively, EF gasifiers can be fed with a "bioslurry" composed of condensate and suspended char particles produced through flash pyrolysis of biomass. Residual gas from the flash pyrolysis process can be combusted in the plant's combined cycle power block. Several commercial technologies exist for the flash pyrolysis of biomass (Henrich and Weirich 2004). The efficiency of the flash pyrolysis process (from biomass to bioslurry) is estimated to be 90% (Zwart, Boerrigter et al. 2006).

Fischer-Tropsch Conversion

The biomass syngas that emerges from an entrained flow gasifier at high temperature and pressure must be cleaned and conditioned prior to conversion to liquid fuels and chemicals. As noted previously, perhaps the most important advantage to the EF gasifier is its high operating temperature, which destroys tars that would otherwise have to be laboriously cleaned from the syngas stream. The raw syngas, containing carbon monoxide, hydrogen, carbon dioxide and contaminants, emerges from the EF gasifier at extremely high temperatures and must be quenched prior to cleanup. This quench creates steam which can be used to meet on-site needs or sent to the Heat Recovery Steam Generator (HRSG) for electric power production. The quenched gas contains small amounts of particulates, trace inorganic compounds as well as nitrogen and sulfur compounds that can be scrubbed using commercially available technologies. If not removed, these impurities will quickly foul downstream catalysts even at low concentrations. Fortunately, biomass contains much less sulfur than coal: biomass sulfur content ranges from 0.07 to 0.6%, while coal ranges from 0.2 to 7% (Haq 2002).

The appropriate conditioning of the cleaned syngas depends on the intended downstream use. For the production of Fischer-Tropsch fuels (assumed in this analysis) the carbon monoxide concentration should be reduced so that the ratio H_2:CO equals approximately two. The carbon monoxide concentration can be decreased and the hydrogen increased with a shift reactor. Also, using an iron catalyst in the Fischer-Tropsch reactor will catalyze this shift reaction in addition to synthesizing long chain hydrocarbons. The shift reaction creates additional carbon dioxide which can be removed using commercial acid gas removal systems like Selexol and Rectisol. As with CTL, this carbon dioxide can be cleaned, pressurized and sold for various uses. Coupling biomass feed with carbon capture and sequestration could in theory lead to a Fischer-Tropsch fuel that boasts net *negative* life cycle carbon emissions.

Once the syngas is cleaned and conditioned, it is ready to be sent to the low-temperature Fischer-Tropsch reactor unit, using either iron- or cobalt-based catalyst, for conversion to longer-chain hydrocarbons. This process is identical to the process used in CTL and discussed in the preceding CTL report; thus the details will not be covered again here.

Biomass Feedstock Supply Curves

Before considering biomass feedstock economics, it is important to first note that there are economies of scale available for BTL plants, just as there are for GTL and CTL plants. Simply put, all other things being equal, a project developer should build the largest BTL plant possible to take advantage of these economies of scale and achieve the lowest average capital cost per unit of capacity, referred to here as "unit capex". The economies of scale are generally expressed mathematically with the scaling equation,

$$UC_d = UC_k * \left(\frac{S_k}{S_d} \right)^g$$

Where UC_d is the Unit Capex of the plant with desired capacity, UC_k is the Unit Capex for the plant of known capacity, S_k is the capacity of the known plant, S_d is the desired capacity, and g is the scaling factor, typically about 0.7 (Boerrigter 2006a). As Figure 1 shows, these economies of scale eventually go to zero. But, as we will see, before all the economic benefits of building a larger plant are exhausted, feedstock economics will pull with increasing force in the opposite direction, checking the size of the plant.

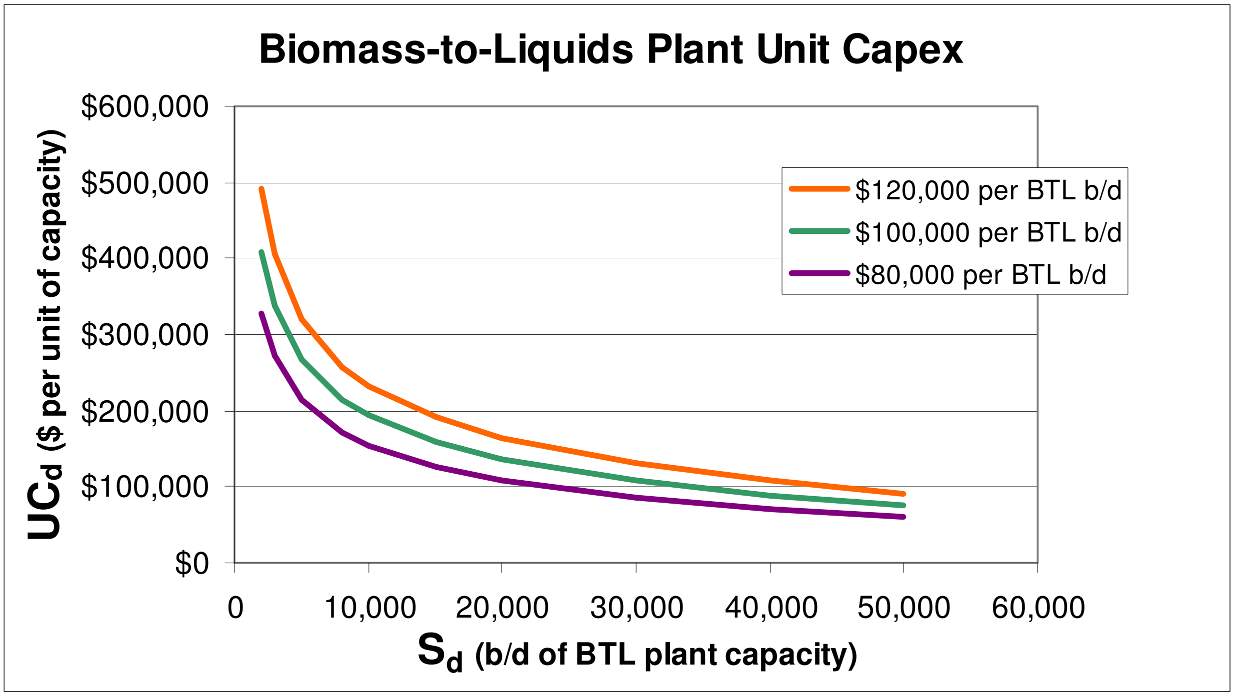


Figure 12 The relationship between plant capacity and unit capex instructs the project developer to build the largest plant possible to take advantage of decreasing unit capex. Closer analysis shows that feedstock economics must also figure into determining the optimal size of the BTL plant. The marginal feedstock price paid by the BTL plant will increase with increasing plant capacity. Therefore the project developer will have to balance the benefits of economies of scale from a larger plant with the increasing marginal feedstock cost that results as plant size increases.

Of the techno-economic literature researched for this report, it was found that many investigators model BTL projects using a constant feedstock price for biomass (Calis, Haan et al. 2002; Hamelinck, Faaij et al. 2004; Zwart, Boerrigter et al. 2006; Boerrigter 2006a). This is a fine assumption if one potential BTL production method is being compared to another, or if a plant's biomass is purchased through a near perfect market (i.e. many buyers and sellers and the plant alone cannot affect price.) But for this analysis of a U.S.-based BTL plant that is fed with biomass transported by land, this assumption is conceptually unsatisfying. In this model, as the capacity of the BTL plant increases, so does the marginal price paid for a ton of biomass. Intuitively it is straightforward to understand why it is the case that the marginal cost of biomass increases with increasing plant capacity. To begin with, consider a two dimensional graph that plots plant capacity on the x-axis and marginal feedstock price on the y-axis. (Note that this x-axis is identical to the x-axis in the graph of unit capex.) In the short run, the amount of biomass available in the area surrounding a BTL plant is fixed.

Initially, the plant will take the least cost biomass – perhaps urban wood waste like pallets, for which they may even receive a disposal fee. Moving outward on the plant capacity x-axis, the urban wood waste available is exhausted and more expensive resources like forestry or agricultural residues must be purchased. As capacity grows, increasingly more expensive feedstocks must be purchased to meet the plant's appetite. Eventually, the marginal price per ton of biomass may spike as the BTL plant must outbid existing buyers of certain types of biomass. At some point along the x-axis of plant capacity, the rise in marginal cost will negate the benefits of increasing the plant capacity to achieve lower unit capex.

The shape and intercept of the marginal feedstock price curve for a BTL plant will be primarily location dependent. During the research for this report, only one study examining the relationship between plant capacity and marginal feedstock cost was identified (Graham, Liu et al. 1995). Other investigators have attempted to develop national-, regional- and state-level biomass feedstock curves that are significant to the policymaker but of little use to the project developer (Graham, Allison et al. 1996; Haq 2002; Gallagher, Dikeman et al. 2003). For the y-axis "Marginal Feedstock Price", the x-axis of importance to the project developer is "Plant Capacity" at a specific site; the x-axis of importance to the policymaker is "Quantity of Biomass Available" in his/her state or region. While the units and the shapes of the two curves may be nearly identical, the implications are very different. The policymaker's curve shows, at a given price, how much biomass is available in the area as a whole, without regard to how this biomass is geographically distributed. The project developer's curve shows, at a given price, how much biomass is available to supply a BTL plant *at a particular site*.

To determine the marginal feedstock cost curve for a BTL plant, we begin by identifying all biomass sources in the area. In this hypothetical scenario, we consider each biomass source as a discrete location that is distance d_i (in kilometers) away from the BTL plant gate. Transportation cost (in $/ton*km) is considered to be a constant, τ. Each biomass source location has its own unique supply curve, $f_i(P)$, where P is price per ton. We might think of a biomass source location, call it Location Y, as a county in which there is a city, forestland and a lumber mill. The lowest cost source of biomass is the city's wood waste, which includes pallets, construction debris, etc. The next lowest cost source of biomass are the small pole trees and other residues from forestry operations on the location's forestlands. Finally, residues from the lumber mill, which are presently sold to other buyers for industrial uses, make up the highest cost source of feasibly-attainable biomass.

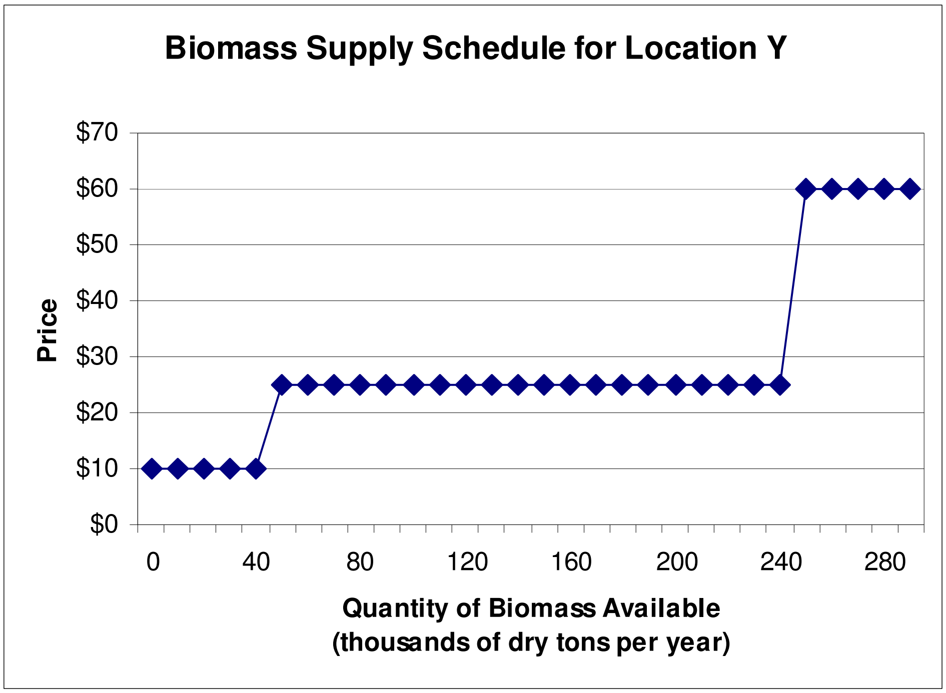


Figure 13. In this simple scenario, Location Y offers three sources of biomass. At price $10, all urban wood waste, 50,000 dry tons, is available each year. At price $25, all forestry residues, 200,000 dry tons per year, become available, and at price $60, an additional 50,000 dry tons of mill residues are available each year. Total annual cost of feedstock is simply the area under the curve from the origin to the last ton feedstock purchased.

Realistically, the marginal feedstock cost curve will not be a step function as illustrated in this simplistic scenario. A best-fit regression of the price-quantity points for a given location will likely have a smooth third-order polynomial curvature to it, as reflected in most regional-level biomass supply curves (see Figure 3.) These curves show an initial quantity available at a relatively low price, and, at the tail end, a rapid increase in price suggesting that a competing biomass user must be outbid. In between, there is often a long stretch of quantity that is available when a certain class of biomass suppliers, such as forestry operations, can achieve the necessary return at the offered price. This large quantity that becomes available can be formally called an interval of "highly elastic response" (Gallagher, Dikeman et al. 2003) or, informally, a "sweet spot".

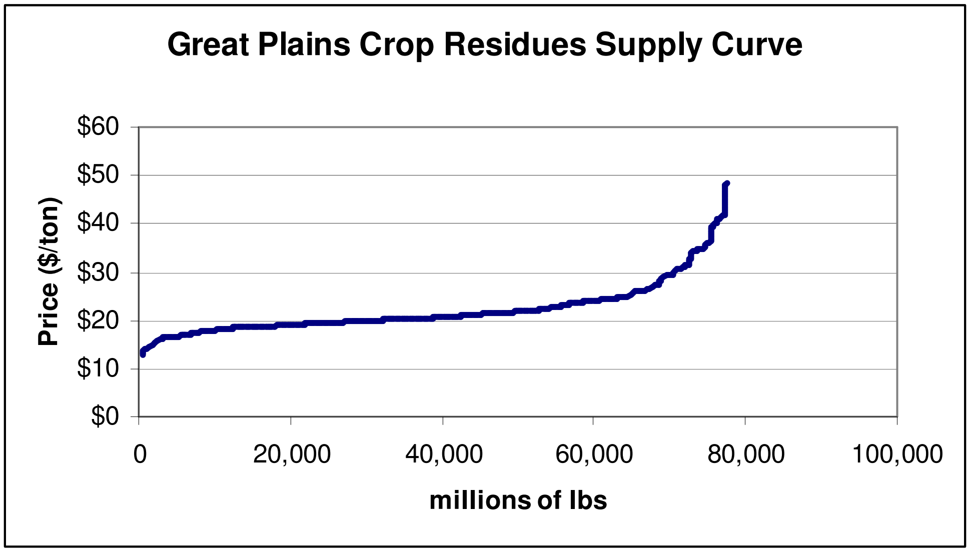
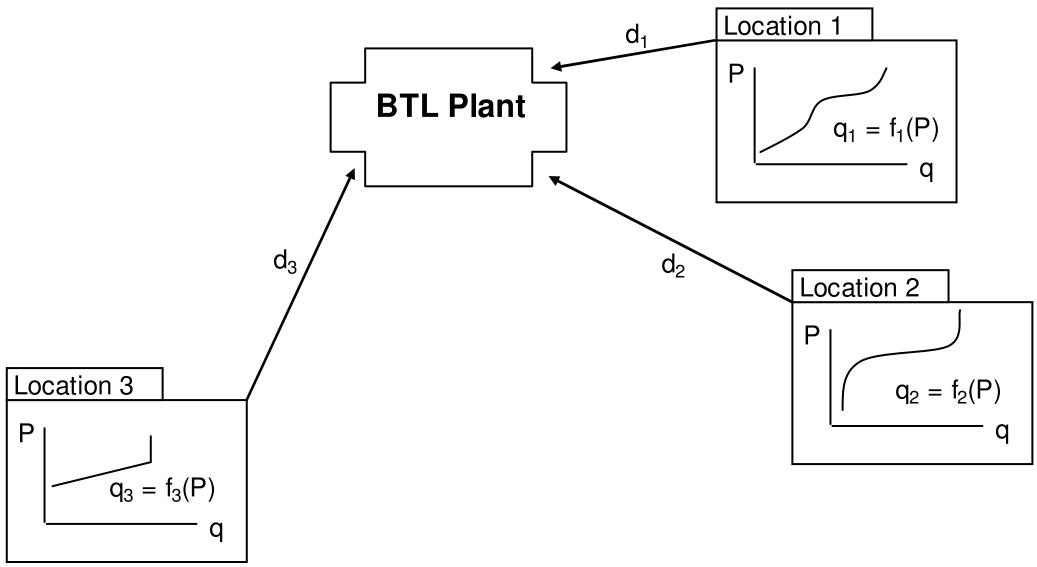


Figure 14. An example of a regional-level biomass supply curve, the marginal cost of crop residues in the Great Plains of the U.S., shows the smooth third-order polynomial curve that is characteristic of biomass supply curves. Figure is from Gallagher, Dikeman, et al. 2003.

The shape of the curve for any location will be unique. Inflection points and other characteristics will depend on environmental and economic factors particular to that location. We know that, unlike for more fungible commodities with robust markets, the biomass supply curve will slope upwards with increasing plant capacity. For this analysis, we leave each location's supply curve described simply as a function, $f_i(P)$ and illustrate the differences between locations with arbitrary cartoon supply curves. A BTL plant will have multiple locations from which to source biomass, referred to here as Locations 1 through 3. For simplicity, the transport distance for each unit of biomass from a given Location to the BTL plant gate is uniform, d_i.



To determine a BTL plant's overall marginal supply curve, where *Q* is total quantity supplied at price *P*, we simply sum across locations from i=1, the first location, to I, the final possible location. Note that the quantity available from each location is not simply the result of the supply curve function at the given price, *P*. The quantity q_i available from a Location is given by the result of the marginal cost function at the price *P* less the cost of transporting the biomass to the BTL plant, $d_i * \tau$. In this way, the quantity available from any given location at a given price can be compared to the quantity available from any other location at the same price without concern for transportation distance.

$$q_1 = f_1(P - d_1\tau)$$
$$q_2 = f_2(P - d_2\tau)$$
$$q_3 = f_3(P - d_3\tau)$$
$$Q = \sum_{i=1}^{I} q_i$$
$$Q = \sum_{i=1}^{I} f_i(P - d_i\tau)$$

BTL Project Economics

It was shown in the Herold GTL and CTL reports that models of hypothetical plants must address the large uncertainties in important cost items. Key sources of uncertainty include the future unit capex of a GTL or CTL plant and feedstock cost. Because there is less operating history for BTL projects and biomass gasification, there is even greater uncertainty in future unit capex of a BTL plant. As discussed above, there is greater uncertainty in feedstock costs as well. Until a particular location is chosen and supply contracts are negotiated, we can only speculate about a plant's marginal cost curve. While we may know that the curve will slope upward with increasing plant capacity, we know neither the intercept nor the precise shape of this curve. Compound these two key uncertainties with the general volatility and unpredictability of world oil and refining markets, and it becomes clear that, at best, a hypothetical GTL/CTL plant economics model can deliver the diesel price range necessary to achieve a certain rate of return under a set of parameters. This is our intention with this BTL project economics model. Incumbent on the project developer are the more site-specific analyses that will determine actual plant economics.

Background and Assumptions

In this model, unit capex is a variable, in units $ per dry tons input/yr, that multiplies with plant capacity, another variable in units dry tons input/yr, to determine total plant capital cost. Unit capex is varied within a range determined through several sources (Faaij 2006; U.S. Energy Information Administration 2006; Zeus Development Corp. 2006). In models with changing plant capacity and feedstock curve, we initially fix unit capex and then allow it to decline quadratically with increasing plant capacity to show the effect of economies of scale. From the minimum plant size, 1 million dry tons/year, to the maximum plant size, 10 million dry tons/year, the unit capex declines from $600 per dry ton/yr to $450 per dry ton/yr, a savings of 25%.

The slope of the marginal feedstock cost curve is derived through a linear regression of data from short rotation woody crops in Western Tennessee from Graham, Liu, et al 1996. While a third order polynomial regression provides a better fit to biomass marginal supply data in general (Western Tennessee woody crops included), using the polynomial curve was too risky for our purposes. Testing with a third order polynomial regression equation showed that it was extremely sensitive to model parameters over which there was uncertainty. Given that the shape of the marginal cost curve will vary widely from one location to another, a linear marginal cost curve is the safest assumption if not the most precise. We vary the *intercept* of this linear marginal cost curve to test the response of the plant to changes in feedstock price. No matter what the intercept, the slope of the marginal cost curve remains the same, as determined by the regression of data from Western Tennessee.

In this BTL project economics model, we focus on the financial rather than the engineering dimensions. We do not make explicit equipment or site decisions, but when determining overall plant efficiency, we use data from entrained flow gasification followed by low-temperature Fischer-Tropsch conversion to long chain hydrocarbons. After compiling energy content and efficiency data, two key parameters emerge, called here

- φ, the efficiency with which biomass is converted to BTL diesel in units barrels of BTL diesel output per dry ton of biomass input, and
- ε, the efficiency with which biomass is converted to exportable electricity in units MWhr output per dry ton of biomass input.

Beyond these two important values, we say nothing explicit about plant engineering. In arriving at φ and ε, we use data on the energy content of BTL diesel from ECN and CHOREN Industries (Matthias 2005; Boerrigter 2006a), as well as data on the average energy content of woody biomass from several sources (McKendry 2002a; Patzek and Pimentel 2005; Zwart, Boerrigter et al. 2006). The efficiencies with which the BTL plant turns biomass into diesel and electricity come from several sources as well (Boerrigter and Uil 2002; Calis, Haan et al. 2002; Faaij 2006). The final values are presented in the table below.

Table 5. The parameters φ and ε, the liquids and electricity output efficiencies respectively, are critical to examining BTL project economics. The values input to derive these parameters were cross-referenced across multiple sources.

	φ	ε
Units	bbl out/dry ton in	MWhr out/dry ton in
Value	1.250	0.466
BTL diesel energy content	38 MJ/l	-
Biomass energy content	18.5 MJ/kg	18.5 MJ/kg
Conversion efficiencies	45%	10%

Several important assumptions not pertaining to capital cost or feedstock were required to construct the plant economics model. These include operations and maintenance cost, economic life (i.e. depreciation period), depreciation method, technical life, tax rate, production tax credit, debt/equity ratio, return on equity and electricity price. Operations and maintenance cost came from several sources which quoted the annual cost as a percentage of capital cost (Boerrigter and Uil 2002; Faaij 2006; Boerrigter 2006a). Because capital cost is a variable in this model, O&M is a fixed parameter that multiplies with capacity to arrive at total annual O&M cost.

Table 6. Several important parameters and the value assumed for the project economics model.

Parameter	Value
Annual O & M Cost	$8.30/dry ton/yr
Economic Life	10 years
Depreciation Method	straight line
Technical Life	25 years
Tax Rate	35%
Production Tax Credit	$21/barrel
Debt	0%
Equity	100%
Return on Equity	14%
Electricity Price	$60/MWhr
Capital Outlay	overnight

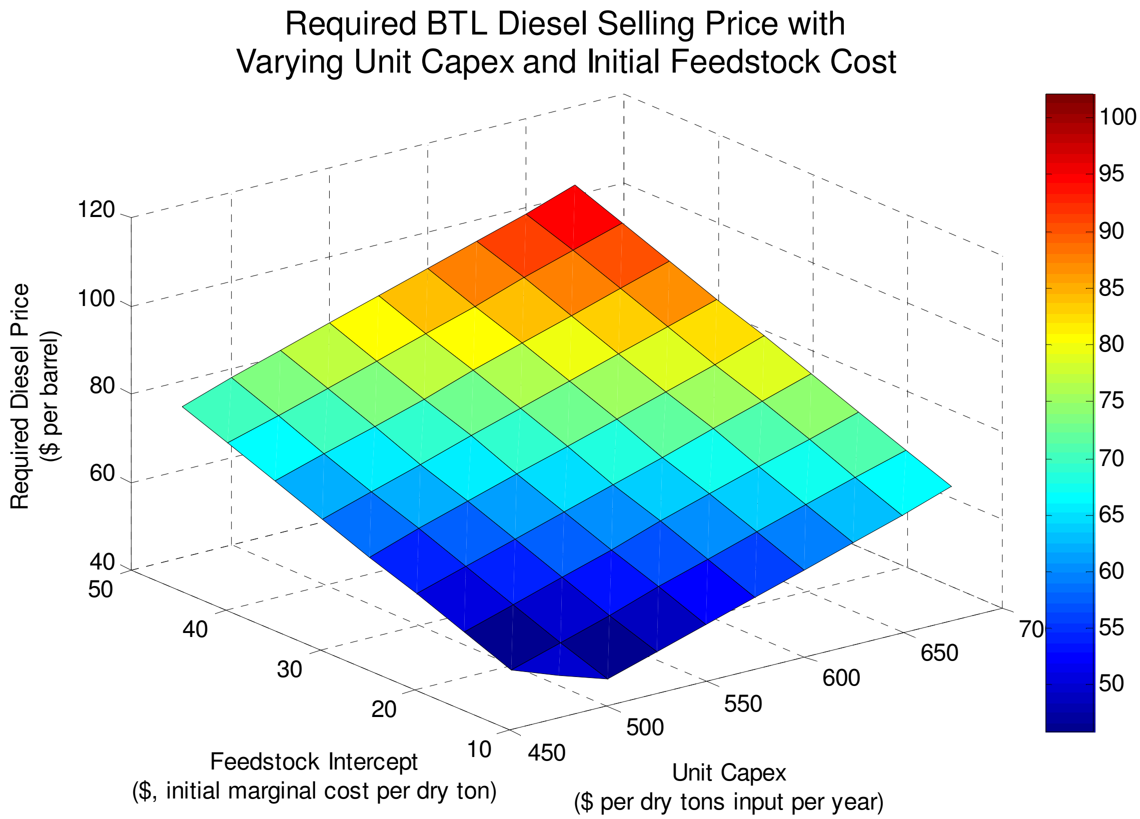
Unlike the Herold GTL and CTL models, the BTL project economics model had three variables and multiple values for each variable, thus requiring thousands of iterations. MATLAB®, a high-level programming environment, was used in place of spreadsheet software. The MATLAB function "fzero" was used to find the diesel selling price at which the net present value of the BTL project was equal to zero; that is, the price at which the plant's expenses and cost of capital are met. The required selling price was calculated under scenarios that allowed each variable to take any value in its given range.

Results

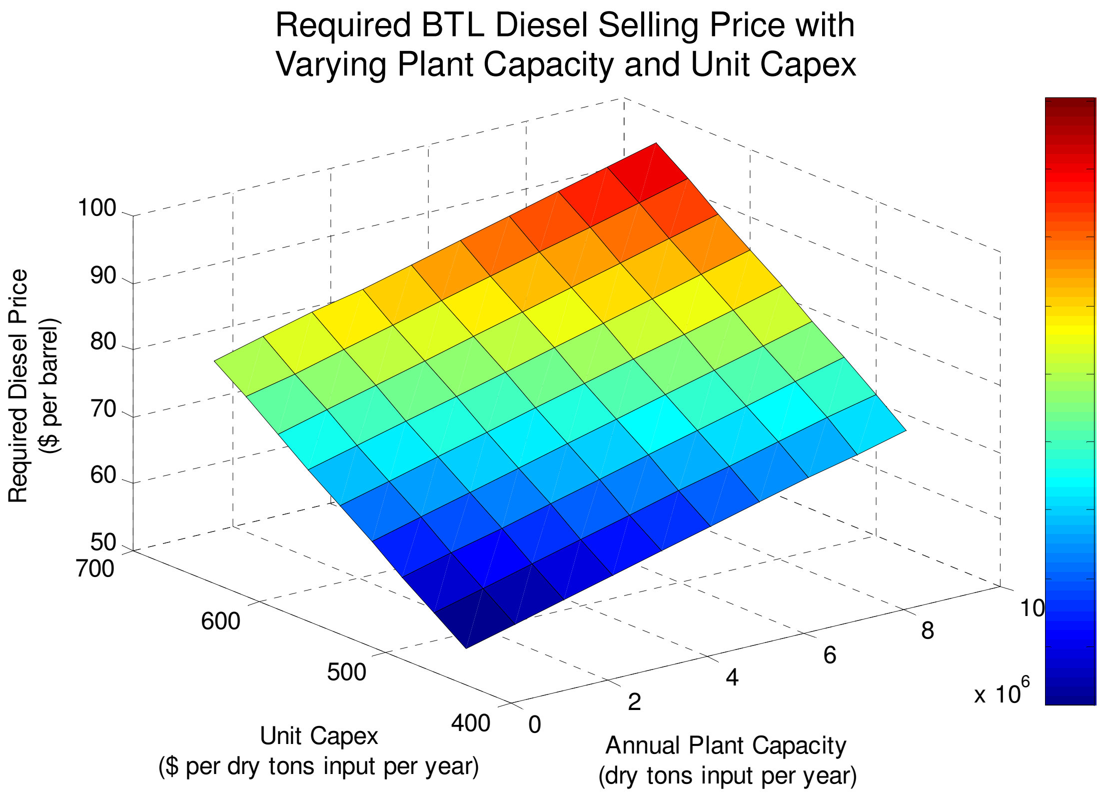
Results are given as three dimensional MATLAB surface figures. The colorbar to the right corresponds to the surface color, which indicates the diesel price required for the project to achieve zero net present value given the parameters on the x and y axes. The required diesel price is always given on the z-axis.

Because capital cost is an extremely large component of the total cost of these projects, the economics are materially affected by the ability of the development firm to take advantage of the tax shields created by depreciation expense. Therefore, two sets of results are presented, one for a large company that can offset existing tax burden using depreciation expense and one for a small company that can only carry forward their accounting losses to eliminate current and future tax bills.

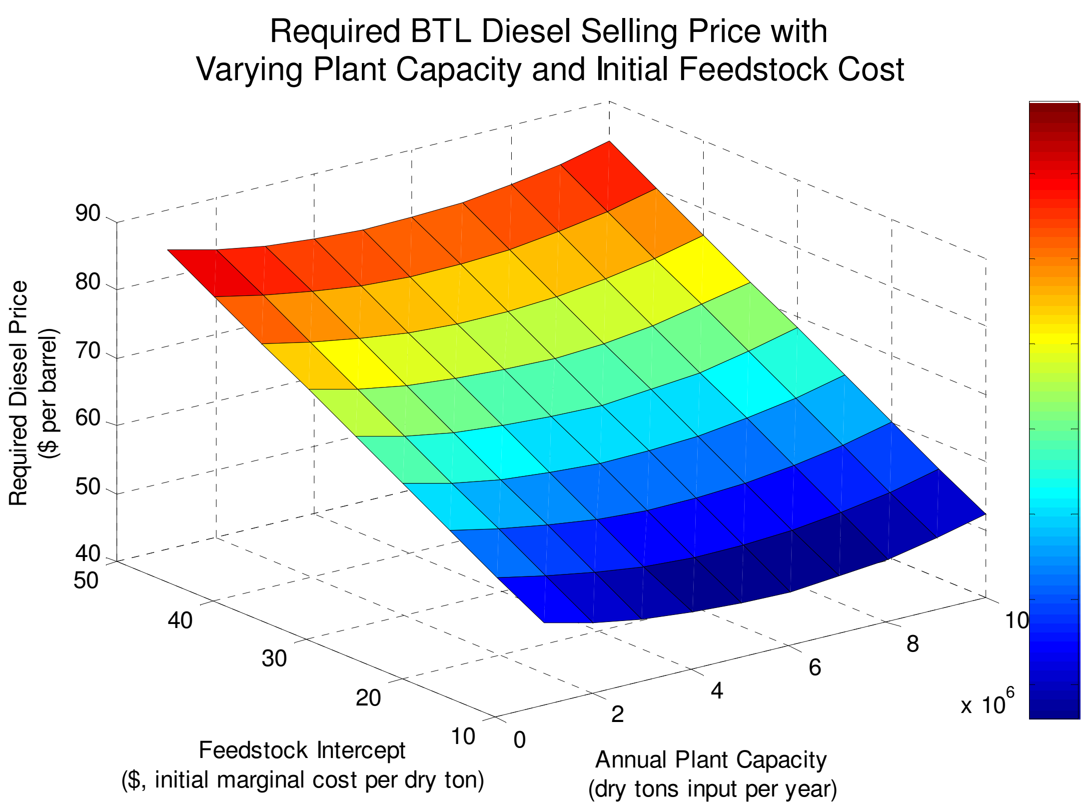
I. Results: Large Firm



Output 3.

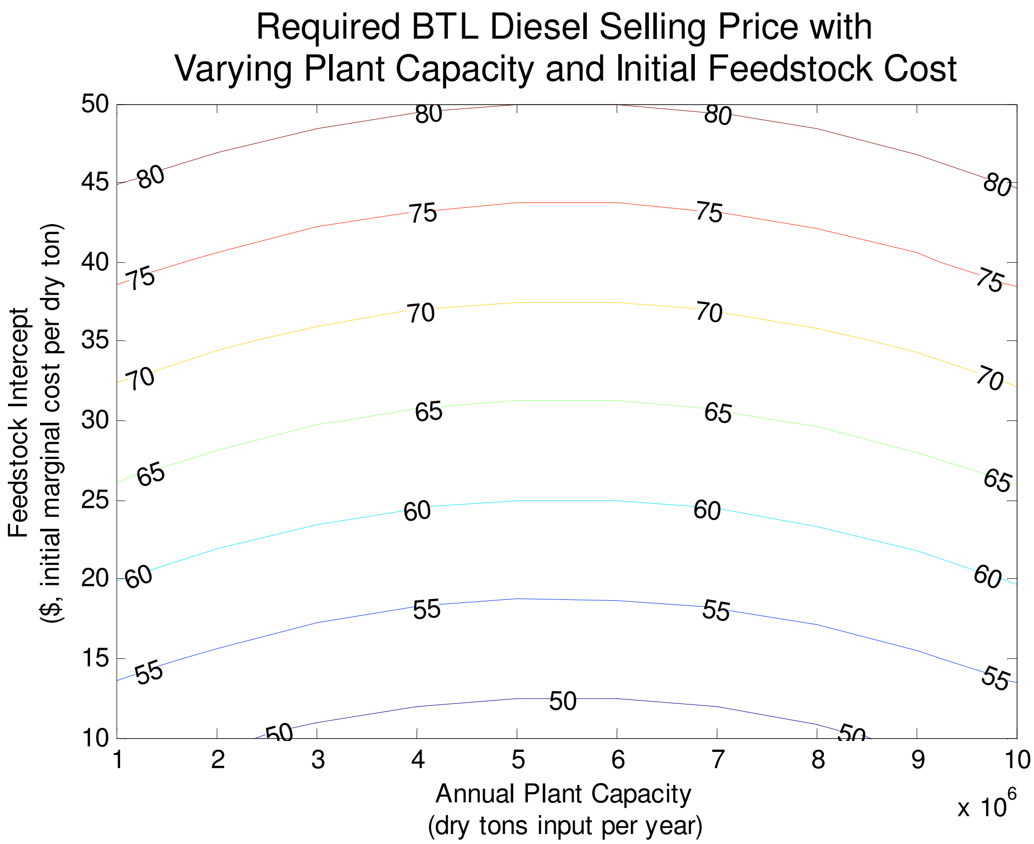


Output 4.



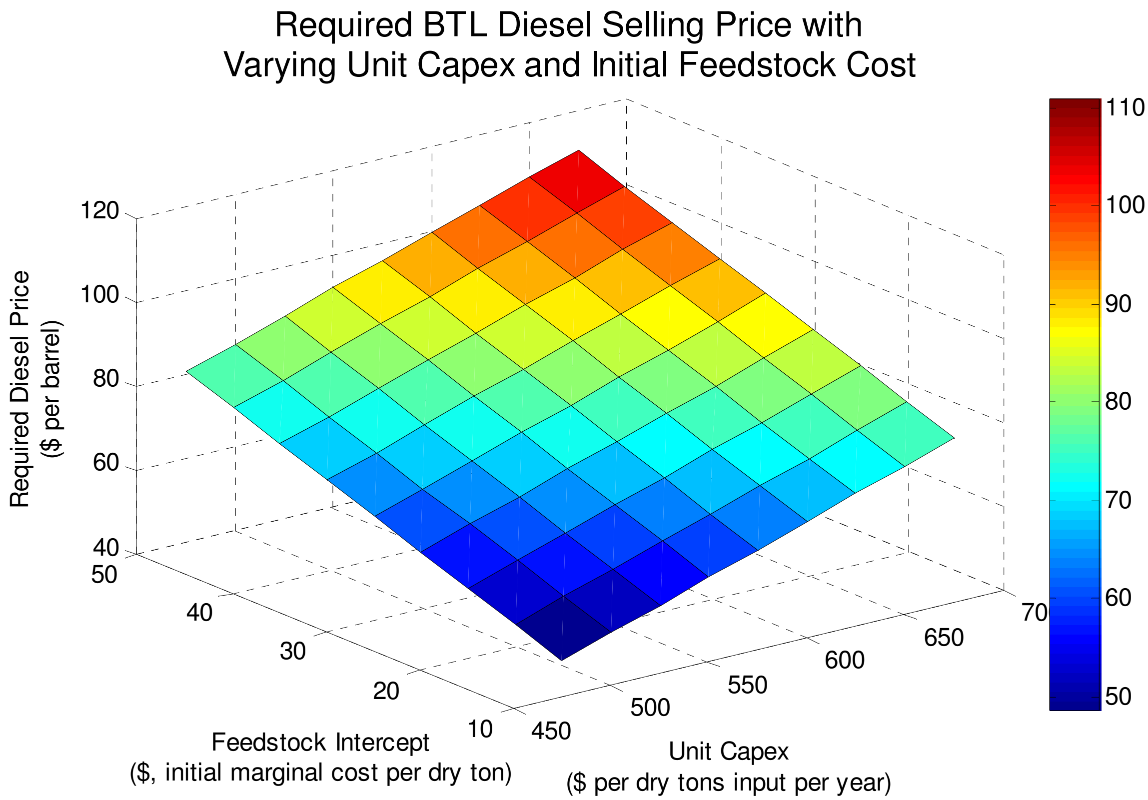
Output 5. This plot of varying Feedstock Intercept and Annual Plant Capacity shows how the economies of scale available as plant capacity increases exert downward pressure on the required diesel price. Unit

Capex declines from $600 (per dry ton/yr) at 1 million dry tons/yr to $450 at 10 million dry tons/yr. It is evident that there exists an opportunity for optimization of plant size. As plant capacity grows, economies of scale allow for a lower unit capex and thus lower required diesel price. At a certain point – in this case approximately 5 million dry tons/yr – the rise in marginal feedstock cost that occurs with increasing plant capacity nullifies the benefit of leveraging greater economies of scale.

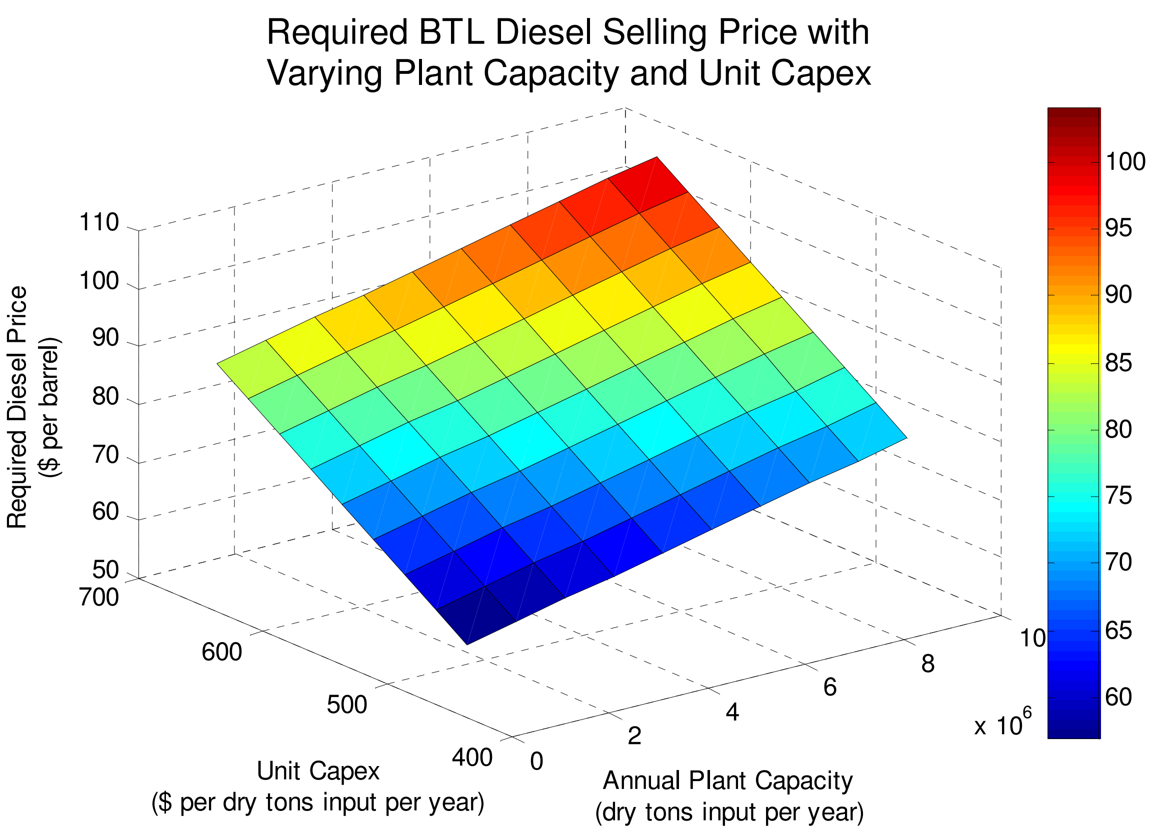


Output 6. The results presented in this figure are identical to the results in Output 4. This figure illustrates that, regardless of feedstock price, plants at the extremes of size require higher diesel prices to achieve the same return as plants of mid-range size.

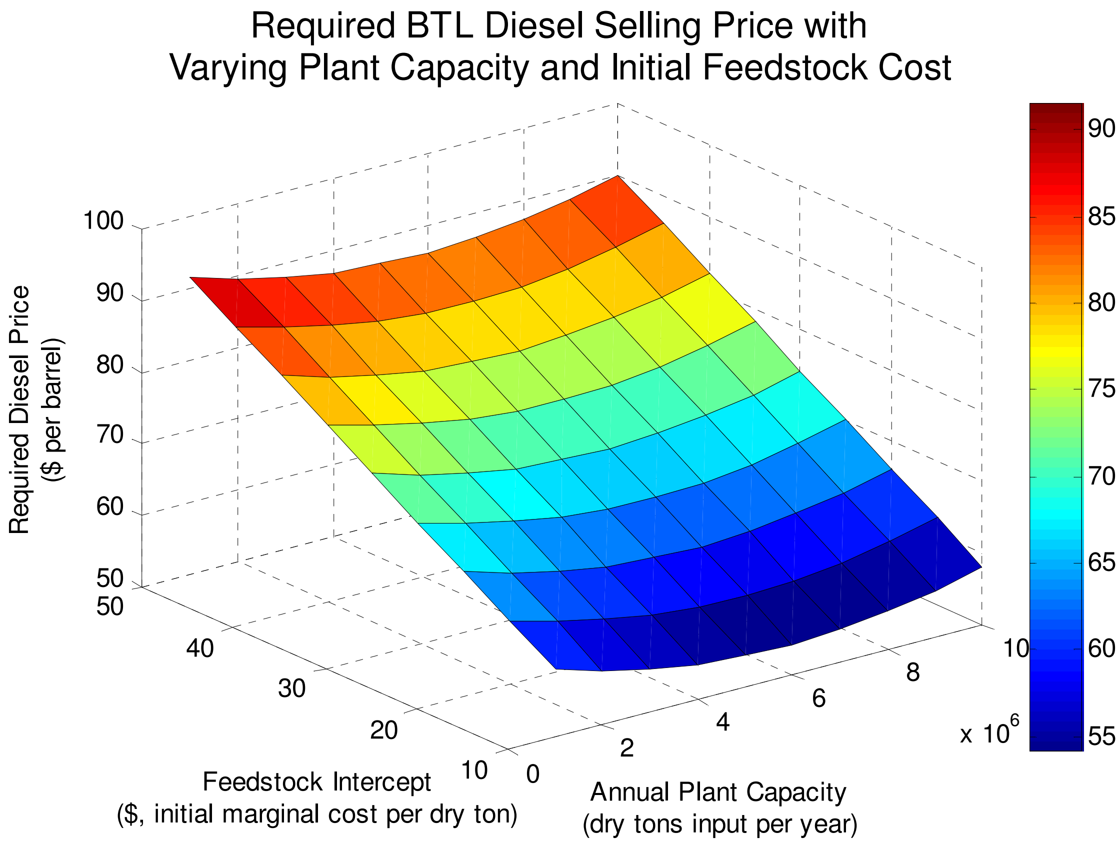
II. Results: Small Firm



Output 7.

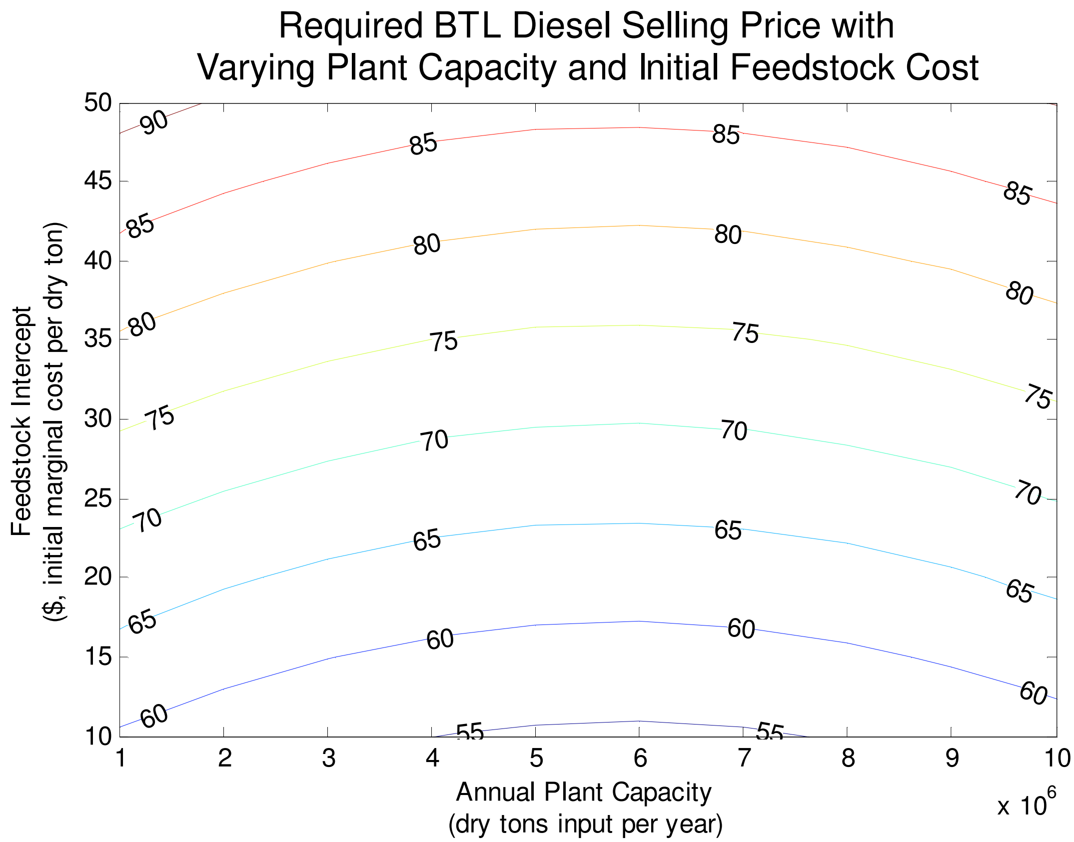


Output 6.



Required BTL Diesel Selling Price with
Varying Plant Capacity and Initial Feedstock Cost
Required Diesel Price
($ per barrel)
100
90
80
70
60
50
50
40
30
20
10
0
2
4
6
8
10
x 10^6
Feedstock Intercept
($, initial marginal cost per dry ton)
Annual Plant Capacity
(dry tons input per year)
90
85
80
75
70
65
60
55

Output 7.



Output 8.

Discussion

In a middle of the road scenario for a large development firm ($30 per dry ton feedstock intercept and $575 per dry ton/yr unit capex) the required diesel price is approximately $75 per barrel. When compared to prices over the past 20 years, biomass-to-liquids seems like a high cost source of diesel fuel. However, in the tight oil and petroleum product markets of recent years, $75 diesel seems reasonable. The model outputs show that the required price is quite sensitive to changes in plant capacity, feedstock curve intercept and, especially, unit capex. Determining the long-term availability and price of biomass feedstock will be a key first step in BTL project development. Armed with that information, developers should have an opportunity to optimize plant size to take maximum advantage of economies of scale by increasing plant capacity. Of course, lack of commercial experience injects significant uncertainty in the total capital cost of a BTL plant, regardless of size. Indeed the final capital cost of a given plant may not be known until the plant construction is completed.

V. Conclusion

This report concludes that both CTL and BTL have great potential to supplement or supplant conventional petroleum-derived fuels and chemicals. While there are likely as yet unknown technical problems, large scale CTL deployment may have a substantial effect on global and U.S. transportation fuel supply in the short term. However, large scale deployment of CTL is threatened by the high life-cycle carbon dioxide intensity of the produced fuels. Without carbon capture and sequestration, the process emissions from CTL may prove unacceptably high. Governments' carbon dioxide policy will play a key role – second only to world oil price – in determining the final market size of coal-derived liquid fuels.

Biomass-to-liquids is presently less economic than CTL, but it may eventually offer a means for producing low or negative carbon intensity transportation fuels from renewable sources. This report shows that there are technical and economic hurdles to be overcome before BTL is ready for widespread commercial deployment. In the U.S. the federal tax credit of $0.50 per gallon ($21 per barrel) for BTL diesel (and for CTL diesel) is a boon for the economics of BTL plants, but further research will be necessary before project developers are comfortable with the reliability of the technologies involved, particularly biomass pretreatment and gasification.

The German BTL firm CHOREN Industries is planning the first commercial scale (4,500 barrels per day) BTL plant with partner Shell Oil (Green Car Congress 2005). The technical and economic fate of this project will have international repercussions. For world governments looking to tackle the intertwined issues of energy insecurity and global climate change, the commercial success of biomass-to-liquids could be a major breakthrough.

VI. Frequently-used Terms and Abbreviations

BTL	Biomass-to-Liquids, gasification of biomass followed by synthesis of fuels and/or chemicals
b/d	Barrels per day
CTL	Coal-to-Liquids, gasification of coal followed by synthesis of fuels and/or chemicals
CFB	Circulating Fluidized Bed Gasification – bed particles in the gasifier are circulated throughout the reaction vessel
EF	Entrained Flow Gasification – gasification material in entrained in a stream that flows rapidly through the gasifier
Fischer-Tropsch	Synthesis of hydrocarbons from syngas through the use of cobalt or iron catalysts
EIA	U. S. Energy Information Administration, a unit of the U.S. Department of Energy
IEA	International Energy Agency of the Organization for Economic Co-operation and Development
LHV	Lower heating value, i.e. energy content of a fuel not including latent heat in produced water vapor
lignin	Major polymer in plant material that gives structural strength, particularly in woody plants
metric ton	Also “tonne” or “t”, equal to ~1.1 tons
MMBtu	Million British thermal units, equal to ~1.05 gigajoules
O & M	Operations and Maintenance
short ton	Also simply a “ton”, equal to ~0.91 metric ton
syngas	Gas produced through gasification, composed of carbon monoxide and hydrogen
unit capex	The total capital cost of a plant divided by the total plant capacity

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